NPCC, Inc.

1040 Avenue of the Americas - 10th Floor
New York, New York 10018-3703

NPCC Regional Standards Committee
Preliminary Agenda--Draft
Meeting # 11-5

October 26, 2011 10:00 a.m. - 5:00 p.m.
October 27, 2011 8:00 a.m. - 3:00 p.m.

Hyatt Harborside at Boston's Logan International Airport
101 Harborside Drive
Boston, Massachusetts

Dress Business Casual

RSC@npcc.org

Call in 719-785-1707, Guest Code 8287#

Note: Glossary of Terms Used in NERC Reliability Standards dated August 4, 2011 included in the Meeting Materials.

1. **Introductions-Agenda Review-Roster**
   a. RSC membership changes.

2. **RSC August, 2011 Meeting Minute Approval and Antitrust Guidelines** (in Meeting Materials Package)
   a. Discussion of the August, 2011 RSC Meeting minutes.

3. **Action Item Assignment List and Ongoing Assignments** (in Meeting Materials Package), (Refer to Action Item Table [Item 65] at the back of Agenda)
   a. NPCC Members on NERC Drafting Teams

4. **Review Executive Tracking Summary** (in Meeting Materials Package)
   a. Review entries.

5. **FERC** (in Meeting Materials Package)

a. FERC News--September 15, 2011. Items from FERC Sunshine Open Meeting.
   1. September 15, 2011 Meeting Summaries.
b. October 2011 Meeting Summaries.

NOPRs					
Item	NOPR	Docket No.	Posted	End Date	When Effective
T1	Version 4 Critical Infrastructure Protection Reliability Standards	RM11-11-000	9/15/11		
T2	Transmission Relay Loadability Reliability Standard	RM11-16-000	9/15/11		
T3	Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards	RM11-20-000	10/20/11	60 days after publication in the Federal Register	
T4	Transmission Planning Reliability Standards	RM11-18-000	10/20/11	60 days after publication in the Federal Register	

Letters of Approval			
Item	Docket No.	Posted	Summary
U1	RR10-12-001	8/25/11	Letter Order Issued Approving NERC Standards Process Manual Modifications
U2	RD11-7-000	9/15/11	FERC approves Reliability Standard PER-003-1
U3	RD11-8-000	10/20/11	FERC approves NPCC Regional Reliability Standard PRC-002-NPCC-01, and NERC's requested implementation plan.

Petitions			
Item	Docket No.	Posted	Title
V1	RD11-6-000	8/2/11	Petition of the North American Electric Reliability Corporation for Approval of the Reliability Standard CIP-001-2a – Sabotage Reporting with a Regional Variance for Texas Reliability Entity
V2	Docket No. RM11-__-000	9/9/11	Petition of the North American Electric Reliability Corporation For Approval of Interpretations to Requirements of Reliability Standards EOP-001-0 and EOP-001-2— Emergency Operations Planning
V3	Docket No. RM__-__-___	10/19/11	Petition of the North American Electric Reliability Corporation For Approval of a Revised Transmission Planning System Performance Requirements Reliability Standard and Five New Glossary Terms and for Retirement of Four Existing Reliability Standards

Motion To Defer Further Action			
Item	Docket No.	Posted	Summary
W1	RM09-13-000	8/11/11	NERC requests that FERC defer action on BAL-004-1 to allow further research and analysis to be performed by NERC.
W2	RM09-13-000	8/11/11	NERC requests that FERC continue to defer action regarding the BAL-004-1 Time Error Correction standard.

Compliance Filing			
Item	Docket No.	Posted	Summary
X1	RM06-16-000	8/31/11	Second Quarter 2011 Compliance Filing of NERC in Response to Paragraph 629 of Order No. 693--timeframe to restore power to the auxiliary power systems of U.S. nuclear power plants following a blackout.

Final Rule			
Item	Docket No.	Posted	Summary
Y1	RM10-29-000; Order No. 753	9/15/11	FERC approves NERC's proposed interpretation of Reliability Standard, TOP-

			001-1, Requirement R8, which pertains to the restoration of real and reactive power during a system emergency.
Y2	RM10-6-000; Order No. 754	9/15/11	FERC rejects the NOPR for an alternative interpretation of Requirement R1.3.10 of Reliability Standard TPL-002-0. FERC approves NERC's proposed interpretation.

Other			
Item	Docket No.	Posted	Summary
Z1	RM08-13-004	9/15/11	Order Denying Reconsideration And Granting Clarification In Part And Denying Clarification In Part (Order No. 733-B)
Z2	RD11-5-000	9/26/11	Order Approving Interpretation Of Reliability Standards
Z3	RR10-1-001	9/28/11	Annual Report Of The North American Electric Reliability Corporation On Wide-Area Analysis Of Technical Feasibility Exceptions
Z4	AD-12-1-000 Notice of Technical Conference	10/7/11	FERC will hold a Technical Conference on Tuesday, November 29, 2011, from 1:00 p.m. to 5:00 p.m. and Wednesday, November 30, 2011, the purpose of which will be to discuss policy issues related to reliability of the Bulk-Power System.
Z5	RR11-3-000	10/17/11	Petition for Approval of Amendments to Delegation Agreement with NPCC.

Z6	RD11-9-000	10/20/11	Order Approving Interpretation Of Reliability Standards. FERC approves NERC's proposed interpretation of Requirement R10 of Reliability Standard TOP-002-2a, and approves the interpretation, referred to as Reliability Standard TOP-002-2b.
Z7	RR11-7-000	10/20/11	Order Accepting 2012 Business Plan And Budget of the North American Electric Reliability Corporation

6. **Current and Pending Ballots:**

a.	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	Initial Ballot	11/7/11	11/16/11
b.	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC	Initial Ballot	11/8/11	11/17/11
c.	Project 2010-07 - Generator Requirements at the Transmission Interface	Initial Ballot	11/9/11	11/18/11

7. **Overlapping Postings** (in Meeting Materials Package)

a.				

8. **Join Ballot Pools:**

a.	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	Join Ballot Pool	10/4/11	11/2/11
b.	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC	Join Ballot Pool	10/4/11	11/3/11
c.	Project 2010-07 - Generator Requirements at the Transmission Interface	Join Ballot Pool	10/5/11	11/4/11

9. Posted for Comment: (in Meeting Materials Package)

a.	Project 2010-17 - Bulk Electric System (BES) Definition - Rules of procedure Modifications to Support BES Exception Requests BES Exception Process (Appendix 5C to NERC Rules of Procedure)--Redline Section 509 of NERC Rules of Procedure: Exceptions to the Definition of BES Section 1703 of NERC Rules of Procedure: Challenges to NERC Determinations of BES Exception Requests Under 509 Flow Charts Sample Form: Request for Exception to BES Definition Announcement	Comment Form (Word version in Meeting Materials)	9/13/11	10/27/11
b.	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company Draft 1--SAR MOD-028-2--Redline to Last Approved Implementation Plan FPL Request for Interpretation Announcement	Comment Form (Word version in Meeting Materials)	10/3/11	11/16/11
c.	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC Draft 2 Interpretation--Redline to Last Posting Announcement	Comment Form (Word version in Meeting Materials)	10/4/11	11/17/11

d.	Project 2010-07 - Generator Requirements at the Transmission Interface FAC-001-1--Redline to Last Posted Redline to Last Approved FAC-003-x--Redline to Last Posted Redline to Last Approved FAC-003-3--Redline to Last Posted PRC-004-2.1--Redline to Last Approved Implementation Plans: FAC-001-1--Redline FAC-003-3--Redline FAC-003-x--Redline PRC-004-2--Clean Technical Justification Technical Justification for FAC-001-1 Announcement	Comment Form (Word version in Meeting Materials)	10/5/11	11/18/11
e.	CAN-0010--Definition of "Annual" and Implementation of Annual Requirements	CAN Comment Form to be Sent to cancomments@nerc.net	10/10/11	10/31/11
f.	CAN-0011--PRC-005-1 R2: New Equipment	CAN Comment Form to be Sent to cancomments@nerc.net	10/10/11	10/31/11
g.	CAN-0012--Completion of Periodic Activity Requirements During Implementation Plan	CAN Comment Form to be Sent to cancomments@nerc.net	10/10/11	10/31/11
h.	CAN-0013--PRC-023 R1 and R2 Effective Dates for Switch-on-to-Fault Schemes	CAN Comment Form to be Sent to cancomments@nerc.net	10/10/11	10/31/11
i.	CAN-0015--Unavailability of NERC Software Tools	CAN Comment Form to be Sent to cancomments@nerc.net	10/10/11	10/31/11
j.	CAN-0022--VAR-002-1.1b R1 and R3 Generator Operation in Manual Mode	CAN Comment Form to be Sent to cancomments@nerc.net	10/10/11	10/31/11
k.	CAN-0024--CIP-002 R3 Routable Protocols and Data Diode Devices	CAN Comment Form to be Sent to cancomments@nerc.net	10/10/11	10/31/11

l.	CAN-0026--TOP-006 R3 Protection Relays	CAN Comment Form to be Sent to cancomments@nerc.net	10/10/11	10/31/11
m.	CAN-0028--TOP-006-1 R1.2 Reporting Responsibilities	CAN Comment Form to be Sent to cancomments@nerc.net	10/10/11	10/31/11
n.	Project 2008-10 - Interpretation of CIP-006-1 R1.1 by Progress Energy Draft Interpretation--Redline to Last Posting Form CIP-006-3C Announcement	Comment Form (Word version in Meeting Materials)	10/12/11	11/21/11
o.	Draft Directive Regarding Generator Transmission Leads Draft Directive Attachment 1--Examples of Typical Generation Transmission Tie Lines Attachment 2--Pro Forma Memorandum of Understanding (MOU) Appendix 1 to the MOU--Application Standards	Comments to be forwarded to NERC Staff: Jim Hughes, Jack Wiseman, Stacia Ann-Chambers	10/17/11	11/15/11
p.	CAN-0020--TPL-002, TPL-003, TPL-004 and TOP-002 Equipment Maintenance Outages Redline	CAN Comment Form to be Sent to cancomments@nerc.net	10/19/11	11/9/11
q.	CAN-0030--Attestations Redline	CAN Comment Form to be Sent to cancomments@nerc.net	10/19/11	11/9/11

a-beneath--CIP 706 Drafting Team Meeting Notes, September, 2011.
b-beneath--PRC-024 variance--Hydro-Quebec.
c-beneath--Protection and Control Subcommittee Joint Meetings--materials.
Discussion of SPS and related items.
d-beneath--FERC Technical Conference--CIP-006-2, Oct. 25, 2011.
e-beneath--CAN Comment Form--template.

10. Reference Documents Posted For Comment

a.				

11. Concluded Ballots (in Meeting Materials Package)

https://standards.nerc.net/Ballots.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)					Results of Ballot	RSC Recommend/Date
a.	Project 2010-11 - TPL Table 1, Footnote B	Recirculation Ballot	1/26/11	2/5/11	Quorum: 93.61% Approval: 86.54%	Yes 1/5/11
b.	Project 2007-07 - Vegetation Management - FAC-003	Successive Ballot and Non-Binding Poll	2/18/11	2/28/11	Quorum: 79.28% Approval: 79.34%	Yes 2/22/11
c.	Project 2006-06 - Reliability Coordination - COM-001, COM-002, IRO-001, and IRO-014	Initial Ballot	2/25/11	3/7/11	Quorum: 87.10% Approval: 49.54%	Yes 3/2/11
d.	Project 2007-23 - Violation Severity Levels	Non-binding Poll	2/9/11	2/18/11	Ballot Pool: 310 Opinions: 141 72% Support	Yes 10/28/10
e.	Project 2010-13 - Relay Loadability Order - PRC-023	Successive Ballot and Non-Binding Poll	1/24/11	2/13/11	Quorum: 83.95% Approval: 65.71%	Yes 2/11/11
f.	Project 2010-13 - Relay Loadability Order - PRC-023	Recirculation Ballot	2/24/11	3/6/11	Quorum: 87.35% Approval: 68.83%	Yes 2/11/11
g.	Project 2010-15 - Urgent Action Revisions to CIP-005-3	Successive Ballot and Non-Binding Poll	4/19/11	4/28/11	Quorum: 79.66% Approval: 38.00%	No 4/19/11
h.	Project 2009-06 - Facility Ratings	Cast Ballot	4/21/11	5/2/11	Quorum: 86.01% Approval: 48.74%	Abstain 4/26/11
i.	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	Successive Ballot and Non-Binding Poll	5/3/11	5/12/11	Quorum: 78.33% Approval: 67.00%	No Recommendation

j.	Project 2009-06 - Facility Ratings - FAC-008 and FAC-009	Recirculation Ballot	5/12/11	5/23/11	Quorum: 91.25% Approval: 78.92%	Yes 5/12/11
k.	Project 2006-02 - Assess Transmission and Future Needs - TPL-001 through TPL-006	Successive Ballot and Non-Binding Poll	5/18/11	5/31/11	Quorum: 92.07% Approval: 73.99	----
l.	Project 2007-03 - Real-time Operations - TOP-001 through TOP-008 and PER-001	Initial Ballot and Non-Binding Poll	5/31/11	6/9/11	Quorum: 88.47% Approval: 48.64%	Reject 5/31/11
m.	Project 2007-09 – Generator Verification – MOD-026-1 Ballot Results Revised because of NERC IT problem	Cast Ballot	7/22/11	8/1/11	Quorum: 90.25% Approval: 46.53%	No Consensus 7/28/11
n.	Project 2007-09 – Generator Verification – MOD-026-1	Cast Non-Binding Poll Opinion	7/22/11	8/1/11	Quorum: 88.75% Approval: 56.00%	----
o.	Project 2007-09 – Generator Verification – PRC-024-1 Ballot Results Revised because of NERC IT problem	Cast Ballot	7/22/11	8/1/11	Quorum: 90.82% Approval: 18.23%	No Consensus 7/28/11
p.	Project 2007-09 – Generator Verification – PRC-024-1	Cast Non-Binding Poll Opinion	7/22/11	8/1/11	Quorum: 88.35% Approval: 20.79%	----
q.	Project 2007-17 – Protection System Maintenance and Testing – PRC-005	Recirculation Ballot and Non-Binding Poll	6/20/11	6/30/11	Quorum: 82.97% Approval: 64.76%	Yes 6/28/11
r.	Project 2006-02 - Assess Transmission and Future Needs	Cast Ballot	7/13/11	7/22/11	Quorum: 94.33% Approval: 75.37%	----
s.	Project 2006-06 - Reliability Coordination - IRO-002-3	Cast Ballot	7/15/11	7/25/11	Quorum: 94.13% Approval: 76.99%	Yes 7/22/11
t.	Project 2006-06 - Reliability Coordination - IRO-005-4	Cast Ballot	7/15/11	7/25/11	Quorum: 94.13% Approval: 75.17%	Yes 7/22/11

u.	Project 2006-06 - Reliability Coordination - IRO-014-2	Cast Ballot	7/15/11	7/25/11	Quorum: 94.13% Approval: 76.27%	Yes 7/22/11
v.	Project 2006-06 - Reliability Coordination - IRO-002-3	Cast Non-Binding Poll Opinion	7/15/11	7/25/11	Quorum: 75.37% Approval: 93%	----
w.	Project 2006-06 - Reliability Coordination - IRO-005-4	Cast Non-Binding Poll Opinion	7/15/11	7/25/11	Quorum: 75.66% Approval: 93%	----
x.	Project 2006-06 - Reliability Coordination - IRO-014-2	Cast Non-Binding Poll Opinion	7/15/11	7/25/11	Quorum: 75.37% Approval: 89%	-----
y.	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	Initial Ballot	9/19/11	9/28/11 9/29/11--Technical Difficulties	Quorum: 84.86% Approval: 61.10%	Yes 9/21/11
z.	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	Non-Binding Poll VRFs and VSLs	9/19/11	9/28/11 9/29/11--Technical Difficulties	Quorum: 83.13% Approval: 68.68%	----
aa.	Project 2010-17 - Definition of Bulk Electric System - Initial Ballot of Definition of BES	Initial Ballot	9/30/11	10/10/11	Quorum: 92.97% Approval: 71.68%	No Consensus 10/3/11
bb.	Project 2010-17 - Definition of Bulk Electric System - Initial Ballot of Detailed Information to Support BES Exceptions Request	Initial Ballot	9/30/11	10/10/11	Quorum: 89.53% Approval: 64.03%	No Consensus 10/7/11
cc.	Project 2007-07 - Vegetation Management	Recirculation Ballot	10/4/11	10/13/11	Quorum: 87.17% Approval: 86.25%	Yes 2/22/11

12. <u>Posted For 30-Day Pre-Ballot Review (Open Ballot Pools) Between RSC Meetings</u>:

a.				

13. <u>Comment Forms Submitted</u> (in Meeting Materials Package), (red entries added since prior RSC Meeting)

a.	Standards Project Prioritization Reference Document and Tool	Comment Form	1/21/11	2/10/11
b.	Project 2007-12 - Frequency Response	Comment Form	2/4/11	3/7/11
c.	Project 2007-07 - Vegetation Management - FAC-003	Comment Form	1/27/11	2/28/11
d.	Project 2007-23 - Violation Severity Levels	Comment Form	1/20/11	2/18/11
e.	Project 2006-06 - Reliability Coordination - COM-001, COM-002, IRO-001, and IRO-014	Comment Form	1/18/11	3/7/11
f.	Regional Reliability Standards - PRC-006-NPCC-1 - Automatic Underfrequency Load Shedding	Comment Form (no comments submitted)	1/10/11	2/24/11
g.	CAN-0015--Draft CAN-0015 Unavailability of NERC Tools	Comments	2/4/11	2/18/11
h.	CAN-0016--Draft CAN-0016 CIP-001-1 R1 - Applicability to Non-BES	Comments	2/4/11	2/18/11
i.	CAN-0017--Draft CAN-0017 CIP-007 R5 System Access and Password Controls	Comments	2/11/11	3/4/11
j.	CAN-0018--Draft CAN-0018 FAC-008 R.1.2.1 - Terminal Equipment	Comments	2/4/11	2/18/11
k.	Proposed Changes to Rules of Procedure to Add Section 1700 - Challenges to Determinations	Comments	2/14/11	3/7/11
l.	Project 2009-06 - Facility Ratings - FAC-008 and FAC-009	Comment Form	3/17/11	5/2/11
m.	Project 2010-15 - Urgent Action Revisions to CIP-005-3 - CIP-005	Comment Form	3/29/11	4/28/11
n.	Project 2009-02 - Real-time Reliability Monitoring and Analysis Capabilities	Comment Form	2/16/11	4/4/11
o.	Notice of Proposed Changes to RFC Rules of Procedure and Request for Comments	Comments (No comments submitted)	3/1/11	4/15/11
p.	Proposed Amendments to NERC Rules of Procedure Appendices 3B and 3D	Comments	3/1/11	4/15/11
q.	Project 2010-07 - Generator Requirements at the Transmission Interface	Informal Comment Period	3/4/11	4/4/11

r.	Project 2009-01 - Disturbance and Sabotage Reporting	Comment Form	3/9/11	4/8/11
s.	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	Comment Form	4/13/11	5/12/11
t.	Project 2010-17 - Definition of Bulk Electric System	Comment Form	4/28/11	5/27/11
u.	Project 2006-02 - Assess Transmission and Future Needs	Comment Form	4/18/11	5/31/11
v.	Project 2007-03 - Real-time Operations - TOP-001 through TOP-008 and PER-001	Comment Form	4/26/11	6/9/11
w.	Project 2010-17 - Definition of Bulk Electric System	Comment Form	5/11/11	6/10/11
x.	Rules of Procedure Development Team: BES Definition Exception Process	Comment Form	5/11/11	6/10/11
y.	CAN-0024--Draft CAN-0024 CIP-002 through CIP-009 Routable Protocols and Data Diodes	Comments	5/20/11	6/10/11
z.	CAN-0029--Draft CAN-0029 PRC-004-1 R1, R2 and R3 Misoperations	Comments	5/20/11	6/10/11
aa.	CAN-0030--Draft CAN-0030 Attestations	Comments	5/20/11	6/10/11
bb.	CAN-0039--Draft CAN-0039 DOE Form 407	Comments	5/20/11	6/10/11
cc.	Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)	Comment Form	6/10/11	7/11/11
dd.	Project 2007-09 – Generator Verification – MOD-025-2, MOD-027-1, PRC-019-1	Comment Form	6/15/11	7/15/11
ee.	Project 2007-09 – Generator Verification – MOD-026-1 and PRC-024-1	Comment Form	6/15/11	8/1/11
ff.	Project 2010-07 – Generator Requirements at the Transmission Interface – Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR standards	Comment Form	6/17/11	7/17/11
gg.	Proposed Changes to NERC Rules of Procedure and associated Appendices (Appendix 4B – Sanction Guidelines; and Appendix 4C – Compliance Monitoring and Enforcement Program)	Sent Comments to ROPcomments@nerc.net	6/30/11	8/15/11
hh.	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	Comment Form	8/15/11	9/29/11 (Extended from 9/28/11 because of NERC network problems)

ii.	Compliance Application Notice (CAN) Process	Comment Form	8/15/11	9/6/11
jj.	CAN-0016 CIP-001 R1 - Sabotage Reporting Procedure	Comment Form	8/15/11	9/6/11
kk.	Project 2010-17 - Definition of Bulk Electric System - Initial Ballot of Definition of BES	Comment Form	8/26/11	10/10/11
ll.	Project 2010-17 - Definition of Bulk Electric System - Initial Ballot of Detailed Information to Support BES Exception Request	Comment Form	8/26/11	10/10/11
mm.	Proposed Changes to NERC Rules of Procedure and All Appendices	Sent Comments to cancomments@nerc.net No Comments Submitted	9/2/11	10/17/11
nn.	NERC 2012-2014 Reliability Standards Development Plan	Comment Form	9/12/11	9/26/11
oo.	DRAFT CANs Posted for Comment and Retirement of CAN-0001 through 0004 (See note below table)	Sent Comments to cancomments@nerc.net	8/31/11	9/21/11
pp.	New CAN Template, five DRAFT CANs for Industry review, and CANs Status posted to NERC Compliance's Web site.	Sent Comments to cancomments@nerc.net	9/23/11	10/14/11

For Item 13oo--Draft letter from Jerry Mosier regarding CAN-0006. No comments for CAN-0006 had been received for CAN-0006 or submitted by RSC. Soliciting RSC input.

a-beneath--Project 2008-06 Cyber Security Order 706 – Draft Version 5 (CIP-002-CIP-011) Webinar August 24, 2011.

14. Reference Documents Posted For Comment Between RSC Meetings

a.				

15. Drafting Team Nominations Open (Current and between RSC Meetings)

a.	Project 2007-17 - Protection System Maintenance and Testing Drafting Team	Nomination Period	9/1/11	9/23/11

16. **NERC Meetings** (in Meeting Materials Package)
    a. Board of Trustees Meeting August 4, 2011.
        1. Approved four Standards--Project 2006-02 Assess Transmission Future Needs and Develop Transmission Plans (TPL-001-2), and Project 2006-06 Reliability Coordination (IRO-002-3, IRO-005-4 and IRO-014-2)
    b. Member Representatives Committee Meeting August 3, 2011.
        1. Nominations and Elections.
    c. Compliance Committee Meeting August 3, 2011.
    d. Planning Committee Meeting Sept. 13-14, 2011.
    e. Standards and Compliance Workshop--Oct. 26-28, 2011.

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17. **NERC RSG** (in Meeting Materials Package)
    a. NERC Regional Reliability Standards Evaluation Procedure to be considered by the RSG.

18. **Standards Committee Report** (in Meeting Materials Package)
    a. August 11, 2011 Meeting.
    b. 2012-2013 Standards Committee elections. Nominations due Nov. 1, 2011.
    c. October, 2011 Meeting.

19. **SPCS Meeting** (in Meeting Materials Package)
    a.

20. **NERC Compliance Application Notices (CANs)** (in Meeting Materials Package--see sections 9 and 13 above)
    a. Compliance Application Notices (CANs) and Bulletins (see Items 9 and 13).
    b. General discussion (CO-11 request).
    c. Updated CAN Status Spreadsheet.
    d. Final dispositions of:
        1. CAN Process.
        2. CAN-0016: CIP-001 R1 Sabotage Reporting Procedure.
    e. NERC Compliance Announcement Oct. 19, 2011.
        1. CIP Table Three Entities

21. **NERC Bulk Electric System Definition** (in Meeting Materials Package)
    a. August 8-11, 18 meetings. Presentation to NERC Standards Committee August 18, 2011.
    b. Bulk Electric System Definition Project - Fact Sheet, Fact Sheet with revisions.
    c. NARUC Resolution on BES Definition.
    d. Webinar--September 28, 2011.
    e. Hydro-Quebec request for discussion of ballot decisions.
    f. October 18-20, 2011 Definition of BES Drafting Team Meeting.

22. NPCC Regional Standards, and More--Update (in Meeting Materials Package)

a. Disturbance Monitoring (PRC-002-NPCC-01)
   1. FERC approval October 20, 2011.

b. Underfrequency Load Shedding
   1. Authorization to Post CEAP and Pre Ballot for UFLS PRC -006-01.

c. Regional Reserve Sharing Groups
   1. Draft RSAR developed
   2. TFCO will be the Drafting Team. NPCC, and NERC soliciting for additional Drafting Team members.

d. NPCC Glossary of Terms--for RSC approval, retirement of Criteria A-7 NPCC Glossary of Terms.

23. NPCC Cost Effectiveness Analysis, Triage Process (in Meeting Materials Package)

a. Cost Effectiveness Analysis Procedure.

b. Triage process--discuss for posting.

24. NY adoption of more stringent/specific NPCC Criteria

a. The New York filing (as well as an update to the applicable NPCC Criteria in Nova Scotia that were approved by the Nova Scotia Utility and Review Board earlier this year), will be filed by the end of October, 2011.

25. Directory and Regional Work Plan Status

a. Directory Development and Revision Manual--for RSC approval.

Directory Number	Title	Lead Group, Status	Current Activity
#1 (A-2)	Design and Operation of the Bulk Power System	Approved on 12/1/2009	TFCP has charged CP11 with a comprehensive review of Directory #1 to include the triennial document review, an examination of the NERC TPL standards, the existing NPCC planning criteria, and the implementation of Phase 2 of the Directory Project which will reformat existing Directory criteria into NERC style requirements. TFCO has assigned CO-8 to review the TO requirements within the Directory #1 criteria. TFCP/CP-11 is ready to post the document for its initial Open Process posting upon conclusion of the TFCO/CO-8 review. Open Process posting expected in mid December, 2011.
#2 (A-3)	Emergency Operation	Approved on 10/21/08.	Automatic UFLS language transferred to Directory #12. Next TFCO review Oct. 21, 2011.
#3 (A-4)	Maintenance Criteria for BPS Protection.	Approved on 7/11/08.	Phase 2 reformatting pending.

#4 (A-5)	Bulk Power System Protection Criteria	Approved on 12/1/09.	TFSP expects to begin Phase 2 review of Directory #4 in early 2012.
#5 (A-6)	Operating Reserve	TFCO	Directory#5 was approved by the Full Members on December 2, 2010. TFCO is working to resolve several open issues including how imports from HQ are wheeled within the Region. A TFCO special meeting is scheduled for Dec. 6, 2011 to finalize proposed revisions to Directory #5 in advance of an Open Process posting.
#6 New	Reserve Sharing	TFCO	TFCO has posted a draft of a new Directory#6 on Regional Reserve Sharing which would replace C-38 until a Regional Standard is developed. An Open Process posting for Directory #6 concluded on Oct. 24, 2011.
#7 (A-11)	Special Protection Systems	Approved on 12/27/07.	TFSP, TFSS, and TFCP are revising Directory #7. TFSP to incorporate current NRAP revisions (including Appendix A) of the document into a Phase 2 version and post for member comment after the November, 2011 TFSP Meeting.
#8 (A-12)	System Restoration	Approved on 10/21/08.	CO-11 has recently made revisions to the Directory #8 criteria. These revisions will be incorporated into the draft Phase 2 reformatting of Directory #8 which will be addressed by CO-8 early next year.
#9 (A-13)	Verification of Generator Real Power Capability	Approved on 12/22/08.	TFCO has posted the initial Phase 2 drafts of both Directories #9 and #10 to the Open Process. The initial open process concluded on June 14, 2011. TFCO reviewed comments and posted the revised Directories for a second posting which concluded on 10/24/2011. TFCO expects to present Directories #9 and #10 to the RCC in November, 2011, and anticipates a Full Member ballot of both Directories #9 and #10 in December, 2011.
#10(A14)	Verification of Generator Reactive Power Capability	Approved on 12/22/08.	Refer to Directory #9 preceding.
#12	UFLS Program Requirements	Approved on 6/26/09.	

26. Review RFC, MRO Standards Relevant to NPCC (in Meeting Materials Package)

a. RFC Standards Under Development webpage
https://rsvp.rfirst.org/default.aspx

b. RFC Standard Voting Process (RSVP) webpage
ReliabilityFirst Corporation - Reliability Standards Voting Process

	Standard Under Development	Status	Start Date	End Date
1.	MOD-024-RFC-01.1 (Generator Verification - Real Power) Modified Violation Severity Levels (VSLs)	15 Days Prior to Category Ballot	8/10/11	8/24/11
2.	MOD-024-RFC-01.1 (Generator Verification - Real Power) Modified Violation Severity Levels (VSLs)	15 Day Category Ballot	8/25/11	9/8/11
3.	PRC-006-RFC-01 (Automatic Underfrequency Load Shedding)	Comment Period	9/28/11	10/27/11
	NERC Posting PRC-006-RFC-01	Comment Form	10/3/11	11/2/11

c. Midwest Reliability Organization Approved Standards
http://www.midwestreliability.org/STA_approved_mro_standards.html
(click on RSVP under the MRO header)

d. Midwest Reliability Organization Reliability Standard Voting Process webpage (table lists standards under development)
Midwest Reliability Organization - Reliability Standards Voting Process

	Standard Under Development	Status	Start Date	End Date
1.	PRC-006-MRO-01 - Underfrequency Load Shedding Requirements (see e. below)	Posted for second 30 day comment period	5/19/10	6/17/10
2.				

e. As of June 14, 2010 MRO suspended its regional standards development.

27. **Report on NERC, NAESB and Regional Activities** (in Meeting Materials Package)
    a. Report on NERC, NAESB and Regional Activities
        1. August, 2011.
        2. September, 2011.

28. **Task Force Assignments, et al.** (in Meeting Materials Package)
    a.

From the May 18-19, 2011 RSC Meeting--The Regions are discussing how to report misoperations. NPCC uses the CDAA. If there is no access to the CDAA then E-mail can be used to report. An Action Item will be created to put questions together regarding misoperations.

Guy Zito raised the question of who should develop RSAWs. It was suggested that the Drafting Team do it, but they most likely are not familiar with compliance issues.

Ron Falsetti inquired about the criteria for categorizing events. Do Regions develop their own criteria? Ralph Rufrano said no, but Ron believed they did. Ron Falsetti and Ralph will discuss outside the meeting.

Additional information from Ben Eng (NPCC) (refer to the sample letter in the Meeting Materials)--

- The notes are correct in that misoperations are currently being emailed to me (and copied to Henry) for the short term. The long term goal is to modify CDAA so that the reminders and capture mechanism are automated.
- RSAWs already exist for PRC-004. The requirements are that analysis, corrective action plans and implementation must be done by the entity to prevent recurrence. The RSAW/Standard is not prescriptive in describing how, or to what degree, analysis should be done, and the correct actions to resolve the misoperation. Nor should it, since protective relaying is an "art"
- The criteria for the categories were established by the SPCS in the NERC Misoperation Reporting Template, and do not conflict with the NERC Glossary. A NERC webinar on Misoperation Reporting was conducted and an extensive list of Questions and Answers was developed into a document. The references and guidance for Misoperation Reporting are posted on NPCC's public website "Documents; Compliance; CDAA": https://www.npcc.org/Compliance/CDAA/Forms/Public%20List.aspx
- The process is in place to capture misoperation reports. Improvements to the process are planned.
- Initial notification for 3rd Quarter Misoperation Reports sent about 3 weeks prior to the due date.
- Follow up reminder sent the week before the due date
- The notification contained the link to the pertinent materials on the new NPCC Website

- SP-7 has been compiling and reviewing the misoperations and formalizing reports to NERC as scheduled.
- Ensuring that all reportable misoperations that happen in NPCC's footprint has been the biggest challenge.

29. Future Meetings and Other Issues (in Meeting Materials Package)

a. Filings and rulings regarding the NERC and NPCC applications for approval of Reliability Standards and Criteria in Nova Scotia.
b. FERC, NERC joint inquiry into Sept. 8, 2011 Southwest power outage.
   1. Blackout news.
c. Balloting, voting process (WECC).
d. NERC Webinars.
   1. Critical Cyber Asset Identification: An Overview of a Process, Sept. 1, 2011.
   2. Project 2008-06 Cyber Security Order 706 – Draft Version 5 (CIP-002-CIP-011), August 24, 2011.
   3. FAC Recommendation Update, September 22, 2011.
e. NERC's New Enforcement Initiative.
f. NERC Webinars.
   1. Sept. 2, 2011 CANs Process
   2. Sept. 9, 2011 Registration and Certification JRO-CFR Webinar
   3. Sept. 15, 2011 Project 2007-17 Protection System Maintenance and Testing Webinar.
g. NERC News.
   1. August, 2011.
   2. September, 2011.

h. NERC Lessons Learned--August 10, 2011, October 20, 2011.
   1. Backup Control Center Operation and Training
   2. Special Protection Systems Maintenance Precautions
   3. Protection Relaying – Out of date prints
   4. Transmission Relaying – Voltage Transformer Failure
   5. Transmission Relaying – Removing Unused Components
   6. Plant Instrument and Sensing Equipment Freezing Due to Heat Trace and Insulation Failures
   7. Plant Fuel Switching and Cold Weather
i. FERC, NERC Report on Outages And Curtailments During the Southwest Cold Weather Event Of February 1-5, 2011.
j. Southwest Power Pool Compliance Update (contains standards information).
k. IESO Market Rules.
l. NERC standard prioritization.
m. Standards effective dates in Ontario.
n. NERC--ERO Best Practices.
o. NERC--Modifications to Mandatory Effective Dates Web page for US Reliability Standards.

p. SERC postings.
   1. The SERC Underfrequency Load Shedding (UFLS) Regional Standard (PRC-006-SERC-01) was posted for a 15-day review period.
   2. SERC Regional Standard Development Procedure.

q. FERC Open Meeting Schedule.

r. NERC--The Key Reliability Standard Spot Check (KRSSC) Program.

s. RSC Work Plan for 2012 -2013.

t. CIPC Meeting--September 14-15, 2011 Meeting--notes.

u. NERC--Report Assessing Risk to Reliability Performance of Bulk Power System.

v. NERC Event Analysis Process.

w. RSC Meeting schedule for 2012.
   1. NPCC Board of Directors proposed meeting dates.
   2. RCC Meeting dates.

x. NERC News.
   1. September, 2011.

y. SPP Compliance Update. Lists standards information.

z. RCC June 1, 2011 Meeting--Minutes.

aa. NERC--Electric Reliability Organization Compliance Analysis Report--Reliability Standard TOP-002 Normal Operations Planning, October, 2011.

bb. NERC Whitepaper on Regional Standards and Variances. Sent to RSG for their comments. Comments due October 28, 2011.

cc. The Reliability Standard Audit Worksheets (RSAW).

dd. New Brunswick Energy Blueprint.

ee. NERC 2012 Actively Monitored List of Reliability Standards and 2012 ERO CMEP Implementation Plan.

ff. WECC Newsletter--September/October 2011.

gg. Regional Reliability Standards Announcement
Comment Period Open for VAR-001-2 WECC Variance
October 20 – December 5, 2011.

hh. NERC--Conference Calls and Meeting Agendas.
   1. Standards Oversight and Technology Committee Meeting--Nov. 2, 2011.
   2. Compliance Committee Meeting--Nov. 2, 2011.
   3. Member Representatives Committee Meeting--Nov. 2, 2011.
   4. NERC Board of Trustees Meeting--Nov. 3, 2011.

RSC 2011 Meeting Dates

Dec. 1-2, 2011--Joint Meeting with the CC Dec. 2, 2011 Toronto, Ontario

2011 RSC Conference Call Schedule

(call 719-785-1707, Guest Code 8287#)

Nov. 10, 2011 (Thursday)
Dec. 16, 2011
Dec. 30, 2011

BOD 2011/2012 Meeting Dates

October 26, 2011 Teleconference
November 30, 2011 Toronto
January 31, 2012
February 1, 2012
March 13, 2012 (BES Special Teleconference)
May 1, 2012 (Teleconference)
June 26, 2012
August 7, 2012 (Teleconference)
September 18, 2012
October 30, 2012 (Teleconference)
November 28, 2012

RCC, CC, and Task Force Meeting Dates--2011/2012

RCC	Nov. 29, 2011
	2012-- March 1, June 6, Sept. 6, Nov. 27
CC	Nov. 16, Dec. 13-15
TFSS	
TFCP	Nov. 2
TFCO	
TFIST	
TFSP	Nov. 15-17

Respectfully Submitted,

Guy V. Zito, Chair RSC
Assistant Vice President-Standards
Northeast Power Coordinating Council Inc.

Northeast Power Coordinating Council, Inc. (NPCC)
Antitrust Compliance Guidelines

It is NPCC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. The antitrust laws make it important that meeting participants avoid discussion of topics that could result in charges of anti-competitive behavior, including: restraint of trade and conspiracies to monopolize, unfair or deceptive business acts or practices, price discrimination, division of markets, allocation of production, imposition of boycotts, exclusive dealing arrangements, and any other activity that unreasonably restrains competition.

It is the responsibility of every NPCC participant and employee who may in any way affect NPCC's compliance with the antitrust laws to carry out this commitment. Participants in NPCC activities (including those participating in its committees, task forces and subgroups) should refrain from discussing the following throughout any meeting or during any breaks (including NPCC meetings, conference calls and informal discussions):

- Industry-related topics considered sensitive or market intelligence in nature that are outside of their committee's scope or assignment, or the published agenda for the meeting;
- Their company's prices for products or services, or prices charged by their competitors;
- Costs, discounts, terms of sale, profit margins or anything else that might affect prices;
- The resale prices their customers should charge for products they sell them;
- Allocating markets, customers, territories or products with their competitors;
- Limiting production;
- Whether or not to deal with any company; and
- Any competitively sensitive information concerning their company or a competitor.

Any decisions or actions by NPCC as a result of such meetings will only be taken in the interest of promoting and maintaining the reliability and adequacy of the bulk power system.

Any NPCC meeting participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NPCC's antitrust compliance policy is implicated in any situation should call NPCC's Secretary, Andrianne S. Payson at 212-259-8218.

Action Item List

Action Item Number	Agenda Item Number	Description	Owner	Due	Status
32	16b	To discuss with Herbert Schrayshuen how HQ, because of its unique operational requirements, will be addressed in standards development	Guy Zito--member of Standards Committee Process Subcommittee	RSC Meeting	Ongoing as of 2/10/10. Sylvain Clermont, and David Kiguel working with Guy Zito. Herbert Schrayshuen replaced Gerry Adamski at NERC. The new NERC management team will have to be made familiar with this item.
August 20-21, 2008					
Feb. 17-18, 2009					
June 17-18, 2009					
August 6-7, 2009					
60	3a	NPCC representatives from NERC drafting teams that have documents posted for comments report at RSC Meetings	Lee Pedowicz	RSC Meeting	Ongoing.
Sept. 24-25, 2009					
Nov. 4-5, 2009					

Action Item Number	Agenda Item Number	Description	Owner	Due	Status
April 21-22, 2010					
63	----	Coordination with the Compliance Committee to develop Joint Activity Action List	Greg Campoli	RSC Meeting	Outgrowth of RSC/CC joint session April 21, 2010. Ongoing. Joint RSC/CC Meeting this meeting. Ralph Rufrano rejoined the RSC in the capacity of NPCC Compliance liaison. Comments not to be submitted on the CCEP.
June 29-30, 2010					
65	----	RSC to review the NPCC Members on NERC Drafting Teams list. Saurabh Saksena to maintain. Will get input from Carol Sedewitz.	RSC	RSC Meeting	Ongoing.
August 18-19, 2010					
66	----	Status of Memorandum of Understanding	Sylvain Clermont	RSC Meeting	Provide update. (MOU in Meeting Materials Package)

Action Item Number	Agenda Item Number	Description	Owner	Due	Status
Nov. 30, 2010,					
Dec. 2, 2010					
69	----	Revise RSC Scope	Guy Zito	RSC Meeting	Approved at the August 3, 2011 RSC Meeting. To be presented to the NPCC Board of Directors.
Feb. 2-3, 2011					
71	----	Talk to Compliance about Regional Reliability Standard RSAWs. There should be a Compliance Committee representative on the Drafting Team.	Guy Zito	RSC Meeting	Ongoing.
73	----	Discuss consistency with the RSG.	Guy Zito	RSC Meeting	Ongoing.
March 16-17, 2011					
75	11f	Non-convergent contingencies enumerated in Project 2010-13 - Relay Loadability Order - PRC-023 Attachment B4a.	Guy Zito	RSC Meeting	To be discussed with Sal Buffamante.
August 3-4, 2011					
76	18a	Handling of definitions	Guy Zito	RSC Meeting	To discuss with Pete Heidrich

AGREEMENT
ON THE DEVELOPMENT OF ELECTRIC POWER TRANSMISSION RELIABILITY STANDARDS AND OF PROCEDURES AND A PROGRAM FOR THE MONITORING OF THE APPLICATION OF THESE STANDARDS FOR QUÉBEC

BETWEEN

Régie de l'énergie, a public body established under the *Act respecting the Régie de l'énergie* (R.S.Q., c. R-6.01) with headquarters at Tour de la Bourse, P.O. Box 001, 800 Place Victoria, 2nd floor, Suite 2.55, Montréal, Québec H4Z 1A2, acting through Jean-Paul Théorêt, Chairman, duly authorized pursuant to subsection 85.4 of the *Act respecting the Régie de l'énergie* (R.S.Q., c. R-6.01),

hereinafter referred to as "the Régie"

AND

North American Electric Reliability Corporation, a corporate body established under the *New Jersey Nonprofit Corporation Act*, New Jersey Statutes Title 15A, with headquarters at 116-390 Village Boulevard, Princeton, New Jersey, United States, 08540-5721, acting through Richard P. Sergel, President and Chief Executive Officer, duly authorized pursuant to Article VI, Section 1, of the Bylaws of the North American Electric Reliability Corporation,

hereinafter referred to as "NERC"

AND

Northeast Power Coordinating Council, Inc., a corporate body established under Section 402 of the *New York State Not-for-Profit Corporation Law*, with headquarters at 1515 Broadway, 43rd floor, New York, New York, United States, 10036, acting through Edward A. Schwerdt, President and Chief Executive Officer, duly authorized pursuant to the Amended and Restated Bylaws of the Northeast Power Coordinating Council, Inc.,

hereinafter referred to as "NPCC."

WHEREAS subsection 85.2 of the *Act respecting the Régie de l'énergie* (the "Act") provides for the Régie to ensure that electric power transmission in Québec is carried out in accordance with the reliability standards it adopts;

WHEREAS reliability refers to the degree of performance of an electric power transmission system that results in electricity being delivered to customers within accepted standards and in the amount desired and may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply;

WHEREAS subsection 85.4 of the Act further provides that the Régie, with the authorization of the Government of Québec, may enter into an agreement with a body that proves it has the expertise to establish or monitor the application of electric power transmission reliability standards for the purpose of developing such standards for Québec, carrying out inspections and investigations as part of plans to monitor compliance with the reliability standards that the Régie adopts, and providing the Régie with opinions and recommendations;

WHEREAS NERC is a New Jersey, United States (U.S.), not-for-profit corporation sponsored by all sectors of the utility industry, including those in Québec, whose mission is the development and enforcement of reliability standards to protect the reliability, adequacy, and security of the bulk power system in North America. NERC is the successor to the North

American Electric Reliability Council. NERC coordinates its activities with eight (8) regional entities in North America, including NPCC;

WHEREAS NERC has established the *NERC Reliability Standards Development Procedure,* in which all Québec entities subject to the reliability standards referred to in subsection 85.3 of the Act may participate;

WHEREAS the American National Standards Institute ("ANSI") has accredited the *NERC Reliability Standards Development Procedure* as being consistent with ANSI's standards development principles;

WHEREAS the U.S. Federal Energy Regulatory Commission ("FERC") has certified NERC as the Electric Reliability Organization, in accordance with the *Electricity Modernization Act of 2005*, to develop, submit to it for approval and enforce reliability standards for the bulk power system in the United States, subject to certain delegation provisions for the eight (8) regional entities in North America, including the delegation provisions for NPCC described below;

WHEREAS by means of legislation or other provisions, Ontario, New Brunswick, Manitoba, British Columbia, Alberta, Saskatchewan and Nova Scotia, have made or will make mandatory the NERC reliability standards;

WHEREAS the Régie has concluded that NERC has proven that it has the expertise to develop and monitor the application of electric power transmission reliability standards;

WHEREAS NPCC is a not-for-profit corporation in New York State, United States, having the purpose of promoting and enhancing the reliable and efficient operation of the international, interconnected bulk power systems in northeastern North America through the development of regional reliability standards and compliance assessment and enforcement of continent-wide and regional reliability standards, coordination of system planning, design and operations, and assessment of reliability, pursuant to an agreement with NERC which designates NPCC as a cross-border regional entity for the northeastern United States and delegates authority from FERC. Additionally, NPCC establishes regionally specific, more stringent reliability criteria and monitors and enforces compliance with such criteria;

WHEREAS NPCC has developed the *NPCC Regional Reliability Standards Development Procedure*, approved by NERC on October 23, 2007 and adopted by FERC on March 21, 2008, for the purpose of developing specific reliability standards for interconnected networks in northeastern North America in which Québec entities subject to the reliability standards referred to in subsection 85.3 of the Act may participate;

WHEREAS the Régie has concluded from NPCC's more than four decades of international reliability assurance that NPCC has the expertise to develop, monitor the application of, and assess compliance with electric power transmission reliability standards and criteria;

WHEREAS the Régie has resolved, for the reasons set out above, to mandate NERC and NPCC to develop reliability standards that the Régie adopts for electric power transmission in Québec and the procedures and a program for the monitoring of the application of these standards, and provide the Régie with opinions and recommendations pursuant to the present agreement (the "Agreement");

WHEREAS pursuant to subsection 85.5 of the Act, the Régie designated a reliability coordinator for Québec in its Decision D-2007-95;

WHEREAS pursuant to subsection 85.6 of the Act, the said reliability coordinator must file with the Régie the reliability standards proposed by a body that has entered into an agreement with the Régie under subsection 85.4 of the Act, as well as any variant or other standard the reliability coordinator considers necessary, an evaluation of the relevance and impact of the standards filed and the identification of the entities that may be subject to the reliability standards;

WHEREAS pursuant to subsection 85.7 of the Act, the Régie may request the reliability coordinator to modify a standard filed or submit a new one;

WHEREAS pursuant to subsection 85.7 of the Act, the Régie shall adopt the reliability standards and set the date for their coming into force;

WHEREAS pursuant to subsection 85.7 of the Act, the reliability standards may provide for a schedule of sanctions, including financial penalties, that apply if standards are not complied with and refer to reliability standards set by a standardization agency that has entered into an agreement with the Régie;

WHEREAS pursuant to subsection 85.8 of the Act, the reliability coordinator shall submit to the Régie a guide describing criteria to be taken into account in determining the sanction for non-compliance with a reliability standard;

WHEREAS pursuant to subsection 85.9 of the Act, if an entity is the object of a violation allegation to a reliability standard, it has at least twenty (20) days to submit observations to the body mandated by the Régie for the monitoring of the application of the reliability standards before this body reports to the Régie and recommends the application of a sanction, if need be;

WHEREAS pursuant to subsection 85.13 of the Act, the reliability coordinator must submit to the Régie, for approval, a register identifying the entities subject to the reliability standards adopted by the Régie;

WHEREAS the parties to the Agreement recognize the need to coordinate and to cooperate for the enhancement of the reliability of the North American bulk power system, including Québec's electric power transmission system, and to facilitate the exchange of experience, information and data related to that system;

WHEREAS the Québec electric power transmission system is an asynchronous interconnection and NERC and NPCC have recognized it as an Interconnection, it may, therefore, require reliability standards or variants of such standards specific to this Interconnection;

NOW THEREFORE, the Régie, NERC and NPCC agree as follows:

1. INTERPRETATION

1.1 Exclusivity of Agreement

This Agreement constitutes the entire agreement between the parties with respect to the development of reliability standards applicable to Québec and of the procedures and a program for the monitoring of the application of such standards, and opinions and recommendations provided by NERC or NPCC with respect to such standards and the electric power transmission reliability in Québec. It supersedes all prior agreements and understandings, both written and oral, among the parties with respect to the subject matter of this Agreement.

1.2 Governing law and competent jurisdiction

This Agreement shall be governed by the laws of Québec, and the courts of Québec shall have exclusive jurisdiction to settle any disputes arising herefrom.

1.3 Headings

The headings of this Agreement are for convenience of reference only and shall not define, limit, or otherwise affect any of the terms or provisions hereof.

2. REPRESENTATIVES

For the purposes of the application of the Agreement, the Régie designates Gilbert Neveu, Executive Director, as its representative; NERC designates David Cook, Vice President, as its

representative; and NPCC designates Edward A. Schwerdt, President, as its representative. Each of the parties undertakes to expeditiously advise the other parties of any change in its representative.

3. PURPOSE OF AGREEMENT

3.1 The Régie hereby retains the services of NERC and NPCC as experts in the development of electric power transmission reliability standards. NERC and NPCC shall develop, in accordance with their standards development procedures, electric power transmission reliability standards applicable to Québec, and propose them to the reliability coordinator for adoption by the Régie. The services of NERC and NPCC are also required as technical experts to advise the Régie with respect to the review of the reliability standards and of the sanction guide which will be filed by the reliability coordinator, and to provide the Régie with opinions and recommendations.

3.2 The Régie also retains the services of NERC and NPCC as experts in the monitoring of the application of electric power transmission reliability standards. NERC and NPCC shall develop, taking into account Québec's legal and regulatory environment and in accordance with their applicable compliance monitoring procedures, specific procedures and a program for the monitoring of the application of electric power transmission reliability standards in Québec which they are able to implement. The Régie shall be responsible for the said procedures and program.

3.3 The said specific procedures and program for the monitoring of the application of electric power transmission reliability standards in Québec will be submitted to a consultation with the entities subject to the reliability standards.

3.4 Subsequent to the said consultation and upon authorization from the Government of Québec, a second agreement shall detail the mandates granted by the Régie to NERC and to NPCC with respect to the implementation of the said procedures and program for the monitoring of the application of electric power transmission reliability standards in Québec and the provision of opinions and recommendations to the Régie in this regard.

4. UNDERTAKINGS OF NERC AND NPCC

4.1 NERC and NPCC undertake to develop electric power transmission reliability standards applicable to Québec in accordance with their procedures, namely the *NERC Reliability Standards Development Procedure* and the *NPCC Regional Reliability Standards Development Procedure*. To this end, NERC and NPCC undertake, within the framework of their respective procedures, to take note of the comments and opinions submitted by the Québec reliability coordinator, the electric power carriers and users of electric power transmission services in Québec.

4.2 NERC and NPCC undertake to ascertain that any electric power transmission reliability standards specific to Québec, and/or any variant of such standards specific to Québec, which the reliability coordinator deems necessary to ensure the reliability of electric power transmission in Québec, is as stringent as the NERC reliability standards applicable in the rest of North America.

4.3 NERC and NPCC undertake to develop, in accordance with their compliance monitoring procedures, namely the *NERC Rules of Procedures,* the *NERC Uniform Compliance Monitoring and Enforcement Program* and the *NPCC Compliance Monitoring and Enforcement Program,* specific program and procedures for the monitoring of the application of electric power transmission reliability standards adapted to Québec's legal and regulatory environment.

4.4 NERC and NPCC undertake to have representatives present or, as necessary, to testify as technical experts at the hearings the Régie will hold, if need be, when filings regarding reliability standards are examined by the Régie pursuant to subsections 85.6 and 85.7 of the Act, and when the sanction guide filed by the reliability coordinator pursuant to subsection 85.8 of the Act is reviewed.

4.5 NERC and NPCC undertake to submit to the Régie, at the Régie's request, opinions or recommendations during the proceedings referred to in Article 4.4, including but not limited to opinions or recommendations respecting matters submitted to the Régie's consideration by the reliability coordinator.

4.6 NERC and NPCC undertake to inform the Régie promptly of potential threats to the reliability of the electric power transmission system in Québec.

4.7 NERC and NPCC undertake to submit to the Régie, at the Régie's request or on their own initiative, opinions or recommendations on all matters related to the reliability of electric power transmission in Québec.

4.8 NERC and NPCC undertake to collaborate closely with the Régie on the implementation of this Agreement and to take into consideration all instructions and recommendations from the Régie related to this Agreement.

4.9 NERC and NPCC undertake to develop the procedures and a program for the monitoring of the application of the electric power transmission reliability standards for Québec which they will be able to implement, and to provide the Régie with opinions and recommendations.

4.10 NERC and NPCC hereby represent and warrant that during the term of this Agreement each of them shall remain validly existing and in good standing pursuant to all applicable laws relevant to this Agreement.

5. REMUNERATION

5.1 The total remuneration received by NERC and NPCC for, among other things, developing and monitoring the application of electric power transmission reliability standards in the United States and Canada (and, in the case of NERC only, in Mexico) is allocated in accordance with the currently effective calculation method approved by the NERC Board of Trustees.

5.2 Québec's share of that total remuneration is currently paid by Hydro-Québec TransÉnergie, Québec's electric power carrier, as approved by the Régie in its decisions in which it fixes or modifies the electric power carrier's rates pursuant to section 49 of the Act.

5.3 Québec's share of the total remuneration approved by NERC's Board of Trustees in consideration of the monitoring of the application of electric power transmission reliability standards in Québec by NERC and NPCC will be paid by the Régie as of the date of signing the Agreement and shall cover all the services they undertake to provide to the Régie under this Agreement.

5.4 Québec's share of the total remuneration will continue to be paid by Hydro-Québec TransÉnergie, as approved by the Régie, with the exception of the portion of Québec's share, referred to in Article 5.3, which will be paid by the Régie as of the date of signing the Agreement.

5.5 NERC and NPCC agree that this remuneration shall cover all the services they undertake to provide under this Agreement.

5.6 NERC and NPCC shall provide the Régie with the draft versions of their respective annual Business Plans and Operating Budgets by May 31st of each year and with the final versions of the said documents by August 15th of each year.

5.7 By December 1st of each year, at the latest, NERC and NPCC shall provide the Régie with their final budgets for the coming calendar year for the portion of Québec's share that will be paid by the Régie, in order to allow the Régie to prepare its own budget.

5.8 If the Régie objects to the budgets or any invoice(s) submitted under this Agreement, it shall promptly notify NERC and/or NPCC in writing. The parties agree that, should the

Régie object to an invoice, payment shall be effected under protest and the objection resolved pursuant to Article 9.

6. DECLARATIONS

NERC and NPCC do hereby declare that no applicable law, contract or other legal obligation prevents them from executing this Agreement and fulfilling their obligations hereunder.

The Régie declares that it has been duly authorized by the Government of Québec to make this Agreement, pursuant to subsection 85.4 of the Act.

7. TERM OF AGREEMENT AND TERMINATION

This Agreement is effective as of the date of the last signing by the parties.

Either party may terminate this Agreement upon one year's notice to the other party.

8. DEFAULT AND CURE

Upon the failure of a party to perform or observe any material term, condition or covenant of the Agreement, the non-breaching party shall give written notice of such breach to the breaching party (the "Default Notice"). Subject to a suspension of the following deadlines as specified below, the breaching party shall have thirty (30) days from receipt of the Default Notice within which to cure such breach; provided however, that if such breach is not capable of cure within thirty (30) days, the breaching party shall commence such cure within thirty (30) days after notice and continuously and diligently complete such cure within ninety (90) days from receipt of the Default Notice; and, if cured within such time, the breach specified in such notice shall cease to exist. Subject to the limitation specified in the following sentence, if a breach is not cured as provided in this Article, or if a breach is not capable of being cured within the period provided for herein, the nonbreaching party shall have the right to declare a default and resiliate this Agreement by written notice at any time until cure occurs, and be relieved of any further obligation hereunder. The deadlines for cure and the right to declare a default and terminate this Agreement shall be suspended during the pendency of any efforts or proceedings in accordance with Article 9 of this Agreement to resolve a dispute as to whether a breach has occurred. Resiliation of this Agreement does not extinguish any obligation existing at the time of the resiliation.

9. DISPUTE RESOLUTION

In the event a dispute arises under this Agreement between the Régie, NERC and/or NPCC, representatives of the parties with authority to settle the dispute shall meet and confer in good faith in an effort to resolve the dispute in a timely manner. In the event the designated representatives are unable to resolve the dispute within thirty (30) days or such other period as the parties may agree upon, each party shall have all rights to pursue all remedies, except as expressly limited by the terms of this Agreement. Neither party shall have the right to pursue other remedies until the Dispute Resolution procedures of this Article 9 have been exhausted. This Article 9 shall not apply to enforcement actions against registered entities.

10. LIMITATION OF LIABILITY

The Régie agrees not to sue NERC or NPCC or their directors, officers, employees, and persons serving on their committees and subgroups based on any act or omission of any of the foregoing in the performance of duties pursuant to this Agreement or in conducting activities under the authority of the Act, except to the extent that NERC or NPCC is found liable for gross negligence or intentional misconduct.

11. ASSIGNMENT

NERC and NPCC may not assign their rights and obligations under this Agreement without the consent of the Régie. However, nothing in this provision shall prohibit NERC or NPCC from contracting with other entities to assist them in carrying out their responsibilities under

the Agreement. NERC and NPCC shall, however, remain responsible for their obligations under this Agreement.

12. CONFIDENTIALITY

The information contained in the opinions and recommendations of NERC or NPCC to the Régie may not be copied, disclosed or distributed without the prior written permission of the Régie. In their opinions and recommendations, NERC and NPCC may identify the information they deem to be confidential.

During the course of the parties' performance under this Agreement, a party may receive Confidential Information, as defined in Section 1500 of NERC's Rules of Procedure or information of the same nature considered confidential by the Régie. Except as set forth herein, the parties agree to keep in confidence and not to copy, disclose, or distribute any Confidential Information or any part thereof, without the prior written permission of the issuing party, unless disclosure is required by subpoena, law, or other directive of a court, administrative agency, or arbitration panel, in which event the recipient hereby agrees to provide the party that provided the Confidential Information with prompt notice of such request or requirement in order to enable such issuing party to (a) seek an appropriate protective order or other remedy, (b) consult with the recipient with respect to taking steps to resist or narrow the scope of such request or legal process, or (c) waive compliance, in whole or in part, with the terms of this Article. In the event a protective order or other remedy is not obtained or the issuing party waives compliance with the provisions, the recipient agrees to furnish only that portion of the Confidential Information which the recipient's counsel advises is legally required and to exercise best efforts to obtain assurance that confidential treatment will be accorded to such Confidential Information. In addition, each party shall ensure that its officers, trustees, directors, employees, subcontractors and subcontractors' employees, and agents to whom Confidential Information is exposed are under obligations of confidentiality that are at least as restrictive as those contained herein.

13. NO THIRD PARTY BENEFICIARIES

Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any third party.

14. NOTICE

Whether expressly so stated or not, all notices, demands, requests, and other communications required or permitted by or provided for in this Agreement shall be given in writing to a party at the address set forth below, or at such other address as a party shall designate for itself in writing in accordance with this Article, and shall be delivered by hand or reputable overnight courier.

The Régie: Mr. Gilbert Neveu, Executive Director
Fax: (514) 873-3037
Email: gilbert.neveu@regie-energie.qc.ca

NERC: Mr. David Cook, Vice President
Fax: (609) 452-9550
Email: david.cook@nerc.net

NPCC: Mr. Edward A. Schwerdt, President
Fax: (212) 302-2782
Email: eschwerdt@npcc.org

15. EXECUTION OF COUNTERPARTS

This Agreement is executed in four (4) counterparts in French and four (4) counterparts in English and each has the same force and effect as the original.

IN WITNESS WHEREOF, the parties have caused the Agreement, in French and in English, both versions being regarded as equally authentic and valid, to be executed by their duly authorized representatives.

Signed for and on behalf of the Régie

Jean-Paul Théorêt
President
Régie de l'énergie
(514) 873-2452, extension 281

Date : 8 mai 2009

Signed for and on behalf of NERC

Richard P. Sergel
President and Chief Executive Officer
North American Electric Reliability Corporation
(609) 452-8060

Date : 8 mai 2009

Signed for and on behalf of NPCC

Edward A. Schwerdt
President and Chief Executive Officer
Northeast Power Coordinating Council, Inc.
(212) 840-1070

Date : 8 mai 2009

NPCC, Inc.

1040 Avenue of the Americas - 10th Floor
New York, New York 10018-3703

NPCC Regional Standards Committee
Preliminary Minutes--Draft
Meeting # 11-4

August 3, 2011 10:00 a.m. - 5:00 p.m.
August 4, 2011 8:00 a.m. - 3:00 p.m.

Marriott SpringHill Suites - Old Montreal
King Edward Meeting Room
445, rue Saint-Jean-Baptiste
Montreal, Quebec

Dress Business Casual
RSC@npcc.org
Call in 719-785-1707, Guest Code 8287#

Note: Glossary of Terms Used in NERC Reliability Standards dated May 24, 2011 included in the Meeting Materials.

Items in red from August 3, 2011.
Items in green from August 4, 2011.

Meeting called to order at 10:02 a.m.
Meeting called to order at 8:00 a.m.

1. **Introductions-Agenda Review-Roster**
   a. Welcome to David Ramkalawan as a new RSC Member.
   b. RSC membership changes.

	Name	***Organization***	***Sector***
1.	Michael Lombardi	Northeast Utilities	1
2.	David Ramkalawan	Ontario Power Generation, Inc.	4
3.	Michael Schiavone	National Grid	1
4.	Howard Gugel (guest)	NERC	
5.	Si-Truc Phan	TransEnergie (Hydro-Quebec)	2
6.	David Kiguel	Hydro One Networks Inc.	1
7.	Ben Wu	Orange & Rockland Utilities, Inc.	1
8.	Kal Ayoub (guest--8-3-11)	FERC	
9.	Chris de Graffenried	Consolidated Edison Company of New York, Inc.	1
10.	Brian Evans-Mongeon	Utility Services, Inc.	5
11.	Greg Campoli	New York Independent System Operator	2
12.	Kathleen Goodman	ISO - New England	2
13.	Guy Zito	NPCC	
14.	Lee Pedowicz	NPCC	
15.	Gerry Dunbar	NPCC	

On the Phone

	Name	***Organization***	***Sector***
1.	Mike Garton	Dominion Resources Services, Inc.	4
2.	Wayne Sipperly	New York Power Authority	4
3.	Don Nelson (guest)	Massachusetts Department of Public Utilities	
4.	Esther Kim (guest, proxy for Kurtis Chong)	Independent Electricity System Operator	2
5.	Ralph Rufrano (guest)	NPCC	

Item 1a--David Ramkalawan (Ontario Power Generation) was introduced. He is Brian Gooder's replacement on the RSC.

Item 1b--Brian Gooder retired from Ontario Power Generation. Kurtis Chong (IESO) changed positions at IESO, and will no longer be participating on the RSC. Esther Kim (phone) has Kurtis Chong's proxy.

All attendees introduced themselves, and Guy Zito summarized what topics the meeting will address.

2. **RSC May, 2011 Meeting Minute Approval and Antitrust Guidelines** (in Meeting Materials Package)
   a. Discussion of the May, 2011 RSC Meeting minutes.

   Item 2a--No changes were made to the Minutes. Greg Campoli made a motion to approve, Michael Lombardi seconded the motion. With the exception of Esther Kim (abstained), all the attendees approved the Minutes as read.

3. **Action Item Assignment List and Ongoing Assignments** (in Meeting Materials Package), (Refer to Action Item Table [Item 65] at the back of Agenda)
   a. NPCC Members on NERC Drafting Teams

   Item 3a--posted on the NPCC Website.

4. **Review Executive Tracking Summary** (in Meeting Materials Package)
   a. Review entries.

   Item 4a--posted on NPCC Website. Ongoing.

5. **FERC** (in Meeting Materials Package)

   a. June, 2011 Meeting Summaries.

   Item 5a--Guy Zito reviewed the June, 2011 Meeting Summaries contained in the Meeting Materials package.

Item	NOPR	Docket No.	Posted	End Date	When Effective
T1	Notice of Proposed Rulemaking re: Availability of E-tag Information to Commission Staff under RM11-12	RM11-12-000	6/27/11		
T2	Petition of the North American Electric Reliability Corporation For Approval Of Interpretation to Reliability Standard TOP-001-1 — Reliability Responsibilities and Authorities, Requirement R8	RM10-29-000	6/24/11		

T3	Petition of the North American Electric Reliability Corporation for Approval of Proposed NPCC Regional Reliability Standard PRC-002-NPCC-01 — Disturbance Monitoring	RM11-27-000 Changed to RD11-8-000 on June 30, 2011.	5/31/11		
T4	Electric Reliability Organization Interpretation of Transmission Operations Reliability Standard, Docket No. RM10-29-000	RM10-29-000	4/21/11		
T5	Comments Of The North American Electric Reliability Corporation In Response To Notice Of Proposed Rulemaking	RM11-12-000	6/27/11		
T6	Comments Of The North American Electric Reliability Corporation In Support Of The Supplemental Comments Of Edison Electric Institute, The American Public Power Association, The National Rural Electric Cooperative Association, The Electric Power Supply Association, The Transmission Access Policy Study Group, And The Canadian Electricity Association	RM10-6-000	7/13/11		
T7	Supplemental Comments Of The Edison Electric Institute, The American Public Power Association, The National Rural Electric Cooperative Association, The Electric Power Supply Association, The	RM10-6-000	7/13/11		

	Transmission Access Policy Study Group, And the Canadian Electricity Association				
T8	Request Of The North American Electric Reliability Corporation For Clarification Or, In The Alternative, Rehearing Of The Order Denying Appeals Of Electric Reliability Organization Registration Determinations	RC11-1-000 RC11-2-000	7/18/11		

Item	FERC Orders	Docket No.	Posted	Summary
U1	Order No. 722	RD11-1-000	6/30/11	Letter order approving NERC's January 6, 2011 Compliance Filing regarding revised VSLs for the approved FAC Reliability Standards.
U2		RM11-11-000	6/30/11	Second set of responses of NERC to FERC requesting additional information regarding petition seeking approval of the proposed CIP Version 4 Reliability Standards.
U3		RD10-6-001 RD09-7-003	6/29/11	Violation Risk Factors and Violation Severity Levels for Version 2 and Version 3 Critical Infrastructure Protection Reliability Standards
U4	Order Nos. 748-A and 749-A	RM10-15-001 RM10-16-001	7/13/11	On March 17, 2011, the Commission issued Order Nos. 748 and 749, which approved new and revised Reliability Standards, including IRO-004-2 and EOP-001. Grant the NERC request for clarification of Order No. 748 including: (1) the proper effective date

				language for Reliability Standard IRO-004-2; (2) the correct version identification for the approval of EOP-001 intended by the Commission; and (3) the proper effective date for Reliability Standard EOP-001-2. The Commission also grants NERC's request for clarification of Order No. 749 with respect to the version EOP-001 the Commission intended to approve and its effective date.
U5	Order On Smart Grid Interoperability Standards	RM11-2-000	7/19/11	Section 1305(d) of the Energy Independence and Security Act of 2007 directs the Commission to institute a rulemaking proceeding to adopt such standards and protocols as may be necessary to insure smart-grid functionality and interoperability in interstate transmission of electric power, and regional and wholesale electricity markets once it is satisfied that the work of the National Institute of Standards and Technology has led to "sufficient consensus" on smart grid interoperability standards. The Commission finds that there is insufficient consensus for the five families of standards under consideration. For this reason, the Commission will not institute a rulemaking proceeding at this time with respect to these standards and terminates this docket. In this order, the Commission encourages stakeholders to actively participate in the NIST

				interoperability framework process to work on the development of interoperability standards and to refer to that process for guidance on smart grid standards.
U6	Order No. 733-A	RM08-13-000	7/21/11	Informational Filing Of The North American Electric Reliability Corporation In Response To Order 733-A On Rehearing, Clarification, And Request For An Extension Of Time
U7		RR06-1-000, RR09-7-000	7/29/11	Informational report of the North American Electric Reliability Corporation On Analysis Of Standard Process Results For The Second Quarter 2011
U8	Order No. 1000	RM10-23-000	7/21/11	Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities

Petitions		
Item	Posted	Title
V1	6/15/11	Petition Of The North American Electric Reliability Corporation For Approval Of Proposed Reliability Standard FAC-008-3 -- Facility Ratings
V2	6/21/11	Petition Of The North American Electric Reliability Corporation For Approval Of Reliability Standard CIP-001-2a—Sabotage Reporting With A Regional Variance For Texas Reliability Entity

Item 5T1--FERC wants entity information to be sent directly to them, and that NERC shouldn't be the only supplier of this information to them.

Item 5T2--Addresses the responsibility for balancing and reactive power.

Items 5T3, 5T4--For information.

Items 5T5 through 5T8--Guy Zito reviewed the material.

Item 5U1--For information.

Item 5U2--Guy Zito is concerned about how data can be manipulated and shown. The purpose was to get data, not a compliance issue.

Item 5U3--For information.

Item 5U4--Addressed effective dates of revised Standards.

Item 5U5--For information.

Item 5U6--Standard to be developed in the second quarter 2012. A time extension is being requested.

Item 5U7--For information.

Item 5U8--Directs cost allocation. What will be the impact of the new BES definition? There will be implications that might not affect the RSC.

Item 5V1--The attendees discussed that FAC-008-2 is "dead". The Standard's revisions will go from revision 1 (FAC-008-1) to revision 3 (FAC-008-3).

Item 5V2--Kal Ayoub reported that it was approved yesterday. Has been added to the Meeting Materials package. The effective date is Oct. 1, 2011.

After reviewing these materials, there was no need to develop comments.

6. **Current and Pending Ballots:** (in Meeting Materials Package)

a.				

7. **Overlapping Postings** (in Meeting Materials Package)

a.				

8. Join Ballot Pools: (in Meeting Materials Package)

a.				

9. Posted for Comment: (in Meeting Materials Package)

a.	Proposed Changes to NERC Rules of Procedure and associated Appendices (Appendix 4B – Sanction Guidelines; and Appendix 4C – Compliance Monitoring and Enforcement Program)	Send Comments to ROPcomments@nerc.net	6/30/11	8/15/11

Item 9a--This is a compliance related item. It was reiterated that comments were to be sent to ROPcomments@nerc.net by August 15, 2011. Kathleen Goodman will share her concerns about the document, and it will be determined if there needs to be a RSC comment response. Section 414 is the issue. Meeting participants will take back to their organizations and provide appropriate comments. As suggested, Lee Pedowicz sent the NPCC staff the link and information on the Rules of Procedure changes.

10. Reference Documents Posted For Comment

a.				

11. Concluded Ballots (in Meeting Materials Package)

https://standards.nerc.net/Ballots.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)					Results of Ballot	RSC Recommend/Date
a.	Project 2010-11 - TPL Table 1, Footnote B	Recirculation Ballot	1/26/11	2/5/11	Quorum: 93.61% Approval: 86.54%	Yes 1/5/11

b.	Project 2007-07 - Vegetation Management - FAC-003	Successive Ballot and Non-Binding Poll	2/18/11	2/28/11	Quorum: 79.28% Approval: 79.34%	Yes 2/22/11
c.	Project 2006-06 - Reliability Coordination - COM-001, COM-002, IRO-001, and IRO-014	Initial Ballot	2/25/11	3/7/11	Quorum: 87.10% Approval: 49.54%	Yes 3/2/11
d.	Project 2007-23 - Violation Severity Levels	Non-binding Poll	2/9/11	2/18/11	Ballot Pool: 310 Opinions: 141 72% Support	Yes 10/28/10
e.	Project 2010-13 - Relay Loadability Order - PRC-023	Successive Ballot and Non-Binding Poll	1/24/11	2/13/11	Quorum: 83.95% Approval: 65.71%	Yes 2/11/11
f.	Project 2010-13 - Relay Loadability Order - PRC-023	Recirculation Ballot	2/24/11	3/6/11	Quorum: 87.35% Approval: 68.83%	Yes 2/11/11
g.	Project 2010-15 - Urgent Action Revisions to CIP-005-3	Successive Ballot and Non-Binding Poll	4/19/11	4/28/11	Quorum: 79.66% Approval: 38.00%	No 4/19/11
h.	Project 2009-06 - Facility Ratings	Cast Ballot	4/21/11	5/2/11	Quorum: 86.01% Approval: 48.74%	Abstain 4/26/11
i.	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	Successive Ballot and Non-Binding Poll	5/3/11	5/12/11	Quorum: 78.33% Approval: 67.00%	No Recommendation
j.	Project 2009-06 - Facility Ratings - FAC-008 and FAC-009	Recirculation Ballot	5/12/11	5/23/11	Quorum: 91.25% Approval: 78.92%	Yes 5/12/11
k.	Project 2006-02 - Assess Transmission and Future Needs - TPL-001 through TPL-006	Successive Ballot and Non-Binding Poll	5/18/11	5/31/11	Quorum: 92.07% Approval: 73.99	----

l.	Project 2007-03 - Real-time Operations - TOP-001 through TOP-008 and PER-001	Initial Ballot and Non-Binding Poll	5/31/11	6/9/11	Quorum: 88.47% Approval: 48.64%	Reject 5/31/11
m.	Project 2007-09 – Generator Verification – MOD-026-1	Cast Ballot	7/22/11	8/1/11	Quorum: Approval:	No Consensus 7/28/11
n.	Project 2007-09 – Generator Verification – MOD-026-1	Cast Non-Binding Poll Opinion	7/22/11	8/1/11	Quorum: Approval:	
o.	Project 2007-09 – Generator Verification – PRC-024-1	Cast Ballot	7/22/11	8/1/11	Quorum: Approval:	No Consensus 7/28/11
p.	Project 2007-09 – Generator Verification – PRC-024-1	Cast Non-Binding Poll Opinion	7/22/11	8/1/11	Quorum: Approval:	
q.	Project 2007-17 – Protection System Maintenance and Testing – PRC-005	Recirculation Ballot and Non-Binding Poll	6/20/11	6/30/11	Quorum: 82.97% Approval: 64.76%	Yes 6/28/11
r.	Project 2006-02 - Assess Transmission and Future Needs	Cast Ballot	7/13/11	7/22/11	Quorum: 94.33% Approval: 75.37%	----
s.	Project 2006-06 - Reliability Coordination - IRO-002-3	Cast Ballot	7/15/11	7/25/11	Quorum: 94.13% Approval: 76.99%	Yes 7/22/11
t.	Project 2006-06 - Reliability Coordination - IRO-005-4	Cast Ballot	7/15/11	7/25/11	Quorum: 94.13% Approval: 75.17%	Yes 7/22/11
u.	Project 2006-06 - Reliability Coordination - IRO-014-2	Cast Ballot	7/15/11	7/25/11	Quorum: 94.13% Approval: 76.27%	Yes 7/22/11
v.	Project 2006-06 - Reliability Coordination - IRO-002-3	Cast Non-Binding Poll Opinion	7/15/11	7/25/11	Quorum: Approval:	

w.	Project 2006-06 - Reliability Coordination - IRO-005-4	Cast Non-Binding Poll Opinion	7/15/11	7/25/11	Quorum: Approval:	
x.	Project 2006-06 - Reliability Coordination - IRO-014-2	Cast Non-Binding Poll Opinion	7/15/11	7/25/11	Quorum: Approval:	

i, q--Why did the recirculation ballot fail after the Successive Ballot passed?

Item 11b--There were issues raised by NERC that need to be addressed. The intent is to post the response to comments received, and then go to a Recirculation Ballot.

Item 11c--The project was split up because of significant comments on some of the Standards.

Item 11g--The Drafting Team will be disbanded, and reformed for Version 5.

Items 11i, 11q--It has been reported that some changes will be made. It may be re-balloted. Entities shouldn't be penalized if they can't meet requirements that are more stringent than those defined in the Standard, but meet those that are in the Standard. Entities' procedures should not be audited, only that which is enforceable. It is still not definite as to how this will proceed.

Howard Gugel reported that the Drafting Team for Project 2007-17 will not be changing the SAR. Plan to repost the existing SAR for a 45 day informal comment period. PRC-005-2 has been revised. It will be posted for a formal 45 day comment period in parallel with the SAR. This will be followed by a ballot period. The interval for testing batteries became an issue, and the expansion of the BES. There will be a Webinar, and this will be treated as an initial posting. There will be a 10 day ballot period. Reportedly will be happening within the next couple of weeks.

Guy Zito suggested to Howard Gugel that for the posting of a Standard's effective date, a link should be provided to the associated FERC documents.

12. <u>Posted For 30-Day Pre-Ballot Review (Open Ballot Pools) Between RSC Meetings</u>:

a.				

13. <u>Comment Forms Submitted</u> (in Meeting Materials Package), (red entries added since prior RSC Meeting)

a.	Standards Project Prioritization Reference Document and Tool	Comment Form	1/21/11	2/10/11
b.	Project 2007-12 - Frequency Response	Comment Form	2/4/11	3/7/11
c.	Project 2007-07 - Vegetation Management - FAC-003	Comment Form	1/27/11	2/28/11
d.	Project 2007-23 - Violation Severity Levels	Comment Form	1/20/11	2/18/11
e.	Project 2006-06 - Reliability Coordination - COM-001, COM-002, IRO-001, and IRO-014	Comment Form	1/18/11	3/7/11
f.	Regional Reliability Standards - PRC-006-NPCC-1 - Automatic Underfrequency Load Shedding	Comment Form (no comments submitted)	1/10/11	2/24/11
g.	CAN-0015--Draft CAN-0015 Unavailability of NERC Tools	Comments	2/4/11	2/18/11
h.	CAN-0016--Draft CAN-0016 CIP-001-1 R1 - Applicability to Non-BES	Comments	2/4/11	2/18/11
i.	CAN-0017--Draft CAN-0017 CIP-007 R5 System Access and Password Controls	Comments	2/11/11	3/4/11
j.	CAN-0018--Draft CAN-0018 FAC-008 R.1.2.1 - Terminal Equipment	Comments	2/4/11	2/18/11
k.	Proposed Changes to Rules of Procedure to Add Section 1700 - Challenges to Determinations	Comments	2/14/11	3/7/11
l.	Project 2009-06 - Facility Ratings - FAC-008 and FAC-009	Comment Form	3/17/11	5/2/11
m.	Project 2010-15 - Urgent Action Revisions to CIP-005-3 - CIP-005	Comment Form	3/29/11	4/28/11
n.	Project 2009-02 - Real-time Reliability Monitoring and Analysis Capabilities	Comment Form	2/16/11	4/4/11
o.	Notice of Proposed Changes to RFC Rules of Procedure and Request for Comments	Comments (No comments submitted)	3/1/11	4/15/11
p.	Proposed Amendments to NERC Rules of Procedure Appendices 3B and 3D	Comments	3/1/11	4/15/11
q.	Project 2010-07 - Generator Requirements at the Transmission Interface	Informal Comment Period	3/4/11	4/4/11
r.	Project 2009-01 - Disturbance and Sabotage Reporting	Comment Form	3/9/11	4/8/11

s.	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	Comment Form	4/13/11	5/12/11
t.	Project 2010-17 - Definition of Bulk Electric System	Comment Form	4/28/11	5/27/11
u.	Project 2006-02 - Assess Transmission and Future Needs	Comment Form	4/18/11	5/31/11
v.	Project 2007-03 - Real-time Operations - TOP-001 through TOP-008 and PER-001	Comment Form	4/26/11	6/9/11
w.	Project 2010-17 - Definition of Bulk Electric System	Comment Form	5/11/11	6/10/11
x.	Rules of Procedure Development Team: BES Definition Exception Process	Comment Form	5/11/11	6/10/11
y.	CAN-0024--Draft CAN-0024 CIP-002 through CIP-009 Routable Protocols and Data Diodes	Comments	5/20/11	6/10/11
z.	CAN-0029--Draft CAN-0029 PRC-004-1 R1, R2 and R3 Misoperations	Comments	5/20/11	6/10/11
aa.	CAN-0030--Draft CAN-0030 Attestations	Comments	5/20/11	6/10/11
bb.	CAN-0039--Draft CAN-0039 DOE Form 407	Comments	5/20/11	6/10/11
cc.	Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)	Comment Form	6/10/11	7/11/11
dd.	Project 2007-09 – Generator Verification – MOD-025-2, MOD-027-1, PRC-019-1	Comment Form	6/15/11	7/15/11
ee.	Project 2007-09 – Generator Verification – MOD-026-1 and PRC-024-1	Comment Form	6/15/11	8/1/11
ff.	Project 2010-07 – Generator Requirements at the Transmission Interface – Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR standards	Comment Form	6/17/11	7/17/11

b.1--Project 2007-12 Frequency Response--Webinar.
e.1--Project 2006-06 Reliability Coordination--Webinar.
ee. Project 2007-09 Generator Verification--Webinar.

Item 13--The responses on Comment Forms submitted by NPCC include inputs from Drafting Teams. It was suggested to go to the NPCC representatives on Drafting Teams to get the responses to the comments submitted by NPCC.

When a Standard is reposted, Lee Pedowicz will send out to the RSC members ONLY the responses to the NPCC comments that were submitted. The RSC members will be responsible for getting the comment responses to the appropriate SMEs to get feedback on whether the responses were adequate. David Kiguel suggested that the Drafting Team notify the people that submitted comments when the comment responses are finalized.

Item 13b--The attendees emphasized that this project must be paid attention to because of the importance of maintaining system frequency.

14. Reference Documents Posted For Comment Between RSC Meetings

a.				

15. Drafting Team Nominations Open (Current and between RSC Meetings)

a.	CIP Standards Interpretation Drafting Team	Drafting Team	5/5/11	5/18/11
b.	Project 2010-05.1 Protection System Misoperations Drafting Team	Drafting Team	5/20/11	6/3/11

16. NERC Meetings (in Meeting Materials Package)

a. Board of Trustees Conference Call May 24, 2011.
b. Legal Advisory Committee conference call May 19, 2011.

Item 16--Guy Zito discussed Sylvain Clermont's MRC, and NERC BOT notes.

17. NERC RSG (in Meeting Materials Package)

a. May 16, 2011 Meeting.
b. Regional Standards Development Planning.
c. First Report for ERO Executive Management Group from Regional Standards Group--June 14, 2011
d. Draft Regional Standard Development Project template.
e. June 13, 2011 teleconference and webinar.
f. Regulatory Order administration.

Item 17--The coordination between the ERO and the Regions has to improve. For NERC, Howard Gugel reported that Barb Nutter is dedicated to Regional Standards. Kathleen Goodman commented that there has to be a way of developing Regional Standards that are more stringent than corresponding NERC Standards, but because of the increased stringency get an Entity in trouble with NERC Standards.

18. **Standards Committee Report** (in Meeting Materials Package)
    a. July 13-14, 2011 Meeting, Portland, Oregon.

Item 18--Michael Lombardi suggested to Howard Gugel that on the NERC Website's Reliability Standards--Effective Dates for Mandatory Enforcement not only list the date of an update, but the substance of what was changed as well.

Item 18a--David Kiguel stated that the SC should not get involved with the technical details of the BES definition, just the process. There will probably be a Webinar on the Standard Prioritization Tool. Rapid Revision Project proposal is going to be presented.

19. **SPCS Meeting** (in Meeting Materials Package)
    a. June 28-30, 2011 Meeting, CIP 706 notes.

Item 19a--A definition of Special Protection System is needed. It is important that this definition be developed to guide industry. It was brought up that NPCC has Type 1, Type 2, and Type 3 SPS.

20. **NERC Compliance Application Notices (CANs)** (in Meeting Materials Package)
    a. June 14, 2011 webinar.
    b. July 15, 2011 webinar
    c. Compliance Application Notices (CANs) and Bulletins.

Guy Zito reported that the comments provided to Valerie Agnew have been disregarded. Mike Schiavone stated that the RSC is the right forum for commenting on CANs. David Kiguel commented that the RSC Scope includes the review of CANs. The response to CANs comments is posted on the NERC Website, however the commenters are not identified.

21. **NERC Bulk Electric System Definition** (in Meeting Materials Package)
    a. Costs associated with any change in the definition of BES.
    b. Reliability Practices for BES.
    c. NERC can create and maintain Reliability Standards to BES and non-BES assets.
    d. Summary of the June 2011 Definition of BES Drafting Team meetings.
    e. Notes--Project 2010-17 Definition of Bulk Electric System, June 7-9, 2011.
    f. Notes--Project 2010-17 Definition of Bulk Electric System, June 16, 2011.
    g. Notes--Project 2010-17 Definition of Bulk Electric System, June 21-23, 2011.
    h. Summary of the July 19-21, 2011 Definition of BES Drafting Team Meeting.
    i. Notes-- Project 2010-17 Definition of Bulk Electric System, July 19-21, 2011.
        1. 75MW technical justification outline.

Item 21b--Resulted from RCC, NPCC Executive teams. Envisioned to be a sharing activity amongst members. It was viewed as an opportunity to use any Entity's procedure or procedures as a best practice, and it could possibly lead to the development of a procedure.

Item 21c--The Drafting Team is awaiting technical justification for the 75MVA threshold. Expected in September or October of this year. If it will not be available, this will be a topic of discussion at next week's meeting in Washington, D.C. NPCC is not supportive of the 75MVA threshold. Brian Evans-Mongeon discussed the generator rating threshold. A discussion followed regarding the validity of having any generator rating threshold because of the impact of the loss of any generator on the Bulk Electric and Bulk Power Systems.

Item 21--Brian Evans-Mongeon questioned how A-10 will be affected by the new BES definition. Guy Zito responded that there will be no move to retire it. There will be a FERC/NERC BES, and a NPCC BPS.

22. <u>NPCC Regional Standards--Update</u> (in Meeting Materials Package)

a. Disturbance Monitoring (PRC-002-NPCC-01)
   1. Filed with FERC May 31, 2011 (refer to Item 5T3 above).
   2. Filed in New Brunswick, Quebec, Ontario, and with the National Energy Board on June 8, 2011.

b. Underfrequency Load Shedding
   1. Applicability revised and Open Process comments addressed.
   2. Revised Standard to be presented to RCC in September, 2011.
   3. RSC approval needed for 30 day pre-ballot review and subsequent 10 day ballot.

c. Special Protection System

d. Regional Reserve Sharing
   1. Draft RSAR developed
   2. TFCO soliciting for Drafting Team members.

Item 22a--FERC has the filing. No NOPR is needed. Refer to Item 5T3 above.
Item 22b--The Drafting Team was reconvened to address applicability issues. Applicability to Generator Owners, Planning Coordinators, Planning Coordinators, Transmission Owners, and Distribution Providers. The Standard is to be presented to the RCC at its Sept. 8, 2011 meeting. Seeking TFSS concurrence. RSC will then be asked to post for ballot. Discussions on a decision to post will probably will be done via teleconference.
Item 22c--Not being moved forward because of related activity at NERC. The outcome of the BES definition decision will also affect this, and the SPS definition also. A SPS continent wide standard is planned to be developed in the 2012/2013 time frame.
Item 22d--Reserve Sharing Directory being worked on at the present time.

23. NPCC Cost Effectiveness Analysis, Triage Process (in Meeting Materials Package)

a. Cost Effectiveness Analysis Procedure.
b. Triage process.

Item 23a--Responses to questions asked by the CEAP will be compiled and reviewed by the NPCC Staff because proprietary information might have been submitted. The group was asked to review the document and provide any suggestions for improvements. The plan is to have the document posted for 45 days to get industry opinions. It will then be submitted to RSC for approval, and then the NPCC Board of Directors. The CEAP is not meant to be for economics or metrics. The intent is for it to just provide cost information to the industry.

Brian Evans-Mongeon made a motion to have the document posted for 45 days. Chris de Graffenried and David Kiguel seconded the motion. All attendees were in favor. The CEAP was sent to the Open Process for the 45 day comment period August 5, 2011.

Item 23b--It is desired to send the Triage Process to the Task Force chairs for their input. The RSC has until August 19, 2011 to provide comments. The plan is to have the Triage Process then post it for comments.

24. NY adoption of more stringent/specific NPCC Criteria

a. Status of the filing.

Item 24a--NPCC's Margaret Mayora has this. Needs to be followed up.

25. Directory and Regional Work Plan Status

a. Directory effective dates.

Directory Number	Title	Lead Group, Status	Current Activity
#1 (A-2)	Design and Operation of the Bulk Power System	Approved on 12/1/2009	TFCP has charged CP11 with a comprehensive review of Directory #1 to include the triennial document review, an examination of the NERC TPL standards, the existing NPCC planning criteria, and the implementation of Phase 2 of the Directory Project which will reformat existing Directory criteria into NERC style requirements. CP11 on schedule to post the document for a second time in late August, and anticipate Full Member approval by the end of 2011.
#2 (A-3)	Emergency Operation	Approved on 10/21/08.	Automatic UFLS language transferred to Directory #12. Next TFCO review Oct. 21, 2011.

#3 (A-4)	Maintenance Criteria for BPS Protection.	Approved on 7/11/08.	
#4 (A-5)	Bulk Power System Protection Criteria	Approved on 12/1/09.	
#5 (A-6)	Operating Reserve	TFCO	Directory#5 was approved by the Full Members on December 2, 2010. TFCO working to resolve outstanding reserve issues associated with Directory #5. TFCO expects to post a revised version of Directory #5 to the Open Process incorporating further changes to the document this Fall.
#6 New	Reserve Sharing	TFCO	TFCO considering draft of a new Directory on Regional Reserve Sharing which would replace C38 until a Regional Standard is developed. TFCO expects to post an initial draft of Directory #6 to the Open Process this Fall.
#7 (A-11)	Special Protection Systems	Approved on 12/27/07.	TFSP nearing completion of NRAP review of Directory #7. TFSP to incorporate these recent NRAP revisions (including Appendix A) of the document into a Phase 2 version and post for member comment this Fall.
#8 (A-12)	System Restoration	Approved on 10/21/08.	TFCO made revisions to criteria for battery testing in October, 2010. Next review date July 9, 2012.
#9 (A-13)	Verification of Generator Real Power Capability	Approved on 12/22/08.	TFCO has posted the initial Phase 2 drafts of both Directories #9 and #10 to the Open Process. TFCO currently developing responses to comments received during the initial posting and a second Open Process posting for both documents is anticipated in late August, 2011. Expect Full member approval of both Directory #9 and #10 by December , 2011.
#10(A14)	Verification of Generator Reactive Power Capability	Approved on 12/22/08.	Refer to Directory #9 preceding.
#12	UFLS Program Requirements	Approved on 6/26/09.	

b. Directory Work Plan for Phase 2 Reformatting.

Item 25b--Task Forces have to look at the Directory Work Plan for Phase 2. TFCO is looking at Directory #6. TFSP is looking at Directory #7. Hope to ballot Phase 2 of Directory #7 by the end of the year. TFCP is looking at Directory #1. There was a conference call held to deal with how to develop compliance measures. Guy Zito questioned who should draft the measures. Discussion ensued that revolved around Task Forces, or Compliance? Prior to the Phase 2 program the Directories did not have Measures. The Directories in Phase 2 have to have Measures. Discussion then revolved around whether Directories should have measures at all. An opinion expressed was that well written requirements don't need measures. The results based standards initiative may demand the inclusion of measures.

c. Directory Development and Revision Manual.
d. NPCC Glossary of Terms Used by Directories.

Item 25d--There are two separate glossaries; one for Directories, and a glossary for other NPCC documents. The intent is to ultimately have one glossary, and Criteria will be done away with. Ultimately there will be no Criteria ("A" documents). Some Guideline ("B" documents) and Procedures ("C" documents) may remain. There will be a need for consistency.

26. Review RFC, MRO Standards Relevant to NPCC (in Meeting Materials Package)

a. RFC Standards Under Development webpage
https://rsvp.rfirst.org/default.aspx

b. RFC Standard Voting Process (RSVP) webpage
ReliabilityFirst Corporation - Reliability Standards Voting Process

	Standard Under Development	Status	Start Date	End Date
1.	MOD-025-RFC-01 - Verification and Data Reporting of Generator Gross and Net Reactive Power Capability	Posted for Comments	4/8/11	5/23/11
2.	MOD-024-RFC-01.1 - Verification and Data Reporting of Generator Gross and Net Real Power Capability) modified Violation Severity Levels (VSLs)	Posted for Comments	6/22/11	7/21/11
3.	EOP-007-RFC-02 (System Restoration Plans)	15 Day Category Ballot (for Standard's retirement)	7/14/11	7/28/11

c. Midwest Reliability Organization Approved Standards
http://www.midwestreliability.org/STA_approved_mro_standards.html
(click on RSVP under the MRO header)

d. Midwest Reliability Organization Reliability Standard Voting Process webpage (table lists standards under development)
Midwest Reliability Organization - Reliability Standards Voting Process

	Standard Under Development	**Status**	**Start Date**	**End Date**
1.	PRC-006-MRO-01 - Underfrequency Load Shedding Requirements (see e. below)	Posted for second 30 day comment period	5/19/10	6/17/10
2.				

e. As of June 14, 2010 MRO suspended its regional standards development.

Item 26--For information.

27. Report on NERC, NAESB and Regional Activities (in Meeting Materials Package)

a. Report on NERC, NAESB and Regional Activities
   1. May, 2011.
   2. June, 2011
   3. July, 2011.

Item 27--For information.

28. Task Force Assignments, et al. (in Meeting Materials Package)

a. TFCO April 14-15, 2011 Meeting minutes.

Item 28--The role of TFCO in Directory development was discussed.

29. Future Meetings and Other Issues (in Meeting Materials Package)

a. NPCC new Website development.

Item 29a--New NPCC Website anticipated to be rolled out the week of August 8, 2011. The Website is being completely redone.

b. RCC June 1, 2011 Meeting.
c. NERC 2010 Annual Report.
d. Cauley Testifies at House Energy and Commerce Subcommittee Hearing.
e. NERC 2012 Business Plan and Budget--Draft 2 and Final.
f. NERC Newsletter
   1. May, 2011.
   2. June, 2011.
   3. July, 2011.

g. Ballot Results: SERC Regional UFLS Standard--PRC-006-SERC-01.
   1. SERC Ballot Results
   2. Comment period--6/29/11 - 8/15/11 (link to documents)
h. Geomagnetic Disturbances.
i. FERC affirms NERC decision to classify wind generators as transmission owners, operators.
j. New NERC Headquarters is opened in Atlanta, Ga.
k. SPP UFLS Regional Standard: Draft 6.

Items 29b through 29k--Reviewed for information.

l. Use of "Regional Reliability Organization", "Regional Entities" and "Electric Reliability Organization" in Reliability Standards.

Item 29l--Howard Gugel discussed the NERC Glossary format. He also discussed the NERC Website and standards for Quebec. Si-Truc Phan to send Howard Quebec standards information. All the Canadian participants are to check their NERC Website pages and send any corrections to Howard Gugel.

m. Planning Committee Strategic Plan - Next Steps and Future Work Plan.
n. NPCC 2012 Business Plan and Budget.
o. Call for Potential Projects for Standards Development--comments were due July 29, 2011.
p. Regional Entities 2012 Business Plans and Budgets – FINAL.
q. Nova Scotia approvals.
r. NARUC Board of Director Policy Resolutions.
s. NERC Standards Oversight and Technology Committee Meeting August 3, 2011--Agenda.
t. Regional Reliability Standard IRO-006-TRE-1 for comments--7/7/11-8/22/11.

Items 29m through 29t--Reviewed for information.

u. NERC Lessons Learned.
   1. Zone 3 Line Relay Mis-operation.
   2. Sub-Synchronous Interaction between Series-Compensated Transmission Lines and Generation.
   3. Insulator Coating.
   4. Protective Relay Field Revisions.
   Other Lessons Learned by going to NERC Lessons Learned.

Item 29u--Ralph Rufrano discussed. If more information is needed on the Lessons Learned, NERC will have to be contacted. Any suggestions for the program should be given to Ralph Rufrano. Lessons Learned can result in revisions to the standards. Guy Zito suggested that to make it part of the Events Analysis process to have any relevant standards reviewed for the need for change because of the event.

v. NERC Standards Report, Status and Timetable for Addressing Regulatory Directives.
w. NERC Pilot State of Standards Webinar July 25, 2011.
x. Partial decision on adoption of electricity transmission reliability standards and approval of related documents.
y. NPCC Board of Directors Policy Input to the August 3, 2011 NERC Member Representatives Committee and August 4, 2011 NERC Board of Trustees Meetings.
z. SERC Regional Standards Development Procedure--Comment Form.

Guy Zito discussed the "GRID Act" and its impact on emergency provisions, and how it affects restoration plans, and because of geomagnetic disturbances not being as severe as forecast, the possible effect on GMD observational satellites. Lee Pedowicz sent out copies of the GRID Act House of Representatives and Senate versions to the RSC August 8, 2011.

Not on the Agenda were the revisions to the NPCC Regional Reliability Standards Development Procedure. Guy Zito, Lee Pedowicz, and Michael Lombardi will go over questions submitted by Kurtis Chong, and Brian Gooder.

Meeting adjourned at 16:49.
Meeting adjourned at 11:27.

RSC 2011 Meeting Dates

October 26-27, 2011 Boston, Massachusetts	Dec. 1-2, 2011--Joint Meeting with the CC Dec. 2, 2011 Toronto, Ontario

2011 RSC Conference Call Schedule
(call 719-785-1707, Guest Code 8287#)

August 19, 2011	Oct. 14, 2011
Sept. 2, 2011	Nov. 10, 2011 (Thursday)
Sept. 16, 2011	Dec. 16, 2011
Sept. 30, 2011	Dec. 30, 2011

BOD 2011 Meeting Dates

September 20, 2011 NPCC	October 26, 2011 Teleconference
November 30, 2011 Toronto	

RCC, CC, and Task Force Meeting Dates--2011

RCC	Sept. 8, Nov. 29
CC	August 17, Sept. 21-22, Oct. 19, Nov. 16, Dec. 13-15
TFSS	Sept. 15-16
TFCP	August 17, Nov. 2
TFCO	August 11-12, Oct. 6-7
TFIST	
TFSP	Sept. 27-29, Nov. 15-17

Respectfully Submitted,

Guy V. Zito, Chair RSC
Assistant Vice President-Standards
Northeast Power Coordinating Council Inc.

Northeast Power Coordinating Council, Inc. (NPCC)
Antitrust Compliance Guidelines

It is NPCC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. The antitrust laws make it important that meeting participants avoid discussion of topics that could result in charges of anti-competitive behavior, including: restraint of trade and conspiracies to monopolize, unfair or deceptive business acts or practices, price discrimination, division of markets, allocation of production, imposition of boycotts, exclusive dealing arrangements, and any other activity that unreasonably restrains competition.

It is the responsibility of every NPCC participant and employee who may in any way affect NPCC's compliance with the antitrust laws to carry out this commitment. Participants in NPCC activities (including those participating in its committees, task forces and subgroups) should refrain from discussing the following throughout any meeting or during any breaks (including NPCC meetings, conference calls and informal discussions):

- Industry-related topics considered sensitive or market intelligence in nature that are outside of their committee's scope or assignment, or the published agenda for the meeting;
- Their company's prices for products or services, or prices charged by their competitors;
- Costs, discounts, terms of sale, profit margins or anything else that might affect prices;
- The resale prices their customers should charge for products they sell them;
- Allocating markets, customers, territories or products with their competitors;
- Limiting production;
- Whether or not to deal with any company; and
- Any competitively sensitive information concerning their company or a competitor.

Any decisions or actions by NPCC as a result of such meetings will only be taken in the interest of promoting and maintaining the reliability and adequacy of the bulk power system.

Any NPCC meeting participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NPCC's antitrust compliance policy is implicated in any situation should call NPCC's Secretary, Andrianne S. Payson at 212-259-8218.

Action Item List

Action Item Number	Agenda Item Number	Description	Owner	Due	Status
32	16b	To discuss with Herbert Schrayshuen how HQ, because of its unique operational requirements, will be addressed in standards development	Guy Zito--member of Standards Committee Process Subcommittee	RSC Meeting	Ongoing as of 2/10/10. Sylvain Clermont, and David Kiguel working with Guy Zito. Herbert Schrayshuen replaced Gerry Adamski at NERC. The new NERC management team will have to be made familiar with this item.
August 20-21, 2008					
Feb. 17-18, 2009					
June 17-18, 2009					
August 6-7, 2009					
60	3a	NPCC representatives from NERC drafting teams that have documents posted for comments report at RSC Meetings	Lee Pedowicz	RSC Meeting	Ongoing.
Sept. 24-25, 2009					
Nov. 4-5, 2009					

Action Item Number	Agenda Item Number	Description	Owner	Due	Status
April 21-22, 2010					
63	----	Coordination with the Compliance Committee to develop Joint Activity Action List	Greg Campoli	RSC Meeting	Outgrowth of RSC/CC joint session April 21, 2010. Ongoing. Joint RSC/CC Meeting this meeting. Ralph Rufrano rejoined the RSC in the capacity of NPCC Compliance liaison. Comments not to be submitted on the CCEP.
June 29-30, 2010					
65	----	RSC to review the NPCC Members on NERC Drafting Teams list. Saurabh Saksena to maintain. Will get input from Carol Sedewitz.	RSC	RSC Meeting	Ongoing.
August 18-19, 2010					
66	----	Status of Memorandum of Understanding	Sylvain Clermont	RSC Meeting	Provide update. (MOU in Meeting Materials Package)

Action Item Number	Agenda Item Number	Description	Owner	Due	Status
Nov. 30, 2010,					
Dec. 2, 2010					
69	----	Revise RSC Scope	RSC	RSC Meeting	
Feb. 2-3, 2011					
71	----	Talk to Compliance about Regional Reliability Standard RSAWs. There should be a Compliance Committee representative on the Drafting Team.	Guy Zito	RSC Meeting	Ongoing.
~~72~~	~~----~~	~~Find out what other Regions are doing regarding interpretations.~~	~~Guy Zito~~	~~RSC Meeting~~	~~Ongoing.~~
73	----	Discuss consistency with the RSG.	Guy Zito	RSC Meeting	Ongoing.
March 16-17, 2011					
75	11f	Non-convergent contingencies enumerated in Project 2010-13 - Relay Loadability Order - PRC-023 Attachment B4a.	Guy Zito	RSC Meeting	To be discussed with Sal Buffamante.
August 3-4, 2011					
76	18a	Handling of definitions	Guy Zito	RSC Meeting	To discuss with Pete Heidrich

Action Item 32--ongoing.
Action Item 60--ongoing.
Action Item 63--participants were urged to to start thinking about the joint meeting with the CC in December, 2011. Greg Campoli and Gerry Dunbar participated in a CCEP conference call August 4, 2011.
Action Item 65--Michael Jones has been taking care of this in Saurabh Saksena's absence.
Action Item 66--Complete translation of the standards expected by year end. An appendix is to be added to account for those items unique to Quebec. Si-Truc Phan is working to ensure that the translations are accurate. There are 95 Standards that have been translated and filed with the Regie. Corrections are being made. Upon acceptance, 140 Standards in total will have been translated and filed. Open issues remaining are who will register the entities in Quebec, and also uncertainty surrounding the Provincial Bulk Electric System.
Action Item 69--Kathleen Goodman made a motion to approve. Michael Lombardi seconded. With the exception of David Ramkalawan who abstained, all voted in favor. Guy Zito to bring to the NPCC Board of Directors for their approval.
Action Item 71--To be discussed with the Compliance Committee, and is ongoing.
Action Item 72--Guy Zito approached the RSG to get information. Other Regions have their interpretation information available on their Websites. Guy Zito is concerned about consistency and uniformity in interpretations. Having Regional interpretations creates the potential for problems. All interpretations **must** be consistent. This item to be removed. Guy Zito reported that a rapid revision procedure is being looked at. Guy Zito will discuss with the RSG and SC.
Action Item 73--ongoing.
Action Item 75--ongoing.

NPCC Members on NERC Drafting Teams

Updated: July 27, 2010--Oct. 21, 2011 no changes							
Project No.	**Project Title**	**DT Type**	**NPCC Representatives**	**Company**	**Telephone**	**E-mail Address**	**Comments**
2006-02	Assess Transmission Future Needs & Develop Transmission Plans	Standard	Dana Walters	National Grid	781-907-2501	dana.walters@us.ngrid.com	
2006-02	Assess Transmission Future Needs & Develop Transmission Plans	Standard	Yury Tsimberg	Kinectrics	416-207-6000 X6106	Yury.Tsimberg@Kinectrics.com	Observer
2006-03	System Restoration & Blackstart	Standard	Steve Cooper	IESO	905-855-6159	steve.cooper@ieso.ca	
2006-03	System Restoration & Blackstart	Standard	David Mahlmann	NYISO	518-356-6101	dmahlmann@nyiso.com	
2006-03	System Restoration & Blackstart	Standard	Will Houston	National Grid	508-421-7690	will.houston@us.ngrid.com	
2006-04	Backup Facilities	Standard	John Procyk	Hydro One Networks	705-792-3210	john.procyk@hydroone.com	
2006-04	Backup Facilities	Standard	Mike Schiavone	National Grid	315-460-2472	michael.schiavone@us.ngrid.com	Vice-Chair
2006-06	Reliability Coordination	Standard	Earl Barber	National Grid	315-428-5532	earl.barber@us.ngrid.com	
2006-07	ATC/TTC/AFC & CBM/TRM Revisions	Standard	Cheryl Mendrala	ISO-NE	413-535-4184	cmendrala@iso-ne.com	
2006-08	Transmission Loading Relief	Standard	Ben Li	Ben Li Associates, Inc.	647-388-1498	Ben@BenLi.ca	Chair
2007-01	Underfrequency Load Shedding	Standard	Brian Evans-Mongeon	Utility Services	802-552-4022	brian.evans-mongeon@utilitysvcs.com	
2007-01	Underfrequency Load Shedding	Standard	Si Truc Phan	Hydro Quebec - TransEnergie	514-879-4100 X3610	Phan.Si_Truc@hydro.qc.ca	
2007-02	Operating Personnel Communications Protocols	Standard	Tom Irvine	Hydro One Networks	705-792-3004	tom.irvine@hydroone.com	
2007-03	Real-time Operations	Standard	Phil Lavallee	National Grid	508-389-2827	phil.lavallee@us.ngrid.com	
2007-04	Certifying System Operators	Standard	Rob MacDonald	Hydro One Networks	705-792-3095	Rob.Macdonald@HydroOne.com	
2007-05	Balancing Authority Controls	Standard	Guy Quintin	Hydro Quebec - TransEnergie	514-289-2211 X3150	Quintin.Guy@hydro.qc.ca	
2007-06	System Protection Coordination	Standard	Aaron Cooperberg	Hydro One Networks	416-345-5172	cooperberg@HydroOne.com	
2007-06	System Protection Coordination	Standard	David Cirka	National Grid	781-907-3240	david.cirka@us.ngrid.com	
2007-07	Vegetation Management	Standard	Dave Morrell	New York State Dept of Public Svc	518-486-7322	david_morrell@dps.state.ny.us	
2007-07	Vegetation Management	Standard	Orville Cocking	Con Edison			
2007-09	Generator Verification	Standard	Les Hajagos	Kestrel Power Engineering Ltd.	905-272-2191	les@kestrelpower.com	
2007-11	Disturbance Monitoring	Standard	Jeff Pond	National Grid	781-907-3222	jeff.pond@us.ngrid.com	
2007-12	Frequency Response	Standard	Harvey Happ	New York State Dept of Public Svc	518-486-2939	hhh@dps.state.ny.us	
2007-12	Frequency Response	Standard	Mike Potishnak	ISO-NE	413-535-4308	mpotishnak@iso-ne.com	
2007-14	Permanent Change to CI Table	Standard	No representation				
2007-17	Protection System Maintenance & Testing	Standard	John Ciufo	Hydro One Networks	416-345-5258	john.ciufo@hydroone.com	
2007-17	Protection System Maintenance & Testing	Standard	Leonard Swanson	National Grid	315-428-5250	leonard.swanson@us.ngrid.com	
2007-18	Reliability-based Control	Standard	Mike Potishnak	ISO-NE	413-535-4308	mpotishnak@iso-ne.com	
2007-23	Replace Levels of Noncompliance w/VSL	Standards	No representation				
2008-01	Reactive Planning and Control	SAR	Edwin E Thompson,	Con Edison	212-460-8199	thompsonedwin@coned.com	
2008-04	Facility Ratings for Order 705	Standard	No representation				
2008-06	Cyber Security for Order 706	Standard	John Lim	Con Edison	212-460-2712	limj@coned.com	Chair
2008-06	Cyber Security for Order 706	Standard	Frank Kim	Hydro One Networks	705-792-3033	Frank.Kim@HydroOne.com	
2008-06	Cyber Security for Order 706	Standard	Doug Johnson	Exelon-Commonwealth Edison	630-691-4593	douglas.johnson@comed.com	
2008-06	Cyber Security for Order 706	Standard	Robert Antonishen	Ontario Power Generation	905-262-2674	rob.antonishen@opg.com	
2008-06	Cyber Security for Order 706	Standard	Thomas Stevenson	Constellation Energy			
2008-08	Revise VSLs for Emergency Operations Standards	Standard	No Representation				
2008-12	Coordinate Interchange Modifications	Standard	Cheryl Mendrala	ISO-NE	413-535-4184	cmendrala@iso-ne.com	
2008-14	Cyber Security Violation Severity Levels	Standard	Mark Engels	Dominion	804-775-5263	mark.engels@dom.com	
2008-14	Cyber Security Violation Severity Levels	Standard	David Dunn	IESO	905-855-6286	david.dunn@ieso.ca	

NPCC Members on NERC Drafting Teams

Updated: July 27, 2010--Oct. 21, 2011 no changes							
2009-01	Disturbance and Sabotage Reporting	Standard	Brian Evans-Mongeon	Utility Services	802-552-4022	brian.evans-mongeon@utilitysvcs.com	Vice-Chair
2009-01	Disturbance and Sabotage Reporting	Standard	Michelle Draxton	Constellation Energy Group	410-474-2993	Michelle.l.draxton@constellation.com	
2009-01	Disturbance and Sabotage Reporting	Standard	Drew Phillips	IESO	905-855-4114	drew.phillips@ieso.ca	
2009-01	Disturbance and Sabotage Reporting	Standard	Thomas J Curran	Con Edison	347-672-4621	currant@coned.com	
2009-02	Real-time Best Tools	SAR	Scott Vidler	Hydro One Networks	705-627-1436	scott.vidler@hydroone.com	
2009-07	Reliability of Protection Systems	SAR	Xiaodong Sun	Ontario Power Generation	289-257-0405	xiaodong.sun@opg.com	
2009-07	Reliability of Protection Systems	SAR	Dean V. Sorensen	National Grid	508-389-2301	Dean.Sorensen@us.ngrid.com	
2009-07	Reliability of Protection Systems	SAR	Stanley J. Lewis	Con Edison	212-780-2845	lewiss@coned.com	
2009-05	Resource Adequacy Assessments	Standard	Curt Dahl	National Grid	516-545-3662	cdahl@keyspanenergy.com	
2009-05	Resource Adequacy Assessments	Standard	Greg Drake	NYISO	518-356-6038	gdrake@nyiso.com	
2009-05	Resource Adequacy Assessments	Standard	Phil Fedora	NPCC	212-840-4909	pfedora@npcc.org	Vice-Chair
2010-05	Protection Systems: Phase 1 (Misoperations)	Standard	Paul Difilippo	Hydro One	647-328-7068	paul.difilippo@hydroone.com	
2010-07	Generator Requirements at the Transmission Interface	SAR	Benjamin Church	FPL Group - NextEra Energy	561-304-5463	benjamin.church@fpl.com	
2010-10	FAC Order 729	Standard	No representation				
2010-17	Proposed Definition of Bulk Electric System	Standard	Jennifer Dering	NYPA		Jennfer.Dering@nypa.gov	
			Brian Evans-Mongeon	Utility Services	802-552-4022	brian.evans-mongeon@utilitysvcs.com	
			Phil Fedora	NPCC	212-840-4909	pfedora@npcc.org	
			Ajay Garg	Hydro One Networks	416.345.5420	ajay.garg@HydroOne.com	
IRO-004	Require Timely Submission of Data	SAR	No representation				
NUC-001-1	Nuclear Plant Interface Coordination for FERC Order 716	SAR	Michael Schiavone	National Grid	315-460-2472	Michael.Schiavone@us.ngrid.com	
RRSWG	Regional Reliability Standards Working Group	N/A	Guy Zito	NPCC	212-840-1070	gzito@npcc.org	
FMWG	Functional Model Working Group	N/A	Mike Yealland	IESO			
FMWG	Functional Model Working Group	N/A	Ben Li	Ben Li Associates, Inc.	647-388-1498	Ben@BenLi.ca	
FMWG	Functional Model Working Group	N/A	Guy Zito	NPCC	212-840-1070	gzito@npcc.org	
FMWG	Functional Model Working Group	N/A	John Walewski	Hydro One Networks	416-345-5878	John.Walewski@HydroOne.com	
FMWG	Functional Model Working Group	N/A	Michael Gildea	Dominion	804-273-4624	michael.gildea@dom.com	
FMWG	Functional Model Working Group	N/A	Peter Munn	Air Liquide LI USA	713-438-6420	peter.munn@airliquide.com	
FM DRAT	Functional Model Demand Response Advisory Team	N/A	Phil Davis	Schneider Electric	404-567-6090	phil.davis@us.schneider-electric.com	
FM DRAT	Functional Model Demand Response Advisory Team	N/A	Stephen C. Knapp	Constellation	410-470-3374	steve.knapp@constellation.com	
FM DRAT	Functional Model Demand Response Advisory Team	N/A	Donna Pratt	NYISO	518-356-8758	dpratt@nyiso.com	
FM DRAT	Functional Model Demand Response Advisory Team	N/A	Ken Clark	Consert, Inc	919-244-7655	kclark@consert.com	
FM DRAT	Functional Model Demand Response Advisory Team	N/A	Aaron Breidenbaugh	EnerNOC	617-224-9918	abreidenbaugh@enernoc.com	
FM DRAT	Functional Model Demand Response Advisory Team	N/A	Eric Winkler	ISO-NE	413-540-4513	ewinkler@iso-ne.com	

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Tab Name	Last Revised	Summary of Changes
NERC RS Exec Tracking Summary	10/5/2011	- Project 2007-07 Vegetation Management - Project 2009-17 Interpretation of PRC-004-1 and PRC-005-1 R2 by Y-W Electric and Tri-State G & T - Project 2009-22 Interpretation of COM-002-2 R2 by the IRC - Project 2010-07 Generator Requirements at the Transmission Interface - Project 2011-INT-01 Interpretation of MOD-028 for FPL
NERC CANs	9/23/2011	- CAN-0009, CAN-0017, CAN-0029, CAN-0031, and CAN-0039 Revisions Posted - Comment period ends 10/14/11
NPCC RRS Tracking Summary	10/3/2011	- PRC-006-NPCC-01 Automatic UFLS Program
NPCC Doc Tracking Summary	9/16/2011	- Cost Effectiveness Analysis Procedure (CEAP) - Posted to Open Process - Comment period through 9/19/11
NPCC Directory Tracking Summary	9/16/2011	- Directory #6, #9 and #10 Posted to Open Process - Comment period through 10/24/11

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Line No.	Project No. / Title	High Priority?	Associated Standard	SAR Posted?	Posted for Comment?	Posted For Ballot?	Industry Approved?	NERC BOT Approved?	Petitioned for FERC Approval?	FERC Approved	Comments	Project Status
1	Project 2007-01 — Underfrequency Load Shedding	No	EOP-003-1 and PRC-006-1	Yes 3rd (Thru 3/29/07)	Yes 3rd (Thru 7/16/10)	Yes 6th (Recirc Thru 10/28/10)	Yes (10/28/10)	Yes (11/4/10)	Yes (3/31/11)			Pending Regulatory Approval
2	Project 2008-06 — Cyber Security — Order 706 (CIP-002-4)	High	CIP-002-4 thru CIP-009-4	x	Yes 1st (Thru 11/3/10)	Yes Recirc Thru 12/30/10) - passed	Yes (12/30/10)	Yes (1/24/11)	Yes (2/10/11)		- FERC NOPR issued 9/15/11 - NOPR would require NERC to make a filing to fully comply with Order No. 706 by the end of the third quarter of 2012. Comments on the proposed rule (RM11-11) are due 60 days after publication in the Federal Register. - Posted in Federal Register on 9/21/11 - Comments are due 11/21/11	Pending Regulatory Approval
3	Project 2008-09 — Interpretation of EOP-001-0 R1 by Regional Entity Compliance Managers	No	EOP-001-0, R1	x	x	Yes 4th (Recirc Thru 10/14/10)	Yes (10/14/10)	Yes (11/4/10)	Yes (9/9/11)			Pending Regulatory Filing
4	Project 2008-14 — Cyber Security Violation Severity Levels	No	CIP family of standards	Yes 2nd (Thru 04/20/09)	Yes 1st (Thru 04/20/09)	Yes (Recirc Thru 7/16/09)	Yes (7/16/09)	Date?	Date?			Pending Regulatory Approval
5	Project 2009-06 — Facility Ratings	Normal	FAC-008-3 (was FAC-008-2)	Yes 2nd (Thru 9/9/09)	Yes 3rd (Formal Thru 5/2/11)	Yes 6th (Recirculation Thru 5/23/11)	Yes (5/23/11)	Yes (5/24/11)	Yes (6/15/11)		FERC issued an Order on March 17, 2011 that requires NERC to file a version of FAC-008 that addresses all directives from Order 693 related to FAC-008 by June 15, 2011.	
6	Project 2009-10 — Interpretation of PRC-005-1 R1 by Compliance Monitoring Processes Working Group (CMPWG)	No	PRC-005-1, R1	x	x	Yes (Recirc Thru 8/6/09)	Yes (8/6/09)	Yes (11/5/09)	Yes (11/17/09)		NOPR issued 12/16/10 - Comments are due 2/25/11	Pending Regulatory Approval
7	Project 2009-28 — Interpretation of EOP-001-1 and EOP-001-2 R2.2 by FMPP	No	EOP-001-1 and EOP-001-2	x	x	Yes (Recirc Thru 10/15/10)	Yes (10/15/10)	Yes (11/4/10)	Yes (9/9/11)			Pending Regulatory Filing
8	Project 2010-10 — FAC Order 729	No	FAC-013-2	Yes 1st (Thru 4/29/10)	Yes 3rd (Thru 1/8/11)	Yes 3rd (Recirc Thru 1/23/11)	Yes (1/23/11)	Yes (1/24/11)	Yes (1/28/11)			Under Development
9	Project 2010-11 — TPL Table 1 Order	No	TPL-002 Footnote b	Yes 1st (Thru 5/26/10)	Yes 3rd (Thru 1/5/11)	Yes 3rd (Recirc Thru 2/5/11)	Yes (2/5/11)	Yes (2/17/11)	Yes (3/31/11)		Ref: FERC 3/18/10 Order Setting Deadline for Compliance [Docket RM06-16-009] -- NERC to clarify Std TPL 002-0	Pending Regulatory Approval
10	Project 2010-13 — Relay Loadability Order	Normal	PRC-023-2	Yes 1st (Thru 9/19/10)	Yes 3rd (Thru 12/16/10)	Yes 3rd (Recirculation Thru 3/6/11)	Yes (3/6/11)	Yes (3/10/11)	Yes (3/18/11)		- FERC NOPR issued 9/15/11 - NOPR proposes to approve Reliability Standard PRC-023-2 (Transmission Relay Loadability). The proposed Reliability Standard modifies an existing standard addressing setting protective relays to ensure they reliably detect and protect the electric network from fault conditions but do not limit transmission loadability or interfere with system operators' ability to protect system reliability. - Posted in Federal Register on 9/21/11 - Comments are due 11/21/11	Pending Regulatory Approval
11	Urgent Action SAR for Revision	No	BAL-004-1	Yes 2nd (Thru 10/18/07)	Yes 2nd (Thru 10/18/07)	Yes 1st (Recirc Thru 12/4/07)	Yes (12/4/07)	Yes (3/26/08)	Yes (3/11/09)		- NERC Motion to Further Defer Action Issued 8/11/11 - NERC Motion to Defer Action Issued 8/20/10 - FERC NOPR [Docket RM09-13-000 (March 18, 2010)] - Commission proposes to remand BAL-004-1	Pending Regulatory Approval
12	Project 2006-02 — Assess Transmission and Future Needs	High	TPL-001-2	Yes 3rd (Thru 3/16/07)	Yes 5th (Formal Thru 5/31/11)	Yes (Recirculation Thru 7/22/11)	Yes (7/22/11)	Yes (8/4/11)				
13	Project 2006-06 — Reliability Coordination	Normal	COM-001-2, COM-002-3, IRO-001-2 and IRO-014-2 (possibly IRO-003-2 - see comments)	Yes 3rd "Supp" (Thru 9/3/10)	Yes 4th (Thru 3/7/11)	Yes 2nd (Initial Thru 7/25/11)	IRO-002-3 IRO-005-4 IRO-014-2 Yes (7/25/11)	Yes (8/4/11)			DT to address comments on Supplemental SAR. SAR proposes to expand the scope of work under to address some directives from Order 693 that are associated with IRO-003-2	Under Development
14	Project 2009-27 — Interpretation of TOP-002-2a R10 by FMPP	No	TOP-002-2a, R10	x	x	Yes (Recirc Thru 10/16/10)	Yes (10/16/10)	Yes (11/4/10)				Pending Regulatory Filing
15	Project 2010-09 — Cyber Security Order 706B — Nuclear Plant Implementation Plan	No	Various CIP Standards	Yes 1st (Thru 3/15/10)	Yes 1st (Thru 3/15/10)	Yes (Recirc Thru 7/2/10)	Yes (7/2/10)	Yes (8/5/10)				Pending Regulatory Filing
16	Project 2009-20 — Interpretation of BAL-003-0 R2 and R5 by Energy Mark, Inc.	No	BAL-003-0.1b	x	x	Yes (Recirc Thru 2/26/10)	Yes (2/26/10)					Under Development
17	Project 2007-03 — Real-time Operations	High	TOP-001-2, TOP-002-3 and TOP-003-2	Yes 2nd (Thru 9/07/07)	Yes 5th (Formal Thru 6/9/11)	Yes 1st (Initial Thru 6/9/11)						Under Development
18	Project 2007-07 — Vegetation Management	Normal	FAC-003-2	Yes 3rd (Thru 7/17/07)	Yes 5th (Thru 2/28/11)	Yes 6th (Recirculation Thru 10/13/11)						Under Development
19	Project 2007-09 — Generator Verification	High	MOD-026-1 and PRC-024-1* MOD-024-2** MOD-025-2, MOD-027-1, PRC-019-1***	Yes 1st (Thru 5/21/07)	*Yes 2nd (Thru 8/1/11) **Yes 1st (Thru 2/18/10) ***Yes 1st (Thru 7/15/11)	*Yes 1st (Thru 8/1/11)						Under Development
20	Project 2007-17 — Protection System Maintenance & Testing RE-INITIATED	High	PRC-005-2	Yes 1st (Thru 9/28/11)	Yes 1st (Thru 9/28/11)	Yes 1st (Initial Thru 9/28/11)						Under Development
21	Project 2008-10 — Interpretation of CIP-006-1 R1.1 by Progress Energy	No	CIP-006, R1.1	x	x	Yes 2nd (Initial Thru 10/12/09)					Since at least one negative ballot included a comment, the results are not final. A second (or recirculation) ballot must be conducted.	Under Development
22	Project 2009-22 — Interpretation of COM-002-2 R2 by the IRC	High - Interp.	COM-002-2	x	2nd (45 day Formal thru 11/17/11)	Yes 1st (Initial Thru 11/17/11)						Under Development
23	Project 2009-24 — Interpretation of EOP-005-1 R7 by FMPA	No	EOP-005-1, R7	x	x	Yes 1st (Initial Thru 1/15/10)					Balloting Deferred per Standards Committee	Under Development
24	Project 2009-26 — Interpretation of CIP-004-1 by WECC	No	CIP-004-1, R2, R3 and R4	x	x	Yes 1st (Initial Thru 1/19/10)					Balloting Deferred per Standards Committee	Under Development
25	Project 2010-07 — Generator Requirements at the Transmission Interface	High	FAC-001-1, FAC-003-3, FAC-003-X	Yes 1st (Thru 3/15/10)	Yes 3rd (45 Day Formal Thru 11/18/11)	Yes 1st (Initial Thru 11/18/11)						Under Development
26	Project 2010-07 — Generator Requirements at the Transmission Interface	High	PRC-004-2	Yes 1st (Thru 3/15/10)	Yes 1st (45 Day Formal Thru 11/18/11)	Yes 1st (Initial Thru 11/18/11)					9/8/11 - SC waived initial 30 day comment period	Under Development

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Line No.	Project No. / Title	High Priority?	Associated Standard	SAR Posted?	Posted for Comment?	Posted For Ballot?	Industry Approved?	NERC BOT Approved?	Petitioned for FERC Approval?	FERC Approved	Comments	Project Status
27	Project 2010-17 — Definition of Bulk Electric System	High	NERC Glossary Of Terms	Yes 1st (Thru 1/21/11)	- Yes 3rd (Definition Thru 10/10/11) - Yes 2nd (ROP & Tech Principles Thru 10/10/11)	Yes 2nd (Definiton Intitial Thru 10/10/11) Yes 2nd (Tech Principles Thru 10/10/11) Yes 2nd (ROP Thru 10/27/11)						
28	Project 2011-INT-01 Interpretation of MOD-028 for FPL	No	MOD-028	Yes 1st (Thru 11/16/11)	Yes 1st (Thru 11/16/11)	Yes 1st (Thru 11/16/11)						Under Development
29	Project 2007-02 — Operating Personnel Communications Protocols	High	COM-003-1 and COM-002-2	Yes 2nd (Thru 5/2/07)	Yes 1st (Thru 1/15/10)							Under Development
30	Project 2007-06 — System Protection Coordination	High	PRC-001-1	Yes 1st (Thru 7/10/07)	Yes 1st (Thru 10/26/09)							Under Development
31	Project 2007-11 — Disturbance Monitoring	No	PRC-002-1 and PRC-018-1	Yes 1st (Thru 4/20/07)	Yes 1st (Thru 3/18/09)							Under Development
32	Project 2007-12 — Frequency Response	High	BAL-003-1	Yes 3rd (Thru 3/09/07)	Yes 1st (Thru 3/7/11)						Posted for 30 day formal comment period	Under Development
33	Project 2008-12 — Coordinate Interchange Standards	No	INT-004-, INT-006-4, INT-009-2, INT-010-2 and INT-011-1	Yes 1st (Thru 7/31/08)	Yes 1st (Thru 12/11/09)							Under Development
34	Project 2009-01 — Disturbance and Sabotage Reporting	High	EOP-004-2	Yes 1st (Thru 5/21/09)	Yes 2nd (Formal Thru 4/8/11)							Under Development
35	Project 2009-02 — Real-time Reliability Monitoring and Analysis Capabilities	No	"New"	Yes 2nd (Thru 2/18/10)	Yes 1st (Informal Thru 4/4/11)						Concept White Paper posted for informal comment period	Under Development
36	Project 2010-05.1 — Protection Systems: Phase 1 (Misoperations)	High	PRC-004-3	Yes 1st (Informal Thru 7/11/11)	Yes 1st (30 Day Formal Thru 7/11/11)						".1" refers to Phase 1 of the Project	
37	Project 2010-16 — Definition of System Operator	No	NERC Glossary Of Terms	Yes 1st (Thru 12/3/10)	Yes 1st (Thru 12/3/10)							Under Development
38	Project 2010-INT-05 CIP-002-1 Requirement R3 for Duke Energy	No	CIP-002-1, R3	x	Yes 1st (Thru 10/8/10)						To be worked in parallel with Project 2009-26	Under Development
39	Project 2008-01 — Voltage and Reactive planning and control	No	VAR-001 and VAR-002	Yes 2nd (Thru 3/26/10)								Under Development
40	Project 2008-02 — Undervoltage Load Shedding	No	PRC-010-0 and PRC-022-1	Yes 1st (Thru 02/19/10)							June 2010 SC meeting - Project deferred until Higher Priority projects are completed	Project Deferred
41	Project 2009-03 — Emergency Operations	No	EOP-001, EOP-002, EOP-003 and IRO-001	Yes 1st (Thru 1/15/10)								Under Development
42	Project 2009-05 — Resource Adequacy Assessments	No	"New"	Yes 2nd (Thru 3/30/06)								Under Development
43	Project 2009-07 — Reliability of Protection Systems	No	"New"	Yes 1st (Thru 2/18/09)							Pending prioritization - may be postponed	Under Development
44	Project 2009-17 — Interpretation of PRC-004-1 and PRC-005-1 R2 by Y-W Electric and Tri-State G & T	No	PRC-004-1 and PRC-005-1	x	x	Yes 3rd (Recirc Thru 12/3/10)	Yes (12/3/10)	Yes (2/17/11)	Yes (4/15/11)	Yes (9/26/11)		Completed
45	Project 2010-08 — Functional Model Glossary Revisions	No		Yes 1st (Thru 2/22/10)							June 2010 SC meeting - Project deferred until Higher Priority projects are completed	Project Deferred
46	Project 2008-06 — Cyber Security — Order 706 -- CIP Version 5 Standards										Posting for comment and ballot planned for November 2011	Under Development
47	Project 2009-04 — Phasor Measurement Units	No										Project has not started
48	Project 2010-01 — Support Personnel Training	No										Project has not started
49	Project 2010-02 — Connecting New Facilities to the Grid	No										Project has not started
50	Project 2010-03 — Modeling Data	No										Project has not started
51	Project 2010-04 — Demand Data	No										Project has not started
52	Project 2010-06 — Results-based Reliability Standards	No	Results-based Reliability Standards Transistion Plan								Transistion Plan posted 7/26/10	
53	Project 2010-14 — Balancing Authority Reliability-based Control	No									As of July 28, 2010 this project has merges Project 2007-18 - Reliability-based Controls and is now Project 2010-14 - Balancing Authority Reliability-based Control into a single project	Under Development
54	Project 2010-INT-01 Interpretation of TOP-006-2 R1.2 and R3 for FMPP	No	TOP-006-2, R1.2 and R3								Requester has been contacted to see if CAN provides necessary clarication - awaiting response	On Hold
55	Project 2010-INT-02 Interpretation of TOP-003-1 R2 for FMPP	No	TOP-003-1, R2								Requester has been contacted to see if a CAN would satisfy their concerns until the standard is revised - awaiting response	On Hold
56	Project 2010-INT-03 Interpretation of TOP-002-2a R2, R8, and R19 for FMPP	No	TOP-002-2a, R2, R8 and R19								Requester has been contacted to see if a CAN would satisfy their concerns until the standard is revised - awaiting response	On Hold
57	Project 2012-01 Equipment Monitoring and Diagnostic Devices	No	FUTURE									
58	Project 2012-02 Physical Protection	No	FUTURE									
59	Pre-2006 — Operate Within Interconnection Reliability Operating Limits	No	IRO-008-1, IRO-009-1 and IRO-010-1a	Yes 2nd (Thru 9/23/02)	Yes 9th (Thru 4/25/08)	Yes 1st (Recirc Thru 8/21/08)	Yes (8/21/08)	Yes (10/17/08)	Yes (12/31/09)	Yes (3/17/11)	- Order on Rehearing published in Federal Register on July 19, 2011 - Rule published in Federal Register on March 23, 2011	Completed
60	Project 2006-01 — System Personnel Training	No	PER-004-2 and PER-005-1	Yes 2nd (Thru 3/20/06)	Yes 4th (Thru 7/17/08)	Yes 5th (Recirc Thru 12/22/08)	Yes (12/22/08)	Yes (04/01/09)	Yes (9/30/09)	Yes (11/18/10)		Completed
61	Project 2006-03 — System Restoration and Blackstart	No	EOP-001-1, EOP-005-2 and EOP-006-2	Yes 2nd (Thru 3/09/07)	Yes 4 th (Thru 11/18/08)	Yes 5th (Recirc Thru 5/18/09)	Yes (5/18/09)	Yes (8/5/09)	Yes (12/31/09)	Yes (3/17/11)	- Order on Rehearing published in Federal Register on July 19, 2011 (Effective Std EOP-001-2) - Rule published in Federal Register on March 23, 2011	Completed
62	Project 2006-04 — Backup Facilities	No	EOP-008-1	Yes 2nd (Thru 3/16/07)	Yes 5th (Thru 3/8/10)	Yes 7th (Recirc Thru 7/26/10)	Yes (7/26/10)	Yes (8/5/010)	Yes (2/11/11)	Yes (4/21/11)	Posted in Federal Register on 4/28/11	Completed
63	Project 2006-08 — Transmission Loading Relief	No	IRO-006-5 and IRO-006-East-1	Yes (For DT Nomination 1/12/07)	Yes 4th (Thru 11/30/09)	Yes 6th (Recirc Thru 8/30/10)	Yes (8/30/10)	Yes (11/4/10)	Yes (1/13/11)	Yes (4/21/11)		Completed
64	Project 2007-04 — Certifying System Operators	Normal	PER-003-1	Yes 2nd (Thru 1/31/08)	Yes 1st (Thru 11/20/09)	Yes 3rd (Recirc Thru 12/13/10)	Yes (12/31/10)	Yes (2/17/11)	Yes (4/29/11)	Yes (9/15/11)		Completed

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Line No.	Project No. / Title	High Priority?	Associated Standard	SAR Posted?	Posted for Comment?	Posted For Ballot?	Industry Approved?	NERC BOT Approved?	Petitioned for FERC Approval?	FERC Approved	Comments	Project Status
65	Project 2007-05 — Balancing Authority Controls	No	NA	NA	NA	NA	NA	NA	NA	NA	As of July 28, 2010 this project has been merged with Project 2007-18 - Reliability-based Controls and is now Project 2010-14 - Balancing Authority Reliability-based Control	NA
66	Project 2007-17 — Protection System Maintenance & Testing	High	PRC-005-2	Yes 1st (Thru 7/10/07)	Yes 4th (30 day formal Thru 5/12/11)	Yes 8th (Recirculation Thru 6/30/11)	Failed to reach ballot pool aproval	NA	NA	NA	After PRC-005-2 failed to reach ballot pool approval in the recirculation ballot that ended on 6/30/11, the drafting team revised the standard. The Standards Committee authorized re-initiating the project with a posting of the SAR and revised standard for a 45-day comment period, with an initial ballot of the standard conducted during the last 10 days of the comment period.	Re-initiated
67	Project 2007-18 — Reliability-based Control	No	NA	NA	NA	NA	NA	NA	NA	NA	As of July 28, 2010 this project has been merged with Project 2007-18 - Reliability-based Controls and is now Project 2010-14 - Balancing Authority Reliability-based Control	NA
68	Project 2007-23 — Violation Severity Levels	No	Six sets of VSLs for various standards	Yes 2nd "Supp" (Thru 9/16/10)	Yes 6th (Thru 2/18/11)	Yes (Non-Binding Poll Thru 2/18/11	NA - Non Binding Poll Only	Yes (3/10/11)	Yes (3/21/11)	Yes (5/19/11)		Completed
69	Project 2007-24 - Interpretation of TPL-002 and TPL-003	No	TPL-002-0a and TPL-003-0a	x	x	Yes 2nd (Thru 7/7/08)	Yes (7/7/08)	Yes (7/30/08)	Yes (10/24/08)	Yes (4/23/10)		Completed
70	Project 2007-27 — Interpretation of CIP-006 R1.1 by SCE&G	No	CIP-006, R1.1	x	x	Yes (Recirc Thru 12/4/07)	Yes (12/4/07)	Yes (2/12/08)	Yes (12/22/09)	Yes (5/19/11)		Completed
71	Project 2008-06 — Cyber Security — Order 706 (VRFs and VSLs)	No	CIP VRFs and VSLs	x	Yes 1st (Thru 4/20/09)	Yes (Recirc Thru 11/12/09)	Yes (11/12/09)	Yes (12/16/09)	Yes (12/18/09)	Yes (1/20/11)		Completed
72	Project 2008-07 — Interpretation of EOP-002-2 R6.3 and R7.1 by Brookfield Power	No	EOP-002-2, R6.3 and R7.1	x	x	Yes (Recirc Thru 8/31/09)	Yes (8/31/09)	No (Remanded 2/16/10)	NA	NA	2/16/10 NERC BOT: (1) Remands the proposed interpretation of EOP-002-2, Requirements R6.3 and R7.1, to the Standards Committee because the proposed interpretation adds requirements not in the standard, thereby exceeding the permissible scope of an interpretation, and (2) Directs the Standards Committee to initiate action to revise EOP-002-2 as appropriate	NA
73	Project 2008-08 — EOP VSL Revisions	No	EOP family of standards	Yes 1st (Thru 5/19/08)	Yes 2nd (Thru 12/3/09)	Yes (Non-Binding Poll Thru 2/18/11	NA - Non Binding Poll Only	Yes (3/10/11)	Yes (3/21/11)	Yes (5/19/11)		Completed
74	Project 2008-11 — Interpretation of VAR-002a by ICF Consulting	No	VAR-002-1.1b	x	x	Yes (Recirc Thru 1/6/09)	Yes (1/6/09)	Yes (2/10/09)	Yes (3/5/09)	Yes (9/16/10)		Completed
75	Project 2008-15 — Interpretation of CIP-006-1a By US Army Corps of Engineers	No	CIP-006-1a, R4	x	x	Yes (Recirc Thru 2/16/09)	Yes (2/16/09)	Yes (8/5/09)	Yes (12/22/09)	Yes (5/19/11)		Completed
76	Project 2008-18 — Interpretation of TOP-005-1 and IRO-005-1 by Manitoba Hydro	No	TOP-005-1 , R3 and IRO-005-1, R12	x	x	Yes (Recirc Thru 4/27/09)	Yes (4/27/09)	Yes (11/5/09)	Yes (11/24/09)	Yes (4/21/11)	Posted in Federal Register on 4/26/11	Completed
77	Project 2009-08 — Nuclear Plant Interface Coordination	No	NUC-001-2	Yes 1st (Thru 3/18/09)	Yes 1st (Thru 3/18/09)	Yes (Recirc Thru 7/20/09)	Yes (7/20/09)	Yes (8/5/09)	Date?	Yes (1/21/10)		Completed
78	Project 2009-09 — Interpretation of CIP-001-1 by Covanta	No	CIP-001-1a	x	x	Yes (Recirc Thru 10/9/09)	Yes (10/09/09)	Yes (2/16/10)	Yes (4/21/10)	Yes (2/2/11)	Approved by Letter Order	Completed
79	Project 2009-11 — Interpretation of IRO-010-1 R1.2 and R3 by WECC Reliability Coordination Subcommittee	No	IRO-010-1 R1.2 and R3 --> IRO-010-1a	x	x	Yes (Recirc Thru 6/5/09)	Yes (6/5/09)	Yes (8/5/09)	Yes (12/31/09)	Yes (3/17/11)	NOPR issued 11/18/10, Comments were due 1/24/11	Completed
80	Project 2009-12 — Interpretation of CIP-005-1 by PacifiCorp	No	CIP-005-3a	x	x	Yes (Recirc Thru 10/26/09)	Yes (10/26/09)	Yes (2/16/10)	Yes (4/21/10)	Yes (2/2/11)	Approved by Letter Order	Completed
81	Project 2009-13 — interpretation of CIP-006-1 by PacifiCorp	No	CIP-006-2c	x	x	Yes (Recirc Thru 12/23/09)	Yes (12/23/09)	Yes (2/16/10)	Yes (4/20/10)	Yes (7/15/10)		Completed
82	Project 2009-14 — Interpretation of TPL-002-0 R1.3.10 by PacifiCorp	No	TPL-002-0, R1.3.10	x	x	Yes (Recirc Thru 8/6/09)	Yes (8/6/09)	Yes (11/5/09)	Yes (11/17/09)	Yes (9/15/11)	Posted in Federal Register on 9/22/11 - Effective Date: This rule will become effective October 24, 2011	Completed
83	Project 2009-15 — Interpretation of MOD-001-1 R2 and R8 and MOD-029-1 R5 and R6 by NYISO	No	MOD-001-1, R2 and R8 and MOD-029-1 R5 and R6	x	x	Yes (Recirc Thru 7/17/09)	Yes (7/17/09)	Yes (11/5/09)	Yes (12/2/09)	Yes (9/16/10)		Completed
84	Project 2009-16 — Interpretation – CIP-007-1, R2 — Systems Security Management	No	CIP-007-2a	x	x	Yes (Intitial Thru 9/21/09)	Yes (9/21/09)	Yes (11/5/09)	Yes (11/17/09)	Yes (3/18/10)		Completed
85	Project 2009-18 — Withdraw Three Midwest ISO Waivers	No	BAL-006-2 and INT-003-3	x	x	Yes (Intitial Thru 9/8/09)	Yes (9/8/09)	Yes (11/5/09)	Yes (11/20/09)	Yes (1/6/11)		Completed
86	Project 2009-19 — Interpretation of BAL-002-0 R4 and R5 by NWPP Reserve Sharing Group	No	BAL-002-0 R4 and R5	x	x	Yes (Intitial Thru 2/26/10)	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11
87	Project 2009-21 — Cyber Security Ninety-day Response — CIP Family of Standards	No	CIP-002 through CIP-009, V3	Yes 1st (Thru 11/12/09)	Yes 1st (Thru 11/12/09)	Yes (Recirc Thru 12/14/09)	Yes (12/14/09)	Yes	Yes (1/19/10)	Yes (3/18/10)		Completed
88	Project 2009-23 — Interpretation of CIP-004-2 R3 by Army Corps of Engineers	No	CIP-004-2	x	x	Yes 2nd (Intitial Thru 4/8/10)	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11
89	Project 2009-25 — Interpretation of BAL-001-01 and BAL-002-0 by BPA	No	BAL-001-0.1a and BAL-002-0	x	x	Yes 1st (Intitial Thru 1/15/10)	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11
90	Project 2009-29 — Interpretation of TOP-002-2a R6 by FMPP	No	TOP-002-2a, R6	x	x	Yes 1st (Intitial Thru 2/22/10)	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11
91	Project 2009-30 — Interpretation of PRC-001-1 R1 by WPSC	No	PRC-001-1	x	x	Yes 1st (Intitial Thru 2/26/10)	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11
92	Project 2009-31 — Interpretation of TOP-001-1 R8 by FMPP	No	TOP-001-1, R8	x	x	Yes 1st (Intitial Thru 3/16/10)	Yes (3/16/10)	Yes (5/12/10)	Yes (7/16/10)	Yes (9/15/11)	Posted in Federal Register on 9/20/11 - Effective Date: This rule will become effective November 21, 2011	Completed
93	Project 2009-32 — Interpretation of EOP-003-1 R3 and R5 by FMPP	No	EOP-003-1, R3 and R5	x	x	Yes 2nd (Re-ballot Thru 3/31/10)	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11
94	Project 2010-12 — Order 693 Directives	No	BAL-002-1, EOP-002-3, FAC-002-1, MOD-021-1, PRC-004-2 and VAR-001-2	Yes 1st (Thru 7/13/10)	Yes 1st (Thru 7/13/10)	Yes 2nd (Recirc Thru 7/31/10)	Yes (7/31/10)	Yes (8/5/10)	Yes (9/9/10)	Yes (1/10/11)		Completed
95	Project 2010-15 — Urgent Action Revisions to CIP-005-3	Urgent	CIP-005-4	Yes 1st (Thru 9/27/10)	Yes 3rd (Thru 4/28/11)	Yes 3rd (Thru 4/28/11)	NA	NA	NA	NA	Absorbed into Project 2008-06; Project 2010-15 curtailed	Project Curtailed
96	Project 2010-INT-04 Interpretation of EOP-001-1 R2.4 for FMPP	No	EOP-001-1, R2.4	x	x	x	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11

NERC Reliability Standards Executive Tracking Summary

Revised: 10/5/2011

Line No.	Project No. / Title	High Priority?	Associated Standard	SAR Posted?	Posted for Comment?	Posted For Ballot?	Industry Approved?	NERC BOT Approved?	Petitioned for FERC Approval?	FERC Approved	Comments	Project Status

Acronyms:
SAR- Standards Authorization Request
RS- Reliability Standard
DT- Drafting Team
SC - NERC Standards Committee
TBD- To Be Determined
BOT- NERC Board of Trustee

NERC Compliance Application Notice Executive Tracking Summary

Revised: **9/23/2011**

Further details regarding the individual documents may be found at: http://www.nerc.com/page.php?cid=3%7C22%7C354

CAN#	Project No. / Title	Associated Standard or Issue	Requirement	Advance Notice?	Posted for Comment?	Comments Posted?	CAN Issued?	Comments
~~CAN-0001~~	~~INT-004-2 R1: Compliance Application Notice~~	~~INT-004-2~~	~~1~~	~~x~~	~~x~~	~~x~~	~~Yes (5/5/10)~~	Retired August 31, 2011
~~CAN-0002~~	~~TOP-003-0 R1.3: Compliance Application Notice~~	~~TOP-003-0~~	~~1.3~~	~~x~~	~~x~~	~~x~~	~~Yes (5/5/10)~~	Retired August 31, 2011
~~CAN-0003~~	~~IRO-006-4.1 R2: Compliance Application Notice~~	~~IRO-006-4.1~~	~~2~~	~~x~~	~~x~~	~~x~~	~~Yes (5/5/10)~~	Retired August 31, 2011
~~CAN-0004~~	~~IRO-004-1 R3: Compliance Application Notice~~	~~IRO-004-1~~	~~3~~	~~x~~	~~x~~	~~x~~	~~Yes (5/5/10)~~	Retired August 31, 2011
CAN-0005	CIP-002-3 R3: Compliance Application Notice (Revised)	CIP-002-3	3	x	Yes 8/31/11 (Thru 9/21/11) - Revision	x	Yes (7/6/11 - Revised)	Under Revision
CAN-0006	EOP-005-1 R7: Compliance Application Notice	EOP-005-1	7	x	Yes 8/31/11 (Thru 9/21/11) - Revision	x	Yes (10/28/10)	Under Revision
CAN-0007	CIP-004-2 R4.2 and CIP-004-3 R4.2: Compliance Application Notice	CIP-004-2, CIP-004-3	4.2, 4.2	x	Yes 8/31/11 (Thru 9/21/11) - Revision	x	Yes (12/2/10)	Under Revision
CAN-0008	PRC-005-1 R2: Pre-June 18, 2007 Evidence	PRC-005-1	R2 Pre-June 18 evidence	x	Yes 8/31/11 (Thru 9/21/11) - Revision	Yes (4/19/11)	Yes (4/19/11)	Under Revision
CAN-0009	Facility Rating and Design Specifications, FAC-008 and FAC-009	FAC-008 & FAC-009	R1, R1, R2	x	Yes 9/23/11 (Thru 10/14/11)			Under Revision - Originally Issued 1/7/11
CAN-0010	Definition of "Annual"	Definition of "Annual"		x	x	Yes (4/19/11)	Yes (4/19/11)	The definition of "annual" and implementation of annual requirements
CAN-0011	PRC-005-1 R2: New Equipment	PRC-005-1	R2 - new equipment	x	x	Yes (4/19/11)	Yes (4/19/11)	NERC Compliance received a request for clarification on PRC-005-1 R2 regarding gatheriing evidence of initial testing for new equipment
CAN-0012	CAN-0012 Completion of Periodic Activity by Effective Dates			x	Yes 1/21/11 (Thru 2/4/11)	x	Yes (7/18/11)	
CAN-0013	CAN-0013 PRC-023-1 R1 and R2 Effective Dates for Switch-On-To-Fault Schemes	PRC-023		x	Yes 1/21/11 (Thru 2/4/11)	x	Yes (6/17/11)	
CAN-0015	CAN-0015 Unavailability of NERC Tools			x	Yes 2/4/11 (Thru 2/18/11)	x	Yes (7/18/11)	
CAN-0016	CAN-0016 CIP-001-1 R1 - Applicability to Non-BES	CIP-001		x	Yes 8/15/11 (Thru 9/6/11) - Revision	x	Yes (6/17/11)	Under Revision
CAN-0017	Technical and Procedural System Access and Password Controls, CIP-007 R5	CIP-007	R5	x	Yes 9/23/11 (Thru 10/14/11)			Under Revision
CAN-0018	CAN-0018 FAC-008 R.1.2.1 Terminal Equipment	FAC-008		x	Yes 8/31/11 (Thru 9/21/11) - Revision	x	Yes (6/17/11)	Under Revision
CAN-0020	Draft CAN-0020 TPL-002, TPL-003, TPL-004 and TOP-002	TPL-002, TPL-003, TPL-004		x	Yes 4/19/11 (Thru 5/11/11)			
CAN-0022	CAN-0022 VAR-002-1.1b R1 and R3	VAR-002		x	Yes 4/19/11 (Thru 5/11/11)	x	Yes (6/17/11)	
CAN-0024	Draft CAN-0024 CIP-002 through CIP-009 Routable Protocols and Data Diodes	CIP-002 through CIP-009		x	Yes 5/20/11 (Thru 6/10/11)			
CAN-0026	CAN-0026 TOP-006-X R3 Protection Relays	TOP-006		x	Yes 4/19/11 (Thru 5/11/11)	x	Yes (6/17/11)	
CAN-0027	Draft CAN-0027 TOP-003 R1.1 and R2 Generator	TOP-003		x	Yes 4/19/11 (Thru 5/11/11)			
CAN-0028	CAN-0028 TOP-006 R1.2 Reporting	TOP-006		x	Yes 4/19/11 (Thru 5/11/11)	x	Yes (7/18/11)	
CAN-0029	Protection System Misoperations, PRC-004-1 R1, R2, R3	PRC-004	R1, R2, R3	x	Yes 9/23/11 (Thru 10/14/11)			Under Revision
CAN-0030	Draft CAN-0030 Attestations	Attestations		x	Yes 5/20/11 (Thru 6/10/11)			
CAN-0031	Acceptable Opening Dimensions, CIP-005 and CIP-006	CIP-005 and CIP-006		x	Yes 9/23/11 (Thru 10/14/11)			Under Development
CAN-0039	Filing DOE Form OE-417 Event Reports, EOP-004-1	EOP-004		x	Yes 9/23/11 (Thru 10/14/11)			Under Revision
CAN-0021	Draft CAN-0021 COM-002 Definition of Directive and Use of Three-Part Communications	COM-002		Yes (5/9/11)				

Acronyms:

CAN - Compliance Application Notice

NPCC Regional Reliability Standards Executive Tracking Summary

Revised: 10/3/2011

Further details regarding the individual documents may be found at: http://www.npcc.org/regStandards/UnderDev.aspx

Line No.	Regional Standard ID	Regional Reliability Standard Title	RSAR Posted?	Posted for Comment?	Posted For Ballot?	Industry Approved?	NPCC BOD Approved?	NERC BOT Approved?	Petitioned for FERC Approval?	FERC Approved	Comments	Project Status
1	BPS-501-NPCC-01	Classification of Bulk Power System Elements (Withdrawn by RSC 8/07/09)	Yes 1st (Thru 2/4/08)	NA	NA	NA	NA	NA	NA	NA	Withdrawn by RSC 8/07/09	Withdrawn
2	PRC-002-NPCC-01	Disturbance Monitoring	Yes 1st (Thru 9/10/08)	Yes 3rd (Thru 10/24/09)	Yes 1st (Thru 1/6/10)	Yes (1/6/10)	Yes (1/9/10)	Yes (11/4/10)	Yes (5/31/11)			Pending Regulatory Approval
3	PRC-006-NPCC-01	Automatic Underfrequency Load Shedding Program	Yes 1st (Thru 8/25/08)	Yes 4th (Thru 11/2/11)	Yes 2nd (Pre-ballot Thru 11/2/11)						Replaces Directory #12, Under frequency Load Shedding Program Requirements	Under Development
4	BAL-002-NPCC-01	Regional Reserve Sharing	Yes 1st (Thru 11/2/10)									Under Development
5	PRC-012-NPCC-01	Special Protection Systems	Yes 1st (thru 8/18/08)									On Hold
6												
7												
8												
9												
10												

Acronyms:
RSAR- Regional Standards Authorization Request
RRS- Regional Reliability Standard
DT- Drafting Team
SC - NERC Standards Committee
TBD- To Be Determined
BOD- NPCC Board of Directors
BOT- NERC Board of Trustee

NPCC Document Open Process Executive Tracking Summary

Revised: 9/16/2011

Further details regarding the individual documents may be found at: http://www.npcc.org/regStandards/opOther.aspx

Line No.	Type	Document	Description	Effective Date	Comments	Status
1	Criteria	A-01	Criteria for Review and Approval of Documents			
2	Criteria	A-07	Revise Critical Component Definition (Glossary of Tterms)			Open Process - Ballot period ended 9/7/11
3	Criteria	A-10	Classification of BPS Elements			
4	Criteria	A-15	Disturbance Monitoring Equipment Criteria			
5	Guideline	B-01	NPCC Guide for the Application of Autoreclosing to the Bulk Power System			
6	Guideline	B-12	Guidelines for On-Line Computer System Performance During Disturbances			
7	Guideline	B-25	Guide to Time Suynchronization			
8	Guideline	B-26	Guide for Application of Disturbance Recording Equipement			
9	Guideline	B-27	Regional Critical Asset Identification Methodology			
10	Guideline	B-28	Guide for Generator Sequence of Events Monitoring			
11	Procedure	C-00	Listing of NPCC Documents by Type			
12	Procedure	C-01	NPCC Emergency Preparedness Conference Call Procedures - NPCC Security Conference Call Procedures			
13	Procedure	C-05	Monitoring Procedures for Emergency Operation Criteria			
14	Procedure	C-07	Monitoring Procedures for the Guide for Rating Generating Capability			
15	Procedure	C-15	Procedures for Solar Magnetic Disturbances Which Affect Electric Power Systems			
16	Procedure	C-17	Procedures for Monitoring and Reporting Critical Operating Tool Failures			Open Process - comment period ended 7/22/11
17	Procedure	C-21	Monitoring Procedures for Conformance with Normal and Emergency Transfer Limits			
18	Procedure	C-25	Procedure to Collect Power System Event Data			
19	Procedure	C-29	Procedures for System Modeling:Data Requirements and Facility Ratings			
20	Procedure	C-30	Procedure for Task Force on System Protection Review of Disturbances and Protection Misoperations			
21	Procedure	C-33	Procedure for Analysis and Classification of Dynamic Control Systems			Open Process - comment period ended 3/27/11
22	Procedure	C-36	Procedures for Communications During Emergencies			
23	Procedure	C-39	Procedure to Collect Major Disturbance Event Data			
24	Procedure	C-42	Procedure for Reporting and Reviewing System Disturbances			
25	Procedure	C-43	NPCC Operational Review for the Integration of New facilities			
26	Procedure	C-44	NPCC Regional Methodology and Procedures for Forecasting TTC and ATC			
27	Procedure	C-45	Procedure for Analysis and Reporting of Protection System Misoperations	5/25/2011	[C-45 was previously reserved for CO-12 Seasonal Assessment Methodology (previously proposed but not issued - information included in the CO-12 Working Group scope instead)]	
28	Procedure	Cost Effectiveness Analysis Procedure - CEAP				Open Process - Comment period through 9/19/11
29	Glossary	NPCC Glossary of Terms				Open Process - Comment period through 9/12/11
30	Criteria	A-02 (retired)	Basic Criteria for Design and Operation Of Interconnected Power Systems		A2 retired	Directory #1 established
31	Criteria	A-03 (retired)	Emergency Operation Criteria		A3 retired	Directory #2 established
32	Criteria	A-04 (retired)	Maintenance Criteria for Bulk Power System Protection		A4 retired 7/11/2008	Directory #3 established
33	Criteria	A-05 (retired)	Bulk Power System Protection Criteria		A5 retired	Directory #4 established
34	Criteria	A-06 (retired)	Operating Reserve Criteria		A6 retired 12/2/2010	Directory #5 established
35	Criteria	A-08 (retired)	NPCC Reliability Compliance and Enforcement Program		A-08 retired	CCEP-1 established
36	Criteria	A-11 (retired)	Special Protection System Criteria			Directory #7 established
37	Criteria	A-12 (retired)	System Restoration Criteria		A12 draft replaced by Directory #8 10/21/08	Directory #8 established
38	Criteria	A-13 (retired)	NPCC Inc. Verification of Generator Gross and Net Real Power Capability		A13 retired 12/22/2008	
39	Criteria	A-14 (retired)	Verification of Generator Gross and Net Reactive Power Capability		A14 retired 12/22/2008	
40	Guideline	B-02 (retired)	Control Performance Guide		B2 retired	Content transferred to Directory #5 App. 5
41	Guideline	B-03 (retired)	Guidelines for Inter-AREA Voltage Control		B3 retired	Replaced by Procedure C-40

NPCC Document Open Process Executive Tracking Summary

Revised: 9/16/2011

Further details regarding the individual documents may be found at: http://www.npcc.org/regStandards/opOther.aspx

Line No.	Type	Document	Description	Effective Date	Comments	Status
42	Guideline	B-04 (retired)	Guidelines for NPCC Area Transmission Reviews		B4 retired	Content transferred to Directory #1 App.B
43	Guideline	B-05 (retired)	Bulk Power System Protection Guide		B5 retired	Content transferred to Directory #4 App. A
44	Guideline	B-06 (retired)	Automatic Load Shedding Employing Underfrequency Threshold Relays		B6 retired	Replaced by Guideline B-07
45	Guideline	B-07 (retired)	Automatic Underfrequency Load Shedding Program		B7 retired	Content transferred to Directory #4 App. A
46	Guideline	B-08 (retired)	Guidelines for Area Review of Resource Adequacy		B8 retired	Content transferred to Directory #1 App.D
47	Guideline	B-09 (retired)	Guide for Rating Generating Capability		B9 retired	Replaced by Criteria A-13 Document on July 18, 2007
48	Guideline	B-10 (retired)	Guidelines for Requesting Exclusions		B10 retired	Content transferred to Directory #1 App. E
49	Guideline	B-11 (retired)	Special Protection System Guideline		B11 retired	Replaced by Criteria A-11
50	Guideline	B-13 (retired)	Guide for Reporting System Disturbances		B13 retired	Replaced by Procedure C-42
51	Guideline	B-21 (retired)	NPCC Guide for Analysis and Reporting of Protection System Misoperations		Superseded by C-45	Replaced by Procedure C-45
52	Guideline	B-22 (retired)	Guidelines for Implementation of the NPCC Compliance Program		B-22 retired	CCEP-1 established
53	Guideline	B-24 (retired)	Security Guidelines for Protection System IEDS		B24 retired	Content transferred to Directory #4 App. A
54	Procedure	C-03 (retired)			C3 retired	Replaced by Procedure C-36
55	Procedure	C-04 (retired)	Monitoring Procedure for Guides Inter-AREA Volt Control		C4 retired	Content transferred to Directory #1 App. G
56	Procedure	C-08 (retired)	Monitoring Procedures for Control Performance Guide		C8 retired	Content transferred to Directory #5 App. #5
57	Procedure	C-09 (retired)	Monitoring Procedures for Operating Reserve Criteria		C9 retired	Content transferred to Directory #5 App. #2
58	Procedure	C-10 (discontinued)			C10 discontinued	
59	Procedure	C-11 (retired)	Monitoring Procedures for Interconnected System Freq Response		C11 retired	Content transferred to Directory #5 App. #1
60	Procedure	C-12 (retired)	Procedure Shared Activation Ten Minute Reserve		C12 retired	Content transferred to Directory #5 Sect 5.8 & App. #4
61	Procedure	C-13 (retired)	Operational Planning Coordination		C13 retired	Content transferred to Directory #1 App. F
62	Procedure	C-14 (retired)			C14 retired	Procedure C-14 was incorporated in Procedure C-13
63	Procedure	C-16 (retired)	Procedure for Review of New or Modified BPS SPS		C16 retired	Content transferred to Directory #7 App.B
64	Procedure	C-18 (retired)	Procedure for Test & Analysis Extreme Contingencies		C18 retired	Content transferred to Directory #1 App.C
65	Procedure	C-20 (retired)	Procedures During Abnormal Operating Conditions		C20 retired	Content transferred to Directory #5 App. #3
66	Procedure	C-22 (retired)	Procedure for Reporting & Review Proposed BPS Protection Systems		C22 retired	Content transferred to Directory #4 App. A
67	Procedure	C-32 (retired)	Review Process for NPCC Reliability Compliance Enforcement Program		C-32 retired	CCEP-1 established
68	Procedure	C-35 (retired)	NPCC Inter-Area Power System Restoration Procedure		C35 retired	Incorporated within Directory #8 System Restoration
69	Procedure	C-37 (retired)	Operating Procedures for ACE Diversity Interchange		C37 retired	Content transferred to Directory #5 Sect.5.11
70	Procedure	C-38 (retired)	Procedure for Operating Reserve Assistance			Content will be transferred to new Directory #5 Reserve
71	Procedure	C-40 (retired)	Procedures for Inter-AREA Voltage Control		C40 retired	Content transferred to Directory #1 App. G & Directory #2 App. B

Acronyms;

NPCC Directory Executive Tracking Summary

Revised: 9/16/2011 Further details regarding the individual documents may be found at: http://www.npcc.org/regStandards/opOther.aspx

Line No.	Document	Developed From	Description	Version Date	Phase	Task Force Review	Posted Open Process?	RCC Approval?	Full Membership Ballot?	Comments	Status
1	Directory #1	Criteria A-2	Design and Operation of the Bulk Power System	12/1/09 (V0)		Yes 1st (Thru 2/28/11)				TFCO comments due 2/28/11	Revision Under Development
2	Directory #2	Criteria A-3	Emergency Operations	1/6/11 (V3)						V3 - Errata	
3	Directory #3	Criteria A-4	Maintenance Criteria for Bulk Power System Protection	6/3/09 (V1)							
4	Directory #4	Criteria A-5	Bulk Power System Protection Criteria	12/1/09 (V0)							
5	Directory #5	Criteria A-6	Reserve	12/2/10 (V0)						Revision sent to TFCO for review on 1/11/11	Revision Under Development
6	Directory #6		Regional Reserve Sharing				Yes (Thru 10/24/11)			RCC has directed TFCO to develop solutions to regional reserve Sharing issues contained in a new draft Directory on Regional Reserve Sharing.	
7	Directory #7	Criteria A-11	Special Protection Systems	12/27/07 (V0)							
8	Directory #8	Criteria A-12	System Restoration	10/22/10 (V1)							
9	Directory #9	Criteria A-13	Verification of Generator Gross and Net Real Power Capability	7/7/09 (V1)			Yes 2nd (Thru 10/24/11)				Phase 2 Reformatting
10	Directory #10	Criteria A-14	Verification of Generator Gross and Net Reactive Power Capability	7/7/09 (V1)			Yes 2nd (Thru 10/24/11)				Phase 2 Reformatting
11	Directory #11										
12	Directory #12		Under frequency Load Shedding Program Requirements	1/6/11 (V2)			Yes (Thru 1/21/11)			V2 - Errata	Will be replaced by Regional Standard PRC-006-NPCC-01
13	Manual	New	Directory Development and Revison manual				Yes (Thru 9/12/11)				

Acronyms:
MC - Members Committee
RCC - Reliability Coordinating Committee

Revised: 10/21/2011

Tab Name	Last Revised	Summary of Changes
NERC RS Exec Tracking Summary	10/21/2011	- Project 2007-01, Underfrequency Load Shedding -- NOPR issued 10/20/11 - Project 2010-11, TPL Table 1 Order -- NOPR issued 10/20/11 - Project 2006-02, Assess Transmission and Future Needs -- Petitioned for FERC Approval - Project 2009-27, Interpretation of TOP-002-2a R10 by FMPP -- FERC Approved - Project 2007-07, Vegetation Management -- On NERC BOT August Agenda
NERC CANs	10/21/2011	- CAN-0016 revision posted 10/14/11
NPCC RRS Tracking Summary	10/20/2011	- PRC-002-NPCC-01 Disturbance Monitoring -- FERC APPROVED 10/20/11
NPCC Doc Tracking Summary	9/16/2011	- Cost Effectiveness Analysis Procedure (CEAP) - Posted to Open Process - Comment period through 9/19/11
NPCC Directory Tracking Summary	9/16/2011	- Directory #6, #9 and #10 Posted to Open Process - Comment period through 10/24/11

NERC Reliability Standards Executive Tracking Summary

Revised: 10/21/2011

Line No.	Project No. / Title	High Priority?	Associated Standard	SAR Posted?	Posted for Comment?	Posted For Ballot?	Industry Approved?	NERC BOT Approved?	Petitioned for FERC Approval?	FERC Approved	Comments	Project Status
1	Project 2009-17 — Interpretation of PRC-004-1 and PRC-005-1 R2 by Y-W Electric and Tri-State G & T	No	PRC-004-1 and PRC-005-1	x	x	Yes 3rd (Recirc Thru 12/3/10)	Yes (12/3/10)	Yes (2/17/11)	Yes (4/15/11)	Yes (9/26/11)		Completed
2	Project 2009-27 — Interpretation of TOP-002-2a R10 by FMPP	No	TOP-002-2a, R10	x	x	Yes (Recirc Thru 10/16/10)	Yes (10/16/10)	Yes (11/4/10)	Yes (4/15/11)	Yes (10/20/11)		Completed
3	Project 2006-02 — Assess Transmission and Future Needs	High	TPL-001-2	Yes 3rd (Thru 3/16/07)	Yes 5th (Formal Thru 5/31/11)	Yes (Recirculation Thru 7/22/11)	Yes (7/22/11)	Yes (8/4/11)	Yes (10/19/11)			Under Development
4	Project 2007-01 — Underfrequency Load Shedding	No	EOP-003-1 and PRC-006-1	Yes 3rd (Thru 3/29/07)	Yes 3rd (Thru 7/16/10)	Yes 6th (Recirc Thru 10/28/10)	Yes (10/28/10)	Yes (11/4/10)	Yes (3/31/11)		NOPR Issued 10/20/11. NOPR proposes to approve Reliability Standards PRC-006-1 (Automatic Underfrequency Load Shedding) and EOP-003-2 (Load Shedding Plans) submitted by NERC. Comments are due 60 days after publication in the Federal Register.	Pending Regulatory Approval
5	Project 2008-06 — Cyber Security — Order 706 (CIP-002-4)	High	CIP-002-4 thru CIP-009-4	x	Yes 1st (Thru 11/3/10)	Yes Recirc Thru 12/30/10) - passed	Yes (12/30/10)	Yes (1/24/11)	Yes (2/10/11)		- FERC NOPR issued 9/15/11 - NOPR would require NERC to make a filing to fully comply with Order No. 706 by the end of the third quarter of 2012. Comments on the proposed rule (RM11-11) are due 60 days after publication in the Federal Register. - Posted in Federal Register on 9/21/11 - Comments are due 11/21/11	Pending Regulatory Approval
6	Project 2008-09 — Interpretation of EOP-001-0 R1 by Regional Entity Compliance Managers	No	EOP-001-0, R1	x	x	Yes 4th (Recirc Thru 10/14/10)	Yes (10/14/10)	Yes (11/4/10)	Yes (9/9/11)			Pending Regulatory Filing
7	Project 2008-14 — Cyber Security Violation Severity Levels	No	CIP family of standards	Yes 2nd (Thru 04/20/09)	Yes 1st (Thru 04/20/09)	Yes (Recirc Thru 7/16/09)	Yes (7/16/09)	Date?	Date?			Pending Regulatory Approval
8	Project 2009-06 — Facility Ratings	Normal	FAC-008-3 (was FAC-008-2)	Yes 2nd (Thru 9/9/09)	Yes 3rd (Formal Thru 5/2/11)	Yes 6th (Recirculation Thru 5/23/11)	Yes (5/23/11)	Yes (5/24/11)	Yes (6/15/11)		FERC issued an Order on March 17, 2011 that requires NERC to file a version of FAC-008 that addresses all directives from Order 693 related to FAC-008 by June 15, 2011.	
9	Project 2009-10 — Interpretation of PRC-005-1 R1 by Compliance Monitoring Processes Working Group (CMPWG)	No	PRC-005-1, R1	x	x	Yes (Recirc Thru 8/6/09)	Yes (8/6/09)	Yes (11/5/09)	Yes (11/17/09)		NOPR issued 12/16/10 - Comments are due 2/25/11	Pending Regulatory Approval
10	Project 2009-28 — Interpretation of EOP-001-1 and EOP-001-2 R2.2 by FMPP	No	EOP-001-1 and EOP-001-2	x	x	Yes (Recirc Thru 10/15/10)	Yes (10/15/10)	Yes (11/4/10)	Yes (9/9/11)			Pending Regulatory Filing
11	Project 2010-10 — FAC Order 729	No	FAC-013-2	Yes 1st (Thru 4/29/10)	Yes 3rd (Thru 1/8/11)	Yes 3rd (Recirc Thru 1/23/11)	Yes (1/23/11)	Yes (1/24/11)	Yes (1/28/11)			Under Development
12	Project 2010-11 — TPL Table 1 Order	No	TPL-002 Footnote b	Yes 1st (Thru 5/26/10)	Yes 3rd (Thru 1/5/11)	Yes 3rd (Recirc Thru 2/5/11)	Yes (2/5/11)	Yes (2/17/11)	Yes (3/31/11)		- FERC NOPR issued 10/20/11. This Notice of Proposed Rulemaking (NOPR) proposes to remand to NERC its proposed modification to Reliability Standard TPL-002, Table 1, footnote 'b' because it does not adequately clarify or define the circumstances in which an entity can plan to shed firm load for a single contingency. Comments are due 60 days after publication in the Federal Register. - Ref: FERC 3/18/10 Order Setting Deadline for Compliance [Docket RM06-16-009] -- NERC to clarify Std TPL 002-0	Pending Regulatory Approval
13	Project 2010-13 — Relay Loadability Order	Normal	PRC-023-2	Yes 1st (Thru 9/19/10)	Yes 3rd (Thru 12/16/10)	Yes 3rd (Recirculation Thru 3/6/11)	Yes (3/6/11)	Yes (3/10/11)	Yes (3/18/11)		- FERC NOPR issued 9/15/11 - NOPR proposes to approve Reliability Standard PRC-023-2 (Transmission Relay Loadability). The proposed Reliability Standard modifies an existing standard addressing setting protective relays to ensure they reliably detect and protect the electric network from fault conditions but do not limit transmission loadability or interfere with system operators' ability to protect system reliability. - Posted in Federal Register on 9/21/11 - Comments are due 11/21/11	Pending Regulatory Approval
14	Urgent Action SAR for Revision	No	BAL-004-1	Yes 2nd (Thru 10/18/07)	Yes 2nd (Thru 10/18/07)	Yes 1st (Recirc Thru 12/4/07)	Yes (12/4/07)	Yes (3/26/08)	Yes (3/11/09)		- NERC Motion to Further Defer Action Issued 8/11/11 - NERC Motion to Defer Action Issued 8/20/10 - FERC NOPR [Docket RM09-13-000 (March 18, 2010)] - Commission proposes to remand BAL-004-1	Pending Regulatory Approval
15	Project 2006-06 — Reliability Coordination	Normal	COM-001-2, COM-002-3, IRO-001-2 and IRO-014-2 (possibly IRO-003-2 - see comments)	Yes 3rd "Supp" (Thru 9/3/10)	Yes 4th (Thru 3/7/11)	Yes 2nd (Initial Thru 7/25/11)	IRO-002-3 IRO-005-4 IRO-014-2 Yes (7/25/11)	Yes (8/4/11)			DT to address comments on Supplemental SAR. SAR proposes to expand the scope of work under to address some directives from Order 693 that are associated with IRO-003-2	Under Development
16	Project 2010-09 — Cyber Security Order 706B — Nuclear Plant Implementation Plan	No	Various CIP Standards	Yes 1st (Thru 3/15/10)	Yes 1st (Thru 3/15/10)	Yes (Recirc Thru 7/2/10)	Yes (7/2/10)	Yes (8/5/10)				Pending Regulatory Filing
17	Project 2007-07 — Vegetation Management	Normal	FAC-003-2	Yes 3rd (Thru 7/17/07)	Yes 5th (Thru 2/28/11)	Yes 6th (Recirculation Thru 10/13/11)	Yes (10/13/11)				On NERC 11/3/11 BOT agenda	Under Development
18	Project 2009-20 — Interpretation of BAL-003-0 R2 and R5 by Energy Mark, Inc.	No	BAL-003-0.1b	x	x	Yes (Recirc Thru 2/26/10)	Yes (2/26/10)					Under Development
19	Project 2007-03 — Real-time Operations	High	TOP-001-2, TOP-002-3 and TOP-003-2	Yes 2nd (Thru 9/07/07)	Yes 5th (Formal Thru 6/9/11)	Yes 1st (Initial Thru 6/9/11)						Under Development
20	Project 2007-09 — Generator Verification	High	MOD-026-1 and PRC-024-1* MOD-024-2** MOD-025-2, MOD-027-1, PRC-019-1***	Yes 1st (Thru 5/21/07)	*Yes 2nd (Thru 8/1/11) **Yes 1st (Thru 2/18/10) ***Yes 1st (Thru 7/15/11)	*Yes 1st (Thru 8/1/11)						Under Development
21	Project 2007-17 — Protection System Maintenance & Testing RE-INITIATED	High	PRC-005-2	Yes 1st (Thru 9/28/11)	Yes 1st (Thru 9/28/11)	Yes 1st (Initial Thru 9/28/11)						Under Development
22	Project 2008-10 — Interpretation of CIP-006-1 R1.1 by Progress Energy	No	CIP-006, R1.1	x	x	Yes 2nd (Initial Thru 10/12/09)					Since at least one negative ballot included a comment, the results are not final. A second (or recirculation) ballot must be conducted.	Under Development

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Line No.	Project No. / Title	High Priority?	Associated Standard	SAR Posted?	Posted for Comment?	Posted For Ballot?	Industry Approved?	NERC BOT Approved?	Petitioned for FERC Approval?	FERC Approved	Comments	Project Status
23	Project 2009-22 — Interpretation of COM-002-2 R2 by the IRC	High - Interp.	COM-002-2	x	2nd (45 day Formal thru 11/17/11)	Yes 1st (Intitial Thru 11/17/11)						Under Development
24	Project 2009-24 — Interpretation of EOP-005-1 R7 by FMPA	No	EOP-005-1, R7	x	x	Yes 1st (Intitial Thru 1/15/10)					Balloting Deferred per Standards Committee	Under Development
25	Project 2009-26 — Interpretation of CIP-004-1 by WECC	No	CIP-004-1, R2, R3 and R4	x	x	Yes 1st (Intitial Thru 1/19/10)					Balloting Deferred per Standards Committee	Under Development
26	Project 2010-07 — Generator Requirements at the Transmission Interface	High	FAC-001-1, FAC-003-3, FAC-003-X	Yes 1st (Thru 3/15/10)	Yes 3rd (45 Day Formal Thru 11/18/11)	Yes 1st (Intitial Thru 11/18/11)						Under Development
27	Project 2010-07 — Generator Requirements at the Transmission Interface	High	PRC-004-2	Yes 1st (Thru 3/15/10)	Yes 1st (45 Day Formal Thru 11/18/11)	Yes 1st (Intitial Thru 11/18/11)					9/8/11 - SC waived initial 30 day comment period	Under Development
28	Project 2010-17 — Definition of Bulk Electric System	High	NERC Glossary Of Terms	Yes 1st (Thru 1/21/11)	- Yes 3rd (Definition Thru 10/10/11) - Yes 2nd (ROP & Tech Principles Thru 10/10/11)	Yes 2nd (Definiton Intitial Thru 10/10/11) Yes 2nd (Tech Principles Thru 10/10/11) Yes 2nd (ROP Thru 10/27/11)						
29	Project 2011-INT-01 Interpretation of MOD-028 for FPL	No	MOD-028	Yes 1st (Thru 11/16/11)	Yes 1st (Thru 11/16/11)	Yes 1st (Thru 11/16/11)						Under Development
30	Project 2007-02 — Operating Personnel Communications Protocols	High	COM-003-1 and COM-002-2	Yes 2nd (Thru 5/2/07)	Yes 1st (Thru 1/15/10)							Under Development
31	Project 2007-06 — System Protection Coordination	High	PRC-001-1	Yes 1st (Thru 7/10/07)	Yes 1st (Thru 10/26/09)							Under Development
32	Project 2007-11 — Disturbance Monitoring	No	PRC-002-1 and PRC-018-1	Yes 1st (Thru 4/20/07)	Yes 1st (Thru 3/18/09)							Under Development
33	Project 2007-12 — Frequency Response	High	BAL-003-1	Yes 3rd (Thru 3/09/07)	Yes 1st (Thru 3/7/11)						Posted for 30 day formal comment period	Under Development
34	Project 2008-12 — Coordinate Interchange Standards	No	INT-004-, INT-006-4, INT-009-2, INT-010-2 and INT-011-1	Yes 1st (Thru 7/31/08)	Yes 1st (Thru 12/11/09)							Under Development
35	Project 2009-01 — Disturbance and Sabotage Reporting	High	EOP-004-2	Yes 1st (Thru 5/21/09)	Yes 2nd (Formal Thru 4/8/11)							Under Development
36	Project 2009-02 — Real-time Reliability Monitoring and Analysis Capabilities	No	"New"	Yes 2nd (Thru 2/18/10)	Yes 1st (Informal Thru 4/4/11)						Concept White Paper posted for informal comment period	Under Development
37	Project 2010-05.1 — Protection Systems: Phase 1 (Misoperations)	High	PRC-004-3	Yes 1st (Informal Thru 7/11/11)	Yes 1st (30 Day Formal Thru 7/11/11)						".1" refers to Phase 1 of the Project	
38	Project 2010-16 — Definition of System Operator	No	NERC Glossary Of Terms	Yes 1st (Thru 12/3/10)	Yes 1st (Thru 12/3/10)							Under Development
39	Project 2010-INT-05 CIP-002-1 Requirement R3 for Duke Energy	No	CIP-002-1, R3	x	Yes 1st (Thru 10/8/10)						To be worked in parallel with Project 2009-26	Under Development
40	Project 2008-01 — Voltage and Reactive planning and control	No	VAR-001 and VAR-002	Yes 2nd (Thru 3/26/10)								Under Development
41	Project 2008-02 — Undervoltage Load Shedding	No	PRC-010-0 and PRC-022-1	Yes 1st (Thru 02/19/10)							June 2010 SC meeting - Project deferred until Higher Priority projects are completed	Project Deferred
42	Project 2009-03 — Emergency Operations	No	EOP-001, EOP-002, EOP-003 and IRO-001	Yes 1st (Thru 1/15/10)								Under Development
43	Project 2009-05 — Resource Adequacy Assessments	No	"New"	Yes 2nd (Thru 3/30/06)								Under Development
44	Project 2009-07 — Reliability of Protection Systems	No	"New"	Yes 1st (Thru 2/18/09)							Pending prioritization - may be postponed	Under Development
45	Project 2010-08 — Functional Model Glossary Revisions	No		Yes 1st (Thru 2/22/10)							June 2010 SC meeting - Project deferred until Higher Priority projects are completed	Project Deferred
46	Project 2008-06 — Cyber Security — Order 706 -- CIP Version 5 Standards										Posting for comment and ballot planned for November 2011	Under Development
47	Project 2009-04 — Phasor Measurement Units	No										Project has not started
48	Project 2010-01 — Support Personnel Training	No										Project has not started
49	Project 2010-02 — Connecting New Facilities to the Grid	No										Project has not started
50	Project 2010-03 — Modeling Data	No										Project has not started
51	Project 2010-04 — Demand Data	No										Project has not started
52	Project 2010-06 — Results-based Reliability Standards	No	Results-based Reliability Standards Transistion Plan								Transistion Plan posted 7/26/10	
53	Project 2010-14 — Balancing Authority Reliability-based Control	No									As of July 28, 2010 this project has merges Project 2007-18 - Reliability-based Controls and is now Project 2010-14 - Balancing Authority Reliability-based Control into a single project	Under Development
54	Project 2010-INT-01 Interpretation of TOP-006-2 R1.2 and R3 for FMPP	No	TOP-006-2, R1.2 and R3								Requester has been contacted to see if CAN provides necessary clarication - awaiting response	On Hold
55	Project 2010-INT-02 Interpretation of TOP-003-1 R2 for FMPP	No	TOP-003-1, R2								Requester has been contacted to see if a CAN would satisfy their concerns until the standard is revised - awaiting response	On Hold
56	Project 2010-INT-03 Interpretation of TOP-002-2a R2, R8, and R19 for FMPP	No	TOP-002-2a, R2, R8 and R19								Requester has been contacted to see if a CAN would satisfy their concerns until the standard is revised - awaiting response	On Hold
57	Project 2012-01 Equipment Monitoring and Diagnostic Devices	No	FUTURE									
58	Project 2012-02 Physical Protection	No	FUTURE									
59	Pre-2006 — Operate Within Interconnection Reliability Operating Limits	No	IRO-008-1, IRO-009-1 and IRO-010-1a	Yes 2nd (Thru 9/23/02)	Yes 9th (Thru 4/25/08)	Yes 1st (Recirc Thru 8/21/08)	Yes (8/21/08)	Yes (10/17/08)	Yes (12/31/09)	Yes (3/17/11)	- Order on Rehearing published in Federal Register on July 19, 2011 - Rule published in Federal Register on March 23, 2011	Completed
60	Project 2006-01 — System Personnel Training	No	PER-004-2 and PER-005-1	Yes 2nd (Thru 3/20/06)	Yes 4th (Thru 7/17/08)	Yes 5th (Recirc Thru 12/22/08)	Yes (12/22/08)	Yes (04/01/09)	Yes (9/30/09)	Yes (11/18/10)		Completed

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Line No.	Project No. / Title	High Priority?	Associated Standard	SAR Posted?	Posted for Comment?	Posted For Ballot?	Industry Approved?	NERC BOT Approved?	Petitioned for FERC Approval?	FERC Approved	Comments	Project Status
61	Project 2006-03 — System Restoration and Blackstart	No	EOP-001-1, EOP-005-2 and EOP-006-2	Yes 2nd (Thru 3/09/07)	Yes 4 th (Thru 11/18/08)	Yes 5th (Recirc Thru 5/18/09)	Yes (5/18/09)	Yes (8/5/09)	Yes (12/31/09)	Yes (3/17/11)	- Order on Rehearing published in Federal Register on July 19, 2011 (Effective Std EOP-001-2) - Rule published in Federal Register on March 23, 2011	Completed
62	Project 2006-04 — Backup Facilities	No	EOP-008-1	Yes 2nd (Thru 3/16/07)	Yes 5th (Thru 3/8/10)	Yes 7th (Recirc Thru 7/26/10)	Yes (7/26/10)	Yes (8/5/010)	Yes (2/11/11)	Yes (4/21/11)	Posted in Federal Register on 4/28/11	Completed
63	Project 2006-08 — Transmission Loading Relief	No	IRO-006-5 and IRO-006-East-1	Yes (For DT Nomination 1/12/07)	Yes 4th (Thru 11/30/09)	Yes 6th (Recirc Thru 8/30/10)	Yes (8/30/10)	Yes (11/4/10)	Yes (1/13/11)	Yes (4/21/11)		Completed
64	Project 2007-04 — Certifying System Operators	Normal	PER-003-1	Yes 2nd (Thru 1/31/08)	Yes 1st (Thru 11/20/09)	Yes 3rd (Recirc Thru 12/13/10)	Yes (12/31/10)	Yes (2/17/11)	Yes (4/29/11)	Yes (9/15/11)		Completed
65	Project 2007-05 — Balancing Authority Controls	No	NA	NA	NA	NA	NA	NA	NA	NA	As of July 28, 2010 this project has been merged with Project 2007-18 - Reliability-based Controls and is now Project 2010-14 - Balancing Authority Reliability-based Control	NA
66	Project 2007-17 — Protection System Maintenance & Testing	High	PRC-005-2	Yes 1st (Thru 7/10/07)	Yes 4th (30 day formal Thru 5/12/11)	Yes 8th (Recirculation Thru 6/30/11)	Failed to reach ballot pool aproval	NA	NA	NA	After PRC-005-2 failed to reach ballot pool approval in the recirculation ballot that ended on 6/30/11, the drafting team revised the standard. The Standards Committee authorized re-initiating the project with a posting of the SAR and revised standard for a 45-day comment period, with an initial ballot of the standard conducted during the last 10 days of the comment period.	Re-initiated
67	Project 2007-18 — Reliability-based Control	No	NA	NA	NA	NA	NA	NA	NA	NA	As of July 28, 2010 this project has been merged with Project 2007-18 - Reliability-based Controls and is now Project 2010-14 - Balancing Authority Reliability-based Control	NA
68	Project 2007-23 — Violation Severity Levels	No	Six sets of VSLs for various standards	Yes 2nd "Supp" (Thru 9/16/10)	Yes 6th (Thru 2/18/11)	Yes (Non-Binding Poll Thru 2/18/11	NA - Non Binding Poll Only	Yes (3/10/11)	Yes (3/21/11)	Yes (5/19/11)		Completed
69	Project 2007-24 - Interpretation of TPL-002 and TPL-003	No	TPL-002-0a and TPL-003-0a	x	x	Yes 2nd (Thru 7/7/08)	Yes (7/7/08)	Yes (7/30/08)	Yes (10/24/08)	Yes (4/23/10)		Completed
70	Project 2007-27 — Interpretation of CIP-006 R1.1 by SCE&G	No	CIP-006, R1.1	x	x	Yes (Recirc Thru 12/4/07)	Yes (12/4/07)	Yes (2/12/08)	Yes (12/22/09)	Yes (5/19/11)		Completed
71	Project 2008-06 — Cyber Security — Order 706 (VRFs and VSLs)	No	CIP VRFs and VSLs	x	Yes 1st (Thru 4/20/09)	Yes (Recirc Thru 11/12/09)	Yes (11/12/09)	Yes (12/16/09)	Yes (12/18/09)	Yes (1/20/11)		Completed
72	Project 2008-07 — Interpretation of EOP-002-2 R6.3 and R7.1 by Brookfield Power	No	EOP-002-2, R6.3 and R7.1	x	x	Yes (Recirc Thru 8/31/09)	Yes (8/31/09)	No (Remanded 2/16/10)	NA	NA	2/16/10 NERC BOT: (1) Remands the proposed interpretation of EOP-002-2, Requirements R6.3 and R7.1, to the Standards Committee because the proposed interpretation adds requirements not in the standard, thereby exceeding the permissible scope of an interpretation, and (2) Directs the Standards Committee to initiate action to revise EOP-002-2 as appropriate	NA
73	Project 2008-08 — EOP VSL Revisions	No	EOP family of standards	Yes 1st (Thru 5/19/08)	Yes 2nd (Thru 12/3/09)	Yes (Non-Binding Poll Thru 2/18/11	NA - Non Binding Poll Only	Yes (3/10/11)	Yes (3/21/11)	Yes (5/19/11)		Completed
74	Project 2008-11 — Interpretation of VAR-002a by ICF Consulting	No	VAR-002-1.1b	x	x	Yes (Recirc Thru 1/6/09)	Yes (1/6/09)	Yes (2/10/09)	Yes (3/5/09)	Yes (9/16/10)		Completed
75	Project 2008-15 — Interpretation of CIP-006-1a By US Army Corps of Engineers	No	CIP-006-1a, R4	x	x	Yes (Recirc Thru 2/16/09)	Yes (2/16/09)	Yes (8/5/09)	Yes (12/22/09)	Yes (5/19/11)		Completed
76	Project 2008-18 — Interpretation of TOP-005-1 and IRO-005-1 by Manitoba Hydro	No	TOP-005-1 , R3 and IRO-005-1, R12	x	x	Yes (Recirc Thru 4/27/09)	Yes (4/27/09)	Yes (11/5/09)	Yes (11/24/09)	Yes (4/21/11)	Posted in Federal Register on 4/26/11	Completed
77	Project 2009-08 — Nuclear Plant Interface Coordination	No	NUC-001-2	Yes 1st (Thru 3/18/09)	Yes 1st (Thru 3/18/09)	Yes (Recirc Thru 7/20/09)	Yes (7/20/09)	Yes (8/5/09)	Date?	Yes (1/21/10)		Completed
78	Project 2009-09 — Interpretation of CIP-001-1 by Covanta	No	CIP-001-1a	x	x	Yes (Recirc Thru 10/9/09)	Yes (10/09/09)	Yes (2/16/10)	Yes (4/21/10)	Yes (2/2/11)	Approved by Letter Order	Completed
79	Project 2009-11 — Interpretation of IRO-010-1 R1.2 and R3 by WECC Reliability Coordination Subcommittee	No	IRO-010-1 R1.2 and R3 --> IRO-010-1a	x	x	Yes (Recirc Thru 6/5/09)	Yes (6/5/09)	Yes (8/5/09)	Yes (12/31/09)	Yes (3/17/11)	NOPR issued 11/18/10, Comments were due 1/24/11	Completed
80	Project 2009-12 — Interpretation of CIP-005-1 by PacifiCorp	No	CIP-005-3a	x	x	Yes (Recirc Thru 10/26/09)	Yes (10/26/09)	Yes (2/16/10)	Yes (4/21/10)	Yes (2/2/11)	Approved by Letter Order	Completed
81	Project 2009-13 — interpretation of CIP-006-1 by PacifiCorp	No	CIP-006-2c	x	x	Yes (Recirc Thru 12/23/09)	Yes (12/23/09)	Yes (2/16/10)	Yes (4/20/10)	Yes (7/15/10)		Completed
82	Project 2009-14 — Interpretation of TPL-002-0 R1.3.10 by PacifiCorp	No	TPL-002-0, R1.3.10	x	x	Yes (Recirc Thru 8/6/09)	Yes (8/6/09)	Yes (11/5/09)	Yes (11/17/09)	Yes (9/15/11)	Posted in Federal Register on 9/22/11 - Effective Date: This rule will become effective October 24, 2011	Completed
83	Project 2009-15 — Interpretation of MOD-001-1 R2 and R8 and MOD-029-1 R5 and R6 by NYISO	No	MOD-001-1, R2 and R8 and MOD-029-1 R5 and R6	x	x	Yes (Recirc Thru 7/17/09)	Yes (7/17/09)	Yes (11/5/09)	Yes (12/2/09)	Yes (9/16/10)		Completed
84	Project 2009-16 — Interpretation – CIP-007-1, R2 — Systems Security Management	No	CIP-007-2a	x	x	Yes (Intitial Thru 9/21/09)	Yes (9/21/09)	Yes (11/5/09)	Yes (11/17/09)	Yes (3/18/10)		Completed
85	Project 2009-18 — Withdraw Three Midwest ISO Waivers	No	BAL-006-2 and INT-003-3	x	x	Yes (Intitial Thru 9/8/09)	Yes (9/8/09)	Yes (11/5/09)	Yes (11/20/09)	Yes (1/6/11)		Completed
86	Project 2009-19 — Interpretation of BAL-002-0 R4 and R5 by NWPP Reserve Sharing Group	No	BAL-002-0 R4 and R5	x	x	Yes (Intitial Thru 2/26/10)	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11
87	Project 2009-21 — Cyber Security Ninety-day Response — CIP Family of Standards	No	CIP-002 through CIP-009, V3	Yes 1st (Thru 11/12/09)	Yes 1st (Thru 11/12/09)	Yes (Recirc Thru 12/14/09)	Yes (12/14/09)	Yes	Yes (1/19/10)	Yes (3/18/10)		Completed
88	Project 2009-23 — Interpretation of CIP-004-2 R3 by Army Corps of Engineers	No	CIP-004-2	x	x	Yes 2nd (Intitial Thru 4/8/10)	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11
89	Project 2009-25 — Interpretation of BAL-001-01 and BAL-002-0 by BPA	No	BAL-001-0.1a and BAL-002-0	x	x	Yes 1st (Intitial Thru 1/15/10)	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11
90	Project 2009-29 — Interpretation of TOP-002-2a R6 by FMPP	No	TOP-002-2a, R6	x	x	Yes 1st (Intitial Thru 2/22/10)	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11
91	Project 2009-30 — Interpretation of PRC-001-1 R1 by WPSC	No	PRC-001-1	x	x	Yes 1st (Intitial Thru 2/26/10)	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11
92	Project 2009-31 — Interpretation of TOP-001-1 R8 by FMPP	No	TOP-001-1, R8	x	x	Yes 1st (Intitial Thru 3/16/10)	Yes (3/16/10)	Yes (5/12/10)	Yes (7/16/10)	Yes (9/15/11)	Posted in Federal Register on 9/20/11 - Effective Date: This rule will become effective November 21, 2011	Completed

NERC Reliability Standards Executive Tracking Summary

Revised: 10/21/2011

Line No.	Project No. / Title	High Priority?	Associated Standard	SAR Posted?	Posted for Comment?	Posted For Ballot?	Industry Approved?	NERC BOT Approved?	Petitioned for FERC Approval?	FERC Approved	Comments	Project Status
93	Project 2009-32 — Interpretation of EOP-003-1 R3 and R5 by FMPP	No	EOP-003-1, R3 and R5	x	x	Yes 2nd (Re-ballot Thru 3/31/10)	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11
94	Project 2010-12 — Order 693 Directives	No	BAL-002-1, EOP-002-3, FAC-002-1, MOD-021-1, PRC-004-2 and VAR-001-2	Yes 1st (Thru 7/13/10)	Yes 1st (Thru 7/13/10)	Yes 2nd (Recirc Thru 7/31/10)	Yes (7/31/10)	Yes (8/5/10)	Yes (9/9/10)	Yes (1/10/11)		Completed
95	Project 2010-15 — Urgent Action Revisions to CIP-005-3	Urgent	CIP-005-4	Yes 1st (Thru 9/27/10)	Yes 3rd (Thru 4/28/11)	Yes 3rd (Thru 4/28/11)	NA	NA	NA	NA	Absorbed into Project 2008-06; Project 2010-15 curtailed	Project Curtailed
96	Project 2010-INT-04 Interpretation of EOP-001-1 R2.4 for FMPP	No	EOP-001-1, R2.4	x	x	x	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11

Acronyms:
SAR- Standards Authorization Request
RS- Reliability Standard
DT- Drafting Team
SC - NERC Standards Committee
TBD- To Be Determined
BOT- NERC Board of Trustee

NERC Compliance Application Notice Executive Tracking Summary

Revised: **10/21/2011**

Further details regarding the individual documents may be found at: http://www.nerc.com/page.php?cid=3%7C22%7C354

CAN#	Project No. / Title	Associated Standard or Issue	Requirement	Advance Notice?	Posted for Comment?	Comments Posted?	CAN Issued?	Comments
~~CAN-0001~~	~~INT-004-2 R1: Compliance Application Notice~~	~~INT-004-2~~	~~1~~	~~x~~	~~x~~	~~x~~	~~Yes (5/5/10)~~	Retired August 31, 2011
~~CAN-0002~~	~~TOP-003-0 R1.3: Compliance Application Notice~~	~~TOP-003-0~~	~~1.3~~	~~x~~	~~x~~	~~x~~	~~Yes (5/5/10)~~	Retired August 31, 2011
~~CAN-0003~~	~~IRO-006-4.1 R2: Compliance Application Notice~~	~~IRO-006-4.1~~	~~2~~	~~x~~	~~x~~	~~x~~	~~Yes (5/5/10)~~	Retired August 31, 2011
~~CAN-0004~~	~~IRO-004-1 R3: Compliance Application Notice~~	~~IRO-004-1~~	~~3~~	~~x~~	~~x~~	~~x~~	~~Yes (5/5/10)~~	Retired August 31, 2011
CAN-0005	CIP-002-3 R3: Compliance Application Notice (Revised)	CIP-002-3	3	x	Yes 8/31/11 (Thru 9/21/11) - Revision	x	Yes (7/6/11 - Revised)	Under Revision
CAN-0006	EOP-005-1 R7: Compliance Application Notice	EOP-005-1	7	x	Yes 8/31/11 (Thru 9/21/11) - Revision	x	Yes (10/28/10)	Under Revision
CAN-0007	CIP-004-2 R4.2 and CIP-004-3 R4.2: Compliance Application Notice	CIP-004-2, CIP-004-3	4.2, 4.2	x	Yes 8/31/11 (Thru 9/21/11) - Revision	x	Yes (12/2/10)	Under Revision
CAN-0008	PRC-005-1 R2: Pre-June 18, 2007 Evidence	PRC-005-1	R2 Pre-June 18 evidence	x	Yes 8/31/11 (Thru 9/21/11) - Revision	Yes (4/19/11)	Yes (4/19/11)	Under Revision
CAN-0009	Facility Rating and Design Specifications, FAC-008 and FAC-009	FAC-008 & FAC-009	R1, R1, R2	x	Yes 9/23/11 (Thru 10/14/11)			Under Revision - Originally Issued 1/7/11
CAN-0010	Definition of "Annual"	Definition of "Annual"		x	x	Yes (10/10/11)	Yes (4/19/11)	On 10/10/11, RE-DRAFTED CANs posted for 21-Day Industry Comment Period ending 10/31/11
CAN-0011	PRC-005-1 R2: New Equipment	PRC-005-1	R2 - new equipment	x	x	Yes (10/10/11)	Yes (4/19/11)	On 10/10/11, RE-DRAFTED CANs posted for 21-Day Industry Comment Period ending 10/31/11
CAN-0012	CAN-0012 Completion of Periodic Activity by Effective Dates			x	Yes 1/21/11 (Thru 2/4/11)	Yes (10/10/11)	Yes (7/18/11)	On 10/10/11, RE-DRAFTED CANs posted for 21-Day Industry Comment Period ending 10/31/11
CAN-0013	CAN-0013 PRC-023-1 R1 and R2 Effective Dates for Switch-On-To-Fault Schemes	PRC-023		x	Yes 1/21/11 (Thru 2/4/11)	Yes (10/10/11)	Yes (6/17/11)	On 10/10/11, RE-DRAFTED CANs posted for 21-Day Industry Comment Period ending 10/31/11
CAN-0015	CAN-0015 Unavailability of NERC Tools			x	Yes 2/4/11 (Thru 2/18/11)	Yes (10/10/11)	Yes (7/18/11)	On 10/10/11, RE-DRAFTED CANs posted for 21-Day Industry Comment Period ending 10/31/11
CAN-0016	CIP-001 R1 Sabotage Reporting Procedure (Revised)	CIP-001		x	Yes 8/15/11 (Thru 9/6/11) - Revision	Yes (10/14/11)	Yes (10/14/11)	Revised CAN posted 10/14/11
CAN-0017	Technical and Procedural System Access and Password Controls, CIP-007 R5	CIP-007	R5	x	Yes 9/23/11 (Thru 10/14/11)			Under Revision
CAN-0018	CAN-0018 FAC-008 R.1.2.1 Terminal Equipment	FAC-008		x	Yes 8/31/11 (Thru 9/21/11) - Revision	x	Yes (6/17/11)	Under Revision
CAN-0020	Draft CAN-0020 TPL-002, TPL-003, TPL-004 and TOP-002	TPL-002, TPL-003, TPL-004		x	Yes 4/19/11 (Thru 5/11/11)			
CAN-0022	CAN-0022 VAR-002-1.1b R1 and R3	VAR-002		x	Yes 4/19/11 (Thru 5/11/11)	Yes (10/10/11)	Yes (6/17/11)	On 10/10/11, RE-DRAFTED CANs posted for 21-Day Industry Comment Period ending 10/31/11
CAN-0024	Draft CAN-0024 CIP-002 through CIP-009 Routable Protocols and Data Diodes	CIP-002 through CIP-009		x	Yes 5/20/11 (Thru 6/10/11)	Yes (10/10/11)		On 10/10/11, RE-DRAFTED CANs posted for 21-Day Industry Comment Period ending 10/31/11
CAN-0026	CAN-0026 TOP-006-X R3 Protection Relays	TOP-006		x	Yes 4/19/11 (Thru 5/11/11)	Yes (10/10/11)	Yes (6/17/11)	On 10/10/11, RE-DRAFTED CANs posted for 21-Day Industry Comment Period ending 10/31/11
CAN-0027	Draft CAN-0027 TOP-003 R1.1 and R2 Generator	TOP-003		x	Yes 4/19/11 (Thru 5/11/11)			
CAN-0028	CAN-0028 TOP-006 R1.2 Reporting	TOP-006		x	Yes 4/19/11 (Thru 5/11/11)	Yes (10/10/11)	Yes (7/18/11)	On 10/10/11, RE-DRAFTED CANs posted for 21-Day Industry Comment Period ending 10/31/11
CAN-0029	Protection System Misoperations, PRC-004-1 R1, R2, R3	PRC-004	R1, R2, R3	x	Yes 9/23/11 (Thru 10/14/11)			Under Revision
CAN-0030	Draft CAN-0030 Attestations	Attestations		x	Yes 5/20/11 (Thru 6/10/11)			
CAN-0031	Acceptable Opening Dimensions, CIP-005 and CIP-006	CIP-005 and CIP-006		x	Yes 9/23/11 (Thru 10/14/11)			Under Development
CAN-0039	Filing DOE Form OE-417 Event Reports, EOP-004-1	EOP-004		x	Yes 9/23/11 (Thru 10/14/11)			Under Revision
CAN-0021	Draft CAN-0021 COM-002 Definition of Directive and Use of Three-Part Communications	COM-002		Yes (5/9/11)				

Acronyms:
CAN - Compliance Application Notice

NPCC Regional Reliability Standards Executive Tracking Summary

Revised: 10/20/2011

Further details regarding the individual documents may be found at: http://www.npcc.org/regStandards/UnderDev.aspx

Line No.	Regional Standard ID	Regional Reliability Standard Title	RSAR Posted?	Posted for Comment?	Posted For Ballot?	Industry Approved?	NPCC BOD Approved?	NERC BOT Approved?	Petitioned for FERC Approval?	FERC Approved	Comments	Project Status
1	BPS-501-NPCC-01	Classification of Bulk Power System Elements (Withdrawn by RSC 8/07/09)	Yes 1st (Thru 2/4/08)	NA	NA	NA	NA	NA	NA	NA	Withdrawn by RSC 8/07/09	Withdrawn
2	PRC-002-NPCC-01	Disturbance Monitoring	Yes 1st (Thru 9/10/08)	Yes 3rd (Thru 10/24/09)	Yes 1st (Thru 1/6/10)	Yes (1/6/10)	Yes (1/9/10)	Yes (11/4/10)	Yes (5/31/11)	Yes (10/20/11)		Completed
3	PRC-006-NPCC-01	Automatic Underfrequency Load Shedding Program	Yes 1st (Thru 8/25/08)	Yes 4th (Thru 11/2/11)	Yes 2nd (Pre-ballot Thru 11/2/11)						Replaces Directory #12, Under frequency Load Shedding Program Requirements	Under Development
4	BAL-002-NPCC-01	Regional Reserve Sharing	Yes 1st (Thru 11/2/10)									Under Development
5	PRC-012-NPCC-01	Special Protection Systems	Yes 1st (thru 8/18/08)									On Hold
6												
7												
8												
9												
10												

Acronyms:
RSAR- Regional Standards Authorization Request
RRS- Regional Reliability Standard
DT- Drafting Team
SC - NERC Standards Committee
TBD- To Be Determined
BOD- NPCC Board of Directors
BOT- NERC Board of Trustee

NPCC Document Open Process Executive Tracking Summary

Revised: 9/16/2011

Further details regarding the individual documents may be found at: http://www.npcc.org/regStandards/opOther.aspx

Line No.	Type	Document	Description	Effective Date	Comments	Status
1	Criteria	A-01	Criteria for Review and Approval of Documents			
2	Criteria	A-07	Revise Critical Component Definition (Glossary of Tterms)			Open Process - Ballot period ended 9/7/11
3	Criteria	A-10	Classification of BPS Elements			
4	Criteria	A-15	Disturbance Monitoring Equipment Criteria			
5	Guideline	B-01	NPCC Guide for the Application of Autoreclosing to the Bulk Power System			
6	Guideline	B-12	Guidelines for On-Line Computer System Performance During Disturbances			
7	Guideline	B-25	Guide to Time Suynchronization			
8	Guideline	B-26	Guide for Application of Disturbance Recording Equipement			
9	Guideline	B-27	Regional Critical Asset Identification Methodology			
10	Guideline	B-28	Guide for Generator Sequence of Events Monitoring			
11	Procedure	C-00	Listing of NPCC Documents by Type			
12	Procedure	C-01	NPCC Emergency Preparedness Conference Call Procedures - NPCC Security Conference Call Procedures			
13	Procedure	C-05	Monitoring Procedures for Emergency Operation Criteria			
14	Procedure	C-07	Monitoring Procedures for the Guide for Rating Generating Capability			
15	Procedure	C-15	Procedures for Solar Magnetic Disturbances Which Affect Electric Power Systems			
16	Procedure	C-17	Procedures for Monitoring and Reporting Critical Operating Tool Failures			Open Process - comment period ended 7/22/11
17	Procedure	C-21	Monitoring Procedures for Conformance with Normal and Emergency Transfer Limits			
18	Procedure	C-25	Procedure to Collect Power System Event Data			
19	Procedure	C-29	Procedures for System Modeling:Data Requirements and Facility Ratings			
20	Procedure	C-30	Procedure for Task Force on System Protection Review of Disturbances and Protection Misoperations			
21	Procedure	C-33	Procedure for Analysis and Classification of Dynamic Control Systems			Open Process - comment period ended 3/27/11
22	Procedure	C-36	Procedures for Communications During Emergencies			
23	Procedure	C-39	Procedure to Collect Major Disturbance Event Data			
24	Procedure	C-42	Procedure for Reporting and Reviewing System Disturbances			
25	Procedure	C-43	NPCC Operational Review for the Integration of New facilities			
26	Procedure	C-44	NPCC Regional Methodology and Procedures for Forecasting TTC and ATC			
27	Procedure	C-45	Procedure for Analysis and Reporting of Protection System Misoperations	5/25/2011	[C-45 was previously reserved for CO-12 Seasonal Assessment Methodology (previously proposed but not issued - information included in the CO-12 Working Group scope instead)]	
28	Procedure	Cost Effectiveness Analysis Procedure - CEAP				Open Process - Comment period through 9/19/11
29	Glossary	NPCC Glossary of Terms				Open Process - Comment period through 9/12/11
30	Criteria	A-02 (retired)	Basic Criteria for Design and Operation Of Interconnected Power Systems		A2 retired	Directory #1 established
31	Criteria	A-03 (retired)	Emergency Operation Criteria		A3 retired	Directory #2 established
32	Criteria	A-04 (retired)	Maintenance Criteria for Bulk Power System Protection		A4 retired 7/11/2008	Directory #3 established
33	Criteria	A-05 (retired)	Bulk Power System Protection Criteria		A5 retired	Directory #4 established
34	Criteria	A-06 (retired)	Operating Reserve Criteria		A6 retired 12/2/2010	Directory #5 established
35	Criteria	A-08 (retired)	NPCC Reliability Compliance and Enforcement Program		A-08 retired	CCEP-1 established
36	Criteria	A-11 (retired)	Special Protection System Criteria			Directory #7 established
37	Criteria	A-12 (retired)	System Restoration Criteria		A12 draft replaced by Directory #8 10/21/08	Directory #8 established
38	Criteria	A-13 (retired)	NPCC Inc. Verification of Generator Gross and Net Real Power Capability		A13 retired 12/22/2008	
39	Criteria	A-14 (retired)	Verification of Generator Gross and Net Reactive Power Capability		A14 retired 12/22/2008	
40	Guideline	B-02 (retired)	Control Performance Guide		B2 retired	Content transferred to Directory #5 App. 5
41	Guideline	B-03 (retired)	Guidelines for Inter-AREA Voltage Control		B3 retired	Replaced by Procedure C-40

NPCC Document Open Process Executive Tracking Summary

Revised: 9/16/2011

Further details regarding the individual documents may be found at: http://www.npcc.org/regStandards/opOther.aspx

Line No.	Type	Document	Description	Effective Date	Comments	Status
42	Guideline	B-04 (retired)	Guidelines for NPCC Area Transmission Reviews		B4 retired	Content transferred to Directory #1 App.B
43	Guideline	B-05 (retired)	Bulk Power System Protection Guide		B5 retired	Content transferred to Directory #4 App. A
44	Guideline	B-06 (retired)	Automatic Load Shedding Employing Underfrequency Threshold Relays		B6 retired	Replaced by Guideline B-07
45	Guideline	B-07 (retired)	Automatic Underfrequency Load Shedding Program		B7 retired	Content transferred to Directory #4 App. A
46	Guideline	B-08 (retired)	Guidelines for Area Review of Resource Adequacy		B8 retired	Content transferred to Directory #1 App.D
47	Guideline	B-09 (retired)	Guide for Rating Generating Capability		B9 retired	Replaced by Criteria A-13 Document on July 18, 2007
48	Guideline	B-10 (retired)	Guidelines for Requesting Exclusions		B10 retired	Content transferred to Directory #1 App. E
49	Guideline	B-11 (retired)	Special Protection System Guideline		B11 retired	Replaced by Criteria A-11
50	Guideline	B-13 (retired)	Guide for Reporting System Disturbances		B13 retired	Replaced by Procedure C-42
51	Guideline	B-21 (retired)	NPCC Guide for Analysis and Reporting of Protection System Misoperations		Superseded by C-45	Replaced by Procedure C-45
52	Guideline	B-22 (retired)	Guidelines for Implementation of the NPCC Compliance Program		B-22 retired	CCEP-1 established
53	Guideline	B-24 (retired)	Security Guidelines for Protection System IEDS		B24 retired	Content transferred to Directory #4 App. A
54	Procedure	C-03 (retired)			C3 retired	Replaced by Procedure C-36
55	Procedure	C-04 (retired)	Monitoring Procedure for Guides Inter-AREA Volt Control		C4 retired	Content transferred to Directory #1 App. G
56	Procedure	C-08 (retired)	Monitoring Procedures for Control Performance Guide		C8 retired	Content transferred to Directory #5 App. #5
57	Procedure	C-09 (retired)	Monitoring Procedures for Operating Reserve Criteria		C9 retired	Content transferred to Directory #5 App. #2
58	Procedure	C-10 (discontinued)			C10 discontinued	
59	Procedure	C-11 (retired)	Monitoring Procedures for Interconnected System Freq Response		C11 retired	Content transferred to Directory #5 App. #1
60	Procedure	C-12 (retired)	Procedure Shared Activation Ten Minute Reserve		C12 retired	Content transferred to Directory #5 Sect 5.8 & App. #4
61	Procedure	C-13 (retired)	Operational Planning Coordination		C13 retired	Content transferred to Directory #1 App. F
62	Procedure	C-14 (retired)			C14 retired	Procedure C-14 was incorporated in Procedure C-13
63	Procedure	C-16 (retired)	Procedure for Review of New or Modified BPS SPS		C16 retired	Content transferred to Directory #7 App.B
64	Procedure	C-18 (retired)	Procedure for Test & Analysis Extreme Contingencies		C18 retired	Content transferred to Directory #1 App.C
65	Procedure	C-20 (retired)	Procedures During Abnormal Operating Conditions		C20 retired	Content transferred to Directory #5 App. #3
66	Procedure	C-22 (retired)	Procedure for Reporting & Review Proposed BPS Protection Systems		C22 retired	Content transferred to Directory #4 App. A
67	Procedure	C-32 (retired)	Review Process for NPCC Reliability Compliance Enforcement Program		C-32 retired	CCEP-1 established
68	Procedure	C-35 (retired)	NPCC Inter-Area Power System Restoration Procedure		C35 retired	Incorporated within Directory #8 System Restoration
69	Procedure	C-37 (retired)	Operating Procedures for ACE Diversity Interchange		C37 retired	Content transferred to Directory #5 Sect.5.11
70	Procedure	C-38 (retired)	Procedure for Operating Reserve Assistance			Content will be transferred to new Directory #5 Reserve
71	Procedure	C-40 (retired)	Procedures for Inter-AREA Voltage Control		C40 retired	Content transferred to Directory #1 App. G & Directory #2 App. B

Acronyms;

NPCC Directory Executive Tracking Summary

Revised: 9/16/2011 Further details regarding the individual documents may be found at: http://www.npcc.org/regStandards/opOther.aspx

Line No.	Document	Developed From	Description	Version Date	Phase	Task Force Review	Posted Open Process?	RCC Approval?	Full Membership Ballot?	Comments	Status
1	Directory #1	Criteria A-2	Design and Operation of the Bulk Power System	12/1/09 (V0)		Yes 1st (Thru 2/28/11)				TFCO comments due 2/28/11	Revision Under Development
2	Directory #2	Criteria A-3	Emergency Operations	1/6/11 (V3)						V3 - Errata	
3	Directory #3	Criteria A-4	Maintenance Criteria for Bulk Power System Protection	6/3/09 (V1)							
4	Directory #4	Criteria A-5	Bulk Power System Protection Criteria	12/1/09 (V0)							
5	Directory #5	Criteria A-6	Reserve	12/2/10 (V0)						Revision sent to TFCO for review on 1/11/11	Revision Under Development
6	Directory #6		Regional Reserve Sharing				Yes (Thru 10/24/11)			RCC has directed TFCO to develop solutions to regional reserve Sharing issues contained in a new draft Directory on Regional Reserve Sharing.	
7	Directory #7	Criteria A-11	Special Protection Systems	12/27/07 (V0)							
8	Directory #8	Criteria A-12	System Restoration	10/22/10 (V1)							
9	Directory #9	Criteria A-13	Verification of Generator Gross and Net Real Power Capability	7/7/09 (V1)			Yes 2nd (Thru 10/24/11)				Phase 2 Reformatting
10	Directory #10	Criteria A-14	Verification of Generator Gross and Net Reactive Power Capability	7/7/09 (V1)			Yes 2nd (Thru 10/24/11)				Phase 2 Reformatting
11	Directory #11										
12	Directory #12		Under frequency Load Shedding Program Requirements	1/6/11 (V2)			Yes (Thru 1/21/11)			V2 - Errata	Will be replaced by Regional Standard PRC-006-NPCC-01
13	Manual	New	Directory Development and Revison manual				Yes (Thru 9/12/11)				

Acronyms:
MC - Members Committee
RCC - Reliability Coordinating Committee

From:	Elizabeth Heenan
To:	reg_corresp_notif
Subject:	NERC: FERC Summaries and Press Release regarding Orders issued today following FERC Sunshine Open Meeting
Date:	Thursday, September 15, 2011 2:41:58 PM
Attachments:	Press Release E-1, E-4, and E-5.pdf

To NERC Management and Regional Entity Executives:

Attached please find a FERC News Release concerning agenda items E-1, E-4, and E-5. Below, please find summaries of the remaining agenda items from today's FERC Sunshine Open Meeting.

FERC grants in part requests for clarification and denies requests for rehearing
E-3, *North American Electric Reliability Corporation,* Docket No. RM08-13-004. This order grants, in part, requests for clarification, and denies requests for rehearing with respect to the February 17, 2010 Order on Rehearing, Clarification and Request for an Extension of Time which dealt with issues arising out of the approval of Transmission Relay Loadability Reliability Standard PRC-023-1. Petitioners argue that the Commission failed to give "due weight" to NERC's technical expertise and challenge the technical reasoning behind several of the Commission's directives and interpretations. This order affirms the Commission's precedent that a directive to submit a new or modified Reliability Standard entitles NERC to develop an equally efficient and effective alternative.

FERC proposes to modify standards for transmission relay loadability
E-6, Transmission Relay Loadability Reliability Standard, Docket No. RM11-16-000. This Notice of Proposed Rulemaking proposes to approve Reliability Standard PRC-023-2 (Transmission Relay Loadability). The proposed Reliability Standard modifies an existing standard addressing setting protective relays to ensure they reliably detect and protect the electric network from fault conditions but do not limit transmission loadability or interfere with system operators' ability to protect system reliability.

FERC approves reliability standards that address operating personnel credentials
E-7, *North American Electric Reliability Corporation*, Docket No. RD11-7-000. This order approves Reliability Standard, PER-003-1 (Operating Personnel Credentials). This Reliability Standard requires reliability coordinators, transmission operators, and balancing authorities to ensure that system operators performing reliability-related tasks are certified through the NERC System Operator Certification Program when filling a real-time operating position responsible for control of the Bulk Electric System. The order also approves the retirement of currently effective Reliability Standard, PER-003-0, which will be superseded by PER-003-1.

Thank you,

Elizabeth A. Heenan
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September 15, 2011
News Media Contact
Craig Cano | 202-502-8680
Docket Nos. (RM11-11-000, RM10-29-000, RM10-6-000)

FEDERAL ENERGY REGULATORY COMMISSION NEWS

FERC Takes Steps to Support Continued Reliability of Electric Grid

The Federal Energy Regulatory Commission (FERC) took steps to support continued transmission system reliability by proposing revisions to eight critical infrastructure protection reliability standards that include a new method of identifying cyber assets that are critical to the nation's bulk power grid.

The proposed "Version 4" CIP standards are an interim step, FERC said in directing the electric industry and the North American Electric Reliability Corp. (NERC) to continue developing a comprehensive approach to assure the grid can withstand a cyber security incident. NERC is the Commission-certified electric reliability organization responsible for developing and enforcing mandatory reliability standards.

The new standard would replace the existing risk-based assessment methodology for identifying critical assets with 17 uniform "bright line" criteria, making the process more consistent and clear by limiting discretion in the identification of such assets.

Today's notice of proposed rulemaking (NOPR) stressed that NERC has not addressed all the modifications directed by the Commission's Order No. 706, which approved the original CIP standards in January 2008. The NOPR would require NERC to make a filing to fully comply with Order No. 706 by the end of the third quarter of 2012. Comments on the proposed rule (RM11-11) are due 60 days after publication in the *Federal Register*.

In other reliability orders, FERC issued final rules approving NERC's interpretation of:

- Transmission Operations Reliability Standard TOP-001-1 on the restoration of real and reactive power during a system emergency (RM10-29). The final rule agreed with NERC's view that the balancing authority is responsible for restoring real power balance and the transmission provider is responsible for restoring reactive balance during a system emergency.

- Transmission Planning Reliability Standard TPL-002-0 addressing system performance following loss of a single bulk electric system element (RM10-6).

R-11-39

(30)

September 2011
Meeting Summaries

These are summaries of orders voted by the Federal Energy Regulatory Commission at its September 15, 2011 public meeting. The summaries are produced by FERC's Office of External Affairs and are intended to provide only a general synopsis of the orders. These are not intended as a substitute for the Commission's official orders. To determine the specific actions and the Commission's reasoning, please consult the individual orders when they are posted to FERC's eLibrary found at www.ferc.gov.

E-1, Press Release

FERC grants in part requests for clarification and denies requests for rehearing

E-3, *North American Electric Reliability Corporation*, Docket No. RM08-13-004. This order grants, in part, requests for clarification, and denies requests for rehearing with respect to the February 17, 2010 Order on Rehearing, Clarification and Request for an Extension of Time which dealt with issues arising out of the approval of Transmission Relay Loadability Reliability Standard PRC-023-1. Petitioners argue that the Commission failed to give "due weight" to NERC's technical expertise and challenge the technical reasoning behind several of the Commission's directives and interpretations. This order affirms the Commission's precedent that a directive to submit a new or modified Reliability Standard entitles NERC to develop an equally efficient and effective alternative.

E-4 & E-5, Press Release

FERC proposes to modify standards for transmission relay loadability

E-6, *Transmission Relay Loadability Reliability Standard*, Docket No. RM11-16-000. This Notice of Proposed Rulemaking proposes to approve Reliability Standard PRC-023-2 (Transmission Relay Loadability). The proposed Reliability

Standard modifies an existing standard addressing setting protective relays to ensure they reliably detect and protect the electric network from fault conditions but do not limit transmission loadability or interfere with system operators' ability to protect system reliability.

FERC approves reliability standards that address operating personnel credentials

E-7, *North American Electric Reliability Corporation*, Docket No. RD11-7-000. This order approves Reliability Standard, PER-003-1 (Operating Personnel Credentials). This Reliability Standard requires reliability coordinators, transmission operators, and balancing authorities to ensure that system operators performing reliability-related tasks are certified through the NERC System Operator Certification Program when filling a real-time operating position responsible for control of the Bulk Electric System. The order also approves the retirement of currently effective Reliability Standard, PER-003-0, which will be superseded by PER-003-1.

FERC conditionally accepts proposed credit-reform related tariff revisions

E-8, *Midwest Independent Transmission System Operator, Inc.*, Docket No. ER11-3970-000. The order conditionally accepts MISO's proposed tariff revisions and generally finds that MISO's proposed tariff revisions comply with the directives of Order Nos. 741 and 741-A. However, acceptance is conditioned upon MISO's filing a further compliance filing, principally to establish periodic compliance verification for market participants' risk management policies and procedures.

FERC denies, without prejudice, request for standards of conduct waiver

E-9, *Bangor Hydro Electric Company*, Docket No. TS11-5-000. The order denies, without prejudice, Bangor Hydro Electric Company's request for waiver of the Standards of Conduct to permit its transmission function employees to engage in actions necessary to effectuate spot market resales of energy in the ISO New England, Inc. real-time market.

FERC conditionally accepts proposed credit-reform related tariff revisions

E-10, *Southwest Power Pool, Inc.*, Docket No. ER11-3967-000. The order conditionally accepts SPP's proposed tariff revisions and generally finds that SPP's proposed tariff revisions comply with the directives of Order Nos. 741 and 741-A. However, acceptance is conditioned upon SPP's filing a further compliance filing, principally to establish periodic compliance verification for market participants' risk management policies and procedures.

FERC denies clarification and rehearing

E-11, *PJM Interconnection, L.L.C. and Trans-Allegheny Interstate Line Company*, Docket No. ER11-3064-001. This order denies clarification and rehearing to one of the underlying co-applicants, Trans-Allegheny Interstate Line Company, regarding an allocation issue not presented by the underlying rate request. The order concludes that this allocation issue, arising under the PJM tariff at Schedule 12 (addressing the system-wide allocation of transmission project costs), is beyond the scope of this proceeding.

FERC conditionally accepts proposed credit-reform related tariff revisions

E-12, *PJM Interconnection, L.L.C.*, Docket No. ER11-3972-000. The order conditionally accepts PJM's proposed tariff revisions and generally finds that PJM's proposed tariff revisions comply with the directives of Order Nos. 741 and 741-A. However, acceptance is conditioned upon PJM's filing a further compliance filing, principally to establish periodic compliance verification for market participants' risk management policies and procedures.

FERC conditionally accepts proposed credit-reform related tariff revisions

E-13, *ISO New England Inc. and New England Power Pool*, Docket No. ER11-3953-000. The order conditionally accepts ISO-NE's proposed tariff revisions and generally finds that ISO-NE's proposed tariff revisions comply with the directives of Order Nos. 741 and 741-A. However, acceptance is conditioned upon ISO-NE's filing a further compliance filing, principally to establish periodic compliance verification for market participants' risk management policies and procedures.

FERC accepts compliance filing, subject to a further compliance filing

E-14, *New York Independent System Operator, Inc.*, Docket Nos. ER11-2224-004, ER11-2224-005, ER11-2224-009. The order addresses two compliance filings by NYISO regarding the implementation of new Installed Capacity (ICAP) demand curve rates for the 2011/2012, 2012/2013, and 2013/2014 capability periods. The order accepts NYISO's compliance filing with regard to the inclusion of property tax abatement in the NYC demand curve. The order also accepts NYISO's additional explanation and support for demand curve input assumptions regarding System Deliverability Upgrade costs, System Upgrade Facility costs, and assumed levels of excess capacity. The order rejects NYISO's explanation regarding its preferred method of calculating the winter/summer adjustment and directs NYISO to calculate the adjustment based on the assumed level of excess capacity.

FERC conditionally accepts proposed credit-reform related tariff revisions

E-15, *New York Independent System Operator, Inc.*, Docket Nos. ER11-3949-000, *et al*. The order conditionally accepts NYISO's proposed tariff revisions and generally finds that NYISO's proposed tariff revisions comply with the directives of Order Nos. 741 and 741-A. However, acceptance is conditioned upon NYISO's filing a further compliance filing, principally to establish periodic compliance verification for market participants' risk management policies and procedures.

FERC conditionally accepts proposed credit-reform related tariff revisions

E-16, *California Independent System Operator Corporation*, Docket No. ER11-3973-000. The order conditionally accepts CAISO's proposed tariff revisions and generally finds that CAISO's proposed tariff revisions comply with the directives of Order Nos. 741 and 741-A. However, acceptance is conditioned upon CAISO's filing a further compliance filing, principally to establish periodic compliance verification for market participants' risk management policies and procedures. Acceptance is also conditioned upon CAISO submitting a further compliance filing to revise its tariff to recognize a letter from a federal agency acknowledging its financial obligations as adequate financial security for the agency to participate in CAISO's congestion revenue rights market.

FERC dismisses requests for clarification and rehearing

E-17, *Idaho Wind Partners 1, LLC,* Docket No. EL11-12-002. This order dismisses Avista Corporation's June 20, 2011 request for clarification or, in the alternative, rehearing of the Commission's May 19, 2011 order as an untimely request for rehearing of an earlier March 17, 2011 order. The March 17, 2011 order held that, once a Qualifying Facility (QF) sells its energy to a third party QF, and then re-purchases that energy un-commingled with any non-QF energy, the QF energy would remain QF energy after the simultaneous sale to and buy-back from the third-party QF and thus may be sold to an electric utility pursuant to the PURPA mandatory purchase obligation at PURPA avoided cost rates. The order also reiterated that, under PURPA, the sale and trading of Renewable Energy Credits is a matter for the states, and not the Commission, to address.

FERC proposes eliminating certain reporting requirements for storage facilities

G-1, *Storage Reporting Requirements of Interstate and Intrastate Natural Gas Companies,* Docket No. RM11-4-000. The Notice of Proposed Rulemaking proposes to eliminate the semi-annual storage reporting requirements for interstate and intrastate natural gas companies that are currently required by the Commission's regulations. The order finds that the reports proposed for elimination are largely duplicative of other reporting requirements.

FERC grants in part and denies in part rehearing requests

H-1, *Duke Energy Carolinas, LLC,* Project Nos. 2698-050 and 2686-062. The order grants in part and denies in part the licensee's rehearing requests of two Commission orders issuing licenses for the 26.175-megawatt East Fork Hydroelectric Project No. 2698 and the 24.6-MW West Fork Hydroelectric Project No. 2686, located on the East and West Forks of the Tuckasegee River in Jackson County, North Carolina.

FERC denies motion for stay

H-2, *Grand Coulee Project Hydroelectric Authority*, Project No. 13681-002. The order denies a motion for stay, pending judicial review, of the Commission's December 14, 2010 order dismissing the Grand Coulee Project Hydroelectric Authority's application for a preliminary permit to study the proposed North Dam Pumped Storage Project. The underlying order concluded that the project would

use the same water resource as a project for which a preliminary permit had already been issued to another entity. The project would have been located in part at Banks Lake, which is a component of the U.S. Bureau of Reclamation's Columbia Basin Project in Washington.

FERC denies rehearing

H-3, *Woodland Pulp LLC*, Docket No. DI10-0-001. The order denies Woodland Pulp LLC's rehearing request of the July 19, 2011 declaratory order, issued by the Director of the Commission's Office of Energy Projects, which found that Woodland Pulp's storage projects on the St. Croix River in Maine contribute to generation at downstream projects and are required to be licensed. The Commission's order affirms the Director's disposition of this matter, which was consistent with prior Commission orders regarding these projects that have been affirmed on judicial review.

FERC issues certificates and grants abandonment authority for natural gas facilities in NY and PA

C-1, *Tennessee Gas Pipeline Company and Dominion Transmission, Inc.*, Docket Nos. CP11-30-000 and CP11-41-000. This order grants authorization to Dominion Transmission, Inc. to abandon by lease 150,000 dekatherms per day of transportation capacity to Tennessee Gas Pipeline Company. The order also grants Dominion authorization to construct and operate its proposed Ellisburg to Craigs Project located in Wyoming and Livingston counties in New York, and Potter County, Pennsylvania to provide the capacity for Tennessee's lease, and it grants Tennessee authorization to construct and operate its Northeast Supply Diversification Project, consisting of 6.77 miles of pipeline and compression facilities to be located in northern Pennsylvania and western New York.

FERC approves abandonment of two compressor stations

C-2, *El Paso Natural Gas Company*, Docket No. CP10-510-000. The order authorizes El Paso Natural Gas Co. to abandon in place two compressor stations – one located in Luna County, NM, the other in Pima County, AZ - on its South Mainline System because the stations are no longer needed to provide firm transportation service to El Paso's existing customers. The order states the abandonment will result in no adverse impact on existing customers and will enable El Paso to avoid repair and maintenance costs for the old and obsolete compressor units.

The order denies several protests alleging that El Paso provided insufficient information regarding current and future throughput on its system to justify abandoning the compressor stations. The order finds that the flow diagrams El Paso filed with its application and its description of the changes that have occurred on its system justify the abandonment with respect to current firm transportation requirements. The lack of response to El Paso's open season for capacity on the South Mainline System supports El Paso's claim that there will not be a future impact on its firm transportation services. Finally, the order denies requests for consolidating this proceeding with El Paso's section 4 rate proceeding and a request for an evidentiary hearing.

From: Philip A. Fedora
To: grpStaff
Subject: September 2011 FERC Open Meeting Summary
Date: Friday, September 16, 2011 11:57:20 AM
Attachments: 20110915124104-summaries.pdf

FYI - See attached.

Phil

The Commission acted on the following Electric items at the September 15, 2011 Commission Meeting:

This page lists only those consent items that were voted on and selected for Fast track treatment. It will be replaced once the Commission issues the "Notice of Action Taken" that will contain all items the Commission voted on.

Item #	Docket #	Company
E-1	RM11-11-000	Version 4 Critical Infrastructure Protection Reliability Standards
E-3	RM08-13-004	Transmission Relay Loadability Reliability Standard
E-4	RM10-6-000	Interpretation of Transmission Planning Reliability Standard
E-5	RM10-29-000	Electric Reliability Organization Interpretation of Transmission Operations Reliability Standard
E-6	RM11-16-000	Transmission Relay Loadability Reliability Standard
E-7	RD11-7-000	North American Electric Reliability Corporation
E-8	ER11-3970-000	Midwest Independent Transmission System Operator, Inc.
E-9	TS11-5-000	Bangor Hydro Electric Company
E-10	ER11-3967-000	Southwest Power Pool, Inc.
E-11	ER11-3064-001	PJM Interconnection, L.L.C. and Trans-Allegheny Interstate Line Company
E-12	ER11-3972-000	PJM Interconnection, L.L.C.
E-13	ER11-3953-000	ISO New England Inc. and New England Power Pool
E-14	ER11-2224-004 ER11-2224-005 ER11-2224-009	New York Independent System Operator, Inc.
E-15	ER11-3949-000 ER11-3949-001 ER11-3951-000	New York Independent System Operator, Inc.
E-16	ER11-3973-000	California Independent System Operator Corporation
E-17	EL11-12-002	Idaho Wind Partners 1, LLC

October 2011
Meeting Summaries

These are summaries of orders voted by the Federal Energy Regulatory Commission at its October 20, 2011 public meeting. The summaries are produced by FERC's Office of External Affairs and are intended to provide only a general synopsis of the orders. These are not intended as a substitute for the Commission's official orders. To determine the specific actions and the Commission's reasoning, please consult the individual orders when they are posted to FERC's eLibrary found at www.ferc.gov.

E-1, Press Release

E-9, Struck

E-11, Press Release

E-23, Struck

E-28, Press Release

FERC proposes rulemaking

E-2, *Transmission Planning Reliability Standards*, Docket No. RM11-18-000. This Notice of Proposed Rulemaking (NOPR) proposes to remand to NERC its proposed modification to Reliability Standard TPL-002, Table 1, footnote 'b' because it does not adequately clarify or define the circumstances in which an entity can plan to shed firm load for a single contingency. The NOPR states that the proposed revision to footnote 'b' does not meet the directives in Order No. 693 to clarify footnote 'b,' nor is the proposal equally effective and efficient. The NOPR also states that the procedural and substantive parameters of NERC's proposal are too undefined to provide assurances that the process will be effective in determining when it is appropriate to plan for interrupting Firm Demand, do not contain NERC-defined criteria on circumstances to determine when an exception for planned interruption of Firm Demand is permissible, and could result in inconsistent results in implementation.

FERC proposes rulemaking

E-3, *North American Electric Reliability Corp*., Docket No. RM11-20-000. This NOPR proposes to approve Reliability Standards PRC-006-1 (Automatic

Underfrequency Load Shedding) and EOP-003-2 (Load Shedding Plans) submitted by NERC. The NOPR also proposes to approve the Violation Risk Factors, Violation Severity Levels, implementation plan, and effective date proposed by NERC. The NOPR also proposes to retire the Commission-approved Reliability Standards PRC-007-0, PRC-009-0 and EOP-003-1 and the NERC-approved Reliability Standard PRC-006-0. Further, the NOPR seeks comments from NERC and interested persons regarding certain issues.

FERC accepts filing

E-4, *North American Electric Reliability Corp.*, Docket No. RR11-07-000. This order accepts NERC's proposed 2012 Business Plan and Budget and the 2012 Business Plans and Budgets of the Regional Entities.

FERC approves interpretation of certain reliability standards

E-6, *North American Electric Reliability Corporation*, Docket No. RD11-9-000. The order approves an interpretation of Requirement R10 of Transmission Operations (TOP) Reliability Standard TOP-002-2a (Normal Operations Planning). Requirement R10 addresses the planning required to meet all System Operating Limits and Interconnection Reliability Operating Limits. In summary, the interpretation supports the stated purpose of the Reliability Standard, clarifies the responsibilities of balancing authorities with regard to normal operations planning, and determines the language of the interpretation is consistent with the language of the requirement.

FERC approves proposed regional reliability standard and regional definitions

E-7, *Northeast Power Coordinating Council*, Docket No. RD11-8-000. This order approves Northeast Power Coordinating Council's proposed regional Reliability Standard PRC-002-NPPC-01 (Disturbance Monitoring) and two associated new regional definitions. The regional Reliability Standard requires transmission owners and generator owners to provide recording equipment capability necessary to monitor the response of the Bulk-Power System to system disturbances, requires each reliability coordinator to establish requirements for its area's dynamic disturbance recording needs, and establishes disturbance data reporting requirements.

FERC denies request for rehearing

E-8, *North American Electric Reliability Corporation*, Docket No. NP10-160-001. The order denies the U.S. Army Corps of Engineers' request for rehearing of an

underlying order allowing a zero-dollar penalty for violations of a Reliability Standard to go into effect, and reaffirms the Commission's prior orders finding that federal entities that are users, owners, or operators of the Bulk-Power System must comply with mandatory Reliability Standards under section 215 of the Federal Power Act.

FERC denies in part and grants in part certain motions for clarification and rehearing related to CAISO's revised transmission planning process

E-10, *California Independent System Operator Corporation; Green Energy Express LLC and 21st Century Transmission Holdings, LLC*, Docket No. ER10-1401-001, et al. This order denies in part and grants in part certain motions for clarification and denies requests for rehearing of the Commission's December 16, 2010 order on CAISO's revised transmission planning process. The Commission also rejects in part and accepts in part a compliance filing, subject to further modification. Further, the order denies the motion to lodge filed by Critical Path Transmission LLC.

FERC denies rehearing requests related to SPP's highway/byway transmission cost allocation proposal

E-12, *Southwest Power Pool, Inc.*, Docket No. ER10-1069-001. This order denies requests for rehearing of a June 17, 2010 order that accepted proposed revisions to SPP's tariff to implement the Highway/Byway Methodology for allocating the costs of certain transmission facilities. Under the Highway/Byway Methodology, costs for new transmission facilities are allocated to SPP member utilities based on the voltage of a transmission facility as follows: (1) the costs of facilities operating at 300 kV and above are allocated 100 percent across the SPP region on a postage stamp basis; (2) the costs of facilities operating above 100 kV and below 300kV are allocated one-third on a regional postage stamp basis and two-thirds to the zone in which the facilities are located; and (3) the costs of facilities operating at or below 100 kV are allocated 100 percent to the zone in which the facilities are located.

FERC conditionally accepts proposed tariff revisions related to out of merit generator dispatch; will require further compliance filings

E-13, *Southwest Power Pool, Inc.*, Docket No. ER11-3627-000. The order conditionally accepts SPP's proposed tariff revision to reflect a new compensation mechanism for out of merit energy dispatch (OOME) during emergencies. These

OOME directives are used to respond to emergency conditions, not economic conditions, and as such they are not reflected in security constrained economic dispatch. The order finds SPP's proposal, as modified, to be a just and reasonable mechanism to fully compensate resources for responding to OOME directives during emergencies. The order also directs SPP to make a compliance filing that provides for a cap on the compensation (at the amount of the under-recovery caused by the OOME directive) to generators for responding to OOME directives.

FERC accepts non-conforming large generator interconnection agreement

E-14, *Southern California Edison Company;California Independent System Operator Corporation*, Docket Nos. ER11-4358-000; ER11-4512-000.
This order accepts the third Large Generator Interconnection Agreement (LGIA) filed by SoCal Ed with a non-conforming partial termination provision, relating to transmission upgrades that will take until 2017 to complete. The LGIA is uncontested.

FERC accepts Pasadena's revised transmission tariff; sets case for hearing

E-15, *City of Pasadena, California*, Docket No. ER11-4375-000. The order accepts and sets for hearing revisions to the City of Pasadena's TO Tariff related to its revised base transmission revenue requirement and high voltage transmission revenue requirment. The order also accepts some ministerial changes to reflect the implementation of the California Independent System Operator Corporation's Market Redesign and Technology Update initiative.

FERC accepts Puget's proposed tariff revisions; sets case for hearing and settlement judge procedures

E-16, *Puget Sound Energy, Inc.*, Docket No. ER11-3735-000. The order accepts Puget's proposed revisions to OATT Schedule 3 (Regulation and Frequency Response Service) and Schedule 13 (Regulation and Frequency Response Service for Generators Selling Outside of Control Area) and suspends them for a five-month period, to become effective January 5, 2012, subject to refund. The order also establishes hearing and settlement judge procedures.

FERC conditionally accepts proposed tariff revisions

E-17, *New York Independent System Operator, Inc.*, Docket Nos. ER11-3881-000 and ER11-3881-001. The order conditionally accepts proposed tariff revisions filed by NYISO that (1) revise the definition of Available Transfer Capability (ATC) in NYISO's Open Access Transmission Tariff (OATT) and (2) update NYISO's OATT to incorporate by reference the North American Energy

Standards Board (NAESB) business practice standards set forth in Order No. 676-E. The Commission conditionally accepts the tariff revisions, subject to NYISO modifying its ATC definition consistent with the ATC definition promulgated by NERC and to NYISO justifying the continuation of certain waivers from the NAESB Wholesale Electric Quadrant standards that were previously granted by the Commission.

FERC accepts and suspends filing and establishes hearing and settlement judge procedures

E-18, *ISO New England Inc.*, Docket No. ER11-3981-000. The order accepts a filing by ISO New England Inc. detailing the results of ISO-NE's fifth Forward Capacity Auction, which procured capacity for the 2014-2015 Capacity Commitment Period, except for the rejected dynamic de-list bid (which was rejected by ISO-NE for reliability reasons) submitted by Entergy Nuclear Nuclear Power Marketing for the Vermont Yankee Power Station, which the order accepts and suspends and makes subject to refund, and sets for hearing and settlement judge procedures.

FERC accepts SPP's tariff revisions and grants ISO-NE's request for clarification

E-19, *Southwest Power Pool Inc.*, Docket Nos. ER09-1050-006, ER09-1192-005, and ER11-121-000. The order accepts SPP's revisions to Attachment AG in its Tariff, effective February 18, 2010, and grants ISO-NE's clarification request. The order clarifies that the necessity of maintaining referral and investigative information as non-public in no way restricts Market Monitoring Units from collaborating with RTOs or ISOs to determine whether market violations are occurring. Further, Market Monitoring Units may collaborate with RTOs and ISOs to identify and review market operations issues as they arise. The order also clarifies that Market Monitoring Units may share referral information with their own ISO or RTO as well as other Market Monitoring Units, ISOs, and RTOs. In addition, the order clarifies that the Office of Enforcement may share investigative information with Market Monitoring Units, RTOs, and ISOs, including referral information and information obtained from third parties, as long as appropriate measures are taken to ensure that such information is not disclosed and remains non-public.

FERC establishes hearing and settlement judge procedures

E-20, *Buckeye Power, Inc. v. American Transmission Systems, Incorporated*, Docket No. EL11-54-000. This order establishes hearing and settlement judge

procedures regarding a Buckeye Power, Inc. (Buckeye) complaint. Buckeye alleges that the American Transmission Systems, Incorporated's (ATSI) voltage-differentiated rates for transmission service in the ATSI zone of PJM (consisting of separate rates for 69 kV and below facilities, and 138 kV and above facilities) are unjust, unreasonable, unduly discriminatory, and preferential, and should be replaced with a rolled-in rate reflecting the cost of all ATSI transmission facilities, regardless of voltage. The order sets a refund effective date of July 18, 2011, the date the complaint was filed.

FERC conditionally accepts tariff revisions

E-21, *Duke Energy Carolinas, LLC,* Docket Nos. ER11-2895-000, ER11-2895-001, and ER11-3585-000. The order conditionally accepts Duke's revisions to its OATT and to an OATT point-to-point service agreement with Carolina Power and Light Company. These revisions implement a formula rate for point-to-point transmission service, network integration transmission service, and scheduling, system control, and dispatch service. The order finds that Duke has provided adequate support to recover the start-up costs for the failed RTO, GridSouth, through its formula rate. Additionally, the order accepts Duke's tariff and service agreement revisions, subject to the conditions that (1) Duke include in its OATT revisions all the rates, terms, and conditions contained in Article II of an agreement that Duke entered into with its transmission customers, and (2) Duke remove the language from its OATT revisions that imposes the Mobile-Sierra "public interest" standard of review on any "initiating party" that seeks to modify "any provisions of the Formula Rate which reflect any . . . provisions" in Article II of the aforementioned agreement.

FERC rules on a complaint filing

E-22, *E.ON Climate & Renewables North America, LLC v. Midwest Independent Transmission System Operator, Inc.*, Docket No. EL11-30-000. This order finds that a provision of MISO's tariff governing the treatment of costs associated with generator interconnection network upgrades is unjust, unreasonable, and unduly discriminatory and should be removed from the tariff. The order directs MISO to submit a compliance filing removing the provision from its tariff, effective March 22, 2011, within 30 days of the date of the order.

FERC denies rehearing

E-24, *Devon Power LLC,* Docket No. ER03-563-067. This order denies rehearing of an order that responded to a remand from the U. S. Court of Appeals for the District of Columbia Circuit. In the underlying order on remand, the Commission determined that the auction results and transition payments arising from a contested settlement approved by the Commission were tariff rates, not

contract rates. The underlying order also explained that the Commission nevertheless had discretion to approve a settlement provision imposing a more stringent application of the statutory just and reasonable standard of review, commonly known as the Mobile-Sierra "public interest" standard of review, when appropriate. In this order, on rehearing, the Commission affirmed both determinations.

FERC responds to remand from the U.S. Court of Appeals for the District of Columbia Circuit

E-25, *Louisiana Public Service Commission v. Entergy Services, Inc.*, Docket No. EL01-88-007. The order responds to remand from the U. S. Court of Appeals for the District of Columbia Circuit. The order, consistent with an order in another proceeding addressing the same issue, explains that it does have the authority to order refunds but that its policy is not to order refunds in the circumstances present here, but then holds its directive not to make refunds in abeyance pending Commission action on rehearing in that other proceeding. Separately, to implement the court's decision on the appropriate phase-out of interruptible load, the order directs Entergy Services to file, within 60 days of the date of the order, a compliance filing that calculates the bandwith payments and receipts for the period June 1, 2005 through December 31, 2005.

FERC dismisses rehearing requests

E-26, *Louisiana Public Service Commission v. Entergy Services, Inc.*, Docket No. EL01-88-008. The order dismisses requests for rehearing of its underlying order deferring action as having been mooted by the contemporaneous issuance of the order on remand (E-25), which addressed the issue of the date when the remedy should be implemented (i.e., June 1, 2005).

FERC affirms findings of an Initial Decision regarding the bandwidth formula

E-27- *Louisiana Public Service Commission v. Entergy Corporation, Entergy Services, Inc., Entergy Louisiana, L.L.C., Entergy Arkansas, Inc., Entergy Mississippi, Inc., Entergy New Orleans,* Docket No. EL09-50-000.
This order affirms an Administrative Law Judge's (ALJ) determination involving the Louisiana Commission's complaint against Entergy regarding the bandwidth formula. The Louisiana Commission argued the bandwidth formula should be modified so that it no longer would functionalize Accumulated Deferred Income Tax (ADIT) in Account 190 associated with a partial sale-leaseback of Entergy's Waterford 3 nuclear power plant to production using a plant allocator. Instead, the

Louisiana Commission argued that the ADIT should be directly assigned to production.
The Commission's order affirms the ALJ's determination that the Louisiana Commission did not meet its burden to demonstrate that the functionalization methodology for Waterford 3 Sale-Leaseback Account 190 ADIT is unjust, unreasonable, unduly discriminatory or preferential. In addition, the Commission affirms the ALJ's determination that it would be unjust, unreasonable, unduly discriminatory or preferential to directly assign Waterford 3 Sale Leaseback Account 190 ADIT.

FERC denies rehearing

G-1, *Colorado Interstate Gas Company*, Docket No. AC10-22-004. The order denies CIG's request for rehearing challenging the determination by the Chief Accountant in a delegated letter order that CIG had not properly accounted for the retirement of its Natural Buttes Facilities, a gas processing plant in that it abandoned by selling it to Chipeta Processing L.L.C..
The order denies rehearing because CIG's proposed methodology does not comply with the Commission's Uniform System of Accounts and misstates the proper amount of accumulated depreciation applicable to the Natural Buttes Facilities.

FERC denies rehearing on reservation charge credit issues, and largely accepts compliance filing

G-2, *Southern Natural Gas Company*, Docket Nos. RP11-60-002 and RP11-60-003. The order denies Southern's request for rehearing of an April 21, 2011 order that required Southern, under section 5 of the Natural Gas Act, to revise its existing tariff provisions addressing reservation charge credits. And accepts Southern's compliance filing.
The order denies rehearing requests which contended that the Commission require full reservation charge credits be provided for the pipeline's failure to provide nominated firm service at secondary points as well as primary points, but clarified both that the amount of reservation charge credits the pipeline must give should be based on the amount of nominated service which the pipeline was unable to deliver and that a seven-day historical average (used as a substitute for actual nominated amounts in calculating the reservation charge credits in certain circumstances) not include days when firm service as unavailable or curtailed.
The order also largely accepts Southern's compliance filing as in compliance with the Commission's directives, but does direct Southern to remove a 98 percent delivery threshold for imposition of reservation charge credits and instead provide such credits whenever it does not deliver 100 percent of scheduled service.

FERC denies rehearing on reservation charge credit issues

G-3, *Natural Gas Supply Association*, Docket No., RP11-1538-001. The order denies requests for rehearing of the Commission's April 21, 2011 order concerning reservation charge credits, because that order was in the nature of a policy statement, and rehearing does not lie since a policy statement is not a final order requiring action by a party. Rather, the April 21 order denied the request that "the Commission exercise its NGA section 5 authority to enforce its policy regarding pipeline crediting during outages and order pipelines to amend their tariffs in accordance with Commission policy," and stated instead that voluntary action by pipelines to bring their tariffs into compliance was a more efficient method of obtaining compliance.

FERC grants certificate for projects that will supply domestic demand and will enable export of Marcellus Shale production to Canada

C-1, *National Fuel Gas Supply Corporation and Tennessee Gas Pipeline Company*, Docket Nos. CP11-128-000 and CP11-133-000. The order grants National Fuel Gas Supply Corporation, in Docket No. CP11-128-000, authorization to construct and operate its proposed Northern Access Project, consisting of a new compressor station and other compression and facility upgrades in Pennsylvania and New York. Additionally, the order grants Tennessee Gas Pipeline Corporation, in Docket No. CP11-133-000, authorization to abandon certain facilities and authorization to upgrade and modify jointly-owned compression on the Niagara Spur Loop Line (Station 230C Project). Currently, the facilities involved in these related proceedings operate to transport natural gas in a north-to-south direction. Together, the proposed Northern Access Project and Station 230C Project will permit bi-directional flows, thereby allowing Marcellus Shale production to be transported south-to-north into Canada.

FERC denies rehearing; requires Pine Prairie to file further tariff revisions

C-2, *Pine Prairie Energy Center, LLC*, Docket Nos. CP11-1-001 and RP11-2201-000. The order denies rehearing of a May 19, 2011 Commission order that authorized Pine Prairie to construct and operate its proposed Phase III Expansion Project subject to the condition that Pine Prairie conduct a new open season and solicit capacity turn-back offers from existing shippers. The project involves an expansion of an existing natural gas storage facility in Evangeline Parish, LA.

The order also requires Pine Prairie to file further revisions to its tariff in order to comply with the finding in the May 19 order that certain tariff language that provides Pine Prairie with the discretion to hold an open season for expansion capacity is unjust and unreasonable.

FERC grants rehearing

H-1, *Northern Illinois Hydropower, LLC*, Project Nos. 12626-002 and 12717-003. This order grants the request for rehearing filed by Exelon Corporation of the Commission's notices denying Exelon's motions to intervene in the licensing proceedings of Northern Illinois Hydropower, LLC's (Northern) for its proposed Dresden Island Hydroelectric Project No. 12626 and its proposed Brandon Road Hydroelectric Project No. 12717.
The order grants rehearing because Exelon did not receive certified mail notice of Northern's license applications, and because the public interest is best served by Exelon's participation in the license proceedings.

FERC denies rehearing

H-2, C*ity of Kaukauna, Wisconsin*, Project No. 2677-020. The order denies the City of Kaukauna's request for rehearing of provisions in its new license that require it to provide whitewater boating opportunities in the area downstream of the U.S. Army Corps of Engineers' Kaukauna dam, located on the Fox River in Outagamie County, Wisconsin. The order relies on evidence from staff's Environmental Assessment to counter the City's argument that whitewater boating in the area would be unsafe and would adversely affect the Corps' operations at the dam.

FERC dismisses preliminary permit applications

H-3, *Kahawai Power 4, LLC and Kekaha Ditch Hydro, LLC*, Project Nos. 14105-000 and 14203-000. The order dismisses applications by Kehawai Power 4, LLC and Kekaha Ditch Hydro, LLC for preliminary permits to study the feasibility of a hydropower project on the Kekaha Ditch Irrigation System near the town of Waimea, Kauai County, Hawaii. In this order, the Commission establishes a general policy of not issuing permits for projects in Hawaii where the project is subject to permissive FPA section 4(e) licensing rather than required FPA section 23(b) licensing to avoid the potential to interfere with Hawaii's state hydropower authorization process.

FERC denies rehearing

H-4, *Upper Yampa Water Conservancy District*, Project No. 9202-177. The order denies a request for rehearing of a Commission staff order denying an application of the Upper Yampa Water Conservancy District to variously remove from the project boundary, sell, lease, and grant easements regarding, lands of the Stagecoach Project No. 9202, located on the Yampa River, in Routt County, Colorado. The order concludes that the licensee has not shown that the lands are no longer needed for project purposes, including recreation and flowage, so that they may not be removed from the project boundary or sold, but explains that the

licensee may be able to lease or grant easements regarding the lands, if these actions are consistent with project purposes.

FERC grants in part a request for rehearing

H-5, *Appalachian Power Company*, Project No. 2210-212. The order grants in part a request for rehearing of an unpublished Commission staff order that responded to a homeowner complaint by requiring Appalachian Power Company, licensee for the Smith Mountain Lake Pumped Storage Project, located on the Roanoke River in Virginia, to take compliance action under the project's shoreline management plan (SMP) to bring three boat docks into compliance with the SMP. The order finds that staff did not err in concluding that the complained-of actions were not consistent with the SMP, but, because this is a case of first impression, there may have been confusion among some of the entities involved. Further, the dock repairs that led to the complaint improved safety and did not enlarge the dock, therefore, no required compliance action is needed in this instance.

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 40

[Docket No. RM11–11–000]

Version 4 Critical Infrastructure Protection Reliability Standards

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: Under section 215 of the Federal Power Act, the Federal Energy Regulatory Commission (Commission) proposes to approve eight modified Critical Infrastructure Protection (CIP) Reliability Standards, CIP–002–4 through CIP–009–4, developed and submitted to the Commission for approval by the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization certified by the Commission. In general, the CIP Reliability Standards provide a cybersecurity framework for the identification and protection of ''Critical Cyber Assets'' to support the reliable operation of the Bulk-Power System. Proposed Reliability Standard CIP–002–4 requires the identification and documentation of Critical Cyber Assets associated with Critical Assets that support the reliable operation of the Bulk-Power System. The ''Version 4'' CIP Reliability Standards propose to modify CIP–002–4 to include ''bright line'' criteria for the identification of Critical Assets. The proposed Version 4 CIP Reliability Standards would replace the currently effective Version 3 CIP Reliability Standards. The Commission also proposes to approve the related Violation Risk Factors and Violation Severity Levels with modifications, the implementation plan, and effective date proposed by NERC.

DATES: Comments are due November 21, 2011.

ADDRESSES: You may submit comments, identified by docket number and in accordance with the requirements posted on the Commission's Web site *http://www.ferc.gov.* Comments may be submitted by any of the following methods:

- *Agency Web Site:* Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format, at *http://www.ferc.gov/docs-filing/efiling.asp.*
- *Mail/Hand Delivery:* Commenters unable to file comments electronically must mail or hand deliver an original copy of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE., Washington, DC 20426. These requirements can be found on the Commission's Web site, see, *e.g.,* the ''Quick Reference Guide for Paper Submissions,'' available at *http://www.ferc.gov/docs-filing/efiling.asp* or via phone from FERC Online Support at 202–502–6652 or toll-free at 1–866–208–3676.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

September 15, 2011.

1. Under section 215 of the Federal Power Act (FPA),[1] the Commission proposes to approve eight modified Critical Infrastructure Protection (CIP) Reliability Standards, CIP–002–4 through CIP–009–4. The proposed ''Version 4'' CIP Standards were developed and submitted for approval to the Commission by the North American Electric Reliability Corporation (NERC), which the Commission certified as the Electric Reliability Organization (ERO) responsible for developing and enforcing mandatory Reliability Standards.[2] In general, the CIP Reliability Standards provide a cybersecurity framework for the identification and protection of ''Critical Cyber Assets'' to support the reliable operation of the Bulk-Power System.[3] In particular, the Version 4 CIP Reliability Standards propose to modify CIP–002–4 to include ''bright line'' criteria for the identification of Critical Assets, in lieu of the currently-required risk-based assessment methodology that is developed and applied by applicable entities. In addition, NERC developed proposed conforming modifications to the remaining cybersecurity Reliability Standards, CIP–003–4 through CIP–009–4.

2. The Commission proposes to approve Version 4, the Violation Risk Factors (VRFs),the Violation Severity Levels (VSLs) with modifications, the implementation plan, and effective date proposed by NERC. The Commission also proposes to approve the retirement of the currently effective Version 3 CIP Reliability Standards, CIP–002–3 to CIP–009–3. The Commission seeks comments on these proposals to approve.

3. While we propose to approve the Version 4 CIP Standards, like NERC, we recognize that the Version 4 CIP Standards represent an ''interim step''[4] to addressing all of the outstanding directives set forth in Order No. 706.[5] We believe that the electric industry, through the NERC standards development process, should continue to develop an approach to cybersecurity that is meaningful and comprehensive to assure that the nation's electric grid is capable of withstanding a Cybersecurity Incident.[6] Below, we reiterate several topics set forth in Order No. 706 that pertain to a tiered approach to identifying Cyber Assets, protection from misuse, and a regional perspective. We expect NERC will continue to improve the CIP Standards to address these and other outstanding matters addressed in Order No. 706.

4. Moreover, as discussed below, the Commission seeks comments from NERC and other interested persons on establishing a reasonable deadline for NERC to satisfy the outstanding directives in Order No. 706 pertaining to the CIP Standards, using NERC's development timeline.

[1] 16 U.S.C. 824o (2006).

[2] *North American Electric Reliability Corp.,* 116 FERC ¶ 61,062, *order on reh'g & compliance,* 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc.* v. *FERC,* 564 F.3d 1342 (D.C. Cir. 2009).

[3] The NERC Glossary of Terms defines Critical Assets to mean ''Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.''

[4] NERC Petition at 6.

[5] *Mandatory Reliability Standards for Critical Infrastructure Protection,* Order No. 706, 122 FERC ¶ 61,040, order on reh'g, Order No. 706–A, 123 FERC ¶ 61,174 (2008), *order on clarification,* Order No. 706–B, 126 FERC ¶ 61,229 (2009).

[6] Section 215(a) of the FPA defines Cybersecurity Incident as ''a malicious act or suspicious event that disrupts, or was an attempt to disrupt, the operation of those programmable electronic devices and communication networks including hardware, software and data that are essential to the reliable operation of the Bulk-Power System.''

I. Background

A. Mandatory Reliability Standards

5. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval. Once approved, the Reliability Standards may be enforced by the ERO, subject to Commission oversight, or by the Commission independently.[7]

6. Pursuant to section 215 of the FPA, the Commission established a process to select and certify an ERO[8] and, subsequently, certified NERC as the ERO.[9] On January 18, 2008, the Commission issued Order No. 706 approving eight CIP Reliability Standards proposed by NERC.

7. In addition, pursuant to section 215(d)(5) of the FPA,[10] the Commission directed NERC to develop modifications to the CIP Reliability Standards to address various concerns discussed in the Final Rule. In relevant part, the Commission directed the ERO to address the following issues regarding CIP–002–1: (1) Need for ERO guidance regarding the risk-based assessment methodology for identifying Critical Assets; (2) scope of Critical Assets and Critical Cyber Assets; (3) internal, management, approval of the risk-based assessment; (4) external review of Critical Assets identification; and (5) interdependency between Critical Assets of the Bulk-Power System and other critical infrastructures. Subsequently, the Commission approved Version 2 and Version 3 of the CIP Reliability Standards, each version including changes responsive to some but not all of the directives in Order No. 706.[11]

B. Current Version 3 CIP Reliability Standards

8. Reliability Standard CIP–002–3 addresses the identification of Critical Assets and associated Critical Cyber Assets. Pursuant to CIP–002–3, a responsible entity must develop a risk-based assessment methodology to identify its Critical Assets. Requirement R1 specifies certain types of assets that an assessment must consider for Critical Asset status and also allows the consideration of additional assets that the responsible entity deems appropriate. Requirement R2 requires the responsible entity to develop a list of Critical Assets based on an annual application of the risk-based assessment methodology developed pursuant to Requirement R1. Requirement R3 provides that the responsible entity must use the list of Critical Assets to develop a list of associated Critical Cyber Assets that are essential to the operation of the Critical Assets.

9. In addition, the Commission approved the following ''Version 3'' CIP Standards:

- CIP–003–3 (Security Management Controls);
- CIP–004–3 (Personnel & Training);
- CIP–005–3 (Electronic Security Perimeter(s));
- CIP–006–3 (Physical Security of Critical Cyber Assets);
- CIP–007–3 (Systems Security Management);
- CIP–008–3 (Incident Reporting and Response Planning);
- CIP–009–3 (Recovery Plans for Critical Cyber Assets).

II. Proposed Version 4 CIP Reliability Standards

A. NERC Petition

10. On February 10, 2011, NERC filed a petition seeking Commission approval of proposed Reliability Standards CIP–002–4 to CIP–009–4 and requesting the concurrent retirement of the currently effective Version 3 CIP Reliability Standards, CIP–002–3 to CIP–009–3.[12] The principal differences are found in CIP–002, where NERC replaced the risk-based assessment methodology for identifying Critical Assets with 17 uniform bright line criteria for identifying Critical Assets. NERC does not propose any changes to the process of identifying the associated Critical Cyber Assets that are then subject to the cyber security protections required by CIP–003 through CIP–009. NERC also submitted proposed VRFs and VSLs and an implementation plan governing the transition to Version 4. NERC proposed that the Version 4 CIP Reliability Standards become effective the first day of the eighth calendar quarter after applicable regulatory approvals have been received.

11. On April 12, 2011, NERC made an errata filing correcting certain errors in the petition and furnishing corrected exhibits and the standard drafting team minutes. In the errata, NERC also replaced the VRFs and VSLs in the February 10 petition with new proposed VRFs and VSLs.[13]

12. In its Petition, NERC states that the Version 4 CIP Standards satisfy the Commission's criteria, set forth in Order No. 672, for determining whether a proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential and in the public interest.[14] According to NERC, CIP–002–4 achieves a specified reliability goal by requiring the identification and documentation of Critical Cyber Assets associated with Critical Assets that support the reliable operation of the Bulk-Power System. NERC opines that the Reliability Standard ''improves reliability by establishing uniform criteria across all Responsible Entities for the identification of Critical Assets.''[15] Further, NERC states that CIP–002–4 contains a technically sound method to achieve its reliability goal by requiring the identification and documentation of Critical Assets through the application of the criteria set forth in Attachment 1 of CIP–002–4.

13. NERC states that CIP–002–4 establishes clear and uniform criteria for identifying Critical Assets on the Bulk-Power System.[16] NERC also states that CIP–002–4 does not reflect any differentiation in requirements based on size of the responsible entity. NERC asserts that CIP–002–4 will not have negative effects on competition or restriction of the grid. NERC also contends that the two-year implementation period for CIP–002–4 is reasonable given the time it will take responsible entities to determine

[7] *See* 16 U.S.C. 824o(e).

[8] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards,* Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g,* Order No. 672–A, FERC Stats. & Regs. ¶ 31,212 (2006).

[9] *North American Electric Reliability Corp.,* 116 FERC ¶ 61,062, *order on reh'g & compliance,* 117 FERC ¶ 61,126 (2006), *aff'd sub nom., Alcoa, Inc.* v. *FERC,* 564 F.3d 1342 (DC Cir. 2009).

[10] 16 U.S.C. 824o(d)(5).

[11] *North American Electric Reliability Corp.,* 128 FERC ¶ 61,291 (2009), *order denying reh'g and granting clarification,* 129 FERC ¶ 61,236 (2009) (approving Version 2 of the CIP Reliability Standards); *North American Electric Reliability Corp.,* 130 FERC ¶ 61,271 (2010) (approving Version 3 of the CIP Reliability Standards).

[12] NERC Petition at 1. The proposed Reliability Standards are not attached to the NOPR. They are, however, available on the Commission's eLibrary document retrieval system in Docket No. RM11–11–000 and are available on the ERO's Web site, *http://www.nerc.com.* Reliability Standards approved by the Commission are not codified in the CFR.

[13] NERC states that the Version 4 VRFs and VSLs are carried over in part from the VRFs and VSLs in the Version 3 CIP Reliability Standards. NERC Petition at 46. The Commission approved the Version 2 and 3 VRFs and VSLs in Docket Nos. RD10–6–001 and RD09–7–003 on January 20, 2011 but required NERC to make modifications in a compliance filing due by March 21, 2011. *North American Electric Reliability Corporation,* 134 FERC ¶ 61,045 (2011). The February 10 petition did not carry over the modified Version 3 VRFs and VSLs since it was filed before the March 21 compliance filing. NERC submitted new Version 4 VRFs and VSLs that carried over the modified Version 3 VRFs and VSLs in the April 12 errata. On June 6, 2011, NERC filed the March 21, 2011 compliance filing in the present docket, Docket No. RM11–11–000.

[14] Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 323–337.

[15] NERC Petition at 4.

[16] *Id.* at 38.

whether assets meet the criteria included in Attachment 1 and to implement the controls required in CIP–003–4 through CIP–009–4 for the newly identified assets.

14. Finally, NERC acknowledges that CIP–002–4 addresses some, but not all, of the Commission's directives in Order No. 706. NERC explains that the standard drafting team limited the scope of requirements in the development of CIP Version 4 ''as an interim step'' limited to the concerns raised by the Commission regarding CIP–002.[17] NERC states that it has taken a ''phased'' approach to meeting the Commission's directives from Order No. 706 and, according to NERC, the standard drafting team continues to address the remaining Commission directives. According to NERC, the team will build on the bright line approach of CIP Version 4.[18]

B. Proposed Reliability Standard CIP–002–4

15. Proposed Reliability Standard CIP–002–4 contains 3 requirements. Requirement R1, which pertains to the identification of Critical Assets, provides:

> The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the criteria contained in CIP–002–4 Attachment 1—Critical Asset Criteria. The Responsible Entity shall update this list as necessary, and review it at least annually.

Attachment 1 provides seventeen criteria to be used by all responsible entities for the identification of Critical Assets pursuant to Requirement R1. The thresholds pertain to specific types of facilities such as generating units, transmission lines and control centers. For example, Criterion 1.1 provides ''[e]ach group of generating units (including nuclear generation) at a single plant location with an aggregate highest rated net Real Power capability of the preceding 12 months equal to or exceeding 1500 MW in a single Interconnection.'' With regard to transmission, Criterion 1.6 provides ''Transmission Facilities operated at 500 kV or higher,'' and Criterion 1.7 provides ''Transmission Facilities operated at 300 kV or higher at stations or substations interconnected at 300 kV or higher with three or more other transmission stations or substations.''

16. Reliability Standard CIP–002–4, Requirement R2 requires responsible entities to develop a list of Critical Cyber Assets associated with the Critical Assets identified pursuant to Requirement R1. As in previous versions, the Requirement further states that to qualify as a Critical Cyber Asset, the Cyber Asset must: (1) Use a routable protocol to communicate outside the Electronic Security Perimeter; (2) use a routable protocol within a control center; or (3) be dial-up accessible. In the proposed version, in the context of generating units at a single plant location, the Requirement limits the designation of Critical Cyber Assets only to Cyber Assets shared by a combination of generating units whose compromise could within 15 minutes result in the loss of generation capability equal to or higher than 1500 MW.

17. Requirement R3 requires that a senior manager or delegate for each responsible entity approve annually the list of Critical Assets and the list of Critical Cyber Assets, even if the lists contain no elements. As mentioned above, proposed Reliability Standards CIP–003–4 to CIP–009–4 only reflect conforming changes to accord with the CIP–002–4 Reliability Standard.

C. Additional Information Regarding Attachment 1 Criteria

18. In response to a Commission data request, NERC provided additional information regarding the bright line criteria for identifying Critical Assets.[19] NERC provided some information regarding the development of the criteria. Further, based on an industry survey, NERC provided information regarding the estimated number of Critical Assets and the number of Critical Assets that have associated Critical Cyber Assets located in the United States that would be identified pursuant to CIP–002–4. For example, NERC indicates that the Version 4 CIP Standards would result in the identification of 532 control centers as Critical Assets with Critical Cyber Assets, and another 21 control centers as Critical Assets without any associated Critical Cyber Assets.[20] Further, 201 control centers would not be identified as Critical Assets. With regard to Blackstart Resources, NERC's survey results indicate that CIP–002–4 would result in the identification of approximately 234 Blackstart Resources as Critical Assets with associated Critical Cyber Assets, 273 identified as Critical Assets without Critical Cyber Assets, and 35 Blackstart Resources not classified as Critical Assets.[21]

III. Discussion

19. Pursuant to FPA section 215(d)(2), the Commission proposes to approve CIP–002–4 to CIP–009–4 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. The Commission proposes to approve the VRFs and VSLs, implementation plan, and effective date proposed by NERC. The Commission also proposes to approve the retirement of the currently effective Version 3 CIP Reliability Standards CIP–002–3 to CIP–009–3 upon the effective date of CIP–002–4 to CIP–009–4. The Commission seeks comments on these proposals.

20. Further, as discussed below, the Commission seeks comments from NERC and other interested persons on the proposal to establish a reasonable deadline for NERC to satisfy the outstanding directives in Order No. 706. Specifically, as explained in detail later, the Commission requests comments on: (1) The proposal to establish a deadline using NERC's development timeline for the next version of the CIP Reliability Standards; (2) how much time NERC needs to develop and file the next version of the CIP Reliability Standards; (3) other potential approaches to Critical Cyber Asset identification; and (4) whether the next version is anticipated to satisfy all of the directives in Order No. 706.

A. The Commission Proposes To Approve the Version 4 CIP Reliability Standards

21. The Commission, in giving due weight to NERC's Filing, proposes to approve the Version 4 CIP Reliability Standards. The Commission also proposes to approve the implementation plan and effective date proposed by NERC. Version 4 provides a change in three respects: (1) Version 4 will result in the identification of certain types of Critical Assets that may not be identified under the current approach; (2) Version 4 uses bright line criteria to identify Critical Assets, eliminating the use of existing entity-defined risk-based assessment methodologies that generally do not adequately identify Critical Assets; and (3) Version 4 provides a level of consistency and clarity regarding the identification of Critical Assets lacking under Version 3. We

[17] NERC Petition at 6 (citing Order No. 706, 122 FERC ¶ 61,040 at P 236).

[18] NERC Petition at 6.

[19] *See* April 17, 2011 Commission staff data request issued in Docket No. RM11–11–000. NERC responded to the data request in staggered filings, on May 27, 2011 and June 30, 2011.

[20] NERC June 30, 2011 Data Response at 2–3.

[21] *Id.* at 3–4. In the June 30, 2011 Data Response, NERC stated that with respect to Blackstart Resources some responsible entities indicated that they had not performed a complete analysis of their systems based on CIP–002–4 and are unsure whether some units may be classified as Critical Assets. *Id.* at 4.

separately address each of these reasons for proposing to approve Version 4 below.

1. Critical Asset Identification

22. In its Petition, NERC indicates that, after conducting reviews of CIP–002 compliance, NERC ''determined that the existing methodologies generally do not adequately identify all Critical Assets.'' [22] While recognizing that CIP version 4 is intended as an ''interim step,'' it appears that the proposed bright line criteria will result in the identification of certain types of Critical Assets (*e.g.* 500 kV substations) that may not be identified by the approach that is currently in effect. This is reflected in NERC's June 30, 2011 data response, in which NERC presented industry survey data reflecting the application of the bright line criteria in Version 4. To facilitate an analysis of the data, NERC also provided observations and data from several of its earlier industry surveys, including the 2009 ''CIP Self-Certification Survey'' and 2010 ''CIP–002 Critical Asset Methodology Data Request.''. For example, NERC states in the June 30, 2011 data response that in the 2009 survey only 50 percent of substations rated 300 kV and above are classified as Critical Assets while that figure would increase to 70 percent under Version 4.[23]

23. The NERC petition indicates that 270 transmission substations rated 500 kV and above are classified as Critical Assets under Version 3 while, according to the data response, the figure would rise to 437 under Version 4.[24] This increase is consistent with Criterion 1.6 of Attachment 1 to CIP–002–4, which identifies all transmission substations rated 500 kV as Critical Assets. According to the data response, the 25 percent of generation units rated 300 MVA and above would be identified as Critical Assets under Version 4. Moreover, the proportion of total Blackstart Resources classified as Critical Assets increases due to the required 100 percent coverage of these under Version 4.[25] Further, the number of control centers identified as Critical Assets increases from 425 under Version 3 to 553 under Version 4, the latter figure representing 74 percent of all control centers. These figures represent increases in certain categories in Critical Asset identification among generation, transmission, and control centers. We also note that NERC's industry survey data indicates decreases in the number of generation and blackstart resources identified as Critical Assets with Critical Cyber Assets. While the bright line thresholds result in the identification of a significant number of additional generation plants rated above 1500 MVA as Critical Assets, the thresholds also result in the identification of less generation below 300 MVA.

24. As NERC recognizes in its filing, the improvements in Critical Asset identification under Version 4 represent an interim step in complying with the directives in Order No. 706.[26] As we discuss below, Version 4 should not be viewed as an endpoint but as a step towards eventual full compliance with Order No. 706.

2. Version 4 Removes Discretion in Identifying Critical Assets

25. The proposed Version 4 CIP Reliability Standards discards the current risk-based methodology for identifying Critical Assets. Under the current CIP–002–3, responsible entities are tasked with identifying Critical Assets based on their own risk-based methodology. In the Petition NERC points out that in Order No. 706 the Commission directed NERC to ''provide reasonable technical support to assist entities in determining whether their assets are critical to the Bulk-Power System.'' [27] NERC explains that it responded to the Commission's direction by developing guidance documents to assist entities in developing their risk-based methodologies and Critical Asset identification.[28]

26. In its Petition, NERC states that it ''conducted various reviews of risk-based methodologies developed by many entities of varying sizes * * * and determined that the existing methodologies generally do not adequately identify all Critical Assets.'' [29] To address this, NERC proposes to replace the current risk-based methodology with uniform, bright line criteria, which will be used by all responsible entities to identify Critical Assets.

27. While risk-based assessment methodologies have merit, we share NERC's concerns about the existing application of the currently effective CIP–002–3, Requirement 1. Thus, in this context, we believe that a shift away from responsible entity-designed risk-based methodologies for identifying Critical Assets, which NERC has found to be inadequate, to the use of NERC-developed criteria is an improvement.

3. Version 4 Provides Consistency and Clarity in the Identification of Critical Assets

28. In its June 30, 2011 data response, NERC states that the survey results from 2009 generated concern ''about the apparent inconsistency in the application of the standards across the system, as evidenced by the apparent variation from region to region.'' [30] NERC states that it subsequently engaged with the Regional Entities and stakeholders to better understand the data, with these efforts resulting in the development of Version 4.

29. We believe that the application of uniform criteria is an improvement over the current approach because they add greater consistency and clarity in identifying Critical Assets. The risks posed by cyber threats suggest a different approach than the possibly inconsistent, inadequate methodologies for identifying Critical Assets, as evidenced by NERC's conclusion that insufficient numbers of Critical Assets were identified using the risk-based assessment methodology. As an integrated system, the protection afforded for Critical Assets and their Critical Cyber Assets is only as strong as its weakest link. In this respect, allowing responsible entities to devise their own methodologies for identifying Critical Assets, especially if these methodologies prove to be weak, may compromise the Critical Assets and Critical Cyber Assets of other responsible entities even if they have adopted a more stringent methodology. The uniform system of Critical Asset identification proposed by NERC in Version 4 helps to address this weakness and places all responsible entities on an equal footing with respect to Critical Asset identification.

30. In addition, clear, bright line criteria should make it easier for Regional Entities, NERC and the Commission to monitor responsible entities and evaluate how they are identifying Critical Assets. A single set of bright line criteria, as opposed to

[22] NERC Petition at 11.

[23] *Id.* at 4.

[24] *Id.* at 5.

[25] NERC Petition at 17 (explaining that each Blackstart Resource identified in a Transmission Operator's restoration plan is a Critical Asset). In the June 30, 2011 Data Response, NERC's survey found that responsible entities identified 93 percent of Blackstart Resources as Critical Assets. NERC stated that confusion over the term Blackstart Resource may have contributed to the lower percentage, and that responsible entities will be educated on the definition of Blackstart Resource prior to the effective date of CIP–002–4. NERC June 30, 2011 Data Response at 4.

[27] *Id.* at 10–11 (citing Order No. 706, 122 FERC ¶ 61,040 at P 255).

[28] *Id.* at 11.

[29] *Id.*

[30] NERC June 30, 2011 Data Response at 3.

myriad entity-designed risk-based methodologies, should improve the CIP compliance process.

31. However, under the currently-effective CIP–002–3, an entity that applies its risk-based assessment methodology considers specific types of assets identified in Requirement R1, as well as ''any additional assets that support the operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.'' Thus, currently, a responsible entity has the flexibility to consider any assets it deems appropriate. The Commission also notes that there are assets currently identified as Critical Assets which would no longer be identified as Critical Assets under the Proposed Reliability Standard CIP–002–4 bright line criteria for Critical Asset identification. The Commission seeks comment whether, under CIP Version 4, a responsible entity retains the flexibility to identify assets that, although outside of the bright line criteria, are essential to Bulk-Power System reliability. Further, we seek comment whether the ERO and/or Regional Entities would have the ability, either in an event-driven investigation or compliance audit, to identify specific assets that fall outside the bright-line criteria yet are still essential to Bulk-Power System reliability and should be subject prospectively to compliance with the CIP Reliability. If so, on what basis should that decision be made?

32. In addition, the Commission is cognizant of one caution that remains concerning a binary bright line criteria protection philosophy, *i.e.,* either an asset satisfies the threshold and is subject to compliance or is below the threshold and not subject to compliance (as opposed to a tiered approach to compliance as discussed below), in terms of applying cybersecurity protections to Cyber Assets. Specifically, bright line criteria that limit legally-mandated cybersecurity protections to certain classes of Bulk-Power System assets may indicate to an adversary the types of assets that fail to meet the threshold and, therefore, are not subject to mandatory CIP compliance. Therefore, the Commission encourages NERC to accelerate development of the next version of the CIP Reliability Standards and to address the concerns discussed herein in Section B.

4. Violation Risk Factors/Violation Severity Levels

33. NERC states that the proposed VRFs and VSLs are consistent with those approved for the Version 3 CIP Reliability Standards.[31] NERC explains that each requirement in Version 4 is assigned a VRF and a set of VSLs and that these elements support the determination of an initial value range for the base penalty amount regarding violations of requirements in Commission-approved Reliability Standards, as defined in the ERO Sanction Guidelines.[32]

34. The principal changes in the proposed Version 4 VRFs and VSLs relate to CIP–002–4. NERC proposes to carry forward the Version 3 VRFs and VSLs for all other Requirements (in CIP–003–4 through CIP–009–4), for which no substantive revisions are proposed. CIP–002–4 no longer contains sub-Requirements and, instead, each of three main Requirements has a single VRF and set of VSLs, consistent with the methodology proposed by NERC and approved by the Commission.[33] The VRF designations for the three Requirements in CIP–002–4 are consistent with those assigned to similar Requirements in previous versions of the CIP Reliability Standards and satisfy our established guidelines. Therefore, the Commission proposes to approve the Version 4 VRFs proposed by NERC and incorporate appropriately the modifications directed to prior versions.

35. With regard to the proposed Version 4 VSLs for CIP–002–4, we are concerned that the VSLs for Requirement R1 and Requirement R2, while carrying forward the wording from corresponding Version 3 VSLs, do not adequately address the purpose of NERC's proposed bright line criteria: To ensure accurate and complete identification of all Critical Assets, so that all associated Critical Cyber Assets become subject to the protections required by the CIP Standards.

36. More importantly, neither set of VSLs address the failure to properly identify either Critical Assets or Critical Cyber Assets in the first place. The failure to identify a Critical Asset, whether inadvertently or through misapplication of the bright line criteria, is paramount because if an Asset is not identified and included on the Critical Asset list, its associated Cyber Assets will not be considered under Requirement R2. Failure to identify those Cyber Assets as Critical Cyber Assets under Requirement R2 then creates the ''weakest link'' circumstance discussed in the Commission's order establishing two CIP VSL Guidelines for analyzing the validity of VSLs pertaining to cyber security.[34]

37. Therefore, the Commission proposes to direct the ERO to modify the VSLs for CIP–002–4, Requirements R1 and R2, to address a failure to identify either Critical Assets or Critical Cyber Assets, as shown in Appendix 1.[35] The Commission proposes to approve the Version 4 VSLs proposed by NERC, as modified, because they would then satisfy our established guidelines, fully address the purpose of NERC's bright line criteria, and incorporate appropriately the modifications directed to prior versions.

5. Implementation Plan and Effective Date

38. NERC proposes an effective date for full compliance with the Version 4 CIP Standards of the first day of the eighth calendar quarter after applicable regulatory approvals have been received. In addition, NERC provides a detailed implementation plan for newly identified Critical Assets and newly registered entities. NERC also presents a number of scenarios intended to explain how CIP–002–4 will be implemented. Depending on the situation, the implementation plan establishes timelines and milestones for entities to reach full compliance with CIP–002–4.

39. The Commission proposes to approve the effective date and implementation plan for CIP–002–4. Under the scenarios presented by NERC, we understand that entities with existing CIP compliance implementation programs will effectively no longer use CIP–002–3 to identify Critical Assets after approval of CIP–002–4 but rather will apply the criteria in Attachment 1 of CIP–002–4. While some responsible entities have already installed the necessary equipment and software to address

[31] *North American Electric Reliability Corp.,* 134 FERC ¶ 61,045 (2011) (approving Version 2 and 3 CIP Reliability Standards VRFs and VSLs but requiring modifications in a compliance filing).

[32] NERC Petition at 37.

[33] *North American Electric Reliability Corp.,* 135 FERC ¶ 61,166, at 8 (2011).

[34] CIP VSL Guideline 1 states, ''Requirements where a single lapse in protection can compromise computer network security, *i.e.,* the ''weakest link'' characteristic, should apply binary rather than gradated VSLs.''

[35] NERC proposes to assign a Severe VSL for a violation of Requirement R1 if a responsible entity does not develop a list of its identified Critical Assets ''even if such list is null.'' NERC does not propose to assign a VSL for a violation of Requirement R1 when a responsible entity fails to identify a Critical Asset that falls within any of the Critical Asset Criteria in Attachment 1, or fails to include an identified Critical Asset in its Critical Asset list. NERC further proposes to assign a Severe VSL to a responsible entity's violation of Requirement R2 only when it fails to include in its list of Critical Cyber Assets a Critical Cyber Asset it has identified. NERC does not propose to assign a VSL for a violation of Requirement R2 resulting from a responsible entity's failure to identify as a Critical Cyber Asset a Cyber Asset that qualifies as a Critical Cyber Asset.

cybersecurity, we recognize that other responsible entities may need to purchase and install new equipment and software to achieve compliance for assets that are brought within the scope of the protections under the CIP–002–4 bright line criteria. Based on these considerations, the Commission believes that the implementation plan proposed by NERC sets reasonable deadlines for industry compliance.

B. Ongoing Development Efforts To Satisfy Directives Set Forth in Order No. 706

40. As acknowledged by NERC, the proposed Version 4 CIP Reliability Standards do not address all of the directives set forth in Order No. 706. Although the Commission proposes to approve CIP–002–4, we highlight the need for NERC, working through the Reliability Standards development process, to address all outstanding Order No. 706 directives as soon as possible.

41. Below, we discuss several directives in Order No. 706 that have yet to be satisfied and propose to give guidance regarding the next version of the CIP Reliability Standards, such as the need to address the NIST framework, data network connectivity, and the potential misuse of control centers or control systems and the adoption of a regional perspective and oversight. Our guidance is intended to more fully ensure that all Cyber Assets serving reliability functions of the Bulk-Power System are within scope of the CIP Reliability Standards. In addition, as discussed below, we seek comments from NERC and other interested persons on a proposal to establish a deadline for NERC to submit modified CIP Reliability Standards that address the outstanding directives set forth in Order No. 706, using NERC's development timeline.

42. The stated purpose of Reliability Standard CIP–002 is the accurate identification of Critical Cyber Assets. Both the currently-effective and proposed CIP–002 Reliability Standards, along with guidance NERC provided to industry,[36] are structured in a staged approach. First, an entity must identify Critical Assets. NERC defines Critical Assets as ''facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.'' [37] Second, based on the Critical Assets identified in the first step, an entity must identify Cyber Assets supporting the Critical Assets. The NERC Glossary defines Cyber Assets as ''programmable electronic devices and communication networks including hardware, software, and data.'' [38] Third, an entity should identify the Critical Cyber Assets by determining, in accordance with the NERC Glossary, the ''Cyber Assets essential to the reliable operation of the Critical Assets.'' [39] In Order No. 706, the Commission did not address whether or not the staged approach outlined above was the only method for identifying Critical Cyber Assets. Rather at that time, focus was placed on addressing specific concerns with the first step—the identification of Critical Assets. Recognizing CIP–002 as the cornerstone of the CIP Reliability Standards,[40] a failure to accurately identify Critical Assets could greatly impact accurate Critical Cyber Asset identification and the overall applicability of the protection measures afforded in CIP–003 through CIP–009.

43. In light of recent cybersecurity vulnerabilities, threats and attacks that have exploited the interconnectivity of cyber systems,[41] the Commission seeks comments regarding the method of identification of Critical Cyber Assets [42] to ensure sufficiency and accuracy. The Commission recognizes that control systems that support Bulk-Power System reliability are ''only as secure as their weakest links,'' and that a single vulnerability opens the computer network and all other networks with which it is interconnected to potential malicious activity.[43] Accordingly, the Commission believes that any criteria adopted for the purposes of identifying a Critical Cyber Asset under CIP–002 should be based upon a Cyber Asset's connectivity and its potential to compromise the reliable operation [44] of the Bulk-Power System, rather than focusing on the operation of any specific Critical Asset(s). The Commission seeks comments on this approach.

44. Further, the Commission seeks comments on how to ensure that the directives of Order No. 706 relative to CIP–002 with respect to the concerns discussed below are addressed, resulting in a method that will lead to sufficient and accurate Critical Cyber Asset identification.

45. The Commission believes that NERC should consider the following three strategies to meet the outstanding directives and seeks comments on these strategies. First, NERC should consider applicable features of the NIST Risk Management Framework to ensure protection of all cyber systems connected to the Bulk-Power System, including establishing CIP requirements based on entity functional characteristics rather than focusing on Critical Asset size. Second, such as in the consideration of misuse, NERC should consider mechanisms for identifying Critical Cyber Assets by examining all possible communication paths between a given cyber resource and any asset supporting a reliability function. Third, NERC should provide a method for review and approval of Critical Cyber Asset lists from external sources such as the Regional Entities or NERC. Each of these strategies is discussed below.

1. NIST Framework

46. In Order No. 706, the Commission directed NERC to ''monitor the development and implementation'' of cybersecurity standards then being developed by the National Institute of Standards and Technology (NIST).[45] The Commission also directed NERC to consider the effectiveness of the NIST standards.[46] At that time, the Commission directed NERC to address any NIST provisions that will better protect the Bulk-Power System in the Reliability Standards development process.[47] While the Commission determined not to require NERC to adopt or incorporate elements of the NIST standards, Order No. 706 left open the option of revisiting the NIST standards at a later time.[48] The Commission is not here proposing to direct that NERC use elements of the NIST standards. However, we continue

[36] North American Reliability Corporation Security Guideline for the Electric Sector: ''*Identifying Critical Cyber Assets*'' Version 1.0, Effective June 17, 2010, at 4–5, and North American Reliability Corporation Security Guideline for the Electric Sector: ''*Identifying Critical Assets*'' Version 1.0, Effective September 17, 2009.

[37] NERC Glossary of Terms at 11.

[38] *Id.*

[39] *Id.*

[40] Order No. 706, 122 FERC ¶ 61,040 at P 234.

[41] These include the discovery of Stuxnet, Night Dragon and RSA breaches from advanced persistent threats in July 2010, February 2011 and March 2011 respectively, where systems were compromised.

[42] In Order No. 706, the Commission declined to direct a method for identifying Critical Cyber Assets, but stated that it may revisit this circumstance in a future proceeding. *See* Order No. 706, 122 FERC ¶ 61,040 at P 284.

[43] *North American Electric Reliability Corp.,* 130 FERC ¶ 61,211, at P 15 (2010).

[44] 16 U.S.C. 824o(a)(4). The term ''reliable operation'' means ''operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.''

[45] Order No. 706, 122 FERC ¶ 61,040 at P 233.

[46] *Id.*

[47] *Id.*

[48] *Id.*

to believe that the NIST framework could provide beneficial input into the NERC CIP Reliability Standards and we urge NERC to consider any such provisions that will better protect the Bulk-Power System.

47. The NIST Risk Management Framework was developed to manage the risks associated with all information systems, and offers a structured yet flexible approach that can now be applied to the electric industry. The NIST Risk Management Framework guides selection and specification of cybersecurity controls and measures necessary to protect individuals and the operations and assets of the organization, while considering effectiveness, efficiency, and constraints due to applicable laws, directives, policies, standards, or regulations. Each of the activities in the Risk Management Framework has an associated NIST security standard and/or guidance document that can be used by organizations implementing the framework. The management of risk is a key element.

48. Two primary features of the NIST Framework are: (1) Customizing protection to the mission of the cyber systems subject to protection (similar to the role identified by the NERC Functional Model); and (2) ensuring that all connected cyber systems associated with the Bulk-Power System, based on their function, receive some level of protection.[49] The Bulk-Power System could benefit from each of these tested approaches.

a. NIST Approach and the NERC Functional Model

49. The purpose of the NERC CIP Reliability Standards is to specify mandatory Requirements for responsible entities to establish, maintain, and preserve the cybersecurity of key information technology systems' assets, the use of which is essential to reliable operation of the Bulk-Power System. The CIP Reliability Standards include Requirements which are based upon the functional roles of the responsible entities as specified in the NERC Functional Model.[50] The identification of cyber systems and assets used to execute these functional roles should be the first step in identifying the systems for coverage under the CIP Reliability Standards for protection. The Functional Model should be used as a starting point when considering the applicability of the NIST Framework for securing the operation of cyber assets to provide for the Reliable Operation of the Bulk-Power System.

b. NIST Tiered Approach

50. If applied to the Bulk-Power System, the NIST Framework would specify the level of protection appropriate for systems based upon their importance to the reliable operation of the Bulk-Power System. Cyber systems connected to the Bulk-Power System require availability, integrity, and confidentiality to effectively ensure the reliability of the Bulk-Power System.

51. The NIST Framework provides for a tiered approach to cybersecurity protection where protection of some type would be applied to all cyber assets connected to the Bulk-Power System. Under the NIST Framework, cyber assets whose compromise or loss of operability could result in a greater risk to Bulk-Power System reliability would be subject to more rigorous cybersecurity protections compared to a less important asset. The NIST Framework recognizes that all connected assets require a baseline level of protection to prevent attackers from gaining a foothold to launch further, even more devastating attacks on other critical systems.

52. Using the NIST framework, all cyber assets would also be reviewed to determine the appropriate level of cyber protection. The level of protection required for a given cyber asset is based upon its mission criticality and its innate technological risks.

2. Misuse of Control Systems

53. In Order No. 706, the Commission directed NERC to consider the misuse of control centers and control systems in the determination of Critical Assets.[51] If a perpetrator is able to misuse an asset, the attacker may navigate across and between control system data networks in order to gain access to multiple sites, which could enable a coordinated multi-site attack. Recent cybersecurity incidents[52] illustrate the importance of restricting connectivity between control systems and external networks, emphasizing the inherent risk exposure created by networking critical cyber control systems. Future mechanisms for identifying when cyber assets require protection will have to examine all possible paths between a given cyber resource and any asset supporting a reliability function.

54. In Order No. 706, the Commission expressed concerns regarding the classification of control centers and the potential misuse of control systems.[53] With regard to control centers, the Commission noted that responsible entities should be required to ''examine the impact on reliability if the control centers are unavailable, due for example to power or communications failures, or denial of service attacks.''[54] In addition, the Commission stated that ''[r]esponsible entities should also examine the impact that misuse of those control centers could have on the electric facilities they control and what the combined impact of those electric facilities could be on the reliability of the Bulk-Power System.''[55] The Commission stated that ''when these matters are taken into account, it is difficult to envision a scenario in which a reliability coordinator, transmission operator or transmission owner control center or backup control center would not properly be identified as a critical asset.''[56]

55. In addition, the Commission raised concerns about the misuse of a control system that controls more than one asset.[57] Specifically, the Commission noted that multiple assets, whether multiple generating units, multiple transmission breakers, or perhaps even multiple substations, could be taken out of service simultaneously due to a failure or misuse of the control system. The Commission stated that even if one or all of the assets would not be considered as a Critical Asset on a stand alone basis, a simultaneous outage resulting from the single point of control might affect the reliability or operability of the Bulk-Power System. The Commission stated ''[i]n that case, the common control system should be considered a Critical Cyber Asset.''[58]

56. The Commission is concerned that the proposed CIP–002–4 bright line criteria do not adequately address the Commission's prior directive regarding the classification of control centers or take the potential misuse of control systems into account in the identification of Critical Assets. For example, the proposed bright line criteria leave a number of Critical Assets

[49] NIST SP800–53, Section 1.4, Organizational Responsibilities.

[50] Reliability Functional Model, Function Definitions and Functional Entities, Version 5, approved by NERC Board of Trustees May 2010; and, Reliability Functional Model Technical Document Version 5, approved by NERC Board of Trustees May 2010.

[51] Order No. 706, 122 FERC ¶ 61,040 at P 282.

[52] These include the discovery of Stuxnet, Night Dragon and RSA breaches from advanced persistent threats in July 2010, February 2011 and March 2011 respectively, where systems were compromised.

[53] Order No. 706, 122 FERC ¶ 61,040 at P 280–281.

[54] *Id.* P 280.

[55] *Id.*

[56] *Id.*

[57] *Id.* P 281.

[58] *Id.*

with potentially unprotected cyber assets, including a total of 222 [59] control centers with no legal obligation to apply cybersecurity measures. These potentially unprotected control centers involve an unknown number of associated control systems.

57. Consider the following example: Electric grid control system operation in part consists of the collection of raw data needed to run the grid, collected by a SCADA system from intelligent electronic devices (IEDs) (*e.g.,* RTUs and synchrophasors). The SCADA data is typically aggregated by an energy management system (EMS). The EMS may, in some cases, calculate area control error (ACE) and transmit it to a balancing authority, which in turn makes computer based decisions about balancing load and generation. Those decisions are then used by the balancing authority or generation operator as part of an automated generation control (AGC) process. At each of these one or more sites, there are many data network interconnection points with other entities, (*e.g.,* neighboring transmission operators, generation operators, and reliability coordinators) and additional connectivity to corporate data networks and elsewhere, employing several communications technologies. This results in a complex interconnection of cyber assets (including the data of those cyber assets) demanding vigilant protection.[60] These cyber systems require comprehensive protection because the interconnected system is only as strong as its weakest link.

58. Any failure to take into account the interconnectivity of control systems represents a significant reliability gap. Where modern data networking technology is used for operation of the Bulk-Power System (*e.g.,* control systems, synchrophasors, smart grid), a network-based cyber attack could result in multiple simultaneous outages of grid equipment and cyber systems alike through misuse of a single point of control (*e.g.,* a SCADA control host system). Such an attack could take place by way of a cyber system associated with an asset that falls outside the CIP–002–4 bright line criteria yet is connected in common with other cyber systems on the Bulk-Power System. The risk of a cyber attack is greater now than when Order No. 706 was issued, as borne out by the recent increased frequency and sophistication of cyber attacks. It is critical, therefore, that the Commission's concerns regarding the potential misuse of control centers and associated control systems be addressed in the CIP Reliability Standards.

3. Regional Perspective

59. In Order No. 706, the Commission directed NERC to ''develop a process of external review and approval of critical asset lists based on a regional perspective.'' [61] The Commission found that ''Regional Entities must have a role in the external review to assure that there is sufficient accountability in the process [and] * * * because the Regional Entities and ERO are ultimately responsible for ensuring compliance with Reliability Standards.'' [62]

60. The Commission is concerned that the lack of a regional review in the identification of cyber assets might result in a reliability gap. In Order No. 706, the Commission expressed concerns regarding the need for developing a process of external review and approval of Critical Asset lists based on a regional perspective, and that such lists are considered from a wide-area view. This process would help to identify trends in Critical Asset identification. Further, while we recognize that individual circumstances may likely vary, an external review will provide an appropriate level of consistency.[63] For example, reliability coordinators may communicate through a common system and compromise of that system could propagate across multiple regions. A cyber compromise can easily propagate across these data and control networks with potential adverse consequences to the Bulk-Power System on multi-region basis.

61. This problem may become exacerbated by any future revisions to the CIP Reliability Standards that opt to reserve a high level of independent authority to the registered entity to categorize and prioritize its cyber assets. Looking forward, it will be essential for NERC and the Regional Entities to actively review the designation of cyber assets that are subject to the CIP Reliability Standards, including those which span regions, in order to determine whether additional cyber assets should be protected.

4. Summary

62. In summary, the Commission proposes to approve NERC's proposed Version 4 CIP Standards pursuant to section 215(d)(2) of the FPA. As discussed above, it appears that the Version 4 CIP Standards represent an improvement in three respects in that they: (1) Will result in the identification of certain types of Critical Assets that may not be identified under the current approach; (2) use bright line criteria to identify Critical Assets, thus limiting the discretion of responsible entities when identifying Critical Assets; and (3) provide a level of consistency and clarity regarding the identification of Critical Assets.

63. While we believe that the Version 4 CIP Reliability Standards satisfy the statutory standard for approval, we also believe that more improvement is needed. As NERC explains in its Petition, the Version 4 CIP Reliability Standards are intended as ''interim'' and future versions will build on Version 4. We believe that the electric industry, through the NERC standards development process, should continue to develop an approach to cybersecurity that is meaningful and comprehensive to assure that the nation's electric grid is capable of withstanding a Cybersecurity Incident.[64] As discussed above, we believe that some of the essential components of such a meaningful and comprehensive approach to cybersecurity are set forth in Order No. 706.

[59] NERC June 30, 2011 Data Response at 3.

[60] *See* generally, Ron Ross, Managing Enterprise Risk in Today's World of Sophisticated Threats, National Institute of Standards and Technology (2007).

[61] Order No. 706, 122 FERC ¶ 61,040 at P 329.

[62] *Id.* P 327.

[63] *Id.* P 322.

[64] Section 215(a) of the FPA defines Cybersecurity Incident as ''a malicious act or suspicious event that disrupts, or was an attempt to disrupt, the operation of those programmable electronic devices and communication networks including hardware, software and data that are essential to the reliable operation of the Bulk-Power System.''

5. Reasonable Deadline for Full Compliance With Order No. 706

64. The Commission issued Order No. 706 on January 18, 2008. In Order No. 706, the Commission approved Version 1 of the CIP Reliability Standards while also directing modifications pursuant to section 215(d)(5) of the FPA, some of which are described above. Later approved versions of the CIP Reliability Standards, and now the proposed Version 4 CIP Reliability Standards, addressed some of the directives in Order No. 706, but other directives remain unsatisfied.

65. Over three years have elapsed since the Commission issued the Final Rule in January 2008. As discussed above, we believe that it is important for the successful implementation of a comprehensive approach to cybersecurity that NERC timely addresses the modifications directed by the Commission in Order No. 706. Accordingly, the Commission proposes to set a deadline for NERC to file the next version of the CIP Reliability Standards, which NERC indicates will address all outstanding Order No. 706 directives.[65] This proposal is consistent with the views expressed in the January 2011 Audit Report of the Department of Energy's Inspector General, who found ''that the Commission could have, but did not impose specific deadlines for the ERO to incorporate changes to the CIP standards.'' [66] Similarly, our proposal is responsive to the Audit Report finding that ''the CIP standards implementation approach and schedule approved by the Commission were not adequate to ensure that systems-related risks to the Nation's power grid were mitigated or addressed in a timely manner.'' [67]

66. The Commission understands that, under NERC's timeline for the ongoing effort to address all outstanding Order No. 706 directives, it anticipates submitting the next version of the CIP Reliability Standards to the NERC Board of Trustees by the second quarter of 2012, and filing that version the Commission by the end of the third quarter of 2012.[68]

67. The Commission proposes to establish NERC's current development timeline above as a deadline for compliance with the outstanding Order No. 706 CIP Standard directives. The Commission seeks comments from NERC and other parties concerning this proposal. Further, NERC and other parties may propose and support an alternative compliance deadline.

IV. Information Collection Statement

68. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping requirements (collections of information) imposed by an agency.[69] The information contained here is also subject to review under section 3507(d) of the Paperwork Reduction Act of 1995.[70] We will submit this proposed rule to OMB for review.

69. As stated above, the Commission previously approved Reliability Standards similar to the proposed Reliability Standards that are the subject of the current rulemaking.[71]

70. The principal differences in the information collection requirements and resulting burden imposed by the proposed Reliability Standards in this rule are triggered by the proposed changes in Reliability Standard CIP–002–4. The previous risk-based assessment methodology for identifying Critical Assets will be replaced by 17 uniform ''bright line'' criteria for identifying Critical Assets (in CIP–002–4, Attachment 1, ''Critical Asset Criteria''). Proposed Reliability Standard CIP–002–4 would require each responsible entity to use the bright line criteria as a ''checklist'' to identify Critical Assets, initially and in an annual review, instead of performing the more technical and individualized risk analysis involved in complying with the currently-effective CIP Reliability Standards. As in past versions, each Responsible Entity will then identify the Critical Cyber Assets associated with its updated list of Critical Assets. If application of the bright line criteria result in the identification of new Critical Cyber Assets, such assets become subject to the remaining standards (proposed CIP–003–4, CIP–004–4, CIP–005–4a, CIP–006–4c, CIP–007–4, CIP–008–4, and CIP–009–4), and the information collection requirements contained therein.

71. We estimate that the burden associated with the annual review of the assets (by the estimated 1,501 entities) will be simplified by the ''Critical Asset Criteria'' in proposed Reliability Standard CIP–002–4. Rather than each entity annually reviewing and updating a Risk-Based Assessment Methodology that frequently required technical analysis and judgment decisions, the proposed bright line criteria will provide a straight forward checklist for all entities to use. Thus, we estimate that the proposal will reduce the burden associated with the annual review, as well as provide a consistent and clear set of criteria for all entities to follow.

72. The estimated changes to burden as contained in the proposed rule in RM11–11 follow.

[65] *See* NERC's May 27, 2011 Responses to Data Requests, Response 1 (''[t]he standard drafting team expects that the filing for the next version of the CIP Reliability Standards will address the remaining FERC Order No. 706 directives'').

[66] Department of Energy Inspector General Audit Report, *Federal Energy Regulatory Commission's Monitoring of Power Grid Cybersecurity* at 6 (January 2011).

[67] *Id.* at 2.

[68] *See* NERC's May 27, 2011 Responses to Data Requests, Response 1. *See also North American Electric Reliability Corporation Reliability Standards Development Plan 2011–2013 Informational Filing Pursuant to Section 310 of the NERC Rules of Procedure,* Docket Nos. RM05–17–000, RM05–25–000, RM06–16–000 at 14 (filed April 5, 2011).

[69] 5 CFR 1320.11.

[70] 44 U.S.C. 3507(d).

[71] *North American Electric Reliability Corporation,* 130 FERC ¶ 61,271 (2010).

FERC–725B Data collection (per proposed Version 4)	Number of respondents [72] (1)	Average number of annual responses per respondent (2)	Average number of burden hours per response [73] (3)	Effect of NOPR in RM11–11, on total annual hours (1) × (2) × (3)	Annual burden hours upon implementation of RM11–11
Entities that (previously and now) will identify at least one Critical Cyber Asset [category a].	345 [no change]	1	1,880 [reduction of 40 hours from 1,920 to 1,880 hours].	reduction of 13,800 hours.	648,600
Entities that (previously and now) will not identify any Critical Cyber Assets [category b].	1,144 [reduction of 12 entities from 1156 to 1,144].	1	120 [no change]	Reduction of 1,440 hours [for the 12 entities].	137,280
Entities that will newly identify a Critical Asset/Critical Cyber Asset due to the requirements in RM11–11 [74] [category c].	increase of 12 [formerly 0].	1	3,840 [75]	increase of 46,080	46,080
Net Total	1,501 [72]			+30,840	831,960

The revisions to the cost estimates based on requirements of this proposed rule are:

• Each entity that has identified Critical Cyber Assets has a reduction of 40 hours (345 entities × 40 hrs. × @$96/hour = $1,324,800 reduction).

• 12 Entities that formerly had not identified Critical Cyber Assets, but now will have them, has

○ A reduction of 120 hours and an increase of 3,840 hours (for a net increase of 3,720 annual hours), giving 12 entities × 3,720 hrs.@$96/hour = $4,285,440.

○ Storage costs = 12 entities@$15.25/entity = $183.

Total Net Annual Cost for the FERC–725B requirements contained in the NOPR in RM11–11 = $2,960,823 ($4,285,440 + $183 −$1,324,800).

The estimated hourly rate of $96 is the average cost of legal services ($230 per hour), technical employees ($40 per hour) and administrative support ($18 per hour), based on hourly rates from the Bureau of Labor Statistics (BLS) and the 2009 Billing Rates and Practices Survey Report.[76] The $15.25 per entity for storage costs is an estimate based on the average costs to service and store 1 GB of data to demonstrate compliance with the CIP Standards.[77]

Title: Mandatory Reliability Standards, Version 4 Critical Infrastructure Protection Standards.

Action: Proposed Collection FERC–725B.

OMB Control No.: 1902–0248.

Respondents: Businesses or other for-profit institutions; not-for-profit institutions.

Frequency of Responses: On Occasion.

Necessity of the Information: This proposed rule proposes to approve the requested modifications to Reliability Standards pertaining to critical infrastructure protection. The proposed Reliability Standards help ensure the reliable operation of the Bulk-Power System by providing a cybersecurity framework for the identification and protection of Critical Assets and associated Critical Cyber Assets. As discussed above, the Commission proposes to approve NERC's proposed Version 4 CIP Standards pursuant to section 215(d)(2) of the FPA because they represent an improvement to the currently-effective CIP Reliability Standards.

Internal Review: The Commission has reviewed the proposed Reliability Standards and made a determination that its action is necessary to implement section 215 of the FPA.

73. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426 [*Attention:* Ellen Brown, Office of the Executive Director, *e-mail: DataClearance@ferc.gov, phone:* (202) 502–8663, *fax:* (202) 273–0873].

74. For submitting comments concerning the collection(s) of information and the associated burden estimate(s), please send your comments to the Commission, and to the Office of Management and Budget, Office of Information and Regulatory Affairs,

[72] The NERC Compliance Registry as of 9/28/2010 indicated that 2,079 entities were registered for NERC's compliance program. Of these, 2,057 were identified as being U.S. entities. Staff concluded that of the 2,057 U.S. entities, approximately 1,501 were registered for at least one CIP related function. According to an April 7, 2009 memo to industry, NERC noted that only 31% of entities responding to an earlier survey reported that they had at least one Critical Asset, and only 23% reported having a Critical Cyber Asset. Staff applied the 23% (an estimate unchanged for Version 4 standards) to the 1,501 figure to estimate the number of entities that identified Critical Assets under Version 3 CIP Standards.

[73] Calculations for figures prior to applying reductions:

Respondent category b:

3 employees × (working 50%) × (40 hrs/week) × (2 weeks) = 120 hours.

Respondent category c:

20 employees × (working 50%) × (40 hrs/week) × (8 weeks) = 3200 hours.

20 employees × (working 20%) × (3200 hrs) = 640 hours.

Total = 3840.

Respondent category a:

50% of 3840 hours (category d) = 1920.

[74] We estimate 12 (or 1%) of the existing entities that formerly had no identified Critical Cyber Assets will have them under the proposed Reliability Standards. This proposed rule does not affect the burden for the 6 new U.S. Entities that were estimated to newly register or otherwise become subject to the CIP Standards each year in FERC–725B, and therefore are not included in this chart.

[75] This estimated burden estimate applies only to the first three year audit cycle. In subsequent audit cycles these entities will move into category a, or be removed from the burden as an entity that no longer is registered for a CIP related function.

[76] Bureau of Labor Statistics figures were obtained from *http://www.bls.gov/oes/current/naics2_22.htm,* and 2009 Billing Rates figure were obtained from *http://www.marylandlawyerblog.com/2009/07/average_hourly_rate_for_lawyer.html.* Legal services were based on the national average billing rate (contracting out) from the above report and BLS hourly earnings (in-house personnel). It is assumed that 25% of respondents have in-house legal personnel.

[77] Based on the aggregate cost of an advanced data protection server.

Washington, DC 20503 [*Attention:* Desk Officer for the Federal Energy Regulatory Commission, *phone:* (202) 395–4638, *fax:* (202) 395–7285]. For security reasons, comments to OMB should be submitted by e-mail to: *oira_submission@omb.eop.gov.* Comments submitted to OMB should include Docket Number RM11–11 and OMB Control Number 1902–0248.

V. Environmental Analysis

75. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[78] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[79] The actions proposed here fall within this categorical exclusion in the Commission's regulations.

VI. Regulatory Flexibility Act Certification

76. The Regulatory Flexibility Act of 1980 (RFA)[80] generally requires a description and analysis of final rules that will have a significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a proposed rule and that minimize any significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[81] The SBA has established a size standard for electric utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million megawatt hours.[82]

77. The Commission analyzed the affect of the proposed rule on small entities. The Commission's analysis found that the DOE's Energy Information Administration (EIA) reports that there were 3,276 electric utility companies in the United States in 2009,[83] and 3,015 of these electric utilities qualify as small entities under the Small Business Administration (SBA) definition. Of these 3,276 electric utility companies, the EIA subdivides them as follows: (1) 875 Cooperatives of which 843 are small entity cooperatives; (2) 1,841 municipal utilities, of which 1,826 are small entity municipal utilities; (3) 128 political subdivisions, of which 115 are small entity political subdivisions; (4) 171 power marketers, of which 113 individually could be considered small entity power marketers;[84] (5) 200 privately owned utilities, of which 93 could be considered small entity private utilities; (6) 24 state organizations, of which 14 are small entity state organizations; and (7) 9 federal organizations of which 4 are small entity federal organizations.

78. Many of the entities that have not previously identified Critical Assets and Critical Cyber Assets are considered small entities. The new CIP version 4 bright line criteria generally result in the identification of relatively larger Bulk-Power System equipment as Critical Assets. For the most part, the small entities do not own or operate these larger facilities. There is a limited possibility that these entities would have facilities that meet the bright line criteria and therefore be subject to the full CIP standards (CIP–002 through CIP–009). The Commission expects only a marginal increase in the number of small entities that will identify at least one Critical Asset under the Version 4 CIP Reliability Standards that have not done so previously.

79. The Commission estimates that only one percent (12) of the small and medium-sized entities that have not previously identified Critical Assets and Critical Cyber Assets will have an increased cost due to the proposed Reliability Standards and their identification of new Critical Cyber Assets. For each of those 12 entities, we anticipate a cost increase associated with creating a cyber security program along with the actual cyber security protections associated with the identified Critical Cyber Assets. The Commission requests comment on the potential implementation cost and subsequent cost increases that could be experienced by such small entities. Small and medium-sized entities that continue to have no Critical Assets will not see any change in their burden.

80. In general, the majority of small entities are not required to comply with mandatory Reliability Standards because they are not regulated by NERC pursuant to the NERC Registry Criteria. Moreover, a small entity that is registered but does not identify critical cyber assets pursuant to CIP–002–4 will not have compliance obligations pursuant to CIP–003–4 through CIP–009–4.

81. The Commission also investigated possible alternatives. These included the Commission's adoption in Order No. 693 of the NERC definition of bulk electric system, which reduces significantly the number of small entities responsible for compliance with mandatory Reliability Standards. The Commission also noted that small entities could join a joint action agency or similar organization, which could accept responsibility for compliance with mandatory Reliability Standards on behalf of its members and also may divide the responsibility for compliance with its members.

82. Based on the foregoing, the Commission certifies that the proposed Reliability Standards will not have a significant impact on a substantial number of small entities. Accordingly, no regulatory flexibility analysis is required.

VII. Comment Procedures

83. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due November 21, 2011. Comments must refer to Docket No. RM11–11–000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

84. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's Web site at *http://www.ferc.gov.* The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

85. Commenters unable to file comments electronically must mail or hand deliver an original copy of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE., Washington, DC 20426.

[78] Order No. 486, *Regulations Implementing the National Environmental Policy Act of 1969,* FERC Stats. & Regs., Regulations Preambles 1986–1990 ¶ 30,783 (1987).

[79] 18 CFR 380.4(a)(2)(ii).

[80] 5 U.S.C. 601–612.

[81] 13 CFR 121.101.

[82] 13 CFR 121.201, Sector 22, Utilities & n.1.

[83] *See* Energy Information Administration Database, Form EIA–861, Dept. of Energy (2009), *available at http://www.eia.doe.gov/cneaf/electricity/page/eia861.html.*

[84] Most of these small entity power marketers and private utilities are affiliated with others and, therefore, do not qualify as small entities under the SBA definition.

86. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VIII. Document Availability

87. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (*http://www.ferc.gov*) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington, DC 20426.

88. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

89. User assistance is available for eLibrary and the Commission's Web site during normal business hours from FERC Online Support at 202–502–6652 (toll free at 1–866–208–3676) or e-mail at *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659. E-mail the Public Reference Room at *public.referenceroom@ferc.gov.*

List of Subjects in 18 CFR Part 40

Electric power, Electric utilities, Reporting and recordkeeping requirements.

By direction of the Commission.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2011–24102 Filed 9–21–11; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 284

[Docket No. RM11–4–000]

Storage Reporting Requirements of Interstate and Intrastate Natural Gas Companies

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Commission proposes to eliminate the semi-annual storage reporting requirements for Interstate and Intrastate Natural Gas Companies that are currently codified in our regulations. The Commission finds that the reports now proposed for elimination are largely duplicative with other reporting requirements.

DATES: Comments are due November 21, 2011.

ADDRESSES: Comments, identified by docket number, may be filed in the following methods:

- Electronic Filing through *http://www.ferc.gov.* Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- *Mail/Hand Delivery:* Those unable to file electronically may mail or hand-deliver an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE., Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, see the Comment Procedures Section of this document.

FOR FURTHER INFORMATION CONTACT: Vince Mareino (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–6167, *Vince.Mareino@ferc.gov.*

Thomas Russo (Technical Information), Office of Enforcement, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–8792, *Thomas.Russo@ferc.gov.*

SUPPLEMENTARY INFORMATION:

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September 15, 2011.

1. The Commission proposes to eliminate the semi-annual storage reporting requirements for: (1) Interstate natural gas companies subject to the Commission's jurisdiction under the Natural Gas Act (NGA), as codified in 18 CFR 284.13(e); (2) intrastate pipelines providing interstate services pursuant to section 311 of the Natural Gas Policy Act of 1978 (NGPA),[1] as codified in 18 CFR 284.126(c); and (3) Hinshaw [2] pipelines providing interstate services subject to the Commission's Natural Gas Act (NGA) jurisdiction pursuant to blanket certificates issued under § 284.224 of the Commission's regulations, as also codified in 18 CFR

[1] 15 U.S.C. 3372.

[2] Section 1(c) of the NGA exempts from the Commission's NGA jurisdiction pipelines which transport gas in interstate commerce if (1) They receive natural gas at or within the boundary of a state, (2) all the gas is consumed within that state, and (3) the pipeline is regulated by a state Commission. This exemption is referred to as the Hinshaw exemption after the Congressman who introduced the bill amending the NGA to include § 1(c). *See ANR Pipeline Co.* v. *Federal Energy Regulatory Comm'n,* 71 F.3d 897, 898 (1995) (briefly summarizing the history of the Hinshaw exemption).

September 15, 2011
News Media Contact
Craig Cano | 202-502-8680
Docket Nos. (RM11-11-000, RM10-29-000, RM10-6-000)

FEDERAL ENERGY REGULATORY COMMISSION NEWS

FERC Takes Steps to Support Continued Reliability of Electric Grid

The Federal Energy Regulatory Commission (FERC) took steps to support continued transmission system reliability by proposing revisions to eight critical infrastructure protection reliability standards that include a new method of identifying cyber assets that are critical to the nation's bulk power grid.

The proposed "Version 4" CIP standards are an interim step, FERC said in directing the electric industry and the North American Electric Reliability Corp. (NERC) to continue developing a comprehensive approach to assure the grid can withstand a cyber security incident. NERC is the Commission-certified electric reliability organization responsible for developing and enforcing mandatory reliability standards.

The new standard would replace the existing risk-based assessment methodology for identifying critical assets with 17 uniform "bright line" criteria, making the process more consistent and clear by limiting discretion in the identification of such assets.

Today's notice of proposed rulemaking (NOPR) stressed that NERC has not addressed all the modifications directed by the Commission's Order No. 706, which approved the original CIP standards in January 2008. The NOPR would require NERC to make a filing to fully comply with Order No. 706 by the end of the third quarter of 2012. Comments on the proposed rule (RM11-11) are due 60 days after publication in the *Federal Register*.

In other reliability orders, FERC issued final rules approving NERC's interpretation of:

- Transmission Operations Reliability Standard TOP-001-1 on the restoration of real and reactive power during a system emergency (RM10-29). The final rule agreed with NERC's view that the balancing authority is responsible for restoring real power balance and the transmission provider is responsible for restoring reactive balance during a system emergency.

- Transmission Planning Reliability Standard TPL-002-0 addressing system performance following loss of a single bulk electric system element (RM10-6).

R-11-39

(30)

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136 FERC ¶ 61,184
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

Docket No. RM11-11-000

Version 4 Critical Infrastructure Protection Reliability Standards

(September 15, 2011)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: Under section 215 of the Federal Power Act, the Federal Energy Regulatory Commission (Commission) proposes to approve eight modified Critical Infrastructure Protection (CIP) Reliability Standards, CIP-002-4 through CIP-009-4, developed and submitted to the Commission for approval by the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization certified by the Commission. In general, the CIP Reliability Standards provide a cybersecurity framework for the identification and protection of "Critical Cyber Assets" to support the reliable operation of the Bulk-Power System. Proposed Reliability Standard CIP-002-4 requires the identification and documentation of Critical Cyber Assets associated with Critical Assets that support the reliable operation of the Bulk-Power System. The "Version 4" CIP Reliability Standards propose to modify CIP-002-4 to include "bright line" criteria for the identification of Critical Assets. The proposed Version 4 CIP Reliability Standards would replace the currently effective Version 3 CIP Reliability Standards. The Commission also proposes to approve the related Violation Risk Factors

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and Violation Severity Levels with modifications, the implementation plan, and effective date proposed by NERC.

DATES: Comments are due [Insert date that is 60 days after publication in the **FEDERAL REGISTER**].

ADDRESSES: You may submit comments, identified by docket number and in accordance with the requirements posted on the Commission's website http://www.ferc.gov. Comments may be submitted by any of the following methods:

- Agency Web Site: Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format, at http://www.ferc.gov/docs-filing/efiling.asp.
- Mail/Hand Delivery: Commenters unable to file comments electronically must mail or hand deliver an original copy of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426. These requirements can be found on the Commission's website, see, e.g., the "Quick Reference Guide for Paper Submissions," available at http://www.ferc.gov/docs-filing/efiling.asp or via phone from FERC Online Support at 202-502-6652 or toll-free at 1-866-208-3676.

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SUPPLEMENTARY INFORMATION:

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136 FERC ¶ 61,184
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Version 4 Critical Infrastructure Protection Reliability Standards

Docket No. RM11-11-000

NOTICE OF PROPOSED RULEMAKING

(September 15, 2011)

1. Under section 215 of the Federal Power Act (FPA),[1] the Commission proposes to approve eight modified Critical Infrastructure Protection (CIP) Reliability Standards, CIP-002-4 through CIP-009-4. The proposed "Version 4" CIP Standards were developed and submitted for approval to the Commission by the North American Electric Reliability Corporation (NERC), which the Commission certified as the Electric Reliability Organization (ERO) responsible for developing and enforcing mandatory Reliability Standards.[2] In general, the CIP Reliability Standards provide a cybersecurity framework for the identification and protection of "Critical Cyber Assets" to support the reliable operation of the Bulk-Power System.[3] In particular, the Version 4 CIP Reliability Standards propose to modify CIP-002-4 to include "bright line" criteria for the identification of Critical Assets, in lieu of the currently-required risk-based assessment

[1] 16 U.S.C. 824o (2006).

[2] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g & compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[3] The NERC Glossary of Terms defines Critical Assets to mean "Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System."

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methodology that is developed and applied by applicable entities. In addition, NERC developed proposed conforming modifications to the remaining cybersecurity Reliability Standards, CIP-003-4 through CIP-009-4.

2. The Commission proposes to approve Version 4, the Violation Risk Factors (VRFs),the Violation Severity Levels (VSLs) with modifications, the implementation plan, and effective date proposed by NERC. The Commission also proposes to approve the retirement of the currently effective Version 3 CIP Reliability Standards, CIP-002-3 to CIP-009-3. The Commission seeks comments on these proposals to approve.

3. While we propose to approve the Version 4 CIP Standards, like NERC, we recognize that the Version 4 CIP Standards represent an "interim step"[4] to addressing all of the outstanding directives set forth in Order No. 706.[5] We believe that the electric industry, through the NERC standards development process, should continue to develop an approach to cybersecurity that is meaningful and comprehensive to assure that the nation's electric grid is capable of withstanding a Cybersecurity Incident.[6] Below, we reiterate several topics set forth in Order No. 706 that pertain to a tiered approach to identifying Cyber Assets, protection from misuse, and a regional perspective. We expect

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[4] NERC Petition at 6.

[5] *Mandatory Reliability Standards for Critical Infrastructure Protection*, Order No. 706, 122 FERC ¶ 61,040, *order on reh'g*, Order No. 706-A, 123 FERC ¶ 61,174 (2008), *order on clarification*, Order No. 706-B, 126 FERC ¶ 61,229 (2009).

[6] Section 215(a) of the FPA defines Cybersecurity Incident as "a malicious act or suspicious event that disrupts, or was an attempt to disrupt, the operation of those programmable electronic devices and communication networks including hardware, software and data that are essential to the reliable operation of the Bulk-Power System."

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NERC will continue to improve the CIP Standards to address these and other outstanding matters addressed in Order No. 706.

4. Moreover, as discussed below, the Commission seeks comments from NERC and other interested persons on establishing a reasonable deadline for NERC to satisfy the outstanding directives in Order No. 706 pertaining to the CIP Standards, using NERC's development timeline.

I. Background

A. Mandatory Reliability Standards

5. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval. Once approved, the Reliability Standards may be enforced by the ERO, subject to Commission oversight, or by the Commission independently.[7]

6. Pursuant to section 215 of the FPA, the Commission established a process to select and certify an ERO[8] and, subsequently, certified NERC as the ERO.[9] On January 18, 2008, the Commission issued Order No. 706 approving eight CIP Reliability Standards proposed by NERC.

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[7] *See* 16 U.S.C. 824o(e).

[8] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[9] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g & compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom., Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

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7. In addition, pursuant to section 215(d)(5) of the FPA,[10] the Commission directed NERC to develop modifications to the CIP Reliability Standards to address various concerns discussed in the Final Rule. In relevant part, the Commission directed the ERO to address the following issues regarding CIP-002-1: (1) need for ERO guidance regarding the risk-based assessment methodology for identifying Critical Assets; (2) scope of Critical Assets and Critical Cyber Assets; (3) internal, management, approval of the risk-based assessment; (4) external review of Critical Assets identification; and (5) interdependency between Critical Assets of the Bulk-Power System and other critical infrastructures. Subsequently, the Commission approved Version 2 and Version 3 of the CIP Reliability Standards, each version including changes responsive to some but not all of the directives in Order No. 706.[11]

B. Current Version 3 CIP Reliability Standards

8. Reliability Standard CIP-002-3 addresses the identification of Critical Assets and associated Critical Cyber Assets. Pursuant to CIP-002-3, a responsible entity must develop a risk-based assessment methodology to identify its Critical Assets. Requirement R1 specifies certain types of assets that an assessment must consider for Critical Asset status and also allows the consideration of additional assets that the responsible entity deems appropriate. Requirement R2 requires the responsible entity to

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[10] 16 U.S.C. 824o(d)(5).

[11] *North American Electric Reliability Corp*., 128 FERC ¶ 61,291 (2009), *order denying reh'g and granting clarification*, 129 FERC ¶ 61,236 (2009) (approving Version 2 of the CIP Reliability Standards); *North American Electric Reliability Corp.*, 130 FERC ¶ 61,271 (2010) (approving Version 3 of the CIP Reliability Standards).

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develop a list of Critical Assets based on an annual application of the risk-based assessment methodology developed pursuant to Requirement R1. Requirement R3 provides that the responsible entity must use the list of Critical Assets to develop a list of associated Critical Cyber Assets that are essential to the operation of the Critical Assets.

9. In addition, the Commission approved the following "Version 3" CIP Standards:

- CIP-003-3 (Security Management Controls)
- CIP-004-3 (Personnel & Training)
- CIP-005-3 (Electronic Security Perimeter(s))
- CIP-006-3 (Physical Security of Critical Cyber Assets)
- CIP-007-3 (Systems Security Management)
- CIP-008-3 (Incident Reporting and Response Planning)
- CIP-009-3 (Recovery Plans for Critical Cyber Assets)

II. Proposed Version 4 CIP Reliability Standards

A. NERC Petition

10. On February 10, 2011, NERC filed a petition seeking Commission approval of proposed Reliability Standards CIP-002-4 to CIP-009-4 and requesting the concurrent retirement of the currently effective Version 3 CIP Reliability Standards, CIP-002-3 to CIP-009-3.[12] The principal differences are found in CIP-002, where NERC replaced the

[12] NERC Petition at 1. The proposed Reliability Standards are not attached to the NOPR. They are, however, available on the Commission's eLibrary document retrieval system in Docket No. RM11-11-000 and are available on the ERO's website, www.nerc.com. Reliability Standards approved by the Commission are not codified in the CFR.

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risk-based assessment methodology for identifying Critical Assets with 17 uniform bright line criteria for identifying Critical Assets. NERC does not propose any changes to the process of identifying the associated Critical Cyber Assets that are then subject to the cyber security protections required by CIP-003 through CIP-009. NERC also submitted proposed VRFs and VSLs and an implementation plan governing the transition to Version 4. NERC proposed that the Version 4 CIP Reliability Standards become effective the first day of the eighth calendar quarter after applicable regulatory approvals have been received.

11. On April 12, 2011, NERC made an errata filing correcting certain errors in the petition and furnishing corrected exhibits and the standard drafting team minutes. In the errata, NERC also replaced the VRFs and VSLs in the February 10 petition with new proposed VRFs and VSLs.[13]

12. In its Petition, NERC states the that Version 4 CIP Standards satisfy the Commission's criteria, set forth in Order No. 672, for determining whether a proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential and in

[13] NERC states that the Version 4 VRFs and VSLs are carried over in part from the VRFs and VSLs in the Version 3 CIP Reliability Standards. NERC Petition at 46. The Commission approved the Version 2 and 3 VRFs and VSLs in Docket Nos. RD10-6-001 and RD09-7-003 on January 20, 2011 but required NERC to make modifications in a compliance filing due by March 21, 2011. *North American Electric Reliability Corporation*, 134 FERC ¶ 61,045 (2011). The February 10 petition did not carry over the modified Version 3 VRFs and VSLs since it was filed before the March 21 compliance filing. NERC submitted new Version 4 VRFs and VSLs that carried over the modified Version 3 VRFs and VSLs in the April 12 errata. On June 6, 2011, NERC filed the March 21, 2011 compliance filing in the present docket, Docket No. RM11-11-000.

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the public interest.[14] According to NERC, CIP-002-4 achieves a specified reliability goal by requiring the identification and documentation of Critical Cyber Assets associated with Critical Assets that support the reliable operation of the Bulk-Power System. NERC opines that the Reliability Standard "improves reliability by establishing uniform criteria across all Responsible Entities for the identification of Critical Assets."[15] Further, NERC states that CIP-002-4 contains a technically sound method to achieve its reliability goal by requiring the identification and documentation of Critical Assets through the application of the criteria set forth in Attachment 1 of CIP-002-4.

13. NERC states that CIP-002-4 establishes clear and uniform criteria for identifying Critical Assets on the Bulk-Power System.[16] NERC also states that CIP-002-4 does not reflect any differentiation in requirements based on size of the responsible entity. NERC asserts that CIP-002-4 will not have negative effects on competition or restriction of the grid. NERC also contends that the two-year implementation period for CIP-002-4 is reasonable given the time it will take responsible entities to determine whether assets meet the criteria included in Attachment 1 and to implement the controls required in CIP-003-4 through CIP-009-4 for the newly identified assets.

14. Finally, NERC acknowledges that CIP-002-4 addresses some, but not all, of the Commission's directives in Order No. 706. NERC explains that the standard drafting team limited the scope of requirements in the development of CIP Version 4 "as an

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[14] Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 323-337.

[15] NERC Petition at 4.

[16] *Id.* at 38.

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interim step" limited to the concerns raised by the Commission regarding CIP-002.[17] NERC states that it has taken a "phased" approach to meeting the Commission's directives from Order No. 706 and, according to NERC, the standard drafting team continues to address the remaining Commission directives. According to NERC, the team will build on the bright line approach of CIP Version 4.[18]

B. Proposed Reliability Standard CIP-002-4

15. Proposed Reliability Standard CIP-002-4 contains 3 requirements. Requirement R1, which pertains to the identification of Critical Assets, provides:

> The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the criteria contained in *CIP-002-4 Attachment 1 – Critical Asset Criteria*. The Responsible Entity shall update this list as necessary, and review it at least annually.

Attachment 1 provides seventeen criteria to be used by all responsible entities for the identification of Critical Assets pursuant to Requirement R1. The thresholds pertain to specific types of facilities such as generating units, transmission lines and control centers. For example, Criterion 1.1 provides "[e]ach group of generating units (including nuclear generation) at a single plant location with an aggregate highest rated net Real Power capability of the preceding 12 months equal to or exceeding 1500 MW in a single Interconnection." With regard to transmission, Criterion 1.6 provides "Transmission Facilities operated at 500 kV or higher," and Criterion 1.7 provides "Transmission

[17] NERC Petition at 6 (citing Order No. 706, 122 FERC ¶ 61,040 at P 236).

[18] NERC Petition at 6.

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Facilities operated at 300 kV or higher at stations or substations interconnected at 300 kV or higher with three or more other transmission stations or substations."

16. Reliability Standard CIP-002-4, Requirement R2 requires responsible entities to develop a list of Critical Cyber Assets associated with the Critical Assets identified pursuant to Requirement R1. As in previous versions, the Requirement further states that to qualify as a Critical Cyber Asset, the Cyber Asset must: (1) use a routable protocol to communicate outside the Electronic Security Perimeter; (2) use a routable protocol within a control center; or (3) be dial-up accessible. In the proposed version, in the context of generating units at a single plant location, the Requirement limits the designation of Critical Cyber Assets only to Cyber Assets shared by a combination of generating units whose compromise could within 15 minutes result in the loss of generation capability equal to or higher than 1500 MW.

17. Requirement R3 requires that a senior manager or delegate for each responsible entity approve annually the list of Critical Assets and the list of Critical Cyber Assets, even if the lists contain no elements. As mentioned above, proposed Reliability Standards CIP-003-4 to CIP-009-4 only reflect conforming changes to accord with the CIP-002-4 Reliability Standard.

C. Additional Information Regarding Attachment 1 Criteria

18. In response to a Commission data request, NERC provided additional information regarding the bright line criteria for identifying Critical Assets.[19] NERC provided some

[19] *See* April 17, 2011 Commission staff data request issued in Docket No. RM11-11-000. NERC responded to the data request in staggered filings, on May 27, 2011 and

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information regarding the development of the criteria. Further, based on an industry survey, NERC provided information regarding the estimated number of Critical Assets and the number of Critical Assets that have associated Critical Cyber Assets located in the United States that would be identified pursuant to CIP-002-4. For example, NERC indicates that the Version 4 CIP Standards would result in the identification of 532 control centers as Critical Assets with Critical Cyber Assets, and another 21 control centers as Critical Assets without any associated Critical Cyber Assets.[20] Further, 201 control centers would not be identified as Critical Assets. With regard to Blackstart Resources, NERC's survey results indicate that CIP-002-4 would result in the identification of approximately 234 Blackstart Resources as Critical Assets with associated Critical Cyber Assets, 273 identified as Critical Assets without Critical Cyber Assets, and 35 Blackstart Resources not classified as Critical Assets.[21]

III. Discussion

19. Pursuant to FPA section 215(d)(2), the Commission proposes to approve CIP-002-4 to CIP-009-4 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. The Commission proposes to approve the VRFs and VSLs, implementation plan, and effective date proposed by NERC. The Commission also proposes to approve the retirement of the currently effective Version 3 CIP Reliability

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June 30, 2011.

[20] NERC June 30, 2011 Data Response at 2-3.

[21] *Id*. at 3-4. In the June 30, 2011 Data Response, NERC stated that with respect to Blackstart Resources some responsible entities indicated that they had not performed a complete analysis of their systems based on CIP-002-4 and are unsure whether some units may be classified as Critical Assets. *Id.* at 4.

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Standards CIP-002-3 to CIP-009-3 upon the effective date of CIP-002-4 to CIP-009-4. The Commission seeks comments on these proposals.

20. Further, as discussed below, the Commission seeks comments from NERC and other interested persons on the proposal to establish a reasonable deadline for NERC to satisfy the outstanding directives in Order No. 706. Specifically, as explained in detail later, the Commission requests comments on: (1) the proposal to establish a deadline using NERC's development timeline for the next version of the CIP Reliability Standards; (2) how much time NERC needs to develop and file the next version of the CIP Reliability Standards; (3) other potential approaches to Critical Cyber Asset identification; and (4) whether the next version is anticipated to satisfy all of the directives in Order No. 706.

A. The Commission Proposes to Approve the Version 4 CIP Reliability Standards

21. The Commission, in giving due weight to NERC's Filing, proposes to approve the Version 4 CIP Reliability Standards. The Commission also proposes to approve the implementation plan and effective date proposed by NERC. Version 4 provides a change in three respects: (1) Version 4 will result in the identification of certain types of Critical Assets that may not be identified under the current approach; (2) Version 4 uses bright line criteria to identify Critical Assets, eliminating the use of existing entity-defined risk-based assessment methodologies that generally do not adequately identify Critical Assets; and (3) Version 4 provides a level of consistency and clarity regarding the identification

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of Critical Assets lacking under Version 3. We separately address each of these reasons for proposing to approve Version 4 below.

1. Critical Asset Identification

22. In its Petition, NERC indicates that, after conducting reviews of CIP-002 compliance, NERC "determined that the existing methodologies generally do not adequately identify all Critical Assets."[22] While recognizing that CIP version 4 is intended as an "interim step," it appears that the proposed bright line criteria will result in the identification of certain types of Critical Assets (e.g. 500 kV substations) that may not be identified by the approach that is currently in effect. This is reflected in NERC's June 30, 2011 data response, in which NERC presented industry survey data reflecting the application of the bright line criteria in Version 4. To facilitate an analysis of the data, NERC also provided observations and data from several of its earlier industry surveys, including the 2009 "CIP Self-Certification Survey" and 2010 "CIP-002 Critical Asset Methodology Data Request.". For example, NERC states in the June 30, 2011 data response that in the 2009 survey only 50 percent of substations rated 300 kV and above are classified as Critical Assets while that figure would increase to 70 percent under Version 4.[23]

23. The NERC petition indicates that 270 transmission substations rated 500 kV and above are classified as Critical Assets under Version 3 while, according to the data

[22] NERC Petition at 11

[23] *Id*. at 4.

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response, the figure would rise to 437 under Version 4.[24] This increase is consistent with Criterion 1.6 of Attachment 1 to CIP-002-4, which identifies all transmission substations rated 500 kV as Critical Assets. According to the data response, the 25 percent of generation units rated 300 MVA and above would be identified as Critical Assets under Version 4. Moreover, the proportion of total Blackstart Resources classified as Critical Assets increases due to the required 100 percent coverage of these under Version 4.[25] Further, the number of control centers identified as Critical Assets increases from 425 under Version 3 to 553 under Version 4, the latter figure representing 74 percent of all control centers. These figures represent increases in certain categories in Critical Asset identification among generation, transmission, and control centers. We also note that NERC's industry survey data indicates decreases in the number of generation and blackstart resources identified as Critical Assets with Critical Cyber Assets. While the bright line thresholds result in the identification of a significant number of additional generation plants rated above 1500 MVA as Critical Assets, the thresholds also result in the identification of less generation below 300 MVA.

24. As NERC recognizes in its filing, the improvements in Critical Asset identification under Version 4 represent an interim step in complying with the directives in Order

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[24] *Id.* at 5.

[25] NERC Petition at 17 (explaining that each Blackstart Resource identified in a Transmission Operator's restoration plan is a Critical Asset). In the June 30, 2011 Data Response, NERC's survey found that responsible entities identified 93 percent of Blackstart Resources as Critical Assets. NERC stated that confusion over the term Blackstart Resource may have contributed to the lower percentage, and that responsible entities will be educated on the definition of Blackstart Resource prior to the effective date of CIP-002-4. NERC June 30, 2011 Data Response at 4.

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No. 706.[26] As we discuss below, Version 4 should not be viewed as an endpoint but as a step towards eventual full compliance with Order No. 706.

2. Version 4 Removes Discretion in Identifying Critical Assets

25. The proposed Version 4 CIP Reliability Standards discards the current risk-based methodology for identifying Critical Assets. Under the current CIP-002-3, responsible entities are tasked with identifying Critical Assets based on their own risk-based methodology. In the Petition NERC points out that in Order No. 706 the Commission directed NERC to "provide reasonable technical support to assist entities in determining whether their assets are critical to the Bulk-Power System."[27] NERC explains that it responded to the Commission's direction by developing guidance documents to assist entities in developing their risk-based methodologies and Critical Asset identification.[28]

26. In its Petition, NERC states that it "conducted various reviews of risk-based methodologies developed by many entities of varying sizes . . . and determined that the existing methodologies generally do not adequately identify all Critical Assets."[29] To address this, NERC proposes to replace the current risk-based methodology with uniform, bright line criteria, which will be used by all responsible entities to identify Critical Assets.

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[27] *Id.* at 10-11 (citing Order No. 706, 122 FERC ¶ 61,040 at P 255).

[28] *Id.* at 11.

[29] *Id.*

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27. While risk-based assessment methodologies have merit, we share NERC's concerns about the existing application of the currently effective CIP-002-3, Requirement 1. Thus, in this context, we believe that a shift away from responsible entity-designed risk-based methodologies for identifying Critical Assets, which NERC has found to be inadequate, to the use of NERC-developed criteria is an improvement.

3. Version 4 Provides Consistency and Clarity in the Identification of Critical Assets

28. In its June 30, 2011 data response, NERC states that the survey results from 2009 generated concern "about the apparent inconsistency in the application of the standards across the system, as evidenced by the apparent variation from region to region."[30] NERC states that it subsequently engaged with the Regional Entities and stakeholders to better understand the data, with these efforts resulting in the development of Version 4.

29. We believe that the application of uniform criteria is an improvement over the current approach because they add greater consistency and clarity in identifying Critical Assets. The risks posed by cyber threats suggest a different approach than the possibly inconsistent, inadequate methodologies for identifying Critical Assets, as evidenced by NERC's conclusion that insufficient numbers of Critical Assets were identified using the risk-based assessment methodology. As an integrated system, the protection afforded for Critical Assets and their Critical Cyber Assets is only as strong as its weakest link. In this respect, allowing responsible entities to devise their own methodologies for identifying Critical Assets, especially if these methodologies prove to be weak, may

[30] NERC June 30, 2011 Data Response at 3.

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compromise the Critical Assets and Critical Cyber Assets of other responsible entities even if they have adopted a more stringent methodology. The uniform system of Critical Asset identification proposed by NERC in Version 4 helps to address this weakness and places all responsible entities on an equal footing with respect to Critical Asset identification.

30. In addition, clear, bright line criteria should make it easier for Regional Entities, NERC and the Commission to monitor responsible entities and evaluate how they are identifying Critical Assets. A single set of bright line criteria, as opposed to myriad entity-designed risk-based methodologies, should improve the CIP compliance process.

31. However, under the currently-effective CIP-002-3, an entity that applies its risk-based assessment methodology considers specific types of assets identified in Requirement R1, as well as "any additional assets that support the operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment." Thus, currently, a responsible entity has the flexibility to consider any assets it deems appropriate. The Commission also notes that there are assets currently identified as Critical Assets which would no longer be identified as Critical Assets under the Proposed Reliability Standard CIP-002-4 bright line criteria for Critical Asset identification. The Commission seeks comment whether, under CIP Version 4, a responsible entity retains the flexibility to identify assets that, although outside of the bright line criteria, are essential to Bulk-Power System reliability. Further, we seek comment whether the ERO and/or Regional Entities would have the ability, either in an event-driven investigation or compliance audit, to identify specific assets that fall outside

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the bright-line criteria yet are still essential to Bulk-Power System reliability and should be subject prospectively to compliance with the CIP Reliability. If so, on what basis should that decision be made?

32. In addition, the Commission is cognizant of one caution that remains concerning a binary bright line criteria protection philosophy, *i.e.*, either an asset satisfies the threshold and is subject to compliance or is below the threshold and not subject to compliance (as opposed to a tiered approach to compliance as discussed below), in terms of applying cybersecurity protections to Cyber Assets. Specifically, bright line criteria that limit legally-mandated cybersecurity protections to certain classes of Bulk-Power System assets may indicate to an adversary the types of assets that fail to meet the threshold and, therefore, are not subject to mandatory CIP compliance. Therefore, the Commission encourages NERC to accelerate development of the next version of the CIP Reliability Standards and to address the concerns discussed herein in Section B.

4. Violation Risk Factors/Violation Severity Levels

33. NERC states that the proposed VRFs and VSLs are consistent with those approved for the Version 3 CIP Reliability Standards.[31] NERC explains that each requirement in Version 4 is assigned a VRF and a set of VSLs and that these elements support the determination of an initial value range for the base penalty amount regarding violations

[31] *North American Electric Reliability Corp.*, 134 FERC ¶ 61,045 (2011) (approving Version 2 and 3 CIP Reliability Standards VRFs and VSLs but requiring modifications in a compliance filing).

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of requirements in Commission-approved Reliability Standards, as defined in the ERO Sanction Guidelines.[32]

34. The principal changes in the proposed Version 4 VRFs and VSLs relate to CIP-002-4. NERC proposes to carry forward the Version 3 VRFs and VSLs for all other Requirements (in CIP-003-4 through CIP-009-4), for which no substantive revisions are proposed. CIP-002-4 no longer contains sub-Requirements and, instead, each of three main Requirements has a single VRF and set of VSLs, consistent with the methodology proposed by NERC and approved by the Commission.[33] The VRF designations for the three Requirements in CIP-002-4 are consistent with those assigned to similar Requirements in previous versions of the CIP Reliability Standards and satisfy our established guidelines. Therefore, the Commission proposes to approve the Version 4 VRFs proposed by NERC and incorporate appropriately the modifications directed to prior versions.

35. With regard to the proposed Version 4 VSLs for CIP-002-4, we are concerned that the VSLs for Requirement R1 and Requirement R2, while carrying forward the wording from corresponding Version 3 VSLs, do not adequately address the purpose of NERC's proposed bright line criteria: to ensure accurate and complete identification of all Critical Assets, so that all associated Critical Cyber Assets become subject to the protections required by the CIP Standards.

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[32] NERC Petition at 37.

[33] *North American Electric Reliability Corp.*, 135 FERC ¶ 61,166, at 8 (2011).

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36. More importantly, neither set of VSLs address the failure to properly identify either Critical Assets or Critical Cyber Assets in the first place. The failure to identify a Critical Asset, whether inadvertently or through misapplication of the bright line criteria, is paramount because if an Asset is not identified and included on the Critical Asset list, its associated Cyber Assets will not be considered under Requirement R2. Failure to identify those Cyber Assets as Critical Cyber Assets under Requirement R2 then creates the "weakest link" circumstance discussed in the Commission's order establishing two CIP VSL Guidelines for analyzing the validity of VSLs pertaining to cyber security.[34]

37. Therefore, the Commission proposes to direct the ERO to modify the VSLs for CIP-002-4, Requirements R1 and R2, to address a failure to identify either Critical Assets or Critical Cyber Assets, as shown in Appendix 1.[35] The Commission proposes to approve the Version 4 VSLs proposed by NERC, as modified, because they would then satisfy our established guidelines, fully address the purpose of NERC's bright line criteria, and incorporate appropriately the modifications directed to prior versions.

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[34] CIP VSL Guideline 1 states, "Requirements where a single lapse in protection can compromise computer network security, i.e., the "weakest link" characteristic, should apply binary rather than gradated VSLs."

[35] NERC proposes to assign a Severe VSL for a violation of Requirement R1 if a responsible entity does not develop a list of its identified Critical Assets "even if such list is null." NERC does not propose to assign a VSL for a violation of Requirement R1 when a responsible entity fails to identify a Critical Asset that falls within any of the Critical Asset Criteria in Attachment 1, or fails to include an identified Critical Asset in its Critical Asset list. NERC further proposes to assign a Severe VSL to a responsible entity's violation of Requirement R2 only when it fails to include in its list of Critical Cyber Assets a Critical Cyber Asset it has identified. NERC does not propose to assign a VSL for a violation of Requirement R2 resulting from a responsible entity's failure to identify as a Critical Cyber Asset a Cyber Asset that qualifies as a Critical Cyber Asset.

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5. Implementation Plan and Effective Date

38. NERC proposes an effective date for full compliance with the Version 4 CIP Standards of the first day of the eighth calendar quarter after applicable regulatory approvals have been received. In addition, NERC provides a detailed implementation plan for newly identified Critical Assets and newly registered entities. NERC also presents a number of scenarios intended to explain how CIP-002-4 will be implemented. Depending on the situation, the implementation plan establishes timelines and milestones for entities to reach full compliance with CIP-002-4.

39. The Commission proposes to approve the effective date and implementation plan for CIP-002-4. Under the scenarios presented by NERC, we understand that entities with existing CIP compliance implementation programs will effectively no longer use CIP-002-3 to identify Critical Assets after approval of CIP-002-4 but rather will apply the criteria in Attachment 1 of CIP-002-4. While some responsible entities have already installed the necessary equipment and software to address cybersecurity, we recognize that other responsible entities may need to purchase and install new equipment and software to achieve compliance for assets that are brought within the scope of the protections under the CIP-002-4 bright line criteria. Based on these considerations, the Commission believes that the implementation plan proposed by NERC sets reasonable deadlines for industry compliance.

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B. Ongoing Development Efforts to Satisfy Directives Set Forth in Order No. 706

40. As acknowledged by NERC, the proposed Version 4 CIP Reliability Standards do not address all of the directives set forth in Order No. 706. Although the Commission proposes to approve CIP-002-4, we highlight the need for NERC, working through the Reliability Standards development process, to address all outstanding Order No. 706 directives as soon as possible.

41. Below, we discuss several directives in Order No. 706 that have yet to be satisfied and propose to give guidance regarding the next version of the CIP Reliability Standards, such as the need to address the NIST framework, data network connectivity, and the potential misuse of control centers or control systems and the adoption of a regional perspective and oversight. Our guidance is intended to more fully ensure that all Cyber Assets serving reliability functions of the Bulk-Power System are within scope of the CIP Reliability Standards. In addition, as discussed below, we seek comments from NERC and other interested persons on a proposal to establish a deadline for NERC to submit modified CIP Reliability Standards that address the outstanding directives set forth in Order No. 706, using NERC's development timeline.

42. The stated purpose of Reliability Standard CIP-002 is the accurate identification of Critical Cyber Assets. Both the currently-effective and proposed CIP-002 Reliability

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Standards, along with guidance NERC provided to industry,[36] are structured in a staged approach. First, an entity must identify Critical Assets. NERC defines Critical Assets as "facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System."[37] Second, based on the Critical Assets identified in the first step, an entity must identify Cyber Assets supporting the Critical Assets. The NERC Glossary defines Cyber Assets as "programmable electronic devices and communication networks including hardware, software, and data."[38] Third, an entity should identify the Critical Cyber Assets by determining, in accordance with the NERC Glossary, the "Cyber Assets essential to the reliable operation of the Critical Assets."[39] In Order No. 706, the Commission did not address whether or not the staged approach outlined above was the only method for identifying Critical Cyber Assets. Rather at that time, focus was placed on addressing specific concerns with the first step – the identification of Critical Assets. Recognizing CIP-002 as the cornerstone of the CIP Reliability Standards,[40] a failure to accurately identify Critical Assets could greatly impact accurate Critical Cyber Asset identification

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[36] North American Reliability Corporation Security Guideline for the Electric Sector: "*Identifying Critical Cyber Assets*" Version 1.0, Effective June 17, 2010, at 4-5, and North American Reliability Corporation Security Guideline for the Electric Sector: "*Identifying Critical Assets*" Version 1.0, Effective September 17, 2009.

[37] NERC Glossary of Terms at 11.

[38] *Id.*

[39] *Id.*

[40] Order No. 706, 122 FERC ¶ 61,040 at P 234.

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and the overall applicability of the protection measures afforded in CIP-003 through CIP-009.

43. In light of recent cybersecurity vulnerabilities, threats and attacks that have exploited the interconnectivity of cyber systems,[41] the Commission seeks comments regarding the method of identification of Critical Cyber Assets[42] to ensure sufficiency and accuracy. The Commission recognizes that control systems that support Bulk-Power System reliability are "only as secure as their weakest links," and that a single vulnerability opens the computer network and all other networks with which it is interconnected to potential malicious activity.[43] Accordingly, the Commission believes that any criteria adopted for the purposes of identifying a Critical Cyber Asset under CIP-002 should be based upon a Cyber Asset's connectivity and its potential to compromise the reliable operation[44] of the Bulk-Power System, rather than focusing on the operation of any specific Critical Asset(s). The Commission seeks comments on this approach.

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[41] These include the discovery of Stuxnet, Night Dragon and RSA breaches from advanced persistent threats in July 2010, February 2011 and March 2011 respectively, where systems were compromised.

[42] In Order No. 706, the Commission declined to direct a method for identifying Critical Cyber Assets, but stated that it may revisit this circumstance in a future proceeding. *See* Order No. 706, 122 FERC ¶ 61,040 at P 284.

[43] *North American Electric Reliability Corp.*, 130 FERC ¶ 61,211, at P 15 (2010).

[44] 16 U.S.C. 824o(a)(4). The term "reliable operation" means "operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

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44. Further, the Commission seeks comments on how to ensure that the directives of Order No. 706 relative to CIP-002 with respect to the concerns discussed below are addressed, resulting in a method that will lead to sufficient and accurate Critical Cyber Asset identification.

45. The Commission believes that NERC should consider the following three strategies to meet the outstanding directives and seeks comments on these strategies. First, NERC should consider applicable features of the NIST Risk Management Framework to ensure protection of all cyber systems connected to the Bulk-Power System, including establishing CIP requirements based on entity functional characteristics rather than focusing on Critical Asset size. Second, such as in the consideration of misuse, NERC should consider mechanisms for identifying Critical Cyber Assets by examining all possible communication paths between a given cyber resource and any asset supporting a reliability function. Third, NERC should provide a method for review and approval of Critical Cyber Asset lists from external sources such as the Regional Entities or NERC. Each of these strategies is discussed below.

1. NIST Framework

46. In Order No. 706, the Commission directed NERC to "monitor the development and implementation" of cybersecurity standards then being developed by the National Institute of Standards and Technology (NIST).[45] The Commission also directed NERC to

[45] Order No. 706, 122 FERC ¶ 61,040 at P 233.

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consider the effectiveness of the NIST standards.[46] At that time, the Commission directed NERC to address any NIST provisions that will better protect the Bulk-Power System in the Reliability Standards development process.[47] While the Commission determined not to require NERC to adopt or incorporate elements of the NIST standards, Order No. 706 left open the option of revisiting the NIST standards at a later time.[48] The Commission is not here proposing to direct that NERC use elements of the NIST standards. However, we continue to believe that the NIST framework could provide beneficial input into the NERC CIP Reliability Standards and we urge NERC to consider any such provisions that will better protect the Bulk-Power System.

47. The NIST Risk Management Framework was developed to manage the risks associated with all information systems, and offers a structured yet flexible approach that can now be applied to the electric industry. The NIST Risk Management Framework guides selection and specification of cybersecurity controls and measures necessary to protect individuals and the operations and assets of the organization, while considering effectiveness, efficiency, and constraints due to applicable laws, directives, policies, standards, or regulations. Each of the activities in the Risk Management Framework has an associated NIST security standard and/or guidance document that can be used by organizations implementing the framework. The management of risk is a key element.

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[46] *Id.*

[47] *Id.*

[48] *Id.*

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48. Two primary features of the NIST Framework are: (1) customizing protection to the mission of the cyber systems subject to protection (similar to the role identified by the NERC Functional Model); and (2) ensuring that all connected cyber systems associated with the Bulk-Power System, based on their function, receive some level of protection.[49] The Bulk-Power System could benefit from each of these tested approaches.

a. NIST Approach and the NERC Functional Model

49. The purpose of the NERC CIP Reliability Standards is to specify mandatory Requirements for responsible entities to establish, maintain, and preserve the cybersecurity of key information technology systems' assets, the use of which is essential to reliable operation of the Bulk-Power System. The CIP Reliability Standards include Requirements which are based upon the functional roles of the responsible entities as specified in the NERC Functional Model.[50] The identification of cyber systems and assets used to execute these functional roles should be the first step in identifying the systems for coverage under the CIP Reliability Standards for protection. The Functional Model should be used as a starting point when considering the applicability of the NIST Framework for securing the operation of cyber assets to provide for the Reliable Operation of the Bulk-Power System.

b. NIST Tiered Approach

50. If applied to the Bulk-Power System, the NIST Framework would specify the

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[49] NIST SP800-53, Section 1.4, Organizational Responsibilities.

[50] Reliability Functional Model, Function Definitions and Functional Entities, Version 5, approved by NERC Board of Trustees May 2010; and, Reliability Functional Model Technical Document Version 5, approved by NERC Board of Trustees May 2010.

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level of protection appropriate for systems based upon their importance to the reliable operation of the Bulk-Power System. Cyber systems connected to the Bulk –Power System require availability, integrity, and confidentiality to effectively ensure the reliability of the Bulk-Power System.

51. The NIST Framework provides for a tiered approach to cybersecurity protection where protection of some type would be applied to all cyber assets connected to the Bulk-Power System. Under the NIST Framework, cyber assets whose compromise or loss of operability could result in a greater risk to Bulk-Power System reliability would be subject to more rigorous cybersecurity protections compared to a less important asset. The NIST Framework recognizes that all connected assets require a baseline level of protection to prevent attackers from gaining a foothold to launch further, even more devastating attacks on other critical systems.

52. Using the NIST framework, all cyber assets would also be reviewed to determine the appropriate level of cyber protection. The level of protection required for a given cyber asset is based upon its mission criticality and its innate technological risks.

2. Misuse of Control Systems

53. In Order No. 706, the Commission directed NERC to consider the misuse of control centers and control systems in the determination of Critical Assets.[51] If a perpetrator is able to misuse an asset, the attacker may navigate across and between control system data networks in order to gain access to multiple sites, which could enable

[51] Order No. 706, 122 FERC ¶ 61,040 at P 282.

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a coordinated multi-site attack. Recent cybersecurity incidents[52] illustrate the importance of restricting connectivity between control systems and external networks, emphasizing the inherent risk exposure created by networking critical cyber control systems. Future mechanisms for identifying when cyber assets require protection will have to examine all possible paths between a given cyber resource and any asset supporting a reliability function.

54. In Order No. 706, the Commission expressed concerns regarding the classification of control centers and the potential misuse of control systems.[53] With regard to control centers, the Commission noted that responsible entities should be required to "examine the impact on reliability if the control centers are unavailable, due for example to power or communications failures, or denial of service attacks."[54] In addition, the Commission stated that "[r]esponsible entities should also examine the impact that misuse of those control centers could have on the electric facilities they control and what the combined impact of those electric facilities could be on the reliability of the Bulk-Power System."[55] The Commission stated that "when these matters are taken into account, it is difficult to envision a scenario in which a reliability coordinator, transmission operator or transmission owner control center or backup control center would not properly be

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[52] These include the discovery of Stuxnet, Night Dragon and RSA breaches from advanced persistent threats in July 2010, February 2011 and March 2011 respectively, where systems were compromised.

[53] Order No. 706, 122 FERC ¶ 61,040 at P 280-281.

[54] *Id.* P 280.

[55] *Id.*

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identified as a critical asset."[56]

55. In addition, the Commission raised concerns about the misuse of a control system that controls more than one asset.[57] Specifically, the Commission noted that multiple assets, whether multiple generating units, multiple transmission breakers, or perhaps even multiple substations, could be taken out of service simultaneously due to a failure or misuse of the control system. The Commission stated that even if one or all of the assets would not be considered as a Critical Asset on a stand alone basis, a simultaneous outage resulting from the single point of control might affect the reliability or operability of the Bulk-Power System. The Commission stated "[i]n that case, the common control system should be considered a Critical Cyber Asset."[58]

56. The Commission is concerned that the proposed CIP-002-4 bright line criteria do not adequately address the Commission's prior directive regarding the classification of control centers or take the potential misuse of control systems into account in the identification of Critical Assets. For example, the proposed bright line criteria leave a number of Critical Assets with potentially unprotected cyber assets, including a total of 222[59] control centers with no legal obligation to apply cybersecurity measures. These

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[56] *Id.*

[57] *Id.* P 281.

[58] *Id.*

[59] NERC June 30, 2011 Data Response at 3.

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potentially unprotected control centers involve an unknown number of associated control systems.

57. Consider the following example: Electric grid control system operation in part consists of the collection of raw data needed to run the grid, collected by a SCADA system from intelligent electronic devices (IEDs) (e.g., RTUs and synchrophasors). The SCADA data is typically aggregated by an energy management system (EMS). The EMS may, in some cases, calculate area control error (ACE) and transmit it to a balancing authority, which in turn makes computer based decisions about balancing load and generation. Those decisions are then used by the balancing authority or generation operator as part of an automated generation control (AGC) process. At each of these one or more sites, there are many data network interconnection points with other entities, (e.g., neighboring transmission operators, generation operators, and reliability coordinators) and additional connectivity to corporate data networks and elsewhere, employing several communications technologies. This results in a complex interconnection of cyber assets (including the data of those cyber assets) demanding vigilant protection.[60] These cyber systems require comprehensive protection because the interconnected system is only as strong as its weakest link.

58. Any failure to take into account the interconnectivity of control systems represents a significant reliability gap. Where modern data networking technology is used for operation of the Bulk-Power System (e.g., control systems, synchrophasors, smart grid), a

[60] *See* generally, Ron Ross, Managing Enterprise Risk in Today's World of Sophisticated Threats, National Institute of Standards and Technology (2007).

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network-based cyber attack could result in multiple simultaneous outages of grid equipment and cyber systems alike through misuse of a single point of control (e.g., a SCADA control host system). Such an attack could take place by way of a cyber system associated with an asset that falls outside the CIP-002-4 bright line criteria yet is connected in common with other cyber systems on the Bulk-Power System. The risk of a cyber attack is greater now than when Order No. 706 was issued, as borne out by the recent increased frequency and sophistication of cyber attacks. It is critical, therefore, that the Commission's concerns regarding the potential misuse of control centers and associated control systems be addressed in the CIP Reliability Standards.

3. Regional Perspective

59. In Order No. 706, the Commission directed NERC to "develop a process of external review and approval of critical asset lists based on a regional perspective."[61] The Commission found that "Regional Entities must have a role in the external review to assure that there is sufficient accountability in the process [and] . . . because the Regional Entities and ERO are ultimately responsible for ensuring compliance with Reliability Standards."[62]

60. The Commission is concerned that the lack of a regional review in the identification of cyber assets might result in a reliability gap. In Order No. 706, the Commission expressed concerns regarding the need for developing a process of external

[61] Order No. 706, 122 FERC ¶ 61,040 at P 329.

[62] *Id.* P 327.

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review and approval of Critical Asset lists based on a regional perspective, and that such lists are considered from a wide-area view. This process would help to identify trends in Critical Asset identification. Further, while we recognize that individual circumstances may likely vary, an external review will provide an appropriate level of consistency.[63] For example, reliability coordinators may communicate through a common system and compromise of that system could propagate across multiple regions. A cyber compromise can easily propagate across these data and control networks with potential adverse consequences to the Bulk-Power System on multi-region basis.

61. This problem may become exacerbated by any future revisions to the CIP Reliability Standards that opt to reserve a high level of independent authority to the registered entity to categorize and prioritize its cyber assets. Looking forward, it will be essential for NERC and the Regional Entities to actively review the designation of cyber assets that are subject to the CIP Reliability Standards, including those which span regions, in order to determine whether additional cyber assets should be protected.

4. Summary

62. In summary, the Commission proposes to approve NERC's proposed Version 4 CIP Standards pursuant to section 215(d)(2) of the FPA. As discussed above, it appears that the Version 4 CIP Standards represent an improvement in three respects in that they: (1) will result in the identification of certain types of Critical Assets that may not be identified under the current approach ; (2) use bright line criteria to identify Critical

[63] *Id.* P 322.

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Assets, thus limiting the discretion of responsible entities when identifying Critical Assets; and (3) provide a level of consistency and clarity regarding the identification of Critical Assets.

63. While we believe that the Version 4 CIP Reliability Standards satisfy the statutory standard for approval, we also believe that more improvement is needed. As NERC explains in its Petition, the Version 4 CIP Reliability Standards are intended as "interim" and future versions will build on Version 4. We believe that the electric industry, through the NERC standards development process, should continue to develop an approach to cybersecurity that is meaningful and comprehensive to assure that the nation's electric grid is capable of withstanding a Cybersecurity Incident.[64] As discussed above, we believe that some of the essential components of such a meaningful and comprehensive approach to cybersecurity are set forth in Order No. 706.

5. Reasonable Deadline for Full Compliance with Order No. 706

64. The Commission issued Order No. 706 on January 18, 2008. In Order No. 706, the Commission approved Version 1 of the CIP Reliability Standards while also directing modifications pursuant to section 215(d)(5) of the FPA, some of which are described above. Later approved versions of the CIP Reliability Standards, and now the proposed Version 4 CIP Reliability Standards, addressed some of the directives in Order No. 706, but other directives remain unsatisfied.

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[64] Section 215(a) of the FPA defines Cybersecurity Incident as "a malicious act or suspicious event that disrupts, or was an attempt to disrupt, the operation of those programmable electronic devices and communication networks including hardware, software and data that are essential to the reliable operation of the Bulk-Power System."

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65. Over three years have elapsed since the Commission issued the Final Rule in January 2008. As discussed above, we believe that it is important for the successful implementation of a comprehensive approach to cybersecurity that NERC timely addresses the modifications directed by the Commission in Order No. 706. Accordingly, the Commission proposes to set a deadline for NERC to file the next version of the CIP Reliability Standards, which NERC indicates will address all outstanding Order No. 706 directives.[65] This proposal is consistent with the views expressed in the January 2011 Audit Report of the Department of Energy's Inspector General, who found "that the Commission could have, but did not impose specific deadlines for the ERO to incorporate changes to the CIP standards."[66] Similarly, our proposal is responsive to the Audit Report finding that "the CIP standards implementation approach and schedule approved by the Commission were not adequate to ensure that systems-related risks to the Nation's power grid were mitigated or addressed in a timely manner."[67]

66. The Commission understands that, under NERC's timeline for the ongoing effort to address all outstanding Order No. 706 directives, it anticipates submitting the next version of the CIP Reliability Standards to the NERC Board of Trustees by the second quarter of 2012, and filing that version the Commission by the end of the third quarter of

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[65] *See* NERC's May 27, 2011 Responses to Data Requests, Response 1 ("[t]he standard drafting team expects that the filing for the next version of the CIP Reliability Standards will address the remaining FERC Order No. 706 directives").

[66] Department of Energy Inspector General Audit Report, *Federal Energy Regulatory Commission's Monitoring of Power Grid Cybersecurity* at 6 (January 2011).

[67] *Id.* at 2.

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2012.[68]

67. The Commission proposes to establish NERC's current development timeline above as a deadline for compliance with the outstanding Order No. 706 CIP Standard directives. The Commission seeks comments from NERC and other parties concerning this proposal. Further, NERC and other parties may propose and support an alternative compliance deadline.

III. Information Collection Statement

68. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping requirements (collections of information) imposed by an agency.[69] The information contained here is also subject to review under section 3507(d) of the Paperwork Reduction Act of 1995.[70] We will submit this proposed rule to OMB for review.

69. As stated above, the Commission previously approved Reliability Standards similar to the proposed Reliability Standards that are the subject of the current rulemaking.[71]

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[68] *See* NERC's May 27, 2011 Responses to Data Requests, Response 1. *See also North American Electric Reliability Corporation Reliability Standards Development Plan 2011-2013 Informational Filing Pursuant to Section 310 of the NERC Rules of Procedure*, Docket Nos. RM05-17-000, RM05-25-000, RM06-16-000 at 14 (filed April 5, 2011).

[69] 5 CFR 1320.11.

[70] 44 U.S.C. 3507(d).

[71] *North American Electric Reliability Corporation*, 130 FERC ¶ 61,271 (2010).

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70. The principal differences in the information collection requirements and resulting burden imposed by the proposed Reliability Standards in this rule are triggered by the proposed changes in Reliability Standard CIP-002-4. The previous risk-based assessment methodology for identifying Critical Assets will be replaced by 17 uniform "bright line" criteria for identifying Critical Assets (in CIP-002-4, Attachment 1, "Critical Asset Criteria"). Proposed Reliability Standard CIP-002-4 would require each responsible entity to use the bright line criteria as a "checklist" to identify Critical Assets, initially and in an annual review, instead of performing the more technical and individualized risk analysis involved in complying with the currently-effective CIP Reliability Standards. As in past versions, each Responsible Entity will then identify the Critical Cyber Assets associated with its updated list of Critical Assets. If application of the bright line criteria result in the identification of new Critical Cyber Assets, such assets become subject to the remaining standards (proposed CIP-003-4, CIP-004-4, CIP-005-4a, CIP-006-4c, CIP-007-4, CIP-008-4, and CIP-009-4), and the information collection requirements contained therein.

71. We estimate that the burden associated with the annual review of the assets (by the estimated 1,501 entities) will be simplified by the "Critical Asset Criteria" in proposed Reliability Standard CIP-002-4. Rather than each entity annually reviewing and updating a Risk-Based Assessment Methodology that frequently required technical analysis and judgment decisions, the proposed bright line criteria will provide a straight forward checklist for all entities to use. Thus, we estimate that the proposal will reduce the

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burden associated with the annual review, as well as provide a consistent and clear set of criteria for all entities to follow.

72. The estimated changes to burden as contained in the proposed rule in RM11-11 follow.

FERC-725B Data Collection (per proposed Version 4)	**No. of Respondents[72] (1)**	**Average No. of Annual Responses Per Respondent (2)**	**Average No. of Burden Hours Per Response[73] (3)**	**Effect of NOPR in RM11-11, on Total Annual Hours (1)x(2)x(3)**	**Annual Burden Hrs. upon Implementation of RM11-11**
Entities that (previously and now) will identify at least one	345 [no change]	1	1,880 [reduction of 40 hours from 1,920 to 1,880	reduction of 13,800 hours	648,600

[72] The NERC Compliance Registry as of 9/28/2010 indicated that 2,079 entities were registered for NERC's compliance program. Of these, 2,057 were identified as being U.S. entities. Staff concluded that of the 2,057 U.S. entities, approximately 1,501 were registered for at least one CIP related function. According to an April 7, 2009 memo to industry, NERC noted that only 31% of entities responding to an earlier survey reported that they had at least one Critical Asset, and only 23% reported having a Critical Cyber Asset. Staff applied the 23% (an estimate unchanged for Version 4 standards) to the 1,501 figure to estimate the number of entities that identified Critical Assets under Version 3 CIP Standards.

[73] Calculations for figures prior to applying reductions:

Respondent category b:

3 employees X (working 50%) X (40 hrs/week) X (2 weeks) = 120 hours

Respondent category c:

20 employees X (working 50%) X (40 hrs/week) X (8 weeks) = 3200 hours

20 employees X (working 20%) X (3200 hrs) = 640 hours

Total = 3840

Respondent category a:

50% of 3840 hours (category d) = 1920

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Critical Cyber Asset [category a]			hours]		
Entities that (previously and now) will not identify any Critical Cyber Assets [category b]	1,144 [reduction of 12 entities from 1156 to 1,144]	1	120 [no change]	reduction of 1,440 hours [for the 12 entities]	137,280
Entities that will newly identify a Critical Asset/Critical Cyber Asset due to the requirements in RM11-11[74] [category c]	increase of 12 [formerly 0]	1	3,840[75]	increase of 46,080	46,080
Net Total	1,501 [72]			+30,840	831,960

<u>The revisions to the cost estimates based on requirements of this proposed rule are:</u>

- Each entity that has identified Critical Cyber Assets has a reduction of 40 hours (345 entities X 40 hrs. X @$96/hour = $1,324,800 reduction
- 12 Entities that formerly had not identified Critical Cyber Assets, but now will have them, has

[74] We estimate 12 (or 1%) of the existing entities that formerly had no identified Critical Cyber Assets will have them under the proposed Reliability Standards. This proposed rule does not affect the burden for the 6 new U.S. Entities that were estimated to newly register or otherwise become subject to the CIP Standards each year in FERC-725B, and therefore are not included in this chart.

[75] This estimated burden estimate applies only to the first three year audit cycle. In subsequent audit cycles these entities will move into category a, or be removed from the burden as an entity that no longer is registered for a CIP related function.

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- a reduction of 120 hours and an increase of 3,840 hours (for a net increase of 3,720 annual hours), giving 12 entities X 3,720 hrs.@$96/hour = $4,285,440
- storage costs = 12 entities@$15.25/entity = $183

Total Net Annual Cost for the FERC-725B requirements contained in the NOPR in RM11-11= $2,960,823 ($4,285,440 +$183 -$1,324,800).

The estimated hourly rate of $96 is the average cost of legal services ($230 per hour), technical employees ($40 per hour) and administrative support ($18 per hour), based on hourly rates from the Bureau of Labor Statistics (BLS) and the 2009 Billing Rates and Practices Survey Report.[76] The $15.25 per entity for storage costs is an estimate based on the average costs to service and store 1 GB of data to demonstrate compliance with the CIP Standards.[77]

Title: Mandatory Reliability Standards, Version 4 Critical Infrastructure Protection Standards

Action: Proposed Collection FERC-725B.

OMB Control No.: 1902-0248.

Respondents: Businesses or other for-profit institutions; not-for-profit institutions.

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[76] Bureau of Labor Statistics figures were obtained from http://www.bls.gov/oes/current/naics2_22.htm, and 2009 Billing Rates figure were obtained from http://www.marylandlawyerblog.com/2009/07/average_hourly_rate_for_lawyer.html. Legal services were based on the national average billing rate (contracting out) from the above report and BLS hourly earnings (in-house personnel). It is assumed that 25% of respondents have in-house legal personnel.

[77] Based on the aggregate cost of an advanced data protection server.

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Frequency of Responses: On Occasion.

Necessity of the Information: This proposed rule proposes to approve the requested modifications to Reliability Standards pertaining to critical infrastructure protection. The proposed Reliability Standards help ensure the reliable operation of the Bulk-Power System by providing a cybersecurity framework for the identification and protection of Critical Assets and associated Critical Cyber Assets. As discussed above, the Commission proposes to approve NERC's proposed Version 4 CIP Standards pursuant to section 215(d)(2) of the FPA because they represent an improvement to the currently-effective CIP Reliability Standards.

Internal Review: The Commission has reviewed the proposed Reliability Standards and made a determination that its action is necessary to implement section 215 of the FPA.

73. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, e-mail: DataClearance@ferc.gov, phone: (202) 502-8663, fax: (202) 273-0873].

74. For submitting comments concerning the collection(s) of information and the associated burden estimate(s), please send your comments to the Commission, and to the Office of Management and Budget, Office of Information and Regulatory Affairs, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395-4638, fax: (202) 395-7285]. For security reasons, comments to OMB should be submitted by e-mail to: oira_submission@omb.eop.gov.

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Comments submitted to OMB should include Docket Number RM11-11 and OMB Control Number 1902-0248.

IV. Environmental Analysis

75. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[78] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[79] The actions proposed here fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act Certification

76. The Regulatory Flexibility Act of 1980 (RFA)[80] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a proposed rule and that minimize any significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[81] The SBA has established a size standard for electric utilities, stating

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[78] Order No. 486, *Regulations Implementing the National Environmental Policy Act of 1969*, FERC Stats. & Regs., Regulations Preambles 1986-1990 ¶ 30,783 (1987).

[79] 18 CFR 380.4(a)(2)(ii).

[80] 5 U.S.C. 601-612.

[81] 13 CFR 121.101.

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that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million megawatt hours.[82]

77. The Commission analyzed the affect of the proposed rule on small entities. The Commission's analysis found that the DOE's Energy Information Administration (EIA) reports that there were 3,276 electric utility companies in the United States in 2009,[83] and 3,015 of these electric utilities qualify as small entities under the Small Business Administration (SBA) definition. Of these 3,276 electric utility companies, the EIA subdivides them as follows: (1) 875 cooperatives of which 843 are small entity cooperatives; (2) 1,841 municipal utilities, of which 1,826 are small entity municipal utilities; (3) 128 political subdivisions, of which 115 are small entity political subdivisions; (4) 171 power marketers, of which 113 individually could be considered small entity power marketers;[84] (5) 200 privately owned utilities, of which 93 could be considered small entity private utilities; (6) 24 state organizations, of which 14 are small entity state organizations; and (7) 9 federal organizations of which 4 are small entity federal organizations.

78. Many of the entities that have not previously identified Critical Assets and Critical Cyber Assets are considered small entities. The new CIP version 4 bright line criteria

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[82] 13 CFR 121.201, Sector 22, Utilities & n.1.

[83] See Energy Information Administration Database, Form EIA-861, Dept. of Energy (2009), available at http://www.eia.doe.gov/cneaf/electricity/page/eia861.html.

[84] Most of these small entity power marketers and private utilities are affiliated with others and, therefore, do not qualify as small entities under the SBA definition.

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generally result in the identification of relatively larger Bulk-Power System equipment as Critical Assets. For the most part, the small entities do not own or operate these larger facilities. There is a limited possibility that these entities would have facilities that meet the bright line criteria and therefore be subject to the full CIP standards (CIP-002 through CIP-009). The Commission expects only a marginal increase in the number of small entities that will identify at least one Critical Asset under the Version 4 CIP Reliability Standards that have not done so previously.

79. The Commission estimates that only one percent (12) of the small and medium-sized entities that have not previously identified Critical Assets and Critical Cyber Assets will have an increased cost due to the proposed Reliability Standards and their identification of new Critical Cyber Assets. For each of those 12 entities, we anticipate a cost increase associated with creating a cyber security program along with the actual cyber security protections associated with the identified Critical Cyber Assets. The Commission requests comment on the potential implementation cost and subsequent cost increases that could be experienced by such small entities. Small and medium sized entities that continue to have no Critical Assets will not see any change in their burden.

80. In general, the majority of small entities are not required to comply with mandatory Reliability Standards because they are not regulated by NERC pursuant to the NERC Registry Criteria. Moreover, a small entity that is registered but does not identify critical cyber assets pursuant to CIP-002-4 will not have compliance obligations pursuant to CIP-003-4 through CIP-009-4.

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81. The Commission also investigated possible alternatives. These included the Commission's adoption in Order No. 693 of the NERC definition of bulk electric system, which reduces significantly the number of small entities responsible for compliance with mandatory Reliability Standards. The Commission also noted that small entities could join a joint action agency or similar organization, which could accept responsibility for compliance with mandatory Reliability Standards on behalf of its members and also may divide the responsibility for compliance with its members.

82. Based on the foregoing, the Commission certifies that the proposed Reliability Standards will not have a significant impact on a substantial number of small entities. Accordingly, no regulatory flexibility analysis is required.

VI. Comment Procedures

83. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due [Insert date that is [60] days from publication in the **FEDERAL REGISTER**]. Comments must refer to Docket No. RM11-11-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

84. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at http://www.ferc.gov. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not

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in a scanned format. Commenters filing electronically do not need to make a paper filing.

85. Commenters unable to file comments electronically must mail or hand deliver an original copy of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

86. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VII. Document Availability

87. In addition to publishing the full text of this document in the *Federal Register*, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington DC 20426.

88. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

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89. User assistance is available for eLibrary and the Commission's web site during normal business hours from FERC Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

List of subjects in 18 CFR Part 40

Electric power; Electric utilities; Reporting and record keeping requirements.

By direction of the Commission.

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Document Content(s)

RM11-11-000.DOC.....1-49

136 FERC ¶ 61,187
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Parts 39.10 and 40

[Docket No. RM11-16-000]

Transmission Relay Loadability Reliability Standard

(September 15, 2011)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: Pursuant to section 215 of the Federal Power Act, the Commission proposes to approve Reliability Standard PRC-023-2 (Transmission Relay Loadability) submitted to the Commission for approval by the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization (ERO) certified by the Commission. The proposed Reliability Standard requires transmission owners, generator owners, and distribution providers to set relays according to specific criteria in order to ensure that the relays reliably detect and protect the electric network from fault conditions, but do not limit transmission loadability or interfere with system operators' ability to protect system reliability. The Commission seeks comment from interested persons on the proposed Reliability Standard. The Commission also proposes to approve NERC Rules of Procedure Section 1700 – Challenges to Determinations. This proposed rule provides registered entities a means to challenge determinations made by planning coordinators under Reliability Standard PRC-023.

DATES: Comments are due **[Insert date 60 days after publication in the FEDERAL REGISTER]**

ADDRESSES: You may submit comments, identified by docket number RM11-16-000 and in accordance with the requirements posted on the Commission's web site, http//www.ferc.gov. Comments may be submitted by any of the following methods:

- Agency Web Site: http://ferc.gov. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format, at http://www.ferc.gov/docs-filing/efiling.asp.
- Mail/Hand Delivery: Commenters unable to file comments electronically must mail or hand deliver their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

These requirements can be found on the Commission's web site, see, e.g., the "Quick Reference Guide for Paper Submissions," available at http://www.ferc.gov/docs-filing/efiling.asp or via phone from FERC Online Support at (202) 502-6652 or toll-free at 1-(866) 208-3676.

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Hagerstown, MD 21740
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SUPPLEMENTARY INFORMATION:

136 FERC ¶ 61,187
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Relay Loadability Reliability Standard Docket No. RM11-16-000

NOTICE OF PROPOSED RULEMAKING

(September 15, 2011)

1. Pursuant to section 215 of the Federal Power Act (FPA),[1] the Commission proposes to approve Reliability Standard PRC-023-2 (Transmission Relay Loadability) submitted by the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization (ERO) certified by the Commission. The proposed Reliability Standard requires transmission owners, generation owners, and distribution providers to set load-responsive phase protective relays according to specific criteria in order to ensure that the relays reliably detect and protect the electric network from fault conditions, but do not limit transmission loadability[2] or interfere with system operators' ability to protect system reliability. The Commission seeks comment from interested persons on the proposed Reliability Standard. The Commission also proposes to approve NERC Rules of Procedure Section 1700 – Challenges to Determinations also included in

[1] 16 U.S.C. § 824o (2006).

[2] In the context of the proposed Reliability Standard, "loadability" refers to the ability of protective relays to refrain from operating under load conditions.

NERC's filing. This proposed rule provides registered entities a means to challenge determinations made by planning coordinators under Reliability Standard PRC-023.

I. Background

A. Relay Protection Systems

2. Protective relays are devices that detect and initiate the removal of faults on an electric system.[3] They are designed to read electrical measurements, such as current, voltage, and frequency, and can be set to recognize certain measurements as indicating a fault. When a protective relay detects a fault on an element of the system under its protection, it sends a signal to an interrupting device(s) (such as a circuit breaker) to disconnect the element from the rest of the system. Impedance relays are the most common type of relays used to protect transmission lines. They continuously measure voltage and current on the protected transmission line and operate when the measured magnitude and phase angle of the impedance (voltage/current) falls within the settings of the relay. Impedance relays can also provide backup protection and protection against remote circuit breaker failure.

3. On March 18, 2010, the Commission issued a Final Rule approving Reliability Standard PRC-023-1 (Transmission Relay Loadability), a Standard that requires transmission owners, generator owners, and distribution providers to set load-responsive

[3] A "fault" is defined in the NERC Glossary of Terms used in Reliability Standards as "[a]n event occurring on an electric system such as a short circuit, broken wire, or an intermittent connection."

phase protection relays according to specific criteria to ensure that the relays reliably detect and protect the electric network from all fault conditions, but do not operate during non-fault load conditions.[4] In addition, under section 215(d)(5) of the FPA, the Commission directed the ERO to develop modifications to the Standard to address certain issues identified by the Commission. At issue in the immediate proceeding is a revised Reliability Standard that addresses our directives in that order and will replace the currently effective PRC-023-1.

B. Reliability Standard PRC-023-1 and Order No. 733

4. Currently effective Reliability Standard PRC-023-1 applies to relay settings on (1) all transmission lines and transformers with low-voltage terminals operated or connected at or above 200 kV; and (2) those transmission lines and transformers with low voltage terminals operated or connected between 100 kV and 200 kV that are designated by planning coordinators as critical to the reliability of the bulk electric system.[5] The Reliability Standard consists of three compliance requirements and Attachment A. Requirement R1 requires entities with certain transmission facilities to set their relays according to one of thirteen specific settings (sub-parts R1.1 through R1.13) designed to

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[4] *Transmission Relay Loadability Reliability Standard,* Order No. 733, 130 FERC ¶ 61,221 (2010), *order on reh'g and clarification*, Order No. 733-A, 134 FERC ¶ 61,127 (2011); *clarified*, Order No. 733-B, 136 FERC ¶ 61,185, (2011). Order No. 733-B is issuing concurrently with this Notice of Proposed Rule Making.

[5] Pursuant to section 40.3 of the Commission's regulations, all Commission-approved Reliability Standards are available on NERC's website at www.nerc.com. *See* 18 CFR 40.3.

maximize loadability while maintaining Reliable Operation of the bulk electric system for all fault conditions. Requirement R2 provides additional obligations for entities that elect certain settings. Requirement R3 requires planning coordinators to designate facilities, operated between 100 kV and 200 kV, that are critical to the reliability of the bulk electric system and are therefore subject to Requirement R1. Attachment A specifies the protection systems that are subject to and excluded from the Standard's Requirements.

1. Currently Effective Requirement R1

5. Requirement R1 states that each transmission owner, generator owner, and distribution provider subject to Reliability Standard PRC-023-1 shall use one of the criteria prescribed in sub-parts R1.1 through R1.13 for any specific circuit terminal to prevent its phase protective relay setting from limiting transmission system loadability while maintaining reliable protection of the bulk electric system for all fault conditions.

6. In Order No. 733, the Commission directed the ERO, under section 215(d)(5) of the FPA, to develop modifications to Requirement R1 to: (1) require that transmission owners, generator owners, and distribution providers give their transmission operators a

list of transmission facilities that implement sub-part R1.2;[6] (2) require entities that have protective relays set pursuant to sub-part R1.10 to verify that the limiting piece of equipment is capable of sustaining the anticipated overload for the longest clearing time associated with a fault;[7] and (3) require the ERO to document, subject to audit by the Commission, and to make available for review to users, owners, and operators of the Bulk-Power System, by request, a list of those facilities that have protective relays set pursuant to sub-part R1.12.[8]

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[6] Order No. 733, 130 FERC ¶ 61,221 at P 186. Sub-part R.1.2 allows transmission owners, generation owners and distribution providers to "set transmission line relays so they do not operate at or below 115[percent] of the highest seasonal 15-minute Facility Rating of a circuit (expressed in amperes)." The Standard includes a footnote that states "[w]hen a 15-minute rating has been calculated and published for use in real-time operations, the 15 minute rating can be used to establish the loadability requirement for the protective relays."

[7] *Id.* P 203. Sub-part R.1.10 allows transmission owners, generation owners and distribution providers to set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer . . . at or below the greater of:

[a.] 150 [percent] of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment[; or]

[b.] 115 [percent] of the highest operator established emergency transformer rating.

[8] *Id.* P 224. Sub-part R1.12 addresses setting transmission line distance relays to a maximum of 125 percent of the apparent impedance (at the impedance angle of the transmission line), subject to specified constraints, when the transmission line's desired capability is limited by the requirement to adequately protect the transmission line.

2. Currently Effective Requirement R2

7. Requirement R2 states that transmission owners, generator owners, and distribution providers that use a circuit with the protective relay settings determined by the practical limitations described in specified R1 sub-parts must use the calculated circuit capability as the circuit's facility rating and must obtain the agreement of the planning coordinator, transmission operator, and reliability coordinator with the calculated circuit capability.

3. Currently Effective Requirement R3

8. Requirement R3 requires planning coordinators to designate which transmission lines and transformers with low-voltage terminals operated or connected between 100 kV and 200 kV are critical to the reliability of the bulk electric system and therefore subject to Requirement R1. Sub-part R3.1 requires planning coordinators to have a process to identify critical facilities. Sub-part R3.1.1 specifies that the process must consider input from adjoining planning coordinators and affected reliability coordinators. Sub-parts R3.2 and R3.3 require planning coordinators to maintain a list of critical facilities and provide it to reliability coordinators, transmission owners, generator owners, and distribution providers within 30 days of initially establishing it, and 30 days of any subsequent change.

9. Under section 215(d)(5) of the FPA, the Commission directed the ERO to modify Requirement R3 to: (1) apply an "add in" approach to sub-100 kV facilities that are owned or operated by currently registered entities or entities that become registered

entities in the future, and are associated with a facility that is included on a critical facilities list defined by the Regional Entity;[9] (2) specify the test that planning coordinators must use to determine whether a sub-200 kV facility is critical to the reliability of the Bulk-Power System;[10] and (3) add the Regional Entity to the list of entities that receive a list of sub-200 kV facilities determined by the planning coordinator to be critical to the reliability of the bulk electric system.[11] In addition, the Commission directed the ERO to develop an appeals process for entities to challenge a criticality determination.[12]

4. Currently Effective Attachment A

10. Attachment A to Reliability Standard PRC-023-1 specifies which protection systems are subject to and excluded from the Standard's Requirements. Section 1 of Attachment A provides that the Reliability Standard applies to any protective functions that can operate with or without time delay, on load current, including but not limited to: (1) phase distance; (2) out-of-step tripping; (3) switch-on-to-fault; (4) overcurrent relays; and (5) communication-aided protection applications. Section 2 states that the Reliability

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[9] *Id.* P 60.

[10] *Id.* P 69.

[11] *Id.* P 237.

[12] *Id.* P 97.

Standard requires evaluation of out-of-step blocking schemes[13] to ensure that they do not operate for faults during the loading conditions defined in the Standard's Requirements. Finally, section 3 expressly excludes certain relay elements and protection systems from the Reliability Standard's Requirements, such as relay elements enabled only when other relays or associated systems fail (e.g., overcurrent elements enabled only during abnormal system conditions or a loss of communications) and protection relay systems intended for the detection of ground fault conditions or for protection during stable power swings.

11. The Commission, under section 215(d)(5) of the FPA, directed the ERO to modify Attachment A to: (1) include section 2 as an additional Requirement with the appropriate violation risk factor and violation severity level in the Reliability Standard;[14] and (2) include supervising relay elements on the list of relays and protection systems that are specifically subject to the reliability Standard.[15]

5. Currently Effective Implementation Plan

12. Reliability Standard PRC-023-1 established staggered effective dates for various Requirements and facilities. The Standard also included a footnote (exceptions footnote)

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[13] "Out-of-step blocking" refers to a protection system that is capable of distinguishing between a fault and a power swing. If a power swing is detected, the protection system, "blocks," or prevents the tripping of its associated transmission facilities.

[14] *Id.* P 244.

[15] *Id.* P 264.

to the "Effective Dates" section honoring temporary exceptions from enforcement actions approved by the NERC Planning Committee before NERC proposed the Reliability Standard.

13. In Order No. 733, the Commission directed the ERO, under section 215(d)(5), to modify the Reliability Standard to include an implementation plan for sub-100 kV facilities[16] and to remove the exceptions footnote from the "Effective Dates" section of the Reliability Standard.[17]

II. NERC Petition for Proposed Reliability Standard PRC-023-2 and Rule of Procedure, Section 1700 – Challenges to Determinations

14. In a March 18, 2011 filing (NERC Petition), NERC requests Commission approval of both its proposed Reliability Standard PRC-023-2 (Transmission Relay Loadability) and its proposed NERC Rules of Procedure Section 1700 – Challenges to Determinations.

15. NERC states that the proposed Reliability Standard requires transmission owners, generator owners, and distribution providers to verify relay loadability using methods that achieve "the reliability goal of this Standard in an effective and efficient manner familiar to the responsible entities."[18] The proposed Standard also applies to out-of-step blocking systems as well as to load-responsive phase protections systems. NERC specifically

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[16] *Id.* P 283.

[17] *Id.* P 284.

[18] NERC Petition at 42.

identifies the benefits of proposed Reliability Standard PRC-023-2, as including (a) consistent identification of operationally critical circuits operated below 200 kV that must comply with the Requirements of the Standard, and (b) providing transmission operators, planning coordinators, reliability coordinators, and the ERO with more information regarding the criteria selected by entities for verifying relay loadability.[19]

A. Reliability Standard PRC-023-2

16. Proposed Reliability Standard PRC-023-2 contains six requirements with the stated purpose of ensuring that protective relay settings do not limit transmission loadability; do not interfere with system operators' ability to take remedial action to protect system reliability; and are set to reliably detect all fault conditions and protect the electrical network from these faults.[20] The proposed Reliability Standard also includes two attachments. Attachment A specifies the protection systems that are subject to and excluded from the Standard's Requirements. Attachment B specifies the criteria for determining the circuits which must comply with Requirements R1 through R5.

1. Proposed Requirement R1

17. The ERO describes proposed Reliability Standard PRC-023-2 Requirement R1 as follows:

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[19] NERC Petition at 5.

[20] Reliability Standard PRC-023-2, Section A.3 (Purpose).

> Requirement R1 mandates that each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the identified criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the [bulk electric system] for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and power factor angle of 30 degrees[.][21]

18. With the exception of clarifying language and the addition of criterion 10.1, proposed Requirement R1 retains the same criteria as currently existing PRC-023-1. Criteria 1 through 13 prescribe specific criteria to be used for certain transmission system configurations. These criteria account for the presence of devices such as series capacitors and address circuit and transformer thermal capability.

19. Criterion 1 specifies transmission line relay settings based on the highest seasonal facility rating using the 4-hour thermal rating of a transmission line, plus a design margin of 150 percent. Criterion 2 allows transmission line relays to be set so that they do not operate at or below 115 percent of the highest seasonal 15-minute facility rating of a circuit, when a 15-minute rating has been calculated and published for use in real-time operations. Criterion 3 allows transmission line relays to be set so that they do not operate at or below 115 percent of the maximum theoretical power capability. Criterion 4 may be applied where series capacitors are used on long transmission lines to increase power transfer. Criterion 5 applies in cases where the maximum end-of-line three-phase fault current is small relative to the thermal loadability of the conductor. Criterion 6 may

[21] NERC Petition at 30.

be used for system configurations where generation is remote from load busses or main transmission busses.

20. Criterion 7 is appropriate for system configurations that have load centers that are remote from the generation center. Criterion 8 applies to system configurations that have one or more transmission lines connecting a remote, net importing load center to the rest of the system. Criterion 9 applies to the same system configuration, but applies to the load end. Criterion 10 is specific to transmission transformer fault protective relays and transmission lines terminated only with a transformer. Criterion 11 may be used for transformer overload protection relays when criterion 10 cannot be met. Criterion 12 may be used when the circuits have three or more terminals. The limited circuit loading capability established by this criterion will become the facility rating of the circuit. Finally, criterion 13 is intended to apply when otherwise supportable situations and practical limitations are identified under criteria 1 through 12.

21. Proposed Reliability Standard PRC-023-2 modifies PRC-023-1 by adding criterion 10.1 to address the Commission's directive that entities with protective relays set pursuant to criteria R1.10 must verify that the limiting piece of equipment is capable of sustaining the anticipated overload for the longest clearing time associated with a fault.[22] The criterion requires coordination so that settings on a transformer's load responsive relay do not expose the transformer to a fault level and duration that exceeds the

[22] *Id.* at 20.

transformer's mechanical withstand capability.[23] NERC states that, for through-faults, it is not possible to set fault protection relays to both meet the relay loadability requirement in criterion 10 and coordinate a transformer's thermal limits, but the mechanical damage threshold is more limiting than the thermal damage threshold. Moreover, NERC states, the permissible time duration to avoid thermal damage is longer than the maximum expected duration for which a through-fault would remain before being cleared by the protection system. Thus, requiring that transformer fault protection relays are set to not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability assures the transformer will be capable of withstanding an overload for the longest clearing time associated with a fault on the low-voltage side of the transformer.[24]

22. NERC believes that Requirement 10.1 is equally effective and efficient as the approach directed in Order No. 733.[25] It states that as a result of design constraints, transformers are more limiting than other series elements with regard to through-fault capability. Accordingly, coordinating transformer fault protection relays with the

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[23] The mechanical withstand capability is determined on the basis of the transformer's design and the maintenance of that capability by the owner. Maintenance would be an issue if, for example, the moisture level in a transformer is allowed to increase above the design value but still within dielectric acceptance, the dielectric withstand capability could be compromised.

[24] *Id.* at 22-23.

[25] *Id.* at 20-21.

transformer mechanical withstand capability addresses the Commission's concerns underlying its directive even though it does not reference the most limiting piece of equipment. Because the fault withstand capability of terminal equipment is not always readily available, requiring entities to provide evidence that equipment in series with the transformer is capable of withstanding a through-fault current for the expected duration, NERC argues, is not necessary to address the Commission's concerns and places an unnecessary burden on entities.[26]

2. Proposed Requirement R2

23. Proposed Reliability Standard PRC-023-2 adds a new Requirement R2 that requires each transmission owner, generation owner, and distribution provider to set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions modeled under Requirement R1. NERC states that Requirement R2 has been added to proposed Reliability Standard PRC-023-2 to address the Commission's directive to include section 2 of PRC-023-1 Attachment A as an additional Requirement with the appropriate violation risk factor and violation severity level.[27] NERC has assigned this proposed Requirement a high Violation Risk Factor and a severe Violation Severity Level reflecting the impact to reliability of violating the Requirement.

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[26] *Id.* at 23.

[27] NERC Petition at 24.

3. Proposed Requirements R3, R4, and R5

24. Requirement R3 in proposed Reliability Standard PRC-023-2 renumbers and makes conforming edits to Requirement R2 from PRC-023-1. Proposed new Requirement R4 requires an entity that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability to provide its planning coordinator, transmission operator, and reliability coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year. Similarly, proposed Reliability Standard PRC-023-2 adds a new Requirement R5 that requires entities that set transmission line relays according to Requirement R1 criterion 12 to provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, to allow the ERO to compile a list of all circuits that have protective relays settings that limit circuit capability. NERC states that new Requirements R4 and R5, respectively, address the Commission's directives relating to providing transmission operators a list of transmission facilities that implement criterion 2 and directing that the ERO create a list of those facilities that have protective relays set pursuant to criterion 12.[28]

4. Proposed Requirement R6

25. Requirement R6 of proposed Reliability Standard PRC-023-2 requires each planning coordinator to conduct an assessment at least once each calendar year (but no

[28] *Id.* at 23-24.

less frequently than every 15 months) by applying the criteria in Attachment B to determine the circuits in its planning coordinator area for which entities must comply with Requirements R1 through R5. Sub-part 6.1 requires the planning coordinator to maintain a list of circuits subject to PRC-023-2 per application of Attachment B identifying the year in which any criterion in Attachment B applies. Sub-part 6.2 requires the planning coordinator to provide the list to all Regional Entities, reliability coordinators, transmission owners, generators owners, and distribution providers within its planning coordinator area within 30 calendar days of establishing the initial list, and 30 days of any subsequent change thereto. NERC states that the proposed sub-part 6.2, formerly Requirement R3.3 in PRC-023-1, modifies the Requirement in order to address the Commission's directive to add the Regional Entity to the list of entities that receive the list of critical facilities.[29]

5. Proposed Attachment A

26. Attachment A to proposed Reliability Standard PRC-023-2 includes a new section 1.6 that extends the Standard's applicability to include phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. In addition, conforming changes are made to proposed section 2.1, formerly section 3.1 of the PRC-023-1, to

[29] *Id.* at 24.

recognize that elements described in new section 1.6 are no longer excluded from the proposed Standard's scope. NERC states that these changes have been made to address the Commission's directives to include supervising relay elements on the list of relays and protection systems that are specifically subject to the Reliability Standard.[30]

27. NERC states that it believes proposed section 1.6 of Attachment A is equally effective and efficient in addressing the Commission's concern as the approach directed in Order No. 733.[31] It states that modifying Attachment A to extend the scope of the proposed Reliability Standard to include all supervising relays as directed would have an unintended negative impact on system reliability by reducing the dependability and security of certain protection system, e.g., supervising phase distance (impedance) elements. It contends that the description in section 1.6 is tailored to avoid the negative impacts on reliability that could occur with an overly broad application of the proposed Standard to supervising relays.[32]

6. Proposed Attachment B

28. Proposed Reliability Standard PRC-023-2 adds an Attachment B to specify six criteria that planning coordinators must use to identify sub-200kV facilities that, upon being so identified, are required to comply with the proposed Reliability Standard. The

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[30] *Id.* at 25.

[31] *Id.*

[32] *Id.* at 26-27.

proposed criteria identify facilities using bright line criteria and analyses. A facility meets the bright line criteria if it:

- is a monitored facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored facility in the Quebec Interconnection, that has been included to address reliability concerns for loading of that circuit (Criteria B1);
- is a monitored facility of an interconnection reliability operating limit, where the limit was determined in the planning horizon pursuant to Reliability Standard FAC-010 (System Operating Limits Methodology for Planning Horizon) (Criteria B2); or
- forms a path to supply off-site power to a nuclear plant as established in the nuclear plant interface requirements pursuant to Reliability Standard NUC-001 (Nuclear Plant Interface Coordination) (Criteria B3).[33]

A facility is identified through the analysis criteria if it:

- is identified through a sequence of power flow analyses specified in Attachment B and performed by the planning coordinator (Criteria B4);

[33] As we stated previously, "[w]e would expect that any [nuclear plant interface requirements] agreed to between a nuclear plant generator operator and transmission entity would include all facilities needed to transmit offsite power and auxiliary power to the nuclear facility. *Mandatory Reliability Standard for Nuclear Plant Interface Coordination*, 125 FERC ¶ 61,065, at P 51 (2008).

- is selected by the planning coordinator based on technical studies or assessments other than those specified above, in consultation with the facility owner (Criteria B5); or
- is mutually agreed upon for inclusion by the planning coordinator and the facility owner (Criteria B6).

NERC states that while the six criteria presented in Attachment B vary from some of the guidance provided in Order No. 733, they nonetheless identify all facilities that must be subject to proposed Reliability Standard PRC-023-2 in order to achieve the Standard's reliability objective.[34] NERC further reports that it is in the process of applying the test to a representative sample of utilities from each of the three Interconnections and plans to file the results of these tests by February 17, 2013. NERC plans to revise Attachment B, if necessary, pending the results of this test and clarifications made in Order No. 733-A.[35]

29. Attachment B, unlike currently effective Reliability Standard PRC-023-1, does not state that the goal of screening sub-200 kV facilities is to identify those that are "critical to the reliability of the bulk electric system." Instead, NERC states that the test in Attachment B "is designed to identify circuits that if tripped on relay loadability following an initiating event could contribute to undesirable system performance similar

[34] NERC Petition at 14.

[35] *Id.* at 13.

to what occurred during the August 2003 Blackout. . . ."[36] This change in wording, NERC states, eliminates potential confusion regarding the use of the phrase "critical to the reliability of the bulk electric system" in the context of this Reliability Standard compared to other Standards such as those addressing critical infrastructure, and it presents the same meaning in an equally effective and efficient approach for referring to the circuits identified through the planning coordinators' assessments.

30. The proposed Reliability Standard also omits reference to sub-100 kV facilities "that Regional Entities have identified as critical to the reliability of the [b]ulk [e]lectric [s]ystem" in favor of referring to "transmission lines operated below 100 kV and transformers with low voltage terminal connected below 100 kV that are part of the [bulk electric system]." NERC states that sub-100 kV circuits identified by the Regional Entities as critical facilities should be included in the definition of the bulk electric system and the proposed language conveys the same meaning in an equally effective and efficient manner.[37] This change in wording, NERC states, responds to confusion arising from the fact that very few such facilities have, as yet, been identified.

31. NERC is taking a three phase approach to addressing the various directives in Order No. 733. Phase I is intended to address directed modifications to PRC-023-1. Phase II entails development of a new Reliability Standard addressing generator relay

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[36] *Id.* at 15.

[37] *Id.* at 16.

loadability, and Phase III consists of developing a new Reliability Standard addressing protective relay operations due to stable power swings. According to the NERC Petition, transmission lines that tripped unnecessarily during the August 2003 Blackout did not trip as a result of power swings up through the tripping of the Argenta-Battle Creek and the Argenta-Tompkins 345 kV lines, but subsequent line trips were due to power swings. While the power system did experience stable swings following each line trip prior to losing these two lines, the swings were not of significant magnitude and dampened quickly allowing the system to return to a new steady-state condition. For this reason, NERC asserts that analysis using steady-state base cases is the appropriate tool to assess the potential for lines to trip under similar conditions, and dynamic base cases are the appropriate tool to assess line tripping due to power swings. NERC has elected to limit the applicability test in Attachment B to power flow analysis with steady-state base cases and to address dynamic base cases in its Phase III Reliability Standard addressing power swings. This election, NERC states, is an equally efficient and effective approach to addressing all facets of the unnecessary line tripping caused by relay loadability that occurred during the August 2003 Blackout.

32. Order No. 733 provided guidance that a test to determine critical sub-200 facilities should include the same simulations and assessments as the Transmission Planning (TPL) Reliability Standards. While the TPL Standards permit manual system adjustments between two contingencies, NERC believes it is more informative, and in line with the reliability objective, to require testing of double contingencies without such manual adjustments, thereby modeling a situation in which an operator fails to, or does not have

time to, make appropriate system adjustments. This focused testing exceeds the requirements of the TPL Standards and, NERC asserts, is an equally efficient and effective approach to addressing the Commission's concern that the test must be sufficiently robust to provide assurance that all appropriate facilities are identified and made subject to the Reliability Standard for the Standard to achieve its purpose.

33. Order No. 733 also provided guidance regarding elements of a definition of desirable system performance that must inform any test to determine which sub-200 kV circuits are critical to system reliability. The Commission's guidance stated, among other things, that the power system should maintain all facilities within their applicable thermal (i.e., current), voltage, or stability ratings (short time ratings are applicable). NERC asserts that it is most appropriate to focus on avoiding thermal loading of transmission circuits. In order to achieve its reliability goal, NERC believes, Reliability Standard PRC-023-2 must apply to circuits whose relays will be challenged by excessive thermal loading to the point that a relay hampers the system operator's ability to take remedial action. The system performance measure in this test is less rigorous than that required by TPL-003 (System Performance Following Loss of Two or More BES Elements) because it ignores voltage and stability ratings. But, NERC points out that the contingency condition in Attachment B is more stringent than that in TPL-003 and the contingency and system performance measure were developed together in order to align with the reliability objective of the proposed Standard. NERC believes this test is an equally effective and efficient approach to addressing the Commission's concern regarding the rigorousness of the test.

7. Proposed Implementation Plan

34. NERC proposes staggered effective dates for Reliability Standard PRC-023-2, i.e., the mandatory compliance date after an allotted implementation period, for each of the Standard's requirements. The implementation plan provides 18 months for planning coordinators to apply the criteria in Attachment B and determine which sub-200 kV circuits must be subject to the Standard. Those entities responsible for compliance on circuits identified by a planning coordinator pursuant to Requirement R6 are provided until the first day of the first calendar quarter 39 months following notification to become compliant, or until the first day of the first calendar year in which any criterion in Attachment B applies if the planning coordinator indentifies the circuit in an assessment of a future year more than 39 months beyond the year in which the assessment is conducted.

8. Violation Risk Factors/Violation Severity Levels

35. To determine a base penalty amount for a violation of a Requirement within a Reliability standard, NERC must first determine an initial range for the penalty amount. To do so, NERC assigns a violation risk factor to each Requirement of a Reliability Standard that relates to the expected or potential impact of a violation of the Requirement on the reliability of the Bulk-Power System. NERC may propose either a lower, medium, or high violation risk factor for each Requirement. The Commission has established guidelines for evaluating the validity of each violation risk factor

assignment.[38] NERC also assigns each Requirement one of four violation severity levels – low, moderate, high, and severe – as measurements for the degree to which the requirement was violated in a specific circumstance.[39] NERC assigns Requirements R1, R2, and R6 a "high" violation risk factor, Requirement R3 a "medium" violation risk factor, and Requirements R4 and R5 a "lower" violation risk factor. The NERC Petition proposes violation severity levels for each of the Requirements of proposed Reliability Standard PRC-023-2.

B. NERC Rules of Procedure Section 1700—Challenges to Determinations

36. Proposed NERC Rules of Procedure Section 1700—Challenges to Determinations allows registered entities to challenge a planning coordinator's determination made under a Reliability Standard or terms defined in the Glossary of Terms Used in NERC Reliability Standards. Proposed Rule 1702 sets out the procedure for challenging a determination by a planning coordinator under Reliability Standard PRC-023-2. It provides that a registered entity is encouraged, but not required, initially to meet with the planning coordinator to resolve any dispute. If the matter cannot be resolved, the registered entity may challenge the determination with the appropriate Regional Entity,

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[38] *See North American Electric Reliability Corp.,* 135 FERC ¶ 61,166 (2011); *North American Electric Reliability Corp.,*119 FERC ¶ 61,145, *order on reh'g*, 120 FERC ¶ 61,145, at P 8-13 (2007).

[39] *See North American Electric Reliability Corp.,* 135 FERC ¶ 61,166; *North American Electric Reliability Corp.,* 123 FERC ¶ 61,284 (2008).

and if not satisfied with the Regional Entity's decision, may appeal to NERC. Review by NERC would initially be handled by a panel appointed by the NERC Board of Trustees. The Board of Trustees would then have the authority, but not the duty, to review the matter upon the request of the planning coordinator or registered entity. The final NERC decision may then be appealed to the applicable governmental authority, e.g., the Commission for appeals within the United States.

III. Discussion

37. We agree with NERC that the proposed Reliability Standard PRC-023-2 addresses the reliability gaps identified in Order No. 733 that relate specifically to Reliability Standard PRC-023-1 and represents an improvement in the Reliability Standard. Accordingly, under section 215(d)(2) of the FPA, the Commission proposes to approve the new Reliability Standard, including its Violation Risk Factors and Violation Severity Levels, as just, reasonable, not unduly discriminatory or preferential, and in the public interest. Also, under section 215(f) of the FPA, the Commission proposes to approve NERC Rule of Procedure Section 1700 – Challenges to Determinations as just, reasonable, not unduly discriminatory or preferential, in the public interest, and satisfying the requirements of section 215(c) of the FPA. NERC reports that it is in the process of applying the test set forth in Attachment B to a representative sample of utilities from each of the three Interconnections and will file the results of these tests in a report on or before February, 2013 (Report). In order to better understand the practical application of the test, the Commission proposes to direct the ERO to address specific matters described below in the Report.

38. Based on our review of NERC's petition and accompanying information, we propose to find that the proposed Reliability Standard and NERC Rule of Procedure Section 1700 – Challenges to Determinations adequately address the directed modifications set forth in Order No. 733 regarding Reliability Standard PRC-023-1. Specifically, we propose to find that proposed Reliability Standard PRC-023-2 and the proposed NERC Rule of Procedure address the following Order No. 733 directives: (1) adopt an "add in" approach to sub-100 kV facilities and modify Requirement R3 to specify the test planning coordinators must use to determine whether a sub-200 kV facility is critical to reliability; (2) establish a mechanism for registered entities to challenge criticality determinations; (3) require applicable entities to notify transmission operators of facilities that implement sub-requirement R1.2; (4) modify sub-requirement R1.10 to require verification that the limiting piece of equipment can sustain the anticipated overload; (5) direct the ERO to document facilities that have protective relays set pursuant to sub-requirement R1.12; (6) add Regional Entities to the list of those that receive the critical facilities list pursuant to sub-requirement 3.3; (7) include section 2 of Attachment A as an additional Requirement; (8) revise section 1 of Attachment A to include supervising relay elements associated with the identified reliability concern subject to the Standard; (9) create an implementation plan for sub-100 kV facilities; and (10) remove the exceptions footnote from the "Effective Dates" section. In light of the manner in which it addresses these directives, the proposed Reliability Standard represents an improvement in transmission relay loadability.

39. Attachment A to the proposed Reliability Standard has been modified to extend coverage of the Standard to phase overcurrent supervisory elements associated with current-based, communication-assisted schemes capable of tripping for loss of communications. While the description of the supervisory elements is more specific than the directive in Order No. 733,[40] the proposed Attachment A reflects industry comment regarding the potential for unintended, negative reliability consequences that could arise from an overly broad description. In light of the explanation provided and our reliability concern,[41] we consider the proposed alternative solution to be an equally effective and efficient approach to addressing the Commission's reliability concerns.

40. Transmission relay loadability is important to ensuring the reliability of the Bulk-Power System. The ERO has proposed changes to currently effective Reliability Standard PRC-023-1 on many issues, including (1) extending its coverage to communication assisted supervising elements and out-of-step blocking schemes; (2) requiring that a uniform test is applied consistently by planning coordinators utilizing their judgment to identify sub-200 kV circuits to which the Reliability Standard must apply; (3) requiring that load responsive transformer fault protection relays be set to reflect the transformer's mechanical withstand capability; and (4) ensuring communication regarding the ratings used to verify transmission facility relay loadability.

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[40] Order No. 733, 130 FERC ¶ 61,221 at P 264.

[41] *Id.* P 251.

These changes extend and strengthen the reliability benefits currently effective Reliability Standard PRC-023-1 was designed to achieve.

41. Attachment B to the proposed Reliability Standard specifies the test planning coordinators are required to use to determine whether a sub-200 kV facility is critical to reliability. NERC states that it plans to revise the test, if necessary, based on the results of this testing and the clarifications regarding the test made in Order No. 733-A.[42] The Commission seeks to better understand the implementation and effects of Requirement R6, and criteria B4 and B5, as they are used to identify operationally critical sub-200 kV facilities.

Questions Regarding Test to Determine Critical Sub-200 kV Facilities

42. Criterion B4 of Attachment B requires application of proposed Reliability Standard PRC-023-2 to any circuit identified through a specified set of power flow analyses performed by planning coordinators. Planning coordinators must apply their engineering judgment in the simulation of double contingency combinations in order to determine which combinations of contingencies result in undesirable tripping. In guidance given in Order No. 733, the Commission stated that for Category C contingencies (i.e., events resulting in the loss of two or more elements) desirable system performance includes, among other things, the maintenance of all facilities within their

[42] NERC Petition at 13.

applicable thermal, voltage, or stability ratings (short time ratings are applicable).[43] An impedance relay reads the magnitude and phase angle of both the current and voltage quantities, and if the combination results in an apparent impedance that encroaches or penetrates the relay's operational settings, the relay is susceptible to undesirable tripping. The performance standard proposed in Attachment B requires the planning coordinator to monitor thermal ratings but does not consider the other parameters that could result a relay trip event without high currents.

43. NERC states that though "the system performance measure in this test is less stringent than required for Category C contingencies in TPL-003, it is important to note that the contingency itself is more stringent than a Category C contingency [because it does not allow manual system adjustments between the two contingencies as does a Category C contingency], and the contingency and system performance measure have been developed together. . . ."[44] However, the standard is silent as to the rigor of the simulations other than requiring the planning coordinators to apply their engineering judgment. We propose that the ERO address in the Report whether the power system assessment proposed in criterion B4 includes the critical system conditions utilized under

[43] Order No. 733, 130 FERC ¶ 61,221 at P 84.

[44] NERC Petition at 19.

Reliability Standard TPL-003-0 Requirement R1.3.2[45] and whether applicable entities evaluate relay loadability under the B4 criterion consistent with Requirement R1 which requires, in part, that they "evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees" in addition to applicable current criteria. If the evaluation uses other per unit voltage and power factor angle assumptions, we propose that the Report include a comparison of results obtained from those that would be achieved were the assumptions consistent with Requirement R1.

44. Criterion B5 of Attachment B requires compliance with the proposed Reliability Standard with respect to a "circuit …selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner." The Commission proposes that the Report comment on what "technical studies or assessments" planning coordinators use to identify critical facilities.

45. According to the NERC Petition, "[d]uring the standard development process, a number of industry comments expressed concern with potential confusion regarding use of the phrase 'critical to the reliability of the bulk electric system' in the context of PRC-023-1 versus other standards such as those addressing critical infrastructure."[46] As a

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[45] Reliability Standard TPL-003-0 Requirement R1.3.2 provides that a transmission planner assessment shall "[c]over critical system conditions and study years as deemed appropriate by the responsible entity."

[46] NERC Petition at 15.

result, the proposed Requirement R6 omits that phrase and refers instead to circuits "for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5." In contrast, however, the Blackout Report used the phrase "operationally significant," and the test in Attachment B is "designed to identify circuits that if tripped on relay loadability following an initiating event could contribute to undesirable system performance similar to what occurred during the August 2003 Blackout."[47] Notwithstanding the various phrases used to describe the reliability objective, the NERC Petition indicates that the test is intended to identify all circuits in a planning coordinator's area that could have an operational impact on the reliability of the bulk electric system. The Commission proposes that the Report assess whether Attachment B is sufficiently comprehensive to capture all such circuits.

Summary

46. In summary, the Commission proposes to approve proposed Reliability Standard PRC-023-2 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. We also propose to approve proposed NERC Rules of Procedure Section 1700 – Challenges to Determinations as just, reasonable, not unduly discriminatory or preferential, in the public interest, and satisfying the requirements of section 215(c) of the FPA. In addition, the Commission proposes that NERC addresses in the Report

[47] *Id.*

questions regarding the system assessment simulations and results of the power flow analyses criterion in the proposed test for critical facilities.

IV. Information Collection Statement

47. The Office of Management and Budget (OMB) regulations require approval of certain information collection requirements imposed by agency rules.[48] Upon approval of a collection(s) of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirement of this rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number. The Paperwork Reduction Act (PRA)[49] requires each federal agency to seek and obtain OMB approval before undertaking a collection of information directed to ten or more persons, or continuing a collection for which OMB approval and validity of the control number are about to expire.[50]

48. The Commission is submitting these reporting and recordkeeping requirements to OMB for its review and approval under section 3507(d) of the PRA. Comments are solicited on the Commission's need for this information, whether the information will have practical utility, the accuracy of provided burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods

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[48] 5 CFR 1320.11.

[49] 44 U.S.C .3501-20

[50] 44 U.S.C. 3502(3)(A)(i), 55 USC 3507(a)(3).

for minimizing the respondent's burden, including the use of automated information techniques.

49. This Notice of Proposed Rulemaking proposes to approve Reliability Standard PRC-023-2 (Transmission Relay Loadability) which will replace currently effective Reliability Standard PRC-023-1 approved by the Commission in Order No. 733. Rather than creating entirely new requirements regarding the setting of protective relays, the proposed Reliability Standard instead modifies and improves the existing Reliability Standard. Thus this proposed rulemaking does not impose entirely new burdens on the effected entities. For example, the currently effective Reliability Standard PRC-023-1 requires transmission owners, generation owners, and distribution providers to each have evidence to show that each of its transmission relays are set according to one of the criteria in criteria R1.1 through R1.13. Similarly, proposed Reliability Standard PRC-023-2 requires transmission owners, generation owners, and distribution providers to have evidence that each of its transmission relays is set according to one of the 13 criteria in Requirement R1 but adds that each such entity shall also have evidence that relays set according to criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the Standard. Thus, the recordkeeping obligations for some Requirements are more specific but not necessarily more expansive than those of currently effective Reliability Standard PRC-023-1. However, proposed PRC-023-2 does add new Requirements, each of which has new recordkeeping obligations.

50. Proposed Requirement R2 will require each transmission owner, generator owner, and distribution provider to have evidence that its out-of-step blocking elements are set in

accordance with the Standard, and proposed Requirements R4 and R5 will require those same entities to maintain evidence that they have informed the appropriate parties of their updated lists of certain circuits. Under Requirement R6, planning coordinators will be required to execute a test for applicability of the Standard as set forth in Attachment B and retain analyses, calculation summaries, or study reports to evidence execution of the test, whereas under the currently effective PRC-023-1, a test was required but only the results needed to be retained. Because an unspecified test is currently required to be carried out on facilities operated at between 100 kV and 200 kV under currently effective Reliability Standard PRC-023-1, for purposes of this analysis, we assume that there is little additional cost for planning coordinators to implement and document that portion of the test. However, the proposed Requirement R6 imposes the new burdens of performing the test on sub-100 kV facilities, maintaining appropriate records, and distributing the list of circuits identified by the test to Regional Entities.

51. Public Reporting Burden: Our estimate below regarding the number of respondents is based on the NERC compliance registry as of July 29, 2011. According to the NERC compliance registry, there are 335 transmission owners, 793 generation owners, 553 distribution providers, and 72 planning coordinators. However, under NERC's compliance registration program, entities may be registered for multiple functions, so these numbers incorporate some double counting. The net number of entities responding will be approximately 645 entities registered as a transmission owner, a distribution provider, or a generation owner that is also a transmission owner and/or a

distribution owner, and 72 planning coordinators.[51] The estimated burden for the requirements in this Order follow:

Changes to FERC-725G Data Collection	**Number of Respondents Annually (1)**	**Number of Responses Per Respondent (2)**	**Average Burden Hours Per Response[52] (3)**		**Total Annual Hours (1x2x3)**
R1 criterion 1.10: TOs, GOs, and DPs must analyze and document criterion 1.10 compliance	645	1	*Analysis for compliance documents*	8	5,160
			Record Retention	2	1,290
R2: TOs, GOs, and DPs must perform analysis and retain evidence of compliance	645	1	*Analysis for compliance documents*	8	5,160
			Record Retention	2	1,290
R4 and R5: TOs, GOs, and DPs must distribute updated lists and retain evidence that lists were distributed	645	1	*Reporting (dist. of list)*	10	6,450
			Record Retention	10	6,450

[51] Under its applicability provisions, proposed Reliability Standard applies to specified circuits such that very few, if any, generator owners that are not also a transmission owner and/or a distribution provider will be subject to the Standard.

[52] The burden hours are based on estimates that the Commission has used for similar reporting requirements.

R6: PC must perform assessment, distribute list of circuits and retain evidence of testing and distribution[53]	72	1	*Reporting (assess-ment and dist. of list)*	20	1,440
			Record Retention	10	720
Total					27,960

Information Collection Costs: The Commission seeks comments on the costs to comply with these requirements and recordkeeping burden associated with Reliability Standard PRC-023-2.

- Total Annual Hours for Collection: (Reporting and Record Retention) = 27,960 hours.
- Total Estimated Reporting/Analysis Cost = 18,210 hours @ $120/hour = $2,185,200.
- Total Estimated Record Retention Cost = 9,750 hours @ $28/hour = $273,000.
- Total Estimated Annual Cost (reporting + Record Retention)[54] = $2,458,200.
- Title: Mandatory Reliability Standards for the Bulk-Power System

[53] This applies to the portion of R6 that deals with testing for sub-100 kV facilities as described in the text. In addition it includes burden hours associated with adding Regional Entities to the list of entities to receive a list of circuits from the planning coordinator.

[54] The hourly reporting cost is based on the estimated cost of an engineer to implement the requirements of the rule. The record retention cost comes from Commission staff research on record retention requirements.

- Action: FERC 725G, Proposed Modification to FERC-725G.
- OMB Control No: 1902-0252.
- Respondents: Business or other for profit, and/or not for profit institutions.
- Frequency of Responses: On occasion.
- Necessity of the Information: This proposed rule would approve a revised Reliability Standard that modifies an existing requirement regarding setting protective relays according to specific criteria in order to ensure that the relays reliably detect and protect the electric network from all fault conditions, but do not limit transmission loadability or interfere with system operators' ability to protect system reliability. Proposed Reliability Standard PRC-023-2 requires entities to set transmission relays according to specified criteria and to retain evidence of compliance. It also requires planning coordinators to implement a test to determine which sub-200 kV facilities are critical to the reliability of the power system and subjects such facilities to the requirements of the proposed Standard. The proposed Reliability Standard requires entities to maintain records subject to review by the Commission and NERC to ensure compliance with the Reliability Standard.
- Internal review: The Commission has reviewed the requirements pertaining to the proposed Reliability Standard for the Bulk-Power System and determined that the proposed requirements are necessary to meet the statutory provisions of the Energy Policy Act of 2005. These requirements conform to the Commission's plan for efficient information collection, communication and management within the energy industry. The

Commission has assured itself, by means of internal review, that there is specific objective support for the burden estimates associated with the information requirements.

52. Interested persons may obtain information on the reporting requirements by contacting: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, e-mail: DataClearance@ferc.gov, Phone: (202) 502-8663, fax: (202) 273-0873]. Comments on the requirements of this order may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission]. For security reasons, comments should be sent by e-mail to OMB at oira_submission@omb.eop.gov. Please reference OMB Control Number 1902-0252 and the docket number of this Order in your submission.

V. Environmental Analysis

53. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[55] The actions proposed here fall within the categorical exclusion in the Commission's regulations for rules that are clarifying, corrective or

[55] *Regulations Implementing the National Environmental Policy Act*, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Regulations Preambles 1986-1990 ¶ 30,783 (1987).

procedural, for information gathering, analysis, and dissemination.[56] Accordingly, neither an environmental impact statement nor environmental assessment is required.

VI. Regulatory Flexibility Act Analysis

54. The Regulatory Flexibility Act of 1980 (RFA)[57] generally requires a description and analysis of proposed and final rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a proposed order and that minimize any significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[58] The SBA has established a size standard for electric utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million megawatt-hours.[59]

55. Proposed Reliability Standard PRC-023-2 modifies currently existing Reliability Standard PRC-023-1 which requires applicable entities to set protective relays according to specific criteria, to communicate about such settings with specified entities, and to

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[56] 18 CFR 380.4(a)(5).

[57] 5 U.S.C. 601-612.

[58] 13 CFR 121.101.

[59] 13 CFR 121.201, Sector 22, Utilities & n. 1.

conduct assessments to determine the applicability of the Standard to 100-200 kV facilities. The proposed standard modifies PRC-023-1 by (1) increasing communication and documentation requirements, (2) extending the applicability of the Standard to formerly excluded relays, and (3) standardizing the terms of the assessment whose terms were formerly not specified. In addition, proposed PRC-023-2 extends the current requirement that planning coordinators annually assess which 100-200 kV circuits must be brought into compliance with the Standard and will require planning coordinators to carry out the assessment with respect to some sub-100 kV facilities.

56. Comparison of the NERC compliance registry with data submitted to the Energy Information Administration on Form EIA-861 indicates that perhaps as many 103 transmission owners, 329 distribution providers, 46 generation owners, and 8 planning coordinators qualify as small entities. However, under NERC's compliance registration program, entities may be registered for multiple functions, so these numbers incorporate some double counting. The net number of registered entities that qualify as small entities responding to this rule will be approximately 339 entities registered as a transmission owner, a distribution provider, or a generation owner that is also a transmission owner and/or a distribution provider, and 8 planning coordinators. The proposed rule directly affects each of the small entities. Therefore, FERC has determined that this proposed rule will have an impact on a substantial number of small entities. However, the Commission has determined that the impact on entities affected by the proposed rule will not be significant. The Commission estimates that in order to comply with the Standard's modification of existing requirements each of the small entities registered as planning

coordinators will face a cost of $2,680 and each of the remaining small entities (transmission owners, distribution providers, or generation owners that are also transmission owners and/or distribution providers) will face a cost of $3,512. Accordingly, the Commission determines that the incremental cost of Reliability Standard PRC-023-2 (going from PRC-023-1 to PRC-023-2) is minimal, and should not present a significant operating cost to any of the small entities.

57. Based on this understanding, the Commission certifies that this Reliability Standard will not have a significant economic impact on a substantial number of small entities. Accordingly, no regulatory flexibility analysis is required.

58. The Commission invites comment from members of the public regarding the accuracy of the certification provided here, the economic analysis, and its underlying assumptions.

VII. Comment Procedures

59. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due [Insert date 60 days from publication in the **FEDERAL REGISTER**]. Comments must refer to Docket No. RM11-16-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

60. Commenters may submit comments, identified by Docket No. RM11-16-000 and in accordance with the requirements posted on the Commission's web site, http://www.ferc.gov. Comments may be submitted by any of the following methods:

- Agency Web Site: Documents created electronically using word processing software should be filed in native applications or print-to-PDF format, and not in a scanned format, at http://www.ferc.gov/docs-filing/efiling.asp.
- Mail/Hand Delivery: Commenters unable to file comments electronically must mail or hand deliver their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426. These requirements can be found on the Commission's web site, see, e.g., the "Quick Reference Guide for Paper Submissions," available at http://www.ferc.gov/docs-filing/efiling.asp or via phone from FERC Online Support at (202) 502-6652 or toll-free at 1-(866) 208-3676.

61. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VIII. Document Availability

62. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (http://www.ferc.gov) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

63. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft

Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

64. User assistance is available for eLibrary and the FERC's website during normal business hours from FERC Online Support at (202)-502-6652 (toll free at 1-(866) 208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

By direction of the Commission.

Nathaniel J. Davis, Sr.,
Deputy Secretary.

share), was greater than $60 million (positive or negative) but none of these items was greater than $300 million (positive or negative) at the end of, or for, its fiscal year that ended in calendar year 2012.

(ii) A minority-owned U.S. affiliate if, on a fully consolidated basis, or, in the case of real estate investment, on an aggregated basis, any one of the three items listed in paragraph (c)(1) of this section (not just the foreign parent's share), was greater than $60 million (positive or negative) at the end of, or for, its fiscal year that ended in calendar year 2012. (A ''minority-owned'' U.S. affiliate is one in which the combined direct and indirect ownership interest of all foreign parents of the U.S. affiliate is 50 percent or less.)

(3) Form BE–12C must be completed by a U.S. affiliate if, on a fully consolidated basis, or, in the case of real estate investment, on an aggregated basis, none of the three items listed in paragraph (c)(1) of this section for a U.S. affiliate (not just the foreign parent's share), was greater than $60 million (positive or negative) at the end of, or for, its fiscal year that ended in calendar year 2012.

(4) BE–12 Claim for Not Filing will be provided for response by persons that are not subject to the reporting requirements of the BE–12 survey but have been contacted by BEA concerning their reporting status.

(d) *Aggregation of real estate investments.* All real estate investments of a foreign person must be aggregated for the purpose of applying the reporting criteria. A single report form must be filed to report the aggregate holdings, unless written permission has been received from BEA to do otherwise. Those holdings not aggregated must be reported separately on the same type of report that would have been required if the real estate holdings were aggregated.

(e) *Due date.* A fully completed and certified Form BE–12A, BE–12B, BE–12C, or BE–12 Claim for Not Filing is due to be filed with BEA not later than May 31, 2013.

[FR Doc. 2011–24267 Filed 9–20–11; 8:45 am]

BILLING CODE 3510–06–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Parts 39 and 40

[Docket No. RM11–16–000]

Transmission Relay Loadability Reliability Standard

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: Pursuant to section 215 of the Federal Power Act, the Commission proposes to approve Reliability Standard PRC–023–2 (Transmission Relay Loadability) submitted to the Commission for approval by the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization (ERO) certified by the Commission. The proposed Reliability Standard requires transmission owners, generator owners, and distribution providers to set relays according to specific criteria in order to ensure that the relays reliably detect and protect the electric network from fault conditions, but do not limit transmission loadability or interfere with system operators' ability to protect system reliability. The Commission seeks comment from interested persons on the proposed Reliability Standard. The Commission also proposes to approve NERC Rules of Procedure Section 1700—Challenges to Determinations. This proposed rule provides registered entities a means to challenge determinations made by planning coordinators under Reliability Standard PRC–023.

DATES: Comments are due November 21, 2011.

ADDRESSES: You may submit comments, identified by docket number RM11–16–000 and in accordance with the requirements posted on the Commission's Web site, *http// www.ferc.gov.* Comments may be submitted by any of the following methods:

- *Agency Web site: http://ferc.gov.* Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format, at *http://www.ferc.gov/docs-filing/efiling.asp.*
- *Mail/Hand Delivery:* Commenters unable to file comments electronically must mail or hand deliver their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE., Washington, DC 20426. These requirements can be found on the Commission's Web site, see, *e.g.,* the ''Quick Reference Guide for Paper Submissions,'' available at *http://www.ferc.gov/docs-filing/efiling.asp* or via phone from FERC Online Support at (202) 502–6652 or toll-free at 1-(866) 208–3676.

FOR FURTHER INFORMATION CONTACT:

Terence A. Burke (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–6498.

Kenneth U. Hubona (Technical Information), Office of Electric Reliability, Division of Reliability Standards, Federal Energy Regulatory Commission, 13511 Label Lane, Suite 203, Hagerstown, MD 21740, (301) 665–1608.

SUPPLEMENTARY INFORMATION:

Notice of Proposed Rulemaking

September 15, 2011.

1. Pursuant to section 215 of the Federal Power Act (FPA),[1] the Commission proposes to approve Reliability Standard PRC–023–2 (Transmission Relay Loadability) submitted by the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization (ERO) certified by the Commission. The proposed Reliability Standard requires transmission owners, generation owners, and distribution providers to set load-responsive phase protective relays according to specific criteria in order to ensure that the relays reliably detect and protect the electric network from fault conditions, but do not limit transmission loadability[2] or interfere with system operators' ability to protect system reliability. The Commission seeks comment from interested persons on the proposed Reliability Standard. The Commission also proposes to approve NERC Rules of Procedure Section 1700—Challenges to Determinations also included in NERC's filing. This proposed rule provides registered entities a means to challenge determinations made by planning coordinators under Reliability Standard PRC–023.

I. Background

A. Relay Protection Systems

2. Protective relays are devices that detect and initiate the removal of faults

[1] 16 U.S.C. 824o (2006).

[2] In the context of the proposed Reliability Standard, ''loadability'' refers to the ability of protective relays to refrain from operating under load conditions.

on an electric system.[3] They are designed to read electrical measurements, such as current, voltage, and frequency, and can be set to recognize certain measurements as indicating a fault. When a protective relay detects a fault on an element of the system under its protection, it sends a signal to an interrupting device(s) (such as a circuit breaker) to disconnect the element from the rest of the system. Impedance relays are the most common type of relays used to protect transmission lines. They continuously measure voltage and current on the protected transmission line and operate when the measured magnitude and phase angle of the impedance (voltage/current) falls within the settings of the relay. Impedance relays can also provide backup protection and protection against remote circuit breaker failure.

3. On March 18, 2010, the Commission issued a Final Rule approving Reliability Standard PRC–023–1 (Transmission Relay Loadability), a Standard that requires transmission owners, generator owners, and distribution providers to set load-responsive phase protection relays according to specific criteria to ensure that the relays reliably detect and protect the electric network from all fault conditions, but do not operate during non-fault load conditions.[4] In addition, under section 215(d)(5) of the FPA, the Commission directed the ERO to develop modifications to the Standard to address certain issues identified by the Commission. At issue in the immediate proceeding is a revised Reliability Standard that addresses our directives in that order and will replace the currently effective PRC–023–1.

B. Reliability Standard PRC–023–1 and Order No. 733

4. Currently effective Reliability Standard PRC–023–1 applies to relay settings on (1) All transmission lines and transformers with low-voltage terminals operated or connected at or above 200 kV; and (2) those transmission lines and transformers with low voltage terminals operated or connected between 100 kV and 200 kV that are designated by planning coordinators as critical to the reliability of the bulk electric system.[5] The Reliability Standard consists of three compliance requirements and Attachment A. Requirement R1 requires entities with certain transmission facilities to set their relays according to one of thirteen specific settings (sub-parts R1.1 through R1.13) designed to maximize loadability while maintaining Reliable Operation of the bulk electric system for all fault conditions. Requirement R2 provides additional obligations for entities that elect certain settings. Requirement R3 requires planning coordinators to designate facilities, operated between 100 kV and 200 kV, that are critical to the reliability of the bulk electric system and are therefore subject to Requirement R1. Attachment A specifies the protection systems that are subject to and excluded from the Standard's Requirements.

1. Currently Effective Requirement R1

5. Requirement R1 states that each transmission owner, generator owner, and distribution provider subject to Reliability Standard PRC–023–1 shall use one of the criteria prescribed in sub-parts R1.1 through R1.13 for any specific circuit terminal to prevent its phase protective relay setting from limiting transmission system loadability while maintaining reliable protection of the bulk electric system for all fault conditions.

6. In Order No. 733, the Commission directed the ERO, under section 215(d)(5) of the FPA, to develop modifications to Requirement R1 to: (1) Require that transmission owners, generator owners, and distribution providers give their transmission operators a list of transmission facilities that implement sub-part R1.2;[6] (2) require entities that have protective relays set pursuant to sub-part R1.10 to verify that the limiting piece of equipment is capable of sustaining the anticipated overload for the longest clearing time associated with a fault;[7] and (3) require the ERO to document, subject to audit by the Commission, and to make available for review to users, owners, and operators of the Bulk-Power System, by request, a list of those facilities that have protective relays set pursuant to sub-part R1.12.[8]

2. Currently Effective Requirement R2

7. Requirement R2 states that transmission owners, generator owners, and distribution providers that use a circuit with the protective relay settings determined by the practical limitations described in specified R1 sub-parts must use the calculated circuit capability as the circuit's facility rating and must obtain the agreement of the planning coordinator, transmission operator, and reliability coordinator with the calculated circuit capability.

3. Currently Effective Requirement R3

8. Requirement R3 requires planning coordinators to designate which transmission lines and transformers with low-voltage terminals operated or connected between 100 kV and 200 kV are critical to the reliability of the bulk electric system and therefore subject to Requirement R1. Sub-part R3.1 requires planning coordinators to have a process to identify critical facilities. Sub-part R3.1.1 specifies that the process must consider input from adjoining planning coordinators and affected reliability coordinators. Sub-parts R3.2 and R3.3 require planning coordinators to maintain a list of critical facilities and provide it to reliability coordinators, transmission owners, generator owners, and distribution providers within 30 days of initially establishing it, and 30 days of any subsequent change.

9. Under section 215(d)(5) of the FPA, the Commission directed the ERO to modify Requirement R3 to: (1) Apply an ''add in'' approach to sub-100 kV facilities that are owned or operated by currently registered entities or entities that become registered entities in the future, and are associated with a facility that is included on a critical facilities

[3] A ''fault'' is defined in the NERC Glossary of Terms used in Reliability Standards as ''[a]n event occurring on an electric system such as a short circuit, broken wire, or an intermittent connection.''

[4] *Transmission Relay Loadability Reliability Standard,* Order No. 733, 130 FERC ¶ 61,221 (2010), *order on reh'g and clarification,* Order No. 733–A, 134 FERC ¶ 61,127 (2011); *clarified,* Order No. 733–B, 136 FERC ¶ 61,185 (2011). Order No. 733–B is issuing concurrently with this Notice of Proposed Rulemaking.

[5] Pursuant to section 40.3 of the Commission's regulations, all Commission-approved Reliability Standards are available on NERC's Web site at *http://www.nerc.com. See* 18 CFR 40.3.

[6] Order No. 733, 130 FERC ¶ 61,221 at P 186. sub-part R.1.2 allows transmission owners, generation owners and distribution providers to ''set transmission line relays so they do not operate at or below 115 [percent] of the highest seasonal 15-minute Facility Rating of a circuit (expressed in amperes).'' The Standard includes a footnote that states ''[w]hen a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.''

[7] *Id.* P 203. sub-part R.1.10 allows transmission owners, generation owners and distribution providers to set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer * * * at or below the greater of:

[a.] 150 [percent] of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment[; or]

[b.] 115 [percent] of the highest operator established emergency transformer rating.

[8] *Id.* P 224. Sub-part R1.12 addresses setting transmission line distance relays to a maximum of 125 percent of the apparent impedance (at the impedance angle of the transmission line), subject to specified constraints, when the transmission line's desired capability is limited by the requirement to adequately protect the transmission line.

list defined by the Regional Entity; [9] (2) specify the test that planning coordinators must use to determine whether a sub-200 kV facility is critical to the reliability of the Bulk-Power System; [10] and (3) add the Regional Entity to the list of entities that receive a list of sub-200 kV facilities determined by the planning coordinator to be critical to the reliability of the bulk electric system.[11] In addition, the Commission directed the ERO to develop an appeals process for entities to challenge a criticality determination.[12]

4. Currently Effective Attachment A

10. Attachment A to Reliability Standard PRC–023–1 specifies which protection systems are subject to and excluded from the Standard's Requirements. Section 1 of Attachment A provides that the Reliability Standard applies to any protective functions that can operate with or without time delay, on load current, including but not limited to: (1) Phase distance; (2) out-of-step tripping; (3) switch-on-to-fault; (4) overcurrent relays; and (5) communication-aided protection applications. Section 2 states that the Reliability Standard requires evaluation of out-of-step blocking schemes [13] to ensure that they do not operate for faults during the loading conditions defined in the Standard's Requirements. Finally, section 3 expressly excludes certain relay elements and protection systems from the Reliability Standard's Requirements, such as relay elements enabled only when other relays or associated systems fail (*e.g.,* overcurrent elements enabled only during abnormal system conditions or a loss of communications) and protection relay systems intended for the detection of ground fault conditions or for protection during stable power swings.

11. The Commission, under section 215(d)(5) of the FPA, directed the ERO to modify Attachment A to: (1) Include section 2 as an additional Requirement with the appropriate violation risk factor and violation severity level in the Reliability Standard; [14] and (2) include supervising relay elements on the list of relays and protection systems that are specifically subject to the reliability Standard.[15]

5. Currently Effective Implementation Plan

12. Reliability Standard PRC–023–1 established staggered effective dates for various Requirements and facilities. The Standard also included a footnote (exceptions footnote) to the ''Effective Dates'' section honoring temporary exceptions from enforcement actions approved by the NERC Planning Committee before NERC proposed the Reliability Standard.

13. In Order No. 733, the Commission directed the ERO, under section 215(d)(5), to modify the Reliability Standard to include an implementation plan for sub-100 kV facilities [16] and to remove the exceptions footnote from the ''Effective Dates'' section of the Reliability Standard.[17]

II. NERC Petition for Proposed Reliability Standard PRC–023–2 and Rule of Procedure, Section 1700—Challenges to Determinations

14. In a March 18, 2011 filing (NERC Petition), NERC requests Commission approval of both its proposed Reliability Standard PRC–023–2 (Transmission Relay Loadability) and its proposed NERC Rules of Procedure Section 1700—Challenges to Determinations.

15. NERC states that the proposed Reliability Standard requires transmission owners, generator owners, and distribution providers to verify relay loadability using methods that achieve ''the reliability goal of this Standard in an effective and efficient manner familiar to the responsible entities.'' [18] The proposed Standard also applies to out-of-step blocking systems as well as to load-responsive phase protections systems. NERC specifically identifies the benefits of proposed Reliability Standard PRC–023–2, as including (a) Consistent identification of operationally critical circuits operated below 200 kV that must comply with the Requirements of the Standard, and (b) providing transmission operators, planning coordinators, reliability coordinators, and the ERO with more information regarding the criteria selected by entities for verifying relay loadability.[19]

A. Reliability Standard PRC–023–2

16. Proposed Reliability Standard PRC–023–2 contains six requirements with the stated purpose of ensuring that protective relay settings do not limit transmission loadability; do not interfere with system operators' ability to take remedial action to protect system reliability; and are set to reliably detect all fault conditions and protect the electrical network from these faults.[20] The proposed Reliability Standard also includes two attachments. Attachment A specifies the protection systems that are subject to and excluded from the Standard's Requirements. Attachment B specifies the criteria for determining the circuits which must comply with Requirements R1 through R5.

1. Proposed Requirement R1

17. The ERO describes proposed Reliability Standard PRC–023–2 Requirement R1 as follows:

> Requirement R1 mandates that each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the identified criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the [bulk electric system] for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and power factor angle of 30 degrees[.] [21]

18. With the exception of clarifying language and the addition of criterion 10.1, proposed Requirement R1 retains the same criteria as currently existing PRC–023–1. Criteria 1 through 13 prescribe specific criteria to be used for certain transmission system configurations. These criteria account for the presence of devices such as series capacitors and address circuit and transformer thermal capability.

19. Criterion 1 specifies transmission line relay settings based on the highest seasonal facility rating using the 4-hour thermal rating of a transmission line, plus a design margin of 150 percent. Criterion 2 allows transmission line relays to be set so that they do not operate at or below 115 percent of the highest seasonal 15-minute facility rating of a circuit, when a 15-minute rating has been calculated and published for use in real-time operations. Criterion 3 allows transmission line relays to be set so that they do not operate at or below 115 percent of the maximum theoretical power capability. Criterion 4 may be applied where series capacitors are used on long transmission lines to increase power transfer. Criterion 5 applies in cases where the maximum end-of-line

[9] *Id.* P 60.

[10] *Id.* P 69.

[11] *Id.* P 237.

[12] *Id.* P 97.

[13] ''Out-of-step blocking'' refers to a protection system that is capable of distinguishing between a fault and a power swing. If a power swing is detected, the protection system, ''blocks,'' or prevents the tripping of its associated transmission facilities.

[14] *Id.* P 244.

[15] *Id.* P 264.

[16] *Id.* P 283.

[17] *Id.* P 284.

[18] NERC Petition at 42.

[19] NERC Petition at 5.

[20] Reliability Standard PRC–023–2, Section A.3 (Purpose).

[21] NERC Petition at 30.

three-phase fault current is small relative to the thermal loadability of the conductor. Criterion 6 may be used for system configurations where generation is remote from load busses or main transmission busses.

20. Criterion 7 is appropriate for system configurations that have load centers that are remote from the generation center. Criterion 8 applies to system configurations that have one or more transmission lines connecting a remote, net importing load center to the rest of the system. Criterion 9 applies to the same system configuration, but applies to the load end. Criterion 10 is specific to transmission transformer fault protective relays and transmission lines terminated only with a transformer. Criterion 11 may be used for transformer overload protection relays when criterion 10 cannot be met. Criterion 12 may be used when the circuits have three or more terminals. The limited circuit loading capability established by this criterion will become the facility rating of the circuit. Finally, criterion 13 is intended to apply when otherwise supportable situations and practical limitations are identified under criteria 1 through 12.

21. Proposed Reliability Standard PRC–023–2 modifies PRC–023–1 by adding criterion 10.1 to address the Commission's directive that entities with protective relays set pursuant to criteria R1.10 must verify that the limiting piece of equipment is capable of sustaining the anticipated overload for the longest clearing time associated with a fault.[22] The criterion requires coordination so that settings on a transformer's load responsive relay do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability.[23] NERC states that, for through-faults, it is not possible to set fault protection relays to both meet the relay loadability requirement in criterion 10 and coordinate a transformer's thermal limits, but the mechanical damage threshold is more limiting than the thermal damage threshold. Moreover, NERC states, the permissible time duration to avoid thermal damage is longer than the maximum expected duration for which a through-fault would remain before being cleared by the protection system. Thus, requiring that transformer fault protection relays are set to not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability assures the transformer will be capable of withstanding an overload for the longest clearing time associated with a fault on the low-voltage side of the transformer.[24]

22. NERC believes that Requirement 10.1 is equally effective and efficient as the approach directed in Order No. 733.[25] It states that as a result of design constraints, transformers are more limiting than other series elements with regard to through-fault capability. Accordingly, coordinating transformer fault protection relays with the transformer mechanical withstand capability addresses the Commission's concerns underlying its directive even though it does not reference the most limiting piece of equipment. Because the fault withstand capability of terminal equipment is not always readily available, requiring entities to provide evidence that equipment in series with the transformer is capable of withstanding a through-fault current for the expected duration, NERC argues, is not necessary to address the Commission's concerns and places an unnecessary burden on entities.[26]

2. Proposed Requirement R2

23. Proposed Reliability Standard PRC–023–2 adds a new Requirement R2 that requires each transmission owner, generation owner, and distribution provider to set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions modeled under Requirement R1. NERC states that Requirement R2 has been added to proposed Reliability Standard PRC–023–2 to address the Commission's directive to include section 2 of PRC–023–1 Attachment A as an additional Requirement with the appropriate violation risk factor and violation severity level.[27] NERC has assigned this proposed Requirement a high Violation Risk Factor and a severe Violation Severity Level reflecting the impact to reliability of violating the Requirement.

3. Proposed Requirements R3, R4, and R5

24. Requirement R3 in proposed Reliability Standard PRC–023–2 renumbers and makes conforming edits to Requirement R2 from PRC–023–1. Proposed new Requirement R4 requires an entity that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability to provide its planning coordinator, transmission operator, and reliability coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year. Similarly, proposed Reliability Standard PRC–023–2 adds a new Requirement R5 that requires entities that set transmission line relays according to Requirement R1 criterion 12 to provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, to allow the ERO to compile a list of all circuits that have protective relays settings that limit circuit capability. NERC states that new Requirements R4 and R5, respectively, address the Commission's directives relating to providing transmission operators a list of transmission facilities that implement criterion 2 and directing that the ERO create a list of those facilities that have protective relays set pursuant to criterion 12.[28]

4. Proposed Requirement R6

25. Requirement R6 of proposed Reliability Standard PRC–023–2 requires each planning coordinator to conduct an assessment at least once each calendar year (but no less frequently than every 15 months) by applying the criteria in Attachment B to determine the circuits in its planning coordinator area for which entities must comply with Requirements R1 through R5. Sub-part 6.1 requires the planning coordinator to maintain a list of circuits subject to PRC–023–2 per application of Attachment B identifying the year in which any criterion in Attachment B applies. Sub-part 6.2 requires the planning coordinator to provide the list to all Regional Entities, reliability coordinators, transmission owners, generators owners, and distribution providers within its planning coordinator area within 30 calendar days of establishing the initial list, and 30 days of any subsequent change thereto. NERC states that the proposed sub-part 6.2, formerly Requirement R3.3 in PRC–023–1, modifies the Requirement in order to address the Commission's directive to add the Regional Entity to the list of entities that receive the list of critical facilities.[29]

5. Proposed Attachment A

26. Attachment A to proposed Reliability Standard PRC–023–2

[22] *Id.* at 20.

[23] The mechanical withstand capability is determined on the basis of the transformer's design and the maintenance of that capability by the owner. Maintenance would be an issue if, for example, the moisture level in a transformer is allowed to increase above the design value but still within dielectric acceptance, the dielectric withstand capability could be compromised.

[24] *Id.* at 22–23.

[25] *Id.* at 20–21.

[26] *Id.* at 23.

[27] NERC Petition at 24.

[28] *Id.* at 23–24.

[29] *Id.* at 24.

includes a new section 1.6 that extends the Standard's applicability to include phase overcurrent supervisory elements (*i.e.,* phase fault detectors) associated with current-based, communication-assisted schemes (*i.e.,* pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. In addition, conforming changes are made to proposed section 2.1, formerly section 3.1 of the PRC–023–1, to recognize that elements described in new section 1.6 are no longer excluded from the proposed Standard's scope. NERC states that these changes have been made to address the Commission's directives to include supervising relay elements on the list of relays and protection systems that are specifically subject to the Reliability Standard.[30]

27. NERC states that it believes proposed section 1.6 of Attachment A is equally effective and efficient in addressing the Commission's concern as the approach directed in Order No. 733.[31] It states that modifying Attachment A to extend the scope of the proposed Reliability Standard to include all supervising relays as directed would have an unintended negative impact on system reliability by reducing the dependability and security of certain protection system, *e.g.,* supervising phase distance (impedance) elements. It contends that the description in section 1.6 is tailored to avoid the negative impacts on reliability that could occur with an overly broad application of the proposed Standard to supervising relays.[32]

6. Proposed Attachment B

28. Proposed Reliability Standard PRC–023–2 adds an Attachment B to specify six criteria that planning coordinators must use to identify sub-200kV facilities that, upon being so identified, are required to comply with the proposed Reliability Standard. The proposed criteria identify facilities using bright line criteria and analyses. A facility meets the bright line criteria if it:

- Is a monitored facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored facility in the Quebec Interconnection, that has been included to address reliability concerns for loading of that circuit (Criteria B1);
- Is a monitored facility of an interconnection reliability operating limit, where the limit was determined in the planning horizon pursuant to Reliability Standard FAC–010 (System Operating Limits Methodology for Planning Horizon) (Criteria B2); or
- Forms a path to supply off-site power to a nuclear plant as established in the nuclear plant interface requirements pursuant to Reliability Standard NUC–001 (Nuclear Plant Interface Coordination) (Criteria B3).[33]

A facility is identified through the analysis criteria if it:

- Is identified through a sequence of power flow analyses specified in Attachment B and performed by the planning coordinator (Criteria B4);
- Is selected by the planning coordinator based on technical studies or assessments other than those specified above, in consultation with the facility owner (Criteria B5); or
- Is mutually agreed upon for inclusion by the planning coordinator and the facility owner (Criteria B6).

NERC states that while the six criteria presented in Attachment B vary from some of the guidance provided in Order No. 733, they nonetheless identify all facilities that must be subject to proposed Reliability Standard PRC–023–2 in order to achieve the Standard's reliability objective.[34] NERC further reports that it is in the process of applying the test to a representative sample of utilities from each of the three Interconnections and plans to file the results of these tests by February 17, 2013. NERC plans to revise Attachment B, if necessary, pending the results of this test and clarifications made in Order No. 733–A.[35]

29. Attachment B, unlike currently effective Reliability Standard PRC–023–1, does not state that the goal of screening sub-200 kV facilities is to identify those that are ''critical to the reliability of the bulk electric system.'' Instead, NERC states that the test in Attachment B ''is designed to identify circuits that if tripped on relay loadability following an initiating event could contribute to undesirable system performance similar to what occurred during the August 2003 Blackout * * *.''[36] This change in wording, NERC states, eliminates potential confusion regarding the use of the phrase ''critical to the reliability of the bulk electric system'' in the context of this Reliability Standard compared to other Standards such as those addressing critical infrastructure, and it presents the same meaning in an equally effective and efficient approach for referring to the circuits identified through the planning coordinators' assessments.

30. The proposed Reliability Standard also omits reference to sub-100 kV facilities ''that Regional Entities have identified as critical to the reliability of the [b]ulk [e]lectric [s]ystem'' in favor of referring to ''transmission lines operated below 100 kV and transformers with low voltage terminal connected below 100 kV that are part of the [bulk electric system].'' NERC states that sub-100 kV circuits identified by the Regional Entities as critical facilities should be included in the definition of the bulk electric system and the proposed language conveys the same meaning in an equally effective and efficient manner.[37] This change in wording, NERC states, responds to confusion arising from the fact that very few such facilities have, as yet, been identified.

31. NERC is taking a three phase approach to addressing the various directives in Order No. 733. Phase I is intended to address directed modifications to PRC–023–1. Phase II entails development of a new Reliability Standard addressing generator relay loadability, and Phase III consists of developing a new Reliability Standard addressing protective relay operations due to stable power swings. According to the NERC Petition, transmission lines that tripped unnecessarily during the August 2003 Blackout did not trip as a result of power swings up through the tripping of the Argenta-Battle Creek and the Argenta-Tompkins 345 kV lines, but subsequent line trips were due to power swings. While the power system did experience stable swings following each line trip prior to losing these two lines, the swings were not of significant magnitude and dampened quickly allowing the system to return to a new steady-state condition. For this reason, NERC asserts that analysis using steady-state base cases is the appropriate tool to assess the potential for lines to trip under similar conditions, and dynamic base cases are the appropriate tool to assess line tripping due to power swings. NERC has elected to limit the applicability test in Attachment B to power flow analysis with steady-state base cases and to address dynamic base cases in its Phase III Reliability Standard addressing power swings. This

[30] *Id.* at 25.

[31] *Id.*

[32] *Id.* at 26–27.

[33] As we stated previously, ''[w]e would expect that any [nuclear plant interface requirements] agreed to between a nuclear plant generator operator and transmission entity would include all facilities needed to transmit offsite power and auxiliary power to the nuclear facility. *Mandatory Reliability Standard for Nuclear Plant Interface Coordination,* 125 FERC ¶ 61,065, at P 51 (2008).

[34] NERC Petition at 14.

[35] *Id.* at 13.

[36] *Id.* at 15.

[37] *Id.* at 16.

election, NERC states, is an equally efficient and effective approach to addressing all facets of the unnecessary line tripping caused by relay loadability that occurred during the August 2003 Blackout.

32. Order No. 733 provided guidance that a test to determine critical sub-200 facilities should include the same simulations and assessments as the Transmission Planning (TPL) Reliability Standards. While the TPL Standards permit manual system adjustments between two contingencies, NERC believes it is more informative, and in line with the reliability objective, to require testing of double contingencies without such manual adjustments, thereby modeling a situation in which an operator fails to, or does not have time to, make appropriate system adjustments. This focused testing exceeds the requirements of the TPL Standards and, NERC asserts, is an equally efficient and effective approach to addressing the Commission's concern that the test must be sufficiently robust to provide assurance that all appropriate facilities are identified and made subject to the Reliability Standard for the Standard to achieve its purpose.

33. Order No. 733 also provided guidance regarding elements of a definition of desirable system performance that must inform any test to determine which sub-200 kV circuits are critical to system reliability. The Commission's guidance stated, among other things, that the power system should maintain all facilities within their applicable thermal (i.e., current), voltage, or stability ratings (short time ratings are applicable). NERC asserts that it is most appropriate to focus on avoiding thermal loading of transmission circuits. In order to achieve its reliability goal, NERC believes, Reliability Standard PRC–023–2 must apply to circuits whose relays will be challenged by excessive thermal loading to the point that a relay hampers the system operator's ability to take remedial action. The system performance measure in this test is less rigorous than that required by TPL–003 (System Performance Following Loss of Two or More BES Elements) because it ignores voltage and stability ratings. But, NERC points out that the contingency condition in Attachment B is more stringent than that in TPL–003 and the contingency and system performance measure were developed together in order to align with the reliability objective of the proposed Standard. NERC believes this test is an equally effective and efficient approach to addressing the Commission's concern regarding the rigorousness of the test.

7. Proposed Implementation Plan

34. NERC proposes staggered effective dates for Reliability Standard PRC–023–2, *i.e.,* the mandatory compliance date after an allotted implementation period, for each of the Standard's requirements. The implementation plan provides 18 months for planning coordinators to apply the criteria in Attachment B and determine which sub-200 kV circuits must be subject to the Standard. Those entities responsible for compliance on circuits identified by a planning coordinator pursuant to Requirement R6 are provided until the first day of the first calendar quarter 39 months following notification to become compliant, or until the first day of the first calendar year in which any criterion in Attachment B applies if the planning coordinator indentifies the circuit in an assessment of a future year more than 39 months beyond the year in which the assessment is conducted.

8. Violation Risk Factors/Violation Severity Levels

35. To determine a base penalty amount for a violation of a Requirement within a Reliability standard, NERC must first determine an initial range for the penalty amount. To do so, NERC assigns a violation risk factor to each Requirement of a Reliability Standard that relates to the expected or potential impact of a violation of the Requirement on the reliability of the Bulk-Power System. NERC may propose either a lower, medium, or high violation risk factor for each Requirement. The Commission has established guidelines for evaluating the validity of each violation risk factor assignment.[38] NERC also assigns each Requirement one of four violation severity levels—low, moderate, high, and severe—as measurements for the degree to which the requirement was violated in a specific circumstance.[39] NERC assigns Requirements R1, R2, and R6 a ''high'' violation risk factor, Requirement R3 a ''medium'' violation risk factor, and Requirements R4 and R5 a ''lower'' violation risk factor. The NERC Petition proposes violation severity levels for each of the Requirements of proposed Reliability Standard PRC–023–2.

B. NERC Rules of Procedure Section 1700—Challenges to Determinations

36. Proposed NERC Rules of Procedure Section 1700—Challenges to Determinations allows registered entities to challenge a planning coordinator's determination made under a Reliability Standard or terms defined in the Glossary of Terms Used in NERC Reliability Standards. Proposed Rule 1702 sets out the procedure for challenging a determination by a planning coordinator under Reliability Standard PRC–023–2. It provides that a registered entity is encouraged, but not required, initially to meet with the planning coordinator to resolve any dispute. If the matter cannot be resolved, the registered entity may challenge the determination with the appropriate Regional Entity, and if not satisfied with the Regional Entity's decision, may appeal to NERC. Review by NERC would initially be handled by a panel appointed by the NERC Board of Trustees. The Board of Trustees would then have the authority, but not the duty, to review the matter upon the request of the planning coordinator or registered entity. The final NERC decision may then be appealed to the applicable governmental authority, *e.g.,* the Commission for appeals within the United States.

III. Discussion

37. We agree with NERC that the proposed Reliability Standard PRC–023–2 addresses the reliability gaps identified in Order No. 733 that relate specifically to Reliability Standard PRC–023–1 and represents an improvement in the Reliability Standard. Accordingly, under section 215(d)(2) of the FPA, the Commission proposes to approve the new Reliability Standard, including its Violation Risk Factors and Violation Severity Levels, as just, reasonable, not unduly discriminatory or preferential, and in the public interest. Also, under section 215(f) of the FPA, the Commission proposes to approve NERC Rule of Procedure Section 1700—Challenges to Determinations as just, reasonable, not unduly discriminatory or preferential, in the public interest, and satisfying the requirements of section 215(c) of the FPA. NERC reports that it is in the process of applying the test set forth in Attachment B to a representative sample of utilities from each of the three Interconnections and will file the results of these tests in a report on or before February, 2013 (Report). In order to better understand the practical application of the test, the Commission proposes to direct the ERO to address specific matters described below in the Report.

38. Based on our review of NERC's petition and accompanying information, we propose to find that the proposed

[38] *See North American Electric Reliability Corp., 135 FERC ¶ 61,166 (2011); North American Electric Reliability Corp.,*119 FERC ¶ 61,145, *order on reh'g,* 120 FERC ¶ 61,145, at P 8–13 (2007).

[39] *See North American Electric Reliability Corp.,* 135 FERC ¶ 61,166; *North American Electric Reliability Corp.,* 123 FERC ¶ 61,284 (2008).

Reliability Standard and NERC Rule of Procedure Section 1700—Challenges to Determinations adequately address the directed modifications set forth in Order No. 733 regarding Reliability Standard PRC–023–1. Specifically, we propose to find that proposed Reliability Standard PRC–023–2 and the proposed NERC Rule of Procedure address the following Order No. 733 directives: (1) Adopt an ''add in'' approach to sub-100 kV facilities and modify Requirement R3 to specify the test planning coordinators must use to determine whether a sub-200 kV facility is critical to reliability; (2) establish a mechanism for registered entities to challenge criticality determinations; (3) require applicable entities to notify transmission operators of facilities that implement sub-requirement R1.2; (4) modify sub-requirement R1.10 to require verification that the limiting piece of equipment can sustain the anticipated overload; (5) direct the ERO to document facilities that have protective relays set pursuant to sub-requirement R1.12; (6) add Regional Entities to the list of those that receive the critical facilities list pursuant to sub-requirement 3.3; (7) include section 2 of Attachment A as an additional Requirement; (8) revise section 1 of Attachment A to include supervising relay elements associated with the identified reliability concern subject to the Standard; (9) create an implementation plan for sub-100 kV facilities; and (10) remove the exceptions footnote from the ''Effective Dates'' section. In light of the manner in which it addresses these directives, the proposed Reliability Standard represents an improvement in transmission relay loadability.

39. Attachment A to the proposed Reliability Standard has been modified to extend coverage of the Standard to phase overcurrent supervisory elements associated with current-based, communication-assisted schemes capable of tripping for loss of communications. While the description of the supervisory elements is more specific than the directive in Order No. 733,[40] the proposed Attachment A reflects industry comment regarding the potential for unintended, negative reliability consequences that could arise from an overly broad description. In light of the explanation provided and our reliability concern,[41] we consider the proposed alternative solution to be an equally effective and efficient approach to addressing the Commission's reliability concerns.

40. Transmission relay loadability is important to ensuring the reliability of the Bulk-Power System. The ERO has proposed changes to currently effective Reliability Standard PRC–023–1 on many issues, including (1) Extending its coverage to communication assisted supervising elements and out-of-step blocking schemes; (2) requiring that a uniform test is applied consistently by planning coordinators utilizing their judgment to identify sub-200 kV circuits to which the Reliability Standard must apply; (3) requiring that load responsive transformer fault protection relays be set to reflect the transformer's mechanical withstand capability; and (4) ensuring communication regarding the ratings used to verify transmission facility relay loadability. These changes extend and strengthen the reliability benefits currently effective Reliability Standard PRC–023–1 was designed to achieve.

41. Attachment B to the proposed Reliability Standard specifies the test planning coordinators are required to use to determine whether a sub-200 kV facility is critical to reliability. NERC states that it plans to revise the test, if necessary, based on the results of this testing and the clarifications regarding the test made in Order No. 733–A.[42] The Commission seeks to better understand the implementation and effects of Requirement R6, and criteria B4 and B5, as they are used to identify operationally critical sub-200 kV facilities.

Questions Regarding Test to Determine Critical Sub-200 kV Facilities

42. Criterion B4 of Attachment B requires application of proposed Reliability Standard PRC–023–2 to any circuit identified through a specified set of power flow analyses performed by planning coordinators. Planning coordinators must apply their engineering judgment in the simulation of double contingency combinations in order to determine which combinations of contingencies result in undesirable tripping. In guidance given in Order No. 733, the Commission stated that for Category C contingencies (*i.e.,* events resulting in the loss of two or more elements) desirable system performance includes, among other things, the maintenance of all facilities within their applicable thermal, voltage, or stability ratings (short time ratings are applicable).[43] An impedance relay reads the magnitude and phase angle of both the current and voltage quantities, and if the combination results in an apparent impedance that encroaches or penetrates the relay's operational settings, the relay is susceptible to undesirable tripping. The performance standard proposed in Attachment B requires the planning coordinator to monitor thermal ratings but does not consider the other parameters that could result in a relay trip event without high currents.

43. NERC states that though ''the system performance measure in this test is less stringent than required for Category C contingencies in TPL–003, it is important to note that the contingency itself is more stringent than a Category C contingency [because it does not allow manual system adjustments between the two contingencies as does a Category C contingency], and the contingency and system performance measure have been developed together * * *.''[44] However, the standard is silent as to the rigor of the simulations other than requiring the planning coordinators to apply their engineering judgment. We propose that the ERO address in the Report whether the power system assessment proposed in criterion B4 includes the critical system conditions utilized under Reliability Standard TPL–003–0 Requirement R1.3.2[45] and whether applicable entities evaluate relay loadability under the B4 criterion consistent with Requirement R1 which requires, in part, that they ''evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees'' in addition to applicable current criteria. If the evaluation uses other per unit voltage and power factor angle assumptions, we propose that the Report include a comparison of results obtained from those that would be achieved were the assumptions consistent with Requirement R1.

44. Criterion B5 of Attachment B requires compliance with the proposed Reliability Standard with respect to a ''circuit * * * selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.'' The Commission proposes that the Report comment on what ''technical studies or assessments'' planning coordinators use to identify critical facilities.

45. According to the NERC Petition, ''[d]uring the standard development

[40] Order No. 733, 130 FERC ¶ 61,221 at P 264.

[41] *Id.* P 251.

[42] NERC Petition at 13.

[43] Order No. 733, 130 FERC ¶ 61,221 at P 84.

[44] NERC Petition at 19.

[45] Reliability Standard TPL–003–0 Requirement R1.3.2 provides that a transmission planner assessment shall ''[c]over critical system conditions and study years as deemed appropriate by the responsible entity.''

process, a number of industry comments expressed concern with potential confusion regarding use of the phrase 'critical to the reliability of the bulk electric system' in the context of PRC–023–1 versus other standards such as those addressing critical infrastructure.''[46] As a result, the proposed Requirement R6 omits that phrase and refers instead to circuits ''for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5.'' In contrast, however, the Blackout Report used the phrase ''operationally significant,'' and the test in Attachment B is ''designed to identify circuits that if tripped on relay loadability following an initiating event could contribute to undesirable system performance similar to what occurred during the August 2003 Blackout.''[47] Notwithstanding the various phrases used to describe the reliability objective, the NERC Petition indicates that the test is intended to identify all circuits in a planning coordinator's area that could have an operational impact on the reliability of the bulk electric system. The Commission proposes that the Report assess whether Attachment B is sufficiently comprehensive to capture all such circuits.

Summary

46. In summary, the Commission proposes to approve proposed Reliability Standard PRC–023–2 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. We also propose to approve proposed NERC Rules of Procedure Section 1700—Challenges to Determinations as just, reasonable, not unduly discriminatory or preferential, in the public interest, and satisfying the requirements of section 215(c) of the FPA. In addition, the Commission proposes that NERC addresses in the Report questions regarding the system assessment simulations and results of the power flow analyses criterion in the proposed test for critical facilities.

IV. Information Collection Statement

47. The Office of Management and Budget (OMB) regulations require approval of certain information collection requirements imposed by agency rules.[48] Upon approval of a collection(s) of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirement of this rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number. The Paperwork Reduction Act (PRA)[49] requires each federal agency to seek and obtain OMB approval before undertaking a collection of information directed to ten or more persons, or continuing a collection for which OMB approval and validity of the control number are about to expire.[50]

48. The Commission is submitting these reporting and recordkeeping requirements to OMB for its review and approval under section 3507(d) of the PRA. Comments are solicited on the Commission's need for this information, whether the information will have practical utility, the accuracy of provided burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques.

49. This Notice of Proposed Rulemaking proposes to approve Reliability Standard PRC–023–2 (Transmission Relay Loadability) which will replace currently effective Reliability Standard PRC–023–1 approved by the Commission in Order No. 733. Rather than creating entirely new requirements regarding the setting of protective relays, the proposed Reliability Standard instead modifies and improves the existing Reliability Standard. Thus this proposed rulemaking does not impose entirely new burdens on the effected entities. For example, the currently effective Reliability Standard PRC–023–1 requires transmission owners, generation owners, and distribution providers to each have evidence to show that each of its transmission relays are set according to one of the criteria in criteria R1.1 through R1.13. Similarly, proposed Reliability Standard PRC–023–2 requires transmission owners, generation owners, and distribution providers to have evidence that each of its transmission relays is set according to one of the 13 criteria in Requirement R1 but adds that each such entity shall also have evidence that relays set according to criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the Standard. Thus, the recordkeeping obligations for some Requirements are more specific but not necessarily more expansive than those of currently effective Reliability Standard PRC–023–1. However, proposed PRC–023–2 does add new Requirements, each of which has new recordkeeping obligations.

50. Proposed Requirement R2 will require each transmission owner, generator owner, and distribution provider to have evidence that its out-of-step blocking elements are set in accordance with the Standard, and proposed Requirements R4 and R5 will require those same entities to maintain evidence that they have informed the appropriate parties of their updated lists of certain circuits. Under Requirement R6, planning coordinators will be required to execute a test for applicability of the Standard as set forth in Attachment B and retain analyses, calculation summaries, or study reports to evidence execution of the test, whereas under the currently effective PRC–023–1, a test was required but only the results needed to be retained. Because an unspecified test is currently required to be carried out on facilities operated at between 100 kV and 200 kV under currently effective Reliability Standard PRC–023–1, for purposes of this analysis, we assume that there is little additional cost for planning coordinators to implement and document that portion of the test. However, the proposed Requirement R6 imposes the new burdens of performing the test on sub-100 kV facilities, maintaining appropriate records, and distributing the list of circuits identified by the test to Regional Entities.

51. *Public Reporting Burden:* Our estimate below regarding the number of respondents is based on the NERC compliance registry as of July 29, 2011. According to the NERC compliance registry, there are 335 transmission owners, 793 generation owners, 553 distribution providers, and 72 planning coordinators. However, under NERC's compliance registration program, entities may be registered for multiple functions, so these numbers incorporate some double counting. The net number of entities responding will be approximately 645 entities registered as a transmission owner, a distribution provider, or a generation owner that is also a transmission owner and/or a distribution owner, and 72 planning coordinators.[51] The estimated burden for the requirements in this Order follow:

[46] NERC Petition at 15.

[47] *Id.*

[48] 5 CFR 1320.11.

[49] 44 U.S.C. 3501–20.

[50] 44 U.S.C. 3502(3)(A)(i), 55 U.S.C. 3507(a)(3).

[51] Under its applicability provisions, proposed Reliability Standard applies to specified circuits such that very few, if any, generator owners that are not also a transmission owner and/or a distribution provider will be subject to the Standard.

Changes to FERC–725G data collection	Number of respondents annually (1)	Number of responses per respondent (2)	Average burden hours per response [52] (3)	Total annual hours (1 × 2 × 3)
R1 criterion 1.10: TOs, GOs, and DPs must analyze and document criterion 1.10 compliance.	645	1	*Analysis for compliance documents*—8 ...	5,160
			Record Retention—2	1,290
R2: TOs, GOs, and DPs must perform analysis and retain evidence of compliance.	645	1	*Analysis for compliance documents*—8 ...	5,160
			Record Retention—2	1,290
R4 and R5: TOs, GOs, and DPs must distribute updated lists and retain evidence that lists were distributed.	645	1	*Reporting (dist. of list)*—10	6,450
			Record Retention—10	6,450
R6: PC must perform assessment, distribute list of circuits and retain evidence of testing and distribution [53].	72	1	*Reporting (assessment and dist. of list)*—20.	1,440
			Record Retention—10	720
Total	.....	.....	.....	27,960

Information Collection Costs: The Commission seeks comments on the costs to comply with these requirements and recordkeeping burden associated with Reliability Standard PRC–023–2.

• *Total Annual Hours for Collection:* (Reporting and Record Retention) = 27,960 hours.

• *Total Estimated Reporting/Analysis Cost* = 18,210 hours @ $120/hour = $2,185,200.

• *Total Estimated Record Retention Cost* = 9,750 hours @ $28/hour = $273,000.

• *Total Estimated Annual Cost (reporting + Record Retention)* [54] = $2,458,200.

• *Title:* Mandatory Reliability Standards for the Bulk-Power System.

• *Action:* FERC 725G, Proposed Modification to FERC–725G.

• *OMB Control No:* 1902–0252.

• *Respondents:* Business or other for profit, and/or not for profit institutions.

• *Frequency of Responses:* On occasion.

• *Necessity of the Information:* This proposed rule would approve a revised Reliability Standard that modifies an existing requirement regarding setting protective relays according to specific criteria in order to ensure that the relays reliably detect and protect the electric network from all fault conditions, but do not limit transmission loadability or interfere with system operators' ability to protect system reliability. Proposed Reliability Standard PRC–023–2 requires entities to set transmission relays according to specified criteria and to retain evidence of compliance. It also requires planning coordinators to implement a test to determine which sub-200 kV facilities are critical to the reliability of the power system and subjects such facilities to the requirements of the proposed Standard. The proposed Reliability Standard requires entities to maintain records subject to review by the Commission and NERC to ensure compliance with the Reliability Standard.

• *Internal review:* The Commission has reviewed the requirements pertaining to the proposed Reliability Standard for the Bulk-Power System and determined that the proposed requirements are necessary to meet the statutory provisions of the Energy Policy Act of 2005. These requirements conform to the Commission's plan for efficient information collection, communication and management within the energy industry. The Commission has assured itself, by means of internal review, that there is specific objective support for the burden estimates associated with the information requirements.

52. Interested persons may obtain information on the reporting requirements by contacting: Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426 [*Attention:* Ellen Brown, Office of the Executive Director, *e-mail: DataClearance@ferc.gov, Phone:* (202) 502–8663, *fax:* (202) 273–0873]. Comments on the requirements of this order may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission]. For security reasons, comments should be sent by e-mail to OMB at *oira_submission@omb.eop.gov.* Please reference OMB Control Number 1902–0252 and the docket number of this Order in your submission.

V. Environmental Analysis

53. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[55] The actions proposed here fall within the categorical exclusion in the Commission's regulations for rules that are clarifying, corrective or procedural, for information gathering, analysis, and dissemination.[56] Accordingly, neither an environmental impact statement nor environmental assessment is required.

VI. Regulatory Flexibility Act Analysis

54. The Regulatory Flexibility Act of 1980 (RFA) [57] generally requires a description and analysis of proposed and final rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a proposed order and that minimize any significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[58] The SBA has established a size standard for electric utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve

[52] The burden hours are based on estimates that the Commission has used for similar reporting requirements.

[53] This applies to the portion of R6 that deals with testing for sub-100 kV facilities as described in the text. In addition it includes burden hours associated with adding Regional Entities to the list of entities to receive a list of circuits from the planning coordinator.

[54] The hourly reporting cost is based on the estimated cost of an engineer to implement the requirements of the rule. The record retention cost comes from Commission staff research on record retention requirements.

[55] *Regulations Implementing the National Environmental Policy Act,* Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Regulations Preambles 1986–1990 ¶ 30,783 (1987).

[56] 18 CFR 380.4(a)(5).

[57] 5 U.S.C. 601–612.

[58] 13 CFR 121.101.

months did not exceed four million megawatt-hours.[59]

55. Proposed Reliability Standard PRC–023–2 modifies currently existing Reliability Standard PRC–023–1 which requires applicable entities to set protective relays according to specific criteria, to communicate about such settings with specified entities, and to conduct assessments to determine the applicability of the Standard to 100–200 kV facilities. The proposed standard modifies PRC–023–1 by (1) Increasing communication and documentation requirements, (2) extending the applicability of the Standard to formerly excluded relays, and (3) standardizing the terms of the assessment whose terms were formerly not specified. In addition, proposed PRC–023–2 extends the current requirement that planning coordinators annually assess which 100–200 kV circuits must be brought into compliance with the Standard and will require planning coordinators to carry out the assessment with respect to some sub-100 kV facilities.

56. Comparison of the NERC compliance registry with data submitted to the Energy Information Administration on Form EIA–861 indicates that perhaps as many 103 transmission owners, 329 distribution providers, 46 generation owners, and 8 planning coordinators qualify as small entities. However, under NERC's compliance registration program, entities may be registered for multiple functions, so these numbers incorporate some double counting. The net number of registered entities that qualify as small entities responding to this rule will be approximately 339 entities registered as a transmission owner, a distribution provider, or a generation owner that is also a transmission owner and/or a distribution provider, and 8 planning coordinators. The proposed rule directly affects each of the small entities. Therefore, FERC has determined that this proposed rule will have an impact on a substantial number of small entities. However, the Commission has determined that the impact on entities affected by the proposed rule will not be significant. The Commission estimates that in order to comply with the Standard's modification of existing requirements each of the small entities registered as planning coordinators will face a cost of $2,680 and each of the remaining small entities (transmission owners, distribution providers, or generation owners that are also transmission owners and/or distribution providers) will face a cost of $3,512. Accordingly, the Commission determines that the incremental cost of Reliability Standard PRC–023–2 (going from PRC–023–1 to PRC–023–2) is minimal, and should not present a significant operating cost to any of the small entities.

57. Based on this understanding, the Commission certifies that this Reliability Standard will not have a significant economic impact on a substantial number of small entities. Accordingly, no regulatory flexibility analysis is required.

58. The Commission invites comment from members of the public regarding the accuracy of the certification provided here, the economic analysis, and its underlying assumptions.

VII. Comment Procedures

59. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due November 21, 2011. Comments must refer to Docket No. RM11–16–000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

60. Commenters may submit comments, identified by Docket No. RM11–16–000 and in accordance with the requirements posted on the Commission's Web site, *http://www.ferc.gov.* Comments may be submitted by any of the following methods:

• *Agency Web site:* Documents created electronically using word processing software should be filed in native applications or print-to-PDF format, and not in a scanned format, at *http://www.ferc.gov/docs-filing/efiling.asp.*

• *Mail/Hand Delivery:* Commenters unable to file comments electronically must mail or hand deliver their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE., Washington, DC 20426. These requirements can be found on the Commission's Web site, see, *e.g.,* the ''Quick Reference Guide for Paper Submissions,'' available *at http://www.ferc.gov/docs-filing/efiling.asp* or via phone from FERC Online Support at (202) 502–6652 or toll-free at 1 (866) 208–3676.

61. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VIII. Document Availability

62. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (*http://www.ferc.gov*) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington, DC 20426.

63. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

64. User assistance is available for eLibrary and the FERC's Web site during normal business hours from FERC Online Support at (202) 502–6652 (toll free at 1 (866) 208–3676) or e-mail at *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659. E-mail the Public Reference Room at *public.referenceroom@ferc.gov.*

By direction of the Commission.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2011–24167 Filed 9–20–11; 8:45 am]

BILLING CODE 6717–01–P

[59] 13 CFR 121.201, Sector 22, Utilities & n. 1.

POSTAL SERVICE

39 CFR Part 121

Proposal To Revise Service Standards for First-Class Mail, Periodicals, and Standard Mail

AGENCY: Postal Service™.

ACTION: Advance notice of proposed rulemaking; request for comments.

SUMMARY: The Postal Service seeks public comment on a proposal to revise the service standard regulations contained in 39 CFR part 121. Among other things, the proposal involves eliminating the expectation of overnight service for First-Class Mail and Periodicals, and, for each of these classes, narrowing the two-day delivery range and enlarging the three-day delivery range. One major effect of the proposal would be to facilitate a significant consolidation of the Postal Service's processing and transportation networks.

137 FERC ¶ 61,067
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

Docket No. RM11-20-000

Automatic Underfrequency Load Shedding and Load Shedding Plans
Reliability Standards

(October 20, 2011)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: Under section 215 of the Federal Power Act, the Federal Energy Regulatory Commission (Commission) proposes to approve Reliability Standards PRC-006-1 (Automatic Underfrequency Load Shedding) and EOP-003-2 (Load Shedding Plans), developed and submitted to the Commission for approval by the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization certified by the Commission. The proposed Reliability Standards establish design and documentation requirements for automatic underfrequency load shedding programs that arrest declining frequency and assist recovery of frequency following system events leading to frequency degradation. The Commission also proposes to approve the related Violation Risk Factors and Violation Severity Levels, implementation plan, and effective date proposed by NERC.

DATES: Comments are due **[INSERT DATE 60 days after publication in the FEDERAL REGISTER]**

ADDRESSES: Comments, identified by docket number, may be filed in the following ways:

- Electronic Filing through http://www.ferc.gov. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- Mail/Hand Delivery: Those unable to file electronically may mail or hand-deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, see the Comment Procedures Section of this document

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

137 FERC ¶ 61,067
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards — Docket No. RM11-20-000

NOTICE OF PROPOSED RULEMAKING

(October 20, 2011)

1. Under section 215 of the Federal Power Act (FPA),[1] the Commission proposes to approve proposed Reliability Standards PRC-006-1 (Automatic Underfrequency Load Shedding) and EOP-003-2 (Load Shedding Plans). The proposed Reliability Standards were developed and submitted for approval to the Commission by the North American Electric Reliability Corporation (NERC), which the Commission certified as the Electric Reliability Organization (ERO) responsible for developing and enforcing mandatory Reliability Standards.[2] The proposed Reliability Standards establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs, which are meant to arrest declining frequency and assist recovery of frequency following underfrequency events and provide last resort system preservation measures.

2. The Commission proposes to approve the related Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs), implementation plan, and effective date proposed

[1] 16 U.S.C. 824o (2006).

[2] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g & compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

by NERC. The Commission also proposes to approve the retirement of the currently effective Reliability Standards PRC-007-0, PRC-009-0, and EOP-003-1, and the NERC-approved Reliability Standard PRC-006-0.

3. The Commission seeks comments from NERC and other interested persons on specific issues concerning the proposed Reliability Standards.

I. Background

A. Underfrequency Load Shedding

4. An interconnected electric power system must balance load and generation in order to maintain frequency within a reliable range.[3] The balance between generation and load within an interconnected electric power system is shown in the frequency of the system.[4] Underfrequency protection schemes are drastic measures employed if the system frequency falls below a specified value.[5] The Blackout Report provides the following explanation:

> [A]utomatic under-frequency load-shedding (UFLS) is designed for use in extreme conditions to stabilize the balance between generation and load after an electrical island has been formed, dropping enough load to allow frequency to stabilize within the island. All synchronous generators in North America are designed to operate at 60 cycles per second (Hertz) and frequency reflects how well load and generation are balanced—if there is more load than generation at any moment, frequency drops below 60 Hz, and it rises above that level if there is more generation than load. By dropping load to match available generation within the island, UFLS is a safety net that helps to prevent the complete blackout of the

[3] Electric Power Research Institute, *EPRI Power Systems Dynamics Tutorial*, Chapter 4 at page 4-78 (2009), *available at* www.epri.com (EPRI Tutorial).

[4] *Id*.

[5] *Id.*

> island, which allows faster system restoration afterward. UFLS is not effective if there is electrical instability or voltage collapse within the island.[6]

5. UFLS programs are designed for each defined area or system, and they are commonly implemented with devices installed on the distribution side of the power system.[7] Factors considered in developing a UFLS program include: (1) underfrequency set point, (2) minimum amount of load to shed, and (3) what load and at what locations to shed.

1. Underfrequency Set Point

6. The underfrequency set point is the frequency at which a specified load will disconnect from the system in a UFLS program.[8] Separately, generators have their own underfrequency set points, which will disconnect them from the system if the frequency drops to a certain value, thus protecting them from damage.[9] Underfrequency set points

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[6] *U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* at 92-93 (2004) (Blackout Report).

[7] UFLS programs are designed to maintain a balance between resources and demand in a defined area (e.g., Interconnection, Regional Entity area, or planning coordinator area).

[8] In Order No. 693-A, the Commission directed NERC to collect the frequency and magnitude of load in UFLS systems. *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053, at P 145 (2007). NERC submitted a response to this request on February 1, 2008 that included the underfrequency set points and magnitude of load shed in each Regional Entity. NERC, *Response to FERC Supplemental Request for Information on the Status of Underfrequency Load Shedding*, Docket No. RM06-16-000 (filed Feb. 1, 2008).

[9] EPRI Tutorial at page 4-81.

for load shedding are set above the frequencies at which generators disconnect.[10] This is done to prevent losing additional resources that would exacerbate the imbalance between resources and demand, resulting in further frequency declines. UFLS programs initiate at a specified point to shed the first load block, and if necessary additional load blocks at other lower set points, to arrest system frequency decline prior to the loss of additional resources.[11]

7. Once a frequency threshold[12] is identified, the balance of resources and demand to be maintained to prevent the system from reaching that frequency threshold is determined. UFLS programs use validated models of the power system, which consist of mathematical representations of static (e.g., transformers and transmission lines) and dynamic (e.g., generators and motor loads) components of the power system aggregated to simulate how the system performs during system operations.[13] Models are validated, typically, by comparing actual system operations against simulated system operations to ensure the simulated system operations are within a defined and acceptable margin of tolerance relative to actual system operations. Inaccurate power system models may result in a UFLS program that does not perform as desired, thus undermining the reliability objective of UFLS.

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[10] *Id.*

[11] *Id.* at P 4-78, 4-79.

[12] A frequency threshold is a pre-determined frequency that UFLS programs are designed to avoid reaching, as the system may become unstable at this frequency.

[13] *See, e.g.,* PowerTech Labs Inc., *2010 Evaluation and Assessment of Southwest Power Pool (SPP) Under-Frequency Load Shedding Scheme, available at* http://www.spp.org/publications/SPP-2010-UFLS-Final.pdf.

8. A UFLS program is designed to shed sufficient load to arrest system frequency decline without shedding too much load such that frequency increases above 60 Hz. If a UFLS program is not effective, either because of invalid power system models or miscoordination of the UFLS program with entities inside and outside of the intended island, it may not achieve the reliability objective of preventing cascading outages. This, in turn, could further undermine reliability and recovery of the Bulk-Power System during a system emergency.[14]

2. Minimum Amount of Load to Shed

9. The amount of load to disconnect is the amount of load shed at each underfrequency set point, typically expressed in megawatts or percent of system peak load or both.[15]

3. What Load to Shed

10. In addition to determining the amount of load to disconnect based on validated power system models, a UFLS program identifies what loads to shed and their locations. Therefore, in deciding what specific loads to shed, consideration is given to whether the load is critical (e.g., hospitals, police stations, or fire stations). These loads would typically not be included in a UFLS program.

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[14] For example, if not enough load is shed to arrest frequency decline, additional resources may disconnect from the Interconnection to prevent damage to generators, and thus system frequency will continue to collapse. Conversely, if too much load is shed, the system frequency could exceed 60 Hz also causing resources to disconnect from the Interconnection to prevent damage to generators. EPRI Tutorial at page 4-78.

[15] EPRI Tutorial at page 4-78.

B. Mandatory Reliability Standards

11. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval. Once approved, the Reliability Standards may be enforced by the ERO, subject to Commission oversight, or by the Commission independently.[16]

12. Pursuant to section 215 of the FPA, the Commission established a process to select and certify an ERO[17] and, subsequently, certified NERC as the ERO.[18] On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 Reliability Standards filed by NERC, including Reliability Standards PRC-007-0, PRC-009-0, and EOP-003-1.[19] The Commission neither approved nor remanded NERC-approved Reliability Standard PRC-006-0 in Order No. 693.[20]

C. NERC-Approved Reliability Standard

1. PRC-006-0

13. NERC-approved Reliability Standard PRC-006-0 addresses the development of a regional UFLS program that is used as a last resort to preserve islanding operation

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[16] *See* 16 U.S.C. 824o(e).

[17] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[18] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g & compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom., Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[19] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 603.

[20] *Id.* P 1479.

following a major system event on the Bulk-Power System that could otherwise cause the island system frequency to collapse. PRC-006-0 requires regional reliability organizations to develop, coordinate, document and assess UFLS program design and effectiveness at least every five years. In Order No. 693, the Commission determined neither to approve nor remand this "fill-in-the-blank" Reliability Standard because the regional procedures had not been submitted, and the Commission held that it would not propose to approve or remand PRC-006-0 until the ERO submitted the additional information.[21]

D. Currently Effective Reliability Standards

1. PRC-007-0

14. Reliability Standard PRC-007-0 requires transmission owners, transmission operators, load serving entities (LSEs) and distribution providers to provide, and annually update, their underfrequency data to facilitate the regional reliability organization's maintenance of the UFLS program database.

2. PRC-009-0

15. Reliability Standard PRC-009-0 requires that the performance of a UFLS system be analyzed and documented following an underfrequency event by requiring the transmission owner, transmission operator, LSE and distribution provider to document the deployment of their UFLS systems in accordance with the regional reliability organization's program.

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[21] *Id.* P 1477, 1479.

3. EOP-003-1

16. Reliability Standard EOP-003-1 addresses load shedding plans and requires that balancing authorities and transmission operators operating with insufficient transmission and/or generation capacity have the capability and authority to shed load rather than risk a failure of the system. It includes requirements to establish plans for automatic load shedding for underfrequency or undervoltage, manual load shedding to respond to real-time emergencies, and communication with other balancing authorities and transmission operators.

II. Proposed Reliability Standards

17. On March 31, 2011, NERC filed a petition seeking Commission approval of proposed Reliability Standards PRC-006-1 and EOP-003-2 and requesting the concurrent retirement of the currently effective Reliability Standards PRC-007-0, PRC-009-0, and EOP-003-1 and NERC-approved Reliability Standard PRC-006-0.[22] NERC requests an effective date for PRC-006-1 and EOP-003-2 of one year following the first day of the first calendar quarter after applicable regulatory approvals with respect to all Requirements of the proposed Reliability Standards except Parts 4.1 through 4.6 of Requirement R4 of PRC-006-1. With respect to Parts 4.1 through 4.6 of Requirement R4 of PRC-006-1, NERC requests an effective date of one year following the receipt of

[22] NERC Petition at 1. The proposed new Reliability Standards are not attached to the NOPR. They are, however, available on the Commission's eLibrary document retrieval system in Docket No. RM11-20-000 and are available on the ERO's website, www.nerc.com. Reliability Standards approved by the Commission are not codified in the CFR.

generation data as would be required in draft Reliability Standard PRC-024-1[23] but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1.

A. PRC-006-1

18. Proposed Reliability Standard PRC-006-1 would apply to planning coordinators, "UFLS entities,"[24] and transmission owners that "own Elements identified in the UFLS program established by the Planning Coordinators." NERC states that the primary purpose of the proposed Reliability Standard is the establishment of design and document requirements for UFLS programs that arrest declining frequency and assist recovery of frequency following system events leading to frequency degradation.

19. NERC states that PRC-006-1 satisfies the Commission's criteria, set forth in Order No. 672, for determining whether a proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential and in the public interest.[25]

20. According to NERC, PRC-006-1 is designed to achieve a specific reliability goal by establishing design and documentation requirements for automatic UFLS programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures. NERC contends that PRC-006-1 contains a technically sound method to achieve its reliability goal by establishing a

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[23] PRC-024-1 addresses "Generator Performance During Frequency and Voltage Excursions" and is currently being developed in the NERC standard drafting process.

[24] PRC-006-1 defines "UFLS entities" as: "All entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators."

[25] Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 323-37.

framework for developing, designing, assessing and coordinating UFLS programs, and that PRC-006-1 is clear and unambiguous regarding what is required and who is required to comply with the Reliability Standard.

21. NERC states that PRC-006-1 does not reflect "best practices" without regard to implementation cost.[26] NERC contends that it achieves a specific reliability goal of establishing design and documentation requirements for automatic UFLS programs to arrest declining frequency and assist recovery following underfrequency events, and that UFLS programs provide last resort system preservation measures by shedding load during system disturbances that result in substantial imbalance between load and generation. NERC also maintains that PRC-006-1 does not aim at a "lowest common denominator" but instead establishes common performance characteristics that all UFLS programs must meet to effectively protect Bulk-Power System reliability.[27]

22. NERC states that PRC-006-1 does not include any differentiation in requirements based on entity size, though it provides the opportunity for planning coordinators to consider input from smaller entities when developing the UFLS program. NERC further explains that PRC-006-1 would apply throughout North America, with variances for entities within the Western Electricity Coordinating Council (WECC) and the Quebec Interconnections.

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[26] NERC Petition at 24.

[27] *Id.* at 26.

23. As proposed by NERC, PRC-006-1 has 14 requirements and 19 sub-requirements, summarized as follows:

Requirement R1: Requires each planning coordinator to develop and document criteria to identify portions of the bulk electric system that may form islands.

Requirement R2: Requires each planning coordinator to identify the islands to serve as a basis for designing its UFLS program. Sub-Requirements 2.1, 2.2, and 2.3 serve as a checklist of items that the entity must consider when identifying islands.

Requirement R3: Requires each planning coordinator to develop a UFLS program, including notification of and a schedule for implementation by the UFLS entities within its area, that meets the specific performance characteristics set forth in sub-Requirements 3.1 through 3.3 in simulations of underfrequency conditions resulting from an imbalance of up to 25 percent within the identified island.

Requirement R4: Requires each planning coordinator to conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2, with sub-Requirements 4.1 through 4.7 specifying items that the simulation must model.

Requirement R5: Requires each planning coordinator to coordinate its UFLS design with all other planning coordinators whose areas or portions of whose areas are also part of the same identified island through specific actions identified in Requirement R5.

Requirement R6: Requires each planning coordinator to maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and

assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities.

Requirement R7: Requires each planning coordinator to provide its UFLS database to other planning coordinators within its Interconnection within 30 calendar days of request.

Requirement R8: Requires each UFLS entity to provide data to its planning coordinator(s) according to the format and schedule specified by the planning coordinator(s) to support maintenance of the UFLS database.

Requirement R9: Requires each UFLS entity to provide automatic tripping of load in accordance with the UFLS program design and schedule for application determined by its planning coordinator(s) in each planning coordinator area in which it owns assets.

Requirement R10: Requires each transmission owner to provide automatic switching of its existing capacitor banks, transmission lines, and reactors to control overvoltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application determined by the planning coordinator(s) in each planning coordinator area in which the transmission owner owns transmission.

Requirement R11: Requires each planning coordinator, in whose area a bulk electric system islanding event results in system frequency excursions below the initializing set points of the UFLS program, to conduct and document an assessment of the event within one year of event actuation that evaluates the performance of the UFLS equipment (sub-Requirement 11.1), and the effectiveness of the UFLS program (sub-Requirement 11.2).

Requirement R12: Requires each planning coordinator, in whose islanding event assessment (Requirement R11) UFLS program deficiencies are identified, to conduct and

document a UFLS design assessment to consider the identified deficiencies within two years of event actuation.

Requirement R13: Requires each planning coordinator, in whose area a bulk electric system islanding event occurred that also included the area(s) or portions of area(s) of other planning coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, to coordinate its event assessment (in accordance with Requirement R11) with all other planning coordinators whose areas or portions of whose areas were also included in the same islanding event by either: (i) conducting a joint event assessment per Requirement R11 among the planning coordinators whose areas or portions of whose areas were included in the same islanding event; or (ii) conducting an independent event assessment per Requirement R11 that reaches conclusions and recommendations consistent with those of the event assessments of the other planning coordinators whose areas or portions of whose areas were included in the same islanding event; or (iii) conducting an independent event assessment per Requirement R11 and where the assessment fails to reach conclusions and recommendations consistent with those of the event assessments of the other planning coordinators whose areas or portions of whose areas were included in the same islanding event, identifying differences in the assessments that likely resulted in the differences in the conclusions and recommendations and report these differences to the other planning coordinators whose areas or portions of whose areas were included in the same islanding event and to the ERO.

Requirement R14: Requires the planning coordinator to respond to written comments submitted by UFLS entities and transmission owners within its planning coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the UFLS program, including a schedule for implementation (sub-Requirement 14.1) and the UFLS design assessment (sub-Requirement 14.2).

B. EOP-003-2

24. Proposed Reliability Standard EOP-003-2 would apply to balancing authorities and transmission operators. NERC states that EOP-003-2 makes minimal changes to EOP-003-1 by removing references to UFLS, which NERC describes as redundant in light of proposed Reliability Standard PRC-006-1, and instead focuses proposed Reliability Standard EOP-003-2 on undervoltage conditions.

III. Discussion

25. Pursuant to section 215(d)(2) of the FPA, the Commission proposes to approve Reliability Standard PRC-006-1 and EOP-003-1 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. The Commission believes that the UFLS program addressed in the proposed Reliability Standards is important to arresting declining frequency and assisting recovery of frequency following system events that lead to system instability, which can result in a blackout. The Commission finds that the proposed Reliability Standards are necessary for reliability because UFLS is used in extreme conditions to stabilize the balance between generation and load after an electrical island has been formed, dropping enough load to allow frequency to stabilize

within the island. Reliability Standard PRC-006-1, in conjunction with the conforming changes to EOP-003-2, provides last resort Bulk-Power System preservation measures by establishing the first national Reliability Standard of common performance characteristics that all UFLS programs must meet. In addition, the Commission proposes to approve the related VRFs and VSLs, implementation plan, and effective date proposed by NERC. Finally, the Commission proposes to approve the retirement of the currently effective Reliability Standards PRC-007-0, PRC-009-0, and EOP-003-1, and the NERC-approved Reliability Standard PRC-006-0.

26. The Commission addresses or seeks comments from the ERO and other interested persons on aspects of the proposed Reliability Standards. Specifically, we address or seek comments on the following issues: (A) impact of resources not connected to the bulk electric system; (B) validation of power system models used to simulate ULFS programs; (C) scope of UFLS events assessments; (D) impact of generator owner trip settings outside of the UFLS program; (E) UFLS program coordination with other protection systems; (F) identification of island boundaries in UFLS programs; (G) automatic load shedding in PRC-006-1 and manual load shedding in EOP-003-2; (H) elimination of balancing authority responsibilities in EOP-003-2; and (I) the “Lower VSL” for Requirement R8 and the “Medium” VRF for Requirement R5 of PRC-006-1. These issues also apply to the corresponding Requirements in the requested regional variance for WECC in PRC-006-1.

A. Impact of Resources Not Connected to Bulk Electric System Facilities

27. As described above, UFLS programs are designed to maintain balance between resources and load in a defined area (e.g., an Interconnection, Regional Entity area, or planning coordinator area). When a resource is lost, load exceeds supply causing frequency to decrease below its scheduled value (e.g., 60 Hz in the United States). Conversely, a loss of load or excess supply can result in higher frequencies than scheduled, resulting in an overfrequency condition. As a last resort, UFLS programs are initiated during extreme underfrequency conditions to reestablish balance by shedding load at predetermined frequencies and times to prevent system-wide blackouts.

28. Requirement R2 of PRC-006-1 requires planning coordinators to identify islands to serve as a basis for designing UFLS programs. Requirement R3 addresses performance characteristics for UFLS programs. Requirement R4 requires each planning coordinator to conduct and document the assessment of its UFLS design and determine if the UFLS program meets the performance characteristics in Requirement R3 for each island identified in Requirement R2.

29. The simulations outlined in Requirement R4 all concern individual generating units greater than 20 MVA gross nameplate rating or generating plants/facilities greater then 75 MVA "connected to the bulk electric system." However, some generation that meets the 20 MVA and 75 MVA criteria is not connected to bulk electric system facilities. Accordingly, those resources not connected to bulk electric system facilities would not be modeled pursuant to Requirement R4. However, a resource not connected to the bulk electric system may serve load designed to be shed in a UFLS program. The

Commission is concerned that failure to account for resources not connected to the bulk electric system in a planning coordinator's UFLS program could result in the planning coordinator being unaware of how such resources respond to underfrequency conditions. If the planning coordinator is unaware of how these facilities have responded, it may plan to shed more load than is required for an area's frequency to return to normal. This could lead to an unintended overfrequency condition if the plan is carried out in the operating timeframe. These conditions, in turn, could lead the plan to violate the performance characteristics specified in Requirement R3.

30. The performance characteristics identified in Requirement R3 provide acceptable parameters for developing UFLS programs that are designed to restore balance between resources and load. However, the Commission is concerned that generation resources or facilities that are not connected to the bulk electric system may not be considered during the development of UFLS programs.

31. The Commission seeks comments from the ERO and other interested persons as to whether and how all resources required for the reliable operation of the bulk electric system, including resources not connected to bulk electric system facilities, are considered in the development of UFLS programs under Requirements R3 and R4.

B. Validation of Power System Models

32. Power systems consist of static components (e.g., transformers and transmission lines) and dynamic components (e.g., generators and motor loads). Mathematical representations of these components are aggregated to create an area's power system

model. Power system planners[28] and system operators base decisions on simulations, both static and dynamic, using area power system models to meet requirements in both Commission-approved planning and operational Reliability Standards.[29]

33. Requirements R4 and R11 of PRC-006-1 require applicable entities to use dynamic simulations to design and assess the effectiveness of UFLS programs. As previously discussed, UFLS programs are designed to provide last resort system preservation measures by: (1) arresting declining frequency; and (2) assisting recovery of frequency following underfrequency events. Dynamic simulations that do not accurately represent the power system can result in an UFLS program that is ineffective.

34. The Commission believes that the UFLS program design requirements established in Requirement R2 and the required assessments established in Requirements R4 and R11 of PRC-006-1 are generally acceptable and include improvements above the current Reliability Standards. Accordingly, the Commission believes that the language in the proposed Requirements is appropriate.

C. UFLS Event Assessments

1. Assessments in the Absence of Island Formation

35. Requirement R11 of PRC-006-1 requires planning coordinators to conduct assessments after a "BES islanding event results in system frequency excursion below the initializing set points of the UFLS program." The Commission is concerned whether the

[28] Power system planners may include functional entities such as transmission planners and planning coordinators.

[29] *See*, *e.g.*, Reliability Standards MOD-010-0, MOD-012-0 and TOP-002-2a, Requirement R19.

phrase “BES islanding event” could be interpreted to mean that a planning coordinator only has to assess an event if it meets both of the following requirements: (1) system frequency excursions fall below the initializing set point for UFLS; and (2) bulk electric system islands form within the Interconnection. If the frequency falls below the initializing UFLS set point but islands do not form (e.g., because the event was not severe enough to isolate portions of the Interconnection, or UFLS or other protection systems failed to operate properly to form islands), an assessment of the performance of the UFLS program for this event is still useful because it can determine if the UFLS program operated as expected.

36. The Commission seeks clarification from the ERO regarding what actions must planning coordinators take under Requirement R11 if an event results in system frequency excursions falling below this initializing set point for UFLS but without the formation of a bulk electric system island.

2. Coordination of Assessments and Results

37. Requirements R5 and R13 of PRC-006-1 require planning coordinators that share identified islands to coordinate UFLS program design and event assessment. The options for coordinating designs of UFLS programs in Requirement R5 include: (1) developing a common program; (2) conducting a joint UFLS design assessment among the planning coordinators whose area or portions of whose areas are part of the same identified island; or (3) conducting an independent design assessment and, in the event the UFLS design assessment fails to meet Requirement R3, identify modifications to the UFLS program(s)

to meet Requirement R3 and report these modifications as recommendations to the other planning coordinators.

38. The options for coordinating event assessments in Requirement R13 include: (1) conducting a joint event assessment per Requirement R11 among planning coordinators whose areas were affected; (2) conducting an independent event assessment per Requirement R11 that reaches conclusions and recommendations consistent with other planning coordinators whose areas were affected; or (3) conducting an independent event assessment per Requirement R11 and where the assessment fails to reach conclusions and recommendations consistent with those of the other planning coordinators whose areas were affected by the same islanding event, identify differences in the assessments and report these differences to the other affected planning coordinators. The Commission seeks comments from the ERO and other interested persons as to whether the differences should be subsequently reported to the reliability coordinator for resolution in the event that the process does not resolve differences in the assessments.

39. The Commission believes that Requirements R5 and R13 provide flexibility in coordinating UFLS design programs and event assessments among planning coordinators whose areas fall within the same island or whose areas are affected by the same event. Accordingly, the Commission believes that the language in the proposed Requirements is appropriate.

3. Assessment Timeline for Completion

40. Requirement R11 of Reliability Standard PRC-006-1 requires a planning coordinator to perform an island event assessment within one year of an event. If the planning coordinator identifies program deficiencies, Requirement R12 requires the planning coordinator to conduct and document UFLS design assessments, which are meant to consider the deficiencies, within two years of an event. The Commission is concerned that this time frame may be too long since it appears that island event assessments and consideration of deficiencies could reasonably be conducted in a much shorter time frame. Under NERC's proposal, deficiencies could remain within a UFLS program for two years from an event exposing the Bulk-Power System to instability, uncontrolled separation and cascading outages should a frequency event occur that the UFLS program mishandles. NERC provided no explanation of its basis for the proposed two-year time frame.

41. The Commission asks the ERO and other interested persons what the basis is for proposing a two-year time frame. In addition, the Commission seeks clarification from the ERO as to how soon after event actuation would an entity need to implement corrections in response to any deficiencies identified in the event assessment under Requirements R11.

D. Generator Owner Trip Settings Outside of the UFLS Program

42. Requirements 4.1 through 4.7 of Reliability Standard PRC-006-1 are intended to capture the effects of generators that trip prior to UFLS initiation. As previously discussed, a generator trip normally creates an imbalance between resources and load

causing system frequency to decline. Some generators may need to disconnect from the system prior to reaching underfrequency set points to protect their components from permanent damage. If this loss occurs during a system event, the generator can no longer provide a response to assist in arresting frequency decline. This resource loss also counteracts the response provided by other resources to arrest frequency decline, increasing the likelihood of instability, uncontrolled separation, and cascading outages.

43. We agree that planning coordinators should consider generators that trip prior to underfrequency set points when developing their UFLS programs. The Commission seeks comments from the ERO and other interested persons on how generation losses outside of the UFLS set points (i.e., generators having trip settings prior to the UFLS underfrequency set points) should be accounted for in UFLS programs (e.g., generator owners who trip outside of the UFLS set points could procure load to shed to account for the loss in generation).

E. UFLS Program Coordination with Other Protection Systems

44. Recommendation 21C of the Blackout Report addresses the coordination of protection systems.[30] The recommendation states that NERC shall "determine the goals and principles needed to establish an integrated approach to relay protection for generators and transmission lines and the use of underfrequency and undervoltage load shedding (UFLS and UVLS) programs. An integrated approach is needed to ensure that at the local and regional levels, these interactive components provide an appropriate balance of risks and benefits in terms of protecting specific assets and facilitating overall

[30] Blackout Report at 159.

grid survival."[31] Accordingly, an integrated approach requires coordination of all types of protection systems (e.g., UFLS, UVLS), internally and externally to an entity's area, to be responsive to the Blackout Report.

45. While PRC-006-1 requires coordination of UFLS programs among planning coordinators in Requirements R5, R7, and R13, it does not appear to capture the same level of coordination with other protection systems as in Requirement R1.2.8 of PRC-006-0.[32] The Commission seeks comments from NERC and other interested persons on whether and how coordination with other protection systems is or is not achieved under the new requirements.

F. Identification of Island Boundaries

46. Requirement R1 of PRC-006-1 directs planning coordinators to develop criteria to select areas that may form islands based on historical events and system studies. Historical events and system studies provide planning coordinators with the data necessary to determine where islands will occur based on the physics of the system. Requirement R2.3 clarifies that islands identified in Requirement R1, which span two or more Regional Entity areas, should be broken up such that each Regional Entity area forms an island. Requirement R2.3 allows planning coordinators to "adjust the island boundaries to differ from the Regional Entity area boundaries by mutual consent where necessary" to preserve contiguous island boundaries that better reflect simulations. The

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[31] *Id.*

[32] Requirement 1.2.8 of PRC-006-0 encompasses "[a]ny other schemes that are part of or impact the UFLS program."

Commission agrees that identifying island boundaries based on where they are likely to occur due to system characteristics, as opposed to maintaining rigid Regional Entity area boundaries, should result in more effective UFLS programs. Accordingly, the Commission encourages cooperation among entities to create UFLS programs that set island boundaries based on where separations are expected to occur during an underfrequency event.

47. In its petition, NERC states that the Requirements allow planning coordinators to "select islands including interconnected portions of the bulk electric system in adjacent Planning Coordinator areas and Regional Entity areas, without the need for coordinating this selection with Planning Coordinators in neighboring regions."[33] Requirement R2.3 of PRC-006-1, however, requires "mutual consent" to adjust island boundaries from Regional Entity boundaries. The Commission seeks clarification from the ERO concerning the required degree of cooperation and/or "mutual consent" between planning coordinators under the proposed Reliability Standard in order for island boundaries to be set so that, while deviating from Regional Entity boundaries, they better approximate actual island separation boundaries.

G. Automatic Load Shedding and Manual Load Shedding

48. Proposed Reliability Standard PRC-006-1 requires automatically shedding predetermined amounts of load if frequency declines to the UFLS set point in order to rebalance resources and demand and prevent frequency decline that might cause instability, uncontrolled separation, or cascading outages. Proposed Reliability Standard

[33] NERC Petition at 75-76.

EOP-003-2 requires manual load shedding plans, which may be employed in addition to the automatic load shedding in the UFLS program, or to mitigate other reliability issues. If load allocated to be shed automatically is also planned for manual load shedding, then that load resource would be double-counted. Once load is disconnected from the system, either automatically or manually, it cannot be used again to arrest frequency decline. In the event that a load resource is double-counted and removed during automatic UFLS, the manual load shedding cannot be completed if called upon. Even if additional load is located and shed to compensate for this missing load, the system would be put into an un-studied state and could have unpredicted, negative responses. Accordingly, resources allocated to each type of load shedding (i.e., automatic and manual) should not overlap.

49. There are no requirements in PRC-006-1 to coordinate automatic load shedding by UFLS and manual load shedding under EOP-003-2. The Commission seeks comments from the ERO and other interested persons on how the coordination of automatic and manual load shedding is considered in light of the fact that the proposed Reliability Standards do not explicitly require coordination.

H. Elimination of Requirements for Balancing Authorities in EOP-003-2

50. Requirements R2, R4, and R7 of the currently-effective Reliability Standard EOP-003-1 apply to transmission operators and balancing authorities. Proposed Reliability Standard EOP-003-2 proposes to eliminate balancing authorities from Requirements R2, R4, and R7.

51. Under the proposed modification, balancing authorities would no longer: (i) establish plans for automatic load shedding for underfrequency or undervoltage

conditions (Requirement R2); (ii) consider factors (including frequency, rate of frequency decay, voltage level, rate of voltage decay, or power flow levels) in designing an automatic undervoltage load shedding scheme (Requirement R4); and (iii) coordinate automatic load shedding throughout its area with underfrequency isolation of generating units, tripping of shunt capacitors, and other automatic actions that will occur under abnormal frequency, voltage, or power flow conditions (Requirement R7). In its petition, NERC explains that balancing authorities were deleted from Requirements R2 and R4 "because the frequency related aspects of these requirements were removed, leaving only consideration of automatic undervoltage load shedding in these two requirements."[34] NERC's petition, however, does not explain why balancing authorities were removed from Requirement R7. Moreover, given that balancing authorities would no longer be subject to Requirements R2, R4, and R7 of EOP-003-2 and are not listed as applicable entities in PRC-006-1, the proposed Reliability Standards do not preserve these existing balancing authority responsibilities.

52. The Commission seeks clarification from the ERO as to why these existing balancing authority responsibilities were not incorporated into Reliability Standards PRC-006-1 or EOP-003-2. The Commission also seeks comments from the ERO and other interested persons as to why balancing authorities should not be informed of UFLS program plans that directly impact balancing authority functions.

[34] NERC Petition at 42.

I. Violation Risk Factors and Violation Severity Levels

53. NERC states that each primary requirement in PRC-006-1 and EOP-003-2 is assigned a Violation Risk Factor (VRF) and Violation Severity Level (VSL) and that these elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in Commission-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

54. The Commission proposes to approve the VRFs and VSLs in PRC-006-1 and EOP-003-2. However, the Commission seeks comments from the ERO and other interested persons regarding one proposed VSL and one proposed VRF for PRC-006-1.

55. The "Lower VSL" assignment for Requirement R8 in PRC-006-1 applies when a UFLS entity fails to provide data to its planning coordinator for 5 to 10 calendar days following the schedule specified by the planning coordinator. Requirement R8 of PRC-006-1 does not include a 5-day grace period for providing data to planning coordinators. Accordingly, the subject VSL assignment may be inconsistent with the Commission's VSL Guideline 3. The guideline states that a VSL "should not appear to redefine or undermine the requirement."[35] The five-day grace period implicit in the proposed VSL appears to be inconsistent with this guideline. In addition, the proposed VSL creates a compliance issue. Specifically, it is unclear where a UFLS entity falls in the VRF and VSL matrices if it fails to provide data to its planning coordinator within 1 to 5 days of its scheduled date.

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[35] *North American Electric Reliability Corp.*, 123 FERC ¶ 61,284, at P 32 (2008).

56. The VRF for Requirement R5, which requires planning coordinators to coordinate their UFLS program design with other planning coordinators whose area is in part of the same identified island, is proposed as "Medium." NERC states that Requirement R5 is "not related to similar reliability goals in other standards."[36] However, coordination of load shedding plans is required in a similar manner in Requirement R3 of currently effective Reliability Standard EOP-003-1,[37] which includes a VRF of "High." The lack of coordination of UFLS programs among planning coordinators within the same identified island could lead to ineffective UFLS operations and further cascading outages within the island when UFLS is activated.

57. Guideline 3 of the Commission's VRF Guidelines states that "[a]bsent justification to the contrary, the Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably."[38] The Commission seeks clarification from the ERO why coordination of load shedding plans is a "High" VRF for transmission operators and balancing authorities in EOP-003-2 but NERC proposes a "Medium" VRF for planning coordinators in PRC-006-1.

J. Implementation Plan and Effective Date

58. NERC requests an effective date for PRC-006-1 and EOP-003-2 of one year following the first day of the first calendar quarter after applicable regulatory approvals

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[36] NERC Petition at 46.

[37] Proposed Reliability Standard EOP-003-2 includes the same VRF assignment of "High" for Requirement R3.

[38] *North American Electric Reliability Corp.*, 119 FERC ¶ 61,145, at P 25 (2007).

with respect to all Requirements of the proposed Reliability Standards except Parts 4.1 through 4.6 of Requirement R4 of PRC-006-1. With respect to Parts 4.1 through 4.6 of Requirement R4 of PRC-006-1, NERC requests an effective date of one year following the receipt of generation data as required in Reliability Standard PRC-024-1,[39] but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1.

59. NERC contends that the proposed implementation plan is not excessively long and allows sufficient time for entities to transition and install the necessary processes to become compliant. NERC maintains that the one year phase-in for compliance provides planning coordinators sufficient time: (1) to develop, modify, or validate (to determine that an existing program meets required performance characteristics) existing UFLS programs; and (2) to establish a schedule for implementation, or validate a schedule for completion of program revisions already in progress. Moreover, NERC states that transmission owners and distribution providers will comply with the schedule determined by planning coordinators but no sooner than the effective date of the standard.

60. The Commission proposes to accept the implementation plan and effective date proposed by the ERO for PRC-006-1 and EOP-003-2. However, the Commission seeks comments from the ERO and other interested persons about any potential reliability gaps that may occur during the development and implementation of PRC-024-1, such as how

[39] PRC-024-1 addresses "Generator Performance During Frequency and Voltage Excursions" and is currently being developed in the NERC standard drafting process under Project 2007-09 (Generator Verification), which is one of NERC's priority projects.

the planning coordinators will adequately determine and apply UFLS simulations and plans in the absence of generator trip settings.

IV. Information Collection Statement

61. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping (collections of information) imposed by an agency.[40] Upon approval of a collection(s) of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirements of this rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

62. The Commission is submitting these reporting and recordkeeping requirements to OMB for its review and approval under section 3507(d) of PRA. Comments are solicited on the Commission's need for this information, whether the information will have practical utility, the accuracy of provided burden estimate, ways to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques.

63. This Notice of Proposed Rulemaking proposes to approve Reliability Standards PRC-006-1 and EOP-003-2, which would replace currently effective Reliability Standards PRC-007-0, PRC-009-0, EOP-003-1 and NERC-approved Reliability Standard

[40] 5 CFR 1320.11.

PRC-006-0.[41] As noted previously, Reliability Standard PRC-006-0 was never approved by the Commission, and therefore has never been mandatory and enforceable. On the other hand, Reliability Standards PRC-007-0 and PRC-009-0 were approved by the Commission and are currently mandatory and enforceable. Because Proposed Reliability Standard PRC-006-1 incorporates the requirements from Reliability Standards PRC-006-0, PRC-007-0, and PRC-009-0 some of the existing requirements will become mandatory and enforceable (where previously they were voluntary), while others continue to be so. To properly account for the burden on respondents, the Commission will treat the burden resulting from NERC-approved Reliability Standard PRC-006-0 as essentially new to the industry, even though it is likely that most applicable entities have already been complying.[42]

64. The reporting requirements in proposed Reliability Standard EOP-003-2 are virtually the same as those in currently effective Reliability Standard EOP-003-1. The difference is that proposed Reliability Standard EOP-003-2 proposes to eliminate

[41] PRC-006-0 was not approved by the Commission but remained effective as a NERC-approved standard (but not mandatory or enforceable). The other three standards were approved by the Commission. *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[42] This statement is made because currently effective Reliability Standards PRC-007-0 and PRC-009-0 required UFLS entities to follow the UFLS program implemented by Reliability Standard PRC-006-0. Therefore, it is likely that entities have already been following the requirements contained in Reliability Standard PRC-006-0.

balancing authorities from Requirements R2 and from Measure M1.[43] This requirement and measure deal with establishing and documenting automatic load shedding plans.

65. Public Reporting Burden: Our estimate below regarding the number of respondents is based on the NERC compliance registry as of 7/29/11. According to the NERC compliance registry, there are 72 planning coordinators and 126 balancing authorities. The individual burden estimates are based on the time needed to gather data, run studies, and analyze study results to design or update the UFLS programs. Additionally, documentation and the review of UFLS program results by supervisors and management is included in the administrative estimations. These are consistent with estimates for similar tasks in other Commission approved standards.

PRC-006-1 (Automatic Underfrequency Load Shedding)[44]	Number of Respondents Annually (1)	Number of Responses per Respondent (2)	Average Burden Hours Per Response (3)	Total Annual Burden Hours (1)x(2)x(3)
PCs*: Design and document Automatic UFLS Program	72	1	120	8,640
PCs: Management Review of Documentation			40	2,880
PCs: Record Retention			16	1,152

[43] Balancing authorities are also removed from Requirements R4 and R7, but these do not have reporting requirements associated with them.

[44] Proposed Reliability Standard PRC-006-1 applies to both planning coordinators and to UFLS entities. However, the burden associated with the UFLS entities is not new because it was accounted for under Commission approved Reliability Standards PRC-007-0 and PRC-009-0.

Total					12,672
EOP-003-2 (Load Shedding Plans)[45]					
Removal of BAs* from Reporting Requirements in R2 and M1 (Burden Reduction)	126	1	Reporting	-10	-1260
			Record Retention	-1	-126
Total					-1,386
Net Change in Burden					11,286

*PC=Planning Coordinator; BA=Balancing Authority

Total Annual Hours for Collection: (Compliance/Documentation) = 11,286 hours.

Total Reporting Cost for Planning Coordinators: = 11,520 hours @ $120/hour = $1,382,400.

Total Record Retention Cost for Planning Coordinators: 1,152 hours @ $28/hour = $32,256.

Total Reporting and Record Retention Cost Savings for Balancing Authorities: = (1,260 hours @ $120/hour) + (126 hours @ $28/hour) = $154,728.

[45] Transmission operators also have to comply with Reliability Standard EOP-003-2 but since the applicable reporting requirements (and associated burden) have not changed from the existing standard to the proposed standard these entities are not included here.

Total Annual Cost (Reporting + Record Retention)[46]: = $1,414,656 - $154,728 = $1,259,928.

Title: Mandatory Reliability Standards for the Bulk-Power System

Action: Proposed Collection FERC-725A.

OMB Control No.: 1902-0244.

Respondents: Businesses or other for-profit institutions; not-for-profit institutions.

Frequency of Responses: On Occasion.

Necessity of the Information: This proposed rule proposes to approve the requested modifications to Reliability Standards pertaining to automatic underfrequency load shedding. The proposed Reliability Standards help ensure the reliable operation of the bulk electric system by arresting declining frequency and assisting recovery of frequency following system events leading to frequency degradation.

Internal Review: The Commission has reviewed the proposed Reliability Standards and made a determination that its action is necessary to implement section 215 of the FPA. These requirements, if accepted, should conform to the Commission's expectation for UFLS programs as well as procedures within the energy industry.

66. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE

[46] The hourly reporting cost is based on the cost of an engineer to implement the requirements of the rule. The record retention cost comes from Commission staff research on record retention requirements.

Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, e-mail: DataClearance@ferc.gov, phone: (202) 502-8663, fax: (202) 273-0873].

67. For submitting comments concerning the collection(s) of information and the associated burden estimate(s), please send your comments to the Commission and to the Office of Management and Budget, Office of Information and Regulatory Affairs, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395-4638, fax: (202) 395-7285]. For security reasons, comments to OMB should be submitted by e-mail to: oira_submission@omb.eop.gov. Comments submitted to OMB should include Docket Number RM11-20 and OMB Control Number 1902-0244.

V. Environmental Analysis

68. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[47] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[48] The actions proposed here fall within this categorical exclusion in the Commission's regulations.

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[47] Order No. 486, *Regulations Implementing the National Environmental Policy Act of 1969*, FERC Stats. & Regs., Regulations Preambles 1986-1990 ¶ 30,783 (1987).

[48] 18 CFR 380.4(a)(2)(ii).

VI. Regulatory Flexibility Act Certification

69. The Regulatory Flexibility Act of 1980 (RFA)[49] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a proposed rule and that minimize any significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[50] The SBA has established a size standard for electric utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million megawatt hours.[51]

70. Proposed Reliability Standard PRC-006-1 proposes to establish design, assessment, and documentation requirements for automatic UFLS program. It will be applicable to planning coordinators and entities that are responsible for the ownership, operation, or control of UFLS equipment. Proposed Standard EOP-003-2 proposes to remove balancing authorities from having to comply with R2 and M1 of the standard. Comparison of the NERC compliance registry with data submitted to the Energy Information Administration on Form EIA-861 indicates that perhaps as many as 8 small entities are registered as planning coordinators and 18 small entities are registered as

[49] 5 U.S.C. 601-612.

[50] 13 CFR 121.101.

[51] 13 CFR 121.201, Sector 22, Utilities & n.1.

balancing authorities. The Commission estimates that the small planning coordinators to whom the proposed Reliability Standard will apply will incur compliance and recordkeeping costs of $157,184 ($19,648 per planning coordinator) associated with the Standard's requirements. The small balancing authorities will receive a savings of $154,728 ($8,596 per balancing authority). Accordingly, proposed Reliability Standards PRC-006-1 and EOP-003-2 should not impose a significant operating cost increase or decrease on the affected small entities.

71. Based on this understanding, the Commission certifies that these Reliability Standards will not have a significant economic impact on a substantial number of small entities. Accordingly, no regulatory flexibility analysis is required.

VII. Comment Procedures

72. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due [**INSERT DATE 60 days after publication in the FEDERAL REGISTER]**]. Comments must refer to Docket No. RM11-20-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

73. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at http://www.ferc.gov. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not

in a scanned format. Commenters filing electronically do not need to make a paper filing.

74. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

75. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VIII. Document Availability

76. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

77. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

78. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

List of subjects in 18 CFR Part 40

Electric power; Electric utilities; Reporting and record keeping requirements.

By direction of the Commission. Commissioner Spitzer is not participating.

Nathaniel J. Davis, Sr.,
Deputy Secretary.

137 FERC ¶ 61,077
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

Docket No. RM11-18-000

Transmission Planning Reliability Standards

(October 20, 2011)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: Transmission Planning (TPL) Reliability Standards are intended to ensure that the transmission system is planned and designed to meet an appropriate and specific set of reliability criteria. Reliability Standard TPL-002-0a references a table which identifies different categories of contingencies and allowable system impacts in the planning process. The table includes a footnote regarding planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization, requests approval of a revision to the footnote. In this notice, the Commission proposes to remand NERC's proposed revision to the footnote.

DATES: Comments are due **[60 days after publication in the FEDERAL REGISTER]**

ADDRESSES: You may submit comments, identified by docket number by any of the following methods:

- Agency Web Site: http://ferc.gov. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- Mail/Hand Delivery: Commenters unable to file comments electronically must mail or hand deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

FOR FURTHER INFORMATION CONTACT:

Robert T. Stroh (Legal Information)
Office of the General Counsel
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
Telephone: (202) 502-8473

Eugene Blick (Technical Information)
Office of Electric Reliability
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
Telephone: (202) 502-8066

SUPPLEMENTARY INFORMATION:

137 FERC ¶ 61,077
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning Reliability Standards Docket No. RM11-18-000

NOTICE OF PROPOSED RULEMAKING

(October 20, 2011)

1. On March 31, 2011, the North American Electric Reliability Corporation (NERC) filed a petition seeking approval of Table 1, footnote 'b' of four Reliability Standards: Transmission Planning: TPL-001-1– System Performance Under Normal (No Contingency) Conditions (Category A), TPL-002-1b – System Performance Following Loss of a Single Bulk Electric System Element (Category B), TPL-003-1a – System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), and TPL-004-1– System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).[1] Pursuant to section 215(d)(4) of the Federal Power Act (FPA)[2], the Commission proposes to remand the proposed Table 1, footnote b. As discussed below, the Commission believes that the proposed Reliability Standard does not meet the statutory criteria for approval that it be

[1] While footnote 'b' appears in all four of the above referenced TPL Reliability Standards, its relevance and practical applicability is limited to TPL-002-0a.

[2] 18 U.S.C. 824o(d)(4) (2006).

just, reasonable, not unduly discriminatory or preferential, and in the public interest.[3] The Commission seeks comments on its proposal.

I. Background

2. Section 215 of the FPA requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval. Approved Reliability Standards are enforced by the ERO, subject to Commission oversight, or by the Commission independently.

3. Pursuant to section 215 of the FPA, the Commission established a process to select and certify an ERO[4] and, subsequently, certified NERC as the ERO.[5] On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 Reliability Standards filed by NERC, including Reliability Standard TPL-002-0, Table 1, footnote 'b.'[6] In addition, pursuant to section 215(d)(5) of the FPA,[7] the Commission directed

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[3] 16 U.S.C. 824o(d)(2) (2006).

[4] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[5] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g & compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom., Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[6] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

NERC to develop modifications to 56 of the 83 approved Reliability Standards, including footnote 'b' of Reliability Standard TPL-002-0.[8]

A. Transmission Planning (TPL) Reliability Standards

4. Currently-effective Reliability Standard TPL-002-0a addresses Bulk-Power System planning and related system performance for single element contingency conditions. Requirement R1 of TPL-002-0a requires that each Planning Authority and Transmission Planner "demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I."[9] Table I identifies different categories of contingencies and allowable system impacts in the planning process. With regard to system impacts, Table I further provides that a Category B (single) contingency must not result in cascading outages, loss of demand or curtailed firm transfers, system instability or exceeded voltage or thermal limits. With regard to the clause regarding loss of demand, current footnote 'b' of Table 1 states:

> Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems.

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[7] 16 U.S.C. 824o(d)(5)(2006).

[8] Order No. 693, FERC Stats & Regs. ¶ 31,242 at P 1797.

[9] Reliability Standard TPL-002-0a, Requirement R1.

> To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

B. Order No. 693 Directive

5. In Order No. 693, the Commission stated that it believes that the transmission planning Reliability Standard should not allow an entity to plan for the loss of non-consequential firm load in the event of a single contingency.[10] The Commission directed the ERO to develop certain modifications, including a clarification of Table 1, footnote 'b'. The Commission stated that:

> Based on the record before us, we believe that the transmission planning Reliability Standard should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency. The Commission directs the ERO to clarify the Reliability Standard. Regarding the comments of Entergy and Northern Indiana that the Reliability Standard should allow entities to plan for the loss of firm service for a single contingency, the Commission finds that their comments may be considered through the Reliability Standards development process. However, we strongly discourage an approach that reflects the lowest common denominator. The Commission also clarifies that an entity may seek a regional difference to the Reliability Standard from the ERO for case-specific circumstances.[11]

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[10] *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1794. Non-consequential load loss includes the removal, by any means, of any planned firm load that is not directly served by the elements that are removed from service as a result of the contingency. Currently-effective footnote 'b' deals with both consequential load loss and non-consequential load loss. NERC's proposed footnote 'b' characterizes both types of load loss as "Firm Demand." The focus of this NOPR is NERC's proposed treatment of non-consequential load loss or planned interruption of "Firm Demand."

[11] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1794 (footnotes omitted).

6. In a subsequent clarifying order, the Commission stated that it believed that a regional difference, or a case-specific exception process that can be technically justified, to plan for the loss of firm service "at the fringes of various systems" would be an acceptable approach in limited circumstances.[12] Specifically, the Commission clarified that:

> Moreover, the Commission, in … Order No. 693, then provided a clarification that an entity may seek a regional difference to the Reliability Standard from the ERO for case-specific circumstances. We believe that a regional difference, or a case-specific exception process that can be technically justified, to plan for the loss of firm service "at the fringes of various systems" would be an acceptable approach. Thus, the Commission did not dictate a single solution as NERC and others now claim. In any event, NERC must provide a strong technical justification for its proposal.[13]

C. NERC's Petition for Approval of TPL-002-0a, Footnote b

7. On March 31, 2011, NERC filed a petition seeking approval of its proposal to revise and clarify footnote 'b' "in regard to load loss following a single contingency."[14] NERC stated that it did not eliminate the ability of an entity to plan for the loss of non-consequential load in the event of a single contingency but drafted a footnote that, according to NERC, "meets the Commission's directive while simultaneously meeting the needs of industry and respecting jurisdictional bounds."[15] NERC states that its

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[12] *Mandatory Reliability Standards for the Bulk Power System*, 131 FERC ¶ 61,231, at P 21 (2010) (June 2010 Order).

[13] *Id.*

[14] NERC Petition at 10.

[15] *Id.*

proposed footnote ‘b’ establishes the requirements for the limited circumstances when and how an entity can plan to interrupt Firm Demand for Category B contingencies. It allows for planned interruption of Firm Demand when "subject to review in an open and transparent stakeholder process."[16] NERC’s proposed footnote ‘b’ states:

> An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate redispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner’s planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address [Bulk Electric System] performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

D. <u>Supplemental Information</u>

8. On June 7, 2011, in response to a Commission deficiency letter, NERC explained that "the approach proposed in footnote ‘b’ is equally efficient because many of the stakeholder processes that will be used in footnote ‘b’ planning decisions are already in place, as implemented by FERC in Order No. 890 and in state regulatory jurisdictions.”[17] NERC also pointed to state public utility commission processes or processes existing in

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[16] *Id.*

[17] NERC Data Response at 4.

local jurisdictions that address transmission planning issues that could serve to provide a case-specific review of the planned interruption of Firm Demand. NERC added that an ERO-sponsored planning process is not likely to be efficient or effective because of extensive jurisdictional issues between NERC, the Commission, and the many authorities having jurisdiction that would have to be resolved before implementation could occur. NERC added that an ERO-specific process would lead to conflicts among federal, provincial, state and local governing bodies that have jurisdiction over various parts of the planning, siting and construction process. NERC also believes that a NERC-centered process would duplicate planning actions occurring elsewhere (e.g., where resource allocation decisions are actually being made), and such a process could lead to inconsistent results. NERC concluded that a more reasonable and expeditious path would be to rely on existing stakeholder processes. According to NERC, such processes would more likely engage the appropriate local-level decision-makers and policy-makers.

9. With respect to review and oversight by NERC and the Regional Entities, NERC submitted that an ERO-specific process would place the ERO in the position of managing and actively participating in a planning process, which conflicts with its role as the compliance monitor and enforcement authority. NERC also stated that neither the ERO nor the Regional Entities will review decisions regarding planned interruptions. Their role will be limited to reviewing whether the registered entity participated in a stakeholder process when planning to interrupt Firm Demand. NERC explained that Regional Entities will have oversight after-the-fact by auditing the entity's implementation of footnote 'b' to determine if the entity planned on interrupting Firm

Demand and whether the decision by the entity to rely on planned interruption of Firm Demand was vetted through the stakeholder process and qualified as one of the situations identified in footnote b.

10. Furthermore, NERC stated that an objective of the planning process should be to minimize the likelihood and magnitude of planned Firm Demand interruptions. NERC recognizes that there may be topological or system configurations where allowing planned interruptions of Firm Demand may provide more reliable service. NERC contends that due to the wide variety of system configurations and regulatory compacts, it is not feasible for the ERO to develop a one-size-fits-all criterion for limiting the planned firm load interruptions for Category B events. According to NERC, the standards drafting team evaluated setting a certain magnitude of planned interruption of Firm Demand, but there was no analytical data to support a single value, and it would be viewed as arbitrary.

II. Discussion

11. The Commission proposes to remand NERC's proposal to modify Reliability Standard TPL-002-0a, Table 1, footnote 'b.' The Commission believes that NERC's proposal does not meet the directives in Order No. 693 and the June 2010 Order and does not clarify or define the circumstances in which an entity can plan to interrupt Firm Demand for a single contingency. Specifically, the Commission is concerned that the procedural and substantive parameters of NERC's proposed stakeholder process are too undefined to provide assurances that the process will be effective in determining when it is appropriate to plan for interrupting Firm Demand, does not contain NERC-defined

criteria on circumstances to determine when an exception for planned interruption of Firm Demand is permissible, and could result in inconsistent results in implementation. In proposing a stakeholder process without specification of any technical means by which exceptions are to be evaluated, the proposed footnote effectively turns the processes into a reliability standards development process outside of NERC's existing procedures. Furthermore, the Commission believes that regardless of the process used, the result could lead to inconsistent reliability requirements within and across reliability regions. While the Commission recognizes that some variation among regions or entities is reasonable given varying grid topography and other legitimate considerations, there are no technical or other criteria to determine whether varied results are arbitrary or based on meaningful distinctions. While the Commission acknowledges that NERC has flexibility in developing alternative approaches, we believe that the proposed approach is not equally efficient or effective as the Commission's directives and that NERC has failed to provide a strong technical justification for its proposal.

12. As an initial matter, the Commission is concerned that the process lacks parameters. The standard requires that, when planning to interrupt Firm Demand, the Firm Demand interruption must be "subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments."[18] However, without any substantive parameters governing the stakeholder process, the enforceability of this obligation by NERC and the Regional Entities' would be limited to a review to

[18] NERC Petition at 10.

ensure only that a stakeholder process occurred. Indeed, NERC's explanation appears to confirm this concern, as NERC explained that Regional Entities' involvement is limited to oversight after-the-fact by auditing the entity's implementation of footnote 'b' to determine if the entity planned on interrupting Firm Demand and whether the decision by the entity to rely on planned interruption of Firm Demand was vetted through the stakeholder process and qualified as one of the situations identified in footnote 'b'.

13. Further, the Commission is concerned that the NERC proposal leaves undefined the circumstances in which it is allowable to plan for Firm Demand to be interrupted in response to a Category B contingency. The TPL-002-0a Reliability Standard requires Planning Authorities and Transmission Planners to demonstrate through a valid assessment that the transmission system is planned and can be operated to supply projected Firm Demand at all demand levels over a range of forecasted system demands.[19] Moreover, the planner must consider all single contingencies applicable to Table I, Category B and demonstrate that system performance is met. For those instances where system performance is not met, the planner must provide a written summary of its plans to achieve system performance including implementation schedules, in service dates of facilities and implementation lead times.[20] In regard to NERC's proposal, the Commission is concerned that footnote 'b' would function as a means to override the reliability objective and system performance requirements of the TPL Reliability

[19] Reliability Standard TPL-002-0a, Requirement R1.

[20] Reliability Standard TPL-002-0a, Requirements R1.5 and R2.

Standard without any technical or other criteria specified to determine when planning to interrupt Firm Demand would be allowable. In this case NERC has provided no technically sound means of determining situations in which planning to interrupt Firm Demand would be allowable, and instead has removed such decision-making to an unspecified stakeholder process without any assurance that such processes will deploy technically sound means of approving or denying exceptions. Without any technical or other criteria specified to determine when planning to interrupt Firm Demand would be allowable, the Commission is concerned that multiple stakeholder processes across the country engaging in such determinations could lead to inconsistent and arbitrary exceptions including, potentially, allowing entities to plan to interrupt any amount of Firm Demand in any location and at any voltage level. While the Commission recognizes that some variation among regions or entities is reasonable given varying grid topography and other legitimate considerations, there are no technical or other criteria to determine whether varied results are arbitrary or based on meaningful distinctions. The Commission is thus concerned that there may be a lack of consistency in determinations to allow the planned interruption of Firm Demand. The proposed stakeholder process does not have any parameters except for openness and transparency. As a result, multiple processes that could be adopted across the country would likely lead to inconsistent determinations to allow for the planned interruption of Firm Demand.

14. The Commission believes that a remand would give NERC and industry flexibility to develop an approach that would address the issues identified by the Commission with

the proposed footnote 'b' stakeholder process including, as discussed below, definition of the process and criteria or guidelines for the process.

A. Lack of Technical or Other Criteria

15. NERC's proposal does not prescribe the criteria that would define the parameters of permissible interruption of Firm Demand. In Order No. 693 the Commission expressed concern that, as a general rule, footnote 'b' should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency and directed NERC to clarify the standard. The Commission stated in the June 2010 Order that a regional difference or a case-specific exception process that could be technically justified would be acceptable. While the Commission allows NERC to propose an equally effective and efficient solution to a Commission's proposed solution, the Commission does not believe that the proposal is equally effective and efficient. First, NERC's proposed footnote 'b' contains no constraints and could allow an entity to plan to interrupt any amount of Firm Demand, in any location or at any voltage level as needed for any single contingency, provided that it is documented and subjected to a stakeholder process. This result is contrary to the underlying standard and our prior orders.[21] Further, NERC did not technically justify its proposal, instead relying on the benefit of having transparency in the process. The Commission does not believe transparency in this instance can substitute for a technical justification.

[21] *See* Order No. 693, *see also* June 2010 Order.

16. In its supplemental filing, NERC states that it is not feasible for the ERO to develop a one-size-fits-all criterion for limiting the planned interruption of Firm Demand due to the wide variety of system configurations and regulatory compacts.[22] NERC states that the standards drafting team believes there is no analytical data to support a single level and therefore any single value was viewed as arbitrary.

17. We are not persuaded by NERC's reasoning. First, both NERC and the Commission have developed thresholds in other reliability contexts that have overcome similar claims of arbitrariness. For example, the threshold for conducting vegetation management pursuant to Reliability Standard FAC-003-1 applies to all transmission lines operated at 200 kV and above.[23] In the same vein, NERC's Statement of Compliance Registry Criteria has numerous thresholds for determining eligibility for registration.[24] The Commission did not suggest a one size fits all exceptions process. If the ERO were to perform an exception process, it might include flexibility in decisions based on disparate topology or on other matters since it could utilize its technical expertise to determine the reliability impact from one region to another. Moreover, the Commission's proposal to remand revised footnote 'b' due to a lack of criteria does not preclude NERC from developing another alternative, provided that it is equally "efficient and effective."

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[22] NERC Data Response at 6.

[23] Reliability Standard FAC-003-1.

[24] *See, e.g.*, NERC Statement of Registry Criteria, Section III. The Commission approved Statement of Registry Criteria in Order No. 693.

18. Finally, the Commission understands that there are a wide variety of system configurations and regulatory compacts. NERC indicates that the standards drafting team considered a variety of limits; however, it is not clear whether NERC considered a blend of quantitative and qualitative thresholds. For example, a standard could require a process with a quantitative limitation on how much Firm Demand could be planned for interruption and that standard could provide an exception process where a registered entity would submit documents and explanation to the ERO or a Regional Entity for approval based upon certain considerations.[25] In short, we believe that a more defined process would be needed but, by itself, would not be adequate without NERC-defined technical or other criteria to determine planned interruption of Firm Demand. The Commission seeks comment on these proposals.

B. Stakeholder Process

19. The Commission believes that NERC's proposed footnote 'b' stakeholder process does not meet Order No. 693 and the June 2010 Order directive. According to NERC, the type of stakeholder process used under its proposed footnote 'b' can vary from one planning entity to the next. NERC offers several stakeholder processes as examples, such as the Order 890-type process, a state public utility commission or local jurisdiction

[25] While we encourage NERC to exercise flexibility in designing an appropriate standard, under this example, the exception process could consist of a stakeholder process that has some level of due process as long as that process does not allow the entity that proposes its exception to make the decision on whether to grant the exception.

process, or a Regional Transmission Organization/Independent System Operator (RTO/ISO) stakeholder process.

20. First, because NERC's proposed footnote 'b' does not define the stakeholder process, the express terms of the standard would allow an applicable entity to form or participate in any stakeholder process and be compliant with the proposed standard. Second, as we have mentioned, NERC has offered no technical justification for exceptions to be granted through the stakeholder process and therefore no means for the Commission to judge whether the process will protect the reliability of the Bulk-Power System. Nothing in the proposed footnote 'b' restricts the stakeholder process, other than that it must be an open and transparent stakeholder process that includes addressing stakeholder comments. The Commission is concerned that any meeting that is open to stakeholders could meet this standard. Further, because the stakeholder process is not defined, the proposal could allow a transmission planner to develop a process that provides insufficient process and transparency and still comply with the standard. The Commission believes that such process would be insufficient because it allows any stakeholder process to essentially become a reliability standards development processes outside of NERC's existing procedures. Furthermore, the Commission believes that regardless of the stakeholder process used, the outcome could lead to inconsistent results, with no technical or other criteria to determine whether varied results are arbitrary or based on meaningful distinctions. The Commission seeks comment on whether a stakeholder process is the appropriate vehicle to approve or deny exceptions to allow

entities to plan to interrupt Firm Demand for a single contingency and if so, whether the proposed footnote ‘b’ would require any stakeholder due process.

21. Nor does the standard describe what would be entailed in addressing the stakeholder comments. As described above, the process under the standard does not provide for any technical rigor to address stakeholder concerns. While the standard requires transparency and an opportunity for stakeholder comments on the transmission planner's proposed plan to interrupt Firm Demand, it does not mandate any particular stakeholder involvement, nor does it mandate that interested governmental authorities be afforded notice and an opportunity to comment. As we read the proposed standard, a responsible entity could define when it would plan to interrupt Firm Demand on its own, then ask for stakeholder input on that plan. While the standard requires the responsible entity to “address” stakeholder comments, the responsible entity is not required to specify or support the technical basis upon which it rendered a decision**.** The Commission believes that the stakeholder process in proposed footnote ‘b’ would allow the transmission planner to define the circumstances when it would rely on planned interruption of Firm Demand, provide that definition for review by regulators and other stakeholders, receive comments from regulators and stakeholders requesting a more narrow definition, and explain to the regulators and stakeholders why it is declining the request and maintaining the broader definition, even if every other transmission planner facing similar circumstances would reach the opposite conclusion.

22. In Order No. 693 and the June 2010 Order, the Commission stated that a regional difference or a case-specific exception process, among other things, would be an

acceptable approach. With regard to a case-specific process, NERC replied it would "create undesirable delays and uncertainty in the transmission planning process."[26] However, the proposed footnote 'b' does not provide a time limitation by which planning decisions to interrupt Firm Demand must be made. The Commission is not persuaded that NERC's proposed approach ameliorates this concern. The Commission seeks comment on whether an exceptions process that provides defined criteria, with some allowance or consideration for unique circumstances, could be crafted that would resolve NERC's concerns of "undesirable delays" and "uncertainty."

23. In sum, the Commission is concerned that the stakeholder process set forth in the NERC proposal is not sufficiently defined, rendering it potentially unenforceable. As mentioned above, the proposed stakeholder process includes no parameters other than openness and transparency. NERC states that it and the Regional Entities will review a responsible entity's decision to plan to interrupt Firm Demand using an after-the-fact audit, to determine if the entity's implementation of footnote 'b' to plan Firm Demand interruption and whether the decision by the entity was vetted through the stakeholder process and qualified as one of the situations identified in footnote 'b.'[27] The Commission believes that this could result in a transmission planner invoking a process that provides for minimal stakeholder involvement, providing scant reasons to reject any stakeholder input and then defending its decision by claiming that it has satisfied the

[26] NERC Data Response at 2.

[27] NERC Data Response at 7-8.

provision. While the Compliance Enforcement Authority would verify that the process fulfilled the letter of NERC's proposed footnote 'b' - that some open, transparent stakeholder process was involved and that the responsible entity in some way addressed stakeholder concerns - there is no mechanism for the ERO or a Regional Entity to enforce a finding that the evidence does not support an acceptable instance of planned interruption of Firm Demand. The Commission seeks comment on the concerns raised above.

C. Commission Proposal

24. The Commission believes that NERC's proposed footnote 'b' does not meet the Commission's Order No. 693 directives, nor is it an equally effective and efficient alternative. On this basis, the Commission proposes to remand the proposal to NERC.

25. The Commission also proposes to provide further guidance on acceptable approaches to footnote 'b'. We seek comment on all of the options below. In addition, while the Commission is proposing certain options for revising footnote 'b', we also seek comment on other potential options to solve the concerns outlined in this NOPR. As noted above, the Commission understands that there are a wide variety of system configurations and regulatory compacts. We believe that a more defined process than that provided in the proposed footnote 'b' would be needed but, by itself, would not be

adequate without NERC-defined technical or other criteria to determine an acceptable planned interruption of Firm Demand at the fringes of the system.[28]

26. We acknowledge that the standards drafting team considered a variety of limits; however, setting some form of criteria within the standard itself for planning to interrupt Firm Demand may be an acceptable approach to setting criteria for footnote 'b' and would be an option for NERC to consider. We also seek comment on whether existing protocols could provide guidance to NERC in devising criteria. For example, the Department of Energy's Electric Emergency Incident and Disturbance Report (Form OE-417) requires, among other things, an entity to report the uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident, load shedding of 100 Megawatts or more implemented under emergency operational policy, and the loss of service for more than 1 hour to 50,000 customers. While these are reporting requirements for the operational timeframe, and may include distribution level load shedding, the Commission requests comments on whether they could also serve as a basis for setting limits on when an entity can plan to interrupt Firm Demand on the Bulk-Power System. Another existing document that could provide guidance on how to set a limit on the planned interruption of Firm Demand is NERC's Statement of Compliance Registry Criteria, which uses, for example, 25 MW as a threshold in determining when a load-serving entity or distribution provider should register with NERC. We seek

[28] Any exceptions process to determine specific requests for planned interruption of Firm Demand may not necessarily be limited to the fringes of the system.

comments on this proposed option, and any other external documents that could be used to guide a revision to footnote 'b.'

27. Second, as stated above, it is not clear whether NERC considered a blend of quantitative and qualitative thresholds. The Commission seeks comments on whether this would be an option for providing criteria that would be generally applicable, but also for allowing for certain cases that may exceed the criteria. For example, a standard could require a process with a quantitative limitation on how much Firm Demand could be planned for interruption and that standard could provide an exception process where a registered entity would submit documents and explanation to the ERO or a Regional Entity for approval based upon certain considerations. NERC has raised concerns about conflicts among federal, provincial, state and local governing bodies that have jurisdiction over various parts of the planning, siting and construction process. The Commission believes that this approach may satisfy the need for technical criteria that we have described, while accounting for NERC's concerns about the difficulty of developing a one-size-fits-all criterion for limiting planned Firm Demand interruptions and the appropriateness and feasibility of managing and actively participating in each planning process. As NERC states, the objective of footnote 'b' should be to minimize the likelihood and magnitude of planned Firm Demand interruptions. The Commission believes that setting generally applicable criteria for when an applicable entity can plan to shed Firm Demand, coupled with an exceptions process overseen by NERC and the Regional Entities, could mean that few exception requests must be processed by NERC and the Regional Entities. We seek comment on this option, and which entities should be

involved in the review and subsequent determination as to whether an exception should be allowed.

28. NERC has raised concerns about conflicts among federal, provincial, state and local governing bodies that have jurisdiction over various parts of the planning, siting and construction process. There also may be concerns about the costs of planning to avoid Firm Demand shedding. The Commission seeks comment on whether a feasible option would be to revise footnote 'b' to allow for the planned interruption of Firm Demand in circumstances where the transmission planner can show that it has customer or community consent and there is no adverse impact to the Bulk-Power System. This presumably would not require affirmative consent by every individual retail customer, but we recognize that either term, customer or community, would need to be adequately defined. The Commission therefore seeks comments on who might be able to represent the customer or community in this option and how customer or community consent might be demonstrated. Additionally, we seek comment on how it would be determined that firm demand shedding with customer consent would not adversely impact the Bulk-Power System. However, we also seek comment on whether a customer who would otherwise consent to having its planning authority or transmission planner plan to interrupt Firm Demand pursuant to this option could instead select interruptible or conditional firm service under the tariff to address cost concerns.

29. Finally, regardless of how NERC revises footnote 'b' to resolve the concerns outlined in this NOPR and in previous orders, the Commission notes that NERC will need to support the revision to footnote 'b.' If there is a threshold component to the

revised footnote, the Commission believes that NERC would need to support the threshold and show that instability, uncontrolled separation, or cascading failures of the system will not occur as a result of planning to shed Firm Demand up to the threshold. In addition, if there is an individual exception option, the Commission believes that the applicable entities should be required to find that there is no adverse impact to the Bulk-Power System from the exception and that it is considered in wide-area coordination and operations. Further, we believe that any exception should be subject to further review by the Regional Entity, NERC, and the Commission. This does not necessarily mean that the Regional Entity, NERC, or the Commission should have to approve the exception, but that any of the three could later audit its implementation.

30. In conclusion, while the Commission provides three options for revising footnote 'b' in this Notice of Proposed Rulemaking, we seek comments on the feasibility of the options and on ways in which the options might be improved. In addition, we seek comment on whether there are other ways for NERC to solve the concerns outlined above in an equally effective and efficient manner.

III. Information Collection Statement

31. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping (collections of information) imposed by an

agency.[29] The information contained here is also subject to review under section 3507(d) of the Paperwork Reduction Act of 1995.[30]

32. As stated above, the subject of this NOPR is NERC's proposed modification to Table 1, footnote 'b' applicable in four TPL Reliability Standards. This NOPR proposes to remand the footnote 'b' modification to NERC. By remanding footnote 'b' the applicable Reliability Standards and any information collection requirements are unchanged. Therefore, the Commission will submit this NOPR to OMB for informational purposes only.

33. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, e-mail: data.clearance@ferc.gov, phone: (202) 502-8663, or fax: (202) 273-0873].

IV. Regulatory Flexibility Act

34. The Regulatory Flexibility Act of 1980 (RFA)[31] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a proposed rule and that minimize any significant economic impact on a substantial number of small entities. The Small Business

[29] 5 CFR § 1320.11.

[30] 44 U.S.C. § 3507(d).

[31] 5 U.S.C. § 601-612.

Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[32] The SBA has established a size standard for electric utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million megawatt hours.[33] The RFA is not implicated by this NOPR because the Commission is remanding footnote' b' and not proposing any modifications to the existing burden or reporting requirements. With no changes to the Reliability Standards as approved, the Commission certifies that this NOPR will not have a significant economic impact on a substantial number of small entities.

V. Comment Procedures

35. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due 60 days from publication in the FEDERAL REGISTER. Comments must refer to Docket No. RM11-18-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

36. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at http://www.ferc.gov. The Commission accepts

[32] 13 CFR § 121.201.

[33] *Id.* n.22.

most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

37. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

38. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VI. Document Availability

39. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (http://www.ferc.gov) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington DC 20426.

40. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary,

type the docket number excluding the last three digits of this document in the docket number field.

41. User assistance is available for eLibrary and the FERC's website during normal business hours from FERC Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

By direction of the Commission. Commissioner Spitzer is not participating.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426
OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RR10-12-001

August 25, 2011

North American Electric Reliability Corporation
1120 G Street N.W., Suite 990
Washington, D.C. 20005-3801

Attention: Holly A. Hawkins, Attorney

Reference: Standard Processes Manual Compliance Filing

Dear Ms. Hawkins,

1. On December 1, 2010, the North American Electric Reliability Corporation (NERC) submitted, pursuant to section 215(f) of the Federal Power Act and section 39.10 of the Commission's regulations,[1] a request to approve a modification to NERC's Standard Processes Manual (Manual) in compliance with the Commission's September 2010 Order.[2]

2. In accordance with the September 2010 Order,[3] NERC seeks a modification to the section of its Manual that identifies the elements of a Reliability Standard by, among other things, replacing the heading "Mandatory and Enforceable Sections of a Standard" with a new heading, "Requirements and Elements Necessary to Demonstrate Compliance and Monitor and Assess Compliance with Requirements." On May 17, 2011, NERC made a supplemental filing in which it stated "the use of the word 'necessary' in the revised heading is intended to indicate that standards developed under the process described in the [Manual] must conform to a template that includes all of the elements under this

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[1] 18 C.F.R. § 39.10 (2011).

[2] *North American Electric Reliability Corporation*, 132 FERC ¶ 61,200 (2010) (September 2010 Order).

[3] *Id.* at P 11.

heading. The use of the word 'necessary' is not intended to have any connotation relative to enforcement."[4]

3. Notice of the December 1, 2010 filing was issued on January 6, 2011, with protests or motions to intervene due on or before January 24, 2011. Notice of the May 17, 2011 filing was issued on May 18, 2011, with protests or motions to intervene due on or before May 31, 2011.

4. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2011), notices of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding. No interventions or protests were filed.

5. NERC's proposed changes to its Manual presented in its uncontested filing, as clarified by its May 17, 2011 supplemental filing, are approved pursuant to the authority delegated to the Director, Office of Electric Reliability, under 18 C.F.R. § 375.303 (2011).

6. This action shall not be construed as approving any other application including Electric Reliability Organization or Regional Entity rules or procedures pursuant to 18 C.F.R. § 375.303(a)(2)(i). This action shall not be construed as approving any contingency plan pursuant to 18 C.F.R. § 375.303(a)(1)(i) or any other data or report pursuant to 18 C.F.R. § 375.303(b)(3)(iv). Such approval shall not be deemed as recognition of any claimed right or obligation associated therewith; and such approval is without prejudice to any findings or orders which have been or which may hereafter be made by the Commission in any proceeding now or pending or hereafter instituted by or against NERC.

7. This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.R.R. § 385.713 (2011).

Sincerely,

Joseph H. McClelland, Director
Office of Electric Reliability

[4] NERC May 17, 2011 filing, Docket No. RR10-12-001 at 2.

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136 FERC ¶ 61,177
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Marc Spitzer, Philip D. Moeller,
John R. Norris, and Cheryl A. LaFleur.

North American Electric Reliability Corporation Docket No. RD11-7-000

ORDER APPROVING RELIABILITY STANDARD

(Issued September 15, 2011)

1. On April 19, 2011, the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), submitted a petition for Commission approval of Personnel Performance, Training and Qualification (PER) Reliability Standard PER-003-1 (Operating Personnel Credentials). This Reliability Standard requires reliability coordinators, transmission operators, and balancing authorities to ensure that system operators performing reliability-related tasks are certified through the NERC System Operator Certification Program when filling a real-time operating position responsible for control of the Bulk Electric System (BES). NERC also requests that the Commission approve the retirement of currently effective Reliability Standard PER-003-0 concurrent with the effective date of the proposed Reliability Standard PER-003-1.

2. In this order, the Commission finds proposed Reliability Standard PER-003-1 to be just, reasonable, not unduly discriminatory or preferential, and in the public interest. Therefore, the Commission approves Reliability Standard PER-003-1 with an effective date, i.e., the date on which applicable entities are subject to mandatory compliance with the Reliability Standard, of the first calendar day of the first calendar quarter twelve months after the date of Commission approval. The Commission also approves NERC's proposed assignment of associated Violation Risk Factors and Violation Severity Levels and the retirement of currently-effective Reliability Standard PER-003-0 on the effective date of PER-003-1.

I. Background

3. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, which are subject to Commission

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review and approval. Once approved, the Reliability Standards may be enforced by the ERO, subject to Commission oversight, or by the Commission independently.[1]

4. Pursuant to section 215 of the FPA, the Commission established a process to select and certify an ERO[2] and, subsequently, certified NERC as the ERO.[3]

5. On March 16, 2007, the Commission issued Order No. 693 approving 83 Reliability Standards proposed by NERC, including Reliability Standard PER-003-0 (Operating Personnel Credentials).[4] Reliability Standard PER-003-0 contains a single Requirement, Requirement R1, which provides:

> [e]ach Transmission Operator, Balancing Authority, and Reliability Coordinator shall staff all operating positions that meet both of the following criteria with personnel that are NERC-certified for the applicable functions: R1.1 Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System. R1.2 Positions directly responsible for complying with NERC standards.

6. In Order No. 693, the Commission also directed the ERO to modify Reliability Standard PER-003-0 to: (i) specify the minimum competencies that a system operator must demonstrate to become and remain a certified system operator; and (ii) identify the minimum competencies operating personnel must demonstrate to be certified.[5] In addition, the Commission, noting that there are some long tenured unionized transmission

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[1] *See* 16 U.S.C. § 824o(e).

[2] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[3] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g & compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom., Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[4] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[5] *Id*. P 1408-1409.

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operators who are very capable operators but who may be unable to secure certification, directed the ERO to consider grandfathering certification requirements for such transmission operator personnel.[6]

II. NERC Petition

7. In its April 29, 2011 petition,[7] NERC requests Commission approval of proposed Reliability Standard PER-003-1, and concurrent retirement of currently-effective Reliability Standard PER-003-0. NERC states that Reliability Standard PER-003-1 ensures that all real-time operators responsible for reliability-related tasks are proficient to perform their role under normal and emergency conditions, and that non-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator.[8]

8. The stated purpose of Reliability Standard PER-003-1 is to ensure that system operators performing reliability-related tasks of the Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a real-time operating position responsible for control of the Bulk Electric System. Proposed Reliability Standard PER-003-1 contains three main Requirements.

9. Requirement R1 requires each reliability coordinator to staff its real-time operating positions performing reliability coordinator reliability-related tasks with system operators who have demonstrated minimum competency in the "areas of competency" listed in the Sub-requirement, by obtaining and maintaining a valid NERC Reliability Operator certificate. Requirements R2 and R3 are identical except that they apply, respectively, to transmission operators and balancing authorities. Each of the three Requirements includes a Sub-requirement that lists the "areas of competency" that related to performing reliability coordinator reliability-related tasks, transmission operator reliability-related tasks, or balancing authority reliability-related tasks. Reliability Standard PER-003-1 further requires that non-NERC certified personnel performing a reliability-related task of an operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position who maintains the

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[6] *Id*. P 1407 and 1409.

[7] *North American Electric Reliability Corp*., April 29, 2011 Petition for Approval of a Personnel Performance, Training, and Qualifications Reliability Standard (NERC Petition).

[8] *Id*. at 10.

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ultimate responsibility for the performance of the reliability-related tasks. NERC states that this explains the responsibilities of NERC Certified System Operators when non-NERC certified "trainee" personnel are performing any reliability-related task, and removes ambiguities in the existing standard PER-003-0.[9]

10. NERC states that proposed Reliability Standard PER-003-1 improves upon currently effective Reliability Standard PER-003-0 and addresses the Commission's directives in Order No. 693.[10] NERC states that Reliability Standard PER-003-1 improves reliability by requiring system operators who are filling a real-time operating position for a reliability coordinator, balancing authority or transmission operator to be NERC certified through the NERC System Operator Certification Program and by requiring demonstration of minimum competencies in certain areas dependent upon the position being filled. NERC explains that its System Operator Certification Program provides the framework for the examinations used to obtain initial certification in one of four NERC credentials: transmission operator; balancing and interchange operator; balancing, interchange and transmission operator; and reliability operator. The System Operator Certification Program awards certification credentials to those individuals who demonstrate that they have attained sufficient knowledge relating to NERC Reliability Standards as well as the basic principles of Bulk-Power System operations. The certification must be maintained by accumulating a specified number of continuing education hours within a specified period of time. Last, NERC states that PER-003-1 satisfies the factors set forth in Order No. 672, which the Commission uses to determine whether a Reliability Standard is just, reasonable, not unduly discriminatory or preferential and in the public interest.[11]

11. NERC also requests Commission approval of an effective date for Reliability Standard PER-003-1 that is the first day of the first calendar quarter twelve months after the date of Commission approval. The effective date is the date upon which the new Reliability Standard becomes mandatory and enforceable. NERC also seeks Commission approval of the retirement of currently effective Reliability Standard PER-003-0 on the effective date of PER-003-1.

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[9] *Id*. at 21.

[10] *Id*.

[11] *Id*. at 12-33. *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

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12. With respect to the Order No. 693 directive that NERC consider "grandfathering" certain transmission operator personnel, NERC states that the standard drafting team extensively considered the issue and decided against allowing grandfathering.[12] NERC states that the major factors for not allowing grandfathering were as follows. First, the standards drafting team (SDT) concluded that passing a certification examination is NERC's only available method to verify the minimum knowledge level of a System Operator. Second, the SDT found no convincing evidence that experienced system operators would not be able to pass a certification exam. Third, the SDT did not find that employers may face a labor relations issue if part of its workforce were required to hold a NERC System Operator Certification. Last, in response to the concern about smaller entities being able to retain personnel once they obtain a NERC System Operator Certification, which may make such system operators more "marketable," the SDT found that the importance of verifying a system operator's competency through the certification process is more important than possible personnel retention concerns.

13. Finally, NERC states that proposed Reliability Standard PER-003-1 includes clear and understandable consequences for a violation by assigning a violation risk factor (VRF) and violation severity level (VSL) to each primary requirement. Specifically, NERC has assigned a VRF of "High" and a VSL of "Severe" to each main Requirement.

III. Notice of Filing, Interventions and Comments

14. On July 5, 2011, notice of NERC's Filing was published in the *Federal Register* with interventions and protests due on or before July 18, 2011.[13] A motion to intervene was timely filed by American Municipal Power, Inc. (AMP). Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure,[14] the timely, unopposed motion to intervene serves to make AMP a party to this proceeding.

IV. Commission Determination

15. The Commission finds Reliability Standard PER-003-1 to be just, reasonable, not unduly discriminatory or preferential and in the public interest.[15] By specifying the minimum competencies which must be demonstrated to obtain and maintain a NERC System Operator Certification, PER-003-1 improves the currently-effective Reliability Standard PER-003-0, and addresses the relevant directive in Order No. 693.

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[12] NERC Petition at 7.

[13] 76 Fed. Reg. 39,081-39,082 (July 5, 2011).

[14] 18 C.F.R. § 385.214 (2011).

[15] 16 U.S.C. § 824(d)(2).

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16. The Commission also finds that the comprehensive discussion of "grandfathering" in NERC's petition demonstrates that the standard drafting team met the Commission's second directive to consider that issue.

17. Accordingly, the Commission approves Reliability Standard PER-003-1 and the proposed implementation plan. Specifically, the "effective date" for mandatory compliance with Reliability Standard PER-003-1 will be the first day of the first calendar quarter twelve months after the date of Commission approval. In addition the Commission approves the retirement of currently-effective Reliability Standard PER-003-0 concurrent with the effective date of Reliability Standard PER-003-1.

V. Violation Risk Factors/Violation Severity Levels

18. To determine a base penalty amount for a violation of a Reliability Standard Requirement, NERC must first determine an initial range for the base penalty amount. To do so, NERC assigns a VRF to each Requirement of a Reliability Standard that relates to the expected or potential impact of a violation of the Requirement on the reliability of the Bulk-Power System. The Commission has established guidelines for evaluating the validity of each VRF assignment.[16]

19. NERC also assigns each Requirement one of VSLs – low, moderate, high, and severe – as measurements for the degree to which the Requirement was violated in a specific circumstance. On June 19, 2008, the Commission issued an order establishing four guidelines for the development of VSLs.[17]

20. On May 19, 2011, the Commission accepted a revised approach to assigning VRFs and VSLs proposed by NERC to address potential confusion relating to the assignment of VRFs and VSLs to both a main requirement and associated components.[18] Under the new approach, each main Requirement will have a single VRF that will, if necessary, consider the main requirement and components in their entirety to the extent that the components contribute to the specific reliability outcome of the main requirement.[19]

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[16] *See North American Electric Reliability Corp.*, 119 FERC ¶ 61,145, *order on reh'g*, 120 FERC ¶ 61,145, at P 8-13 (2007).

[17] *North American Electric Reliability Corp.*, 123 FERC ¶ 61,284, at P 20-35, *order on reh'g & compliance*, 125 FERC ¶ 61,212 (2008).

[18] *North American Electric Reliability Corp.*, 135 FERC ¶ 61,166 (2011).

[19] *Id.* P 12.

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VSLs will be assigned similarly based on an analysis of the performance required to satisfy a particular requirement.[20]

21. With respect to Reliability Standard PER-003-1, NERC has assigned a VRF of "High" and a VSL of "Severe" to each main Requirement.[21]

22. The Commission finds the proposed VRF and VSL assignments are consistent with Commission guidelines. Therefore, the Commission approves the VRFs and VSLs assigned to the three main Requirements in Reliability Standard PER-003-1.

VI. Information Collection Statement

23. The Office of Management and Budget (OMB) regulations require approval of certain information collection requirements imposed by agency action.[22] The information contained here is also subject to review under section 3507(d) of the Paperwork Reduction Act of 1995.[23]

24. As stated above, Reliability Standard PER-003-1 clarifies which NERC certification(s) are applicable to each class of affected entities and identifies evidence required to show compliance. Currently effective Reliability Standard PER-003-0 currently requires each applicable entity to staff all operating positions that either have primary responsibility for the real-time operation of the Bulk Electric System or are directly responsible for complying with NERC standards with NERC-certified personnel. Therefore, the clarification provided in Reliability Standard PER-003-1 concerning the specific NERC certifications required will not impose a new burden on the affected entities. In addition, currently effective Reliability Standard PER-003-0 generally identifies the evidence that will be used to monitor compliance. The evidence identified in Reliability Standard PER-003-1 reflects the evidence that an affected entity would maintain for audit purposes under usual and customary industry practices. Specifically, it is usual and customary for affected entities to create, maintain and store the same or equivalent information identified in Reliability Standard PER-003-1 for the purposes of exhibiting compliance with Reliability Standard PER-003-0. For example, a list of real-

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[20] *Id.* P 13.

[21] Requirements R1, R2, and R3 of proposed Reliability Standard PER-003-1 are binary requirements written in a pass/fail format. Binary requirements are assigned a "severe" VSL designation.

[22] 5 CFR § 1320.11.

[23] 44 U.S.C. § 3507(d).

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time operating positions and a list of System Operators assigned to those positions, information which is now specifically identified as necessary evidence of compliance in Reliability Standard PER-003-1, are necessary to conduct the analysis called for in Reliability Standard PER-003-0 to show compliance on a triennial basis. Finally, it is usual and customary for affected entities to maintain evidence of compliance for the full period in between audits, typically approximately every three years, in order to exhibit compliance with the Reliability Standards for the full audit period. Thus, this order does not impose new burdens on the affected entities.[24] The order relates to modification to an existing Reliability Standard, and the Commission does not expect it to affect entities' current reporting burden. Accordingly, we will submit this order to OMB for informational purposes only.

The Commission Orders:

(A) Reliability Standard PER-003-1, submitted by the North American Electric Reliability Corporation, is approved, as discussed in the body of this order.

(B) Reliability Standard PER-003-0 shall be retired upon the effective date of Reliability Standard PER-003-1, as discussed in the body of this order.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

[24] 5 C.F.R. § 1320.3(b)(2)

Document Content(s)

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137 FERC ¶ 61,043
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
and Cheryl A. LaFleur.

North American Electric Reliability Corporation Docket No. RD11-8-000

ORDER APPROVING REGIONAL RELIABILITY STANDARD

(Issued October 20, 2011)

1. On May 31, 2011, the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), submitted a petition for Commission approval of the Northeast Power Coordinating Council's (NPCC) Protection and Control (PRC) regional Reliability Standard PRC-002-NPCC-01 (Disturbance Monitoring) and two associated new definitions. The regional Reliability Standard requires transmission owners and generator owners to provide recording capability necessary to monitor the response of the Bulk-Power System to system disturbances, including scheduled and unscheduled outages; requires each reliability coordinator to establish requirements for its area's dynamic disturbance recording needs; and establishes disturbance data reporting requirements.

2. In this order, we approve regional Reliability Standard PRC-002-NPCC-01, finding that it is just, reasonable, not unduly discriminatory or preferential, and in the public interest. Also, we approve NERC's requested implementation plan which provides staggered effective dates, i.e., the date on which applicable entities are subject to mandatory compliance, with full compliance required within four years of regulatory approval.

I. Background

3. Section 215 of the Federal Power Act (FPA) requires the ERO to develop mandatory and enforceable Reliability Standards, which provide for the reliable operation of the Bulk-Power System, subject to Commission review and approval.[1] Section 215(d)(2) of the FPA states that the Commission may approve, by rule or order, a proposed Reliability Standard or modification to a Reliability Standard if it determines that the Reliability Standard is just, reasonable, not unduly discriminatory or preferential,

[1] 16 U.S.C. § 824o(d) (2006).

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and in the public interest. Once approved, the Reliability Standard may be enforced by the ERO, subject to Commission oversight, or by the Commission independently.[2]

4. Reliability Standards that the ERO proposes to the Commission may include Reliability Standards that are developed by a Regional Entity.[3] On April 19, 2007, the Commission approved delegation agreements between NERC and eight Regional Entities, including NPCC.[4] In the Delegation Agreement Order, the Commission accepted NPCC as a Regional Entity and accepted NPCC's Standards Development Manual, which sets forth the process for NPCC's development of regional Reliability Standards.[5] The NPCC region is a less than interconnection-wide region, and its standards apply only to that part of the Eastern Interconnection within the NPCC geographical footprint.

5. In Order No. 672, the Commission urged uniformity of Reliability Standards, but recognized a potential need for regional differences.[6] Accordingly, the Commission stated that:

> As a general matter, we will accept the following two types of regional differences, provided they are otherwise just, reasonable, not unduly discriminatory or preferential and in the public interest, as required under the statute: (1) a regional difference that is more stringent than the continent-wide Reliability Standard, including a regional difference that addresses matters that the continent-wide Reliability Standard does not; and (2) a regional Reliability Standard that is necessitated by a physical difference in the Bulk-Power System.[7]

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[2] *See* 16 U.S.C. § 824o(e).

[3] *Id.* § 824o(e)(4).

[4] *See North American Electric Reliability Corp.*, 119 FERC ¶ 61,060, at P 316-350 (Delegation Agreement Order), *order on reh'g*, 120 FERC ¶ 61,260 (2007).

[5] *Id.* P 302.

[6] *Rules Concerning Certification of the Electric Reliability Organization; Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 290, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[7] Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 291.

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6. On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 Reliability Standards filed by the ERO.[8] In that order, the Commission determined that it would not take action on certain proposed Reliability Standards that required supplemental information from regional reliability organizations. Such Reliability Standards refer to regional criteria or procedures that had not been submitted to the Commission for approval and, as such, are referred to as "fill-in-the-blank" standards. Pending Reliability Standard PRC-002-1 (Define Regional Disturbance Monitoring and Reporting) is one such fill-in-the-blank standard and, therefore, is not enforceable. NERC's continent-wide, fill-in-the-blank standard PRC-002-1 would require regional reliability organizations to establish: (i) installation requirements for sequence of event recording, fault recording, and dynamic disturbance recording, and (ii) reporting requirements for recorded disturbance data. Because PRC-002-1 is an unenforceable and unapproved fill-in-the-blank standard, NPCC's proposed regional Reliability Standard PRC-002-NPCC-01 is intended to fill the reliability gap related to disturbance monitoring and reporting by establishing enforceable disturbance monitoring and reporting requirements for the NPCC region.

II. NERC Petition and Notice of Filing

7. In its May 31, 2011 petition,[9] NERC requests Commission approval of proposed regional Reliability Standard PRC-002-NPCC-01 (Disturbance Monitoring) and two associated new definitions. NERC states that PRC-002-NPCC-01 is intended to ensure that adequate disturbance data is available to facilitate bulk electric system event analyses and thereby improve system reliability by promoting improved system design and operations.

8. The standard is applicable to transmission owners, generator owners, and reliability coordinators and contains 17 requirements that identify the proper locations for sequence of events recorders, fault recorders, and dynamic disturbance recorders within the NPCC region and specify the data to be captured and reported by this equipment.

9. Sequence of events recorders capture the sequences of events for monitored changes of state in equipment and protection systems occurring in substations, switchyards, or power plants. Requirement R1 requires that each transmission owner and

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[8] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[9] *North American Electric Reliability Corp.*, May 31, 2011 Petition for Approval of Proposed NPCC Regional Reliability Standard PRC-002-NPCC-01 — Disturbance Monitoring (NERC Petition).

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generator owner provide sequence of events recording capability at specified locations either through installation of sequence of events recorders or as part of another device such as a remote terminal unit or a generator plant digital (or distributed) control system.

10. Fault recorders capture and store power system waveforms that can be used to analyze transients and abnormalities in system frequency. Requirement R2 requires each transmission owner to provide fault recording capability for specified elements of the Bulk-Power System, and Requirement R3 requires that each transmission owner have fault recording capability that determines the "Current Zero Time" for loss of bulk electric system transmission elements. "Current Zero Time" is a new defined term used in PRC-002-NPCC-01 to mean the precise time of circuit interruption. It is defined as "the time of the final current zero on the last phase to interrupt."

11. Requirement R4 requires each generator owner to provide fault recording capability for "Generating Plants" at and above 200 MVA and connected through a generator step-up transformer to a bulk electric system element, unless such recording capability is provided by the transmission owner. "Generating Plants" is a new term defined as "one or more generators at a single physical location whereby a single contingency can affect all the generators at that location." The term appears in this Requirement and in Requirement R1's description of where sequence of event recording capability is to be located. It is used to clarify that, for the sake of efficiency, one sequence of event recorder or a single fault recorder may be used where it will capture all the information from a single contingency affecting all the generators at a single location, and multiple recorders would be redundant.

12. Because certain data are necessary for post-event analysis, Requirement R5 requires each transmission owner and generator owner to record for faults sufficient electrical quantities for each monitored bulk electric system element to determine: (i) three phase-to-neutral voltages; (ii) three phase currents and neutral currents; (iii) polarizing currents and voltages, if used; (iv) frequency; and (v) real and reactive power. Requirement R6 sets out the recording specifications required of the fault recording equipment in order to ensure the monitored data is captured in sufficient detail for it to be meaningfully used in analyses.

13. Dynamic disturbance recorders monitor power system conditions when the system experiences dynamic events such as low frequency oscillations, or frequency or voltage excursions. Requirement R7 requires each reliability coordinator to establish dynamic disturbance recording needs for its area in accordance with specified recording requirements, and Requirement R8 requires that dynamic disturbance recorders function continuously. To capture system disturbance data with sufficient detail for use in post-event analyses, Requirement R9 specifies the minimal recording duration, sample rate and trigger events for dynamic disturbance recorders. Requirement R10 requires each reliability coordinator to establish requirements to ensure that certain specified data are monitored or derived where dynamic disturbance recorders are installed.

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14. Requirement R11 requires each reliability coordinator to document additional settings and deviations from the required trigger settings described in Requirement R9 and the required list of monitored quantities described in Requirement R10 and to report these settings and deviations to the Regional Entity upon request. Requirement R12 requires each reliability coordinator to specify its dynamic disturbance recording requirements, including trigger settings, to transmission owners and generator owners.

15. Each transmission owner and generator owner that receives a request from its reliability coordinator to install a dynamic disturbance recorder is required, under Requirement R13, to acquire and install the recorder in accordance with an implementation schedule agreed to with the reliability coordinator. They also are required by Requirement R14 to establish a maintenance and testing program for their stand alone disturbance monitoring equipment (i.e., equipment whose only purpose is disturbance monitoring). The Requirement lists elements of such a program.

16. Requirement R15 requires that each reliability coordinator, transmission owner, and generator owner share data within 30 days upon request, and each generator owner must provide recorded disturbance data from disturbance monitoring equipment within 30 days of receipt of a request for information from NERC, the Regional Entity, the reliability coordinator, or transmission or generator owners within NPCC. Requirement R16 specifies the format requirements for data files. Requirement R17 requires each reliability coordinator, transmission owner and generator owner to maintain, record and provide to the Regional Entity, upon request, specified data regarding the disturbance monitoring equipment installed to meet regional Reliability Standard PRC-002-NPCC-01.

17. Notice of NERC's filing was published in the *Federal Register*, 76 Fed. Reg. 40,350 (2011), with interventions and protests due on or before August 1, 2011. No motion to intervene or protest was received.

III. <u>Discussion</u>

18. The Commission approves regional Reliability Standard PRC-002-NPCC-01 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. To that end, the Commission finds that PRC-002-NPCC-01 satisfies the Order No. 672 factors on how the Commission determines whether a regional Reliability Standard is just and reasonable in that PRC-002-NPCC-01: (1) is clear and unambiguous regarding what is required and who is required to comply (transmission owners, generator owners, and reliability coordinators within the NPCC region); (2) has clear and objective measures for compliance and achieves a reliability goal (namely, ensuring that adequate disturbance data is available to facilitate bulk electric system event analyses); and (3) is "more stringent" than NERC's existing unapproved and unenforceable continent-wide disturbance monitoring and reporting standard, PRC-002-1.

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19. Regional Reliability Standard PRC-002-NPCC-01 includes two new defined terms that apply only to the NPCC region: "Current Zero Time" and "Generating Plant." The two proposed regional terms do not conflict with any existing terms in the NERC Glossary of Terms. Accordingly, the Commission approves the inclusion of the two regional terms related to PRC-002-NPCC-01 in the NERC Glossary specifically as NPCC regional terms.

20. The Commission finds that the NERC's violation risk factors and violation severity levels for regional Reliability Standard PRC-002-NPCC-01 are consistent with the Commission's established guidelines.[10] We therefore approve the assigned violation risk factors and violation severity levels.

21. As requested by NERC, the Commission approves the implementation plan for regional Reliability Standard PRC-002-NPCC-01.

IV. Information Collection Statement

22. The Office of Management and Budget (OMB) regulations require approval of certain information collection requirements imposed by agency actions.[11] Upon approval of a collection of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirement of this order will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number. The Paperwork Reduction Act (PRA)[12] requires each federal agency to seek and obtain OMB approval before undertaking a collection of information directed to ten or more persons, or continuing a collection for which OMB approval and validity of the control number are about to expire.[13]

23. The Commission will submit these reporting and recordkeeping requirements to OMB for its review and approval under section 3507(d) of the PRA.[14] Comments are

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[10] *See North American Electric Reliability Corp.*, 119 FERC ¶ 61,145, *order on reh'g*, 120 FERC ¶ 61,145, at P 8-13 (2007); *North American Electric Reliability Corp.*, 123 FERC ¶ 61,284, at P 20-35, *order on reh'g & compliance*, 125 FERC ¶ 61,212 (2008); *North American Electric Reliability Corp.*, 135 FERC ¶ 61,166 (2011).

[11] 5 C.F.R. § 1320.10.

[12] 44 U.S.C . § 3501-20.

[13] 44 U.S.C. 3502(3)(A)(i), 44 U.S.C. § 3507(a)(3).

[14] 44 U.S.C. 3507(d).

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solicited within sixty days of the date this order is published in the *Federal Register* on the Commission's need for this information, whether the information will have practical utility, the accuracy of provided burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques. Comments should be submitted following the Commission's submission guidelines at http://www.ferc.gov/help/submission-guide.asp and should reference Docket No. RD11-8-000.

24. This Order approves regional Reliability Standard PRC-002-NPCC-01 (Disturbance Monitoring) which introduces new mandatory and enforceable requirements for the applicable entities. It generally identifies the evidence that will be used to monitor compliance. NPCC presently has criteria addressing monitoring equipment and published guidance addressing maintenance and testing of such equipment. The Disturbance Monitoring Equipment Criteria[15] seek the same or equivalent information identified in Reliability Standard PRC-002-NPCC-01, and NPCC's guidance establishes maintenance and testing expectations similar to those imposed by the regional Reliability Standard.[16] Thus, it is currently usual and customary for affected entities within NPCC to create, maintain and store some of the same or equivalent information identified in Reliability Standard PRC-002-NPCC-01. Therefore, many of the requirements contained in PRC-002-NPCC-01 do not impose new burdens on the affected entities.[17]

25. Several requirements contained in regional Reliability Standard PRC-002-NPCC-01 do introduce entirely new responsibilities for the applicable entities. Each such requirement is discussed below. Requirement R13 requires that each transmission owner and generator owner retain evidence that it acquired and installed dynamic disturbance recorders in accordance with the specifications requested by the reliability coordinator, and that the generator owner, transmission owner, and reliability coordinator retain evidence that they agreed on an implementation schedule. Requirement R14 requires that each transmission owner and generator owner establish a maintenance and testing program for stand-alone disturbance monitoring equipment. Sub-requirements 14.5 specifies that the program must require active analog quantities to be verified monthly, and Sub-requirement 14.7 requires that if failed units cannot be returned to service within

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[15] Disturbance Monitoring Equipment Criteria (Aug. 2007), *available at* https://www.npcc.org/Standards/Criteria/A-15.pdf (Disturbance Monitoring Criteria).

[16] Guide for Application of Disturbance Recording Equipment (Sept. 2006), *available at* https:/www.npcc.org/Standards/Guides/B-26.pdf (Application Guide).

[17] 5 C.F.R. § 1320.3(b)(2) (2011).

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90 days, the owner must record its efforts to restore the equipment to service. These components of the program have not been included in NPCC's current Disturbance Monitoring Criteria or Application Guide. Requirement R17 requires each reliability coordinator, transmission owner, and generator owner to maintain and record specific data on installed disturbance monitoring equipment, and submit the data to the Regional Entity upon request. Under the Disturbance Monitoring Criteria, the reliability coordinator was not obligated to maintain these records or provide the records to the Regional Entity.

26. Public Reporting Burden: The estimate below regarding the number of respondents is based on the NERC compliance registry as of August 29, 2011. According to the NERC compliance registry, there are 35 transmission owners, 136 generation owners, and five reliability coordinators in the NPCC region. However, under NERC's compliance registration program, entities may be registered for multiple functions, so these numbers incorporate some double counting. The net number of entities responding will be approximately 167 entities registered as a transmission owner, generation owner, or reliability coordinator. This includes eight entities registered as both a generation owner and transmission owner, as well as one entity registered as both a transmission owner and a reliability coordinator.

27. We estimate that annually, approximately one entity within NPCC will have to procure dynamic disturbance recording capability. Based on Commission staff outreach and analysis, we estimate the total acquisition and installation cost will range between $150,000 and $750,000. We also estimate that an entity will experience a unit failure greater than 90 days once every five years. Therefore, 20 percent of NPCC's 163 generator owners and transmission owners will experience a unit failure of this duration each year. The estimated burden for the requirements in this Order follow:

PRC-002-NPCC-01	**Number of Respondents Annually (1)**	**Number of Responses Per Respondent (2)**	**Average Burden Hours Per Response (3)**	**Total Annual Hours (1x2x3)**

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R13: GO[18] and TO to document acquisition and installation of dynamic disturbance recorders. GO, TO, and RC to develop and employ implementation schedule	1	1	*Record Retention*	10	10
R14.5: GO and TO maintenance and testing program for stand-alone disturbance monitoring equipment includes monthly verification of active analog quantities	163	12	*Record Retention*	5	9,780
R14.7: GO and TO requirement to return failed units to service in 90 days. Record kept of efforts if greater than 90 days	33	1	*Reporting (assessment and dist. of records)*	10	330
			Record Retention	10	330
R17: RC maintains data on equipment, and provide to RE upon request	5	1	*Reporting (assessment and dist. of data)*	5	25
			Record Retention	10	50
Total			***Reporting (assessment and dist)***		**355**
			Record Retention		**10,170**

[18] For purposes of this chart, generation owner is abbreviated to GO, transmission owner is abbreviated to TO, and reliability coordinator is abbreviated to RC.

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Information Collection Costs: The Commission seeks comments on the costs to comply with these requirements and recordkeeping burden associated with regional Reliability Standard PRC-002-NPCC-01.

- Total Annual Hours for Collection: (Reporting and Record Retention) = 10,525 hours.
- Total Estimated Annual Record Retention Cost[19] = 10,170 hours @ $28/hour = $ 284,360
- Total Estimated Annual Reporting Cost = 355 hours @ $120/hour = $ 42,600
- Total Estimated Annual Compliance Cost (acquisition and installation of dynamic disturbance recorders) = $750,000
- Total Estimated Annual Cost = $1,077,640
- Title: NPCC Regional Reliability Standards
- Action: Proposed Collection FERC-725I.
- OMB Control No: To be determined.
- Respondents: Business or other for profit, and/or not for profit institutions.
- Frequency of Responses: On occasion.
- Necessity of the Information: This proposed rule would approve a new regional Reliability Standard that requires entities within the NPCC region to identify the proper locations for sequence of events recorders, fault recorders, and dynamic disturbance recorders and specify the data to be captured and reported by this equipment.
- Internal review: The Commission has reviewed the requirements pertaining to the proposed regional Reliability Standard and determined that the proposed requirements are necessary to meet the statutory provisions of the Energy Policy Act of 2005. These requirements conform to the Commission's plan for efficient information collection, communication and management within the energy industry. The Commission has assured itself, by means of internal review, that there is specific objective support for the burden estimates associated with the information requirements.

28. Interested persons may obtain information on the reporting requirements by contacting: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, e-mail: DataClearance@ferc.gov, Phone: (202) 502-8663, fax: (202) 273-0873].

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[19] The hourly reporting cost is based on the estimated cost of an engineer to implement the requirements of the rule. The record retention cost comes from Commission staff research on record retention requirements.

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The Commission orders:

Regional Reliability Standard PRC-002-NPCC-01, its assigned VRFs and VSLs, inclusion of the terms “Current Zero Time” and “Generating Plant” in the NERC Glossary of Terms Used in Reliability Standards, and the implementation plan proposed by NERC are herby approved, as discussed in this order.

By the Commission. Commissioner Spitzer is not participating.

(S E A L)

Kimberly D. Bose,
Secretary.

Document Content(s)

RD11-8-000.DOC.....1-11

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426
OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD11-6-000

August 2, 2011

North American Electric Reliability Corporation
1120 G Street N.W., Suite 990
Washington, D.C. 20005-3801

Attention: Holly A. Hawkins, Attorney

Reference: Petition of the North American Electric Reliability Corporation for Approval of the Reliability Standard CIP-001-2a – Sabotage Reporting with a Regional Variance for Texas Reliability Entity

Dear Ms. Hawkins:

1. On June 21, 2011, the North American Electric Reliability Corporation (NERC) submitted a Petition for Approval of Reliability Standards CIP-001-2a – Sabotage Reporting with a Regional Variance for Texas Reliability Entity.

2. NERC explains that the Texas Regional Entity (TRE) has included two additional Applicable Entities to Reliability Standard CIP-001. Within TRE, Transmission Owners and Generator Owners will be listed with the other Applicable Entities of the Standard; Reliability Coordinators, Balancing Authorities, Transmission Operators, Generator Operators, and Load Serving Entities; and will have to comply with its Requirements.

3. Notice of this filing was issued on June 22, 2011 with comments, protests or motions to intervene due on or before July 13, 2011. Notices of intervention and unopposed timely filed motions to intervene are granted pursuant to the operation of Rule 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.214). Any opposed or untimely filed motions to intervene are governed by the provisions of Rule 214. No protests or adverse comments were filed.

4. NERC's uncontested filing is accepted pursuant to the authority delegated to the Director, Office of Electric Reliability, under 18 C.F.R. § 375.303.

5. This action shall not be construed as accepting any other contingency plan pursuant to 18 C.F.R. § 375.303(a)(1)(i) or any other data or report pursuant to 18 C.F.R. § 375.303(b)(3)(iv). This action shall not be construed as approving any other application including Electric Reliability Organization or Regional Entity Rules or procedures pursuant to 18 C.F.R. § 375.303(a)(2)(i). Such acceptance or approval shall not be deemed as recognition of any claimed right or obligation associated therewith; and such acceptance or approval is without prejudice to any findings or orders which have been or which may hereafter be made by the Commission in any proceeding now or pending or hereafter instituted by or against NERC.

6. This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713.

Sincerely,

Joseph H. McClelland, Director
Office of Electric Reliability

September 9, 2011

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: *North American Electric Reliability Corporation,*
Docket No. *RM11-___-___*

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits this petition in accordance with Section 215(d)(1) of the Federal Power Act ("FPA") and Part 39.5 of the Federal Energy Regulatory Commission's ("FERC" or "the Commission") regulations seeking approval of EOP-001-0b and EOP-001-2b — Emergency Operations Planning, which has appended to it an interpretation of Requirements R1 and R3.2 to FERC-approved NERC Reliability Standards EOP-001-0 and Requirements R1 and R2.2 to EOP-001-2 — Emergency Operations Planning, as set forth in **Exhibit B** and **Exhibit C** to this petition.

Specifically, this petition is seeking approval of:

- an interpretation to Requirement R1 of EOP-001-0 — Emergency Operations Planning as set forth in **Exhibit A** to the petition to become effective concurrent with the date of a FERC Order approving this petition;

- an interpretation to Requirement R3.2 of EOP-001-0 Emergency Operations Planning also set forth in **Exhibit A** to this petition to become effective concurrent with the date of a FERC Order approving this petition;
- Reliability Standard EOP-001-0b — Emergency Operations Planning, that includes the appended interpretation of Requirement R1 and R3.2 as set forth in **Exhibit B** to the petition to become effective concurrent with the date of a FERC Order approving this petition;
- Retirement of Reliability Standard EOP-001-0b — Emergency Operations Planning effective as of midnight on June 30, 2013; and
- Reliability Standard EOP-001-2b — Emergency Operations Planning, that includes the appended interpretations to Requirement R1 and R2.2 as set forth in **Exhibit C** to the petition to become effective on July 1, 2013, consistent with FERC's approval date of the EOP-001-2 Reliability Standard approved in FERC Order Nos. 748 and 749.[1]

These interpretations were approved by the NERC Board of Trustees on November 4, 2010.

NERC's petition consists of the following:

- This transmittal letter;
- A table of contents for the filing;
- A narrative description explaining the interpretations and how they meet the reliability goal of the standard;

[1] *Mandatory Reliability Standards for Interconnection Reliability Operating Limits*, 134 FERC ¶ 61,213, Order No. 748 (2011); *System Restoration Reliability Standards*, 134 FERC ¶ 61,215, Order No. 749 (2011); *Mandatory Reliability Standards for Interconnection Reliability Operating Limits; System Restoration Reliability Standards*, 136 FERC ¶ 61,030, Order Nos. 748-A and 749-A (2011).

- Interpretations of Requirements R1 and R3.2 of EOP-001-0 — Emergency Operations Planning (**Exhibit A**);
- Proposed Reliability Standard EOP-001-0b — Emergency Operations Planning, that includes the appended interpretations of Requirements R1 and R3.2 of EOP-001-0 — Emergency Operations Planning, submitted for approval (**Exhibit B**);
- Reliability Standard EOP-001-2b — Emergency Operations Planning, that includes the appended interpretations of Requirement R1 and R2.2 (**Exhibit C**)
- Consideration of Comments for interpretations to Requirements R1 of EOP-001-0 — Emergency Operations Planning (**Exhibit D**)
- Consideration of Comments for interpretations to Requirements R3.2 of EOP-001-0 — Emergency Operations Planning (**Exhibit E**)
- The complete development record of the interpretation Requirement R1 of EOP-001-0 — Emergency Operations Planning (**Exhibit F**);
- The complete development record of the interpretation Requirement R3.2 of EOP-001-0 — Emergency Operations Planning (**Exhibit G**); and
- A roster of the interpretation drafting team for the interpretations of Requirements R1 EOP-001-0 — Emergency Operations Planning **(Exhibit H**).
- A roster of the interpretation drafting team for the interpretations of Requirements R3.2 EOP-001-0 — Emergency Operations Planning **(Exhibit I**).

Please contact the undersigned if you have any questions.

Respectfully submitted,

/s/ Andrew M. Dressel
Andrew M. Dressel
Attorney for North American Electric Reliability Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	**)** **)**	**Docket No. RM11-__-000**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF INTERPRETATIONS TO REQUIREMENTS OF RELIABILITY STANDARDS EOP-001-0 and EOP-001-2— EMERGENCY OPERATIONS PLANNING

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I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC")[2] hereby requests the Federal Energy Regulatory Commission ("FERC" or "Commission") to approve, in accordance with Section 215(d)(1) of the Federal Power Act ("FPA")[3] and Section 39.5 of FERC's Regulations,[4] Reliability Standard EOP-001-0b[5] — Emergency Operations Planning (EOP-001-0b), to become effective concurrent with the date of a FERC Order approving this petition, and Reliability Standard EOP-001-2b,[6] to become effective on July 1, 2013, consistent with the effective date of the EOP-001-2 Reliability Standard approved in FERC Order Nos. 748 and 749.[7]

Specifically, this petition is seeking approval of:

- an interpretation to Requirement R1 of EOP-001-0 — Emergency Operations Planning (EOP-001-0) as set forth in **Exhibit A** to this petition to become effective concurrent with the date of a FERC Order approving this petition;

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[2] NERC was certified by FERC as the electric reliability organization ("ERO") authorized by Section 215 of the Federal Power Act. FERC certified NERC as the ERO in its order issued July 20, 2006 in Docket No. RR06-1-000 *Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 61,062 (2006) ("ERO Certification Order").

[3] 16 U.S.C. 824o (2006).

[4] 18 C.F.R. § 39.5 (2011).

[5] NERC is requesting that the proposed standard with both interpretations appended (for R1 and R3.2 respectively) be labeled as EOP-001-0b. If only one of the two interpretations are approved the proposed standard with one interpretation appended shall be designated EOP-001-0a.

[6] As in Footnote 5, NERC is requesting that the proposed standard with both interpretations appended (for R1 and R2.2 respectively) be labeled as EOP-001-2b. If only one of the two interpretations are approved the proposed standard with one interpretation appended shall be designated EOP-001-2a.

[7] *Mandatory Reliability Standards for Interconnection Reliability Operating Limits*, 134 FERC ¶ 61,213, Order No. 748 (2011); *System Restoration Reliability Standards*, 134 FERC ¶ 61,215, Order No. 749 (2011); *Mandatory Reliability Standards for Interconnection Reliability Operating Limits; System Restoration Reliability Standards*, 136 FERC ¶ 61,030, Order Nos. 748-A and 749-A (2011).

- an interpretation to Requirement R3.2 of EOP-001-0 — Emergency Operations Planning (EOP-001-0)[8] also set forth in **Exhibit A** to this petition to become effective ;
- Reliability Standard EOP-001-0b — Emergency Operations Planning, that includes the appended interpretation s of Requirements R1and R3.2 as set forth in **Exhibit B** to this petition, to become effective concurrent with the date of a FERC Order approving this petition;
- Retirement of Reliability Standard EOP-001-0— Emergency Operations Planning with EOP-001-0b effective as of midnight on June 30, 2013;
- Reliability Standard EOP-001-2b — Emergency Operations Planning, , that includes the appended interpretation s of Requirements R1and R2.2 as set forth in **Exhibit C** to this petition, to become effective July 1, 2013, consistent with FERC's approval date of the EOP-001-2 Reliability Standard approved in FERC Order Nos. 748 and 749.[9]

Upon Commission approval, NERC will refer to the Reliability Standards affected by this interpretation as:

- EOP-001-0b — Emergency Operations Planning (EOP-001-0b)
- EOP-001-2b — Emergency Operations Planning (EOP-001-2b)

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[8] Requirement R3.2 in EOP-001-0 is the same requirement as Requirement R2.2 in EOP-001-2. EOP-001-2 has been approved by FERC but will not be effective until July 1, 2013. However, because EOP-001-0 is the currently-effective and enforceable Reliability Standard and EOP-001-2 is not yet effective, NERC chose to refer to R3.2 in EOP-001-0 throughout the body of this filing. NERC requests FERC consider these alternate references as equivalent as they are referring to the same requirement.

[9] *Mandatory Reliability Standards for Interconnection Reliability Operating Limits*, 134 FERC ¶ 61,213, Order No. 748 (2011); *System Restoration Reliability Standards*, 134 FERC ¶ 61,215, Order No. 749 (2011); *Mandatory Reliability Standards for Interconnection Reliability Operating Limits; System Restoration Reliability Standards*, 136 FERC ¶ 61,030, Order Nos. 748-A and 749-A (2011).

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NERC's interpretation process does not allow for modification to the language contained in a Reliability Standard nor its requirements through a request for an interpretation. A valid interpretation request is one that requests additional clarity about one or more requirements in a regulatory-approved Reliability Standard and does not request verification as to whether or not a specific approach will be judged as complying with one or more requirements in a regulatory-approved Reliability Standard. A valid interpretation in response to a request for interpretation provides additional clarity about one or more requirements within a Reliability Standard, but does not expand or limit the Reliability Standard or any of its requirements beyond the language contained in the standard.

The original request for the interpretation for Requirement R1 was written to seek clarity regarding Requirement R1 of EOP-001-0 and Requirement R2.2 of EOP-001-1. However, because EOP-001-1 will not become a mandatory and effective Reliability Standard, and EOP-001-2 — Emergency Operations Planning (EOP-001-2) will not be effective until July 1, 2013,[10] NERC is seeking approval of the interpretations to be appended to currently effective EOP-001-0 standard until June 30, 2013, at which time the interpretations will be appended to the EOP-001-2 Reliability Standard upon its implementation date of July 1, 2013. The NERC Board of Trustees approved both of the interpretations to EOP-001 on November 4, 2010.

Exhibit A to this petition sets forth the interpretations of Requirements R1 and R3.2 to EOP-001-0. **Exhibit B** to this petition contains proposed Reliability Standard

[10] *Mandatory Reliability Standards for Interconnection Reliability Operating Limits*, 134 FERC ¶ 61,213, Order No. 748 (2011); *System Restoration Reliability Standards*, 134 FERC ¶ 61,215, Order No. 749 (2011); *Mandatory Reliability Standards for Interconnection Reliability Operating Limits; System Restoration Reliability Standards*, 136 FERC ¶ 61,030, Order Nos. 748-A and 749-A (2011).

EOP-001-0b — Emergency Operations Planning, which includes the appended interpretations of Requirements R1 and R3.2. **Exhibit C** to this petition contains proposed Reliability Standard EOP-001-2b — Emergency Operations Planning, which includes the appended interpretations of Requirements R1 and R2.2. **Exhibit D** to this petition contains the drafting team's consideration of industry comments for the interpretations to Requirements R1. **Exhibit E** to this petition contains the drafting team's consideration of industry comments for the interpretations to Requirements R3.2. **Exhibit F** contains the complete development history of the Interpretation of Requirement R1 of EOP-001-0. **Exhibit G** to this petition contains the complete development history of the Interpretation of Requirement R3.2 of EOP-001-0— Emergency Operations Planning. **Exhibit H** to this petition contains the roster of the interpretation drafting team that drafted the interpretation of Requirement R1. **Exhibit I** to this petition contains the roster of the interpretation drafting team that drafted the interpretation of Requirement R3.2.

NERC is also filing this interpretation with applicable governmental authorities in Canada.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:

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III. BACKGROUND

a. Regulatory Framework

By enacting the Energy Policy Act of 2005,[11] Congress entrusted FERC with the duties of approving and enforcing rules to ensure the reliability of the Nation's bulk power system, and with the duties of certifying an electric reliability organization ("ERO") that would be charged with developing and enforcing mandatory Reliability Standards, subject to FERC approval. Section 215 states that all users, owners and operators of the bulk power system in the United States will be subject to FERC-approved Reliability Standards.

b. Basis for Approval of Proposed Reliability Standard

The proposed Reliability Standard contains interpretations of two requirements within a Commission-approved Reliability Standard but does not represent a new or

[11] Energy Policy Act of 2005, Pub. L. No. 109-58, Title XII, Subtitle A, 119 Stat. 594, 941 (2005) (codified at 16 U.S.C. § 824o).

modified Reliability Standard. The proposed Reliability Standard provides additional clarity with regard to the intent of the Reliability Standard. Therefore, NERC requests that the Commission approve the proposed interpretations.

c. Reliability Standards Development Procedure and Interpretation

All persons who are directly or materially affected by the reliability of the North American bulk power system are permitted to request an interpretation of a Reliability Standard, as discussed in NERC's *Standard Processes Manual,*[12] which is incorporated into the NERC Rules of Procedure as Appendix 3A.

The process for responding to a valid request for interpretation requires NERC to assemble a team with the relevant expertise to address the interpretation request. The interpretation drafting team is then required to draft a response to the request for interpretation and then present that response for industry ballot. If approved by the ballot pool and the NERC Board of Trustees, the interpretation is appended to the Reliability Standard and filed for approval by FERC and applicable governmental authorities in Canada. Then, when the affected Reliability Standard undergoes its next substantive revision, the interpretation will be incorporated into the Reliability Standard, as appropriate.

The Operating Reliability Subcommittee Executive Committee ("ORS EC") was appointed as the interpretation drafting team to draft the response to the request for

[12] Note that FERC approved the new *Standard Processes Manual* in the Commission's *Order Approving Petition and Directing Compliance Filing*, (132 FERC ¶ 61,200 (2010)), which replaced the NERC's *Reliability Standards Development Procedure Version 7* in its entirety. NERC developed these interpretations in accordance with the *Reliability Standards Development Procedure Version 7* until the *Standard Processes Manual* was approved on September 3, 2010. NERC's *Reliability Standards Development Procedure* is available on NERC's website at: http://www.nerc.com/fileUploads/File/Standards/RSDP_V6_1_12Mar07.pdf. The Standard Processes Manual is available at: http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20100903.pdf.

interpretation of Requirement R1 of EOP-001-0. The interpretation to Requirement R1 is included as **Exhibit A** to this petition. The roster for the interpretation drafting team for EOP-001-0 Requirement R1 is contained in **Exhibit H**. The proposed interpretation included as **Exhibit A** to this petition was approved by the ballot pool on October 14, 2010 with a weighted segment approval of 99.14%. The proposed interpretation was approved by the NERC Board of Trustees on November 4, 2010.

A separate interpretation drafting team was appointed to draft the response to the request for interpretation of Requirement R3.2 of EOP-001-0. The roster for this interpretation drafting team is contained in **Exhibit I**. The interpretation drafted by the interpretation drafting team is also included in **Exhibit A** to this petition. The interpretation to Requirement R3.2 was approved by industry stakeholders with a 94.78% weighted-segment vote on October 15, 2010. The interpretation was approved by the NERC Board of Trustees on November 4, 2010.

The interpretation drafting team's considerations of comments for the interpretation of Requirement R1 is contained in **Exhibit D**. The interpretation drafting team's considerations of comments for the interpretation of Requirement R3.2 is contained in **Exhibit E**. The complete development record for the interpretations, including the requests for the interpretation, the responses to the requests for the interpretation, the ballot pool, and the final ballot results by registered ballot body members, stakeholder comments received during the balloting and an explanation of how those comments were considered are set forth in **Exhibits F** (Requirement R1) and **G** (Requirement R3.2). **Exhibit H** (Requirement R1) and **I** (Requirement R3.2) contain the rosters of the team members who developed the proposed interpretations.

IV. Proposed Reliability Standard EOP-001-0b and EOP-001-2b — Emergency Operations Planning

In Section IV(a), below, NERC summarizes the justification for the proposed interpretations of Requirements R1 and R3.2 of EOP-001-0 and EOP-001-2b — Emergency Operations Planning and explains the development of the interpretations. Section IV(b), below, describes the development proceedings for these interpretations. Section IV(b) includes the stakeholder ballot results and provides an explanation of how stakeholder comments were considered and addressed by the interpretation drafting teams assembled to develop the interpretations.

a. Justification for Approval of Interpretations

1. Requirement R1

On April 2, 2008 the Regional Entity Compliance Managers ("RECM")[13] requested an interpretation of Requirement R1 of EOP-001-0. Requirement R1 of EOP-001-0 states:

> **R1.** Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

Specifically, the RECM sought clarification with respect to the following language in EOP-001-0, Requirement 1:

1. What is the definition of emergency assistance in the context of this standard?

   What scope and time horizons, if any, are considered necessary in this definition?

[13] The RECM requesting this interpretation consisted of representatives from the Florida Reliability Coordinating Council, Northeast Power Coordinating Council, Midwest Reliability Organization, Reliability*First* Corporation, SERC Reliability Corporation, Southwest Power Pool Regional Entity, Texas Regional Entity, and Western Electricity Coordinating Council.

2. What was intended by using the adjective "adjacent" in Requirement 1? Does "adjacent" Balancing Authorities mean "All" or something else? Is there qualifying criteria to determine if a very small adjacent Balancing Authority area has enough capacity to offer emergency assistance?
3. What is the definition of the word "remote" as stated in the last phrase of Requirement 1? Does remote mean every Balancing Authority who's area does not physically touch the Balancing Authority attempting to comply with this Requirement?
4. Would a Balancing Authority that participates in a Reserve Sharing Group Agreement, which meets the requirements of Reliability Standard BAL-002-0, Requirement 2, be required to establish additional operating agreements to achieve compliance with Reliability Standard EOP-001-0, Requirement 1?

The interpretation drafting team was provided the following guidelines for developing a response to the RECM's request for interpretation:

> With a clear understanding of the standard's purpose and the technical engineering approach that best serves reliability, the team must judge whether the standard as written can be interpreted consistent with these interests using the following principles:
>
> a. The interpretation cannot change the requirement or standard. That is, the interpretation cannot expand the scope of the requirement beyond the language in the requirement.
> b. The interpretation must address the question posed or the team must explain why it cannot address the question.
> c. The interpretation drafting team has full latitude to respond to a question using requirements in other reliability standards that were not identified specifically in the request if that information addresses the issue.

d. The interpretation itself must add clarity and not be ambiguous or subject to interpretation.

e. The interpretation should address the intent of the requirement and be in the best interest of reliability.

The interpretation of the requirement, which if implemented by the applicable entities, will provide for a reliable bulk power system, in a manner consistent with good utility practice and the public interest. These principles and application guideline intend that the interpretation will not lower the current level of compliance to the requirement by the applicable entities.[14]

In response to the RECM interpretation request, the interpretation drafting team developed, and the industry stakeholders approved, the following interpretation:

1. *What is the definition of emergency assistance in the context of this standard?*

   What scope and time horizons, if any, are considered necessary in this definition?

   Response:

   In the context of this standard, emergency assistance is emergency energy. Emergency energy would normally be arranged for during the current operating day. The agreement should describe the conditions under which the emergency energy will be delivered to the responsible Balancing Authority.

2. *What was intended by using the adjective "adjacent" in Requirement 1? Does "adjacent" Balancing Authorities mean "All" or something else? Is there qualifying criteria to determine if a very small adjacent Balancing Authority area has enough capacity to offer emergency assistance?*

   Response:

   The intent is that all Balancing Authorities, interconnected by AC ties or DC (asynchronous) ties within the same Interconnection, have emergency energy assistance agreements with at least one Adjacent Balancing Authority and have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. However, the standard does not require emergency energy assistance agreements with all Adjacent Balancing Authorities, nor does it preclude having an emergency assistance agreement across Interconnections.

[14] These were the guidelines for drafting interpretations in force at the time the interpretation proposed for approval was developed.

3. *What is the definition of the word "remote" as stated in the last phrase of Requirement 1? Does remote mean every Balancing Authority who's area does not physically touch the Balancing Authority attempting to comply with this Requirement?*

   Response:

   A remote Balancing Authority is a Balancing Authority other than an Adjacent Balancing Authority. A Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with any remote Balancing Authorities. A Balancing Authority's agreement(s) with Adjacent Balancing Authorities does (do) not preclude the Adjacent Balancing Authority from purchasing emergency energy from remote Balancing Authorities.

4. Would a Balancing Authority that participates in a Reserve Sharing Group Agreement, which meets the requirements of Reliability Standard BAL-002-0, Requirement 2, be required to establish additional operating agreements to achieve compliance with Reliability Standard EOP-001-0, Requirement 1?

   Response:

   A Reserve Sharing Group agreement that contains provisions for emergency assistance may be used to meet Requirement R1 of EOP-001-0.

The interpretation to Requirement R1 of EOP-001-0 is consistent with the stated purpose of the Reliability Standard, that each Transmission Operator and Balancing Authority needs to develop, maintain, and implement a set of plans to mitigate operating emergencies and that such plans need to be coordinated with other Transmission Operators and Balancing Authorities, and the Reliability Coordinator.

2. Requirement R3.2

The Florida Municipal Power Pool ("FMPP") requested an interpretation of Requirement R3.2 [15]of EOP-001-0 on October 15, 2009. Requirement R3.2 of EOP-001-0 states:

> **R3.2.** [Each Transmission Operator and Balancing Authority shall:] develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.

FMPP requested clarity with respect to the emergency plans the Balancing Authority must have and asked the following regarding Requirement R3.2:

> *Does the Balancing Authority need to develop a plan to maintain a load-interchange-generation balance during operating emergencies and follow the directives of the Transmission Operator?*

In response to FMPPs request for an interpretation of Requirement R3.2 of EOP-001-0, the interpretation drafting team developed, and the industry stakeholders and NERC Board of Trustees later approved, the following interpretation:

> The answer to both parts of the question is yes. The Balancing Authority is required by the standard to develop, maintain, and implement a plan. The plan must consider the relationships and coordination with the Transmission Operator for actions directly taken by the Balancing Authority. The Balancing Authority must take actions either as directed by the Transmission Operator or the Reliability Coordinator (reference TOP-001-1, Requirement R3), or as previously agreed to with the Transmission Operator or the Reliability Coordinator to mitigate transmission emergencies. As stated in Requirement R5, the emergency plan shall include the applicable elements in "Attachment 1 – EOP-001-0."

[15] FMPP requested an interpretation of Requirement R2.2 of EOP-001-1 and EOP-001-2 but the currently-effective standard is EOP-001-0 and the equivalent requirement is Requirement R3.2 of EOP-001-0. As stated above, EOP-001-1 shall not become an effective Reliability Standard; *i.e.,* EOP-001-0 will be replaced by EOP-001-2.

b. Summary of the Reliability Standard Development Proceedings

1. Requirement R1

NERC presented the interpretation of Requirement R1 for a first initial ballot from June 19, 2008, through July 2, 2008 in which162 ballots were returned with an affirmative vote, a negative vote or an abstention. The result of the first initial ballot achieved an affirmative weighted segment approval of 85.7 percent. Of the 162 ballots, 14 affirmative votes were cast with a comment and 15 negative votes were cast with a comment. Because there were negative votes cast which included comments, the results from the first initial ballot were not final.

In summary, several comments received following the first initial ballot requested additional clarification of certain terms used in the interpretation such as dc voltages, the definition of "adjacent" regarding Balancing Authorities, and how much was "enough" emergency energy assistance. A few entities suggested increased requirements for emergency energy assistance and Reserve Sharing Group participation.

In response to the comments received during the first initial ballot, the interpretation drafting team modified the language in the interpretation to use the term "Adjacent Balancing Authority," a defined term in the NERC Glossary of Terms Used in Reliability Standards, and clarified that Requirement R1 does not compel energy assistance agreements with all Adjacent Balancing Authorities. The standard process in place at the time of development of the interpretation did not allow any modifications to the interpretation between the initial and recirculation ballots without posting the revised interpretation for a new initial ballot. Accordingly, the drafting team determined that,

although the interpretation received sufficient affirmative votes to pass, the improved clarity desired by the stakeholders warranted another pre-ballot review and initial ballot.

The revised interpretation was posted for a second initial ballot from February 27, 2009, through March 9, 2009 in which 165 ballots were returned. The second initial ballot received an affirmative weighted segment approval of 89.03 percent. Of the 165 votes cast, 6 affirmative votes were cast with a comment and 11 negative votes were cast with a comment.

In response to the comments received during the second initial ballot, the interpretation drafting team 1) modified the language in paragraph 2 of the interpretation to insert the phrase "interconnected by AC ties or DC (asynchronous) ties within the same Interconnection;" 2) modified the language in the second sentence of paragraph 3 by changing the word "all" to "any;" and 3) modified paragraph 4 of the interpretation to "A Reserve Sharing Group agreement that contains provisions for emergency assistance may be used to meet Requirement R1 of EOP-001-0."

Following the comments received during the second initial ballot, the drafting team made additional substantive changes which required a third initial ballot. The third ballot ran from November 5, 2009, through November 16, 2009 and 190 stakeholder ballots were returned. The third initial ballot achieved an affirmative weighted segment approval of 98.07%. Of the 190 votes cast, eight affirmative votes were cast with a comment and three negative votes were cast with a comment. These comments included concerns that the wording in the response to question 2 appeared to limit the Balancing Authority to agreements with Balancing Authorities within the same Interconnection, which may be interpreted to nullify the use of existing agreements that cross

Interconnections as sufficient to meet this requirement. In response to these comments the interpretation drafting team revised paragraph 2 of the interpretation to state,

> "The intent is that all Balancing Authorities, interconnected by AC ties or DC (asynchronous) ties within the same Interconnection, have emergency energy assistance agreements with at least one Adjacent Balancing Authority and have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. However, the standard does not require emergency energy assistance agreements with all Adjacent Balancing Authorities, nor does it preclude having an emergency assistance agreement across Interconnections."

Due to the fact that the interpretation drafting team again made substantive changes to the interpretation, the revised interpretation was posted for a fourth initial ballot from April 15, 2010, through April 26, 2010. Two hundred votes were cast in the fourth initial ballot. The result of the fourth initial ballot achieved an affirmative weighted segment approval of 98.64 percent. Of the 200 ballots returned, two affirmative votes were cast with a comment and two negative votes were cast with a comment.

Because there were negative votes cast which included comments, the results from the fourth initial ballot were not final and a final recirculation ballot was conducted. The recirculation ballot for the interpretation was held from October 4, 2010, through October 14, 2010. The result of the final recirculation ballot achieved an affirmative weighted segment approval of 99.14 percent. The NERC Board of Trustees approved the interpretation on November 4, 2010.

2. Requirement R3.2

NERC presented the interpretation to Requirement R3.2[16] for pre-ballot review on January 11, 2010. The initial ballot ran from February 10, 2010 through February 22, 2010, achieving a quorum of 87.36 percent with a weighted affirmative approval of 91.79

[16] As noted in Footnote 8, Requirement R3.2 in EOP-001-0 is the same requirement as Requirement R2.2 in EOP-001-2.

percent. Because NERC received some negative votes with comments, the results from the initial ballot could not be used to approve the interpretation. There were three comments received in total – one associated with an affirmative vote and two associated with negative votes.

Balloters who submitted negative votes with comments expressed concern about a possible expansion of the scope of the standard as a result of the interpretation. The balloters pointed out that the interpretation implied that the standard required Balancing Authorities to have "agreements" and implied that the Balancing Authority is required to follow Transmission Operator directives, but does not specifically require either of these actions. The drafting team responded as follows:

> The drafting team recognizes it went outside the bounds of EOP-001-1 and EOP-001-2 in the effort to provide additional clarification in the interpretation. Accordingly, the drafting team replaced the word "agreements" in the third sentence with "coordination." [17]

Because the changes resulting from the comments were minor in nature,[18] a recirculation ballot was held rather than a full re-posting of the ballot. The recirculation ballot was posted from October 5, 2010 through October 15, 2010 and achieved a quorum of 92.19 percent and approval of 94.78 percent. The NERC Board of Trustees approved the interpretation on November 4, 2010.

c. Future Action

The EOP-001-2 Reliability Standard was approved by the Commission in Order Nos. 748 and 749, issued March 17, 2011. Upon Commission approval of the requested

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[17] *Consideration of Comments*, attached as Exhibit D.

[18] In the current FERC-approved NERC *Standard Processes Manual* interpretation drafting teams are allowed to make non-substantive changes to an interpretation between an initial ballot and a recirculation ballot. Previously, under the *Reliability Standards Development Procedure Version 7*, interpretation drafting teams were not allowed to make any changes to an interpretation between ballots.

interpretations, the interpretations shall remain in effect until such time as the interpretation can be incorporated into a future revision of the standard.

NERC's *Reliability Standards Development Plan:2011-2013* contains Project 2009-03 Emergency Operations. This project will address the following standards:

- EOP-001-0 — Emergency Operations Planning
- EOP-002-2 — Capacity and Energy Emergencies
- EOP-003-1 — Load Shedding Plans

This project is not currently active but is in the project prioritization category of "Additional Projects to be Initiated in Order of Priority." That is, as existing high priority or nearly completed projects move to the final balloting stage and receive Board and regulatory approval, NERC staff and industry resources will be freed up and can then work on the projects in this category as prioritized by the Standards Committee.

V. CONCLUSION

NERC respectfully requests that FERC approve the Proposed Reliability Standard EOP-001-0b — Emergency Operations Planning, which includes the interpretations of Requirements R 1 and R3.2 of EOP-001-0 — Emergency Operations Planning , as set out in **Exhibit C**, in accordance with Section 215(d)(1) of the FPA and Part 39.5 of FERC's regulations. NERC requests that the EOP-001-0b Reliability Standard become effective concurrent with the date of a FERC Order approving this petition. Additionally, NERC requests that the Commission approve Reliability Standard EOP-001-2b, to become effective on July 1, 2013, consistent with FERC's approval date of the EOP-001-2 Reliability Standard approved in FERC Order Nos. 748 and 749.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 9th day of September, 2011.

/s/ Andrew M. Dressel

Andrew M. Dressel
Attorney for North American Electric Reliability Corporation

Exhibit A

Interpretations of Requirement R1 and R3.2 of Reliability Standard EOP-001-0 — Emergency Operations Planning

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Note: an Interpretation cannot be used to change a standard.

Request for an Interpretation of a Reliability Standard
Date submitted: March 20, 2008
Date accepted: March 20, 2008
Contact information for person requesting the interpretation:
Name:
Organization: Regional Entity Compliance Managers
Telephone:
E-mail: rcm@nerc.com
Identify the standard that needs clarification:
Standard Number (include version number): EOP-001-0
Standard Title: Emergency Operations Planning
Identify specifically what requirement needs clarification:

Requirement Number and Text of Requirement:

R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

Clarification needed:

The Regional Entity Compliance Managers (RECM) request a formal interpretation of Reliability Standard EOP-001-0 — Emergency Operations Planning Requirement R1 in accordance with the Reliability Standards Development Procedure.

What is the definition of emergency assistance in the context of this standard? What scope and time horizons, if any, are considered necessary in this definition?

What was intended by using the adjective "adjacent" in Requirement 1? Does "adjacent Balancing Authorities" mean "All" or something else? Is there qualifying criteria to determine if a very small adjacent Balancing Authority area has enough capacity to offer emergency assistance?

What is the definition of the word "remote" as stated in the last phrase of Requirement 1? Does remote mean every Balancing Authority who's area does not physically touch the Balancing Authority attempting to comply with this Requirement?

Would a Balancing Authority that participates in a Reserve Sharing Group Agreement, which meets the requirements of Reliability Standard BAL-002-0, Requirement 2, have to establish additional operating

agreements to achieve compliance with Reliability Standard EOP-001-0, Requirement 1?
Identify the material impact associated with this interpretation:
Identify the material impact to your organization or others caused by the lack of clarity or an incorrect interpretation of this standard. (Requesters were not required to provide this information at the time the request was submitted.)

Revised Interpretation of EOP-001-0 Emergency Operations Planning Requirement R1 for the Regional Entity Compliance Managers (Project 2008-09)
Requirement Number and Text of Requirement
R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.
Question
1. What is the definition of emergency assistance in the context of this standard? What scope and time horizons, if any, are considered necessary in this definition? 2. What was intended by using the adjective "adjacent" in Requirement 1? Does "adjacent Balancing Authorities" mean "All" or something else? Is there qualifying criteria to determine if a very small adjacent Balancing Authority area has enough capacity to offer emergency assistance? 3. What is the definition of the word "remote" as stated in the last phrase of Requirement 1? Does remote mean every Balancing Authority who's area does not physically touch the Balancing Authority attempting to comply with this Requirement? 4. Would a Balancing Authority that participates in a Reserve Sharing Group Agreement, which meets the requirements of Reliability Standard BAL-002-0, Requirement 2, have to establish additional operating agreements to achieve compliance with Reliability Standard EOP-001-0, Requirement 1?
Response[1]

[1] At the time of posting for this response (January 11, 2010), EOP-001-0 is the current Federal Energy Regulatory Commission (FERC)-approved version of the EOP-001 Reliability Standard in the United States and is therefore mandatory and enforceable. EOP-001-1 and EOP-001-2 have been filed with but not yet approved by FERC; therefore, EOP-001-1 and EOP-001-2 are not mandatory and enforceable in the Unites States at this time. The requirement in question, Requirement R2.2 of EOP-001-1 and EOP-001-2, exists in EOP-001-0 as Requirement R3.2.

1. In the context of this standard, emergency assistance is emergency energy. Emergency energy would normally be arranged for during the current operating day. The agreement should describe the conditions under which the emergency energy will be delivered to the responsible Balancing Authority.

2. The intent is that all Balancing Authorities, interconnected by AC ties or DC (asynchronous) ties within the same Interconnection, have emergency energy assistance agreements with at least one Adjacent Balancing Authority and have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. However, the standard does not require emergency energy assistance agreements with all Adjacent Balancing Authorities, nor does it preclude having an emergency assistance agreement across Interconnections.

3. A remote Balancing Authority is a Balancing Authority other than an Adjacent Balancing Authority. A Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with any remote Balancing Authorities. A Balancing Authority's agreement(s) with Adjacent Balancing Authorities does (do) not preclude the Adjacent Balancing Authority from purchasing emergency energy from remote Balancing Authorities.

4. A Reserve Sharing Group agreement that contains provisions for emergency assistance may be used to meet Requirement R1 of EOP-001-0.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Note: an Interpretation cannot be used to change a standard.

Request for an Interpretation of a Reliability Standard
Date submitted: October 15, 2009
Date accepted: November 30, 2009
Contact information for person requesting the interpretation:
Name: Thomas E Washburn
Organization: Florida Municipal Power Pool
Telephone: 407-384-4066
E-mail: twashburn@ouc.com
Identify the standard that needs clarification:
Standard Number (include version number): EOP-001-1 and EOP-001-2
Standard Title: Emergency Operations Planning
Identify specifically what requirement needs clarification:
Requirement Number and Text of Requirement: R2.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system. **Clarification needed:** According to the NERC Functional Model, the BA is responsible for maintaining load-generation-interchange balance within the BA Area and supports interconnection frequency in real-time. This is done using frequency control through tie-line bias, regulation service deployment, load-following through economic dispatch, and interchange implementation. The BA is not responsible for plans to mitigate operating emergencies on the transmission system. The BA does follow the directives of the TOP when they are implementing their plans. Does the BA need to develop a plan to maintain a load-interchange-generation balance during operating emergencies and follow the directives of the TOP?
Identify the material impact associated with this interpretation:
Identify the material impact to your organization or others caused by the lack of clarity or an incorrect interpretation of this standard. Not having the correct interpretation of this requirement could cause the BA to be found non-compliant.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2009-28: Response to Request for an Interpretation of EOP-001-1 and EOP-001-2, Requirement R2.2, for Florida Municipal Power Pool
The following interpretation of EOP-001-1 and EOP-001-2 — Emergency Operations Planning, Requirement R2.2, was developed by the Project 2006-03 (System Restoration and Blackstart) drafting team.
Requirement Number and Text of Requirement
R2.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.
Question
Does the BA need to develop a plan to maintain a load-interchange-generation balance during operating emergencies and follow the directives of the TOP?
Response[1]
The answer to both parts of the question is yes. The Balancing Authority is required by the standard to develop, maintain, and implement a plan. The plan must consider the relationships and coordination with the Transmission Operator for actions directly taken by the Balancing Authority. The Balancing Authority must take actions either as directed by the Transmission Operator or the Reliability Coordinator (reference TOP-001-1, Requirement R3), or as previously agreed to with the Transmission Operator or the Reliability Coordinator to mitigate transmission emergencies. As stated in Requirement R4, the emergency plan shall include the applicable elements in "Attachment 1 –EOP-001-0."

[1] At the time of posting for this response (January 11, 2010), EOP-001-0 is the current Federal Energy Regulatory Commission (FERC)-approved version of the EOP-001 Reliability Standard in the United States and is therefore mandatory and enforceable. EOP-001-1 and EOP-001-2 have been filed with but not yet approved by FERC; therefore, EOP-001-1 and EOP-001-2 are not mandatory and enforceable in the Unites States at this time. The requirement in question, Requirement R2.2 of EOP-001-1 and EOP-001-2, exists in EOP-001-0 as Requirement R3.2.

Exhibit B

Proposed Reliability Standard EOP-001-0b — Emergency Operations Planning, that includes the appended interpretations of Requirements R1 and R3.2 of EOP-001-0 — Emergency Operations Planning

(Clean and Red-line)

A. Introduction

1. **Title:** **Emergency Operations Planning**

2. **Number:** EOP-001-0b

3. **Purpose:** Each Transmission Operator and Balancing Authority needs to develop, maintain, and implement a set of plans to mitigate operating emergencies. These plans need to be coordinated with other Transmission Operators and Balancing Authorities, and the Reliability Coordinator.

4. **Applicability**

   4.1. Balancing Authorities.

   4.2. Transmission Operators.

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

R2. The Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes.

R3. Each Transmission Operator and Balancing Authority shall:

R3.1. Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.

R3.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.

R3.3. Develop, maintain, and implement a set of plans for load shedding.

R3.4. Develop, maintain, and implement a set of plans for system restoration.

R4. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include:

R4.1. Communications protocols to be used during emergencies.

R4.2. A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions.

R4.3. The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.

R4.4. Staffing levels for the emergency.

R5. Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001-0b when developing an emergency plan.

R6. The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.

R7. The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable:

R7.1. The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.

R7.2. The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.

R7.3. The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)

R7.4. The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.

C. Measures

M1. The Transmission Operator and Balancing Authority shall have its emergency plans available for review by the Regional Reliability Organization at all times.

M2. The Transmission Operator and Balancing Authority shall have its two most recent annual self-assessments available for review by the Regional Reliability Organization at all times.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframes

The Regional Reliability Organization shall review and evaluate emergency plans every three years to ensure that the plans consider the applicable elements of Attachment 1-EOP-001-0b.

The Regional Reliability Organization may elect to request self-certification of the Transmission Operator and Balancing Authority in years that the full review is not done.

Reset: one calendar year.

1.3. Data Retention

Current plan available at all times.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: One of the applicable elements of Attachment 1-EOP-001-0b has not been addressed in the emergency plans.

2.2. Level 2: Two of the applicable elements of Attachment 1-EOP-001-0b have not been addressed in the emergency plans.

2.3. Level 3: Three of the applicable elements of Attachment 1-EOP-001-0b have not been addressed in the emergency plans.

2.4. Level 4: Four or more of the applicable elements of Attachment 1-EOP-001-0b have not been addressed in the emergency plans or a plan does not exist.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by the Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0b	November 4, 2010	Adopted by the Board of Trustees	Project 2008-09 - Interpretation of Requirement R1
0b	November 4, 2010	Adopted by the Board of Trustees	Project 2009-28 - Interpretation of Requirement R2.2

Attachment 1-EOP-001-0b

Elements for Consideration in Development of Emergency Plans

1. Fuel supply and inventory — An adequate fuel supply and inventory plan that recognizes reasonable delays or problems in the delivery or production of fuel.

2. Fuel switching — Fuel switching plans for units for which fuel supply shortages may occur, e.g., gas and light oil.

3. Environmental constraints — Plans to seek removal of environmental constraints for generating units and plants.

4. System energy use — The reduction of the system's own energy use to a minimum.

5. Public appeals — Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.

6. Load management — Implementation of load management and voltage reductions, if appropriate.

7. Optimize fuel supply — The operation of all generating sources to optimize the availability.

8. Appeals to customers to use alternate fuels — In a fuel emergency, appeals to large industrial and commercial customers to reduce non-essential energy use and maximize the use of customer-owned generation that rely on fuels other than the one in short supply.

9. Interruptible and curtailable loads — Use of interruptible and curtailable customer load to reduce capacity requirements or to conserve the fuel in short supply.

10. Maximizing generator output and availability — The operation of all generating sources to maximize output and availability. This should include plans to winterize units and plants during extreme cold weather.

11. Notifying IPPs — Notification of cogeneration and independent power producers to maximize output and availability.

12. Requests of government — Requests to appropriate government agencies to implement programs to achieve necessary energy reductions.

13. Load curtailment — A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety, and welfare of the community. Address firm load curtailment.

14. Notification of government agencies — Notification of appropriate government agencies as the various steps of the emergency plan are implemented.

15. Notifications to operating entities — Notifications to other operating entities as steps in emergency plan are implemented.

Appendix 1

Requirement Number and Text of Requirement
R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.
Questions:
1. What is the definition of emergency assistance in the context of this standard? What scope and time horizons, if any, are considered necessary in this definition? 2. What was intended by using the adjective "adjacent" in Requirement 1? Does "adjacent Balancing Authorities" mean "All" or something else? Is there qualifying criteria to determine if a very small adjacent Balancing Authority area has enough capacity to offer emergency assistance? 3. What is the definition of the word "remote" as stated in the last phrase of Requirement 1? Does remote mean every Balancing Authority who's area does not physically touch the Balancing Authority attempting to comply with this Requirement? 4. Would a Balancing Authority that participates in a Reserve Sharing Group Agreement, which meets the requirements of Reliability Standard BAL-002-0, Requirement 2, have to establish additional operating agreements to achieve compliance with Reliability Standard EOP-001-0, Requirement 1?
Responses:
1. In the context of this standard, emergency assistance is emergency energy. Emergency energy would normally be arranged for during the current operating day. The agreement should describe the conditions under which the emergency energy will be delivered to the responsible Balancing Authority. 2. The intent is that all Balancing Authorities, interconnected by AC ties or DC (asynchronous) ties within the same Interconnection, have emergency energy assistance agreements with at least one Adjacent Balancing Authority and have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. However, the standard does not require emergency energy assistance agreements with all Adjacent Balancing Authorities, nor does it preclude having an emergency assistance agreement across Interconnections. 3. A remote Balancing Authority is a Balancing Authority other than an Adjacent Balancing Authority. A Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with any remote Balancing Authorities. A Balancing Authority's agreement(s) with Adjacent Balancing Authorities does (do) not preclude the Adjacent Balancing Authority from purchasing emergency energy from remote Balancing Authorities. 4. A Reserve Sharing Group agreement that contains provisions for emergency assistance may be used to meet Requirement R1 of EOP-001-0.

Appendix 2

Requirement Number and Text of Requirement
R2.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.
Questions:
Does the BA need to develop a plan to maintain a load-interchange-generation balance during operating emergencies and follow the directives of the TOP?
Questions:
The answer to both parts of the question is yes. The Balancing Authority is required by the standard to develop, maintain, and implement a plan. The plan must consider the relationships and coordination with the Transmission Operator for actions directly taken by the Balancing Authority. The Balancing Authority must take actions either as directed by the Transmission Operator or the Reliability Coordinator (reference TOP-001-1, Requirement R3), or as previously agreed to with the Transmission Operator or the Reliability Coordinator to mitigate transmission emergencies. As stated in Requirement R4, the emergency plan shall include the applicable elements in "Attachment 1 –EOP-001-0."

A. Introduction

1. Title: **Emergency Operations Planning**

2. Number: EOP-001-~~0~~0b

3. Purpose: Each Transmission Operator and Balancing Authority needs to develop, maintain, and implement a set of plans to mitigate operating emergencies. These plans need to be coordinated with other Transmission Operators and Balancing Authorities, and the Reliability Coordinator.

4. Applicability

4.1. Balancing Authorities.

4.2. Transmission Operators.

5. Effective Date: April 1, 2005

B. Requirements

R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

R2. The Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes.

R3. Each Transmission Operator and Balancing Authority shall:

R3.1. Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.

R3.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.

R3.3. Develop, maintain, and implement a set of plans for load shedding.

R3.4. Develop, maintain, and implement a set of plans for system restoration.

R4. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include:

R4.1. Communications protocols to be used during emergencies.

R4.2. A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions.

R4.3. The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.

R4.4. Staffing levels for the emergency.

R5. Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001-~~0~~0b when developing an emergency plan.

R6. The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.

R7. The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable:

R7.1. The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.

R7.2. The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.

R7.3. The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)

R7.4. The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.

C. Measures

M1. The Transmission Operator and Balancing Authority shall have its emergency plans available for review by the Regional Reliability Organization at all times.

M2. The Transmission Operator and Balancing Authority shall have its two most recent annual self-assessments available for review by the Regional Reliability Organization at all times.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframes

The Regional Reliability Organization shall review and evaluate emergency plans every three years to ensure that the plans consider the applicable elements of Attachment 1-EOP-001-~~0~~0b.

The Regional Reliability Organization may elect to request self-certification of the Transmission Operator and Balancing Authority in years that the full review is not done.

Reset: one calendar year.

1.3. Data Retention

Current plan available at all times.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: One of the applicable elements of Attachment 1-EOP-001-~~0~~0b has not been addressed in the emergency plans.

2.2. Level 2: Two of the applicable elements of Attachment 1-EOP-001-~~0~~0b have not been addressed in the emergency plans.

2.3. Level 3: Three of the applicable elements of Attachment 1-EOP-001-~~0~~0b have not been addressed in the emergency plans.

2.4. Level 4: Four or more of the applicable elements of Attachment 1-EOP-001-~~0~~0b have not been addressed in the emergency plans or a plan does not exist.

E. **Regional Differences**

None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by the Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0b	November 4, 2010	Adopted by the Board of Trustees	Project 2008-09 - Interpretation of Requirement R1
0b	November 4, 2010	Adopted by the Board of Trustees	Project 2009-28 - Interpretation of Requirement R2.2

Attachment 1-EOP-001-~~0~~0b

Elements for Consideration in Development of Emergency Plans

1. Fuel supply and inventory — An adequate fuel supply and inventory plan that recognizes reasonable delays or problems in the delivery or production of fuel.

2. Fuel switching — Fuel switching plans for units for which fuel supply shortages may occur, e.g., gas and light oil.

3. Environmental constraints — Plans to seek removal of environmental constraints for generating units and plants.

4. System energy use — The reduction of the system's own energy use to a minimum.

5. Public appeals — Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.

6. Load management — Implementation of load management and voltage reductions, if appropriate.

7. Optimize fuel supply — The operation of all generating sources to optimize the availability.

8. Appeals to customers to use alternate fuels — In a fuel emergency, appeals to large industrial and commercial customers to reduce non-essential energy use and maximize the use of customer-owned generation that rely on fuels other than the one in short supply.

9. Interruptible and curtailable loads — Use of interruptible and curtailable customer load to reduce capacity requirements or to conserve the fuel in short supply.

10. Maximizing generator output and availability — The operation of all generating sources to maximize output and availability. This should include plans to winterize units and plants during extreme cold weather.

11. Notifying IPPs — Notification of cogeneration and independent power producers to maximize output and availability.

12. Requests of government — Requests to appropriate government agencies to implement programs to achieve necessary energy reductions.

13. Load curtailment — A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety, and welfare of the community. Address firm load curtailment.

14. Notification of government agencies — Notification of appropriate government agencies as the various steps of the emergency plan are implemented.

15. Notifications to operating entities — Notifications to other operating entities as steps in emergency plan are implemented.

Appendix 1

Requirement Number and Text of Requirement
R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.
Questions:
1. What is the definition of emergency assistance in the context of this standard? What scope and time horizons, if any, are considered necessary in this definition? 2. What was intended by using the adjective "adjacent" in Requirement 1? Does "adjacent Balancing Authorities" mean "All" or something else? Is there qualifying criteria to determine if a very small adjacent Balancing Authority area has enough capacity to offer emergency assistance? 3. What is the definition of the word "remote" as stated in the last phrase of Requirement 1? Does remote mean every Balancing Authority who's area does not physically touch the Balancing Authority attempting to comply with this Requirement? 4. Would a Balancing Authority that participates in a Reserve Sharing Group Agreement, which meets the requirements of Reliability Standard BAL-002-0, Requirement 2, have to establish additional operating agreements to achieve compliance with Reliability Standard EOP-001-0, Requirement 1?
Responses:
1. In the context of this standard, emergency assistance is emergency energy. Emergency energy would normally be arranged for during the current operating day. The agreement should describe the conditions under which the emergency energy will be delivered to the responsible Balancing Authority. 2. The intent is that all Balancing Authorities, interconnected by AC ties or DC (asynchronous) ties within the same Interconnection, have emergency energy assistance agreements with at least one Adjacent Balancing Authority and have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. However, the standard does not require emergency energy assistance agreements with all Adjacent Balancing Authorities, nor does it preclude having an emergency assistance agreement across Interconnections. 3. A remote Balancing Authority is a Balancing Authority other than an Adjacent Balancing Authority. A Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with any remote Balancing Authorities. A Balancing Authority's agreement(s) with Adjacent Balancing Authorities does (do) not preclude the Adjacent Balancing Authority from purchasing emergency energy from remote Balancing Authorities. 4. A Reserve Sharing Group agreement that contains provisions for emergency assistance may be used to meet Requirement R1 of EOP-001-0.

Appendix 2

Requirement Number and Text of Requirement
R2.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.
Questions:
Does the BA need to develop a plan to maintain a load-interchange-generation balance during operating emergencies and follow the directives of the TOP?
Questions:
The answer to both parts of the question is yes. The Balancing Authority is required by the standard to develop, maintain, and implement a plan. The plan must consider the relationships and coordination with the Transmission Operator for actions directly taken by the Balancing Authority. The Balancing Authority must take actions either as directed by the Transmission Operator or the Reliability Coordinator (reference TOP-001-1, Requirement R3), or as previously agreed to with the Transmission Operator or the Reliability Coordinator to mitigate transmission emergencies. As stated in Requirement R4, the emergency plan shall include the applicable elements in "Attachment 1 –EOP-001-0."

~~15.~~

Exhibit C

Proposed Reliability Standard EOP-001-2b — Emergency Operations Planning, that includes the appended interpretations of Requirements R1 and R2.2 of EOP-001-0 — Emergency Operations Planning

(Clean and Red-line)

A. Introduction

1. **Title:** **Emergency Operations Planning**

2. **Number:** EOP-001-2b

3. **Purpose:** Each Transmission Operator and Balancing Authority needs to develop, maintain, and implement a set of plans to mitigate operating emergencies. These plans need to be coordinated with other Transmission Operators and Balancing Authorities, and the Reliability Coordinator.

4. **Applicability**

   4.1. Balancing Authorities.

   4.2. Transmission Operators.

5. **Proposed Effective Date:** Twenty-four months after the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect twenty-four months after Board of Trustees adoption.

B. Requirements

R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

R2. Each Transmission Operator and Balancing Authority shall:

R2.1. Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.

R2.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.

R2.3. Develop, maintain, and implement a set of plans for load shedding.

R3. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include:

R3.1. Communications protocols to be used during emergencies.

R3.2. A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions.

R3.3. The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.

R3.4. Staffing levels for the emergency.

R4. Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001-0b when developing an emergency plan.

R5. The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.

R6. The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable:

R6.1. The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.

R6.2. The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.

R6.3. The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)

R6.4. The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.

C. Measures

M1. The Transmission Operator and Balancing Authority shall have its emergency plans available for review by the Regional Reliability Organization at all times.

M2. The Transmission Operator and Balancing Authority shall have its two most recent annual self-assessments available for review by the Regional Reliability Organization at all times.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

The Regional Reliability Organization shall review and evaluate emergency plans every three years to ensure that the plans consider the applicable elements of Attachment 1-EOP-001-0b.

The Regional Reliability Organization may elect to request self-certification of the Transmission Operator and Balancing Authority in years that the full review is not done.

Reset: one calendar year.

1.3. Data Retention

Current plan available at all times.

1.4. Additional Compliance Information

Not specified.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for less than 25% of the adjacent BAs. Or less than 25% of those agreements do not contain provisions for emergency assistance.	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 25% to 50% of the adjacent BAs. Or 25 to 50% of those agreements do not contain provisions for emergency assistance.	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 50% to 75% of the adjacent BAs. Or 50% to 75% of those agreements do not contain provisions for emergency assistance.	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 75% or more of the adjacent BAs. Or more than 75% of those agreements do not contain provisions for emergency assistance.
R2	The Transmission Operator or Balancing Authority failed to comply with one (1) of the sub-components.	The Transmission Operator or Balancing Authority failed to comply with two (2) of the sub-components.	N/A	The Transmission Operator or Balancing Authority has failed to comply with three (3) of the sub-components.
R2.1	The Transmission Operator or Balancing Authority's emergency plans to mitigate insufficient generating capacity are missing minor details or minor program/procedural elements.	The Transmission Operator or Balancing Authority's has demonstrated the existence of emergency plans to mitigate insufficient generating capacity emergency plans but the plans are not maintained.	The Transmission Operator or Balancing Authority's emergency plans to mitigate insufficient generating capacity emergency plans are neither maintained nor implemented.	The Transmission Operator or Balancing Authority has failed to develop emergency mitigation plans for insufficient generating capacity.
R2.2	The Transmission Operator or Balancing Authority's plans to mitigate transmission system emergencies are missing minor details or minor program/procedural elements.	The Transmission Operator or Balancing Authority's has demonstrated the existence of transmission system emergency plans but are not maintained.	The Transmission Operator or Balancing Authority's transmission system emergency plans are neither maintained nor implemented.	The Transmission Operator or Balancing Authority has failed to develop, maintain, and implement operating emergency mitigation plans for emergencies on the transmission system.

Requirement	Lower	Moderate	High	Severe
R2.3	The Transmission Operator or Balancing Authority's load shedding plans are missing minor details or minor program/procedural elements.	The Transmission Operator or Balancing Authority's has demonstrated the existence of load shedding plans but are not maintained.	The Transmission Operator or Balancing Authority's load shedding plans are partially compliant with the requirement but are neither maintained nor implemented.	The Transmission Operator or Balancing Authority has failed to develop, maintain, and implement load shedding plans.
R3	The Transmission Operator or Balancing Authority failed to comply with one (1) of the sub-components.	The Transmission Operator or Balancing Authority failed to comply with two (2) of the sub-components.	The Transmission Operator or Balancing Authority has failed to comply with three (3) of the sub-components.	The Transmission Operator or Balancing Authority has failed to comply with all four (4) of the sub-components.
R3.1	The Transmission Operator or Balancing Authority's communication protocols included in the emergency plan are missing minor program/procedural elements.	N/A	N/A	The Transmission Operator or Balancing Authority has failed to include communication protocols in its emergency plans to mitigate operating emergencies.
R3.2	The Transmission Operator or Balancing Authority's list of controlling actions has resulted in meeting the intent of the requirement but is missing minor program/procedural elements.	N/A	The Transmission Operator or Balancing Authority provided a list of controlling actions, however the actions fail to resolve the emergency within NERC-established timelines.	The Transmission Operator or Balancing Authority has failed to provide a list of controlling actions to resolve the emergency.

Requirement	Lower	Moderate	High	Severe
R3.3	The Transmission Operator or Balancing Authority has demonstrated coordination with Transmission Operators and Balancing Authorities but is missing minor program/procedural elements.	N/A	N/A	The Transmission Operator or Balancing Authority has failed to demonstrate the tasks to be coordinated with adjacent Transmission Operator and Balancing Authorities as directed by the requirement.
R3.4	The Transmission Operator or Balancing Authority's emergency plan does not include staffing levels for the emergency	N/A	N/A	N/A
R4	The Transmission Operator and Balancing Authority's emergency plan has complied with 90% or more of the number of sub-components.	The Transmission Operator and Balancing Authority's emergency plan has complied with 70% to 90% of the number of sub-components.	The Transmission Operator and Balancing Authority's emergency plan has complied with between 50% to 70% of the number of sub-components.	The Transmission Operator and Balancing Authority's emergency plan has complied with 50% or less of the number of sub-components
R5	The Transmission Operator and Balancing Authority is missing minor program/procedural elements.	The Transmission Operator and Balancing Authority has failed to annually review one of it's emergency plans	The Transmission Operator and Balancing Authority has failed to annually review two of its emergency plans or communicate with one of it's neighboring Balancing Authorities.	The Transmission Operator and Balancing Authority has failed to annually review and/or communicate any emergency plans with its Reliability Coordinator, neighboring Transmission Operators or Balancing Authorities.
R6	The Transmission Operator and/or the Balancing Authority failed to comply with one (1) of the sub-components.	The Transmission Operator and/or the Balancing Authority failed to comply with two (2) of the sub-components.	The Transmission Operator and/or the Balancing Authority has failed to comply with three (3) of the sub-components.	The Transmission Operator and/or the Balancing Authority has failed to comply with four (4) or more of the sub-components.

Requirement	Lower	Moderate	High	Severe
R6.1	The Transmission Operator or Balancing Authority has failed to establish and maintain reliable communication between interconnected systems.	N/A	N/A	N/A
R6.2	The Transmission Operator or Balancing Authority has failed to arrange new interchange agreements to provide for emergency capacity or energy transfers with required entities when existing agreements could not be used.	N/A	N/A	N/A
R6.3	The Transmission Operator or Balancing Authority has failed to coordinate transmission and generator maintenance schedules to maximize capacity or conserve fuel in short supply.	N/A	N/A	N/A
R6.4	The Transmission Operator or Balancing Authority has failed to arrange for deliveries of electrical energy or fuel from remote systems through normal operating channels.	N/A	N/A	N/A

E. **Regional Differences**

None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by the Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	October 17, 2008	Deleted R2 Replaced Levels of Non-compliance with the February 28, 2008 BOT approved Violation Severity Levels Corrected typographical errors in BOT approved version of VSLs	Revised IROL Project
2	August 5, 2009	Removed R2.4 as redundant with EOP-005-2 Requirement R1 for the Transmission Operator; the Balancing Authority does not need a restoration plan.	Revised Project 2006-03
2	August 5, 2009	Adopted by NERC Board of Trustees: August 5, 2009	Revised
2	March 17, 2011	FERC Order issued approving EOP-001-2 (Clarification issued on July 13, 2011)	Revised
2b	November 4, 2010	Adopted by NERC Board of Trustees	Project 2008-09 - Interpretation of Requirement R1
2b	November 4, 2010	Adopted by NERC Board of Trustees	Project 2009-28 - Interpretation of Requirement R2.2

Attachment 1-EOP-001-0b

Elements for Consideration in Development of Emergency Plans

1. Fuel supply and inventory — An adequate fuel supply and inventory plan that recognizes reasonable delays or problems in the delivery or production of fuel.

2. Fuel switching — Fuel switching plans for units for which fuel supply shortages may occur, e.g., gas and light oil.

3. Environmental constraints — Plans to seek removal of environmental constraints for generating units and plants.

4. System energy use — The reduction of the system's own energy use to a minimum.

5. Public appeals — Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.

6. Load management — Implementation of load management and voltage reductions, if appropriate.

7. Optimize fuel supply — The operation of all generating sources to optimize the availability.

8. Appeals to customers to use alternate fuels — In a fuel emergency, appeals to large industrial and commercial customers to reduce non-essential energy use and maximize the use of customer-owned generation that rely on fuels other than the one in short supply.

9. Interruptible and curtailable loads — Use of interruptible and curtailable customer load to reduce capacity requirements or to conserve the fuel in short supply.

10. Maximizing generator output and availability — The operation of all generating sources to maximize output and availability. This should include plans to winterize units and plants during extreme cold weather.

11. Notifying IPPs — Notification of cogeneration and independent power producers to maximize output and availability.

12. Requests of government — Requests to appropriate government agencies to implement programs to achieve necessary energy reductions.

13. Load curtailment — A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety, and welfare of the community. Address firm load curtailment.

14. Notification of government agencies — Notification of appropriate government agencies as the various steps of the emergency plan are implemented.

15. Notifications to operating entities — Notifications to other operating entities as steps in emergency plan are implemented.

Appendix 1

Requirement Number and Text of Requirement
R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.
Questions:
1. What is the definition of emergency assistance in the context of this standard? What scope and time horizons, if any, are considered necessary in this definition? 2. What was intended by using the adjective "adjacent" in Requirement 1? Does "adjacent Balancing Authorities" mean "All" or something else? Is there qualifying criteria to determine if a very small adjacent Balancing Authority area has enough capacity to offer emergency assistance? 3. What is the definition of the word "remote" as stated in the last phrase of Requirement 1? Does remote mean every Balancing Authority who's area does not physically touch the Balancing Authority attempting to comply with this Requirement? 4. Would a Balancing Authority that participates in a Reserve Sharing Group Agreement, which meets the requirements of Reliability Standard BAL-002-0, Requirement 2, have to establish additional operating agreements to achieve compliance with Reliability Standard EOP-001-0, Requirement 1?
Responses:
1. In the context of this standard, emergency assistance is emergency energy. Emergency energy would normally be arranged for during the current operating day. The agreement should describe the conditions under which the emergency energy will be delivered to the responsible Balancing Authority. 2. The intent is that all Balancing Authorities, interconnected by AC ties or DC (asynchronous) ties within the same Interconnection, have emergency energy assistance agreements with at least one Adjacent Balancing Authority and have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. However, the standard does not require emergency energy assistance agreements with all Adjacent Balancing Authorities, nor does it preclude having an emergency assistance agreement across Interconnections. 3. A remote Balancing Authority is a Balancing Authority other than an Adjacent Balancing Authority. A Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with any remote Balancing Authorities. A Balancing Authority's agreement(s) with Adjacent Balancing Authorities does (do) not preclude the Adjacent Balancing Authority from purchasing emergency energy from remote Balancing Authorities. 4. A Reserve Sharing Group agreement that contains provisions for emergency assistance may be used to meet Requirement R1 of EOP-001-0.

Appendix 2

Requirement Number and Text of Requirement
R2.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.
Questions:
Does the BA need to develop a plan to maintain a load-interchange-generation balance during operating emergencies and follow the directives of the TOP?
Questions:
The answer to both parts of the question is yes. The Balancing Authority is required by the standard to develop, maintain, and implement a plan. The plan must consider the relationships and coordination with the Transmission Operator for actions directly taken by the Balancing Authority. The Balancing Authority must take actions either as directed by the Transmission Operator or the Reliability Coordinator (reference TOP-001-1, Requirement R3), or as previously agreed to with the Transmission Operator or the Reliability Coordinator to mitigate transmission emergencies. As stated in Requirement R4, the emergency plan shall include the applicable elements in "Attachment 1 –EOP-001-0."

A. Introduction

1. Title: **Emergency Operations Planning**

2. Number: EOP-001-~~2~~2b

3. Purpose: Each Transmission Operator and Balancing Authority needs to develop, maintain, and implement a set of plans to mitigate operating emergencies. These plans need to be coordinated with other Transmission Operators and Balancing Authorities, and the Reliability Coordinator.

4. Applicability

4.1. Balancing Authorities.

4.2. Transmission Operators.

5. Proposed Effective Date: Twenty-four months after the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect twenty-four months after Board of Trustees adoption.

B. Requirements

R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

R2. Each Transmission Operator and Balancing Authority shall:

R2.1. Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.

R2.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.

R2.3. Develop, maintain, and implement a set of plans for load shedding.

R3. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include:

R3.1. Communications protocols to be used during emergencies.

R3.2. A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions.

R3.3. The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.

R3.4. Staffing levels for the emergency.

R4. Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001-~~0~~0b when developing an emergency plan.

R5. The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.

R6. The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable:

R6.1. The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.

R6.2. The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.

R6.3. The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)

R6.4. The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.

C. Measures

M1. The Transmission Operator and Balancing Authority shall have its emergency plans available for review by the Regional Reliability Organization at all times.

M2. The Transmission Operator and Balancing Authority shall have its two most recent annual self-assessments available for review by the Regional Reliability Organization at all times.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

The Regional Reliability Organization shall review and evaluate emergency plans every three years to ensure that the plans consider the applicable elements of Attachment 1-EOP-001-~~0~~0b.

The Regional Reliability Organization may elect to request self-certification of the Transmission Operator and Balancing Authority in years that the full review is not done.

Reset: one calendar year.

1.3. Data Retention

Current plan available at all times.

1.4. Additional Compliance Information

Not specified.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for less than 25% of the adjacent BAs. Or less than 25% of those agreements do not contain provisions for emergency assistance.	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 25% to 50% of the adjacent BAs. Or 25 to 50% of those agreements do not contain provisions for emergency assistance.	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 50% to 75% of the adjacent BAs. Or 50% to 75% of those agreements do not contain provisions for emergency assistance.	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 75% or more of the adjacent BAs. Or more than 75% of those agreements do not contain provisions for emergency assistance.
R2	The Transmission Operator or Balancing Authority failed to comply with one (1) of the sub-components.	The Transmission Operator or Balancing Authority failed to comply with two (2) of the sub-components.	N/A	The Transmission Operator or Balancing Authority has failed to comply with three (3) of the sub-components.
R2.1	The Transmission Operator or Balancing Authority's emergency plans to mitigate insufficient generating capacity are missing minor details or minor program/procedural elements.	The Transmission Operator or Balancing Authority's has demonstrated the existence of emergency plans to mitigate insufficient generating capacity emergency plans but the plans are not maintained.	The Transmission Operator or Balancing Authority's emergency plans to mitigate insufficient generating capacity emergency plans are neither maintained nor implemented.	The Transmission Operator or Balancing Authority has failed to develop emergency mitigation plans for insufficient generating capacity.
R2.2	The Transmission Operator or Balancing Authority's plans to mitigate transmission system emergencies are missing minor details or minor program/procedural elements.	The Transmission Operator or Balancing Authority's has demonstrated the existence of transmission system emergency plans but are not maintained.	The Transmission Operator or Balancing Authority's transmission system emergency plans are neither maintained nor implemented.	The Transmission Operator or Balancing Authority has failed to develop, maintain, and implement operating emergency mitigation plans for emergencies on the transmission system.

Requirement	Lower	Moderate	High	Severe
R2.3	The Transmission Operator or Balancing Authority's load shedding plans are missing minor details or minor program/procedural elements.	The Transmission Operator or Balancing Authority's has demonstrated the existence of load shedding plans but are not maintained.	The Transmission Operator or Balancing Authority's load shedding plans are partially compliant with the requirement but are neither maintained nor implemented.	The Transmission Operator or Balancing Authority has failed to develop, maintain, and implement load shedding plans.
R3	The Transmission Operator or Balancing Authority failed to comply with one (1) of the sub-components.	The Transmission Operator or Balancing Authority failed to comply with two (2) of the sub-components.	The Transmission Operator or Balancing Authority has failed to comply with three (3) of the sub-components.	The Transmission Operator or Balancing Authority has failed to comply with all four (4) of the sub-components.
R3.1	The Transmission Operator or Balancing Authority's communication protocols included in the emergency plan are missing minor program/procedural elements.	N/A	N/A	The Transmission Operator or Balancing Authority has failed to include communication protocols in its emergency plans to mitigate operating emergencies.
R3.2	The Transmission Operator or Balancing Authority's list of controlling actions has resulted in meeting the intent of the requirement but is missing minor program/procedural elements.	N/A	The Transmission Operator or Balancing Authority provided a list of controlling actions, however the actions fail to resolve the emergency within NERC-established timelines.	The Transmission Operator or Balancing Authority has failed to provide a list of controlling actions to resolve the emergency.

Requirement	Lower	Moderate	High	Severe
R3.3	The Transmission Operator or Balancing Authority has demonstrated coordination with Transmission Operators and Balancing Authorities but is missing minor program/procedural elements.	N/A	N/A	The Transmission Operator or Balancing Authority has failed to demonstrate the tasks to be coordinated with adjacent Transmission Operator and Balancing Authorities as directed by the requirement.
R3.4	The Transmission Operator or Balancing Authority's emergency plan does not include staffing levels for the emergency	N/A	N/A	N/A
R4	The Transmission Operator and Balancing Authority's emergency plan has complied with 90% or more of the number of sub-components.	The Transmission Operator and Balancing Authority's emergency plan has complied with 70% to 90% of the number of sub-components.	The Transmission Operator and Balancing Authority's emergency plan has complied with between 50% to 70% of the number of sub-components.	The Transmission Operator and Balancing Authority's emergency plan has complied with 50% or less of the number of sub-components
R5	The Transmission Operator and Balancing Authority is missing minor program/procedural elements.	The Transmission Operator and Balancing Authority has failed to annually review one of it's emergency plans	The Transmission Operator and Balancing Authority has failed to annually review two of its emergency plans or communicate with one of it's neighboring Balancing Authorities.	The Transmission Operator and Balancing Authority has failed to annually review and/or communicate any emergency plans with its Reliability Coordinator, neighboring Transmission Operators or Balancing Authorities.
R6	The Transmission Operator and/or the Balancing Authority failed to comply with one (1) of the sub-components.	The Transmission Operator and/or the Balancing Authority failed to comply with two (2) of the sub-components.	The Transmission Operator and/or the Balancing Authority has failed to comply with three (3) of the sub-components.	The Transmission Operator and/or the Balancing Authority has failed to comply with four (4) or more of the sub-components.

Requirement	Lower	Moderate	High	Severe
R6.1	The Transmission Operator or Balancing Authority has failed to establish and maintain reliable communication between interconnected systems.	N/A	N/A	N/A
R6.2	The Transmission Operator or Balancing Authority has failed to arrange new interchange agreements to provide for emergency capacity or energy transfers with required entities when existing agreements could not be used.	N/A	N/A	N/A
R6.3	The Transmission Operator or Balancing Authority has failed to coordinate transmission and generator maintenance schedules to maximize capacity or conserve fuel in short supply.	N/A	N/A	N/A
R6.4	The Transmission Operator or Balancing Authority has failed to arrange for deliveries of electrical energy or fuel from remote systems through normal operating channels.	N/A	N/A	N/A

E. **Regional Differences**

None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by the Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	October 17, 2008	Deleted R2 Replaced Levels of Non-compliance with the February 28, 2008 BOT approved Violation Severity Levels Corrected typographical errors in BOT approved version of VSLs	Revised IROL Project
2	~~To be determined~~August 5, 2009	Removed R2.4 as redundant with EOP-005-2 Requirement R1 for the Transmission Operator; the Balancing Authority does not need a restoration plan.	Revised Project 2006-03
2	August ~~8~~5, 2009	Adopted by NERC Board of Trustees: August 5, 2009	Revised
2	March 17, 2011	FERC Order issued approving EOP-001-2 (Clarification issued on July 13, 2011)	Revised
2b	November 4, 2010	Adopted by NERC Board of Trustees	Project 2008-09 - Interpretation of Requirement R1
2b	November 4, 2010	Adopted by NERC Board of Trustees	Project 2009-28 - Interpretation of Requirement R2.2

Attachment 1-EOP-001-~~0~~0b

Elements for Consideration in Development of Emergency Plans

1. Fuel supply and inventory — An adequate fuel supply and inventory plan that recognizes reasonable delays or problems in the delivery or production of fuel.

2. Fuel switching — Fuel switching plans for units for which fuel supply shortages may occur, e.g., gas and light oil.

3. Environmental constraints — Plans to seek removal of environmental constraints for generating units and plants.

4. System energy use — The reduction of the system's own energy use to a minimum.

5. Public appeals — Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.

6. Load management — Implementation of load management and voltage reductions, if appropriate.

7. Optimize fuel supply — The operation of all generating sources to optimize the availability.

8. Appeals to customers to use alternate fuels — In a fuel emergency, appeals to large industrial and commercial customers to reduce non-essential energy use and maximize the use of customer-owned generation that rely on fuels other than the one in short supply.

9. Interruptible and curtailable loads — Use of interruptible and curtailable customer load to reduce capacity requirements or to conserve the fuel in short supply.

10. Maximizing generator output and availability — The operation of all generating sources to maximize output and availability. This should include plans to winterize units and plants during extreme cold weather.

11. Notifying IPPs — Notification of cogeneration and independent power producers to maximize output and availability.

12. Requests of government — Requests to appropriate government agencies to implement programs to achieve necessary energy reductions.

13. Load curtailment — A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety, and welfare of the community. Address firm load curtailment.

14. Notification of government agencies — Notification of appropriate government agencies as the various steps of the emergency plan are implemented.

15. Notifications to operating entities — Notifications to other operating entities as steps in emergency plan are implemented.

Appendix 1

Requirement Number and Text of Requirement
R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.
Questions:
1. What is the definition of emergency assistance in the context of this standard? What scope and time horizons, if any, are considered necessary in this definition? 2. What was intended by using the adjective "adjacent" in Requirement 1? Does "adjacent Balancing Authorities" mean "All" or something else? Is there qualifying criteria to determine if a very small adjacent Balancing Authority area has enough capacity to offer emergency assistance? 3. What is the definition of the word "remote" as stated in the last phrase of Requirement 1? Does remote mean every Balancing Authority who's area does not physically touch the Balancing Authority attempting to comply with this Requirement? 4. Would a Balancing Authority that participates in a Reserve Sharing Group Agreement, which meets the requirements of Reliability Standard BAL-002-0, Requirement 2, have to establish additional operating agreements to achieve compliance with Reliability Standard EOP-001-0, Requirement 1?
Responses:
1. In the context of this standard, emergency assistance is emergency energy. Emergency energy would normally be arranged for during the current operating day. The agreement should describe the conditions under which the emergency energy will be delivered to the responsible Balancing Authority. 2. The intent is that all Balancing Authorities, interconnected by AC ties or DC (asynchronous) ties within the same Interconnection, have emergency energy assistance agreements with at least one Adjacent Balancing Authority and have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. However, the standard does not require emergency energy assistance agreements with all Adjacent Balancing Authorities, nor does it preclude having an emergency assistance agreement across Interconnections. 3. A remote Balancing Authority is a Balancing Authority other than an Adjacent Balancing Authority. A Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with any remote Balancing Authorities. A Balancing Authority's agreement(s) with Adjacent Balancing Authorities does (do) not preclude the Adjacent Balancing Authority from purchasing emergency energy from remote Balancing Authorities. 4. A Reserve Sharing Group agreement that contains provisions for emergency assistance may be used to meet Requirement R1 of EOP-001-0.

Appendix 2

Requirement Number and Text of Requirement
R2.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.
Questions:
Does the BA need to develop a plan to maintain a load-interchange-generation balance during operating emergencies and follow the directives of the TOP?
Questions:
The answer to both parts of the question is yes. The Balancing Authority is required by the standard to develop, maintain, and implement a plan. The plan must consider the relationships and coordination with the Transmission Operator for actions directly taken by the Balancing Authority. The Balancing Authority must take actions either as directed by the Transmission Operator or the Reliability Coordinator (reference TOP-001-1, Requirement R3), or as previously agreed to with the Transmission Operator or the Reliability Coordinator to mitigate transmission emergencies. As stated in Requirement R4, the emergency plan shall include the applicable elements in "Attachment 1 –EOP-001-0."

~~15.~~

Exhibit D

Consideration of Comments for interpretations to Requirements R1 of EOP-001-0 — Emergency Operations Planning

Project 2008-09
RECM Request for Interpretation - EOP-001-0 - Emergency Operations Planning

Related Files

Status:
Approved by the Board of Trustees on November 4, 2010.

Purpose/Industry Need:
In accordance with the Reliability Standards Development Procedure, the interpretation must be posted for a 30-day pre-ballot review, and then balloted. There is no public comment period for an interpretation. Balloting will be conducted following the same method used for balloting standards. If the interpretation is approved by its ballot pool, then the interpretation will be appended to the standard and will become effective when adopted by the NERC Board of Trustees and approved by the applicable regulatory authorities. The interpretation will remain appended to the standard until the standard is revised through the normal standards development process. When the standard is revised, the clarifications provided by the interpretation will be incorporated into the revised standard.

Draft	Action	Dates	Results	Consideration of Comments
Draft 4 RECM Interpretation for EOP-001-0 Clean	Recirculation Ballot Info>> | Vote>>	10/04/10 - 10/14/10	Summary>> Full Record>>	
Revision 3 RECM Interpretation for EOP-001-0 **Revised Interpretation** Clean | Redline	Initial Ballot Info>> | Vote>>	04/15/10 - 04/26/10 (closed)	Summary>> Full Record>>	Consideration of Comments **(4)**
	Pre-ballot Review Info>> | Join>>	03/16/10 - 04/15/10 (closed)		
Revision 2 RECM Interpretation for EOP-001-0	Initial Ballot Info>> | Vote>>	11/05/09 - 11/16/09 (closed)	Summary>> Ballot Results>>	Consideration of Comments **(3)**
Revised Interpretation Clean	Pre-ballot	10/06/09 -		

| Redline Request for Interpretation	Review Info>> | Join>>	11/05/09 (closed)		
Revision 1 RECM Interpretation for EOP-001-0 Revised Interpretation Clean | Redline Request for Interpretation	Initial Ballot Info>> | Vote>>	02/27/09 - 03/09/09 (closed)	Summary>> Ballot Results>>	Consideration of Comments **(2)**
	Pre-ballot Review Info>> | Join>>	01/28/09 – 02/26/09 (closed)		
RECM Interpretation for EOP-001-0	Recirculation Ballot Info>> (Conducted in error Results are void)	01/06/09 - 01/15/09 (closed)		
RECM Interpretation for EOP-001-0 Interpretation Request for Interpretation	Ballot Window Info>> | Vote>>	06/19/08 – 07/02/08 (closed)	Summary>> Full Record>>	Consideration of Comments **(1)**
	Pre-ballot Review Info>> | Join>>	05/19/08 – 06/19/08 (closed)		

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Consideration of Comments on Initial Ballot RECM Interpretation Request — EOP-001, R1

Summary Consideration: Some entities requested clarification for using dc voltages, the definition of adjacent regarding Balancing Authorities, and how much was “enough” energy emergency assistance. A few entities suggested increased requirements for emergency energy assistance and reserve sharing group participation. The drafting team modified the language in the interpretation to use the defined term Adjacent Balancing Authority and clarified that the requirement does not require energy assistance agreements with all Adjacent Balancing Authorities. The team will submit certain suggestions regarding requirements to the manager of standards development.

Segment	Entity	Ballot	Comments
1	Bonneville Power Administration	Affirmative	In Item 2, we recommend replacing "AC" with "AC and/or DC tie lines in the same interconnection" We strongly support the item 4 interpretation regarding reserve sharing groups.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn’t limit interconnections to AC ties.			
1	Consolidated Edison Co. of New York	Negative	DC ties should have been referenced and included in the interpretation, agreements with ALL adjacent BAs should be required. Specific Emergency Energy Agreements should either be explicit parts of the operating agreements or developed separately and in place as well. Also, participation in a Reserve Sharing Group may be insufficient to meet Requirement R1
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn’t limit interconnections to AC ties. The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain an adequate level of reliability. The technical criteria for establishing what constitutes sufficient emergency assistance should be established through the Standards Development Process.			
1	Duke Energy Carolina	Affirmative	Duke Energy appreciates the opportunity to comment on this Interpretation . Duke Energy supports the concepts in this Interpretation; however, there remain some issues that should be dealt within a Standards Authorization Request to revise the standard. In addition, using a general term such as "enough" still keeps the Balancing Authority in the position of a compliance team interpretation of "enough". Duke Energy believes that the Interpretation should clarify that in the context of this standard, emergency assistance is emergency energy. Emergency energy would normally be arranged for during the current operating day. The agreement should describe the conditions

Segment	Entity	Ballot	Comments
			under which the emergency energy will be delivered to the responsible Balancing Authority. The intent of this standard is that all Balancing Authorities should have sufficient emergency assistance agreements in order to meet Control Performance Standards, Disturbance Control Standards and other applicable standards. Therefore emergency assistance agreements are not required with all adjacent Balancing Authorities. Such agreements may also be in place with remote Balancing Authorities, but are not required.
Response: The drafting team agrees with your comments and will submit them to the manager of standards development for inclusion in the Standards "Issues" database.			
1	FirstEnergy Energy Delivery	Affirmative	FirstEnergy supports the interpretation provided for EOP-001 Requirement R1 and believes it further clarifies Balancing Authority expectations related to emergency assistance agreements with other Balancing Authorities. It is expected that the standards drafting team working on Project 2008-03 will reference this interpretation when completing revisions to the EOP-001 standard to achieve greater clarity within the standard's requirements and measures. The only question we raise and seek clarification to is in regards to item #2 and we question why the interpretation excludes DC ties when defining an adjacent Balancing Authority? As written, would a Balancing Authority be precluded from obtaining emergency assistance from a BA with whom they may only have DC interconnection(s)? Or, is the intent that a DC tie is considered a remote Balancing Authority and covered by item #3?
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties.			
1	National Grid	Negative	National Grid agrees with the comments made by NPCC and other NPCC members: EOP-001, R1 states "Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities. We feel that emergency assistance agreements should be made with ALL adjacent BAs which is contrary to the interpretation which states the intent is to have emergency agreements with at least one adjacent BA. Additionally, the interpretation states that "The responsible Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with all remote Balancing Authorities". We feel that emergency agreements with ALL adjacent BAs further needs to be in place in order for a BA to get remote assistance from a non-adjacent or through an adjacent BA. DC ties should have been referenced and included in the interpretation. The interpretation furthers states that a BA that is compliant with BAL-002 —" Disturbance Control Performance Requirement R2 through participation in a Reserve

Segment	Entity	Ballot	Comments
			Sharing Group Agreement, is not required to establish additional operating agreements for EOP-001-0 Requirement R1. We feel that participation in a Reserve Sharing Group may be insufficient to meet Requirement 1.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties. The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain an adequate level of reliability. The technical criteria for establishing what constitutes sufficient emergency assistance should be established through the Standards Development Process.			
1	New Brunswick Power Transmission Corporation	Negative	DC ties should have been referenced and included in the interpretation, agreements with ALL adjacent BAs should be required. Specific Emergency Energy Agreements should either be explicit parts of the operating agreements or developed separately and in place as well. Also, participation in a Reserve Sharing Group may be insufficient to meet Requirement R1.
Response: The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain an adequate level of reliability. The technical criteria for establishing what constitutes sufficient emergency assistance should be established through the Standards Development Process.			
1	New York Power Authority	Negative	DC ties should have been referenced and included in the interpretation, agreements with ALL adjacent BAs should be required. Specific Emergency Energy Agreements should either be explicit parts of the operating agreements or developed separately and in place as well. Also, participation in a Reserve Sharing Group may be insufficient to meet Requirement R1.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties. The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain an adequate level of reliability. The technical criteria for establishing what constitutes sufficient emergency assistance should be established through the Standards Development Process.			
1	Northeast Utilities	Negative	DC ties should be referenced and included in the interpretation. Agreements with ALL adjacent BAs should be required. Specific Emergency Energy Agreements should either be explicit parts of the operating agreements, or developed separately and in place as well.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which			

Segment	Entity	Ballot	Comments
doesn't limit interconnections to AC ties. The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain an adequate level of reliability.			
2	Independent Electricity System Operator	Negative	While the IESO agrees with various aspects of the clarification provided, which we believe helpful, we nonetheless disagree with a number of the clarifications we deem significantly flawed for reasons noted below and must vote NO to the interpretations: 1. The interpretation offered indicated that being part of a RSG is sufficient to meet the obligation of this requirement — we do not agree with this position. Two BAs may engage in a reserve sharing agreement that is designed to offset reserve requirements or to provide support for DCS recover from an incident. However, if the operating agreement does not explicitly address energy assistance under emergency conditions, and the scope and condition of the emergency, emergency energy may not flow. Additionally, reserve sharing agreement addresses the amount of reserve that each participating member needs to carry to meet the overall group and/or individual BAs reserve requirements. Situation can exist that while the shared reserve is used up and a BA is still short of resource, and additional energy delivery is required to take care of the emergency. 2. The SDT indicated that it is OK not to have emergency energy assistance agreements with all adjacent BAs â€“ this is contrary to the NPCC position which dictates that an entity (the responsible BA) must have emergency energy assistance agreements with all adjacent BA entities â€“ this could be either as part of the operating agreement or as a separate explicit agreement by itself. 3. Further, the interpretation precludes adjacent BAs which are connected with only DC ties. It is IESO view that provision of emergency assistance should also be available from areas that are interconnected by DC ties.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties. The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain an adequate level of reliability. The technical criteria for establishing what constitutes sufficient emergency assistance should be established through the Standards Development Process.			
2	ISO New England, Inc.	Negative	DC ties should be included in the interpretation, not just AC ties. Agreements with ALL adjacent BAs should be required. Specific Emergency Energy

Segment	Entity	Ballot	Comments
			Agreements should either be explicit parts of the operating agreements or developed separately and in place as well. Participation in a Reserve Sharing Group may be insufficient to meet Requirement R1 unless such agreement explicitly contains Emergency Energy Agreements among parties.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties. The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain an adequate level of reliability. The technical criteria for establishing what constitutes sufficient emergency assistance should be established through the Standards Development Process.			
3	Bonneville Power Administration	Affirmative	Related to the Subcommittee's recommended interpretation #2 BPA suggests the following language changes: An adjacent Balancing Authority is one that has AC and/or DC tie lines in the same interconnection with the responsible BA. We like the interpretation #4 and do want to see it changed.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties.			
3	Consolidated Edison Co. of New York	Negative	DC ties should have been referenced and included in the interpretation, agreements with ALL adjacent BAs should be required. Specific Emergency Energy Agreements should either be explicit parts of the operating agreements or developed separately and in place as well. Also, participation in a Reserve Sharing Group may be insufficient to meet Requirement R1"
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties. The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain an adequate level of reliability. The technical criteria for establishing what constitutes sufficient emergency assistance should be established through the Standards Development Process.			
3	Consumers Energy	Affirmative	We agree with the intent of the interpretation to Question 4, but suggest it would be unequivocally clear to state: "A Balancing Authority that is compliant with Reliability Standard BAL-002-0, Requirement R2 through participation in a Reserve Sharing Group Agreement shall be deemed to be fully compliant with Requirement R1 of EOP-001-1."
Response: Your comment will be submitted to the manager of standards development for inclusion in the Standards "Issues" database as a potential modification to the associated standard.			
3	FirstEnergy Solutions	Affirmative	"FirstEnergy supports the interpretation provided for EOP-001 Requirement R1

Segment	Entity	Ballot	Comments
			and believes it further clarifies Balancing Authority expectations related to emergency assistance agreements with other Balancing Authorities. It is expected that the standards drafting team working on Project 2008-03 will reference this interpretation when completing revisions to the EOP-001 standard to achieve greater clarity within the standard's requirements and measures. The only question we raise and seek clarification to is in regards to item #2 and we question why the interpretation excludes DC ties when defining an adjacent Balancing Authority? As written, would a Balancing Authority be precluded from obtaining emergency assistance from a BA with whom they may only have DC interconnection(s)? Or, is the intent that a DC tie is considered a remote Balancing Authority and covered by item #3? "
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties.			
3	Hydro One Networks, Inc.	Negative	Hydro One Networks Inc. casts a Negative vote with the following comments: 1. DC ties should have been referenced and included in the interpretation. 2. Agreements with ALL adjacent BAs should be required. 3. Specific Emergency Energy Agreements should either be explicit parts of the operating agreements or developed separately and in place as well. 4. Participation in a Reserve Sharing Group may be insufficient to meet Requirement R1.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties. The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain an adequate level of reliability. The technical criteria for establishing what constitutes sufficient emergency assistance should be established through the Standards Development Process.			
3	Louisville Gas and Electric Co.	Affirmative	E.ON US votes YES and wishes to emphasize in our comments the value and importance of Reserve Sharing Groups (RSGs) to first and foremost ensure, reliability on a real-time basis, and also to lower the cost of providing electrical power to our customers. Due to this value, NERC and the Industry should support, encourage and seek expansion of RSGs. Our specific points are as follows. The reliability benefits to the parties of RSGs are: – The parties have access to the Contingency Reserve generation capacity of all members on a real time basis and have certainty of emergency energy supply. – The parties utilize a computerized process that immediately dispatches generation and spinning reserves and ten-minute quick-start Contingency Reserves when called upon by a party with a

Segment	Entity	Ballot	Comments
			sudden loss of supply – resulting in an immediate response to the supply loss. – The diversity and large number of generating units quickly ramping up to provide emergency power further ensure certainty and an immediate response to the supply loss. – The parties coordinate in advance TRM to ensure that emergency energy for Contingency Reserves can flow in real-time when called on, resulting in certainty of transmission for the flow of emergency energy. The lower cost benefits to the end user customers of the parties of RSGs are: – More efficient use of supply due to reduced Operating Reserves for each BA, despite the size of each BA, in RSGs. (The Midwest ISO has stated that they have conducted studies that have demonstrated that each MW of spinning reserve has a value of $350,000. Thus, the 300 MW of spinning reserves to be provided at the start of the ASM to the Midwest ISO load by MCRSG parties external to the Midwest ISO footprint equate to approximately $100 million in annual value. This value will become an annual cost to the Midwest ISO load upon sunset of the MCRSG. This does not include the savings of similar nature to the external BAs.) – The flexibility to transact more energy between BAs with freed-up generation and transmission capacity is achieved even if the Midwest BA grows and the External CRSG BAs decrease to only a few parties. – The advance coordination of TRM reduces the amount of TRM needed. Due to these points, RSGs among BAs, including BAs which are large ISOs operating day ahead and real-time markets along with Operating Reserve markets, should be encouraged. Also, E.ON US – YES vote supports the NERC interpretation that Emergency Assist agreements (EAAs) between interconnected BAs are not required between every interconnect BA to meet NERC Standards. Since the nature of EAAs is for a BA to provide emergency power to a BA, with a supply emergency, immediately or in the near term future (next hour, day or week), E.ON US suggest that NERC should encourage all BAs to file unilateral EAAs at the appropriate rate, MBR or CBR where applicable. Such unilateral filings would establish agreements and rates to provide non-firm emergency power if available after BAs and their associated LSEs have ensured adequate supply to native load and firm transactions (Designated Network Load).

Segment	Entity	Ballot	Comments
Response: Your comments will be submitted to the manager of standards development.			
3	New York Power Authority	Negative	DC ties should have been referenced and included in the interpretation agreements with ALL adjacent BAs should be required. Specific Emergency Energy Agreements should either be explicit parts of the operating agreements or developed separately and in place as well. Also, participation in a Reserve Sharing Group may be insufficient to meet Requirement R1.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties. The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain n adequate level of reliability. The technical criteria for establishing what constitutes sufficient emergency assistance should be established through the Standards Development Process.			
3	Niagara Mohawk (National Grid Company)	Negative	DC ties should have been referenced and included in the interpretation agreements with ALL adjacent BAs should be required. Specific Emergency Energy Agreements should either be explicit parts of the operating agreements or developed separately and in place as well. Also, participation in a Reserve Sharing Group may be insufficient to meet Requirement R1.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties. The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain an adequate level of reliability. The technical criteria for establishing what constitutes sufficient emergency assistance should be established through the Standards Development Process.			
4	Consumers Energy	Affirmative	We agree with the intent of the interpretation to Question 4, but suggest it would be unequivocally clear to state: "A Balancing Authority that is compliant with Reliability Standard BAL-002-0, Requirement R2 through participation in a Reserve Sharing Group Agreement shall be deemed to be fully compliant with Requirement R1 of EOP-001-1."
Response: Your comment will be submitted to the manager of standards development for inclusion in the Standards "Issues" database as a potential modification to the associated standard.			
5	Bonneville Power Administration	Affirmative	BPA agrees in principle with the interpretation with a couple of comments. - With regards to number 2; BPA would recommend the inclusion DC ties and suggests the following language changes: "An adjacent Balancing Authority is one that has AC or DC tie lines in the same interconnection with the responsible BA" This would allow for the inclusion of the Pacific DC intertie

Segment	Entity	Ballot	Comments
			between BPA and LADWP. - BPA fully supports interpretation 4. with regards to reserve sharing groups.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties.			
5	Louisville Gas and Electric Co.	Affirmative	E.ON US votes YES and wishes to emphasize in our comments the value and importance of Reserve Sharing Groups (RSGs) to first and foremost ensure, reliability on a real-time basis, and also to lower the cost of providing electrical power to our customers. Due to this value, NERC and the Industry should support, encourage and seek expansion of RSGs. Our specific points are as follows. The reliability benefits to the parties of RSGs are: – The parties have access to the Contingency Reserve generation capacity of all members on a real time basis and have certainty of emergency energy supply. – The parties utilize a computerized process that immediately dispatches generation and spinning reserves and ten-minute quick-start Contingency Reserves when called upon by a party with a sudden loss of supply resulting in an immediate response to the supply loss. – The diversity and large number of generating units quickly ramping up to provide emergency power further ensure certainty and an immediate response to the supply loss. – The parties coordinate in advance TRM to ensure that emergency energy for Contingency Reserves can flow in real-time when called on, resulting in certainty of transmission for the flow of emergency energy. The lower cost benefits to the end user customers of the parties of RSGs are: – More efficient use of supply due to reduced Operating Reserves for each BA, despite the size of each BA, in RSGs. (The Midwest ISO has stated that they have conducted studies that have demonstrated that each MW of spinning reserve has a value of $350,000. Thus, the 300 MW of spinning reserves to be provided at the start of the ASM to the Midwest ISO load by MCRSG parties external to the Midwest ISO footprint equate to approximately $100 million in annual value. This value will become an annual cost to the Midwest ISO load upon sunset of the MCRSG. This does not include the savings of similar nature to the external BAs.) – The flexibility to transact more energy between BAs with freed-up generation and transmission capacity is achieved even if the Midwest BA grows and the External CRSG BAs decrease to only a few parties.

Segment	Entity	Ballot	Comments
			– The advance coordination of TRM reduces the amount of TRM needed. Due to these points, RSGs among BAs, including BAs which are large ISOs operating day ahead and real-time markets along with Operating Reserve markets, should be encouraged. Also, E.ON US – YES vote supports the NERC interpretation that Emergency Assist agreements (EAAs) between interconnected BAs are not required between every interconnect BA to meet NERC Standards. Since the nature of EAAs is for a BA to provide emergency power to a BA, with a supply emergency, immediately or in the near term future (next hour, day or week), E.ON US suggest that NERC should encourage all BAs to file unilateral EAAs at the appropriate rate, MBR or CBR where applicable. Such unilateral filings would establish agreements and rates to provide non-firm emergency power if available after BAs and their associated LSEs have ensured adequate supply to native load and firm transactions (Designated Network Load).
Response: Your comments will be submitted to the manager of standards development.			
6	Bonneville Power Administration	Affirmative	In Item 2, we recommend replacing "AC" with "AC and/or DC tie lines in the same interconnection. "We strongly support the item 4 interpretation regarding reserve sharing groups.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties.			
6	Consolidated Edison Co. of New York	Negative	DC ties should have been referenced and included in the interpretation, agreements with ALL adjacent BAs should be required. Specific Emergency Energy Agreements should either be explicit parts of the operating agreements or developed separately and in place as well. Also, participation in a Reserve Sharing Group may be insufficient to meet Requirement R1.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties. The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain an adequate level of reliability. The technical criteria for establishing what constitutes sufficient emergency assistance should be established through the Standards Development Process.			
6	Entergy Services, Inc.	Affirmative	While we agree with the interpretation, we believe there are some items to consider for clarification if this interpretation must go back for recirculation or re-balloting: Question 1 interpretation: the interpretation should address both a Capacity Emergency and Energy Emergency, as defined in the NERC Glossary. Further clarification to explain that emergency assistance is

Segment	Entity	Ballot	Comments
			applicable to both situations (capacity, energy or both) will minimize any confusion in the requirement and interpretation. (note —" there appears to be little, if any difference in the definition of the terms; further clarification of the terms or eliminating one of the terms/consolidating the terms this would be an area for improvement in the NERC Standards) Question 2 interpretation: the interpretation should use the approved term from the NERC Glossary: Adjacent Balancing Authority Question 3 interpretation: the term "emergency assistance, as defined in Question 1 should be used in lieu of "emergency energy assistance," or alternatively use the NERC Glossary terms Capacity Emergency and Energy Emergency Question 4 interpretation: the interpretation should specify that RSG agreements may be used if they contain provisions for use during a Capacity Emergency or Energy Emergency
Response: Your comments will be submitted to the manager of standards development for inclusion in the Standards "Issues" database as a potential modification to the associated standard.			
6	FirstEnergy Solutions	Affirmative	FirstEnergy supports the interpretation provided for EOP-001 Requirement R1 and believes it further clarifies Balancing Authority expectations related to emergency assistance agreements with other Balancing Authorities. It is expected that the standards drafting team working on Project 2008-03 will reference this interpretation when completing revisions to the EOP-001 standard to achieve greater clarity within the standard's requirements and measures. The only question we raise and seek clarification to is in regards to item #2 and we question why the interpretation excludes DC ties when defining an adjacent Balancing Authority? As written, would a Balancing Authority be precluded from obtaining emergency assistance from a BA with whom they may only have DC interconnection(s)? Or, is the intent that a DC tie is considered a remote Balancing Authority and covered by item #3?
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties.			
6	Louisville Gas and Electric Co.	Affirmative	E.ON US votes YES and wishes to emphasize in our comments the value and importance of Reserve Sharing Groups (RSGs) to first and foremost ensure, reliability on a real-time basis, and also to lower the cost of providing electrical power to our customers. Due to this value, NERC and the Industry should support, encourage and seek expansion of RSGs. Our specific points are as follows. The reliability benefits to the parties of RSGs are: – The parties have access to the Contingency Reserve generation capacity of all members on a real time basis and have certainty of emergency energy supply. – The parties utilize a computerized process that immediately dispatches generation and spinning reserves and ten-minute quick-

Segment	Entity	Ballot	Comments
			start Contingency Reserves when called upon by a party with a sudden loss of supply resulting in an immediate response to the supply loss. – The diversity and large number of generating units quickly ramping up to provide emergency power further ensure certainty and an immediate response to the supply loss. – The parties coordinate in advance TRM to ensure that emergency energy for Contingency Reserves can flow in real-time when called on, resulting in certainty of transmission for the flow of emergency energy. The lower cost benefits to the end user customers of the parties of RSGs are: – More efficient use of supply due to reduced Operating Reserves for each BA, despite the size of each BA, in RSGs. (The Midwest ISO has stated that they have conducted studies that have demonstrated that each MW of spinning reserve has a value of $350,000. Thus, the 300 MW of spinning reserves to be provided at the start of the ASM to the Midwest ISO load by MCRSG parties external to the Midwest ISO footprint equate to approximately $100 million in annual value. This value will become an annual cost to the Midwest ISO load upon sunset of the MCRSG. This does not include the savings of similar nature to the external BAs.) – The flexibility to transact more energy between BAs with freed-up generation and transmission capacity is achieved even if the Midwest BA grows and the External CRSG BAs decrease to only a few parties. – The advance coordination of TRM reduces the amount of TRM needed.
Response: Your comments will be submitted to the manager of standards development.			
9	Commonwealth of Massachusetts Department of Public Utilities	Negative	Interpreters should: 1) reconsider inclusion of BAs with DC ties, or explain why BAs with DC ties should be excluded; 2) specify that Reserve Sharing Agreements have provisions addressing emergency assistance and that there be a demonstration that the Reserve Sharing Agreement is sufficient to mitigate reasonably anticipated energy emergencies; and, 3) reconsider requiring that BAs have agreements with all adjacent BAs or explain why an agreement with one adjacent BA is sufficient under the Requirement 1 language.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties.			

Segment	Entity	Ballot	Comments
The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain an adequate level of reliability. The technical criteria for establishing what constitutes sufficient emergency assistance should be established through the Standards Development Process.			
9	National Association of Regulatory Utility Commissioners	Negative	Interpreters should: 1) reconsider inclusion of BAs with DC ties, or explain why BAs with DC ties should be excluded; 2) specify that Reserve Sharing Agreements have provisions addressing emergency assistance and that there be a demonstration that the Reserve Sharing Agreement is sufficient to mitigate reasonably anticipated energy emergencies; and, 3) reconsider requiring that BAs have agreements with all adjacent BAs or explain why an agreement with one adjacent BA is sufficient under the Requirement 1 language.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties. The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain an adequate level of reliability. The technical criteria for establishing what constitutes sufficient emergency assistance should be established through the Standards Development Process.			
10	Northeast Power Coordinating Council, Inc.	Negative	DC tie lines should have been included in the interpretation. Agreements with all adjacent BAs should be required. Participation in a Reserve Sharing Group is insufficient to meet Requirement R1, unless the Reserve Sharing Group agreement contains emergency assistance provisions.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties. The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain an adequate level of reliability. The technical criteria for establishing what constitutes sufficient emergency assistance should be established through the Standards Development Process.			

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Initial Ballot for the Revised Interpretation of EOP-001-0 Requirement R1 for the Regional Entity Compliance Managers (Project 2008-09)

Ballot conducted from February 27 to March 9, 2009

Summary Consideration:

There were three primary areas of concern expressed by balloters who submitted a negative vote:

1. EOP-001-0 should be applied on an Interconnection basis. Therefore, balloters recommended modifying paragraph 2 of the interpretation by inserting the phrase "interconnected by AC ties or DC (asynchronous) ties within the same Interconnection." The Operating Reliability Subcommittee Executive Committee (ORS EC), which is serving as the drafting team for the interpretation, agrees with these balloters and proposes to modify paragraph 2 accordingly.

2. Several balloters questioned the use of the word "all" in the second sentence paragraph 3 of the interpretation. Use of the word all in this context implied to balloters that "at least one" was required. The ORS EC agrees with balloters and proposes to modify the interpretation by changing the word "all" to "any" in the second sentence of paragraph 3.

3. Several balloters questioned whether a Reserve Sharing Group agreement could substitute for an emergency assistance agreement with adjacent Balancing Authorities. Without an emergency assistance agreement, the conditions under which emergency energy assistance could be provided will remain undefined. The ORS EC agrees with balloters and proposes to modify paragraph 4 of the interpretation to read, "A Reserve Sharing Group agreement that contains provisions for emergency assistance may be used to meet Requirement R1 of EOP-001-0."

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
Stanley M Jaskot	Entergy Corporation	5	Negative	1. We believe this standard should be applied on an Interconnection basis. Therefore, we recommend Item #2 be revised to "The intent is that all Balancing Authorities, interconnected by AC ties or DC (asynchronous) ties within the same Interconnection, have emergency ..." 2. We also recommend the "responsible Balancing Authority" be revised to "deficient Balancing Authority" in Item #3. Item # 3. A remote Balancing Authority is a Balancing Authority other than an Adjacent Balancing Authority. The responsible DEFICIENT Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with all remote Balancing Authorities. The responsible DEFICIENT Balancing Authority's agreement(s) with the Adjacent Balancing Authorities does (do) not preclude the Adjacent Balancing Authority from purchasing emergency energy from remote Balancing Authorities on behalf of the responsible DEFICIENT Balancing Authority. 3. We agree with the clarification that BAs are not required to have agreements with ALL Adjacent BAs.
Response: Comment 1 – The Operating Reliability Subcommittee Executive Committee (ORS EC) agrees with the balloter and will insert the phrase "interconnected by AC ties or DC (asynchronous) ties within the same Interconnection" in the first sentence of paragraph 2. Comment 2 – The ORS EC agrees to eliminate the term "responsible" from the second, third, and forth sentences of paragraph 3. The ORS EC does not agree to insertion of the term "deficient." EOP-001-0 is applicable to all Balancing Authorities. In addition, the ORS EC proposes to reword the last sentence of paragraph 3 to eliminate "on behalf of the responsible BA." Comment 3 - The ORS EC agrees with the balloter; however, in response to other balloters, the ORS EC proposes to modify the interpretation by changing the word "all" to "any" in paragraph 3.				
Paul Rocha	CenterPoint Energy	1	Negative	CenterPoint Energy recommends further clarification of the terms "adjacent" and "neighboring" to address that such terms are not applicable to interconnection-wide regions, such as WECC and ERCOT. The proposed definition failed to explain the term "adjacent" as requested.
Response: The ORS EC agrees with the balloter and will insert the phrase "interconnected by AC ties or DC (asynchronous) ties within the same Interconnection" in the first sentence of paragraph 2 of the interpretation.				

Voter	Entity	Segment	Vote	Comment
Robert Martinko	FirstEnergy Energy Delivery	1	Affirmative	FirstEnergy supports the interpretation provided for EOP-001 Requirement R1 and believes it further clarifies Balancing Authority expectations related to emergency assistance agreements with other Balancing Authorities. It is expected that the standards drafting team that will work on Project 2009-03 will incorporate this interpretation when completing revisions to the EOP-001 standard to achieve greater clarity within the standard's requirements and measures.
Joanne Kathleen Borrell	FirstEnergy Solutions	3	Affirmative	FirstEnergy supports the interpretation provided for EOP-001 Requirement R1 and believes it further clarifies Balancing Authority expectations related to emergency assistance agreements with other Balancing Authorities. It is expected that the standards drafting team that will work on Project 2009-03 will incorporate this interpretation when completing revisions to the EOP-001 standard to achieve greater clarity within the standard's requirements and measures.
Douglas Hohlbaugh	Ohio Edison Company	4	Affirmative	FirstEnergy supports the interpretation provided for EOP-001 Requirement R1 and believes it further clarifies Balancing Authority expectations related to emergency assistance agreements with other Balancing Authorities. It is expected that the standards drafting team that will work on Project 2009-03 will incorporate this interpretation when completing revisions to the EOP-001 standard to achieve greater clarity within the standard's requirements and measures.
Kenneth Dresner	FirstEnergy Solutions	5	Affirmative	FirstEnergy supports the interpretation provided for EOP-001 Requirement R1 and believes it further clarifies Balancing Authority expectations related to emergency assistance agreements with other Balancing Authorities. It is expected that the standards drafting team that will work on Project 2009-03 will incorporate this interpretation when completing revisions to the EOP-001 standard to achieve greater clarity within the standard's requirements and measures.
Mark S Travaglianti	FirstEnergy Solutions	6	Affirmative	FirstEnergy supports the interpretation provided for EOP-001 Requirement R1 and believes it further clarifies Balancing Authority expectations related to emergency assistance agreements with other Balancing Authorities. It is expected that the standards drafting team that will work on Project 2009-03 will incorporate this interpretation when completing revisions to the EOP-001 standard to achieve greater clarity within the standard's requirements and measures.
Response: The ORS EC agrees with the balloters.				

Voter	Entity	Segment	Vote	Comment
Roy D. McCoy	Electric Reliability Council of Texas, Inc.	2	Negative	Interpretation should clarify what "adjacent" and "neighboring" means. Does it mean that EOP-001 applies to registered functional entities with AC ties or DC ties "within" an Interconnection and does not apply to DC ties "between" Interconnections?
Response: The ORS EC agrees with the balloter and will insert the phrase "interconnected by AC ties or DC (asynchronous) ties within the same Interconnection" in the first sentence of paragraph 2 of the interpretation.				
Alden Briggs	New Brunswick System Operator	2	Negative	NBSO disagrees with this interpretation for two reasons: Firstly, 4. A Balancing Authority that is compliant with Reliability Standard BAL-002-0, Requirement R2 through participation in a Reserve Sharing Group Agreement is not required to establish additional operating agreements as described in Requirement R1 of EOP-001-0. Reserve Sharing agreements may not include emergency energy agreements. Secondly, From the 3rd paragraph on the interpretation: The responsible Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with all remote Balancing Authorities. This statement appears to state that an agreement is required with a remote BA. Though it is believed that this was not the intent of the interpretation it can cause confusion.
Response: Comment 1 – The ORS EC agrees with balloter and proposes to modify paragraph 4 of the interpretation to read, "A Reserve Sharing Group agreement that contains provisions for emergency assistance may be used to meet Requirement R1 of EOP-001-0." Comment 2 - The ORS EC agrees with balloter and proposes to modify paragraph 3 of the interpretation by changing the word "all" to "any" in the second sentence.				
Richard Kinas	Orlando Utilities Commission	5	Affirmative	Since you decided to place Adjacent into the NERC glossary, I'm suprised that you did not decide to do the same with "remote" i.e. Remote - any entity that is not Adjacent
Response: The term Adjacent Balancing Authority is in the *Glossary of Terms Used in Reliability Standards*. The *Glossary of Terms Used in Reliability Standards* may not be modified via an interpretation.				

Voter	Entity	Segment	Vote	Comment
Kim Warren	Independent Electricity System Operator	2	Negative	The IESO views the Reserve Sharing Group (RSG) and emergency assistance agreements as distinct and serving two separate and necessary functions. Under this interpretation we envisage situations where, despite the existence of the RSG agreement, emergency assistance (that may be needed for a lengthy period) may not be provided because its scope and conditions of supply are not defined. We believe this therefore leaves room for non-compliance and would expose the system to unreliable operation when emergency assistance is needed but cannot be arranged or delivered absent an operating agreement. We agree that a RSG agreement may be adequate to meet EOP-001-0, R1 but only if it explicitly includes provisions for emergency energy assistance.
Response: The ORS EC agrees with balloter and proposes to modify paragraph 4 of the interpretation to read, "A Reserve Sharing Group agreement that contains provisions for emergency assistance may be used to meet Requirement R1 of EOP-001-0."				
James Armke	Austin Energy	1	Negative	The Interpretation should clarify that the adjective "adjacent" is intended for neighboring Balancing Authorities interconnected by AC ties. For ERCOT, the requirement would be unnecessary and burdensom with no impact to reliability because flows across the DC ties remain at their scheduled values and do not impact neighboring Balancing Authorities.
Response: The ORS EC agrees with the balloter and will insert the phrase "interconnected by AC ties or DC (asynchronous) ties within the same Interconnection" in the first sentence of paragraph 2 of the interpretation.				
Gregory Campoli	New York Independent System Operator	2	Negative	The NYISO is concerned with the second sentence in Paragraph 3 that says, 'The responsible Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with all remote Balancing Authorities.' We are concerned that this means that a BA is required to have an agreement in place for purchasing emergency energy with at least one remote BA. We do not support this interpretation and believe that existing standard only obligates a BA to have agreements in place with adjacent BA's. The NYISO is also concerned that a Reserve Sharing Group (RSG) can be a substitute for emergency assistance agreement with adjacent BA's. Without an emergency assistance agreement, the scope of and conditions under which emergency energy assistance could be provided, will remain undefined.
Response: Comment 1 – The ORS EC agrees with balloter and proposes to modify paragraph 3 of the interpretation by changing the word "all" to "any" in the				

Voter	Entity	Segment	Vote	Comment
second sentence. Comment 2 – The ORS EC agrees with balloter and proposes to modify paragraph 4 of the interpretation to read, "A Reserve Sharing Group agreement that contains provisions for emergency assistance may be used to meet Requirement R1 of EOP-001-0."				
Kent Saathoff	Electric Reliability Council of Texas, Inc.	10	Negative	The original interpretation was correct. This revised interpretation would apply requirements appropriate for adjacent entities connected synchronously by AC lines to entities connected only by asynchronous DC lines. Such requirements would serve no reliability purpose and be a waste of resources for entities connected solely by DC ties which have no uncontrolled flows.
Response: The ORS EC agrees with the balloter and will insert the phrase "interconnected by AC ties or DC (asynchronous) ties within the same Interconnection" in the first sentence of paragraph 2 of the interpretation.				
James R. Keller	Wisconsin Electric Power Marketing	3	Negative	The sentence within #3 of the EOP-001-1 R1 interpretation "The responsible Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with all remote Balancing Authorities." is stating that the Responsible BA must have arrangements with some remote BAs. The "all" needs to be replaced with "any" in this sentence.
Linda Horn	Wisconsin Electric Power Co.	5	Negative	The sentence within #3 of the EOP-001-1 R1 interpretation "The responsible Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with all remote Balancing Authorities." is stating that the Responsible BA must have arrangements with some remote BAs. The "all" needs to be replaced with "any" in this sentence.
Response: The ORS EC agrees with balloter and proposes to modify paragraph 3 of the interpretation by changing the word "all" to "any" in the second sentence.				
Anthony Jankowski	Wisconsin Energy Corp.	4	Negative	The wording related to Remote Balancing Authorities should read "with any" instead of "with all" in paragraph #3.
Response: The ORS EC agrees with balloter and proposes to modify paragraph 3 of the interpretation by changing the word "all" to "any" in the second sentence.				

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Project 2009-23: Interpretation of EOP-001-0 for the Regional Entity Compliance Managers
Consideration of Comments for Initial Ballot of Revision 2 (November 5–16, 2009)

Summary Consideration: A few balloters explained that the wording in the response to question 2 appeared to limit the Balancing Authority to agreements with Balancing Authorities within the same interconnection, which may be interpreted to nullify the use of existing agreements that cross interconnections as sufficient to meet this requirement. In response to those comments, the Executive Committee of the Operating Reliability Subcommittee, which is serving as the drafting team for this interpretation, revised paragraph 2 to read, "The intent is that all Balancing Authorities, interconnected by AC ties or DC (asynchronous) ties within the same Interconnection, have emergency energy assistance agreements with at least one Adjacent Balancing Authority and have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. However, the standard does not require emergency energy assistance agreements with all Adjacent Balancing Authorities, nor does it preclude having an emergency assistance agreement across Interconnections."

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Voter	Entity	Segment	Vote	Comment
Paul B. Johnson	American Electric Power	1	Negative	AEP appreciates the additional work of the SDT to improve the EOP-001-0 R1 interpretation. In most cases, AEP agrees with the changes that have been made. However, AEP is concerned that the word choice in the response to question 2. The wording appears to limit the BA to agreements with BAs within the same interconnection. In doing so, the standard may be interpreted to nullify the use of existing agreements that cross interconnections as sufficient to meet this requirement. AEP suggests that the wording be rephrased to avoid this implication. AEP also disagrees with the need to add the phrase "that contains provisions for emergency assistance may be used to meet" since the intent of entities participating in Reserve Sharing Groups is to have Reserves (Emergency Energy) available to them in the event of such a contingency. Access to "emergency assistance" (Emergency Energy by this interpretation) is only one aspect of an emergency operations plan. There are other elements of the emergency operations plan that can be deployed in an emergency to alleviate the issue in more lengthy events. To imply in this standard that conditions exists, such as "emergency assistance may be needed for xduration," is not accurate; to suggest otherwise expands the scope of the existing requirement. It is AEP's belief that to expand the scope of this requirement to the extent IESO and NBSO suggests should require a full discussion of the industry in the next version of this standard.

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
Raj Rana	American Electric Power	3	Negative	AEP appreciates the additional work of the SDT to improve the EOP-001-0 R1 interpretation. In most cases, AEP agrees with the changes that have been made. However, AEP is concerned that the word choice in the response to question 2. The wording appears to limit the BA to agreements with BAs within the same interconnection. In doing so, the standard may be interpreted to nullify the use of existing agreements that cross interconnections as sufficient to meet this requirement. AEP suggests that the wording be rephrased to avoid this implication. AEP also disagrees with the need to add the phrase "that contains provisions for emergency assistance may be used to meet" since the intent of entities participating in Reserve Sharing Groups is to have Reserves (Emergency Energy) available to them in the event of such a contingency. Access to "emergency assistance" (Emergency Energy by this interpretation) is only one aspect of an emergency operations plan. There are other elements of the emergency operations plan that can be deployed in an emergency to alleviate the issue in more lengthy events. To imply in this standard that conditions exists, such as "emergency assistance may be needed for xduration," is not accurate; to suggest otherwise expands the scope of the existing requirement. It is AEP's belief that to expand the scope of this requirement to the extent IESO and NBSO suggests should require a full discussion of the industry in the next version of this standard.
Edward P. Cox	AEP Marketing	6	Negative	AEP appreciates the additional work of the SDT to improve the EOP-001-0 R1 interpretation. In most cases, AEP agrees with the changes that have been made. However, AEP is concerned that the word choice in the response to question 2. The wording appears to limit the BA to agreements with BAs within the same interconnection. In doing so, the standard may be interpreted to nullify the use of existing agreements that cross interconnections as sufficient to meet this requirement. AEP suggests that the wording be rephrased to avoid this implication. AEP also disagrees with the need to add the phrase "that contains provisions for emergency assistance may be used to meet" since the intent of entities participating in Reserve Sharing Groups is to have Reserves (Emergency Energy) available to them in the event of such a contingency. Access to "emergency assistance" (Emergency Energy by this interpretation) is only one aspect of an emergency operations plan. There are other elements of the emergency operations plan that can be deployed in an emergency to alleviate the issue in more lengthy events. To imply in this standard that conditions exists, such as "emergency assistance may be needed for xduration," is not accurate; to suggest otherwise expands the scope of the existing requirement. It is AEP's belief that to expand the scope of this requirement to the extent IESO and NBSO suggests should require a full discussion of the industry in the next version of this standard.

Voter	Entity	Segment	Vote	Comment
Response: The Operating Reliability Subcommittee (ORS) Executive Committee agrees with AEP's comment and will add the phrase, "nor does it preclude having an emergency assistance agreement across Interconnections" at the end of paragraph 2. The ORS Executive Committee disagrees with the second part of AEP's comment because some Reserve Sharing Groups limit access to emergency assistance.				
Robert Martinko	FirstEnergy Energy Delivery	1	Affirmative	FirstEnergy Corp. supports the interpretation and has voted Affirmative. We offer the following comments: Since this interpretation is specific to Version "0" of EOP-001, it is not clear how NERC staff will integrate this interpretation into Board Approved (October 2008) Version "1" of EOP-001. We suggest that NERC add this interpretation to the Version 1 standard which was revised per the NERC project "Operate Within Interconnection Reliability Operating Limits" which is currently pending filing with FERC.
Joanne Kathleen Borrell	FirstEnergy Solutions	3	Affirmative	FirstEnergy Corp. supports the interpretation and has voted Affirmative. We offer the following comments: Since this interpretation is specific to Version "0" of EOP-001, it is not clear how NERC staff will integrate this interpretation into Board Approved (October 2008) Version "1" of EOP-001. We suggest that NERC add this interpretation to the Version 1 standard which was revised per the NERC project "Operate Within Interconnection Reliability Operating Limits" which is currently pending filing with FERC.
Douglas Hohlbaugh	Ohio Edison Company	4	Affirmative	FirstEnergy Corp. supports the interpretation and has voted Affirmative. We offer the following comments: Since this interpretation is specific to Version "0" of EOP-001, it is not clear how NERC staff will integrate this interpretation into Board Approved (October 2008) Version "1" of EOP-001. We suggest that NERC add this interpretation to the Version 1 standard which was revised per the NERC project "Operate Within Interconnection Reliability Operating Limits" which is currently pending filing with FERC.
Kenneth Dresner	FirstEnergy Solutions	5	Affirmative	FirstEnergy Corp. supports the interpretation and has voted Affirmative. We offer the following comments: Since this interpretation is specific to Version "0" of EOP-001, it is not clear how NERC staff will integrate this interpretation into Board Approved (October 2008) Version "1" of EOP-001. We suggest that NERC add this interpretation to the Version 1 standard which was revised per the NERC project "Operate Within Interconnection Reliability Operating Limits" which is currently pending filing with FERC.
Mark S Travaglianti	FirstEnergy Solutions	6	Affirmative	FirstEnergy Corp. supports the interpretation and has voted Affirmative. We offer the following comments: Since this interpretation is specific to Version "0" of EOP-001, it is not clear how NERC staff will integrate this interpretation into Board Approved (October 2008) Version "1" of EOP-001. We suggest that NERC add this interpretation to the Version 1 standard which was revised per the NERC project "Operate Within Interconnection Reliability Operating Limits" which is currently pending filing with FERC.

Voter	Entity	Segment	Vote	Comment
Response: The ORS Executive Committee concurs with the comments of FirstEnergy.				
Kim Warren	Independent Electricity System Operator	2	Affirmative	The IESO thanks the Executive Committee of the NERC Operating Reliability Subcommittee for the effort that went into refining this interpretation. We also wish to highlight that inclusion of the phrase "within the same interconnection" in the revised response to Question 2, seems to preclude the possibility of adjacent Balancing Authorities that are not in the same interconnection, from entering into emergency energy assistance agreements.
Response: The ORS Executive Committee agrees with IESO's comment and will add the phrase, "nor does it preclude having an emergency assistance agreement across Interconnections" at the end of paragraph 2.				
Kirit S. Shah	Ameren Services	1	Affirmative	While the interpretation in 3) seemingly added the opportunity to use remote BAs ("A Balancing Authority's agreement(s) with Adjacent Balancing Authorities does (do) not preclude the Adjacent Balancing Authority from purchasing emergency energy from remote Balancing Authorities.") it does not address the obligation currently included in the standard. To wit, if a BA intends to use a remote BA for emergency assistance (as all or part of the energy it has identified that it needs to meet reasonably anticipated emergencies), It MUST have an agreement(s) with adjacent BAs "in the path" to facilitate this emergency assistance in addition to the agreement it will have with the remote BA. This additional sentence should be added to the Interpretation as the closing sentence in 3).
Mark Peters	Ameren Services	3	Affirmative	While the interpretation in 3) seemingly added the opportunity to use remote BAs ("A Balancing Authority's agreement(s) with Adjacent Balancing Authorities does (do) not preclude the Adjacent Balancing Authority from purchasing emergency energy from remote Balancing Authorities.") it does not address the obligation currently included in the standard. To wit, if a BA intends to use a remote BA for emergency assistance (as all or part of the energy it has identified that it needs to meet reasonably anticipated emergencies), It MUST have an agreement(s) with adjacent BAs "in the path" to facilitate this emergency assistance in addition to the agreement it will have with the remote BA. This additional sentence should be added to the Interpretation as the closing sentence in 3).
Response: The interpretation requires an emergency energy agreement with at least one adjacent Balancing Authority. However, it does not preclude having additional emergency energy agreements with remote Balancing Authorities. Specifying the appropriate arrangements to deliver the emergency energy goes beyond the scope of the request for interpretation.				

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Consideration of Comments on Initial Ballot — RECM Interpretation — EOP-001-0 (Project 2008-09)

Summary Consideration: An initial ballot of an interpretation of EOP-001-0, Requirement R1 was conducted from April 15-26, 2010 and achieved a quorum and a weighted approval of 98.64%. There were only two ballots submitted with negative comments, as shown in the table below. The ORS Executive Committee (Interpretation Drafting Team) disagrees with the comments included with the two negative ballots received. No changes were made to the interpretation following the initial ballot.

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herbert Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Voter	Entity	Segment	Vote	Comment
Ralph Frederick Meyer	Empire District Electric Co.	1	Affirmative	Very good interpritation. Very Logical. This clears up uncertanty with this standard.
Response: The ORS Executive Committee thanks Empire District Electric Co. its comment.				
Kevin Querry	FirstEnergy Solutions	3	Affirmative	No Comment
Response: The ORS Executive Committee thanks FirstEnergy Solutions for its Affirmative vote.				
Karl Bryan	U.S. Army Corps of Engineers Northwestern Division	5	Negative	It appears that the SDT is rewriting the Rel Stndrd by defining "emergency assistance" to mean "emergency energy" whereas emergency assistance can also imply physical assistance, technical support, etc... Also, since when does a plural mean a singular? "Balancing Authorities shall have agreements with adjacent Balancing Authorities", this implies multiple agreements with multiple BAs. Making this singular is rewriting the Rel Stndrd and is beyond the scope of the SDT in performing interpretations.
Response: The interpretation is not redefining emergency assistance. The request for interpretation is in the context of Requirement R1. The ORS Executive Committee believes emergency assistance is limited to emergency energy. In the context of R1, it does not include other physical assistance (i.e., mutual assistance agreements) entities may have with their neighbors. The ORS Executive Committee is not rewriting R1. In addition, in the context of R1, the ORS Executive Committee has interpreted Balancing Authorities to mean "at least one."				
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Negative	The Standards Drafting Team (SDT) interprets the standard that "emergency assistance" is "emergency energy". In its interpretation, the SDT introduced the term "emergency energy assistance" in place of the "emergency assistance" when it refers to language in the standard. This modifies the language of the standard which is not appropriate. Emergency assistance is undefined and can be any arrangement not limited to energy. The SDT interprets the standard to

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
				mean agreements with at least one adjacent BA. This would not be consistent with the language which uses plural form of BA, meaning more than one BA. The interpretation should have pointed out that there must be agreements with more than one adjacent BA. Finally, there is no basis cited for these interpretations. It also does not follow the interpretations by other teams which relied strictly on the text of the requirement or documents directly connected with the standard.
Response: The interpretation is not redefining emergency assistance. The request for interpretation is in the context of Requirement R1. The ORS Executive Committee believes emergency assistance is limited to emergency energy. In the context of R1, it does not include other physical assistance (i.e., mutual assistance agreements) entities may have with their neighbors. The ORS Executive Committee is not rewriting R1. In addition, in the context of R1, the ORS Executive Committee has interpreted Balancing Authorities to mean "at least one."				

Exhibit E

Consideration of Comments for interpretations to Requirements R3.2 of EOP-001-0 — Emergency Operations Planning

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Project 2009-28: Interpretation of EOP-001-1 and EOP-001-2 for the Florida Municipal Power Pool
Consideration of Comments for Initial Ballot (February 10–22, 2010)

Summary Consideration:
Balloters who submitted negative votes with reasons were concerned about a possible expansion of the Balancing Authority requirements as a result of the interpretation. The balloters pointed out that, according to the standard as written, there is no requirement for agreements or for the Balancing Authority to follow Transmission Operator directives.

The drafting team recognizes it went outside the bounds of EOP-001-1 and EOP-001-2 in the effort to provide additional clarification in the interpretation. Accordingly, the drafting team is replacing the word "agreements" in the third sentence with "coordination."

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Voter	Entity	Segment	Vote	Comment
Kevin Querry	FirstEnergy Solutions	3	Affirmative	No Comment
Anthony Jankowski	Wisconsin Energy Corp.	4	Negative	The answer does not provide a clear understanding of the standard. The third sentence of the answer adds a requirement that the BA plan include consideration for relationships and agreements, there is no requirement to have agreements. The second part of sentence four "or as previously agreed to with the Transmission Operator or the Reliability Coordinator to mitigate transmission emergencies" is not a standard requirement, thereby expanding the scope of the standard.
Response: The drafting team thanks you for your comments and is replacing the word "agreements" in the third sentence with "coordination." The drafting team recognizes it went outside the bounds of EOP-001-1 and EOP-001-2 in the effort to provide additional clarification in the interpretation.				
Kim Warren	Independent Electricity System Operator	2	Affirmative	The IESO is concerned that in recent months, there have been an increasing number of simplistic interpretations being put in front of the entire balloting body. In our view, some of the inquiries could have been addressed via other avenues than the formal interpretation process. We suggest that NERC expeditiously develop an alternative approach, similar to the Information Request Program established by the FRCC, to field industry questions before they rise up to the

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
				formal interpretation request level. Industry participants should be encouraged to use other available resources and avenues instead of or before proceeding to a formal interpretation process to obtain understanding of standard applicability and compliance.
Response: The drafting team thanks you for your comment.				
Kent Saathoff	Electric Reliability Council of Texas, Inc.	10	Negative	The requirement in R2.2 is that BAs and TOPs develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system. The interpretation states that the BA must have a plan and must take actions as directed by the TOP or the RC. The plain language of the requirement states that the BA must have a plan to mitigate operating emergencies. However, neither this particular requirement, nor any other part of the Standard (including the list of plan elements in Attachment 1-EOP-001-0 to the Standard) requires the BA to follow the directives of the TOP. That obligation is not a requirement under this Standard.
Response: The drafting team recognizes it went outside the bounds of EOP-001-1 and EOP-001-2 in the effort to provide additional clarification in the interpretation. The drafting team is replacing the word “agreements” in the third sentence with “coordination.”				

Exhibit F

Complete Record of Development of the Interpretation of Requirement R1 of EOP-001-0 — Emergency Operations Planning

Project 2008-09
RECM Request for Interpretation - EOP-001-0 - Emergency Operations Planning

Related Files

Status:
Approved by the Board of Trustees on November 4, 2010.

Purpose/Industry Need:
In accordance with the Reliability Standards Development Procedure, the interpretation must be posted for a 30-day pre-ballot review, and then balloted. There is no public comment period for an interpretation. Balloting will be conducted following the same method used for balloting standards. If the interpretation is approved by its ballot pool, then the interpretation will be appended to the standard and will become effective when adopted by the NERC Board of Trustees and approved by the applicable regulatory authorities. The interpretation will remain appended to the standard until the standard is revised through the normal standards development process. When the standard is revised, the clarifications provided by the interpretation will be incorporated into the revised standard.

Draft	Action	Dates	Results	Consideration of Comments
Draft 4 RECM Interpretation for EOP-001-0 Clean**(32)**	Recirculation Ballot Info**(33)** | Vote>>	10/04/10 - 10/14/10	Summary **(35)** Full Record**(34)**	
Revision 3 RECM Interpretation for EOP-001-0 **Revised Interpretation** Clean**(25)** | Redline**(26)**	Initial Ballot Info**(28)** | Vote>>	04/15/10 - 04/26/10 (closed)	Summary **(30)** Full Record**(29)**	Consideration of Comments **(31)**
	Pre-ballot Review Info**(27)** | Join>>	03/16/10 - 04/15/10 (closed)		
Revision 2	Initial Ballot	11/05/09 - 11/16/09	Summary **(23)**	Consideration of Comments

RECM Interpretation for EOP-001-0 Revised Interpretation Clean(18) | Redline(19) Request for Interpretation(17)	Info(21) | Vote>>	(closed)	Ballot Results(22)	(24)
	Pre-ballot Review Info(20) | Join>>	10/06/09 - 11/05/09 (closed)		
Revision 1 RECM Interpretation for EOP-001-0 Revised Interpretation Clean(10) | Redline(11) Request for Interpretation(9)	Initial Ballot Info(13) | Vote>>	02/27/09 - 03/09/09 (closed)	Summary (15) Ballot Results(14)	Consideration of Comments (16)
	Pre-ballot Review Info(12) | Join>>	01/28/09 – 02/26/09 (closed)		
RECM Interpretation for EOP-001-0	Recirculation Ballot Info(8) (Conducted in error Results are void)	01/06/09 - 01/15/09 (closed)		
RECM Interpretation for EOP-001-0 Interpretation(2) Request for Interpretation(1)	Ballot Window Info(4) | Vote>>	06/19/08 – 07/02/08 (closed)	Summary (6) Full Record(5)	Consideration of Comments(7)
	Pre-ballot Review Info(3) | Join>>	05/19/08 – 06/19/08 (closed)		

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April 2, 2008

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116-390 Village Blvd.
Princeton, NJ 08540

Re: Formal Interpretation Request for Reliability Standard EOP-001-0, Requirement 1

Dear Maureen,

The Regional Entity Compliance Managers (RECM) request a formal interpretation of Reliability Standard EOP-001-0 — Emergency Operations Planning Requirement R1 in accordance with the Reliability Standards Development Procedure.

Material Impact: A formal interpretation is required for Regional Entities to consistently assess compliance with this standard and to ensure Registered Entities are meeting their obligation and responsibility as intended by the standard.

Clarification is needed for Reliability Standard EOP-001-0 Requirement R1 which states:

R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

Specifically, the RECM requests an interpretation and clarity for the following language listed in EOP-001-0, Requirement 1:

1. What is the definition of emergency assistance in the context of this standard? What scope and time horizons, if any, are considered necessary in this definition?
2. What was intended by using the adjective "adjacent" in Requirement 1? Does "adjacent" Balancing Authorities mean "All" or something else? Is there qualifying criteria to determine if a very small adjacent Balancing Authority area has enough capacity to offer emergency assistance?
3. What is the definition of the word "remote" as stated in the last phrase of Requirement 1? Does remote mean every Balancing Authority who's area does not physically touch the Balancing Authority attempting to comply with this Requirement?

4. Would a Balancing Authority that participates in a Reserve Sharing Group Agreement, which meets the requirements of Reliability Standard BAL-002-0, Requirement 2, be required to establish additional operating agreements to achieve compliance with Reliability Standard EOP-001-0, Requirement 1?

If you have any questions concerning this request please contact Susan Morris, Manager of Regional Compliance Program Oversight at susan.morris@nerc.net or (609) 240-6784.

Sincerely,

Regional Entity Compliance Managers:

Barry Pagel, Florida Reliability Coordinating Council
Stanley Kopman, Northeast Power Coordinating Council
Wayne VanOsdol, Midwest Reliability Organization
Ray Palmieri, Reliability*First* Corporation
Tom Galloway, SERC Reliability Corporation
Ron Ciesiel, Southwest Power Pool Regional Entity
Mark Henry, Texas Regional Entity
Steve McCoy, Western Electricity Coordinating Council

CC: David Taylor
Gerry Adamski
Regional Entity Compliance Monitoring Group
Compliance Department

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RELIABILITY CORPORATION

Interpretation of EOP-001-0 Emergency Operations Planning Requirement R1 for the Regional Entity Compliance Managers

Request for Interpretation Received from Regional Entity Compliance Managers on March 20, 2008:

Request:
The Regional Entity Compliance Managers (RECM) request a formal interpretation of Reliability Standard EOP-001-0 — Emergency Operations Planning Requirement R1 in accordance with the Reliability Standards Development Procedure.

1. *What is the definition of emergency assistance in the context of this standard? What scope and time horizons, if any, are considered necessary in this definition?*
2. *What was intended by using the adjective "adjacent" in Requirement 1? Does "adjacent Balancing Authorities" mean "All" or something else? Is there qualifying criteria to determine if a very small adjacent Balancing Authority area has enough capacity to offer emergency assistance?*
3. *What is the definition of the word "remote" as stated in the last phrase of Requirement 1? Does remote mean every Balancing Authority who's area does not physically touch the Balancing Authority attempting to comply with this Requirement?*
4. *Would a Balancing Authority that participates in a Reserve Sharing Group Agreement, which meets the requirements of Reliability Standard BAL-002-0, Requirement 2, have to establish additional operating agreements to achieve compliance with Reliability Standard EOP-001-0, Requirement 1?*

EOP-001-0
R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

The following interpretation of EOP-001-0 — Emergency Operations Planning Requirement R1 was developed by the Executive Committee of the NERC Operating Reliability Subcommittee on May 9, 2008:

Interpretation of EOP-001-0 Requirement R1:

1. In the context of this standard, emergency assistance is emergency energy. Emergency energy would normally be arranged for during the current operating day. The agreement should describe the conditions under which the emergency energy will be delivered to the responsible Balancing Authority.
2. An adjacent Balancing Authority is one that has AC tie lines with the responsible Balancing Authority. The standard does not require emergency energy assistance agreements with *all* adjacent Balancing Authorities. The intent is that all Balancing Authorities have emergency energy assistance agreements with at least one adjacent Balancing Authority and have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies.

3. A remote Balancing Authority is a Balancing Authority other than an adjacent Balancing Authority. The responsible Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with all remote Balancing Authorities. The responsible Balancing Authority's agreement(s) with the adjacent Balancing Authorities does (do) not preclude the adjacent Balancing Authority from purchasing emergency energy from remote Balancing Authorities on behalf of the responsible Balancing Authority.
4. A Balancing Authority that is compliant with Reliability Standard BAL-002-0, Requirement R2 through participation in a Reserve Sharing Group Agreement is not required to establish additional operating agreements as described in Requirement R1 of EOP-001-0.

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Standards Announcement

Ballot Pool and Pre-ballot Window Opens
May 19–June 19, 2008

Now available at: https://standards.nerc.net/BallotPool.aspx

Pre-ballot Window and Ballot Pool for Interpretation of EOP-001-0 Requirement R1 for Regional Entity Compliance Managers (Project 2008-09)

The Regional Entity Compliance Managers group submitted a **Request for an Interpretation** of EOP-001-0 — Emergency Operations Planning Requirement 1. Under Requirement 1, the Balancing Authority must have operating agreements with adjacent Balancing Authorities that contain provisions for emergency assistance, including emergency assistance from remote Balancing Authorities. The request asked for the following clarifications:

- Define the scope and time horizon associated with "emergency assistance."
- Does "adjacent Balancing Authority" mean one or all adjacent Balancing Authorities?
- What is a "remote Balancing Authority?"
- Does a Balancing Authority participating in a Reserve Sharing Group under BAL-002-0 need additional operating agreements to be compliant with EOP-001-0 Requirement R1?

The **Interpretation** provides the following clarifications:

- Emergency assistance is emergency "energy" and would normally be arranged for during the current operating day. The agreement should describe the conditions under which the emergency energy will be delivered to the responsible Balancing Authority.
- An adjacent Balancing Authority is one that has AC tie lines with the responsible Balancing Authority and the standard does not require agreements with all adjacent Balancing Authorities.
- A remote Balancing Authority is a Balancing Authority other than an adjacent Balancing Authority and the responsible Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with all remote Balancing Authorities.
- A Balancing Authority that is compliant with BAL-002-0 — Disturbance Control Performance Requirement 2 through participation in a Reserve Sharing Group Agreement, is not required to establish additional operating agreements for EOP-001-0 Requirement 1.

A new **ballot pool** to vote on this interpretation has been formed and will remain open up until 8 a.m. (EDT) Thursday, June 19, 2008. During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." The list server for this ballot pool is: **bp-Intp_EOP-001_R1_RECM_in@nerc.com**

Standards Development Process

The ***Reliability Standards Development Procedure*** contains all the procedures governing the standards

development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Maureen Long, Standards Process Manager, at maureen.long@nerc.net or at (813) 468-5998.

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Standards Announcement

Ballot Window Open
June 19–June 30, 2008

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Ballot Window for Interpretation of EOP-001-0 Requirement R1 for Regional Entity Compliance Managers is Open

The initial ballot for the Interpretation of EOP-001-0 — Emergency Operations Planning Requirement R1 for the Regional Entity Compliance Managers is open through **8 p.m. EDT, Monday, June 30, 2008**.

The Regional Entity Compliance Managers group submitted a Request for an Interpretation of EOP-001-0 — Emergency Operations Planning Requirement R1. Under Requirement R1, the Balancing Authority must have operating agreements with adjacent Balancing Authorities that contain provisions for emergency assistance, including emergency assistance from remote Balancing Authorities. The request asked for the following clarifications:

- Define the scope and time horizon associated with "emergency assistance."
- Does "adjacent Balancing Authority" mean one or all adjacent Balancing Authorities?
- What is a "remote Balancing Authority?"
- Does a Balancing Authority participating in a Reserve Sharing Group under BAL-002-0 need additional operating agreements to be compliant with EOP-001-0 Requirement R1?

The Interpretation provides the following clarifications:

- Emergency assistance is emergency "energy" and would normally be arranged for during the current operating day. The agreement should describe the conditions under which the emergency energy will be delivered to the responsible Balancing Authority.
- An adjacent Balancing Authority is one that has AC tie lines with the responsible Balancing Authority and the standard does not require agreements with all adjacent Balancing Authorities.
- A remote Balancing Authority is a Balancing Authority other than an adjacent Balancing Authority and the responsible Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with all remote Balancing Authorities.
- A Balancing Authority that is compliant with BAL-002-0 — Disturbance Control Performance Requirement R2 through participation in a Reserve Sharing Group Agreement, is not required to establish additional operating agreements for EOP-001-0 Requirement R1.

Standards Development Process

The *Reliability Standards Development Procedure Manual* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Maureen Long, Standards Process Manager, at maureen.long@nerc.net or at (813) 468-5998.

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Reliability Standards

Ballot Results	
Ballot Name:	Interpretation Request - EOP-001 - R1 - RECM_in
Ballot Period:	6/19/2008 - 7/2/2008
Ballot Type:	Initial
Total # Votes:	162
Total Ballot Pool:	191
Quorum:	**84.82 % The Quorum has been reached**
Weighted Segment Vote:	85.79 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	55	1	40	0.889	5	0.111	2	8
2 - Segment 2.	9	0.8	6	0.6	2	0.2	0	1
3 - Segment 3.	51	1	36	0.9	4	0.1	1	10
4 - Segment 4.	10	0.8	8	0.8	0	0	0	2
5 - Segment 5.	32	1	26	0.963	1	0.037	0	5
6 - Segment 6.	21	1	15	0.882	2	0.118	1	3
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	2	0.2	2	0.2	0	0	0	0
9 - Segment 9.	3	0.3	1	0.1	2	0.2	0	0
10 - Segment 10.	8	0.7	5	0.5	2	0.2	1	0
Totals	**191**	**6.8**	**139**	**5.834**	**18**	**0.966**	**5**	**29**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services Company	Kirit S. Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Jason Shaver	Abstain	
1	Arizona Public Service Co.	Cary B. Deise		
1	Avista Corp.	Scott Kinney	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	View
1	Central Maine Power Company	Brian Conroy		
1	Consolidated Edison Co. of New York	Edwin E. Thompson PE	Negative	View
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	William L. Thompson	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	View
1	E.ON U.S. LLC	Larry Monday	Affirmative	

1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	C. Martin Mennes	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg		
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Kansas City Power & Light Co.	Jim Useldinger	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Manitoba Hydro	Michelle Rheault	Affirmative	
1	Minnesota Power, Inc.	Carol Gerou	Affirmative	
1	Municipal Electric Authority of Georgia	Jerry J Tang	Affirmative	
1	National Grid	Michael J Ranalli	Negative	View
1	New Brunswick Power Transmission Corporation	Wayne N. Snowdon	Negative	View
1	New York Power Authority	Ralph Rufrano	Negative	View
1	New York State Electric & Gas Corp.	Henry G. Masti		
1	Northeast Utilities	David H. Boguslawski	Negative	View
1	Northern Indiana Public Service Co.	Joseph Dobes	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	lorees Tadros		
1	Oncor Electric Delivery	Charles W. Jenkins	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	PacifiCorp	Robert Williams		
1	Potomac Electric Power Co.	Richard J. Kafka	Affirmative	
1	PP&L, Inc.	Ray Mammarella	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Sacramento Municipal Utility District	Dilip Mahendra	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Christopher M. Turner	Affirmative	
1	Sierra Pacific Power Co.	Richard Salgo	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Tampa Electric Co.	Thomas J. Szelistowski	Affirmative	
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tucson Electric Power Co.	Ronald P. Belval		
1	Xcel Energy, Inc.	Gregory L. Pieper	Affirmative	
2	Alberta Electric System Operator	Anita Lee		
2	British Columbia Transmission Corporation	Phil Park	Affirmative	
2	California ISO	David Hawkins	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Roy D. McCoy	Affirmative	
2	Independent Electricity System Operator	Kim Warren	Negative	View
2	ISO New England, Inc.	Kathleen Goodman	Negative	View
2	Midwest ISO, Inc.	Terry Bilke	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
3	Alabama Power Company	Robin Hurst	Affirmative	
3	Allegheny Power	Bob Reeping	Affirmative	
3	American Electric Power	Raj Rana	Affirmative	

3	Arizona Public Service Co.	Thomas R. Glock	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	View
3	City of Tallahassee	Rusty S. Foster		
3	City Public Service of San Antonio	Edwin Les Barrow	Affirmative	
3	Cleco Utility Group	Bryan Y Harper	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	View
3	Consumers Energy	David A. Lapinski	Affirmative	View
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Jalal (John) Babik	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	Entergy Services, Inc.	Matt Wolf	Affirmative	
3	Farmington Electric Utility System	Alan Glazner	Affirmative	
3	FirstEnergy Solutions	Joanne Kathleen Borrell	Affirmative	View
3	Florida Municipal Power Agency	Michael Alexander	Affirmative	
3	Florida Power & Light Co.	W.R. Schoneck		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Leslie Sibert	Affirmative	
3	Georgia System Operations Corporation	Edward W Pourciau	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Negative	View
3	Kissimmee Utility Authority	Gregory David Woessner		
3	Lincoln Electric System	Bruce Merrill		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	View
3	Manitoba Hydro	Ronald Dacombe	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Affirmative	
3	New York Power Authority	Christopher Lawrence de Graffenried	Negative	View
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Negative	View
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	PECO Energy an Exelon Co.	John J. McCawley		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Rochester Public Utilities	Gerald Steffens		
3	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C. Young		
3	Tampa Electric Co.	Ronald L. Donahey	Affirmative	
3	Tennessee Valley Authority	Cynthia Herron		
3	Wisconsin Electric Power Marketing	James R. Keller	Affirmative	
3	Wisconsin Public Service Corp.	James A. Maenner		
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	View
4	Florida Municipal Power Agency	Ralph Anderson	Affirmative	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Affirmative	
4	Northern California Power Agency	Fred E. Young	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Rochester Public Utilities	Greg Woodworth		
4	Seattle City Light	Hao Li	Affirmative	

4	Seminole Electric Cooperative, Inc.	Steven R. Wallace		
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Alabama Electric Coop. Inc.	Tim Hattaway	Affirmative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	View
5	City of Farmington	Clinton J Jacobs	Affirmative	
5	City of Tallahassee	Alan Gale	Affirmative	
5	Colmac Clarion/Piney Creek LP	Harvie D. Beavers	Affirmative	
5	Conectiv Energy Supply, Inc.	Richard K. Douglass	Affirmative	
5	Dairyland Power Coop.	Warren Schaefer		
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	Douglas Keegan	Affirmative	
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	JEA	Donald Gilbert	Affirmative	
5	Lincoln Electric System	Dennis Florom		
5	Louisville Gas and Electric Co.	Charlie Martin	Affirmative	View
5	Manitoba Hydro	Mark Aikens	Affirmative	
5	New York Power Authority	Gerald Mannarino	Negative	
5	Orlando Utilities Commission	Richard Kinas	Affirmative	
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Reliant Energy Services	Thomas J. Bradish	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Southeastern Power Administration	Douglas Spencer	Affirmative	
5	Southern California Edison Co.	David Schiada	Affirmative	
5	Southern Company Services, Inc.	Roger D. Green	Affirmative	
5	Tampa Electric Co.	Frank L Busot	Affirmative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Stephen J. Beuning		
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	View
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	View
6	Dominion Resources, Inc.	Louis S Slade	Affirmative	
6	Entergy Services, Inc.	William Franklin	Affirmative	View
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	View
6	Florida Municipal Power Agency	Robert C. Williams	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Lincoln Electric System	Eric Ruskamp		
6	Louisville Gas and Electric Co.	Daryn Barker	Affirmative	View
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	New York Power Authority	Thomas Papadopoulos	Negative	
6	Progress Energy Carolinas	James Eckelkamp	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Salt River Project	Mike Hummel	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	Southern California Edison Co.	Marcus V Lotto	Affirmative	
6	Southern Indiana Gas and Electric Co.	Brad Lisembee		
6	Tampa Electric Co.	Jose Benjamin Quintas	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Other	Michehl R. Gent	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	

9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Negative	View
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Negative	View
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	Larry Brusseau	Affirmative	
10	New York State Reliability Council	Alan Adamson	Negative	
10	Northeast Power Coordinating Council, Inc.	Edward A. Schwerdt	Negative	View
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Southwest Power Pool	Charles H. Yeung	Affirmative	
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	

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Standards Announcement

Initial Ballot Results for Project 2008-09

Now available at: https://standards.nerc.net/Ballots.aspx

Initial Ballot Results for Interpretation of EOP-001 Requirement R1 for the Regional Entity Compliance Managers

The initial ballot for the Interpretation of Requirement R1 in EOP-001-0 — Emergency Operations Planning (for the Regional Entity Compliance Managers), was conducted from June 19 through July 2, 2008.

The ballot achieved a quorum, however there were some negative ballots with comments, initiating the need to review the comments before proceeding. The drafting team will be reviewing comments submitted with the ballot and preparing its consideration of those comments. (Detailed Ballot Results)

Quorum:	84.82 %
Approval:	85.79 %

Standards Development Process

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For more information or assistance, please contact Maureen Long, Standards Process Manager, at maureen.long@nerc.net or at (813) 468-5998.

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Consideration of Comments on Initial Ballot RECM Interpretation Request — EOP-001, R1

Summary Consideration: Some entities requested clarification for using dc voltages, the definition of adjacent regarding Balancing Authorities, and how much was “enough” energy emergency assistance. A few entities suggested increased requirements for emergency energy assistance and reserve sharing group participation. The drafting team modified the language in the interpretation to use the defined term Adjacent Balancing Authority and clarified that the requirement does not require energy assistance agreements with all Adjacent Balancing Authorities. The team will submit certain suggestions regarding requirements to the manager of standards development.

Segment	Entity	Ballot	Comments
1	Bonneville Power Administration	Affirmative	In Item 2, we recommend replacing "AC" with "AC and/or DC tie lines in the same interconnection" We strongly support the item 4 interpretation regarding reserve sharing groups.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn’t limit interconnections to AC ties.			
1	Consolidated Edison Co. of New York	Negative	DC ties should have been referenced and included in the interpretation, agreements with ALL adjacent BAs should be required. Specific Emergency Energy Agreements should either be explicit parts of the operating agreements or developed separately and in place as well. Also, participation in a Reserve Sharing Group may be insufficient to meet Requirement R1
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn’t limit interconnections to AC ties. The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain an adequate level of reliability. The technical criteria for establishing what constitutes sufficient emergency assistance should be established through the Standards Development Process.			
1	Duke Energy Carolina	Affirmative	Duke Energy appreciates the opportunity to comment on this Interpretation . Duke Energy supports the concepts in this Interpretation; however, there remain some issues that should be dealt within a Standards Authorization Request to revise the standard. In addition, using a general term such as "enough" still keeps the Balancing Authority in the position of a compliance team interpretation of "enough". Duke Energy believes that the Interpretation should clarify that in the context of this standard, emergency assistance is emergency energy. Emergency energy would normally be arranged for during the current operating day. The agreement should describe the conditions

Segment	Entity	Ballot	Comments
			under which the emergency energy will be delivered to the responsible Balancing Authority. The intent of this standard is that all Balancing Authorities should have sufficient emergency assistance agreements in order to meet Control Performance Standards, Disturbance Control Standards and other applicable standards. Therefore emergency assistance agreements are not required with all adjacent Balancing Authorities. Such agreements may also be in place with remote Balancing Authorities, but are not required.
Response: The drafting team agrees with your comments and will submit them to the manager of standards development for inclusion in the Standards "Issues" database.			
1	FirstEnergy Energy Delivery	Affirmative	FirstEnergy supports the interpretation provided for EOP-001 Requirement R1 and believes it further clarifies Balancing Authority expectations related to emergency assistance agreements with other Balancing Authorities. It is expected that the standards drafting team working on Project 2008-03 will reference this interpretation when completing revisions to the EOP-001 standard to achieve greater clarity within the standard's requirements and measures. The only question we raise and seek clarification to is in regards to item #2 and we question why the interpretation excludes DC ties when defining an adjacent Balancing Authority? As written, would a Balancing Authority be precluded from obtaining emergency assistance from a BA with whom they may only have DC interconnection(s)? Or, is the intent that a DC tie is considered a remote Balancing Authority and covered by item #3?
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties.			
1	National Grid	Negative	National Grid agrees with the comments made by NPCC and other NPCC members: EOP-001, R1 states "Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities. We feel that emergency assistance agreements should be made with ALL adjacent BAs which is contrary to the interpretation which states the intent is to have emergency agreements with at least one adjacent BA. Additionally, the interpretation states that "The responsible Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with all remote Balancing Authorities". We feel that emergency agreements with ALL adjacent BAs further needs to be in place in order for a BA to get remote assistance from a non-adjacent or through an adjacent BA. DC ties should have been referenced and included in the interpretation. The interpretation furthers states that a BA that is compliant with BAL-002 —" Disturbance Control Performance Requirement R2 through participation in a Reserve

Segment	Entity	Ballot	Comments
			Sharing Group Agreement, is not required to establish additional operating agreements for EOP-001-0 Requirement R1. We feel that participation in a Reserve Sharing Group may be insufficient to meet Requirement 1.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties. The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain an adequate level of reliability. The technical criteria for establishing what constitutes sufficient emergency assistance should be established through the Standards Development Process.			
1	New Brunswick Power Transmission Corporation	Negative	DC ties should have been referenced and included in the interpretation, agreements with ALL adjacent BAs should be required. Specific Emergency Energy Agreements should either be explicit parts of the operating agreements or developed separately and in place as well. Also, participation in a Reserve Sharing Group may be insufficient to meet Requirement R1.
Response: The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain an adequate level of reliability. The technical criteria for establishing what constitutes sufficient emergency assistance should be established through the Standards Development Process.			
1	New York Power Authority	Negative	DC ties should have been referenced and included in the interpretation, agreements with ALL adjacent BAs should be required. Specific Emergency Energy Agreements should either be explicit parts of the operating agreements or developed separately and in place as well. Also, participation in a Reserve Sharing Group may be insufficient to meet Requirement R1.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties. The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain an adequate level of reliability. The technical criteria for establishing what constitutes sufficient emergency assistance should be established through the Standards Development Process.			
1	Northeast Utilities	Negative	DC ties should be referenced and included in the interpretation. Agreements with ALL adjacent BAs should be required. Specific Emergency Energy Agreements should either be explicit parts of the operating agreements, or developed separately and in place as well.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which			

Segment	Entity	Ballot	Comments
doesn't limit interconnections to AC ties. The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain an adequate level of reliability.			
2	Independent Electricity System Operator	Negative	While the IESO agrees with various aspects of the clarification provided, which we believe helpful, we nonetheless disagree with a number of the clarifications we deem significantly flawed for reasons noted below and must vote NO to the interpretations: 1. The interpretation offered indicated that being part of a RSG is sufficient to meet the obligation of this requirement — we do not agree with this position. Two BAs may engage in a reserve sharing agreement that is designed to offset reserve requirements or to provide support for DCS recover from an incident. However, if the operating agreement does not explicitly address energy assistance under emergency conditions, and the scope and condition of the emergency, emergency energy may not flow. Additionally, reserve sharing agreement addresses the amount of reserve that each participating member needs to carry to meet the overall group and/or individual BAs reserve requirements. Situation can exist that while the shared reserve is used up and a BA is still short of resource, and additional energy delivery is required to take care of the emergency. 2. The SDT indicated that it is OK not to have emergency energy assistance agreements with all adjacent BAs â€“ this is contrary to the NPCC position which dictates that an entity (the responsible BA) must have emergency energy assistance agreements with all adjacent BA entities â€“ this could be either as part of the operating agreement or as a separate explicit agreement by itself. 3. Further, the interpretation precludes adjacent BAs which are connected with only DC ties. It is IESO view that provision of emergency assistance should also be available from areas that are interconnected by DC ties.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties. The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain an adequate level of reliability. The technical criteria for establishing what constitutes sufficient emergency assistance should be established through the Standards Development Process.			
2	ISO New England, Inc.	Negative	DC ties should be included in the interpretation, not just AC ties. Agreements with ALL adjacent BAs should be required. Specific Emergency Energy

Segment	Entity	Ballot	Comments
			Agreements should either be explicit parts of the operating agreements or developed separately and in place as well. Participation in a Reserve Sharing Group may be insufficient to meet Requirement R1 unless such agreement explicitly contains Emergency Energy Agreements among parties.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties. The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain an adequate level of reliability. The technical criteria for establishing what constitutes sufficient emergency assistance should be established through the Standards Development Process.			
3	Bonneville Power Administration	Affirmative	Related to the Subcommittee's recommended interpretation #2 BPA suggests the following language changes: An adjacent Balancing Authority is one that has AC and/or DC tie lines in the same interconnection with the responsible BA. We like the interpretation #4 and do want to see it changed.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties.			
3	Consolidated Edison Co. of New York	Negative	DC ties should have been referenced and included in the interpretation, agreements with ALL adjacent BAs should be required. Specific Emergency Energy Agreements should either be explicit parts of the operating agreements or developed separately and in place as well. Also, participation in a Reserve Sharing Group may be insufficient to meet Requirement R1"
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties. The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain an adequate level of reliability. The technical criteria for establishing what constitutes sufficient emergency assistance should be established through the Standards Development Process.			
3	Consumers Energy	Affirmative	We agree with the intent of the interpretation to Question 4, but suggest it would be unequivocally clear to state: "A Balancing Authority that is compliant with Reliability Standard BAL-002-0, Requirement R2 through participation in a Reserve Sharing Group Agreement shall be deemed to be fully compliant with Requirement R1 of EOP-001-1."
Response: Your comment will be submitted to the manager of standards development for inclusion in the Standards "Issues" database as a potential modification to the associated standard.			
3	FirstEnergy Solutions	Affirmative	"FirstEnergy supports the interpretation provided for EOP-001 Requirement R1

Segment	Entity	Ballot	Comments
			and believes it further clarifies Balancing Authority expectations related to emergency assistance agreements with other Balancing Authorities. It is expected that the standards drafting team working on Project 2008-03 will reference this interpretation when completing revisions to the EOP-001 standard to achieve greater clarity within the standard's requirements and measures. The only question we raise and seek clarification to is in regards to item #2 and we question why the interpretation excludes DC ties when defining an adjacent Balancing Authority? As written, would a Balancing Authority be precluded from obtaining emergency assistance from a BA with whom they may only have DC interconnection(s)? Or, is the intent that a DC tie is considered a remote Balancing Authority and covered by item #3? "
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties.			
3	Hydro One Networks, Inc.	Negative	Hydro One Networks Inc. casts a Negative vote with the following comments: 1. DC ties should have been referenced and included in the interpretation. 2. Agreements with ALL adjacent BAs should be required. 3. Specific Emergency Energy Agreements should either be explicit parts of the operating agreements or developed separately and in place as well. 4. Participation in a Reserve Sharing Group may be insufficient to meet Requirement R1.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties. The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain an adequate level of reliability. The technical criteria for establishing what constitutes sufficient emergency assistance should be established through the Standards Development Process.			
3	Louisville Gas and Electric Co.	Affirmative	E.ON US votes YES and wishes to emphasize in our comments the value and importance of Reserve Sharing Groups (RSGs) to first and foremost ensure, reliability on a real-time basis, and also to lower the cost of providing electrical power to our customers. Due to this value, NERC and the Industry should support, encourage and seek expansion of RSGs. Our specific points are as follows. The reliability benefits to the parties of RSGs are: – The parties have access to the Contingency Reserve generation capacity of all members on a real time basis and have certainty of emergency energy supply. – The parties utilize a computerized process that immediately dispatches generation and spinning reserves and ten-minute quick-start Contingency Reserves when called upon by a party with a

Segment	Entity	Ballot	Comments
			sudden loss of supply – resulting in an immediate response to the supply loss. – The diversity and large number of generating units quickly ramping up to provide emergency power further ensure certainty and an immediate response to the supply loss. – The parties coordinate in advance TRM to ensure that emergency energy for Contingency Reserves can flow in real-time when called on, resulting in certainty of transmission for the flow of emergency energy. The lower cost benefits to the end user customers of the parties of RSGs are: – More efficient use of supply due to reduced Operating Reserves for each BA, despite the size of each BA, in RSGs. (The Midwest ISO has stated that they have conducted studies that have demonstrated that each MW of spinning reserve has a value of $350,000. Thus, the 300 MW of spinning reserves to be provided at the start of the ASM to the Midwest ISO load by MCRSG parties external to the Midwest ISO footprint equate to approximately $100 million in annual value. This value will become an annual cost to the Midwest ISO load upon sunset of the MCRSG. This does not include the savings of similar nature to the external BAs.) – The flexibility to transact more energy between BAs with freed-up generation and transmission capacity is achieved even if the Midwest BA grows and the External CRSG BAs decrease to only a few parties. – The advance coordination of TRM reduces the amount of TRM needed. Due to these points, RSGs among BAs, including BAs which are large ISOs operating day ahead and real-time markets along with Operating Reserve markets, should be encouraged. Also, E.ON US – YES vote supports the NERC interpretation that Emergency Assist agreements (EAAs) between interconnected BAs are not required between every interconnect BA to meet NERC Standards. Since the nature of EAAs is for a BA to provide emergency power to a BA, with a supply emergency, immediately or in the near term future (next hour, day or week), E.ON US suggest that NERC should encourage all BAs to file unilateral EAAs at the appropriate rate, MBR or CBR where applicable. Such unilateral filings would establish agreements and rates to provide non-firm emergency power if available after BAs and their associated LSEs have ensured adequate supply to native load and firm transactions (Designated Network Load).

Segment	Entity	Ballot	Comments
Response: Your comments will be submitted to the manager of standards development.			
3	New York Power Authority	Negative	DC ties should have been referenced and included in the interpretation agreements with ALL adjacent BAs should be required. Specific Emergency Energy Agreements should either be explicit parts of the operating agreements or developed separately and in place as well. Also, participation in a Reserve Sharing Group may be insufficient to meet Requirement R1.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties. The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain n adequate level of reliability. The technical criteria for establishing what constitutes sufficient emergency assistance should be established through the Standards Development Process.			
3	Niagara Mohawk (National Grid Company)	Negative	DC ties should have been referenced and included in the interpretation agreements with ALL adjacent BAs should be required. Specific Emergency Energy Agreements should either be explicit parts of the operating agreements or developed separately and in place as well. Also, participation in a Reserve Sharing Group may be insufficient to meet Requirement R1.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties. The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain an adequate level of reliability. The technical criteria for establishing what constitutes sufficient emergency assistance should be established through the Standards Development Process.			
4	Consumers Energy	Affirmative	We agree with the intent of the interpretation to Question 4, but suggest it would be unequivocally clear to state: "A Balancing Authority that is compliant with Reliability Standard BAL-002-0, Requirement R2 through participation in a Reserve Sharing Group Agreement shall be deemed to be fully compliant with Requirement R1 of EOP-001-1."
Response: Your comment will be submitted to the manager of standards development for inclusion in the Standards "Issues" database as a potential modification to the associated standard.			
5	Bonneville Power Administration	Affirmative	BPA agrees in principle with the interpretation with a couple of comments. - With regards to number 2; BPA would recommend the inclusion DC ties and suggests the following language changes: "An adjacent Balancing Authority is one that has AC or DC tie lines in the same interconnection with the responsible BA" This would allow for the inclusion of the Pacific DC intertie

Segment	Entity	Ballot	Comments
			between BPA and LADWP. - BPA fully supports interpretation 4. with regards to reserve sharing groups.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties.			
5	Louisville Gas and Electric Co.	Affirmative	E.ON US votes YES and wishes to emphasize in our comments the value and importance of Reserve Sharing Groups (RSGs) to first and foremost ensure, reliability on a real-time basis, and also to lower the cost of providing electrical power to our customers. Due to this value, NERC and the Industry should support, encourage and seek expansion of RSGs. Our specific points are as follows. The reliability benefits to the parties of RSGs are: – The parties have access to the Contingency Reserve generation capacity of all members on a real time basis and have certainty of emergency energy supply. – The parties utilize a computerized process that immediately dispatches generation and spinning reserves and ten-minute quick-start Contingency Reserves when called upon by a party with a sudden loss of supply resulting in an immediate response to the supply loss. – The diversity and large number of generating units quickly ramping up to provide emergency power further ensure certainty and an immediate response to the supply loss. – The parties coordinate in advance TRM to ensure that emergency energy for Contingency Reserves can flow in real-time when called on, resulting in certainty of transmission for the flow of emergency energy. The lower cost benefits to the end user customers of the parties of RSGs are: – More efficient use of supply due to reduced Operating Reserves for each BA, despite the size of each BA, in RSGs. (The Midwest ISO has stated that they have conducted studies that have demonstrated that each MW of spinning reserve has a value of $350,000. Thus, the 300 MW of spinning reserves to be provided at the start of the ASM to the Midwest ISO load by MCRSG parties external to the Midwest ISO footprint equate to approximately $100 million in annual value. This value will become an annual cost to the Midwest ISO load upon sunset of the MCRSG. This does not include the savings of similar nature to the external BAs.) – The flexibility to transact more energy between BAs with freed-up generation and transmission capacity is achieved even if the Midwest BA grows and the External CRSG BAs decrease to only a few parties.

Segment	Entity	Ballot	Comments
			– The advance coordination of TRM reduces the amount of TRM needed. Due to these points, RSGs among BAs, including BAs which are large ISOs operating day ahead and real-time markets along with Operating Reserve markets, should be encouraged. Also, E.ON US – YES vote supports the NERC interpretation that Emergency Assist agreements (EAAs) between interconnected BAs are not required between every interconnect BA to meet NERC Standards. Since the nature of EAAs is for a BA to provide emergency power to a BA, with a supply emergency, immediately or in the near term future (next hour, day or week), E.ON US suggest that NERC should encourage all BAs to file unilateral EAAs at the appropriate rate, MBR or CBR where applicable. Such unilateral filings would establish agreements and rates to provide non-firm emergency power if available after BAs and their associated LSEs have ensured adequate supply to native load and firm transactions (Designated Network Load).
Response: Your comments will be submitted to the manager of standards development.			
6	Bonneville Power Administration	Affirmative	In Item 2, we recommend replacing "AC" with "AC and/or DC tie lines in the same interconnection. "We strongly support the item 4 interpretation regarding reserve sharing groups.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties.			
6	Consolidated Edison Co. of New York	Negative	DC ties should have been referenced and included in the interpretation, agreements with ALL adjacent BAs should be required. Specific Emergency Energy Agreements should either be explicit parts of the operating agreements or developed separately and in place as well. Also, participation in a Reserve Sharing Group may be insufficient to meet Requirement R1.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties. The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain an adequate level of reliability. The technical criteria for establishing what constitutes sufficient emergency assistance should be established through the Standards Development Process.			
6	Entergy Services, Inc.	Affirmative	While we agree with the interpretation, we believe there are some items to consider for clarification if this interpretation must go back for recirculation or re-balloting: Question 1 interpretation: the interpretation should address both a Capacity Emergency and Energy Emergency, as defined in the NERC Glossary. Further clarification to explain that emergency assistance is

Segment	Entity	Ballot	Comments
			applicable to both situations (capacity, energy or both) will minimize any confusion in the requirement and interpretation. (note —" there appears to be little, if any difference in the definition of the terms; further clarification of the terms or eliminating one of the terms/consolidating the terms this would be an area for improvement in the NERC Standards) Question 2 interpretation: the interpretation should use the approved term from the NERC Glossary: Adjacent Balancing Authority Question 3 interpretation: the term "emergency assistance, as defined in Question 1 should be used in lieu of "emergency energy assistance," or alternatively use the NERC Glossary terms Capacity Emergency and Energy Emergency Question 4 interpretation: the interpretation should specify that RSG agreements may be used if they contain provisions for use during a Capacity Emergency or Energy Emergency
Response: Your comments will be submitted to the manager of standards development for inclusion in the Standards "Issues" database as a potential modification to the associated standard.			
6	FirstEnergy Solutions	Affirmative	FirstEnergy supports the interpretation provided for EOP-001 Requirement R1 and believes it further clarifies Balancing Authority expectations related to emergency assistance agreements with other Balancing Authorities. It is expected that the standards drafting team working on Project 2008-03 will reference this interpretation when completing revisions to the EOP-001 standard to achieve greater clarity within the standard's requirements and measures. The only question we raise and seek clarification to is in regards to item #2 and we question why the interpretation excludes DC ties when defining an adjacent Balancing Authority? As written, would a Balancing Authority be precluded from obtaining emergency assistance from a BA with whom they may only have DC interconnection(s)? Or, is the intent that a DC tie is considered a remote Balancing Authority and covered by item #3?
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties.			
6	Louisville Gas and Electric Co.	Affirmative	E.ON US votes YES and wishes to emphasize in our comments the value and importance of Reserve Sharing Groups (RSGs) to first and foremost ensure, reliability on a real-time basis, and also to lower the cost of providing electrical power to our customers. Due to this value, NERC and the Industry should support, encourage and seek expansion of RSGs. Our specific points are as follows. The reliability benefits to the parties of RSGs are: – The parties have access to the Contingency Reserve generation capacity of all members on a real time basis and have certainty of emergency energy supply. – The parties utilize a computerized process that immediately dispatches generation and spinning reserves and ten-minute quick-

Segment	Entity	Ballot	Comments
			start Contingency Reserves when called upon by a party with a sudden loss of supply resulting in an immediate response to the supply loss. – The diversity and large number of generating units quickly ramping up to provide emergency power further ensure certainty and an immediate response to the supply loss. – The parties coordinate in advance TRM to ensure that emergency energy for Contingency Reserves can flow in real-time when called on, resulting in certainty of transmission for the flow of emergency energy. The lower cost benefits to the end user customers of the parties of RSGs are: – More efficient use of supply due to reduced Operating Reserves for each BA, despite the size of each BA, in RSGs. (The Midwest ISO has stated that they have conducted studies that have demonstrated that each MW of spinning reserve has a value of $350,000. Thus, the 300 MW of spinning reserves to be provided at the start of the ASM to the Midwest ISO load by MCRSG parties external to the Midwest ISO footprint equate to approximately $100 million in annual value. This value will become an annual cost to the Midwest ISO load upon sunset of the MCRSG. This does not include the savings of similar nature to the external BAs.) – The flexibility to transact more energy between BAs with freed-up generation and transmission capacity is achieved even if the Midwest BA grows and the External CRSG BAs decrease to only a few parties. – The advance coordination of TRM reduces the amount of TRM needed.
Response: Your comments will be submitted to the manager of standards development.			
9	Commonwealth of Massachusetts Department of Public Utilities	Negative	Interpreters should: 1) reconsider inclusion of BAs with DC ties, or explain why BAs with DC ties should be excluded; 2) specify that Reserve Sharing Agreements have provisions addressing emergency assistance and that there be a demonstration that the Reserve Sharing Agreement is sufficient to mitigate reasonably anticipated energy emergencies; and, 3) reconsider requiring that BAs have agreements with all adjacent BAs or explain why an agreement with one adjacent BA is sufficient under the Requirement 1 language.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties.			

Segment	Entity	Ballot	Comments
The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain an adequate level of reliability. The technical criteria for establishing what constitutes sufficient emergency assistance should be established through the Standards Development Process.			
9	National Association of Regulatory Utility Commissioners	Negative	Interpreters should: 1) reconsider inclusion of BAs with DC ties, or explain why BAs with DC ties should be excluded; 2) specify that Reserve Sharing Agreements have provisions addressing emergency assistance and that there be a demonstration that the Reserve Sharing Agreement is sufficient to mitigate reasonably anticipated energy emergencies; and, 3) reconsider requiring that BAs have agreements with all adjacent BAs or explain why an agreement with one adjacent BA is sufficient under the Requirement 1 language.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties. The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain an adequate level of reliability. The technical criteria for establishing what constitutes sufficient emergency assistance should be established through the Standards Development Process.			
10	Northeast Power Coordinating Council, Inc.	Negative	DC tie lines should have been included in the interpretation. Agreements with all adjacent BAs should be required. Participation in a Reserve Sharing Group is insufficient to meet Requirement R1, unless the Reserve Sharing Group agreement contains emergency assistance provisions.
Response: The drafting team agrees with your comment and proposes to use the NERC Glossary of Terms definition of Adjacent Balancing Authority, which doesn't limit interconnections to AC ties. The intent of the interpretation is to require energy assistance agreements with enough BAs to have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. Having emergency energy assistance agreements with all BAs may exceed what is required to maintain an adequate level of reliability. The technical criteria for establishing what constitutes sufficient emergency assistance should be established through the Standards Development Process.			

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Two Recirculation Ballots
January 6–15, 2009

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Recirculation ballot windows for the following projects are now open until 8 p.m. EST on January 15, 2009:

Interpretation of EOP-001-0 Requirement R1 for Regional Entity Compliance Managers (Project 2008-09)

The Regional Entity Compliance Managers group submitted a Request for an Interpretation of EOP-001-0 — Emergency Operations Planning Requirement R1. Under Requirement R1, the Balancing Authority must have operating agreements with adjacent Balancing Authorities that contain provisions for emergency assistance, including emergency assistance from remote Balancing Authorities. The request asked for the following clarifications:

- Define the scope and time horizon associated with "emergency assistance."
- Does "adjacent Balancing Authority" mean one or all adjacent Balancing Authorities?
- What is a "remote Balancing Authority?"
- Does a Balancing Authority participating in a Reserve Sharing Group under BAL-002-0 need additional operating agreements to be compliant with EOP-001-0 Requirement R1?

This version of interpretation includes edits to the version posted for initial ballot. The request and interpretation are posted on the following page: http://www.nerc.com/filez/standards/EOP-001-0_Interpretation_RECM.html

Interpretation of VAR-002-1a — Generator Operation for Maintaining Network Voltage Schedules (Project 2008-11)

ICF Consulting submitted a formal Request for Interpretation, which asked for the following clarifications:

- Which requirements in VAR-002 apply to Generator Operators that operate generators that do not have automatic voltage regulation (AVR) capability?
- Does the standard require a Generator Owner to acquire AVR devices to comply with the requirements in this standard?

The interpretation provides the following clarifications:

- All the requirements and associated subrequirements in VAR-002-1a apply to Generator Owners and Generator Operators that own or operate generators whether equipped with an automatic voltage regulator or not.
- There are no requirements in the standard that require a generator to have an automatic voltage regulator, nor are there any requirements for a Generator Owner to modify its generator to add an automatic voltage regulator.

The request and interpretation are posted on the following page:
http://www.nerc.com/filez/standards/Project2008-11_VAR-002_Interpretation.html

Recirculation Ballot Process

The Standards Committee encourages all members of the Ballot Pool to review the consideration of comments submitted with the initial ballots. In the recirculation ballot, votes are counted by exception only — if a Ballot Pool member does not submit a revision to that member's original vote, the vote remains the same as in the first ballot. Members of the ballot pool may:

- Reconsider and change their vote from the first ballot.
- Vote in the second ballot even if they did not vote on the first ballot.
- Take no action if they do not want to change their original vote.

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

April 2, 2008

Maureen Long
Standards Process Manager
North American Electric Reliability Corporation
116-390 Village Blvd.
Princeton, NJ 08540

Re: Formal Interpretation Request for Reliability Standard EOP-001-0, Requirement 1

Dear Maureen,

The Regional Entity Compliance Managers (RECM) request a formal interpretation of Reliability Standard EOP-001-0 — Emergency Operations Planning Requirement R1 in accordance with the Reliability Standards Development Procedure.

Material Impact: A formal interpretation is required for Regional Entities to consistently assess compliance with this standard and to ensure Registered Entities are meeting their obligation and responsibility as intended by the standard.

Clarification is needed for Reliability Standard EOP-001-0 Requirement R1 which states:

R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

Specifically, the RECM requests an interpretation and clarity for the following language listed in EOP-001-0, Requirement 1:

1. What is the definition of emergency assistance in the context of this standard? What scope and time horizons, if any, are considered necessary in this definition?
2. What was intended by using the adjective "adjacent" in Requirement 1? Does "adjacent" Balancing Authorities mean "All" or something else? Is there qualifying criteria to determine if a very small adjacent Balancing Authority area has enough capacity to offer emergency assistance?
3. What is the definition of the word "remote" as stated in the last phrase of Requirement 1? Does remote mean every Balancing Authority who's area does not physically touch the Balancing Authority attempting to comply with this Requirement?

4. Would a Balancing Authority that participates in a Reserve Sharing Group Agreement, which meets the requirements of Reliability Standard BAL-002-0, Requirement 2, be required to establish additional operating agreements to achieve compliance with Reliability Standard EOP-001-0, Requirement 1?

If you have any questions concerning this request please contact Susan Morris, Manager of Regional Compliance Program Oversight at susan.morris@nerc.net or (609) 240-6784.

Sincerely,

Regional Entity Compliance Managers:

Barry Pagel, Florida Reliability Coordinating Council
Stanley Kopman, Northeast Power Coordinating Council
Wayne VanOsdol, Midwest Reliability Organization
Ray Palmieri, Reliability*First* Corporation
Tom Galloway, SERC Reliability Corporation
Ron Ciesiel, Southwest Power Pool Regional Entity
Mark Henry, Texas Regional Entity
Steve McCoy, Western Electricity Coordinating Council

CC: David Taylor
Gerry Adamski
Regional Entity Compliance Monitoring Group
Compliance Department

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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Revised Interpretation of EOP-001-0 Emergency Operations Planning Requirement R1 for the Regional Entity Compliance Managers

Request for Interpretation Received from Regional Entity Compliance Managers on March 20, 2008:

Request:
The Regional Entity Compliance Managers (RECM) request a formal interpretation of Reliability Standard EOP-001-0 — Emergency Operations Planning Requirement R1 in accordance with the Reliability Standards Development Procedure.

1. *What is the definition of emergency assistance in the context of this standard? What scope and time horizons, if any, are considered necessary in this definition?*
2. *What was intended by using the adjective "adjacent" in Requirement 1? Does "adjacent Balancing Authorities" mean "All" or something else? Is there qualifying criteria to determine if a very small adjacent Balancing Authority area has enough capacity to offer emergency assistance?*
3. *What is the definition of the word "remote" as stated in the last phrase of Requirement 1? Does remote mean every Balancing Authority who's area does not physically touch the Balancing Authority attempting to comply with this Requirement?*
4. *Would a Balancing Authority that participates in a Reserve Sharing Group Agreement, which meets the requirements of Reliability Standard BAL-002-0, Requirement 2, have to establish additional operating agreements to achieve compliance with Reliability Standard EOP-001-0, Requirement 1?*

EOP-001-0
R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

The following revised interpretation of EOP-001-0 — Emergency Operations Planning Requirement R1 was developed by the Executive Committee of the NERC Operating Reliability Subcommittee:

Interpretation of EOP-001-0 Requirement R1:

1. In the context of this standard, emergency assistance is emergency energy. Emergency energy would normally be arranged for during the current operating day. The agreement should describe the conditions under which the emergency energy will be delivered to the responsible Balancing Authority.
2. The intent is that all Balancing Authorities have emergency energy assistance agreements with at least one Adjacent Balancing Authority and have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. However,

the standard does not require emergency energy assistance agreements with all Adjacent Balancing Authorities.

3. A remote Balancing Authority is a Balancing Authority other than an Adjacent Balancing Authority. The responsible Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with all remote Balancing Authorities. The responsible Balancing Authority's agreement(s) with the Adjacent Balancing Authorities does (do) not preclude the Adjacent Balancing Authority from purchasing emergency energy from remote Balancing Authorities on behalf of the responsible Balancing Authority.
4. A Balancing Authority that is compliant with Reliability Standard BAL-002-0, Requirement R2 through participation in a Reserve Sharing Group Agreement is not required to establish additional operating agreements as described in Requirement R1 of EOP-001-0.

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Revised Interpretation of EOP-001-0 Emergency Operations Planning Requirement R1 for the Regional Entity Compliance Managers

Request for Interpretation Received from Regional Entity Compliance Managers on March 20, 2008:

Request:
The Regional Entity Compliance Managers (RECM) request a formal interpretation of Reliability Standard EOP-001-0 — Emergency Operations Planning Requirement R1 in accordance with the Reliability Standards Development Procedure.

1. *What is the definition of emergency assistance in the context of this standard? What scope and time horizons, if any, are considered necessary in this definition?*
2. *What was intended by using the adjective "adjacent" in Requirement 1? Does "adjacent Balancing Authorities" mean "All" or something else? Is there qualifying criteria to determine if a very small adjacent Balancing Authority area has enough capacity to offer emergency assistance?*
3. *What is the definition of the word "remote" as stated in the last phrase of Requirement 1? Does remote mean every Balancing Authority who's area does not physically touch the Balancing Authority attempting to comply with this Requirement?*
4. *Would a Balancing Authority that participates in a Reserve Sharing Group Agreement, which meets the requirements of Reliability Standard BAL-002-0, Requirement 2, have to establish additional operating agreements to achieve compliance with Reliability Standard EOP-001-0, Requirement 1?*

EOP-001-0
R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

The following revised interpretation of EOP-001-0 — Emergency Operations Planning Requirement R1 was developed by the Executive Committee of the NERC Operating Reliability Subcommittee ~~on May 9, 2008~~:

Interpretation of EOP-001-0 Requirement R1:

1. In the context of this standard, emergency assistance is emergency energy. Emergency energy would normally be arranged for during the current operating day. The agreement should describe the conditions under which the emergency energy will be delivered to the responsible Balancing Authority.
2. ~~An adjacent Balancing Authority is one that has AC tie lines with the responsible Balancing Authority. The standard does not require emergency energy assistance agreements with *all* adjacent Balancing Authorities.~~The intent is that all Balancing Authorities have emergency

energy assistance agreements with at least one ~~adjacent~~Adjacent Balancing Authority and have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. However, the standard does not require emergency energy assistance agreements with all Adjacent Balancing Authorities.

3. A remote Balancing Authority is a Balancing Authority other than an ~~adjacent~~Adjacent Balancing Authority. The responsible Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with all remote Balancing Authorities. The responsible Balancing Authority's agreement(s) with the ~~adjacent~~Adjacent Balancing Authorities does (do) not preclude the ~~adjacent~~Adjacent Balancing Authority from purchasing emergency energy from remote Balancing Authorities on behalf of the responsible Balancing Authority.

4. A Balancing Authority that is compliant with Reliability Standard BAL-002-0, Requirement R2 through participation in a Reserve Sharing Group Agreement is not required to establish additional operating agreements as described in Requirement R1 of EOP-001-0.

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Standards Announcement

Ballot Pool and Pre-ballot Window
January 28–February 26, 2009

Now available at: https://standards.nerc.net/BallotPool.aspx

Revised Interpretation of EOP-001-0 Requirement R1 for Regional Entity Compliance Managers (Project 2008-09)

The revised interpretation of EOP-001-0 Requirement R1 for the Regional Entity Compliance Managers is posted for a 30-day pre-ballot review. Registered Ballot Body members may join the ballot pool to be eligible to vote on these revisions **until 8 a.m. EST on February 26, 2009.**

After the initial ballot, the drafting team made some significant modifications to clarify the interpretation. We continued to a recirculation ballot in error – because the modifications were significant, the revised interpretation should have been posted for a new 30-day pre-ballot review. This posting corrects that error, and a new ballot will be conducted following the 30-day pre-ballot window. The 30-day pre-ballot review includes the formation of a new ballot pool.

The revised interpretation uses the term "Adjacent Balancing Authority" as defined in the *NERC Glossary of Terms Used in Reliability Standards*. The changes to the interpretation are shown in the redline version of the interpretation posted for review.

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-RFI_EOP-001-0_RECM_in.

Background

The Regional Entity Compliance Managers group submitted a request for interpretation for EOP-001-0 — Emergency Operations Planning Requirement R1. Under Requirement R1, the Balancing Authority must have operating agreements with adjacent Balancing Authorities that contain provisions for emergency assistance, including emergency assistance from remote Balancing Authorities. The request asked for the following clarifications:

- Define the scope and time horizon associated with "emergency assistance."
- Does "adjacent Balancing Authority" mean one or all adjacent Balancing Authorities?
- What is a "remote Balancing Authority?"

- Does a Balancing Authority participating in a Reserve Sharing Group under BAL-002-0 need additional operating agreements to be compliant with EOP-001-0 Requirement R1

Project Page: http://www.nerc.com/filez/standards/EOP-001-0_Interpretation_RECM.html

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

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Standards Announcement

Initial Ballot Window Open

February 27–March 9, 2009

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Revised Interpretation of EOP-001-0 Requirement R1 for Regional Entity Compliance Managers (Project 2008-09)

An initial ballot window for a revised interpretation of EOP-001-0 — Emergency Operations Planning Requirement R1 for the Regional Entity Compliance Managers is now open **until 8 p.m. EDT on March 9, 2009.**

Background

The Regional Entity Compliance Managers group submitted a request for interpretation for EOP-001-0 Requirement R1. Under Requirement R1, the Balancing Authority must have operating agreements with adjacent Balancing Authorities that contain provisions for emergency assistance, including emergency assistance from remote Balancing Authorities. The request asked for clarification on specific terminology and the applicability of Reserve Sharing Group Agreements. The revised interpretation uses the term "Adjacent Balancing Authority" as defined in the *NERC Glossary of Terms Used in Reliability Standards*. The changes to the interpretation are shown in the redline version of the interpretation posted for review.

Project Page: http://www.nerc.com/filez/standards/EOP-001-0_Interpretation_RECM.html

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
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Ballot Results	
Ballot Name:	Request for Interpretation - EOP-001-0 - RECM_in
Ballot Period:	2/27/2009 - 3/9/2009
Ballot Type:	Initial
Total # Votes:	165
Total Ballot Pool:	184
Quorum:	**89.67 % The Quorum has been reached**
Weighted Segment Vote:	89.03 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	56	1	45	0.938	3	0.063	1	7
2 - Segment 2.	9	0.8	4	0.4	4	0.4	0	1
3 - Segment 3.	45	1	39	0.975	1	0.025	0	5
4 - Segment 4.	13	1	11	0.917	1	0.083	0	1
5 - Segment 5.	34	1	29	0.935	2	0.065	1	2
6 - Segment 6.	17	1	15	1	0	0	0	2
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	2	0.2	2	0.2	0	0	0	0
9 - Segment 9.	2	0.2	2	0.2	0	0	0	0
10 - Segment 10.	6	0.5	4	0.4	1	0.1	0	1
Totals	**184**	**6.7**	**151**	**5.965**	**12**	**0.736**	**2**	**19**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit S. Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Jason Shaver	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Negative	View
1	Avista Corp.	Scott Kinney		
1	BC Transmission Corporation	Gordon Rawlings	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	

1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	CenterPoint Energy	Paul Rocha	Negative	View
1	Central Maine Power Company	Brian Conroy		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Alan L Cooke	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dominion Virginia Power	William L. Thompson	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	E.ON U.S. LLC	Larry Monday	Affirmative	
1	Entergy Corporation	George R. Bartlett		
1	Exelon Energy	John J. Blazekovich	Affirmative	
1	Farmington Electric Utility System	Alan Glazner	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	C. Martin Mennes	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Damon Holladay		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	ITC Transmission	Elizabeth Howell	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Kissimmee Utility Authority	Joe B Watson	Negative	
1	Manitoba Hydro	Michelle Rheault	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	Minnesota Power, Inc.	Carol Gerou	Affirmative	
1	National Grid	Michael J Ranalli	Affirmative	
1	New York Power Authority	Ralph Rufrano	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Abstain	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Affirmative	
1	PacifiCorp	Robert Williams		
1	Potomac Electric Power Co.	Richard J. Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PP&L, Inc.	Ray Mammarella		
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Puget Sound Energy, Inc.	Catherine Koch	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SaskPower	Wayne Guttormson	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sierra Pacific Power Co.	Richard Salgo	Affirmative	
1	South Texas Electric Cooperative	Richard McLeon	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
2	Alberta Electric System Operator	Anita Lee	Affirmative	
2	British Columbia Transmission Corporation	Phil Park	Affirmative	
2	California ISO	David Hawkins	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Roy D. McCoy	Negative	View
2	Independent Electricity System Operator	Kim Warren	Negative	View
2	Midwest ISO, Inc.	Terry Bilke		
2	New Brunswick System Operator	Alden Briggs	Negative	View
2	New York Independent System Operator	Gregory Campoli	Negative	View
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
3	Alabama Power Company	Robin Hurst	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	American Electric Power	Raj Rana	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	Avista Corp.	Robert Lafferty		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City Public Service of San Antonio	Edwin Les Barrow		
3	Cloverland Electric Cooperative	Daniel M Dasho	Affirmative	

3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Jalal (John) Babik	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	FirstEnergy Solutions	Joanne Kathleen Borrell	Affirmative	View
3	Florida Power & Light Co.	W. R. Schoneck	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Leslie Sibert	Affirmative	
3	Georgia System Operations Corporation	Edward W Pourciau	Affirmative	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	JEA	Garry Baker		
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Affirmative	
3	New York Power Authority	Michael Lupo	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	PacifiCorp	John Apperson	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Southern California Edison Co.	David Schiada		
3	Tampa Electric Co.	Ronald L. Donahey	Affirmative	
3	Wisconsin Electric Power Marketing	James R. Keller	Negative	View
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Thomas Reedy		
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Affirmative	
4	Northern California Power Agency	Fred E. Young	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	View
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Sacramento Municipal Utility District	Dilip Mahendra	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R. Wallace	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	Avista Corp.	Edward F. Groce	Abstain	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	City of Tallahassee	Alan Gale	Affirmative	
5	Colmac Clarion/Piney Creek LP	Harvie D. Beavers	Affirmative	
5	CPS Energy	Robert B Stevens		
5	Dairyland Power Coop.	Warren Schaefer	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Entergy Corporation	Stanley M Jaskot	Negative	View
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	View
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin	Affirmative	

5	Manitoba Hydro	Mark Aikens	Affirmative	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern States Power Co.	Liam Noailles	Affirmative	
5	Oklahoma Gas and Electric Co.	Kim Morphis	Affirmative	
5	Orlando Utilities Commission	Richard Kinas	Affirmative	View
5	PacifiCorp Energy	David Godfrey	Affirmative	
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Power LLC	Thomas Piascik	Affirmative	
5	Reliant Energy Services	Thomas J. Bradish	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Southeastern Power Administration	Douglas Spencer	Affirmative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Wisconsin Electric Power Co.	Linda Horn	Negative	View
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol		
6	Dominion Resources, Inc.	Louis S Slade		
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	View
6	Louisville Gas and Electric Co.	Daryn Barker	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	New York Power Authority	Thomas Papadopoulos	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Progress Energy	James Eckelkamp	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	
6	Salt River Project	Mike Hummel	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Negative	View
10	Northeast Power Coordinating Council, Inc.	Guy Zito	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Southwest Power Pool	Charles H. Yeung		
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	

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Standards Announcement

Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

Revised Interpretation of EOP-001-0 Requirement R1 for Regional Entity Compliance Managers (Project 2008-09)

Since at least one negative ballot was submitted with a comment, a recirculation ballot will be held. The recirculation ballot will be held after the drafting team responds to voter comments submitted during this ballot.

The initial ballot for the revised interpretation of EOP-001-0 — Emergency Operations Planning Requirement R1 for the Regional Entity Compliance Managers ended March 9, 2009. The ballot results are shown below. The Ballot Results Web page provides a link to the detailed results.

Quorum:	89.67%
Approval:	89.03%

Project page: http://www.nerc.com/filez/standards/EOP-001-0_Interpretation_RECM.html

Ballot Criteria

Approval requires both:

- A quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention; and
- A two-thirds majority of the weighted segment votes cast must be affirmative. The number of votes cast is the sum of affirmative and negative votes, excluding abstentions and nonresponses.

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

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Consideration of Comments on Initial Ballot for the Revised Interpretation of EOP-001-0 Requirement R1 for the Regional Entity Compliance Managers (Project 2008-09)

Ballot conducted from February 27 to March 9, 2009

Summary Consideration:

There were three primary areas of concern expressed by balloters who submitted a negative vote:

1. EOP-001-0 should be applied on an Interconnection basis. Therefore, balloters recommended modifying paragraph 2 of the interpretation by inserting the phrase "interconnected by AC ties or DC (asynchronous) ties within the same Interconnection." The Operating Reliability Subcommittee Executive Committee (ORS EC), which is serving as the drafting team for the interpretation, agrees with these balloters and proposes to modify paragraph 2 accordingly.

2. Several balloters questioned the use of the word "all" in the second sentence paragraph 3 of the interpretation. Use of the word all in this context implied to balloters that "at least one" was required. The ORS EC agrees with balloters and proposes to modify the interpretation by changing the word "all" to "any" in the second sentence of paragraph 3.

3. Several balloters questioned whether a Reserve Sharing Group agreement could substitute for an emergency assistance agreement with adjacent Balancing Authorities. Without an emergency assistance agreement, the conditions under which emergency energy assistance could be provided will remain undefined. The ORS EC agrees with balloters and proposes to modify paragraph 4 of the interpretation to read, "A Reserve Sharing Group agreement that contains provisions for emergency assistance may be used to meet Requirement R1 of EOP-001-0."

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
Stanley M Jaskot	Entergy Corporation	5	Negative	1. We believe this standard should be applied on an Interconnection basis. Therefore, we recommend Item #2 be revised to "The intent is that all Balancing Authorities, interconnected by AC ties or DC (asynchronous) ties within the same Interconnection, have emergency ..." 2. We also recommend the "responsible Balancing Authority" be revised to "deficient Balancing Authority" in Item #3. Item # 3. A remote Balancing Authority is a Balancing Authority other than an Adjacent Balancing Authority. The responsible DEFICIENT Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with all remote Balancing Authorities. The responsible DEFICIENT Balancing Authority's agreement(s) with the Adjacent Balancing Authorities does (do) not preclude the Adjacent Balancing Authority from purchasing emergency energy from remote Balancing Authorities on behalf of the responsible DEFICIENT Balancing Authority. 3. We agree with the clarification that BAs are not required to have agreements with ALL Adjacent BAs.
Response: Comment 1 – The Operating Reliability Subcommittee Executive Committee (ORS EC) agrees with the balloter and will insert the phrase "interconnected by AC ties or DC (asynchronous) ties within the same Interconnection" in the first sentence of paragraph 2. Comment 2 – The ORS EC agrees to eliminate the term "responsible" from the second, third, and forth sentences of paragraph 3. The ORS EC does not agree to insertion of the term "deficient." EOP-001-0 is applicable to all Balancing Authorities. In addition, the ORS EC proposes to reword the last sentence of paragraph 3 to eliminate "on behalf of the responsible BA." Comment 3 - The ORS EC agrees with the balloter; however, in response to other balloters, the ORS EC proposes to modify the interpretation by changing the word "all" to "any" in paragraph 3.				
Paul Rocha	CenterPoint Energy	1	Negative	CenterPoint Energy recommends further clarification of the terms "adjacent" and "neighboring" to address that such terms are not applicable to interconnection-wide regions, such as WECC and ERCOT. The proposed definition failed to explain the term "adjacent" as requested.
Response: The ORS EC agrees with the balloter and will insert the phrase "interconnected by AC ties or DC (asynchronous) ties within the same Interconnection" in the first sentence of paragraph 2 of the interpretation.				

Voter	Entity	Segment	Vote	Comment
Robert Martinko	FirstEnergy Energy Delivery	1	Affirmative	FirstEnergy supports the interpretation provided for EOP-001 Requirement R1 and believes it further clarifies Balancing Authority expectations related to emergency assistance agreements with other Balancing Authorities. It is expected that the standards drafting team that will work on Project 2009-03 will incorporate this interpretation when completing revisions to the EOP-001 standard to achieve greater clarity within the standard's requirements and measures.
Joanne Kathleen Borrell	FirstEnergy Solutions	3	Affirmative	FirstEnergy supports the interpretation provided for EOP-001 Requirement R1 and believes it further clarifies Balancing Authority expectations related to emergency assistance agreements with other Balancing Authorities. It is expected that the standards drafting team that will work on Project 2009-03 will incorporate this interpretation when completing revisions to the EOP-001 standard to achieve greater clarity within the standard's requirements and measures.
Douglas Hohlbaugh	Ohio Edison Company	4	Affirmative	FirstEnergy supports the interpretation provided for EOP-001 Requirement R1 and believes it further clarifies Balancing Authority expectations related to emergency assistance agreements with other Balancing Authorities. It is expected that the standards drafting team that will work on Project 2009-03 will incorporate this interpretation when completing revisions to the EOP-001 standard to achieve greater clarity within the standard's requirements and measures.
Kenneth Dresner	FirstEnergy Solutions	5	Affirmative	FirstEnergy supports the interpretation provided for EOP-001 Requirement R1 and believes it further clarifies Balancing Authority expectations related to emergency assistance agreements with other Balancing Authorities. It is expected that the standards drafting team that will work on Project 2009-03 will incorporate this interpretation when completing revisions to the EOP-001 standard to achieve greater clarity within the standard's requirements and measures.
Mark S Travaglianti	FirstEnergy Solutions	6	Affirmative	FirstEnergy supports the interpretation provided for EOP-001 Requirement R1 and believes it further clarifies Balancing Authority expectations related to emergency assistance agreements with other Balancing Authorities. It is expected that the standards drafting team that will work on Project 2009-03 will incorporate this interpretation when completing revisions to the EOP-001 standard to achieve greater clarity within the standard's requirements and measures.
Response: The ORS EC agrees with the balloters.				

Voter	Entity	Segment	Vote	Comment
Roy D. McCoy	Electric Reliability Council of Texas, Inc.	2	Negative	Interpretation should clarify what "adjacent" and "neighboring" means. Does it mean that EOP-001 applies to registered functional entities with AC ties or DC ties "within" an Interconnection and does not apply to DC ties "between" Interconnections?
Response: The ORS EC agrees with the balloter and will insert the phrase "interconnected by AC ties or DC (asynchronous) ties within the same Interconnection" in the first sentence of paragraph 2 of the interpretation.				
Alden Briggs	New Brunswick System Operator	2	Negative	NBSO disagrees with this interpretation for two reasons: Firstly, 4. A Balancing Authority that is compliant with Reliability Standard BAL-002-0, Requirement R2 through participation in a Reserve Sharing Group Agreement is not required to establish additional operating agreements as described in Requirement R1 of EOP-001-0. Reserve Sharing agreements may not include emergency energy agreements. Secondly, From the 3rd paragraph on the interpretation: The responsible Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with all remote Balancing Authorities. This statement appears to state that an agreement is required with a remote BA. Though it is believed that this was not the intent of the interpretation it can cause confusion.
Response: Comment 1 – The ORS EC agrees with balloter and proposes to modify paragraph 4 of the interpretation to read, "A Reserve Sharing Group agreement that contains provisions for emergency assistance may be used to meet Requirement R1 of EOP-001-0." Comment 2 - The ORS EC agrees with balloter and proposes to modify paragraph 3 of the interpretation by changing the word "all" to "any" in the second sentence.				
Richard Kinas	Orlando Utilities Commission	5	Affirmative	Since you decided to place Adjacent into the NERC glossary, I'm suprised that you did not decide to do the same with "remote" i.e. Remote - any entity that is not Adjacent
Response: The term Adjacent Balancing Authority is in the *Glossary of Terms Used in Reliability Standards*. The *Glossary of Terms Used in Reliability Standards* may not be modified via an interpretation.				

Voter	Entity	Segment	Vote	Comment
Kim Warren	Independent Electricity System Operator	2	Negative	The IESO views the Reserve Sharing Group (RSG) and emergency assistance agreements as distinct and serving two separate and necessary functions. Under this interpretation we envisage situations where, despite the existence of the RSG agreement, emergency assistance (that may be needed for a lengthy period) may not be provided because its scope and conditions of supply are not defined. We believe this therefore leaves room for non-compliance and would expose the system to unreliable operation when emergency assistance is needed but cannot be arranged or delivered absent an operating agreement. We agree that a RSG agreement may be adequate to meet EOP-001-0, R1 but only if it explicitly includes provisions for emergency energy assistance.
Response: The ORS EC agrees with balloter and proposes to modify paragraph 4 of the interpretation to read, "A Reserve Sharing Group agreement that contains provisions for emergency assistance may be used to meet Requirement R1 of EOP-001-0."				
James Armke	Austin Energy	1	Negative	The Interpretation should clarify that the adjective "adjacent" is intended for neighboring Balancing Authorities interconnected by AC ties. For ERCOT, the requirement would be unnecessary and burdensom with no impact to reliability because flows across the DC ties remain at their scheduled values and do not impact neighboring Balancing Authorities.
Response: The ORS EC agrees with the balloter and will insert the phrase "interconnected by AC ties or DC (asynchronous) ties within the same Interconnection" in the first sentence of paragraph 2 of the interpretation.				
Gregory Campoli	New York Independent System Operator	2	Negative	The NYISO is concerned with the second sentence in Paragraph 3 that says, 'The responsible Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with all remote Balancing Authorities.' We are concerned that this means that a BA is required to have an agreement in place for purchasing emergency energy with at least one remote BA. We do not support this interpretation and believe that existing standard only obligates a BA to have agreements in place with adjacent BA's. The NYISO is also concerned that a Reserve Sharing Group (RSG) can be a substitute for emergency assistance agreement with adjacent BA's. Without an emergency assistance agreement, the scope of and conditions under which emergency energy assistance could be provided, will remain undefined.
Response: Comment 1 – The ORS EC agrees with balloter and proposes to modify paragraph 3 of the interpretation by changing the word "all" to "any" in the				

Voter	Entity	Segment	Vote	Comment
second sentence. Comment 2 – The ORS EC agrees with balloter and proposes to modify paragraph 4 of the interpretation to read, "A Reserve Sharing Group agreement that contains provisions for emergency assistance may be used to meet Requirement R1 of EOP-001-0."				
Kent Saathoff	Electric Reliability Council of Texas, Inc.	10	Negative	The original interpretation was correct. This revised interpretation would apply requirements appropriate for adjacent entities connected synchronously by AC lines to entities connected only by asynchronous DC lines. Such requirements would serve no reliability purpose and be a waste of resources for entities connected solely by DC ties which have no uncontrolled flows.
Response: The ORS EC agrees with the balloter and will insert the phrase "interconnected by AC ties or DC (asynchronous) ties within the same Interconnection" in the first sentence of paragraph 2 of the interpretation.				
James R. Keller	Wisconsin Electric Power Marketing	3	Negative	The sentence within #3 of the EOP-001-1 R1 interpretation "The responsible Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with all remote Balancing Authorities." is stating that the Responsible BA must have arrangements with some remote BAs. The "all" needs to be replaced with "any" in this sentence.
Linda Horn	Wisconsin Electric Power Co.	5	Negative	The sentence within #3 of the EOP-001-1 R1 interpretation "The responsible Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with all remote Balancing Authorities." is stating that the Responsible BA must have arrangements with some remote BAs. The "all" needs to be replaced with "any" in this sentence.
Response: The ORS EC agrees with balloter and proposes to modify paragraph 3 of the interpretation by changing the word "all" to "any" in the second sentence.				
Anthony Jankowski	Wisconsin Energy Corp.	4	Negative	The wording related to Remote Balancing Authorities should read "with any" instead of "with all" in paragraph #3.
Response: The ORS EC agrees with balloter and proposes to modify paragraph 3 of the interpretation by changing the word "all" to "any" in the second sentence.				

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April 2, 2008

Maureen Long
Standards Process Manager
North American Electric Reliability Corporation
116-390 Village Blvd.
Princeton, NJ 08540

Re: Formal Interpretation Request for Reliability Standard EOP-001-0, Requirement 1

Dear Maureen,

The Regional Entity Compliance Managers (RECM) request a formal interpretation of Reliability Standard EOP-001-0 — Emergency Operations Planning Requirement R1 in accordance with the Reliability Standards Development Procedure.

Material Impact: A formal interpretation is required for Regional Entities to consistently assess compliance with this standard and to ensure Registered Entities are meeting their obligation and responsibility as intended by the standard.

Clarification is needed for Reliability Standard EOP-001-0 Requirement R1 which states:

R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

Specifically, the RECM requests an interpretation and clarity for the following language listed in EOP-001-0, Requirement 1:

1. What is the definition of emergency assistance in the context of this standard? What scope and time horizons, if any, are considered necessary in this definition?
2. What was intended by using the adjective "adjacent" in Requirement 1? Does "adjacent" Balancing Authorities mean "All" or something else? Is there qualifying criteria to determine if a very small adjacent Balancing Authority area has enough capacity to offer emergency assistance?
3. What is the definition of the word "remote" as stated in the last phrase of Requirement 1? Does remote mean every Balancing Authority who's area does not physically touch the Balancing Authority attempting to comply with this Requirement?

4. Would a Balancing Authority that participates in a Reserve Sharing Group Agreement, which meets the requirements of Reliability Standard BAL-002-0, Requirement 2, be required to establish additional operating agreements to achieve compliance with Reliability Standard EOP-001-0, Requirement 1?

If you have any questions concerning this request please contact Susan Morris, Manager of Regional Compliance Program Oversight at susan.morris@nerc.net or (609) 240-6784.

Sincerely,

Regional Entity Compliance Managers:

Barry Pagel, Florida Reliability Coordinating Council
Stanley Kopman, Northeast Power Coordinating Council
Wayne VanOsdol, Midwest Reliability Organization
Ray Palmieri, Reliability*First* Corporation
Tom Galloway, SERC Reliability Corporation
Ron Ciesiel, Southwest Power Pool Regional Entity
Mark Henry, Texas Regional Entity
Steve McCoy, Western Electricity Coordinating Council

CC: David Taylor
Gerry Adamski
Regional Entity Compliance Monitoring Group
Compliance Department

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Revised Interpretation of EOP-001-0 — Emergency Operations Planning Requirement R1 for the Regional Entity Compliance Managers (Project 2008-09)

Request for Interpretation Received from Regional Entity Compliance Managers on March 20, 2008:

Request:
The Regional Entity Compliance Managers (RECM) request a formal interpretation of Reliability Standard EOP-001-0 — Emergency Operations Planning Requirement R1 in accordance with the Reliability Standards Development Procedure.

1. *What is the definition of emergency assistance in the context of this standard? What scope and time horizons, if any, are considered necessary in this definition?*
2. *What was intended by using the adjective "adjacent" in Requirement 1? Does "adjacent Balancing Authorities" mean "All" or something else? Is there qualifying criteria to determine if a very small adjacent Balancing Authority area has enough capacity to offer emergency assistance?*
3. *What is the definition of the word "remote" as stated in the last phrase of Requirement 1? Does remote mean every Balancing Authority who's area does not physically touch the Balancing Authority attempting to comply with this Requirement?*
4. *Would a Balancing Authority that participates in a Reserve Sharing Group Agreement, which meets the requirements of Reliability Standard BAL-002-0, Requirement 2, have to establish additional operating agreements to achieve compliance with Reliability Standard EOP-001-0, Requirement 1?*

EOP-001-0
R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

The following revised (October 2009) interpretation of EOP-001-0 — Emergency Operations Planning Requirement R1 was developed by the Executive Committee of the NERC Operating Reliability Subcommittee:

Interpretation of EOP-001-0 Requirement R1:

1. In the context of this standard, emergency assistance is emergency energy. Emergency energy would normally be arranged for during the current operating day. The agreement should describe the conditions under which the emergency energy will be delivered to the responsible Balancing Authority.
2. The intent is that all Balancing Authorities, interconnected by AC ties or DC (asynchronous) ties within the same Interconnection, have emergency energy assistance agreements with at least one Adjacent Balancing Authority and have sufficient emergency energy assistance

agreements to mitigate reasonably anticipated energy emergencies. However, the standard does not require emergency energy assistance agreements with all Adjacent Balancing Authorities.

3. A remote Balancing Authority is a Balancing Authority other than an Adjacent Balancing Authority. A Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with any remote Balancing Authorities. A Balancing Authority's agreement(s) with Adjacent Balancing Authorities does (do) not preclude the Adjacent Balancing Authority from purchasing emergency energy from remote Balancing Authorities.
4. A Reserve Sharing Group agreement that contains provisions for emergency assistance may be used to meet Requirement R1 of EOP-001-0.

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Revised Interpretation of EOP-001-0 — Emergency Operations Planning Requirement R1 for the Regional Entity Compliance Managers (Project 2008-09)

Request for Interpretation Received from Regional Entity Compliance Managers on March 20, 2008:

Request:
The Regional Entity Compliance Managers (RECM) request a formal interpretation of Reliability Standard EOP-001-0 — Emergency Operations Planning Requirement R1 in accordance with the Reliability Standards Development Procedure.

1. *What is the definition of emergency assistance in the context of this standard? What scope and time horizons, if any, are considered necessary in this definition?*
2. *What was intended by using the adjective "adjacent" in Requirement 1? Does "adjacent Balancing Authorities" mean "All" or something else? Is there qualifying criteria to determine if a very small adjacent Balancing Authority area has enough capacity to offer emergency assistance?*
3. *What is the definition of the word "remote" as stated in the last phrase of Requirement 1? Does remote mean every Balancing Authority who's area does not physically touch the Balancing Authority attempting to comply with this Requirement?*
4. *Would a Balancing Authority that participates in a Reserve Sharing Group Agreement, which meets the requirements of Reliability Standard BAL-002-0, Requirement 2, have to establish additional operating agreements to achieve compliance with Reliability Standard EOP-001-0, Requirement 1?*

EOP-001-0
R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

The following revised (October 2009) interpretation of EOP-001-0 — Emergency Operations Planning Requirement R1 was developed by the Executive Committee of the NERC Operating Reliability Subcommittee:

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1. In the context of this standard, emergency assistance is emergency energy. Emergency energy would normally be arranged for during the current operating day. The agreement should describe the conditions under which the emergency energy will be delivered to the responsible Balancing Authority.
2. The intent is that all Balancing Authorities, interconnected by AC ties or DC (asynchronous) ties within the same Interconnection, have emergency energy assistance agreements with at least one Adjacent Balancing Authority and have sufficient emergency energy assistance

agreements to mitigate reasonably anticipated energy emergencies. However, the standard does not require emergency energy assistance agreements with all Adjacent Balancing Authorities.

3. A remote Balancing Authority is a Balancing Authority other than an Adjacent Balancing Authority. ~~The~~A ~~responsible~~ Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with ~~all~~ any remote Balancing Authorities. ~~The~~A ~~responsible~~ Balancing Authority's agreement(s) with ~~the~~ Adjacent Balancing Authorities does (do) not preclude the Adjacent Balancing Authority from purchasing emergency energy from remote Balancing Authorities ~~on behalf of the responsible Balancing Authority~~.

4. A ~~Balancing Authority that is compliant with Reliability Standard BAL-002-0, Requirement R2 through participation in a~~ Reserve Sharing Group ~~A~~agreement that contains provisions for emergency assistance may be used to meet ~~is not required to establish additional operating agreements as described in~~ Requirement R1 of EOP-001-0.

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Standards Announcement

Ballot Pool and Pre-ballot Window
October 6–November 5, 2009

Now available at: https://standards.nerc.net/BallotPool.aspx

Project 2008-09: Interpretation of EOP-001-0 for Regional Entity Compliance Managers (Revision 2)

A revised interpretation of EOP-001-0 — Emergency Operations Planning Requirement R1 for the Regional Entity Compliance Managers is posted for a 30-day pre-ballot review. Registered Ballot Body members may join the ballot pool to be eligible to vote on this interpretation **until 8 a.m. EST on November 5, 2009**.

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-2008-09_RFI_RECM-Rv2_in.

Next Steps

Voting will begin shortly after the pre-ballot review closes.

Project Background

The Regional Entity Compliance Managers group submitted a request for interpretation for EOP-001-0 Requirement R1. Under Requirement R1, the Balancing Authority must have operating agreements with adjacent Balancing Authorities that contain provisions for emergency assistance, including emergency assistance from remote Balancing Authorities. The request asked for clarification on specific terminology and the applicability of Reserve Sharing Group Agreements.

This is the second revision of the interpretation. The drafting team revised the interpretation to address balloter concerns regarding 1) application on an Interconnection basis, 2) whether an agreement was required with a remote Balancing Authority, and 3) whether a Reserve Sharing Group agreement could substitute for an emergency assistance agreement with adjacent Balancing Authorities. The changes to the interpretation are shown in a redline version posted for review. The team has also posted a response to comments received during the initial ballot (February 2009) of the first revision. Project page: http://www.nerc.com/filez/standards/EOP-001-0_Interpretation_RECM.html

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

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Standards Announcement

Initial Ballot Window Open
November 5–16, 2009

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Project 2008-09: Interpretation of EOP-001-0 for Regional Entity Compliance Managers (Revision 2)

An initial ballot window for a revised interpretation of standard EOP-001-0 — Emergency Operations Planning, Requirement R1, for the Regional Entity Compliance Managers is now open **until 8 p.m. EST on November 16, 2009**.

Instructions

Members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

Next Steps

Voting results will be posted and announced after the ballot window closes.

Project Background

The Regional Entity Compliance Managers group submitted a request for an interpretation of EOP-001-0 Requirement R1. Under Requirement R1, the Balancing Authority must have operating agreements with adjacent Balancing Authorities that contain provisions for emergency assistance, including emergency assistance from remote Balancing Authorities. The request asked for clarification on specific terminology and the applicability of Reserve Sharing Group Agreements.

This is the second revision of the interpretation. The drafting team revised the interpretation to address balloter concerns regarding 1) application on an Interconnection basis, 2) whether an agreement was required with a remote Balancing Authority, and 3) whether a Reserve Sharing Group agreement could substitute for an emergency assistance agreement with adjacent Balancing Authorities. The changes to the interpretation are shown in a redline version posted for on the project page. The team has also posted a response to comments received during the initial ballot (conducted in February 2009) of the first revision.

Project page: http://www.nerc.com/filez/standards/EOP-001-0_Interpretation_RECM.html

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

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Ballot Results

Ballot Name:	Project 2008-09 - Interpretation - RECM - Revision 2_in
Ballot Period:	11/5/2009 - 11/16/2009
Ballot Type:	Initial
Total # Votes:	190
Total Ballot Pool:	221
Quorum:	**85.97 % The Quorum has been reached**
Weighted Segment Vote:	98.07 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	58	1	47	0.959	2	0.041	1	8
2 - Segment 2.	11	1	10	1	0	0	0	1
3 - Segment 3.	52	1	40	0.976	1	0.024	5	6
4 - Segment 4.	11	0.9	9	0.9	0	0	0	2
5 - Segment 5.	42	1	30	0.968	1	0.032	3	8
6 - Segment 6.	26	1	19	0.95	1	0.05	3	3
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	6	0.5	5	0.5	0	0	0	1
9 - Segment 9.	7	0.4	4	0.4	0	0	1	2
10 - Segment 10.	8	0.8	8	0.8	0	0	0	0
Totals	**221**	**7.6**	**172**	**7.453**	**5**	**0.147**	**13**	**31**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips		
1	Ameren Services	Kirit S. Shah	Affirmative	View
1	American Electric Power	Paul B. Johnson	Negative	View
1	American Transmission Company, LLC	Jason Shaver	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman		
1	Avista Corp.	Scott Kinney	Negative	
1	BC Transmission Corporation	Gordon Rawlings	Affirmative	
1	Black Hills Corp	Eric Egge	Affirmative	

1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy	Paul Rocha	Affirmative	
1	Central Maine Power Company	Brian Conroy	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dominion Virginia Power	William L. Thompson	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Damon Holladay	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Albert Poire	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	ITC Transmission	Elizabeth Howell	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Long Island Power Authority	Jonathan Appelbaum	Affirmative	
1	Manitoba Hydro	Michelle Rheault		
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Nebraska Public Power District	Richard L. Koch	Affirmative	
1	New York State Electric & Gas Corp.	Henry G. Masti	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	PacifiCorp	Mark Sampson	Affirmative	
1	Potomac Electric Power Co.	Richard J. Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Affirmative	
1	PP&L, Inc.	Ray Mammarella	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Puget Sound Energy, Inc.	Catherine Koch	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa		
1	Sierra Pacific Power Co.	Richard Salgo	Affirmative	
1	Southern California Edison Co.	Dana Cabbell		
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Tri-State G & T Association Inc.	Keith V. Carman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Jason L. Murray	Affirmative	
2	BC Transmission Corporation	Faramarz Amjadi	Affirmative	
2	California ISO	Greg Tillitson	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Affirmative	
2	Independent Electricity System Operator	Kim Warren	Affirmative	View
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Jason L Marshall	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung	Affirmative	
3	Alabama Power Company	Bobby Kerley	Affirmative	
3	Allegheny Power	Bob Reeping		
3	Ameren Services	Mark Peters	Affirmative	View
3	American Electric Power	Raj Rana	Negative	View
3	Anaheim Public Utilities Dept.	Kelly Nguyen	Abstain	

3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Farmington	Linda R. Jacobson	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Constellation Energy	Carolyn Ingersoll	Affirmative	
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Jalal (John) Babik	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	Entergy Services, Inc.	Matt Wolf	Affirmative	
3	FirstEnergy Solutions	Joanne Kathleen Borrell	Affirmative	View
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Leslie Sibert	Affirmative	
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory David Woessner	Affirmative	
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C Parent		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Affirmative	
3	Muscatine Power & Water	John Bos	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Abstain	
3	PacifiCorp	John Apperson	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Abstain	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock		
3	South Carolina Electric & Gas Co.	Hubert C. Young	Abstain	
3	Southern California Edison Co.	David Schiada		
3	Tampa Electric Co.	Ronald L. Donahey		
3	Wisconsin Electric Power Marketing	James R. Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	LaGen	Richard Comeaux		
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	View
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li		
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Affirmative	
5	Avista Corp.	Edward F. Groce	Negative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Calpine Corporation	Duncan Brown	Affirmative	
5	City of Tallahassee	Alan Gale	Affirmative	
5	City Water, Light & Power of Springfield	Karl E. Kohlrus	Affirmative	
5	Colmac Clarion/Piney Creek LP	Harvie D. Beavers	Affirmative	
5	Consolidated Edison Co. of New York	Edwin E Thompson	Affirmative	

5	Consumers Energy	James B Lewis	Affirmative	
5	Dairyland Power Coop.	Warren Schaefer	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Robert Smith	Affirmative	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	First Wind	Mary J. Cooper		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	View
5	Great River Energy	Cynthia E Sulzer		
5	Lakeland Electric	Thomas J Trickey	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Manitoba Hydro	Mark Aikens	Abstain	
5	MidAmerican Energy Co.	Christopher Schneider	Abstain	
5	Mint Farm Energy Center	John Walsh		
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Affirmative	
5	Northern States Power Co.	Liam Noailles	Affirmative	
5	Orlando Utilities Commission	Richard Kinas		
5	PacifiCorp Energy	David Godfrey	Affirmative	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Power LLC	Thomas Piascik	Affirmative	
5	Sacramento Municipal Utility District	Bethany Wright	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Seattle City Light	Michael J. Haynes		
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	South California Edison Company	Ahmad Sanati	Abstain	
5	Southeastern Power Administration	Douglas Spencer		
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
6	AEP Marketing	Edward P. Cox	Negative	View
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol		
6	Dominion Resources, Inc.	Louis S Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	View
6	Great River Energy	Donna Stephenson		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Louisville Gas and Electric Co.	Daryn Barker	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Abstain	
6	New York Power Authority	Thomas Papadopoulos	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	PacifiCorp	Gregory D Maxfield	Affirmative	
6	Progress Energy	James Eckelkamp	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Salt River Project	Mike Hummel		
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seattle City Light	Dennis Sismaet	Abstain	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Southern California Edison Co.	Marcus V Lotto	Affirmative	
6	SunGard Data Systems	Christopher K Heisler	Affirmative	
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8	Edward C Stein	Edward C Stein	Affirmative	
8	James A Maenner	James A Maenner	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini		
8	Roger C Zaklukiewicz	Roger C Zaklukiewicz	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	

9	California Energy Commission	William Mitchell Chamberlain		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	Maine Public Utilities Commission	Jacob A McDermott	Abstain	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	New York State Department of Public Service	Thomas G Dvorsky		
9	Oregon Public Utility Commission	Jerome Murray	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck	Affirmative	
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Dan R Schoenecker	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	

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Standards Announcement
Initial Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

Project 2008-09: Interpretation of EOP-001-0 for Regional Entity Compliance Managers (Revision 2)
The initial ballot for a revised interpretation of standard EOP-001-0 — Emergency Operations Planning, Requirement R1, for the Regional Entity Compliance Managers ended on November 16, 2009.

Ballot Results
Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 85.97%
Approval: 98.07%

Since at least one negative ballot included a comment, these results are not final. A second (or recirculation) ballot must be conducted. Ballot criteria are listed at the end of the announcement.

Next Steps
As part of the recirculation ballot process, the drafting team must draft and post responses to voter comments. The drafting team will also determine whether or not to make revisions to the balloted item(s). Should the team decide to make revisions, the revised item(s) will return to the initial ballot phase.

Project Background
The Regional Entity Compliance Managers group submitted a request for an interpretation of EOP-001-0 Requirement R1. Under Requirement R1, the Balancing Authority must have operating agreements with adjacent Balancing Authorities that contain provisions for emergency assistance, including emergency assistance from remote Balancing Authorities. The request asked for clarification on specific terminology and the applicability of Reserve Sharing Group Agreements.

This is the second revision of the interpretation. The drafting team revised the interpretation to address balloter concerns regarding 1) application on an Interconnection basis, 2) whether an agreement was required with a remote Balancing Authority, and 3) whether a Reserve Sharing Group agreement could substitute for an emergency assistance agreement with adjacent Balancing Authorities. The changes to the interpretation are shown in a redline version posted for on the project page. The team has also posted a response to comments received during the initial ballot (conducted in February 2009) of the first revision.

Project page: http://www.nerc.com/filez/standards/EOP-001-0_Interpretation_RECM.html

Standards Development Process
The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Ballot Criteria

Approval requires both a (1) quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention, and (2) A two-thirds majority of the weighted segment votes cast must be affirmative; the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and nonresponses. If there are no negative votes with reasons from the first ballot, the results of the first ballot shall stand. If, however, one or more members submit negative votes with reasons, a second ballot shall be conducted.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

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Project 2009-23: Interpretation of EOP-001-0 for the Regional Entity Compliance Managers
Consideration of Comments for Initial Ballot of Revision 2 (November 5–16, 2009)

Summary Consideration: A few balloters explained that the wording in the response to question 2 appeared to limit the Balancing Authority to agreements with Balancing Authorities within the same interconnection, which may be interpreted to nullify the use of existing agreements that cross interconnections as sufficient to meet this requirement. In response to those comments, the Executive Committee of the Operating Reliability Subcommittee, which is serving as the drafting team for this interpretation, revised paragraph 2 to read, "The intent is that all Balancing Authorities, interconnected by AC ties or DC (asynchronous) ties within the same Interconnection, have emergency energy assistance agreements with at least one Adjacent Balancing Authority and have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. However, the standard does not require emergency energy assistance agreements with all Adjacent Balancing Authorities, nor does it preclude having an emergency assistance agreement across Interconnections."

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Voter	Entity	Segment	Vote	Comment
Paul B. Johnson	American Electric Power	1	Negative	AEP appreciates the additional work of the SDT to improve the EOP-001-0 R1 interpretation. In most cases, AEP agrees with the changes that have been made. However, AEP is concerned that the word choice in the response to question 2. The wording appears to limit the BA to agreements with BAs within the same interconnection. In doing so, the standard may be interpreted to nullify the use of existing agreements that cross interconnections as sufficient to meet this requirement. AEP suggests that the wording be rephrased to avoid this implication. AEP also disagrees with the need to add the phrase "that contains provisions for emergency assistance may be used to meet" since the intent of entities participating in Reserve Sharing Groups is to have Reserves (Emergency Energy) available to them in the event of such a contingency. Access to "emergency assistance" (Emergency Energy by this interpretation) is only one aspect of an emergency operations plan. There are other elements of the emergency operations plan that can be deployed in an emergency to alleviate the issue in more lengthy events. To imply in this standard that conditions exists, such as "emergency assistance may be needed for xduration," is not accurate; to suggest otherwise expands the scope of the existing requirement. It is AEP's belief that to expand the scope of this requirement to the extent IESO and NBSO suggests should require a full discussion of the industry in the next version of this standard.

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
Raj Rana	American Electric Power	3	Negative	AEP appreciates the additional work of the SDT to improve the EOP-001-0 R1 interpretation. In most cases, AEP agrees with the changes that have been made. However, AEP is concerned that the word choice in the response to question 2. The wording appears to limit the BA to agreements with BAs within the same interconnection. In doing so, the standard may be interpreted to nullify the use of existing agreements that cross interconnections as sufficient to meet this requirement. AEP suggests that the wording be rephrased to avoid this implication. AEP also disagrees with the need to add the phrase "that contains provisions for emergency assistance may be used to meet" since the intent of entities participating in Reserve Sharing Groups is to have Reserves (Emergency Energy) available to them in the event of such a contingency. Access to "emergency assistance" (Emergency Energy by this interpretation) is only one aspect of an emergency operations plan. There are other elements of the emergency operations plan that can be deployed in an emergency to alleviate the issue in more lengthy events. To imply in this standard that conditions exists, such as "emergency assistance may be needed for xduration," is not accurate; to suggest otherwise expands the scope of the existing requirement. It is AEP's belief that to expand the scope of this requirement to the extent IESO and NBSO suggests should require a full discussion of the industry in the next version of this standard.
Edward P. Cox	AEP Marketing	6	Negative	AEP appreciates the additional work of the SDT to improve the EOP-001-0 R1 interpretation. In most cases, AEP agrees with the changes that have been made. However, AEP is concerned that the word choice in the response to question 2. The wording appears to limit the BA to agreements with BAs within the same interconnection. In doing so, the standard may be interpreted to nullify the use of existing agreements that cross interconnections as sufficient to meet this requirement. AEP suggests that the wording be rephrased to avoid this implication. AEP also disagrees with the need to add the phrase "that contains provisions for emergency assistance may be used to meet" since the intent of entities participating in Reserve Sharing Groups is to have Reserves (Emergency Energy) available to them in the event of such a contingency. Access to "emergency assistance" (Emergency Energy by this interpretation) is only one aspect of an emergency operations plan. There are other elements of the emergency operations plan that can be deployed in an emergency to alleviate the issue in more lengthy events. To imply in this standard that conditions exists, such as "emergency assistance may be needed for xduration," is not accurate; to suggest otherwise expands the scope of the existing requirement. It is AEP's belief that to expand the scope of this requirement to the extent IESO and NBSO suggests should require a full discussion of the industry in the next version of this standard.

Voter	Entity	Segment	Vote	Comment
Response: The Operating Reliability Subcommittee (ORS) Executive Committee agrees with AEP's comment and will add the phrase, "nor does it preclude having an emergency assistance agreement across Interconnections" at the end of paragraph 2. The ORS Executive Committee disagrees with the second part of AEP's comment because some Reserve Sharing Groups limit access to emergency assistance.				
Robert Martinko	FirstEnergy Energy Delivery	1	Affirmative	FirstEnergy Corp. supports the interpretation and has voted Affirmative. We offer the following comments: Since this interpretation is specific to Version "0" of EOP-001, it is not clear how NERC staff will integrate this interpretation into Board Approved (October 2008) Version "1" of EOP-001. We suggest that NERC add this interpretation to the Version 1 standard which was revised per the NERC project "Operate Within Interconnection Reliability Operating Limits" which is currently pending filing with FERC.
Joanne Kathleen Borrell	FirstEnergy Solutions	3	Affirmative	FirstEnergy Corp. supports the interpretation and has voted Affirmative. We offer the following comments: Since this interpretation is specific to Version "0" of EOP-001, it is not clear how NERC staff will integrate this interpretation into Board Approved (October 2008) Version "1" of EOP-001. We suggest that NERC add this interpretation to the Version 1 standard which was revised per the NERC project "Operate Within Interconnection Reliability Operating Limits" which is currently pending filing with FERC.
Douglas Hohlbaugh	Ohio Edison Company	4	Affirmative	FirstEnergy Corp. supports the interpretation and has voted Affirmative. We offer the following comments: Since this interpretation is specific to Version "0" of EOP-001, it is not clear how NERC staff will integrate this interpretation into Board Approved (October 2008) Version "1" of EOP-001. We suggest that NERC add this interpretation to the Version 1 standard which was revised per the NERC project "Operate Within Interconnection Reliability Operating Limits" which is currently pending filing with FERC.
Kenneth Dresner	FirstEnergy Solutions	5	Affirmative	FirstEnergy Corp. supports the interpretation and has voted Affirmative. We offer the following comments: Since this interpretation is specific to Version "0" of EOP-001, it is not clear how NERC staff will integrate this interpretation into Board Approved (October 2008) Version "1" of EOP-001. We suggest that NERC add this interpretation to the Version 1 standard which was revised per the NERC project "Operate Within Interconnection Reliability Operating Limits" which is currently pending filing with FERC.
Mark S Travaglianti	FirstEnergy Solutions	6	Affirmative	FirstEnergy Corp. supports the interpretation and has voted Affirmative. We offer the following comments: Since this interpretation is specific to Version "0" of EOP-001, it is not clear how NERC staff will integrate this interpretation into Board Approved (October 2008) Version "1" of EOP-001. We suggest that NERC add this interpretation to the Version 1 standard which was revised per the NERC project "Operate Within Interconnection Reliability Operating Limits" which is currently pending filing with FERC.

Voter	Entity	Segment	Vote	Comment
Response: The ORS Executive Committee concurs with the comments of FirstEnergy.				
Kim Warren	Independent Electricity System Operator	2	Affirmative	The IESO thanks the Executive Committee of the NERC Operating Reliability Subcommittee for the effort that went into refining this interpretation. We also wish to highlight that inclusion of the phrase "within the same interconnection" in the revised response to Question 2, seems to preclude the possibility of adjacent Balancing Authorities that are not in the same interconnection, from entering into emergency energy assistance agreements.
Response: The ORS Executive Committee agrees with IESO's comment and will add the phrase, "nor does it preclude having an emergency assistance agreement across Interconnections" at the end of paragraph 2.				
Kirit S. Shah	Ameren Services	1	Affirmative	While the interpretation in 3) seemingly added the opportunity to use remote BAs ("A Balancing Authority's agreement(s) with Adjacent Balancing Authorities does (do) not preclude the Adjacent Balancing Authority from purchasing emergency energy from remote Balancing Authorities.") it does not address the obligation currently included in the standard. To wit, if a BA intends to use a remote BA for emergency assistance (as all or part of the energy it has identified that it needs to meet reasonably anticipated emergencies), It MUST have an agreement(s) with adjacent BAs "in the path" to facilitate this emergency assistance in addition to the agreement it will have with the remote BA. This additional sentence should be added to the Interpretation as the closing sentence in 3).
Mark Peters	Ameren Services	3	Affirmative	While the interpretation in 3) seemingly added the opportunity to use remote BAs ("A Balancing Authority's agreement(s) with Adjacent Balancing Authorities does (do) not preclude the Adjacent Balancing Authority from purchasing emergency energy from remote Balancing Authorities.") it does not address the obligation currently included in the standard. To wit, if a BA intends to use a remote BA for emergency assistance (as all or part of the energy it has identified that it needs to meet reasonably anticipated emergencies), It MUST have an agreement(s) with adjacent BAs "in the path" to facilitate this emergency assistance in addition to the agreement it will have with the remote BA. This additional sentence should be added to the Interpretation as the closing sentence in 3).
Response: The interpretation requires an emergency energy agreement with at least one adjacent Balancing Authority. However, it does not preclude having additional emergency energy agreements with remote Balancing Authorities. Specifying the appropriate arrangements to deliver the emergency energy goes beyond the scope of the request for interpretation.				

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Revised Interpretation of EOP-001-0 Emergency Operations Planning Requirement R1 for the Regional Entity Compliance Managers (Project 2008-09)

Request for Interpretation Received from Regional Entity Compliance Managers on March 20, 2008:

Request:
The Regional Entity Compliance Managers (RECM) request a formal interpretation of Reliability Standard EOP-001-0 — Emergency Operations Planning Requirement R1 in accordance with the Reliability Standards Development Procedure.

1. *What is the definition of emergency assistance in the context of this standard? What scope and time horizons, if any, are considered necessary in this definition?*
2. *What was intended by using the adjective "adjacent" in Requirement 1? Does "adjacent Balancing Authorities" mean "All" or something else? Is there qualifying criteria to determine if a very small adjacent Balancing Authority area has enough capacity to offer emergency assistance?*
3. *What is the definition of the word "remote" as stated in the last phrase of Requirement 1? Does remote mean every Balancing Authority who's area does not physically touch the Balancing Authority attempting to comply with this Requirement?*
4. *Would a Balancing Authority that participates in a Reserve Sharing Group Agreement, which meets the requirements of Reliability Standard BAL-002-0, Requirement 2, have to establish additional operating agreements to achieve compliance with Reliability Standard EOP-001-0, Requirement 1?*

EOP-001-0
R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

The following revised (March 2010) interpretation of EOP-001-0 — Emergency Operations Planning Requirement R1 was developed by the Executive Committee of the NERC Operating Reliability Subcommittee:

Interpretation of EOP-001-0 Requirement R1:

1. In the context of this standard, emergency assistance is emergency energy. Emergency energy would normally be arranged for during the current operating day. The agreement should describe the conditions under which the emergency energy will be delivered to the responsible Balancing Authority.
2. The intent is that all Balancing Authorities, interconnected by AC ties or DC (asynchronous) ties within the same Interconnection, have emergency energy assistance agreements with at least one Adjacent Balancing Authority and have sufficient emergency energy assistance

agreements to mitigate reasonably anticipated energy emergencies. However, the standard does not require emergency energy assistance agreements with all Adjacent Balancing Authorities, nor does it preclude having an emergency assistance agreement across Interconnections.

3. A remote Balancing Authority is a Balancing Authority other than an Adjacent Balancing Authority. A Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with any remote Balancing Authorities. A Balancing Authority's agreement(s) with Adjacent Balancing Authorities does (do) not preclude the Adjacent Balancing Authority from purchasing emergency energy from remote Balancing Authorities.
4. A Reserve Sharing Group agreement that contains provisions for emergency assistance may be used to meet Requirement R1 of EOP-001-0.

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Revised Interpretation of EOP-001-0 Emergency Operations Planning Requirement R1 for the Regional Entity Compliance Managers (Project 2008-09)

Request for Interpretation Received from Regional Entity Compliance Managers on March 20, 2008:

Request:
The Regional Entity Compliance Managers (RECM) request a formal interpretation of Reliability Standard EOP-001-0 — Emergency Operations Planning Requirement R1 in accordance with the Reliability Standards Development Procedure.

1. *What is the definition of emergency assistance in the context of this standard? What scope and time horizons, if any, are considered necessary in this definition?*
2. *What was intended by using the adjective "adjacent" in Requirement 1? Does "adjacent Balancing Authorities" mean "All" or something else? Is there qualifying criteria to determine if a very small adjacent Balancing Authority area has enough capacity to offer emergency assistance?*
3. *What is the definition of the word "remote" as stated in the last phrase of Requirement 1? Does remote mean every Balancing Authority who's area does not physically touch the Balancing Authority attempting to comply with this Requirement?*
4. *Would a Balancing Authority that participates in a Reserve Sharing Group Agreement, which meets the requirements of Reliability Standard BAL-002-0, Requirement 2, have to establish additional operating agreements to achieve compliance with Reliability Standard EOP-001-0, Requirement 1?*

EOP-001-0
R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

The following revised (~~October 2009~~March 2010) interpretation of EOP-001-0 — Emergency Operations Planning Requirement R1 was developed by the Executive Committee of the NERC Operating Reliability Subcommittee:

Interpretation of EOP-001-0 Requirement R1:

1. In the context of this standard, emergency assistance is emergency energy. Emergency energy would normally be arranged for during the current operating day. The agreement should describe the conditions under which the emergency energy will be delivered to the responsible Balancing Authority.
2. The intent is that all Balancing Authorities, interconnected by AC ties or DC (asynchronous) ties within the same Interconnection, have emergency energy assistance agreements with at least one Adjacent Balancing Authority and have sufficient emergency energy assistance

agreements to mitigate reasonably anticipated energy emergencies. However, the standard does not require emergency energy assistance agreements with all Adjacent Balancing Authorities~~.~~, nor does it preclude having an emergency assistance agreement across Interconnections.

3. A remote Balancing Authority is a Balancing Authority other than an Adjacent Balancing Authority. A Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with any remote Balancing Authorities. A Balancing Authority's agreement(s) with Adjacent Balancing Authorities does (do) not preclude the Adjacent Balancing Authority from purchasing emergency energy from remote Balancing Authorities.
4. A Reserve Sharing Group agreement that contains provisions for emergency assistance may be used to meet Requirement R1 of EOP-001-0.

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Standards Announcement

Ballot Pool and Pre-ballot Window
March 16–April 15, 2010

Now available at: https://standards.nerc.net/BallotPool.aspx

Project 2008-09: Interpretation of EOP-001-0 for Regional Entity Compliance Managers (Revision 3)

An interpretation of standard EOP-001-0 — Emergency Operations Planning, Requirement R1, for the Regional Entity Compliance Managers is posted for a 30-day pre-ballot review. Registered Ballot Body members may join the ballot pool to be eligible to vote on this interpretation **until 8 a.m. Eastern on April 15, 2010**.

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-2008-09_RFI_RECM-Rv3_in@nerc.com.

Next Steps

Voting will begin shortly after the pre-ballot review closes.

Project Background

The Regional Entity Compliance Managers group submitted a request for an interpretation of EOP-001-0 Requirement R1. Under Requirement R1, the Balancing Authority must have operating agreements with adjacent Balancing Authorities that contain provisions for emergency assistance, including emergency assistance from remote Balancing Authorities. The request asked for clarification on specific terminology and the applicability of Reserve Sharing Group Agreements.

This is the third revision of the interpretation. The drafting team revised the interpretation to address balloter concerns regarding the wording in the response to question 2. Balloters indicated the wording appeared to limit the Balancing Authority to agreements with Balancing Authorities within the same interconnection, which may be interpreted to nullify the use of existing agreements that cross interconnections as sufficient to meet this requirement.

The changes to the interpretation are shown in a redline version posted on the project page. The team has also posted a response to comments received during the initial ballot (conducted in November 2009) of the second revision.

Project page: http://www.nerc.com/filez/standards/EOP-001-0_Interpretation_RECM.html

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Lauren Koller at Lauren.Koller@nerc.net

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Standards Announcement

Initial Ballot Window Open
April 15–26, 2010

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Project 2008-09: Interpretation of EOP-001-0 for Regional Entity Compliance Managers (Revision 3)

An initial ballot window for an interpretation of standard EOP-001-0 — Emergency Operations Planning, Requirement R1, for the Regional Entity Compliance Managers is now open **until 8 p.m. Eastern on April 26, 2010**.

Instructions

Members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

Next Steps

Voting results will be posted and announced after the ballot window closes.

Project Background

The Regional Entity Compliance Managers group submitted a request for an interpretation of EOP-001-0 Requirement R1. Under Requirement R1, the Balancing Authority must have operating agreements with adjacent Balancing Authorities that contain provisions for emergency assistance, including emergency assistance from remote Balancing Authorities. The request asked for clarification on specific terminology and the applicability of Reserve Sharing Group Agreements.

This is the third revision of the interpretation. The drafting team revised the interpretation to address balloter concerns regarding the wording in the response to question 2. Balloters indicated the wording appeared to limit the Balancing Authority to agreements with Balancing Authorities within the same interconnection, which may be interpreted to nullify the use of existing agreements that cross interconnections as sufficient to meet this requirement.

The changes to the interpretation are shown in a redline version posted on the project page. The team has also posted a response to comments received during the initial ballot (conducted in November 2009) of the second revision.

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Ballot Results

Ballot Name:	Project 2008-09 - Interpretation - RECM - Revision 3_in
Ballot Period:	4/15/2010 - 4/26/2010
Ballot Type:	Initial
Total # Votes:	200
Total Ballot Pool:	244
Quorum:	**81.97 % The Quorum has been reached**
Weighted Segment Vote:	98.64 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	70	1	52	0.963	2	0.037	1	15
2 - Segment 2.	10	0.8	8	0.8	0	0	0	2
3 - Segment 3.	60	1	49	1	0	0	2	9
4 - Segment 4.	16	1	14	1	0	0	1	1
5 - Segment 5.	44	1	33	0.943	2	0.057	1	8
6 - Segment 6.	28	1	20	1	0	0	2	6
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	6	0.6	6	0.6	0	0	0	0
9 - Segment 9.	2	0.1	1	0.1	0	0	1	0
10 - Segment 10.	8	0.4	4	0.4	0	0	1	3
Totals	**244**	**6.9**	**187**	**6.806**	**4**	**0.094**	**9**	**44**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips		
1	Ameren Services	Kirit S. Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Jason Shaver		
1	Avista Corp.	Scott Kinney	Affirmative	
1	BC Transmission Corporation	Gordon Rawlings	Affirmative	
1	Beaches Energy Services	Joseph S. Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge		

1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	CenterPoint Energy	Paul Rocha	Affirmative	
1	Central Maine Power Company	Brian Conroy	Affirmative	
1	City of Vero Beach	Randall McCamish		
1	City Utilities of Springfield, Missouri	Jeff Knottek		
1	Cleco Power LLC	Danny McDaniel		
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Deseret Power	James Tucker		
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	E.ON U.S. LLC	Larry Monday		
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	View
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	ITC Transmission	Elizabeth Howell	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stan T. Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Jonathan Appelbaum	Affirmative	
1	Manitoba Hydro	Michelle Rheault	Affirmative	
1	MEAG Power	Danny Dees	Negative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnesota Power, Inc.	Randi Woodward	Affirmative	
1	National Grid	Saurabh Saksena		
1	New York Power Authority	Arnold J. Schuff		
1	New York State Electric & Gas Corp.	Henry G. Masti		
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	PacifiCorp	Mark Sampson	Affirmative	
1	Portland General Electric Co.	Frank F. Afranji	Affirmative	
1	Potomac Electric Power Co.	Richard J. Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Negative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Puget Sound Energy, Inc.	Catherine Koch	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sierra Pacific Power Co.	Richard Salgo	Affirmative	
1	South Texas Electric Cooperative	Richard McLeon	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Tri-State G & T Association Inc.	Keith V. Carman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Jason L. Murray	Affirmative	
2	BC Transmission Corporation	Faramarz Amjadi	Affirmative	
2	California ISO	Timothy VanBlaricom		
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Affirmative	

2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Jason L Marshall	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung		
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Allegheny Power	Bob Reeping		
3	Ameren Services	Mark Peters	Affirmative	
3	American Electric Power	Raj Rana	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blue Ridge Power Agency	Duane S. Dahlquist		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R. Jacobson		
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Leesburg	Phil Janik		
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F Gildea	Abstain	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	East Kentucky Power Coop.	Sally Witt	Affirmative	
3	Entergy Services, Inc.	Matt Wolf	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Municipal Power Agency	Joe McKinney		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	JEA	Garry Baker		
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory David Woessner	Affirmative	
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Affirmative	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Ocala Electric Utility	David T. Anderson	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	PacifiCorp	John Apperson	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C. Young	Affirmative	
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey		
3	Wisconsin Electric Power Marketing	James R. Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	

4	City of Clewiston	Kevin McCarthy	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette		
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	Black Hills Corp	George Tatar	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	City of Tallahassee	Alan Gale	Affirmative	
5	Conectiv Energy Supply, Inc.	Kara Dundas	Affirmative	
5	Consolidated Edison Co. of New York	Edwin E Thompson		
5	Consumers Energy	James B Lewis	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer		
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann		
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	JEA	Donald Gilbert	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink	Affirmative	
5	Kissimmee Utility Authority	Mike Blough		
5	Lakeland Electric	Thomas J Trickey	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin		
5	Manitoba Hydro	Mark Aikens	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Affirmative	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Affirmative	
5	Orlando Utilities Commission	Richard Kinas	Affirmative	
5	PacifiCorp	Sandra L. Shaffer		
5	Portland General Electric Co.	Gary L Tingley		
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Power LLC	David Murray	Affirmative	
5	RRI Energy	Thomas J. Bradish	Affirmative	
5	Sacramento Municipal Utility District	Bethany Wright	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Negative	View
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Negative	View
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Black Hills Corp	Tyson Taylor		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Dominion Resources, Inc.	Louis S Slade	Abstain	
6	Duke Energy Carolina	Walter Yeager	Affirmative	

6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Municipal Power Pool	Thomas E Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell		
6	Kansas City Power & Light Co.	Thomas Saitta		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Louisville Gas and Electric Co.	Daryn Barker	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	New York Power Authority	Thomas Papadopoulos	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Abstain	
6	PacifiCorp	Gregory D Maxfield	Affirmative	
6	Progress Energy	James Eckelkamp	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson		
6	RRI Energy	Trent Carlson	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard	Affirmative	
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons		
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini	Affirmative	
8	Shafer, Kline, & Warren Inc. (SKW)	Michael J Bequette, P.E.	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	Dan R. Schoenecker	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith		
10	SERC Reliability Corporation	Carter B Edge		
10	Western Electricity Coordinating Council	Louise McCarren		

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Standards Announcement
Initial Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

Project 2008-09: Interpretation of EOP-001-0 R1 by Regional Entity Compliance Managers
The initial ballot window for an interpretation of standard EOP-001-0 — Emergency Operations Planning, Requirement R1, for the Regional Entity Compliance Managers ended on April 26, 2010.

Ballot Results
Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 81.97 %
Approval: 98.64 %

Since at least one negative ballot included a comment, these results are not final. A second (or recirculation) ballot must be conducted. Ballot criteria are listed at the end of the announcement.

Next Steps
As part of the recirculation ballot process, the drafting team must draft and post responses to voter comments. The drafting team will also determine whether or not to make revisions to the balloted item(s). Should the team decide to make revisions, the revised item(s) will return to the initial ballot phase.

Project Background
The Regional Entity Compliance Managers group submitted a request for an interpretation of EOP-001-0 Requirement R1. Under Requirement R1, the Balancing Authority must have operating agreements with adjacent Balancing Authorities that contain provisions for emergency assistance, including emergency assistance from remote Balancing Authorities. The request asked for clarification on specific terminology and the applicability of Reserve Sharing Group Agreements.

This is the third revision of the interpretation. The drafting team revised the interpretation to address balloter concerns regarding the wording in the response to question 2. Balloters indicated the wording appeared to limit the Balancing Authority to agreements with Balancing Authorities within the same interconnection, which may be interpreted to nullify the use of existing agreements that cross interconnections as sufficient to meet this requirement.

The changes to the interpretation are shown in a redline version posted on the project page. The team has also posted a response to comments received during the initial ballot (conducted in November 2009) of the second revision.

More information is available on the project page: http://www.nerc.com/filez/standards/EOP-001-0_Interpretation_RECM.html

Standards Development Process

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Ballot Criteria

Approval requires both a (1) quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention, and (2) A two-thirds majority of the weighted segment votes cast must be affirmative; the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and non-responses. If there are no negative votes with reasons from the first ballot, the results of the first ballot shall stand. If, however, one or more members submit negative votes with reasons, a second ballot shall be conducted.

For more information or assistance,
please contact Lauren Koller at Lauren.Koller@nerc.net

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Consideration of Comments on Initial Ballot — RECM Interpretation — EOP-001-0 (Project 2008-09)

Summary Consideration: An initial ballot of an interpretation of EOP-001-0, Requirement R1 was conducted from April 15-26, 2010 and achieved a quorum and a weighted approval of 98.64%. There were only two ballots submitted with negative comments, as shown in the table below. The ORS Executive Committee (Interpretation Drafting Team) disagrees with the comments included with the two negative ballots received. No changes were made to the interpretation following the initial ballot.

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herbert Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Voter	Entity	Segment	Vote	Comment
Ralph Frederick Meyer	Empire District Electric Co.	1	Affirmative	Very good interpritation. Very Logical. This clears up uncertanty with this standard.
Response: The ORS Executive Committee thanks Empire District Electric Co. its comment.				
Kevin Querry	FirstEnergy Solutions	3	Affirmative	No Comment
Response: The ORS Executive Committee thanks FirstEnergy Solutions for its Affirmative vote.				
Karl Bryan	U.S. Army Corps of Engineers Northwestern Division	5	Negative	It appears that the SDT is rewriting the Rel Stndrd by defining "emergency assistance" to mean "emergency energy" whereas emergency assistance can also imply physical assistance, technical support, etc... Also, since when does a plural mean a singular? "Balancing Authorities shall have agreements with adjacent Balancing Authorities", this implies multiple agreements with multiple BAs. Making this singular is rewriting the Rel Stndrd and is beyond the scope of the SDT in performing interpretations.
Response: The interpretation is not redefining emergency assistance. The request for interpretation is in the context of Requirement R1. The ORS Executive Committee believes emergency assistance is limited to emergency energy. In the context of R1, it does not include other physical assistance (i.e., mutual assistance agreements) entities may have with their neighbors. The ORS Executive Committee is not rewriting R1. In addition, in the context of R1, the ORS Executive Committee has interpreted Balancing Authorities to mean "at least one."				
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Negative	The Standards Drafting Team (SDT) interprets the standard that "emergency assistance" is "emergency energy". In its interpretation, the SDT introduced the term "emergency energy assistance" in place of the "emergency assistance" when it refers to language in the standard. This modifies the language of the standard which is not appropriate. Emergency assistance is undefined and can be any arrangement not limited to energy. The SDT interprets the standard to

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
				mean agreements with at least one adjacent BA. This would not be consistent with the language which uses plural form of BA, meaning more than one BA. The interpretation should have pointed out that there must be agreements with more than one adjacent BA. Finally, there is no basis cited for these interpretations. It also does not follow the interpretations by other teams which relied strictly on the text of the requirement or documents directly connected with the standard.
Response: The interpretation is not redefining emergency assistance. The request for interpretation is in the context of Requirement R1. The ORS Executive Committee believes emergency assistance is limited to emergency energy. In the context of R1, it does not include other physical assistance (i.e., mutual assistance agreements) entities may have with their neighbors. The ORS Executive Committee is not rewriting R1. In addition, in the context of R1, the ORS Executive Committee has interpreted Balancing Authorities to mean "at least one."				

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Revised Interpretation of EOP-001-0 Emergency Operations Planning Requirement R1 for the Regional Entity Compliance Managers (Project 2008-09)

Request for Interpretation Received from Regional Entity Compliance Managers on March 20, 2008:

Request:
The Regional Entity Compliance Managers (RECM) request a formal interpretation of Reliability Standard EOP-001-0 — Emergency Operations Planning Requirement R1 in accordance with the Reliability Standards Development Procedure.

1. *What is the definition of emergency assistance in the context of this standard? What scope and time horizons, if any, are considered necessary in this definition?*
2. *What was intended by using the adjective "adjacent" in Requirement 1? Does "adjacent Balancing Authorities" mean "All" or something else? Is there qualifying criteria to determine if a very small adjacent Balancing Authority area has enough capacity to offer emergency assistance?*
3. *What is the definition of the word "remote" as stated in the last phrase of Requirement 1? Does remote mean every Balancing Authority who's area does not physically touch the Balancing Authority attempting to comply with this Requirement?*
4. *Would a Balancing Authority that participates in a Reserve Sharing Group Agreement, which meets the requirements of Reliability Standard BAL-002-0, Requirement 2, have to establish additional operating agreements to achieve compliance with Reliability Standard EOP-001-0, Requirement 1?*

EOP-001-0
R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

The following revised (March 2010) interpretation of EOP-001-0 — Emergency Operations Planning Requirement R1 was developed by the Executive Committee of the NERC Operating Reliability Subcommittee:

Interpretation of EOP-001-0 Requirement R1:

1. In the context of this standard, emergency assistance is emergency energy. Emergency energy would normally be arranged for during the current operating day. The agreement should describe the conditions under which the emergency energy will be delivered to the responsible Balancing Authority.
2. The intent is that all Balancing Authorities, interconnected by AC ties or DC (asynchronous) ties within the same Interconnection, have emergency energy assistance agreements with at least one Adjacent Balancing Authority and have sufficient emergency energy assistance

agreements to mitigate reasonably anticipated energy emergencies. However, the standard does not require emergency energy assistance agreements with all Adjacent Balancing Authorities, nor does it preclude having an emergency assistance agreement across Interconnections.

3. A remote Balancing Authority is a Balancing Authority other than an Adjacent Balancing Authority. A Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with any remote Balancing Authorities. A Balancing Authority's agreement(s) with Adjacent Balancing Authorities does (do) not preclude the Adjacent Balancing Authority from purchasing emergency energy from remote Balancing Authorities.
4. A Reserve Sharing Group agreement that contains provisions for emergency assistance may be used to meet Requirement R1 of EOP-001-0.

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Standards Announcement

Recirculation Ballot Window Open
October 4–14, 2010

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Interpretation of EOP-001-0 Emergency Operations Planning Requirement R1 for the Regional Entity Compliance Managers (Project 2008-09)

A recirculation ballot window for an interpretation of EOP-001-0 Requirement R1 for the Regional Entity Compliance Managers is now open **until 8 p.m. EDT on October 14, 2010**.

Project Background

The Regional Entity Compliance Managers group submitted a request for an interpretation of EOP-001-0 Requirement R1. Under Requirement R1, the Balancing Authority must have operating agreements with adjacent Balancing Authorities that contain provisions for emergency assistance, including emergency assistance from remote Balancing Authorities. The request asked for clarification on specific terminology and the applicability of Reserve Sharing Group Agreements.

Recirculation Ballot Process

The Standards Committee encourages all members of the Ballot Pool to review the consideration of comments submitted with the initial ballots. In the recirculation ballot, votes are counted by exception only. If a Ballot Pool member does not submit a revision to that member's original vote, the vote remains the same as in the first ballot. Members of the ballot pool may:

- Reconsider and change their vote from the first ballot
- Vote in the second ballot even if they did not vote on the first ballot
- Take no action if they do not want to change their original vote

Transition from Reliability Standards Development Procedure Version 7 to Standard Processes Manual

Under the Reliability Standards Development Procedure Version 7, interpretations did not have any comment period and were posted for ballot once they were drafted. Under the Standard Processes Manual, each interpretation is posted for a 30-day formal comment period; then the drafting team responds to comments; then the interpretation (revised if needed) is posted for a 45-day formal comment period conducted in parallel with an initial ballot. If there are no significant changes to the interpretation and the initial ballot sufficient affirmative votes for approval, then the interpretation proceeds to a recirculation ballot.

The addition of a comment period before the pre-ballot review period and the addition of a comment period in parallel with the initial ballot, are steps that were added to the process based on stakeholder comments indicating that interpretations needed more stakeholder input before being finalized.

This interpretation had already been through an initial ballot when the Standard Processes Manual was

approved, and no changes were made to the interpretation following the initial ballot; thus, this interpretation is moving forward for a recirculation ballot.

Next Steps

Voting results will be posted and announced after the recirculation ballot window closes.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

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Ballot Results

Ballot Name:	Project 2008-09 - Interpretation - RECM - Revision 3_rc
Ballot Period:	10/4/2010 - 10/14/2010
Ballot Type:	recirculation
Total # Votes:	215
Total Ballot Pool:	244
Quorum:	**88.11 % The Quorum has been reached**
Weighted Segment Vote:	99.14 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	70	1	56	0.966	2	0.034	1	11
2 - Segment 2.	10	0.9	9	0.9	0	0	0	1
3 - Segment 3.	60	1	50	1	0	0	3	7
4 - Segment 4.	16	1	13	1	0	0	3	0
5 - Segment 5.	44	1	35	0.972	1	0.028	3	5
6 - Segment 6.	28	1	23	1	0	0	2	3
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	6	0.6	6	0.6	0	0	0	0
9 - Segment 9.	2	0.2	2	0.2	0	0	0	0
10 - Segment 10.	8	0.5	5	0.5	0	0	1	2
Totals	**244**	**7.2**	**199**	**7.138**	**3**	**0.062**	**13**	**29**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips		
1	Ameren Services	Kirit S. Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Jason Shaver		
1	Avista Corp.	Scott Kinney	Affirmative	
1	BC Transmission Corporation	Gordon Rawlings	Affirmative	
1	Beaches Energy Services	Joseph S. Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge		

1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	CenterPoint Energy	Paul Rocha	Affirmative	
1	Central Maine Power Company	Brian Conroy	Affirmative	
1	City of Vero Beach	Randall McCamish	Affirmative	
1	City Utilities of Springfield, Missouri	Jeff Knottek		
1	Cleco Power LLC	Danny McDaniel		
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Deseret Power	James Tucker	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	E.ON U.S.	Larry Monday	Affirmative	
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	ITC Transmission	Elizabeth Howell	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stan T. Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Jonathan Appelbaum	Affirmative	
1	Manitoba Hydro	Michelle Rheault	Affirmative	
1	MEAG Power	Danny Dees	Negative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnesota Power, Inc.	Randi Woodward	Affirmative	
1	National Grid	Saurabh Saksena		
1	New York Power Authority	Arnold J. Schuff		
1	New York State Electric & Gas Corp.	Henry G. Masti		
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	PacifiCorp	Mark Sampson	Affirmative	
1	Portland General Electric Co.	Frank F. Afranji	Affirmative	
1	Potomac Electric Power Co.	Richard J Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Negative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Puget Sound Energy, Inc.	Catherine Koch	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	South Texas Electric Cooperative	Richard McLeon	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Tri-State G & T Association, Inc.	Keith V. Carman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Jason L. Murray	Affirmative	
2	BC Transmission Corporation	Faramarz Amjadi	Affirmative	
2	California ISO	Timothy VanBlaricom		
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Affirmative	

2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Jason L Marshall	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung	Affirmative	
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Allegheny Power	Bob Reeping		
3	Ameren Services	Mark Peters	Affirmative	
3	American Electric Power	Raj Rana	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Blue Ridge Power Agency	Duane S. Dahlquist		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R. Jacobson	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Abstain	
3	City of Leesburg	Phil Janik	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F Gildea	Abstain	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	East Kentucky Power Coop.	Sally Witt	Affirmative	
3	Entergy Services, Inc.	Matt Wolf	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Municipal Power Agency	Joe McKinney		
3	Florida Power Corporation	Lee Schuster	Abstain	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	JEA	Garry Baker		
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory David Woessner	Affirmative	
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Affirmative	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Ocala Electric Utility	David T. Anderson	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	PacifiCorp	John Apperson	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C. Young	Affirmative	
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey		
3	Wisconsin Electric Power Marketing	James R. Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	

4	City of Clewiston	Kevin McCarthy	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	Avista Corp.	Edward F. Groce	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	City of Tallahassee	Alan Gale	Affirmative	
5	Conectiv Energy Supply, Inc.	Kara Dundas	Affirmative	
5	Consolidated Edison Co. of New York	Edwin Thompson		
5	Consumers Energy	James B Lewis	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer		
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	JEA	Donald Gilbert	Abstain	
5	Kansas City Power & Light Co.	Scott Heidtbrink	Affirmative	
5	Kissimmee Utility Authority	Mike Blough		
5	Lakeland Electric	Thomas J Trickey	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin	Affirmative	
5	Manitoba Hydro	Mark Aikens	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Affirmative	
5	Orlando Utilities Commission	Richard Kinas	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Portland General Electric Co.	Gary L Tingley		
5	PPL Generation LLC	Mark A Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Power LLC	David Murray	Affirmative	
5	RRI Energy	Thomas J. Bradish	Affirmative	
5	Sacramento Municipal Utility District	Bethany Wright	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	View
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Abstain	View
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Black Hills Corp	Tyson Taylor		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Dominion Resources, Inc.	Louis S Slade	Abstain	
6	Duke Energy Carolina	Walter Yeager	Affirmative	

6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Municipal Power Pool	Thomas E Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell		
6	Kansas City Power & Light Co.	Thomas Saitta		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Louisville Gas and Electric Co.	Daryn Barker	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	New York Power Authority	Thomas Papadopoulos	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Abstain	
6	PacifiCorp	Gregory D Maxfield	Affirmative	
6	Progress Energy	James Eckelkamp	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	
6	RRI Energy	Trent Carlson	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard	Affirmative	
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini	Affirmative	
8	Shafer, Kline, & Warren Inc. (SKW)	Michael J Bequette, P.E.	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	Dan R. Schoenecker	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith		
10	SERC Reliability Corporation	Carter B Edge		
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	

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Standards Announcement

Final Ballot Results for Three Interpretations

Now available at: https://standards.nerc.net/Ballots.aspx

Recirculation Ballots for the following interpretations have closed and all three interpretations were approved by their associated ballot pools.

Project 2008-09 – Interpretation of EOP-001-0 Emergency Operations Planning Requirement R1 for the Regional Entity Compliance Managers

The recirculation ballot for this interpretation ended October 14, 2010. Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 88.11%
Approval: 99.14%

The request and interpretation can be found on the project page:
http://www.nerc.com/filez/standards/EOP-001-0_Interpretation_RECM.html

Project 2009-28 – Interpretation of EOP-001-1, EOP-001-2 – Emergency Operations Planning for the Florida Municipal Power Pool

The recirculation ballot for this interpretation ended October 15, 2010. Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 92.19%
Approval: 94.78%

The request and interpretation can be found on the project page:
http://www.nerc.com/filez/standards/Project2009-28_EOP-001-1-2_R2.2_FMPP.html

Project 2009-27 – Interpretation of TOP-002-2a – Normal Operations Planning for the Florida Municipal Power Pool

The recirculation ballot for this interpretation ended October 16, 2010. Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 91.21%
Approval: 93.44%

The request and interpretation can be found on the project page:
http://www.nerc.com/filez/standards/Project2009-27_TOP-002-2a_R10_RFI_FMPP.html

Next Steps

All three interpretations will be presented to the Board of Trustees for approval.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

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Exhibit G

Complete Record of Development of the Interpretation of Requirement R3.2 of EOP-001-0 — Emergency Operations Planning

Project 2009-28
Interpretation of EOP-001-1 and EOP-001-2 R2.2

Related Files

Status:
Approved by the Board of Trustees on November 4, 2010.

Purpose/Industry Need:
Florida Municipal Power Pool (FMPP) is seeking clarification as to whether the BA needs to develop a plan to maintain a load-interchange-generation balance during operating emergencies and follow the directives of the TOP.

In accordance with the Reliability Standards Development Procedure, the interpretation must be posted for a 30-day pre-ballot review, and then balloted. There is no public comment period for an interpretation. Balloting will be conducted following the same method used for balloting standards. If the interpretation is approved by its ballot pool, then the interpretation will be appended to the standard and will become effective when adopted by the NERC Board of Trustees and approved by the applicable regulatory authorities. The interpretation will remain appended to the standard until the standard is revised through the normal standards development process. When the standard is revised, the clarifications provided by the interpretation will be incorporated into the revised standard.

Draft	Action	Dates	Results	Consideration of Comments
FMPP EOP-001-1 and EOP-001-2 Requirement R2.2 Interpretation Clean**(9)** | Redline**(10)** Request for Interpretation**(8)**	Recirculation Ballot Vote>> | Info**(12)**	10/05/10 - 10/15/10 (closed)	Summary**(14)** Full Record**(13)**	
	Pre-ballot Review Join>> | Info**(11)**	03/24/10 - 04/23/10 (closed)		
FMPP EOP-001-1 and EOP-001-2 Requirement R2.2 Request for Interpretation**(2)** Interpretation**(1)**	Initial Ballot Vote>> | Info**(4)**	02/10/10 - 02/22/10 (closed)	Summary**(6)** Full Record**(5)**	Consideration of Comments**(7)**
	Pre-ballot Review Join>> | Info**(3)**	01/11/10 - 02/10/10 (closed)		

To download a file click on the file using your right mouse button, then save it to your computer in a directory of your choice.

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Note: an Interpretation cannot be used to change a standard.

Request for an Interpretation of a Reliability Standard	
Date submitted: October 15, 2009	
Date accepted: November 30, 2009	
Contact information for person requesting the interpretation:	
Name:	Thomas E Washburn
Organization:	Florida Municipal Power Pool
Telephone:	407-384-4066
E-mail:	twashburn@ouc.com
Identify the standard that needs clarification:	
Standard Number (include version number):	EOP-001-1 and EOP-001-2
Standard Title:	Emergency Operations Planning
Identify specifically what requirement needs clarification:	
Requirement Number and Text of Requirement: R2.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system. **Clarification needed:** According to the NERC Functional Model, the BA is responsible for maintaining load-generation-interchange balance within the BA Area and supports interconnection frequency in real-time. This is done using frequency control through tie-line bias, regulation service deployment, load-following through economic dispatch, and interchange implementation. The BA is not responsible for plans to mitigate operating emergencies on the transmission system. The BA does follow the directives of the TOP when they are implementing their plans. Does the BA need to develop a plan to maintain a load-interchange-generation balance during operating emergencies and follow the directives of the TOP?	
Identify the material impact associated with this interpretation:	
Identify the material impact to your organization or others caused by the lack of clarity or an incorrect interpretation of this standard. Not having the correct interpretation of this requirement could cause the BA to be found non-compliant.	

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Project 2009-28: Response to Request for an Interpretation of EOP-001-1 and EOP-001-2, Requirement R2.2, for Florida Municipal Power Pool
The following interpretation of EOP-001-1 and EOP-001-2 — Emergency Operations Planning, Requirement R2.2, was developed by the Project 2006-03 (System Restoration and Blackstart) drafting team.
Requirement Number and Text of Requirement
R2.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.
Question
Does the BA need to develop a plan to maintain a load-interchange-generation balance during operating emergencies and follow the directives of the TOP?
Response[1]
The answer to both parts of the question is yes. The Balancing Authority is required by the standard to develop, maintain, and implement a plan. The plan must consider the relationships and agreements with the Transmission Operator for actions directly taken by the Balancing Authority. The Balancing Authority must take actions either as directed by the Transmission Operator or the Reliability Coordinator (reference TOP-001-1, Requirement R3), or as previously agreed to with the Transmission Operator or the Reliability Coordinator to mitigate transmission emergencies. As stated in Requirement R4, the emergency plan shall include the applicable elements in "Attachment 1 –EOP-001-0."

[1] At the time of posting for this response (January 11, 2010), EOP-001-0 is the current Federal Energy Regulatory Commission (FERC)-approved version of the EOP-001 Reliability Standard in the United States and is therefore mandatory and enforceable. EOP-001-1 and EOP-001-2 have been filed with but not yet approved by FERC; therefore, EOP-001-1 and EOP-001-2 are not mandatory and enforceable in the Unites States at this time. The requirement in question, Requirement R2.2 of EOP-001-1 and EOP-001-2, exists in EOP-001-0 as Requirement R3.2.

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Note: an Interpretation cannot be used to change a standard.

Request for an Interpretation of a Reliability Standard
Date submitted: October 15, 2009
Date accepted: November 30, 2009
Contact information for person requesting the interpretation:
Name: Thomas E Washburn
Organization: Florida Municipal Power Pool
Telephone: 407-384-4066
E-mail: twashburn@ouc.com
Identify the standard that needs clarification:
Standard Number (include version number): EOP-001-1 and EOP-001-2
Standard Title: Emergency Operations Planning
Identify specifically what requirement needs clarification:
Requirement Number and Text of Requirement: R2.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system. **Clarification needed:** According to the NERC Functional Model, the BA is responsible for maintaining load-generation-interchange balance within the BA Area and supports interconnection frequency in real-time. This is done using frequency control through tie-line bias, regulation service deployment, load-following through economic dispatch, and interchange implementation. The BA is not responsible for plans to mitigate operating emergencies on the transmission system. The BA does follow the directives of the TOP when they are implementing their plans. Does the BA need to develop a plan to maintain a load-interchange-generation balance during operating emergencies and follow the directives of the TOP?
Identify the material impact associated with this interpretation:
Identify the material impact to your organization or others caused by the lack of clarity or an incorrect interpretation of this standard. Not having the correct interpretation of this requirement could cause the BA to be found non-compliant.

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Standards Announcement

Ballot Pool and Pre-ballot Window
January 11–February 10, 2010

Now available at: https://standards.nerc.net/BallotPool.aspx

Project 2009-28: Interpretation of EOP-001-1 and EOP-001-2 for the Florida Municipal Power Pool (FMPP)

An interpretation of standard versions EOP-001-1 and EOP-001-2 — Emergency Operations Planning, Requirement R2.2, for FMPP is posted for a 30-day pre-ballot review. Registered Ballot Body members may join the ballot pool to be eligible to vote on this interpretation **until 8 a.m. EST on February 10, 2010**.

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-2009-28_RFI_FMPP_in@nerc.com

Next Steps

Voting will begin shortly after the pre-ballot review closes.

Project Background

FMPP is seeking clarification regarding Requirement R2.2. FMPP asked if the Balancing Authority needs to develop a plan to maintain a load-interchange-generation balance during operating emergencies and follow the directives of the Transmission Operator.

The request and interpretation can be found on the project page:
http://www.nerc.com/filez/standards/Project2009-28_EOP-001-1-2_R2.2_FMPP.html

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

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Standards Announcement

Initial Ballot Window Open
February 10-22, 2010

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Project 2009-28: Interpretation of EOP-001-1 and EOP-001-2 for the Florida Municipal Power Pool (FMPP)

An initial ballot window for an interpretation of standard versions EOP-001-1 and EOP-001-2 — Emergency Operations Planning, Requirement R2.2, for FMPP is now open **until 8 p.m. EST on February 22, 2010**.

Instructions

Members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

Next Steps

Voting results will be posted and announced after the ballot window closes.

Project Background

FMPP is seeking clarification regarding Requirement R2.2. FMPP asked if the Balancing Authority needs to develop a plan to maintain a load-interchange-generation balance during operating emergencies and follow the directives of the Transmission Operator.

The request and interpretation can be found on the project page:
http://www.nerc.com/filez/standards/Project2009-28_EOP-001-1-2_R2.2_FMPP.html

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
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-Registered Ballot Body
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Ballot Results

Ballot Name:	Project 2009-28 - Interpretation - EOP-001-1 and EOP-001-2 for FMPP_in
Ballot Period:	2/10/2010 - 2/22/2010
Ballot Type:	Initial
Total # Votes:	235
Total Ballot Pool:	269
Quorum:	**87.36 % The Quorum has been reached**
Weighted Segment Vote:	91.79 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	75	1	58	0.906	6	0.094	3	8
2 - Segment 2.	11	1	9	0.9	1	0.1	0	1
3 - Segment 3.	63	1	53	0.964	2	0.036	2	6
4 - Segment 4.	18	1	14	0.875	2	0.125	0	2
5 - Segment 5.	50	1	38	1	0	0	2	10
6 - Segment 6.	34	1	27	0.964	1	0.036	2	4
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	6	0.4	4	0.4	0	0	0	2
9 - Segment 9.	4	0.3	2	0.2	1	0.1	1	0
10 - Segment 10.	8	0.5	4	0.4	1	0.1	2	1
Totals	**269**	**7.2**	**209**	**6.609**	**14**	**0.591**	**12**	**34**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Jason Shaver	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman		
1	Avista Corp.	Scott Kinney	Abstain	
1	Baltimore Gas & Electric Company	John J. Moraski	Affirmative	

1	BC Transmission Corporation	Gordon Rawlings	Affirmative	
1	Beaches Energy Services	Joseph S. Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy	Paul Rocha	Abstain	
1	Central Maine Power Company	Brian Conroy	Affirmative	
1	City of Vero Beach	Randall McCamish	Affirmative	
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	William L. Thompson		
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	E.ON U.S. LLC	Larry Monday		
1	East Kentucky Power Coop.	George S. Carruba		
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor, II	Negative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg		
1	ITC Transmission	Elizabeth Howell	Affirmative	
1	JEA	Ted E Hobson		
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stan T. Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Jonathan Appelbaum	Affirmative	
1	Manitoba Hydro	Michelle Rheault	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	National Grid	Saurabh Saksena	Affirmative	
1	New York State Electric & Gas Corp.	Henry G. Masti	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	PacifiCorp	Mark Sampson	Affirmative	
1	Potomac Electric Power Co.	Richard J. Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Puget Sound Energy, Inc.	Catherine Koch	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Linda Brown	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.	Negative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sierra Pacific Power Co.	Richard Salgo	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Southwestern Power Administration	Gary W Cox		
1	Tampa Electric Co.	Thomas J. Szelistowski	Negative	
1	Tri-State G & T Association Inc.	Keith V. Carman	Affirmative	
1	Westar Energy	Allen Klassen	Negative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	

1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Jason L. Murray	Affirmative	
2	BC Transmission Corporation	Faramarz Amjadi	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Negative	
2	Florida Municipal Power Pool	Thomas E Washburn	Affirmative	
2	Independent Electricity System Operator	Kim Warren	Affirmative	View
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Jason L Marshall	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung	Affirmative	
3	Alabama Power Company	Bobby Kerley	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	American Electric Power	Raj Rana	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Black Hills Power	Andy Butcher	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R. Jacobson		
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City Public Service of San Antonio	Edwin Les Barrow		
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Jalal (John) Babik	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	Entergy Services, Inc.	Matt Wolf	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	W. R. Schoneck	Abstain	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Negative	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory David Woessner	Affirmative	
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson		
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Ocala Electric Utility	David T. Anderson	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	PacifiCorp	John Apperson	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Scott Peterson		

3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C. Young	Affirmative	
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey	Negative	
3	Wisconsin Electric Power Marketing	James R. Keller	Affirmative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	City of Clewiston	Kevin McCarthy	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas W. Richards	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Negative	
4	Integrys Energy Group, Inc.	Christopher Plante	Affirmative	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Affirmative	
4	Northern California Power Agency	Fred E. Young	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer		
5	Avista Corp.	Edward F. Groce	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	City of Tallahassee	Alan Gale	Affirmative	
5	City Water, Light & Power of Springfield	Karl E. Kohlrus	Affirmative	
5	Colmac Clarion/Piney Creek LP	Harvie D. Beavers	Affirmative	
5	Consolidated Edison Co. of New York	Edwin E Thompson	Affirmative	
5	Consumers Energy	James B Lewis	Affirmative	
5	Dairyland Power Coop.	Warren Schaefer	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Robert Smith	Affirmative	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	FPL Energy	Benjamin Church		
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	JEA	Donald Gilbert	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	Thomas J Trickey	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin		
5	Manitoba Hydro	Mark Aikens	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Affirmative	
5	New York Power Authority	Gerald Mannarino		
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Affirmative	
5	Northern States Power Co.	Liam Noailles	Affirmative	
5	Orlando Utilities Commission	Richard Kinas		
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Portland General Electric Co.	Gary L Tingley		
5	PowerSouth Energy Cooperative	Tim Hattaway	Affirmative	
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Power LLC	David Murray	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik		
5	RRI Energy	Thomas J. Bradish	Affirmative	
5	Sacramento Municipal Utility District	Bethany Wright	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	

5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	South California Edison Company	Ahmad Sanati		
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	South Mississippi Electric Power Association	Jerry W Johnson		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson		
6	Black Hills Corp	Tyson Taylor		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Chris Lyons	Affirmative	
6	Dominion Resources, Inc.	Louis S Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell		
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Thomas Saitta	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Louisville Gas and Electric Co.	Daryn Barker	Negative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	New York Power Authority	Thomas Papadopoulos	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Abstain	
6	PacifiCorp	Gregory D Maxfield	Affirmative	
6	Progress Energy	James Eckelkamp	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	RRI Energy	Trent Carlson	Affirmative	
6	Salt River Project	Mike Hummel	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seattle City Light	Dennis Sismaet	Abstain	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	Southern California Edison Co.	Marcus V Lotto	Affirmative	
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8	Edward C Stein	Edward C Stein		
8	James A Maenner	James A Maenner	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini		
8	Roger C Zaklukiewicz	Roger C Zaklukiewicz	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	Maine Public Utilities Commission	Jacob A McDermott	Abstain	
9	Utah Associated Municipal Power Systems	Tom Florence	Negative	
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Negative	View
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	Dan R. Schoenecker	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith		
10	SERC Reliability Corporation	Carter B Edge	Abstain	
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	

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Standards Announcement
Initial Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

Project 2009-28: Interpretation of EOP-001-1 and EOP-001-2 for the Florida Municipal Power Pool (FMPP)
The initial ballot for an interpretation of standard versions EOP-001-1 and EOP-001-2 — Emergency Operations Planning, Requirement R2.2, for FMPP ended on February 22, 2010.

Ballot Results
Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 87.36%
Approval: 91.79%

Since at least one negative ballot included a comment, these results are not final. A second (or recirculation) ballot must be conducted. Ballot criteria are listed at the end of the announcement.

Next Steps
As part of the recirculation ballot process, the drafting team must draft and post responses to voter comments. The drafting team will also determine whether or not to make revisions to the balloted item(s). Should the team decide to make revisions, the revised item(s) will return to the initial ballot phase.

Project Background
FMPP is seeking clarification regarding Requirement R2.2. FMPP asked if the Balancing Authority needs to develop a plan to maintain a load-interchange-generation balance during operating emergencies and follow the directives of the Transmission Operator.

The request and interpretation can be found on the project page:
http://www.nerc.com/filez/standards/Project2009-28_EOP-001-1-2_R2.2_FMPP.html

Standards Development Process
The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Ballot Criteria
Approval requires both a (1) quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention, and (2) A two-thirds majority of the weighted segment votes cast must be affirmative; the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and nonresponses. If there are no negative votes with reasons from the first ballot, the results of the first ballot shall stand. If, however, one or more members submit negative votes with reasons, a second ballot shall be conducted.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

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Project 2009-28: Interpretation of EOP-001-1 and EOP-001-2 for the Florida Municipal Power Pool
Consideration of Comments for Initial Ballot (February 10–22, 2010)

Summary Consideration:
Balloters who submitted negative votes with reasons were concerned about a possible expansion of the Balancing Authority requirements as a result of the interpretation. The balloters pointed out that, according to the standard as written, there is no requirement for agreements or for the Balancing Authority to follow Transmission Operator directives.

The drafting team recognizes it went outside the bounds of EOP-001-1 and EOP-001-2 in the effort to provide additional clarification in the interpretation. Accordingly, the drafting team is replacing the word "agreements" in the third sentence with "coordination."

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Voter	Entity	Segment	Vote	Comment
Kevin Querry	FirstEnergy Solutions	3	Affirmative	No Comment
Anthony Jankowski	Wisconsin Energy Corp.	4	Negative	The answer does not provide a clear understanding of the standard. The third sentence of the answer adds a requirement that the BA plan include consideration for relationships and agreements, there is no requirement to have agreements. The second part of sentence four "or as previously agreed to with the Transmission Operator or the Reliability Coordinator to mitigate transmission emergencies" is not a standard requirement, thereby expanding the scope of the standard.
Response: The drafting team thanks you for your comments and is replacing the word "agreements" in the third sentence with "coordination." The drafting team recognizes it went outside the bounds of EOP-001-1 and EOP-001-2 in the effort to provide additional clarification in the interpretation.				
Kim Warren	Independent Electricity System Operator	2	Affirmative	The IESO is concerned that in recent months, there have been an increasing number of simplistic interpretations being put in front of the entire balloting body. In our view, some of the inquiries could have been addressed via other avenues than the formal interpretation process. We suggest that NERC expeditiously develop an alternative approach, similar to the Information Request Program established by the FRCC, to field industry questions before they rise up to the

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
				formal interpretation request level. Industry participants should be encouraged to use other available resources and avenues instead of or before proceeding to a formal interpretation process to obtain understanding of standard applicability and compliance.
Response: The drafting team thanks you for your comment.				
Kent Saathoff	Electric Reliability Council of Texas, Inc.	10	Negative	The requirement in R2.2 is that BAs and TOPs develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system. The interpretation states that the BA must have a plan and must take actions as directed by the TOP or the RC. The plain language of the requirement states that the BA must have a plan to mitigate operating emergencies. However, neither this particular requirement, nor any other part of the Standard (including the list of plan elements in Attachment 1-EOP-001-0 to the Standard) requires the BA to follow the directives of the TOP. That obligation is not a requirement under this Standard.
Response: The drafting team recognizes it went outside the bounds of EOP-001-1 and EOP-001-2 in the effort to provide additional clarification in the interpretation. The drafting team is replacing the word “agreements” in the third sentence with “coordination.”				

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Note: an Interpretation cannot be used to change a standard.

Request for an Interpretation of a Reliability Standard
Date submitted: October 15, 2009
Date accepted: November 30, 2009
Contact information for person requesting the interpretation:
Name: Thomas E Washburn
Organization: Florida Municipal Power Pool
Telephone: 407-384-4066
E-mail: twashburn@ouc.com
Identify the standard that needs clarification:
Standard Number (include version number): EOP-001-1 and EOP-001-2
Standard Title: Emergency Operations Planning
Identify specifically what requirement needs clarification:
Requirement Number and Text of Requirement: R2.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system. **Clarification needed:** According to the NERC Functional Model, the BA is responsible for maintaining load-generation-interchange balance within the BA Area and supports interconnection frequency in real-time. This is done using frequency control through tie-line bias, regulation service deployment, load-following through economic dispatch, and interchange implementation. The BA is not responsible for plans to mitigate operating emergencies on the transmission system. The BA does follow the directives of the TOP when they are implementing their plans. Does the BA need to develop a plan to maintain a load-interchange-generation balance during operating emergencies and follow the directives of the TOP?
Identify the material impact associated with this interpretation:
Identify the material impact to your organization or others caused by the lack of clarity or an incorrect interpretation of this standard. Not having the correct interpretation of this requirement could cause the BA to be found non-compliant.

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Project 2009-28: Response to Request for an Interpretation of EOP-001-1 and EOP-001-2, Requirement R2.2, for Florida Municipal Power Pool
The following interpretation of EOP-001-1 and EOP-001-2 — Emergency Operations Planning, Requirement R2.2, was developed by the Project 2006-03 (System Restoration and Blackstart) drafting team.
Requirement Number and Text of Requirement
R2.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.
Question
Does the BA need to develop a plan to maintain a load-interchange-generation balance during operating emergencies and follow the directives of the TOP?
Response[1]
The answer to both parts of the question is yes. The Balancing Authority is required by the standard to develop, maintain, and implement a plan. The plan must consider the relationships and coordination with the Transmission Operator for actions directly taken by the Balancing Authority. The Balancing Authority must take actions either as directed by the Transmission Operator or the Reliability Coordinator (reference TOP-001-1, Requirement R3), or as previously agreed to with the Transmission Operator or the Reliability Coordinator to mitigate transmission emergencies. As stated in Requirement R4, the emergency plan shall include the applicable elements in "Attachment 1 –EOP-001-0."

[1] At the time of posting for this response (January 11, 2010), EOP-001-0 is the current Federal Energy Regulatory Commission (FERC)-approved version of the EOP-001 Reliability Standard in the United States and is therefore mandatory and enforceable. EOP-001-1 and EOP-001-2 have been filed with but not yet approved by FERC; therefore, EOP-001-1 and EOP-001-2 are not mandatory and enforceable in the Unites States at this time. The requirement in question, Requirement R2.2 of EOP-001-1 and EOP-001-2, exists in EOP-001-0 as Requirement R3.2.

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Request for an Interpretation of a Reliability Standard
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Requirement Number and Text of Requirement
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Question
Does the BA need to develop a plan to maintain a load-interchange-generation balance during operating emergencies and follow the directives of the TOP?
Response[1]
The answer to both parts of the question is yes. The Balancing Authority is required by the standard to develop, maintain, and implement a plan. The plan must consider the relationships and ~~agreements~~ coordination with the Transmission Operator for actions directly taken by the Balancing Authority. The Balancing Authority must take actions either as directed by the Transmission Operator or the Reliability Coordinator (reference TOP-001-1, Requirement R3), or as previously agreed to with the Transmission Operator or the Reliability Coordinator to mitigate transmission emergencies. As stated in Requirement R4, the emergency plan shall include the applicable elements in "Attachment 1 –EOP-001-0."

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Standards Announcement

Ballot Pool and Pre-ballot Window
March 24–April 23, 2010

Now available at: https://standards.nerc.net/BallotPool.aspx

Project 2009-28: Interpretation of EOP-001-1 and EOP-001-2 for Florida Municipal Power Pool (FMPP)

A revised interpretation of standard versions EOP-001-1 and EOP-001-2 — Emergency Operations Planning, Requirement R2.2, for FMPP is posted for a 30-day pre-ballot review **until 8 a.m. Eastern on April 23, 2010**.

Instructions

Registered Ballot Body members may join the ballot pool to be eligible to vote in the upcoming ballot at the following page: https://standards.nerc.net/BallotPool.aspx.

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-2009-28_RFI_FMPP_Rev_in@nerc.com.

Next Steps

Voting will begin shortly after the pre-ballot review closes.

Project Background

FMPP is seeking clarification regarding Requirement R2.2. FMPP asked if the Balancing Authority needs to develop a plan to maintain a load-interchange-generation balance during operating emergencies and follow the directives of the Transmission Operator.

This is a revised version of the interpretation. The drafting team revised the interpretation to address balloter concerns about a possible expansion of the Balancing Authority requirements resulting from the original interpretation.

The changes to the interpretation are shown in a redline version posted on the project page. The team has also posted a response to comments received during the initial ballot (conducted in February 2010) of the original interpretation.

The request and interpretation can be found on the project page:
http://www.nerc.com/filez/standards/Project2009-28_EOP-001-1-2_R2.2_FMPP.html

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Lauren Koller at Lauren.Koller@nerc.net

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Standards Announcement

Recirculation Ballot Window Open
October 5–15, 2010

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Interpretation of EOP-001-1, EOP-001-2 – Emergency Operations Planning for the Florida Municipal Power Pool (Project 2009-28)

A recirculation ballot window for an interpretation of EOP-001-1 and EOP-001-2 — Emergency Operations Planning, Requirement R2.2 for Florida Municipal Power Pool (FMPP) is now open **until 8 p.m. EDT on October 15, 2010**.

Project Background

FMPP is seeking clarification regarding Requirement R2.2. FMPP asked if the Balancing Authority needs to develop a plan to maintain a load-interchange-generation balance during operating emergencies and follow the directives of the Transmission Operator.

The request and interpretation can be found on the project page:
http://www.nerc.com/filez/standards/Project2009-28_EOP-001-1-2_R2.2_FMPP.html

Recirculation Ballot Process

The Standards Committee encourages all members of the Ballot Pool to review the consideration of comments submitted with the initial ballots. In the recirculation ballot, votes are counted by exception only. If a Ballot Pool member does not submit a revision to that member's original vote, the vote remains the same as in the first ballot. Members of the ballot pool may:

- Reconsider and change their vote from the first ballot
- Vote in the second ballot even if they did not vote on the first ballot
- Take no action if they do not want to change their original vote

Transition from Reliability Standards Development Procedure Version 7 to Standard Processes Manual

Under the Reliability Standards Development Procedure Version 7, interpretations did not have any comment period and were posted for ballot once they were drafted. Under the Standard Processes Manual each interpretation is posted for a 30-day formal comment period; then the drafting team responds to comments; then the interpretation (revised if needed) is posted for a 45-day formal comment period conducted in parallel with an initial ballot. If there are no significant changes to the interpretation and the initial ballot sufficient affirmative votes for approval, then the interpretation proceeds to a recirculation ballot.

The addition of a comment period before the pre-ballot review period and the addition of a comment period in parallel with the initial ballot, are steps that were added to the process based on stakeholder comments

indicating that interpretations needed more stakeholder input before being finalized.

This interpretation had already been through an initial ballot when the Standard Processes Manual was approved, and no changes were made to the interpretation following the initial ballot; thus, this interpretation is moving forward for a recirculation ballot.

Next Steps

Voting results will be posted and announced after the recirculation ballot window closes.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

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-Proxy Voters

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Ballot Results

Ballot Name:	Project 2009-28 - Interpretation - EOP-001-1 and EOP-001-2 for FMPP_rc
Ballot Period:	10/5/2010 - 10/15/2010
Ballot Type:	recirculation
Total # Votes:	248
Total Ballot Pool:	269
Quorum:	**92.19 % The Quorum has been reached**
Weighted Segment Vote:	94.78 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	75	1	61	0.968	2	0.032	7	5
2 - Segment 2.	11	1	9	0.9	1	0.1	0	1
3 - Segment 3.	63	1	54	0.982	1	0.018	5	3
4 - Segment 4.	18	1	15	1	0	0	2	1
5 - Segment 5.	50	1	37	0.974	1	0.026	6	6
6 - Segment 6.	34	1	28	1	0	0	3	3
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	6	0.4	4	0.4	0	0	1	1
9 - Segment 9.	4	0.3	2	0.2	1	0.1	1	0
10 - Segment 10.	8	0.5	4	0.4	1	0.1	2	1
Totals	**269**	**7.2**	**214**	**6.824**	**7**	**0.376**	**27**	**21**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Jason Shaver	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman		
1	Avista Corp.	Scott Kinney	Abstain	
1	Baltimore Gas & Electric Company	John J. Moraski	Affirmative	

1	BC Transmission Corporation	Gordon Rawlings	Affirmative	
1	Beaches Energy Services	Joseph S. Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy	Paul Rocha	Abstain	
1	Central Maine Power Company	Brian Conroy	Affirmative	
1	City of Vero Beach	Randall McCamish	Affirmative	
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	William L. Thompson		
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	E.ON U.S.	Larry Monday	Abstain	
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor, II	Abstain	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg		
1	ITC Transmission	Elizabeth Howell	Affirmative	
1	JEA	Ted E Hobson		
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stan T. Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Jonathan Appelbaum	Affirmative	
1	Manitoba Hydro	Michelle Rheault	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	National Grid	Saurabh Saksena	Affirmative	
1	New York State Electric & Gas Corp.	Henry G. Masti	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	PacifiCorp	Mark Sampson	Affirmative	
1	Potomac Electric Power Co.	Richard J Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Puget Sound Energy, Inc.	Catherine Koch	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Linda Brown	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Tampa Electric Co.	Thomas J. Szelistowski	Negative	
1	Tri-State G & T Association, Inc.	Keith V. Carman	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	

1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Jason L. Murray	Affirmative	
2	BC Transmission Corporation	Faramarz Amjadi	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Negative	View
2	Florida Municipal Power Pool	Thomas E Washburn	Affirmative	
2	Independent Electricity System Operator	Kim Warren	Affirmative	View
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Jason L Marshall	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung	Affirmative	
3	Alabama Power Company	Bobby Kerley	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	American Electric Power	Raj Rana	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Black Hills Power	Andy Butcher	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R. Jacobson	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Edwin Les Barrow		
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Jalal (John) Babik	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	Entergy Services, Inc.	Matt Wolf	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	W. R. Schoneck	Abstain	
3	Florida Power Corporation	Lee Schuster	Abstain	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Abstain	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory David Woessner	Affirmative	
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	Manitoba Hydro	Greg C Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson		
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Ocala Electric Utility	David T. Anderson	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	PacifiCorp	John Apperson	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Scott Peterson		

3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C. Young	Affirmative	
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey	Negative	
3	Wisconsin Electric Power Marketing	James R. Keller	Affirmative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	City of Clewiston	Kevin McCarthy	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas W. Richards	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Affirmative	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Abstain	
4	Northern California Power Agency	Fred E. Young	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	View
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	Avista Corp.	Edward F. Groce	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	City of Tallahassee	Alan Gale	Affirmative	
5	City Water, Light & Power of Springfield	Karl E. Kohlrus	Affirmative	
5	Colmac Clarion/Piney Creek LP	Harvie D. Beavers	Affirmative	
5	Consolidated Edison Co. of New York	Edwin Thompson	Affirmative	
5	Consumers Energy	James B Lewis	Affirmative	
5	Dairyland Power Coop.	Warren Schaefer	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Robert Smith	Affirmative	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	JEA	Donald Gilbert	Abstain	
5	Kansas City Power & Light Co.	Scott Heidtbrink	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	Thomas J Trickey	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin	Abstain	
5	Manitoba Hydro	Mark Aikens	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	
5	New York Power Authority	Gerald Mannarino		
5	NextEra Energy Resources, LLC	Benjamin Church		
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Affirmative	
5	Orlando Utilities Commission	Richard Kinas		
5	PacifiCorp	Sandra L. Shaffer	Abstain	
5	Portland General Electric Co.	Gary L Tingley		
5	PowerSouth Energy Cooperative	Tim Hattaway	Affirmative	
5	PPL Generation LLC	Mark A Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Power LLC	David Murray	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik	Affirmative	
5	RRI Energy	Thomas J. Bradish	Affirmative	
5	Sacramento Municipal Utility District	Bethany Wright	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	

5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	South California Edison Company	Ahmad Sanati		
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	South Mississippi Electric Power Association	Jerry W Johnson	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Abstain	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	Black Hills Corp	Tyson Taylor		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Chris Lyons	Affirmative	
6	Dominion Resources, Inc.	Louis S Slade	Abstain	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell		
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Thomas Saitta	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Louisville Gas and Electric Co.	Daryn Barker	Abstain	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	New York Power Authority	Thomas Papadopoulos	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Abstain	
6	PacifiCorp	Gregory D Maxfield	Affirmative	
6	Progress Energy	James Eckelkamp	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	RRI Energy	Trent Carlson	Affirmative	
6	Salt River Project	Mike Hummel	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	Southern California Edison Co.	Marcus V Lotto	Affirmative	
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8		James A Maenner	Affirmative	
8		Edward C Stein	Abstain	
8		Roger C Zaklukiewicz	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	Maine Public Utilities Commission	Jacob A McDermott	Abstain	
9	Utah Associated Municipal Power Systems	Tom Florence	Negative	
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Negative	View
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	Dan R. Schoenecker	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith		
10	SERC Reliability Corporation	Carter B Edge	Abstain	
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Final Ballot Results for Three Interpretations

Now available at: https://standards.nerc.net/Ballots.aspx

Recirculation Ballots for the following interpretations have closed and all three interpretations were approved by their associated ballot pools.

Project 2008-09 – Interpretation of EOP-001-0 Emergency Operations Planning Requirement R1 for the Regional Entity Compliance Managers

The recirculation ballot for this interpretation ended October 14, 2010. Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 88.11%
Approval: 99.14%

The request and interpretation can be found on the project page:
http://www.nerc.com/filez/standards/EOP-001-0_Interpretation_RECM.html

Project 2009-28 – Interpretation of EOP-001-1, EOP-001-2 – Emergency Operations Planning for the Florida Municipal Power Pool

The recirculation ballot for this interpretation ended October 15, 2010. Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 92.19%
Approval: 94.78%

The request and interpretation can be found on the project page:
http://www.nerc.com/filez/standards/Project2009-28_EOP-001-1-2_R2.2_FMPP.html

Project 2009-27 – Interpretation of TOP-002-2a – Normal Operations Planning for the Florida Municipal Power Pool

The recirculation ballot for this interpretation ended October 16, 2010. Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 91.21%
Approval: 93.44%

The request and interpretation can be found on the project page:
http://www.nerc.com/filez/standards/Project2009-27_TOP-002-2a_R10_RFI_FMPP.html

Next Steps

All three interpretations will be presented to the Board of Trustees for approval.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

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Exhibit H

Roster of the Interpretation Drafting Team for the Interpretation of Requirement R1 of EOP-001-0 — Emergency Operations Planning

Project 2008-09 Interpretation of EOP-001-0 for RECM

Name and Title Affiliation Contact Info	Bio
Colleen Frosch Manager of System Operations Electric Reliability Council of Texas 2705 West Lake Drive Taylor, Texas 76574 (512) 248-4219 cfrosch@ercot.com	Colleen Frosch is the vice chair of the NERC Operations Reliability Subcommittee (ORS), as well as a member of the NERC Reliability Coordinator Working Group (RCWG) and the ORS Executive Committee. Colleen has over 20 years of experience in the utility industry with the bulk of her career spent in system operations. At ERCOT, were she has been employed since 1996, Colleen is responsible for real-time operations which include the Reliability Coordinator (RC), Balancing Authority (BA), and Transmission Operator (TOP) functions, as well as the Training program for the ERCOT ISO System Operators. Prior to ERCOT, Colleen worked for 12 year at Central and South West Services. Colleen received an Associates of Applied Science in 1995 and has been a NERC Certified System Operator at the RC level since Sept. 1998.
Frank Koza Executive Director Operations Support PJM Interconnection 955 Jefferson Avenue Norristown, PA 19403 (610) 666-4228 (610) 666-4286 Fx kozaf@pjm.com	Frank J. Koza is the chair of the NERC Operations Reliability Subcommittee and vice chair of the NERC Geomagnetic Task Force. He received a BSME Degree from the University of Pennsylvania, a Master of Engineering Degree from Widener University and is also a registered professional engineer in the State of Pennsylvania (PE028372E). He has almost 39 years experience in the utility industry with experience in system operations, system planning, transmission construction and maintenance. At PJM, Frank is responsible for system operations processes, except for the control room operators. Prior to PJM, Frank worked for 29 years at PECO Energy in a variety of positions in transmission and generation..
Don M. Shipley Director, SPP Operations Southwest Power Pool 415 N McKinley Little Rock, AR 72205 (501) 614-3581 (501) 851-1784 Fax dshipley@spp.org	Don M. Shipley is the Chairman of the NERC Reliability Coordinator Working Group (RCWG), as well as a member of the NERC Operating Reliability Subcommittee (ORS) and the ORS Executive Committee. He received a Bachelor of Science degree in Organizational Management from John Brown University in Siloam Springs, Arkansas. Don has 33 years of experience in the utility industry with experience in Distribution Emergency Operations, Transmission System Operations and is a NERC Certified System Operator (RC200506247). Currently at Southwest Power Pool (SPP) Don is responsible for real time operations including Reliability Coordination, Energy Imbalance Market, Tariff Administration, and Interchange functions. Prior to SPP, he was a System Operator in the Reliability Coordinator (RC) and Balancing Authority (BA) functions at Entergy for 7 years. Don worked for 21 years at TXU in Dallas, Texas in various positions in the Distribution function.
Joel G. Wise Manager Reliability Operations	Joel G. Wise is a member of the NERC Operating Reliability Subcommittee (ORS), as well as the ORS Executive Committee. He is also a member of the NERC Reliability Coordinator Working Group. He currently serves as the

Tennessee Valley Authority 1101 Market St., PCC 02A Chattanooga, TN 37402 (423) 697-4165 (423) 697-4120 Fax jgwise@tva.gov	Chair of the Southeastern Reliability Corporation (SERC) Reliability Coordinator Subcommittee. Joel has almost 23 years of experience in the utility industry. Currently at TVA Joel manages the two 24X7 operating desks that provide Reliability Coordinator services for the TVA Reliability Coordinator Area. Prior to this he was a System Operator in the Reliability Coordinator (RC) Balancing Authority (BA) functions. Joel worked for 13 years at Duke Energy Carolinas. Joel began as a Generator Operator in conventional and pumped storage hydro. He then moved into system operations working as a System Operator in the RC, BA, Interchange Authority (IA), Transmission Service Provider (TSP) functions. Joel is NERC certified at the RC level.

Exhibit I

Roster of the Interpretation Drafting Team for the Interpretation of Requirement R3.2 of EOP-001-0 — Emergency Operations Planning

Project 2009 - 28 EOP-001-2 and EOP-001-2 R2.2 - Interpretation Drafting Team

Name and Title Affiliation Contact Info	Bio
Richard Kafka (Retired) PEPCO Holdings, Inc. 4009 Highview Drive Silver Springs, MD 20906 Business : (301) 946-5515 Cell: (601) 594-6736 vahrjk@verizon.net	Mr. Kafka was assigned to Pepco's system restoration study team in 1979, which produced one of the first formal power flow studies for a system restoration plan. This plan and the process used to develop it were published as IEEE Transactions. As a result, IEEE established the Power System Restoration Working Group and Mr. Kafka was a charter member. Mr. Kafka is a Fellow of the IEEE, elected based on his system restoration planning contributions. Mr. Kafka supervised all Pepco system restoration plan developments since 1979. Mr. Kafka was part of the Violation Risk Factors SDT - the VRF SDT has reviewed all requirements for every standard and has identified general issues to be addressed on the standards. Mr. Kafka also served as Chair of the System Restoration and Blackstart SDT.
Francis Esselman Managing Partner Proven Compliance Solutions Business: (262) 510-2446 Cell: (608) 509-5908 fesselman@provencompliance.com	Mr. Esselman has 36 years of industry experience in fossil plant operations and system operations management. He recently (until Feb. 2010) managed Forward Operations engineering at American Transmission Co. where he was involved in almost every aspect of transmission operations, operations planning, and transmission interconnection processes. As part of Emergency planning coordination related to project 2009-28 Mr. Esselman has been an industry leader in the emergency operations areas including for MISO development of the blackstart tariff technical papers and has held leadership roles on the blackstart system restoration emergency response subcommittee also in MISO. Mr. Esselman has led most aspects of Operations major emergency response coordination since 1990 at Wisconsin Power & Light Co. and subsequently at Alliant Energy and American Transmission Co. where the emergency plans of the four contributing companies were combined into a single Transmission Operations emergency plan that is coordinated with the then local Balancing Areas. Mr. Esselman is currently an independent consultant with an emphasis on emergency planning and NERC standards.

Mark Kuras Senior Lead Engineer PJM Interconnection, L.L.C. 955 Jefferson Avenue Valley Forge Corporate Center Norristown, PA 19403 Business : (610) 666-8924 Cell: (484) 994-8324 kuras@pjm.com	Mr. Kuras has 22 years of Planning and standards development experience. He is the current Chairman of the NERC Reliability Assessment Subcommittee and the NERC Data Coordination Subcommittee. He also chairs three ReliabilityFirst standard drafting teams; one on generator verification, one on system restoration and blackstart, and one on underfrequency load shedding. He also served as a member of the NERC System Restoration and Blackstart Standard Drafting Team and several other NERC and RFC standards drafting teams. Mark has extensive experience on NERC compliance (as an auditor and planning compliance lead). He was the past chair and present database coordinator of the Eastern Interconnection Reliability Assessment Group's Multiregional Modeling Working Group (ERAG MMWG). Mr. Kuras has worked at PJM for 16 years in Planning, Compliance and Regional Coordination. Mark previously worked at Northeast Power Coordinating Council in Planning and New York Power Authority in Operations Planning.
David Mahlmann Manager, Operations Engineering New York Independent System Operator 3890 Carman Road Schenectady, NY 12303 Business: (518) 356-6101 dmahlmann@nyiso.com	Mr. Mahlmann has 33 years of industry experience in fossil plant operations, transmission planning, operations engineering, and system operator training. He serves as a member of the Northeast Power Coordinating Council Restoration Working Group, and is a continuing member of the NYISO Restoration Working Group. Mr. Mahlmann has led the development of the NYISO System Operations Training Simulator. This tool allows remote monitoring and participation, and provides a real time look and feel to restoration exercises. David incorporated simulation into the NYISO System Operating Training Seminars, the NYISO annual restoration drill, and the NPCC Multi-Area Restoration exercises. Mr. Mahlmann is currently the Manager of Operations Engineering at the New York ISO; among other responsibilities, his staff conducts the review and expansion of the NYISO Restoration Plan.

Steve Cooper Independent Electricity System Operator Station A Box 4474 Toronto, ON L5J 4R9 Business: (905) 855-6159 steve.cooper@ieso.ca	Biographic information not available.
Al McMeekin Standards Development Coordinator North American Electric Reliability Corporation 116-390 Village Boulevard Princeton, NJ 08540 Business: (803) 530-1963 al.mcmeekin@nerc.net	Al McMeekin is the NERC Staff Coordinator for this interpretation response development team. Prior to joining NERC in 2009 as a Standards Development Coordinator, Mr. McMeekin worked at South Carolina Electric & Gas Company (SCE&G) for 29 years with various assignments in engineering and operations within the Distribution and Transmission Groups. In Transmission Operations Planning, Mr. McMeekin was the lead engineer responsible for: providing the day ahead and real-time operational plans to System Control; overseeing the monthly transmission billing functions and inadvertent checkout; administering the SCE&G OATT and developing business practices; participating in SCE&G's ERO Working Group to ensure compliance with NERC standards; and representing SCE&G on various national, regional, and subregional groups. Mr. McMeekin was a member of the SERC Operating Committee and served as Chair of the SERC Operations Planning Subcommittee. Al was a member of the SERC Standards Committee and the SERC Available Transfer Capability Working Group. He also served as Chair of the VACAR South Reliability Coordinator Procedures Working Group and was a member of NERC's System Restoration and Blackstart Standards Drafting Team. Al is a graduate of Clemson University and is a licensed Professional Engineer in the states of South Carolina and Georgia.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

October 19, 2011

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: ***North American Electric Reliability Corporation***
Docket No. RM__-__-___

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits this filing in accordance with Section 215(d)(1) of the Federal Power Act ("FPA") and Part 39.5 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, seeking approval for one proposed revised Reliability Standard, the associated Violation Risk Factors and Violation Severity Levels, and five new definitions to be added to the NERC Glossary of Terms, as well as the retirement of four approved Reliability Standards and the withdrawal of two pending Reliability Standards. NERC also seeks approval of the attached implementation plan which establishes the schedule for implementing the proposed Reliability Standard.

NERC seeks the Commission's approval of the following revised Reliability Standard contained in **Exhibit A** to this petition: TPL-001-2 - Transmission System Planning Performance Requirements. NERC also seeks FERC approval of the

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proposed definitions of Bus-tie Breaker, Consequential Load Loss, Long-Term Transmission Planning Horizon, Non-Consequential Load Loss, and Planning Assessment.

This proposal also includes a request that FERC retire four existing Reliability Standards:

- TPL-001-1 — System Performance Under Normal (No Contingency) Conditions (Category A)
- TPL-002-1b — System Performance Following Loss of a Single [Bulk Electric System] ("BES") Element (Category B)
- TPL-003-1a — System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
- TPL-004-1 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

In addition, this proposal includes a request for the withdrawal of two pending Reliability Standards:

- TPL-005-0 — Regional and Interregional Self-Assessment Reliability Reports
- TPL-006-0.1 – Data From the Regional Reliability Organization Needed to Assess Reliability

The proposed TPL-001-2 Reliability Standard addresses the important reliability goal of establishing transmission planning performance requirements for reliable Bulk Electric System ("BES") operations across normal and Contingency conditions. TPL-001-2 — Transmission System Planning Performance Requirements

will serve as the foundational standard for annual planning assessments conducted by Planning Coordinators and Transmission Planners to plan the Bulk Electric System ("BES") reliably in response to a range of potential contingencies. The standard presents clear, measurable, and enforceable Requirements that each Planning Coordinator and Transmission Planner must follow when planning its System.

The proposed TPL-001-2 standard combines elements of the approved Reliability Standards TPL-001-1 — System Performance Under Normal (No Contingency) Conditions (Category A), TPL-002-1b — System Performance Following Loss of a Single BES Element (Category B), TPL-003-1a — System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), and TPL-004-1 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements. The proposed standard also incorporates and expands upon the revised Footnote "b" to Table 1 of the previously approved TPL group of standards. The requirements from the two Reliability Standards not approved in FERC Order No. 693 (TPL-005-0 — Regional and Interregional Self-Assessment Reliability Reports and TPL-006-0.1 — Data from the Regional Reliability Organization Needed to Assess Reliability) have been moved to Sections 803 and 804 of the NERC Rules of Procedure.

In replacing these previous standards, TPL-001-2 introduces significant revisions and improvements including increased specificity of data requirements and modeling conditions. For example, sensitivity studies varying one or more modeling conditions by a sufficient amount to stress the system will be required. Annual assessments addressing Near-Term and Long-Term Planning Horizons for steady state, short circuit, and stability conditions must be conducted under the proposed standard. Planners will be required to address the impact of the unavailability of long lead-time critical equipment in a manner consistent with their entity's spare equipment strategy. The proposed standard clarifies how load loss may be utilized by transmission planners. Proper assessments conducted in accordance with the proposed standard will include an entity's criteria outlining acceptable voltage limits and deviations as well as the criteria used for analysis of instability. These assessments will then be distributed to other nearby entities for the purpose of facilitating a peer review so that entities may coordinate and improve their planning assessments across an Interconnection.

Proposed TPL-001-2 addresses twenty-seven Commission directives issued in Order No. 693 and subsequent orders as well as addressing numerous other concerns expressed by stakeholders, including the industry and the Commission Staff, during the development of the standard. Twenty-four of the responses to the Commission's

directives directly adhere to the directives issued. The standard drafting team addressed an additional three directives by equally effective and efficient solutions as provided for in Order No. 693.[1]

Accordingly, NERC respectfully requests that the proposed TPL-001-2 Reliability Standard be approved because it serves the important reliability goal of ensuring that a Transmission System is planned to operate reliably under normal and Contingency conditions. Additionally, the proposed standard improves uniformity and transparency in the planning process and clarifies the instances where planners may utilize load loss.

The TPL-001-2 — Transmission System Planning Performance Requirements Reliability Standard was approved by the NERC Board of Trustees on August 4, 2011.

This petition consists of the following:

- This transmittal letter;
- A table of contents for the entire petition;
- A narrative description explaining how the proposed Reliability Standard TPL-001-2 — Transmission System Planning Performance Requirements meets FERC's requirements;
- Reliability Standard TPL-001-2 — Transmission System Planning Performance Requirements submitted for approval (**Exhibit A**);

[1] *Mandatory Reliability Standards for the Bulk-Power* System, Order No. 693, FERC Stats. & Regs. ¶ 31,242 (2007), *order on reh'*g Order No. 693-A, 120 FERC ¶ 61,053 (2007)("Order No. 693") at P 31.

- Implementation Plan for Reliability Standard TPL-001-2 — Transmission System Planning Performance Requirements submitted for Approval (**Exhibit B**);
- Violation Risk Factors and Violation Severity Levels analysis for TPL-001-2 (**Exhibit C**)
- Consideration of Comments Reports created during the development of Reliability Standard TPL-001-2 — Transmission System Planning Performance Requirements (**Exhibit D)**
- Mapping Document Explaining the transposition of requirements from previous TPL Reliability Standards to TPL-001-2 — Transmission System Planning Performance Requirements (**Exhibit E**);
- The complete development record of the proposed Reliability Standard (**Exhibit F**); and
- The Standard Drafting Team roster and biographical information for NERC Standards Development Project 2006-02 Assess Transmission Future Needs and Develop Transmission Plans (**Exhibit G**).

For the reasons stated above and in this petition, NERC respectfully requests that

the Commission approve the standard presented herein for approval.

Respectfully submitted,

/s/ Andrew M. Dressel

Andrew M. Dressel
Attorney
North American Electric Reliability Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	**)** **)**	**Docket No. RM__-__-___**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF A REVISED TRANSMISSION PLANNING SYSTEM PERFORMANCE REQUIREMENTS RELIABILITY STANDARD AND FIVE NEW GLOSSARY TERMS AND FOR RETIREMENT OF FOUR EXISTING RELIABILITY STANDARDS

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October 19, 2011

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Exhibit A — Reliability Standard TPL-001-2 — Transmission System Planning Performance Requirements submitted for approval

Exhibit B — Implementation Plan for Reliability Standard TPL-001-2 — Transmission System Planning Performance Requirements submitted for Approval

Exhibit C — Violation Risk Factors and Violation Severity Levels analysis for TPL-001-2 — Transmission System Planning Performance Requirements

Exhibit D — Consideration of Comments Reports created during the development of Reliability Standard TPL-001-2 — Transmission System Planning Performance Requirements

Exhibit E — Mapping Document Explaining the transposition of requirements from previous TPL Reliability Standards to TPL-001-2 — Transmission System Planning Performance Requirements

Exhibit F — The complete development record of the proposed Reliability Standard

Exhibit G — The Standard Drafting Team roster and biographical information for NERC Standards Development *Project 2006-02 Assess Transmission Future Needs and Develop Transmission Plans*

I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC")[1] respectfully requests the Federal Energy Regulatory Commission ("FERC" or "the Commission") approve, in accordance with Section 215(d)(1) of the Federal Power Act ("FPA")[2] and Section 39.5 of FERC's regulations, 18 C.F.R. § 39.5, one proposed revised Reliability Standard:TPL-001-2 — Transmission System Planning Performance Requirements, the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs"), and the implementation plan which establishes the schedule for implementing the proposed Reliability Standard. NERC is also requesting the retirement of four existing Reliability Standards: (1) TPL-001-1 — System Performance Under Normal (No Contingency) Conditions (Category A), (2) TPL-002-1b — System Performance Following Loss of a Single [Bulk Electric System] ("BES") Element (Category B), (3) TPL-003-1a — System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), and (4) TPL-004-1 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D). Additionally, NERC is requesting to withdraw two standards TPL-005-0 — Regional and Interregional Self-Assessment Reliability Reports, and TPL-006-0.1 – Data From the Regional Reliability Organization Needed to Assess Reliability which were never approved by the Commission.

The NERC Board of Trustees approved this proposed Reliability Standard on August 4, 2011. NERC requests that the Commission approve the proposed Reliability Standard to become effective in accordance with the effective date provisions set forth in the proposed Reliability

[1] NERC has been certified by FERC as the Electric Reliability Organization ("ERO") authorized by Section 215 of the Federal Power Act. FERC certified NERC as the ERO in its order issued July 20, 2006 in Docket No. RR06-1-000. 116 FERC ¶ 61,062 (2006) ("ERO Certification Order).
[2] 16 U.S.C. 824o.

Standard and the Implementation Plan. Specifically, NERC is requesting that TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1 be

> retired at midnight the day before TPL-001-2 becomes effective as the previous standards are replaced in their entirety by TPL-001-2. TPL-005-0 and TPL-006-0.1 are being retired at midnight the day before TPL-001-2 becomes effective because their requirements are adequately covered by the revised TPL-001-2 and NERC's Rules of Procedure, Section 800. However, during this 24-month period, all aspects of the latest enforceable versions of TPL-001 through TPL-006 shall remain in effect for compliance monitoring. This 24 month period is to allow entities to develop, perform or validate new or modified studies, methodologies, assessments, procedures, etc. necessary to implement and meet the TPL-001-2 requirements.[3]

Thus, all of the requirements of the previously-approved TPL standards will remain in effect until all of the requirements in the proposed standard become effective.

Exhibit A to this filing sets forth the proposed Reliability Standard. **Exhibit B** to this filing is the Implementation Plan for Reliability Standard TPL-001-2 — Transmission System Planning Performance Requirements submitted for Approval. **Exhibit C** is an analysis demonstrating that the proposed VRFs and VSLs for TPL-001-2 meet the Commission-approved VRF and VSL guidelines. **Exhibit D** contains the Matrix of FERC Directives and Industry Issues Considered in the development of this proposed standard. **Exhibit E** contains the Mapping Document which explains the transposition of requirements from previous TPL Reliability Standards to TPL-001-2 — Transmission System Planning Performance Requirements. **Exhibit F** is the complete development record of the proposed Reliability Standard. **Exhibit G** includes the standard drafting team ("SDT") roster and a short biography of each SDT member that developed the proposed Reliability Standard.

NERC is also filing this proposed Reliability Standard with applicable governmental authorities in Canada.

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[3] Implementation Plan for TPL-001-2, **Exhibit B,** *infra*.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:

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*Persons to be included on FERC's service list are indicated with an asterisk. NERC requests waiver of FERC's rules and regulations to permit the inclusion of more than two people on the service list.

III. EXECUTIVE SUMMARY

The proposed TPL-001-2 Reliability Standard addresses the important reliability goal of establishing transmission planning performance requirements for the reliable planning of the Bulk Electric System ("BES") across normal and Contingency conditions. TPL-001-2 — Transmission System Planning Performance Requirements will serve as the foundational standard for annual planning assessments conducted by Planning Coordinators and Transmission Planners to plan the BES reliably in response to a range of potential contingencies. The standard presents clear, measurable, and enforceable Requirements that each Planning Coordinator and Transmission Planner must follow when planning its System.

The proposed TPL-001-2 combines elements of the approved Reliability Standards TPL-001-1 — System Performance Under Normal (No Contingency) Conditions (Category A), TPL-002-1b — System Performance Following Loss of a Single BES Element (Category B), TPL-003-1a — System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), and TPL-004-1 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements.

In replacing the TPL-001-1 through TPL-004-1 standards, the proposed TPL-001-2 standard introduces significant revisions and improvements including increased specificity of data requirements and modeling conditions. The proposed standard also incorporates and expands upon the revised Footnote "b" to Table 1 of the previously approved TPL group of standards. Sensitivity studies varying one or more modeling conditions by a sufficient amount to stress the system will be required. Annual assessments addressing Near-Term and Long-Term Planning Horizons for steady state, short circuit, and stability conditions must be conducted under the proposed standard. Planners will be required to address the impact of the unavailability of long lead-time critical equipment in a manner consistent with their entity's spare equipment strategy. The proposed standard also provides limitations on the conditions under which planned load loss is permitted. Proper assessments conducted in accordance with the proposed standard will include an entity's criteria outlining acceptable voltage limits and deviations as well as the criteria used for analysis of instability. These assessments will then be distributed to affected entities for the purpose of facilitating a peer review so that entities may coordinate and improve their planning assessments across an Interconnection.

Proposed TPL-001-2 addresses twenty-seven Commission directives issued in Order No. 693 and subsequent orders as well as addressing numerous other concerns expressed by

stakeholders, including the industry and the Commission Staff, during the development of the standard. Twenty-four of the responses to the Commission's directives directly conform to the directives issued. The standard drafting team addressed an additional three directives through equally effective and efficient solutions as permitted in Order No. 693.[4]

Accordingly, the proposed TPL-001-2 Reliability Standard should be approved because it serves the important reliability goal of ensuring that a Transmission System is planned to operate reliably under normal and Contingency conditions. Additionally, the proposed standard improves uniformity and transparency in the planning process and clarifies the instances where planners may utilize load loss. This standard will improve achieve reliability performance beyond that achieved by the previous standards being replaced.

The proposed TPL-001-2 Reliability Standard was approved by a ballot pool that was conducted from July 13 to July 24, 2011. With a 94.33 percent quorum participating in the ballot; the proposed Reliability Standard achieved a weighted segment approval vote of 75.37 percent. The proposed Reliability Standard thus achieved the required two-thirds weighted segment vote and at least a 75 percent quorum of the ballot pool. The Transmission System Planning Performance Requirements Reliability Standard was approved by the NERC Board of Trustees on August 4, 2011.

IV. BACKGROUND

a. Regulatory Framework

By enacting the Energy Policy Act of 2005,[5] Congress entrusted FERC with the duties of approving and enforcing rules to ensure the reliability of the Nation's bulk power system, and

[4] *Mandatory Reliability Standards for the Bulk-Power* System, Order No. 693, FERC Stats. & Regs. ¶ 31,242 (2007), *order on reh'*g Order No. 693-A, 120 FERC ¶ 61,053 (2007)("Order No. 693") at P 31.
[5] Energy Policy Act of 2005, Pub. L. No. 109-58, Title XII, Subtitle A, 119 Stat. 594, 941 (2005) (codified at 16 U.S.C. § 824o).

with the duties of certifying an Electric Reliability Organization ("ERO") that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215 states that all users, owners, and operators of the BPS in the United States will be subject to Commission-approved Reliability Standards.

b. Basis for Approval of Proposed Reliability Standard

Section 39.5(a) of FERC's regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes to become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes to be made effective. The Commission has the regulatory responsibility to approve standards that protect the reliability of the BPS. In discharging its responsibility to review, approve, and enforce mandatory Reliability Standards, FERC is authorized to approve those proposed Reliability Standards that meet the criteria detailed by Congress. The Federal Power Act states, "the Commission may approve, by rule or order, a proposed Reliability Standard or modification to a Reliability Standard if it determines that the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest."[6]

When evaluating proposed Reliability Standards, the Commission is expected to give "due weight" to the technical expertise of the ERO.[7] The technical expertise of the ERO is derived from the SDT. For this project, the SDT consisted of 13 industry experts with over 395 years of collective experience. The SDT included several registered professional engineers, a number of individuals with advanced engineering degrees, and industry thought leaders that generously lend their expertise to NERC and other professional organizations such as the Institute of Electrical and Electronics Engineers ("IEEE"), the International Council on Large

[6] Section 215(d)(2) of the FPA, 16 U.S.C. § 824o(d)(2) (2005).
[7] *Id.*

Electric Systems ("CIGRE"), and the Electric Power Research Institute ("EPRI"). The SDT members on this project provided a diversity of transmission planning experience ranging across North America, including both the continental United States and Canada. A detailed set of biographical information for each of the team members is included along with the SDT roster in **Exhibit G**.

Order No. 672 provides guidance on the factors the Commission will consider when determining whether proposed Reliability Standards meet the statutory criteria.[8]

c. Basis for Proposed Changes to Reliability Standards

The proposed Reliability Standard, TPL-001-2 — Transmission System Planning Performance Requirements, is intended to ensure that a set of coordinated Planning Assessments are in place and that planners have engaged in system planning based on established performance criteria. The proposed standard will apply to Planning Coordinators and Transmission Planners.

The proposed standard represents a substantial revision yielding significant improvements relative to the current set of enforceable standards. This project advances the overall quality of the transmission planning ("TPL") standards group, eliminating gaps in the requirements, removing ambiguity, eliminating the "fill-in-the-blank" components, and addressing numerous FERC regulatory directives, as highlighted here and shown in **Exhibit D**.

Highlights of the improvements are that the proposed standard:

- Clarifies when loss of load may be utilized for Transmission Planning drawing distinctions between Consequential Load Loss and Non-Consequential Load Loss
- Provides a clear requirement for the Transmission Planner and Planning Coordinator to maintain System models for performing studies by requiring:

[8] *Rules Concerning Certification of the Electric Reliability Organization; Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards, FERC Stats. & Regs.*, ¶ 31,204 at PP 320-338 ("Order No. 672"), *order on reh'g*, FERC Stats. & Regs. ¶ 31,212 (2006) ("Order No. 672-A").

- A direct linkage to the MOD-010-0 and MOD-012-0 Reliability Standards
- That items from Corrective Action Plans need to be included in the models
- That projected system conditions shall be represented
- Specified list of items to be represented in the models

- Requires distribution of Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. Planning Assessments must also be distributed to other registered entities with a reliability-related need that submit a written request for the information. This will allow all of an applicable entity's peers to review Planning Assessments for events that will impact their System.
- Requires an annual Planning Assessment that:
  - Addresses both the Near-Term Transmission Planning Horizon and the Long-Term Transmission Planning Horizon
  - Requires steady state, short circuit, and stability analysis supported by required studies
- Requires that studies shall be based on:
  - A Contingency list for planning events and extreme events
  - Simulation of the removal of multiple elements where a protection system or other automatic control are expected to disconnect them for a Contingency
  - Tripping of elements that are expected to be disconnected because of voltage ride-through issues, relay loadability issues or transient swings
- Includes sensitivity studies varying one or more conditions by a sufficient amount to stress the system
- Addresses the need to plan for the unavailability of major equipment with a lead time of one year or more based on an entity's spare equipment strategy
- Qualifies when past studies may be used to support the Planning Assessment
- Requires the creation of System deficiencies lists and Corrective Action Plans when system analyses indicate an inability to meet performance requirements

- Requires criteria for acceptable System steady-state voltage limits, post-Contingency voltage deviations, and transient voltage response
- Requires registered entities to submit the criteria or methodology utilized to identify System instability
- Determines and identifies individual or joint responsibilities for the Planning Assessment
- Includes a complete revision of Table 1 to clearly articulate the contingencies that must be evaluated to ensure that the planned System meets the performance requirements. These changes include changing the classification of the events, clarifying events and Fault types, and removing the ambiguity of performance requirements.
- For extreme events, the revised Table 1 describes System performance for Wide Area events, including cyber attacks, and the standard clearly defines when further evaluation is required

NERC is also requesting that FERC approve five new definitions:

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies.

The proposed revisions consolidate requirements from four existing standards into one standard. Thus NERC is proposing to retire the following four Reliability Standards: (1) TPL-001-1 — System Performance Under Normal Conditions, (2)TPL-002-1b — System Performance Following Loss of a Single BES Element, (3) TPL-003-1a — System Performance Following Loss of Two or More BES Elements, and (4) TPL-004-1 — System Performance Following Extreme BES Events, because they are no longer needed. In addition, NERC is proposing to withdraw two Reliability Standards (1) TPL-005-0 — Regional and Interregional Self-Assessment Reliability Reports, and (2) TPL-006-0.1 — Data From the Regional Reliability Organization Needed to Assess Reliability in their entirety.[9]

As shown in **Exhibit D** the changes in this proposed standard reflect consideration of a number of issues that were captured during NERC's original translation of former Operating Policies and Planning Standards to what are called the "Version 0" standards. Also considered were issues noted during the development of compliance measures for the Phase III and Phase IV Reliability Standards Project developed subsequent to Version 0 development, the development of Violation Risk Factors Project in 2006, Order No. 693, and subsequent FERC Orders.

d. Background of proposed Transmission Planning standard footnotes "9" and "12" to Table 1 and Previously Filed Version 1, Footnote "b"

On March 31, 2011, NERC submitted a Petition for Approval of Four Transmission Planning System Performance Reliability Standards and Retirement of Four Existing Reliability

[9] These two proposed standards were among the group of 24 proposed standards that the Commission withheld action on when it issued Order No. 693, because the standards applied only to Regional Reliability Organizations.

Standards[10] ("March 31 Footnote B Filing") pursuant to FERC's March 18, 2010 Order Setting Deadline for Compliance on the TPL-002-0 standard[11] to comply with the directives in Order No. 693.[12] In the March 31 Footnote B Filing, NERC proposed a solution to FERC's directive from Order No. 693 that is as efficient and effective as the approach described in the directive. On May 17, 2011[13] FERC issued a data request to NERC requesting additional information on NERC's proposed Footnote b, and NERC responded to the data request on June 7, 2011.[14] Procedurally, NERC's proposed Footnote b is still pending in FERC Docket No. RM11-18-000.

For the Commission's reference, the proposed Footnote b of Table 1 for version 1 of the following transmission planning Reliability Standards is identical for each of the four standards:

- TPL-001-1 - System Performance Under Normal (No Contingency) Conditions (Category A), TPL-002-1b - System
- Performance Following Loss of a Single Bulk Electric System Element (Category B),
- TPL-003-1a - System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), and
- TPL-004-1 - System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

Version 1 of these four transmission planning reliability standards was filed with the Commission with the March 31 Footnote B Filing and has not yet been acted on by the Commission. Version 2 of the transmission planning reliability standard TPL-001-2, which is the standard proposed in this filing, replaces in their entirety the four version 1 transmission planning reliability standards identified immediately above. In creating TPL-001-2, the proposed Footnote b of Table 1 of version 1 of the transmission planning reliability standards ("Footnote

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[10] *Petition of the North American Electric Reliability Corporation for Approval of Four Transmission Planning System Performance Reliability Standards and Retirement of Four Existing Reliability Standards*, Docket No. RM11-18-000 (March 31,2011).
[11] *Setting Deadline For Compliance*, 130 FERC ¶ 61,200 (2010).
[12] Order No. 693 at P 1773.
[13] Letter from the Commission seeking additional information from NERC regarding Reliability Standards TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1, Docket No. RM11-18-000 (May 17, 2011).
[14] *Response of the North American Electric Reliability Corporation to the Federal Energy Regulatory Commission's May 17, 2011 Letter Requesting Additional Information Regarding NERC's Request for Approval of Four Transmission Planning System Performance Reliability Standards*, Docket No. RM11-18-000 (June 7, 2011).

b") was modified slightly and carried over as Steady State & Stability Performance Footnotes 9 and 12 ("Notes "9" and 12") in TPL-001-2.

Footnote b reads as follows:

> An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

While proposed Note 9 reads as follows:

> An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.

And Note 12 states:

> An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to address BES performance requirements. When Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss is documented, including alternatives evaluated; and where the utilization of Non-Consequential Load Loss is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

Where Non-Consequential Load Loss is proposed to be defined in TPL-001-2 as: "Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment."

Proposed Notes 9 and 12 addresses the directives from Order No. 693, as clarified in the Commission's June 11, 2010 order denying rehearing and granting partial clarification.[15] In the Commission's June 11 Order, the Commission did not strictly prohibit planning to shed firm Load in all circumstances. The Commission stated:

> 21. [] the above passage from Order No. 693 acknowledged that the ERO could consider the comments of Entergy and Northern Indiana regarding planning for the loss of firm service "at the fringes of various systems," as NERC now characterizes the issue.[f.n. omitted] However, the Commission expressed concern that whatever approach is chosen by the ERO does not reflect a "lowest common denominator," i.e., "[t]he proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice – the so-called 'lowest common denominator' – if such practice does not adequately protect Bulk-Power System reliability." [f.n. omitted] Moreover, the Commission, in the same passage from Order No. 693, then provided a clarification that an entity may seek a regional difference to the Reliability Standard from the ERO for case-specific circumstances. We believe that a regional difference, or a case-specific exception process that can be technically justified, to plan for the loss of firm service "at the fringes of various systems" would be an acceptable approach. Thus, the Commission did not dictate a single solution as NERC and others now claim. In any event, NERC must provide a strong technical justification for its proposal.[16]

NERC addressed FERC's instruction to clarify Footnote b regarding Load loss following a single contingency, specifying the amount and duration of load loss and system adjustments permitted after the first contingency to return the system to a normal operating state. However, NERC did not delete in its entirety the ability of an entity "to plan for the loss of non-consequential load in the event of a single contingency." Rather, both Footnote b and Notes 9 and 12 meet the Commission's objective while simultaneously meeting the needs of industry and respecting jurisdictional bounds. No longer can those registered with NERC as Planning

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[15] *Order Denying Rehearing and Granting Partial Clarification, Denying Request for Stay, and Granting Extension of Time*, 131 FERC ¶ 61,231 (2010)
[16] *Id.* at P 21.

Authorities or Transmission Planners plan to interrupt Load under a Category B (N-1) Contingency event unless the registered functions meet the specified conditions detailed in the Footnote.

After extensive consideration during the standards development process of the Commission's suggestion in Order No. 693 that NERC develop a case-specific exceptions procedure,[17] NERC, through the standards development process, chose a response that NERC believes is at least as efficient and effective as the Commission's suggested process. As described in the March 31 Footnote B Filing, NERC believes that an ERO-sponsored planning process is not likely to be efficient or effective because of complex jurisdictional issues between NERC, FERC, and the many authorities having jurisdiction that would have to be resolved in perhaps forty-eight states and Canada, before implementation could occur. A NERC-centered process would at best duplicate planning actions going on elsewhere (where resource allocation decisions are actually being made), and such a process could lead to inconsistent results. It appeared to the industry and to NERC that a more reasonable and expeditious path would be to rely on existing stakeholder processes, many of which are driven by other FERC orders. Such processes would be more likely to engage the appropriate local-level decision-makers and policy-makers. For these reasons, NERC's March 31 Footnote B Filing proposed an efficient and effective alternative in responding to the directive and implementing Footnote b planned outages by leveraging current, existing stakeholder processes already established to address transmission planning choices. The same rationale applies to Notes 9 and12 as well.

FERC already mandates transmission planning processes through specific requirements addressed in Order No. 890 and subsequent orders. Order No. 890 reformed the *pro forma* Open Access Transmission Tariff to require each public utility transmission provider to have a

[17] Order No. 693 at P 1794.

coordinated, open, and transparent regional transmission planning process. FERC's recent Order No. 1000 builds upon Order No. 890 by broadening participation in regional transmission planning processes.[18] Specifically, Order No. 1000 requires that each public utility transmission provider participate in a regional transmission planning process that produces a regional transmission plan.[19]

FERC's Order No. 1000 bolsters Commission-mandated transmission planning processes by broadening participation in stakeholder processes. FERC enhanced transmission planning requirements by finding that "it is necessary to have an affirmative obligation in these transmission planning regions to evaluate alternatives that may meet the needs of the region more efficiently or cost-effectively."[20] FERC stated that "In the absence of the reforms implemented below, we are concerned that public utility transmission providers may not adequately assess the potential benefits of alternative transmission solutions at the regional level that may meet the needs of a transmission planning region more efficiently or cost-effectively than solutions identified by individual public utility transmission providers in their local transmission planning process."[21]

Additionally, Order No. 1000 provides a mechanism for Regional Entity engagement and broadens the scope to include public policy considerations. FERC's reinforcement of stakeholder processes in Order No. 1000 avoids the competing jurisdictional concerns that could result from a new process created exclusively for the purpose of assuring reliability.

The planning principles articulated by the Commission in Order No. 1000 reinforces NERC's position presented in the March 31, 2011 Footnote b filing, NERC's June 17, 2011

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[18] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 136 FERC ¶ 61,051, Order No. 1000 (2011) at P 1, 3, Sec. III. ("Order No. 1000").
[19] *Id.* at P 80
[20] *Id.*.
[21] *Id.* at P 81.

response to the data request, and reiterated in this petition for approval of the proposed TPL-001-2 standard. Specifically, the Commission, through Order No. 1000, is promoting a stakeholder process that includes: coordination; openness; transparency; information exchange; comparability; dispute resolution; and economic planning studies.

Accordingly, relying on existing stakeholder processes to implement Footnote b and Note 9, including stakeholder processes developed under FERC Order Nos. 890 and 1000, will provide mechanisms for NERC and the Regional Entities to effectively monitor an entity's planned interruptions of Firm Transmission Service by making these planned interruptions visible. Proposed Note 9 recognizes that it is generally inappropriate to plan to interrupt Firm Transmission Service to meet reliability performance metrics. However, in limited circumstances, an entity may rely on planned Load shedding. The magnitude and timeframe for which the entity plans to rely on Load shedding will be limited to circumstances where its use is documented and subject to an open and transparent stakeholder process.

The language in Note 12 of the proposed TPL-001-2 standard specifically provides that: "[w]hen Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss is documented, including alternatives evaluated; and where the utilization of Non-Consequential Load Loss is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments." In other words, the language in Note 12 specifically provides for a review of how the Non-Consequential Load Loss was determined, whether any alternatives were evaluated, and how the determination to plan to shed Non-Consequential Load Loss was made through an open and transparent stakeholder process.

In an audit or spot check of an entity, one of the first questions asked will be whether the entity planned on interrupting Firm Demand to meet reliability performance requirements. If so, the entity will be required to provide all relevant documents pertaining to such transmission planning decisions, including any documentation used to make such a determination through an open and transparent stakeholder process. This documentation should include the specifics of what Load will be shed and under what circumstances. The entity will also be required to provide a description of other alternatives the entity considered and a description of the stakeholder process in which the decision to rely on Load shedding was made. Additionally, the audit or spot check will include a discussion of the activity or participation by the relevant governmental authority with jurisdiction over the matter. Based on all of this information, NERC or the Regional Entities will be able to determine whether the decision by the entity to rely on Load shedding to meet performance requirements was reasonable given the circumstances.

Accordingly, for the reasons stated in NERC's March 31 Footnote B Filing, NERC's June 17, 2011 response to FERC's data request, and in this petition, the approach proposed in Notes 9 and 12 presents an equally efficient and effective alternative to responding to the Commission's Order No. 693 directive because many of the stakeholder processes that will be used in planning decisions are already in place, as implemented by FERC in Order No. 890 and in state regulatory jurisdictions, or will be in place, pursuant to FERC's Order No. 1000. More localized decision-making is preferable to an ERO-centric exceptions process because of the inevitable debate about cost which is implicit in planning decisions. Additionally, the approach is effective because the ERO process will be able to monitor any planned use of Notes 9 and 12 through audits of the transmission planners. These audits will ensure that the use of Notes 9 and

12 is being addressed under the open and transparent guidelines established there. For these reasons, the approach presented in Notes 9 and 12 fulfills the FERC directive in an equally efficient and effective manner, and is achievable in a reasonably short time frame having gained the acceptance of the industry. Proposed Notes 9 and 12 raises the bar because it now requires full documentation and disclosure of planning choices impacting reliability.

V. REGULATORY DIRECTIVES

The SDT addressed twenty-seven directives issued by the Commission in Order No. 693.[22] These directives are presented below with resolutions proposed by the SDT. The text of the complete proposed standard TPL-001-2— Transmission System Planning Performance Requirements is included in **Exhibit A**. These resolutions are summarized in **Exhibit D** along with the resolutions to industry concerns.

1. Paragraph 1691(of Order No. 693) - Ensure that the planning requirements are specific enough to promote rigor and consistency in assessments and provide clear and measurable rules for mandatory and enforceable Reliability Standards.
    - SDT resolution: The SDT directly addressed the specifics of this directive. The proposed standard strikes a balance between rigidity for specific requirements (for example, Table 1 event descriptions and performance requirements) and flexibility where individual system concerns are best served through engineering judgment (for example, Requirement R2, Parts 2.1.4 & 2.4.3 list the factors and sensitivities that should be addressed to stress the System). The proposed Reliability Standard ensures that the planning process and the BES are robust enough to be able to withstand a range of probable

[22] *Mandatory Reliability Standards for the Bulk-Power* System, Order No. 693, FERC Stats. & Regs. ¶ 31,242 (2007), *order on reh'*g Order No. 693-A, 120 FERC ¶ 61,053 (2007)("Order No. 693").

contingencies while reliably serving customer demand and preventing identified outages. Conversely the standard is flexible enough to accommodate a broad range of system conditions over a planning horizon to account for the lead times needed to place facilities in service. This will promote rigor and consistency in assessments and provide clear and measurable rules for mandatory and enforceable standards.

2. Paragraph 1691 - The planning standards should require planning entities to consider the probable range of contingencies when determining critical system conditions but only those deemed to be significant need to be assessed with the documentation provided that explain the rationale for selection. Additionally, the Commission stated "that it would be appropriate for planning entities to conduct sensitivity studies to 'bracket' the range of probable outcomes."[23]
    - SDT resolution: The SDT has directly adopted the specifics of this suggestion. In the proposed TPL-001-2, Requirement R2, Part 2.1 mandates the types of sensitivity studies that must be run. Building upon Requirement R2, Requirement R3 demands that an entity must perform Planning Assessments that meet system performance criteria for steady-state conditions. Requirement R3, Part 3.1 requires analysis of those contingencies that may cause the most severe system impact as determined in Requirement R3, Part 3.4. A similar expectation is found in Requirement R4 for stability studies in Parts 4.1 and 4.4.

[23] Order 693 at P 1694.

3. Paragraph 1692 - Consider integrating TPL-001 through TPL-004 into a single Reliability Standard.
    - SDT resolution: The SDT directly adopted this directive. The proposed TPL-001-2 incorporates TPL-001-1 through TPL-004-1.
4. Paragraph 1693 - Submit an informational filing, in addition to regional criteria, addressing all utility and RTO/ISO differences in transmission planning criteria that are more stringent than those specified by the TPL group of Reliability Standards.
    - SDT resolution: The data was collected and filed by the ERO and distributed to the SDT. The SDT reviewed the compiled information and found that the majority of the planning practices identified in the survey were based on local conditions and not applicable to a continent-wide standard. However, one common practice, a generation outage coupled with another single Contingency without load loss treated as a single Contingency, was adopted by the SDT as part of planning category P3 (loss of generator unit followed by System adjustments ((g-1)+(n-1)) in Table 1.
5. Paragraph 1716 - System performance should be assessed based on single contingencies that faithfully duplicate what will happen in the actual power system.
    - SDT resolution: The SDT directly adopted the specifics of this directive in Requirement R3, Part 3.3.1 and Requirement R4, Part 4.4.1 of the proposed standard.
6. Paragraph 1716 - Entities that have planned and designed their systems on the basis of a different approach to single contingencies based on the existing standards should work with NERC in developing plans to transition to this new approach.

- SDT resolution: The SDT directly addressed this directive. The SDT considered this issue and determined that a phased implementation approach to this proposed standard will allow entities to transition to the new or changed requirements in this proposed standard. Consequently, a phased implementation plan has been proposed.

7. Paragraph 1719 - Consider appropriate revisions to the Reliability Standards to address cyber security events. The system impacts of cyber security events are best addressed in the TPL group of Reliability Standards, particularly TPL-004-0 (extreme events).
    - SDT resolution: The SDT has addressed this directive by adding Cyber security events to the list of steady state Wide Area extreme events in Table 1, Steady State, 3.a.v, in proposed TPL-001-2.
8. Paragraph 1755 - Require a peer review of planning assessments with neighboring entities.
    - SDT resolution: The SDT developed an equally effective and efficient manner to provide for the appropriate sharing of information with neighboring systems. This is covered in proposed TPL-001-2, Requirement R3, Part 3.4.1, Requirement R4, part 4.4.1, and Requirement R8.
    - Requirement R8 addresses the appropriate sharing of information with neighboring systems. The SDT believes that requiring applicable entities to distribute to adjacent Planning Coordinators and Transmission Planners is a better approach than a "peer review" approach, as an entity may always decline an offer to participate in a peer review even when they should

participate. The distribution approach means that the entity will always receive the Planning Assessment. Requirement R8 ensures that information is shared in a timely manner[24] with those affected and input from those systems is received, without dictating how the two-way sharing must take place. In the course of the continuing cycle of Planning Assessments, comments from other entities at the end of a planning cycle will be utilized at the beginning of the next cycle as the planner moves forward in time. This approach does not dictate how information is shared but still makes certain that the goal is achieved. This is an equally effective and efficient approach to the directive in Order No. 693.

- To cover those entities that may not be adjacent, the proposed standard requires the Transmission Planner and Planning Coordinator to distribute the Planning Assessment to additional entities that exhibit a "reliability-related need," who have requested information in writing, and require a documented response to their comments. This is an equally, effective and efficient manner to provide for the appropriate sharing of information with neighboring systems.
- Requirement R3, Part 3.4.1 and Requirement R4, Part 4.4.1 address the concern expressed by the Commission regarding sharing information and coordinating responses to system contingencies that may affect adjacent[25] Systems.

[24] Requirement R8 requires distribution to adjacent Planning Coordinators and Transmission Planners within 90 days and to others with a reliability related need that submits a request within 30 days of receiving such a request.
[25] Although Order No. 693 uses the term "neighboring" the proposed Reliability Standard uses "adjacent." "Adjacent" better clarifies the intent of the requirement to cover transmission systems that interconnect with the

9. Paragraph 1759 - Modify Requirement R1.3 to substitute the reference to Regional Reliability Organization with Regional Entity.
    - SDT resolution: The SDT directly adopted the specifics of this directive. All references to the Regional Reliability Organization have been removed. Furthermore, all new and future revisions to all NERC Reliability Standards will use the term Regional Entity instead of the previous term Regional Reliability Organization.
10. Paragraph 1765 - Determine critical system conditions and study years by conducting sensitivity analysis with due consideration of the factors outlined by the Commission.
    - SDT resolution: The SDT directly addressed the specifics of this directive. This is covered in proposed TPL-001-2, Requirement R2, Part 2.1.4 for steady state and Requirement R2, Part 2.4.3 for stability analyses. Inclusion of sensitivity analyses represent an important improvement to the proposed planning standard aimed at better understanding a range of probable outcomes of potential system conditions. Proposed TPL-001-2, Requirement R1 requires the System model to represent projected System conditions. Specifically, the proposed Reliability Standard requires planners to assess the potential impact of one or more changes to these assumed conditions which stress the system. The results of the sensitivity analyses help the planner develop a portfolio of information by identifying performance issues related to credible assumptions. This information is valuable to the planner to identify which set of assumptions have the most severe impacts on the performance of

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entity's System whereas "neighbor" is vague and could include systems in the vicinity of an entity's system, but not directly connected.

the planned system. Because the end of one planning cycle is the beginning of the next planning cycle, the results of the sensitivity studies will be available to the planner as they develop the following year's projected System conditions and to direct additional sensitivity analysis in future assessments.

11. Paragraph 1769 - Address concerns with footnote (a) of Table 1 with regard to applicability of emergency ratings and consistency of normal ratings and voltages with values obtained from other reliability standards.
    - SDT resolution: The SDT directly addressed the specifics of this directive. Proposed TPL-001-2, Requirement R3, Part 3.1 requires that studies shall be performed for planning events to determine that the BES meets the performance requirements in Table 1. Table 1, header notes 'e' and 'f' are part of the performance requirements of Table 1. Header note 'e' states that planned system adjustments must be executable within the time duration applicable to the facility ratings. Header note 'f states that applicable facility ratings shall not be exceeded.
12. Paragraph 1773 – Submit a modification to Footnote (b) that clarifies that firm load shedding or curtailment of firm transfers is not allowed as part of the system adjustments.
    - SDT resolution: NERC addressed this directive in *Project 2010-11 TPL Table 1* and its subsequent petition requesting approval of four TPL standards

submitted March 31, 2011.[26] The SDT has transferred that solution to the proposed TPL-001-2 as footnotes 9 and 12 in Table 1.

13. Paragraph 1786 - Require assessments of planned outages of critical long lead-time equipment, consistent with an entity's spare equipment strategy.
    - SDT resolution: The SDT directly adopted the specifics of this directive. This is covered in proposed TPL-001-2, Requirement R2, Part 2.1.5. The proposed requirement addresses steady state conditions to determine system response when equipment is unavailable for prolonged periods of time. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 under the conditions that the system is expected to experience during the possible periods of unavailability of the long lead-time equipment. Stability impacts related to outages of critical long lead-time equipment will not be addressed in a separate requirement but rather will be analyzed in the normal planning process in the evaluation of multiple Contingency events. Additionally, any known equipment outages of six months or more must be included in the modeled system in proposed TPL-001-2, Requirement R1.
14. Paragraph 1787 - Requires all generators to ride through the same set of Category B and C contingencies, as required by wind generators in Order No. 661, or to simulate those generators without this capability as tripping during modeling.
    - SDT resolution: The SDT directly adopted the specifics of this directive in proposed TPL-001-2, Requirement R3, Part 3.3.1.1 and Requirement R4, Part

[26] *Petition of the North American Electric Reliability Corporation for Approval of Four Transmission Planning System Performance Reliability Standards and Retirement of Four Existing Reliability Standards*, Docket No. RM11-18-000 (March 31, 2011) ("March 31 Petition").

4.3.1.1. No distinctions are made among different generation resources in the proposed Requirements.

15. Paragraph 1788 - Consider comments clarifying that for operations purposes clarifying that the N-1 state is always analyzed from the conditions being experienced.
    - SDT resolution: The SDT considered the comments and agrees with the Commission that these conditions are real-time oriented and not part of a planning process. N-1 conditions are studied as part of planning events P1 and P2 in the proposed TPL-001-2, Table 1.
16. Paragraph 1789 - Document the load models used in system studies and the supporting rationale for their use.
    - SDT resolution: The SDT directly addressed the specifics of this directive in proposed TPL-001-2, Requirement R2 which requires entities to document assumptions made in their Planning Assessments.
17. Paragraph 1790 - Clarify the phrase "permit operating steps necessary to maintain system control" in footnote (a) to clarify the use of emergency ratings.
    - SDT resolution: The SDT directly addressed the specifics of this directive. Proposed TPL-001-2, Requirement R3, Part 3.1 requires performing studies for planning events to determine whether the BES meets the performance requirements in Table 1. Additionally, Table 1, header notes 'e' and 'f,' that are a part of the performance requirements of Table 1, demand more details. Header note 'e' states that planned system adjustments must be executable

within the time duration applicable to the facility ratings. Header note ‘f states that applicable facility ratings shall not be exceeded.

18. Paragraph 1794 – The standard should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency. The standard should be clarified accordingly.
    - SDT resolution: This directive was addressed in *Project 2010-11 TPL Table 1* and the SDT has transferred that solution to the proposed TPL-001-2 as footnotes 9 and 12 in Table 1.
19. Paragraph 1795 - Consider developing a ceiling on the amount and duration of consequential load loss that will be acceptable.
    - SDT resolution: The directive was to “consider” the need for a ceiling on load and duration and if “appropriate” to develop the ceiling through the standards development process. The SDT originally included requirements covering the reporting of the magnitude and duration of Consequential Load Loss. Industry overwhelming protested the inclusion of these requirements which were panned as additional administrative tasks that did not address any reliability need. Initial comments submitted by industry focused more on the topic of duration than magnitude so the SDT attempted to craft a compromise position. The duration element of the requirement was deleted and a revised requirement covering only magnitude of Consequential Load Loss was crafted and posted for comment.
    - The SDT was again overwhelmed by negative industry comments pushing back about the inclusion of an administrative task without a reliability need in

a Reliability Standard. At that point, the SDT discussed the matter at length, determined they agreed with the industry comments, and decided to delete the requirement in its entirety. The SDT addressed the directive to "consider developing a ceiling" as directed in Order No. 693 as evidenced in meeting notes and by its attempt to include the requirements for an equally effective method in the proposed Reliability Standard. Therefore, the SDT considers that it has fulfilled its obligation in this regard.

20. Paragraph 1796 - Clarify footnote (b) in regard to load loss following a single contingency to specify the amount and duration of consequential load loss and what types of system adjustments are permitted after the first contingency to return the system to a normal operating state, provided these adjustments can be accomplished within the time period allowed by the short term or emergency ratings.
    - SDT resolution: NERC addressed this directive in *Project 2010-11 TPL Table 1*, the March 31 Petition,[27] and the SDT has addressed a solution to the proposed TPL-001-2 in footnotes 9 and 12 in Table 1.
21. Paragraph 1818 - Clarify the term "controlled load interruption".
    - SDT resolution: The term "controlled load interruption" is not included in the proposed TPL-001-2 Reliability Standard.
22. Paragraph 1820 - The Reliability Standard must define and document the proxies necessary to simulate cascading outages.

[27] *Id.* See also *Response of the North American Electric Reliability Corporation to the Federal Energy Regulatory Commission's May 17, 2011 Letter Requesting Additional Information Regarding NERC's Request for Approval of Four Transmission Planning System Performance Reliability Standards*, Docket No. RM11-18-000, (June 7, 2011).

- SDT resolution: The SDT directly adopted the specifics of this directive. This is covered in proposed TPL-001-2 in Requirement R6. This requirement mandates that the entity must define and document its criteria or methodology (proxies) used in its analysis.

23. Paragraph 1821, 1835 - Tailor the purpose statement to reflect the specific goal of the standard.

    - SDT resolution: The SDT directly adopted the specifics of this directive. The purpose statement of proposed TPL-001-2 has been rewritten to reflect the specific goal of the proposed standard.

24. Paragraph 1822 - Address Nuclear Regulatory Commission ("NRC") concerns as described in TPL-003 through the standards development process.

    - SDT resolution: The SDT considered the comments and agrees with the Commission that the NRC's concerns involve real-time issues and not the planning process. N-1 conditions are studied as part of planning events P1 and P2 in the proposed TPL-001-2, Table 1.[28]

25. Paragraph 1833 - Identify options for reducing the probability or impacts of extreme events that cause cascading.

    - SDT resolution: The SDT directly addressed the specifics of this directive. This is covered in proposed TPL-001-2, Requirement R3, Part 3.5 & Requirement R4, Part 4.5. The requirements state that if an analysis concludes cascading will be caused by the occurrence of certain extreme events, applicable entities shall conduct an evaluation of possible actions

[28] *See* 14 above addressing P 1788.

designed to reduce the likelihood of those events from occurring or mitigate the consequences and adverse impacts of the event.

26. Paragraph 1836 - Expand the list of category D events to include recent actual events.
    - SDT resolution: The SDT has directly adopted the specifics of this directive. The list of Table 1 Steady State and Stability Extreme Events has been expanded to include wide-area events in extreme events 3b (steady state) and 2f (stability).
27. Paragraph 1841 - Utilize input from the Commission's technical conferences on regional planning as directed in Order No. 890 into the Reliability Standards development process to improve this standard.
    - SDT resolution: The SDT directly adopted the specifics of this directive. The SDT utilized knowledge gained from the Commission's technical conferences and added Requirement R8 to proposed TPL-001-2 to facilitate the distribution of planning results and to provide a mechanism for obtaining input from various entities. Additionally, TPL-001-2 will complement FERC's ongoing transmission planning efforts set forth in Order Nos. 890 and 1000.

In addition to addressing the FERC directives, the SDT has incorporated many other clarifications, improvements, and enhancements to the existing standards as outlined below:

- In Footnote 461 of Order No. 693, FERC stated "Consequential load is the load that is directly served by the elements that are removed from service as a result of the Contingency." The proposed definition for Consequential Load Loss in the proposed Reliability Standard states, "All Load that is no longer served by the Transmission

system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault." The proposed definition parallels the language required for Contingency analyses mandated in the proposed TPL-001-2, Requirement R3, Part 3.3.1 and Requirement R4, Part 4.3.1.

- In addition to the definition of Consequential Load Loss, the SDT determined that a corresponding definition for Non-Consequential Load Loss was necessary to adequately describe how a planner may consider planned load loss for specific events. These events are described in Table 1 of the proposed TPL-001-2. In the proposed standard, Non-Consequential Load Loss is defined as:

> Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Importantly, this clarifies that interruptible load, *i.e*. load that is under contract or agreement for curtailment, is not Non-Consequential Load. Additionally, the definition clarified that "the response of voltage sensitive Load" or "Load that is disconnected from the System by end-user equipment" are not Non-Consequential Load. The SDT determined that the planner cannot control the sensitivity of load to voltage excursions or whether load may be disconnected by end-user equipment under certain conditions. The planner may have a valid plan that may include load loss that the planner cannot control because of one or both of these situations. The planner should not be held accountable for those situations. Consequently, the planner should not depend on this load loss to meet the performance requirements. Therefore, the SDT added Head Note "i" to Table 1 – Steady State & Stability Performance Planning Events,

to ensure that the planned system can meet performance requirements while serving the load, including the voltage sensitive load. Head note "i" states that "The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements."

- The Implementation Plan consists of three effective dates – 12 months, 24 months, and 84 months following regulatory approval – that provides industry the time needed to transition to new reliability expectations.
    - Two of the eight reliability requirements (Requirements R1 and R7) of proposed standard TPL-001-2 are proposed to become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval.
        - In Requirement R1, the Transmission Planner and Planning Coordinator must develop and maintain system simulation models representing projected system conditions.
        - In Requirement R7, the Transmission Planner and Planning Coordinator will work together to identify each entity's individual and joint responsibilities for completing the required planning studies associated with the standard. The 12 month period is necessary to allow planners sufficient time to meet these new, more detailed modeling and coordination requirements.
    - The remaining requirements of the standard – Requirements R2 through R6 and R8 – are proposed to be effective on the first day of the first calendar

quarter, 24 months after applicable regulatory approval (except for certain performance requirements stated in Table 1 that represent a significant change for industry related to planning of the BES transmission system). This 24 month period is needed to allow the applicable entities to develop, perform, and validate new or modified studies, methodologies, assessments, and procedures to implement and meet the proposed requirements in TPL-001-2. The effective date allows sufficient time for proper assessment of the available options necessary to create a viable Corrective Action Plan compliant with the proposed TPL-001-2.

- An extended implementation period beyond the 24 month milestone is permitted for situations where loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain planning events. In such cases, the proposed TPL-001-2 allows an additional 60 months because Corrective Action Plans created by the Transmission Planner and Planning Coordinator may have significant budget, siting, permitting, and construction impacts on many Transmission Owners and developers. During the extended 60 month transition period, the Transmission Planner and Planning Coordinator may continue to rely on Non-Consequential Load Loss and interruption of firm transfers within its submitted Corrective Action Plan related to the select planning events.
- As stated in the implementation plan (**Exhibit B)**, for 84 months beginning the first calendar day of the first calendar quarter following approval, Corrective Action Plans applying to certain categories of Contingencies and

events identified in TPL-001-2, Table 1 will be allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service that would not otherwise be permitted by the requirements of TPL-001-2.

- Requirement R1
    - Requirement R1 of the proposed TPL-001-2 explicitly requires the Transmission Planner and Planning Coordinator to maintain System models. This represents an improvement over the existing TPL standards where the requirement to maintain the model was only implied, not explicitly required.
    - The proposed TPL-001-2 also provides a specific list of items required for the System models in Requirement R1, Part 1.1. The proposed TPL-001-2 links the models to the data provided in accordance with MOD-010-0 and MOD-012-0 to ensure that the planner utilizes data that is consistent with the data provided to the planner but still allows the data to be supplemented by data from other sources as needed. The proposed TPL-001-2, Requirement R1 also incorporates Requirement R1.4 from the existing TPL standard by including items represented in the Corrective Action Plan.
    - Requirement R1 also requires that the System models represent projected System conditions. The planner is required to model the items that are variable, such as load and generation dispatch, based specifically on the expected system conditions. For example, for a 60% load level study, the planner should model the load at 60% of the peak value and the generation that is expected to be operating at that load level. Therefore, generation with low run times, such as combustion turbines, would not be utilized for this load

level, unless the planner had specific knowledge that they would be expected to operate for this load level.

- Requirement R1, Part 1.1.2 mandates that the System models "shall represent … known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months." Requirement R1.3 of the existing TPL-001-1 standard states, "The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)." Requirement R1.3.12 of the existing TPL-002-0b standard addresses planned (including maintenance outages) and is one of the following categories referenced in Requirement R1.3. Therefore, in the existing TPL-002-0b standard, the specific elements selected to be evaluated as a part of Requirement R1.3.12 were selected by the Transmission Planner or Planning Coordinator and must be acceptable to the associated Regional Reliability Organization. The SDT determined that having the planner select specific planned outages to include in their studies was not the appropriate manner to address this issue. Furthermore, the Regional Entities should not have the role of determining the appropriateness for inclusion or exclusion of specific planned outages in the studies in today's regulatory framework. Therefore, the SDT adopted a bright-line test to determine whether an outage should be included in the system models.
- The SDT determined that the appropriate manner to address planned outages, including maintenance outages, in the planning horizon begins with determining what length of outages could readily be scheduled without

impacting BES reliability at peak load conditions. The SDT determined that, in the planning horizon, a six-month or longer outage duration would necessarily extend over a seasonal peak load period and should be included in the planning models. Requirement R1.3.12 of the existing standard included Protection Systems or their components in the items that could be selected by the planner. However, since Protection System maintenance or other outages are not ever anticipated to last six months, this language was not included in the proposed standard. The language in proposed TPL-001-2, R1, Part 1.1.2 removes the ambiguity of what the planner needs to include in the specific studies and requires the planner to evaluate all of the six-month or longer duration outages within its system. These outages are the significant outages that need to be evaluated in the planning horizon to ensure that the outages can be accommodated and still meet performance requirements.

- Requirement R2
    - To further enhance the evaluation of known outages, the SDT added Requirement R2, Part 2.1.3 that requires the planner to assess system performance utilizing a current annual study or qualified past study for each known outage with a duration of at least six months for Table 1, P1 events. This requirement ensures planners evaluate every known outage with known duration of six months or more, even if the known outage is not within one of the study years selected by the planner as required by the proposed Requirement R2, Part 2.1.1 or 2.1.2.

- The existing TPL standards refer to valid assessments, but ambiguity exists regarding what constitutes a valid assessment leading to inconsistency. Subjectivity that was allowed before is now replaced with specifics. The requirements and parts of proposed TPL-001-2 leave no doubt as to what a valid study must entail, timeframes for use of past studies, minimum conditions (years and peak/off-peak conditions), what needs to be included in the model, and what performance must be achieved.
- The proposed TPL-001-2 Requirement R2 mandates that short-circuit studies must be included in the assessment. Short-circuit studies were not included in the existing TPL standards. Short-circuit studies ensure that when a planner is considering System improvements that the interrupting capability of the breakers is addressed. Therefore, the inclusion of short-circuit studies represents a significant improvement in the proposed TPL-001-2 over the prior TPL standards.
- The proposed TPL-001-2 clarifies that qualified past studies can be utilized in the analysis while tightly defining the qualifications for those studies. Currently, there are no limits on the use of past studies in the existing TPL standards. The use of qualified past studies allows an entity to continue to use validated studies to complete its assessment. This allows computational efficiency, maintains the legitimacy of the studies, and allows the planner to better utilize limited resources.
- The proposed TPL-001-2 standard provides greater clarity for near-term planning horizon steady-state and stability studies. The existing TPL

standards are vague and open to entity discretion regarding the studies to be performed. Proposed TPL-001-2, Requirement R2, Parts 2.1 and 2.4 now explicitly require both peak and off-peak studies for both steady-state and stability. This change provides the industry greater clarity over the existing standard.

- The SDT has introduced sensitivity analyses to be completed as part of a Planning Assessment in proposed TPL-001-2, Requirement R2, Part 2.1.4 (for steady state) and Requirement R2, Part 2.4.3 (for stability). Conducting a sensitivity analysis is an important improvement to the proposed standard that will improve planners' understanding of the range of probable outcomes of potential system conditions. Sensitivity analyses demand that planners assess the potential impact of one or more changes in the assumed System conditions to stress the System. The results of the sensitivity studies help planners develop a portfolio of information by identifying potential performance issues related to credible assumptions. This information is valuable to the planner to identify which set of assumptions have the most severe impact on the performance of the planned system. Because the end of one planning cycle is the beginning of the next planning cycle, the results of the previous sensitivity studies will be available to the planners when they develop their System's projected conditions and also for directing additional sensitivity analysis in the following year's assessment. Furthermore, the proposed Requirement R2, Part 2.7.2 addresses the issue of how to address performance deficiencies

identified in multiple sensitivity studies. This represents a significant improvement in the planning process.

- An entity's spare equipment strategy is addressed in proposed Requirement 2.1.5 by requiring that entities account for equipment that will be unavailable for prolonged periods of time when determining the system response for steady state conditions. Studies shall be performed for the P0, P1, and P2 categories identified in Table 1 under the conditions a System can be expected to experience during the possible unavailability of critical long lead-time equipment. Stability impacts related to critical outages of long lead-time equipment are not included as a separate requirement because they are required to be analyzed in the normal planning process by evaluating multiple Contingency events. Any known equipment outages of six months or more must be included in the modeled system as shown in proposed TPL-001-2, Requirement R1. This condition was not included in the existing TPL standards, which created a reliability gap that will now be filled.
- Proposed Requirement R2, Part 2.2 offers a significant improvement over the existing TPL standards by requiring an annual "fresh" or "current year" steady-state study for the long-term planning horizon. During the standard development process, the SDT responded to industry comments and indicated that the requirement to conduct a current annual study for one of the study years in the long-term transmission planning horizon will enable earlier identification of potential transmission performance limitations and earlier

development of Corrective Action Plans. These study results may then be used as qualified past studies in later years.

- The proposed TPL-001-2 includes a new requirement, Requirement R2, Part 2.7.3 that allows Transmission Planners and Planning Coordinators to utilize Non-Consequential Load Loss to meet performance requirements if the applicable entities are unable to complete a Corrective Action Plan due to circumstances beyond their control. This requirement is necessitated by the improvements within the proposed TPL-001-2 that do not allow the Loss of Non-Consequential Load where it was previously allowed in the existing TPL standards, *e.g.*, planning event P2-3 for EHV. Historically, the planners could have planned for controlled interruption of demand for this event. That option is no longer available under the proposed TPL-001-2. Without proposed Requirement R2, Part 2.7.3, a planner may develop a valid Corrective Action Plan that resolves an issue and begin work on the plan with a realistic expectation to complete the plan six months before the required in-service date. However, actions beyond the control of the planner may derail that plan and make the Corrective Action Plan no longer viable. Some examples of situations beyond the control of the planner could include a state road-widening project taking substation land that was targeted for expansion or a ruling preventing the entity from condemning the land necessary for a project. For these situations, planners need to be able to take temporary steps to ensure bulk power system reliability until alternative permanent solutions can be developed and implemented. In some cases, it may be necessary and

advisable to plan for the loss of non-consequential load rather than to risk more widespread systemic problems. The proposed standard requires that the planner must document the situation necessitating the use of Non-Consequential Load Loss including alternatives evaluated in the planning assessment to ensure transparency. This represents an improvement over the existing TPL standards which allow for planned load loss without documentation of the circumstances that necessitated dropping load.

- Requirements R3 and R4[29]

  The proposed Requirement R3 describes the requirements for steady state studies and the proposed Requirement R4 elucidates the requirements for stability studies. This is an improvement from the existing standard in which the study requirements for stability and steady state analysis were combined creating confusion.

  - In addition, the proposed TPL-001-2, Requirement R3, Part 3.3.1 and Requirement R4, Part 4.3.1 require that simulations faithfully duplicate what will happen in an actual power system based on the expected performance of the Protection Systems. These requirements ensure that if a Protection System is designed to remove multiple Elements from service for an event that the simulation will be run with all of those Elements removed from service. This proposal instills event-based analysis over simple Element analysis which will provide for more accurate simulations.
  - Proposed Requirement R3, Parts 3.3.1.1 and 3.3.1.2 are new requirements that ensure that steady state analyses include: (1) the impact of subsequent tripping

[29] TPL-001-2 Requirements R3 and R4 largely mirror each other. R3 addresses the steady state portion of the Planning Assessment while R4 addresses the stability portion.

of generators for voltage ride through or steady-state voltage limits, and (2) tripping of transmission elements where relay loadability limits are exceeded. This will provide consistent treatment of the event impacts and improve the accuracy of the simulation.

- Requirement R4, Parts 4.3.1.1, 4.3.1.2 and 4.3.1.3 are new requirements that ensure that the stability analyses include: (1) the impact of subsequent successful and unsuccessful high-speed re-closing of circuits, (2) tripping of generators for low-voltage ride through, and (3) tripping of transmission lines and transformers where transient swings cause Protection System operation. This will ensure consistent treatment of event impacts and improve the accuracy of the simulations.
- The proposed TPL-001-2, Requirement R3, Part 3.3.2 and Requirement R4, Part 4.3.2 each require simulation of expected automatic operations of existing and planned control devices with more detail than the existing TPL standards. This will ensure consistent treatment of the event impacts and improve the accuracy of the simulation.
- The proposed TPL-001-2, Requirement R3, Part 3.4.1 and Requirement R4, Part 4.4.1 are new requirements that assure the planners coordinate with other Transmission Planners and Planning Coordinators to develop their Contingency list to ensure that contingencies on adjacent systems that may impact the planner's system are included in the Contingency list. This will ensure coordination between planners and improve the accuracy of the simulation.

- The proposed TPL-001-2, Requirement R3, Part 3.5 and Requirement R4, Part 4.5 are new requirements that require the planners to conduct an evaluation of possible actions designed to reduce the likelihood or the consequences of extreme events that cause cascading. Table 1 of the existing TPL-004-1 standard required planners to evaluate the risk and consequences of Category 'D' events but did not require the evaluation of possible actions. The evaluation of possible mitigating actions provides transparency of possible solutions to minimize the likelihood and impact of cascading caused by extreme events.

- Requirement R5

  The proposed TPL-001-2 offers improvement over the existing TPL standards related to voltage criteria and voltage performance. In proposed Requirement R5, each Transmission Planner and Planning Coordinator must have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its system. For transient voltage response the criteria shall, at a minimum, specify a low-voltage level and a maximum length of time that transient voltages may remain below that level. This requirement will establish more robust transmission planning for organizations and greater consistency as these voltage criteria are shared.

- Requirement R6

  Proposed Requirement R6 specifies that an entity must define and document the criteria or methodology used to identify system instability for conditions such as cascading, voltage instability, or uncontrolled islanding within its Planning

Assessment. This specificity in identifying what some including the Commission refer to as "proxies" is an important clarification in the proposed revised standard and will lead to greater transparency in the planner's evaluation techniques. This transparency should enable better understanding of what is required in the assessment and lead to the adoption of more consistent criteria and methodologies as information is shared.

- Requirement R7

  Proposed Requirement R7 mandates coordination of individual and joint responsibilities for the Planning Coordinator and the Transmission Planner. This eliminates confusion regarding the responsibilities of the applicable entities and assures that all Elements needed for regional and Wide Area studies are defined with a specific entity responsible for each Element and that no gaps will exist in planning for the BPS.

- Requirement R8

  Proposed Requirement R8 addresses the sharing of Planning Assessments with neighboring Systems. The requirement ensures that information is shared with and input received from adjacent entities and other entities with a reliability related need that may be affected an entity's System planning.

- Withdrawal of TPL-005-0 and TPL-006-0 Reliability Standards

  This project recommends the dismissal of pending Reliability Standards TPL-005-0 and TPL-006–0. These standards required the Regional Reliability Organizations to assume certain regional and interregional assessment responsibilities. These standards mandated the Regional Reliability Organizations conduct assessments and

supply the resulting data and reports to the ERO. These two proposed standards were among the group of 24 proposed standards that the Commission withheld action on when it issued Order No. 693, because the standards applied only to Regional Reliability Organizations. This type of standard is no longer needed because the issue has been addressed by amendments to the ERO Rules of Procedure ("ROP"). The ROP allows the ERO to request reliability-related data and reports at any time and mandate that the requested entities must supply that information.[30]

- Table 1Steady State & Performance Planning Events

  Similar to the existing TPL standards, the proposed TPL-001-2 includes a table, Table 1, that serves as an integral part of the transmission planning reliability requirements. Table 1 describes system performance requirements for a range of potential system contingencies required to be evaluated by the planner. Many of the contingencies are similar to the existing table; however, the table has been revised to categorize the events as either "planning events" or "extreme events" compared to the existing Category A, B, C, and D structure. The proposed table lists seven Contingency planning events (P1 through P7) that require steady-state and stability analysis as well as five extreme event contingencies – three for steady-state and two for stability. Each planning event and extreme event contains multiple sub-parts. The proposed table also includes a no Contingency "event" labeled as P0 which requires steady-state analysis.

[30] NERC Rules of Procedure Sections 803 and 804. Available at http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20110825.pdf.

The proposed Table 1will help establish more robust transmission planning across the ERO footprint and offers a number of enhancements over the existing TPL standards including:

- The proposed standard reclassifies some existing multiple Contingency (Category C) events as single Contingency planning events. The proposed planning event P2 includes bus faults and internal breaker faults as a single Contingency due to the events initiated by a single common mode condition that typically removes multiple BES facilities due to automatic action by Protection Systems. The proposed standard also establishes a higher performance level for these reclassified single Contingency events. Non-Consequential Load Loss and interruption of firm transfer is no longer permitted for the proposed P2 event when evaluating the extra-high voltage (> 300kV) ("EHV") Transmission Systems, which are considered the backbone of many Systems.
- In addition to the proposed P2 event described above, other planning events also include bifurcated performance criteria expectations placing a higher level of reliability on the EHV systems. Proposed planning events P4 (stuck breaker) and P5 (relay failure) are multiple Contingency events which must also meet a higher level of reliability for the EHV systems. These changes are viewed as significant improvements in establishing BES reliability.
- The proposed planning event P3 is another enhancement that provides another example of an event whose performance requirement is presently treated as a multiple Contingency (Category C) event. A P3 event considers the loss of a

generator unit followed by the loss of another single element such as a transmission circuit, generator, or transformer. Based on the high probability of a generator unit outage in combination with another facility outage, the proposed TPL-001-2 no longer allows the loss of non-consequential load or interruption of firm transfers for this event.

- Table 1 has also been enhanced by explicitly including reactive power shunt devices as an element outage that must be evaluated in various Contingency events.
- The proposed planning event P5 and the accompanying footnote 13 add clarity and consistency in how delayed Fault clearing will be modeled in planning studies. The SDT recognizes that the BES Protection Systems are complex systems and can vary widely in their design. However, the basic elements of any BES Protection System design involve inputs (current, d.c. voltage, a.c. voltage, *etc.*) to protective relays and outputs (trip signals, close signals, alarms, *etc.*) from protective relays. The SDT determined that a more focused approach than that utilized in the existing TPL standards was desirable, so it adopted an approach that addresses specific relay types to more effectively analyze the impact of delayed Fault clearing.
- BES reliability issues associated with improper clearing of a Fault on the BES can result from the failure of hundreds of individual Protection System components in a BES substation. However, while the population of components that could fail and result in improper clearing is quite large, that population can be reduced dramatically by eliminating those components

which share failure modes with other components. The critical components in BES Protection Systems are the protective relays themselves and a failure of a non-redundant protective relay will often result in undesired consequences during a Fault. Other Protection System components related to the protective relay could fail and lead to a BES issue, but the event to be studied would be identical, from both transient and steady state perspectives, to the event resulting from a protective relay failure if the population of protective relays to be considered is adequate.

- For example, the failure of a current transformer applied in a typical stepped distance transmission line protection system would compromise the system and likely prevent the distance relay from detecting a fault within its protection zone. The failure of the distance relay to function, regardless of root cause, would require reliance on protection systems functioning in a backup role to the failed distance relay. Similarly, the loss of a non-redundant pilot (communications) channel such as a fiber optic cable or microwave radio channel between two BES substations would result in delayed clearing for faults near either end of a transmission line. However, the failure of the pilot relay would result in the same failure mode and lead to the same event in terms of BES reliability. Focusing on these critical components (the protective relays) allows the planner to efficiently assess the BES performance during almost any conceivable protection system failure pertinent to BES reliability.

- Virtually all BES protection systems fall into a few general design types centered on a few critical protective relay types and typically includes one or more tripping relays . Transmission line Protection Systems fall into three general classes of Protection Systems: (1) a stepped distance, impedance measurement-based system with distance relays applied, (2) a pilot-based system where directional or distance relays communicate Fault direction from end to end via a communications medium (*e.g.* fiber, power line carrier, etc.) where pilot relays and either distance or directional relays are applied, or (3) a multi-location current differential system with differential relays applied.
- Protection Systems designed to protect virtually any BES Facility in one location such as transformers, capacitor banks, reactors, busses, etc., generally fall into two general classes of protection systems: (1) a differential-based system with differential relays applied or (2) an over/under voltage/current system with current relays or voltage relays applied.
- Selecting an adequate population of protective relays to consider and focusing only on those failures will allow the planner to efficiently assess the performance of the BES during virtually any Protection System failure.
- The proposed TPL-001-2, Table 1, P5 events are limited to the Single Line to Ground ("SLG") Fault type consistent with the comparable C6 – C9 events from Table 1 in the existing TPL standards. The proposed TPL-001-2 standard treats SLG and three phase Faults as different events even if an SLG event migrates into a three phase Fault. Three phase events in the existing

TPL standards are shown in Table 1, D1 – D4 and are retained in TPL-001-2, Table 1, extreme events.

- In total, this is an equal and effective alternative approach to match the performance requirements in Table 1 of the existing TPL standards. The proposed extreme events have been improved to require evaluation of Wide Area events including those based on operating experience as well as those initiated by a cyber attack. Overall, the proposed Table 1 adds significant clarity and raises the bar on performance expectations in several areas.

VI. JUSTIFICATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARDS

This section summarizes the development of the proposed Reliability Standard, TPL-001-2 — Transmission System Planning Performance Requirements and demonstrates the proposed Reliability Standard meets the criteria for approval set by the Commission, that is, the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.

Exhibit D identifies the comments received on the various postings of the proposed Reliability Standard and discusses how the SDT addressed those comments. The complete development record for the proposed Reliability Standard is available in **Exhibit F**. This record includes the Standard Authorization Request ("SAR"), the draft of the proposed Reliability Standard through the development, the implementation plan, the ballot pool, and the final ballot results by registered ballot body members, stakeholder comments received during the development of the proposed Reliability Standard, and consideration of those comments by the SDT in developing the proposed Reliability Standard.

The purpose of the proposed TPL-001-2 standard is to "establish Transmission system planning performance requirements within the planning horizon to develop a BES that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies."[31] The proposed TPL-001-2 standard applies to Planning Coordinators and Transmission Planners and consists of eight requirements and associated parts, addressing the following topics:

- Maintaining System models with consistent data including items in the Corrective Action Plan and representing projected System conditions
- Preparation of an annual Planning Assessment with requisite documentation and covering the Near-Term and Long-Term Transmission Planning Horizons for steady state, short circuit, and stability analysis
- Inclusion of sensitivity studies varying one or more conditions not already included in the normal studies by a sufficient amount to stress the system
- The need for a spare equipment strategy
- Defining when past studies may be used in the Planning Assessment
- Creation of Corrective Action Plans when performance is not met
- For steady state and stability analyses, defining the events that must be studied to ensure performance is maintained
- Defining the extreme events that must be studied
- Establishing criteria for acceptable voltage limits
- Establishing criteria for identifying system instability
- Determining responsibilities for performing studies
- Distribution of Planning Assessments to adjacent and necessary entities

Currently-effective Reliability Standards TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1 are proposed to be retired in their entirety. All of the requirements from these standards are now included in the proposed TPL-001-2 standard, and the reliability objectives of the earlier TPL standards are met by the proposed standard. Additionally, Reliability Standards TPL-005-0 and TPL-006.1 will be withdrawn.

[31] TPL-001-2 — Transmission System Planning Performance Requirements, at A.3.

The implementation plan (**Exhibit B**) for this proposed standard requires compliance consistent with the scheduled effective dates of twelve, twenty-four, or eighty-four months after the first day of the first calendar quarter following applicable regulatory approval depending on the requirement. In those jurisdictions where no regulatory approval is required, all requirements go into effect twelve, twenty-four, or eighty-four months after NERC Board of Trustees adoption depending on the requirement as detailed in the implementation plan.

a. Demonstration that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential and in the public interest

Section 215 of the FPA requires that Reliability Standards be just, reasonable, not unduly discriminatory or preferential, and in the public interest.[32] In Order No. 672, the Commission identified criteria it will use to analyze proposed Reliability Standards to ensure that the requirements of Section 215 are met. A review of the proposed Reliability Standards for consistency with these criteria is presented below.

1. Proposed Reliability Standards must be designed to achieve a specified reliability goal

> Order No. 672 at P 321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cyber security protection.

The proposed Reliability Standard, TPL-001-2 — Transmission System Planning Performance Requirements, establishes Transmission system planning performance requirements

[32] Section 215(d)(2)(A) of the FPA; 18 C.F.R. §39.5.

within the planning horizon to develop a BES that will operate reliably over a broad spectrum of System conditions and following a wide range of Contingencies. This standard includes specific requirements for Planning Assessments in both the near-term and long-term time horizons as well as studies for steady state, short circuit, and stability analysis and describes the coordination and documentation required to properly prepare such assessments.

2. Proposed Reliability Standards must contain a technically sound method to achieve the goal

> Order No. 672 at P 324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.

The proposed Reliability Standard contains technically sound methods to achieve the goal of establishing acceptable Transmission system planning performance. This proposed standard describes:

- What must be in the models employed in the assessment (Requirement R1).
- What studies must be performed and for what years in the respective time horizons they must be done (Requirement R2).
- Steady state (Requirement R3) and stability performance requirements (Requirement R4).
- Establishing criteria for voltage limits and responses (Requirement R5).
- Establishing criteria for defining conditions for voltage instability, cascading, and uncontrolled islanding (Requirement R6).
- Identification of respective responsibilities (Requirement R7).
- Distribution of the Planning Assessment (Requirement R8).

The requirements in the proposed Reliability Standard define the various aspects of planning that need to be completed by the planner to ensure that the as-planned system meets acceptable

performance levels throughout the planning horizon. The details within the requirements provide the necessary specifics starting from the maintenance of the System models, through the simulations and assessments that need to be completed, the documentation of criteria and corrective action plans, and conclude with the distribution of the results of the planning assessment. When combined with the table, which articulates performance requirements for the planning and extreme events, the requirements frame the elements necessary to ensure that the system is planned to provide BES reliability.

3. Proposed Reliability Standards must be applicable to users, owners, and operators of the bulk power system, and not others

> Order No. 672 at P 322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.

The proposed Reliability Standard is applicable to users, owners, and operators of the bulk power system, and not others. The proposed standard is specifically applicable to Planning Coordinators and Transmission Planners, both of which are users, owners, or operators of the bulk power system.

4. Proposed Reliability Standards must be clear and unambiguous as to what is required and who is required to comply

> Order No. 672 at P 325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.

The proposed Reliability Standard is clear and unambiguous as to what is required and who is required to comply. Each requirement clearly states the applicable entities must comply with the requirement and what those entities are required to do. For example, Requirement R1 of the proposed revised standard now clearly states that Transmission Planners and Planning Coordinators shall maintain System models for performing the studies needed to complete their

Planning Assessments as well as what conditions must be included in those models. It also defines the division of effort and responsibilities between the Planning Coordinator and the Transmission Planner (Requirement R7).

5. **Proposed Reliability Standards must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation**

   Order No. 672 at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

The proposed Reliability Standard includes clear and understandable consequences. Each primary requirement is assigned a Violation Risk Factor ("VRF") and a Violation Severity Level ("VSL") which supports the determination of a base penalty amount for violations of the requirements as required by NERC Sanction Guidelines. NERC's review of the VSLs for this proposed standard for consistency with FERC's VRF and VSL guidelines is included in Section VII and **Exhibit C** of this document.

6. **Proposed Reliability Standards must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner**

   Order No. 672 at P 327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.

The proposed Reliability Standard identifies clear and objective criteria to support enforcement in a consistent and non-preferential manner. Each requirement has an associated measure, and each requirement clearly identifies the expected performance that will serve as the basis for development of compliance enforcement objectives. The language used in the requirements clearly identifies what is expected of the applicable entity.

7. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost

> Order No. 672 at P 328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.

The proposed Reliability Standards achieve their reliability goal effectively and efficiently. Expanding the requirements to meet the reliability objectives of the standards was carefully considered in the Reliability Standards development process, and the proposed standard was structured to address the objective without unduly burdening the applicable entities. For example, the implementation plan for the proposed standard has been phased to allow entities that have previously planned and designed their systems on the basis of the existing approach to single Contingencies time to transition to the new, higher performance requirements.

8. Proposed Reliability Standards cannot be "lowest common denominator," *i.e.*, cannot reflect a compromise that does not adequately protect bulk power system reliability

> Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.

The proposed Reliability Standard is more stringent than current set of TPL standards in several areas. As described above, details of what model data must be utilized, requiring simulations to model actual behavior, and including actions from the Corrective Action Plan in subsequent years' data (Requirement R1), mandating sensitivity studies (Requirement R2, Parts 2.1.4 and 2.4.3), detailing a requirement for Contingency analysis (Requirement R3, Part 3.3 and

Requirement R4, Part 4.3), establishing criteria for voltage limits, deviations, and response (Requirement R5), establishing criteria for identifying system instability conditions (Requirement R6), requiring distribution of Planning Assessments (Requirement R8), and elevating performance for facilities greater than 300 kV and eliminating dropping firm load for single contingencies (Table 1 - P1-2, P1-3, P2-1, P2-2, and P2-3), all reflect significant increases in responsibilities and expectations for applicable entities and clearly do not represent a lowest common denominator.

9. Proposed Reliability Standards may consider costs to implement for smaller entities but not at consequence of less than excellence in operating system reliability

> Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.

The proposed Reliability Standards do not differentiate among entities based on size or cost. These requirements apply to all Planning Coordinator and Transmission Planner entities with responsibility for planning equally.

10. Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one area or approach

> Order No. 672 at P 331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and

ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.

The proposed Reliability Standards are designed to apply continent-wide. The proposed standard proposes no regional differences or variances.

11. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid

Order No. 672 at P 332. As directed by section 215 of the FPA, the Commission itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.

NERC does not anticipate that the proposed Reliability Standards will adversely affect competition or restrict available transmission capability.

12. The implementation time for the proposed Reliability Standards must be reasonable

Order No. 672 at P 333. In considering whether a proposed Reliability Standard is just and reasonable, the Commission will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.

The proposed Reliability Standard includes a reasonable implementation schedule for this standard. As noted, the proposed Reliability Standard is more stringent in several areas: details of what model data must be utilized, requiring simulations to model actual behavior, and including actions from the Corrective Action Plan in subsequent years data (Requirement R1), mandating sensitivity studies (Requirement R2, Parts 2.1.4 and 2.4.3), detailing requirement for Contingency analysis (Requirement R3, Part 3.3 and Requirement R4, Part 4.3), establishing

criteria for voltage limits, deviations, and response (Requirement R5), establishing criteria for identifying system instability conditions (Requirement R6), requiring distribution of Planning Assessments (Requirement R8), and elevating performance for facilities greater than 300 kV and eliminating dropping firm load for single contingencies (Table 1 - P1-2, P1-3, P2-1, P2-2, and P2-3).

Additionally, NERC believes the proposed effective dates represent a reasonable time frame to allow all entities to adequately prepare for compliance with the new requirements. Compliance is already required for Reliability Standards TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1.

13. The Reliability Standard development process must be open and fair

> Order No. 672 at P 334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by the Commission

NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC *Standard Processes Manual*,[33] which is included in the Rules of Procedure as Appendix 3A. In the ERO Certification Order, FERC found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards. The development process is open to any person or entity with a legitimate interest in

[33] FERC approved NERC's *Standard Processes Manual* on September 3, 2010 (FERC Docket No. RR10-12-000). The *Standard Processes Manual* replaced the previous FERC-approved *Reliability Standards Development Procedure* in its entirety. The SDT developed this standard in accordance with the then-effective standards development processes until the *Standard Processes Manual* was approved in 2010, at which time the *Standard Processes Manual* was used to complete development of the proposed standard.

the reliability of the bulk power system. NERC considers the comments of all stakeholders and a vote of stakeholders and the NERC Board of Trustees is required to approve a proposed Reliability Standard for submission to the Commission.

The proposed Reliability Standard set out in **Exhibit A** has been developed and approved by industry stakeholders using the process found in NERC's *Standard Processes Manual*, and was approved by the NERC Board of Trustees on August 4, 2011. Therefore, NERC developed the proposed standard in a manner that is open and fair.

14. Proposed Reliability Standards must balance with other vital public interests

> Order No. 672 at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

This proposed standard focuses on ensuring that transmission system planning performance principles within the planning horizon are met in order to develop a BES that will operate reliably over a broad spectrum of System conditions and following a wide range of probable contingencies. No other environmental, social, or other goals are reflected or considered in this proposed standard. NERC does not, however, anticipate any conflicts with other vital public interests.

15. Proposed Reliability Standards must consider any other relevant factors

> Order No. 672 at P 323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.
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> Order No. 672 at P 337. In applying the legal standard to review of a proposed Reliability Standard, the Commission will consider the general factors above. The ERO should explain in its application for approval of a proposed Reliability Standard how well the proposal meets these factors and explain how the Reliability Standard balances conflicting factors, if any. the Commission may

> consider any other factors it deems appropriate for determining if the proposed Reliability Standard is just and reasonable, not unduly discriminatory or preferential, and in the public interest. The ERO applicant may, if it chooses, propose other such general factors in its ERO application and may propose additional specific factors for consideration with a particular proposed Reliability Standard.

Exhibit D presents an overview of the issues raised in consideration of the proposed standard that demonstrates how industry comments, as well as directives from Order No. 693, are addressed in this standard development project.

VII. Violation Risk Factors and Violation Severity Levels

The proposed Reliability Standard includes VRFs and VSLs that are specific to individual Requirements. The ranges of penalties for violations of standards are based on the applicable VRFs and VSLs and will be administered based on the Sanctions Table and supporting penalty determination process described in Commission-approved NERC Sanction Guidelines, which is Appendix 4B in NERC's Rules of Procedure. The assignment of VRFs and VSLs included consideration of the NERC guidelines. Consistent with NERC's August 10, 2009 informational filing,[34] assignments of VRFs and VSLs were made at the main requirement level of the proposed standard.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines. **Exhibit C** demonstrates the analysis of the chosen VRFs and VSLs in accordance with the VRF and VSL guidelines.

[34] *Informational Filing of the North American Electric Reliability Corporation Regarding the Assignment of Violation Risk Factors and Violation Severity Levels*, Docket Nos. RM08-11-000, RR08-4-000, RR07-9-000, and RR07-10-000 (August, 10, 2009).

VIII. SUMMARY OF THE RELIABILITY STANDARD DEVELOPMENT PROCEEDINGS

a. Reliability Standards Development Procedure

NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC *Standard Processes Manual*[35] which is incorporated into the Rules of Procedure as Appendix 3A. In its ERO Certification Order,[36] FERC found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards and thus satisfies certain of the criteria for approving Reliability Standards.[37]

The development process is open to any person or entity with a legitimate interest in the reliability of the bulk power system. NERC considers the comments of all stakeholders and a vote of stakeholders and the NERC Board of Trustees is required to approve a proposed Reliability Standard before its submission to the Commission.

The proposed Reliability Standard set out in **Exhibit A** was approved by the NERC Board of Trustees on August 4, 2011.

b. Progress in Improving Proposed Reliability Standards

NERC continues to develop new and revised Reliability Standards that address the issues NERC identified in its initial filing of proposed Reliability Standards on April 4, 2006, the concerns noted in the Commission Staff Report issued on May 11, 2006 and the directives the Commission has included in multiple subsequent orders pertaining to NERC's Reliability

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[35] As stated in Footnote 33, *supra*, this project predates the Standard Processes Manual. The SDT utilized the then-effective standard development processes prior to the implementation of the *Standard Processes Manual* in September 2010.

[36] *Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 61,062 (2006).

[37] Order No. 672 at PP 268, 270.

Standards.[38] NERC has incorporated these activities into its *Reliability Standards Development Plan: 2011-2013*,[39] submitted to FERC on April 5, 2011.

c. Development History

On April 2, 2002, NERC received, and the Standards Committee accepted, a standards authorization request ("SAR") proposing to establish a standard for assessing and planning the transmission systems in North America. The SAR was posted for two industry comment opportunities and then approved by the Standards Committee for standard development on November 18, 2005. The project was delayed in starting, but work resumed in late 2006. Due to the amount of time between the acceptance of the SAR and the start of work, a supplemental SAR was drafted to incorporate changes in thinking on planning needs during the delay. The supplemental SAR was posted once for industry comment and was accepted by the Standards Committee on April 10, 2007 as *Project 2006-02: Assess Transmission Future Needs and Develop Transmission Plans*.

The assigned SDT posted the draft standard for a 45-day industry comment period from September 12, 2007 to October 26, 2007. In response, 80 sets of comments were received from representatives of 80 organizations representing 233 individuals and 9 of the 10 industry segments. Comments primarily addressed the proposed definitions, sensitivity studies, Corrective Action Plans, modeling data, and performance issues.

The SDT revised the draft standard accordingly and re-posted for industry comment from August 14, 2008 to September 29, 2008. This time, 80 sets of comments were received from 100

[38] *Mandatory Reliability Standards for the Bulk-Power System*, 118 FERC ¶ 61,218, FERC Stats. & Regs. ¶ 31,242 (2007) ("Order No. 693"), *order on reh'g*, *Mandatory Reliability Standards for the Bulk-Power System*, 120 FERC ¶ 61,053 ("Order No. 693-A") (2007).
[39] *North American Electric Reliability Corporation Reliability Standards Development Plan 2011-2013 Informational Filing Pursuant to Section 310 of the NERC Rules of Procedure*, Docket Nos. RM05-17-000, RM05-25-000, and RM06-16-000 (April 5, 2011).

organizations representing 150 individuals and 9 of the 10 industry segments. The comments received focused on the revised definitions, maintenance of system models; items to be included in Planning Assessments and studies; merger of the steady state and stability performance tables; measures; VRFs; VSLs; and the implementation plan.

The SDT again revised the draft standard to accommodate industry concerns and posted the revised draft standard for comments between May 26, 2009 and July 9, 2009. There were 85 sets of comments from 85 organizations representing 170 individuals and 9 of the 10 industry segments. Comments dealt with revised definitions, clarity of requirements text, criteria for formal documentation of criteria for acceptable system steady state voltage limits, post-Contingency voltage deviations, transient voltage response, and revisions to the implementation plan.

NERC posted the fourth draft of the standard from September 16, 2009 through October 16, 2009. There were 67 sets of comments from 85 companies representing 180 individuals and all of the ten Industry Segments. In response to these stakeholder comments, the SDT modified one definition, and made some small clarifying modifications to the requirements, measures, and compliance elements. The SDT did not believe that the changes were substantive and requested approval from the Standards Committee to move to the ballot process.

d. Issues Raised during the Development Process including Minority Issues

During the development process, the SDT considered the following comments, issues, and concerns. The minority issues are issues raised by commenters during the development process that the SDT chose not to address in the manner that a minority of commenters preferred.

- Some commenters wanted two separate performance tables – one for steady state and one for stability. This would have resulted in a great deal of repeated text and would have created confusion at times as to where to go for

guidance. In addition, it may have created a maintenance problem. The SDT decided to incorporate all of the necessary requirements into one cohesive, comprehensive Reliability Standard with one encompassing performance table.

- The currently enforceable Reliability Standards are unclear as to what data the planner should utilize in their assessments and studies. The SDT addressed this problem by establishing a definitive starting point; requiring that simulations mirror actual conditions and mandating that data from the previous Corrective Action Plans be incorporated into subsequent year's studies.
- The SDT had to answer questions such as: "what year(s) needed to be studied?" and "do studies need to be run for every year in the planning horizon?" The SDT determined that assessments must be completed every year but only specific years in the Planning Horizon need to be studied. Due to the cyclical nature of the assessments, once this proposed Reliability Standard is approved and implemented it will result in a portfolio of studies covering the different years in the planning horizon. Additionally, the SDT defined the circumstances when an entity could utilize past studies in its assessment.
- The SDT believed that Systems needed to be stressed in the studies in order to ensure that proper planning takes place. This led to the inclusion of mandatory sensitivity studies as part of the planning process. This will force planners to stress their Systems beyond levels typically seen in existing

studies and could point to potential problem areas that may have previously remained undetected.

- A need exists to ensure that Wide Area coordination is taking place in the assessments and studies. The SDT was concerned that planning may be taking place in a vacuum without sufficient understanding of what takes place in neighbors Systems. To address this concern, the SDT crafted several requirements starting with studying contingencies in adjacent Systems and finishing by requiring the distribution of Planning Assessments to affected entities.
- The SDT needed to incorporate the Order No. 693 directive barring the loss of non-consequential load for single contingencies.[40] Through the various industry comment periods, the SDT created the new performance criteria and detailed the process in footnotes 9 and 12.
- The SDT wanted to heighten System performance by crafting more stringent performance criteria for certain parts of the System. The SDT accomplished this by creating a dividing line at the 300 kV level. Anything above 300 kV is considered to be the backbone of the interconnected transmission System and it was therefore determined by the SDT that more stringent criteria was warranted at that level.

Minority Issues

- Interchange should not be modeled because it is an economic issue and not involved in reliability.

  Response:

[40] Order No. 693 at P 1794.

The SDT countered that the proposed TPL-001-2 standard requires inclusion of known commitments for interchange and is not for economic purposes, but rather planning to meet obligations.

- Dynamic behavior of Load should not be required in the model, claiming that software was not developed enough to be accurate.

  Response:

  The SDT believes that the correct modeling of the characteristics of Load is an important aspect of having an accurate model. The requirement to represent the dynamic behavior of the Load is necessary to ensure BES reliability.

- Distribution of Planning Assessments should not be required, as it creates a large workload for the entities involved.

  Response:

  The standard only requires distribution of the Planning Assessment, which should not require a large amount of work; posting the Planning Assessment could meet the requirement to distribute.

- TPL-001-2 should not move forward until footnote 'b' is resolved with FERC.

  Response:

  Any changes in response to FERC actions can easily be folded back into TPL-001-2. The improvements to System planning associated with approval of the new standard should not be delayed.

e. Initial Ballot

NERC conducted an initial ballot from February 19, 2010 through March 1, 2010. With a 91.38 percent quorum participating in the ballot, the proposed Reliability Standard achieved a weighted segment vote of 35.36 percent. There were 168 negative ballots submitted for the initial ballot, and 103 of those ballots included a comment, which created a need for a recirculation ballot. However, due to the massive number of negative votes and changes required to accommodate the voter's concerns, the SDT decided to re- post the standard in order to properly vet the changes made to the proposed standard.

There were five main themes to the comments supplied with the initial balloting:

1. Loss of Non-Consequential Load: A large number of commenters felt that the SDT was not allowing for Non-Consequential Load Loss in as many situations as the old standard.
2. Description of the Table 1 P5 event (Fault plus Protection System failure to operate): NERC received many comments regarding the use of the defined term, Protection System, in the event description. These commenters stated that fully redundant protection systems would be required on all BES equipment to meet the performance requirements for P5, which is not required by the existing standards. The SDT clarified that its intent was not to require fully redundant protection systems on all BES equipment in revised language for P5.
3. Relay and Load modeling: Comments expressed the opinion that the proposed Reliability Standard would require the addition of detailed relay models and detailed dynamic load models into the planning models. These commenters

expressed the opinion that these additions would create large volumes of additional work and extend the computation time for very little reliability benefit. The commenters further stated that the dynamic load models are not developed enough to require their use in Reliability Standards. . (This is addressed in the Minority Issues section VIII.b above.)

4. Spare equipment strategy: Several commenters believed that a spare equipment strategy does not belong in the planning standard.
5. Implementation timeframe: Many requests were made to extend the implementation timeframe from 60 to 84 months.

f. Balloting and Approval

The SDT addressed all of the ballot comments[41] and made several changes to the proposed standard as a result. The SDT posted its Consideration of Comments reports to the initial ballot comments as part of a posting from August 3, 2010 through September 2, 2010. Comments were received from 77 different people from approximately 69 companies representing six of the ten Industry Segments. Based on stakeholder comments, the SDT modified one definition, and made clarifying changes to requirements, measures, and compliance elements. The SDT did not believe that the changes were substantive and requested approval from the Standards Committee to again move to the ballot process.

NERC posted the proposed standard as part of a concurrent posting/balloting period from April 18, 2011 through May 31, 2011. With a 92.07 percent quorum participating in the ballot, the proposed Reliability Standard achieved an affirmative weighted segment vote of 73.99 percent. There were 72 negative ballots with comments submitted for the initial ballot, which

[41] *See* Exhibit D for consideration of comments and Exhibit F for the complete development history.

created the need for a recirculation ballot. NERC conducted the recirculation ballot from July 13, 2011 through July 24, 2011. With a 94.33 percent quorum participating in the ballot, the proposed Reliability Standard achieved a weighted segment approval vote of 75.37 percent. The proposed Reliability Standard achieved the required two-thirds weighted segment vote and at least a 75 percent quorum of the ballot pool.

The NERC Board of Trustees approved the proposed standard during its August 4, 2011 meeting.

IX. CONCLUSION

For the reasons stated above, NERC respectfully requests that the Commission approve one proposed revised Reliability Standard:TPL-001-2 — Transmission System Planning Performance Requirements, the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs"), and the implementation plan which establishes the schedule for implementing the proposed Reliability Standard. NERC is also requesting the retirement of four existing Reliability Standards: (1) TPL-001-1 — System Performance Under Normal (No Contingency) Conditions (Category A), (2) TPL-002-1b — System Performance Following Loss of a Single BES Element (Category B), (3) TPL-003-1a — System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), and (4) TPL-004-1 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D). Additionally, NERC is requesting to withdraw two standards TPL-005-0 — Regional and Interregional Self-Assessment Reliability Reports, and TPL-006-0.1 – Data From the Regional Reliability Organization Needed to Assess Reliability which were never approved by the Commission.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 19th day of October, 2011.

/s/ Andrew M. Dressel
Andrew M. Dressel

Attorney for North American Electric Reliability Corporation

Exhibit A

Reliability Standard Proposed for Approval

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-2**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required on the first day of the first calendar quarter 84 months after Board of Trustees adoption, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-2, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-2:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1
   - P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes

Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1,

and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that

Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when

such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
d. Simulate Normal Clearing unless otherwise specified.
e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.
g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
h. Planning event P0 is applicable to steady state only.
i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
   a. Loss of a tower line with three or more circuits.[11]
   b. Loss of all Transmission lines on a common Right-of-Way[11].
   c. Loss of a switching station or substation (loss of one voltage level plus transformers).
   d. Loss of all generating units at a generating station.
   e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
   a. Loss of two generating stations resulting from conditions such as:
      i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
      ii. Loss of the use of a large body of water as the cooling source for generation.
      iii. Wildfires.
      iv. Severe weather, e.g., hurricanes, tornadoes, etc.
      v. A successful cyber attack.
      vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
   b. Other events based upon operating experience that may result in wide area disturbances.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
   a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   e. 3Ø internal breaker fault.
   f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to address BES performance requirements. When Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss is documented, including alternatives evaluated; and where the utilization of Non-Consequential Load Loss is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	

Exhibit B

Implementation Plan for Reliability Standard TPL-001-2

Implementation Plan for TPL-001-2

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

TPL-001-2 — Transmission System Planning Performance Requirements

In revising the TPL standards, the SDT is assuming that planners will receive valid data from the MOD standards link described in TPL-001-2, Requirement R1. Furthermore, there is a tacit assumption that future revisions of the MOD standards will include steps to validate MOD based data.

Revision to Sections of Approved Standards and Definitions

There are multiple new definitions in the proposed standard.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.

Compliance with Standards

Standard	Functions That Must Comply With the Associated Requirements	
TPL-001-2 — Transmission System Planning Performance Requirements	Transmission Planner	Planning Coordinator
	X	X

Effective Dates

The effective date is the date entities are expected to meet the performance identified in this standard.

Note – The changes shown below were done solely to make the effective date language used in the Implementation Plan consistent with that shown in the proposed standard effective date section. No changes were made to the content or context of the dates, durations, or requirements.

Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.

For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required on the first day of the first calendar quarter 84 months after Board of Trustees adoption, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-2, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-2:

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1 are being retired at midnight the day before TPL-001-2 becomes effective as they are replaced in their entirety by TPL-001-2. TPL-005-0 and TPL-006-0.1 are being retired at midnight the day before TPL-001-2 becomes effective because their requirements are adequately covered by the revised TPL-001-2 and NERC's Rules of Procedure, Section 800. However, during this 24-month period, all aspects of TPL-001-0 through TPL-006-0 shall remain in effect for compliance monitoring. This 24 month period is to allow entities to develop, perform and/or validate new and/or modified studies, methodologies, assessments, procedures, etc. necessary to implement and meet the TPL-001-2 requirements. The specified effective dates are expected to allow sufficient time for proper assessment of the available options necessary to create a viable Corrective Action Plan that is compliant with the new Standard.

R1. This Requirement is related to maintaining System models and the data needed to do so. This requirement shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes into effect on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

R7. This Requirement identifies an obligation to determine individual and joint responsibilities for performing studies needed to do the Planning Assessment. This requirement shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes into effect on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

TPL-001-2 'raises the bar' in several areas where performance requirements have been changed in the new Standard versus those in existing TPL-001-1, TPL-002-1b, TPL-003-1a and TPL-004-1 because loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain events, whereas the existing Standards were interpreted by many to allow such actions. As shown in Table 1 of TPL-001-2, the performance requirements associated with the following events represent "raising the bar":

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

This "raising the bar" is beyond the control of the Transmission Planner and Planning Coordinator and may have significant budget, siting, permitting, and construction impacts on many Transmission Owners. To provide stakeholders with sufficient time to implement changes, a timeframe coincident with the end of the Near-Term Transmission Planning Horizon has been provided

Any entity which cannot eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for these performance elements by that date shall submit a mitigation plan to its Regional Entity outlining the steps it will take to correct the problem. If the entities follow the established ERO procedure for mitigation, it is the intent of the SDT that no penalties will be assessed.

Exhibit C

Violation Risk Factors and Violation Severity Levels Analysis for TPL-001-2

Violation Risk Factor Analysis for Proposed TPL-001-2

This chart provides the analysis the SDT used to determine the appropriate Violation Risk Factor ("VRF") for each Requirement of the proposed TPL-001-2 — Transmission System Planning Performance Requirements Reliability Standard utilizing the FERC-approved VRF Guidelines.[1]

VRF for Proposed TPL-001-2, Requirement R1: Medium

R#	Guideline 2 - Consistency within a Reliability Standard.	Guideline 3 - Consistency among Reliability Standards.	Guideline 4 - Consistency with NERC's Definition of the Violation Risk Factor Level	Guideline 5 - Treatment of Requirements that Co-mingle More Than One Obligation
R1.	The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.	Requirements R1.3.5, R1.3.7, R1.3.8, and R1.3.9 to the currently-effective TPL-001-0.1 have been assigned a Medium VRF and are similar in purpose and effect to TPL-001-2 Requirement R1. The requirements are viewed as similar because they refer to models that include firm transfers, existing and planned facilities, reactive power requirements, and refer to the P0 condition. A Medium VRF for Requirement R1 is consistent with past FERC guidance.	Failure to maintain System models in a planning time frame could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BES.	Proposed TPL-001-2, Requirement R1 contains only one objective, therefore only one VRF was assigned.

[1] *Order on Violation Risk Factors*, 119 FERC ¶ 61,145 (2007), order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007).

VRF for Proposed TPL-001-2, Requirement R2: High

R#	Guideline 2 - Consistency within a Reliability Standard.	Guideline 3 - Consistency among Reliability Standards.	Guideline 4 - Consistency with NERC's Definition of the Violation Risk Factor Level	Guideline 5 - Treatment of Requirements that Co-mingle More Than One Obligation
R2.	The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.	A similar requirement (Requirement R1) in approved TPL-002-0a was assigned a High VRF. The requirements are viewed as similar because they both address the validity of the Planning Assessment.	Failure to perform Planning Assessments in the appropriate planning time frame could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BES.	Proposed TPL-001-2, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for Proposed TPL-001-2, Requirement R3:

R#	Guideline 2 - Consistency within a Reliability Standard.	Guideline 3 - Consistency among Reliability Standards.	Guideline 4 - Consistency with NERC's Definition of the Violation Risk Factor Level	Guideline 5 - Treatment of Requirements that Co-mingle More Than One Obligation
R3.	The requirement has no sub-requirements; only one VRF was assigned so there is no conflict	A similar requirement (Requirement R1.3.7) in approved TPL-001-0.1 was assigned a Medium VRF. The requirements are viewed as similar since they refer to performing studies to demonstrate performance.	Failure to perform appropriate studies could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system.	Proposed TPL-001-2, Requirement R3 contains only one objective, therefore only one VRF was assigned.

VRF for Proposed TPL-001-2, Requirement R4: Medium

R#	Guideline 2 - Consistency within a Reliability Standard.	Guideline 3 - Consistency among Reliability Standards.	Guideline 4 - Consistency with NERC's Definition of the Violation Risk Factor Level	Guideline 5 - Treatment of Requirements that Co-mingle More Than One Obligation
R4.	The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.	Proposed TPL-001-2, Requirement R4 is a new requirement but is essentially the Stability equivalent to proposed TPL-001-2, Requirement R3 (see above) which was assigned a Medium VRF.	Failure to perform appropriate studies could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BES.	Proposed TPL-001-2, Requirement R4 has only one objective, therefore only one VRF was assigned.

VRF for Proposed TPL-001-2, Requirement R5: Medium

R#	Guideline 2 - Consistency within a Reliability Standard.	Guideline 3 - Consistency among Reliability Standards.	Guideline 4 - Consistency with NERC's Definition of the Violation Risk Factor Level	Guideline 5 - Treatment of Requirements that Co-mingle More Than One Obligation
R5.	The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.	Proposed TPL-001-2, Requirement R5 is a new requirement, for which there are no comparable requirements.	Failure to have established criteria for certain System conditions in the planning time horizons could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BES.	Proposed TPL-001-2, Requirement R5 contains only one objective. Therefore only one VRF was assigned.

VRF for Proposed TPL-001-2, Requirement R6: Low

R#	Guideline 2 - Consistency within a Reliability Standard.	Guideline 3 - Consistency among Reliability Standards.	Guideline 4 - Consistency with NERC's Definition of the Violation Risk Factor Level	Guideline 5 - Treatment of Requirements that Co-mingle More Than One Obligation
R6.	The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.	Proposed TPL-001-2, Requirement R6 is a new requirement, for which there are no comparable requirements.	Failure to have established criteria for determining System instability is an administrative requirement affecting a planning time frame. Violations of this requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the BES.	Proposed TPL-001-2, Requirement R6 contains only one objective. Therefore only one VRF was assigned to the requirement. Therefore, this requirement is assigned a Low VRF.

VRF for Proposed TPL-001-2, Requirement R7: Low

R#	Guideline 2 - Consistency within a Reliability Standard.	Guideline 3 - Consistency among Reliability Standards.	Guideline 4 - Consistency with NERC's Definition of the Violation Risk Factor Level	Guideline 5 - Treatment of Requirements that Co-mingle More Than One Obligation
R7.	The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.	Proposed TPL-001-2, Requirement R7 is a new requirement, for which there are no comparable requirements to compare VRFs.	Failure to have established individual and joint planning responsibilities is an administrative requirement affecting a planning time frame. Violations of this requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the BES.	Proposed TPL-001-2, Requirement R7 addresses a single objective and has a single VRF.

VRF for Proposed TPL-001-2, Requirement R8: Medium

R#	Guideline 2 - Consistency within a Reliability Standard.	Guideline 3 - Consistency among Reliability Standards.	Guideline 4 - Consistency with NERC's Definition of the Violation Risk Factor Level	Guideline 5 - Treatment of Requirements that Co-mingle More Than One Obligation
R8.	The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.	Proposed TPL-001-2, Requirement R8 is a new requirement, so there are no comparable requirements for which to compare VRFs.	Failure to distribute the Planning Assessment is a requirement that, while administrative in nature, has definite impacts in terms of the importance of obtaining input into the planning assessment from other parties. Violations of this requirement could, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system.	Proposed TPL-001-2, Requirement R8 addresses a single objective and has a single VRF.

Note: *The team did not address Guideline 1, "Consistency with the Conclusions of the Final Blackout Report" directly because of a conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.*

The SDT applied the following NERC criteria when proposing VRFs for the requirements in proposed TPL-001-2:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or

restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

Violation Severity Level Analysis for Proposed TPL-001-2

This chart provides the analysis the SDT used to determine the appropriate Violation Severity Level ("VSL") for each Requirement of the proposed TPL-001-2 — Transmission System Planning Performance Requirements Reliability Standard utilizing the FERC-approved VSL Guidelines.[1]

VSLs for Proposed TPL-001-2, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines – There is an incremental aspect to the violation and the	The most comparable VSL for a similar requirement is for the approved TPL-001-0.1. That VSL is also based on a single violation and is binary. Thus, the	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

[1] *Order On Violation Severity Levels Proposed By The Electric Reliability Organization*, 123 FERC ¶ 61,284 (2008).

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
	VSLs follow the guidelines for incremental violations.	VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	penalties for similar violations.		

VSLs for Proposed TPL-001-2, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSL for a similar requirement is for the approved TPL-002-0a, Requirement R1. That VSL is also incremental. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TPL-001-2, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines – There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	There is a similar requirement in the approved TPL-001-0.1, Requirement R1.3.7. The VSL for that requirement is binary while this requirement adopts an incremental approach. This is justified by the increased number of tasks described in the new requirement and how an entity would go about fulfilling those tasks. Thus, the VSLs	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
		in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.			

VSLs for Proposed TPL-001-2, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	This requirement parallels Requirement R3 where Requirement R3 is for steady-state and this requirement is for Stability. The VSLs for this requirement mirror those for Requirement R3.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TPL-001-2, Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for Proposed TPL-001-2, Requirement R6:

R#	Compliance with NERC's Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for Proposed TPL-001-2, Requirement R7:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TPL-001-2, Requirement R8:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R8.	Meets NERC's VSL guidelines. There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in proposed TPL-001-2 meets the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

> Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

> A violation of a "binary" type requirement must be a "Severe" VSL. Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on a Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

Exhibit D

Consideration of Comments

Project 2006-02
Assess Transmission Future Needs and Develop Transmission Plans

Related Files

Status:
The NERC Board of Trustees adopted the TPL-001-2 standard on August 4, 2011. The Implementation Plan for TPL-001-2 will retire TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1 at midnight the day before TPL-001-2 becomes effective as they are replaced in their entirety by TPL-001-2 (subject to regulatory approval). The Implementation Plan also calls for retiring TPL-005-0 and TPL-006-0.1 at that time (subject to regulatory approval) because the Requirements are either covered by the revised TPL-001-2 or by Section 800 of NERC's Rules of Procedure.

Purpose/Industry Need:
The revisions to the following standards would improve technical clarity and address concerns identified by stakeholders and FERC:

- TPL-001 — System Performance under Normal Conditions
- TPL-002 — System Performance Following Loss of a Single BES Element
- TPL-003 — System Performance Following Loss of Two or More BES Elements
- TPL-004 — System Performance Following Extreme BES Events
- TPL-005 — Regional and Interregional Self-Assessment Reliability Reports
- TPL-006 — Data from the Regional Reliability Organization Needed to Assess Reliability

The final SAR is to establish a standard for assessing and planning the transmission systems in North America. The transmission system must be assessed and planned to ensure that it performs its intended functions in providing reliable delivery of power for the future needs of customers.

Draft	Action	Dates	Results	Consideration of Comments
Draft 8 TPL-001-2 Clean | Redline to last posting **Implementation Plan** Clean | Redline New Definitions for Approval VRFs and VSLs for	Recirculation Ballot>> Info>>	7/13/11 - 7/22/11 (closed)	Summary>> Full Record>> Ballot Comments>>	

Draft	Action	Dates	Results	Consideration of Comments
Draft 8 TPL-001-2 Clean | Redline to last posting **Implementation Plan** Clean | Redline New Definitions for Approval VRFs and VSLs for TPL-001-2 **Supporting Materials:** TPL-001-1 TPL-002-1b TPL-003-1a TPL-004-1 TPL-005-0 TPL-006-0.1	Recirculation Ballot>> Info>>	7/13/11 - 7/22/11 (closed)	Summary>> Full Record>> Ballot Comments>>	
Draft 7 TPL-001-2 — Transmission System Planning Performance Requirements Clean | Redline to last posting | TPL-001-2 Redline to last balloted Implementation Plan **Supporting Materials:** Comment Form TPL-001-1 TPL-002-1b TPL-003-1a TPL-004-1 TPL-005-0 TPL-006-0.1	Join ballot pool>>	4/18/11 - 5/18/11 (closed)	Summary>> Full Record>> Non-Binding Results>>	Consideration of Comments**(10)**
	Successive Ballot and Non-Binding Poll>> Info>>	5/18/11 - 5/31/11 (closed)		
	30-day Formal Comment Period Submit Comments>> Info>>	4/18/11 - 5/31/11 (closed)	Comments Received>>	

Draft 6 TPL-001-2 — Transmission System Planning Performance Requirements Clean | Redline to last posting	Info>>			
Draft 5 TPL-001-2 — Transmission System Planning Performance Requirements Clean | Redline Implementation Plan Clean | Redline **Supporting Materials:** Comment Form (Word)	30-day Informal Comment Period Submit Comments>> Info>>	08/03/10 - 09/02/10	Comments Received>>	Consideration of Comments**(9)**
TPL-001-1 — Transmission System Planning Performance Requirements Clean | Redline Implementation Plan Clean | Redline **Supporting Materials:** Issues Database VRF and VSL Documentation	Initial Ballot Vote>> | Info>>	02/19/10 - 03/01/10 (closed)	Summary>> Full Record>>	Consideration of Comments**(8)**
	Pre-ballot Review Join>> | Info>>	01/20/10 - 02/19/10 (closed)		
Draft 4 TPL-001-1 —	Comment Period	09/16/09 - 10/16/09 (closed)	Comments Received>>	Consideration of Comments**(7)**

Transmission System Planning Performance Requirements Clean | Redline to last posting **Supporting Materials:** Comment Form (Word) Implementation Plan Clean **|** Redline	Info>> Submit Comments>>			
Draft 3 TPL-001-1 — Transmission System Planning Performance Requirements Clean | Redline to last posting **Supporting Materials:** Comment Form (Word) Implementation Plan	Comment Period Info>> Submit Comments>>	05/26/09 - 07/09/09 (closed)	Comments Received>>	Consideration of Comments**(6)**
Draft 2 TPL-001-1 — Transmission System Planning Performance Requirements Clean | Redline to last posting **Supporting Materials:** Comment Form (Word)	Comment Period Info>> Submit Comments>>	08/14/08 - 9/29/08 (closed)	Comments Received>>	Consideration of Comments**(5)**
Industry WebEx and Conference Call to Provide Overview of First Draft of TPL-001-1 — Transmission System Planning Performance Requirements		October 10, 2007		

Info>>				
Draft 1 TPL-001-1 — Transmission System Planning Performance Requirements Clean	Comment Period Info>> Submit Comments>>	09/12/07 - 10/26/07 (closed)	Comments Received>>	Response to Comments**(4)**
ATFN Supplemental SAR Supplemental SAR Version 2 Redline to 1st Posting				
ATFN Supplemental SAR Supplemental SAR Version 1	Comment Period Info>> Submit Comments>>	02/15/07 - 03/16/07 (closed)	Comments Received>>	Consideration of Comments**(3)**
Final SAR				
Assess Transmission Future Needs SAR Drafting Team Draft SAR Version 3	Submit Nomination>>	November 18, 2005 (closed)		
Draft SAR Version 2		05/05/04 - 06/05/04 (closed)	Comments Received>>	Consideration of Comments**(2)**
Draft SAR Version 1		04/02/02 - 05/03/02 (closed)	Comments Received>>	Consideration of Comments**(1)**

Assess Transmission Future Needs and Develop Transmission Plans SAR

Consideration of Industry Comments on SAR Version 1
(SAR Originally Posted for Comment 4/02/02 – 5/03/02)

Background:

Version 1 of the **"Assess Transmission Future Needs and Develop Transmission Plans"** SAR was an abbreviated SAR, which included an "Industry Need" statement and a brief description of the proposed standard, but did not include a detailed description. The purpose of this first posting was to collect feedback from the industry on the following questions:

- Is there a reliability-related need for this SAR?

If there is such a need, how should the scope of the SAR be changed?
- The scope of the SAR is fine as is
- The scope of the SAR should be reduced to eliminate……
- The scope of the SAR should be expanded to include…..

In January 2004, the Standards Authorization Committee (SAC) appointed a Drafting Team (DT) to address industry answers and comments to the questions posed. The DT was also charged with refining the SAR and drafting a detailed description of the proposed standard in preparation for the 2nd posting of the SAR.

This document contains the DT responses to the first set of comments on the original SAR. Because almost 2 years have elapsed since the comments were collected, some have become dated and no longer apply to the present situation. Thus, the DT has not addressed each and every comment, but rather only those that are still timely and represent a general consensus from industry.

Please note that the original comments from industry respondents are shown as underlined text, while the SAR DT responses are shown in yellow highlight.

Question: *"Is there a Reliability-Related Need for this SAR?*

Development of this SAR is not needed or is premature.
Industry comments were overwhelmingly in favor of a standard on transmission assessment and planning, so the SAR DT feels we should proceed with the preparation of a final SAR to be posted for industry comment.

Question: *"Scope of this SAR Should be Reduced to Eliminate ……."*

Standard should not go beyond assessment & planning of the bulk transmission system.
We agree. The DT feels that this SAR as presently written does not go beyond assessment and planning of the bulk transmission system.

Standard should not apply to intrastate systems.
These standards are being drafted to apply to ALL North American bulk electric systems.

Market solutions are outside NERC's scope with respect to development of reliability policies.
Agreed. The present SAR does not require transmission plans to facilitate market operation -- instead, the emphasis is on ensuring reliability.

Definition of "what" core reliability standards are needed is encouraged. However, "how" they are achieved and implemented should not be included at this time, until there is clarity on SMD & RTO formation, and NERC/NAESB interface is defined.
We agree. Industry responses to postings of other SARs and standards indicate that it is widely felt that NERC standards should concentrate on "what" the requirements are, not "how" to achieve them.

SAR should only address creation of Planning Standards. Plan Development is a compliance issue.
The Standard will not tell people "how" to achieve the solutions, but only require that they have a Plan. This is in accordance with the Functional Model, which requires that each Planning Authority have a documented Plan to address inadequacies identified in a transmission needs assessment.

SAR should only define the reliability requirements, not specific solutions.
Agreed.

Eliminate the function relating to "assessing" transmission performance. Only "plan" future transmission expansion.
Assessment of the transmission system is needed to identify anticipated deficiencies that proper planning will correct. Thus, the SAR DT feels that both "assessment" and "planning" are essential components of this SAR.

Standard should only apply to the long-term planning function. Should be a parallel standard for operational planning.
We agree. The standard will only address long term planning, which is defined in the Functional Model as 1 year and beyond.

Standard must not become a mandate for all to use the same load flow model.
Agreed.

Question: *"Scope of this SAR Should be Expanded to Include ……."*

Scope should be expanded to include generation as well.
The SAR DT understands this requirement to "include" generation to mean developing transmission plans that include (as inputs to the transmission adequacy assessment) resources, adequacy plans and load forecasts of LSE's . According to the Functional Model, the Planning Authority must develop an integrated plan from both Transmission Planners and Resource Planners. We agree generation should be included; however, we do not believe that there should be a single standard that integrates resource adequacy planning and transmission adequacy planning. This standard should address only transmission adequacy planning. Separate RA standards may be developed, applicable to different entities; e.g., transmission standards for TOs, resource standards for LSEs .

NERC should guard against establishing a one-dimensional standard that fails to take into account all dimensions that guide the planning process.
Agreed.

SAR should include a requirement to plan the system so that it can be operated within operating limits .
The SAR DT believes that complying with a properly-designed planning standard will result in a system that can be operated within operating limits.

Scope should include planning associated with IPPs
See our response to the comment above that the "scope should be expanded to include generation as well".

NERC should ensure that the standards defined include a definition of how the planning model is created.
The SAR DT has attempted to address this issue in the proposed SAR.

Standard should be specific and measurable and define what "normal", "extreme", and "abnormal" system conditions are.
Agreed. The DT has deleted these terms from the SAR and instead has included a requirement that the standard use the contingency events identified in Table 1 of existing Planning Standard I.A.

Minimum set of criteria for assessing acceptability of plans is needed.
The SAR DT believes the proposed SAR establishes minimum system performance standards, but does not direct how to meet those standards. For a Plan to be acceptable, anticipated system performance under the Plan must meet the minimum criteria established by the standard.

May be a need for multiple expansion plans because of timing of generator projects that are dictated by commercial rather than system adequacy considerations.
The SAR DT does not envision that the standard will address commercial or market issues. However, the standard will require documentation and disclosure of generation assumptions used to develop the Transmission Plan.

Must define what minimum need is. Some regulatory backstop is needed if expansion plans are deemed insufficient to meet needs.
The DT feels that the SAR as written will result in a standard that defines the minimum need.

SAR should identify who has obligation to implement transmission plans.
The Functional Model identifies which functions have the responsibility to implement transmission plans. The SAR DT (in the Comment Form posted with Version 2 of the SAR) has asked for industry guidance on the monitoring of implementation plans.

Must use a reasonable planning horizon (less than or equal to 5 years).
The DT believes that the SAR as written will result in a standard that requires the use of a reasonable planning horizon.

Provision for interim use of Remedial Action Plans (RAP) & Special Protection Schemes (SPS) is needed.
The SAR DT feels that the standard will neither require nor preclude the use of RAP or SPS for either interim or permanent use to meet the reliability criteria contained in the standard.

Regional differences should be recognized.
Agreed. The SAR DT has asked for industry input to identify such differences. See the Comment Form posted with the SAR – V2.

Requirement to provide assessment at all demand levels should be added.
The SAR DT has developed language to consider the variability of load in the development of the standard.

Responsibility for assessing and defining adequate operating reserves and reactive support should be added.
The SAR DT believes operating reserves is an operational issue that should be addressed by operating standards. However, voltage support and reactive power will be addressed in this standard.

Planning criteria should be expanded to include maintainability of system.
The SAR DT has asked for industry input on this issue. Refer to the Comment Form posted with the SAR – V2.

When studies indicate that the system may not meet performance requirements, plans should be developed to address the situation and studies should demonstrate that implemented plans meet requirements.
We agree.

Core standard for reliability should be specific & measurable.
Agreed.

"Miscellaneous Comments"

Technical specifications should ensure that they do not prohibit worthwhile commercial negotiations or commercial activity.
Agreed.

Must have coordination with operating procedures and protocols of RTOs.
The standard will be applicable to all functional responsibilities included in the Functional Model.

Must be close coordination with NAESB and RTOs to meet both reliability objectives and commercial needs.
The standard will define reliability criteria without precluding or dictating viable commercial solutions.

Measuring for compliance is extremely difficult. It is also difficult to determine if events will result in "cascading outages".
We believe the standard will clarify and explicitly state the requirements for compliance. Agreed that a clearer definition of "cascading outages" is needed, and the definition is being developed.

SAR will not accomplish its intent without credible models from which to do analysis.
Agreed.

SAR seems large – divide it up?
The SAR does cover a large scope, but the DT feels that dividing the SAR and standard is premature at this point.

Scope of SAR is poorly written. It does not convey transmission planning responsibilities.
Scope is being revised to add more details and become clearer.

Separate SAR should be established for implementation of SPS. Develop plans to address operational issues for interconnected grids where SPS is needed to mitigate against system deficiencies.
There is a separate SAR that addresses Protection Systems. To the extent that SPS affects transmission assessment and planning, some aspects of SPS may be addressed in this SAR.

SAR does not set standard, but tries to assign responsibility for setting standard.
As envisioned, this SAR will address BOTH the standard and the responsibility.

END OF INDUSTRY COMMENTS/DT RESPONSES FOR SAR – V1

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Note: Questions refer to the 6 questions posed to industry on the SAR Comment Form, posted with SAR Version 2. Some of the question statements listed in this Table of Contents have been abbreviated or paraphrased from their original form. Question statements are shown in their entirety in the body of this document.

BACKGROUND

The Standard 500 **S**tandard **A**uthorization **R**equest **(SAR)**, "Assess Transmission Future Needs and Develop Transmission Plans", was posted for a second public comment period from May 5 through June 5, 2004. The SAR Drafting Team (DT) asked industry participants to provide feedback on the revisions made to the SAR through a special Comment Form posted with the SAR (Version 2).

The SAR (Version 2) Comment Form posed 6 questions, some of which were multi-part. There was a total of 28 sets of comments returned, with 121 individuals responding. The industry comments can be viewed in their original format at:

ftp://www.nerc.com/pub/sys/all_updl/standards/sar/TRNS_NDS_&_PLNS_DT_01_02_Comments.pdf

The Standard 500: "Assess Transmission Future Needs and Develop Transmission Plans" SAR Drafting Team met and considered each of the sets of responses to the questions posed with the SAR (Version 2) Comment Form. The questions were aimed at gathering feedback on the changes made (or proposed to be made) to the SAR.

In consideration of these industry comments, the SAR DT drafted a third version of the SAR for consideration by the Standards Authorization Committee (SAC). The SAR (Version 3), if accepted by the SAC, will serve as specifications for a Standards Drafting Team to draft the new Standard 500. The Standards Drafting Team will have access to all industry comments made on the SAR (Version 2), and well as the SAR DT's consideration of these comments.

FORMAT OF THIS DOCUMENT

In this document, comments from industry participants are shown under each question, along with the SAR Drafting Team's summary of results and consideration of the comments, provided in blue text immediately under each question.

In most cases, a single response has been provided to show how the comments were considered. In some cases, the SAR DT provided a short note to indicate how a unique comment was considered.

At the end of this document there is an Industry Commenter Key listing each entity, industry segment (e.g., Transmission Owner, Generator, ISO, etc.) and the individual names of those responding via the SAR Comment Form.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give EVERY comment serious consideration in this process! If you feel there has been an error or omission, you can contact John Twitchell in the NERC office. John can be reached at 609-452-8060 or at John.Twitchell@nerc.net. Or you can contact this SAR's DT's Facilitator, Margaret Stambach at 518-384-1062 or at mr.stambach@ieee.org.

QUESTION 1(A): DO YOU BELIEVE THAT THE EVENTS IN TABLE I OF EXISTING PLANNING STANDARD I.A ARE CLASSIFIED CORRECTLY?

Question in its entirety:

1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

(a). Do you believe that the events in Categories B, C & D are classified correctly? Comments?

SUMMARY:

YES (entities)	21	NO (entities)	5
YES (individuals)	76	NO (individuals)	42
	NO definitive answer	1 (1 entity, 1 individual) - AEP	

Consideration by the SAR DT:

The SAR DT is recommending a review of existing Table I, including the likelihood, duration and impact of events, as well as the definition of applicable ratings (A/R). This review may result in a re-classification of Table I events for the new Standard. The review may also result in other changes, such as addition or deletion of categories, events or performance requirements, use of probabilistic planning methods, or re-naming of categories based on event probability ranges.

Entities responding YES to Question 1(a) – the events in Table I are classified correctly:

AES, AESO, ALLEGHENY, ATC, CWLP, DUKE, ENTERGY, ERCOT, IMO, ISONE, ISO/RTO, KCPL, MAAC/Horakh, MAAC/Kuras, NPCC, NYSRC, R.Snow, SCGEM, SERC, SOUTHERNCO, SPP, TVA, WESTAR (21 entities, 76 individuals).

SOME ENTITIES RESPONDING YES TO QUESTION 1 (a) [THE EVENTS ARE CLASSIFIED CORRECTLY] HAD THE FOLLOWING ADDITIONAL COMMENTS:	
AESO:	Generally the B and C events are classified correctly. However, there is a need to reconsider the grouping of the D events on some consistent basis (e.g. such as using outage frequency as a determinant). There should also be some means to include double-circuit lines and buses as B events if their probability of outage is comparable to that of other category B contingencies.
ENTERGY, SERC, SOUTHERNCO, SCGEM:	Entities listed believe that Category C events are more likely to occur than Category D events and should require higher performance expectations.
MAAC/Horakh	Categories B, C and D should be renamed as follows – Category B – High Probability Contingency Event

	Category C – Medium Probability Contingency Event Category D – Low Probability Contingency Event The difference in the categories should NOT be stated in terms of how many elements are out of service, but rather should be stated in terms of the PROBABILITY of the initiating event that occurs. The difference in the categories is in the "stress" the system is allowed to experience and in the "fix" required. For B, a high probability event, stress should be low and the only fix allowed is system reinforcement. For D, a low probability event, severe system stress is allowed, and system reinforcement is not mandated. C is somewhere in between, a medium probability, with medium system stress permitted, and some loss of load and/or curtailment of transfers allowed in lieu of system reinforcement. Table I can then be simplified by removing the column labeled "Elements Out of Service", because it is unnecessary and not relative. Actually, the columns labeled "Thermal Limits", "Voltage Limits", "System Stable" and "Cascading Outages" can be eliminated too, because they are the same for each Category A, B and C (but notes for each column should be retained).
MAAC/Kuras:	I believe that an in depth investigation of the probability of each possible contingency occurring be investigated by NERC to determine each contingency's relative probability and those results used to re-rank the contingency list, if necessary.
R.Snow:	Without a rigorous Probabilistic Risk Analysis, moving any of these events to a category D event is bad practice. All of the events have occurred at one time or another, especially circuit breaker and bus faults. Moving them to a category D essentially removes them from requiring action to mitigate/solve the impact on reliability.
WESTAR**:**	"Loss of single component without a fault" should become Category B5 and be included in the listing of items in category C3 *{See similar comments: SPP comment under Question 4, Choice (2) and KCPL comment under Question 4, Choice (3)}.*

QUESTION 1(B): IF YOUR ANSWER TO THE ABOVE QUESTION IS NO, HOW WOULD YOU RE-CLASSIFY THE EVENTS?

Question in its entirety:

1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

(a). Do you believe that the events in Categories B, C & D are classified correctly?

(b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

SUMMARY: 5 entities (42 individuals) answered NO to Question 1(a) and therefore responded to Question 1(b).

Also included in this section are two miscellaneous comments on whether events are classified correctly: one comment from AEP, who had no definitive answer to Question 1(a), and one comment from MAPP, who answered NO to Question 1(a).

Consideration by the SAR DT:

The SAR DT is recommending a review of existing Table I, including the likelihood, duration and impact of events, as well as the definition of applicable ratings (A/R). This review may result in a re-classification of Table I events for the new Standard. The review may also result in other changes, such as addition or deletion of categories, events or performance requirements, use of probabilistic planning methods, or re-naming of categories based on event probability ranges.

Entities responding NO to Question 1(a) – the events in Table I are NOT classified correctly:

AMEREN, BPA, MAPP, MEC and WECC (WECC-1 plus WECC-2). (5 entities, 42 individuals)

ENTITIES RESPONDING TO QUESTION 1(b) [i.e., ENTITIES RESPONDING NO TO QUESTION 1(a) - THE EVENTS ARE NOT CLASSIFIED CORRECTLY]	
Ameren	All category C outages that have a direct impact on serving load because of the system configuration (straight bus or tapped load) should be reclassified, including C-1, C-2, C-5, and C-9 to provide more latitude. For category C events, we should be more concerned that the system holds together and not that the local load may be at risk for these multiple contingency events.
BPA	Outage categories C1, C2 and C9 do not appear to be classified correctly as verified by the attached *outage probability data.* There is consistency between the categories except that C1, C2 and C9 outages have a much lower probability of occurrence than the other Category C outages. ***{See Attached Companion Document: Excel File – "BPAdata". Or contact: Marv Landauer, (503) 230-4105, mjlandauer@bpa.gov}***
MAPP & MEC	MAPP and MEC would reclassify certain low probability events such as Category C1 events, C2 events, certain Category C3 events (two transformers, transmission circuit plus a transformer, two transmission circuits, DC line plus a transformer, DC line plus a transmission circuit, and two DC lines), C6 events, C7 events, C8 events, and C9 events to either a new

	category between C and D with performance characteristics between that of the present Categories C and D or to Category D. *[MEC supports creating a new category between C & D].* MAPP and MEC would require that the interconnected transmission system be planned, designed, and constructed to protect for instability, cascading, and uncontrolled separation for the low probability events in the new sub-category. Regions should develop procedures for determining that systems are properly protected for instability, cascading and uncontrolled separation. MAPP & MEC believe the attached *outage probability data* supports this new reclassification by demonstrating that the events that MAPP & MEC recommend for reclassification are the low probability Category C events. ***{See Attached Companion Document: Word File – "MAPP-MECdata". Or contact: Tom Mielnik, (563) 333-8129, tcmielnik@midamerican.com}***
MEC	MidAmerican Energy believes the interconnected transmission system should be planned, designed, and constructed to withstand high probability events and to withstand low probability events with significant negative consequences. MidAmerican believes it is a waste of the ratepayers' money to plan, design, and construct the interconnected transmission system for low probability events without significant negative consequences.
WECC-1 & WECC-2	The Categories should be based on the probability of occurrence of the initiating events. A review of Table I (Standard I.A) shows that the contingencies in the same Categories seem to have very different probabilities of occurrence.
WECC-1	Category D needs to be split into two categories, the more probable Category D events should not be allowed to cascade. For example, the new "No Cascading" category should include: Loss of 2 units at a plant Loss of adjacent lines in a right of way Loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker. There is no defined performance level for 3 phase fault, stuck breaker, and loss of one line. For support of this position, see the NERC/WECC Planning Standards
WECC-2	A new category should be defined between Category C and Category D. The more probable Category D events and the less probable Category C events should be placed in this new category and not be allowed to cascade. This WECC group supports moving C.2 and C.9 to a new Category between the current C and D Categories. WECC Planning Standards do not support reclassification of C.3.

MISCELLANEOUS COMMENTS ON WHETHER EVENTS ARE CLASSIFIED CORRECTLY	
AEP	Need to see outage probability data in order to answer definitively. Based on good data, the probabilities of existing C and D events could be estimated. The events could then be grouped into higher probability events

	(Category C) and lower probability events (Category D). AEP would be able to provide some outage data to support this analysis. ***{Contact Ali Al-Fayez, Manager – Transmission Asset Performance (614 552-1649)}***
MAPP:	The definition of applicable ratings needs to be clarified. The SAR DT should also indicate if it is feasible to have different applicable ratings for different categories of events. The SAR DT should review the history of the original classification. This review should include all classes. If outage statistics are used to classify events, how many years of data are appropriate? If the data window is too small, the results will be skewed. Moreover, is it appropriate to use outage data for all these categories of events? Outage data over a long period of time may provide insight into equipment performance, but is it appropriate to reflect weather related contingency events – the data may not reflect the effect of a once in a 100 year storm? **Consideration by the SAR DT:** *The SAR DT is recommending that the new Standard clarify ambiguities in performance requirements, specifically cascading outages and A/R. We are also recommending the new Standard clarify that different ratings may be applicable to different categories of events, and perhaps to different types of events within a category (specified by entities in accordance with STD 600).*

QUESTION 1(C): WHICH APPROACH DO YOU FAVOR?: (1) KEEP THE SAME CATEGORIES AND RE-CLASSIFY CERTAIN EVENTS AS CATEGORY D, (2) CREATE A NEW CATEGORY BETWEEN C & D, (3) KEEP THE SAME CATEGORIES AND ALLOW FOR GOOD CAUSE EXCEPTIONS.

Question in its entirety:

1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

(c). Which of the following approaches do you favor regarding Table 1 of existing Planning standard I.A?
(1) Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events. Please explain your choice.
(2) Create a new category between C and D with performance characteristics between that of the present categories C and D. Please explain your choice.
(3) Keep the same categories as now exist, but allow for "good cause exceptions" upon showing a low probability of occurrence (and low consequence) of specific Category C events. Please explain your choice.

SUMMARY:

Entities supporting Choice (1)	4 (9 individuals)
Entities supporting Choice (2)	7 (46 individuals)
Entities supporting Choice (3)	6 (24 individuals)
Entities supporting NONE of the choices	11 (44 individuals)

Consideration by the SAR DT:

The SAR DT is recommending a review of existing Table I, including the likelihood, duration and impact of events, as well as the definition of applicable ratings (A/R). This review may result in a re-classification of Table I events for the new Standard. The review may also result in other changes, such as addition or deletion of categories, events or performance requirements, use of probabilistic planning methods, or re-naming of categories based on event probability ranges.

Since there was no clear consensus on how to address re-classification of events, the SAR DT feels that a thorough review of existing Table I will assure that events are properly classified for the new Standard.

Entities supporting Choice (1) – keep same categories and re-classify certain events as Cat. D

AEP, AMEREN, CWLP, MAPP (4 entities, 9 individuals)

ENTITIES SUPPORTING CHOICE (1) – KEEP SAME CATEGORIES AND RE-CLASSIFY CERTAIN EVENTS AS CATEGORY D	
AEP	Four categories are sufficient and generally understood by the industry. Specific changes that are supported by outage probabilities can be made, as appropriate, by moving Category C tests to Category D.
AMEREN	Reclassify C-1,C-2, and C-9 to category D (less probable events). C-3 (line and a generator combination) should be reclassified as category B event (more probable than other C-3 events. Also, why is a loss of a tower line with two circuits category C (C-5) while loss of a tower line with 3 circuits is category D (D-6), though a probability of loss of a tower line may be the same ? We may want to be consistent in categorizing the event – loss of a multi-circuit tower line.
CWLP	(No explanation given.)
MAPP	If the events are low probability, then some should be considered for moving to C or D.
MISCELLANEOUS COMMENT ON CHOICE (1) – KEEP SAME CATEGORIES & RE-CLASSIFY CERTAIN EVENTS AS CATEGORY D	
MEC	MidAmerican does NOT support this choice, since MEC believes that reclassifying less likely Category C events as Category D events will result in planners ignoring low-probability contingencies that result in significant consequences: cascading, uncontrolled separation, and instability.

Entities supporting Choice (2) – create new category between C & D.

AESO, BPA, CWLP, MAAC/Kuras, MAPP, MEC, WECC (WECC-1 plus WECC-2). (7 entities, 46 individuals)

ENTITIES SUPPORTING CHOICE (2) – CREATE A NEW CATEGORY BETWEEN C & D	
AESO	There are D contingencies that are probable although rare (e.g. loss of multiple circuits on separate tower lines on a common right-of-way). These contingencies may result in loss of load or generation but should not allow cascading. Other D contingencies such as loss of all lines on a multi-line corridor or the loss of a complete station would be difficult to contain. These events should be treated differently than the former.
BPA	The C2 (with respect to a bus section breaker failure) and the C9 outages should be in this new category. Although these outages have extremely low probability, they should not cause cascading. This is especially true of C2, which is a single contingency failure of a bus section breaker. Therefore we favor adding a new category between Level C and D (or moving these two outages to Level D) with performance requirements of no cascading and system stable but with no requirement to be within applicable ratings. ***[See similar comment from WECC-2 under Question 5, Regional Differences]***

CWLP	Multiple contingencies have lower and varying probabilities of occurrence.
MAAC/Kuras	This is the best choice of the ones mentioned here but see my comment in 1.(a) above for another approach. This approach allows for some levels of performance between C and D such as restricting the performance to "no cascading or system instability" for some C and maybe even D events.
MAPP & MEC	Improvements should be planned for those Category C events that are high probability events regardless of the consequences. Planners should also review all Category C events for instability, cascading, and uncontrolled separation. Improvements should be planned for those Category C events (both high probability and low probability events) which have significant consequences, that is, that result in instability, cascading, and uncontrolled separation.
MEC	The approach that results in the most appropriate transmission system design is the one recommended by MEC. It is MEC's belief that the intent of the drafting team that originally developed the existing NERC Planning Standards was to require the NERC member to plan to protect for instability, cascading, and uncontrolled separation for Category C events.
WECC-1 & WECC-2	A "No Cascading" performance requirement is needed for this new category. There are Category C events, which have a very low probability of occurrence. Such events, even if they occurred, should not lead to cascading, even though local facility ratings or voltage limits may be exceeded. Very often, the solution for such low probability contingencies would be to install a relay system to interrupt load or generation. The probability of relay misoperation to prevent potential problems resulting from the contingency may be higher than the probability of the contingency itself. Thus the impact on the users of the grid may not be significantly reduced. Nevertheless, the system reliability would be better served if we can add a category for such low probability contingencies (which would not result in cascading), and the risk of which is acceptable.

Entities supporting Choice (3) – keep same categories and allow for good cause exceptions.

ATC, BPA, DUKE, KCPL, SPP, TVA, WESTAR. (6 entities, 24 individuals).

{Note: BPA not counted in this choice. BPA counted in Choice (2) "New Category", since that is their preferred choice}

ENTITIES SUPPORTING CHOICE (3) – KEEP SAME CATEGORIES AND ALLOW FOR GOOD CAUSE EXCEPTIONS	
ATC	The outages listed in the existing categories are reasonable but, because we don't know all the specific details about a certain part of the system, there should be some mechanism to consider exceptions.
BPA	Although this is not our preferred choice, allowing the use of "good cause exceptions" (which we assume is the same as probabilistic methods which could move contingencies to a lower performance level although this is inconsistent with other statements in the SAR) to verify exceptions to the present categories would also be acceptable. For the C2 example, showing that these events statistically occur every 1200-1300 years and would not cause cascading problems on the system should provide enough evidence that a lower performance level is appropriate.

DUKE	Allow the flexibility for reasonable exceptions to the general categories based on frequency of occurrence. This may mean the possibility of a particular contingency moving up or down in category. This allowance permits appropriate exercise of engineering judgment in the planning process.
KCPL	KCPL supports the recommendation that the Standard should allow for the development and use of probabilistic planning methods in reliability assessment. However, KCP&L does not support any reclassification of the existing Categories. The probability of occurrence of some contingencies may, in actuality, be very low. However, this should not diminish the importance of their assessment in the Category that they are currently found.
SPP	SPP would like to see a definition of "good cause exceptions" at a minimum. SPP encourages the development of probabilistic techniques to assess reliability but caution needs to be exercised prior to implementation to ensure support from all stakeholders.
TVA	This "good cause exception" approach allows documentation of an assessment of low consequence to substitute for the expenditure of an unwarranted solution, but maintains the integrity of the event probability assessment. Since others may have different ideas of what is low probability, this approach would be best with sufficient justification of low probability.
WESTAR	Once an analysis has been performed, a subsequent "assessment" can easily dismiss low consequence events. However, low probability with high consequence should not be granted an exception. The initial premise of the Planning Standards did not contemplate probabilistic or Monte Carlo analysis. "Good Cause Exception" must be carefully defined before entities are allowed to shield high consequence events regardless of probability of occurrence.
MISCELLANEOUS COMMENTS ON CHOICE (3) - KEEP SAME CATEGORIES & ALLOW FOR GOOD CAUSE EXCEPTIONS	
AEP	"Good cause exceptions" can always be considered, but this approach should not be institutionalized.
MAPP & MEC	MAPP & MEC believe that allowing for "good cause exceptions" is not the preferable approach. We believe that the events listed by MAPP & MEC for reclassification are much less likely than the other Category C events generally throughout NERC. This means that these events should be reclassified in general throughout NERC and not just in certain "good cause exceptions". (Although, it should be noted that MAPP & MEC do support Regional Differences where appropriate.) Besides, there are issues associated with the development and utilization of a process for approving "good cause exceptions".
NYSRC	In accordance with the NERC process for developing reliability standards, an entity may include a Regional Difference as part of the NERC standard if there is such a condition. Therefore, there is no need for the standard to include "good cause exceptions".

Entities supporting NONE of the 3 choices:

ENTERGY, ERCOT, IMO, ISONE, ISO/RTO, MAAC/Horakh, NPCC, NYSRC, SCGEM, SERC, SOUTHERNCO, (11 entities, 44 individuals).

ENTITIES SUPPORTING NONE OF THE CHOICES - NO CHANGES TO CATEGORIES/EVENTS	
ENTERGY, SCGEM, SERC, SOUTHERNCO	Since the events are currently categorized correctly, above Questions 1 (b) and 1 (c) are not applicable. Entities listed agree that low consequence Category C events should be considered compliant. However, as we interpret Table I, a Category C event that results in low consequences (e.g. no cascading) is already considered compliant since entities can drop load or curtail firm transfers to return to applicable thermal or voltage ratings.
ERCOT, IMO, ISONE, ISO/RTO, NPCC, NYSRC	Any of the above three choices would weaken the present NERC standards. All entities listed take the position that there should be No Changes to Categories B, C, and D as they now exist in the present Planning Standards.
MAAC/Horakh	NONE OF THE ABOVE. Keep the three categories, but rename them as in 1.a. above. Adding an additional category would introduce too much confusion in planning the system. Assuming that the contingencies in B, C and D are already in their correct probability categories, no changes need to be made. If someone could prove that a contingency in B is Low Probability the same as the contingencies in D, that contingency could be moved.

QUESTION 2: DO YOU BELIEVE THE STANDARD SHOULD REQUIRE REPORTING ON *IMPLEMENTING* THE TRANSMISSION PLANS?

Question in its entirety:

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

SUMMARY:

YES (entities)	13	NO (entities)	13
YES (individuals)	60	NO (individuals)	53
	NO definitive answer	1 (1 entity, 7 individuals) - MAPP	

Consideration by the SAR DT:

There was no clear consensus on whether reporting on the progress or status of implementing the plans should be included in the Standard. This SAR Drafting Team is recommending that the new Standard address requirements for reporting (perhaps to the Regions) on the progress or status of implementing the plans, but such requirements should not impose undue burdens upon transmission entities.

Any such reporting requirements shall be consistent with the Resource & Transmission Adequacy's RTATF Recommendation #2: "Among other items, the new Reliability Standards should clearly define the key elements of an acceptable mitigation plan to achieve compliance with the standard(s) and a general process to ensure implementation of the mitigation plan".

Entities responding YES to Question 2 – the standard SHOULD require implementation reporting.

AEP, AMEREN, BPA, IMO, ISONE, ISO/RTO, ERCOT, KCPL, MAAC/Horakh, MAAC/Kuras, NPCC, NYSRC, R.Snow, SPP, WESTAR (13 entities, 60 individuals)

SOME ENTITIES RESPONDING YES TO QUESTION 2 [THE STANDARD SHOULD REQUIRE IMPLEMENTATION REPORTING] HAD THE FOLLOWING ADDITIONAL COMMENTS:	
AEP	The reporting requirements should not be burdensome, but they are needed to ensure a minimum level of accountability.
AMEREN	The reporting requirement should not be onerous.
BPA	A plan without a requirement to update progress on implementing the plan has little value. This is essential for an effective standard. This should not be an extensive reporting procedure and could easily be met during the subsequent compliance report.
KCPL	KCP&L supports a requirement for reporting the status of implementing the mitigation plans. On a regional basis, mitigation plans should be reported by the Transmission Planner, as a minimum, on an annual basis through the regional model building process and assessed through the regional

	assessment studies performed by the Regional Reliability Coordinator.
MAAC/Kuras	It's one thing to develop plans and another to follow through on them. PJM can offer suggestions on how this tracking could be accomplished.
R.Snow	Developing plans without a follow up program is a waste of time and money. One of the most telling comments from the August Blackout report was that a number of the items were the same as in other blackouts.
SPP	SPP supports this reporting requirement, but notes that this burden should not be imposed more frequently than annually.
WESTAR	Having a "plan" that is not implemented is of no value.

Entities responding NO to Question 2 – the standard SHOULD NOT require implementation reporting.

AES, AESO, ALLEGHENY, ATC, CWLP, DUKE, ENTERGY, MEC, SCGEM, SERC, SOUTHERNCO, TVA, WECC-1, WECC-2 (13 entities, 53 individuals)

SOME ENTITIES RESPONDING NO TO QUESTION 2 [THE STANDARD <u>SHOULD NOT</u> REQUIRE IMPLEMENTATION REPORTING] HAD THE FOLLOWING ADDITIONAL COMMENTS:	
AES	AES does not favor an implementation report. However, major facility additions, delayed additions, or deletions that effect the reliability of the system could be included as part of the regional form 715 base case yearly filings and listed as changes from last year's cases. This would allow older cases to easily be updated and used.
AESO	It is not clear to whom the reporting would go to and how it would be used. Normally, reporting would be required for the regulatory process in the affected jurisdiction. The scope of that reporting would not be limited to reliability only but also other aspects of the transmission plan (e.g. customer connections, efficiency improvements, etc).
ATC	While an entity should be implementing plans to maintain or improve the reliability required by the standards, having to report on the implementation could become quite complicated. Plans are often changing to meet changing system conditions, sometimes so much so that what seemed reasonable to do last year is replaced by entirely new plans.
MEC	MidAmerican Energy believes that this standard should not include requirements for reporting on the progress or status of implementing the plans developed in accordance with this standard. There are too many conditions beyond the control of the NERC member for this to be a part of a standard requiring compliance review. Complex environmental, regulatory, and political issues prevent many transmission facilities from being constructed or being constructed in a scheduled manner. The Not-In-My-Back-Yard philosophy has hit even the rural areas so that there is no part of the NERC area where a NERC member can confidently predict completion of transmission system improvements in plans. Further, conditions can change even during a year to such an extent that compliance review for implementation from one year to the next is problematic. Further, regulatory oversight provides for appropriate review of plan implementation anyway. MidAmerican urges that the SAR drafting team not pursue this well-meaning but problematic approach.

SCGEM, SOUTHERNCO	Too burdensome for the perceived benefits.
TVA	This reporting would constitute a logistical burden counterproductive to the total planning effort.
WECC-1 & WECC-2	Since many of the transmission plans are dependent upon factors such as, resource plans, local load projections, new technology, permitting, to name a few, it would not be meaningful to report on the status of implementation of a transmission plan. In any case, if a potential transmission problem is not solved, it will show up again in subsequent years, so there will be pressure to solve it. This continuous "certification" would ensure that any potential transmission problem, once identified, would not be left unsolved even without NERC requiring status reports on implementation.

MISCELLANEOUS COMMENT ON WHETHER THE STANDARD SHOULD REQUIRE IMPLEMENTATION REPORTING (Neither Yes/No Box Checked)	
MAPP	Requirements for reporting on the progress or status of implementing the plans should be left to the regions and appropriate regulatory bodies. The MAPP Regional Transmission Committee currently has a regional planning process for compliance for implementing transmission plans.

QUESTION 3: IF YOUR ANSWER TO *QUESTION 2* IS YES, HOW WOULD YOU PROPOSE ACCOUNTING FOR CHANGES IN A TRANSMISSION PLAN?

Question in its entirety:

3. If your answer to Question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan?

SUMMARY: 13 entities (60 individuals) answered YES to Question 2 and therefore responded to Question 3.

Consideration by the SAR DT:

There was no clear consensus on whether reporting on the progress or status of implementing the plans should be included in the Standard. This SAR Drafting Team is recommending that the new Standard address requirements for reporting (perhaps to the Regions) on the progress or status of implementing the plans, but such requirements should not impose undue burdens upon transmission entities.

Any such reporting requirements shall be consistent with the Resource & Transmission Adequacy's RTATF Recommendation #2: "Among other items, the new Reliability Standards should clearly define the key elements of an acceptable mitigation plan to achieve compliance with the standard(s) and a general process to ensure implementation of the mitigation plan".

Entities responding YES to Question 2 (The standard SHOULD require implementation reporting) and therefore responding to Question 3 (How would you account for changes in a Transmission Plan?).

AEP, AMEREN, BPA, ERCOT, IMO, ISONE, ISO/RTO, KCPL, MAAC/Horakh, MAAC/Kuras, NPCC, NYSRC, R.Snow, SPP, WESTAR (13 entities, 60 individuals)

ENTITIES RESPONDING TO QUESTION 3 – HOW WOULD YOU PROPOSE ACCOUNTING FOR CHANGES IN A TRANSMISSION PLAN? [i.e., ENTITIES RESPONDING YES TO QUESTION 2 - THE STANDARD SHOULD REQUIRE IMPLEMENTATION REPORTING]:	
AEP	A simple narrative explanation should be provided that explains what factors have eliminated the need for the transmission modification/addition or changed its timing. In cases where a modified solution has been developed, the Transmission Planner should demonstrate the effectiveness of the modified approach and compare to the original approach.
AMEREN	Provide the following: (i) Annual update with a short note to document changes. (ii) Smaller projects (cap bank addition, change of terminal equipment like switches, wavetrap, or CT) may be combined as a group in such reporting to avoid providing a long list of updates.
BPA	Once a transmission plan is identified in a compliance report, progress on that project should be reported in subsequent compliance reports. If system conditions change, this should be described along with the consequences to the proposed plans. If project need goes away, the project can be canceled.

	However, if the project need still exists and the responsible entity has not implemented a plan to correct the deficiency, it should be listed as non-compliant. Legitimate problems with regulatory and siting issues should be acceptable reasons for project delay.
ERCOT, IMO, ISONE, ISO/RTO, NPCC	All entities listed favor periodic transmission reviews to address changes in plans. In the northeast, the NPCC Annual Transmission Reviews address this and in addition NPCC keeps a "Major Projects List" to "track" BPS additions and modifications and includes transmission, generation and other major equipment identified as a BPS element. The entities suggest that the resultant NERC standard not be overly prescriptive in requirements for reporting progress/status on the standard and flexibility be afforded to allow various documentation and processes already in place to achieve compliance. They suggest it be done annually.
KCPL	Any out-of-cycle changes to the mitigation plan should be reported to the Reliability Coordinator and re-evaluated on an as-needed basis. Coordinated planning between other regions and entities will be critical.
MAAC/Horakh	Reporting should be on a "delay" basis. Known delays to the plan should be reported, along with the reason for the delay and use of alternate solutions.
MAAC/Kuras	A plan is a plan at that point in time. Plans change. Periodic checks of implementation of plans can uncover these plan changes that should be allowed.
NYSRC	Updated transmission plans should be reported along with compliance assessments as required.
R. Snow	When there is a significant change in the assumptions, the plan needs to be re-studied and revised as appropriate. The SAR must require such re-studies. Any plan is only as good as its assumptions. Whenever there is a significant change in the assumptions, the plan needs to be revised to account for the change. Having a plan that assumes there will be specific generation projects is worthless when those specific projects are changed, canceled or if other generation retires.
SPP	Although SPP is implementing a 2 year planning cycle, project updates are collected on an annual basis. To ensure compliance with reliability criteria, mitigation reviews are also provided on an annual basis consistent with the annual model building process. Updates due to new "out of cycle" projects or significant scope/timing changes associated with major projects in the approved regional expansion plan and its assessments are evaluated on an as-needed basis. Coordinated planning and model building using consistent definitions with neighboring regions/entities will be critical. Efforts should be undertaken to put data collection, modeling building and transmission assessment processes for neighboring regions/entities on the same cycles.
WESTAR	In the annual process to update power flow models, there are necessarily changes to the load forecast, use of the interconnected network, and financial constraints which must be taken into account. Reporting to the Regional Reliability Organization should include a discussion of substantive changes and reasons behind them. There should not be a judgment made by the RRO that the explanation is "adequate" so long as the explanation is made. The changes are critical information that must be taken into account when evaluating transmission service requests. Reporting should not be more frequent than the model-building cycle.

QUESTION 4: SHOULD THE REQUIREMENT TO CONSIDER PLANNED OUTAGES IN ADDITION TO EACH CONTINGENCY REMAIN PART OF THIS PLANNING STANDARD?

Question in its entirety:

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

The SAR drafting team believes that it is impractical to exhaustively test for every contingency described in each category plus every conceivable planned outage. Should the requirement to consider planned outages in addition to each Category A through D contingency remain part of this planning standard?
(1) Yes, consider planned outages in all Categories A through D.
(2) Yes, consider planned outages in some Categories only – Please specify which Categories.
(3) No, do not consider planned outages in addition to each contingency in any Category.

SUMMARY:

Entities supporting Choice (1)	6 (16 individuals)
Entities supporting Choice (2)	15 (76 individuals)
Entities supporting Choice (3)	8 (27 individuals)

Miscellaneous Comment (No choice selected) – 1 entity (2 individuals) - Seminole

Consideration by the SAR DT:

The SAR Drafting Team believes there is confusion surrounding the planned outage requirement in Table I of the existing standard. The SAR DT is recommending that the new Planning Standard clarify the issue of how a planned outage should be used in a planning assessment.

The new Standard should specify whether the planned outage requirement should be retained for Categories B and C. If retained, the requirement should be clarified in such a way that it can be practically implemented. In particular, the Transmission Planner should not be required to exhaustively test their systems for every conceivable planned (including maintenance) outage in addition to every conceivable Category B and C contingency.

The new Standard should clarify that the planned outage requirement does not apply to Categories A and D.

Entities supporting Choice (1) – consider planned outages in ALL Categories A through D.

ERCOT, ISO/RTO, NYSRC, MAAC/Kuras, TVA (half of group), WESTAR (6 entities, 16 individuals)

ENTITIES SUPPORTING CHOICE (1) – CONSIDER PLANNED OUTAGES IN ALL CATEGORIES A THROUGH D	
ERCOT, ISO/RTO, NYSRC	Again, the existing standards should not be weakened.

MAAC/Kuras	Contingencies don't only happen when all lines are in service. Outages should be modeled during all types of contingency evaluation. This may be a fairly daunting task but this evaluation will help the system operators be prepared for the reality of operating the system in a less than ideal state. Possible ways to select lines to outage may be to look at lines with high unscheduled outage rates, lines close to sources of contamination, lines through areas that have historically had vegetation contact problems, and especially lines that when outaged can cause operating problems.
TVA	**{Half of group}.** Everyone in the group agreed that planned outages should be considered, but the group didn't agree on which categories to apply. About half believed they should be applied to all categories while the other half believed only A and B categories should have planned outages studied for the one year and beyond horizon.
WESTAR	The notion of including maintenance outages is to ensure that system restorations correctly evaluate single elements that would be removed in groups under a breaker-to-breaker outage analysis. The intent should not be to have any single element out for maintenance AND withstand the next contingency and should be stated as such.

Entities supporting Choice (2) – consider planned outages in SOME Categories only.

AEP, AESO, ALLEGHENY, CWLP, ENTERGY, IMO, ISONE, MAAC/Horakh, NPCC, R. Snow, SCGEM, SERC, SOUTHERNCO, SPP, TVA (half of group), WECC (WECC-1 plus WECC-2). (15 entities, 76 individuals)

ENTITIES SUPPORTING CHOICE (2) – CONSIDER PLANNED OUTAGES IN <u>SOME</u> CATEGORIES.	
AEP	**{B, C & D only}.** For Categories where planned maintenance is considered, it should only be necessary to test the most significant planned outages, not all possible planned outages.
AESO	**{A, B & C only}.** There is a need to clarify what constitutes the "normal" condition when a facility (transmission or generation) is on a long duration planned outage (is it a day, a week, etc). The A to C contingency categories can then be applied to the "normal" condition as defined. The testing requirement could perhaps be stated in a way that leaves it to the judgment of the Planning Authority as to the critical combinations of outages that need to be tested.
ALLEGHENY	**{A & B only}.** Allegheny Power feels that it is practical to consider planned outages in categories A and B.
CWLP	**{B and some C}.** No further comments.
ENTERGY	**{B & C only}.** It is not necessary to include planned maintenance outages in addition to Category A (no contingencies) because Category A plus planned outages equals Category B (single contingency). Therefore inclusion of maintenance outages in Category A is superfluous. The current standards do not require planned outages with Category A for that very reason. Maintenance outages should be considered for only Category B and C contingencies. Category D recognizes that cascading will occur in conjunction with the contingencies, so adding on more planned outages seems unnecessary,

	especially since Category D outages are very low probability events.
IMO, ISONE, NPCC	**{A, B & C only}.** We reiterate that the existing standards should not be weakened and request that the SAR be clarified to remove ambiguity regarding what is meant by "considering" a planned outage. Planned outages at present are considered however this is deemed an Operational Planning issue and is conducted so as to set Operational Limits for those conditions on a pre-contingency basis to allow for N-1 conditions. This particular SAR will ultimately result in a "planning" Reliability Standard. The wording, as it has been phrased, infers that the system must be planned, designed and built to N-2 standards (i.e. a line out for maintenance on top of a circuit element outage). Treatment of planned outages should be considered to some extent and the listed entities suggest the drafting team receive direction from the SAC regarding planned outages. The listed entities suggest that planned outages should be considered only in categories in A through C.
MAAC/Horakh	**{A & B only}.** Consider planned outages in Categories A & B only, since these categories are high probability and therefore could easily occur during a planned outage.
R.Snow	**{A, B & C only}.** Categories A through C should be considered. Category D does not require action so the analysis with outages does not add anything. Most planning software allows the sue of scripts to run multiple analysis without intervention. The state of modern computers is such that the added testing is not significant. Also, for most systems, this type of analysis is performed to define which load levels and generation dispatch would allow the maintenance (the problem in reverse).
SCGEM, SOUTHERNCO	**{A & B only}.** The requirement to consider planned outages in addition to each Category A and B contingency should remain part of this planning standard. We agree with the SAR drafting team that exhaustive testing for every contingency described and every load level in each category is not practical.
SERC	**{A & B only}.** The SERC PSS agrees that the requirement to consider planned outages in addition to each Category A and B contingency remain part of this planning standard. The SERC PSS could not reach consensus on the requirement to consider planned outages in addition to each Category C and D contingency. However, the SERC PSS does agree that exhaustive testing for every contingency described in each category is not required. The I.A compliance templates state that they must *"Be performed and evaluated only for those Category [B, C, and D] contingencies that would produce the more severe system results or impacts."*
SPP	**{B & C only}.** C.3. needs to be modified to address N-1-1 concerns. Category B (B1, B2, B3 or B4, including loss of an element without a fault) or in the alternative create Category B5 to Loss of an element without a fault. The latter is preferred. *[See similar comments - KCPL comment under Question 4 Choice (3) below, and Westar comment under Question 1(a) above]* Planned outages are typically not evaluated more than one year in advance and are not scheduled during peak load conditions. However, the existing Planning Standard 1.A is problematic in that it requires the system to be designed to accommodate planned outages during peak load conditions.
TVA	**{A & B only – half of group}.** Everyone in the group agreed that planned

	outages should be considered, but the group didn't agree on which categories to apply. About half believed they should be applied to all categories while the other half believed only A and B categories should have planned outages studied for the one year and beyond horizon.
WECC-1 & WECC-2	**{A, B & C (except C-3)}.** All contingencies where a single point of failure could cause facilities to be lost should be tested for compliance with the standards even under planned maintenance conditions. However, it should never be necessary to exhaustively test every possible combination of outages. Those contingencies that are clearly not critical outages should not have to be simulated.

Entities supporting Choice (3) – do NOT consider planned outages in addition to each contingency in any Category.

AES, AMEREN, ATC, BPA, DUKE, KCPL, MAPP, MEC (8 entities, 27 individuals)

ENTITIES SUPPORTING CHOICE (3) – DO NOT CONSIDER PLANNED OUTAGES IN ADDITION TO EACH CONTINGENCY IN ANY CATEGORY.	
AES	I would modify C-3 since it has the same effect as or similar to a C-3 event to include (line out followed by a category B event).
AMEREN	Is the issue planning the system or granting the outage? Local load may be exposed for granting a maintenance/construction outage, but the system should not be at risk. If the system is planned with category C requirements, in most cases it should meet category A and B requirements during a planned outage. To meet requirements of categories A and B during planned outage should be adequate. Planned outages for maintenance or construction are generally managed in the operating horizon, and are granted only during specific load levels (off-peak), generation patterns, and interchange patterns when the transmission system is not expected to be fully utilized. We agree that clarification should be provided on how this information should be used in an assessment. However, as the scope of planning assessments is for the planning horizon of one year or more (SAR-4, paragraph 2) and not the operating horizon, we do not believe that the requirement for planning for maintenance outages should be included in planning assessments.
ATC	Planning the system should consider the need for planned outages but should not require the capability to plan outages at peak system loads.
BPA	This requirement should be addressed in operational planning studies (less than one year). This standard is not appropriate for Transmission Planning studies except possibly as a tool to measure or compare the robustness or availability of transmission plans. This is not an item that should require any compliance action.
DUKE	The first priority should be to clarify the requirements of the I.A table. Utilities/ regions are interpreting the table differently. What was the original basis for the contingency categories and required response in the table? Clarify whether the original intent was to perform thermal, voltage and stability screens for all categories and the frequency at which the screenings were intended to performed. It is impractical to expect all screenings of all categories on a frequent basis. It may be appropriate to state that the table is for general guidance and that

	transmission owners may determine frequency at which studies should be performed based on load growth, system loading and significance of changes to the system.
KCPL	Planned outages are typically short-term (less than 1 year) and should be considered in the operating horizon. A planned outage is typically allowed during system load conditions when they will have minimal impact on the system. KCPL would prefer to clarify the existing Category B contingency that states "Loss of an element without a fault" be listed as the B5 contingency on the Table. Then, in Category C under Contingency 3, the revised wording should read "3. Category B (B1, B2, B3, B4, or B5) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, B4, or B5) contingency. This will allow for the first contingency to include a planned outage (B5 without a fault) as well as a contingency with one of the fault conditions described in B1, B2, B3, and B4. {*See similar comments - Westar comment under Question 1(a) and SPP comment under Question 4, Choice (2).*}
MAPP & MECC	Planned Outages can be scheduled and analyzed in advance in the operating horizon (less than one year). Therefore, it should not be necessary to require that "systems must be capable of meeting Category C requirements while accommodating the planned outage of any bulk electric equipment..." Planned outages should be studied in advance by the requesting control area and be reviewed by the governing Reliability Coordinator to determine if overloads could occur. If studies show that overloads could occur, the planned outage should be deferred or operating guides prepared which would be used in the event a contingency does occur.
MEC	There is no need to plan or build facilities to meet Planning Standard 1.A when Planned Outages can be accommodated within the frame work of existing guidelines and procedures. Studies conducted for the operating horizon are not the subject of this standard.

MISCELLANEOUS COMMENT ON CONSIDERING PLANNED OUTAGES – (No Choice Selected)	
SEMINOLE	Many grid operations difficulties occur when a line is scheduled out for maintenance. If this SAR is going to address required N-2 planning assessments, then it must be clear and specific regarding the conditions when N-2 assessments are appropriate and the specific criteria for N-2 assessments.

QUESTION 5: ARE YOU AWARE OF ANY REGIONAL OR INTERCONNECTION DIFFERENCES IN REQUIREMENTS FOR ASSESSING AND PLANNING TRANSMISSION SYSTEMS IN NORTH AMERICA?

Question in its entirety:

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

SUMMARY: 10 entities (68 individuals) responded to this question and gave examples of Regional/Interconnection differences.

Consideration by the SAR DT:

The SAR Drafting Team considered each comment individually, as shown in the table below.

Entities responding to Question 5 – are you aware of any Regional/Interconnection differences?

BPA, CWLP, KCPL, NYSRC, SCGEM, SEMINOLE, SOUTHERNCO, SPP, R, Snow, WECC (WECC-1 plus WECC-2), WESTAR. (10 entities, 68 individuals)

ENTITIES RESPONDING TO QUESTION (5) – ARE YOU AWARE OF ANY REGONAL/INTERCONNECTION DIFFERENCES?	
BPA	Although WECC has several requirements in its standards that are more stringent than the existing NERC criteria, it also has two standards that are less stringent (C2 and C9). Depending on the resolution of question #1 above, C2 and C9 may be a regional difference. WECC has a formal Probabilistic Planning process that allows adjustment of performance levels of contingencies in either direction. As this SAR states that the existing NERC Table I is the minimum criteria for probabilistic methods, this will be a regional difference for WECC. This is discussed more in our comments on the SAR document. **Consideration by the SAR DT** *The present SAR no longer states that existing Table I is the minimum criteria for probabilistic methods, only that Table I should be used as a starting point for a review of the existing standard. Thus, probabilistic planning could allow for adjustment of performance requirements in either direction.* *The SAR DT is recommending that the review of the existing standard include the likelihood, duration and impact of events, as well as the definition of applicable ratings (A/R). This review may result in a re-classification of Table I events for the new Standard. The review may also result in other changes, such as addition or deletion of categories, events or performance requirements, use of probabilistic planning methods, or re-naming of categories based on event probability ranges.* *Since there was no clear consensus on how to address re-classification of events, the SAR DT feels that a thorough review of existing Table I will assure that events are properly classified for the new Standard.* *If differences in the classification of events or performance requirements remain after the draft Standard is posted, please provide your specific*

	comments at that time
CWLP	WECC has asked the NERC PC for waivers for some of the Category C requirements. **Consideration by the SAR DT** *See the SAR DT response to WECC-1 & WECC-2 in this table.*
KCPL	KCPL is aware of neighboring regional council differences in classification of Category B and C contingencies between SPP and MAPP. **Consideration by the SAR DT** *The SAR DT is recommending a review of existing Table I, which may result in a re-classification of Table I events for the new Standard. The review may also result in other changes, such as addition or deletion of categories, events or performance requirements, use of probabilistic planning methods, or re-naming of categories based on event probability ranges.* *Since there was no clear consensus on how to address re-classification of events, the SAR DT feels that a thorough review of existing Table I will assure that events are properly classified for the new Standard.* *If differences in the classification of Category B and C contingencies remain after the draft Standard is posted, please provide your specific comments at that time.*
NYSRC	It is the NYSRC's position that (1) NERC specifies minimum standards, (2) a Region may establish more stringent standards for its members separate from the NERC standards, and (3) it is unnecessary to include these more stringent standards within the framework of the NERC standards. **Consideration by the SAR DT** *The SAR DT agrees with this position.*
SCGEM, SOUTHERNCO	Not aware of any at this time. However, Regional Differences could develop and each request for a Regional Difference should be considered individually. **Consideration by the SAR DT** *The SAR DT agrees with this position.*
SEMINOLE	In Florida, with the state requirements for the siting of facilities, the planning horizon should be adjusted from 5 YRS to 8 YRS. The 5 YR horizon is too short for some major transmission line projects and/or studies of transmission interconnections/upgrades for base load central station generating facilities. **Consideration by the SAR DT** *The present SAR provides for a planning horizon of 5 years or more.*
SPP	SPP is aware of differences between SPP and the neighboring regions of ERCOT, MAPP and WECC. **Consideration by the SAR DT** *If differences remain after the draft Standard is posted, please provide your specific comments at that time.*
R. Snow	Each region has their own requirements.

	Consideration by the SAR DT *Each Region has the right to request Regional differences for approval as part of the Standard.*
WECC-1 & WECC-2	The existing NERC Standard C-9 (and C-2 for bus sectionalizing breakers) as it applies to WECC should be modified so that thermal limit and voltage limit violations are allowed for bus sectionalizing breaker failures. This is because bus sectionalizing breaker failure is a relatively low probability event. Use of a bus sectionalizing breaker should be encouraged because it reduces the impact of a disturbance to a portion of the load only. Without the proposed modification there is no incentive to use the sectionalizing breaker. However, under no conditions should system instability or cascading outages be allowed for bus sectionalizing breaker failures. **Consideration by the SAR DT** *The SAR DT is recommending a review of existing Table I, including the likelihood, duration and impact of events, as well as the definition of applicable ratings (A/R). This review may result in a re-classification of Table I events for the new Standard. The review may also result in other changes, such as addition or deletion of categories, events or performance requirements, use of probabilistic planning methods, or re-naming of categories based on event probability ranges.* *Since there was no clear consensus on how to address re-classification of events, the SAR DT feels that a thorough review of existing Table I will assure that events are properly classified for the new Standard.* *If differences in the classification of events or performance requirements remain after the draft Standard is posted, please provide your specific comments at that time.*
WESTAR	Yes. MAPP categorizes some contingencies differently. **Consideration by the SAR DT** *The SAR DT is recommending a review of existing Table I, which may result in a re-classification of Table I events for the new Standard. The review may also result in other changes, such as addition or deletion of categories, events or performance requirements, use of probabilistic planning methods, or re-naming of categories based on event probability ranges.* *Since there was no clear consensus on how to address re-classification of events, the SAR DT feels that a thorough review of existing Table I will assure that events are properly classified for the new Standard.* *If differences in the categorization of events remain after the draft Standard is posted, please provide your specific comments at that time.*

QUESTION 6: DO YOU HAVE ANY OTHER COMMENTS ON THE SAR (V2)?

Question in its entirety:

6. Do you have any other comments on Version 2 of the SAR? Please list and explain.

SUMMARY: Most of the 28 entities (121 individuals) responded to this question and provided additional comments on the SAR (Version 2).

Consideration by the SAR DT:

The SAR Drafting Team considered each comment individually, as shown in the tables below.

The additional comments were divided into the following headings:

- *General – Is there a need for this SAR? How will this SAR fit in with the new Version 0 Standards? Will the existing standards be weakened?*
- *Scope of Standard*
- *Planning Horizon*
- *Use of Operating Procedures*
- *Transition Between Operating & Planning Standards*
- *Functions to Which the Standard Applies*
- *Applicable Portions of Existing Standards*
- *System Models*
- *Resource Planning*
- *Use of Generation or Load as Solutions*
- *Formatting of the SAR*
- *Demand Levels for Modeling*
- *Definition of Terms*
- *Variability of Load & Generation*
- *Probabilistic Planning Methods*
- *Planned Outages*
- *Applicable Ratings*
- *Short Circuit Current*
- *Other Areas that Should be Added or Clarified*

GENERAL COMMENTS ON THE SAR (VERSION 2)

ATC	The SAR drafting team seems to have its arms around the issues and seems ready to proceed to Standard development. **Consideration by the SAR DT** *The SAR DT agrees with this position and appreciates the vote of confidence.* On p. 3 of the SAR, Market Interface Principles, Question 5 stating that the Standard will not require public disclosure of commercially sensitive information: Depending on the level of public exposure of the load flow and stability models, generation cost data and stability parameter data may be deemed by some entities as confidential market information. **Consideration by the SAR DT** *This SAR does not establish the level of public exposure of data. The Standard Drafting Team will determine these requirements. Please submit your comments at the time of the draft Standard posting.*
IMO, ISONE, NPCC	The entities listed believe that the relationship between the concept of the Version 0 Standards and all the developing Version 1 Standards needs to be consistent. The reliability attributes of the Version 0 standards must be "carried through and into" the Version 1 Standards and there needs to be coordination to ensure this occurs. **Consideration by the SAR DT** *There will certainly be changes between V0 and the developing V1 Standards (V1 will be a revision of V0) but these changes must be approved by the industry, thus assuring carry-through and acceptance of reliability attributes.*
IMO, ISONE, NPCC, NYSRC	It is the opinion of NYSRC, ISONE, IMO, and the Northeast Power Coordinating Council's CP9 working group participating members that the existing NERC criteria should not be weakened, including the NERC Planning Standards listed in the SAR as the starting point to be used in drafting a new standard. Our comments support our position that the existing Planning Standards should not be weakened. **Consideration by the SAR DT** *The majority of industry comments have indicated that this SAR is needed to consider content changes in existing Standards. There will be changes between the Version 0 standards (existing standards with formatting changes) and the developing Version 1 standards (V1 will be a revision of V0), but these changes must be approved by the Industry.* *All parties will have an opportunity to participate in the Standard drafting process, including commenting on the draft Standard. Concerns that changes made may weaken the Standard should be brought up at that time.*
NYSRC	<u>With the advent of the Version 0 standards, we believe that there is no longer a need for this SAR.</u> The comments in the "Consideration of Industry Comments" paper indicate that comments received in 2002 on SAR Version 1 were in favor of a standard on transmission assessment and planning, which was the SAR DT's reason for preparing this SAR. However, the Version 0

	standards development process will now provide a transmission planning standard, without requiring the preparation of this new SAR. Despite this position, if the DT does get sufficient support to go forward with a new standard, NYSRC has additional comments, as shown below. **Consideration by the SAR DT** *Version 0 Standards are intended to re-format the existing Standards without changing content, using Functional Model terminology. The majority of industry comments have indicated that this SAR is indeed required to consider content changes in existing Standards.* The relationship with the Version 0 standards should be recognized in the SAR, including the mechanism of how this "Version 1" standard would replace Version 0. **Consideration by the SAR DT** *Version 0 Standards are intended to re-format existing Standards without changing content, using Functional Model terminology. The present SAR uses these existing approved Standards as a starting point to consider content changes for a new Planning Standard. There will be changes between V0 and the developing V1 standards (V1 will be a revision of V0), but these changes must be approved by the Industry.*
SPP	Implementation of this SAR needs to be coordinated with the activities of the Version 0 Standards Drafting Team. **Consideration by the SAR DT** *See our response to NYSRC above.*
WESTAR	How will this SAR integrate with Version 0 Standards? **Consideration by the SAR DT** *Version 0 Standards are intended to re-format the existing Standards without changing content, using Functional Model terminology. The present SAR uses these existing approved Standards as a starting point to consider content changes for a new Planning Standard.*

COMMENTS ON SCOPE OF STANDARD

AESO	The SAR drafting team should clarify through rules, tests, definitions, etc. the portion of an entity's transmission system that shall be planned under the full NERC Standard and what portion may be exempted. **Consideration by the SAR DT** *All NERC Standards apply to the bulk electric power system.* *The SAR DT felt that the definition of "bulk transmission" is an issue too large to be handled by one DT alone, and should be defined at a higher level. Accordingly, the SAR DT referred this issue to the NERC Director of Standards.*
IMO, ISO/RTO	This standard should make it abundantly clear that it applies to both internal and external systems, that is the system under study and adjacent systems, or the entire interconnection if appropriate. **Consideration by the SAR DT** *The SAR DT agrees with this position. If the commenter believes the Standard does not sufficiently address this issue, we encourage the commenter to provide specific language to address this concern when a draft Standard is posted.*
SEMINOLE	The SAR should require joint transmission planning - at a minimum, joint transmission planning should be required between transmission service providers and their network service customers. **Consideration by the SAR DT** *Based on industry feedback to the first posting (V1) of the SAR, this present SAR indicates the Standard will identify reliability performance requirements, but not specify how to achieve such requirements. Joint planning is one way to achieve the reliability requirements, and is neither precluded nor required by this SAR.*

COMMENTS ON THE PLANNING HORIZON

ALLEGHENY	This paragraph and the next **(the 2nd & 3rd paragraphs of posted SAR-Version 2)** are unclear and appear to be conflicting. This first paragraphs specifies that the "scope of such assessments and plans is for a planning horizon of one year or more". The next paragraph specifies, "Assessments should cover a planning horizon of at least 5 years". This appears to be a conflict. It may be that the term "planning horizon" is being used differently in these two paragraphs. It is unclear to us what is the intention of the first of these two paragraphs. **Consideration by the SAR DT** *As a result of your comment, the present SAR has been clarified to indicate that the planning period starts at one year and extends to 5 years or more.*
NYSRC	**From SAR Version 2:** "……..The planning horizon must be long enough to permit timely implementation of viable solutions to remedy the potential inadequacies found. Assessments should cover a planning horizon of at least 5 years. The horizon may be longer than 5 years, based on regulatory or legislative requirements, or on the judgment of the Transmission Planner or Planning Authority……" In paragraph above, 2nd sentence, insert "and plans" after "Assessments". The last sentence is not needed. A Region or other entity may have more stringent requirements than NERC – therefore, such a statement is not needed. **Consideration by the SAR DT** *The SAR DT agrees and accepts your first comment for inclusion in the revised SAR. The SAR DT decided to retain the last sentence in the referenced paragraph to clarify the requirement about the planning horizon.*
R. Snow	While some of the information about generation additions and load growth are considered reliable for five (5) years, a long-term study of approximately ten (10) years is necessary to identify global issues such as import limitations to a region that would require projects that have traditionally taken more than five (5) years. Suggest the following wording: *"Assessments shall cover a detailed planning horizon consistent with available information but no less than five (5) years. The five year horizon shall include load growth, new internal and external firm generation, generation retirements/failures, uncontrollable loop flows, reliance on external generation (identify both firm and market), topology changes, and firm transactions. A longer term study using a variety of scenarios that are expected to cover the most likely long term activity, shall be conducted to identify projects that take longer than five years to implement."* **Consideration by the SAR DT** *The SAR DT considered your alternative wording to be overly prescriptive. However, in the present SAR, the wording has been changed to clarify that the planning horizon extends to 5 years or more.*
SEMINOLE	In Florida, with the state requirements for the siting of facilities, the planning horizon should be adjusted from 5 YRS to 8 YRS. The 5 YR horizon is too short for some major transmission line projects and/or studies of transmission interconnections/upgrades for base load central station generating facilities. **Consideration by the SAR DT** *In the present SAR, the wording has been changed to clarify that the planning*

	horizon extends to 5 years or more.

COMMENTS ON USE OF OPERATING PROCEDURES

AMEREN	" …there is no intent to exclude appropriate operating procedures…". What is "appropriate"? Could generation redispatch be an appropriate operating procedure? If yes, what level of redispatch is appropriate? The standard should include a definition of "appropriateness" of operating procedures so that they are developed and applied on a uniform and consistent basis. **Consideration by the SAR DT** *The SAR DT believes it to be problematic to produce an exhaustive list of all appropriate operating procedures. Furthermore, industry feedback to the first posting (V1) of the SAR indicated a strong industry preference for the Standard not to specify how to achieve the reliability requirements. However, if you believe the draft Standard, when posted, does not sufficiently address this issue, please submit your comments at that time.*
MAPP	MAPP is concerned that the SAR does not limit manual or automatic readjustments for certain lower probability or low consequence events. MAPP urges that the SAR drafting team add additional provisions to require the drafting team to consider which manual and automatic readjustments are allowed and when in meeting the criteria that is included in the standards. **Consideration by the SAR DT** *See the SAR DT response to AMEREN, above.*
R. Snow	***From SAR Version 2:*** "……..While the planning horizon is intended to provide for facility additions, there is no intent to exclude appropriate operating procedures from the transmission plan……..." Replace this sentence with "The planning horizon is intended to provide for facility additions. Operating procedures shall not be used as a substitute for good system design and shall only be applicable during maintenance outages and while facilities are being constructed." *[The original language would allow what was identified as the root cause of the Italian blackout. Namely, an operating procedure that had to be executed within 15 minutes. The operator had to call another area and ask them to perform an operating procedure. The procedure was underway but did not happen fast enough to avoid the next line trip. Operating procedures should never be a long term substitute for constructing facilities needed to assure reliability.]* **Consideration by the SAR DT** *Industry feedback to the first posting (V1) of the SAR indicated a strong industry preference for the Standard not to specify how to achieve the reliability requirements. Therefore, the SAR DT did not accept your suggestion. However, when the draft Standard is posted, feel free to submit your comments at that time.*

COMMENTS ON TRANSITION BETWEEN PLANNING & OPERATING STANDARDS

BPA	*Transition to Operating Standards:* The Planning Standards include multi-layered requirements for different types of outages, i.e., Level B single contingencies, Level C and D multiple contingencies. Compliance with these requirements is to be defined and monitored via the new Reliability Standards. However, once the system moves into the Operational timeframe (one year or less), Policy 2 presently requires meeting N-1 contingencies only with no requirements for Levels C and D. The transition between planning and operations needs further exploration. **Consideration by the SAR DT** *As a result of your comment and others, the present SAR has been revised to require that the new Standard consider the transition between operating and planning standards. In particular, the new Planning Standard will be coordinated with other standards, such as Standard 600, "Determine Facility Ratings, Operating Limits and Transfer Capabilities", which also applies to operations.*
MAPP & MEC	MAPP & MEC are concerned that the SAR does not provide for the coordination of the requirements of the planning standards in NERC Standard 500, "Assess Transmission Future Needs and Develop Transmission Plans", with the NERC Operating Standards provided in NERC Standard 600, "Determine Facility Ratings, Operating Limits, and Transfer Capabilities." The criteria that are proposed as a starting point for 500 in this SAR (events from Categories A through D) differ from the criteria that are included in the latest draft of NERC Standard 600 (Categories A and B). If these approaches are continued, then studies run for the operating horizon will differ significantly from studies run for the planning horizon. These differences in studies will carry over to the calculation of quantities used to offer transmission service, that is, Total Transfer Capacity and Available Transmission Capacity. If NERC does not coordinate these two standards, there will be a discontinuity in TTC and ATCs when the Planning Horizon begins and the Operating Horizon ends or from one day less than one year to one year. MAPP & MEC urge the SAR drafting team to consider this discontinuity and coordinate the SAR for 500 with the Standard that is being written for 600. If a discontinuity between criteria is allowed to continue in the SAR for Standard 500, the SAR drafting team should have a clear explanation for all market participants as to the reason for the discontinuity and how that should be dealt with by the elements of the NERC Functional Model. **Consideration by the SAR DT** *See the SAR DT's response to BPA above.*

COMMENTS ON FUNCTIONS TO WHICH THE STANDARD APPLIES

AMEREN	**From SAR Version 2:** "…….The Standard shall identify reliability requirements, but shall not specify how to achieve such requirements. These requirements shall apply to Transmission Planners and to Planning Authorities……..." Should the requirements be applied to Transmission Owners also? **Consideration by the SAR DT** *Yes. After reviewing your comment, we deleted the last sentence of the referenced paragraph, since page 2 of the SAR already lists TO as a function to which the Standard applies.*
R. Snow	The standards should apply to Transmission Owners, Transmission Operators, Transmission Planners, anyone who is connecting facilities to the transmission system, control areas, and reliability coordinators. ***Consideration by the SAR DT*** *After reviewing your comment, we deleted the last sentence of the referenced paragraph. On SAR page 2 is a list of functions to which the Standard applies. The functions listed are: RA, PA, TP, TO, LSE. This list is consistent with the Functional Model.*

COMMENTS ON APPLICABLE PORTIONS OF EXISTING STANDARD

NYSRC	***From SAR Version 2:*** "……The applicable portions of the following existing NERC Planning Standards will be used as the starting point in drafting these requirements: • I.A Transmission Systems • I.B Reliability Assessment • I.D Voltage Support & Reactive Power • II.A System Data • II.D Actual and Forecast Demands……." Define "applicable portion". List the specific standards and measurements that are intended to be used as the starting point. ***Consideration by the SAR DT*** *The SAR DT believes this level of specificity is not needed in a SAR. If this concern is not addressed in the posted draft Standard, please feel free to submit your comments at that time.*
R. Snow	***From SAR Version 2:*** "……The applicable portions of the following existing NERC Planning Standards will be used as the starting point in drafting these requirements: • I.A Transmission Systems • I.B Reliability Assessment • I.D Voltage Support & Reactive Power • II.A System Data • II.D Actual and Forecast Demands……." Add the following after the bullets. *"In addition to the above, the standard shall provide requirements on methodology of forecasting and normalizing load. This would include methods of determining the normalized load over a large geographic area with different weather patterns and norms. The "normalized" load should not be the load associated with the median weather over a summer or winter period but the load level that will provide sufficient reliability to supply all firm load obligations. Each region shall provide a definition as to what is sufficient reliability. The definition shall clearly define the risk that is being assumed in terms similar to the LOLE for lack of generation. In addition to the above two risk variables, a methodology shall be identified to quantify the risk of not being able to deliver the difference between the local load and generation. This is essentially the ability of the transmission system to respond to different generation dispatch patterns."* ***Consideration by the SAR DT*** *The SAR DT believes this level of specificity is not needed in a SAR. If these concerns are not addressed in the posted draft Standard, please feel free to submit your comments at that time.*
SCGEM	It would also be beneficial to the generation sector if the SDT for this new Planning Standard could summarize the differences between the existing Planning Standards I.A, I.B, I.D, II.A, and II.D and the new Planning Standard as it is being developed. This would gauge the potential impact to the plants. The main concerns have been 1) how to address regional differences (primarily related to Category C events), 2) how to differentiate Table I's application to the Planning world versus the Operations world, and 3) how to state the requirements more clearly. ***Consideration by the SAR DT*** *Since the revised Standard has not yet been drafted, the summary you*

	requested cannot be provided at this time. This summary comparison will be addressed in the Implementation Document that accompanies the new Standard.
SEMINOLE	The SAR should define specific planning voltage criteria for consistency between transmission owners/providers. Voltage Criteria should be specifically defined for normal condition and N-1 conditions and can be specified differently for: • Bulk power - non-load serving buses • Meshed/Looped - load serving buses • Radial - load serving buses ***Consideration by the SAR DT*** *The SAR DT believes this level of specificity is not needed in a SAR. If this concern is not addressed in the posted draft Standard, please feel free to submit your comments at that time.*

COMMENTS ON SYSTEM MODELS

AESO	We believe that the assumptions made for the amount, type and location of future supply are important considerations in assessing the future needs of transmission systems. The SAR drafting team should consider this forecast requirement in developing this Standard. Similarly, there is difficulty in separating planning for reliability and planning for overall system efficiency and economy, and the Standard must be clear on this differentiation. ***Consideration by the SAR DT*** *The SAR DT believes the present SAR addresses most of these concerns. With regard to your last concern, the SAR DT believes there is not always a clear differentiation between reliability, efficiency & economy considerations. However, NERC standards primarily focus on reliability and do not directly address efficiency & economy considerations. If you have specific suggestions after the draft Standard is posted, please comment at that time.*
AMEREN	We believe that for planning of robust transmission systems, the Standard should include (1) some incremental transfer capability requirement in addition to what is "projected" or modeled in the base case, (2) a combination of a line and a generator outage should be included in category B. ***Consideration by the SAR DT*** *With regard to (1) the SAR requires each Planning Authority and Transmission Planner to document the methodology for incorporating planned generation assets in the model. In response to your comment, the present SAR has been revised to specify that the methodology for incorporating planned generation assets (including transfers) must be documented. However, the SAR DT believes any specific incremental transfer capability requirement in the new Standard would be overly prescriptive.* *With regard to (2), the Standard Drafting Team will be reviewing the likelihood, duration and impact of events, as well as performance requirements of the existing Table I Categories. If this issue is still a concern when the draft Standard is posted, please submit your comments at that time.*
AMEREN	Why document and disclose methodologies limited to planned generation only? What about planned transmission and interchange? Is it because there is more uncertainty for speculative generation than transmission? What about differences in modeling details required for different type of analyses, such as thermal or voltage, regional or local? It is our experience that more detailed representation (lower voltage facilities) is required for voltage analysis than thermal analysis. Perhaps the standard should state that additional detail may need to be added to the model to adequately represent the system for specific studies. ***Consideration by the SAR DT*** *In response to your comment, the present SAR has been revised to require documentation of modeling assumptions, including generation modeling assumptions. The SAR DT highlighted generation assumptions because the SAR DT believes such assumptions are particularly important. Furthermore, given unbundling of generation resources from transmission in some areas, we believe there is considerable additional uncertainty in these assumptions,*

	both with regard to new generating units and dispatch of new and existing units.
ATC	New standard needs to consider the difficulties, particularly for stand-alone transmission companies, in obtaining resource information so models can balance load and resources. ***Consideration by the SAR DT*** *The present SAR does indicate that the Standard shall require that system models be developed, maintained and shared in a manner consistent with the Functional Model. The SAR also states that the Standard shall consider a requirement for LSEs to provide forecast resource data for input to the models. If the commenter has specific suggestions to further address this concern, please provide specific suggestions when the draft Standard is posted.*
KCPL	In regards to developing accurate regional models, all known firm transmission service, including rollover provisions for all firm transmission service, should be included in the base case models. ***Consideration by the SAR DT*** *The SAR DT believes this provision does not need to be in the SAR for the new Standard. Rollover provisions for firm transmission service is a FERC tariff issue that does not apply to entities outside of FERC's jurisdiction. Therefore, the SAR DT believes this provision would be overly prescriptive.*
MAPP	MAPP is concerned that there is no reference in the SAR to the need to handle firm contracts that may roll-over in the futures. Plans developed for the transmission system must recognize that the transmission system must have sufficient capacity to handle roll-overs. MAPP urges the SAR drafting team to include an appropriate description of the requirement for the plans with regard to roll-overs. ***Consideration by the SAR DT*** *The SAR DT believes this provision does not need to be in the SAR for the new Standard. Rollover provisions for firm transmission service is a FERC tariff issue that does not apply to entities outside of FERC's jurisdiction. Therefore, the SAR DT believes this provision would be overly prescriptive.*
R. Snow	**From SAR Version 2:** "……..The Standard shall require that system models be developed, maintained and shared in a manner consistent with the Functional Model. Included will be requirements that each Planning Authority and Transmission Planner document and disclose the methodology used for incorporating planned generation assets in the model, as well as how such generation is dispatched. While methodologies and assumptions must be documented, the Standard will not prescribe specific tools to be used in the performance assessment of the planned systems……" Replace the last sentence with *"while the standard will not prescribe specific tools, it shall identify methodologies to validate and procedures to operate the tools so that the identified outcomes from the analysis are not dependent on the tool or the way the tool was used or initialized."* ***Consideration by the SAR DT*** *Industry feedback to the first posting (V1) of the SAR indicated a strong industry preference for the Standard not to specify how to achieve the*

	reliability requirements. Therefore, the SAR DT did not accept your suggestion.
SCGEM, SOUTHERNCO	In relation to the methodology being used for incorporating planned generation assets in the model and how generation is dispatched: the type of each generating unit, the primary fuel type for each generating unit, and a dispatch order of the generating units should be required. In addition, a general description of the dispatch methodology used for the system should also be required. However, no cost information should be required. ***Consideration by the SAR DT*** *The SAR DT believes the referenced language addresses this concern by requiring system model sharing and documentation of generation modeling assumptions. The SAR DT agrees with the commenter that cost data should not be required because it would violate Market Interface Principle 5 (see SAR p. 3) which prohibits requiring the public disclosure of commercially-sensitive information.*
SEMINOLE	It is recommended that these models be "region-wide" system models that are developed utilizing a documented, consistent, region-wide criteria. ***Consideration by the SAR DT*** *The SAR DT believes this provision would be overly prescriptive.*

COMMENTS ON RESOURCE PLANNING

DUKE	Resource planning cannot be excluded from the standard. Guidance should be provided on incorporation of resource data from all LSE's and how resource deficiencies in outyear models should be handled (e.g. model fictitious generation with no reactive capability to ensure sufficient reactive resources are planned for if power is purchased from off system in the future). The increasingly frequent changes in resource designations are causing greater uncertainty in performance of planning for reliable system operation. ***Consideration by the SAR DT*** *The SAR DT agrees that generation resource modeling is an important data requirement for transmission assessment and planning. However, the SAR distinguishes resource information as an input to transmission planning studies from a requirement to assess and ensure the adequacy of generation resources (i.e., resource planning).* *The SAR DT believes it is an open issue as to what level of specificity the Standard should require for model building. If this issue is still a concern when the draft Standard is posted, please submit your comments at that time.* *Note: Whether to check the Resource Planning box on page. 2 of the SAR (as a function to which the Standard applies) has been deferred to the NERC Director of Standards.*
ENTERGY, SCGEM, SERC, SOUTHERNCO	Entities agree the Standard should not address resource planning. However, the Standard should include requirements for the LSEs to provide forecast resource data required to develop power flow models as required in the current II.D Standards. Accordingly, this new Standard should also apply to LSEs. (Thus, entities believe the "LSE" box on p.2 of SAR should be checked as an applicable function). ***Consideration by the SAR DT*** *The SAR DT believes commenters have raised a valid point. The SAR DT believes it is an open issue as to what level of specificity the Standard should require for model building. Therefore, the present SAR has been revised to indicate that the Standard shall consider a requirement for the Load Serving Entities to provide forecast resource data.* *Note: LSE box on page 2 of the SAR has also been checked.*
ENTERGY	In addition, the Standard should require the Transmission Planner to document and describe the methodology used to plan the transmission system around the generation dispatch assumptions used by the Transmission Planner to meet the LSE load when and if the LSE provided resources do not equal the LSE provided load. ***Consideration by the SAR DT*** *The SAR DT believes it is an open issue as to what level of specificity the Standard should require for model building. If this issue is still a concern when the draft Standard is posted, please submit your comments at that time.*
IMO, ISONE, NPCC	The entities listed recognize that Resource Planning is not covered in the proposed Standard because it is considered as being handled by market

	mechanisms that are/will be in place or perhaps addressed in a separate standard. Therefore, we assume that the generation and load information required to perform the planning studies are provided as described in section II.A of the existing Planning Standards. If not, sections II.B, II.E and III of the existing Planning Standards should also be used as the starting point in drafting of the reliability requirements. ***Consideration by the SAR DT*** *The SAR DT believes it is an open issue as to what level of specificity the Standard should require for model building. If this issue is still a concern when the draft Standard is posted, please submit your comments at that time.*
NYSRC	We agree that a transmission planning standard should not include Resource Planning requirements. However, the NYSRC strongly believes that NERC should develop a separate Resource Planning Standard. ***Consideration by the SAR DT*** *The Resource and Transmission Adequacy Task Force (RTATF) proposed and NERC accepted that a Resource Adequacy SAR should be developed.*
WECC-2	In order to develop any meaningful standard, the resource part of the power system should be addressed by including standards for the modeling of existing resources, planned retirement of resources, and planned resources in the next 5 to 10 years time frame. This information will be necessary in order to assess whether future systems can or can not meet the reliability standards. ***Consideration by the SAR DT*** *The SAR DT believes the present SAR as written addresses this concern. Specifically, the SAR requires the documentation and sharing of system models, including the methodology of incorporating planned generation assets in the model as well as how such generation is dispatched.*

COMMENT ON USE OF GENERATION OR LOAD AS SOLUTIONS

AMEREN	If generation is considered in lieu of transmission reinforcement, the system must be able to withstand the loss of that generation plus another single contingency. The reason for this is that generation can be on or off due to economic and other factors after its installation, while transmission is almost always "on". ***Consideration by the SAR DT*** *The SAR DT agrees with this position. The loss of a generating unit plus another single contingency is already an event against which transmission systems must be tested in the existing Standards, and the present SAR provides for the new Standard to use the existing Standards as a starting point. If this issue is still a concern when the draft Standard is posted, please submit your comments at that time.*

COMMENT ON SAR FORMATTING

ALLEGHENY	***From SAR Version 2:*** "……..While the Standard should start from and closely align with the existing Planning Standards I.A, .B, .D, II.A,.D, the system conditions to be studied or assessed may need to be better defined or clarified. For example, the Standard should clarify that the requirement to assess the performance at **all** demand levels does not mean that a multitude of transmission models need to be created for every possible demand level, only that a representative sample covering critical operating conditions needs to be modeled in accordance with regionally-defined criteria……..." This paragraph starting "While the Standard should start from…" has a problem with it's second sentence. The sentence "For example…" does not really apply to the first sentence. We recommend that this paragraph be changed as follows: *"While the Standard should start from and closely align with the existing Planning Standards I.A, .B, .D, II.A,.D, the system conditions to be studied or assessed may need to be better defined or clarified.* *Examples of areas that should be considered for clarification in the Standard include:* *The Standard should clarify that the requirement to assess the performance at ALL demand levels does not mean that a multitude of transmission models need to be created for every possible demand level, only that a representative sample covering critical operating conditions needs to be modeled in accordance with regionally-defined criteria.* *The Standard should provide a clearer definition of "cascading outages".** *And so on".* ***Consideration by the SAR DT*** *In response to your comment, we have revised the SAR to reflect the new formatting.*

COMMENT ON DEMAND LEVELS FOR MODELING

SEMINOLE	***From SAR Version 2:*** "……For example, the Standard should clarify that the requirement to assess the performance at **all** demand levels does not mean that a multitude of transmission models need to be created for every possible demand level, only that a representative sample covering critical operating conditions needs to be modeled in accordance with regionally-defined criteria……..." Regarding " … a representative sample covering critical operating conditions …" It is recommended that this standard include specific requirements; such as, at what load levels and how many different load levels is intended by this part of the SAR. A suggestion would be 100% and 80%, and perhaps the 60% load level. ***Consideration by the SAR DT*** *The SAR DT considered your suggestions for specific load levels to be overly prescriptive.*

COMMENTS ON DEFINITION OF TERMS

AMEREN	In addition to the definition of "cascading outages" , clarification is needed for identification of a cascading state. For example, we are not sure that assumption of some percent overload, say 125% of emergency rating, is a good proxy for cascading. ***Consideration by the SAR DT*** *The SAR DT agrees that a clearer definition of cascading outages (including what constitutes a cascading state) must be provided in the new Standard, and be fully coordinated with the definition in other new Standards. The present SAR has been revised accordingly.*
ERCOT, IMO, ISONE, ISO/RTO, NPCC	All entities listed suggest that the definition for Cascading Outage be fully coordinated with the STDs 200 and 600. ***Consideration by the SAR DT*** *The SAR DT agrees with this position. The SAR DT believes a clearer definition of cascading outages must be provided in the new Standard, and be fully coordinated with the definition in other new Standards. The SAR has been revised accordingly.*
IMO, ISONE, NPCC	NPCC has submitted a suggested definition of "cascading outage" in the comments for the last posting of STD 200, which is endorsed by the other entities listed: *Cascading Outage- "The uncontrolled successive loss of Bulk Electric System elements that propagate beyond a defined area (Balancing Area's) boundaries.""* ***Consideration by the SAR DT*** *The SAR DT agrees that a clearer definition of cascading outages must be provided in the new Standard, and be fully coordinated with the definition in other new Standards. Your specific suggestion is inconsistent with the definition in the latest version of STD 600. Please provide additional comments and suggestions when the draft Standard is posted.*
IMO, ISONE, NPCC	NPCC would also like to submit a proposed definition of Bulk Power System, as follows, and would like it to be considered as a "building block" for the NERC BES (Bulk Electric System) definition. The definition is endorsed by the other listed entities: *Bulk Power System-BPS-(or BES in NERC documents) — "The interconnected electrical systems within northeastern North America comprising generation and transmission facilities on which faults or disturbances can have a significant adverse impact outside of the local area. In this context, local areas are determined by the Council members."* ***Consideration by the SAR DT*** *The SAR DT feels that the definition of "bulk transmission" is an issue too large to be handled by one Drafting Team alone, and should be defined at a higher level. Accordingly, the SAR DT referred this issue to the NERC Director of Standards.*
NYSRC	***From SAR Version 2:*** "…….The Standard should provide a clearer definition of "cascading

	outages"……". Replace "provide" with "consider". ***Consideration by the SAR DT*** *The SAR DT retained the word "provide", since we believe a clearer definition of cascading outages must be provided in the new Standard, and be fully coordinated with the definition used in other developing Standards.* *The present SAR has been revised to require that definitions be coordinated and consistent with other Standards being drafted by NERC.*
SERC	The SERC PSS agrees that the Standard should provide a clearer definition of "cascading outages." In addition the SERC PSS recommends that the Standard provide a clearer definition of what is meant by "system stable." ***Consideration by the SAR DT*** *The SAR DT agrees, and the SAR has been revised to recommend that the new Standard provide a clearer definition of "system stable".*
SCGEM, SOUTHERNCO	In general, the NERC Standards need to have a common definition across the board for any definition used in a Standard. For example, the definition for "Cascading Outages" needs to be coordinated with the Standards Drafting Team (SDT) for the "Determine Facility Ratings, Operating Limits, and Transfer Capability" standard (STD 600). ***Consideration by the SAR DT*** *The SAR DT agrees with this position. The SAR DT believes a clearer definition of cascading outages must be provided in the new Standard, and be fully coordinated with the definition in other new Standards. The SAR has been revised accordingly.*
SCGEM, SOUTHERNCO	Southern agrees that the Standard should provide a clearer definition of "cascading outages." We suggest that the following be considered: *Cascading — "The uncontrolled successive loss of system elements triggered by contingencies which results in widespread electric service interruption 1) that drops 1000 MW of load or more or 2) that crosses control area boundaries."* In addition, Southern recommends that the Standard provide a clearer definition of what is meant by "system stable." We suggest that the following be considered: *System stable — "For Category A and B simulations, system stable means that no generating units pull out of synchronism. For Category C events, system stable means that if units pull out of synchronism, 1) the resulting impedance swings are not out into the transmission system and 2) the total amount of generation lost because of out-of-step tripping does not exceed the control area operating reserve level."* ***Consideration by the SAR DT*** *The SAR DT will pass these suggested definitions along to the Standard Drafting Team for consideration.*

COMMENTS ON VARIABILITY OF GENERATION & LOAD

IMO, ISO/RTO	Seasonal and weather related variability should be considered in studies. ***Consideration by the SAR DT*** *The SAR DT agrees with this position. We believe the present SAR as written takes into account seasonal and weather-related variations.*
MAPP	MAPP is concerned that there is no provision for recognizing the variability of generation in the SAR. MAPP asks the SAR drafting team to add another bullet to the SAR which states, "The Standard should take into account the variability of generation due to factors such as weather and time of day." ***Consideration by the SAR DT*** *The SAR DT agrees with this position. We have not added a bullet to the SAR, but rather have revised the existing bullet to take your suggestion into account.*

COMMENTS ON PROBABILISTIC PLANNING METHODS

AESO	The basis of probabilistic planning, in our view, is to make planning decisions based on the metrics, such frequency, duration and impact, derived from probabilistic assessments. This is usually difficult to do in planning the bulk portion of the transmission system, since outage events are rare but their impact is significant (like multiplying infinity and zero). The categorization of contingencies in Table 1 using outage frequency as a determinant is a step in applying probabilistic techniques in this Standard but it is not probabilistic planning in its true sense. The SAR development team should clarify what it intends with regard to "the use of probabilistic planning methods". ***Consideration by the SAR DT*** *In response to your comment, the SAR DT has revised the present SAR to clarify our intent with regard to probabilistic planning methods.*
AMEREN	**From SAR Version 2:** "……..The Standard should allow for the development and use of probabilistic planning methods. The minimum requirements of probabilistic methods are the contingencies as described in Table 1 of existing Planning Standard I.A.. There should be NERC approval of acceptable levels of risk……." The second sentence about "The minimum requirements of probabilistic methods …. Does this mean that probability should be assigned to at least all of the contingencies included in Table I.A.? AMEREN believes that defining acceptable levels of risk will be a major undertaking. Isn't the level of risk dependent upon the entity and/or perception? Using a deterministic methodology in the planning horizon for single contingency provides a margin to handle many multiple unplanned facility outages or unforeseen system conditions in the operating horizon. ***Consideration by the SAR DT*** *The SAR DT is recommending the continued use of deterministic criteria in the Standard, but is also recommending probabilistic planning methods as an alternative or augmentation to the deterministic criteria. The SAR DT believes probabilistic planning methods are another way of defining acceptable levels of risk. For example, the existing deterministic criteria considers all line outages to be the same level of risk, but a probabilistic method may differentiate transmission line outages by length of line. The SAR DT has revised the present SAR to clarify this point in response to your comment.*
ATC	**From SAR Version 2:** "……..The Standard should allow for the development and use of probabilistic planning methods. The minimum requirements of probabilistic methods are the contingencies as described in Table 1 of existing Planning Standard I.A.. There should be NERC approval of acceptable levels of risk……." This may also go back to question 1 in the Comment Form, but the statement, "There should be NERC approval of acceptable levels of risk" needs to be better defined. For example does this mean that a utility can't decide to increase the operating temperature of a line conductor without NERC approval? ***Consideration by the SAR DT*** *The SAR DT agrees that the sentence concerning NERC approval was unclear. The SAR DT has removed the referenced sentence and added*

	wording to clarify our intent regarding the "use of probabilistic planning methods".
BPA	The handling of probabilistic criteria in the SAR seems quite convoluted, i.e. it can only be used to *increase* performance levels AND has to be approved by NERC. This is not the way probabilistic planning should work. WECC presently has a process (Seven Step Reliability Performance Evaluation) to allow changes in performance requirements (both up and down) for specific outages based on rigorous analysis and monitoring actual performance. It is mostly applicable to requirements beyond the NERC criteria (such as outages of adjacent circuits on separate towers). Use of these methods should be allowed with approval of affected regions. This process should allow for movement below Table 1, i.e. moving Category C outage to Category D. One way to resolve this would be to replace the word "minimum" in the SAR to "starting". ***Consideration by the SAR DT*** *In response to your comment, the SAR DT has added wording to clarify our intent regarding the "use of probabilistic planning methods". Specifically, there is no longer reference to "minimum criteria", but rather a recommendation that the existing Standards be used as a "starting point", allowing movement above or below existing Table I. The reference to NERC approval has also been removed.*
NYSRC	Is the probabilistic method referred to here considered a replacement for the NERC Criteria or a supplement to NERC Criteria? NERC should not allow such a method as a substitute for NERC criteria. I am not aware that NERC has completed an analysis to evaluate and compare the level of reliability of probabilistic criteria with NERC criteria. Such an evaluation would be needed. ***Consideration by the SAR DT*** *The SAR DT is recommending the continued use of deterministic criteria in the Standard, but is also recommending probabilistic planning methods as an alternative or augmentation to the deterministic criteria. The SAR DT has revised the present SAR to clarify this point in response to your comment.*
R. Snow	**From SAR Version 2:** "……..The Standard should allow for the development and use of probabilistic planning methods. The minimum requirements of probabilistic methods are the contingencies as described in Table 1 of existing Planning Standard I.A.. There should be NERC approval of acceptable levels of risk……." Add a sentence after the first sentence *"The probabilistic methodology shall not ignore specific cases that would result in significant load dump or cascading outages. Each region shall identify how to resolve such outages." The last sentence "Acceptable levels of risk in terms of maximum consequential and programmatic load dump and maximum durations for the outages shall be defined."* ***Consideration by the SAR DT*** *The SAR DT believes this level of specificity is not needed in a SAR. However, the SAR DT appreciates your comment, and has revised the present SAR to clarify the potential application of probabilistic planning methods. If this issue is still a concern when the Standard is posted, feel free to submit your comments at that time.*

WECC-1	It appears to us that as written, the standard that flows from this SAR can only allow the probabilistic planning methods to make the standard more, not less, stringent than the existing Standard IA. This is not the way probabilistic planning methods should work. This statement also does not make sense when you read the next sentence, "There should be NERC approval of acceptable levels of risk." If the standard can only be more stringent, then there is no need for NERC to approve the level of risk, or even the probability of occurrence of the contingency. One way to resolve this issue would be to change the word "minimum" to "starting". ***Consideration by the SAR DT*** *In response to your comment, the SAR DT has added wording to clarify our intent regarding the "use of probabilistic planning methods". Specifically, there is no longer reference to "minimum criteria", but rather a recommendation that the existing Standards be used as a "starting point", allowing movement above or below existing Table I. The reference to NERC approval has also been removed.*
WECC-2	The Standard should also allow for the use of Probabilistic Criteria. In WECC, Probabilistic Planning refers to the application of fixed planning standards to a given problem to determine the probable or expected load not served. Probabilistic Criteria is used to refer to adjusting the performance category based on the probability of the event for a specific facility. The performance category can move up or down depending on actual or planned performance. Therefore, Table 1 would be the starting point for making probabilistic criteria adjustments. Probabilistic adjusted criteria would be the basis for Probabilistic Planning. ***Consideration by the SAR DT*** *See the SAR DT's response to WECC-1 and BPA above.*
WECC-1 & WECC-2	The NERC Planning Standards should follow what WECC is doing with regard to listing disturbances as a guide, but say that other disturbances with the same probability should be included. List the probability ranges (outages per year), Category B: >= 0.33, Category C: 0.33 to 0.033; Category D1 (no cascading): 0.033 to .0033, Category D2: < .0033. The standard should allow for changes in the required performance for given disturbances if a probability in another range has been established for a given disturbance. NERC should require that the Regional Councils specify voltage dip and minimum frequency standards similar to WECC (i.e., the voltage dip and minimum frequency should be within Applicable Ratings). We are not proposing that NERC set fixed values for these standards that would be the same throughout the ten NERC Regions. NERC should not set the standards. WECC recommends that the approval of acceptable levels of risk be at the regional level. ***Consideration by the SAR DT*** *In response to your comment, the SAR DT has added wording to clarify our intent regarding the "use of probabilistic planning methods".*

	The SAR DT believes the existing Standard allows Regions to apply voltage dip and voltage stability Regional requirements under the "voltage limits" section of Table I. The SAR DT believes that frequency standards are outside the scope of Transmission Planning for most Regions, and has not included frequency standards in the NERC SAR. This does not preclude Regions where frequency standards have transmission adequacy implications from developing their own standards.

COMMENTS ON PLANNED OUTAGES

AMEREN	We do not believe that the requirement for planning for maintenance outages should be included in planning assessments. See AMEREN's response/comments to Question 4 in this document. ***Consideration by the SAR DT*** *In reviewing industry responses, there was no clear consensus on the issue of including planned outages in planning assessments. See the SAR DT's response to MAPP below. We believe the revised wording in the present SAR adequately addresses these concerns.*
MAPP	MAPP urges the SAR drafting team to add words under this bullet to more clearly explain the SAR drafting team's position with regard to prior planned outages. ***Consideration by the SAR DT*** *The SAR DT believes there is confusion surrounding the planned outage requirement in the existing standard. The SAR DT is recommending that the new Standard specify whether to retain this requirement for Categories B and C. If retained, the Standard should clarify the requirement in such a way that the requirement can be practically implemented.* *In particular, the SAR DT has revised the present SAR to clarify that transmission entities are not required to exhaustively test their systems for every conceivable planned (including maintenance) outage in addition to every conceivable Category B and C contingency. The SAR DT has also revised the SAR to delete the planned outage requirement for Categories A and D.*
MEC	MEC urges the SAR drafting team to add the following words to this bullet to more clearly explain the SAR drafting team's position with regard to planned outages: *"In particular, it is incorrect to have a requirement to exhaustively test for every contingency described in each category plus every conceivable planned outage.* *Planned Outages can be scheduled and analyzed in advance in the operating horizon (less than one year). Therefore, it should not be necessary to require that "systems must be capable of meeting Category C requirements while accommodating the planned outage of any bulk electric equipment..." Planned outages should be studied in advance by the requesting control area and be reviewed by the governing Reliability Coordinator to determine if overloads could occur. If studies show that overloads could occur, the planned outage should be deferred or operating guides prepared which would be used in the event a contingency does occur.* *There is no need to plan or build facilities to meet Planning Standard 1.A when Planned Outages can be accommodated within the frame work of existing guidelines and procedures. Studies conducted for the operating horizon are not the subject of this standard.* *Therefore, the SAR drafting team directs the standard drafting team to delete the requirement for the prior planned outage from the standard given that known planned outages must be included in studies that are conducted during the operating horizon which are not the subject of this standard but which are required in accordance with NERC Standard 200, "Operate Within Interconnection Reliability Operating Limits Standard" and NERC Standard 600, "Determine Facility Ratings, Operating Limits, and Transfer Capabilities".*

	Note: The above suggested wording is similar to the MAPP/MEC comment for Question 4, and the SAR DT is offering a similar consideration: ***Consideration by the SAR DT*** *See the SAR DT's response to MAPP above. We believe the revised wording in the present SAR adequately addresses these concerns.*
SEMINOLE	Many grid operations difficulties occur when a line is scheduled out for maintenance. If this SAR is going to address required N-2 planning assessments, then it must be clear and specific regarding the conditions when N-2 assessments are appropriate and the specific criteria for N-2 assessments. ***Consideration by the SAR DT*** *See the SAR DT's response to MAPP above. We believe the revised wording in the present SAR adequately addresses these concerns*

COMMENTS ON APPLICABLE RATINGS

ALLEGHENY	**From SAR- Version 2:** "…….Performance requirements for Category C events shall be re-evaluated. For example, for certain Category C events, such as #2, #3 and #9 events, consider removing references to "Applicable Ratings" to clarify that the performance requirement is "No Cascading Outages are Allowed"……". This bullet does not appear necessary. "No Cascading Outages" is already part of Table I for these events. Removing "Applicable Ratings" would not add to the clarity. ***Consideration by the SAR DT*** *The wording in the present SAR was revised to remove the referenced language.* *The SAR DT is recommending that the Standard DT conduct a review to determine whether the events in existing Table I are classified correctly. In conducting its review of the likelihood of events and acceptable performance requirements, the Standard DT should clarify ambiguities in performance requirements, specifically cascading outages and Applicable Ratings (A/R).* *For example, the Standard should clarify tests used for considering cascading, such as divergent power flow, overload limits post contingency, voltage magnitudes, etc. The Standard should also clarify that different ratings may be applicable to different categories of events and perhaps to different types of events with a category (specified by entities in accordance with STD 600).*
AMEREN	We agree that some of the contingency categories should be reviewed. See AMEREN's comment for Question 1 (c) in this document – approach (1): keep same categories but re-classify certain events as Category D. ***Consideration by the SAR DT*** *See the SAR DT's global consideration of your Question 1(c) comment.*
BPA	Applicable Ratings: There is a need to tighten up the methodology for Applicable Ratings to ensure that compliance with this standard is measurable. We assume that this will take place in the Determine Facility Ratings Standard although we are concerned about how this is progressing. ***Consideration by the SAR DT*** *The SAR DT is recommending that Applicable Ratings (A/R) be clarified by the Standard DT and the Standard DT will evaluate your comment at that time.*
IMO, ISONE, NPCC	We are not in favor of removing references to "Applicable Ratings". Despite the fact that the performance requirement would be "No Cascading Outages are Allowed", the "Applicable Ratings" should always be respected. ***Consideration by the SAR DT*** *The SAR DT is recommending that Applicable Ratings (A/R) be clarified by the Standard DT and the Standard DT will evaluate your comment at that time.*

MAPP	MAPP urges the SAR drafting team to clarify the meaning of the term "Applicable Ratings" and determine if it is possible to have different A/Rs for different categories. ***Consideration by the SAR DT*** *The SAR DT is recommending that Applicable Ratings (A/R) be clarified by the Standard DT and the Standard DT will evaluate your comment at that time.*
MEC	**From SAR- Version 2:** "……..Performance requirements for Category C events shall be re-evaluated. For example, for certain Category C events, such as #2, #3 and #9 events, consider removing references to "Applicable Ratings" to clarify that the performance requirement is "No Cascading Outages are Allowed"……". MEC urges the SAR drafting team to add Category C#1, #6, #7 and #8 events to the bullet above, to clarify the performance requirement for certain Category C events. ***Consideration by the SAR DT*** *The wording concerning A/R has been revised in the present SAR.* *There was no clear consensus from industry that the events in Categories B, C and D in Table I should be or should not be re-classified. The SAR DT is recommending that the Standard DT conduct a review to evaluate whether the events are classified correctly.* *All parties will have an opportunity to participate in the Standard drafting process, including commenting on the draft Standard. Specific concerns should be brought up at that time.*
MEC	MEC urges the SAR drafting team to direct the Standard Drafting Team to remove references to "Applicable Ratings" from all events listed (see MEC comment above), since information is readily available which demonstrates that the listed events are much less likely than other Category C events. ***Consideration by the SAR DT*** *The SAR DT is recommending that Applicable Ratings (A/R) be clarified by the Standard DT and the Standard DT will evaluate your comment at that time.*
MEC	MEC urges the SAR drafting team to include the following statement in the SAR: "The Standard should clarify how breaker failure events (Category C2, C6, C7, C8, and C9 events) are to be considered given that operating a breaker with disconnects open or eliminating a breaker are technically acceptable mitigation schemes for such events. Such mitigation schemes actually result in less reliable system designs and system operating configurations. Thus including Applicable Ratings in the Standard for these lower probability breaker failure events can send the wrong reliability signals to NERC members." This statement reflects another reason why breaker failure events should be reclassified such that Applicable Ratings is no longer considered a requirement for these low probability events. ***Consideration by the SAR DT*** *See the SAR DT's consideration of MEC's first comment above.*

MEC	MEC urges the SAR drafting team to consider NOT reclassifying any of the Category C events to Category D but instead deleting the Applicable Rating requirements from the lower probability Category C events. MEC believes that the performance requirements for lower probability Category C events should be to protect for cascading, instability, and uncontrolled separation. It is MEC's belief that this was the intent of the drafting team that originally developed the existing NERC Planning Standards. ***Consideration by the SAR DT*** *See the SAR DT's consideration of MEC's first comment above.*
NYSRC	**From SAR- Version 2:** "……..Performance requirements for Category C events shall be re-evaluated. For example, for certain Category C events, such as #2, #3 and #9 events, consider removing references to "Applicable Ratings" to clarify that the performance requirement is "No Cascading Outages are Allowed"…….". The above bullet should be removed. This would be a weakening of the criteria. ***Consideration by the SAR DT*** *There was no clear consensus from industry that the events in Categories B, C and D in Table I should be or should not be re-classified. The SAR DT is recommending that the Standard DT conduct a review to evaluate whether the events are classified correctly.* *All parties will have an opportunity to participate in the Standard drafting process, including commenting on the draft Standard. Concerns that changes made may weaken the Standard should be brought up at that time.*
R. Snow	Clarify that the "applicable ratings" for multiple events should be consistent with supplying firm load and firm transactions until the outages are repaired or switching mitigates the overloads. For example, one applicable rating would be the short time rating of equipment that was stressed when a transformer failed. However, there must be a method of supplying the load pocket for the duration to repair/replace the transformer that does not involve long term rotating blackouts. Just achieving "no cascading outages" is not sufficient. ***Consideration by the SAR DT*** *The SAR DT is recommending that Applicable Ratings (A/R) be clarified by the Standard DT and the Standard DT will evaluate your comment at that time.*

COMMENT ON SHORT CIRCUIT CURRENT

AMEREN	We assume that short circuit current refers to fault duty or interrupting current. ***Consideration by the SAR DT*** *Fault duty and interrupting current refer to the ratings of transmission facilities. The short circuit current is compared to these ratings.*

COMMENTS ON OTHER AREAS THAT SHOULD BE ADDED OR CLARIFIED

AESO	There should be a clear distinction between the appropriate use and application of RAS (or SPS) and "safety nets". ***Consideration by the SAR DT*** *Based on industry comments on the first posting (V1) of the SAR, there was a strong preference not to specify how to achieve reliability performance requirements. Therefore, the SAR does not specifically address these issues/distinctions.*
AMEREN	The "projected level of transfers" defined in the Standard – what does this include? Should it include/consider all transmission reservations including roll-over-rights? ***Consideration by the SAR DT*** *The present SAR has been revised to specify that system models must be developed and shared, including documenting the methodology for incorporating planned generation assets (including transfers) in the model. The projected levels of transfers are determined by each Transmission Planner, and these may include rollover provisions as appropriate.* *Note: See KCPL & MAPP comments under the "System Models" table in this document, and the SAR DT's consideration of those comments.*
MAPP	MAPP asks that the SAR drafting team add a bullet to the SAR that requires that the Standard drafting team consider the development of reactive power margin and transfer power margin standards which expand beyond existing NERC Standard I.D. ***Consideration by the SAR DT*** *The NERC Planning Committee is reviewing Regional reactive power and voltage control practices. Their findings may need to be incorporated into the new Planning Standard (STD 500) when this review is completed. Standard 600 addresses system operating limits and transfer capability. Whereas this SAR DT did not attempt to duplicate these efforts, the present SAR does not preclude the Standard Drafting Team from further refining reactive power margins and/or power transfer margins.* *In the present SAR, a bullet has been added that the Standard address requirements on reactive planning, with specific reference to steady state and transient voltage stability criteria.*
MAPP	MAPP notes that Standard 600, "Determine Facility Ratings, Operating Limits, and Transfer Capabilities" has been drafted to do away with the references to Categories A through D. The criteria are just listed in the standard. MAPP asks that the SAR drafting team require that the standard drafting team for Standard 500 also eliminate the category references to be consistent with the Standard 600 approach. ***Consideration by the SAR DT*** *This SAR 500 DT does not believe that Standard 500 necessarily has to have*

	the same format as Standard 600. However, we have revised the present Standard 500 SAR to provide for coordination between the two Standards.
MAPP & MEC	In general, MAPP and MEC support the six bullets that the SAR drafting team has provided on page SAR-5 (of SAR-Version 2) with the amendments and additions described above in our comments. These bullets add needed details to the SAR. ***Consideration by the SAR DT*** *The present SAR has been revised to reflect appropriate details.*
R. Snow	New section: The subject of assuring that generation is deliverable to the load should be added. This should not be vague but should be defined by a specific set of tests and the expected range of results. In doing these tests, reliance on capacity assigned to other regions should be limited to amounts identified and accepted by adjacent regions. For example, if a region is assuming it will have net purchases from adjacent regions, the other regions must show a net sale. ***Consideration by the SAR DT*** *The NERC Planning Committee is tackling this deliverability issue, as identified by the Resource and Transmission Adequacy Task Force (RTATF). This new Transmission Planning Standard (STD 500) may need to be revised in the future to reflect integration with Resource Adequacy Standards.*

INDUSTRY COMMENTER KEY

TOTAL ENTITIES COMMENTING; 28

TOTAL INDIVIDUALS COMMENTING 121

AEP: AEP Service Corp, Raj Rana

AES: Allegheny Energy Supply (Generator), Ken Githens

AESO: Alberta Electric System Operator (ISO), Neil Brausen, group chair. Includes:

Neil Brausen, Jeff Billinton, Bob Chow

ALLEGHENY: Allegheny Power (Transmission Owner), William J. Smith

AMEREN: Ameren (Transmission Owner), Kirit Shah

ATC: American Transmission Company (Transmission Owner), Peter Burke (on behalf of ATC's David Smith).

BPA: Bonneville Power Administration (Transmission Owner), Marv Landauer, group chair. Includes:

Paul Arnold, Rebecca Berdahl, Mark Bond, Gordon Comegys, Angela DeClerk, Don Gold, Kyle Kohne, Mike Kreipe, Chuck Matthews, Bill Mittlestadt, James Murphy, Melvin Rodrigues, Mike Viles, Paul Ferron

CWLP: City Water, Light & Power (Illinois- Generator), Karl Kohlrus

DUKE: Duke Energy (Transmission Owner), Thomas Pruitt, Robert W. Pierce

ENTERGY: Entergy Services, Inc (Transmission Owner), Ed Davis

ERCOT: Electric Reliability Council of Texas, Bill Bojorquez

IMO: Independent Electricity Market Operator; Khaqan Khan

ISONE: ISO New England, Kathleen Goodman

ISO/RTO: ISO/RTO Council Standards Review Committee, Karl Tammar (NYISO), group chair. Includes:

AESO, Dale McMaster
CAISO, Ed Riley
ERCOT, Sam Jones
IMO, Don Tench
ISO-NE, Peter Brandien
MISO, Bill Phillips
NYISO, Karl Tammar
PJM, Bruce Balmat
SPP, Carl Monroe

KCPL: Kansas City Power & Light (Transmission Owner), Jim Useldinger

MAAC/Horakh: Mid-Atlantic Area Council, John Horakh
MAAC/Kuras: Mid-Atlantic Area Council, Mark J. Kuras

MAPP: Mid-Continent Area Power Pool, Tom Mielnik (MEC), group chair. Includes:

MidAmerican Energy Company (MEC), Tom Mielnik, Dennis Kimm
Great River Energy (GRE), Delyn Helm
MH, David Jacobson
XEL, Dean Schiro
Otter Tail Power (OTP), Jason Weiers
Western Area Power Administration, Steve Sanders

MEC: MidAmerican Energy Company (Load Serving Entity), Tom Mielnik

NPCC: Northeast Power Coordinating Council, Guy Zito (NPCC), group chair. Includes:

TransEnergie (Quebec), Roger Champagne
New York Power Authority, Ralph Rufrano
Hydro One Networks (Ontario), David Kiguel
Nova Scotia Power, David Little
ISO New England, Kathleen Goodman, Dan Stosick
US National Grid, Peter Lebro
New York ISO, James Practico
Niagara Mohawk, Larry Eng
Independent Electricity Market Operator, Ontario, Khaquan Khan
New York State Reliability Council, Alan Adamson
NPCC, Guy Zito, John Mosier, Briam Hogue (satff)

NYSRC: New York State Reliability Council, Alan Adamson

R.Snow: Robert Snow, Individual Commenter (Small Electricity User).

SCGEM: Southern Company Generation & Energy Marketing (Brokers, Aggregators, Marketers), Roman Carter, group chair. Includes:

Roman Carter, Joel Dison, Lucius Burris, Tony Reed, Lloyd Barnes, Clifford Shepard.

SEMINOLE: Seminole Electric Coop.(TDU), K. Bachor & S. Wallace

SERC: Southeastern Electric Reliability Council, Bob Jones (Southern Company Services), group chair. Includes:

Alabama Electric Coop., Darrell Pace
Duke Power, Brian Moss
Entergy Services, Kham Vongkhamchanh
South Carolina Electric & Gas, Clay Young
South Carolina Public Service Authority, Arthur Brown
Southern Company Services, Bob Jones
Tennessee Valley Authority, Byron Stewart
SERC Staff, Pat Huntley

SOUTHERNCO: Southern Company Services, Inc. (Transmission Owner), Marc Butts, group chair. Includes:

Rod Hardiman,, Jonathan Gildewell, Bobby Jones, Marc Butts
Bill Pope – Gulf Power (Load Serving Entity)

SPP: Southwest Power Pool – Transmission Working Group, Ronnie Frizzell, group chair. Includes:

Arkansas Electric Coop Corp., Ronnie Frizzell
Sunflower Electric Power Coop., Norman Williams
Westar Energy, Donald Taylor
Kansas City Power & Light, Jim Useldinger
Southwestern Public Service, John Fulton
American Electric Power, Matt McGee
Empire District Electric, Sam McGarrah
Western Farmers Electric Coop., Mitch Williams
ETEC, John Chiles
Entergy, Mak Nagle
Associated Electric Coop., Inc., Jim Kistner
Southwest Power Pool, Alex Lau
Oklahoma Gas & Electric, Phil Crissup
City Utilities of Springfield, MO, Howard Conus
Aquila Networks, Alan Myers
Southwestern Power Administration, David Sargent

TVA: Tennesse Valley Authority (Government Entity). Includes:

David Till, David Marler, Brenda Eberhart, Darrin Church, Byron Stewart, William Tiller

WECC-1: Western Electricity Coordinating Council, Peter Mackin (TANC), group chair. Includes:

Arizona Public Service, Peter Krzykos
Pacific Gas & Electric, Chifong Thomas
Transmission Agency of Northern California (TANC), Peter Mackin
Basin Electric Power Coop, Matthew Stoltz
Western Area Power Administration, Bob Easton
Salt River Project, Charles Russell
Puget Sound Energy, Joe Seabrook

WECC-2: Western Electricity Coordinating Council, Ben Morris (PG&E), group chair. Includes:

Arizona Public Service, Baj Agrawal
British Columbia Transmission Corp., Phil Park
California ISO, Jeff Miller
Idaho Power, Ron Schellberg
Nevada Power, Rahn Sorensen
Pacific Gas & Electric, Ben Morris, Rick Padilla, Chifong Thomas
Sacramento Municipal Utility District, Dilip Mahendra
Salt River Project, Brian Keel
Southern California Edison, Dana Cabbell, Mohan Kondragunta
Snohomish County PUD, John Martinsen

WESTAR: Westar Energy, Inc. (Transmission Owner), Donald Taylor

Consideration of Comments on 1st Posting of SAR to Supplement the Assess Transmission Future Needs SAR

The Supplemental Assess Transmission Future Needs SAR Drafting Team thanks all commenters who submitted comments on the Supplemental Assess Transmission Future Needs SAR. This SAR was posted for a 30-day public comment period from February 15 through March 16, 2007. The requesters asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 16 sets of comments, including comments from 42 different people associated with more than 37 companies or organizations representing 8 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received, the drafting team is recommending that the Standards Committee approve the Supplemental SAR to be moved forward to the standards drafting stage of the process.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easy to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Assess-Transmission-Future-Needs.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

No changes were made to the SAR based on received comments. The only changes that were made to the SAR at this time were to add references and appropriate supporting material to address the FERC Order 693 and to update the attachment to reflect the latest version of the Standard Review Guidelines.

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	James H. Sorrels, Jr.	AEP	✓				✓	✓				
2.	Anita Lee (G1)	AESO		✓								
3.	Ken Goldsmith (G3)	ALT										✓
4.	Dave Rudolph (G3)	BEPC										✓
5.	Brent Kingsford (G1)	CAISO		✓								
6.	Ed Thompson (G2)	ConEdison										✓
7.	Steve Myers (G1) (I)	ERCOT		✓								
8.	Eric Mortenson	Exelon										
9.	Dick Pursley (G3)	GRE										✓
10.	Roger Champagne	HQT	✓									
11.	Ron Falsetti (G1) (G2) (I)	IESO		✓								
12.	Kathleen Goodman (G2) (I)	ISO-NE										✓
13.	Matt Goldberg (G1)	ISO-NE		✓								
14.	Brian Thumm	ITC Transmission	✓									
15.	Jim Cyrulewski	JDRJC Associates								✓		
16.	Michael Gammon	KCPL	✓									
17.	Eric Ruskamp (G3)	LES										✓
18.	Robert Coish, Chair (G3)	Manitoba Hydro										✓
19.	Ron Mazur	Manitoba Hydro	✓		✓		✓	✓				
20.	David Rudolph (G3)	MidAmerican										✓
21.	Jason Marshall	MISO		✓								
22.	Terry Bilke (G3)	MISO										✓
23.	William Phillips (G1)	MISO		✓								
24.	Carol Gerou (G3)	MP										✓
25.	Mike Brytowski (G3)	MRO										✓

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
26.	Randy Macdonald (G2)	New Brunswick System Opeartor		✓								✓
27.	Murale Gopinathan (G2)	Northeast Utilities										✓
28.	Guy V. Zito (G2)	NPCC										✓
29.	Al Boesch (G3)	NPPD										✓
30.	Greg Campoli (G2)	NY ISO										✓
31.	Mike Calamino (G1) (I)	NYISO		✓								
32.	Ralph Rufrano (G2)	NYPA										✓
33.	Al Adamson (G2)	NYSRC										✓
34.	Mark Ringhausen	Old Dominion Electric Coop.				✓						
35.	Todd Gosnell (G3)	OPPD										✓
36.	Alicia Daugherty (G1)	PJM		✓								
37.	Linda Brown	San Diego Gas and Electric	✓									
38.	Charles Yeung (G1)	SPP		✓								
39.	Roger Champagne (G2)	TransEnergie HydroQuebec										✓
40.	Jim Haigh (G3)	WAPA										✓
41.	Neal Balu (G3)	WPSR										✓
42.	Pam Oreschnik (G3)	XCEL										✓

Legend:

- G1 - IRC Standards Review Committee
- G2 – NPCC CP9 Working Group
- G3 – MRO
- I – Individual comments were submitted in addition to comments submitted as part of a group

Index to Questions, Comments, and Responses

1. Do you believe that there is a reliability-related need to provide additional detail, including specific issues for consideration, to the requirements in this set of standards as proposed in this supplemental SAR? 5

2. Do you agree with the expanded scope of the proposed project as set forth in this supplemental SAR? 8

3. Do you think that there are any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the April 30, 2006 version of the original SAR and this supplemental SAR?.....12

1. **Do you believe that there is a reliability-related need to provide additional detail, including specific issues for consideration, to the requirements in this set of standards as proposed in this supplemental SAR?**

Summary Consideration: All respondents agreed with the statement. The affirmative responses that included comments mainly dealt with procedural issues as opposed to content. The SAR DT believes that we have answered those concerns in the provided responses and that no additional changes to the SAR are required.

Question #1			
Commenter	**Yes**	**No**	**Comment**
Exelon	☑		I believe that most of the additional information contained in the draft 'supplemental' SAR is valuable and will assist the SDT in addressing the various stakeholder concerns. I am concerned with conflicting information addressed below. I am not familiar with the concept of a supplemental SAR and am not sure if there are going to be two SARs now, or if this new effort supercedes the existing SAR. This is especially a concern when there appear to be differences between them regarding functional applicabilities and principles, as well as the expansion of scope. I understand the Standards Development Procedure to require the original SAR to be modified, when it states, "If the standard drafting team determines it is necessary to expand the scope of the standard ot to modify the scope in a way that is no longer consistent with the scope defined in the SAR, then the drafting team may initiate or recommend another requestor initiate a new SAR (Step 1) to develop the expanded or modified scope. At no time will a drafting team develop a standard that is not within the scope ot the SAR that was authorized for development."
Response: The SDT recognized that the scope of the original SAR needed to be broadened to encompass changes in the industry since the approval of the original SAR. We decided to use the concept of a supplement rather than completely re-writing the original SAR. These are not intended to be two distinct SARs. The Supplemental SAR is intended to be a true supplement to the original SAR in every sense of the word.			
ODEC	☑		The planning of the transmission system is critical to the reliability of the transmission system. Additional details provided to all stakeholders are crucial to ensure that transmission is built in a timley manner to protect the relability of the system. Also, by making the process and information available to all stakeholders, you ensure that everyone's interest is heard in the process and not just the large transmission owner/operators, but all users of the transmission system. The assumptions used in the evaluation process must be vetted by all stakeholders as they are the critical drivers on what transmission is needed and when it is needed.
Response: Stakeholders will receive their opportunity to vet the assumptions used in the evaluation process during comment			

Question #1			
Commenter	**Yes**	**No**	**Comment**
and balloting of the standards.			
ERCOT	☑		I recommend that you clarify that these lists of items in Appendix B are topics to consider, not topics that must be included. Also, I recommend that any standards requirements that are evident as Good Utility Practice or procedural in nature be retired as requirements, but retained in the form of reference documents, operating guidelines, or some other similar form that will be available to any industry participant that wishes to use them.
Response: The following excerpt is from point #3 of the Supplemental SAR Purpose Statement – "…***consider*** the items mentioned in the Technical Issues Lists prepared by the NERC staff…" (emphasis added). The intent was always to consider the issues and not to make them necessarily mandatory changes. The comment on good utility practice and procedural requirements will be passed on to the SDT. Please note that Appendix B as it was included in the Supplemental SAR was prepared prior to the final FERC Order. Directions included with that Order must be specifically addressed in the standards drafting process.			
MISO	☑		As the standards are written now, all of the requirements apply to both the Transmission Planner and Planning Authority. The NERC Functional Model Version 3 replaced the Planning Authority with the Planning Coordinator . The standards should reflect this change as well as the division of responsibilities between Transmission Planner and Planning Coordinator in the functional model. Additionally, they should seek to clarify the relationship between Transmission Planner and Planning Coordinator. How many transmission planners can their be per Planning Coordinator. Can there be overlapping Planning Coordinators?
Response: Functional Model v3 will be used as the reference. Your comment and questions will be passed on to the SDT.			
ITC Transmission	☑		The original SAR did a good job of capturing many of the reliability improvements necessary to the TPL Standards. Now that additional information is available from the various stakeholder groups and drafting teams, it is clear that additional reliability-related improvements to the Standards can be made. It is not clear how to quantify the additional improvement the supplemental SAR will make to the existing Standard Drafting effort, but certainly there are additional reliability improvements to be made to each of the subject Standards.
Response: Agreed.			
Manitoba Hydro	☑		Manitoba Hydro believes the planning standards should ensure that complete and consistent assessments are conducted by the responsible entities.
Response: Agreed.			
AEP	☑		

Question #1			
Commenter	**Yes**	**No**	**Comment**
HQT	☑		
IESO	☑		
ISO New England	☑		
KCPL	☑		
MRO	☑		
NPCC CP9 Working Group	☑		
NYISO	☑		
San Diego Gas & Electric	☑		
IRC Standards Review Committee	☑		

2. Do you agree with the expanded scope of the proposed project as set forth in this supplemental SAR? (The scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high-quality, enforceable, and technically sufficient bulk power system reliability standards. Please consider these items as non-mandatory and only for consideration by the drafting team.)

Summary Consideration: The majority of respondents agreed to the proposition. The negative opinions ranged from procedural matters to items that dealt with providing the SDT with sufficient flexibility to do their job or issues that are more appropriately addressed at the standards drafting stage. In particular, there was concern that some of the applicable entities checked on the supplementary SAR were not appropriate. The SAR DT felt that the Transmission Owner & Generator Owner might potentially provide data that could come into play for some of the requirements in TPL-005 & 006. The SAR DT wanted to provide maximum flexibility to the SDT so these entities as well as the Reliability Coordinator were included. However they are only for consideration and not mandatory. The SAR DT believes that we have addressed these concerns in the responses provided and that no additional changes to the SAR are required.

Question #2			
Commenter	**Yes**	**No**	**Comment**
Exelon		☑	The approved SAR is of type 'New Standard' while the supplemental SAR type is not, but rather, 'Revision to existing Standards' as well as, 'Withdraw of existing Standard (possible)'. Regarding the Reliability Function Applicabilities, the supplemental SAR does not include the Reliability Authority or the Planning Authority which were included in the approved SAR, and the supplemental SAR includes the Resource Planner and Generation Owner functions, which are not included in the approved SAR. I believe that the Planning Authority needs to be addressed in terms of the FERC NOPR discussion, summarized on pages B3 and B4 of the supplemental SAR. The supplemental SAR includes item 7 in the Applicable Reliability Principles, while the approved SAR does not. If there are going to be two SARs then I believe that the supplemental SAR should include the previously approved SAR in the 'Related SARs' section on page 7. The concise summaries of the Version 0 Industry comments are appreciated, but these should be made more clear in that these will probably become key to any actual changes to planning contingencies. For example, it is not clear what, 'Address deliverability of generation to load' means. Also, does, 'Don't include generation runback or redispatch'

Question #2			
Commenter	**Yes**	**No**	**Comment**
			mean that this shouldn't be addressed or that the standard should be worded to specifically not include them. Other terms such as, 'Don't include planning outage', and 'single terminals are not included' should also be more thoroughly described.
Response: The SDT recognized that the scope of the original SAR needed to be broadened to encompass changes in the industry since the approval of the original SAR. We decided to use the concept of a supplement rather than completely re-writing the original SAR. These are not intended to be two distinct SARs. The Supplemental SAR is intended to be a true supplement to the original SAR in every sense of the word. The full text of all comments referenced in the Supplemental SAR Appendix B has been made available to the SDT so that there should be no confusion as to the intent or meaning of the comment.			
ODEC		☑	These are transmission planning standards and as such, should only apply to TPs, not RP, TO and GO entities. Certainly, information must be provided from the TOs and GOs on their facilities to be able to run the planning studies, but the MOd standards should cover this obligation. And RC are operating entities and not planning entities.
Response: The SAR DT felt that the TO & GO might potentially provide data that could come into play for some of the requirements in TPL-005 & 006. The SAR DT wanted to provide maximum flexibility to the SDT so these entities as well as the RC were included. However they are only for consideration and not mandatory. Your comments will be passed on to the SDT.			
ISO New England		☑	We do not support a long-term planning standards applying to RCs. The NERC functional model is very clear that RCs are operational entities. Is the intent to replace RRO with RC for the fill-in-the-blank standards? That would be an inappropriate solution. A more appropriate solution would be to consider replacing the RRO with the planning coordinator. We also do not understand how a transmission planning standard could apply to the additional functional entities: Transmission Owner and Generator Owner.
Response: The SAR DT felt that the TO & GO might potentially provide data that could come into play for some of the requirements in TPL-005 & 006. The SAR DT wanted to provide maximum flexibility to the SDT so these entities as well as the RC were included. However they are only for consideration and not mandatory. Your comments will be passed on to the SDT.			
MISO		☑	We do not support a long-term planning standards applying to RCs. The NERC functional model is very clear that RCs are operational entities. Is the intent to replace RRO with RC for the fill-in-the-blank standards? That would be an inappropriate solution. A more appropriate solution would be to consider replacing the RRO with the planning coordinator.
Response: The SAR DT felt that the TO & GO might potentially provide data that could come into play for some of the			

Question #2			
Commenter	**Yes**	**No**	**Comment**
requirements in TPL-005 & 006. The SAR DT wanted to provide maximum flexibility to the SDT so these entities as well as the RC were included. However they are only for consideration and not mandatory. Your comments will be passed on to the SDT.			
NYISO		☑	It is unclear as to what obligations the RC, TO, and GO would have in a long-term planning standard. The NERC functional model is very clear that RCs are operational entities. The RC, TO, GO ,should not have a direct obligation in the process, but should be a resource for input into the process.
Response: The SAR DT felt that the TO & GO might potentially provide data that could come into play for some of the requirements in TPL-005 & 006. The SAR DT wanted to provide maximum flexibility to the SDT so these entities as well as the RC were included. However they are only for consideration and not mandatory. Your comments will be passed on to the SDT.			
IRC Standards Review Committee		☑	We do not support a long-term planning standards applying to RCs. The NERC functional model is very clear that RCs are operational entities. Is the intent to replace RRO with RC for the fill-in-the-blank standards? That would be an inappropriate solution. A more appropriate solution would be to consider replacing the RRO with the planning coordinator. We also do not understand how a transmission planning standard could apply to the additional functional entities: Transmission Owner and Generator Owner.
Response: The SAR DT felt that the TO & GO might potentially provide data that could come into play for some of the requirements in TPL-005 & 006. The SAR DT wanted to provide maximum flexibility to the SDT so these entities as well as the RC were included. However they are only for consideration and not mandatory. Your comments will be passed on to the SDT.			
ITC Transmission		☑	Standard Drafting Teams should not be responding so heavily to comments made by FERC in a NOPR. The NOPR is just that … "Proposed." There may be additional changes required as a result of the final Rule. The final Rule may even negate some of the proposed changes made in the NOPR. If the drafting team thinks that FERC hit on a good idea for improvement, then it would be appropriate for inclusion in the Standard, but simply to make changes to a Standard because an idea surfaced in a Proposed Rule is premature.
Response: The following excerpt is from point #3 of the Supplemental SAR Purpose Statement – "…*consider* the items mentioned in the Technical Issues Lists prepared by the NERC staff…" (emphasis added). The intent was always to consider the issues and not to make them necessarily mandatory changes. Directions included with the FERC Final Order must be specifically addressed in the standards drafting process.			
AEP	☑		Considering the current scope, the Std DT should be encouraged to consider a major re-write of TPL-001 thru TPL-006, possibly including a restructuring into a single standard

Question #2			
Commenter	**Yes**	**No**	**Comment**
			rather than the present multiple standards.
Response: We agree with the general concept and the SDT will be provided with this option**.**			
Manitoba Hydro	☑		Manitoba Hydro agrees in principle with the expanded scope, but believes that this scope should be a part of the Standards Development Procedures manual so all stakeholders have a voice in the requirements in Appendix A. We have some concern that the SAR gives the drafting team the power to add additional improvements beyond the SAR as this provides an opportunity for SDT members to forward specific owner agendas.
Response: The material in Appendix A is excerpted from the Reliability Standards Development Work Plan 2007 – 2009 that was reviewed and approved by the Standards Committee. As stated, it represents general guidelines and not mandatory changes for the revision of existing standards. Stakeholders will receive their opportunity to vet the assumptions used in the evaluation process during comment and balloting of the standards**.**			
ERCOT	☑		Please also see my response to Question #1.
Response: Please see the response to your comment on question #1.			
HQT	☑		
IESO	☑		
KCPL	☑		
MRO	☑		
NPCC CP9 Working Group	☑		
San Diego Gas & Electric	☑		

3. Do you think that there are any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the April 30, 2006 version of the original SAR and this supplemental SAR?

Summary Consideration: Only two respondents suggested revisions. In both cases the comments are more appropriately addressed at the standards drafting stage. The SAR DT believes that we have satisfactorily addressed the expressed concerns with the provided responses and that no additional changes to the SAR are required.

Question #3			
Commenter	**Yes**	**No**	**Comment**
Manitoba Hydro	☑		The SAR should considering adding a requirements to the standards to mandate tests for robustness by doing sensitivity to critical system paramenters such as load growth rate, load power factor, etc., to provide insight into the margin between the operating point and unacceptable performance. There should also be a specific requirement to assess reactive power adequacy, voltage stability and system damping.
Response: The SAR DT is aware of the interest in these items. The scope of both the original and supplemental SARs allows these items to be incorporated in the standards drafting process. We will pass your comments on to the SDT.			
San Diego Gas & Electric	☑		SDG&E believes that there are additional revisions that need to be incorporated into this set of standards. The Supplemental SAR dated January 17, 2007, has an Appendix B that summarizes issues to be resolved in this new set of standards. Those issues are a collection of comments from FERC NOPR, FERC Staff Report, Industrial comments on version 0, Phase III/IV, etc. In order to develop a set of reliability standards for transmission planners, SDG&E believes there are a few more issues to be addressed and/or clarified in this set of standards. 1. Critical System Conditions These "Critical System Conditions" are referring to system conditions to be studied for the transmission planning. Typically, entities deem several system conditions as critical on the basis of accumulative institutional knowledge. However, in recent FERC NOPR, FERC directs industry to conduct sensitivity studies to identify these critical system conditions and document the sensitivity studies. The sensitivity factors in FERC's direction include load power factors, generation

Question #3			
Commenter	**Yes**	**No**	**Comment**
			retirements, generation dispatch, transaction patterns, controllable loads, demand side management, transmission outages. As those will result in extensive scope of study, we would like to see this set of standards clearly answer following questions: a. How often do we required to perform such sensitivity studies to identify critical system conditions? b. Do we check those sensitivity factors one by one to find the worst, or do we define the worst combination as the critical? Or c. Do we continue to leave the "critical system conditions" determination to study performer's discretion? 2. Contingencies In Appendix B of the latest Supplementary SAR for TPL standards, comments and modification requests were summarized. Contingencies for planning studies is one of critical elements. This can be split into three issues and SDG&E provides following comments for each of them: a. Study all contingencies One of the comments suggests to study "all contingencies". Clearly, "All contingencies" need to be clarified. The additional workload incurred due to the dismissal of planners' accumulative institutional knowledge may be unreasonable. b. Study non-common mode contingencies The issue regarding reasonable workload also applies to the "non-common mode" contingencies. The non-common mode refers to combination of unrelated elements, say one 230 kV line in CFE (Mexico) and other 230 kV line in Alberta, Canada, as one contingency. This too needs clarification. c. Study event-based contingencies Evaluating the impact of "event-based" contingencies makes sense. However, translating an event, such as an earthquake, into a list of elements to be taken out for power flow and stability computer simulation, will need clear guidelines. 3. "Identification of options for reducing the probability or impacts of extreme events that cause cascading" This is a direct quote of FERC's directed modification in its NOPR.

Question #3			
Commenter	**Yes**	**No**	**Comment**
			a. If the impacts only need to be identified with conceptual methods, how do we maintain "consistency" among entities? b. If FERC intends to request the entities to identify the probability/impacts with quantitative methods, then there is a long list of issues to be addressed before a transmission planner could in reality perform such an analysis: • How to define "cascading" in system simulation analysis. • Reasonable and feasible probabilistic variables need to be defined. For instance, in addition to the equipment failure as probabilistic variable, other probabilistic variables need to be considered to meet FERC's direction, such as hurricanes, fires, earthquakes, lightening, flooding, landslides and even an airplane falling into a critical substation, and so on. • Regional efforts need to be taken to develop a probabilistic methodology and probabilistic database that can be applied uniformly so entities can be treated equally. • Regional efforts need to be taken to guide selection and/or development of probabilistic analysis software tools. Such tools have to be ready for transmission planners to use and derive quantified solutions.
Response: The following excerpt is from point #3 of the Supplemental SAR Purpose Statement – "…***consider*** the items mentioned in the Technical Issues Lists prepared by the NERC staff…" (emphasis added). The intent was always to consider the issues and not to make them necessarily mandatory changes. Directions included with the FERC Final Order must be specifically addressed in the standards drafting process. The Supplemental SAR was intended to be a true supplement to the original SAR in every sense of the word. The SAR DT is aware of the interest in these items. The scope of both the original and supplemental SARs allows these items to be incorporated in the standards drafting process. We will pass your comments on to the SDT. We refer the commenter to the NERC web site for previous meeting notes and comments concerning related issues.			
ODEC		☑	This should be more than enough to try to get into these transmission planning standards.
Response: Most stakeholders who commented seemed to agree with you.			
MISO		☑	
MRO		☑	
NPCC CP9 Working Group		☑	
NYISO		☑	

Question #3			
Commenter	**Yes**	**No**	**Comment**
IRC Standards Review Committee		☑	
AEP		☑	
ERCOT		☑	
HQT		☑	
IESO		☑	
ISO New England		☑	
ITC Transmission		☑	
KCPL		☑	

Consideration of Comments — 1st Draft of TPL-001-1 — Transmission System Planning Performance Requirements

The Assess Transmission Future Needs Standards Drafting Team thanks all commenters who submitted comments on the first draft of the standard. This standard was posted for a 30-day public comment period from September 12, 2007 through October 26, 2007. The drafting team asked stakeholders to provide feedback on the standard through a special Standard Comment Form. There were more than 80 sets of comments, including comments from 236 different people from more than 80 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received, the drafting team is recommending a second posting of the revised standard.

Definitions and the following requirements have been changed due to industry comment as specifically cited in the responses:

Definitions

- Base Case - the SDT removed "Base Case" as a defined term.
- Bus-tie Breaker – the SDT added a definition.
- Consequential Load Loss – the SDT reworded the definition to better clarify that this is Load loss that occurs when the source to that Load is lost or Load that is lost due to the Load's transient response to the event being studied and to eliminate confusion regarding references to concepts such as fault clearing action, mis-operation, or radial Load.
- Extreme Events – the SDT revised the definition to clarify that Extreme Events have a "lower probability of occurrence than Planning Events."
- Long-Term Transmission Planning Horizon - the SDT revised the definition to clarify when the horizon may extend beyond ten years
- Non-Consequential Load Loss - the SDT revised the definition to improve its clarity and to specify that this is non-interruptible load
- Planning Assessment - the SDT revised the definition to be more succinct, to eliminate the description of the possible range of assumptions, and to clarify that the assessment is an evaluation of Transmission System performance (not needs) and Corrective Action Plans associated with identified deficiencies.
- Planning Coordinator – the SDT added the definition from the Functional Model.
- Plant Stability Study - the SDT replaced the word, "plant" with the term, "generating unit," and modified the wording to improve its clarity.
- System Stability Study - the SDT revised the definition to add further clarity
- Year One - the SDT modified the definition to clarify that Year One is the first year that requires assessment, not study, and to clarify that the planning window begins 12 to 18 months from the completion of the previous assessment.

Sensitivity Studies

The need to conduct sensitivity studies was a directive in FERC Order 693 paragraphs 1694,1704, and 1706. The revised standard provides guidance on what needs to be included in sensitivity studies while not being totally prescriptive.

- Requirement R2.1.3 and Requirement R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies.
- Requirement R2.1.4 and Requirement R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system.
- Requirement R2.4.3 was modified to stipulate that the entity shall provide rational for why sensitivity on the list were or were not included in the sensitivity studies and that the entity may consider additional sensitivities that are appropriate for its own System.
- Requirement R.2.4.3.2 (related to stability analysis) was changed to use the same phrase as used in R.2.1.3.2 (related to steady state analysis) "Modification of expected transfers"
- Requirement R.2.4.3.4 (related to stability analysis) was changed to use the same phrase as used in R.2.1.3.4 (related to steady state analysis) "Variability and outages of reactive resources."
- A new requirement, now numbered as Requirement R2.7.2, has been added to clarify that the sensitivity studies do not in themselves establish the need for a corrective action but the entity must explain how the sensitivities affected the Corrective Action Plan.

Corrective Action Plans

Requirements for corrective action plans have been modified to clarify that these do not need to be developed solely to meet performance requirements for sensitivities and to eliminate subrequirements that distinguished between “committed” and “proposed” projects. The standard now refers to “actions” needed to achieve required System performance without trying to distinguish between “committed” and “proposed” projects. The following adjustments were made to the list of elements that must be included in Corrective Action Plans:

- Sub-requirement R2.7.1 was modified to clarify that there are many options that can be used to achieve required system performance when studies show system deficiencies, including DSM.
- Sub-requirement R2.7.2 to perform re-test has been removed. The purpose of the Corrective Action Plan is to list the actions that are needed to meet performance requirements. The studies, current, and/or past as appropriate, as well as the extent of the size of the study area, are performed to support compliance and demonstrate that the requirements are met. The standard assumes that the actions were developed and verified using the current and past studies that were used to uncover deficiencies and confirm adherence to the performance requirements.
- Sub-requirement R2.7.3 to document the criteria for determining committed and proposed projects and to identify each project as either committed or proposed has been deleted.
- Sub-requirement R2.7.4 that included language restricting the removal of committed projects has been deleted.

- A new Sub-requirement R2.7.2 has been added that requires a description of the consideration of sensitivity studies was applied to the actions needed to achieve system performance

Performance Requirements

- The SDT modified the performance requirements relative to Non-Consequential Loss of Load and revised Tables 1 & 2 to add greater detail and provide for more situations where it is acceptable to lose Non-Consequential Load.
- The second draft proposes that no Non-Consequential Load may be tripped for the loss of a 300 kV (or higher) bus section for a first contingency event.
- The second draft proposes permitting the loss of Non-Consequential Load to meet the Transmission performance requirements for events where there are two independent overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. (See Performance Table Planning Event P6.)
- The second draft proposes allowing load shedding as an acceptable system adjustment action for the entire BES following the loss of the second Transmission outage.
- Moved P2-3 into the P1 category as loss of a single pole of a dc line is similar to loss of a generator or transmission circuit.
- Clarified the distinction between Generating Unit Stability Study and System Stability Study by adding a definition of Generating Unit Stability Study and modifying the definition of System Stability Study – and making modifications to R2.5.
- Removed Extreme Event #9 from Stability Analyses for Extreme Events (3-phase fault and loss of all generating units at a station). The events which remove all of a generating unit from the System occur over a longer period of time which is more applicable in the steady state analyses. These are Extreme Events which are relevant for steady state but not for Stability analyses.
- Modified R2.4.1 to recognize the difficulty of obtaining accurate dynamic Load models including induction motors.
- Modified Requirement R 3.6 (now R3.5) of the steady state portion of the Planning Assessment to specify the conditions under which manual and automatic generation runback and tripping can be used to meet single and multiple Contingency performance requirements and to make it clear that all Facilities must always remain within applicable thermal and voltage ratings.

Generation Run Back and Tripping

- Added R3.5.2 and R3.5.3 to clarify that manual or automatic generation run-back is allowed as a response to single and multiple Contingencies as long as all Facilities shall be operating within their Facility Ratings and as long as a sustainable, stable, operating condition is maintained.
- Modified Requirement R 3.5 to specify the conditions under which automatic (or manual) generation runback can be used to meet single (or multiple) contingency performance requirements and to make it clear that all facilities must always remain within applicable thermal and voltage ratings.
- Modified R3.5 to allow the use of SPS/RAS for single or multiple Contingencies with limitations described in Requirements R3.5.1 through R3.5.3.

Modeling

- A new requirement was added (to replace R1.4) to perform the tests outlined in the performance requirements table and demonstrate that thermal and voltage limits are met, however, all manual and/or automatic actions are allowed (within time constrained ratings) including curtailing firm transfers and controlled shedding of Non-Consequential firm Load.

- In addition, both performance tables have been changed.

Some other major changes included:

- Created a new requirement concerning short circuit analysis.
- Created a requirement to document proxies for instability, cascading outages and uncontrolled islanding.
- Changed requirements to clarify the actions allowed to prepare for the next Contingency.
- Changed requirements to clarify that Facility Ratings may be different for, and a function of, different durations

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Assess-Transmission-Future-Needs.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	William Quaintance	ABB Grid Systems Consulting										
2.	John Bussman	AECI	✓									
3.	Anita Lee	AESO		✓								
4.	Darrell Pace (G11)	Alabama Electric Coooperative	✓									
5.	Wesley O. Davis	Alcoa Power Generating, Inc.	✓		✓		✓		✓			
6.	William J. Smith	Allegheny Power	✓									
7.	Ken Goldsmith (G9)	ALTW										
8.	Rick Foster (G12)	Ameren										
9.	John Sullivan (G11)	Ameren	✓									
10.	Curtis Stepanek (G14)	Ameren	✓									
11.	Eugene Warnecke (G14)	Ameren	✓									
12.	John E. Sullivan	Ameren Services	✓									
13.	Thad K. Ness (G2)	American Electric Power	✓		✓		✓	✓				
14.	Takis Laios (G2)	American Electric Power	✓									
15.	Jon Riley (G2)	American Electric Power	✓									
16.	Rob O'Keefe (G2)	American Electric Power	✓									
17.	Navin Bhatt (G2)	American Electric Power	✓									
18.	Scott Rainbolt (G2)	American Electric Power	✓									
19.	Omar Hellalat (G2)	American Electric Power	✓									
20.	Roger Bentz (G2)	American Electric Power	✓									
21.	Vance Beauregard (G2)	American Electric Power	✓									
22.	Phil Cox (G2)	American Electric Power					✓	✓				
23.	E. Nick Henery (G4)	APPA			✓	✓						
24.	Allen Mosher (G4)	APPA			✓	✓						
25.	Baj Agrawal	Arizona Public Service Co.	✓		✓		✓					

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
26.	Jason Shaver	ATC	✓									
27.	Phil Park	BCTC		✓								
28.	Dave Rudolph (G9)	BEPC										
29.	Chris Bradley (G14)	Big Rivers Electric Corporation	✓									
30.	Chuck Matthews (G3)	BPA Transmission	✓									
31.	Berhanu Tesema (G3)	BPA Transmission	✓									
32.	Kendall Rydell (G3)	BPA Transmission	✓									
33.	Kyle Kohne (G3)	BPA Transmission	✓									
34.	Melvin Rodrigues (G3)	BPA Transmission	✓									
35.	David Albers	Brazos Electric Cooperative	✓									
36.	Charles Cumpton	California ISO		✓								
37.	Paul Rocha (see attachment)	CenterPoint Energy	✓									
38.	David M Conroy (see attachment)	Central Maine Power Company	✓									
39.	Gary Brinkworth (G7)	City of Tallahassee	✓									
40.	Jeff Knottek	City Utilities/Springfield	✓		✓							
41.	Karl Kohlrus (G8)	City Water, Light & Power (IL)					✓					
42.	Karl E. Kohlrus	City Water, Light and Power			✓	✓	✓					
43.	Edwin Thompson (G10)	ConEd										
44.	Michael Gildea (G10)	Constellation Energy										
45.	Blake Williams	CPS Energy	✓									
46.	John K. Loftis, Jr. (G1)	Dominion VA Power	✓									
47.	Kirit Doshi (G1)	Dominion VA Power	✓									
48.	Graig Crider (G1)	Dominion VA Power	✓									
49.	Solomon Yirga (G1)	Dominion VA Power	✓									
50.	Nelson Burks (G1)	Dominion VA Power	✓									
51.	Ashwani Vaswani (G1)	Dominion VA Power	✓									
52.	Mehdi Shakibafar (G1)	Dominion VA Power	✓									
53.	Abdur Masood (G1)	Dominion VA Power	✓									
54.	Thanh Nguyen (G1)	Dominion VA Power	✓									
55.	Ed Broasdale (G1)	Dominion VA Power	✓									

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
56.	Al MacDonald (G1)	Dominion VA Power	✓									
57.	William Bigdely (G1)	Dominion VA Power	✓									
58.	Ronnie Bailey (G1)	Dominion VA Power	✓									
59.	Greg Rowland	Duke Energy	✓		✓							
60.	Anthony Williams (G12)	Duke Energy Carolinas										
61.	Brian D. Moss (G14)	Duke Energy Carolinas	✓									
62.	Keith Yocum	E ON US										
63.	Larry Rodriguez	Entegra Power					✓	✓				
64.	Sujit Mandal (G12)	Entergy										
65.	Charles Long (G11)	Entergy	✓									
66.	Kham Vongkhamchanh (G14)	Entergy	✓									
67.	Charles W. Long	Entergy Services, Inc.	✓		✓		✓					
68.	Doug Powell	Entergy Services, Inc.	✓		✓		✓					
69.	H. Steven Myers	ERCOT ISO		✓								
70.	Eric Mortenson	Exelon	✓		✓							
71.	Doug Hohlbaugh (G5)	FirstEnergy Corporation	✓		✓		✓	✓				
72.	John Stephens (G5)	FirstEnergy Corporation	✓		✓		✓	✓				
73.	Dave Folk (G5)	FirstEnergy Corporation	✓		✓		✓	✓				
74.	Sam Ciccone (G5)	FirstEnergy Corporation	✓		✓		✓	✓				
75.	W. R. Schoneck (G7)	Florida Power & Light Company			✓							
76.	C. Martin Mennes (G7)	Florida Power & Light Company	✓									
77.	Robert A. Birch (G7)	Florida Power & Light Company					✓					
78.	John W. Shaffer (G7)	Florida Power & Light Company			✓							
79.	A. L. Barredo (G7)	Florida Power & Light Company			✓							
80.	Hector Sanchez (G6)	Florida Power and Light	✓		✓		✓					
81.	Marty Mennes (G6)	Florida Power and Light	✓		✓		✓					
82.	W. R. Schoneck (G6)	Florida Power and Light	✓		✓		✓					
83.	R. A. Birch (G6)	Florida Power and Light	✓		✓		✓					
84.	A. L. Barredo (G6)	Florida Power and Light	✓		✓		✓					
85.	C. Candelaria (G6)	Florida Power and Light	✓		✓		✓					
86.	J. W. Shaffer (G6)	Florida Power and Light	✓		✓		✓					

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
87.	Fred McNeill (G7)	Florida Reliability Coordinating Council										✓
88.	Vicente Ordax (G7)	FRCC										✓
89.	Earl Fair (G7)	Gainesville Regional Utilities	✓									
90.	Angela Battle	Georgia Transmission Corp	✓									
91.	Ken Wofford (G14)	Georgia Transmission Corp.	✓									
92.	David Kiguel (G10)	Hydro One Networks										
93.	Roger Champagne (G10)	HydroQuebec TransEnergie										
94.	Sylvain Clermont (G10)	HydroQuebec TransEnergie										
95.	Roger Champagne	Hydro-Québec TransÉnergie	✓									
96.	Ron Falsetti	IESO		✓								
97.	Kathleen Goodman (G10)	ISO New England										
98.	Brian F. Thumm	ITC Holdings										
99.	Jim Cyrulewski (G8)	JDRJC Associates								✓		
100.	Donald Gilbert (G7)	JEA					✓					
101.	Ted E. Hobson (G7)	JEA	✓									
102.	Gary Baker (G7)	JEA			✓							
103.	Don Gilbert	JEA	✓		✓		✓					
104.	Harold G. Wyble	Kansas City Power and Light	✓									
105.	Tim Wu	LADWP	✓		✓		✓					
106.	Scotty Touchette	Lafayette Utilities System	✓		✓		✓					
107.	Paul Elwing (G7)	Lakeland Electric					✓					
108.	Richard Gilbert (G7)	Lakeland Electric			✓							
109.	Larry E. Watt (G7)	Lakeland Electric	✓									
110.	Paul Shipps (G7)	Lakeland Electric						✓				
111.	Sergio Garza	LCRA TSC	✓									
112.	Eric Ruskamp (G9)	LES										
113.	Donald Nelson (G10)	MA Dept of Public Utilities										
114.	Joseph DePoorter (G8)	Madison Gas & Electric				✓						
115.	Ron Mazur	Manitoba Hydro	✓		✓		✓	✓				
116.	Jerry Tang (G14)	MEAG	✓									
117.	David Weekley (G11)	MEAG Power	✓									

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
118.	Robert Coish (G9)	MHEB										
119.	David Jacobson (G9)	MHEB										
120.	Ron Mazur (G9)	MHEB										
121.	Allen McKee (G11)	Midwest ISO (MISO)		✓								
122.	Allen McKee (G8)	Midwest ISO, Inc.		✓								
123.	Carol Gerou (G9)	Minnesota Power										
124.	Terry Bilke (G9)	MISO										
125.	Tom Mielnik (G9)	MRO		✓								
126.	Michael Brytowski (G9)	MRO										
127.	Jerry Tang	Municipal Electric Authority of Georgia	✓									
128.	Lewis Ross	Muscatine Power and Water	✓		✓		✓			✓		
129.	Carol Sedewitz	National Grid	✓									
130.	Denise Roeder (G14)	NC Municipal Power Agency #1			✓							
131.	James R. Manning	NCEMC			✓	✓	✓					
132.	Robert S. Beadle	NCEMC			✓	✓	✓					
133.	Denise Roeder	NCMPA			✓							
134.	Bob Cummings	NERC Transmission Issues Subc.										
135.	Randy MacDonald (G10)	New Brunswick System Operator										
136.	Kathleen Goodman	New England ISO		✓								
137.	Walter A. Pfuntner	New York ISO		✓								
138.	Greg Campoli (G10)	New York ISO										
139.	Ralph Rufrano (G10)	New York Power Authority										
140.	Al Adamson (G10)	New York State Reliability Council										
141.	Michael Ranalli (G10)	Ngrid US										
142.	Reza Rizvi (G10)	Northeast Power Coordinating Council										
143.	Rick White	Northeast Utilities	✓									
144.	Murale Gopinathan (G10)	Northeast Utilities										
145.	John Leland	Northwestern Energy	✓									
146.	Guy V. Zito (G10)	NPCC										✓
147.	Gregory Sullivan	Nstar Electric and Gas Corp.	✓		✓							
148.	John P. Mayhan	OPPD	✓		✓			✓				
149.	Keith Mutters (G7)	Orlando Utilities Commission			✓							

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
150.	Ganesh Velummylum (G17)	PJM (ISO/RTO)		✓								
151.	John Collins	Platte River Power Authority	✓									
152.	Mark Byrd	Progress Energy Carolinas	✓		✓		✓	✓				
153.	John O'Connor (G12)	Progress Energy Carolinas										
154.	Phil Creech (G14)	Progress Energy Carolinas	✓									
155.	Lee Schuster (G7)	Progress Energy Florida			✓							
156.	Bart White (G7)	Progress Energy Florida			✓							
157.	Bart White	Progress Energy Florida, Inc.	✓		✓		✓	✓				
158.	Jeffrey Mitchell	ReliabilityFirst Corp.										✓
159.	Mark Kuras (G17)	RFC		✓								
160.	Mahendra Patel (G17)	RFC		✓								
161.	Paul McGlynn (G17)	RFC		✓								
162.	Mohamed Osman (G17)	RFC		✓								
163.	Chuck Liebold (G17)	RFC		✓								
164.	Leanne Harrison (G17)	RFC		✓								
165.	Susan McGill (G17)	RFC		✓								
166.	Terry Blackwell (G13)	Santee Cooper	✓		✓		✓	✓				
167.	James Peterson (G13)	Santee Cooper	✓									
168.	Shawn T. Abrams (G13)	Santee Cooper	✓									
169.	Vicky Budreau (G13)	Santee Cooper	✓									
170.	Art Brown (G13)	Santee Cooper	✓									
171.	William Gaither (G13)	Santee Cooper	✓									
172.	Glenn Stephens (G13)	Santee Cooper	✓									
173.	Rene' Free (G13)	Santee Cooper	✓									
174.	Frank Caston (G13)	Santee Cooper	✓									
175.	Rick Thornton (G13)	Santee Cooper	✓									
176.	James M. Jackson (G13)	Santee Cooper	✓									
177.	Wayne Guttormson	SASK Power	✓		✓		✓	✓				

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
178.	Al McMeekin (G14)	SC Electric & Gas Company	✓									
179.	Clay Young (G14)	SC Electric & Gas Company			✓							
180.	Phil Kleckley (G11)	SC Electric and Gas			✓							
181.	Scott Inglebritson	Seattle City Light	✓		✓	✓	✓					
182.	Sharma Kolluri (G12)	SERC EC DRS	✓									
183.	Travis Sykes (G11)	SERC EC PSS	✓									
184.	Pat Huntley (G11)	SERC Reliability Corp										✓
185.	Carter Edge (G14)	SERC Reliability Corporation										✓
186.	Maria Haney (G14)	SERC Reliability Corporation										✓
187.	Jim Peterson (G14)	SERC RRS OPS	✓									
188.	Philip R. Kleckley	South Carolina Electric & Gas	✓		✓		✓					
189.	John Ciza (G15)	Southern Company - Generation	✓									
190.	Tom Higgins (G15)	Southern Company - Generation					✓					
191.	Terry Crawley (G15)	Southern Company - Generation					✓					
192.	Roman Carter (G15)	Southern Company - Generation	✓									
193.	Marc Butts (G15)	Southern Company - Transmission	✓									
194.	J. T. Wood (G15)	Southern Company - Transmission	✓									
195.	Jim Viikinsalo (G15)	Southern Company - Transmission	✓									
196.	Keith Calhoun (G15)	Southern Company - Transmission	✓									
197.	Shih-Min Hsu (G15)	Southern Company - Transmission	✓									
198.	Tom Sims (G15)	Southern Company - Transmission	✓									
199.	Gary Gorham (G15)	Southern Company - Transmission	✓									
200.	Dave Slovensky (G15)	Southern Company - Transmission	✓									
201.	Jeremy Bennett (G15)	Southern Company - Transmission	✓									
202.	Bob Jones (G15)	Southern Company - Transmission	✓									
203.	Bill Botters (G15)	Southern Company - Transmission	✓									
204.	Mike Bartlett (G15)	Southern Company - Transmission	✓									
205.	Maryanne Mujica (G15)	Southern Company - Transmission	✓									
206.	Lee Taylor (G15)	Southern Company -	✓									

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
		Transmission										
207.	Perry Stowe (G15)	Southern Company - Transmission	✓									
208.	Rod Hardiman (G15)	Southern Company - Transmission	✓									
209.	Doug McLaughlin (G15)	Southern Company - Transmission	✓									
210.	Randy Castello (G15)	Southern Company - Transmission	✓									
211.	Chuck Chakravarthi (G15)	Southern Company - Transmission	✓									
212.	Roger Green (G15)	Southern Company - Transmission					✓					
213.	Bob Jones (G11)	Southern Company Services	✓									
214.	Jim Busbin (G15)	Southern Company Services, Inc.	✓									
215.	Bob Jones (G12)	Southern Company Services, Inc. - Trans										
216.	Lee Taylor (G12)	Southern Company Services, Inc. - Trans										
217.	Rod Hardiman (G14)	Southern Company Services, Inc. - Trans	✓									
218.	Doug McLaughlin (G14)	Southern Company Services, Inc. - Trans	✓									
219.	Jonathan Sykes	SRP	✓									
220.	Ronald L. Donahey	Tampa Electric Company			✓							
221.	Thomas J. Szelistowski (G7)	Tampa Electric Company	✓									
222.	Scott Helyer	Tenaska, Inc.					✓					
223.	Tom Cain (G12)	Tennessee Valley Authority										
224.	Ian Grant (G14)	Tennessee Valley Authority	✓									
225.	Marjorie Parsons (G14)	Tennessee Valley Authority	✓									
226.	Michael Clements (G14)	Tennessee Valley Authority	✓									
227.	David Till	Tennessee Valley Authority	✓									
228.	Biju Gopi (G10)	The IESO, Ontario										
229.	Alex Boutsioulis	The United Illuminating Company	✓									
230.	Mark Graham	Tri-State G&T										
231.	Gary Trent	Tucson Electric Power Company	✓									
232.	Jim Haigh (G9)	WAPA										
233.	Steve Rueckert (G16)	WECC Committees and Subgroups										✓
234.	Christopher Plante	Wisconsin Public Service Corp			✓	✓	✓					

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
235	Neal Balu (G9)	WPS			✓		✓	✓				
236	Pam Oreschnick (G9)	XCEL										

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group
G1 – Dominion Virginia Power
G2 – American Electric Power
G3 – BPA Transmission
G4 – American Public Power Association
G5 – FirstEnergy Corporation
G6 – Florida Power & Light Company
G7 – FRCC
G8 – Midwest ISO, Inc. (MISO)
G9 – Midwest Reliability Organization (MRO)
G10 – NPCC RCG
G11 – SERC EC PSS
G12 – SERC EC DRS
G13 – Santee Cooper
G14 – SERC RRS OPS
G15 – Southern Company Services, Inc.
G16 – WECC Committees and Subgroups
G17 – PJM (ISO/RTO)

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A) New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

1) **Q1. Base Case: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.**

Summary Response: After reviewing the comments to this proposed definition and the use of the term "base case" in the standard, the SDT determined that "Base Case" does not need to be a defined term.

Organization	Q1. **Comment**	Agree.	Don't agree.
AECC	Neutral. This is a little wordy but I don't have a better answer.		
ABB	Agree but delete "or node". It is unnecessary.	X	
AEP	Consider replacing"computer" with "model".	X	
ATC	We agree with the definition given in the draft standard date Sep-12, 2007. The last sentence is not consistent with the definition given in the draft standard.		X
CenterPoint CPS Energy	Firm transaction obligations are not used throughout all regions in NERC. Change "including firm transaction obligations" to "including firm transaction obligations where applicable."		X
E ON US	Why define a term that is used only once in the document (R.2.1.2.1) and is, by definition, applicable to a[ny] specific point in time.		X
FPL & FRCC	"Computer" is not appropriate. Replace with "Data model" or "Database model". The last sentence is not clear as to what type of ratings (i.e., normal, short-term emergency, long-term emergency, etc.). Suggest removing sentence completely or rewording as follows: "... in accordance with the documented methodologies required by FAC-008 for each Transmission Owner and Generator Owner."		X
Georgia Transm. Corp	The base case is also a representation of firm transactions through a BES, generation resources, and models reactive components.		X
LADWP	A basecase is a representation of the interconnected power system network at a given instant of time which correctly models an expected network topology in sufficient details (transmission lines, shunt and series compensations, transformers, breakers, phase-shifting transformers, etc.) , the forecasted loads, and a dispatch of connected generations that would achieve load-generation balance to allow a numerical solution without violation of any reliability standards. The resultant flows on the transmission lines are dictated by the Kirchhoff's laws, not laws of commerce, and therefore, cannot		X

Organization	Q1. **Comment**	Agree.	Don't agree.
	be interpreted as either firm or non-firm commercial transactions. A basecase is just a starting point from which transmission planners can make use of to further stress the portion of the systems that are of interests, to properly evaluate the robustness and reliability of the system and to determine line (non-thermal) ratings or network expansions, as needed.		
Northwestern Energy	NWE recommends the words "and may include non-firm transactions" after the words "firm transaction obligations".	X	
NERC TIS	The definition should differentiate between powerflow and dynamics base cases.	X	
LCRA	Should read "Computer model representation of…"	X	
PJM	Also FAC-010.	X	X
Santee Cooper	Delete the phrase "and reactive resources." It is redundant.	X	
SERC RRS OPS	Delete the phrase "and reactive resources."	X	
RFC	To add clarity, the terms "power flow" and "dyanamic" should be included in the definition above. It seems that the defintion may be more detailed than needed without these two terms.		X
Southern Transmission	As stated the definition does not appear to allow for equivalenced system representation since it refers to "each bus on the interconnected Transmission System". The words "as represented in the model" should be added after "interconnected Transmission System" or another sentence should be added stating that equivalenced system representation is acceptable. A definition of a dynamics base case should also be considered.		X
Response: Definition of "base case" has been deleted. Therefore concern is no longer applicable.			
City Water Light and Power	This should not be a defined term in the Glossary, instead there should be a Standard that provides the industry with the requirements for completing a Base Case Study.		X
Response: Definition of "base case" has been deleted, as suggested. However, the SDT believes this standard contains requirements for planning reliable transmission systems, including performing appropriate studies.			
APPA	This should not be a defined term in the Glossary, instead there should be a Standard written that provides the industry with the requirements for completing a Base Case Study. This is the first step in completing the Transmission Studies required in TPL-001. There is no guarantee that the rules used by the transmission planners for the base case studies are done in a reliable manner. The Standard needs to be expanded to insure oversight by the compliance monitors to ensure that the base case is sound from a reliability perspective. Also, both reliability and transparency require that the results of the base case study along with the assumptions used to develop the study must be shared with responsible entities within contiguous areas of the BES, not just with contiguous Planning Coordinators and Transmission Planners. To insure consistent results, the Standard should require that a properly conducted Base Case Study be based on agreed rules for conducting such studies within each		X

Organization	Q1. **Comment**	Agree.	Don't agree.
	interconnection and use of consistent data/assumptions by other entities in the region; otherwise, the results of each PC's and TP's planning horizon studies and the operation planning studies will be brought into question.		
Response: Definition of "base case" has been deleted, as suggested. However, the SDT believes this standard contains requirements for planning reliable transmission systems, including performing appropriate studies. The remainder of APPA's comments is not responsive to Q1 and will be addressed in response to Q43.			
Central Maine Power HQTE National Grid New England ISO NU NPCC RCWS NSTAR United Illuminating	There are a few undefined terms in this definition: "Transmission System" and "interconnected Transmission System". The definition needs to specifically identify what should be modeled and in a manner consistent with other NERC definitions. The definition refers to Facility ratings rather than the general reference to FAC-008 & FAC-009		X
Response: Definition of "base case" has been deleted. However, "Transmission System" is not intended as a new term. "Transmission" and "System" are defined in the NERC Glossary of Terms.			
City Utilities/Springfield	The manner in which the forecasted bus load is determined needs to be defined with clear and consistent assumptions and methodologies such that the results of transmission studies are reasonably valid throughout the entire planning horizon.		X
Response: The SDT believes the additional requirements are too prescriptive for this standard but, if appropriate, may be further detailed in MOD standards, which could be further modified through submittal of a SAR if necessary.			
WECC BPA TSGT TEP	A Base Case can only represent the amount of transactions required to serve connected load modeled in the case (local load?). A Path Rating case (developed to represent maximum transfers on a path) would not be considered a base case under this definition. WECC develops base cases to study high power transfers under stressed conditions. Such high power transfers necessarily include both firm and non-firm transaction obligations. Therefore, a base case that represents firm transactions to support "connected load" only, cannot be used to support studies of maximum possible power transfer and is of limited value in WECC. We agree that the above definition is one definition of a base case, but we feel that it can not be the only definition or the limiting definition. We suggest that wording be included that reflects the concept of modeling forecasted or above forecasted load levels if desired, and both firm and non-firm transactions if necessary to model anticipated maximum transfers and represent stressed system conditions as well. The definition should refer to the base case as a Computer Simulation Model of the power system, not a Computer Representation of the transmission system, since it is used within a computer program and represents load and generation in addition to	X	X

Organization	Q1. **Comment**	Agree.	Don't agree.
	transmission. References to "the generation dispatch and firm transaction obligations to supply the connected load" should be removed. A base case is a starting case for any condition that needs to be studied, not just a firm transactions case. Firm obligations across the transmission system are many times independent of a specific load service obligation.		
Response: Definition of "base case" has been deleted. However, the SDT believes some of these issues, particularly relating to the need to study variations from base case conditions, are addressed by Requirement 2.1.3.			
Ameren	Yes, we agree that the "base case" is a power flow model and is the starting point of the analysis. What we are concerned with are the assumptions that go into the development of the "base case". The season, time of day, load level, generation dispatch assumptions, facilities in service, and interchange assumptions (all based on best available data) are just a small subset of the issues that need to be addressed in the development of the base case. We have concerns that so-called "stressed cases" proposed in the standard for compliance testing may in reality be contingency cases, from which additional compliance performance testing would be required.	X	
Response: Definition of "base case" has been deleted. Furthermore, the term "stressed cases" is no longer used in the revised draft.			
ITC	Firm obligations may possibly include obligations beyond "firm transactions" which most likely means grandfathered transactions and TSRs as you have written it. The planning base cases should have sufficient margins to cover uncertainties as well as "firm transactions". The ATCTDT has "drafts" in place which require that TRM and CBM be included in transmission planning studies for both the near-term and long-term planning horizons. While they are drafts at this stage, consideration should be given to including their requirements in your drafts.	X	
Response: Definition of "base case" has been deleted. The SDT appreciates your comments on TRM and CBM; however, these issues will be covered by a separate drafting team.			
Allegheny Power		X	
New York ISO		X	
NCEMC		X	
Manitoba Hydro		X	
MEAG Power		X	
MISO		X	
SaskPower		X	
Seattle City Light		X	
SERC EC DRS		X	
SERC EC PSS		X	
MRO		X	
Muscatine P&W		X	

Organization	Q1. **Comment**	Agree.	Don't agree.
AECI	No comment.	X	
Brazos Electric	No comment.	X	
Dominion	No comment.	X	
ERCOT ISO	It is a fair description for an initial base case.	X	
IESO	The proposed definition fairly reflects the starting point system model used for planning and operations studies.	X	
Duke Energy		X	
KCPL		X	
LUS		X	
Entegra		X	
Entergy		X	
Exelon		X	
FirstEnergy		X	
Progress–Carolinas		X	
Progress–Florida		X	
SCANA		X	
Tenaska		X	
TVA		X	
BCTC		X	
CAISO	It is a fair description for an initial base case.	X	
WPSC		X	
Response:	Thank you. Please see the Summary Response.		

2) Q2. Consequential Load Loss: Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.

Summary Response: The SDT reworded the definition to better clarify that Consequential Load Loss is Load loss that occurs when the source to that Load is lost or Load that is lost due to the Load's transient response to the event being studied. Also the SDT revised this definition as follows to eliminate confusion regarding references to concepts such as fault clearing action, mis-operation, or radial Load:

Consequential Load Loss: Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.

Commenter	Q2. **Comment**	Agree.	Don't agree.
ABB	See Q6. Also, from your definition above, a better term would be "directly-connected load loss". This is clear and to the point.		X
Response: The SDT revised this definition to include Load that is no longer connected to a source as a result of the event being studied. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the Load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.			
AECC	My primary concern with TPL-001-1 is that the problems with footnote B of Table 1 in the current TPL standards have merely been given a different dress and makeup and are now being passed off in the definitions of Consequential Load Loss and Non-Consequential Load Loss. I hope this is not the intent and that my concern is a matter of education. None the less, my first impression leads me to the interpretation above. I will attempt to explain. My concern is based in the methodology used to conduct studies and as a result how the consequential and non-consequential definitions will apply. Specifically the use of a breaker to breaker (BtB) contingency methodology verses an element by element (EtE) methodology. By EtE an element is defined as any switchable device either manual or automatic.		X

Commenter	Q2. **Comment**	Agree.	Don't agree.
	BtB may be useful and may have a place in some system analysis but it only gives a very limited view of the impacts and does not take into account the corresponding operational actions that will take place as a result of a fault event. BtB also does not provide for impacts that might occur during system reconfiguration due to maintenance. EtE provides a much more comprehensive evaluation of the impacts that might be seen on a system and in my opinion is a best practice as opposed to BtB. My concern was raised when during the drafting teams webex on October 11, I heard comments made by the drafting team that "the system should be studied as it is operated". If this comment was intended to mean that events should be studied beyond their initial response then fine otherwise the comment should be clarified. Without clarification, statements like this can be interrupted to mean and only reinforce the mentality that BtB or other inadequate study methods are adequate and can continue to be used. What has all this to do with consequential vs. non-consequesntial load loss? I am getting there. If BtB analysis is permissiable then I disagree with the definitions of consequential and non-consequential load loss. Here is why: It is understandable that a load being normally served (prior to an event) by a radial (meaning one source) will be lost if an event occurs that removes the source. This to me is consequential load. On the other hand, if a load is being served from a transmission line with sources and breakers at both ends (networked) and the line experiences a fault, how is the load on the faulted line classified? Before you jump to an answer, let me explain why I asked. If a fault occurs on a section of the line then obviously both breakers should operate to clear the fault and the load would be removed from the system. This is what is mimicked in breaker to breaker analysis. The problem is that breaker to breaker analysis stops there and some may argue that this is adequate and that the load lost is consequential. I beg to differ. In reality the transmission line will be sectionalized to restore service to the load and isolate the faulted portion of the line. A new steady state condition results one or two radials replacing the faulted transmission line. The impacts of which would be captured if EtE analysis occurs. Because the load is served after the event it should not be classified as consequential. The load being served by resulting radials would not be classified as consequential until the next fault event occurred. Because the system can be sectionalized by switchable devices to establish the new steady state is one reason why switchable devices need to be added to the definition of element.		

Commenter	Q2. **Comment**	Agree.	Don't agree.
	It can be expected from the examples above that the resulting radial(s) serving the load may create greater impacts on the system than the original networked line. The load in this case is not consequential. This is what happens in actual operations, this is what needs to be studied, and the standard needs to ensure that the BES maintains the ability to adequately serve the load following such an event. Having the capability to serve load following the isolation of a faulted section of line is one of the reasons why the networked system was developed in the first place. Another example of radial configuration of networked lines occurs during maintenance. A section of line is taken out of service and ALL load is still served. In this case the load is not consequential because no fault has occurred and again the impacts may be greater than the original networked line. Again these impacts can only be determined by studying the system on an EtE basis. Today's world often forgets that serving load is the reason the BES exist. The BES therefore should be capable of adequately serving the load not only under normal operating conditions and the most common contingency conditions but also under the resulting steady state configuration following a contingency. The BES should be planned in a manner that addresses these contingencies and not in a manner that just seeks to do enough to be able to report compliance. In conclusion, I offer the following recommendations: #1: The definition of Element in the NERC Glossary should be modified to: 1. Include switchable devices either manual or automatic. 2. Clearly define what constitutes an element Suggested modification: Element = Any switchable electrical device (either automatic or manual) with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more elements. The last sentence was struck because you can't define something using the term you are trying to define. #2: The definition of consequential load loss needs further clarification. Consider replacing "due to fault clearing action or misopertion" with "as a result of new steady state conditions following a Planning or Extreme Event."		

Commenter	Q2. **Comment**	Agree.	Don't agree.
	#3: The definition of Planning Events should not be limited to the initial event such as breaker opening for a fault but should include any and all actions taken to sectionalize so that at the end of a Planning Event you have a system that is in steady state and serving as much load as possible. Suggestion: Planning Events = Events which remove one or more Elements and require Transmission system performance requirements to be met. This definition includes the initial event and any after event actions that result in the system returning to a steady state condition and preventing as serving as much Consequential load as possible. #4: The standard should include the expectation that the BES will be studied at some level (at least n-1) using EtE methodology.		
Response: One of the drivers for developing the definitions for Consequential Load and the use of some entities of BtB methodology referred to in your comments were concerns expressed in interviews by NERC TIS and FERC.. The interviews revealed that some planners were running simulations of single contingency by removing "elements" modeled in the simulation, e.g. impedance data from one bus number to another. This removed "element" did not even necessarily represent a real life switchable system element and this is reflected in requirements R3.2 and R4.2 of the Standard. The concept of Consequential Load was needed to clarify that under certain circumstances the standard allows for load to be dropped following the first contingency. As you indicated the planner must consider how the system can be switched and reconfigured to the point that loadings can be returned to within acceptable limits. The SDT has revised the definition to provide more clarity.			
PJM	Need to tighten definition example- load that trips in sympathy with fault (motor trips as a direct result but not in protection zone)	X	X
Response: The SDT revised the definition to better clarify what constitutes Consequential Load Loss in response to various comments.			
ATC	Voltage sensitive load loss (not due to operator action or UVLS) in response to a disturbance should constitute consequential load loss. Loss (drop) of voltage sensitive load must be included in this definition --- it is not non-consequential loss of load.		X
Response: The SDT revised this definition to include Load that is lost as a result of the Load's response to the transient conditions of the event. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when			

Commenter	Q2. **Comment**	Agree.	Don't agree.
Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.			
E ON US	I agree with the definiton except for "or mis-operation". The requirements do not, and should not, include mis-operation of protection schemes. We would never finish a study of all potential mis-operations.		X
Response: The SDT revised this definition to exclude any information that could be confusing, including the mention of misoperations. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.			
BCTC	For the reasons discussed below, we do not agree with the proposed definition. To address our concerns and address the FERC staff concern regarding ambiguity, the proposed definition could be made acceptable to us by modifying it as follows: Load that is no longer served because it either (a) was supplied (wholly or partly) by an element(s) of a radial system or local network that was removed from service due to fault clearing action, was disconnected by controlled interruption to avoid overload of remaining elements of a radial system or local network, or protection or SPS/RAS mis-operation or (b) has dropped out or been tripped during a transient stability period, including an automatic reclosing period, due to a fault on the radial system or local network, including on branches not directly supplying the load. We also offer the following alternative: Resultant loss or controlled interruption of customers supplied by a radial system or local network, due to a fault on or loss of a facility in the radial system or local network. The definition proposed by the SDT removes the second sentence of footnote (b), as directed by FERC, and replaces the first sentence of footnote (b) with a new definition. We agree with the removal of the second sentence of footnote (b). However, we have a concern with this definition replacing the first sentence of footnote (b). We believe that the existing first sentence is a more appropriate definition of consequential load loss and that the proposed definition is more stringent and will have unacceptable impacts on reliability and/or add transmission costs that cannot be justified.		X

Commenter	Q2. **Comment**	Agree.	Don't agree.
	The coining of the term "Consequential Load Loss" has been a significant improvement in terminology compared to our reference to footnote (b). However, FERC only used this phase descriptively and did not order NERC to reconsider what would be acceptable consequential load loss (i.e. revise the first sentence of footnote (b)). The definition appears to be based on an interpretation of the new term rather than defining what this term was coined to describe. Order 693 requires that footnote (b) be clarified to not allow loss of firm load or firm transfers - i.e. delete the second sentence. Order 693 then refers to the remaining first sentence as consequential load loss. Order 693 does not address issues regarding whether this should further be restricted to only radial lines, not permitting load loss for outages on local networks. Nothing in the NOPR or the staff paper implies otherwise. The staff paper discusses potential ambiguity regarding which single contingencies load interruption is permitted for. The definition attempts to address this by referring to "directly connected" load. However, this is now ambiguous as "directly connected" might be interpreted to mean only the facility that the load is physically connected to and excluding any upstream facility. BCTC submits that the upstream facilities need to include both radial facilities and local networks. NERC has stated that looped configurations are key for reliable operation. We consider looped configurations and local networks to be the same thing. The proposed definition will make it more difficult to transition from a radial supply to a looped configuration. For radial loads connected by a single radial line, when the load exceeds the line capacity, the transmission owner has alternatives of upgrading the line, adding a second circuit, or converting to a local network by providing a loop from another supply. With the addition of a second circuit or conversion to local network, controlled load interruption may be necessary for loss of one circuit to avoid overload of the second line. Without the option of controlled load interruption, these alternatives will not provide N-1 capability for all loads they supply without addition of a third circuit. This will lead to a economic preference to upgrading of the existing circuit to meet criteria, thereby perpetuating the single radial line configuration. Other alternatives could include splitting the load between the lines or operating with one line out of service so that a single contingency does not overload the facilities remaining in service. However, the addition of a second circuit with controlled load interruption will provide a more reliable load serve than any of these		

Commenter	Q2. **Comment**	Agree.	Don't agree.
	alternatives, because under N-1 more load will remain continuously on line. We expect that the proposed definition will provide greater assurance that existing local networks with N-1 capability will continue to have N-1 capability. However, we have concluded that the definition will introduce an additional unacceptable barrier to transition from N-0 to N-1 supply and that this barrier is not acceptable. We believe that this barrier would be a more significant issue for improving the reliability of supply to all customers than the current situation of permitting some controlled load interruption on local networks. Another issue that arises if local networks are excluded is load response during transient periods. Customers can connect voltage sensitive loads, such as large motors, on long weak systems. During the transient stability period, voltages can dip to below the ride through capability of the load. The fault need not be on the circuit directly supplying the customer, but may be downstream or on another branch facility. Automatic reclosing is often employed to shorten restoration times, but with the consequence of worsening the transient period. Customers have options to install different types of motors, motor controls, local voltage support to mitigate impacts of transient voltage swings, or simply restart motors following the disturbance. If transmission systems are required to ensure no loss of load during transient stability periods for external faults, a first course of action may be to remove automatic reclosing, which will reduce reliability. Alternatively, customer load connections may be denied or additional transmission circuits may be required, which can be costly compared to the customer load options.		
City Water Light and Power	This could be load lost which is on a radial line or load served by facilites which do not have fault-interrupting breakers.	X	
Duke Energy	It is unclear what is meant by "mis-operation". The SDT also needs to address load lost during the transient time frame (e.g. load dropout due to low voltages as a result of a fault) that may not be directly connected to the element removed from service.		X
Entegra	Further examination is needed to determine how to correctly treat loads served downstream from the faulted element, but not directly connected.		X
Georgia Transm. Corp	This definition implies that load that is lost past the directly connected load is allowed. Therefore the definition should be changed to include radially connected load and load that is radialized as a result of a contingency or mis-operation.		X
LADWP	The existing standards do not allow load loss for N-1 contingency unless the load is a radial load of the outage element. This new definition appears an attempt to weaken the requirement by broadening it to anything "directly connected" to an element that is removed from service. While it may be argued that probably only radially connected loads fit this definition, this new definition will lead to more creative		X

Commenter	Q2. **Comment**	Agree.	Don't agree.
	interpretation of the word "consequential" and leads all of us down unintended consequence. A radial load is a very specific and clearly defined technical term and should not be changed to a new term that is less precise.		
MRO	The MRO could not agree on the correct definition.		X
Santee Cooper	The term "mis-operation" introduces ambiguity into the definition, and should be deleted. The definition needs further clarification for consequential and non-consequential loads. For example, loads served downstream from the faulted element but not directly connected should also be considered to be consequential loads. A better name for this would be "direct load loss".		X
FirstEnergy	We suggest that the team remove "or misoperation" from the definition. This could suggest that an overtrip of protection equipment could result in consequential load loss.		X
NCEMC SERC EC PSS	The term "mis-operation" introduces ambiguity into the definition, and should be deleted. The definition needs further clarification for consequential and non-consequential loads. For example, loads served downstream from the faulted element but not directly connected should also be considered to be consequential loads.		X
NERC TIS	MISOPERATION has to be qualified as being a misoperaiton on the system element that trips.	X	
RFC	Should the above definition contain a statement that the load is not intentionally lost, since non-consequential load loss is intentional?		X
SERC EC DRS	Add the following to the end of the definition: "or unintentional load lost as a direct result of the event (e.g. load dropout due to low voltages as a result of a fault)."		X
Southern Transmission	This definition only relates to load that is "directly connected" to the specific element being removed. It does not allow for any load that may be or becomes radially connected through another branch that is not part of the facility removed. It does not make sense to not allow the loss of load that is actually electrically radial to the facility being outaged. The definition may work better as "Load that is no longer served because it is directly connected to or radially served through an element(s) that is removed from service due to fault clearing action." The word "mis-operation" is not needed in this definition because none of the contingency events use this term.		X
BPA	Support comments submitted by WECC. The definition needs to consider loads that are tripped sympathetically that may not be directly connected to the element that is removed from service for fault clearing.	X	X
WECC TSGT TEP	Agree with the definition in concept. However, the wording makes the definition seem unrealistic. There are many examples where a certain amount of voltage sensitive load or motor drives sensitive to angle changes are dropped due to normally cleared electrical faults on the transmission system. These loads are not directly connected to the element being removed from service. This type of sympathetic loss of load is	X	X

Commenter	Q2. **Comment**	Agree.	Don't agree.
	unique to the individual customer load. The design of these loads is not under the control of the utilities when it comes to ability to ride through normally cleared faults. We suggest that this definition be modified to include the loss of sensitive load that is not directly connected to the element being removed. We propose the following the definition : Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation, and because of sympathetic tripping associated with normal clearing or mis-operation. Load that is lost because it trips due to low voltages experienced during and immediately following the fault (4-6 cycles?) is also considered consequential load loss. We believe this additional recognition is needed because load lost due to low fault voltages is unavoidable and should not result in a standard violation.		
Response: The SDT reworded the definition to better clarify that Consequential Load Loss is Load loss that occurs when the source to that Load is lost or Load that is lost due to the Load's transient response to event being studied. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.			
AEP	Consider replacing "Consequential" with better wording (no specific suggestion to offer at this time).	X	
Ameren	A better name for this would be "direct load loss". The definition should include load served by the faulted element but not directly connected to the faulted element.	X	
SERC RRS OPS	The term "mis-operation" introduces ambiguity into the definition, and should be deleted. The definition needs further clarification for consequential and non-consequential loads. For example, loads served downstream from the faulted element but not directly connected should also be considered to be consequential loads. A better name for this would be "Planned Load Loss."		X
Entergy	Delete "mis-operation". For purposes of planning, all consequential load loss should reflect intended fault clearing actions and not unintended fault clearing actions (i.e., mis-operations). Include load loss due to UVLS & SPS in consequential load loss category. Consider using the terms in the existing standard; "Planned Load Loss" and "Unplanned Load Loss" in lieu of Consequential and Non-consequential as they may be		X

Commenter	Q2. **Comment**	Agree.	Don't agree.
	easier to define with each Transmission Owner/Planning Authority responsible for defining the terms considering the impact on the Bulk Electric System. If the terms remain as proposed, the definition needs further clarification for consequential and non-consequential loads. For example, loads entirely dependent on the faulted element but not directly connected should also be defined to be consequential loads.		
HQTE	``directly-connected`` load loss would be more clear	X	X
ITC	Suggest a change in terminology to "direct".	X	
MEAG Power	MEAG believes that deleting the term "mis-operation" as some may have suggested, would significantly narrow the definition of Consequential Load Loss, which in turn would unreasonably increase the amount of load that is Non-Consequential. The Non-consequential load loss, which is not allowed in P1-P5. For example, if mis-operation is deleted from the definition and we consider a relay mis-operation where a breaker fails to clear a fault, then any additional load interrupted by the back-up to the failed breaker/relay is Non-Consequential Load (and the standard appears to be violated since only a single transmission circuit was faulted and Non-Consequential Load was lost).	X	
MISO	Midwest ISO suggests this definition be changed to "Direct Load Loss", as "Consequential Load Loss" may include elements that are not directly connected to the faulted element.		X
SCANA	"Consequential Load Loss" should be termed "Intentional or Planned Load Loss". Not only should direct connected load loss be included, but loads served by or downstream from the faulted element, that is not directly connected to the faulted element, should also be included.		X
Tenaska	Using consequential and non-consequential seem to be misleading. Perhaps using "direct" and "indirect". Also, mis-operation needs some more explanation and to why it should be included here.		X
TVA	We recommend that the terms consequential and non-consequential be changed to direct and indirect. Also, the term should be better defined. We recommend that the definition be "loads that have been de-energized by fault-clearing action or loads that are lost even though the system performance remains within acceptable limits."		X

Response: The SDT reworded the definition to better clarify that Consequential Load Loss is Load loss that occurs when the source to that Load is lost or Load that is lost due to the Load's transient response to the event being studied. The SDT is concerned that the use of alternative terms might be confusing. Among other things, the terms used in the proposed standard are consistent with terms used by FERC.

Consequential Load Loss: Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's

Commenter	Q2. **Comment**	Agree.	Don't agree.
response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements**.**			
FPL FRCC	Need to clarify what constitues an element (e.g., breaker-to-breaker, line segment to line segment, transformer or capacitor bank)		X
Response: "Element" has been removed.			
SaskPower	What is meant by directly connected? Local area network load is allowed to be shed in Saskatchewan. The Saskatchewan Regulatory Jurisdiction has no plans to change this unless there is technical evidence to justify the increase in reliability.		X
Response: The SDT reworded the definition to better clarify that Consequential Load Loss is Load loss that occurs when the source to that Load is lost or Load that is lost due to the Load's transient response to the event being studied.. Without knowing under what conditions network Load can be shed in Saskatchewan, the SDT does not know whether the proposed standard would cause a change in Saskatchewan's practices or reliability. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements**.**			
Manitoba Hydro	If load losses due to stuck breaker and back-up breaker operations (which would frequently result in the loss of two or more network transmission elements) are not going to be qualified as "Consequential", where should they be placed? MH cannot visualize them as "Non-Consequential", as defined in Q6. Either another "load" category must be developed for these loads, or they should remain as "Consequential". In addition, Consequential Load Loss should include the concept of local area load loss to cover a scenario of islanding with a UFLS in the island, or a small network served at the end of a radial line.Can the SDT comment on why this Local Area defined in the existing TPL stds has been removed?	X	
Response: The SDT reworded the definition to better clarify that Consequential Load Loss is Load loss that occurs when the source to that Load is lost or Load that is lost due to the Load's transient response to the event being studied. However, Load losses associated with a stuck breaker would be considered consequential if they were the result of the initiating event. UFLS activation should not occur on a single Contingency event and would not be considered consequential. A radial Load is directly connected since it has no other source post event and would be consequential. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due~~			

Commenter	Q2. **Comment**	Agree.	Don't agree.
~~to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements**.**			
APPA	This definition will help define what cascading outage is. There is confusion in the industry and FERC as to "what is a cascading outage." The planning process needs to address this confusion and define exactly what a cascading outage consists. Some want a cascading outage to be when loads beyond the primary or secondary protection equipment are dropped.	X	
Response: The SDT agrees that additional clarification is needed regarding cascading outages. FERC is currently working on modifying this definition. However, the definition of cascading outages is a separate issue from the definition of Consequential Load Loss.			
ERCOT ISO	Agree with the definition.	X	
Northwestern Energy		X	
CAISO	Agree with the definition	X	
CenterPoint		X	
Central Maine Power		X	
City Utilities/Springfield		X	
CPS Energy		X	
Allegheny Power		X	
Exelon		X	
Brazos Electric		X	
LCRA		X	
IESO	This is the same understanding of the IESO.	X	
KCPL		X	
LUS		X	
Muscatine P&W		X	
National Grid		X	
New England ISO		X	
New York ISO		X	
NU		X	
NPCC RCWS		X	
Nstar		X	
Progress–Carolinas		X	
Progress–Florida		X	
Seattle City Light		X	
Dominion		X	

Commenter	Q2. **Comment**	Agree.	Don't agree.
United Illuminating		X	
WPSC		X	
Response: Thank you. Please see the Summary Response.			

3) Q3. Extreme Events: Events which are more severe than Planning Events and have a low probability of occurrence.

Summary Response: Industry comments were mixed, with some commenters agreeing with the proposed definition and others disagreeing. Among the disagreeing commenters, several noted that a more accurate characterization of Extreme Events would be that Extreme Events have a "lower probability of occurrence than Planning Events" because even Planning Events have a low probability of occurrence. Based on the comments, the SDT revised this definition as follows:

Extreme Events: Events which are more severe and have a lower probability of occurrence than Planning Events ~~and have a low probability of occurrence~~.

Commenter	Q3. **Comment**	Agree.	Don't agree.
Ameren	Most planning events have a low probability of occurrence. It appears that the SDT is trying to make a distinction that these Extreme Events would have a lower probability of occurrence than planning events. Consideration should be given to adding the performance requirements with the definition.		X
ITC	R3.4 implies that "Extreme Events" will be studied as per the table. The definition seems functionally correct as applied to the standard but somewhat confusing. The existing wording implies that a mitigation plan should be developed if studies show that "Extreme Events" might cause cascading. If the mitigation plan is a true requirement, saying it is not a planning event can be confusing. "Extreme Events are more severe than Planning Events, have a low probability of occurrence and only require___?????_____ in the event of cascade."	X	
WPSC	By definition, Extreme Events are not Planning Events. However, only the definition Planning Events has a requirement to meeting performance requirements. I believe Extreme Events also have performance requirements under R3.4 and its definition should reflect this.		X
Response: The SDT revised this definition in response to various comments. However, the SDT disagrees that performance requirements should be included in the definition as is proposed in the comment. **Extreme Events**: Events which are more severe and have a lower probability of occurrence than Planning Events ~~and have a low probability of occurrence~~.			
ATC Central Maine Power	Suggest "Events which are more severe and have a lower probability of occurrence than the Planning Events"		X
AECC	This is too vague. The old Table 1 did a better job of defining Extreme Events.		X
City Water Light and Power	More needs to be added here, especially to define the phrase "low probability of occurrence". Does this refer to N-1, N-2, N-3 etc.? We have a 300 foot long interconnection line between two substations. In this case even N-1 has a low probability of occurrence. This N-1 event has a much lower probability of occurrence than an N-2 event which involves generator outages. We also have an N-1 SPS event		X

Commenter	Q3. **Comment**	Agree.	Don't agree.
	which hasn't occurred in 25 years.		
E ON US	I disagree with the phrase "and have a low probability of occurance". All the Planning Events, except possibly a generator outage (P1.1), have a low probability of occurance.		X
ERCOT ISO CAISO	Add specificity in this definition. Suggest the following wording: Outage of two or more elements from service with lower probability of occurrence than Planning Events.		X
BCTC	Alternative wording proposed: Events which have a low probability of occurrence and are typically more severe than Planning Events. Explanation: The primary consideration is the probability of occurrence. We do not exclude events simply because they are more severe.		X
Entegra	The statement would be clearer if "low" were changed to "lower".		X
MEAG Power NCEMC Santee Cooper SERC EC DRS SERC EC PSS SERC RRS OPS TVA	A number of the non-Extreme Events also have a low probability. Recommend change the word to "lower." The definition for "Extreme Events" should reference Table 1.		X
MISO	Extreme Events are clearly described on Table 1. Change definition from "low probability of occurrence to "lower probability of occurrence".		X
MRO	Low probability of occurrence should be in reference to something to be more meaningful. The MRO suggests that the definition be changed to state "lower probability of occurrence than Planning Events."		X
Entergy	Revise to, "Events which are beyond the normal scope of Planning Events and have a lower probability of occurrence."		X
KCPL	Suggest changing "low" to "lower".	X	
LCRA	Define "low probability of occurrence"	X	
National Grid New England ISO Sask Power United Illuminating	Modify to "Events which are more severe,but have a lower probability of occurrence, than Planning Events".		X
FPL FRCC HQTE IESO	Suggest reword as follows: "Events which are more severe and have a lower probability of occurrence than planning events."		X

Commenter	Q3. **Comment**	Agree.	Don't agree.
Manitoba Hydro NYISO NU NPCC RCWS NSTAR			
PJM	Agree with concept but need better definition	X	X
Southern Transmission	Recommend modifying the definition to read: "Events which are more severe than Planning events that are evaluated as required by TPL-001-1 Tables 1 and 2, in part, to identify potential Cascading Outages.		X
Tenaska	I think most people understand, but in this new world we need to put some more specificity around the words "low probability".		X
Response: The SDT revised this definition in response to various comments. **Extreme Events**: Events which are more severe and have a lower probability of occurrence than Planning Events ~~and have a low probability of occurrence~~			
APPA	The definition is needed; however, this term is dependent on a clear definition of Planning Events, which does not exist.		X
Response: The SDT revised the definition of Planning Events in response to comments received for Q8 with the intent of adding more clarity to this definition. **Planning Events:** Events ~~which~~ that require Transmission system performance requirements to be met.			
Georgia Transm. Corp	All events on the BES have a low probability of occurrence. Extreme Events are those events that have a high consequence to the BES if they were to occur.		X
Response: The SDT revised this definition in response to various comments. Specifically, in response to the recommendation of several commenters, the SDT revised the definition of Extreme Events to indicate these events have a lower probability of occurrence than Planning Events. However, the consequence is determined by simulating these lower probability events. Therefore, the SDT believes it would be inappropriate to define the consequence. **Extreme Events**: Events which are more severe and have a lower probability of occurrence than Planning Events ~~and have a low probability of occurrence~~			
LADWP	Extreme Events for transmission planning should be defined as anything more than N-2. The proposed definition is subjective and not precise. There are examples in this standard as to how this definition can be mis-construed, e.g., cyber attack, wild-fire, hurricanes, etc. These are Extreme Events that belong in emergency planning, not transmission planning.		X
Response: The SDT revised this definition in response to various comments. Specifically, in response to the recommendation of several commenters, the SDT revised the definition of Extreme Events to indicate these events have a lower probability of occurrence than Planning Events. The SDT also modified the standard to clarify Extreme Events.			

Commenter	Q3. **Comment**	Agree.	Don't agree.
Extreme Events: Events which are more severe and have a lower probability of occurrence than Planning Events ~~and have a low probability of occurrence~~			
NERC TIS	The use of the term Extreme should be limited to those events that are truly extreme. A single line-to-ground fault with delayed clearing (for whatever reason) may require remote clearing of the fault, and trips multiple system elements, without time between elements being outaged. Such events are far too common occurrences to call them extreme.		X
Response: The SDT revised this definition in response to various comments. The SDT also modified the performance tables in response to various comments. **Extreme Events**: Events which are more severe and have a lower probability of occurrence than Planning Events ~~and have a low probability of occurrence~~			
WECC BPA TSGT TEP	Please add the phrase "two or more elements out of service" to the definition from the previous definition in Table I.	X	X
Response: The SDT revised this definition in response to various comments. However, the SDT believes the suggested phrase would be imprecise for the standard as currently drafted because some Extreme Events do not necessarily involve "two or more elements out of service". For example, one type of "extreme event" is loss of a large Load or major Load center, which might possibly occur without two or more elements out of service. **Extreme Events**: Events which are more severe and have a lower probability of occurrence than Planning Events ~~and have a low probability of occurrence~~			
Dominion	To make this "crisp", it is suggested that this definition be extended as "Events which …..occurrence. The Transmission system performance requirements do not apply to Extreme Events".	X	
Response: The SDT revised this definition in response to various comments. However, the SDT is concerned that the language proposed in this comment may cause confusion because requirement R3.4 applies to Extreme Events. **Extreme Events**: Events which are more severe and have a lower probability of occurrence than Planning Events ~~and have a low probability of occurrence~~			
FirstEnergy	The definition is OK, but we question its use in the standard. Many of the items listed as Extreme Events are not considered events. For example, high river temperature is not really an event, it is a condition. The resulting event might be the shut-down of multiple generators.	X	
Response: The SDT revised this definition in response to various comments. The SDT also modified the standard to clarify Extreme Events. **Extreme Events**: Events which are more severe and have a lower probability of occurrence than Planning Events ~~and have a low probability~~			

Commenter	Q3. **Comment**	Agree.	Don't agree.
~~of occurrence~~			
ABB		X	
Allegheny Power		X	
AEP		X	
Brazos Electric		X	
CenterPoint		X	
City Utilities/Springfield		X	
CPS Energy		X	
Exelon		X	
Duke Energy		X	
LUS		X	
Muscatine P&W		X	
Northwestern Energy		X	
Progress–Carolinas		X	
Progress–Florida		X	
RFC		X	
SCANA		X	
Seattle City Light		X	
AECI	However this could be very subjective.	X	
Response: Thank you. Please see the Summary Response.			

4) Q4. Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond.

Summary Response: Most commenters agreed with the proposed definition, but a few commenters raised issues about the use of the term "beyond". Therefore, the SDT revised the definition as follows to clarify when the horizon may extend beyond ten years:

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Commenter	Q4. **Comment**	Agree.	Don't agree.
Central Maine Power NU NSTAR United Illuminating	"A Planning Assessment period that covers years six through ten", is sufficient for the standard." Suggest changing the name to Long-Term Planning Assessment.		X
Response: The SDT believes the term "or beyond" after "years Six through Ten" is necessary for the proposed standard as currently drafted to agree with Requirement R2.2.1, which requires a planning horizon beyond ten years if necessary. Moreover, the use of the phrase "planning horizon" in this definition is intended to indicate the period of time applicable to the assessment.			
FRCC	The definition does not have a reference year when the counting starts. Add the following to the end of the sentence: "… from the current study year."		X
Response: The SDT concurs that a reference year when the counting starts is necessary. The SDT proposed Year One as the reference year when the counting starts.			
AECC	With the time it takes to get transmission planned, approved and built the 10 year time frame is too short. Six to ten year studies are fine but longer term studies need to be performed occasionally. If the requirement remains vague and says 6 to 10 years then what will happen is only 6 year studies. Coupled with the 1 to 5 years in the Near Term Horizon then you potentially set up a situation where you could have a 5 and a 6 year study done. This defeats the purpose of what the intent of the defintion should be. I suggest that 1, 2, 5, 10, 15 year studies be required.		X
Response: The SDT believes the definition should clarify the intent that assessments will cover ten years and may extend beyond ten years if necessary (see Requirement R2.2.1). This definition was revised for additional clarity. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.			
LADWP	The objection is not so much about the definition as about what comes after the definition. This standard proposed to include operating and market studies (calling them sensitivities) in the "near-term" planning studies. It appears that the SDT believes this would be easier to justify if the sensitivities is limited to near-term and		X

Commenter	Q4. **Comment**	Agree.	Don't agree.
	not long-term, hence the motivation for breaking the planning horizon. But this is misguided; operating studies belongs in operating standards. They should be addressed appropriately in the TOP for operating scenarios and Market related studies should be addressed in MOD, for example. There are no benefits to include these in transmission planning studies and therefore no need to break up the planning horizon.		
Response: The SDT disagrees and believes sensitivity studies should be performed in the planning horizon. Furthermore, the requirement for sensitivity studies is responsive to FERC Order 693.			
National Grid New England ISO	"Transmission planning period that covers years six through ten", is sufficient for the standard."		X
SRP	Reword to: Transmission planning period that covers years six or beyond.	X	
Response: The SDT believes the definition should clarify the intent that assessments will cover ten years and may extend beyond ten years if necessary (see Requirement R2.2.1). This definition has been revised for additional clarity. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.			
ABB		X	
ATC		X	
Brazos Electric		X	
City Water Light and Power		X	
Dominion		X	
E ON US		X	
ERCOT ISO		X	
Northwestern Energy		X	
AECI		X	
Allegheny Power		X	
AEP		X	
APPA	This definition is needed to eliminate the confusion that exists in the industry.	X	
BPA		X	
BCTC		X	
CAISO	Agree with the definition	X	
CenterPoint		X	
City Utilities/Springfield		X	
CPS Energy		X	
Duke Energy		X	
Entegra		X	
Entergy		X	
Exelon		X	

Commenter	Q4. **Comment**	Agree.	Don't agree.
FirstEnergy		X	
FPL		X	
Georgia Transm. Corp		X	
HQTE		X	
IESO	Consistent with the IESO's understanding.	X	
ITC		X	
KCPL		X	
LUS		X	
LCRA		X	
Manitoba Hydro		X	
MEAG Power		X	
MISO		X	
MRO		X	
Muscatine P&W		X	
NERC TIS		X	
New York ISO		X	
NCEMC		X	
NPCC RCWS		X	
Progress–Carolinas		X	
Progress–Florida		X	
RFC		X	
Santee Cooper		X	
SaskPower		X	
Seattle City Light		X	
SERC EC DRS		X	
SERC EC PSS		X	
SERC RRS OPS		X	
SCANA		X	
Southern Transmission	No Additional Comments.	X	
Tenaska		X	
TVA		X	
TSGT		X	
TEP		X	
WECC		X	
Response: Thank you. Please see the Summary Response.			

5) Q5. Near-Term Transmission Planning Horizon: Transmission planning period that covers years one through five.

Summary Response: The majority of the commenters agreed with the proposed definition; therefore, the SDT did not modify the definition.

Commenter	Q5. **Comment**	Agree.	Don't agree.
AECC	I agree with the definition but I don't think studies should necessarily be required for all of the years 1 through 5. Years 1 and 2 probably need to be required because of they are sometimes used as the basis for the development of seasonal models and studies used in the opertional horizon in many Open Access Tariffs.	X	
Response: The minimum requirements for the near term are identified under Requirement R2.1. Past studies can also be included as identified in Requirement R2.6.			
Ameren Santee Cooper SERC RRS OPS	It is suggested that another definition be added for "operations planning horizon".		
Response: The reference to Operations Planning in Q11 was erroneous. The term "operations planning horizon" is not defined because it is not used in the standard.			
LADWP	See my comment above; the only part about the definition that I would retain is to require each of the first five years in a typical ten-year plan be studied instead of just picking one or two years out of the first five years.		X
Response: LADWP's comment does not appear to be directed solely at Q5. In addition, the SDT disagrees with the proposed modification of the requirement.			
Central Maine Power	Suggest changing the name to Near-Term Planning Assessment, and introduce the description the same was as above.	X	
New England ISO NU NSTAR United Illuminating	Suggest changing the name to Near-Term Planning Assessment.	X	
Response: The use of the phrase "planning horizon" in this definition is intended to indicate the period of time applicable to the assessment.			
ABB		X	
ATC		X	
Brazos Electric		X	
City Water Light and Power		X	
Dominion		X	
E ON US		X	
ERCOT ISO	Agree with definition.	X	
Northwestern Energy		X	
AECI		X	
AESO		X	

Commenter	Q5. **Comment**	Agree.	Don't agree.
Allegheny Power		X	
AEP		X	
APPA	This definition is needed to eliminate the confusion that exists in the industry.	X	
BPA		X	
BCTC		X	
CAISO	Agree with the definition	X	
CenterPoint		X	
City Utilities/Springfield		X	
CPS Energy		X	
Duke Energy		X	
Entegra		X	
Entergy		X	
Exelon		X	
FirstEnergy		X	
FPL		X	
FRCC		X	
Georgia Transm. Corp		X	
HQTE		X	
IESO	Same as above.	X	
ITC		X	
KCPL		X	
LUS		X	
LCRA		X	
Manitoba Hydro		X	
MEAG Power		X	
MISO		X	
MRO		X	
Muscatine P&W		X	
National Grid		X	
NERC TIS		X	
New York ISO		X	
NCEMC		X	
NPCC RCWS		X	
Progress–Carolinas		X	
Progress–Florida		X	
RFC		X	
SaskPower		X	

Commenter	Q5. **Comment**	Agree.	Don't agree.
Seattle City Light		X	
SERC EC DRS		X	
SERC EC PSS		X	
SCANA		X	
Southern Transmission	No Additional Comments.	X	
Tenaska		X	
TVA		X	
TSGT		X	
TEP		X	
WECC		X	
Response: Thank you.			

6) **Q6. Non-Consequential Load Loss: Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.**

Summary Response: Based on comments, the SDT revised this definition to specify that this is non-interruptible load as follows to add further clarity:

Non-Consequential Load Loss: ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.

Commenter	Q6. **Comment**	Agree.	Don't agree.
AECC	See my comments on Consequential Load Loss. The definition is too vague to just say "load loss other than Consequential Load Loss". The defintion should be clear and examples should not be used to make the definition. This is a bad habit that NERC has which leads the industry to establish status quo based on the examples and not the definition itself. It sounds like Consequential Load Loss is being tied to short circuit fault events and Non-Consequential Load Loss is being tied to events other than short circuit fault events. Remember that undervoltage, underfrequency and SPS are still triggered by "faults". If that is the intent then say it. Don't put forth a vague definition and then try to justify its meaning by an example.		X
IESO	Suggest to either stop at "automatic operations" or to include other examples since the list is not exhaustive, for example: load that drops out due to unacceptable voltage levels (not tripped intentionally by UVLS.		X
New York ISO	Suggest that examples not be listed or a more exhaustive list be developed.		X
Response: See responses to Q2. The SDT revised the definitions of Consequential Load Loss and Non-Consequential Load Loss in response to various comments. However, the SDT believes that the examples add clarity, even if not exhaustive. **Non-Consequential Load Loss:** ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.			
PJM	Non-Consequential Load Loss should not include load loss due to manual, UVLS and UFLS.	X	X
Response: The SDT believes that Load loss that occurs from manual action, UVLS, or UFLS is not a direct consequence of the event being studied and is in fact the type of distinction the SDT intended to make. The SDT believes that Consequential Load Loss is Load loss that			

Commenter	Q6. **Comment**	Agree.	Don't agree.
occurs when the source to that Load is lost or Load that is lost due to the Load's response to a transient condition of the event being studied. All other Load that is lost is non-consequential.			
ABB	Most people will think of inconsequential, which often means irrelevant, unimportant, or insignificant. But what you are trying to define is the opposite: load loss that is significant, important, and needs to be prevented. Also, whatever you call it, your examples (UVLS, UFLS, SPS) should be expanded to include unintentional and uncontrolled load loss due to low voltage, high current, impedance relays, etc.		X
Ameren Santee Cooper	A better name for this would be "indirect load loss".		
Georgia Transm. Corp HQTE	Suggest a change in title to Indirect Load Loss		X
MISO	Midwest ISO suggests this definition be changed to "Indirect Load Loss", as "Non-Consequential Load Loss" may be confusing regarding the cause-and-effect relationship between a faulted element and subsequent loss of load.		X
SERC RRS OPS	A better name for this would be "Unplanned Load Loss". Load loss that occurs from UFLS, UVLS, load shedding or SPS should be moved to Planned Load Loss. Unplanned load loss would be all other load loss other than planned.		X
TVA	See comment for Q2. We recommend that this term is defined as "load loss other than consequential load loss".		X
ITC	May want to change the terminology as some may interpret this to mean load that is not important and can routinely be shed for any contingency. Suggest 'direct load loss' and 'indirect load loss'. Potential Definition: Load that is not intended to be lost for normal fault clearing or during mis-operation but could be lost either by design, such as under frequency relaying, SPS or backup breaker clearing, or thru manual operator action.	X	
Response: See responses to Q2. The SDT revised this definition in response to various comments. However, the SDT is concerned that the use of alternative terms might be confusing. Among other things, the terms used in the proposed standard are consistent with terms used by FERC. Moreover, in response to SERC's comment, the SDT believes that Load loss that occurs from UFLS, UVLS, Load shedding or SPS is not a direct consequence of the event being studied and is in fact the type of distinction the SDT intended to make. **Non-Consequential Load Loss:** ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.			
ATC	Reference to SPS must be excluded from this definition. We recommend that the SDT address what System Elements and/or Load may be tripped by an SPS for each Planning Event in the performance table after N-1-1 scenarios for P3-P5 events.		X

Commenter	Q6. **Comment**	Agree.	Don't agree.
FirstEnergy	We suggest eliminating the reference to Special Protection Systems (SPS). Some SPSs could result in tripping of load in association with a fault. By specifically listing SPSs here, it could imply that if that situation occurs, it would not be considered consequential load drop.		X
Response: The SDT believes that Load loss that occurs from an SPS is not a direct consequence of the event being studied and is in fact the type of distinction the SDT intended to make. FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load Loss.			
City Water Light and Power APPA	This definition should go beyond just saying "Load loss other than Consequential Load Loss." Recommend adding the following: " . . . including Load Loss that occurs through planned manual (Transmission Operator, Distribution Provider, and so-on) operation or planned automatic operation of load shedding equipment such as under-frequency Load shedding devices or Special Protection Systems."		X
Response: See responses to Q2. The SDT revised this definition in response to various comments. **Non-Consequential Load Loss:** ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.			
CAISO	Add Remedial Action Schemes (RAS) after "Systems"		X
ERCOT ISO	Add Remedial Action Schemes (RAS) after "Systems" Amend sentence beginning "For example, Load loss that "directly" occurs…		X
Response: The NERC Glossary of Terms clarifies that the terms "Special Protection System" and "Remedial Action Scheme" can be used interchangeably.			
BCTC	See comments on Consequential Load Loss. Propose the following definition to clarify situations for which NCLL is acceptable: Load loss other than Consequential Load Loss to avoid cascading, voltage stability, or blackout of the BES. For example, load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage load shedding, under-frequency load shedding, or SPS/RAS.		X
SCANA	This term is not needed. See comments on "Consequential Load Loss/Intentional Load Loss".		X
Response: See responses to Q2. The SDT revised this definition in response to various comments. However, the SDT is concerned that the use of alternative terms might be confusing. Among other things, the terms used in the proposed standard are consistent with terms used by FERC. **Non-Consequential Load Loss:** ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual~~			

Commenter	Q6. **Comment**	Agree.	Don't agree.
~~(operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.			
Entergy	We recommend to treat load losses due to UVLS & SPS as examples of consequential load loss (refer to question 2).		X
Response: The SDT believes that Load loss that occurs from an SPS or UVLS is not a direct consequence of the event being studied and is in fact the type of distinction the SDT intended to make. FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load Loss			
FPL FRCC	Reword as follows: "Firm load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems, excluding curtailments, DSM, and voltage reduction."		X
Response: The SDT revised this definition in response to various comments. However, the SDT ddisagrees with curtailments, DSM, and voltage reduction as these are real-time operating actions that must be taken pre-Contingency and are unrelated to Consequential Load Loss and Non-Consequential Load Loss. **Non-Consequential Load Loss:** ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.			
LADWP	See my comment on the Consequential load loss. Why introduce two new and less precise definitions to replace one existing clearly defined definition? Radial load is precise and clearly defined to transmission planners.		X
Response: See responses to Q2. The SDT revised the definitions of Consequential Load Loss and Non-Consequential Load Loss in response to various comments. However, radial Load is not sufficiently precise and is itself confusing if left as the sole explanation. **Non-Consequential Load Loss:** ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.			
Tenaska	See Q2 answer.		X
Response: Please refer to the SDT reply to Q2 comments.			
TSGT	same as WECC group comments		X
BPA	Support comments submitted by WECC.		X
WECC	Please add "or Remedial Action schemes" to the end of the definition. FERC Order		X

Commenter	Q6. **Comment**	Agree.	Don't agree.
TEP	693, paragraph 1773 states (6)"clarifies footnote (b) to Table 1 to allow no firm load or firm transactions to be interrupted except for consequential load loss." There needs to be a distinction made between Interruptible Load and Firm Demand.		
Response: The SDT revised this definition in response to various comments. However, the NERC Glossary of Terms clarifies that the terms "Special Protection System" and "Remedial Action Scheme" can be used interchangeably. **Non-Consequential Load Loss:** ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.			
SaskPower			X
Response: The SDT revised this definition in response to various comments. **Non-Consequential Load Loss:** ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.			
Northwestern Energy	Include the words "not directly connected" before period of first sentence; and what does "load loss" mean?	X	X
Response: See responses to Q2. The SDT revised this definition in response to various comments. However, the SDT is concerned that the use of alternative terms might be confusing. Moreover, the SDT believes the term "Load loss" is largely self-explanatory and is further clarified by the examples provided in the definition. **Non-Consequential Load Loss:** ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.			
AEP	Consider replacing "Non-Consequential" with better wording (no specific suggestion to offer at this time).	X	
RFC	Recommend adding that this load loss is "intentional".	X	
Response: See responses to Q2. The SDT revised this definition in response to various comments. However, the SDT is concerned that the use of alternative terms might be confusing. **Non-Consequential Load Loss:** ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection~~			

Commenter	Q6. **Comment**	Agree.	Don't agree.
~~Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.			
AECI		X	
Allegheny Power		X	
Brazos Electric		X	
CenterPoint		X	
Central Maine Power		X	
City Utilities/Springfield		X	
CPS Energy		X	
Duke Energy		X	
Entegra		X	
Exelon		X	
Dominion		X	
E ON US		X	
KCPL		X	
LUS		X	
LCRA		X	
Manitoba Hydro		X	
MEAG Power		X	
MRO		X	
Muscatine P&W		X	
National Grid		X	
New England ISO		X	
NCEMC		X	
NCMPA		X	
NU		X	
NPCC RCWS		X	
Nstar		X	
Progress–Carolinas		X	
Progress–Florida		X	
Seattle City Light		X	
SERC EC DRS		X	
SERC EC PSS		X	
Southern Transmission	Agree assuming the change in Q2 is made.	X	
United Illuminating		X	
WPSC		X	

Commenter	Q6. **Comment**	Agree.	Don't agree.
Response: Thank you. Please see the Summary Response.			

7) **Q7. Planning Assessment: Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.**

Summary Response: Based on the comments, the SDT revised this definition to be more succinct and eliminate the description of the possible range of assumptions. The definition was also modified to clarify that the assessment is an evaluation of Transmission System performance (not needs) and Corrective Action Plans associated with identified deficiencies.

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~

Commenter	Q7. **Comment**	Agree.	Don't agree.
AECC	Planning assessments shouldn't be limited to the future. Sometimes an assessment needs to be made to benchmark and validate models. Strike: future		X
Response: The SDT revised this definition in response to various comments. However, the purpose of the standard is to assess future transmission needs. Other standards are related to benchmarking and validating models. **Planning Assessment:** Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~			
City Water Light and Power	This definition is too vague. A Planning Assessment should cover the Near-Term or Long-Term Planning Horizon and include Base Case and Contingency Analysis according to NERC Standards.		X
Response: Based on the comments, the SDT revised this definition to be more succinct. Other requirements explain the horizon and conditions required to be studied and should not be included in the definition. **Planning Assessment:** Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~			
APPA	This is too general. Just about any kind of review will qualify as a Planning Assessment. Suggested definition: "Documented evaluation of future Bulk Electric System needs by the use of performance studies such as NERC Steady State Transmission Studies or Plant Stability Studies conducted in accordance with the NERC Reliability Standards."		X
BCTC	Need to insert the word "supported", as below, and further refine, to clarify that the Planning Assessment is not just studies, but includes evaluation of contingencies to be run, sensitivities to consider, etc.		X

Commenter	Q7. **Comment**	Agree.	Don't agree.
	Documented evaluation of future BES needs, measures to mitigate adverse reliability impacts, and assessments of residual impacts, supported by the use of performance studies ….		
City Utilities/Springfield	Definition should be more clearly defined. Documented evaluation of future Bulk Electric System needs based on the performance requirements as defined for NERC Steady State Transmission Studies or Plant Stability Studies conducted in accordance with the NERC Reliability Standards or more restrictive local area criteria.		
Tenaska	May be best to stop the definition after the word assumptions and cover the details as part of the requirements in the standard itself.		X
Response: Based on the comments, the SDT revised this definition to be more succinct and eliminate the description of the possible range of assumptions. The definition was also modified to clarify that the assessment is an evaluation of Transmission System performance (not needs) and Corrective Action Plans associated with identified deficiencies. **Planning Assessment:** Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~			
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating	Eliminate "capital" from the definition. It is not defined or consistently applicable to the standard. Reference to vague "other factors, such as asset conditions and age" should be removed from this standard; there are no consistent definitions or industry standards on which to base this requirement, nor does it appear to be a necessary addition to the standard.		X
Entergy	Remove "and other factors, such as asset conditions and age" from definition. The terms "age" and "condition" are subjective and the age of equipment, if it is well maintained, has little impact on reliability.		X
Exelon	'Other factors' such as condition and age should not be required, but may be utilized if these factors are an integral component of the study.		X
FPL FRCC	Last part of the last sentence should be removed "… and other factors, such as asset conditions and age" does not make sense for planning studies. Equipment condition and age are maintenance issues not transmission planning issues.		X
Georgia Transm. Corp	Asset conditions and age should not be included in the definition. Equipment replacement, in general, is dependent on performance, not age.		X
LADWP	The assessment of asset conditions and age of equipment belongs in maintenance practices, not a transmission planning issue. Similarly, Operating procedures is an operating matter, not planning studies. They have their own standards that could and		X

Commenter	Q7. **Comment**	Agree.	Don't agree.
	should address any issue the SDT may have in mind. Using transmission planning as a catch-all is a wrong headed approach.		
MEAG Power	Bulk Electric System deficiencies rather than needs should be evaluated. We do not agree that the planning assessment should include asset conditions and age. This is a preventive maintenace issue. The age of equipment, if it is well maintained, has little impact on reliability.		X
NCEMC	Generally, we agree but would request NERC to clarify accounting for asset conditions and age within planning assessments. Wouldn't these already be taken into account in the FAC-008 & FAC-009 ratings?	X	
Progress–Carolinas	Planning assessments should not include asset conditions and age.	X	X
Santee Cooper SERC EC PSS SERC RRS OPS	Bulk Electric System deficiencies rather than needs should be evaluated. We do not agree that the planning assessment should include asset conditions and age. The age of equipment, if it is well maintained, has little impact on reliability. The term "and other factors" should be better defined or deleted.		X
SaskPower	What is the intent "and other factors, such as asset condition and age"? Seems to broad and outside the scope of NERC. Remove it.		X
SERC EC DRS	Delete the word "needs" and the phrase "such as asset conditions and age." We do not agree that the planning assessment should include asset conditions and age. The age of equipment, if it is well maintained, has little impact on reliability.		X
Southern Transmission	The term "needs" should be replaced by a term that more aptly describes what is being evaluated. The definition should be ended after the word "assumptions." We do not agree that the planning assessment should include asset conditions and age. The age of equipment, if it is well maintained, has little impact on reliability.		X
TVA	Use of the word "deficiencies" instead of "needs" provides better consistency throughout the standard. We do not agree that the planning assessment should directly include asset conditions and age. Asset condition should be part of the ratings process. The age of equipment, if it is well maintained, has little impact on reliability.		X
Ameren	We do not agree that the planning assessment should include asset conditions and age. The age of equipment, if it is well maintained, has little impact on reliability. If NERC wants a standard to deal with age and maintenance of equipment, then it should develop a separate standard for asset management and not overburden TPL-001-1 with such issues.		X
ATC	We do not agree that "asset conditions and age" belongs in this definition. Furthermore, these factors are not addressed in any requirement.		X
E ON US	I agree that Asset Managers need to consider asset condition and age in their spare equipment and replacement strategies but the impact of these factors is beyond the scope of a deterministic Planning Assessment.		X
Entegra	Should also include validation of reactive power supplies.		X

Commenter	Q7. **Comment**	Agree.	Don't agree.
Response: Based on the comments, the SDT revised this definition to be more succinct and eliminate the description of the possible range of assumptions. **Planning Assessment:** Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~			
FirstEnergy	We suggest replacing "performance studies" with "past or present studies or information".		X
Response: The requirements define the studies that qualify for use in assessments and are not part of the definition.			
LCRA	"Documented evaluation of future Bulk Electric System performance conducted through performance studies…"		
Response: Based on the comments, the SDT revised this definition to be more succinct and eliminate the description of the possible range of assumptions. The definition was also modified to clarify that the assessment is an evaluation of Transmission System performance (not needs) and Corrective Action Plans associated with identified deficiencies. The requirements define the studies that qualify for use in assessments and are not part of the definition. **Planning Assessment:** Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~			
MRO	This definition is too general. It could be interpreted that the performance studies include resource planning rather than transmission system planning, as well as, asset management. Asset management issues should be beyond the scope of this transmission planning standard. Asset management is an engineering discipline that would require a separate standard or standards and is still a developing activity, for example, there is no industry-wide practice for studying aging issues of transmission equipment while there are industry-wide practices for steady-state, stability, and short circuit modeling and planning of transmission systems. The MRO suggests that the word transmission be added to the definition when referring to needs, performance, and reinforcements and that references to asset management be deleted. Here is a proposed definition "Documented evalution of future Bulk Electric System TRANSMISSION needs by the use of TRANSMISSION SYSTEM performance studies that cover a range of assumptions regarding TRANSMISSION system conditions, time frames, future plans including TRANSMISSION IMPROVEMENTS and operating procedures and other factors." The words in all caps were added or inserted to replace the Drafting Team's original words.		X
Dominion	Suggest to change "…by the use of performance studies that cover……" to "…by the use of past or current performance studies that cover……".	X	X
Northwestern Energy	Insert before performance studies the words "current or past that is known to be	X	X

Commenter	Q7. **Comment**	Agree.	Don't agree.
	valid".		
WECC BPA TEP TSGT	As identified by the modifications above, we believe the definition should be changed to read, "Documented evaluation of future Bulk Electric System needs by the use of performance studies (steady state and dynamic) that cover a range of reasonable or expected assumptions regarding system conditions, applicable time frames, and future plans; including capital reinforcements and operating procedures, SPS/RAS, and other factors (such as asset conditions and age)."	X	X
Response: Based on the comments, the SDT revised this definition to be more succinct and eliminate the description of the possible range of assumptions. The definition was also modified to clarify that the assessment is an evaluation of Transmission System performance (not needs) and Corrective Action Plans associated with identified deficiencies. The requirements define the studies that qualify for use in assessments and are not part of the definition. **Planning Assessment:** Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~			
New York ISO	The word "Documented" is unnecessary. Suggest simplifying the definition to: Evaluation of future BPS needs to meet forecast demand under the assumed system conditions for the time frame studied.		X
Response: Documentation is required as proof that evaluation was performed and guidance is provided as to the content of the documentation.			
RFC	Recommend adding power flow and dynamic analyses to this definition. Short circuit analyses should not be included.		
Response: Based on the comments, the SDT revised this definition to be more succinct and eliminate the description of the possible range of assumptions. Requirements define the studies that must be performed. **Planning Assessment:** Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~			
SCANA	Bulk Electric System deficiencies rather than needs should be evaluated.		X
Response: The definition was modified to clarify that the assessment is an evaluation of Transmission System performance (not needs) and Corrective Action Plans associated with identified deficiencies.			
IESO	The definition covers too much detail on the "how" part, and the "documented" qualifier doesn't seem to be required. Suggest to change it to: Evaluation of future Bulk Electric System needs to meet forecast demand under the assumed system conditions for the time frame studied.	X	X
Response: Based on the comments, the SDT revised this definition to be more succinct and eliminate the description of the possible range of assumptions. The definition was also modified to clarify that the assessment is an evaluation of Transmission System performance (not needs) and Corrective Action Plans associated with identified deficiencies. The requirements define the studies that qualify for use in			

Commenter	Q7. **Comment**	Agree.	Don't agree.
assessments and are not part of the definition. Documentation is required as proof that evaluation was performed and guidance is provided as to the content of the documentation. **Planning Assessment:** Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~			
Brazos Electric	Some discussion of what 'documented' means is needed each time it is mentioned. Is this some form of written report at all times or are 'saved' cases with contingency analysis sufficient at certain times or is it just a means to show that an 'assessment' was performed in some fashion.	X	
Response: Documentation is required as proof that evaluation was performed and guidance is provided as to the content of the documentation. Documentation requirements are contained in the standard itself. For example, Requirement R2.7.3 requires documentation of the criteria for determining committed and proposed projects. More clarity may be provided through the subsequent development of compliance measures and auditor worksheets.			
Duke Energy	We have a concern with what will be considered acceptable documentation, particularly as it relates to asset conditions and age. Delete the word "needs" and the phrase "such as asset conditions and age". When measures are developed it should be made clear what will constitute an acceptable Planning Assessment.	X	
Response: The SDT revised this definition in response to various comments. Documentation requirements are contained in the standard itself. For example, Requirement R2.7.3 requires documentation of the criteria for determining committed and proposed projects. More clarity may be provided through the subsequent development of compliance measures and auditor worksheets. **Planning Assessment:** Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~			
ABB		X	
AECI		X	
Allegheny Power		X	
AEP		X	
CenterPoint		X	
CPS Energy		X	
ERCOT ISO CAISO	Agree with the definition.	X	
ITC		X	
KCPL		X	
LUS		X	
Manitoba Hydro	A planning assessment should include performance studies.	X	

Commenter	Q7. **Comment**	Agree.	Don't agree.
MISO		X	
Muscatine P&W		X	
NERC TIS		X	
Progress–Florida		X	
Seattle City Light		X	
Response: Thank you. Please see the Summary Response.			

8) Q8. Planning Events: Events which require Transmission system performance requirements to be met.

Summary Response: The majority of the commenters agreed with the proposed definition; therefore, the SDT did not modify the definition.

Commenter	Q8. **Comment**	Agree.	Don't agree.
AECC	The definition is too vague and does not go far enough to distinguish it from something like and operational event, which only addresses the intial system response and does carry through to the resulting system following the event and subsequent steps that may be taken. Suggest: Planning Events = Events which remove one or more Elements and require Transmission system performance requirements to be met. This definition includes the initial event and any after event actions that result in the system returning to a steady state condition and preventing as serving as much Consequential load as possible.		
Ameren	Consideration should be given to adding the performance requirements in the definition.		X
ATC			X
APPA	What are "performance requirements?" This is too general a statement to be of value for writing specific standards.		X
City Water Light and Power	This statement is too general. Performance Requirements are not defined.		X
City Utilities/Springfield	Minimum performance requirements need to be clearly defined.		X
Georgia Transm. Corp	Performance requirements should be added to the definition.		X
E ON US	Recommend: Events to be simulated is studies (listed in Tables 1 and 2 of TPL-001) which must be documented with Corrective Action Plans when performance requirements of TPL-001 are not met.		X
ERCOT ISO	Needs clarity. Suggest the following wording: Outage of power system elements such as shown in Tables 1 and 2 that need to be considered and simulated to assess Transmission System Performance.		X
CAISO	Needs clarity. Suggest the following wording: Outage of power system elements such as shown in Tables 1 and 2 that need to be considered and simulated to assess Transmission System Performance		X
Central Maine Power HQTE National Grid New England ISO NU NPCC RCWS NSTAR United Illuminating	Propose, "Events for which Transmission performance requirements must be met".		X

Commenter	Q8. **Comment**	Agree.	Don't agree.
LADWP	The term Event has such a broad connotation that it can be misused by layperson. In fact, it is already misused in this standard as evidenced by including events such as cyber attacks, hurricans, tonados, etc as transmission planning events. These events belongs in "emergency" planning, not transmission planning.		X
Southern Transmission	Change to, "Events that are simulated or assessed to test the transmission system to ensure that performance requirements are met as defined in TPL-001-1 Tables 1 and 2."		X
MEAG Power NCEMC Santee Cooper SERC EC PSS SERC RRS OPS	Change to: "Events that are simulated or assessed to test the transmission system to ensure that performance requirements are met."		X
SCANA	Prefer alternate language, "Events for which Transmission system performance requirements must be met."		X
Response: The majority of the commenters agreed with the proposed definition; therefore, the SDT did not modify the definition.			
FirstEnergy	We ask that the SDT reword the definition to include reference to the planning events in Table 1 and 2 of this standard. This definition should be specific to this standard and not be included in the NERC glossary.		X
Response: The majority of the commenters agreed with the proposed definition; therefore, the SDT did not modify the definition. Moreover, the SDT believes the definition should be included in the NERC Glossary of Terms to provide common industry terminology.			
IESO NYISO	Linking it to Transmission system performance requirements presents "loop around" argument. Suggest to change it to: Events which need to be considered and simulated in planning assessments to evaluate Transmission system performance.		X
Response: The majority of the commenters agreed with the proposed definition; therefore, the SDT did not modify the definition. Moreover, the proposed revision would not suffice because Extreme Events must also be considered and simulated in planning assessments.			
Manitoba Hydro	The definition of a planned event should relate to the probablity of occurance. Table shows single contingency planned events and multiple contingency planned events. Why has the SDT gone away from the existing categories of events which sorted the events into categories with different levels probability.		X
Response: The majority of the commenters agreed with the proposed definition; therefore, the SDT did not modify the definition. In response to this specific comment, Planning events were considered to have sufficiently high probability of occurrence as to require planned corrective actions - hence the term Planning Event. However, Planning Events have still been sorted into categories with different performance requirements corresponding to different levels of probability and consequence.			
RFC	I don't believe that this is really the definition of "planning events". This defintion should describe generally what the planning events are, not that they must meet performance requirements.		X
Response: The majority of the commenters agreed with the proposed definition; therefore, the SDT did not modify the definition. The SDT believes that a general description of what the planning events are includes the fact that these are the types of events for which performance			

Commenter	Q8. **Comment**	Agree.	Don't agree.
requirements must be met.			
Seattle City Light	List specific types of failures or direct us to a specific table which describes planning events.		X
Response: The majority of the commenters agreed with the proposed definition; therefore, the SDT did not modify the definition. The SDT believes a definition should be established that does not reference a particular part of the standard.			
ABB	Agree but adjust language. You are saying "require requirements to be met". Duh. Even if you took out one of them and said "requirements must be met", this is also redundant. The definition of "requirement" is that it is required. How about "Events for which there are strict transmission performance standards that must be met." This may also be slightly redundant, but not as much as the original.	X	
Response: The majority of the commenters agreed with the proposed definition; therefore, the SDT did not modify the definition. We believe the language, with respect to the use of require and requirements, is correct, and the suggested language does not offer substantive improvement.			
Northwestern Energy		X	
AECI		X	
Allegheny Power		X	
AEP		X	
BPA		X	
BCTC		X	
Brazos Electric		X	
CenterPoint		X	
CPS Energy		X	
Duke Energy		X	
Entegra		X	
Entergy		X	
Exelon		X	
CPS Energy		X	
FPL		X	
FRCC		X	
Dominion		X	
ITC		X	
KCPL		X	
LCRA		X	
LUS		X	
MISO		X	
MRO		X	
Muscatine P&W		X	

Commenter	Q8. **Comment**	Agree.	Don't agree.
NERC TIS		X	
Progress–Carolinas		X	
Progress–Florida		X	
SaskPower		X	
SERC EC DRS		X	
Tenaska		X	
TVA		X	
TSGT		X	
TEP		X	
WECC		X	
Response: Thank you.			

9) **Q9. Plant Stability Study: Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.**

Summary Response: Based on the responses to Q32 the SDT believes the majority of comments have been addressed. Please refer to responses to Q32 and the revised definition for additional clarification. The SDT revised this definition as follows to further clarify intent:

Generating Unit Stability Study: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations.

~~**Plant Stability Study**: Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~

Commenter	Q9. **Comment**	Agree.	Don't agree.
ABB	I don't see any reason to differentiate between "Plant Stability" and "System Stability". These are not commonly separated. A better differentiation would be between generator (or angular) stability and load (or voltage) stability. These are usually independently studied and independently occurring.		X
Ameren	It seems that the SDT is trying to divide the stability issues between plant (local) and system. As the system load representation and its damping characteristics affect both plant and system stability, it is difficult to separate plant versus system stability studies. The focus of the studies may be only slightly different, depending on the location, type, and duration of the fault conditions assumed.		X
Central Maine Power NPCC RCWS	A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.		X
FirstEnergy	We believe that this definition is not needed. The Plant Stability Study is similar to the System Stability Study.		X
FPL FRCC	There should be no distinction between Plant Stability and System Stability. All stability studies must meet the Performance Requirements for Planning Events in Table 2 - Stability Performance. If there were different Performance Requirements then the distinction would be warranted.		X
HQTE National Grid New England ISO NU	A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.		X

Commenter	Q9. **Comment**	Agree.	Don't agree.
NSTAR United Illuminating			
BPA	Support comments submitted by WECC. Plant Stability is a subset of System Stability.		X
WECC	Plant Stability seems to be a subset of System Stability. Introducing a new term can cause confusion.		X
Progress–Carolinas	Don't need to differentiate between plant and system. These are not usually separated. It would be better to separate angular stability and voltage stability. They are studied independently.		X
Tenaska	Not convinced that this study needs to be differentiated from a System Stability Study.		X
TEP	Plant Stability seems to be a subset of System Stability. Introducing a new term can cause confusion.		X

Response: The SDT revised this definition in response to various comments. The SDT believes that it is important to maintain the distinction between Plant and System Stability studies. Based on the responses to Q32 the SDT believes the majority of comments have been addressed. Please refer to responses to Q32 and the revised definition for additional clarification.

Generating Unit Stability Study: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations.

~~Plant Stability Study: **Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.**~~

ATC	Suggest eliminating the sentence after the semi-colon -- the defined term Stability implies what is addressed in the second sentence and is also noted as a performance requirement in footnote 1.a.i to the Stability Performance Table. We also suggest that reference to "in the vicinity" be replaced by "that affect the plant Stability".		X
Santee Cooper SERC RRS OPS	The definition should end at the semi-colon. The remaining part of the definition should be moved to the definition of "System Stability Study."		X

Response: The SDT revised this definition in response to various comments, although much of the sentence after the semi-colon has been retained for clarity regarding generating unit performance. Based on the responses to Q32 the SDT believes the majority of comments have been addressed. Please refer to responses to Q32 and the revised definition for additional clarification.

Generating Unit Stability Study: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations.

Commenter	Q9. **Comment**	Agree.	Don't agree.
~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
City Water Light and Power	Insert "Generating" prior to "Plant" for clarity.		X
APPA	Insert "electric generating" prior to "plant" for clarity. It is unclear as to the intent of this statement. The Standard should require the Transmission Planner to consider contingencies in the vicinity of a particular electric generation plant. However, the ultimate goal of the "Stability Study" is to determine the stability of the BES and not just the "electric generation plant." It is recommended that this be rewritten to make clear the intent of this statement.		X
WPSC	This definition mixes the use of the word "plant" and "generator" which have two different meanings. Suggest re-naming as Generator Stability Study and allow the study of multiple generators at a single site as a plant. The use of "generator" vs. "plant" should also be consistent throughout the standard.		X
Response: The term "plant" has been deleted and the term "generating unit" is being used in the description of the type of study required. The new definition is for a "Generating Unit Stability Study". The SDT made these changes in response to various comments. Please refer to responses to Q32 and the revised definition for additional clarification. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations.			
~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
ERCOT ISO CAISO	Definition is not clear. Suggest the following wording: Study of an individual generating plant's capability to remain in synchronism and exhibit damping of the generating units' power oscillations for various contingencies in the vicinity of the plant.		X
IESO	Suggest to replace "Contingencies" with "Planning events", and change the definition as follows: Study of an individual generating plant's capability to remain in synchronism and exhibit damping of the generating units' power oscillation for various Planning events. Note that "in the vicinity of the plant" is removed to not restrict simulations of events only in the vicinity of the plants as experience has shown that an event remote from the plant could also subject the plant to lose synchronism and/or oscillate without		X

Commenter	Q9. **Comment**	Agree.	Don't agree.
	acceptable damping.		
New York ISO	"Contingencies" should be replaced with "Planning Events". "in the vicinity of the plant" is too restrictive. Suggest: Study of an individual generating plant's capability to remain in synchronism with damping power oscillation for various Planning Events.		X
Response: The SDT revised this definition in response to various comments. The new definition further clarifies the SDT's intent regarding the "vicinity" that must be considered, although additional buses further away can be studied if desired. Please refer to responses to Q32 and the revised definition for additional clarification. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
Northwestern Energy	System stability studies covers this definition.		X
Response: The SDT believes that it is important to maintain the distinction between Plant and System Stability studies. The SDT revised this definition in response to various comments. Based on the responses to Q32 the SDT believes the majority of comments have been addressed. Please refer to responses to Q32 and the revised definition for additional clarification. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
Duke Energy	Delete the term "the effect on the System of." The reference to "System" causes confusion with the term "System Stability Study.		X
Entergy	Delete the term "the effect on the System of." The reference to "System" causes confusion with the term "System Stability Study." Section R4.6 should identify the Generator Owner as the applicable party for doing the Plant Stability Studies.		X
Response: The reference to the "system" has been deleted from the new definition. SDT revised this definition in response to various comments. Based on the responses to Q32 the SDT believes the majority of comments have been addressed. However, the SDT disagrees			

Commenter	Q9. **Comment**	Agree.	Don't agree.
that the Generator Owner is the applicable party responsible for performing Generating Unit Stability Studies for the purpose of assessing and planning the transmission system, as contemplated by this standard. Please refer to responses to Q32 and the revised definition for additional clarification. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
Exelon	Wording should be changed to allow for engineering judgment to determine which contingencies are applied. There may be instances where contingencies outside of the immediate vicinity of the plant may be significant to its stability. Suggest replacing the word 'System' with 'Transmission System'.		X
NERC TIS	Should not be limited to contingencies in the vicinity of the plant. Remove the terms "in the vicinity of the plant." Engineering judgement can then be used without having to define "vicinity." Plant instability can be caused by system events many (sometimes hundreds of) miles away. Plants were shaken off line in British Columbia due to the tripping of units in Arizona in June 2004.		X
Seattle City Light	"…in the vicinity of the plant…" needs to be more specific. How far away must we study?	X	X
Response: The SDT revised this definition in response to various comments. The new definition further clarifies the SDT's intent regarding the "vicinity" that must be considered, although additional buses further away can be studied if desired. Based on the responses to Q32 the SDT believes the majority of comments have been addressed. Please refer to responses to Q32 and the revised definition for additional clarification. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
LADWP	When performing transient stablity studies using either PSSE or PSLF, loss of synchronism and oscillation damping are automatically part of the performance evaluation; it is not a separate study and should not be classifed as a separate study. In the context of transmission planning, unless someone on the SDT use programs		X

Commenter	Q9. **Comment**	Agree.	Don't agree.
	that do not have transient stability package similar to PSSE and PSLF, or has a completely different understanding on the meaning of loss of synchronism and/or damping, there is no need to introduce two new terms to explain a very well understood and established single term known as "transient stability" .		
Response: The SDT believes that it is important to retain the terms to maintain clarity. The SDT revised this definition in response to various comments. However, few if any other commenters expressed concerns about verbiage relating to loss of synchronism and damping of power oscillations. Therefore, this verbiage remained relatively unchanged. Based on the responses to Q32 the SDT believes the majority of comments have been addressed. Please refer to responses to Q32 and the revised definition for additional clarification. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
SERC EC DRS	Delete the term "the effect on the System of." The reference to "System" causes confusion with the term "System Stability Study."		X
Response: The SDT revised the definition in response to various comments to eliminate the reference to the "system". Based on the responses to Q32 the SDT believes the majority of comments have been addressed. Please refer to responses to Q32 and the revised definition for additional clarification. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
TSGT	Plant stability should be called Station stability. The term "plant" is reserved for aggregates such as total coal plant or total peaking plant, meaning all generating units in that category.		X
Response: The SDT revised the definition to be more general with respect to closely-coupled generating units. Please refer to responses to Q32 and the revised definition for additional clarification. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power			

Commenter	Q9. **Comment**	Agree.	Don't agree.
oscillations. ~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
KCPL	Suggest adding "Bulk Electric" before "System".	X	
Manitoba Hydro MISO MRO	The words "Bulk Electric" should be added before "System".		X
MEAG Power SERC EC PSS	Change " the System" to "local area of the Bulk Electric System." It also need a definition for "plant."	X	
Response: The SDT revised the definition in response to various comments and clarified that the study focuses on an individual generating unit's or electrically closely-coupled generating units' Stability. Please refer to responses to Q32 and the revised definition for additional clarification. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
AECI		X	
Allegheny Power		X	
AEP		X	
BCTC		X	
Brazos Electric		X	
CenterPoint		X	
City Utilities/Springfield		X	
CPS Energy		X	
Entegra		X	
Georgia Transm. Corp		X	
ITC		X	
LCRA		X	
LUS		X	
Muscatine P&W		X	
NCEMC		X	
Progress–Florida		X	

Commenter	Q9. **Comment**	Agree.	Don't agree.
SCANA		X	
Southern Transmission	No Additional Comments.	X	
TVA		X	
Response: Thank you. Please see the Summary Response.			

10) Q10. System Stability Study: Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.

Summary Response: Based on the comments, the SDT revised this definition as follows to add further clarity:

System Stability Study: ~~Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.~~ Study that focuses on portions of the System, which may include many generating units, to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.

Commenter	Q10. **Comment**	Agree.	Don't agree.
Ameren	See comments above in the response to Q9. Specific inclusion of voltage (load) stability seems to be missing from the definition. Also, angular stability is mentioned only as part of the definition for System Stability Study and not Plant Stability Study. It would seem that this item would be part of both types of study.		X
PJM	Does "inter-area oscillations are damped" imply that you also have to do frequency domain analysis? (Because some industry experts would claim that without small signal analysis you cannot ensure that inter-area oscillations are damped.)	X	X
Response: The SDT revised this definition in response to various comments. Based on the responses to Q32 the SDT believes the majority of comments have been addressed. Please refer to responses to Q32 and the revised definition for additional clarification. **System Stability Study:** ~~Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.~~ Study that focuses on portions of the System, which may include many generating units, to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.			
ABB	See Q9.		X
Santee Cooper	see Q9 above.		X
SERC RRS OPS	see Q9 above.		X
Response: See response for Q9.			
ATC	Truncate the definition to "……ensure that Stability is maintained." Note that we suggest that "angular" be deleted so that the definition is comprehensive and it includes both voltage and angular stability. Suggest moving the performance attributes in the definition (after the comma) as footnotes to the Stability Performance Table.		X
Response: The SDT believes that it is important to retain the terms to maintain clarity. Please refer to responses to Q32 and the revised definition for additional clarification.			
ERCOT ISO	This definition is for a stable system. Study is performed to determine whether system		X

Commenter	Q10. **Comment**	Agree.	Don't agree.
CAISO IESO	is stable or not. Suggest the following wording: Study of the system or portions of the system to assess the system's performance in terms of angular stability, power oscillations and voltage limits during dynamic simulation.		
New York ISO	The study is an assessment. Suggest: Study of the System or portions of the System to assess the System's performance in the domain of angular stability, inter-area oscillations and voltage profile during dynamic simulation.		X
Response: The SDT revised this definition to reflect that the study is for portions of the system. The applicable portions of the System still must be studied and the wording was modified to describe that the study determines whether the System remains stable, not that it ensures stability is maintained. Please refer to responses to Q32 and the revised definition for additional clarification. **System Stability Study:** ~~Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.~~ Study that focuses on portions of the System, which may include many generating units, to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.			
Central Maine Power HQTE National Grid New England ISO NU NPCC RCWS NSTAR United Illuminating	See comment on Q9; proposed modification, "Study of the System or portions of the System to determine whether plant and system angular Stability is maintained, power oscillations are damped, and voltages during the dynamic simulation stay within acceptable perfomance limits.		X
Progress–Carolinas	Don't need to differentiate between plant and system. These are not usually separated. It would be better to separate angular stability and voltage stability. They are studied independently.		X
Response: The SDT believes that it is important to maintain the distinction between Generating Unit (formerly Plant) and System Stability studies. Please refer to responses to Q32 and the revised definition for additional clarification.			
FPL FRCC	Dynamic voltage ratings do not add value and are only an approximation for modeling limitations. The definition should not address performance and should only seek to define the term. Reword as follows: "Study of the System or portions of the System to assess angular Stability and inter-area power oscillations."		X
Response: The SDT believes that it is important to retain the information explaining the purpose of the study. Please refer to responses to Q32 and the revised definition for additional clarification.			
LADWP	This comment should be taken together with the comment on Plant stability and I would recommend not to create new terms and go back to use well established engineering terms like Transient Stability Study which covers synchronism, damping,		X

Commenter	Q10. **Comment**	Agree.	Don't agree.
	voltage limits, angular stability, etc. There are many text books that could be used to support this.		
Response: The SDT believes that it is important to retain the terms to maintain clarity. Please refer to responses to Q32 and the revised definition for additional clarification.			
Exelon	Suggest replacing 'System' with 'Transmission System'.	X	
KCPL	Suggest adding "Bulk Electric" before "System".	X	
Manitoba Hydro MISO MRO	The words "Bulk Electric" should be added before both occurances of "System".		X
SERC EC PSS	Change "System" to "Bulk Electric System."	X	
MEAG Power	Change "System or portions of the system" to "Bulk Electric System's components associated with the Transmission Planer."	X	
Response: The SDT believes the reference to the "System" correctly describes the scope of the study. Please refer to responses to Q32 and the revised definition for additional clarification.			
APPA	This is a very clear definition that can be used in Standards. The author did a good job of using defined terms in this definition.		
Northwestern Energy		X	
AECI		X	
Allegheny Power		X	
AEP		X	
BPA		X	
BCTC		X	
Brazos Electric		X	
CenterPoint		X	
City Utilities/Springfield		X	
CPS Energy		X	
Duke Energy		X	
Entegra		X	
Entergy		X	
Dominion		X	
FirstEnergy		X	
Georgia Transm. Corp		X	
ITC		X	
LCRA		X	
LUS		X	
Muscatine P&W		X	
NCEMC		X	

Commenter	Q10. **Comment**	Agree.	Don't agree.
NERC TIS		X	
Progress–Florida		X	
Seattle City Light		X	
SERC EC DRS		X	
SCANA		X	
Southern Transmission	No Additional Comments.	X	
Tenaska	A generator's loss of synchronism and oscillation issues will be seen in this study.	X	
TVA		X	
TSGT		X	
TEP		X	
WECC		X	
Response: Thank you. Please see the Summary Response.			

11) Q11. Year One: The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.

Summary Response: Based on the comments, the SDT modified the definition to clarify that Year One is the first year that requires assessment, not study; and that the planning window begins 12 to 18 months from the completion of the previous assessment. The change reflects the variability in the timing of assessments among different Transmission Planners.

Year One: The first year that a Transmission Planner is responsible for ~~studying~~ assessing. This is further defined as the planning window that begins ~~the next calendar year from the time the Transmission Planner submits their annual studies~~ 12-18 months from the completion of the previous annual Planning Assessment.

Commenter	Q11. **Comment**	Agree.	Don't agree.
ABB	Agree but delete "annual". Unnecessarily restrictive. Aren't there non-annual studies for which the definition of "year one" is important?	X	
E ON US	"studies" should be replaced with "Planning Assessment", the Planning Assessment is the documentation (of past and current studies) submitted for review. Note: the definition in Q11 does not match TPL-001.		X
WPSC	Suggest replacing the words "annual studies" with "Planning Assessment".		X
ATC	The definition here is not consistent with what is in the posted standard (the last sentence is extra) -- we agree with the definition in the posted standard.		X
Entergy	The last sentence in the above definition was not included in the definition listed in the draft standard. Consider deleting the last sentence or providing additional examples.		X
FPL	The last sentence of this definition is not included in the Standard. Reword as follows: "The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner performs their annual studies and submits the results to the RRO."		X
FRCC	The last sentence of this definition is not included in the Standard and should be deleted.		X
MEAG Power Santee Cooper SERC EC PSS SERC RRS OPS Southern Transmission TVA	The last sentence in the above definition was not included in the definition listed in the draft standard, nor should it be.	X	
Response: In the course of reviewing comments, the SDT realized that the definition of Year One in the draft standard varied from the definition of Year One in Q11 of the comment form. The SDT revised this definition in response to various comments.			

Commenter	Q11. **Comment**	Agree.	Don't agree.
Year One: The first year that a Transmission Planner is responsible for ~~studying~~ assessing. This is further defined as the planning window that begins ~~the next calendar year from the time the Transmission Planner submits their annual studies~~ 12-18 months from the completion of the previous annual Planning Assessment.			
AECC	Year One should be the first year following the current year. The first sentence defines year one just fine. Lose the last two sentences. Completely disagree with the last sentence. Studies are not necessarily conducted on calender year basis and the study publication is irrelevant. This is a planning standard and not an opertions standard. Operational vs planning are driven by the horizon time frame and not a study publication date.		X
ERCOT ISO CAISO	Suggest a shorter definition: Planning window beginning next calendar year.		X
Central Maine Power	Modify to, "The first year that a Tranmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner completes its annual studies."		X
Duke Energy	Need to provide an example to clarify what this means.		X
FirstEnergy	Although we agree with the concept, the definition is confusing. We suggest simplifying the definition to "The first 12 month period that begins one year and one day from the completion of the study."		X
Georgia Transm. Corp	The first sentence in not necessary. A Planner may use the base case to further assess a problem in the current year. The definition should begin with "The next planning year following current annual studies".		X
HQTE National Grid New England ISO NU NPCC RCWS NSTAR United Illuminating	Modify to, "The first year that a Tranmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner completes and communicates its annual studies."	X	X
NCEMC	This definition could use further clarification to eliminate inconsistencies in how it may be interpreted. Operations planning horizons may typically be 13 to 18 months from the current date due to the reality that transmission upgrades to address operational performance issues may not be able to be implemented inside this period. Some may assume a 24-36 month operations planning window. Based on this assumption, Year 1 could start anywhere from 13 months from the current date to as much as 37 months from the current date.		X
Brazos Electric	Planners do not 'submit' their studies to ERCOT for evaluation or other. Certain projects are submitted to the group for review and comment but not all studies are	X	

Commenter	Q11. **Comment**	Agree.	Don't agree.
	submitted as normal pratice in all cases. It may be better to use 'create their base cases' or simply 'performs their annual studies' instead of 'submit their annual studies'		
Response: The SDT revised this definition in response to various comments. **Year One:** The first year that a Transmission Planner is responsible for ~~studying~~ assessing. This is further defined as the planning window that begins ~~the next calendar year from the time the Transmission Planner submits their annual studies~~ 12-18 months from the completion of the previous annual Planning Assessment.			
APPA	There is a term in the Glossary that is "Operation Plan;" however, there is not a term defining Operations Planning. It is recommended that the SDT drop the last sentence and define the term Operations Planning for the Glossary. Change "their" to "its."		X
BCTC	One problem with this definition is that it assumes that the Transmission Planner submits annual studies. We need definitions for Operating Horizon and Planning Horizon. Then: Year One: The first year of the Planning Horizon.		X
IESO	Not sure why we need this definition. The standard can simply be worded such that a Transmission Planner is responsible for assessing system needs for time frame beyond the current year. Introducing Operations Planning creates confusion as it is unclear whether this term describes a function or an entity in the context of the proposed definition. Further, the sentence "Analysis conducted for time horizon within the current year from the study publication are assumed to be conducted under the auspices of Operations Planning" is (a) confusing time frame wise, (b) invites debates on the role and responsibility for a term that is not defined in NERC standard or the Functional Model, and (c) is perceived to be prescriptive in organizational setup/responsibility allocation (e.g. why can't a transmission planner conduct operational planning studies?).		X
Response: In the course of reviewing comments, the SDT realized that the definition of Year One in the draft standard varied from the definition of Year One in Question 11 of the comment form. The term "Operations Planning" was used in Q11 but not in the draft standard. Therefore, the SDT revised the definition of Year One in response to various comments but will not introduce a definition for Operations Planning. **Year One:** The first year that a Transmission Planner is responsible for ~~studying~~ assessing. This is further defined as the planning window that begins ~~the next calendar year from the time the Transmission Planner submits their annual studies~~ 12-18 months from the completion of the previous annual Planning Assessment.			
ITC	Adding a statement specifying that this is at least ??? number of months into the future may be prudent.		
Response: The SDT revised this definition in response to various comments. However, in the course of considering this definition and reviewing comments, the SDT believes that the start of Year One will not be a fixed point in time for all Transmission Planners. For example, see NCEMC's comment.			

Commenter	Q11. **Comment**	Agree.	Don't agree.
Year One: The first year that a Transmission Planner is responsible for ~~studying~~ assessing. This is further defined as the planning window that begins ~~the next calendar year from the time the Transmission Planner submits their annual studies~~ 12-18 months from the completion of the previous annual Planning Assessment.			
Seattle City Light	Base cases are developed and studied for seasons, not calendar years. Can the Year One reference be changed to "the year beginning at the next Winter season" instead of the specific "…next calendar year"?	X	X
Response: The SDT revised this definition in response to various comments. However, the SDT has members from a wide variety of NERC regions. In the course of discussing how to define Year One, the team found that practices vary across different regions. For example, many southern regions concentrate on summer peak seasons while others, such as Seattle City Light, may concentrate on winter seasons. The modified definition is intended to accommodate such regional variation. **Year One:** The first year that a Transmission Planner is responsible for ~~studying~~ assessing. This is further defined as the planning window that begins ~~the next calendar year from the time the Transmission Planner submits their annual studies~~ 12-18 months from the completion of the previous annual Planning Assessment.			
Northwestern Energy		X	
AECI		X	
Allegheny Power		X	
AEP		X	
Ameren		X	
BPA		X	
CenterPoint		X	
City Utilities/Springfield		X	
CPS Energy		X	
Dominion		X	
Entegra		X	
Exelon		X	
KCPL		X	
LUS		X	
LADWP	very good clarification!	X	
LCRA		X	
Manitoba Hydro		X	
MISO		X	
MRO		X	
Muscatine P&W		X	
NERC TIS		X	
New York ISO		X	

Commenter	Q11. **Comment**	Agree.	Don't agree.
Progress–Carolinas		X	
Progress–Florida		X	
RFC		X	
SaskPower		X	
SERC EC DRS		X	
SCANA		X	
Tenaska		X	
TSGT		X	
TEP		X	
WECC		X	
Response: Thank you**.** Please see the Summary Response.			

B) Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

12) Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Summary Response: The SDT believes that there is a need to perform sensitivity studies and to set a minimum level of sensitivities to be considered. To achieve that, the SDT is providing some guidance on what could be included in the sensitivity studies without being too prescriptive. Requirement R2.1.3 and Requirement R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.1.4 and Requirement R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system.

The following requirements were changed due to industry comments:

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:
R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:
R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

R2.7.2. ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.

Question 12			
Commenter	**Yes**	**No**	**Comment**
ABB		☑	No. However, as long as we're talking about it, NERC should set a standard for the definition of the "peak load" to be planned for. Some utilities use the 50% probability peak load. Some use 90%. A big difference that will result in a big difference in how they are prepared for the peak load days. The sensitivity section is not sufficient to address this. Also, outages of reactive resources should be (and are) in the list of contingencies, not sensitivities.
Response: The standard does not prescribe what percentage of Load needs to be studied. The peak Load to be planned for is defined by the individual entity. The consideration of a higher or lower probability of peak Load is only one of the sensitivity conditions listed in R2.1.3.			

Question 12			
Commenter	**Yes**	**No**	**Comment**
R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:			
Ameren		☑	For the purposes of compliance, we believe that the existing requirement R1 in Standard TPL-001-0 adequately defines the sensitivities that need to be covered in a valid assessment, and no additional clarification is necessary. Deterministic tests of a limited number of system conditions require the application of engineering judgment to evaluate the complex multi-variable problems involved in planning analyses. We all agree that performing contingency analyses on a single snapshot of expected system conditions is not adequate to plan the transmission system, but planning is not a cookbook exercise, and neither is an engineering assessment of planning activities demonstrating required system performance. Further, we believe that a test of incremental transfer capability determined from some of the sensitivity cases needs to be added to the standard and would go a long way to address how much margin exists in the transmission system to handle the unknown or previously undefined variables.
Response: The SDT believes that there is a need to perform sensitivity studies and to set a minimum level of sensitivities to be considered. To achieve that, the SDT is providing some guidance on what could be included in the sensitivity studies without being too prescriptive. R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. Further the standard is not intended to address how much margin exists in the Transmission System to handle the unknown or previously undefined variables, but to provide base line performance requirements. The entity can provide as much margin as it feels is appropriate. R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.			
AEP	☑		Consider requiring a minimum of two sensitivity cases.
Allegheny Power		☑	Scenario analysis should be based on the unique aspect of the particular Transmission zone. Transmission Planners should work to select the best scenarios related to the specific system and adequately describe the selection process.

Question 12			
Commenter	**Yes**	**No**	**Comment**
APPA		☑	The term Base Case should not be used in this manner. The conditions of the Base Case Study should not be in a Standard to insure that all instability cases are covered.
City Water Light and Power	☑		The term Base Case should not be used in this manner. The conditions of the Base Case Study should be in a Standard to insure that all sensitivity cases are covered.
BCTC	☑	☑	The number of sensitivity cases should be tied to the number of resource plans and range of possible load growth forecast.
Brazos Electric		☑	More descretion should be allowed by the TO or planner in deciding the number of cases.
CenterPoint		☑	The number and type of sensitivity studies should be left to the judgement of Transmission Planners. Having too many prescriptive requirements results in concentrating on meeting the requirements rather than on formulating the most effective and efficient improvements.
CPS Energy		☑	The number of sensitivity studies should be at the discretion of Transmission Planners.
Dominion		☑	Transmission Planning engineers have good engineering judgment and need to have some flexibility in selecting the variables that need to be studied.
Duke Energy		☑	The entity performing the studies has the best system specific knowledge to select the appropriate sensitivities that needs to be evaluated. When Measures are developed, they should provide planners with the flexibility to perform appropriate sensitivity studies.
Entergy		☑	The appropriate studies that should be done by each applicable entity is highly dependent on the transmission system being studied. Being too prescriptive may cause irrelevant studies to be completed while diverting resources and attention from sensitivity studes that the entity most familiar with the transmission system believes could result in more meaningful analysis. The Committee should not lose sight of the importance of good engineering judgment exercised by those most familiar with the characteristics of the particular system. While appropriate sensitivity analyses are beneficial in evaluating system performance, it should be clearly stated that projects and/or mitigation plans are left to the discretion of the Transmission Planners.
ERCOT ISO CAISO		☑	The TP or PA is the best to determine the number and type of sensitivities that are more applicable to their system.
FirstEnergy		☑	We suggest that the SDT reword the standard to allow the Transmission Owner additional latitude as to which stress conditions to study. We suggest modifying R2.4.3 to indicate sensitivities "such as those listed below" be studied. That way the standard would be providing examples but would not dictate specific sensitivity studies that should be performed.
FPL		☑	Not all Regions' sensitivity concerns are the same.
FRCC		☑	Not all Regions' concerns are the same and therefore each Region should determine which sensitivities are appropriate.
Georgia Transm.		☑	Sensitivity analyses should not be prescribed. In one system there may be various sensitivites based on region, generation location, number of long range projects, etc. The Planner should provide a summary of the critical sensitivities and documentation supporting their definitionis.

Question 12			
Commenter	**Yes**	**No**	**Comment**
IESO		☑	We do not support introducing sensitivity testing as requirements in the standard, let alone specifying the number of sensitivity cases that need to be developed. In general, there are two interpretations of sensitivity testing - the type to assist in scoping out planning studies and the type to test the stretched capability of the proposed plans. In the first case, sensitivity testing is conducted to assist in identifying restricting parameters/phenomena, critical faults, and scoping out the conditions that need to be assessed, etc. As such, the scenarios to be included in sensitivity testing vary from one Transmission Planner to another depending on local needs and system characteristics, and even from one study to another for the same area to be assessed. The scope of sensitivity testing is therefore difficult to pin down. In the second case, while variations such as percentage of forecast peak demand can be picked as a common parameter for sensitivity testing, the follow-on actions, or inactions, after obtaining the test results would be at the sole discretion of the Transmission Planner unless they are specifically addressed by reliability standards. Requiring a Transmission Planner to conduct sensitivity testing, and even to require it to study a specific number of cases case may put a Transmission Planner in a quandary. For example, if sensitivity testing for a case with 5% higher than forecast peak load shows that the system needs a new 500 kV line in a certain area, should the Transmission Planner propose the new line? If so, what are the reliability and economic justifications when it is clearly demonstrated that the line is needed only if the load for that studied time frame turns out to be 5% higher than forecast? If the answer is yes (to propose adding the line), then why don't we simply require that all planning studies assume a condition that is more conservative than that forecast, and stipulate these conditions in the standard accordingly? If not, will the Transmission Planner be criticized for not taking proactive action to manage the potential risk? Similarly, a Transmission Planner is faced with a much wider study scope if it is required to study the condition assuming one or more major transmission facility is unavailable due to forced outages. These scenarios are more aptly addressed in operations planning or near operations time frame when transmission facility and other system conditions become more predictable. Studies conducted well in advance of real time already rely on many enabling assumptions. Introducing a requirement for sensitivity testing and with specific number of test cases would render the study task difficult to manage, and may put the Transmission Planner in a quandary dealing with the test results. If the standard should require a Transmission Planner to study up to one transmission facility out of service, then this requirement should be clearly stipulated.
ITC	☑		The standard should provide a minimum number of sensitivity cases that should be developed and should include at least a higher load forecast (90/10 vs. 50/50) and a higher generator unavailiablity (LOLE - 1 in 10).
KCPL		☑	N-1 and N-2 analyses should identify any additional sensitivity cases that need to be studied. This

Question 12			
Commenter	**Yes**	**No**	**Comment**
			standard should not specify the number and type of sensitivities to be studied.
LADWP		☑	the FERC orders are market focused, not reliability focused; to the extent that these orders require sensitivity studies as outlined in this proposed standards, they belongs in operating studies and real time market studies, not transmission planning studies which are to meet reliability based criteria.
Manitoba Hydro		☑	Sensitivity analysis that could be considered will vary from region to region or subregion to subregion.
MEAG Power		☑	The entity performing the studies should be allowed to determine the appropriate number of cases that need to be evaluated. Different utilities have different input assumptions, therefore the selection of sensitivities to study are different. For example, some utility needs to study the water availability for its hydro units, while other utility needs to evalauate the sensitivity of gas availability.
MISO		☑	Requirements 2.1.3 and 2.4.3 call for sensitivity cases that stress the system, with documentation as to the rationale for why a particular sensitivity was selected. Midwest ISO believes that the standard must balance clarity and specificity with flexibility and discretion. If the standard is too prescriptive in the system conditions to be evaluated, sensitivity studies that reflect critical system conditions that experience dictates are appropriate for a given system could be construed as being outside of the standards. Such a determination could make the regulatory approvals of facilties needed for reliability purposes difficult or impossible to obtain. Midwest ISO believes hat the language in the existing standard TPL-001-0, R1.3.2, which states that "PA and TP assessments shall cover critical system conditions and study years as deemed appropriate by the responsible entity" provides the proper balance of these issues.
Muscatine P&W			Leave it open so it can be driven by local issues including those not in the standards. i.e. Running near term criteria on the long term horizon, additional contingencies beyond currently required, etc. as appropriate for the area.
New York ISO		☑	NYISO does not support the introduction of sensitivity testing in the Planning Standards as a requirement. Sensitivity testing should be dictated by the local needs and system characteristics. The nature of planning studies incorporates assumptions that would make sensitivity analysis difficult to interpret.
NCEMC		☑	There should be a stakeholder process for all entities (all Load-Serving Entities and Transmission Customers) involved or impacted within the defined area to provide input to determine which sensitivity cases are to be performed and the appropriate number of cases that need to be evaluated. Not every sensitivity case should be required for every system.
Northwestern Energy		☑	The current list is too prescriptive as many may not apply to a specific TP, yet they would be required to study it.
Progress–Carolinas		☑	This should be system specific.
ReliabilityFirst	☑		A minimum of at least one or two that contain certain scenarios chosen from the list should be required.

Question 12			
Commenter	**Yes**	**No**	**Comment**
Santee Cooper		☑	These factors vary between areas and regions. In addition the TP should be allowed to assess an alternate sensitivity if they can document that it is more appropriate,
SERC EC DRS		☑	The entity performing the studies has the best system specific knowledge to select the appropriate sensitivities that needs to be evaluated.
SERC EC PSS		☑	The entity performing the studies should be allowed to determine the appropriate number of cases that need to be evaluated.
SERC RRS OPS		☑	These factors vary between areas and regions. In addition the TP should be allowed to assess an alternate sensitivity if they can document that it is more appropriate,
SCE&G		☑	The standard may offer guidance but the entity performing the sensitivity studies should be able to determine the number of cases required.
Southern Transm.		☑	This should not be a "one shoe fits all" exercise. It appears that at least one of these items listed is required even though they may not be the most appropriate ones for all entities. There should be the ability to perform other sensitivity analysis instead of these as long as the "rationale" is provided for the choice. The entity should be allowed to determine the appropriate sensitivity cases.
Tenaska	☑		The question may be misleading as number of sensitivity cases is not the issue. Enough studies should be conducted to appropriately define the boundaries of how the system will perform. The standard identifies various issues that may be used as sensitivity cases, but the list may or may not be all inclusive. The team should ask the industry whether any other sensitivities should be included in the standard.
TVA		☑	The entity performing the studies should be allowed to determine the appropriate number of cases that need to be evaluated.
TEP		☑	The TP or PA is the most familiar with the system and so would be the best to determine the sensitivities that are more applicable to their particular system. The Standard should not be overly prescriptive. The Standard can make suggestions or list potential sensitivities but let the TP or PA determine those variables to study and the reasonable range of the sensitivities.
WPS			Sensitivity cases do not consider/mention new transmission facilities additions. Although the Transmission Planner should have the ability to determine appropriate sensitivities, system performance based on the delay of new transmission facilities should be considered (may be covered under R2.1.3.3 but could be more explicit).

Response: The SDT believes that there is a need to perform sensitivity studies and to set a minimum level of sensitivities to be considered. To achieve that, the SDT is providing some guidance on what could be included in the sensitivity studies without being too prescriptive. R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system.

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:

R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission

Question 12			
Commenter	**Yes**	**No**	**Comment**
Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.			
E ON US	☑		The proposed requirements P2, P3 and P4 significantly increase system performance. I agree with the requirements but I do not think it is appropropriate to layer extreme load, extreme transfers and other sensitivities on top of these. The analsysis of any Senistivities should be under the umbrella of Extreme Events or limited to meeting the P1 requirements.
HQTE NPCC RCS		☑	The standard is unclear whether or not it mandates the requirement to develop action plans in accordance with consequences of problems highlighted as a result of one of the sensitivity case study. Suggest modification to, "…sensitivity testing that stresses the System shall be considered, and documentation with the rationale for the sensitivity testing shall be supplied. The sensitivity case(s) may include one or more of the following conditions:"
JEA		☑	Transmission Planners when developing system improvement options should identify their system specific sensitivity cases that best assesses the robustness of the options under consideration. Project evaluation is not addressed in the NERC standards and performing sensitivity assessments that only lead to operational remedies consistent with the standards, are best performed within the operational horizon where information and assumptions are more certain than within the planning horizon.
PJM	☑	☑	At the least, it should provide a measure that indicates that you meet the requirement. Need to modify 2.4.3 to specify what if any performance requirement needs to be met.
Central Maine Power National Grid New England ISO NU NSTAR United Illuminating		☑	The standard is unclear whether or not it mandates the requirement to develop action plans for problems highlighted as a result of one of the sensitivities. Suggest modification to, "…sensitivity testing that stresses the System shall be considered, and documentation with the rationale for the sensitivity testing shall be supplied. The sensitivity case(s) may include one or more of the following conditions:" 2.1.3.3 should refer only to planned facilities that may be delayed. 2.1.3.4 - "variability" is too vague for a standard; the standard needs to be more specific as to the intent. 2.1.3.7 should be consistent with 1.4. These comments also apply to 2.4.3.
Response: The standard requires that deficiencies identified from the results of the current studies need to be addressed via Corrective			

Question 12			
Commenter	**Yes**	**No**	**Comment**
Actions Plan while leaving it to the entity's discretion to decide which deficiencies, if any, identified through sensitivity studies should be addressed by the Corrective Action Plan. Requirement R2.7.2 has been modified to make it clear that the entity must explain changes, if any, to the Corrective Action Plans as a result of considering the sensitivity studies. In addition, the SDT believes that there is a need to perform sensitivity studies and to set a minimum level of sensitivities to be considered. To achieve that, the SDT is providing some guidance on what could be included in the sensitivity studies without being too prescriptive. R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. R2.**7.2.** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.			
MRO		☑	The Drafting Team has provided the appropriate level of detail by indicating that one or more of the following conditions are to be used. However, the MRO notes that R.2.1.3.1 should be changed to match R.2.4.3.1, that is, R.2.1.3. 1 should be changed to state "Variations in Load model assumptions."
Response: The SDT disagrees. The wording in Requirement R.2.4.3.1 is stability related and refers to device characteristics such as motor load as mentioned in Requirement R2.4.1. The wording in Requirement R.2.1.3. 1 refers to "demand" load for steady statae studies.			
Seattle City		☑	Sensitivity studies should be performed at a level higher than LSE or BA. It seems more appropriate for a RC or RRO to determine regional contingencies.
Response: Requirement R2 in the standard states that Planning Assessments, including the sensitivity studies, should be performed by the TP or PC.			
WECC BPA		☑	The TP or PA is the most familiar with the system and so would be the best to determine the sensitivities that are more applicable to their particular system. The Standard should not be overly

Question 12			
Commenter	**Yes**	**No**	**Comment**
TSGT			prescriptive. The Standard can make suggestions or list potential sensitivities but let the TP or PA determine those variables to study and the reasonable range of the sensitivities.
Response: Requirement R2 in the standard states that Planning Assessments, including the sensitivity studies, should be performed by the TP or PC. The SDT believes that there is a need to perform sensitivity studies and to set a minimum level of sensitivities to be considered. To achieve that, the SDT is providing some guidance on what could be included in the sensitivity studies without being too prescriptive. Requirement R2.1.3 and Requirement R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.1.4 and Requirement R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.			
AECC		☑	
AECI		☑	
Exelon		☑	
LCRA		☑	
NERC TIS		☑	
Progress–Florida		☑	
SaskPower		☑	
ATC	☑		
City Utilities/Springfield	☑		
Response: Thank you. Please see the Summary Response.			

13) Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Summary Response: The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. In either case the entity must document the technical rationale for why each was selected. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance.

In addition a new requirement, now numbered as Requirement R2.7.2, has been added to clarify that the sensitivity studies do not in themselves establish the need for a corrective action but the entity must explain how the sensitivities affected the Corrective Action Plan.

Note: The words "reasonably stressed" are only used in the question and do not reference any particular requirement in the standard; therefore, no definition is required.

The following requirements were changed due to industry comments:

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:
R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.
R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:
R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.
R2.7.2. ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.

Question 13			
Commenter	**Yes**	**No**	**Comment**
Ameren		☑	There is no need to build a multitude of sensitivity cases to assess the reliability of the system. The sensitivity issues should be handled on an individual system basis by the local transmission planners as applicable to the study system. Conditions that are considered as "stressed" for one area may require all facilities to be in service in another area. Power flow cases utilizing a number of the

Question 13			
Commenter	**Yes**	**No**	**Comment**
			items listed under R2.1.3 or R2.4.3 could be produced for in-house study work, but such work should not be required as part of standards compliance. The standard should not be dictating what types of sensitivities should be investigated or considered for all parts of the transmission system.
AEP		☑	Consider requiring that the most severe sensitivity cases be included in the studies as determined by the entities conducting the studies.
Brazos Electric		☑	Again, descretion should be allowed by the TO when selecting the criteria.
CenterPoint		☑	See comment to Q12.
Dominion		☑	Transmission Planning engineers have good engineering judgment and need to have some flexibility in selecting the variables that need to be studied.
CPS Energy		☑	The type of sensitivty studies should be at the discretion of Transmission Planners.
Duke Energy		☑	The sensitivities are best selected by those most familiar with the specific system.
Entergy		☑	Should be left to Transmission Planners discretion and good engineering judgement. (see response to Q12)
Exelon		☑	The required changes should not be specified because they may not impact a particular transmission system based upon its geographic location within the interconnection. Required changes should be determined by the entity performing the study.
ERCOT ISO CAISO		☑	Let the TP or PA decide the type of stressing needed for a particular case.
FPL FRCC		☑	The Transmission Planner needs the flexibility to define what are considered "reasonably stressed" cases for their respective systems. This would not a be a proper application of a one size fits all definition.
Georgia Transm.		☑	See comment to Q12.
IESO		☑	See comments above. Also, the term "reasonably stressed" is not measurable.
KCPL		☑	Transmission Planner has best knowledge of conditions that create greatest stress on local transmission system.
LADWP		☑	A "reasnably stressed" case in transmission planning is whether or not the transmission system is stressed. To stress a transmission system, the key parameter to monitor are the line flows. Line flows are dictated by network topology and physics of electricity and very much depends on the objectives of each study, i.e., it is case by case. Standard should focus on what criteria shall be complied, not how to comply. This proposed standard is so prescriptive on how to comply that it reads like a tutorial.
MEAG Power		☑	The standard may offer guidance but what constitutes a "reasonably stressed" case will vary from Transmission Planner to Transmission Planner. Therefore, it should be left to the discretion of the entity performing the study.

Question 13			
Commenter	**Yes**	**No**	**Comment**
MISO		☑	This appears to be a case of expecting that "one size fits all" in requiring that certain scenarios be evaluated. Since the goal here is to improve reliability, it makes more sense to have transmission planners identify appropriate sentivities for area under study. The appropriate sensitivity is likely to vary depending on the portion of system being studied.
Muscatine P&W			Leave it open so it can be driven by local issues including those not in the standards. i.e. Running near term criteria on the long term horizon, additional contingencies beyond currently required, etc. as appropriate for the area.
NCEMC		☑	The standard should offer guidance but what constitutes a "reasonably stressed" case should be left to a stakeholder process as noted in Q12 with some discretion of the entity performing the study.
Northwestern Energy		☑	Each TP's stressed conditions vary, making a list that is applicable to all will not achieve the desired purpose.
Progress–Carolinas		☑	This should be system specific.
Santee Cooper		☑	The standard may offer guidance but what constitutes a "reasonably stressed" case should be left to the discretion of the entity performing the study, since they are the best judge of what stresses the system.
SERC EC DRS		☑	The entity performing the studies has the best system specific knowledge to determine what constitutes a reasonable stressed case.
SERC EC PSS		☑	The standard may offer guidance but what constitutes a "reasonably stressed" case should be left to the discretion of the entity performing the study.
SERC RRS OPS		☑	The standard may offer guidance but what constitutes a "reasonably stressed" case should be left to the discretion of the entity performing the study, since they are the best judge of what stresses the system.
SCE&G		☑	The standard may offer guidance but what constitutes a "reasonably stressed" case should be left to the discretion of the entity performing the study.
Southern Transm.		☑	See comment above. [This should not be a "one shoe fits all" exercise. It appears that at least one of these items listed is required even though they may not be the most appropriate ones for all entities. There should be the ability to perform other sensitivity analysis instead of these as long as the "rationale" is provided for the choice. The entity should be allowed to determine the appropriate sensitivity cases.]
TEP		☑	No, as in the response for Question #12. The TP is the best to determine the type of stressing needed for a particular case. This is very evident in the type of cases used for studies in the different parts of the NERC regions.
TVA		☑	The standard may offer guidance but what constitutes a "reasonably stressed" case should be left to the discretion of the entity performing the study.
Response: The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own			

Question 13			
Commenter	**Yes**	**No**	**Comment**
system. In either case the entity must document the technical rationale for why each was selected. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance. Note: The words "reasonably stressed" are only used in the question and do not reference any particular requirement in the standard; therefore, no definition is required. **R2.1.3.** For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.1.4.** In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. **R2.4.3.** For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: **R2.4.4.** In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. .			
Allegheny Power		☑	Providing examples would be helpful but specifically stating the required thresholds are transmission system dependent. Providing some methodologies to follow may be prudent such as forecast levels like 90/10; 80/20; or 50/50.
BCTC		☑	Should be tied to the data provided under R1.
Response: The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. In either case the entity must document the technical rationale for why each was selected. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance. **R2.1.3.** For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.1.4.** In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. **R2.4.3.** For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected~~			

Question 13			
Commenter	**Yes**	**No**	**Comment**
~~sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: **R2.4.4.** In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.			
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating		☑	The standard is unclear whether or not it mandates the requirement to mitigate consequences of problems highlighted as a result of one of the sensitivities. Reasonably stressed conditions are dependent upon the study area under review and the standard is not likely to be able to be crafted to provide sufficent and consistent direction. However, it might be helpful if the standard clarified whether the base case should include any unplanned generator outages or whether, aside from potential sensitivities, unplanned generator outages are considered only through P1, P3 or P4 Contingencies. If the standard addresses unplanned generator outages only through P1, P3 and P4, then it is recommended that a mandatory sensitivity analysis, with required mitigation, include various potential combinations of a reasonable amount of unplanned outages. The combinations should be based on the part of the system that is under study.
Response: A new requirement, now numbered as Requirement R2.7.2, has been added to clarify that the sensitivity studies do not in themselves establish the need for a corrective action but the entity must explain how the sensitivities affected the Corrective Action Plan. Requirement R1.4 of the standard requires that long term planned outages are part of the base studies. The performance table provides for specific contingency conditions. The entity may elect to run additional sensitivity studies for even more unplanned outages as stated in Requirement R2.1.4 and document its rationale for doing so. Note: The words "reasonably stressed" are only used in the question and do not reference any particular requirement in the standard; therefore, no definition is required. **R2.**7.2. ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.			
JEA		☑	Transmission Planners when developing system improvement options should identify their system specific "reasonable stressed" cases including opportunities for additional economic margins that best assesses the economic benefits of the options under consideration. Project evaluation is not addressed in the NERC standards and performing assessments on "reasonable stressed" cases that only lead to operational remedies consistent with the standards, are best performed within the operational horizon where information and assumptions are more certain than within the planning horizon.

Question 13			
Commenter	**Yes**	**No**	**Comment**
Response: Reliability Standards set the minimum performance requirements and any margins can be set /established and implemented by the entity. The standard covers reliability performance issues and not market or economic performance issues. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. In either case the entity must document the technical rationale for why each was selected. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance. Note: The words "reasonably stressed" are only used in the question and do not reference any particular requirement in the standard; therefore, no definition is required. **R2.1.3.** For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.1.4.** In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. **R2.4.3.** For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: **R2.4.4.** In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.			
ITC	☑		"Modification of expected transfers" should include unexpected loopflow caused by 3rd parties where applicable. In addition to the obvious impacts on system margins, loopflows have been identified as a major reason that FTR feasibility is hard to predict. Also, see answer to Q12 above. Some level of flexibility for some of the stressed cases should be left to the individual Planning areas as they would know typical load/stresses seen by their systems that should be studied and solutions identified for problems.
MRO		☑	This is unnecessary micro-management of the planning process. The MRO recommends that the Drafting Team proceed with the high-level requirement as provided with the minor changes recommended by the MRO in other parts of this comment form.
ReliabilityFirst		☑	A list of suggestions is sufficient. The flexibility to use different stresses on different systems is

Question 13			
Commenter	**Yes**	**No**	**Comment**
			needed.
SaskPower		☑	Unnecessary micro-management of the planning process in the Saskatchewan Regulatory Jurisdiction.
WECC BPA TSGT		☑	No, as in the response for Question #12. The TP is the best to determine the type of stressing needed for a particular case. This is very evident in the type of cases used for studies in the different parts of the NERC regions.

Response: The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 and Requirement R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.1.4 and Requirement R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. In either case the entity must document the technical rationale for why each was selected.

In addition a new requirement, now numbered as R2.7.2, has been added to clarify that the sensitivity studies do not in themselves establish the need for a corrective action but the entity must explain how the sensitivities affected the Corrective Action Plan.

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:
R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.
R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:
R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

New York ISO		☑	See comment to Q12. Additionally, what is the definition of "reasonably stressed"?

Response: The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 and Requirement R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.1.4 and Requirement R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. In either case the entity must document the technical rationale for why each was selected. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance.

In addition a new requirement, now numbered as Requirement R2.7.2, has been added to clarify that the sensitivity studies do not in themselves establish the need for a Corrective Action but the entity must explain how the sensitivities affected the Corrective Action Plan.

Question 13

Commenter	Yes	No	Comment
Note: The words "reasonably stressed" are only used in the question and do not reference any particular requirement in the standard; therefore, no definition is required. **R2.1.3.** For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.1.4.** In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. **R2.4.3.** For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: **R2.4.4.** In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. **R2.7.2.** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.			
WPS		☑	The Transmission Planner should have the ability to determine appropriate sensitivities based on changes to the assumptions within the study. However, those sensitivities should be developed in an open transmission planning process consistent with the transmission planning principles within FERC Order 890.

Response: The SDT agrees. Nothing in the standard precludes an open process.

The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 and Requirement R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.1.4 and Requirement R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. In either case the entity must document the technical rationale for why each was selected.

In addition a new requirement, now numbered as Requirement R2.7.2, has been added to clarify that the sensitivity studies do not in themselves establish the need for a Corrective Action but the entity must explain how the sensitivities affected the Corrective Action Plan.

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:

Question 13			
Commenter	**Yes**	**No**	**Comment**
R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. **R2.4.3.** For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: **R2.4.4.** In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. R2.**7.2.** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.			
ABB		☑	
AECC		☑	
AECI		☑	
E ON US		☑	
FirstEnergy		☑	
LCRA		☑	
NERC TIS		☑	
Progress–Florida		☑	
Response: Thank you.			
PJM	☑	☑	Again, 'reasonable' is a very subjective term. Refer to comments on question 12
Tenaska	☑		However, what is meant by "reasonably stressed".
Response: Note: The words "reasonably stressed" are only used in the question and do not reference any particular requirement in the standard; therefore, no definition is required.			
APPA	☑		The Standard should indicate a list that says "the list will include but not be limited to:" and then list the minimum necessary to adequately cover the changes in the study.
City Water Power and Light	☑		The Standard should indicate a list which says "the list will include but not be limited to:" then list the minimum changes necessary to adequately cover the changes in the study.
Response: The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 and Requirement R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.1.4 and Requirement R2.4.4 have been added to specifically state that the entity may consider			

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Commenter	**Yes**	**No**	**Comment**
additional sensitivities that are appropriate for its own system. In either case the entity must document the technical rationale for why each was selected. **R2.1.3.** For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.1.4.** In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. **R2.4.3.** For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: **R2.4.4.** In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.			
Manitoba Hydro	☑		R.2.1.3.2: clarify the intent of modification of expected transfers. Does this apply to firm transfers only, or does it also encompass non-firm transfers? Should this encompass simultaneous non-firm transfers? Planning for non-firm falls into an economic study of cost/benefit and not a relibility requirement. R2.1.3.3: There is little value in identifying the impact of unavailability of planned facilities. From a reliability perspective, these facilities are required to meet performance requirements. Near term SOLs and IROLs will insure reliability if the facility is late. R.2.1.3.4: This requirement should be removed and outages of reactive resources should be included in the Table 1 contingencies (assuming the intent is to investigate robustness to voltage instability). R.2.1.3.5: This requirement should be removed as this is covered, or should be, by the facility connection standard(s). R.2.1.3.6: This requirement should be removed as this is covered by requirement R2.1.3.1. There is no need to list "decreased effectiveness of controllable loads or DSM" as this is already covered by sensitivity to forecast load and power factor - this will cause confusion. R.2.1.3.7: Modification of planned Transmission outages should be deleted. The need to assess outages in the planning horizon is questionable, so assessing sensitivity to timing of these outages is of very little value. Furthermore, this standard already covers prior outages in its other requirements.
Response: The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 and Requirement R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.1.4 and Requirement R2.4.4 have been added to specifically state that the entity may consider			

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Commenter	**Yes**	**No**	**Comment**

additional sensitivities that are appropriate for its own system. In either case the entity must document the technical rationale for why each was selected.

In addition a new requirement, now numbered as Requirement R2.7.2, has been added to clarify that the sensitivity studies do not in themselves establish the need for a Corrective Action but the entity must explain how the sensitivities affected the Corrective Action Plan.

It is the planning entity's decision to establish and document which transfers under Requirement R2.1.3.2 are more significant to study system responses.

The intent of Requirement R2.1.3.3 is for the planning entity to determine the need for alternative plans in the event that previously planned facilities are not installed on time.

Requirement R2.1.3.4 (variability and outages of reactive resources) provides for more unusual or unexpected combination of situations. The contingencies listed in Table 1 usually consider more specific conditions in that the reactive resources are typically connected to circuits or bus sections which are included in Table 1.

Requirement R2.1.3.5 (generation additions, retirements, or other dispatch scenarios) covers future conditions that might exist (such as location, size, numger of facilities) after known connections are made. The FAC standards only consider the initial conditions for known facilities when an entity is requesting connection to the system. Requirement R2.1.3.5 covers the on-going conditions that exist after that connection is made. In addition the requirement covers dispatch scenarios which are not part of the FAC standards.

Requirement R2.1.3.1 is intended to cover all load before any adjustments. This can vary on its own. Requirement R2.1.3.6 covers only a portion of that load and can vary independent of the load forecast. The standard is not just addressing the "net" load but its components.

Requirement R2.1.3.7 parallels Requirement R2.1.3.3 in that "planned" outage durations may vary. It is the entity's responsibility to determene the actions necessaruy to handle extended outages.

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:
R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.
R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:
R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for

Question 13			
Commenter	**Yes**	**No**	**Comment**
why each was selected shall be supplied. **R2.7.2.** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.			
ATC	☑		
City Utilities/Springfield	☑		
Seattle City	☑		
Response: Thank you. Please see the Summary Response.			

14) Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Summary Response: The need to conduct sensitivity analysis was a directive in FERC Order 693 paragraphs 1694,1704, and 1706. The commenters generally agree with the concept of considering sensitivities for near-term Stability analysis. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3.1 provides the flexibility to allow the planning entity to decide how a variation in Load on the entity(ies) System should best be studied. Requirement R2.4.3 has been modified to require documentation of the rationale for why each of the listed sensitivities was or was not selected for running studies. Requirement R2.4.4 has been added to specifically state that the entity may consider additional sensitivities that are deemed appropriate for its own System and document the rationale for selecting each of them.

R2.1.3.1. Higher or lower Load than forecast~~s~~ed ~~from the Base Case~~ with variability of Load/demand and Load power factors due to season, weather, or time of day.
R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:
R2.4.3.2. ~~Expected simultaneous transfers including non-firm~~ Modification of expected transfers**.**
R2.4.3.4. ~~Reactive dispatch of generators and other reactive power devices~~ Variability and outages of reactive resources.
R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

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Commenter	**Yes**	**No**	**Comment**
Ameren		☑	The biggest problem with performing stability analysis is getting the stability cases to match up with the power flow cases, and only a limited number of stability cases are developed each year. Further, for those systems that are planned in excess of the NERC Standards regarding stability (3-L-G or 2-L-G vs. 1-L-G as in the Standard), there are no benefits to performing additional sensitivity studies to demonstrate compliance with this standard.
City Water Power and Light		☑	The requirement for sensitivity studies multiplies the study efforts. It will be burdensome especially when interregional studies are performed. It is better to have quality than quantity.
Dominion		☑	Not all the items listed under "B. Sensitivity Studies" may be applicable to stability analysis and also depends on type of stability analysis (Plant/System; angular/voltage). For instance, in some locations stability margins are wide. In such cases, practical experience has shown that such sensitivity analysis is unnecessary. Therefore, this should be applied as applicable, at the engineering judgment of the planning engineers rather than be required by the Standards. In summary, R2.4.3 should be eliminated entirely.
E ON US		☑	Stability studies are a labor intensive task. Off-peak studies (with max plant gen) is severe enough.
SCE&G		☑	Stability studies examine generator and system responses to specific conditions. Because the exact system conditions can not be determined in advance, the sensitivity analysis may not be very

Question 14			
Commenter	**Yes**	**No**	**Comment**
			useful. In addition, stability studies are more time consuming than conventional power flow studies. A preferred approach is to include pre-existing system conditions that additionally stress the system during the contingencies under study so as to verify that stability is preserved under conditions that go beyond those envisioned for the contingency.
TSGT		☑	Sensitivity studies are most often used to determine operating relationships of a system - sensitivity to generation patterns is deliverability analysis; sensitivity to load growth is margin analysis. Sensitivity analysis should not be required explicitly. The criteria should be stated in terms of load margins, deliverability, and capability to withstand generator or transaction forced outages. The TP can use sensitivity studies or other reasonable methods to assess reliability
TVA	☑		Consideration should be given to the fact that stability studies are more time consuming than conventional power flow studies. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.
FirstEnergy	☑		Although we concur with the use of sensitivity analysis in dynamic studies, the standard should not dictate the specific sensitivities studies to be performed.
LADWP	☑		This standard is mixing operational studies with planning studies. The suggested sensitivities in this proposed standards are what operating studies would and should address. It adds no value to the transmission planning by requiring sensitivities in transmission planning just for the sake of it. In addition, performing operating studies more than one year ahead, generally, is quite useless as a general requirement.
Manitoba Hydro	☑		R2.4.3.1: This requirement should include variation in load power factor, as this has a significant impact on transient performance. R2.4.3.3: There is little value in identifying the impact of unavailability of planned facilities. From a reliability perspective, these facilities are required to meet performance requirements. Near term SOLs and IROLs will insure reliability if the facility is late. R.2.4.3.4: This requirement should be removed and dispatch of reactive power devices should be included in the Table 2 contingencies (assuming the intent is to investigate robustness to voltage instability). R.2.4.3.5: This requirement should be removed as this is covered, or should be, by the facility connection standard(s).

Response: The need to conduct sensitivity analysis was a directive in FERC Order 693 paragraphs 1694,1704, and 1706. The SDT agrees with you that dynamic analysis is generally more labor intensive than steady state analysis. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. The SDT has modified Requirement R2.4.3 to stipulate that the entity shall provide rational for why sensitivity on the list were or were not included in the sensitivity studies and that the entity may consider additional sensitivities that are appropriate for its own System.

R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected~~

Question 14			
Commenter	**Yes**	**No**	**Comment**
~~sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:			
AEP			We concur with the use of sensitivity studies, but object to the requirement on what sensitivities to include. The flexibility to determine if sensitivity studies are appropriate, and the flexibility to choose what parameters are appropriate to study for sensitivity should be left open. R2.4.3 as written is restrictive to certain sensitivities and should not be.
CenterPoint		☑	The number and type of sensitivity studies should be left to the judgement of Transmission Planners.
CPS Energy		☑	The number and type of sensitivity studies should be at the discretion of Transmission Planners.
Duke Energy	☑	☑	Sensitivity studies can be useful, but they should only be requried for System Stability Studies. Due to the intensive nature of the studies, the planning engineer should have flexibility to determine appropriate sensitivities to analyze.
ERCOT ISO CAISO		☑	Although we concur with the sensitivity analysis,the TP should determine what sensitivities are more appropriate for their system. Sensitivities should not be scripted in the Standard.
ITC	☑		Both peak and off-peak models have been historically used for stability analysis and should continue to be used. The need for additional sensitivity studies should be left to the discreton of the Transmission Planner.
MEAG Power	☑		The entity performing the studies should be allowed to determine the appropriate sensitivity studies that need to be evaluated. An alternate approach is to include pre-existing system conditions that additionally stress the system during the contingencies under study so as to verify that stability is preserved under conditions that go beyond those envisioned for the contingency. Stability studies are more time consuming than conventional power flow studies. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.
MISO		☑	Use of sensitivities should not be required for Stability analysis, but the Standard should rather allow sensitivities at the discretion of the planning engineer. Due to the computationally intensive nature of these studies, a study rotation would be appropriate. For example, one year would be peak base case, next year off-peak case, and following year a sensitivity case. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.
NCEMC	☑		The entity performing the studies should be allowed to determine the appropriate sensitivity studies that need to be evaluated with a stakeholder process for those impacted by these studies as noted above. An alternate approach is to include pre-existing system conditions that additionally stress the system during the contingencies under study so as to verify that stability is preserved under conditions that go beyond those envisioned for the contingency. Stability studies are more time consuming than conventional power flow studies. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.

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Commenter	**Yes**	**No**	**Comment**
Northwestern Energy	☑	☑	The TP should have the ability to determine the sensitivity to use.
Santee Cooper	☑		The entity performing the studies should be allowed to determine the appropriate sensitivity studies that need to be evaluated. An alternate approach is to include pre-existing system conditions that additionally stress the system during the contingencies under study so as to verify that stability is preserved under conditions that go beyond those envisioned for the contingency. Stability studies are more time consuming than conventional power flow studies. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.
SERC EC PSS SERC RRS OPS	☑		The entity performing the studies should be allowed to determine the appropriate sensitivity studies that need to be evaluated. An alternate approach is to include pre-existing system conditions that additionally stress the system during the contingencies under study so as to verify that stability is preserved under conditions that go beyond those envisioned for the contingency. Stability studies are more time consuming than conventional power flow studies. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.
AECI		☑	We believe that only the worst case would need to be addressed for stability purposes.
WECC BPA TEP	☑	☑	We concur with the use of sensitivities as long as the TPs are allowed to determine the sensitivities that are the more appropriate for their systems and not have the sensitivities scripted in the Standard.
Muscatine P&W	☑		If reasonable and appropriate and allow for local issues including those not in the standards..
Response: The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. The SDT has modified Requirement R2.4.3 to stipulate that the entity shall provide rational for why sensitivity on the list were or were not included in the sensitivity studies and that the entity may consider additional sensitivities that are appropriate for its own system. **R2.4.3**. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied**:**			
Entergy		☑	The new requirements for stability studies, including but not limited to the sensitivity studies, will result in a tremendous increase in workload. Because stability studies are so much more time intensive that steady state analysis and because they require personnel with a highly specialized skill set, the number of stability studies required should be increaed only as determined necesssary to evaluate worst-case contingencies. It would seem that the sensitivity analyses as well as many of the multiple contingency analyses could be done for steady state and only worst cases analyzed again by dynamic studies.
FPL FRCC		☑	The standards require near term base case cases to be studied for a broad range of planning and Extreme Events. The sensitivity analysis requirements contained R.2.4.3. will essentially require every dynamic simulation to be run at least twice regardless of whether or not there is any

Question 14			
Commenter	**Yes**	**No**	**Comment**
			engineering insight to be gained. While improved understanding may result from sensitivity analysis of certain key event scenarios, the overall benefits of the sensitivity study requirements contained in section R.2.4.3 do not justify the huge increase in engineering effort to conduct and document these simulations.
Response: The SDT agrees with you that dynamic analysis is generally more labor intensive then steady state analysis. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. The SDT has modified Requirement R2.4.3 to stipulate that the entity shall provide rational for why sensitivity on the list were or were not included in the sensitivity studies and that the entity may consider additional sensitivities that are appropriate for its own System. **R2.4.3**. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied**:**			
KCPL		☑	Dynamic studies should be performed when new generation or transformers are added to the system. Should be performed on a periodic basis, not annually.
Response: The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. The SDT has modified Requirement R2.4.3 to stipulate that the entity shall provide the rational for why sensitivities on the list were or were not included in the sensitivity studies and that the entity may consider additional sensitivities that are appropriate for its own System. The standard allows that the Planning Assessment can be supported by current or past studies. While an assessment is to be done annually, there is no intent to rerun the same studies "annually" unless the standard specifically requires such. Studies you mentioned can be used to support the assessment and be retained as "past" studies as appropriate. **R2.4.3**. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:			
MRO		☑	The MRO is okay with requiring the sensitivity studies but is concerned with the R.2.4.3.2 requirement as written in that it unnecessarily requires that the sensitivity studies to "simultaneous transfer" to include "non-firm transfers". The MRO recommends that this be changed to match R.2.1.3.2 "Modification of expected TRANSFERS." The MRO also questions the wording of R.2.4.3.4 which provides a more limiting description of the sensitivity to reactive. The MRO recommends that the wording of this requirement be changed to match R.2.1.3.4, "Variability and outages of reactive resources."
Response: Requirements R2.4.3.2 and R2.4.3.4 have both been revised to match with R2.1.3.2 and R2.1.3.4 respectively. **R2.4.3.2**. ~~Expected simultaneous transfers including non-firm~~ Modification of expected transfers. **R2.4.3.4**. ~~Reactive dispatch of generators and other reactive power devices~~ Variability and outages of reactive resources.			
LCRA		☑	

Question 14			
Commenter	**Yes**	**No**	**Comment**
IESO		☑	For similar reasons stated in Q13, above.
New York ISO		☑	See comments to Q12 & Q13.
Response: Thank you.			
PJM	☑	☑	Yes, however, clear direction is needed. Specific wording that defines if you have done enough, and met the compliance requirements.
Response: The need to conduct sensitivity analysis was a directive in FERC order 693 paragraphs 1694,1704, and 1706. The SDT agrees with you that dynamic analysis is generally more labor intensive then steady state analysis. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. The SDT have modified Requirement R2.4.3 to stipulate that the entity shall provide rationale for why sensitivities on the list were or were not included in the sensitivity studies and that the entity may consider additional sensitivities that are appropriate for its own System. The standard requires that deficiencies identified from the results of the current studies need to be addressed via Corrective Actions Plan while leaving at the entity 's discretion to decide which deficiencies, if any, identified through sensitivity studies should be addressed by the Corrective Action Plan. **R2.4.3.** For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:			
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating	☑		The standard is unclear whether or not it mandates the requirement to mitigate consequences of problems highlighted as a result of one of the sensitivities. Suggest modification to, "…sensitivity testing that stresses the System should be considered. Sensitivity case(s) might include among the following conditions:" 2.4.3 shold mimic 2.1.3 except in regard to load models.
Response: The standard requires that deficiencies identified from the results of the current studies need to be addressed via Corrective Actions Plan while leaving at entity's discretion to decide which deficiencies, if any, identified through sensitivity studies should be addressed by the Corrective Action Plan. The SDT has modified wording of Requirement R2.4.3 to be consistent with Requirement R2.1.3 as you suggested. **R2.4.3**. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied**:**			
SERC EC DRS	☑		Use of sensitivity studies is appropriate only for System Stability Studies.
Response: Thank you**.**			

Question 14			
Commenter	**Yes**	**No**	**Comment**
Southern Transm.	☑		Some sensitivity analysis is reasonable. Other comments: 1. The wording regarding transfer sensitivity for stability analysis should be the same as the wording used in steady state analysis "modification of expected transfers". 2. The list of sensitivities may not be the most appropriate for all entities. There should be the ability to perform other sensitivity analsysis instead of these as long as the "rationale" is provided for the choice.
Response: The SDT has modified the standard so that R2.1.3.2 and R2.4.3.2 are worded consistently. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. The SDT has modified requirement R2.4.3 to stipulate that the entity shall provide rational for why sensitivity on the list were or were not included in the sensitivity studies and that the entity may consider additional sensitivities that are appropriate for its own system. **R2.4.3.2**. ~~Expected simultaneous transfers including non-firm~~ Modification of expected transfers.			
ABB	☑		Absolutely**.**
Allegheny Power	☑		
APPA	☑		This is absolutely necessary; it will help with the operational planning that will be needed next. In addition, it will help to determine the amount of study uncertainty that the Transmission Planner believes will be in the plan. This is very important for the Year One.
ATC	☑		
BCTC	☑		
Brazos Electric	☑		
City Utilities/Springfield	☑		
Entegra	☑		Planners should use appropriate sensitivity cases.
Exelon	☑		
Georgia Transm.	☑		
JEA	☑		
NERC TIS	☑		
Progress–Carolinas	☑		
Progress–Florida	☑		

Question 14			
Commenter	**Yes**	**No**	**Comment**
Seattle City	☑		
Tenaska	☑		
WPS	☑		
Response: Thank you. Please see the Summary Response.			

15) Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Summary Response: Commenters generally agreed that sensitivities are not needed in long-term planning horizon studies since the studies are typically based on a number of assumptions regarding future conditions and uncertainties. Sensitivities of uncertain models could result in even more uncertain and probably unrealistic conditions, the use of which may cloud the actual trends. Closer in years tend to be more certain and applying sensitivities is necessary to ensure that unexpected conditions would not significantly affect reliability. The standard does not preclude entities from performing long term sensitivity studies which may even provide some basis for the base models used for analysis.

Question 15			
Commenter	**Yes**	**No**	**Comment**
AECC		☑	In the long range the confidence in some variables such as load growth may become fuzzy. Sensitivity analysis let you gauge the impacts that variences in a particular variable may have. I don't think it should be performed for every study but occasional study to maintain sanity is appropiate.
Response: Because the assumptions for the longer term are fuzzy, the SDT did not feel that it was appropriate to require prescriptive sensitivities since such studies could result in an even more distorted model. The SDT felt that the entity should determine if such sensitivities are appropriate knowing their own unique circumstances			
Northwestern Energy		☑	However, the TP should have the ability to determine the sensitivity to use.
Response: The TP can always perform and use sensitivities in addition to those required in the standard.			
AEP		☑	Consider requiring the same sensitivity analysis that is conducted under the near-term studies.
NERC TIS		☑	Since the long-term planning is completely couched in uncertainty, at least some generalized sensitivities should be required.
NCEMC		☑	Some sensitivity analysis in the long term years should be done (90/10 load with higher than expected transfers and/or delayed baseload generation) so that higher voltage issues are adequately tested to identify long lead time upgrades, in a similar manner as was done to justify the backbone projects that have been identified in the PJM Interconnection. A stakeholder process should be used by the entity performing the study to compile input on impacted LSEs and other Transmission Customers.
Response: Commenters generally agreed that sensitivities are not needed in long-term planning horizon studies since the studies are typically based on a number of assumptions regarding future conditions and uncertainties. The standard does not preclude entities from performing long term sensitivity studies which may even provide some basis for the base models used for analysis.			
BCTC	☑	☑	Long term needs to address sensitivities since it usually takes more than five years to contruct new transmission lines.
ITC	☑		We believe that both near-term and long-term studies should include sensitivity studies. Near-term studies may produce either operating solutions and more limited transmission solutions. It is just as or more important in a standard like this one to also do sensitivity analysis for the 6-10 year and

Question 15			
Commenter	**Yes**	**No**	**Comment**
			beyond period. This is necessary to provide the needed advance notice for long-lead time alternatives to problems which are uncovered. Focusing on the next 5 years limits alternatives that can be implemented. In fact, it makes sense to perform more sensitivity analysis on the longer term as assumptions become less probable the further out into the future you get. If a problem is identified in one snapshot 10 years out it may be less relevant than if it shows up in several varying snapshots 10 years out into the future. The use of sensitivity studies for the 6-10+ year horizon will hopefully have the effect of minimizing the use of band-aid type approaches to identified problems.
Tenaska		☑	Any analysis that is performed needs to include some sort of sensitivity analysis. In fact, the sensitivity analysis may yield more information that is helpful in making decisions today than sensitivities performed on a near term study. A way of conducting a sensitivity analysis for long term studies may be to require long term studies to be performed for several years instead of only the one year that is required in the 6-10 year horizon.
Response: Commenters generally agreed that sensitivities are not needed in long-term planning horizon studies since the studies are typically based on a number of assumptions regarding future conditions and uncertainties. The standard does not preclude entities from performing long term sensitivity studies which may provide some basis for the base models used for analysis nor does it preclude studying multiple years if more critical trends are detected.			
TSGT		☑	It is just as important for long range plans of service to provide acceptable operation as it is for near-term facility plans. To specify different criteria for different time periods seems unreasonable.
Response: Commenters generally agreed that sensitivities are not needed in long-term planning horizon studies since the studies are typically based on a number of assumptions regarding future conditions and uncertainties. This is not the same for the near-term. The SDT feels that the level of uncertainty for the two time period justifies a different approach. In any case, the standard does not preclude entities from performing long term sensitivity studies.			
ERCOT ISO CAISO WECC	☑		Agree. The Standard should state that sensitivity studies are not required but the TP or PA could use sensitivities if desired.
TEP	☑		We agree with this conclusion. The Standard language should state that sensitivities are not required in Long-Term Transmission System Planning Horizon but the TP could use sensitivities if desired.
Response: The SDT feels the standard reflects your comment. The standard does not preclude the entity from using sesitivities if more critical trends are detected.			
Georgia Transm.	☑		The sensitivities should be determined by the Planner. As part of the development of long range projects, sensitivity analyses should be performed.
Response: The SDT feels the standard reflects your comment in that even though the standard does not require sensitivities, it does not preclude the entity from using sesitivities if desired. Commenters generally agreed that sensitivities are not needed in long-term planning horizon studies since the studies are typically based on a number of assumptions regarding future conditions and uncertainties.			
Ameren	☑		There are more unknowns in the longer-term studies than in the near-term studies, which would

Question 15			
Commenter	**Yes**	**No**	**Comment**
			indicate that more sensitivity studies would need to be performed and not less. However, it is more reasonable to suggest that if near-term sensitivity studies show a problem in a particular part of the system, then similar sensitivity studies need to be performed in the longer-term analyses.
IESO	☑		We agree, but this raised a question on why did the SDT introduce a requirement for sensitivity testing for year one to year 5 studies but not the year 6 and beyond studies. Wouldn't the degree of uncertainty be higher in the longer time frame?
Response: Commenters generally agreed that sensitivities are not needed in long-term planning horizon studies since the studies are typically based on a number of assumptions regarding future conditions and uncertainties. Closer in years tend to be more certain and applying sensitivities is necessary to ensure that unexpected conditions would not significantly affect reliability. The standard does not preclude entities from performing long term sensitivity studies which may even provide some basis for the base models used for analysis.			
LADWP	☑		This applies to both long- and near- term, the type of sensitivities proposed here do not belong in transmission planning studies.
Response: The SDT felt that it is necessary for planners to consider certain factors that clearly could impact system responses to contingencies. The standard, sub requirements for R2.1 and R2.4, has been modified to require that the planner document why or why not the listed factors were used in the assessment. In addition the standard does not preclude entities from performing long term sensitivity studies which may provide some basis for the base models used for analysis nor does it preclude studying multiple years if more critical trends are detected.			
Muscatine P&W	☑		Local issues may drive a different approach
Response: The SDT feels the standard reflects your comment in that even though the standard does not require sensitivities, it does not preclude the entity from using sesitivities if desired, such as local issues as you suggest.			
New York ISO	☑		NYISO does not agree with the requirement of sensitivity studies in the near-term or long-term.
Response: Commenters generally agreed that sensitivities are not needed in long-term planning horizon studies since the studies are typically based on a number of assumptions regarding future conditions and uncertainties. Closer in years tend to be more certain and applying sensitivities is necessary to ensure that unexpected conditions would not significantly affect reliability.			
WPS	☑		The standard should require long-term sensitivity studies to the extent that the open transmission planning process within FERC Order 890 identifies the need for the sensitivities.
Response: Commenters generally agreed that sensitivities are not needed in long-term planning horizon studies since the studies are typically based on a number of assumptions regarding future conditions and uncertainties. In addition the SDT feels that such sensitivities were not required by the Order. The standard does not preclude entities from performing long term sensitivity studies which may provide some basis for the base models used for analysis nor does it preclude studying multiple years if more critical trends are detected.			
Brazos Electric	☑		Longer term studies should be performed in the broadest sense, the cases are difficult to create accurately and a greater range of sensitivities do not improve the results.
City Water Power and Light	☑		
Dominion	☑		We concur that no sensitivity studies should be required for the LT planning horizon.
E ON US			I agree with the approach.

Question 15			
Commenter	**Yes**	**No**	**Comment**
AECI	☑		
Allegheny Power	☑		No sensistivity needed for long term assessment.
APPA	☑		The sensitivity study of year 6 and beyond is of little value. The uncertainty (standard deviations) in the input assumptions used to complete the studies for 6 years and longer are so large it would not provide useful answers to make sound decisions regarding the need to build, remove, or improve BES facilities.
ATC	☑		
BPA	☑		
CenterPoint	☑		
Central Maine Power	☑		There is no need for sensitivity analysis.
City Utilities/Springfield	☑		
CPS Energy	☑	☑	We concur with not requiring sensitivity studies for the Long Term Assessment.
Duke Energy	☑		Agreed, sensitivity studies should not be required for the Long-Term.
Entergy	☑		
Exelon	☑		
FirstEnergy	☑		Yes, we concur with this approach and sensitivity analysis should not be required.
FPL	☑		There should be no sensitivity studies/analyses for the Long-Term Transmission System Planning Horizon.
FRCC	☑		
HQTE	☑		There is no need for sensitivity analysis.
JEA	☑		
KCPL	☑		Long term planning horizon has significantly greater uncertainty in future conditions and sensitivity studies are unlikely to contribute to reliability because of this.
LCRA	☑		There are two questions asked and the response is yes to both. In the ERCOT region, load flow cases are not currently availbale for years 6-10 and this limits the long-term study activity that Transmsion Owners and Transmission Planners can acarry out. As currently proposed (R2.2) is appropriate.
Manitoba Hydro	☑		The models for Long-Term Transmission System Planning Horizon typically contain such uncertainty that the base planning is a sensitivity study itself. Sensitivity studies in these years would be a waste of time. The long term analysis should be used to indicate trends such as a reduction in transfer capability, reduction in damping, etc, but not necessarily seek mitigation of such trends.

Question 15			
Commenter	**Yes**	**No**	**Comment**
MEAG Power	☑		We concur with the current approach.
MISO	☑		Long-term planning horizon studies are typically based on a number of assumptions regarding future conditions and uncertainties. While testing various load conditions, generator operation assumptions, and power interchange variables may be useful for modeling expected economic value, such analysis does not contribute to reliability.
MRO	☑		The models for Long-Term Transmission System Planning Horizon typically contain such uncertainy that the base planning is a sensitivity study iteself. The MRO believes that sensitivity studies in these years would be a waste of time.
National Grid	☑		There is no need for sensitivity analysis.
New England ISO	☑		There is no need for sensitivity analysis.
NCMPA			
NU	☑		There is no need for sensitivity analysis.
NPCC RCS	☑		There is no need for sensitivity analysis.
Nstar	☑		There is no need for sensitivity analysis.
PJM	☑	☑	PJM agrees that no sensitivity analysis is required for long term period
Progress–Carolinas	☑		Sensitivities should not be required for Long-Term
Progress–Florida	☑		PEF concurs with the draft standard's approach with regard to Q15 that sensitivities should not be required for years six through ten.
ReliabilityFirst	☑		
Santee Cooper	☑		We concur with the current approach.
SaskPower	☑		
Seattle City	☑		Conditions six years or more in the future are unpredictable and sensitivity studies would provide results of limited usefulness.
SERC EC DRS	☑		We agree that sensitivity studies should not be required for the Long-Term..
SERC EC PSS	☑		We concur with the current approach.
SERC RRS OPS	☑		We concur with the current approach.
SCE&G	☑		
Southern Transm.	☑		Yes, we concur with this approach.
TVA	☑		

Question 15			
Commenter	**Yes**	**No**	**Comment**
United Illuminating	☑		There is no need for sensitivity analysis.
Response: Thank you.			

C) Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

16) Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Summary Response: DSM refers to reduction in the net Load that could be used to mitigate generation deficiency or Transmission overload. DSM could be invoked pre-Contingency or as a part of automatic or manual System adjustment post-Contingency. The use of DSM is optional and entities do not have to include DSM in the Corrective Action Plan. However, if DSM is included in the Corrective Action Plan, the entity that included it must justify the DSM amount and associated uncertainties. If an entity can show that DSM is effective, the standard does not bar them from using it.

The following requirement was changed due to industry comments:

R2.7.1 - ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.

Q16			
Commenter	**Yes**	**No**	**Comment**
AECC		☑	Yes - DSM impact should be included if it is known and can be treated the same a generation as far a dependibility, capability, and its known impacts. No - most DSM on our system is already figured into the load.
Response: The SDT provided DSM as a possible action. The entity may choose to use this option or provide additional actions to improve System response.			
Ameren	☑	☑	If DSM can be implemented in the required operating time, we have no objections to using DSM as the planned mitigation to relieve overloads or low system voltages for multiple contingency conditions, but not as a long-term solution for single contingency conditions. However, from our experience, we believe that developing enough DSM in the required time at specific locations in the

Q16			
Commenter	**Yes**	**No**	**Comment**
			system will be difficult, and that plain load-shedding would be required to supplement the DSM to achieve the desired performance.
BPA	☑	☑	Support comments submitted by WECC. There is a concern with using DSM as a corrective action if it is not directly controlled by the utility and the benefits do not materialize as planned.
Brazos Electric		☑	If DSM is not viable due to market failings, then its inclusion in any CAPs provides an inaccurate soltion to achieve the required system performance.
City Water Power and Light		☑	DSM is not always available and is usually not available without operator action. Therefore, asuming it is alwasys available could give a false sense of security. The system could collapse before DSM is able to be implemented.
Georgia Transm.		☑	DSM should not be a requirement in considering Corrective Action Plans. Because DSM cannot be counted on or controlled, its use as a Corrective Action Plan should not be assumed.
MISO	☑	☑	Yes, DSM should be considered in transmission studies, but should be limited to firmly contracted DSM resources that are demonstrably applicable for transmission capacity mitigation. DSM is better compared to supply-side resources as they are evaluated for reserve margin contribution. No, the challenge in considering DSM, is that Transmission Planners are not aware of DSM potential on the system and it must be communicated to them for consideration.
WECC TEP		☑	It is unclear whether "DSM" in this question refers to reduction in load or increases in distributed resources, or if the resources are directly controllable by the transmission operator. DSM could be used in the mix of solutions that are used to determine the optimal solution for a transmission issue. However, we have concerns about the use of DSM, that is not under the direct control of the Transmission Operator as a stand alone transmission system solution. Please remember the overstated returns from DSM in the last decade that did not materialize. If these overstated values had been used as a transmission system enhancement, then the system would have been compromised with emergency operating solution until the effective transmission enhancements could be realized.
Response: DSM refers to reduction in net Load. The standard does allow for consideration of DSM but other factors may disallow inclusion of DSM in the Corrective Action Plan. The amount and uncertainty of DSM needs to be justified by the entity when it is included in their Correction Action Plan. If an entity can show that DSM is effective, the standard does not bar them from using it.			
E ON US		☑	DSM and generation improvements should be excluded. What is a "generation improvement"? New technologies could apply to anything, does the SDT mean "new Transmission technologies"?
Response: DSM refers to reduction in net Load. The standard does allow for consideration of DSM but other factors may disallow the use of DSM as a corrective action. The amount and uncertainty of DSM needs to be justified by the entity when it is included in their Corrective Action Plan. If an entity can show that DSM is effective, the standard does not bar them from using it. The term "generation improvements" means any change or modification to a generator which results in an increase in generation output and/or reactive support. New technologies include any technology that is not currently in use on the electric power System that helps improve efficiency (i.e., energy storage/production technologies, low sag conductors, solid state interrupters, etc.)			
Northwestern Energy		☑	The word "including" should be "may include", mandating what should be studied is not appropriate.

Q16			
Commenter	**Yes**	**No**	**Comment**
			Also, including DSM in the list presumes the balancing area is deficient in generation, which may not always be the case.
Response: The use of DSM is optional. Requirement R2.7.1 has been modified based on your comments to use "may include" instead of "including". DSM typically has been used to compensate for generation deficiency but it can also be used to reduce transmission loading for special conditions and may provide a justifiable corrective action. The standard does allow for the use of DSM but other factors may disallow the use of DSM as a corrective action. **R2.7.1** - ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.			
CenterPoint		☑	CenterPoint Energy is not aware of DSM ever being identified as an effective option to correct a transmission system deficiency. If such an application of DSM was identified and implemented, load growth would quickly negate the DSM impact, and other measures would have to be taken.
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating	☑		DSM should be included to the extent that its performance is sufficiently and consistently understood. The standard does not use the term "optimal" Therefore, the Drafting Team appears to be interpreting the Standard to require a vertically-integrated Planner to produce a so-called optimal-mix of resources plan. This would be an incorrect assumption and is not required. In areas with independent planners and competitive wholesale markets, it is sufficent to identify system needs and produce a plan that identifies regulated transmission solutions in the event that market-based resources (such as DSM) do not address those identified needs. Therefore, while DSM can be as effective a resource as generation, per Commission Orders, in areas with ISOs/RTOs and a competitive wholesale market, the NERC Standard cannot prescribe the development so-called optimized (as is suggesgted by the Drafting Team) resource-mix plans, as identified by a central planner.
NERC TIS	☑	☑	Yes, if it can be counted on for relieving transmission constraints. Some DSM contracts do not allow for interruption for anything other than resource adequacy events, or have time-based or economics-based implementation limitations.
New York ISO	☑		NYISO suggests that the impact included in studies should consider past performance of DSM participants.
Response: The standard does allow for consideration of DSM but other factors may disallow the use of DSM as a corrective action. The amount and uncertainty of DSM needs to be justified by the entity when it is included in their Corrective Action Plan.			
CPS Energy		☑	Performance of the DSM is not necessarily controlled by the Transmission Owner and cannot be considered "firm". Therefore, use of DSM should be optional, but not mandated.
Response: The use of DSM is optional. Requirement R2.7.1 has been modified based on your comments to use "may include" instead of "including". If an entity can show that DSM is effective, the standard should not bar them from using it.			

Q16			
Commenter	**Yes**	**No**	**Comment**
R2.7.1 - ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.			
FirstEnergy		☑	We do not feel that the standard should specify, limit, or suggest methods for mitigating system performance deficiencies. We suggest rewording R2.7.1 by ending the first sentence after the words "System performance". The items currently described could be moved to a reference document which could include DSM and other mitigation methods.
Response: The use of DSM is optional. Requirement R2.7.1 has been modified based on your comments to use "may include" instead of "including". The SDT feels it is more useful to include examples of what the Corrective Action Plan may include. The list of examples should help minimize questions regarding what is valid as a corrective action. **R2.7.1** - ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.			
IESO		☑	No, the amount DSM is, in some established markets, a market-arranged quantity that depends on both the offered price and the discretion of the LSE or load customer at the time such a price signal presents itself. The resultant amount of DSM that can actually be realized when needed is unpredictable. This requirement also brings up a broader issue. Requirement 2 generally applies to Planning Coordinator and Transmission Planner, there is no distinction made as to which sub-requirements apply to which entity. In some markets, the Transmission Planner is responsible for assessing future needs for transmission facility only. It does not have the authority to even suggest a corrective plan that involves generation improvement or DSM. The way R2 and its sub-requirements is written is more suited for an integrated planning process, which may not exist in some places/developed markets.
Response: The use of DSM is optional. Requirement R2.7.1 has been modified based on your comments to use "may include" instead of "including". The standard does allow for consideration of DSM but other factors may disallow inclusion of DSM in the Corrective Action Plan. The amount and uncertainty of DSM needs to be justified by the entity when it is included in their Correction Action Plan. The standard is applicable not only to the Transmission Planner but also to the Planning Coordinator and the Resources Planner. These entities are expected to establish relationships to provide for intergrated analysis and resultant Corrective Action Plan which may include generation, transmission and DSM components. **R2.7.1** - ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including~~			

Q16			
Commenter	**Yes**	**No**	**Comment**
~~Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.			
LADWP		☑	We should be very careful about using DSM as Corrective Action for transmission problem. What this would lead to is to have a "built-in" transmission problem which would require DSM as the de facto rolling brown-outs or black-outs. DSM should be part of the resource and load forecasting consideration; transmission planning should design tranmission that can properly serve the forecasted loads with the expected resources; not to "live with" or include transmission contraints that rely on DSM as a solution. If the industry truly wants to use DSM as mitigation for transmission deficiencies, let's do it as a deliberate action, not an unintended consequence. "System deficiencies" may be corrected with an integrated approach as suggested, but "transmission deficiencies" are solved by transmission improvement. The classic example is Path 15 in WSCC/WECC. The transmssion deficiency of PAth15 was well known for many years (like since '80s) and in the "pre-deregulated" dates, the deficiency was indeed managed by an integrated approach when the utility can operate its assets integrally. Then de-regulation happened and the integrated approach became unbundled and impossible resulted in numerous brown-outs and black-outs in California in 2000-01 until a third transmission line is added. Transmission deficiencies, if not mitigated, will significantly affect the accessibility to transmission services, a key concern of ferc 890. As for new technology, just how the SDT proposes to define what constitutes a new technology? And how to measure for compliance against such a requirement? Hopefully, this is just another case of overly prescriptive standard.
Response: DSM refers to reduction in net Load. The standard does allow for consideration of DSM but other factors may disallow the use of DSM as a corrective action. The amount and uncertainty of DSM needs to be justified by the entity when it is included in their correction action plan. New technologies include any technology that is not currently in general use, or is in the development stages, on the electric power system that helps improve efficiency (i.e. energy storage/production technologies, low sag conductors, solid state interrupters, etc.)			
Manitoba Hydro		☑	DSM and generation improvements should be removed from Requirement R2.7.1, as they should not be mandated by a NERC standard are not in the tool box of the transmission planner. DSM may already be in the load forecast and sensitivities to load forecast variations are included in near term planning horizon sensitivity analysis. Additional DSM shouldn't be part of transmission planners mitigation plan. If the corrective plan is too expensive the load serving entity could consider DSM and revise their forecast in the next planning cycle.
MRO		☑	DSM should already be in the load forecast and sensitivities to the load forecast variations are included in the near term planning horizon sensitivity analysis. Additional DSM shouldn't be part of the transmission planner's corrective plan. Additional DSM can be considered in the next planning

Q16			
Commenter	**Yes**	**No**	**Comment**
			cycle.
Response: The use of DSM is optional. Requirement R2.7.1 has been modified based on your comments to use "may include" instead of "including". DSM refers to reduction in net load that could be used to compensate for a generation deficiency or to reduce transmission overloads. If an entity can show that DSM is effective, the standard should not bar them from using it. **R2.7.1** - ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.			
Southern Transm.		☑	It should not be a requirement that DSM be considered but DSM should be one of the allowable alternatives. The way the present standard is written, it is unclear whether "all" of the named items (except operating procedures with the "or" statement) are required to be considered or whether only one or more of the items need to be included. It is suggested that the following statement replace the word "including" in line two of R2.7.1: "that may include one or more of the following:". This should clarify that all of the items are not required to be in the action plan for compliance. It also is not clear what the phrase "including the duration of interim Operating Procedure" means. Does this mean how many years you would anticipate using the Operating Procedure or does it mean how long it takes to "repair" the cause of the outage that necessitated the use of the Operating Procedure? Assuming that the meaning is the second one, the requirement to document the "mean time to repair" is new and there does not seem to be a very useful purpose for this requirement. As long as the system performance standards are met and the system is prepared for the next outage, what is the purpose of recording and documenting the length of time that you anticpate it to take to fix the problem? This is variable at best and does not provide useful information.
Response: The use of DSM is optional. Requirement R2.7.1 has been modified based on your comments to use "may include" instead of "including". DSM refers to reduction in net load that could be used to compensate for a generation deficiency or to reduce transmission overloads. If an entity can show that DSM is effective, the standard should not bar them from using it. Your first interpretaion is correct (how many years you expect to use the procedure). **R2.7.1** - ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.			
TSGT		☑	DSM should not be considered except as a load forecast variable. Rather, the load forecast probability index should be prescribed (specific probability of exceedance)

Q16			
Commenter	**Yes**	**No**	**Comment**
Response: The use of DSM is optional. If an entity can show that DSM is effective, the standard should not bar them from using it. The use of DSM is optional. Requirement R2.7.1 has been modified based on your comments to use "may include" instead of "including". DSM refers to reduction in net load that could be used to compensate for a generation deficiency or to reduce transmission overloads. **R2.7.1** - ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.			
AECI		☑	
LCRA		☑	
SaskPower		☑	
Seattle City		☑	
Response: Thank you for your response.			
AEP	☑		Consider requiring that problem contingencies be simulated on base case that models the lower load level that would result with the DSM implemented.
Response: The standard does allow for consideration of DSM which is effectively the situation you are describing.			
APPA	☑		This is a conditional Yes. The Resource Planner or Transmission Planner must provide assurance that the specific "Demand" reduction that is incorporated into the scenario analyses will actually be reduced through either customer action or direct load shedding by the Balancing Authority. This type of controllable "Demand" does exist, but it is rare that planners and operators actually have such resources in their portfolios to help with System Deficiencies.
Response: The use of DSM is optional. If an entity can show that DSM is effective, the standard should not bar them from using it. The amount and uncertainty of DSM needs to be justified by the entity when it is included in their Corrective Action Plan.			
ITC	☑		DSM alternatives should focus on existing contractual relationships only. DSM is an alternative to "capacity solutions" and you have to give weight to how well you can count on it during capacity emergencies. Will the load be there to cut? How certain are you (contractually) that the load will be shed voluntarily when called upon to do so?
Response: The use of DSM is optional. If an entity can show that DSM is effective, the standard should not bar them from using it. The standard does allow for consideration of DSM but other factors may disallow the use of DSM as a corrective action. The amount and uncertainty of DSM needs to be justified by the entity when it is included in their Corrective Action Plan.			
KCPL	☑		Only for DSM that is contractually "firm" and which can demonstrate mitigation performance (comparable to generation resource) as related to the transmission system.
MEAG Power	☑		DSM should be included if it is a tool made available to the TP for this purpose, but only to the extent that it is available for curtailment by the System Operator and without the option to buy through and remain in service.

Q16			
Commenter	**Yes**	**No**	**Comment**
Response: The use of DSM is optional. The standard does allow for consideration of DSM but other factors may disallow inclusion of DSM in the Corrective Action Plan. If an entity can show that DSM is effective, the standard does not bar them from using it.			
NCEMC	☑		It should be included if it is a tool made available to the TP for this purpose, but only to the extent that it is considered firm.
Santee Cooper	☑		It should be included if it is a tool made available to the TP for this purpose, but only to the extent that it is considered controllable and quantifiable resource.
SERC EC PSS SERC RRS OPS SCE&G	☑		It should be included if it is a tool made available to the TP for this purpose, but only to the extent that it is considered firm.
TVA	☑		It should be included if it is a tool made available to the TP for this purpose, but only to the extent that it is considered firm. However, the standards should not determine which type of fix a utility should use to meet system requirements.
Response: The use of DSM is optional. If an entity can show that DSM is effective, the standard should not bar them from using it.			
ABB	☑		First of all, you are not exactly requiring that DSM be considered or analyzed. You have simply listed it as one of the possible solutions. And you should mention the possibility of "integrated plan" in the standard itself. Since DSM is simply optional, let the planners figure out themselves how to consider DSM.
Allegheny Power	☑		It should be included if there are specific mandated or approved DSM programs in place during the study period.
ATC	☑		
BCTC	☑		DSM should be a load reduction.
CAISO	☑		We agree to include DSM among a mix of solutions to a system problem. However, the difficulty is that DSM is unpredictable when needed. Another issue is how much DSM is actually under the control of the Transmission Operator.
City Utilities/Springfield	☑		Controllable demand that will be available to both the planner and operator must be well defined and readily available when called upon including operating procedures.
Dominion	☑		An appropriate level of DSM should be included in studies.
Duke Energy	☑		DSM should be carefully included based upon consideration of the particular DSM measures available and the uncertainty associated with each.
Entegra	☑		
Entergy	☑		DSM should be considered, but it should be done prudently and in accordance with the contracts that govern the specific DSM program and only in cases where the Transmission Owner has direct load control. Transmission Owners should be allowed to include UVLS and SPS systems as a part of their Corrective Action Plans.
ERCOT ISO	☑		

Q16			
Commenter	**Yes**	**No**	**Comment**
Exelon	☑		DSM should be directly controllable with accurate information as the the magnitude and location. System stability should not be dependent on the operation of DSM.
FPL FRCC	☑		If DSM is included as part of an integrated Corrective Action plan, then the impact of DSM should be included by specifying the location and expected quantity of DSM that will mitigate a system deficiency. The use of DSM, whether exclusively or in conjunction with other measures, is an acceptable operating procedure for use in a Corrective Action Plan, as long as the Transmission Owner demonstrates availability and accuracy of DSM data and its viability as an operating procedure for each applicable scenario.
Muscatine P&W	☑		We do not have DSM but I could see where it could be used to relieve overloads or low voltage.
PJM	☑	☑	Yes- DSM should be modeled consistent with how it is expected to be operated based on contractual/operating relationships.
Progress–Carolinas	☑		State regulatory requirements mandate that we consider DSM alternatives. The DSM contracts would have to adequately support the intended use.
Progress–Florida	☑		The use of DSM, whether exclusively or in conjunction with other measures, is an acceptable operating procedure for use in a Corrective Action Plan, as long as the Transmission Owner demonstrates availability and accuracy of DSM data and its viability as an operating procedure for each applicable scenario.
Tenaska	☑		While DSM may, or may not, be manually operated, it is critical to understand the impacts of DSM and whether different ways of implementing DSM are of value.
WPS	☑		The effect of DSM should be considered in corrective action plans to the extent that DSM can reduce overall load growth and change the timing of new transmission facilities.
Response: Thank you. DSM refers to reduction in net Load. The use of DSM is optional. If an entity can show that DSM is effective, the standard does not bar them from using it. The standard does allow for consideration of DSM but other factors may disallow the use of DSM as a corrective action. The amount and uncertainty of DSM needs to be justified by the entity when it is included in their Corrective Action Plan.			

17) Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Summary Response: The specific requirement to perform re-test has been removed. The purpose of the Corrective Action Plan is to list the actions that are needed to meet performance requirements. The studies, current, and/or past as appropriate, as well as the extent of the size of the study area, are performed to support compliance and demonstrate that the requirements are met. The standard assumes that the actions were developed and verified using the current and past studies that were used to uncover deficiencies and confirm adherence to the performance requirements.

The following requirement was deleted due to industry comments:

R2.7.2 ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~

Q17			
Commenter	**Yes**	**No**	**Comment**
AECC		☑	A new study should not be required. The impact of "fix" should be evaluated as part of determining it as a viable solution.
Response: The SDT agrees with your comment and has revised the requirements to agree with your comment. **R2.7.2** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~			
Ameren		☑	This proposed requirement is unnecessary and a waste of time. Keep in mind this is a planning assessment and not a facilities study. Further, such a requirement implies a distrust of the transmission planners to develop valid corrective action plans to meet the requirements of the TPL standard. For more complex system facility additions, it would be inconceivable that a Transmission Planner or Owner or Planning Coordinator would proceed without performing power flow simulations to determine the efficacy of the system addition. But these studies would be performed over time considering the best available information and latest standards performance requirements. The majority of transmission projects consist of the upgrading of terminal equipment or conductor on one or more branches. The only significant change that such upgrade work would produce in a power flow model would be that the branch ratings would change. It is not necessary to rerun power flow simulations for such cases, as it can be determined by inspection whether the upgrade

Q17			
Commenter	**Yes**	**No**	**Comment**
			work would be sufficient to move the facility rating above the expected normal or contingency flow.
Response: The purpose of the Corrective Action Plan is to list the actions that are needed to meet performance requirements. The studies are performed to support compliance and demonstrate that the requirements are met. The specific requirement to re-test has been removed. **R2.7.2** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ The SDT has removed the Requirement R2.7.2 but kept the orignal R2.7.5 requirement, which was re-numbered as Requirement R2.7.3, (subsequent annual assessments report on the status of Corrective Action Plans).			
Dominion		☑	In the normal course of business, a planner out of necessity will need to check to see if the proposed improvements will actually fix the problem. The prospect of making a multi-million dollar mistake is sufficient incentive to insure this study occurs without the additional burden of creating an audit trail to meet a NERC standard. Requirements for what study area should be used and documentation of the process are not necessary. If, per chance, a study is not performed immediately, the next set of studies will show the deficiencies, if any.
Response: The intent is to ensure that for a specific problem the Corrective Action Plan is checked to the extent that the Corrective Action Plan does not cause any additional problems. The SDT has removed the Requirement R2.7.2 but kept the orignal 2.7.5 requirement, which was re-numbered as Requirement R2.7.3, (subsequent annual assessments report on the status of Corrective Action Plans). **R2.7.2** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~			
E ON US		☑	Re-testing is part of the normal study process of developing the Corrective Action Plan (CAP). Most CAP should be developed in the Long-Term horizon. The next annual study and all subsequent studies provide sufficient review without developing another set of cases and additional testing in the initial assessment.
Response: The intent of the standard is to develop a Corrective Action Plan that will create a system capable of meeting system performance requirements. The intent of the standard is to provide verification at the time the Corrective Action Plan is developed and not wait a year to perform the verification. This is critical to ensure that plans are coordinated between entities. The SDT has removed the Requirement R2.7.2 but kept the orignal 2.7.5 requirement, which was re-numbered as Requirement R2.7.3, (subsequent annual assessments report on the status of Corrective Action Plans). **R2.7.2** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~			
Brazos Electric	☑		It is difficult to understand what is meant by 'retested'. The evaluation of a CAP includes testing the recommended option to see how it performs and to insure that it does not create other problems. We assume this is what is meant by retested. In our evaluation we insure that it does not negatively impact all other facilities in the BES and if so what extent and if it is managable. We do not always create a separate 'study area' each time for each system improvement.

Q17			
Commenter	**Yes**	**No**	**Comment**
CenterPoint	☑	☑	Many problems identified in future studies and associated transmission improvements are fictitious due to the speculative nature of predicting load and generation growth. Requiring exhaustive studies to determine the full impact of fictitious transmission projects is unnecessarily prescriptive and burdensome, and provides little, if any, value in identifying and solving real transmission problems.
CPS Energy		☑	Should be conducted for Near Term Planning Assessment only with the study area determined at the discretion of the Transmission Planners.
FPL FRCC		☑	Incremental benefits do not justify the magnitude of additional studies. Corrective Action plans should be tested, but not as a new study with all of the Corrective Action Plans included simultaneously. The proposed language is inferior to the existing language (TPL-002-0 R2) and suggest replacing with language from TPL-002-0 R2.
Georgia Transm.		☑	This is the essence of planning. All entities should ensure that Corrective Action Plans address the identified constraints and work within the BES infrastructure. It is not clear what the intent of "new" studies is. Since the evaluation of Corrective Action Plans is part of the planning process, what new studies is this requirement referring to. The determination of the study area should be by the Planner.
LADWP		☑	This is a redundant and unnecessary requirement. How can one come up with a corrective action plan if it has not been demonstrated the plan can mitigate the problem? And if the corrective plan has been able to demonstrate that it can mitigate the problem, why repeat the study again.
Manitoba Hydro	☑		At some point the corrective action plan should be tested to verify the plan meets the performance requirements. The way the standard is written is that the transmission plan should be perfect for the entire planning horizon for all sensitivities tested. Any issues should be immediately addressed. The standard does not allow any time to develop a corrective plan through an open and transparent process. Based on the NERC definition, a Corrective Action Plan is the list of actions and an associated timetable for implementation to remedy a specific problem. A Corrective Action Plan could mean that load forecasts at the station will be verified, facility ratings verified and alternatives to fix the identified problem to be determined before the next Planning Assessment. Standard R2.7 seems to be mixing the idea of a Corrective Action Plan with the original TPL idea of determining corrective plans to achieve required performance. A corrective plan wil be the end goal of a Corrective Action Plan. Furthermore, corrective action plans should not be requierd to address issues raised by sensitivity studies. Corrective action plans are developed to meet base case needs which are based on expected load forecasts, transfers, etc. Sensitivity studies are done to measure the robustness of the base case plan. It should be left up to the Planner to decide if the corrective action plan is adequate based on the likelihood of the scenario studied, even if the sensitivity analysis shows some performance violations.
MISO		☑	Sufficient analysis, including re-testing, must have been performed in creating the Corrective Action Plans. Requiring demonstration by the transmission planner that this is the basis of the Plans is superfluous.

Q17			
Commenter	**Yes**	**No**	**Comment**
MRO		☑	The MRO is concerned with this requirement particularly since the standard indicates that System Assessment shall be conducted each year while studies are not required each year. MRO members typically conduct this exercise at the time that studies are originally conducted with regard to improvements. By requiring a new study with improvements (some of which were justified in past studies) demonstrating that these improvements work essentially results in the Transmission Owner needing to clear a new unfair hurdle for improvements. This results in a requirement which will result in wide-spread non-compliance. The SDT should clarify that this requirement can be met by past studies. The MRO recommends that R2.7.2 be removed because it is redundant since development of the corrective action plan will have included these studies. At some point the corrective action plan should be tested to verify the plan meets the performance requirements. The way the standard is written is that the transmission plan should be perfect for the entire planning horizon for all sensitivities tested. Any issues should be immediately addressed. The standard does not allow any time to develop the corrective plan through an open and transparent process. Based on the Nerc definition, a Corrective Action Plan is the list of actions and an associated timetable for implementation to remedy a specific problem. A Corrective Action Plan could mean that load forecasts at the station will be verified, facility ratings verified and alternatives to fix the identified problem to be determined before the next Planning Assessment. Standard R2.7 seems to be mixing the idea of a Corrective Action Plan with the original TPL idea of determining corrective plans to achieve required performance. A corrective plan wil be the end goal of a Corrective Action Plan.
PJM	☑	☑	Yes – At a minimum the system conditions and / or contingency that identified the system deficiency should be evaluated to determine that it has corrected the issue. The extent of the study area needs to be consistent with the size / complexity of the corrective action plan.
Progress–Florida		☑	Each Corrective Action Plan as stated in the original assessments should be trusted as effective, provided the Transmission Owner can demonstrate with its own internal assessments the effectiveness of each Corrective Action Plan.
Santee Cooper		☑	Re-testing should be required only where the correction may impact network flows. The study area should be determined by the TP. The TP has the most knowledge of how the system responds to changes. The majority of transmission projects consist of the upgrading of terminal equipement or conductor on one or more branches. The only significant change that such upgrade work would change in a powerflow model would be that of the branch (facility) ratings would change. It is not necessary to rerun powerflow simulations for such cases, as it can be determined by inspections whether the upgrade work would be sufficient to move the facility rating above the expected normal or contingency flow. We agree that the Planning process should ensure that corrective actions for a particular defeciency do not lead to other deficiencies. However, the process for ensuring this is not necessarly The

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Commenter	**Yes**	**No**	**Comment**
			development of new study cases which include facilities comprising the corrective action plan and the suscetesting is not needed.
Southern Transm.	☑	☑	A properly conducted study should determine that the recommended Corrective Action Plan actually solves the problem and does not cause other problems. If not, it is not a Corrective Action Plan. What appears to be intended here is whether the combination of Corrective Action Plans interact with each other and create additional problems. In the conference call Mr. Odom stated that it was not the intent for "all" the corrective plans be put back into the cases and all of the simulations be redone but only look at local area analysis. If that is the case, what is necessary to be in compliance with R2.7.2 and what type of documentation is required? This is very unclear. The study area should be determined by the TP. The TP has the most knowledge of how the system responds to changes
WECC BPA TSGT TEP		☑	No, this is too onerous. We recognize that, when planning the system and developing a Corrective Action Plan, the transmission planner would have added the potential projects individually (or in small groups) into a case to re-test the system performance. Hoever, R2.7.2 seems to require that all potential projects be added back into the case simultaneously for retesting. There could be many different alternative solutions for each potential problem identified in the different study years without having the base solution first determined for a nearer term case. There can be many combinations of potential solutions for cases further into the future that satisfy the condition being studied. For example, a voltage problem can be solved by the addition of capacitors, completing a bus tie, adding a short line, operating procedure, changing generation dispatch, etc. Even assuming that one set of solutions are picked so the verification study can be performed, logistically this demonstration may be too close to the assessment in the following year. Instead of retesting the potential projects in the Corrective Action Plan on the original base case, it may be better to test them in the base cases prepared for following year's study. Any potential problem that is unresolved will show up again in the following year's assessment. Therefore, a separate demonstration using an "older" case may not be an efficient use of the TPs' and PAs' time and resources.
WPS	☑	☑	It is difficult to fully prescribe a methodology to define a "study area". It is most appropriate for the Transmission Planning to develop study areas based on and consistent with the transmission planning principles within Order 890.

Response: The intent of the standard is to develop a corrective action plan that will create a system capable of meeting system performance requirements. The standard assumes that the actions were developed and verified using the current and past studies that were used to uncover deficiencies and confirm adherence to the performance requirements. The SDT has removed Requirement R2.7.2 but kept the orignal 2.7.5 requirement, which was re-numbered as Requirement R2.7.3, (subsequent annual assessments report on the status of Corrective Action Plans).

R2.7.2 ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance~~

Q17			
Commenter	**Yes**	**No**	**Comment**
~~requirements in the tables~~			
ABB	☑	☑	Any area where there might possibly be an impact. I.e., engineering judgement.
Muscatine P&W		☑	Large enough to ensure negative impacts will not occur. This could best be covered in regional studies. (See Q43 Comment #3)
Response: The specific requirement to perform re-test has been removed. The purpose of the Corrective Action Plan is to list the actions that are needed to meet performance requirements. The studies, current and/or past as appropriate as well as the extent of the size of the study area, are performed to support compliance and demonstrate that the requirements are met.			
R2.7.2 ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~			
AECI		☑	
SaskPower		☑	
Response: Thank you for your response.			
Alcoa	☑		NERC is revising the Transmission Planning Standards beginning with TPL-001. Alcoa agrees with NERC's approach to revising TPL-001 wherein NERC is consolidating duplicative Standards to promote consistent requirements of the planning process and thus improving reliability. Also, Alcoa agrees that new studies should not result in inadvertent negative impacts on the system especially when such studies have not taken into account the negative impact on an adjacent system. However, Alcoa believes that the current draft of the TPL fails to address FERC Order 890's requirements of an open and transparent Planning Process. Such a process provides Market Participants an equal opportunity for consideration in the Planning Assessments for contingency impact on transmission availability. (See FERC Order 890 ¶¶ 140, 207, 212, 323, 327, 337). Alcoa also believes that the current draft of the TPL fails to address and incorporate FERC Order 890's new requirement that transmission providers coordinate "…ATC calculations with their neighboring systems." For example, while Planning Assessments may indicate no NERC Compliance violations where the Table 1 and Table 2 Requirements are met, Market Participants are harmed and not provided protection from unequal treatment of their circumstance. This problem occurs when an analysis of a contingency event results in no IROL or SOL (all facilities remain within established ratings), but resultant transmission constraints cause reductions of ATC and subsequent market impact. As part of the System Planning Process, this is unacceptable, and, as a minimum, this type of situation must be included as a scenario reviewed in the required sensitivity analysis under the NERC TPL-001-1 Standard. The impact of such practices by large transmission providers on the ATC of smaller transmission

Q17			
Commenter	**Yes**	**No**	**Comment**
			providers can be significant. For instance, small transmission providers similar to Alcoa that operate non base-load resources such as hydropower, peaking units or wind power can easily see their ATC's reduced when sensitivity analyses are not performed under TPL-001-1. Alcoa believes that such sensitivity analyses should be a requirement. Alcoa believes that for consistency with the provisions of Order 890, NERC must re-visit not only the Planning Assessment implications on transmission availability but also couple this review with the revision of the NERC Modeling Data and Assessment Standards (MOD). Alcoa recommends that the MOD and TPL Standards be addressed in similar fashion to: 1) Incorporate the intent of Order 890 requirements of an "Open and transparent Regional Planning Process to provide non-discriminatory planning" for ALL Market Participants 2) Assure that the revised MOD and TPL Standards fully address implications of burdens on the Bulk Electric System (BES) related to transmission availability for contingencies in the Planning Process. FERC Order 890 ¶ 523 - Coordinate planning with interconnected systems. In addition to preparing a system plan for its own control area on an open and nondiscriminatory basis, each Transmission Provider will be required to coordinate with interconnected systems to (1) share system plans to ensure that they are simultaneously feasible and otherwise use consistent assumptions and data and (2) identify system enhancements that could relieve congestion or integrate new resources. (Emphasis added). 3) Sensitivity Analysis should include the potential impact on transmission availability and/or reductions in ATC on adjacent systems. Where ATC on an interface is reduced for a single contingency (N-1 planning, mitigation options must be provided). (This may require a threshold level of ATC reduction where a percentage reduction would be specified as acceptable on the N-1 basis, and a greater reduction than that threshold would be considered a Standard's Violation).
Response: The purpose of this standard is to develop corrective actions that can eliminate system performance deficiencies. The standard does not judge if the action listed is the only or the best action to be taken on an economic or market basis. It is the responsibility of the entity to resolve such issues and conform to FERC Order 890.			
AEP	☑		Consider limiting study area to immediately adjacent systems.
Allegheny Power	☑		Study area should be at least two buses beyond deficiency and plan elements.
BCTC	☑		The Assessment should state how the study area was determined, including input from adjacent Planning Coordinators. WECC has processes for coordination of planning information so that Planning Coordinators are informed of plans in other areas.

Q17			
Commenter	**Yes**	**No**	**Comment**
Entergy	☑		Study area should be determined on a case by case basis by the Transmission Planner. SEAMS agreements and other regional planning coordination activities should provide for adequate cooperation.
Exelon	☑		The study area should be at least the size of the original study area. Some engineering judgment is required to determine the subset of studies. Next year's study would include the full set of screenings for the future additions.
IESO	☑		We feel that having the requirement to retest the conditions which show a performance deficiency, but now with the proposed corrective measures, would suffice. To illustrate or require "how a study area should be determined" would be micro-managing, and the term "a study area" is not defined anywhere in the standard and is subject to different interpretation. For example, does it mean the physical area of study or does it mean the various areas in the study that need to be explored. We are therefore unable to offer any view as to "how a study area should be determined".
ITC	☑		Without further study once a “solution” has been proposed how can one be sure it will work and not create “other” issues? The area of study should be developed using good engineering judgment with input from any neighboring parties that might be impacted.
KCPL	☑		Corrective Action Plans taken by a transmission operator should not burden any of its' directly interconnected transmission operators. Study area should include at least all transmission operators directly interconnected to the transmission operator who took the initial corrective action. It may be appropriate to use the entire RTO/ISO/RRO as study area.
LCRA	☑		The question is not clear regarding "study area"; however, re-testing with corrective action / system improvement(s) in place is a must. The re-test must consider the same simulations that identified the initial deficiency. In addition, in the re-test, the action/ system improvement must be considered as a Planning Event itself (i.e., if the initial test showed a specific contingency causing a deficiency, then a physical connection of the system improvement to the identified contingency should be avoided or minimized - minimize the creation of Extreme Events.). In other words, planning solutions should be long-term and a system "fix" for the present should not result in a system problem in the foreseeable future.
MEAG Power	☑		Re-testing should be required only where the correction may impact network flows. The study area should be determined by the TP. The TP has the most knowledge of how the system responds to changes and should be allowed to choose the study area based on the prudent utility practice.
NCEMC	☑		Re-testing should be required particularly where the correction may impact network flows. The study area should be discussed within a stakeholder process to the TP may compile input from network customers or LSEs that might be affected by the analysis.
Northwestern Energy	☑		R2.7.2 does not refer to "how a study area should be determined". This added statement should be eliminated.
Progress–Carolinas	☑		There are separate regional processes for coordination with neighboring utilities.

Q17			
Commenter	**Yes**	**No**	**Comment**
ReliabilityFirst	☑		The study area should be determined by the Transmission Planner and Planning Coordinator.
Seattle City	☑		Sensitivity studies should be adequate to determine the study area. Starting at the corrective facility, work out bus by bus, determining sensitivity to the facility's loss. Boundaries of the study area would be defined at buses where loss sesitivity is (for example) 1% or less.
SERC EC PSS SERC RRS OPS SCE&G TVA	☑		Re-testing should be required only where the correction may impact network flows. The study area should be determined by the TP. The TP has the most knowledge of how the system responds to changes.
Tenaska	☑		The study area should be the same as in the original study unless the Corrective Action Plans require changes/additions outside of the original study area. If chagnes/additions are made outisde the original area, then the study area must be expanded to include, at a minimum, the area that includes the new changes/additions.
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating	☑		The study area should be based upon planning expertise and knowledge of the system, giving due consideration to external impacts.
City Water Power and Light	☑		The system should be retested with new facilities in place to ensure that no new problems arise with the addition of new facilities.
Response: Based on industry comment, the SDT has removed Requirement R2.7.2 but kept the orignal 2.7.5 requirement, which was re-numbered as Requirement R2.7.3, (subsequent annual assessments report on the status of Corrective Action Plans). **R2.7.2** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~			
FirstEnergy	☑		Although we agree with the concept of retesting, the standard should reference that a re-study is only required in the vicinity or portion of the system affected by new facility additions. Determination of the study area should be left to the Transmission Planner's judgment.
Response: The SDT has removed the specific requirement to perform re-testing with the understanding that the purpose of the Corrective Action Plan is to list the actions that are needed to meet performance requirements. The studies, current and/or past as appropriate as well as the extent of the size of the study area, are performed to support compliance and demonstrate that the requirements are met. The standard assumes that the actions were developed and verified using the current and past studies that were used to uncover deficiencies and confirm adherence to the performance requirements. **R2.7.2** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance~~			

Q17			
Commenter	**Yes**	**No**	**Comment**
~~requirements in the tables~~			
NERC TIS	☑		All Corrective Action Plans should be tested on an interconnection-wide basis to screen for potential adverse impacts throughout the interconnection, not just the TOs area.
Response: Please see Requirement R8 for the coordination and peer review requirements.			
APPA	☑		This is necessary to insure the planners did not accidentally take the system and the future operation of the system from the frying pan into the fire.
ATC	☑		
City Utilities/Springfield	☑		Corrective action plans must be appropriately modeled in order to verify that implementing the plans results in a BES that will perform based on the applicable NERC Reliability Standards or more restrictive local area criteria.
Duke Energy	☑		New studies should be performed, but the study conditions should be determined based upon the judgment of the planner.
ERCOT ISO CAISO	☑		We agree that the system should be retested with the corrective measures to ensure that the defficiency has been cured and that there are no inadvertant negative impacts. Regarding Study Area, it is not a defined term, and it could vary depending on the size of the project or nature of the disturbance being evaluated.
New York ISO	☑		NYISO Agrees
Response: Thank you but due to the preponderance of industry response to this question, this requirement has been deleted.			

18) Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Summary Response: Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted the original Requirement R2.7.2 through Requirement R2.7.4. A new Requirement R2.7.2 has been added. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions".

The following requirements were changed due to industry comments:

R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.
R2.7.2. ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.
R2.7.3. ~~Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~
R2.7.4. ~~Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~

Q18			
Commenter	**Yes**	**No**	**Comment**
Ameren		☑	We understand that there are differences between committed and proposed projects in an RTO environment where there is cost sharing for facility upgrades. From a NERC Standards compliance perspective, however, we do not see a need to differentiate between proposed and committed projects in the corrective action plan, as long as either properly addresses the required performance issue. We are not sure why there is a need to develop or maintain information on committed projects. This tracking is not needed to meet the existing TPL standards. Compliance requirements should be kept separate from administrative data requests. What is the perceived need to track committed projects that has not been presented here? Is this another example of distrust for transmission owners to build the proper facilities to create a more robust system?
Brazos Electric		☑	What is the difference? We assume committed means you have begun work on the project and can no longer stop. It would seem this would need to be defined more clearly and it is probably different for each project or entity. Why is this differentiation even needed?
Response: The SDT agrees with your comment that from a planning perspective, there is no benefit in trying to distinguish between "committed" and "proposed". Therefore, the SDT has modified Requirement R2.7.1 and deleted the original Requirement R2.7.2 through Requirement R2.7.4 to reflect "actions" needed to achieve required System performance without trying to distinguish between committed and			

Q18			
Commenter	**Yes**	**No**	**Comment**
proposed projects. **R2.7.1.** ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. **R2.7.2.** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1. **R2.7.3.** ~~Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~ **R2.7.4.** ~~Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~			
AECI	☑		However, the question as to what is considered committed versus proposed. There are variuos step in the approval process for our company and we are not sure which approval would be considered committed.
AEP		☑	Consider adding clear definition of "proposed" and "committed" projects (definition may impact response to this question).
Allegheny Power	☑		There needs to be a clear definition developed for committed and proposed projects and those definitions need to be included in the definition section of the standard.
APPA	☑		While it is good to know the difference, it should be made clear in the Standard that if a project is listed as committed, it may be changed the next year to proposed project. Definitions for "committed" and "proposed" are needed to ensure consistent data/assumptions within each region.
BPA		☑	Support comments submitted by WECC. Also, one reason not to differentiate between committed and proposed projects is that regardless of whether a project is committed or not in a future case, the committment to implement a Corrective Action Plan becomes mandatory as time moves closer to the need date due to required system performance.
WECC TSGT TEP		☑	The definition of these terms can be vastly different across all TPs. How would this be effectively monitored for compliance with such different definitions? Also, each TO's criteria to go from a proposed project to a committed project can change over time due to other needs and requirements.
Central Maine Power National Grid New England ISO NU NPCC RCS NSTAR	☑		They should be viewed differently in the Near-Term. However, these should be defined terms.

Q18			
Commenter	**Yes**	**No**	**Comment**
United Illuminating			
City Utilities/Springfield	☑		Definitions of both “committed” and “proposed” are needed.
City Water Power and Light	☑		"Committed" and "proposed" projects need to be defined.
CPS Energy		☑	The treatment of each project should be at the dscretion of the Transmission Planners.
Duke Energy		☑	Even committed projects may not be built due to a variety of circumstances. Either type of project can be deferred or cancelled for a variety of reasons, including circumstances beyond the transmission planner's control.
Entergy	☑		Committed projects should be tested for effectiveness, however, the effectiveness of Proposed projects, as they are subject to change, should not require the same level of documentation as committed projects.
Georgia Transm.	☑		They are inherently treated differently. "Committed" projects are a part of the base assumptions in the base case, while "proposed" projects are evaluated until a point where corporate commitment has been made.
HQTE	☑		They should be viewed differently in the Near-Term.
E ON US		☑	MISO has spent years on trying to make a distinction. If this remains, then "Committed Project" must be defined.
ERCOT ISO CAISO		☑	The definition of "committed" projects varies from TP to TP. Also projects that are proposed today become committed in the planning horizon. Similarly, committed projects drop out due to variety of reasons. In terms of system studies, both committed and proposed projects are modeled and evaluated in the same system. How do we distinguish between the two?
FirstEnergy		☑	Unless there is an industry agreed upon distinction and definition between "committed" and "proposed" projects, we do not agree that they should be introduced in this standard.
FPL FRCC		☑	All projects should be called "Planned" projects. There is no distinction in a model between committed and proposed projects that would treat them differently. They are either in the model or not in the model. This sub-requirement does not follow the major requirement wording in R2.7 ".....Such plans shall:" The intent of Requirements R2.7.3 and R2.7.4 should be combined and added into R2.7.1.1. Rather than adding the addtional requirement to document a criteria, the requirement should be that in the Near-Term Planning Horizon, projects cannot be removed (or modified) without demonstrating that the revised plan meets performance criteria. Suggested wording for R2.7.1.1. “Transmission and generation improvement projects for the Near-Term Transmission Planning Horizon, shall have in-service dates provided (to whom?), and shall not have in-service dates changed, or be removed from planning models, without documentation to show that the revised plan meets performance requirements.”
IESO	☑	☑	Yes, the distinction should be made as committed projects have a higher degree of certainty to be available for the period under study, whereas a proposed project is one that is supported by the

Q18			
Commenter	**Yes**	**No**	**Comment**
			assessment but the commitment to proceed is not yet secured. However, we do not see the need (a) to establish criteria for committed projects and proposed projects, and (b) to distinguish between the criteria between them. If the standard should require a TP to assess both scenarios - with and without proposed projects, then this should be clearly stipulated.
ITC		☑	All projects should naturally become committed projects at some point prior to the need date. The time frame should be dependant on the scale and voltage class of the project.
LADWP		☑	Seems like every company would have its own definition of committed vs propsoed project.
Manitoba Hydro	☑		However, since each planner is allowed to define the criteria, there will be no consistency as to what is included in the base case models.
NCEMC	☑		Projects that are underway (i.e. being built) and are not subject to be potentially delayed and are absolutely needed for reliability should be differentiated between those that are not. Perhaps definitions for each of these terms should be considered for clarification.
NERC TIS	☑	☑	No concensus in TIS after extensive disucussion, but it will be discussed further.
Northwestern Energy		☑	No, there are no clear guidelines on how to make this distinction.
PJM	☑	☑	We agree that there needs to be a differentiation between committed and proposed projects. Proposed projects, particularly generation interconnections and their associated network upgrades need to be identified as a group so that they can be removed from cases if the proposed generation interconnection does not move forward.
Progress–Carolinas		☑	Are projects are proposed until they are completed.
Progress–Florida		☑	This differentiation is meaningless when modeling projects in cases for planning analysis. The standard should instead set criteria for when models can be relied upon for planning purposes such that changes to the future plan will not have an impact on reliability.
Seattle City		☑	Since compliance with performance guidelines is mandated, aren't all projects defined in the corrective action plans "committed" projects? Proposed projects in the context of Requirement 2.7 should only exist in the studies to determine which remedial solution(s) comprise the Corrective Action Plan.
Southern Transm.		☑	This requirement does not appear to have any major benefit, particularly coupled with R2.7.4 discussed in Q19. The standards require that an assessment be done every year and that the system must meet performance requirements or a Corrective Action Plan be developed. Therefore, if a project has been previously specified as a "committed" project, removing it and or replacing it with something else must also meet performance requirements under this standard or a violation occurs. Also, this performance of the system with the "committed" Corrective Action Plan" removed or modified must be documented. Therefore, requirement R2.7.4 is automatically met and is superfluous in the standard and should be removed. There is no benefit from the distinction between a project definition of "committed" and "proposed".
WPS	☑	☑	If the standard makes a differentiation between "committed" and "proposed" projects, definitions for

Q18			
Commenter	**Yes**	**No**	**Comment**
			each, within the standard itself, are necessary. Within the context of R2.7, it is not clear what impact the differentiation between "committed" and "proposed" has on the requirement itself. R2.7 requires Corrective Action Plans to address deficiencies within the performance analysis of the events in Table 1 and Table 2. A fundamental underpinning of R2.7 should be that Corrective Action Plans are developed consistent with the transmission planning principles of Order 890.
Response: The SDT agrees that if the standard is going to include "committed" and "proposed", they will need to be defined. However, the SDT agrees that it will be very difficult to develop definitions of "committed" and "proposed" that are applicable for the entire NERC footprint. Therefore, the SDT has modified Requirement R2.7.1 and deleted the original Requirement R2.7.2 through Requirement R2.7.4 to reflect "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. **R2.7.1.** ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. **R2.7.2.** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1. **R2.7.3.** ~~Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~ **R2.7.4**. ~~Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~			
MEAG Power		☑	The goal is to meet the system performance requirements outlined in the standard. Whether a project is proposed or committed is not relevant.
Santee Cooper SERC EC PSS SERC RRS OPS SCE&G		☑	The goal is to meet the system performance requirements outlined in the standard. Whether a project is proposed or committed is irrelevant. R2.7.3 should be deleted.
Response: The SDT agrees with your comment and has modified Requirement R2.7.1 and deleted the original Requirements R2.7.2 through R2.7.4 to reflect "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. **R2.7.1.** ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.			

Q18			
Commenter	**Yes**	**No**	**Comment**
R2.7.2. ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1. **R2.7.3.** ~~Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~ **R2.7.4**. ~~Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~			
ABB	☑		Yes, it helps when considering other issues in the same area. You would know whether or not you can count on a project going in.
AECC	☑		not only should a distinction be made but committed projects should be further classified as committed and under construction. There is a difference between a project be committed and actually being built. This difference can be many years. It would also be nice to know projects that are in the conceptual stage. This allow other stakeholders to share their thoughts and collaborate on projects of mutual interest before a project reaches the committed stage. Once a project is committed it is very difficult to make modifications.
ATC	☑		
BCTC	☑		
Dominion	☑		
Entegra	☑		
Exelon	☑		
KCPL	☑		
LCRA	☑		
MISO	☑		
MRO	☑		
Muscatine P&W	☑		
New York ISO	☑		NYISO Agrees
ReliabilityFirst	☑		
SaskPower	☑		
Tenaska	☑		
TVA	☑		

Q18			
Commenter	Yes	No	Comment
Response: Thank you but due to the majority of industry response to this question, the requirements have been changed as indicated in the summary.			

19) Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Summary Response: Commenters generally agreed that "committed" plans are difficult to define and may have a different meaning for many entities. In addition, even considering the generally accepted understanding of what "committed" plans means would still lead to the fact that such plans could change up until the plan is actually implemented. Therefore the SDT has modified Requirement R2.7.1 and deleted the original Requirement R2.7.2 through Requirement R2.7.4 to require only the Corrective Action Plan and goes on to state what is intended by the word "actions".

The following requirements were changed due to industry comments:

R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.
R2.7.2. ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.
R2.7.3. ~~Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~
R2.7.4. ~~Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~

Q19			
Commenter	**Yes**	**No**	**Comment**
Ameren		☑	As stated above, we are not sure why there is a need to develop or maintain information on committed projects. This tracking is not required in the existing TPL standards. As long as the revised corrective action plan meets the reliability performance requirements, what difference does it make if a committed project is cancelled or changed to a proposed project from a compliance perspective? We need to keep compliance requirements separate from administrative data requests or survey responses.

Response: The SDT agrees with your comment and has modified Requirement R2.7.1 and deleted the original Requirement R2.7.2 through Requirement R2.7.4 to require only the Corrective Action Plan and indicates what is intended by the word "actions". The SDT feels that documenting the assessment and making it available to others will by its very nature provide all the information necessary to understand which plans changed and the basis for the new plans.

R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating~~

Q19			
Commenter	**Yes**	**No**	**Comment**
~~Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. **R2.7.2.** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1. **R2.7.3.** ~~Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~ **R2.7.4.** ~~Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~			
Brazos Electric		☑	This seems like more documention is needed however if the new CAP analysis will suffice for documentation regarding removal of the 'committed project' then this is acceptable. However, that kind of makes having such a thing as a 'committed project' fairly useless if you can change it. This appears to just be more unnecessary documention.
Dominion		☑	We are of the opinion that committed projects could be removed without documentation. Once a project is removed, the next set of studies will show the deficiencies, if any.
Response: The SDT agrees with your comment that "committed" plans can change. The SDT has modified Requirement R2.7.1 and deleted the original Requirement R2.7.2 through Requirement R2.7.4 to require only the Corrective Action Plan and indicates what is intended by the word "actions". The SDT feels that documenting the assessment and making it available to others will by its very nature provide all the information necessary to understand which plans changed and the basis for the new plans. **R2.7.1.** ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. **R2.7.2.** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1. **R2.7.3.** ~~Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~ **R2.7.4.** ~~Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~			
E ON US		☑	Our planning process includes documentation of the need, acceleration, delay, or elimination of all projects. As worded, I do not need to document the delay of a Committed project.
Northwestern Energy		☑	Same problem as Q18; but it isn't clear what level of documentation is needed.
BPA		☑	See response to Q18.

Q19			
Commenter	**Yes**	**No**	**Comment**
CenterPoint		☑	This is overly prescriptive. Allow each Transmission Planner to determine the best way to handle planned projects.
CPS Energy		☑	The treatment of each project should be at the discretion of the Transmission Planners.
Duke Energy		☑	The annual assessment will show that the revised plan meets performance requirements.
FirstEnergy		☑	Unless there is an industry agreed upon distinction and definition between "committed" and "proposed" projects, we do not agree that they should be introduced in this standard.
Georgia Transm.		☑	See responses to Q17 and Q18.
KCPL		☑	Corrective Action Plans must demonstrate performance based on the expected system configuration. Committed projects can be changed or discontinued before completion.
LADWP		☑	All this does is create more bureaucratic tracking and paper pushing. People probably won't classify anything as committed until concrete has been poured just so not to have to deal with all these paperwork.
Manitoba Hydro		☑	The standard does not allow any time to develop a corrective plan through an open and transparent process. Based on the NERC definition, a Corrective Action Plan is the list of actions and an associated timetable for implementation to remedy a specific problem. A Corrective Action Plan could mean that load forecasts at the station will be verified, facility ratings verified and alternatives to fix the identified problem to be determined before the next Planning Assessment. This standard seems to be mixing the idea of a Corrective Action Plan with the original TPL idea of determining corrective plans to achieve required performance. A corrective plan wil be the end goal of a Corrective Action Plan.
MEAG Power		☑	See response to Q18.
MISO			The current Corrective Action Plan should show the performance of the system with the best information available. These Plans will change year by year as conditions change and new information becomes available. Requiring that Plan projects from previous years may not be modified "without documentation" adds a additional unneeded paperwork.
MRO		☑	The MRO disagrees with this requirement. This is an unnecessary requirement since each year Corrective Action Plans must meet the system performance requirements.
Santee Cooper SERC EC PSS SERC RRC OPS SCE&G		☑	The goal is to meet the system performance requirements outlined in the standard. Whether a project is proposed or committed is irrelevant. R2.7.4 should be deleted.
Southern Transm.		☑	See comments for Q18. [This requirement does not appear to have any major benefit, particularly coupled with R2.7.4 discussed in Q19. The standards require that an assessment be done every year and that the system must meet performance requirements or a Corrective Action Plan be developed. Therefore, if a project has been previously specified as a "committed" project, removing it and or replacing it with something else must also meet performance requirements under this

Q19			
Commenter	**Yes**	**No**	**Comment**
			standard or a violation occurs. Also, this performance of the system with the "committed" Corrective Action Plan" removed or modified must be documented. Therefore, requirement R2.7.4 is automatically met and is superfluous in the standard and should be removed. There is no benefit from the distinction between a project definition of "committed" and "proposed".]
Tenaska		☑	Add after the word "requirements" the following: "without the committed projects."
TSGT		☑	R2.7.4 calls for change monitoring. If documentation of changes is required, just say so. Do not restrict changes.
WECC TEP		☑	The requirement is similar to the question posed in Question 17. What is the documentation that proves this is needed?
SaskPower		☑	
BCTC	☑	☑	We have a larger concern. If a project is Committed and is proceeding with construction, why would a transmission planner not consider this is in planning studies. Showing that a committed project is not needed and removing it from the plans, does not necessarily remove it from the future system. In addition to showing that the revised plan meets the performance requirements, the planner needs to include documentation to show that the Committed project has been cancelled.
IESO	☑	☑	We agree that committed projects should not be removed from the revised plan. But we question the need for this sub-requirement which calls for: "Revisions to the Corrective Action Plans are allowed over time but shall meet the performance requirements.." Committed projects are normally included in the planning studies for which the performance is assessed. Deficiency, if identified, will have a corrective plans developed. We do not understand the need to remove or revise the committed plan in this context.
NERC TIS	☑	☑	Any revision to the Corrective Action Plan should be tested to ensure that the revised plan meets the precribed performance requirements. Documentation of that testing is appropriate.
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating	☑		It is unclear as to what the commited project is being removed from. Suggested language "…removed from the plan…".
ERCOT ISO CAISO	☑		We agree that committed projects should not be removed from the revised plan. These are supposed to be included in the planning studies which determine the system performance in the first place. The definition of "committed" projects varies from TP to TP so this would require a standard definition.

Q19			
Commenter	**Yes**	**No**	**Comment**
Seattle City	☑		To agree with the comment in Q18, the requirement should read "Corrective Action Plans shall not be modified without documentation to show that the revised plan meets the performance requirements."

Response: Based on your comment and the comment of others that state that "committed" plans could change up until the plan is exercised, the SDT has modified Requirement R2.7.1 and deleted the original Requirement R2.7.2 through Requirement R2.7.4 to require only the Corrective Action Plan and indicates what is intended by the word "actions". The SDT feels that documenting the assessment and making it available to others will by its very nature provide all the information necessary to understand which plans changed and the basis for the new plans.

R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.
R2.7.2. ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.
R2.7.3. ~~Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~
R2.7.4. ~~Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~

FPL		☑	All projects should be called "Planned" projects. Additionally, see response to question 18.
FRCC		☑	See response to question 18.

Response: Although the comment suggests referring to all plans as "planned", the comment of others that stated that "committed" plans ("planned" in your case) could change up until the plan is exercised; the SDT has modified Requirement R2.7.1 and deleted the original Requirement R2.7.2 through Requirement R2.7.4 to require only the Corrective Action Plan and indicates what is intended by the word "actions". The SDT feels that documenting the assessment and making it available to others will by its very nature provide all the information necessary to understand which plans changed and the basis for the new plans.

R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.
R2.7.2. ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list

Q19			
Commenter	**Yes**	**No**	**Comment**
of actions developed in accordance with Requirement R2.7.1. **R2.7.3.** ~~Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~ **R2.7.4.** ~~Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~			
ABB	☑		It's kind of obvious. If you require a solution to begin with, then if that solution is removed, another solution must be planned. However, if the removed project is not directly related to the study or problem at hand, then engineering judgment will be needed as to whether or not to repeat the study.
AECC	☑		It should also show the justification for the revision. This is especially true if transmission service is going to be sold using models that contain committed projects. If a plan is revised I would hope the revision would meet the performance requirements better than the project it replaces.
AECI	☑		
Allegheny Power	☑		
AEP	☑		
APPA	☑		It may be necessary, as a band-aid-type substitute, to replace a committed project with a Remedial Action Scheme (RAS)/Special Protection Systems in lieu of new facilities. Whatever the revised plan, it must be shown to meet the performance requirements.
ATC	☑		
City Water Power and Light	☑		
City Utilities/Springfield	☑		
Entegra	☑		
Entergy	☑		
Exelon	☑		
ITC	☑		We agree.
LCRA	☑		
Muscatine P&W	☑		
New York ISO	☑		NYISO Agrees
NCEMC	☑		
PJM	☑		
Progress–Carolinas	☑		We always should be able to show that we meet performance requirements.

Q19			
Commenter	**Yes**	**No**	**Comment**
Progress–Florida	☑		
TVA	☑		
WPS	☑		As stated in response to Q18, it is unclear why the differentiation between "committed" and "proposed" is actually necessary. The standard must allow flexibility, so that the evolution of a Corrective Action Plan can occur within the context of the transmission planning principles of FERC Order 890.
Response: Thank you but due to the majority of industry response to this question, the requirements have been changed			

D) Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

20) Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV

Summary Response: The SDT has considered industry comments and has incorporated changes in the definition of Consequential Load Loss. The SDT has also revised Tables 1 & 2 to add greater detail and provide for more situations where it is acceptable to lose Non-Consequential Load. However, the SDT did not feel that any change needed to be made to this requirement. Note: P2-1 from the original draft is now P2-2 in the revision.

Many of the responders have asked the question why the distinction for bus sections above 300 kV. The SDT has prepared the following response.

The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission Systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT believed the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated above 300 kV generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers where the energy is then delivered by other Transmission or sub-Transmission Systems to end-use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability.

When EHV Systems are compromised, the large volumes of power they serve can place a severe amount of stress on parallel EHV or lower voltage paths. For example, if a large EHV transformer experiences a catastrophic failure, not only are other systems Facilities required to carry more Load but the System is also exposed to other N-1 conditions for long periods of time while awaiting a replacement or repair of the failed equipment. Large generation sources are typically connected at EHV levels and maintenance of the EHV transmission lines within the vicinity of large generation plants must often be coordinated during scheduled unit outages, resulting again in multiple Facility outages over extended periods of time.

Therefore, it was the conclusion of the SDT in Draft 1 to propose greater reliability and operational flexibility through more stringent performance requirements when considering certain N-1 and N-1-1 Contingency events of EHV Systems. Throughout the industry, substation arrangements at EHV levels reflect the importance of these systems as the designs often consist of the more flexible and reliable ring-bus, breaker-and–a-half or double bus-double breaker protection schemes as compared to the simpler, lower cost single bus arrangements that are commonly found on lower voltage systems.

The feedback received from the industry was divided related to the SDT's emphasis placed on a higher expectation for the 300 kV and higher systems. Some commenters questioned the importance and the high costs that may be needed to mitigate existing system designs. Others agreed with the SDT's approach and indicated that the impact to their systems would be minimal. Some commenters even questioned why the more stringent approach was not applied to the entire 100 kV and higher systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission System.

Q20			
Commenter	**Agree**	**Disagree**	**Comment**
ABB			Loss of load is not usually considered by tranmission planners. In power flow studies, they look at flows and voltages versus limits. In stability studies, they are looking for angles, speeds, and voltages that stabilize at good values, possibly with temporary excursions less than some limits. How should all these be converted to a loss of load value? Normally we ensure no loss of load <because> we meet thermal, voltage, and stability requirements. Maybe you are saying that planners should not use load tripping as a solution for these violations?
Response: Tripping of Load can be used as an operating tool to maintain or restore a System to acceptable performance. The standard needs to quantify whether this action is acceptable from a planning perspective and, if so, then it needs to quantify the acceptable situations and limits. This second draft is proposing that no Non-Consequential Load may be tripped for the loss of a 300 kV (or higher) bus section for a first contingency event. (See Table 1)			
LADWP			There is a fundamental fatal flaw in having different reliability requirements using an arbitrary separation of the connected bulk electrical systems into above 300kV and below 300kV. The standard should be re-draft without this separation and comments be solicited at that time. These questions are fundamentally unfair without first settling whether or not it is wise to arbitrary separate the bulk system into two different classes. This is like asking someone "Did you hit your spouse today?"
Response: Draft 2 has been modified for 300 kV and higher systems regarding N-1-1 conditions: Based on industry feedback the SDT has made changes in proposed Draft 2 requirements related to two independent overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. Draft 2 now permits the loss of Non-Consequential Load to meet the Transmission performance requirements for these types of events. Please refer to performance tables Planning Event P6. It is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission for the less probable, but greater risk single Contingency events. Please refer to performance tables Planning Event P2 and note that bus section faults and internal breaker faults (non-bus tie) associated with above 300 kV Facilities are held to a higher performance standard than those operated at 300 kV or below. Please see also summary response.			
Muscatine P&W			See Q43 Comment #5.
Response: See Q43 response.			
Dominion		☑	Usually, this type of outage will not involve non-consequential load loss,

Q20			
Commenter	**Agree**	**Disagree**	**Comment**
			however, there may be specific situations where local non-consequential load loss could be justified. This is consistent with how transmission systems have been designed for many years and approved by State commissions. Transmission Owners need to have some flexibility to balance grid reliability vs. cost to the ratepayer. In some instances, the expense required to eliminate all local non-consequential load loss cannot always be justified if there is no significant improvement in wide area bulk power system reliability. In other words, making the standards more stringent by "raising the bar" is not going to result in a dramatic improvement in system reliability. Even the best designed systems are susceptible to human error. Dominion has at least 5 years of transmission outage data clearly illustrating that any resulting loss of load (both consequential and non-consequential) has had an average duration of only 4-7 customer-minutes per year. Going forward, the emphasis and focus should be on planning and operating the bulk electric system so as to confine any transmission outages to the immediate, local area, and not allow the cascading of outages beyond control area boundaries.
Response: The SDT agrees that typically systems are designed such that Non-Consequential Load won't be lost, which should minimize the exposure to non-compliance for most companies. The SDT agrees that the focus of the standard needs to be on network performance and has added greater detail to Tables 1 & 2 which address the comment. The standard is a planning document; so although the SDT agrees that operating the BES is an important issue, it is not the focus of this standard.			
Northwestern Energy		☑	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
Response: Consequential and Non-Consequential Load Loss involves Transmission System actions not customer equipment response to system performance, which in some cases may be within a tolerable system bandwidth, but not within the customer set points. The standard anticipates that the system will be designed to meet the expected Load, which implies that customer tripping of its own Load should not be the focus in planning studies. This has been addressed in the definition of Consequential Load Loss.			
BCTC		☑	Do not agree based on SDT definition for Consequential and Non-Consequential Load Loss. Will agree subject to proposed revisions to definitions of Consequential and Non-Consequential Load loss.
Response: The SDT has considered industry comments and has incorporated changes in the definition of Consequential Load Loss which should address your concerns.			
CAISO		☑	Loss of bus section is Category C for which the current NERC criteria allows controlled loss of load. The NERC system has been designed with this criteria. To create a more stringent standard would require to build hundreds of miles of new transmission lines to bring the existing system to NERC compliance. What are the potential benefits of this stringent criteria? Also, what is the

Q20			
Commenter	**Agree**	**Disagree**	**Comment**
			reasoning behind selecting 300 kV as a cut off level?
Tenaska		☑	May need to consider using 500 kV as some transmission providers serve load off of the 345 kV system which could be triggered by this event.
Response: It is not clear if the comment is referring to Consequential or Non-Consequential Load, but greater detail has been added to Tables 1 & 2, which should address your comment.			
Exelon	☑	☑	We do not agree with disallowing non-consequential load loss for these scenarios for the peak load conditions. These are very low probability contingencies, and some non-consequential load loss should be allowed at peak load. We would agree that it would be reasonable to dis-allow non-consequential load loss for these contingencies at a lower load level, such as 75% of peak load.
MEAG Power		☑	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
FPL FRCC		☑	This loss is currently distinguished from other single contingencies because of its lower probability of occurrence and a more stringent performance requirement than currently exists is not warranted.
MRO		☑	This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this change to customers. Alternatively, the SDT should define a level (such as 1000 MW) of non-consequential load that is acceptable for such low probability events.
Progress–Florida		☑	This single contingency event has a very low probability of occurrence, and thus a more stringent performance requirement than currently exists is not warranted.
NCEMC	☑		Although this is a relatively low probability event, we do agree that it should be assessed given the widespread effects. It may not justify the need for a network upgrade but at least deserves consideration for an operating or corrective action procedure should the event occur. Also, given this analysis might be new for some TPs, consideration should be given to a transition period after the start of this type of assessment.
Santee Cooper		☑	We do not agree with the concept of non-consequential load loss. To maintain system reliability, the disconnect of any load should be allowed.
SCE&G		☑	SCE&G does not agree with the concept of non-consequential load loss. To maintain system reliability, the disconnect of any load should be allowed. If not allowed, unprecedented new transmission costs will be required. These costs will be for local area improvements and will NOT result in increased

Q20			
Commenter	**Agree**	**Disagree**	**Comment**
			transfer capabilities for markets.
SaskPower		☑	The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
SERC EC DRS SERC EC PSS SERC RRS OPS		☑	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Southern Transm.		☑	By not allowing non-consequential load loss, utilities will incur significant expenditures. The marginal increase in reliability for this low probability event does not justify the huge costs involved.
Response: To address your concern, the SDT will consider a transition policy as part of the implementation plan to allow for Transmission Owners to respond to requirements that involve raising the bar. The implementation plan will be developed for a subsequent posting. As a first step the SDT has added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose non-consequential load.			
TEP		☑	R1 and R2 address some Load Forecast issues, but are not exhaustive specifications of what Load Forecast range to use in studies. There needs to be some mention of exceedance probability (ExPr) in Load Forecast criteria. For example, we use a forecast with a low ExPr in our studies because we are concerned that, if the system was planned for 50% ExPr (a lower forecast), actual deviation from that forecast might result in load at certain locations exceeding operating margins built into the interconnected transmission system designed to serve only the 50% ExPr forecast load. Load Specifications in R2.4 are ambiguous for the reasons stated above. Maximum study ages in R2.6.1 and R2.6.2 seem arbitrary. The time limit does not seem to add anything to the criteria if no material changes have occurred. If spot checks of the most critical areas indicated no criteria violations, there should be no reason to rerun studies. To correct this problem, we suggest using the term "assessment" rather than "study". For most people, "study" implies detailed modeling and simulation analyses summarized in a report, whereas "assessment" implies a reasonable, systematic evaluation of a system which does not necessarily include detailed analysis for the entire system.
Response: The SDT has made several changes to the referenced sections. The SDT agrees that "assessment" and "study" have different implications and reflected that in this revision.			
WECC BPA TSGT		☑	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with

Q20			
Commenter	**Agree**	**Disagree**	**Comment**
			the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Response: It is not clear if the comment is referring to consequential or non-consequential load, but greater detail has been added to Tables 1 & 2, which provides for more situations where it is acceptable to lose load and may address part of the comment. The following response is provided to the issue raised relative to the 300 kV cut-off. Draft 2 Changes for 300 kV and higher systems regarding N-1-1 conditions**:** Based on industry feedback the SDT has made changes in proposed Draft 2 requirements related to two independent overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. Draft 2 now permits the loss of Non-Consequential Load to meet the Transmission performance requirements for these types of events. Please refer to performance tables Planning Event P6. It is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission for the less probable, but greater risk single Contingency events. Please refer to performance tables Planning Event P2 and note that bus section faults and internal breaker faults (non-bus tie) associated with above 300 kV facilities are held to a higher performance standard than those operated at 300 kV or below. Please see also summary response.			
WPS		☑	It is not clear why the standard has established 300 kV as the differentiation point between allowing non-consequential load loss and not allowing it. The standard has established different planning requirements for different voltage levels without establishing why the differentiation is necessary. While transmission facilities over 300 kV in some areas of the country may be considered the "backbone", it is not universally applicable; in some areas, 230 kV and even 138 kV represent the "backbone" of the transmission system. The standard should not bisect the transmission system and apply two different planning requirements without clearly establishing why the differentiation is necessary.

Q20			
Commenter	**Agree**	**Disagree**	**Comment**
			Additionally, Table 1 needs to clarify the use of the term "Firm Transfers" and the interruption of "Firm Transfers" as an acceptable response to an event. "Firm transfers" is not a standard transmission service offering under the ProForma OATT. The standard must be consistent with service types defined under the ProForma OATT. Suggest that the phrasse "Firm Transfers" be replaced with "Firm Transmission Service consisting of Point-to-Point and Network Integration Transmission Service"
Response: The following response is provided to the issue raised relative to the 300 kV cut-off. Draft 2 Changes for 300 kV and higher systems regarding N-1-1 conditions**:** Based on industry feedback the SDT has made changes in proposed Draft 2 requirements related to two independent overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. Draft 2 now permits the loss of Non-Consequential Load to meet the Transmission performance requirements for these types of events. Please refer to performance tables Planning Event P6. It is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission for the less probable, but greater risk single Contingency events. Please refer to performance tables Planning Event P2 and note that bus section faults and internal breaker faults (non-bus tie) associated with above 300 kV facilities are held to a higher performance standard than those operated at 300 kV or below. Please see also summary response. With regards to 'Firm Transfers', 'Firm Transmission Service' is now referenced in the Tables.			
Entergy	☑		Table 1 does not specify "SLG"
PJM	☑		Should be a 3 phase fault not a single line to ground fault.
Response: The tables have been revised and Table 2 differentiates between SLG and 3 phase faults.			
HQTE	☑		The term "bus section" needs to be clarified. Some examples should be given showing actual diagram of substation layout.
Response: The SDT discussed the definition of a 'bus section', but elected not to include a definition or examples in the standard.			
ITC	☑		Should also consider no or limited loss of load for facilities 100 kV and above.
Response: ITC may elect to apply the greater than 300 kV requirement to Facilities greater than 100kV for their own use. However, the SDT feels application to the greater than 300 kV is more appropriate for the requirements in this standard.			
Manitoba Hydro	☑		With the caveat that if the loss of load is localized, it is acceptable. Raising the bar will result in a cost increase for owners and users of the transmission system. What evidence does the SDT have to show this is justified.

Q20			
Commenter	**Agree**	**Disagree**	**Comment**
Response: The ATFNSDT has added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose load.			
AECC	☑		neither should consequential load be lost for any n-1 faults on the 300 kv system and higher.
AECI	☑		
Allegheny Power	☑		
AEP	☑		
APPA	☑		Note to APPA members – Please examine closely and give us specific comments on Q20 – Q29. If you disagree we need to know.
ATC	☑		
Ameren	☑		No significant material change identified.
CenterPoint	☑		
Central Maine Power	☑		
City Utilities/Springfield	☑		
CPS Energy	☑		
Duke Energy	☑		
Entegra	☑		
Brazos Electric	☑		
City Water Power and Light	☑		
E ON US	☑		
ERCOT ISO	☑		
FirstEnergy	☑		
Georgia Transm.	☑		No change from current standards.
IESO	☑		We agree, since the loss of a bus is a single contingency. This is a criterion already adopted by the IESO and other members in the NPCC region, for which non-consequential loss of load is not permitted.
ISO/RTO	☑		
KCPL	☑		
LCRA	☑		

Q20			
Commenter	**Agree**	**Disagree**	**Comment**
MISO	☑		No indirect (non-consequential) loss of load for single contingency events, else operator is in SOL pre-contingency without such planning.
National Grid	☑		
NERC TIS	☑		Loss of a bus section is a single contingency. Non-consequential load loss should not be allowed.
New England ISO	☑		
New York ISO	☑		
NU	☑		
NPCC RCS	☑		
Nstar	☑		
PRPA	☑		
Progress–Carolinas	☑		
Seattle City	☑		
SRP	☑		
United Illuminating	☑		
Response: Thank you.			

21) Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit

Summary Response: Based on industry feedback, the SDT has made changes in proposed Draft 2 requirements related to two independent overlapping single Contingencies (N-1-1) involving two Transmission Facilities operated at a voltage level above 300 kV. Draft 2 now permits the loss of Non-Consequential Load to meet the Transmission performance requirements for these types of events. Please refer to performance tables Planning Event P6.

It is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission for the less probable, but greater risk single Contingency events. Please refer to performance tables Planning Event P2 and note that bus section faults and internal breaker faults (non-bus tie) associated with above 300 kV Facilities are held to a higher performance standard than those operated at 300 kV or below.

Q21			
Commenter	**Agree**	**Disagree**	**Comment**
Muscatine P&W			See Q43 Comment #5.
Response: See responses for Q43.			
Ameren		☑	Load pockets supplied by a single EHV substation with only two supplies would not meet this proposed requirement, whereas the existing TPL-003-0 standard would allow the dropping of load for the multiple outage event. A significant material change to build new facilities would be needed to meet the new requirement.
AEP	☑		Consider adding clear definition of "system adjustments", including the amount of time permited to implement prior to the loss of the second facility.
CenterPoint		☑	The forced outage of two independent lines has a low probability of occurrence and should be considered an improbable event with non-consequential load loss permitted.
Central Maine Power HQTE New England ISO NU NPCC RCS NSTAR United Illuminating		☑	Given the low probability of extended overlapping outages of overhead facilities, systems have been designed assuming that load shedding following the loss of a second transmission line is permissible. Eliminating any allowance for load shedding for this condition may require significant system expansion and cost to to customers. However, it would be reasonable to consider establishing an upper bound to the amount of load that could be shed for these purposes.
E ON US		☑	Outage of two 345 kV circuits can create local area issues that result in loss of load but do not affect the integrity of the BES.
ERCOT ISO CAISO		☑	This event falls under Category C for which controlled loss of load is allowed. Clear net benefits should be demonstrated to justify adapting to a new stringent criteria.
Duke Energy		☑	Allow indirect (Non-Consequential) loss of load for events involving short duration outages, such as typical line outages that do not result in cascading outages.
Entergy		☑	N-1-1 requires an increase in investment that will place an undue cost burden on all customers for low probability events.

Q21			
Commenter	**Agree**	**Disagree**	**Comment**
			See comments to Q43.
Exelon	☑	☑	We do not agree with disallowing non-consequential load loss for these scenarios for the peak load conditions. These are very low probability contingencies, and some non-consequential load loss should be allowed at peak load. We would agree that it would be reasonable to dis-allow non-consequential load loss for these contingencies at a lower load level, such as 75% of peak load.
FirstEnergy		☑	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused soley by the first contingency.
FPL FRCC		☑	Systems have been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis. In addition, by not allowing loss of non-consequential load, the system may remain in a less secure state or condition.
Georgia Transm.		☑	This requirement appears unreasonable for a network system and, particularly, for a series of events. This requirement would be well above current reliability standards. The requirement would also result in higher investment costs for the utilities.
MISO		☑	Allow indirect (Non-Consequential) loss of load for events involving short duration outages, such as typical line outages.
MRO		☑	This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this change to customers. Alternatively, the SDT should define a level (such as 1000 MW) of non-consequential load that is acceptable for such low probability events.
Progress–Carolinas	☑		It is absolutely necessary, however, to allow interruption of firm transfers as a System adjustment. To do otherwise would cause extremely large expenditures for very low probability independent events.
Progress–Florida		☑	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration. Furthermore, the greater-than-300 kV Bulk Electric System has been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis, placing particular importance on confining the event to a single area (i.e., not resulting in a cascading outage). Past assessments as well as actual events have demonstrated that by not allowing loss of non-consequential load, the Bulk Electric System may actually remain in a less secure state or condition, i.e. in more danger of experiencing cascading outages.
Santee Cooper		☑	We do not agree with the concept of non-consequential load loss. To maintain system reliability, the disconnect of any load should be allowed. By not allowing non-consequential load loss,

Q21			
Commenter	**Agree**	**Disagree**	**Comment**
			utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Seattle City		☑	Loss of two major HV elements can drive our region into undervoltage conditions, forcing us to shed non-consequential load per UVLS standard requirements. Loss of two major HV elements can drive our region into undervoltage conditions, forcing us to shed non-consequential load per UVLS standard requirements.
SERC EC DRS SERC EC PSS SERC RRS OPS SCE&G		☑	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Southern Transm.		☑	This is a very significant change in the performance requirements in this reliability standard. It involves facilities from 345 kV through 764kV which carry significant amounts of power. These also are facilities that require significant lead time to construct in the Southern Balancing Authority with estimates up to 7-10 years in the state of Georgia. If a performance problem is detected under these new requirements, it could take that long to come into compliance and at a very significant cost if a new major 500kV line is required. These facilities can run as much as $4.0 million a mile or more in urban areas. We understand that a few areas of the country presently have this requirement but most do not. In the areas where the requirement has not been in place, the reliability of the system has been acceptable to the local Public Service Commissions that have governed the service to Retail customers. There has been no evidence presented that there is a need for an increase in reliability, particulary at the extensive time delay and expense possible from this particular requirement. An adoption of this standard without such evidence can only be considered arbitrary and capricious at best. Increased reliability is, in general, a worthy goal where it is cost effective. It may be appropriate to adopt this type of reliability requirement for areas that deem the resulting reliability increase to be cost effective for their customers. But it is inappropriate to "require" everyone else to be forced to live under this arbitrarily developed expansion of reliability requirements.
TVA		☑	By not allowing non-consequential load loss, utilities will incur significant expenditures to construct a transmission solution for some extremely low probability events with low consequence. Each utility should have the flexibility to base action on probability and consequence. Load shed by UVLS or other means should remain an option to maintain reliability if probability is extremely low, but the high consequence of an event determines that a solution is necessary.
Response: The SDT has added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose load.			
Dominion		☑	See comment for Question 20 above.
Response: See response to question 20.			
Northwestern Energy		☑	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this

Q21			
Commenter	**Agree**	**Disagree**	**Comment**
			requirement and to correct it would be costly.
Response: Consequential and Non-Consequential Load Loss involves Transmission System actions not customer equipment response to system performance, which in some cases may be within a tolerable system bandwidth, but not within the customer set points. The standard anticipates that the System will be designed to meet the expected Load, which implies that customer tripping of its own Load should not be a consideration in planning studies. This has been addressed in the definition of Consequential Load Loss.			
BCTC		☑	Do not agree based on SDT definitions. Also do not agree for first outage being a forced outage. Will agree subject to above revisions to definitions of Consequential and Non-Consequential Load loss for the first outage being a planned outage but not a forced outage. To meet this requirement for forced outages, estimate that this change could cost $3 to 5 Billion.
Response: The SDT has considered industry comments and has incorporated changes in the definition of Consequential Load Loss, which should address your concerns.			
CPS Energy		☑	Should be determined at the discretion of the Transmission Planners.
Response: The standard needs to provide some consistency and needs to define the desired level of System reliability, which will provide a level playing field and will provide guidance and support for the Transmission Planners as they deal with external entities.			
MEAG Power		☑	See Q20 above.
Response: See response to question 20.			
SRP		☑	The time to adjust the system needs to be provided (when does a N-1-1 become a N-2?). If the cause of the outage is transient (temporary) the operator needs some time to test and restore the element (could be minutes up to several hours). If the element is lost indefinitly, the operator will need some minimum time to adjust the system. If this time is not available prior to the next N-1 then the standard should allow Non-Consequetial Loss of Load.
Response: The time the operators have will depend on their time dependent ratings that they have to work with. Many users have a 30 minute rating.			
SaskPower		☑	The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Response: The SDT has added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose load, which should reduce the increased cost exposure.			
Tenaska		☑	See comment in Q20.
Response: See response to question 20.			
WECC BPA TSGT TEP		☑	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance?

Q21			
Commenter	**Agree**	**Disagree**	**Comment**
			Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Response: Draft 2 Changes for 300 kV and higher systems regarding N-1-1 conditions**:** Based on industry feedback the SDT has made changes in proposed Draft 2 requirements related to two independent overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. Draft 2 now permits the loss of Non-Consequential Load to meet the Transmission performance requirements for these types of events. Please refer to performance tables Planning Event P6. It is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission for the less probable, but greater risk single Contingency events. Please refer to performance tables Planning Event P2 and note that bus section faults and internal breaker faults (non-bus tie) associated with above 300 kV facilities are held to a higher performance standard than those operated at 300 kV or below. Please see also summary response. With regards to 'Firm Transfers', 'Firm Transmission Service' is now referenced in the Tables.			
WPS		☑	See response to Q20.
Response: See response to question 20.			
IESO	☑	☑	The sequence of events is too general that under some condition, it contradicts with the loss of 2 circuits on the same tower for which non-consequential loss of load is permitted. If the sequence of events is specified such that the two transmission circuits that can be lost are unrelated, then non-consequential loss of load should generally not be allowed following system adjustments after the loss of the first transmission circuit.
Response: Thank you but due to the majority of industry response to this question, the requirement has been changed.			
ITC	☑		Should also consider no or limited loss of Non-consequential load for facilities 100 kV and above. This should be no loss for load levels where the TO would expect to perform system maintenance.
Response: ITC may elect to apply the greater than 300 kV requirement to facilities greater than 100kV for their own use. However, the ATFNSDT feels application to the greater than 300 kV is more appropriate for the requirements in this standard.			
New York ISO	☑		We are assuming the second circuit is un-related to the first. If that is not the intent then it contracts the loss of multiple related circuits (same tower or protection zone) for which non-consequential load loss is allowed.
NCEMC	☑		We do agree that given the widespread effects of these facilities above 300 kV that these should be subjected to more rigorous assessments.

Q21			
Commenter	**Agree**	**Disagree**	**Comment**
AECC	☑		neither should consequential load be lost for any n-1 faults on the 300 kv system and higher.
AECI	☑		
Allegheny Power	☑		
APPA	☑		
ATC	☑		
Brazos Electric	☑		
City Utilities/Springfield	☑		
City Water Power and Light	☑		
Entegra	☑		
ISO/RTO	☑		
KCPL	☑		
LCRA	☑		
Manitoba Hydro	☑		
National Grid	☑		
NERC TIS	☑		This becomes a differentiation between an event and a contingency - if there is time to adjust the system, it is really two events. Non-consequential load loss based on the first event is hard to fathom. Loss of load following the second event is either consequential to the second event (even if load was isolated by the first event) or non-consequential to the second event.
PJM	☑		
Response: Thank you but due to the majority of industry response to this question, the requirement has been changed			

22) Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV

Summary Response: Draft 2 Changes for 300 kV and higher systems regarding N-1-1 conditions**:**

Based on industry feedback the SDT has made changes in proposed Draft 2 requirements related to two overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. Draft 2 now permits the loss of Non-Consequential Load to meet the Transmission performance requirements for these types of events. Please refer to performance tables Planning Event P6.

It is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission for the less probable, but greater risk single Contingency events. Please refer to performance tables Planning Event P2 and note that bus section faults and internal breaker faults (non-bus tie) associated with above 300 kV facilities are held to a higher performance standard than those operated at 300 kV or below.

Why the distinction for above 300 kV Transmission?

The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission Systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT felt the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability.

When EHV systems are compromised, the large volumes of power served by them can place a severe amount of stress on parallel EHV or lower voltage paths. For example, if a large EHV transformer experiences a catastrophic failure, not only are other systems Facilities required to carry more load but the system is also exposed to other N-1 conditions for long periods of time while awaiting a replacement or repair of the failed equipment. Large generation sources are typically connected at EHV levels and maintenance of the EHV Transmission lines within the vicinity of larges generation plants must often be coordinated during scheduled unit outages, resulting again in multiple Facility outages over extended periods of time.

Therefore, it was the conclusion of the SDT in Draft 1 to propose greater reliability and operational flexibility through more stringent performance requirements when considering certain N-1 and N-1-1 Contingency events of EHV systems. Throughout the industry substation arrangements at EHV levels reflect the importance of these systems as the designs often consist of the more expensive ring-bus, breaker-and –a-half or double bus-double breaker protection schemes as opposed to the more simplistic and lesser cost single bus arrangements that are commonly found on lower voltage systems.

The feedback received from industry was divided related to SDT's emphasis placed on a higher expectation for the 300 kV and higher systems. Some commenter's questioned the importance and the high costs that may be needed to mitigate existing system designs.

Others agreed with the SDT's approach and indicated that the impact to their systems would be minimal. Some commenter's even questioned why the more stringent approach was not applied to the entire 100kV and higher systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV transmission system.

Q22			
Commenter	**Agree**	**Disagree**	**Comment**
Muscatine P&W			See Q43 Comment #5.
Response: See Q43 response.			
Dominion		☑	See comment for Question 20 above.
MEAG Power		☑	See Q20 above.
Tenaska		☑	See comment in Q20.
TVA		☑	See Q20.
WPS		☑	See response to Q20.
Response: See response to Q20.			
E ON US		☑	Outage of two 345 kV circuit and a transformer can create local area issues that result in loss of load but do not affect the integrity of the BES.
Response: The condition you describe appears to be more stringent then the outage the SDT was asking industry to consider; N-1-1 involving a line and transformers where each are operated at a voltage level above 300 kV. However, based on industry feedback the SDT has made changes in proposed requirements for two overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. We have adjusted our approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response area for additional information.			
Northwestern Energy		☑	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
Response: Please see the proposed Glossary Definition for Non-Consequential Load. The proposed definition for Consequential Load clarifies that losing a motor due to motor contactor action is considered to be the loss of Consequential Load.			
BCTC		☑	Same comments as for Q21. We do not foresee any cost due to this standard at this time because we do not have any transformers with low side voltage rating above 300 kV.
CAISO		☑	This event also falls under Category C for which the current NERC criteria allows controlled loss of load. Clear net benefits should be demonstrated to justify adapting to a new stringent criteria.
MRO		☑	This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this

Q22			
Commenter	**Agree**	**Disagree**	**Comment**
			change to customers. Alternatively, the SDT should define a level (such as 1000 MW) of non-consequential load that is acceptable for such low probability events.
Santee Cooper SERC EC DRS SERC EC PSS SERC RRS OPS SCE&G		☑	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
SaskPower		☑	The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Southern Transm.		☑	See comments for Q21. [This is a very significant change in the performance requirements in this reliability standard. It involves facilities from 345 kV through 764kV which carry significant amounts of power. These also are facilities that require significant lead time to construct in the Southern Balancing Authority with estimates up to 7-10 years in the state of Georgia. If a performance problem is detected under these new requirements, it could take that long to come into compliance and at a very significant cost if a new major 500kV line is required. These facilities can run as much as $4.0 million a mile or more in urban areas. We understand that a few areas of the country presently have this requirement but most do not. In the areas where the requirement has not been in place, the reliability of the system has been acceptable to the local Public Service Commissions that have governed the service to Retail customers. There has been no evidence presented that there is a need for an increase in reliability, particulary at the extensive time delay and expense possible from this particular requirement. An adoption of this standard without such evidence can only be considered arbitrary and capricious at best. Increased reliability is, in general, a worthy goal where it is cost effective. It may be appropriate to adopt this type of reliability requirement for areas that deem the resulting reliability increase to be cost effective for their customers. But it is inappropriate to "require" everyone else to be forced to live under this arbitrarily developed expansion of reliability requirements.]
NCEMC	☑		We do agree that given the widespread effects of these facilities above 300 kV that these should be subjected to more rigorous assessments.
Progress–Carolinas	☑		It is absolutely necessary, however, to allow interruption of firm transfers as a System adjustment. To do otherwise would cause extremely large expenditures for very low probability independent events.
WECC BPA TSGT TEP		☑	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance?

Q22			
Commenter	**Agree**	**Disagree**	**Comment**
			Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Response: Based on industry feedback the SDT has made changes in proposed requirements for two overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. We have adjusted our approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
Central Maine Power United Illuminating		☑	Should also consider the initial loss of a transformer, followed by the loss of a Transmission circuit. This should state a transformer with a "high-side" rating above 300 kV.
Response: The SDT agrees that it previously missed the situation described and have accounted for this sequence of events in our new Planning Event P6. Also, notes have been added to the bottom of the performance table to clarify the EHV transformer versus other BES transformers.			
Duke Energy		☑	Allow indirect (Non-Consequential) loss of load for events involving short duration outages, such as typical line outages that do not result in cascading outages.
Response: The specific outage considered involves a circuit and a transformer. An unplanned EHV transformer outage will likely be a long duration outage that needs to be reviewed with other N-1 events and should require a higher level of expected reliability. However, based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. We have adjusted our approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
Entergy		☑	N-1-1 requires an increase in investment that will place an undue cost burden on all customers for low probability events. See comments to Q43.
Response: Your concern related to increased cost is shared with others. Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. We have adjusted our approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information. See response to Q43.			
FirstEnergy		☑	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused soley by the first contingency.
Response: The SDT appreciates your support that Non-Consequential Load dropping would not be permissible following the first Contingency event. However, from a planning viewpoint, the SDT also believes that it should not be permissible to drop Load as part of adjusting the System to prepare for the second on the EHV System. The FERC directed this approach in Order 693, see discussion in paragraphs 1782 and			

Q22			
Commenter	**Agree**	**Disagree**	**Comment**
1796. Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. We have adjusted our approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
FPL FRCC		☑	Systems have been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis. In addition, by not allowing loss of non-consequential load, the system may remain in a less secure state or condition.
Progress–Florida		☑	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration. Furthermore, the greater-than-300 kV Bulk Electric System has been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis, placing particular importance on confining the event to a single area (i.e., not resulting in a cascading outage). Past assessments as well as actual events have demonstrated that by not allowing loss of non-consequential load, the Bulk Electric System may actually remain in a less secure state or condition, i.e. in more danger of experiencing cascading outages.
Response: The events considered are not simultaneous N-2, but intended to be N-1-1 with system adjustments allowed in between the outages. Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. We have adjusted our approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
NERC TIS	☑		See Q 21 Comment
New York ISO	☑		Same comment as with Q21.
SRP		☑	Same as Q21.
Seattle City		☑	Same as Q21, loss of elements of this size may initiate UVLS.
Response: See response to Q21.			
Exelon	☑	☑	We do not agree with disallowing non-consequential load loss for these scenarios for the peak load conditions. These are very low probability contingencies, and some non-consequential load

Q22			
Commenter	**Agree**	**Disagree**	**Comment**
			loss should be allowed at peak load. We would agree that it would be reasonable to dis-allow non-consequential load loss for these contingencies at a lower load level, such as 75% of peak load.
Response: Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. We have adjusted our approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information. The lower (non-peak) Load study that you reference is a good suggestion that could be adopted as an internal company criteria for assessing maintenance flexibility.			
IESO	☑	☑	Similar reason as above. In this case, the first transmission may also remove a transformer from service if they are in the same protection zone. The next contingency can be the loss of the companion transformer, without a fault on the transformer itself but not on the transmission circuit. If the transmission circuit and the transformer are unrelated, then we would agree that non-consequential loss of load should not be allowed.
Response: The intent of this event is to cover two unrelated single Contingency Transmission outages that are non-generator outages. They are to be viewed as an N-1, with system adjustments, followed by the second N-1. The standard will require that Contingency events be modeled to reflect actual removal of all elements within the protection zone. Therefore a single (N-1) Contingency could result in multiple Facilities being removed from service. The N-1-1 event should accurately reflect all Facilities that would be removed from service. Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. We have adjusted our approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
ITC	☑		Should also consider no or limited loss of non-consequential load for facilities 100 kV and above. No loss should be allowed for load levels at which the TO would plan to perform maintenance. Also system adjustment should consider time required for adjustment verses the ratings utilized.
Response: Based on industry feedback, the SDT has made adjustments to the expected Transmission System performance to N-1-1 events. The entire BES is treated the same now for these outage scenarios and the loss of Non-Consequential Load is now permitted. Please refer to performance tables, Planning Event P6. See the above Summary Response for additional information.			
AEP	☑		Consider adding clear definition of "system adjustments", including the amount of time permited to implement prior to the loss of the second facility.
Response: Non-Consequential Load Loss is not permitted for the first N-1 event as part of the permissible system adjustments that can be made to return the system to a "new" normal operating state. The time permitted is based on the time dependent emergency Facility Ratings of the affected Transmission equipment. Following the loss of the second Transmission outage, Load shed is considered an allowable system			

Q22			
Commenter	**Agree**	**Disagree**	**Comment**
adjustment action for the entire BES. This is a change in Draft 2 of the TPL-001-1. Please see performance tables, Planning Event P6 for additional information.			
MISO	☑		Do not allow indirect (Non-Consequential) loss of load for events involving long duration outages, such as transformer outages. (Transformer outage could occur first).
Response: While some SDT members agree with your approach, others on the SDT do not as well many of the industry comments to our Draft 1 standard. The standard does require sensitivity studies and unavailability of long lead time Facilities to be included in the sensitivity study area. Additionally, a TO will be required to notify their PC for long-term Transmission outages with consideration to spare equipment strategy. This would result in a new initial study system (N-0) and performance requirements for other Contingencies would be required subsequent to the long-term outage item.			
National Grid New England ISO NU NPCC RCS NSTAR	☑		Should also consider the initial loss of a transformer, followed by the loss of a Transmission circuit. This should state a transformer with a "high-side" rating above 300 kV.
Response: The SDT agrees that it previously missed the situation described and have accounted for this sequence of events in new Planning Event P6. Also, notes have been added to the bottom of the performance table to clarify the EHV transformer versus other BES transformers.			
Progress–Carolinas	☑		It is absolutely necessary, however, to allow interruption of firm transfers as a System adjustment. To do otherwise would cause extremely large expenditures for very low probability independent events.
Response: The SDT has adjusted the tables in the second revision.			
Ameren			No opinion as we do not have any transformers with the low side voltages rated above 300 kV. Transmission owners with transformers meeting this requirement should be consulted to determine if a material change would be required.
ERCOT ISO			We will comment on this at a later date.
Georgia Transm.			Not applicable to our existing system.
AECC	☑		neither should consequential load be lost for any n-1 faults on the 300 kv system and higher.
AECI	☑		
Allegheny Power	☑		
APPA	☑		
ATC	☑		
Brazos Electric	☑		
City Water Power and Light	☑		
City Utilities/Springfield	☑		

Q22			
Commenter	**Agree**	**Disagree**	**Comment**
Entegra	☑		
HQTE	☑		
ISO/RTO	☑		
KCPL	☑		
LCRA	☑		
Manitoba Hydro	☑		
PJM	☑		
Response: Thank you but due to the majority of industry response to this question, the requirement has been changed			

23) Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer

Summary Response: Draft 2 Changes for 300 kV and higher systems regarding N-1-1 conditions:

Based on industry feedback the SDT has made changes in proposed Draft 2 requirements related to two independent overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. Draft 2 now permits the loss of Non-Consequential Load to meet the Transmission performance requirements for these types of events. Please refer to performance tables Planning Event P6.

It is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission for the less probable, but greater risk single Contingency events. Please refer to performance tables Planning Event P2 and note that bus section faults and internal breaker faults (non-bus tie) associated with above 300 kV Facilities are held to a higher performance standard than those operated at 300 kV or below.

Why the distinction for above 300 kV Transmission?

The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission Systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT felt the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability.

When EHV systems are compromised, the large volumes of power served by them can place a severe amount of stress on parallel EHV or lower voltage paths. For example, if a large EHV transformer experiences a catastrophic failure, not only are other systems Facilities required to carry more Load but the System is also exposed to other N-1 conditions for long periods of time while awaiting a replacement or repair of the failed equipment. Large generation sources are typically connected at EHV levels and maintenance of the EHV Transmission lines within the vicinity of larges generation plants must often be coordinated during scheduled unit outages, resulting again in multiple Facility outages over extended periods of time.

Therefore, it was the conclusion of the SDT in Draft 1 to propose greater reliability and operational flexibility through more stringent performance requirements when considering certain N-1 and N-1-1 Contingency events of EHV systems. Throughout the industry substation arrangements at EHV levels reflect the importance of these systems as the designs often consist of the more expensive ring-bus, breaker-and–a-half or double bus-double breaker protection schemes as opposed to the more simplistic and lesser cost single bus arrangements that are commonly found on lower voltage systems.

The feedback received from industry was divided related to the SDT's emphasis placed on a higher expectation for the 300 kV and higher systems. Some commenters questioned the importance and the high costs that may be needed to mitigate existing system designs.

Others agreed with the SDT's approach and indicated that the impact to their systems would be minimal. Some commenters even questioned why the more stringent approach was not applied to the entire 100kV and higher systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission system.

Q23			
Commenter	**Agree**	**Disagree**	**Comment**
Muscatine P&W			See Q43 Comment #5.
Response: See Q43 response.			
NERC TIS			See Q 21 Comment
SRP		☑	Same as Q21.
Seattle City		☑	Same as Q21.
New York ISO	☑		Same comment as with Q21.
Response: See Q21 response.			
Dominion		☑	See comment for Question 20 above.
MEAG Power		☑	See Q20 above.
Tenaska		☑	See comment in Q20.
TVA		☑	See Q20.
WPS		☑	See response to Q20.
Response: See Q20 response.			
E ON US		☑	Outage of two 345 kV transformers can create local area issues that result in loss of load but do not affect the integrity of the BES.
Response: The condition you describe appears to be more stringent then the outage the SDT was asking industry to consider; N-1-1 involving a line and transformers where each are operated at a voltage level above 300 kV. However, based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. The SDT has adjusted its approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
Northwestern Energy		☑	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
Response: Please see the proposed Glossary Definition for Non-Consequential Load. The proposed definition for Consequential Load clarifies that losing a motor due to motor contactor action is considered to be the loss of Consequential Load.			
BCTC		☑	Same comments as for Q21/22. Furthermore, a double transformer loss forced outage has a very low probability as transformers are very reliable. A more practical approach would be to

Q23			
Commenter	**Agree**	**Disagree**	**Comment**
			use single phase transfomers and provide a spare phase.
CAISO		☑	This event also falls under Category C for which the current NERC criteria allows controlled loss of load. Clear net benefits should be demonstrated to justify adapting to a new stringent criteria.
MRO		☑	This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this change to customers. Alternatively, the SDT should define a level (such as 1000 MW) of non-consequential load that is acceptable for such low probability events.
Santee Cooper SERC EC DRS SERC EC PSS SERC RRS OPS SCE&G		☑	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
SaskPower		☑	The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Southern Transm.		☑	See comments for Q21. [This is a very significant change in the performance requirements in this reliability standard. It involves facilities from 345 kV through 764kV which carry significant amounts of power. These also are facilities that require significant lead time to construct in the Southern Balancing Authority with estimates up to 7-10 years in the state of Georgia. If a performance problem is detected under these new requirements, it could take that long to come into compliance and at a very significant cost if a new major 500kV line is required. These facilities can run as much as $4.0 million a mile or more in urban areas. We understand that a few areas of the country presently have this requirement but most do not. In the areas where the requirement has not been in place, the reliability of the system has been acceptable to the local Public Service Commissions that have governed the service to Retail customers. There has been no evidence presented that there is a need for an increase in reliability, particulary at the extensive time delay and expense possible from this particular requirement. An adoption of this standard without such evidence can only be considered arbitrary and capricious at best. Increased reliability is, in general, a worthy goal where it is cost effective. It may be appropriate to adopt this type of reliability requirement for areas that deem the resulting reliability increase to be cost effective for their customers. But it is inappropriate to "require" everyone else to be forced to live under this arbitrarily developed expansion of reliability requirements.]
WECC BPA TSGT TEP		☑	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for

Q23			
Commenter	**Agree**	**Disagree**	**Comment**
			compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
ITC	☑		Should also consider no or limited loss of non-consequential load for facilities 100 kV and above. No loss should be allowed for load levels at which the TO would plan to perform maintenance. Also system adjustment should consider time required for adjust.ment verses the facility ratings utilized.
NCEMC	☑		We do agree that given the widespread effects of these facilities above 300 kV that these should be subjected to more rigorous assessments.
Progress–Carolinas	☑		It is absolutely necessary, however, to allow interruption of firm transfers as a System adjustment. To do otherwise would cause extremely large expenditures for very low probability independent events.
Response: Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. The SDT has adjusted its approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
Duke Energy		☑	Allow indirect (Non-Consequential) loss of load for events involving short duration outages that do not result in cascading outages.
Response: The specific outage considered involves a circuit and a transformer. An unplanned EHV transformer outage will likely be a long duration outage that needs to be reviewed with other N-1 events and should require a higher level of expected reliability. However, based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. The SDT has adjusted its approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
Entergy		☑	N-1-1 requires an increase in investment that will place an undue cost burden on all customers for low probability events. See comments to Q43.
Response: Your concern related to increased cost is shared with others. Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. The SDT has adjusted its approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information. See response to Q43.			
FirstEnergy		☑	Shedding load could be part of the system adjustment in preparation for the next possible

Q23			
Commenter	**Agree**	**Disagree**	**Comment**
			contingency but load drop would not be acceptable for problems caused soley by the first contingency.
Response: We appreciate your support that Non-Consequential Load dropping would not be permissible following the first Contingency event. However, from a planning viewpoint, the SDT also believes that it should not be permissible to drop Load as part of adjusting the system to prepare for the second on the EHV system. The FERC directed this approach in Order 693, see discussion in paragraphs 1782 and 1796. Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. The SDT has adjusted its approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
FPL FRCC		☑	Systems have been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis. In addition, by not allowing loss of non-consequential load, the system may remain in a less secure state or condition.
Progress–Florida		☑	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration. Furthermore, the greater-than-300 kV Bulk Electric System has been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis, placing particular importance on confining the event to a single area (i.e., not resulting in a cascading outage). Past assessments as well as actual events have demonstrated that by not allowing loss of non-consequential load, the Bulk Electric System may actually remain in a less secure state or condition, i.e. in more danger of experiencing cascading outages.
Response: The events considered are not simultaneous N-2, but intended to be N-1-1 with system adjustments allowed in between the outages. Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. The SDT has adjusted its approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
Central Maine Power National Grid New England ISO NU NSTAR		☑	This should state a transformer with a "high-side" rating above 300 kV.

Q23			
Commenter	**Agree**	**Disagree**	**Comment**
United Illuminating			
Response: The SDT agrees that it previously missed the situation described and have accounted for this sequence of events in new Planning Event P6. Also, notes have been added to the bottom of the Performance table to clarify the EHV transformer versus other BES transformers.			
Exelon	☑	☑	We do not agree with disallowing non-consequential load loss for these scenarios for the peak load conditions. These are very low probability contingencies, and some non-consequential load loss should be allowed at peak load. We would agree that it would be reasonable to dis-allow non-consequential load loss for these contingencies at a lower load level, such as 75% of peak load.
Response: Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. The SDT has adjusted its approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information. The lower (non-peak) Load study that you reference is a good suggestion that could be adopted as an internal company criterion for assessing maintenance flexibility.			
IESO	☑	☑	Similar reason as above.
Response: The intent of this event is to cover two unrelated single Contingency Transmission outages that are non-generator outages. They are to be viewed as an N-1, with system adjustments, followed by the second N-1. The standard will require that Contingency events be modeled to reflect actual removal of all elements within the protection zone. Therefore a single (N-1) Contingency could result in multiple Facilities being removed from service. The N-1-1 event should accurately reflect all Facilities that would be removed from service. Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. The SDT has adjusted its approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
AEP	☑		Consider adding clear definition of "system adjustments", including the amount of time permited to implement prior to the loss of the second facility.
Response: The time permitted is based on the time dependent emergency Facility Ratings of the affected Transmission equipment. Planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings.			
MISO	☑		Do not allow indirect (Non-Consequential) loss of load for events involving long duration outages, such as transformer outages.
Response: While some SDT members agree with your approach, others on the SDT do not as well many of the industry comments to our Draft 1 standard. The standard does require sensitivity studies and unavailability of long lead time Facilities to be included in the sensitivity study area. Additionally, a TO will be required to notify their PC for long-term Transmission outages with consideration to spare equipment strategy. This would result in a new initial study system (N-0) and performance requirements for other Contingencies would be required subsequent to the long-term outage item.			

Q23			
Commenter	**Agree**	**Disagree**	**Comment**
Ameren			No opinion as we do not have any transformers with the low side voltages rated above 300 kV. Transmission owners with transformers meeting this requirement should be consulted to determine if a material change would be required.
ERCOT ISO			We will comment on this at a later date.
AECC	☑		neither should consequential load be lost for any n-1 faults on the 300 kv system and higher.
AECI	☑		
Allegheny Power	☑		
APPA	☑		
ATC	☑		
Brazos Electric	☑		
City Water Power and Light	☑		
City Utilities/Springfield	☑		
Entegra	☑		
Georgia Transm.	☑		Not applicable to our existing system.
HQTE	☑		
ISO/RTO	☑		
KCPL	☑		
LCRA	☑		
Manitoba Hydro	☑		
NPCC RCS	☑		
PJM	☑		
Response: Thank you but due to the majority of industry response to this question, the requirement has been changed			

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

24) Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Summary Response: A majority of the commenters indicated that a definition for "bus-tie breaker" as well as clarification of the Tables is needed. Based on the comments from the industry, the drafting team has proposed a definition for bus–tie breakers, incorporated changes to the definition of Consequential Load and added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose Non-Consequential Load. However, the SDT felt that this was one situation where the bar should be raised and no change was made to this event.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)

Consequential Load Loss: Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.

Q24			
Commenter	**Agree**	**Disagree**	**Comment**
Manitoba Hydro			Until the SDT should defines a non-bus tie breaker this is impossible to answer.
ERCOT ISO CAISO		☑	Same response as for Q21, and What is the definition of non-bus tie breaker? Doesn't it just refer to line, transformer, and generation breakers?
Response: The SDT has accordingly proposed a definition for bus-tie breaker.			
Muscatine P&W			See Q43 Comment #5.
Response: Please see response to Q43.			
Dominion		☑	See comment for Question 20 above.
MEAG Power		☑	See Q20 above.
TVA		☑	See Q20.
WPS		☑	See response to Q20.
Response: Please see response to Q20.			
E ON US		☑	EHV station configurations are either ring-bus or breaker and one-half. Breaker failure protection isolates two EHV Facilites which may cause local area issues without affecting the BES.

Q24			
Commenter	**Agree**	**Disagree**	**Comment**
Northwestern Energy		☑	Non-consequential load loss should be permitted for this contingency.
Duke Energy		☑	Depends upon the definition of non-bus tie breaker. By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence.
Entergy		☑	N-1-1 requires an increase in investment that will place an undue cost burden on all customers for low probability events. See comments to Q43.
FPL FRCC		☑	This loss is currently distinguished from other single contingencies because of its lower probability of occurrence and a more stringent performance requirement than currently exists is not warranted.
Progress–Florida		☑	This single contingency event has a very low probability of occurrence, and thus a more stringent performance requirement than currently exists is not warranted.
SaskPower		☑	The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Response: Based on industry feedback the SDT has made changes in Draft 2 on requirements related to two independent overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. However, it is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission for the less probable, but greater risk single Contingency events. Please refer to performance tables Planning Event P2 and note that bus section faults and internal breaker faults (non-bus tie) associated with above 300 kV Facilities are held to a higher performance standard than those operated at 300 kV or below. Although not unanimous, the majority of the SDT felt the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering contingencies of two EHV Facilities due to one Event. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. Please see also summary response to Q22.			
BCTC		☑	Do not agree due to definitions of Consequential and Non-Consequential Load Loss. Can agree subject to the proposed revised definitions to address loss of load during the transient stability period. System is already planned to meet this requirement based on the first sentence of footnote (b).
Response: The drafting team has considered industry comments and has incorporated changes in the definition of Consequential Load Loss. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet			

Q24			
Commenter	**Agree**	**Disagree**	**Comment**
steady state performance requirements.			
CenterPoint		☑	The loss of a non-bus tie breaker due to an internal fault has a low probability of occurrence and should be considered an improbable event with non-consequential load loss permitted. However, the loss of any breaker, whether by internal fault, external flashover, or stuck breaker, should not result in a cascading failure.
CPS Energy		☑	Should be determined at the discretion of the Transmission Planners.
PJM	☑		Agree with performance requirement. The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?
Response: The SDT has added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose Non-Consequential Load.			
Exelon		☑	P6 allows for non-consequential load loss for a bus tie breaker, which has the same probability of failure as a non-bus tie breaker.
Response: In Draft 1, P6 is for loss of Bus-tie Breaker below 300 kV. This initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT felt the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering contingencies of two EHV Facilities due to one Event. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. Please see also summary response to Q22.			
Georgia Transm.		☑	The standard needs to clearly define a non-bus tie breaker. It is also not clear whether the focus of the standard is the kV level or the equipment type. A material change to build new facilities would be needed to meet this new requirement.
Response: The drafting team has considered industry comments and has incorporated changes in the definition of Consequential Load Loss. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.			

Q24			
Commenter	**Agree**	**Disagree**	**Comment**
This initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT felt the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering contingencies of two EHV Facilities due to one Event. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. Please see also summary response to Q22.			
LADWP		☑	Don't understand why there is such an obsession with bus tie breakers? Is this a common practice in the East? I am not aware of any issue in WECC, let alone at above 300 kV systems.
Response: For straight buses, loss of a Bus-tie Breaker could remove from service multiple bus sections simultaneously resulting in loss of all elements connecting to the impacted bus sections. However, Bus-tie Breakers also have lower probability of outage. The reason for providing performance requirements for Bus-tie Breakers that are different from the performance requirements for non-Bus-tie Breakers is to encourage the installation of Bus-tie Breakers in straight busses.			
MRO		☑	This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this change to customers. Alternatively, the SDT should define a level of non-consequential load that is acceptable for such low probability events such as 1000 MW.
Response: The SDT will consider interim Operating Procedures to allow for Transmission Owners to respond and guidelines that may allow quantifiable and limited exposure to loss of Non-Consequential Load. This may include, for example, providing for defined exclusions during construction of new Facilties. This initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT felt the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering contingencies of two EHV Facilities due to one Event. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. Please see also summary response to Q22.			
Seattle City		☑	Adequacy of HV supply is outside of our control but may have a detrimental effect on our system. We should not be required to supplement the existing high-voltage infrastructure when it is the

Q24			
Commenter	**Agree**	**Disagree**	**Comment**
			responsibility of the transmission owner. If the intent of this requirement is to prevent downstream load loss caused by a fault in the 300kV beloning to the transmission owner, then we agree. We must be able to shed load when our supply is cut.
Response: The treatment of Transmission infrastructure costs is outside the scope of the NERC reliability standards. The SDT will consider interim Operating Procedures to allow for Transmission Owners to respond and guidelines that may allow quantifiable and limited exposure to loss of Non-Consequential Load. This may include, for example, providing for defined exclusions during construction of new facilties.			
Santee Cooper SERC EC DRS SERC EC PSS SERC RRS OPS SCE&G Southern Transm.		☑	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost. It would be helpful if "bus tie breaker" was defined (e.g. is the middle breaker in a breaker and a half scheme considered a bus tie breaker?).
Response: The SDT will consider interim Operating Procedures to allow for Transmission Owners to respond and guidelines that may allow quantifiable and limited exposure to loss of Non-Consequential Load. This may include, for example, providing for defined exclusions during construction of new facilties. The drafting team has considered industry comments and has incorporated changes in the definition of Consequential Load Loss. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.			
Tenaska		☑	Why should we distinquish between a bustie breaker and a non-bus tie breaker? Also, 300 kV may be too low. This is really an issue that should be driven by the customers.
ABB	☑	☑	When talking about breaker outages, I see no reason to differentiate between "non-bus tie" and "bus tie" breakers. Are bus tie breakers inherently more reliable? If the effect on the system due to a tie breaker outage is very bad, then this should be fixed. All other contingencies seem to be slotted based on probability. Shouldn't breakers? Maybe bus tie breakers are weak points in the transmission system that need to be improved.
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR	☑		It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

Q24			
Commenter	**Agree**	**Disagree**	**Comment**
United Illuminating			
ITC	☑		Loss of non-consequential load should not be permitted, however this should also apply to other breakers across the system including bus tie breakers.
Response: Depending on the bus configuration loss of a Bus-tie Breaker could remove from service multiple bus sections simultaneously resulting in loss of all elements connecting to the impacted bus sections. However, Bus-tie Breakers also have lower probability of outage. The reason for providing performance requirements for Bus-tie Breakers that are different from the performance requirements for non-Bus-tie Breakers is to encourage the installation of Bus-tie Breakers in straight busses.			
WECC BPA TSGT TEP		☑	We disagree that non-consequential loss of load should not be permitted for this contingency event. We believe that planned and controlled interruption of non-consequential load should be permitted for loss of a non-bus tie breaker (above 300 kV). Losing a non-bus tie breaker could result in simultaneous loss of two or more elements, depending on the bus configuration. Allowing planned and controlled disconnection of some load in the areas would not only prevent cascading and instability (which could result in uncontrolled loss of a larger amount of load), but also enables faster load restoration. Losing a breaker due to an internal fault is a low probability event. To meet this requirement as proposed would require severe pre-contingency curtailment of power transfers, that could impact commerce and/or construction of large number of transmission facilities with the attendant environmental impacts and increased cost to customers
Response: The SDT will consider interim Operating Procedures to allow for Transmission Owners to respond and guidelines that may allow quantifiable and limited exposure to loss of Non-Consequential Load. This may include, for example, providing for defined exclusions during construction of new facilties.			
Ameren	☑	☑	This part of the proposed standard language is confusing. From our perspective, the failure of any 300 kV or above non-bus-tie circuit breaker should not result in the non-consequential loss of load. Further, EHV circuit breakers failing as a result of internal faults are extremely rare, bus-ties or not. Also, it is not clear what would be considered a non-bus tie breaker for ring bus and breaker-and-a-half bus configurations. It would seem that performance requirements for EHV bus-tie breakers (and not non-bus-tie breakers) should be distinguished from other breakers.
Response: Depending on the bus configuration loss of a Bus-tie Breaker could remove from service multiple bus sections simultaneously resulting in loss of all elements connecting to the impacted bus sections. However, Bus-tie Breakers also have lower probability of outage. The reason for providing performance requirements for Bus-tie Breakers that are different from the performance requirements for non-Bus-tie Breakers is to encourage the installation of Bus-tie Breakers in straight busses. In response to industry comments, the SDT has accordingly proposed a definition for Bus-tie Breaker. **Bus-tie Breaker:** A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)			
AEP	☑		Consider adding clear definition of "bus tie breaker" and "non-bus tie breaker".
Response: In response to industry comments, the SDT has accordingly proposed a definition for Bus-tie Breaker.			

Q24			
Commenter	**Agree**	**Disagree**	**Comment**
Bus-tie Breaker: A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)			
FirstEnergy	☑		The tables' use of internal faults and stuck breaker faults is confusing since they have the same result.
Response: The probability of loss of a breaker due to the breaker internal fault would be higher than loss of a Transmission element coupled with a stuck breaker associated with the faulted element. Tables 1 and 2 have been modified to provide greater clarity.			
NERC TIS	☑		By its very nature, the event described is a breaker failure and the fault will typically need to be cleared by the next set of breakers, often remotely. Tripping out to the backup protection breakers typically can cause significant Consequential load loss. That should not be misconstrued as non-consequential load loss. Non-consequential load loss beyond that is unacceptable.
Response: Whether tripping of additional Facilities by backup protection will lead to more Consequential Load Loss will depend on whether any Load is connected directly to such Facilities. In the second draft the SDT has modified the definition of Consequential Load Loss. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.			
AECC	☑		neither should consequential load be lost for any n-1 faults on the 300 kv system and higher.
AECI	☑		
Allegheny Power	☑		
APPA	☑		
ATC	☑		
Brazos Electric	☑		
City Water Power and Light	☑		
City Utilities/Springfield	☑		
IESO	☑		Agree. In general, non-consequential loss of load should not be permitted for any single contingencies.
Entegra	☑		
ISO/RTO	☑		
KCPL	☑		No Non-Consequential loss of load for N-1 event.

Q24			
Commenter	**Agree**	**Disagree**	**Comment**
LCRA	☑		
MISO	☑		No indirect (Non-Consequential) loss of load for outage of single EHV element.
New York ISO	☑		
NCEMC	☑		See response for Q20.
Progress–Carolinas	☑		
Response: Thank you.			

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

25) Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Summary Response: A majority of the commenters indicated that a definition for "Bus-tie Breaker" as well as clarification of the Tables is needed. Based on the comments from the industry, the drafting team has proposed a definition for Bus–tie Breakers, incorporated changes to the definition of Consequential Load and added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose Non-Consequential Load. The SDT has re-categorized the table to try to clarify what was meant but no changes have been made to this requirement as a result of industry comments.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)

Consequential Load Loss: Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.

Q25			
Commenter	**Agree**	**Disagree**	**Comment**
Muscatine P&W			See Q43 Comment #5.
Response: Please see response to Question 43 #5.			
Ameren		☑	The loss of two or more elements at any EHV substation at time of peak would likely result in loss of non-consequential load. If the intent of the proposed standard is to encourage the development of ring bus or breaker-and-a-half bus arrangements at the EHV level, we would concur where it is physically possible and makes for good engineering practice. However, we must remind the SDT that there are some existing facilities that cannot be converted practically or economically from their present straight bus configuration because of physical limitations. A significant material change, potentially several million dollars per substation, would be required to retrofit facilities, where possible. It would appear that performance requirements for EHV bus-tie breakers (and not non-bus-tie breakers) should be distinguished from other breakers.
Duke Energy		☑	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence.
Entergy		☑	N-1-1 requires an increase in investment that will place an undue cost burden on all customers

Q25			
Commenter	**Agree**	**Disagree**	**Comment**
			for low probability events. See comments to Q43..
SaskPower		☑	The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Santee Cooper SERC EC DRS SERC EC PSS SERC RRS OPS SCE&G Southern Transm.		☑	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Northwestern Energy		☑	Non-consequential load loss should be permitted for this contingency.
Response: Based on industry feedback the SDT has made changes in Draft 2 on requirements related to two independent overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. However, it is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission. Although not unanimous, the majority of the SDT felt the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering Contingencies of two EHV facilities due to one Event. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. Please see also summary response to Q22.			
Dominion		☑	See comment for Question 20 above.
MEAG Power		☑	See Q20 above.
TVA		☑	See Q20.
WPS			See response to Q20.
NCEMC	☑		See response for Q20.
Response: Please see response to Q20.			
E ON US		☑	This event needs to be reworded. Does the stuck non-bus tie breaker condition only apply to the bus fault or to all faults? Does (above 300 kV) only apply to the stuck non-bus tie breaker or is this limited to faults on facilities above 300 kV?
Response: The stuck non-Bus tie Breaker condition applies to all faults listed in P3 in Tables 1 and 2. The ATFNSDT has added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose non-consequential firm load.			
ERCOT ISO CAISO		☑	Do not agree for loss of a bus, or loss of a stuck non-bus tie breaker for the reasons as in the response to Q21.
Response: Please see response to Q21.			
BCTC		☑	Do not agree due to definitions of Consequential and Non-Consequential Load Loss. Can agree subject to the proposed revised definitions to address loss of load during the transient stability

Q25			
Commenter	**Agree**	**Disagree**	**Comment**
			period. System is already planned to meet this requirement based on the first sentence of footnote (b).
MISO	☑		With the clarification that direct (Consequential) loss of load is associated with all outage elements: both SLG element and stuck breaker element.
Response: The drafting team has considered industry comments and has incorporated changes in the definition of Consequential Load Loss. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.			
CenterPoint		☑	The loss of either a generator, a Transmission cirucit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV) has a low probability of occurrence and should be considered an extreme event with non-consequential load loss permitted.
CPS Energy		☑	Should be determined at the discretion of the Transmission Planners.
FirstEnergy		☑	The wording of P3-1 is unclear. We suggest rewording to say "Fault on a generator, line, transformer, or bus and a stuck breaker when the fault is being cleared". We agree with the concept of not dropping load for an EHV stuck breaker with the exception of the bus fault item. We do not believe that it is very realistic to postulate a bus fault along with a stuck breaker and believe that it is a very low probability event.
Response: The SDT has added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose Non-Consequential Load.			
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating		☑	It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.
Response: For straight buses, loss of a Bus-tie Breaker could remove from service multiple bus sections simultaneously resulting in loss of all elements connecting to the impacted bus sections. However, Bus-tie Breakers also have lower probability of outage. The reason for providing performance requirements for Bus-tie Breakers that are different from the performance requirements for non-Bus-tie Breakers so as to encourage the installation of Bus-tie Breakers in straight busses.			
FPL		☑	Systems have been designed such that Multiple Contingency events (N-2) above 300 kV may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis. In

Q25			
Commenter	**Agree**	**Disagree**	**Comment**
			addition, by not allowing loss of non-consequential load, the system may remain in a less secure state or condition. This new category P3-1 is essentially a replacement for Category C5-9 except the only protection element failure to be considered is the failure of a circuit breaker to open. This definition eliminates the need to examine failure of the relay to operate which in many cases has a more serious impact on grid reliability.
FRCC		☑	This new category P3-1 is essentially a replacement for Category C5-9 except the only protection element failure to be considered is the failure of a circuit breaker to open. This definition eliminates the need to examine failure of the relay to operate which in many cases has a more serious impact on grid reliability.
Response: The SDT has added greater detail to Tables 1 & 2, which provides separately for events that involve stuck breakers and protection system failure.			
Georgia Transm.		☑	A material change to build new facilities would be needed to meet this new requirement.
MRO		☑	This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this change to customers. Alternatively, the SDT should define a level of non-consequential load that is acceptable for such low probability events such as 1000 MW.
WECC BPA TSGT TEP		☑	We disagree that non-consequential loss of load should not be permitted for this contingency event. We believe that planned and controlled interruption of non-consequential load should be permitted for loss of either a generator, a transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV). This contingency event could result in simultaneous loss of two or more elements, depending on the bus configuration. Allowing planned and controlled disconnection of some load in the areas would not only prevent cascading and instability (which could result in uncontrolled loss of a larger amount of load), but also enables faster load restoration. These contingencies are low-probability events. To meet this requirement as proposed would require severe pre-contingency curtailment of power transfers, that could impact commerce and/or construction of a large number of transmission facilities with the attendant environmental impacts and increased cost to customers.
Response: The SDT has re-categorized the table to try to clarify what was meant but no changes have been made to this requirement as a result of industry comments.			
LADWP		☑	Ditto (24)
Seattle City		☑	As in Q24. Certain combinations in the HV supply system will force us to shed load.
NERC TIS	☑		See comment to Q24.
Response: Please see response to Q24.			
Manitoba Hydro		☑	The SDT seems fixated on loss of load. The existing std for this type of event allowed for loss of load and firm transfer could be adjusted. While MH could rationalize that load should not be

Q25			
Commenter	**Agree**	**Disagree**	**Comment**
			interrupted, we could not agree that firm transfer can not be reduced. This would amount to n-2 planning to maintain a firm transfer that is backed up by reserves. The requirement to maintain firm transfer will cost MH and the industry millions of dollars with no reliability benefit - a show stopper.
Tenaska		☑	This is really an issue that should be driven by the customers.
Exelon	☑	☑	We do not agree with disallowing non-consequential load loss for these scenarios for the peak load conditions. These are very low probability contingencies, and some non-consequential load loss should be allowed at peak load. We would agree that it would be reasonable to dis-allow non-consequential load loss for these contingencies at a lower load level, such as 75% of peak load.
Response: The SDT must address FERC Order 693. FERC has jurisdiction over firm Transmission service. FERC allows the use of "equally or more efficient or effective approach" and Non-Consequential Load is being used as a proxy for firm Transmission service.			
Progress–Carolinas		☑	This is a very low probability multiple contingency and would cost an extreme sum of money to remedy. Need to clarify whether or not the stuck breaker was connected with loss of element.
Response: The SDT has re-categorized the table to try to clarify what was meant but no changes have been made to this requirement as a result of industry comments. The SDT has added greater detail to Tables 1 & 2 to provide more clarity.			
Progress–Florida		☑	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration. Furthermore, the greater-than-300 kV Bulk Electric System has been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis, placing particular importance on confining the event to a single area (i.e., not resulting in a cascading outage). Past assessments as well as actual events have demonstrated that by not allowing loss of non-consequential load, the Bulk Electric System may actually remain in a less secure state or condition, i.e. in more danger of experiencing cascading outages. In addition, it should be noted that the technical specifications of this category contain a major oversight. This new Category P3-1 is essentially a replacement for the existing Categories C5-9, except that the only protection element failure being considered is the failure of a circuit breaker to open. This definition eliminates the need to examine failure of the relay to operate, which in many cases has a more serious impact on grid reliability.
Response: The SDT must address FERC Order 693. FERC has jurisdiction over firm Transmission service. FERC allows the use of "equally or more efficient or effective approach" and Non-Consequential Load is being used as a proxy for firm Transmission service. The SDT has added greater detail to Tables 1 & 2, which provides for events that involve stuck breakers and protection system failure.			
ABB	☑	☑	Table 1 P3 is a little hard to read/understand. The second column should start out something like "A stuck breaker following the outage of any 1 of the following:" However, P3 will be completely redundant with P2 because, in power flow analysis, there is no difference between a breaker internal fault and a stuck breaker following an external fault. The final outaged equipment is the

Q25			
Commenter	**Agree**	**Disagree**	**Comment**
			same. This will cause extra unnecessary work.
Response: The SDT has added greater detail to Tables 1 & 2.			
AEP	☑		Consider adding clear definition of "bus tie breaker" and "non-bus tie breaker".
Response: The SDT has accordingly proposed a definition for Bus-tie Breaker. **Bus-tie Breaker:** A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)			
ITC	☑		Should also consider no loss of non-consequential load for facilities 100 kV and above and this should also apply to other breakers across the system including bus tie breakers.
Response: The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission Systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT felt the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering single events that can result in Contingencies of two EHV Facilities. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. Loss of Facilities below 300 kV is not expected to have the same impact. Please see also summary response to Q22.			
AECC	☑		neither should consequential load be lost for any n-1 faults on the 300 kv system and higher.
AECI	☑		
Allegheny Power	☑		
APPA	☑		
ATC	☑		
Brazos Electric	☑		
City Water Power and Light	☑		
City Utilities/Springfield	☑		
Entegra	☑		
IESO	☑		See reason stated for Q24, above.
ISO/RTO	☑		
KCPL	☑		Must recognize that there may be Consequential loss of load.

Q25			
Commenter	**Agree**	**Disagree**	**Comment**
LCRA	☑		
New York ISO	☑		
PJM	☑		
Response: Thank you.			

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

26) Q26. P4-1: Loss of a Generator followed by System adjustment[2] followed by loss of another Generator

Summary Response: The SDT notes that FERC's direction with regard to Non-Consequential firm Load and the TPL standards is stated in paragraph 1795 of FERC Order No. 693 as follows: "Based on the record before us, we believe that the transmission planning Reliability Standard should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency." Paragraph 1795 also states, "Therefore, the ERO should modify the sentence to indicate that manual system adjustments, except for shedding firm load or curtailment of firm transfers, are permitted after the first contingency to bring the system back to a normal operating state." These statements which indicate that loss of Non-Consequential firm Load and interruption of firm Transmission service should not be permitted for a single Contingency are meant to apply to Facilities covered by reliability standards regardless of voltage, economics, or rate recovery issues.

These events are on higher voltage facilities on the BES. Therefore, the SDT has drafted the standard to not permit loss of Non-Consequential Load or interruption of firm Transmission service for the loss of a generator followed by System adjustment followed by the loss of another generator. The majority of the commenters in response to the first posting of the standard agreed with the SDT's approach in this regard.

Issues of cost recovery are beyond the scope of the standard.

Q26			
Commenter	**Agree**	**Disagree**	**Comment**
Muscatine P&W			See Q43 Comment #5.
Response: Please see Q43 #5 response.			
City Utilities/Springfield			Would like to see more explanation for the these scenarios.
ABB	☑		For Table 1 P4, rewrite it to read "Loss of a generator followed by a System adjustment followed by the loss of any one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. A shunt device

[2] System adjustment can be manual or automatic

Q26			
Commenter	**Agree**	**Disagree**	**Comment**
			5. Single pole of DC line." This structure is easier to read and understand. The order should be like this to match P1. Shunt devices should be included. P3 should be structured similarly.
Response: The SDT has changed the performance table and language to clarify the specific scenarios. The SDT will be seeking comments on the new performance table.			
Brazos Electric		☑	Need a definition of generator. The entire train, largest unit at a site or other.
Response: The SDT has made changes to the performance table and language to define what is included in an individual generator outage**.**			
Northwestern Energy		☑	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
Response: The SDT has revised the proposed definition of Consequential Load Loss in the second draft. Per the SDT proposed definition, losing a motor due to motor contactor action is not considered Non-Consequential or Consequential Loss of Load. The SDT has made changes to the definition of Consequential Load Loss to clarify how this incident is to be treated with regard to system performance. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements. With regard to the comment on cost, this requirement is consistent with FERC Order No. 693 and the SDT believes this is a more probable event than other events and therefore, the System should be designed per this requirement.			
BCTC		☑	Do not agree due to the definition for Consequential Load Loss. Definition needs to include local networks for this contingency to be acceptable.
Response: See responses to Question 2 and 6.			
CenterPoint		☑	CenterPoint Energy believes the assumption that this is a high probability event is incorrect. Furthermore, an absolute requirement prohibiting non-consequential loss of load has economic and landowner impacts that cannot be ignored.
Response: The majority of commenters in response to the first posting of the draft standard agreed with this approach. With regard to the commenter's second comment, the SDT notes that in Order 693 FERC directs NERC to prohibit loss of Non-Consequential firm Load for a single Contingency and therefore the SDT believes that this is an appropriate requirement for the standard. FERC's direction is meant to apply to BES Facilities covered by reliability standards regardless of land-use, voltage, economics, or rate recovery issues. Issues of land-use, economics, and cost recovery are beyond the scope of the SDT. The majority of commenters in response to the first posting of			

Q26			
Commenter	**Agree**	**Disagree**	**Comment**
the draft standard agreed with this approach. See also the SDT's summary response.			
Central Maine Power New England ISO NU NPCC RCS NSTAR United Illuminating		☑	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of 2 additional generators.
National Grid		☑	If mitigation plans are required that are based on studies that already include unplanned generator outages, then some load loss may be reasonable following the subsequent loss of 2 additional generators.
FPL FRCC		☑	Systems should be planned such that the loss of a generator, followed by System adjustment, followed by the loss of another generator would not result in Non-consequential Load Loss, and equipment ratings would not be exceeded etc. However, the initial state of the system must be clarified in all performance table scenarios (including P4-1).If the Base Case contained known planned outages of generating units, as implied by the requirement R1.4, then the standard performance requirements could be interpreted to require planning for all G-1-1-1 events.
Response: The SDT agrees that the draft standard could reasonably be interpreted that if a major generating outage lasts more than 1 year that the System still needs to be able to meet G-1, System adjustment and then, a 2nd G-1 without the loss of any Non-Consequential Load. This interpretation would require new construction to meet any G-1 + G-1 + G-1, because there would be a violation of the standard if any plant outage occurred and was not available over the peak period during the planning horizon. The SDT believes this is beyond most present planning across NERC. Therefore, the SDT has made a change to the proposed standard to develop a new requirement to replace R1.4 in the modeling section. The new requirement will be to perform the tests outlined in the performance requirements table and demonstrate that thermal and voltage limits are met, however, all manual and/or automatic actions are allowed (within time constrained ratings) including curtailing firm transfers and controlled shedding of Non-Consequential firm Load.			
CPS Energy		☑	Should be determined at the discretion of the Transmission Planners.
Entergy		☑	This would require an increase in investment that will place an undue cost burden on all customers for low probability events. It does not appear that there has been any meaningful balancing of the potential benefits against the significant increase in cost that will be required. See comments to Q43.
LADWP		☑	This is N-2 and load loss should be permitted. As for whether or not this is a high probability event, there should be an objective measure (such as 1 in 5, 1 in 50, or 1 in 100, etc.) as to what constitute high probability, i.e., are there any outage history that would support any of the contention here that these are high probablity events? It is a mistake to arbitrary injecting "subjective" probability into a deterministic based reliability standard unless the industry is ready to move into 100% probabilistic based reliability standards.
Response: The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by another generator outage is higher than an event involving a single transmission line. The SDT notes that in Order 693 FERC directs NERC to prohibit loss of Non-Consequential firm Load for a single Contingency and therefore the SDT believes that this is an			

Q26			
Commenter	**Agree**	**Disagree**	**Comment**
appropriate requirement for the standard. The majority of commenters in response to the first posting of the draft standard agreed with this approach. See also the SDT's summary response.			
FirstEnergy		☑	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused soley by the first contingency.
Response: The SDT notes that in Order 693 FERC directs NERC to prohibit Non-Consequential loss of Load for a single Contingency in the planning horizon whether it is to meet the System performance after the outage or to prepare for the next Contingency and therefore the SDT believes that this is an appropriate requirement for the standard. The majority of commenters in response to the first posting of the draft standard agreed with this approach. See also the SDT's summary response. The SDT notes that when operating the System, the System Operator may have to drop Non-Consequential loss of Load as a last resort to maintain the reliability of the interconnected network. This would typically be for operating situations with more than a single prior outage for the Contingency event.			
Progress–Florida		☑	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration. Specifically, the sudden loss of a large generator followed soon thereafter by the loss of a second generator would often result in such a large generation-to-load mismatch that Non-Consequential Loss of Load would be inevitable. It is clear, however, that the Bulk Electric System should be planned such that any generator can be maintained (offline) and the system can be operated to the contingency of another generator. This is accomplished in the Security Constrained unit commitment process. However, if the intent of this requirement is that the system should be planned such that there can be no Non-Consequential Load Loss for the loss of a second generator (after System adjustment), then the requirement is too stringent in that the planner would essentially have to plan for 3 generator contingencies. Finally, the probability of an event should not be the primary factor determining whether or not Non-Consequential Loss of Load is permitted, but rather the presence or absence of cascading for the event.
Response: The SDT agrees that the draft standard could reasonably be interpreted that if a major generating outage lasts more than 1 year that the System still needs to be able to meet G-1, System adjustment and then, a 2nd G-1 without the loss of any Non-Consequential Load. This interpretation would require new construction to meet any G-1 + G-1 + G-1, because there would be a violation of the standard if any plant outage occurred and was not available over the peak period during the planning horizon. The SDT believes this is beyond most present planning across NERC. Therefore, the SDT has made a change to the proposed standard to develop a new requirement to replace R1.4 in the modeling section. The new requirement will be to perform the tests outlined in the performance requirements table and demonstrate that thermal and voltage limits are met, however, all manual and/or automatic actions are allowed (within time constrained ratings) including curtailing firm transfers and controlled shedding of Non-Consequential firm Load. The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by another generator outage is higher than an event involving a single transmission line. The SDT notes that in Order 693 FERC directs NERC to prohibit loss of Non-Consequential firm Load for a single Contingency and therefore the SDT believes that this is an appropriate requirement for the standard. The majority of commenters in response to the first posting of the draft standard agreed with this approach. See also the SDT's summary response.			

Q26			
Commenter	**Agree**	**Disagree**	**Comment**
SRP		☑	The time to adjust the system needs to be provided (when does a N-1-1 become a N-2?). If the cause of the outage is transient (temporary) the operator needs some time to test and restore the element (could be minutes up to several hours). If the element is lost indefinitly, the operator will need some minimum time to adjust the system. If this time is not available prior to the next N-1 then the standard should allow Non-Consequetial Loss of Load. Some distinction needs to be made the amount of generation connected at a single point on the BES. a wind farm might have many small generators connected to the BES with an aggregate total of 300Mw or more. This requirement will should only apply to generating sources that might be connected to the BES through a single transformer (i.e. wind farm) with minimum agregate total of 300 MW (for N-1).
Response: The SDT believes that the time to adjust that is used in planning needs to be consistent with the time periods for which the Facility Ratings are designed. This time to adjust is different for different types of Facilities, as well as, for individual Facilities. The SDT has clarified this point in the standard but does not provide a specific time to be used for planning across NERC. The SDT has made changes to the performance table and language to define what is included in an individual generator outage. Treatment of wind farm in modeling and analysis needs to be addressed in MOD-010 through MOD-013.			
Santee Cooper		☑	The event should be tested for ensuring or maintaining reliability of the BES, however direct load loss should be allowed.
SERC RRS OPS TVA		☑	It is agreed that this event should be tested for maintaining reliability of the BES, however planned load loss should be allowed.
SCE&G		☑	Planned load loss should be allowed.
Response: The SDT agrees that Consequential (direct) Load Loss should be allowed but disagrees that planned loss of Non-Consequential firm Load should be allowed. The standard has been drafted to allow Consequential direct Load Loss for this event but not Non-Consequential Load Loss for this Contingency event. The SDT has outage data for representative facilities which shows that the probability of an event involving one generator outage followed by another generator outage is higher than an event involving a single Transmission line. The SDT notes that in Order 693 FERC directs NERC to prohibit loss of Non-Consequential firm Load for a single Contingency and therefore the SDT believes that this is an appropriate requirement for the standard. The majority of commenters in response to the first posting of the draft standard agreed with this approach. See also the SDT's summary response.			
SaskPower		☑	Local area network load is allowed to be shed in Saskatchewan. The Saskatchewan Regulatory Jurisdiction has no plans to change this unless there is technical evidence to justify the increase in reliability. The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Response: The SDT is required to address FERC Order 693 and cannot default to lowest common denominator. This issue is beyond the scope of the Standard Drafting Team and needs to be addressed at the NERC level. However, an Entity can request an "Entity Variance" in accordance with the NERC Reliability Standards Development Procedure (Page 27).			
Tenaska	☑		This is really an issue that should be driven by the customers
Response: FERC Order No. 693 and the Energy Policy Act of 2005 has driven changes embodied by this question.			

Q26			
Commenter	**Agree**	**Disagree**	**Comment**
HQTE	☑		Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of 2 additional generators.
Response: FERC Order 693 indicates that only Consequential Load Loss should be allowed while Non-Consequential Load loss should not. See also the SDT's summary response.			
IESO	☑		The loss of a generator is different from the loss of a transmission facility. The former usually does not result in changes to the system topology nor system operating limits. While loss of 2 generators may result in resource deficiency, the decision to shed load would only be made when operating reserve cannot be replenished after the first contingency, and when the second contingency would result in violation of any SOLs or IROLs or BAL standards for which adjustment cannot be made within the required time line.
Response: The SDT agrees with the comment, although that is not the reason for the proposed changes. FERC Order 693 indicates that only consequential load loss should be allowed while non-consequential load loss should not. See also the SDT's summary response.			
ITC	☑		Also use of system adjustment should consider time required to complete adjustment.
Response: The SDT agrees and has proposed changes to the tables to clarify.			
Manitoba Hydro	☑		With the caveat that firm transfer is included in the adjustment, otherwise there is a huge cost with minimal reliability benefit. A further comment is what rationale was applied by the SDT to come up with these combinations of events? is there a statistical basis? the viable combinations of multiple contingency events should be left to the experience of the transmission planner.
Response: FERC Order 693 indicates that firm transfers are not to be curtailed either to meet the System performance for a single Contingency or to prepare for the next Contingency. This is the basis for not allowing firm transfer. See also the SDT's summary response and Order 693, Paragraph 1796 for additional FERC clarification with regard to prohibiting curtailment of firm transfers after a single Contingency. The combinations of events were chosen drawing on the experience of members of the SDT. If there are any additional events that should be added to the tables, please provide specific suggestions during the next comment period.			
NCEMC	☑		In the case of generating capacity replacement, some guidance as to allowable system adjustments might be needed for clarification. Is calling on contingency reserves from a Reserve Sharing Group immediately prior to internal redispatch of available resources OK? What about Network Customer generation not at maximum output but available for redispatch ? What about transmission reconfiguration, cutting firm purchases (pro-rata or in entirety) acceptable?
Response: The SDT agrees with the comment and the SDT has proposed changes to clarify what System adjustments are allowed.			
WPS	☑		It is inappropriate to rely on Non-consequential loss of load as an ultimate Corrective Action Plan for this event. However, non-consequential load loss can provide interim relief until such time as the Corrective Action Plan is actually constructed and in-service.
Response: The SDT agrees with this comment and has proposed an interim relief provision for the standard.			
Ameren	☑		The outage of any two generators should not result in any non-consequential loss of load.

Q26			
Commenter	**Agree**	**Disagree**	**Comment**
AECC	☑		neither should consequential load be lost. The system should operate to all performance criteria for loss of any one generator station (all units).
AECI	☑		
Allegheny Power	☑		
AEP	☑		
APPA	☑		
ATC	☑		
APS			
BPA	☑		
City Water Power and Light	☑		
Dominion	☑		Dominion agrees with these proposed standards as they are relatively higher probability events and reflect very closely to the Company's internal planning criteria.
Duke Energy	☑		
Entegra	☑		
E ON US	☑		
ERCOT ISO CAISO	☑		Non consequential loss of load should not be permitted for this type of event. Loss of a generator has higher probability and longer duration than many other contingencies. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Exelon	☑		
Georgia Transm.	☑		
ISO/RTO	☑		
KCPL	☑		
LCRA	☑		
MEAG Power	☑		
MISO	☑		
MRO	☑		
NERC TIS	☑		

Q26			
Commenter	**Agree**	**Disagree**	**Comment**
New York ISO	☑		
PJM	☑		
Progress–Carolinas	☑		
Seattle City	☑		
SERC EC DRS	☑		
SERC EC PSS	☑		
Southern Transm.	☑		These are relatively higher probability events and the increase in performance requirements is justified.
WECC TSGT TEP	☑		We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Response: Thank you.			

27) Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line

Summary Response: The SDT notes that FERC's direction with regard to Non-Consequential firm Load and the TPL standards is stated in paragraph 1795 of FERC Order No. 693 as follows: "Based on the record before us, we believe that the transmission planning Reliability Standard should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency." Paragraph 1795 also states, "Therefore, the ERO should modify the sentence to indicate that manual system adjustments, except for shedding firm load or curtailment of firm transfers, are permitted after the first contingency to bring the system back to a normal operating state." These statements which indicate that loss of Non-Consequential firm Load and interruption of firm Transmission service should not be permitted for a single Contingency are meant to apply to Facilities covered by reliability standards regardless of voltage, economics, or rate recovery issues.

These events are on higher voltage facilities on the BES. The probability of the outage of one generator followed by the outage of another generator is higher than the probability of a single Transmission line outage. Therefore, the SDT has drafted the standard to not permit loss of Non-Consequential Load or interruption of firm Transmission service for the loss of a generator followed by System adjustment followed by the loss of another generator. The majority of the commenters in response to the first posting of the standard agreed with the SDT's approach in this regard.

Issues of cost recovery are beyond the scope of the standard.

Q27			
Commenter	**Agree**	**Disagree**	**Comment**
Muscatine P&W			See Q43 Comment #5.
Response: Please see response to Q43 #5.			
Northwestern Energy		☑	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
BCTC		☑	Similar to Q26.
Central Maine Power New England ISO NU NSTAR United Illuminating		☑	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a monopolar DC line
National Grid		☑	If mitigation plans are required that are based on studies that already include unplanned generator outages, then some load loss may be reasonable following the subsequent loss of an additional generator and a monopolar DC line
FirstEnergy		☑	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused soley by the first contingency.
FPL FRCC		☑	Systems should be planned such that the loss of a generator, followed by System adjustment, followed by the loss of another generator would not result in Non-consequential Load Loss, and

Q27			
Commenter	**Agree**	**Disagree**	**Comment**
			equipment ratings would not be exceeded etc. However, the initial state of the system must be clarified in all performance table scenarios (including P4-1).If the Base Case contained known planned outages of generating units, as implied by the requirement R1.4, then the standard performance requirements could be interpreted to require planning for all G-1-1-1 events.
LADWP		☑	Ditto (26)
SRP		☑	Same as Q26.
Santee Cooper SERC RRS OPS		☑	Same comment as question #26.
SaskPower		☑	Local area network load is allowed to be shed in Saskatchewan. The Saskatchewan Regulatory Jurisdiction has no plans to change this unless there is technical evidence to justify the increase in reliability. The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
HQTE	☑		Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a monopolar DC line
IESO	☑		Same reason as above except in this case, the loss of a monopolar dc line could interrupt import. Again, it is a resource issue, not a transmission reliability issue.
ITC	☑		Also use of system adjustment should consider time required to complete adjustment.
Manitoba Hydro	☑		With the caveat that firm transfer is included in the adjustment, otherwise there is a hugh cost with minimal reliability benefit.
Tenaska	☑		This is really an issue that should be driven by the customers
Response: Please see response to #26.			
CenterPoint		☑	CenterPoint Energy believes the assumption that this is a high probability event is incorrect. Furthermore, an absolute requirement prohibiting non-consequential loss of load has economic and landowner impacts that cannot be ignored.
Response: The SDT disagrees with the commenter's first statement. The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by a DC line is within an order of magnitude of an event involving a single Transmission line. With regard to the commenter's second comment, the SDT notes that in Order 693 FERC directs NERC to prohibit loss of Non-Consequential firm Load for a single Contingency and therefore the SDT believes that this is an appropriate requirement for the standard. FERC's direction is meant to apply to BES Facilities covered by reliability standards regardless of land-use, voltage, economics, or rate recovery issues. Issues of land-use, economics, and cost recovery are not to be addressed by the SDT as being beyond the scope of the SDT. The majority of commenters in response to the first posting of the draft standard agreed with this approach. See also the SDT's summary response.			
Entergy		☑	This would require an increase in investment that will place an undue cost burden on all customers for low probability events. It does not appear that there has been any meaningful balancing of the potential benefits agains the significant increase in cost that will be required.

Q27			
Commenter	**Agree**	**Disagree**	**Comment**
			See comments to Q43.
Response: The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by a DC line is within an order of magnitude of an event involving a single Transmission line. With regard to the commenter's second comment, the SDT notes that in Order 693 FERC directs NERC to prohibit loss of Non-Consequential firm Load for a single Contingency and therefore the SDT believes that this is an appropriate requirement for the standard. FERC's direction is meant to apply to BES Facilities covered by reliability standards regardless of land-use, voltage, economics, or rate recovery issues. Issues of land-use, economics, and cost recovery are not to be addressed by the SDT as being beyond the scope of the SDT. The majority of commenters in response to the first posting of the draft standard agreed with this approach. See also the SDT's summary response.			
Progress–Florida		☑	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration, provided that the Non-Consequential Loss of Load is confined to a single control area (i.e., not resulting in a cascading outage). Furthermore, the frequency of an event should not be the primary factor determining whether or not Non-Consequential Loss of Load is permitted, but rather the presence or absence of cascading for the event. Existing Category C requirements are adequate for this type of event.
Response: The SDT agrees that the draft standard could reasonably be interpreted that if a major generating outage lasts more than 1 year that the System still needs to be able to meet G-1, System adjustment and then, a 2nd G-1 without the loss of any Non-Consequential Load. This interpretation would require new construction to meet any G-1 + G-1 + G-1, because there would be a violation of the standard if any plant outage occurred and was not available over the peak period during the planning horizon. The SDT believes this is beyond most present planning across NERC. Therefore, the SDT has made a change to the proposed standard to develop a new requirement to replace R1.4 in the modeling section. The new requirement will be to perform the tests outlined in the performance requirements table and demonstrate that thermal and voltage limits are met, however, all manual and/or automatic actions are allowed (within time constrained ratings) including curtailing firm transfers and controlled shedding of Non-Consequential firm Load. The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by a DC line is within an order of magnitude of an event involving a single Transmission line. With regard to the commenter's second comment, the SDT notes that in Order 693 FERC directs NERC to prohibit loss of Non-Consequential firm Load for a single Contingency and therefore the SDT believes that this is an appropriate requirement for the standard. FERC's direction is meant to apply to BES Facilities covered by reliability standards regardless of land-use, voltage, economics, or rate recovery issues. Issues of land-use, economics, and cost recovery are not to be addressed by the SDT as being beyond the scope of the SDT. The majority of commenters in response to the first posting of the draft standard agreed with this approach. See also the SDT's summary response.			
SCE&G		☑	Planned load loss should be allowed.
TVA		☑	It is agreed that this event should be tested for maintaining reliability of the BES, however planned load loss should be allowed.
Response: The SDT agrees that Consequential (direct) Load Loss should be allowed but disagrees that planned loss of Non-Consequential firm Load should be allowed. The standard has been drafted to allow Consequential direct Load Loss for this event but not Non-Consequential Load Loss for this Contingency event. The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by a DC line outage is within an order of magnitude than an event involving a single Transmission line. The SDT notes that in Order 693 FERC directs NERC to prohibit loss of Non-Consequential firm Load for a single Contingency and			

Q27			
Commenter	**Agree**	**Disagree**	**Comment**
therefore the SDT believes that this is an appropriate requirement for the standard. The majority of commenters in response to the first posting of the draft standard agreed with this approach. See also the SDT's summary response.			
MRO	☑		The monopolar DC line words should be revised to "a single pole of a DC line".
Response: The SDT agrees and has made appropriate changes to the tables.			
NPCC RCS	☑		Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a monopolar DC line
Response: See summary response.			
ABB	☑		
Ameren	☑		The outage of a generator and any other element should not result in any non-consequential loss of load.
AECC	☑		neither should consequential load be lost. The system should operate to all performance criteria for loss of any one generator station (all units).
AECI	☑		AECI
Allegheny Power	☑		Allegheny Power
AEP	☑		AEP
APPA	☑		APPA
ATC	☑		ATC
BPA	☑		BPA
Brazos Electric	☑		
City Water Power and Light	☑		
Dominion	☑		Although we do not have any DC lines, Dominion agrees with these proposed standards as they are relatively higher probability events and reflect very closely to the Company's internal planning criteria.
Duke Energy	☑		
Entegra	☑		
ERCOT ISO CAISO	☑		Agree that non consequential loss of load should not be permitted due to higher probability of generator outage.
Exelon	☑		
Georgia Transm.	☑		

Q27			
Commenter	**Agree**	**Disagree**	**Comment**
ISO/RTO	☑		
KCPL	☑		
LCRA	☑		
MEAG Power	☑		
MISO	☑		
NERC TIS	☑		
New York ISO	☑		
PJM	☑		
Progress–Carolinas	☑		
Seattle City	☑		
SERC EC DRS	☑		
SERC EC PSS	☑		
Southern Transm.	☑		See comment for Q26 [These are relatively higher probability events and the increase in performance requirements is justified.
WECC TSGT TEP	☑		We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
WPS	☑		See response to Q26.
Response: Thank you.			

28) Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit

Summary Response: The SDT notes that FERC's direction with regard to Non-Consequential firm Load and the TPL standards is provided in paragraph 1795 of FERC Order No. 693 which indicates that loss of Non-Consequential firm Load and interruption of firm Transmission service should not be permitted for a single Contingency regardless of voltage, economics, or rate recovery issues. Also see summary response to question 26.

These events are on higher voltage facilities on the BES. The probability of the outage of one generator followed by the loss of a Transmission line is within an order of magnitude of a single Transmission line outage. Therefore, the SDT has drafted the standard to not permit loss of Non-Consequential firm Load or interruption of firm Transmission service for the loss of a generator followed by System adjustment followed by the loss of a Transmission line. Issues of land-use, economics, and cost recovery are beyond the scope of the standard.

The majority of the commenters in response to the first posting of the standard agreed with the SDT's approach in this regard.

Q28			
Commenter	**Agree**	**Disagree**	**Comment**
Muscatine P&W			See Q43 Comment #5.
Response: Please see response to Q43 #5.			
Brazos Electric		☑	Need definition of system adjustment.
Response: The SDT agrees that system adjustment needed to be clarified. The SDT has made clarifying changes to the tables.			
Northwestern Energy		☑	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
BCTC		☑	Similar to Q26.
Central Maine Power New England ISO NU NSTAR United Illuminating		☑	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a Transmission circuit
National Grid		☑	If mitigation plans are required that are based on studies that already include unplanned generator outages, then some load loss may be reasonable following the subsequent loss of an additional generator and a Transmission circuit
FirstEnergy		☑	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused soley by the first contingency.
FPL FRCC		☑	Systems should be planned such that the loss of a generator, followed by System adjustment, followed by the loss of another generator would not result in Non-consequential Load Loss, and equipment ratings would not be exceeded etc. However, the initial state of the system must be

Q28			
Commenter	**Agree**	**Disagree**	**Comment**
			clarified in all performance table scenarios (including P4-1).If the Base Case contained known planned outages of generating units, as implied by the requirement R1.4, then the standard performance requirements could be interpreted to require planning for all G-1-1-1 events.
LADWP		☑	Ditto (26)
SRP		☑	Same as Q26.
SaskPower		☑	Local area network load is allowed to be shed in Saskatchewan. The Saskatchewan Regulatory Jurisdiction has no plans to change this unless there is technical evidence to justify the increase in reliability. The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
HQTE	☑		Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a Transmission circuit.
IESO	☑		Similar reason as above. In this case, while the second contingency is the loss of a transmission circuit, the first contingency (loss of a generator) has not changed the system topology. Hence, the system condition after having been adjusted following the first contingency should in essence be similar to the all transmission facilities in service condition for which the non-consequential loss of load performance for single contingencies is expected.
ITC	☑		Also use of system adjustment should consider time required to complete adjustment. Ability for generation adjustment should include the time required for unit startup if applicable.
Manitoba Hydro	☑		With the caveat that firm transfer is included in the adjustment, otherwise there is a hugh cost with minimal reliability benefit.
Tenaska	☑		This is really an issue that should be driven by the customers
Response: See response to #26.			
CenterPoint		☑	CenterPoint Energy believes the assumption that this is a high probability event is incorrect. Furthermore, an absolute requirement prohibiting non-consequential loss of load has economic and landowner impacts that cannot be ignored.
Response: The SDT disagrees with the commenter's first statement. The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by a Transmission line is within an order of magnitude of an event involving a single Transmission line. With regard to the commenter's second comment, see the summary response with regard to FERC Order No. 693.			
CPS Energy		☑	Should be determined at the discretion of the Transmission Planners.
Entergy		☑	This would require an increase in investment that will place an undue cost burden on all customers for low probability events. It does not appear that there has been any meaningful balancing of the potential benefits against the significant increase in cost that will be required. See comments to Q43.
Response: The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage			

Q28			
Commenter	**Agree**	**Disagree**	**Comment**
followed by a Transmission line is within an order of magnitude of an event involving a single Transmission line. With regard to the commenter's second comment, see the summary response with regard to FERC Order No. 693.			
JEA		☑	I do agree that long term plans should be implemented with the goal to eliminate non-consequential load shedding as a response to this failure mode. However, it may be more beneficial for investing in system improvements to reach this state of robustness where there may be a few years or seasons of potential exposure for utilizing non-consequential load shedding. This should be prudent utility practice as long as post-contingency response is executed within the time frame allowed by the facility emergency ratings and load shedding is limited to TP's contracted or tariff loads.
Response: SDT agrees that sufficient time must be provided for transition and will provide for that in the implementation plan for the standard. With regard to other comments, see summary response.			
Progress–Florida		☑	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration, provided that the Non-Consequential Loss of Load is confined to a single control area (i.e., not resulting in a cascading outage). Furthermore, the frequency of an event should not be the primary factor determining whether or not Non-Consequential Loss of Load is permitted, but rather the presence or absence of cascading for the event. Existing Category C requirements are adequate for this type of event.
Response: The SDT agrees that the draft standard could reasonably be interpreted that if a major generating outage lasts more than 1 year that the System still needs to be able to meet G-1, System adjustment and then, a 2nd G-1 without the loss of any Non-Consequential Load. This interpretation would require new construction to meet any G-1 + G-1 + G-1, because there would be a violation of the standard if any plant outage occurred and was not available over the peak period during the planning horizon. The SDT believes this is beyond most present planning across NERC. Therefore, the SDT has made a change to the proposed standard to develop a new requirement to replace R1.4 in the modeling section. The new requirement will be to perform the tests outlined in the performance requirements table and demonstrate that thermal and voltage limits are met, however, all manual and/or automatic actions are allowed (within time constrained ratings) including curtailing firm transfers and controlled shedding of Non-Consequential firm Load. The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by a Transmission line is within an order of magnitude of an event involving a single Transmission line. With regard to the commenter's second comment, see the summary response with regard to FERC Order No. 693.			
Santee Cooper SERC RRS OPS		☑	Same comment as question #26.
SCE&G		☑	Planned load loss should be allowed.
TVA		☑	It is agreed that this event should be tested for maintaining reliability of the BES, however planned load loss should be allowed.
Response: The SDT agrees that Consequential (direct) Load Loss should be allowed but disagrees that planned loss of Non-Consequential firm Load should be allowed. The standard has been drafted to allow Consequential direct Load Loss for this event but not Non-Consequential Load Loss for this Contingency event. The SDT has outage data for representative Facilities which show that the probability of an event			

Q28			
Commenter	**Agree**	**Disagree**	**Comment**
involving one generator outage followed by a DC line outage is within an order of magnitude than an event involving a single Transmission line. Also, see the summary response with regard to FERC Order No. 693.			
IESO	☑		Similar reason as above. In this case, while the second contingency is the loss of a transmission circuit, the first contingency (loss of a generator) has not changed the system topology. Hence, the system condition after having been adjusted following the first contingency should in essence be similar to the all transmission facilities in service condition for which the non-consequential loss of load performance for single contingencies is expected.
ITC	☑		Also use of system adjustment should consider time required to complete adjustment. Ability for generation adjustment should include the time required for unit startup if applicable.
Manitoba Hydro	☑		With the caveat that firm transfer is included in the adjustment, otherwise there is a hugh cost with minimal reliability benefit.
NPCC RCS	☑		Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a Transmission circuit
Response: Please see response to Q27.			
ABB	☑		
Ameren	☑		The outage of a generator and any other element should not result in any non-consequential loss of load.
AECC	☑		neither should consequential load be lost. The system should operate to all performance criteria for loss of any one generator station (all units).
AECI	☑		
Allegheny Power	☑		
AEP	☑		
APPA	☑		
ATC	☑		
BPA	☑		
CAISO	☑		Same reason as in Q26.
City Water Power and Light	☑		
Dominion	☑		Dominion agrees with these proposed standards as they are relatively higher probability events and reflect very closely to the Company's internal planning criteria.
Duke Energy	☑		
Entegra	☑		

Q28			
Commenter	**Agree**	**Disagree**	**Comment**
E ON US	☑		
ERCOT ISO	☑		Same reason as in Q26.
Exelon	☑		
Georgia Transm.	☑		
ISO/RTO	☑		
KCPL	☑		
LCRA	☑		
MEAG Power	☑		
MISO	☑		
MRO	☑		
NERC TIS	☑		
New York ISO	☑		
NCEMC	☑		See reply to Q26.
PJM	☑		
Progress–Carolinas	☑		
Seattle City	☑		
SERC EC DRS	☑		
SERC EC PSS	☑		
Southern Transm.	☑		See comment for Q26 [These are relatively higher probability events and the increase in performance requirements is justified.
WECC TSGT TEP	☑		We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
WPS	☑		See response to Q26.
Response: Thank you.			

29) Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer

Summary Response: The SDT notes that FERC's direction with regard to Non-Consequential firm Load and the TPL standards is provided in paragraph 1795 of FERC Order No. 693 which indicates that loss of Non-Consequential firm Load and interruption of firm Transmission service should not be permitted for a single Contingency regardless of voltage, economics, or rate recovery issues. See summary response to Q26.

These events are on higher voltage facilities on the BES. The probability of the outage of one generator followed by the loss of a transformer is within an order of magnitude of a single Transmission line outage. Therefore, the SDT has drafted the standard to not permit loss of Non-Consequential firm Load or interruption of firm Transmission service for the loss of a generator followed by System adjustment followed by the loss of a transformer. The majority of the commenters in response to the first posting of the standard agreed with the SDT's approach in this regard.

Q29			
Commenter	**Agree**	**Disagree**	**Comment**
Muscatine P&W			See Q43 Comment #5.
Response: Please see response to Q43 #5.			
Brazos Electric		☑	See above.
Northwestern Energy		☑	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
BCTC		☑	Similar to Q26.
Central Maine Power New England ISO NU NSTAR United Illuminating		☑	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a transformer
National Grid		☑	If mitigation plans are required that are based on studies that already include unplanned generator outages, then some load loss may be reasonable following the subsequent loss of an additional generator and a transformer
FirstEnergy		☑	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused soley by the first contingency.
FPL FRCC		☑	Systems should be planned such that the loss of a generator, followed by System adjustment, followed by the loss of another generator would not result in Non-consequential Load Loss, and equipment ratings would not be exceeded etc. However, the initial state of the system must be clarified in all performance table scenarios (including P4-1).If the Base Case contained known planned outages of generating units, as implied by the requirement R1.4, then the standard performance requirements could be interpreted to require planning for all G-1-1-1 events.

Q29			
Commenter	**Agree**	**Disagree**	**Comment**
JEA		☑	See comment on P4-3.
LADWP		☑	Ditto (26)
SRP		☑	Same as Q26.
Santee Cooper SERC RRS OPS		☑	Same comment as question #26.
HQTE	☑		Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a transformer.
IESO	☑		Similar reason as above.
ITC	☑		Also use of system adjustment should consider time required to complete adjustment. Ability for generation adjustment should include the time required for unit startup if applicable.
Manitoba Hydro	☑		With the caveat that firm transfer is included in the adjustment, otherwise there is a hugh cost with minimal reliability benefit.
Tenaska	☑		This is really an issue that should be driven by the customers
Response: Please see response to Q26.			
CenterPoint		☑	CenterPoint Energy believes the assumption that this is a high probability event is incorrect. Furthermore, an absolute requirement prohibiting non-consequential loss of load has economic and landowner impacts that cannot be ignored.
Response: The SDT disagrees with the commenter's first statement. The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by a transformer is within an order of magnitude of an event involving a single Transmission line. With regard to the commenter's second comment, see summary response.			
CPS Energy		☑	Should be determined at the discretion of the Transmission Planners.
Entergy		☑	This would require an increase in investment that will place an undue cost burden on all customers for low probability events. It does not appear that there has been any meaningful blancing of the potential benefits against the significant increase in cost that will be required See comments to Q43.
Response: The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by a transformer is within an order of magnitude of an event involving a single Transmission line. With regard to the commenter's second comment, see summary response			
Progress–Florida		☑	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration, provided that the Non-Consequential Loss of Load is confined to a single control area (i.e., not resulting in a cascading outage). Furthermore, the frequency of an event should not be the primary factor determining whether or not Non-Consequential Loss of Load is permitted, but rather the presence or absence of cascading for the event. Existing Category C requirements are adequate for this

Q29			
Commenter	**Agree**	**Disagree**	**Comment**
			type of event.
NPCC RCS	☑		Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a transformer
Response: Please see response to Q27.			
SCE&G		☑	Planned load loss should be allowed.
TVA		☑	It is agreed that this event should be tested for maintaining reliability of the BES, however planned load loss should be allowed.
Response: The SDT agrees that Consequential (direct) Load Loss should be allowed but disagrees that planned loss of Non-Consequential firm Load should be allowed. The standard has been drafted to allow Consequential direct Load Loss for this event but not Non-Consequential Load Loss for this Contingency event. The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by a DC line outage is within an order of magnitude than an event involving a single Transmission line. Also, see the summary response with regard to FERC Order No. 693.			
Duke Energy	☑		Table in TPL-001-1 doesn't include the last part of P4-4 (low side voltage rating above 300 kV). We assume the inclusion of 300kV here in the comment form is in error.
Response: The SDT notes that the original comment form was in error as described in your comment. The SDT noticed the error and revised the comment form and reposted it to correct the error.			
MISO	☑		Note - No voltage limit for generator and transformer per Table 1, P4-4
KCPL	☑		Need voltage limit in Table 1.
Response: The SDT disagrees because voltage limits differ from system to system.			
ABB	☑		
Ameren	☑		The outage of a generator and any other element should not result in any non-consequential loss of load.
AECC	☑		neither should consequential load be lost. The system should operate to all performance criteria for loss of any one generator station (all units).
AECI	☑		
Allegheny Power	☑		
AEP	☑		
APPA	☑		
ATC	☑		
BPA	☑		
City Water Power and Light	☑		

Q29			
Commenter	**Agree**	**Disagree**	**Comment**
Dominion	☑		Dominion agrees with these proposed standards as they are relatively higher probability events and reflect very closely to the Company's internal planning criteria.
E ON US	☑		
Entegra	☑		
ERCOT ISO CAISO	☑		Same reason as in Q26.
Exelon	☑		
Georgia Transm.	☑		
ISO/RTO	☑		
LCRA	☑		
MEAG Power	☑		
MRO	☑		
NERC TIS	☑		
New York ISO	☑		
NCEMC	☑		See reply to Q26.
PJM	☑		
Progress–Carolinas	☑		
Seattle City	☑		
SERC EC DRS	☑		
SERC EC PSS	☑		
Southern Transm.	☑		See comment for Q26 [These are relatively higher probability events and the increase in performance requirements is justified.
WECC TSGT TEP	☑		We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
WPS	☑		See response to Q26.
Response: Thank you.			

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

30) Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Summary Response: Some commenters that agreed with curtailing firm transfers that are dependent on a DC line when the DC line is outaged indicated that such curtailment should apply to AC lines as well. Also, some of these parties indicated concern that other transfers such as interruptible transfers should be also allowed. The SDT did not make a change in response to these comments because many of the transfers over DC lines are automatically curtailed when the DC line is outaged and because the ability to interrupt other transfers such as non-firm transfers are already provided for in the standard.

Q30			
Commenter	**Agree**	**Disagree**	**Comment**
Muscatine P&W			See Q43 Comment #5.
Response: The SDT does not see how Muscatine Power and Water's Comment #5 to Q43 relates to this question. The SDT does not make any change to the standard with regard to Q30 as a result of this comment.			
Ameren		☑	If the system cannot withstand the outage of the single element (AC or DC) without curtailment of the transfer, then the transaction should not be considered as firm.
AECC		☑	
BCTC		☑	Disagree with this unless AC lines are treated the same. There should be no distinction between AC and DC lines.
Duke Energy		☑	DC and AC line contingencies should have the same requirements.
Entergy	☑	☑	Why are only DC lines exempt for this requirement? Consider exemptions for AC transmission elements as well.
FPL		☑	The proposed standard does not distinguish between asynchronous DC ties and the more common parallel connected DC tie. With an asynchronous DC tie, the transfer is lost with the tie. With a parallel DC tie, the transfer will be shifted to the parallel AC system, therefore, AC lines should have the same performance criteria as DC lines.
FRCC		☑	DC and AC lines should not be treated differently. System response is similar for the loss of an AC line versus the loss of a parallel connected DC tie. For the loss of a parallel DC tie the transfer is shifted to the parallel AC system in the same manner as a loss of an AC line. The decision in selecting DC vs. AC in transmission lines has traditionally been based on the break-even cost and performance of the two alternatives. The lower performance requirement may wrongly influence decisions on project alternatives in favor of DC facilities with less stringent requirements. Therefore, AC lines should have the same performance criteria as DC lines.
Progress–Carolinas		☑	DC and AC lines should be treated comparably.

Q30			
Commenter	**Agree**	**Disagree**	**Comment**
Santee Cooper		☑	AC and DC contingency events should be treated the same.
SaskPower	☑		Why is this concept not applied to AC tie-lines between systems, whether single or multiple? In Saskatchewan's case there is very little difference.
SERC EC DRS		☑	DC and AC contingency events should be treated the same.
SERC RRS OPS		☑	DC and AC contingency events should be treated the same. The question is somewhat obscure.
SCE&G		☑	General there should be no difference between AC and DC; however, the answer to this question depends on the contractual arrangements associated with the transfer.
Southern Transm.		☑	Why should the reliability level for a transaction on a DC line be different from a transaction over AC? Also, when the transfer over DC is removed, the load it was serving still has to be picked up in the AC network because load cannot be dropped. Therefore, this places a burden on the AC network to serve additional load. If you allow transfers over DC to be interrupted, you should also allow the interruption of transfers over AC for the same events.
LADWP		☑	If the transfer is on a line experiencing outage, then the transfer is interrupted. Whether or not the transfer is firm is immaterial. Whether or not it is on the dc or ac line is also immaterial.
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating	☑		This should also apply to firm transfers via single or double ac facilities as well. In either case, the transfer could be linked to dedicated facilities.
ITC	☑		However, the owners of the firm transfers may not agree. If they don't, a system impact study needs to be part of the assessment IF THE OWNERS OF THE FIRM TRANSFERS DO NOT AGREE. It must be clear to the original TSR requester that this was truly conditional on the DC line being in service. If it was granted without telling them this, then the interruption of firm transfers should NOT be permitted.
TVA	☑		There are also conditions where this interruption should be allowed for a single AC tie line.
Response: The SDT did not make a change in response to your comment because many of the transfers over DC lines are automatically curtailed when the DC line is outaged.			
IESO		☑	Whether or not interruption of firm transfers should be allowed is more a business arrangement issue than a transmission reliability issue. Usually, delivery over a DC line, either as an import or access to internal or external resources, is factored into the resource integration plan to support meeting demand and energy transfers. The commitment for firm transfers may be made on the reliance of this delivery. However, the contingent loss of any resources including import is assessed in determining the amount and terms of firm transfers to a third part. This is a business

Q30			
Commenter	**Agree**	**Disagree**	**Comment**
			and resource allocation issue, not a transmission reliability issue.
Response: While it is true that there are business issues associated with the subject of this question, the SDT disagrees with the commenter with regard to the relevance for reliability. How firm transfers will be treated in the standard will have significant impact on Transmission System reliability across NERC. The SDT has not directly made any changes to the standard as a result of this comment but has considered this comment in deciding how to proceed with firm transfers in the standard.			
Progress–Florida		☑	The proposed standard does not distinguish between asynchronous DC ties and the more common parallel connected DC tie. With an asynchronous DC tie, the transfer is lost with the tie. With a parallel DC tie, the transfer will be shifted to the parallel AC system and should have the same performance requirements.
Response: The SDT deleted the reference to asynchronous DC ties in the tables.			
WECC BPA TSGT TEP	☑	☑	We agree with the question asked. In addition, transactions that can be interrupted due to the loss of a DC line should not be limited to the firm transactions, that are dependent on the DC line. It should also include interruptible transactions and other transactions made available through negotiated agreements on both AC and DC lines.
Response: The SDT did not make a change in response to your comment because many of the transfers over DC lines are automatically curtailed when the DC line is outaged and because the ability to interrupt other transfers such as non-firm transfers are already provided for in the standard**.**			
Manitoba Hydro	☑		MH agrees that reduction of firm transfer to readjust the system after a contingency should be allowed for all events. The requirement to maintain firm transfer is a more stringent requirement that in the existing standard. The need to maintain firm transfer amounts to N-2 planning with no reliability benefit. Reduction in firm transfer is not equivalent to loss of load as the transfer is backed up by reserves. MH could not accept a standard mandating that firm transfer can not be interrupted. MH also recommends P2-3 be moved into the P1 bucket as loss of a single pole of a dc line is similar to loss of a generator or transmission circuit.
Response: The SDT does not agree with your first comment on the need to allow reduction of firm transfer for all events since changes have been made to the standard to comply with FERC Order No. 693 which does not allow curtailment of firm transfer or dropping Non-Consequential Load for single Contingencies. The SDT agrees with your second comment and has made the change in the tables.			
MRO	☑		The MRO questions why interruptions of firm transfers are not allowed in other cases since load dropping is allowed for these cases.
Response: The SDT did not make a change in response to your comment because the ability to interrupt other transactions, such as interruptibles, is already provided for in the standard.			
ABB	☑		Yes, this is the purpose of HVDC. It carries the power your want, no more, no less. Both the good and bad of parallel flows are avoided.
Brazos Electric	☑		

Q30			
Commenter	**Agree**	**Disagree**	**Comment**
City Water Power and Light	☑		
Dominion			Not applicable since Dominion has no DC lines.
E ON US			No opinion, we do not operate DC.
ERCOT ISO CAISO	☑		In addition, the interruptible and other negotiated transactions should also be allowed.
Northwestern Energy	☑		
AECI	☑		
Allegheny Power	☑		
AEP	☑		
APPA	☑		
Exelon	☑		
FirstEnergy	☑		
ISO/RTO	☑		
KCPL	☑		"Firm" capacity dependent on DC line is similar reliability as a generator.
MISO	☑		The key word in this question is "dependent". Transfer is "firm" if DC line is in service.
NERC TIS			TIS will discuss this in further review of the standards development.
New York ISO	☑		NYISO agrees from a reliability aspect.
NCEMC	☑		Not applicable.
PJM	☑		
Seattle City	☑		Otherwise, we need reserve transfer capacity equal to the total of the firm transfers, which is not very cost effective!
Tenaska	☑		
WPS	☑		
Response: Thank you.			

E) Stability

31) Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Summary Response: Some respondents thought that the Contingencies are the same for steady state and Stability or should be made the same with only one table. Some respondents thought that having two tables was confusing while others thought it improved clarity. The large majority agreed that separating Stability from steady state was the appropriate approach. The SDT will continue to have Stability and steady state analysis separate with two tables.

Q31			
Commenter	**Yes**	**No**	**Comment**
Ameren		☑	We understand the need to clarify the different requirements in the steady- state vs. the stability analyses. However, for each contingency category we expect to see both the steady-state requirements and the corresponding stability requirements in the same table. We believe that it would be better to recombine the steady-state and stability tables and present the information in a landscape format.
Response: The Contingencies are different in the extreme category. Therefore, it will be less clear to have only one table which includes both. The SDT decided to keep two tables.			
BCTC		☑	Disagree with the assumption that steady state and stability analysis are different and should be separated. There are only minor differences between the tables and the reasons are not apparent. The separate tables appear to be unnecessary and is confusing, especially the same contingency numbering for both tables. Any contingency that must be studied in the stability period should also be considered in the post transient steady state period. Request that the SDT provide an explanation of their assumption.
FPL		☑	The separation of steady state and dynamic response analysis requirements into two tables (with different contingencies) is inferior to the analysis requirements outlined in Table 1 of the existing TPL Standard. The structure of Table 1 reinforces the requirement for grid stability and maintaining the grid within applicable limits for Category B and C contingencies. Dynamic simulations of Category B and C contingencies that demonstrate grid stability should be followed up with post transient power flow analysis to assess voltage and thermal limits.
FRCC		☑	There are two points of view for this question. One view is that having the performance requirement for steady state and dynamics on two separate tables is a good idea. It makes it easier to identify the performance requirements for steady state and dynamics. The other view is that separation of these requirements into two tables is not necessary because the existing tables are clear and FERC Order 693 only required the footnotes to be clarified not to redevelop the tables. The structure of existing Table 1 reinforces the requirement for grid stability and maintaining the grid within

Q31			
Commenter	**Yes**	**No**	**Comment**
			applicable limits.
HQTE		☑	The contingency studied are the same and as a result should be combined into one table. Only the performance might be different. We understand the need to clarify the different requirements in the steady state vs. the stability analyses. However, for each contingency category we expect to see both the steady-state requirements and the corresponding stability requirements in the same table. We believe that it would be better to recombine the steady-state and stability tables and present the information in a landscape format.
LADWP			There is no vote needed here because even under the current standards, the performance requirements for steady state and stability are clearly separated. So what is being added?
IESO	☑	☑	We agree that the performance requirements for steady state analysis differ from those for stability analysis, but not the contingency requirements. While the specification of, for example, a line to ground fault on a single facility does not mean much to a steady state analysis, and in fact the loss of a single facility is all that it matters, the system is subject to the same type of contingency regardless of the type of analysis to be performed and hence the same contingency needs to be tested in both steady-state and dynamic simulations.
Response: The SDT decided to separate steady state from Stability because the models used in the two analyses are different and the Contingencies required are different. Therefore, the SDT decided to keep two tables.			
FirstEnergy		☑	While we agree that steady-state and stability are different situations, in general we believe that the tables are confusing, overly worded, and should be combined. The initiating events are the same regardless of steady-state or stability so there should be no reason not to combine the tables as was done in the previous standards.
Response: The initiating events are different in the extreme category. Therefore, it will be less clear to have only one table. The SDT decided to keep two tables.			
New England ISO		☑	Only the difference between steady-state and stability analysis should be the performance requirements. The list of contingencies should be identical regardless of the type of analysis.
NPCC RCS		☑	The contingency studied are the same and as a result should be combined into one table.
Manitoba Hydro	☑		Yes but the definition of contingencies in table 1 and table 2 should be identical.
Progress–Florida		☑	The separation of steady state and dynamic response analysis requirements into two tables (with different contingencies) is unnecessary, and is inferior to the analysis requirements outlined in Table 1 of the existing TPL Standard. The structure of the existing Table 1 reinforces the requirement for grid stability and maintaining the grid within applicable limits for Category B and C contingencies. Dynamic simulations of Category B and C contingencies that demonstrate grid stability should be followed up with post transient power flow analysis to assess voltage and thermal limits.
Tenaska		☑	The same set of contingency tests need to be applied to in both steady state and stability studies. The performance levels may need to be characterized a little differently, but at the end of the day we

Q31			
Commenter	**Yes**	**No**	**Comment**
			are trying maintain a reliable system for the same initiating event both in a stability timeframe and a steady state timeframe.
Response: The SDT believes that some contingencies are only appropriate for steady state analysis and not for stability. The SDT believes that two tables are clearer than having only one.			
BPA	☑	☑	Support comments sent by WECC. There is a link between transient stability and steady state performance for a given event since they model serial time frames for the event.
WECC TSGT TEP	☑	☑	We agree with the question asked. In addition, because of the time sequence from the start of the fault, through fault clearing and transient dynamic period, the post-transient period to the steady state post-contingency period, there needs to be clear links between the performance requirements in the transient dynamic time period and the steady state time period. For example, if generator dropping or controlled load interruption is allowed in the transient dynamic period, it should also be allowed in the steady state time period that follows. Otherwise, it would put the Transmission Planners and the Planning Authorities in an untenable situation because, once a generator or load is dropped in the first few cycles after the disturbance; it cannot be required to be on line in the minutes that immediately follow.
Response: The SDT agrees that there should be a clear link between performance requirements in the transient period and the steady state period. We believe the standard as written provides this.			
ERCOT ISO	☑		Agree that the two analyses should be treated separately. It is not clearly defined what is steady state and what is stability. For example, are Voltage Stability (PV analysis) studies steady state or stability? Also what are the differences between System Stability and Plant Stability? Are stability studies only required for the near term planning horizon?
Response: Generally, most parties did not express confusion over the issues that are raised by this question. The SDT believes the general industry understanding is as follows: • Voltage Stability (PV analysis) is considered to be a steady state study. • Generating Unit Stability focuses on an individual generating unit or electrically closely-coupled generating units at maximum power and is concerned with Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of Interconnection or one bus away from that point. System Stability studies focus on portions of the System, which may include many generating units possibly at maximum power with Contingencies in that area of the System. System studies would also include Contingencies in large Load areas (using Load models with induction motors properly represented) which could result in fast voltage collapse. • System Stability studies are only required in the Near-Term Planning Horizon. Generating Unit Stability studies could be required for the Long-Term Planning Horizon if the commercial operation date of the plant is in the long term.			
ITC	☑		We agree but consideration should be given to the amount of work needed by entities to meet these requirements. Full scale annual stability studies may not be needed. If possible, criteria should be developed as to when stability studies need to be repeated (if at all) and to what level (i.e. every bus on the system or just the generator busses or somewhere in between).
Response: Full scale annual Stability studies are not necessarily required by the standard. Allowance is made for the use of past studies in the current year assessment.			

Q31			
Commenter	**Yes**	**No**	**Comment**
ABB	☑		Yes, I like this. You can maintain them to be as similar as possible, while still containing the requisite differences.
AECC	☑		
AECI	☑		
Allegheny Power	☑		
AEP	☑		
APPA	☑		
ATC	☑		
Brazos Electric	☑		
City Water Power and Light	☑		
CAISO	☑		Agree that the two analysis should be treated separately.
CenterPoint	☑		Separating the stability requirements into a second table improved the clarity.
Central Maine Power	☑		
CPS Energy	☑		
Duke Energy	☑		
Entergy	☑		This approach clarifies the types of stability studies/simulations to be performed. The performance criteria/guidelines are more explicit under the proposed Standard.
Exelon	☑		
Dominion	☑		
E ON US	☑		
Georgia Transm.	☑		
ISO/RTO	☑		
KCPL	☑		
LCRA	☑		
MEAG Power	☑		
MISO	☑		

Q31			
Commenter	**Yes**	**No**	**Comment**
MRO	☑		The MRO commends the SDT in separating the two tables. The single table for both types of studies has generated confusion in the industry.
Muscatine P&W	☑		
National Grid	☑		
NERC TIS	☑		Although there are many similarities, separation of the testing requirements makes the standard far more understandable.
New York ISO	☑		
NCEMC	☑		
NU	☑		
Nstar	☑		
PJM	☑		
Progress–Carolinas	☑		
ReliabilityFirst	☑		
Santee Cooper	☑		
SaskPower	☑		
Seattle City	☑		
SERC EC DRS	☑		
SERC EC PSS	☑		
SERC RRS OPS	☑		
SCE&G	☑		
Southern Transm.	☑		
TVA	☑		
United Illuminating	☑		
WPS	☑		
Northwestern Energy	☑		
Response: Thank you.			

32) Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Summary Response: The respondents were divided on this question. Most of the negative opinions expressed a view that there is no material distinction between plant and System Stability, with some indicating that the analysis and requirements are the same for both types of studies. Others also suggested that plant Stability is simply a subset of System Stability. In response to these comments, the SDT modified the standard to clarify the distinction between Generating Unit and System Stability.

The following items were changed due to industry comments:

Generating Unit Stability Study: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations.

~~**Plant Stability Study**: Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~

System Stability Study: ~~Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.~~ Study that focuses on portions of the System, which may include many generating units, to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.

R2.5. The ~~plant~~ Generating Unit Stability analysis portion of the Planning Assessment shall be analyzed consistent with Requirement ~~R4.6~~ R5.6 with studies for the year when the following changes that could affect Stability margins occur:

Q32			
Commenter	**Yes**	**No**	**Comment**
ABB		☑	I don't see any reason to differentiate between "Plant Stability" and "System Stability". These are not commonly separated, and this distinction is not standard in the industry. You should not be inventing a distinction that doesn't exist. A better differentiation would be between generator (or angular) stability and load (or voltage) stability. These are usually independently studied and independently occurring.
CenterPoint		☑	CenterPoint Energy does not see the distinction between system stability and plant stability studies as defined in the draft standard. Meeting the performance requirements set in R4.5 should suffice for all stability studies. The requirements in R4.6 seem overly prescriptive and could potentially result in numerous studies being required that would have very little positive effect on transmission systems throughout the country.
FirstEnergy		☑	We do not see the difference between plant stability and system stability. Both are based on anuglar stability of machines connected to the system and therefore, they should be treated the same.

Q32			
Commenter	**Yes**	**No**	**Comment**
Progress–Carolinas		☑	Don't need to differentiate between plant and system. These are not usually separated. It would be better to separate angular stability and voltage stability. They are studied independently.
Tenaska		☑	It is not clear that there is any difference between the two studies.

Response: See summary response. To make the distinction clearer, the SDT has modified the definitions as well as R 2.5. The SDT also believes that specificity in R 2.5 will reduce the burden of performing the Stability studies necessary to ensure a reliable BES.

Generating Unit Stability Study: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations.

~~**Plant Stability Study**: Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~

System Stability Study: ~~Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.~~ Study that focuses on portions of the System, which may include many generating units, to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.

R2.5. The ~~plant~~ Generating Unit Stability analysis portion of the Planning Assessment shall be analyzed consistent with Requirement ~~R4.6~~ R5.6 with studies for the year when the following changes that could affect Stability margins occur:

CAISO		☑	Plant stability studies are a subset of system stability studies in which loss of a generator is already evaluated to meet performance requirements. In specific situations, sensitivity analysis can be done as deemed appropriate by the TP to address a particular system problem.
Central Maine Power HQTE New England ISO NU NPCC RCS NSTAR United Illuminating		☑	A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.
National Grid		☑	As defined in R2.5, a Plant Stability Study should be a part of a System Stability Study. The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.
Northwestern Energy		☑	Plant stability is an artificial distinction and is a subset of transient stability.
LADWP		☑	See my comment on the definition of Plant Stability. Unless the standard drafting team has something completely different from the common understanding of loss of synchronism and so on,

Q32			
Commenter	**Yes**	**No**	**Comment**
			transient stability covers both the so called Plant Stability and System Stability Studies.
Response: The SDT agrees that Generating Unit Stability studies can be viewed as a subset of System Stability studies. The requirements specific to Generating Unit Stability (Requirements R 2.5 and R 4.6 (now R 5.6)) reflect that view. The SDT believes that the specific focus on Generating Unit Stability in Requirement R 2.5 will reduce the burden of performing the Stability studies necessary to ensure a reliable BES.			
FPL FRCC		☑	There should be no such distinction. All stability studies must meet the Performance Requirements for Planning Events in Table 2 - Stability Performance. If there were different Performance Requirements then the distinction may be warranted. However system stability studies should be sufficient and not warrant additional work.
Progress–Florida		☑	There should be no such distinction. All stability studies must meet the Performance Requirements for "Planning Events in Table 2 - Stability Performance". If there were different Performance Requirements then the distinction may be warranted. If the format for "Planning Events in Table 2 - Stability Performance" remains in its existing state, however, system stability studies are sufficient and performing studies under the guise of Plant Stability would constitute additional work with no incremental benefit.
Response: See summary response concerning the distinction between Generating Unit and System Stability as described in Requirements R 2.4 and R 2.5 as well as Requirements R 4.5 and R 4.6 (now Requirements R 5.5 and R 5.6). To make the distinction clearer, the SDT has modified the definitions as well as Requirements R 2.5. The SDT also believes that specificity in Requirements R 2.5 will reduce the burden of performing the stability studies necessary to ensure a reliable BES. In addition, the required Contingencies for Generating Unit Stability studies are different than the Contingencies for System Stability studies. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study**: Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~ **System Stability Study**: ~~Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.~~ Study that focuses on portions of the System, which may include many generating units, to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits. **R2.5**. The ~~plant~~ Generating Unit Stability analysis portion of the Planning Assessment shall be analyzed consistent with Requirement ~~R4.6~~ R5.6 with studies for the year when the following changes that could affect Stability margins occur:			
Dominion		☑	More clarification is needed to distinguish the difference in studies performed for plant stability vs. system stability. For example, is a system study mainly a study of inter-area (i.e. - small signal) oscillations?

Q32			
Commenter	**Yes**	**No**	**Comment**
Response: To make the distinction clearer, the SDT has modified the definitions as well as Requirement R 2.5. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study**: Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~ **System Stability Study**: ~~Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.~~ Study that focuses on portions of the System, which may include many generating units, to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits. **R2.5**. The ~~plant~~ Generating Unit Stability analysis portion of the Planning Assessment shall be analyzed consistent with Requirement ~~R4.6~~ R5.6 with studies for the year when the following changes that could affect Stability margins occur:			
BCTC		☑	Plant stability is a Generator Interconnection study, addressed by FAC-001. By including this requirement in TPL, costs may be transferred. TPL-001 need not distinguish between system stability and plant stability. For Planning Assessments, these are the same thing. Plant stability arises when doing generator interconnection.
Response: The SDT has considered your comments and believes that FAC-001, as currently written does not ensure that Generating Unit Stability studies are performed or that specific performance requirements are met. The SDT also believes that the distinction between Generating Unit and System Stability as described in Requirements R 2.4 and R 2.5 as well as Requirements R 4.5 and R 4.6 (now R 5.5 and R 5.6) is warranted. The SDT believes that specificity in Requirement R 2.5 will reduce the burden of performing the Stability studies necessary to ensure a reliable BES.			
Manitoba Hydro		☑	The need to assess Plant Stability should be removed from this standard. The generator connection standard and the proforma tariff interconnection process ensure the plant stability meets performance requirements. Furthermore, the System Assessment provides an overall assessment of the integrated system performance, which includes the impact of the plant. The requirement for plant stability studies appears to be redundant and would be a waste of assessment resources.
Response: The SDT has considered your comments and believes that neither FAC-001, as currently written, nor the pro forma tariff, ensures that Generating Unit Stability studies are performed or that specific performance requirements are met. Furthermore, not all entities within North America are subject to FERC's OATT.			
MRO		☑	The MRO sees the need for plant stability study requirements somewhere in NERC standards although adding this requirement into this study requires a rehash of the plant stability studies that are conducted throughout ten years or more in an annual assessment. This seems to be an unnecessary duplication. The MRO recommends that this requirement be deleted from this standard and that the

Q32			
Commenter	**Yes**	**No**	**Comment**
			SDT recommend to the NERC SAC that this requirement be covered by the appropriate future SAR.
Response: The SDT believes that the draft requirements do not lead to duplicative studies. If the studies that you reference meet the requirements of TPL-001-1, those studies would in fact satisfy the requirements and additional studies would not be necessary. Furthermore, we believe Requirement R2.5 will reduce the number of studies required because it only requires restudy for generator additions or material changes to the System near the generator.			
WECC BPA TSGT TEP		☑	It appears that Plant Stability Study is a subset of System Stability Study. R4.6.2 states these shall be performed for changes in real power output of a generating unit by more than 10%. Then it states they shall be performed for planning events. R4.5 already covers any contingencies that are an issue and the system already needs to meet some level of performance for loss of the generator. It seems that a change in generation would already be analyzed from a system standpoint as stated in R2.4.3. It appears that material changes to existing generators should be reflected in modeling requirements elsewhere.
Response: The SDT agrees that Generating Unit Stability studies can be viewed as a subset of System Stability studies. The requirements specific to Generating Unit Stability (Requirements R 2.5 and R 4.6 (now R 5.6)) reflect that view. The SDT believes that the specific focus on Generating Unit stability in Requirement R 2.5 will reduce the burden of performing the Stability studies necessary to ensure a reliable BES. To be clear, the 10 % change in generation capability (captured in Requirement R 5.6.2) is what drives the need for a revised study.			
CPS Energy		☑	
Response: Thank you.			
IESO	☑	☑	We agree that both plant stability and system stability have to be studied and that both must exhibit acceptable performance to deem a testing acceptable. The performance requirements for the two could be different, but not the contingency set that must be tested.
Response: The SDT believes that extreme event Contingencies are not required for Generating Unit stability studies.			
Ameren	☑		We appreciate the SDT concern for performing repeated plant stability studies without any change in plant/machine characteristics. However, as the system load representation and its damping characteristics affect both plant and system stability, it is difficult to separate plant versus system stability studies. On some systems in which load and generation are tightly coupled, the focus of plant or system stability studies may differ only slightly with the location and duration of applied fault events. As such, the scope and manner of conducting System Stability study work under Requirement R2.4. for such portions of the interconnected system is not clear. Differences between Plant Stability Studies and System Stability Studies need to be made more clear.
Response: The SDT recognizes that the specific studies required to satisfy the Generating Unit and System Stability requirements will be System specific. In that regard, for some Systems there may be little or no distinction and a single set of studies could satisfy all Stability requirements.			
City Water Power and Light	☑		Yes but the distinction is not clear in the definitions. A Plant Stability Study would typically be done as part of the Generator Interconnection Request and have all units in the area at maximum output. Is the System Stability Study done on the Base Case or is generation maximized within some area(s)?

Q32			
Commenter	**Yes**	**No**	**Comment**
Response: To make the distinction clearer, the SDT has modified the definitions as well as Requirement R 2.5 Also, as indicated in Requirement R 2.4, the System Stability studies should be run using base cases (peak and off-peak) as well as various sensitivity cases (Requirement R2.4.3). **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study**: Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~ **System Stability Study**: ~~Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.~~ Study that focuses on portions of the System, which may include many generating units, to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits. **R2.5**. The ~~plant~~ Generating Unit Stability analysis portion of the Planning Assessment shall be analyzed consistent with Requirement ~~R4.6~~ R5.6 with studies for the year when the following changes that could affect Stability margins occur:			
New York ISO	☑		NYISO agrees with the concept of splitting plant and system stability studies, but only in the area of performance requirements. The studied contingencies should be identical.
Response: The SDT believes that the selection of study Contingencies is System specific. Although it is not required, for some Systems it may be appropriate to use the same Contingency set for Generating Unit and System Stability studies.			
AECI	☑		
Allegheny Power	☑		
AEP	☑		
APPA	☑		This has been needed for some time.
ATC	☑		
Brazos Electric	☑		
E ON US	☑		
ERCOT ISO	☑		Agree with this additional analysis.
Duke Energy	☑		
Entergy	☑		See response to Q9

Q32			
Commenter	**Yes**	**No**	**Comment**
Exelon	☑		
Georgia Transm.	☑		
ISO/RTO	☑		
ITC	☑		See response to Q31.
KCPL	☑		
LCRA	☑		
MEAG Power	☑		
MISO	☑		
Muscatine P&W	☑		
NERC TIS	☑		Planning Coordinators should study plant stability at the time of interconnection, and it should be reviewed for significant system or plant modifications that may impact the plant's stability.
NCEMC	☑		
PJM	☑		
ReliabilityFirst	☑		
Santee Cooper	☑		
Seattle City	☑		
SERC EC DRS	☑		
SERC EC PSS	☑		
SERC RRS OPS	☑		
SCE&G	☑		
Southern Transm.	☑		
TVA	☑		
WPS	☑		
Response: Thank you. Please see the Summary Response.			

33) Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of Extreme Events? If not, please explain.

Summary Response: The majority of commenter's agree with excluding the loss of all generating units at a plant in the Stability analysis of Extreme Events. The SDT agrees with not including this condition in Table 2. Nevertheless any TP or PC could study this Contingency if they believe such a study is warranted.

Q33			
Commenter	**Yes**	**No**	**Comment**
ABB		☑	No. Good idea. A whole plant may be out because of a shortage of cooling water, but this is an orderly shutdown, not a sudden event. It is only appropriate for steady-state.
Brazos Electric		☑	
Dominion		☑	It is unlikely that all units at a plant would trip simultaneously within a short time frame (20 second or so) for which stability simulations are performed.
E ON US		☑	I agree with the SDT's conclusion.
AECI		☑	Agree with the statement above as to the time frame regarding stability.
CenterPoint		☑	CenterPoint Energy agrees with the SDT's assessment.
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating		☑	Difficult to envision how such an event would occur.
CPS Energy		☑	
Duke Energy		☑	We agree with the basis laid out (in the question) by the SDT.
FirstEnergy		☑	We do not believe that this condition should be required to be tested using stability analysis of Extreme Events. This is due to the fact that these events should be required to be studied using steady state analysis, and stability analysis results would not add value.
Georgia Transm.		☑	
ITC		☑	If it is not probable, then why study it. Realistic probabilities need to be established and defined for study.

Q33			
Commenter	**Yes**	**No**	**Comment**
KCPL		☑	Agree it is difficult to develop scenario where all units trip simultaneously in stability timeframe.
Muscatine P&W		☑	Unless there is a reasonable reason to expect all the units to trip.
Progress–Carolinas		☑	
Progress–Florida		☑	Analysis of this condition should not be required in stability analysis of Extreme Events due to the fact that no stability simulation (e.g., SLG or 3-phase faults) can be conceived for the Bulk Electric System that would result in simultaneous tripping of all units at a plant.
SERC EC DRS		☑	This question conflicts with Table 2 Extreme Event 9. However, we feel it is not necessary to simulate loss of all units at a station because simultaneous loss of all units is unlikely.
SERC RRS OPS		☑	It is not necessary to simulate loss of all units at a station. The Transmission Planner or Planning Authority should have the discretion to consider the appropriate number of units to be tripped based on station design, relay design, etc.
Southern Transm.		☑	
Response: Thank you.			
BCTC		☑	Stability should be treated the same as steady state. If there is a common mode event that could cause the loss of all generating units at a plant, all relevant simulations should be done. If a common mode contingency of all units at a generating plant is not relevant for stability, then it is not relevant as an extreme event for steady state either. However, operation with all units at a plant off line may be relevant as a sensitivity case for Planning Events. The Transmission Planner needs some lattitude to determine what needs to be considered under Extreme Events and the standards should not be overly prescriptive.
Response: The SDT disagrees with this point of view. There are Extreme Events which are relevant for steady state but not for Stability analyses.			
Entergy		☑	This question conflicts with Table 2 item 9. However, we feel it is not necessary to simulate loss of all units at a station. The Transmission Planner or Planning Authority should have the discretion to consider the appropriate number of units to be tripped based on station design, relay design, etc. Since there is no specific question related to R3.4 that requires an evaluation be conducted of implementing a change designed to reduce or mitigate the likelihood of such consequences. More specific direction should be provided in this regard.
LADWP		☑	Loss of a plant as an extreme contingency has been on the book forever and it has never been interpreted as exempted from stability simulation (at least not in WECC) if this scenario is chosen as an extreme event. However, there is no mandatory requirement that loss of all generating units at a plant must be studies for every generating plant. If the design of a generating plant, such as use of redundancy, separate control console/rooms, etc., are such that all unit tripping simultaneously is unlikely, then it should not be required to be studied just because all the units are inside the fence.
Response: The SDT agrees that the removal of the Requirement to consider the loss of all generating units at a plant in Stability analysis,			

Q33			
Commenter	**Yes**	**No**	**Comment**
from the Extreme Events of Table 2 does not preclude the Planner from performing this study. The language in R3.4. allows the TP or PC to evaluate the risks versus the costs of implementing mitigation or a reduction of the possibility of that Contingency.			
FPL FRCC		☑	The question does not match what is included the Extreme Events section of Table 2. Loss of all generating units at a plant should be considered in the Steady State Performance - Extreme Events but not in the Stability Performance - Extreme Events because of the very low probability of the event occurring within the timeframe of the Stability simulation. Therefore, the performance requirement number 9 for Extreme Events in Table 2 - Stability Performance should be deleted.
Response: The SDT agrees and has removed the Contingency from Table 2.			
MEAG Power NCEMC SERC EC PSS SCE&G		☑	Generator protection is designed to trip only those units required. In addition, it is the magnitude of generation tripped rather than the number of units tripped that is of the greatest significance to the stability of the grid.
Response: The SDT agrees that the magnitude of the generation being tripped is significant and should be studied when applicable. The SDT agrees that the removal of the Requirement to consider the loss of all generating units at a plant in Stability analysis from the Extreme Events of Table 2 does not preclude the Transmission Planner or Planning Coordinator from performing this study.			
New York ISO		☑	Examples of loss of entire generation station: Complete loss of right-of-way exiting facility, simultaneous relay operations due to common cause or mode.
Response: Your examples may be applicable to a site in your area and if you desire, you can continue to study steady state and Stability but the removal of this note from the Table does not stop the TP or PC from performing the stability studies if desired.			
Santee Cooper		☑	The transmission planner should have discretion to consider the appropriate number of units to be tripped based on the station design, and/or relay design.
Response: The SDT agrees that the removal of the Requirement, to consider the loss of all generating units at a plant in Stability analysis, from the Extreme Events of Table 2 does not preclude the Transmission Planner or Planning Coordinator from performing this study.			
SaskPower		☑	What is the purpose of requiring this event or any other extreme event to be studied? We see little benefit in this. In the Saskatchewan context we accept the risk and consequences for Extreme Events as there is usually very little justification for the increase in reliability versus the economic cost. Saskatchewan plans and designs its system to fail safe in those events and restores the system thereafter.
Response: The SDT agrees with your comment and that is the reason Question 33 was asked of the industry.			
Tenaska		☑	Only on a case by case basis where a common mode/single point of failure can be identified that results in the loss of an entire plant.
Response: The SDT agrees with your statement.			
TVA		☑	This question conflicts with Table 2 Extreme Event #9.
Response: The SDT agrees that this is in conflict with Table #2 Extreme Event #9 and that is why the SDT has now removed it from the Table.			
WECC		☑	We agree with the SDT that simultaneous 3-phase fault on all generating units in a plant is

Q33			
Commenter	**Yes**	**No**	**Comment**
BPA TSGT TEP			improbable and effort should be better spent studying more probable events. In any case, this Extreme Event is to be considered in the Steady State Table, and stability cases can be run if it is shown to be needed in the power flow study results. We are, however, confused by this question. This question states that the SDT did not include the requirement to consider loss of all generators at a plant in the stability, yet the Extreme Event in the stability table shows in No. 9, "3Ø fault with loss of all generating units at a station".
Response: The SDT agrees with your comment and apologizes for the confusion from the wording of the Question. The Contingency has been removed from the Table.			
Northwestern Energy	☑	☑	If such a standard is constructed, it should be based on a common mode of failure mechanism.
Response: The SDT agrees in removing this from the Table #2. However, the Standard language does not preclude a Transmission Planner or Planning Coordinator from studying this, if applicable. The Standard will allow the TP or PC to perform the study without it being a Requirement.			
AEP	☑		Extreme Event #9 in Table 2 has 3-phase fault and loss of all generating units at a station. Was this left in by mistake? This type of scenario could conceivably lead to low interconnection frequency or cascading due to consequent transmission overloading or low voltage, and could be studied by dynamic simulation. There have been a number of just such generation loss events as this in the past.
Response: The SDT did not leave the 3-phase fault in by mistake; it was intentional and follows with the other Requirements in the Table. Rather, Question 33 was phrased incorrectly in stating that this requirement had been removed from the Table. However, by not having this listed in the Requirements does not preclude the Transmission Planner or Planning Coordinator from studying this condition if applicable to their system.			
APPA	☑		This is a conditional Yes. If the plant design was such that a fault at the plant could remove all units, then all units should be considered. However, if the plant design is such that the likelihood of all plants going down at one time is improbable, then the SDT's approach is very reliable.
Response: The proposed removal of note #9 in the Table will not preclude Transmission Planners or Planning Coordinators from studying this condition if applicable.			
IESO	☑		Consistent with our comments provided under Q31, while the performance requirements may be different, there should be no distinction made to the type of contingencies that need to be applied to steady state testing and stability testing. An entire generating station may be lost due to various possible reasons: lost of right of way of transmission lines emanating from the generating station; generic protective relaying problems which cause all relays to operate due to a common cause or common mode event.
Manitoba Hydro	☑		Isn't 2.d such an event? In a breaker-and-1/3 or 1/2 generating station, if one station bus is off-line for maintenance, faulting the other bus will kill the station, or at least cause a major disruption with individual generators connected to other stations by separated lines. That is certainly worthy of consideration as a feasible "extreme" event Further, the same low likeihood argument could be applied for the majority of Extreme Events in Table 2.The emphasis should be on what the response is for Extreme Events rather than the likelihood of the event.

Q33			
Commenter	**Yes**	**No**	**Comment**
Response: The SDT and the majority of the industry do not think that this should be required in Stability analysis for Extreme Events. The events which remove all of a generating unit from the System occur over a longer period of time which is more applicable in the steady state analyses. These are Extreme Events which are relevant for steady state but not for Stability analyses.			
MRO	☑		In a breaker-and-1/3 or breaker-and-1/2 generating station, if one station bus is off-line for maintenance, faulting the other bus will kill the station, or at least cause major disruption with individual generators connected to other stations by separated lines or AC separated DC converter transformers via isolated station bays. That is certainly worthy of consideration as a feasible "extreme" event.
Response: The SDT and the majority of the industry do not think that this should be required in Stability analysis for Extreme Events. The events which occur to remove all of a plant from the system occur over a longer preiod of time which is more applicable in the steady state analyses.			
NERC TIS	☑		Simultaneous loss of the entire generating stations have occurred on 4 occasions in the last 3 years, with simultaneous losses ranging from 1,100 MW to over 3,700 MW. It is important to understand the stability implications to the system and other plants.
Response: The SDT and the majority of the Industry do not think that this should be required in Stability analysis for Extreme Events. The SDT does not believe these events would result in the loss of all generation in a Stability timeframe.			
PJM	☑		Yes, but should model the true clearing times of each individual unit. Also the standard should clearly state that system reinforcement should not be required for this Extreme Events.
Response: The SDT and the majority of the industry do not think that this should be required in Stability analysis. However, by not having it listed in the Requirements does not preclude a Transmission Planner or Planning Coordinator from studying this particular condition. Also, refer to the language of current standard Requirement R5.5.4 which addresses the reinforcement logic.			
Allegheny Power	☑		
Ameren	☑		A good test of the robustness of the interconnected system is its ability to handle import plus heavy inrush conditions, such as might occur with loss of a large plant. While the probability of such random events would be very low, the possibility still exists that intentional sabotage could result in such an event.
ATC	☑		
Response: The loss of a large gas pipeline into a region is not the same as a 3 phase fault at the generator bus location. If the gas line were ruptured, the units would be shut down over a period of minutes, not in a stability time frame. The E3.a in Table 1 is for steady state analysis.			
City Water Power and Light	☑		If there is any single contingency event that could take out an entire plant, it should be studied.
ERCOT ISO CAISO	☑		It will be consistent with the performance requirements under Steady State conditions. Also, loss of entire generating station is possible for a variety of reasons such as, loss of all lines emanating from the station, loss of the gas pipeline feeding the plant, etc.
Response: The loss of a large pipeline would not result in the sudden shutdown of all units within a stability timeframe. The shutdown occurs over tens of minutes.			

Q33			
Commenter	**Yes**	**No**	**Comment**
AECC	☑		It should also be considered in steady state analysis.
Exelon	☑		
ISO/RTO	☑		
LCRA	☑		
MISO	☑		
Seattle City	☑		
WPS	☑		
Response: Thank you.			

34) Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Summary Response: There is consensus that slow voltage recovery is an observed phenomenon that requires study and potential corrective action. However, nearly all responders noted the difficulty of obtaining accurate dynamic Load models. Based on the responses, the study of this phenomenon is in its relative infancy. Most responders are looking for guidelines for these studies whether they answered 'yes' or 'no'. The Transmission Issues Subcommittee (TIS) is forming a working group (TIS WG) to write a technical white paper on this issue. The SDT has recommended that this group include guidelines for load models in their white paper.

Based on industry comments, the SDT believes that this is such an important issue that a Requirement should be in place. As such Requirement R2.4.1 was changed. It will be up to those performing the studies to document their dynamic Load models.

R2.4.1. System peak Load for one of the five years. For peak System Load levels, ~~the~~ a Load model shall ~~include the dynamic effects~~ be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads.

Q34			
Commenter	**Yes**	**No**	**Comment**
E ON US		☑	I agree that this is an issue but I do not have sufficient data to accurately simulate the condition. This is also complicated by dynamic behavior of distribution capacitors which are not modeled.
SERC RRS OPS		☑	There is a lack of data to support the amount and characteristics of the detailed induction load models in many areas. Transmission planners should be able to use the latest information and techniques.
SCE&G		☑	There should be an attempt to represent the dynamic behavior of induction motor loads in the generic system load representations. However, the state of induction motor load modeling is not adequate to permit discrete induction motor load models.
AEP		☑	The statements of fact in the question may be true for some study areas, but not necessarily for all. Requiring this type of load representation when it might not be appropriate to the study is excessively burdensome. This is a judgment better left to those conducting the studies. The percentage of load to be so represented, the extent of the study area over which to apply induction machine representations, and the specific modeling parameters are all judgments just as important as whether or not to include this type of representation. There is a limit as to how far a standard can replace engineering judgment and that limit is reached here.
CenterPoint		☑	CenterPoint Energy includes the dynamic effects of induction motor loads in stability studies. However, this requirement is overly prescriptive since some utilities may not need to include the dynamic effects of induction motors and should not be required to do so.
Central Maine Power National Grid New England ISO		☑	This requirement is too specific and limited. Induction motors are only one component of a complex load model. Complex load models are not always necessary, nor are they always the most conservative, depending on the analysis that is being conducted. Where complex load models are

Q34			
Commenter	**Yes**	**No**	**Comment**
NU NPCC RCS NSTAR United Illuminating			required, they should be considered; this may involve use of complex motor and lighting loads or polynomial load representations with or without frequency dependence. This question also suggests the need for an industry standard regarding transient voltage recovery.
Duke Energy		☑	In general, it is a good practice for System Stability studies of seasonal load conditions to include the effects of induction motors. However, there is currently a lack of data to support the amount and characteristics of detailed induction load models in many areas. Prior to making this a requirement, the industry needs guidance as to how this data should be developed, shared and maintained for near-term and long-term models. A long term transition period is required to incorporate motor models into dynamics studies.
Entergy		☑	In general this is a good practice. Dynamic studies of seasonal load conditions should include the effects of induction motors, and particularly in areas where traditional load models have indicated a problem. Unfortunately, there is a lack of data to support the amount and characteristics of the detailed induction load models in many areas. In addition to the consideration of the dynamic effects of induction motor loads, the effects of static capacitor banks installed at distribution voltage levels would need to be considered as well. Prior to making this a requirement in the reliability standards, the industry needs guidance as to how this data should be developed and maintained for models in future years. This should be a business practice and thus removed from the standard. While we agree that each entity should appropriately model their loads, it would seem appropriate for the MMWG to address the issues of induction motor load modeling. Note that meeting such a requirement would necessitate a significant increase in the dynamic data needed to represent the system. Maintenance of such load model data would require significant resources. Load characteristics valid for a near term model might not be valid for future years.
FPL FRCC		☑	The issue of delayed voltage recovery is a special phenomenon that can occur in some large urban areas under peak conditions. The modeling of the delayed voltage recovery response is considerably more complex than simply representing induction motor effects. The scope of the delayed voltage recovery issue is extremely limited and its effect on the grid is generally self correcting due to automatic disconnection of the affected air conditioners. While improvements in the accuracy of load models used for the study of grid dynamic response are desirable, this area is not suitable for compliance enforcement. Requirements for specific types of load models are not appropriate in the TPL standard.
KCPL		☑	Transmission operators are required to maintain reactive reserve requirements.
MEAG Power NCEMC SERC EC DRS SERC EC PSS TVA		☑	Dynamic studies of seasonal load conditions should include the effects of induction motors, and particularly in areas where traditional load models have indicated a problem. Unfortunately, there is a lack of data to support the amount and characteristics of the detailed induction load models in many areas. In addition to the consideration of the dynamic effects of induction motor loads, the effects of static capacitor banks installed at distribution voltage levels would need to be considered as

Q34			
Commenter	**Yes**	**No**	**Comment**
			well. Prior to making this a requirement in the reliability standards, the industry needs guidance as to how this data should be developed and maintained for models in future years. Note that meeting such a requirement would necessitate a significant increase in the dynamic data needed to represent the system. Maintenance of such load model data would require significant resources. Load characteristics valid for a near term model might not be valid for future years. Also, summer peak load, winter peak load, and off-peak load characteristics would differ.
Muscatine P&W			We have not seen this on our system based on the review of digital fault recorders (DFR). The difficulty with including induction motors is getting reasonable data from customers about their motors so they can be adequately modeled. (We did ask our consultant to include motor effect in our coordination study since the motors could act as a weak source.)
PJM		☑	No. This is good in theory but is impractical to implement with the large interconnected systems that span large geographical areas.
Progress–Florida		☑	Requiring detailed modeling of every induction motor on the Bulk Electric System for stability analysis is onerous. Specifically, obtaining a complete set of data for existing induction motors would be infeasible, as would tracking future installations of induction motors. The benefits of such an effort are significantly outweighed by the logistical difficulties. To address the technical merits, the modeling of the delayed voltage recovery response that has been observed in some large urban areas during periods of high air conditioning usage is considerably more complex than can be addressed by simply representing induction motor effects. The scope of the delayed voltage recovery issue is extremely limited and its effect on the grid is generally self correcting due to automatic disconnection of the affected air conditioners. Requirements for specific types of load models are not appropriate in the TPL standard.
Santee Cooper		☑	The characteristics of detailed induction load are generally lacking to properly model induction loads. Load modeling should be left to the judgment of the TP.
Response: See the summary response, The SDT has recommended that the TIS WG writing the white paper on this phenomenon review your suggestions and comments.			
CPS Energy		☑	
Response: See summary response.			
AECC		☑	if someone want to study the effect of large motor load then fine but it should not be a requirement of a standard
Response: The SDT has received comments regarding the technical merits to include such behavior when appropriate. The SDT feels that proposing this requirement could potentially result in System studies that indicate System response that would meet the performance requirements when in fact the response may fall short.			
Ameren	☑	☑	Dynamic studies of peak load conditions should include the effects of induction motors, and particularly in areas where traditional load models have indicated a problem. Unfortunately, there is a lack of data to support the amount and characteristics of the detailed induction load models in

Q34			
Commenter	**Yes**	**No**	**Comment**
			many areas. In addition to the consideration of the dynamic effects of induction motor loads, the effects of static capacitor banks installed at both distribution and transmission voltage levels would need to be considered as well. The industry would be looking to NERC for some guidance as to how this data should be developed and maintained for models in future years. Note that meeting such a requirement would necessitate a significant increase in the dynamic data needed to represent the system. Also, maintenance of such load model data would need to be considered. Load characteristics valid for a near term model might not be valid for future years. Also, summer peak load, winter peak load, and off-peak load characteristics would differ.
Dominion	☑	☑	The dynamic effects of induction motor load at peak load conditions should be studied only on a limited/selected basis and should not be required for the entire system as a routine study practice. The following are examples where such an effort might be warranted: (a) where slow voltage recovery has been actually observed in the field following a fault clearance (b) where steady state analysis (P-V & Q-V curves) indicates a possible voltage collapse scenario for stressed system conditions (c) for a non-convergent (or very difficult to solve) power-flow case for stressed system conditions while solving for a contingency scenario.
Exelon	☑	☑	This is more pertinent to longer term voltage stability, so the load model should be developed and available for these types of studies.
WECC TSGT TEP BPA	☑	☑	The requirement to include motor load should be extended to other load level periods and not be limited to peak load period only. However, to capture slow voltage recover phenomena, especially in areas of high penetration of refrigerated air conditioning load (e.g. 50% to 60%), would require modeling down to the distribution system voltage level and explicitly representing shunt capacitors and various induction motor types (e.g. equivalents for single phase motors). If the requirement is not extended, dynamic simulations will likely differ significantly from observed system events. We recommend a phase-in period so that the requirement for use of load models should only include regionally accepted load models for which data are available. This requirement can be extended or modified as the Region in which the entities reside adopts new load modeling guidelines.
Brazos Electric	☑		However, acquiring load data may be difficult if not impossible and would require increased manpower. A more reasonable approach is to vary the load data to see the effects instead of wasting effort on load surveys.
City Water Power and Light	☑		However, low voltage often causes motors and air conditioner compressors to trip, significantly reducing peak loads.
ERCOT ISO CAISO	☑		The requirement to include motor load should be extended to other load levels as appropriate.
FirstEnergy	☑		We agree with this concept but believe that enforcing it would be very difficult. There are no standards on modeling induction motor load, be it type of models, percentage of load that is motor

Q34			
Commenter	**Yes**	**No**	**Comment**
			load, or percentage of large vs small motors.
HQTE	☑		This requirement is too specific and limited. Induction motors are only one component of a complex load model. Complex load models are not always necessary, nor are they always the most conservative, depending on the analysis that is being conducted. Where complex load models are required, they should be considered; this may involve use of complex motor and lighting loads or polynomial load representations with or without frequency dependence. This question also suggests the need for an industry standard regarding transient voltage recovery.
IESO	☑		Dynamic testing should assess response of moving equipment including induction motor loads.
ITC	☑		However this will require the Load Serving Entities provide specific data for each bus on the system which may not be in the direct control of the entity performing the studies. The standard should be written with this understanding in mind. Failure of a LSE to provide such data should not cause a penalty to be imposed on a Transmission Provider.
LADWP	☑		This is a qualified yes to the extent that accurate induction motor models are available and the overall load modeling (non-induction motor loads) allow such analysis. Otherwise, focusing only on induction motors would not provide added information than what is being performed today. The current WECC requirement concerning induction motor modeling should be deemed adequate to meet this requirement.
Manitoba Hydro	☑		R2.4.1 should be clarified to limit a requirement for detailed modeling (for example, dynamic effects of induction motors loads) to local areas where the planner expects a local emerging voltage recovery issue.
MISO	☑		Yes, we agree that appropriate induction motor loads should be modeled. No, it is not be practical to model all induction motor loads. There needs to be size and location considerations. Data is not readily available today.
MRO	☑		The MRO agrees that R2.4.1 should provide for the inclusion of dynamic behavior of induction motor loads, however, recommends that there should be a limitation on only requiring such behavior where significant such as large motor loads over a certain MW amount. As written, it could be interpreted that the Transmission Planner is non-compliant if all induction motors are not represented.
Progress–Carolinas	☑		This needs to be done but we currently don't have sufficient data and tools to properly perform the analysis. More interconnection-wide testing and data collection needs to be performed. We will need to transition into these studies over time.
ABB	☑		Yes, but the impact on the models and studies is unknown. Some testing needs to be done with full Eastern and Western Interconnection models to see how they handle motor models at every load. I've performed numerous studies where loads in an entire utility or state have been converted to a large % of motors, and the effect can be shocking. The programs (PSS/E and PSLF) may completely bog down if this is done for a whole interconnection. Many stability problems will be found. We definitely need to transition to this, but with care.
Northwestern Energy	☑		

Q34			
Commenter	**Yes**	**No**	**Comment**
AECI	☑		However, getting all the modeling data is not easy and may take some time.
Allegheny Power	☑		
APPA	☑		The SDT is correct to include the effects of induction motors in simulating the loads. Voltage issues are and will continue to become more critical in the operation of the BES as time goes by. It will be a big help to planners and operators to know the impacts of such loads.
ATC	☑		
BCTC	☑		
Georgia Transm.	☑		
ISO/RTO	☑		
LCRA	☑		
NERC TIS	☑		If such known phenomena are not properly modeled, how can the resultant study results be expected to be correct and a proper prediction of future system behavior. The modeling shortcomings of the Western Interconnection prior to the August 1996 western blackout showed no potential stability problems for the events that occurred; the system proved otherwise.
New York ISO	☑		
SaskPower	☑		
Seattle City	☑		
Southern Transm.	☑		
WPS	☑		
Response: See the summary response, The SDT has recommended that the TIS WG writing the white paper on this phenomenon review your suggestions and comments.			

35) Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Summary Response: Most responders said or implied that all adjustments should be allowed for both single and multiple Contingencies. Some respondents further clarify their response by adding the adjustments must be achieved within a specific timeframe such as meeting performance requirements or the ability to keep the generator on-line. A small number of responders replied that no adjustments should be allowed for single Contingencies but then agreed that adjustments may be allowed for multiple Contingencies.

The SDT has modified Requirement R 3.6 (now R3.5) of the steady state portion of the Planning Assessment to specify the conditions under which manual and automatic generation runback and tripping can be used to meet single and multiple Contingency performance requirements and to make it clear that all Facilities must always remain within applicable thermal and voltage ratings.

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:

Q35	
Commenter	**Comment**
ABB	For multiple, only automatic schemes. For single, only automatic schemes if the loss of MW is shown to be acceptable.
Ameren	No adjustment of firm (network resource) generation should be allowed for the long-term mitigation of a single contingency. Allowing post-contingency shifts of firm generation as a long-term mitigation of a single contingency event is short-sighted and would not produce a robust system that is required to handle more than single contingency events. Redispatch of firm generation may be required in the near-term as an interim operating guide or procedure until the limiting transmission element can be uprated or other system reinforcement is in place. Generation redispatch should also be allowed to prepare for the next single contingency. For responding to multiple contingencies, redispatch of firm generation should be allowed in the mitigation plan provided that the redispatch can be accomplished in the required operating time and the contingency overloads are not overly severe (indicating possible cascading). Firm generation should also be tripped to quickly mitigate contingencies involving multiple generation outlet transmission circuits. Non-firm (energy only) generation can be tripped or redispatched for any contingency event as needed to keep facility loadings within ratings.
City Water Power and Light	Dispatching quick start units such as combustion turbines or diesels, Contingency Reserve Sharing Group response, redispatch, adjust reactive resources as necessary.
Dominion	For a single contingency, no generation adjustment should be allowed. For multiple transmission element contingencies, generation reduction (automatic or manual runback) may be allowed. Unit trip should only be allowed if a unit becomes unstable.
E ON US	single – none
ERCOT ISO CAISO	Manual such as tripping the generators, automatic such as AVR, excitation systems, stabilizer, and governor adjustments. From a Planning perspective, you would not want to allow for manual tripping in the time frame of a stability study.

Q35	
Commenter	**Comment**
BCTC	No restrictions on adjustments that are practical and can be achieved within the timeframe required.
Northwestern Energy	All adjustments should be allowed as long as they are realistic and achievable in the time frame required and consistent with other study parameters. Also, if a RAS (or special protection system) is the adjustment and if cascading could result from the event, then redundancy should be required.
MEAG Power NCEMC SERC EC PSS SCE&G	Adjustments that should be allowed are those that can be performed in time to prevent the system from failing to meet performance requirements. These adjustments may include automatic voltage regulator action, governor action, generator runback, and generator tripping.
AECI	Whatever the generator is capable of.
Allegheny Power	Should not be limited.
AEP	The existing TPL standards imply that generator tripping is not permissible in connection with Category B events in that footnote b does not mention it, whereas it is mentioned in connection with Category C events in footnote c. Generation is a system resource and should be protected against the more common single contingency transmission events. We agree with the status quo on this issue being maintained in the new standard, with the provision for regional variance in R3.6. The provision for manual and automatic runback in R3.5 is okay. We also agree with manual adjustments remaining acceptable in response to any contingencies in the new standard consistent with C3 in existing TPL-003.
Central Maine Power HQTE National Grid New England ISO NU NPCC PCS NSTAR United Illuminating	Manual or automatic adjustments should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment. Manual system adjustment should be allowed in between the multiple Contingencies described in P5, provided that the adjustment can be made between contingencies using short-term reserves (10-30 minute).
Duke Energy	This question is not clear. Manual and automatic adjustments should be allowed for single and multiple contingencies as long as Performance Requirements are met.
Exelon	Generator MW and Mvar output adjustments should be allowed, both manual and automatic.
FirstEnergy	As long as thermal, voltage, and stability requirements are met, either automatic or manual runback of the unit should be allowed. Tripping of the unit should be allowed also if the particular unit(s) can be restarted within some relatively short time - say one hour. With this requirement, it appears that only CTs and hydro units would be allowed to be tripped.
FPL FRCC	Manual and automatic adjustment (increase or decrease) of Var output and manual and automatic tripping or reduction of overall MW output of generators should be allowed.
Georgia Transm.	Special Protection Schemes should be allowed for single and multiple contingencies.
IESO	Automatic adjustments should include AVR, excitation system, stabilizer and governor, all of which have pre-determined settings. These adjustments should be allowed for any type of contingencies. Manual adjustments that should or can be made other than removal of the generating units from service could include manual switching of

Q35	
Commenter	**Comment**
	transmission and adjustment to Phase Angle Regulators for so long that these actions are documented as applicable operating procedures.
ITC	There should be no change in generation for single contingencies. An approved SPS in those areas that use them might be an exception however system damage for failure to operate should not be allowed beyond the station with the SPS. Also, loss of load should not be allowed for failure to operate. An automated adjustment for multiple contingencies is not unrealistic.
KCPL	Generation redispatch should not be allowed for N-1 events. Generation redispatch is appropriate for multiple contingencies. Appropriate SPS and generation runback schemes should be allowed, where the system is designed with those schemes.
LADWP	Whatever is needed to bring the system into balance.
Manitoba Hydro	1) Reducing or increasing generation while keeping the units on-line or by bringing additional units on line. The amount of generation change should be limited to that amount that can be accomplished within the allowed readjustment period. Due consideration should be given to start up time and ramp rates of the units. 2) Generator tripping should be added to requirement R3.5 in addition to runback. Generator tripping is used extensively in regions where remote generation is delivered via long transmission. 3) Adjustment of firm transfer must be allowed for single and multiple contingency events. MH could not accept the revised standard that removed this existing requirement.
MISO	Generation redispatch should not be performed for single contingencies. Generation redispatch is appropriate for multiple contingencies. Appropriate SPS and generation runback schemes should be allowed, where the system is designed with those schemes.
MRO	Here are the adjustments that the MRO believes the MRO systems are presently designed to meet and what an MRO Augmentation Drafting Team is proposing to require its members to follow for Category B and C events: 1. Generation adjustments - Reducing or increasing generation while keeping the units on-line or by bringing additional units on line. The amount of generation change is limited to that amount that can be accomplished within the allowed readjustment period. Due consideration shall be given to start up time and ramp rates of the units. 2. Generation rejection to the extent possible within the allowed readjustment period. Generation rejection shall not exceed the normal operating reserve of the generation reserve sharing pool to which the MRO Member belongs or of the MRO Member itself if the MRO Member self-provides generation reserves.
Muscatine P&W	Whatever the local entity sees as appropriate and is reasonable versus the cost of fixing the problem. (See Q43 Comment #3)
NERC TIS	If system adjustments are allowed between events in steady state analysis, manual and automatic adjustments should both be allowed. However, in stability analysis, only automatic adjustments capabilities that are actually in place should be used.
New York ISO	Automatic: Pre-determined ranges of AVR, excitation system, stabilizer and governor. Manual: switching and PAR adjustments covered by applicable operating procedures.
PJM	Adjustments should be allowed consistent the time periods being studied.
Progress–Carolinas	Both manual and automatic adjustments should be allowed.

Q35	
Commenter	**Comment**
Progress–Florida	Provided events are confined to a single area (i.e., no cascading outages), manual and automatic adjustment (increase or decrease) of Var output and manual and automatic tripping or reduction of overall output of generators should be allowed
Santee Cooper SERC RRS OPS TVA	Any adjustments should be allowed that protects the reliability of the BES.
SaskPower	The amount of generation change should be limited to the amount that can be accomplished within the allowed readjustment period. Due consideration should be given to start up time and ramp rates of the units. Generation rejection should not exceed the normal operating reserve.
Seattle City	Any adjustment required to respond to a contingency should be allowed, unless it adversely impacts the regional system.
SERC EC DRS	Manual and automatic adjustments should be allowed for single and multiple contingencies as long as performance requirements are met.
SERC EC PSS SCE&G	Adjustments that should be allowed are those that can be performed in time to prevent the system from failing to meet performance requirements. These adjustments may include automatic voltage regulator action, governor action, generator runback, and generator tripping.
Southern Transm.	Automatic generator tripping should be allowed for single contingency events and for multiple contingency events.
Tenaska	Any adjustment(manual, automatic, runback, tripping) should be allowed as long as the performance requirements are achieved as described in standard after the adjustments have been made.
WECC BPA TSGT TEP	All adjustments should be allowed as long as they are realistic and achievable in the time frame required and consistent with other study parameters. For example, automatic adjustments would be required for correction of a stability problem, but manual adjustment should be allowed for correction of a thermal problem if there is no instability problem.
AECC	any that are realistic, can be accomplished in the appropriate timeframe and are within the capability of the units
Response: Based on the majority of industry responses, the SDT has modified Requirement R 3.6 (now R 3.5) to specify conditions under which manual and automatic generation runback and tripping can be used to meet single and multiple Contingency performance requirements for the steady state portion of the Planning Assessment. **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:	
APPA	I do not understand the question. Is this dealing with voltage adjustment or power adjustment?
Response: Generation runback deals with a machine's power adjustment.	
Entergy	This question is not clear and more explanation should be provided, such as, whether the adjustments are pre or post contingency, whether the contingency involves faults etc. Does this question pertain to plant or system stability?
Response: Adjustments are post-Contingency. Based on the majority of industry responses, the SDT has modified Requirement R 3.6 (now R 3.5) to specify conditions under which manual and automatic generation runback and tripping can be used to meet single and multiple Contingency performance requirements for the steady state portion of the Planning Assessment.	

Q35	
Commenter	**Comment**
R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:	

F) Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

36) Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Summary Response: The overwhelming majority of respondents believe that generator runback should be allowed for single Contingencies. One respondent thought that runback of firm generation should only be allowed as an interim Operating Procedure until System reinforcements are installed. Another thought that a generator that must reduce output for N-1 is not "firm" generation capacity. Another cautioned that runback may not be fast enough to avoid voltage instability. The draft standard will continue to allow manual or automatic generation run-back as a response to single and multiple Contingencies as long as all Facilities shall be operating within their Facility Ratings and as long as a sustainable, stable, operating condition is maintained.

The following requirements have been added due to industry comments:

R3.5.2. Such action would not violate safety, equipment, regulatory or statutory requirements.
R3.5.3. A sustainable, stable, operating condition is maintained.

Q36			
Commenter	**Yes**	**No**	**Comment**
Ameren		☑	The runback of firm generation should only be allowed as a valid interim operating procedure until a system reinforcement would be installed to uprate or unload the limiting facility. The use of the runback scheme should not be allowed as the long-term solution to a single contingency event. As mentioned above in the response to Q35, non-firm (energy only) generation should be tripped or redispatched for any contingency event as needed to keep facility loadings within ratings.
Response: The SDT and the majority of the industry do not agree that generation runback should be used only as a temporary solution.			
Dominion		☑	For a single contingency, no generation adjustment should be allowed. For multiple transmission element contingencies, generation reduction (automatic or manual runback) may be allowed. Unit

Q36			
Commenter	**Yes**	**No**	**Comment**
			trip should only be allowed if a unit becomes unstable.
Response: The SDT and the majority of the industry agree that the use of generation runback should be allowed for single Contingencies.			
AECC		☑	Generation runback should only be permitted if there are no impacts to area interchange and firm transactions are not altered.
Response: The allowable impact to firm transactions is specified in the performance tables. The use of generation runback is only allowed if the performance requirements are met.			
E ON US		☑	I do not agree that the system has to be returned to a "normal state" after a single contingency. The system can continue to be operated in the "emergency state" as long as the next contingency does not cause flows above emergency ratings.
Response: The SDT agrees that the System can be operated in an emergency state as long as the next Contingency does not cause flows above emergency ratings. However, this does not preclude the use of runback to get flows back within normal ratings.			
BCTC		☑	We do not accept R3.5, which does not limit runback to contingencies based on thermal limits, only that Facility Ratings are not exceeded. If an SOL is based on voltage stability (which is often studied in the post disturbance steady state), Facility Ratings may not be exceeded but runback may not be fast enough to avoid voltage instability. Furthermore, runback for single contingencies should be subject to any conditions that might apply to generator tripping for single contingencies. See response to Question 39.
Response: Requirement R3.5 now has two additional qualifiers on the use of generator runback other than Facilities must be within Facility Ratings: **R3.5.2**. Such action would not violate safety, equipment, regulatory or statutory requirements. **R3.5.3**. A sustainable, stable, operating condition is maintained.			
KCPL		☑	All generators must have "firm" transmission outlet capacity for their nameplate rating. This means delivery of full output under N-1 conditions. A generator that must reduce output for N-1 is not "firm" generation capacity.
Response: The SDT believes that if an n-1 Contingency results in flows within emergency ratings, then the generator has firm Transmission outlet capacity even if it must be backed down to get the System back within normal ratings.			
MISO	☑	☑	Yes, where the transmission system is designed with these schemes. No, in general when there is no designed SPS or runback for the generator.
Response: The SDT believes that runback should be allowed both for existing schemes and for new schemes.			
ABB	☑		Every single event will eventually require preparing for the next event. But we cannot plan for every next event. Only specific single and multiple contingencies should be planned for, all flows must be within an established rating of some kind (continuous, 12-hour, 4-hour, 15-min, whatever), and the idea of the "next event" should not be included in a planning standard. Now maybe there should be a limit as to how short the time of a rating can be in Planning. For example, planning to a 15-min rating is a bad idea. That rating can be used by operators in emergencies, but planners need to do something better. A minimum should be set (e.g. 1 hour

Q36			
Commenter	**Yes**	**No**	**Comment**
			rating). I guess if a company wants to use a 15-min rating and then AUTOMATICALLY transition to a 1-hour or 12-hour rating with runback or something else, that is reasonable.
Response: The SDT considered minimum time duration for the emergency ratings used in planning. However, the SDT decided this would be too restrictive.			
AEP	☑		Question: Why would a runback scheme be needed to move from an emergency state to a normal state when that could be accomplished by regular redispatch?
Response: If regular redispatch can adjust the System following a single Contingency in preparation for the next Contingency in the time frame required by emergency ratings, then no automatic runback is needed.			
APPA	☑		However, it should be pointed out that RAS are band-aid solutions to building needed BES infrastructure. Experience has shown that an interconnection can have so many RAS that one RAS will counter another RAS designed for another problem in the interconnection. This problem requires additional study by a NERC task force.
Response: The SDT and the majority of the industry do not agree that automatic generation runback (by use of an RAS) should be used only as a temporary (or band-aid) solution.			
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating	☑		Generation runback should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment
Response: The SDT agrees.			
Exelon	☑		An automated run-back scheme should be allowed but not required for these scenarios - an operator should be able to manually adjust unit output.
Response: If an operator can adjust the system following a single contingency in preparation for the next contingency in the time frame required by emergency ratings, then no automatic runback is needed.			
FirstEnergy	☑		As long as thermal, voltage, and stability requirements are met, either automatic or manual runback of the unit should be allowed. Tripping of the unit should be allowed also if the particular unit(s) can be restarted within some relatively short time - say one hour. With this requirement, it appears that only CTs and hydro units would be allowed to be tripped.
Response: The SDT agrees that automatic or manual runback should be allowed. We do not agree that only CTs and hydro units could be tripped by SPS.			
Manitoba Hydro	☑		Generator tripping should be added in addition to runback. Generator tripping is used extensively in regions where remote generation is delivered via long transmission There will be a large cost penalty to construct transmisison to remote generation if generator tripping is not allowed. Since the amount of tripping is covered by operating eserves, there is no impact on reliability. Generator tripping should be an option for the planner in the standard as opposed to a regional difference or the need to

Q36			
Commenter	**Yes**	**No**	**Comment**
			install an SPS.
Response: The SDT agrees that generator tripping should be allowed for single and multiple Contingencies (See R 3.5)			
New York ISO	☑		What is the difference between a SPS and RAS? Would not one term be sufficient? SPSs should not be considered a permanent solution. They should only be used as a stop gap before a permanent solution can be implemented.
Response: SPS and RAS are synonymous terms. The SDT and the majority of the industry do not agree that SPS should be used only as a temporary solution.			
ERCOT ISO	☑		Agree
Northwestern Energy	☑		
AECI	☑		
Allegheny Power	☑		
ATC	☑		
BPA	☑		
Brazos Electric	☑		
CAISO	☑		Agree
CenterPoint	☑		
City Water Power and Light	☑		
City Utilities/Springfield	☑		
CPS Energy	☑		
Duke Energy	☑		We see this as an acceptable form of manual or automatic redispatch, which should be allowed as a cost beneficial way of operating the system in a reliable manner, as long as it can be accomplished within the time frame before emergency ratings are exceeded.
Entegra	☑		As long as the system would be within normal ratings after runback.
Entergy	☑		
FPL	☑		
FRCC	☑		
Georgia Transm.	☑		
IESO	☑		Generation rejection and runback are not uncommon to be employed as special protection systems (SPS) to achieve a stable state and/or reduce transmission loading to within pre-determined levels.

Q36			
Commenter	**Yes**	**No**	**Comment**
			SPSs, when employed, are designed to operate in order to meet performance requirements following specific contingencies or when specific system conditions are present. As such, when a contingency occurs or when the conditions should arise for which the SPS (in this case, generation runback) is designed to operate, such actions should be simulated.
ISO/RTO	☑		
ITC	☑		
LADWP	☑		Generator runback is allowed under the current standards, why single this out? Hopefully this is not a sign of equating generator runback with generator tripping as the title of this section might suggested. Generator runback is not and should not be classified as an SPS! It is critical to keep as many units on line as possible post contingency. In many instances, use of generator runback would avoid the need to trip a unit if that was the only way to reduce the generations to return to load-generation balances.
MEAG Power	☑		
MRO	☑		
Muscatine P&W	☑		
NERC TIS	☑		This is simply a recognition that the system operators will take action to return the system to a stable and secure operating posture following an event.
NCEMC	☑		
PJM	☑		
Progress–Carolinas	☑		
Progress–Florida	☑		
SRP	☑		
Santee Cooper	☑		
SaskPower	☑		
Seattle City	☑		
SERC EC DRS	☑		
SERC EC PSS	☑		
SERC RRS OPS	☑		
SCE&G	☑		

Q36			
Commenter	**Yes**	**No**	**Comment**
Southern Transm.	☑		
Tenaska	☑		
TVA	☑		
TSGT	☑		
TEP	☑		
WECC	☑		
WPS	☑		
Response: Thank you. Please see the Summary Response.			

37) Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Summary Response: Respondents appeared to overwhelmingly favor allowance of automatic generation runback to prevent thermal overloads. However, as some respondents indicated the question was not clear and a number indicated that Requirement R 3.5 could be made clearer. Many respondents suggested various conditions be added to the requirements. The SDT has modified Requirement R 3.5 to specify the conditions under which automatic (or manual) generation runback can be used to meet single (or multiple) contingency performance requirements and to make it clear that all facilities must always remain within applicable thermal and voltage ratings.

The following requirement was changed due to industry comments:

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:

Q37			
Commenter	**Yes**	**No**	**Comment**
Dominion		☑	For a single contingency, no generation adjustment should be allowed. For multiple transmission element contingencies, generation reduction (automatic or manual runback) may be allowed. Unit trip should only be allowed if a unit becomes unstable.
Duke Energy		☑	Runback should not be used if the disturbance caused you to exceed emergency ratings (i.e. thermal overload).
Ameren		☑	No generation runbacks should be allowed as long-term solutions for single contingency conditions.
Entergy	☑	☑	The question is not clear. Generation runback schemes are acceptable as long as emergency ratings are not violated. Runbacks should not be used to restore an element to within emergency ratings.
MISO	☑	☑	No, this should be the exception, not the rule. Yes, there are mine mouth plants with DC outlet lines, which must be runback if the DC line trips. There are also generators which used to serve large on site loads. The large loads are gone (plants retired) and generator outlet is limited. There are also some generators which have known contingent outlet limits and the generators are OK with runback, if the contingency occurs.
AECI	☑		We do not have the capability to have automatic runback at this time. However if an entity does have the capability to perform automatic runback than it should be allowed to prevent overloads. That would be the purpose.
Progress–Florida	☑		Provided events are confined to a single area (i.e., no cascading outages), automatic runback of generators should be allowed.
SERC EC DRS		☑	The question is not clear. Generation runback schemes are acceptable as long as emergency ratings are not violated. Runback schemes should not be used to restore an element to within emergency ratings.

Q37			
Commenter	**Yes**	**No**	**Comment**
Response: Industry comments strongly support allowing for the use of generator runback for single Contingencies. Generation runback will be permitted for all Contingencies, and the SDT has modified the standard language accordingly (See Requirement R 3.5). **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:			
ITC		☑	We believe that the BES should be able to operate for N-1 events without reliance on operating schemes. Assuming that some areas allow this, there should be criteria to evaluate the consequences of 2nd contingencies occurring during the runback. In addition, short-time ratings need to be confirmed which limit the time for runback. The system is at risk until the runback is completed and this risk must be evaluated and REQUIRED in the planning assessment.
Response: Industry comments strongly support allowing for the use of generator runback to prevent thermal overloads. The SDT has modified the standard language to clarify this view, including the requirement to remain within Facility Ratings during the course of the runback.			
KCPL		☑	All generators must have "firm" transmission outlet capacity.
Response: Industry comments strongly support allowing for the use of generator runback to prevent thermal overloads. The SDT has modified the standard language to clarify this view.			
ABB	☑	☑	No. Following a single contingency, all flows must be within some kind of established rating. After that, runback can be used to get under a longer-term rating. For multiple contingencies, some type of cross-tripping is OK, but runback is too slow and unreliable.
AECC		☑	Implementing an automatic runback scheme will only mask the impacts of the event. You want to know what happens when an event occurs not set up some psuedo fix that takes place before you know what the problem is.
Response: Industry comments strongly support allowing for the use of generator runback for single contingencies. The SDT has modified the standard language accordingly.			
BCTC	☑	☑	See our response to Question 36. In addition, since this runback is effectively a RAS/SPS with respect to protecting the transmission system from cascading, it must meet all the reliability requirements of a RAS.
Response: The SDT agrees that an automatic generation runback scheme is an SPS, and it must meet the applicable reliability requirements.			
PJM	☑	☑	Yes. At a minimum the emergency rating needs to be coordinated with the SPS timing.
Brazos Electric	☑		Can be including in a RAP or SPS with a long term CAP.
City Water Power and Light	☑		Coordination with neighboring systems is essential when considering generation redispatch.
ERCOT ISO CAISO	☑		1. Run back of generation should not result in tripping of firm load, 2. Power flow should be within the applicable ratings, 3. Frequency should be within the allowable limits
WECC	☑		Yes. Agree. Conditions for generation run back for N-1: 1) Run back of generation cannot result in

Q37			
Commenter	**Yes**	**No**	**Comment**
BPA TSGT TEP			tripping of firm load, 2) power flow should be within the time-limited equipment ratings, 3) frequency should be within allowable limits.
Northwestern Energy	☑		Yes, (1) if the failure of the runback scheme results in cascading, then it should not be allowed; (2) the power flow should be within the time-limited equipment ratings; and (3) the frequency should be within allowable limits.
Allegheny Power	☑		This could be permitted provided the run back will allow for the ability to prepare for the next operational contingency and not affect load.
AEP	☑		Ensure that the scheme is enabled to automatically runback for the problem conditions.
APPA	☑		Care must be taken to insure runbacks of one event will not cancel the effects of other runback plans in the same interconnections.
Central Maine Power HQTE National Grid NU NPCC RCS New England ISO NSTAR United Illuminating	☑		However, this should only be allowed where failure of an automatic runback that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.
Exelon	☑		Run-back schemes should be allowed for certain single contingencies that can result in unit outlet constraints. Not all emergency ratings are thermal - some are relay or stability limits. In these instances, generator run-back should not be allowed.
FirstEnergy	☑		Yes, only if the Transmission Owner has documented short term ratings that would not be exceeded during the runback.
FPL FRCC	☑		At a minimum the emergency ratings should allow sufficient time for the runback scheme to operate reliably
Georgia Transm.	☑		Generation curtailment should allow the system to operate within the facility capabilities and should not put the generator at risk of violating its NERC requirements during curtailment.
IESO	☑		Please see our response to Q36 for the rationale for allowing the runback scheme to operate. The conditions that need to be met in order to allow the scheme to operate depends specifically on what that SPS (runback scheme) is designed for. Some schemes are designed to operate upon detecting the opening of specific transmission lines, others are designed to operate upon detection of circuit loading reaching a particular threshold. There is no universal rule as to the conditions that must be met for a runback scheme to operate. The use of runback scheme is similar to using special operating procedure, such as cross tripping, operator instructions to open a circuit, etc. There might be design requirements to ensure the scheme meet certain performance criteria. However, these should be covered in the standards for special protection system. In TPL-001, the requirement would be to include simulation of the runback scheme operation only as the conditions that would prompt the

Q37			
Commenter	**Yes**	**No**	**Comment**
			scheme to operate occur, and a requirement to include SPS misoperation, i.e., failure to operate and operate when not initiated, as a contingency.
Manitoba Hydro	☑		I see no problem in using a runback scheme to prevent thermal overloads. Most emergency ratings are based on 30 minute values to allow for operator action. An automatic runback could be accomplished in 5-15 minutes depending on the ramp rate of the generator. The runback scheme may allow higher emergency ratings depending on the rating methodology. At no point would emergency ratings be exceeded and at the end, loading would be within normal values.
MEAG Power NCEMC SERC EC PSS SCE&G TVA	☑		The generator runback scheme should complete its action within the time allowed by the emergency ratings of elements that exceed their normal thermal ratings.
NERC TIS	☑		This is simply a recognition that the system operators will take action to return the system to a stable and secure operating posture following an event. This is also common practice in generator protection/controls for generators with multiple GSUs for loss of one of the GSUs.
New York ISO	☑		Testing scenarios will have to be developed on a case by case basis depending on the design of the SPS. There is not universal rule that can be made for these unique cases.
Progress–Carolinas	☑		If the rating is a 2 hour rating then the adjustment should be complete within 2 hours.
SRP	☑		The loss of transmission line (N-1) may require Gen drop to prevent instability or violation. Studies will need to be performed that study the congestion of generation and transmission corridors and loss of various elements.
Santee Cooper	☑		Generator runback schemes should be able to be implemented before emergency thermal rating time limits are exceeded.
SaskPower	☑		Several generation run back or generation rejection schemes are used in Saskatchewan to restore facility loading to with normal ratings. The costs of not using these schemes would involve substantial increased investments and environmental impacts unacceptable in the Saskatchewan Regulatory Jurisdiction. Conditions are determined on a case by case basis. However, the generation runback or generation rejection scheme should not exceed the normal operating reserve.
Seattle City	☑		Runback should be allowed to prevent a possible cascading outage which might result from the thermal overload, but only to that level needed to protect the equipment, to address the contingency, or to prepare for the next contingency. If the runback level is lower than the normal rating, it should be shown that this runback will not harm the stability of the system.
Southern Transm.	☑		Yes, as long as no emergency ratings are violated.
Tenaska	☑		So long as the performance requirements are met then this is not an issue.
Response: The SDT agrees with your comments.			
MRO	☑		Generally, the historical MRO practices and requirements have been to require that following a single

Q37			
Commenter	**Yes**	**No**	**Comment**
			contingency the loading of facilities are to be maintained within emergency ratings. Adjustments are allowed to move the system from conditions within emergency ratings to conditions within normal ratings. However, in a limited number of cases, the use of Special Protection Systems are used to initiate fast generation run back, generation rejection, or automatic tripping of a remote transmission facility to get below a longer term emergency rating (30 minutes or longer.) In some cases, these involve parts of the network where remote generation is connected to load where the costs of not using the SPS would involve substantial increased investments and environmental impacts. Requirement 3.5 needs more clarification. What rating should not be exceeded?
Response: The SDT agrees with your comment and has modified the language of R 3.5 for clarity. **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:			
LADWP	☑		It was never disallowed under the current standards.
Response: The SDT believes that the current standards are silent on the use of SPS such as automatic generation runback. The standard language has been modified to explicitly identify the conditions under which an SPS may be used (See Requirement R 3.5). **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:			
WPS	☑		The use of RAS or SPS should not constitute a long-term Corrective Action Plan to address deficiencies. The use of RAS and SPS should be limited to that period of time necessary to place facilities in-service to address the deficiency.
Response: Industry comments do not support the use of runback only as an interim measure. Accordingly, the current draft standard language does not impose such a limitation on the use of SPS.			
ATC	☑		
CenterPoint	☑		
CPS Energy	☑		
ISO/RTO	☑		
Muscatine P&W	☑		Reasonable and workable.
SERC RRS OPS	☑		
Response: Thank you. Please see the Summary Response.			

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

38) Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Summary Response: From the survey of industry responses regarding automatic readjustment of generation using SPS/RAS, the industry agrees that SPS/RAS may be allowed for single Contingencies. As a result, the SDT has modified the language in the standard such that it will allow the use of SPS/RAS for single or multiple Contingencies.

The following requirements have been changed due to industry comments:

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:
R3.5.1. All Facilities shall be operating within their Facility Ratings.
R3.5.2. Such action would not violate safety, equipment, regulatory or statutory requirements.
R3.5.3. A sustainable, stable, operating condition is maintained

Q38			
Commenter	**Yes**	**No**	**Comment**
ABB		☑	It makes the system too complex and less reliable. Single contingencies need to be handled without any fancy controls.
KCPL		☑	Tripping generation for single contingency other than GSU failure or fault is unacceptable.
LCRA		☑	Only until plans are implemented to address a single contingency-identified deficiency. In general, plans should always be developed to exit SPS or RAS when economically feasible
Central Maine Power National Grid New England ISO NSTAR United Illuminating	☑		Only allowed where the failure of an SPS that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.
NU	☑		It is not recommended that an SPS be used in this situation, that over time, the proliferation of SPSs may degrade system reliability and unduly complicate system operations. If allowed an SPS should only be used where the failure of the SPS that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.
NPCC RCS	☑		A SPS may be used to provide protection for infrequent contingencies, or for temporary conditions that may exist such as project delays, unusual combinations of system demand and equipment outages or availability, or specific equipment maintenance outages. An SPS may also be applied to preserve system integrity in the event of severe facility outages and extreme contingencies. The decision to employ an SPS shall take into account the complexity of the scheme and the consequences of correct or incorrect operation as well as its benefits.

Q38			
Commenter	**Yes**	**No**	**Comment**
SCE&G	☑		A RAS or SPS should be allowed for single contingencies if its failure or misoperation can be compensated for during the time allowed by the emergency ratings of the elements that exceed their normal thermal ratings.
Response: The Industry response to this question has prompted the SDT to change the language to allow SPS/RAS for single or multiple Contingencies. The standard language now lists qualifiers of the use of SPS/RAS, listed in Requirements R3.5.1, R3.5.2 and R3.5.3. **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met: **R3.5.1**. All Facilities shall be operating within their Facility Ratings. **R3.5.2**. Such action would not violate safety, equipment, regulatory or statutory requirements. **R3.5.3**. A sustainable, stable, operating condition is maintained			
City Water Power and Light		☑	SPS use should be limited and SPSs should be of a temporary nature. A mitigation plan with a timeframe for implementation should accompany all SPSs and RASs.
ITC		☑	We wouldn't agree to this without knowing what you mean by limited use. RAS or SPS as a common practice does not "raise the bar" in planning standard. An RAS or SPS should be allowable as a temporary measure to allow one to meet the standard and two to protect the components of the BES. When used in this capacity, a plan should be being either developed or implemented such that the RAS or SPS can be removed from service.
Response: The overall Industry response prompted the SDT to not include the qualifier about temporary use of SPS/RAS.			
CPS Energy		☑	
Response: See summary response.			
AECC		☑	this question is not clear. are you asking if the SPS/RAS be studied as a contingency or if the SPS/RAS is a viable solution for impacts caused by a contintgency. In either case SPS/RAS impacts and effectiveness needs to be evaluated. Especially if they are used as a mitigation for contingency impacts. It should be knownif the SPS/RAS is effective for the model being studied and if not another mitigation should be determined
Response: The SDT is attempting to explicitly state under what conditions a SPS/RAS can be used to mitigate undesirable System response to single Contingency events. The current standards are silent on this issue.			
Ameren	☑		Yes, but only as interim operating procedures until the limiting facilities can be uprated or unloaded. SPS or RAS should be allowed to trip non-firm (energy only) generation to keep facility loadings within ratings.
Response: The overall response from the Industry prompted the SDT to change the language in the Standard to allow SPS/RAS for all single and multiple contingencies with the qualifiers of Requirements R3.5.1, R3.5.2 and R3.5.3. The Standard does not differentiate performance for different generation types. **R3.5.** Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:			

Q38			
Commenter	**Yes**	**No**	**Comment**
R3.5.1. All Facilities shall be operating within their Facility Ratings. **R3.5.2**. Such action would not violate safety, equipment, regulatory or statutory requirements. **R3.5.3.** A sustainable, stable, operating condition is maintained			
Progress–Florida	☑		This requirement is addressed in PRC-005 and these requirements should not be addressed again in this Standard. However, the use of RAS or SPS should be allowed as necessary for any single contingency event, provided that such use does not result in cascading outages. It should be noted that the performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. Revision of the existing TPL standards will require updating of the contingency references in PRC-012-0.
Response: The conditions for the use and application of SPS/RAS are addressed in the TPL Standards. The SDT does not agree that the PRC Standards addresses the use of SPS/RAS.			
Southern Transm.	☑		RAS and SPS should be defined such that they may only be used for low probability events.
Response: The overall response from the Industry prompted the SDT to change the language in the Standard to allow SPS/RAS for all single and multiple contingencies with the qualifiers of Requirements R3.5.1, R3.5.2, and R3.5.3. There are no qualifications of the use of SPS/RAS based on the probability of the contingency. **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met: **R3.5.1**. All Facilities shall be operating within their Facility Ratings. **R3.5.2**. Such action would not violate safety, equipment, regulatory or statutory requirements. **R3.5.3**. A sustainable, stable, operating condition is maintained			
IESO	☑		SPS and RAS should be allowed for single contingencies. However, a more fundamental requirement is that the SPS (and RAS) should generally be regarded as a stop gap measure before planned transmission expansion or reinforcement becomes available. SPS should in general not be used as a substitute for transmission facilities.
New York ISO	☑		As stated previously SPSs should only be a temporary solution used to protect elements prior to a permanent solution implementation.
WPS	☑		The use of RAS or SPS should not constitute a long-term Corrective Action Plan to address deficiencies. The use of RAS and SPS should be limited to that period of time necessary to implement expansion of facilities to address the deficiency.
Response: The overall Industry response prompted the SDT to allow the use of SPS/RAS as a permanent Corrective Action measure and not just as a temporary measure.			
Brazos Electric	☑		
Dominion	☑		
ERCOT ISO	☑		Agree

Q38			
Commenter	**Yes**	**No**	**Comment**
Northwestern Energy	☑		
AECI	☑		
Allegheny Power	☑		
AEP	☑		As long as they are automatic.
APPA	☑		As the SDT has said under certain situations.
ATC	☑		
APS			
BPA	☑		
BCTC	☑		
CAISO	☑		Agree
CenterPoint	☑		
Duke Energy	☑		RAS and SPS are economical solutions that planners ought to be able to use.
Entergy	☑		RAS or SPS may be allowed for single contingencies when they aid in meeting System Performance requirements. RAS and SPS should not be used to restore an element to within emergency ratings.
Exelon	☑		
FirstEnergy	☑		As long as thermal, voltage, and stability requirements are met, RAS or SPS should be allowed provided it does not shed load for a single contingency event.
FPL FRCC	☑		The performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. If the proposed TPL standard is adopted the contingency references in PRC-012-0 would need to be updated.
Georgia Transm.	☑		
HQTE	☑		A SPS may be used to provide protection for infrequent contingencies, or for temporary conditions that may exist such as project delays, unusual combinations of system demand and equipment outages or availability, or specific equipment maintenance outages. An SPS may also be applied to preserve system integrity in the event of severe facility outages and extreme contingencies. The decision to employ an SPS shall take into account the complexity of the scheme and the consequences of correct or incorrect operation as well as its benefits.
ISO/RTO	☑		
Manitoba Hydro	☑		MH sees no reason to limit the application of SPSs. The SPS is a viable planning option that allows large savings in cost in stability limited system where there is no need to increase thermal capability.
MEAG Power	☑		

Q38			
Commenter	**Yes**	**No**	**Comment**
MISO	☑		
MRO	☑		
Muscatine P&W	☑		
NERC TIS	☑		
NCEMC	☑		
PJM	☑		
Progress–Carolinas	☑		
SRP	☑		As long as Non-Consequential Loss of Load is not a solution for single contingencies (N-1).
Santee Cooper	☑		
SaskPower	☑		
Seattle City	☑		
SERC EC DRS	☑		
SERC EC PSS	☑		
SERC RRS OPS	☑		
Tenaska	☑		
TVA	☑		TVA does not allow generator tripping for a single contingency. However, we recognize that there are certain instances for which this makes practical and economic sense.
TSGT	☑		
TEP	☑		
WECC	☑		
Response: Thank you. Please see the Summary Response.			

39) Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Summary Response: Requirement R3.5 has been written such that it allows RAS or SPS for single or multiply Contingencies with limitations described in Requirements R3.5.1 through R3.5.3. Requirement R3.5.2 allows for "regulatory or statutory requirements" that may prohibit or limit the use of RAS or SPS.

In addition, most responders said, or implied, that the failure of SPS/RAS schemes should be studied. Most said that the failure of the schemes should not cause cascade, with some suggesting that there shouldn't be any Non-Consequential Load Loss. The SDT believes that failure of SPS should not be used to establish requirements in the TPL-001-1 standard. Instead, this standard sets requirements when SPS can be used, and relies on the relevant PRC standards to set the requirements for studies and designs to implement the SPS. In response to those that commented regarding existing RRO standards becoming more stringent than the resulting North American standards, there are provisions to allow for regions to have and implement more restrictive standards.

Q39	
Commenter	**Comment**
ABB	They could be used in the short term until a permanent fix is available. Limit to <5 years.
Ameren	SPS and RAS should be used only as interim operating procedures to mitigate single contingency events until the limiting facilities can be uprated or unloaded. SPS and RAS should be allowed to trip non-firm (energy only) generation as needed to keep facility loadings within ratings.
Northwestern Energy	RAS or SPS should not be allowed for non three phase single line faults. If cascading could result from the failure of the RAS to operate properly, then redundancy should be required.
HQTE	See response to Q38.
ITC	Temporary in nature.
KCPL	RAS/SPS should not limit generation output for N-1 conditions.
LCRA	Short-term with exit plans; Loss of significant generation or load resulting from SPS /RAS action.
Manitoba Hydro	An automatic runback should be accomplished in 5-15 minutes depending on the ramp rate of the generator. The runback scheme may allow higher emergency ratings depending on the rating methodology. At no point would emergency ratings be exceeded and at the end, loading would be within normal values. Generator tripping should be allowed. Generator tripping is used extensively in regions where remote generation is delivered via long transmission. MH sees no reason to limit the application of SPSs. The SPS is a viable planning option that allows large savings in cost in stability limited system where there is no need to increase thermal capability.
MRO	The MRO believes the MRO systems are presently designed to meet system performance, in some cases, with the use of SPS to initiate fast generation runback, generation rejection, and automatic tripping of a remote transmission facility for a single contingency event. The fast generation runback or generation rejection should not exceed the normal operating reserve of the generation reserve sharing pool to which the planner belongs or of the planner itself if the planner self-provides generation reserves.

Q39	
Commenter	**Comment**
New York ISO	Must be temporary, approved by the NYSRC, tested annually with evidence of preventive maintenance submitted annually.
NPCC RCS	See response to Q38.
Southern Transm.	Generator tripping or runback and reconfiguration should be allowed for lower probability single contingency events such as bus faults; we suggest that SPS not be used for events that are more likely to occur.
WPS	The use of RAS or SPS should not constitute a long-term Corrective Action Plan to address deficiencies. The use of RAS and SPS should be limited to that period of time necessary to implement expansion of facilities to address the deficiency.
Response: Your suggestion was seriously considered but restrictions were limited to those sub-requirements of Requirement R3.5.	
Brazos Electric City Water Power and Light	Taken directly from the ERCOT operating Guides for RAPs and SPSs: Any RAP must meet the following requirements: a. Coordinated and approved with the owners and operators of facilities included in the RAP. b. Use is limited to the time required to construct replacement Transmission Facilities. However, the RAP will remain in effect, if replacement Transmission Facilities have been determined by the Control Area Authority to be impractical. c. Complies with all applicable ERCOT and NERC requirements. d. ERCOT develops and posts a methodology to include the RAP in the Total Transfer Capability (TTC) calculations, if appropriate. e. Clearly defines and documents operator actions. f. Includes the option for the transmission operator to override the procedures if the RAP will not improve system reliability. g. Operators must be trained in RAP implementation. For SPSs 13. Special Protection Systems (SPS) are protective relay systems designed to detect abnormal ERCOT System conditions and take pre-planned corrective action (other than the isolation of faulted elements) to provide acceptable ERCOT System performance. SPS actions include among others, changes in demand, generation, or system configuration to maintain system stability, acceptable voltages, or acceptable Facility loadings. An SPS does not include underfrequency or undervoltage load shedding. A Type 1 SPS is any SPS that has wide-area impact and specifically includes any SPS that a) is designed to alter generation output or otherwise constrain generation or imports over DC Ties, or b) is designed to open 345 kV transmission lines or other lines that interconnect TDSPs and impact transfer limits. Any SPS that has only local-area impact and involves only the Facilities of the owner-TDSP is a Type 2 SPS. The determination of whether an SPS is Type 1 or Type 2 will be made by ERCOT upon receipt of a description of the SPS from the SPS owner. Any SPS, whether Type 1 or Type 2, shall meet all requirements of NERC Standards relating to SPSs, and shall additionally meet the following ERCOT requirements: • The SPS owner shall coordinate design and implementation of the SPS with the owners and operators of Facilities included in the SPS, including but not limited to Generation Resources and HVDC ties. • The SPS shall be automatically armed when appropriate. • The SPS shall not operate unnecessarily. To avoid unnecessary SPS operation, the SPS owner may provide a

Q39	
Commenter	**Comment**
	real-time status indication to the owner of any Generation Resource controlled by the SPS to show when the flow on one or more of the SPS's monitored facilities exceeds 90% of the flow necessary to arm the SPS. The cost necessary to provide such status indication shall be allocated as agreed by the SPS owner and the Generation Resource owner. • The status indication of any automatic or manual arming of the SPS shall be provided as SCADA alarm inputs to the owners of any facility(ies) controlled by the SPS.. • When a Transmission Operator (TO) removes a SPS from service, the TO shall immediately notify ERCOT operations. ERCOT shall modify its reliability constraints to recognize the unavailability of the SPS and notify the Market. When a SPS is returned to service, the TO shall immediately notify ERCOT operations. ERCOT shall modify its reliability constraints to recognize the availability of the SPS. 14. The owner(s) of an existing, modified, or proposed SPS shall submit documentation of the SPS to ERCOT for review and compilation into an ERCOT SPS database. The documentation shall detail the design, operation, functional testing, and coordination of the SPS with other protection and control systems. • ERCOT shall conduct a review of each proposed SPS and each proposed modification to an existing SPS. Additionally, it shall conduct a review of each existing SPS every five years, or sooner as required by changes in system conditions. Each review shall proceed according to a process and timetable documented in ERCOT Procedures and posted on the ERCOT website. • For a proposed Type 1 SPS, the review must be completed before the SPS is placed in service, unless ERCOT specifically determines that exemption of the proposed SPS from the review completion requirement is warranted. The timing of placing the SPS into service must be coordinated with and approved by ERCOT. The implementation schedule must be confirmed through submission of a Service Request to ERCOT. • For a proposed Type 2 SPS, the SPS may be placed into service before completion of the ERCOT review, with advanced prior notice to ERCOT in the form of a Service Request. The timing of placing the SPS into service must be coordinated with and approved by ERCOT. Existing SPSs that have already undergone at least one review shall remain in service during any subsequent review, and proposed modifications to existing SPSs may be implemented, upon notice to ERCOT, and approval of ERCOT before completion of the required ERCOT review. • The process and schedule for placing an SPS into service must be consistent with documented ERCOT Procedures. The schedule must be coordinated among ERCOT and the owners of any facility(ies) controlled by the SPS, and shall provide sufficient time to perform any necessary testing prior to its being placed in service. • An ERCOT SPS review shall verify that the SPS complies with ERCOT and NERC criteria and guides. The review shall evaluate and document the consequences of failure of a single component of the SPS, which would result in failure of the SPS to operate when required. The review shall also evaluate and document the consequences of misoperation, incorrect operation, or unintended operation of an SPS, when considered by itself, and without any other system contingency. If deficiencies are identified, a plan to correct the deficiencies shall be developed and implemented. The current review results shall be kept on file and supplied to NERC on request within thirty (30) days. • As part of the ERCOT review and unless judged to be unnecessary by ERCOT, the appropriate ROS working groups such as the Steady State Working Group, the Dynamics Working Group, and/or the System Protection Working Group shall review the SPS and report any comments, questions, or issues to ERCOT for resolution. ERCOT may work

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	with the owner(s) of facilities controlled by the SPS as necessary to address all issues. • ERCOT shall develop a methodology to include the SPS in the Commercially Significant Constraint (CSC) limit calculations, if appropriate. • ERCOT's review shall provide an opportunity for and include consideration of comments submitted by Market Participants affected by the SPS. 15. SPS owners shall notify ERCOT of all SPS operations. Documentation of SPS failures or misoperations shall be provided to ERCOT using the Relay Misoperation Report located in Section 6 of these Operating Guides. ERCOT shall conduct an analysis of all SPS operations, misoperations, and failures. If deficiencies are identified, a plan to correct the deficiencies shall be developed and implemented. 16. For each SPS, the owner shall either identify a preferred exit strategy or explain why no exit strategy is needed to ERCOT. This shall take place according to a timetable documented in ERCOT Procedures and posted on the ERCOT website. Once an exit strategy is complete and a SPS is no longer needed, the owner of an existing SPS shall notify ERCOT, using a Service Request, whenever the SPS is to be permanently disabled, and shall do so according to a timetable coordinated with and approved by ERCOT and the owners of all facilities controlled by the SPS
Response: The SDT anticipates that ERCOT will be able to maintain the existing requirements that you suggest. Requirement R3.5.2 allows for "regulatory or statutory requirements" which may limit RAS or SPS.	
Dominion	For single contingency events, a SPS scheme should not result in loss of load.
Response: Non-Consequential Load Loss is not allowed for single Contingency events.	
ERCOT ISO CAISO	RAS or SPS should generally be regarded as a stop gap measure before transmission expansion or reinforcement becomes available. It should not be used as a substitute for transmission facilities.
Response: Your suggestion was seriously considered but restrictions were limited to those sub-requirements of Requirement R3.5. The SDT anticipates that ERCOT will be able to maintain the existing requirements that you suggest. Requirement R3.5.2 allows for "regulatory or statutory requirements" which may limit RAS or SPS.	
Allegheny Power	The use of these system should be limited and not used as a preferred solution and also be approved by a stringent review process through the RTO & RE.
AEP	Should be allowed as long as they have been approved by the applicable Regional Reliability Organization.
APPA	See Question 36.
BCTC	RAS should be permitted when the system performance conforms with the performance requirements laid out in the tables. Generator tripping should be permitted for single contingency events. R3.6 proposes to limit generator tripping for single contingencies except for certain conditions which are not listed. Without knowing what these conditions might be, we find ourselves speculating on what might be proposed. On the 10 October 2007 conference call, it was suggested that there are concerns regarding generator reserves and loss of reactive capability. We have some observations regarding these concerns. With respect to reserves, some concerns would also apply to runback, since units on runback could not also be on AGC and could not be reallocated to AGC until the transmission contingency is returned to service. There was also a concern regarding tripping of steam units and the delay in bringing them back on line. This is a resource adequacy issue that should be addressed with the customer, not a transmission reliability issue. Regarding the loss of reactive capability, this would be addressed by

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	the post mitigation plan studies to demonstrate that the reactive reserves meet the requirements, whatever they are determined to be. We would generally expect that the reduction in MW transfers would reduce the need for reactive support, so the new condition might not require the reactive support. Nevertheless, the post mitigation studies will address this. Therefore, we conclude that these concerns are not applicable to transmission planning standards. BCTC plans and operates a transmission system that interconnects generation comprised of about 90% hydroelectric. Often the extreme generation patterns for which we consider generator tripping occur for a limited time period during the year at off peak. These would be during high runoff and/or light local load periods. For these conditions, there is typically plenty of other generation that can be used as reserves for generator tripping. BCTC currently strives to avoid use of RAS for N-1, especially on the 500 kV transmission system. However, for example, if avoiding generator tripping were to trigger the need for hundreds of km of 500 kV transmission line for an off peak operating condition or a low capacity factor or intermittent resource, we would likely consider RAS, especially for transmission radial to the generator. In the lower voltage systems we often have consequential loss of small generators and consider generator tripping for radial lines and local networks. In most cases, this generator loss is addressed through sensitivity studies and discussions with generator owners and transmission customers with respect to the costs they are willing to incur and what is required by Resource Planners to meet their planning criteria. Operating reserves requirements are also a consideration. Any loss of generation due to tripping or ramping that is less than the amount lost due to consequential loss should be acceptable without question. In summary, we would be prepared to review and comment on a proposal from the SDT on limitations on generator tripping. BCTC suggests that the SDT list the limitations rather than the permitted conditions and that these limitations should also apply to generator ramping.
Georgia Transm. SERC EC DRS	None.
Muscatine P&W	As long as they work and are reasonable - none. (See Q43 Comment #3)
MISO	The use of SPS/RAS may be the appropriate transmission system design. If it is economic to mitigate the SPS, then upgrades should be made.
Response: See the summary response.	
Central Maine Power National Grid New England ISO NU NSTAR United Illuminating	Only allowed where SPS failure would not have significant adverse impact on the Bulk Electric System; non-Consequential loss of load should be allowed up to an amount potentially specified in the standard.
Response: See the summary response. As to your suggestion on Non-Consequential Loss of Load, it is prohibited for single Contingencies and is not prohibited for multiple Contingencies.	
Duke Energy	You should not have any wide area cascading if the RAS or SPS fails to operate as expected, or operates when it shouldn't.

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Commenter	**Comment**
Response: See the summary response: PRC standards address SPS failure.	
Entergy	RAS or SPS may be allowed for single contingencies when they aid in meeting System Performance requirements. RAS and SPS should not be used to restore an element to within emergency ratings.
Response: See the summary response. Requirement R3.5.1 restricts RAS/SPS such that facility ratings must be honored at all times.	
FirstEnergy	As long as thermal, voltage, and stability requirements are met, RAS or SPS should be allowed provided it does not shed load for a single contingency event.
Response: See the summary response. Non-Consequential Load Loss is not permitted for single Contingency events.	
FPL FRCC	The performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. If the proposed TPL standard is adopted the contingency references in PRC-012-0 would need to be updated.
Response: See Requirement R3.5. There are no longer any limitations on the use of SPS as long as they meet this criteria.	
IESO	Please see comments provided under Q38, above, regarding the use of SPS not as a substitute for transmission facilities. In addition, there should be requirements to simulate failure of SPS operation as a contingency in addition to the initiating single contingency. In cases where an SPS is intended to achieve acceptable stability performance which can affect interconnection reliability, the SPS should be classified as BES impactive and as such, redundancy may be required. When redundancy is provided, simulation of SPS failing to operate may be waived.
Response: Your suggestions were considered but the only limitations to RAS/SPS are those listed as sub-requirements of Requirement R3.5. PRC standards address SPS failure.	
MEAG Power NCEMC SERC EC PSS SERC RRS OPS SCE&G TVA	RAS or SPS should meet the same criteria as any protection system.
Response: See summary response as regards to planning standards. The PRC standards for SPS will be maintained as you have suggested.	
Progress–Florida	The use of RAS or SPS should be allowed as necessary for any single contingency event, provided that such use does not result in cascading outages. It should be noted that the performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. Revision of the existing TPL standards will require updating of the contingency references in PRC-012-0.
Response: The SDT agrees that the PRC standards address performance and may need to be updated.	
ReliabilityFirst	The requirements for the use of SPS and RAS should be contained in a separate standard. That standard should dictate when the RAS and SPS can be used. The planning studies would then simulate those conditions.
Response: This was considered but the consensus was to keep requirements in TPL-001-1. RAS/SPS is allowed as per Requirement R3.5 and its sub-requirements.	
SRP	Non-Consequential Loss of Load should not be allowed for single contingencies (N-1) and the system must remain stable with no violations.
Response: The SDT agrees and Non-Consequential Load Loss is not permitted.	
Santee Cooper	There should be no stability impacts, and system security must be maintained. RAS or SPS should meet the same criteria as any protection system.

Q39	
Commenter	**Comment**
Response: See the summary response. The PRC standards address protection system criteria.	
SaskPower	Delegate this issue to the Planning Coordinators.
Response: See the summary response. The PC is just one of many applicable functional entities.	
Seattle City	All RAS or SPS schemes should be evaluated to determine the impact on the interconnected system. Actions that derate transfer paths should not be allowed unless essential to protecting equipment or anticipating the next contingency.
Response: See the summary response. The SDT expects that all SPS/RAS will still be subject to the regional scrutiny that you have suggested.	
AECC	See comment to Q38.
Response: See response to Q38.	
Tenaska	The system, following the use of an RAS or SPS in response to a single contingency, shall meet the performance requirements.
Response: The standard allows for RAS/SPS as per Requirement R3.5 but these types of corrective actions are expected to meet the performance requirements as per the tables.	
WECC BPA TSGT TEP	Based on the interpretation of the above question, we are providing two responses to this question. The first responds to the limitations placed on RAS, regardless of what action the RAS initiates. The second response specifically addresses RAS that trips generation. Response 1: RAS should be allowed for single contingency events. Any sort of RAS should be permitted, but there should be a review of the RAS. If the local entities agree to the RAS, it should be allowed. This addresses cost vs. benefit balance. Entities affected should be the ones that determine the best solution for their situation. Response 2: Generation tripping can be used for single contingency if such application can be demonstrated through transmission planning studies that: • The generation tripping is planned and controlled ("planned and controlled" means a pre-planned action(s) based on predetermined system conditions that take corrective measure(s) to maintain acceptable system performance). • The generation tripping does not result in non-consequential load loss. • System frequency should be within allowable limits. • System voltage dip and deviation should be within allowable limits. • The generator owner(s) agrees to the tripping as planned.
Response: Requirement R3.5 allows for the use of SPS and RAS and Requirement R3.5.2 would allow for the kinds of review that you're suggesting.	

40) 40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Summary Response: There was a wide variety of responses that described the conditions that should be met when an RAS or SPS is applied but the majority of the responses can be characterized as follows:

- Requirements for SPS are outlined in the PRC standards
- Maintain System Stability
- Prevent cascading
- Prevent loss of load
- Should be used as a short-term mitigation solution

Other suggestions include:

- Non-Consequential Loss of Load should not be allowed for single Contingencies (N-1)
- Allow to prepare for next Contingency
- If an SPS is used to solve a single Contingency problem, then full redundancy should be required.
- Generator tripping or runback and reconfiguration should be allowed for lower probability single Contingency events such as bus faults.
- SPS not be used for events that are more likely to occur.
- Should not constitute a long-term Corrective Action Plan to address deficiencies.

The SDT has modified Requirement R3.6 (now Requirement R3.5) to specify the conditions under which manual and automatic generation runback and tripping can be used to meet single and multiple Contingency performance requirements and to make it clear that all Facilities must always remain within applicable thermal and voltage ratings.

The following requirements have been changed due to industry comments:

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:

R3.5.1. All Facilities shall be operating within their Facility Ratings.

R3.5.2. Such action would not violate safety, equipment, regulatory or statutory requirements.

R3.5.3. A sustainable, stable, operating condition is maintained.

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Commenter	**Comment**
Ameren	RAS and SPS should be allowed only as an interim operating procedure to mitigate single contingency conditions or to mitigate multiple contingency events on a long-term basis. The RAS or SPS must be effective in mitigating the contingencies and can be implemented within the required operating time.
Response: Industry comments do not support the use of runback only as an interim measure. The current draft standard language does not	

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Commenter	**Comment**
impose such a limitation on the use of SPS.	
Brazos Electric	See above.
BCTC	See Q39. Also, WECC RAS Reliability requirements must be met for new systems.
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating	System must remain stable with acceptable voltages and all equipment within applicable emergency limits.
Duke Energy	See response to Q36 and Q37 above. No additional conditions beyond meeting the performance requirements.
Entergy	Following a contingency, power flows on lines should be within their emergency ratings, voltages should be at adequate levels and system should be stable.
FirstEnergy	As long as thermal, voltage, and stability requirements are met, RAS or SPS should be allowed provided it does not shed load for a single contingency event, and only if the Transmission Owner has documented short term ratings that would not be exceeded during the runback.
JEA	RAS/SPS should not limit generation output for N-1 conditions.
Manitoba Hydro	1) Reducing or increasing generation while keeping the units on-line or by bringing additional units on line. The amount of generation change should be limited to that amount that can be accomplished within the allowed readjustment period. Due consideration should be given to start up time and ramp rates of the units. 2) Generator tripping should be added to requirement R3.5 in addition to runback. Generator tripping is used extensively in regions where remote generation is delivered via long transmission. 3) Capacitor and reactor switching - The number of capacitors and reactors, which may be switched, should be limited to those which could be switched during the allowed readjustment period. 4) Adjustment of load tap changers (LTCs) to the extent possible within the allowed readjustment period. 5) Adjustment of phase shifters to the extent possible within the allowed readjustment period. 6) An increase or decrease to the flow on HVDC facilities to the extent possible within the allowed readjustment period. 7) Transmission reconfiguration - Automatic tripping of transmission lines or transformers to the extent possible within the allowed readjustment period. 8) Automatic tripping of interruptible load or curtailment of or redispatching of Firm Transmission Service to the extent possible within the allowed readjustment period.
MISO	SPS may be used if it maintains similar level of system reliability and security as transmission upgrades.
MRO	SPS are often used in the MRO area to avoid unnecessary expenditures and environmental impacts. SPS are sometimes used to prevent instability. The SPS may initiate fast generation run back, automatic generation rejection, or automatic tripping of a facility for a remote event. The MRO notes that the scheme must be automatic, fast acting, consistent with short term equipment ratings. The MRO notes the following general conditions for adjustments, that

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Commenter	**Comment**
	perhaps would be useful in designing performance requirements for allowable system adjustments in addition to the description in Question 39: 1. Generation adjustments - Reducing or increasing generation while keeping the units on-line or by bringing additional units on line. The amount of generation change is limited to that amount that can be accomplished within the allowed readjustment period. Due consideration shall be given to start up time and ramp rates of the units. 2. Capacitor and reactor switching - The number of capacitors and reactors, which may be switched, is limited to those which could be switched during the allowed readjustment period. This includes those capacitors and reactors that would be switched by automatic controls within the same period. 3. Adjustment of load tap changers (LTCs) to the extent possible within the allowed readjustment period. This includes both LTCs which would automatically adjust and those under operator control which could be adjusted within the readjustment period. 4. Adjustment of phase shifters to the extent possible within the allowed readjustment period. 5. An increase or decrease to the flow on HVDC facilities to the extent possible within the allowed readjustment period. 6. Transmission reconfiguration - Automatic tripping of transmission lines or transformers to the extent possible within the allowed readjustment period. 7. Automatic tripping of interruptible load or curtailment of or pre-determined redispatching of Firm Transmission Service to the extent possible within the allowed readjustment period.
Muscatine P&W	Reasonable and workable. (See Q43 Comment #3)
NERC TIS	No special conditions required as long as the RAS or SPS are tested to meet the performance requirements.
Seattle City	Actions should be intended to address contingency, prevent damage, or prepare for next contingency.
SERC EC DRS	No additional conditions except meeting performance requirements.
Southern Transm.	If an SPS is used to solve a single contingency problem, then full redundancy should be required. Generator tripping or runback and reconfiguration should be allowed for lower probability single contingency events such as bus faults; we suggest that SPS not be used for events that are more likely to occur.
Tenaska	The system, following the use of an RAS or SPS in response to a single contingency, shall meet the performance requirements.
WECC BPA TSGT TEP	System adjustment involves operator intervention that would be beyond the time frame of RAS operation. Therefore, if a unit is already dropped during RAS or SPS action, it should be assumed to be off-line during system adjustment period.

Response: Based on the majority of industry responses, the SDT has modified Requirement R3.6 (now Requirement R3.5) to specify conditions under which manual and automatic generation runback and tripping can be used to meet single and multiple Contingency performance requirements for the steady state portion of the Planning Assessment.

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:

Q40	
Commenter	**Comment**
R3.5.1. All Facilities shall be operating within their Facility Ratings. **R3.5.2.** Such action would not violate safety, equipment, regulatory or statutory requirements. **R3.5.3**. A sustainable, stable, operating condition is maintained.	
City Water Power and Light	Maintain system stability, prevent loss of load and prevent cascading outages.
Response: The SDT agrees with your comment and has modified Requirement R3.6 (now Requirement R3.5) to specify conditions under which manual and automatic generation runback and tripping can be used to meet single and multiple contingency performance requirements. **R3.5.** Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met: **R3.5.1.** All Facilities shall be operating within their Facility Ratings. **R3.5.2.** Such action would not violate safety, equipment, regulatory or statutory requirements. **R3.5.3**. A sustainable, stable, operating condition is maintained.	
ERCOT ISO CAISO	1. RAS or SPS must be simple and manageable. 2. Number of contingencies triggering a RAS or SPS should be very limited (4 allowed by CAISO). 3. RAS or SPS should generally monitor only local facilities that are either directly connected to the plant or one bus away.
Response: The SDT agrees with your comment in (1) and believes this is covered in the requirements of the PRC standards. Based on the majority of industry responses, the SDT has modified Requirement R3.6 (now Requirement R3.5) to specify conditions under which manual and automatic generation runback and tripping can be used to meet single and multiple Contingency performance requirements for the steady state portion of the Planning Assessment. Applying additional requirements needs to be done as a regional difference. **R3.5.** Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met: **R3.5.1.** All Facilities shall be operating within their Facility Ratings. **R3.5.2.** Such action would not violate safety, equipment, regulatory or statutory requirements. **R3.5.3**. A sustainable, stable, operating condition is maintained.	
Northwestern Energy	RAS or SPS should meet performance requirements including reserve requirements.
Allegheny Power	The system should remain stable, reliable, allow for operational preparation for the next contingency and failure of the RAS/SPS should not lead to a cascading event.
AEP	They include redundancy and their failure does not result in cascading.
APPA	Maintain system stability and prevent the loss of load.
SRP	Non-Consequential Loss of Load should not be allowed for single contingencies (N-1) and the system must remain

Q40	
Commenter	**Comment**
	stable with no violations.
Response: The SDT agrees.	
FPL FRCC	The performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. If the proposed TPL standard is adopted the contingency references in PRC-012-0 would need to be updated.
Progress–Florida	The use of RAS or SPS should be allowed as necessary for any single contingency event, provided that such use does not result in cascading outages. It should be noted that the performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. Revision of the existing TPL standards will require updating of the contingency references in PRC-012-0.
Georgia Transm.	PRC Standards
MEAG Power NCEMC SERC EC PSS TVA	The conditions required by SPS standards (PRC).
Santee Cooper	There should be no stability impacts, and system security must be maintained. The requirements are outlined in PRC-015,016, and 017.
SERC RRS OPS	The requirements are outlined in PRC-015, 016, and 017.
SCE&G	The conditions required by SPS Reliability Standards.
Response: The SDT has considered your comments and concludes that the PRC standards describe the performance requirements for SPS but do not specify how the SPS requirements are applied to the Planning Assessment	
IESO	As indicated in the comments provided under Q38 and Q39, the conditions to simulate operation of the RAS and SPS would depend on the conditions they are designed to protect. We do not believe such conditions can be generalized.
ITC	This should be limited to the time until a physical solution is possible (i.e., a temporary solution).
WPS	The use of RAS or SPS should not constitute a long-term Corrective Action Plan to address deficiencies. The use of RAS and SPS should be limited to that period of time necessary to implement expansion of facilities to address the deficiency.
Response: Industry comments do not support the use of runback only as an interim measure. The current draft standard language does not impose such a limitation on the use of SPS.	
LCRA	Systems must have a balance between security and dependability. System must be reviewed annually or as system conditions change.
New York ISO	This would be dependent on the characteristics of each unique protection scheme.
Response: The SDT agrees with your comment and believes this is covered in the requirements of the PRC standards.	
Progress–Florida	The use of RAS or SPS should be allowed as necessary for any single contingency event, provided that such use does not result in cascading outages. It should be noted that the performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. Revision of the existing TPL standards will require updating of the contingency references in PRC-012-0.
Response: Please see Requirement R3.5. The use of SPS is allowed for generation tripping or runback as long as the criteria is met	
AECC	See response to Q38.
Response: See response to Q38.	

Q40	
Commenter	**Comment**
SaskPower	Delegate this issue to the Planning Coordinators.
Response: The SDT believes that it should be a coordinated effort between the Planning Coordinator and the Transmission Planner.	

G) General Questions

41) Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Summary Response: Few comments were received indicating that regional variances would be required although some pointed out that variances may be required depending on the final version of the standard. The standard has been modified with respect to the issue of generation tripping and that should reduce or eliminate the stated level of concern and may make a regional variance unnecessary.

The following requirement was changed due to industry comments:

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~iesy~~ ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:

Q41			
Commenter	**Yes**	**No**	**Comment**
ABB		☑	
Brazos Electric		☑	
Dominion		☑	
E ON US		☑	
AECI		☑	
Allegheny Power		☑	
AEP		☑	
CenterPoint		☑	
CPS Energy		☑	
Duke Energy		☑	
Entegra			
Entergy		☑	
FirstEnergy		☑	
FPL FRCC		☑	No, if the comments to the above questions are incorporated. The FRCC system is a peninsular system having only one interface with the rest of the interconnected NERC system, and has historically demonstrated exceptionally high reliability with no events in recent history cascading beyond the FRCC system. The adequacy of the existing TPL standards as they apply to the FRCC System have been extensively documented.

Q41			
Commenter	**Yes**	**No**	**Comment**
Georgia Transm.		☑	
IESO		☑	
ITC		☑	Variances should not be a reason to change the standard (lower the bar).
KCPL		☑	
MISO		☑	
National Grid		☑	We're not aware of any at this time. However, future modifications of the standard may highlight a need for regional variances.
New York ISO		☑	
PJM		☑	
Progress–Florida		☑	No, but PEF reserves the right to apply for variances based on the completed version of this or any other standard.
Santee Cooper		☑	
SERC EC DRS		☑	
SERC RRS OPS		☑	
SCE&G		☑	
Southern Transm.		☑	
Tenaska		☑	
TVA		☑	
WPS		☑	
Central Maine Power New England ISO NU NSTAR United Illuminating	☑	☑	Unsure due to ambiguities in the standard. Depending upon the final standard, New England may need exceptions for existing facilities or allowance for a transition period to develop a compliance plan.
HQTE NPCC RCS	☑	☑	Until section R3.6.1 is finalized, we will be unable to determine whether a regional variance is required.
Response: Few comments were received indicating that regional variances would be required although some pointed out that variances may be required depending on the final version of the standard.			
Manitoba Hydro	☑	☑	MH does not like the idea of a long transition period. Either NERC adopts the concept of generation rejection or the MRO will need to submit a regional variation. I much prefer the planned loss of generation via an SPS rather than via out-of-step tripping as proposed in the Table 2. In certain

Q41			
Commenter	**Yes**	**No**	**Comment**
			areas of the MRO that are stability limited because of long lines to bring generation at the energy source (such as mine mouth plants, hydro plants, etc.) to the load, generation rejection is used to return from an emergency state to a normal state. If generation rejection is not allowed in these cases, extraordinary cost and extraordinary negative environmental impacts will result. As an example, removing one SPS will require new 500 kV transmission between Winnipeg and Minneapolis at a cost of $1 billion to MRO utilities.
BCTC	☑		WECC may require a regional difference for generator tripping depending on the conditions imposed in R3.6.1. Other regional variances would not necessarily be in the context of regional difference as defined in the Standards Manual, but rather exceptions for long weak systems for which it is not economic to meet criteria applicable to tightly interconnected systems.
ERCOT ISO CAISO	☑		ISO relies upon tripping of generators to meet single contingency performance requirements. ISO also relies upon planned and controlled load shedding for the proposed Planning Events P4 and P5.
LADWP	☑		Too many to be listed with the separation above and below 300kV being the worst one that will undermine the overall reliability of the electric system in North America. Another major omission in this proposed standard is the complete lack of recognition of the importance of post-transient requirements. Mixing commercial (firm or non-firm transactions, etc.) and reliability in transmission planning criteria would be in conflicts with WECC rules and practices.
MRO	☑		If the SDT proceeds with an approach that does not allow generation rejection for contingencies, the MRO will need to submit a regional difference. In certain areas of the MRO that are stability limited because of long lines to bring generation at the energy source (such as mine mouth plants, hydro plants, etc.) to the load, generation rejection is used to return from an emergency state to a normal state. If generation rejection is not allowed in these cases, extraordinary cost and extraordinary negative environmental impacts will result. As an example, if one particular SPS is removed, new 500 kV transmission will be required between Winnipeg and Minneapolis at a cost of $1billion to the customers of MRO utilities.
NERC TIS	☑		There may be some in the application of RAS or SPS for N-1 contingencies.
Northwestern Energy	☑		WECC allows N-1 generator tripping, and the transmission systems have been designed around this criteria. Moving away from this criteria is not necessary, and for critical N-1 events, redundancy is in place.
WECC BPA TSGT TEP	☑		Yes. WECC allows tripping of generators to meet single contingency performance requirements. WECC also allows planned and controlled load shedding for the proposed Planning Events P2-1, P2-2, P3, P4 and P5, although we agree with the proposed requirements for P4 due to the higher probability of occurrence. If the standard does not allow for non-consequential load shedding of 300 kV and above for P5 scenarios, WECC will develop a regional variance".
Response: The standard has been modified with respect to the issue of generation tripping that should reduce the stated level of concern and may make a regional variance unnecessary.			

Q41			
Commenter	**Yes**	**No**	**Comment**
R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~iesy~~ ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met**:**			
LCRA	☑		See ERCOT Planning Criteria. Also, through the regional coordinators, NERC recently conducted a survey of transmission planners/owners regarding use of more stringent criteria used in their own systems. The std. drafting team should include a review of the survey results and incorporate into this NERC std as necessary.
Response: The SDT will review the survey.			
MEAG Power	☑		Facilities rating methodology are different from region to region and company to company.
Response: Ratings methodologies are not covered in this standard.			
AECC	☑		I am more concerned about the regions performing studies consistently than identifying regional variences. My company sits stradle the Southwest Power Pool and SERC. There are considerable difference between the two when it comes to study criteria, assumptions, and how studies are performed. These differences have led to situations where it is near impossible to get models and perform studies near the seams that produce results in which you can have confidence and are comparable. The Southwest Power Pool and its members do a very good job of analyzing and evaluating their region. SPP has criteria that specifically requires EtE analysis and the process used to develop their Transmission Expansion Plan contains treatment of SPS/RAS schemes as mitigations.
Response: The SDT recognizes the regional differences that can exist. However, resolution of all regional variances is outside the scope of the SDT.			
APPA	☑		The WECC will probably have a couple.
ATC	☑		
City Water Power and Light	☑		
ISO/RTO	☑		
PRPA	☑		
Progress–Carolinas	☑		
Response: Thank you.			

42) Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Summary Response: Few comments were received indicating conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement. A few potential issues were identified in areas of the standard that have been modified in the second posting. These areas will need to be re-assessed based on the specific revisions made.

The following requirements were changed due to industry comment:

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~iesy~~ ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:

R9. Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information.

R10. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information.

R11. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information.

R12. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information.

R13. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information.

R14. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to Transmission Lines, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies, within ninety days of a request for such information.

Q42			
Commenter	**Yes**	**No**	**Comment**
ABB		☑	

Q42			
Commenter	**Yes**	**No**	**Comment**
AECC		☑	
Ameren		☑	The proposed standard, as well as the existing standards, makes no distinction between firm (network resource) and non-firm (energy only) generation. The standard should clearly state that the standard does not apply to non-firm generation.
City Water Power and Light		☑	
E ON US		☑	
ERCOT ISO		☑	Not aware of any.
AECI		☑	
Allegheny Power		☑	
AEP		☑	
APPA		☑	
BCTC		☑	
CAISO		☑	Not aware of any
Central Maine Power		☑	
CPS Energy		☑	
Duke Energy		☑	
FirstEnergy		☑	
FPL		☑	
FRCC		☑	
Georgia Transm.		☑	
HQTE		☑	
IESO		☑	
ITC		☑	
Manitoba Hydro		☑	
MISO		☑	
MRO		☑	

Q42			
Commenter	**Yes**	**No**	**Comment**
National Grid		☑	
New England ISO		☑	
New York ISO		☑	
NU		☑	
NPCC RCS		☑	
Nstar		☑	
PJM		☑	
Progress–Carolinas		☑	
Progress–Florida		☑	
SERC EC DRS		☑	
SERC RRS OPS		☑	Not currently aware of any.
SCE&G		☑	
Southern Transm.		☑	
Tenaska		☑	
United Illuminating		☑	
Santee Cooper		☑	The proposed standard as well as the existing standards, makes no distinction between firm (network resource) and non-firm (energy only) generation. The standards should clearly state that the standard does not apply to non-firm generation.
WPS		☑	
Response: Thank You. The SDT is not aware that the proposed requirements conflict with the tariff provisions of firm versus non-firm Transmission and no specific conflict was provided in the comments.			
WECC BPA TSGT TEP	☑		1) FERC Order 693, Paragraph 1825 regarding TPL-003, Category C – The Commission directed the ERO to modify footnote (c) to Table 1 to clarify the term "controlled load interruption" rather than eliminate its applicability to this performance requirement. 2) FAC-010-1, R2.3 – "…planned or controlled interruption…" This conflicts with "No" for non-consequential load loss allowed in draft TPL.
Response: The SDT believes the draft standard does not conflict with FERC Order 693. Paragraph 1794 specifically prohibits loss of Non-Consequential Load for a single Contingency. The SDT has modified the standard for consistency with FAC-010-1, R2.3. Alternatively, to the extent a conflict still exists, FAC-010-1 would need to be revised to comply with the FERC Order.			
CenterPoint	☑		FPA section 215(i)(2) "does not authorize the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for

Q42			
Commenter	**Yes**	**No**	**Comment**
			adequacy or safety of electric facilities or services." However, adherence to TPL-001-1 as currently drafted, will require, de facto, the construction of additional transmission facilities. CenterPoint Energy believes this standard goes far beyond the legislative intent of mandatory reliability standards and will result in construction of transmission capacity in order to remain compliant.
Dominion	☑		Current planning criteria are approved by State commissions. It is unlikely that the commissions would agree that rate payers should incur the significant cost increases required to meet more stringent planning criteria (i.e. - "raising the bar") when the corresponding improvements in transmission system reliability cannot be quantified.
Response: The SDT's understanding is that the ERO believes it has the authority to set performance requirements for reliability.			
KCPL	☑		In the past, Missouri Public Service Commission Staff have required KCPL to demonstrate that generators have "firm" transmission outlet capacity.
Response: The SDT does not believe that the proposed requirements conflict with the stated MO PSC requirement.			
NCEMC	☑		Modeling data requirements in R1 applicable to many entities may be either redundant with the MOD submittals or may be conflict for entities that are required to submit this data to Transmission Providers to comply with deadlines in their Tarffs. In addition, data submitted by entities named may be confidential so this issue will have to be addressed among those submitting and receiving needed data.
Response: The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. The SDT agrees that there may be situations where confidentiality issues will have to be addressed. **R9.** Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information. **R10.** Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information. **R11.** Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information. **R12.** Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information.			

Q42			
Commenter	**Yes**	**No**	**Comment**
R13. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information. **R14.** Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to Transmission Lines, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies, within ninety days of a request for such information.			
Northwestern Energy	☑		Eliminating the N-1 RAS in the West could cause problems for utilities in the West with local jurisdictional cost recovery.
Response: The standard has been modified with respect to the issue of application of RAS/SPS that should reduce the stated level of concern and remove any conflict. **R3.5.** Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~iesy~~ ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met**:**			
ATC	☑		
ISO/RTO	☑		
Response: The SDT believes the referenced requirement is necessary to ensure an appropriate balance between reliability requirements and right-of-way considerations.			

43) Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Summary Response: Several of the commenters reinforced or embellished the comments they submitted in prior questions. Although the SDT has provided responses to all comments submitted as part of this question, more detailed responses and summaries are provided in the prior questions.

However, several comments were received that were different from other prior comments. The SDT has made many changes to requirements based on comments submitted just for Question #43. Some of the major changes are:

1. Created a new requirement concerning short circuit analysis
2. Created a requirement to document proxies for instability, cascading outages and uncontrolled islanding
3. Changed requirements to clarify the actions allowed to prepare for the next Contingency
4. Changed requirements to clarify that Facility Ratings may be different for, and a function of, different durations
5. Added a definition for Bus-tie Breaker.

Other less significant changes were made by the SDT based on the remaining few comments. These are detailed in the responses to the individual comments below.

The following requirements were changed as a result of industry comments:

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)

Consequential Load Loss: Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.

Non-Consequential Load Loss: ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.

R1. ~~Each Resource Planner, Transmission Planner, Transmission Owner, Generator Owner, and Load-Serving Entity shall each provide its respective Planning Coordinator with the following modeling information required for System performance studies upon request (within 30 calendar days) :~~ Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to

complete their Planning Assessment. The models shall use data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources.

R2.1. ~~The steady state portion of~~ The Near-Term Transmission Planning Horizon ~~Planning Assessment~~ portion of the steady state analysis shall ~~address all five years of the assessment period~~ be assessed annually and be supported at a minimum by the following annual current studies, supplemented with qualified past studies as ~~shown~~ indicated in Requirement R2.6:

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:

R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

R2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually and supported by current or past studies.

R2.4 The ~~System Stability portion of the~~ Near-Term Transmission Planning Horizon portion of the Stability analysis ~~Planning Assessment~~ shall be assessed annually ~~address all five years of the assessment period,~~ and be supported by current or past studies. The following studies are required ~~annually~~:

R2.4.1. System peak Load for one of the five years. For peak System Load levels, ~~the~~a Load model shall ~~include the dynamic effects~~ be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads.

R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:

R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

R2.5. The ~~plant~~Generating Unit Stability analysis portion of the Planning Assessment shall be analyzed consistent with Requirement ~~R4.6~~ R5.6 with studies for the year when the following changes that could affect stability margins occur:

R2.5.1. New generator(s) are added or generation modifications are made such as ~~increasing~~changes in generation capability or replacing the exciter ~~or addition of a power System stabilizer~~

R2.5.2. Material Transmission System changes ~~in the electrical vicinity of existing generation are made~~ are made at or near the point of Interconnection of existing Generation such as the ~~addition or~~ removal of a Transmission Line ~~at or near the point of Interconnection~~ or the addition of a new substation in one of the Transmission Lines connected to the plant.

R2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

R2.6.1. For steady state, short circuit, or System Stability analysis: ~~if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market structure changes~~ the study shall be five calendar years old or less.

R2.6.2. For steady state, short circuit ~~analysis~~, Generating Plant Stability, or System Stability analysis: ~~if the study is less than five years old and no material changes have occurred to the System in the intervening period.~~ the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area.
R2.6.3. ~~For plant and System Stability analysis: until material changes in the System make the study no longer valid. Material changes in the system include the addition of a Transmission Line or a generator.~~

R2.7 - For Planning Events shown in Table 1 – Steady State Performance and Table 2 – Stability Performance, when the analysis indicates an inability of the System to meet the performance requirements in the tables, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed ~~over time~~ in subsequent assessments but the System shall continue to meet the performance requirements in the tables. ~~Such plans shall:~~ Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities**.**

R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.

R2.7.2. ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.

R3.3.2.2. Following single Contingency events, ~~System adjustments other than shedding of firm Load or curtailment of firm transfers are permitted to meet performance requirements provided these adjustments can be accomplished within the time period allowed by the applicable time limited ratings.~~ Transmission configuration changes and redispatch of generation are allowed provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits.

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~ if the following conditions are met:

R3.5.1. All Facilities shall be operating within their Facility Ratings.

R3.5.2. Such action would not violate safety, equipment, regulatory or statutory requirements**.**

R3.5.3. A sustainable, stable, operating condition is maintained.

R5.2. Contingency analyses shall simulate the removal of all elements including those that System protection and other automatic controls are ~~is~~ expected to disconnect for each Contingency without operator intervention**.**

R5.5.2 Performance shall meet the requirements for Planning Events in Table 2 – Stability Performance**.**

R5.5.3. Automatic generation tripping is allowed to mitigate Stability violations if the following conditions are met:

R6. For the short circuit portion of the Planning Assessment, as described in Requirement R2.3, each Transmission Planner and Planning Coordinator shall assess the short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties.

R8. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~affected entities~~ neighboring systems, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890.

R9. Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information.

R10. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information.

R11. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information.

R12. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information.

R13. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information.

R14. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to Transmission Lines, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies, within ninety days of a request for such information.

Q43			
Commenter	**Yes**	**No**	**Comment**
ABB	☑		1. In Table 2 P3, more clarification is needed for "above 300 kV". For generators, does that mean those whose POI is >300kV? For transformers, is it the secondary voltage? Also, is the footnote referencing correct? "A transformer with low side rating above 300 kV" is confusing for transformers with 3 windings. What's the low-side rating of a 500/345/13.8 kV transformer? You should say "a secondary voltage rating above 300 kV" and define "secondary voltage rating" as the second highest voltage rating. This is standard nomenclature. Also, I assume you know that there aren't very many of these. The possibilities are 765/500, 500/345, and 765/345. The first two are uncommon, and the 3rd is only common in AEP and HQ. 2. In P3, does the 300 kV limit apply to the transmission circuits as well? It is hard to tell. 3. In R1, you say "Each … shall each …" Delete the second "each", which is redundant. Also delete "required for system performance studies". These words are not part of the requirement. They are part of the justification for the requirement. 4. Table 1, Extreme Event Descriptions, 3d and 3f are almost identical. 5. Table 1, P9-1, rewrite as "… (excluding circuits that share common structures for one mile or less)". P9-1 uses "structure" whereas Extreme 2a uses "tower". Make consistent. 6. P9-2 monopolar is already covered under P4-2. 7. For all of the multiple contingencies with System Adjustment in the middle, group them together something like this (for those with the same requirements): "Outage of any one of the following: 1.

Q43			
Commenter	**Yes**	**No**	**Comment**
			2. 3. 4. followed by System Adjustments followed by outage of any one of the following: a. b. c. d." This is easier to understand than separately writing each possible combination of 2. 8. Overall, the structures of the Tables needs to be made clearer and more consistent. But the ideas are good. 9. The transition is going to be critical for some of the standards that may require significantly more study work and significant capital investments in transmission infrastructure.

Response: 1. The SDT has added a footnote reference to the BES Elements Out of Service column to provide clarity on this issue. The note excludes tertiary windings.
2. The 300 kV threshold also applies to transmission circuits. The SDT has added greater detail to Tables 1 & 2.
3. The SDT has modified Requirement R1 (first draft) as Requirements R9 – R14 and the comment is addressed in the re-write.

R9. Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information.

R10. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information.

R11. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information.

R12. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information.

Q43			
Commenter	**Yes**	**No**	**Comment**
R13. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information. **R14.** Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to Transmission Lines, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies, within ninety days of a request for such information. 4. The Extreme Event descriptions have been revised in Tables 1 and 2 to clear up this wording. 5. P9-1 (P7-1 in second draft) is intended to include all structures in a tower line. Extreme Event 2a refers to a tower line. So they are consistent. 6. The SDT has revised Tables 1 and 2 so that this only shows up in one place now, P7. 7. The SDT has revised the tables as requested. 8. The SDT has revised Tables 1 and 2 as requested. 9 - This will be addressed later in the Implementation Plan.			
AECC	☑		I am not sure what is meant by "not the least common denominator" in the background section. One long time goal of NERC has been to raise the bar and not settle for the status quo which I support. If by this phrase the drafting team is looking to minimize loopholes, remove waffle factor, and eliminate some of the innovative interpretations of requirements then I am in agreement. However, if the drafting team is thinking that the least common denominator is a level of system study that should be performed and that studies should only be performed at some higher level then I disagree and consider this attitude as contradictory to the long term goal of raising the bar. If NERC is serious about reliability then we must get this standard right. Planning is where reliability starts. If reliability is not planned for adequately and built into the system it can not be expected that the future holds much promise for a reliable system. Reliability will not happen on its own. Industry best practices should take precedence over attempts to water down the standards in order to maintain status quo. Do any of the requirements under R1 conflict or repeat any of the requirements set for in any of the other NERC standards, especially some of the MOD and FAC standards? if so R1 should be modified, sections deleted, or reference the appropriate standard. I would like to thank the drafting team for taking on such a formitable task.
Response: The SDT felt that none of the current requirements should be weakened. The SDT felt that it is necessary to develop more stringent requirements where appropriate but not be limited by the fact that companies may need to reinforce their Systems to meet the new requirements.			

Q43			
Commenter	**Yes**	**No**	**Comment**
The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.			
Ameren	☑		1. Much of the language under R1 appears to be redundant with model data requirements as listed in Reliability Standard MOD-010 and MOD-011. Such information would typically be used to produce an annual series of powerflow cases. Instead of supplying such information in a piecemeal manner to the Planning Coordinator as a separate annual effort, the Planning Coordinator should make use of the most recent set of powerflow models. This requirement, as written, could cause a needless duplication of work effort. 2. It is not clear what is meant by 'stressed System conditions' in Requirement R1.2. Does this mean higher than predicted load, lower than expected reactive resources, or other meaning? It is also not clear what is covered by 'load models' in the same requirement. 3. It is not clear how expected transfers are to be modified in Requirement R2.1.3.2. Possibilities include higher or lower in the same transfer direction, turn transfer directions around so that importers become exporters, the inclusion of non-firm transfers that can be cut, or change import/export directions. There should be some basis for the sensitivity change. 4. It is not clear how planned transmission outages are to be modified in Requirement R2.1.3.7. Possibilities include modification of the outage duration, or modifications involving more or less facilities. Since outages are scheduled in the operations planning horizon, based on the best information available at the time of the outage request, it is questionable whether they should not be included in standards that apply to planning in years 1-5 or year 6-10 and beyond. 5. Requirement R2.2.1. should be deleted. Uncertainties involved with studies looking at system conditions out to ten years in the future would preclude the need to extend a Planning Assessment beyond the ten year period. Any corrective actions needed to resolve problems found during study of long-term system conditions could be noted in the Planning Assessment without the need to extend beyond ten years. 6. In Requirement R2.3, the scope of the study work involving the short circuit portion of the Planning Assessment is not clear. It is not clear whether the study work should be based on three-phase faults only, three-phase and single-phase faults, or whether classical representation or more a more detailed representation should be utilized. 7. We assume that Requirement R2.4.3.5 would require only known generation additions,

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Commenter	**Yes**	**No**	**Comment**
			retirements, or other dispatch scenarios, and that those performing the planning scenarios would not speculate on unkown generation additions and retirements. 8. A market structure change in Requirement R2.6.1 would not constitute a material change in an area with an abundance of low cost base load generation that was always on before the market change and would still be on after the market change. 9. Under Requirement R2.6.3., Plant and System Stability analyses are considered valid until material changes in the System invalidate previous study work. Here, material changes in the system include addition of a transmission line or generator. Addition of a transmission line or generator would only have an impact on stability of generators near the new facility installation. This is not clear from the wording of the standard, which would appear to require restudy of all generators if a transmission line or generator is added anywhere on the system. 10. What would be the duration of interim operating procedures in Requirement R2.7? 11. Requirement R.2.7.1.1. states that a project initiation date should be included in the Corrective Action Plan for each project, as well as an in-service date. A project initiation date may be of use to the particular project design engineering staff, but is of little use in planning the system. Keep in mind that this is a Planning Assessment and not a data request. 12. The wording of Requirements R3.2 and R4.2 appear to require taking all transmission elements as contingencies, plus modeling contingencies which would remove all elements automatically via System protection equipment. Based on comments from the SDT, the inclusion of all single elements in the set of contingencies to be considered is not intended as part of these requirements. Please verify this in writing. 13. The wording of Requirement R3.2.1., dealing with generator minimum voltage limitations, is vague with respect to what is required. It is not clear who would determine the minimum steady-state voltage limitations for all generators, and for what conditions. Note that it may be difficult to obtain some information from IPP generating facilities. 14. Requirement R3.2.2. appears redundant with requirement R1.2.1 of FAC-008-1, which deals with Facility Ratings. Relay load limits are one component already considered in establishing facility ratings. 15. Requirement R3.3.2.1., which deals with the amount and duration of Consequential Load loss, cannot be addressed adequately. Because an outage might be caused by a transitory event with

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Commenter	**Yes**	**No**	**Comment**
			quick restoration of the outaged facility, or be caused by extensive damage requiring lengthy repairs, there would be no single value for expected duration for any given outage event in the planning horizon. Therefore, this requirement should be removed from TPL-001-1. 16. Requirement R3.3.2.2, describing permissible actions following single contingency events to meet performance requrirements, should be removed from TPL-001-1. System adjustments following single contingencies should not be permitted to meet system performance requirements. For similar reasons, Requirement R3.5, describing generator adjustments permissible as responses to single and multiple contingencies, should be modified to remove the reference to single contingencies. 17. What additional single contingencies would there be that should be considered in Requirement R3.3.3? 18. Consequential generation loss needs to be considered in Requirement R3.6 for those generators directly connected (through transformation) to transmission lines. 19. Interconnection requirements establish that generators must have low-voltage ride through capability. It is not clear how is the transmission planner performing the studies would be able to consider this capability in Requirement R4.3. 20. In Requirement R6, there is no longer a requirement to send the Planning Assessment and Corrective Plan to the regional entities, but to the Reliability Coordinators instead. Why has this change been made? RTOs should not be involved in assessing compliance. 21. In reference to Table 1, bullet point #3, it is not clear how voltage instability, cascading outages, or uncontrolled islanding would be determined under steady state conditions. 22. Under Table 1, P1, cutting of firm transfers is not permitted as a response to a single contingency. However, it is not clear whether, in preparation for a subsequent contingency, reduction in firm transfers would be permitted. Reduction in firm transfers should be permissible in this instance. 23. In Table 1, for contingency categories P5 and P8, how would loss of a transmission circuit above 300 kV followed by loss of a transmission circuit below 300 kV be handled? 24. Under the Extreme Event Description section of Table 1, note that item 3e. is a duplicate of item 3c. One of these can be deleted. Also, for items 3d. and 3f. the notation regarding early shutdown of nuclear facilities for tornadoes is not realistic. The current state of the art of weather prediction

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Commenter	**Yes**	**No**	**Comment**
			does not permit adequate forecasting of tornadoes a day or more ahead of time which might be a cause for concern for a particular nuclear facility. 25. With respect to Table 2, contingency types P5 and P8, it would seem that events should include the same items as shown for contingency type P4. 26. In Table 2, for contingency types P1, P3, P4, P5, P8, and P9, clarification is needed as to whether distribution transformers (138-69 kV or 138-34.5 kV, for example) would be included in the events, or whether the transformers mentioned would be restricted to transmission transformers. 27. For the various stability scenarios, note that Consequential Load Loss would be a function of how System protection equipment is set up for particular scenarios. Delayed clearing time/Zone 2 clearing times could result in load dropped that would not have been dropped for events cleared in primary clearing time. 28. In Table 2, Note 1 ii., is it the intent of the drafting team to require dynamic model representation of relaying equipment? General comments: 29. We are not sure that a wholesale replacement of the existing standards TPL-001-0 through TPL-004-0 is required. We agree that additional clarification is needed for some items, and particularly for the study assumptions that go into the development of models to be used for the performance testing, but we do not agree that the proposed replacement standard provides that necessary clarification. Further, we believe that the replacement standard relies too much on the accompanying tables. More text needs to be included in the standard regarding the system performance requirements. 30. There is a lot of subjectivity involved in developing the study assumptions that need to be considered in the sensitivity models for study. How can we be sure that one or more of the sensitivity requirements in R2.1.3 stated for consideration are of the same level of importance by both auditors and those performing the studies? We are interested to see what the measures for all the requirements of the standard will be when they are developed. 31. Additional planning standard requirements for the EHV system to meet all N-2 conditions without dropping some load will require significant material changes, where feasible. We do not believe that the significant additional costs required for compliance would produce tangible benefits and a corresponding significant improvement in system reliability. What is the justification for the separate

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Commenter	**Yes**	**No**	**Comment**
			treatment for the EHV (>300 kV) facilities? One obvious effect of such requirements is to create a bias against any straight bus configuration for facilities above 300 kV. As stated in response to Question 25, there are existing facilities which cannot be converted from their present configuration. For those facilities which could be upgraded, an implementation period of several years would be needed to meet such requirements. 32. Meeting the requirements of this standard should not be a full time job. There are many more planning activities that need to be performed other than simulation testing to demonstrate compliance. The existing TPL standards require a significant manpower effort to perform the required studies and develop the planning assessment and corrective action plan. We are concerned that the replacement standard, as proposed, will create an even greater burden on the transmission owners without a commensurate benefit to the system reliability. 33. It is not within NERC's or ERO's scope of responsibility to address load loss. The focus of the standard should be on the system capabilities and not how much local load is dropped for a substation outage in a defined service area. A few reports showing the resultant bus voltages and facility loadings on a percentage basis for all single and a the more severe multiple contingency events, including operator or automatic mitigation procedures, should be adequate to demonstrate compliance.

Response: 1. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.
2. The SDT agrees with your concerns and has revised this requirement (now Requirement R9). The terms "stressed System conditions" and "load models" have been removed.

R9. Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information.

3. The SDT is providing some guidance under Requirement R2.1.3 on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. It is the entity's decision to establish and document which transfers are more significant to study System responses. The sensitivity studies do not in themselves establish the need for a plan, only the areas of the System for which the analysis is needed.

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:

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Commenter	**Yes**	**No**	**Comment**
			4. The SDT is providing some guidance under Requirement R2.1.3 on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. It is the entity's decision to establish and document if there are any "planned" outages such as a multi-year Transmission right-of-way rebuilds where outage durations may vary. It is the entity's responsibility to determene the actions necessary to handle extended outages and which are more significant to study System responses. 5. The SDT felt that this wording was appropriate based on comments by FERC in their orders concerning long lead time projects. 6. R2.3 - The studies should be based on the individual TO's practices which are assumed to be in agreement with good utility practice. An annual assessment of the results of these studies is required. 7. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.4.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.4.4 has been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. In either case the entity must document the reason for running or not running cases for the items listed. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance. It is the entity's decision to establish and document if it needs to consider future additions and retirements. It is the entity's responsibility to determene the actions necessary to handle such items and which are more significant to study System responses. **R2.4.3**. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: **R2.4.4**. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. 8. The SDT removed market changes from the requirement (see Requirement R2.6.2) **R2.6.2**. For steady state, short circuit, Generating Plant Stability, or System Stability analysis: the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. 9. The SDT added wording to Requirement R2.6.2 to clarify this concern. 10. The "interim Operating Procedure" was deleted in response to Industry requests for more clarification as being an unnecessary modification of the more general term "Operating Procedure" that is already a defined term in the NERC Glossary.

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Commenter	**Yes**	**No**	**Comment**

11. Requirement R8 (old Requirement R6)which focuses on the distribution of the Planning Assessment results to affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old Requirement R6). Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. The SDT believes that initiation dates are required for near-term Corrective Action Plans to give an indication that the Corrective Action Plans can be implemented in time.

12. In Requirement R3.2 and Requirement R4.2, the SDT revised the event descriptions to provide clarity on simulations in response to FERC Order 693. For example, Requirement R3.2 would require modeling breaker-to-breaker outages rather than modeling bus-to-bus outages in a study.

13. Generator high and low voltage limits are part of the constraints and are considered part of Facility Ratings in FAC-008. FAC-009 provides that the information be provided by the Generator Owner.

14. R3.2.2 - While FAC-008-1 generally addresses this issue, the SDT felt that the relay loadability issue needed to be specifically addressed to ensure its impact was not inadvertently ommitted from Contingency analysis.

15. R3.3.2.1 - FERC required documentation of Consequential Load loss in Order 693, paragraph 1795, (not Non-Consequential) and duration should be based on best judgment for the common cause of the event.

16. R3.3.2.2 has been changed to clarify the concern.

R3.3.2.2 – Following single Contingency events, ~~System adjustments other than shedding of firm Load or curtailment of firm transfers are permitted to meet performance requirements provided these adjustments can be accomplished within the time period allowed by the applicable time limited ratings.~~ Transmission configuration changes and redispatch of generation are allowed provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits.

17. The requirement refers to everything over and above single Contingencies.

18. Requirement R3.6 was completely re-written in Requirement R3.5.

R3.5 Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:

19. The SDT feels that planning studies should be of sufficient scope to cover this situation.

20. R6 (first draft) - does not specify any action by the Reliability Coordinator - the Planning Coordinator coordinates distribution. This action

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Commenter	Yes	No	Comment
			does not involve assessing compliance but involves peer review and coordination of analysis. 21. In the steady state time frame, voltage instability can occur typically during high power transfer and/or peak demand periods. Voltage instability can be assessed using a long-term Stability program. However, it can also be assessed using a power flow program that simulates governor action. There are a number of IEEE papers (e.g., G. Morison, B. Gao, and P. Kundur, "Voltage stability analysis using static and dynamic approaches," IEEE Transactions on Power Systems, vol. 8, no. 3, pp. 1159 – 1171, August 1993) that can provide suggestions on the methodology. Cascading outages and uncontrolled islanding can also occur, for example, when the Transmission Facilities Load beyond the corresponding relay trip settings. This could cause uncontrolled tripping of Transmission Facilities beyond those required to clear the fault. Even though these events are rare, the Transmission Planner should be aware of their possibility when performing studies. 22. The SDT has replaced the term "firm transfer" with "firm transmission service" in Tables 1 and 2. 23. Loss of a Transmission circuit above 300 kV followed by loss of a Transmission circuit below 300 kV would be treated the same as loss of Facilities below 300 kV. 24. The SDT has revised Tables 1 and 2. Items 3d and 3f are meant to capture shutting down of a nuclear power plant as a result, not in anticipation, of events such as tornadoes. 25. Table 2 has been revised so that the elements are now the same. 26. See footnote 2 and 3 in Table 2 for clarification. 27. The SDT agrees. The Load lost as a result of the event specified can be different for different Contingency scenarios (i.e., normal versus delayed clearing). 28. This should already be in your models. 29. TPL-001-1 is based on the existing TPL standards and is not a wholesale replacement but an aggregate of TPL-001 through -004, but does contain new elements and clarifying language. FERC Order 693 asked the SDT to consider combining the 4 standards. Please provide any comments on specific elements needing additional clarification in future responses in the standard development process. 30. Measures will be added later in the process. 31. The SDT felt that it was appropriate to raise the bar on situations that would impact the reliability and performance of the System and considered above 300 kV as the backbone of the System and thus needs to be extremely reliable and was an appropriate place for raising of the bar. Implementation Plan will be supplied with a later draft.

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Commenter	**Yes**	**No**	**Comment**
32. Resources and expenditures versus adequate level of reliability are being given due consideration throughout the process and will ultimately be determined by the industry through the ballot process. 33. FERC has jurisdiction over firm Transmission service. FERC allows the use of "equally or more efficient or effective approach" and firm Load is being used as a proxy for firm Transmission service.			
Brazos Electric	☑		1. In R1.1.1. it appears the data that is being requested requires some amount of survey to determine the mix. This data would require a great deal of manpower and provide little more benefit than simply varying the data for comparison. However it does say in R1 upon request so does this allow the Planning Coordinator the descretion as needed on this type data? 2. R1.2, What is 'supporting rationale' and 'validated' mean? What are "stressed" System conditions? It appears (from 2.1.3) that stressed means various sensitivities. 3. R1.4, define 'long-term', generation outages are considered confidential information in ERCOT and thus are not available to all TOs, see next comment 4. R1.5 somewhere (perhaps in R1) the language should include "its respective portions of the data" or something to that effect meaning that a TO should not be held accountable for a GOs data. R1 appears to read that each entity shall provide the requested data. This seems to be intuitive BUT there are GOs that feel the data responsibility for the entire system belongs to the TOs and this leads to delays in getting accurate information if its uncertain as to who provides what data. 5. In R2 the language indicates the TP and PC shall each perform studies. There should be some clarity here. Also, it indicates that each shall assess "its portion of the BES". This needs to be clarified as well, obviously contingencies on other portions of the BES may cause issues within different portions. again, what constitutes documentation? 6. R2.1 it appears from the wording (shall "address" all five years) that the planning assessment must be done on all five years but 2.1.1 appears to state only 2 years are required. Please clarify. 7. R2.1.3 this seems to indicate that the studies mentioned in 2.1.1 and 2.1.2 should be "stressed" by the conditions listed below or just by one of them. We assume this means using only one is acceptable with proper documentation. Is that correct? Further, the sensitivities are ambiguous. How does one justify higher load levels or even know what they are without input from other TOs or the PC? How does one even guess at the other variables? what is meant by 'long lead time facility'? IF this only means for a TOs "portion of the BES" then it makes more sense but are these even valuable considering the wide range of data. The only variable that can be adjusted with any accuracy is the generation and ERCOT maintains the confidential data in this area. We assume R2.1 to mean you

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Commenter	**Yes**	**No**	**Comment**
			need to assess two peak summer cases, one off peak and then look at varying generation patterns on those cases. This appears to be the latitude given. Is this correct? 8. R2.2.1 are generation additions considered a "project"? If this means that a case must be created and assessed by all TOs for a known generation addition that is 12 years out, then this will lead to unnecessary studies. We assume this to mean, in the case of a generation addition, that the connecting TO should make an assessment once the PC considers this new addition to be valid for study. Is that correct? 9. R2.3 what is meant by "past studies" and how long must these be kept? Or is this at the TOs discretion? 10. R2.3.1 how does one know if the changes will result in increased fault currents until studies are done? This implies that studies SHALL be done for just about ANY change to the BES. There must be discretion allowed here. The word "shall" does not afford any discretion. 11. R2.4 the same comments for R2.1. apply here concerning years of study and defining 'stressed'. Additionally this type study seems to provide better results when done for the BES which would require input from all TOs thus a study based only on "its portion of the BES" would not have as much value unless you are referring to generation additions and localized studies. 12. R2.5.1 does not allow any discretion, for any and all all modifications, additions, etc…a study shall be performed. This is not needed in all cases. 13. R2.5.2 Wording such as "material changes" and "vicinity" are ambiguous terms without discretion being allowed the planner. Voltage level Line changes, amount of generation, something needs to be added to clarify. 14. R2.6.1 again, what are material changes? Topology changes and generation changes happen monthly, weekly. Are studies to be invalidated for each 'material change'? 15. R2.6.3 who determines if the study is no longer valid? The TO, PC or the agreement of both? 16. R2.7.1 what is a 'project initiation date' and why is this needed? 17. R2.7.2 Projects are added to cases after an analysis has been performed to see if the project is an acceptable alternative. In that analysis the project is 'retested' to see if it is effective. This is assume to be acceptable for the definition of 'retesting'.

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Commenter	**Yes**	**No**	**Comment**
			18. R2.7.3 unsure what 'committed' means regarding projects nor understand the need to have this documented anywhere. 19. R3.2.2 what is 'relay loadability' and where would you note how it is supposed to be treated? 20. R3.3.1 how is this different than R3.1? 21. R3.3.2.1 why is there a need to know how much non-consequential load loss exists for each contingency and how can one predict the length of time this will last? 22. R3.3.2.2 Do we need to document the 'system adjustment' for each contingency? 23. R3.3.3 what is a severe impact and what is one that is less severe? 24. R3.4 what is the difference to 3.3.3? The definition given in the NERC Glossary from May of 2007 of Cascading Outage is still vague, it appears to allow the TP or PC the discretion to determine it based on studies. Is this the intent? 25. R3.5 what is the time limit for run-back? 26. R4.4 how can TPs identify what generation upgrades are needed (protection and control modifications)? 27. R4.5.2 whats the difference between this and 4.5.1? 28. R4.6 the generation levels could be too low for the studies to be useful, perhaps voltage levels should also be added or allow for TP/PC discretion. 29. R4.6.3 seems to allow some TP discretion in deciding which planning events are more severe but how does one know that without studies? 30. R5 this seems to have no direction for either party. 31. R6 is ambiguous Table 1 32. terms such as voltage instability, cascading outage and uncontrolled islanding should be defined

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Commenter	**Yes**	**No**	**Comment**
			or allowed to be defined by the PC. If consequential load loss is allowed for all cases then why even mention it? Isn't this like saying if the line trips, it will be out of service? why would one want to document this amount, perhaps for some sort of ranking? Planning events 33. what is a 'system adjustment'? if this means to manually redispatch the BES for each condition then these studies shown under P4 will take so long to complete that they will be invalid by the time they are done. In ERCOT, the economics of redispatch are not known to the TP thus this is done by the PC. an automatic computer simulated redispatch will possibly not have the same results. Define 'generator' for is this a single unit, the whole train, the largest unit or other? 34. For P6 events and above, if consequential load loss and non consequential are allowed, they why study these events? Do TPs plan and build transmission to eliminate the overloads for these events or just study them so that the results are known? Studying every possible event or combination does not make the studies better or provide a higher insight to areas of concern. A number of the combinations have a low probability of occuring and performing the studies and analizing the results will be a manpower burden and provide no better clarity on needs of the system. Table 2 35. The number of events to consider seems excessive although this is not our area of expertise. If each of these is to be run for each 'material change' in the BES then this list is excessive without more leeway or guidance provided.

Response: 1. The SDT believes that models must reflect the expected Load mix of industrial, commercial and residential Loads to appropriately reflect the behavior of the System.

2. The SDT agrees with your concerns and has revised this requirement (now Requirement R9). The terms "stressed System conditions", "validated", and "supporting rationale" have been removed.

3. The SDT has revised this requirement based on industry comments to clarify intent and to be responsive to FERC Order 693, paragraph 1725. Further, it is not the intent of the standard to require consideration of confidential information that is not available.

4. The standard has been revised to identify specific entities responsible for providing the required information.
5. The extent of coordination between the TP and PC can vary depending on many factors such as whether you are part of an ISO/RTO, vertically integrated Investor Owned Utility, or Transmission only company. The Functional Model envisions that planning entities will not only need to use overlapping models to simulate how the System will respond to Contingencies, but they will also be layered to provide for more locally focused studies as well as more global studies. Planning Coordinators need input from the planners doing the local studies to complete their overall studies. Planners need to coordinate their activities and sort out which entity will be detailing its studies to what extent. Documentation of entity studies needs to demonstrate that the System response to Contingencies and any Corrective Action Plan has been screened so as to meet the performance requirements stated in the standard, such as not exceeding applicable voltages and ratings.

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Commenter	**Yes**	**No**	**Comment**
6. Requirement R2 states that the "Planning Assessment shall use current or past studies …." The Planning Assessment is to cover the five year period but the entity is only required to run a limited number of studies. It is the responsibility of the entity to determine if past studies can demonstrate that the performance requirements are met. If past studies in conjunction with the required studies do not demonstrate that the system can meet the performance needed, the entity will need to run additional current studies that demonstrate it can meet the requirements. Requirement R2.1.1 is in reference to Requirement R2.1 which states that the Planning Assessment "be supported at a minimum by the following annual current studies, supplemented with qualified past studies as indicated in Requirement R2.6:" To further clarify, the SDT has deleted the "all five years" language. 7. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.1.4 has been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own System. In either case the entity must document the reason for running or not running cases for the items listed. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance. It is the entity's decision to establish and document which senstiviyies are more significant to study System responses. The sensitivity studies do not in themselves establish the need for a plan, only the areas of the system for which the analysis is needed. **R2.1.3.** For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.1.4**. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. 8. Known generation additions are considered a project and must be studied if the lead times are longer than 10 years. 9. R2.3 - See Requirement R.2.6.2 where this is defined. 10. The SDT has revised the wording of R2.3 to try to clarify that short circuit analysis must be conducted annually but that past studies as defined in Requirement R2.6.2 may be used as appropriate. R2.3 The short circuit analysis portion of the Planning Assessment shall be conducted annually and supported by current or past s 11. Requirement R2.4 has been re-worded to clarify this situation. **R2.4** The ~~System Stability portion of the~~ Near-Term Transmission Planning Horizon portion of the Stability analysis ~~Planning Assessment~~ shall be assessed annually ~~address all five years of the assessment period,~~ and be supported by current or past studies. The following studies are required ~~annually~~:			

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Commenter	**Yes**	**No**	**Comment**

12. See Requirement R5.6.2 which provides the bounds you are looking for.

13. and 14. This wording is intentional to allow the planner some discretion.

15. The SDT has revised Requirement R2.6.3 as the new requirement R2.6.2 to clarify this concern.

R2.6.2 For steady state, short circuit ~~analysis~~, Generating Plant Stability, or System Stability analysis: ~~if the study is less than five years old and no material changes have occurred to the System in the intervening period.~~ the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area.

16. Requirement R8 (old requirement R6) which focuses on the distribution of the Planning Assessment results among affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old requirement R6). Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. Typically the date would indicate when significant resources will begin to be employed This covers any project proposed for the near term. The SDT believes that initiation dates are required for near-term Corrective Action Plans to give an indication that the Corrective Action Plans can be implemented in time.

17. The specific requirement to perform re-test has been removed. The purpose of the Corrective Action Plan is to list the actions that are needed to meet performance requirements. The studies, current and/or past as appropriate as well as the extent of the size of the study area, are performed to support compliance and demonstrate that the requirements are met.

18. Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted Requirements R2.7.2 through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions".

R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.

19. R3.2.2 - The SDT used the term "relay loadability" to describe the maximum Transmission line loading on a specific circuit that is permitted before line relays might see the Load current as a fault and trip the circuit. In those cases where the relay loadability limit is lower than the circuits thermal or Stability rating, the relay loadability limit should be applied as the benchmark for meeting the performance requirements.

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Commenter	**Yes**	**No**	**Comment**
20. Requirement R3.1 requires studies to be performed. Requirement R3.3.1 requires that the results meet the requirements of the standard. 21. R3.3.2.1 - FERC required documentation of Consequential Load loss in Order 693, paragraph 1795, (not Non-Consequential) and duration should be based on best judgment for the common cause of the event. 22. Yes. 23. The intent is to allow the Transmission Planner flexibility for deciding which multiple Contingency Planning Events are run during its annual studies. The standard leaves the classification of "severity" to the engineering judgement of the Transmission Planner based on experience of the System, past study results, input from operations staff, etc. The Transmission Planner will need to explain why others would be known to be less severe. For example a N-1-1 involving two non-related and distant Facilities could be excluded by the TP if desired. 24. Requirement R3.4 covers Extreme Events, Requirement R3.3.3 covers Planning Events. The SDT did not propose a new definition for cascading outage or cascading. 25. The use of the defined term 'Facility Ratings' dictates the time limit. 26. The outcome of the assessment should identify the actions required. 27. In new Requirement R5.5.2, clarification has been provided to differentiate the events. **R5.5.2**. Performance shall meet the requirements for Planning Events in Table 2 – Stability Performance. 28. Those values are based on Large Generator Interconnection Procedures as approved by FERC. 29. It does allow some discretion but good engineering judgement is assumed and you must document your rationale. 30. This requirement assumes that the two parties will react in a professional manner to resolve any differences. 31. The new Requirement R8 clarifies this. **R8**. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~affected entities~~ neighboring systems, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890. 32. In general, new definitions are proposed along with the proposed standard, and will be included in the Glossary of Terms upon approval of			

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Commenter	**Yes**	**No**	**Comment**
the standard. Definitions for Cascading and Stability are included in the NERC Glossary. Further uncontrolled islanding, while not defined, is a common term that is well understood. The SDT does not propose to improve the definitions for Cascading and Stability or propose a new definition for cascading outages and uncontrolled islanding. There are a number of IEEE papers (e.g., P. Kundur, J. Paserba, V. Ajjarapu, G. Anderson, A. Bose, C. Canizares, N. Hatziargyriou, D. Hill, A. Stankovic, C. Taylor, T. V. Custem, V. Vittal, "Definition and Classification of Power System Stability", IEEE Transactions on Power Systems, vol. 19, no. 2, pp. 1387 – 1401, May 2004) that provide descriptions for voltage instability. The requirement concerning Consequential Load is to address FERC Order 693, which directs that the ERO, among other things, to clarify footnote (b) in regard to Load loss following a single Contingency, specifying the amount and duration of Consequential Load Loss and System adjustments that are permitted after the first Contingency to return the System to a normal operating state. 33. The term "System adjustment" is used in the existing TPL Standards, and is intended to have the same meaning in the proposed TPL standard, and includes both manual and automatic actions. 34. For P6 and more severe Events, loss of Consequential and Non-Consequential Load is allowed. The events will still need to be studied to ensure that System reliability and security is maintained and that any outage would not result in unacceptable System performance, such as, cascading, instability and uncontrolled separation. 35. The SDT understands the potential work load increases. Requirement R3.3.3 requires evaluation of only those Planning Events (involving multiple Contingencies) that are expected to produce more severe System impacts.			
City Water Power and Light	☑		The Standards are a great start in getting a set of requirements in place that will provide a planning methodology that will be transparent to the Functional entities in the interconnections and will produce results that will permit reliable planning and operations of the BES. The SDY should remove all Requirements that are subjective and can't be measured. The assumptions the Transmission Planners and Planning Coordinators use to conduct the studies should be posted.
Response: The SDT has endeavored to draft Requirements that are objective and measurable. Since this comment did not include specific Requirements that the commenter proposes should be deleted, the comment relating to removal of subjective, unmeasurable Requirements is unactionable. The SDT believes the comment relating to posting assumptions implies that the standard should not have study assumption Requirements but should only require that assumptions be posted. The SDT is unclear where assumptions would be "posted" but in any event if study assumption Requirements were removed, then the SDT believes there would be little or no value in having study assumptions "posted".			
Dominion	☑		GENERAL COMMENTS: (1) Making the standards more stringent by "raising the bar" is not going to result in a dramatic improvement in system reliability. Even the best designed systems are susceptible to human error. Dominion has at least 5 years of transmission outage data clearly illustrating that any resulting loss of load (both consequential and non-consequential) has had an average duration of only 4-7 customer-minutes per year. Going forward, the emphasis and focus should be on planning and

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Commenter	**Yes**	**No**	**Comment**
			operating the bulk electric system so as to confine any transmission outages to the immediate, local area, and not allow the cascading of outages beyond control area boundaries. (2) Although we are unable to put specific numbers on the impact of "raising the bar "with respect to non-consequential load loss, it will be enormous. Increased staffing levels may be required, and we would likely incur significant increased transmission maintenance and construction costs. It is likely that State commissions everywhere (not just Virginia) would agree that rate payers should not incur the significant cost increases required to meet more stringent planning criteria (i.e. - "raising the bar") when the corresponding improvements in transmission system reliability cannot be quantified. SPECIFIC COMMENTS PERTAINING TO REFERENCED SECTIONS OF THE STANDARD: (1) The last block in Category C of Table 1 of the existing standards deals with protection system failure. We interpreted this as, among other things, having a fault beyond the first-zone coverage of the primary protection scheme with the carrier equipment failure resulting in a second-zone trip of the faulted line (even though only one element will be lost). The second-zone trip time is generally in the range of 30-35 cycles. This may be critical from the stability aspect. The proposed Table 2 of TPL-001-1 is silent about this. Is there a reason why this requirement was left out? (2) The requirement R4.6.2 may cause some confusion due to the last part "….whichever is greater". It is suggested that the entire wording for this requirement be replaced as listed below to avoid any misunderstanding. "Shall be performed for changes in the real power output of a generating unit if either of the following applies: (a) the increase is more than 10 % of the existing capacity (regardless of the amount of MW increase) (b) the increase is more than 20 MW (regardless of the % increase). Something to think about regarding a cut-off limit of 10% or 20 MW: We had a unit with 800 MW existing capacity and the request was to increase it by 15 MW making the total new capacity of 815 MW. The requested increase was less than 10% of the existing capacity and also less than 20 MW, meaning the plant stability study is not required. However, we found that the increase of 15 MW made the plant unstable and we had to come up with a solution (and we did). This example warrants to include something like…. "However, in cases where a stability margin is known (or estimated) to be slim, stability study should be performed regardless of the % or MW

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Commenter	**Yes**	**No**	**Comment**
			amount of increase (this leads to defining "Stability Margin"). (3) Table I, bullet 3 states that "Voltage Instability, cascading outages and uncontrolled islanding shall not occur." There is no definition for "voltage instability" anywhere in the proposed standard. (4) R.3.3.2.1. states "Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment." This requirement creates significant unnecessary work without adding any value to system reliability. (5) Extreme Event Description 3.d. states: "Shutdown of a nuclear power plant(s) and other facilities a day or more prior to a hurricane, tornado or wildfire, or for other common causes." It would appear that day ahead planning for a tornado is not possible, or applicable, for inclusion in this listing.
Response: Specific 1. The SDT agrees with your concern and is working on a solution for a future draft. 2. The wording was lifted from FERC and has not been changed. 3. There are a number of IEEE papers (e.g., P. Kundur, J. Paserba, V. Ajjarapu, G. Anderson, A. Bose, C. Canizares, N. Hatziargyriou, D. Hill, A. Stankovic, C. Taylor, T. V. Custem, V. Vittal, "Definition and Classification of Power System Stability", IEEE Transactions on Power Systems, vol. 19, no. 2, pp. 1387 – 1401, May 2004) that provide descriptions of voltage instability. 4. FERC required documentation of Consequential Load loss in Order 693, paragraph 1795, (not Non-consequential) and duration should be based on best judgment for the common cause of the event. 5. Extreme Events notes have been changed to address this concern.			
E ON US	☑		1. R1.4 "including protective relays with consideration given to spare equipment strategy" I do not understand the intent of this phrase or what it adds to the requirement. 2. R2.6.1 "and market structure changes" What is this, does it require a definition? 3. R2.7.1.1 What is the project initiation date; the date approval is sought, received, materials are ordered, construction begins? Many projects are upgrades or replacements that this will be meaningless. Don't you really only want multiyear projects? 4. R2.7.2 The initial study process will incorporate testing. This will require the creation of additional cases and additonal testing prior to the Planning Assessment submittal. Most projects should be identified during the Long Range time frame. Inclusion of the project in the next years base cases and subsequent testing should be adequate. 5. R2.7.3 Define a "Committed Project". MISO has spent years on this. 6. R2.7.4 Changes in timing of all projects should be documented in the Planning Assessment. Why would you document Committed Projects that are removed but not any delays or accelerations?

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Commenter	**Yes**	**No**	**Comment**
			7. R3 Sensitivity studies (if retained) should have less stringent performance requirements than the other cases required by R2.1. 8. R3.3.2.1 Unless this is limited to above 300 kV, many hours will be spent for naught. The lower voltage systems often have tapped loads that will trip with the line. The time required to restore will vary on the fault location, and time for switching, sometimes remote and sometimes manual. I do not see the need for or the benefit of this requirement. Please explain. 9. P3 Event is poorly worded, see response to Q25. 10. P6.1 above 300 kV, below 300 kV or all? The tables need to be reviewed to make sure that the voltage applicability is clearly stated. 11. P9.6 Why is this a requirement? It should be much less severe than any of the prior requirements. 12. Extreme Event 9 (3ph fault with loss of all generating units at a station) is in conflict with Q33 which says it was not included). Am I missing something? 13. Other, it appears that we are not required to study the outage of a transmission line or transformer followed by the outage of a generator. Was this overlooked, or did I miss it? Would system adjustment be allowed?

Response: 1. The SDT has revised this requirement based on industry comments to clarify intent and to be responsive to FERC Order 693, paragraph 1725.
2. R2.6.1 - The change must be "material" as stated in the standard meaning it must have an impact on the study results or may only make some results invalid and not relevant.
3. Requirement R8 (old requirement R6) which focuses on the distribution of the Planning Assessment results among affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old requirement R6). Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. Typically the date would indicate when significant resources will begin to be employed. This covers any project proposed for the near term. The SDT believes that initiation dates are required for near-term Corrective Action Plans to give an indication that the Corrective Action Plans can be implemented in time
4. Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted Requirements R2.7.2 through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions".

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Commenter	**Yes**	**No**	**Comment**
R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. 5. Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted Requirements R2.7.2 through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions". 6. Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted Requirements R2.7.2 through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions". 7. The SDT is providing some guidance under Requirement R2.1.3 on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. It is the entity's decision to establish and document which transfers are more significant to study system responses. The sensitivity studies do not in themselves establish the need for a plan, only the areas of the system for which the analysis is needed. **R2.1.3**. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: 8. R3.3.2.1 - FERC required documentation of Consequential Load loss in Order 693, paragraph 1795, (not Non-Consequential) and duration should be based on best judgment for the common cause of the event. 9. Please see response to comments on Q25. 10. The SDT has revised Tables 1 and 2 to provide more clarity. 11. P9.6 was to address FERC directive in Order 693 to consider spare equipment strategy. The SDT has revised Tables 1 and 2 to remove P9.6 and included this consideration in R11 of the second draft of the standard to address this issue. 12. In Q33 the SDT posted a question to the industry to request guidance on whether simultaneous tripping of all generating units in a power plant should be included in the Extreme Events in Table 2 (on Stability Studies). 13. Tables 1 and 2 have been revised to address your comments. P3 is meant to cover the combination of overlapping outages regardless of the sequence in which the outages occur.			
ERCOT ISO	☑		1. R1.1.1 - Are percentage of load that is industrial, commercial, and residential needed? 2. R1.2 - The wording is confusing. If the power factor is based on historical measured values, does it have to be during contingency (stressed)? 3. R1.5 - "Planned Facilities defined in accordance with the documented criteria of the Planning Coordinator" - what is meant by this?

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Commenter	**Yes**	**No**	**Comment**
			4. R2.1.1, R2.1.2, R2.1.3.1 - are all studies to be run using all the contingencies defined in Table 1 - Steady State Performance? 5. R2.6.1, R2.6.2, R2.6.3 - past studies will never be able to be used if the addition of a transmission line makes them invalid! 6. R3.2.1 - What is meant by "minimum steady state voltage limitations of all generators"? 7. R3.2.2 - Relay "loadability"?? What is meant by this? Sounds unreasonable for steady state studies as facility rating should reflect limitations of relay equipments such as CT"s. 8. General comment: If this proposed standard is approved, since it contains requirements that are more restrictive than current standards, there will need to be a transition period to allow transmission to be built to allow systems to meet the new requirements.

Response: 1. The SDT believes that models must reflect the expected Load mix of industrial, commercial and residential Loads to correctly reflect the behavior of the System.
2. The SDT has revised this requirement based on industry comments to clarify intent.
3. The referenced verbiage has been deleted from the revised standard
4. Regarding Requirements R2.1.1 and R2.1.2, Requirement R2 states that the "Planning Assessment shall use current or past studies …." The Planning Assessment is to cover the five year period but the entity is only required to run a limited number of studies. It is the responsibility of the entity to determine if past studies can demonstrate that the performance requirements are met. If past studies in conjunction with the required studies do not demonstrate that the System can meet the performance needed, the entity will need to run additional current studies that demonstrate it can meet the requirements.
Regarding Requirement R2.1.3.1, the SDT is providing some guidance under Requirement R2.1.3 on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. It is the entity's decision to establish and document which transfers are more significant to study System responses. The sensitivity studies do not in themselves establish the need for a plan, only the areas of the system the analysis is needed.

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:

5. R2.6.1, R2.6.2, R2.6.3 - The change must be "material" as stated in the standard meaning it must have an impact on the study results or may only make some results invalid and not relevant.
6. R3.2.1 - Generator high and low voltage limits are part of the constraints and are considered part of Facility Ratings in FAC-008. FAC-009 provides that the information be provided by the Generator Owner.

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Commenter	**Yes**	**No**	**Comment**
7. R3.2.2 - The SDT used the term "relay loadability" to describe the maximum Transmission line loading on a specific circuit that is permitted before line relays might see the Load current as a fault and trip the circuit. In those cases where the relay loadability limit is lower than the circuit's thermal or stability rating, the relay loadability limit should be applied as the benchmark for meeting the performance requirements. The SDT believes that equipment ratings, such as CT ratings, should also be reflected, but not necessarily as part of the "relay loadability" limit. 8. The SDT agrees and that will be addressed in the future			
AECI	☑		1. Based on the p1 to P9 events one would have to model a breaker to breaker instead of bus to bus. This would be a large undertaking and it seems that it would be more conservative to have a bus to bus model. 2. Question on P4 - does this apply to all generators on a system or is there a MW limit to the size of the generator. 3. P5 Does this mean running N-2 for the 300 KV for all seven cases that would be required. This could take a large amount of computer run time. 4. We are stating that this change to the standard is not warranted. However, if all these changes are implemented what used to take approximately 1 month to assess will now take approximately 4 months and we are not that big of a system. I assume that the time and manpower to perform all the contingencies has been considered.
Response: 1. The SDT revised the event descriptions to provide clarity on simulations in response to FERC Order 693. Depending on the configuration, modeling bus-to-bus outages in a study is not necessarily more conservative than modeling breaker-to-breaker outages. The SDT understands the potential increases in work load. The draft standard allows the use of past studies to meet the current year assessment and study requirements. 2. The intent is that the standard would apply to all Facilities (including generators) that are represented in the transmission planning simulation. 3. Requirement R3.3.3 requires evaluation of only those Planning Events (involving multiple Contingencies) that are expected to produce more severe System impacts. 4. The SDT understands the potential increases in work load. The draft standard allows the use of past studies to meet the current year assessment and study requirements.			
Allegheny Power	☑		General Comments: 1). We believe the 300 kV cutoff should not be used. It should be based on the definition of a Backbone Facility. The 300 kV and above standards should only apply to backbone facilities that are used to provide overall energy transfer and ties to other systems and not facilities that provide load serving purposes. Backbone facilites should be specifically defined and accepted as Backbone facilities through RTO and RE review and acceptance.

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Commenter	**Yes**	**No**	**Comment**
			2). Planning Scenarios should be forced to include a market based scenario under the Planning Authority obligation which should include long range market projections for generation dispatch, significant energy price changes due to environmental issues or fuels, and market impact of large transmission reinforcements. 3). It should be noted in the process that additional planning resource additions (maybe as much as 30%) will be required to met these new study requirements since they are much more expansive than the existing requirements. 4). These standards could require substantial (millions) upgrades to the system to meet the proposed changes. These are primarily due to the 300 kV and above standard revisions and the non-consequential load drop criteria adjustments.
Response: 1. The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission Systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT believed that the 300 kV and higher Systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many Systems in the various Interconnections and that the more stringent requirements were appropriate when considering Contingencies of two EHV Facilities due to one Event. Systems operated at these voltage levels generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers the energy is delivered by the other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. **2.** Marketing and economics are beyond the scope of the SDT. This is a reliability based standard. 3. Resources and expenditures versus adequate level of reliability are being given due consideration throughout the process and will ultimately be determined by the industry through the ballot process. 4. Resources and expenditures versus adequate level of reliability are being given due consideration throughout the process and will ultimately be determined by the industry through the ballot process.			
AEP	☑		(1) Consider clarifying system performance requirements that would be applicable during (a) the first two minutes after the system disturbance when slow-acting automatic system adjustments (such as the operation of motor-operated-air-break switches that are relayed to sectionalize the faulted segment of a multi-terminal circuit; the changing of taps on tap-changing-under-load transformers; the switching of capacitor banks; etc.) would not allowed to be considered, (b) the next three minutes (two to five minutes after the system disturbance) when these slow-acting automatic system adjustments would be allowed to be considered, (c) the next twenty-five minutes (five to thirty minutes after the system disturbance) when manual system adjustments would be allowed to be considered, and (d) the time period beyond thirty minutes after the system disturbance when no system adjustments of any kind would be allowed to be considered. (2) Consider clarifying which functional entity is expected to provide what information specified in this standard, especially in requirement 1.

Q43			
Commenter	**Yes**	**No**	**Comment**
			(3) Consider clarifying the need for functional entities to provide competitive sensitive information such as planned outages. (4)The system stability study documentation requirements R2.4 and R4.5 do not specify a level on the scope of studies or indicate the extent of coverage across a system required for acceptability. A reasonable scope of such studies might include studies of a system nature in association with dynamic devices, or voltage collapse or cascading scenarios, but what else would be required? Or, how much more stability study documentation beyond what is necessary to comply with TPL-001 through 004 would be required? Specific comments regarding R2.4 are as follows: what does "address" all five years mean? How much of the system do you need to study (for example, do you need to apply faults at every bus)? Again, you wouldn't know how much studying needs to be done before this requirement is satisfied. In R2.4.1 and R2.4.2, depending upon the study at hand, some other load condition such as shoulder peak may be more appropriate. Why should you be required to do peak and off-peak cases in such an instance? In R2.4.3 you are forced into doing at least one of the sensitivity studies listed (i.e., "to reflect one or more of the following conditions..."). Is this intentional? Depending upon the study at hand, none of these may be worthwhile doing, and there may be some other parameter that would be better looked at for sensitivity purposes. Existing TPL-001 through 004, Table 1, Category C3 requires any combination of generator, transmission line, transformer, or HVDC pole block in succession. The new standard excludes several of these combinations from being required in P4, P5, P8 and P9. Is this an intentional exclusion? If so, why? The standard should state explicitly that existing generation does not need to be studied unless R2.5.1 or R2.5.2 apply.
Response: 1. NERC Standards are to specify the requirements, which must be met and not "how" they are met. The System adjustments that can take place during various time periods are different in different systems, and should be based on agreements and coordinated among the entities performing the studies. 2. The SDT does not believe it is necessary to be so prescriptive but only requires that accurate data be provided in order to build accurate models. 3. Commercially sensitive and confidential information is covered by existing rules and regulations and can't be altered by the SDT. 4. Address means that you must cover all 5 years in the assessment. Good engineering judgement must be applied. The requirements are minimal and one can always do additional studies. Yes, this is intentional but good engineering judgement may imply that you need to do more than one sensitivity. The SDT has interpreted C3 as described in the tables. The SDT feels that the conditions are properly identified.			
APPA	☑		The Standards are a great start in getting a set of requirements in place that will provide a planning methodology that will be transparent to the Functional entities in the interconnections and will produce results that will permit reliable planning and operations of the BES. 1. Requirement 5 is a start at attempting to share the results of the planning studies with the correct entities. However, because this is such an important part of reliable planning, this requirement

Q43			
Commenter	**Yes**	**No**	**Comment**
			should be rewritten to be much more definitive and comprehensive. It is recommended the SDT review the FAC-014 Standard where this Standard deals with who is to receive the methodology for calculating SOLs. The SDT needs to insure that the Transmission Planners and Planning Coordinators share their Near-Term Planning Horizon Studies with the Transmission Operators (Operation Planners) and the appropriate Regional Entity Planning Committees and Operating Committees. 2. It is also recommended that the SDT remove all Requirements that are subjective and cannot be measured. For example, who must the Transmission Planner share information with? Requirement R5.2 states that information must be shared with Transmission Planners of neighboring impacted areas. A Compliance Monitor cannot determine if a neighbor is being impacted. In fact, from an enforcement perspective, if the involved parties must go before a Judge, who will determine if someone is impacted or not? 3. In addition, the assumptions the Transmission Planners and Planning Coordinators use to conduct the Studies are not required to be shared or posted. As an example, in some parts of the BES Transmission Planners and Planning Coordinators use Flowgate Methodology to study the BES, while others use Rated System Paths, and still others use Area Interchange (Network Methodology). 4. This standard needs to be modified to respond to several requests from Order 890 and Order 693. These Orders request that through the Standards, information be made available, posted, and shared with the appropriate reliability functions. This information includes the results of Planning Horizon Studies, Operating Horizon Studies, and eventually the determination of Available Transfer Capabilities. This information also includes, but is not necessarily limited to: how do the planners treat the "counter flows" in their studies, what are the generation and transmission planned outage schedules used in the planning studies, how are Network Loads and Network Facilities treated in planning studies; and how do the planners treat Grandfathered Transmission and Grandfathered Power and Energy Contracts in the planning studies?
Response: 1. The SDT assumes that this is actually referring to Requirement R6. This requirement has been re-written as Requirement R8 and ties back to FERC Order 890 for distribution. **R8**. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~affected entities~~ neighboring systems, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890. 2. The SDT has attempted to not add subjective requirements. However, as measures are developed in a subsequent release, the SDT will review all requirements for subjectivity. 3. Documentation is required in your assement to decribe that you have met the requirements. 4. Information will be shared as required in various orders and regulations as shown in the new Requirement R8 for example.			
ATC	☑		Following are additional comments on the proposed standard.

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Commenter	**Yes**	**No**	**Comment**
			1. R1 Each sub-requirement (R1.1 to R1.5) should specify which Functional Entity (of those listed in R1) is responsible for providing the modeling data. For example, while logically it appears that R1.1 is applicable to the LSE only, it may be argued that parts of it may be applicable to the Transmission Planner also. 2. R1.1.3 We do not agree with identifying the DSM load reduction "consistent with operational requirements" for the purpose of modeling Load in planning studies. This is because DSM is typically employed either for Capacity deficiencies, but not for operations needs. 3. R1.3 "Firm transfers/Interchange Schedules and….." Should say either firm transfers or interchange schedules but not both since they are not equivalent. If the intent here is to model each Balancing Authority's Firm resources and Firm "commitments" needed to supply the Firm Load, then we suggest using the term Firm Commitments defined as the Native Load plus Firm Transmission Service plus LTTRs. 4. Firm Transfer -- Either define this term or use the existing NERC Glossary term Firm Transmission Service instead. Alternatively, use the term Firm Commitments defined as the Native Load plus Firm Transmission Service and LTTRs. Further, in Table 1, the "Interruption of Firm Transfer Allowed" performance requirement should be clarified/reworded to indicate if firm transfer was intended to comprise both firm point-to-point and network transmission service. If so, then curtailment of firm point-to-point transmission service should be permitted for all events P1-P4. Alternatively, the performance requirement could be changed to "Generation Redispatch Allowed". Given the future Day 3 MISO market structure, standards that refer to Generation Redispatch must include Demand Response. 5. R1.4 We believe that each Reliability Coordinator (RC) already receives the planned outage information from all TOs and GOs and maintains it in the Outage Scheduler. Can the Planning Coordinator obtain this information from the RC's operating in its footprint? 6. R1.5 The Transmission Planner is also very likely to have a documented criteria for planned (committed? see R2.7.3) facilities, so this requirement should say TP/PC instead of only PC. What standard will require the TP to have criteria? There should be a separate requirement that applies to the Generator Owner and includes specifics, such as reporting contemplated additions, modifications, and retirements. 7. R2.1.3.1 It is not clear what additional "variability of Load/demand and Load power factors due

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Commenter	**Yes**	**No**	**Comment**
			to season, weather, or time of day" over and above what is modeled in the seasonal base case is expected here. For example, what additional load variability can be studied in a summer peak base case which already represents the system snapshot of a hot (weather) summer (season) mid-afternoon (time of day) loading condition? 8. R2.5.2 Please provide more examples of what would comprise "material changes" that trigger a plant stability study (besides the addition/removal of transmission line). Would it be better to say electrical proxmity (to capture the concept of electrically "close" instead of electrical vicinity? 9. R2.6.1 to R2.6.3 Should all "material changes" trigger a new study? Shouldn't a new study be done only for those changes that are expected to have an adverse impact on system performance? For example, adding a transmission line outlet at a generating station will rarely have an adverse impact on plant stability. Suggest that these requirements specify the need for a new study to support the planning assessment only when changes "that have an adverse material impact on system performance" have occured. 10. R2.7.1.1 It is unclear what is the need/benefit of including a the project initiation date; the project in-service date should be enough in a corrective action plan. Suggest deletion of project initiation date from the requirement. 11. R2.7.3 What is the difference between "committed projects" referred here versus the "planned facilities" referred to in R1.5? Please explain distinction between committed, planned and proposed projects/facilties. 12. R2.7.4 "Not remove committed projects……" Note that a committed project may not get cancelled but can very likely be deferred --- how should deferred projects be handled? 13. R.3 Per this requirement, the BES should be analyzed for normal (N-0) performance. However, Table 1 does not include the corresponding performance requirements. Further, R3.1 refers to studies for evaluating performance requirements in Table 1. Shouldn't Table 1 include normal system performance requirements? 14. System Adjustment -- What automatic/manual actions comprise this term? It will be helpful if the standard explicitly states which post-event system adjustments are acceptable/permitted to meet performance requirements for single contingency events (P1, P2 or P6) versus which pre-event system adjustments (specifically load shedding) are allowed/permitted to prepare for the next contingency (after the N-1 contingency has occurred) in multiple contingency events (P3-P5, P7-P9). This distinction does not appear to be addressed by requirement R3.3.2.2 in the draft

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Commenter	**Yes**	**No**	**Comment**
			standard. 15. R3.3.2.2 is inconsistent with the Planning Events in Table 1. While the requirement states that shedding firm load and curtailing firm transfers are not permitted for single contingencies, these are allowed for event P6 in Table 1. Further, although the requirement implies that these two types of system adjustments are permitted for multiple contingencies, at least one of them is not allowed for the multiple contingency events P3, P4 and P5 in Table 1. 16. System Adjustment Duration -- What is the allowable time for completion of system adjustment? Requirement R3.3.2.2 states that it is the time period allowed by the Transmission Owner's applicable time-limited (emergency) equipment rating. However, R3.3.2.2 is only applicable to single contingency events -- that is, events P1, P2, P6 in Table 1. Shouldn't this concept of allowable system adjustment duration apply uniformly to all Planning Events P1-P9 in Table 1? 17. R3.5 allows generation runback for single and multiple contingencies -- that is, for ALL planning events P1-P9. It appears that this requirement lends itself to be included as another bullet item in the Performance Requirements at the top of Table 1. In fact, why not define what comprises System Adjustment (see comment above) and then tabulate the system adjustments that are (not) permitted for each planning event within Table 1? 18. System Stability studies: The standard must clearly define what types of stability analyses fall under this umbrella term. While it is generally understood that this includes angular stability analysis, which is the only one that is explicitly mentioned in the Table 2 footnotes, the standard does not indicate whether dynamic voltage stability analysis or small-signal stability analysis are also expected to be done as part of system stability studies. 19. Requirement R2 and its sub-requirements are intended to address all aspects of Planning Assessment. However, it is unclear which requirement(s) in the draft standard cover the scope of R1.3.12 in the existing TPL-002 and TPL-003 standards, which requires "Include the planned (including maintenance) outages of any bulk electric equipment at those demand levels for which planned (including maintenance) outages are performed. Further, we are unsure if the direction provided in FERC Order 693 paragraphs 1724 and 1786 with respect to planned (maintenance) outages have been adequately and clearly addressed in the draft standard. Can the SDT point us to the specific requirements that address the above issues? 20. We recommend that the SDT give consideration to acknowledging or addressing the directives in FERC Order 890 for performing transmission system loss analysis and economic assessments --

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Commenter	**Yes**	**No**	**Comment**
			can they be considered within the scope of reliability assessments? EDITORIAL COMMENTS 21. R4.5.1 and R4.5.2 -- It appears that the intent of these sub-requirements within R4.5 for System Stability study is very similar to the intent of R3.3.3 and R3.4 for Steady State studies. If so, then why have different heirarchical numbering for the latter case? Suggest changing R3.3.3 and R3.4 to sub-requirements R3.4.1 and R3.4.2 respectively within R3.4 for Steady State study. Table 1 22. Event P3 -- The performance requirement in column 3 "Interruption of firm transfer allowed" should be simply "NO" (outaged dc line performance is not applicable). 23. Event P5.3 -- Clarify if the "loss of another transformer" is intended to be the loss of a transformer with low-side voltage >300kV or *any* transformer in the BES. 24. Event P9.1 -- Is the one mile intended to be one *contiguous* mile? If so, recommend inserting the qualifier "contiguous" to claridy the intent. 25. Event P9.6 -- The contingency description is very confusing regarding the role of spare transfomer. Is spare transformer part of the system adjustment? Please reword to clarify the intent. 26. Extreme Event Descriptions -- Items 3e and 3f are repetitions of items 3c and 3d. Delete any one pair. Item 3h is too vague --- either provide more specificity or delete it. Table 2 27. Extreme Events - Evaluation Requirements -- Inclusion of item 9 (3-ph fault with loss of all generating units at a station) in the table is inconsistent with Q.33. 28. Having both bullets at the beginning of the table and footnotes at the end of the table, which deal with similar subject matter, tends to be confusing and should be addressed. 29. The different types of Stability analysis (steady state voltage stability, dynamic voltage stability, dynamic generator unit angular stability, and dynamic inter-area power oscillation stability) be clearly and concisely stated in one location and the perfomance requirements for each type of stability should be more clearly stated in appropriate locations.

Response: 1. The standard has been revised (see Requirements R9 through R13) to identify specific entities responsible for providing the required information.

R9. Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including

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the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information. **R10**. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information. **R11**. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information. **R12**. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information. **R13**. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information 2. The SDT has determined that DSM is included in MOD and is no longer explicitly included here. 3. The SDT understands your concern and has modified the requirement (now Requirement R10) to clarify intent. The intent is to include modeling information for firm Transmission service data, Interchange Schedules, and resources required to serve Load. 4. The SDT agrees with your comment concerning the ambiguity of the term "Firm Transfer". The revised requirement (now Requirement R10) and revised Table 1 use the existing NERC Glossary Term Firm Transmission Service, as you suggested. However, the SDT does not agree that curtailment of Firm Transmission Service should be permitted for events P1-P4. 5. Few commenters raised this concern, so the SDT is uncertain whether the necessary information could be obtained from the RC in all regions. The ultimate source of the information is the TO and the GO. In the revised standard, this requirement has been separated into two requirements to clarify the intent for transmission equipment planned outages and long-term outages (Requirement R11) and generation equipment planned outages and long-term outages (Requirement R12). If the TO and GO provide the necessary information to the RC in a given region, it is possible that the TO and GO could arrange for the RC to provide the information to the PC to demonstrate compliance with the requirements or, alternatively, send the information to both the PC and RC. 6. The SDT has modified the standard based on various comments. The phrase "in accordance with the documented criteria of the Planning Coordinator" has been deleted. This requirement has been further revised and separated into two requirements applicable to the Resource Planner and Transmission Planner, respectively. 7. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.1.4 has been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. In either case the entity must document the reason for running or not running cases for the items listed. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance. It is the entity's decision to establish and document which senstivities are more significant to study System responses. The sensitivity studies do not in themselves establish the need for a plan, only the areas of the System for which the analysis is needed. For example an entity's base case Load level may be modeled as a 50/50 Load level which represents what the entity considers normal peak weather conditions. A sensitivity to that may be a 90/10 Load level case which represents extreme weather conditions.			

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Commenter	**Yes**	**No**	**Comment**
			R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.1.4**. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. 8. Requirement R2.5.2 was changed for clarification. **R2.5.2** Material Transmission System changes ~~in the electrical vicinity of existing generation are made~~ are made at or near the point of Interconnection of existing Generation such as the ~~addition or~~ removal of a Transmission Line ~~at or near the point of Interconnection~~ or the addition of a new substation in one of the Transmission Lines connected to the plant. 9. R2.6.1 – R2.6.3 – Requirement R2.6.2 was changed for clarification. **R2.6.2** For steady state, short circuit ~~analysis~~, Generating Plant Stability, or System Stability analysis: ~~if the study is less than five years old and no material changes have occurred to the System in the intervening period.~~ the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. 10. Requirement R8 (old requirement R6) which focuses on the distribution of the Planning Assessment results among affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old requirement R6). Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. Typically the date would indicate when significant resources will begin to be employed. This covers any project proposed for the near term. The SDT believes that initiation dates are required for near-term Corrective Action Plans to give an indication that the Corrective Action Plans can be implemented in time. 11. Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted Requirements R2.7.2 through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions". **R2.7.1.** ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.

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Commenter	**Yes**	**No**	**Comment**
12. Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and Requirements deleted R2.7.2 through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions". 13. The SDT has revised Table 1 to include N-0. 14. The term "System adjustment" is used in the existing TPL Standards, and is intended to have the same meaning in the proposed TPL standard, and includes both manual and automatic actions. 15. The SDT has made extensive changes to the tables to address these concerns. 16. and 17. The use of the defined term 'Facility Ratings' includes time elements which accommodate your concern. 18. You must perform any Stability analysis that is required to meet the performance requirements. 19. Requirement R11 contains this language. 20. The scope of the SAR and standard being prepared is only related to reliability assessments. 21. The SDT attempted to make Steady State and Stability identical but this was not always possible. 22. The SDT believes that the reference to the outaged DC line is appropriate. 23, 24, 26, and 27. P5.3 is intended to be the loss of a second transformer with low-side voltage >300 kV. P9.6 was to address the FERC directive in Order 693 to consider spare equipment strategy. In Q33 the SDT posted a question to the industry to request guidance on whether simultaneous tripping of all generating units in a power plant should be included the Extreme Events in Table 2 (on Stability Studies). The SDT has revised Tables 1 and 2 and included this consideration in Requirement R11 of the second draft of the standard to address this issue. Tables 1 and 2 have also been revised to address your comments on P3 and P9.1, the repeated Extreme Event Items 3c – 3f and Item 3h. For P9.1 (P7.1 in the second draft), the SDT did not change the table to include "contiguous" for the 1 mile (or less) exclusion because the standard does not limit the number of instances where two circuits can share a common tower only that each exclusion applies to a length of one mile or less. 25. The SDT agrees and has eliminated that requirement. 28. Editorial change made to alleviate confusion. 29. You must perform any Stability analysis that is required to meet the performance requirements.			
APS	☑		R 2.5.1 and R 4.6 require plant stability studies for all generators greater than 20 MVA for changes in excitation system or PSS addition. Generally plant stability is a problem only for large plants with large generators. Changes in the excitation system of a small generator or PSS addition does not significantly impact the plant stability. In fact, in most cases it improves the plant stability. When an excitation system or a PSS is commissioned in the field, part of the commissioning tests ensure that turbine-generator is stable and that the performance of the excitation system and PSS are acceptable. If an excitation system change or PSS addition is causing a plant stability problem in simulation, it is generally a data issue and can be best handled in MOD standards. Requiring stability studies to be redone does not in any way contribute to the system reliability. There are hundreds of old generators in the US which are going through excitation system retrofits in a given year. Requiring a stability study for each change would add additional study burden without any value to the system. This is unnecessary work with little consequence on the system performance or reliability.

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Commenter	**Yes**	**No**	**Comment**
			Note: We have additional comments on these standards but they have been covered by comments from WECC. We fully support all of those comments.
Response: Those values are based on Large Generator Interconnection Procedures as approved by FERC. Unit controls are an integral part of the power system and must be analyzed when changes are made.			
BPA	☑		Support comments sent by WECC. In addition,BPA has the following comments: 1. R2.3.1 - The way the requirement is written sounds like the short circuit study should be run after changes are made to the BES. The study needs to be done sufficiently in advance to allow for needed equipment replacements as a result of the study. Also, "current" in the first senetence should be changed because it is confusing whether it refers to "present" or "amps". 2. There needs to be better definition what is meant by "bus tie breaker". It is assumed this includes both bus tie breakers between a main and auxiliary bus, as well as bus sectionalizing breakers between two main bus sections. 3. In general the table seems unnecessarily complex. It would appear to make more sense to group events by performance as done in the previous Table 1. Also, in general the resulting events for the element contingencies in the table should be compared and like events grouped together since they would be are modeled the same and show the same performance in powerflow studies. 5. P9.1 - It is recommended to exclude multiple circuits sharing a common structure for no more than three miles, rather than one mile. Our analysis shows river crossing systems can be up to three miles and it is impractical to plan for common corridor outages of up to this distance. 6. Planning event P9.6 is the same as P8.3 with the only difference being the restoration time. 7. Regarding extreme event descriptions: - Item 3.a is not a Transmission Planning, but is relevent for Resource Adequacy. - Item 3.b is an operational issue not relevent to Transmission Planning. Successful cyber attack would need to be defined. Also, how would the consequences of a successful cyber attack be predicted? - Regarding item 3.c, generation capabilities should already be modeled in base cases within the planning horizon. - Items 3.d through 3.f are not relevent to Transmission Planning. These are Resource Adequacy issues within a short term operational horizon. - Items 3.e and 3.f appear redundant to items 3.c and 3.d. - Item 3.g is not really a planning issue. The system should be designed to meet required

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Commenter	**Yes**	**No**	**Comment**
			performance for selected contingencies regardless of age or maintenance pratices. - In general, the Extreme Events layed out in the previous Table 1 is a much more practical approach to planning the transmission system.
Response: 1. Requirement R2.3.1 has been deleted. In Requirement R2.3, the wording has been revised to be clear that an annual assessment is required and what studies may be used. Requirement R2.6 provides further detail about which past short circuit studies may be used. Requirement R4 explains the conditions that the studies should analyze. 2. The SDT has included a proposed definition of a Bus-tie Breaker in the second draft. **Bus-tie Breaker:** A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.) 3. Tables 1 and 2 have been revised to provide greater clarity. 5. The SDT notes that distances greater than a mile present comparability issues with regard to other situations such as bay crossings, harbor crossings, and other longer spans. The SDT has not revised the requirement as a result in the interest of maintaining comparability without opening the waiver up to other situations. 6. The SDT has deleted P9.6. 7. With regard the Items 3.e and 3.f appearing to be redundant to items 3.c and 3.d., the SDT agrees and has made the appropriate changes to the standard. With regard to the other comments about the Extreme Events, the SDT notes that in Order No. 693, paragraph 1834, the FERC gave examples of Extreme Events that the FERC would expect to see in the revised standard. These examples are consistent with the items that the SDT included in the standard as examples of Extreme Events to be considered. For example paragraph 1834 include "(1) loss of a large gas pipeline into a region or multiple regions that have significant gas-fired Generation; (2) a successful cyber attack; (3) regulation that restricts or eliminates the use of a river or lake or other body of water as the cooling source for generation; (4) tornado or wildfire, or other event and (5) the loss of older transmission lines, which may not be constructed to meet an entity's present radial ice loading requirements…" In paragraph 1834, the FERC directs NERC to expand the list of events with examples such as those described in the paragraph. The SDT believes that the Extreme Event items that the commenter has raised concerns about are consistent with the list of examples provided in paragraph 1834. Further, the SDT notes that while the commenter is correct that some of these events have traditionally been treated as deliverability issues, nonetheless they will dramatically impact the reliability of the interconnected network and are logical Extreme Events for which the probability and consequences should be evaluated when considering ways to make the Transmission System more robust with Operating Procedures and/or System improvements that are reasonable in cost in comparison to the probability and consequences of the Extreme Event. The SDT did not change the standard with regard to these comments.			
BCTC	☑		1. We have some questions of clarification for the Standards Drafting Team, that may resolve some of our concerns. (i) Is it the intention of NERC that the more stringent performance requirements in this standard would be applicable for determining System Operating Limits before Transmission Owners are able to implement Corrective Action Plans? The BCTC system is part of the western interconnection and BCTC is a member of WECC. WECC members apply a principle that Planning Standards are also applicable for determining System Operating Limits. If the answer to this

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Commenter	**Yes**	**No**	**Comment**
			question is "no", then BCTC may be able to support some aspects of raising the bar, with the understanding that SOLs would be determined based on the performance standards that the system is planned to. (ii) Has the Standards Drafting Team considered how Transmission Planners will address discrepancies between Corrective Action Plans for this standard and the reality of what can be constructed due to regulatory approvals, siting problems, financing issues, etc.? For example, is it the intention that Transmission Planners should continue to study Corrective Action Plans to meet an N-1-1 Planning Event (e.g. P5-1) without generator tripping when the practical situation is that we may be fortunate to be able to build to meet N-1 with some generator tripping? We are concerned that if we cannot meet the performance requirement for P5-1 due to delay or denial, continuing to assess Corrective Action Plans to meet P5-1 does not provide much useful information compared to planning to meet a doable target. Item 2 below provides a proposal to address this. 2. There is always the possibility that a regulator may deny funding for a Corrective Action Plan or approve funding for a Corrective Action Plan that does not fully meet the performance standards, a siting process may delay or block a Corrective Action Plan, or some other process may frustrate the ability follow through with a Corrective Action Plan to meet NERC performance standards. To avoid the need for a Transmission Planner to continue to study Corrective Action Plans that cannot be implemented, we suggest adding the following Requirement R2.7.6: The Planning Assessment is not required to include a Corrective Action Plan and address the subsequent requirements (of R2.7) in cases that (a) an applicable regulatory agency has ordered that a Corrective Action Plan is not to proceed or that an alternative Corrective Action Plan that does not meet the performance standards is to be implement or (b) the Transmission Planner has documented evidence indicating that such an outcome is likely to occur. Other Requirements for Five and Ten year Assessments may also be exempted depending on the regulatory order. The Planning Assessment will include evidence of the order. 3. R3.3.3, R3.4, R4.5.1, R4.5.2 - A rationale for the selected contingencies should be sufficient. It should not be necessary to explain why the remaining contingencies would produce a less severe result. 4. Table 2, P1 should include shunt devices. 5. A definition or reference to a definition for Firm Load and Firm Transfers is required. The present situation is that these terms are "defined" as those loads and transfers that can be supplied while meeting Category B requirements. In other words, the standards define the terms. The commercial uses of firm and non-firm may not be applicable and they actually mean non-recallable and recallable service, not directly related to system performance, but incorporating aspects of

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Commenter	**Yes**	**No**	**Comment**
			reservation times. 6. Extreme Events of Tables 1 and 2 should not be subject to the same study requirements as Planning Events. Table 1 Extreme Events need not be studied for both the Near Term and Long Term Horizon (ref. R3.4, R3, R2.1 and R2.2) and for all five years of the Near-Term Horizon (ref R3.4, R3, R2.1). Table 2 Extreme Events should not be required for all five years of the Near-Term Transmission Planning Horizon (ref. R4 and R2.4). When conditions warrant, only a single assessment representing a selected reasonable planning horizon should be required, and an update required only when past studies are no longer representative. We are concerned that many of the proposed Table 1 Extreme Events (Item 3. a, c, d, e, f) are resource adequacy issues (we also observe that c and e appear to be identical). Transmission Planning Assessments of these events should be initiated at the request of Resource Planners. It should not be necessary for Transmission Planners to initiate and maintain current studies of these Extreme Events. We suggest that Extreme Events be removed from R3 and R4 and addressed in a separate Requirement. 7. The Purpose of this standard should be restated as: Establish requirements for Planning Assessments, including Corrective Action Plans, to be conducted over range of forecast conditions based on system planning performance requirements. Explanation: This revised wording more accurately describes the content of the standard. The Requirements of this standard are to perform Studies and Assessments. The performance tables are referenced by the Requirements and are supporting to the Requirements, but are not a "capital R" Requirement.

Response: 1. NERC, in its response to FERC's NOPR on the FAC-010, FAC-011, and FAC-014 standards, committed to revising the FAC and ATC standards when there is consensus on the TPL standards.
The intent of the Corrective Action Plan is to establish a doable set of actions that are to meet the performance requirements. Senstivitiy studies have been specifially added to the standard to allow the planner to assess the impact of corrective actions being delayed. It is the entity's responsibility to assess these impacts and adjust the next set of actions planned to meet performance. The standard also requires that the assessment cover more than the ten year period if the entity deems it necessary to accommodate any long range projects that may take years to complete due to ROW acquisition, hearings, etc. In addition, generation tripping for single Contingencies has been added back into the standard and the N-1-1 performance requirement has been revised to allow generator tripping and Non-Consequential Load dropping.
2. The SDT does not believe that it is necessary to add the words concerning regulatory delays or denials. The intent of the Corrective Action Plan is to establish a plausible set of actions that, when implemented, achieve the performance requirements. Senstivitiy studies have been specifially added to the standard to allow the planner to assess the impact of modification to or delay of a corrective action plan.
It is the entity's responsibility to assess the impacts of a modification or implemetation delay and adjust the next set of corrective actions or modify the proposed plan to meet the performance requirement as prescribed in the standard.
The standard also requires that the assessment cover more than the ten year period if the entity deems it necessary to accommodate any long range projects that may take years to complete due to ROW acquisition, hearings, etc.
3. The SDT believes that it is necessary as part of a complete documentation set explaining why and what was done.

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Commenter	**Yes**	**No**	**Comment**
4. This was added as requested. 5. In reviewing this comment, the SDT noted that Firm Demand and Interruptible Load are defined in the NERC Glossary. The SDT believes Load that is not Interruptible Load as defined in the NERC Glossary best fits the intention of the requirements pertaining to Firm Load in the TPL standard. Therefore, the SDT modified the references to Firm Load to refer instead to non-Interruptible Load in the TPL standard. With this change, Firm Load does not need to be defined in this standard. 6. The SDT agrees with the comment that Extreme Events should not be subject to the same study requirements as Planning Events; however, the SDT proposes to resolve the issue by clarifying the study requirements in the table and the text without removing the Extreme Events from Requirements R3 and R4 and addressing Extreme Events in a separate Requirement. With regard to the comments about resource adequacy issues, as noted in the BPA 7 answer, these events that have been traditionally considered resource adequacy issues are included as Extreme Events to be consistent with FERC Order No. 693 and because such events could dramatically impact the reliability of the interconnected network. As a result, the Transmission Planner/Planning Coordinator should investigate these Extreme Events regardless of whether the Resource Planner considers them to be an issue or not. In this way, the Transmission Planner/Planning Coordinater considers ways to make the Transmission System more robust with Operating Procedures and/or System improvements that are reasonable in cost in comparison to the probability and consequences of the Extreme Event. The SDT did not change the standard with regard to these comments. 7. Since most commenters did not express concern with the Purpose language, the SDT felt that no change was necessary.			
CAISO	☑		1. First, and as a general matter, the TPL-001 standard needs to accurately reflect the roles of PA'S and TP'S in areas with organized competitive markets and where the PA'S and TP'S are not vertically integrated utilities. In those areas, the TPL standard should recognize that compliance with the standard is achieved through the publication of a Plan that identifies system needs – and leaves open to the marketplace the specific mix of resources that investors construct to meet those needs. As a result, the Plan need not be, and should not be, prescriptive as to the resource mix that must be achieved. It is important for plans to be equally open to generation, demand response and transmission and not be presecriptive to the actual resource mix. Further, not all organized competitive markets have a mechanism in place to develop an integrated resource and transmission plan to meet future needs. Some markets conduct forecast assessment, thereby providing signals to market participants to make investment decisions. 2. Similarly, reflecting the divested nature of the industry in areas operated by ISOs and RTOs, the modeling standards should be reviewed to make sure that asset owners (e.g., generator owners and transmission owners) are required to give information in the level of detail and granularity that will allow PA's and TP's to develop plans and models consistent with these standards. 3. As highlighted in question 16, DSM should be considered an acceptable solution to system needs. However, DSM is generally considered in meeting resource requirements rather than as one of means to relieve transmission constraints. In planning studies, loads that are identified as DSM type (contracted or potential) are modeled as firm loads for reliability assessment. We would therefore seek the SDT's suggestion on how specifically DSM should be explicitly modeled or used to aid in

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Commenter	**Yes**	**No**	**Comment**
			achieving transmission reliability in the planning horizon. Further, the drafting team must consider whether DSM providers are covered in the Compliance Registry and how the NERC Standards should obligate them to provide the requisite information to PA'ss and TP's so that they are fully taken into account. 4. Finally, the standards need to be improved to better distinguish the responsibility of Planning Authorities versus Transmission Planners. Currently, the Standard refers to both entities as carrying out the requirements. This appears to be reundant.
Response: 1. The SDT believe that the standard is not prescriptive in the way described in the comments. 2. Comment is beyond the scope of the standard under development and should be addressed through proposed changes to the appropriate MOD standards. 3. The use of DSM is optional. Requirement R2.7.1 has been modified based on comments received to use "may include" instead of "including". The standard does allow for consideration of DSM but other factors may disallow inclusion of DSM in the Corrective Action Plan. The amount and uncertainty of DSM needs to be justified by the entity which includes it in its Correction Action Plan. **R2.7.1**. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. The standard is applicable not only to the Transmission Planner but also to the Planning Coordinator and the Resources Planner. These entities are expected to establish relationships to provide for intergrated analysis and resultant Corrective Action Plan which may include generation, transmission and DSM components. 4. Requirement R2 specifies that each entity is responsible for "its" portion of the BES. Even so there will likely be overlap and joint responsibility in some instances as identified in Requirement R5.			
CenterPoint	☑		1. TPL-001-1 focuses solely on reliability to the exclusion of economic cost/benefits, prudent avoidance, and landowner impacts, which have been the hallmarks of good utility practice that have governed transmission planning and construction for decades. FPA section 215(i)(2) "does not authorize the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services." However, adherence to TPL-001-1 as currently drafted, will require, de facto, the construction of additional transmission facilities. CenterPoint Energy believes this standard excludes proven, historical good utility practice to reach far beyond what is intended by the FPA. TPL-001-1 contains an excessive number of requirements (over 50). The SDT should consider the removal or modification of the following unnecessary, redundant or overly prescriptive

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Commenter	**Yes**	**No**	**Comment**
			requirements: 2. R1.1. This is a modeling requirement and should be incorporated into the modeling (MOD) standards. Remove or modify this requirement to eliminate any redundancy with existing modeling standards. If certain subrequirements of R1.1 of TPL-001 are not currently requirements in a MOD standard, it should be questioned, then, whether or not these specific subrequirements are actually needed in ANY standard. 3. R2.1.3 and R2.4.3 should be removed because they introduce new, vague requirements. 4. R2.2. Analysis beyond five years has little value due to the speculative nature of predicting load and generation growth. Furthermore, ERCOT does not annually create Long-Term Planning Horizon cases because ERCOT does not believe it is necessary. This requirement should be removed. 5. R2.5 and R4.6. These requirements are overly prescriptive and unnecessary for the reasons stated in the response to Q32. They should be removed. 6. R2.7.1 through 2.7.5. Requiring Corrective Action Plans that address how performance requirements will be met is reasonable; however, these standard requirements are overly prescriptive and unnecessary. R2.7.1 through R2.7.5 would result in the development, documentation and explanation of fictitious solutions to fictitious problems. They should be removed. 7. R3.3.2.1. The requirement to identify consequential load loss for single contingencies in the Planning Assessment is unnecessary and burdensome and should be removed. 8. R5. The roles of the Transmission Planner and Planning Coordinator are already addressed in the approved NERC definitions and further described in the approved NERC Reliability Functional Model. This requirement is unnecessary and should be removed. 9. Table 1 and Table 2 - P4, P5, P8, and P9. Including all combinations of two components (generator, Transmission circuit, transformer, monopolar DC line) with generation adjustments is impractical and overly burdensome. For multiple contingencies, CenterPoint Energy recommends including only two-circuit tower lines and the two components (generator, Transmission circuit, transformer, monopolar DC line) that would be cleared by a breaker failure (i.e., stuck breaker).
Response: 1. The SDT's understanding is that the ERO has the authority to set performance requirements for reliability. 2. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD			

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Commenter	**Yes**	**No**	**Comment**
standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. 3. The SDT feels it is appropriate to set a minimum level of sensitivity cases to be looked at. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. The SDT has modified Requirements R2.1.3 and R2.4.3 to clearly stipulate that the entity shall provide rational for why sensitivities on the list were or were not included in the sensitivity studies and that the entity may consider additional sensitivities that are appropriate for its own system. The Standard requires that deficiencies identified from the results of the current studies need to be addressed via Corrective Actions Plans while leaving it at the entity's discretion to decide which deficiencies, if any, identified through sensitivity studies should be addressed by the Corrective Action Plan. **R2.1.3**. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.4.3**. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: 4. The SDT feels that this requirement is appropriate based on its understanding of planning practices throughout North America. This is also mentioned in FERC Order 693. 5. See response to Q32. 6. After careful consideration, the SDT agrees that if the Corrective Action Plan is going to include "committed" and "proposed" projects, they will need to be defined. However, the SDT agrees that it will be very difficult to develop definitions of "committed" and "proposed" that are applicable for the entire NERC footprint. Therefore, the SDT has modified Requirement R2.7.1 and deleted the original Requirements R2.7.2 through R2.7.4 to reflect "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. **R2.7.1**. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. 7. FERC required documentation of Consequential Load loss in Order 693, paragraph 1795, (not Non-Consequential) and duration should be based on best judgment for the common cause of the event. 8. The Functional Model is intended as a guide and aid in drafting reliability standards. Nothing stated in the Functional Model is enforceable in and of itself. Only requirements in approved reliability standards, which may mirror the Functional Model assuming that industry consensus is received on the subject matter, are enforceable.			

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Commenter	**Yes**	**No**	**Comment**
9. The analyses of the combinations of two components are required by the existing TPL standards. The SDT understands the concerns in the potential increase in work load. Requirement R3.3.3 requires evaluation of only those Planning Events (involving multiple Contingencies) that are expected to produce more severe System impacts.			
HQTE	☑		1. We think that the proposed fusion of previous TPL-001 to TPL-004 and the addition of more specific contingencies involves too much change at once. It would have been better to make specific change to each individual standards. That way, it would have been more practical to evaluate the impact of the proposed changes. 2. A major concept before evaluating the impact of a standard is to know on what system it will be applied to. In the tables, the notion of a voltage treshold (>300 kV) is introduced. It is our interpretation that the standard as drafted applies only to BPS elements part of that treshold (>300 kV) and not every ">300 kV" element. The SDT should indicate if they have the same interpretation as ours. 3. We reiterate our comment that it would be preferable to have only one table that would include both steady state and stability contingencies with their respective expected performance. 4. There might be some protection standards that would need to be developped/clarified before some proposed changes in this standard. 5. The SDT has made an effort to define Base Case, yet has not used the term in the standard. At a minimum, Base Case should be referred to in sections 2.1.1, 2.1.2 In addition to the comments from Central Maine Power.
Response: 1. Much of the wording and underlying concepts are the same for the four standards today – the major difference being that each refers to normal, single, multiple or extreme Contingencies. All four use the same table. Merging them into one standard has simply eliminated much of the duplication and brought together the smaller portions of each standard that were different. Past experience has shown that since the four are so closely related that a change in one has a tendency to reflect a change in another – merging the four together helps keep all the changes and relationships in a single point of view. Commenters in general have supported the concept of merging the four standards together. In addition, Paragraph 1692 of Order 693 "directs the ERO to consider integrating Reliability Standards TPL-001-0 through TPL-004-0 into a single Reliability Standard through the Reliability Standards development process". In addition this Order, in conjuction with Order 890, enurmerate attributes of planning standards that the FERC feels should be incorporated into the consolidated standard. SDT believes that the first draft of the standard is consistent with Orders 693 and 890 without being unduley burdensome. 2. As proposed, the standard is intended to apply to all BES (not BPS) Facilities, but for some events the performance requirements are different for Facilities above and below 300 kV. When EHV Systems are compromised, the large volumes of power served by them can place a severe amount of stress on parallel EHV or lower voltage paths. For example, if a large EHV transformer experiences a catastrophic failure			

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Commenter	**Yes**	**No**	**Comment**
not only are other System Facilities required to carry more Load but the System is also exposed to other N-1 conditions for long periods of time while awaiting a replacement or repair of the failed equipment. Large generation sources are typically connected at EHV levels and maintenance of the EHV transmission lines within the vicinity of large generation plants must often be coordinated during scheduled unit outages, resulting again in multiple Facility outages over extended periods of time. 3. The majority of commenters support the development of the two tables as opposed to the single table in the existing TPL standards. Further, the SDT believes that the two tables provide the ability to clarify issues associated with Stability performance and evaluation requirements versus steady-state performance and evaluation requirements. Based on industry feedback, the SDT has completely reformatted the performance tables in Draft 2 of the TPL-001-1 standard. The new format more closely mimics the existing approved TPL standard Table 1, with enhancements we feel the industry will find valuable. 4. Since the SDT is considering specific references to items such as SPS, the SDT will need to address any direct effect on other standards. The SDT encourages the commenter to provide comments on any specific instances where such a clarification or change may be needed. In addition there is a standard under development that will be addressing integration of all Protective Systems. That team will be coordinating with the TPL team. 5. Base Case has been deleted as suggested.			
NPCC RCS	☑		The SDT has made an effort to define Base Case, yet has not used the term in the standard. At a minimum, Base Case should be referred to in sections 2.1.1, 2.1.2 In addition to the comments by Central Maine Power.
Response: After reviewing the comments to this proposed definition and the use of the term "base case" in the standard, the SDT determined that "Base Case" does not need to be a defined term.			
Central Maine Power National Grid New England ISO NU NSTAR United Illuminating	☑		1. There should be a "P0" standard that applies to system performance without any contingencies. 2. Standard should be clear that stabiltiy analysis is not required for Long-Term Planning Assessment. 3. R.1.1 Load forecasts should be addressed in MOD standards, not TPL. 4. R 1.4 This should only refer to known long-term outages, not planned outages. Delete "including protective relays"; this is addressed through other provisions. 5. R.2.1 Shorten "Near-Term Transmission Planning Horizon Planning Assessment" to "Near-Term Planning Assessment". 6. R 2.2 Shorten "Long-Term Transmission Planning Horizon Planning Assessment" to "Long-Term Planning Assessment". 7. R2.1, 2.2, 2.3 & 2.4 – The initial paragraph should have identical language regarding 'annual', and 'current or past' aspects.

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Commenter	**Yes**	**No**	**Comment**
			8. R2.1.1 There should not be a requirement to look at years one and two; a 5 year study should be sufficient. If there has been an ongoing 5 year study, there should be no major unexpected problems occurring in years 1 and 2. Studies of earlier years should only be required if an unanticipated event occurred that had not been considered in prior studies. The TPL should not address shorter term "Operating Studies" or operating issues. 9. R 2.2.1 Modify to "If any known projects have a lead time that is longer than ten years, the Planning Assessment shall be extended accordingly." 10. R 2.6 Steady-state, short circuit, and stability analysis should be required no more than every 5 years unless there is a significant change the system. 11. R 2.6.1 Remove reference to "market structure changes". The purpose of it's inclusion is unclear. 12. R 2.7.1.1 Project initiation date should be deleted. If it is retainted, it needs to be defined. 13. R 2.7.3 Committed and Proposed projects should be defined. 14. R 3.2.1/R 4.3 - What is the intent of this requirement? There should probably be an MOD associated with Generator Owner requirement to provide related generator protection/ limiter data or other plant information. 15. R 3.4/R 4.5.2 Remove the requirement to implement changes to reduce or mitigate the likelihood of such consequences of Extreme Events. This may not be reasonable or achieveable. 16. R 3.2 Sectionalizing schemes shall be considered when reflecting the post-contingent system. 17. R 3.2.2 - Propose deleting this. Line ratings should already take relay loadability into account. 18. R 3.3.2.1 - Proposed deleting "expected duration". This would be dependent upon the damage to the element due to the iniating event and other factors. 19. R 3.3.2.2 - The requirements of this section do not match P6. 20. R 3.3.3 - Change introductory language to read "Those multiple Contingencies that are…"

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Commenter	**Yes**	**No**	**Comment**
			21. R 3.5 - Generation tripping should be allowed as well as generation run-back. In addition, all performance requirements shall be met, rather than just meeting facility rating requirements. Suggested lanague "Manual and automatic generation run-back and/or generation tripping is allowed as a response to single and multiple Contingencies as long as the performance requirements of this standard are met." If these changes are accepted, R 3.6 can be deleted. 22. R 4 and R 4.1 - The language should be made similar to R 3 and R 3.1. 23. Suggest bringing language similar R4.4 into the R 3, the steady state section. 24. R 4.2 - High speed automatic reclosing schemes shall be considered. 25. R 6.3 - Change to read "Planning Coordinators of neighboring impacted areas". 26. Table 1 3 b and c Extreme Event descriptions are vague concepts that cannot be practically simulated. 3 d and e are not reasonable or practically useful to simulate. 27. Table 1, P8 - Language needs to be clarifed as to how the 300 kV threshold is to be treated for transformers. Is this for the high side, low side, or both sides? P5 is much clearer. 28. Table 2 - Clarification needs to be made that the faults being simulated are permanent faults. This can be addressed under the "Performance Requirements" portion at the beginning of the table, or modify each fault description. 29. Table 2 P9. Recommend that this be changed to require that faults should be on different phases of each of two adjacent transmission circuits on a multiple circuit transmission tower 30. Table 1, P9(6) and Table 2 P9 - It is unclear as to what is meant by "A spare transformer inserted to replace an outaged transformer followed by System adjustments". Unclear as to what is to be tested. 31. General comment - Transmission System is used throughout the document and is an undefined term The New England Transmission Owners and ISO New England transmission planners met several times to discuss the proposed standard and develop consensus comments based on our experience. The preceding comments are what was developed.

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Commenter	**Yes**	**No**	**Comment**
			Attached to the e-mail sending these comments is the September 12 Draft 1 TPL-001-1 Reliability Standard in Word format, red-lined with changes to the posted standard which are intended to reflect all of the comments above. This document was maintained by Central Maine Power Company during the course of the New England transmission planner discussions, and any variance (though none are expected) in not intended. It is expected that this red-lined TPL document will be helpful to the ATFN SDT in reviewing our comments.

Response: 1. The SDT concurs for the steady state performance requirements and has added a P0 Planning Event at the top of Table 1 to address the N-0 (existing Category A) condition. However, "normal System" is already included as part of the description of the initial System conditions associated with the fault for the stability study. Therefore, it is not necessary to include P0 in Table 2.
2. The SDT agrees. The requirement only specifies Near-Term.
3. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.
4. The SDT has revised this requirement based on industry comments to clarify intent and to be responsive to FERC Order 693, paragraph 1725.
5. The intent of the suggestion was adopted.
6. The intent of the suggestion was adopted.
7. Identical language was not used; the same words were used in a different order and context. Requirement R2 and the following four sub-requirements each address a slightly different aspect of what studies are to be run. Requirement R2 only mentions current and past in general terms since more specifics are provided in the sub-requirements. Requirement R2.1 makes reference to "annual current" studies to emphasize the fact that the Requirements R2.1.1 and R2.1.2 require specific studies be run each and every calendar year. Requirements R2.2 is consistent with Requirement R2.1.1 in that it requires a specific run each and every calendar year. Requirement R2.3 does not require specific run every year but allows for current or past to support the Assessment; this is also true for Requirement R2.4.
8. Requirement R2.1.1 requires you to study years one "or" two and five. The SDT feels that requirement to run a peak load study for two of the years in the Near-Term Horizon is a minimum required for an adequate Planning Assessment. The SDT felt that the Year One or two study should provide operations with the best information to transition to the Operating Horizon. The year five planning study is the first near term study from the long term set. Five years is a short time if unexpected new facilities are required. Areas with faster growth should appreciate the extra studies.
Requirement R2 includes a statement which states that "Planning Assessment shall use current or past studies." Requirement R2.1 allows for the Planning Assessment to be "...supplemented with qualified past studies…" If you have past studies which are applicable, the standard allows for such.
9. The SDT believes that the present draft language captures the same concept.
10. The SDT agrees with your recommendation and has revised Requirement R.2.6.1 to show a five year shelf-life.

R2.6.1. For steady state, short circuit, or System Stability analysis: ~~if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market~~

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Commenter	**Yes**	**No**	**Comment**
~~structure changes~~ the study shall be five calendar years old or less. 11. The SDT concern was that such structure changes could potentially affect dispatch scenarios, or even transfers being modeled – both of which are sensitivities. 12. Requirement R8 (old Requirement R6) which focuses on the distribution of the Planning Assessment results among affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old Requirement R6) Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. Typically the date would indicate when significant resources will begin to be employed. This covers any project proposed for the near term. The SDT continues to believe that providing the expected project intiation date of System improvements provides useful information to neighboring entities. The SDT believes that initiation dates are required for near-term corrective action plans to give an indication that the corrective action plans can be implemented in time. 13. After careful consideration, the SDT agrees that if the standard is going to include "committed" and "proposed", they will need to be defined. However, the SDT agrees that it will be very difficult to develop definitions of "committed" and "proposed" that are applicable for the entire continent. Therefore, based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted Requirements R2.7.2 through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between "committed" and "proposed" projects. It also lists examples of what is intended by the word "actions". **R2.7.1**. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. R6.2.2 - Whereas the SDT agrees that the suggested re-phrasing has merit, the proposed rephrasing is potentially problematic because "Long-Term Planning Assessment" is not a defined term. 14. The intent is that what is modelled is true to real-life expectations. Changes to MOD are not within scope. 15. The SDT feels that this is an appropriate requirement based on understanding of existing practice within North America. 16. That was the intent of this requirement. 17. The SDT has received numerous comments in support of these requirements. Requirement R3.2.2 is included to provide clarity on simulations in response to FERC Order 693. Relay Loadability is included to be clear that this factor must be taken into account in the planning studies. The SDT has not made changes in response to this comment. 18. The requirement concerning Consequential Load is to address FERC Order 693, which directs the ERO, among other things, to clarify footnote (b) in regard to Load loss following a single Contingency, specifying the amount and duration of Consequential Load Loss and System adjustments that are permitted after the first Contingency to return the System to a normal operating state. 19. Requirement R3.3.2.2 was changed to correct this discrepancy.			

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Commenter	**Yes**	**No**	**Comment**
R3.3.2.2 Following single Contingency events, ~~System adjustments other than shedding of firm Load or curtailment of firm transfers are permitted to meet performance requirements provided these adjustments can be accomplished within the time period allowed by the applicable time limited ratings.~~ Transmission configuration changes and redispatch of generation are allowed provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits. 20. The reference to Table 1 will need to be included because Requirement R3.3.3 applies only to Steady State performance to distinguish this requirement from those in Requirements R4.5.1 and R4.5.2, which apply to Stability Performance. 21. The SDT agrees and has changed Requirement R3.5 **R3.5** Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met: **R3.5.1**. All Facilities shall be operating within their Facility Ratings. **R3.5.2**. Such action would not violate safety, equipment, regulatory or statutory requirements. **R3.5.3**. A sustainable, stable, operating condition is maintained 22. The SDT attempted to make this language similar to the extent possible. 23. The SDT believes that Requirement R2.7 covers this matter for Steady State but will discuss this matter further for subsequent drafts. 24. The intent of this requirement is to model the system as it would be operated and high speed reclosing would therefore be included. 25. The SDT believes that your comment has already been addressed by the words "affected entities" (now directly adjacent Transmission Planner) in Requirement R8 (old Requirement R6). Impacted is difficult to measure. In addition, the purpose of the "peer review" is to help ensure that a Corrective Action Plan is inclusive and some potentially impacted areas are not overlooked. 26. As noted in the BPA 7 answer, these events are included as Extreme Events to be consistent with FERC Order No. 693 and because such events could dramatically impact the reliability of the interconnected network. 27. The SDT agrees that the language for P8 needs to be clarified with regard to the 300 kV threshold. As a result, the SDT has made changes to the standard to clarify the 300 kV threshold. 28. The SDT agrees and has changed the standard to clarify that the faults being simulated are permanent faults. 29. The SDT has made the recommended change in P7. 30. This item was deleted. 31. Transmission is a defined term in the NERC Glossary as is System.			
City Utilities/Springfield	☑		Requirement R3.2: Contingency analyses representing only the removal of elements that System protection is expected to automatically disconnect which includes Consequential Load Loss is a reduction in reliability. Excluding the contingency analyses between all elements including those with manually operated switches will result in lowering existing reliability standards and ultimately limit the load restoration capabilities of the BES. Minimum performance standards should be adhered to for all applicable contingencies including outages of elements that may be switched both automatically and manually taking into account controlled load curtailment that is allowed. Requirement R3.3.2.1: The expected duration of Consequential Load Loss was noted to be required in a Planning Assessment following a single Contingency without any indication as to the assumed

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Commenter	**Yes**	**No**	**Comment**
			cause of the outage. The basis for such estimations of time needs to be defined such that these assessments are developed on a consistent basis.
Response: 1. One of the drivers for assessing the System performance based on removing all elements that System Protection is expected to disconnect (breaker-to-breaker) upon clearing the fault is to address concerns expressed in interviews by NERC TIS and FERC. The premise is that the assessment must examine all phases after a fault occurs. This includes the initial response of the System immediately after the fault clears, as well as after any existing or planned switching actions, such as the ones to which the commenter refers. 2. The proposed TPL-001-1 standard does not place limits on the amount of Consequential Load Loss or the outage duration. In Requirement R.3.3.2.1 the Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment. The SDT believes it is necessary to obtain this data to evaluate the future need for and establish a basis to define maximum amounts of Consequential Load Loss that would be allowed.			
CPS Energy	☑		1. R1.1. This is a modeling requirement and should be incorporated into the modeling (MOD) standards. Remove or modify this requirement to eliminate any redundancy with existing modeling standards. If certain subrequirements of R1.1 of TPL-001 are not currently requirements in a MOD standard, it should be questioned, then, whether or not these specific subrequirements are actually needed in ANY standard. 2. R2.2. ERCOT does not study the Long-Term Planning Horizon because ERCOT does not believe it is necessary. Remove or modify to state "as applicable by region." 3. R2.7.1.1 Duration of projects vary between Transmission Owners and statement of the project initiation date has no value to reliability. 4. R3.3.2 Relay loadability is considered as an MLSE component to the circuit rating as identified in MOD-008 and MOD-009. 5. R3.3.2.1. The requirement to identify consequential load loss for single contingencies in the Planning Assessment is unnecessary and burdensome and should be removed. 6. R3.6 Automatic generation tripping should be allowed for radial-connected wind resources. 7. Table 1 - P6.1, P6.3, and P6.4 These events are triggered by a single credible event and should not allow for loss of Non-Consequential Load. 8. Table 1 - P9.1 Loss of double-circuit tower lines are triggered by a single credible event and should not allow for loss of Non-Consequential Load. 9. Table 1 and Table 2 - P4, P5, P8, and P9. Including all combinations of two components (generator, Transmission circuit, transformer) with generation adjustments is impractical and overly

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Commenter	**Yes**	**No**	**Comment**
			burdensome. For multiple contingencies, include only double-circuit tower lines and the two components (generator, Transmission circuit, transformer) that would be cleared by breaker failure.

Response: 1. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.
2. The SDT believes that the purpose of the long term horizon is to uncover any unexpected trends that might appear after the first five years. Although planning may not be performed as stated in the draft standard, the standard does provide a level of confidence that unusual or unexpected trends or events could always affect the current planning process and allows for planners to propose potentially long term economic solutions that could not be envisioned in the shorter term.
3. Requirement R8 (old Requirement R6) which focuses on the distribution of the Planning Assessment results among affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old Requirement R6) Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. Typically the date would indicate when significant resources will begin to be employed. This covers any project proposed for the near term. The SDT continues to believe that providing the expected project intiation date of System improvements provides useful information to neighboring entities. The SDT believes that initiation dates are required for near-term corrective action plans to give an indication that the corrective action plans can be implemented in time.
4. The SDT has received numerous comments in support of these requirements. Requirement R3.2.2 is included to provide clarity on simulations in response to FERC Order 693. Relay Loadability is included to be clear that this factor must be taken into account in the planning studies. The SDT has not made changes in response to this comment.
5. The requirement concerning Consequential Load is to address FERC Order 693, which directs the ERO, among other things, to clarify footnote (b) in regard to Load loss following a single Contingency, specifying the amount and duration of Consequential Load Loss and System adjustments that are permitted after the first Contingency to return the System to a normal operating state.
6. The SDT has made a change to allow for tripping under certain conditions.

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:
R3.5.1. All Facilities shall be operating within their Facility Ratings.
R3.5.2. Such action would not violate safety, equipment, regulatory or statutory requirements.
R3.5.3. A sustainable, stable, operating condition is maintained.

7. These events are on lower voltage facilities on the BES. The probability of the outage of one breaker or a bus section is much lower than the probability of a single Transmission line outage. Therefore, the SDT has drafted the standard to permit loss of Non-consequential firm Load or interruption of firm Transmission service for the loss of a lower voltage breaker or lower voltage bus section. The majority of the commenters in response to the first posting of the standard agreed with the SDT's approach in this regard.
8. This event is a lower probability event, for example the probability of the outage of one common tower event is much lower than the probability of a single Transmission line outage. Therefore, the SDT has drafted the standard to permit loss of Non-Consequential firm Load

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Commenter	**Yes**	**No**	**Comment**
or interruption of firm Transmission service for the loss of a common tower event. The majority of the commenters in response to the first posting of the standard agreed with the SDT's approach in this regard. 9. The analyses of the combinations of two components are required by the existing TPL standards. The SDT understands the concerns in the potential increase in work load. Requirement R3.3.3 requires evaluation of only those Planning Events (involving multiple Contingencies) that are expected to produce more severe System impacts.			
Entergy	☑		1. Significant Increase in Study Activity Workload on Transmission Planners The increase in both steady state and dynamic studies required to ensure compliance with the proposed standards will result in increased costs and staff additions. The more specific format and additional requirements of the "Corrective Action Plan" require the TP to provide a significant amount of documentation for each deficiency identified by the studies. Also, R3.2 requires that the studies simulate the protection scheme for all events. The current software tools cannot automate these studies for bus faults and breaker failure events, requiring each scenario to be studied manually. Additionally, experienced staff capable of performing analyses as described in the proposed standard have become increasingly difficult to find and retain and the talent pool of people with these skills has recently become depleted to alarming levels. 2. Implementation Plan Given the intent of the proposed standard to encourage large scale investment in the EHV system, full implementation will take years, perhaps decades. Acquirement of right-of-way for new EHV lines has become increasingly difficult in recent years and increasingly expensive due to the environmental and social issues associated with new Transmission. Legal, regulatory, and other difficult issues often take several years to navigate, even for 115kV lines. The Implementation Plan timeframe, if set too short, would be unduly burdensome on Transmission Owners, extraordinarily expensive, and possibly unachievable. The proposed implementation plan should include provisions for those cases where viable solutions simply can not be implemented in time due to circumstances beyond the control of Transmission owners. We recommend a minimum of 15 years for the transition. 3. Design and Construction Constraints Even if right-of-way and other legal and regulatory hurdles are cleared, and the capital funding for such a tremendous level of investment was not an issue, the other resources required to actually construct the projects are equally difficult and costly to secure. Raw material prices on commodities like copper and steel have skyrocketed in recent years. Additionally, the skilled labor and Engineering resources are constrained with labor rates almost keeping up with other resource costs. Overall project costs have more than doubled over the last 7-10 years. Recent press releases concerning new generation being planned and then scrapped due to the rapid escalation of project costs are public evidence of this. The inflationary mark-up is impossible to estimate but much less will be built with the same capital investment than is currently envisioned due to the competition for both human and material resources.

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Commenter	**Yes**	**No**	**Comment**
			4. Cost-Benefit Analysis It will be extremely expensive, requiring unprecedented levels of capital investment in Transmission facilities, to become compliant with a proposed standard without any evidence that such increased requirements are justified. Before the standard comes to official vote, it would be prudent for a cost-benefit analysis to be performed to determine if the reliability improvements justify the huge expenditures certain under the proposed standard. A clear understanding of the reliability benefits and economic costs to customers is critical prior to final action on the proposed standard. While tightening standards will result in a more secure system, overbuilding the system at a significant cost to withstand more severe but less likely contingencies may not be in the public interest. Additionally, it is unclear whether the propose standard is in conflict with section 215 of the Energy Policy Act of 2005. 5. System Adjustment Clarification The term "System Adjustment" as outlined in the tables should be better defined. The use of generation for redispatch may have nuances which preclude or otherwise limit their use for studies. Perhaps some clearer guidelines on what is allowed such as committing units, de-committing units, firm and non-firm use, etc. would facilitate transparency and coordination between Transmission Planners. 6. Transmission Service Evaluation Another concern is that the proposed standard appears to be inconsistent with the current requirements for evaluating firm transmission service, generally based on an N-1 standard. To the extent this standard is adopted as proposed, the new standard would also need to be incorporated into the standards against which new transmission service is granted.
Response: 1. Much of the work that the commenter sites as additional is something that is required by the current approved standards. For example, Requirement R3.2 requires that the planner not just "outage" each power flow model element but reflect outage conditions that truly exists in the real world, e.g., a fault on a three terminal circuit should be modeled as three power flow elements being removed from the case to reflect actual operation. The concepts of "re-testing" and "committed" projects have been removed from the Corrective Action Plan so that only the value added concept of listing the actions necessary to achieve the desired level of system performance remains. Although sensitivity cases are now specifically required, they were considered by many utilities to determine the level of risk that remained after the addition of the proposed reinforcement projects. 2. The SDT understands that there are extended transitionary issues associated with responsible entities becoming compliant with the new standard. The SDT plans to draft an extended implementation plan to accommodate such issues. The plan will be provided for the third posting of the standard. 3. The SDT is unsure of the intent of the comment. While it is becoming increasingly difficult to build new Facilities, the fact is not in itself a valid reason for not complying with the performance requirements of this standard. The responsible entity is required to annually assess the compliance with the performance requirements and to have a Corrective Action Plan when the assessment indicates an inability to meet the			

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Commenter	**Yes**	**No**	**Comment**
performance requirements. A Corrective Action Plan does not necessarily result in building new Facilities. If it is impossible to correct the failure then a mitigation plan should be submitted for approval. 4. The SDT shares your concern on the benefits and cost to meet the proposed increase in some requirements. The SDT and a large number of commenters felt that the proposed changes in requirements were reasonable and will help improve reliability. The SDT is including in the next draft, a schedule for compliance in the Implementation Plan which should give some time for entities to become compliant with the new requirements. The TPL standard is not a standard "to build"; it is a standard to plan for System reliability. The individual entities have the option of deciding how best to meet the growing load and associated reliability needs. 5. The Transmission performance tables have been modified to bring clarity to the Contingencies required for performance studies and when Non-Consequential Load Loss is permitted to meet requirements. The use of manual or automatic System adjustments to revise System topology as well as generation redispatch is always permitted so long as the actions can be performed while adhering to Facility Ratings. 6. The provisions for an entity to grant Transmission service in the US is part of the entity's OATT and is beyond the scope of this standard.			
Exelon	☑		1. There should be more specific requirements for the long-range studies. The P requirements should be run on the long range case but corrective action plans need only be proposed and not committed. 2. R3.3.2.1 appears to require consequential load loss identification including peak demand and duration. however there is no requirement addressing the use of this information. Why is this required? 3. R3.3.3 should be clarified. It is our interpretation that not each of the P contingencies be studied if sufficient rationale is provided to determine the most critical. It would seem that each of the planning category events would need to be addressed. 4. What is the expectation regarding sensitivity analysis in R2.1.3 and R.2.4.3 if there are no performance requirements defined? 5. It should be clear in the performance tables that the 'event column' contingencies are logically 'or' events.
Response: 1. The performance requirements apply to both the "near-term" and the "long-term"assessments. Compliance with the performance requirements should be documented through assessments and a Corrective Action Plan. The SDT has modified the requirements in the new draft to remove the phrase "committed projects." 2. The requirement concerning Consequential Load is to address FERC Order 693, which directs the ERO, among other things, to clarify footnote (b) in regard to Load loss following a single Contingency, specifying the amount and duration of Consequential Load Loss and System adjustments that are permitted after the first Contingency to return the System to a normal operating state. 3. Requirement R3.3.3 requires evaluation of only those Planning Events (involving multiple Contingencies) that are expected to produce more severe System impacts. Requirement R3.3.3 also requires that the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. 4. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirements			

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Commenter	**Yes**	**No**	**Comment**
R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirements R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own System. The sensitivity studies do not in themselves establish the need for a plan, only the areas of the System for which the analysis is needed. **R2.1.3.** For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.1.4**. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. **R2.4.3**. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: **R2.4.4.** In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. 5. The SDT has made changes to clarify the table.			
FirstEnergy	☑		1. - R1. Load flow model submittal is redundant with various MOD standards and should not be required by this standard. To the extent any new requirements are introduced, we suggest that existing MOD standards be revised or new MOD standards be created as needed. 2. - R2 Organization of this requirement could be improved by grouping by Near Term and Long Term and then by steady state, short circuit, and stability requirements. 3. - R2.1 Too many annual studies are being required by this standard for the Near Term. We suggest limiting the current study year requirement be limited to one Near Term study. As written, it appears that this requirement forces a study for each of the 5 years, however the requirement should to be able to assess the entire 5 year period but not study each year. 4. - R2.1.1: As written, 2 studies are needed to meet this Near Term assessment requirement. It should be left up to the TO to determine the appropriate year in the short and long term periods. It's particularly odd given the fact that the TO could select year six for the Long Term study which would end up giving him back to back year 5 and 6 studies. The requirement should be to study one year in

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Commenter	**Yes**	**No**	**Comment**
			the 1 to 5 and one year in the 6 to 10 year periods. 5. - R2.2: This wording is very confusing. We are assuming that it means that you must continuously have to have a study that is less than one year old for the year 6 to 10 period. If so, wording needs to be clarified. 6. - R2.4.1: The idea of modeling induction motor loads is good in concept, be we question the practicality for an auditor to enforce. To date, a definitive way to model induction motor load does not exist. For example, what is the right mix for percent of load to be motor load or percent of large vs small induction motors. 7. - R2.6.1: Unless "material change" is specifically defined, the requirement is ambiquous and difficult to enforce consistently. What constitutes a "topology" change? 8. - R2.6.2: Same comment as R2.6.1 above, material change needs to be defined. 9. - R2.6.3. Same comment as R2.6.1 above, material change needs to be defined. 10. - R.2.7.1.1: We don't think it is reasonable nor necessary for the TO to provide an initiation date. No one should care when it was initiated as long as it is in service by the time it is needed. 11. - R2.7.1.2. Requiring an in-service year for the long-term may not be feasible for the initial study assessment. Based on the number of issues that could occur in the long-term horizon it may take a TP another 6 months to a year of more detailed area studies study to find the optimal solution(s) to resolve multiple system deficiences. In the long-term, only a list of SOLs problems along with year problem is initially anticipated should be required. 12. - R3.2.1: We suggest the following rewording "R3.2.1. Studies shall include the minimum steady state voltage limitations for all generators, and generators shall be simulated to trip for voltage below the minimum steady state limitation." 13. - R3.2.2: This is unnecessary in this standard. This is already addressed in the FAC standards dealing with equipment rating. Additionally, the proposed PRC-023 relay loadability standard addresses this concern. Alternatively, reword the requirement to say "if a relay is expected to trip because of an overload then the resulting facility shall be simulated in addition to the initiating event". 14. - R3.3.3. How do you know which events beyond single contingencies result in producing "more

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Commenter	**Yes**	**No**	**Comment**
			severe" impacts without running all? Either you test or you don't. We suggest some type of cyclical expectation for testing each of the less probable Planning Events, i.e. every three years each must be covered etc.the most critical 15. - R3.4 Same comment as R3.3.3, you need to test each to understand which produces the most severe impact. We suggest some type of cyclical expectation for testing each of the Extreme Events. The frequency of testing should be less often that the items covered in R3.3.3. It appears the only expectation is to consider some type of change to reduce or mitigate potential Cascade for Extreme Events. It should be clearly written that there in no mandatory expectation to remove the Cascade risk that may be associated with an Extreme Event. 16. - R4.5.1. Same comment as R3.3.3 (Steady-State) applies for this Stability requirement. 17. - R4.5.2. Same comment as R3.4 (Steady-State) applies for this Stability requirement. 18. - R4.6.1. We agree with the requirement but the SDT should assure consistency with data submittal requirements in the MOD standards. PERFORMANCE TABLES - General 19. In general, we feel the tables are overly complicated and difficult to follow. We suggest the SDT give consideration to merging the proposed tables back together to a single performance table. We also question why the team chose to leave the NERC A, B, C, D concept. The concept of Planning Events could reflect that NERC A, B & C categories must be met for Planning Events and that Category D are Extreme Events. Drastic deviation from the historical NERC performance classifications will require significant re-write of existing TP planning criteria documentation. 20. 300kV Level - It is confusing how the 300kV level requirements are placed within the tables. We suggest separate columns for performance requirements for 300kV and higher and below 300kV. This way, the same Planning Event could easily be reference on the same line and the expectations for each system level could be more readily determined. TABLE 1 - Steady-State Performance Table 21. We suggest that the "Initial Condition" column that is included in Table 2 - Stability Performance Table - also be added to Table 1. This would allow each to have the same look and feel, and would cut down on the lengthy wording such as: "Loss of a generator followed by System adjustment followed by loss of a generator" 22. Bullet 1 - "Equipment Ratings should not be exceeded." It is not clear which equipment rating

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Commenter	**Yes**	**No**	**Comment**
			would be the applicable rating. 23. Bullet 3 - "Voltage instability, cascading outages and uncontrolled islanding shall not occur". These terms require a definition to ensure consistent interpretation and application from an auditor. 24. It is not clear why stuck breaker items are distinguished from an internal breaker fault. Each will create the same resulting system condition. 25. Why are non-bus tie breakers treated separate from other breakers? 26: P2: Why is a stuck breaker listed as a single contingency? 27. P8: What about a transformer followed by a line outage? Why not just simply list the components and say any combination of the two. 28. P9: "Loss of a transformer followed by a System adjustment with a spare transformer available followed by the loss of another transformer." It is not clear why this is needed? Wouldn't the spare be a possible mitigation of the initial contingency? Extreme Event Descriptions: 29) For item 1, it's understood that for the N-2 items listed, the "extreme" aspect is that the second event occurs without system adjustment. However, we question whether a two generators simultaneously out should be considered an extreme condition. 30) We agree with the items listed in item 2 as they line-up well with the prior category D events from the existing TPL standards performance table. 31) Many of the classifications listed in item 3 are subjective and can not be tested. We propose that these items should not be requirements. TABLE 2 - Stability Performance Table 32. With regard to Table 2, much of the proposed testing required for stability are not necessary from a reliability standpoint. Some test items are included that are not, at least in the eastern interconnection, going to impact stability any worse than the relatively simpler requirements of the present standards. By testing single phase local faults in conjunction with a stuck breaker and remote faults with back up clearing for each line emanating from a power plant, you'll cover 99% of your stability issues. Also, this table does not adress relay scheme failures (back up clearing) that were

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Commenter	**Yes**	**No**	**Comment**
			covered in the present standard and which can have a significant impact on the stability of a unit/system. 33. Under the "Event Column", it is inconvenient to need to look back and forth on the table to reference other events, the items should be written in full text. For example, under P4 it is indicated that the "Initial Condition" is a single generator out and the "Event Column" indicates apply "P1.2 Contingency, P1.3 Contingency, etc." These items should be written out so that the user of the Table does not need to flip back and forth to see what the referenced contingencies entail. 34. Regarding P1, why require dynamic analysis for an unexpected loss of the listed equipment without a fault? The fault iniated outage will always be worse. 35. As stated above for Table 1, It is not clear why stuck breaker items are distinguished from an internal breaker fault. Each will create the same resulting system condition. 36. P5, P8, P9: The analysis suggested to run these multiple contingencies in dynamics would be extremely time consuming and produce little value. We suggest that the steady-state anlysis be used to screen those contingencies which show the potential to cause system cascade and then run dynamic analysis on those items. 37. As stated for Table 1 above, "Loss of a transformer followed by a System adjustment with a spare transformer available followed by the loss of another transformer." It is not clear why this is needed? Wouldn't the spare be a possible mitigation of the initial contingency? 38. In the Notes section shown under Table 2, for item "ii", we are not sure this could be accomplished as our relay models are not reflected in our data set used for dynamics simulation analysis. Two separate and unique software tools house the data and we believe this to be common among most companies.

Response: 1. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.
2. Changing the order or sequence of the specific requirements has been discussed by the SDT but the decision was to retain the current sequence to avoid more confusion among the commenters. The benefit of changing the sequence did not outweigh the benefit of continuity at this point. The commenter is welcome to make a specific proposal for change in the next round of comments.
3. Requirement R2.1 does not require a study for each of the five years. The Planning Assessment shall cover the five year period. Requirements R2.1.1, R2.1.2, and R2.1.3 cover peak loading, off-peak loading, and sensitivities. The SDT feels that the requirement to run a peak load study for two of the years in the Near-Term Horizon is a minimum required for an adequate Planning Assessment. The SDT felt that

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Commenter	**Yes**	**No**	**Comment**
in Requirement R2.1.1 the Year One or two study should provide operations with the best information to transition to the operating horizon. The year five planning study is the first near term study from the long term set. Five years is a short time if unexpected new facilities are required. Requirement R2 includes a statement which states that "Planning Assessment shall use current or past studies." R2.1 allows for the Planning Assessment to be "…supplemented with qualified past studies…" If you have past studies which are applicable, the standard allows for such. 4. The SDT feels that the requirement to run a peak load study for two of the years in the Near-Term Horizon is a minimum required for an adequate Planning Assessment. The SDT felt that in Requirement R2.1.1 the Year One or two study should provide operations with the best information to transition to the operating horizon. The year five planning study is the first near term study from the long term set. Five years is a short time if unexpected new facilities are required. Requirement R2 includes a statement which states that "Planning Assessment shall use current or past studies." R2.1 allows for the Planning Assessment to be "…supplemented with qualified past studies…" If you have past studies which are applicable, the standard allows for such. 5. The intent of Requirement R2.2 is to study one year in the five year period each year. The timing of annual planning studies may mean that the most recent study is slightly over one year old in some years. Over time, the entity should have a portfolio of studies for the long term period as the basis to confirm the assessment of the period. 6. The SDT has softened the wording of Requirement R2.4.1 to address this issue. **R2.4.1**. System peak Load for one of the five years. For peak System Load levels, ~~the~~a Load model shall ~~include the dynamic effects~~ be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. 7, 8, and 9. The SDT agrees this is difficult and has modified the requirement to add some clarity. Most of the studies now have a backstop age of five years where they are no longer useable. **R2.6.** Past studies may be used to support the Planning Assessment if they meet the following requirements: **R2.6.1**. For steady state, short circuit, or System Stability analysis: ~~if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market structure changes~~ the study shall be five calendar years old or less. **R2.6.2**. For steady state, short circuit ~~analysis~~, Generating Plant Stability, or System Stability analysis: ~~if the study is less than five years old and no material changes have occurred to the System in the intervening period.~~ the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. **R2.6.3**. ~~For plant and System Stability analysis: until material changes in the System make the study no longer valid. Material changes in the system include the addition of a Transmission Line or a generator.~~ 10. Requirement R8 (old Requirement R6) which focuses on the distribution of the Planning Assessment results among affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old Requirement R6) Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. Typically the date would indicate when significant resources will begin to be employed. This covers any project proposed for the near term. The SDT			

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			continues to believe that providing the expected project intiation date of System improvements provides useful information to neighboring entities. The SDT believes that initiation dates are required for near-term corrective action plans to give an indication that the corrective action plans can be implemented in time. 11. Requirement R8 (old Requirement R6) which focuses on the distribution of the Planning Assessment results among affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old Requirement R6) Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. Typically the date would indicate when significant resources will begin to be employed. This covers any project proposed for the near term. The SDT continues to believe that by providing the expected project intiation date of System improvements provides useful information to neighboring entities. The SDT believes that initiation dates are required for near-term corrective action plans to give an indication that the corrective action plans can be implemented in time. 12. Requirement R3.2.1 was meant to allow the Planning Coordinator and the Transmission Planner the discretion on the treatment of the generators that may exceed their maximum or minimum voltage limits. 13. The SDT has received numerous comments in support of these requirements. Requirement R3.2.2 is included to provide clarity on simulations in response to FERC Order 693. Relay Loadability is included to be clear that this factor must be taken into account in the planning studies. In addition, Requirement R.3.2.2 only requires the studies to consider relay loadability and identify how loadability is treated in the steady state simulation, not to study relay loadibility. The SDT has not made changes in response to this comment. 14, 15, 16, and 17. The SDT believes it is appropriate for the Transmission Provider/Planning Coordinator to decide how to determine the events that result in the "more severe" impacts. The SDT believes that the standard as written is clear and does not indicate a "mandatory expectation to remove the Cascade risk" for Extreme Events. For example, Requirement R3.3.1 indicates that performance criteria shall be met only for System normal conditions and for Planning Events in Table 1. Requirement R3.3.1 does not include the requirement that the performance criteria be met for Extreme Events. 18. The SDT has added requirements R9 through R13. **R9.** Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information. **R10**. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information. **R11**. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information. **R12**. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information. **R13**. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each

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Commenter	Yes	No	Comment
year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information 19 and 20. The majority of commenters support the development of the two tables as opposed to the single table in the existing TPL standards. Further, the SDT believes that the two tables provide the ability to clarify issues associated with Stability performance and evaluation requirements versus steady-state performance and evaluation requirements. These issues were expressed by commenters during the development of the SAR that initiated the re-write of the TPL standards. By the same token, comments were expressed during the development of the SAR about the need to consider significantly changing the classification of outages to these categories and even to consider eliminating the categories. The SDT took the approach of eliminating the categories in order to concentrate on defining the performance requirements individually for each event as appropriate. The SDT does not see a need at this time to revert to the previous classifications. The SDT has made changes to the tables to clarify the performance and evaluation requirements as the SDT agrees with the commenter that further clarification from the standard issued in the first comment period was required. The SDT agrees with the commenter concerning the need for clarification of the 300 kV performance requirements and, as a result, made changes to the standard intended to accomplish this purpose. 21. The SDT has implemented the suggestion to add an initial condition column to Table 1. 22. The SDT notes that Equipment Ratings are covered in the FAC standards and are set by the Transmission Owner. The SDT does not see the need to add any further requirements with regard to Equipment Ratings. 23. Definitions for cascading and stability are included in the NERC Glossary. Further uncontrolled islanding, while not defined, is a common term that is well understood. The SDT does not propose to improve the definitions for Cascading and Stability or propose a new definition for cascading outages and uncontrolled islanding. The SDT believes that while it may be helpful to either develop a voltage instability definition or else specify performance requirements for voltage instability, there are not generally accepted performance requirements for voltage instability across NERC making it difficult for the SDT to write a voltage instability performance requirement at this time. For example, it has been found that an acceptable margin for voltage Stability varies bus to bus and therefore, is not suitable for a general instability requirement on a PV curve or alternative. There are a number of IEEE papers (e.g., P. Kundur, J. Paserba, V. Ajjarapu, G. Anderson, A. Bose, C. Canizares, N. Hatziargyriou, D. Hill, A. Stankovic, C. Taylor, T. V. Custem, V. Vittal, "Definition and Classification of Power System Stability", IEEE Transactions on Power Systems, vol. 19, no. 2, pp. 1387 – 1401, May 2004) that provide descriptions of voltage instability. It is important to understand what events are being modeled even when conducting steady state studies so as to ensure that studies are being conducted recognizing the FERC indicated in paragraph 1707 of Order No. 693 that planning assessment "faithfully duplicate what will happen in the actual power system and not a generic listing of outages." As a result, the SDT is not proposing to make changes to the standard in response to this comment. 24. The SDT feels that the resulting conditions are not the same. Stuck breaker is described in the notes in the tables. An internal fault is a single Contingency but a stuck breaker is not. 25. The reason for separate treatment of Non-Bus-tie Breaker and Bus-tie Breaker is that there are different System consequences for the 2. 26. The SDT agrees that a stuck breaker is not a single Contingency. It requires a fault-initiated Contingency followed by the failure of the breaker or the System Protection to operate properly. As a result, the stuck breaker is a lower probability Contingency. The SDT has changed the identification of the outage in the table. 27. The SDT agrees with this suggestion and has made the change to the table. 28. P9.6 was an attempt to include outages involving long lead time equipment considering spare equipment strategies in the table as			

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Commenter	**Yes**	**No**	**Comment**
directed by the FERC in Order No. 693. The SDT has deleted P9.6 and included this consideration in Requirement R11 of the second draft of the standard to address this issue. 29. Whether two generators out without System adjustment in between is an event which severely stresses the System would depend on the individual System under study; the SDT believes it is appropriate to not include this as a Planning Event and therefore has not revised the table as suggested. 30. Thanks for the support. 31. With regard to the comments about the Extreme Events in Item 3, the SDT notes that in Order No. 693, paragraph 1834, the FERC gave examples of Extreme Events and Item 3 is consistent with paragraph 1834 in the FERC order. See the response to BPA 7 for more details. Further, the SDT notes that these events dramatically impact the reliability of the interconnected network and are logical extreme events for which the probability and consequences should be evaluated when considering ways to make the transmission system more robust with operating procedures and/or system improvements that are reasonable in cost in comparison to the probability and consequences of the extreme event. The SDT did not change the standard with regard to these comments about Extreme Events in Item 3. 32. The SDT believes that all Stability requirements are necessary for reliability based on an understanding of current practices within North America. Protection systems will be addressed in subsequent versions. 33. The SDT has completely re-formatted the tables due to industry comments. 34. The SDT agrees and has made the change to the table. 35. The SDT feels that the resulting conditions are not the same. Stuck breaker is described in the notes in the tables. An internal fault is a single Contingency but a stuck breaker is not. 36. The SDT believes that Requirement R5.5.1 provides the distinction you are looking for. 37. Spare terminology has been deleted. 38. The intent of the note is the system must meet performance and that the loss of any generator is not greater than your Contingency reserve. You can simulate relay models using other techniques.			
FPL	☑		1. General Comment: NERC Standards TPL 001-0 through TPL 004-0 are approved standards that only required modifications pursuant to FERC Order 693. In this proposed draft standard TPL 001-1 the Standard Drafting Team (SDT) has far exceeded the recommendations suggested by FERC in that Order as well as created unnecessary confusion. FPL believes that the SDT's decision to combine NERC Standards TPL 001-0 through TPL 004-0 into one standard was not a specific requirement by FERC Order 693 and may not have been a good decision by the STD, therefore it should be reconsidered after reviewing all of the comments. At a minimun, the team should somehow clearly demonstrate changes in the standard's wording and required performance levels as compared to the existing standards. The new proposed draft of TPL-001 creates unnecessary confusion and interpretation of new ambiguous language, which is inconsistant with the stated objectives, instead of providing clarity to the standards. As an example of how to provide additional clarity, the existing standards have unnecessary redundancy in the tables, for example, it would have been nice to clean up (clarify) the tables such that the table for TPL-001 would only contain the performance criteria for Category A, with footnotes only applicable to that category, clarified as directed by FERC in Order 693. Similarly, TPL-002 would only contain performance criteria for Category B, and so on.

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Commenter	**Yes**	**No**	**Comment**
			2. In addition to combining the standards, the SDT has significantly changed contingency specifications and required performance levels. In many cases the changes represent a very significant increase in required performance standards that will require unjustified major capital expenditures and/or reductions in ATC. This also could have an adverse impact on commercial transactions. In other cases, the performance criteria are not clearly defined, such as the timing between multiple contingencies, and the level of readiness of the system after Planning Events. The benefits from the additional performance requirements have not been identified in the proposed standard. Is there a planned phased in approachto move from the existing standard to the new proposed standards. If so, what is it? 3. Finally, the SDT has chosen to eliminate the footnotes in the current standards, contrary to the direction of FERC in Order 693 to "clarify" the footnotes. The purpose of the footnotes is to further explain terms in the tables, provide guidance in interpreting the expected performance criteria, and specify any exceptions to the criteria. Footnotes also serve the purpose of keeping the standard concise by eliminating repetitiveness. Specific comments on the Draft Standard Performance Criteria 4. The performance requirements table should clearly define what the initial state of the system is assumed to be before any Planning Events, and what the state of the system is assumed to be after the Planning Event. For example, P1 (single contingency) events: assuming that the system is to be compliant, the state of the system prior to the event must be "secure" such that the event could occur and there is no interruption of firm transfer or loss of load, Equipment Ratings are not exceeded, System steady state voltages and post-transient voltage deviation are within acceptable limits. However, the system is not as it was before the event. The system could be described as "normal" but perhaps not "secure". If the requirement is that the system must also be "secure" after the event, then the standard must clarify what is allowed for "system adjustments" after the first Planning event to prepare for the next. FERC Order 693 directed the ERO to modify the second sentence of footnote (b) to clarify that manual system adjustments other than shedding of firm load or curtailment of firm transfers are permitted to return the system to a normal operating state after the first contingency. However, in order to bring the system to a secure state, as is necessary for the second contingency of a category C3 or C5 event, footnote (c) allows curtailment of firm transfers, and FERC Order 693 only required footnote (c) to be clarify the term "controlled load interruption", leaving the curtailment language intact. The implication of this interpretation is critical to peninsular Florida. The Category B loss of one 500 kV line from Florida to Georgia is sustainable, such that the system is "normal" after the event. However, in order to be prepared for the next contingency, (the loss of the second 500 kV line), firm transfers must be curtailed. (Interruption of Firm Transfer) Without the ability to curtail firm transfers, a "super-firm" priority of service is created,

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Commenter	**Yes**	**No**	**Comment**
			which is unjustified. Comments on New Performance Tables: 5. The draft TPL standard represents a major change in the Table 1 contingency definitions and required performance levels. 6. Table 1 Contingencies C1 and C2 are being moved to the single contingency category. While C1 and C2 represent single element outages, their probability of occurrence is much lower than the other Category B contingencies and they do not belong in the single contingency performance requirements group. 7. Footnote (b) which permits, as a limited exception in unique circumstances with a sound rational basis, some localized load reduction for single contingencies, has been removed. This is a very significant change for some utilities. Footnote (c) which permits load shedding and curtailment of firm transfers has been removed from C1, C2 and most of C3. This is a very significant increase in required performance level that is not justified. 8. The "applicable rating" for loading and voltages in Table 1 has been removed so that essentially, the same ratings and voltage restrictions apply to both B and C contingencies. Some utilities plan to a normal rating for single contingencies but will allow a higher short term rating for Category C events. This practice will apparently be disallowed. 9. Several new Category D "Extreme Events" have been added which greatly expand the scope and complexity of Category D studies. These are (1) any two unrelated single element outages and (3) wide area events a. through h. These represent a major increase in the scope of Category D studies and probably a doubling of required SWG studies. The fault with protection element failure categories D1 through D4 have been substantially changed to eliminate analysis of relay failure contingencies. The philosophy contained in the existing TPL-004 standard is that faults with a protection failure should be evaluated whether that failure is a circuit breaker, relay or CT; the proposed standard restricts the analysis to breaker failure. 300 kV Threshold Performance Level 10. The TPL-001-1 draft sets a threshold of higher performance to facilities above 300 kV than previously established in the existing standard. We do not agree that such a threshold is necessary or warranted nor have they been justified. Requirements which are more stringent for these facilities may wrongly influence decisions on project alternatives in favor of facilities with less stringent requirements.

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			DC Line Performance Requirement 11. The TPL-001-1 draft sets a lower performance requirement for the loss of a single pole of a DC line than in the existing standard by allowing interruption of firm transfer if the transfer is deemed to be dependent on the outaged line. Firm transfers are also dependent upon AC lines. The proposed standard does not distinguish between asynchronous DC ties and the more common parallel connected DC tie. With an asynchronous DC tie, the transfer is lost with the tie. With a parallel DC tie, the transfer will be shifted to the parallel AC system and should have the same performance requirements. We do not agree that such an exception for DC lines is necessary or warranted. The decision in selecting DC vs. AC in transmission lines has traditionally been based on the break-even cost and performance of the two alternatives. The lower performance requirement may wrongly influence decisions on project alternatives in favor of DC facilities with less stringent requirements. Distinction Between Committed and Proposed Projects: 12. Models cannot discern the difference between a "committed" project, and a "proposed" project in a performance analysis. The standard should instead set criteria for when models can be relied upon for planning purposes such that changes to the future plan will not have an impact on reliability. The intent of Requirements R2.7.3 and R2.7.4 should be combined and added into R2.7.1.1. Rather than adding the additional requirement to document a criteria, the requirement should be that in the Near-Term Planning Horizon, projects cannot be removed (or modified) without demonstrating that the revised plan meets performance criteria. In addition, the requirement in R2.7.1.1 to supply a "project initiation date" is ambiguous. What will constitute "project initiation" …construction start date? …Engineering complete date? …Land procurement date? Funds allocated date (budgeted)? Suggested wording for R2.7.1.1. "Transmission and generation improvement projects for the Near-Term Transmission Planning Horizon, shall have in-service dates provided, and shall not have in-service dates changed, or be removed from planning models, without documentation to show that the revised plan meets performance requirements." In addition to the concerns mentioned above, how are delays in meeting project in-service dates, which are not in the direct control of the Transmission Owner, caused by siting and Right of Way difficulties (public outcry, exercising eminent domain, court process, etc) addressed? The standard needs to have provisions to recognize these types of issues allowing a Transmission Owner to be compliant as long as he is using due diligence to overcome these types of delays. Analysis of Relay Protection Failures: 13. This draft of the TPL standard ignores studies required for analysis of relay protection failures. There is a widespread misconception that studying breaker failure scenarios covers for relay protection failures. This is a false assumption. Typical delayed clearing for a stuck breaker is in the order of 8 to 20 cycles. This is accomplished by the local relay system sensing the stuck breaker and tripping the adjacent elements. However in the case of a protective relay failure the fault must

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Commenter	**Yes**	**No**	**Comment**
			usually be cleared remotely by tripping all lines connected to the station. Typical delays for a relay failure can easily be greater than 30 cycles. Where as breaker failure action just trips a couple of adjoining elements and leaves the rest of the station intact. A typical example of this difference is to assume a bus fault. For breaker failure, all bus breakers except the stuck one would trip. The breaker failure relay scheme then would time out and trip the adjoining breaker and the remote end of the adjoining line would trip. This could all happen in less than 20 cycles. Now consider a bus fault with the differential relay failed. The local relays don't sense the fault because they have failed, nor does the local breaker failure scheme activate because no local detection has occurred. The only way to clear this fault is to trip all lines from the remote terminals. This may take 30 cycles or more. With breaker failure, the bus and one line trips in about 20 cycles. With relay failure, all lines trip remotely isolating the substation in about 30 cycles. Both scenarios must be studied with relay failure being the worse case. Generally, different solutions are required to address relay failure verses breaker failure. Load Modeling Requirements: 14. The proposed TPL Standard contains numerous references to load modeling. The goal of improving and verifying the load model is worthwhile but is not appropriate for the TPL standards. Assessment of load model accuracy is best accomplished through detailed analysis of grid disturbance events. The main difficulties in accomplishing this are (1) grid events that significant reduce transmission voltages throughout a load area are infrequently occurring and (2) the process of Recreating the event through simulation studies is extremely complex and time consuming. While these efforts should be encouraged they should remain a RRO prerogative. 15. R1.1.1 Use of expected Load mix based on the actual or expected aggregate mix of industrial, commercial, and residential Loads. – This requirement is not justified as the load model may be developed through disturbance analysis rather than load type synthesis by customer class. Some LSE's may have great difficulties in creating load forecasts based on customer class. Load forecasting requirements are adequately addressed in the existing MOD standards and do not belong in the proposed TPL standard. 16. R1.2. Load models with supporting rationale that include power factor data that may be based on historical System performance, validated by measurement during stressed System conditions, or documented Transmission planning area requirements. This requirement is not appropriate fot the TPL standarsds. 17. R2.4.1. System peak Load for one of the five years. For peak System Load levels, the Load model shall include the dynamic effects of induction motor Loads.

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Commenter	**Yes**	**No**	**Comment**
			18. Specific types of load models should not be required in this standard. 19. Short Circuit Requirements: The new TPL standard also contains numerous references to short circuit analysis, which are new requirements that expand the TPL standards, but without specific testing or performance criteria. Evidence that short circuit studies have been performed is currently required in the existing FAC-002-0 Standard. Since the primary concern is the appropriate sizing of equipment and the prevention of equipment damage as opposed to overall grid reliability, we do not see the need for a set of requirements within the proposed TPL standard for short circuit studies. 20. Given the aforementioned issues, we believe the proposed TPL standard is inferior to the existing Board approved TPL Standards, creates unnecessary confusion, and will require many iterations of industry comment and revision. As an intermediate approach, we would strongly urge the Standard Drafting Team that the existing TPL standards be modified to respond to FERC Order 693 directives, clarify any ambiguities, and not pursue the proposed new standard any further. This would bring a much needed part of the Reliability Standards into the framework of mandatory enforcement and provide guidance on this longer term effort to improve the TPL standards.

Response: 1. The SDT must not only consider directives made in the FERC Orders, but it must also consider the direction given in the two associated SARs. Much of the wording and format in the current standards is repetitive. They all share the same performance table. Historically many have commented that because of the duplication in wording and format that the four should be merged together so that consistency would follow. It would also be easier to find and see the differences for each level of contingency. The SDT will continue to minimize repetitive language, simplify tables, minimize the number of notes, etc.
Commenters in general have supported the concept of merging the four standards together. In addition, Paragraph 1692 of order 693 "directs the ERO to consider integrating Reliability Standards TPL-001-0 through TPL-004-0 into a single Reliability Standard through the Reliability Standards development process". In addition, this order, in conjuction with 890, enurmerates attributes of planning standards that the FERC feels should be incorporated into the consolidated standard. SDT believes that the first draft of the standard is consistent with orders 693 and 890 without being unduly burdensome.
2. The SDT understands that there are extended transition issues associated with responsible entities becoming compliant with the new standard. The SDT plans to draft an implementation plan to accommodate such issues. The plan will be included in the third posting of the standard.
3. The requirement concerning Consequential Load Loss is to address FERC Order 693, which directs the ERO, among other things, to clarify footnote (b) in regard to Load loss following a single Contingency, specifying the amount and duration of Consequential Load Loss and System adjustments that are permitted after the first Contingency to return the System to a normal operating state. In regard to your comment regarding the general use of footnotes, the SDT agrees that notes can add clarity and we have included footnotes where useful in the newly formatted tables.
4. The SDT agrees with the comment that the initial conditions must be clarified in Table 1. Therefore, the SDT has made changes to add an initial condition column to Table 1. The SDT agrees that the System must remain secure after an event and therefore has clarified the standard by adding words to cover this requirement.
Further, the SDT agrees that the overlapping single Contingencies in C3 or the multiple circuit tower Contingency of C5 in the existing TPL

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Commenter	Yes	No	Comment
			standards are much lower probability but given that the performance requirements are only raised on these events for facilities above 300 kV, the SDT does not believe that the proposed changes are unreasonable especially since the changes are consistent with FERC Order No. 693. Please see the SDT responses to Question 22 for more details. 5. The SDT agrees with the comment and believes that this is consistent with FERC Order No. 693. 6. The SDT agrees that C1 and C2 in the existing TPL standards are much lower probability but given that the performance requirements are only raised on C1 and C2 events for facilities above 300 kV, the SDT does not believe that the proposed changes are unreasonable especially since the changes are consistent with FERC Order No. 693. Please see the SDT responses to Question 22 for more details. 7. The SDT has added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose Load. 8. The SDT has referenced Facility Ratings in general terms in Requirements R3.3.2.3 and R3.6.1 to provide flexibility with time based ratings. 9. The SDT has reviewed and revised Extreme Events in Tables 1 & 2. 10. The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission Systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT felt the 300 kV and higher Systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. When EHV Systems are compromised, the large volumes of power served by them can place a severe amount of stress on parallel EHV or lower voltage paths. For example, if a large EHV transformer experiences a catastrophic failure not only are other System Facilities required to carry more Load but the System is also exposed to other N-1 conditions for long periods of time while awaiting a replacement or repair of the failed equipment. Large generation sources are typically connected at EHV levels and maintenance of the EHV Transmission lines within the vicinity of larges generation plants must often be coordinated during scheduled unit outages, resulting again in multiple Facility outages over extended periods of time. Therefore, it was the conclusion of the SDT in Draft 1 to propose greater reliability and operational flexibility through more stringent performance requirements when considering certain N-1 and N-1-1 Contingency events of EHV Systems. Throughout the industry substation arrangements at EHV levels reflect the importance of these Systems as the designs often consist of the more expensive ring-bus, breaker-and –a-half or double bus-double breaker protection schemes as opposed to the more simplistic and lesser cost single bus arrangements that are commonly found on lower voltage systems. The feedback received from industry was divided related to the SDT's emphasis placed on a higher expectation for the 300 kV and higher Systems. Some commenter's questioned the importance and the high costs that may be needed to mitigate existing System designs. Others agreed with the SDT's approach and indicated that the impact to their Systems would be minimal. Some commenters even questioned why the more stringent approach was not applied to the entire 100 kV and higher Systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission System. 11. As a controllable element, a DC terminal can carry more load than it might otherwise based on an impedance split in an all AC System. With most DC providing asynchronous DC ties, the SDT has elected to allow interruption of service. 12. Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted Requirements R2.7.2

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Commenter	**Yes**	**No**	**Comment**
through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions". The SDT continues to believe that by providing the expected project intiation date of System improvements provides useful information to neighboring entities however the region defines "initiation". **R2.7.1**. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. 13. Protection system failures are being studied and will be covered in a future version. 14. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. 15. The SDT believes that models must reflect the expected Load mix of industrial, commercial and residential Loads to correctly reflect the behavior of the System. 16. The SDT has revised this requirement based on industry comments to clarify the intent that Load data be based on expected or historical System performance. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. 17 & 18. The SDT believes that the dynamic effects of induction motors must be considered. The standard does not specify the details of how to model induction motors. Therefore, the SDT believes the standard includes the necessary requirement without being overly prescriptive. 19. Your reference to FAC-002 only addresses the study of a specific request for Interconnection. The TPL draft addresses on-going System changes and increases in available fault current due to the additions of circuits and resources, as listed in the Corrective Action Plan. Short circuit studies help determine appropriate equipment sizing and setting of protective relays. Such studies will help provide for a complete Corrective Action Plan, i.e., the installation of a transformer to resolve a System performance deficiency may require the installation of additional circuit breakers. FERC also noted the need to include this analysis to cover such conditions. 20. The SDT believes that the present course of drafting the four standards as one standard with a revised table of "Contingencies" is the best solution to addressing all FERC directives, following the SARs, considering past comments and providing a single standard outlining the fundamental planning analysis.			
FRCC	☑		General Comment: 1. The SDT has significantly changed contingency specifications and required performance levels. In many cases the changes represent a very significant increase in required performance standards that will require unnecessary major capital expenditures and/or reductions in ATC which will have an

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Commenter	**Yes**	**No**	**Comment**
			adverse impact on commerce. Neither of these outcomes is desirable. Specific comments on the Draft Standard Performance Criteria 2. The performance requirements table should clearly define what the initial state of the system is assumed to be before any Planning Events, and what the state of the system is assumed to be after the Planning Event. For example, P1 (single contingency) events: assuming that the system is to be compliant, the state of the system prior to the event must be "secure" such that the event could occur and there is no interruption of firm transfer or loss of load, Equipment Ratings are not exceeded, System steady state voltages and post-transient voltage deviation are within acceptable limits. However, the system is not as it was before the event. The system could be described as "normal" but perhaps not "secure". If the requirement is that the system must also be "secure" after the event, then the standard must clarify what is allowed for "system adjustments" after the first Planning event to prepare for the next. FERC Order 693 directed the ERO to modify the second sentence of footnote (b) to clarify that manual system adjustments other than shedding of firm load or curtailment of firm transfers are permitted to return the system to a normal operating state after the first contingency. However, in order to bring the system to a secure state, as is necessary for the second contingency of a category C3 or C5 event, footnote (c) allows curtailment of firm transfers, and FERC Order 693 only required footnote (c) to be clarify the term "controlled load interruption", leaving the curtailment language intact. The implication of this interpretation is critical to peninsular Florida. The Category B loss of one 500 kV line from Florida to Georgia is sustainable, such that the system is "normal" after the event. However, in order to be prepared for the next contingency, (the loss of the second 500 kV line), firm transfers must be curtailed. (Interruption of Firm Transfer) Without the ability to curtail firm transfers, a "super-firm" priority of transmission service is created for non-native load customers. Comments on New Performance Tables: The draft TPL standard represents a major change in the Table 1 contingency definitions and required performance levels. 3. Table 1 Contingencies C1 and C2 are being moved to the single contingency category. While C1 and C2 represent single element outages, their probability of occurrence is much lower than the other Category B contingencies and they do not belong in the single contingency performance requirements group. 4. Footnote (b) which permits, as a limited exception in unique circumstances with a sound rational basis, some localized load reduction for single contingencies, has been removed. This is a

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Commenter	**Yes**	**No**	**Comment**
			very significant change for some utilities and this limited exception should be maintained. Footnote (b) was worked on extensive and achieved industry consensus at one time defining the maximum amount of load that could be shed at 100 MW. Footnote (c) which permits load shedding and curtailment of firm transfers has been removed from C1, C2 and most of C3. This is a very significant increase in required performance level that is not justified. 5. It is not clear what is meant by the phrase "Equipment Ratings" found in the performance requirements of Table 1. Utilities have different equipment ratings such as normal, long term, short term and emergency ratings. It is not clear that these type of ratings will be permitted in the proposed standard. 6. Several new Category D "extreme events" have been added which greatly expand the scope and complexity of Category D studies. These are (1) any two unrelated single element outages and (3) wide area events a. through h. These represent a major increase in the scope of Category D studies and probably a doubling of required stability studies. Analysis of Relay Protection Failures: 7. The fault with protection element failures have been substantially changed to eliminate analysis of relay failure contingencies. The philosophy contained in the existing standards is that faults with a protection failure should be evaluated whether that failure is a circuit breaker, relay or CT; the proposed standard does not require the analysis of any protection failure. This draft of the TPL standard ignores studies required for analysis of relay protection failures. There is a widespread misconception that studying breaker failure scenarios covers for relay protection failures. This is a false assumption. Typical delayed clearing for a stuck breaker is in the order of 8 to 20 cycles. This is accomplished by the local relay system sensing the stuck breaker and tripping the adjacent elements. However in the case of a protective relay failure the fault must usually be cleared remotely by tripping all lines connected to the station. Typical delays for a relay failure can easily be greater than 30 cycles. Where as breaker failure action just trips a couple of adjoining elements and leaves the rest of the station intact. A typical example of this difference is to assume a bus fault. For breaker failure, all bus breakers except the stuck one would trip. The breaker failure relay scheme then would time out and trip the adjoining breaker and the remote end of the adjoining line would trip. This could all happen in less than 20 cycles. Now consider a bus fault with the differential relay failed. The local relays don't sense the fault because they have failed, nor does the local breaker failure scheme activate because no local detection has occurred. The only way to clear this fault is to trip all lines from the remote terminals. This may take 30 cycles or more. With breaker failure, the bus and one line trips in about 20 cycles. With relay failure, all lines trip remotely isolating the substation in about 30 cycles. Both scenarios must be studied with relay failure being the worse case. Generally, different solutions are required to

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Commenter	**Yes**	**No**	**Comment**
			address relay failure verses breaker failure. 300 kV Threshold Performance Level 8. The TPL-001-1 draft sets a threshold of higher performance to facilities above 300 kV than previously established in the existing standard. We do not agree that such a threshold is necessary or warranted. Requirements which are more stringent for these facilities may wrongly influence decisions on project alternatives in favor of facilities with less stringent requirements. Load Modeling Requirements: 9. The proposed TPL Standard contains numerous references to load modeling. These modeling requirements should be addressed in the MOD Standards. The goal of improving and verifying the load model is worthwhile but is not appropriate for the TPL standards. Assessment of load model accuracy is best accomplished through detailed analysis of grid disturbance events. The main difficulties in accomplishing this are (1) grid events that significant reduce transmission voltages throughout a load area are infrequently occurring and (2) the process of Recreating the event through simulation studies is extremely complex and time consuming. While these efforts should be encouraged they should remain a RRO prerogative. * R1.1.1 Use of expected Load mix based on the actual or expected aggregate mix of industrial, commercial, and residential Loads. – This requirement is not justified as the load model may be developed through disturbance analysis rather than load type synthesis by customer class. Some LSE's may have great difficulties in creating load forecasts based on customer class. Load forecasting requirements are adequately addressed in the existing MOD standards and do not belong in the proposed TPL standard. * R1.2. Load models with supporting rationale that include power factor data that may be based on historical System performance, validated by measurement during stressed System conditions, or documented Transmission planning area requirements. This requirement is not appropriate for the TPL standards. 10. * R2.4.1. System peak Load for one of the five years. For peak System Load levels, the Load model shall include the dynamic effects of induction motor Loads. Prescribing specific types of load models in this standard is not appropriate because system topology and load make up may be unique from area to area. 11. Short Circuit Requirements: The new TPL standard also contains numerous references to short circuit analysis, which are new requirements that expand the TPL standards, but without specific testing or performance criteria. These performance criteria are better suited in the FAC

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Commenter	**Yes**	**No**	**Comment**
			Standards since evidence that short circuit studies have been performed is currently required in the existing FAC-002-0 Standard. Since the primary concern is the appropriate sizing of equipment and the prevention of equipment damage as opposed to overall grid reliability, we do not see the need for a set of requirements within the proposed TPL standard for short circuit studies. 12. Table 2 Angular Stability Notes: The requirement of generation loss not exceeding BA spinning reserve requirement (1.a.ii.) is an unjustified increase in required performance level from the existing TPL Standard which require the grid response to be stable and within applicable ratings. The portion of the notes requiring generator out-of-step protection are inappropriate and unwarranted. First, the simulation result may show the generator being tripped by backup distance or loss of field protection which may be acceptable to the generator owner. Second, the requirement for impedance swings not causing other transmission elements to trip is inappropriate and in conflict with manufacturer recommendations and prevailing practice for generator out of step protection. Most generator out of step relays are set to trip on the "way out" so as to limit phase angle difference across the opening contacts. With this practice, one can not prevent transmission line tripping due to zone 1 pickup without installing out of step blocking should the swing impedance passes through zone 1 relay. Out of step blocking of zone 1 relays is a bad idea as it opens the door to prolonged asynchronous connection of generators. 13. Circuit Breaker Contingencies: The proposed TPL standard separates circuit breaker related contingencies based on the intended use of the circuit breaker. If the circuit breaker is used to connect busses together (i.e. bus tie breaker) a lower level of performance is required than for other uses and configurations. The existing TPL standards have the contingency events and required level of performance appropriately ordered based on the probability of occurrence. We are not aware of different failure rates for bus ties breakers as opposed to the general circuit breaker population. The proposed standard requires an unjustified higher level of performance for non bus tie breakers and would encourage the use of low cost switching station arrangements such as single breaker/single bus which are less reliable. 14. Need to clarify the performance requirements that apply to sensitivity studies. These requirements should not be the same. 15. A.3. - Suggest replacing the word "probable" with "credible" for consistency with the white paper from the Operating Limit Definitions Task Force. 16. R2.1 - It is not clear how the requirement to address all 5 years can be accomplished when the annual studies do not require all 5 years to be studied. Is the planner expected to study the

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Commenter	**Yes**	**No**	**Comment**
			other years also, but that the required set of cases does not link to each of the 5 years? 17. R2.2.1 - This requirement creates compliance concerns. Therefore, it is suggested that the SDT clarify that the Long Term Assessment is not required beyond 10 years. 18. R2.7.3 - The term "proposed" may not be a good choice here ... especially since that's not a term used in other reliability assessments .... should another term be chosen or perhaps this definition could be matched up with work being done now on classification of resources for RAS. Steady State Performance Table: 19. P1 - If the transmission line outaged is the facility defined by contract as being the only contract path for the firm transfer, then the firm transfer will be interrupted. P1 should be clarified that this is acceptable. 20. P3 - Are these elements meant to be combined into a multiple contingency or considered separately (since they are listed with commas)? Or is this meant to be one of the 3 elements listed first AND the stuck breaker? Not clear the way this is worded. Or maybe the structure needs to be different in the sentence (like bullets for the first 3 that would make the "and" stick out more). 21. NERC Standards TPL 001-0 through TPL 004-0 are approved standards that only required modifications pursuant to FERC Order 693. In this proposed draft standard TPL 001-1 the Standard Drafting Team (SDT) has far exceeded the recommendations suggested by FERC in that Order. The proposed draft standard is a large change in the magnitude of the performance requirements from the exiting TPL Standards. The SDT needs to consider how this proposed standard will be implemented in this new mandatory compliance environment and ensure that reasonable compliance measures can be developed from the proposed standard.

Response: 1. The SDT recognizes that it has it has raised the bar on performance in some areas. The SDT realizes that this will have an impact and is working on an Implementation Plan that will address some of the concerns. This is a performance based reliability standard and does not and should not consider economics. FERC Order 693 clearly states the FERC position on Non-Consequential Load loss. The SDT has made numerous changes to the tables in an attempt to provide further clarity as to what needs to be done to achieve performance.
2. An Initial Conditions column has been added to the tables.
3. The SDT studied available data and practices and determined that these Contingencies do belong in the single Contingency performance group.
4. Local Load pockets are recognized as a problem and the SDT will address them in a future revision.
5. Equipment Ratings is a defined term in the NERC Glossary.
6. The SDT was responding to FERC Order 693 in the details for Extreme Events.

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Commenter	**Yes**	**No**	**Comment**
7. The SDT is still working on the Protection System elements of the standard and will provide more detail in a future revision. 8. The SDT feels that 300 kV and above represents the backbone of the BES and as such warrants more stringent criteria. 9. The SDT feels that the current MOD standards do not cover all of the modeling requirements for a planner. Therefore, the specific areas found lacking are described in the TPL standard. Once the MOD standards are revised appropriately, these requirements can be deleted from TPL. The SDT has re-written these requirements and they are now numbered Requirement R9 through R13. 10. The SDT feels that the Load model used in the study should represent actual conditions as accurately as possible. It has been shown during the reconstruction of the events of the August 14, 2003 blackout in the Northeast that the Load model was critical. One of the recommendations involved developing better Load models. 11. Short circuit studies are required as part of the Interconnection process. The TPL draft addresses on-going System changes and increases in available fault current due to the additions of circuits and resources, as listed in the Corrective Action Plan. Short circuit studies help determine appropriate equipment sizing and setting of protective relays. Such studies will help provide for a complete Corrective Action Plan, i.e., the installation of a transformer to resolve a System performance deficiency may require the installation of additional circuit breakers. FERC also noted the need to include this analysis to cover such conditions. 12. The note on spinning reserve has been corrected. The existing standard does not define what it means for the grid response to be stable. The SDT has attempted to do that with the footnote you referenced. The SDT believes that an excessive amount of generation pulling out of synchronism and tripping is not a stable grid response. Therefore, we have limited the amount which can trip to the amount of the Contingency reserve of the Balancing Authority. If a generator pulls out of synchronism, the SDT believes there should be some means to trip the generator from the grid. Otherwise, the generator could be damaged and the quality of power on the grid suffers. The footnote has been modified to require that the generator must have "out-of-step protection or some other means to trip the generator". The requirement for impedance swings to not cause the tripping of other Transmission elements is most appropriate. A stable response of the grid would not include losing additional Transmission elements. Out of step blocking on lines is not allowed as a solution. The requirement is for the impedance swing not to pass through relay characteristics which would result in tripping Transmission elements. This requires the system to be improved so that the impedance swings do not go out on the Transmission System. 13. Based on the available outage data, the SDT has decided that bus tie breakers are less likely to be exposed to stuck breaker opportunities 14. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirements R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirements R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own System. The sensitivity studies do not in themselves establish the need for a plan, only the areas of the System the analysis is needed. **R2.1.3.** For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.1.4**. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.			

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Commenter	**Yes**	**No**	**Comment**
R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. 15. The SDT feels that 'probable' is a better choice of words here and the majority of commenters have supported the SDT decision on how the purpose is stated 16. The SDT believes that a planner will be able to aggregate current and past studies in a portfolio or archive that will fulfill the requirement. 17. The SDT believes that the requirement as written is clear that studies longer than 10 years are only required if the known lead time of critical projects is longer than 10 years. The standard as written does not mandate a study longer than 10 years out but recognizes that a 15 year out study conducted to adress anticipated long lead time projects can be used to fufill the requirement of "Long-Term Planning Horizon". Paragraph 1692 of order 693 "directs the ERO to consider integrating Reliability Standards TPL-001-0 through TPL-004-0 into a single Reliability Standard through the Reliability Standards development process". In addition this order, in conjuction with 890, enumerates attributes of planning standards that the FERC feels should be incorporated into the consolidated standard. SDT believes that the first draft of the standard is consistent with orders 693 and 890 without being unduly burdensome. The SDT is cognizant that reasonal compliance measures and an achievable implemetation plan need to be developed as part of the standard development process. 18. The indicated language has been deleted from the second revision. 19. P1 - If service to Load by contract can be interrupted for defined conditions, then the SDT does not view this as firm. 20. The SDT has re-formatted the tables to clear up any confusion on this item. 21. The SDT followed the suggestion of FERC in Order 693 to consolidate the 4 standards into 1 if possible.			
Georgia Transm.	☑		R1.4: The planning assessment is to identify the needs of the BES. A spare equipment strategy should support the needs of the BES, not vice versa. Long-term outages need to be defined. R2.2.1 Not clear on the purpose of this requirement. Is the concern that the Planner perform a ten year analysis even when the in - service years are outside of the current ten-year planning horizon? The extension period should be defined. R3.2 Current models do not have the capability of performing the assessments necessary to meet this requirement.
Response: 1. The SDT has revised this requirement based on industry comments to clarify intent and to be responsive to FERC Order 693, paragraph 1725. 2. The SDT believes that the requirement as written is clear that studies longer than 10 years are only required if the known lead time of critical projects is longer than 10 years. The standard as written does not mandate a study longer than 10 years out but recognizes that a 15 year out study conducted to adress anticipated long lead time projects can be used to fufill the requirement of "Long-Term Planning Horizon".			

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Commenter	**Yes**	**No**	**Comment**
3. The SDT feels strongly that the assessment should be based on study of the System as it is expected to perform. The requirement that "Contingency analyses shall simulate the removal of all elements including those that System protection is expected to disconnect for each Contingency without operator intervention" is consistent with that philosophy. A Contingency modeling methodology that reflects how real Systems would operate will need to be constructed if it doesn't already exist.			
IESO	☑		(1) Pertaining to Q1 to Q11: we do not see the need to define this many terms for this standard. Many of the terms are easily understood and have been used in transmission planning for years that the majority of planners in the industry know what they mean. For example: base case, extreme contingencies (these are in fact listed in the table), planning assessment, planning event, etc. Furthermore, the terms plant stability and system stability are also well understood to mean "machine synchronism" and "system oscillation/damping". Among the proposed definitions, only the following terms need to be defined to add clarity: a. Consequential (and non-consequential) loss of load b. Long-term vs near-term (suggest to change it to short-term) planning horizons (2) We do not see the need to use the term RAS (Remedial Action Scheme). The term SPS (Special Protection System) is common used in the industry to generally mean any protection scheme that is designed to initiate actions to control flows, voltage, generation runback or high speed rejection, switching of shunt devices, cross-tripping in response to some pre-determined parameters such as loss of a circuit or some threshold voltage or line flow level. Introducing the term RAS would be confusing to suggest that they do not equate to or are not a part of the SPS. (3) We interpret the requirement stipulated in R1.1.1 is intended to enable more accurate simulations of load response - both in steady state and dynamic analyses. However, we do not support having this level of granularity (eg: industrial, commercial, residential etc.) stipulated in a planning assessment standard as similar requirements already exist in several MOD standards that deal with forecasted load and modeling. We suggest the mix of load detailed requirements be addressed in the latter set of standards. Similarly, R1.2 is best addressed in the MOD standards. Specific to R1.2, we do not agree with the requirement to provide supporting rationale that include power factor data based on historical System performance, validated by measurement during stressed System conditions, or documented Transmission planning area requirements. Load forecast data already provides projected mix of real and reactive demands and type of load. (4) R1.4 and R2.1.3 require outages be considered in the planning process. We suggest the SDT clearly stipulate that only known planned long term outages (with a minimum duration to be defined) need to be considered. This suggests is made on the basis that:

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Commenter	**Yes**	**No**	**Comment**
			- Only known outages should be modeled. The need to model unknown outages would render study scope to be too wide to manage - Only planned outages should be modeled for the same reason. - Only known planned outages > a certain period should be modeled since it would be unrealistic and unmanageable to model and propose planning solutions to system constraints that appear to last less than, say, 2 weeks. As a general practice, many planners apply a 4 week period as the minimum for inclusion in planning assessment. Without narrowing the scope, planning assessment will be an enormous task and difficult to manage.
Response: 1. The SDT deleted the Base Case definition in response to various comments. However, few if any other commenters suggested deleting the other terms proposed in this comment and several suggestions were received from various commenters to include additional definitions. Furthermore, various comments indicated lack of a consensus understanding of the Stability terms, prompting the SDT to retain and clarify the initially proposed definitions. 2. RAS and SPS are interchangeable terms as per the NERC Glossary. 3. The SDT believes that models must reflect the expected Load mix of industrial, commercial and residential Loads to correctly reflect the behavior of the System. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. 4. The SDT intent was for the planner to model known planned outages. Sensitivities may be needed to confirm how much affect the duration of the known outage may have on the assessment. Requirement R1.4 which applies to the whole standard calls for "Known planned outages…"			
ISO/RTO	☑		
Response: Thank you.			
ITC	☑		1. A modeling issue that we would like to see standardized is the modeling of generation resources when the load exceeds or is very near the installed reserve level (low generation reserve margin). This would occur in future years when new resources are unknown or not announced yet. It is a concern of ours because we are an independent transmission company and are not always apprised of new resources. We also have a concern with some models which "assume" where new generation would be located or fake generation has been added to meet the load requirements. This can produce distorted transmission assessments because the generation location assumption is not firm. We would prefer to see generation scaling, or an assumption that the power will be imported or a combination of scaling and imports. Assuming 100% generator availability is also not a good assumption just to balance load and generation. Other modeling issues:

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Commenter	**Yes**	**No**	**Comment**
			2. Should not rely on a single generator being dispatched (redispatched) to solve a problem. 2. Using a single generator for redispatch should not be an acceptable corrective action (i.e. rely on a generator that might not be there or may take an extended period to start up). 3. Sensitivities for both the planning horizons should consider load forecast error and variability. You shouldn't just stick with one assumption, such as a 50/50 probability of occurrence. The system needs to be able to operate to loads exceeding 50/50 probability of occurance. 4. We would also like to see additional requirements be put on "corrective action" solutions to reliability violations resulting from planning assessments. Any corrective action should be restudied to insure that it does not cause other reliability problems for system conditions other than those for which the corrective action is intended to resolve. For example, if redispatch under a transmission outage condition is acceptable, it should not cause any additional reliability violations for the next contingency.
Response: 1. NERC Standards are to specify the requirements, which must be met and not "how" they are met. Whether a single generator can be used in a Corrective Action Plan would depend on whether the resultant Transmission System can meet the other requirements of NERC Reliability Standards. Therefore, when a single generator is used in a Corrective Action Plan, the System must also demonstrate that it can meet System performance requirements for loss of that generator. 2. NERC Standards are to specify the requirements, which must be met and not "how" they are met. Whether a single generator can be used in a Corrective Action Plan would depend on whether the resultant Transmission System can meet the other requirements of NERC Reliability Standards. Therefore, when a single generator is used in a Corrective Action Plan, the System must also demonstrate that it can meet System performance requirements for loss of that generator. If the generator is not yet on line, then additional sensitivity studies should be performed to cover the assumption that it may not be available. 3. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Due to the nature of future analysis, the SDT did not draft specific language to mandate Load growth be a sensitivity analysis for future assessments. Industry feedback is that future assessments already include a variation in projected Load growth. The standard does not preclude any entity from performing studies for any planning horizon that envolve a wide range of sensitivities. The specific requirement to perform re-test has been removed. 4. The SDT believes that as part of obtaining the appropriate corrective action, the solution is tested as part of the study to make sure it meets the performance requirements.			
JEA	☑		In reference to the use of Non-consequential load shedding under single contingency events: I do agree that long term plans should be implemented with the goal to eliminate non-consequential load shedding as a response to this failure mode. However, it may be more beneficial for investing in system improvements to reach this state of robustness where there may be a few years (or seasons) of potential exposure for utilizing non-consequential load shedding. This should be prudent utility practice as long as post-contingency response is executed within the time frame allowed by the

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Commenter	**Yes**	**No**	**Comment**
			facility emergency ratings and load shedding is limited to Transmission Provider's contracted or tarrif loads. For example, adding or upgrading transmission facilities into a load area where future generation additions are planned to be in-service within the short term horizon (mitigating thermal or voltage violations assessed under P1 and P4-1 through P4-4) would not be the best investment for the overall economic benefit of the bulk electric system.
Response: Draft 2 Changes for 300 kV and higher systems regarding N-1-1 conditions: Based on industry feedback the SDT has made changes in proposed Draft 2 requirements related to independent overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. Draft 2 now permits the loss of Non-Consequential Load to meet the Transmission performance requirements for these types of events. Please refer to performance tables Planning Event P6. It is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission for the less probable, but greater risk single Contingency events. Please refer to performance tables Planning Event P2 and note that bus section faults and internal breaker faults (non-Bus Tie) associated with above 300 kV Facilities are held to a higher performance standard than those operated at 300 kV or below.			
KCPL	☑		It is redundant to require provision of modeling data in this Standard. This is covered in Standards MOD 10, 12, 16-25.
Response: The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.			
LUS	☑		The Planning Authority/Transmission Planner should use valid acceptable assessments to plan their systems to operate and supply customer demand and Firm Transmission Service. If the Planning Authority/Transmission Planner determines other methods (such as operational guides) to resolve system overloads for "N-1 Contingency", the operational guides should be limited to only native network facilities that are in direct control and ownership of the Planning Authority/Transmission Planner. Operational guides should be considered only as short term solution to resolve the overloads and shall be used in all studies and approval for transmission service requests. If the operational guide do not completely resolve the overload or restricts access to transmission service, then the Planning Authority/Transmission Planner shall determine facilities to be constructed to resolve the overloaded or restricted facility.
Response: NERC Standards are to specify the requirements, which must be met and not "how" they are met. The draft standard does not preclude the use of operating solutions.			
LADWP	☑		This proposed standard is very tutorial in nature and far too prescriptive for a standard. A standard should be about what are the criteria and measurables, not about how to meet the criteria. This propsoed standard should also recognized that it is just a part of many standards being formulated by NERC, know its boundary as transmission planning standard, and not try to be an all

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Commenter	**Yes**	**No**	**Comment**
			encompassing standard for every facit of the power system. Do what we do best as transmission planner and not try to take over others like marketer, operator, generators, etc.
Response: The goal of the SDT is to provide more information but not be too prescriptive.			
LCRA	☑		1. The NERC PC and OC are currently working on a definiton that defines "adequate levels of reliability". The SDT should take this definition into consideration and ensure it is applied in the proposed NERC Std. revision. Along the same lines, if this has not been done yet, the SDT needs to consider the NERC "Reliability Criteria and Operating Limits Concepts" white paper and incorporate applicable elemetns of that white paper to the propsoed NERC Std. revision accordingly. It would not make sense for these (the propsoed NERC std. and the noted white paper to be inconsistent or at opposite ends in terms of what is expected of a reliability-based planned transmission system). other editorial comments: 2. R1. Delete one of the "each" 3. R1. Should state that data submittals should be "in accordance with regional procedures or process". This will eliminate the region getting data in all sorts of formats. 4. Table 1 - the allowance of loosing "consequential load" should be evaluated based on options to provide temporary emergency back-up support as well as size of load, for example. Structure failures can take an extended period of time to restore and can have significant impacts on a raial load that does not have remote or distribution back-up support. This performance requirment of transmisssion radial-supplied loads should be left to regions or to transmission owners/planners for their own areas based on specific area needs (type and size of load, back-up availbailiyt, etc.). 5. Table 1 - How does NERC define a "transmission circuit"? Does it include a sinlge transmission line as well as a double circuit transmission line? 6. Other than the probability of occurrence, what is the difference between a structure failure of a single circuit and a structure failure on a double circuit configuration? Why is a double circuit not considered a single contingency?
Response: 1. The SDT has reviewed the definition of adequate level of reliability and has included it in its deliberations. The SDT has reviewed the "Reliability Concepts" white paper and find that the document is largely consistent with the current standard as written by the SDT. One notable difference is that the white paper seems to indicate that the Transmission System is designed and operated so that cusomers should only be interrupted that are directly connected to the outaged element for events including Transmission line or transformer faults, breaker or switch failures, or generator trips. (See page 11 of the white paper.) If the SDT were to use this approach then SDT should not allow Non-Consequential Load Loss for P6.1 and P6.3, even though these breakers are below 300 kV.			

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Commenter	**Yes**	**No**	**Comment**
As indicated in the responses to other comments, the SDT has taken the position that the probability of the outage of one breaker is much lower than the probability of a single Transmission line outage. Therefore, the SDT has drafted the standard to permit loss of Non-Consequential firm Load or interruption of firm Transmission service for the loss of a lower voltage breaker. (The SDT does not permit the loss of Non-Consequential firm Load or interruption of firm Transmisssion service for the loss of a breaker above 300 kV.) The majority of the commenters in response to the first posting of the standard agreed with the SDT's approach in this regard. 2. Editorial change was made. 3. The SDT has revised this requirement based on industry comments to specify only that modeling data must be exchanged and allows entities to develop their own formats. It is beyond the scope of the standard to specify the process for data exchange. 4. The standard allows for loss of Consequential Load and does not address restoration requirements. 5. and 6. The Tables treat circuits differently if they share a common tower and they define the maximum length that a double circuit can still be treated as independent circuits as one mile.			
Manitoba Hydro	☑		1. MH would prefer that many of the categories in the existing Table 1 be retained. The SDT has resort the contingency buckets with no explanation as to how this was done. can the SDT provide statistical outage date to justify the changes. MH is not convinced the SDT has addressed the few confusioning issues in Table 1. 2. R1: MH does not believe R1 is required in this standard. The modelling standards should cover the requirement of the data owners to provide data to the PC. Further this data needs to be provided to the TP as well. 3. R1.4: requires planned outage data to be provided to planners. I do not believe this is a requirement for planning. It is not economic to add facilities to accommodate future planned outages. Secondly, the Table 1 multiple contingencies already mandate that planners consider the impacts of an outage with system adjustment followed by testing for the next contingency. 4. R1.5: requires the PC to define "planned facilities" which should be included in the model. This will lead to inconsistency in what is modelled, as experience has shown that there will be a wide range of assumptions in the definition. This standard should offer a definition for stakeholder debate. The SDT should clarify what is intended by including Protection System Equipment and control devices. 5. R2.1: It is not necessary to assess all five years of the near term planning horizon – year one, three and five will be more than sufficient. What is the reliability benefit driving the SDT to mandate each of the first five years be assessed? 6. R2.1.2 and R2.4.2 -- It is important to assess off peak loads with high simultaneous transfers as this is the period where extensive economic interchange occurs, and transient stability issues arise as less uneconomic peak units are off, leaving the load to be supplied by remote generation with reduced local reactive supply, voltage and damping control.

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Commenter	**Yes**	**No**	**Comment**
			7. R2.2: The long term assessment should also include an off peak case with simultaneous transfers to provide some indication if the system performance is expected to degrade. 8. R2.3: The short circuit study is a design issue that would more appropriately covered by a FAC standard. MH recommends it be removed from the Planning standard. 9. R2.6.1: Why would a past study be invalidated if there is a change in market structure? It would seem that the operation of any market would have to respect reliability criteria. 10. R.3.3.2.2: Curtailment of firm transfers is allowed as a system adjustment in the existing standard. This ability must be retained in the new standard. Curtailment of a firm transaction is not equivalent to curtailment of load, but is more comparable to runback/tripping of generators. Both are events that can be backed up by contingency reserves and do not result in consequential load loss. Disallowing firm transfer curtailment will result in numerous violations of the performance requirements and result in a requirement to build millions of dollars of transmission. MH can not accept a standard which mandates that firm transfers can not be curtialed following a contingency. 11. R3.3.3: If rationale for the contingencies selected for evaluation is available then this rationale will state why the selected contingencies are expected to be the most severe. The requirement does not need to state "and shall include an explanation of why the remaining Contingencies would produce less severe System resuts".This is redundant. 12. R3.4 and R4.5.2: Evaluating a change designed to mitigate the consequences of an exteme event can require significant work. Since there is no requirement to implement corrective plans for Extreme Events, what is the purpose of this evaluation? 13. R3.5: Generator tripping should be added in addition to runback. Generator tripping is used extensively in regions where remote generation is delivered via long transmission. 14. R6: Requires distribution of results and “coordinating analysis of these results through an open and transparent process”. Can the SDT clarify what the intent is? As written, it implies the PC/TP just shares assessment results with neighbours. There should be a requirement to conduct joint assessments on inter-regional transfer capability. The assessments should also be provided to the Regional Entities/NERC. Table 1 -Steady State Performance

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Commenter	**Yes**	**No**	**Comment**
			15. MH requests the SDT to provide rationale for how the planning events where resorted from the existing Table 1 Categories to the proposed Planned events. 16. Performance Requirements: As this is a steady state table, how does one assess if voltage instability, cascading outages or islanding occurs? "Simulate Normal Clearing unless otherwise specified." should be deleted from this Steady State Performance table. 17. This table should have an Initial Condition column as well as an Event column, as in Table 2. The wording of event descriptions in Table 1 should follow the wording of similar event descriptions in Table 2. 18. Event: What is a non-bus tie breaker? Is this any breaker that is not a bus tie breaker? 19. Interruption of Firm Transfer Allowed: Interruption of firm transfer should be allowed following a single contingency – this is a change from the existing standard where system adjustment after a Cat B event could include reduction of firm transfer. Similar to generation tripping/runback, the loss of a firm transaction does not result in Consequential load loss as it is backed up by contingency reserve. 20. P6-2: What is the justification for classifing a bipolar DC line loss as a single contingency? The existing standard classifies this event as a Cat C multiple contingency event. 21. P6-3: Why is a breaker internal fault classified as a single contingency? One would assume such a fault would be cleared by backup protection resulting in the loss of multiple elements. 22. P9-1: Is there any justification for the selection of one mile? Would the fact that there is line shielding be justification for increasing this length? A more reasonable selection could be 5% of the length of the longer of the two circuits. 23. P9-2: A monopolar DC line loss may be covered in P4-2 (and no non-consequential load loss is allowed). Does loss of a monopolar DC line refer to loss of a single pole of a bipolar line or a bipolar dc line? Can the PC/TP choose between the loss of a monopolar DC line and the loss of a bipolar DC line? 24. P9-3, P9-4 and P9-5: When the DC line loss is bipolar, the event should be moved to the extreme event category. Does loss of a monopolar DC line refer to loss of a single pole of a bipolar line or a bipolar dc line? Can the PC/TP choose between the loss of a monopolar DC line and the loss of a bipolar DC line?

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Commenter	**Yes**	**No**	**Comment**
			25. Exteme Events Evaluation Requirements 3: This should be removed as this is the Steady State Performance table. 26. Extreme Event Descriptions: How did the SDT determine what events should be classified as Extreme Events? Was statistical data analyzed? 27. Extreme Event 1: In the existing TPL standards, the simultaneous loss of two elements was considered a Cat C multiple element event. What is the SDT rational for the change? 28. Extreme Event 2c: Why is the loss of a single large load an Extreme Event? 29. Extreme Event 3f: This is a repeat of Extreme Event 3d. 30. Extreme Event 3g: What is the rationale for distinguishing between old vs. new design for the loss of multiple lines due to icing? Is the SDT implying that new lines must be desined to prevent multiple line loss due to icing? Table 2 - Stability Performance Table 31. Performance Requirements: The MRO adds 1/2 to 1 cycle to the Normal Clearing time during simluations as an additional safety margin. The SDT should consider enforcing this practice. 32. Event: What is a non-bus tie breaker? Is this any breaker that is not a bus tie breaker? 33. P1: There should be a P1-4 event for a shunt device (ie. "4. A shunt device (including FACTS devices)"). 34. P6-2: What is the justification for classifing a bipolar DC line loss as a single contingency? The existing standard classifies this event as a Cat C multiple contingency event. 35. P6-3: Why is a breaker internal fault classified as a single contingency? One would assume such a fault would be cleared by backup protection resulting in the loss of multiple elements. 36. P9-1: Is there any justification for the selection of one mile? Would the fact that there is line shielding be justification for increasing this length? A more reasonable selection could be 5% of the length of the longer of the two circuits. 37. P9-3: This contingency should be classified as an Extreme Event since statistically, the outage

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Commenter	**Yes**	**No**	**Comment**
			duration of a dc circuit (assume you mean a bipole) is less than 2 hours for MH bipoles, so the probability of a second outage is very low. . 38. P9-6: Isn't this the same as P1-3? If the outaged tranformer is replaced by a spare transformer, this restores the system to a normal state prior to the event ("Apply a P1.3 Contingency."). What is the point? 39. Note 1.a.i.: Planning Event P3.2 does not exist. 40. Note 1.a.ii: This definition of angular stability should be deleted and the definition in Note 1.a.i. should apply to all Planning Events. The system should not be considered to be angular stable when generators are pulling out of synchronism. 41. Note 1.a.iii.: This standard should define a minimum damping factor and allow the PC/TP to have a more restrictive damping requirement if they choose to.

Response: 1. The SDT looked at available historical, statistical data and used that data for guidance in re-ordering the table.
2. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.
3. Planned outages that are long-term need to be provided to the planners in order for them to appropriately represent the topology of the system. This does not imply that one must build in order to accommodate a planned outage and to be responsive to FERC Order 693, paragraph 1725.
4. The referenced verbiage has been deleted from the revised standard.
5. Assessement does not mean that studies have to be run for each of the years, only for Year One or two and five for peak load and for any one of the 5 years for off-peak load. If no changes occurred between the years the assessment will be very simple. However, if the required Corrective Action Plan is delayed, or there is a long planned or forced outage to a major generation or Transmision Facility, or it is believed that some of the sensitivities may have to be addressed, etc., there may be a need to assess each of the years.
6. Agree if that is the case for your System. Each entity is responsible for demonstrating the appropriateness of the assumptions used in the current studies. To some entities this case may be their base case and others it may be a sensitivity case.
7. Requirement R2.2 requires as a minimum a peak load study for one of the 5 years in the Long-term horizon. This does not preclude any entity from running more studies, including for off-peak load conditions.
8. Actions listed in the Corrective Action Plan will more often than not result in higher fault, requiring the installation of even more additional equipment to accommodate the higher fault duty. This requirements ensures that the "entire" effect of the corrective action is captured in the plan. In addition by considering the "entire" effect of a proposed corrective action the entity may find it more economically to propose another action. Therefore, the SDT feels that this should be part of the Planning Assesment.
9. R2.6.1 - The SDT has revised R2.6.1 to delete the reference to market structure.

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Commenter	**Yes**	**No**	**Comment**
R2.6.1. For steady state, short circuit, or System Stability analysis: ~~if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market structure changes~~ the study shall be five calendar years old or less. 10. Curtailment of firm transfers is allowed for some specific Contingencies in compliance with FERC Order 693. 11. R3.3.3 - The SDT recognizes some may consider these words redundant. However, it should be noted that many commenters have asked for the SDT to add words to make other requirements perfectly clear. Since these words do not hurt the requirement and may help some to better understand the requirement, the SDT has not deleted these words. 12. As noted in Requirements R3.4 and R5.7.6, there is an expectation that facilities are designed to reduce or mitigate the likelihood of Extreme Event situations that expose the System to cascading events. 13. This has been added. **R3.5** Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met: 14. R6 - By meeting this requirement for "coordinating analysis of these results through an open and transparent process", the SDT meant a stakeholder process that was set up to meet the requirements of FERC Order No. 890 with regard to an Attachment K filing of a Transmission Provider's Transmission Planning Process. The SDT has made a change to clarify this requirement (see R8 in draft 2). **R8**. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~affected entities~~ neighboring systems, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890. 15. The SDT reviewed each planning event considering the likelihood of the event, the potential outcome of the event and the directives from FERC concerning loss of Non-Consequential Load and determined the expected performance for each event. Then, the SDT re-ordered the events and grouped them by the type of outage and the expected outcomes. Performance requirements: 16. The SDT has reviewed and revised Tables 1 & 2. In the steady state time frame, voltage instability can occur typically during high power transfer and/or peak demand periods. Voltage instability can be assessed using a long-term Stability program. However, it can also be assessed using a power flow program that simulates governor action. There are a number of IEEE papers (e.g., G. Morison, B. Gao, and P. Kundur, "Voltage stability analysis using static and dynamic approaches," IEEE Transactions on Power Systems, vol. 8, no. 3, pp. 1159 – 1171, August 1993) that can provide suggestions on the methodology. Cascading outages and uncontrolled islanding can also occur, for example, when the Transmission Facilities load beyond the corresponding relay trip settings. This could cause uncontrolled tripping of Transmission Facilities beyond those required to clear the fault. Even though these events are rare, the Transmission Planner should be aware of their possibility when performing studies. The SDT did not change Table 1 to remove "Normal Clearing" because depending on the bus configuration, delayed clearing would result in removing more Facilities from service than normal clearing in the steady state post-Contingency period. 17. The SDT has revised Tables 1 & 2 accordingly.			

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18. The SDT has accordingly proposed a definition for Bus-tie Breaker. **Bus-tie Breaker:** A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.) 19. The SDT has reviewed and revised Tables 1 & 2. "Firm Transfer" has been replaced with "Firm Transmission Service". 20. P6.2 - The SDT has reviewed and revised Tables 1 & 2. 21. P6.3 - It is true that multiple elements are impacted, but it is still a single Contingency event. 22. P9.1 - The one mile allows for some measurable physical constraints to building separate lines in all locations, but limits the exposure to a fixed length, which is universally applicable. A percentage doesn't provide the same limitation and consistency. 23. It refers to the loss of a monopolar DC line or one pole of a bipolar DC line. 24. P9.3, P9.4, and P9.5 - The SDT feels that the loss of a bipolar DC line is a multiple Contingency Planning Event. The tables have been revised to provide clarity. 25. Extreme Events 3 - The SDT has revised Extreme Events in Tables 1 & 2 and to comply with FERC Order 693. 26. Extreme Event Descriptions - The analysis of Extreme Events is an effort to assess potential impact of plausible but unlikely events. The selection of events is deterministic, not probabilistic. The SDT also notes that in Order No. 693, paragraph 1834, the FERC gave examples of Extreme Events that the FERC would expect to see in the revised standard. These examples are consistent with the items that the SDT included in the standard as examples of Extreme Events to be considered. For example, paragraph 1834 includes "(1) loss of a large gas pipeline into a region or multiple regions that have significant gas-fired Generation; (2) a successful cyber attack; (3) regulation that restricts or eliminates the use of a river or lake or other body of water as the cooling source for generation; (4) tornado or wildfire, or other event and (5) the loss of older transmission lines, which may not be constructed to meet an entity's present radial ice loading requirements…" In paragraph 1834, the FERC directs NERC to expand the list of events with examples such as those described in the paragraph. 27. Extreme Event 1 - In the existing Table 1 the non-simultaneous loss of two unrelated elements with System adjustment in between is in Category C3, the simultaneous loss of two circuits on a common structure is in Category C5. In the proposed standard Table 1, Extreme Event 1 covers loss of two unrelated elements with no System adjustment in between. If the reference is to a single Contingency, then the focus should be on the Contingency rather than the number of elements affected by the Contingency. 28. Extreme Event 2c - Event 2c is the loss of a station. Event 2e is the loss of Load. The loss of a single large Load or major Load center assumes that multiple events need to occur to realize this level of impact. 29. Extreme Event 3f - The SDT has reviewed and revised Tables 1 & 2. 30. Extreme Event 3g - The issue reflects the exposure during a period where an entity is taking older lines out of service to rebuild them to newer design standards. 31. The SDT has reviewed this requirement and has determined that at this time this is not appropriate for a North American standard. 32. The SDT has provided a definition of a Bus-tie Breaker. 33. Shunt devices have been added to the table. 34. This is now listed as a multiple Contingency (P7). 35. The table has been re-done to emphasize that you need to study events and not just single pieces of equipment. 36. One mile was based on the SDT's review and understanding of existing conditions. 37. The SDT has revised the table (P6) to make it clear that this is for a single pole.			

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38. The language referring to a spare transformer has been deleted form the table. 39. Editorial error has been corrected. 40. The SDT has reviewed the definition of angular Stability and feels that it is appropriate. 41. The SDT has reviewed this requirement and has determined that at this time this is not appropriate for a North American standard.			
MEAG Power	☑		To the extent that the new standard is more stringent, additional time should be allowed to implement the corrective action plan, with fines suspended until reasonable time has passed to allow implementation. I.E., If the solution is 20 miles of new 500 kV T/L, then allowing fines to the short-term horizon is unreasonable – building 20 miles of 500 kV T/L is not possible in 2 or 3 years.
Response: The SDT understands that there are extended transitionary issues associated with responsible entities becoming compliant with the new standard. The SDT plans to draft an extended implementation plan to accommodate such issues. The plan will be provided for the third posting of the standard.			
MISO	☑		The Midwest ISO appreciates the opportunity to offer the following recommendations: 1. Requirements for providing modeling data in R1. are redundant with the exising requirements of MOD-010-0, MOD-012-0, and MOD-016-0 through MOD-025-1. Adding these requirements to the TPL Standard is unnecessary and may create confusion. 2. The Standard does not address the return of direct (consequential) load loss following a contingent event. How long of an outage event acceptable?
Response: 1. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. 2. The proposed TPL-001-1 standard does not place a limit on the amount of Consequential Load Loss or the outage duration. In Requirement R3.3.2.1 the Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment. The SDT believes it is first necessary to obtain data on these items to allow comparison of similar sized Systems and it drives transparancey to expected outcomes.			
MRO	☑		The MRO commends the SDT on the difficult task of rewriting some of the most important NERC standards: the TPL standards. The MRO has a number of comments and suggestions. 1. Load modeling data in R1.1 and R1.2 do not belong in the TPL standards. It should be provided for in the MOD standards which provide the numerous load model data requirements. At a minimum, R1.2 should be revised to only require documentation of stressed system conditions. It is unnecessary and micro management to provide for "measurement during stressed System conditions". Further, it is unusual standards drafting to provide for a measurement of load in an assessment standard. 2. R1.4 should be revised to separate "known planned outages" from the rest of the requirement in

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Commenter	**Yes**	**No**	**Comment**
			separate sentences. This is because the reference to spare equipment outages does not have any bearing on the "known planned outages" requirement. Further the consideration of spare equipment strategy is not explained enough to understand what is required here. Further it is not clear as to what equipment must have consideration of spare equipment. The MRO recommends that R1.4 be rewritten as follows: "Known planned outages. Long-term forced outages for transformers with low-side voltages of 100 kV and above and generator step-up transformers should be identified where lack of spare transformers could result in outages of the transformers over the annual peak demand hour." 3. It is unreasonable for R1.5 to provide that planned facilities that are included in System Assessments include circuit breakers, and protection system equipment. These two items should be dropped from R1.5 since these are engineering details that are typically not available at the time that the System Assessment is made. 4. R.2.1.1 - The system peak load study requirements for studies for two of the near-term period seems to be excessive. The MRO recommends that only one year in the near-term period be required. 5. R2.6 should be deleted. The MRO believes that R2.1 and R2.4 are sufficient in describing when current studies are required. R2.6 will result in unnecessary restudy of the system. Alternatively, if R2.6 is kept, then the requirement should be a performance requirement, that as long as material changes do not require restudy then restudy is not required. The Transmission Planner and Planning Coordinator could be required to document why restudy is not required. Material changes should be expanded to refer to only those "significant" transmission line additions or generator additions. 6. R2.71 should be revised to delete "including the duration of interim Operating Procedures" or else the SDT should explain what is meant by this with additional information about what interim Operating Procedures are. 7. R2.7.1.1. should be revised to delete the requirement for project initiation date. This information is not typically available at the time of performing a System Assessment since this is detailed engineering information not pertinent to planning. 8. R2.7.5 should be deleted. The MRO believes the such detailed review of the status of the installation of projects to be beyond the scope of the TPL standard. Since NERC has no authority to require the installation of facilities, how does NERC have authority to require a review of the status of such facilities?

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			9. R3.2.1 and R3.2.2 seem unnecessary details that are micro-management of the planning process. Both requirements could be met by the transmission planner and planning coordinator with general statements of little value. Also, relay loadability is included in facility ratings and does not need to be covered in TPL. 10. In Table 1, "a shunt device (including FACTS devices)" is too general. Arresters and potential devices for metering and relaying are shunt devices. This should be changed to a specific listing such as: transmission capacitors (100 kV and above), transmission reactors (100 kV and above), …" and whatever other devices that the SDT intends to be included here. 11. In Table 1, Single pole of DC line should be moved to P1. 12. In both tables, "monopolar DC line" should be replaced with a "single pole of a DC line". 13. The revised tables are confusing in descriptions of various outages particularly since the interconnected transmission system has been planned for the past decade using the previous Table I. The SDT should limit its changes to Table I to a limited number of changes that have been known to cause issues in the past rather than raising the bar in a number of cases. 14. The Extreme Event descriptions in Table 1 should be revised to provide definitions of local area and wide area. 3 d. (3f.) and 3 c. (3 e.) are duplicates and should be combined. Wide area events as listed are such unusual events, which are difficult to analyze or model. The requirement should provide that the number of these wide area events to be studied is limited to a minimum of one. 15. The MRO does not believe that contingency reserve is necessarily synonymous with spinning reserve. The SDT should clarify note ii to Table 2. 16. The SDT should clarify the wording in the tables to better explain the events which are either above or below 300 kV. For example, in P5 change 1. IS IT "A Transmission circuit followed by a System adjustment above 300 kV followed by the loss of another Transmission circuit above 300 kV." or is it "A Transmission circuit followed by another Transmission circuit resulting in impacts on 300 kV facilities"? P5 3. should be revised to say, "A transformer with a low side voltage rating above 300 kV followed by a System adjustment followed by the loss of another transformer with low side voltage rating above 300 kV." or is it "A transformer followed by the loss of another transformer resulting in impacts on 300 kV facilities."

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			17. R2.1.3 - R2.1.3 reguires sensitivity studies that involve many potential scenarios that would be difficult to create in a Planning Assessment. Planners can not model the unknown and to assume the unknown may be a difficult task to complete. Instead of "shall be run and", the language should be "shall be considered based on current knowledge of system including" 18. Extreme Events description for common right-of-way should be defined. Does this include line crossing points? Suggest exclusion for corridors one mile or less similar to P9.1. 19. The language description of the even should be substantially the same between Table 1 and Table 2. Table 2 format is a bit cleaner with initial condition and event separated. Table 1 should follow this format. 20. The loss of a shunt device (e.g. SVC) should be added to Table 2 (P1.4). 21. Note 1ai. to Table 2 refers to event P3.2 which doesn't exist in the Table 2. 22. Note 1aii. to Table 2 allows generating units to "cascade trip" for certain events that were this would not be allowed in the existing TPL standards. The MRO recommends that the more of the events be listed in 1ai. so as to at least maintain reliability. 23. Note 1aiii talks about acceptable damping. NERC should have a standard requiring development and documentation of damping criteria by the planning coordinator. 24. P9 should be changed from referring to a monopolar or bipolar dc line to a single pole of a DC line. THE FOLLOWING ARE RON MAZUR'S COMMENTS. 25. The MRO does not believe R1 is required in this standard. The modelling standards should cover the requirement of the data owners to provide data to the PC. Further this data needs to be provided to the TP as well. 26. R1.4: requires planned outage data to be provided to planners. The MRO does not believe this is a requirement for planning. It is not economic to add facilities to accommodate future planned outages. Secondly, the Table 1 multiple contingencies already mandate that planners consider the

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Commenter	**Yes**	**No**	**Comment**
			impacts of an outage with system adjustment followed by testing for the next contingency. 27. R1.5: requires the PC to define "planned facilities" which should be included in the model. This will lead to inconsistency what is modelled, as experience has shown that there will be a wide range of assumptions in the definition. This standard should offer a definition for stakeholder debate. The SDT should clarify what is intended by including Protection System Equipment and control devices. 28. R2: The SDT should define the elements of an acceptable assessment in more detail. 29. The MRO recommends that the need to assess Plant Stability be removed from this standard. The generator connection standard and the proforma tariff interconnection process ensure the plant stability meets performance requirements. The System Assessment provides an overall assessment of the integrated system performance, which includes the impact of the plant. This requirement appears to be redundant. 30. R2.1: It is important to assess off peak loads with high simultaneous transfers as this is the period where extensive economic interchange occurs, and transient stability issues arise as less uneconomic peak units are off, leaving the load to be supplied by remote generation with reduced local reactive supply, voltage and damping control. 31. R2.1.3: The requirement for sensitivity cases is excellent. The SDT should consider: R.2.1.3.1: separate real MW load variation and Power Factor variation R.2.1.3.2: clarify the intent of modification of expected transfers. Does this apply to firm transfers only, or does it also encompass non-firm transfers. ..R.2.1.3.4: Instead of a sensitivity, the reactive devices should be included in the Table 1 &2 contingencies. If the intent is to investigate robustness to voltage instability, the SDT should clarify. R.2.1.3.5: Generation additions/retirements should be removed as this is covered, or should be, by the interconnection standards. The SDT should clarify.the need for generation additions/retirement. 32. R2.2: The long term assessment should also include an off peak case with simultaneous transfers to provide some indication if the system performance is expected to degrade. 33. R2.3: The short circuit study is not a reliability assessment issue but a design issue that is more appropriately covered by a Facility Rating Standard. The time required to conduct and report on this analysis in an assessment is better spent on more contingency or sensitivity analysis. 34..R2.4: Similar to the comment on R2.1,. It is important to assess off peak loads with high simultaneous transfers as this is the period where extensive economic interchange occurs, and

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Commenter	**Yes**	**No**	**Comment**
			transient stability issues arise as less uneconomic peak units are off, leaving the load to be supplied by remote generation with reduced local reactive supply, voltage and damping control. 35. R2.4.1: Should be clarified to limit the detailed modeling to local areas where the planner expects an emerging voltage recovery issue due to unusually high concentration of induction motor load. This is a local issue, and a bulk system reliability issue that is imposed system wide. The MRO believes this should be moved to the sensitivity case requirements R2.4.3. 36. R2.4.3: Sensitivity Case requirements should mirror the steady state comments, subject to the suggestion provided above for R2.1.3. That is: ..R.2.4.3.1: should also include power factor variation (actually a separate requirement) as in the stability world, the dynamic modelling of load has a significant influence in meeting transient performance requirements. R.2.4.3.2: I agree it should simultaneous non-firm transfers. This should be applied to the steady state sensitivity as well (see R.2.1.3.2). ..R.2.4.3.3: delete ..R.2.4.3.4: Needs to be clarified. See R.2.1.3.4. . R.2.4.3.5: see R.2.1.3.5 37. R2.5: Plant stability analysis should be deleted. 38. R2.6.1: Nowhere else in the standard is there a requirement to assess reliability impacts of market structure changes, so why would a study become invalidated if there is a change in market structure. It would seem to me that the operation of any market would have to respect the reliability criteria. 39. R2.7: Corrective Action Plans: Is the intent that corrective action plans also address issues raised by the sensitivity studies. The MRO argument would be that it should not be mandated. The plans are developed to meet base case needs which are based on expected load forecasts, transfers, etc. Sensitivity studies are done to measure the robustness of the base case plan. It should be left up to the Planner to decide if the plan is adequate based on the likelihood of the scenario studied, even if the sensitivity analysis shows some performance violations. 40 Also, if rationale is provided for contingencies selected as they are expected to be most severe, then by default those not selected are less severe. Why is there a requirement to explain why you did not select a contingency. 41. R3.4: Requires extra analysis compared to TPL-004-0. Developing mitigation for Extreme Events

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Commenter	**Yes**	**No**	**Comment**
			can require significant work. Since there is no requirement to implement corrective plans for Extreme Events, what is the purpose? 42. R3.5: Generator tripping should be added in addition to runback. Generator tripping is used extensively in regions where remote generation is delivered via long transmission. Generator tripping should be an available option for the planner to use as opposed to requiring justification as a regional difference. 43. R4: The requirement to assess Plant stability is redundant as this is assessed as part of the generator interconnection. It should be deleted. 44. R4.5.2: The MRO disagrees on the need to define mitigation for Extreme Events. 45. R4.6: Should be deleted. 46. R6: Requires distribution of results and "coordinating analysis of these results through an open and transparent process". Can the SDT clarify what the intent is? As written, it implies the PC/TP just shares assessment results with neighbours. The MRO believes there should be a requirement to conduct joint assessments on inter-regional transfer capability. 47. Table 1 Performance Requirements: • As this is a steady state table, how does one assess if voltage instability, cascading outages or islanding occurs? • Generator tripping for single contingencies should be added to the allowable actions. • How did the SDT classify which event was single contingency vs. multiple contingency vs. extreme? Was statistical data analysed? • What is a non-bus tie breaker? Is this any breaker that is not a bus tie breaker? • Event P2-3 should be relocated to the P1 event category. • What is the SDT rationale for defining bus faults >300 k as single contingency events? Is there any statistical dat to warrant this extra requirement? Now a Cat C? Since little load is served off >300 kV it may be a moot point. • P6 single contingency: What is the justification for classify P6-2, a bipolar dc loss as a single contingency? The existing standard classifies this event as a Cat C multiple contingency event? • P6-3: Why is a breaker fault classified as a single contingency? One would assume such a fault would be cleared by backup protection resulting in the loss of multiple elements? • P9-1; Is there any justification for selection of one mile? Can it be two miles? More? Why not no more than 5% of line length? Would the fact that there is line shielding be justification for

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Commenter	**Yes**	**No**	**Comment**
			increased length? 48. Extreme Events • Event 3.g: what is the rationale for distinguishing between old vs. new design for the loss of multiple lines due to icing? Is the SDT implying that new lines must be designed to prevent multiple line loss due to icing? 49. Table 2 Stability Performance • MRO Comments on Table one for the same contingencies should also be applied here. 50. P6-2 should be a multiple contingency, as it is in the existing TPL standards. 51. P9-3: should be an extreme event. 52. P9-6: Please clarify the requirement to indicate that it relates to long lead times. 53. The definition for Angular Stability should be modified to allow planned tripping of a generator following a line trip. Why are generators allowed to pull out of synchronism for other planning events? This is cascading. The SDT should clarify if they are refering to local or regional damping modes in 1.a.iii.

Response: 1. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.
2. The SDT has revised this requirement based on industry comments to clarify the intent that *known* planned outages and long-term outages for Transmission equipment, including the impact of spare equipment strategy, be considered, and to be responsive to FERC Order 693, paragraph 1725.
3. The SDT does not agree. The SDT believes circuit breakers and protective equipment should be considered when developing criteria since these can affect System performance.
4. The SDT feels that requirement to run a peak load study for two of the years in the Near-Term Horizon is a minimum required for an adequate Planning Assessment. The SDT felt that the Year One or two study should provide operations with the best information to transition to the operating horizon. The year five planning study is the first near term study from the long term set. Five years is a short time if unexpected new facilities are required.
5. R2.6 - The SDT has revised this requirement in response to the numerous comments received.

R2.6.1. For steady state, short circuit, or System Stability analysis: ~~if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market~~

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Commenter	Yes	No	Comment
~~structure changes~~ the study shall be five calendar years old or less. **R2.6.2**. For steady state, short circuit ~~analysis~~, Generating Plant Stability, or System Stability analysis: ~~if the study is less than five years old and no material changes have occurred to the System in the intervening period.~~ the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. **R2.6.3**. ~~For plant and System Stability analysis: until material changes in the System make the study no longer valid. Material changes in the system include the addition of a Transmission Line or a generator.~~ 6. Interim Operating Procedure is required to ensure that the all the performance requriements in Table 1 and Table 2 are met. It could include SPSs, pre-Contingency interruption of non-firm Loads, uneconomic generation dispatch, etc. The SDT recgnizes that this is a temporary measure until a permanent solution is put in place and that is why its duration is required. 7. Requirement R8 (old Requirement R6) which focuses on the distribution of the Planning Assessment results among affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old Requirement R6) Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. Typically the date would indicate when significant resources will begin to be employed. This covers any project proposed for the near term. The SDT continues to believe that by providing the expected project intiation date of System improvements provides useful information to neighboring entities. The SDT believes that initiation dates are required for near-term corrective action plans to give an indication that the corrective action plans can be implemented in time. 8. The standard requires that the identified future deficiencies be addressed by the Corrective Action Plan. The standard does not prescribe what this plan should be but entities have to demonstrate that the Corrective Action Plan or its alternatives will in fact be implemented in time to address the identified deficiencies. If the parts or all of the Corrective Action Plan turns out to be unrealistic due to something like a regulatory order, you still need to meet the performance requirements and a revised or new Corrective Action Plan that meets the performance requirements will need to be developed. The determination of when to update the Corrective Action Plan is based on good engineering judgment. 9. R3.2.1 & R3.2.2 - The SDT has received numerous comments in support of these requirements. Requirements R3.2.1 and R3.2.2 are included to provide clarity on simulations in response to FERC Order 693. Relay Loadability is included to provide the connection between facility ratings and planning studies. The SDT has not made changes in response to this comment. 10. The SDT has revised the table references to shunt Contingency events and removed the paranthetical reference to FACTS devices. The SDT believes it is more appropriate to leave the event more general based on the difficulty of maintaining an up to date reference to emerging technologies. 11. The SDT concurs with your observation. We have made several changes to the performance table organization based on industry input. The single pole DC outage is now reflected as a P1 Planning Event. 12. The SDT concurs with your feedback and the suggested change has been made in Tables 1 and 2. 13. The SDT has completely reformatted the performance tables in Draft 2 of the TPL-001-1 standard. The new format more closely mimics the existing approved TPL standard Table 1, with enhancements the SDT feels the industry will find valuable. The SDT has responded to industry comments regarding higher performance requirements for Facilities above 300 kV and has adjusted requirements for N-1-1 non-generator outages to permit Non-Consequential Load shed post-Contingency following the second event. The SDT has retained a higher			

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Commenter	**Yes**	**No**	**Comment**
expectation for certain N-1 Contingencies occuring on the EHV System. See the Summary Considerations in Q20 through Q23 for additional information. The SDT believes that this approach is consistent with FERC Order 693. 14. The SDT has revised the Extreme Event references and has removed the duplications you reference. The reference to local and wide area events has been retained as we did not receive a significant amount of comments opposing its use and it seems to be generally understood that local are extreme Contingencies eminating from a single location (substation, plant or ROW), whereas the wide area tend to cover a much larger landscape due to a natural disaster or cyber attack. The TP is given flexibility in which Extreme Events it wishes to cover, see Requirement R3.4. 15. The SDT agrees and has revised the note accordingly. 16. The SDT has completely reformatted the performance tables in Draft 2 of the TPL-001-1 standard based on feedback from the industry and input from SDT members. The new format more closely mimics the existing approved TPL standard Table 1, with enhancements the SDT feels the industry will find valuable. The SDT believes the new format will more closely meet your needs. 17. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirements R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirements R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. The sensitivity studies do not in themselves establish the need for a plan, only the areas of the system for which the analysis is needed. **R2.1.3.** For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.1.4**. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. **R2.4.3**. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: **R2.4.4**. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. P5.3 - The table format has been revised for clarity. We have added notes at the end of each table to clarify when a transformer is considered EHV (above 300 kV) or a BES transformer below the EHV level. 18. Tables 1 and 2 have been revised to bring greater clarity. 19. The SDT revised the performance Tables 1 and 2 for clarity based on industry feedback. The SDT has included the initial condition column in each and the events correlate one to one in both tables.			

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Commenter	**Yes**	**No**	**Comment**
20. The single Contingency loss of a shunt device is now included as Planning Event P1.4 in Tables 1 and 2. 21. The SDT has corrected the problem in Table 2. 22. The SDT believes that we are not reducing the reliability of the System as compared to the existing standards. 23. The SDT has reviewed this requirement and has determined that at this time this is not appropriate for a North American standard. 24. Tables 1 and 2 have been revised to include a variety of new improvements. The reference to monopolar is now "single pole of a DC line". The SDT has however retained a bipolar DC line outage; see Planning Event P7.2. 25. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. 26. The SDT has revised this requirement based on industry comments to clarify the intent that *known* planned outages and long-term outages for Transmission equipment, including the impact of spare equipment strategy, be considered, and to be responsive to FERC Order 693, paragraph 1725. 27. The requirement for the PC to define planned Facilities has been deleted from the revised standard. The SDT did not receive many requests for additional clarification of Protection System equipment and control devices and therefore did not revise the standard to address this concern. 28. The SDT has modified the assessment language dealing with steady state analysis in Requirement R2.1 to better define those requirements along with adding Requirement R2.1.4 to allow any additional sensitivities to be run that may be deemed necessary. In addition, Requirement R2.2 has been revised to specifically address steady state analysis: Requirements R2.4 and R2.5 have had many changes to better address the Stability portion of the assessment, Requirement R2.6 better details what past studies may be used in the Planning Assessment, and Requirement R2.7 better addresses Corrective Action Plans and System deficiencies. The SDT believes that all these changes result in better defined portions of the Planning Assessment. **R2.1**. ~~The steady state portion of~~ The Near-Term Transmission Planning Horizon ~~Planning Assessment~~ portion of the steady state analysis shall ~~address all five years of the assessment period~~ be assessed annually and be supported at a minimum by the following annual current studies, supplemented with qualified past studies as ~~shown~~ indicated in Requirement R2.6: **R2.1.4**. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. **R2.7**. For Planning Events shown in Table 1 – Steady State Performance and Table 2 – Stability Performance, when the analysis indicates an inability of the System to meet the performance requirements in the tables, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed ~~over time~~ in subsequent assessments but the System shall continue to meet the performance requirements in the tables. ~~Such plans shall:~~ Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities. The Corrective Action Plan shall: 29. The SDT has reviewed the need for Plant Stability and has concluded that it is appropriate to include it in this standard. It also felt that			

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			this was responsive to FERC Order 693. 30. Requirement R2.2 requires as a minimum a peak load study for one of the 5 years in the Near-Term Horizon. This does not preclude any entity from running more studies, including for off-peak load conditions. 31. The standard is providing some guidance on what needs to be included in sensitivity studies without being totally prescriptive. In response to some comments, the standard was modified to clarify the language to state that at least one of the sensitivities listed in Requirements R2.1.3 and R2.4.3 should be studied and reasons be given for not studying the other ones. Furthermore, the standard also allows for entities to study sensitivity not included on the list that are more appropriate for their respective systems. 32. R2.2 - The Draft 2 version remains unchanged in regard to your comment. There was no overwhelming response from industry that compelled the SDT to make the change proposed. The standard requires off-peak analysis for near-term. In the long-term Requirement R2.2 states "…at a minimum, a current System peak Load study is required annually." This requirement is to capture long lead-time events for peak-Load periods. The peak system is typically the more troublesome period for most planners as Loads are higher and Facility Ratings are lower. Your concern is valid that in the off-peak, transfers across a system can be elevated and it is expected that if a particular System is subject to heavy transfers that a prudent Transmission planner would cover such situations based on their own identified need through sensitivity studies. Howver, such off-peak anlysis is not mandated by the standard for the Long-Term Planning Horizon. 33. R2.3 - The SDT respectfully disagrees and believes that the requirement for short circuit analysis is an improvement and covers a gap in the existing Transmission planning standards. It is essesntial that as System changes are introduced that increase the strength of the System and result in increase short-circuit fault currents, that the Transmission planner not simply look at steady-state Facility Ratings but also consider the short-circuit as well. Having steady-state, short-circuit and Stability in a single cohesive standard ensures that the Transmission planning engineer is evaluating all aspects of proposed changes to the System. 34. R2.4 - The Draft 2 version remains unchanged in regard to your comment. There was no overwhelming response from industry that compelled the SDT to make the change proposed. The standard requires off-peak analysis for near-term. In the long-term Requirement R2.2 states "…at a minimum, a current System peak Load study is required annually." This requirement is to capture long lead-time events for peak-Load periods. The peak system is typically the more troublesome period for most planners as Loads are higher and Facility Ratings are lower. Your concern is valid that in the off-peak, transfers across a system can be elevated and it is expected that if a particular System is subject to heavy transfers that a prudent Transmission planner would cover such situations based on their own identified need through sensitivity studies. Howver, such off-peak anlysis is not mandated by the standard for the Long-Term Planning Horizon. 35. The SDT feels that the Load model used in the study should represent actual conditions as accurately as possible. It has been shown during the reconstruction of the events of the August 14, 2003 blackout in the Northeast that the Load model was critical. One of the recommendations involved developing better Load models. 36. To the degree possible, the SDT has revised the standard to better align steady state and stability sensitivity lists. 37. The SDT has reviewed the need for Plant Stability and has concluded that it is appropriate to include it in this standard. It also felt that this was responsive to FERC Order 693. 38. R2.6.1 - The SDT agrees with your view and references to market structure changes have been removed in Draft 2. 39. Agree. Addressing or not addressing deficiencies discovered as a result of runing sensitivity studies is at the discretion of individual entities. The language of the standard was be modified to clarify this. 40. In developing a rationale why a selected Contingency is the most severe will require some sort of comparison to other Contingencies. In doing so the explanation required in the standard is already addressed. 41. The SDT feels that the current TPL-004 provides limited value to improve System reliability. Performing studies and not even considering

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Commenter	**Yes**	**No**	**Comment**
possible corrective actions (as is the case with the current standard), may result in over looking relatively inexpensive corrective actions which could significantly help improve reliability. It is appropriate to add another requirement to help improve reliability System development. The purpose of the requirement is to assess the risk of cascading outages or a catastrophic event, develop corrective actions and actually implement such actions if it is reasonable, for example installing a SPS. This is also consistent with Paragraph 1833 in FERC Order 693, which directs NERC to modify TPL-004-0 to identify options for reducing the probability or impacts of extreme events that cause cascading. 42. This has been added. **R3.5** Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met: 43. The SDT has reviewed the need for Plant Stability and has concluded that it is appropriate to include it in this standard. It also felt that this was responsive to FERC Order 693. 44. The SDT has reviewed this requirement and has determined that at this time this is appropriate for a North American standard. 45. The SDT has reviewed the need for Plant Stability and has concluded that it is appropriate to include it in this standard. It also felt that this was responsive to FERC Order 693. 46. R6 - By meeting the requirement for "coordinating analysis of these results through an open and transparent process", the SDT meant a stakeholder process that was set up to meet the requirements of FERC Order No. 890 with regard to an Attachment K filing of a Transmission Provider's Transmission Planning Process. The SDT has made a change to clarify this requirement. (see R8 in draft 2) **R8**. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~affected entities~~ neighboring systems, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890. 47. Performance requirements: The Draft 2 version includes a new Requirement (R6) which indicates that each TP must define and document proxies used in simulation studies to identify System instability for conditions such as cascading outages. voltage instability, or uncontrolled islanding. In the steady state time frame, voltage instability can occur typically during high power transfer and/or peak demand periods. Voltage instability can be assessed using a long-term Stability program. However, it can also be assessed using a power flow program that simulates governor action. There are a number of IEEE papers (e.g., G. Morison, B. Gao, and P. Kundur, "Voltage stability analysis using static and dynamic approaches," IEEE Transactions on Power Systems, vol. 8, no. 3, pp. 1159 – 1171, August 1993) that can provide suggestions on the methodology. Cascading outages and uncontrolled islanding can also occur in the steady state time frame, for example, when the Transmission Facilities load beyond the corresponding relay trip settings. This could cause uncontrolled tripping of Transmission Facilities beyond those required to clear the fault. Even though these events are rare, the Transmission Planner should be aware of their possibility when performing studies. **R6**. For the short circuit portion of the Planning Assessment, as described in Requirement R2.3, each Transmission Planner and Planning Coordinator shall assess the short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties.			

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The SDT agreed to make this change, Requirement R3.5 of the second draft of the standard now allows genration tripping for single Contingencies. **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~iesy~~ ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met: To address the directive from FERC in Order 693, the SDT classifies Contingencies by events instead of by the number of Transmission elements lost. One event, for example loss of a breaker, can remove from service upon fault clearing all elements connecting to the breaker. Statistical data available from regional databases were analyzed in developing the draft standard. A Bus-tie Breaker is often used in straight bus substation layouts to sectionalize an otherwise long continuous bus into smaller sections. The SDT has proposed a definition of a Bus-tie Breaker in the second draft. **Bus-tie Breaker:** A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.) Tables 1 and 2 have been revised and Event P2-3 has is now shown as Planning Event P1.5, and loss of a bipolar DC line has been reclassified as a multiple Contingency event. The SDT recognizes that bus section faults can and often do trip multiple Transmission Facilities. The Planning Event P2 defines single Contingency events that are somewhat lower probability than those in P1 but often result in higher consequence impacts due to loss of multiple Transmission elements for the single electrical fault. In more reliable station designs (ring, breaker and a half,etc) this type of condition is minimized. The new TPL Draft 2 continues to emphasize a higher expectation of performance for bus section faults and other P2 events on the Transmission System above 300 kV. See Summary Response for questions Q20 through Q23 for more details on the team's rationale for continuing to seek this level of reliability improvement. The SDT concurs with your view and has made the change. A bipolar dc loss is no longer a single Contingency Planning Event. You are correct in describing the outcome – multiple Facility outages. However, the SDT is describing an internal fault of a breaker, not a stuck breaker condition. Therefore the SDT is treating these as a single Contingency event. The SDT agrees that these are lower probability events than the "typical single Contingency" events but they pose greater risks. The SDT has separated the single Contingencies as P1 and P2 based on their probabilities of occurrence. Also, allowable responses to the P2 events differ from those for the P1 events. It is noted that stuck breaker events are treated separately as P4 Planning Events. The choice of one mile was based on a review of various regional practices. 48. The reference to this item has been removed and more general weather conditions resulting in extreme Contingency conditions are assessed in the Extreme Events area. 49. See comments for Table 1.			

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Commenter	**Yes**	**No**	**Comment**
50. The SDT agrees and has revised the table accordingly. 51. The SDT has reviewed this requirement and has determined that at this time this is appropriate for a North American standard. 52. The SDT has removed the terminology referring to spare transformers. 53. The SDT has reviewed the issue and revised Requirement R5.5.3 to provide clarification. **R5.5.3**. Automatic generation tripping is allowed to mitigate Stability violations if the following conditions are met:			
Muscatine P&W	☑		Muscatine Power & Water (MPW) is a municipal utility with approximately 33 miles of 161 kV lines (2 lines) and 33 miles of 69 kV lines with three – 161/69 kV substations and seven – 69/13.8 kV substations. The service territory is approximately 24 square miles. Our last system peak was 149.9 MW on July 29, 1999 with a more recent peak of 146.9 MW on July 17, 2006 with generating capacity of approximately 253 MW from four units. The main problem we have is keeping up with the standards changes with our limited resources. We would suggest: 1. It was good to see the definitions section. We would also suggest including all acronyms including those in common use. Acronyms have become so common and they are now being reused to mean different things to different groups that for new people, multitasking individuals, or those not dedicated to a specific standard acronyms add confusion. Where possible, we would suggest using existing terms and, if appropriate, preferably already defined or have them defined in IEEE standard #100 dictionary. 2. Can you address adequate documentation? I'm not looking for detail formats or requirements but more minimum requirements and suggested layout etc. One of the problems I have during audits is how much documentation to provide without going over board. More is not good considering time requirements. Our goal is to make it easy for us and the auditors. We met the standard but have we proved it. Being a small utility with little impact on the bulk system how much should we provide? 3. In our region the MAPP Design Review Subcommittee (DRS) and in some cases the Subregional Planning Groups (SPGs) review new and proposed changes to facilities. In many cases they would have to approve any RAS or SPS and thus provide a peer review/reasonable and workable check. 4. R.2.6.1 - Being a small utility we are concerned about the planning study must be less than 3 years old. We budget for studies every three years but adjust that based on whether material changes have occurred to the system. Our last cycle was 6 years only because our load hasn't been growing and we still haven't hit our peak of 1999. Since we are dependent on consultants, we also have a concern for how long it can take for them to complete the study. Since we are small the bigger customer gets the attention. We do use the same criteria for near and long term planning horizons. We also participate in MAPP and ITWG studies for the annual and bulk system review and

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Commenter	**Yes**	**No**	**Comment**
			since our issues in studies are more local rather than the bulk transmission system. How should/could the sensitivity studies be covered for us at the regional level? 5. 300 kV and above questions: MPW is a small utility that doesn't have any facilities above 161 kV or any DC lines. I can see requiring more stringent performance for EHV and possibly lower voltage facilities in some cases, however, whether to allow the loss of Non-Consequential load should be left to local entities to decide since the cost of the "corrective action" could exceed the cost of the load loss and put undo burden on the customers. Depending on the type of load the customer may not want/be willing to pay for the extra reliability. If ordered, how will the cost be recovered? The cost should be recovered by the users not just the local customers. Thanks for the opportunity to comment!
Response: 1. The proposed definitions in the draft standard will be incorporated into the Glossary of Terms when the standard is approved. We believe it is better to have the terms listed in the NERC Glossary of Terms rather than pointing to the IEEE standard since the NERC Glossary is more readily available for use in the reliability standards environment. We have reduced the number of definitions in Draft 2 to try and have a more pointed impact where a definitional term is most needed. 2. Your concern is a compliance matter and not directly related to the reliability requirements. Although not yet available in Draft 2, the SDT will be adding compliance measures in a future draft. If the measures do not clearly address your concern please raise a more specific question related to the appropriate requirements/measures. 3. Thank you for your comment. 4. R2.6.1 - The SDT has revised R2.6.1 to allow the use of past studies that are 5 calendar years old or less. **R2.6.1**. For steady state, short circuit, or System Stability analysis: ~~if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market structure changes~~ the study shall be five calendar years old or less. 5. The SDT has added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose Load. With regards to the loss of Load, the standards don't address cost recovery.			
NERC TIS	☑		1. In definition of "CONSEQUENTIAL LOAD," misoperations need to be defined better or removed, i.e. inadvertent tripping of elements due to protection system failure, including inadvertent SPS operation, may cause loss of load NOT connected to the element tripped off. In context of the definition, it appears that the misoperation should be on the protection system for the element that is tripped. {PARTLY COVERED} 2. Even when post-contingency voltage remains within prescribed limits, some voltage-sensitive customer load could still be dropped off due to their inherent sensitivity to allowed changes in voltage. Should such cases be considered as dropping non-consequential load or are the performance requirements met as long as post-contingency voltage stays within the prescribed limits? Such load losses can rarely be predicted by steady state analysis unless the

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Commenter	**Yes**	**No**	**Comment**
			loads and their distinct characteristics are explicitly modeled, but may be detectible in dynamic analysis since it is often the first swing voltage excursion that trips such loads. 3. Assuming the standard is passed, especially if the bar is raised, there should be some reasonable implementation period specified to allow entities that do not meet the standard's requirements presently and time to implement changes to become compliant. 4. Why is there a 300 kV threshold? Is there evidence that increasing the redundancy of the high voltage network will provide the largest reliability benefits? 5. Need to specifically define when it is OK to use "permanent" SPSs to meet performance requirements following the first contingency, i.e. separating a balance island should be OK. It is OK to utilize temporary SPS while the permanent corrective measure is being put in place. 6. Need to define, perhaps in the list of definitions, what is the "bus-tie breaker." Differentiation of center breakers in breaker-and-one-half schemes is a crucial item not to be subject to interpretation and possible confusion. 7. Need to clarify that "stuck breaker", regardless of whether cause by protection system failure, breaker failure to operate, or a slow breaker, is de-facto delayed clearance and causes additional contingency (ies). 8. Firm Transfer Cell for P3 does not make sense. 9. Need to strengthen the notion, in the bullets at the top of Table 1, that the assessment should also cover n-0 or "normal state (seems to be adequately covered in the body of the standard, but does not jump out from the Table 1 bullets at the head of the table.) 10. Include SHUNT DEVICES in P3–P9 planning contingencies. The same comment is applicable for stability table. 11. Need to clearly specify what documentation would be required to fulfill the standard's requirements for assessing extreme contingencies. 12. Replace "all" in the Extreme Events subheading with a more appropriate term. 13. Replace "all" in the table for Extreme Events for both Steady State and Stability tables with a more appropriate term to manage documentation requirements. 14. Use different designations for planned and extreme events in steady state and stability tables, e.g. PS and ES for steady state and PD and ED for stability (D for dynamic). 15. Throughout the tables, do not refer to "internal" breaker faults but use breaker fault instead. Faults can occur internal to the breaker, flashed bushings, or a fault (on or within) a free-

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Commenter	**Yes**	**No**	**Comment**
			standing CT associated with the breaker. 16. Modify bullet 5 in the Stability Table to include SPS failures to read: "Simulate the removal of all elements that Protection Systems, SPS or RAS systems, and controls are expected to disconnect for each Contingency." If an SPS or RAS is expected to operate for a contingency, it must be modeled as such for that contingency study. 17. In R1.2 need to add "for the period analyzed" and defined what "stressed" conditions means. 18. In R 2.1.3.7 need to insert "long-term" in front of "transmission outages." There is also a need to clarify/describe/define what long-term transmission outage is. 19. There are concerns, particularly for NON-vertically integrated TPs, about need of including Plant Stability requirements. 20. Define what "material" change is in R2.5.2. 21. Presumably the standard will be stamped with a CEII designation 22. Additional granularity should be included showing the correlation between Requirements and their applicability to any of the Functional Model Entities cited in the Standard. 23. Obligations to study and share results of the following should be clear in the TPL Standards: • Analysis of impacts on your system for contingencies outside of your system footprint. • Analysis of impacts on other systems for contingencies within your system. The owners of the other systems should be notified of your findings and joint analysis should be done if warranted. • Powerflow and stability analysis of contingencies that have interconnection-wide impacts. This may best be accomplished through modifications to existing standard TPL-005.

Response: 1. The SDT revised this definition in response to various comments.

Consequential Load Loss: Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet

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Commenter	Yes	No	Comment
steady state performance requirements. 2. The SDT revised this definition in response to various comments. The SDT believes the revised definition addresses the concern expressed in this comment. **Non-Consequential Load Loss:** ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss. 3. The SDT is sensitive to need for an implementation policy to allow for Transmission Owners to respond to requirements that involve raising the bar, but an implementation plan was not developed for this posting. The SDT anticipates developing an implementation plan in response to the next posting. 4. The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT felt the 300 kV and higher Systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. When EHV Systems are compromised, the large volumes of power served by them can place a severe amount of stress on parallel EHV or lower voltage paths. For example, if large EHV transformers experiences a catastrophic failure, not only are other System Facilities required to carry more Load but the System is also exposed to other N-1 conditions for long periods of time while awaiting a replacement or repair of the failed equipment. Large generation sources are typically connected at EHV levels and maintenance of the EHV Transmission lines within the vicinity of larges generation plants must often be coordinated during scheduled unit outages, resulting again in multiple Facility outages over extended periods of time. Therefore, it was the conclusion of the SDT in Draft 1 to propose greater reliability and operational flexibility through more stringent performance requirements when considering certain N-1 and N-1-1 Contingency events of EHV Systems. Throughout the industry substation arrangements at EHV levels reflect the importance of these Systems as the designs often consist of the more expensive ring-bus, breaker-and –a-half or double bus-double breaker protection schemes as opposed to the more simplistic and lesser cost single bus arrangements that are commonly found on lower voltage Systems. The feedback received from industry was divided related to the SDT's emphasis placed on a higher expectation for the 300 kV and higher Systems. Some commenter's questioned the importance and the high costs that may be needed to mitigate existing System designs. Others agreed with the SDT's approach and indicated that the impact to their Systems would be minimal. Some commenter's even questioned why the more stringent approach was not applied to the entire 100kV and higher Systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission System.			

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Commenter	Yes	No	Comment
5. The SDT has revised requirements to include changes related to the allowable use of SPSs related to N-1 events. See new Requirement R3.5 of the Draft 2 TPL-001 standard which indicates SPSs are permitted for automatic generation runback or tripping following a single contingency event. **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~iesy~~ ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met: 6. The SDT has proposed a definition for bus-tie breaker in the second draft. **Bus-tie Breaker:** A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.) 7. Tables 1 and 2 have been revised to provide greater clarity. The SDT has accounted for both stuck breaker and Protection System failures as two unique Planning Events. See performance table requirements for Planning Events P4 and P5. 8. The SDT concurs and changes have been made to the performance Tables 1 and 2. The SDT has completely reformatted the performance tables in Draft 2 of the TPL-001-1 standard. The new format more closely mimics the existing approved TPL standard Table 1, with enhancements we feel the industry will find valuable. 9. The SDT concurs and has added a P0 Planning Event at the top of Table 1 to address the N-0 (existing Category A) condition. 10. The SDT has modified the tables to include shunt devices where appropriate. 11. Changes were made to simplify and clarify Extreme Event expectations. Please refer to both performance tables and Requirements R3.4 (steady-state) and R5.5.4 (Stability). 12. The statement has been revised to say "For all Extreme Events considered". 13. The statement has been revised to say "For all Extreme Events considered". 14. The Planning Events for steady-state and Stability now correlate one-for-one, so the SDT does not feel a need to distinguish each uniquely. The Extreme Events are not presently listed in a tabular format with the formality of the Planning Events. This is somewhat intentional to draw greater emphasis and focus to the Planning Events. If you feel changes are needed in our presentation of the Extreme Events within the performance tables, the SDT would be open to a suggested format from TIS. 15. Tables 1 and 2 have been revised to explain "internal breaker fault" (see Note 5 in Table 1 and Note 4 in Table 2). With this change the term "internal breaker fault" was retained. 16. The SDT believes that SPS/RAS is included in Protection Systems as defined in the NERC Glossary. 17. The SDT has revised the data and modeling requirements based on industry comments to clarify intent. **R9.** Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information. **R10**. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission			

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Commenter	**Yes**	**No**	**Comment**
planning horizon, within ninety days of a request for such information. **R11.** Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information. **R12**. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information. **R13**. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information 18. Since this requirement is relating to sensitivity, it is up to the entity to determine if it is appropriate to reduce the length of or increase the length of the "planned outage" that it has considered in its base case studies. 19. The SDT has reviewed the need for Plant Stability and has concluded that it is appropriate to include it in this standard. It also felt that this was responsive to FERC Order 693. 20. The SDT has changed the wording to provide clarity. **R2.5.2**. Material Transmission System changes ~~in the electrical vicinity of existing generation are made~~ are made at or near the point of Interconnection of existing Generation such as the ~~addition or~~ removal of a Transmission Line ~~at or near the point of Interconnection~~ or the addition of a new substation in one of the Transmission Lines connected to the plant. 21. The Standard is public information. Individual reports may need to be reviewed by the individual entity to ensure compliance with CEII. 22. References to entities have been added. 23. R6 requires "coordinating analysis of these results through an open and transparent process". By this requirement the SDT meant a stakeholder process that was set up to meet the requirements of FERC Order No. 890 with regard to an Attachment K filing of a Transmission Provider's Transmission Planning Process. The SDT has made a change to clarify this requirement (see R8 in draft 2). **R8**. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~affected entities~~ neighboring systems, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890.			
NCEMC	☑		1. Planning Coordinator: The definition of Planning Coordinator should be kept within this document rather than relying on the NERC Functional Model as we believe that this entity has an important role in insuring coordination of transmission and resource plans. Coordination: 2. During the teleconference, one issue brought up was the matter of external contingencies being

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Commenter	**Yes**	**No**	**Comment**
			tested as a part of a TP's analysis. The reply was that this issue will be addressed outside this draft standard (TPL-005 and TPL-006) or would be accounted for in the coordination efforts among Transmission Planners. NCEMC is of the opinion that Requirements R5 and R6 need further details to insure adequate anlysis between and among Transmission Planners having varying local planning criteria so that Seams Issues are addressed that are not currently being address in regional and inter-regional studies. To the extent possible, timing of studies should be required to insure coordination between regional and inter-regional groups. Significant Increase in Study Activity Workload on Transmission Planners: 3. The increase in both steady state and dynamic studies required to ensure compliance with the proposed standards will result in increased costs and staff additions. The addition of the "Corrective Action Plan" requires the TP to provide a significant amount of documentation for each deficiency identified by the studies. Also, R3.2 requires that the studies simulate the protection scheme for all events. The current software tools cannot automate these studies for bus faults and breaker failure events, requiring each scenario to be studied manually. Additionally, experienced staff capable of performing analyses as described in the proposed standard have become increasingly difficult to find and retain and the talent pool of people with these skills has recently become depleted to alarming levels. Implementation Plan: 4. Given the intent of the proposed standard to encourage large scale investment in the EHV system, full implementation will take years, perhaps decades. Acquirement of right-of-way for new EHV lines has become increasingly difficult in recent years and inreasingly expensive. Legal, regulatory, and other difficult issues often take several years to navigate, even for 115kV lines. The Implementation Plan timeframe, if set too short, would be unduly burdensome on Transmission Owners forcing them to be less dicretionary with funds than would be prudent. The proposed implementation plan should include provisions for those cases where viable solutions simply can not be implemented in time due to circumstances beyond the control of Transmission owners. A reasonable period for transition is order. Design and Construction Constraints: 5. Even if right-of-way and other legal and regulatory hurdles are cleared, and the capital funding for such a tremendous level of investment was not an issue, the other resources required to actually construct the projects are equally difficult and costly to secure. Raw material prices on comodities like copper and steel have skyrocketed in recent years. Additionally, the skilled labor and Engineering resources are constrained with labor rates almost keeping up with other resource costs. Overall project costs have more than doubled over the last 7-10 years. Recent press releases concerning new generation being planned and then scrapped due to the rapid escalation of project

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Commenter	**Yes**	**No**	**Comment**
			costs are public evidence of this. The inflationary mark-up is impossible to estimate but much less will be built with the same capital investment than is currently envisioned. Cost-Benefit Analysis: 6. The proposed standard will be exceedingly expensive to become compliant with unprecedented levels of capital investment in Transmission facilities. Before the standard comes to official vote, it would be prudent for a cost-benefit analysis to be performed to determine if the reliability improvements truly justify the huge expenditures certain under the proposed standard. Additionally, as many jurisdictional rate structures share the cost of such investments between retail and wholesale customers, cost-benefit analyses should be completed for both retail and wholesale customers. System Adjustment Clarification: 7. It has already been noted earlier but deserves repeating here: The term "System Adjustment" as outlined in the tables should be better defined. The use of generation for redispatch may have nuances which preclude or otherwise limit their use for studies. Perhaps some clearer guidelines on what is allowed would facilitate transparency and coordination between Transmission Planners. Transmission Service Evaluation: 8. A major concern is that the proposed standard appears to be disjointed from the requirements for selling firm Transmission Service. The increase in reliability gained from the proposed standard would, in some regions, quickly be eroded by new firm sales if those sales are based on the historical N-1 ATC requirements. The proposed standard must be applied to long-term firm transmission service requests if Transmission reliability is to be truly enhanced. If the standard is not applied to Transmission Service evaluation, reliability levels for the different classes of firm customers will diverge. Stakeholder Process: 9. As a Transmission-Dependent Utility and Network Customer within 3 different Balancing Autorities with one being a Regional Transmission Organization, NCEMC cannot stress enough the need for a Stakeholder Process for coordination Transmission Planning that may impact Load-Serving Entities and other entities involved. It is critical to address reliability needs of all taking transmission service today and in years to come.
Response: 1. The SDT modified the definition and the definition will be approved with the standard and added to the Glossary of Terms Used in Reliability Standards. 2. R5 (R7 in second draft) requires the determination of the entities responsible for the portion of the studies. R6 (R8 in second draft) requires "coordinating analysis of these results through an open and transparent process". By this requirement the SDT meant a stakeholder process that was set up to meet the requirements of FERC Order No. 890 with regard to an Attachment K filing of a Transmission Provider's			

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Commenter	**Yes**	**No**	**Comment**
Transmission Planning Process. In addition, NERC Standards are to specify the requirements, which must be met and not "how" they are met. The SDT has made a change to clarify this requirement (see R8 in draft 2). **R8**. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~affected entities~~ neighboring systems, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890. 3. The SDT understands the potential increases in work load. The draft standard allows the use of past studies to meet the current year assessment and study requirements. Requirement R3.2 does not require study of the protective scheme for all events, only that "Contingency analyses shall simulate the removal of all elements including those that System protection is expected to disconnect for each Contingency without operator intervention". For example, the requirement is that the outage simulation should be from breaker to breaker. In addition, Requirement R.3.2.2 only requires the studies consider relay loadability and identify how loadability is treated in the steady state simulation, not to study relay loadibility. 4. The SDT understands that there are extended transitionary issues associated with responsible entities becoming compliant with the new standard. The SDT plans to draft an extended implementation plan to accommodate such issues. The plan will be provided for the third posting of the standard. 5. The SDT understands that there are extended transitionary issues associated with responsible entities becoming compliant with the new standard. The SDT plans to draft an extended implementation plan to accommodate such issues. The plan will be provided for the third posting of the standard. 6. Cost issues are outside the scope of NERC reliability standards. 7. The Transmission performance tables have been modified to bring clarity to the Contingencies required for performance studies and when Non-Consequential Load Loss is permitted to meet requirements. The use of manual or automatic System adjustments to revise System topology as well as generation redispatch is always permitted so long as the actions can be performed while adhering to Facility Ratings. 8. Any requests for long-term Transmission service need to be studied in accordance with peformance requirements. 9. This draft standard addresses the requirement for coordination of studies in an open and transparent process (see Requirement R8 in draft 2).			
NCMPA	☑		Much of the language in R1 is redundant, because the MOD standards already address what data are required for modeling purposes. Including data requirements here, as well as in the MOD standards, will introduce the possibility of inconsistencies between the two as well as unnecessary duplication of work for entities providing the data. If any changes need to be made to what data are collected or to whom it is provided, those changes should be made in the MOD standards, not by adding data requirements to this standard. As for most every standard written, some consideration should be given to the cost of meeting the more stringent requirements proposed for this standard. While it might be possible to make incremental improvements in reliability, it may not be cost-effective, particularly given the low probability of some of the events addressed in the standard. Before stakeholders are asked to vote on this standard, a cost-benefit analysis should be performed to provide what would be an otherwise missing, but very important piece, of information about whether the costs of complying with the

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Commenter	**Yes**	**No**	**Comment**
			requirements of this standard are justified based on the reliability improvements that would be achieved.
Response: 1. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. 2. The treatment of Transmission infrastructure costs is outside the scope of the NERC reliability standards.			
OPPD	☑		The terms Bus Tie Breaker and Non-Bus Tie Breaker used in Tables 1 and 2 are not well defined. To prevent misinterpretation of the standard, include diagrams that point out examples of bus tie breakers and non-bus tie breakers for each of the following bus schemes: 1) Single bus 2) Ring bus 3) Breaker and a half 4) Double bus double breaker.
Response: The SDT has proposed a definition for Bus-tie Breaker in the second draft. **Bus-tie Breaker:** A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)			
PJM	☑		1. Delayed clearing due to primary relay system communication failure 2. Bus Contingencies should not be included for sensitivity/stressed case 3. Sensitivity case should not be included for long term study 4. Need to clearly define number of studies required for Load Flow/Stability and what performance criteria must be met. • Peak Case • Off Peak • Sensitivity 5. Need to allow SPS operation after a first contingency, system readjustment and a "second " first contingency. 6. SPSs can include generation tripping
Response: 1. The SDT does not understand the question and therefore can't respond. 2. Bus Contingencies are just one type of sensitivity that could be included but is not mandated. 3. Sensitivities are not required for long-term. 4. The SDT believes that the number of studies is clearly defined. 5 and 6. The SDT agrees that SPS can include generation tripping. The SDT has modified the requirements to allow SPS for single and multiple Contingencies (See Requirement R 3.5). **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:			

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Commenter	**Yes**	**No**	**Comment**
PRPA	☑		1) P5 and P8 in Tables 1 and 2 – If you keep the "300 kV bar" for distinction between P5 and P8, then please make an exception for P5 to be "Yes" on Non-Consequential Load Loss where load pockets (a.k.a. local load-serving areas) are concerned because "system adjustments" might not be possible to avoid the need for Non-Consequential Load Loss after the loss of another line into the load pocket. Example - A city, which is a type of load pocket, is served by three transmission lines. If one of the lines into the city is removed from service for maintenance, "system adjustments" within the city might not be possible to prevent steady-state voltages from dropping below an acceptable limit after loss of a second line into the city. If during such an "N-1Line-N1Line" Planning Event the city voltages become extremely low, then shedding of some of the city's load should be allowed, i.e. Non-Consequential Load Loss, for all voltages 100 kV and above. In this example, when one line into the city is removed from service, the TOP could either arm an SPS or RAS for automatic load shedding, or alert the operators to possible implementation of an Operating Procedure for manual load shedding. The city, along with its TO and other authorities, may decide by their own wishes to "raise the bar" and add facilities to maintain acceptable voltages for the worst "N-1Line-1Line" affecting only its local area. However, a facility addition type of solution, driven by a "No" for Non-Consequential Load Loss in P5, should not be mandated. "Controlled interruption of electric supply to customers (load shedding)" should be allowed for all voltages 100 kV and above as Footnote (c) in TPL-003 allows. Consistent with this request to allow load shedding for this type of disturbance for all voltages 100 kV and above, FERC Order No. 693 in Paragraph 1825 regarding TPL-003 for Category C disturbances (including "N-1Line-1Line") does not ask for "controlled load interruption" to be eliminated, but rather FERC directed the ERO to modify footnote (c) to Table 1 to clarify the term "controlled load interruption". And please note FAC-010-1, R2.5 – "Planned or controlled interruption…(load shedding)…" for TPL-003 conflicts with "No" for Non-Consequential Load Loss in P5 of Draft TPL. 2) Proposed revision to R3.5 – "Manual and automatic generation runback and generator tripping are allowed as a response to single and multiple contingencies as long as Facility Ratings are not exceeded and the result of the generator action, such as location and ramp-up speed of the AGC unit(s) responding to the generation trip or runback, loss of reactive resource, impact on reserves, and restart time of tripped unit(s), meets the performance requirements." Planning and Operations need flexibility to coordinate with the requirements of Engineering who established the Facility Ratings. It should not matter which method of generation redispatch is employed if all impacts of tripping vs. running back a generator are properly considered and performance requirements are met. The time period for a particular Emergency Rating might require

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Commenter	**Yes**	**No**	**Comment**
			faster generation redispatch than a runback or set of runbacks are capable of providing. Therefore, it may be necessary to trip one 100 MW unit rather than runback several units for a total of 100 MW. No need for R3.6 with above revision to R3.5.
Response: 1. The SDT has completely reformatted the performance tables in Draft 2 of the TPL-001-1 standard. The new format more closely mimics the existing approved TPL standard Table 1, with enhancements we feel the industry will find valuable. The SDT has responded to industry comments regarding higher performance requirements for facilities above 300 kV and have adjusted requirements for N-1-1 non-generator outages to permit Non-Consequential Load shed post-Contingency following the second event. We have retained a higher expectation for certain N-1 Contingencies occuring on the EHV System. See the Summary Response in Q20 through Q23 for additional information. 2. The SDT agrees that SPS can include generation tripping. The SDT has modified the requirements to allow SPS for single and multiple Contingencies (See Requirement R 3.5). **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:			
Progress–Carolinas	☑		1. In R4.6 and other locations, the generator exemption of 20 MW should be increased to 75 MVA. 2. Need to define bus-tie breaker. Is center breaker in a breaker and a half scheme a bus-tie breaker? 3. Need to continue to allow interruptions to firm transfers. This is essentially allowing redispatch and is an economically sensible solution to low probability high impact multiple contingencies. 4. Need to clarify if the "stuck breaker" is associated with the first event in multiple event contingencies or does one have to choose a breaker not involved with the first event. Note that a breaker cannot be "stuck" if there is no demand to trip. Therefore, a stuck breaker that is not adjacent to the first event will not have a demand to trip. 5. Need to distinguish what the difference is between a "stuck breaker" and a "[loss of breaker due to] internal fault". The specific meaning could make the difference in the clearing time selected for stability studies (normal clearing time versus delayed clearing time). 6. In the Table 2 (for stability) the last bullet under Planning events says to "simulate normal clearing times unless otherwise specified". Does this mean that "stuck breaker" events should be simulated with normal clearing times? Note that in the real world, internally faulted breakers may clear in either normal or delayed clearing time, depending on the relaying and CT configuration.
Response: 1. The limits cited are consistent with the registry criteria, Large Generator Interconnection Procedures, and FERC Orders. 2. No, a center breaker in a breaker and a half scheme is not considered a Bus-tie Breaker. The SDT has proposed a definition for Bus-tie			

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Commenter	**Yes**	**No**	**Comment**
Breaker in the second draft. **Bus-tie Breaker:** A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.) 1. Tables 1 and 2 have been revised to replace "firm transfer" with "firm Transmission service". 2. The SDT agrees and appreciates the feedback. The SDT has re-worked the tables, and believes the wording used for stuck breaker will satisfy your concern. Please see Planning Event P4 in each performance table. 3. Tables 1 and 2 have been revised to provide clarity. Please see Planning Events P2.1 and P2.3. 6. The sentence "simulate normal clearing times unless otherwise specified" refers to the events sepcified in the Tables. A stuck breaker would have clearing time that is "otherwise specified". The intent is to simulate "real world" events using the clearing times appropriate for the specific fault and breaker/Protective System configuration.			
Progress–Florida	☑		General Comments 1. NERC Standards TPL 001-0 through TPL 004-0 are approved standards that only required modifications pursuant to FERC Order 693. In this proposed draft standard TPL 001-1, the Standard Drafting Team (SDT) has far exceeded the recommendations suggested by FERC in the Order and has created unnecessary confusion. We disagree with the SDT's decision to combine NERC Standards TPL 001-0 through TPL 004-0 into one standard. Some changes to the existing TPL Standards may be warranted. One particular improvement would be clarifying the tables such that the table for TPL-001, for example, would only contain the performance criteria for Category A, with footnotes only applicable to that category, clarified as directed by FERC in Order 693. Similarly, TPL-002 would only contain performance criteria for Category B, and so on. In addition to combining the standards, the SDT has significantly changed contingency specifications and required performance levels. In many cases the changes represent a very significant increase in required performance standards that will result in the following: a) major capital expenditures, some of which will be of a magnitude unprecedented for the Bulk Electric System. Many of these projects would be constructed to mitigate one single low-probability event. The ratepayers, upon discovery of this necessity and realization that these significant expenditures will be passed on to them in their rates, will certainly object to these efforts and will question the wisdom of NERC's mandating change on such a massive scale without the knowledge or input of the public. The SDT stated in its continent-wide conference call on October 10, 2007 that the intent of many of the objectives contained in the proposed TPL-001-1 was to "raise the bar" for electric utilities. We would like to know specifically what this means. The phrase "raise the bar" is vague and overused in North American vernacular in general, and it is particularly irresponsible to use such vagaries when proposing standards which will result in unaffordable upgrades to the North

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Commenter	**Yes**	**No**	**Comment**
			American Bulk Electric System. b) reductions in ATC. To be compliant with the more stringent requirements of TPL-001-1, Transmission Operators would in many cases be forced to reduce ATC in order to decrease transmission flows to a point at which corrective actions may be taken without the result of cascading. This is diametrically in opposition to one of the key objectives of deregulation and comparable treatment for all entities engaged in transactions on the Bulk Electric System. c) Reduced Reliability. The elimination of footnote (b) will result in many outage scenarios for which loss of Non Consequential Load is presently unavoidable, but subsequently prohibited. For some scenarios, Transmission Owners may seek to avoid the excessive cost of a project by simply removing breakers from substations, thereby increasing the range of the initial breaker-to-breaker operation and essentially converting the disallowed Non Consequential Load to Consequential Load. This is obviously an undesirable option and in opposition to fundamental principles of reliability, but might be rendered necessary due to the increased requirements of TPL-001-1. d) Inability to react to issues of non-compliance. The dynamic nature of planning analysis is such that, from one annual planning cycle to the next, the constantly changing load and generation forecasts invariably result in emerging transmission projects unforeseen in previous cycles. With the increased stringency of TPL-001-1, reacting to these emerging needs in time to demonstrate compliance will be impossible, and thus non-compliance is seen as an inevitability. To further clarify, the major transmission projects that TPL-001-1 would necessitate would be of a magnitude such that extensive engineering, land acquisition and involvement with regulatory and governmental agencies would be required, which could result in project lead times of 10 years or more. Not only would a lengthy transition period be needed for TPL-001-1, but upon the Standard's effective date the ability to implement all future projects would need to be given special consideration in light of these challenges. In other cases, the performance criteria are not clearly defined, such as the timing between multiple contingencies, and the level of readiness of the system before and after Planning Events. Finally, the SDT has chosen to eliminate the footnotes in the current standards, contrary to the direction of FERC in Order 693 to "clarify" the footnotes. The purpose of the footnotes is to further explain terms in the tables, provide guidance in interpreting the expected performance criteria, and specify any exceptions to the criteria. Footnotes also serve the purpose of keeping the standard concise by eliminating repetitiveness.

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Commenter	**Yes**	**No**	**Comment**
			Specific comments on the Draft Standard Performance Criteria 2. The performance requirements table should clearly define what the initial state of the system is assumed to be before any Planning Events, and what the state of the system is assumed to be after the Planning Event. For example, P1 (single contingency) events: assuming that the system is to be compliant, the state of the system prior to the event must be "secure" such that the event could occur and there is no interruption of firm transfer or loss of load, Equipment Ratings are not exceeded, System steady state voltages and post-transient voltage deviation are within acceptable limits. However, the system is not as it was before the event. The system could be described as "normal" but perhaps not "secure". If the requirement is that the system must also be "secure" after the event, then the standard must clarify what is allowed for "system adjustments" after the first Planning event to prepare for the next. FERC Order 693 directed the ERO to modify the second sentence of footnote (b) to clarify that manual system adjustments other than shedding of firm load or curtailment of firm transfers are permitted to return the system to a normal operating state after the first contingency. However, in order to bring the system to a secure state, as is necessary for the second contingency of a category C3 or C5 event, footnote (c) allows curtailment of firm transfers, and FERC Order 693 only required footnote (c) to be clarify the term "controlled load interruption", leaving the curtailment language intact. The implication of this interpretation is critical to peninsular Florida. The Category B loss of one 500 kV line from Florida to Georgia is sustainable, such that the system is "normal" after the event. However, in order to be prepared for the next contingency, (the loss of the second 500 kV line), firm transfers must be curtailed (Interruption of Firm Transfer). Without the ability to curtail firm transfers, a "super-firm" priority of transmission service is created for non-native load customers, and thus comparable treatment no longer exists. Comments on New Performance Tables: The draft TPL standard represents a major change in the Table 1 contingency definitions and required performance levels. 3. Table 1 Contingencies C1 and C2 are being moved to the single contingency category. While C1 and C2 represent single element outages, their probability of occurrence is much lower than the other Category B contingencies and they do not belong in the single contingency performance requirements group. 4. Footnote (b) which permits, as a limited exception in unique circumstances with a sound rational basis, some localized load reduction for single contingencies, has been removed. This is a very significant change for some utilities. Footnote (c) which permits load shedding and curtailment of

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Commenter	**Yes**	**No**	**Comment**
			firm transfers has been removed from C1, C2 and most of C3. This is a very significant increase in required performance level that is not justified. 5. The "applicable rating" for loading and voltages in Table 1 has been removed so that essentially, the same ratings and voltage restrictions apply to both B and C contingencies. Some utilities plan to a normal rating for single contingencies but will allow a higher short term rating for Category C events. This practice appears to be either disallowed or inadequately described in TPL-001-1. Transmission Owners should allowed to base ratings on manufacturer specifications or other reasonable criteria using sound engineering judgment. 6. Several new Category D "Extreme Events" have been added which greatly expand the scope and complexity of Category D studies. These are (1) any two unrelated single element outages and (2) wide area events a. through h. These represent a major increase in the scope of Category D studies and probably a doubling of required SWG studies. It should be note that the existing Categories D1 through D4 have been substantially changed to eliminate analysis of relay failure contingencies. The philosophy contained in the existing TPL-004 standard is that faults with a protection failure should be evaluated whether that failure is a circuit breaker, relay or CT; the proposed standard restricts the analysis to breaker failure. 300 kV Threshold Performance Level 7. The TPL-001-1 draft sets a threshold of higher performance to facilities above 300 kV than previously established in the existing standard. We do not agree that such a threshold is necessary or warranted. Requirements which are more stringent for these facilities may wrongly influence decisions on project alternatives in favor of facilities with less stringent requirements. Additionally, facilities above 300 kV naturally tend to transport larger amounts of power. The loss of single or multiple facilities above 300 kV generally results in an immediate generation-to-load mismatch too great to avoid either curtailment of firm transactions or loss of Non Consequential Load, or both. Singling out facilities above 300 kV for more stringent requirements is therefore clearly unreasonable. DC Line Performance Requirement 8. The TPL-001-1 draft sets a lower performance requirement for the loss of a single pole of a DC line than in the existing standard by allowing interruption of firm transfer if the transfer is deemed to be dependent on the outaged line. Firm transfers are also dependent upon AC lines. The proposed standard does not distinguish between asynchronous DC ties and the more common parallel connected DC tie. With an asynchronous DC tie, the transfer is lost with the tie. With a parallel DC tie, the transfer will be shifted to the parallel AC system and should have the same performance requirements. We do not agree that such an exception for DC lines is necessary or warranted. The decision in selecting DC vs. AC in transmission lines has traditionally been based on the break-even

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Commenter	**Yes**	**No**	**Comment**
			cost and performance of the two alternatives. The lower performance requirement may wrongly influence decisions on project alternatives in favor of DC facilities with less stringent requirements. Distinction Between Committed and Proposed Projects: 9. Models cannot discern the difference between a "committed" project, and a "proposed" project in a performance analysis. The standard should instead set criteria for when models can be relied upon for planning purposes such that changes to the future plan will not have an impact on reliability. The intent of Requirements R2.7.3 and R2.7.4 should be combined and added into R2.7.1.1. Rather than adding the additional requirement to document a criteria, the requirement should be that in the Near-Term Planning Horizon, projects cannot be removed (or modified) without demonstrating that the revised plan meets performance criteria. In addition, the requirement in R2.7.1.1 to supply a "project initiation date" is ambiguous. What will constitute "project initiation" …construction start date? …Engineering complete date? …Land procurement date? Funds allocated date (budgeted)? Suggested wording for R2.7.1.1. "Transmission and generation improvement projects for the Near-Term Transmission Planning Horizon, shall have in-service dates provided, and shall not have in-service dates changed, or be removed from planning models, without documentation to show that the revised plan meets performance requirements." Load Modeling Requirements: 10. The proposed TPL Standard contains numerous references to load modeling. The goal of improving and verifying the load model is worthwhile but is not appropriate for the TPL standards. Assessment of load model accuracy is best accomplished through detailed analysis of grid disturbance events. The main difficulties in accomplishing this are (1) grid events that significant reduce transmission voltages throughout a load area are infrequently occurring and (2) the process of recreating the event through simulation studies is extremely complex and time consuming. While these efforts should be encouraged they should remain a RRO prerogative. A few concerns not previously addressed by comments to Questions 1-42 include the following: R1.1.1 Use of expected Load mix - based on the actual or expected aggregate mix of industrial, commercial, and residential Loads. – This requirement is not justified as the load model may be developed through disturbance analysis rather than load type synthesis by customer class. Some Load Serving Entities may have great difficulty in creating load forecasts based on customer class. Load forecasting requirements are adequately addressed in the existing MOD standards and do not belong in the proposed TPL standard. R1.2. Load models with supporting rationale - that include power factor data that may be based on historical System performance, validated by measurement during stressed System conditions, or

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Commenter	**Yes**	**No**	**Comment**
			documented Transmission planning area requirements. This requirement is not appropriate for the TPL standards. 11. R.3.3.2.1. Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment. – this Requirement in its present wording could be construed to mean that the precise amount of load between breakers should be specified and reevaluated with every assessment. This would unnecessary and burdensome, and we therefore seek clarification of this Requirement or its removal altogether. 12. Requirements for studies using Sensitivity cases: R2.4.3 appears to place equal importance on base cases and sensitivity cases with regard to the need to implement projects or Corrective Action Plans. Terms in TPL-001-1 using forms of the word "sensitivity" need to be clearly defined by the SDT. Additionally, the SDT needs to clarify its intent regarding required action based on results from sensitivity studies. We do not agree that results from sensitivity studies should be given equal standing with results from base scenarios, and we would particularly object to any insinuation that projects would need to be implemented to mitigate violations seen in a sensitivity involving speculative non-firm transfers. 13. Short Circuit Requirements: The new TPL standard also contains numerous references to short circuit analysis, which are new requirements that expand the TPL standards, but without specific testing or performance criteria. Evidence that short circuit studies have been performed is currently required in the existing FAC-002-0 Standard. Since the primary concern is the appropriate sizing of equipment and the prevention of equipment damage as opposed to overall grid reliability, we do not see the need for a set of requirements within the proposed TPL standard for short circuit studies. FRCC Specifics: One final specific issue concerns the topography and performance history of the Bulk Electric System in our particular region (FRCC). The FRCC system is a peninsular system having only one interface with the rest of the interconnected NERC system, and has historically demonstrated exceptionally high reliability with no events in recent history cascading beyond the FRCC system. While other areas of the NERC system may require some increased stringency in the TPL standards, PE feels that the adequacy of the existing TPL standards as they apply to the FRCC System has been extensively documented. Conclusion In conclusion, we believe that TPL-001-1 is unnecessary and burdensome. In particular, the

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Commenter	**Yes**	**No**	**Comment**
			elimination of footnote (b) will deny Transmission Owners and Transmission Operators the right to curtail Non Consequential Load in order to restore the Bulk Electric System. This elimination has absolutely nothing to do with the reliability of the Bulk Electric System; rather, it places the reduction of Customer Minutes of Interruption (CMI) ahead of reliability. Essentially, the emphasis of TPL-001-1 is inappropriately placed on the reliability of distribution feeders rather than the reliability of the Bulk Electric System. The fundamental objective of the existing TPL Standards has been to protect the reliability of the Bulk Electric System, and we believe all future TPL Standards should do the same. Given the aforementioned issues, we believe the proposed TPL standard is inferior to the existing Board approved TPL Standards, creates unnecessary confusion, and will require many iterations of industry comment and revision. As an intermediate approach, we would strongly urge the Standard Drafting Team that the existing TPL standards be modified to respond to FERC Order 693 directives, clarify any ambiguities, and that the proposed new standard not be pursued any further.

Response: 1. The SDT followed the suggestion of FERC in Order 693 to consolidate the 4 standards into 1 if possible. The SDT recognizes that it has it has raised the bar on performance in some areas and has done that due to criticisms and suggestions from various parties. The SDT realizes that this will have an impact and is working on an Implementation Plan that will address some of the concerns. This is a performance based reliability standard and does not and should not consider economics. The SDT has made numerous changes to the tables in an attempt to provide further clarity as to what needs to be done to achieve performance.
2. An Initial Conditions column has been added to the tables. The SDT has also changes several requirements in the tables to allow for more instances of where Load can be dropped.
3. The SDT studied available data and practices and determined that these Contingencies do belong in the single Contingency performance group.
4. Local Load pockets are recognized as a problem and the SDT will address them in a future revision.
5. The use of the defined term Facility Ratings was intentional to answer problems such as described here.
6. The SDT was responding to FERC Order 693 in the details for Extreme Events.
7. The SDT feels that 300 kV and above represents the backbone of the BES and as such warrants more stringent criteria.
8. This is the only comment received on this issue so no changes were made to the second revision of the standard. However, the SDT will continue to review the performance table in subsequent revisions.
9. This verbiage has been removed from the standard.
10. The SDT feels that the current MOD standards do not cover all of the modeling requirements for a planner. Therefore, the specific areas found lacking are described in the TPL standard. Once the MOD standards are revised appropriately, these requirements can be deleted from TPL. The SDT has re-written these requirements and they are now numbered Requirement R9 through R13.
11. R3.3.2.1 - FERC required documentation of Consequential Load loss in Order 693, paragraph 1795, (not Non-Consequential) and duration should be based on best judgment for the common cause of the event.
12. Addressing or not addressing deficiencies discovered as a result of runing sensitivity studies is at the discretion of individual entities. The language of the standard has been changed to require that the entity document why or why not the results of the sensitivities have affected the Corrective Action Plan.

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13. Short circuit studies are required as part of the Interconnection process. The TPL draft addresses on-going System changes and increases in available fault current due to the additions of circuits and resources, as listed in the Corrective Action Plan. Short circuit studies help determine appropriate equipment sizing and setting of protective relays. Such studies will help provide for a complete Corrective Action Plan, i.e., the installation of a transformer to resolve a System performance deficiency may require the installation of additional circuit breakers. FERC also noted the need to include this analysis to cover such conditions. The SDT has thoroughly considered the comments of all reponders. We believe that the revised draft of TPL-001-1 places the proper focus on BES reliability and the BES' mission to serve all firm Load under an appropriate range of Contingency events. Furthermore, the SDT believes that the current draft does in fact respond to the FERC Order 693 directives.			
ReliabilityFirst	☑		The requirement for short circuit studies (mentioned in R2 and included in all of R2.3) should be removed from this standard. Relay and protection engineers use a different type of software (Aspen and CAPE) for different reasons (to calculate phase and ground faults and perform relay coordination studies). Those types of studies should not be included in this standard and are totally separate from performing power flow and dynamics studies.
Response: The SDT believes that it is appropriate to include an assessment of the results of short circuit studies in the assessment of the reliability of the Transmission system. The standard does not specify requirements related to software or specific requirements of the studies.			
SRP	☑		The SDT should be commended for very good work at identifying many different issues of the TPL standards. However, TPL-001-1 should take into account the consequences of a Security-Based or Dependability-Based Misoperation (and failure) of the Protection System. 1) A Security-Based Misoperation of the Protection System may remove additional elements of the BES and could be listed in the table under "multiple contingency". 2) A Dependability-Based Misoperation (or Failure) of a non-redundant Protection System could cause long time delays in clearing faults and clear a large area of BES around the faulted Element. This type of failure may not provide local tripping or breaker failure initiation and remote Protection Systems would need to operate to isolate the fault or disturbance. Often the operation of the remote Protection Systems would cause long time delays in isolating faults and disturbances. a) The BES should be studied and those elements need to be identified where Dependability-Based Misoperations (or failures) would prevent meeting the performance requirements of Table 1 (Steady State) or Table 2 (Stability). This type of Misoperation (or Failure) will have to be included in the Tables. For example, some parts of the BES may be able to survive long time delayed clearing of faults caused by Dependability-Based Protection System Misoperations (or failures) and still meet the performance requirements of the tables. But other parts of the BES may experience cascading outages for this same scenario. One solution to minimize the consequences of Dependability-Based Misoperations (or failures) is to install redundant Protection Systems. The redundant Protection Systems would reduce the possibility of a single Dependability-Based Misoperation (or failure) from

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Commenter	**Yes**	**No**	**Comment**
			affecting the isolation of faults and disturbances. In addition, the TPL-001 standard will need definitions of Security-Based Misoperation and Dependability-Based Misoperation. The following definitions are used for PRC-004-WECC-1: Security-Based Misoperation: The incorrect operation of a Protection System or RAS for faults or disturbances outside the intended zone of protection. Security is a component of reliability and is the measure of a device's certainty not to operate falsely. Dependability-Based Misoperation: Any of the following ▪ The absence of a Protection System or RAS operation when intended ▪ A Protection System or RAS equipment failure is alarmed or indicated to operating personnel. ▪ A Protection System or RAS equipment failure is discovered. Dependability is a component of reliability and is the measure of a device's certainty to operate when required.
Response: To date, the SDT has done the following: Tables 1 and 2 have been revised. A Contingency involving the failure in the Protection System has been added as P5 in Tables 1 and 2. Also 2a-2d were added in the Table 2 Extreme Events. The SDT is continuing discussion on Protection System issues and will be making additional changes as appropriate in future versions.			
Santee Cooper	☑		1. Transmission Planners are currently able to maintain adequate levels of reliability using the existing TPL-001 thru TPL-004 standards. While incremental improvements can be made, it is not evident that prescribing more stringent planning requirements will result in significant reliability improvements. 2. Table 1 in the column titled "Interruption of Firm Transfer Allowed," does it pertain to point-to-point only, or does it also apply to network loads? Please explain how this provision is consistent with the requirement to re-dispatch to address system constraints. 3. There are no explicit performance requirements for normal system performance. 4. Requirement R1.1.2 refers to "normal weather patterns as agreed to by the Planning Coordinator(s) and the Transmission Planner(s)…" The standard and the ERAG MMWG need to be made consistent. 5. Requirement R2.3 There are no performance requirements for Short Circuit Studies. 6. Requirement R2.7.1.1 specifies a "project initiation date". This information is not needed for system reliability purposes.

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Commenter	**Yes**	**No**	**Comment**
			7. Requirement R3.2. There should be some flexibility for simulation of planning events. For certain areas of the BES, the resulting configuration after operator intervention could be more severe than the removal of all elements. For example, the operation of a transmission line with one end open may be more severe than opening both ends of the line. This respresents actual operation in order to restore service to stations on the line. 8. Requirement R3.3.2.1 requires an evaluation for "Consequential Load loss (expected maximum demand and expected duration). Load loss is not an ERO responsibility. 9.Requirement R3.3.2.2 does not permit the "shedding of firm Load or curtailment of firm transfers". This is not an ERO responsibility. 10. Requirement R3.6 states "Manual and automatic generation tripping is allowed for multiple Contingencies and for single Contingencies only in situations that meet all of the following conditions: TBD. Generators should be allowed to trip for single and multiple contingencies as long as Facility Ratings are not exceeded. In addition, generators should be allowed to trip for any condition that imperils the generator. System performance should be the criteria, not generator operating state. 11. Requirement R4.2 states "Contingency analyses shall simulate the removal of all elements including those that the System protection is expected to disconnect for each Contingency without operator intervention." Delete "including those". 12. Requirement R4.6.1 states that Plant Stability studies "Shall be performed for individual generating units 20 MW or greater…" Does this mean that studies must be performed for all units? Many plants have "sister units" that are essentially the same. This requirement seems to be excessive. 13. The R1 requirements should be deleted from this standard and should remain on the MOD standards. (MOD-010, MOD-012, and MOD-018) 14. Requirement R4.6.2 states that Plant Stability studies "Shall be performed for changes in the real power output of a generating unit by more than 10% of the existing capability or more than 20 MW whichever is greater." The meaning of this wording is unclear. 15. Requirement R4.6.3 states that Plant Stability studies "Shall be performed and evaluated for those Planning Events that would produce more severe System impacts and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. The

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Commenter	**Yes**	**No**	**Comment**
			identified Contingencies, at a minimum, shall be evaluated." The use of "evaluation/evaluated is unclear. Is an evaluation the same as performing a study? If not, what does it mean to select a contingency for evaluation? 16. The standard needs to define or describe the difference between a "bus" and a "bus section". 17. Table I, P3, P7.2, P9.6 and Table 2, P7 need some punctuation for clarification. Table I, P9.6 and Table 2, P9, why study replacing an outaged transformer with a spare? 18. The use of the terms "bus", "non-tie bus", and "bus section" are not clear. In P7-2 what is meant by the phrase or a bus and a stuck non-bus tie breaker ? Does this imply a bus or a bus section? How would you model this?

Response: 1. The SDT believes that more stringent planning ("raising the bar") is appropriate in some areas of the standard and will improve reliability.
2. The term "firm transfer" in Tables 1 and 2 has been replaced with "firm Transmission service".
3. Table 1 has been revised to include normal System performance requirements.
4. This requirement has been eliminated in response to various industry comments.
5. Short circuit duty is a Facilitiy Rating, and Facility Ratings shall not be exceeded.
6. The SDT agrees that this information is not required to meet reliability standards. It was specifically added as an additional piece of information in the Planning Assessment to allow some level of peer review within the NERC community and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them.
7. R3.2 - The SDT has added a line end open condition in P2.
8. R3.3.2.1 - FERC has jurisdiction over firm Transmission service. FERC allows the use of "equally or more efficient or effective approach" and firm Load is being used as a proxy for firm Transmission service.
9. This requirement is consistent with FERC Order 693.
10. The SDT agrees that SPS can include generation tripping. The SDT has modified the requirements to allow SPS for single and multiple Contingencies (See Requirement R 3.5).

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:

11. The SDT feels that the wording is equivalent.
12. The answer is yes it does.
13. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.

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Commenter	**Yes**	**No**	**Comment**
14. The SDT feels that the wording is clear as stated. 15. Evaluation is based on good professional judgment and knowledge of the System. It is not the same as a study. 16. "Bus section" is in the existing TPL standards; the SDT is not proposing to change its meaning. The SDT considered but has decided not to include a definition for "bus section". 17. Tables 1 and 2 have been revised. P9.6 has been deleted and replaced with a reference in Requirement R11 in the second draft. **R11**. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information. 18. The SDT has included a definition for Bus-tie Breaker. The SDT has clarified the event description for P7-2 (now P-4 in the second draft). **Bus-tie Breaker:** A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)			
SaskPower	☑		Saskatchewan commends the SDT for taking on this difficult and important task. We wish you good fortune. 1. Local area network load is allowed to be shed in Saskatchewan for single contingencies, and the interruption of firm transfers are allowed over our DC tie and AC tie-lines. The Saskatchewan Regulatory Jurisdiction has no plans to change this unless there is technical evidence to justify the increase in reliability versus the cost. 2. Also for P9-1, is there any justification for the selection of one mile? If there is none the development of exemption criterion should be delegated to the Planning Coordinator. It is not what Saskatchewan has used in designing its system, and it is going to involve a significant capital outlay for Saskatchewan with questionable reliability benefits. Saskatchewan will not support the default value of 1 mile unless there is a technical study (including reliability benefit versus cost) to support it as opposed to any other distance.
Response: 1. The SDT is required to address FERC Order 693 and cannot default to lowest common denominator. This issue is beyond the scope of the SDT and needs to be addressed at the NERC level. However, an Entity can request an "Entity Variance" in accordance with the NERC Reliability Standards Development Procedure (Page 27). **2.** The one mile allows for some measurable physical constraints to building separate lines in all locations, but limits the exposure to a fixed length, which is universally applicable. SaskPower can request an "Entity Variance" in accordance with the NERC Reliability Standards Development Procedure (Page 27).			
Seattle City	☑		The additional studies required by this proposed standards are going to put a burden on our utility. We do not have the additional human resources available to perform so much additional work. Also, the stipulation that no "non-consequential load" loss may occur will put a financial burden on our utility. We have always planned assuming that we would able to be shed residential load in case of

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Commenter	**Yes**	**No**	**Comment**
			an emergency caused by a N-2 event or regional outage beyond our control.
Response: The SDT believes that more stringent planning ("raising the bar") is appropriate in some areas of the standard and will improve reliability.			
SERC EC DRS	☑		1.In the Stability Performance Table, under contingency P8 with a line out add a generator contingency. and with a transformer out add a generator and a line contingency. 2. In the Stability table change the Extreme Events numbering to E1, E2, etc. 3. In R4.6 and other locations, the generator exemption of 20 MW should be increased to 75 MVA.
Response: 1. The transformer – line combination has been added. The SDT does not feel that the other cited events are a legitimate combination. If you have specific data to indicate otherwise, please provide it. 2. The SDT made changes to the format of Extreme Events. 3. This is consistent with FERC Order 693, the Large generator Interconnection procedures, and the registry criteria.			
SERC EC PSS	☑		Significant Increase in Study Activity Workload on Transmission Planners: 1. The increase in both steady state and dynamic studies required to ensure compliance with the proposed standards will result in increased costs and staff additions. The addition of the "Corrective Action Plan" requires the TP to provide a significant amount of documentation for each deficiency identified by the studies. Also, R3.2 requires that the studies simulate the protection scheme for all events. The current software tools cannot automate these studies for bus faults and breaker failure events, requiring each scenario to be studied manually. Additionally, experienced staff capable of performing analyses as described in the proposed standard have become increasingly difficult to find and retain and the talent pool of people with these skills has recently become depleted to alarming levels. Implementation Plan: 2. Given the intent of the proposed standard to encourage large scale investment in the EHV system, full implementation will take years, perhaps decades. Acquirement of right-of-way for new EHV lines has become increasingly difficult in recent years and inreasingly expensive. Legal, regulatory, and other difficult issues often take several years to navigate, even for 115kV lines. The Implementation Plan timeframe, if set too short, would be unduly burdensome on Transmission Owners forcing them to be less dicretionary with funds than would be prudent. The proposed implementation plan should include provisions for those cases where viable solutions simply can not be implemented in time due to circumstances beyond the control of Transmission owners. We recommend a minimum of 15 years for the transition. Design and Construction Constraints: 3. Even if right-of-way and other legal and regulatory hurdles are cleared, and the capital funding for such a tremendous level of investment was not an issue, the other resources required to actually

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Commenter	**Yes**	**No**	**Comment**
			construct the projects are equally difficult and costly to secure. Raw material prices on comodities like copper and steel have skyrocketed in recent years. Additionally, the skilled labor and Engineering resources are constrained with labor rates almost keeping up with other resource costs. Overall project costs have more than doubled over the last 7-10 years. Recent press releases concerning new generation being planned and then scrapped due to the rapid escalation of project costs are public evidence of this. The inflationary mark-up is impossible to estimate but much less will be built with the same capital investment than is currently envisioned. Cost-Benefit Analysis: 4. The proposed standard will be exceedingly expensive to become compliant with unprecedented levels of capital investment in Transmission facilities. Before the standard comes to official vote, it would be prudent for a cost-benefit analysis to be performed to determine if the reliability improvements truly justify the huge expenditures certain under the proposed standard. Additionally, as many jurisdictional rate structures share the cost of such investments between retail and wholesale customers, cost-benefit analyses should be completed for both retail and wholesale customers. System Adjustment Clarification: 5. The term "System Adjustment" as outlined in the tables should be better defined. The use of generation for redispatch may have nuances which preclude or otherwise limit their use for studies. Perhaps some clearer guidelines on what is allowed would facilitate transparency and coordination between Transmission Planners. Transmission Service Evaluation: 6. A major concern is that the proposed standard appears to be disjointed from the requirements for selling firm Transmission Service. The increase in reliability gained from the proposed standard would, in some regions, quickly be eroded by new firm sales if those sales are based on the historical N-1 ATC requirements. The proposed standard must be applied to long-term firm transmission service requests if Transmission reliability is to be truly enhanced. If the standard is not applied to Transmission Service evaluation, reliability levels for the different classes of firm customers will diverge.
Response: 1. The SDT understands the potential increases in work load. The draft standard allows the use of past studies to meet the current year assessment and study requirements. Requirement R3.2 does not require study of the protective scheme for all events, only that "Contingency analyses shall simulate the removal of all elements including those that System protection is expected to disconnect for each Contingency without operator intervention". For example, the requirement is that the outage simulation should be from breaker to breaker. In addition, Requirement R.3.2.2 only requires the studies consider relay loadability and identify how loadability is treated in the steady state simulation, not to study relay loadibility. 2. The SDT understands that there are extended transitionary issues associated with responsible entities becoming compliant with the new			

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Commenter	**Yes**	**No**	**Comment**
standard. The SDT plans to draft an extended implementation plan to accommodate such issues. The plan will be provided for the third posting of the standard. 3. The SDT understands that there are extended transitionary issues associated with responsible entities becoming compliant with the new standard. The SDT plans to draft an extended implementation plan to accommodate such issues. The plan will be provided for the third posting of the standard. Cost issues are outside the scope of NERC reliability standards. 4. The treatment of Transmission infrastructure costs is outside the scope of the NERC reliability standards. 5. The Transmission performance tables have been modified to bring clarity to the Contingencies required for performance studies and when Non-Consequential Load Loss is permitted to meet requirements. The use of manual or automatic System adjustments to revise System topology as well as generation redispatch is always permitted so long as the actions can be performed while adhering to Facility Ratings. 6. The SDT plans to draft an implementation plan. This implementation plan will address, among other issues, the other standards, which will need to be brought into alignment with this standard. The plan will be provided for the third posting of the standard.			
SERC RRS OPS	☑		Cost-Benefit Analysis: 1. Transmission Providers are currently able to maintain adequate levels of reliability using existing standards. While incremental improvements can be made, it is not evident that prescribing more stringent planning requirements will necessarily result in significant reliability improvements. 2. The proposed standard will be exceedingly expensive to become compliant with unprecedented levels of capital investment in Transmission facilities. Before the standard comes to official vote, it would be prudent for a cost-benefit analysis to be performed to determine if the reliability improvements truly justify the huge expenditures under the proposed standard. 3. In Table 1 in the column titled "Interruption of Firm Transfer Allowed," does it pertain to point-to-point only, or does it also apply to network loads? Please explain how this provision is consistient with the requirement to re-dispatch to address system constraints. 4. The terms "Consequential Load Loss" and "Non-consequential Load Loss" should be deleted and Table 1 should be modified to discuss "Planned Load Loss" and "Unplanned Load Loss". It should not matter if the load is directly connected to the failed facility or downstream and served by the failed facility. If the plan to protect the interconnected grid is to disconnect those loads using a manual process or an automatic scheme, then it should be allowed. 5. The R1 requirements should be deleted from this standard and should remain in the MOD standards.
Response: 1. The SDT believes that more stringent planning ("raising the bar") is appropriate in some areas of the standard and will improve reliability. 2. Any changes in the new draft Standard have been carefully weighed and discussed by the SDT. The SDT does not believe that a formal cost benefit analysis is required. However, if you have cost data which you would be willing to supply to the SDT, we will take it under			

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Commenter	**Yes**	**No**	**Comment**
consideration. 3. Tables 1 and 2 have been revised to replace the term "firm transfer" with "firm Transmission service". 4. The SDT feels that the terms are being used consistent with FERC Order 693. 5. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.			
SCE&G	☑		General Comment. 1. Cost/Benefit analyses should be conducted on each change in a standard or new standard. 2. Requirement 7.2 will require a 2 bus outage test on the SCE&G transmission system. Most of our busses are straight busses and a stuck line-terminal breaker will result in a clearing of the connected bus (and all facilities connected to that bus). Our read of this requirement is that we must design the system to accommodate a stuck breaker event (outaging all connected facilities) while a different bus (and all of its connected facilities) is already outaged. This is a significant leap in the required performance of our system and will result in tremendous unwarranted costs and years of new local area transmission construction. 3. Requirement R1.1.2 refers to "normal weather patterns as agreed to by the Planning Coordinator(s) and the Transmission Planner(s)…" The ERAG MMWG considers normal weather to be such that the weather affected load to be that which has a 50% probability of, plus or minus. The standard and the ERAG MMWG need to be made consistent. 4. Requirement R2.7.1.1 specifies a "project initiation date". This information is not needed for system reliability purposes. 5. Requirement R3.3.2.1 requires an evaluation for "Consequential Load loss (expected maximum demand and expected duration). Load loss is not an ERO responsibility. 6. Requirement R3.3.2.2 does not permit the "shedding of firm Load or curtailment of firm transfers". This is not an ERO responsibility. 7. Requirement R3.6 states "Manual and automatic generation tripping is allowed for multiple Contingencies and for single Contingencies only in situations that meet all of the following conditions: TBD. Generators should be allowed to trip for single and multiple contingencies as long as Facility Ratings are not exceeded. In addition, generators should be allowed to trip for any condition that imperils the generator. System performance should be the criteria, not generator operating state.

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Commenter	**Yes**	**No**	**Comment**
			8. Requirement R4.2 states "Contingency analyses shall simulate the removal of all elements including those that the System protection is expected to disconnect for each Contingency without operator intervention." Delete "including those". 9. Requirement 4.6.1 states that Plant Stability studies "Shall be performed for individual generating units 20 MW or greater…" Does this mean that studies must be performed for all units? Many plants have "sister units" that are essentially the same. This requirement seems to be excessive. 10. Requirement 4.6.2 states that Plant Stability studies "Shall be performed for changes in the real power output of a generating unit by more than 10% of the existing capability or more than 20 MW whichever is greater." The meaning of this wording is unclear. 11. Requirement 4.6.3 states that Plant Stability studies "Shall be performed and evaluated for those Planning Events that would produce more severe System impacts and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. The identified Contingencies, at a minimum, shall be evaluated." The use of "evaluation/evaluated is unclear. Is an evaluation the same as performing a study? If not, what does it mean to select a contingency for evaluation? 12. The standard needs to define or describe the difference between a "bus" and a "bus section" and ensure that the use of these terms in the standard are as intended. 13. Table I, P3, P7.2, P9.6 and Table 2, P7 need some punctuation for clarification. 14. Table I, P9.6 and Table 2, P9, why study replacing an outaged transformer with a spare?

Response: 1. Any changes in the new draft Standard have been carefully weighed and discussed by the SDT. The SDT does not believe that a formal cost benefit analysis is required. However, if you have cost data which you would be willing to supply to the SDT, we will take it under consideration.
2. The SDT feels that this requirement is appropriate for a North American standard. The eventual Implementation Plan will address the timeframe for compliance.
3. This requirement has been eliminated in response to various industry comments.
4. The SDT agrees that this information is not required to meet reliability standards. It was specifically added as an additional piece of information in the Planning Assessment to allow some level of peer review within the NERC community and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them.
5. The SDT disagrees. FERC Order 693, Paragraph 1794 specifically prohibits loss of Non-Consequential Load for a single Contingency. Furthermore, FERC required documentation of Consequential Load loss in Order 693, paragraph 1795.
6. R3.3.2.2 - R3.3.2.2 has been revised and the phrase "shedding of firm Load or curtailment of firm transfers" has been deleted.

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Commenter	**Yes**	**No**	**Comment**
R3.3.2.2. Following single Contingency events, ~~System adjustments other than shedding of firm Load or curtailment of firm transfers are permitted to meet performance requirements provided these adjustments can be accomplished within the time period allowed by the applicable time limited ratings.~~ Transmission configuration changes and redispatch of generation are allowed provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits. 7. The SDT agrees that generation tripping can be included. The SDT has modified the requirements (See Requirement R 3.5). **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met: 8. The SDT feels that the wording is equivalent and no changes are necessary. 9. and 10. This is consistent with FERC Order 693, the Large generator Interconnection procedures, and the registry criteria. 11. Evaluation is based on good professional judgment and knowledge of the System. It is not the same as a study. 12. The SDT considered but decided against adding a definition because the term "Bus Section" is in the existing TPL Standards and its meaning is generally understood. 13. Tables 1 and 2 have been revised. 14. P9.6 has been deleted and replaced with a reference in Requirement R11 in the second draft. **R11**. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information.			
Southern Transm.	☑		REQUIREMENTS: 1. The standard is not clear on whether corrective action plans are required for performance failures during the sensitivity analysis required for both steady-state and stability studies. In the phone conference John Odom stated that it was not the intent of the Drafting team to require that facililities be constructed for these conditions. The standard should be made clear on this point. 2. The Load Forecast section (R1.1) is new and is a duplicate of the requirements in the MOD standards and is unclear as written. Having similar requirements in multiple standards creates the possiblility of conflicting requirements for the industry. If there are different requirements necessary, the MOD standards should be modified and not introduce a new section to the TPL standards. 3. R1.1.1 is unclear in what is intended by the "actual or expected aggregate mix of industrial, commercial, and residential load". Does the word "aggregrate" mean that the split between customer classes should be at the Balancing Authority level or at each load bus represented in the model. In many cases this could place a requirement for substantial load research on the the industry which may take a substantial amount of time and expense to accomplish. The use of the phrase "actual or

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Commenter	**Yes**	**No**	**Comment**
			expected" indicates an expectation that it be based on research and not general industry averages as may be more practical in some cases. 4. The wording in section R1.2 is very unclear. Is the intent to allow for three different methods for obtaining power factor models, i.e. historical system performance, validated by measurements during stressed System conditions, or documented Transmission planning area requirements? The other understanding is that the historical System performance is only measured during stressed System conditions. If this is the intent, what is the definition of stressed system conditions that is intended? Is this just heavy loadings, such as peak times, or is it during sytem disturbances? This is not clear. We suggest that the following words be used instead: "Load models validated by measurement during load levels typically studied or documented Transmission planning area requirements." 5. Requirement R1.4 should be qualified as only the outages within the Planning Horizon. There is no need to include protective relays because outages of relays in the Planning Horizon would not be known. We suggest the following words: "Known planned outages within the Planning Horizon and long-term outages greater than one year within the Planning Horizon for Transmission and generation equipment with consideration given to spare equipment strategy." 6. R1.5: If this places a requirement on the PC to define what constitutes "planned facilities", then this should be explicitly stated as a requirement. 7. R2.1 allows Assessments to be supplemented with "qualified" past studies which are defined in R2.6. R2.6.1 specifies these to be less than three years old for steady-state analysis and certain changes could not have occurred in the "System". There should be some qualification to the definition of "System" to include "the vicinity" of the area under evaluation. We would surmise that there always be some change in topology in the Eastern Interconnect which would preclude the use of past studies. Note that the "in the vicinity of" wording is used with the plant stability studies already. Also, is the intent with the "less than" to eliminate the use of studies three years old? Similar comments can be made for R2.6.2 and R 2.6.3. 8. R2.1 The wording/structure is confusing. The "Planning Assessment shall address all five years", but this does not require all five years be studied. It appears that the minimum study requirements would be two peak studies (years 1 or 2 & 5), one off peak study (any year), and one senstitivity case for each. Is this a correct reading? 9. In R.2.1.3.1 it is unclear what is intended. The study can be for higher or lower load "forecasts" with a different load power factor due to season, weather, or time of day. If you are looking at different seasons, weather, or time of day you will have a different load forecast. Is the intent to

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Commenter	**Yes**	**No**	**Comment**
			require the studies to model different seasons or times of day that will generate different power factors or is it to focus on higher or lower loads, i.e. is it a load forecast exercise or a power factor exercise? Can we look at Spring conditions and have it qualify for this requirement even though the loads are consistent with my Base Case load forecast? 10. Requirement R2.1.3.3 lists "unavailability of long lead time facilities" as one of the sensitivity(ies) that should be evaluated. It is unclear whether this refers to the construction of projects with long lead times or for replacement of failed equipment that have long lead times for obtaining replacements. One of the drafting team members suggested it was the latter understanding that was intended. We suggest that the language be changed to "Delayed restoration to service of failed facilities with long lead times for repair". This may clarify the intent of the requirement. 11. R2.1.3.7 should be modified to read "Modification of planned long term Transmission outages." 12. R2.3.1 Does "current study" refer to an updated study or is this referring to some type of short-circuit analysis? It appears that analysis is required only every five years unless changes in the BES occur. Is this a correct reading? 13. R2.4: Need to clarify that "address all five years of the assessment period" does not necessarily require that each year must be studied individually. A study of one year could cover all 5 years if it is the worst case. 14. R2.4.3.2 Is the purpose of including non-firm transfers to identify generation limits? Please clarify that the intent is not to require constraints associated with non-firm transfers to be addressed. 15. R2.5.2: The addition of a transmission line always helps plant stability. Therefore, this should not be included as a change requiring a new study. 16. R2.7.1.1 requires that the action plan include a project initiation date as well as the in-service date. The project "initiation date" is not defined and can be interpreted as being when you thought up the project, when you started spending money on design, or when you actually started construction. As long as you have the in-service date when the project is needed, we do not see any major benefit from recording and documenting an "initiation" date. The length of time that it requires to complete a project is extremely variable based on many conditions so we're not sure what benefit, if any, will be gained by recording and documenting the initiation date. It may be impossible for someone not familiar with the legal, regulatory, etc. requirements in a given area to judge whether the timing is appropriate or not. This requirement should be eliminated.

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Commenter	**Yes**	**No**	**Comment**
			17. R2.7.5 calls for the review of the implementation status of facilities. This imposes a large documentation requirement which has no benefit in reliability. We suggest making this requirement on an "as requested" basis. 18. Requirements 3.2 and 4.2: Delete the words "including those" so that it reads "the removal of all elements that System protection is expected...". As currently written, it sounds like you are going to remove more elements than the protection will remove. 19. R3.2 requires that the contingency analysis shall simulate the removal of all elements including those that System protection is expected to disconnect for each contingency without operator intervention. At present most steady state analysis uses single "element" contingency with element defined as transmission lines or transformers as defined in the Power Flow cases. In a significant number of cases these individual "lines" are part of a larger "protection control group" (PCG). that would remove multiple elements encompased by the breakers in the PCG The present load flow tools (PSS/E) do not have features that will allow this type of analysis in an automated manner. To facilitate this change in required analysis, program modification will be needed or additional programs written. For an example with a line from bus A to B and then B to C with breakers at A and C and load at B, the outage of either A to B or B to C with load service remaining at Bus B may produce a more stringent condition than removing A to B to C. It appears that the new requirement is requiring the A to B to C analysis instead of the more stringent A to B or B to C. 20. Requirement R3.2.1 is unclear. Generators generally have both a high and a low voltage limitation on the terminal voltage related to station service reqirements. Most load flow representations for generators tend to hold the voltage on the high side of the GSU instead of the low side. Is this requirement attempting to say that the voltage limitations on the generator terminals must be considered or is it something else? This should be made clear in the requirement. 21. R3.3.2.1 requires that the amount of "consequential Load loss following a single Contingency shall be identified and the anticipated duration be recorded". This is an arbitrary requirement that will require significant time and effort to document and will provide no useful information from a planning perspective. Also the inclusion of an "expected" duration is more arbitrary than the actual amount of load. The time required to restore the facilities is a pure guess at best since it will vary substantially based on circumstances and conditions. Since we are also required to remove all elements that the protection control group (PCG) will open instead of just a single "power flow model" line, some of the load may be restored during switching action for tapped loads and some may not. This creates an additonal confusion of what is required to be recorded in terms of duration and load reduction. We see no benefit from identifying and documenting either the amount of consequential

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Commenter	**Yes**	**No**	**Comment**
			load lost or the estimated duration that would justify the time and effort required. 22. R3.3.2.2 This states that curtailments of firm transfers are not permissible following single contingency events to meet the performance criteria. Please clarify whether "firm transfers" refers to firm point to point service only, or if firm network service is also included. Said another way, is the curtailment of a network resource permissible following single contingency events to meet the performance criteria? If not, please clarify how redispatch service as required by Order 890 should be considered. If curtailment of a network resource is permited, please clarify why curtailment of PTP would be held to a higher standard. Also, please clarify whether R3.3.2.2 applies to P6. Lastly, please clarify how Conditional Firm Service (CFS) as required by Order 890 should be considered in meeting R3.3.2.2. CFS allows the curtailment of "firm" PTP transfers. This appears to be in conflict with the performance criteria. 23. Requirement R3.6 is not clear. It could be interpreted as generator tripping allowed for multiple contingencies only for the situations that meet the "to be determined" conditions. Generator tripping should always be allowed for multiple contingencies. 24. R4.5 and R4.6: We suggest dropping the words "For the" in each of these. 25. R4.6.1: Plant stability studies should not be required for generating units as small as 20 MW. The threshhold should be 100 MW or greater. 26. R4.6.3: The last sentence "The identified Contingencies, at a minimum, shall be evaluated" is redundant because the requirement already says "shall be performed and evaluated" The last sentence should therefore be deleted. TABLE 1 - STEADY STATE PERFORMANCE: 27. In Table 1 in the column titled "Interruption of Firm Transfer Allowed," does it pertain to point-to-point only, or does it also apply to network loads? Please explain how this provision is consistient with the requirement to re-dispatch to address system constraints. 28. Steady state table, extreme event description, section 3: Items d and f are operating issues and therefore should not be included in the table. Also, items c and d are identical. Items d and f are identical. 29. Steady state table: Add the requirement to study n-0 to the table so it will be complete. Call it P0.

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Commenter	**Yes**	**No**	**Comment**
			30. Steady state table and stability table: Change the heading which now says "For all Planning Events" to say "The following performance requirements must be met for the Planning events evaluated in addition to the requirements given in the columns" 31. Steady state table: For the event in P3, it is not clear what the "above 300 kV" applies to. Is it only the transformer? Or it it also the transmission circuit and generator? Also, the third column mentions DC when there is no DC in the event. 32. The event description in P3 is confusing. Please consider rewording in the 1,2,3 format of the other event descriptions. The term "non-bus tie breaker" is confusing. Please consider using "breaker (excluding bus ties)". Also, above 300 kV, most construction is either ring bus or breaker and a half. Please considered deleting the bus outage contingency. Lastly, please clarify how redispatch and CFS should be considered in the context of P3 and P4, in which the curtailment of firm transfers is not permissible to meet the performance criteria. 33. Steady state table: For transformers below 300 kV, P9.6 is no different from P8.3. We suggest adding the clarification of "above 300 kV" for P9.6. 34. Steady state table Extreme Event: 3.b "A successful cyber attack" needs to be clarified. What should the contingency be? 3.g Add the words "As applicable" to the beginning. 3.h This should be changed to "Other events as deemed appropriate by the PC based upon operating experience". Otherwise there will be no end to the contingencies that must be studied. 35. Several events in the tables use the term "internal fault" for a breaker. The SDT needs to explain what is intended by this term. 36. Steady State Performance Requirement, Table 1, Performance Levels P1-P4, should allow for the interruption of firm transfers if the transfer is dependent upon on the outaged equipment (whether AC or DC) to provide an electrical path specified in the transfer. Therefore, the current verbiage used for the outage of a DC Line should be applied to all levels and state, “Yes, if transfer is dependent on the outaged equipment to provide an electrical path for service” 37. Steady state and stability tables: in the Extreme Events section heading, the word "all" implies that all events must be evaluated when this is not the intent. Either make the heading "For Extreme Events" or make it "For all Extreme Events evaluated".

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Commenter	**Yes**	**No**	**Comment**
			TABLE 2 - STABILITY PERFORMANCE TABLE: 38. Stability table, note 1.a.i: P3.2 should be P2.3. 39. Several events in the tables use the term "internal fault" for a breaker. The SDT needs to explain what is intended by this term. 40. In event P7.2, does the "below 300 kV" apply to the generator, transmission circuit, transformer, and bus as well as to the stuck breaker? Or does it apply only to the stuck breaker? 41. The event description in P3 is confusing. Please consider rewording in the 1,2,3 format of the other event descriptions. The term "non-bus tie breaker" is confusing. Please consider using "breaker (excluding bus ties)". Also, above 300 kV, most construction is either ring bus or breaker and a half. Please considered deleting the bus outage contingency. Lastly, please clarify how redispatch and CFS should be considered in the context of P3 and P4, in which the curtailment of firm transfers is not permissible to meet the performance criteria. 42. Steady state table and stability table: Change the heading which now says "For all Planning Events" to say "The following performance requirements must be met for the Planning events evaluated in addition to the requirements given in the columns" 43. Steady state and stability tables: in the Extreme Events section heading, the word "all" implies that all events must be evaluated when this is not the intent. Either make the heading "For Extreme Events" or make it "For all Extreme Events evaluated". 44. Stability table, footnote 1.a.ii. After "out-of-step protection", add the words "or some other means to trip the generator for this condition". GENERAL: 45. The overall level of documentation required by this standard is excessive.
Response: 1. The SDT is providing some guidance under Requirement R2.1.3 on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. It is the entity's decision to establish and document which transfers are more significant to study System responses. Requirement R 2.7.2 has been added to require a description of how and why the list of actions was modified and/or expanded as a result of the inclusion of the sensitivities selected. The SDT fells that the standards are clear that the sensitivity studies do not in themselves establish the need for a plan, only the areas of the System for which the analysis is needed.			

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Commenter	**Yes**	**No**	**Comment**
R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.7.2**. ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1. 2. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. 3. The terms "actual" and "aggregate" have been deleted. However, the SDT believes the term "expected" allows for flexibility in determining the necessary modeling information. 4. The SDT's initial attempt was to allow any of the three methods listed for obtaining power factor models. The SDT has removed Requirement R1.2 from the draft and replaced it with a new Requirement R9 in the revised draft to have the Distribution Provider provide real and reactive Load forecast data based on expected or historical system performance. **R9.** Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information. 5. The SDT has revised this requirement based on industry comments to delete the reference to "protective relays" and to clarify the intent that *known* planned outages and long-term outages for Transmission equipment, including the impact of spare equipment strategy, be considered, and to be responsive to FERC Order 693, paragraph 1725. 6. The referenced verbiage has been deleted from the revised standard. 7. The intent of the requirements was to put an upper bound on the shelf life of the study and bracket the applicability of the study such that, if changes were made that may effect results of the previous studies, they shouldn't be used. The SDT agrees with your comment and clarified the wording in Requirements R 2.6.1, 2.6.2, and 2.6.3. **R2.6.1**. For steady state, short circuit, or System Stability analysis: ~~if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market structure changes~~ the study shall be five calendar years old or less. **R2.6.2**. For steady state, short circuit ~~analysis~~, Generating Plant Stability, or System Stability analysis: ~~if the study is less than five years old and no material changes have occurred to the System in the intervening period.~~ the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study			

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area.

R2.6.3. ~~For plant and System Stability analysis: until material changes in the System make the study no longer valid. Material changes in the system include the addition of a Transmission Line or a generator~~

8. You are correct. The standard does not require that all 5 years be studied. The standard only requires that the assessment address the five year period. Section 2 provides guidance as to the minimum number of current studies required to produce a meaningful assessment without being totally prescriptive. It is the responsibility of the entity to determine if past studies, in conjunction current studies, sufficiently demonstrate that the performance requirements are met. If past studies in conjunction with the required current studies are not sufficient to demonstrate that the system can meet the performance needed, the entity will need to run additional current studies that demonstrate it can meet the requirements.
9. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3.1 provides the flexibility to allow the planning entity to decide how a variation in load on the entity(ies) system should best be studied. Requirement R2.4.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.4.4 has been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own System. In either case the entity must document the reason for running or not running cases for the items listed. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance. It is the entity's decision to establish and document if it needs to consider future additions and retirements. It is the entity's responsibility to determine the actions necessary to handle such items and which are more significant to study system responses.

R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:

R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

10. The SDT is providing guidance regarding the sensitivity studies while not being totally prescriptive. Requirement R2.1.3.3 provides the flexibility to allow the planning entity(ies) to elect the type of long lead time project that should be included in the analysis. It can be either a long lead time from replacement for failed equipment or a long lead time associated with constructing a new facility. Requirement R2.4.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.4.4 has been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own System. In either case the entity must document the reason for running or not running cases for the items listed. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance. It is the entity's decision to establish and document if it needs to consider future additions and retirements. It is the entity's responsibility to determene the actions necessary to handle such items and which are more significant to study system responses.
11. Since this requirement is relating to sensitivity, it is up to the entity to determine if it is appropriate to reduce the length of or increase

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Commenter	**Yes**	**No**	**Comment**
the length of the "planned outage" that it has considered in its base case studies. 12. In the standard, "current study" is intended to refer to an updated study (i.e., as opposed to a "past study"). The SDT received comments that "current" study could be misconstrued in reference to short circuit "current" (amperes) versus the intended meaning. The SDT revised the standard in an attempt to clarify the intent. A current study will need to be performed as part of the annual Assessment if there are changes warranting one. Until such time as a BES change occurs, studies have to be refreshed at least every five years. 13. The use of the terms "shall address" is trying to convey that message, the requirements detail the studies needed. 14. R2.4.3.2 - Non-firm transfers are included in Requirement R2.4.3.2 to be investigated as sensitivity. The second draft of the proposed standard clarifies in Requirement R2.7 that the corrective actions do not need to be developed solely to meet the performance requirements for sensitivities. **R2.7** - For Planning Events shown in Table 1 – Steady State Performance and Table 2 – Stability Performance, when the analysis indicates an inability of the System to meet the performance requirements in the tables, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed ~~over time~~ in subsequent assessments but the System shall continue to meet the performance requirements in the tables. ~~Such plans shall:~~ Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities. 15. The language was changed to reflect this comment. **R2.5.2**. Material Transmission System changes ~~in the electrical vicinity of existing generation are made~~ are made at or near the point of Interconnection of existing Generation such as the ~~addition or~~ removal of a Transmission Line ~~at or near the point of Interconnection~~ or the addition of a new substation in one of the Transmission Lines connected to the plant. 16. Requirement R8 (old Requirement R6) which focuses on the distribution of the Planning Assessment results among affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old Requirement R6). Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. Typically the date would indicate when significant resources will begin to be employed. This covers any project proposed for the near term. The SDT continues to believe that by providing the expected project intiation date of System improvements provides useful information to neighboring entities. The SDT believes that initiation dates are required for near-term corrective action plans to give an indication that the corrective action plans can be implemented in time. 17. The SDT does not percieve this as an onerous report requirement. The intent is that a list of proposed upgrades be reviewed and modified on a periodic basis. The intent of making the information available is to notify parties that may be impacted by a particular project of a change in the implementation of the project. 18. Based on industry comments, the language referenced in this comment was retained but modified in revised Requirement R5.2 to clarify intent. **R5.2**. Contingency analyses shall simulate the removal of all elements including those that System protection and other automatic controls are ~~is~~ expected to disconnect for each Contingency without operator intervention.			

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Commenter	**Yes**	**No**	**Comment**

19. There may also be the case where the outage of A to C overloads a parallel circuit whereas having the C to B line is service does not overload the parallel circuit. The outage of the A to C line by automatic interruption is the more realistic outage because of the interrupting devices on the ends of the line. Both conditions are now covered in Table 1 and Table 2.
20. Most commenters did not express confusion over this requirement, so it was not modified. Requirement R3.2.1 is intended to address all voltage limitations applicable to generators, which could include nuclear plant operating voltage limits, generator terminal voltage limitations, and station service voltage limitations, for example.
21. R3.3.2.1 - The requirement concerning Consequential Load is to address FERC Order 693, which directs the ERO, among other things, to clarify footnote (b) in regard to Load loss following a single Contingency, specifying the amount and duration of Consequential Load Loss and System adjustments that are permitted after the first Contingency to return the System to a normal operating state.
22. The SDT has revised this requirement accordingly. The SDT does not feel that this standard distinguishes between PTP and network service. P6 has been revised and now shows as P2 in the revised table and shows a separation for performance above and below 300 kV. The SDT is still studying CFS and results will be shown in future revisions.

R3.3.2.2. Following single Contingency events, ~~System adjustments other than shedding of firm Load or curtailment of firm transfers are permitted to meet performance requirements provided these adjustments can be accomplished within the time period allowed by the applicable time limited ratings.~~ Transmission configuration changes and redispatch of generation are allowed provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits.

23. The SDT has modified the requirements for single and multiple Contingencies (See Requirement R 3.5).

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:

24. The SDT feels the wording is equivalent and no change was made.
25. This is consistent with FERC Order 693, the Large generator Interconnection procedures, and the registry criteria.
26. The SDT has made this correction.
27. Tables 1 and 2 have been revised to replace the term "firm transfer" with "firm Transmission service".
28. The SDT revised the Extreme Events accordingly.
29. Table 1 has been revised to include N-0.
30. The SDT made a change to the heading.
31. A footnote reference has been added for clarity.
32. Tables 1 and 2 have been revised to provide clarity. The term "Firm Transfer" has been replaced with "Firm Transmission Service". In addition, the SDT has proposed a definition for Bus-tie Breaker in the second draft.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)

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Commenter	**Yes**	**No**	**Comment**
33. Tables 1 and 2 have been revised. P9.6 has been deleted and replaced with a reference in Requirement R11 in the second draft. **R11**. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information. 34. Tables 1 and 2 have been revised. The SDT cannot add "as applicable" to a standard because this term will make the standard unenforceable. The SDT notes that Requirements R3.4 and R4.5.2 allow for identifying and evaluating only those Extreme Events that are expected to produce more severe System impacts. 35. Breaker internal fault is a term used in the existing TPL standard. The SDT has added clarifying footnote number 5 in Table 1 and footnote number 4 to Table 2. 36. The SDT has revised Tables 1 and 2 to replace the term "Firm Transfer" with "Firm Transmission Service". 37. The SDT has made this change. 38. The SDT corrected the note. 39. This is explained in Table 1 - Note 5. 40. 300 kV applies to the equipment being studied and as defined for transformers and generators in Table 1 – Note 3. 41. The tables have been re-formatted for clarity. The SDT considers the term Non-Bus-tie Breaker as common nomenclature and has provided a definition of Bus-tie Breaker for clarity. The SDT feels that this requirement must remain to cover those situations where ring busses are not employed. CFS is still being studied by the SDT and will be handled in future revisions. 42. The SDT has changed the heading. 43. The SDT has made this change. 44. The SDT has made this change. 45. The SDT expects that increased documentation will improve coordinated Planning Assessments among the Planning Coordinator and the Transmission Planners.			
Tenaska	☑		The proposed standard contains a number of areas that need further definition, more explanation, or more specificity. 1. For example, requirement R1 should be rewritten as follows to make it clear who has responsibility for each requirement AND sub-requirement as the standard as written could be read to imply that Transimssion Owners and Generation Owners have to supply a load forecast to the Planning Coordinator: R1. Each Resource Planner, Transmission Planner, Transmission Owner, Generator Owner, and Load-Serving Entity shall each provide, as specified below, its respective Planning Coordinator with the following modeling information required for System performance studies upon request (within 30 calendar days) : [Violation Risk Factor: TBD] [Time Horizon: TBD] R1.1. Each Load Serving Entity shall provide the Planning Coordinator load forecasts adhering, at a

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Commenter	**Yes**	**No**	**Comment**
			minimum, to the following criteria: R1.1.1. Use of expected Load mix based on the actual or expected aggregate mix of industrial, commercial, and residential Loads. R1.1.2. Based on normal weather patterns as agreed to by the Planning Coordinator(s) and the Transmission Planner(s) for the area(s) of their responsibility. R1.1.3. Identification of Demand Side Management (DSM) Load reductions consistent with operational requirements. R1.2. Each Load Serving Entity shall provide the Planning Coordinator load models with supporting rationale that include power factor data based on historical System performance, validated by measurement during stressed System conditions, or documented Transmission planning area requirements. R1.3. Each Load-Serving Entity shall provide the Planning Coordinator the Firm transfers/Interchange Schedules and resources required to supply Load for each Balancing Authority. R1.4. Each Transmission Owner and Generation Owner shall provide the Planning Coordinator with known planned outages and long-term outages for Transmission and Generation equipment including protective relays with consideration given to spare equipment strategy. R1.5. Each Transmission Owner, Generation Owner, Resource Planner, and Transmission Planner shall provide known planned Facilities defined in accordance with the documented criteria of the Planning Coordinator, including but not limited to: Transmission Lines, generators, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies. The above is an example and I apologize for the poor pagination. However, the drafting team should look at each requirement/sub-requirement and specify precisely to which entity the requirement/sub-requirement applies. Other comments/concerns/questions with the proposed standard: 2. Does requirement R2 mean that you could have two assessments: one performed by the Transmission Planner and one performed by the Planning Coordinator? This could result in two assessments of the same facilities which may or may not be desired. 3. In Requirement 2.5.1, what is meant by increasing generation? Is there a minimum amount of increased generation or is it any increase? 4. In Requirements 2.5.2, 2.6.1, 2.6.2, and 2.6.3, what is meant by "material"? This needs more

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Commenter	**Yes**	**No**	**Comment**
			definition wherever the word "material" is used throughout the standard. 5. In Requirements 2.6.1, 2.6.2, and 2.6.3, the word System and system are both used. Whose System or system needs to be defined. Does that include neighboring system(s)? 6. In Requirement 2.7.3, "committed" and "proposed" need to be defined. 7. In Requirement 2.7.5, what needs to happen as a result of such review? Is something supposed to happen in the Corrective Action Plans depending on the implementation status of identified System Facilities and Operating Procedures? 8. In R3, what is "normal" performance (n-0)? Should this be a defined term? 9. In R3.2.1 and 3.2.2, why are these issues covered in a TPL standard as it seems to be more applicable to the Facility Ratings standards or the MOD10, 11, 12, and 13 standards? The TPL standard should probably reference these other standards for issues associated with ratings. 10. In R3.3.2, the reference to "single contingency" should reference the category (P1, P@, P#, etc.) in Table 1. 11. In R3.3.2.2, the term "firm transfers" needs to be defined. 12. In R3.3.3 and R3.4, reference is made to "expected to produce more servere System impacts." How does somebody determine what Extreme Events that are "expected to produce more servere System impacts?"

Response: 1. The standard has been revised to identify specific entities responsible for providing the required information.
2. The SDT expects that the Transmission Planner is coordinating assessments with the Planning Coordinator
3. The term is 'increasing generation capability', e.g., if your generator is rated at 100 MW today and 110 MW tomorrow, the 10 MW differential is the increased generation capability. The minimum is defined in Requirement R5.6.
4. Requirements R2.5 and R2.6 have been modified to address this concern. The SDT expects that the Transmission Planner and Planning Coordinator would exercise good engineering judgement when determining the need to perform a new study.

R2.5. The ~~plant~~Generating Unit Stability analysis portion of the Planning Assessment shall be analyzed consistent with Requirement ~~R4.6~~ R5.6 with studies for the year when the following changes that could affect stability margins occur:
R2.5.1. New generator(s) are added or generation modifications are made such as ~~increasing~~changes in generation capability or replacing the exciter ~~or addition of a power System stabilizer~~.
R2.5.2. Material Transmission System changes ~~in the electrical vicinity of existing generation are made~~ are made at or near the point of Interconnection of existing Generation such as the ~~addition or~~ removal of a Transmission Line ~~at or near the point of Interconnection~~ or the

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addition of a new substation in one of the Transmission Lines connected to the plant.

R2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:
R2.6.1. For steady state, short circuit, or System Stability analysis: ~~if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market structure changes~~ the study shall be five calendar years old or less.
R2.6.2. For steady state, short circuit ~~analysis~~, Generating Plant Stability, or System Stability analysis: ~~if the study is less than five years old and no material changes have occurred to the System in the intervening period.~~ the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area.
R2.6.3. ~~For plant and System Stability analysis: until material changes in the System make the study no longer valid. Material changes in the system include the addition of a Transmission Line or a generator.~~

5. R2.6.1, 2.6.2, 2.6.3 – Requirements R2.6.1, R2.6.2, and R2.6.3 have been revised to clarify intent.

R2.6.1. For steady state, short circuit, or System Stability analysis: ~~if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market structure changes~~ the study shall be five calendar years old or less.
R2.6.2. For steady state, short circuit ~~analysis~~, Generating Plant Stability, or System Stability analysis: ~~if the study is less than five years old and no material changes have occurred to the System in the intervening period.~~ the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area.
R2.6.3. ~~For plant and System Stability analysis: until material changes in the System make the study no longer valid. Material changes in the system include the addition of a Transmission Line or a generator.~~

6. Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted Requirements R2.7.2 through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions".

R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.

7. The intent is that a list of proposed upgrades be reviewed and modified on a periodic basis. The intent of making the information available is to notify parties that may be impacted by a particular project of a change in the implementation of the project.
8. Normal performance (n-0) describes the performance of the BES with no Contingencies. No other commenter expressed confusion. The

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Commenter	**Yes**	**No**	**Comment**
SDT does not believe a defined term is necessary. 9. Most commenters did not express concern regarding inclusion of these requirements in the proposed standard, so they were retained. The two requirements referenced relate to evaluation of Contingencies and are not addressed by the MOD or FAC standards. These requirements are intended to simulate the removal of Facilities that System protection is expected to disconnect for each Contingency without operator intervention in the steady state portion of the Planning Assessment. 10. R3.3.2.2 - Tables 1 and 2 have been modified to reflect your suggestion. 11. R3.3.2.2 – Requirement R3.3.2.2 has been revised and the term "firm transfers" has been deleted. **R3.3.2.2**. Following single Contingency events, ~~System adjustments other than shedding of firm Load or curtailment of firm transfers are permitted to meet performance requirements provided these adjustments can be accomplished within the time period allowed by the applicable time limited ratings.~~ Transmission configuration changes and redispatch of generation are allowed provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits**.** 12. R3.3.3 & R3.4 **-** The proposed standard allows the PC and TP to use engineering judgment and experience.			
TVA	☑		1. Requirement R1 does not belong in this standard. These requirements are covered by MOD standards. 2. Spare equipment strategy should be covered as a sensitivity study, but not included in the base case. 3. R2.1.1 should not be so prescriptive as to which years of 1-5 are studied. 4. The wording for R2.1.3 and R2.4.3 should be consistent. 5. Consideration should be given to the specific phases which are faulted in the simultaneous faults for P9 of the stability table. The results can be much different if the simultaneous faults occur on the same phase or different phases. 6. More guidance should be given for the term "Interruption of Firm Transfer Allowed" in Table 1. Firm transfer is not defined in the NERC glossary. The type of transmission service should be outlined here. 7. R2.7.1.1 - The project initiation date is not relevant in a reliability standard. 8. Extreme Event Descriptions 2. a. and b. should include mileage threshholds. 3. e. The term "large load" is vague and should be clarified. d. and f. are duplicates.

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Commenter	**Yes**	**No**	**Comment**
			c. and e. are duplicates. 9. Minimum generator voltage data required for R3.2.1 will be require extensive and costly generator testing and analysis to provide data necessary for transmission system studies. 10. R3.3.2.1 is an operational issue rather than a planning issue. 11. The addition of the "Corrective Action Plan" requires the TP to provide a significant amount of documentation for each deficiency identified by the studies. 12. Also, R3.2 requires that the studies simulate the protection scheme for all events. The current software tools cannot automate these studies for bus faults and breaker failure events, requiring each scenario to be studied manually. 13. The planning event designations are confusing because both the steady-state and stability tables have events P1-P9. A different designation should be used for one of the tables. 14. In R4.6 and other locations, the individual generator exemption of 20 MW should be increased to 75 MVA.

Response: 1. The SDT feels that some modeling requirements are not currently handled in the current MOD standards and has included them here until the MOD standards are revised.
2. The SDT assumed that all entities have a spare policy today. The studies are to be performed on that basis. Duration of Contingencies considered in the studies will be based on this policy as will be the applicable equipment ratings. If the entity feels that the policy may or can change, the entity may elect to add this change as a sensitivity study.
3. The SDT is providing guidance regarding the studies that could be incorporated in an assessment while not being totally prescriptive. The standard does not require that all 5 years be studied. The standard requires the assessment addresses the five year period. Section 2 provides guidance as to the minimum number of current studies required to produce a meaningful assessment without being totally prescriptive. It is the responsibility of the entity to determine if past studies, in conjunction current studies, sufficiently demonstrate that the performance requirements are met. If past studies in conjunction with the required current studies are not sufficient to demonstrate that the System can meet the performance needed, the entity will need to run additional current studies that demonstrate it can meet the requirements.
4. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. The wording in Requirement R2.1.3 describes sensitivities for the steady state horizon while Requirement R2.4.3 describes the sensitivities for dynamic analysis. The wording in these requirements is different but parrallel. To increase the consistency Requirement R2.4.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies.

R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected~~

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Commenter	**Yes**	**No**	**Comment**
~~sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: 5. The SDT agrees that the results can be different. However, the SDT feels that in most instances, the person performing the study will select a three phase fault which is the most severe case and easiest to simulate. 6. The SDT has revised Tables 1 and 2 to replace the term "Firm Transfer" with "Firm Transmission Service". 7. The SDT agrees that this information is not required to meet reliability standards. It was specifically added as an additional piece of information in the Planning Assessment to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. 8. The SDT believes that there should not be a threshold as you are trying to understand the robustness of the System. Large is left to the discretion and good professional judgment of the evaluator. Note 3 has been re-written for clarity and to delete duplications. 9. The requirement is intended to provide for the simulation of generator tripping in response to low system voltages that would cause auxiliary system motors to trip in the steady state portion of the Planning Assessment. 10. The requirement concerning Consequential Load is to address FERC Order 693, which directs that the ERO, among other things, to clarify footnote (b) in regard to Load loss following a single Contingency, specifying the amount and duration of Consequential Load Loss and System adjustments that are permitted after the first Contingency to return the System to a normal operating state. 11. The SDT does not percieve this as an onerous report requirement. The intent is that a list of proposed upgrades be reviewed and modified on a periodic basis. The intent of making the information available is to notify parties that may be impacted by a particular project of a change in the implementation of the project. 12. The SDT agrees that most automated Contingency analysis tools do not do this unless you actually modeled the bus in detail. However, we expect that "engineering judgment", based on intimate knowledge of the System, will be exercised by the planner to distinguish between what studies are important and those that aren't. The requirement is not intended to cover all possible scenarios. 13. The SDT discussed this suggestion and decided to retain the current designations. 14. This is consistent with FERC Order 693, the Large generator Interconnection procedures, and the registry criteria.			
TSGT	☑		1. R1 and R2 address some Load Forecast issues, but are not exhaustive specifications of what Load Forecast range to use in studies. There needs to be some mention of exceedance probability (ExPr) in Load Forecast criteria. For example, we use a forecast with a low ExPr in our studies because we are concerned that, if the system was planned for 50% ExPr (a lower forecast), actual deviation from that forecast might result in load at certain locations exceeding operating margins built into the interconnected transmission system designed to serve only the 50% ExPr forecast load. 2. Load Specifications in R2.4 are ambiguous for the reasons stated above. 3. Maximum study ages in R2.6.1 and R2.6.2 seem arbitrary. The time limit does not seem to add anything to the criteria if no material changes have occurred. If spot checks of the most critical areas indicated no criteria violations, there should be no reason to rerun studies. To correct this problem, we suggest using the term "assessment" rather than "study". For most people, "study" implies detailed modeling and simulation analyses summarized in a report, whereas "assessment" implies a

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Commenter	**Yes**	**No**	**Comment**
			reasonable, systematic evaluation of a system which does not necessarily include detailed analysis for the entire system.
Response: 1 & 2. Requirement R1 has been modified to make TPL-001-1 comport with existing modeling standards and to require documentation when modification of data provided in these standards is necessary for the planning studies addressed in TPL-001-1. Requirement R2.1.3.1 addresses your concern about Load forecast issues and allows for sensitivity studies of the variability of forecasts based on a number of factors. **R1**. ~~Each Resource Planner, Transmission Planner, Transmission Owner, Generator Owner, and Load-Serving Entity shall each provide its respective Planning Coordinator with the following modeling information required for System performance studies upon request (within 30 calendar days) :~~ Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources. 3. The SDT set the age limit on studies to 5 years based on the fact that relatively "small" changes can accumulate with time to the extent that study results might be affected. Requirement R2.6.2 sets reasonable criteria on what System changes might materially affect existing study results, and the SDT does not consider the criteria to be arbitrary. The term "study" was deemed more appropriate as used here than "assessment".			
AESO	☑		The Alberta Electric System Operator (AESO) supports the comments from WECC with the exception of Question #19 where the AESO agrees with the proposed requirement R2.7.4 by the SDT.
Response: The SDT has modified the standard to require only the Corrective Action Plan and indicates what is meant by the word plans. The SDT feels that the assessment and making it available to others will by its very nature provide all the information necessary to understand which plans changed and the basis for the new plans.			
WECC TEP	☑		1. R1.3 requires the provision of firm transfer/Interchange Schedules and resources required to supply load for each Balancing Authority. It may not be possible to have reasonably accurate information on firm transfers and Interchange Schedules for years into the future. Within WECC, we develop base cases that represent reasonably stressed conditions that model power flows stressing various paths. Therefore, within WECC, we design the system to operate at levels that can support all sorts of commerce, including the effects of loop flow, and firm and non-firm contracts, in addition to other possibilities. It would be difficult to develop information from this mixture that includes only firm transactions for such future base cases. In addition, WECC does not allow operations at levels not previously studied. Therefore, an exercise to determine firm transaction/schedules would produce information that will be of little value to support reliability in WECC. 2. R2.7.1.2 requires identification of system deficiencies and accociated corrective action for the Long Term Transmission Planning Horizon. This requirement needs to tie to the lead times to implement the corrective action(s). For example, if a 500 kV transmission line is needed to correct a deficiency that surfaces in the tenth year, then this requirement is reasonable. However, if the deficiency is on a low voltage system, that can be resolved with short lead-time projects (such as

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Commenter	**Yes**	**No**	**Comment**
			installing a small capacitor bank) then this requirement would seem to be too prescriptive. 3. R1.5 requires providing modeling information as part of R1 on a number of transmission planned facilities, including circuit breakers. Since circuit breakers are part of a transmission line, we are not sure how a circuit breaker would be modeled separately, as required. 4. R3.2.1 requires that "studies shall consider the minimum steady state voltage limitations of all generators". Since generators (as well as other facilities) have both high and low voltage limits, the standard should require consideration of both high and low voltage limits. 5. In R.3.2.2, please provide a reference for relay loadability. 6. R.3.3.2.1. requires that Consequential Load loss (expected maximum demand and expected duration) following a single contingency shall be identified in the Planning Assessment. We suggest deleting this requirement. By definition, consequential load loss following a contingency can not be avoided and should not be considered an impact on the operation of the BES. It should be part of local service reliability between an entity and its local regulatory agency or contractual relationship between individual parties and not in a NERC Standard governing the operation of a BES. 7. Proposed revision to R3.5 – "Manual and automatic generation runback and generator tripping are allowed as a response to single and multiple contingencies as long as Facility Ratings are not exceeded and the result of the generator action, such as loss of reactive resource, impact on reserves, and restart time of tripped unit(s), meets the performance requirements in the tables." Example for the need for flexibility in the selection of generation runback and/or tripping to meet the requirements of R3.5 – The time period for a particular Emergency Rating might require faster generation redispatch than a runback or set of runbacks are capable of providing. Therefore, it may be necessary to trip one 100 MW unit rather than runback several units for a total of 100 MW. Planning and Operations need flexibility to coordinate with the requirements of Engineering who established the Facility Ratings. No need for R3.6 with above revision to R3.5. 8. Performance standard "P5" (Q.21- 23) does not allow for the use of load shedding (safety nets) required by some utilities to protect against cascading outages if a transmission line is already out of service and a forced outage of another major element occurs. "System adjustments" might not be possible in a load pocket or local load-serving area to prevent "non-consequential load loss" after loss of a second transmission line to the load-serving area. The use of load shedding for such rare

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Commenter	**Yes**	**No**	**Comment**
			events is an established practice and least cost alternative that does not unreasonably compromise reliability of the WECC system. It is also an acceptable and necessary tradeoff from over burdening customers with additional expensive transmission lines and permitting risk in the West where remote generation resources have historically required power to be carried over long distances. The tradeoffs between economics (building hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation versus load shedding schemes) and the impact of these rare events should be under the purview of local and state jurisdictions, as long as impacts do not result in cascading events outside of the affected jurisdiction. As long as interconnected reliability or neighboring system operation is not negatively impacted, customer interruption size and frequency should be left to the Transmission Providers discretion and to the jurisdiction of state regulators. The amount of load to be shed and its frequency is primarily an issue for state jurisdiction because it is a matter of the cost/benefit associated with customer service regardless of the voltage level problem. In general, incidences of non-consequential loss of customer load events related to contingencies on the back-bone transmission system are rare when compared to other causes of customer outages. Assuming interruptions to customer service are significant, the state regulators and other related constituents will ultimately be responsible for approving any transmission line facilities or generation additions needed to assure reliability. Implementing an immediate change to this current established practice is not rational or technically feasible due to the long and arduous regulatory and permitting processes that are required to construct new transmission facilities or new load-side generation. Implementation of the standard as written would take many years. At a minimum, even if it is determined that Congress's intent was to create stricter standards, a phase-in period must be included to allow utilities time to obtain necessary permits, regulatory approval and cost recovery to meet the stricter standards.

Response: 1. The SDT understands your concern. The SDT only anticipates that known firm transfers and schedules be included in the base cases. Non-firm transfers may be included in the sensitivity studies as detailed in Requirement R2.1.3. Requirement R1.3 in the first draft of TPL-001-1 is now shown as Requirement R10 in the revised draft.

R10. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information.

2. Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted Requirements R2.7.2 through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions".

R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission~~

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Commenter	**Yes**	**No**	**Comment**
			~~and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. 3. The SDT agrees that circuit breakers are generally not modeled separately in planning simulations. However, the addition or removal of a circuit breaker could modify network topology as modeled for planning simulations, which this requirement attempts to capture. 4. Voltage limits are included in the tables to cover both high and low voltage limits. However, the minimum limits in Requirement R3.2.1 are, generally, the more critical concern for system performance scenarios and this requirement was included by team consensus. 5. NERC document "Relay Loadability Exceptions, Determination and Application of Practical Relaying Loadability Ratings ", is contained on this ftp site: ftp://ftp.nerc.com/pub/sys/all_updl/pc/spctf/ExceptionsV1.pdf. Other information may also be obtained from: http://www.nerc.com/~filez/spctf.html 6. R3.3.2.1 - The requirement concerning Consequential Load is to address FERC Order 693, which directs the ERO, among other things, to clarify footnote (b) in regard to Load loss following a single Contingency, specifying the amount and duration of Consequential Load Loss and System adjustments that are permitted after the first Contingency to return the System to a normal operating state. 7. The SDT has modified the requirements to allow for single and multiple Contingencies tripping (See Requirement R 3.5). **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met: 8. The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission Systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT believed the 300 kV and higher Systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many Systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. When EHV Systems are compromised, the large volumes of power served by them can place a severe amount of stress on parallel EHV or lower voltage paths. For example, if a large EHV transformer experiences a catastrophic failure not only are other System Facilities required to carry more Load but the System is also exposed to other N-1 conditions for long periods of time while awaiting a replacement or repair of the failed equipment. Large generation sources are typically connected at EHV levels and maintenance of the EHV Transmission lines within the vicinity of larges generation plants must often be coordinated during scheduled unit outages, resulting again in multiple Facility outages over extended periods of time. Therefore, it was the conclusion of the SDT in Draft 1 to propose greater reliability and operational flexibility through more stringent performance requirements when considering certain N-1 and N-1-1 Contingency events of EHV Systems. Throughout the industry substation arrangements at EHV levels reflect the importance of these Systems as the designs often consist of the more expensive ring-bus, breaker-and –a-half or double bus-double breaker protection schemes as opposed to the more simplistic and lesser cost single bus arrangements that are

Q43			
Commenter	**Yes**	**No**	**Comment**
commonly found on lower voltage Systems. The feedback received from industry was divided related to the SDT's emphasis placed on a higher expectation for the 300 kV and higher Systems. Some commenter's questioned the importance and the high costs that may be needed to mitigate existing System designs. Others agreed with the SDT's approach and indicated that the impact to their Systems would be minimal. Some commenter's even questioned why the more stringent approach was not applied to the entire 100kV and higher Systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission System. The SDT plans to draft an implementation plan. This implementation plan will address, among other issues, the other standards, which will need to be brought into alignment with this standard. The plan will be provided for the third posting of the standard.			
WPS	☑		Within R1.1.2, the Planning Coordinator and the Transmission Planner is required to define what constitutes "normal weather patterns" for the purpose of establishing load forecasts. However, the PC and/or TP are not the appropriate entities to establish "normal weather patterns"; the LSEs, who actually develop load forecasts and have the expertise, are the appropriate entities to establish normal weather patterns. Additionally, this requirement should consider requiring the 50/50 probability load forecast from the LSEs.
Response: This requirement has been eliminated in response to various industry comments.			
Duke Energy		☑	
Northwestern Energy		☑	
New York ISO		☑	
Response: Thank you.			

Comments for 2nd Draft of Standard TPL-001-1 — Assess Transmission Future Needs (Project 2006-02)

The Assess Transmission Future Needs Standards Drafting Team thanks all commenters who submitted comments on the 2nd draft of reliability standard TPL-00101 — System Performance under Normal Conditions. The proposed standard was posted for a 45-day public comment period from August 14, 2008 through September 29, 2008. The stakeholders were asked to provide feedback on the proposed metrics through a special electronic Standard Comment Form. There were more than 80 sets of comments, including comments from more than 150 different people from more than 100 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

Due to the large number of comments received and the addition of VRF, Time Horizons, Measures, Data Retention requirements, and VSL, the SDT recommends an additional posting for this standard.

Due to industry comments, the following definitions have been changed: Bus-tie Breaker, Consequential Load Loss, Non-Consequential Load Loss, and Year One.

Due to industry comments, the following definitions have been deleted: Generating Unit Stability Study, Planning Coordinator, and System Stability Study.

Due to industry comments, the following definitions have been added: Load Reduction and Supplemental Load Loss.

Due to industry comments, the following requirements have been changed: R1, R1.1, R1.1.1, R1.1.2, R1.1.3, R1.1.4, R1.1.5, R1.1.6, R2, R2.1, R2.1.3, R2.1.3.4, R2.1.5, R2.2, R2.3, R2.4.1, R2.4.3, R2.6.1, R2.6.2, R2.6.2.1, R2.6.2, R2.7, R2.7.1, R2.7.1, R2.8, R2.8.1, R2.8.2, R2.9, R2.10, R3, R3.1, R3.2, R3.3, R3.3.1, R3.3.2, R3.3.3, R3.3.4, R3.5, R3.6, R5, R5.1, R5.2, R5.3, R5.3.2, R5.5, R5.6, R6, and R8.

Due to industry comments, the following requirements have been deleted: R2.1.4, R2.4.4, R2.5, R2.5.1, R2.5.2, R2.7.4, R3.4, R3.7, R4, R5.4, R5.5.1, R5.5.2, R5.5.3, R5.5.3.1, R5.5.3.2, R5.5.3.3, R5.7, R9, R10, R11, R12, R13, and R14.

Due to industry comments, the following table notes have been changed: Header note 'b', 'e', 'i', Footnotes 1.a.ii, 3, 5, 10 and 12.

The two table concept has been replaced by a single table with necessary corresponding changes to the notes and footnotes as appropriate. In addition, a typo in Extreme Event 2b was corrected due to an industry comment.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards,

Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses:

1. The SDT has modified the definitions and requirements associated with System Stability and Generating Unit Stability (formerly Plant Stability) in response to industry comments. Do you concur with the modified definitions for stability and, if not, please state why and/or suggest specific changes. 12

2. Do you concur with the modified Requirements R2.4, R2.5, R5.4, and R5.5? If not, please state why and/or suggest specific changes. 41

3. The SDT has modified the definitions of Consequential and Non-Consequential Load Loss in response to industry comments. Do you concur with the modified definitions of Consequential and Non-Consequential Load Loss? If not, please state why and/or suggest specific changes. 103

4. The SDT has modified Requirement R3.5 and eliminated Requirement R3.6 from the first draft to clarify that manual and automatic generation run-back (redispatch) and tripping is allowed as a Corrective Action Plan as long as the conditions in Requirements R3.5.1, R3.5.2 and R3.5.3 are met. Do you agree that generation run-back and tripping (manual and automatic) should be limited by these conditions? If not, please explain why you disagree with the proposed requirements. 144

5. The SDT has modified the modeling requirements. Some commenters expressed concern that the modeling requirements contained in Requirement R1 of the first draft of TPL-001-1 were either duplicative of the requirements in the MOD standards, or to the extent new modeling requirements were proposed, that the appropriate venue for such modeling requirements would be the MOD standards. The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has incorporated these additional requirements with the intent that they will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. The SDT has also modified proposed modeling requirements contained in Requirement R1 of the first draft of TPL-001-1 based on industry comments and moved these requirements to Requirements R9 through R14 in the second draft for ease of removal later on. Furthermore, in response to industry comments, the SDT has separated the modeling requirements into individual requirements for each responsible entity. Do you concur with the modifications reflected in Requirements R9 – R14? If not, please state why and/or suggest specific changes.. 160

6. The SDT has modified the requirements relating to short circuit analysis Do you concur with the modifications reflected in Requirements R2.3 and R4. If not, please state why and/or suggest specific changes. 189

7. The SDT has reformatted the Steady State and Stability Performance Tables. Do you concur with the modified format? If not, please state why and/or suggest specific changes. 206

8. A new definition for "Bus-Tie Breaker" was added to clarify the type of substation design and breaker position that qualify as a Bus-tie Breaker. Do you agree with the proposed definition? If not, please explain.....258

9. Some commenters questioned why a Bus-tie Breaker would have a different performance requirement than a non-Bus-tie Breaker, stating that all breakers have the same probability for failure. It may be true that generally the probability for failure of any given breaker would not vary substantially among similar types of breakers, but the Bus-tie Breaker reduces exposure and consequences of bus faults. The different performance expectations in Tables 1 and 2 are based on promoting a higher level of reliability for the Transmission Systems operated above 300 kV. It is recognized by

the SDT that a straight bus design has some undesirable exposure to bus faults, but that Bus-tie Breakers can be utilized to improve reliability for bus faults and problems associated with exit breakers. As a result, the risk of an internal breaker fault was deemed to be significantly less than the benefit that is gained by reducing the exposure to a total bus failure. Therefore, provisions were built into the performance requirements that would not discourage their use. Do you agree that non-Bus-tie Breakers rated above 300 kV should have more stringent performance requirements than Bus-tie Breakers? If not, please explain why and/or suggest specific changes. . 267

10. The SDT made modifications in this second draft to the requirements relating to sensitivity cases. Do you concur with the modifications reflected in Requirements R2.1.3 and 2.1.4? If not, please state why and/or suggest specific changes. 285

11. In response to industry comments, the SDT modified Table 1 requirements for Planning Event P6. Planning Event P6 involves independent overlapping single contingencies (n-1-1) involving two Transmission Facilities excluding generators. This Planning Event generally correlates to P5 of the first draft and now includes shunt devices. The P6 event was also revised to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300 kV. Do you concur with the modifications? If not, please state why and/or suggest specific changes. 320

12. Comments from some entities received from the posting of the 1st draft standard indicated that significant additional costs will be required to meet the proposed requirements and performance tables. Commenters also indicated that it would take several years to install the additional facilities needed to meet the change in requirements. The SDT has attempted to adjust and clarify the proposed requirements and performance in light of these initial comments; however, the SDT needs more specific information on these concerns so that it can put the proposed requirements in perspective and make more adjustments as appropriate. Questions 12, 13 & 14 address these concerns. 341

13. Documentation: 355

14. System Reinforcement: One time cost, capital investment, to expand your system reinforcement program (due to lead times associated with different types of facilities, this will probably be an accumulated cost over several years). How many years do you estimate that it will take to complete this initial expanded system reinforcement program: 361

15. (A) Do you generally support the revised standard? (B) Are you unsure whether you generally support the revised standard? or (C) Do you definitely not support the revised standard? Please check the appropriate box below. If your response is either (B) or (C), please explain your single biggest concern with the revised standard, including which specific requirement or set of requirements causes you the most concern and why. 370

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Thad Ness	AEP	x		x		x	x				
2.	Anita Lee	Alberta Electric System Operator		x								
3.	John E. Sullivan	Ameren	x		x		x	x				
4.	Jason Shaver	American Transmission Company	x									
5.	Baj Agrawaal	Arizona Public Service Co.	x									
6.	Ronnie Frizzell	Arkansas Electric Coop. Corp.				x						
7.	James C. Armke	Austin Energy	x				x					
8.	Phil Park	BCTC		x								
9.	Eric Egge	Black Hills Corporation	x									
10.	J. David Carpenter	Brazos Electric Power Cooperative, Inc.	x		x		x					
11.	Paul Rocha	CenterPoint Energy and CPS Energy	x									
Additional Member	Additional Organization	Region	Segment Selection									
1.	Glenn Pressler	City of San Antonio City Public Service (CPS Energy)	ERCOT	1								
12.	David M. Conroy	Central Maine Power Company	x									

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
13.	Gary S. Brinkworth, P.E.	City of Tallahassee, FL	x		x		x					
14.	Karl Kohlrus	City Water, Light & Power - Springfield, Illinois	x		x		x					
15.	Marv Landauer	ColumbiaGrid										
16.	John Blazekovich (Exelon Corporation)	Compliance Elements Development Resource Pool (CEDRP)										
17.	John Loftis (Dominion Virginia Power)	Dominion - Electric Transmission Planning	x									

Additional Member	Additional Organization	Region	Segment Selection
1.	John Loftis	SERC	1
2.	Ronnie Bailey	SERC	1
3.	Peter Nedwick	SERC	1
4.	William Bigdely	SERC	1
5.	Mark Gill	SERC	1
6.	Larry Carter	SERC	1
7.	Mehdi Shakibafar	SERC	1
8.	Kirit Doshi	SERC	1
9.	Craig Crider	SERC	1
10.	Solomon Yirga	SERC	1
11.	Matthew Gardner	SERC	1

18.	Greg Rowland	Duke Energy	x		x		x	x				
19.	Keith Yocum - Manger, Transmission Strategy & Planning	E.ON U.S. Transmission Planning	x									
20.	Dennis Malone	El Paso Electric Company	x		x		x					
21.	Charles W. Long	Entergy Services, Inc.	x									
22.	Jay Teixeira (ERCOT)	ERCOT System Planning		x								

Additional Member	Additional Organization	Region	Segment Selection
1.	John Schmall	ERCOT	ERCOT 2

23.	Eric Mortenson	Exelon Transmission Planning	x		x							
24.	Sam Ciccone	FirstEnergy Corp.	x		x	x	x	x				

Additional Member	Additional Organization	Region	Segment

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
			Selection									
1.	John Stephens	FE RFC	1									
2.	Doug Hohlbaugh	FE RFC	1, 3, 4, 5, 6									
3.	Don Morrison	FE RFC	1									
4.	Art Buanno	FE RFC	1									
25.	Hector J. Sanchez	Florida Power and Light	x		x		x					
	Additional Member	Additional Organization / Region	Segment Selection									
1.	Bob Schoneck	FRCC	1									
2.	Kiko Barredo	FRCC	1									
3.	John W. Shaffer	FRCC	1									
4.	Carlos Candelaria	FRCC	1									
26.	Richard Becker (FRCC)	Florida Reliability Coordinating Council, Inc										x
	Additional Member	Additional Organization / Region	Segment Selection									
1.	Ballard Keith Mutters	Orlando Utilities Commission / FRCC	3									
2.	Rodney Hawkins	Lee County Electric Cooperative / FRCC	1									
3.	Roger Allen Westphal	Gainesville Regional Utilities / FRCC	3									
4.	Luther E. Fair	Gainesville Regional Utilities / FRCC	1									
5.	Ted E. Hobson	JEA / FRCC	1									
6.	Garry Baker	JEA / FRCC	3									
7.	Donald Gilbert	JEA / FRCC	5									
8.	W. R. Schoneck	Florida Power & Light Co. / FRCC	3									
9.	Hector Sanchez	Florida Power & Light Co. / FRCC	1									
10.	John Shaffer	Florida Power & Light Co. / FRCC	5									
11.	Kiko Barredo	Florida Power & Light Co. / FRCC	1									
12.	Ronald L. Donahey	Tampa Electric Co. / FRCC	3									
13.	Gary S. Brinkworth	City of Tallahassee / FRCC	1									
14.	Larry E Watt	Lakeland Electric / FRCC	1									
15.	Bart B White	Florida Power Corporation / FRCC	1									
27.	Earl Fair	Gainesville Regional Utilities	x		x		x					
28.	Roger Champagne	Hydro-Québec TransÉnergie (HQT)	x									
29.	Milorad Papic	Idaho Power Company										
30.	Dan Rochester	IESO		x								

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
31.	Kathleen Goodman	ISO New England Inc.		x								
32.	Raymond Kershaw (ITC Holdings)	ITC Holdings: ITC, METC, ITC Midwest	x									
33.	Don Gilbert	JEA					x					
34.	Gary Newell (Thompson Coburn LLP -- Counsel to Lafayette Utilities System)	Lafayette Utilities System	x		x		x					
35.	Mace Hunter	Lakeland Electric	x		x		x					
36.	Larry Watt	Lakeland Electric	x									
37.	Sergio Garza	LCRA TSC	x									
38.	Tim Wu	Los Angeles Department of Water and Power	x		x		x					
39.	Kris Manchur	Manitoba Hydro	x		x		x	x				
40.	Tom Mielnik	MidAmerican Energy Company	x		x		x	x				
41.	Marie Knox	Midwest ISO										
42.	Spencer Tacke	Modesto Irrigation District	x		x		x	x				
43.	Tom Mielnik (MEC)	MRO NERC Standards Review Subcommittee	x		x		x	x				

Additional Member	Additional Organization	Region	Segment Selection
1.	Neal Balu	WPS	MRO	3, 4, 5, 6
2.	Terry Bilke	MISO	MRO	2
3.	Carol Gerou	MP	MRO	1, 3, 5, 6
4.	Jim Haigh	WAPA	MRO	1, 6
5.	Charles Lawrence	ATC	MRO	1
6.	Ken Goldsmith	ALTW	MRO	4
7.	Pam Sordet	XCEL	MRO	1, 3, 5, 6
8.	Dave Rudolph	BEPC	MRO	1, 3, 5, 6
9.	Eric Ruskamp	LES	MRO	1, 3, 5, 6
10.	Joseph Knight	GRE	MRO	1, 3, 5, 6
11.	Joe DePoorter	MGE	MRO	3, 4, 5, 6
12.	Larry Brusseau	MRO	MRO	10

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
13.	Michael Brytowski	MRO MRO 10										
44.	Carol Sedewitz	National Grid	x									
45.	Andrew Wilcox	NB Power Transmission	x			x						
46.	Patrick Brown (PJM Interconnection, L.L.C.	NERC and Regional Coordination		x								
47.	Gregory Campoli	New York Independent System Operator		x								
48.	James Manning	North Carolina Electric Membership Corp			x	x	x	x				

Additional Member	Additional Organization	Region	Segment Selection
1.	Bob Beadle	NCEMC SERC	3, 4, 5, 6

49.	Rick White	Northeast Utilities	x									
50.	Guy Zito (NPCC)	NPCC										x

Additional Member	Additional Organization	Region	Segment Selection
1.	David Kiguel	Hydro One Networks Inc.	NPCC 1
2.	Ralph Rufrano	New York Power Authority	NPCC 5
3.	Dan Rochester	Independent Electricity System Operator	NPCC 2
4.	Rick White	Northeast Utilities	NPCC 1
5.	Lee Pedowicz	NPCC	NPCC 10
6.	Gerry Dunbar	NPCC	10
7.	Brian Hogue	NPCC	10
8.	Alan Adamson	New York State Reliability Council	NPCC 10
9.	Donald E. Nelson	Massachusetts Dept. of Public Utilities	NPCC 9
10.	Kathleen Goodman	ISO - New England	NPCC 2
11.	Gregory Campoli	New York Independent System Operator	NPCC 2
12.	Chris De Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC 1
13.	Brian Gooder	Ontario Power Generation Incorporated	NPCC 5

51.	Steven Masse	NSTAR Electric	x		x							
52.	John P. Mayhan	Omaha Public Power District	x		x		x	x				
53.	Greg Ward / Darryl Curtis	Oncor Electric Delivery	x									
54.	Matthew J Muldoon	OPUC									x	
55.	Aaron Staley	Orlando Utilities Commission	x		x		x	x				

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
56.	Chifong Thomas	Pacific Gas and Electric Co.	x									
57.	Sandra Shaffer	PacifiCorp	x									
58.	John Collins	Platte River Power Authority	x		x			x				
59.	John Cummings	PPL EnergyPlus					x	x				
60.	Mark Byrd	Progress Energy Carolinas	x		x		x					
61.	Bart White	Progress Energy Florida, Inc.	x		x							
62.	Tom Duane	Public Service Company of New Mexico	x		x							
63.	Joe Seabrook	Puget Sound Energy, Inc.	x		x							
64.	Herb Schrayshuen (SERC Reliability Corporation)	SERC Dynamics Review Subcommittee										x
65.	Herbert Schrayshuen (SERC Reliability Corporation)	SERC Reliability Review Subcommittee and Planning Standards Subcommittee										x
66.	Jessica Rice	Sierra Pacific Power Company/Nevada Power Company	x									
67.	Dilip Mahendra	SMUD	x		x		x	x				
68.	Dana Cabbell	Southern California Edison	x	x								
69.	Roman Carter	Southern Company Transmission	x									

Additional Member	Additional Organization	Region	Segment Selection
1.	JT Wood	SOCO Transmission SERC	1
2.	Jim Busbin	SOCO Transmission SERC	1
3.	Shih-Min Hsu	SOCO Transmission SERC	1
4.	Rod Hardiman	SOCO Transmission SERC	1
5.	Randy Cobb	SOCO Transmission SERC	1
6.	Chase Battaglio	SOCO Transmission SERC	1
7.	Bill Botters	SOCO Transmission SERC	1
8.	Tom Sims	SOCO Transmission SERC	1
9.	Chuck Chakravarthi	SOCO Transmission SERC	1
10.	Gary Gorham	SOCO Transmission SERC	1
11.	Chris Wilson	SOCO Transmission SERC	1

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
12. Terry Coggins, SOCO Transmission, SERC, 1 13. Bob Jones, SOCO Transmission, SERC, 1 14. Raymond Vice, SOCO Transmission, SERC, 1												
70.	Brian K. Keel	SRP	x									
71.	Tacoma Power	Tacoma Power	x									
72.	Scott Helyer	Tenaska, Inc.	x									
73.	Dave Larsen	Transmission Agency of Northern California	x									
74.	Denise Koehn (BPA)	Transmission Reliability Program	x		x		x	x				
Additional Member, Additional Organization, Region, Segment Selection 1. Chuck Matthews, Transmission Planning, WECC, 1 2. Berhanu Tesema, Transmission Planning, WECC, 1 3. Kendall Rydell, Transmission Planning, WECC, 1												
75.	Andy Leoni	Tri-State G&T	x									
76.	Mark Graham	Tri-State Generation and Transmission Association, Inc.	x									
77.	Gary Trent	Tucson Electric Power Company	x		x		x					
78.	B. David Till (TVA)	TVA System Planning	x									
79.	Karl Bryan	US Army Corps of Engineers, Northwestern Division					x					
80.	Jay Seitz	US Bureau of Reclamation					x					

1. **The SDT has modified the definitions and requirements associated with System Stability and Generating Unit Stability (formerly Plant Stability) in response to industry comments. Do you concur with the modified definitions for stability and, if not, please state why and/or suggest specific changes.**

Summary Consideration:

By a significant majority (about 2/3), the industry did not agree with the two definitions as modified in the second draft. Most of those disagreeing still express a fundamental disagreement with the approach of separating plant Stability from System Stability. Essentially many argue that plant Stability is simply a subset of System Stability, and the standard requirements could be simplified by focusing on Stability performance in a generic way. In this way Stability performance could be viewed in the context of individual units (generating unit Stability) or groups of units (System Stability). Some of these same commenters also argue that generating unit Stability is already covered by FAC–001 and -002 and, therefore, should be dropped from the TPL-001-1 standard; otherwise double jeopardy could apply. Many of these same commenters also suggested that if separation of generating unit Stability is retained in the final draft, then certain refinements of the requirements language should be made.

Others who voted 'No', as well as some who generally support the language of the current draft, recommended a variety of changes to the definitions and requirements for further clarity.

Only some 20+ percent of the commenters supported the current draft Stability definitions without reservation.

The SDT agrees with the Industry's majority view that generating unit Stability and System Stability need not and should not be treated as distinct issues. Consequently, the two new Stability terms have been removed from the third draft, and this revised draft references the already approved term "Stability." Furthermore, as indicated by the SDT's response to commenters, the Stability related requirements have been modified to create a single generic set of requirements that no longer distinguishes between generating unit and System Stability.

In summary, due to these and other industry comments in response to this question, the SDT has changed the following definition and requirements:

Consequential Load Loss: ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions.

R2. Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses ~~including both System and Generating Unit Stability~~.

R2.1 The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported ~~at a minimum~~ by the following annual current studies, supplemented with qualified past studies as indicated in Requirement R2.6:

R2.2 For the Long-Term Transmission Planning Horizon portion of the steady state analysis, ~~at a minimum,~~ a current System peak Load study is required annually for one of the years in the assessment period to support the annual Planning Assessment.

R2.6.1 (now 2.5.1) For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less.

R2.6.2 (now 2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:

R3.3.1 (now 3.3.2) For all generators, studies shall consider the minimum steady state voltage limitations ~~of all generators~~ and identify how the generators are ~~treated~~ analyzed in the steady state simulation.

R5. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, ~~the~~any proxies used in ~~simulation studies~~ the analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.

The wording of sub-requirements R5.6.1 and R5.6.2 was modified and relocated to become bullets under Requirement R2.5.2.

- The addition/deletion/change of individual generating unit capability of 20 MW or greater.
- An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater.

The definitions of Generating Unit Stability Study and System Stability Study as well as the following sub-requirements were deleted: R2.5, R2.5.1, R2.5.2, and R5.5.

Organization	Question 1:	Question 1 Comments:
NPCC	No	There should be no difference between System and Generating Unit Stability studies. Each requires discretion regarding which events need to be tested. The consequences are potentially similar: either the instability of one or more generators. Extreme Events should be considered for any stability analysis, again, recognizing that discretion needs to be applied when selecting or dismissing particular contingencies. Therefore, the definition of Generating Unit Stability Study should be stricken from the standard.
Los Angeles	No	Changing the name does not change the fact that this is wrong. The stability criteria in the standards are all measured on

Organization	Question 1:	Question 1 Comments:
Department of Water and Power		the high-side, i.e., the system side. So when a stability simulation is performed, if there is any problems, whether it be loss of synchronism, out-of-step, damping, inter-area oscillations, etc, they will all appear on the same run and there is no distinctions between system stability or unit stability. To separate the two implies there is a difference and requires two different simulations is either confusing at best or imply ignorance of the physics. Maybe the drafting team is concerned with the proper modeling of the generator in a stability simulation. There may be practice to "lump" similar units in a plant as one "unit" or the dynamic characteristics of a unit were not explicitly or correctly modeled; in such instances, the behavior of individual unit cannot be observed. But if that is the case, the entire stability simulation is incorrect to begin with anyway, even on the system side. To properly deal with unit modeling, the standard should prohibit lumping of units and require all dynamic data (including governor controls, exciters, stabilizers, etc.) are included in the simulation model.
National Grid	No	There should be no difference between System and Generating Unit Stability studies. Each requires discretion regarding which events need to be tested. The consequences are potentially similar: either the instability of one of more generators. Extreme Events should be considered for any stability analysis, again, recognizing that discretion needs to be applied when selecting or dismissing particular contingencies. If no distinction is made between System and Generating Unit Stability studies is made, then the definition of Generating Unit Stability Study should be stricken from the standard.
PacifiCorp	Yes and No	We generally concur with the changes for the Requirements associated with the Generating Unit and System Stability, however, Generating unit stability studies are typically performed at the time of interconnection. Even though stability studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of generating units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units. Will every TP have to benchmark their generating unit stability study for its entire fleet with the acceptance of this Standard? In other words, will every TP has to recreate documentation for all its older units? We would appreciate that the SDT more clearly define the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study with examples.
Hydro-Québec TransEnergie (HQT)	No	There should be no difference between System and Generating Unit Stability studies. Each requires discretion regarding which events need to be tested. The consequences are potentially similar: either the instability of one of more generators. Extreme Events should be considered for any stability analysis, again, recognizing that discretion needs to be applied when selecting or dismissing particular contingencies. Therefore, the definition of Generating Unit Stability Study should be stricken from the standard.
CenterPoint Energy and CPS Energy	No	Most industry commenters from the previous draft advised against making a distinction between system and generating unit stability, which are not commonly accepted industry terms. We (CenterPoint Energy and CPS Energy) remain unconvinced that the distinction is needed. If most industry commenters concur after this second draft, we believe the

Organization	Question 1:	Question 1 Comments:
		SDT should listen.
Austin Energy	No	There is no need to separate system stability studies and generating unit stability studies. Requirement R5.4 should be written to include generating unit stability analysis.
Tri-State Generation and Transmission Association, Inc.	No	Starting from this version, we think it would be clearer to not distinguish between generator and system stability studies, but rather list both as requirements for Stability Studies. Generating unit analyses would include tests of models such as generator exciters, and System Stability studies would model such things as bus faults.
Brazos Electric Power Cooperative, Inc.	No	We do not see the need to have 2 separate requirement sections nor definitions for both System and Generating stability studies. The section for stability studies should simply suggest when these studies should be performed, when new generation is added, conditions for that, etc? Confusion continues to come from the ambiguous use of language such as 'Material Transmission System changes' or 'changes in generation capability'. Of note in 2.5.2, requiring stability studies for the addition of a new substation in a transmission line connected to a generator is completely unnecessary most of the time but the wording in 2.5 does not appear to allow flexibility. Discretion should be provided to the TP.A first course of action would be to bring the related stability criteria under one section. It seems like 5.6 can be combined under a requirements section for stability studies.
Northeast Utilities	No	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
North Carolina Electric Membership Corp	Yes and No	We think we understand the direction that the SDT is heading but needs to be clearer. Angular stability for a single unit is the focus of Generating Unit Stability where as System Stability involves multiple generating machines or plants, and may also encompass voltage stability of loads which should be addressed separately in our opinion since different tools are used for this assessment.
ERCOT System Planning	No	Most industry commenters from the previous draft advised against making a distinction between system and generating unit stability, which are not commonly accepted industry terms. The only difference between the two seems to be location of contingencies tested. ERCOT suggests removing specific requirements for Generating Unit stability, as System Stability covers everything.
Central Maine Power Company	No	There should be no difference between System and Generating Unit Stability studies. Each requires discretion regarding which events need to be tested. The consequences are potentially similar: either the instability of one of more generators. Extreme Events should be considered for any stability analysis, again, recognizing that discretion needs to be applied when selecting or dismissing particular contingencies. Therefore, the definition of Generating Unit Stability Study should

Organization	Question 1:	Question 1 Comments:
		be stricken from the standard.
NSTAR Electric	No	There should be no difference between System and Generating Unit Stability studies. Each requires discretion regarding which events need to be tested. The consequences are potentially similar: either the instability of one of more generators. Extreme Events should be considered for any stability analysis, again, recognizing that discretion needs to be applied when selecting or dismissing particular contingencies. If no distinction is made between System and Generating Unit Stability studies is made, then the definition of Generating Unit Stability Study should be stricken from the standard.
New York Independent System Operator	No	There should be no difference between System and Generating Unit Stability studies. Each requires discretion regarding which events need to be tested. The consequences are potentially similar: either the instability of one of more generators. Extreme Events should be considered for any stability analysis, again, recognizing that discretion needs to be applied when selecting or dismissing particular contingencies. Therefore, the definition of Generating Unit Stability Study should be stricken from the standard.
ISO New England Inc.	No	There should be no difference between System and Generating Unit Stability studies. Each requires discretion regarding which events need to be tested. The consequences are potentially similar: either the instability of one of more generators. Extreme Events should be considered for any stability analysis, again, recognizing that discretion needs to be applied when selecting or dismissing particular contingencies. If no distinction is made between System and Generating Unit Stability studies is made, then the definition of Generating Unit Stability Study should be stricken from the standard.
Entergy Services, Inc.	Yes and No	Entergy agrees with the intent. However, there will be some confusion because the industry standard terms for stability are omitted. It should be clear that the System Stability Study is a wide area view/assessment of both angular and voltage stability. In contrast, the Generating Unit Stability Study is focused on a specific unit or plant and the immediate area. Typically, this study looks at angular stability. The confusion may be exacerbated by the exclusion of a definition for voltage (or load) stability in the notes on page 31. There is a discussion of angular stability, but voltage stability is conspicuously missing. An improvement for the System Stability Study definition is to clarify that it is a study that focuses on the impact to the system itself and covers an area larger than one Generating Plant, covering a large geographical area. See specific proposal below: System Stability Study - Study that focuses on how contingencies impact a larger portion of the System than a Generating Unit Study. These studies would examine issues such as angular Stability, inter-area power oscillation, and dynamic voltages.
BPA Transmission	No	Generating Unit Stability is adequately addressed by the System Stability studies and does not need to be evaluated separately. Footnote 5.a.i in the notes following the Performance Requirements Tables, already specifies the

Organization	Question 1:	Question 1 Comments:
Reliability Program		requirements to meet. Therefore, we recommend removing the section on Generating Unit Stability Studies from standard TPL-001-1. The focus of this standard should be on "System Stability" which encompasses all generating units.

Response: The SDT agrees and has modified the definitions and Requirements accordingly.

R2. Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses ~~including both System and Generating Unit Stability~~.

R2.6.1 (now 2.5.1) For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less.

R2.6.2 (now 2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:

R5. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~

The wording of sub-requirements R5.6.1 and R5.6.2 was modified and relocated to become bullets under Requirement R2.5.2.

The addition/deletion/change of individual generating unit capability of 20 MW or greater.

An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater.

The definitions of Generating Unit Stability Study and System Stability Study as well as the following sub-requirements were deleted: R2.5, R2.5.1, R2.5.2, and R5.5

Progress Energy Carolinas	No	The System Stability Study definition could be improved by clarifying that it is a study that focuses on the impact of contingencies to the system itself and covers a larger geographical area than one Generating Plant. A specific proposal is as follows. System Stability Study - Study that focuses on how contingencies impact a larger portion of the System than a Generating Unit Study. These studies would examine issues such as angular stability, inter-area power oscillations, and dynamic voltages.

Organization	Question 1:	Question 1 Comments:
Ameren	No	Agree with the revised definition of Generating Unit Stability Study. Propose new definition for System Stability Study, as follows - "Study that focuses on portions of the System, including the impact of contingencies on multiple generating units in an area. These studies would examine issues such as angular Stability, inter-area oscillation, and voltages during dynamic simulations."
SERC Dynamics Review Subcommittee	No	An improvement for the System Stability Study definition is to clarify that it is a study that focuses on the impact to the system itself and covers an area larger than one Generating Plant, covering a large geographical area. See specific proposal below: System Stability Study - Study that focuses on how contingencies impact a larger portion of the System than a Generating Unit Study. These studies would examine issues such as angular Stability, inter-area power oscillation, and dynamic voltages.
Southern Company Transmission	No	We suggest the following for the System Stability Study definition: Study that focuses on large portions of the System (which may include many generating units) and how contingencies affect that larger area to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.
American Transmission Company	No	Generating Unit Stability Study definition - We suggest deleting the text, "on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point.", because certain Generation Facility contingencies should be considered and key Transmission Facility contingencies can be more than one bus away from the interconnection point. System Stability Study definition - We suggest this alternate wording: "Study that focuses on portions of the System, which may include many generating units with various Contingencies. This study is concerned with loss of synchronism, lack of damping of inter-area power oscillations, and voltages during the dynamic simulation." We suggest this wording because the definition of a study should not give the criteria, but rather the general elements of the study.
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	No	There is an inconsistency between the defined terms “Generating Unit Stability Study” and “System Stability Study” and the usage within the standard. The requirements refer to these terms by omitting the word “study” .An improvement for the System Stability Study definition is to clarify that it is a study that focuses on the impact to the system itself and covers an area larger than one Generating Plant, covering a large geographical area. See specific proposal below: System Stability Study - Study that focuses on how contingencies impact a larger portion of the System than a Generating Unit Study. These studies would examine issues such as angular Stability, inter-area power oscillation, and dynamic voltages.?

Organization	Question 1:	Question 1 Comments:
Response: The SDT appreciates your suggested improvements. However, a majority of the Industry believes that there should be no distinction between System Stability and Generating Unit Stability.		
Platte River Power Authority	Yes and No	"Generator Unit Stability Study" assessments are applicable to FAC-001 and FAC-002. If specific requirements for a "Generator Unit Stability Study" are to be added to a standard, then those requirements belong in either a Revised FAC-001 or a Revised FAC-002 and not in a TPL standard. The "System Stability Study" assessments which are appropriate for TPL standards will capture both the performance of the system and the performance of specific generators at the various demand and stressed sensitivity levels studied.
BCTC	No	BCTC agrees with many other commenters, ABB, Ameren, Central Maine Power, NPCC RCWS, FirstEnergy, WECC, HQTE, Tenaska, FPL, FRCC, National Grid, New England ISO, NU, NStar, United Illuminating, BPA, Progress-Carolinas, TEP, and Northwestern Energy that there is no significant distinction between generator and system stability. These entities have significant experience with stability studies. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without any explanation. We believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequate addressed by open access tariffs and FAC-001. This should not be duplicated in TPL.
Manitoba Hydro	No	Manitoba Hydro does not believe there is a need to distinguish between System Stability Study and Generating Unit Stability Study. Both these studies as defined require that synchronous operation of generators is maintained (i.e. angular stability) and damping is acceptable (i.e. small signal stability). The stability assessment would cover the issues being requested in the Generating Unit stability Study. We suggest the definition for System Stability Study - A study that determines whether angular stability is maintained, inter-area power oscillations are acceptably damped, and transient voltage swings remain within acceptable limits. Further, contrary to the SDT interpretation in the response to our first posting comments, Manitoba Hydro believes the Generating Unit Stability Study is a duplication of what is required in FAC-002-0 as the FAC requirements mandate system performance required by the NERC Reliability Standards. Manitoba Hydro continues to believe this additional study is redundant. Should the SDT decide to retain the Generating Unit stability study, then Manitoba Hydro recommends that, consistent with the wording in other requirements of this assessment section, it would be more appropriate to require that "Generating Unit Stability be assessed using current or qualifying past studies." This would allow use of current interconnection studies mandated by FAC-002-0 to be used to comply with the Generating Unit Study requirement. Currently, the wording in R2.5 requires that Generating unit stability be analyzed with studies for the conditions in R2.5.1 and/or R2.5.2.
Transmission Agency of	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is

Organization	Question 1:	Question 1 Comments:
Northern California		important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to “develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies”. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
OPUC	Yes and No	We cannot evaluate the need to distinguish generating unit stability and system stability without greater explanation inclusive of examples. We also need clarification of the intended interactions of this proposed standard with of FAC-001 and 2 to avoid duplication of efforts. Finally, if FAC-001 will cover generating unit or interconnection stability R 2.5 should clearly address existing older generators.
Pacific Gas and Electric Co.	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to "develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies". If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not

Organization	Question 1:	Question 1 Comments:
		need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
Public Service Company of New Mexico	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to "develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies". If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
Puget Sound Energy, Inc.	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit

Organization	Question 1:	Question 1 Comments:
		Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to "develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies". If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
Idaho Power Company	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to “develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies”. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequate addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to

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		say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
SMUD	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study focuses on an individual generating units or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to “develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies”. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
Sierra Pacific Power Company / Nevada Power Company	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study focuses on an individual generating units or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies? If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability.

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		Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequate addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
Black Hills Corporation	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to "develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies". If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
SRP	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the

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		objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study focuses on an individual generating units or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies?. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
Tucson Electric Power Company	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to ?develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies?. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability

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		problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
Modesto Irrigation District	No	Comments: We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study focuses on an individual generating units or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to “develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies”. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1.In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
Tri-State G&T	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to ?develop a Bulk Electric System that will

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		operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies?. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
Southern California Edison	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to ?develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies?. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection? to invoke a study.

Organization	Question 1:	Question 1 Comments:
Alberta Electric System Operator	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to ?develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies?. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
US Bureau of Reclamation	No	Comments: We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to ?develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies?. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1.In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units

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		at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say "only when" the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, "material Transmission System change" and "at or near the point of Interconnection" to invoke a study.

Response: The SDT disagrees with your view that generating unit Stability assessments should be covered in FAC-001 or FAC-002. The SDT recognizes that such studies are performed for new generator interconnection, following the requirements of the appropriate FAC Standards. However, the TPL-001-1 Standard is intended to ensure on-going assessments of generating unit Stability so as to capture any significant performance changes over the course of time. Nevertheless, the SDT has eliminated the distinction between generating unit Stability and System Stability by modifying the definitions and Requirements as shown.

R2. Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses ~~including both System and Generating Unit Stability~~.

R2.6.1 (now 2.5.1) For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less.

R2.6.2 (now 2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:

R5. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~

The wording of sub-requirements R5.6.1 and R5.6.2 was modified and relocated to become bullets under Requirement R2.5.2.

The addition/deletion/change of individual generating unit capability of 20 MW or greater.

An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater.

The definitions of Generating Unit Stability Study and System Stability Study as well as the following sub-requirements were deleted: R2.5, R2.5.1, R2.5.2, and

Organization	Question 1:	Question 1 Comments:
R5.5.		
Gainesville Regional Utilities	No	Our small system does not have the present resources to deal with the large increase in stability type studies that this section seems to be requesting. Our system changes very little if at all from year to year. The ranking of the regional facilities where priority is given for stability study to the top 100 fault current buses shows that we do not have even a bus listed until position 611. We suggest that R2.4.1 should allow for only doing buses that have a ranking impact on the regional BES or no more that every 7 years for those systems without changes or are so small that their total separation or lost of their largest or almost total generation is not an issue for the RC. Stability should not have to be analyzed annually for small, unchanging systems.
Response: Where material changes do not occur as you describe for your System, studies would not have to be run any more frequently than once every five years, as described in Requirement R2.6 (now R2.5).		
ITC Holdings: ITC, METC, ITC Midwest	Yes and No	Requirement R 5.4.4: Consider changing the last sentence to the following: “If the Extreme Events analysis concludes there are widespread cascading outages, an evaluation of implementing a change designed to reduce or mitigate the likelihood of such consequences shall be conducted.”
Response: The wording suggested is basically identical to what is already there. The SDT does not feel that this change provides any clarity or alters the context of the present text. Also, widespread is an ambiguous term and not measurable. No change made.		
Progress Energy Florida, Inc.	No	Progress Energy Florida, Inc. (PEF) does not believe that Stability Analysis should be or can be successfully divided into the proposed two distinct concepts of System Stability and Generating Unit Stability. Most textbooks dealing with the matter of Stability Analysis divide the issue into two parts, steady state and transient, and then subdivide the transient part into power angle stability and voltage stability. PEF has been unable to find any engineering treatise that argues for dividing transient Stability Analysis into System Stability and Generating Unit Stability. NERC's present definition of Stability, "The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances", succinctly and correctly addresses the fact that stability issues regarding plants cannot be extricated from analysis of the rest of the system. PEF feels that this existing definition is accurate and not in need of clarification or improvement. To cite an example, if under the auspices of Generating Unit Stability, a transmission line trips, or if a load shedding scheme is activated, does the event then get defined as a System Stability event (or both)? It should be noted that the SDT attempted to both improve and clarify the definition of Stability in Note 5 of Table 2. The SDT's wording in Table 2 Note 5, while not containing any inappropriate or inaccurate information, has two fundamental flaws: a) it unnecessarily replaces the existing definition and b) it does not contain any language tying in the new definitions of System Stability and Generating Unit Stability. Furthermore, given that both of the new definitions are held to the exact same requirements, those found in Table 2, PEF can see no tangible benefit to two definitions, and therefore recommends removal of the new definitions of System Stability and Generating Unit Stability, and a return to the existing

Organization	Question 1:	Question 1 Comments:
		definition of Stability. Stability analyses that are taking place under the present definition and under the existing TPL Standards are more than adequate to demonstrate reliability of the BES, and PEF feels that the introduction of two new definitions would only serve to cause confusion and discussion regarding unmerited additional analyses.

Response: The SDT agrees and has modified the definitions and Requirements accordingly. Furthermore, with these changes, the SDT believes that Note 5 of Table 2 has value to the Industry as a clarification of the existing Stability definition and should no longer be viewed as a replacement definition.

R2. Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses ~~including both System and Generating Unit Stability~~.

R2.6.1 (now 2.5.1) For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less.

R2.6.2 (now 2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:

R5. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~

The wording of sub-requirements R5.6.1 and R5.6.2 was modified and relocated to become bullets under Requirement R2.5.2.

The addition/deletion/change of individual generating unit capability of 20 MW or greater.

An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater.

The definitions of Generating Unit Stability Study and System Stability Study as well as the following sub-requirements were deleted: R2.5, R2.5.1, R2.5.2, and R5.5

Lafayette Utilities System	No	Lafayette Utilities System (Lafayette) does not dispute the need for stability studies, especially in connection with significant system topology changes. We are concerned, however, by the possibility of inconsistencies between the results of interconnection studies conducted for new generating units pursuant to the Large Generator Interconnection Procedures prescribed by FERC and Generating Unit Stability Studies conducted as part of the TPL-001 planning assessment. For example, if a TPL-001 stability analysis indicates the need for more costly or extensive transmission upgrades that were indicated in an earlier LGIP interconnection study, the generation developer could be placed in an

Organization	Question 1:	Question 1 Comments:
		untenable situation: it would have proceeded with its project based on the assumption of responsibility for LGIP-indicated upgrades, but then could face demands for the funding of additional upgrades pursuant to the TPL-001 stability analysis. Improved integration between the two sets of stability studies appears warranted, in order to avoid placing generation developers in this position.
Response: The SDT understands your concerns; however, we believe that TPL-001-1 will not create an untenable position for generation developers following the LGIP. Studies to interconnect the generator in accordance with the LGIP will identify those Facilities to be incorporated in the Interconnection Agreement. Future studies carried out in compliance with TPL-001-1 will ensure on-going System reliability, and any Facility upgrades required for that purpose will be the responsibility of the Transmission Owner, not the generation developer.		
Arizona Public Service Co.	Yes and No	We generally concur with the changes for the Requirements associated with the Generating Unit and System Stability, however, Generating unit stability studies are typically performed at the time of interconnection. Even though stability studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of generating units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units. Will every TP have to benchmark their generating unit stability study for its entire fleet with the acceptance of this Standard? In other words, will every TP has to recreate documentation for all its older units?? We would appreciate that the SDT more clearly define the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study with examples.
ColumbiaGrid	Yes and No	We generally concur with the changes for the Requirements associated with the Generating Unit and System Stability, however, Generating unit stability studies are typically performed at the time of interconnection. Even though stability studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of generating units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units. Will every TP have to benchmark their generating unit stability study for its entire fleet with the acceptance of this Standard? In other words, will every TP has to recreate documentation for all its older units?? We would appreciate that the SDT more clearly define the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study with examples.
Response: The SDT believes that the modified definitions and Requirements in the third draft address your concerns. **R2**. Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses ~~including both System and Generating Unit Stability~~		

Organization	Question 1:	Question 1 Comments:
R2.6.1 (now R2.5.1) For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less. **R2.6.2** (now R2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: **R5**. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~ The wording of sub-requirements R5.6.1 and R5.6.2 was modified and relocated to become bullets under Requirement R2.5.2. The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater. The definitions of Generating Unit Stability Study and System Stability Study as well as the following sub-requirements were deleted: R2.5, R2.5.1, R2.5.2, and R5.5 Specifically, as to your question regarding "benchmarking," the revised requirements would not necessitate studies of each individual generating unit or generating plant.		
Florida Power and Light	No	This draft did not modify the existing NERC definition of Stability. Footnote 5 of the Tables describes the expected acceptable performance of a System that is stable, but the terms "System Stability" and "Generating Unit Stability" are not defined, except as studies. All stability studies must meet the Performance Requirements for Planning Events in Table 2 - Stability Performance. If there were different Performance Requirements then the distinction may be warranted. However system stability studies should be sufficient and not warrant additional work. R6 requires Transmission Planners to define proxies used to identify instability. Presumably the "proxies" would be used as a checklist for assessment of stability; however, not all stability limitations can be simplified as a proxy in the load flow. Proxies should only be used as indicative of a potential stability issue, not "to identify System instability", or replace stability studies, since a stability study to identify the issue was initially required to define the proxy. The requirement should be reworded to state "R6. If proxies are used in simulation studies to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding, then each Transmission Planner and Planning Coordinator shall define the proxies used in the simulation studies."

Organization	Question 1:	Question 1 Comments:
Orlando Utilities Commission	No	I support the comments from Florida Power & Light regarding System Stability vs. Generating unit studies and proxies.

Response: The SDT agrees and has modified the definitions and Requirements accordingly. Furthermore, the SDT has also modified the wording of R6 to address your concern.

R2. Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses ~~including both System and Generating Unit Stability~~.

R2.6.1 (now R2.5.1) For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less.

R2.6.2 (now R2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:

R5. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~

The wording of sub-requirements R5.6.1 and R5.6.2 was modified and relocated to become bullets under Requirement R2.5.2.

The addition/deletion/change of individual generating unit capability of 20 MW or greater.

An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater.

The definitions of Generating Unit Stability Study and System Stability Study as well as the following sub-requirements were deleted: R2.5, R2.5.1, R2.5.2, and R5.5.

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, ~~the~~any proxies used in ~~simulation studies~~ the analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.

Exelon Transmission	Yes and No	The definitions of System Stability and Generating Unit Stability are clear. We agree that there is value in performing small signal analysis but we are concerned about the availability of software and expertise required to execute the

Organization	Question 1:	Question 1 Comments:
Planning		analysis.R5.3 is ambiguous, as it is not clear what the requirement to consider the voltage ride through capability of all generators entail. Ride through could involve the unit or station having the capability to ride through without tripping or the unit could trip but the system remain stable. General Observations R3.2.1 should be reworded so as not to be misinterpreted that GOs are prescribing their 'required' voltage levels. R2.6.2 should be Unit not Plant with regard to stability studies. R2.7.1 and elsewhere - The NERC Glossary specifies that SPSs are 'Special Protection Systems' (not 'schemes'). R5.2 Wording should be changed from '...disconnect for each contingency..' to '..isolate the disturbance... .' R5.5.1 There are too many studies required. The 20 MW threshold for unit studies may be too low. There should be a mechanism to provide a proxy for smaller units on 138 or possible 230 kV systems that can't affect system stability rather than to automatically require a study every 5 years. R2.1 and 2.2 should have the words 'at a minimum' removed with regards to describing which studies are required annually. The requirement to supply a 'project initiation date' for near-term Corrective Action Plans should be removed. If it remains, it should be clarified (Project identification date, construction start date, PUC certification date, executive approval date, etc?)

Response: The intent of Requirement R5.3 is to ensure that the generating unit models realistically replicate the behavior of the generator in response to a low voltage condition encountered during the simulation.

The requirement on voltage ride through has been changed to provide clarity (now R4.3.2).

R3.2.1 (now R3.3.2) For all generators, studies shall consider the minimum steady state voltage limitations ~~of all generators~~ and identify how the generators are ~~treated~~ analyzed in the steady state simulation.

The SDT has deleted the distinction between Unit/Plant and System Stability based on other comments.

The SDT agrees that SPS means “Special Protection Systems” and the third draft uses this terminology consistently.

The SDT disagrees with your suggested rewording of Requirement R5.2 because the concept that the requirement is addressing relates to the resultant topology of the system after the fault is cleared and not the removal of the disturbance.

In response to your comment on Requirement R5.5.1, the SDT believes that all of the studies needed to satisfy this requirement are essential to maintain reliability. The SDT has thoroughly debated the 20 MW generating unit threshold and continues to believe that this is the appropriate value.

In Requirements R2.1 and R2.2, the SDT has removed the words “at a minimum” as you have suggested.

Organization	Question 1:	Question 1 Comments:
R2.1 The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported ~~at a minimum~~ by the following annual current studies, supplemented with qualified past studies as indicated in Requirement R2.6: **R2.2** For the Long-Term Transmission Planning Horizon portion of the steady state analysis, ~~at a minimum,~~ a current System peak Load study is required annually for one of the years in the assessment period to support the annual Planning Assessment. In response to your comment on "project initiation date," the SDT considered your suggestion; however, the SDT believes that the current language is satisfactory, and few comments were received suggesting need for a modification.		
MidAmerican Energy Company	Yes and No	MidAmerican Energy Company (MEC) believes the definitions are improved. However, MEC suggests that the SDT clarify what stability analyses are required such as angular and voltage stability for which time frames such as the transient and steady state time frames and for what planning horizons such as the Near-Term and Long-Term planning horizons.
MRO NERC Standards Review Subcommittee	No	The MRO believes the definitions are improved. However, the MRO suggests that the SDT clarify what stability analysis are required such as angular and voltage stability for which time frames such as the transient and steady state time frames and for what planning horizons such as the Near-Term and Long-Term planning horizons. Generating Unit Stability Study definition - The MRO suggests deleting the text, "on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point.", because certain Generation Facility contingencies should be considered and key Transmission Facility contingencies can be more than one bus away from the interconnection point. System Stability Study definition - The MRO suggests this alternate wording: "Study that focuses on portions of the System, which may include many generating units with various Contingencies. This study is concerned with loss of synchronism, lack of damping of inter-area power oscillations, and voltages during the dynamic simulation." We suggest this wording because the definition of a study should not give the criteria, but rather the general elements of the study.
Response: The SDT believes that your comments requesting clarifications have been addressed through the changes made as shown. **R2**. Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses ~~including both System and Generating Unit Stability~~. **R2.6.1** (now R2.5.1) For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less. **R2.6.2** (now R2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: **R5**. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning		

Organization	Question 1:	Question 1 Comments:
Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~— Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~ The wording of sub-requirements R5.6.1 and R5.6.2 was modified and relocated to become bullets under Requirement R2.5.2. The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater. The definitions of Generating Unit Stability Study and System Stability Study as well as the following sub-requirements were deleted: R2.5, R2.5.1, R2.5.2, and R5.5		
Arkansas Electric Coop. Corp.	Yes and No	There are situations where one bus away may not be far enough. While one bus may cover most situations the standard shouldn't limit the study to just one bus away. Suggested language change: Transmission Facilities connected to that generating unit(s) point(s) of interconnection, one bus away from the electrically closely-coupled units.
Response: The definition for Generating Unit Stability Study has been deleted so the offending phrase is no longer in this standard.		
NERC and Regional Coordination (PJM)	No	In the definition of Consequential Load Loss - Revise Transmission Planning Entities to Transmission Planners; or otherwise clearly identifying the entities that are meant to be addressed by the term "Transmission Planning Entities. "Revise "which" to "that" as indicated by the text below that is in quotes and Upper Case: Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation connected to a source as a result of the event being studied or "THAT" is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load "THAT" is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, [Transmission planning entities] TRANSMISSION PLANNERS are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements. Regarding the definition of Planning Event -The given words do not define the term. For example is an event meant to be an forced outage condition; or is meant to be any set of state conditions. If an event can be anything, then the term is not a definition. Planning Coordinator -Explicitly state that this definition will be deleted when the functional model definition for this entity is approved May consider deleting the term because it is not unique to this standard. The term is already defined in the Functional Model.R1.1 ? Data changes are routine in such studies and need to better quantify when technical justification is required.

Organization	Question 1:	Question 1 Comments:
Response: The definition of Consequential Load Loss has been changed in an attempt to clear up issues such as you addressed. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions.		
IESO	No	(i) Generating Unit Stability Study: We do not agree with the phrase "…or one bus away from that point." This limits the scope of the testing to only the next bus. At times, contingencies that remove critical transmission facilities several buses away from a generating plant may affect generating unit stability performance. We suggest to reword this phrase to "..or in the nearby vicinity that can have an adverse reliability impact on the generating units' stability performance."(ii) Long-Term Transmission Planning Horizon: A nit-picking suggestion to change the first "longer" to "long".(iii) Planning Coordinator: We not see the need to repeat a definition that is already provided in the NERC Glossary of Terms and the Functional Model. There is a plan to implement a wholesale change from Planning Authority to Planning Coordinator. This is expected to occur in the first half of 2009.(iv) System Stability Study: Since voltage performance is included in this assessment, we suggest to add to the phrase "?which may include many generating units AND GROUPS OF TRANSMISSION FACILITIES..".(v) Year One: The second part of the definition is confusing. By "12-18 months from the completion of the previous annual Planning Assessment." does it mean 12-18 months from the "complete date" of the previous assessment, or from the "end of the previous assessment period"? For example, a previous assessment was completed on April 30, 2008 that covers a 12 month period from May 1, 2008 to April 30, 2009. Does year one for the subsequent assessment start from May 1, 2009 or May 1, 2010? In view of the confusion, having only the first sentence would suffice. In fact, there is only one reference made in the requirement (R2.1.1). Qualifying "year one" can easily be made in that requirement without having to have a defined term. Adding defined terms without a good cause adds to the maintenance task for the glossary of terms. Further, it begs the question on why "year two" and "year five" referenced in that same requirement are not defined.
Response: With regard to your comments (i) and (iv), the SDT agrees and has modified the definitions and Requirements accordingly. **R2**. Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses ~~including both System and Generating Unit Stability~~. **R2.6.1** (now R2.5.1) For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less.		

Organization	Question 1:	Question 1 Comments:
R2.6.2 (now R2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: **R5**. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~ The wording of sub-requirements R5.6.1 and R5.6.2 was modified and relocated to become bullets under Requirement R2.5.2. The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater. The definitions of Generating Unit Stability Study and System Stability Study as well as the following sub-requirements were deleted: R2.5, R2.5.1, R2.5.2, and R5.5. (ii) Thank you for your suggestion. The SDT sees no material difference in the suggested change and has decided to leave the definition unchanged. (iii) As you note, NERC is transitioning from the use of the term Planning Authority to the term Planning Coordinator. Since the new terminology has not been officially adopted yet in the Functional Model, it must be defined in this standard revision. (v) The definition is intended to be flexible to accommodate different practices and schedules. The key points are: 1) an assessment must be done each year and completed any time during the year, 2) the first year of the assessment period should be beyond the period examined to address operational planning issues, and 3) the time to complete the assessment could vary and take up to 18 months. In your example, if you have chosen Year One to be May 1, 2008 to April 30, 2009, then Year One for the subsequent assessment would begin May 1, 2009.		
Dominion - Electric Transmission Planning	Yes	
TVA System Planning	Yes	
City Water, Light & Power -	Yes	

Organization	Question 1:	Question 1 Comments:
Springfield, Illinois		
Tenaska, Inc.	Yes	
US Army Corps of Engineers, Northwestern Division	Yes	
JEA	Yes	
Midwest ISO	Yes	
AEP	Yes	
Lakeland Electric	Yes	
LCRA TSC	Yes	
E.ON U.S. Transmission Planning	Yes	
Duke Energy	Yes	
Oncor Electric Delivery	Yes	NA
FirstEnergy Corp.	Yes	
Response: Thank you for your response.		

2. Do you concur with the modified Requirements R2.4, R2.5, R5.4, and R5.5? If not, please state why and/or suggest specific changes.

Summary Consideration:

In response to industry comments, the SDT decided that generating unit Stability and System Stability need not and should not be treated as distinct issues. The Stability related requirements have been modified to create a single generic set of requirements that no longer distinguishes between generating unit and System Stability. This should address any potential conflict between this standard and the FAC standards.

Requirement R2.4.1 has been modified to clarify that a detailed dynamic Load model is not required at each bus. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Because of this clarification, the SDT believes that a 24 month implementation period for this requirement is sufficient.

Requirement R2.4.3 has been modified to remove the need for stating the technical rationale for why or why not a particular sensitivity was selected. Requirement R2.4.4 was deleted because it was essentially a voluntary requirement. The specific wording for each of the sensitivities to be considered has been changed and should be clearer as to what is needed. The TP is allowed to use its judgment as to how the variations of the sensitivity parameters should be made.

The requirement to include "known planned and long term outages of Transmission or generation equipment" has been removed from Requirement R5. This is covered in the revised Requirement R1.1.1.

Stability studies will continue to be required for smaller entities. Smaller entities have the option of not registering as a TP to avoid compliance concerns. Furthermore, it would be difficult to establish criteria for exempting “smaller entities.”

The definitions for Generating Unit Stability Study and System Stability Study have been deleted and the following requirements have been added or changed due to industry comments:

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R2.1.3 For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.1.4 When an entity’s spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

- ~~Variations in~~ Load model assumptions
- ~~Modification of e~~Expected transfers
- ~~Unavailability of long lead time Facilities~~ Timing of the installation of new or modified Facilities.
- ~~Variability and outages of r~~Reactive resource~~s~~ capability.

R2.6.2 (now R2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:

- The addition/deletion/change of individual generating unit capability of 20 MW or greater.
- An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater.

R3 For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. ~~The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to c~~Contingencies ~~in Table 1 – Steady State Performance.~~ The studies shall be based on computer simulations using models utilizing data provided in Requirement R1.

R3.4 (now R3.5) Those Extreme Events in Table 1 ~~– Steady State Performance~~ that are expected to produce more severe System impacts shall be identified~~,~~ and a list of those events to be evaluated for System performance in Requirement R3.2 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results. If the ~~Extreme Events~~ analysis concludes there are cascading outages caused by the occurrence of Extreme Events, an evaluation of ~~implementing a change~~ possible actions designed to reduce ~~or mitigate~~ the likelihood or mitigate ~~of such~~the consequences and adverse impacts of the event(s) shall be conducted.

R5. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted~~

R5.2 (now R4.3 and R4.3.1) Contingency analyses shall: ~~s~~Simulate the removal of all elements ~~including those~~ that the Protection System ~~protection~~ and other automatic controls are expected to disconnect for each Contingency without operator intervention.

R5.4.4 (now R4.5) ~~At a minimum, t~~Those Extreme Events in Table ~~2~~1 ~~– Stability Performance~~ that ~~would~~are expected to produce more severe System impacts shall be identified and a list of those events to be~~,~~ evaluated for System performance in Requirement R5.2 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results. If the ~~Extreme Events~~ analysis concludes there are cascading outages caused by the occurrence of Extreme Events, an evaluation of ~~implementing a change~~ possible actions designed to reduce ~~or mitigate~~ the likelihood or mitigate ~~of such~~the consequences of the event(s) shall be conducted.

The following requirements were deleted due to industry comment:

R2.4.4 ~~In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and the Planning Assessment shall include documentation of the technical rationale for why each was selected shall be supplied.~~

R2.5 ~~The Generating Unit Stability analysis portion of the Planning Assessment shall be analyzed consistent with Requirement R5.5 with studies for the year when the following changes that could affect stability margins occur:~~

R2.5.1 ~~New generator(s) are added or generation modifications are made such as changes in generation capability or replacing the exciter.~~

R2.5.2 ~~Material Transmission System changes are made at or near the point of Interconnection of existing Generation such as the removal of a Transmission Line or the addition of a new substation in one of the Transmission Lines connected to the plant.~~

R5.4.3 ~~Automatic generation tripping is allowed to mitigate Stability violations if the following conditions are met:~~

R5.4.3.1 ~~All Facilities shall be operating within their Facility Ratings~~

R5.4.3.2 ~~Such action would not violate safety, equipment, regulatory or statutory requirements~~

R5.4.3.3 ~~A sustainable, stable, operating condition is maintained~~

R5.5 ~~For the Generating Unit Stability studies:~~

R5.5.1 ~~Shall be performed for individual generating units 20 MW or greater directly connected through a step-up transformer to the BES and for generating units at the same location which total 75 MW or greater, directly connected through their step-up transformer(s) to the BES.~~

R5.5.2 ~~Shall be performed for changes in the real power output of a generating unit by more than 10% of the existing capability or more than 20 MW whichever is greater.~~

R5.5.3 ~~Shall be performed and evaluated for those Planning Events that would produce more severe System impacts and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results.~~

R5.5.4 ~~Shall meet Performance requirements for Planning Events in Table 2 – Stability Performance~~

Organization	Question 2:	Question 2 Comments:
Dominion - Electric Transmission Planning	No	Comments are subdivided according to different sections as listed below: R2.4.1: In principal, we agree that the dynamic behavior of loads, including consideration of the behavior of induction motor loads, should be represented. However, it is not easy to get the data on such loads. Most customers, including industrial ones, have no information/knowledge regarding their load characteristics. Also, the software tools currently in use do not accommodate the modeling of certain material effects (for example the load reduction due to thermal trips on large HVAC compressor motors). Additionally, if the entire case is populated with such detail dynamic load data, the case could not be solved. A lot of research would be required. A phase-in period of several years should be considered in order to accomplish the fundamental objective of dynamic load modeling. Please refer to Item 4 of Question 15 for further thoughts on modeling requirements. R2.4.3: It is acceptable to perform studies that include various sensitivity factors, but to document all rationales why they were chosen or not chosen for each study performed is burdensome. R2.5.1: Reduction in generation does not decrease stability margins. Therefore, the previous version's "increasing in generation" should be kept instead of changing it to "changes in generation." R5.4.3: This requirement allows automatic generation tripping to mitigate Stability violations (subject to meeting three listed conditions there in). Automatic generator trips should not be allowed for N-1 contingency studies (beginning with system normal and evaluating for the very first contingency) should the full output of the generating unit be classified as a capacity resource. Allowing a capacity resource generator to trip for N-1 contingency could result in reduced system reliability.

Response: Requirement R2.4.1 has been modified to clarify that a detailed dynamic Load model is not required at each bus. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Because of this clarification, the SDT believes that a 24 month implementation period for this requirement is sufficient. This will be covered in the Implementation Plan which will be posted along with the third draft of the standard.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.3: The SDT agrees and has modified the language of Requirement R2.4.3 to not require the rationale for why a sensitivity was chosen or not.

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

Organization	Question 2:	Question 2 Comments:
R2.5.1: The SDT has removed the distinction between System Stability and generating unit Stability. Requirement R2.5.1 has been deleted. R5.4.3: This requirement has been deleted.		
NPCC	No	a. A MOD standard should be developed to address the assembly of dynamic load models, rather than specifying modeling in paragraph 2.4.1 (dynamic behavior of loads). Paragraph 2.4.1 should instead read, "System Peak Load for one of the five years." b. In paragraph R.2.4.3.4, what does "variability" mean? c. Add a new requirement "R5.4.3.4 Automatic generator tripping shall not have an Adverse Reliability Impact on overall system reliability." d. Remove Heading R5.5 and make generator unit stability a section of overall stability requirements. e. Modify R5.5.1 to become R5.4.5, with the following, "Shall be performed for the addition of an individual generating unit or generating units at the same interconnection point of 20 MW or greater that are directly connected to the BES." There may be little difference between the stability performance of a single 20 MW unit and an aggregation of units totaling 20 MW at the same BES interconnection point f. Strike R5.5.3 and R5.5.4, as they become redundant to R5.4.1
Hydro-Québec TransEnergie (HQT)	No	a. A MOD standard should be developed to address the assembly of dynamic load models, rather than specifying modeling in paragraph 2.4.1 (dynamic behavior of loads). Paragraph 2.4.1 should instead read, "System Peak Load for one of the five years." b. In paragraph R.2.4.3.4, what does "variability" mean? c. Add a new requirement, "R5.4.3.4 Automatic generator tripping shall not have an significant adverse impact on overall system reliability." d. Remove Heading R5.5 and make generator unit stability a section of overall stability requirements. e. Modify R5.5.1 to become R5.4.5, with the following, "Shall be performed for the addition of an individual generating unit or generating units at the same interconnection point 20 MW or greater that are directly connected to the BES." There may be little difference between the stability performance of a single 20 MW unit and an aggregation of units totaling 20 MW at the same BES interconnection point f. Strike R5.5.3 and R5.5.4, as they become redundant to R5.4.1
New York	No	a. A MOD standard should be developed to address the assembly of dynamic load models, rather than specifying

Organization	Question 2:	Question 2 Comments:
Independent System Operator		modeling in paragraph 2.4.1 (dynamic behavior of loads). Paragraph 2.4.1 should instead read, "System Peak Load for one of the five years." b. In paragraph R.2.4.3.4, what does "variability" mean? c. Add a new requirement, "R5.4.3.4 Automatic generator tripping shall not have an significant adverse impact on overall system reliability." d. Remove Heading R5.5 and make generator unit stability a section of overall stability requirements. e. Modify R5.5.1 to become R5.4.5, with the following, "Shall be performed for the addition of an individual generating unit or generating units at the same interconnection point 20 MW or greater that are directly connected to the BES." There may be little difference between the stability performance of a single 20 MW unit and an aggregation of units totaling 20 MW at the same BES interconnection point. f. ---- g. Strike R5.5.3 and R5.5.4, as they become redundant to R5.4.1

Response: a: The SDT disagrees and believes it is appropriate to require this in the TPL standard. Requirement R2.4.1 has been modified to clarify that an aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. It is not necessary to have a dynamic Load model which is specific to each bus.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

b: The specific wording for Requirement R2.4.3.4 has been changed to variations in "reactive resource capability". The sub-requirement is now also part of a bulleted list. This could mean a degradation of the capability of a reactive resource. The TP is allowed to use its judgment as to how the variations of the sensitivity parameters should be made.

~~Variability and outages of r~~Reactive resource~~s~~ capability.

c: The SDT has decided to remove Requirement R5.4.3 because the sub-requirements are already implicitly covered by the standard. Your suggested sub-requirement is also already implicitly covered by the standard.

d: In response to industry comments, the SDT has removed the distinction in the standard between System Stability and generating unit Stability.

e: The SDT agrees that there is little distinction between a single unit of a specific MW and an aggregation of the same number of MW. The requirement for study has been changed to 20 MW for a single generator or for an aggregate of generators. This requirement is now located at Requirement R2.5.2.

Organization	Question 2:	Question 2 Comments:
R2.5.2 For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater. **f**: Generating unit Stability and System Stability have been combined.		
Northeast Utilities	No	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
ISO New England Inc.	No	a. A MOD standard should be developed to address the assembly of dynamic load models, rather than specifying modeling in paragraph 2.4.1 (dynamic behavior of loads, including consideration of the behavior of induction motor Loads). Paragraph 2.4.1 should instead read, "System Peak Load for one of the five years." The remainder of the paragraph should be deleted. b. In paragraph R.2.4.3.4, what does "variability" mean? Is variability more of a concern than an outage? Suggest changing paragraph R.2.4.3.4 to simple say "Outages of Reactive Resources" c. Add a new requirement, "R5.4.3.4 Automatic generator tripping shall not have an significant adverse impact on overall system reliability." d. Remove Heading R5.5 and make generator unit stability for a new facility a section of overall stability requirements. e. Modify R5.5.1 to become R5.4.5, with the following, "Shall be performed for the addition of an individual generating unit or generating units at the same interconnection point 20 MW or greater that are directly connected to the BES." There may be little difference between the stability performance of a single 20 MW unit and an aggregation of units totaling 20 MW at the same BES interconnection point. f. If planning assessment studies all generators or stations above 20 MW, as suggested by R5.5.1, then this provision is unnecessary and R5.5.2 should be deleted. g. If the output of a generating station does not change by more than 20MW, then no new study is required and, it should be acceptable to rely on past stability assessments. This is not clear in R5.5.1. h. With respect to section R5 - The concept of planned and long-term outages should be addressed uniformly for the general Planning Assessment. It should not be specific to the Stability Assessment. i. Planned and long-term outages are two fundamentally different concepts and should be treated separately.

Organization	Question 2:	Question 2 Comments:
		Planned and Long-Term outages should be defined. Define how planning events in Tables 1 and 2 are associated with each type of outage. Define length of a "Long Term" outage. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizon. j. The provisions of Section R.5.3 should be included in a MOD standard and applied to a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertent trip of the generator. Such a provision should include " other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation. k. Strike R5.5.3 and R5.5.4, as they become redundant to R5.4.1
National Grid	No	a. A MOD standard should be developed to address the assembly of dynamic load models, rather than specifying modeling in paragraph 2.4.1 (dynamic behavior of loads, including consideration of the behavior of induction motor Loads). Paragraph 2.4.1 should instead read, "System Peak Load for one of the five years." The remainder of the paragraph should be deleted. b. In paragraph R.2.4.3.4, what does "variability" mean? Is variability more of a concern than an outage? Suggest changing paragraph R.2.4.3.4 to simple say "Outages of Reactive Resources" c. Add a new requirement, "R5.4.3.4 Automatic generator tripping shall not have an significant adverse impact on overall system reliability." d. Remove Heading R5.5 and make generator unit stability for a new facility a section of overall stability requirements. e. Modify R5.5.1 to become R5.4.5, with the following, "Shall be performed for the addition of an individual generating unit or generating units at the same interconnection point 20 MW or greater that are directly connected to the BES." There may be little difference between the stability performance of a single 20 MW unit and an aggregation of units totaling 20 MW at the same BES interconnection point. f. If planning assessment studies all generators or stations above 20 MW, as suggested by R5.5.1, then this provision is unnecessary and R5.5.2 should be deleted. g. If the output of a generating station does not change by more than 20MW, then no new study is required and, it should be acceptable to rely on past stability assessments. This is not clear in R5.5.1. h. With respect to section R5 - The concept of planned and long-term outages should be addressed uniformly for the general Planning Assessment. It should not be specific to the Stability Assessment. i. Planned and long-term outages are two fundamentally different concepts and should be treated separately. Planned and Long-Term outages should be defined. Define how planning events in Tables 1 and 2 are associated with each type of outage. Define length of a "Long Term" outage. Planned outages should be addressed in the

Organization	Question 2:	Question 2 Comments:
		operating horizon unless otherwise defined in the planning horizon. j. The provisions of Section R.5.3 should be included in a MOD standard and applied to a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertent trip of the generator. Such a provision should include " other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation. k. Strike R5.5.3 and R5.5.4, as they become redundant to R5.4.1
Central Maine Power Company	No	a. A MOD standard should be developed to address the assembly of dynamic load models, rather than specifying modeling in paragraph 2.4.1 (dynamic behavior of loads, including consideration of the behavior of induction motor Loads). Paragraph 2.4.1 should instead read, "System Peak Load for one of the five years." The remainder of the paragraph should be deleted. b. In paragraph R.2.4.3.4, what does "variability" mean? Is variability more of a concern than an outage? Suggest changing paragraph R.2.4.3.4 to simple say "Outages of Reactive Resources" c. Add a new requirement, "R5.4.3.4 Automatic generator tripping shall not have an significant adverse impact on overall system reliability." d. Remove Heading R5.5 and make generator unit stability for a new facility a section of overall stability requirements. e. Modify R5.5.1 to become R5.4.5, with the following, "Shall be performed for the addition of an individual generating unit or generating units at the same interconnection point 20 MW or greater that are directly connected to the BES." There may be little difference between the stability performance of a single 20 MW unit and an aggregation of units totaling 20 MW at the same BES interconnection point. f. If planning assessment studies all generators or stations above 20 MW, as suggested by R5.5.1, then this provision is unnecessary and R5.5.2 should be deleted. g. If the output of a generating station does not change by more than 20MW, then no new study is required and, it should be acceptable to rely on past stability assessments. This is not clear in R5.5.1. h. With respect to section R5, the concept of planned and long-term outages should be addressed uniformly for the general Planning Assessment. It should not be specific to the Stability Assessment. i. Planned and long-term outages are two fundamentally different concepts and should be treated separately. Planned and Long-Term outages should be defined. Define how planning events in Tables 1 and 2 are associated with each type of outage. Define length of a "Long Term" outage. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizon.

Organization	Question 2:	Question 2 Comments:
		j. The provisions of Section R.5.3 should be included in a MOD standard and applied to a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertent trip of the generator. Such a provision should include "other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation. k. Strike R5.5.3 and R5.5.4, as they become redundant to R5.4.1

Response: a: The SDT disagrees and believes it is appropriate to require this in the TPL standard. Requirement R2.4.1 has been modified to clarify that an aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. It is not necessary to have a dynamic Load model which is specific to each bus.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

b: The specific wording for Requirement R2.4.3.4 has been changed to variations in "reactive resource capability". The sub-requirement has also been changed to become a part of a bulleted list. This could mean a degradation of the capability of a reactive resource. The TP is allowed to use its judgment as to how the variations of the sensitivity parameters should be made.

~~Variability and outages of r~~Reactive resource~~s~~ capability.

c: The SDT has decided to remove Requirement R5.4.3 because the sub-requirements are already implicitly covered by the standard. Your suggested sub-requirement is also already implicitly covered by the standard.

d: In response to industry comments, the SDT has removed the distinction in the standard between System Stability and generating unit Stability.

e: The SDT agrees that there is little distinction between a single unit of a specific MW and an aggregation of the same number of MW. The requirement for study has been changed to 20 MW for a single generator or for an aggregate of generators. This requirement is now located at Requirement R2.5.2.

R2.5.2 For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:

The addition/deletion/change of individual generating unit capability of 20 MW or greater.

An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater.

f: There are no longer two requirements covering this. The new generator size which requires a study and the change of generator size which requires a study have been combined into Requirement R2.6.2.

Organization	Question 2:	Question 2 Comments:
g: Requirement R5.5.1 has been deleted. h and i: The requirement to include "known planned and long term outages of Transmission or generation equipment" has been removed from Requirement R5. Planned outages are covered in Requirement R1.1.1 for both Stability and Steady State. Long term outages are covered in new Requirement R2.1.4. **R1.1.1** Planned outages of generation and Transmission Facilities, if specifically known. **R2.1.4** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment. j: This is the subject of PRC-024 currently under development. But the question of how you treated this in your planning studies belongs in TPL. **k**: Generating unit Stability and System Stability have been combined.		
NSTAR Electric	No	1. A MOD standard should be developed to address the assembly of dynamic load models, rather than specifying modeling in paragraph 2.4.1 (dynamic behavior of loads, including consideration of the behavior of induction motor Loads). Paragraph 2.4.1 should instead read, "System Peak Load for one of the five years." The remainder of the paragraph should be deleted. 2. Change paragraph R.2.4.3.4 to "Outages of Reactive Resources". It is not clear what "variability" means and why it would be more severe than outages. 3. Add a new requirement, "R5.4.3.4 Automatic generator tripping schemes shall not be overly complex or have an significant adverse impact on overall system reliability." 4. Requirements of R5.5 should be rolled into R5.4 and made applicable to all stability studies. 5. Modify R5.5.1 to the following "Shall be performed for an individual generating unit or generating units at the same interconnection point 20 MW or greater that are directly connected to the BES." There may be little difference between the stability performance of a single 20 MW unit and an aggregation of units totaling 20 MW at the same BES interconnection point. 6. Delete R5.5.2. If planning assessment studies all generators or stations above 20 MW, as suggested by R5.5.1, then this provision is unnecessary. If the system has not changed, it should be acceptable to rely on past stability assessments. 7. With respect to section R5, the concept of planned and long-term outages should be addressed uniformly for the general Planning Assessment. It should not be specific to the Stability Assessment.

Organization	Question 2:	Question 2 Comments:
		8. Planned and long-term outages are two fundamentally different concepts and should be treated separately. Planned and Long-Term outages should be defined. Define how planning events in Tables 1 and 2 are associated with each type of outage. Define length of a "Long Term" outage. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizion. 9. The provisions of Section R.5.3 should be included in an MOD standard and applied to a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertent trip of the generator. Such a provision should include "…other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation.

Response: 1: The SDT disagrees and believes it is appropriate to require this in the TPL standard. Requirement R2.4.1 has been modified to clarify that an aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. It is not necessary to have a dynamic Load model which is specific to each bus.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

2: The specific wording for old Requirement R2.4.3.4 has been changed to "reactive resource capability". This could mean a degradation of the capability of a reactive resource. The TP is allowed to use its judgment as to how the variations of the sensitivity parameters should be made.

~~Variability and outages of r~~Reactive resource~~s~~ capability.

3: The SDT has decided to remove Requirement R5.4.3 because the sub-requirements are already implicitly covered by the standard. Your suggested sub-requirement is also already implicitly covered by the standard.

4: In response to industry comments, the SDT has removed the distinction in the standard between System Stability and generating unit Stability.

5: The SDT agrees that there is little distinction between a single unit of a specific MW and an aggregation of the same number of MW. The requirement for study has been changed to 20 MW for a single generator or for an aggregate of generators. This requirement is now located at Requirement R2.5.2.

R2.5.2 For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:

The addition/deletion/change of individual generating unit capability of 20 MW or greater.

An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater.

Organization	Question 2:	Question 2 Comments:
6: There are no longer two requirements covering this. The new generator size which requires a study and the change of generator size which requires a study have been combined into Requirement R2.5.2. 7 and 8: The requirement to include "known planned and long term outages of Transmission or generation equipment" has been removed from R5. Planned outages are covered in Requirement R1.1.1 for both Stability and Steady State. Long term outages are covered in new Requirement R2.1.4. **R1.1.1** Planned outages of generation and Transmission Facilities, if specifically known. **R2.1.4** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment. 9: This is the subject of PRC-024 currently under development. But the question of how you treated this in your planning studies belongs in TPL.		
City Water, Light & Power - Springfield, Illinois	No	Near term stability analysis should not need to be performed each year unless there is a significant change to the system or the previous study(ies) showed marginal performance.
Response: The near term Stability analysis does NOT have to be performed every year as long as you have a qualified past study which covers it.		
Progress Energy Carolinas	No	R 2.4.1 Load models that appropriately represent the dynamic behavior of induction motors are currently under development and may not be available for sometime. We believe that modeling the dynamic effects of loads is becoming increasingly necessary to obtain meaningful results. Therefore, it is appropriate that the revised standards address this. However, the present state of the industry is such that effective implementation of this requirement, as currently written, cannot be realistically achieved in the near term. The software tools currently in use do not accommodate the modeling of certain material effects (for example the load reduction due to thermal trips on HVAC compressor motors). Additionally, detailed load information necessary to allow the models which are available to be populated with meaningful data is not typically available or readily obtainable. Without resolving these issues, load model data submitted via the MMWG process will not improve simulation accuracy and could actually reduce the accuracy of results. Therefore, we would recommend R 2.4.1 rewritten to either a) allow a multi-year, phased approach to incorporating dynamic load modeling in simulation dynamic databases or b) provide an effective date for this particular requirement well into the future. This will accomplish the fundamental objective in a more accurate and meaningful manner. At least 48 months should be allowed before this requirement becomes effective. R 2.4.3 The proposed sensitivities create significant amount of additional work for the sole purpose of demonstrating compliance to this standard without any demonstratable benefit towards improving system reliability. While sensitivities should be appropriately considered in studies, this standard should not be overly prescriptive with respect to specific sensitivities or study methodologies. We propose removing the enumerated list of sensitivities starting with

Organization	Question 2:	Question 2 Comments:
		R2.4.3.1 and rewording R2.4.3 as follows: R2.4.3 For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, sensitivity case(s) that stress the System to reflect one or more conditions such as variations in dynamic Load model assumptions, modification of expected transfers, unavailability of long lead time Facilities, variability and outages of reactive resources, generation additions, retirements, or other dispatch scenarios shall be performed. The rationale for the sensitivity(ies) selected shall be documented. R 2.4.3.1 As stated above, this sub-requirement should be removed. However, if it is to remain, it should be clearly stated whether the Load model refers to system load or the dynamic load model at individual busses.
Response: Requirement R2.4.1 has been modified to clarify that an aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. It is not necessary to have a dynamic Load model which is specific to each bus. Because of this clarification, the SDT believes that a 24 month implementation period for this requirement is sufficient. This will be covered in the Implementation Plan which will be posted along with the third draft of the standard. Requirement R2.4.3: The SDT believes that running sensitivity cases will give the TP a better understanding of its System and better understanding yields a more reliable System. The SDT believes an enumerated list is more appropriate than the list that you suggest and an enumerated list must have a sub-requirement format. The requirement for sensitivity studies is not overly prescriptive. There is much room for the engineering judgment of the TP. **R2.4.1** System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: R2.4.3.1: The variations in Load model assumptions are to be applied to the aggregate System Load model which represents the overall dynamic behavior of the Load		
BCTC	No	BCTC's open access tariff requires generator owners to apply for interconnection studies and facility studies to interconnect to our system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. In fact, we may only be aware of the changes indentified in these requirements when generator owners make these applications. The generator owners are required to pay for these studies. Study requirements for generator interconnections are further defined by NERC Standards FAC-001 and FAC-002 (Coordination of Plans for New Facilities). By including these requirements in TPL, BCTC is concerned that generator owners may think that they are no longer required to pay for the studies. Furthermore, the NERC standards would have redundant requirements. If SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Any

Organization	Question 2:	Question 2 Comments:
		studies resulting from new generators or increases in existing generator output should be charged to the owner.
Response: The SDT agrees with the Industry's majority view that generating unit Stability and System Stability need not and should not be treated as distinct issues. The Stability related requirements have been modified to create a single generic set of requirements that no longer distinguishes between generating unit and System Stability. This should address your concern with potential conflicts with the FAC standards.		
Manitoba Hydro	Yes and No	R2.4: Agree with change except:R2.4.1.1: Needs to provide more detail on what is required to be compliant with respect to what is required to "appropriately represent the dynamic behavior of Loads including consideration of the behavior of induction motor Loads". Is the appropriate modeling left to the judgment of the TP/PC, supported by peer review by adjacent planners? Should the TP be required to document why the dynamic modeling is appropriate. The requirement implies a requirement to consider detailed dynamic load modeling at every bus in the model as opposed in areas of high concentration of such load. - needs clarification. R2.4.3: Generally agree, except:R2.4.3.1:Can the SDT clarify if the Variations in load model refer to variations in dynamic load modeling" R2.4.3.4, what is meant by variability of reactive resources? R2.4.4: The use of the words "shall be run" implies that additional scenario(s) are mandatory. Was this the intent of the SDT? R2.5: As stated in Q1 above, Manitoba Hydro continues to believe the Generating Unit Stability Analysis duplicates the FAC-002-0 requirements, creating potential for contradiction/non-compliance of both standards. The SDT should ensure there is no duplication of requirements of the FAC-002-0 standard. R2.5 should allow use of current or qualifying past studies. R2.5.1: Is it the SDTs intent that the TP could rely on the Planning Assessment R2.5 and/or R5.6 to assess the impact of a generator addition or modification. This function should be the subject of an interconnection study conducted in accordance with the FERC tariff (LGIP) or other similar TP interconnection process. R2.5.2: The TP planning process for addition of facilities should be used to verify the impact of changes to the network, including changes near existing generators . A planning assessment is not the appropriate process. Other Comments related to R2:R2: There appears to be no requirement for an assessment of system stability in the long-term planning horizon. Was this the intent of the SDT? R2.1: States the "steady state analysis shall be assessed annually and be supported at a minimum by the following annual current studies: Does the term ?annual current studies? preclude doing an assessment by using only qualified past studies? Please clarify!

Organization	Question 2:	Question 2 Comments:
		R2.1.1 & R2.1.2: NERC/ERAG will likely have to the models developed annually to ensure appropriate models are available. For example, in any given model series produced in past, there may not be a year five. Also, does System off-peak load refer to summer off peak? R2.1.3: While Manitoba Hydro supports the need for scenario assessments, this significantly increase the workload for studies and documentation. The requirement to document why a scenario was not selected will present a problem, since without doing the study, the planner may not have a good justification. The long term objective to improve reliability could be met by requesting only different sensitivity per year, and dropping the need to justify why others were not done. R2.6: Manitoba Hydro suggests that this requirement be converted to a definition of Past Studies. The definition should state that both R2.6.1 and 2.6.2 are necessary to qualify as a past study? R2.7:In the case were a CAP is required to meet the system performance requirements, will the assessment be deemed to be compliant on the assumption that the CAP will be put in place in a timely manner? R2.7.1.1: Can the SDT please clarify project initiation date? What is it? date permitting starts? Date construction starts? Etc R5.4: System Stability. The SDT should clarify if contingencies are to be applied to all elements in the case, or is it left to the judgment of the planner. Since there are numerous combinations of multiple contingencies, it is an impossible task to explain why the ?remaining Contingencies" were not selected. If this is not the intent, can the SDT explain what is required? The requirement should simply allow the planner the discretion to use judgment to select these more severe Contingencies, and the elements they are applied to, with explanation as to why they are expected to be more severe. R5.4.1: Manitoba Hydro agrees that the rationale for Contingencies selected should be provided. However, it is an onerous task, and of little value to provide rationale for the contingencies not selected. R5.4.2: Manitoba Hydro's preference is that the performance requirements should be in the standard body. The approach in Table 2 is inconsistent. R5.4.2 refers to Table 2 for Planning Event performance requirements, however, for the Extreme Events, the Table 2 refers back to R5.4.4. R5.4.3: Manitoba Hydro agrees and commends the SDT for recognizing generator tripping as a viable option for meeting the performance requirements in certain systems. R5.4.3.2: Agree that regulatory and statutory requirements must be met; however, the references to safety violations and equipment requirements are very generic. It is difficult to imagine what type of safety violation may be caused by

Organization	Question 2:	Question 2 Comments:
		a generator trip considering this is a widely used practice in many regions. The SDT should also be more specific as to what is meant by "equipment requirements". The requirement to be within Facility (equipment) Ratings is already covered in R3.5.1. Manitoba Hydro recommends the reference to safety and equipment be removed. R5.4.3.3: can the SDT clarify how they want the planner to determine that "a sustainable operating condition is maintained". Demonstrating stability over a 20 second stability run may be sufficient, or is the SDT looking for longer time frame stability modeling. R5.4.4 The requirement to explain why extreme events were not chosen add extra documentation. The TP has to explain why certain events were chosen, consequently, events not chosen are judged to have less impact. What would the SDT deem an adequate explanation? R5.5: Generating Unit Stability - As stated above, Manitoba Hydro does not agree that assessment of Generating Unit Stability is necessary as it is covered by FAC-002-0. R5.5.1: This requirement implies the Generating Unit Study should consider every unit exceeding 20 MW. Consistent with R2.5, the SDT should clarify that only new generators need be studied. R5.5.3: Given the numerous possible contingencies that could be run if multiple contingencies are considered, it is impossible to explain why the remaining contingencies were not selected. Other Comments related to Requirement R5:R5: The sentence ?The studies shall be based on computer simulations using models using data provided in Requirements R9 to R14 ?..? should apply to both steady state (R3) and stability portions, yet it is only included in R5. R5.1: Essentially repeats the requirement in the first sentence of R5 - suggest deleting. R5.2: Suggest deleting the words ?including those? R5.3: Manitoba Hydro suggests that frequency ride through be added in addition to voltage ride through. The language "how the generators are treated in the simulation" is not crisp. Is the SDT looking for information on how the voltage ride through and frequency ride through are modeled in the study?
Response: R2.4.1 has been modified to clarify that an aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. It is not necessary to have a dynamic Load model which is specific to each bus. The determination of the aggregate Load model is left to the judgment of the TP/PC. **R2.4.1** System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.		

Organization	Question 2:	Question 2 Comments:

R2.4.3.1: The variations in load model assumptions are to be applied to the aggregate system Load model which represents the overall dynamic behavior of the Load.

R2.4.3.4: The specific wording for Requirement R2.4.3.4 has been changed to variations in "reactive resource capability". The sub-requirement has also been changed to become a part of a bulleted list. This could mean a degradation of the capability of a reactive resource. The TP is allowed to use his judgment as to how the variations of the sensitivity parameters should be made.

~~Variability and outages of r~~Reactive resource~~s~~ capability.

R2.4.4: Requirement R2.4.4 has been deleted.

R2.5: The SDT agrees with the Industry's majority view that generating unit Stability and System Stability need not and should not be treated as distinct issues. The Stability related requirements have been modified to create a single generic set of requirements that no longer distinguishes between generating unit and System Stability. This should address your concern with potential conflicts with the FAC standards.

Other Comments related to R2: Yes, no System Stability is required for the Long-term Planning Horizon.

R2.1: Yes, current studies are required for Requirement R2.1. The assessment for steady state cannot be based solely on past studies.

R2.1.1 & R2.1.2: Not necessarily. The intent was that off-peak refers to any Load level other than peak that the TP deems appropriate.

R2.1.3: R2.1.3 and R2.4.3 have been modified to remove the requirement for specifying the technical rationale for why or why not a particular sensitivity was selected.

R2.1.3 For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.6: A formal definition would apply to all NERC standards. The SDT believes this explanation of what qualifies as a past study should only apply to this standard.

R2.7: Not necessarily. While the SDT can't answer as to formal compliance, the intent was that If the corrective action will not be in place at the time it is needed, the PC/TP will not be in compliance unless it can find an acceptable way (perhaps an Operating Procedure) to meet the performance requirement.

R2.7.1.1: This requirement is now Requirement R2.6.2. It is left up to the individual entity to define and document what is meant by the project initiation date. This requirement was intended to represent the same thing as Requirement R2.1 in the existing TPL-002-0.

R5.4 and R5.4.1 (now R3.4): The SDT believes the existing wording does allow the planner the discretion to use judgment to select these more severe Contingencies, and the elements they are applied to, with explanation as to why they are expected to be more severe.

Organization	Question 2:	Question 2 Comments:
R5.4.2: The SDT agrees that this cross-referencing is inconsistent. The reference back to Requirement R5.4.4 has been removed from the Table. R5.4.3: Thank you for your comment. R5.4.3.2 and R5.4.3.3: The SDT agrees and has removed these requirements. R5.4.4: The SDT believes that Transmission Planners know their Systems well enough to select Contingencies for which they suspect cascading or severe problems will result. Since there are an infinite number of possible scenarios to study, judgment is a necessity to limit scope to a reasonable level. The judgment of the TP is assumed to be a sufficient explanation as to why certain Contingencies were chosen. R5.5: The distinction between Generating Unit Stability and System Stability has been removed from the standard. R5.5.3: The requirement has been deleted. R5: Requirement R3 has been modified to be consistent with Requirement R5. **R3** For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. ~~The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to c~~Contingencies in Table 1 – Steady State Performance. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. R5.1: There is a difference between the two. The first sentence of Requirement R5 says to run Contingencies. Requirement R5.1 says to meet performance requirements. R5.2: The SDT agrees and has removed those words from new Requirements R4.3 and 4.3.1: **R5.2 (new R4.3 and R4.3.1)** Contingency analyses shall: ~~s~~Simulate the removal of all elements ~~including those~~ that the Protection System ~~protection~~ and other automatic controls are expected to disconnect for each Contingency without operator intervention. R5.3: The SDT is looking for how generators were treated in the study when there were voltage excursions. Did you trip them or not? What criteria do you use to decide if they should be tripped?		
Los Angeles Department of Water and Power	No	R2.4.3 requires sensitivity on various operating scenarios. These are best required under TOP, not TPL. It is totally useless and a waste of time to look at operating scenarios under planning horizon by planners, whether it be short term or long term. Operating scenarios are absolutely necessary under operating horizons but they need not be repeated and required in TPL when TOP already addressed these. R2.5 See my comment on question 1. This may be a suitable place to require proper modeling of the generator units to replace the existing languages.

Organization	Question 2:	Question 2 Comments:
		R5.4 is fine. R5.5 See my comment on question 1. The language here actually infers the size of a unit that should be modeled individually and not be lumped. But it should be more precise to prohibit any lumping as well as the explicit modeling of all dynamic data of any generator unit meeting the size requirement.
Response: R2.4.3: The SDT does not view the required sensitivity studies as operating studies. These are planning studies intended to investigate conditions that are different from the base case to bracket the range of possible outcomes if conditions vary from expected. R2.5: The SDT agrees with the majority of the Industry, including your comments, that there is no significant distinction between generator and System Stability and has modified the third draft to remove that distinction. R5.4: Thanks for your comment. R5.5: This requirement has been deleted.		
Transmission Agency of Northern California	Yes and No	R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirements in sub requirements of R5.4.3. We believe these conditions should be met for a
Response: R2.4: thanks for your comment. The SDT agrees and has deleted Requirement R5.4.3.		
Pacific Gas and Electric Co.	Yes and No	R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirement in sub requirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable? We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT

Organization	Question 2:	Question 2 Comments:
		needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. ? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Public Service Company of New Mexico	Yes and No	R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirements in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable? We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. ? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or

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		modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Puget Sound Energy, Inc.	Yes and No	R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirements in sub-requirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Idaho Power Company	Yes and No	R2.4 is acceptable. Please consider deleting R5.4.3. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner

Organization	Question 2:	Question 2 Comments:
		may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. ? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariff requires Generator Owner to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
SMUD	Yes and No	R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirements in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable.? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. 'Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.

Organization	Question 2:	Question 2 Comments:
Sierra Pacific Power Company / Nevada Power Company	Yes and No	R2.4 is acceptable. Please consider deleting R5.4.3. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariff requires Generator Owner to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to 'cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Black Hills Corporation	Yes and No	R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirement in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or

Organization	Question 2:	Question 2 Comments:
		REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
SRP	Yes and No	R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirements in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable.? We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. ? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by

Organization	Question 2:	Question 2 Comments:
		the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Tucson Electric Power Company	Yes and No	In general, R2.4 is acceptable but some of the sub-requirements are to prescriptive. We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. Off-peak analysis (R2.4.2) in the Planning Horizon is of limited value for smaller entities. This analysis is best left to the Operating Horizon. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirements in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable.? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Modesto Irrigation District	Yes and No	Comments: R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to

Organization	Question 2:	Question 2 Comments:
		specifically call out these requirements in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable.? We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network.? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 andFAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yetR5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Tri-State G&T	Yes and No	R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirements in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable.? We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and

Organization	Question 2:	Question 2 Comments:
		assessments would be onerous and would not yield reliability benefits for the network. ? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
ColumbiaGrid	Yes and No	R2.4 is acceptable. Please consider deleting R5.4.3. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariff requires Generator Owner to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase

Organization	Question 2:	Question 2 Comments:
		in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Southern California Edison	Yes and No	R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirement in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable.? We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. ? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Alberta Electric System Operator	No	R2.4 is acceptable. - Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirement in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or

Organization	Question 2:	Question 2 Comments:
		are generic. Otherwise, R5.4 is acceptable.- The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Generator Owners are to apply for interconnection to the transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. – Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
US Bureau of Reclamation	No	Comments: R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirement in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable.? We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network.? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 andFAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yetR5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator.

Organization	Question 2:	Question 2 Comments:
		The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Response: R5.4.3: This requirement and its sub-requirements have been deleted. R2.4 and R5.4: Stability studies will continue to be required for smaller utilities. Small entities have the option of not registering as a TP to avoid compliance concerns. Furthermore, it would be difficult to establish criteria for exempting "smaller entities". R2.5 and R5.5: The SDT changed the language to reflect that updated Stability studies only need to be performed as specified in Requirements R2.5.2. The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater. R5.5.2 This has been clarified with the words "change of individual generating unit capability". This is now covered in Requirement R2.5.2		
Gainesville Regional Utilities	Yes and No	For smaller systems, please see Comment 1. As far as R.2.4.1, if the various loads are basic and not a large industrial type load (very large motors with across the line starting, electric arc furnaces, etc.) then the dynamic behavior of the load should not require special consideration. Using proper power factors for the load should be enough for the transmission system evaluation. Under 2.4.3, as mentioned in Comment 1, evaluating the stressing of the smaller systems through a large amount of sensitivities does not add any reliability to the BES. It only adds much addition work to a limited resource entity. If the neighboring large systems agree that the smaller system can not impact them, this should support that the BES is not affected by any sensitivity that could exist on the smaller system. For R5.5, a threshold should be set to consider only the larger size units within the region. For a smaller system, the stability of a 50-100 MW unit probably would not perturb the interconnected regional BES's.
Response: R2.4.1: Residential air conditioners and other small motors can have a significant impact on dynamic simulations of the System. Using proper power factors for the Load is definitely not enough for dynamic simulations of Systems with large amounts of residential air conditioning. R2.4.3: In Order 693, FERC directed NERC to modify the TPL standard to require that critical System conditions be determined by conducting sensitivity studies. The SDT believes this should apply to any entity regardless of size that is registered as a Transmission Planner.		

Organization	Question 2:	Question 2 Comments:
R5.5: The SDT believes the appropriate size to study is any generator of 20 MW or more.		
JEA	Yes and No	R2.4.1 Do we mean "Appropriate" for overall regional system response/behavior or for individual customer behavior. JEA would agree to an "appropriate" overall regional system response/behavior model with unique individual or sub-regional customer behavior models if determined significant. R2.4.3.1 JEA would agree to a load characteristic sensitivity studies if conducted within the scope of a RRO study. Suggest modifying wording to "Variations in Regional Load model assumptions" R2.4.3.3 Not sure what we mean by Unavailability of long-lead time facilities. Need to add a definition. If the standard is suggesting to treat the unavailability of autotransformers like the unavailability of generators i.e. N-2 assessments with no firm consequential load shedding, then JEA does not agree that the failure rate of autotransformers is on the same level as generators and do not agree this requires a minimum performance standard to maintain grid reliability. In addition, a utility is most likely to be successful in finding a reasonable useful spare autotransformer somewhere in the world to replace the failed unit. R2.5 JEA agrees. R5.4.2 See comments for steady state requirements for Table 1 P5.R5.4.3 JEA does not understand what is meant by Stability violations. Do we mean to say "unstable system conditions"? R5.5 JEA agrees

Response: R2.4.1: The intent is "appropriate for overall System behavior", but not just on a "Regional" basis. Requirement R2.4.1 has been modified to clarify that a detailed dynamic Load model is not required at each bus. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.3.1: The SDT believes that this requirement should apply to an individual TP, not on a Regional level.

R2.4.3.3: The requirement for unavailability of long lead time Facilities has been broken into two pieces for better clarity. Old Requirement R2.4.3.3 has been clarified with the words "Timing of the installation of new or modified Facilities". For example, this would include consideration of a new line not being in service by the scheduled date. Also a new requirement, Requirement R2.1.4 has been added to cover unavailability of major Transmission equipment. These modifications should help alleviate your concerns.

~~Unavailability of long lead time Facilities~~ Timing of the installation of new or modified Facilities.

R2.1.4 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more

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(such as a transformer), an analysis of the impact on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment. R2.5: Thank you for your comment. R5.4.2: "Stability violations" means that the System did not meet performance requirements for Stability studies. R5.5: Thank you for your comment.		
PacifiCorp	Yes and No	av? We generally agree that utilities or large TPs and PCs need to perform and be held accountable for these Requirements; however, the SDT needs to define a organization size level, below which these requirements for the associated TP may be slightly relaxed. There are numerous TPs; (e.g., those associated with PUDs, Municipals or REA, etc.), for which performing these type of studies and assessments are onerous and do not yield reliability benefits for the network.
Arizona Public Service Co.	Yes and No	We generally agree that utilities or large TPs and PCs need to perform and be held accountable for these Requirements; however, the SDT needs to define a organization size level, below which these requirements for the associated TP may be slightly relaxed. There are numerous TPs; (e.g., those associated with PUDs, Municipals or REA, etc.), for which performing these type of studies and assessments are onerous and do not yield reliability benefits for the network.
Response: Stability studies will continue to be required for smaller entities. Smaller entities have the option of not registering as a TP to avoid compliance concerns. Furthermore, it would be difficult to establish criteria for exempting "smaller entities.		
ITC Holdings: ITC, METC, ITC Midwest	Yes and No	? R 2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. R 2.4.2 System Off-Peak Load for one of the five years. Is there an inconsistency here in that the requirement for peak system load levels specifies details on what is needed for the load models, but the off-peak does not specify this? We don't believe this is the intent but it creates an appearance that the dynamic behavior of loads is not required for off-peak.? Regarding R2.4 and R2.5 (& R5.4.1): It should be made clear that redoing studies is only necessary when it is not certain as to whether or not a system change will have a negative impact on system stability. An explanation should be sufficient if a study is unnecessary based on technical knowledge.. As to dynamic load models, we agree with a much longer implementation period than the rest of the standard.

Organization	Question 2:	Question 2 Comments:
		We have concerns that an auditor may not agree with our judgment as to what studies should be run or not run (R2.4, R2.5 and particularly in the case of R5.4.1). Additional guidelines, perhaps in the measurements section, would be appreciated.?
Response: R2.4.1 and R2.4.2: The dynamic behavior of induction motor loads has caused problems (e.g., slow voltage recovery) at higher System Load levels. Thus the requirement in the TPL standard is to make sure you properly represent the behavior of induction motor Loads at high Load levels, i.e., peak. It is not as much of a problem at lower Load levels and therefore there is no requirement for off-peak Load levels. Of course, even at off-peak a proper representation of Loads is needed. But for lower system Load levels, standard models are usually sufficient. R2.4 and R2.5: For R2.4 (Stability Studies) current or qualified past studies must be used to show that the five year period has been assessed. This means the TP must be able to demonstrate with engineering judgment that past studies are still valid. Dynamic load models: R2.4.1 has been modified to clarify that a detailed dynamic Load model is not required at each bus. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Because of this clarification, the SDT believes that a 24 month implementation period for this requirement is sufficient. This will be covered in the Implementation Plan which will be posted along with the third draft of the standard. **R2.4.1** System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. R2.4 and R2.5: The SDT does not believe that additional guidelines are needed. The standard leaves room for appropriate engineering judgment by the TP.		
Progress Energy Florida, Inc.	No	R2.4.4 as worded does not make sense, and could potentially create illogical situations where the Transmission Planner or Planning Coordinator would "offer up" additional sensitivities specific to their systems, for which they might not presently be analyzing and immediately have to self-report non-compliance. As a substitute to the language in R2.4.4, PEF suggests either returning to the language in each existing Standard's R1.3.2, or adding an R2.4.3.6 that states "Other known critical system conditions specific to the system studied by the Transmission Planner or Planning Coordinator. Regarding R5.4 and R5.5, PEF disagrees to the extent that a differentiation has been made between System Stability and Generating Unit Stability (see Question 1 comments). Given that System Stability and Generating Unit Stability are held to precisely the same standards in Table 2, PEF feels that significant modification is required to R5.4 and R5.5, specifically that the two sections need to be consolidated into a single section. Given the complex nature of Stability Analysis, and the fact that Generators are inextricably intertwined with all other components of the BES, the distinction that the SDT is attempting to make with this issue makes no sense from a power systems engineering perspective.
Response: R2.4.4: The SDT agrees and has deleted this requirement.		

Organization	Question 2:	Question 2 Comments:
R5.4 and R5.5: In response to industry comments, the SDT decided that generating unit Stability and System Stability need not and should not be treated as distinct issues. The Stability related requirements have been modified to create a single generic set of requirements that no longer distinguishes between generating unit and System Stability.		
Lafayette Utilities System	Yes and No	Requirement 2.4.1 directs the furnishing of information that would reveal the location of new large inductive loads. Large inductive loads typically are induction motors used in industrial applications. Therefore, a Distribution Provider's forecasts about the expected level of its inductive load could effectively reveal non-public information about the anticipated location of new industrial loads. If a Distribution Provider were required to disclose such information to its Transmission Planner, the confidentiality of information having considerable commercial and competitive significance could be compromised. This would be of particular concern if the Transmission Planner and the Distribution Provider also happen to be competitors for new retail loads.
Lakeland Electric	No	Modeling the dynamic behavior of Loads is difficult at best and merits a discussion or white paper. Recommend requirement 2.4.1 specify the size of induction motor that should be considered and comment on modeling of small induction motor loads such as air conditioning.
Orlando Utilities Commission	No	OUC supports the comments from FPL and Lakeland Electric on this issue.
Response: Requirement R2.4.1 has been modified to clarify that a detailed dynamic load model is not required at each bus. An aggregate system load model which represents the overall dynamic behavior of the Load is acceptable. **R2.4.1** System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.		
Ameren	Yes and No	In R2.4, it is suggested that the word "System" be re-inserted ahead of the word "Stability". It is believed that the sub-requirements of R2.4 are for System studies as opposed to Plant or Generator stability studies. In R2.4.1, agree that the system peak load should be studied for at least one of the five years in the near-term planning horizon. What is the meaning of the term "appropriate", and who decides what dynamic representation of load is "appropriate", and for what conditions? Guidelines for the development of load models used in power flow and dynamic models to represent residential air conditioner induction motor load response including the effects of underground distribution cable and distribution capacitor banks are not available. Why can't the standard load representation be used to meet R2.4.1, and the more detailed load representation,

Organization	Question 2:	Question 2 Comments:
		including dynamic system induction motor load response, be used to meet R2.4.3? In R2.4.2, agree that off-peak load levels should be covered for one of the five years. In R2.4.3, there should not be a requirement to explain why sensitivities were not selected. Further, these items in R2.4.3.1-5 appear to be options and not sub-requirements, and therefore are too prescriptive and inappropriate for inclusion here. The proposed sensitivities appear to over-focus on the particular issues listed and may result in the detriment of overall system reliability. Engineering judgment should be used to develop the sensitivity scenarios, and it should be encouraged that the same scenarios should not be performed every year so that a portfolio of sensitivity scenarios would be developed over time. The standard should not include an enumerated list of required sensitivities. If two sensitivities are required to be performed each year, then the standard should state so, but we believe that more than one sensitivity scenario for each peak and off-peak case is burdensome. We are unsure if R2.4.4 is a requirement or an option. If R2.4.3 were not so prescriptive, the additional sensitivity could be covered under the engineering judgment comment provided above. The prescriptive listing of sensitivities under 2.4.3.1 through 2.4.3.5 should be eliminated. Proposed alternative wording for R2.4.3 which addresses above concerns is as follows:R2.4.3. "For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, sensitivity case(s) that stress the System to reflect one or more conditions such as variations in dynamic Load model assumptions, modification of expected transfers, variability and outages of reactive resources, generation additions, retirements, or other dispatch scenarios are integral to a thorough assessment of reliability. Document how and why appropriate sensitivities were selected." R2.5 should be reworded as follows. "The Generating Unit Stability portion of the Planning Assessment shall be assessed for the year and conditions when the following changes that could affect stability margins occur:" Agree with most of R5.5. In R5.5.4, a risk/benefit vs. cost analysis should be included in the evaluation of implementing a change to mitigate the likelihood of cascading outages for the extreme events. Agree with R5.6.
Response: R2.4: Adding the word "System" is no longer necessary because the SDT has eliminated the distinction between System Stability and Generating Unit Stability. R2.4.1: The TP and PC decide what is appropriate for their System. R2.4.1: The sensitivity of studying effects of induction motor Loads may not be chosen by the TP. The SDT thinks that studies incorporating the effects of induction motor Loads must be done for peak Load levels.		

Organization	Question 2:	Question 2 Comments:
R2.4.2: Thank you for your comment. R2.4.3: The requirement to explain why or why not sensitivities were selected has been deleted. The sub-requirements have been converted into bullet lists. R2.4.4: Requirement R2.4.4 has been deleted. R2.4.3: The SDT believes an enumerated list is more appropriate than the list that you suggest and as stated above, an enumerated list must have a sub-requirement format. The requirement for sensitivity studies is not overly prescriptive. There is much room for the engineering judgment of the TP. R2.5: In response to industry comments, Generating Unit Stability has been combined with System Stability. Requirement R2.5 on Generating Unit Stability has therefore been deleted. R5.5.4: This requirement has been deleted. R5.6: Thank you for your comment. The separate requirement for Generating Unit Stability Studies has been deleted.		
Florida Power and Light	No	R2.4.4 is inappropriate for a compliance assessment. Essentially R2.4.4 requires the Transmission Planner or Planning Coordinator to deem appropriate and justify inclusion or exclusion of any sensitivity other than the required sensitivities listed in R2.4.3. The only way that a an entity could be found non-compliant is if the entity deems a sensitivity as appropriate, and then inexplicably did not perform the sensitivity, which makes no sense. The requirement seems to put a burden of justifying by "technical rationale" a sensitivity that is deemed appropriate already. R2.4.4 could be eliminated and its intent absorbed in R2.4.3 by changing its wording slightly: "R2.4.3 For each of the studies in Requirement R2.4.1 and Requirement R2.4.2, sensitivity case(s) deemed appropriate by the Transmission Planner or Planning Coordinator that stress the System to reflect conditions including, but not limited to, one or more of the following conditions, shall be run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied."
Response: The SDT agrees and has deleted Requirement R2.4.4. Other sensitivities deemed appropriate by the TP or PC can always be run.		
Exelon Transmission Planning	No	R2.4 should be specific as to applicability to generator stability, system stability or both. R2.4.1 requires the use of load models for motors. Detailed load data may not be available and studies would therefore produce questionable results. It is our understanding that the industry has recognized the importance of using better load models and there are multiple ongoing initiatives to improve our ability to do this modeling but these initiatives are not complete. However, the industry's ability to provide accurate models is not sufficient to ensure compliance at this time. The sensitivities for near-term studies in R2.4.3 aren't clearly defined, especially R2.4.3.3, 'Unavailability of Long Lead Time Facilities'. Doesn't the study that determined the original need for these facilities document the consequence of

Organization	Question 2:	Question 2 Comments:
		unavailability? The peer review component of the Planning Assessment has CEII concerns, especially with regard to extreme contingencies and whether or not they involve cascading.

Response: R2.4: In response to industry comments, Generating Unit Stability has been combined with System Stability. Therefore, Requirement R2.4 applies to Stability analysis.

R2.4.1: The intent of R2.4.1 is to have dynamic Load models which are appropriate for overall system behavior, not necessarily on an individual substation basis. The SDT believes that type of model is available. Requirement R2.4.1 has been modified to clarify that a detailed dynamic Load model is not required at each bus. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.3 and R2.4.3.3: The sensitivities in Requirement R2.4.3 have been reworded for better clarity. Old Requirement R2.4.3.3 for unavailability of long lead time facilities has been broken into two pieces for better clarity. Old Requirement R2.4.3.3 has been clarified with the words "Timing of the installation of new or modified Facilities". For example, this would include consideration of a new line not being in service by the scheduled date and how you would plan to get around that problem. Also, a new Requirement R2.1.4 has been added to cover unavailability of major Transmission equipment.

~~Unavailability of long lead time Facilities~~ Timing of the installation of new or modified Facilities.

R2.1.4 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment.

Peer review comment: The SDT does not believe this to be an issue because the existing standards TPL-001 through TPL-004 already require in Requirement R1.3 a review of assessments by Regional Reliability Organizations.

CenterPoint Energy and CPS Energy	No	We believe the requirements are overly broad and overly prescriptive. We further believe the extent of the "problem" these requirements would address does not justify such overly broad and overly prescriptive requirements. To clarify, we wholeheartedly agree that transmission planners should consider and selectively study potential stability concerns. However, we believe that transmission planners are already considering and selectively studying potential stability concerns. We are not aware of any significant bulk electric reliability problem actually occurring in recent memory due to the failure of transmission planners to perform the assessments and studies this standard proposes to require. Some might argue that instability occurred in the northeast blackout, and we would agree. However, requiring transmission planners to perform all the assessments and all the studies proposed herein would not have prevented instability from occurring in that event. A targeted approach focusing on the specific vulnerabilities of that area of the

Organization	Question 2:	Question 2 Comments:
		network would be far more effective than the scattergun approach proposed here. Furthermore, even if all the stability analyses proposed in this standard were performed and audited, the studies likely would not have revealed the actual underlying reliability concern. In the end, the root cause of the failure was thermal overloading, not stability. Instability eventually occurred when the root cause (thermal overloading) led to a situation where circuits sequentially tripped over the course of an hour or so. Events that occur over the course of an hour are generally outside the scope of stability analyses, so these proposed requirements are off the mark for that event. We recommend deletion of R2.4.3, R2.4.4, R2.5, R5.2, R5.3, R5.4 (or 5.5), and R5.5 (or R5.6). Removing this excess baggage would allow transmission planners to use their judgment to selectively analyze stability concerns germane to their system. We realize such an approach requires a recognition that transmission planners are already doing the appropriate analyses, and we encourage the SDT to be receptive to this premise. To further clarify this last point, some would argue that assuming entities are already doing the right thing belies the underlying premise behind enforceable reliability standards. We believe that acceptance of the need for enforceable reliability standards does not pre-suppose that some or all entities are always doing the wrong thing all the time in all aspects of their business. Nor does acceptance of mandatory reliability standards require acceptance that all aspects of the business are equally likely to produce reliability concerns. We believe most or all entities are already doing some things well such that, in some aspects of the business, there is no evidence that a "problem" actually exists. If the SDT accepts this premise, it would focus its attention on actual problem areas, not imaginary ones. We submit that performing appropriate stability studies is not a "problem" that requires an the overly prescriptive requirements proposed here. Rather than solving an actual problem, these requirements are more likely to detract resources from actual concerns by causing planning resources to be expended documenting and defending to auditors that imaginary concerns do not exist.
Response: The SDT disagrees and believes the Stability requirements are necessary to ensure that appropriate studies are being made.		
MidAmerican Energy Company	No	a. MEC disagrees with the proposed R2.4.1 text. This inclusion of this requirement may be premature at this time for several reasons. There is presently no industry consensus on how the dynamic behavior of loads should be properly represented and analyzed. In addition, it would be a large and difficult effort to identify, collect, and maintain the pertinent information. It is presently difficult to obtain and maintain the percentage of residential, commercial, and industrial load at each transmission interconnection point, much less try to get the proper percentage of the various types of induction motor loads. If this requirement is retained then R2.4.1 should be modified to specify a minimum threshold size where dynamic induction motor load or dynamic load behavior becomes significant such as near mining areas. The SDT should consider a 25 MW size threshold for induction motors and a 100 MW size threshold for industrial complexes where the dynamic loads are inadequately represented by normal power flow dynamic assumptions. b. R2.4 as stated refers to Near-Term Transmission Planning Horizon Stability analysis but there is no requirement in the standard referring to Long-Term Transmission Planning Horizon Stability analysis. The SDT should reword R2.4 so that it is clear that no Long-Term Stability analysis is required by stating that "Stability analysis for the Near-Term

Organization	Question 2:	Question 2 Comments:
		Transmission Planning Horizon shall be assessed annually?.". ? In R2.4.4, we believe this requirement should not be added. Why was it included? It seems superfluous, because any entity can study other sensitivities if they want. Why should TP or PC have to study what the other entity wants to study? Who would be the judge in case of disagreement over the technical rationale?? In R2.5.2, Why was the addition of a new substation included? We would not expect a new substation to negatively impact the system or generating unit stability. We note the R5.5 and R5.6 should really have been updated to refer to 5.4 and R5.5.
Response: a: The intent of Requirement R2.4.1 is to have dynamic Load models which are appropriate for overall system behavior, not necessarily on an individual substation basis. The SDT believes that type of model is available. Requirement R2.4.1 has been modified to clarify that a detailed dynamic Load model is not required at each bus. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. **R2.4.1** System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. b: There is no requirement in the standard for Long-Term Transmission Planning Horizon Stability analysis. The only requirement is for Near-Term Transmission Planning Horizon Stability analysis. The SDT believes this is clear in the standard. R2.4.4: The SDT agrees and has deleted Requirement R2.4.4. R2.5.2: A new substation in a line could change the requirements for relaying on the new shorter line so that the generating unit remains stable. Zone 2 clearing from the generator end of the line may not be fast enough on a shorter line. Requirement R5 has been re-numbered due to deletions and the sub-requirement numbering is now correct.		
SERC Dynamics Review Subcommittee	No	R 2.4.1 Load models that appropriately represent the dynamic behavior of induction motors are under development and may not be available for some time. The implementation plan should take this into account and allow at least 36 months for implementation; otherwise this requirement will not be achievable in the near term. R 2.4.3 One should only explain why sensitivity was performed. In general we believe that breaking these requirements into specific sub-requirements focusing on specific sensitivities is too prescriptive and inappropriate; it will lead to over-focus on these particular issues to the detriment of system reliability. There should be no enumerated list of required sensitivities. Engineering judgment needs to be permitted. R 2.4.3.1 It should be clearly stated whether the load model refers to system load or the dynamic load model at individual busses. We have a specific proposal for R2.4.3 which addresses the above concerns as follows: R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, sensitivity case(s) that stress the

Organization	Question 2:	Question 2 Comments:
		System to reflect one or more conditions such as variations in dynamic Load model assumptions, modification of expected transfers, unavailability of long lead time Facilities, variability and outages of reactive resources, generation additions, retirements, or other dispatch scenarios. Document why each sensitivity was selected.
Response: R2.4.1: Requirement R2.4.1 has been modified to clarify that a detailed dynamic Load model is not required at each bus. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Because of this clarification, the SDT believes that a 24 month implementation period for this requirement is sufficient. This will be covered in the Implementation Plan which will be posted along with the third draft of the standard. **R2.4.1** System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. R2.4.3: The requirement to explain why or why not sensitivities were selected has been deleted. The sub-requirements are now part of a bullet list. For Requirement R2.4.3.1: The variations in Load model assumptions are to be applied to the aggregate System Load model which represents the overall dynamic behavior of the Load		
MRO NERC Standards Review Subcommittee	No	a. The MRO disagrees with the proposed R2.4.1 text. This inclusion of this requirement may be premature at this time for several reasons. There is presently no industry consensus on how the dynamic behavior of loads should be properly represented and analyzed. In addition, it would be a large and difficult effort to identify, collect, and maintain the pertinent information. It is presently difficult to obtain and maintain the percentage of residential, commercial, and industrial load at each transmission interconnection point, much less try to get the proper percentage of the various types of induction motor loads. If this requirement is retained then R2.4.1 should be modified to specify a minimum threshold size where dynamic induction motor load or dynamic load behavior becomes significant such as near mining areas. The SDT should consider a 25 MW size threshold for induction motors and a 100 MW size threshold for industrial complexes where the dynamic loads are inadequately represented by normal power flow dynamic assumptions. b. R2.4 as stated refers to Near-Term Transmission Planning Horizon Stability analysis but there is no requirement in the standard referring to Long-Term Transmission Planning Horizon Stability analysis. The SDT should reword R2.4 so that it is clear that no Long-Term Stability analysis is required by stating that "Stability analysis for the Near-Term Transmission Planning Horizon shall be assessed annually?.". ? The MRO does not accept the R2.4.3.1 text and want some explanation of the what, when, and how to provide the technical rationale for why each condition was or was not used. ? In R2.4.3.1, what is meant by “variations” (e.g. how much variation is enough)? ?

Organization	Question 2:	Question 2 Comments:
		In R2.4.3.2, what is meant by “modification” (e.g. how much modification is enough) and "expected transfers" (e.g. firm or non-firm transfers)? ? In R2.4.3.3, what is meant by “long lead time” (e.g. 1 month, 1 season, 1 year, 2 years, etc.)? The MRO suggests that “long lead time” be stated 18 months or more.? In R2.4.4, we believe this requirement should not be added. Why was it included? It seems superfluous, because any entity can study other sensitivities if they want. Why should TP or PC have to study what the other entity wants to study? Who would be the judge in case of disagreement over the technical rationale?? In R2.5.2, Why was the addition of a new substation included? We would not expect a new substation to negatively impact the system or generating unit stability. The MRO notes that R5.5 and R5.6 should really have been updated to refer to 5.4 and R5.5. In R5.4.3.1, we suggest that the time-limited aspect of Facility Ratings should be included in the Glossary Definition by adding the words "within the applicable time period of the rating" and then it would not need to be clarified in various locations (R3.3.2.2, R3.5.1, R5.4.3.1, Table 1-Note 1, & Table 2-Note 1) throughout the standard.

Response: a: The intent of Requirement R2.4.1 is to have dynamic Load models which are appropriate for overall System behavior, not necessarily on an individual substation basis. The SDT believes that type of model is available. Requirement R2.4.1 has been modified to clarify that a detailed dynamic Load model is not required at each bus. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

b: R2.4: There is no requirement in the standard for Long-Term Transmission Planning Horizon Stability analysis. The only requirement is for Near-Term Transmission Planning Horizon Stability analysis. The SDT believes this is clear in the standard.

R2.4.3: The requirement to explain why or why not sensitivities were selected has been deleted.

R2.4.3.1: The variations in load model assumptions are to be applied to the aggregate system Load model which represents the overall dynamic behavior of the Load. The amount of variation is left to the judgment of the TP and PC.

~~Variations in~~ Load model assumptions

R2.4.3.2: The wording has been changed to variations in expected transfers. The amount of variation is left to the judgment of the TP and PC.

~~Modification of e~~Expected transfers

R2.4.3.3: The requirement for unavailability of long lead time Facilities has been broken into two pieces for better clarity. Old Requirement R2.4.3.3 has been

Organization	Question 2:	Question 2 Comments:
clarified with the words "Timing of the installation of new or modified Facilities". For example, this would include consideration of a new line not being in service by the scheduled date. Also a new Requirement R2.1.5 has been added to cover unavailability of major Transmission equipment. These modifications should help alleviate your concerns. ~~Unavailability of long lead time Facilities~~ Timing of the installation of new or modified Facilities. **R2.1.4** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment. R2.4.4: The SDT agrees and has deleted Requirement R2.4.4. R2.5.2: This requirement has been deleted. Requirement R5 has been re-numbered due to deletions and the sub-requirement numbering is now correct. R5.4.3.1: The SDT believes the existing definitions of Facility Rating and Equipment Rating sufficiently cover the time limited aspect of the ratings.		
Austin Energy	No	The routine sensitivity cases requirement contained in R2.4.3 is overly burdensome and unnecessary and should be deleted. Sensitivity analysis should be limited to what may be deemed appropriate by the Transmission Planner or Planning Coordinator. Similarly, R2.5 and R5.5 requirements for Generating Unit Stability should be deleted. Removing these burdensome requirement will allow transmission planners and/or the Planning Coordinator (ISO) to determine the appropriate Generator Unit Stability analysis needed as part of R5.4 System Stability.
Response: R2.4.3: The SDT believes that running sensitivity cases will give the TP a better understanding of its System and better understanding yields a more reliable System. The requirement for sensitivity studies is not overly prescriptive. There is much room for the engineering judgment of the TP. The sub-requirements have been converted into a bullet list. R2.5 and R5.5: The separate System and Generator Unit Stability Requirements have been removed from the Standard and replaced with Requirement R2.4, which addresses all Stability studies. Appropriate levels of generation additions are listed as bullets under Requirement R2.5.2; The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater.		
Midwest ISO	No	The language in R2.4 retains the appropriate clarification that while annual assessments are required, these assessments do not necessarily have to be based upon annually performed simulations. This same distinction should be retained for steady-state assessments required under requirement R2.1, not withstanding the fact that steady-state simulations are easier to perform. The principle is the same for both. Requirement R2.4.1 is to open ended in

Organization	Question 2:	Question 2 Comments:
		specifying the years to be studied. Rather, it should parallel requirement R2.1.1 in requiring that at a minimum either year one or two should be evaluated, and additional years at the option of the responsible entity. If the system could go unstable in the next 1-2 years, it is important to know this. Regarding R2.4.3 & R2.4.4, the standards should not require analysis for which corrective action is optional regardless of the conclusion of the analysis. Requirement R2.7 establishes that corrective action to any sensitivities is optional. Therefore, the performance of sensitivities should be at the discretion of the applicable entity. If the SDT believes it is important to recommend that sensitivities be performed then those Requirements addressing sensitivities should state that the performance of the sensitivity is recommended but optional. If you keep sensitivities in the standard then the requirement in R2.4.4 to document why an entity performed sensitivities in addition to the Requirements should be dropped. As long as the entity selected a sensitivity and documented the results of the sensitivity there should be no reason to explain why he tested it. Requirement R2.5.2 is unclear with respect to when generator unit stability needs to be retested following modifications to the transmission system. Nearly all additions to the transmission system will tend to improve generator stability. We suggest this language be modified to say: "Material transmission system changes are made at or near the point of interconnection of existing generation that would tend to degrade stability margins of that generation, such as the removal of a transmission line, or associated with the addition of new generation, or other system changes as determined by the Planning Coordinator or Transmission Planner". R5.4.3.1 & R5.4.3.3 are redundant with the stated requirement to mitigate stability. Under the sub requirement of R5.4.3.2 it may not be possible for the PC/TP to determine whether the safety, equipment, regulatory or statutory requirements are violated without collaboration with the Transmission Owner and/or the Generator Owner. Therefore, if this sub requirement is retained it should be amended to include the following sentence: "Applicable Transmission Owners and/or Generator Owners shall collaborate with the PC/TP in determining whether such action would violate safety, equipment, regulatory or statutory requirements". Subrequirements R5.4.3.X are superfluous; we suggest removing these subrequirements. However, if this requirement is retained it should be amended to include the following sentence: "Automatic generation tripping is allowed to mitigate Stability violations if the performance criteria in Table 2 is met".

Response: R2.4 The Requirement is allowing the TP and PC the option to determine which time frame to study so as not to be as prescriptive as Requirement R 2.1.1.

R2.4.3 & R2.4.4: The language of Requirement R2.4.3 has been changed to clearly state the objective of sensitivity analyses and their applicability.

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

Organization	Question 2:	Question 2 Comments:
R2.5.2: This language has been removed from the Standard. R5.4.3.1 & R5.4.3.3: The specific sub-Requirements have been removed from the Standard; they are already implicitly covered in the Standard.		
Tri-State Generation and Transmission Association, Inc.	Yes and No	R2.4.1 "System peak load" needs a definition. Forecast descriptions by the utility should describe probability levels and other specifics.
Response: The SDT has changed this language in Requirement R2.4.3 by allowing the use of sensitivities already considered in the base case. **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
AEP	No	We are concerned about unintended consequences with regard to System Stability studies, specifically, the possibility of generating unnecessary work. We would like the SDT to consider language changes that recognize the following realities. (1) While System Stability studies may be justified as a more detailed look at contingency scenarios whose observed severity in steady-state analysis suggests the need for more in-depth study, they cannot be expected to achieve the same breadth of scope as steady-state analyses. In decoupling System Stability studies from steady-state analysis, the draft standard may unnecessarily tend to force stability study scopes to approach those of steady-state analyses. (2) The characteristic limiting factors of systems are generally known (whether thermally limited, voltage drop limited, or transient or small-signal stability limited) and in many systems the limiting factors are thermal or steady-state voltage, but not stability. The draft standard may end up forcing System Stability studies to be done solely for compliance. It is not that independent System Stability studies are never justified (they are, for example, where inter-area small-signal instability is a known factor), but in many systems, they are not necessary. We observe that as sub-requirements of R2 and R5, R2.5 and R5.5 are the responsibility of the Transmission Planner and Planning Coordinator. Is it the SDT's intention that these entities be responsible for conducting the Generating Unit Stability analysis, irrespective of the ownership of the generating units? Should the Generator Owner be responsible for conducting the Generating Unit Stability analysis?
Response: (1) The SDT agrees that Stability studies are more in-depth; the study requirements for Stability are less than that of Steady State. (2) Not in all areas, there are numerous Systems that are limited by Stability, not just thermal limits. R2 and R5, R2.5 and R5.5: The distinction between Generating Unit Stability and System Stability has been removed.		

Organization	Question 2:	Question 2 Comments:
Southern Company Transmission	No	R 2.4 needs to have the word System inserted in front of the word Stability. R 2.4.3 One should only have to explain why a sensitivity was performed, not why it was not performed. In general we believe that breaking these requirements into specific sub requirements focusing on specific sensitivities is too prescriptive and inappropriate. It will lead to over focus on these particular issues to the detriment of system reliability. There should be no list of sensitivities enumerated as subrequirements. Engineering judgment needs to be permitted. R 2.4.3.1 It should be clearly stated whether the load model refers to system load or the dynamic load model at individual busses A specific proposal for R2.4.3 which addresses the above concerns is provided as follows:R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, sensitivity case(s) shall be run and documented that stress the System to reflect one or more conditions such as variations in dynamic Load model assumptions, modification of expected transfers, unavailability of long lead time facilities, variability and outages of reactive resources, generation additions, retirements, or other dispatch scenarios. Document why each sensitivity was selected.
Response: R 2.4: The distinction between Unit and System Stability has been deleted. R 2.4.3 The SDT has changed the language of R2.4.3 to reflect this; to examine one or more sensitivities and the documentation of the technical rationale for why each of the sensitivities was not chosen has been removed. R 2.4.3.1: The language has been changed to allow the Transmission Planner to use their judgment in application of sensitivities. ~~Variations in~~ Load model assumptions R2.4.3 The SDT wanted to keep the sensitivities clear from the rest of the language for base case study requirements. The language of this section has been changed and the use of documentation has been removed. **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
Brazos Electric Power Cooperative, Inc.	No	We do agree with the wording change in 2.4 which uses 'assessed annually'. 2.4.1 and 2.4.2 are ok. 2.4.3 is not agreeable, as it implies or could imply a number of studies are required. Stability studies are not required as often as steady state studies. A new in-line load serving substation can certainly impact the steady state results of an area but would not have the same impact from a steady state perspective. In other words, we feel that running stability studies for a number of small variables does not provide any added benefit and thus stability studies should not be treated the same as steady state studies from a requirement standpoint. More emphasis should continue to be

Organization	Question 2:	Question 2 Comments:
		placed on the steady state analysis. 2.4.3 should be edited to say "Sensitivity cases as deemed appropriate by the TP or PC, that stress the System (or BES) may be run reflecting one or more of the following conditions. Other sensitivities not included below may also be run. Appropriate documentation should be included describing the rationale for the selection of the cases and conditions "delete 2.4.4 as it is taken care of in 2.4.3 2.5 can be deleted as it adds nothing to the stability requirements2.5.1 should be modified to be included under 2.4 as a required study with the caveats from 5.6 brought over defining parameters, or delete 2.5.1 altogether as 5.6 covers the addition of generation.2.5.2 is still fairly ambiguous even with the changes and should be deleted. However if kept it should be modified to remove the last part of the sentence beginning with "or the addition of a new substation?". The addition of a simple in-line substation does not have a material impact on the stability of a near-by plant.2.6.1 and 2.6.2 should be combined to remove the mention of generating plant stability. deleting 5.4 is ok Not sure of the need to add 5.5.2. Isn't that the intent of the whole Standard? 5.5.3 seems to be acceptable.
Response: R2.4: Thanks for your comment. R2.4.3: The SDT has changed this language to clarify the requirement; the use of documentation has been removed from the language. **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: R2.4.4: This part of the Standard language has been removed. R2.5: This part of the Standard language has been removed and bullets under (new) Requirements R2.5.2 have been added to the language to clarify this position. The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater. R5.5.2: This requirement was deleted.		
NERC and Regional	No	PJM concurs with the general direction; however the sensitivity analysis section as written requires explanation of why

Organization	Question 2:	Question 2 Comments:
Coordination		certain sensitivities were not selected. However the sensitivity requirement must be defined. Prove the rationing. R2.4 should state for stability we should use light load rather than system peak which is for steady state analysis. R2.4 should be modified as followsR2.4 should be modified as followsR2.4 The Near-Term Transmission Planning Horizon portion of the Stability analysis requires: Suggest making all sub requirements bullets under R2.4 The words in R2.4 seem to state that the "analysis must be assessed annually" which seems to leave open the option of assessing an old study, whereas R2.2. and R2.3 state a study is required each year, and a study is conducted each year. The words need R2 must be clearer and more consistent. System stability requirements seem to be poorly defined. It appears that there is going to be an expectation that inter-area oscillation and small signal analysis be performed frequently over a variety of conditions. I'm not sure how geared up industry is for this. R2.4.1 is too ambiguous. This sub requirement requires a model that "appropriately represents the dynamic behavior of loads". However, the requirement does not reference how that judgment is made nor who would make the judgment. The sub bullets are vague and again provide no basis for performance or for arbitration. R2.4.4 should be deleted as it will deter TPs and PCs from conducting additional studies. R2.4.4.1-5; Should clearly define words like variation, modification, unavailability of long lead time facility, variability of reactive resources. R2.5 is ambiguous regarding the definition of "affects stability margins". What is the technical performance margin for "affect"? If not defined in the standard then who makes the decision? The TP? the auditor? NERC staff? Do you mean critical clearing time and how much of change for example percentage or cycle.

Response: The SDT has changed this language to reflect that this is to examine one sensitivity or more and the documentation requirement has been removed.

R2.1.3 For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.4: The SDT has determined that both Peak and Off-Peak should be studied; another Load case can be evaluated as a sensitivity.

R2.4 does state that an assessment shall be performed each year and the applicability of past studies is listed in Requirement R2.6.

R2.2. and R2.3: The language clearly states that a study is required for one of the years in the assessment period.

The SDT believes that each TP and PC should have discretion to determine the appropriate Stability studies applicable to their System.

Organization	Question 2:	Question 2 Comments:
R2.4.1: The SDT has changed this language to clarify that aggregate Load can be used here as well. This Requirement is to make you properly represent the dynamic behavior of Loads at high System Load levels. **R2.4.1** System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. R2.4.4 The SDT has deleted this section. R2.4.4.1-4 (now R2.4.3): The SDT has changed the language in these sections and made them a bulleted list. ~~Variations in~~ Load model assumptions ~~Modification of e~~Expected transfers ~~Unavailability of long lead time Facilities~~ Timing of the installation of new or modified Facilities. ~~Variability and outages of r~~Reactive resource~~s~~ capability. R2.5 This section of the Standard language has been removed.		
IESO	No	A. R2.4(i) We suggest to remove words such as "consideration of" and "deemed appropriate" since these are not measurable and not enforceable. Further, we continue to disagree with mandating sensitivity testing with descriptive subrequirements. Sensitivity testing (ii) Specific to R2.4.3, we continue to express our disagreement to include sensitivity testing in the requirements. We are disappointed that despite disagreements by the majority of the commenters and their suggestions to leave sensitivity testing to the TPs and PCs discretion, the SDT continues to stipulate detailed requirements for sensitivity testing. The SDT in its summary response to comments indicates that these testing are intended as "?providing some guidance on what could be included in the sensitivity studies without being too prescriptive." If these are indeed intended as guidance rather than enforceable requirements, then they should be provided in a technical document or a reference document that supports the standard, not in the standard itself. B. R2.5 (i) Similar to our comments under Q1 (i), the requirements should not restrict to changes at or near the Interconnection point. Transmission changes several buses removed from the generator's Interconnection point may also affect the stability performance of the generators. Suggest to reword it to "? in the nearby vicinity that can have an adverse reliability impact on the generating units' stability performance".(ii) There seems to be a hole or incomplete scenario in R2.5.2 in the sentence: "removal of a Transmission Line or the addition of a new substation in one of the Transmission Lines connected to the plant." We agree that removal of a transmission line in the vicinity needs to be assessed; we also believe that addition of not just a substation but also any transmission facilities in the vicinity should be assessed. We therefore suggest to reword this to: "removal of a Transmission Line or the addition of new

Organization	Question 2:	Question 2 Comments:
		transmission facilities in the generating plant's nearby vicinity that can have an adverse reliability impact on the generating units' stability performance. C. R3.4 (i) We do not agree with the requirement that: "If the Extreme Events analysis concludes there are cascading outages, an evaluation of implementing a change designed to reduce or mitigate the likelihood of such consequences shall be conducted." Future transmission systems are planned and designed accordingly to Planning Events. It should not be a surprise that applying Extreme Events to the planned transmission system for which it is not designed to withstand such events would show instability and/or cascading outages. The follow on actions should be to evaluate possible actions to contain and minimize the impact of cascading outages, rather than to come up with options or alternative designs to reduce or mitigate the likelihood of such occurrences (since doing so will imply that we design and plan for Extreme Events). We therefore suggest to reword it to: "If the Extreme Events analysis concludes there are cascading outages, an evaluation of possible actions to contain and minimize the impacts of cascading outages.

Response: The SDT examined the use of these terms and still believes that these are the best terms to use here.

The SDT has changed the language of Requirement R2.4.3 to examine one or more sensitivities and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed.

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.5: This section of the Standard language has been removed.

R3.4: The SDT has modified this requirement (now Requirement R3.5 and also Requirement R5.5.4 – now Requirement R4.5) to include mitigating the "adverse impacts of the event(s)."

R3.5 Those Extreme Events in Table 1 ~~– Steady State Performance~~ that are expected to produce more severe System impacts shall be identified~~,~~ and a list of those events to be evaluated for System performance in Requirement R3.2 created~~,~~. ~~and~~ ~~t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results. If the ~~Extreme Events~~ analysis concludes there are cascading outages caused by the occurrence of Extreme Events, an evaluation of ~~implementing a change~~ possible actions designed to reduce ~~or mitigate~~ the likelihood or mitigate ~~of such~~the consequences and adverse impacts of the event(s) shall be conducted.

R4.5 ~~At a minimum, t~~Those Extreme Events in Table ~~2~~1 ~~– Stability Performance~~ that ~~would~~are expected to produce more severe System impacts shall be identified and a list of those events to be~~,~~ evaluated for System performance in Requirement R4.2 created~~,~~. ~~and~~ ~~t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results. If the ~~Extreme Events~~ analysis concludes there are cascading outages caused by the occurrence of Extreme Events, an evaluation of ~~implementing a change~~ possible actions designed to reduce ~~or mitigate~~ the likelihood or mitigate ~~of such~~the consequences of the event(s) shall be conducted

Organization	Question 2:	Question 2 Comments:
North Carolina Electric Membership Corp	No	We assume that 2.4 is supposed to be for "System" Stability. Please confirm.R2.4.1 - Is this for On-Peak? Please confirm. Also the subrequirement that requires a model that "appropriately represents the dynamic behavior of loads" is too ambiguous. The requirement does not reference how that judgment is made nor who would makes the judgment. The sub bullets are vague and provide no basis for performance. It should be clarified. How does the TP/PC model 3rd party loads from LSEs or DPs within its area that it interconnects? Is there an additional requirement to LSE/DPs needed in R9-R14 to collect such characteristics of load data? There is concern with load modeling requirements (use of word “appropriately” in R2.4.1). Does this requirement mandate the use of specific load models for each bus, or would an aggregate load model which represents the system as a whole be sufficient? Does the use of the PSS/E CONL function satisfy the requirements for a load model? The subrequirements of R2.4.3 are much too vague and are subject to various interpretations. These should be more specific as to what should be assessed, e.g. 5% variation in load model. Why aren't the last 2 subrequirements already accounted for within the assessment? R2.5 is ambiguous. What is meant by "affects stability margins"? What is the technical performance margin for "affect"? As defined by whom? The TP/PC? the auditor? Is this a % change or what? R5.4 – OK R5.5 - We are OK with changes made, but we do share a concern with others that the requirement to perform simulations on 20 MW generators (to be consistent with the Registration Criteria) per R5.5.1 may be too much, and we recommend also a 75 MW generator cutoff for required simulations.

Response: R2.4: The terms ‘unit’ and ‘System’ have been removed from the language and Stability has replaced them.

R2.4.1: Yes, this is for peak conditions. Requirement R2.4.2 is listed for Off-Peak Load.

R2.4.1: The SDT has changed this language to clarify that aggregate Load can be used here as well. This Requirement is to make you properly represent the dynamic behavior of Loads at high System Load levels.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.3: This list of sensitivities is not overly prescriptive and allows the use of engineering judgment of the Planner. Language has been changed to provide clarity.

Organization	Question 2:	Question 2 Comments:
		~~Variations in~~ Load model assumptions ~~Modification of e~~Expected transfers ~~Unavailability of long lead time Facilities~~ Timing of the installation of new or modified Facilities. ~~Variability and outages of r~~Reactive resource~~s~~ capability. The specific wording for Requirement R2.4.3.4 has been changed to "Reactive resource capability". This could mean a degradation of the capability of a reactive resource. This would not normally be covered in the assessment unless sensitivity studies require it. R.2.4.3.5. Generation additions, retirements, or other dispatch scenarios would not necessarily be studied in the assessment unless there were firm plans to change generation. The purpose of sensitivity studies is to answer "what if" questions which would not otherwise be covered in the assessment. R2.5: This language has been removed from the Standard. R5.5 The requirement for study has been changed to 25MW for a single generator or for an aggregate of generators. This language is now in Requirement R2.5.2. The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater.
E.ON U.S. Transmission Planning	Yes and No	R2.4 The Near-Term Transmission Planning Horizon portion? implies that there are other portions of the [System] Stability analysis. This needs to be reworded to make it clear that there are no other portions. Add the word "System" to make it clear. R5 The data to be included in all models for the Planning Assessment is included in R1. The discussion here is redundant. This should be deleted. R5.4.3.1 Is this the intent? ? Following Single Contingency events, Transmission configuration changes and redispatch of generation can be simulated to return the system to Normal Rating provided that all Facilities shall be operating within their Emergency Rating.
Response: R2.4: The wording used is appropriate; there are no Stability Requirements beyond Near-Term R5: That language has been removed and replaced by language in Requirement R1. **R5** (now R4.) For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in~~		

Organization	Question 2:	Question 2 Comments:
~~Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted~~ R5.4.3.1: This section of the language has been removed but these principles are applicable throughout the Standard.		
ERCOT System Planning	No	ERCOT believes R2.4.3, R2.4.4, R2.5, R5.2, and R5.3 should be deleted and R5.4 and R5.5 should be combined as follows: R2.4.3 should be deleted due to the unacceptable increase of stability runs required to meet the requirement. Considering sensitivities for outages of reactive resources and various dispatches and retirements for at least two different load levels is beyond the capability of most organizations, for both technical and manpower reasons. R2.4.4 is unbounded and not measurable, and should not be included as a requirement. R2.5 and all requirements for Generating Unit Stability analysis should be deleted since there is little or no difference between this and System Stability. R5.2 should be deleted because contingency definition standards should be defined in a modeling standard.R5.3 Voltage ride through capability should be included in the model provided by the generator and should not be necessary as a requirement in the TPL standard. R5.4 and R5.5 could be combined, as there is little or no difference between Generating Unit Stability analysis and System Stability analysis. In this case, R5.5.1 and R5.5.2 would be moved to R5.4 and R5.5.3 would be removed (repeats R.5.4.1).Also, it appears that R5.4.1 is in conflict with R5.4.2 because R5.4.1 says ?identified and evaluated for System Performance? but not have to meet requirements but R5.4.2 says ?meet requirements ? Table 2?. Also, R5.4.2 is repetitious with text of R5.
Response: The SDT has changed the language of R2.4.3 to examine one or more sensitivities and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed. **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: R2.4.4 and R2.5 were deleted from the language of this draft Standard. R5.2 and R5.3 The SDT did not agree to delete this language; language is needed to be in the Standard describing Contingencies and the use of low voltage ride through in studies. (Note that in the revised standard, Requirements R5.2 and R5.3 have become Requirements R4.3 through R4.3.2.) R5.4 & 5.5: The SDT has removed the distinction between System Stability and generator unit Stability.		

Organization	Question 2:	Question 2 Comments:
American Transmission Company	No	We disagree with the proposed R2.4.1 text. This inclusion of this requirement may be premature at this time for several reasons. There is presently no industry consensus on how the dynamic behavior of loads should be properly represented and analyzed. In addition, it would be a large and difficult effort to identify, collect, and maintain the pertinent information. It is presently difficult to obtain and maintain the percentage of residential, commercial, and industrial load at each transmission interconnection point, much less try to get the proper percentage of the various types of induction motor loads. We do not accept the R2.4.3.1 text and want some explanation of the what, when, and how to provide the technical rationale for why each condition was or was not used. In R2.4.3.1, what is meant by ?variations? (e.g. how much variation is enough)? In R2.4.3.2, what is meant by ?modification? (e.g. how much modification is enough) and "expected transfers" (e.g. firm or non-firm transfers)? In R2.4.3.3, what is meant by ?long lead time? (e.g. 1 month, 1 season, 1 year, 2 years, etc.)? In R2.4.4, we believe this requirement should not be added. Why was it included? It seems superfluous, because any entity can study other sensitivities if they want. Why should TP or PC have to study what the other entity wants to study? Who would be the judge in case of disagreement over the technical rationale? In R2.5.2, Why was the addition of a new substation included? We would not expect a new substation to negatively impact the system or generating unit stability. We note the R5.5 and R5.6 should really have been updated to refer to 5.4 and R5.5. In R5.4.3.1, we suggest that the time-limited aspect of Facility Ratings be included in the Glossary Definition and then it would not need to be clarified in various locations (R3.3.2.2, R3.5.1, R5.4.3.1, Table 1-Note 1, & Table 2-Note 1) throughout the standard.

Response: R2.4.1: The SDT has changed the language of Requirement R2.4.1. The SDT has changed this language to clarify that aggregate Load can be used here as well. This Requirement is to make you properly represent the dynamic behavior of Loads at high System Load levels.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.3.1 The SDT has changed the language of R2.4.3 to examine one or more sensitivities and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed.

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why~~

Organization	Question 2:	Question 2 Comments:
~~each of the conditions was or was not selected shall be supplied~~ included in the Assessment: R2.4.3.2, The SDT has changed the language of R2.4.3 to examine one or more sensitivities and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed. R2.4.4 has been removed from the language of this Standard draft. R2.5.2: This language has also been removed from this draft Standard. R5.5 and R5.6: This new version contains renumbering which should address your concerns. R5.4.3.1: This section of the language has been removed but these principles are applicable all throughout the Standard.		
Duke Energy	No	R2.4.1 Load models that appropriately represent the dynamic behavior of induction motors are under development and may not be available for sometime. The implementation plan should take this into account and allow at least 36 months for implementation. This requirement is not immediately achievable. R2.4.3 - Although we agree with the perceived intent of R2.4.3, we believe the wording should be revised to make it very clear that it is not necessary to perform studies to substantiate your technical rationale for choosing not to perform any particular sensitivity study. Documented engineering judgment to support the decision not to perform the particular sensitivity studies should be sufficient. R2.4.3.1 should clearly state whether the load model refers to overall system load or parameters of the dynamic load model at individual busses. Recommend renumbering R2.4.4 to R2.4.3.6, and reword R2.4.3.6 as follows: Any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems.R2.4 should say "System Stability", not just "Stability".
Response: R2.4.1 has been modified to clarify that a detailed dynamic Load model is not required at each bus. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Because of this clarification, the SDT believes that a 24 month implementation period for this requirement is sufficient. This will be covered in the Implementation Plan which will be posted along with the third draft of the standard. **R2.4.1** System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. R2.4.3 The SDT has changed the language of R2.4.3 to reflect this, to examine one or more sensitivity and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed. **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why~~		

Organization	Question 2:	Question 2 Comments:
~~each of the conditions was or was not selected shall be supplied~~ included in the Assessment: R2.4.3.1 The SDT has changed this language to clarify that aggregate load can be used here as well. This Requirement is to make you properly represent the dynamic behavior of loads at high system load levels. R2.4.4 to R2.4.3.6.The SDT has removed the distinction in the Standard between System Stability and generator unit Stability.		
Florida Reliability Coordinating Council, inc	No	R2.4.4 and R2.4.3 as written can create issues during the compliance assessment. These requirements place the burden of justifying the inclusion / exclusion of the sensitivities on the TP or PC. Thus, only a sensitivity deem appropriate by the TP or PC and not performed can be found non-compliant.R2.4.4 can be eliminated by changing the wording in R2.4.3 to include sensitivities? deemed appropriate by the TP or PC as follows:? For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, sensitivity case(s) deemed appropriate by the Transmission Planner or Planning Coordinator that stress the System to reflect, but not limited to, one or more of the following conditions shall be run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied.?
Response: The SDT has changed the language of Requirement R2.4.3 to examine one or more sensitivities and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed. **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	Yes and No	R2.4. No The word “System” was deleted during the re-write and only “Stability” is used. However, the sub-sections appear to be more appropriate to a “System Stability” assessment than for a “Generating Unit Stability” assessment. “Generating Unit Stability” assessments are the subject of Section R2.5 and “System Stability” assessments appear to be the intent of Section R2.4. Why does Requirement 2.4. specify the near-term transmission planning horizon “portion”? We recommend removal of the words “portion of the”. R2.4.1. No Change “Peak System Load” to “System On-Peak Load”. This is the term defined in the “NERC Glossary” and is consistent with the usage of “Off-Peak Load”. This change would be required through out the TPL Standard as well as in other standards. There is concern with load modeling requirements (use of word “appropriately” in R2.4.1). Does this requirement mandate the use of specific load models for each bus, or would an aggregate load model which represents the system as a whole be sufficient? Does the use of the PSS/E CONL function satisfy the requirements for a load model?

Organization	Question 2:	Question 2 Comments:
		R2.4.3 NoIn general we believe that breaking these requirements into specific sub-requirements, focusing on specific sensitivities, is too prescriptive and inappropriate. It will lead to over focus on these particular issues to the detriment of system reliability. The standard should not include an enumerated list of required sensitivities. Engineering judgment needs to be permitted. R2.5 Concur R5.4 Concur R5.5 No There is a concern with R5.5.1 with the requirement to perform simulations on 20 MW generators (to be consistent with the Registration Criteria). We recommend a 75 MW generator cutoff for required simulations.

Response: R2.4: The SDT has removed the distinction between System Stability and generator unit Stability.

R2.4.1 – The SDT does not believe there is any ambiguity in the term "peak System Load" and will continue to use that term.

R2.4.1 The SDT has changed this language to clarify that aggregate Load can be used here as well. This Requirement is to make you properly represent the dynamic behavior of Loads at high System Load levels.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.3 The SDT has changed the language of Requirement R2.4.3 to reflect examining one or more sensitivity and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed.

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R5.5: The SDT agrees that there is little distinction between a single unit of a specific MW and an aggregation of the same number of MW. The requirement for study has been changed to 20 MW for a single generator or for an aggregate of generators. This is now located at Requirement R2.5.2.

The addition/deletion/change of individual generating unit capability of 20 MW or greater.

An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater.

Oncor Electric Delivery	No	For Requirement R2.4 would prefer to see more clarification on the System Off-Peak stability studies required and their purpose. Define/quantify type of stability issues to be addressed with this type of study. For sub requirement R2.4.3 the level of detail in the load modeling is very subjective and greatly impacts the analysis

Organization	Question 2:	Question 2 Comments:
		and results.

Response: R2.4: Transient Stability is generally worse at lower System Load levels when base load units are still generating near maximum output. All of the Contingencies in the table are to be considered for Off-Peak Load levels

R2.4.3 The SDT has changed this language to clarify that aggregate Load can be used here as well. This Requirement is to make you properly represent the dynamic behavior of Loads at high System Load levels. The SDT has changed the language of Requirement R2.4.3 to examine one or more sensitivity and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed.

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment

FirstEnergy Corp.	No	R2.4.1 ? This requirement should be separated into two requirements as it covers two distinct topics; a) peak load study for one of the near-term years and b) dynamic load modeling. The use of the words "appropriately represents" and "consideration" is too vague and not strong enough for requirement language. Also, the requirement needs to better describe what is needed related to the modeling of induction motor load. What % of the load needs to be represented as motor load for various load classes ? commercial, industrial, residential? An industry white paper is needed to provide direction related to this undertaking. The SDT, when considering their Implementation Plan, will need to allow sufficient time to complete the dynamic load modeling which largely does not exist today. R2.4.3 ? Typo, need to remove strikethrough text on the word sensitivity. R2.4.4 ? Suggest making this a sub-requirement of R2.4.3 and only require documentation as to why each sensitivity case was selected. Documenting why something was not selected does not seem constructive and places an unneeded burden on documentation. It should be expected that over time, a range of sensitivities would be covered as a library of studies is built.

Response: R2.4.1: The SDT has changed this language to clarify that aggregate Load can be used here as well. This Requirement is to make you properly represent the dynamic behavior of Loads at high System Load levels.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable

R2.4.3 The SDT did not find the typo indicated.

R2.4.4 The language of R2.4.4 was deleted from the Standard language.

Organization	Question 2:	Question 2 Comments:
Entergy Services, Inc.	No	General Comments: The enhanced requirements in this standard will result in an exponential increase in the amount of studies required to become compliant. Some of the changes such as the list of specific sensitivity studies will make it difficult to audit. Standards need to be measurable. As currently written, these requirements are difficult to measure. Furthermore, as indicated in the later questions, there could be significant costs to comply with these revised requirements Specific Comments: In 2.4.1, it would be better to address the "consideration of the behavior of induction motor Loads" in the sensitivity studies bullet, 2.4.3.1.,if this bullet is to be included at all. Furthermore, induction motor modeling is primarily required in areas with high load concentration that could be subject to angular and voltage stability issues. Considerable effort is required to collect information on motors. Therefore, studies to evaluate induction motor effects should be included in the sensitivity analysis section. In 2.4.3, what was the rationale for including only a portion of the sub-bullets included in 2.1.3? Also, in 2.1.3.7, does "Modification of planned Transmission outages" imply changes in dates? It seems unlikely that the cancellation of an outage would have negative impacts. More clarification is needed on what "modification" means in this requirement. R 2.4.3Each transmission provider has its own transmission planning needs and requirements. While it is true there are common elements and considerations that have to be incorporated in every transmission provider's planning process, it is difficult, if not impossible, to prescribe a list of sensitivities that is, or should be, applicable to everyone. Entergy has specific concerns regarding the following sensitivities. R.2.4.3.2 Modification of expected transfers: The use of "expected" transfer levels suggests that one can expect certain transfer patterns beyond what is modeled in base cases as firm. These sensitivities could result in an endless string of "what-if" scenarios where transmission users would attempt to influence these studies to advantage their respective market positions. Any system improvements based on such "expected" use of the system shall not result in discriminatory treatment of transmission users. R.2.4.3.5. Generation additions, retirements, or other dispatch scenarios. Generation additions are addressed by FERC-mandated study criteria. These requests are handled through the generation interconnection and system impact study processes. Generation retirements and other dispatch scenarios can have both positive and negative impacts on reliability. However, assumptions used to pick which resources are changed, and in what way, will likely be difficult to justify. R5.5 There is a concern with R5.5.1 with the requirement to perform simulations on 20 MW generators (to be consistent with the Registration Criteria). We recommend a 75 MW generator cutoff for required simulations.
Response: R2.4.1 The SDT has changed this language to clarify that aggregate Load can be used here as well. This Requirement is to make you properly represent the dynamic behavior of Loads at high System Load levels. **R2.4.1** System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic		

Organization	Question 2:	Question 2 Comments:
behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable R2.4.3The SDT has changed the language of Requirement R2.4.3 to examine one or more sensitivity and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed. **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: ~~Variations in~~ Load model assumptions ~~Modification of e~~Expected transfers ~~Unavailability of long lead time Facilities~~ Timing of the installation of new or modified Facilities. ~~Variability and outages of r~~Reactive resource~~s~~ capability. R2.4.3.5: These are changes to consider as possible sensitivities to give the TP a better understanding of its System. There is no justification of your assumptions required by the Standard. R5.5 The requirement for study has been changed to 20 MW for a single generator or for an aggregate of generators. This is now located at Requirement R2.5.2. The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater		
BPA Transmission Reliability Program	No	R2.4.1 references the use of a load model which appropriately represents the dynamic behavior of loads. However, such load models have not been developed yet. We recommend removing that requirement for load models until these models have been developed and approved. R2.5 and R5.5 refer to Generating Unit Stability studies. As stated above under Item 1, Generating Unit Stability is adequately addressed by the System Stability studies and does not need to be evaluated separately. Footnote 5.a.i in the notes following the Performance Requirements Tables, already specifies the requirements to meet. Therefore, we recommend removing the section on Generating Unit Stability Studies from standard TPL-001-1. The focus of this standard should be on "System Stability" which encompasses all generating units .Some of the requirements listed under R5.4 apply more generally than just within this section and are already covered elsewhere in the standards. R5.4.3.1 is already covered in Note 1 of Table 1. R5.4.3.2 is not relevant to Reliability Standards and would already be addressed by the relevant regulations, so it does not belong in this Standard. R5.4.3.3 is already covered in Note 1 of

Organization	Question 2:	Question 2 Comments:
		Table 2. Because these requirements are already covered by other sections of the Standard, they can be removed from R5.4.

Response: R2.4.1 The SDT has changed this language to clarify that aggregate Load can be used here as well. This Requirement is to make you properly represent the dynamic behavior of Loads at high System Load levels.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable

R2.5 and R5.5: In response to industry comments, the SDT has to remove the distinction in the standard between System Stability and generating unit Stability.

R5.4.3.1: The SDT has decided to remove Requirement R5.4.3 because the sub-requirements are already implicitly covered by the standard. Your suggested sub-requirement is also already implicitly covered by the standard.

PPL EnergyPlus	Yes and No	R2.4.3 and 2.4.4 together with R2.7 are a very good effort to direct TSPs to not let scenarios drive their plans. Rather, the base case should drive the plan. If anything, the language in the standard could be strengthened.

Response: R2.4.4 has been removed from the language.

R2.4.3: The SDT has changed the language of Requirement R2.4.3 to one or more sensitivity and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed.

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

~~Variations in~~ Load model assumptions

~~Modification of e~~Expected transfers

~~Unavailability of long lead time Facilities~~ Timing of the installation of new or modified Facilities.

~~Variability and outages of r~~Reactive resource~~s~~ capability.

TVA System Planning	Yes	
Tenaska, Inc.	Yes	

Organization	Question 2:	Question 2 Comments:
US Army Corp of Engineers, Northwestern Division	Yes	
Arkansas Electric Coop. Corp.	Yes	
LCRA TSC	Yes	
Response: Thank you for your response.		

3. **The SDT has modified the definitions of Consequential and Non-Consequential Load Loss in response to industry comments. Do you concur with the modified definitions of Consequential and Non-Consequential Load Loss? If not, please state why and/or suggest specific changes.**

Summary Consideration:

In response to numerous concerns the following changes were made to the draft standard:

- The definitions of Consequential Load Loss and Non-Consequential Load Loss were modified to be more direct.
- New definitions were added for Load Reduction and Supplemental Load Loss to address issues that were previously included in the Consequential Load Loss definition.
- Changes were made in the notes for Table 1 (item b) to address application of the revised definitions.
- Note 'b' in Table 1 has been revised to associate comments on Load loss to Steady State rather than Stability.
- Footnotes 5 & 10 were added to the Table to differentiate between Firm Transfer Service and Load Loss.
- The SDT didn't feel non-interruptible Load needed to be defined because Interruptible Load is a defined term.
- The requirement (old Requirement R3.3.2.1 – new Requirement R2.9) to specify the amount and duration of Load that may be lost was clarified to be the maximum for any Contingency and the requirement for duration was eliminated.

There is lingering concern in the industry with the following issues:

- The inability to shed firm Load for a first Contingency event
  - The SDT considered this issue, but did not change the standard because it was specifically prohibited in FERC Order 693, Section 1773.
- The different treatment for Facilities greater than 300 kV versus Facilities less than 300 kV
  - The SDT considered this issue, but did not change its perspective since the last posting. The following is the response provided in response to the first posting and the SDT has not been convinced that it should change:

    "The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission Systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT believed the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated above 300 kV generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers where the energy is then delivered by other Transmission or sub-Transmission Systems to end-

use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability.

When EHV Systems are compromised, the large volumes of power they serve can place a severe amount of stress on parallel EHV or lower voltage paths. For example, if a large EHV transformer experiences a catastrophic failure, not only are other systems Facilities required to carry more Load but the System is also exposed to other N-1 conditions for long periods of time while awaiting a replacement or repair of the failed equipment. Large generation sources are typically connected at EHV levels and maintenance of the EHV Transmission lines within the vicinity of large generation plants must often be coordinated during scheduled unit outages, resulting again in multiple Facility outages over extended periods of time.

Therefore, it was the conclusion of the SDT in Draft 1 to propose greater reliability and operational flexibility through more stringent performance requirements when considering certain N-1 and N-1-1 Contingency events of EHV Systems. Throughout the industry, substation arrangements at EHV levels reflect the importance of these systems as the designs often consist of the more flexible and reliable ring-bus, breaker-and–a-half, or double bus-double breaker protection schemes as compared to the simpler, lower cost, single bus arrangements that are commonly found on lower voltage systems.

The feedback received from the industry was divided related to the SDT's emphasis placed on a higher expectation for the 300 kV and higher systems. Some commenters questioned the importance and the high costs that may be needed to mitigate existing system designs. Others agreed with the SDT's approach and indicated that the impact to their systems would be minimal. Some commenters even questioned why the more stringent approach was not applied to the entire 100 kV and higher systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission System."

There was no change with regards to the definition of Year One. The drafting team felt that if the studies referenced in the comments are duplicative, then the language in the Standard would allow them to use one study for both applications.

The definition for Planning Coordinator was deleted because the term has already been defined and added to the NERC Glossary by another SDT.

With regards to comments on the definitions creating a disincentive to build network Facilities, the Standards do not specify how an entity will comply.

The following changes have been made to the definitions due to industry comment:

Consequential Load Loss: ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions.

Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event.

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~.

Supplemental Load Loss: Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.

The following requirement was added due to industry comments:

R2.9 The Planning Assessment shall identify the maximum permissible Non-Consequential Load Loss (megawatt Demand) for those Planning Events where Non-Consequential Load Loss is allowed in Table 1.

The following notes in the Table have been changed due to industry comment: ‘b’, ‘e’, and ‘i’.

Organization	Question 3:	Question 3 Comments:
Dominion - Electric Transmission Planning	No	Non-Consequential Load Loss: In the example provided with the definition of Non-Consequential Load Loss, it indicates that non-interruptible load loss that occurs through manual or automatic operations such as under voltage load shedding (UVLS), under-frequency load shedding (UFLS) or Special Protection Systems (SPS) would be considered Non-Consequential Load Loss. We recommend that the following statement be added to the standard in the definition -- "Interruptible loads such as the pump of a Pumped Storage Plant interrupted by an SPS should not be considered as a Non-Consequential load".
Response: The definition of the Non-Consequential Load Loss is qualified as ‘Non-Interruptible Load”. In your example, the Pumped Hydro load is defined as ‘interruptible’. There is nothing in the standard that associates Interruptible Load with Non-Consequential Load and nothing that prohibits the interruption of Interruptible Load. However, the SDT did change the definition to provide additional clarity. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~.		
NPCC	No	In the Consequential Load Loss definition, the word 'source' needs to be defined or explained further since it is unclear.
Hydro-Québec TransEnergie (HQT)	Yes and No	In the Consequential Load Loss definition, the word 'source' needs to be defined or explained further since it is unclear. It should be indicated that this also applies to " stability performance requirements" (refer to the end of last sentence of the definition).

Organization	Question 3:	Question 3 Comments:
Ameren	Yes and No	The revised definition of Consequential Load Loss needs to be simplified, as follows, "Consequential Load Loss: Load that is no longer served because it has been isolated from its network supply by a planned protection system operation to mitigate fault conditions." Additional clarifications as to when Consequential Load loss is allowed should not be included in the definition, but should instead be included in the Tables 1 and 2.Agree with the revised definition of Non-Consequential Load Loss.
Midwest ISO	No	Under the definition of consequential load, it is not clear who the term "Transmission planning entities" is referring to. Perhaps it should say "entities to which the standard is applicable". The last sentence could be amended to say: "Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS?..
Brazos Electric Power Cooperative, Inc.	No	Non-consequential is fine. For 'Consequential Load Loss' the entire last part of the definition that begins with "Although Load which is lost?" can be deleted or at least deleted to the part that begins with "Transmission planning entities are not allowed?". We think the last part of the sentence is intuitive.
Northeast Utilities	No	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
American Transmission Company	No	For Consequential Load Loss definition, we suggest that the last sentence be deleted because it is application text, rather than definition text. We accept the Non-Consequential Load Loss definition as written.
Florida Reliability Coordinating Council, inc	No	Propose changing the word ?a? to ?any? in the definition of Consequential Load Loss. Consequential Load Loss: Load that is no longer connected to ?ANY? source as a result ? The second sentence in the definition could be interpreted to disallow voltage dependent load models to meet Steady State Performance requirements. Since many planning events result in steady state voltage significantly lower than nominal, system load would be reduced. This definition would be clarified by differentiating load that is lost (no longer connected to a source) and load that is reduced as a result of reduced system voltage. Although Load which is lost (no longer connected to a source) as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load Loss to meet steady state performance requirements.
New York Independent System Operator	No	In the Consequential Load Loss definition, the word 'source' needs to be defined or explained further since it is unclear.

Organization	Question 3:	Question 3 Comments:
Response: The definition of 'Consequential Load Loss' has been revised to make it more direct, which has resulted in the elimination of the reference. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions.		
TVA System Planning	Yes	TVA agrees with the modified definitions. However, the definition for "Consequential Load Loss" can still be confusing. Suggest definition of "Load that is deenergized by relay action as a result of the event being studied ?." Additional wording in "Consequential load loss" about transient conditions can be confusing as well - we suggest including this additional information later in the document. For Non-consequential load loss, suggest use of "Firm" instead of "Non - Interruptible" Load Loss.
Response: The definition of 'Consequential Load Loss' has been revised to make it more direct and has eliminated the reference to 'transient'. There are potential associations with the term 'Firm' that the SDT is trying to avoid in this definition and therefore has decided to stay with the reference to Non-interruptible. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions.		
Progress Energy Carolinas	Yes	The definition of Consequential load loss has been appropriately modified to include loss of Load as a result of the Load's response to the transient condition. This recognizes the fact that when subjected to fault voltages of sufficient depth and duration, the resulting Load dynamics will result is loss of Load. Therefore, in order to more accurately replicate real-world behavior through dynamic stability simulation analysis, the proper representation of expected real world loss of load is acceptable. It is also proper that the computation of expected consequential Load loss and duration is not required for stability analysis. Attempts at determining additional Load loss due to load dynamics would not result in any useful information contributing to increased reliability.
Response: New definitions have been created to recognize other forms of acceptable Load loss that might occur in response to an event. The calculation of the potential Load loss for anything other than Consequential Load Loss is not required and the analysis is not expected to include it (see new 'Supplemental Load Loss' definition). However, a calculation of the maximum expected contingent Consequential Load Loss is expected (see Requirement R2.9). Note 'b" in the table has been revised to associate requirements to serve Supplemental Load Loss in Steady State rather than Stability. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response~~		

Organization	Question 3:	Question 3 Comments:
~~to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions. **R2.9** The Planning Assessment shall identify the maximum permissible Non-Consequential Load Loss (megawatt Demand) for those Planning Events where Non-Consequential Load Loss is allowed in Table 1. **Note "b":** Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss ~~is allowed for all events shown.~~are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements.		
BCTC	No	Our understanding of these definitions and the performance requirements in Tables 1 and 2 is that they may eliminate the existing provision in Footnote (b) that allows loss of firm load for contingencies in local networks. Disconnection of loads on local networks in response to contingencies normally requires RAS/SPS, and the definition of NCLL states that this is NCLL. We are not clear whether our concern is with the definitions of CLL/NCLL, the Tables, or the definition of BES. In the Consideration of Comments on First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is CLL, we do not see where FERC has ruled out the use of RAS/SPS for CLL - see BCTC comments on the First Draft at page 28 of the Consideration of Comments. BCTC concurs with SaskPower and Manitoba Hydro that that CLL needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. In addition, BCTC cannot meet the proposed P1 (A) > 300 kV Steady State Performance of no Non-Consequential Load Loss for part of our 500 kV system. One radial segment of the BCTC 500 kV transmission system, a single circuit 450 km 500 kV transmission system, serves load and interconnects generation. For outages of the 500 kV transmission line, a RAS is used to shed load to match the generation in this island. We have no plans for transmission reinforcements (280 miles of 500 kV transmission line) to remove this RAS. Therefore, we will require some further clarification of the proposed P1 (A) >300 kV requirement of no Non-Consequential Load Loss for this requirement to be suitable for all of our system.
Response: FERC Order 693 Section 1773 does not permit loss of Non-Consequential Load (see reference). There is no provision in the FERC Order to allow		

Organization	Question 3:	Question 3 Comments:
loss of Load with the use of an RAS/SPS or to provide exceptions for local networks. The SDT's interpretation of the Order is that FERC is indicating that other alternatives must be pursued to eliminate this operating scheme. However, the SDT has provided an exception (Requirement R2.6.4) if a situation arises that is beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe. "1773. The Commission proposed in the NOPR to approve Reliability Standard TPL-002-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we proposed to direct NERC to submit a modification to TPL-002-0 that: (1) requires that critical system conditions be determined in the same manner as proposed for TPL-001-0; (2) requires the inclusion of the reliability impact of the entity's existing spare equipment strategy; (3) explicitly requires all generators to ride through the same set of Category B and C contingencies as required for wind generators in Order No. 661; (4) requires documentation of load models used in system studies and supporting rationale for their use; (5) clarifies the phrase "permit operating steps necessary to maintain system control" and (6) clarifies footnote (b) to Table 1 to allow no firm load or firm transactions to be interrupted except for consequential load loss."		
Manitoba Hydro	No	The definition of Consequential Load Loss implies the load lost as a result of "response to the transient condition of the event" need not be load directly connected to the element impacted by the event, but load in the local area. This definition could result in an interpretation that would justify unlimited load loss resulting from say voltage depression in an area impacted by a transient system swing. This opens a loop hole for allowing load loss for many single contingencies as a result of a transient swing causing a voltage dip and motor contactor drop-out as an example. There is a fine line between providing adequate voltage support or operating guides to avoid such load loss. Should a maximum level of load loss be specified? Comments on Other Definitions: Extreme Events: The definition should clarify whether or not Transmission system performance requirements must be met. – Events should be changed to Event - same for Planning Events Planning Coordinator: The Planning Coordinator definition should be left to the functional model. Having the term defined here may cause future confusion. For example, the FMWG has discussed the possible elimination of the PC, based on the realization that it is the Transmission Planner who integrates resources into the transmission plans.
Response: The standard is not designed to address regional performance standards, which should govern relative to acceptable voltage depressions or the magnitude of acceptable loss of Load during Planned Events or in response to Extreme Events. This is the responsibility of the Planning Coordinator and the Transmission Owner, which has been included as notes 'e' and 'i' in Table 1. **Header note 'e"** For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. **Header note 'i'**: ~~Dynamic voltages~~Transient voltage response shall be within acceptable limits established by the Planning Coordinator (or Transmission Planner if more restrictive).		

Organization	Question 3:	Question 3 Comments:
The reference has been reviewed and revised as appropriate. When the reference is to all events, such as in the title to Table 1, then 'Events' is correct. When the reference is to a single event, such as in the column header to Table 1, then 'Event' is correct. The definition for Planning Coordinator was deleted because the term has already been defined and added to the NERC Glossary by another SDT.		
Los Angeles Department of Water and Power	No	In general, support the comment from WECC on this question, however, where there are different performance allowed solely based on an arbitrary voltage class separation, it is discriminatory and without any scientific or historical basis.
Response: Many responders have asked the question why the distinction for bus sections above 300 kV. The SDT has prepared the following response. The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission Systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT believed the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated above 300 kV generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers where the energy is then delivered by other Transmission or sub-Transmission Systems to end-use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. When EHV Systems are compromised, the large volumes of power they serve can place a severe amount of stress on parallel EHV or lower voltage paths. For example, if a large EHV transformer experiences a catastrophic failure, not only are other systems Facilities required to carry more Load but the System is also exposed to other N-1 conditions for long periods of time while awaiting a replacement or repair of the failed equipment. Large generation sources are typically connected at EHV levels and maintenance of the EHV Transmission lines within the vicinity of large generation plants must often be coordinated during scheduled unit outages, resulting again in multiple Facility outages over extended periods of time. Therefore, it was the conclusion of the SDT in Draft 1 to propose greater reliability and operational flexibility through more stringent performance requirements when considering certain N-1 and N-1-1 Contingency events of EHV Systems. Throughout the industry, substation arrangements at EHV levels reflect the importance of these systems as the designs often consist of the more flexible and reliable ring-bus, breaker-and–a-half, or double bus-double breaker protection schemes as compared to the simpler, lower cost, single bus arrangements that are commonly found on lower voltage systems. The feedback received from the industry was divided related to the SDT's emphasis placed on a higher expectation for the 300 kV and higher systems. Some commenters questioned the importance and the high costs that may be needed to mitigate existing system designs. Others agreed with the SDT's approach and indicated that the impact to their systems would be minimal. Some commenters even questioned why the more stringent approach was not applied to the entire 100 kV and higher systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission System.		
Transmission Agency of Northern	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the

Organization	Question 3:	Question 3 Comments:
California		interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversely impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Pacific Gas and Electric Co.	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service

Organization	Question 3:	Question 3 Comments:
		reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Public Service Company of New Mexico	Yes and No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49,

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		response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Puget Sound Energy, Inc.	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection used to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer will be degraded without commensurate improvement in overall system reliability. In addition, existing design of many such local networks may use RAS/SPS to disconnect loads on local networks in response to low probability contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to

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		include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Idaho Power Company	No	We generally do not disagree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to

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		eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
SMUD	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable.

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Sierra Pacific Power Company / Nevada Power Company	No	We generally do not disagree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet

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		steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Black Hills Corporation	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Arizona Public	Yes and No	We generally agree with the definition but have concerns about a potential unintended consequence. This definition will

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Service Co.		severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. At a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability.
SRP	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load

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		Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Tucson Electric Power Company	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.

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Modesto Irrigation District		Comments: We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashioner avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require AS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6.While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote bof the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss disallowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Tri-State G&T	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for

Organization	Question 3:	Question 3 Comments:
		loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
ColumbiaGrid	No	We generally do not disagree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in

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		overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Southern California Edison	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the

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		faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
US Bureau of Reclamation	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting Comment Form for 2nd Draft of Standard TPL-001-1Assess Transmission Future Needs (Project 2006-02)Page 5 of 12the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without comments urate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6.While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential

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		Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote bof the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.

Response: With regards to the disincentives of the Consequential Load definition, the Standards do not specify how an entity will comply.

The SDT has made changes to the definitions and has clarified acceptable loss of Load situations. This includes moving the last sentence of the Consequential Load definition to the Table. However, FERC Order 693 Section 1773 does not permit loss of Non-Consequential Load (see reference). There is no provision in the FERC Order to allow loss of Load with the use of an RAS/SPS or to provide exceptions for local networks. Our interpretation of the Order is that FERC is indicating that other alternatives must be pursued to avoid loss of Non-Consequential Load. However, the SDT has provided an exception (Requirement R2.7.4) if a situation arises that is beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe.

Consequential Load Loss: ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions.

Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event.

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~.

Organization	Question 3:	Question 3 Comments:
Supplemental Load Loss: Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions. **Note 'b":** Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss ~~is allowed for all events shown.~~are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements. "1773. The Commission proposed in the NOPR to approve Reliability Standard TPL-002-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we proposed to direct NERC to submit a modification to TPL-002-0 that: (1) requires that critical system conditions be determined in the same manner as proposed for TPL-001-0; (2) requires the inclusion of the reliability impact of the entity's existing spare equipment strategy; (3) explicitly requires all generators to ride through the same set of Category B and C contingencies as required for wind generators in Order No. 661; (4) requires documentation of load models used in system studies and supporting rationale for their use; (5) clarifies the phrase "permit operating steps necessary to maintain system control" and (6) clarifies footnote (b) to Table 1 to allow no firm load or firm transactions to be interrupted except for consequential load loss."		
National Grid	No	a. In the Consequential Load Loss definition, the word 'source' needs to be defined or explained further since it is unclear. b. Non-Consequential references non-interruptible load. Non-Interruptible load should be defined. Suggest: "Demand that the end-use customer has not made available to its Load-Serving Entity via contract or agreement for curtailment." c. The Consequential Load definition should specify "Interruptible and Non-Interruptible Load that is no longer connected to a source?" d. The inclusion of "or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes)" confuses the definition of Consequential Load Loss, because of the imbedded exception for steady state performance. It seems that the intent of this provision is to recognize that this type of load loss could occur for either transient or steady state conditions and that Planning Assessments should not be required to remedy this type of situation. However, this does seem to be at odds with the application and stated acceptability of Consequential Load Loss as noted in Table 1. Note: Table 2 has no reference to the treatment of Consequential Load Loss. It may be helpful to address the transient load loss situation in a separate definition. As proposed in the draft, Firm Transmission Service is treated equal to load. In New England and New York, we focus on stressing transfer limits across and within the systems. By so doing, we preserve the internal transfer capabilities by design rather than modeling specific contractual transfers, which may not stress the internal interfaces. The exception is for the inter-Area ties. For inter-Area ties, the import or export capability is comparable to a generating unit, which we believe is acceptable to interrupt. We therefore feel that it should be acceptable to interrupt Firm Transmission Service over inter-Area ties and that Firm Transmission Service shouldn't be treated equally with load. Suggested changes: Change "Consequential Load Loss" to "Consequential Interruption". Change the definition to "Load, Firm Demand, or Firm Transmission Service that is no longer connected ..."Change "Non-Consequential Load Loss" to "Non-Consequential Interruption". Change the definition to "Non-Interruptible Load, Firm Demand, or loss of Firm Transmission Service other than Consequential Interruption that occurs

Organization	Question 3:	Question 3 Comments:
		through manual (operator initiated), automatic operations (such as under-voltage load shedding, under-frequency load shedding, or Special Protection Systems), or uncontrolled loss of a local area which does not significantly impact the Bulk Electric System."
Central Maine Power Company	No	There are a few significant concerns with these definitions: The definitions should be expanded to include interruption of Firm Transmission Service in a manner that is comparable to interruption of load; otherwise, Firm Transmission Service (FTS) is being treated in a manner that is superior to load. (The expansion of the definitions to include FTS would also address stated concerns associated with loss of radial or single facilities over which Firm Transmission arrangements have been made). There are perceived limitations to what constitutes Non-Consequential Load Loss. It must be clear that Non-Consequential load loss allows the cascading loss of a local area that does not adversely impact the BES. It would be impractical and unnecessary to anticipate that every such situation could be or needs to be managed by operator action or automatic control. Non-Interruptible load should be defined as, "Demand that the end-use customer has not made available to its Load-Serving Entity via contract or agreement for curtailment." The Consequential Load definition should specify "Interruptible and Non-Interruptible Load that is no longer connected to a source?" The inclusion of "or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes)" confuses the definition of Consequential Load Loss, because of the imbedded exception for steady state performance. It seems that the intent of this provision is to recognize that this type of load loss could occur for either transient or steady state conditions and that Planning Assessments should not be required to remedy this type of situation. However, this does seem to be at odds with the application and stated acceptability of Consequential Load Loss as noted in Table 1. Note: Table 2 has no reference to the treatment of Consequential Load Loss. It may be helpful to address the transient load loss situation in a separate definition. Recommended Changes: Change "Consequential Load Loss" and definition to "Consequential Interruption - Load, Firm Demand, or Firm Transmission Service that is no longer connected?" Change "Non-Consequential Load Loss" and definition to "Non-Consequential Interruption - Non-Interruptible Load, Firm Demand, or Firm Transmission Service loss other than Consequential Interruption loss that occurs through manual (operator initiated), automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems, or uncontrolled loss of a local area which does not significantly impact the BES."
NSTAR Electric	No	There are a few significant concerns with these definitions: The definitions need to be expanded to include interruption of Firm Transmission Service in a manner that is comparable to interruption of load; otherwise, Firm Transmission Service (FTS) is being treated in a manner that is superior to load. The expansion of the definitions to include FTS would also address stated concerns associated with loss of radial or single facilities over which Firm Transmission arrangements have been made. There are perceived limitations to what constitutes Non-Consequential Load Loss. It must be clear that Non-Consequential load loss allows for the cascading loss of a local area that does not adversely impact the BES. It would be impractical and unnecessary to anticipate that every such situation could be or needs to be managed by operator action or automatic control. Non-Interruptible load needs to be defined as," Demand that the end-use customer has not made available to its Load-Serving Entity via contract or agreement for curtailment." The Consequential Load definition should

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		specify "Interruptible and Non-Interruptible Load that is no longer connected to a source?" The inclusion of "or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes)" confuses the definition of Consequential Load Loss, because of the imbedded exception for steady state performance. It seems that the intent of this provision is to recognize that this type of load loss could occur for either transient or steady state conditions and that Planning Assessments should not be required to remedy this type of situation. However, this does seem to be at odds with the application and stated acceptability of Consequential Load Loss as noted in Table 1. Note: Table 2 has no reference to the treatment of Consequential Load Loss. It may be helpful to address the transient load loss situation in a separate definition. Recommended Changes: Change "Consequential Load Loss" and definition to "Consequential Interruption - Load, Firm Demand, or Firm Transmission Service that is no longer connected?" Change "Non-Consequential Load Loss" and definition to "Non-Consequential Interruption - Non-Interruptible Load, Firm Demand, or Firm Transmission Service loss other than Consequential Interruption loss that occurs through manual (operator initiated), automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems, or uncontrolled loss of a local area which does not significantly impact the BES."
ISO New England Inc.	No	There are a few significant concerns with these definitions: The definitions need to be expanded to include interruption of Firm Transmission Service in a manner that is comparable to interruption of load; otherwise, Firm Transmission Service (FTS) is being treated in a manner that is superior to load. (The expansion of the definitions to include FTS would also address stated concerns associated with loss of radial or single facilities over which Firm Transmission arrangements have been made). There are perceived limitations to what constitutes Non-Consequential Load Loss. It must be clear that Non-Consequential load loss allows the cascading loss of a local area that does not adversely impact the BES. It would be impractical and unnecessary to anticipate that every such situation could be or needs to be managed by operator action or automatic control. Non-Interruptible load needs to be defined as," Demand that the end-use customer has not made available to its Load-Serving Entity via contract or agreement for curtailment." The Consequential Load definition should specify "Interruptible and Non-Interruptible Load that is no longer connected to a source?" The inclusion of "or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes)" confuses the definition of Consequential Load Loss, because of the imbedded exception for steady state performance. It seems that the intent of this provision is to recognize that this type of load loss could occur for either transient or steady state conditions and that Planning Assessments should not be required to remedy this type of situation. However, this does seem to be at odds with the application and stated acceptability of Consequential Load Loss as noted in Table 1. Note: Table 2 has no reference to the treatment of Consequential Load Loss. It may be helpful to address the transient load loss situation in a separate definition. Recommended Changes: Change "Consequential Load Loss" and definition to "Consequential Interruption - Load, Firm Demand, or Firm Transmission Service that is no longer connected?" Change "Non-Consequential Load Loss" and definition- "Non-Consequential Interruption - Non-Interruptible Load, Firm Demand, or Firm Transmission Service loss other than Consequential Interruption loss that occurs through manual (operator initiated), automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems, or uncontrolled loss of a local area which does not significantly impact the BES."

Organization	Question 3:	Question 3 Comments:
Orlando Utilities Commission	No	The definition refers to "A source" which implies that an area served by several sources that loses access to one source could lose some load since it lost "a source" or "its source". This is a different meaning then the one expressed on the national conference call. As written this definition also implies that the triggering of a UVLS, UFLS or load shedding SPS is not acceptable under the conditions for which non-consequential load loss is not allowed. If the Drafting team's intent is to forbid the use of these devices for certain levels of contingencies then it should be done directly in the standard not hidden in a definition. (While an SPS may or may not include load loss, UVLS and UFLS are effective because of the load loss.)
Response: Definitions have been changed to clarify the definition of Consequential Load Loss. The reference to 'source' has been eliminated. The SDT does not believe that a definition for Non-Interruptible load is necessary because Interruptible Load is defined. Notes have been added to provide conditions and clarifications relative to the interruptions of Firm Transmission Service. The definition of Non-Consequential Load Loss has also been changed to remove the reference to UFLS and UVLS, which are systems used for operations and are not applicable to a planning standard. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions. **Note 'b":** Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss ~~is allowed for all events shown.~~are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements.		
OPUC	Yes and No	The concept of Consequential Load Loss is generally acceptable. However, the presentation, notes and cross referencing need to be adjusted to avoid confusion.
Response: The SDT has reviewed references for consistency as part of the changes made in response to the comments received in this posting.		
JEA	Yes	Recommend changing "Non-Interruptible Load" to "non-Interruptible Load" (first occurrence of use in the new definition.

Organization	Question 3:	Question 3 Comments:
Response: The first use is at the beginning of a sentence and the SDT feels that the term is correctly capitalized.		
PacifiCorp	Yes and No	? We generally agree with the definition but have concerns about a potential unintended consequence. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. At a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability.
Response: With regards to the disincentives of the Consequential Load definition, the Standards do not specify how an entity will comply. However, if Systems are upgraded such that Load is not interrupted for first Contingency events, then there will be improvements to the overall reliability of the System.		
Progress Energy Florida, Inc.	No	The Definitions of ?Consequential Load Loss? and ?Non-Consequential Load Loss?, bring to mind the following concerns: Both Definitions are confusing and unclear as to their intent and meaning, and as presently worded it is PEFs belief that these particular Definitions can be interpreted in ways not intended by the SDT. For example, the definition of Consequential Load Loss contains the phrase "Load that is no longer connected to a source"; presumably this means "Load that is no longer connected to any source", but is not stated as such. PEF would note, however, its disagreement with the definition even with the wording change, given how the definition would be applied. UVLS, UFLS and SPS schemes are excluded from Consequential Load Loss, and thus are not allowed as mitigations for several outage scenarios. The SDT is essentially discouraging Transmission Owners from constructing such schemes, which is counterproductive to reliability, and actually reduces reasonable options left for Transmission Owners to the point that possible outcomes might be a) radializing of systems or b) removing breakers in order to convert load previously deemed Non-Consequential Load into Consequential Load. PEF maintains that where particular outage scenarios dictate the need for UVLS, UFLS and SPS schemes, the right to implement them should be allowed regardless of the category of event, so long as implementation in lieu of a more expensive project will not compromise the reliability of the BES. Whether or not UVLS, UFLS and SPS schemes continue to be categorized as Non-Consequential Load Loss, however, PEF disagrees with the definition given how it would be applied.
Response: With regards to the disincentives of the Consequential Load definition, the Standards do not specify how an entity will comply. The SDT has made changes to the definitions and has clarified acceptable loss of Load situations. This includes moving the last sentence of the Consequential Load definition to the Table. However, FERC Order 693 Section 1773 does not permit loss of Non-Consequential Load (see reference). There is no provision in the FERC Order to allow loss of Load with the use of an RAS/SPS or to provide exceptions for local networks. Our interpretation of the Order is that FERC is indicating that other alternatives must be pursued to avoid loss of Non-Consequential Load. However, the SDT has provided an exception (Requirement R2.6.4) if		

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a situation arises that is beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe. "1773. The Commission proposed in the NOPR to approve Reliability Standard TPL-002-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we proposed to direct NERC to submit a modification to TPL-002-0 that: (1) requires that critical system conditions be determined in the same manner as proposed for TPL-001-0; (2) requires the inclusion of the reliability impact of the entity's existing spare equipment strategy; (3) explicitly requires all generators to ride through the same set of Category B and C contingencies as required for wind generators in Order No. 661; (4) requires documentation of load models used in system studies and supporting rationale for their use; (5) clarifies the phrase "permit operating steps necessary to maintain system control" and (6) clarifies footnote (b) to Table 1 to allow no firm load or firm transactions to be interrupted except for consequential load loss." The definition of Non-Consequential Load Loss has been changed to remove the reference to UFLS and UVLS, which are systems used for operations and are not applicable to a planning standard. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~		
Lafayette Utilities System	No	Non-consequential load loss is described as including non-interruptible load lost that results from manual or automatic operations "such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems ?." It should be clarified that the quoted items are not intended to be exhaustive of the non-manual Load loss situations that would be considered the loss of Non-consequential Load. For instance, some types of industrial applications that are power-quality dependent may be expected to disconnect or shut down in the event of fluctuations in frequency, voltage or current. Foreseeable load interruptions of this nature should be treated as "Non-consequential Load loss" even if the mechanism by which the load disconnects is other than a UFLS, UVLS or SPS system operated by the Distribution Provider.
Response: The definition of 'Consequential Load Loss' has been revised to make it more direct. New definitions have also been created to recognize other forms of acceptable Load loss that might occur in response to an event. The definition of Non-Consequential Load Loss has also been changed to remove the reference to UFLS and UVLS, which are systems used for operations and are not applicable to a planning standard. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event.		

Organization	Question 3:	Question 3 Comments:
Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.		
Exelon Transmission Planning	No	UVLS should be allowed for in the definition of non-consequential load shedding in certain lower probability contingencies above 300 kV. The complete disallowance seems to disincentive their use, contrary to the NERC Blackout Recommendation 13c. There is a value in their use for certain voltage stability situations. There does not appear to be any limit (except no cascading) to the amount of acceptable load loss once non-consequential load loss is allowed.
Response: Recommendation 13c appears to be focused on reviewing practices. It does not appear to make a recommendation relative to any of those practices. "Recommendation 13c: The Planning Committee, working in conjunction with the regional reliability councils, shall within two years reevaluate the criteria, methods, and practices used for system design, planning, and analysis; and shall report the results and recommendations to the NERC board. This review shall include an evaluation of transmission facility ratings methods and practices, and the sharing of consistent ratings information. Regional reliability councils may consider assembling a regional database that includes the ratings of all Bulk Electric System (100-kV and higher voltage) transmission lines, transformers, phase angle regulators, and phase shifters. This database should be shared with neighboring regions as needed for system planning and analysis. NERC and the regional reliability councils should review the scope, frequency, and coordination of interregional studies, to include the possible need for simultaneous transfer studies. Study criteria will be reviewed, particularly the maximum credible contingency criteria used for system analysis. Each control area will be required to identify, for both the planning and operating time horizons, the planned emergency import capabilities for each major load area." As a result, it is unclear whether the proposed Standard is actually contrary to the recommendation as you suggest. The definition of Non-Consequential Load Loss has also been changed to remove the reference to UFLS and UVLS, which are systems used for operations and are not applicable to a planning standard. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~.		
MidAmerican Energy Company	No	MEC notes that Non-Consequential Load Loss is defined by the SDT to include load dropped by Special Protection Systems while Consequential Load Loss does not exclude load dropped by Special Protection Systems. The SDT should resolve this contradiction between these two definitions by adding an appropriate reference to Special Protection Systems in the Consequential Load Loss.
MRO NERC Standards Review	No	Non-Consequential Load Loss is defined by the SDT to include load dropped by Special Protection Systems while Consequential Load Loss does not exclude load dropped by Special Protection Systems. The SDT should resolve this

Organization	Question 3:	Question 3 Comments:
Subcommittee		contradiction between these two definitions by adding an appropriate reference to Special Protection Systems in the Consequential Load Loss. For Consequential Load Loss definition, The MRO suggests that the last sentence be deleted because it is application text, rather than definition text.
Response: The definition of 'Consequential Load Loss' and 'Non-Consequential Load Loss' have been revised to make them more direct. New definitions have also been created to recognize other forms of acceptable Load loss that might occur in response to an event. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.		
SERC Dynamics Review Subcommittee	Yes	The modified definitions of Consequential load loss has been appropriately modified to include loss of Load as a result of the Load's response to the transient condition. This recognizes the fact that when subjected to fault voltages of sufficient depth and duration, the resulting Load dynamics will result is loss of Load. Therefore, in order to more accurately replicate real-world behavior through dynamic stability simulation analysis, the proper representation of expected real world loss of load is acceptable. It is also proper that the computation of expected consequential Load loss and duration is not required for single contingency stability analysis. If there is a need, Load loss due to the resulting transmission system configuration would be captured by steady state analysis. Attempts at determining additional Load loss due to load dynamics would not result in any useful information contributing to increased reliability.
Response: In response to other industry comments, the SDT has added a new definition which covers the loss of Load due to Load dynamics - Supplemental Load Loss. It is no longer included as part of Consequential Load Loss. In dynamic studies, Supplemental Load Loss is allowed for any planning or extreme event. The tabulation of Load lost due to a Contingency does not include Supplemental Load Loss.		
Arkansas Electric Coop. Corp.	No	These definitions are still confusing. I offer the following example to explain: If you have a networked transmission line serving several loads, a fault occurs on the line, and the load is dropped because of the line breakers at either end of the line operating. As a result the operator would normally sectionalize the line and isolate the faulted section. This results in the networked line now being two radials and the load is restored. From a planning standpoint the resulting steady state is

Organization	Question 3:	Question 3 Comments:
		the resulting two radials and there should not be any consequential load loss. From an operational standpoint steady state would have occurred at the time of the breakers opening and dropping the load. Operationally the load is consequential load loss. This being a planning standard the standard should require that all the load be served and the transmission line meet the (planning)steady state performance requirements. If the SDT agrees that the resulting radials should be capable of serving all the load and meet the planning steady state performance requirements then I can agree with the definition. If not then I disagree. In the planning environment systems should be studied and assessed based on an switchable element to switchable element basis and not just breaker to breaker. on-Consequential Load Loss - 1. Is it the intent of the SDT that Non-Consequential Load Loss be all firm load other than Consequential Load Loss? If not it should be. Is there a definition of "Non-Interruptible Load"? Didn't see it in the Glossary. 2. additional language should be added stating that the examples given are not inclusive. I have a problem with NERC providing examples in definitions because often the examples are interpreted as the definition itself when in reality their purpose is to clarify.

Response: In your example**,** Consequential Load Loss occurs with the initial event. The standard does not address the size of the Consequential Load or whether alternative sources are required to restore Consequential Load Loss.

Non-Consequential Load is intended to be Firm, which is evident by FERC Order 693 which states:

"1773. The Commission proposed in the NOPR to approve Reliability Standard TPL-002-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we proposed to direct NERC to submit a modification to TPL-002-0 that: (1) requires that critical system conditions be determined in the same manner as proposed for TPL-001-0; (2) requires the inclusion of the reliability impact of

the entity's existing spare equipment strategy; (3) explicitly requires all generators to ride through the same set of Category B and C contingencies as required for wind generators in Order No. 661; (4) requires documentation of load models used in system studies and supporting rationale for their use; (5) clarifies the phrase "permit operating steps necessary to maintain system control" and (6) clarifies footnote (b) to Table 1 to allow no firm load or firm transactions to be interrupted except for consequential load loss."

The definition of 'Consequential Load Loss' has been revised to make it more direct. New definitions have also been created to recognize other forms of acceptable Load loss that might occur in response to an event.

Consequential Load Loss: ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions.

Organization	Question 3:	Question 3 Comments:
Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions. The SDT didn't feel non-Interruptible Load needed to be defined because Interruptible Load is a defined term		
Tri-State Generation and Transmission Association, Inc.	Yes	We agree with the definitions in concept - that Consequential Load Loss is load which would be unserved following a specific outage event, without any load shedding relay operations. However, there is some ambiguity in how things are defined for N-1-1 contingencies. For example, a firm contract or firm resource would not be automatically curtailed upon the first outage (N-1), but operators may need to curtail the contract or resource schedule to restore the system to acceptable operating limits, or arm relay schemes that would interrupt certain facilities for the second outage (N-1-1). It seems unreasonable that some such operator actions would not be allowed.
Response: The SDT has revised the definitions and tables to provide greater clarification on what can be curtailed. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions. **Note 'b":** Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss ~~is allowed for all events shown.~~are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements.		
AEP	No	Should clarify that it's load that is no longer connected since the transmission facilities to which it is connected have been outaged as expected by the normal relay response to the event being studied. In other words, the loss of load that is connected to facilities that have cascaded as a result of the event being studied is not consequential load loss (nor is it non-

Organization	Question 3:	Question 3 Comments:
		consequential load loss). See load loss definitions under Attachment D of PJM Manual 14B for additional wording suggestions.
Response: The definition of 'Consequential Load Loss' has been revised to make it more direct, which clarifies that the causal event is a 'fault' that is cleared by 'planned protection system operation'. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions.		
Lakeland Electric	No	Recommend: Consequential: Load that is no longer served because its electrical path to the BES is open as a direct result of system response to the event under study. Load lost due to event induced transients is Consequential load loss; however, the this load must be included in the model during steady-state analysis. Load lost due to UFLS, UVLS, Special Protection Schemes and operator actions are not considered Consequential. Non-Consequential: Load that is no longer served for any reason other than those identified in the definition on Consequential.
Response: The SDT has made changes to the definitions which are conceptually consistent with your suggestion. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.		
Southern Company Transmission	Yes and No	Yes on the definition. The definition of Consequential Load Loss has been appropriately modified to include loss of load as a result of the load's response to the transient condition. This recognizes the fact that when subjected to fault voltages of sufficient depth and duration, the load undervoltage protection will result in loss of Load. Therefore, in order to more accurately replicate real-world behavior through dynamic stability simulation analysis, the proper representation of expected

Organization	Question 3:	Question 3 Comments:
		real world loss of load is acceptable. No on R3.3.2.1 dealing with Consequential Load. The computation of expected consequential load loss and duration does not result in any useful information contributing to increased reliability. Therefore, this requirement R3.3.2.1 should be dropped. If the computation is not deleted, at least the duration part of it should be dropped. In a Planning analysis, the duration is indeterminate.
Response: New definitions have been created to recognize other forms of acceptable Load loss that might occur in response to an event. The calculation of the potential Load loss for anything other than Consequential Load Loss is not required and the analysis is not expected to include it (see new 'Supplemental Load Loss' definition). However, a calculation of the maximum expected contingent Consequential Load Loss is expected (see Requirement R2.9). Requirement R3.3.2.1 has been rewritten as Requirement R2.9 to more specifically identify what is required and 'duration' has been dropped. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions. **R2.9** The Planning Assessment shall identify the maximum permissible Non-Consequential Load Loss (megawatt Demand) for those Planning Events where Non-Consequential Load Loss is allowed in Table 1.		
North Carolina Electric Membership Corp	No	Although the modified definitions are an improvement over the previous version, addressing the following issues in the Consequential Load Loss definition will further improve clarity:1) Redundancy: The second sentence in the definition says "Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed,?". It appears that "?and is permitted when Consequential Load Loss is allowed,?" is redundant and may be omitted/deleted -- isn't this *always* permitted for all events, except P0 (normal)? (See head note 4 in Table 1 -- Steady State Performance). 2) Who are the "planning entities"? Suggest replacing with Functional Model terms Transmission Planner and Planning Coordinator. 3) Verbosity: It appears that the intent of the second sentence in the definition can be conveyed more concisely. Consider

Organization	Question 3:	Question 3 Comments:
		changing to "However, relying upon the expected Load loss during transient conditions of the event to meet steady state performance requirements is not allowed." 4) If the verbiage proposed above is found acceptable, we offer a follow-up suggestion. Because the second sentence in the definition essentially characterizes the exception to the allowed Consequential Load Loss during steady state performance evaluation, we suggest moving it out of the definition and appending it within head note 4 in Table 1 -- Steady State Performance. 5) While the Consequential Load Loss definition employs the acronyms UFLS and UVLS, their expanded descriptions have been used in the Non-Consequential Load Loss definition. Suggest that these terms be used consistently in both definitions. Also, why is Special Protection Systems included as an example of what constitutes Non-Consequential Load Loss but is excluded from the list of exceptions to Consequential Load Loss (whereas UVLS and UFLS appear consistently in both)? Perhaps examples of each are needed: Consequential Load Loss examples might be a) tapped load from an outaged networked line from main station breaker to main station breaker of entire line, b) outaged T/T transformer serving radial load that that taps the networked transmission line, c) load served from a radial feeder from a single source. Non-consequential might include a) manual load dump or generator trip to mitigate cascading or uncontrolled load loss or an overload during adverse conditions, b) SPS addressing above, c) UFLS, d) UVLS.
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	No	Comments: Although the modified definitions are a good improvement over the previous version, addressing the following issues in the Consequential Load Loss definition will further improve clarity:1) Redundancy: The second sentence in the definition says "Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed,?". It appears that "?and is permitted when Consequential Load Loss is allowed,?" is redundant and may be omitted/deleted -- isn't this *always* permitted for all events? (See head note 4 in Table 1 -- Steady State Performance). 2) Who are the "planning entities"? Suggest replacing with Functional Model terms Transmission Planner and Planning Coordinator. 3) Verbosity: It appears that the intent of the second sentence in the definition can be conveyed more concisely. Consider changing to "However, relying upon the expected Load loss during transient conditions of the event to meet steady state performance requirements is not allowed." 4) If the verbiage proposed above is found acceptable, we offer a follow-up suggestion. Because the second sentence in the definition essentially characterizes the exception to the allowed Consequential Load Loss during steady state performance evaluation, we suggest moving it out of the definition and appending it within head note 4 in Table 1 -- Steady State Performance. 5) While the Consequential Load Loss definition employs the acronyms UFLS and UVLS, their expanded descriptions have been used in the Non-Consequential Load Loss definition. Suggest that these terms be used consistently in both

Organization	Question 3:	Question 3 Comments:
		definitions. Also, why is Special Protection Systems included as an example of what constitutes Non-Consequential Load Loss but is excluded from the list of exceptions to Consequential Load Loss (whereas UVLS and UFLS appear consistently in both)?
Response: The SDT has made changes to the definitions and text, which are conceptually consistent with your suggestions. The revised definitions are more direct and eliminate examples. The reference to Planning Entities has been deleted. The definition of Non-Consequential Load Loss has also been changed to remove the reference to UFLS and UVLS, which are systems used for operations and are not applicable to a planning standard. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.		
ERCOT System Planning	No	ERCOT feels the amount and duration of load loss should be considered in the definition.
Response: Requirement R3.3.2.1 has been rewritten as Requirement R2.9 to more specifically identify what is required. As part of that review, the consensus was that duration is too difficult to accurately prescribe and had no value in a Planning Standard and has been dropped. **R2.9** The Planning Assessment shall identify the maximum permissible Non-Consequential Load Loss (megawatt Demand) for those Planning Events where Non-Consequential Load Loss is allowed in Table 1.		
Alberta Electric System Operator	No	We generally agree with the definitions by themselves but have concerns about regarding application, please refer to response in Q15. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of

Organization	Question 3:	Question 3 Comments:
		such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, recommend moving this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Response: Definitions have been changed to clarify Consequential Load Loss and the last sentence in the definition has been moved to the tables. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Note 'b":** Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss ~~is allowed for all events shown.~~are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements.		
FirstEnergy Corp.	No	Regarding the definition of "Consequential Load Loss" we do not agree with the inclusion of Load which is lost as a result of the Load's response to the transient conditions of the event and recommend that the team restrict the definition to account for only load which is directly served by the facilities which were de-energized as a result of the contingency event. To include this within in the definition seems counterproductive to the planning of the transmission system that is required by this reliability standard. Comments on other definitions:1) Planning Coordinator (PC) ? The SDT included a new definition for PC for inclusion in the NERC Glossary of Terms. We agree that this addition better aligns the Glossary with the PC applicable entity which is prevalent in a variety of standards. However, we are curious why the SDT did not indicate a deletion of the Planning Authority (PA) definition and what steps, if any, are being made by NERC to align registry criteria which uses Planning Authority (PA) to the reliability standards use of the PC. 2) Year-One: The definition for Year-One is awkwardly written. We suggest that the definition be adjusted to read "The planning year that begins with the upcoming annual period under study". We believe the attempt to try and delineate between the near-term planning horizon and operational planning horizon is not needed within the TPL standard and that the near-term period should account for the upcoming annual study periods. If not revised, the need for two near-term studies on an annual basis is overly burdensome as many transmission planning organizations perform upcoming annual seasonal assessments for seasonal peak (summer/winter) periods. Requiring an additional two studies near-term does not provide significant benefit. Further reasoning for making the change is the allowance of operating procedures as part of Corrective Action plans. Operating procedures can easily be developed and implemented to mitigate projected performance violations prior to an upcoming seasonal period. 3) BES ? The acronym BES is used throughout the standard but never defined. We suggest this could easily be done in

Organization	Question 3:	Question 3 Comments:
		the purpose statement by simply adding the text "(BES)" after the reference to Bulk Electric System.
Response: Definitions have been changed to clarify Consequential Load Loss. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. The definition for Planning Coordinator was deleted because the term has already been defined and added to the NERC Glossary by another SDT. The standard does not require that studies are duplicated. If an operating study can be used to demonstrate an assessment for planning purposes, then the operating study would be sufficient. Bulk Electric System will be spelled out in the first reference.		
Entergy Services, Inc.	No	To the extent stakeholders agree with the use of UVLS or other special protection systems to mitigate events and avoid costly infrastructure improvements, the load that is reduced due to the operation of these systems should be capable of being classified as consequential load. In some cases, these systems can enhance grid reliability by removing components that have no significant impact on the BES. The definition of Non-consequential Load Loss includes load dropped by UVLS, UFLS, as well as SPS. However, Consequential Load Loss does not name SPS load loss as an exception, while UVLS and UFLS are named specifically. Shouldn't load lost by SPS action also be included in this exception to reduce confusion? There also seems to be another category missing. Non-consequential load loss could also be a result of "regular" protection systems beyond those directly protecting the faulted equipment. The second part of the Consequential Load loss definition is confusing - "Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements." While it Is part of consequential load loss per the definition, planners are not allowed by the standard to plan for it. Therefore, this definition seems to make the Performance Tables incorrect. With this statement we seem to need another term like "Allowable Consequential Load loss."
Response: The SDT has made changes to the definitions and text, which are conceptually consistent with your suggestion. The definition of Non-consequential Load Loss has also been changed to remove the reference to UFLS and UVLS, which are systems used for operations and are not applicable to a planning standard. Examples have been removed from definitions. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response~~		

Organization	Question 3:	Question 3 Comments:
~~to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.		
BPA Transmission Reliability Program	No	The definition of Consequential Load Loss needs to be modified to include all of the concepts that were contained in footnote b of the existing TPL standards.
Response: "All of the concepts that were contained" are subject to interpretation and there are different interpretations of what the concepts are. Therefore it is not clear what you would like to see. The SDT has continued to revise the definitions in response to the comments received subsequent to the second posting. Notes have been added to provide conditions and clarifications relative to the interruptions of Firm Transmission Service. Hopefully these changes will address your concerns. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions. **Note 'b":** Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss ~~is allowed for all events shown.~~are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements.		

Organization	Question 3:	Question 3 Comments:
PPL EnergyPlus	Yes	The SDT conference call was helpful to my understanding of non-consequential. As I understand it, non-consequential load loss allows transmission planners to drop load that chooses to be dropped under certain conditions. This is a useful tool as not all loads demand the same quality of service.
Response: Yes, interruption of Interruptible Load is acceptable.		
City Water, Light & Power - Springfield, Illinois	Yes	
Platte River Power Authority	Yes and No	
Tenaska, Inc.	Yes	
Gainesville Regional Utilities	Yes	
US Army Corp of Engineers, Northwestern Division	Yes	
ITC Holdings: ITC, METC, ITC Midwest	Yes	
Florida Power and Light	Yes	None.
Austin Energy	Yes	
LCRA TSC	Yes	

Organization	Question 3:	Question 3 Comments:
NERC and Regional Coordination	Yes	
IESO	Yes	
E.ON U.S. Transmission Planning	Yes	
Duke Energy	Yes	
Oncor Electric Delivery	Yes	NA
Response: Thank you for your response. However, the majority of commenters requested changes to the definitions which can be seen in the summary response above.		

4. **The SDT has modified Requirement R3.5 and eliminated Requirement R3.6 from the first draft to clarify that manual and automatic generation run-back (redispatch) and tripping is allowed as a Corrective Action Plan as long as the conditions in Requirements R3.5.1, R3.5.2 and R3.5.3 are met. Do you agree that generation run-back and tripping (manual and automatic) should be limited by these conditions? If not, please explain why you disagree with the proposed requirements.**

Summary Consideration:

By a nearly unanimous response the industry agrees with the modification to Requirement R3.5 in the latest draft that allows manual and automatic generation run-back and tripping as a response to a single or multiple Contingency. However, in response to the question, only a small percentage of the commenters supported the current modification including the conditions in Requirements R3.5.1, R3.5.2, and R3.5.3 without reservation. A wide variety of changes, additions and clarifications to these conditions were suggested.

The SDT agrees with the industry's majority view that the Sub-requirement conditions for manual and automatic generation run-back or tripping as a response to a single or multiple Contingency and the Sub-requirement conditions for automatic generation tripping as a response to mitigate Stability violations are applicable to all requirements of the TPL Standard and are already stated elsewhere in the Standard or should be eliminated because they are specified in other ways, including national codes such as OSHA and NESC. Consequently, these conditions, specified in Requirements R3.5.1, R3.5.2, and R3.5.3 have been removed from this third draft.

In summary, due to industry comments in response to this question, the SDT changed the following requirements and footnote:

R2.7.1. (now R2.6.1)– added bullet #3: Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.

R2.7.1. (now R2.6.1)– added bullet #4: Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations.

R2.9 The Planning Assessment shall identify the maximum permissible Non-Consequential Load Loss (megawatt Demand) for those Planning Events where Non-Consequential Load Loss is allowed in Table 1.

R3.2 (now R3.3 and R3.3.1) Contingency analyses shall simulate the removal of all elements ~~including those~~ that the Protection System ~~protection is~~ and other automatic controls are expected to disconnect for each contingency without operator intervention.

R3.2.1 (now R3.3.2) For all generators, studies shall consider the minimum steady state voltage limitations ~~of all generators~~ and identify how the generators are ~~treated~~ analyzed in the steady state simulation.

Footnote #10 – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load.

Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.

In addition, the following requirements have been deleted:

R3.5 ~~Manual and automatic generation run-back/tripping is allowed as a response to a single or multiple Contingency if the following conditions are met~~

R3.5.1 ~~All Facilities shall be operating within their Facility Ratings~~

R3.5.2 ~~Such action would not violate safety, equipment, regulatory or statutory requirements~~

R3.5.3 ~~A sustainable, stable, operating condition is maintained~~

R5.4.3 ~~Automatic generation tripping is allowed to mitigate Stability violations if the following conditions are met:~~

R5.4.3.1 ~~All Facilities shall be operating within their Facility Ratings~~

R5.4.3.2 ~~Such action would not violate safety, equipment, regulatory or statutory requirements~~

R5.4.3.3 ~~A sustainable, stable, operating condition is maintained~~

Organization	Question 4:	Question 4 Comments:
Dominion - Electric Transmission Planning	No	We generally agree with the modification, but feel that further clarification needs to be added as follows -- "Neither generation run-back (redispatch) nor tripping should be allowed to address deficiencies identified in single contingency (N-1) studies should the full output of the generation choose to be considered as a capacity resource". Should generation run-back be allowed, then a NERC Reliability Standard should be developed to require generator field testing to prove that generation run-back is a viable solution.
Duke Energy	Yes	Generation run-back and tripping should be allowed and the proposed sub-requirements are appropriate.
Progress Energy Carolinas	Yes	Furthermore, PEC believes that generation run-back and tripping should not be allowed as a CAP for N-1 events with the possible exception of small reductions of generation.

Organization	Question 4:	Question 4 Comments:
BCTC	Yes	We agree that runback/tripping should be permitted for all contingencies. However, we are concerned that listing runback/tripping as an acceptable alternative, at least as currently worded, may encourage use when system reinforcements should be built. BCTC would prefer TPL-001 to be silent on this issue and that R3.5 be deleted. The list of conditions is very generic and should apply to all of TPL-001. If R3.5 is retained, the list of conditions should also require that all generation reserves requirements are met.
ITC Holdings: ITC, METC, ITC Midwest	No	We do not believe that generation runback or tripping should be a CAP for a single contingency. This is particularly true if the generation scheme puts the system one contingency away from another potential condition requiring corrective action, such as load shedding. At a minimum R3.5.3 needs further definition as to what a ?sustainable, stable, operating conditions? is. For example, creating another N-1 scenario is not a sustainable condition. Allowing for SPS is not raising the bar.
AEP	No	Generator tripping should not be regarded the same as generator runback. With tripping, a resource is lost from the system and there is no assurance that it can be restored to service within a reasonable time. Runback allows the resource to stay connected and the original MW level is potentially restorable if the precipitating factors for runback can be resolved. The generator may be valuable for MVAR as well as MW. The existing TPL standards imply that generator tripping is not permissible in connection with Category B events in that Table 1 footnote b does not mention it, whereas it is mentioned in connection with Category C events in footnote c; we agree with this. Generation is a system resource and should be protected against the more common single contingency transmission events. We would like to see the present implied restriction on generator tripping following single contingencies to be maintained and clearly articulated in the new standard, with a provision for regional variance. In contrast to tripping, what the standard has now for manual or automatic runback in R3.5 is okay.
Response: By a nearly unanimous response the Industry favors manual and automatic generation run-back and tripping as a response to a single or multiple Contingency. Therefore, the SDT has modified Sub-requirement R3.5 for Contingency events and relocated it to become Sub-requirement R2.6.1- bullet #4. Likewise, the SDT has modified Sub-requirement R5.4.3 for Stability events and relocated it to become Sub-requirement R2.6.1- bullet #3. **R2.6.1. – bullet #3:** Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations. **R2.6.1. – bullet #4:** Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations.		
NPCC	No	We do not feel that R3.5.1, R3.5.2 and R3.5.3 are limiting enough. Add paragraph 3.5.4 "Manual and automatic generator tripping shall not have an Adverse Reliability Impact."
Northeast Utilities	No	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.

Organization	Question 4:	Question 4 Comments:
TVA System Planning	Yes	Suggest applicable voltage limits must also be maintained during runback and tripping.
National Grid	No	We do not feel that R3.5.1, R3.5.2 and R3.5.3 are limiting enough. We suggest adding a paragraph which be numbered 3.5.4 and would read "Manual and automatic generator tripping shall not have a significant adverse impact on the system."
Tenaska, Inc.	Yes	R.3.3.2.2 needs some re-wording to clarify that generator runback (re-dispatch) and tripping are allowed.
Gainesville Regional Utilities	No	R3.5.3 is somewhat ambiguous. We need clarification as to whether the system needs to prepare for the next contingency (a secure state) or whether it needs to be maintained in a stable operating condition which is sustainable but not secure.
Hydro-Québec TransEnergie (HQT)	No	We do not feel that R3.5.1, R3.5.2 and R3.5.3 are limiting enough. Add paragraph 3.5.4 "Manual and automatic generator tripping shall not have an Adverse Reliability Impact."
Central Maine Power Company	No	R3.5.1, R3.5.2 and R3.5.3 are not limiting enough. Add paragraph 3.5.4 "Automatic generator tripping shall not impose undue complexity and risk to the operation and reliability of the system."
NSTAR Electric	No	R3.5.1, R3.5.2 and R3.5.3 are not limiting enough. Add paragraph 3.5.4 "Automatic generator tripping schemes shall not be overly complex and risk to the operation and reliability of the system." Complex SPSs or multiple installations of SPSs can have an adverse impact on the ability to reliably operate the system, especially during maintenance outage conditions.
New York Independent System Operator	No	We do not feel that R3.5.1, R3.5.2 and R3.5.3 are limiting enough. Add paragraph 3.5.4 "Manual and automatic generator tripping shall not have an Adverse Reliability Impact."
ISO New England Inc.	No	We do not feel that R3.5.1, R3.5.2 and R3.5.3 are limiting enough. Add paragraph 3.5.4 "Manual and automatic generator tripping shall not have a significant adverse impact on the system."
Response: The SDT appreciates your suggested improvements. However, the SDT has eliminated these conditions in Sub-requirements R3.5.1, R3.5.2 and R3.5.3 for Contingency events as well as similar conditions in Sub-requirements R5.4.3.1, R5.4.3.2 and R5.4.3.3 for Stability events in the third draft. Accordingly, the SDT has modified Sub-requirement R3.5 for Contingency events and relocated it to become Sub-requirement R2.6.1- bullet #4. Likewise, the SDT has		

Organization	Question 4:	Question 4 Comments:
modified Sub-requirement R5.4.3 for Stability events and relocated it to become Sub-requirement R2.6.1 – bullet #3. **R2.6.1. – bullet# 3:** Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations. **R2.6.1. – bullet #4:** Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations.		
City Water, Light & Power - Springfield, Illinois	Yes and No	There should be a time limit for manual generation runback.
Response: As stated in Footnote 10 of Table 1, planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
Manitoba Hydro	Yes	Manitoba Hydro commends the SDT for recognizing that generator run-back and tripping is a valid option in the transmission planner's tool box, not unlike more expensive devices such as FACTs devices. Can the SDT confirm that the conditions in R3.5.1, R3.5.2 and R3.5.3 apply to post generator tripping period. R3.5.2: The references to safety violations and equipment requirements are very generic. It is difficult to imagine what type of safety violation may be caused by a generator trip considering this is a widely used practice in many regions. The SDT should also be more specific as to what is meant by "equipment requirements". The requirement to be within Facility (equipment) Ratings is already covered in R3.5.1. Manitoba Hydro recommends the to "safety, equipment" be deleted from R3.5.2. Other Requirement R3 Comments:R3: In the first sentence, "perform analysis? should be changed to "perform studies? and the word ?studies? after Horizon should be deleted. R3.2: Delete the words ?including those?. R3.2.1: Can the SDT clarify what is required? Is the requirement to ensure the generator undervoltage ride through is not violated? If so, Manitoba Hydro recommends overvoltage ride-through (maximum voltage) should also be added. Also, is ?For all Generators? and ?of all generators? both needed?

Organization	Question 4:	Question 4 Comments:
		R3.3.1: Appears to be a repeat of R3.1.R3.3.2: R3.3.1 requires performance criteria to be met for Planning Events, which includes both single and multiple contingency events. Doesn't R3.3.2 repeat R3.3.1? R3.3.2.1:The requirement to report duration of the Consequential Load Loss would be a wild guess as the duration will relate to the nature of the event, so Manitoba Hydro questions the value. For example, the event is a simple lightning hit on a line, the restoration time is expected to be short, but if the cause of the line loss is a tornado that takes down structures, it could be days. Can the SDT clarify the requirement. R3.3.2.2: Are ?Transmission reconfiguration changes and redispatch of generators? only allowed for single contingencies? Is redispatch allowed if such redispatch results in curtailment of Firm Transmission Service? R3.3.2: It appears that R3.3.2 can be deleted, and its subrequirements placed under R3.3.3: The contingencies that ?are expected to produce more severe System impacts? are very likely multiple contingencies. Since there are numerous combinations of multiple contingencies, it is an impossible task to explain why the ?remaining Contingencies were not selected. If this is not the intent, can the SDT explain what is required? The requirement should simply allow the planner the discretion to use judgment to select these more severe Contingencies, and the elements they are applied to, with explanation as to why they are expected to be more severe.

Response: The SDT has eliminated these conditions in Sub-Requirements R3.5.1, R3.5.2 and R3.5.3 for Contingency events as well as similar conditions in Sub-Requirements R5.4.3.1, R5.4.3.2 and R5.4.3.3 for Stability events in the third draft. Accordingly, the SDT has modified Sub-Requirement R3.5 for Contingency events and relocated to become Sub-Requirement R2.6.1. Likewise, the SDT has modified Sub-Requirement R5.4.3 for Stability events and relocated to become Sub-Requirement R2.6.1.

R3.5.2 – The SDT has modified Sub-requirement R3.5 for Contingency events and relocated it to become Sub-requirement R2.6.1 – bullet #4. Likewise, the SDT has modified Sub-requirement R5.4.3 for Stability events and relocated it to become Sub-requirement R2.6.1 – bullet #3.

R2.6.1. – bullet #3: Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.

R2.6.1. – bullet #4: Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations.

The SDT appreciates your suggested changes to Requirement R3 but after reviewing the suggestion has decided that the original wording is correct.

Your suggested change to Requirement R3.2 (now Requirement R3.3.1) has been adopted.

R3.3.1 Contingency analyses shall simulate the removal of all elements ~~including those~~ that the Protection System ~~protection is~~ and other automatic controls are expected to disconnect for each contingency without operator intervention.

Requirement R3.2.1 (now Requirement R3.3.2) is intended to require realistic representation in simulations of whether a generator will trip due to low voltage; it is not a requirement that the generator be able to ride through a low voltage condition. Your suggested deletion was accepted.

Organization	Question 4:	Question 4 Comments:
R3.3.2 For all generators, studies shall consider the minimum steady state voltage limitations ~~of all generators~~ and identify how the generators are ~~treated~~ analyzed in the steady state simulation. Regarding your comments on old Requirements R3.3.1 and R3.3.2, there is a subtle difference. Requirement R3.3.1 addresses performance criteria, while Requirement R3.3.2 deals with the Contingencies that need to be evaluated and to which the performance criteria should be applied. The requirement to report duration of Consequential Load Loss in R3.3.2.1 (now Requirement R2.9) has been removed from this draft. **R2.9** The Planning Assessment shall identify the maximum permissible Non-Consequential Load Loss (megawatt Demand) for those Planning Events where Non-Consequential Load Loss is allowed in Table 1. Curtailment of Firm Transmission Service is explained in the new footnote #10 in the Table. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. The SDT has considered your comments regarding the requirement to explain why less severe Contingencies were not selected; however, there were few other comments that raised this concern, and the SDT has retained the original language.		
Los Angeles Department of Water and Power	Yes and No	R3.5.1, 3.5.2, and 3.5.3 are redundant and already covered in other standards or safety codes such as FAC, TOP, OSHA, NRC, NESC, etc. If these kind of "reminder" is required here just to make sure planners do not ignore all the relevant codes, then it could also be argued that an absence of such reminders in other section would mean that these codes do not need to be observed unless they are specifically called out. I think they should all be deleted to avoid such twisted argument but potential loopholes.
Transmission Agency of Northern California	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Pacific Gas and Electric Co.	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability

Organization	Question 4:	Question 4 Comments:
		study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Public Service Company of New Mexico	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
JEA	Yes and No	R3.5.1 JEA does not understand what measure will be applied to determine that Facility Ratings were not violated during the generator run-back period.R3.5.2 JEA does not understand what measure will be applied to determine compliance that generator trips and runbacks will not violate safety, equipment, regulatory, or statutory requirements.R3.5.3 JEA does not understand what is meant by the word "Sustainable". Needs a practical definition.
PacifiCorp	Yes and No	? We generally agree, however, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest moving R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Puget Sound Energy, Inc.	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Idaho Power Company	Yes	We generally agree, however, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.

Organization	Question 4:	Question 4 Comments:
SMUD	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables. Reference 3.5.1: In cases where an SPS is deployed to reduce thermal overloads such that flows are brought within established facility ratings, but, for a short duration (seconds) until it is fully executed, the facility flows exceed the established rating, is that considered a violation or an acceptable engineering judgment that facilities are judiciously being brought to operate within ratings? Or, should the facility owner ensure establishment of a documented rating even for the short duration of seconds?
Progress Energy Florida, Inc.	No	PEF does not disagree with the conditions described in Requirements R3.5.1, R3.5.2 and R3.5.3 when taken in particular contexts. PEF, however, is compelled to check "no" for this question due to the fact that no specification has been made as to when such CAPs can be applied. PEF feels that the CAPs specified (as well as the curtailment of Firm Transactions and Non-Consequential Load) should be allowed following any N-1 event, and also as system adjustment actions in between the two events of a P6 event. Given that no such specification has been made here, PEF objects to the wording, and suggests that the language be modified to clarify that the application of these CAPs are allowable after N-1 events and in between the two events of Event P6.
Sierra Pacific Power Company / Nevada Power Company	Yes	We generally agree, however, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Black Hills Corporation	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Arizona Public Service Co.	Yes and No	We generally agree, however, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other

Organization	Question 4:	Question 4 Comments:
		Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest moving R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Florida Power and Light	No	The sub-requirements of R3.5 are not clear as to whether the conditions apply to before or after generator run-back/tripping and mixes together N-1 and N-2 contingencies. In addition, the phrase "sustainable, stable, operating condition" in R3.5.3. is ambiguous as to whether it means the system is secure (prepared for the next contingency), or the system is maintained in a stable operating condition which is sustainable but not secure.
Exelon Transmission Planning	Yes and No	We agree that manual and automatic generation run-back and tripping should be allowed in these situations. We do not agree with the portion of R3.5.2 that states that non-compliance would result if the action were to violate statutory or regulatory requirements. A local governmental body could impose a restriction that would then trigger NERC compliance issues without independent or sufficient review. Other regulatory entities have their own enforcement mechanisms. It should be clear that SPSs, by definition, are allowed for other purposes than generation runback or tripping (such as system reconfiguration with automated breaker operation).
SRP	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Tucson Electric Power Company	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
SERC Dynamics Review Subcommittee	Yes	Generation run-back and tripping should be allowed and the proposed sub-requirements are appropriate.

Organization	Question 4:	Question 4 Comments:
Modesto Irrigation District	Yes	Comments: We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Midwest ISO	Yes and No	Under the subrequirement of R3.5.2 it may not be possible for the PC/TP to determine whether the safety, equipment, regulatory or statutory requirements are violated without collaboration with the Transmission Owner and/or the Generator Owner. Therefore, if this subrequirement is retained it should be amended to include the following sentence: "Applicable Transmission Owners and/or Generator Owners shall collaborate with the PC/TP in determining whether such action would violate safety, equipment, regulatory or statutory requirements".
Tri-State Generation and Transmission Association, Inc.	Yes	Agree with the described corrective actions, but wonder whether the sub-requirements R3.5.1 - R3.5.3 must be specifically listed.
Tri-State G&T	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Southern Company Transmission	No	Generation run-back and tripping should be allowed and most of the proposed sub-requirements are appropriate. However, R3.5.2 is overly broad. We suggest that regulatory and statutory requirements should be deleted from R3.5.2.
NERC and Regional Coordination	No	Delete R3.5.2 as redundant. The limit data provided by the asset owners is expected to ensure that safety, equipment, regulatory and statutory requirements are met. For example to require the PC to ensure that equipment is not at risk would require the PC to make financial decisions that belong to the asset owner (e.g. the owner may be willing to exchange loss of equipment life for short term financial gains).R3.5.3 - the term sustainable, stable condition is not defined. Further the

Organization	Question 4:	Question 4 Comments:
		maintenance of such a state is beyond a PC's capability.
ColumbiaGrid	Yes	We generally agree, however, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
IESO	Yes and No	We agree with the conditions stipulated in R3.5.2 and R3.5.3 but do not agree with R3.5.1. This is one of the performance objectives that the use of manual and/or automatic generation run-back/tripping is intended to achieve, and it is already stipulated in Table 1. Suggest to remove this condition.
Southern California Edison	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
North Carolina Electric Membership Corp	Yes and No	The generation run-back/trip should not put any load or firm transfer at risk of also being harmed. Maybe this is implied within the conditions required.
ERCOT System Planning	No	The requirement is unclear whether runback is allowed if the conditions are met or if runback is allowed to meet the conditions. What is the need for generation run-back/tripping if all facilities are within their Facility Ratings? Many times the run-back/tripping of units, such as wind farms, is necessary to remove a post-contingency overload associated with these units. The protection scheme includes the run-back/tripping to allow these units to generate at higher levels pre-contingency.
Florida Reliability Coordinating Council, inc	No	R3.5.1 ? This requirement should be clarified to state that all facilities shall operate within their Facility Ratings before, during and after system adjustments including generation adjustments.R3.5.2 ? How can an entity demonstrate that it is not violating this requirement.. The SDT should indicate the type of regulatory and/or statutory requirement that this requirement trying to address (i.e., FERC, EPA, etc.)?. Otherwise, the FRCC recommends removing R3.5.2.R3.5.3 ?The SDT should clarify this requirement to define what is meant by sustainable and stable. Sustainable and stable may not necessarily be the same as

Organization	Question 4:	Question 4 Comments:
		being in a secure condition (ready for the next possible event).
Alberta Electric System Operator	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest R3.5 and R3.4.3 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Orlando Utilities Commission	No	The requirement R3.5.1 is not clear. If the intent is that following a single or multiple contingency facilities are within their ratings before, during and after the generation adjustment it's should be specified that way. "All facilities shall operate within their facility ratings prior to, during, and after the generation adjustment". Also I am unclear on how I would prove that I am not violating and safety or statutory requirements, that seems to be attempting to prove a negative since it is not specific on which requirements. Maybe ?Not violating any known safety and statutory requirements? if it is necessary to have this part. However since any real statutory and safety requirements have their own enforcement mechanism it is unnecessary to have the NERC auditor monitor these in addition to the existing monitors. I am not sure on the definition of sustainable? Is it a system that requires no further adjustment to be within it's long term ratings? Or is it a system that is prepared for the next event (Secure)?
Entergy Services, Inc.	Yes and No	The intent seems reasonable, but the wording needs work. There needs to be consistent verb usage. All 3 sub-bullets need to use "shall" instead of "would" and "is."
US Bureau of Reclamation	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
BPA Transmission Reliability Program	No	R3.5 is not a requirement, but an allowed action in order to meet performance criteria. Therefore, the statement about generation run-back/tripping in R3.5 should be moved to become part of the notes in the Performance Tables and not part of the requirements text. The conditions described under R.3.5.1 through R.3.5.3 are covered elsewhere in the standards and should be removed from this section. Since R3.5 and R5.4 contain some similar wording, also see comments relating to R5.4 under Item 2, above.
Response: The SDT agrees and has eliminated these conditions in Sub-requirements R3.5.1, R3.5.2 and R3.5.3 for Contingency events as well as similar conditions in Sub-requirements R5.4.3.1, R5.4.3.2 and R5.4.3.3 for Stability events in the third draft. Accordingly, the SDT has modified Sub-requirement R3.5 for		

Organization	Question 4:	Question 4 Comments:
Contingency events and relocated it to become Sub-requirement R2.6.1 – bullet #4. Likewise, the SDT has modified Sub-requirement R5.4.3 for Stability events and relocated it to become Sub-requirement R2.6.1 – bullet #3. **R2.6.1. – bullet #3:** Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations. **R2.6.1. – bullet #4:** Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations.		
Lafayette Utilities System	No	Requirement R.3.5 states that generation run-back is allowed as a response to single or multiple contingencies, as long as certain conditions are met. Lafayette's concern is that the allowance for generation run-back is not limited to generation owned by the Transmission Planner or under the Transmission Planner's direct operational control. For that reason, the language could be interpreted to permit reliance (for planning purposes) on redispatch of generation owned by third-party generation owners that is undertaken in compliance with Reliability Coordinator directives during a Transmission Loading Relief event. During the SDT conference call held on August 26, 2008, the SDT representative stated that the team did not intend that R.3.5 would permit a Transmission Planner to rely on third-party generation redispatch, and that the intent was only to permit reliance on run-back (redispatch) of generation owned by or under the direct control of the Transmission Planner. Lafayette believes the language of R.3.5 needs to be clarified to state in express terms the limitation intended by the SDT. Reliance on third-party redispatch should not be permitted unless a Transmission Planner has entered into a contractual arrangement with the generation owner authorizing such use.
Response: The SDT agrees that if a Transmission Planner does intend to rely upon third party generation as an option to meet this requirement then the Transmission Planner's contractual arrangements between that Generation Owner and the Transmission Operator must be in place. However, the SDT does not believe that this needs to be stated as a Requirement in this Standard.		
Ameren	Yes	R3.5.1 should be modified as "All Facilities shall be operating within their applicable Facility Ratings, including the use of short-time emergency ratings."
E.ON U.S. Transmission Planning	Yes and No	R3.5.1 Is this the intent? ? Following Single Contingency events, Transmission configuration changes and redispatch of generation can be simulated to return the system to Normal Rating provided that all Facilities shall be operating within their Emergency Rating.
Response: As stated in Footnote 10 of Table 1, planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within		

Organization	Question 4:	Question 4 Comments:
applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
American Transmission Company	No	We generally accept this text, but would like the Facility Rating reference to include the applicable time frame (see response to Question 2.)
Response: As stated in Footnote 1 of Table 1, planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings.		
PPL EnergyPlus	Yes and No	My concern is that some TSPs over-use RAS and at some point, system improvements must take place. The best approach is a collaborative effort of all stakeholders (esp. operations folks) to prevent abusing RAS. Possibly R3.5 could tie to or be put under an Requirement that involves collaboration with stakeholders.
Response: The SDT has modified Sub-requirement R3.5 for Contingency events and relocated it to become Sub-requirement R2.6.1 – bullet #4. Likewise, the SDT has modified Sub-requirement R5.4.3 for Stability events and relocated it to become Sub-requirement R2.6.1 – bullet #3. Collaboration between the Transmission Planner and the Planning Coordinator is referenced in Requirements R5, R6, and R7. **R2.6.1. – bullet #3:** Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations. **R2.6.1. – bullet #4:** Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations.		
OPUC	Yes	
US Army Corp of Engineers, Northwestern Division	Yes	
CenterPoint Energy and CPS Energy	Yes	

Organization	Question 4:	Question 4 Comments:
MidAmerican Energy Company	Yes	
MRO NERC Standards Review Subcommittee	Yes	
Austin Energy	Yes	
Lakeland Electric	Yes	
Brazos Electric Power Cooperative, Inc.	Yes	
LCRA TSC	Yes	
Oncor Electric Delivery	Yes	NA
FirstEnergy Corp.	Yes	
Platte River Power Authority	Yes	
Response: Thank you for your response.		

5. **The SDT has modified the modeling requirements. Some commenters expressed concern that the modeling requirements contained in Requirement R1 of the first draft of TPL-001-1 were either duplicative of the requirements in the MOD standards, or to the extent new modeling requirements were proposed, that the appropriate venue for such modeling requirements would be the MOD standards. The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has incorporated these additional requirements with the intent that they will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.**

   The SDT has also modified proposed modeling requirements contained in Requirement R1 of the first draft of TPL-001-1 based on industry comments and moved these requirements to Requirements R9 through R14 in the second draft for ease of removal later on. Furthermore, in response to industry comments, the SDT has separated the modeling requirements into individual requirements for each responsible entity. Do you concur with the modifications reflected in Requirements R9 – R14? If not, please state why and/or suggest specific changes..

Summary Consideration:

In response to industry comments, the SDT has removed requirements R9-R14 and enhanced requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments. Any comments received from the industry on MOD standards will be forwarded to NERC staff for inclusion in NERC Reliability Standards Development Projects 2010-04 Modeling Data and 2010-05 Demand Data.

The following requirements have been changed due to industry comments:

R1. Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R1.1 ~~The Planning Assessment shall include documentation of the technical rationale for modification of any data that was provided in Requirement R9 through R14, MOD-010, and MOD-012.~~Models for the Planning Assessment shall represent:

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R1.1.2 New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon, such as:

- Transmission Lines
- Generators
- Circuit breakers
- Reactive Power devices

- Protection System equipment
- Control devices
- New technologies

R1.1.3 Real and reactive Demand of Load

R1.1.4 Firm Transmission Service

R1.1.5 Interchange

R1.1.6 Network resources required to supply Load

R2.1.4 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment.

Organization	Question 5:	Question 5 Comments:
Dominion - Electric Transmission Planning	Yes and No	For requirements R9, R12, R13, the wording should be changed from ..."shall provide its respective Planning Coordinator with modeling information ..." to "shall provide its respective Planning Coordinator and Transmission Planner with modeling information ..."
NPCC	No	With respect to R9 "including the expected mix of industrial, commercial and residential loads", this provision may be inadequate to be practically useful. The potential issues include the variation in end-use load mix through the daily load cycle, seasonal load composition variations, and the ability to translate these end-uses into reasonable and useful steady-state and dynamic load models. It is important to understand how the information will be used and how much additional detail, such as distribution network detail, is also required. It is also important to note that some Canadian Provinces do not "classify" their load mix using "industrial, commercial and residential" designations but their load modeling is sufficient, accurate and granular enough to simulate system response. Add to the last sentence of R9 through R14 the following phrase, "within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator."
TVA System Planning	No	TVA provides the following comments: " Distribution Provider" in R9 should be replaced with "Load Serving Entity." Also in R9, is the expected mix of load to be presented individually or as a total of commercial, residential, and industrial loads? Would requiring this mix of load forecasts also result in a change to any MOD or FAC requirements dealing with

Organization	Question 5:	Question 5 Comments:
		load forecasts?” Transmission Planner" in R10 should be "Transmission Service Provider." Is this requirement also in MODs? In R11, R12, and R13 suggest adding "Transmission Planner" to "Planning Coordinator". In R13, Resource Planner may not have knowledge of Reactive Power devices and new technologies.
Manitoba Hydro	Yes and No	R1: Requirement R1 places the obligation for maintaining a model on the PC/TP. While the PC/TP can maintain data for its system(s), the models generally used for planning assessments are regional models developed and maintained by the Regions. Could the SDT explain its expectation of the scope and responsibilities of the model to be maintained? R9-R14: This TPL draft includes Requirements R9 to R14 that impose obligations on the PC/TP that differ from the way planning models are compiled in accordance with the existing MOD standards. Manitoba Hydro comments on R9 to R14, as follows: R9: Agree. R10: The TSP is the Functional Model entity that should provide the Firm Transmission Service data and Interchange Schedules to the PC. R11: Agree R12: Agree R13: We disagree that the Resource planner is responsible for Reactive Power devices. Can the SDT explain what they consider should be included in new technologies? R14: While we agree that the TP can provide the PC data of planned faculties, isn't this data already required to be provided under the MOD standards?
Transmission Agency of Northern California	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
OPUC	Yes	R9. — 14 can be addressed in the MOD standards.
Pacific Gas and Electric Co.	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective

Organization	Question 5:	Question 5 Comments:
		tariffs, and should not be included again in the proposed TPL-001-1 Standard.
US Army Corsp of Engineers, Northwestern Division	Yes and No	R12 requires the GO to provide "modeling information" for planned outages and/or changes to the generator owner facilities to the Planning Coordinator for each year of the Transmission planning horizon. You need to be more specific with what type of "modeling information" you are requesting from the GO. The GO may have the model parameters for their equipment but this doesn't mean that they have expertise necessary to model system responses or even run a model simulation. So if you are expecting the GO to perform model simulations for each year of the Transmission planning horizon the GO may not have the expertise necessary to comply. Recommend you clarify what you mean by "modeling information".
Public Service Company of New Mexico	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
Puget Sound Energy, Inc.	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
ITC Holdings: ITC, METC, ITC Midwest	Yes and No	In general, we approve and concur with these requirements. The requirement R9 that the distribution providers submit the expected mix of residential, commercial, and industrial loads is necessary to model the dynamic behavior of loads as required in R 2.4.1. This requirement will better model the dynamic response of loads to voltage changes. In R10, the Transmission Planner provides OASIS type information. The TSP should provide this not the TP. R-13 ? Reactive Power Devices and new technologies belongs under every entity, i.e., Distribution Planners should be included as a provider of reactive power devices as well as Resource Planner and Transmission Planner.
Idaho Power Company	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
Hydro-Québec TransEnergie (HQT)	No	With respect to R9 "including the expected mix of industrial, commercial and residential loads", this provision may be inadequate to be practically useful. The potential issues include the variation in end-use load mix through the daily load

Organization	Question 5:	Question 5 Comments:
		cycle, seasonal load composition variations, and the ability to translate these end-uses into reasonable and useful steady-state and dynamic load models. It is important to understand how the information will be used and how much additional detail such as distribution network detail is also required. It is also important to note that some Canadian Provinces do not "classify" their load mix using "industrial commercial and residential" designations but their load modeling is sufficient, accurate and granular enough to simulate system response. Add to the last sentence of R9 through R14 the following phrase, "within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator."
Sierra Pacific Power Company / Nevada Power Company	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
Black Hills Corporation	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
Florida Power and Light	No	The requirement that “all projected firm transfers modeled” (appropriate for the load level being studied) currently in the TPL Standards does not appear in the proposed standard. Does the SDT feel that Transmission Planners should have unlimited latitude in deciding which types of power transfers to assume in their reliability studies? R9. is not an appropriate requirement as the distribution provider will in many cases not know the exact mix of load types at each ?transmission node? The meaning of “transmission node” is unclear, is this substation? R11. is unclear as to what is meant by “consideration given to spare equipment strategy.” What is the appropriate consideration for compliance? What facilities are required to have a spare equipment strategy for compliance? Maintenance outages and times for all BES equipment are not likely to be scheduled or known throughout the entire planning horizon. Rather than specifying "for each year of the planning horizon" it should be limited to "if specifically known”. The Resource Planners identified in R13. should know about future generation additions and retirements as well as expected range DSM capabilities but would not generally know about reactive power devices or new technologies. Reactive power devices or new technologies should be removed from R13.
CenterPoint Energy	No	We believe the SDT should have reflected the views of most commenters in this revised draft. Requirements R9 through R14 are overly prescriptive and do not solve an actual problem. Furthermore, we are concerned about requirement

Organization	Question 5:	Question 5 Comments:
and CPS Energy		"creep" where standards include new requirements appropriately addressed in other standards (in this case, the MOD standards) because a different SDT believes the approved standard is inadequate. To clarify our main premise that the excess, misplaced requirements do not solve an actual problem, we believe one would need an extensive imagination to conjure a scenario where insufficient modeling by transmission planners in the subject matter addressed by requirements R9 through R14 have contributed or are reasonably likely to contribute in any meaningful way to a significant reliability event. In summary, we concur with the majority of commenters from the previous draft that R9 through R14 should be deleted. We also believe R1.1 is hopelessly unrealistic. In fact, we are concerned it is counter-productive and more likely to degrade reliability than improve it. R1.1 discourages transmission planners from revising inaccurate, speculative, or outdated modeling data by imposing new documentation burdens and compliance liability. We recommend that R1.1 be deleted.
SRP	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
Tucson Electric Power Company	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in addition to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
SERC Dynamics Review Subcommittee	No	For R9 the LSE should provide the load forecast instead of the DP. For R9 - R14, It is not clear that the specification of data flow appropriate for both RTO and non-RTO situations because there are significant differences in the role of planning coordinator. For example: 1) Who builds and manages the base cases? Shouldn't the data be submitted to this entity? 2) According to the definition provided in this standard, the Planning Coordinator is ?The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.? Additionally, we recommend the TPL SDT write a SAR to get the data related changes into the MOD standards or adding it the issues to be considered by the drafting team in the development plan under project number 2010-04 otherwise it will be difficult to remember to include these items in the revised MOD standards.
Modesto Irrigation District	Yes	Comments: While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the

Organization	Question 5:	Question 5 Comments:
		respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
Arkansas Electric Coop. Corp.	No	R9. I disagree with providing the mix of industrial, commercial and residential, especially within a 90 day period. It is difficult enough to be able to develop a forecast must less try to quesstimate the mix of the loads.R9 through R14 -- the timing requirement should be tied to the regions model development schedule and not 90 days. The 90 days is too restrictive and not practical however model data should be updated at least annually.
Midwest ISO	No	Since the Transmission Planner has the primary model building responsibility it makes sense to have them aggregate model building information. Therefore, requirement R9 should have the Distribution Provider providing the Transmission Planner and Planning Coordinator with modeling information for real and reactive load forecast? etc. The data of R10 such as firm TS data may not be known by the Transmission Planner (ofter a TO in the RTOs). Also the language implies that there are more than one BA under a TP, also not a typical arrangement in an RTO/ISO. A hierarchical approach might be more appropriate such that the Distribution Provider, the Transmission Provider, and the Transmission Owner supply the data they control to the Transmission Planner and the Planning Authority so that those entities can build models they need to meet the study requirements of the standard.
Tri-State Generation and Transmission Association, Inc.	Yes	We are pleased the SDT pulled out these Requirements. Does the SDT plan to leave them in the standard as notes until they can be incorporated into other standards where they belong? In R11, the term "long-term" is not clear.
Tri-State G&T	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
AEP	Yes	However, although the responsible entities listed for each individual requirement are correct from a functional model (compliance) perspective, in actual practice the data flow may not (and in many instances does not) follow the paths outlined in this draft. For example, the node loads, scheduled interchanges, generation models, facility additions, etc., are all provided to the Transmission Owner (TO), since it's the TO that typically builds the planning models for their transmission footprint and then provides those models to the Transmission Planner and Planning Coordinator. Therefore, the Transmission Owner should be added as a recipient of this type of data.
Austin Energy	No	Requirements R9 through R14 should be deleted and re-introduced later as part of a change to MOD standards. R1.1 imposes burdensome documentation requirements which will likely become a disincentive for revising modeling data and

Organization	Question 5:	Question 5 Comments:
		should be deleted.
Lakeland Electric	No	It is sufficient to direct the TP or PC to obtain and include the appropriate data outlined in R9 through R14 in their respective model cases. The proposed addition of R9-R14 just adds more evidential paperwork requirements to the TP or PCs plate.
Southern Company Transmission	No	R9 needs to be clarified that the forecast is based on expected mix of residential, commercial, and industrial loads, but that this mix does not have to be supplied.
Brazos Electric Power Cooperative, Inc.	Yes	R9-R14 do not belong in this Standard. Adding requirements in the wrong location only adds to the confusion by forcing review of more Standards by other less relevant entities and causing additional burden by insuring the requirements match between Standards for the SDT. R1.1 should be deleted. Tracking all those changes (outages, etc?) is unreasonable and will essentially be unenforceable, for if the data is not tracked, how will anyone know it is not tracked?. Requiring large amounts of documentation that provide no additional benefit or causes undo burden will result in fewer studies or effort placed into proper study.
ColumbiaGrid	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
Southern California Edison	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
Northeast Utilities	No	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
North Carolina Electric Membership Corp	Yes	We would like to add a couple of items for clarification. 1) Planning Coordinators and Transmission Planners should make it clear to LSEs, DPs and GOs as to what extent they model loads, reactive devices, and generators and not just rely on FAC-001, FAC-002 or the entities Facility Connection Requirements document to convey that information. 2) If requirements 9 through 14 are to be removed at a later date, then the SDT should be required to initiate the

Organization	Question 5:	Question 5 Comments:
		appropriate action or SAR before its disbanding to insure this happens.
ERCOT System Planning	No	ERCOT recommends that R1.1 be deleted. ERCOT shares the opinion of some that R1.1 is counter-productive and more likely to degrade reliability than improve it. R1.1 discourages transmission planners from revising inaccurate, speculative, or outdated modeling data by imposing new documentation burdens and compliance liability. Adding additional requirements to document changes to data required in requirements R9 through R14, MOD-010, and MOD-012 could induce an atmosphere of using inaccurate data to eliminate the need to document a needed change. Furthermore, it is believed that all modeling requirements should exist in a Modeling standard not a performance standard.
Duke Energy	Yes	In order to ensure these requirements move to the MOD standards, the TPL SDT is encouraged to write a SAR to get the data related changes into the MOD standards or add it to the issues to be considered by the drafting team in the development plan under project number 2010-04.
Central Maine Power Company	No	a. With respect to R9 "including the expected mix of industrial, commercial and residential loads", this provision may be inadequate to be practically useful. The potential issues include the variation in end-use load mix through the daily load cycle, seasonal load composition variations, and the ability to translate these end-uses into reasonable and useful steady-state and dynamic load models. It is important to understand how the information will be used and how much additional detail such as distribution network detail is also required. b. Add to the last sentence of R9 through R14 the following phrase, "within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator."
New York Independent System Operator	No	With respect to R9 "including the expected mix of industrial, commercial and residential loads", this provision may be inadequate to be practically useful. The potential issues include the variation in end-use load mix through the daily load cycle, seasonal load composition variations, and the ability to translate these end-uses into reasonable and useful steady-state and dynamic load models. It is important to understand how the information will be used and how much additional detail such as distribution network detail is also required. Add to the last sentence of R9 through R14 the following phrase, "within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator."
Alberta Electric System Operator	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.

Organization	Question 5:	Question 5 Comments:
FirstEnergy Corp.	No	FE does not support the modeling requirements within the TPL standard and suggest that the SDT remove these requirements. This standard should be viewed on a premise that a valid and appropriate system model exist so that the fundamental focus of the standard is as stated in its purpose statement "Establish Transmission System planning performance requirements... to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions." If the R9 through R14 requirements remain, we offer the following comments: R9 - In requirement R9, the DP is to provide nodal load projections and include the expected mix of industrial, commercial, and residential Loads. System planning software can not presently accommodate this level of detail along with other load codes/classifications that may already be in use; i.e. municipal load, rural electric cooperative load, etc. Is the intent to require this information in models built and maintained by industry, i.e. MMWG? R10 - The TP does not have access to Interchange Schedules and resources required to supply Load for each of its Balancing Authority. This information may need to be provided by the Resource Planner or some other appropriate entity.
US Bureau of Reclamation	Yes	Comments: While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
BPA Transmission Reliability Program	No	Requirements for data gathering and load modeling belong in the MOD Standard and not in TPL-001-1. Requirements for dynamic load models should not be specified at this time, because the models have not been developed yet or approved by the RRO (also see comments regarding R2.4.1 under Item 2, above).

Response: In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments.

R1. Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R1.1 ~~The Planning Assessment shall include documentation of the technical rationale for modification of any data that was provided in Requirement R9 through R14, MOD-010, and MOD-012.~~Models for the Planning Assessment shall represent:

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R1.1.2 New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon, such as Transmission Lines

Organization	Question 5:	Question 5 Comments:
Generators Circuit breakers Reactive Power devices Protection System equipment Control devices New technologies **R1.1.3** Real and reactive Demand of Load **R1.1.4** Firm Transmission Service **R1.1.5** Interchange **R1.1.6** Network resources required to supply Load		
Los Angeles Department of Water and Power	Yes	See the comment from WECC
Response: The SDT did not receive any specific comments from WECC.		
National Grid	No	a. With respect to R9 "including the expected mix of industrial, commercial and residential loads", this provision may be inadequate to be practically useful. The potential issues include the variation in end-use load mix through the daily load cycle, seasonal load composition variations, and the ability to translate these end-uses into reasonable and useful steady-state and dynamic load models. It is important to understand how the information will be used and how much additional detail such as distribution network detail is also required. b. Add to the last sentence of R9 through R14 the following phrase, "within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator." c. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R10 to read as follows: R10. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator.

Organization	Question 5:	Question 5 Comments:
		d. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R11 to read as follows R11. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator. e. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R12 to read as follows: R12. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator. f. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R13 and R14 as follows:R13. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator.. [Violation Risk Factor: TBD] [Time Horizon: TBD] R14. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to Transmission Lines, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator. [Violation Risk Factor: TBD] [Time Horizon: TBD] g. Planned and long-term outages are two fundamentally different concepts and should be treated separately. Planned and Long-Term outages should be defined. Define how planning events in Tables 1 and 2 are associated with each type of outage (e.g. P4, P5, or P6). Should there be specific contingency descriptions associated with long-term outages? Define length of a "Long Term" outage. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizon.
MidAmerican Energy Company	No	MEC disagrees with the approach of temporary requirements because of the problems that arise due to conflicting or uncoordinated standards (e.g. conflicting requirements between FAC-010-1 and TPL-002-0). We suggest the drafting team submit SARs to make the desired changes in the appropriate MOD standards. However, if these requirements are retained than we suggest the following few changes to R9-R14: The R9 wording on providing "the expected mix of industrial, commercial, and residential loads" should be dropped as the representative mix is difficult to quantify and verify while the benefit to representing the mix is unproven versus normal regional dynamic load representation practices. Many regions already convert normal steady state powerflow loads to standard mixes of, constant MVA, constant current, and shunt admittances which accounts for dynamic behavior. If the SDT decides not to drop these words, the MRO recommends "the expected mix of industrial, commercial, and residential loads" be changed to "the forecasted mix of industrial, commercial,

Organization	Question 5:	Question 5 Comments:
		and residential loads”. In R9 through R13 the responsible entities should be giving their information to the Transmission Planner in addition to the Planning Coordinator. In R10, revise the text to: "Each Transmission Service Provider shall provide ?" In R11, is the text referring to "known planned outages" and "known long term outages"? What is the distinction that is meant to be made between the two specified types of outages? In R12, revise the text to: "? modeling information for planned facilities changes, known planned outages ?". Also, is the text referring to "known planned outages" and "known long term outages"? What is the distinction that is meant to be made between the two specified types of outages? In R13, revise the text to: "? for planned facilities changes for each year of the Transmission planning horizon including but not limited to generators, and new technologies ?". This wording broadens the meaning from simply "new" facilities to also include any "changes" to existing facilities. In R14, revise the text to: "? for planned facilities changes for each year ?". This wording broadens the meaning from simply "new" facilities to also include any "changes" to existing facilities.
MRO NERC Standards Review Subcommittee	No	The MRO disagrees with the approach of temporary requirements because of the problems that arise due to conflicting or uncoordinated standards (e.g. conflicting requirements between FAC-010-1 and TPL-002-0). We suggest the drafting team submit SARs to make the desired changes in the appropriate MOD standards. However, if these requirements are retained than we suggest the following few changes to R9-R14: In R9, revise the text to: "? load forecast data for at least the coincident peak of each year ?" The R9 wording on providing "the expected mix of industrial, commercial, and residential loads" should be dropped as the representative mix is difficult to quantify and verify while the benefit to representing the mix is unproven versus normal regional dynamic load representation practices. Many regions already convert normal steady state powerflow loads to standard mixes of, constant MVA, constant current, and shunt admittances which accounts for dynamic behavior. If the SDT decides not to drop these words, the MRO recommends "the expected mix of industrial, commercial, and residential loads" be changed to "the forecasted mix of industrial, commercial, and residential loads”. In R9 through R13 the responsible entities should be giving their information to the Transmission Planner in addition to the Planning Coordinator. In R9, revise the text to: "? load forecast data for at least the coincident peak of each year ?"In R10, revise the text to: "Each Transmission Service Provider shall provide ?" In R11, is the text referring to "known planned outages" and "known long term outages"? What is the distinction that is

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		meant to be made between the two specified types of outages? In R12, revise the text to: "? modeling information for planned facilities changes, known planned outages ?". Also, is the text referring to "known planned outages" and "known long term outages"? What is the distinction that is meant to be made between the two specified types of outages? In R13, revise the text to: "? for planned facilities changes for each year of the Transmission planning horizon including but not limited to generators, and new technologies ?". This wording broadens the meaning from simply "new" facilities to also include any "changes" to existing facilities. We suggested removing the reference to Reactive Power Devices because these devices would not be owned by Resource Planners. In R14, revise the text to: "? for planned facilities changes for each year ?". This wording broadens the meaning from simply "new" facilities to also include any "changes" to existing facilities.
LCRA TSC	No	R-11 states that "Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment." This is typically achieved through outage coordination between the individual Transmission Operators and the System Operator. More clarification may help by defining the difference between planned outages and long-term outages as they are used in R-11. This may be an Operations standard versus a Planning standard requirement.
NERC and Regional Coordination	No	R9 - Reactive load forecasts are not generally provided by distribution provider to the Transmission Planner.R11 - The requirements for providing “long term outages” to the Planning Coordinator is vague. What is a “long term outage” and do I need to plan for it? I think the right answer is only if it is expected to occur over the period that the TP establishes their critical system conditions. SDT should initiate the appropriate SAR prior to disbanding.
American Transmission Company	No	We disagree with the approach of temporary requirements because of the problems that arise due to conflicting or uncoordinated standards (e.g. conflicting requirements between FAC-010-1 and TPL-002-0). We support the approach of developing appropriate MOD standards SARs to make the desired changes. However, if these requirements are retained than we suggest the following few changes to R9-R14.In R9, revise the text to: "? load forecast data for at least the coincident peak of each year In R10, revise the text to: "Each Transmission Service Provider shall provide "In R11, is the text referring to "known planned outages" and "known long term outages" What is the distinction that is meant to be made between the two specified types of outages In R12, revise the text to: "? modeling information for planned facilities changes, known planned outages ?". Also, is the text referring to "known planned outages" and "known long term outages"? What is the distinction that is meant to be made between the two specified types of outages

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		In R13, revise the text to: "? for planned facilities changes for each year of the Transmission planning horizon including but not limited to generators, and new technologies ?". This wording broadens the meaning from simply "new" facilities to also include any "changes" to existing facilities. We suggested removing the reference to Reactive Power Devices because these devices would not be owned by Resource Planners. In R14, revise the text to: "for planned facilities changes for each year ?". This wording broadens the meaning from simply "new" facilities to also include any "changes" to existing facilities.
Florida Reliability Coordinating Council, inc	No	R9 through R14 ?R9 through R14 should not be addressed in this TPL Standard. Requirements R9 through R14 should be included in future revisions to the MOD standards. If R9 through R14 remain in the Standard, then the following comments are appropriate: R9 ? Recommend adding ?and season (as defined by the Planning Coordinator)? after ?? load forecast data for each year? .Recommend adding ?(as defined by the Planning Coordinator)? after ?Transmission nodes? to allow the Planning Coordinator to appropriately define the term Transmission node. Recommend deleting ?including the expected mix of industrial, commercial, and residential Loads,? from the requirement since this information is not required by Transmission Planners or the Planning Coordinator. Many distribution providers will not know the mix of load type for a given Transmission node. R11 ?Recommend the removal of ?with consideration given to spare equipment strategy,? from this requirement. We feel that the consideration of spare equipment strategy would be better suited in an operating horizon standard (TOPs) rather than in the TPL standard. The term ?long-term outage? in this requirement is vague and the text ?and long-term outages? should be eliminated. The FERC language in Order 693 P-1725 states ?Accordingly, the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy.? There is no mention of ?long-term outages? in conjunction with spare equipment strategy. R12 ? Recommend rewording as follows: ?Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned generator outages for each year of the Transmission planning horizon, within ninety days of a request for such information." The language ?long-term outages for generation equipment? is vague and unclear as to what is a long-term outage and what specific type of generation equipment should be considered. R13 ? Propose adding ?and any changes to existing plans? after ?new planned facilities? as shown below: ?Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned Facilities and any changes to existing plans for each year of the Transmission planning horizon??
NSTAR Electric	No	1. With respect to R9 "including the expected mix of industrial, commercial and residential loads", this provision may be inadequate to be practically useful. The potential issues include the variation in end-use load mix through the daily load

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		cycle, seasonal load composition variations, and the ability to translate these end-uses into reasonable and useful steady-state and dynamic load models. It is important to understand how the information will be used and how much additional detail such as distribution network detail is also required. 2. Add to the last sentence of R9 as follows "within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator." 3. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R10 to read as follows: "R10. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator." 4. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R11 to read as follows:"R11. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator." 5. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R12 to read as follows:"R12. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator." 6. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R13 and R14 to read as follows:"R13. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator.. [Violation Risk Factor: TBD] [Time Horizon: TBD] R14. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to Transmission Lines, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator.. [Violation Risk Factor: TBD] [Time Horizon: TBD] " 7. Planned and long-term outages are two fundamentally different concepts and should be treated separately. Planned and Long-Term outages should be defined. Define how planning events in Tables 1 and 2 are associated with each type of outage (e.g. P4, P5, or P6). There should be specific contingency descriptions associated with long-term outages.

Organization	Question 5:	Question 5 Comments:
		Define length of a "Long Term" outage. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizon.
ISO New England Inc.	No	a. With respect to R9 "including the expected mix of industrial, commercial and residential loads", this provision may be inadequate to be practically useful. The potential issues include the variation in end-use load mix through the daily load cycle, seasonal load composition variations, and the ability to translate these end-uses into reasonable and useful steady-state and dynamic load models. It is important to understand how the information will be used and how much additional detail such as distribution network detail is also required. b. Add to the last sentence of R9 through R14 the following phrase, "within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator." c. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R10 to read as follows: R10. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator. d. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R11 to read as followsR11. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator. e. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R12 to read as follows: R12. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator. f. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R13 and R14 as follows:R13. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator.. [Violation Risk Factor: TBD] [Time Horizon: TBD] R14. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to Transmission Lines, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator.

Organization	Question 5:	Question 5 Comments:
		[Violation Risk Factor: TBD] [Time Horizon: TBD] g. Planned and long-term outages are two fundamentally different concepts and should be treated separately. Planned and Long-Term outages should be defined. Define how planning events in Tables 1 and 2 are associated with each type of outage (e.g. P4, P5, or P6). Should there be specific contingency descriptions associated with long-term outages? Define length of a "Long Term" outage. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizon.

Response: In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments.

The SDT agrees that the wording regarding modeling of outages is confusing. In response the SDT has eliminated Requirement R11 and included a new Requirement R1.1.1 to require modeling of planned outages of generation and Transmission Facilities when they are specifically known.

R1. Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources, ~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R1.1 ~~The Planning Assessment shall include documentation of the technical rationale for modification of any data that was provided in Requirement R9 through R14, MOD-010, and MOD-012.~~Models for the Planning Assessment shall represent:

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R1.1.2 New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon, such as

- Transmission Lines
- Generators
- Circuit breakers
- Reactive Power devices
- Protection System equipment
- Control devices
- New technologies

R1.1.3 Real and reactive Demand of Load

R1.1.4 Firm Transmission Service

Organization	Question 5:	Question 5 Comments:
R1.1.5 Interchange **R1.1.6** Network resources required to supply Load		
Gainesville Regional Utilities	Yes and No	I agree with the approach you are taking concerning this modeling data. I understand that "long term outages" for transmission and generation elements refer to a time frame greater that one year. But I am unclear if the "known planned outage" refers to the same time frame or does it apply to a normal scheduled maintenance type outage of less that one year. Are these "shorter that one year" outages better handled by sensitivity studies since they are normally during an non-peak seasons of the year? Again, the smaller utilities should provide all the requested data to the RRO, but should only have to answer to issues involving their elements discovered at the RRO level.
Response: The SDT agrees that the wording regarding modeling of outages is confusing. In response the SDT has eliminated Requirement R11 and included a new Requirement R1.1.1 to require modeling of planned outages of generation and Transmission Facilities when they are specifically known. **R1.1.1** Planned outages of generation and Transmission Facilities, if specifically known		
JEA	Yes and No	R9. JEA does not agree that the Transmission Planners should have the responsibility to perform load development or sanity checks on the DP's forecasted real and reactive loads based upon superfluous information like the customer mix. Also, JEA recommends adding language that gives the Planning Coordinator the option to require the forecast by season. R10. JEA agrees R11. JEA recommends that R11 be split into two functional requirements: (A) the provision of known planned outage information, and (B) the provision of "potential long-term forced outages of transmission equipment where readily available spares are not identified". JEA can support requirement (A), but believes that requirement (B) should be part of an operating horizon standard (TOP?) where the availability of spares and spare equipment strategies can be refined in a responsive manner as the opportunities evolve. JEA does not believe that the industry should overbuild its system for the possibility of a rare "low probability" equipment failure event will occur and no reasonable replacement alternative will exist in the world. R12. Need to define long-term outages R13. JEA agrees R14. JEA agrees
Ameren	No	We consider the proposed requirements R9-R14 to be largely a duplication of the MOD standards and do not agree that they belong in the proposed TPL-001-1. We would propose that a reference to the MOD standards would be more appropriate so as not to create a double-jeopardy compliance situation. If it is determined that the requirements R9-R14

Organization	Question 5:	Question 5 Comments:
		need to stay, the proposed standard needs to reflect the existing data flow processes and consider who builds the models, which is the Transmission Planner, and not the Planning Coordinator. According to the definition provided in this standard, the Planning Coordinator is "The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems." In our case, the Transmission Planner receives: a) load forecast (real and reactive) information from the Distribution Planner or Load Serving Entity, b) transmission ratings/impedance/topology(outage) information from the Transmission Owners, c) generation ratings/capabilities/outage information from the Generation Owners, and d) designated network resources (existing and future), as well as external obligations, from Resource Planners. The Transmission Planner develops powerflow and corresponding dynamic models from this information including load magnitude and distribution, generation dispatch, and net scheduled interchange, and provides the models or modeling components to the Reliability Coordinator and Planning Coordinator. Other organizations may have similar problems with data flow processes as specified in R9-R14.We view the R9 requirement of the proposed TPL-001-1 for the Distribution Provider to provide real and reactive load forecast data, including load mix information, to conflict with R1.4 of MOD-013-1 which has the RRO as setting the requirement for the dynamic load data. R10 needs to be modified to reflect the RTO activities related to the coordination and sale of Firm Transmission Service, which is not a Transmission Planning activity.R11 needs to be modified to drop the "spare equipment strategy". This is not a modeling issue and should be covered in standard TOP-002-2 (see R1 and R6).R13 needs to be modified to drop the "Reactive Power devices and new technologies" because Resource Planners typically do not know about these devices. The Transmission Planner or Owner may be the more appropriate entity. We view R14 as an extension of Standards MOD-010-0, MOD-011-0, MOD-012-0, and MOD-013-0.
Exelon Transmission Planning	Yes and No	R11 shouldn't include consideration of a spare equipment strategy. All known planned and long-term outages of transmission equipment should be included regardless of the spare equipment strategy.
IESO	Yes and No	A. R9: Agreed B. R10: Holding the TP to provide modeling information on Firm Transmission Service, (a TSP's role), Interchange Schedules (also a TSP's role), and resources required to supply Load for each of its Balancing Authorities (Resource Planner's role) may not be appropriate. In fact, the TP relies on others to provide this set of information for developing its own study model. We suggest to change the responsible entities to these specific entities; or if the TP is required to provide the PC with the model, then there should be requirements in other standards to obligate these other entities to provide the TP with the needed information. C. R11: The phrase "with consideration given to spare equipment strategy" is vague (not enforceable or measurable) and does not appear to add anything to the required product which should already have the spare strategy and capability taken into account when outage plans are developed. We suggest to remove this phrase. If this was retained, the follow on question is why R12 doesn't have a similar requirement (note that a generator outage may not be due to maintenance of the generator itself; it could be due to outages to step-up transformers, breakers or switches for which spares may be

Organization	Question 5:	Question 5 Comments:
		carried). D. R12: Agreed. E. R13: We are not sure what purpose to include "and new technologies" would serve if such technologies do not result in the provision of generators and/or reactive sources which are already covered. Further, this is vague to determine what constitutes "new technologies" and hence this is not enforceable or measurable. We suggest to remove this term. F. R14: Same comment as in R13 on "new technologies".

Response: In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments.

The standard's wording regarding "spare equipment strategy" has also been revised and removed from the modeling requirements. Requirement R2.1.5 now addresses how a Transmission Planner's "spare equipment strategy" should be considered in Transmission planning.

R1. Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R1.1 ~~The Planning Assessment shall include documentation of the technical rationale for modification of any data that was provided in Requirement R9 through R14, MOD-010, and MOD-012.~~Models for the Planning Assessment shall represent:

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R1.1.2 New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon, such as

- Transmission Lines
- Generators
- Circuit breakers
- Reactive Power devices
- Protection System equipment
- Control devices
- New technologies

R1.1.3 Real and reactive Demand of Load

Organization	Question 5:	Question 5 Comments:
R1.1.4 Firm Transmission Service **R1.1.5** Interchange **R1.1.6** Network resources required to supply Load **R2.1.4** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment.		
Progress Energy Florida, Inc.	No	PEF as a general rule believes that Requirements R9-14 can and should be addressed in a MOD Standard. Individual comments on particular ones that PEFs sees as problematic are as follows:R9: This requirement is problematic in its present wording. As worded it would appear to infringe upon the outlined process regarding provision of load forecast data as stipulated in PEFs Attachment K document, mandated to be included as an Attachment to our Tariff per FERC Order 890. In PEF's Attachment K, load forecast data, as submitted by all entities responsible for providing such data for PEF native load, must be submitted by January 1 of each year. Implementation of R9 would thus set in place two binding regulatory processes for a situation in which only one is needed. Furthermore, the requirement uses the term "transmission node", a term which is ambiguous and not easily applicable in the electric utility business. Terms such as "feeders", "substations" or "delivery points" might be more appropriate.R11: PEF appreciates the consideration given with the term "known planned outages", given that specific dates for planned outages in the long-term planning horizon are often difficult to know. This point concludes, however, with the addition of the phrase ?with consideration given to spare equipment strategy?, and PEF does not understand what is meant by this term nor why it is given special consideration in a discussion of planned outages. Spare equipment is just as crucial, if not more so, in the event of an unplanned outage. Furthermore, consideration of spare equipment strategy is already handled as part of PEF's planning processes and as part of the existing TPL Standards. PEF therefore requests that the phrase "with consideration given to spare equipment strategy" be removed from R11.R13: PEF is unsure as to the meaning of "for each year of the Planning horizon". PEF would point out that if from one planning cycle to the next, the modeling of a particular planned generator has not changed, the Resource Planners should not have to re-submit the same data over and over again on an annual basis. Additionally, PEF asserts that its Resource Planners are not involved in the development or implementation of Reactive Power devices or new technologies, and therefore requests that these specifications be removed.
Response: In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments. The standard's wording regarding "spare equipment strategy" has also been revised and removed from the modeling requirements. Requirement R2.1.4 now addresses how a Transmission Planner's "spare equipment strategy" should be considered in Transmission planning. The phrase "for each year of the Transmission Planning Horizon" was deleted in the associated requirements. Requirement R1.1.2 now addresses that the models		

Organization	Question 5:	Question 5 Comments:
shall represent each year of the Near-Term and Long Term Transmission Planning Horizon. The SDT agrees with your comment on the Resource Planner. The standard is no longer applicable to the Resource Planner and the requirement has been deleted. **R1.** Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations. **R1.1** ~~The Planning Assessment shall include documentation of the technical rationale for modification of any data that was provided in Requirement R9 through R14, MOD-010, and MOD-012.~~Models for the Planning Assessment shall represent: **R1.1.1** Planned outages of generation and Transmission Facilities, if specifically known. **R1.1.2** New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon, such as Transmission Lines Generators Circuit breakers Reactive Power devices Protection System equipment Control devices New technologies **R1.1.3** Real and reactive Demand of Load **R1.1.4** Firm Transmission Service **R1.1.5** Interchange **R1.1.6** Network resources required to supply Load **R2.1.4** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment.		
Lafayette Utilities	No	In Draft 2 of TPL-001, the SDT has adopted ?Planning Coordinator? as a new defined term. That term is used frequently in the new draft Reliability Standard (including in Requirements R9 - R14 but also, most notably, in Section A.4.1.1). The

Organization	Question 5:	Question 5 Comments:
System		SDT explained in its response to comments on Draft 1 that it had taken the definition of "Planning Coordinator" from the NERC Functional Model. However, the term "Planning Coordinator" is not used in the NERC Registry Criteria, nor does it appear in the NERC Glossary. Because the latter form the basis for allocating compliance responsibilities, the SDT should eliminate use of "Planning Authority" and should adopt in its stead a term that is used in the Registry Criteria (such as "Planning Authority"). With respect to the incorporation of data provided under Reliability Standards MOD-010 and MOD-012 into the studies contemplated by the revised version of TPL-001 (see Requirements R1 and R5), Lafayette urges the SDT to clarify entities? obligations with respect to the provision and use of this data, particularly with respect to Planning Coordinators/Authorities. As presently drafted, MOD-010 and MOD-012 do not apply to Planning Coordinators or Planning Authorities, and these standards also do not provide for these entities to receive MOD-010 and MOD-012 data from the entities that are subject to these two Standards. Further, to the extent that Requirements R1 and R5 require Transmission Planners to use MOD-010 and MOD-012 data, is it contemplated that Transmission Planners will obtain this data from Resource Planners and Transmission/Generation Owners in their areas, or will Transmission Planners merely be obligated to incorporate the data that they themselves provide under MOD-010 and MOD-012 into their studies? Requirement R9 directs each Distribution Provider to furnish its "Planning Coordinator" with modeling information that includes "real and reactive load forecast data" at Transmission nodes" and "the expected mix of industrial, commercial, and residential Loads." As discussed previously with respect to Requirement 2.4.1, Distribution Providers may consider the information required by R9 to be commercially sensitive such that its disclosure could have adverse competitive effects. The information specified in R9 therefore should be protected from disclosure unless the provider of the information authorizes its release or other appropriate protections are in place. Additionally, given that this requirement directs the provision of "load forecast data," it seems more appropriate that the requirement apply to "Load-Serving Entities," "Distribution Providers that serve load" or "Distribution Providers that are also Load-Serving Entities." Requirement R10 assumes that the Transmission Planner has access at all times (and, therefore, is in a position to provide within 90 days of a request) to Firm Transmission Service Data, Interchange Schedules, and resources required to serve load for each of its Balancing Authorities for each year of the transmission planning horizon. The Transmission Planner, however, may only receive such information periodically (e.g., annually or semi-annually) from its Balancing Authorities for use in the planning process. It is more likely that, at any point during the year, the Transmission Owner, Transmission Operator, or Transmission Service Provider would have access to the specified information. Requirement R10 should be expanded to include these other entities, which probably will have access to the data throughout the planning cycle. Requirement R11 does not specify whether outage information provided by a Transmission Owner must be updated (e.g., if the outage schedule changes after being provided upon request by the Planning Coordinator). The Transmission Owner's obligations with respect to providing updated information should be clearly stated. Additionally, it is not clear what the SDT means by the phrase "giving consideration to spare equipment strategy." If the intent is that Transmission Owners shall factor into their outage decisions and timing the availability of spare equipment that might affect the need for or duration of an outage, that intent should be stated in clear terms.
Response: v4 of the Functional Model which has been approved by the BOT includes the term 'Planning Coordinator'. The definition has been deleted from this		

Organization	Question 5:	Question 5 Comments:

posting as it has already been implemented in another project.

In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments.

The standard's wording regarding "spare equipment strategy" has also been revised and removed from the modeling requirements. Requirement R2.1.4 now addresses how a Transmission Planner's "spare equipment strategy" should be considered in Transmission planning.

R1. Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R1.1 ~~The Planning Assessment shall include documentation of the technical rationale for modification of any data that was provided in Requirement R9 through R14, MOD-010, and MOD-012.~~Models for the Planning Assessment shall represent:

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R1.1.2 New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon, such as

- Transmission Lines
- Generators
- Circuit breakers
- Reactive Power devices
- Protection System equipment
- Control devices
- New technologies

R1.1.3 Real and reactive Demand of Load

R1.1.4 Firm Transmission Service

R1.1.5 Interchange

R1.1.6 Network resources required to supply Load

R2.1.4 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment.

Organization	Question 5:	Question 5 Comments:
E.ON U.S. Transmission Planning	Yes and No	R1 states "Each Transmission Planner and Planning Coordinator shall maintain System models " and R7 states "Each Transmission Planner and Planning Coordinator shall determine and identify individual and joint responsibilities" but R9-R14 requires that data flow through the Planning Coordinator. Requirements R9-R14 should allow the data to be provided to either, as appropriate for the situation.R9 ?neighboring systems? should be replaced with more descriptive terms such as Planning Coordinators of ? or Transmission Planners of ? R10 The Transmission Planner is a user of this data, just like the Planning Coordinator, and is not the source of this data. The responsibility should be placed on the "source provider" like R9 and R11-R14. R11 The requirement should be limited to planned outages and existing outages that may be long-term due to the spare equipment strategy. The contingency analysis covers all other future outages. R12 The requirement should be limited to planned outages and existing outages that may be long-term due to the spare equipment strategy. The contingency analysis covers all other future outages.

Response: In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments.

The SDT agrees that the wording regarding modeling of outages is confusing. In response the SDT has eliminated Requirement R11 and included a new Requirement R1.1.1 to require modeling of planned outages of generation and Transmission Facilities when they are specifically known.

The standard's wording regarding "spare equipment strategy" has also been revised and removed from the modeling requirements. Requirement R2.1.4 now addresses how a Transmission Planner's "spare equipment strategy" should be considered in Transmission planning.

R1. Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R1.1 ~~The Planning Assessment shall include documentation of the technical rationale for modification of any data that was provided in Requirement R9 through R14, MOD-010, and MOD-012.~~Models for the Planning Assessment shall represent:

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R1.1.2 New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon, such as

- Transmission Lines
- Generators
- Circuit breakers
- Reactive Power devices

Organization	Question 5:	Question 5 Comments:
Protection System equipment Control devices New technologies **R1.1.3** Real and reactive Demand of Load **R1.1.4** Firm Transmission Service **R1.1.5** Interchange **R1.1.6** Network resources required to supply Load **R2.1.4** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment.		
Orlando Utiliites Commission	No	If improvements are needed to the MOD standards then those should be addressed in the MOD standards. This is beyond the scope of the TPL standards. Creating requirements that are not within the scope of a particular standard invites compliances issues and also creates an environment where it may not be possible to comply with both standards. However if you are going to retain these please consider: R7: Revising to state "Each Transmission Planner and their associated Planning Coordinator" otherwise this could be interpreted that every TP & PC has to have an agreement with every other TP and PC in existence on their joint and individual responsibilities. R8: This seems to be redundant with the FERC order 890 requirements for an Attachment K process. That process already has an audit mechanism in FERC and a reporting mechanism in the form of the clients of that process. Having NERC auditors monitor this type of process seems a distraction from their purpose of enhancing system reliability.
Response: In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments. **R1.** Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources, ~~-~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations. **R1.1** ~~The Planning Assessment shall include documentation of the technical rationale for modification of any data that was provided in Requirement R9 through R14, MOD-010, and MOD-012.~~Models for the Planning Assessment shall represent:		

Organization	Question 5:	Question 5 Comments:
R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known. **R1.1.2** New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon, such as Transmission Lines Generators Circuit breakers Reactive Power devices Protection System equipment Control devices New technologies **R1.1.3** Real and reactive Demand of Load **R1.1.4** Firm Transmission Service **R1.1.5** Interchange **R1.1.6** Network resources required to supply Load Regarding the comment pertaining to Requirement R7, the SDT believes there is an inherent association between the TP and its PC and it should not be interpreted that every TP needs an agreement with every other TP and PC. Regarding the comment pertaining to Requirement R8, the SDT believes the requirement captures the intent of FERC Order 890.		
BCTC	Yes	We can live with the proposed Requirements, but expect some problems may arise with implementation. For example, to accurately model our system for stability studies, we require models of adjacent systems. It is not clear how we will coordinate this requirement within the WECC base case process.
PacifiCorp	Yes	We agree that the MOD Standards need modifications and additions to be used for Transmission Planning, We also agree with the movement of the R1of the first draft to the R9 through R14 of this draft, We also agree that when the MOD Standards are replaced, then remove these Requirements from the TPL Standard.
Arizona Public Service Co.	Yes	We agree that the MOD Standards need modifications and additions to be used for Transmission Planning, We also agree with the movement of the R1of the first draft to the R9 through R14 of this draft, We also agree that when the MOD Standards are replaced, then remove these Requirements from the TPL Standard.

Organization	Question 5:	Question 5 Comments:
City Water, Light & Power - Springfield, Illinois	Yes	
Progress Energy Carolinas	Yes	
Platte River Power Authority	Yes	
Tenaska, Inc.	Yes	
SMUD	Yes	
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	Yes	
Oncor Electric Delivery	Yes	NA
Entergy Services, Inc.	Yes	
Response: Thank you for your response but the majority of the industry has responded negatively and the SDT has changed the requirements as shown in the summary response. .		

6. The SDT has modified the requirements relating to short circuit analysis Do you concur with the modifications reflected in Requirements R2.3 and R4. If not, please state why and/or suggest specific changes.

Summary Consideration:

The majority of commenters responded negatively. In general, commenters indicated a need for clarifying what specific short-circuit studies were required. While it's an annual requirement, what year or years should be studied? Is there both a short-term and long-term requirement or is it just short-term? In addition, the need for studies beyond those of a "normal system" was also questioned. To provide clarity on these issues, the SDT changed Requirements R2.3 and R2.6.2 and created a new Requirement, R2.7, to address the need for corrective actions specific to when fault interrupting duties are exceeded while also deleting Requirement R4 as those requirements are now included in Requirement R2.3. In addition, some entities suggested these requirements belong in a separate standard such as FAC-002 or a new standard. However, the SAR for this project specified that short-circuit requirements would be included in TPL-001; therefore, the suggestion to move these short-circuit study requirements to a separate standard cannot be implemented. Also, the need for, or applicability, of 'single Contingencies' in Requirement R4 was dropped when Requirement R4 was merged into Requirement R2.3.

In response to industry comments, Requirement R4 has been deleted and the following requirements have been changed:

R2.3 The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area.

R2.6.2 (now R2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:

- The addition/deletion/change of individual generating unit capability of 20 MW or greater.
- An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater.

R2.7 For short circuit analysis, if the short circuit current interruption duty on fault interrupting devices determined in Requirement R2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

R2.7.1 List System deficiencies and the associated actions needed to achieve required System performance.

R2.7.2 Be reviewed in subsequent annual Planning Assessments as to implementation status.

Organization	Question 6:	Question 6 Comments:
NPCC	No	In R4, suggest striking, "that would result in greater circuit breaker interrupting duties?".
Los Angeles Department of Water and Power	No	Short circuit study is a static study, there is no dynamic involved. The main purpose of short circuit study, from a planning perspective, is to size the breakers to ensure the breakers can interrupt a fault in the system when called upon. R4 requires simulation including contingencies, for what purpose is not known. The language implies there are single contingencies that could result in higher duties. I disagree. The highest duty a circuit breaker will see is when the system is whole and with all generator units in service and the fault to be cleared is a bus fault. Any single contingency that involve losing a unit or any component in the system will result in a weaker system and less short circuit duties. This is elementary. I cannot envision of any single contingency that would put more units on line or switch in additional transmission facilities beyond a full system with all unit already in service. In R2.3, the requirement is to do the study on an annual basis "and" support of past studies. If the intent is to allow past studies to substitute for annual study, the word "and" should be changed to "or". If the intent is to mandate annual study, then the support of past studies is irrelevant since the annual study supersedes past ones. In addition, short circuit study does not need to be performed annually unless there is substantive addition to the system in the form of a generating unit or a major transmission facility. So it make sense to allow past studies in lieu of annual study if there is no substantive addition to the system.
Transmission Agency of Northern California	Yes and No	We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute ?normal? condition or ?following any single Contingency condition?. Also, by specifying the normal and single contingency conditions, R4 is straying into ?how? to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
OPUC	Yes and No	What constitutes a ?normal condition? still needs further clarity.
Pacific Gas and Electric Co.	Yes and No	We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute “normal” condition or “following any single Contingency condition”. Also, by specifying the normal and single contingency conditions, R4 is straying into ?how? to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
Public Service Company of New Mexico	Yes and No	We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion

Organization	Question 6:	Question 6 Comments:
		whether the result would constitute ?normal? condition or ?following any single Contingency condition?. Also, by specifying the normal and single contingency conditions, R4 is straying into “how” to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
PacifiCorp	Yes and No	We agree with R2.3. However, R4 requires assessment of “Short circuit capability of its equipment under normal condition and following any single Contingency condition that would result in greater circuit breaker interrupting duties”. Since short circuit studies are typically performed by applying a three phase fault on a Facility starting from a normal condition, please clarify whether the result would constitute ?normal? condition or ?following any single Contingency condition?.
Puget Sound Energy, Inc.	Yes and No	We agree with R2.3. However, R4 requires assessment of “Short circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties”. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute “normal” condition or “following any single Contingency condition”. Also, by specifying the normal and single contingency conditions, R4 is straying into “how” to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
Idaho Power Company	Yes and No	We agree with R2.3. However, R4 requires assessment of “Short circuit capability of its equipment under normal condition and following any single Contingency condition that would result in greater circuit breaker interrupting duties”. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute “normal” condition or ?following any single Contingency condition”. Also, by specifying the normal and single contingency conditions, R4 is straying into “how” to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
SMUD	Yes and No	We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute ?normal? condition or ?following any single Contingency condition?. Also, by specifying the normal and single contingency conditions, R4 is straying into ?how? to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
Hydro-Quebec TransEnergie (HQT)	No	In R4, suggest striking, "that would result in greater circuit breaker interrupting duties?".
Sierra Pacific Power Comapny	Yes and No	We agree with R2.3. However, R4 requires assessment of “Short circuit capability of its equipment under normal condition and following any single Contingency condition that would result in greater circuit breaker interrupting duties”. Since short circuit

Organization	Question 6:	Question 6 Comments:
/ Nevada Power Company		studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute “normal” condition or “following any single Contingency condition”. Also, by specifying the normal and single contingency conditions, R4 is straying into “how” to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
Black Hills Corporation	Yes and No	We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute “normal” condition or “following any single Contingency condition”. Also, by specifying the normal and single contingency conditions, R4 is straying into “how” to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
Arizona Public Service Co.	Yes and No	We agree with R2.3. However, R4 requires assessment of “Short circuit capability of its equipment under normal condition and following any single Contingency condition that would result in greater circuit breaker interrupting duties”. Since short circuit studies are typically performed by applying a three phase fault on a Facility starting from a normal condition, please clarify whether the result would constitute “normal” condition or “following any single Contingency condition”.
Exelon Transmission Planning	No	R2.3 is not clear as to which year’s studies are required. Is the Planning Assessment time frames in R2 also applicable to R4? The phrase 'years one or two of the near-term planning horizon' should be included.
SRP	Yes and No	We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute ?normal? condition or ?following any single Contingency condition?. Also, by specifying the normal and single contingency conditions, R4 is straying into ?how? to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
Tucson Electric Power Company	Yes and No	We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute ?normal? condition or ?following any single Contingency condition?. Also, by specifying the normal and single contingency conditions, R4 is straying into ?how? to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.

Organization	Question 6:	Question 6 Comments:
SERC Dynamics Review Subcommittee	Yes	It is not clear in the standard what is meant by ?single contingency?? Is the concern in Requirement R4 limited to single contingencies that may result in a system state which results in a greater circuit breaker interrupting duty?
Austin Energy	Yes and No	Transmission Planners should assess equipment short-circuit capability under normal conditions, but the need assess its capability following a contingency is so rare it should be left to the planner's selective analysis and not made a specific requirement in the standards.
Modesto Irrigation District	Yes and No	Comments: We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute ?normal? condition or ?following any single Contingency condition?. Also, by specifying the normal and single contingency conditions, R4 is straying into “how” to perform a study, which is not necessary in a standard. We suggest deleting there reference to the contingencies to be used in the study.
Tri-State Generatino and Transmission Association, Inc.	Yes and No	R2.3 is acceptable as written. R4 is redundant and should be eliminated. Also, the contingency short circuit study requirement does not appear to meet the purpose described in this draft standard (breaker duty monitoring). Three-phase short circuits on an intact system should cover the highest fault conditions, and thus the most critical breaker duty conditions.
Tri-State G&T	Yes and No	We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute “normal” condition or “following any single Contingency condition.” Also, by specifying the normal and single contingency conditions, R4 is straying into “how” to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
Lakeland Electric	No	R2.3 or R4 should specify how many and / or how to choose which years of the planning horizon shall be studied. R4 should specify method of choosing which single contingencies to study as larger systems will require an inordinate amount of work to outage every element during each of the study years of the short circuit analysis.
Brazos Electric Power Cooperative, Inc.	No	2.3 is acceptable, the deletion was recommended in our previous comments.R4 should not be added to this Standard. It adds nothing to the document the way it is worded and is quite similar to 2.3.

Organization	Question 6:	Question 6 Comments:
NERC and Regional Coordination	No	Attributes of the short circuit analysis needs to be better define. For example which studies need to be done, for what period and how often.
ColumbiaGrid	Yes and No	We agree with R2.3. However, R4 requires assessment of “Short circuit capability of its equipment under normal condition and following any single Contingency condition that would result in greater circuit breaker interrupting duties”. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute “normal” condition or “following any single Contingency condition”. Also, by specifying the normal and single contingency conditions, R4 is straying into “how” to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study. We suggest R4 be modified to read “Short circuit capability of its equipment under plausible system configurations that would result in the greatest circuit breaker interrupting duties”.
Midwest ISO	No	The language throughout the standard is not precise as relates to "studies", "analysis", and "assessments". R2.3 appears to say that the actual simulations upon which the annual assessments are made need not be a current year study. If that is the intent the following wording would be more clear: "Short-circuit assessments shall be conducted annually and may be supported by current or past studies. R4 should be grouped with R2.4. In general the standard seems to meander and elements of the same types of studies are scattered, making it difficult to grasp the study requirements with clarity. Also the language of R4 is unclear as it describes short circuit studies in terms of contingencies. Better language would be "shall assess the short-circuit capability of its equipment under system intact topology and any single facility (or branch) out condition that is expected to result in greater ?".
Southern California Edison	Yes and No	We agree with R2.3. However, R4 requires assessment of “Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute “normal” condition or “following any single Contingency condition”. Also, by specifying the normal and single contingency conditions, R4 is straying into “how” to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
Northeast Utilities	No	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
Duke Energy	No	It is not clear in R4 what is meant by ?single contingency? and this situation is unlikely to increase fault current. The phrase ?under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting

Organization	Question 6:	Question 6 Comments:
		duties? should be deleted.
Central Maine Power Company	No	a. R2.3 should be changed to indicate the year(s) for short circuit analysis. b. In R4, suggest replacing, " and following any single Contingency condition that would result in greater circuit breaker interrupting duties" with, " giving due consideration to the potential sequence of equipment operation". c. It should be stated in the standard that assumptions should be based on procedures provided by each Transmission Planner and by the Planning Coordinator.
NSTAR Electric	No	1. R2.3 should be changed to indicate the year(s) for short circuit analysis. 2. In R4, suggest replacing, " and following any single Contingency condition that would result in greater circuit breaker interrupting duties" with , " giving due consideration to the potential sequence of equipment operation". 3. It should be stated in the standard that assumptions should be based on procedures provided by each Transmission Planner and by the Planning Coordinator.
New York Independent System Operator	No	In R4, suggest striking, "that would result in greater circuit breaker interrupting duties?".
Alberta Electric System Operator	No	We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute ?normal? condition or ?following any single Contingency condition?. Also, by specifying the normal and single contingency conditions, R4 is straying into ?how? to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
ISO New England Inc.	No	a. R2.3 should be changed to indicate the year(s) for short circuit analysis. b. In R4, suggest replacing, " and following any single Contingency condition that would result in greater circuit breaker interrupting duties" with , " giving due consideration to the potential sequence of equipment operation". c. It should be stated in the standard that assumptions should be based on procedures provided by each Transmission Planner and by the Planning Coordinator.
US Bureau of	No	Comments: We agree with R2.3. However, R4 requires assessment of “Short circuit capability of its equipment under normal

Organization	Question 6:	Question 6 Comments:
Reclamation		conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties". Comment Form for 2nd Draft of Standard TPL-001-1Assess Transmission Future Needs (Project 2006-02)Page 7 of 12Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute ?normal? condition or ?following any single Contingency condition?. Also, by specifying the normal and single contingency conditions, R4 is straying into ?how? to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
BPA Transmission Reliability Program	Yes and No	We agree with R2.3. However, we recommend removing the reference to single contingency conditions in R4, for the same reasons as described in the WECC comments. See below: "Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute "normal" condition or "following any single Contingency condition". Also, by specifying the normal and single contingency conditions, R4 is straying into "how" to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
Response: Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. Also, the need for, or applicability, of 'single Contingencies' in Requirement R4 was dropped when Requirement R4 was merged into Requirement R2.3. **R2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area.		
City Water, Light & Power - Springfield, Illinois	Yes and No	For R2.4 stability studies should not be required annually but should only be required if there is a significant change to the system or system stability was marginal as shown in previous studies.
Response: This question is related to short circuit, Requirement R2.3, not Requirement R2.4, Stability. However, if past studies are applicable, it is not necessary to rerun Stability studies more often than once every 5 years. Your examples are good examples of when a Stability study may need to be rerun more often than once every 5 years.		
BCTC	Yes	R.3 and R4 are acceptable, although we note the R4 gets into details of how to do short circuit analysis which is unnecessary for this standard. In some cases it may be necessary to consider multiple contingencies. Should R2.6.2 say "the SYSTEM shall not include material changes?"?
Response: Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. **R2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can		

Organization	Question 6:	Question 6 Comments:
be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area. The SDT has changed Requirement R2.6.2 (now R2.5.2) to provide clarification. **R2.5.2** For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:		
Manitoba Hydro	No	R4: The wording for the assessment should be changed from "shall assess the short circuit ability of its equipment" to "shall assess whether bus short circuit levels are within the capability of its equipment". The short circuit assessment should only be required if changes to system topology or generation occur. While short circuit levels are critical for system equipment specifications, ten year planning horizon models are generally not adequate for this purpose as ultimate system fault levels are required. The SDT should clarify the modelling details required for the short circuit assessment and the deliverable of the short circuit assessment. The standard doesn't stipulate if an existing NERC model will need to be modified to include the sequence data and thus allow for three phase and SLG fault analysis or if the planner is to use our "in house" models and just report the results. Typically, short circuit models used for fault studies are not load or season specific, and the simulation is conducted using a flat-analysis (load ignored and voltage at 1.0 pu). Typically, all elements are in service to ensure maximum fault contribution. Can the SDT provide details on what cases have to be assessed ? Year One, each of the first five year, etc. What is the generation dispatch that should be considered? For purposes of equipment rating, a dispatch considering all available generation may need to be considered. Manitoba Hydro requests the SDT to provide some specifics on the need for doing intact and n-1 fault analysis. We think the requirement to consider single contingency conditions is getting into the details of bus modeling to maximize the fault level. If so this seems to be getting into short circuit study methodology and is too prescriptive and unnecessary. To explain this comment, we include a summary of the process used at Manitoba Hydro as follows: Manitoba Hydro follows a two step procedure when studying breaker capability of our system:1. Breaker Rating vs. Bus Fault - Breakers are required to accommodate the entire bus maximum symmetrical fault current at nominal bus voltage with no consideration given to what the circuit breaker may actually be required to interrupt due to its location in the ring. Stations with fault levels above 95% of rated breaker interrupting capability are flagged for further study. This type of analysis will accurately rule out a high percentage of breakers whose capability is adequate. If an appropriate model is available, this step could take up to three person-months for the Manitoba Hydro system. 2. Detailed Examination of Breaker Duty and Location - By considering faults on both the equipment and bus side of the breaker the exact fault current that the breaker must interrupt can be determined. In a ring bus arrangement the breaker in question is assumed the last breaker to clear the fault. In addition, factors such as X/R ratio & operating voltage are also taken into account. To provide a safety margin to account for modeling tolerances we recommend a circuit breaker for replacement when the fault value is greater then 95% of the breaker rating. Other companies may use different breaker replacement threshold levels. This detailed analysis could require up to one person-month, depending on the size of the station, for each detailed assessment. The standard should specify what is to be reported as a result of the short circuit study. Should the report include:? Documentation of the criteria used for the study? A

Organization	Question 6:	Question 6 Comments:
		listing of the SLG and three phase fault levels compared to the lowest breaker capability at a bus. ? Documentation of more detailed analysis of for breakers whose capability is within threshold of the station fault level.? A listing of the breakers to be replaced. Alternatively, should the standard just require the planner have a separate report on the fault analysis that can be provided on request.
Response: Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. **R2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area. The SDT has chosen not to prescribe all conditions but expects that studies would assume all equipment in service, which could impact the study area, to calculate maximum potential fault currents.		
National Grid	No	a. R2.3 should be changed to indicate the year(s) for short circuit analysis. b. In R4, suggest replacing, " and following any single Contingency condition that would result in greater circuit breaker interrupting duties" with , " giving due consideration to the potential sequence of equipment operation". c. It should be stated in the standard that assumptions should be based on procedures provided by each Transmission Planner and by the Planning Coordinator.
Response: (a) & (b): Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. Also, the need for, or applicability, of 'single Contingencies' in Requirement R4 was dropped when Requirement R4 was merged into Requirement R2.3. **R2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area. (c) Procedures used to meet short-circuit requirements of Requirement R2.3 should be included in Requirement R2.7.1 mandated Corrective Action Plans.		
Gainesville Regional Utilities	Yes and No	With a small system like ours, I would like to see a provision where if you do not have any changes in our local portion of the BES, then the previous studies would support my assessment.
Response: This is addressed in the revised Requirement R2.6.2 (now R2.5.2). **R2.5.2** For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:		

Organization	Question 6:	Question 6 Comments:
The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater.		
JEA	Yes and No	JEA can agree to this requirement; however, JEA would like to see it addressed in FAC-002 to maintain consistency with the FAC standard requirements.
Response: FAC-002 references the TPL standards to ensure that a short-circuit study is run for new Facilities. The SDT believes that the consistency will continue to exist. The SAR for TPL-001-1 specified that short-circuit studies were to be included in the requirements.		
Progress Energy Florida, Inc.	No	PEF disagrees with, and recommends removal of both R2.3 and R4 on the following grounds:R2.3: Evidence that short circuit analysis has been performed is already mandated through Requirement R1.4 NERC Standard FAC-002-0. Inclusion of the mandate in the TPL Standard is redundant.R4: While the fundamental inadequacy of the short circuit issue is its inclusion in the TPL Standard to begin with (see R2.3 comments), PEF is perplexed at the proposed requirement to perform short circuit analysis for single contingencies. PEF cannot conceive of a scenario for which a single contingency scenario would result in increased fault duty. Such a mindset essentially considers short circuit analysis as equivalent to load flow analysis, which it clearly is not. Short circuit analysis is performed to adequately set relays, size equipment and prevent equipment damage, and as such is not appropriate for inclusion in a TPL Standard.
Florida Power and Light	No	R4. Why is short circuit analysis required for single contingencies? Removing equipment through contingency outages lowers available short circuit duty. Short circuit analysis is not a parallel version of load flow analysis. Evidence that short circuit studies have been performed is currently required in the existing FAC-002-0 Standard. Since the primary concern is the appropriate sizing of equipment and the prevention of equipment damage as opposed to overall grid reliability, we do not see the need for a set of requirements within the proposed TPL standard for short circuit studies.
Florida Reliability Coordinating Council, inc	No	Recommend for the removal of both R2.3 and R2.4. Short Circuit analysis should be addressed in FAC-002 by revising the standard to include additional detail within FAC-002. Another option would be to develop a new standard addressing short circuit studies and requirements.
Response: FAC-002 requires coordination for new Facilities but points back to the TPL standards for requirements that must be coordinated. The SDT believes short-circuit requirements belong in TPL-001-1 and the SAR for TPL-001-1 specified that short-circuit studies were to be included in requirements. Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. **R2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System		

Organization	Question 6:	Question 6 Comments:
short circuit model with any generation and Transmission Facilities in service which could impact the study area.		
Lafayette Utilities System	No	Lafayette has identified two issues with respect to the Short Circuit Analysis required in TPL-001. First, Requirements R2.3 and R4 do not describe the required Short Circuit Analyses in sufficient detail to ensure that these studies are performed using topology assumptions that are consistent with the assumptions used in the Steady-State and Stability Studies. If inconsistent topology assumptions are used, the results of the analyses would not present a clear and consistent picture for planning purposes. Second, interconnection studies performed under the FERC LGIP procedures typically include considerable short-circuit analysis of the interconnecting transmission system. Entities required to perform an annual Planning Assessment should be permitted to use, for TPL-001 compliance purposes, any up-to-date short-circuit analyses that may have been conducted for an LGIP interconnection study. Forcing these entities to re-perform the analyses for TPL-001 compliance would impose unnecessary cost.
Response: Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. **R2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area. Please note that this requirement allows for the utilization of past studies.		
Ameren	No	Requirement R4 should be modified to remove the Planning Coordinator such that the "Transmission Planner shall assess the short-circuit capability of its equipment considering maximum interrupting duty for normal or single element outage conditions".
Response: The Planning Coordinator is the appropriate entity in some areas. In those areas where this is not the case, the Planning Coordinator may defer to the Transmission Planner's studies. This is a joint responsibility between the Transmission Planner and Planning Coordinator.		
CenterPoint Energy and CPS Energy	No	We believe R4 is unnecessary and, judging from industry comments to the previous draft, likely to cause confusion among auditors and planners alike. Furthermore, we believe R4 does not address an actual problem. We are not aware of situations where equipment has been under-rated from the standpoint of short circuit ratings. We recommend that R4 be deleted.
Response: The SDT does not believe that the concepts of Requirement R4 should be eliminated as without them, there would be a requirement for short-circuit studies with no specific result expected. However, Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. **R2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System		

Organization	Question 6:	Question 6 Comments:
short circuit model with any generation and Transmission Facilities in service which could impact the study area.		
MidAmerican Energy Company	No	a. Since the TPL contingency requirements already require bus fault, stuck breaker, and breaker failure contingencies, MEC asks the SDT to clarify the purpose of the short circuit study requirements. The benefit to additional short-circuit studies is minimal since analyses already ensure that the system can withstand bus faults and breaker failures. b. The SDT should clarify what single contingencies are to be studied for short circuit studies in R2.4. Is it single contingency as defined in Table 1? Or is it a broader or narrower definition? MEC recommends that since this is a new requirement, that TPL-001-1 be limited to raise the bar only to involve the single contingencies identified in P1. Failure to do so will require a great deal of additional modeling work in short-circuit studies if single contingencies in P2 are to be included in these studies with minimal benefit.
Response: (a) These requirements apply to steady state (load flow) and Stability analysis but they do not specifically address short-circuit requirements. The performance requirements in Requirement R2.3 are specific to short-circuit studies. (b) Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. Also, the need for, or applicability, of 'single Contingencies' in Requirement R4 was dropped when Requirement R4 was merged into Requirement R2.3. **R2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area.		
MRO NERC Standards Review Subcommittee	No	a. Since the TPL contingency requirements already require bus fault, stuck breaker, and breaker failure contingencies, the MRO asks the SDT to clarify the purpose of the short circuit study requirements. The benefit to additional short-circuit studies is minimal since analyses already ensure that the system can withstand bus faults and breaker failures. b. The SDT should clarify what single contingencies are to be studied for short circuit studies in R2.4. Is it single contingency as defined in Table 1? Or is it a broader or narrower definition? The MRO recommends that since this is a new requirement, that TPL-001-1 be limited to raise the bar only to involve the single contingencies identified in P1. Failure to do so will require a great deal of additional modeling work in short-circuit studies if single contingencies in P2 are to be included in these studies with minimal benefit. c. The MRO suggests added clarification of the following questions: 1. Should analysis be performed for the near-term and long-term planning horizon? 2. Should only the peak system condition be analyzed? 3. What does the analysis include (e.g. breaker over duty evaluation and protective relay coordination)? R4 - Clarify that the "short-circuit capability of its equipment under normal conditions" (P0) refers to interruptible rating for breakers only.
Response: (a) These requirements apply to steady state (load flow) and Stability analysis but they do not specifically address short-circuit requirements. The		

Organization	Question 6:	Question 6 Comments:
performance requirements in Requirement R2.3 are specific to short-circuit studies. (b) Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. Also, the need for, or applicability, of 'single Contingencies' in Requirement R4 was dropped when Requirement R4 was merged into Requirement R2.3. **R2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area. (c) The SDT believes that the concerns raised here are covered in the revised requirement R2.3.		
Arkansas Electric Coop. Corp.	No	R2.3.1 should not be deleted. While system wide short circuit analysis should be done annually, there are situations where changes in the BES do impact the short circuit. If these changes result in new equipment needing to be ordered then this needs to be know as soon as possible in order to prevent exceeding equipment ratings or delays because of lead times on equipment.
Response: Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. **R2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area. The SDT has added Requirement R2.7 to provide a Corrective Action Plan. **R2.7** For short circuit analysis, if the short circuit current interruption duty on fault interrupting devices determined in Requirement R2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall: **R2.7.1** List System deficiencies and the associated actions needed to achieve required System performance. **R2.7.2** Be reviewed in subsequent annual Planning Assessments as to implementation status.		
ERCOT System Planning	No	ERCOT believes R4 is unnecessary and does not address an actual problem; ERCOT recommends that R4 be deleted. ERCOT does not presently possess the capability or have access to the data needed to perform the calculations required by R4 as this requirement should apply to only the equipment owner (GO or TO).
Response: The Planning Coordinator is the appropriate entity in some areas. In those areas where this is not the case, the Planning Coordinator may defer to the Transmission Planner's studies. This is a joint responsibility between the Transmission Planner and Planning Coordinator. Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. **R2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can		

Organization	Question 6:	Question 6 Comments:
be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area.		
American Transmission Company	No	We suggest added clarification of the following questions: 1. Should analysis be performed for the near-term and long-term planning horizon? 2. Should only the peak system condition be analyzed? 3. What does the analysis include (e.g. breaker over duty evaluation and protective relay coordination)? 4. Does the analysis of single contingency for greater duties refer to only the P1 category or both the P1 and P2 categories?R4 - Does the equipment capability reference include the ground grid and bus structures?
Response: The SDT did not add references to equipment beyond interrupting equipment. Circuit breaker or interrupting device ratings should already include support equipment. Lines are rated by the most limiting element and interrupting equipment ratings should also be rated by the most limiting equipment. Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. **R2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area.		
FirstEnergy Corp.	No	We do not feel that it is necessary to annually update the short circuit analysis. We suggest the SDT consider increasing this timeframe. In addition, short circuit analysis should be reviewed in areas where transmission or generation changes are planned. Lastly, we feel it would be beneficial for the standard to provide examples of contingencies that could increase fault duties.
Response: An annual "assessment" must be made, but this doesn't necessarily mean a new study unless topology changes accordingly. The SDT has revised Requirement R2.6.2 (now R2.5.2) which allows for the use of past studies. **R2.5.2** For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater. Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. **R2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System		

Organization	Question 6:	Question 6 Comments:
short circuit model with any generation and Transmission Facilities in service which could impact the study area.		
Orlando Utiliites Commission	Yes and No	OUC agrees with other commentors that if there is a need for monitoring this, it should perhaps be in a different standard.
Response: The SAR for TPL-001-1 specified that short-circuit studies were to be included in the requirements.		
Dominion - Electric Transmission Planning	Yes	
TVA System Planning	Yes	
Progress Energy Carolinas	Yes	
Platte River Power Authority	Yes	
Tenaska, Inc.	Yes	
ITC Holdings: ITC, METC, ITC Midwest	Yes	
Southern Company Transmission	Yes	
LCRA TSC	Yes	
IESO	Yes	

Organization	Question 6:	Question 6 Comments:
North Carolina Electric Membership Corp	Yes	
E.ON U.S. Transmission Planning	Yes	
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	Yes	
Oncor Electric Delivery	Yes	NA
Entergy Services, Inc.	Yes	
Response: Thank you for your response.		

7. **The SDT has reformatted the Steady State and Stability Performance Tables. Do you concur with the modified format? If not, please state why and/or suggest specific changes.**

Summary Consideration:

In responding to the reformatted performance tables, industry stakeholders had several comments related to the format changes and also took an opportunity to provide feedback on the table content as well. A summary of the more common industry responses is provided below along with the SDT's reply to each.

FORMAT COMMENTS:

1. The most common input received from industry related to the format of the tables was a desire for the SDT to consider a single table design covering both steady-state and stability. The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table design.

2. Many commenters felt the two table design was unduly long covering 13 pages compared to the two (2) pages used for the existing FERC approved TPL standards. Based on the redesigned single format table, the SDT has condensed the information to only 3 pages in the proposed Draft 3 version.

3. Another format change requested was to repeat the header row of column headings on each page. The SDT agrees and has made this change.

4. A few commenters correctly pointed out confusion between the introductory notes and the footnotes which both used numeric references. The SDT corrected this problem by using alpha character references for the introductory notes. The references within the table now clearly point to the footnotes and follow a more logical numerical order.

5. Several stakeholders suggested a Planning Event category naming convention for Planning Steady-State as (P1, P2, P3, …) and Stability as (S1, S2, S3, …) for the two table design. The SDT did not make this change based on a redesign to a single performance table. The team has retained the P1 through P7 references for Planning Events.

CONTENT COMMENTS:

1. The SDT agrees with a number of stakeholders that expressed an opinion on the need to allow for all types of conditional Firm Transmission Service Interruptions, not just those limited to HVDC. The SDT recognizes that the prior Draft 2 version unintentionally provided preferential treatment to HVDC. In the new performance Table 1, a new footnote has been added (see footnote 5) to the column title "Interruption of Firm Transmission Service Allowed" that corrects the problem identified.

2. Some commenters questioned the distinction in performance requirements for the above 300 kV systems. The SDT believes the Draft 2 changes are responsive to the prior industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission System. The team has now included a slightly modified version of stated performance requirements in Draft 3. The SDT has clarified that interruption of Firm Transmission Service is warranted for some Contingencies. The SDT has added footnotes 5 and 10 related to Firm Transmission Service. Footnote 5 indicates that interruption of conditional firm Transmission service is permitted for all Planning Events and footnote 10 indicates that interruption of Firm Transmission Service coupled with appropriate generation re-dispatch can be utilized for multiple Contingency events as a System adjustment, where indicated in Table 1 as being part of the Initial System Condition, and as a post-Contingency corrective action so long as no interruption of Non-Consequential Load occurs and all Facility Ratings are maintained.

3. A number of commenters expressed concern related to Planning Event P5 "Protection System Failure" and the need to evaluate a single component failure of a BES Protection System; particularly a failure of a station battery. The SDT has revised the P5 Planning Event description to remove the reference to "single component failure" and the event description was changed to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to normal fault clearing. A Protection System failure resulting in loss of the substation (one voltage level plus transformers) would not qualify as a P5 Planning Event since that event is considered an Extreme Event. A Standard Authorization Request (SAR) has been issued for industry comment (1/20/2009 through 2/18/2009) based on work completed by the System Protection and Controls Task Force (SPCTF). The proposed project will address the need for Protection System redundancy, based on an n-1 failure of individual components of the Protection System.

4. Some commenters were confused by Planning Event P2.1 and the SDT has added footnote 8 to better clarify the intent of the P2.1 Contingency review.

5. Many stakeholders correctly noted that Extreme Event item 1 excluded the reference to shunt device. This has been corrected and now includes shunt devices.

6. Some commenters questioned the order of the Planning Events and questioned if they were based on a high to low probability order. The SDT chose to order the table by three main areas: 1) no Contingency (P0), 2) single Contingency

(P1 and P2), and multiple Contingency (P3 through P7). While the SDT agrees there is some overlap in probability order, for example, between P2 and P3, the SDT has more importantly made the proper performance level requirements based on a reliability "risk" level where risk accounts for impact times (x) probability of occurrence.

7. Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these system designs are permissible under the presently approved TPL-002-0 standard. FERC, in Order 693, was clear in paragraph 1794 that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement. As an alternative, an entity could seek an entity variance for the situation described through their Regional Entity organization. In paragraph 1794, FERC clarified that "…an entity may seek a regional difference to the Reliability Standard from the ERO for case-specific circumstances". The process described by FERC as a regional difference is described in detail in the "NERC Standards Development Procedure" document under the subsection titled "Variances to NERC Reliability Standards".

The following changes have been made to the standard based on industry comments:

Requirements:

R2.8 The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1.

R2.9 The Planning Assessment shall identify the maximum permissible Non-Consequential Load Loss (megawatt Demand) for those Planning Events where Non-Consequential Load Loss is allowed in Table 1.

Table 1 Header Notes

e. For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

h. Planning Event P0 is applicable to steady state only.

Table 1 - Extreme Events – Steady State:

1. Loss of a single generator, Transmission Circuit, DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, DC Line, shunt device, or transformer forced out of service prior to System adjustments.

3b. ~~Loss of two Transmission lines in different rights-of-way prior to System adjustments for conditions such as:~~

Table 1 Footnotes:

2. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level for stated performance criteria applies regarding allowances for interruptions of Firm Transmission Service and loss of Non-Consequential Load.

3. Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø fault study indicating criteria are being met shall provide sufficient evidence that a SLG condition would also meet criteria.

5. When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed.

7. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.

8. Inadvertent tripping of breakers on one end of a normally networked Transmission circuit such that the line is now open at that end and possibly serving Load radial from a single source point.

10. Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.

11. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) breaker, only one pole is assumed to remain closed. ~~The~~A stuck breaker ~~event~~ introduces a delayed clearing mode. ~~Normal Clearing is when the Protection System operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Breaker fail relay operation is a predetermined time that occurs after the Protection System operates and the breaker has failed. Breaker fail relaying will also isolate a predetermined portion of the electric system to isolate the failed breaker. Delayed clearing of a Fault is due to failure of any Protection System component that prevents the Protection System from operating normally.~~

Organization	Question 7:	Question 7 Comments:
Dominion - Electric Transmission Planning	Yes and No	(1) Dominion - Electric Transmission is okay with the format changes, but suggests that consideration be given to changing the category naming convention for Stability Performance Table 2 to S1, S2, etc. rather than P1, P2, etc. for clarity and to distinguish them from Steady State Performance Table 1.(2) The tables could be improved if the headings were put on each separate page.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". This change has negated the need for the Planning		

Organization	Question 7:	Question 7 Comments:
Event category naming convention changes suggested by the commenter and the SDT retained the P1 through P7 references for Planning Events. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages.		
NPCC	No	In both Table 1 and Table 2, the "Interruption of Firm Transmission Service Allowed" column. It is problematic to try to create an "exemption" based on type of facility such as HVDC. There are many other situations in which Firm Transmission Service has been provided, but may need to be curtailed partially or completely following an outage. It is recommended that a note be added stating that the only exception would be for curtailment of conditioned (or Conditional) Firm Transmission Service, recognizing that there may need to be some form of grandfathering in order to avoid having to rewrite transmission service agreements. In both Table 1 and Table 2, the "Extreme Event Descriptions" item 1 should add "or shunt device." In Table 1, the "Extreme Event Descriptions" item 3b should be deleted; it is redundant with Item 1. In Table 2, Note 5 includes significant clarifications and should not be buried in the bottom of the contingency table; Note 5 would be better placed in the definitions section. In Table 1 and Table 2, Contingency P5 requires a fault plus Protection System Failure, such as a battery system, which may remove ALL protection at some substations. This Contingency P5 requires all voltages and loadings to remain within criteria, and a stable system response; without interruption of firm transmission service and without Non-Consequential Load Loss, at voltages above 300 kV. Was this an intended outcome of this standard?
Northeast Utilities	No	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
Response: The SDT team agrees with the commenter's opinion on the need to allow for all types of conditional Firm Transmission Service Interruptions and that the prior Draft 2 version unintentionally provided preferential treatment to HVDC. In the new performance Table 1, a new footnote has been added (see footnote 5) to the column title "Interruption of Firm Transmission Service Allowed" that corrects the problem identified by the commenter. **5**. When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed. The SDT agrees that shunt devices were excluded in Extreme Event item 1 of the Steady-State and Stability tables and the problem has been corrected. The SDT agrees with the commenter regarding the opinion that item 3B in the Extreme Event portion of the prior Daft 2 Table 1 Steady-State was redundant and the item has been removed and is no longer referenced in this draft. **Extreme Events - 3b**. ~~Loss of two Transmission lines in different rights-of-way prior to System adjustments for conditions such as:~~ The SDT appreciates the input related to the footnote on "System Stable" (new footnote 1). The SDT has chosen to leave the information within a footnote and		

Organization	Question 7:	Question 7 Comments:
did not include it as a new definition for the NERC Glossary of Terms as suggested by the commenter. Related to the P5 "Protection System Failure" Planning Event the SDT has not deviated from its stance of requiring more stringent performance requirements for the above 300 kV System. The SDT has revised the P5 Planning Event description to remove the reference to "single component failure" and the event description was changed to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to the normal fault clearing. A Protection System failure resulting in loss of the substation (one voltage level plus transformers) would not qualify as a P5 Planning Event since that event is considered an Extreme Event. A Standard Authorization Request (SAR) has been issued for industry comment (1/20/2009 through 2/18/2009) based on work completed by the System Protection and Controls Task Force (SPCTF). The proposed project will address the need for Protection System redundancy, based on an n-1 failure of individual components of the Protection System.		
TVA System Planning	Yes	TVA believes that the new table format does make the tables much easier to follow. However, the tables can be a little hard to follow for those categories that have both over and under 300-kV categories. Also having header pages at the top of each page of the tables would also help. Should P6 and P7 events be moved to Extreme Events since firm transmission and non-consequential load can be dropped for these events? Seems like these events are very similar to the Extreme Events.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages. The SDT has elected to retain both P6 (N-1-1) and P7 (Common Tower N-2) Planning Events in this third draft. There was no compelling industry opinion for the change and the events were considered by the SDT to be credible events and warrant the Planning Event level of scrutiny. There are more severe versions of these events contained with the Extreme Event area.		
City Water, Light & Power - Springfield, Illinois	Yes and No	Place the titles on each page and put the borders back in.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages. The SDT believes the new table will also address your concern regarding the borders. If not, please provide a more specific comment in your review of the Draft		

Organization	Question 7:	Question 7 Comments:
3 standard.		
Progress Energy Carolinas	Yes	The readability of the tables could be improved if the headings were put on each separate page. Separating out the tables for steady state and stability greatly improves and clarifies the requirements of the standard. Additionally, we would prefer that dynamic planning events use labeling such as D1, D2, etc. instead of P1, P2, etc. to differentiate them from steady state events.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table has negated the need for the Planning Event category naming convention changes suggested by the commenter and the team retained the P1 through P7 references for Planning Events. The move to a single table was based on a significant number of comments and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages.		
Platte River Power Authority	Yes and No	I like the emphasis on stability performance but I prefer one table combining steady-state and stability Categories since the Planning Events are common to both. Divide notes, Evaluation Requirements, and Extreme Events Descriptions into two sub-tables.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of commenters, like yourself, who felt a single table would suffice. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The SDT divided the top notes between those that are applicable to Steady-state, Stability or both as suggested by the commenter.		
BCTC	No	The differences in the tables requiring two tables are not apparent. Furthermore, we have become familiar with working with the current Table 1. Changing to these new tables will result in transition costs. We see no problems with continuing to use the current Table 1 and would prefer to retain it.
Response: While the new tables and naming conventions will require some effort for industry adaption, the SDT believes the tables provide greater clarity and drive the reliability improvements desired by FERC Order 693.		

Organization	Question 7:	Question 7 Comments:
Manitoba Hydro	No	There appears to be little difference between Table I and II other than the performance requirements at the start of each table, which should be embedded within standard. Manitoba Hydro would prefer one table as we believe it serves to simplify the standard readability. Additional Comments on Table 1:The Performance Requirements (Items 1 to 6) should have a heading "Evaluation Requirements". These evaluation requirements should be included in the standard body. Also they should be labeled A to F to avoid confusion with the Notes at the end of the Table. Item 6 is not applicable for steady state analysis. Suggest changing "Notes" to "Table I Notes" for improved readability if more than one table is retained. Planning Events: In cases where Non-consequential Load Loss is allowed, has the SDT discussed limiting the amount of load lost? Planning Events: For the multiple contingency events, in cases where Interruption of Firm Transmission Service or Non-Consequential Load Loss is allowed, the SDT should clarify that such loss is only allowed after the second event. P1: Similar to DC lines, interruption of Firm Transmission Service should be allowed for AC transmission lines, as in many cases, the firm transmission service is dependent on the outaged AC transmission line or transformer, that is, the contract path. P2-1: Suggest changing :single ended line: to "open ended line". P3: Similar to DC lines, interruption of Firm Transmission Service should be allowed if transfer is dependent on the outaged AC transmission line or transformer - the contract path. Planning Events >300 kV: Interruption of firm transfer should be allowed if AC contract path is lost due to an event. In many cases the majority of the firm transfer is carried by the contract path ac line, not that unlike the case of the DC line. MH has sold Firm Transmission Service, the delivery of which is dependent on the single circuit Winnipeg-Twin Cities 500 kV line being in-service, This Firm Transmission Service is available in the order of 99.6% of the time. Assuming two 5 day planned maintenance outages per year the availability is 97.3% per year. MH's transmission customers did not want to pay some $800 million in capital costs for a second 500 kV line to increase the Firm Transmission Service availability by 2%, especially considering that Firm Transmission Service loss does not result in loss of load, but results in a call for redispatch (call for Operating Reserves being carried to cover for loss of the largest generator or largest loaded transmission line with associated fast generation runback (SPS)). The inability to interrupt Firm Transmission Service will drive expensive new line construction, or require withdrawal of 1500 MW of firm transmission service from the market. P4: Greater than 300 kV - Interruption of Firm Transmission Service should be allowed if transfer is dependent on the outaged AC transmission line or transformer. The low probability of P4 events does not warrant the cost of raising the reliability performance requirements.

Organization	Question 7:	Question 7 Comments:
		P5: Greater than 300 kV - Interruption of Firm Transmission Service should be allowed if transfer is dependent on the outaged AC transmission line or transformer. NERC defines a Protection System as "Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry. In many cases, the protective relays, associated communication circuits and DC control circuits consist of two separate or redundant systems, but the voltage and current devices and station battery may be common. Is the SDT considering a current sensing device, or the station battery, for example, to be a single point of failure? Table 1 Note 4: Imposes a requirement on FACTS devices, and therefore should be elevated to the Requirements in the standard body. Also FACTs devices can be put in a series connection as well as shunt. Perhaps some additional clarification is required. Additional Comments on Table 2: Stability Performance Requirements: ?The Performance Requirements (Items 1 to 5) should have a heading "Evaluation Requirements". These evaluation requirements should be included in the standard body. Also they should be labeled A to E to avoid confusion with the Notes at the end of the Table 2 – Item 4: should the simulation also include the effect of reclosing where applicable? Planning Events: Same as comments on Table 1 regarding treatment of Firm Transmission Service and Non-Consequential Load Loss for >300 kV P4: Greater than 300 kV - Interruption of Firm Transmission Service should be allowed if transfer is dependent on the outaged AC transmission line or transformer. P5: Greater than 300 kV - Interruption of Firm Transmission Service should be allowed if transfer is dependent on the outaged AC transmission line or transformer. Multiple Contingency events (P3, P6): Does the SDT envision these multiple events being simulated as a stability run for the second event using a base case with an adjusted system - considering the first event is typically P1 which has been previously run as a separate simulation, typically a P1 event? P5: see Table 1 comment re what is considered a single point of failure. Extreme Events: Evaluation Requirement 1 - R5.5.4 should be R5.4.4 Extreme Event Description 2H: A 3 phase bus fault on a switching station would not normally result in loss of a voltage level and transformers at a station. The event should just be loss of one voltage level plus transformers in a substation. Table 2 Notes: Suggest changing "Notes" to "Table 2 Notes" if more than one table is retained. Note 5 a. Stipulates requirements for generating unit performance - should not be buried in the notes. Also, what is the SDT rationale for allowing units to pull out of synchronism for single contingency events like P2, or P5 - stuck breaker, or P7 - common tower, which is a normal clearing event.

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		P1: Similar to DC lines, interruption of Firm Transmission Service should be allowed if transfer is dependent on the outaged AC transmission line or transformer. P3: Similar to DC lines, interruption of Firm Transmission Service should be allowed if transfer is dependent on the outaged AC transmission line or transformer. It is important for a probabilistic measure of likelihood to be considered in designing Table 1 and Table 2. The various categories of contingencies, P1 to P7, for example, should be ideally arranged in order of magnitude of likelihood, so that the acceptable consequences or the performance requirements may be in an increasing level of severity. However, there are events with intrinsically different probabilities currently classified within each of these contingency categories. For example, in P3 (following loss of a generator followed by system adjustments), another generator forced outage is more likely than a transformer forced outage. In P2 (single contingency), loss of a bus section is less likely than the P3 event of a double generator contingency. Therefore, these P categories, as currently defined, overlap one another in the scale of likelihood. As a result of it, Table 1 and Table 2 have allowed for certain rarer events (e.g., included in single-contingency P2 and double-contingency P3 categories) to incur some significant consequences with unspecified limits, e.g., interruption of firm transmission services or "non-consequential" load loss. It may be better to follow the NERC Reliability Concepts White Paper's approach of displaying these tables in categories of event likelihood, so that the acceptable consequences would be in an increasing level of severity. This approach would then be consistent with Probabilistic Risk Assessment, when the industry has collected enough transmission outage data to enable such a method be applied. Though the US power industry does not have transmission outage statistics collected and analyzed across the industry, Canadian utilities do have excellent data. It seems to be possible for the various contingency events in the current Tables 1 and 2 to be recategorized according to five or six groups of "order of magnitude of likelihood", e.g., M0, M1, M2, M3, M4 and M5. Each order of magnitude of likelihood is ten times less likely than the preceding order. For example, the first order (M1) would be for outage probabilities greater than 1%. The second order (M2) would be for outage probabilities between 0.1% and 1%. The third order (M3) would be between 0.01% and 0.1%, etc. Multiple independent contingencies could be classified based on the product of their individual probabilities, e.g., a generator outage is of order M1, and a transmission circuit outage is of order M2. Therefore, a double contingency of a generator and a transmission circuit is of order M3, but a double generator contingency is of order M2. Having placed the initiating contingencies in these orders of likelihood, it is then feasible for the industry stakeholders to try to agree on the level of acceptable consequences for these magnitude orders of likelihood. In the current draft of this standard, there is no quantified variable degree of acceptable consequences, as envisioned in the NERC Reliability Concept White Paper.There is distinctly different treatment of whether the out-of-service element is below or above 300KV. There is difference in allowing or not allowing firm transaction interruption and/or non-consequential load loss, but neither of them has a specified limit on the MW amounts. With the current layout of Tables 1 and 2, it is not readily apparent that the proposed standard is consistent with a sound risk approach. Having a sound risk approach is very important because investment decisions will be made according to these new, proposed and still-deterministic standards. Planners may find out in their studies that the costs of meeting some unlikely contingencies requiring expensive transmission investments are very high and that these costs are not justifiable based on avoiding those rare consequences. On the other hand, because the amounts of acceptable firm transaction interruption and non-consequential load loss are not specified, the transmission system designed to that

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		standard with unspecified limits may become vulnerable to cascading events that initiate in the transmission grid below 300 KV. Many entries in the Tables allow non-consequential load losses, but no limits are specified. It raises the question, "If any non-consequential load loss is acceptable, is there a need to study that contingency scenario?" Without a reasonable set of limits, the criteria may not be effective in assuring system reliability. NERC's event analysis group has been using five categories of consequences to classify recent blackouts or major disturbances. A condensed summary of this is as follows. Category 1. Abnormal frequencies > 5min; or inter-area oscillations Cateorgy 2. System separation with no loss of load or generation; or loss of generation (between 1,000 and 2,000 MW in the EI or WI and between 500 MW and 1,000 MW in ERCOT) Category 3. Loss of load (less than 1,000 MW); or loss of generation (> 2,000 MW in the EI or WI and > 500 MW in ERCOT); System separation or islanding with loss of load or generation (less than 1,000 MW). Category 4. System separation or islanding of more than 1,000 MW of load; or loss of load (1,000 to 9,999 MW). Category 5. Loss of load (10,000 MW or more) Lay persons as well as transmission planners can understand and appreciate these ways of defining consequences, e.g., category 5 events mean more than 10,000 MW of load or generation loss. A way to propose reasonable limits to the highly unlikely but potentially severe contingencies, e.g., M3, M4, and M5, would be to limit their designed consequences to Category 2, 3 or 4. A well designed transmission system should limit the consequences of potential cascading outages and their likelihood so that fewer major blackouts would occur, while balancing the cost of investment to the cost of outages to the customers. A number of utilities are already performing PRA studies for their transmission planning. The advantages of using PRA have been demonstrated in the nuclear power industry. It would be desirable to have a pathway for the power industry to transition from the still-deterministic planning criteria in TPL-001 to a probabilistic planning criteria, without having to wait for another major revision to the TPL standard. If the Tables 1 and 2 are arranged and presented consistently with the NERC Reliability Concepts White Paper, the approach will enable that transition to take place naturally. If the TPL-001 standards establish a PRA-compatible Table 1 and Table 2, with contingency categories sorted in order of magnitude of likelihood, and their acceptable consequences also arranged in order of consequences (such as the five categories), the reliability requirement is already seen in the PRA-compatible way of a constant Risk level, Risk = Likelihood x Consequence. When the industry has good data to quantify the probabilities of these various contingencies, the implication of this ?already-accepted? Risk Level would be clear and numerically expressable. What is useful at this time is for the industry to make a forward-looking estimate of what this Risk level would be like, and consider whether it is appropriate and consistent with sound economic and risk principles.

Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled “Steady State and Stability Performance”. The move to a single table was based on a significant number of comments and based on the SDT’s view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages.

The top introductory notes have been retained and are now referred to alphabetically to avoid confusion with the referenced footer notes. The top notes also

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better clarify which are applicable to steady-state, stability or both.

The standard does not place a limit on the amount of Non-Consequential Load loss allowed. However, the maximum Consequential Load loss and its associated Contingency require documentation. See Requirements R2.9 and 2.10.

R2.8 The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1.

R2.9 The Planning Assessment shall identify the maximum permissible Non-Consequential Load Loss (megawatt Demand) for those Planning Events where Non-Consequential Load Loss is allowed in Table 1.

In regards to the Planning Event P3, the SDT team agrees with the commenter's opinion on the need to allow for all types of conditional Firm Transmission Service interruptions and that the prior Draft 2 version unintentionally provided preferential treatment to HVDC. In the new performance Table 1, a new footnote has been added (see footnote 5) to the column title "Interruption of Firm Transmission Service Allowed" that corrects the problem identified by the commenter. The SDT believes that interruption of Firm Transmission Service may be justified, so long no firm load loss occurs if the performance requirements do not permit the load shed. See new footnote 10 regarding the SDT stance on interruption of Firm Transmission Service and its use in multiple contingency Planning Events.

In regards to Planning Event P2.1, the reference to "single ended" has been removed and footnote 8 was added to further clarify the event required for study.

Based on feedback received the SDT was not compelled to alter its stance on the provision for Non-Consequential Load shed for a P4 and P5 event. However, the SDT has added footnotes 5 and 10 related to Firm Transmission Service. Footnote 5 indicates that interruption of conditional firm transfers is permitted for all Planning Events and footnote 10 indicates that interruption of Firm Transmission Service coupled with appropriate generation re-dispatch can be utilized for multiple Contingency events as a System adjustment, where indicated in Table 1 as being part of the Initial System Condition, and as a post-Contingency corrective action so long as no interruption of Non-Consequential Load occurs and all Facility Ratings are maintained.

The SDT has revised the P5 Planning Event description to remove the reference to "single component failure" and the event description was changed to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to the normal fault clearing. A Protection System failure resulting in loss of the substation (one voltage level plus transformers) would not qualify as a P5 Planning Event since that event is considered an Extreme Event. A Standard Authorization Request (SAR) has been issued for industry comment (1/20/2009 through 2/18/2009) based on work completed by the System Protection and Controls Task Force (SPCTF). The proposed project will address the need for Protection System redundancy, based on an n-1 failure of individual components of the Protection System.

The SDT agrees that FACTS can be series devices and the footnote reference has been modified to better clarify the intent is shunt devices, connected to ground. See footnote 7.

7. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.

The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of

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comments and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages. The requirements do not require study of reclosing actions. Only the initial Protection System responses must be simulated. P3 – see above response for Table 1. Based on feedback received the SDT was not compelled to alter its stance on the provision for Non-Consequential Load shed for a P4 and P5 event. However, the SDT has added footnotes 5 and 10 related to Firm Transmission Service. Footnote 5 indicates that interruption of conditional firm transfers is permitted for all Planning Events and footnote 10 indicates that interruption of Firm Transmission Service coupled with appropriate generation re-dispatch can be utilized for multiple Contingency events as a System adjustment, where indicated in Table 1 as being part of the Initial System Condition, and as a post-Contingency corrective action so long as no interruption of Non-Consequential Load occurs and all Facility Ratings are maintained. In the multiple Contingency P3 (Gen + 1) and P6 (N-1-1), within a stability study only the 2nd outage is required to be reviewed. The first Contingency is a precondition that needs to be modeled but not evaluated for its Stability response if the P3 or P6 condition is studied for Stability. The SDT has revised the P5 Planning Event description to remove the reference to "single component failure" and the event description was changed to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to the normal fault clearing. A Protection System failure resulting in loss of the substation (one voltage level plus transformers) would not qualify as a P5 Planning Event since that event is considered an Extreme Event. A Standard Authorization Request (SAR) has been issued for industry comment (1/20/2009 through 2/18/2009) based on work completed by the System Protection and Controls Task Force (SPCTF). The proposed project will address the need for Protection System redundancy, based on an n-1 failure of individual components of the Protection System. In the Extreme Events area of the Stability table the reference to Requirement R5.5.4 has been removed due to a circular reference between the requirements and the table. The Extreme Event item 2h is written consistent with the presently approved TPL D8 and D9 contingencies. The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages. The SDT team agrees with the commenter's opinion on the need to allow for all types of conditional Firm Transmission Service interruptions and that the prior Draft 2 version unintentionally provided preferential treatment to HVDC. In the new performance Table 1, a new footnote has been added (see footnote 5) to the		

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column title "Interruption of Firm Transmission Service Allowed" that corrects the problem identified by the commenter Regarding bottom note 5a, now shown as footnote 1, the SDT believes that no unit should be allowed to pull out of synchronism for more likely single Contingency events such as a three-phase fault on a line, transformer, or generator - a P1 event. The P2 events, even though classified as single Contingency events with normal clearing, are less likely to occur (bus faults, internal breaker faults, etc.). P5 and P7 are multiple Contingency events and are less likely to occur. The SDT believes it is appropriate to allow units to pull out of synchronism for less likely events as long as the other conditions of footnote 1 are maintained. The Planning Events, in general are ordered based on level of probability. However, the SDT chose to order the table by three main areas: 1) no Contingency (P0), 2) single Contingency (P1, P2) and 3) multiple Contingency (P3 through P7). While the SDT agrees with the commenter that there is some overlap in probability order, for example between P2 and P3, we believe the SDT has more importantly made the proper performance level requirements based on a reliability "risk" level where risk accounts for impact times (x) probability of occurrence. The commenter's proposed shift from deterministic planning to probabilistic planning is outside the scope of the SAR for this project. The SDT believes the commenters suggested focus on more detailed probabilistic analysis is better addressed after the industry obtains additional outage data and insight obtained through the TADS effort.		
Los Angeles Department of Water and Power	No	The performance table allows different performance for same contingency at different voltage classes that is arbitrary separated. This is discriminatory and without any scientific or historical basis. There should be only one class for the whole transmission system. Transmission system at below 300kV should not be granted preferential treatment. Mindful also that the initiating causes of last two major continental wide blackouts(one in WECC and the other in the Eastern Interconnections) both started in system at less than 300kV.
Response: The SDT believes it has provided sufficient reasoning why the above 300 kV System should be held to a higher standard. The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission Systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT believed the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated above 300 kV generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers where the energy is then delivered by other Transmission or sub-Transmission Systems to end-use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. Additionally, loss of the EHV system stresses the lower voltage parallel paths. EHV transformers can be exposed to long duration outages. Therefore, it was the conclusion of the SDT in Draft 1 to propose greater reliability and operational flexibility through more stringent performance requirements when considering certain N-1 and N-1-1 Contingency events of EHV Systems. Throughout the industry, substation arrangements at EHV levels reflect the importance of these Systems as the designs often consist of the more flexible and reliable ring-bus, breaker-and–a-half or double bus-double breaker protection schemes as compared to the simpler, lower cost single bus arrangements that are commonly found on lower voltage systems. The feedback received from the industry was divided related to the SDT's emphasis placed on a higher expectation for the 300 kV and higher systems. Some commenters questioned the importance and the high costs that may be needed to mitigate existing system designs. Others agreed with the SDT's approach and indicated that the impact to their systems would be minimal. Some commenters even questioned why the more stringent approach was not applied to the entire		

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100 kV and higher systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission System.		
Transmission Agency of Northern California	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.
Public Service Company of New Mexico	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.
Puget Sound Energy, Inc.	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for events could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not

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Black Hills Corporation	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.
Tucson Electric Power Company	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.The proposed format covers multiple pages. Add the header rows to each page for easier reading.

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Pacific Gas and Electric Co.	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.
Idaho Power Company	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some maybe some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SGT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believes there should be no distinction between the voltage classes and supports the use of load shed for all cases identified in P4 through P7.
SMUD	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state.

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Sierra Pacific Power Comapny / Nevada Power Company	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some maybe some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SGT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believes there should be no distinction between the voltage classes and supports the use of load shed for all cases identified in P4 through P7.
SRP	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.
Tucson Electric	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two

Organization	Question 7:	Question 7 Comments:
Power Company		Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.The proposed format covers multiple pages. Add the header rows to each page for easier reading.
Modesto Irrigation District	Yes and No	Comments: We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.
Tri-State G&T	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate

Organization	Question 7:	Question 7 Comments:
		interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.
ColumbiaGrid	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some maybe some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SGT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Please explain/define the term "single ended line" used in Table 1, P2.1. We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.
Alberta Electric System Operator	No	We do not agree with the proposed format changes of the Tables, separating into two Tables is not necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.
US Bureau of Reclamation	No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not

Organization	Question 7:	Question 7 Comments:
		modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.

Response: The SDT agrees with the commenter related to the prior two table format and based on feedback received from the Draft 2 standard the SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The SDT believes the commenter will find that the new format is greatly condensed and more user friendly from a readability view.

The commenter is correct that the use of the term "fault" in the P4 and P5 events is not needed from a steady-state view; however, the SDT felt the term is needed to accurately describe the event to be analyzed. From a steady-state perspective, only the resulting condition would be analyzed. Also, with the combined format the term is now better used as the Planning Events also describe the type of fault to be studied within a Stability study. Footnote 3 clarifies that the type of fault is referenced only for the Stability studies.

In regards to the P2.1 event, the intent is to capture a potential condition of serving Load that is tapped from a normally networked line from a single source location. If a line exists (breaker to breaker) that does not directly serve Load, the P2.1 condition would not apply and only the normal N-1 condition of the line would be studied. See the newly added footnote 8 that better describes the intent of the P2.1 Planning Event.

The SDT believes it provided sufficient justification in its Draft 1 response as to why a greater expectation is placed on the above 300 kV (EHV) system. The feedback received from the industry was divided related to the SDT's emphasis placed on a higher expectation for the 300 kV and higher systems. Some commenters questioned the importance and the high costs that may be needed to mitigate existing system designs. Others agreed with the SDT's approach and indicated that the impact to their systems would be minimal. Some commenters even questioned why the more stringent approach was not applied to the entire 100 kV and higher systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission System.

Based on feedback received the SDT was not compelled to alter its stance on the provision for non-consequential load shed. However, the SDT has added footnotes 5 and 10 related to Firm Transmission Service. Footnote 5 indicates that interruption of conditional firm transfers is permitted for all Planning Events and footnote 10 indicates that interruption of Firm Transmission Service coupled with appropriate generation re-dispatch can be utilized for multiple Contingency events as a System adjustment, where indicated in Table 1 as being part of the Initial System Condition, and as a post-Contingency corrective action so long as no interruption of Non-Consequential Load occurs and all Facility Ratings are maintained.

5. When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed.

Organization	Question 7:	Question 7 Comments:
National Grid	No	a. In the column "Interruption of Firm Transmission Service Allowed" in both Tables 1 and 2, it is problematic to try to create an "exemption" based on type of facility such as HVDC. There are many other situations in which Firm Transmission Service has been provided, but may need to be curtailed partially or completely following an outage. b. The term 'Firm' may have several different definitions. If 'Firm' Transmission Service or load may be interrupted for exceptional events, then it is conditional and 'Conditional Firm' should be defined. It is recommended that a note be added stating that "the only exception would be for curtailment of conditioned (or Conditional) Firm Transmission Service", recognizing that there may need to be some form of grandfathering in order to avoid having to rewrite transmission service agreements. c. In both Table 1 and Table 2, the "Extreme Event Descriptions" item 1 should add "or shunt device." d. In Table 1, the "Extreme Event Descriptions" items 3a and 3b should be deleted; they are redundant with Item 1. e. In Table 2, Note 5 includes significant clarifications and should not be buried in the bottom of the contingency table; Note 5 would be better placed in the definitions section. f. In Table 1 and Table 2, Contingency P5 requires a fault plus Protection System Failure. Assuming that the battery system is included in the Protection System, which it is in NPCC, then ALL protection at substations with single battery systems would be lost. This Contingency P5 requires a stable system response while all bus voltages and loadings to remain within criteria, without interruption of firm transmission service and without Non-Consequential Load Loss, at system voltages above 300 kV. Was this an intended outcome of this standard?
Central Maine Power Company	No	a. In both Table 1 and Table 2, the "Interruption of Firm Transmission Service Allowed" column. It is problematic to try to create an "exemption" based on type of facility such as HVDC. There are many other situations in which Firm Transmission Service has been provided, but may need to be curtailed partially or completely following an outage. b. The term 'Firm' may have several different definitions. If 'Firm' Transmission Service or load may be interrupted for exceptional events, then it is conditional and 'Conditional Firm' should be defined. It is recommended that a note be added stating that "the only exception would be for curtailment of conditioned (or Conditional) Firm Transmission Service", recognizing that there may need to be some form of grandfathering in order to avoid having to rewrite transmission service agreements. c. In both Table 1 and Table 2, the "Extreme Event Descriptions" item 1 should add "or shunt device." d. In Table 1, the "Extreme Event Descriptions" items 3a and 3b should be deleted; they are redundant with Item 1. e. In Table 2, Note 5 includes significant clarifications and should not be buried in the bottom of the contingency table; Note 5 would be better placed in the definitions section.

Organization	Question 7:	Question 7 Comments:
		f. In Table 1 and Table 2, Contingency P5 requires a fault plus Protection System Failure. Assuming that the battery system is included in the Protection System, which it is in NPCC, then ALL protection at substations with single battery systems would be lost. This Contingency P5 requires a stable system response while all bus voltages and loadings to remain within criteria, without interruption of firm transmission service and without Non-Consequential Load Loss, at system voltages above 300 kV. Was this an intended outcome of this standard?
NSTAR Electric	No	1. Referring to both Table 1 and Table 2, the "Interruption of Firm Transmission Service Allowed" column, it is problematic to try to create an "exemption" based on the type of facility such as HVDC. There are situations in which Firm Transmission Service has been provided, but may need to be curtailed partially or completely following an outage. The term 'Firm' may have several different definitions. If 'Firm' Transmission Service or load may be interrupted for exceptional events, then it is conditional and 'Conditional Firm' should be defined. It is recommended that a note be added stating that "the only exception would be for curtailment of conditioned (or Conditional) Firm Transmission Service", recognizing that there may need to be some form of grandfathering in order to avoid having to rewrite transmission service agreements. 2. In both Table 1 and Table 2, the "Extreme Event Descriptions" item 1 should add "or shunt device." 3. In Table 1, the "Extreme Event Descriptions" items 3a and 3b should be deleted; they are redundant with Item 1. 4. Table 2, Note 5 includes significant clarifications which should not be buried in the back; they are better placed in the definitions section. 5. In Table 1 and Table 2, Contingency P5 requires a fault plus Protection System Failure. Protection System Failure should be defined and noted if the battery system is included.
New York Independent System Operator	No	In both Table 1 and Table 2, the "Interruption of Firm Transmission Service Allowed" column. It is problematic to try to create an "exemption" based on type of facility such as HVDC. There are many other situations in which Firm Transmission Service has been provided, but may need to be curtailed partially or completely following an outage. It is recommended that a note be added stating that the only exception would be for curtailment of conditioned (or Conditional) Firm Transmission Service, recognizing that there may need to be some form of grandfathering in order to avoid having to rewrite transmission service agreements. In both Table 1 and Table 2, the "Extreme Event Descriptions" item 1 should add "or shunt device." In Table 1, the "Extreme Event Descriptions" item 3b should be deleted; it is redundant with Item 1. In Table 2, Note 5 includes significant clarifications and should not be buried in the bottom of the contingency table; Note

Organization	Question 7:	Question 7 Comments:
		5 would be better placed in the definitions section. In Table 1 and Table 2, Contingency P5 requires a fault plus Protection System Failure, such as a battery system which may remove ALL protection at some substations. This Contingency P5 requires all voltages and loadings to remain within criteria, and a stable system response; without interruption of firm transmission service and without Non-Consequential Load Loss, at voltages above 300 kV. Was this an intended outcome of this standard?
ISO New England Inc.	No	a. In both Table 1 and Table 2, the "Interruption of Firm Transmission Service Allowed" column. It is problematic to try to create an "exemption" based on type of facility such as HVDC. There are many other situations in which Firm Transmission Service has been provided, but may need to be curtailed partially or completely following an outage. b. The term 'Firm' may have several different definitions. If 'Firm' Transmission Service or load may be interrupted for exceptional events, then it is conditional and 'Conditional Firm' should be defined. It is recommended that a note be added stating that "the only exception would be for curtailment of conditioned (or Conditional) Firm Transmission Service", recognizing that there may need to be some form of grandfathering in order to avoid having to rewrite transmission service agreements. c. In both Table 1 and Table 2, the "Extreme Event Descriptions" item 1 should add "or shunt device." d. In Table 1, the "Extreme Event Descriptions" items 3a and 3b should be deleted; they are redundant with Item 1. e. In Table 2, Note 5 includes significant clarifications and should not be buried in the bottom of the contingency table; Note 5 would be better placed in the definitions section. f. In Table 1 and Table 2, Contingency P5 requires a fault plus Protection System Failure. Assuming that the battery system is included in the Protection System, which it is in NPCC, then ALL protection at substations with single battery systems would be lost. This Contingency P5 requires a stable system response while all bus voltages and loadings to remain within criteria, without interruption of firm transmission service and without Non-Consequential Load Loss, at system voltages above 300 kV. Was this an intended outcome of this standard?

Response:

The SDT agrees with the commenter's opinion on the need to allow for all types of conditional Firm Transmission Service interruptions and that the prior Draft 2 version unintentionally provided preferential treatment to HVDC. In the new performance Table 1, a new footnote has been added (see footnote 5) to the column title "Interruption of Firm Transmission Service Allowed" that corrects the problem identified by the commenter.

The SDT agrees with the commenter that interruption of Firm Transmission Service may be justified, so long as firm Non-Consequential Load is not interrupted if the performance requirements do not permit the Load shed. See new footnote 10 regarding the SDT stance on interruption of Firm Transmission Service and its use in multiple Contingency Planning Events.

Organization	Question 7:	Question 7 Comments:
The SDT agrees that shunt devices were excluded in Extreme Event item 1 of the Steady-State and Stability tables and the problem has been corrected. The SDT agrees with the commenter regarding the opinion that item 3B in the Extreme Event portion of the prior Daft 2 Table 1 Steady-State was redundant and the item has been removed and is no longer referenced in this draft. **Extreme Events - 3b**. ~~Loss of two Transmission lines in different rights-of-way prior to System adjustments for conditions such as:~~ The SDT appreciates the input related to the footnote on "System Stable" (new footnote 1) but the SDT chose to keep it as a footnote reference for convenience to the TPL standard and not include it as a new definition for the NERC Glossary of Terms as suggested by the commenter. Related to the P5 "Protection System Failure" Planning Event the SDT has not deviated from its stance of requiring more stringent performance requirements for the above 300 kV System. The SDT has revised the P5 Planning Event description to remove the reference to "single component failure" and the event description was changed to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to the normal fault clearing. A Protection System failure resulting in loss of the substation (one voltage level plus transformers) would not qualify as a P5 Planning Event since that event is considered an Extreme Event. A Standard Authorization Request (SAR) has been issued for industry comment (1/20/2009 through 2/18/2009) based on work completed by the System Protection and Controls Task Force (SPCTF). The proposed project will address the need for Protection System redundancy, based on an n-1 failure of individual components of the Protection System.		
Tenaska, Inc.	Yes and No	Should add a column to the tables indicated when automatic generation runback/tripping is allowed.
Response: Redispatch of generation is allowed for all Planning Events provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits. The requirement has been removed and replaced with Table 1 header note "e" since the text in the former requirement was explanatory of what was allowed and not requirement language. **Header note 'e'**: For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.		
Gainesville Regional Utilities	No	Some of the notes at the top of each table could be considered to apply to some of the events within the table that conflict in part with the standard and with what was stated in the nation wide phone conference. I would also like to see a note in the tables that reflect a technical rationale for the range of elements considered, since some may be impractical and of no technical value for contingencies involving certain facilities especially those on the smaller systems within the interconnected region.
Response: The SDT has adjusted the top notes and refer to them with alpha character references to avoid confusion with the table footnotes that are referenced within the table. The set of Contingencies considered are not greatly different than those in the currently approved TPL suite of standards. We have attempted to add simplicity as to those Contingencies that are deemed to be Planning Events, thus requiring corrective action plans, and the Extreme Events which do not require corrective action plans.		

Organization	Question 7:	Question 7 Comments:
ITC Holdings: ITC, METC, ITC Midwest	Yes and No	While we like the tables, we don't understand what ?Interruption of Firm Transmission Service Allowed? means in a stability study (as per table 2). How would you interpret that in real-time & study terms? Would you make the stability scenario a limit to selling transmission service? In table 2, should we interpret SLG or 3-phase Fault in P1 and P3 to mean that SLG is the criteria (minimum) but you can run and document the more severe 3 phase faults for compliance purposes? What is the minimum criteria?
Response: The SDT has added footnotes 5 and 10 related to Firm Transmission Service. Footnote 5 indicates that interruption of conditional firm transfers is permitted for all Planning Events and footnote 10 indicates that interruption of Firm Transmission Service coupled with appropriate generation re-dispatch can be utilized as a System adjustment, where indicated in Table 1 as being part of the Initial System Condition, and as a post-Contingency corrective action so long as no interruption of Non-Consequential Load occurs and all Facility Ratings are maintained. In some instances, it may be necessary to interrupt Firm Transmission Service in preparation for the studied condition. It could be that from a Stability point of view such action would be beneficial under some conditions. **Footnote 5.** When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. The SDT has corrected the confusion related to the "SLG or 3-phase" fault reference that the commenter describes in the P1 Planning Event. The table now says 3-phase. We added footnote #3 to clarify the fault types and what study results are sufficient for the case of an SLG fault condition. **3.** Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø fault study indicating criteria are being met shall provide sufficient evidence that a SLG condition would also meet criteria.		
Hydro-Quebec Transenergie (HQT)	No	In both Table 1 and Table 2, the "Interruption of Firm Transmission Service Allowed", a definition should be provided to clarify that term. That term is more of a Market concept not used by all TOs and defined in their Transmission Tariff. Also, the standard might need to introduce a new term "Consequential Transmission Service Loss" as it does for the Load. Firm Transmission services are generally defined as a service of the same priority as the one for the native load. That does not mean it could not be interrupted. In both Table 1 and Table 2, the "Extreme Event Descriptions" item 1 should add "or shunt device." In Table 1, the "Extreme Event Descriptions" item 3b should be deleted; it is redundant with Item 1.

Organization	Question 7:	Question 7 Comments:
		In Table 2, Note 5 includes significant clarifications and should not be buried in the bottom of the contingency table; Note 5 would be better placed in the definitions section. In Table 1 and Table 2, Contingency P5 requires a fault plus Protection System Failure. The "Protection System Failure" aspect of this contingency brings the necessity to define more clearly what is intended. The notion of needed redundancy or single elements of the protection system, be it physical or electric, has to be addressed to clearly understand the implication of that contingency. Until such clarification is included in this standard or in the future "Redundancy standard", this contingency should not be effective.

Response: The NERC Glossary of Terms presently defines Firm Transmission Service as "The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." FERC in Order 693 was clear that no planned interruption of Firm Transmission Service should be permitted for single Contingency conditions. We agree that there may be times when Firm Transmission Service should be permitted. The SDT has added footnotes 5 and 10 related to Firm Transmission Service. Footnote 5 indicates that interruption of conditional firm transfers is permitted for all Planning Events and footnote 10 indicates that interruption of Firm Transmission Service coupled with appropriate generation re-dispatch can be utilized for multiple Contingency events as a System adjustment, where indicated in Table 1 as being part of the Initial System Condition, and as a post-Contingency corrective action so long as no interruption of Non-Consequential Load occurs and all Facility Ratings are maintained.

5. When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed.

Footnote #10 – Curtailment of firm transmission service , when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.

The SDT agrees that shunt devices were excluded in Extreme Event item 1 of the Steady-State and Stability tables and the problem has been corrected.

Extreme Event Steady State #1

Loss of a single generator, Transmission Circuit, DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, DC Line, shunt device, or transformer forced out of service prior to System adjustments.

The SDT agrees with the commenter regarding the opinion that item 3B in the Extreme Event portion of the prior Daft 2 Table 1 Steady-State was redundant and the item has been removed and is no longer referenced in this draft.

Extreme Event – Steady State:

3b. ~~Loss of two Transmission lines in different rights-of-way prior to System adjustments for conditions such as:~~

The SDT appreciates the input related to the footnote on "System Stable" (new footnote 1) but the SDT chose to keep it as a footnote reference for convenience

Organization	Question 7:	Question 7 Comments:
to the TPL standard and not include it as definition for the NERC Glossary of Terms as suggested by the commenter. Related to the P5 "Protection System Failure" Planning Event the SDT has not deviated from its stance of requiring more stringent performance requirements for the above 300 kV System. The SDT has revised the P5 Planning Event description to remove the reference to "single component failure" and the event description was changed to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical facilities being removed when compared to the normal fault clearing. A Protection System failure resulting in loss of the substation (one voltage level plus transformers) would not qualify as a P5 Planning Event since that event is considered an Extreme Event. A Standard Authorization Request (SAR) has been issued for industry comment (1/20/2009 through 2/18/2009) based on work completed by the System Protection and Controls Task Force (SPCTF). The proposed project will address the need for Protection System redundancy, based on an n-1 failure of individual components of the Protection System.		
Progress Energy Florida, Inc.	No	The Steady State and Stability Tables (Tables 1 and 2), are overly long, confusing, and contain circular references. PEF strongly advises returning to the content and format of Table 1 in the existing TPL Standards, or at the very least, consolidation of the Tables into a single Table. Furthermore, for certain events in Tables 1 and 2, the SDT's intent concerning the scope of the events and how the events would be simulated in Transmission Planning analyses is not clear. PEF furthermore does not agree with "Interruption of Firm Transmission Service Allowed" and "Non-Consequential Load Loss Allowed" as benchmarks for whether or not a particular BES is reliable (see additional comments in Question 15 on this issue). Tables 1 and 2 at present are 13 pages in total, whereas the existing Table 1, which PEF feels is comprehensive and not in need of revision, is merely 1.5 pages long. PEF understands that the reason behind the length and complexity of Tables 1 and 2 stems from a desire by some to contain all of the primary TPL compliance issues in a tabular format. The end result, however, is not effective and must be made more concise.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. The new format more closely mimics the existing TPL table in its readability. The set of Contingencies considered are not greatly different than those in the currently approved TPL suite of standards. The SDT has attempted to add simplicity as to those Contingencies that are deemed to be Planning Events, thus requiring corrective action plans, and the Extreme Events which do not require corrective action plans. The change in performance expectations for the above 300 kV System are supported by many in the industry. Please see our response to Q15 for further information.		
Ameren	Yes	The tables could be improved by including the column headings on each page.

Organization	Question 7:	Question 7 Comments:
		Separating the steady-state and stability performance requirements for each planning event helps to provide clarification.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages.		
City of Tallahassee, FL	Yes and No	while this was an improvement, the tables are still confusing and make determination of the compliance requirements difficult. Especially where there are multiple events within a single event category (like P3 or P6) there's confusion about what would be allowed between the two element outages.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments to do so and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. The SDT believes the changes improve the readability of the tables. There are concerns expressed by numerous respondents that after the first single Contingency and System adjustment, curtailment of Firm Transmission Services (or firm transfers) and shedding of firm Load would not be allowed in preparation for the second Contingency. The SDT added Footnote # 10 to the end of Table 1 to reflect that Curtailment or Interruption of Firm Transmission Service in preparation for the next Contingency will be allowed as long as firm Load, not outaged by the initial event, continues to be served. **Footnote #10** – Curtailment of firm transmission service , when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
Florida Power and	No	The Table format is extremely confusing and too long.

Organization	Question 7:	Question 7 Comments:
Light		The allowed and disallowed actions as well as the applicable time frames for them is not clearly stated. The tables 1 &2 should be combined and condensed so that they can be read more easily. In their current format, these tables sprawl across 13 pages. The use of footnotes or expanded information in the Table headings is needed to understand the performance requirements.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments to do so and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. The SDT believes the changes improve the readability of the tables. The changes to the new table have removed the need for repeat headers. Regarding the commenter's statement "The allowed and disallowed actions as well as the applicable time frames for them is not clearly stated." It is assumed that this is in reference to the P6 N-1-1 Planning Event. There are concerns expressed by numerous respondents that after the first single Contingency and System adjustment, curtailment of Firm Transmission Services (or firm transfers) and shedding of firm Load would not be allowed in preparation for the second Contingency. The SDT added Footnote # 10 to the end of Table 1 to reflect that Curtailment or Interruption of Firm Transmission Service in preparation for the next Contingency will be allowed as long as firm Load, not outaged by the initial event, continues to be served. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
Exelon Transmission Planning	No	Tables 1 and 2 should be changed such that the header should read 'BES Elements Overloaded' rather than 'BES Elements out of Service' regarding the voltage distinction. The header notes should either not be numbered or numbered with a different scheme to differentiate them from the numbered footnotes to avoid confusion. It is not obvious that all of the footnotes are used in the Tables. The headings should be repeated on each page. Could these tables be made smaller by eliminating some of the unused space such as the large boxes containing a single

Organization	Question 7:	Question 7 Comments:
		'x'?
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments to do so and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. The SDT believes the changes improve the readability of the tables. The confusion with regards to the prior "BES Elements Overloaded" has been eliminated in the new table as the prior columns have been deleted. The commenters' suggestion to repeat table headings was a common response from industry, but is no longer a need based on the new table design. The SDT has now utilized alpha character references for the top notes of the table to avoid confusion with the footnotes which are referenced throughout the table. All footnotes are accounted for with the table and are now referenced sequentially for improved readability.		
CenterPoint Energy and CPS Energy	No	We originally believed that eliminating the old Category A, B, C, and D nomenclature would be beneficial. However, looking at the contingency types now being proposed, we are concerned that more confusion has been created. For example, matching applicable facility ratings to Category A, B, and C conditions is reasonably manageable. Matching applicable facility ratings to 7 contingency "buckets" is more confusing, less manageable, and unnecessary. NYISO proposed the concept of analyzing credible multiple contingencies in the operating realm. Most industry opined that NYISO's proposal lacked merit for operating requirements, and we agreed. However, we believe the proposal may have merit for planning requirements. The concept of applying reasonable credibility criteria to multiple contingencies to be studied offers a way to limit multiple contingency analysis to credible scenarios. Less credible (or incredible) scenarios would then fall into the Extreme category. As proposed, the multiple (seven-fold) approach of categorizing contingencies, combined with various sensitivities or alternative scenarios, for multiple years, is unrealistic and unnecessary. We believe creating a separate table for stability performance might be beneficial, but we believe 7 buckets of contingencies is hopelessly unrealistic for stability analyses.
Response: The set of Contingencies considered are not greatly different than those in the currently approved TPL suite of standards. The SDT tried to better clarify those Contingencies that are deemed to be Planning Events, thus requiring corrective action plans, and the Extreme Events which do not require corrective action plans. Most in industry are receptive to the new Contingency categorization so the TPL SDT has not altered its organization of the performance requirements. The SDT believes the Planning Events describe the credible Contingencies that warrant more rigorous study and the Extreme Events represent the less credible events that need to be reviewed on a more selective basis by the individual transmission planner. In regards to matching an applicable Facility Rating to the 7 Planning Event categories, the SDT believes the 7 categories do not add any additional level of		

Organization	Question 7:	Question 7 Comments:
complexity. The need to cover sensitivity analysis is based on a FERC directive from Order 693 and the SDT believes it is a reasonable request which will drive the industry to better understand their individual Transmission Systems. At this time all Planning Events are still within the scope of possible System conditions that could require a Stability review. The SDT believes the proposed TPL explicitly clarifies that only the "more severe" events require Stability analysis as stated in Requirement R4.4. At this time all Planning Events are still within the scope of possible system conditions that could require a Stability review. The SDT believes the proposed TPL explicitly clarifies that only the "more severe" events require Stability analysis which was implicitly understood within industry for the Version 0 standards as the commenter describes. Many of the conditions described by the commenter could be used as the basis for how a Transmission Planner would select the subset of Planning Events requiring a Stability review.		
MidAmerican Energy Company	No	MEC suggests that the Categories symbols in Table 1 and Table 2 be different to help distinguish between them (e.g. P1:S1, P2:S2, P3.2:S3.2, etc.) MEC suggests that the header text (i.e. Category, Initial System Condition, etc.) be repeated on every applicable page to be more reader-friendly. The superscripts do not refer clearly to the respective notes. (There are numbered notes in the beginning of the table, numbered items in the extreme events evaluation requirements section, numbered items in extreme event description section, and numbered notes at the end of the table). Perhaps the referenced notes should have unique numerology or format to make the superscript references clearer.
MRO NERC Standards Review Subcommittee	No	The MRO suggests that the Categories symbols in Table 1 and Table 2 be different to help distinguish between them (e.g. P1:S1, P2:S2, P3.2:S3.2, etc.) The MRO suggests that the header text (i.e. Category, Initial System Condition, etc.) be repeated on every applicable page to be more reader-friendly. The superscripts do not refer clearly to the respective notes. (There are numbered notes in the beginning of the table, numbered items in the extreme events evaluation requirements section, numbered items in extreme event description section, and numbered notes at the end of the table). Perhaps the referenced notes should have unique numerology or format to make the superscript references clearer.
American Transmission Company	No	We think that the tables are so similar that they should be recombined into one. This would require reasonable adaptation of the tables. If the tables are kept separate, then we suggest that the Categories symbols in Table 1 and Table 2 be different to help distinguish between them (e.g. P1:S1, P2:S2, P3.2:S3.2, etc. We suggest that the header text (i.e. Category, Initial System Condition, etc.) be repeated on every applicable page to be

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		more reader-friendly. The superscripts do not refer clearly to the respective notes. (There are numbered notes in the beginning of the table, numbered items in the extreme events evaluation requirements section, numbered items in extreme event description section, and numbered notes at the end of the table). Perhaps the referenced notes should have unique numerology or format to make the superscript references clearer.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". This changed has negated the need for the Planning Event category naming convention changes suggested by the commenter and the team retained the P1 through P7 references for Planning Events. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages. The SDT agrees with the commenter regarding the top notes within the table. We have changed the references to alpha characters to avoid confusion with the footnotes that are referenced with the tables using superscript characters.		
SERC Dynamics Review Subcommittee	Yes	The tables could be improved if the headings were put on each separate page. Separating out the tables for steady state and stability improves and clarifies the requirements of the standard.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". This changed has negated the need for the Planning Event category naming convention changes suggested by the commenter and the team retained the P1 through P7 references for Planning Events. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages. The move to a single table was based on a significant number of comments and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table.		
Austin Energy	No	Matching facility rating to seven contingency categories is confusing. Furthermore, these seven categories combined with alternative scenarios and sensitivity studies for several years into the future is overly burdensome, unnecessary, and unrealistic.
Response: In regards to matching an applicable Facility Rating to the 7 Planning Event categories, the SDT believes the 7 categories do not add any additional level of complexity. The set of Contingencies considered are not greatly different than those in the currently approved TPL suite of standards. The SDT tried to		

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better clarify those Contingencies that are deemed to be Planning Events, thus requiring corrective action plans, and the Extreme Events which do not require corrective action plans. Most in industry are receptive to the new Contingency categorization so the TPL SDT has altered its organization of the performance requirements. The need to cover sensitivity analysis is based on a FERC directive from Order 693 and the SDT believes it is a reasonable request which will drive the industry to better understand their individual transmission systems.		
Arkansas Electric Coop. Corp.	No	I disagree with statement #4 for the reasons given in my comments on question 3. Also, if you are going to allow it then consequential generation loss needs to be defined. I also disagree with statement #5. This is a planning standard and as such systems should be planned for planning steady state. Statement #5 should only be allowed if the resulting operator actions are taken into account. A fault on a networked transmission line may open the breakers at each end. Statement #5 stops here when in reality operator actions would isolate the faulted sections and service restored with the transmission line now being operated as two radials. The resulting two radials are what need to meet the performance requirements. Events should be taken to their logical conclusions and the resulting system topology be what meets the performance requirements. The tables need some borders and section dividers. Headers should be on each page. No firm transmission or Non-Consequential Load Loss should be allowed for P2. I think the SDT has it backwards. Non-Consequential Load Loss should never occur and the tables should reflect what is allowed to happen with Consequential Load Loss for each event. Many of the scenarios reflect what should happen with Consequential Load Loss and not Non-Conseqeuntial Load Loss. For example: P2 Bus Section for less than 300 kV -- The load on that bus under this contingency would be Consequential NOT Non-Consequential. For the loss of that bus the load connected to that bus should be ALL the load that is lost, therefore no Non-Consequential Load Loss should occur.
Response: Please see the SDT's response to your question 3 comment regarding your disagreement with statement #4. The SDT concluded from the overall industry comments that a definition for consequential generation loss was not needed and therefore was not added to the standard at this time. The commenter disagrees with statement #5 of the Draft 2 standard which states "Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each event." However, FERC Order 693 paragraph 1707 references that within the NOPR that preceded the Final Rule "…the Commission believes that the simulations used in planning assessments should faithfully duplicate what will happen in the actual power system and not a generic listing of outages" In paragraph 1716, the Final Rule further clarified that this is the intent of the Commission. Therefore, the wording in the proposed standard. The commenter's disagreement seems to be based on a feeling of needing to plan for no Load drop for single Contingency events; however, in paragraph 1773 it is clear the FERC does allow the loss of Consequential Load. Therefore, Consequential Load Loss that occurs with the initial event is permitted. Serving radial Load tapped from a networked line, from a "singled ended" view or from a single source end (one end of the line open) is covered by Planning Event P2.1 and new footnote 8 should help alleviate the commenter's concerns. Under P2.1 it should be expected that no Load loss would occur. **Footnote 8**: Inadvertent tripping of breakers on one end of a normally networked Transmission circuit such that the line is now open at that end and possibly		

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serving Load radial from a single source point. The need for headers on each page has been alleviated based on the SDT reformatting of the table to a single table format and greatly condensing the tabular information. The SDT disagrees with the commenter that the SDT "has it backwards" related to the references of Consequential Load Loss and Non-Consequential Load Loss for each event. The performance table accurately depicts when Non-Consequential Load Loss is permitted for various events. Consequential Load Loss is allowed for all events. The table does not try to categorize a type of Load (Consequential or Non-Consequential) that the event is causing to lose electrical service. The initial Protection System actions to the event always trip Consequential Load. The performance table merely clarifies if the Transmission Planner can drop any additional Firm Load (Non-Consequential Load Loss) to alleviate the event and meet performance requirements. In the P2.2 (bus section) event that the commenter references, the difference between the EHV and HV performance requirements is that the Transmission Planner is allowed to drop additional Non-Consequential Load for the HV event.		
Midwest ISO	No	Please add a General Requirements heading before items 1-6 (Steady State) and 1-5 (Stability) which appear to be applicable to all events for each table. The two columns under "BES elements out of Service" could be stricken for simplicity and clarity. If there is a voltage distinction needed, then add it next to the "Yes" or "No" under the "Interuption of Firm Service" or "Loss of Load" columns. Items P0 through P7 are identical in Table 1 - Steady State Performance and Table 2 Stability Performance. The only distinctions are the notes or whether it is an outaged event in Table 1 or a 3 phase/SLG fault in Table 2. Having two tables is redundant and unnecessary, and does not add clarity. It is also recommended that you combine the notes and extreme events from Table 1 - Steady State Performance and Table 2 - Stability Performance into one table. If both tables are to be retained then it is recommended that the SDT take into consideration the following suggestions. With the old Version 0 table, where there was not a separate stability table, it was understood that each of the event types needed to be assessed, but only those that the responsible entity knew were the more severe from a stability perspective needed to have stability analysis performed. By listing events such as single circuit faults (P1) under Table 2, this implies that all events should be simulated with dynamics, though requirement 5.4.1 states events "that would produce more severe System impacts shall be identified,...". The burden to explain why certain events were not selected can be construed now as having to run dynamics on all line faults, or explain why each line was not selected. Most lines embedded within the grid and not near generators or of particular significance to grid dynamic stability need not be studied. We do not believe that the SDT is requiring any additional burden of proof as to why every line in the system is not studied with dynamics, but the standard makes that question more murky than it was before. An overzealous compliance monitor could be confused by the new layout at great expense to the industry. If Table 2 remains, change

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		Table 2 - Stability Performance to only those events that are important to Stability Analysis. For example the following faults to run would be: 1) Faults near large generators (generator buses, generator lines or transformers near generators)2) Faults with delayed clearing near large generators3) Faults on long or heavily loaded lines with large phase angle differences between terminals. A majority of faults on lines less than 200kV are rarely severe so it is recommended to have the standards reflect this in Table 2 - Stability Performance.
Response: The SDT was persuaded by the commenter and other industry respondents that the two performance tables presented in Draft 2 were redundant in many areas. The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance" The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. At this time all Planning Events are still within the scope of possible system conditions that could require a Stability review. The SDT believes the proposed TPL explicitly clarifies that only the "more severe" events require Stability analysis which was implicitly understood within industry for the Version 0 standards as the commenter describes. Many of the conditions described by the commenter could be used as the basis for how a Transmission Planner would select the subset of Planning Events requiring a Stability review.		
Tri-State Generation and Transmission Association, Inc.	Yes and No	It does not seem that there should be different performance limits for DC and AC lines. It is unclear why there is a separation of voltage classes. Perhaps it would be helpful for each TP to specify which voltage levels are considered Bulk on their particular system, then split studies according to that definition. We applaud the SDT's efforts to split contingencies into groups with more-or-less the same system impact. We encourage the SDT that it would be very beneficial to regroup them in order of probability of occurrence, or even better, to group them by order-of-magnitude of occurrence probability. The P categories as now defined seem to overlap in likelihood. For example, in P3 following loss of a generator followed by system adjustments, another generator forced outage is more likely than a transformer forced outage. Loss of a bus section (P2 single contingency) is less likely than the P3 event of a double generator contingency. There is more on the concept of grouping Performance Tables in order of event likelihood in the NERC White Paper, "Reliability Concepts". At the least, notes in the tables - regarding 1) system impact and 2) likelihood of events listed - would be most welcome.
Response: The SDT agrees with the commenter's opinion on the need to allow for all types of conditional Firm Transmission Service interruptions and that the prior Draft 2 version unintentionally provided preferential treatment to HVDC. In the new performance Table 1, a new footnote has been added (see footnote 5) to the column title "Interruption of Firm Transmission Service Allowed" that corrects the problem identified by the commenter. **5**. When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed.		

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The SDT believes it provided sufficient justification in its Draft 1 response as to why a greater expectation is placed on the above 300 kV (EHV) System. The feedback received from the industry was divided related to the SDT's emphasis placed on a higher expectation for the 300 kV and higher Systems. Some commenters questioned the importance and the high costs that may be needed to mitigate existing System designs. Others agreed with the SDT's approach and indicated that the impact to their Systems would be minimal. Some commenters even questioned why the more stringent approach was not applied to the entire 100 kV and higher Systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission System. The performance requirements only apply to the Bulk Electric System and the split in voltage provides a subset of the BES. The Planning Events, in general, are ordered based on level of probability. However, the SDT chose to order the table by three main areas: 1) no Contingency (P0), 2) single Contingency (P1, P2) and 3) multiple Contingency (P3 through P7). While the SDT agrees with the commenter that there is some overlap in probability order, for example between P2 and P3, the SDT believes it has more importantly made the proper performance level requirements based on a reliability "risk" level where risk accounts for impact times (x) probability of occurrence.		
AEP	Yes	The formatting is okay. We would like to see the two tables merged. Except in the extreme disturbances sections, Table 1 and Table 2 are nearly identical (the only difference is that fault types are added to Table 2). The tables could easily be merged into one, including the extreme disturbances sections to some extent.
Response: The SDT was persuaded by the commenter and others industry respondents that the two performance tables presented in Draft 2 were redundant in many areas. The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance" The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed.		
NB Power Transmission	No	In the past, power systems within the NPCC Region have been designed to meet NPCC design criteria, which is basically that any design contingency does not cause instability of the NPCC defined bulk power system, and does not result in any emergency limit violations (thermal, voltage or stability), unless those violations are contained within a small local area of the system and can be mitigated. Design to NPCC criteria may include, and does include in many cases, interruption or curtailment of firm transmission service, underfrequency load shedding, undervoltage load shedding or SPS tripping of generation and/or load. The proposed table introduces new design criteria for which present power systems within NPCC are not presently designed to - being the restrictions on interruption of firm transmission service and consequential load for certain contingencies as outlined in the table, which up to this point was acceptable by NPCC design criteria, and the present NERC TPL Standard. The table should not impose new design criteria on the existing power system and should be relaxed such that present NPCC design criteria is acceptable into the future, as historically it has been proven to provide acceptable levels of reliability in the NPCC area. There would be enormous impacts on existing transmission service agreements and compliance issues if the design criteria outlined in the table is imposed. Meeting the design criteria outline in the table would require building new transmission facilities with, in some cases, very little benefit to the

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		loads in terms of reliability. For example, there is an area of the system consisting predominately load. This area is supplied by two 345 kV transmission lines and three 138 kV lines. Studies show that under certain low probability, but predictable, conditions that the loss of one of the 345 kV supplies will result in unacceptable low voltage or thermal limit violations on equipment within the area. Therefore, an SPS has been utilized which trips load within the area on the loss of the 345 kV line in order to prevent unacceptable low voltage or thermal limit violations under these low probability conditions. In this case these loads are considered non-consequential and tripping them for a loss of a 345 kV line is unacceptable as per P1 in the table. Now assume that this arrangement has been in service operationally for the past 10 years and has only operated twice resulting in a 2 hour outage to these loads each time. Now also assume that these same loads have been interrupted 15 times (for a total of 30 hours) in the past 10 years because outages of a radial line within the area that these loads connected to. In this case, the loads are considered consequential and these interruptions are acceptable. Compliance with the design criteria in the table in this case would require building additional transmission into this area to prevent the load loss by SPS on the loss of the 345 kV line. Assume the cost of this new transmission is 80 million dollars and its net benefit would be to prevent (historically) 2 interruptions out of 17 total interruptions to only the loads in question within the area. The design criteria in the table in this case do not provide adequate benefit for cost for these loads in this area. Adequate transmission planning must take into account engineering judgment concerning cost/benefit ratio to loads as well as type of loads served, expectations of loads in terms of interruptions and where money can be best spent to reduce interruptions to loads. The criteria outlined in the table does not achieve this in all cases. The table should not dictate what contingencies can result in consequential load loss or interruption of firm transmission service. These decisions should be left to local planning engineers who have in-depth knowledge of local transmission issues (as well the interconnected power system)and reliability needs of loads involved. The table should only state that the listed contingencies will not result in system instability or violations of emergency thermal and voltage limits following all automatic actions. Table 1 in the existing version of the TPL Standards with its footnotes b) and C) presently allows for this and does not have criteria as stringent as the new table. The new table should not introduce new, more stringent design criteria.

Response: The NB Power Transmission company has two primary concerns within their response: 1) an inability to interrupt Firm Transmission Service and 2) the inability to shed local Load for what they deem a low probability single Contingency event involving a 345 kV line.

Regarding the Firm Transmission Service concern, the SDT has added footnotes 5 and 10 that should help alleviate the NB Power Transmission company's concerns. Footnote 5 indicates that interruption of conditional firm transfers is permitted for all Planning Events and footnote 10 indicates that interruption of Firm Transmission Service coupled with appropriate generation re-dispatch can be utilized for multiple Contingency events as a System adjustment, where indicated in Table 1 as being part of the Initial System Condition, and as a post-Contingency corrective action so long as no interruption of Non-Consequential Load occurs and all Facility Ratings are maintained.

Footnote 5 – When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed.

Footnote 10 – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a

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System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. NB Power expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that they rely on an SPS to drop local area network Load in response to some single Contingency events and that these system designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of the TPL-001-1 and most stakeholders (and the SDT) aligned with FERC's position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement. As an alternative, an entity could seek an entity variance for the situation described. The process for obtaining an entity variance is described in detail in the "NERC Standards Development Procedure" document under the subsection titled "Variances to NERC Reliability Standards" The commenter seems to be confused by the term Consequential Load Loss based on the statement "…The proposed table introduces new design criteria for which present power systems within NPCC are not presently designed to - being the restrictions on interruption of firm transmission service and consequential load for certain contingencies as outlined in the table…" The proposed standard places no restrictions on Consequential Load Loss for any of the Planning Events or Extreme Events. The as designed Protection System actions to the event always trip Consequential Load. The performance table merely clarifies if the Transmission Planner can drop any additional Firm Load (Non-Consequential Load Loss) to alleviate the event and meet performance requirements.		
Lakeland Electric	No	Separating steady-state from dynamic (stability) in the tables makes sense. Several suggestions: On page 11 move the planning events note 1 below the Planning Events title or begin note 1 with "For planning events ?" to remove confusion between planning events and extreme event requirements. Include an analysis section in the steady-state and stability requirements sections of TPL-1 that explicitly lays out the performance requirements (including the notes) - this would make the performance requirements very clear on a line item basis and the tables would become a quick reference. Special attention should be given to defined period of time between multiple events and the actions available to the operator. In table 2 (page 17) note 3 should be changed to: "Uncontrolled cascading and islanding ?" in order to be consistent with R5.4.4. " . . . If the evaluation of implementing a change . . . shall be conducted."
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages		

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that the prior Table 1 and Table 2 encompassed. In the new table format, the top notes were placed under the heading of "Planning Events" as the commenter and other industry participants of suggested. It is not exactly clear what the commenter has in mind related to the "analysis section" described in the response. However, the SDT believes the new table format provides a better "at glance" view of what is needed. However, this does not negate the need to fully understand all requirements within the standard. The time period for allowable System adjustments made to avert performance requirement violations must be completed within the time duration rating and respect the ratings limit. The reference to Requirement R5.4.4 has been deleted.		
Southern Company Transmission	Yes and No	We suggest that the word "requirements" be added to the title of the tables as in Steady State Performance Requirements. We also suggest for header note 2 of Table 2 that the words be changed from "Dynamic voltages shall" to "Voltages during dynamic simulation shall"
Response: The SDT did not include the proposed use of "requirements" in the title of the performance table since they are not within the requirements section of the standard. The SDT agrees with the proposed change in note two of Table 2. The two tables have been consolidated into one table and the header note reference for this item is now note "h". **Header note 'h'**: Planning Event P0 is applicable to steady state only.		
Brazos Electric Power Cooperative, Inc.	No	Compared to the new table format, the old Categories were better. Perhaps if there is confusion with the old table or format, this should be cleaned up. We suggest the old tables remain, or combine some of the new sections to reduce the number of categories.
Response: The set of Contingencies considered are not greatly different than those in the currently approved TPL suite of standards. The SDT tried to better clarify those Contingencies that are deemed to be Planning Events, thus requiring corrective action plans, and the Extreme Events which do not require corrective action plans. Most in industry are receptive to the new Contingency.		
IESO	Yes and No	Condition (5) at the top of Table 1, and Condition (4) at the top of Table 2 are not required since they are already covered by R3.2 and R5.2, respectively. Further, Condition (6) in Table (1) and Condition (5) in Table 2 should be stipulated in R3 and R5 since these are not performance requirements, but rather the analysis (simulation) requirements.

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Response: The commenter is correct that Condition 5 of the Table 1 and condition 4 of Table 2 which state "Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each event" is also within the standard's requirement language. However, the SDT has retained this information within the new performance table as it is key information repeated for clarity and convenience. In regards to the comments on condition 6 and condition 5 which refer to "normal clearing", the SDT believes that Requirements R3 and R4 which refer to the need to meet performance requirements stated within Table 1 cover the concern raised. The table note that references "simulate Normal Clearing unless otherwise specified" is now introductory note "d".		
North Carolina Electric Membership Corp	Yes and No	We would like the headings to be repeated at the head of each page. Also, enumerate Stability Tables different from the Steady State to distinguish between them.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". This changed has negated the need for the Planning Event category naming convention changes suggested by the commenter and the team retained the P1 through P7 references for Planning Events. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Therefore, the need for repeating headers on subsequent pages has been eliminated as all Planning Events are presented on a single page.		
ERCOT System Planning	No	The table is hard to read and follow since it spans multiple pages and the table headers are not repeated on each page. ERCOT believes that there are two many categories. For example, in Table 1 both Category P1 and Category P3 are not necessary. Since they require the same system performance and P3 is more severe than P1, it can be assumed that successful simulation of P3 would result in successful simulation of P1. Category P2-1 can not be simulated without modification to typical transmission models. Normal steady state power flow software typically has as a line either in or out of service, but not half in and half out. "Breaker Fault" and "Stuck Breaker" definitions are included in the table notes, but would probably be better placed with the other defined terms. It is somewhat unclear as to why there are multiple names as the steady state system impact and requirements are the same. Also, the stability impacts would be more severe for a stuck breaker assuming delayed clearing. This would allow for removal of P2-3 and P2-4 in both Tables 1 & 2. It appears that P4 and P5 are duplicating efforts as well. It is not specified which entity is responsible to define and provide contingency definitions in industry standard software format such as those requiring knowledge of protection system failures and lines on the same structure for more than 1 mile. Only entities such as TOs and GOs have access to that knowledge.

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Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages.

The set of Contingencies considered are not greatly different than those in the currently approved TPL suite of standards. The SDT tried to better clarify those Contingencies that are deemed to be Planning Events, thus requiring corrective action plans, and the Extreme Events which do not require corrective action plans. Most in industry are receptive to the new Contingency categorization so the TPL SDT has not altered its organization of the performance requirements. The P3 and P1 Contingency events are unique and can provide differing results since they result in unique generation dispatch. The SDT believes it is import to study both conditions.

In regards to the P2.1 event, the intent is to capture a potential condition of serving Load that is tapped from a normally networked line from a single source location in the Contingency (single ended) condition. If a line exists (breaker to breaker) that does not directly serve Load, the P2.1 condition would not apply and only the normal N-1 condition of the line would be studied. See the newly added footnote 8 that better describes the intent of the P2.1 Planning Event. The SDT believe existing transmission models will not require adjustment for the P2.1 event, however, Contingency lists run against the model may require some adjustments.

8. Inadvertent tripping of breakers on one end of a normally networked Transmission circuit such that the line is now open at that end and possibly serving Load radial from a single source point.

The stuck breaker reference remains as a footnote to the table – see footnote #11.

11. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) breaker, only one pole is assumed to remain closed. ~~The~~A stuck breaker ~~event~~ introduces a delayed clearing mode. ~~Normal Clearing is when the Protection System operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Breaker fail relay operation is a predetermined time that occurs after the Protection System operates and the breaker has failed. Breaker fail relaying will also isolate a predetermined portion of the electric system to isolate the failed breaker. Delayed clearing of a Fault is due to failure of any Protection System component that prevents the Protection System from operating normally.~~

The commenter is correct that some conditions such as "stuck breaker" or "internal breaker fault" would yield similar outcomes from a steady-state perspective, however, when considered from a dynamic Stability analysis each could have unique outcomes. As the commenter notes a delayed clearing mode, such as the stuck breaker analysis, would be expected to be more severe from a Stability mode. The SDT has retained P2.3 and P2.4 as they are considered single Contingency events as compared to the multiple Contingency stuck breaker event.

The P4 and P5 are unique Planning Events. The P5 Protection System failure can produce various outcomes depending on the Protection System element which failed – relay, CT, PT, battery, etc. The SDT has revised the P5 event description to remove the reference to "single component failure" and has revised the P5 event description to retain what is stated in the currently approved TPL standards under Category C6 through C9 related to the study of Protection System failures. It is left to the judgment of the Transmission Planner and the Planning Coordinator to select the appropriate review and it is expected that a worst case scenario that is something less than loss of the substation, which is considered an Extreme Event, would be evaluated. Finally, as noted in Requirement R3.4,

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the Transmission Planner and Planning Coordinator is provided flexibility in selecting the more severe P5 events for study related to their system and it is not expected that every possible scenario for Protection System failure would be studied. It most cases it is unlikely that detailed system protection knowledge would be needed to develop the Contingency lists needed to perform Transmission planning studies. Ultimately it is the Transmission Planner and Planning Coordinator responsibility to ensure the simulated Contingencies accurately simulate the removal of all elements that the Protection Systems are expected to disconnect for a given event. If assistance is needed from asset owners then it is the Transmission Planner and/or Planning Coordinator's responsibility to coordinate such a review. The standard does not place requirements on the asset owners.		
Duke Energy	Yes	Separating the steady state and stability tables greatly improves and clarifies the requirements of the standard. The tables could be improved if the headings were put on each separate page. Placing headers in the requirements section of the standard would improve understanding of the flow of the document.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments to do so and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The SDT feels that with the consolidation of requirements that were made for the third posting that headings within the body of the requirements are not needed and NERC legal staff does not support the use of headings to subdivide requirements.		
Florida Reliability Coordinating Council, inc	No	The Steady State and Stability Performance Tables are very long (currently the these two table are 13 pages) and confusing. Please consider combining and condensing the two tables into one, and either add footnotes or expand the table headings to allow better understanding of the performance requirements.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Therefore, the need for repeating headers on subsequent pages has been eliminated as all Planning Events are presented on a single page.		

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The SDT believes the new table format improves the readability of the expected performance requirements.		
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	Yes	We recommend that the headings be repeated at the head of each page.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages.		
Oncor Electric Delivery	No	In Table 1-Steady State Performance several terms more relating to system stability performance appear such as post-transient voltage, voltage instability, fault plus stuck breaker, etc. These terms would appear to be most appropriate in only Table 2-Stability Performance, where this type of analysis is performed, e.g.- placing a fault at a location based on available short circuit MVA at that point in the transmission system and then analyzing the post transient voltage and generator response.
Response: The SDT agrees that the prior draft Table 1 included some terms that were more appropriate for stability analysis references. The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments to do so and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The SDT believes the new table format improves the readability of the expected performance requirements. Additionally, the SDT took great care to separate the introductory table notes for those items that apply to both steady-state and stability analysis as well as independently to one or the other.		
FirstEnergy Corp.	Yes	The overall table format is much improved over Draft 1 and it provides better alignment between the steady-state and stability tables. The SDT is encouraged to consider consolidation into one table based on the minimal differences within the two tables. FE offers the following additional comments related to the tables:TABLE 1, STEADY-STATE & TABLE 2, STABILITY: 1) Do the table notes at the top of the table only apply to the Planning Events? If so, it is suggested to move the row that says Planning Events to be positioned above the notes.

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		2) Top Table Notes, Item 2 - It is our opinion that it should be based on the TPs criteria. 3) Top Table Notes, Item 3 - These should read consistent on both tables. Also, is cascading well understood and how is it tested for? 4) The use of numeric notes at both the top and bottom of the table causes confusion related to the superscript number references on various terms within the table. The superscript items appear to be footnote references to the notes area at the bottom of the table. It is suggested that the items listed at the top of the table use alpha character references to demarcate each item. 5) Remove the footnote reference to note 3 on the Header titled "Event" (column 3). The reference in column 4 is better suited and covers the intent of the note. 6) For the P3 contingencies, it is unnecessary to individually analyze all BES generation units within a footprint along with an additional contingency. The planner allowed to use reasonable judgment and run only a subset of the larger units in this scenario. For example, there would be no need to contingencies against an outage of each unit at a multi-unit plant. Checking the contingencies against the outage of the largest unit at that plant would be sufficient. 7) A header row should be repeated on each page for improved readability. TABLE 1, STEADY-STATE: 1) Extreme event descriptions, item 2e ? why is this needed? How would this occur? What would be evaluated, high voltage? Stability issues? Note that it wouldn't be stability concern - this is the steady state table. 2) Extreme event descriptions, item 3b - how is this condition any different than what is studied in extreme event item 1 (N-2, no adjustment)? We suggest that item 3b be removed. 3) Extreme event descriptions, item 3c is too vague and it is suggested that it be removed. 4) Notes section (bottom of table), item 1 - Various topics are covered within this note - stuck breaker, breaker relay failure, normal clearing, delayed clearing - it should be broken up. Why include a discussion about delayed clearing in a steady-state table? 5) Notes section (bottom of table), item 4 ? We interpret FACTS to mean Flexible AC Transmission Devices and this means different things to different companies. FACTS devices can be series devices and not necessarily shunts as referred to in the table. It is noted that there is not footnote reference pointing to item 4 within the table. TABLE 2, Stability: 1) Planning Event P1 - Indicates SLG or 3-PH, which one is needed? This should be clarified in the requirements that reference this table. The intent is likely that most planners would perform the less labor intensive 3-PH simulation and if criteria were met, then the conclusion would be that SLG is also met. However, as presently written, the "OR" could be manipulated to allow someone to meet criteria for SLG but not the 3-PH. The requirements should provide clear

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		expectations in this regard. (Same comment applies to P3 and P6) 2) Planning Event P1.2 - At what position on the line is the fault to be tested? Either the table or requirements that reference this Planning Event should be clear in what is required. 3) Planning Event P1.3 ? Is the fault to be placed on the high-side or low-side of the transformer? Either the table or requirements that reference this Planning Event should be clear. 4) Planning Events P1 and P2 - Is the intent that a TP would need to run all possible P1 and P2 events in dynamic stability simulations? If not, the requirements should be worded to allow the TP some flexibility in selecting the items having the most impact. To expect all of these events to be simulated within dynamics is unrealistic and unnecessary. 5) Planning Event P2.1 ? While we agree this event is warranted in steady-state, we question the need to cover this item within stability. Wouldn't breaker action clearing a fault always produce a more severe system disturbance than an inadvertent breaker trip? 6) Extreme Events ? The reference to R5.5.4 should be R5.4.4 7) Extreme Events - Items 2, a,b,c,d - should "protection system" be capitalized as the defined term in the NERC Glossary? 8) Extreme Events - Items 2f and 2gshould be removed. It is inconceivable that the simultaneous faults described could occur. 9) Notes section (bottom of table), item 1 - Does not read consistent with Note 1 from Table 1 Steady-State. As stated above, various topics are covered within this note - stuck breaker, breaker relay failure, normal clearing, delayed clearing - it should be broken up. 10) Note number 4 from Table 1 Steady-State (item on shunt/FACTS) is missing in Table 2. The first 5 notes from Table 1 should be reflected in Table 2 with the existing Table 2 note 5 being re-numbered to item 6. 11) Table 2 Note 5.a.ii. - We question whether the number of units totaling the Contingency reserve is a good criteria. Also, with regard to the phrase "the resulting apparent impedance swings must not pass through relay characteristics that would result in the tripping of any Transmission System elements", we suggest a change to "the resulting power swing shall not cause the system to separate or form electrical islands".
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled “Steady State and Stability Performance”. The move to a single table was based on a significant number of comments to do so and based on the SDT’s view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table.		

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SDT RESPONSE TO THE COMMENTS MADE THAT ARE APPLICABLE TO BOTH TABLE 1 AND TABLE 2:

1) The notes at the top of the table are intended for the Planning Events. The SDT has taken the advance offered by FE and others within industry and moved the "Planning Events" title to be positioned above the introductory notes.

2) Regarding prior Top note 2, now note "g". The SDT did not make the change recommended and believes both the Transmission Planner and Planning Coordinator criteria need to be considered and the more restrictive criteria applied if warranted. Generally, the criteria used for applicable facilities would be known and agreed upon between the Transmission Planner and Planning Coordinator, for example within an RTO environment.

3) Top Table note item 3 is now referred to as note "a". The inconsistency described by the commenter is now corrected with the single table format. Cascading is a defined term in the NERC Glossary of Terms.

4) The SDT has adjusted the top notes and refer to them with alpha character references to avoid confusion with the table footnotes that are referenced within the table.

5) The footnote reference to note 3 on the Header titled "Event" (column 3) of the prior Table version has been removed. The footnote recommended by the commenter is now used and is referenced as footnote 2 in the new table.

2. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level for stated performance criteria applies regarding allowances for interruptions of Firm Transmission Service and loss of Non-Consequential Load.

6) Contingency P3 is considered a multiple Contingency event and as described in Requirement R3.4 the Transmission Planner is expected to cover those Contingencies "… that are expected to produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results." Therefore, the SDT agrees with the commenter that the Transmission Planner would not be required to run every generation outage in combination with an addition single Contingency.

7) The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages.

SDT RESPONSE TO THE COMMENTS MADE THAT ARE APPLICABLE ONLY TO TABLE 1:

1) The 2e Extreme Event came from the existing TPL standard, category D11 contingency. The SDT considers this to be more appropriate for steady state analysis than for Stability analysis and that the main intent is to guard against an extreme voltage rise.

2) The SDT agrees with FE related to Extreme Event item 3b and it has been removed in the new table.

3b. ~~Loss of two Transmission lines in different rights-of-way prior to System adjustments for conditions such as:~~

3) The SDT disagrees with the commenter that "Extreme event description item 3c is too vague and it is suggested that it be removed."

4) The SDT agrees that a variety of topics were covered in the prior footnote 1 of Table 1 and that a discussion on delayed clearing was not applicable to a steady-state table. We have revised this footnote which is now footnote 11 to focus on the stuck breaker topic. Many of the prior references in this note were

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NERC Glossary of Terms definitions and have been removed.

11. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) breaker, only one pole is assumed to remain closed. ~~The~~A stuck breaker ~~event~~ introduces a delayed clearing mode. ~~Normal Clearing is when the Protection System operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Breaker fail relay operation is a predetermined time that occurs after the Protection System operates and the breaker has failed. Breaker fail relaying will also isolate a predetermined portion of the electric system to isolate the failed breaker. Delayed clearing of a Fault is due to failure of any Protection System component that prevents the Protection System from operating normally.~~

5) The SDT has corrected the footnote reference to FACTS to better clarify that the SDT's intent of referring to only those FACTS devices which are shunt devices. The new footnote is footnote 7 and is now referenced within the Planning Event table information.

7. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.

SDT RESPONSE TO THE COMMENTS MADE THAT ARE APPLICABLE ONLY TO TABLE 2:

1) The confusion in Planning Event P1 – indicating a "SLG or 3-PH" has been resolved and now more clearly indicates that a 3-PH fault must be passed. The P3 and P6 Planning Events now indicate the intent is to pass a SLG event for these items. However, as stated in footnote 3, if a Stability study indicates that criteria is met for a 3-PH analysis, the results of that test are sufficient to meet the less stringent SLG criteria.

2) This is left to the judgment of the Transmission Planner and the Planning Coordinator. It is expected that you study the worst case fault location.

3) This is left to the judgment of the Transmission Planner and the Planning Coordinator. It is expected that you study the worst case fault location.

4) It is not expected that a Transmission Planner would analyze every Planning Event scenario for P1 and P2 within a Stability study. Requirement R4.5 provides the Transmission Planner the flexibility desired by FE in selecting the items having the most impact.

5) No. Sometimes opening a breaker produces a more severe dynamic voltage swing than clearing a fault at that location. A fault can stimulate machine exciters into a faster response. A slower response from exciters due to opening a breaker can result in larger dynamic voltage swings.

6) The reference to requirement R5.5.4 has been removed as some commenters felt this created a circular reference between the table and the requirement language.

7) The commenter is correct that the term "Protection System" as used in Extreme (Stability) Events items 2, a,b,c,d is a NERC defined term in the NERC Glossary of Terms and is now correctly capitalized within these Extreme Event descriptions

8) Extreme (Stability) Events items 2f and 2g have been retained by the SDT and these items are consistent with the current FERC approved TPL-004 category D6 and D7. Other commenters have not objected to these items.

9) The SDT agrees that a variety of topics were covered in the prior footnote 1 of Table 2 and that a discussion on delayed clearing was not applicable to a steady-state table. We have revised this footnote which is now footnote 11 to focus on the stuck breaker topic. Many of the prior references in this note were NERC Glossary of Terms definitions and have been removed. The prior footnote 1 inconsistencies indicated by the commenter have been resolved by moving to

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the single table format. 10) The SDT agrees that there were missing footnotes in Table 2 when compared to the prior Table 1 footnotes. This is no longer an issue in the single table format as only one set of footnotes is used. 11) The SDT believes that the Contingency reserve is the appropriate maximum amount of generation which should be allowed to be lost for Planning events P2-P7. Also, the SDT believes the appropriate performance requirement for Planning Events is for no additional lines to be allowed to trip due to apparent impedance swings.		
Orlando Utiliites Commission	Yes and No	I like the concept of the new performance tables however if they could be made shorter that would be handy. I have the following specific suggestions, although they may be moot if the table is redesigned. The way the notes at the top of table 1 and table 2 are written it appears that they apply to planning single, planning multiple and extreme event sub-tables. However this is in conflict with some parts of the standard itself and the team's comments on the conference call. For example Requirement R3.3.2.2 applies facility ratings only to planning single contingencies only, so which is correct the requirement or the note that applies it to everything? I have several suggestions to fix this: 1. Move the "notes" to under the Planning Event sub table 2. Making 4 tables with the Extreme Events being a table 2 & 4 respectively 3. Indicating the notes as only applying to specific planning events. The discrepancy between requirement R3.3.2.2, the table note and comments on the conference call also needs to be corrected either by expanding the applicability of R3.3.2.2 to multiple contingencies or reducing the scope of the corresponding note. It should be clarified somewhere that the Transmission Planner and Planning Coordinator select the range of the system contingencies for N-1. Otherwise some may interpret this as only having to test contingencies on their own system (insufficient from a reliability perspective for many systems) while some auditors may interpret this as requiring every possible n-1 in the US and Canada as necessary. For example a requirement R3.2.3 could be added stating "The planning assessment should include a technical rationale for the range of transmission lines, transformers and other equipment considered". This could also be handled as a note on the tables to the effect of "The study should include a technical rationale for the range of transmission line and generators considered."
Response: The introductory notes have been moved under the "Planning Event" portion of the performance table as suggested by the commenter. The notes apply to all Planning Events – system normal (n-0), single Contingency and multiple Contingency. The commenter raises a valid point of confusion related to allowable System adjustments as Requirement R3.3.2.2 seems to imply that the System adjustments may only be applicable for single Contingency. Redispatch of generation and other System adjustments are allowed for provided that all Facilities shall be operating within their Facility Ratings. The requirement has been removed and replaced with Table 1 header note "e" since the text in the former requirement was explanatory of what was allowed and not requirement language. **e.** For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such		

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adjustments are executable within the time duration applicable to the Facility Ratings. The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. The list of Contingencies is expected to cover the Transmission Planner or Planning Coordinator system for which they are responsible for, including any tie-lines to adjacent Transmission systems. The standard does not preclude the Transmission Planner or Planning Coordinator to expand the list of Contingencies to include some Contingencies of interest or known impact for the adjacent System(s). It is expected that through peer reviews, the Transmission Planner or Planning Coordinator may initially learn of any new event within an adjacent System that impacts their own System.		
Entergy Services, Inc.	Yes and No	Given the type of information the SDT was trying to convey in the Tables, the format is fine. However, the enhanced standards create a conflict between the planning criteria used for evaluating transmission service (typically a standard N-1 thermal only analysis for ATC/AFC calculations) and the criteria for reliability as proposed by this standard. This disconnect will unfairly shift the cost of expanding the transmission system to the native load customers while wholesale and point-to-point transmission customers will reap the benefits of the additional capacity installed.
Response: The SDT has added footnotes 5 and 10 related to Firm Transmission Service. Footnote 5 indicates that interruption of conditional firm transfers is permitted for all Planning Events and footnote 10 indicates that interruption of Firm Transmission Service coupled with appropriate generation re-dispatch can be utilized for multiple Contingency events as a System adjustment, where indicated in Table 1 as being part of the Initial System Condition, and as a post-Contingency corrective action so long as no interruption of Non-Consequential Load occurs and all Facility Ratings are maintained. **5**. When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
BPA Transmission Reliability Program	No	We suggest that the tables for Steady State and Stability Performance could be combined into one table, for simplicity. Separate columns could be used for Steady State versus Stability performance criteria.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments to do so and based on the SDT's view that the Planning Events were the same for		

Organization	Question 7:	Question 7 Comments:
both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages.		
PPL EnergyPlus	Yes	The new format is a nice improvement. On the SDT conference call, it was stated that table 1 and table 2 assume different starting points; if so, could this be spelled out in the standard? Also, consequential generation loss isn't defined.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages. The initial system conditions are described for each of the Planning Events and are the same for both steady-state and Stability. The SDT did not feel the need to define consequential generation loss for the standard.		
PacifiCorp	Yes	We agree with the proposed format changes of the Tables.
JEA	Yes and No	JEA can live with them as is, but would also welcome enhancements. Will defer enhancements to others.
Lafayette Utilities System	Yes	
Arizona Public Service Co.	Yes	We agrees with the proposed format changes of the Tables.
LCRA TSC	Yes	
NERC and Regional Coordination	Yes	

Organization	Question 7:	Question 7 Comments:
E.ON U.S. Transmission Planning	Yes	

Response: Thank you for your response. The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance".

The move to a single table was based on a significant number of comments and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table.

The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages.

8. **A new definition for "Bus-Tie Breaker" was added to clarify the type of substation design and breaker position that qualify as a Bus-tie Breaker. Do you agree with the proposed definition? If not, please explain.**

Summary Consideration:

Based on the comments received from the industry, the SDT has revised the definition of Bus-tie Breaker.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual ~~straight bus~~ substation bus configurations. ~~(Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)~~.

Organization	Question 8:	Question 8 Comments:
NPCC	No	The definition provided is too limiting. It says that if you have two rings with a bus tie breaker in between, it is no longer a bus tie breaker. NPCC Participating Members Recommend, "A circuit breaker that is positioned to connect two individual station configurations." We do not agree that, "(Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)", as we have examples where stations of this nature are connected through a single "bus-tie breaker".
TVA System Planning	Yes	TVA does appreciate this clarification, but suggests the following wording: "A circuit breaker that is positioned to connect two individual straight bus substation configurations that if faulted results in both bus sections being cleared."
Omaha Public Power District	No	The term "straight bus" is not an industry-standard term. Replace "straight bus" by "single-bus, single-breaker".
Progress Energy Carolinas		The use of the word "straight" in the definition raised questions. We recommend the word straight be removed or change the definition to the following. "Bus-tie Breaker: A circuit breaker positioned to connect two individual buses with one or more other breaker positions on each bus. (Substation configurations such as a ring-bus, breaker-and-a-half, or double-breaker do not generally include bus-tie breakers.)"
Platte River Power Authority	Yes and No	Delete the sentence in parentheses.
BCTC	No	Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. What would these breakers be called? We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.

Organization	Question 8:	Question 8 Comments:
Manitoba Hydro	Yes	The Bus-tie Breaker definition provides the clarification Manitoba Hydro requested in our draft 1 comments. However, we suggest the wording in brackets should be deleted as it is possible to add bus-tie breakers to schemes like the breaker-and-a-third bus in large stations.
Transmission Agency of Northern California	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
National Grid	No	The definition provided is too limiting. It says that if you have a two rings with a bus tie breaker in between, it is no longer a bus tie breaker. We recommend modifying the definition to read, "A circuit breaker that is positioned to connect two individual station configurations. We do not agree that, "(Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)", as we have examples where stations of this nature are connected through a single "bus-tie breaker".
OPUC	Yes and No	A better definition of Bus-Tie Breaker might be: “A circuit breaker that divides a bus section with multiple tap off points into two bus sections.”
Pacific Gas and Electric Co.	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
Public Service Company of New Mexico	No	We do not disagree with the proposed definition change. However, we do not agree that “Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
Puget Sound Energy, Inc.	No	We do not disagree with the proposed definition change. However, we do not agree that “Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two

Organization	Question 8:	Question 8 Comments:
		bus sections.
Idaho Power Company	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
SMUD	No	We do not disagree with the proposed definition change. However, we do not agree that “Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
Hydro-Qu?bec Trans?nergie (HQT)	No	? The definition provided is too limiting. It says that if you have a two rings with a bus tie breaker in between, it is no longer a bus tie breaker. HQT recommend, "A circuit breaker that is positioned to connect two individual station configurations. We do not agree that, "(Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)", as we have examples where stations of this nature are connected through a single "bus-tie breaker".
Sierra Pacific Power Comapny / Nevada Power Company	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
Ameren	No	To provide clarity, a revised definition is proposed. "A bus-tie breaker is a circuit breaker that connects two individual bus sections with one or more breaker positions on each bus; substation configurations such as ring-bus, breaker-and-a-half, or double bus-double-breaker do not have bus-tie circuit breakers."
SRP	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.

Organization	Question 8:	Question 8 Comments:
MidAmerican Energy Company	No	MEC suggests applying the proposed definition to a new term, "Straight Bus-Tie Breaker". The creation of a narrow, special application definition of "bus tie breaker" is generally confusing and misleading. The term "bus tie breakers" is widely used in the industry in the context of various bus configurations. In addition, this narrow definition may create confusion if other Standards refer to bus-tie breaker in a different context.
Tucson Electric Power Company	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
SERC Dynamics Review Subcommittee	No	The use of the word ?straight? in the definition raised questions. We recommend the word straight be removed or change the definition to the suggestion below: Suggestion: Bus-tie breakers are defined as a circuit breaker position that connects two individual buses with one or more breaker positions on each bus.
MRO NERC Standards Review Subcommittee	No	The MRO suggests applying the proposed definition to a new term, "Straight Bus-Tie Breaker". The creation of a narrow, special application definition of "bus tie breaker" is generally confusing and misleading. The term "bus tie breakers" is widely used in the industry in the context of various bus configurations. In addition, this narrow definition may create confusion if other Standards refer to bus-tie breaker in a different context.
Modesto Irrigation District	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
Tri-State G&T	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
Brazos Electric Power Cooperative,	No	Part of the definition of a bus tie breaker as outlined in this Standard should be that it is the ONLY connection between 2 substation buses. Not sure why the word 'straight' is used in this definition. If a bus with a 90 degree turn is connected to another bus by a single tie breaker, does this not apply? Also, breaker and a half schemes do

Organization	Question 8:	Question 8 Comments:
Inc.		sometimes have a bus tie breaker in them although its probably not common. Including those specifics in not needed.
ColumbiaGrid	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
Southern California Edison	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
Northeast Utilities	No	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
North Carolina Electric Membership Corp	No	To provide clarity, a revised definition is proposed. A bus-tie breaker is a circuit breaker that connects two individual bus sections in a straight bus substation configuration. Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double-breaker do not have bus-tie circuit breakers.
American Transmission Company	No	We suggest applying the proposed definition to a new term, "Straight Bus-Tie Breaker". The creation of a narrow, special application definition of "bus tie breaker" is generally confusing and misleading. The term "bus tie breakers" is widely used in the industry in the context of various bus configurations. In addition, this narrow definition may create confusion if other Standards refer to bus-tie breaker in a different context.
Duke Energy	No	The use of the word ?straight? in the definition raised questions and did not seem crucial to the definition. We recommend the word ?straight? be removed from the definition.
Central Maine Power Company	No	The definition provided is too limiting. It indicates that if a substation has two rings with a bus tie breaker in between, that breaker is no longer a bus tie breaker. Recommend instead, "A circuit breaker that is positioned to connect two individual station configurations. The breakers in a bus scheme are not bus tie breakers but the breakers that tie bus schemes together are bus-tie breakers."
NSTAR Electric	No	The definition provided is too limiting and should be changed to "A circuit breaker that is positioned to connect two individual station configurations. The breakers in a bus scheme are not bus tie breakers but the breakers that tie bus

Organization	Question 8:	Question 8 Comments:
		schemes together are bus-tie breakers."
New York Independent System Operator	No	The definition provided is too limiting. It says that if you have a two rings with a bus tie breaker in between, it is no longer a bus tie breaker. Recommend, "A circuit breaker that is positioned to connect two individual station configurations. We do not agree that, "(Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)", as we have examples where stations of this nature are connected through a single "bus-tie breaker".
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	No	To provide clarity, a revised definition is proposed. A bus-tie breaker is a circuit breaker that connects two individual bus sections in a straight bus substation configuration. Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double-breaker do not have bus-tie circuit breakers.
Alberta Electric System Operator	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: "A circuit breaker that's only protective purpose is to isolate a segment of a bus."
ISO New England Inc.	No	he definition provided is too limiting. It says that if you have two rings with a bus tie breaker in between, it is no longer a bus tie breaker. Recommend, "A circuit breaker that is positioned to connect two individual station configurations. The breakers in a bus scheme are not bus tie breakers but the breakers that tie bus schemes together are bus-tie breakers."
Orlando Utiliites Commission	Yes and No	I neither for or against breaking out these breakers as a separate class. However a graphic or sketch of some example an easier concept to understand both in terms of what it is and why it is worthy of special attention.
Entergy Services, Inc.	No	Change term from ?Bus-tie Breaker? to ?Straight Bus Substation Bus-tie Breaker? with the following definition: A bus-tie breaker is a circuit breaker that connects two individual bus sections in a straight bus substation configuration. References to Bus-tie Breaker in the standard would also need to be changed accordingly.
US Bureau of Reclamation	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two

Organization	Question 8:	Question 8 Comments:
		bus sections.
BPA Transmission Reliability Program	No	The term "Bus Tie" implies tying any two buses together. However, the intent of this standard is actually referring to connecting the main buses of two adjacent main and auxiliary configured substations together. Therefore, we recommend changing the term "Bus Tie Breaker" to "Bus Sectionalizing Breaker". We also recommend removing the parentheses portion of the Bus Tie Breaker definition. It does not provide clarification and may not apply to all utilities' systems.
Response: The SDT has revised the definition as follows: **Bus-tie Breaker**: A circuit breaker that is positioned to connect two individual ~~straight bus~~ substation bus configurations. ~~(Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)~~		
Progress Energy Florida, Inc.	No	PEF understands the intent behind the wording of the definition, but neither agrees with the definition nor its use in various applications in the Standard. Bus tie breakers as defined in the draft Standard are limited to connecting two straight bus configurations. In reality, the term bus-tie breaker can be, and is used for other applications. PEF suggests that the SDT further research the use of this term in the industry. But more to the point, PEF does not see the need for a distinction between bus tie and non bus tie breakers and ultimately recommends that this be removed from the Standard.
Florida Power and Light	No	Bus tie breakers are defined exclusively to straight bus configurations. They can be used for other breaker configurations. We do not see the need for a distinction between bus tie and non bus tie breakers.
Response: The SDT notes that a number of commenters disagreed with the definition. However, the number who indicate that the distinction should be eliminated is in the minority. Therefore, the SDT has retained the distinction while having made changes to provide a simpler and broader definition of bus-tie breaker.		
Dominion - Electric Transmission Planning	Yes	
City Water, Light & Power - Springfield, Illinois	Yes	

Organization	Question 8:	Question 8 Comments:
Los Angeles Department of Water and Power	Yes	
Tenaska, Inc.	Yes	
Gainesville Regional Utilities	Yes	
JEA	Yes	
PacifiCorp	Yes	We agree with the proposed format changes of the Tables.
ITC Holdings: ITC, METC, ITC Midwest	Yes	
Tacoma Power	Yes	
Lafayette Utilities System	Yes	
Black Hills Corporation	Yes	
Arizona Public Service Co.	Yes	We agree with the proposed definition change.
Exelon Transmission Planning	Yes	
Austin Energy	Yes	
Midwest ISO	Yes	This is a good definition.

Organization	Question 8:	Question 8 Comments:
Tri-State Generation and Transmission Association, Inc.	Yes	
AEP	Yes	
Lakeland Electric	Yes	
Southern Company Transmission	Yes	
LCRA TSC	Yes	
NERC and Regional Coordination	Yes	
IESO	Yes	
E.ON U.S. Transmission Planning	Yes	
ERCOT System Planning	Yes	
Oncor Electric Delivery	Yes	NA
FirstEnergy Corp.	Yes	
Response: The SDT thanks you for your response but the majority of commenters expressed a desire to change the definition.		

9. **Some commenters questioned why a Bus-tie Breaker would have a different performance requirement than a non-Bus-tie Breaker, stating that all breakers have the same probability for failure. It may be true that generally the probability for failure of any given breaker would not vary substantially among similar types of breakers, but the Bus-tie Breaker reduces exposure and consequences of bus faults. The different performance expectations in Tables 1 and 2 are based on promoting a higher level of reliability for the Transmission Systems operated above 300 kV.**

   It is recognized by the SDT that a straight bus design has some undesirable exposure to bus faults, but that Bus-tie Breakers can be utilized to improve reliability for bus faults and problems associated with exit breakers. As a result, the risk of an internal breaker fault was deemed to be significantly less than the benefit that is gained by reducing the exposure to a total bus failure. Therefore, provisions were built into the performance requirements that would not discourage their use.

   Do you agree that non-Bus-tie Breakers rated above 300 kV should have more stringent performance requirements than Bus-tie Breakers? If not, please explain why and/or suggest specific changes.

Summary Consideration:

While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV.

A number of commenters raised concerns with the less stringent requirement for DC systems. The SDT has removed the less stringent requirements for DC lines in the Table.

Due to industry comments, the SDT has changed/added the following:

Footnote 5 - When the conditions and/or event(s) being studied form the basis for conditional firm transmission service, curtailment of that conditional firm transmission service is allowed

Footnote #10 – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.

Consequential Load Loss: ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions.

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~

Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event.

Supplemental Load Loss: Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.

Organization	Question 9:	Question 9 Comments:
TVA System Planning	No	Since an internal fault on any breaker is a low probability event, we believe that Non-consequential Load Loss should be allowed.
Alberta Electric System Operator	No	We believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class.
Response: While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV.		
BCTC	Yes	BCTC agrees with different performance levels. However, we have a different rationale. Our reasoning is that a bus fault has a lower probability than a line fault. Bus tie breakers are called on to interrupt faults less often than line breakers. The failure probably may be the same but the frequency of failure is lower (because they are not called on to operate as often). The explanation given above by the SDT appears to be more related to a WECC issue that bus breaker failure should be Category D.
Response: Thank you for your support of the SDT's position.		
Platte River Power Authority	No	I think the performance for non-bus-tie breakers should be the same for all BES voltages for the same reason I agree with the performance of P2.4 Internal Breaker Fault (bus tie) and P4.6 Stuck Breaker where the Stuck Breaker could be a bus-tie or "sectionalizing" breaker.

Organization	Question 9:	Question 9 Comments:
Manitoba Hydro	No	Based on industry outage statistics, event P4, the non-bus tie breaker failure has a lower probability of occurrence than event P7, the common structure event. Consequently, Manitoba Hydro recommends that the performance requirement for >300 kV should be the same as P7. Imposing a higher performance expectation on the >300 kV facilities will require significant bus reconfiguration costs to ensure compliance for existing stations. The additional cost can not be justified by the reliability gain given the low probability of the event.
Transmission Agency of Northern California	Yes and No	We interpret ?exit breakers? to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes.
Pacific Gas and Electric Co.	Yes and No	We interpret “exit breakers” to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes
Public Service Company of New Mexico	Yes and No	We interpret “exit breakers” to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes.
PacifiCorp	No	We do not agree with the rationale for the requiring more stringent performance requirement levels for non-bus tie breakers above 300 kV. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes.
Idaho Power Company	Yes and No	We interpret ?exit breakers? to mean a breaker on an element that comes in from outside the substation. We agree with the rationale for the requiring more stringent performance requirement levels for non-bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes

Organization	Question 9:	Question 9 Comments:
SMUD	Yes and No	We interpret ?exit breakers? to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes
Sierra Pacific Power Company / Nevada Power Company	Yes	We interpret ?exit breakers? to mean a breaker on an element that comes in from outside the substation. We agree with the rationale for the requiring more stringent performance requirement levels for non-bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes
Black Hills Corporation	Yes and No	We interpret ?exit breakers? to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes
Arizona Public Service Co.	No	We do not agree with the rationale for the requiring more stringent performance requirement levels for non-bus tie breakers above 300 kV. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes.
SRP	Yes and No	We interpret ?exit breakers? to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes
MidAmerican Energy Company	No	MEC recognizes that the addition of this requirement is an attempt to raise the bar above the existing standards. However, the more stringent non-bus-tie performance criteria should only be adopted if there is sufficient evidence to demonstrate the expected reliability risk (i.e. system impact x probability of occurrence) is high enough to warrant the cost of the system modifications that would be needed to meet the criteria. System modifications that involve the installation of line and substation facilities >300 kV will likely take years and cost tens to hundreds of millions to build. There should be a reliability risk analysis that justifies the application of this performance criteria before it is adopted.

Organization	Question 9:	Question 9 Comments:
Tucson Electric Power Company	Yes and No	We interpret “exit breakers” to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes
MRO NERC Standards Review Subcommittee	No	The MRO recognizes that the addition of this requirement is an attempt top raise the bar above the existing standards. However, the more stringent non-bus-tie performance criteria should only be adopted if there is sufficient evidence to demonstrate the expected reliability risk (i.e. system impact x probability of occurrence) is high enough to warrant the cost of the system modifications that would be needed to meet the criteria. System modifications that involve the installation of line and substation facilities >300 kV will likely take years and cost tens to hundreds of millions to build. There should be a reliability risk analysis that justifies the application of this performance criteria before it is adopted.
Modesto Irrigation District	Yes and No	Comments: We interpret “exit breakers” to mean a breaker on an element that come in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes
Tri-State G&T	Yes and No	We interpret “exit breakers” to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes
ColumbiaGrid	Yes	Please explain/define the term “exit breakers”. We agree with the rationale for the requiring more stringent performance requirement levels for non-bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes.
Southern California Edison	Yes and No	We interpret “exit breakers” to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly

Organization	Question 9:	Question 9 Comments:
		different for different voltage classes
American Transmission Company	No	We recognize that the addition of this requirement is an attempt top raise the bar above the existing standards. However, the more stringent non-bus-tie performance criteria should only be adopted if there is sufficient evidence to demonstrate the expected reliability risk (i.e. system impact x probability of occurance) is high enough to warrant the cost of the system modifications that would be needed to meet the criteria. System modifications that involve the installation of line and substation facilities >300 kV will likely take years and cost tens to hundreds of millions to build. It would be helpful to have a reliability risk analysis that justifies the application of this performance criteria before it is adopted.
Entergy Services, Inc.	No	The probability of an EHV breaker failure is extremely low. Statistically, the probability of an internal breaker failure on any given day in our system is approximately 1 failure every 10,000 days. The probability of a stuck EHV breaker in our system is approximately 1 failure every 21,000 days. While the impact of such events can be severe, the significant cost to remedy such low probability events seems unlikely to pass any reasonable cost/benefit analysis.
US Bureau of Reclamation	No	We interpret “exit breakers” to mean a breaker on an element that come in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes
Response: The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV.		
Los Angeles Department of Water and Power	No	The arbitrary separation based on voltage class is discriminatory and without any scientific or historical basis. The probability of breaker failure do not increase with voltage class. In fact, breaker failures are seldom heard of at above the 300kV classes. Most breaker failures occur in lower voltage classes such as 230kv, 115kv, etc. where the short circuit current tends to be higher and thus stressing breaker contacts more severely giving rise to breaker failures. Delete any separation of voltage classes.
Response: The SDT believes that the separation for a more stringent requirement at above 300 kV is not “arbitrary”. The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems		

Organization	Question 9:	Question 9 Comments:
operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. The SDT believes that the separation above 300 kV is not “discriminatory” in that the standard is intended to be in place for all operators, owners, and users of the Transmission System. Finally, the SDT believes that there is scientific and historical basis in the sense that our representation of the differences between Systems above 300 kV as opposed to below 300 kV are a reasonable review of the uses of the NERC-wide Transmission System including scientific and historical considerations. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV.		
National Grid	No	They should have the same performance requirements, however we understand that it is better to encourage bus-tie breakers in some applications than to hold them to the higher standard. Future station designs that need this differential treatment should be discouraged.
Central Maine Power Company	No	They should have the same performance requirements, however we understand that it is better to encourage bus-tie breakers in some applications than to hold them to the higher standard. Future station designs that need this differential treatment should be discouraged.
NSTAR Electric	No	They should have the same performance requirements. The performance standards should not encourage differential treatment for the same equipment.
FirstEnergy Corp.	Yes and No	Fundamentally, from a purest perspective, we believe that all breakers should be treated as having the same probability of failure. However, we understand the SDT's intent and agree to the higher performance expectations for the above 300kV transmission system. We also agree that without the exception provided for bus-tie breakers, some entities may take the approach to simply operate their bus-tie breakers open in order to meet the performance requirements, which would be counterproductive to the improved reliability sought by the team. The alternative would be back to back bus-tie breaker installations which may not even be feasible due to space limitations. On a going forward basis, future station designs at this voltage level should avoid straight bus designs.
ISO New England Inc.	No	They should have the same performance requirements, however we understand that it is better to encourage bus-tie breakers in some applications than to hold them to the higher standard. Future station designs that need this differential treatment should be discouraged.

Organization	Question 9:	Question 9 Comments:
Northeast Utilities	Yes	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
Response: The SDT understands your comment as being supportive of the more stringent requirement for non-Bus-tie Breakers above 300 kV and of a more stringent requirement for Bus-tie Breakers above 300 kV in new substations. While there are a significant number of parties that commented negatively about the higher system performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the industry has indicated support for the higher performance requirement for non-Bus-tie Breakers above 300 kV and for a lower performance requirement for Bus-tie Breakers above 300 kV. Therefore, the SDT has not altered the higher system performance requirement for loss of non-Bus-tie Breakers above 300 kV and has not raised the system performance requirement for loss of Bus-tie Breakers above 300 kV for new substations.		
Tenaska, Inc.	Yes and No	Voltage is a questionable criteria for determining whether a breaker's performance requirements should be different. May want to consider a lower voltage cutoff (below 100 or below 200) as lower performance MAY have less of an impact.
Response: The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV and has not raised the system performance requirement for loss of breakers at lower voltages.		
Gainesville Regional Utilities	Yes	Our control area operates at 138 kV. Does everyone think that holding the owners of above 300 kV operating voltage systems to a higher standard really increases the total BES reliability? Does giving the DC systems a pass on some of the requirements really make sense in the world of reliability?
Response: The SDT believes that holding the owners of above 300 kV operating voltage systems to a higher standard increases the total BES reliability. The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV. A number of commenters raised concerns with the less stringent requirement for DC systems. The SDT has removed the less stringent requirements for DC lines.		

Organization	Question 9:	Question 9 Comments:
Progress Energy Florida, Inc.	No	PEF is opposed to distinction between non-Bus-tie breakers and Bus-tie breakers, and furthermore is opposed to the more stringent requirements for both in facilities above 300 kV. One primary reason has already been acknowledged by the SDT, that breakers have the same failure rate no matter the configuration in which they are placed. PEF can see two potential outcomes to the missteps being made regarding the breaker distinction: a) multiple redundancy of breakers for both Bus-tie and non-Bus-tie breaker schemes, which will require tearing down many Substations, acquiring additional property in many cases, and completely rebuilding the Substations to allow room for redundancy of breakers in series with one another; b) choosing to remove existing breakers for which a scenario of non-compliance is imminent, which could potentially pose a reliability risk to the system and possibly result in heightened risk for other Event categories.
Response: The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. Cost estimates were requested in other questions and were utilized by the SDT in determining a balance between such costs and reliability. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV. The SDT understands your argument about discouraging the use of breakers with a higher breaker failure performance requirement. However, the SDT notes that the Transmission Planner has always needed to plan for breaker failure since it is an event that does occur. Any reliability risk that is created by taking a breaker out of service to respond to this new higher performance requirement should be covered by the responsible entity by conducting system analysis using the new standard. If the reliability risk created by eliminating a breaker results in a failure to meet the performance requirements as outlined in the new standard, then the responsible entity will be required to develop Corrective Action Plans to mitigate the risk.		
Lafayette Utilities System	No	See paragraph (b) in response to Question 15.
Response: Lafayette Utilities System indicated in paragraph b in response to Question 15 that “Adopting less stringent performance requirements for loss of elements below 300 kV may be discriminatory.” Lafayette Utilities System further indicated that this may be because more wholesale customer Load may be served at these lower voltages than Transmission Owner Load. The SDT believes that the separation above 300 kV is not “discriminatory” in that the standard is intended to be in place for all operators, owners, and users of the Transmission System. Further, the SDT disagrees with the notion that it may be discriminatory in that more wholesale Load is served from under 300 kV than the Transmission Owner’s Load. As indicated in the SDT’s responses to the comments of others, the SDT believes that systems operating above 300 kV generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers.		

Organization	Question 9:	Question 9 Comments:
Ameren	Yes and No	Yes: The installation of bus-tie circuit breakers in a straight bus configuration would reduce exposure to a) bus faults or to b) line faults with breaker failure without adding much risk for internal fault in the bus-tie breaker. Those entities that employ a straight bus substation design with bus-tie breakers have recognized that failure of the bus-tie breaker, a very low probability event, would result in the loss of multiple transmission elements and perhaps firm load for a short time until the bus sections can be restored, but bus-tie breakers are an investment worth the risk. Therefore, it is generally agreed that the outage of non-bus-tie circuit breakers should have higher performance requirements than the outage of bus-tie circuit breakers. The SDT should be commended for this change since the previous draft version. No: However, it is not clear that adopting a higher standard of performance for planning events involving transmission facilities 345 kV and above will improve overall system reliability. Some areas of the continent already have n-2 planning criteria, yet these systems have still experienced significant outages including blackouts. It is suggested that a review of the Transmission Availability Data System (TADS) data, when available, should be conducted to help assess what system performance requirements need to be strengthened before arbitrarily determining to "raise the bar" for certain voltage levels and system designs. The industry should not be forced to invest a great deal of capital to meet a new standard requirement when it would not have an immediate impact on system reliability. Some sort of cost/benefit analysis should be performed to justify any change from the present TPL-001 through 004 standard requirements. On the Ameren system, there is no indication that transmission system reliability has been degraded through the use of straight bus configurations. Also, further clarification is required to explain how to drop consequential load without cutting firm transmission service to those affected/outaged customers, and this needs to be added to the notes in Tables 1 and 2.
North Carolina Electric Membership Corp	Yes and No	The installation of bus-tie circuit breakers in a straight bus configuration would reduce exposure to a) bus faults or to b) line faults with breaker failure without adding much risk for internal fault in the bus-tie breaker. Those entities that employ a straight bus substation design with bus-tie breakers have recognized that failure of the bus-tie breaker, a very low probability event, would result in the loss of multiple transmission elements and perhaps firm load for a short time until the bus sections can be restored, but bus-tie breakers are an investment worth the risk. Therefore, it is generally agreed that the outage of non-bus-tie circuit breakers should have higher performance requirements than the outage of bus-tie circuit breakers. The SDT should be commended for this change since the previous draft version. However, it is not clear that adopting a higher standard of performance for planning events involving transmission facilities 345 kV and above will improve overall system reliability. Some areas of the continent already have n-2 planning criteria, yet these systems have still experienced significant outages including blackouts. It is suggested that a review of the Transmission Availability Data System (TADS) data, when available, should be conducted to help assess what system performance requirements need to be strengthened before arbitrarily determining to "raise the bar" for certain voltage levels and system designs. The industry should not be forced to invest a great deal of capital to meet a new standard requirement when it would not have an immediate impact on system reliability. Some sort of cost/benefit analysis should be performed to

Organization	Question 9:	Question 9 Comments:
		justify any change from the present TPL-001 through 004 standard requirements. Also, further clarification is required to explain how to drop consequential load without cutting firm transmission service to those affected/outaged customers, and this needs to be added to the notes in Tables 1 and 2.
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	No	The installation of bus-tie circuit breakers in a straight bus configuration would reduce exposure to a) bus faults or to b) line faults with breaker failure without adding much risk for internal fault in the bus-tie breaker. Those entities that employ a straight bus substation design with bus-tie breakers have recognized that failure of the bus-tie breaker, a very low probability event, would result in the loss of multiple transmission elements and perhaps firm load for a short time until the bus sections can be restored, but bus-tie breakers are an investment worth the risk. Therefore, it is generally agreed that the outage of non-bus-tie circuit breakers should have higher performance requirements than the outage of bus-tie circuit breakers. The SDT should be commended for this change since the previous draft version. However, it is not clear that adopting a higher standard of performance for planning events involving transmission facilities 345 kV and above will improve overall system reliability. Some areas of the continent already have n-2 planning criteria, yet these systems have still experienced significant outages including blackouts. It is suggested that a review of the Transmission Availability Data System (TADS) data, when available, should be conducted to help assess what system performance requirements need to be strengthened before arbitrarily determining to "raise the bar" for certain voltage levels and system designs. The industry should not be forced to invest a great deal of capital to meet a new standard requirement when it would not have an immediate impact on system reliability. Some sort of cost/benefit analysis should be performed to justify any change from the present TPL-001 through 004 standard requirements. Also, further clarification is required to explain how to drop consequential load without cutting firm transmission service to those affected/outaged customers, and this needs to be added to the notes in Tables 1 and 2.

Response: The SDT thanks you for your support with regard to the reason for a less stringent requirement for Bus-tie breakers**.** The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. Cost estimates were requested in other questions and were utilized by the SDT in determining a balance between such costs and reliability. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV.

The SDT understands your issue with regard to explaining the dropping of consequential Load without cutting Firm Transmission Service to those affected/outaged customers. The SDT has made changes to footnotes 5 and 10 in the table and revised the definition of Consequential Load Loss and Non-Consequential Load Loss to clarify the issue.

Footnote 5 - When the conditions and/or event(s) being studied form the basis for conditional firm transmission service, curtailment of that conditional firm

Organization	Question 9:	Question 9 Comments:
transmission service is allowed. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~ **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.		
Florida Power and Light	No	These provisions made to not discourage the use of bus tie breakers will also not discourage the use of the single breaker/single bus substation arrangement which can have very severe consequence when used on critical BES substations. The TPL-001-1 draft also sets a threshold of higher performance to facilities above 300 kV than previously established in the existing standard. We do not agree that such a threshold is necessary or warranted. Requirements which are more stringent for these facilities may wrongly influence decisions on project alternatives in favor of facilities with less stringent requirements. Related to the more stringent requirements for facilities above 300 kV, FPL also disagrees with the performance requirements contemplated by the proposed draft standard for DC lines. The SDT stated performance requirements for DC lines as currently drafted, is discriminatory as compared to AC line performance, and needs to be addressed. This could be viewed as an exemption for DC lines and violates FERC's comparability principle as it relates to reliability performance. The TPL-001-1 draft sets a lower performance requirement for the loss of a single pole of a DC line than in the existing standard by allowing interruption of firm transfer if the transfer is deemed to be dependent on the outaged line. Firm transfers are also dependent upon AC lines. The proposed standard does not distinguish between asynchronous DC ties and the more common parallel connected DC tie. With an asynchronous DC tie, the transfer is lost with the tie, which is analogous to Consequential Load Loss which is already allowed. With a parallel DC

Organization	Question 9:	Question 9 Comments:
		tie, the transfer will be shifted to the parallel AC system and should have the same performance requirements. We do not agree that such an exception for DC lines is necessary or warranted. The decision in selecting DC vs. AC in transmission lines has traditionally been based on the break-even cost and performance of the two alternatives. The lower performance requirement may wrongly influence decisions on project alternatives in favor of DC facilities because of the less stringent reliability performance requirements.
Response: The SDT understands that the standard as drafted does not discourage the use of straight bus arrangements below 300 kV by allowing interruption of Firm Transmission Service and Non-Consequential Load Loss for all P4 events below 300 kV. The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV. A number of commenters raised concerns with the less stringent requirement for DC systems. The SDT has removed the less stringent requirements for DC lines.		
Tri-State Generatino and Transmission Association, Inc.	No	Performance requirements should depend on the potential loss of load impact of a breaker failure, not the voltage level.
Response: The SDT believes that while theoretically there would be potential merit in a loss of load impact approach to performance requirements for breaker failure; it would result in performance requirements that would be difficult to enforce. For example, such an approach would require completing estimates of the loss of Load for Contingencies for various conditions and then documenting it. The auditor would need to review these estimates as well as the documentation to become convinced that the correct performance requirement was used for each breaker. This review would need to be in addition to any other activity performed by the auditor to ensure compliance with the standard. The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV.		

Organization	Question 9:	Question 9 Comments:
Brazos Electric Power Cooperative, Inc.	Yes	Yes but this seems to add another category of items to provide for in the assessment.
Response: Thank you for your support.		
IESO	No	We hold the view that all breakers can be exposed to the same types of event, i.e., they can have internal faults and can be "stuck" when attempting to open as instructed. As such, there should not be any difference in the expected system performance among them in response to system events, and regardless of the voltage levels. We suggest the SDT to revised Tables 1 and 2 such that their expected performance are identical.
Response: The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV.		
Duke Energy	No	In Table 1, Category P4, Events 1 through 5 addressing a stuck non-bus tie breaker >300kV should allow Interruption of Firm Transmission Service and Non-Consequential Load Loss, because P4 addresses a multiple contingency.
Response: The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV. The SDT recognizes that Duke Energy has indirectly brought up the issue as to how the interruption of Firm Transmission Service relates to the dropping of Load in its comment. The SDT has made changes to footnotes 5 and 10 in the table and revised the definition of Consequential Load Loss and Non-Consequential Load Loss to clarify the issue. **Footnote 5** - When the conditions and/or event(s) being studied form the basis for conditional firm transmission service, curtailment of that conditional firm		

Organization	Question 9:	Question 9 Comments:
transmission service is allowed. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~ **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.		
Orlando Utilities Commission	Yes and No	If they are going to be two classes of equipment with an arbitrary cut off 300 kV is a good cutoff. However I would prefer to see the decision on what is "super BES" and regular "BES" less arbitrary and more reliability driven, such as letting the regions define this cut off just as they define BES in a manner suitable to the design of their regional system.
Response: The SDT believes that the separation for a more stringent requirement above 300 kV is not "arbitrary". The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. The SDT is preparing a NERC-wide standard for which a region can submit a regional difference that is justified based upon physical differences in that region and/or to result in a regional difference that is a higher performance requirement than the NERC-wide standard. Therefore, if a region has good cause for a different "cutoff", then the region can submit a regional difference through the NERC standards development process. This regional difference could even be submitted as part of this standards writing effort. However, it should be noted that once the regional difference is approved through the NERC standards development process, then it will be submitted to FERC and other regulatory authorities for approval. While there are a significant number of parties that commented negatively about the higher system performance requirement for non-Bus-tie Breakers above 300		

Organization	Question 9:	Question 9 Comments:
kV, higher performance requirements are encouraged by FERC Order No. 693 and the industry has indicated support for the higher performance requirement. Therefore, the SDT has not altered the higher system performance requirement for loss of non-Bus-tie Breakers above 300 kV.		
BPA Transmission Reliability Program	Yes	In general, performance requirements should be more stringent for higher voltage systems. Therefore, we agree that non-bus-tie breakers above 300 kV should have more stringent requirements.
Dominion - Electric Transmission Planning	Yes	
NPCC	Yes	
City Water, Light & Power - Springfield, Illinois	Yes	
Progress Energy Carolinas	Yes	
JEA	Yes	
Puget Sound Energy, Inc.	Yes	We agree that the failure of non-bus tie breakers above 300 kV to operate can have much higher consequence.
ITC Holdings: ITC, METC, ITC Midwest	Yes	
Tacoma Power	Yes	
Hydro-Quebec TransEnergie	Yes	

Organization	Question 9:	Question 9 Comments:
(HQT)		
Exelon Transmission Planning	Yes	
SERC Dynamics Review Subcommittee	Yes	The logic and the proposal seem reasonable.
Austin Energy	Yes	
Arkansas Electric Coop. Corp.	Yes	
Midwest ISO	Yes	
AEP	Yes	
Lakeland Electric	Yes	
Southern Company Transmission	Yes	
LCRA TSC	Yes	
NERC and Regional Coordination	Yes	Comments: PJM supports the use of bus tie breakers.
E.ON U.S. Transmission Planning	Yes	

Organization	Question 9:	Question 9 Comments:
ERCOT System Planning	Yes	
Oncor Electric Delivery	Yes	NA
Response: Thank you for your response.		

10. The SDT made modifications in this second draft to the requirements relating to sensitivity cases. Do you concur with the modifications reflected in Requirements R2.1.3 and 2.1.4? If not, please state why and/or suggest specific changes.

Summary Consideration:

A number of commenters agreed with the concept of the sensitivity analysis but were concerned that there is a conflict with sensitivities already included in base studies, sensitivity details, explaining why sensitivities were not run and how they affected Corrective Actions. The SDT has made the following changes:

1 – Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written, the standard is requiring at a minimum, one case run for each required year for steady state and Stability. The entity may run as many additional cases as it deems appropriate to understand how the System responds to the variances.

The revision also includes the removal of the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. Since these are sensitivities, any and all variances provide some level of information as to how the System responds to such variances.

2 – The sensitivities listed in Requirement R2.1.3 were revised for clarity; however, the SDT did not want to be more prescriptive because of the huge number of possible variances that can occur. It is up to the planning entity to determine which and how much of a variance is appropriate for its studies.

3 – Requirements R2.1.4 and R2.4.4 that require explanation of performing additional sensitivities that are not listed in Requirement R2.1.3 have been deleted.

4 – Requirement R2.6 has been revised for clarity. The entity can use any sensitivity studies it has performed in conjunction with the required current and past studies to develop its Corrective Action Plan.

The following requirements were changed due to industry comments:

R2.1.3 For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.7 (now R2.6) For Planning Events shown in Table 1 ~~– Steady State Performance and Table 2 – Stability Performance~~, when the analysis indicates an inability of the System to meet the performance requirements in the tables, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed in subsequent assessments but the System shall continue to meet the performance requirements in the tables. Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3 and R2.4.3. The Corrective Action Plan shall:

Organization	Question 10:	Question 10 Comments:
Dominion - Electric Transmission Planning	No	We are of the opinion that the proof of a negative that is required for sensitivity cases (i.e. - that the sensitivity cases were more severe for those selected conditions vs. those not tested) is burdensome. The burden of proof lies on the transmission planner.
NPCC	No	If a TP/PC conducts the studies specified in R2.1.1 and R2.1.2 with one or more of the sensitivities which stress the system in the normal course of study are we to assume that fulfills the requirements of R2.1 completely, without additional studies of a less-stressed system?
Hydro-Qu?bec Trans?nergie (HQT)	No	If a TP/PC conducts the studies specified in R2.1.1 and R2.1.2 with one or more of the sensitivities which stress the system in the normal course of study, are we to assume that fulfills the requirements of R2.1 completely, without additional studies of a less-stressed system?
Northeast Utilities	No	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.

Response: R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment".

R2.1.3 For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

Organization	Question 10:	Question 10 Comments:
TVA System Planning	No	We recommend that sensitivity studies not be required for each of the near term years as required in R2.1.3 and R2.1.1. Sensitivities should only be required for only one year in the near term. These sensitivity study requirements are too prescriptive. Many examples of sensitivities are already inherent in the existing requirements. Sensitivity studies of load variation are inherent in the fact that several different study years and conditions are already being required. Outages of reactive sources and generation should already be included in studies of multiple contingencies. The process of planning new generation (system impact studies) will include studies of the future with and without the proposed new equipment. The TP and PC can better select the most appropriate sensitivities for their system.
Response: The standard is requiring at a minimum one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the System responds to the variances. Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written, the standard is requiring at a minimum, one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the System responds to the variances. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
Progress Energy Carolinas	No	These requirements are overly prescriptive. Many examples of sensitivities are already inherent in the existing requirements. Some sensitivity studies are in effect adding an additional level of contingency (N-2 or N-3). Sensitivity studies of load variation are already inherent in the fact that several different study years and conditions are already being required. Outages of reactive sources and generation should already be included in studies of multiple contingencies. The process of planning new generation (system impact studies) will include studies of the future with and without the proposed new equipment. Proper consideration and selection of the most appropriate sensitivities is within the engineering judgment of the Transmission Planner and Planning Coordinator. Singling out and creating sub-requirements for the sensitivities listed in the current TPL draft creates a special focus on these specific sensitivities that may not be warranted for a given system. This could easily lead to an over focus on these particular issues to the detriment of overall system reliability. There should be no enumerated list of required sensitivities. Engineering judgment needs to be permitted.
Response: The SDT believes that sensitivities are necessary and consistent with the requirements of FERC Order 693. The draft standard includes the		

Organization	Question 10:	Question 10 Comments:
requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions", FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed. In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed System conditions. The SDT has included several parameters that can be varied to create the requisite sensitivity case(s). Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written, the standard is requiring at a minimum, one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the System responds to the variances. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
Los Angeles Department of Water and Power	No	R2.1.3 and 2.1.4 deal with operating scenarios that need to be studied by operating engineers under TOP but is duplicative and serve no useful purpose when performed by planning engineers for the purpose of future expansions. Transmission planning is to ensure that future system is expanded to handle expected system growth. Mixing operating studies in the planning of future system shows a confused perspective on the different roles between operating studies and planning studies. A responsible utility must perform both types of studies but they should not be mixed together or be required under two different standards, the TOP and TPL. The consideration of load variations, different dispatching scenarios, planned or unplanned transmission outages, system expansion not coming in on schedule, etc., are operating issues that should be and must be addressed in operating studies, and the proper place is in TOP, not TPL.
Response: The SDT believes that planners must consider these possible variances and reinforce the System so that when it comes to Real-time operation, the TOP will have a System sufficiently robust to operate around any of the conditions. Commenters generally agree that these are the responsibility of planning.		
Transmission Agency of Northern	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how

Organization	Question 10:	Question 10 Comments:
California		these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the “base case” condition. R2.7 also states that “Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities”. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the ?base case?, will the judgment of the Transmission Planner be then questioned because the “base case” used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Pacific Gas and Electric Co.	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the “base case” condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the ?base case?, will the judgment of the Transmission Planner be then questioned because the “base case” used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Public Service Company of New Mexico	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how

Organization	Question 10:	Question 10 Comments:
		these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the "base case" condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the "base case", will the judgment of the Transmission Planner be then questioned because the "base case" used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
PacifiCorp	Yes and No	We generally agree with the concept of the sensitivity analysis. However, clarifications of the following is needed: For example, if a TP performs studies on the "base case" of which the loads are 90/10, does this constitute a sensitivity analysis. If so, will the TP have to then perform additional less stringent studies at the 50/50 load level to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the TP should not have to explain why they feel that this higher level (90/10) of load is the "base case" condition.? R2.7 also states that Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a TP that has built transmission based on the 90/10 load assumed in the "base case", will the judgment of the TP be then questioned because of it's sensitivity "base case" and not a 50/50 base case?
Puget Sound Energy, Inc.	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the "base case" of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance?

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		R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the "base case" condition. R2.7 also states that "Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities". Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the "base case", will the judgment of the Transmission Planner be then questioned because the "base case" used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Idaho Power Company	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans.If a Transmission Planner performs studies on the "base case" of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the "base case" condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the ?base case?, will the judgment of the Transmission Planner be then questioned because ?base case? used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Sierra Pacific Power Company / Nevada Power Company	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage

Organization	Question 10:	Question 10 Comments:
		entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the ?base case? condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the ?base case?, will the judgment of the Transmission Planner be then questioned because ?base case? used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Black Hills Corporation	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the ?base case? condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the ?base case?, will the judgment of the Transmission Planner be then questioned because the “base case” used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Arizona Public Service Co.	Yes and No	We generally agrees with the concept of the sensitivity analysis. However, clarifications of the following is needed: For example, if a TP performs studies on the ?base case? of which the loads are 90/10, does this constitute a sensitivity analysis. If so, will the TP have to then perform additional less stringent studies at the 50/50 load level to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the TP should not have to explain why they feel that this higher level (90/10) of load is the “base case” condition. R2.7 also states that

Organization	Question 10:	Question 10 Comments:
		Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a TP that has built transmission based on the 90/10 load assumed in the ?base case?, will the judgment of the TP be then questioned because of it's sensitivity "base case" and not a 50/50 base case?
SRP	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the ?base case? condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the ?base case?, will the judgment of the Transmission Planner be then questioned because the "base case" used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Tucson Electric Power Company	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the ?base case? condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for

Organization	Question 10:	Question 10 Comments:
		sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the ?base case?, will the judgment of the Transmission Planner be then questioned because the “base case” used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Modesto Irrigation District	Yes and No	We generally agree with the concept of the sensitivity analysis since this is a standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the “base case” of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the “base case” condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the “base case”, will the judgment of the Transmission Planner be then questioned because the “base case” used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Tri-State G&T	Yes and No	e generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the “base case” condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for

Organization	Question 10:	Question 10 Comments:
		sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the “base case”, will the judgment of the Transmission Planner be then questioned because the “base case” used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Southern California Edison	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans .If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the “base case” condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the “base case”, will the judgment of the Transmission Planner be then questioned because the “base case” used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Alberta Electric System Operator	No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the ?base case? condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for

Organization	Question 10:	Question 10 Comments:
		sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the "base case", will the judgment of the Transmission Planner be then questioned because the "base case" used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
US Bureau of Reclamation	No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain Comment Form for 2nd Draft of Standard TPL-001-1Assess Transmission Future Needs (Project 2006-02) Page 9 of 12 why they feel that this higher level (1 in 10 year adverse weather) of load is the ?base case? condition. R2.7 also states that "Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities". Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the ?base case?, will the judgment of the Transmission Planner be then questioned because the ?base case? used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?

Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities".

R2.1.3 For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

The SDT agrees and has deleted Requirement R2.1.4.

Requirement R2.7 (now R2.6) has been revised for clarity. The entity can use any sensitivities studies it has performed in conjunction with the required current and

Organization	Question 10:	Question 10 Comments:
past studies to develop its Corrective Action Plan. **R2.6** For Planning Events shown in Table 1 ~~– Steady State Performance and Table 2 – Stability Performance~~, when the analysis indicates an inability of the System to meet the performance requirements in the tables, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed in subsequent assessments but the System shall continue to meet the performance requirements in the tables. Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3 and R2.4.3. The Corrective Action Plan shall:		
National Grid	No	a. With respect to R2.1.3., delete "... that Stress the System with sensitivities ...". b. R2.1.3 should be revised to clarify that if a TP/PC conducts the studies specified in R2.1.1 and R2.1.2 with one or more of the sensitivities which stress the system in the normal course of study, then additional studies of a less-stressed system are not required. c. The intention of Paragraph R2.1.4 is unclear and appears to be unnecessary; therefore, it should be removed.
Response: a. and b. Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: c. Requirement R2.1.4 has been deleted.		
Gainesville Regional Utilities	No	If the RRO or the larger neighboring utilities agree, See Comment 1, it should be unnecessary for the smaller utility to performance any sensitivities except for those agreed to and performed by the RRO level. If the smaller utility has any of their elements that create issues in these regionally conducted sensitivities, then they could be accountable for providing potential remedies (most sensitivities do not necessarily require a remedy or project, per say). The variety of sensitivities suggested to be performed for a smaller utility probably will not add any reliability to the regional BES while the effort will take up a very large amount of the smaller utilities' manpower resources.
Response: All planning entities need to follow the same set of requirements. Smaller entities may not have the resources to perform some studies but can depend on and point to studies run by larger surrounding entities to satisfy their planning requirements.		

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JEA	Yes and No	Will stress JEA resources to provide auditable evidence depending on the final measure applied.
Response: The SDT believes that sensitivities are necessary and consistent with the requirements in FERC Order 693. The draft standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed. The standard is requiring at a minimum one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the system responds to the variances.		
ITC Holdings: ITC, METC, ITC Midwest	No	While we appreciate that the addition of sensitivity studies is commendable and agree with 2.1.3 and 2.1.4 per se, the later clarification in R2.7 that "Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities" negates project justification (to many) based on sensitivity studies. Explaining as per R2.4.3 the reasons why you did or did not run a sensitivity study is less important, in many respects, than why you did or did not provide a Corrective Action Plan for performance failures observed in sensitivity studies. I.e., the study is the "cart" and the CAP is the "horse". Hence, at a minimum some form of Corrective Action Plan should be required.
PPL EnergyPlus	Yes and No	All of the sensitivity requirements should be structured to keep sensitivities from forcing un-needed construction. R2.1.3 & 4 are a good step but the point about planning around the base case might be made even more forcefully.
Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". Embedding the sensitivity in the "base case" will result in a CAP that addresses the particular "sensitivities". **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: In addition, Requirement R2.7 (now R2.6) has been revised for clarity. The entity can use any sensitivities studies it has performed in conjunction with the required current and past studies to develop its Corrective Action Plan. **R2.6** For Planning Events shown in Table 1 ~~– Steady State Performance and Table 2 – Stability Performance~~, when the analysis indicates an inability of the System to meet the performance requirements in the tables, the Planning Assessment shall include Corrective Action Plans addressing how the performance		

Organization	Question 10:	Question 10 Comments:
requirements will be met. Revisions to the Corrective Action Plans are allowed in subsequent assessments but the System shall continue to meet the performance requirements in the tables. Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3 and R2.4.3. The Corrective Action Plan shall:		
SMUD	Yes and No	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables .Added Reference 3.5.1: In cases where an SPS is deployed to reduce thermal overloads such that flows are brought within established facility ratings, but, for a short duration (seconds) until it is fully executed, the facility flows exceed the established rating, is that considered a violation or an acceptable engineering judgment that facilities are judiciously being brought to operate within ratings? Or, should the facility owner ensure establishment of a documented rating even for the short duration of seconds? Q10:TSS response: We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the “base case” condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the ?base case?, will the judgment of the Transmission Planner be then questioned because the “base case” used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case? Is some Non-Consequential Load Loss for an N-1 contingency on a sensitivity case using an extremely high load forecast acceptable as a Corrective Action Plan in the planning phase?
Response: The SDT agrees with your comment and has deleted Requirements R3.5.1, R3.5.2 and R3.5.3. Requirements R2.1.3 and R2.4.3 have been revised to make it clear that “sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the		

Organization	Question 10:	Question 10 Comments:
studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: The SDT agrees and has deleted Requirement R2.1.4. Requirement R2.7 (now R2.6) has been revised for clarity. The entity can use any sensitivities studies it has performed in conjunction with the required current and past studies to develop its Corrective Action Plan. **R2.6** For Planning Events shown in Table 1 ~~– Steady State Performance and Table 2 – Stability Performance~~, when the analysis indicates an inability of the System to meet the performance requirements in the tables, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed in subsequent assessments but the System shall continue to meet the performance requirements in the tables. Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3 and R2.4.3. The Corrective Action Plan shall:		
Progress Energy Florida, Inc.	No	PEF has significant concerns with each of the sub-Requirements listed in R2.1.3. Each is ambiguous, vague and open to variations in interpretation. It therefore makes no sense that "documentation of the technical rationale for why each of the conditions was or was not selected" is a requirement. Indeed, given that all of the sub-Requirements of R2.1.3 are vague, unspecific, unwieldy concepts, PEF is not sure how said documentation could be accomplished. Concerning R2.1.4, PEF has the same concerns that were expressed regarding the modified requirements mentioned in Question 2, and similarly here would suggest a substitute to the language in R2.1.4. Significant concerns with the previous sub-Requirements notwithstanding, PEF suggests either returning to the language in each existing Standard's R1.3.2, or adding an R2.1.3.8 that states "Other known critical system conditions specific to the system studied by the Transmission Planner or Planning Coordinator."
Response: The SDT did not want to be more prescriptive because of the huge number of possible variances that can occur. It is up to the planning entity to determine which and how much of a variance is appropriate for its studies. In addition, Requirements R2.1.3 and R2.4.3 have been revised to remove the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. Since these are sensitivities, any and all variances provide some level of information as to how the System responds to such variances. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical~~		

Organization	Question 10:	Question 10 Comments:
~~rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
Lafayette Utilities System	No	As to the performance of sensitivity analyses under R2.1.3, Lafayette believes that insufficient detail is provided to define with clarity cases that involve ?modification of expected transfers? (per R2.1.3.2). For example, it is unclear whether the phrase ?modification of expected transfers? is intended to refer to a change in directional bias in the model, a reduction in flows due to variation between reservations and schedules, or something else. Additional definition should be provided to ensure that sensitivity cases performed pursuant to R2.1.3.2 are meaningful and useful.
Response: The SDT did not want to be more prescriptive because of the huge number of possible variances that can occur. It is up to the planning entity to determine which and how much of a variance is appropriate for its studies		
Ameren	No	Similar to our comment above for R2.4.3, there should not be a requirement to explain why sensitivities were not selected. Also, it is not clear if R2.1.4 is a requirement or an option. While we agree that the system cannot be adequately planned based on a single snapshot of expected system conditions, these items in R2.1.3.1-7 are too prescriptive and are inappropriate for inclusion here. The sensitivities listed appear to be options and not sub-requirements, and may result in over-focusing on the particular issues listed to the detriment of overall system reliability. Some sensitivity studies are in effect adding an additional level of contingency to the analysis work (n-2 or n-3). Outages of reactive sources and generation should already be included in studies of multiple contingencies. The process of planning new generation (system impact studies) will include studies of the future system with and without the proposed new equipment. Engineering judgment should be used to develop the sensitivity scenarios, and it should be encouraged that the same scenarios should not be performed every year so that a portfolio of sensitivity scenarios would be developed over time. The standard should not include an enumerated list of required sensitivities. If two sensitivities are required to be performed each year, then the standard should state so, but we believe that more than one sensitivity scenario for each peak and off-peak case per year for assessment is too burdensome to run complete contingency analyses. Proposed alternative wording for R2.1.3 which addresses above concerns is as follows:R2.1.3. "For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System to reflect one or more conditions such as variation in load assumptions, modification of expected transfers, variability and outages of reactive resources, generation additions, retirements, or other dispatch scenarios are integral to a thorough assessment of reliability. Document how and why appropriate sensitivities were selected."
Response: Requirements R2.1.3 and R2.4.4 have been revised to remove the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run.		

Organization	Question 10:	Question 10 Comments:
Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written, the standard is requiring at a minimum, one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the System responds to the variances. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
Florida Power and Light	No	The words ?documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied? should be removed from R2.4.3. The sensitivity selection is necessarily subjective and judgmental. It is not clear what constitutes a valid rationale document. Compliance assessment of such a document would be subjective and is not needed.
Response: Requirements R2.1.3 and R2.4.3 have been revised to remove the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. The SDT believes that documentation of why a sensitivity was selected for study should be provided. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
Exelon Transmission Planning	No	We support efforts to improve load and dynamic load modeling, however we have concerns in being able to do so in an accurate manner - See comments to question #2. The state of industry development is such that this is not ready for inclusion in a standard such as R2.4.1 and R2.4.3.1.
Response: As with all planning models, assumptions must be made that the entity feels are representative of how the system will respond and perform. Models can only attempt to simulate the System based on expected conditions. The standard has been modified to explain that "an aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable".		

Organization	Question 10:	Question 10 Comments:
R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable		
CenterPoint Energy and CPS Energy	No	We believe R2.1.3 and R2.1.4 are overly prescriptive and should be deleted. It requires engineering judgment and experience to know whether a planning analysis is materially impacted by certain assumptions and, if so, which sensitivity analyses should be performed. Literally interpreted by an auditor, R2.1.3 would require at least one sensitivity analysis for each one of the contingencies shown in Tables 1 and 2 for each study specified in R2.1.1 and R2.1.2 and documentation for each contingency of each study why each sensitivity specified in R2.1.3 was or was not selected. The likely result is not value-added engineering analysis of actual reliability concerns. Instead, the likely outcome is unnecessary and burdensome additional analysis and documentation that is impractical, creating confusion and uncertainty as to what the practical interpretation of impractical requirements might ultimately be.
SERC Dynamics Review Subcommittee	No	These requirements are very prescriptive. Many examples of sensitivities are already inherent in the existing requirements. Some sensitivity studies are in effect adding an additional level of contingency (N-2 or N-3). Sensitivity studies of load variation are already inherent in the fact that several different study years and conditions are already being required. Outages of reactive sources and generation should already be included in studies of multiple contingencies. The process of planning new generation (system impact studies) will include studies of the future with and without the proposed new equipment. The TP and PC can better select the most appropriate sensitivities for their system. In general we believe that breaking these requirements into specific sub requirements, focusing on specific sensitivities, is too prescriptive and inappropriate. It will lead to over focus on these particular issues to the detriment of system reliability. There should be no enumerated list of required sensitivities. Engineering judgment needs to be permitted.
Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written the standard is requiring at a minimum one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the system responds to the variances. In addition, Requirements R2.1.4 and R2.4.4 have been deleted. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the~~		

Organization	Question 10:	Question 10 Comments:
~~conditions was or was not selected shall be supplied~~ included in the Assessment:		
MidAmerican Energy Company	No	a. MEC is not sure why R2.4.3.1 for sensitivities for Stability studies is a less definitive definition for load model variations then the steady state studies in R2.1.3.1. MEC recommends that R2.1.3.1 be changed to "Variations in Load model assumptions." b. MEC believes R2.1.4 and R2.4.4 should be deleted because its unnecessary to make a requirement of sensitivities that an entity chooses to do above and beyond the requirements in R2.1.3 and R2.4.3. If the SDT chooses not to delete these requirements, then MEC believes that R2.1.4 should be a subrequirement of R2.1.3 and R2.4.4 should be made a subrequirement of R2.4.3. The responsible entity should be allowed to select the appropriate sensitivity that should be performed. This is especially necessary given the need to perform each of these sensitivity analyses for six situations each year: peak and off-peak for two short-term years and one long-term year. Even with the requirement for one sensitivity for each case that amounts to six additional sets of analysis for steady-state and six for stability.
Response: a. As with all planning models, assumptions must be made that the entity feels are representative of how the System will respond and perform. Models can only attempt to simulate the System based on expected conditions. The standard has been modified to explain that "an aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable". **R2.4.1** System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable b. Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written, the standard is requiring at a minimum, one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the system responds to the variances. In addition, Requirements R2.1.4 and R2.4.4 have been deleted. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
MRO NERC	No	a. The MRO is not sure why R2.4.3.1 for sensitivities for Stability studies is a less definitive definition for load model

Organization	Question 10:	Question 10 Comments:
Standards Review Subcommittee		variations then the steady state studies in R2.1.3.1. The MRO recommends that R2.1.3.1 be changed to "Variations in Load model assumptions." b. The MRO believes R2.1.4 and R2.4.4 should be deleted because its unnecessary to make a requirement of sensitivities that an entity chooses to do above and beyond the requirements in R2.1.3 and R2.4.3. If the SDT chooses not to delete these requirements, then MRO believes that R2.1.4 should be a subrequirement of R2.1.3 and R2.4.4 should be made a subrequirement of R2.4.3. The responsible entity should be allowed to select the appropriate sensitivity that should be performed. This is especially necessary given the need to perform each of these sensitivity analyses for six situations each year: peak and off-peak for two short-term years and one long-term year. Even with the requirement for one sensitivity for each case that amounts to six additional sets of analysis for steady-state and six for stability. c. For R2.1.4, we suspect that these analysis are similar to extreme event contingencies and do not have specific performance requirements. We would also like some explanation of what and how to provide the technical rationale for why each condition was or was not used.

Response: As with all planning models, assumptions must be made that the entity feels are representative of how the System will respond and perform. Models can only attempt to simulate the System based on expected conditions. The standard has been modified to explain that "an aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable".

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

b. Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written, the standard is requiring at a minimum, one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the system responds to the variances. In addition, Requirements R2.1.4 and R2.4.4 have been deleted.

R2.1.3 For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

c. Requirement R2.1.4 has been deleted.

Organization	Question 10:	Question 10 Comments:
Austin Energy	No	Appropriate sensitivity analysis should be determined by the Transmission Planner and/or the Planning Coordinator (ISO or RTO) and not made a routine requirement. Therefore, R2.1.3 should be deleted.
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	No	These requirements are very prescriptive. Many examples of sensitivities are already inherent in the existing requirements. Some sensitivity studies are in effect adding an additional level of contingency (N-2 or N-3). Sensitivity studies of load variation are already inherent in the fact that several different study years and conditions are already being required. Outages of reactive sources and generation should already be included in studies of multiple contingencies. The process of planning new generation (system impact studies) will include studies of the future with and without the proposed new equipment. The TP and PC can better select the most appropriate sensitivities for their system. In general we believe that breaking these requirements into specific sub requirements, focusing on specific sensitivities, is too prescriptive and inappropriate. It will lead to over focus on these particular issues to the detriment of system reliability. The standard should not include an enumerated list of required sensitivities Engineering judgment needs to be permitted.

Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written the standard is requiring at a minimum one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the system responds to the variances.

R2.1.3 For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

Midwest ISO	No	This reminds us of Category D from original table--requiring us to study something but take no action. Sensitivities are not appropriate nor effective in a planning world in which you require an array of sensitivity studies but require no action will be taken. While running sensitivities enables us to better understand system limits, why have it as a requirement if there is no action plan obligation.

Response: The requirement was added to ensure that the entities do run certain variances that would stress the System. Requirement R2 requires that such studies are documented as part of the Planning Assessment. The entity is to determine the risk associated with not modifying the Corrective Action Plan to consider these studies. The documentation puts the entity on record as stating that the variance was considered but may or may not have been incorporated in the Plan makes the entity liable for its decision.

Organization	Question 10:	Question 10 Comments:
Tri-State Generation and Transmission Association, Inc.	No	We appreciate the extra detail describing sensitivity cases, but do not think it is reasonable to require explanations of why each condition suggested in R2.1.3.1-R2.1.3.7 was or was not studied. It should be sufficient that sensitivity studies are considered appropriate by the individual utility. R2.1.4 should be demoted to R2.1.3.8 (and the "shall include rationale" clause removed).
Response: Requirements R2.1.3 and R2.4.3 have been revised to remove the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. The SDT believes that documentation of why a sensitivity was selected for study should be provided. Requirements R2.1.4 and R2.4.4 have been deleted. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
Lakeland Electric	No	R2.1.3.1 requires other than peak sensitivity studies while R2.1.2 requires Off peak studies. Recommend further defining of R2.1.2 to specific load level or points on forecast demand curves to eliminate any overlap between two requirements.
Response: The SDT has used the defined term "Off-Peak" and believes that this is sufficient.		
Southern Company Transmission	No	R 2.1.3 One should only have to explain why sensitivity was performed, not why it was not performed. In general we believe that breaking these requirements into specific sub requirements focusing on specific sensitivities is too prescriptive and inappropriate. It will lead to over focus on these particular issues to the detriment of system reliability. There should be no list of sensitivities enumerated as subrequirements. Engineering judgment needs to be permitted. A specific proposal for R2.1.3 which addresses the above concerns is provided as follows:R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) shall be run and documented that stress the System to reflect one or more conditions such as higher or lower Load than forecasted with variability of Load/demand and Load power factors due to season, weather, or time of day; modification of expected transfers; unavailability of long lead time Facilities; variability and outages of reactive resources; generation additions, retirements, or other dispatch scenarios; decreased effectiveness of controllable Loads and Demand Side Management; modification of planned Transmission outages. Document why each sensitivity was selected.
Response: Requirements R2.1.3 and R2.4.4 have been revised to remove the requirement you reference. In addition, Requirements R2.1.3 and R2.4.3 have been		

Organization	Question 10:	Question 10 Comments:
revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
Brazos Electric Power Cooperative, Inc.	No	2.1.3 should have been left alone. We have a real problem with the addition of 'technical' and documenting why things were NOT selected. We would also like to see more leeway provided to the TP and PC by adding language similar to that mentioned above such as "as deemed necessary by the TP or PC".2.1.4 should be incorporated into 2.1.3 in a similar fashion as our suggested changes for 2.4.3.
Response: Requirements R2.1.3 and R2.4.4 have been revised to remove the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. In addition, Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, Requirements R2.1.4 and R2.4.4 have been deleted. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
NERC and Regional Coordination	No	The standard as worded:? Implies all tests are run for a given sensitivity the standard should be revised to read applicable testing for the applicable sensitivity.? Requires proof of negative o Why a sensitivity was not selected? Requires that expansion plans identify the impact of sensitivity o Many sensitivities may have varying impacts on an expansion plan. Suggested changes:R2.1.3 - For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that reflect one or more of the following conditions shall be incorporated into the assessment. Documentation of the

Organization	Question 10:	Question 10 Comments:
		technical rationale for why each of the conditions was selected and the portion of the assessment that included each selected sensitivity shall be supplied. R2.1.4, R2.4.3, and R2.4.4 - need to be modified accordingly. Delete R2.1.4 as it is superfluous. If a PC runs a sensitivity study and includes that analysis in its Plan, then why would NERC mandate that the PC explain why the non-mandated sensitivity study was run. If a study is required then it should be mandated. If a study is not mandated then he PC should not be held accountable for explaining the un-mandated study.R2.4.3.1 ? Variation in load model. Specific numbers should be included. R2.4.3.2 - Modification of expected transfers ? Be more specific. Firm or non-firm transfer and amount of MWR2.4.3.3 - Unavailability of long lead time Facilities. How many years out we are looking at and for how long it must be out of service.R2.4.3.4 - Variability of Reactive Source ? need to be more specific (give me MVARS). We already test this under FAC 010 for lost of shunt capacitor.R2.4.3.5 - This should already been taken into account when we do studies. So be more specific.R2.7.2 - Include a description of how results of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 impacted the list of actions developed in accordance with R2.7.1.R2.1 - Revise wording - The annual assessment of the of the NT Planning Horizon shall include: then go into the sub-bullets. The SDT must clarify exactly explicitly how many studies (in terms of numbers) must be done each planning horizon for short term and long term and how much sensitivity study for term.

Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities".

Also, Requirements R2.1.3 and R2.4.3 have been revised to remove the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run.

R2.1.3 For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

The SDT agrees with the commenter and has deleted Requirements R2.1.4 and R2.4.4.

The SDT did not want to be more prescriptive and provide specific details and number for variances that the entity may select because of the huge number of possible variances that can occur. It is up to the planning entity to determine which and how much of a variance is appropriate for its studies.

Requirement R2, along with its sub-requirements, requires the sensitivities run are to be documented. Requirement R2.6 requires that the Corrective Actions be listed. The entity can add the details and further explanation of how the sensitivities were incorporated into the Plans.

Organization	Question 10:	Question 10 Comments:
Since the basis of the standard is to allow the entity to support the Planning Assessment using current and past studies, the standard cannot dictate the specific number of studies to be made. The standard does specify the current cases that must be run in Requirements R2.1.1, R2.1.2, R2.2, R2.4.1 and R2.4.2.		
IESO	No	As we commented on R2.4.3, we continue to express our disagreement to include sensitivity testing in R2.1.3 and R2.1.4. We are disappointed that despite disagreements by the majority of the commenters and their suggestions to leave sensitivity testing to the TP's and PC's discretion, the SDT continues to stipulate detailed requirements for sensitivity testing. The SDT in its summary response to comments indicates that these testing are intended as "?providing some guidance on what could be included in the sensitivity studies without being too prescriptive." If these are indeed intended as guidance rather than enforceable requirements, then they should be provided in a technical document or a reference document that supports the standard, not in the standard itself.
Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written, the standard is requiring at a minimum, one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the System responds to the variances.		
North Carolina Electric Membership Corp	Yes and No	Sensitivities to base assumptions for studies are always good utility practice. But we agree with others that these may be overly prescriptive in requiring each and every one. Allow the TP and PC to select the appropriate sensitivities for the annual assessments with input from customers and affected stakeholders. We are concerned that the requirement for every sensitivity each and every year would result in excessive burden to existing PCs and TPs doing this analysis with no resulting improvement to reliability.
Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written the standard is requiring at a minimum one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the System responds to the variances.		
E.ON U.S. Transmission Planning	Yes and No	2. R2.1.3.2 refers to modification of expected transfers as a sensitivity test. Does this include transfers across the system, such as a transfer from Cinergy to TVA?
Response: The SDT did not want to be more prescriptive because of the huge number of possible variances that can occur. It is up to the planning entity to determine which and how much of a variance is appropriate for its studies		

Organization	Question 10:	Question 10 Comments:
ERCOT System Planning		The sensitivity cases suggested are unnecessary and unfeasible. For example, generation additions to cases that can already meet the load under contingency conditions do not create a reliability problem as the new generator can always be turned off. On the other extreme, sensitivity analysis of possible, unknown and uncontrollable generation retirements along with the Table 1 requirements of P3 (Generator + 1) contingency analysis presents an overwhelming study and documentation burden that will not add a corresponding benefit to the study and the results would be meaningless.
Response: The SDT believes that planners must consider these possible variances and reinforce the System so that when it comes to Real-time operation, the TOP will have a system sufficiently robust to operate around any of the conditions. Commenters generally agree that these are the responsibility of planning. Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
American Transmission Company	No	For R2.1.3, we would like further explanation of what technical rationale is expected and how it should be provided as to why each condition sensitivity was or was not used. In the subrequirements, we are unsure of what is exactly meant by "variability of load demand and load power factors", "modification of expected transfers", "long lead time Facilities", and "modification of planned outages". For R2.1.4, it is unclear what specific performance requirements must be met for these other sensitivities. We would also like some explanation of what technical rationale is expected and how it should be provided as to why each condition sensitivity was or was not used.
Response: Requirements R2.1.3 and R2.4.4 have been revised to remove the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. Since these are sensitivities, any and all variances provide some level of information as to how the system responds to such variances. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the~~		

Organization	Question 10:	Question 10 Comments:
~~conditions was or was not selected shall be supplied~~ included in the Assessment: The SDT did not want to be more prescriptive because of the huge number of possible variances that can occur. It is up to the planning entity to determine which and how much of a variance is appropriate for its studies. Also, Requirements R2.1.4 and R2.4.4 have been deleted.		
Duke Energy	No	Although we agree with the perceived intent of R2.1.3, we believe the wording should be revised to make it very clear that it is not necessary to perform studies to substantiate your technical rationale for choosing not to perform any particular sensitivity study. Documented engineering judgment to support the decision not to perform the particular sensitivity studies should be sufficient. Recommend renumbering R2.1.4 to R2.1.3.8 and reword as follows: Any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems.
Florida Reliability Coordinating Council, inc	No	R2.1.3 and R2.1.4 as written can create issues during the compliance assessment. These requirements place the burden of justifying the inclusion / exclusion of the sensitivities on the TP or PC. Thus, only a sensitivity deem appropriate by the TP or PC and not performed can be found non-compliant. R2.1.4 can be eliminated by modifying the wording in R2.1.3 as follows:? For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, at least one sensitivity shall be performed that stress the system based on one or more of the following conditions, plus any additional conditions determined by the Transmission Planer and Planning Coordinator. The Planning Assessment will also include the technical rationale for why each of the conditions was or was not selected for study that year.?
Response: Requirements R2.1.3 and R2.4.4 have been revised to remove the requirement to explain why sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. Since these are sensitivities, any and all variances provide some level of information as to how the system responds to such variances. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
Central Maine Power Company	No	a. With respect to R2.1.3 delete "that Stress the System with sensitivities". b. R2.1.3 should be revised to clarify that if a TP/PC conducts the studies specified in R2.1.1 and R2.1.2 with one or more of the sensitivities which stress the system in the normal course of study, then additional studies of a less-stressed system are not required.

Organization	Question 10:	Question 10 Comments:
		c. The intention of Paragraph R2.1.4 is unclear and appears to be unnecessary; therefore, it should be removed.
ISO New England Inc.	No	a. With respect to R2.1.3 delete " that Stress the System with sensitivities". b. R2.1.3 should be revised to clarify that if a TP/PC conducts the studies specified in R2.1.1 and R2.1.2 with one or more of the sensitivities which stress the system in the normal course of study, then additional studies of a less-stressed system are not required. c. The intention of Paragraph R2.1.4 is unclear and appears to be unnecessary; therefore, it should be removed.
ColumbiaGrid	Yes	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the ?base case? condition.
Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: The SDT agrees and has deleted R2.1.4.		
NSTAR Electric	No	1. With respect to R2.1.3 delete "that Stress the System with sensitivities".2. R2.1.3 should be revised to clarify that if a TP/PC conducts the studies specified in R2.1.1 and R2.1.2 with one or more of the sensitivities which stress the system in the normal course of study, then additional studies of a less-stressed system are not required.3. The intention of Paragraph R2.1.4 is unclear and appears to be unnecessary; therefore, it should be removed.
Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with		

Organization	Question 10:	Question 10 Comments:
~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: Requirements R2.1.4 and R2.4.4 have been deleted.		
New York Independent System Operator	No	If a TP/PC conducts the studies specified in R2.1.1 and R2.1.2 with one or more of the sensitivities which stress the system in the normal course of study, we assume that fulfills the requirements of R2.1 completely, without additional studies of a less-stressed system. Is that correct?
Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: The standard expects that at least one more of those variances listed in Requirement R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written the standard is requiring at a minimum one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the System responds to the variances.		
Oncor Electric Delivery	Yes	Generally agree with modifications although would again stress that detailed load modeling for stability analysis may be as revealing as some of the sensitivity studies recommended in R2.1.3 if they were only run with steady state analysis.
Response: As with all planning models, assumptions must be made that the entity feels are representative of how the System will respond and perform. Models can only attempt to simulate the System based on expected conditions. The standard has been modified to explain that "an aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable". **R2.4.1** System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic		

Organization	Question 10:	Question 10 Comments:
behavior of the Load is acceptable.		
FirstEnergy Corp.	No	The requirements related to sensitivity cases as written in draft 2 are an improvement over draft 1 as they now allow flexibility in choosing sensitivities, compared to what use to be a fixed list of options. However, we do not agree with the need to document the technical rationale for why each listed condition was or was not selected. This seems to create a needless paper trail from an auditing viewpoint. If any documentation is needed, it should be limited to why the sensitivity was selected and it should not be required to indicate why others were not selected. Therefore, we suggest rewording 2.3.1 as follows: "For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation of the technical rationale for why each of the conditions was selected shall be supplied:"R2.1.4 - This is an optional requirement and should be worked into the list of options within 2.1.3. As a stand alone requirement, what type of measure or VSL would be applicable for this requirement? We suggest re-numbering this requirement as a new 2.1.3.8 and reword it as follows: "Any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems".R2.1.3.3 ? This requirement indicates sensitivity is needed for "Unavailability of long lead time facilities." Why is this required in a near-term planning horizon? How long is long? Doesn't the N-1-1 (Planning Event P6) test already account for this related to the outage of existing equipment which may present long lead times? Same comments apply for R2.4.3 and R2.4.4 in the stability study section.
Response: Requirements R2.1.3 and R2.4.3 have been revised to remove the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: The STD agrees. Requirements R2.1.4 and R2.4.4 have been deleted. The near-term horizon extends from one to five years. Equipment scheduled for installation in five years requires ordering today. Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities".		
Orlando Utilities	Yes and No	I generally agree with the intent of requiring studies beyond just one load level and system condition; however I have some

Organization	Question 10:	Question 10 Comments:
Commission		specific suggestions, questions and comments. R2.1.3: As worded I have several concerns: 1. This would make any study performed that did not include sensitivities useless for performing the assessment. I recommend identify sensitivities and studies separately, with sensitivities just being smaller versions of studies. (Our usual definition is that a study demonstrates specific solutions to problems identified, whereas a sensitivity merely comments on the presence or lack of problems and how they relate to what is seen in the more formal studies. Obviously a problem found in a sensitivity not seen in a regular study receives additional focus.) 2. This would force the study to look only at the sensitivities listed rather then allow one or more of the conditions, plus additional conditions all in one run. This would force an entity to run additional studies if they wished to exceed the requirements rather then a single study that meets and exceeds the requirements. I suggest the following wording instead to still require the sensitivities, but allow flexibility in how they are performed. "R 2.1.3: At least one sensitivity shall be performed that stress the system based on one or more of the following conditions, plus any additional conditions determined by the transmission planner and planning coordinator. The Planning Assessment will also include the technical rationale for why each of the conditions was or was not selected for study that year. R.2.1.3.1- Suggest adding system growth, for example "season, weather, unpredicted system growth, or time of day". As written it does not seem to allow a study based on the long range load growth prediction being off, but instead only on a change in season, weather or time of day. R2.1.4: What was intended by using the phrase "Documentation of the technical rationale" instead of simply saying "shall include technical rationale"? I suggest dropping the "documentation of the" as this could cause confusion on an audit as to what is the difference between the "technical rationale" and "documentation of the technical rationale" unless the drafting team plans to define what "documentation of technical rationale is" other then the rationale itself.

Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written, the standard is requiring at a minimum, one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the system responds to the variances.

R2.1.3 For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

The SDT did not want to be more prescriptive because of the huge number of possible variances that can occur. It is up to the planning entity to determine which

Organization	Question 10:	Question 10 Comments:
and how much of a variance is appropriate for its studies. Requirements R2.1.3 and R2.4.4 have been revised to remove the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. Since these are sensitivities, any and all variances provide some level of information as to how the system responds to such variances. Requirements R2.1.4 and R2.4.4 have been deleted		
Entergy Services, Inc.	No	R2.1.3.2 - Modification of expected transfers: Modification of expected transfers infers that non-firm transmission use would be estimated based on historical data or perhaps an economic outlook. To plan the system for such non-firm use is an imprudent burden on rate payers. Economic tools are available to ascertain the benefits of system upgrades and prudently allocate the costs of such upgrades. Generation assets and the future plans of those assets is market sensitive information that could easily be extracted from such sensitivity analyses. Results of these sensitivity studies should be used to aid in reliably operating the system. They should not be a basis for constructing transmission facilities for reliability. These types of studies are aligned with the operating horizon. See also comments made above regarding 2.1.3.4 and 2.1.3.7.In general, we believe that breaking these requirements into specific sub requirements, focusing on specific sensitivities, is too prescriptive and inappropriate. It will lead to over focus on these particular issues to the detriment of system reliability. There should be no enumerated list of required sensitivities. Engineering judgment needs to be permitted. Many examples of sensitivities are already inherent in the existing requirements. Some sensitivity studies are in effect adding an additional level of contingency (N-2 or N-3). Sensitivity studies of load variation are already inherent in the fact that several different study years and conditions are already being required. Outages of reactive sources and generation should already be included in studies of multiple contingencies. The process of planning new generation (system impact studies) will include studies of the future with and without the proposed new equipment. The TP and PC can better select the most appropriate sensitivities for their system. We recommend that engineering judgment continue to be recognized as a vital component of planning.
Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written, the standard is requiring at a minimum, one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the system responds to the variances. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		

Organization	Question 10:	Question 10 Comments:
The SDT believes that planners must consider these possible variances and reinforce the System so that when it comes to Real-time operation, the TOP will have a System sufficiently robust to operate around any of the conditions. Commenters generally agree that these are the responsibility of planning. The SDT did not want to be more prescriptive because of the huge number of possible variances that can occur. It is up to the planning entity to determine which and how much of a variance is appropriate for its studies.		
BPA Transmission Reliability Program	No	For those conditions that are "not" studied, it makes sense to explain why that particular condition was not selected. However, we do not agree with R2.1.3 that a rationale needs to be provided for why a particular sensitivity "is" selected for study. Running additional sensitivities provides a better understanding of system performance and doesn't need further justification. Requirement R2.1.4 is not needed and should be removed. It should be up to the Transmission Provider's discretion whether they run additional sensitivity studies beyond what the standard requires in R2.1.3, and it should not be necessary to justify why they chose to run them. What a sensitivity study consists of, needs further clarification. For example, if a system assessment is performed using a case with transmission paths stressed near their limits, is this considered the baseline or a sensitivity? If it is considered the baseline, would a sensitivity be required at reduced stress levels and what purpose would this serve when the original case produced the more severe system impacts? This needs further clarification.
Response: Requirements R2.1.3 and R2.4.3 have been revised to remove the requirement to explain why sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: Requirements R2.1.4 and R2.4.4 have been deleted. Requirements R2.1.3 and R2.4.3 have been revised to make it clear that “sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment”. The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as “sensitivities”.		
City Water, Light & Power - Springfield, Illinois	Yes	

Organization	Question 10:	Question 10 Comments:
Platte River Power Authority	Yes	
BCTC	Yes	
Manitoba Hydro	Yes	
Tenaska, Inc.	Yes	
Arkansas Electric Coop. Corp.	Yes	
AEP	Yes	
LCRA TSC	Yes	
Response: Thank you for your response.		

11. **In response to industry comments, the SDT modified Table 1 requirements for Planning Event P6. Planning Event P6 involves independent overlapping single contingencies (n-1-1) involving two Transmission Facilities excluding generators. This Planning Event generally correlates to P5 of the first draft and now includes shunt devices. The P6 event was also revised to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300 kV.**

    Do you concur with the modifications? If not, please state why and/or suggest specific changes.

Summary Consideration:

A substantial majority of the industry respondents agree with the revision to permit loss of Non-Consequential Load to meet performance requirements for P6 Events involving systems above as well as below 300 kV, considering the low probability of such Events.

There are concerns that this change would make it difficult for scheduling maintenance outages because the existing TPL-003-0 allows shedding of Non-Consequential Load after the next outage . However, in the proposed standard, If a facility is scheduled out of service for maintenance, the next outage would be considered a single Contingency Event, and loss of Non-Consequential Load is not permitted.

There are concerns expressed by numerous respondents that after the first single Contingency and System adjustment, curtailment of Firm Transmission Services (or firm transfers) and shedding of firm Load would not be allowed in preparation for the second Contingency. The SDT added Footnote # 10 to the end of Table 1 to reflect that Curtailment or Interruption of Firm Transmission Service in preparation for the next Contingency will be allowed. However, until the next Contingency occurs, System performance will need to meet the requirements for a single Contingency Event. As such, the proposed standard will not allow loss of any firm Non-Consequential Load, except for contracted Interruptible Loads, in preparation for the next Contingency. Nonetheless, the SDT has provided an exception (Requirement R2.6.4) to address those situations, which may arise that are beyond the control of the Transmission Planner or Planning Coordinator, and, which can prevent the implementation of the relevant Corrective Action Plan in the required timeframe.

Some respondents requested that System adjustment be defined. The SDT believes that Header note ‘e’ and the new Footnote # 10 provides the description of the System adjustments allowed after a first Contingency Event.

There were also requests for clarification between a P1 Event, which occurred after another Facility has been out of service, for example, for scheduled maintenance, and a P6 Event, since the former will not allow loss of Non-Consequential Load, while the latter would allow it. The SDT believes that the difference between these two Events is whether the prior outage was planned (such as maintenance) or anticipated (such as extended outage). Therefore, if the Prior outage is planned or anticipated, then the next N-1 is a single Contingency Event, otherwise, it would be a P6 Event.

Concerns were also expressed that the TP and PC should have discretion on the Contingencies (for example, shunt devices) to study and analyze. One response suggests that the P6 Event to be studied should have a common reason to occur. The SDT modified Requirement R3.3 (now R3.4) to allow the PC and TP to determine the single and multiple Contingencies to be included in the planning analyses. This would give the TP and the PC the discretion to study the Contingency most suited to the area of study, and they can choose not to study loss of shunt devices, or those P6 Events that do not have a common reason to occur, if these are less severe than the Events studied.

Some responses suggest that there should be a specific limit to the amount of Load loss allowed. While the SDT does not disagree with having some specific limits below which Load loss would be allowed, arriving at such an amount may be too case-specific and too prescriptive for a Continent-wide Standard.

One response disagrees that the requirement should be so much more severe for an internal breaker fault as opposed to two single line outages for elements over 300 kV. The SDT believes that an internal breaker fault would remove from service all Facilities connecting to the faulted breaker simultaneously, which would likely be more severe than outage of two single lines.

As a result of industry comments, the following requirements were changed:

R3.3.3 (now R3.4) Those Planning Event Contingencies in Table 1 ~~– Steady State Performance~~ ~~not covered in Requirement R3.3.2~~ that are expected to produce more severe System impacts shall be identified~~,~~ and a list of those Contingencies to be evaluated for System performance in Requirement R3.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results.

Header note 'e' - For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Footnote #10 – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.

Organization	Question 11:	Question 11 Comments:
Dominion - Electric Transmission Planning	No	For Bulk Electric System (BES) Elements out of Service above 300 kV, interruption of Firm Transmission Service and Non-Consequential Load Loss should not be allowed. We favor the language proposed in the previous draft.
ITC Holdings: ITC, METC, ITC Midwest	No	Allowing load loss for shutdown plus contingency might seriously jeopardize maintenance outages when you actually encounter this situation in real-time. It's easy to say these things in the ?planning horizon? but it might be politically unacceptable for "real-time". This is particularly true for higher voltage systems above 300kV. We understand that there could be "load-pocket" situations at lower voltages where this might be allowed but EHV systems are back-bone systems. This would set a bad precedent if allowed.
Lafayette Utilities	No	Lafayette does not agree that the loss of Non-Consequential Load should be permitted as a corrective action. See also

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System		paragraph (b) in response to Question 15.
Arkansas Electric Coop. Corp.	No	Non-Consequential Load Loss should not be allowed. See comments to question 7.
Response: Thank you for your comments but the majority of the industry respondents agree with the revision to permit loss of Non-Consequential Load to meet performance requirements for P6 Events involving Systems above as well as below 300 kV considering the low probability of such Events.		
City Water, Light & Power - Springfield, Illinois	Yes and No	Shunt devices should only need to be included in contingency analysis at the discretion of the TP or PC.
CenterPoint Energy and CPS Energy	No	We believe P6 should be deleted. As noted earlier, we believe credible multiple contingencies should be studied as planning events, with incredible multiple contingencies possibly considered as extreme events. If P6 is retained, we believe loss of shunt devices should not be studied and believes the ability to systematically study the contingency loss of every individual switched shunt device is not supported by commercially available PTI software because up to this point it has not generally been recognized as a necessary or desirable analysis to perform. Also, if P6 is retained, we believe loss of Non-Consequential Load should be permitted at any voltage level for this type of extreme event.
Response: Requirement R3.3.3 (now Requirement R3.4) was modified to allow the PC and TP to determine the single and multiple Contingencies to be included in the planning analyses. This would give the TP and the PC the discretion to study the Contingencies most suited to the study area, including whether to include shunt devices in the analyses. **R3.4** Those Planning Event Contingencies in Table 1 ~~– Steady State Performance~~ ~~not covered in Requirement R3.3.2~~ that are expected to produce more severe System impacts shall be identified~~,~~ and a list of those Contingencies to be evaluated for System performance in Requirement R3.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results.		
Progress Energy Carolinas	No	While we agree interruption of firm transmission service and non-consequential load loss should not be allowed to meet the planning requirements for the first system contingency (defined as initial system condition in the table), these system adjustments should be allowed to prepare for the second event so that the system will meet the requirements following the second event. We recommend that clarifying changes be made to ensure that this is clearly understood. One suggestion would be to include the following footnote to P6 in both the Steady State and Stability Tables.? Foot note: Interruption of firm transmission service and/or non-consequential load loss is allowed after the first event as a System adjustment to prepare

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		for and meet the requirements of the second event. See also our related response to question 15.
Gainesville Regional Utilities	Yes and No	I believe some clarification is needed to specify that you can or can not curtail firm transmission service prior to the next event, because as written it could lead to compliance audit issues. I don't believe the intend of order 693 was to cause a need for utilities to be exposed to large cost increases for their customers while very little to no improvement in reliability is provided as it deals with very low probability conditions which would yield no increase in transfer capability.
JEA	Yes and No	JEA agrees with the changes on the surface, but still does not agree with the concept that it can not curtail Firm Transmission Service after the first N-1 event in preparation for the second N-1 event. JEA's existing Firm Transmission Service customers understand the need to maintain these existing transmission loading relief procedures in order to maintain security of the BES. The only JEA system element that causes this concern has a very high availability and would have a very costly infrastructure improvement to meet this requirement resulting in all of JEA's Firm Transmission Service Customers experiencing increased service cost or in the worst case having their service opportunities permanently curtailed.
Florida Power and Light	No	The P6 Planning Event is not clearly defined. It appears that the Initial System Condition is the Planning Event of P1, with the ?System Adjustments? allowed under P1 to keep facilities within the applicable ratings. R3.5.3. requires that a sustainable, stable, operating condition is maintained. This does not state prepared for the next contingency?. Given FERC's interpretation of TPL-002-0 Category B (see paragraphs below for excerpts from Order 693) that the system is not required to be able to withstand another N-1 contingency, the proposed new standard appears to require that this state be "sustained" indefinitely after a P1 event, or until the P6 Event, which is loss of the second element, with no mention of the time duration between the initial system condition and the event. The performance criteria for a P1 event can be met as long as it does not contemplate another event that would change the event to a P6 event. However, a P6 event is a TPL-003-0 Category C event which must contemplate a second contingency after the first. The existing TPL standards accomplished this with footnote b) in the Tables for all of the TPL standards, allowing system adjustments including curtailment of contracted firm transfers to prepare for the next contingency. Since FERC clearly states that this is not a requirement under TPL-002-0, but that it is addressed in TPL-003-0, they directed the ERO to modify the footnote for TPL-002-0. In TPL-003-0 the Category C3 event refers to a "Category B contingency, manual system adjustments, followed by another Category B contingency", however since the footnote for Category B contained the "To prepare for the next contingency?." language, and it is contained in the Table for TPL-003-0, that language must apply to the C3 event. Further, in Order 693, on TPL-003-0, FERC (1) did not direct the ERO to modify the same footnote which is contained in TPL-003-0, (2) recognizes that these are low probability events, and (3) stated that it "does not intend to recommend action on this issue [the appropriateness and value of including the ability of the system to withstand two simultaneous Category B contingencies for major load pockets] at

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		this time and, instead, directs the ERO to consider the comments in possible future revisions to the Reliability Standard.? The SDT has inappropriately applied the direction of FERC on TPL-002-0 to the P6 event (which is similar to TPL-003-0 C3) without regard to its implications on the industry, the ratepayers, or even its own standards, as the impact of the team's interpretation would require changes in the methods of determining TTC's, ATC's, and SOL's. The additional costs (both monetary and intangible) incurred by ratepayers for no gain in the ability to transfer firm electric power, far outweigh any gain in reliability benefits for these low probability events. Just to provide one example to illustrate this point, if the SDT's current interpretation for a P6 event is not modified, FPL would have to spend in excess of $ 1 Billion dollars, in order to meet this performance criteria for 500 kV facilities, for an event with a probability of less than 0.07 per hundred mile-years (based on FPL's 500 kV facilities), which would be passed on to its ratepayers. There are many other examples on the FPL system, as well as other systems. This interpretation is fatally flawed and makes no sense from a reliability or cost perspective, not to mention the intangible impacts of siting, right-of-way acquisition, EMF, NIMBY, etc. Further, assuming the SDT interpretation, how could one justify the need before state commissions, and exercise eminent domain in the courts to take someone's land for right-of-way, a process that could take as long as 8-10 years, for minimal increase in reliability, and no increase in transfer capability. In order to assist the SDT, these paragraphs are included with references to FERC Order 693, to show that it has misinterpreted Order 693. The following captions stated below should help clarify this point. Order 693 states: P.1788 ?Under TPL-002-0 the system is not required to be able to withstand another N-1 contingency. That N-1 requirement is a Category C contingency which is addressed by TPL-003-0.? Therefore, the end state of P1 is not a ?secure? state, but a ?normal operating state?, as stated in P. 1796 ?The Commission, therefore, directs the ERO to modify the second sentence of footnote (b) to clarify that manual system adjustments other than shedding of firm load or curtailment of firm transfers are permitted to return the system to a normal operating state after the first contingency, provided these adjustment can be accomplished within the time period allowed by the short term or emergency ratings.? These two determinations by FERC together show that their interpretation of normal operating state is not the secure, ready for the next contingency state, rather, it is the state in which the performance criteria have been met for that planning event. With regard to the FERC direction of Order 693 on TPL-003 and ?the appropriateness and value of including the ability of the system to withstand two simultaneous Category B contingencies for major load pockets?, FERC states in P. 1824, ?Many commenters indicated that this was a very low probability event and the costs for addressing such an event would be significant. As a result, EEI states that a dialogue must first be initiated within the industry and with state public utility commissions to identify such load pockets, to target the required potentially significant transmission investments and to develop plans for allocating the costs of such investments. In light of these comments, the Commission does not intend to recommend action on this issue at this time and, instead, directs the ERO to consider the comments in possible future revisions to the Reliability Standard.?FPL agrees with the increased performance requirement for the P3 multiple contingency event that assumes the loss of a generator as the first contingency. Firm transfers should not depend upon specific generators being on line, however firm transfers must depend upon transmission lines being in-service.
SERC Dynamics	Yes	The changes are more practical. If two or more 500kV lines are lost, it makes complete sense to allow loss of non-consequential load so long as cascading outages are not triggered. While we agree interruption of firm transmission service

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Review Subcommittee		and non-consequential load loss should not be allowed to meet the planning requirements for the first system contingency (defined as initial system condition in the table), these system adjustments should be allowed to prepare for the second event so that the system will meet the requirements following the second event. We recommend that clarifying changes be made to incorporate this concept. We recommend that the statement above be included as modification or as a footnote for the P6 portion of the table as follows:Foot note: Interruption of firm transmission service and non-consequential load loss should be allowed after the first event as a system adjustment to prepare for the second event and meet the requirements following the second event.See our related response to question 15.
Southern Company Transmission	Yes and No	The requirements are more practical now. If two or more 500kV lines are lost, it makes complete sense to allow loss of non-consequential load so long as cascading outages are not triggered. While we agree interruption of firm transmission service and non-consequential load loss should not be allowed to meet the planning requirements for the first system contingency (to get loadings back within normal ratings), these system adjustments should be allowed to prepare for the second event so that the system will meet the requirements following the second event. We recommend that clarifying changes be made to incorporate this concept. We recommend that the statement below be included as modification or as a footnote for the P6 portion of the table as follows: Interruption of firm transmission service and non-consequential load loss are allowed after the first event as a system adjustment to prepare for the second event in order to meet the requirements following the second event.
Duke Energy	Yes	The changes are more practical. If two or more 500kV lines are lost, it makes complete sense to allow loss of non-consequential load so long as cascading outages are not triggered.? While we agree interruption of firm transmission service and non-consequential load loss should not be allowed to meet the planning requirements for the first system contingency (defined as initial system condition in the table), these system adjustments should be allowed to prepare for the second event so that the system will meet the requirements following the second event.? We recommend that clarifying changes be made to incorporate this concept. We recommend that the statement above be included as a modification or as a footnote for the P6 portion of the Steady State and Stability tables as follows: "For P6 multiple contingency events, Transmission configuration changes and redispatch of generation are allowed provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits. Permissible Transmission configuration changes include dropping of load and firm transfers needed to prepare for the second contingency. See our related response to question 15.
SERC Reliability Review Subcommittee and Planning Standards	Yes	Since Event P6 is essentially a sub-set of the existing Category C.3 Contingency events, we support these modifications which make the system performance requirements for P6 consistent with what exist today for Category C.3. While we agree interruption of firm transmission service and non-consequential load loss should not be allowed to meet the planning requirements for the first system contingency, these system adjustments should be allowed to prepare for the second event so that the system will meet the requirements following the second event. We recommend that clarifying changes be made to incorporate this concept. We recommend that the statement below be included as modification or as a footnote for the P6 portion of the table as follows: Interruption of firm transmission service and non-consequential load loss are allowed after the

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Subcommittee		first event as a system adjustment to prepare for the second event in order to meet the requirements following the second event.
Orlando Utilities Commission	Yes and No	As written the standard does not seem to forbid the adjustment of firm transfers and non-consequential load in preparation for the second part of an N-1-1, however that conflicts with the teams statements on the recent national call. If the intent is to forbid the adjustment of firm transfers and non-consequential load in preparation for the second part of an n-1-1 that needs to be made explicitly clear in the standard. This is especially important since one of the current understandings of the standards relating to Transmission Planning and System Operating Limits clearly allow such adjustments, and to not make it clear is building a compliance trap for the unwary. While I do not support the creation of this n-1-1 threshold if it is going to be established it needs to be abundantly clear.
Entergy Services, Inc.	Yes and No	Since Event P6 is essentially a sub-set of the existing Category C.3 Contingency events, we support these modifications which make the system performance requirements for P6 consistent with what exist today for Category C.3.While we agree interruption of firm transmission service and non-consequential load loss should not be allowed to meet the planning requirements for the first system contingency (to get loadings back within normal ratings), these system adjustments should be allowed to prepare for the second event so that the system will meet the requirements following the second event. We recommend that clarifying changes be made to incorporate this concept. We recommend that the statement below be included as modification or as a footnote for the P6 portion of the table as follows: Interruption of firm transmission service and non-consequential load loss are allowed after the first event as a system adjustment to prepare for the second event in order to meet the requirements following the second event. As the requirement is now implemented in the table, transmission service would need to be made available only if they can be accommodated for N-2 events. This would place these services on equal footing from a reliability perspective but would virtually eliminate the firm transmission market.
Response: Footnote #10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency. However, until the next Contingency occurs, System performance will need to meet the requirements for Event P1. As such, the proposed standard will not allow loss of any Non-Consequential Load, except for contracted Interruptible Loads, in preparation for the next Contingency. Nonetheless, the SDT has provided an exception (R2.6.4) to address those situations, which may arise that are beyond the control of the Transmission Planner or Planning Coordinator, and, which can prevent the implementation of the relevant Corrective Action Plan in the required timeframe. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
Transmission	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above

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Agency of Northern California		300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
Pacific Gas and Electric Co.	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
Public Service Company of New Mexico	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
Puget Sound Energy, Inc.	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300 kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power

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		transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
Idaho Power Company	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
SMUD	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
Sierra Pacific Power Company / Nevada Power Company	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1

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		and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
Black Hills Corporation	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
SRP	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
Tucson Electric Power Company	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow

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		the Non-consequential Load Loss, while the latter would prohibit it.
Modesto Irrigation District	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the nextN-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
Tri-State G&T	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
ColumbiaGrid	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.

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Southern California Edison	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
Alberta Electric System Operator	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
US Bureau of Reclamation	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the nextN-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
BPA Transmission	Yes and No	We agree with the revision to permit the loss of Non-Consequential Load to meet performance requirements for Systems above 300 kV. However, a better definition is needed for "system adjustments". For example, are curtailments permitted as

Organization	Question 11:	Question 11 Comments:
Reliability Program		part of "system adjustments"? Within category P6, there needs to be a common reason for the overlapping outage to occur, such as lines on a common tower, and the appropriate reasons need to be clearly identified in the requirements. In general, we believe that performance category P6 should be part of the Operating Standards rather than the Planning Standards. For these types of events, it is the responsibility of Operations to determine the necessary system adjustments to prepare for the next contingency within the operating horizon prior to year one as defined in the Planning Standards. Therefore, the performance requirements for this category of contingencies, do not belong in the Planning Standards.
Response: Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. Regarding the difference between overlapping single Contingencies as denoted in Event P6 (N-1-1), and one where a single Contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (i.e., N-1), the difference would be whether the prior outage was planned (such as maintenance) or anticipated (such as extended outage). If the Prior outage is planned or anticipated, then the next N-1 is a P1 Event, otherwise, it is a P6 Event.		
Progress Energy Florida, Inc.	No	PEF is pleased that between the 1st and 2nd drafts, the "no" was changed to "yes" concerning allowance of curtailment of Firm Transmission Service or curtailment of Non-Consequential Load for Event P6. PEF has significant concerns, however, regarding the issue of "System Adjustments" associated with P6 and P6's direct association with P1, and thus must check "no" on this Question despite the improvements that have been made. A major misstep has been made with regard to development of P6. Every P1 event is by default the first half of a P6 event. Given that fact, PEF sees several concerns with this issue. First, for P1 events, neither curtailment of Firm Transmission Service nor curtailment of Non-Consequential Load are allowed, regardless of voltage. Both are allowed, however, for a P6 event. In order for the two events to not contradict each other, the conclusion that must be reached is that curtailment of Firm Transmission Service and curtailment of Non-Consequential Load are not allowed as part of System Adjustments, i.e. they are not allowed in between the two steps of P6, only after the 2nd step of P6 (Note: this is not clear partly due to the fact that the term "System Adjustments" is not defined anywhere in the Standard, and PEF therefore requests that the SDT define the term, and that the term should include the allowance of curtailment of Firm Transmission Service and the loss of Non-Consequential Load). PEF has two very serious concerns with that conclusion: a) FERC in its Order 693 stated that the BES is not required to have to withstand another N-1 contingency. Specifically, in Paragraph 1788 of Order 693 FERC states that ?Under TPL-002-0 the system is not required to be able to withstand another N-1 contingency. That N-1 requirement is a Category C contingency which is addressed by TPL-003-0.? Thus FERC clearly made a distinction between N-1 events for which a 2nd N-1 event never happens and N-1-1 events. The SDT, however, has

Organization	Question 11:	Question 11 Comments:
		not written the draft TPL Standard in such a way that Transmission Owners can reasonably and fairly plan for the 2nd N-1 event as TPL-003-0 has done. b) PEF has several 1st N-1 events on their 500 kV system for which "System Adjustments" are necessarily going to have to include either the curtailment of Firm Transmission Service or the curtailment of Non-Consequential Load in order to prepare for the 2nd N-1 event. The draft TPL Standard, while far from definitive on this matter, appears to allow neither as part of System Adjustments. PEF will thus be forced to i) construct redundant 500 kV facilities, at a cost to our ratepayers that will doubtless run into the range of billions of dollars, or ii) significantly reduce the posted levels of ATC/TTC of the various transmission paths available. Option (ii) is not a better option than option (i), for two main reasons: reducing ATC/TTC essentially puts marketing entities out of business, and forces utilities to build more generation sites to compensate for the loss of energy brought in using the previously higher ATC values. Either option results in prohibitively high costs to be passed on to the ratepayers for no measurable increase in BES reliability. This discussion also brings up additional concerns that include the lack of consideration of State government jurisdiction, the lack of public involvement, and ultimately, the lack of sufficient reason to construct such redundancy. PEF has never had a 500 kV N-1-1 event on its system. For this draft Standard to require redundancy projects costing billions of dollars for events that to date have never occurred is preposterous (note: additional comments concerning public outreach, no State government involvement, etc., are contained in the response to Question 15).
Response: Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency. However, until the next Contingency occurs, System performance will need to meet the requirements for a single Contingency Event. As such, the proposed standard will not allow loss of any Non-Consequential Load, except for contracted Interruptible Loads, in preparation for the next Contingency. Header note 'e' provides the System adjustments allowed after a first Contingency Event. **Header note 'e'** -- For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
Ameren	No	Please clarify that the shunt devices to be considered for outage are those that are directly connected to the transmission system. For the P6 events involving a transmission facility and a shunt device, local voltage instability issues may result in dropping of load in the vicinity of the outaged facilities, but the concern should be that the load dropped is not wide-spread. The words "Voltage instability" should be removed from Header Note 3 of Table 1 so that it becomes "Cascading outages and uncontrolled islanding shall not occur."

Organization	Question 11:	Question 11 Comments:
Response: Requirement R3.3.3 (now Requirement R3.4) was modified to allow the PC and TP to determine the single and multiple Contingencies to be included in the planning analyses. This would give the TP and the PC the discretion to study the Contingency most suited to the study area. **R3.4** Those Planning Event Contingencies in Table 1 ~~– Steady State Performance not covered in Requirement R3.3.2~~ that are expected to produce more severe System impacts shall be identified~~,~~ and a list of those Contingencies to be evaluated for System performance in Requirement R3.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results. However, "voltage instability" has not been removed from the Header Note 3 (now Note a) because voltage instability in a local area can spread to the rest of the System if not arrested in time, and a planning analysis is needed to ascertain if there is a voltage stability problem, and, if so, the corrective actions needed.		
Exelon Transmission Planning	No	We do not agree that the requirement should be so much more severe for an internal breaker fault as opposed to two single line outages for elements over 300 kV.
Response: An internal breaker fault is a single event covered in FERC Order 693. In addition, an internal breaker fault would remove from service all Facilities connecting to the faulted breaker simultaneously, which would likely be more severe than the outage of two single lines.		
MidAmerican Energy Company	No	MEC suggests that there be more explanation of what system adjustments are permitted. There should be some specific limit like 100MW below which load loss is allowed. Otherwise, very high cost solutions will be required for very low probability events.
MRO NERC Standards Review Subcommittee	No	The MRO suggests that there be more explanation of what system adjustments are permitted. There should be some specific limit like 100MW below which load loss is allowed. Otherwise, very high cost solutions will be required for very low probability events.
Response: Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency. While the SDT does not disagree with having some specific limits below which load loss would be allowed, arriving at such an amount may be too case-specific and too descriptive for a Continent-wide Standard. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		

Organization	Question 11:	Question 11 Comments:
Austin Energy	No	It should be left to the Transmission Planner and/or Planning Coordinator (ISO or RTO) to select the credible multiple contingencies to be studied as planning events. Therefore P6 should be deleted.
Brazos Electric Power Cooperative, Inc.	No	P6 should be incorporated back into P5. Up to this point, studying all shunt devices has not been considered to have a significant impact on the BES. In addition these are picked up when studying other contingencies. Certain type devices should be reviewed individually, FACTS devices, etc? but this should be at the discretion of the TP or PC. Currently adding shunt devices as a category would require modification to case data or software to be able to automatically run through them all and we are not convinced this is worth the effort.
Response: Requirement R3.3.3 (now Requirement R3.4) was modified to allow the PC and TP to determine the single and multiple Contingencies to be included in the planning analyses. This would give the TP and the PC the discretion to study the Contingency most suited to the study area, and can choose not to study P6 Events if they are less severe than the Events studied. Therefore, P6 is not deleted. **R3.4** Those Planning Event Contingencies in Table 1 ~~– Steady State Performance~~ ~~not covered in Requirement R3.3.2~~ that are expected to produce more severe System impacts shall be identified~~,~~ and a list of those Contingencies to be evaluated for System performance in Requirement R3.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results.		
AEP	Yes	Table 1 does not specify a maximum amount of allowable non-consequential load loss for those categories (including P6) that have a "Yes" listed under the "Non-Consequential Load Loss Allowed" (last) column. See load loss definition under Attachment D of PJM Manual 14B for an example of a maximum amount specification.
Response: While the SDT does not disagree with having some specific maximum amount of allowable Non-Consequential Load loss for these events, arriving at such an amount may be too case-specific and too descriptive for a Continent-wide Standard		
ERCOT System Planning	No	The former P5 of the first draft only required transmission circuits of 300 kV and above to be simulated out of service followed by loss of transmission circuit or transformer. P6 of the second draft requires all BES (100 kV and above) transmission circuits, transformers, dc lines, and shunt devices in combination of another BES circuit, transformer, dc line, and shunt device. The number of contingencies that have to be simulated increased dramatically to an impractical level and would require days of uninterrupted computer run time to complete. This, in combination with other contingencies and sensitivities required in this draft of the standard, is not feasible for large entities. ERCOT recommends that this planning event P6 retain the verbiage regarding transmission lines and transformer low side windings above 300kV.
Response: The previous draft P5 set requirements for N-1-1 300 kV and above; P8 sets requirements for N-1-1 below 300 kV. P6 in this draft combines both P5 and P8 from the previous draft. So, the work load for both drafts would be the same. In addition, Requirement R3.3.3 (now Requirement R3.4) was modified to allow the PC and TP to determine the single and multiple Contingencies to be included in the planning analyses. This would give the TP and the PC the discretion		

Organization	Question 11:	Question 11 Comments:
to study the Contingency most suited to the study area, and can choose not to study P6 Events if they are less severe than the events studied. **R3.4 T**hose Planning Event Contingencies in Table 1 ~~– Steady State Performance~~ ~~not covered in Requirement R3.3.2~~ that are expected to produce more severe System impacts shall be identified~~,~~ and a list of those Contingencies to be evaluated for System performance in Requirement R3.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results.		
American Transmission Company	Yes	We suggest that there be more explanation of what system adjustments are permitted. We understand that the revised P6 allows loss of Non-Consequential Load for Systems below 300 kV as well.
Response: Header note 'e' provides the System adjustments allowed after a first Contingency Event. In addition, Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of firm Transmission Service will be allowed in preparation for the next Contingency. **Header note 'e'** -- For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
Florida Reliability Coordinating Council, inc	No	For P6 events (and all other events that allow system adjustments after the loss of a transmission device), this draft does not clearly define when the requirements in the columns marked as ?Interruption of Firm Transmission Service? or ?Non-consequential Load Loss Allowed? apply. The SDT should clearly state that the requirements in these columns are only applicable after the Event occurs from the Initial System Condition. In addition, the SDT should make it clear whether Interruption of Firm Transmission Service and Non-consequential Load Loss is allowed in preparation for the 2nd Event. On the NERC conference call for the 2nd draft, the SDT chair indicated that Interruption of Firm Transmission Service and Non-consequential Load Loss is not acceptable in preparation for the next event. In Order 693, Para. 1788 - Para. 1796, FERC distinguished between ?preparing for the next contingency? and returning to a system normal state. The SDT removed the allowance that was made in footnote c of TPL-003-0 to ?To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.? (emphasis added) for Category C3 events (now P6 for facilities greater than 300kV). This change in the standard is not directed by the FERC Order 693 and is not a reliability improvement that is cost justified. Forced outage rates for equipment greater than 300kV is very low and the impact on markets is very large. Many utilities have granted long term transmission service to entities with the expectation that the service can be curtailed if required in preparation for the next event. If this is not allowed, entities

Organization	Question 11:	Question 11 Comments:
		within FRCC will have to greatly reduce the long term firm imports into FRCC or construct additional EHV transmission lines from a location well into Georgia down to a point in the southeastern portion of FRCC. While an in-depth cost has not been completed for a project of this size in many years, it is reasonable to expect that a cost in excess of $1.5 - $2.0 Billion. This investment will only slightly increase the amount of firm imports into FRCC (and replace the imports allowed before this change) for an event that may only occur only once every 20+ years. If this event happens, the Transmission Owners will re-dispatch their own generation to curtail their transactions in addition to curtailing the firm transmission service of others, per their OATT. The SDT should clearly state for these Planning Events, all system adjustments including Interruption of Firm Transmission Service and Non-consequential Load Loss is acceptable in preparation for the second Event where system adjustments are allowed between events.
Response: The SDT believes that Table 1 is clear that the events occur from P0 as the starting condition. Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency. However, until the next Contingency occurs, System performance will need to meet the requirements for event P1. As such, the proposed standard will not allow loss of any Non-Consequential Load, except for contracted Interruptible Loads, in preparation for the next Contingency. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
FirstEnergy Corp.	Yes	We agree with the change that now permits the loss of Non-Consequential Load for N-1-1 to meet performance requirements regardless of the voltage level studied. It is well understood that following a single contingency (N-1) that no Non-Consequential Load loss or interruption of Firm Transmission service is permitted. The SDT needs to clarify for industry if interruption of Firm Transfers is permitted pre-contingency to prepare for the 2nd (over-lapping) contingency. This is presently permissible in the existing TPL standards as Table 1 footnote 'b' reads ?? To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.?
Response: Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings		

Organization	Question 11:	Question 11 Comments:
in those regions must be considered.		
PPL EnergyPlus	Yes	
NPCC	Yes	
Northeast Utilities	Yes	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
TVA System Planning	Yes	
Platte River Power Authority	Yes	
BCTC	Yes	
National Grid	Yes	
Tenaska, Inc.	Yes	
OPUC	Yes	
PacifiCorp	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV.
Hydro-Quebec TransEnergie (HQT)	Yes	
Arizona Public Service Co.	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV.

Organization	Question 11:	Question 11 Comments:
Midwest ISO	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Lakeland Electric	Yes	
LCRA TSC	Yes	
NERC and Regional Coordination	Yes	
North Carolina Electric Membership Corp	Yes	
E.ON U.S. Transmission Planning	Yes	
Central Maine Power Company	Yes	
NSTAR Electric	Yes	

Organization	Question 11:	Question 11 Comments:
New York Independent System Operator	Yes	
Oncor Electric Delivery	Yes	NA
ISO New England Inc.	Yes	
Manitoba Hydro	Yes	Considering the very low probability of such an event (based on industry data), Manitoba Hydro agrees that Interruption of Firm Transmission Service and Non-consequential Load Loss is acceptable.
Los Angeles Department of Water and Power	Yes	yes, only because there is no discrimination among different and arbitrary voltage classes.
IESO	Yes	We concur with the need to test N-1-1 contingencies involving transmission facilities allowing interruptions to firm transmission services and non-consequential load loss to meet performance requirements, for any voltage levels as long as adverse reliability impacts on the BES are exhibited.
Response: Thank you for your response.		

12. **Comments from some entities received from the posting of the 1st draft standard indicated that significant additional costs will be required to meet the proposed requirements and performance tables. Commenters also indicated that it would take several years to install the additional facilities needed to meet the change in requirements. The SDT has attempted to adjust and clarify the proposed requirements and performance in light of these initial comments; however, the SDT needs more specific information on these concerns so that it can put the proposed requirements in perspective and make more adjustments as appropriate. Questions 12, 13 & 14 address these concerns.**

    What do you estimate will be your additional approximate costs, if any, to support the proposed requirements and performance tables over and above what you are currently doing for the following: Analysis:

    One time cost to supplement past study portfolio and analyze the supplemental studies (depending on the extent of supplemental work needed, this may be an accumulated cost over more than one year):

    How many years do you estimate that it will take to complete supplemental studies and associated analysis?

    On-going additional cost for expanded studies and analysis:

Summary Consideration:

The SDT has reviewed the responses and will use the data as background information in making any further decisions with regard to this standard. No direct changes were made to any of the requirements at this time based on this information.

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
Dominion - Electric Transmission Planning	It is extremely difficult, if not impossible, to accurately determine the costs required to perform supplemental studies in order to become compliant with these proposed standards. It will take time to just become familiar with the proposed changes as well as developing the necessary documentation to show compliance. What is obvious is that increased staffing levels will be required to perform the assessments. Furthermore, it will take significant time to become fully compliant. Therefore, a grace	As stated above, this is difficult to predict but a grace period of 2 to 3 years should be considered.	At this point we are estimating at least 2 to 3 additional resources may be required to perform the additional studies on an ongoing basis. For Dominion, three (3) additional engineers to perform this analysis is approximately $500,000 per year (including benefits and overheads).

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	period of 2 to 3 years should be granted in order to perform the required assessments and become compliant.		
NPCC	NPCC Participating Members believe some additional cost for analysis and study may be required in order to meet the final requirements of the standard and the associated performance tables. However, the ability to accurately estimate the costs of these studies, how long the analysis may take and how much additional effort may need to be made to compile the documentation is not possible at this time. Many believe posing this question is premature and cannot be quantified at this time, and it may hold questionable value without a better understanding of the complete final requirements of the standard. Many believed that the sensitivity language, although currently being performed to some extent within NPCC, that now appears in the standard, could have a drastic effect on the extent to which this additional analysis is conducted and the associated costs.		
TVA System Planning	One component of these costs is based on modification to the load flow database. A massive effort would need to be undertaken to model bus sections and breaker codes in order to simulate the planning events needed to stay current with the proposed standards. Also, man-power to perform the extra analysis was considered. Additional man-power of 5 engineers (2 years) would	The majority of the time would be spent modifying the load flow database so that the new planning event simulations could be analyzed. ? Time duration estimate of 2 years would be required.	Additional man-power of 4 engineers at costs of $400,000 per year would be required.

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	be required at cost of $1,000,000		
Progress Energy Carolinas	$150,000	3 Years	$50,000/year
BCTC	We estimate an initial one time cost of up to $50,000 for BCTC planners to become familiar with the new format and requirements of the standards and make changes to their assessment process. In addition, additional study costs for sensitivity studies (many stability studies) may cost an additional $50,000. Many segments of the BCTC system are stability limited and we have significant experience with the needs and timelines for doing stability studies. Stability studies identify the need for RAS for multiple contingencies, which is fairly short lead time. We are currently satisfied with the amount of stability studies we do for the near and long term planning horizons. We do not need to do sensitivity studies. We do not expect any significant additional costs for studying Extreme Events because most of the wide area events listed are not applicable to the BCTC system.	1 Year	The additional cost could be from $50,000 to $100,000 per year. We will incur additional study costs for sensitivity studies and expect additional planning administration costs for reconciling between reinforcements required to meet the CLL/NCLL definitions and P3 requirements vs. what we actually propose as doable projects.
Manitoba Hydro	$500,000	2 to 3 person years years	$300,000
Los Angeles Department of Water and Power	I do not object to added studies serving useful purposes; however, duplicative studies are a waste of resources. Mixing operating studies and requiring such studies in the planning of future system shows a confused perspective on the	Please be more specific as to what additional studies are being referred here.	

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	purpose of planning studies verses operating studies.		
National Grid	The comment period was not long enough to develop a thoughtful response to the impact that the new standards might have. Therefore costs can be speculated to be incrementally hundreds of thousands per year.	The comment period was not long enough to develop a thoughtful response to the impact that the new standards might have on the planning studies, but a very rough thought would be that any additional needs would be captured within the normal planning studies, which would likely occur within two study cycles of the effective date of the standard.	If the new requirements are included in the normal study cycle and the costs are the incremental costs required by additional study requirements, then the annual costs will be less than the first year costs, but we still will need additional staffing, which will cost hundreds of thousands per year. In addition to cost, there is a significant concern over whether or not the labor market can provide enough qualified staff to complete the required work.
Pacific Gas and Electric Co.	We expect supplemental studies to be needed for the entire 500 kV system and most of the 230 kV system. We estimate the one time cost for supplemental studies to be around $100,000.	Assuming that the supplemental studies would be added to the on-going work, we estimate the time to complete the supplemental studies to be about 2 to 3 years.	We estimate that the additional cost for the expanded studies and analysis would be about $50,000/year.
Gainesville Regional Utilities	$50,000. I don't feel this is needed for smaller utilities.	3 years. Again, I don't feel this is needed for smaller utilities.	$60,000. Again, I don't feel this is needed for smaller utilities.
JEA	$80,000 per year.	3 years	$80,000 per year.
PacifiCorp	$500,000 (approx)	three years	$250,000
Puget Sound Energy, Inc.	$1,000,000 for the STD in its current form. The recovery of firm transmission following N-1 will be the largest cost for PSE	10 years.	$300,000
ITC Holdings: ITC, METC, ITC Midwest	While we recognize that the standards might require us to garner a little more manpower and will take a little more time, we believe that running these studies is	While we recognize that the standards might require us to garner a little more manpower and will take a little more time, we believe that running these studies is	While we recognize that the standards might require us to garner a little more manpower and will take a little more time, we believe that running these studies is

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	important.	important.	important.
Idaho Power Company	Appx $50k	2 to 3 years	Appx $50k
SMUD		Three study cycles would be my guess. Related matters: Since the definition for “Year One” allows for the start of each assessment to be up to 18 month from the “completion” of the previous Planning Assessment, using the term ?annual?, “annually” in the definition and in various sections of the standard is confusing. An alternate word or dropping the words annual/annually would make more sense. What is considered as “completion” of an assessment (in definition of Year One)?	
Hydro-Québec TransÉnergie (HQT)	HQT believe some additional cost for analysis and study may be required in order to meet the final requirements of the standard and the associated performance tables, however the ability to accurately estimate the costs of these studies, how long the analysis may take and how much additional effort may need to be made to compile the documentation is not possible at this time. Many believe posing this question is premature and cannot be quantified at this time and it may hold questionable value without a better understanding of the complete final requirements of the standard. Many believed that the sensitivity language, although currently being performed to some extent within NPCC, that now appears in		

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	the standard, could have a drastic affect on the extent to which this additional analysis is conducted and the associated costs		
Progress Energy Florida, Inc.	Given that a) PEF has never performed analysis to the extent that the draft TPL Standard is requiring and b) the draft is going through an iterative process and is at present considered a "moving target", a reasonably accurate estimate, or even a wild guess, cannot be provided for this answer. Having said that, it can be reasonably said that any estimate that could safely claim a reasonable degree of accuracy would require analysis performed full-time by several individuals over a period of several months (or possibly a period greater than one year). Just the cost of the assessment analysis alone would present an O&M challenge to PEF's Transmission department.	PEF has assessed this question and determined that any period of time less than 10 years would be inadequate to assess the supplemental nature of the requirements of the draft TPL Standard, to say nothing of the time required to construct the required facilities.	PEF, again stating that this cannot be considered an accurate estimate for the reasons stated in 12a, would estimate the burdened labor cost to perform such supplemental analysis on an ongoing basis to be at least $1M annually.
Sierra Pacific Power Comapny / Nevada Power Company	$400,000	2 Man Years	$250,000/year
Lafayette Utilities System	Lafayette has not analyzed in any detail the resource requirements addressed in this question. Based on available information, we estimate that supplementing existing studies would require at least 1 FTE familiar with stability analysis to be able to complete this portion of TPL. The new steady-state analysis will require the addition of 1 FTE to be able to complete the additional P5-P7	See response to part 1 of Question 12.	See response to part 1 of Question 12.

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	requirements. These will be ongoing expenses whether accomplished by hiring new staff or relying on external service providers.		
Arizona Public Service Co.	Two person-year.	2-years.	one person year.
Ameren	One component of cost is to model in more detail all straight busses and bus-tie breakers at all transmission voltage levels. Contingency scenarios would also need to be developed and/or modified to correspond with the new powerflow models. The sensitivities presently specified will greatly increase the cost and time needed for updating all plant stability studies.	One-time costs to provide additional modeling detail and modify and test the revised contingency lists would be approximately 1 man-month or about $8000. Updating all plant stability studies would take approximately 5 man-years, at an estimated cost of approximately $500,000 (including benefits). Given existing regional requirements to complete the annual assessment by July 1 of the calendar year, additional staffing would likely be needed to complete this work, unless compliance were phased in over a number of years, similar to the MOD-024 and MOD-025 standards with respect to generator testing.	A review of the studies required for R2.1 indicates that at least 6 powerflow modeling scenarios would need to be completed to cover the base cases and sensitivities, which would be a 50% increase in the amount of work presently performed to meet the existing TPL-001 through 004 requirements for the near-term assessment. A review of the studies required for R2.4 indicates that at least 4 stability scenario models would need to be completed, which would be a 100% increase in the amount of work presently performed. Our present compliance performance and analyses activities take approximately 30 man-months to complete. We would expect the additional study analyses to add an additional 20 man-months of work and require 4-5 additional engineers at an annual cost of $400,000 to $500,000 (including benefits), given the regional requirement to complete the annual assessment by July 1.
City of Tallahassee, FL	we estimate a cost of $100,000 minimum since the City would likely have to outsource some of this analysis in addition to the work done by in-house system	hard to give a good estimate since the full ramifications of the required studies is not clear in the current draft. I would estimate 2 years at least.	similar costs to what was estimated above for the supplemental study cost, since staffing level is such that much of this ongoing work will likely be outsourced.

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	planning staff.		
Florida Power and Light	These costs cannot be determined without having experience with the new standard and its analysis requirements. Analysis of existing studies will undoubtedly uncover substantial additional study that would need to be performed, but the costs of such analysis and studies could not be reasonably estimated beyond stating that the costs would be significant resulting from 1000's of man-hours spent on supplemental work that would only determine if we were in compliance, not including any work necessary to determine what would be necessary to bring deficiencies in to compliance.	It would not be unreasonable to find that it takes one full planning horizon (10 years) to complete supplemental studies and analysis for the draft standard, because it is so prescriptive. Requirements such as R2.2.1 that requires that the planning assessment be extended for longer lead time projects (such as the multiple new nuclear projects being considered across the U.S.) and R2.4.1 that specifies "...including the behavior of induction motor loads" will likely invalidate past studies that took considerable time to perform and would have to be reproduced with the newly required considerations. Requirements such as R2.6 (and subrequirenments) invalidate many existing studies, because of subjective terms such as "material changes" and "would impact the study area" without definitions of "material" or "impact". Re-analyzing all existing studies and re-writing the results and conclusions using the new terminology (P0, P1, P5 etc. instead of Category A, B or C2, C3, C5 etc.) used in the new performance tables will also add substantially to the effort needed to insure compliance and make the information auditable.	$ 5 million dollars annually is perhaps very conservative.
CenterPoint Energy and CPS Energy	We have no analysis to support an answer to this question, and we believe any such analysis would be speculative. We believe the reality of the situation is that the requirements are not practically achievable	3-4 years, assuming reasonably practical interpretation of the impractical requirements.	

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	at any cost, so the ultimate cost would depend on practical interpretations of impractical requirements. Even if the cost could be reasonably estimated, we oppose detracting valuable expertise away from necessary, value-added analyses to unnecessary, over-reaching theoretical analyses and documentation for audit purposes.		
SRP	The additional study work associated with this Standard could cost up to SRP $100k.	1 to 2 years to complete these additional studies.	Estimate addition on-going costs of $50k.
MidAmerican Energy Company	MEC estimates that the total cost for one-time software licenses would be about $100,000.	MEC estimates that the lead time to perform supplemental studies and analyses to meet the new requirements would be 2 years.	MEC estimates that the on-going additional cost of expanded studies and analyses to meet the new requirements would be about $150,000 to $200,000 for additional staff and continuing software fees.
Tucson Electric Power Company	$200,000	6 month study performed by consultant	1 man-year
SERC Dynamics Review Subcommittee	The sensitivities will greatly increase the cost and time need for planning because the work is directly proportional to the number of sensitivities.		
MRO NERC Standards Review Subcommittee	The MRO estimates that the additional one-time costs of supplemental studies and analysis to meet the new requirements might be spread over five years because some analysis only has to be updated every five years. The MRO estimates that the total cost over five years for additional staff, consulting services, or software fees would be about $200,000 to $300,000 per	The MRO estimates that the lead time to perform supplemental studies and analysis to meet the new requirements would be up to 5 years.	The MRO estimates that the on-going additional cost of expanded studies and analysis to meet the new requirements would be about $150,000 to $200,000 for additional staff and continuing software fees per responsible entity.

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	responsible entity.		
Modesto Irrigation District	Unknown at this time.		
Midwest ISO	Some additional costs will be required to comply with all the requirements. This is difficult to quantify at this time.	This is difficult to quantify at this time, but any increased requirements should be clearly identified by the SDT and a transition period should be developed if the standards are intended to be more restrictive.	There will be an increase in ongoing cost for expanded studies and analysis. A transition period for staffing and process development will be required.
Tri-State Generation and Transmission Association, Inc.	Scenario assessments will significantly increase workload. Development of dynamic load models is ongoing, and will need a much longer implementation period than the steady state portions of the standard. As much as $500,000 may be required to address all of R2.1.3 scenario requirements.	It would take as much as two years for the initial supplemental studies with existing staff.	Ongoing additional sensitivity and dynamic studies would cost approximately $300,000 per year.
AEP	Additional one-time cost of 33 man-months	2 years	Additional ongoing cost of 12 man-months
Lakeland Electric	Unknown	Unknown	Unknown
Brazos Electric Power Cooperative, Inc.	We have no real way to estimate this or determine these costs.	Again, we have no real feel for making an estimate but it would be safe to say that the studies would take longer than the planning window. In other words, the results would not be completed before we would have to start them over again.	
NERC and Regional Coordination	Clarity about the exact number of supplemental studies required needs to be added to the standard before this question can bee addressed. The requirements		

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	contained within the standard are nebulous. The requirements need to clearly state the depth of the studies required for each time horizon.		
ColumbiaGrid	The new TPL Standard raises the bar of transmission system performance. This can be expected to require significant additional analysis, documentation and system reinforcements (or reduced firm transfers allowed on the system if system reinforcements are not made). We will defer to our members to provide quantification of those elements.		
IESO	Minimal, if any, since the IESO has been conducting and documenting planning studies that meet events and performance criteria that are very similar to those specified in the draft TPL-001 standard. However, this is speculative at this time since we are not sure what the eventual standard will be like. Another uncertain area is the extent to which additional studies are required if sensitivity testing is mandated. Please see our comments under Q2 and Q10 on sensitivity testing. If sensitivity testing should become a requirement, then the scope is very wide and we are unable to have a good handle on the incremental time and cost to supplement past study portfolio.	Minimal, if any, for the reasons indicated above, other than for meeting the sensitivity testing requirements (if mandated) which cannot be quantified.	Minimal, if any, for the reasons indicated above, other than for meeting the sensitivity testing requirements (if mandated) which cannot be quantified.
Northeast Utilities	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
North Carolina Electric Membership Corp	N/A	N/A	N/A
ERCOT System Planning		At least 4 years. It will take as long as the largest entity in our system which has estimated about 4 years. We are totally dependent on them for all data needed for these studies.	he workload to support the existing TPL-001 to TPL-004 has already consumed two full-time senior positions. Add to that the new requirements for steady state studies necessary in this standard would take at least another full time position. The new stability study requirements and short circuit requirement added would double the number of people necessary for a total of approximately six full time positions with moderate to high experience levels. (Four incremental FTEs with estimated annual cost of $650,000). Purchasing additional licenses for study software is an additional expense.
American Transmission Company	We estimate that the additional one-time costs of supplemental studies and analyses to meet the new requirements might be spread over five years because some analysis only has to be updated every five years. So, we estimate that the total cost over five years for additional staff or consulting services may about $200,000 to $300,000.	We estimate that the lead time to perform supplemental studies and analyses to meet the new requirements might be up to 5 years.	We estimate that the on-going additional cost of expanded studies and analyses to meet the new requirements might be about $150,000 to $200,000 for additional staff.
New York Independent System Operator	A very preliminary estimate would be potentially millions of dollars.	Again, a very preliminary estimate would be two years.	Preliminary estimate is on the order of hundreds of thousands of dollars In addition to cost, there is a significant concern over whether or not there will be

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
			enough staff to complete the required work.
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	One component of these costs is based on modification to the loadflow database. A massive effort would need to be undertaken to model bus sections and breaker codes in order to simulate the planning events needed to stay current with the new standards. Also, man-power to perform the extra analysis was considered. Additional man-power: 5 engineers (2 years) Cost: $1,000,000	The majority of the time would be spent modifying the loadflow database so that the new planning event simulations could be analyzed. Time: 2 years	Additional man-power: 4 engineers Costs: $400,000 / year The following analysis was performed by one large integrated utility in SERC. The results are not representative of all utilities in the SERC region, but would be multiplied many times over to fully represent the SERC region as a whole. A comprehensive study of the impact of these proposed and incomplete standards is not feasible until they are finalized. Regarding manpower, aside from the estimated costs there is the very real situation that the number of qualified engineers available in the industry is nowhere near what would be necessary to carry out the studies (including sensitivities) called for by the proposed standard. This reality needs to be taken into consideration by the Standards Drafting Team when it makes its implementation plan recommendations.
Oncor Electric Delivery	Cost to supplement past study portfolio would be between $250,000 to 750,000.	3 to 5 years with added resources (staff)	$500,000 annually
ISO New England Inc.	The comment period was not long enough to develop a thoughtful response to the impact that the new standards might have. Therefore cost can not be reasonably speculated.	The comment period was not long enough to develop a thoughtful response to the impact that the new standards might have on the planning studies, but a very rough thought would be that any additional needs would be captured within the normal planning studies, which would likely occur within two study cycles of the effective date of the standard.	The comment period was not long enough to develop a thoughtful response to the impact that the new standards might have on study effort and the associated cost. In addition to cost, there is a significant concern over whether or not there will be enough staff to complete the required work.

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
Orlando Utilities Commission	$75,000 to supplement past study portfolio. (We have a fairly small system, only 1400 MW)	Two years, one year to recruit additional planner, the second to perform the baseline studies. This assumes there are sufficient trained personnel in the industry and they can be recruited.	$75,000 each year.
Entergy Services, Inc.	Cost will be covered by the on-going study costs as indicated below.	18 to 24 months	$1,200,000 / year
BPA Transmission Reliability Program	This information is not available.	This information is not available.	This information is not available.
Response: The SDT thanks all who responded to this survey question.			

13. **Documentation: One time cost to prepare reporting documentation associated with studies needed to supplement past study portfolio (depending on the time required to complete the supplemental work, this may be an accumulated cost over more than one year) – and on-going additional cost for documentation of expanded studies and analysis:**

Summary Consideration:

The SDT has reviewed the responses and will use the data as background information in making any further decisions with regard to this standard. No direct changes were made to any of the requirements at this time based on this information.

Organization	1 - Question 13 Comments:	2 - Question 13 Comments:
Dominion - Electric Transmission Planning	The initial process development and documentation will be the most difficult and time consuming portion. Dominion - Electric Transmission recommends a period of 3 to 5 years be given for this initial period of becoming compliant and preparing the documentation. As noted above, it is difficult to provide cost estimates, but we expect at least 2 to 3 additional resources will be required, at a minimum.	See response above.
NPCC	See above	
TVA System Planning	Additional man-power of 1 engineer (1 year) would be required at cost of $100,000	Additional man-power of 1 engineer at costs of $100,000 / year
Progress Energy Carolinas	$60,000	$20,000/year
BCTC	Included in the above. We do not do analysis without documentation.	Included in the above. We do not do studies without documenting them
Manitoba Hydro	$200,000	$100,000
Los Angeles Department of Water and Power	This assumes that past studies are inadequate and supplemental studies are needed. The standard does add a lot of duplicative and unnecessary operating scenarios that are already required	

Organization	1 - Question 13 Comments:	2 - Question 13 Comments:
	under TOP and MOD; but they should be deleted because they serve no useful purpose under TPL, why even spend an extra penny if it is for naught.	
National Grid	See response to question 12.	See response to question 12.
Pacific Gas and Electric Co.	This cost would be included in the cost of performing the supplemental studies.	This cost would be included in the cost of performing the expanded studies and analysis
Gainesville Regional Utilities	Probably would be covered in the previously provided annual cost. Again, I don't feel this is needed for smaller utilities.	Probably would be covered in the previously provided annual cost. Again, I don't feel this is needed for smaller utilities.
JEA	Included in Question 12 estimates.	Included in Question 12 estimates.
PacifiCorp	$250,000 over two years	$125,00
Puget Sound Energy, Inc.	$150,000 for the STD in its current form.	$50,000
ITC Holdings: ITC, METC, ITC Midwest	While we recognize that the standards might require us to garner a little more manpower and will take a little more time, we believe that running these studies is important.	While we recognize that the standards might require us to garner a little more manpower and will take a little more time, we believe that running these studies is important.
Idaho Power Company	Appx $50k	Appx $50k
Hydro-Quebec TransEnergie (HQT)	See Q12	
Progress Energy Florida, Inc.	Again, these costs cannot be reasonably estimated given the difficulties stated in the answer to Question 12a. It would reasonable to expect that the number of individuals in PEF's Transmission Planning group would have to dramatically increase, at least doubling in size or possibly significantly more	Documentation cannot be separated from the actual analysis itself, and thus would be included as part of the $1M estimate stated in the answer to Question 12b above.

Organization	1 - Question 13 Comments:	2 - Question 13 Comments:
	than doubling.	
Sierra Pacific Power Comapny / Nevada Power Company	$100,000	$50,000
Lafayette Utilities System	See response to part 1 of Question 12.	See response to part 1 of Question 12.
Arizona Public Service Co.	$200,000.00	$100,000.00
Ameren	Documentation preparation to include the short-circuit assessment, the amount of consequential load dropped for single contingencies, the expanded requirements of the Corrective Action Plan, and how the sensitivities affect the Corrective Action Plan would take a man-week or two at most (no significant cost increase or manpower increase).	Our present documentation activities to develop the assessment and the corrective action plan take approximately 2 man-months to complete. We would expect the documentation to cover the additional study analyses to add an additional 2 man-months of work. The additional documentation for the Consequential Load Loss, short-circuit analysis, expanded requirements of the Corrective Action Plan, and documentation of how the sensitivities studied affect the corrective plan are estimated to double the existing reporting requirements, resulting in an increase of 3.5 man-months and require 2 additional engineers at an annual cost of $200,000 (including benefits), given the regional requirement to complete the assessment by July 1.
City of Tallahassee, FL	documentation cost was included in the cost estimates for #12, since development of the documentation is part of the study work scope.	
Florida Power and Light	These costs cannot be determined without having experience with the new standard and its documentation requirements. Analysis of existing studies will undoubtedly uncover substantial additional documentation that would need to be produced, but the costs of such document production could not be reasonably estimated beyond stating that the costs would be significant resulting from 1000's of man-hours spent on supplemental work	This would be included in the $5 million dollar estimate provided above.

Organization	1 - Question 13 Comments:	2 - Question 13 Comments:
	that would only serve to meet audit requirements.	
CenterPoint Energy and CPS Energy	As with our response to question 12, we believe the answer depends upon the ultimate practical interpretation of the impractical requirements.	
SRP	Estimate $30k to prepare documentation.	Estimate $15k each additional year documentation.
MidAmerican Energy Company	Included in amounts for 12.	Included in amounts in 12.
Tucson Electric Power Company	included in previous question	included in previous question
MRO NERC Standards Review Subcommittee	Included in amounts for 12.	Included in amounts for 12.
Midwest ISO	We agree some additional costs will be incurred for expanded documentation.	ore requirements and more studies will increase documentation costs.
Tri-State Generatino and Transmission Association, Inc.	An additional $100,000 would be required to document studies for compliance purposes.	Perhaps $50,000/year - half of the initial amount required.
AEP	Additional one-time cost of 15 man-months	Additional ongoing cost of 7 man-months
Lakeland Electric	Unknown	Unknown
NERC and Regional Coordination	Clarity about the required documentation and coordination needs to be added to the standard before this question can bee addressed. As written, our interpretation is the increase in documentation requirements is substantial.	

Organization	1 - Question 13 Comments:	2 - Question 13 Comments:
ColumbiaGrid	The new TPL Standard raises the bar of transmission system performance. This can be expected to require significant additional analysis, documentation and system reinforcements (or reduced firm transfers allowed on the system if system reinforcements are not made). We will defer to our members to provide quantification of those elements.	
IESO	Minimal, if any, for the reasons indicated above, other than for meeting the sensitivity testing requirements (if mandated) which cannot be quantified.	Minimal, if any, for the reasons indicated above, other than for meeting the sensitivity testing requirements (if mandated) which cannot be quantified.
Northeast Utilities	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
North Carolina Electric Membership Corp	N/A	N/A
American Transmission Company	We estimate that the one time cost for expanded studies and analysis documentation to meet the new requirements might be about $20,000.	We estimate that the on-going cost for expanded studies and analysis documentation to meet the new requirements might be about $10,000.
New York Independent System Operator	included above	included above
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	Additional man-power: 1 engineer (1 year)Costs: $100,000	Additional man-power: 1 engineer Costs: $100,000 / year. The following analysis was performed by one large integrated utility in SERC. The results are not representative of all utilities in the SERC region, but would be multiplied many times over to fully represent the SERC region as a whole. A comprehensive study of the impact of these proposed and incomplete standards is not feasible until they are finalized. Regarding manpower, aside from the estimated costs there is the very real situation that the number of qualified engineers available in the industry is nowhere

Organization	1 - Question 13 Comments:	2 - Question 13 Comments:
		near what would be necessary to carry out the studies (including sensitivities) called for by the proposed standard. This reality needs to be taken into consideration by the Standards Drafting Team when it makes its implementation plan recommendations.
Oncor Electric Delivery	$250,000	$100,000
ISO New England Inc.	See response to question 12.	See response to question 12.
Orlando Utilities Commission	$25,000	$25,000
Entergy Services, Inc.	$150,000	$100,000 / year
BPA Transmission Reliability Program	This information is not available.	This information is not available.
Response: The SDT thanks all who responded to this survey question.		

14. System Reinforcement: One time cost, capital investment, to expand your system reinforcement program (due to lead times associated with different types of facilities, this will probably be an accumulated cost over several years). How many years do you estimate that it will take to complete this initial expanded system reinforcement program:

Summary Consideration:

The SDT has reviewed the responses and will use the data as background information in making any further decisions with regard to this standard. No direct changes were made to any of the requirements at this time based on this information.

Organization	1 - Question 14 Comments:	2 - Question 14 Comments:
Dominion - Electric Transmission Planning	Difficult to estimate the investment required, but it will be in the millions if not hundreds of millions of dollars.	Siting new transmission in Virginia can take a minimum of 5 to 7 years if new right-of-way acquisition is required. It is difficult to provide an estimate of time, but it will be quite extensive.
NPCC	NPCC participating members have expressed compliance concerns that this standard, and in particular this question, imply NERC has the ability to "force" transmission reinforcements and construction. It should be emphasized and clarified that the standard should require transmission studies only, and per the Energy Policy Act, NERC does not have this authority as the ERO as granted by FERC in the US and NO authority allowing this in Canada. Also NPCC participating members expressed concern that a validly conducted assessment which shows that criteria are not met (in the 5 or 10 year horizon) could result in non-compliance with the Standard. If NERC believes that it can issue monetary penalties for 5 or 10 year assessments that show that performance criteria will not be met under future system conditions, there is a key question that requires explanation: What behavior is NERC attempting to incent through fining parties for conducting assessments which identify problems in a 5 to 10 year horizon? Also, NERC should further explain how it would view the relevance of a State or Provincial decision not to permit new facilities when issuing such a potential penalty such as preclusive siting issues with Generating Plants.	See above

Organization	1 - Question 14 Comments:	2 - Question 14 Comments:
TVA System Planning	Costs would include the implementation of redundant protection schemes for the P5 planning event (fault + failure of protection scheme), additional 500-kV facilities for P2.2 (single contingency - bus section outage) and P4 (fault + stuck breaker) events, and additional 161-kV facilities for the P3 (Generator +1) events. Estimated cost of $1 billion	Time duration of 10 years would be required
Progress Energy Carolinas	$100,000,000	10 years
BCTC	We do not believe that this cost is not relevant for determining the applicable standards and have not estimated it. The reinforcement costs are orders of magnitude greater that the costs of alternatives the changes in this standard propose to prohibit (e.g. use of RAS, curtailment in anticipation of the next contingency). We believe it is very unlikely that we would get approval for the projects that would be required to meet the proposed changes.	It is highly unlikely that we would be able to get funding approval for the system reinforcements required to meet the proposed changes in these standards.
Manitoba Hydro	An estimate of the cost to Manitoba Hydro is $1.0 Billion.	The licensing and construction of facilities to achieve compliance will require at least 10 years.
Los Angeles Department of Water and Power	If this question is referring to discriminatory treatment between different voltage classes that is arbitrary; the effort should be directed to either treat all the voltage classes equally or do come up with a scientific or historical basis to support the requirement. This is an engineering standard, all the criteria should have some scientific/engineering rationale that can be supported either by physics or historical data.	
National Grid	The comment period was not long enough to develop a thoughtful response to the impact that the new standards might have on the construction requirements. Therefore cost can not be reasonably speculated.	At least 5 beyond the study period. Lines requiring new Rights-of-Way may require 10.
Pacific Gas and	The capital investments would be dependent on the system	Any transmission facilities that would require a certification of

Organization	1 - Question 14 Comments:	2 - Question 14 Comments:
Electric Co.	reinforcements needed due to the added requirements. For example, if after the first contingency, redispatch to curtail firm transfers is not allowed in anticipation of the next single contingency, the system reinforcements could easily include more 500 kV lines and related facilities. The costs of such reinforcements could be a few Billion dollars.	public convenience and necessity could take more that five years for permitting, engineering and construction. Transmission Planning could take a few more years depending on the transmission reinforcements to be constructed.
Gainesville Regional Utilities	$50 Million. Again, I don't feel this is needed for smaller utilities.	7 years. Again, I don't feel this is needed for smaller utilities.
Public Service Company of New Mexico	This ultimately depends on the degree to which the local area issues addressed by footnote b of Table 1 of the existing TPL are maintained. Without the local area concepts of the existing TPL, costs could run into the hundreds of millions of dollars.	This ultimately depends on the degree to which the local area issues addressed by footnote b of Table 1 of the existing TPL are maintained. Without the local area concepts of the existing TPL, permitting requirements would result in some projects exceeding 10-years.
JEA	Could be up to $1 Billion and would depend on the physical ability to terminate at existing 500 kV substations and the ability to acquire 500 kV ROW outside of JEA's and Florida's jurisdiction.	Minimum of 7 years if DOE declares a Corridor of National Interest. Otherwise it could be longer and more costly.
PacifiCorp	$100,000,000 + Will not be able to estimate the total cost until after the studies are complete.	10 years
Puget Sound Energy, Inc.	$800,000,000 to recover Firm Transmission capacity with no adjustment following N-1.	15 years
ITC Holdings: ITC, METC, ITC Midwest	Since we have been following the NERC Planning Standards, at this point we do not expect an additional one time system reinforcement cost.	Since we have been following the NERC Planning Standards, at this point we do not expect an additional time-frame for a system reinforcement program.
Idaho Power Company	Not sure	5 years
SMUD	A field test of the revised standard would be the appropriate way to arrive at the approximate costs to support the new/modified	A field test would be the time to get an educated estimate.

Organization	1 - Question 14 Comments:	2 - Question 14 Comments:
	requirements.	
Hydro-Quebec Transenergie (HQT)	HQT and NPCC participating members have expressed compliance concerns that this standard, and in particular this question, imply NERC has the ability to "force" transmission reinforcements and construction. It should be emphasized and clarified that the standard should require transmission studies only, and per the Energy Policy Act, NERC does not have this authority as the ERO as granted by FERC in the US and NO authority allowing this in Canada. Also HQT and NPCC participating members expressed concern that a validly-conducted assessment which shows that criteria are not met (in the 5 or 10 year horizon) could result in non-compliance with the Standard. If NERC believes that it can issue monetary penalties for 5 or 10 year assessments that show that performance criteria will not be met under future system conditions, there is a key question that requires explanation: What behavior is NERC attempting to incent through fining parties for conducting assessments which identify problems in a 5 to 10 year horizon? Also, NERC should further explain how it would view the relevance of a State or Provincial decision not to permit new facilities when issuing such a potential penalty such as preclusive siting issues with Generating Plants.	
Progress Energy Florida, Inc.	Again, due to the difficulties described in the answer to Question 12a, given that the amount of analysis cannot be reasonably estimated, neither can the one-time capital cost. PEF did state in the answer to Question 11 that the cost to our 500 kV system alone would easily run in to the range of costing billions of dollars. How many billions, we are not sure, but we have sufficient experience through presently planned 500 kV projects on our system to know that the cost for such expansion is in the range of billions of dollars. Given that PEF has not been able to comprehensively assess the costs to its 230 kV and 115 kV system, it is likely that the total cost of implementing the draft TPL Standard would be many, many billions of dollars. As stated earlier, this concern is reinforced in the answer to Question 15, but	PEF does not believe the undertaking required in the present draft of the TPL Standard, questionably described here as an "initial" program, could reasonably be implemented in our lifetime. As stated in our answers to Questions 12 and 13, the planning time would run at least 10 years, or one complete long-term planning cycle. Implementation, particularly given the scope of 500 kV projects and challenges with operating the existing system while constructing such large projects, will take an additional 10 years. An estimate of 20 years, however, assumes that the industry is in place to make such projects feasible continent-wide. Just a cursory assessment of the limited resources of the Transmission Construction industry, combined with the global demand for concrete and steel, leads us to conclude that implementation of

Organization	1 - Question 14 Comments:	2 - Question 14 Comments:
	we are extremely concerned that our ratepayers will potentially be burdened with such exorbitant cost for so little benefit, and are certain that our PSC and our ratepayers will agree.	the draft Standard's requirements is not feasible short of a World War II-scale re-tooling of our entire economy. Given the significant challenges the U.S. economy is already facing, the prudency of such a colossal undertaking with minimal benefit becomes even more questionable.
Sierra Pacific Power Company / Nevada Power Company	$800 Million	10 years
Lafayette Utilities System	See response to part 1 of Question 12.	See response to part 1 of Question 12.
Arizona Public Service Co.	Hard to quantify without studying.	5 years
Ameren	Our present interpretation is that the proposed revised standard would have a minimum impact on the reinforcement of the Ameren system. The modification to remove the requirement that bus-tie circuit breakers must have the same performance requirements as non-bus-tie breakers significantly reduces our issues of non-compliance, and particularly for circuit breakers 300 kV and above.	Our present interpretation is that the proposed revised standard would have a minimum impact on the reinforcement of the Ameren system.
City of Tallahassee, FL	depending on the interpretation of the standard as currently drafted, this cost could be substantial (at least $20M) over a 5-year capital budget period (consistent with the City's current practice). It's doubtful this level of funding could be achieved/maintained given other financial pressures for local governments.	Unable to develop an answer to this question, since it depends on the ability to successfully site and permit generation and transmission facilities (which is becoming increasingly harder to complete), and the requirements of any successful siting effort may make the costs prohibitive (ie, underground transmission facilities and/or stringent controls on generating facilities).
Florida Power and Light	These costs cannot be determined without having experience with the new standard and its performance requirements. The costs of such investment could be in the 10's of billions of dollars for FPL because of the increased level of performance contemplated by the draft standard.	If we knew what was needed today, it could conceivably take up to 10 years to complete, if the projects are all feasible. Without knowing what is necessary, a fair estimate would be 20 years. This does not take into consideration that the entire industry would be competing for the same limited resources of material and manpower to complete this reinforcement. Justification would be

Organization	1 - Question 14 Comments:	2 - Question 14 Comments:
		problematic and eminent domain may not be enforceable due to the remote low probability of an N-1-1 event, and lack of a true reliability need.
Exelon Transmission Planning		Analysis has not been completed at this time to determine the extent of the additional burden, but significant expenditures, in terms of personnel, tools and transmission upgrades, are anticipated if this draft were implemented.
CenterPoint Energy and CPS Energy	We believe the proposed requirements may not impose additional capital investment for system re-enforcements for our companies. We believe we are already achieving the reliability goals embodied in the proposed requirements but in a much more efficient and cost-effective way than the overly prescriptive approach proposed in these requirements.	
SRP	Unknown costs, there are numerous raise the bar Standards, hard to determine the additional cost to SRP until the complete studies are performed and evaluated.	Unknown until the reinforcements are determined.
MidAmerican Energy Company	The additional one-time costs of system reinforcements to meet the new requirements would depend on the results of the new studies and be hard to forecast. However, if they involved just a few 345 kV substation modifications and 345 kV line additions, then MEC estimates that it would cost in the range of hundreds of millions of dollars per responsible entity.	The lead time to build new system projects would depend on the results of new studies and be hard to forecast. However, if they involved a 345 kV substation modification or a 345 kV line addition, MEC estimates that it would take 5 to 7 years to complete the new projects.
Tucson Electric Power Company	unable to determine without actual studies	10+ years5 year budget and 10 year plans have been approved. Proposed projects in the 5-10 year time frame would need revised and accelerated and new projects would be proposed following the completion of these proposed projects.
SERC Dynamics Review Subcommittee		The lead time for new line construction is at least 7 years.

Organization	1 - Question 14 Comments:	2 - Question 14 Comments:
MRO NERC Standards Review Subcommittee	The additional one-time costs of system reinforcements to meet the new requirements would depend on the results of the new studies and be hard to forecast. However, if they involved just a few 345 kV substation modifications and 345 kV line additions, then we estimate that it would cost in the range of hundreds of millions of dollars per responsible entity.	The lead time to build new system projects would depend on the results of new studies and be hard to forecast. However, if they involved a 345 kV substation modification or a 345 kV line addition, we estimate that it would take 5 to 7 years to complete the substation project and 8 to 12 years (or more) to complete the new transmission line project.
Midwest ISO	This is difficult to quantify at this time.	This is difficult to quantify at this time.
Tri-State Generatino and Transmission Association, Inc.	We do not anticipate additional investment beyond currently planned facilities.	Transmission projects generally take between 3 and 6 years to complete.
Tri-State G&T		10-Jun
Lakeland Electric	Unknown	Unknown
Southern Company Transmission	These costs cannot be determined without having experience with the new standard and its performance requirements.	
NERC and Regional Coordination	Clarity needs to be added throughout the requirements. Our interpretation of the standards as written will not result in substantial capitol investment. These standards will not have a substantial impact on improved system reliability, however; the requirements do significantly increase the manpower investment in study documentation and efforts associated with reporting study results.	
ColumbiaGrid	The new TPL Standard raises the bar of transmission system performance. This can be expected to require significant additional analysis, documentation and system reinforcements (or reduced firm transfers allowed on the system if system reinforcements are not made). We will defer to our members to provide quantification of those elements.	

Organization	1 - Question 14 Comments:	2 - Question 14 Comments:
IESO	None expected at this time.	None expected at this time.
Northeast Utilities	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
North Carolina Electric Membership Corp	N/A	N/A
American Transmission Company	The additional one-time costs of system reinforcements to meet the new requirements would depend on the results of the new studies and be hard to forecast. However, if they involved just a few 345 kV substation modifications and 345 kV line additions, then we would estimate that it costs may be in the range of hundreds of millions of dollars.	The lead time to build new system projects would depend on the results of new studies and be hard to forecast. However, if they involved a 345 kV substation modification or a 345 kV line addition, we estimate that it might take 5 to 7 years to complete the substation project and 8 to 12 years (or more) to complete the new transmission line project.
New York Independent System Operator	Depending on facilities covered by the standard, it is estimated that the cost to bring facilities into compliance potentially could be on the order of billions of dollars.	A preliminary estimate is that it would take at least five but potentially up to ten years to bring facilities into compliance.
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	Typical costs for a large utility in SERC would include the implementation of redundant protection schemes for the P5 planning event (fault + failure of protection scheme), additional 500-kV facilities for P2.2 (single contingency - bus section outage) and P4 (fault + stuck breaker) events, and additional 161-kV facilities for the P3 (Generator +1) events. Cost: $1 billion	Time: 10 years The following analysis was performed by one large integrated utility in SERC. The results are not representative of all utilities in the SERC region, but would be multiplied many times over to fully represent the SERC region as a whole. A comprehensive study of the impact of these proposed and incomplete standards is not feasible until they are finalized. Regarding manpower, aside from the estimated costs there is the very real situation that the number of qualified engineers available in the industry is nowhere near what would be necessary to carry out the studies (including sensitivities) called for by the proposed standard. This reality needs to be taken into consideration by the Standards Drafting Team when it makes its implementation plan recommendations.
Oncor Electric	Unknown, dependent on results of analysis and solutions	Unknown, dependent on results of analysis and solutions

Organization	1 - Question 14 Comments:	2 - Question 14 Comments:
Delivery	implemented	implemented
ISO New England Inc.	See response to question 12.	See response to question 12.
Orlando Utilities Commission	$0.00 if system adjustment in preparation for the second part of N-1-1 can include firm transfer and non-consequential load adjustments when necessary. $500 Million if n-1-1 conditions must be met without firm transfer and non-consequential load - adjustments before the second event, at 230 kV and above$1 Billion if n-1-1 conditions above are met on load serving systems below 230 kV.	10 Years to meet n-1-1 without curtailment/reduction prior to the second n-1. A significant portion of the work would be in either downtown, established residential or highly sensitive environmental areas, all of which may require extensive legal proceedings to build the projects. There would also be a large amount of simultaneous work going on nationwide that would result in a shortage in construction & design personnel as well a scarcity in needed materials.
Entergy Services, Inc.	Without performing the requisite analyses, Entergy does not know definitively how much it will cost to comply with these revised standards. However, Entergy expects the cost could be up to $1 billion to become fully compliant.	15 - 20 years The time required for construction will be elongated due to the need for significant numbers of new construction projects. This will require that projects be queued by the TPs because of constraints in available materials, labor and other resources.
BPA Transmission Reliability Program	This information is not available.	This information is not available.
Response: The SDT thanks all who responded to this survey question.		

15. (A) Do you generally support the revised standard? (B) Are you unsure whether you generally support the revised standard? or (C) Do you definitely not support the revised standard? Please check the appropriate box below. If your response is either (B) or (C), please explain your single biggest concern with the revised standard, including which specific requirement or set of requirements causes you the most concern and why.

A – Generally support the revised standard
B – Unsure about supporting the revised standard
C – Definitely do not support the revised standard

Summary Consideration: 50% of the commenters voted that they did NOT support the revised standard at this time. 35% are unsure. Some of the major issues that were raised by the industry for Question 15 include:

1. System Adjustment in event P6 - Many commenters believe that after the first N-1 in P6, curtailment of Firm Transmission Service or firm transfers should be allowed as part of System adjustment in preparation for the next N-1, citing that this is presently allowed in footnote b in existing Table 1. Otherwise, the Firm Transmission Service under normal System intact condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. Many believe this would in effect be imposing an N-2 criterion for offering Firm Transmission Service.

SDT response: The SDT agrees that clarification regarding treatment of Firm Transmission Service and Non-Consequential Load Loss during adjustment is necessary. Footnote 10 in Revision 3 of the Standard provides clarification.

2. Dropping local load - Many commenters opposed not being able to drop some local network Load for a single Contingency event as long as Bulk Electric System reliability was not impacted. This is presently allowed in footnote b of the existing TPL-002. However, there is no such allowance any longer for losing Non-Consequential Load for a single Contingency in the proposed draft. Many commenters suggested that orderly dropping of local network Load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. Some local network customer curtailments or local area Load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected System was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service.

SDT response: Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these System designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of the TPL-001-1

and most stakeholders and the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement. As an alternative, an entity could seek an Entity Variance for the situation described through their Regional Entity organization. In paragraph 1794 FERC clarified that "…an entity may seek a regional difference to the Reliability Standard from the ERO for case-specific circumstances". The process described by FERC as a regional difference is described in detail in the "NERC Standards Development Procedure" document under the subsection titled "Variances to NERC Reliability Standards".

3. Raising the bar for 300 kV and above - Many commenters believe that the SDT has not yet justified raising the bar on Facilities above 300 kV. Some pointed out that the higher performance requirements for Facilities >300 kV are tied to very low probability events, so the enhanced reliability is not worth the cost. Some also pointed out that disruptions on lower voltage circuits can cause real and reactive power flow fluctuations across, and eventual separation of, higher-voltage networks. Many believe that there should be no distinction in voltage classes for allowing or not allowing controlled Load shed for applicable events.

SDT response: The SAR for this standard recognized FERC orders which indicated a need to "raise the bar" for the industry. The SDT agrees and is attempting to do this in a reasonable fashion. There is significant flexibility in the Corrective Action Plans allowed for any additional performance requirements which must be met. Industry consensus, through approval of the SAR, is that revision of the existing TPL standards is appropriate.

4. Load modeling for dynamics - Many commenters believe that Load modeling is a significant open issue, such as the models for dynamic studies have yet to be developed and the data is not yet in hand. Many find this conflicting with implementation of the TPL standards due to modeling details being a gating item to completing some System studies.

SDT response: The SDT agrees and believes that industry guidance is needed to capture the appropriate dynamic behavior of Loads. In response to comments, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments. Any comments received from the industry on MOD standards will be forwarded to NERC for inclusion into NERC Reliability Standards Development Projects 2010-04 Modeling Data and 2010-05 Demand Data. Requirement R2.4.1 has been modified to include the following: "An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable."

5. Sensitivity analysis - Another concern of commenters is the prescriptive nature of sensitivity scenarios, listed within Requirement R2.1.3 for steady-state and Requirement R2.4.3 for Stability, and the volume of associated study work. Some commenters feel that the Transmission Planner and Planning Coordinator can better select the most appropriate sensitivities for their System. Commenters also feel that examples of sensitivities are already inherent in the existing requirements, such that some sensitivity studies are in effect adding an additional level of Contingency (N-2 or N-3). Many commenters feel that the additional analyses proposed by the revised standard are not warranted and are already covered adequately in the existing studies and TPL standards.

SDT response: The intent of the SDT in requiring performance of sensitivity studies is to identify critical System conditions and to expand the planners' portfolio of knowledge about vulnerabilities on their System. This is also an expectation from FERC Order 693 paragraphs 1704 - 1706.

As a result of industry comments, the following changes have been made to TPL-001-1:

Consequential Load Loss: ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions.

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~.~~ ~~For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~.

Year One: The first year that a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the ~~completion of the previous annual Planning Assessment~~ current calendar year.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R2 Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses ~~including both System and Generating Unit Stability~~.

R2.1.3 For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

- ~~Variability and outages of r~~Reactive resource~~s~~ capability

R2.1.4 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.6.1 (now R2.5.1) For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less.

R2.6.2 (now R2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:

R2.7 (now R2.6) For Planning Events shown in Table 1 ~~– Steady State Performance and Table 2 – Stability Performance~~, when the analysis indicates an inability of the System to meet the performance requirements in ~~the t~~Table~~s~~ 1, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed in subsequent assessments but the System shall continue to meet the performance requirements in the tables. Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3 and R2.4.3. The Corrective Action Plan shall:

Under Requirement R2.6.1:

- Installation or modification of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations.

R2.8 The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. ~~The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to c~~Contingencies in Table 1 ~~– Steady State Performance.~~ The studies shall be based on computer simulations using models utilizing data provided in Requirement R1.

R3.1 Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 ~~– Steady State Performance.~~ based on the lists created in Requirement R3.4.

R3.3.2 For all generators, studies shall consider the minimum steady state voltage limitations ~~of all generators~~ and identify how the generators are ~~treated~~ analyzed in the steady state simulation

R3.3.3 For all Transmission lines, studies shall consider relay loadability and identify how loadability is ~~treated~~ analyzed in the steady state simulation.

R3.4 Those Planning Event Contingencies in Table 1 ~~– Steady State Performance not covered in Requirement R3.3.2~~ that are expected to produce more severe System impacts shall be identified~~,~~ and a list of those Contingencies to be evaluated for System performance in Requirement R3.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results.

R4 For the Stability portion of the Planning Assessment, as described in Requirement R2.4~~ and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~

R4.3.2 ~~Studies shall consider~~ Simulate generator performance under anticipated conditions including how the voltage ride through capability ~~of all generators and identify how the generators are treated~~ is analyzed~~in the simulation~~.

R4.4 ~~At a minimum, t~~Those Planning Event Contingencies in Table ~~2~~1 – ~~Stability Performance~~ that ~~would~~are expected to produce more severe System impacts shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information with an explanation of why the remaining Contingencies would produce less severe System results.

R7. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among~~ neighboring systems~~ adjacent Planning Coordinators and any functional entity who has indicated a reliability need, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890.

Header note 'e' - For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Extreme Event 2b (steady state) - Loss of all Transmission lines on a common ~~r~~Right-of-~~w~~Way.

Footnote 1.a.ii - For all other Planning Events: No generating unit or units totaling more than the Contingency ~~r~~Reserve of the Balancing Authority (or Reserve Sharing Group if applicable) shall be allowed to pull out of synchronism. Generators that pull out of synchronism must have out-of-step protection or some other means to trip the generator for this condition and the resulting apparent impedance swings must not pass through relay characteristics that would result in the tripping of any Transmission System elements other than the generating unit and its direct connection Facilities.

Footnote 3 - Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø fault study indicating criteria are being met shall provide sufficient evidence that a SLG condition would also meet criteria.

Footnote 5 - When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed.

Footnote #10 – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.

Footnote #12 - Excludes circuits that share a common structure for 1 mile or less.

Organization	Question 15:	Question 15 Comments:
El Paso Electric Company	B — Unsure about supporting the revised standard	While this 2nd draft TPL standard has some positive changes, notably: The allowance to use RAS to trip generation for N-1 (see R3.5 Manual and automatic generation run-back/tripping is allowed as a response to a single or multiple Contingency ...) with some rather generic conditions. The allowance for Non-consequential Load Loss for loss of a transmission Facility, followed by system adjustment, followed by loss of a second transmission Facility (see P6 in draft performance Tables 1 and 2). This is the same as Category C3 in the existing TPL-003-0.On the down side, as proposed, Standard TPL-001-1:1. Will not allow curtailment of firm transfer (or firm transmission service) after the first N-1, in preparation for the next N-1 regardless of transmission voltage level. This is a major issue. Curtailment of firm transfer after the first N-1 has always been a part of system adjustment in preparation for the next N-1 as stated in foot note b of the existing TPL-002-0:"b. Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers." Not allowing this could mean reduction of firm transfer capability pre-contingency unless new circuits are built.2. The existing standard (http://www.nerc.com/files/TPL-003-0.pdf) does not distinguish between voltage classes, curtailment of firm transfer and, planned and controlled load shedding are allowed regardless of voltage class for Category C events. The proposed standard will not allow curtailment of firm transmission service, or planned and controlled load shedding for loss of Facilities with operating voltage above 300 kV involving the following in the proposed Performance Tables 1 and 2:P2-2: Bus Section fault (Category C1) P2-3: Breaker fault (Category C2) P4: SLG Fault + stuck breaker (Categories C6 - C9) P5: SLG Fault + protection system failure (Categories C6 - C9)The number of Facilities lost would depend on the bus configuration for above 300 kV. If you have a ring-bus, breaker and a half or double breaker double bus, you would lose at the most 2 Facilities. But if you have Main-Aux or single breaker double bus, you will lose all Facilities connecting to the faulted Facility.
Response: In response to your comment and those of others in the industry on allowing curtailment of Firm Transmission Service as System adjustment after		

Organization	Question 15:	Question 15 Comments:
an N-1 Contingency, the SDT has added footnotes 5 and 10 to Table 1 - Steady State & Stability Performance. **Footnote 5** - When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed. **Footnote 10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
Dominion - Electric Transmission Planning	B — Unsure about supporting the revised standard	(1) Unsure about cost/effort necessary to meet requirements (2) Uncertain that compliance with the proposed requirements in this standard would significantly improve reliability (3) R2.6.2: The entire sentence is confusing as it is modified. The original sentence in the previous draft made more sense. Please check and correct accordingly. (4) R 5.3: This requirement considers voltage ride-through capability of all generators. Nowhere in this TPL standard or in the MOD standards are Generator Owners specifically required to provide such data to Transmission Planners and Planning Coordinators. Stating the requirements for generator dynamics data and dynamic load characteristics in general terms, as listed below (from the MOD Standards), are vague. (a) shall provide appropriate equipment characteristics (b) shall provide dynamics system modeling and simulation data (c) Shall develop comprehensive dynamics data requirements .... to model and analyze the dynamic behavior... (5) In Table-2 Stability Performance, several places refer to "SLG or 3-phase Faults" . Since it states "or", does this mean we can get by with studying only SLG faults? We do not think that is the intent of this phrase; thus, a clarification is warranted. (6) One of our comments on the previous draft was with respect to a second-zone fault clearing due to protection system failure for a fault beyond zone 1 coverage of primary relies. The SDT's response was (Specific 1): "The SDT agrees with your concern and is working on a solution for a future draft." The question is repeated below, as a pending "to do" item, using the revised 'Table-2 Stability Performance' as reference: Category 5 in 'Table-2 Stability Performance' refers to a protection system failure event. We interpret this as, among other things, having a fault beyond the first-zone coverage of the primary protection scheme with the carrier equipment failure (or the carrier cut-off switch left in "OFF" position by a technician - a human error) resulting in a second-zone trip of the faulted line. The second-zone trip time is generally in the range of 30-35 cycles. This may be critical from the stability aspect for the terminal end at a generating plant even though only one element will be lost. Also, the second-zone trips may need to be studied for transmission lines out of next terminal from the generator end if the next terminal is connected to the generator terminal via a short line. We think that an

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		additional single contingency Category should be added to this Table to cover the "Event" of second-zone trip scenario.

Response: 1. The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus. The SDT is cognizant of the cost factors and additional efforts involved and has taken them into consideration in its deliberations in the development of this draft.

2. The SAR for this standard recognized FERC orders which indicated a need to "raise the bar" for the industry. The SDT agrees and is attempting to do this in a reasonable fashion. There is significant flexibility in the Corrective Action Plans allowed for any additional performance requirements which must be met. Industry consensus, through approval of the SAR, is that revision of the existing TPL standards is appropriate.

3. The SDT has revised the language of Requirement R2.6.2 (now R2.5.2).

R2.5.2 For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:

4. The SDT understands that the Transmission Planner and the Planning Coordinator need data from the Generator Owners. However, revising the MOD standards is beyond the scope of this standard revision. Further, we note that one of the requirements of FERC Order 890 for long-term Transmission planning involves formal data exchange between stakeholders and the Transmission Planner and the Planning Coordinator. It is our understanding that these data exchange processes have been successful in providing better planning information about stakeholders such as independent Generator Owners. Also, we note that there is an ongoing standards development project, Generation Verification Project 2007-2009. You may wish to submit your comment to that SDT about the need for the Generator Owner providing this information to the Transmission Planner and the Planning Coordinator.

5. The SDT has combined the tables into a single table and clarified the "SLG or 3 phase" designations. In addition, the SDT has added footnote 3 to provide clarity.

Footnote 3 - Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø fault study indicating criteria are being met shall provide sufficient evidence that a SLG condition would also meet criteria.

6. The SDT has revised the language in the P5 category to clearly identify the required performance for an event with a Protection System failure. The current draft requires the planner to recognize the equipment that will be removed from service and the timing (including delays with back-up Protection Systems if the primary is out of service) during their Stability studies. The scenario you described is therefore covered by P5. The SDT does not see a need to have a separate event for that scenario.

NPCC	C — Definitely do not support the revised standard	This standard as drafted does not allow exceptions for small parts of the system as long as interconnected system reliability is maintained, which is allowed in the existing TPL standards in footnotes b) and c) in Table 1. Unless such exceptions are allowed significant transfer restrictions or large reinforcements must be made. The applicable TPL footnotes are: Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall

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		reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers. Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (nonrecallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems. This comment form did not allow for the following items to be addressed: a. Definition of the Long-Term Planning Horizon. The planning horizon, for assessment purposes should be limited to 10 years. Such an assessment should be sufficient to identify requirements that may take an extended time to implement. b. Definition of Planning Coordinator is part of the NERC Functional Model, For consistency it should be removed from the Standard. c. Put headings on each section to identify requirements of section. Add headings to the tops of the subsequent pages in the performance tables. Headings only appear on the first page at the beginning of the Table. d. With respect to R2.2 - Delete "current" from the phrase "current System Peak Load study" and replace "study" with "assessment." e. Remove R2.2.1, the requirement to extend the assessment beyond 10 years. What does the length of the project have to do with the assessment? If it takes 15 years to build something, why does this require a review of year 15? What is the purpose of this assessment? f. R3.3.2 requires clarification - This standard needs to permit discretion regarding the single contingencies that need to be tested, similar to R 3.3.3 and R3.4. It is unnecessary to test all events. For example, contingencies may be limited to relevant disturbances that are contained within or directly impact the studied system. g. With respect to R3.2.1 - Clarify whether the intent of the standard is to address station service minimum voltage limitation, maximum leading VAR absorption capability or both at steady state. h. Remove R3.2.2 - Relay loadability is addressed in PRC-023 standard. i. With respect to R3.3.2.1 - Recommend the removal of the requirement to assess the expected duration of Consequential Load loss. It's not considered anywhere else in the standard. j. With respect to R3.3.3 - The paragraph refers to Table 1 Contingencies P3 through P7; this should be explicitly stated. Rationale for inclusion of testing should not be required; should only need to explain why certain Contingencies were not tested. This discretion should be applicable to all contingencies. k. With respect to section R5 - The concept of planned and long-term outages should apply to the general Planning Assessment, or not at all. It should not be specific to the Stability Assessment.

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		l. The provisions of Section R.5.3 should have a corresponding MOD standard apply a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertant trip of the generator. Such a provision should include "other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation. m. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizon.
New York Independent System Operator	C — Definitely do not support the revised standard	This standard as drafted does not allow exceptions for small parts of the system as long as interconnected system reliability is maintained, which is allowed in the existing TPL standards in footnotes b) and c) in Table 1. Unless such exceptions are allowed significant transfer restrictions or large reinforcements must be made. The applicable TPL footnotes are:? b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.? c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (nonrecallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems. This comment form did not allow for the following items to be addressed: a. Definition of the Long-Term Planning Horizion. The planning horizon, for assessment purposes should be limited to 10 years. Such an assessment should be sufficient to identify requirements that may take an extended time to implement. b. Definition of Planning Coordinator is part of the NERC Functional Model, Remove from Standard. c. Put headings on each section to identify requirements of section. d. With respect to R2.2 - Delete "current" from the phrase "current System Peak Load study" and replace "study" with "assessment." e. Remove R2.2.1, the requirement to extend the assessment beyond 10 years. What does the length of the project have to do with the assessment? If it takes 15 years to build something, why does this require a review of year 15? What is the purpose of this assessment? f. R3.3.2 requires clarification - This standard needs to permit discretion regarding the single contingencies that need to be tested, similar to R 3.3.3 and R3.4. It is completely unnecessary to test all events. For example, contingencies may be limited to relevant disturbances that are contained within or directly impact the studied system. g. With respect to R3.2.1 - Clarify whether the intent of the standard is to address station service minimum voltage limitation, maximum leading VAR absorption capability or both at steady state. h. Remove R3.2.2 - Relay loadability is addressed in PRC-023 standard. i. With respect to R3.3.2.1 - Recommend the removal of the requirement to assess the expected duration of

Organization	Question 15:	Question 15 Comments:
		Consequential Load loss. It's not considered anywhere else in the standard. j. With respect to R3.3.3 - The paragraph refers to Table 1 Contingencies P3 through P7; this should be explicitly stated. Rationale for inclusion of testing should not be required; should only need to explain why certain Contingencies were not tested. This discretion should be applicable to all contingencies. k. With respect to section R5 - The concept of planned and long-term outages should apply to the general Planning Assessment, or not at all. It should not be specific to the Stability Assessment. l. The provisions of Section R.5.3 should have a corresponding MOD standard apply a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertant trip of the generator. Such a provision should include "other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation. m. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizion.
Northeast Utilities	C — Definitely do not support the revised standard	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.

Response: Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these System designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of the TPL-001-1 and most stakeholders and the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement. As an alternative, an entity could seek an Entity Variance for the situation described through their Regional Entity organization. In paragraph 1794 FERC clarified that "…an entity may seek a regional difference to the Reliability Standard from the ERO for case-specific circumstances". The process described by FERC as a regional difference is described in detail in the "NERC Standards Development Procedure" document under the subsection titled "Variances to NERC Reliability Standards".

A. The SDT believes that a review of System conditions beyond the 10-year horizon is warranted. FERC Order 693 requires that the planning horizon take into account the lead times for siting and permitting of new long-distance Transmission lines and other long lead time solutions. The SDT has received industry comments regarding the need to exceed a 10-year horizon to account for longer lead time projects. Establishing planning horizons that are shorter than Transmission lead times may create gaps where the identification of a reliability need to which Transmission may be the best solution occurs too late to avert the identified reliability violation. Further, Operating Procedures or alternative short-term capital projects may be needed to limit the impact of the planning event until the planned Facilities can be completed. This information needs to be included in the Assessment.

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B. Planning Coordinator has been defined in another project and as such has been deleted here.

C. The SDT also feels that the Tables need to be as clear and concise as possible. To that end, this version combined Tables 1 and 2 into one table with a revised format. The Planning Events are shown on one page so repeating the headings will not be needed.

D. The SDT believes that the existing language is appropriate. No change made.

E The SDT believes that a review of System conditions beyond the 10-year horizon is warranted under some circumstances. For example, if it takes 15 years to build a Transmission line, then the need for that line would have to be determined 15 years ahead of the in-service date. Therefore, Requirement R2.2.1 requires you to perform an Assessment on year 15 if it takes you 15 years to build a line.

F. The SDT has removed Requirement R3.3.2 and replaced it with additional language in Requirement R3.1. The SDT agrees with your interpretation that it does not require evaluation of all single Contingencies. Rather, the SDT specifically states in Requirement R3.4 that those Contingencies that are expected to produce the more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe results.

R3.1 Studies shall be performed to determine whether the BES meets the performance requirements in Table 1~~ – Steady State Performance.~~ based on the lists created in Requirement R3.5.

G. The SDT has not limited the purpose of this requirement to either minimum acceptable station service voltages or maximum Mvar absorption. The SDT believes that the purpose of Requirement R3.2.1 (now R3.3.2) is to determine if generators will be able to operate or trip off following the Contingency.

H. The SDT believes that relay load limits or loadability needs to be considered in the Contingency analyses. The studies should determine if Transmission line loadings could reach the relay loadability level which may add to the existing Contingency and perhaps, result in an unbounded cascading event. No change made.

I. By definition, Consequential Load Loss is allowed. To meet industry concern as well as FERC Order 693, the SDT has added Requirement R2.~~-~~8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.8.

R2.8 The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1.

J. The SDT agrees that the rationale should be for all Planning Events but not for Extreme Events.

K. The SDT agrees and has moved this concept within Requirement R1 (see Requirement R1.1.1) so that it is applicable to all planning assessments. Further, both Requirements R3 and R5 (now R4) have been revised to make reference to Requirement R1.

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. ~~The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to c~~Contingencies in Table 1 ~~– Steady State Performance.~~ The studies shall be

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based on computer simulations using models utilizing data provided in Requirement R1. **R4** For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~ L. Requirement R5.3. has been modified (now R4.3.2) to address simulation of how generators perform under conditions being studied to address these concerns. "Other equipment" is addressed in Requirement R5.4. **R4.3.2** ~~Studies shall consider~~ Simulate generator performance under anticipated conditions including how the voltage ride through capability ~~of all generators and identify how the generators are treated~~ is analyzed~~in the simulation~~ M. While planned outages are addressed in the operating horizon, it is important that a Transmission Planner review the ability of its System to accommodate planned (maintenance) outages. Additionally, any specific known Facility outages need to be appropriately modeled for the planning horizon studied.		
TVA System Planning	C — Definitely do not support the revised standard	TVA's main concern is that no technical justification for "raising the bar" on facilities above 300-kV has yet been demonstrated such as required on P2, P4, and P5 for 300 kV and above. TVA is very concerned that "raising the bar" would be a financial burden on TVA's ratepayers. TVA would also like to provide the following additional comments to this second draft as follows: 1. In R2.4.1, load models that appropriately represent the dynamic behavior of motor loads are required. TVA believes that industry guidance is needed on how to properly model these loads. Does this requirement mandate the use of specific load models for each bus, or would an aggregate load model which represents the system as a whole be sufficient? It should be clearly stated whether the load model in R2.4.3.1 refers to system load or the dynamic load model at individual busses. 2. In R3.2.1 and R5.3, need industry guidance on how to actually determine the minimum steady state voltage limitations of generators. Is there a MOD or FAC requirement for generation owners to provide this information? 3. Which single contingency events should be included in calculations for Available Transfer Capacity? Should P2 events be included in addition to P1 events since P2 events are also defined as single contingency events in Tables? 4. Would like further clarification from the team on what does P5 exactly includes? For instance, does it include battery failures, CT failures, etc? 5. The existing TPL 002-0 allows for some local load to be dropped for a single contingency event as long as the Bulk system reliability was not impacted. However there is no such allowance any longer for losing such load for a single contingency in the proposed draft. It would be very expensive for TVA to fix all such events in several remote areas that

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		would have very little impact on the overall reliability of the TVA bulk system. TVA believes that the capital spent for these fixes could be used to better strengthen the overall bulk system in much better ways. 6. Suggest rewording R2.2.1 from "To accommodate any known longer lead time projects" to "To identify any potential longer lead time projects". 7. Can operational guides be used indefinitely in R2.7.1 or does the team propose a limit on how long operational guides can be used until a capital fix is implemented? 8. In R3.3.2.1, what is the purpose for needing the expected duration of consequential load loss? There is a concern that this requirement will be very burdensome to keep track of the quantity of consequential load loss as well as expected duration. Who is requesting this info? It appears that this may be a local regulatory issue, not a reliability issue. 9. Suggest changing definition of "Planning Events" in the Definitions to say "Events that have a higher probability of occurrence and require Transmission system performance requirements to be met." 10. Should the proposed standard mention that utilities should run contingencies outside their system that could impact their own internal system? TVA believes that additional documentation be included in the new standard to address this. 11. Functional entity in 4.1.4 should be "LSE" instead of "DP" 12. In the Definitions for "Year One", suggest replacing "previous" with "most recent" to help clarify when the planning window should begin. 13. Should "peak" in R2.1.1 be replaced with "On Peak" as shown in the NERC glossary of terms? Also the requirements in this requirement are too prescriptive - should allow some flexibility to allow the TP which years to study as long as a minimum number of cases are studied. 14. Suggest replacing "Plant" in R2.6.2 with "Unit" to match terms used in Definitions. 15. In R2.7.1.1, what is meant by "project initiation date"? Is it when engineering starts, construction starts, etc? 16. Suggest rewording requirements R3.3.3 and R3.4 to be more clear - such as breaking each of these into several sentences each. Existing wording is very confusing. 17. There is a concern with R5.6.1 with the requirement to perform simulation on 20 MW generators (to be consistent with the Registration Criteria). We recommend a 75 MW generator cutoff for required simulations. Also in R5.6.2, should last word in sentence be "greater" or "lesser"? 18. In the Tables under Extreme Events, is 3.b. (loss of two TLs on different ROWs actually already covered under 1 (loss of two elements prior to system adjustments)? Also in the Tables under Extreme Events, it may be difficult for a TP to know enough about nuclear plant design to perform studies mentioned under 3.a.vi.

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		19. In the notes under Extreme Events, we suggest that notes #2 and #3 be combined together since they are very similar in nature. 20. Should the P3 planning event descriptor (G+1) in the performance tables be (G+N-1) or (G-1, N-1)? The existing descriptor (G+1) tends to note that an element is being added to the system instead of being removed. 21. Should the new standard address specific voltage limit requirements that must be maintained during these planning events? Since different utilities have different voltage limits on their buses, should there be some consolidation to ensure the standard is applied equally at all utilities? 22. The note for Planning Event P1 states that “No generating unit or units shall be allowed to pull out of synchronism. A generator being disconnected from the System by Fault clearing action or by a Special Protection System is not considered pulling out of synchronism.” The standard does not allow consideration for small units with a Zone 2 fault. It is not practical to add pilot relaying on all lines from a plant with a small unit that would be stable for close-in three phase faults, and could be adequately protected when a Zone-2 fault would cause a small generator to trip off with out-of-step (OOS) protection. The table for P1 should allow small units (<75 MW) to trip using SPS or OOS protection.

Response: The SDT is attempting to raise the bar by developing a standard that appropriately supports BES reliability and has industry consensus. The majority of the SDT believes that 300 kV is an appropriate cutoff and that Transmission Systems above this level represent backbone Systems and are part of regional "grids". The SDT is cognizant of the cost factors involved here and is taking them into consideration in its deliberations and has provided for flexibility in Corrective Action Plans. FERC has noted in their orders that many of the concerns about raising the bar show more concern about economics than reliability (examples, Order 890, paragraph 423; Order 693, paragraph 1792, etc.).

1. The SDT agrees and believes that industry guidance is needed to capture the appropriate dynamic behavior of Loads. In response to comments, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments. Any comments received from the industry on MOD standards will be forwarded to NERC for inclusion into NERC Reliability Standards Development Projects 2010-04 Modeling Data and 2010-05 Demand Data. Requirement R2.4.1 has been modified to include the following: "An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable."

2. The SDT believes that FAC-009-1, Requirements R1 and R2 require that generators provide these low voltage limitations as part of their Facility Ratings. Also, PRC-024, which is under development, will attempt to require generators to meet voltage ride-through criteria.

FERC Order 693, paragraph 1773 regarding FERC Commission directed changes to TPL-002 states "...requires all generators to ride through the same set of Category B and C contingencies as required by wind generators in Order No. 661, or to simulate those generators that cannot ride through as tripping".

The current MOD standards that address steady-state and dynamic simulation data requirements do not explicitly require the Generator Operators to provide voltage ride-through capability. These standards are set to be addressed by Project 2010-04 within NERC's Standards Development Work Plan. Based on the proposed TPL requirement, Requirement R5.3 (now R4.3.2), it is expected that the Transmission Planner would contact Generator Operators applicable to their System to obtain such data. If the data is not provided, it would be expected that a Transmission Planner state its assumption on the Vmin used for a generator

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terminal voltage for assessing ride-through capability. It's likely such information could be obtained through generator manufacturers.

3. Questions related to ATC calculations are beyond the scope of this standard. Please see NERC Reliability Standard MOD 001-1, Requirement R7 & Measure M7 for additional information on ATC calculations.

4. The description of the P5 event has been clarified in this Revision of the Standard.

5. Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these System designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of the TPL-001-1 and most stakeholders and the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement.

6. The SDT believes that the existing language is appropriate. An assessment of year 15 would be needed to accommodate a Transmission line if it takes 15 years to build a line.

7. The SDT has not established a limit as to how long Operating Procedures may be used to meet System performance requirements and has left that decision for the Transmission Planner/Planning Coordinator.

8. By definition, Consequential Load Loss is allowed. To meet industry concern, as well as FERC Order 693, the SDT has added Requirement R2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.8.

R2.8 The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1.

9. The definition of Extreme Events already states that these events have a lower probability of occurrence than Planning Events. The SDT did not make the change suggested by the commenter as there was no industry consensus to alter the definition.

10. The list of Contingencies is expected to cover the Transmission Planner's or Planning Coordinator's System for which they are responsible, including any tie-lines to adjacent Transmission Systems. The standard does not preclude the Transmission Planner or Planning Coordinator to expand the list of Contingencies to include some Contingencies of interest or known impact for adjacent System(s). It is expected that through peer reviews, the Transmission Planner or Planning Coordinator may initially learn of any new event within an adjacent System that impacts their own System.

11. Applicability 4.1.4 has been deleted due to the deletion of Requirements R9 – 14.

12. The SDT believes that it is not necessary to replace "previous" with "most recent" since Planning Assessments are required on an annual basis.

13. The SDT believes that the term "System peak Load" is appropriate. The SDT does not believe that Requirement R2.1.1 is too prescriptive, but is the minimum needed to gauge the timing for System reinforcements in the near-term horizon.

14. This draft of standard has been revised to remove word "plant" from Requirement R2.6.2 (now R2.5.2). Requirement R2.5.2 from the last draft of the

Organization	Question 15:	Question 15 Comments:
standard has been deleted. **R2.5.2** For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: 15. The SDT has not defined a project initiation date and will leave that definition to be determined by the Transmission Planner and/or Planning Coordinator. 16. Most of the industry did not seem to find Requirements R3.3.3 and R3.4 unclear or confusing. Therefore, the SDT has decided to not undertake any rewording. Requirements R3.3.3 and R3.4 have been relabeled as Requirements R4.4 and R4.5 respectively. 17. The requirement for study has been changed to 20 MW for a single generator or for an aggregate of generators. This language is now in Requirement R2.5.2. Requirement R5.5.2 was deleted. 18. The SDT agrees and has removed the redundancy found with Extreme Event 3.b. Having multiple nuclear units out of service simultaneously is an Extreme Event, but it has occurred. The SDT recommends that the Transmission Planner consider sensitivities with different combinations of nuclear plants being out of service, including the possibility that they are all shut down simultaneously. To reinforce the more apparent combinations, the Transmission Planner may discuss the operational requirements and the equipment and design similarities of the nuclear plants with the appropriate Resource Planner or Generator Operator to determine credible scenarios which could commonly affect the nuclear plants. 19. The SDT discussed the combining of notes 2 & 3 but felt they wanted them separate for clarity. Note 2 is focusing on interruptions of Firm Transmission Service and Non-Consequential Load and Note 3 refers to transformer outage events. 20. The SDT has deleted the parenthetical to provide clarity. 21. The SDT has addressed this issue by the Header note 'b' for Steady State Only in Table 1 - Steady State & Stability Performance, where the Planning Coordinator sets the acceptable voltage deviations. The SDT believes that adjacent Planning Coordinators can adequately address this concern. 22. The SDT believes that any unit that is tripped by out of synchronism protection is actually in an "out of synchronism" condition and this should not occur for a P1 event regardless of generator size.		
City Water, Light & Power - Springfield, Illinois	A — Generally support the revised standard	
Response: Thank you for your response.		
Omaha Public	B — Unsure	Event 1 of Category P2 in Tables 1 and 2 addresses events consisting of "Breaker(s) opening without a Fault resulting in a

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Power District	about supporting the revised standard	single ended line." Category P2 is labeled as a "single contingency" category, yet it seems like an event consisting of the opening of more than one breaker would actually be a multiple contingency. Please consider whether the "(s)" should be removed after the word "breaker" in the event description so that it addresses only a single breaker opening without a Fault. Table 1 does not address multiple contingencies consisting of loss of a transmission circuit, transformer, single pole of a DC line, or shunt device, followed by System adjustments, followed by the loss of a generator. It seems like Table 1 should be modified to address this type of multiple contingency. In the description of Event 1 of Category P2 in Table 1, remove the text "Loss of one of the following:". In the description of Event 2 of Category P2 in Table 1, replace "Bus section" by "Loss of a bus section". Assuming that this does not change the intent of the drafting team, in R3.3.2.2, R3.5.1, R5.4.3.1, change "shall be operating" to "are operating". In R3.3.2.2, consider removing the phrase "and within their thermal and voltage limits", because it seems like it may be redundant given the definition of the term "Facility Rating". In the event descriptions of Categories P1, P3, and P6 of Table 2, does the term "3-phase fault" apply to DC lines? If not, consider using a separate introductory phrase with the event descriptions of Categories P1, P3, and P6 of Table 2 that involve DC lines. Also consider removing the words "Loss of" in the description of Event 4 of Category P6 in Table 2. Since a definition was developed for "Bus-tie Breaker", capitalize the terms "bus-tie" and "bus tie" wherever they appear in the standard.

Response: The SDT believes that events which can result in a single line or line section being fed radially from one end must be analyzed to ensure that Load served from the line can be reliably served from either end regardless of station configuration.

The SDT expanded the existing Table 1 description to include the requirement to study the loss of any generator followed by the loss of a transmission element. The SDT made this decision based on the fact that generator outages are more probable and in many cases have longer outage durations than transmission element outages. The SDT considered a requirement to study any outage of a transmission element followed by a generator outage but decided that this would be very burdensome for a lower probability event and therefore, decided not to add it in Table 1 of the draft standard.

P2 - The tables have been combined and the words "Loss of" have been removed.

The SDT agrees. Event 2 in P2 has been modified for clarity.

Requirement R3.3.2.2 has been deleted in favor of Header note ‘e’ in the Table. Please note that the two tables in the second draft have been reduced to one table in the third draft. Requirements R3.5.1 and R5.4.3.1 have been deleted from the Standard.

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The "3-phase faults" does not apply to DC lines. The SDT has revised the Table accordingly. P6 - The tables have been combined and the words "Loss of" have been removed. The final draft will have all defined terms capitalized.		
Progress Energy Carolinas	C — Definitely do not support the revised standard	While be believe that in many ways the proposed draft standard represents an improvement of the current standard, we have a number of significant concerns that preclude our endorsement for the proposed standard as currently drafted. These include those discussed in the comments to above questions and the below additional comments.1) In both the Steady State and Stability Tables, Category P6 is the loss of a system element, following system adjustments, followed by the loss of another element. The table columns for this category say that interruption of firm transmission service is allowed. The table, however, is not clear whether the interruption of firm service is allowed as part of the system adjustment (between the outages) or whether it is only allowed after the second outage. It was stated in the NERC TPL SDT WebEx that the interruption is not allowed as part of the system adjustment. If this is the interpretation, this would be a dramatic change from the existing standard and would result in the unintended consequence of significantly reducing transfer capability of interfaces to a fraction of their currently reported capability. This would in effect be imposing an n-2 criteria for offering firm transmission service. This would not be an acceptable situation for the users, owners and operators of the bulk power system. 2) The proposed sensitivities create significant amount of additional work for the sole purpose of demonstrating compliance to this standard without any demonstratable benefit towards improving system reliability. While sensitivities should be appropriately considered in studies, this standard should not be overly prescriptive with respect to specific sensitivities or study methodologies.
Response: 1. The SDT agrees that clarification regarding treatment of Firm Transmission Service and Non-Consequential Load Loss during adjustment is necessary. Footnote 10 in Draft 3 of the Standard provides this clarification. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. 2. The SDT agrees with the respondent that the sensitivities evaluated should be based on the individual situations and therefore, the SDT has not required specific sensitivities, but rather, required that at least one sensitivity should be evaluated for an Assessment to be complete.		
Platte River Power	A — Generally	In Tables 1 and 2, Categories P1 and P3, under the column heading "Interruption of Firm Transmission Service Allowed," change the note in the performance box to read "Yes, if transfer is dependent on the outaged Element." (Not just for a DC

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Authority	support the revised standard	line Element.) This conditional statement applies to most Firm Point-To-Point Transmission Service (Firm PTP) applications where an outaged Element reduces the Transfer Capability of the PTP service if the Element cannot be restored to service after an allowable time frame (30 minutes or so) and the Transfer Capability is reduced to a Prior Outage System Conditions level. This "extended Contingency situation" could cause an interruption or curtailment to the firm service. The interruption and curtailment responses to a Contingency might be different between Firm PTP and Network Integration Transmission Service.
Response: The SDT has removed the "Yes if transfer is dependent on the outaged DC line" comments from the Table to ensure that AC and DC lines are treated equally. The draft standard does not allow interruption of Firm Transmission Service as a System response to Event P1. However, the SDT added Footnotes # 5 and 10 to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service in preparation for the next Contingency will be allowed provided there is no shedding of firm Load. **Footnote 5** - When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
BCTC	C — Definitely do not support the revised standard	BCTC appreciates the efforts of the SDT to explore ways to improve our planning standards. We understand that some of the proposed enhancements may assist Transmission Planners with justifying the need for system reinforcements. Many areas of our system already meet the proposed improvements, for example, most (but not all) of our 500 kV system already meets the proposed standards for systems above 300 kV. We have planned our system without support from a standard. The proposed changes do not really help us in any way and have a number of undesirable consequences. Consequently, BCTC does not support a number of the proposed additions and is uncertain about supporting some of the other changes. Our concerns are summarized below under headings of System Issues and Study Issues. System Issues:1. BCTC plans, manages and operates 18,000 km of transmission in British Columbia. This includes 5700 km of 500 kV transmission lines. For the BCTC system, the proposed definitions for Consequential Load Loss and Non-consequential Load Loss, specifically that load loss due to RAS/SPS is Non-Consequential Load Loss, will provide no reliability benefits for our 500 kV transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection relative to what we have today. No reinforcements of this 500 kV transmission will be required as a result of these more stringent definitions. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level, primarily in rural areas currently served by radial lines. The possible benefits would be small. There is a very low probability that we would get funding approval for these facilities. For most of our system including most of our backbone 500 kV and local networks in

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		metropolitan and urban areas BCTC already meets the requirements for these definitions. As noted in our comments at item 3, a portion of the BCTC system above 300 kV cannot meet the proposed P1(A) > 300 kV. We require further clarification of these definitions such as allowing load shedding in local networks. Otherwise, we will not be planning a doable/plausible set of actions, but rather just generating a list of projects that will not be approved. Our resulting subsequent corrective plan will be to use load shedding RAS, which will conflict with the definitions. Order 693 does not require NERC to prohibit load shedding, only clarify the amount and duration of load shedding that is permitted (paragraphs 1795 and 1797). BCTC's concerns can be addressed by including the local network component of Footnote (b) - modify the definition of Consequential Load Loss to permit the use of RAS in local networks (including local networks interconnecting generation), by allowing Non-Consequential Load Loss for local networks in Tables 1 and 2, or by modifying the definition of BES to exempt local networks from the definition of BES. BCTC could also consider a limit on load shedding if the industry would develop one. BCTC raised these issues in our comments on the first draft. The SDT response (page 332) does not address our concerns. We also note FPL comment 7 (page 359) regarding removal of localized load reduction provided in Footnote (b). We do not believe that the SDT has addressed FPL's issue. Unless the local network component of Footnote (b) is included and we can get a clarification to address our concern with P1 (A), the proposed standard is not suitable for the BCTC system and we do not support the standard. 2. Contingency P1 needs to permit curtailment of firm service for flow through firm transmission service to prepare for the next contingency. If it does not, some flow through open access transmission customers may have less ATC available if RAS is not available to meet the new restrictions on the P6 contingency, while this ATC will be available for services sourcing or sinking within the transmission provider's system. P6 allows the use of RAS in response to the second contingency (Event). For firm service originating or sinking in our system, we can use RAS and have many RAS systems already in place. However, for flow throughs it may not be possible to implement RAS or there may be a time delay until RAS can be installed. If RAS cannot be implemented, it would be preferable to provide the firm service and curtail in preparation for the second contingency rather than deny the firm service (or require that the system be built for N-2 capability, which also may not be possible), which is what we will have to do to adhere to the new standard. The result is that flow through transactions will have to use non-firm service while non-flow-through may use exactly the same transmission for firm. Also keep in mind that while P4 and P5 are only those multiple contingencies initiated by a common mode failure, P6 is any two elements not necessarily common mode. Therefore, P6 can be more limiting than P4 or P5. For P4 and P5 contingencies the BCTC system has less dependence on RAS than does the second event of a P6. Consequently P6 will be more limiting on flow throughs than P4 and P5. Order 693 contains direction to NERC to address Footnote (b). Some commenters have taken issue with the SDT interpretation of Order 693 (e.g. FRCC item 2, page 365). Given the different interpretations and the potential for impacts on ATC, we suggest that the SDT review this issue with FERC and find out if what the SDT is proposing is what they really want. Without this change or clarification we do not support the standard. 3. Regarding Q30 in the Comments on First Draft, BCTC believes that DC and AC lines should have the same performance requirements with respect to interruption of firm transmission service. This relates to our concern above

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		regarding flow through transactions. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable step to prepare for the next contingency of an AC line. We would ask that the SDT provide further explanation of its response that "many of the transfers over DC lines are automatically curtailed when the DC line is outaged" (page 220). We can do the same with AC lines for transfers sinking or sourcing within our system. Is the SDT assuming that RAS/SPS is used? We agree with the comments of FPL, FRCC, Southern Transmission and Manitoba Hydro (pages 219 and 221) and FPL (page 360, item 11). We disagree with the SDT decision to allow different performance for DC than AC lines. We do not support this element of this standard. 4. Contingency P3 should have the same performance requirement as P6. In two recent CPCN approvals for reinforcements of the BCTC backbone system, approval was granted based on generator contingencies being treated the same as transmission contingencies. We believe it highly unlikely that we would have received funding to approval to meet contingency P3. In our local service areas relying on generation for firm supply and for our bulk system, we consider dependable generator capacity on a case by case basis. We do not arbitrary assume a generator N-1 as a preexisting planning condition. We consider firm generator capability as a sensitivity case, not a planning criteria. We disagree with requiring a generator initial system condition having a more stringent performance requirement than other initial conditions. Without this change we do not support this standard. 5. BCTC is concerned that including the generator runback/tripping requirement in this standard will encourage more use of generator runback and tripping and will make it more difficult to get regulatory approval for transmission reinforcements. If retained, there needs to be a tie into reserves requirements. While we agree with permitting generator runback/tripping, at this time we are unsure about supporting this standard with this permissive requirement included. Study Issues:6. R2.5 and R5.5 on Generating Unit Stability studies are adequately addressed by FAC-001 and 002. Triggering events such as increased output or new existers need to go through our generator interconnection process and be paid for by the customer. In fact, we would not be aware of any of these triggering events unless a request comes from a customer. Without clarification of which generator studies are addressed through FAC-001 first, we do not support this standard. 7. We request that the SDT provide an explanation of why it believes it is important to maintain a distinction between system and generating unit stability studies. 8. Table 1 Steady State Performance lists 6 items above the Planning Events title. Should these be listed below the Planning Events title?
Response: 1. The SDT has added footnote 10 and clarified that for a P1 event, Transmission service could be interrupted as long as all of the Non-Consequential Load continued to be served. This draft does not allow “local network” Load to be shed for a P1 event, however, the conditions that you describe could warrant a regional difference.		

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Footnote #10 – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. 2. Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency. However, until the next Contingency occurs, System performance will need to meet the requirements for Event P1. As such, the proposed standard will not allow loss of any Non-Consequential Load, except for contracted interruptible Loads, in preparation for the next Contingency. 3. The SDT has removed this differentiation in the Table such that AC and DC lines will be treated equally. See footnote #10. 4. The SDT believes that the loss of a generator unit is a much more likely to occur than the loss of other major BES elements and thus the P3 event warrants more stringent performance requirements than the P6 event. The performance requirements for P3 have been clarified by addition of footnote 10 in Revision 3 of the Standard. 5. By a nearly unanimous response the Industry favors manual and automatic generation run-back and tripping as a response to a single or multiple Contingency. The SDT has eliminated the conditions in Sub-requirements R3.5.1, R3.5.2, and R3.5.3 for Contingency events as well as similar conditions in Sub-requirements R5.4.3.1, R5.4.3.2, and R5.4.3.3 for Stability events in the third draft. Accordingly, the SDT has modified Sub-requirement R3.5 for Contingency events and relocated it under Requirement R2.6.1. Likewise, the SDT has modified Sub-requirement R5.4.3 for Stability events and relocated it to become a bullet under R2.6.1. The resource adequacy issues are not directly included in this standard. In addition, with the creation of P3, the SDT has addressed the issue of the reduction of generation resources by treating the loss of one generator unit, followed by System adjustment, as the initial condition for all other single Contingencies. Therefore, the SDT does not believe that generation tripping as a corrective action needs to be tied to resource adequacy issues. Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations. Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations 6. Both Requirement R2.5 and Requirement R5.5 have been deleted since, in response to industry comments, Generating Unit Stability is no longer separately addressed in the standard. 7. Based on comments from others, the SDT has removed the requirements for separate Generating Unit Stability analysis and System Stability analysis. 8. The SDT has reformatted and combined the two Tables into a single Table for this draft to address these types of problems.		
Manitoba Hydro	C — Definitely do	Manitoba Hydro can not accept the standard due to the requirements imposed on Firm Transmission Service and on facilities >300 kV. The standard would have to allow Firm Transmission Service to be curtailed in situations where Non-

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	not support the revised standard	consequential Load is not lost. The higher performance requirements for facilities >300 kV are tied to very low probability events, so the enhanced reliability is not worth the cost. TPL-001-1 Other Comment Action Plan: Schedule of Anticipated Actions needs to be revised. - Action 3 shows rev 3 out for ballot in 2Q09. TPL-00101 Purpose: Is the purpose to ?Establish Transmission System planning performance requirements? or to ?Establish planned Transmission System performance requirements? The term ?probable contingencies? is not defined or used in the standard ? use of the term may cause confusion. R7: The TP and PC are required to determine the responsibilities for performing the assessment. Are the responsibilities to be documented as part of the assessment? R8: This requirement should avoid reference to a FERC order as the order does not apply to all entities. The requirement should just require the planner to demonstrate that the assessment was distributed to potentially impacted stakeholders. The last sentence is incomplete.

Response: In response to your comment and those of others in the industry on allowing curtailment of Firm Transmission Service as a System adjustment after an N-1 Contingency, the SDT has added footnotes 5 and 10 to Table 1 - Steady State & Stability Performance.

Footnote 5 - When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed.

Footnote #10 – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.

The schedule has been updated.

The SDT believes the Purpose is accurate as written because it defines planning practices and conditions to be studied. As per A.3, the purpose of Standard TPL-001-1 is to "Establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies." In this definition, the word probable is left up to the Transmission Planner/Planning Coordinator to determine so that they can set System performance requirements locally based on experience.

R7 (now R6). There is no requirement to document the responsibilities as part of the Assessment but Measure M6 in the new draft clearly states that a document must be produced as evidence that Requirement R6 has been successfully completed. This could be a standalone document or part of the Assessment at the discretion of the responsible entity.

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R8 (now R7): The SDT believes the addition of the reference to the FERC Order 890 adds clarity to the expectations of the requirement without making the requirements of the Order applicable to all NERC entities. The incomplete sentence has been deleted.		
Los Angeles Department of Water and Power	C — Definitely do not support the revised standard	I do not support the standard as currently written. There are too many requirements that are discriminatory, duplicative, and arbitrary/punitive. The unintended consequence of this standard would be forcing companies and planners to plan the system to take advantage of some requirements that will result in a future system that is less robust (a single line serving multiple radial loads instead of network, for example) if not to entiely discourage any further expansion of the transmission system above 300kV (the discriminatory treatment of two classes without any rational justification).
Response: The SDT believes that the appropriate justifications have been made. The SDT changes made after the first draft were due to industry consensus. The SDT believes that these changes are justified by the various comments received from industry.		
Transmission Agency of Northern California	B — Unsure about supporting the revised standard	- We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before we can give a full approval of this Standard. - There is no mention in the purpose of the Sta
Response: Measures, VSL's and the Implementation Plan have been addressed in the third draft of the standard.		
National Grid	B — Unsure about supporting the revised standard	Aside from the comments to the prior questions, there are several issues of concern that prevent us from supporting the present draft of the revised standard. We offer the following constructive comments in an effort to support the worthwhile effort that is being pursued so that we can reach a point of satisfaction that we could vote to support the revised standard. Our concerns are listed in a rough order of priority. a. This standard as drafted does not allow exceptions for small parts of the system as long as interconnected system reliability is maintained, which is allowed in the existing TPL standards in footnotes b) and c) in Table 1. Unless such exceptions are allowed significant transfer restrictions or large reinforcements must be made. The applicable TPL footnotes are: Existing TPL footnote b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers. Existing TPL footnote c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (nonrecallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

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		b. This standard does not address base conditions. Without defining base conditions the initial status of generation dispatch and transfers across the system is ill defined. Therefore the contingency analysis doesn't have a predictable basis for a consistent and repeatable study. c. The reference to Special Protection Systems is completely permissive. Although there are good applications for Special Protection Systems, their use must be constrained to have a reliable system and to promote construction of needed infrastructure. d. This standard does not provide flexibility to shed load, which restricts the ability to control post contingency response for low impact events. This may result in advancing need for upgrades in response to low impact events. This is in conflict with FERC's directive to have the Transmission Provider waiting for market response to transmission needs and having the Transmission Provider provide a role to back stop the market. e. Definition of the Long-Term Planning Horizion. The planning horizon, for assessment purposes should be limited to 10 years. Such an assessment should be sufficient to identify requirements that may take an extended time to implement. f. Definition of Planning Coordinator is part of the NERC Functional Model, Remove from Standard. g. Put headings on each section to identify requirements of section. h. With respect to R2.2 - Delete "current" from the phrase"current System Peak Load study" and replace "study" with "assessment." i. Remove R2.2.1, the requirement to extend the assessment beyond 10 years. What does the length of the project have to do with the assessment? If it takes 15 years to build something, why does this require a review of year 15? What is the purpose of this assessment? j. R3.3.2 requires clarification - This standard needs to permit discretion regarding the single contingencies that need to be tested, similar to R 3.3.3 and R3.4. It is completely unnecessary to test all events. For example, contingencies may be limited to relevant disturbances that are contained within or directly impact the studied system. k. With respect to R3.2.1 - Clarify whether the intent of the standard is to address station service minimum voltage limitation, maximum leading VAR absorption capability or both at steady state. l. Remove R3.2.2 - Relay loadability is addressed in PRC-023 standard. m. With respect to R3.3.2.1 - Recommend the removal of the requirement to assess the expected duration of Consequential Load loss. It's not considered anywhere else in the standard. n. With respect to R3.3.3 - The paragraph refers to Table 1 Contingencies P3 through P7; this should be explicitly stated. Rationale for inclusion of testing should not be required; should only need to explain why certain Contingencies were not tested. This discretion should be applicable to all contingencies.

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		o. With respect to section R5 - The concept of planned and long-term outages should apply to the general Planning Assessment, or not at all. It should not be specific to the Stability Assessment. p. The provisions of Section R.5.3 should have a corresponding MOD standard apply a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertent trip of the generator. Such a provision should include "other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation. q. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizon. r. What is a "current" study?

Response: A. Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these System designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement. As an alternative, an entity could seek an Entity Variance for the situation described through their Regional Entity organization. In paragraph 1794, FERC clarified that "…an entity may seek a regional difference to the Reliability Standard from the ERO for case-specific circumstances". The process described by FERC as a regional difference is described in detail in the "NERC Standards Development Procedure" document under the subsection titled "Variances to NERC Reliability Standards".

B. The SDT has modified Requirement R1 to include additional details on what should be modeled in the cases. However, the SDT intentionally provides flexibility for the Transmission Planner/Planning Coordinator to decide which "base case" to use since initial conditions for a System will vary from region to region and will need to be established on a local level, not via a national standard. The required studies and sensitivity analysis ensures that sufficient study is performed to cover an appropriate range of System conditions.

C. The SDT does not believe that it would be appropriate to attempt to specify limitations to the use of Special Protection Systems in this standard. The proposed TPL-001-1 and existing standards provide adequate guidance to the industry on application of Special Protection Systems.

D. The SDT has made clarifications regarding Firm Transmission Service and Non-Consequential Load Loss. Footnote # 10 has been added to the end of Table 1. The standard does not preclude the possibility of obtaining contractually interruptible load. It is the general opinion of the SDT that dropping of Non-Consequential Load should not be allowed for the Planning Events involving only one element as described in Table 1 of the proposed Standard, and to meet the intent of FERC Order 693. Further, this Standard is proposed to "raise the bar" to improve System reliability, which would require responses (Corrective Action Plans) to address those so-called low-impact events that may have been overlooked or ignored with the existing Standard TPL-002-0.

Footnote #10 – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon,

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Facility Ratings in those regions must be considered.

E. The SDT believes that a review of System conditions beyond the 10-year horizon is warranted. FERC Order 693 requires that the planning horizon take into account the lead times for siting and permitting of new long-distance Transmission lines and other long lead time solutions. The SDT has received industry comments regarding the need to exceed a 10-year horizon to account for longer lead time projects. Establishing planning horizons that are shorter than Transmission lead times may create gaps where the identification of a reliability need to which Transmission may be the best solution occurs too late to avert the identified reliability violation. Further, Operating Procedures or alternative short-term capital projects may be needed to limit the impact of the Planning Event until the planned facilities can be completed. This information needs to be included in the Assessment.

F. The definition for Planning Coordinator was deleted because the term has already been defined and added to the NERC Glossary by another SDT.

G. The SDT also feels that the Tables need to be as clear and concise as possible. To that end, the next version will combine Tables 1 and 2 into one table with a revised format.

H. The SDT believes that the existing language is appropriate.

I. The SDT believes that a review of System conditions beyond the 10-year horizon is warranted under some circumstances. For example, if it takes 15 years to build a Transmission line, then the need for that line would have to be determined 15 years ahead of the in-service date. Therefore, Requirement R2.2.1 requires you to perform an Assessment on year 15 if it takes you 15 years to build a line.

J. The SDT has removed Requirement R3.3.2 and replaced it with additional language in Requirement R3.1. The SDT does agree with your interpretation that it does not require evaluation of all single Contingencies. The SDT specifically states in Requirement R3.4 that those Contingencies that are expected to produce the more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe results.

R3.1 Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 ~~– Steady State Performance.~~ based on the lists created in Requirement R3.4.

K. The SDT has not limited the purpose of this requirement to either minimum acceptable station service voltages or maximum Mvar absorption. The SDT believes that the purpose of Requirement R3.2.1 (now R3.3.2) is to determine if generators could continue to operate or if they would trip off following the Contingency.

L. The SDT believes that relay load limits or loadability need to be considered in the Contingency analyses. The studies should determine if Transmission line loadings could reach the relay loadability level, which may add to the existing Contingency and perhaps, result in an unbounded cascading event.

M. To meet industry concern as well as FERC Order 693, the SDT has added Requirement R 2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.8.

R2.8 The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1.

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N. The SDT has re-written Requirement R3.3 (now Requirement R3.4) to address your initial concern. Although the language and format of the proposed Standard have been revised from earlier versions, the SDT continues to believe that the Transmission Planners should evaluate the System performance for the events that are expected to produce the more severe System impacts, including both single and multi-Contingency events. The wording of new Requirement R3.4 (the old Requirement R3.3.3) now requires a listing of the Contingencies to be evaluated, the rationale for their selection and why the remaining Contingencies would be expected to produce less severe results. This will provide a complete evaluation of the potential Contingencies to be studied – those selected and those excluded.

R3.4 Those Planning Event Contingencies in Table 1 ~~– Steady State Performance not covered in Requirement R3.3.2~~ that are expected to produce more severe System impacts shall be identified~~,~~ and a list of those Contingencies to be evaluated for System performance in Requirement R3.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results.

O. The SDT agrees and has moved this concept within Requirement R1 (see Requirement R1.1.1) so that it is applicable to all planning Assessments. Further, both Requirement R3 and Requirement R5 (now R4) have been revised to make reference to Requirement R1.

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. ~~The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to c~~Contingencies ~~in Table 1 – Steady State Performance.~~ The studies shall be based on computer simulations using models utilizing data provided in Requirement R1.

R4 For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~

P. Requirement R5.3 (now R 4.3.2) has been modified to address simulation of how generators perform under conditions being studied. The current MOD standards that address steady-state and dynamic simulation data requirements do not explicitly require the Generator Operators to provide voltage ride-through capability. These standards are set to be addressed by Project 2010-04 within NERC's Standards Development Work Plan. It is expected that the Transmission Planner would contact Generator Operators applicable to their System to obtain such data. If the data is not provided, it would be expected that a Transmission Planner state its assumption on the Vmin used for a generator terminal voltage for assessing ride-through capability. It's likely such information could be obtained through generator manufacturers. The "Other equipment" is addressed in the revised Requirement R4.3.3.

Q. The SDT agrees and therefore has changed R1.1.1 to state "if specifically known."

R. The SDT believes that a current study is a study that has been completed for the latest Assessment, as opposed to a past study that may have been completed up to five years ago.

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Tenaska, Inc.	A — Generally support the revised standard	A few issues that may need some thought include: Are reactive power devices a responsibility of Resource Planners in R13? On the Extreme Events description for local area, what is a load center? Does the loss of a large body of water as a cooling source result in the immediate loss of generation such that it is a contingency which affects steady state, stability, or short circuit studies?
Response: In response to industry comments, the SDT has removed Requirements R9-R14 and thus eliminated the responsibility of a Resource Planner. The SDT believes that a Load center is a location where energy is delivered by Transmission or sub-Transmission Systems to end-use customers. The loss of a large body of water as a cooling source could cause an immediate loss of generation or could only cause some generation reduction. The Transmission Planner or Planning Coordinator would need to analyze their System in order to determine the proper simulation(s).		
Pacific Gas and Electric Co.	B — Unsure about supporting the revised standard	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. ? There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. ? We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions.? We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with “raising the bar”. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. As mention in comments to Q3 above, some local network customer

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Public Service Company of New Mexico	C — Definitely do not support the revised standard	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. ? There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. ? We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions.? We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with ?raising the bar?. Local Network load should be included in Consequential Load and the loss

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Puget Sound Energy, Inc.	C — Definitely do not support the revised standard	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before PSE can give a full approval of this Standard. There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting

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Idaho Power	B — Unsure	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures,

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Company	about supporting the revised standard	VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard.? There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability.? We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions.? We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with ?raising the bar?. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level.? As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms ?interruption of firm transmission service?, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what “Firm Transmission Service” means. Two points, 1) the NERC definition states ?highest quality service offered to customers under a filed rate schedule that anticipates no planned interruption.? The Standard implies anticipation of “unplanned” interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order 890, or firm transfers modeled for the conditions being studied? One way Comment Form for 2nd Draft of Standard TPL-001-1Assess Transmission Future Needs (Project 2006-02)Page 12 of 12to interpret the intent is the firm transfers being modeled for the conditions in the powerflow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption

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SMUD	C — Definitely do not support the revised standard	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before giving a full approval of this Standard. ? There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. ? We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rata curtailments of firm transmission rights during forced and planned outage conditions.? We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with ?raising the bar?. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. ? As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of trade offs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms ?interruption of firm transmission service?, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular

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Sierra Pacific Power Company / Nevada Power Company	B — Unsure about supporting the revised standard	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions. We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with ?raising the bar?. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these

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Black Hills Corporation	B — Unsure about supporting the revised standard	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before a full approval of this Standard can be given. There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions. We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load

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Tucson Electric Power Company	C — Definitely do not support the revised standard	The Standard as presented is clearer, but there are numerous issues that still need resolution. There should be no distinction in voltage classes for allowing or not allowing controlled load shed for applicable events. We support the use of load shed for events at voltages greater than 300 kV where load shed is allowed for the same type of event for voltages below 300 kV. We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. ?

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		There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. ? We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions.? We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with ?raising the bar?. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. ? As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms ?interruption of firm transmission service?, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what ?Firm Transmission Service? means. Two points, 1) the NERC definition states ?highest quality service offered to customers under a filed rate schedule that anticipates no planned interruption.? The Standard implies anticipation of ?unplanned? interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order 890, or firm transfers modeled for the conditions being studied? One way to interpret the intent is the firm transfers being modeled for the conditions in the powerflow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption of firm transmission service should also be allowed for P1 through P5 contingencies in the table. In addition, we believe that DC and AC lines should have the same performance requirements with respect to interruption

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		of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines can automatically be curtailed when the line is outaged.
Tri-State G&T	C — Definitely do not support the revised standard	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. ? There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. ? We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions.? We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with ?raising the bar?. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. ? As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms ?interruption of firm transmission service?, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what “Firm Transmission Service” means. Two points, 1) the NERC definition states ?highest quality service offered to customers under a filed rate schedule that

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		anticipates no planned interruption.? The Standard implies anticipation of "unplanned" interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order 890, or firm transfers modeled for the conditions being studied? One way to interpret the intent is the firm transfers being modeled for the conditions in the powerflow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption of firm transmission service should also be allowed for P1 through P5 contingencies in the table. In addition, we believe that DC and AC lines should have the same performance requirements with respect to interruption of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines can automatically be curtailed when the line is outaged.
ColumbiaGrid	A — Generally support the revised standard	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution. There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions. We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with "raising the bar". Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a

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		local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Interruption of firm transmission service does not mean that firm load is not served. If there is other generation in the system that could increase to meet the firm load requirements if the firm transfer being modeled is interrupted, then interruption of firm transmission service should be allowed for P1 through P5 contingencies in the table. In addition, we believe that DC and AC lines should have the same performance requirements with respect to interruption of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines should be allowed to be curtailed when the line is outaged.
Southern California Edison	B — Unsure about supporting the revised standard	Our Response is (B) and (C).We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions. We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with “raising the bar”. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a

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		result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms “interruption of firm transmission service”, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what “Firm Transmission Service” means. Two points, 1) the NERC definition states ?highest quality service offered to customers under a filed rate schedule that anticipates no planned interruption.? The Standard implies anticipation of “unplanned” interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order 890, or firm transfers modeled for the conditions being studied? One way to interpret the intent is the firm transfers being modeled for the conditions in the powerflow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption of firm transmission service should also be allowed for P1 through P5 contingencies in the table. In addition, we believe that DC and AC lines should have the same performance requirements with respect to interruption of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines can automatically be curtailed when the line is outaged.
Alberta Electric System Operator	C — Definitely do not support the revised standard	We agree that the Standard as presented is clearer, but there are numerous identified issues that still need resolution, in addition to the Measures, VSLs, Implementation Plan, etc., before AESO could give a full approval of this Standard. – There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. – We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions.- We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with ?raising the bar? for loss of Facilities with operating voltages 300 kV or higher (P2, P4, and P5 in the Performance Tables). We believe there should be no distinction between the voltage classes.-

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		Regarding the terms ?interruption of firm transmission service?, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what ?Firm Transmission Service? means. Two points, 1) the NERC definition states ?highest quality service offered to customers under a filed rate schedule that anticipates no planned interruption.? The Standard implies anticipation of ?unplanned? interruption for certain contingencies. 2) Is this referring to a transmission product, or firm transfers modeled for the conditions being studied? One way to interpret the intent is the firm transfers being modeled for the conditions in the powerflow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption of firm transmission service should also be allowed for P1 through P5 contingencies in the table.- In addition, we believe that DC and AC lines should have the same performance requirements with respect to interruption of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines can automatically be curtailed when the line is outaged.
US Bureau of Reclamation	C ? Definitely do not support the revised standard	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard.? There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability.? We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions.? We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with ?raising the bar?. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for

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		high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level.? As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms ?interruption of firm transmission service?, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what “Firm Transmission Service” means. Two points, 1) the NERC definition states ?highest quality service offered to customers under a filed rate schedule that anticipates no planned interruption.? The Standard implies anticipation of ?unplanned? interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order 890, or firm transfers modeled for the conditions being studied? One way Comment Form for 2nd Draft of Standard TPL-001-1Assess Transmission Future Needs (Project 2006-02) Page 12 of 12to interpret the intent is the firm transfers being modeled for the conditions in the powerflow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption of firm transmission service should also be allowed for P1 through P5 contingencies in the table. In addition, we believe that DC and AC lines should have the same performance requirements with respect to interruption of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines can automatically be curtailed when the line is outaged.

Response: Measures, VSL's, and the Implementation Plan will be addressed in the next draft of the standard.

The NERC standards are based on deterministic principles. Probability is considered in a high level perspective as a means of rationalizing the inclusion of various deterministic events; however it is difficult to discuss probability in this context without creating misunderstandings. The SDT recommends that you review the NERC definition of Adequate Level of Reliability (ALR), which is the reliability goal for all NERC standards. In response to your comment and those of others in the industry, the SDT has proposed differentiating between loss of firm Load and loss of Firm Transmission Service. This differentiation is provided in footnotes 5 and 10 to Table 1 - Steady State & Stability Performance. In the event that loss of Firm Transmission Service is inadequate, the SDT believes that there are alternatives to loss of Load or construction. For example, companies may contract with interruptible Load and shed customers voluntarily.

Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these System designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that that interruption of Non-Consequential Load is not

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permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement. Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency. However, until the next Contingency occurs, System performance will need to meet the requirements for Event P1. As such, the proposed standard will not allow loss of any Non-Consequential Load, except for contracted interruptible Loads, in preparation for the next Contingency. "Firm Transmission Service" is a NERC defined term and is also addressed by FERC in OATT. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. The SDT has removed this differentiation in the Table such that AC and DC lines will be treated equally.		
Gainesville Regional Utilities	C — Definitely do not support the revised standard	First, a starting point for the study process (base case) needs to be better defined even if the intent was to allow the TP's & PC's to make the decision. The standard should describe the rules to properly conduct a base case study within each region. This should support any following analysis studies and their finding since you will be starting from the same set of system elements operating at a base condition. Secondly, this standard should focus on what is best for the customer considering 1) the probability of the contingency events, 2) the potential expense to the customer for practically NO improvement in BES reliability, and 3)the extraordinary added burden on the smaller utilities to run additional, no added value studies with documentation to meet an exhausted detailed audit with the potential for penalties probably not proportioned to the utilities revenue stream.
Response: The SDT has modified Requirement R1 to include additional details on what should be modeled in the cases. However, the SDT intentionally provides flexibility for the Transmission Planner/Planning Coordinator to decide which "base case" to use since initial conditions for a system will vary from region to region and will need to be established on a local level, not via a national standard. The required studies and sensitivity analysis ensures that sufficient study is performed to cover an appropriate range of System conditions. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations. The SDT has retained the basis of the previous standard and raised the bar in some respects. While the performance requirements must be met, they do not necessarily mandate a solution. Considerable flexibility in Corrective Action Plans allows for economic considerations. The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus. The SDT is cognizant of the cost factors (including ROW) involved here and is		

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taking them into consideration in its deliberations.		
Lakeland electric	B — Unsure about supporting the revised standard	Suggested changes listed below to more directly address what I think is the intent of the item: Planning Events: Events that require Transmission system performance requirements to be met. Comment: I think that this suggested revision better defines a Planning Event and how they may be used in a study or assessment. Revision to: Planning Events Planning Events: Simulated events that are modeled to test the Transmission system's ability to meet performance requirements. R2.6.2. For steady state, short circuit, Generating Plant Stability, or System Stability analysis: the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Comment: the requirement as stated leaves one guessing about the usability of a study that may have included the changes that occurred in the intervening period. Changes that were studied but not implemented could also invalidate a study they were included in. Revision to R2.6.2R2.6.2. For steady state, short circuit, Generating Plant Stability, or System Stability analysis: the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that were not included in the original study but have occurred in the intervening period and would impact the study area results.
Response: The SDT did not incorporate the commenter's suggested change and the Planning Event definition remains the same as in Draft 2. The SDT believes the stated definition more correctly indicates the intent that for Planning Events the performance requirements must be met, not simply that simulations need to be completed to indicate if the performance requirements are met or not. The SDT does not agree with your comment and believes that the cancellation of a planned Facility that was included in prior models would be a material change to the network model and therefore would not allow the past study to support the Planning Assessment. The key phrase within the requirement is "the study", therefore, the intent is model simulation changes and not limited only to real physical System changes. Therefore, the SDT believes the instance raised by the commenter is adequately covered.		
JEA	C — Definitely do not support the revised standard	The inability to curtail Firm Transmission Service under P6 assessments in preparation for the next N-1 event. Also, under P1 and lower probability contingency events, JEA recommends a standard requirement that allows for the loss of Non-Consequential load during short term periods (suggest allowing up to 3 year minimum) where the system load growth has caused post-contingency remedial action plans to not be completely affective in bringing the Facility(ies) within normal operating limits. As a specific theoretical example, lets say a 10 year assessment shows load growth causing this situation in year 5, but in year 7 generators are added to the area of concern and the issue is resolved, but in year 6, Non-consequential load is required to be shed, do we still need to propose a capital improvement project?
Response: The SDT agrees that clarification regarding treatment of Firm Transmission Service and Non-Consequential Load Loss during adjustment is		

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necessary. Footnote 10 in the Revision 3 of the Standard provides clarification. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. The proposed standard does not require capital improvements, but it does require the performance metrics to be achieved. Certainly there will be circumstances where the addition of Transmission or generation facilities may be the only practical solution. For the specific example that you described, if there were no acceptable Operating Procedures to bridge the time period before the generator comes on line, entering into interruptible Load contracts would be another option. The standard does not preclude such actions.		
PacifiCorp	A — Generally support the revised standard	We generally agree with the Standard as presented so far, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce.
Response: Measures, VSL's, and the Implementation Plan will be addressed in the next draft of the standard. The SDT agrees that clarification regarding treatment of Firm Transmission Service and Non-Consequential Load Loss during adjustment is necessary. Footnote 10 in the Revision 3 of the Standard provides clarification. Requirement R3.3.2.2 has been deleted in favor of Header note 'e' in the Table. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
ITC Holdings: ITC, METC, ITC Midwest	B — Unsure about supporting the revised standard	ITC and ITC Midwest biggest concerns are some missed opportunities to "raise the bar". We believe the draft standard is a significant improvement over existing standards which are largely fill-in-the-blank. However, we have some concerns regarding some of the language wherein CAPs are not required, even though a performance requirement has been violated. For example, providing for a bare minimum sensitivity study and not requiring a CAP based on a performance violation may increase operational awareness but does not ?raise the bar? or improve transmission performance. Allowing for non-consequential load loss following a shutdown and contingency might be an acceptable real time operating

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		procedure but is not a significant advancement on a transmission planning basis. Frequently, operating procedures like this should lead to a planning solution, particularly above 300kV
Response: The SDT translated the existing TPL standards, added clarity, and "raised the bar" in areas where the SDT believes are merited. Even though the existing TPL standards do not address sensitivities, the SDT has added a requirement to complete at least one additional sensitivity. The SDT believes that it is important and valuable for the Transmission Planner and Planning Coordinator to run significant sensitivities and share the results with their neighbors. The SDT did not limit when Operating Procedures, other than Non-Consequential Load loss, could be utilized. The SDT believes that it is important for the Transmission Planner and Planning Coordinator to determine when an Operating Procedure can be utilized and when new Facilities need to be constructed. A Corrective Action Plan is required for all performance violations of all Planning Events in Table 1, except, as you have noted for sensitivity study performance violations. The SDT concurred with the FERC orders that sensitivity study results do not necessarily result in a Corrective Action Plan. From paragraph 1704 of Order 693: "The Commission notes that it is not the purpose of sensitivity studies to identify remedial actions, but, as stated in the NOPR, if different scenarios that lead to criteria violations are probable they require mitigation plans…… In any case, we are not requiring the construction of additional facilities." While the standard does not "require" a Corrective Action Plan, it does not preclude a Corrective Action Plan, particularly if it meets FERC requirements for a "mitigation" plan if the Planning Events are "probable". The majority of the SDT, based on industry comments, did not feel that Non-Consequential Load loss should be precluded from N-1-1 events. A Corrective Action Plan is not required if Non-Consequential Load loss is allowed under local criteria but the standard does not prevent local criteria from prohibiting Non-Consequential Load loss for N-1-1 events.		
Hydro-Quebec Transenergie (HQT)	C — Definitely do not support the revised standard	This standard as drafted does not allow exceptions for small parts of the system as long as interconnected system reliability is maintained, which is allowed in the existing TPL standards in footnotes b) and c) in Table 1. Unless such exceptions are allowed significant transfer restrictions or large reinforcements must be made. The applicable TPL footnotes are:? Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.? Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (nonrecallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.? This comment form did not allow for the following items to be addressed:? a. Definition of the Long-Term Planning Horizon. The planning horizon, for assessment purposes should be limited to 10 years. Such an assessment should be sufficient to identify requirements that may take an extended time to implement.? b. Definition of Planning Coordinator is part of the NERC Functional Model, For consistency it should be removed from the Standard.? c. We propose that the Standard be subdivided by subjects into 4 different Standards : ? TPL-001-1: Modeling and System Assessment (R1, R2, R9 to R14)? TPL-002-1: Short circuit and Steady State Performance (R3, R4)? TPL-003-1: Stability Performance (R5)? TPL-004-1: Coordination (R6, R7, R8)? If the previous proposition is not retained, at least the Standard

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		Requirements should be organized by topics (Modeling, Assessment, Coordination, etc.) and headings put on each section to identify requirements of section. Add headings to the tops of the subsequent pages in the performance tables. Headings only appear on the first page at the beginning of the Table.? d. With respect to R2.2 - Delete "current" from the phrase" current System Peak Load study" and replace "study" with "assessment."? e. Remove R2.2.1, the requirement to extend the assessment beyond 10 years. What does the length of the project have to do with the assessment? If it takes 15 years to build something, why does this require a review of year 15? What is the purpose of this assessment?? f. R3.3.2 requires clarification - This standard needs to permit discretion regarding the single contingencies that need to be tested, similar to R 3.3.3 and R3.4. It is unnecessary to test all events. For example, contingencies may be limited to relevant disturbances that are contained within or directly impact the studied system.? g. With respect to R3.2.1 - Clarify whether the intent of the standard is to address station service minimum voltage limitation, maximum leading VAR absorption capability or both at steady state.? h. Remove R3.2.2 - Relay loadability is addressed in PRC-023 standard.? i. With respect to R3.3.2.1 - Recommend the removal of the requirement to assess the expected duration of Consequential Load loss. It's not considered anywhere else in the standard.? j. With respect to R3.3.3 - The paragraph refers to Table 1 Contingencies P3 through P7; this should be explicitly stated. Rationale for inclusion of testing should not be required; should only need to explain why certain Contingencies were not tested. This discretion should be applicable to all contingencies.? k. With respect to section R5 - The concept of planned and long-term outages should apply to the general Planning Assessment, or not at all. It should not be specific to the Stability Assessment. ? l. The provisions of Section R.5.3 should have a corresponding MOD standard apply a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertent trip of the generator. Such a provision should include "other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation.? m. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizon. ? n. In both Table 1 and Table 2, note 3, "variable frequency transformers" should be removed from the last sentence. A new sentence should be added for reference voltage as it applies to "variable frequency transformers" and "back-to-back" facilities.

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Response: Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these System designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of the TPL-001-1 and most stakeholders and the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement.

A. The SDT believes that a review of System conditions beyond the 10-year horizon is warranted. FERC Order 693 requires that the planning horizon take into account the lead times for siting and permitting of new long-distance Transmission lines and other long lead time solutions. The SDT has received industry comments regarding the need to exceed a 10-year horizon to account for longer lead time projects. Establishing planning horizons that are shorter than Transmission lead times may create gaps where the identification of a reliability need to which Transmission may be the best solution occurs too late to avert the identified reliability violation. Further, Operating Procedures or alternative short-term capital projects may be needed to limit the impact of the planning event until the planned Facilities can be completed. This information needs to be included in the Assessment.

B. The definition for Planning Coordinator was deleted because the term has already been defined and added to the NERC Glossary by another SDT.

C. The SDT agrees with FERC Order 693 in aggregating all of the planning requirements into a single standard. The SDT also feels that the Tables need to be as clear and concise as possible. To that end, this version combined Tables 1 and 2 into one table with a revised format. The Planning Events are shown on one page so repeating the headings will not be needed.

D. The SDT believes that the existing language is appropriate. No change made.

E The SDT believes that a review of System conditions beyond the 10-year horizon is warranted under some circumstances. For example, if it takes 15 years to build a Transmission line, then the need for that line would have to be determined 15 years ahead of the in-service date. Therefore, Requirement R2.2.1 requires you to perform an Assessment on year 15 if it takes you 15 years to build a line.

F. The SDT has removed Requirement R3.3.2 and replaced it with additional language in Requirement R3.1. The SDT agrees with your interpretation that it does not require evaluation of all single Contingencies. Rather, the SDT specifically states in Requirement R3.4 that those Contingencies that are expected to produce the more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe results.

R3.1 Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 ~~– Steady State Performance.~~ based on the lists created in Requirement R3.5.

G. The SDT has not limited the purpose of this requirement to either minimum acceptable station service voltages or maximum Mvar absorption. The SDT believes that the purpose of Requirement R3.2.1 (now R3.3.2) is to determine if generators will be able to operate or trip off following the Contingency.

H. The SDT believes that relay load limits or loadability needs to be considered in the Contingency analyses. The studies should determine if Transmission line loadings could reach the relay loadability level which may add to the existing Contingency and perhaps, result in an unbounded cascading event. No change made.

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I. By definition, Consequential Load Loss is allowed. To meet industry concern as well as FERC Order 693, the SDT has added Requirement R2.~~-~~8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.8. **R2.8** The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1. J. The SDT agrees that the rationale should be for all Planning Events but not for Extreme Events. K. The SDT agrees and has moved this concept within Requirement R1 (see Requirement R1.1.1) so that it is applicable to all planning assessments. Further, both Requirements R3 and R5 (now R4) have been revised to make reference to Requirement R1. **R1.1.1** Planned outages of generation and Transmission Facilities, if specifically known. **R3**. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. ~~The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to c~~Contingencies in Table 1 ~~– Steady State Performance.~~ The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. **R4** For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~ L. Requirement R5.3 (now R4.3.2) has been modified to address simulation of how generators perform under conditions being studied. "Other equipment" is addressed in Requirement R5.4. **R4.3.2** ~~Studies shall consider~~ Simulate generator performance under anticipated conditions including how the voltage ride through capability ~~of all generators and identify how the generators are treated~~ is analyzed~~in the simulation~~ M. While planned outages are addressed in the operating horizon, it is important that a Transmission Planner review the ability of its System to accommodate planned (maintenance) outages. Additionally, any specific known Facility outages need to be appropriately modeled for the planning horizon studied. N. Tables 1 and 2 have been combined into one table for the next posting. The SDT believes that it has adequately addressed "variable frequency transformers" as well as "back-to-back" facilities by including it in the same note as other transformers (Note #3).		
Progress Energy Florida, Inc.	C — Definitely do not support the revised	PEF considers the draft TPL Standard in its present state to be infeasible, unnecessary, burdensome and inferior to the existing Standards. The basic approach to equate reliability of the BES to whether or not Firm Transmission Service and/or Non-Consequential Load Loss can be sustained is an erroneous approach, is not justifiable, infringes upon

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	standard	regulation already in place as part of dealings with the Florida Public Service Commission (PSC), and infringes upon requirements in the OATT. Given the numerous concerns PEF has with the revised draft Standard, expounding on those concerns requires extensive documentation. We therefore cannot reduce our concerns down to a single issue, nor can we single out a single requirement or set of requirements as the top concern, other than to say that the entire Standard development process either needs to be discontinued or the SDT should provide detail as to how much consideration would be given to transmission systems with historically excellent reliability via a variance process. The following is a list of PEF's primary concerns with the revised draft Standard and explanation as to why the Standard development process should be discontinued: 1. PEF has planned to, and demonstrated compliance with, the existing TPL Standards for several years now. PEF is intimately familiar with the existing Standards, and has done an excellent job in planning the PEF system, in conjunction with the other Transmission Owner members of FRCC, non-FRCC adjacent Transmission Owners, and all requestors of Transmission or Generator Interconnection Service using the existing TPL Standards. PEF thus believes that history has shown, particularly within the realm of PEF's Transmission Planning boundaries, that the existing four TPL Standards are not inadequate or inferior in any way. Statements in recent months alluding to the existing Standards? inferiority, confusing language or language subject to opposing interpretations, do not hold up when applied to the PEF and FRCC systems. PEF thus does not believe the Standards require modification. 2. PEF, through its aforementioned participation with FRCC and through its interaction and compliance with regulation by the Florida PSC, has historically demonstrated excellent Transmission Reliability, and can provide documentation to that effect through FRCC and Florida PSC channels. PEF therefore again asserts that modification or increased stringency in the TPL Standards is not merited. 3. The development of TPL-001-1 stems from a fundamental misinterpretation of the intent of FERC Order 693. NERC for the most part, rather than "clarify" or "consider" various matters raised by FERC, chose to accept all suggestions. Specifically, PEF notes the following misinterpretations regarding Order 693:a) In Paragraph 1692, the Commission agreed with one particular utility's assertion that integrating the four existing TPL Standards into a single standard would be an improvement, and directed NERC to "consider" this. NERC, rather than considering this, formed the SDT, which appears to have spent little considering the issue but rather have deemed it a foregone conclusion that the four existing TPL standards must be abolished and a new standard must be written. b) In Paragraphs 1694 and 1706, the Commission recognizes the significant differences in the various transmission systems, and the impossibility of developing a standardized list of "sensitivities" of critical operating conditions that every Transmission Planner and Planning Coordinator must analyze, regardless of their applicability. The Commission therefore stated that it is reasonable for planning entities to have a means to identify an appropriate range of critical operating conditions, without having to anticipate ?every conceivable critical operating condition.? They furthermore state that their conclusion on the whole matter is that ?only those deemed to be significant need to be assessed?. PEF agrees, and thus is perplexed by the erroneous developments in Requirements R2.4, R2.5, R5.4, R5.5, R2.1.3 and R2.1.4. PEF has

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		addressed the inadequacies of these Requirements in the answers to Questions 2 and 10. c) In Paragraph 1704, the Commission, amongst other statements, states that they ?are not requiring the construction of additional facilities?. This general statement made by the Commission is demonstrated to be untrue upon examining the realities of the Standard development process. FERC, by directing NERC to consider various clarifications and/or improvements to the TPL Standards, has set in motion a process which will prohibit either Interruption of Firm Transmission Service or the loss of Non-Consequential Load for various outage scenarios, effectively necessitating the construction of redundant facilities. FERC's statement conflicts with the ongoing process in a major way, and PEF respectfully requests that the SDT confer with appropriate FERC personnel to get clarification on this matter. d) In Paragraph 1725, the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy. PEF does not disagree with the specifics of analyzing events with respect to spare equipment, except to the extent that the Commission appears to think that such analysis is not adequately covered in the existing TPL Standards. PEF believes that the existing TPL Standards adequately address this issue and all other issues pertaining to the planning of a transmission system. Furthermore, the process is to be followed ?consistent with the entity's spare equipment strategy?, thus deferring to the processes and judgment of the individual Transmission Owners, which calls into question the need to include it in the draft Standard. For additional discussion on this issue, see the answer to Question 5 with regard to Requirement R11. e) In Paragraph 1782, PG&E points out the contradiction that FERC creates in Paragraph 1796 by directing NERC to remove the 2nd sentence of footnote (b). The contradiction also involves key statements made by the Commission in Paragraph 1788. For a more detailed explanation of this contradiction, see the answer to Question 11. f) Paragraph 1794 is part of the Commission Determination section. The Commission states its belief that no TPL Standard should allow an entity to plan for the loss of non-consequential load in the event of a single contingency. The Commission then directs NERC to "clarify the Reliability Standard.", and furthermore state that any Transmission Planners or Planning Coordinators seeking to plan for the loss of non-consequential load in the event of a single contingency can make their comments known through a) filing comments in the standards development process, or b) filing for a regional difference for case-specific circumstances. PEF points out that the Commission merely stated their belief and directed NERC to clarify the Standard. They did not order NERC to change the Standard to reflect its beliefs. NERC, while having the leeway to question FERC's approach in this Paragraph, did not question the approach, but rather deferred to the suggestion in Paragraph 1794 (as well as nearly every other suggestion or request for clarification) that FERC made. PEF is concerned that NERC and the SDT appear to be limiting the extent to which they question or make suggestions to FERC. PEF at present will take the approach of stating the prudency and need to plan for the curtailment of Firm Transmission Service and loss of non-consequential load in the event of a single contingency through the comments process. PEF, however, reserves the right to consider the variance approach or legal approaches, depending on further iterations in the development of the Standard. g) In Paragraph 1795, "The Commission" suggests that the ERO consider developing a ceiling on the amount and duration

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		of consequential load loss that will be acceptable. If the ERO determines that such a ceiling is appropriate, it should be developed through the ERO's Reliability Standards development process.? To this effect, the SDT drafted Requirement R.3.3.2.1, which at present states ?Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment.? PEF asserts that this issue is under the jurisdiction of the State Public Service Commissions, who are already doing an excellent job in regulating Consequential Load Loss as part of SAIDI/CMI requirements. FERC and NERC are overstepping their bounds of jurisdiction by attempting to essentially ?double-regulate? an issue that is already adequately regulated via the States. PEF furthermore objects to Requirement R.3.3.2.1 on the grounds that duration of events cannot be estimated with any reasonable degree of accuracy. To handle the challenges of this issue by stating a long-duration worst-case scenario for each outage would be inaccurate, and would tend to foster needless scrutiny and concern on any and all outages associated with Consequential Load Loss. h) In Paragraph 1796, "The Commission" directs the ERO to modify the second sentence of footnote (b) to clarify that manual system adjustments other than shedding of firm load or curtailment of firm transfers are permitted to return the system to a normal operating state after the first contingency, provided these adjustment can be accomplished within the time period allowed by the short term or emergency ratings.? The Commission directed the ERO only to make modifications on the 2nd sentence of footnote (b). The SDT in the draft TPL Standard has eliminated footnote (b) altogether. PEF is surprised and disappointed at the response by FERC to PG&E's very correct assertion that eliminating the allowance of shedding of firm load or curtailment of firm transfers from footnote (b) contradicts the allowance made in footnote (c) regarding C.3 events. FERC's only response was to state that ?manual adjustments referred to in both cases [i.e. Category B and Category C.3 events] apply after the first N-1 contingency?. The fallacy of this statement is that shedding of firm load or curtailment of firm transfers is allowed by footnote (c) for C.3 events, and that every Category B event is by default the first part of a Category C.3 event. PEF asserts that FERC, and consequently the NERC SDT, has created a draft Standard that contradicts direction and suggestion in Order 693 regarding this issue. PEF furthermore asserts that curtailment of Firm Transmission Service or Non-Consequential Load are not valid benchmarks for assessing the reliability of the BES. For additional comments on this issue, see the answer to Question 11. i) Regarding Paragraph 1833, the paragraph in its entirety states: ?MidAmerican states that it supports the proposal to modify TPL-004-0 to require identification of options for reducing the probability or impacts of extreme events that cause cascading. Accordingly, for the reasons cited in the NOPR, the Commission directs the ERO to modify the Reliability Standard to make this modification to the Reliability Standard.? PEF does not understand what FERC has directed on this matter. Furthermore, PEF does not understand the meaning or requirements behind the entire ?Extreme Events? section in the draft Standard, which appears to have resulted from the direction in this particular Paragraph. FERC wants NERC to modify the Standard to ?require identification of options for reducing the probability or impacts of extreme events that cause cascading.? This statement is vague, confusing and does not appear to mandate anything. PEF therefore requests that language in TPL-001-1 to this effect be removed. Furthermore, in Paragraph 1834, the Commission, regarding its preference to expand TPL-004-0 to include analysis of more events such as hurricanes, ice storms, successful cyber

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		attacks, etc., directs NERC to ?expand the list of events with examples of such events identified above.? This request, similar to Paragraph 1833, does not appear to direct NERC to make specific directions in a Standard. If it was FERC's intent that TPL-004 or its successor be modified to include some or all of FERC's suggested events, and to expand the list further, PEF has many concerns concerning this. The direction in Paragraph 1834 has resulted in the aforementioned Extreme Events section, which contains a note 1 referring to Requirement R3.4. PEF has multiple questions and concerns with the language in this Requirement. The Requirement as worded appears to mandate that Transmission Planners and Planning Coordinators must find the most severe Extreme Event scenarios that can be conceived. Such wording would define any reasonable limit as to which Extreme Events are likely and worthy of analysis, and which are not. Furthermore, many of the events suggested by FERC, such as loss of a large gas pipeline, wildfires, hurricanes, tornadoes, cyber attacks, etc., cannot reasonably be studied. To make any assessment of these events that even approached a level of thoroughness is infeasible, and furthermore has no significant benefit. PEF requests that the SDT point out to FERC that these events cannot be studied, and therefore need to be excluded from any TPL Standard. 4. The main approach of the draft TPL Standard consists of whether to allow or disallow load loss for certain outage scenarios (the most problematic Event categories being P1, P2.2, P2.3, P3, P4, P5 and P6), an approach to which PEF is opposed, and furthermore believes that level of service to retail load is not an issue that NERC/FERC should be regulating. The local utility commissions (the Florida PSC, etc.) have already set in place processes for reviewing/approving the level of transmission built to support the level of service to load, and thus FERC and NERC inappropriately attempt to regulate an issue which the States already adequately regulate. PEF can, and has demonstrated in its internal planning assessments and in assessments performed with FRCC that load curtailment and/or Firm Transmission Service curtailment do not adversely impact the reliability of the BES. In fact, certain post-contingency scenarios can be shown to demonstrate that such curtailments actually promote reliability and a speedier, safer, more efficient recovery of the BES after an event. 5. Several Event categories as presently defined in the draft TPL Standard present outage scenarios on the PEF system for which implementation of redundant transmission facilities would be required, at an exorbitant cost to ratepayers. The redundancy requirements at PEF's 500 kV, 230 kV and 115 kV Substations are numerous, and have not yet been comprehensively quantified, although this analysis is underway. One scenario for which PEF is already certain that redundancy of the 500 kV system would be required is the apparent disallowance of curtailment of Firm Transmission Service or Non-Consequential Load as part of ?System Adjustments? in between the two events of P6. PEF again would point out that no definition of ?System Adjustments? exists at present, and the SDT therefore must define it if compliance is expected. Be that as it may, PEF's 500 kV redundancy projects would clearly cost many billions of dollars, with extremely little benefit. PEF would furthermore point out that this is but one example requiring unnecessary Transmission upgrades, and that further analysis will potentially reveal several more Event categories in Tables 1 and 2 for which additional cost-prohibitive and unneeded projects would be mandated. 6. PEF is surprised and disappointed that neither FERC nor NERC have accepted any responsibility to alert the public or the State and local governments to this process. The public have not been involved in the development of the draft

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		standard, nor have they been informed that they would bear the financial impact of the increased stringency. In fact, The SDT on p. 369 of the 1st draft Comments Document has stated that ?This is a performance based reliability standard and does not and should not consider economics.? PEF considers this statement to be reckless and irresponsible, and does not accept FERC's and NERC's apparent position that they have no responsibility in this matter. The fact that the draft Standard and FERC Order 693 can be downloaded by anyone from FERC's and NERC's websites does not constitute a sufficient good-faith notice of this process to the public. PEF requests that FERC and NERC specifically address this issue by explaining their failure to involve and inform the public. Assigning this responsibility to each Transmission Planner and Planning Coordinator is not acceptable. FERC and NERC have set this process in motion, and as creators of the process owe an explanation to those who would "foot the bill" for the process. 7. The low voltage threshold of jurisdiction of the draft Standard, previously defined in NERC's definition of the BES as 100 kV, is not specified in the draft Standard. This is a significant misstep by NERC in that a change to NERC's Glossary Definition of the BES, which would ostensibly be done outside the boundaries of this Standard, could profoundly change the requirement for complying with TPL-001-1 without changing a single word of the Standard. PEF is particularly concerned that this Standard must never have jurisdiction over local load-serving transmission systems, regardless of voltage. Any TPL Standard, existing or future, must focus on the reliability of the BES, i.e. the bulk grid, NOT the local load-serving portions of the transmission system. The draft Standard at present does not address this issue at all and leaves Transmission Planners and Planning Coordinators vulnerable to non-compliance with a mere change in the wording of a Definition outside of the Standard. 8. PEF strenuously objects to the allowance of interruption of Firm Transmission Service in Events P1 and P3 for DC lines, while disallowing the same for AC lines. PEF asserts that the determination should be "Yes" for both, and that disallowance for AC lines a) puts DC systems into an elite class of transmission for no explicable reason and b) encourages owners of AC Transmission Systems to replace them with DC, cost concerns notwithstanding. Furthermore, this differentiation fails to recognize or give consideration to the fact that AC systems support Firm Transmission Service; some areas of the AC transmission system carry significant amounts of Firm Transmission Service, and thus a "No" determination for P1 and P3 essentially mandates either implementing redundancy for those parts of the AC system carrying significant amounts of Firm Transmission Service, or severely curtailing Firm Transmission Service on the existing AC systems.

Response: The SAR for this standard recognized FERC orders which indicated a need to "raise the bar" for the industry. The SDT is attempting to do this in a reasonable fashion. There is significant flexibility in the Corrective Action Plans allowed for any additional performance requirements which must be met. Industry consensus, through approval of the SAR, is that revision of the existing TPL standards is appropriate.

1 & 2. Industry consensus, through approval of the SAR, is that revision of the existing TPL standards is appropriate.

3A. The SDT and industry consensus, at this point in the development process, is that consolidation in a single standard is the best course of action. The SDT did not start out with a preconceived idea that there should only be one TPL standard. The SDT started the drafting process by reviewing all of the available

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documents. This included the existing TPL standards, the SAR, FERC Order 693, and other NERC documents. After reviewing this material, the SDT determined that the majority of the language in the individual standards was in all four of the standards. After much discussion, the SDT determined that the industry would be better served with a single standard instead of staying with four individual standards.

B. Please see the responses provided in questions 2 and 10.

C. The revised TPL-001-1 standard itself does not require construction of additional Facilities although that may be a consequence of application of the standard. Additional operating guides or changes in dispatch are other possible consequences. Footnotes 5 and 10 have been added that provide further clarification regarding interruption of Firm Transmission Service. FERC staff has been available to the SDT for consultation throughout the process.

Footnote 5 - When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed.

Footnote #10 – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.

D The SDT has removed Requirement R11 from the proposed standard and Requirement R2.1.4 has been included to help clarify the spare equipment strategy issue.

R2.1.4 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment.

E. Please see response to your comments on question 11.

F. FERC direction provided in Order 693, SDT expertise, and industry input are all being considered in development of the standard.

G. To meet industry concern as well as FERC Order 693, the SDT has added Requirement R 2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been removed from the draft.

R2.8 The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1.

H. The SDT is being responsive to FERC direction in paragraph 1796 and agrees that clarification regarding Non-Consequential Load Loss and Firm Transmission Service requirements is necessary. Table 1 specifies the specific events when Loss of Non-Consequential Load is allowed. Footnotes #5 & 10 have been added to the end of Table 1 to explain Firm Transmission Service requirements. Also, please see response to your comments on question 11.

I The SDT believes that the requirement to study Extreme Events in the existing TPL-004-0 must remain in this standard. The SDT has not expanded the number of Extreme Events that must be studied but rather gave examples of how the events may occur. The only significant change in the analysis of Extreme

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Events is the new requirement for the Transmission Planner or Planning Coordinator to evaluate whether there are cost effective ways to reduce the likelihood or the impact of a particular event and document those findings. The SDT believes that this is a very reasonable approach to ensuring that these major events, even with a small probability, are reviewed and prudent decisions are made. 4. The issues raised on NERC/FERC regulations are beyond the scope of the SDT. However, changes have been made to the 3rd draft of the standard to further clarify the SDT's position on curtailments and service to Loads. Also, Load curtailments are allowed if those customers have signed an Interruptible Load contract arrangement. **Footnote 5** - the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. 5. The SDT has made the following changes to address the concerns raised by you and others: 1) Added Header note 'e' to the table to show that System adjustments can be made following a single Contingency event, in preparation for the next event; 2) Added footnote 5 to address conditional firm issues, and 3) Added footnote 10 to address re-dispatching resources while continuing to serve firm Load. **Header note 'e' -** For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. **Footnote 5** - When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. 6. NERC is following the officially sanctioned standards development process with regard to this project just as it follows the process for all standards development work. This is an open, transparent process which has been approved by FERC. Any member of the public is free to participate and/or comment. State regulators are included in the process (Segment 9) and comments are welcome from them just as they are from any other segment of the public or industry. Comments are frequently received from state agencies during the lifetime of a project and two regulatory agencies did provide comments on the second posting. As for the comments on economics, it was not reckless but a statement of fact. However, costs are being considered as should be evident by the questions raised (Q12 thru Q14) in the second posting. The SDT is cognizant of the cost factors involved here and is taking them into consideration in its deliberations.		

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7. Revisions to definitions in the NERC Glossary of Terms must be approved in accordance with the standards process and issues with application to existing standards would be considered. In addition, each Regional Entity has the ability to establish its own unique definition of the BES. 8 The SDT has removed this differentiation in the Table such that AC and DC lines will be treated equally.		
Lafayette Utilities System	C — Definitely do not support the revised standard	Lafayette's single biggest concern is that the second draft version of TPL-001 imposes performance requirements that are less stringent than those imposed in the previous draft. As the SDT stated in its response to comments on Draft 1: ?The SDT modified the performance requirements relative to Non-Consequential Loss of Load and revised Tables 1 & 2 to add greater detail and provide for more situations where it is acceptable to lose Non-Consequential Load.? This ?watering down? of the standard appears to result from complaints about the costs that certain commenting parties claimed would be necessary to achieve compliance with the performance requirements set forth in Draft 1. This is evident from the SDT's statement in the foreword to the comments form for Draft 2 that the SDT has ?attempted to adjust and clarify the proposed requirements and performance in light of these initial comments,? and that the SDT needs additional information about cost and other compliance issues so that it can ?make more adjustments as appropriate.? Lafayette questions whether it is appropriate for the SDT to shape the performance standards to alleviate certain commenters? cost concerns. The SDT should be focused on developing performance requirements that are judged to be optimal from the standpoint of protecting reliability consistent with sound engineering and planning. Striking a balance between reliability and cost is a policy determination for which responsibility lies elsewhere than in the SDT. Claims that the standards would impose excessive costs are more properly addressed to FERC when the revised TPL-001 is filed for approval because Congress assigned to FERC the responsibility to make judgments of this sort. The SDT should not be ?adjusting? (that is, watering down) the performance requirements in response to transmission owner arguments about the costs of compliance. The dilution of the performance requirements is manifest in a number of elements contained in the proposed draft, including (but not limited to) the following: a) Table 1 (Steady State Performance) would permit the interruption of Firm Transmission Service and the loss of Non-Consequential Load in three P1 (Single Contingency) scenarios involving AC lines. In Order 693 (at paragraph 1794), however, FERC emphasized that loss of Non-Consequential Load in single contingency situations is not permissible. b) Adopting less stringent performance requirements for loss of elements below 300kV may be discriminatory. Most wholesale customer loads are served from delivery facilities that operate at voltages lower than 300kV. The outage of facilities operating at less than 300kV therefore may encompass 100% of a wholesale customer's load, while it is likely to impact a much smaller portion of the total load served by the owner of the affected transmission facilities. Therefore, adopting less stringent performance requirements for facilities operating at less than 300kV would impose a disproportionate burden on affected wholesale customers, as compared to the transmission owner. c) In addition to its potentially discriminatory effect, the notion of imposing difference performance standards based on operating voltage would incent transmission owners to scrimp on needed improvements to lower voltage facilities. Presumably, the distinction originates from a belief that outages on 300kV and lower facilities will have less impact on the

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		Bulk Electric System. As the August 2003 blackout demonstrated, however, disruptions on lower voltage circuits can cause real and reactive power flow fluctuations across, and eventual separation of, higher-voltage networks. d) Regarding the SDT's elimination of the requirement to re-test cases to ascertain the efficacy of additions included in a Corrective Action Plan (sub-requirement 2.7.2 in Draft 1), it is unclear why this requirement was deleted since very few commenters complained that it would be burdensome. It is hard to see how such a re-testing obligation would impose a significant burden, at least insofar as the steady state analysis is concerned. Eliminating the re-testing requirement seems likely to provide minimal savings, but could be important to verifying that appropriate Corrective Action Plan decisions are made.
Response: There are no intentions by the SDT to "water down" reliability. In fact the SDT has raised the bar in many places; e.g., above 300 kV requirements. Resources and expenditures versus adequate level of reliability are being given due consideration throughout the process and will ultimately be determined by the industry through the ballot process. a Table 1 does *not* permit the interruption of Firm Transmission Service or the loss of Non-Consequential Load in three P1 (Single Contingency) scenarios involving AC lines. b & c. The majority of the SDT believed the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated above 300 kV generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers where the energy is then delivered by other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. d. The retesting of the cases was deleted due to the SDT believing that this requirement was too burdensome; however, any utility may exceed the requirements listed and perform this retesting if they so desire.		
Arizona Public Service Co.	A —Generally support the revised standard	We generally agree with the Standard as presented so far, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard.
Compliance Elements Development Resource Pool (CEDRP)		With regard to Violation Severity Levels for this standard, the CEDRP doesn't believe the version that has be posted for comment can be commented on from a VSL perspective for two reasons 1) it does not have any measures listed and 2) there are so many "sub-requirements" the VSLs would be quite unmanageable, unless each sub-requirement is of equal importance to fulfilling the objective of the standard. Because there are no measures we can't achieve any insight into importance. The SDT may want to consider trimming the standard down to its most basic elements and providing the details (sub-requirements) in a reference document.

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Response: Measures, VSL's, and the Implementation plan will be addressed in the next draft of the standard.		
Ameren	C — Definitely do not support the revised standard	From an engineering perspective, the biggest concerns are the additional requirements, including prescribed sensitivity studies, associated with R2 for both steady-state and stability scenarios. We believe that we already cover the needs of our system with the existing NERC standards and Ameren Transmission Planning Criteria & Guidelines. The additional analyses proposed by the revised standard are not warranted and any upgrades indentified by the additional analyses will not provide any significant increase in system reliability. For 2008 compliance, Ameren performed the following steady-state contingency analyses on each of four near-term models and one long-term model:617 Category B single contingencies involving lines and transformers.30 Category B single contingencies involving generators 50 MW and above.1699 Category B single branch outages.135 Category C-1 bus faults. 260 Category C-2 breaker failures.112,575 Category C-3 double contingencies involving lines and transformers.18,510 Category C3 contingencies involving 617 lines and transformers and 30 generating units.73 Category C-5 double-circuit tower outages. For 2008 compliance, Ameren performed 496 stability scenarios of four near-term models and one long-term model: Assuming that we can acquire the qualified manpower, which is presently not available, we estimate that proposed new requirements will increase our compliance activity time by approximately 24 man-months or 2 man-years in a six-month window (January-June) to produce the same quality studies that we produce now. Consequently, we view these proposed additional study efforts as excessively burdensome. Further, we do not see how the additional study work and documentation required by the proposed standard will lead to any significant improvements in reliability. Additional comments: The question of expected Consequential Load Loss magnitude and duration, as specified in R3.3.2.1, is not germane to the reliability of the Bulk Electric System, and is a matter for Distribution Planners and local regulatory authority and is not needed in this reliability standard.
Response: The SDT has received many comments regarding the increased planning requirements to meet the proposed standard. The SDT has reviewed the study work required to comply with the proposed standard as compared to the existing TPL standards. The SDT believes that we have added some additional study work and asked a question about the additional man-hours required to complete any new analysis. However, after this review, the SDT still believes that the requirements for sensitivity studies must remain to document the selection of critical System conditions and study years used in assessing System conditions (see paragraph 1704 of Order 693) and that System conditions are as important as Contingencies in evaluating the performance of present and future Systems (paragraph 1705). The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus. The SDT is cognizant of the cost factors involved here and is taking them into consideration in its deliberations. To meet industry concern as well as FERC Order 693, the SDT has added Requirement R 2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.8. **R2.8** The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1.		

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City of Tallahassee, FL	C — Definitely do not support the revised standard	The requirement regarding non-interruption of firm transmission service in the steady state performance table for Category P1 events does not properly take into consideration the flexibility necessary for utilities with limited interconnections or interconnections with limited transfer capability. This flexibility, which currently exists in the TPL-001 standard (footnote b in the table), allows a utility to curtail firm transactions to prepare for the next contingency. As drafted, in the circumstance where the single element outage in Category P1 was a tie line, even if this line were critical to supporting the transaction (or were required to be in service by the terms of the power contract), interruption of firm service would be a violation of the proposed standard even though such interruption would be either required or appropriate to ensure the reliability of the bulk electric system. For utilities where tie line capacity is constrained or limited, this requirement for Category P1 will require substantial investment in duplicate facilities to ensure that firm transfers would not be interrupted, and the cost of that investment would likely not offer ratepayers a commensurate benefit (presuming such a duplicate facility could even be sited and permitted).For utilities with just a few large generating units (such as a small municipal utility), the requirements for Category P3 in Table 1 set a threshold for compliance that may not be achievable without substantial investment in additional/duplicate transmission facilities and possibly generating units. The concern relates to the restriction about limiting interruption of firm transmission service or non-consequential load following a G-1/N-1 event; the particular scenario is outlined in the bullets below:? Presume a utility with only two large units and some small gas turbines? Under P3, one of these large units is forced out of service? Reserves are called for and delivered along with replacement power using available import capability? Then presume that the N-1 outage in P3 is a major tie line that is critical to the support of the firm power imports? Under the proposed standard, the utility would be unable to curtail the firm purchase or shed any non-consequential load and remain compliant, even though there would be a significant generation/load imbalance & the appropriate response for the reliability of the grid in the region would be to interrupt the transaction and possibly shed load.The flexibility afforded in the existing TPL-001 standard would in fact allow the utility to respond to this event in a more appropriate way while avoiding a very expensive expansion/duplication of facilities (notwithstanding the considerable challenges that the utility would face for siting and permitting of the necessary facilities).
Response: The SDT has made clarifications regarding Firm Transmission Service and Non-Consequential Load Loss. Footnote # 10 has been added to the end of Table 1. The standard does not preclude the possibility of obtaining contractually interruptible load in lieu of system upgrades in the scenario described. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
Florida Power and Light	C — Definitely do not support the revised	The standard, as currently drafted, is unacceptable. Without the ability to curtail firm transfers to prepare for a next contingency, a "super-firm" priority of transmission service is created for non-native load customers. This goes contrary to the intent of the Open Access Transmission Tariff (OATT) that curtailments be comparable and non-discriminatory. – From

Organization	Question 15:	Question 15 Comments:
	standard	the OATT: – Curtailment of Firm Transmission Service: In the event that a Curtailment on the Transmission Provider's Transmission System, or a portion thereof, is required to maintain reliable operation of such system, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the Transmission Provider will curtail service to Network Customers and Transmission Customers taking Firm Point-To-Point Transmission Service on a basis comparable to the curtailment of service to the Transmission Provider's Native Load Customers. All Curtailments will be made on a non-discriminatory basis, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. When the Transmission Provider determines that an electrical emergency exists on its Transmission System and implements emergency procedures to Curtail Firm Transmission Service, the Transmission Customer shall make the required reductions upon request of the Transmission Provider. However, the Transmission Provider reserves the right to Curtail, in whole or in part, any Firm Transmission Service provided under the Tariff when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Transmission System. The Transmission Provider will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments. The SDT has drafted language contrary to FERC specific requirements on comparability. The FERC has consistently directed Transmission Providers to treat all firm transaction on a comparable basis, yet the SDT, in its latest draft is creating a "super-firm" category for only firm transmission service. By creating a higher priority ("super-firm", non-comparable service) for non-native load customers than for native load, native load customers bear a higher cost burden. This and the costs to the ratepayers for negligible increase in already high reliability due to the performance requirements of the standard makes this draft completely unacceptable for FPL to support. FPL will vote against acceptance of this draft standard unless significant changes are made to comport what FPL believes was the intent of FERC Order 693 with regard to the TPL standards.
Response: The SDT agrees that clarification regarding Firm Transmission Service and Non-Consequential Load Loss is necessary. Footnote # 10 has been added to the end of Table 1: **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
Exelon Transmission Planning	C — Definitely do not support the revised standard	We appreciate the effort involved in improving this planning standard, and believe in this goal. We are not yet able to support this revised at this time due to the concerns expressed above.

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Response: Thank you for your comments.		
CenterPoint Energy and CPS Energy	C — Definitely do not support the revised standard	Without re-iterating previous comments, we will summarize that we find this proposed standard to be an overly prescriptive and unrealistic paper chase that does not add value to the planning process. We also are concerned that this standard demonstrates an unhealthy, one sided approach to planning that does not balance reliability goals against other public policy goals, such as cost and landowner impact.
Austin Energy	C — Definitely do not support the revised standard	The proposed standard is overly burdensome and too prescriptive. It will only result in a marginal improvement in reliability and its primary effect will be to devolve into a paper-chase for auditors.
Response: The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus.		
SRP	B — Unsure about supporting the revised standard	SRP is concerned about what actions will be allowed to meet the higher performance requirements in the transition period and how long will these transition periods last for the different Requirements?
Response: The SDT has developed the Implementation Plan which is included in the 3rd draft of the standard.		
MidAmerican Energy Company	C — Definitely do not support the revised standard	MEC commends the SDT for significantly improving the standard, MEC believes that the standard still must be improved significantly. Probably the most important improvement would be to completely reformat the standard to provide for more organization and clearer VSLs. MEC recognizes that this may result in some initial confusion during the standard writing process, but if such organization results in less confusion over the next decade of applying the standard, the reorganization is well worth it. If the SDT does nothing else, it should reorganize the standard. Here are some suggestions for improvement: R1.1 is not clear. What does this mean? Surely the SDT does not expect that any time the data is modified a rationale is required. Shouldn't this data be updated as necessary? Wouldn't a requirement for providing a rationale each time such changes are made potentially discourage improvements to the models? This requirement should be clarified and limited to a few specific cases that were there are real reliability concerns R2.5.2 - the SDT should revise the material transmission system changes. Addition of a new substation in one of the transmission lines connected to the plant should be revised to specifically refer to a switching station or to a non-

Organization	Question 15:	Question 15 Comments:
		distribution substation. A substation directly serving load is not a good example of a material transmission system change in the context of Generation Unit Stability studies. R2.6.2 - The SDT should revise the material transmission system changes because as presently defined, studies will need to be conducted every year for every year in the assessment period. This is because apparently the SDT has defined any system change as a material change. Since it is rare for there to be a system that does not exhibit some system change from year to year, this will mean ten-year and more studies every year. MEC recommends that the SDT revise this requirement to make clear that only significant system changes are material changes. R2.7.1 - The SDT has written this requirement to include a requirement that the responsible entity must indicate how long Operating Procedures apply. This implies that Operating Procedures should be interim measures. MEC believes that reliability can be maintained with permanent Operating Procedures and recommends that the need to indicate "how long the Operating Procedures will be needed" be deleted from this requirement. R3.3.2.1 - The SDT should delete the need to provide the expected duration of the Consequential Load Loss in this requirement because this requirements a probabilistic calculation and probabilistic planning is not the state-of-the art of the industry. This is reflected in the standard which has been written to continue deterministic planning criteria. As a result, it is a contradiction to require this probabilistic quantity in the middle of this deterministic planning standard. R3.3.2.2 - clarify that the single contingency events are the events in the tab le. R3.4 and R5.4.4 - MEC urges that the SDT delete or revise the words "why the remaining Contingencies would produce less severe System results." Given the expansive nature of the Extreme events it is virtually impossible to comply with this requirement. It is more likely that the responsible entity could show that the more likely and more severe Extreme events were studied. It would be better yet if the SDT would merely require that the responsible entity provide the rationale for the selection of Extreme Events that were studied. R5.5.1 provides an exclusion for changes in individual generating units that require study. Yet R2.6.2 has a broader definition of when Generating Plant Stability is required. These definitions need to be consistent. The definition in R5.5.1 seems to narrow to be a good definition for "material changes." MEC believes that the R5.5.1 should be expanded. Year One definition - MEC suggests that the Standards Drafting Team's (SDT's) Year One definition unnecessarily constrains the time between the completion of assessments as compared to the study period to begin no more or no less than 12 to 18 months. There is no reliability benefits derived by constraining the period between the completion of an assessment and the study period for the next study period. In fact, this may encourage a Transmission Planner to unnecessarily delay "completing" a study just to ensure that the 12 to 18 month requirement is met. For example, lets assume that a Transmission Planner's 2008 Assessment is complete as of May 2008. By the definition of Year One, then the study period for the 2009 Assessment will need to begin from May 2009 through November 2009. This means that the 2009 Assessment must include the 2009-2010 Winter Peak and cannot start with the 2010 Calendar Year. Why??? If a Transmission Planner wants to have a study period that begins with the calendar year, then the Transmission Planner

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		would need to delay completing the study until July 2009. Why??? What is the reliability benefits for delay??? MidAmerican suggests that the definition of Year One be changed to allow the study period to begin no later than 24 months after the completion of the previous year's study.? Accountability: We suggest that Transmission Service Provider be added because we also suggest that the Transmission Service Provider be responsible for R10.? R2.1 - We suggest that this requirement involves too much study work and we ask that the SDT reduce the number of current studies needed for all subrequirements. ? R2.7.1 - We agree with the requirement, but suggest a slight text change replace "? or Special Protection Schemes,?" with " . . . or Special Protection Systems, . . ."? R2.7.1.1 - We disagree with the "include project initiation date" portion of this requirement. The initiation date is often uncertain and subject to change, which may add considerable work to investigate, monitor and update the date. In addition, we do not know why this information is required to assure BES reliability.? R3.3.2.1 - We agree with the requirement, but suggest a slight text change of: ". . . shall be allowed in the Planning Assessment".? R3.3.2.2 - We agree with the requirement, but suggest a slight text change of: ". . . within their Facility Ratings and within the time period allowed by the applicable time limited ratings.".? R5.4.3.1 - We agree with the requirement, but suggest a slight text change of: ". . . within their Facility Ratings and within the time period allowed by the applicable time limited ratings.".? Table 1? Planning Events ? Header: We suggest that the header be repeated on every applicable page to be more reader-friendly.? Superscripts: The superscripts do not refer clearly to the respective notes (e.g. there are number notes in the beginning of the table, in the extreme events evaluation requirements section, in extreme event description section, and at the end of the table). Perhaps the notes at the end of the table should have unique numbering to make the superscript references clearer.? Shunt device: To avoid the need for future interpretation or clarification, we suggest that the meaning of shunt device be explained or defined somewhere in the standard (e.g. cap bank, inductor bank, SVC, STATCOM, etc.). We need to find out how shunt device outages can (or could in the future) be automatically included in the ACCC routine. We interpret that if each stage of a capacitor bank has a circuit switcher, then the outage would be of the largest cap bank stage.? Extreme Event Evaluation Requirements? 3 Extreme Event Descriptions? 2b & 3b - We agree with the descriptions, but suggest referring to the defined term: "Right-of-Way."?

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		Note 4 - We agree with the description, but the acronym FACTS should be explained in the standard or a definition be added for "FACTS". Table 2 Header: We suggest that the header be repeated on every applicable page to be more reader-friendly. Other numbering and format changes suggested for Table 1 should also be considered for Table 2.

Response: A. The SDT agrees and has removed the need for documentation of the technical rationale for modification of any data.

B Requirement R2.5 and its sub-requirements have been removed from the proposed standard. Guidelines for the use of past studies to support the Planning Assessment have been added to what is now Requirement R2.5.2. The SDT did not want to be overly prescriptive when describing the type of changes that could be considered material and has left the text general. It is up to the Transmission Planner and Planning Coordinator to provide specificity as to what type of topology changes constitutes a change sufficient to warrant re-evaluation.

R2.5.2 For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:

C The SDT does not agree that studies are required for every year of the Assessment period. However, please note that Requirement R2.5 and its sub-requirements have been removed from the proposed standard. Guidelines for the use of past studies to support the Planning Assessment have been added to what is now Requirement R2.5.2. The SDT did not want to be overly prescriptive when describing the type of changes that could be considered material and has left the text general. It is up to the Transmission Planner and Planning Coordinator to provide specificity as to what type of topology changes constitutes a change sufficient to warrant re-evaluation.

D The SDT has retained this requirement and believes that this information should be included in the Planning Assessment.

E To meet industry concern as well as FERC Order 693, the SDT has added Requirement R 2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been removed from the draft.

R2.8 The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1.

F The SDT has deleted Requirement R3.3.2 and has replaced it with additional language in Requirement R3.1 which will hopefully clarify things.

R3.1 Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 ~~– Steady State Performance.~~ based on the lists created in Requirement R3.4.

G. The SDT disagrees with your comment. The SDT believes that this language is needed to ensure that the worst possible situation is studied based on engineering judgment and knowledge of the System.

H. To address industry comments such as yours, Generating Unit Stability is no longer explicitly addressed in the standard and the definitions of Consequential and Non-Consequential Load Loss have been modified.

Consequential Load Loss: ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's~~

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~~response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions.

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~.

I. The SDT has changed the definition for Year One to accommodate industry concerns.

Year One: The first year that a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the ~~completion of the previous annual Planning Assessment~~ current calendar year.

In response to industry comments, the SDT has removed Requirements R9-R14.

R2.1 – The SDT has received many comments regarding the increased planning requirements to meet the proposed standard. However, the SDT believes that the requirements for sensitivity studies must remain to satisfy FERC Order 693. FERC has stated that the sensitivity studies would be used to document the selection of critical System conditions and study years used in assessing System conditions (see paragraph 1704) and that System conditions are as important as Contingencies in evaluating the performance of present and future Systems (paragraph 1705).

R2.7.1 (now R2.6.1) – The SDT agrees and had replaced "schemes" with "systems".

Installation or modification of Protection Systems or Special Protection Systems

R2.7.1.1 (now R2.6.2) - The SDT believes that a project initiation date is an effective measure to track a functional entity's planning and engineering activities and its efforts to provide and maintain a reliable BES.

R3.3.2.1 - To meet industry concern as well as FERC Order 693, the SDT has added Requirement R 2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.8.

R3.3.2.2 - Based on your comment, the SDT has addressed the applicable time-limited rating in what was Header note 'a' for Steady State Only in Table 1 - Steady State & Stability Performance. Requirement R3.3.2.2 has been deleted in favor of Header note 'e' in the revised Table. Please note that the two tables in the second draft have been reduced to one table in the third draft.

Header note 'e' - For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

R5.4.3.1 - The SDT has deleted Requirement R5.4.3.1.

Headers - The SDT also feels that the Tables need to be as clear and concise as possible. To that end, Tables 1 and 2 have been combined into one table with

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a revised format. The Planning Events are shown on one page so repeating the headings will not be needed. Superscripts – As part of the change to a single table, the SDT has attempted to clean up various items such as superscripts. Shunt device - The SDT believes that shunt devices are commonly used in the electric utility industry and does not require any further explanation. The SDT recommends contacting the software manufacturer for additional information about the ACCC routine. The SDT believes that the cap bank outage would be based on what elements would need to trip in order to clear the simulated fault condition. Extreme Events - The SDT agrees with your comments and has made the change. The SDT has removed item 3.b. from Extreme Events since this was already covered in Extreme Event 1. **Extreme Event 2b -** Loss of all Transmission lines on a common ~~r~~Right-of-~~w~~Way. Note 4 - The SDT believes that "FACTS" is commonly used in the electric utility industry and does not require any further explanation.		
SERC Dynamics Review Subcommittee	B — Unsure about supporting the revised standard	SERC is in category BA ? Generally support the revised standard ? B ? Unsure about supporting the revised standard ? See three specific concerns below C ? Definitely do not support the revised standard ? 1) Load Modeling is a significant open issue. The models for dynamic studies have yet to be developed and the data is not in hand. This is conflicting with implementation of the TPL standards because modeling details are a gating item to completing some system studies. 2) The proposed sensitivities create significant amount of additional work making the compliance aspect more burdensome and less clear. 3) Category P6 is the loss of a system element, following system adjustments, followed by the loss of another element. The table columns for this category say that interruption of firm transmission service is allowed. The table, however, is not clear whether the interruption of firm service is allowed as part of the system adjustment (between the outages) or whether it is only allowed after the second outage. It was stated in the NERC TPL SDT WebEx that the interruption is not allowed as part of the system adjustment. If this is the interpretation, this will cause many SERC members to not support the revised standard. This would be a dramatic change from the existing standard and would result in the unintended consequence of significantly reducing transfer capability of interfaces to a fraction of their currently reported capability. This would in effect be imposing an n-2 criteria for offering firm transmission service. This would not be an acceptable situation for the users, owners and operators of the bulk power system.
Response: 1. The SDT agrees and believes that industry guidance is needed to capture the appropriate dynamic behavior of Loads. In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments. Any comments received from the industry on MOD standards will be forwarded to NERC for inclusion into NERC Reliability Standards Development Projects 2010-04, Modeling Data and 2010-05, Demand Data. Requirement R2.4.1 has been modified		

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to clarify expectations regarding load modeling for dynamics studies. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations. **R2.4.1** System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. 2. The intent of the SDT in requiring performance of sensitivity studies is to identify critical System conditions and to expand planners' portfolio of knowledge about vulnerabilities on their System. This is also an expectation from FERC Order 693 paragraphs 1704 - 1706. Requirement R2.1.3 has been reworded to account for sensitivity studies already performed by the planner. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: 3. The SDT agrees that clarification regarding treatment of Firm Transmission Service and Non-Consequential Load Loss during adjustment is necessary. Footnote 10 in the Revision 3 of the Standard provides clarification. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
MRO NERC Standards Review Subcommittee	C — Definitely do not support the revised standard	While the MRO commends the SDT for significantly improving the standard, the MRO believes that the standard still must be improved significantly. Here are some suggestions for improvement: a. R1.1 is not clear. What does this mean? Surely the SDT does not expect that any time the data is modified a rationale is required. Shouldn't this data be updated as necessary? Wouldn't a requirement for providing a rationale each time such changes are made potentially discourage improvements to the models? This requirement should be clarified and limited to a few specific cases that were there are real reliability concerns. b. R2.5.2 - the SDT should revise the material transmission system changes. Addition of a new substation in one of the transmission lines connected to the plant should be revised to specifically refer to a switching station or to a non-distribution substation. A substation directly serving load is not a good example of a material transmission system change in the context of Generation Unit Stability studies. c. R2.6.2 - The SDT should revise the material transmission system changes because as presently defined, studies will

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		need to be conducted every year for every year in the assessment period. This is because apparently the SDT has defined any system change as a material change. Since it is rare for there to be a system that does not exhibit some system change from year to year, this will mean ten-year and more studies every year. The MRO recommends that the SDT revise this requirement to make clear that only significant system changes are material changes. d. R2.7.1 - The SDT has written this requirement to include a requirement that the responsible entity must indicate how long Operating Procedures apply. This implies that Operating Procedures should be interim measures. The MRO believes that reliability can be maintained with permanent Operating Procedures and recommends that the need to indicate "how long the Operating Procedures will be needed" be deleted from this requirement. e. R3.3.2.1 - The SDT should delete the need to provide the expected duration of the Consequential Load Loss in this requirement because this requirements a probabilistic calculation and probabilistic planning is not the state-of-the art of the industry. This is reflected in the standard which has been written to continue deterministic planning criteria. As a result, it is a contradiction to require this probabilistic quantity in the middle of this deterministic planning standard. f. R3.3.2.2 - clarify that the single contingency events are the events in the table. g. R3.4 and R5.4.4 - the MRO urges that the SDT delete or revise the words "why the remaining Contingencies would produce less severe System results." Given the expansive nature of the Extreme events it is virtually impossible to comply with this requirement. It is more likely that the responsible entity could show that the more likely and more severe Extreme events were studied. It would be better yet if the SDT would merely require that the responsible entity provide the rationale for the selection of Extreme Events that were studied. h. R5.5.1 provides an exclusion for changes in individual generating units that require study. Yet R2.6.2 has a broader definition of when Generating Plant Stability is required. These definitions need to be consistent. The definition in R5.5.1 seems to narrow to be a good definition for "material changes." The MRO believes that the R5.5.1 should be expanded. i. Year One definition - The MRO suggests that the Standards Drafting Team's (SDT's) Year One definition unnecessarily constrains the time between the completion of assessments as compared to the study period to begin no more or no less than 12 to 18 months. There are no reliability benefits derived by constraining the period between the completion of an assessment and the study period for the next study period. In fact, this may encourage a Transmission Planner to unnecessarily delay "completing" a study just to ensure that the 12 to 18 month requirement is met. For example, let's assume that a Transmission Planner's 2008 Assessment is complete as of May 2008. By the definition of Year One, then the study period for the 2009 Assessment will need to begin from May 2009 through November 2009. This means that the 2009 Assessment must include the 2009-2010 Winter Peak and cannot start with the 2010 Calendar Year. Why? If a Transmission Planner wants to have a study period that begins with the calendar year, then the Transmission Planner would need to delay completing the study until July 2009. Why? What are the reliability benefits for delay? The MRO suggests that the definition of Year One be changed to allow the study period to begin no later than 24 months after the completion of the previous year's study.? Definitions: The MRO agrees with the removal of the "Base Case" definition and

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		the revisions to the other definitions, except as noted below or elsewhere.? Long Term Planning Horizon definition: The MRO suggests a slight text change of: "Transmission planning period that covers years six through ten. Studies beyond ten years are required to accommodate . . .".? Accountability: The MRO suggests that Transmission Service Provider be added because we also suggest that the Transmission Service Provider be responsible for R10.? Requirements: The MRO agrees with the revisions to the Requirements, except as noted below or elsewhere.? R1.1 - The MRO agrees with the requirement, but would like more description of what to provide in the technical rationale.? R2.1 - The MRO suggests that this requirement involves too much study work and we ask that the SDT reduce the number of current studies needed for all subrequirements. ? R2.6.2 - The MRO agrees with the requirement, but suggest a slight text change of: " . . . short circuit, Generating Unit Stability or System Stability analysis . . .".? R2.7 - The MRO agrees with the requirement, as long as it is really required by FERC Order 693 paragraph 1704.? R2.7.1 - The MRO agrees with the requirement, but suggest a slight text change replace "? or Special Protection Schemes,?" with " . . . or Special Protection Systems, . . ."? R2.7.1.1 - The MRO disagrees with the "include project initiation date" portion of this requirement. The initiation date is often uncertain and subject to change, which may add considerable work to investigate, monitor and update the date. In addition, we do not know why this information is required to assure BES reliability.? R2.7.2 - The MRO agrees with the requirement, as long as it is really required by FERC Order 693 paragraph 1704.? R3.2.2 - The MRO agrees with the requirement, but suggest a slight text change of: "For all BES Transmission lines . . .". ? R3.3.2.1 - The MRO agrees with the requirement, but suggest a slight text change of: ". . . shall be allowed in the Planning Assessment".? R3.3.2.2 - The MRO agrees with the requirement, but suggest a slight text change of: ". . . within their Facility Ratings and within the time period allowed by the applicable time limited ratings.".? R5.1 - The MRO agrees with the requirement, but suggest a slight text change of: ". . . the response of the applicable portion of the BES".? R5.2 - This clarifying requirement should also be included in the steady state and short circuit analysis sections.? R5.3 - The MRO agrees with the requirement, but suggest a slight text change of: ". . . capability of all generators that may have a significant adverse effect on the BES."?

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		R5.4.3.1 - The MRO agrees with the requirement, but suggest a slight text change of: ". . . within their Facility Ratings and within the time period allowed by the applicable time limited ratings.".? R6 - The MRO agrees with the requirement, but suggest a slight text change of: ". . . shall provide the rationale for and document . . .".? R8 - The MRO disagrees with the requirement, but suggest a text change of: "Each Planning Coordinator shall establish a list of neighboring system and coordinate the distribution of Planning Assessment results among affected entities the listed neighboring systems, coordinating analysis of these results through an open and transparent peer review process."? Table 1? Planning Events ? Header: The MRO suggests that the header be repeated on every applicable page to be more reader-friendly.? Superscripts: The superscripts do not refer clearly to the respective notes (e.g. there are number notes in the beginning of the table, in the extreme events evaluation requirements section, in extreme event description section, and at the end of the table). Perhaps the notes at the end of the table should have unique numbering to make the superscript references clearer.? Shunt device: To avoid the need for future interpretation or clarification, we suggest that the meaning of shunt device be explained or defined somewhere in the standard (e.g. cap bank, inductor bank, SVC, STATCOM, etc.). We need to find out how shunt device outages can (or could in the future) be automatically included in the ACCC routine. We interpret that if each stage of a capacitor bank has a circuit switcher, then the outage would be of the largest cap bank stage.? P2.2 (>300 kV), P2.3(>300 kV), P3 (>300 kV), P4 (>300 kV), P5 (>300 kV), P6 (>300 kV) - This requirement is raising the bar above the existing standards. In the existing standards, this is a Category C event in which load shedding was allowed. A higher criteria for >300 kV may not be appropriate at this time. The new requirement may require the installation of facilities that are costly and have a very long implementation timeframe. We should consider what the cost of this higher requirement might be for ATC and other utilities. If the new >300 kV requirement is not reduced, then we would want the implementation timeframe to be long enough to allow reasonable time to transition from a system built to the old requirement to a system built for the new requirement. The time needed for planning, design engineering, regulatory approvals, and construction of >300 kV facilities can be very long (e.g. up to 10 or more years).? P6 - Why isn't the generator listed as a one of the possible subsequent element outages?? P7 - The MRO disagrees with this requirement. Wisconsin statues require giving preference to using existing ROW for new transmission circuits, but this requirement discourages building multiple circuits on common ROW. Should there be an exclusion in this standard similar to the TLP-503-MRO-1 standard (e.g. could be slightly more than 1 mile due to review?.? Extreme Event Evaluation Requirements? 2 - The MRO agrees with the requirement, but perhaps a definition be added for "System Controls", since one exists for "System Protection".?

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		3 - The MRO agrees with the requirement, but suggest a slight text change of: "Simulate Normal Clearing unless otherwise specified in the Extreme Event Descriptions."? Extreme Event Descriptions? 2a - The MRO agrees with the description, but suggest a slight text change of: "Loss of a structure or tower line with three or more circuits.."? 2b & 3b - The MRO agrees with the descriptions, but suggest referring to the defined term: "Right-of-Way."? 2e, 3.a.i, & 3.a.ii - The MRO agrees with the descriptions, but how large is "large" and how major is "major"?? 3.a.v - What is meant by successful cyber attack? Is it a type of cyber attack that is documented to have been successful? ? 3c - The MRO agrees with the description, but suggest a slight text change of: "Other events based upon actual operating experience such as:" ? Note 4 - The MRO agrees with the description, but the acronym FACTS should be explained in the standard or a definition be added for "FACTS".? Table 2? 1 - The MRO disagrees with this note. We suggest that it be expanded to include the applicable part as Table 1. "The System shall remain stable. In addition, Facility Equipment Ratings shall not be exceeded. Planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings."? 3 - The MRO disagrees with this note. We suggest that it be expanded to include the applicable part as Table 1. "Dynamic voltage instability, Cascading outages, and uncontrolled islanding shall not occur."? Between 3 & 4 - The MRO disagrees with omitting Note 4 of Table 1 from Table 2. We suggest including: "Consequential Load and consequential generation loss is allowed for all events shown."? Planning Events? Same comments on Header, Superscripts, and Shunt Device as in Table 1.? Same comments about stricter requirements for P2.2 (>300 kV), P2.3(>300 kV), P3 (>300 kV), P4 (>300 kV), P5 (>300 kV), P6 (>300 kV) as in Table 1.? Same comment about P7 as in Table 1.? Extreme Event Evaluation Requirements? Same comment about Requirement 2 and 3 as in Table 1.? 3 - The MRO agrees with the requirement, but suggest a slight text change of: "Simulate Normal Clearing unless otherwise specified in the Extreme Event Descriptions."?

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		Notes5 - The MRO disagrees with limiting this requirement to just Category P1 category. We suggest that the synchronism requirement be applied to more categories.

Response: A. The SDT agrees and has removed the need for documentation of the technical rationale for modification of any data.

B Requirement R2.5 and its sub-requirements have been removed from the proposed standard. Guidelines for the use of past studies to support the Planning Assessment have been added to Requirement R2.6.2 (now R2.5.2). The SDT did not want to be overly prescriptive when describing the type of changes that could be considered material and has left the text general. It is up to the Transmission Planner and Planning Coordinator to provide specificity as to what type of topology changes constitutes a change sufficient to warrant re-evaluation.

R2.5.2 For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:

C The SDT does not agree that studies are required for every year of the Assessment period. However, please note that Requirement R2.5 and its sub-requirements have been removed from the proposed standard. Guidelines for the use of past studies to support the Planning Assessment have been added to what is now Requirement R2.5.2. The SDT did not want to be overly prescriptive when describing the type of changes that could be considered material and has left the text general. It is up to the Transmission Planner and Planning Coordinator to provide specificity as to what type of topology changes constitutes a change sufficient to warrant re-evaluation.

D The SDT has retained this requirement and believes that this information should be included in the Planning Assessment.

E To meet industry concern as well as FERC Order 693, the SDT has added Requirement R 2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been removed from the draft.

R2.8 The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1.

F The SDT has deleted Requirement R3.3.2 and has replaced it with additional language in Requirement R3.1 while adding Header note 'e' and deleting the reference to single Contingencies which will hopefully clarify things.

R3.1 Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 ~~– Steady State Performance.~~ based on the lists created in Requirement R3.4.

Header note 'e' - For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

G. The SDT disagrees with your comment. The SDT believes that this language is needed to ensure that the worst possible situation is studied based on engineering judgment and knowledge of the System.

H. To address industry comments such as yours, Generating Unit Stability is no longer explicitly addressed in the standard and the definitions of Consequential

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and Non-Consequential Load Loss have been modified.

Consequential Load Loss: ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions.

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~.

I. The SDT has changed the definition for Year One to accommodate industry concerns.

Year One: The first year that a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the ~~completion of the previous annual Planning Assessment~~ current calendar year.

Accountability - In response to industry comments, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R1.1 – The SDT agrees and has removed the need for documentation of the technical rationale for modification of any data.

R2.1 – The SDT has received many comments regarding the increased planning requirements to meet the proposed standard. However, the SDT believes that the requirements for sensitivity studies must remain to satisfy FERC Order 693. FERC has stated that the sensitivity studies would be used to document the selection of critical System conditions and study years used in assessing System conditions (see paragraph 1704) and that System conditions are as important as Contingencies in evaluating the performance of present and future Systems (paragraph 1705).

R2.6.2 – Based on comments from others, the SDT has removed the requirements for separate Generating Unit Stability analysis and System Stability analysis.

R2.7.1 (now R2.6.1) – The SDT agrees and had replaced "schemes" with "systems".

Installation or modification of Protection Systems or Special Protection Systems

R2.7.1.1 (now 2.6.2) - The SDT believes that a project initiation date is an effective measure to track a functional entities' planning and engineering activities and their efforts to provide and maintain a reliable BES.

R2.7.2 – The old Requirement R2.7.2 has been deleted.

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R3.2.2 – The Purpose section of the Standard states that this Standard is to develop requirements for the Bulk Electric System, BES.

R3.3.2.1 - To meet industry concern as well as FERC Order 693, the SDT has added Requirement R 2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.8.

R3.3.2.2 - Based on your comment, the SDT has addressed the applicable time-limited rating in what was Header note 'a' for Steady State Only in Table 1 - Steady State & Stability Performance. Requirement R3.3.2.2 has been deleted in favor of Header note 'e' in the revised Table. Please note that the two tables in the second draft have been reduced to one table in the third draft.

Header note 'e' - For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

R5.1 & R5.2 (now R4.1 and R4.2) – Most of the industry did not have difficulty understanding that the analysis is limited to the Transmission Planner's or Planning Coordinator's portion of the BES. Therefore, the SDT is not persuaded by your comment to add extra wording.

R5.3 (now R4.3) – The SDT disagrees with the suggested change due to the additional studies that would be required to determine which generators would have an adverse impact.

R5.4.3.1 - The SDT has deleted Requirement R5.4.3.1.

R6 – The SDT believes "define and document" as written are more appropriate than "rationale for and document". The SDT did not revise Requirement R6 (now R5) as proposed – but did make other modifications to this requirement based on other stakeholder comments..

R8 – The SDT has clarified this in a revised Requirement R7.

R7 Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~neighboring systems~~ adjacent Planning Coordinators and any functional entity who has indicated a reliability need, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890.

Headers - The SDT also feels that the Tables need to be as clear and concise as possible. To that end, Tables 1 and 2 have been combined into one table with a revised format. The headings are repeated on subsequent pages.

Superscripts – As part of the change to a single table, the SDT has attempted to clean up various items such as superscripts.

Shunt device - The SDT believes that shunt devices are commonly used in the electric utility industry and does not require any further explanation. The SDT recommends contacting the software manufacturer for additional information about the ACCC routine. The SDT believes that the cap bank outage would be based on what elements would need to trip in order to clear the simulated fault condition.

P2.2 – The majority of the SDT believed the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated above 300 kV generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers where the energy is then delivered by other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC

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and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. The Implementation Plan will address any need for transition and will be included in the next revision. P6 – This is already covered in P3. P7 – The SDT is cognizant of the concerns surrounding the construction of new Transmission lines, including the desire by many to fully utilize existing Right-of-Ways. In its consideration of Footnote 12 (exclusion for common structures less than 1 mile), the SDT considered the impact that this requirement could have on construction of new Facilities. However, after deliberations the SDT believes that the 1 mile exclusion should be maintained for the reliability of the BES and that individual exceptions can be addressed within the NERC process. Extreme Events 2 - The SDT agrees that "Protection System" is defined in the Glossary of Terms Used In Reliability Standards. However, the SDT believes that these "System Control" issues should be addressed by the NERC SPCTF drafting team. Extreme Events 3 – The SDT has already included "For all Extreme Events Evaluated" at the beginning of the Evaluation Requirements under Extreme Events. Extreme Events 2a – The SDT believes that the Extreme Events #2.a. is already sufficient. Extreme Events 2b & 3b - The SDT agrees with your comments and has made the change. The SDT has removed item 3.b. from Extreme Events since this was already covered in Extreme Event 1. **Extreme Event 2b -** Loss of all Transmission lines on a common ~~r~~Right-of-~~w~~Way. Extreme Event 2e – The SDT suggests that the terms "large", "major", and "successful" be defined between the TP and PC. Extreme Event 3a – A successful cyber attack would be any attack where an unauthorized person gained access to the systems described in the event. Extreme Event 3c – The SDT believes that the wording of 3b (was 3c) is already sufficient. Note 4 - The SDT believes that "FACTS" is commonly used in the electric utility industry and does not require any further explanation. Tables 2 – As part of the 3rd draft of the revised standard, the 2 tables have been merged into a single table and a general clean-up of the text has been made. Table 2, note 1 – The SDT has reviewed your comment and feels that your request to add "Facility Equipment Ratings shall not be exceeded. Planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings." apply to Stability is not appropriate. For the purposes of this standard, Facility Equipment ratings refer to steady state calculated values and planned System adjustments refer to the time frame associated with returning the thermal flow within the applicable steady state Facility Rating. Table 2, note 3 – The SDT agrees with your comment on making general note 3, located at the beginning of Table 1, "Voltage instability, cascading outages, and uncontrolled islanding shall not occur" applicable to both Steady State and Stability and has made that change in the next version. Note 4 – The SDT also agrees that the general note 4, at the beginning of Table 1, applicable to both Steady State and Stability and has made that change in the next version.		

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Note 3 – The SDT has already included "For all Extreme Events Evaluated" at the beginning of the Evaluation Requirements under Extreme Events. Note 5 – The SDT also feels that the synchronism requirement should apply to more than just the P1 Category but under certain conditions. As stated in Note 1.a.ii, for planning events other than P1, no generating unit or units totaling more than the Contingency reserve of the Balancing Authority shall be allowed to pull out of synchronism. If less than the Contingency reserve, then the resulting apparent impedance swings must not pass through relay characteristics that would result in the tripping of any Transmission System elements other than the generating unit and its direct connection Facilities		
Modesto Irrigation District	B — Unsure about supporting the revised standard	Concerns about the following: attempt to introduce interconnection stability studies into TPL studies, and redefinition of Consequential and Non-Consequential Load Loss.
Response: The SDT believes that there is no significant distinction between generator and System Stability and has modified the definitions and Requirements R2, R2.6.1 (now R2.5.1), R2.6.2 (now R2.5.2), R5 (now R4), and R5.5 (now R4.4) in the third draft. **R2** Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses ~~including both System and Generating Unit Stability~~. **R2.5.1** For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less. **R2.5.2** For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: **R4.** For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~ **R4.4** ~~At a minimum, t~~Those Planning Event Contingencies in Table ~~2~~1 – ~~Stability Performance~~ that ~~would~~are expected to produce more severe System impacts shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information with an explanation of why the remaining Contingencies would produce less severe System results. In response to numerous concerns, the following changes were made to the draft standard regarding Consequential and Non-Consequential Load Loss		

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definitions. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~.~~ ~~For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~.		
Arkansas Electric Coop. Corp.	B — Unsure about supporting the revised standard	I have a growing concern that the NERC Reliability Standards are not going far enough to ensure adequate and reliable service to customers and users of the BES. Each revision of the standards seem to be driven by the need to preserve the integrity of the grid and preventing cascading blackouts but stop short of ensuring that load continues to be served under contingency conditions and adequate grid capacity is available. For the customers and end users of the system if their load is allowed to be dropped or can not be served because of the lack of capacity then the BES is not reliable. The definitions of Consequential Load Loss and Non-Consequential Load Loss concern me the most. How these definitions are then applied in the tables is also a great concern. Hopefully my previous comments to the other questions in the comment form provide explanation. Another concern I have is the fact that I tried to provide comments last fall to draft 1 of the standards and they were not allowed. After following the instructions provided I provided my comments before the deadline. I later discovered they were not posted. After repeated attempts asking NERC to determine why my comments were not received and posted and showing evidence that they had been provided by the deadline, the only response I received was pretty much "sorry Charlie". Mistakes happen. NERC should be big enough to admit when they make a mistake instead of just blowing them off. I have no way of knowing if or how many times this may have happened before. I am not trying to say that anything malicious was intended, however it does leaves me with concern that fair treatment is being given to all comments and cast a shadow over confidence in the standards approval process.
Response: The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus. The SDT believes that your concerns are mostly addressed by the revised Table 1 - Steady State and Stability Performance, along with the revised definitions of Non-Consequential Load Loss and Consequential Load Loss in the updated draft of TPL-001 standard. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed,~~		

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~~Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. Comments from AECI were included in the responses to the comments from the first posting. Please go back and review the posted comment form.		
Midwest ISO	C — Definitely do not support the revised standard	We appreciate the hard work of the SDT and understand the difficulty of this task. We applaud the efforts to improve the standard. However, in its present state, in general the revised standard fails in one if its primary stated goals: create a "clear and concise standard". While some of the ideas are an improvement, overall the standard is very meandering and it makes it difficult to figure out what the requirements are for a particular analysis type without flipping back and forth between the scattered requirements. For example R2 addresses various aspects of both Near and long term studies, steady state, short circuit, stability, on peak, off peak and other topics. Then there are separate sections (R3, 4, 5) that speak to the various analysis types again. It probably makes sense to the SDT that has evolved with the drafts and discussions, but when you pick it up it is very confusing. One thing that would help greatly would be to label the major Requirements sections to convey the organization of the document. If the SDT made a topical outline of the standard by major Requirement this could help the team organize the standard better. Resulting topical headers may look something like the following for example, R1: ModelingR2: Study Types and Assessment RequirementsR3: Steady State Analysis MethodsR4: Short Circuit Analysis Methods?R5: Stability Analysis Methods Etc. If it has not been done (and it looks like it has not), the SDT should consider having the language reviewed by the NERC or other legal team. Language that seems clear to experienced engineers may not be precise as is critical for standards that carry monetary penalties. An independent review by a non-engineer lawyer would help greatly. Of course, the SDT would then have to undo some damage that would undoubtedly be done to context by the lawyers - but the pass through legal would be a good step.? ? Other concerns:? P5 requires testing for a single component failure within a Protection System. What is this referencing? How can a PC/TP be expected to be intricately aware of protection systems and effects of single component failures? Under 2.7.2, there is a generic requirement to expand a list of possible corrective actions under 2.7.1 for any sensitivities under R2.1.3, 2.1.4, 2.4.3 and 2.4.4. This is very open ended and subject to interpretation. How can an auditor review such requirements with consistency?
Response: The SDT has attempted to make the latest draft more clear and concise - such as condensing Table 1 and 2 into a single table. The SDT has considered having headers/labels in the document and these are strongly discouraged by NERC's legal staff. The overall format of the tables has been modified to make it more reader friendly. NERC is following the officially sanctioned standards development process with regard to this project just as it follows the process for all standards development		

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work. This is an open, transparent process which has been approved by FERC. Review and comment by any entity's legal staff is welcome, but not a required part of the process. The description of the P5 event has been clarified in draft 3 to address your concern. Requirement R2.7.2 has been removed. The SDT has modified Requirement R2.7 (now R2.6) to clarify that Correction Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3 and R2.4.3. **R2.6** For Planning Events shown in Table 1~~ – Steady State Performance and Table 2 – Stability Performance~~, when the analysis indicates an inability of the System to meet the performance requirements in ~~the t~~Table~~s~~ 1, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed in subsequent assessments but the System shall continue to meet the performance requirements in the tables. Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3 and R2.4.3. The Corrective Action Plan shall:		
Tri-State Generation and Transmission Association, Inc.	A — Generally support the revised standard	We appreciate the efforts of the SDT, considering the difficulty of the task that was and is before them. Our biggest concern is potential confusion regarding sensitivity studies. Secondly, we absolutely must make the Performance Table completely clear and concise. Additional work now will pay big dividends later. Thirdly, there is some ambiguity of several terms used in the Standard that prevents exact interpretation of significant portions of the Standard. Here are a few additional comments we hope the SDT will find helpful: It may simplify considerations of assessments and modeling work to define ?assessment? as including written documentation. Then the Standard would not need to separately include "and shall include written documentation" in the body of the standard titles. Also, the SDT should make it clear that "assessment" is what is required; that annual re-study analysis may not necessarily be required. Thanks to the SDT for keeping this feature. It will greatly simplify our work, and should speed the audit process as well. There seems to be some ambiguity between either 1) requiring specific years to be studied and 2) leaving timeframe selection to the TP. Assessment for year One or Two (R2.1.1) may be performed by either the TOP or the TP. Studies of year One or year Two are generally considered to be operating studies and should probably not be required in TPL-001-1. Also in R2.1.1, year Five is specified as a required study year. No matter what the requirement says, the TP will need to assess performance for critical timeframes. This would lead to additional study if year four were the critical year for example. And for sensitivity studies of delayed facilities (R2.1.3.3) additional study years might be required. Perhaps a reasonable compromise would be to require something in the 2 to 5-year timeframe, and something in the 6 to 10-year timeframe. For coordination with regional study groups in our area, one would logically choose year 5 and year 10, but the specific choice should be up to the TP (and PC if any). Sole-Customers on radial service who are responsible for facility upgrades should be allowed to elect a lower reliability

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		than the rest of the system. It seems that operating scenarios required to be studied by TOP should not need study in the planning horizon by the TP, and should be excluded from this standard. Specific comments concerning other sections of the draft standard: 1. In the definition of Generating Stability Study, we suggest "the lack of damping" be changed to "damping" 2. In R2.1 title, please move listed requirements in the second sentence to sub-requirements (they are already there). 3. In R2.1 title sentence, the term "annual current" presents two additional requirements. We suggest those words be deleted. 4. In R2.1, delete the end of the title sentence, ending the sentence with "the following studies" 5. In R2.1.3.2, the meaning of "transfer" is not clear. 6. In R2.1.3.4, the term "variability" is not clear. do you mean "Operating Capability"? 7. In R2.1, R2.2 and 2.4, the phrase "Near Term (or Long Term) Transmission Planning Horizon portion of the" could be omitted. "Near Term" and "Long Term" study horizons should just be specified as sub-requirements of Steady State, Stability, and Short Circuit 8. In R2.7.3, the term "identified System Facilities" is not clear. System Additions? 9. Heading R3.3 is not needed. Renumber section sub headings to 3.2.3, etc.

Response: In response to industry comments regarding sensitivity studies, the SDT has made changes to Requirements R2.1.3 and R2.4.3 and each of their sub-requirements to clarify expectations related to sensitivity studies.

R2.1.3 For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

The SDT also feels that the Tables need to be as clear and concise as possible. To that end, the next version will combine Tables 1 and 2 into one table with a revised format.

The SDT crafted the definition of Planning Assessment using the term "documented" instead of "written" such that an assessment can be either in written or

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electronic format. Requirement R2 states that the assessment is to be performed annually. The SDT chose the Year One definition such that this would be out of the operational planning horizon and into the planning horizon. The SDT chose the years to be studied such that both the Near-Term and Long-Term Planning Horizons would be adequately studied and has not seen a sufficient number of comments to warrant changing the requirements. . Sole-customers who are responsible for facility upgrades are allowed to elect lower reliability than the rest of the system if those customers have signed an Interruptible Load contract arrangement. The SDT believes that all significant probable Contingencies over a wide range of operating conditions should be studied. 1. The definitions for both Generating Unit Stability Study and System Stability Study have both been removed and these Stability areas have been combined into just one Stability area. 2, 3, and 4. The SDT disagrees with the proposed changes and believes that compliance with Requirement R2.1 can be shown through the use of both current and past studies. 5. The SDT believes that "transfers" is generally understood to mean electric power that is transferred or moved from one area to another, and as such, has not added a definition of transfers. 6. The SDT has revised the language to replace "variability" with reactive resources "capability". ~~Variability and outages of r~~Reactive resource~~s~~ capability. 7. The SDT believes that the format and the language of these requirements are appropriate and no additional changes are needed. 8.,The SDT received only a single comment regarding use of the terms "identified System Facilities" and therefore believes the proposed language is clear and appropriate. "Identified System Facilities" are those new or modified facilities which were identified in previous Corrective Action Plans. 9. Requirement R3.3 has been removed and replaced with additional language in Requirement R3.1. **R3.1** Studies shall be performed to determine whether the BES meets the performance requirements in Table 1~~ — Steady State Performance.~~ based on the lists created in Requirement R3.5.		
Lakeland Electric	B — Unsure about supporting the revised standard	Curtailing firm transmission should explicitly be a viable option when preparing for the next contingency if the previous contingency and a credible next contingency call for curtailing firm transactions for reliabilities sake. Not allowing for firm transmission curtailment in this case seems to be a market requirement driving a reliability requirement. Determining the duration of consequential load loss (R3.3.2.1) is impractical as the root cause of the event vice the defined event type (e.g. - loss of line) determines the duration of the outage. A line can be outaged by a temporary lock out of protection device or 15 spans of a line might be destroyed by fire. The difference between the two make determination of duration impractical.

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		System peak Load (R2.1.1) needs to specify if it is the specific year, season or historical peak demand. Forecasting methodologies affect the system peak load that is projected. Differences between a 50/50 and 80/20 case will result in different forecast peak data.
Response: Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency. However, until the next Contingency occurs, System performance will need to meet the requirements for Event P1. As such, the proposed standard will not allow loss of any Non-Consequential Load, except for contracted Interruptible Loads, in preparation for the next Contingency. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. To meet industry concern as well as FERC Order 693, the SDT has added Requirement R2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been removed from the draft. **R2.8** The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1. The SDT intentionally provides flexibility for the Transmission Planner/Planning Coordinator to decide which Load forecasting methodology to use. The required studies and sensitivity analysis ensures that sufficient study is performed to cover an appropriate range of System conditions.		
Southern Company Transmission	C — Definitely do not support the revised standard	Category P6 is the loss of a system element, followed by system adjustments, followed by the loss of another element. The table columns for this category say that interruption of firm transmission service is allowed. The table, however, is not clear whether the interruption of firm service is allowed as part of the system adjustment (between the outages) or whether it is only allowed after the second outage. It was stated in the NERC TPL SDT WebEx (August 26, 2008) that the interruption is not allowed as part of the system adjustment. If this is the interpretation, this will cause Southern Company to not support the revised standard. This would be a dramatic change from the existing standard and would result in the unintended consequence of significantly reducing transmission system capability to accommodate firm transmission service including reduction of transfer capability of interfaces to a fraction of their currently reported capability. This would in effect be imposing an n-2 criteria for offering firm transmission service. This would not be an acceptable situation for the users, owners and operators of the bulk power system. In addition, the standard should clarify the accommodation of Conditional Firm Service as defined by FERC Order 890.
Response: The SDT agrees that clarification regarding treatment of Firm Transmission Service and Non-Consequential Load Loss during adjustment is		

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necessary. Footnote 10 in draft 3 of the Standard provides clarification. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
Brazos Electric Power Cooperative, Inc.	C — Definitely do not support the revised standard	Our biggest concern is the apparent lack of experience or understanding in the repercussions of including so many required studies and detailed documentation. And to what end? The amount of data that would be required to be saved will be so voluminous no one could go through it all to make any meaningful determination in a timely fashion. It's one thing to study every possible combination of outage but you then have to do something with the results, not just record them somewhere because a standard requires it. On the other hand some progress is being made in removing some of the more ambiguous or useless items so we are getting there to some degree. Deleting 1.1.2, 1.1.3, 2.7.3, 2.7.4, and 5.4 are good starts. However it appears some things were added that are just confusing or are unnecessary. 5.5.2 seems to simply restate the obvious intent of the section, to meet the performance requirements so its not really needed. Phrases such as "document why categories were NOT selected" are intuitively obvious. Categories were not selected because, in the judgment of the TP or PC, they were not deemed useful to study so why document this each time. R6 is also a confusing addition to this Standard and we aren't sure what it's intended to require. Use of the word "proxies" is probably not the best substitute for what was intended. We suggest R6 be deleted as well.
Response: The SDT has received many comments regarding the increased planning requirements to meet the proposed standard. However, the SDT believes that the requirements for sensitivity studies must remain to satisfy FERC Order 693. FERC has stated that the sensitivity studies would be used to document the selection of critical System conditions and study years used in assessing System conditions (see paragraph 1704) and that System conditions are as important as Contingencies in evaluating the performance of present and future Systems (paragraph 1705). Neither FERC, nor the SDT, believes that every possible combination outage needs to be analyzed for every System condition, but FERC expects those that produce the most severe reliability impacts should be documented (paragraph 1706). In response to industry comments, Requirement R5.5 has been deleted since Generating Unit Stability is no longer explicitly addressed in the standard. The SDT agrees and has deleted the phrase from Requirements R2.1.3 and R2.4.3. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical~~		

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~~rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: The industry did not seem to find usage of "proxies" in Requirement R6 (now R5) unclear or confusing. Therefore, the SDT has determined that no change to Requirement R6 is needed with regard to the use of proxies.		
LCRA TSC	A — Generally support the revised standard	LCRA had a comment on the first posting stating that the loss of any two Transmission circuits on a common structure should be viewed as a single contingency as a single component failure (tower, shield wire, conductor, hardware) could in-fact lead to the loss of two circuits. In the second draft, this outage is still being viewed as a Multiple Contingency (P7). At the same time, the loss of a tower line with three or more circuits is being viewed as an Extreme Event, when the same single failure could lead to the loss of multiple circuits. So, even if a double circuit outage is viewed as a Multiple Contingency, shouldn't a multiple circuit outage be viewed the same. In the Definitions of Terms Used in Standard, Extreme Event is defined as Events which are more severe and have a lower probability of occurrence than Planning Events. What is a "lower probability of occurrence"? Is this to be determined by each TP or TO? How is this probability determined? Are we to assume from this definition that we can use probabilistic planning to determine which Events should be studies even at the N-1 level?
Response: The SDT does not believe that the loss of a tower line with three or more circuits is similar in probability to two circuits on a common structure. Therefore, it is appropriate to classify the events differently. The SDT views "lower probability of occurrence" events as those events that occur much less often than Planning Events. The SDT does not intend for this probability to be determined by each utility. The SDT desires that Extreme Events be studied - but do not necessarily have to have Corrective Action Plans.		
NERC and Regional Coordination	C — Definitely do not support the revised standard	Changes should be made to the sensitivity analysis. See question 10 above. R2.6 - The need to restudy previously studied years should be left to the transmission planner when in their judgment there is a material change. Based on the material change the TP should be responsible for determining what aspects of the performance requirements need to be proven
Response: Please see the response to question 10. The SDT believes that past studies must be five calendar years old or less to be relevant and the associated models should not have had material changes. Requirement R2.5 and its sub-requirements have been removed from the proposed standard. Guidelines for the use of past studies to support the Planning Assessment have been added to what is now Requirement R2.5.2. The SDT did not want to be overly prescriptive when describing the type of changes that could be considered material and has left the text general. It is up to the Transmission Planner and Planning Coordinator to provide specificity as to what type of		

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topology changes constitutes changes sufficient to warrant re-evaluation. **R2.5**2 For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:		
IESO	A — Generally support the revised standard	(i) We generally support the direction and principle of the revised standard. It is a step in the right direction to more clearly stipulate the types of events and expected performance requirements with inclusion of multiple element contingencies and multiple single contingencies, and allowance for interruptions to firm transmission services and non-consequential load loss. (ii) More details and refinements are expected to be provided that address the issue of sensitivity testing, reduce the number of layers in the subrequirements (to facilitate ease of developing Measures and Violation Severity Levels), more clearly specify the responsible entities, etc. We look forward to seeing these improvements in the next revision, along with the first draft of Violation Risk Factors, Time Horizons, Measures, Data Retention Periods, and Violation Risk Factors when the requirements approach their near final draft form. (iii) We suggest the SDT review the development plan with the Standard Process Manager, especially the timing for posting the standard for balloting, responding to comments and conducting recalculating ballot. The timing between the initial ballot and recirculation ballot is usually short, and the balloted standard is not supposed to change. The proposed development plan appears to allow a long lead time between the two ballots, and for making changes to the standard between them.
Response: i. Thank you for your comments. ii. The SDT has streamlined the document and the tables to add clarity and has added the elements that were missing from the previous drafts. VRF, tec., have been added to the 3rd draft. iii. All development plans are reviewed with the Process Manager prior to finalization as per established procedure.		
North Carolina Electric Membership Corp	B — Unsure about supporting the revised standard	While we are satisfied that the changes are moving in the right direction, we share concerns that are being expressed by other SERC TPs and PCs that the standard may be overly prescriptive in some areas such as the sensitivities being required.
Response: The SDT agrees and has clarified the language to allow the Transmission Planner and Planning Coordinator to choose the sensitivities (Requirements R2.1.3 & R2.4.3).		

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R2.1.3 For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
E.ON U.S. Transmission Planning	C — Definitely do not support the revised standard	It is confusing that single Contingency and multiple Contingency are used throughout the document when the Categories in Tables 1 and 2 are Single Contingency and Multiple Contingency. Also System normal, normal conditions and Normal System are spread throughout the document. If they all mean the same, use the same wording. If not, explain the difference. R2.4.1. - Does this apply only to motors directly connected to the BES? Is there a size (hp/MW) limit? Who is responsible to provide this data to the Planning Coordinator? I would think it would both the Distribution Providers or the Generator Owners but R9 & R12 do not mention this. R2.4.1 refers to ?the dynamic behavior of Loads? and induction motor loads. How would this model data be developed, and by who? R2.5.2. - Define “Material”. Is an addition of a load tap point material? R2.6.2. ? Define ?study area?. Does a topology change over 300 miles away trigger a stability study for a generating plant? R2.7.1.1. ? Define ?project initiation date?. Would this include going to the PSC to get approval or just when construction begins? R3.2.1 states ?? and identify how the generators are treated in the steady state simulation.? What is meant by ?treated?? I request the use of more descriptive wording. R3.2.2 states ?? and identify how loadability is treated in the steady state simulation.? What is meant by ?treated?? I request the use of more descriptive wording. R3.3.1 “System normal” is a Planning Event included in Table 1. R3.3.2 capitalize ?Single? if you referring to P1 and P2 events. If not, this is confusing. R3.3.2.1 states ?Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment.? Quantification of expected duration requires a probability analysis of load cycles, repair time, and potentially of other factors that will be difficult, if not impossible, to develop with any confidence. The Planning Assessment is based on a deterministic evaluation. Requiring the expected duration is

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		inconsistent and useless. R3.3.2.2 Is this the intent? ? Following Single Contingency events, Transmission configuration changes and redispatch of generation can be simulated to return the system to Normal Rating provided that all Facilities shall be operating within their Emergency Rating. R5.3 states ?? and identify how the generators are treated in the simulation.? What is meant by "treated"? I request the use of more descriptive wording. R5.5.1 and R5.5.2 should be moved to 2.5. These requirements outline the generators and the sensitivities to be analyzed. R5 appears to focus on Tables 1 and 2. R5.5.2 states ?Shall be performed for changes in the real power output?? What types of ?changes?, or ?changes? due to what? Is intention of the requirement, that Generating Unit Stability be assessed at two levels of real power output that differ by more than 10% of the existing capability or more than 20 MW, whichever is greater? R6 states ?? and document the proxies used in the simulation?.? What is meant by ?proxies?? I request the use of more descriptive wording. R8 ends with ?This distribution shall include:? Include what? Table 1 There used to be limits on multiple circuit towers and common ROW greater than 1 mile. Is this left to the Transmission Planner and Planning Coordinator ? Extreme Events ? Item 3b is the same as Item 1, this should be removed. Table 2 Note 5.a.ii How can this be applied when the largest unit in the Balancing Authority Area is larger than the contingency reserve of the Balancing Authority. This requirement is excessive. At some level, subsequent trips of generators and/or lines should be allowed as long as Cascading does not occur.

Response: The row headers are capitalized in the Table. Please note that the two Tables have been changed to just one Table in this draft.

R2.4.1 – The SDT does not believe the requirement applies only to motors directly connected to the BES, nor is there a specific hp/MW limit. In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R2.4.1 – Requirement R2.4.1 has been modified to clarify expectations regarding load modeling for dynamics studies.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic

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behavior of the Load is acceptable.

R2.5.2 – Requirement R2.5 and its sub-requirements have been removed from the proposed standard.

R2.6.2 (now R2.5.2) –The SDT believes that it is up to the Planning Coordinator and Transmission Planner to define the study area and to determine which System changes could impact the study area

R2.7.1.1 (now R2.6.2)– The SDT has not defined a project initiation date and will leave that definition to be determined by the Transmission Planner and Planning Coordinator.

R3.2.1 – "Identify how generators are treated" means that you identify at what voltage you would believe that the generator would trip. Any time you run a dynamic simulation or a steady state simulation and you don't trip the generator, you are implicitly assuming that it will ride through the voltage excursion obtained in the simulation. The requirement is to identify what you are assuming for voltage ride-through criteria for the generators you have modeled.

R3.2.2 – The SDT has changed 'treated' to analyzed'. .

R3.3.2 For all generators, studies shall consider the minimum steady state voltage limitations ~~of all generators~~ and identify how the generators are ~~treated~~ analyzed in the steady state simulation.

Requirement R3.3.1 has been removed and replaced with additional language in Requirement R3.1.

R3.1 Studies shall be performed to determine whether the BES meets the performance requirements in Table 1~~ – Steady State Performance.~~ based on the lists created in Requirement R3.5.

R3.3.2 – This requirement was deleted.

R3.3.2.1 **-** To meet industry concern as well as FERC Order 693, the SDT has added Requirement R2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.8.

R2.8 The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1.

R3.3.2.2 - Based on your comment, the SDT has addressed the applicable time-limited rating in what was Header note 'a' for Steady State Only in Table 1 - Steady State & Stability Performance. Requirement R3.3.2.2 has been deleted in favor of Header note 'e' in the revised Table. Please note that the two tables in the second draft have been reduced to one table in the third draft.

Header note 'e' - For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

R5.3 - The SDT agrees that the word "treated" is vague and has revised Requirement R5.3 (now Requirement R4.3.2) and Requirement R3.2.2 (now R3.3.3) to clarify the requirement.

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R3.3.3 For all Transmission lines, studies shall consider relay loadability and identify how loadability is ~~treated~~ analyzed in the steady state simulation. **R4.3.2** ~~Studies shall consider~~ Simulate generator performance under anticipated conditions including how the voltage ride through capability ~~of all generators and identify how the generators are treated~~ is analyzed~~in the simulation~~. R5.5.1 & R5.5.2 - In response to industry comments, both Requirement R2.5 and Requirement R5.5 have been deleted since Generating Unit Stability is no longer explicitly addressed in the standard. R6 (now R5) - Most of the industry did not find usage of "proxies" in Requirement R6 unclear or confusing. Therefore, the SDT has determined that no change to Requirement R6 is needed with regard to proxies. R8 - The incomplete sentence was a typo and has been deleted from Requirement R8. Footnote 12 has been added to Table 1 to address your comment on the exclusion criterion for multiple circuit towers. **Footnote 12** - Excludes circuits that share a common structure for 1 mile or less. The SDT agrees with removing the redundancy found with Extreme Event 3.b. Please see footnote 1.a.ii for clarification. **Footnote 1.a.ii -** For all other Planning Events: No generating unit or units totaling more than the Contingency ~~r~~Reserve of the Balancing Authority (or Reserve Sharing Group if applicable) shall be allowed to pull out of synchronism. Generators that pull out of synchronism must have out-of-step protection or some other means to trip the generator for this condition and the resulting apparent impedance swings must not pass through relay characteristics that would result in the tripping of any Transmission System elements other than the generating unit and its direct connection Facilities.		
ERCOT System Planning	C — Definitely do not support the revised standard	The NERC reliability standard requirements should represent the minimum studies necessary to achieve reliability given the broad range of entities of various sizes and capabilities. Instead, the standards seem to represent the gold standard of the kind of studies that could be accomplished (steady-state, short circuit, and stability) given infinite time and resources with the number and variety of contingencies and sensitivities necessary. This level of steady state and stability studies can only be undertaken by the larger entities with a deep and experienced engineering staff. Why are most of the requirements applicable to a Transmission Planner and Planning Coordinator? Unless they are the same entity, this is an unnecessary duplication of effort. If a Planning Coordinator has a number of Transmission Planners in its region, then these requirements have to be fulfilled by each Transmission Planner for its individual area and the Planning Coordinator for the region made up of the individual areas? What is the Planning Coordinator coordinating if it is duplicating the work of the Transmission Planner?
Response: The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus. The SDT is cognizant of the cost factors involved here and is taking them into consideration in its deliberations. This standard does not represent the gold standard, but rather the SDT is developing a standard based on consensus industry support.		

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The SDT recognizes that the Transmission Planner and Planning Coordinator must work closely together as defined in the NERC functional model. The Transmission Planner and Planning Coordinator should closely coordinate all work to avoid any unnecessary duplication. Requirement R6 has been included in the standard to ensure that Planning Assessments are complete and coordinated in situations where the Transmission Planner and Planning Coordinator are not the same entity.		
American Transmission Company	B — Unsure about supporting the revised standard	We agree with most of the requirements of revised standard. However, the following list of suggestions and comments are given for consideration. Definitions: We agree with the removal of the "Base Case" definition and the revisions to the other definitions, except as noted above or below. Long Term Planning Horizon definition: We suggest a slight text change of: "Transmission planning period that covers years six through ten. Studies beyond ten years are required to accommodate . . .". Accountability: We suggest that Transmission Service Provider be added because we also suggest that the Transmission Service Provider be the responsible entity for R10. Requirements: We agree with the revisions to the Requirements, except as noted above or below. R1.1 - We agree with the requirement, but would like more description of what to provide in the technical rationale. R2.1 - We agree with the requirement, but suggest this text change, ". . . by the following annual studies . . .". R2.6.1 - We agree with the requirement, but suggest a slight text change of: " . . . short circuit, Generating Unit Stability or System Stability analysis . . .". R2.6.2 - We agree with the requirement, but suggest a slight text change of: " . . . short circuit, Generating Unit Stability or System Stability analysis . . .". R2.7 - We agree with the requirement, as long as it is really required by FERC Order 693 paragraph 1704. R2.7.1 - We agree with the requirement, but suggest a slight text change of: " . . . or Special Protection Systems, . . ." R2.7.1.1 - We disagree with the "include project initiation date" portion of this requirement. The initiation date is often uncertain and subject to change, which may add considerable work to investigate, monitor and update the date. In addition, we do not know why this information is required to assure BES reliability. R2.7.2 - We agree with the requirement, as long as it is really required by FERC Order 693 paragraph 1704. R3.2.2 - We agree with the requirement, but suggest a slight text change of: "For all BES Transmission lines . . .". R3.3.2.1 - We agree with the requirement, but suggest a slight text change of: ". . . shall be allowed in the Planning

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		Assessment". R3.3.2.2 - We agree with the requirement, but suggest a slight text change of: ". . . within their Facility Ratings and within the time period allowed by the applicable time limited ratings.". R5 - Is the text referring to "known planned outages" and "known long term outages"? What is the distinction that is meant to be made between the two specified types of outages? R5.1 - We agree with the requirement, but suggest a slight text change of: ". . . the response of the applicable portion of the BES". R5.2 - This clarifying requirement should also be included in the short circuit analysis section. R5.3 - We agree with the requirement, but suggest a slight text change of: ". . . capability of all generators that may have a significant adverse effect on the BES." R5.4.3.1 - We agree with the requirement, but suggest a slight text change of: ". . . within their Facility Ratings and within the time period allowed by the applicable time limited ratings.". R8 - We disagree with the requirement, but suggest a text change of: "Each Planning Coordinator shall establish a list of neighboring system and coordinate the distribution of Planning Assessment results among affected entities the listed neighboring systems, coordinating analysis of these results through an open and transparent peer review process." Table 1Planning Events Header: We suggest that the header be repeated on every applicable page to be more reader-friendly. Superscripts: The superscripts do not refer clearly to the respective notes (e.g. there are number notes in the beginning of the table, in the extreme events evaluation requirements section, in extreme event description section, and at the end of the table). Perhaps the notes at the end of the table should have unique numbering to make the superscript references clearer. Shunt device: To avoid the need for future interpretation or clarification, we suggest that the meaning of shunt device be explained or defined somewhere in the standard (e.g. cap bank, inductor bank, SVC, STATCOM, etc.). We need to find out how shunt device outages can (or could in the future) be automatically included in the ACCC routine. We interpret that if each stage of a capacitor bank has a circuit switcher, then the outage would be of the largest cap bank stage. P2.2 (>300 kV), P2.3(>300 kV), P3 (>300 kV), P4 (>300 kV), P5 (>300 kV) - We recognize that the addition of this requirement is an attempt top raise the bar above the existing standards. However, the more stringent performance criteria should only be adopted if there is sufficient evidence to demonstrate the expected reliability risk (i.e. system impact x probability of occurrence) is high enough to warrant the cost of the system modifications that would be needed to meet the criteria. System modifications that involve the installation of line and substation facilities >300 kV will likely take years and cost tens to hundreds of millions to build. It would be helpful to have a reliability risk analysis that justifies the application of

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		this performance criteria before it is adopted. If the proposed >300 kV performance requirement is retained, then we would want the implementation timeframe to be long enough to allow reasonable time to transition from a system built to the old requirement to a system built for the new requirement. The time needed for planning, design engineering, regulatory approvals, and construction of >300 kV facilities can be very long (e.g. up to 10 or more years). P7 - We disagree with this requirement. Wisconsin statues require giving preference to using existing ROW for new transmission circuits, but this requirement discourages building multiple circuits on common ROW. Should there be a waiver in this standard similar to the TLP-503-MRO-1 standard for lines slightly more than 1 mile based on a review? Extreme Event Evaluation Requirements2 - We agree with the requirement, but perhaps a definition be added for "System Controls", since one exists for "System Protection". 3 - We agree with the requirement, but suggest a slight text change of: "Simulate Normal Clearing unless otherwise specified in the Extreme Event Descriptions." Extreme Event Descriptions2a - We agree with the description, but suggest a slight text change of: "Loss of a structure or tower line with three or more circuits.." 2b & 3b - We agree with the descriptions, but suggest referring to the defined term: "Right-of-Way." 2e, 3.a.i, & 3.a.ii - We agree with the description a, but how large is "large" and how major is "major"? 3.a.v - What is meant by successful cyber attack? Is it a type of cyber attack that is documented to have been successful? 3c - We agree with the description, but suggest a slight text change of: "Other events based upon actual operating experience such as:" Note 4 - We agree with the description, but the acronym FACTS should be explained in the standard or a definition be added for "FACTS". Table 21 - We disagree with this note. We suggest that it be expanded to include the applicable part as Table 1. "The System shall remain stable. In addition, Facility Equipment Ratings shall not be exceeded. Planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings." 3 - We disagree with this note. We suggest that it be expanded to include the applicable part as Table 1. "Dynamic voltage instability, Cascading outages, and uncontrolled islanding shall not occur." Between 3 & 4 - We disagree with omitting Note 4 of Table 1 from Table 2. We suggest including: "Consequential Load and consequential generation loss is allowed for all events shown." Planning Events Same comments on Header, Superscripts, and Shunt Device as in Table 1.Same comments about stricter requirements for P2.2 (>300 kV), P2.3 (>300 kV), P3 (>300 kV), P4 (>300 kV), P5 (>300 kV) as in Table 1.Same comment

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		about P7 as in Table 1.Extreme Event Evaluation Requirements Same comment about Requirement 2 and 3 as in Table 1. 3 - We agree with the requirement, but suggest a slight text change of: "Simulate Normal Clearing unless otherwise specified in the Extreme Event Descriptions." Notes5 - We disagree with limiting this requirement to just Category P1 category. We suggest that the synchronism requirement be applied to more categories.

Response: The SDT believes that a review of system conditions beyond the 10-year horizon is warranted. FERC Order 693 requires that the planning horizon take into account the lead times for siting and permitting of new long-distance Transmission lines and other long lead time solutions. The SDT has received industry comments regarding the need to exceed a 10-year horizon to account for longer lead time projects. Establishing planning horizons that are shorter than Transmission lead times may create gaps where the identification of a reliability need to which Transmission may be the best solution occurs too late to avert the identified reliability violation. Further, Operating Procedures or alternative short-term capital projects may be needed to limit the impact of the Planning Event until the planned Facilities can be completed. This information needs to be included in the Assessment.

In response to industry comments, the SDT has removed Requirements R9-R14 thus eliminating any need to add the Transmission Service Provider.

R1.1 - The SDT agrees and has removed the need for documentation of the technical rationale for modification of any data.

R2.1 - The SDT believes that the existing language is appropriate and there needs to be a distinction between current and past studies that would allow both to support compliance with the requirement.

R2.6.1 & R2.6.2 - Based on comments from others, the SDT has removed the requirements for separate Generating Unit Stability analysis and System Stability analysis.

R2.7 (now R2.6) – The SDT believes that it is.

R2.7.1 (now R2.6.1) - The SDT agrees with the proposed change.

Installation or modification of Protection Systems or Special Protection Systems.

R2.7.1.1 (now R2.6.2) - The SDT believes that a project initiation date is an effective measure to track a functional entity's planning and engineering activities and their efforts to provide and maintain a reliable BES.

R2.7.2 – Requirement R2.7.2 has been deleted.

R3.2.2 - The Purpose section of the Standard states that this Standard is to develop requirements for the Bulk Electric System, BES. No change required.

R3.3.2.1 – Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.8 which includes the term 'Planning Assessment'.

R2.8 The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1.

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R3.3.2.2 - Based on your comment, the SDT has addressed the applicable time-limited rating in what was Header note 'a' for Steady State Only in Table 1 - Steady State & Stability Performance. Requirement R3.3.2.2 has been deleted in favor of Header note 'e' in the revised Table. Please note that the two tables in the second draft have been reduced to one table in the third draft.

Header note 'e' - For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

R5 - The SDT agrees and has moved this concept within Requirement R1 (see Requirement R1.1.1) so that it is applicable to all Planning Assessments. Further, both Requirements R3 and R5 (now R4) have been revised to make reference to Requirement R1.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. ~~The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to c~~Contingencies ~~in Table 1 – Steady State Performance.~~ The studies shall be based on computer simulations using models utilizing data provided in Requirement R1.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~

R5.1 - Most of the industry did not have difficulty understanding that the analysis is limited to the Transmission Planner's or Planning Coordinator's portion of the BES. Therefore, the SDT is not persuaded by your comment to add extra wording.

R5.2 - The SDT has moved the short circuit analysis from Requirement R4 to Requirement R2.7 and R2 already references BES.

R5.3 - The SDT disagrees with the suggested change due to the additional studies that would be required to determine which generators would have an adverse impact.

The SDT has deleted R5.4.3.1.

The SDT has clarified this issue in Requirement R8 (now R7).

R7 Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~neighboring systems~~ adjacent Planning Coordinators and any functional entity who has indicated a reliability need, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890.

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Header - The SDT also feels that the Tables need to be as clear and concise as possible. To that end, the next version will combine Tables 1 and 2 into one table with a revised format. The Planning Events are shown on one page so repeating the headings will not be needed. Superscripts - All the notes from both tables have been combined and listed numerically. Shunt device - The SDT believes that shunt device is commonly used in the electric utility industry and does not require any further explanation. The SDT recommends contacting the software manufacturer for additional information about the ACCC routine. The SDT believes that the cap bank outage would be based on what elements would need to trip in order to clear the simulated fault condition. P2 - The SDT is attempting to raise the bar by developing a standard that appropriately supports BES reliability and has industry consensus. The majority of the SDT believes that 300 kV is an appropriate cutoff and that Transmission Systems above this level represent backbone Systems and are part of regional "grids". The SDT is cognizant of the cost factors involved here and is taking them into consideration in its deliberations and has provided for flexibility in Corrective Action Plans. The Implementation Plan will be addressed in the next posting of the standard. P7 - The SDT is cognizant of the concerns surrounding the construction of new Transmission lines, including the desire by many to fully utilize existing Right-of-Ways. In its consideration of Footnote 12 (exclusion for common structures less than 1 mile), the SDT considered the impact that this requirement could have on construction of new Facilities. However, after deliberations, the SDT believes that the 1 mile exclusion should be maintained for the reliability of the BES and that individual exceptions can be addressed within the NERC process. Extreme Events 2 - The SDT agrees that "Protection System" is defined in the Glossary of Terms Used In Reliability Standards. However, the SDT believes that this issue should be more properly addressed by the NERC SPCTF drafting team. 3 - The SDT has previously included "For all Extreme Events evaluated" at the beginning of the Evaluation Requirements for Extreme Events. No change required. 2a - The SDT believes that the Extreme Events #2.a. is already sufficient. 2b - The SDT will use the defined term of "Right-of-Way" as suggested (see 2b steady state and 2 g Stability). 2e et al - The SDT suggests that the terms "large", "major", and "successful" be defined between the Transmission Planner and Planning Coordinator. 3a - The SDT believes that the wording (was 3c) is already sufficient. No change required. Note 4 - The SDT believes that "FACTS" is commonly used in the electric utility industry and does not require any further explanation. Table 21 - The SDT has reviewed your comment and feels that your request to add "Facility Equipment Ratings shall not be exceeded. Planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings." apply to Stability is not appropriate. For the purposes of this standard, Facility Equipment Ratings refer to steady state calculated values and planned System adjustments refer to the time frame associated with returning the thermal flow within the applicable steady state Facility Rating. 3 - The SDT agrees with your comment and has made that change in Header note ‘a’ in the next version. Also, the next version will combine Tables 1 and 2			

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into one table with a revised format. 3 & 4 - The SDT has reformatted and combined the two Tables into a single Table for the next draft. 3 – The SDT has already included "For all Extreme Events Evaluated" at the beginning of the Evaluation Requirements for Extreme Events. 5 - The SDT also feels that the synchronism requirement should apply to more than just P1 Category but under certain conditions and has adjusted the notes accordingly. **Footnote 1.a.ii -** For all other Planning Events: No generating unit or units totaling more than the Contingency ~~r~~Reserve of the Balancing Authority (or Reserve Sharing Group if applicable) shall be allowed to pull out of synchronism. Generators that pull out of synchronism must have out-of-step protection or some other means to trip the generator for this condition and the resulting apparent impedance swings must not pass through relay characteristics that would result in the tripping of any Transmission System elements other than the generating unit and its direct connection Facilities.		
Duke Energy	B — Unsure about supporting the revised standard	While we generally support the revised standard, we are unsure of the total cost impact, and whether the additional costs are justified by increased reliability. 1) Load Modeling is a significant open issue. The models for dynamic studies have yet to be developed and the data is not in hand. This standard should allow for the use of the best available information. 2) Category P6 is the loss of a system element, following system adjustments, followed by the loss of another element. The table columns for this category say that interruption of firm transmission service and non-consequential load loss is allowed. The table, however, is not clear whether the interruption of firm service and non-consequential load loss is allowed as part of the system adjustment (between the outages) or whether it is only allowed after the second outage. It was stated in the NERC TPL SDT WebEx that the interruption is not allowed as part of the system adjustment. This would be a dramatic change from the existing standard and would result in the unintended consequence of significantly reducing transfer capability of interfaces to a fraction of their currently reported capability. This would in effect be imposing an n-2 criteria for offering firm transmission service. Duke Energy does not believe this would be an acceptable situation for the users, owners and operators of the bulk power system. 3) The statement in R2.7 "Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities," implies that there are performance requirements for sensitivity studies. Recommend rewording to clarify that there are no performance requirements for sensitivity studies. 4) Recommend rewording R3.3.2.1 as follows: "The single highest consequential load loss and its expected duration following a single contingency shall be documented in the Planning Assessment." 5) In R5.3 the statement, ?and identify how the generators are treated in the simulation,? should be deleted. The word "treated" is vague and typically specific equipment modeling is not identified in studies. The implementation schedule should also take into account the Standard to develop and provide this data is not approved. Since this data is not yet available, please revise the statement as follows: ?Studies shall use the best available information to consider the voltage

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		ride through capability of all generators." 6) In Table 1, Category P2 Event 1 needs to be revised to recognize the impact of this event on Bulk Electric System reliability for events on the system that are > 300 kV vs. events on the system that are <= 300 kV. P2.1 should not allow for interruption of firm transmission service or loss of non-consequential load for > 300kV; however, it should allow for interruption of firm transmission service or loss of non-consequential load for <= 300 kV. The requirement as currently written would require expenditures for the <= 300 KV system where such an event has minimal impact on Bulk Electric System reliability. In addition, the likelihood of events needs to be considered as requirements are developed. A review of Duke Energy Carolinas data shows that the likelihood of a P2.1 event on Duke's 100 kV system is an order of magnitude less than for a P1 event on the same 100 kV system. This is another indicator that the requirement as written would result in the need for expenditures that provide minimal value to enhancing the reliability of the Bulk Electric System.

Response: The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus. The SDT is cognizant of the cost factors involved here and has taken them into consideration in its deliberations in the development of this draft.

1. The SDT agrees and believes that industry guidance is needed to capture the appropriate dynamic behavior of loads. In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments. Requirement R2.4.1 has been modified to clarify expectations regarding Load modeling for dynamics studies.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources, ~~-~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

2. The SDT agrees that clarification regarding treatment of Firm Transmission Service and Non-Consequential Load Loss during adjustment is necessary. Footnote 10 in the Revision 3 of the Standard provides clarification.

Footnote #10 – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.

3. The SDT has modified the language dealing with the sensitivities in Requirement R2.7 (now R2.6) and added the phrase "run in accordance with Requirements R2.1.3 and R2.4.3." However, the performance requirements for sensitivity studies are the same as the performance requirements for the base study. The difference is that a Corrective Action Plan is required when performance requirements are not met in the base study. A Corrective Action Plan is not

Organization	Question 15:	Question 15 Comments:
necessarily required when the performance requirements are not met for a sensitivity study. **R2.6** For Planning Events shown in Table 1~~— Steady State Performance and Table 2 – Stability Performance~~, when the analysis indicates an inability of the System to meet the performance requirements in ~~the t~~Table~~s~~ 1, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed in subsequent assessments but the System shall continue to meet the performance requirements in the tables. Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3 and R2.4.3. The Corrective Action Plan shall: 4. To meet industry concern as well as FERC Order 693, the SDT has added Requirement R2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been removed from the draft. **R2.8** The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1. 5. The SDT has revised Requirement R5.3 (now R4.3.2) to provide clarification in this area. **R4.3.2** ~~Studies shall consider~~ Simulate generator performance under anticipated conditions including how the voltage ride through capability ~~of all generators and identify how the generators are treated~~ is analyzed~~in the simulation~~ 6. The SDT feels that for this event (explained in detail in footnote 8 of draft 3 of this Standard) interruption of neither firm nor Non-Consequential Load should be allowed for any BES voltage level, i.e., above or below 300 kV. This is consistent with FERC Order 693 that does not allow dropping of Non-Consequential firm Load following any single Contingency.		
Florida Reliability Coordinating Council, inc	C — Definitely do not support the revised standard	The SDT should consider and allow, for all planning events, , loss of Non-Consequential load as an interim measure for a period of up to 5 years in the situation where system load growth has caused post-contingency action plans to not effectively bring Facilities within normal operating limits due to unexpected or unforeseen regulatory requirements, equipment capability* and/or the installation of large industrial/commercial customers. *Equipment Capability is added to address unforeseen industry changes in the methodology used to calculating the rating of equipment.
Response: Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these System designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an Interruptible Load contract arrangement.		
Central Maine Power	B —Unsure about supporting the	Aside from the comments to the prior questions, there are several issues of concern that prevent us from supporting the present draft of the revised standard. We offer the following constructive comments in an effort to support the worthwhile effort that is being pursued so that we can reach a point of satisfaction that we could vote to support the revised standard.

Organization	Question 15:	Question 15 Comments:
Company	revised standard	Our concerns are listed in a rough order of priority. a. This standard as drafted does not allow exceptions for small parts of the system as long as interconnected system reliability is maintained, which is allowed in the existing TPL standards in footnotes b) and c) in Table 1. Unless such exceptions are allowed significant transfer restrictions or large reinforcements must be made. The applicable TPL footnotes are: Existing TPL footnote b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers. Existing TPL footnote c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (nonrecallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems. b. This standard does no address base conditions. Without defining base conditions the initial status of generation dispatch and transfers across the system is ill defined. Therefore the contingency analysis doesn't have a predictable basis for a consistent and repeatable study. c. The reference to Special Protection Systems is completely permissive. Although there are good applications for Special Protection Systems, their use must be constrained to have a reliable system and to promote construction of needed infrastructure. d. This standard does not provide flexibility to shed load, which restricts the ability to control post contingency response for low impact events. This may result in advancing need for upgrades in response to low impact events. This may result in advancing need for upgrades in response to low impact events. This is in conflict with FERC's directive to have the Transmission Provider waiting for market response to transmission needs and having the Transmission Provider provide a role to back stop the market. e. Definition of the Long-Term Planning Horizion. The planning horizion, for assessment purposes should be limited to 10 years. Such an assessment should be sufficient to identify requirements that may take an extended time to implement. f. Definition of Planning Coordinator is part of the NERC Functional Model, Remove from the standard. g. Put headings on each section to identify the requirements of the section. h. With respect to R2.2 - Delete "current" from the phrase "current System Peak Load Study" and replace "study" with "assessment." i. Remove R2.2.1, the requirement to extend the assessment beyond 10 years. What does the length of the project have to do with the assessment? If it takes 15 years to build something, why does this require a review of year 15? What is the

Organization	Question 15:	Question 15 Comments:
		purpose of this assessment? j. R3.3.2 requires clarification - This standard needs to permit discretion regarding the single contingencies that need to be tested, similar to R3.3.3 and R3.4. It is completely unnecessary to test all events. For example, contingencies may be limited to relevant disturbances that are contained within or directly impact the studied system. k. With respect to R3.2.1 - Clarify whether the intent of the standard is to address station service minimum voltage limitation, maximum leading VAR absorption capability or both at steady state. l. Remove R3.2.2 - Relay loadibility is addressed in the PRC-023 Standard. m. With respect to R3.3.2.1 - Recommend the removal of the requirement to assess the expected duration of Consequential Load loss. It's not considered anywhere else in the standard. n. With respect to R3.3.3 - The paragraph refers to Table 1 Contingencies P3 through P7; this should be explicitly stated. Rationale for inclusion of testing should not be required; should only need to explain why certain Contingencies were not tested. This discretion should be applicable to all contingencies. o. With respect to section R5 - The concept of planned and long-term outages should apply to the general Planning Assessment, or not at all. It should not be specific to the Stability Assessment. p. The provisions of Section R5.3 should have a corresponding MOD standard apply a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertent trip of the generator. Such a provision should include "other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how those devices are treated in the simulation. q. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizon. r. Recommend allowing the same non-consequential interruption for >300kV as for <300kV. Distinctions and acceptability should be based on consequence, not voltage class. s. What is a "current" study?
ISO New England Inc.	B — Unsure about supporting the revised standard	Aside from the comments to the prior questions, there are several issues of concern that prevent us from supporting the present draft of the revised standard. We offer the following constructive comments in an effort to support the worthwhile effort that is being pursued so that we can reach a point of satisfaction that we could vote to support the revised standard. Our concerns are listed in a rough order of priority. a. This standard as drafted does not allow exceptions for small parts of the system as long as interconnected system reliability is maintained, which is allowed in the existing TPL standards in footnotes b) and c) in Table 1. Unless such exceptions are allowed significant transfer restrictions or large reinforcements must be made. The applicable TPL footnotes

Organization	Question 15:	Question 15 Comments:
		are: Existing TPL footnote b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers. Existing TPL footnote c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (nonrecallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems. b. This standard does no address base conditions. Without defining base conditions the initial status of generation dispatch and transfers across the system is ill defined. Therefore the contingency analysis doesn't have a predictable basis for a consistent and repeatable study. c. The reference to Special Protection Systems is completely permissive. Although there are good applications for Special Protection Systems, their use must be constrained to have a reliable system and to promote construction of needed infrastructure. d. This standard does not provide flexibility to shed load, which restricts the ability to control post contingency response for low impact events. This may result in advancing need for upgrades in response to low impact events. This may result in advancing need for upgrades in response to low impact events. This is in conflict with FERC's directive to have the Transmission Provider waiting for market response to transmission needs and having the Transmission Provider provide a role to back stop the market. e. Definition of the Long-Term Planning Horizion. The planning horizion, for assessment purposes should be limited to 10 years. Such an assessment should be sufficient to identify requirements that may take an extended time to implement. f. Definition of Planning Coordinator is part of the NERC Functional Model, Remove from the standard. g. Put headings on each section to identify the requirements of the section. h. With respect to R2.2 - Delete "current" from the phrase "current System Peak Load Study" and replace "study" with "assessment." i. Remove R2.2.1, the requirement to extend the assessment beyond 10 years. What does the length of the project have to do with the assessment? If it takes 15 years to build something, why does this require a review of year 15? What is the purpose of this assessment? j. R3.3.2 requires clarification - This standard needs to permit discretion regarding the single contingencies that need to be tested, similar to R3.3.3 and R3.4. It is completely unnecessary to test all events. For example, contingencies may be limited to relevant disturbances that are contained within or directly impact the studied system.

Organization	Question 15:	Question 15 Comments:
		k. With respect to R3.2.1 - Clarify whether the intent of the standard is to address station service minimum voltage limitation, maximum leading VAR absorption capability or both at steady state. l. Remove R3.2.2 - Relay loadibility is addressed in the PRC-023 Standard. m. With respect to R3.3.2.1 - Recommend the removal of the requirement to assess the expected duration of Consequential Load loss. It's not considered anywhere else in the standard. n. With respect to R3.3.3 - The paragraph refers to Table 1 Contingencies P3 through P7; this should be explicitly stated. Rationale for inclusion of testing should not be required; should only need to explain why certain Contingencies were not tested. This discretion should be applicable to all contingencies. o. With respect to section R5 - The concept of planned and long-term outages should apply to the general Planning Assessment, or not at all. It should not be specific to the Stability Assessment. p. The provisions of Section R5.3 should have a corresponding MOD standard apply a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertant trip of the generator. Such a provision should include "other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how those devices are treated in the simulation. q. Planned outages should be addressed in the operating horizion unless otherwise defined in the planning horizion. r. Recommend allowing the same non-consequential interruption for >300kV as for <300kV. Distinctions and acceptability should be based on consequence, not voltage class. s. What is a "current" study?
Response: A. Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these System designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement. B. The SDT has modified Requirement R1 to include additional details on what should be modeled in the cases. However, the SDT intentionally provides flexibility for the Transmission Planner/Planning Coordinator to decide which "base case" to use since initial conditions for a System will vary from region to region and will need to be established on a local level, not via a national standard. The required studies and sensitivity analysis ensures that sufficient study is performed to cover an appropriate range of System conditions. C. The SDT does not believe that it would be appropriate to attempt to specify limitations to the use of Special Protection Systems in this standard. The proposed TPL-001-1 and existing standards provide adequate guidance to the industry on application of Special Protection Systems.		

Organization	Question 15:	Question 15 Comments:
D. The SDT has made clarifications regarding Firm Transmission Service and Non-Consequential Load Loss. Footnote # 10 has been added to the end of Table 1. The standard does not preclude the possibility of obtaining contractually interruptible load. It is the general opinion of the SDT that dropping of Non-Consequential Load should not be allowed for the Planning Events involving only one element as described in Table 1 of the proposed Standard, and to meet the intent of FERC Order 693. Further, this Standard is proposed to "raise the bar" to improve System reliability, which would require responses (Corrective Action Plans) to address those so-called low-impact events that may have been overlooked or ignored with the existing Standard TPL-002-0. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. E. The SDT believes that a review of System conditions beyond the 10-year horizon is warranted. FERC Order 693 requires that the planning horizon take into account the lead times for siting and permitting of new long-distance Transmission lines and other long lead time solutions. The SDT has received industry comments regarding the need to exceed a 10-year horizon to account for longer lead time projects. Establishing planning horizons that are shorter than Transmission lead times may create gaps where the identification of a reliability need to which Transmission may be the best solution occurs too late to avert the identified reliability violation. Further, Operating Procedures or alternative short-term capital projects may be needed to limit the impact of the Planning Event until the planned facilities can be completed. This information needs to be included in the Assessment. F. The definition for Planning Coordinator was deleted because the term has already been defined and added to the NERC Glossary by another SDT. G. The SDT also feels that the Tables need to be as clear and concise as possible. To that end, the next version will combine Tables 1 and 2 into one table with a revised format. H. The SDT believes that the existing language is appropriate. I. The SDT believes that a review of System conditions beyond the 10-year horizon is warranted under some circumstances. For example, if it takes 15 years to build a Transmission line, then the need for that line would have to be determined 15 years ahead of the in-service date. Therefore, Requirement R2.2.1 requires you to perform an Assessment on year 15 if it takes you 15 years to build a line. J. The SDT has removed Requirement R3.3.2 and replaced it with additional language in Requirement R3.1. The SDT does agree with your interpretation that it does not require evaluation of all single Contingencies. The SDT specifically states in **R**equirement R3.4 that those Contingencies that are expected to produce the more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe results. **R3.1** Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 ~~– Steady State Performance.~~ based on the lists created in Requirement R3.5. K. The SDT has not limited the purpose of this requirement to either minimum acceptable station service voltages or maximum Mvar absorption. The SDT believes that the purpose of Requirement R3.2.1 is to determine if generators could continue to operate or if they would trip off following the Contingency.		

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L. The SDT believes that relay load limits or loadability need to be considered in the Contingency analyses. The studies should determine if Transmission line loadings could reach the relay loadability level, which may add to the existing Contingency and perhaps, result in an unbounded cascading event.

M. To meet industry concern as well as FERC Order 693, the SDT has added Requirement R 2.9 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.9.

R2.9 The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1.

N. The SDT has re-written Requirement R3.3 (now Requirement R3.5) to address your initial concern. Although the language and format of the proposed Standard have been revised from earlier versions, the SDT continues to believe that the Transmission Planners should evaluate the System performance for the events that are expected to produce the more severe System impacts, including both single and multi-Contingency events. The wording of new Requirement R3.5 (the old Requirement R3.3.3) now requires a listing of the Contingencies to be evaluated, the rationale for their selection and why the remaining Contingencies would be expected to produce less severe results. This will provide a complete evaluation of the potential Contingencies to be studied – those selected and those excluded.

R3.5 Those Planning Event Contingencies in Table 1 ~~– Steady State Performance not covered in Requirement R3.3.2~~ that are expected to produce more severe System impacts shall be identified~~,~~ and a list of those Contingencies to be evaluated for System performance in Requirement R3.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results.

O. The SDT agrees and has moved this concept within Requirement R1 (see Requirement R1.1.1) so that it is applicable to all planning Assessments. Further, both Requirement R3 and Requirement R5 have been revised to make reference to Requirement R1.

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. ~~The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to c~~Contingencies ~~in Table 1 – Steady State Performance.~~ The studies shall be based on computer simulations using models utilizing data provided in Requirement R1.

R5 For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~

P. Requirement R5.3 has been modified to address simulation of how generators perform under conditions being studied. The current MOD standards that address steady-state and dynamic simulation data requirements do not explicitly require the Generator Operators to provide voltage ride-through capability.

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These standards are set to be addressed by Project 2010-04 within NERC's Standards Development Work Plan. It is expected that the Transmission Planner would contact Generator Operators applicable to their System to obtain such data. If the data is not provided, it would be expected that a Transmission Planner state its assumption on the Vmin used for a generator terminal voltage for assessing ride-through capability. It's likely such information could be obtained through generator manufacturers. The "Other equipment" is addressed in the revised R5.4. Q. The SDT agrees and therefore has changed R1.1.1 to state "if specifically known." R. FERC order 693 (see paragraphs 342, 1792, 1794) suggests that Non-Consequential Load loss for single Contingencies is unacceptable. Note from paragraph 1792 of order 693: "We view these arguments as based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." The fact that the table allows Load loss for some "lower probability" N-1 events (some P2 events) for any Transmission voltage is recognition by the SDT that probability impacts both costs and practicality. S. The SDT believes that a current study is a study that has been completed for the latest Assessment, as opposed to a past study that may have been completed up to five years ago.		
NSTAR Electric	B — Unsure about supporting the revised standard	Aside from the comments to the prior questions, listed below are several others issues: 1. This standard does not address base conditions regarding generation dispatch and transfers across the system. Initial condition guidelines would be very important to establishing consistent application of the performance standards. 2. This standard should allow exceptions for loss of small parts of the system as long as reliability is maintained on the interconnected BES. There is such an allowance in the existing TPL standards in Table 1, footnotes b) and c). 3. The reference to Special Protection Systems is too permissive. The use of Special Protection Systems and their inherent complexity should be restricted to ensure a reliable system and to promote construction of needed infrastructure. 4. The Long-Term Planning Horizon should be limited to 10 years, a sufficient timeframe to identify requirements that may take an extended time to implement. 5. Definition of Planning Coordinator is part of the NERC Functional Model. It should be removed from the TPL standard. 6. Put headings on each section to identify the requirements of the section. 7. With respect to R2.2, delete "current" from the phrase "current System Peak Load Study" and replace "Study" with "Assessment." 8. R3.3.2 should be changed to permit discretion regarding the single contingencies that need to be tested, similar to R3.3.3 and R3.4. It is unnecessary to test all possible events. 9. R3.2.1 should be clarified as to whether the intent of the standard is to address station service minimum voltage

Organization	Question 15:	Question 15 Comments:
		limitation, maximum leading VAR absorption capability or both. 10. Remove R3.2.2. Relay loadibility is addressed in the PRC-023 Standard. 11. In R3.3.2.1, remove the requirement to assess the expected duration of Consequential Load loss. This requirement is unnecessary and not considered anywhere else in the standard. 12. With respect to R3.3.3, the paragraph refers to Table 1 Contingencies P3 through P7; this should be explicitly stated. Also, the rationale for inclusion of testing should not be required. It only makes sense to explain why certain Contingencies were not tested. This discretion should be applicable to all contingencies in all sections of the standard.

Response: 1. The SDT has modified Requirement R1 to include additional details on what should be modeled in the cases. However, the SDT intentionally provides flexibility for the Transmission Planner/Planning Coordinator to decide which "base case" to use since initial conditions for a System will vary from region to region and will need to be established on a local level, not via a national standard. The required studies and sensitivity analysis ensures that sufficient study is performed to cover an appropriate range of System conditions.

2. Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these System designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an Interruptible Load contract arrangement. As an alternative, an entity could seek an Entity Variance for the situation described through their Regional Entity organization. In paragraph 1794 FERC clarified that "…an entity may seek a regional difference to the Reliability Standard from the ERO for case-specific circumstances". The process described by FERC as a regional difference is described in detail in the "NERC Standards Development Procedure" document under the subsection titled "Variances to NERC Reliability Standards".

3. The SDT does not believe that it would be appropriate to attempt to specify limitations to the use of Special Protection Systems in this standard. The proposed TPL-001-1 and existing standards provide adequate guidance to the industry on application of Special Protection Systems.

4. The SDT believes that a review of System conditions beyond the 10-year horizon is warranted. FERC Order 693 requires that the planning horizon take into account the lead times for siting and permitting of new long-distance Transmission lines and other long lead time solutions. The SDT has received industry comments regarding the need to exceed a 10-year horizon to account for longer lead time projects. Establishing planning horizons that are shorter than Transmission lead times may create gaps where the identification of a reliability need to which Transmission may be the best solution occurs too late to avert the identified reliability violation. Further, Operating Procedures or alternative short-term capital projects may be needed to limit the impact of the Planning Event until the planned Facilities can be completed. This information needs to be included in the Assessment.

5. The definition for Planning Coordinator was deleted because the term has already been defined and added to the NERC Glossary by another SDT.

6. The SDT has considered this action but NERC's legal staff advised against using headings in the body of standards.

Organization	Question 15:	Question 15 Comments:
7. The SDT believes that the existing language is appropriate. 8. The SDT has removed the Requirement R3.3.2 and replaced it with additional language in Requirement R3.1. The SDT does agree with your interpretation that it does not require evaluation of all single Contingencies. The SDT specifically states in Requirement R3.4 that those Contingencies that are expected to produce the more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe results. **R3.1** Studies shall be performed to determine whether the BES meets the performance requirements in Table 1~~ – Steady State Performance.~~ based on the lists created in Requirement R3.4. 9. The SDT has not limited the purpose of this requirement to either minimum acceptable station service voltages or maximum Mvar absorption. The SDT believes that the purpose of Requirement R3.2.1 (now R3.3.2) is to determine if generators could continue to operate or if they would trip off following the contingency. 10. The SDT believes that relay load limits or loadability need to be considered in the Contingency analyses. The studies should determine if Transmission line loadings could reach the relay loadability limits, which may add to the existing Contingency and perhaps, result in an unbounded cascading event. 11. To meet industry concern as well as FERC Order 693, the SDT has added Requirement R2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been removed from the draft. **R2.8** The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1. 12. Although the implied assumption that the more severe impacts would be identified in the P3 through P7 Contingencies, there may be exceptions and the SDT does not believe it necessary to modify the language in this regard. The wording of new Requirement R3.~~5~~ 4 (the old Requirement R3.3.3) now requires a listing of the Contingencies to be evaluated, the rationale for their selection and why the remaining Contingencies would be expected to produce less severe results. This will provide a complete evaluation of the potential Contingencies to be studied – those selected and those excluded. **R3.4** Those Planning Event Contingencies in Table 1 ~~– Steady State Performance not covered in Requirement R3.3.2~~ that are expected to produce more severe System impacts shall be identified~~,~~ and a list of those Contingencies to be evaluated for System performance in Requirement R3.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results.		
SERC Reliability Review Subcommittee and Planning Standards Subcommittee		C. Definitely do not support the revised standard. A majority of SERC technical experts do not support the revised standard. The primary concern is that the need for additional requirements for planning 300kV systems and above has not been demonstrated. We do not believe that a sufficient case for ?raising the bar? has been provided and that this requirement can have a huge impact on utilities and ratepayers. R2.1.3 and R2.4.3 requirements are very prescriptive. Many examples of sensitivities are already inherent in the existing requirements. Some sensitivity studies are in effect adding an additional level of contingency (N-2 or N-3). Sensitivity studies of load variation are already inherent in the fact that several different study years and conditions are already being

Organization	Question 15:	Question 15 Comments:
		required. Outages of reactive sources and generation should already be included in studies of multiple contingencies. The process of planning new generation (system impact studies) will include studies of the future with and without the proposed new equipment. The TP and PC can better select the most appropriate sensitivities for their system. We recommend that engineering judgment continue to be recognized as a vital component of planning. Category P6 is the loss of a system element, followed by system adjustments, followed by the loss of another element. The table columns for this category say that interruption of firm transmission service is allowed. The table, however, is not clear whether the interruption of firm service is allowed as part of the system adjustment (between the outages) or whether it is only allowed after the second outage. It was stated in the NERC TPL SDT WebEx (August 26, 2008) that the interruption is not allowed as part of the system adjustment. This would be a dramatic change from the existing standard and would result in the unintended consequence of significantly reducing transmission system capability to accommodate firm transmission service including reduction of transfer capability of interfaces to a fraction of their currently reported capability. This would in effect be imposing an n-2 criteria for offering firm transmission service. This would not be an acceptable situation for the users, owners and operators of the bulk power system. Additional Comments: There is concern with load modeling requirements (use of word ?appropriately? in R2.4.1). Does this requirement mandate the use of specific load models for each bus, or would an aggregate load model which represents the system as a whole be sufficient? Does the use of the PSS/E CONL function satisfy the requirements for a load model? There is a concern that R3.3.2.1 is burdensome regarding the need to keep track of the quantity of consequential load loss and expected duration. Who is collecting this information and why is it needed? It appears that this is a local regulatory issue, not a reliability issue. There is a concern with R5.6.1 with the requirement to perform simulations on 20 MW generators (to be consistent with the Registration Criteria). We recommend a 75 MW generator cutoff for required simulations.

Response: The SDT is attempting to raise the bar by developing a standard that appropriately supports BES reliability and has industry consensus. The majority of the SDT believes that 300 kV is an appropriate cutoff and that Transmission Systems above this level represent backbone Systems and are part of regional "grids". The SDT is cognizant of the cost factors involved here and is taking them into consideration in its deliberations and has provided for flexibility in corrective action plans. FERC has noted in their orders that many of the concerns about raising the bar show more concern about economics than reliability (examples, Order 890, paragraph 423; Order 693, paragraph 1792, etc.).

The SDT agrees and have clarified the language to allow the Transmission Planner and Planning Coordinator to chose the sensitivities (Requirements R2.1.3 & R2.4.3)

R2.1.3 For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

Organization	Question 15:	Question 15 Comments:
		R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: The SDT agrees that clarification regarding treatment of Firm Transmission Service and Non-Consequential Load Loss during adjustment is necessary. Footnote 10 in the Revision 3 of the Standard provides clarification. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. The SDT does not believe that specific Load models for each bus are necessary. An aggregate Load model which represents the System behavior as a whole may be used. Requirement R2.4.1 has been revised. The SDT does not believe that the use of PSS/E Activity CONL by itself provides the appropriate representation for dynamic Loads. For example, the SDT believes that using PSS/E Activity CONL is not sufficiently robust to appropriately model summer peak Loads with high concentrations of induction motors during for low voltage/motor stall conditions. A dynamic Load model such as CLOD, in conjunction with Activity CONL to model the non-induction motor load would be required to more accurately assess the system for FIDVR - Fault Induced Delayed Voltage Recovery. **R2.4.1** System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. To meet industry concern as well as FERC Order 693, the SDT has deleted Requirement R3.3.2.1 and replaced it with Requirement R 2.8. The SDT believes that quantifying the single largest Consequential Load Loss and identifying the event causing it provides a useful metric for system performance and reliability. **R2.8** The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1. The requirement for study has been changed to 20 MW for a single generator or for an aggregate of generators. This language is now in Requirement R2.5.2. **R2.5.2** For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:
Oncor Electric Delivery	B — Unsure about supporting the revised	Initially performing outstanding tasks as well as annual maintenance of documentation and regular updates would require extreme significant resources both personal and financial. Transmission Planning to this level requires high level subject matter experts with both specific transmission system knowledge as well as overall industry experience. Considerable expense would also be required to train personal and track activities. The procurement documents necessary to interface

Organization	Question 15:	Question 15 Comments:
	standard	with consultants in this area where "in house" expertise is not available would also be required. Time would also be spent on evaluating new software and analysis tools such as EPRI dynamic models. A phased in approach would be taken to complete the tasks while still performing essential Oncor and ERCOT related activities associated with System Planning.
Response: The SDT has received many comments regarding the increased planning requirements to meet the proposed standard. However, the SDT believes that the requirements for sensitivity studies must remain to satisfy FERC Order 693. FERC has stated that the sensitivity studies would be used to document the selection of critical System conditions and study years used in assessing System conditions (see paragraph 1704) and that System conditions are as important as Contingencies in evaluating the performance of present and future Systems (paragraph 1705). The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus. The SDT is cognizant of the cost factors involved and has considered them in its deliberations. The SDT is developing the Implementation Plan and will include it in the next draft of the standard		
FirstEnergy Corp.	A — Generally support the revised standard	1) For this standard, "Protection System" failure should be limited to only relay event failures. 2) R1 ? As stated in our response to Question 5, FE does not support the modeling requirements within the TPL standard and suggest that the SDT remove these requirements. This standard should be viewed on a premise that a valid and appropriate system model exist so that the fundamental focus of the standard is as stated in its purpose statement "Establish Transmission System planning performance requirements... to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions." If R1 remains, the phrase "and other data sources" should be removed. 3) R1.1 ? this requirement requires the documentation of ANY data modification. Do you really mean ANY? How much detail is needed in the documentation? Is a line by line comparison of all data values before/after needed or is a general overview discussion sufficient? For instance, FE replaces its system model as shown in the MMWG representation with a more detailed system representation model when performing planning studies. This can included many differences from the MMWG system equivalent. How much documentation is needed in this situation? 4) R2.6 ? This is not a requirement and should be removed and shown as explanatory text (footnote). 5) R3 - Requirement R3.1 is redundant to statements in the text of R3 and R3.3 and R3.4. We suggest that R3.1 be removed. It is suggested that R3.4 be indented and become a R3.3 sub-requirement. R3.5 would be better placed ahead of R3.3 along with the existing R3.2.
Response: 1. The SDT believes that these protection issues will be further clarified by the NERC SPCTF drafting team. The spirit of the TPL standard will remain that Load loss must not be planned for any single failure. 2. The SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning		

Organization	Question 15:	Question 15 Comments:
Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations. 3. The SDT agrees and has removed the need for documentation of the technical rationale for modification of any data. 4. The SDT disagrees and believes that the format and language of Requirement R2.6 (now R2.5) and its new sub-requirements are appropriate. 5. The SDT has modified the language of Requirement R3.1 and deleted Requirement R3.3 to eliminate the redundancy. **R3.1** Studies shall be performed to determine whether the BES meets the performance requirements in Table 1~~ – Steady State Performance.~~ based on the lists created in Requirement R3.5.		
Orlando Utilities Commission	C — Definitely do not support the revised standard	This standard is a definite improvement over the current set of standards. The majority of my comments are on details rather then the overall concept. My single biggest concern is the handling of n-1-1. This represents a significant expense to transmission customers and serious restriction on making firm transmission available, but due to the low probability of these events it would represent little if any practical improvement in customer reliability or grid security.
Response: Please see footnote #10 with regard to N-1-1. The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus. The SDT is cognizant of the cost factors involved here and is taking them into consideration in its deliberations. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
Entergy Services, Inc.	C — Definitely do not support the revised standard	No cost-benefit studies have been completed to justify the significant investment and no detailed analysis of the expected reliability impact has been conducted for the Eastern Interconnection. Some research suggests that infrastructure expansion will reduce the number of large BES events, but that each event would impact larger areas with longer restoration times. http://eceserv0.ece.wisc.edu/~dobson/PAPERS/complexsystemsresearch.html Additionally, there is a fatal disconnect between the enhanced reliability standard and the FERC's current standard for selling firm transmission service. A utility cannot be required to build to an N-1-1 standard to satisfy reliability requirements and also be required to sell additional firm transmission service using a lower N-1 reliability standard. Such a situation would create an untenable situation where reliability standards force construction that the utility is then required to make available for sale pursuant to the provisions of the OATT and, once sold in accordance with the OATT, results in the utility being out of compliance with the reliability requirement. Requirement P2.1 in the table will have direct impact on local load reliability but not grid reliability. For example, a long line

Organization	Question 15:	Question 15 Comments:
		in a radial configuration due to a single contingency would only impact the reliability in a local area. Any implementation plan should consider all aspects of obstacles that Transmission owners will encounter including, ROW and land acquisition delays, inflationary impact on raw materials and other resources, capital funding constraints and associated regulatory lag, etc. Category P6 prescribes what is effectively an n-2 criteria for offering firm transmission service by not allowing the curtailment of firm transmission service as a system adjustment. Many areas are limited in how much local generation is available for re-dispatch as a system adjustment and thus compliance would be realized only by costly transmission construction by TPs.
Response: The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus. The SDT is cognizant of the cost factors involved here and is taking them into consideration in its deliberations. The SDT agrees that clarification regarding Firm Transmission Service and Non-Consequential Load Loss is necessary. Footnote # 10 has been added to the end of Table 1: **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. The SDT agrees that the Implementation Plan should consider matters you have listed. Nevertheless, the SDT feels that for this event (explained in detail in the footnote 8 of draft 3 of this Standard) interruption of neither firm nor Non-Consequential Load should be allowed for any BES voltage level, i.e., above or below 300 kV. This is consistent with FERC Order 693 that does not allow dropping Non-Consequential firm Load following any single Contingency. The SDT agrees that clarification regarding treatment of Firm Transmission Service and Non-Consequential Load Loss during adjustment is necessary. Footnote 10 in draft 3 of the Standard provides clarification.		
BPA Transmission Reliability Program	B — Unsure about supporting the revised standard	We are unsure about supporting the revised standard. A couple of additional concerns are described below. The purpose of the Standard is not clearly defined. There should be more clarity given to what reliability means in the context of these standards (e.g. minimize load loss for more probable contingencies, etc.). Regarding the terms "interruption of firm transmission service", there needs to be clarification of what "Interruption" means. Does it include curtailment needed after a particular contingency and adjustments? There also needs to be clarification on what "Firm Transmission Service" means. Two points: 1) the NERC definition states "highest quality of service offered to customers under a filed rate schedule that anticipates no planned interruption." The Standard implies anticipation of "unplanned' interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order

Organization	Question 15:	Question 15 Comments:
		890, or firm transfers modeled for the conditions being studied? One way to interpret the intent, is the firm transfers being modeled for the conditions in the powerflow, to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load, if the transfer being modeled is interrupted, then interruption of firm transmission service should be allowed for P1 through P5 contingencies in the table.
Response: The SDT believes that the Purpose under A.3 adequately captures the main intent which is to develop a "Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies." Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency. However, until the next Contingency occurs, System performance will need to meet the requirements for Event P1. As such, the proposed standard will not allow loss of any Non-Consequential Load, except for contracted Interruptible Loads, in preparation for the next Contingency. "Firm Transmission Service" is a NERC defined term and is also addressed by FERC in OATT. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
PPL EnergyPlus	A — Generally support the revised standard	
Response: Thank you for your support.		

Consideration of Comments on Third Draft of Standard TPL-001-1 — Project 2006-02

The Assess Transmission Future Needs Standard Drafting Team thanks all commenters who submitted comments on the third draft of the TPL-001-1 standard. This standard was posted for a 45-day public comment period from May 26, 2009 through July 9, 2009. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 85 sets of comments, including comments from more than 170 different people from over 85 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

Due to industry comments and continuing review of Order 693 directives applicable to TPL, changes have been made to the following:

Definitions: Consequential Load Loss, Non-Consequential Load Loss, and Year One

Requirements: R1 and parts 1.1, 1.1.1, 1.1.2, 1.1.3, 1.1.4, 1.1.5, and 1.1.6; R2 and parts 2.1, 2.1.3, 2.1.4 (and bullets 1, 3, and 7), 2.1.5, 2.1.6, 2.2, 2.2.1, 2.3, 2.4, 2.4.1, 2.4.3 (and bullets 1 and 3), 2.5, 2.6.1, 2.6.2, 2.7, 2.7.1 bullet 2, 2.7.2, 2.7.5, 2.7.6, 2.8, 2.8.2, 2.9; R3 and parts 3.1, 3.2, 3.3, 3.3.2, 3.3.3, 3.3.4, 3.4, 3.4.1, 3.5, 3.6; R4 and parts 4.1, 4.1.1, 4.1.2, 4.1.3, 4.2, 4.3, 4.3.2, 4.3.3, 4.3.4, 4.4, 4.4.1, 4.5; R5, R6, R7; R8 and part 8.1.

Measures: M1, M5, M7, and M8.

VSLs: R1, R2, R3, R4, R5, R6, R7, and R8.

Table elements: Header notes 'a', 'c', 'f', and 'k'; P4, P7; extreme event 'a', steady state 1, Stability 1; footnotes: 2, 3, 4, 7, 9, 10, and 11

Implementation Plan

In addition, the SDT has reformatted the standard to meet the latest guidelines.

The SDT feels that the volume and scope of these changes warrants a fourth posting of this standard.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

1. Requirement R1 — Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement. 12

2. Requirement R2 — Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement. 59

3. Requirement R3 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement. 176

4. Requirement R4 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement. 211

5. Requirement R5 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement. 238

6. Requirement R6 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement. 245

7. Requirement R7 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement. 250

8. The SDT changed several definitions in response to industry comments to the second posting. Do you agree with these changes? If not, please clearly indicate which definition you disagree with and provide specific comments. 263

9. Do you agree with the changes in the performance elements and notes in Table 1? If not, please provide specific comments by note number, note alpha character, or performance category. Please note that footnotes 5 and 10 are handled separately in question 10. 289

10. The changes to the Table include the addition/revision of footnotes 5 and 10 that address curtailment of Firm Transmission Service and conditional Firm Transmission Service. Do you agree with the footnotes? If not, please provide specific comments.332

11. The SDT has provided an Implementation Plan as part of this posting. The plan includes the retirement of TPL-005-0 and TPL-006-0. Do you agree with the elements of the Plan? If not, please provide specific comments. 343

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	William Bigdely	Dominion - Electric Transmission	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	J. Ronnie Bailey	Dominion - Electric Transmission Planning	SERC	
2.	Kirit Doshi	Dominion - Electric Transmission Planning	SERC	
3.	Craig Crider	Dominion - Electric Transmission Planning	SERC	
4.	Mehdi Shakibafar	Dominion - Electric Transmission Planning	SERC	
5.	Dennis Kaminsky	Dominion - Electric Transmission Planning	SERC	
6.	Solomon Yirga	Dominion - Electric Transmission Planning	SERC	
7.	Michael Gildea	Dominion - Electric Market Policy	SERC	
8.	Louis Slade, Jr.	Dominion - Electric Market Policy	SERC	
9.	Jalal Babik	Dominion - Electric Market Policy	SERC	

2.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ralph Rufrano	New York Power Authority	NPCC	5
2.	Alan Adamson	New York State Reliability Council	NPCC	10
3.	Gregory Campoli	New York Independent System Operator	NPCC	2
4.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
5. Kurtis Chong	Independent Electricity System Operator	NPCC 2										
6. Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC 1										
7. Manuel Couto	National Grid	NPCC 1										
8. Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC 1										
9. Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC 3										
10. Mike Garton	Dominion Resources Services, Inc.	NPCC 5										
11. Brian L. Gooder	Ontario Power Generation Incorporated	NPCC 5										
12. Kathleen Goodman	ISO - New England	NPCC 2										
13. David Kiguel	Hydro One Networks Inc.	NPCC 1										
14. Michael R. Lombardi	Northeast Utilities	NPCC 1										
15. Michael Schiavone	National Grid	NPCC 1										
16. Bruce Metruck	New York Power Authority	NPCC 6										
17. Chris Orzel	FPL Energy/NextEra Energy	NPCC 5										
18. Robert Pellegrini	The United Illuminating Company	NPCC 1										
19. Gerry Dunbar	Northeast Power Coordinating Council	NPCC 10										
20. Lee Pedowicz	Northeast Power Coordinating Council	NPCC 10										
3. Group	W. R. Schoneck	Transmission Planning	X		X							

Additional Member	Additional Organization	Region	Segment Selection
1. John Shaffer	FPL	FRCC	
2. Pedro Modia	FPL	FRCC	
3. Carlos Candelaria	FPL	FRCC	
4. Kiko Barredo	FPL	FRCC	

4. Group	Phillip R. Kleckley	SERC Engineering Committee Planning Standards Subcommittee			X							

Additional Member	Additional Organization	Region	Segment Selection
1. John Sullivan	Ameren	SERC	1
2. Jim Kelley	PowerSouth Energy Coop	SERC	1
3. Pat Huntley	SERC Reliability Corp	SERC	10
4. Bob Jones	Southern Co. Services	SERC	1
5. David Marler	TVA	SERC	1

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
5.	Group	Steve Hill	Modesto Irrigation District	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Spencer Tacke	Modesto Irrigation	WECC	

6.	Group	Matt Muldoon	OPUC									X	

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jerry Murray	OPUC	WECC	9

7.	Group	Richard Kafka	Pepco Holdings, Inc. - Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Mitchell	Delmarva Power & Light	RFC	1
2.	John Radman	Potomac Electric Power Co.	RFC	1
3.	Jim Summers	Atlantic City Electric	RFC	1
4.	Brian Willis	Potomac Electric Power Co.	RFC	1
5.	Lisa Fairchild	Potomac Electric Power Co.	RFC	1

8.	Group	Denise Koehn	Bonneville Power Administration	X				X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Berhanu Tesema	Transmission Planning	WECC	1
2.	Chuck Matthews	Transmission Planning	WECC	1
3.	Kyle Kohne	Transmission Planning	WECC	1
4.	Melivin Rodrigues	Transmission Planning	WECC	1
5.	Kendall Rydell	Transmission Planning	WECC	1
6.	Larry Furumasu	Transmission Planning	WECC	1

9.	Group	Carol Gerou	MRO MRO NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Neal Balu	Wisconsin Public Service	MRO	3, 4, 5, 6
2.	Terry Bilke	Midwest ISO Inc.	MRO	2
3.	Ken Goldsmith	Alliant Energy	MRO	4

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
4. Jim Haigh	Western Area Power Administration	MRO	1, 6									
5. Joseph Knight	Great River Energy	MRO	1, 3, 5, 6									
6. Alice Murdock	Xcel Energy	MRO	1, 3, 5, 6									
7. Scott Nickels	Rochester Public Utilities	MRO	1, 3, 5, 6									
8. Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6									
9. Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6									
10. Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6									
10. Group	Rick Foster	SERC Engineering Committee Dynamics Review Subcommittee (DRS)	X									X

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren Services Company	SERC	1
2.	Anthony Williams	Duke Energy Carolinas	SERC	1
3.	Sujit Mandal	Entergy	SERC	1
4.	Venkat Kolluri	Entergy	SERC	1
5.	John O'Connor	Progress Energy Carolinas	SERC	1
6.	Bob Jones	Southern Company Services, Inc. - Trans	SERC	1
7.	Lee Taylor	Southern Company Services, Inc. - Trans	SERC	1
8.	Robbie Bottoms	Tennessee Valley Authority	SERC	1
9.	Tom Cain	Tennessee Valley Authority	SERC	1
10.	Herb Schrayshuen	SERC Reliability Corporation	SERC	10

11. Group	Ian Grant	SERC Engineering Committee Reliability Review Subcommittee (RRS)	X									X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Curtis Stepanek	Ameren Services Company	SERC	1
2.	Eugene Warnecke	Ameren Services Company	SERC	1
3.	Kevin Hopper	Associated Electric Cooperative, Inc.	SERC	1
4.	Karl Kohlrus	City of Springfield, IL - CWLP	SERC	1
5.	Brian D. Moss	Duke Energy Carolinas	SERC	1
6.	Julia Tucker	East Kentucky Power Cooperative	SERC	1
7.	Kham Vongkhamchanh	Entergy	SERC	1

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
8. Ken Wofford			Georgia Transmission Corporation SERC 1										
9. Mark Kuras			PJM Interconnection, LLC SERC 1										
10. Mark Byrd			Progress Energy Carolinas SERC 1										
11. Clay Young			South Carolina Electric & Gas Company SERC 1										
12. Rod Hardiman			Southern Company Services, Inc. - Trans SERC 1										
13. Timothy Smith			Tennessee Valley Authority SERC 1										
14. Herb Schrayshuen			SERC Reliability Corporation SERC 10										
12.	Group	Doug Hohlbaugh	FirstEnergy Corp	X		X	X	X	X				
Additional Member		**Additional Organization**	**Region** **Segment Selection**										
1. John Stephens		FE	RFC 1										
2. Jeff Mackauer		FE	RFC 1										
13.	Group	Ben Li	IRC Standards Review Committee		X								
Additional Member		**Additional Organization**	**Region** **Segment Selection**										
1. Matt Goldberg		ISO-NE	NPCC 2										
2. Bill Phillips		MISO	MRO 2										
3. Anita Lee		AESO	WECC 2										
4. James Castle		NYISO	NPCC 2										
5. Charles Yeung		SPP	SPP 2										
6. Steve Myers		ERCOT	ERCOT 2										
7. Lourdes Estrada-Salinero		CAISO	WECC 2										
8. Pat Brown		PJM	RFC 2										
14.	Individual	Tim Ponseti, VP	TVA System Planning	X									
15.	Individual	Eric Mortenson	Exelon Transmission Planning	X		X		X					
16.	Individual	Hugh Francis	Southern Company	X		X		X					
17.	Individual	David Bradt	United Illuminating	X									
18.	Individual	Cordell Grand	Louisiana Energy and Power Authority			X							

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
19.	Individual	Mark Graham	System Protection and Transmission Planning Department	X									
20.	Individual	John Cummings	PPL Energy Plus						X				
21.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
22.	Individual	Brandy A. Dunn	Western Area Power Administration	X									
23.	Individual	Min Tra	Tampa Electric	X				X					
24.	Individual	Richard Becker	Florida Reliability Coordinating Council, Inc - Transmission Working Group	X			X	X					X
25.	Group	Frank Gaffney, Regulatory Compliance Officer	FMPA, and it's All-Requirements Project Participants, as follows: Lakeland Electric; Fort Pierce Utilities Authority; Keys Energy Services; City of Vero Beach; Beaches Energy Services; Kissimmee Utility Authority; and Lake Worth Utilities	X		X			X				
26.	Individual	Mark Byrd	Progress Energy Carolina (PEC)	X									
27.	Individual	John Allen	City Utilities of Springfield, MO	X									
28.	Individual	Blake Williams	CPS Energy	X				X					
29.	Individual	Tom Mielnik	MidAmerican Energy Company	X		X		X	X				
30.	Individual	James Tucker	Deseret Generation & Transmission	X		X		X					
31.	Individual	Michael R. Lombardi	Northeast Utilities	X		X	X	X					
32.	Individual	Brian Keel	SRP	X									
33.	Individual	L. Earl Fair	Gainesville Regional Utilities	X									

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
34.	Individual	Don Gilbert	JEA	X		X		X					
35.	Individual	Catherine Mathews	NorthWestern Corporation NorthWestern Energy (NWE) (NWMT)	X		X		X					
36.	Individual	Dilip Mahendra	SMUD	X		X	X	X	X				
37.	Individual	Bart White	Progress Energy Florida, Inc.	X		X							
38.	Individual	Alice Murdock	Xcel Energy	X		X			X				
39.	Individual	Kathleen Goodman	ISO New England, Inc.		X								
40.	Individual	Baj Agrawal	Arizona Public Service Co	X		X							
41.	Individual	Randy MacDonald	New Brunswick System Operator		X								
42.	Individual	Dana Cabbell	Southern California Edison Company	X		X							
43.	Individual	Terry Huval	Lafayette Utilities System										
44.	Individual	Robert Easton	Western Area Power Administration	X								X	
45.	Individual	Robert Priest	Mississippi Delta Energy Agency										
46.	Individual	Roger Champagne	Hydro-Québec TransEnergie (HQT)	X									
47.	Individual	Phil Sanchez	Western Area Power Administration	X								X	
48.	Individual	Chifong Thomas	Pacific Gas and Electric Co,	X		X		X					
49.	Individual	Kirit Shah	Ameren	X		X		X	X				
50.	Individual	Joe Seabrook	Puget Sound Energy, Inc.	X									
51.	Individual	Eric Bryant	Maine Public Advocate								X	X	

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
52.	Individual	Scott Helyer	Tenaska, Inc.					X					
53.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
54.	Individual	Brent Ingebrigtson	E.ON U.S.	X		X		X	X				
55.	Individual	Sergio Garza	LCRA Transmission Services Corporation	X									
56.	Individual	Carol Sedewitz	National Grid	X									
57.	Individual	Edward J Davis	Entergy Services, Inc	X		X		X	X				
58.	Individual	Joe Knight	Great River Energy	X		X		X	X				
59.	Individual	Pat Harrington	BC Hydro			X		X	X				
60.	Individual	Marie Knox	Midwest ISO		X								
61.	Individual	Jessica Rice	NV Energy	X									
62.	Individual	Mark Kuras	PJM		X								
63.	Individual	David Albers	Brazos Electric Cooperative	X									
64.	Individual	James H. Sorrels, Jr.	American Electric Power	X		X		X	X				
65.	Individual	Michael Ayotte	ITC Holdings	X									
66.	Individual	Mary Ann Groszek	Northern Indiana Public Service Company	X									
67.	Individual	Wang, Yu (David)	San Diego Gas and Electric Co	X									
68.	Individual	Peter S. Schommer	Minnesota Power			X		X	X				
69.	Individual	Tim Wu	LADWP	X		X		X					

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
70.	Individual	John Collins	Platte River Power Authority	X									
71.	Individual	Larry Brusseau	MAPPCOR			X							
72.	Individual	Aaron Staley	Orlando Utilities Commission	X				X					
73.	Individual	Jason Shaver	American Transmission Company	X									
74.	Individual	John Mayhan	Omaha Public Power District	X		X		X	X				
75.	Individual	David Angell	Idaho Power	X									
76.	Individual	Casey Hashimoto	Turlock Irrigation District			X							
77.	Individual	Gregory Campoli	New York Independent System Operator		X								
78.	Individual	Greg Rowland	Duke Energy	X		X			X				
79.	Individual	David M. Conroy	Central Maine Power Company	X									
80.	Individual	Darcy O'Connell	California ISO		X								
81.	Individual	Gary Trent	Tucson Electric Power Company	X		X		X					
82.	Individual	Dan Rochester	Independent Electricity System Operator		X								
83.	Individual	Harold Wyble	Kansas City Power & Light	X		X		X	X				
84.	Individual	Rao Somayajula	ReliabilityFirst Corporation										
85.	Individual	Vivian Wang	British Columbia Transmission Corporation										

1. **Requirement R1 — Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.**

Summary Consideration: The SDT has made several clarifying changes to Requirement R1 and its various parts based on industry comments. The major changes made were to delete the phrase "including requirements of regulatory authorities and other legal obligations" from Requirement R1, the addition of "existing facilities' to the parts of Requirement R1, changing 'planned' outages to 'known' outages, combining the part calling for Firm Transmission Service and Interchange, and clarifying the final part as to the use of resources. Measure M1 was revised to provide greater clarity. The VSLs for Requirement R1 have been revised to match the new wording in the requirement.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.

1.1 System models shall represent:

1.1.1 Existing Facilities

1.1.2 Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3 New planned Facilities and changes to existing Facilities

1.1.4 Real and reactive Load forecasts

1.1.5 Known commitments for Firm Transmission Service and Interchange

1.1.6 Resources required to supply Load

M1 Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

R1 VSL	The responsible entity's System model failed to represent one of the Requirement R1, parts 1.1.1 through 1.1.6	The responsible entity's System model failed to represent two of the Requirement R1, parts 1.1.1 through 1.1.6. OR The System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and	The responsible entity's System model failed to represent three of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, parts 1.1.1 through 1.1.6. OR The System model did not represent projected System conditions as described in Requirement

		MOD-012 standards and other sources, including items represented in the Corrective Action Plan.		R1.

Organization	Question 1 Comment
Dominion - Electric Transmission	R1 - Dominion questions the legal authority NERC has to include the recently inserted language "including requirements of regulatory authorities and other legal obligations." This language is too broad and far exceeds the jurisdiction of NERC's mission. R1.1.5 - Dominion has seen base case models built by other transmission entities which do not include area interchanges for all areas and must be solved with area interchange "turned off". Would these base case models be in violation of R.1.1.5?
Response: The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The SDT believes that the base cases should include any area interchange that is planned between utilities. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange	
Northeast Power Coordinating Council	R1--There needs to be some direction provided on the initial conditions used in the assessment. This guidance should include discussion as to whether or not representations of generator forced outages are to be represented in the base case or if they are addressed through the sensitivity testing (Could add R1.1.7 Reasonable representations of unplanned generator outages.) Additionally, the standard is also silent on the treatment of system transfers, both internal and external, as to how they should be modeled in the base case. For some areas, their current practice is to include heavy system stresses in their base case, which leaves little for sensitivity testing. It is unclear if this practice works within the purview of this standard. Guidance is needed on how to treat base case generation dispatch and system transfers. The inclusion of "requirements of regulatory authorities and other legal obligations" is not understood. Even if some version of this language is kept in the final standard, it seems to belong in R2 rather than R1. "Simulate" should be changed to "incorporate". R1.1.1 Priority comment. Only known long-term outages of generation and transmission should be required to be modeled.

Organization	Question 1 Comment
	R1.1.2 comment - Do we need to have the list of equipment to model? How are circuit breakers, and other equipment modeled? Also, what should be the level of detail and the form that Protection System Equipment and Control Devices be modeled? We recommend deleting the list. Make R1.1.2 simply read as follows: R1.1.2--Projected system configuration, taking into account new planned Facilities and changes to existing Facilities, for each year of the Near-Term and Long-Term Transmission Planning Horizon. R1.1.5 comment What specifically needs to be modeled under Interchange "R1.1.6 comment " This needs further definition or it should be deleted. It is not clear what a network resource required to supply load is. Does this refer to Network Resource per FERC LGIP?

Response: The SDT believes that the outages should be modeled to insure the System reliability during the outage durations. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-Contingency. All performance criteria would then apply to that new base case. Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months.

1.1.2 Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange.

1.1.5 Known commitments for Firm Transmission Service and Interchange

The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models within their respective areas for performing the studies needed to complete their Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.

The SDT has changed the word "simulate" to "represent" in Requirement R1.

Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months.

The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices is typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list as they are already covered in the Corrective Action Plan under Requirement R2, part 2.7. Existing Facilities are now shown under Requirement R1, part 1.1.1.

1.1.1 Existing Facilities

Interchange is defined in the NERC glossary as "energy transfers that cross Balancing Authority boundaries" while Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.5 has been revised to include

Organization	Question 1 Comment
known commitments for Firm Transmission Service and Interchange. The intent of the SDT was that this includes network resource as per the FERC LGIP but that it is not limited to that. The SDT has clarified the wording for Requirement R1, part 1.1.6. **1.1.6** Resources required to supply Load	
Transmission Planning	R1.1. COMMENT: Should read: Models for performing the studies needed to complete the Planning Assessment shall represent: instead of Models for the Planning Assessment shall represent: R1.1.1. COMMENT: Should the requirement specify which known outages should be modeled? For example, would it be considered incomplete and therefore a violation if a known generator maintenance outage with a one week duration is not included (not modeled off-line) in a case that represents a full summer season at peak conditions? Please provide guidelines as to what duration outages should be modeled in representative planning horizon cases. (i.e. one day, several days, one week, one month, in a case that represents a significantly longer time period.) R1.1.2. COMMENT: Should add Transformers to this list; COMMENT: What is meant by “represent” - Planning models do not typically include explicit Circuit breaker modeling. The planning models used for power flow, dynamics and short circuit analysis represent the power system with busses and branches. The effect of circuit breakers is taken into account as part of contingency modeling. Including circuit breakers as a sub-requirement is likely to result in transmission planners being required to demonstrate that circuit breakers are modeled. Explicit representation of circuit breakers with existing software would result in major convergence problems due to large number of low impedance branches. COMMENT: Should clarify "Protection System equipment" to apply only to system stability models. Does this mean all relays on the system must be included in the dynamics modeling? While a certain limited number of protective relays can be modeled with the software used for dynamics, it is not practical to model more than a very small percentage of the protection systems used in the BES. Including protective relays as a sub-requirement is likely to result in transmission planners being required to demonstrate that all protective relays are modeled which is an impossible task. The modeling of protective relays should be caveated with as deemed appropriate. COMMENT: "Control devices" Should be specific. Is this for Phase Angle Regulators (PAR), Synchronous Condensers, Static Var Compensators (SVC), exciters, governors etc? Control devices should be specifically defined as the following: PAR, SVC, HVDC. COMMENT: "New technologies" seems too broad. Needs to be better defined. Planning models may not have the capability to adequately model new technologies. R1.1.4. Firm Transmission Service COMMENT: Should add that is expected to be utilized in the study case scenario because not all Firm Transmission Service can be included in every study case model. Some firm transmission reservations (Network Resources that could be Reserves) are used optionally depending upon the availability of other Network resources. The following apply to all VRF, Time Horizon, Measure, Data Retention, and VSL for all requirements in the standard.VRF: Agree. No comment.

Organization	Question 1 Comment
	Time Horizon: COMMENT: Long-Term Planning This is confusing. Is it only the newly defined Long-Term Transmission Planning Horizon? Shouldn't it include the Near-Term Transmission Planning Horizon Suggest Long-Term and Near-Term Transmission Planning Horizon as used in definitions. Measure: Agree. No comment. Data Retention: Agree. No comment. VSL: Are bullets in requirements all required? (I.e. If circuit breakers are not explicitly modeled, as the bullet list in R1.1.2 seems to indicate, is it a violation?) What is meant by did not simulate projected System conditions as described in R1. How are projected System conditions criteria described in R1?

Response: The SDT has reworded the requirement.

1.1 System models shall represent:

Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months.

1.1.2 Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list as they are already covered in the Corrective Action Plan under Requirement R2, part 2.7.

The SDT has revised Requirement R1, part 1.1.2 to provide clarity.

New technologies include any technology that is not currently in use on the electric power System that helps improve efficiency (i.e., energy storage/production technologies, low sag conductors, solid state interrupters, etc.). New technologies were removed from the equipment list under Requirement R1, part 1.1.2 since these are already covered in the Corrective Action Plan under Requirement R2, part 2.7

Models are only specific to the case study. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange.

1.1.5 Known commitments for Firm Transmission Service and Interchange

The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made.

Mitigation Time Horizon - The time horizons available for mitigating a violation to a requirement include the following::

- **Long-term Planning** — a planning horizon of one year or longer.

Organization	Question 1 Comment

- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

Thank you for your response on Measures and Data Retention.

The SDT has removed the equipment list. Transmission lines, generators, and reactive power devices were removed from the equipment list due to already being included in MOD standards. Circuit breakers, Protection System equipment, and control devices were removed from the equipment list since these items are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note c in Table 1. New technologies were removed from the list as they are already covered in the Corrective Action Plan under Requirement R2, part 2.7.

The SDT has deleted the equipment list.

The SDT has replaced "simulate" with "represent" under the Severe VSL category for R1.

R1 VSL	The responsible entity's System model failed to represent one of the Requirement R1, parts 1.1.1 through 1.1.6	The responsible entity's System model failed to represent two of the Requirement R1, parts 1.1.1 through 1.1.6. OR The System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.	The responsible entity's System model failed to represent three of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, parts 1.1.1 through 1.1.6. OR The System model did not represent projected System conditions as described in Requirement R1.

Requirement R1 contains the requirements needed for creating proper base cases.

SERC Engineering Committee Planning Standards	R1.1.2: In bullet three of R1.1.2, are bus-tie circuit breakers to be represented in the models? Typically circuit breakers are included in the contingency definitions along with the protection system equipment used in the power flow models. The number of zero impedance branches which can presently be modeled using PSS/E software is limited to 4000. Also, the number of buses

Organization	Question 1 Comment
Subcommittee	included in the power flow models would increase with additional breaker modeling. Protection System Equipment: The SDT stated during its June 30th Webinar that protection system equipment need not be explicitly represented in models, but had difficulty in determining adequate wording for the proposed sub-requirement. Because protection system action is described in R3.3.1, R3.3.4, R4.3.1, and R4.3.3 we suggest that protection system equipment be removed from the list in R1.1.2.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.	
Modesto Irrigation District	Comment: Are all bullets under R1.1.2 required to be explicitly modeled or are the effect of the devices or the effect of the removal of the devices to be modeled? We don't explicitly model circuit breakers or explicitly model protection system equipment in the steady state model. R1.1.4 should refer to expected transfers to be consistent with the bullet under R2.1.3. Please explain the difference between R1.1.4 and R1.1.5
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. Requirement R1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange Interchange is defined in the NERC glossary as "energy transfers that cross Balancing Authority boundaries" while Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption."	
OPUC	1. Requirement R1 Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.Comments: A: Language in R1.1.2 still needs further clarification. Base case models do not clarify modeling required for the effect or absence of circuit breakers, protection system equipment and control devices. B: Clarity would be increased were R1.1.4 to refer to expected transfers rather than Firm Transmission Service, permitting the elimination of then redundant R1.1.5 C: Removing "including requirements of regulatory authorities and other legal obligations" at the end of R1 would also eliminate redundant text.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices	

Organization	Question 1 Comment
are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. **1.1.3** New planned Facilities and changes to existing Facilities Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective areas for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.	
Bonneville Power Administration PacifiCorp Deseret Generation & Transmission SRP Southern California Edison Company Pacific Gas and Electric Co, NV Energy San Diego Gas and Electric Co California ISO	The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices where it is expected to impact the study outcome. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted. We disagree with the inclusion of the words including requirements of regulatory authorities and other legal obligations at the end of R1. Entities already are required to do this. It does not need to be included in the standard.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. Interchange is defined in the NERC glossary as "energy transfers that cross Balancing Authority boundaries" while Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.5 has been revised to include	

Organization	Question 1 Comment
known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.	
SERC Engineering Committee Dynamics Review Subcommittee (DRS)	There may be a potential conflict between MOD-010 and MOD-012 and legal documents such as Interconnection Agreements e.g. IA may specify a capacity level that exceeds the reported test levels. In the case of such conflicts, which one should rule? An order of precedence is needed as part of this requirement. Suggest adding terminal equipment to the list of planned facilities. The phrase, for each year of the Near-Term and Long-Term Transmission Planning Horizon, should be revised to remove each year because there may not be studies in each year.
Response: The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective areas for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The reference to "year" has been removed from Requirement R1, part 1.1.2 (now part 1.1.3). **1.1.3** New planned Facilities and changes to existing Facilities	
SERC Engineering Committee Reliability Review Subcommittee (RRS)	In bullet three of R1.1.2, are bus-tie circuit breakers to be represented in the models? Typically circuit breakers are included in the contingency definitions along with the protection system equipment used in the powerflow models. The number of zero impedance branches which can presently be modeled using PSS/E software is limited to 4000. Also, the number of buses included in the

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	powerflow models would increase with additional breaker modeling. In R1.1.2, don't we need to also represent the existing transmission system, and not just changes to the existing system In R1.1.2, does the phrase for each year signify each year for which assessment work was performed, or each year of the Near-Term and Long-Term Transmission Planning Horizon? The phrase, for each year of the Near-Term and Long-Term Transmission Planning Horizon, should be revised to remove each year because there may not be studies in each year. In bullet five of R1.1.2, what protection system equipment is to be included in the stability models In bullet seven of Requirement R1.1.2, what "new technologies" are to be represented in the models Concerned about only having one year to implement all new modeling requirements - especially the additional relay requirements noted in R1.1.2. The SDT stated during its June 30th Webinar that protection system equipment need not be explicitly represented in models, but had difficulty in determining adequate wording for the proposed sub-requirement. Because protection system action is described in R3.3.1, R3.3.4, R4.3.1, and R4.3.3 we suggest that protection system equipment be removed from the list in R1.1.2. There may be a potential conflict between MOD-010 and MOD-012 and legal documents such as Interconnection Agreements e.g. IA may specify a capacity level that exceeds the reported test levels. In the case of such conflicts, which one should rule? There may be a need to add definitions to discern the difference between planned and proposed projects. Suggest replacing circuit breakers in R1.1.2 with terminal equipment since circuit breakers are covered by Protection System Equipment. Does there need to be a reference in R1 to NERC Reliability Assessment Guidebook version 1.2 on pp 17-18 for everyone to use a 50/50 load forecast for inclusion in the planning models?? R1.1.4 Firm Transmission Service - a single source can have transmission service to multiple sinks, and can be associated with transmission service in excess of the capacity of the source. There is a lack of clarity regarding the means by which Firm Transmission Service, a marketing term, is to be included in planning models. For example, should the standard define how to model wind farms (100% - off-peak and 20% on-peak, based on firm capacity from the wind generators, or other dispatch levels)? Not sure if this is applicable to Requirement 1 or 2.

Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.

The SDT has revised Requirement R1, part 1.1.1 to include "existing system".

1.1.1 Existing Facilities

The reference to "year" has been removed from Requirement R1, part 1.1.2 (now part 1.1.3)

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	1.1.3 New planned Facilities and changes to existing Facilities Requirement R1, part 1.1.2 (now part1.1.3) has been revised as described above. New technologies include any technology that is not currently in use on the electric power System that helps improve efficiency (i.e., energy storage/production technologies, low sag conductors, solid state interrupters, etc.). New technologies were removed from the equipment list in Requirement R1, part 1.1.2 (now part 1.1.3) since these are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. In Draft 1, the SDT proposed using the terms "planned" and "committed" (similar to your proposal of proposed and planned) to distinguish the "firmness" of projects. Based on industry comments, the SDT eliminated the terms from Draft 2. No change made. Requirement R1, part 1.1.2 (now part1.1.3) has been revised as described above. The SDT does not believe that a reference is needed to the NERC Reliability Assessment Guidebook since most utilities are using at least a 50/50 Load forecast as a minimum. No change made. The SDT believes that all firm Transmission contracts should be modeled. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange
FirstEnergy Corp	As stated in prior comment periods, we hold the opinion that the TPL-001-1 standard should start from the premise that a valid system model exist based on MOD-010, MOD-012 and other FERC approved MOD standards that are not referenced by this TPL-001-1 standard. The inclusion of R1 introduces an overlap and potential for double jeopardy violations that need not occur. The TPL-001-1 standard should not delve into model building and keep to its core purpose of assessing future performance of the BES.Specific comments, Requirements of R1A. R1.1.2: The last bullet "New Technologies" is too vague and should be struck from the requirement. B. R1.1.4: It is not well understood how "Firm Transmission Service" would be evaluated by a compliance auditor when reviewing a simulation model. The models contain agreed upon Interchange Transactions between BA areas, but no details are provided to reflect individual Firm Transmission Service arrangements. In reality only the net-Interchange values between BA areas are reflected in the simulation models. C. R1.1.6: FE believes this requirement would be more accurately assigned to the Resource Planner or Load Serving Entity and not the Transmission Planner.

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	We agree with the stated Measures, VRF, Time-Horizon, Data Retention and VSL of requirement R1

Response: The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements.

> **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.

New technologies include any technology that is not currently in use on the electric power System that helps improve efficiency (i.e., energy storage/production technologies, low sag conductors, solid state interrupters, etc.). The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.

Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange.

> **1.1.5** Known commitments for Firm Transmission Service and Interchange

The SDT believes that the Transmission Planner/Planning Coordinator is responsible for incorporating this information into the System models. No change made.

Thank you for your response on Measures et al.

IRC Standards Review Committee	(1) R1.1.1 requires that models shall represent planned outages of generation and transmission facilities, if specifically known. Does this allow or require a PC/TP to include outages due to maintenance and due to construction programs where certain facilities are out of service during phases of construction as part of the Assessment? Such maintenance and construction schedules are made but may not be finalized over the planning horizon. Further, are planned outages to be treated as creating a "normal system condition" or is the planned outage a contingency from which system adjustments are made prior to subsequent events" (2) MOD 10 and 12 are based on requirements determined by the RRO in MOD 11 and 13 respectively. Is this appropriate? Further, the PC is not an applicable entity in MOD 10 and 12. (3)What are "other data sources"?

Response: The SDT believes that the outages (if known) should be modeled to insure the System reliability during the outage durations. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-contingency. All performance criteria would then apply to that new base case. Requirement R1, part 1.1.2 (now part 1.1.3) has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months.

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1.1.2 Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. The SDT understands that MOD-010 and -012 are impacted by MOD-011 and -013. The Planning Coordinator is not applicable - but has to utilize data provided by others such as in MOD-010 and -012.No change made. The SDT had removed the reference to "other data sources" under Requirement R1. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.	
TVA System Planning	The phrase, for each year of the Near-Term and Long-Term Transmission Planning Horizon, should be revised to remove each year because there may not be studies actually required in each year. The SDT stated during its June 30th Webinar that protection system equipment need not be explicitly represented in models, but had difficulty in determining adequate wording for the proposed sub-requirement. Because protection system action is described in R3.3.1, R3.3.4, R4.3.1, and R4.3.3 we suggest that protection system equipment be removed from the list in R1.1.2. If R1.1.2 is not removed, TVA is concerned about the level of resources that will be required to model these additional relay requirements in the one year allowed in the Implementation Plan. In bullet three of R1.1.2, are bus-tie circuit breakers to be represented in the models? Typically circuit breakers are included in the contingency definitions along with the protection system equipment used in the powerflow models. In bullet seven of Requirement R1.1.2, what "new technologies" are to be represented in the models?
Response: The reference to "year" has been removed from Requirement R1, part 1.1.2 (now part 1.1.3). **1.1.3** New planned Facilities and changes to existing Facilities The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. See Requirement R1, part 1.1.2 comment above New technologies include any technology that is not currently in use on the electric power System that helps improve efficiency (i.e., energy storage/production technologies, low sag conductors, solid state interrupters, etc.). New technologies were removed from the Requirement R1, part 1.1.2 list (now part 1.1.3) and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.	
Southern Company	The VSLs for Requirement R1 incorporates several sub-requirements but neglects one of the three components of the main requirement. Consider that R1 requires the TP and RC to (a) maintain System models, (b) use data consistent with certain MOD standards, and (c) simulate projected System conditions. Because the first component is not a part of the proposed VSL and the

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	purpose of this standard mentions a broad spectrum of System conditions, the recommendation is to add maintaining the system model into the VSLs for R1. R1.1.3 uses the terminology real and reactive Demand of Load. We suggest striking the word "Demand" because it refers only to real power. We recommend the the SDT limit R1 to load flow and stability models. Does R1 apply to short circuit models? If so does this imply that the short circuit model must be the same as the load flow model?
Response: The SDT revised the VSLs for Requirement R1 to align with the changes made to the requirement – note that the revised R1 does not use the word, "simulate." The SDT has modified Requirement R1, part 1.1.3 (now part 1.1.4). **1.1.4** Real and reactive Load forecasts The SDT believes that Requirement R1 also contains some requirements that are necessary for short circuit cases but R1 does not require the models to be the same, since different software applications may be used. No change made.	
United Illuminating Northeast Utilities ISO New England, Inc. Central Maine Power Company	R1 Priority Comment- There needs to be some direction provided on the initial conditions used in the assessment. This guidance should include discussion as to whether or not representations of generator forced outages are to be represented in the base case or if they are addressed through the sensitivity testing (Could add R1.1.7 Reasonable representations of unplanned generator outages.) Additionally, the standard is also silent on the treatment of system transfers, both internal and external, as to how they should be modeled in the base case. For some areas, their current practice is to include heavy system stresses in their base case, which leaves little for sensitivity testing. It is unclear if this practice works within this standard. R1.1.1 Priority comment R1.1.1 should be removed. It seems like there is an overlap between the requirements of this standard and Operational Planning studies with respect to known outages. Planned outages are addressed by our Operational Planning processes and Transmission Operating Procedures removing the need for this to be incorporated into Planning Assessments. In addition, outages are not generally known years in advance R1 Comment We do not understand what it means to include requirements of regulatory authorities and other legal obligations. Even if some version of this language is kept in the final standard, it seems to belong in R2 rather than R1. R1.1.2 comment - Do we need to have the list of equipment to model? How do we model circuit breakers, etc? We recommend deleting the list. Make R1.1.2 simply read: R1.1.2 New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon. R1.1.5 comment What specifically needs to be modeled under Interchange R1.1.6 comment This needs further definition or it should be deleted. It is not clear what a network resource required to supply load is. Does this refer to Network Resource per FERC LGIP?

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Response: The SDT believes that the outages should be modeled to insure the System reliability during the outage durations. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-contingency. All performance criteria would then apply to that new base case. Requirement R1, part 1.1.2 (now part 1.1.3) has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months. **1.1.3** New planned Facilities and changes to existing Facilities Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months. **1.1.2** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. Interchange is defined in the NERC glossary as "energy transfers that cross Balancing Authority boundaries" while Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.6 has been broadened while still incorporating Network Resources. **1.1.6** Resources required to supply Load	
System Protection and Transmission Planning Department	R1 the requirement to maintain System models for performing the studies is redundant with MOD-010, and should be moved to MOD-010. The phrase that requires model data used in Studies used for Annual Assessments be consistent with data submitted under MOD-010 seems OK. R1.1.2, a sub-requirement of R1.1, states that models for Planning Assessments shall represent "new planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon". Is this a requirement for maintaining a case representing every year of the near-term and long-term planning horizons (i.e. 10 cases)? We do not think that is what the SDT had in mind. If all that is required to remain cognizant of Facility In-Service dates so that topology is reliable, please so state. To make this read clearer, we suggest you take out the phrase for each year . Regarding bullet 5 of R1.1.2, does inclusion of Protection System equipment require modeling of all relays in dynamic studies? The NERC definition of Facility pertains to equipment energized at primary voltages, not Protective System equipment. We

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	suggest the Protective Systems be eliminated from this list. To make this read clearer, we suggest you delete text and bullet items following Transmission Planning Horizon. Regarding R1.1.2 bullet items: The bullets list examples of Facilities. This list is not needed, since the term Facility is already defined in the NERC Glossary. If you do not remove all bullets, then we warn you that the bullet "New Technologies" can be interpreted to cover a broad range of topics by an auditor and is not clearly defined by NERC, so we cannot visualize measurable documentation.
Response: The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. No change made. Thank you for your response. The reference to "year" has been removed from Requirement R1, part 1.1.2 (now part 1.1.3). **1.1.3** New planned Facilities and changes to existing Facilities The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The bulleted list has been deleted.	
PPL Energy Plus	PPL agrees with the requirement that regulatory and legal requirements need to be respected in planning studies. Also, Requirement R1.1.6 appears to conflict with FERC Pro-forma OATT Section 30.4 in that Network Resource output should not be limited as this Requirement states.
Response: The SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. Requirement R1, part 1.1.6 has been broadened while still incorporating Network Resources. **1.1.6** Resources required to supply Load	
Western Area Power Administration	Since the modeling data used for the Planning Assessment is initially created and governed per Mod-10 & Mod-12 Standards, this requirement should be clarified to include maintain revisions of the modeling data required to perform the Planning Assessment

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	and not just "maintain system models for performing the studies needed to complete their Planning Assessment?.
Orlando Utilities Commission	-This section is very clear. Section R1.1.1 brings clarity to the question regarding planned outages.-The phrase Models shall use data consistent with MOD-010?, is the intent for the data to be "identical" to the data provided under MOD-10 and -12, or
Kansas City Power & Light	R1 states that the models used in these studies shall be consistent with data provided through MOD-010 and MOD-012. The data submitted for these are updated on a schedule provided by the RRO and not necessarily reflective of any emerging changes that may have occurred between the MOD data collection cycle. The requirement should allow for exceptions to allow the most recent information to be included in the TPL studies.
Response: The SDT has modified Measure M1 to use the latest data available. **M1** Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.	
Tampa Electric	R1 Ensure that statement reflects that TP and PC are only responsible for their planning area. R1.1.2 Add transformers to list and clarify modeling of circuit breakers and protection system equipment. Models should reflect the effect of this equipment, not the actual equipment. R1.1.4 Models should only reflect firm transmission service that is expected to be utilized in the study case. Consider changing effective dates of all requirements to be the same date so that you do not have to meet two standards during the same time period.
Response: The SDT had modified Requirement R1 to state that the Transmission Planner/Planning Coordinator are each responsible for maintaining System models for its respective area. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement r4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT believes that all firm Transmission should be modeled. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange.	

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1.1.5 Known commitments for Firm Transmission Service and Interchange The SDT believes that certain steps need to be taken in succession to allow utilities to progress toward meeting the new requirements - while not placing an undue burden for utilities to meet all the new requirements at the same time. Also additional time is needed for many utilities to meet "raising the bar" requirements that may be required and which could take considerable lead time. No change made.	
Florida Reliability Coordinating Council, Inc - Transmission Working Group	R1 and M1: Consider clarifying that it is not the TP or PC responsibility to independently verify the consistency of the System models for portions of the Bulk Electric System outside of the TP or PC planning area (related to not using data consistent with data submitted as part of MOD-010 and MOD-012, each TP and PC should not have to review the data submitted by those outside of its planning area, but only its own planning area). Please Clarify the phrase Models shall use data consistent with .MOD-010 is the intent for the data to be identical to the data provided under MOD-10 and MOD-12, or consistent meaning that the data might be older or newer depending on when the assessment took place vs when the data was submitted. R1.1 Consider changing Assessment (which does not include models) or re-wording to Models for performing the studies needed to complete the Planning Assessment shall represent:?R1.1.1 Brings clarity to the question regarding planned outages. R1.1.2: Consider adding “Transformers” to the list of facilities. R1.1.2, please clarify what the drafting team intentions are for Circuit Breakers. Planning models used for power flow, dynamics and short circuit do not include circuit breakers. Modeling circuit breakers would cause convergence problems in the models due to that large number of zero impedance line sections. We sugges eliminating circuit breaker from the bullet list. R1.1.2 Protection System equipment this should be clarified to only apply to system stability models. The modeling of protective relays should be caveated with as deemed appropriate. We suggest eliminating Protection System equiptment from the bullet list. R1.1.4 Consider adding that is expected to be utilized in the study case scenario not all Firm Transmission can be included in all studies and are only used upon the availability of other resources . Consider changing the effective dates of R1 and R7 to take effect at the same time as R2 through R6 so you do not have to meet two standards during the same time period. Otherwise, clarify how the effective date impacts which version of the standard is to be used in an assessment before a scheduled compliance audit.
Response: The SDT has modified Requirement R1 to state that the Transmission Planner and Planning Coordinator are each responsible for maintaining System models for its respective area. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has incorporated these additional requirements with the intent that they will be removed from the TPL standard when they are incorporated into the MOD standards at a	

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later date. The SDT has modified Measure M1 to use the latest data available. **M1** Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1. The SDT agrees and has reworded Requirement R1, part 1.1. **1.1** System models shall represent: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange The SDT believes that certain steps need to be taken in succession to allow utilities to progress toward meeting the new requirements - while not placing an undue burden for utilities to meet all the new requirements at the same time. Also additional time is needed for many utilities to meet "raising the bar" requirements that may be required and which could take considerable lead time. No change made.	
FMPA	R1, consider clarifying that it is not the TP or PC responsibility to independently verify the consistency of the System models for portions of the Bulk Electric System outside of the TP or PC planning area (related to not using data consistent with data submitted as part of MOD-010 and MOD-012, each TP and PC should not have to review the data submitted by those outside of its planning area, but only its own planning area). R1.1.2: Consider adding Transformers to the list of facilities. R1.1.2, please clarify what the SDTs intentions are for Circuit Breakers. Planning models used for power flow, dynamics and short circuit do not include circuit breakers. Modeling circuit breakers would cause convergence problems in the models due to that large number of zero impedance line sections. We suggest clarifying that the intent is to develop planned Facility Ratings in the models to reflect new Circuit Breakers, and to reflect the location and timing of circuit breakers in contingency lists, and not to model the actual circuit breakers. R1.1.2 "Protection System equipment should be clarified to only apply to system stability models. The modeling of protective relays should be caveated with as deemed appropriate. We suggest clarifying that the intent is, for power flow and short circuit studies, Protection System Equipment would be incorporated into Facility Ratings and the contingency list. And we suggest further clarifying that the intent is the same for Stability Studies, with the addition of modeling Protection System equipment that could significantly impact stability response (e.g., out-of-step relaying) as deemed appropriate through engineering judgment. R1.1.4 Consider adding "that is expected to be utilized in the study case scenario" not all Firm Transmission can be included in all studies and are only used upon the availability of other resources (for instance, if there are two firm point-to-point contracts in opposite directions across the same Interchange, both probably ought not to be modeled at the same time). Consider changing the effective dates of R1 and R7 to take effect at the same time as R2 through R6 so you do not have to meet

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	two standards during the same time period. Otherwise, clarify how the effective date impacts which version of the standard is to be used in an assessment before a scheduled compliance audit.
Response: The SDT had modified Requirement R1 to state that the Transmission Planner/Planning Coordinator are each responsible for maintaining System models for its respective area. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement r4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT believes that all firm Transmission should be modeled. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange The SDT believes that certain steps need to be taken in succession to allow utilities to progress toward meeting the new requirements - while not placing an undue burden for utilities to meet all the new requirements at the same time. Also additional time is needed for many utilities to meet "raising the bar" requirements that may be required and which could take considerable lead time. No change made.	
Progress Energy Carolina (PEC)	PEC would like clarification on the following: "Models for the Planning Assessment shall represent: Circuit Breakers, Protection System Equipment, etc." The clarification should state that the models do not have to explicitly include these elements as long as their effect can be modeled.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.	
Gainesville Regional Utilities	Concerning the effective dates of R1 & R7, I suggest that you move them to be effective at the same time as R2 through R6 so you will not have to try to meet two standards during the same time period. Effective Date: Clarify how the effective date impacts which version of the standard (and it reference numbering) is to be used in an assessment just before (in cycle) a scheduled compliance audit. Suggest that the term "Corrective Action Plan" be retitled to "Improvement Action Plan" because the first implies that the situation is "wrong or incorrect" which may not be the case.

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Response: The SDT believes that certain steps need to be taken in succession to allow utilities to progress toward meeting the new requirements - while not placing an undue burden for utilities to meet all the new requirements at the same time. Also additional time is needed for many utilities to meet "raising the bar" requirements that may be required and which could take considerable lead time. No change made. The Effective Date of the requirements in force at the time the Planning Assessment is completed will dictate which requirements are the governing requirements. The SDT believes that the term "Corrective Action Plan" (a defined term) is sufficient due to lack of comments received from industry requesting this change. No change made.	
JEA	Reword R1.1.2. New planned Facilities and changes to existing and old planned Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon where such Facilities affect the electric connectivity and topology of the system or affects the accurate simulation of system disturbance response where practical. [Delete bulleted list]Add R1.2. Where it is not practical to model all Facilities composing the electric system connectivity and topology, consideration of those Facilities and their affect on the model simulations shall be documented in detail in the annual Planning Assessment where appropriate. This addition may not be necessary with rewording of R3.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.	
NorthWestern Corporation NorthWestern Energy (NWE) (NWMT)	The system models that are described in MOD-010 Requirement1, MOD-011 Requirement 1, MOD-012 Requirement 1, and MOD-013 Requirement 1 do not address all the bulleted items under R.1.2. Circuit breakers, protection system equipment and control devices are not modeled. Rather, the effect of these devices, such as circuit breaker misoperation, thermal overload, etc., on the transmission system are modeled. The wording of these bullets should be corrected to match what is actually modeled. Firm Transmission Service, listed in R.1.1.4, is not specifically addressed in MOD-010. Requirement 1 of MOD-010 states existing and future Interchange Schedules as data requirements for steady-state modeling and simulation. Models in the West do not model Firm Transmission Service as such. It is difficult to know what the Firm Transmission Service will be in the future. This is particularly true in regions where there is a predominance of merchant generation and proposals for the interconnection of new merchant generation. It is more reasonable to estimate the expected interchanges. The definition for Interchange Energy transfers that cross Balancing Authority boundaries describes the modeling requirement better that the definition of Firm Transmission Service The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruptions. The wording Expected Transfers" is used in R2.1.3 and R2.4.3. To maintain consistency, this term could be used in R.1.1.4 and could also be substituted in Table 1 for Firm Transmission. From a Planning perspective, since Firm Transmission cannot be determined from a study model. R1.1.4 and R1.1.5 should be deleted and replaced with a requirement to model expected transfers on interconnections with neighboring Balancing Authorities. For study purposes R.1.1.6 is not needed either. In the models, the load represented is served by the generators modeled. Network Resources are more in tune with local area studies that ensure that the network load can be served by the network

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	resources over available transmission. The words "including requirements of regulatory authorities and other legal obligations at the end of R1. does not need to be in the standard.
Response: The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. Interchange is defined in the NERC glossary as "energy transfers that cross Balancing Authority boundaries" while Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange The SDT believes that Requirement R1, part 1.1.6 is still required but it has been broadened. **1.1.6** Resources required to supply Load The SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions	
SMUD	R1: The requirement should end after the words "shall simulate projected System conditions.". The following words should be deleted as it results in a clause that is overly broad and does not specify clear and concise reliability requirements: "including requirements of regulatory authorities and other legal obligations".
Response: The SDT agrees and has changed Requirement R1 accordingly. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.	
Progress Energy Florida, Inc.	For R1.1.2, PEF has the following comments:T-T Transformers, as major components of the BES, should be on this list.PEF does not object to the inclusion of Circuit Breakers on this list, provided that representation is not required in steady state load flow

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	cases. Breaker failure scenarios can be extensively studied in the steady state and stability realms by removing from service the transmission facilities that such a breaker event would initiate.PEF assumes that the inclusion of Protection System Equipment applies only to Stability Analysis. As for breakers, relay failure scenarios can be extensively studied in the steady state realm by removing from service the transmission facilities that such a relay event would initiate. Additionally, PEF also assumes that a comprehensive modeling of all Protection System Equipment (e.g. Transformer Sudden Pressure Relays, Bus Diff Relays, etc.) in Stability Analysis is not required, since only a limited amount of relaying in dynamic modeling is needed to adequately model the system with respect to what transmission/generation components would trip for a given event.A lack of specificity on the term Control devices leaves it open to wide interpretation. The SDT should, in detail and/or with examples, state what is intended. The term New technologies is only acceptable for inclusion if provision is made for the fact that Planning analysis software often lags behind the design industry in getting new technologies modeled such that Planners can analyze them. For R1.1.4 on Firm Transmission Service: PEF assumes that the SDT understands that some firm transmission service is not always modeled in every case, depending upon the economics and availability of alternate resources.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. New technologies include any technology that is not currently in use on the electric power System that helps improve efficiency (i.e., energy storage/production technologies, low sag conductors, solid state interrupters, etc.). New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT believes that all firm Transmission should be modeled. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange	
Xcel Energy	R1 states that the models used in these studies shall be consistent with data provided through MOD-010 and MOD-012. The data submitted for these are updated on a schedule provided by the RRO and not necessarily reflective of any emerging changes that may have occurred between the MOD data collection cycle. The requirement should allow for exceptions to allow the most recent information to be included in the TPL studies.
Response: The SDT has modified Measure M1 to use the latest data available. **M1** Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.	
Arizona Public Service Co	The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of

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	the devices or the effect of the removal of the devices only where it is expected to impact the study outcome. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted. We disagree with the inclusion of the words including requirements of regulatory authorities and other legal obligations at the end of R1. Entities already are required to do this. It does not need to be included in the standard. VSL: Under Severe VSL Column: The last sentence The System model did not simulate projected System Conditions as described in Requirement R1 is vague and should be clarified. What is meant by did not simulate. Is it referring to gross errors or something else? We recommend that Sever VSL be assigned only if the Transmission Planner failed to do the planning assessment. Hence it should not apply to R1 at all since R1 is only related to modeling accuracy.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT believes that transfers and Firm Transmission Service can actually be two separate items since Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange The SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The SDT has replaced "simulate" with "represent" in the requirement, measure and under the Severe VSL category for Requirement R1. The SDT believes that the Severe level should be applied as noted in the VSL table since these cases are the basis for having an accurate planning assessment.	
New Brunswick System Operator	It is not clear how TP and PC are to coordinate activities. If R6 provided direction on individual and joint responsibilities then R6 should be referred to in each of the requirements which require TP and PC coordination. The VSL and Measurement for requirement R1 appears focused the number of subrequirements represented in the model. Ideally the focus should be the impacts or error of the results if something is not properly represented. This shift in thinking will allow the planner to assess and focus on those subrequirements which are important to the study results. R1.1.1 Planned outage duration needs to be defined. For example, a planned outage for a year or more should be included in the

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	Near term assessment.

Response: Requirement R7 (formerly Requirement R6) requires the Transmission Planner and Planning Coordinator to determine and identify joint responsibilities. The SDT believes that having this as a separate requirement is sufficient. No change made.

The SDT believes that the VSLs for Requirement R1 are already sufficient based on lack of industry comments. Note that the VSLs were modified to conform to the changes made to the requirement. Violation Risk Factors assess the impact to the BES of violating a requirement – not VSLs.

Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months.

1.1.2 Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

Western Area Power Administration	General, all-encompassing comment: The change in TPL Standards, while well intended, will be difficult to administer since it has taken a simple Performance Table and translated it into a legal-type document that is very complex to relate to the physical system for the planning and operations staff. The performance requirements must be related to the physical response characteristics of the interconnected system operation without depending on a legal advise for training my new transmission system planning staff. The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices where it is expected to impact the study outcome. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted. I disagree with the inclusion of the words including requirements of regulatory authorities and other legal obligations at the end of R1. Entities already are required to do this. It does not need to be included in the standard.

Response: The SDT believes that it is following the intent of FERC and NERC in creating a reliable Bulk Electric System by following the requirements in TPL 001-1.

The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.

The SDT believes that transfers and Firm Transmission Service are actually two separate items since Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange.

1.1.5 Known commitments for Firm Transmission Service and Interchange

The SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements.

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R1 Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.	
Ameren	There may be a potential conflict between MOD-010 and MOD-012 and legal documents such as Interconnection Agreements e.g. IA may specify a capacity level that exceeds the reported test levels. In the case of such conflicts, it is not clear which one should rule. Suggest replacing circuit breakers in R1.1.2 with terminal equipment since circuit breakers are covered by Protection System Equipment. Consider adding a reference in R1 to NERC Reliability Assessment Guidebook version 1.2, pp 17-18 for use of a particular load forecast level for inclusion in the planning models. I n R1.1.2, revise the language to show that we need to also represent the existing transmission system, and not just changes to the existing system. In R1.1.2, Clarification is needed for the phrase for each year should signify only those years for which assessment work was performed, rather than each year of the Near-Term and Long-Term Transmission Planning Horizon. There typically is not a model built for each year of the Near-Term and Long-Term Transmission Planning Horizon. In bullet three of R1.1.2, it is not clear whether bus-tie circuit breakers to be represented in the models. Typically circuit breakers are included in the contingency definitions along with the protection system equipment used in the powerflow models. The number of zero impedance branches which can presently be modeled using PSS/E software is limited to 4000. Also, the number of buses included in the powerflow models would increase with additional breaker modeling. In bullet seven of Requirement R1.1.2, what "new technologies" are to be represented in the models" R1.1.4 Firm Transmission Service - a single source can have transmission service to multiple sinks, and can be associated with transmission service in excess of the capacity of the source. There is a lack of clarity regarding the means by which Firm Transmission Service, a marketing term, is to be included in planning models. For example, should the standard define how to model wind farms (100% - off-peak and 20% on-peak, based on firm capacity from the wind generators, or other dispatch levels)?
Response: The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT does not believe that a reference is needed to the NERC Reliability Assessment Guidebook since most utilities are using at least a 50/50 Load forecast as a minimum. No change made.	

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The SDT has revised Requirement R1, part 1.1.1 to include "existing Facilities". **1.1.1** Existing Facilities The SDT has deleted the reference to year. **1.1.3** New planned Facilities and changes to existing Facilities See response to Requirement R1, part 1.1.2 above. . New technologies include any technology that is not currently in use on the electric power System that helps improve efficiency (i.e., energy storage/production technologies, low sag conductors, solid state interrupters, etc.). New technologies were removed from the list in Requirement R1, part 1.1.2 (now part 1.1.3) and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT believes that all firm Transmission contracts should be modeled. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange	
Puget Sound Energy, Inc.	The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices where it is expected to impact the study outcome. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT believes that transfers and Firm Transmission Service are actually two separate items since Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange	
Tenaska, Inc.	It is not clear that Requirement R1 requires ALL existing generators, substations, transmission line, transformers, etc. to be explicitly modeled for steady state and stability studies. In fact, Requirement 1.1.6 could be interpreted to exclude various generators from the models if they are not contracted to supply load. A suggestion is to re-word R1.1 to read as follows:R1.1 Models for the Planning Assessment shall represent all existing generators, substations (including specific busses within a substation), transmission lines, loads, capacitors, reactors, and other equipment connected to the transmission system and shall

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	further represent the following:(continue with R1.1.1 through R1.1.6) A further refinement to R1.1.6 should also be considered as follows:R1.1.6 Committment and dispatch schedules of resources expected to serve Load for the specific model.
Response: The intent of the SDT is to model all bulk electric Transmission Facilities depending on the model used - whether for load flow, Stability, or short circuit. The SDT has modified Requirement R1, part 1.1 to provide better clarity on these models. **1.1** System models shall represent: Requirement R1, part 1.1.6 has been broadened while still incorporating Network Resources. **1.1.6** Resources required to supply Load	
Manitoba Hydro	Requirement Text: R1: What is meant by including requirements of regulatory authorities and other legal obligations? This phase should be deleted. Can NERC make it an obligation in a standard to follow regulatory authority and other legal obligations? The planner has scope to determine the projected system conditions, and if a local regulator mandated a requirement, the planner would be able to include it without this statement. R1.1.1: Only long duration known planned or scheduled outages that are expected to last over a system peak should be included in the scope of this standard. Known planned or scheduled maintenance outages should not be a part of the planning scope as they are short duration and are planned to be taken when system conditions allow. Suggest wording change to Planned outages of generation and Transmission Facilities with an expected duration of 6 months or longer, if specifically known. R1.1.2: Suggest deleting new technologies as it is unknown as to what this is. If the SDT wants to make the list all inclusive, add words such as shall include but not be limited to in the requirement wording. Circuit breakers are not specifically represented in the planning models in order to keep the number of buses within the program capabilities. However, the effect of the circuit breaker configuration is normally considered in the creation of contingency files. Can the drafting team confirm that circuit breakers do not have to be specifically represented in the model? The same comment can be said about protection system equipment. Some generic zone 1 modeling may be included but in general the effect of protection equipment is included in contingency files. R1.1.4 & R1.1.5: Firm Transmission Service represents a contract that the planner is obligated to include. Based on the NERC definition, Interchange is defined as Energy transfers that cross Balancing Authority boundaries. Including it as a requirement mandates system expansion for non-firm system usage. Interchange is already covered in the sensitivities (Expected Transfers) and should not be a specific sub requirement of R1.1.2. Perhaps simply documenting the value of the Interchange used in the Model is sufficient. This value may change in the sensitivity analysis conducted in R2.1.3 and the TP/PA will decide the level that they will plan on protecting.Measure: The measure requires the planner to provide evidence such as the System model. What further evidence is required to ensure the planner is using data consistent with the MOD standards, is simulating projected system conditions, and that the models represent the required information in accordance with Requirement R1? It is suggested to remove and shall simulate projected System conditions from the main paragraph of R1 and reword R1.1 to System models and contingency files for the Planning Assessment shall represent projected System Conditions including:

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	Requirement R1 is very vague, and the Measure refers back to R1. The MOD standards deal with the building of the model. Most planners provide data in accordance with the MOD standards for a regional model building process. These models form the basis for the models the TPs and the PC use. The R1could be more specific by requiring the PC/TP to provide rationale for the projected system conditions used, which might include the generation schedule assumed, the transfer conditions, why peak or off-peak is important, etc.. VSLs: The requirement is very generic in nature and leans on the MOD requirements. Verification of compliance to this requirement will be problematic. What will be required to prove that the data "is consistent with the data provided in accordance with the MOD-010 and MOD-012 and other data sources"? What are these other data sources?? R1 only stipulates that the planner shall "simulate expected system conditions", so how does one decided that the "model did not simulate projected System Conditions as described in R1" (severe VSL)?

Response: The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements.

> **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.

Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months.

> **1.1.2** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months

New technologies include any technology that is not currently in use on the electric power System that helps improve efficiency (i.e., energy storage/production technologies, low sag conductors, solid state interrupters, etc.). New technologies were removed from the equipment list in Requirement R1.1.2 since these are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.

The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.

Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange.

> **1.1.5** Known commitments for Firm Transmission Service and Interchange

Requirement R1 has been revised to replace "simulate" with "represent".

> **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System

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conditions.

The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has incorporated these additional requirements with the intent that they will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.

The SDT has removed “and other date sources” from Requirement R1.

The SDT has replaced "simulate" with "represent" under the Severe VSL category for Requirement R1.

R1 VSL	The responsible entity’s System model failed to represent one of the Requirement R1, parts 1.1.1 through 1.1.6	The responsible entity’s System model failed to represent two of the Requirement R1, parts 1.1.1 through 1.1.6. OR The System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.	The responsible entity’s System model failed to represent three of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity’s System model failed to represent four or more of the Requirement R1, parts 1.1.1 through 1.1.6. OR The System model did not represent projected System conditions as described in Requirement R1.

E.ON U.S.	R1.Delete and other data sources. Consistency with MOD-010 and MOD-012 standards is measurable and should suffice. Delete including requirements of regulatory authorities and other legal obligations. The term: shall simulate projected System conditions does not exclude the above. If there is some significance to this statement it should be an item in R1.1. R1.1.4.Firm Transmission Service is often sold for less than one year on an as available basis. Also, Firm Transmission Service may be sold on one system without a complete path. As stated, it appears necessary to include these examples in the Planning models. E.ON U.S. believes that there should be some limitations put on this requirement such as Long-Term Firm Transmission Service for a period of 5 or more years.

Response: The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has removed “and other data sources”.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System

Organization	Question 1 Comment
	conditions. The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange
National Grid	Comments: R1: A. Priority Comment- There needs to be some direction provided on the initial conditions used in the assessment. This guidance should encourage the use of initial conditions that reasonably stress transfers across interfaces between companies, areas, regions, into load pockets, and out of constrained areas. The expectation that transfers are reasonably stressed for a variety of interface conditions will require the consideration of different generation dispatches, which goes beyond the single generator out of service requirement of the standard. If initial conditions consider reasonably stressed conditions, then sensitivity analysis is embedded in the process. If sensitivity is embedded in the process, it is unclear if additional sensitivity is still required by the standard. B. In the reference to regulatory authorities and other legal obligations it is suggested that the phrase be changed from "simulate projected System conditions including requirements of regulatory authorities and other legal obligations" to "include projected System conditions and requirements of regulatory authorities and other legal obligation." In common usage of terms, models are used to simulate system response, but models alone do not simulate the system. Violation Severity Levels:R1 Suggest changing the phrase "simulate projected System conditions as described in Requirement R1" to "include projected System as described in Requirement R1," consistent with the recommended change to Requirement R1. Errata:Delete the period after "R1" in the first bullet in the Data Retention section. R1.1.1 Priority comment ? R1.1.1 should be removed. - Planned outages are addressed by Operational Planning processes and Transmission Operating Procedures for up to two years ahead removing the need for this to be incorporated into Planning Assessments. - If outages are planned, but Operations can not accommodate them in real time, then the outages are cancelled. - Outages are not generally known beyond one to two years in advance. R1.1.2 Comment - We recommend deleting the list of facilities:- Circuit breakers are not modeled as elements in a power flow nor are Control Devices and Protection Systems - The list of facilities is not consistent with the definition of "Facilities" in the NERC GlossaryR1.1.2 should simply read:R1.1.2New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon. R1.1.3 Comment - The use of "real and reactive power" is prevalent within the industry, but R1.1.3 should be changed to "Active and reactive Demand of Load." When load is expressed as a complex quantity, active power is the real portion and reactive power is the imaginary portion. Thus for consistency, we should refer to active and reactive. R1.1.5 Comment What specifically needs to be modeled under Interchange" R1.1.6 Comment "This needs further definition or it should be deleted. It is not clear what a "network resource required to supply

Organization	Question 1 Comment
	load" is. Does this refer to Network Resource per FERC LGIP?

Response: Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. However the expected transfers under Requirement R2, part 2.1.3 are to further stress the system as a possible sensitivity analysis.

1.1.5 Known commitments for Firm Transmission Service and Interchange

The SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.

The SDT has replaced "simulate" with "represent" under the Severe VSL category for Requirement R1.

R1 VSL	The responsible entity's System model failed to represent one of the Requirement R1, parts 1.1.1 through 1.1.6	The responsible entity's System model failed to represent two of the Requirement R1, parts 1.1.1 through 1.1.6. OR The System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.	The responsible entity's System model failed to represent three of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, parts 1.1.1 through 1.1.6. OR The System model did not represent projected System conditions as described in Requirement R1.

The SDT agrees and had made this change under Data Retention.

Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months.

1.1.2 Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in

Organization	Question 1 Comment
MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT has modified Requirement R1, part 1.1.4 (former part 1.1.3). **1.1.4** Real and reactive Load forecasts Interchange is defined in the NERC glossary as "energy transfers that cross Balancing Authority boundaries" while Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." The intent is to include, but not be limited to these requirements. The SDT has revised Requirement R1, part 1.1.6. **1.1.6** Resources required to supply Load	
Entergy Services, Inc	Planned facilities and planned changes to existing facilities should be further defined to ensure facilities or changes that are unlikely to be constructed are not included in the models. See the proposed definition of planned facilities in the comments provided to question #8. Facilities included in the models should be only those projects that are committed to by the Transmission Owner or other users of the transmission grid. Consistent with the standards requirement to include only firm transmission service (R1.1.4), uncommitted facilites should not be included because an oversubscription of the grid could occur. R1.1: Please clarify what the SDT means by models for the Planning Assessment shall present, expecially for facilities such as circuit breakers, protection system equipment, and new technologies. Models also need to represent existing facilities R1.1.2: The phrase, for each year of the Near-Term and Long-Term Transmission Planning Horizon, should be revised to remove each year because there may not be studies in each year. R1.1.4: Firm Transmission Service - a single source can have transmission service to multiple sinks, and can be associated with transmission service in excess of the capacity of the source. There is a lack of clarity regarding the means by which Firm Transmission Service, a marketing term, is to be included in planning models. Not sure if this is applicable to Requirement 1 or 2.
Response: The projects that get included under the Corrective Action Plans are presumed to be the utility's best alternatives at that time in order to achieve compliance. The SDT understands that these alternatives may change over time - but these changes must be addressed under Requirement R2, part 2.7.6 in the revised standard. The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement r2, part 2.7.1 in the revised standard. The reference to year has been deleted. The SDT believes that all firm Transmission contracts should be modeled. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange.	

Organization	Question 1 Comment
1.1.5 Known commitments for Firm Transmission Service and Interchange	
Great River Energy	R1.1 is just repeating what should already be in the MOD-010 and MOD-012 requirements. Why re-iterate this in the TPL standard? The planners are expecting that the model building process will already include these components listed in R1.1 otherwise there wouldn't be a functional model. R1.1.1 may be the only thing that needs to be identified in R1 as any known long-term outage or retirement of a facility may have happened after the model building process. If R1.1 is kept I would suggest removing "Models for" so that R1.1 reads "The Planning Assessment shall represent: R 1.1.1 says the assessment shall represent planned outages if specifically known. It does not however distinguish the length of the outage to be considered. Should a 1 week maintenance outage in Year five be included? Should a 2 year complete rebuild outage lasting through year two and three be included? It is GRE's opinion that the SDT needs to add a comment about the length of the planned outage and its relevance to the assessment. In the Violation Severity Levels, R1 seems to be weak since any solved model should meet this requirement. Again this would seem to be more related to the MOD010 and MOD012 process. R1 should focus on documenting changes that are being preformed against the data that was submitted in MOD-010 and MOD-012 process.
Response: The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has incorporated these additional requirements with the intent that they will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT has revised the language in Requirement R1, part 1.1 (now part 1.1.2) based on industry comments. . **1.1.2** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. The SDT believes that the Severe level should be applied as noted in the VSL table since these cases are the basis for having an accurate Planning Assessment. No change made.	
BC Hydro	Comments: Consider just referring to the MOD series of standards, not specific individual MOD standards because the numbering of the MOD standards could change and additional relevant MOD standards could be added. Consider rewording the second sentence to read, The data and models shall meet all requirements of the MOD series of standards. The MOD standards should include the requirements of regulatory authorities and other legal obligations and need not be repeated in the TBL standard(s). R1.1.2: Consider changing to, New planned Facilities and planned changes to existing and changing the fifth bullet to read, Normal actions of Protection System equipment R1.1.3: Consider changing to, "End-use customer loads and generators [how small loads are aggregated should be covered in the MOD standards. A key point is that large industrial customers with significant generation that reduces their net peak demand should not be represented simply as a net load since that would not properly model the dynamic impacts of the load and

Organization	Question 1 Comment
	generation components]. R1.1.4: Consider changing to, Worst-case transfers on Firm Transmission Service Reservations. R1.1.5: Consider removing this requirement. It should be covered by R1.1.4 R1.1.6: Consider changing to, Generating units [the MOD standards should specify the details like how exciters, governors and associated control equipment must be modeled] Comment on M1: Consider changing to, using data consistent with the MOD series of standards, simulating. Consider just referring to the entire series of a particular standard, not specific individual standards because the numbering of the standards being referenced could change and additional relevant individual standards could be added.

Response: The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT referenced the specific MOD standards to ensure that the requirements were limited to those needed to complete the Planning Assessment. When the MOD standards are revised, this standard will be reviewed for conforming changes. The SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements.

> **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.

The SDT has reworded Requirement R1, part 1.1.1 to include existing Facilities.

> **1.1.1** Existing Facilities

The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement r4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.

The SDT has modified Requirement R1, part 1.1.4 (now part 1.1.5) to state "Real and reactive Load Forecasts. Note that the generator modeling is addressed in the MOD standards.

> **1.1.4** Real and reactive Load forecasts

The SDT believes that all contracted firm Transmission should be modeled. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange.

> **1.1.5** Known commitments for Firm Transmission Service and Interchange

See response for Requirement R1, part 1.1.2 above.

The SDT believes that the specific MOD standards should be addressed in this TPL 001-1 draft since they deal directly with the modeling requirements necessary for creating base cases. No change made.

Organization	Question 1 Comment
Midwest ISO	Generally the Midwest ISO agrees with FirstEnergy's comments regarding this requirement. However, if the SDT insists on keeping this requirement as is then we propose the following corrections specific to each requirement. Specific Comments for Requirement 1: A) Under R1 there is language that references "other data sources; can the SDT please offer some clarification on what "other data sources are to be Could other data sources be Tariff requirements" B) Again under R1, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R1 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: Near-Term and Long-Term Transmission Planning. C) Under R1.1.1 it is required that models represent planned outages of generation and transmission facilities, if specifically known. This does not allow or require a Transmission Planner or Planning Coordinator to include outages due to maintenance and/or due to construction programs where certain facilities are out of service during various phases of construction, as part of the Assessment. For this reason, we believe the following language for R1.1.1 would improve this requirement: Planned outages of generation and Transmission Facilities if specifically scheduled or planned for. D) Under R1.1.1 we suggest adding sub-requirement R1.1.7 Generation dispatch patterns deemed appropriate by the Transmission Planner and Planning Coordinator. This clarifies that when building System models, generation dispatch is part of the model building process. E) Under R1.1.2 there is uncertainty around the language of New planned Facilities. We offer the following definition for Planned Facilities to be added to the definition section of this standard and further added to the NERC Glossary of Terms: Planned Facilities Generation and Transmission Facilities that are expected to be implemented with an in service date prior to the plan year being studied. F) Under R1.1.2 a bullet should be added for Relay Loadability Limitations. The standard requirements for relay loadability are included in PRC-023-1.

Response: The SDT has removed the language "and other data sources".

> **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.

The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. No change made. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon.

Mitigation Time Horizon

The time horizons available for mitigating a violation to a requirement include the following:

- **Long-term Planning** — a planning horizon of one year or longer.

Organization	Question 1 Comment
	• **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal. • **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time. • **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system. • **Operations Assessment** — follow-up evaluations and reporting of real time operations. If a transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-contingency. Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months. **1.1.2** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. Requirement R1, part 1.1.6 now states Resources required to supply Load. **1.1.6** Resources required to supply Load Requirement R1, part 1.1.3 covers new planned Facilities and changes to existing Facilities. **1.1.3** New planned Facilities and changes to existing Facilities The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7. Relay loadability is covered under Requirement R3, part 3.3.3. No change made.
PJM	In R1, why require a Planning Coordinator AND a Transmission Planner to maintain models for the same area Concern with the words - for each yearin R1.1.2. Does this mean that a case for each year, at least, will need to be produced? Will five, one for each season and a light load, each year need to be produced R1.1.5 is not clear. Is the Interchange exclusive of Firm Transmission Service as mentioned in R1.1.4 Maybe -non-firm transmission service-- is clearer.
Response: Requirement R7 requires the Transmission Planner and Planning Coordinator to determine and identify joint responsibilities. The SDT has modified Requirement R1 to state that the Transmission Planner and Planning Coordinator are responsible for maintaining System models for their respective areas. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within their respective areas for performing the studies needed to complete their Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The SDT has revised Requirement R1, part 1.1.2 (now part 1.1.3) to delete the reference to "year".	

Organization	Question 1 Comment
1.1.3 New planned Facilities and changes to existing Facilities The SDT believes that transfers and Firm Transmission Service are actually two separate items since Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange	
American Electric Power	Under R1.1.2. Add Transformers, otherwise, revise Transmission Lines to read Transmission Facilities. Also under R1.1.2., add Series Reactors and Capacitors as a distinct category of facilities from Reactive Power devices that include shunt capacitors and reactors, and Control devices that include phase angle regulating and variable frequency transformers, FACTS devices, and other power electronics. These additions would further clarify the types of facilities that should be included, and these comments are made in full recognition that the introductory sentence to R1.1.2. contains the wording such as.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7. The SDT has also revised this requirement to remove 'such as'.	
ITC Holdings	Comments: We question the value of R1.1.1, which requires the inclusion of transmission or generator outages if..known, in a planning standard. If an outage puts you in a compliance deficiency for the duration of any outage, would you be fined for such an instance? Category P6 contingencies should cover these outages and not require a separate requirement such as R1.1.1. This requirement could also make an entity subject to fines for long term outages needed to upgrade or replace equipment as part of a CAP for other category violations. If this requirement is kept, it should be restricted to very long term outages and exclude those outages needed to complete CAPs for other violations. R1.1.6 requires the use of Network Resources to supply load. For many planning studies, particularly beyond the five year window, the capacity additions needed to supply load are frequently unknown. Since there are no requirements or guidelines for assuming what and where these resources will be, assumptions will have to be made regarding the needed resources. Additionally, existing network resources could be retired or re-designated to serve other load. It is unclear as written exactly what would be a violation of this requirement if known network resources are not sufficient to serve projected load. Finally, with the advent of market power, would a dispatch utilizing this type of dispatch be considered a violation of this standard.
Response: The SDT believes that the outages should be modeled to insure the system reliability during the outage durations. Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months. If a transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-contingency. All performance criteria would then apply to that new base case. **1.1.2** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.	

Organization	Question 1 Comment
The SDT has revised Requirement R1, part 1.1.6. to include Resources required to supply Load. **1.1.6** Resources required to supply Load	
Northern Indiana Public Service Company	Under R1.1, insert, "as applicable" after "represent". Since R1 covers steady state, short circuit and dynamic models, data requirements should be applicable to the specific model. Representation of circuits breakers, protection system equipment and control devices is not typical of steady state model inputs.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.	
Minnesota Power	A) Under R1 there is language that references other data sources; can the SDT please offer some clarification on what other data sources are to be? Could other data sources be Tariff requirements? B) Again under R1, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R1 only says Long-term Planning. By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: Near-Term and Long-Term Transmission Planning. C) Under R1.1.1 it is required that models represent planned outages of generation and transmission facilities, if specifically known. However, the requirement does not distinguish the length of the outage to be considered. Should a one week maintenance outage in Year Five be included? Should a two-year complete rebuild outage lasting through the entire years 2 and 3 be included? The SDT team needs to add a comment about the length of the planned outage and its relevance to the assessment. D) R1.1 is repeating what should already be in the MOD-010 and MOD-012 requirements. Is the inclusion of these elements in the TPL standard redundant? The planners expect the model building process will already included the components listed in R1.1, otherwise there would not be a functional model. If R1.1 is kept, we suggest removing the "Models for" so that R1.1 reads "The Planning Assessment shall represent:"
Response: The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. The SDT has deleted the language "and other data sources". **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within their respective areas for performing the studies needed to complete their Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made.	

Organization	Question 1 Comment
Mitigation Time Horizon The time horizons available for mitigating a violation to a requirement include the following: • **Long-term Planning** — a planning horizon of one year or longer. • **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal. • **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time. • **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system. • **Operations Assessment** — follow-up evaluations and reporting of real time operations. The SDT believes that the outages should be modeled to insure the system reliability during the outage durations. If a transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-contingency. All performance criteria would then apply to that new base case. Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months. **1.1.2** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has incorporated these additional requirements with the intent that they will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. The SDT has reworded Requirement R1, part 1.1. **1.1** System models shall represent:	
LADWP	For R1.1.4 the requirements should be based on "expected transfer" instead of "firm transmission service". When projecting into future, the term "firm transmission service" is meaningless because transmission service contracts can be changed overnight. Using "firm transmission service" as a base would also exclude any new contract that are not considered in the study. It is very short-sighted to plan new transmssion facilities only based on "firmed transmission services". R1.1.2 is very confusing. What is a new technology? Is it something we don't know? If we know what it is, is it still a new tchnology? If we don't know, how do we model it? Also, we do not model individual circuit breaker but the effect of the circuit breakers; same apply with control devices or protective system equipment. Need more clarity. In general, a laundry list of items to be represented is a bad idea because it gives the impression that anything not on the list does not need to be modeled.
Response: The SDT believes that transfers and Firm Transmission Service are actually two separate items since Firm Transmission Service is “the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.” Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange	

Organization	Question 1 Comment
New technologies include any technology that is not currently in use on the electric power System that helps improve efficiency (i.e., energy storage/production technologies, low sag conductors, solid state interrupters, etc.). New technologies were removed from the list in Requirement R1, part 1.1.2 and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.	
Platte River Power Authority	R1.1.2. "....for each year of the Near-Term and Long-Term..." Models for each year of the 10 years in the planning horizons are not developed in our Region. Please clarify your intention. R1.1.2. 3rd bullet - "Circuit breakers (or the effects of)" R1.1.2. 4th bullet - "Protection System equipment (or the effects of)" R1.1.2. 5th bullet - "Control devices (or the effects of)" R1.1.2. 6th bullet - "New techonologies (or the effects of)" R1.1.4. "Firm Transmission Service (or expected transfers)
Response: The SDT has deleted "year". **1.1.3** New planned Facilities and changes to existing Facilities The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT believes that transfers and Firm Transmission Service are actually two separate items since Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange	
MAPPCOR	R1 - what it means to include requirements of regulatory authorities and other legal obligations. Even if some version of this language is kept in the final standard, it seems to belong in R2 rather than R1. R1.1.1 - should remove the word specifically since it means nothing. Only known long-term outages of generation and transmission should be required to be modeled. R1.1.2 in the first line should have the word studied to avoid confusion, to read "New planned Facilities and changes to existing Facilities for each year studied of the "?

Organization	Question 1 Comment
	R1 states that the models used in these studies shall be consistent with data provided through MOD-010 and MOD-012. The data submitted for these are updated on a schedule provided by the RRO and not necessarily reflective of any emerging changes that may have occurred between the MOD data collection cycle. The requirement should allow for exceptions to allow the most recent information to be included in the TPL studies.

Response: : The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements.

> **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within their respective areas for performing the studies needed to complete their Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.

The SDT has deleted 'if specifically known'.

> **1.1.2** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

The SDT has deleted "year".

The SDT has modified Measure M1 to use the latest data available.

> **M1** Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

Idaho Power	The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices where it is expected to impact the study outcome. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted.

Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement r3, part 3.3, Requirement r4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.

The SDT believes that transfers and Firm Transmission Service are actually two separate items since Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange.

Organization	Question 1 Comment
1.1.5 Known commitments for Firm Transmission Service and Interchange	
Turlock Irrigation District	TPL 001-1 R1 could potentially result in a WECC auditor having to determine compliance with requirements of regulatory authorities and other legal obligations, beyond the scope of its expertise. TID proposes that if that language is to be retained, it shall be assumed that the requirements of regulatory authorities and other legal obligations are being simulated unless those other entities have formally found the member to be in violation of their requirements or obligations.
Response: The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.	
New York Independent System Operator	R1.1.1 requires that models shall represent planned outages of generation and transmission facilities, if specifically known. The standard should be clarified to state whether it allows or requires a PC/TP to include as part of the Assessment outages due to maintenance and due to construction programs where certain facilities are out of service during phases of construction. Such maintenance and construction schedules are established but may not be finalized over the planning horizon. Further, the standard is not clear whether planned outages are to be treated as creating a normal system condition or as a contingency from which system adjustments are made prior to subsequent eventsMOD 10 and 12 are based on requirements determined by the RRO in MOD 11 and 13 respectively. Is this appropriate? Further, the PC is not an applicable entity in MOD 10 and 12. Moreover, the standard should define other data sources. R1.1.2. states that models for facilities such as circuit breakers and protection systems should be represented. Comment - The list of facilities should be deleted for the following reasons:- it is not needed;- the NYISO does not model circuit breakers, Control Devices, and Protection Systems;- it is not consistent with the definition of Facilities in the NERC Glossary.
Response: The SDT believes that the outages should be modeled to insure the System reliability during the outage durations. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-contingency. Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months. **1.1.2** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. The Planning Coordinator is to still use the information provided under MOD-010 and -012. The SDT has removed "and other data sources". **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to	

Organization	Question 1 Comment
complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.	
Duke Energy	Revise R1.1.2 to include the phrase to be studied as follows: New planned Facilities and changes to existing Facilities for each year to be studied of the Near-Term and Long-Term Transmission Planning Horizon, such as :
Response: The SDT has deleted "year". **1.1.3** New planned Facilities and changes to existing Facilities Existing Facilities are now shown under Requirement R1, part 1.1.1. **1.1.1** Existing Facilities	
Tucson Electric Power Company	The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices where it is expected to impact the study outcome. An alternative, instead of specifically listing elements, make a general statement that the models should include those elements required in MOD-010 through MOD-013. If an element is missing, double jeopardy could result due to a violation of the applicable MOD standard and this TPL standard. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted. We disagree with the inclusion of the words including requirements of regulatory authorities and other legal obligations at the end of R1. Entities already are required to do this. It does not need to be included in the standard.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has incorporated these additional requirements with the intent that they will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.	

Organization	Question 1 Comment
The SDT believes that transfers and Firm Transmission Service are actually two separate items since Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.	
Independent Electricity System Operator	1. R1: What modeling/simulation is envisaged by the phrase requirements of regulatory authorities and other legal obligations? Note that this condition is not included in the measure or the VSL, making its compliance (whatever it is) irrelevant. If it is indeed a needed condition, then it should be measured and included in the VSL language under the Severe condition. Further, we suggest replacing simulate with incorporate since R1 deals with building of the system model that will be used to perform simulations governed by Requirement R2. Moreover, we do not think this requirement (to simulate projected System conditions including requirements of regulatory authorities and other legal obligations) belongs to R1, which is a requirement to develop the system model. R2 is the requirement for conducting Planning Assessments which include simulation using the model. We suggest moving this requirement to R2 upon making appropriate changes, where necessary to address our comments on the wording. 2. We recommend introducing applicable before regulatory authorities. 3. R1.1.2: suggest to add Transformers. 4. R1.1.5: suggest to change Interchange to Interchange Schedules or Interchange Transactions. 5. We agree with the VRF, Time Horizon, Measures and VSLs, other than the requirements of regulatory authorities and other legal obligations noted above.
Response: The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.	

Organization	Question 1 Comment
The SDT has changed the word "simulate" to "represent" in Requirement R1. The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange Thank you for your response on VRF et al.	
Kansas City Power & Light	R1 states that the models used in these studies shall be consistent with data provided through MOD-010 and MOD-012. The data submitted for these are updated on a schedule provided by the RRO and not necessarily reflective of any emerging changes that may have occurred between the MOD data collection cycle. The requirement should allow for exceptions to allow the most recent information to be included in the TPL studies.
Response: The SDT has modified Measure M1 to use the latest data available. **M1** Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.	
ReliabilityFirst Corporation	R1.1.1 requires to include Planned outages of generation and Transmission Facilities, "if specifically known" Should the generation be capitalized? Suggest changing it to "All planned Generation and Transmission facilities should be modeled. R1.1.2 Use of the word "such as" is not very clear and may not be enforceable. There are some size limitations in the study tools and it may not be possible to model all circuit breakers. Last three bullets are very hard to model and these are not consistent with MOD-010 and MOD-012. I am not sure what "New Technologies" mean. Does this require a model for each year? This contradicts the requirements in Sections R2.1-R2.1.1, R2.1.2 and R2.2. Suggest changing this to read "New planned Facilities and changes to existing Facilities for Near-Term and Long-Term Transmission Planning Horizon as described in Sections R2.1-R2.1.1, R2.1.2 and R2.2." Modeling of Protection Systems, Control Systems requires new data collection effort and falls under Section 1600 of NERC Rules of Procedure. The list does not include Transformers.Suggest removing Protection System equipment and Control devices from the list and adding another sub-section which states "Models should reflect the limitations imposed by Protective Devices and Control systems characteristics. Define "New Technologies"

Organization	Question 1 Comment
	R1.1.3 Here it is better to include the Type of Forecast (50/50 or 90/10). A reference NERC Reliability Assessment Guidebook can be included here.

Response: Generation is not a defined term itself in the NERC glossary - thus it does not need to be capitalized in Requirement R1.1.1. Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months.

1.1.2 Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

The SDT has revised R1.1.2 to remove "such as". The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.

New technologies include any technology that is not currently in use on the electric power System that helps improve efficiency (i.e., energy storage/production technologies, low sag conductors, solid state interrupters, etc.).

The SDT has deleted "year".

1.1.3 New planned Facilities and changes to existing Facilities

The SDT does not believe that a reference is needed to the NERC Reliability Assessment Guidebook since most utilities are using at least a 50/50 Load forecast as a minimum. No change made.

2. Requirement R2 — Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: The industry had many comments on Requirement R2 but for the most part, the questions were requesting clarification. The SDT has changed a number of the parts of this requirement with the major changes being: part 2.1.4 and part 2.4.3 on sensitivities, additional clarification on part 2.2 for the Long-Term Transmission Planning Horizon and the addition of a new part 2.7.2 on multiple sensitivity deficiencies. The full list of changes is:

Year One: The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.

2.1.4 (previously 2.1.3) For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of planned Transmission outages.

2.1.5 (previously 2.1.4) When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

2.2 The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, part 2.6:

2.2.1 A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3 The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4 The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part2.6. The following studies are required.

2.4.1 System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.3 For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Load level, Load forecast, or dynamic model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5 (new) The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported by current or past studies.

2.6.1 (previously 2.5.1) For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2 (previously 2.5.2) For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

2.7 (previously 2.6) For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7 (previously 2.6) bullet 2: Installation, modification, or removal of Protection Systems or Special Protection Systems

2.7.2 (new) Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.5 (previously 2.6.4) If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The

Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.6 (previously 2.6.5) Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8 (previously 2.7) For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.2 (previously 2.7.2) Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status.

2.9 (previously 2.8) The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.

R2 VSL	The responsible entity failed to comply with Requirement R2, part 2.9 or Requirement R2, part 2.6.	The responsible entity failed to comply withRequirement R2, part 2.3 or part 2.8.	The responsible entity failed to comply with one of the following parts of Requirement R2: part 2.1, part 2.2, part 2.4, part 2.5, or part 2.7	The responsible entity failed to comply with two or more of thefollowing parts of Requirement R2: part 2.1, part 2.2, part 2.4, or part 2.7.

Organization	Question 2 Comment
Dominion - Electric Transmission	R2.1.3 - Dominion suggests that SDT needs to be more specific on which of thevariations to include. Also for the last bullet, the SDT needs to clarify the duration ortiming of planned transmission outages (in relation to Planning horizon). R2.4.1 - While we appreciate the intent of introducing induction motor modeling in simulations, this is a difficult proposal in actual practice. The question of how much of the load is comprised of induction motors and what is a reasonable/practical model has been around now for over twenty years yet is still not resolved satisfactorily. For example, we have heard several experts declare the CLOAD model is inadequate for study. NERC needs to take the lead in developing appropriate models for the widely used simulation software and a methodology for determining load composition prior to requiring induction Load modeling in dynamic simulation studies. Additionally, this requirement states that Aggregate System Load model is acceptable to represent the dynamic behavior of induction motor Loads. Our interpretation is that such aggregate models shall be inserted by the Planners at the time of study, over a specific study area as determined by TP, and these models are not to be represented in the interconnection-wide (i.e. ERAG/MMWG) dynamics base cases. If ERAG/MMWG dynamics base cases are populated with such aggregate load models, the dynamic simulation cases could become very difficult to solve, if not impossible. R2.8 - Dominion does not see any purpose in reporting largest consequential load loss. This is not easily calculated, and

Organization	Question 2 Comment
	would vary from year by year, season by season. R2.9 - Dominion requests further clarification. Is the intent of this requirement to develop criteria for maximum allowable non-consequential load loss prior to requiring a corrective action plan or to just calculate such a load loss where it is permitted in Table 1?

Response: Part 2.1.3 (now Part 2.1.4) has been revised to provide greater clarification. It is intended that the Planning Coordinator or the Transmission Planner will select the variation to include in the sensitivity studies.

2.1.4 For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of planned Transmission outages.

The last bullet in Part R2.1.3 (now Part 2.1.4) is intended to cover planned outages of Facilities in sensitivity studies if such planned outages are known at the time the planning studies are performed, for example, nuclear power plant refueling, generating unit maintenance, etc.

Part 2.4.1 is intended to allow the Planning Coordinator and Transmission Planner the discretion in the use of aggregated System Load models in Stability Studies, if specific models are not available. However, it does not dictate the methodology or the process on how the studies are to be done.

Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only.

2.9 The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.

Northeast Power Coordinating Council	It is recommended to replace the phrase prepare with conduct and document in the first sentence.R2.1.1 Comment The requirement to evaluate year one or year two should be removed. This is not consistent with the time horizon

Organization	Question 2 Comment
	identified in R2. R2.1.3 Comment - The emphasis on sensitivity testing in the existing section appears misdirected and should be focused on reasonable risk. The assessment should have to include a discussion of reasonable risk. The sensitivity list can be used to select sensitivities to assess risk. Having a requirement to perform one sensitivity just to meet the requirement of the standard does not add value to the assessment. R2.1.4 With respect to spare equipment strategy; this requirement imposes severe testing requirements upon the system. However, there is no discussion on the generation dispatch or system transfers that are to be used for this portion of the assessment. The expectations for changes in system stresses need to be clear as part of the standard. Additionally, this section does not contemplate changing the acceptability of load loss. After experiencing a major contingency such as this, some change in the acceptability of load loss should be expected. The standard should consider allowing Non-Consequential load loss for P1 & P2 events. The standard needs to allow Non-Consequential load loss for P3 & P4 events. Remove the wording (such as a transformer). What constitutes "spare equipment strategy"? Would a strategy that involves out-of-merit dispatch or operational restrictions be considered a valid "spare equipment strategy". If a transformer is lost, could a reconfiguration of the transmission system constitute a valid "spare equipment strategy" R2.2 Comment We suggest replacing the phrase a current System peak Load study with a valid System peak Load study in the first sentence. The word current is confusing as some read the word current to mean today's rather than valid. R2.3 Comment Please provide guidance as to what year should be represented when performing short circuit studies. R2.4.1 Comment ? Change to read: "For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads or an aggregate System Load model which represents the overall dynamic behavior of the Load. R2.5.1 Comment We suggest deleting this requirement, and incorporating it into R2.5.2. R2.5.2 Comment To incorporate R.2.5.1 into R2.5.2; please modify the section as follows: For steady state, short circuit, or Stability analysis the study shall be less than five calendar years old or less: the latest Transmission Planning Horizon System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: The addition/deletion/change of individual generating unit capability determined to be material by the Planning Coordinator or Transmission Planner. [A 20 MVA generator is fairly small in a 30,000 MW system and system concerns would already be addressed though the System Impact Study]" An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES determined to be material by the Planning Coordinator or Transmission Planner. R2.6 Priority Comment As written, this section undermines the value of the sensitivity testing. This section should require a corrective action plan to fix problems determined in sensitivity analysis if there is a reasonable risk of occurrence. We suggest making the standard read Provide documentation that explains the reasoning for the sensitivities considered and selected. R2.6 Comment At the end of the second sentence, the phrase in the tables is used. We suggest using more definitive

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	language such as in Table 1. R2.6.2 Comment The phrase Project Initiation Date needs to be defined. It is unclear if this is this the date of ground breaking, purchase orders being issued, solution study initiation, etc. Additionally, in the second sentence the phrase as well as an in-service date should be modified to read as well as a target in-service date. R2.6.3 Comment Plans can provide a target in-service year but not an actual in-service year. R2.6.4 Priority Comment There should be a cutoff point when changes occur beyond a certain date. When that date occurs, further changes will be evaluated in the next year's assessment. Otherwise, if a state makes a decision not to site a project a few weeks prior to the end of the assessment period, there will not be sufficient time to incorporate this into that year's assessment and develop corrective actions. R2.8 Comment Largest consequential load loss is not factored into the Planning Assessment and should therefore be deleted. R2.9 Comment This requirement is unclear. Is this requirement asking for each transmission planner to list their criteria for non-consequential load loss, or is it asking how much non-consequential load loss was being relied upon in the assessment? We recommend that the requirement be modified to require documentation of the maximum amount of non-consequential load loss that was relied upon during the assessment. It is strongly recommended that the standard should consider not allow non-consequential load loss to resolve any violation arising from the planning events in Table 1. Therefore, this requirement would then be deleted. The use of System Off-Peak Load is too general. Is the intention to have the system minimum load used here? Because of the seasonal differences in equipment ratings, seasonal peak and off peak (minimum) loads should be analyzed.

Response: The SDT was not able to locate the word "prepare" in the first sentence of Part 2.1.1. However, Requirement R2 states, "Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses". The SDT assumes that the comment was meant for this sentence. The SDT does not think that replacing "prepare" with "conduct and document" would add clarity, since Requirement R2 includes the requirement to document assumptions and results. No change made.

The SDT disagrees that the requirement to evaluate Year One and year two is inconsistent with the Time Horizon in R2. The new definition defines Year One as the first year that the planner is responsible for assessing. No change made.

Part 2.1.3 (now Part 2.1.4) has been rewritten to clarify the intent of the requirement. The Planning Coordinator or Transmission Planner can include a discussion of risk in response to the new Part 2.7.2 on the actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary. No change made.

In Part 2.1.4 (now Part 2.1.5) when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. Part 2.1.4 is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Actions such as out of

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merit dispatch, operational restrictions, System reconfiguration can be part of a Corrective Action Plan if the System cannot meet performance requirements without the Facility in service. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.2 is intended to require a study performed in the current year, as opposed to studies performed in the past years. Part 2.2 has been revised to provide greater clarity. **2.2** The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: For Part 2.3 the decision on the year to be represented in the study is left to the discretion of the Planning Coordinator or Transmission Planner. Part 2.3 only requires it to be either a study that was performed during the current year or in the past. For example, this year is 2009 and a study performed in 2009 is a current study, the study can investigate the System in a future year, which is at the discretion of the Planning Coordinator or Transmission Planner performing the study. Part 2.3 has been revised to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. Part 2.4.1 was not changed as suggested because the intent of the last sentence is to allow the use of an aggregated System Load model as an appropriate Load representation. The suggested change could be read to mean that an aggregated System Load model would not appropriately represent the dynamic behavior of Loads. However, Part 2.4.1 has been revised to provide greater clarity. **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Parts 2.5 .1 and 2.5.2 (new Parts 2.6.1 and 2.6.2) were not combined. While the SDT appreciates the concern that a 20 MW generation addition can be small compared to a large System, a NERC standard needs to be clear as to the applicability. A requirement, which contains "determined to be material by the Planning Coordinator or Transmission Planner", is not clear. Therefore, changing from 20 MW to "material" will also have to require justification from the Planning Coordinator or Transmission Planner on what is "material". Material has been deleted from the requirement. Part 2.6.2 and 2.6.3 have been removed. Part 2.6 has been modified and included as new Part 2.7. The intent is to allow discretion for the Planning Coordinator or Transmission Planner to correct those deficiencies if they are prevalent (i.e., occur in more than one sensitivity). Although not required, the standard does not preclude the Planning Coordinator or Transmission Planner to develop Corrective Action Plans for high risk scenarios. However, if the scenario is high risk, then it should have been included in the base assumptions in the assessment and the Corrective Action Plan would have been required. The end of the second sentence has been changed to refer to

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Table 1 as suggested. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Part 2.6.4 (now 2.7.5) allows the Planning Coordinator or Transmission Planner to address situations that are beyond its control by utilizing Non-Consequential Load Loss and/or curtailment of Firm Transmission Service, which are normally not permitted. Depending on the urgency of the need, the Corrective Action Plan may be developed outside the normal Assessment cycle at the discretion of the Planning Coordinator or Transmission Planner involved. No change made. Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1. The recommendation that "the standard should consider not allow non-consequential load loss to resolve any violation arising from the planning events in Table 1" will include also the multiple Contingencies, for which loss of Non-Consequential Load is allowed in the existing TPL Standards. While the sentiment is laudable, it may not be practical. No change made. The use of System Off-Peak Load is intended to be general to allow the Planning Coordinator or the Transmission Planner to use their best judgment suited to the study area, since the System must be able to meet performance requirements over all demand levels. The Planning Coordinator or Transmission Planner is not precluded from investigating more System conditions than are required in this standard. No change made.	
Transmission Planning	R2.1.4. COMMENT: For the analysis to reflect the contingencies in Table 1 (P0 through P7 plus Extreme Events) is excessive. R2.5.2. COMMENT: The 20 MW change listed in bullet items are extremely small to larger transmission systems and by themselves would be unlikely to change BES response. As drafted, requirement 2.5 may be interpreted to preclude the use of any previous study in which the base case is not identical to the current planning case. It is recommended 2.5.2 be rewritten as follows; For steady state, short circuit, or Stability analysis: the present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period that would impact the study area. R2.6.2. COMMENT: What is considered a project initiation date is it implying a construction start date, or the first time that it was identified as a mitigation plan? Additionally, R2.6.2 and R2.6.3 are not necessary because a Corrective Action Plan, by definition, includes an "associated timetable for implementation". Recommend deleting this requirement. R2.8. COMMENT: Why is this data collection a requirement? The effort required to determine this data is substantial and the value of this data is questionable. Recommend deleting this requirement. R2.9. COMMENT: Why is this data collection a requirement? The effort required to determine this data is substantial and

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	the value of this data is questionable. Recommend deleting this requirement.

Response: Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

While the SDT appreciates the concern, the proposed revision could be interpreted as removing the threshold for minimum change in generation. Part 2.5.2 has been revised as Part 2.6.2 to include an alternative threshold to be based on the study area's installed generation capacity.

> **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required.

> **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only.

> **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.

SERC Engineering Committee Planning Standards Subcommittee	R2.1: In R2.1, change the reference to requirement R2.6 (at the end of the last line) to R2.5. R2.1.4: In Requirement R2.1.4, recommend that the requirement be revised as follows: "When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience the possible unavailability of the long lead time equipment. R2.4.1: In Requirement R2.4.1, it is suggested that it be reworded to the following: "System peak Load for one of the five years, including Load models which appropriately represents the dynamic behavior of Loads, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

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	R2.5.1:With the elimination of the distinction between system and generating plant stability studies, the blanket requirement in R2.5.1 that all stability analyses be five calendar years old or less, regardless of any material changes to the system, would cause needless work to be performed on those plants or areas of the system where no changes are occurring. Recommend add the following to the end of R2.5.1: unless justification can be provided to demonstrate that the results of an older study are still valid. R2.6.2: In Requirement R2.6.2, what constitutes a "project initiation date," and how will it be used? Please clarify. R2.8: Please explain the reason why Requirement R2.8 is needed in the Assessment. Reporting the largest Consequential Load Loss does not impact reliability. R2.9: Please explain the reason why Requirement R2.9 is needed in the Assessment. Reporting the largest Non-Consequential Load Loss does not impact reliability.

Response: In the new version, Part.2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made.

Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.4.1 has been revised to reflect your suggestion.

> **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

Part 2.5.1 has been revised and included as Part 2.6.1 to address your concerns.

> **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required.

> **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning

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Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Modesto Irrigation District	On pages 6 and 7 under sections R2.1.3 and R2.4.3, I think the magnitude of the variations in the conditions asked for in the sensitivity cases, should be defined and not left to the analyst to decide. On page 8 under Section R2.5.2, examples of material changes for generation are given, but no examples for transmission changes. Shouldn't we include examples of material transmission changes, too Comments: Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES R2.8 and R2.9 load loss comment. We don't agree with R2.8 & R2.9. What reliability purpose is served by these requirements?
Response: The items in Parts R2.1.3 (now Part 2.1.4) and 2.4.3 are intended for use as guides. NERC Standards must allow room for discretion of the Planning Coordinator and/or Transmission Planner who are closer to the issues in their respective areas. In Part 2.5.2 the SDT removed the examples related to the generation changes and therefore have not added examples of transmission changes. Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt and is not specifically related to new planned Facilities. Part 2.3 has been revised to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. Parts 2.8 and R2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
OPUC	2. Requirement R2 Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.Comments: A: Short circuit of over-stressed breakers is already addressed in Table 1.Ex1: P2-3,4 (Internal Breaker Fault),Ex2: P4 (Stuck Breaker while attempting to clear a fault). B: In R2.1.4 Table 1, it is unclear how transformer contingency analysis can be aggregated or batched. It is also still unclear

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	whether corrective action plans are required solely to meet performance requirements for sensitivities.

Response: Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt and is not specifically related to new planned Facilities. This is not the same as the examples cited. Part 2.3 has been revised to provide greater clarity.

> **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.6 has been revised and included as Part 2.7 to state that Corrective Action Plans do not need to be developed solely to meet the performance requirements for a single sensitivity run. Part 2.7.2 has also been added to require that the Corrective Action Plan include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary. The intent is to allow discretion for the Planning Coordinator or Transmission Planner to correct those deficiencies if they are prevalent (i.e., occur is more than one sensitivity).

> **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:
>
> **2.7.2** Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

Bonneville Power Administration	Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). R2.1.1: Peak load modeled for the near term planning horizon may not be Year one or year two. Therefore, R2.1.1 should be revised to say System peak load for one of the five years. Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer.

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	This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement. The 20 MW threshold identified as material change for generation in R2.5 is too small. The limit should be raised or based on a percentage of the study area's installed generating capacity. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event? if it is documented? R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.

Response: Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt and is not specifically related to new planned Facilities. Part 2.3 has been revised to provide greater clarity.

> **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

Part 2.1.1 is intended to require studies for System Peak Load Conditions for 2 of the years in the near-term planning horizon: 1) A Year five case to identify potential problem that can be addressed if the planned projects proceed as scheduled. 2) A Year one or Year two case to identify any potential problems unanticipated in the five-year case, which if not addressed, could impact operations as time progresses. Therefore, the SDT declines to make the change as suggested.

Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.5 has been revised and references to the 20 MW change have been deleted.

> **2.5** The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported by current or past studies.

Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees

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that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
MRO NERC Standards Review Subcommittee	MRO NSRS proposes the following comments for R2: Modify R2.6.2 to remove the obligation to include the project initiation date. The inclusion of this date would add unnecessary work that is not needed to assure adequate BES reliability In addition, it is not clear whether initiation refers to the commencement of engineering, design, construction, etc.Augment R2.6.5 to include annual verification of the continued validity of the Corrective Action Plan because the value of implementation status is dependent on the status of continued validity. MRO NSRS suggests this text: Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status . . . Augment R2.7.2 to include annual verification of the continued validity of the Corrective Action Plan because the value of implementation status is dependent on the status of continued validity. MRO NSRS suggests this text that is similar to R2.6.5: Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status. Remove R2.8. MRO NSRS does not know of any reason why the investigation and inclusion of the largest Consequential Load Loss caused by any P1 or any P2 events is needed to assure adequate BES reliability. In addition, all events involving Consequential Load Loss are studied, not just the largest load loss (see R3.3.1).
Response: In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Parts 2.6.5 and 2.7.2 have been revised and included as Parts 2.7.6 and 2.8.2 respectively to reflect your suggestion. **2.7.6** Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures. **2.8.2** Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status. Part 2.8 is intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed the requirement and agrees that as written, it was unclear. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	

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SERC Engineering Committee Dynamics Review Subcommittee (DRS)	1. R2.1.4 Loss of 2 transformers is itself a very severe contingency. However, when it is combined with R2.1.4 (spare equipment strategy) it can lead to a triple contingenecy which is unnecessarily severe and has an extremely low probability of occurrence. We recommend that the requirement be deleted from the standard. In the subrequirements of 2.1.3 and 2.4.3, the use of the word timing is unclear. Consider using in service date or schedule for. With the elimination of the distinction between system and generating plant stability studies, the blanket requirement in R2.5.1 that all stability analyses be five calendar years old or less, regardless of any material changes to the system, would cause needless work to be performed on those plants or areas of the system where no changes are occurring. Recommend add the following to the end of R2.5.1: unless justification can be provided to demonstrate that the results of an older study are still valid.

Response: Part 2.1.4 (now Part 2.1.5) is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

2.1.5 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Parts 2.1.3 (now Part 2.1.4) and 2.4.3 have been revised to reflect your suggestion.

2.1.4 For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of planned Transmission outages.

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	2.4.3 For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Load level, Load forecast, or dynamic model assumptions. • Expected transfers. • Expected in service dates of new or modified Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. Part 2.5.1 has been revised and included as Part 2.6.1 to address your concerns. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.
SERC Engineering Committee Reliability Review Subcommittee (RRS)	The proposed standard not only raises the bar for system performance requirements, but also raises the bar for reporting and documentation. We need to employ almost as many librarians and technical writers as engineers to develop and keep track of the documentation. Engineers need to spend more time performing the studies and spend less time documenting studies keeping track of documentation for multiple years. R2 Instead of document results the requirement should be to summarize results. While results will be documented, the Planning Assessment should just include a summary. R2.1 What's the value in being able to use qualified past studies if you have to use annual current studies? Strike the words supplemented with and insert the word or. In R2.1, change the reference to requirement R2.6 (at the end of the last line) to R2.5. Do not understand the rationale for being so prescriptive in requiring specific years to be studied in R2.1.1. Why not allow the TP and/or PC to decide on the three years to be studied in the Near Term? In the subrequirements of R2.1.3 and R2.4.3, the use of the word "timing" is unclear. Consider using in service date or schedule for. " In R2.1.3, it is suggested that the studies be referred to as the "base studies" to avoid confusion with the sensitivity studies. Also suggest that another phrase be added at the end for clarity. The entire R2.1.3 would then be as follows: For each of the base studies described in Requirements R2.1.1 and R2.1.2, sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment. Sensitivity studies would include changes to:oIn Requirement R2.1.4, it is suggested that language be added to reflect the possible unavailability of the equipment, such as: When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead

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	time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience the possible unavailability of the long lead time equipment. How would adequate lead times be determined" In Requirement R2.1.4, recommend that the requirement be revised as follows: When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience the possible unavailability of the long lead time equipment. Since R2.3 short circuit analysis is a new raising the bar requirement, should the implementation plan for this be for 5 years like the other new requirements? R2.3 Insert the phrase "one year of after the word addressing. In Requirements R2.3 and R2.4, do we need a reference to Requirement R2.5 for the past studies" Further clarification is needed in R2.4.1 concerning load models that appropriately represent the dynamic behavior of loads. In Requirement R2.4.1, it is suggested that it be reworded to the following: System peak Load for one of the five years, including Load models which appropriately represents the dynamic behavior of Loads, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. R2.4.1: It is not clear how much Load must have a dynamic model. Likely, it must still be proven that the analysis software can accommodate every load in the model having a load model that includes induction motor models. To help address this, revise Load to be Load that could impact the study area is acceptable. Is a NERC drafting team addressing these issues to determine an industry standard? Load models referenced in R2.4.1 should be confined to the consideration of transient stability study work. In Requirement R2.4.3, it is suggested that this sub-requirement be reworded to the following: For each of the base studies described in Requirements R2.4.1 and R2.4.2, sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the base studies shall be included in the Assessment. Sensitivity studies would include changes to: Regarding Requirement R2.6, it is suggested that the word "modeled" be added as follows: For Planning Events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed in subsequent assessments but the System modeled shall continue to meet the performance requirements in the tables. Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3 and R2.4.3. The Corrective Action Plan shall: In bullet three of Requirement R2.6.1, would we allow automatic generation tripping for a single (P1) event if it is not consequential? It seems that tripping of generation should be restricted to P2 events 2 or 3 at a minimum. In bullet five of Requirement R2.6.1, is there a maximum duration that operating procedures can be used before a capital

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	project must be included (or completed) in the Corrective Action Plan? With the elimination of the distinction between system and generating plant stability studies, the blanket requirement in R2.5.1 that all stability analyses be five calendar years old or less, regardless of any material changes to the system, would cause needless work to be performed on those plants or areas of the system where no changes are occurring. Similar to the draft MOD-026-1 standard, this period should be 10 years. With the elimination of the distinction between system and generating plant stability studies, the blanket requirement in R2.5.1 that all stability analyses be five calendar years old or less, regardless of any material changes to the system, would cause needless work to be performed on those plants or areas of the system where no changes are occurring. Recommend add the following to the end of R2.5.1: unless justification can be provided to demonstrate that the results of an older study are still valid. R2.5.2 Suggest deleting the phrase Material generation changes could include: and the two accompanying bullets. A change of 20 MW on a large system may not always be material. In Posting #2, undervoltage load shed, underfrequency load shed, and Special Protection Schemes were considered to be Non-Consequential Load Loss. In R2.6.1, installation or modification of Protection Systems or Special Protection Systems are now allowed as part of the Corrective Action Plan. Should undervoltage and underfrequency load shed also be allowed in the Corrective Action Plan? In Requirement R2.6.2, what constitutes a "project initiation date," and how will it be used? Please clarify. Please explain the reason why Requirement R2.8 is needed in the Assessment and how does reporting the largest Consequential Load Loss impact reliability? Please explain the reason why Requirement R2.9 is needed in the Assessment and how does reporting the largest Non-Consequential Load Loss impact reliability? If contingencies occur inside one utility that affect facilities in another utility, which utility is responsible for running these studies during the annual assessments?? R2.8 and R2.9 should be deleted. We don't see a reliability-related need for these requirements. In R2.9, does the requirement require the maximum non-consequential load that can occur for contingencies in Table 1 or does it require just the maximum that a utility will allow on its system? Suggest clarifying permissible or perhaps using similar language as found in R2.8. R2.9: One cannot determine the maximum permissible Non-Consequential Load Loss for every Planning Event. First of all, this should not be a requirement, as it is, for those events that do not even cause Non-Consequential Load Loss. Secondly, to obtain the maximum permissible value, one would have to stress the system in some way until one of the performance requirements are violated. That is an unreasonable stipulation and cumbersome to perform such an analysis.

Response: Requirement R2 has been revised to reflect your suggestion.

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning

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	Assessment shall use current or past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. In Part 2.1 it is envisioned that not all parts of the studies on which the Assessment is to be based can rely on past studies. For example, a study on year five performed during the past year may not be representative of year five in the current year. A past study can still be used if it can be demonstrated that the requirements for use of past studies are met. No change made. In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made. Part 2.1.1 is intended to require studies for System Peak Load Conditions for 2 of the years in the near-term planning horizon: 1) A Year five case to identify potential problem that can be addressed if the planned projects proceed as scheduled. 2) A Year one or Year two case to identify any potential problems unanticipated in the five-year case, which if not addressed, could impact operations as time progresses. Therefore, the SDT declines to make the change as suggested. Parts 2.1.3 (now Part 2.1.4) and R2.4.3 have been revised to clarify the word "timing". **2.1.4** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Real and reactive forecasted Load. • Expected transfers. • Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. • Controllable Loads and Demand Side Management. • Duration or timing of planned Transmission outages. **2.4.3** For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Load level, Load forecast, or dynamic model assumptions. • Expected transfers. • Expected in service dates of new or modified Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. The SDT reviewed Part 2.1.3 and declined to use the term "base study" because "base study" may have different meanings in different parts of the continent, and

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the term, "studies described in Parts 2.1.1 and R2.1.2" should be sufficient to avoid confusion. No change made. Part 2.1.4 (now Part 2.1.5) is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. The SDT does not feel that Part 2.3 raises the bar as entities should have been performing these studies all along. No change made. The SDT declines to revise Part 2.3 to include short circuit analysis for one of the years in the Near-Term Transmission Planning Horizon because Part 2.3 only requires that a Planning Assessment be performed. Past studies can be used to support the Planning Assessment. No change made. Parts 2.3 and 2.4 have been revised to include the reference to the requirements for use of past studies. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. **2.4** The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required: Part 2.4.1 has been revised to reflect your suggestion. In addition, Requirement R2.4 concerns only "The Near-Term Transmission Planning Horizon portion of the Stability analysis". Part 2.4.1 is a sub-part of Part 2.4, and so should also carry the same limitation. **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. The SDT reviewed Part 2.4.3 and declined to use the term "base study" because "base study" may have different meanings in different parts of the continent, and the term, "studies described in Parts 2.4.1 and R2.4.2" should be sufficient to avoid confusion. No change made. Part 2.6 has been revised and included as Part 2.7 to reflect your suggestion. The third bullet in Part 2.6.1 is intended to meet the requirements in Table 1. Generation tripping is allowed at the discretion of the Planning Coordinator or Transmission Planner for P1 Events as long as there is no loss of firm Non-Consequential Load. In addition, in the fifth bullet, the duration for use of an operating procedure is also at the discretion of the Planning Coordinator or Transmission Planner because it may not be feasible environmentally to implement Transmission reinforcements in some locations. Part 2.5.1 has been revised and included as Part 2.6.1 to address your concerns, but the SDT disagrees that the timeframe should be changed to 10 years. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided

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	to demonstrate that the results of an older study are still valid. Part 2.5 has been revised to reflect your suggestion. **2.5** The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported by current or past studies. Use of generation tripping not precluded within the Standard and the maximum duration for operating procedures in Corrective Action Plans is not addressed within the standard. UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1. If Contingencies occur inside one utility that affect facilities in another utility, the Planning Coordinator or Transmission Planner for the utility, whose system is impacted would be responsible for performing the annual Assessment for those contingencies known to cause the impact. A certain amount of coordination will need to occur between the utilities. The parties can then mutually agree upon a Corrective Action Plan.
FirstEnergy Corp	The standard provides prescriptive language in requirement R2.4.1 regarding dynamic stability load models but is silent on steady-state load modeling. Most transmission planners use a conservative approach of simulating constant power loads in the steady-state environment, but other steady-state load modeling assumptions such as constant impedance load and constant current load can be utilized. At a minimum, the standard should require the transmission planner to document its load modeling assumptions for steady-state simulations. To this end, we suggest a new sub-requirement R2.1.1 be placed ahead of the existing R2.1.1 that parallels R2.4.1 and indicates the TP should document its load modeling assumptions for steady-state simulations. Specific comments, Requirements of R2A. R2.1: The requirement incorrectly references R2.6 which should be a reference to R2.5. B. R2.1.1: We propose that the SDT adjust requirement R2.1.1 to annually require one current year Near-Term and one Long-Term study, with the Long-Term study required to alternate between year six and year ten every other assessment year. This would reduce the workload on the industry and cover the mid-point transition period between the Near-term and

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	Long-Term horizons that the standard team believes needs some attention. We find the requirement to perform two Near-Term studies and one Long-Term study each year overly burdensome, in light of the increased workload caused by sensitivity analysis for each steady-state and stability review that is required. FE believes that one current year study within each time period should suffice in being able to interpolate and extrapolate results to cover the entire assessment range; especially when supplemented with qualified past study results. C. We offer the following comments related to requirement R2.4.1: 1. In the last round of comments we made the following comment "This requirement should be separated into two requirements as it covers two distinct topics; a) peak load study for one of the near-term years and b) dynamic load modeling." The SDT responded "...This Requirement is to make you properly represent the dynamic behavior of Loads at high System Load levels." Apparently, the SDT did not agree with our recommendation to split the requirement as no change was made in this regard. Therefore, as written the standard in R2.4.2 (stability study of the Off-Peak Load level) seems to imply that the appropriate modeling of dynamic behavior of loads, including consideration of induction motor loads, is NOT required for the Off-Peak Load stability study. Please clarify or confirm this view of R2.4.2. 2. R2.4.1: We are still of the opinion that the word "appropriately" is vague and only serves to add confusion within this requirement. It's recommended that "appropriately" be struck from the requirement. 3. R2.4.1: In Draft 3, the SDT added text to this requirement that states "An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable" to clarify that a detailed dynamic Load model is not required at each bus. We understand this to mean that the model is not expected to try and replicate the dynamic behavior of individual end-user Load characteristics and that general approximations for a customer class(es) (residential, commercial or industrial) simulated at a given load bus is acceptable. 4. Based on our comments C.1 through C.3 we propose the following requirement language: R2.4.1. System peak Load for one of the five years.R2.4.2. System Off-Peak Load for on of the five years.R2.4.3. Load models used for stability analysis shall represent the dynamic behavior of Loads, including the behavior of induction motor Loads. The study shall document assumptions made for representing the dynamic behavior of Loads, based on the following load classes - residential, commercial and industrial. D. R2.5.2: For clarity and readability we propose to insert the word "that" between the words "and would" so the requirement reads "...intervening period and that would impact ...". E. R2.6.1: This requirement indicates that an entity's Corrective Action Plans list situations where Table 1 Performance Criteria are not met and the associated actions needed to achieve required System performance. What if the actions and plans associated with newly identified deficiencies (current year studies) are not yet fully known and require further analysis and a more detailed study of various options. Would it be acceptable for a TP to indicate that the planned solution is To Be Determined? This could be a likely scenario for a long-term planning horizon study which may identify a number of deficiencies which require more detailed analysis to determine the appropriate solution. F. R2.6.2: We believe this requirement is overly prescriptive in requiring a project initiate date. The standard should not question an entity's project management but stay focused on whether or not the Correct Action Plan was put in place in a timely fashion. We propose that the team strike from this requirement the reference to project initiation date and focus on

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	whether or not Corrective Action Plans were completed in a timely manner to ensure Table 1 Performance Criteria is met. Additionally, project initiation date is pertinent to a operating procedure solution that is allowed by the standard. R2.6.4: We support requirement R2.6.4 but suggest the word "prudent" be struck from the text of the requirement as it can be subjective and open for debate. G. R2.7: This requirement introduces additional Corrective Action Plan requirements beyond what is stated in R2.6. FE proposes that the SDT restructure the two requirements into a single requirement (and sub-requirements) focused on Corrective Action Plans. H. R2.8: Does this requirement apply to sensitivity simulations? If so, it has limited applications to only those sensitivity analyses that consider variations in load such as a higher forecast (90/10), or increased reactive load (sensitivity to poor power-factor loads), etc. The SDT should consider clarifying the intent of the requirement if each current year study as well as their corresponding sensitivity simulation model(s) is intended to have this information documented within the assessment report. I. R2.9: We ask the SDT to confirm or correct our understanding that the requirement is asking about a TPs criteria for maximum allowable non-consequential load drop and NOT the maximum non-consequential load shed required to meet performance criteria for a particular contingency evaluation. We agree with the stated Measures, VRF, Time-Horizon, Data Retention and VSL of requirement R2

Response: The language does not preclude the documentation of the steady state Load model used because steady state assumption of Load model is a degree of conservativeness. See header note b. No change made.

In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made.

As written, Requirements R2 and Part 2.1.1 provides flexibility for the Planning Coordinator or Transmission Planner to use past studies to support the current year assessment and to assess other years in addition to those identified in Part 2.1.1. So the suggestion to alternate between year six and year ten every other assessment is already allowed as written. No change made.

In Part 2.4.1 the SDT specifies the dynamic Load model representation for on peak because the System voltages are generally lower during on peak. The percentage of motor load, e.g., in air conditioners, could significantly increase reactive power requirements especially when they stall due to low System voltage and can therefore impact dynamic System performance on-peak. However, motor Load would likely not pose the same problem during off-peak as the System voltages are usually higher. So, in Part 2.4.2, it can be left to the discretion of the Planning Coordinator or Transmission Planner whether the dynamic motor Load would need to be represented per Part 2.4.1,

Part 2.5.2 has been modified and included as Part 2.6.2 and the “intervening period” language has been deleted.

2.6.2 For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required.

2.7 For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the

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	Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Part 2.6 has been modified and included as new Part 2.7. Part 2.6.1 requires a Corrective Action Plan be developed to enable the System performance requirements in Table 1 and Part 2.6 states that "revisions to the Corrective Action Plans are allowed in subsequent assessments but the System shall continue to meet the performance requirements in Table 1". This allows the Planning Coordinator or Transmission Planner to develop a Corrective Action Plan that can consist, for example, of a number of potential alternative solutions, and, the Corrective Action Plan can be revised as the study continues. 'Prudent' has been deleted in Part 2.6.4 (now Part 2.7.5). **2.7.5** If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service. Part 2.7: Short circuit duty Assessment has been revised for clarity and included as Part 2.8. **2.8** For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall: Parts 2.8 and R2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.
IRC Standards Review Committee	(1) When a spare equipment strategy does not cover the long lead time unavailability as stated in 2.1.4, will the system be treated as normal system condition or as having a contingency from which system adjustments are to be made prior to subsequent events. (2) Under R2.5 ?Past Studies may be used to support the Planning Assessment if they meet the following requirements and the sub requirement R2.5.2 states that for SS, SC, or stability analysis; the PRESENT system model shall not include any material changes, such as ".Does this mean that past studies may be used to support planning assessments as long as there are no material changes to the present system model" If so, that would be an impossible scenario to recreate.
Response: In Part 2.1.4 (now Part 2.1.5) when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1. Part 2.1.5 is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the	

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performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.5.2 is intended to allow the use of past study if the System that is being modeled for Assessment today has not materially changed from the one modeled in the past study for the study area. While changes are expected to occur between planning cycles, not all changes have significant impacts on System performance. For example, if the load growth in an area has not changed significantly, there is no change in the Transmission System and no addition of new generation, and then a case can be made that the past study can be used to support a new Assessment.	
TVA System Planning	Do not understand the rationale for being so prescriptive in requiring specific years to be studied in R2.1.1. Why not allow the TP and/or PC to decide on the three years to be studied in the Near Term? Since R2.3 short circuit analysis is a new raising the bar requirement, should the implementation plan for this be for 5 years like the other new raising the bar requirements? Further clarification is needed in R2.4.1 concerning load models that appropriately represent the dynamic behavior of loads. Is a NERC drafting team addressing these issues to determine an industry standard? If contingencies occur inside one utility that affect facilities in another utility, which utility is responsible for running these studies during the annual assessments? In R2.6.1, is there any limit to the time duration that a SPS and/or operating procedures can be used in the CAP? In Posting #2, undervoltage load shed, underfrequency load shed, and Special Protection Schemes were considered to be Non-Consequential Load Loss. In R2.6.1, installation or modification of Protection Systems or Special Protection Systems are now allowed as part of the Corrective Action Plan. Should undervoltage and underfrequency load shed also be allowed in the Corrective Action Plan? In R2.9, does the requirement require the maximum non-consequential load that can occur for contingencies in Table 1 or does it require just the maximum that a utility will allow on its system? Suggest clarifying permissible or perhaps using similar language as found in R2.8. Please explain the reason why Requirement R2.9 is needed in the Assessment. Reporting the largest Non-Consequential Load Loss doe not impact reliability. In R2.1, change the reference to requirement R2.6 (at the end of the last line) to R2.5. With the elimination of the distinction between system and generating plant stability studies, the blanket requirement in R2.5.1 that all stability analyses be five calendar years old or less, regardless of any material changes to the system, would

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	cause needless work to be performed on those plants or areas of the system where no changes are occurring. Recommend add the following to the end of R2.5.1: unless justification can be provided to demonstrate that the results of an older study are still valid. In Requirement R2.6.2, what constitutes a "project initiation date," and how will it be used? Please clarify. Please explain the reason why Requirement R2.8 is needed in the Assessment. Reporting the largest Consequential Load Loss does not impact reliability. R2.1 What's the value in being able to use qualified past studies if you have to use annual current studies Strike the words supplemented with and insert the word or R2.3 Insert the phrase one year of after the word addressing. In the subrequirements of 2.1.3 and 2.4.3, the use of the word timing is unclear. Consider using in service date or schedule for. In R2.6, does the Corrective Action Plan need to show all possible alternatives to fix a problem that has been identified - or does only one solution need to be shown for a problem?

Response: As written, Requirement R2 and Part 2.1.1 provides flexibility for the Planning Coordinator or Transmission Planner to use past studies to support the current year Planning Assessment, and to assess other years in addition to those identified in Part 2.1.1. So the suggestion is already allowed as written. No change made.

The SDT does not feel that Part 2.3 raises the bar as entities should have been performing these studies all along. No change made.

Part 2.4.1 requires only that the Load model appropriately represent the dynamic behavior of Loads. It is up to the Planning Coordinator and Transmission Planner, who are closer to the issues in the planning area to determine the application of the Load models. No change made.

If Contingencies occur inside one utility that affect Facilities in another utility, the Planning Coordinator or Transmission Planner for the utility whose System is impacted would be responsible for performing the annual Assessment for those Contingencies known to cause the impact. A certain amount of coordination will need to occur between the utilities. The parties can then mutually agree upon a Corrective Action Plan.

Part 2.6 has been revised and included as Part 2.7 in the new version. In the fifth bullet in Part 2.6.1, the duration for use of an operating procedure is at the discretion of the Planning Coordinator or Transmission Planner because it may not be feasible to implement Transmission reinforcements in some locations.

> **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled Load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. Part.2.6 does not specify how the Corrective Action Plan is written, it only requires that there is a plan to correct the potential problem identified in the Assessment. Therefore, it can be a number of alternatives or a single definitive alternative as long as the potential problem is addressed.

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Part 2.9 has been deleted. In the new version, Part.2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made. Part 2.5.1 has been revised and included as Part 2.6.1 to address your concerns. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required. The SDT believes that Requirement R2, part 2.8 (now part 2.9) supports the objective of ensuring BES reliability by ensuring that the largest expected amount of Consequential Load Loss is reported in an open, transparent process. Part 2.9 has been clarified. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1. In Part 2.1 it is envisioned that not all parts of the studies on which the Assessment is to be based can rely on past studies. For example, a study on year five performed during the past year may not be representative of year five in the current year. A past study can still be used if it can be demonstrated that the requirements for use of past studies are met. Parts 2.1.3 (now Part 2.1.4) and 2.4.3 have been revised to reflect your suggestion. **2.1.4** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Real and reactive forecasted Load. • Expected transfers. • Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. • Controllable Loads and Demand Side Management. • Duration or timing of planned Transmission outages. **2.4.3** For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

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	• Load level, Load forecast, or dynamic model assumptions. • Expected transfers. • Expected in service dates of new or modified Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. Part.2.6 does not specify how the Corrective Action Plan is written, it only requires that there is a plan to correct the potential problem identified in the Assessment. Therefore, it can be a number of alternatives or a single definitive alternative as long as the potential problem is addressed.
Exelon Transmission Planning	There are large amounts of resources required to perform the volume of studies required, including the dynamic and steady state sensitivities, extreme studies, and one-year lead time equipment spares. Many of these studies ultimately do not require additional consideration or reinforcement and have low threshold triggers, such as a 20 MW generation change. Performing these studies will be very burdensome to many TPs and result in few, if any, reliability benefits. We believe that the TP should be given more flexibility to allocate planning resources to areas of maximum benefit. The Spare Strategy in R2.1.4 is still not well defined. What types of equipment are included? How would a one-year lead time element be determined for consideration in this requirement? In R2.4.1, we recommend changing appropriately represents to a dynamic model appropriate for the type of stability study being performed? The TP should be allowed to perform only those specific stability studies needed and pertinent to its system. The same can be said about the dynamic load model. Differing interpretations are possible. We suggest changing the last sentence in R2.4.1 to .., a Load model shall be used which appropriately represents..An aggregate System Dynamic Load model which represents the overall dynamic behavior of the Load is acceptable. In 2.1.3 and 2.4.3 strike Expected from the phrase Expected transfers. Expected transfers should already be in the base case. In R2.5.2, the determination of a Material change is an engineering judgment issue and it should not be categorically defined here. There may be more significant material changes than a 20 MW increase in generation that would be better to study. In the phrase, For steady statesuch as generation or transmission additions/removals, or topology changes and would impact the study area, it is suggested to change would to could and impact the study area to significantly change the previous study results. The term should not be Corrective Action Plan, which implies a violation of a requirement. Suggest changing this term to Future Reliability Plan. What is the intended use for reporting the largest consequential and maximum non-consequential load loss amount and event? This would be a potential security concern if made public. There is a similar concern with the extreme event analysis. In 2.6.2 please define Initiation Date. While we appreciate your previous consideration of this comment, it is still not clear what this means. Is this the date of mitigation identification, regulatory approval date, construction start date, equipment procurement date, etc? If this is a commonly understood term not requiring a formal definition, could you then please

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	provide that definition in your response? If there is going to be a requirement to report on each contingency that results in non-consequential load loss it should be specified.

Response: If there are specific requirements in the standard that you feel would require the Transmission Planner to allocate their resources a certain way then you need to supply those specifics. As it stands, the SDT feels that the Transmission Planner can allocate resources any way they want. The standard does not dictate how they should meet requirements. No change made.

Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service such that the outage won't last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its system, or have an agreement with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.4.1 has been revised to address your concerns.

> **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

The SDT declines to strike "Expected Transfers" from Parts 2.1.3 (now Part 2.1.4) and 2.4.3. Parts 2.1.4 and 2.4.3 are sensitivity cases to be examined, which should cover conditions different from the base case. In any case, the Planning Coordinator or Transmission Planner are only required to examine one of the items from the list, and has the flexibility to choose other sensitivity cases if changes in expected transfer is not applicable.

Part 2.5.2 has been modified and included as Part 2.6.2. The SDT declines to change the term "Corrective Action Plan" to "Future Reliability Plan" because the Standard only requires the System performance to meet requirements. If a System meets requirements, then a Corrective Action Plan would not be necessary. An entity can still choose to install Transmission reinforcements for other reasons, but they would not be required by this Standard.

> **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. The SDT does not believe that this requirement represents a security concern as rewritten.

> **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2

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events in Table 1. In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: The comment – "If there is going to be a requirement to report on each contingency that results in non-consequential load loss it should be specified" does not reference any specific Requirement and therefore, the SDT can't respond. No change made.	
Southern Company	The Lower VSL describes a scenario where the TP or PC fails one or both of two particular sub-requirements. This language does not reconcile how failure of two sub-requirements is consistent with failure of only one of the same requirements. The recommendation is to restructure the VSL such that it is invoked when either sub-requirement is violated (not when both are violated). Generating unit stability has now been combined with system stability to be just one category - Stability. Previously, the shelf life of generating unit stability studies was indefinite -only needed to be restudied when system changes required it. Now the maximum shelf life of Stability studies is five years. Does this mean that generating unit stability studies must be repeated every five years whether system changes make it necessary or not? Requirement 2.3 stating that the short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon. It is not clear if the intent of the requirement is to study every year within Year One and year five. A statement similar to R2.1.1 Year One or two and year five for steady state analysis would be helpful. Some clarification is needed for R2.3 on the term Near-Term. Requirement 2.3 stating that "the analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area. What interrupting devices are included? Would the circuit breakers be enough? Moreover, the term System short circuit model is used for the first time (and the only time) here for the entire document. It is very common to use a different short circuit model for short circuit analysis while the steady state and stability analysis use different System models (power flow models). Some clarification is needed. R2.8 and R2.9 use the term megawatt "Demand". This is redundant. We suggest striking the word demand.

Response: The Lower VSL for Requirement R2 has been revised.

R2 VSL	The responsible entity failed to comply with Requirement R2, part 2.9	The responsible entity failed to comply withRequirement R2, part 2.3 or part 2.8.	The responsible entity failed to comply with one of the following parts of Requirement R2: part 2.1,	The responsible entity failed to comply with two or more of thefollowing parts of Requirement R2: part 2.1,

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			part 2.2, part 2.4, part 2.5, or part 2.7	part 2.2, part 2.4, or part 2.7.

Part 2.5.1 has been revised and included as Part 2.6.1 to address your concerns.

2.6.1 For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

The SDT declines to revise Part 2.3 to include short circuit analysis for one of the years in the Near-Term Transmission Planning Horizon because Part 2.3 only requires that a Planning Assessment be performed. Past studies can be used to support the Planning Assessment.

Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt and is not specifically related to new planned Facilities. Part 2.3 has been revised to provide greater clarity.

2.3 The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

The “megawatt” Is the qualifier for “Demand”. The SDT believe it is clear as written. No change made.

United Illuminating	R2 Comment We recommend replacing the phrase “prepare” with “conduct and document” in the first sentence. R2.1.1 Comment The requirement to evaluate year one or year two should be removed. This is not consistent with the time horizon identified in R2. R2.1.2 Comment The requirement should be removed. With no description of the system stresses and generator outages to be applied when assessing the off-peak load, it is difficult to imagine any issues which would arise which are not revealed in the peak load evaluation that could not be addressed through generation dispatch adjustments. R2.1.3 Comment - The emphasis on sensitivity testing in the existing section appears misdirected and should be focused on reasonable risk. The assessment should have to include a discussion of reasonable risk. The sensitivity list can be used to select sensitivities to assess risk. Having a requirement to perform one sensitivity just to meet the requirement of the standard does not add value to the assessment. R2.1.4 Priority Comment With respect to spare equipment strategy, this requirement imposes severe testing requirements upon the system. However, there is no discussion on the generation dispatch or system transfers that are to be used for this portion of the assessment. The expectations for changes in system stresses need to be clear as part of the standard. Additionally, this section does not contemplate changing the acceptability of load loss. After experiencing a major contingency such as this, some change in the acceptability of load loss should be expected. The standard should consider allowing Non-Consequential load loss for P1 & P2 events. The standard needs to allow Non-Consequential load loss for P3 & P4 events. Why doesn’t the standard state (such as a transformer, generator or power electronic device) and not just

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	(such as a transformer). R2.2 Comment We suggest replacing the phrase "a current System peak Load study" with a valid System peak Load study in the first sentence. The word current is confusing as some read the word current to mean today's rather than valid. R2.3 Comment Please provide guidance as to what year should be represented when performing short circuit studies. R2.4.1 Comment Change to read: "For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads or an aggregate System Load model which represents the overall dynamic behavior of the Load. R2.5.1 Comment? We suggest deleting this requirement, and incorporating it into R2.5.2. R2.5.2 Comment To incorporate R.2.5.1 into R2.5.2; please modify the section as follows: For steady state, short circuit, or Stability analysis the study shall be less than five calendar years old or less: the present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: The addition/deletion/change of individual generating unit capability determined to be material by the Planning Coordinator or Transmission Planner. [A 20 MVA generator is fairly small in a 30,000 MW system and system concerns would already be addressed though the System Impact Study]? An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES determined to be material by the Planning Coordinator or Transmission Planner. R2.6 Priority Comment As written, this section undermines the value of the sensitivity testing. This section should require a corrective action plan to fix problems determined in sensitivity analysis if there is a reasonable risk of occurrence. We suggest making the standard read Provide documentation that explains the reasoning for the sensitivities considered and selected. R2.6 Comment At the end of the second sentence, the phrase "in the tables" is used. We suggest using more definitive language such as in Table 1. R2.6.2 Comment The phrase Project Initiation Date needs to be defined. It is unclear if this is this the date of ground breaking, purchase orders being issued, solution study initiation, etc. Additionally, in the second sentence the phrase "as well as an in-service date" should be modified to read "as well as a target in-service date". R2.6.3 Comment Plans can provide a target in-service year but not an actual in-service year. R2.6.4 Priority Comment There should be a cutoff point when changes occur beyond a certain date. When that date occurs, further changes will be evaluated in the next year's assessment. Otherwise, if a state makes a decision not to site a project a few weeks prior to the end of the assessment period, there will not be sufficient time to incorporate this into that year's assessment and develop corrective actions. R2.8 Comment Largest consequential load loss is not factored into the Planning Assessment and should therefore be deleted. R2.9 Comment This requirement is unclear. Is this requirement asking for each transmission planner to list their criteria for

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	non-consequential load loss, or is it asking how much non-consequential load loss was being relied upon in the assessment? We recommend that the requirement be modified to require documentation of the maximum amount of non-consequential load loss that was relied upon during the assessment.

Response: The SDT does not think that replacing "prepare" with "conduct and document" would add clarity, since Requirement R2 includes a requirement to document assumptions and results. No change made.

The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. No change made. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon.

Mitigation Time Horizon

The time horizons available for mitigating a violation to a requirement include the following:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

Part 2.1.2 requires that the Planning Coordinator and/or Transmission Planner also consider off-peak conditions because the System must be able to meet performance requirements over all demand levels. System peak condition may not represent all stressed conditions. For example, during off-peak, the Load is low, and the generation would have to be turned off to achieve Load-resource balance. Turning down resources within a Load area could result in reliability problems. Lowering the Load in areas with many non-dispatchable resources could also pose potential problems. As the System incorporates more and more renewable resources, some of them are non-dispatchable; a standard must be forward looking so the Planning Coordinator and Transmission Planner can identify potential problems as part of the Assessment. No change made.

Part 2.1.3 (now Part 2.1.4) has been rewritten to clarify the intent of the requirement. The requirement does not preclude a discussion of risk.

> **2.1.4** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.
>
> - Real and reactive forecasted Load.
> - Expected transfers.
> - Expected in service dates of new or modified Transmission Facilities.

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	• Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. • Controllable Loads and Demand Side Management. • Duration or timing of planned Transmission outages. In Part 2.1.4 (now Part 2.1.5) when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. Part 2.1.5 is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the performance of their System. If a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Actions such as out of merit dispatch, operational restrictions, System reconfiguration can be part of a Corrective Action Plan if the System cannot meet performance requirements without the Facility in service. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.2 is intended to require a study performed in the current year, as opposed to studied performed in the past years. Part 2.2 has been revised to provide greater clarity. **2.2** The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: For Part 2.3 the decision on the year to be represented in the study is left to the discretion of the Planning Coordinator or Transmission Planner. Part 2.3 only requires it to be either a study that was performed during the current year or in the past. For example, this year is 2009 and a study performed in 2009 is a current study, the study can investigate the System in a future year, which is at the discretion of the Planning Coordinator or Transmission Planner performing the study. Requirement R2.3 has been revised to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. Part 2.4.1 was revised but not changed as proposed because the intent of the last sentence is to allow the use of an aggregated System Load model as an appropriate Load representation. The suggested change could be read to mean that an aggregated System Load model would not appropriately represent the dynamic behavior of Loads. Parts 2.5 .1 and 2.5.2 (new Parts 2.6.1 and 2.6.2) were not combined. While the SDT appreciates the concern that a 20 MW generation addition can be small compared to a large System, a NERC standard needs to be clear as to the applicability. A requirement which contains "determined to be material by the Planning Coordinator or Transmission Planner" is not clear. Therefore, changing from 20 MW to "material" will also have to require justification from the Planning

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Coordinator or Transmission Planner on what is "material". Material has been deleted. Part 2.6 has been modified and included as new Part 2.7. The intent is to allow discretion for the Planning Coordinator or Transmission Planner to correct those deficiencies if they are prevalent (i.e., occur is more than one sensitivity). Although not required, the standard does not preclude the Planning Coordinator or Transmission Planner to develop Corrective Action Plans for high risk scenarios. However, if the scenario is high risk, then it should have been included in the base assumptions in the assessment and the Corrective Action Plan would have been required. The end of the second sentence has been changed to refer to Table 1 as suggested. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required. Part 2.6.4 allows the Planning Coordinator or Transmission Planner to address situations that are beyond its control by utilizing Non-Consequential Load Loss and/or curtailment of Firm Transmission Service, which are normally not permitted. Depending on the urgency of the need, the Corrective Action Plan may be developed outside the normal Assessment cycle at the discretion of the Planning Coordinator or Transmission Planner involved. Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Louisiana Energy and Power Authority	R2.5. This basic requirement intends, as we understand it, to require that earlier studies not be used for a current assessment if they are no longer accurate. But the phrasing is potentially confusing, and would be clearer if revised. Since the requirement deals with the use of past studies, we suggest that R2.5.2 be revised to state that the study may be used only if there have been no material changes, so that R2.5 reads in full:R2.5. Past studies may be used to support the Planning Assessment if they meet the following requirements: R2.5.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less. R2.5.2. For steady state, short circuit, or Stability analysis: the study may be used only if there have been no material changes, such as generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater. With respect to footnote 10 to Table 1, we fear that the flexibility suggested by those provisions may be excessive for a planning standard. The ambiguity occasioned by stating emergency actions that can properly be taken in a planning standard can be utilized by those who plan the system in a manner which plans to drop non-consequential loads just as footnote b has been used in the past. If this is intended to raise the bar as stated these provisions do not belong in a

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	planning standard, at least as now stated. It may be appropriate to remove the reference to footnote 10, at least in the Initial System Condition entry in P3, where it suggests that it can be invoked after loss of a single generator, and we request the SDT to review that footnote to assure that it is appropriate in the other entries to which it is applied.
Response: Part 2.5 has been revised and included as Part 2.6 as shown. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Footnote 10 (now footnote 9) was added to address the disjoint between how some parties calculate ATC/AFC when assessing Long Term Firm Transmission Service and the currently proposed TPL-001-1 standard. TPL-001-1 requires Transmission Planners to plan their systems to meet multiple contingency events and some parties assess Long Term Firm Transmission Service on a first Contingency basis. Units obligated to re-dispatch, as contemplated in Footnote 9 are those units which are contractually bound to provide the service as well as those obligated to provide the service under Network Integrated Transmission Service, under FERC's pro forma OATT. Under the pro forma OATT, units designated as network resources receiving NITS are obligated to re-dispatch as requested by the Transmission Provider pursuant to Section 33.2 to maintain reliability. The footnote is worded such that curtailment/re-dispatch cannot result in the loss of firm Load preserves the guidance given by FERC in Order 693 that no single Contingency result in the loss of firm Load. No change made. The SDT has reviewed the application of footnote 10 (now footnote 9) and believes that it is correct. No change made.	
System Protection and Transmission Planning Department	R2 - The term "Stability Analysis" is used frequently in the standard, but is not clearly defined. Based on an IEEE paper ("Definition and Classification of Power System Stability," Kundar, et al) there are 5 different categories of stability analysis: 1)small signal angle stability; 2) transient angle stability; 3) frequency stability; 4) large disturbance voltage stability; and 5) small disturbance voltage stability. Does the writing committee intend to make the analysis of all these types of stability issues mandatory? I recommend inserting a new definition into the standard for stability as follows: "Stability Analysis - The study of the bulk electric power system's ability, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance. There are 5 accepted categories of power system stability: 1) small signal angle stability; 2) transient angle stability; 3) frequency stability; 4) large disturbance voltage stability; and 5) small disturbance voltage stability. While there are situations that exist that require small signal angle and voltage stability analysis, only transient angle stability, frequency stability, and large disturbance voltage stability analysis are generally relevant to system planning performance assessments. R2.1.4 is a new requirement directing studies to consider impacts of spare equipment strategy. Does this require the TP to run scenario analysis without certain transformers? It is not clear what is required. How many spare transformers are required? What reliability level is acceptable? R2.1.4 The one year cut-off seems arbitrary. One MONTH may be unacceptably long in some cases. Instead of one year or more, we suggest the requirement state an extended time period.

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	R2.2. The wording on this requirement is not clear. Is it trying to say that a long-term (5-10 year) peak loading study is required to be performed annually R2.2: What is meant by the term current System peak Load study A powerflow study performed under expected peak-load conditions? Or a forecast of peak loads? R2.3 A short circuit analysis requirement is now added to Planning Assessment requirements. Short circuit analysis appears to be in the standard to document adequate ratings for interrupting equipment. That would be the purpose of short circuit studies we perform. If there are other intended meanings, then additional detail is needed. R2.3 We do not agree that a short circuit analysis needs to be conducted annually. The requirement for a new short circuit duty study should be driven by changes in the system, as is done for powerflow study work. In short, until system changes are made, we would not anticipate higher fault duties, and there would be no reason to rerun studies. R2.4.1 requires dynamic load models. Development of dynamic load models is ongoing, and therefore will need a much longer implementation period than the steady state portions of the standard. We are not sure two years will be enough. It depends partly on pending work that is not under our control.R1.1.2, R2.1.4, R2.5.2, R3.3.4, R4.3.3, R5 When text of a Standard Requirement includes the phrase such as or could include, then gives a list of possible choices, we take it to mean "just one of these items, or none of these, or something not listed here". In other words, such as lists are really non-required, non-interpretable, non-measurable options. They should not be included in requirements. Lists such as these belong in transmittal notes and associated SDT commentary, not in Compliance Standard Requirements. R2.5.2 Limits such as "addition/deletion/change to a group of generating units . . . which total 20 MW or greater. are not always appropriate. Appropriateness of Generation netting with load should depend on system size and engineering judgment, not artificial limits. The suggestion list following generation changes could include: should be eliminated. R2.6.2. For the Near-Term Transmission Planning Horizon, include both a project initiation date as well as an in-service date? The assessment report should not require a full project development just a description of what is required to provide adequate service within specified operating criteria. The term project initiation is not clear. Requirement R2.6.2 should be eliminated. R2.8. The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1. is complicated, and may require new modeling software capability to comply. Software vendors would develop this capability. Why is this required? What is the expected benefit to system reliability?

Response: The SDT disagrees that the Standard should include a definition of Stability analysis because it is covered in Requirement R2. "Stability analysis" is not a defined NERC term and is not intended to be defined as in IEEE; however, it does not conflict with the IEEE definition. No change made.

Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service such that the outage won't last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, and may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its system, or have agreement with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than

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one year. The Planning Coordinator and/or Transmission Planner will need to decide which pieces of major Equipment in their respective Systems would be more vulnerable to long term outage. In Part 2.1.5 when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.2 has been revised to provide greater clarity. The standard will require that a study for one year within the Long-Term Transmission Planning Horizon be conducted. The Planning Assessment can be supplemented by past studies. **2.2** The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: Part 2.3 has been revised to provide greater clarity. In addition, Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt and is not specifically related to new planned Facilities. The Assessment is to be supported by a current or past study. Therefore, annual short circuit study is not required if no material change has occurred. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. Part 2.4.1 allows the use of an aggregate System Load model which represents the overall dynamic behavior of the Load that could impact the study area. Part 2.4.1 has been revised to provide greater clarity. In addition, the SDT was not able to locate the phrase "such as" in Requirement R2.4.1. There were two places in Requirement R2 that this phrase appears (Parts 2.1.4 and 2.5.2). In both instances, what follows were examples and not requirements. **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Part 2.5.2 has been revised and included as Part 2.6.2 to address your concerns. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with

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Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Part 2.8 is intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed the requirement and agrees that as written it was unclear. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
PPL Energy Plus	The standard appropriately recognizes that the planning horizon must be as long as the longest lead-time system upgrade, typically 8+ years for a new line. However, while Requirement 2.2.1 states this, it could be more clearly stated. Requirement R2.5.2 should be clarified to point out if the TP has discretion or if the 20 MW is binding. Requirement R2.6.4 should require TP's and PC's to post on an OASIS to assure easy access by affected parties to information on what is "beyond the control of these organizations. Please retain Requirements 2.8 and 2.9 as these are good measures of the quality of the plan produced by the planners.
Response: Part 2.2.1 has been revised because extending the Planning Horizon beyond 10 years for projects with lead time longer than 10 years is already covered in the definition of Long-Term Transmission Planning Horizon. **2.2.1** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected. Part 2.5.2 (now Part 2.6.2) has been revised to address your suggestion. Both bullets included references to 20 MW have been deleted from the revised standard. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. The SDT declines to require a specific venue for the Planning Coordinator and/or Transmission Planner to post the information regarding Part 2.6.4. The way information is shared should be left to the individual entities involved in accordance with Requirement R7, included in the new version as Requirement R8. Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and finds that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
PacifiCorp SRP Arizona Public Service Co	Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this

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Southern California Edison Company Pacific Gas and Electric Co, California ISO Idaho Power San Diego Gas and Electric Co	could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement. The 20 MW threshold identified as material change for generation in R2.5 is too small. The limit should be raised or based on a percentage of the study area's installed generating capacity. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event if it is documented? R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.
NV Energy	Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault).R2.1.3 should be modified to remove the last bullet point. Transmission outages should be a part of operational study work not planning study work. Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement. The 20 MW threshold identified as material change for generation in R2.5 is too small. The limit should be based on a percentage of the study area'sinstalled generating capacity. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event if it is documented R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent,

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	among other things, on the types of load being served. It very well may be a case by case situation.
Western Area Power Administration	Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault).The last bullet under R2.1.3 - "Planned duration or timing of Transmission Outages." does not belong in a long-term planning standard. These-type of seasonal outages are studied and implemetation plans are derived as part of the TOP Standard requirements. In the WECC - this is also covered by the seasonal studies carried out by the Operating Transfer Capability Policy Committee (OTCPC) study groups. Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement - OR simply delete this spare equipment requirement. The 20 MW threshold identified as material change for generation in R2.5 is too small. The limit should be raised or based on a percentage of the study area's installed generating capacity. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event if it is documented? R2.9 should be deleted. This requirement is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.

Response: Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt. Even though the effects of short circuit capability are localized and may be related to new planned Facilities, it is important to BES reliability. Part 2.3 has been revised to provide greater clarity.

> **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

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2.1.5 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.5 has been revised and included as Part 2.6 as shown. The references to a 20 MW threshold have been deleted from the revised standard. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Western Area Power Administration	Short-circuit studies as related to maintaining adequate protection devices and systems are normally performed either by a specific System Protection Group/Department or System Maintenance Department and should not be in this requirement, but Post-Transient Analysis to mitigate voltage collapse scenarios should be included (includes R2.5.1 & R2.5.2). Also, System Protection including mitigation of short-circuit duty above installed facilities capabilities or for new planned facilities are already covered by the PRC Standards and need not be included and duplicated in the TPL Planning Standard such as in R2.3 & R2.7.
Response: Parts 2.3 and 2.7 are intended for the Planning Coordinator and/or Transmission Planner to assess whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt, and develop Corrective Action Plan is needed. As such, they are not specifically related to new planned Facilities. Requirement for Post-transient voltage collapse is included in Table 1, Header note (a), which states "Voltage instability, cascading outages, and uncontrolled islanding shall not occur." No change made.	
Tampa Electric	R2.1 should state R2.5 at the end of requirement instead of R2.6 R2.1.4 Consider revising to only include P0-P2 contingencies. R2.5.1 please clarify whether the 5 years is from the beginning of the assessment or end of the assessment. R2.6 Consider changing the terminology for "Corrective Action Plan" to "Transmission Plan" R2.8 Please clarify the reason for this requirement. This is not necessary for reliability and the effort to collect this information is substantial and does not benefit the BES. R2.9 Please clarify the reason for this requirement. This is not necessary for reliability and the effort to collect this

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	information is substantial.

Response: In the new version, Part.2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference.

Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

For Part 2.5.1 the 5 years should be measured from the completion of the past study to be used to support the current Planning Assessment. However, Part 2.5.1 has been revised and included as Part 2.6.1, which will allow the use of studies older than 5 years if a technical rationale can be provided to demonstrate that the results of an older study are still valid.

> **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

In Part 2.6, the SDT declines to change the term "Corrective Action Plan" to "Transmission Plan" because the Standard only requires the System performance to meet requirements. If a System meets requirements, then a Corrective Action Plan would not be necessary. An entity can still choose to install Transmission reinforcements for other reasons, but they would not be required by this Standard.

Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Requirement R2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only.

> **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.

Florida Reliability Coordinating Council, Inc - Transmission Working Group	Incorrect reference shown at the end of R2.1. The appropriate reference should be R2.5. The end of the first sentence of R2.3 should have a reference to R2.5. The end of the first sentence of R2.4 should have a reference to R2.5. R2.1.4 - Please consider revising this for the analysis to include only Contingencies P0-P2 in Table 1. Alternatively we suggest moving this requirement to be under sections 2.1.3 and 2.4.3 and treated as a sensitivity. R2.5 ? This requirement is very valuable in clarifying that past studies can be used and what criteria needs to be met for them to be used. However it is not clear if all new studies could be met using past studies (e.g. a small system with very few changes year to year) of if some sub-requirements require a new study every year, with past studies only used as supporting information. If the intent is that some sub-requirements can not be met with past studies, then consider making that clear through a foot note or a list under Section 2.5 listing which study requirements may depend only past studies that are still current.

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	R2.5.1 Please clarify if the 5 calendar years is from the date the assessment is "finished" or the date the study process for the assessment begins. R2.5.2 the identified 20 MW threshold is extremely small and would be doubtful to change the response of the BES. This requirement could also be interpreted that a previous study where the base case is not identical to the current planning case could be used. Please consider the following proposed language: For steady state, short circuit, or Stability analysis: the present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period that would impact the study area. (not show the list) R2.6 - Requiring sensitivities but not requiring that they meet specific performance requirements is a sound approach.R2.6 requires a corrective action plan when performance will not be met in the simulations. However, if an entity has already planned a needed facility and/or operation steps for a given conditions, the simulations will not show any deficiencies and therefore no corrective action plan is required. The term Corrective Action Plan implies that the situation is wrong or incorrect, consider changing the approach to be to require an entity to have a planning and Operations plan, Improvement Action Plan?, or simply a Transmission Plan that includes all facilities planned for the BES and descriptions of conditions where an operational process is being used. R2.6.1 (Bullet 2) This requirement should also account for the removal of a Special Protection Systems: Installation, modification or removal of Protection Systems or Special Protection Systems?. R2.6.4 This is an excellent addition R2.8 Please explain the reason for this requirement. The effort required to collect this data is substantial and does not have any benefit to the BES. R2.9 Please explain the reason for this requirement. It seems to cause Entities to develop performance criteria for themselves for Multiple and Extreme Contingencies that are not in Table 1. The effort required to collect this data to compare against any self-imposed criteria is substantial and does not have any benefit to the BES. The requirement will result in inconsistency across North America. There is also no discussion of what happens if a Multiple or Extreme contingency is shown to exceed the Entity's self-imposed criteria, is the Entity then non-compliant? If so, what if the Entity simply changes the self-imposed criteria? We suggest eliminating this requirement.

Response: In the new version, Part.2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference.

Parts 2.3 & 2.4 have been revised to reflect your suggestion.

2.3 The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4 The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part2.6. The following studies are required.

Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the

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System is expected to experience due to the possible unavailability of the long lead time equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. For Part 2.5.1 the 5 years should be measured from the completion of the past study to be used to support the current Planning Assessment. However, Part 2.5.1 has been revised and included as Part 2.6.1, which will allow the use of studies older than 5 years if a technical rationale can be provided to demonstrate that the results of an older study are still valid. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. Part 2.5.2 has been revised and included as Part 2.6.2 to provide greater clarity. The references to a 20 MW threshold have been deleted from the revised standard. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. In Part 2.6 (now Part 2.7), the SDT declines to change the term "Corrective Action Plan" to "Transmission Plan" because the Standard only requires the System performance to meet requirements. If a System meets requirements, then a Corrective Action Plan would not be necessary. An entity can still choose to install Transmission reinforcements for other reasons, but they would not be required by this Standard. Although additions of Protection Systems and Special Projection Systems are usually associated with projects to enable the System to meet performance requirements, the second bullet in Part 2.7 has been modified to include removal of Protection Systems or Special Protection Systems to provide greater clarity. **2.7 bullet 2:** Installation, modification, or removal of Protection Systems or Special Protection Systems Parts 2.8 and R2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
FMPA	Incorrect reference shown at the end of R2.1. The appropriate reference should be R2.5. The end of the first sentence of R2.3 should have a reference to R2.5. The end of the first sentence of R2.4 should have a reference to R2.5. R2.1.4, what does (t)he analysis shall reflect the Contingencies identified in Table 1 mean? Is the intention similar to sensitivities, where there is no direct requirement to meet the performance standards of Table 1? If so, why not include loss of a long lead time Facility followed by other contingencies one of the Sensitivities and not have a separate sub-requirement for it? Or, is the intention that the TP and PC must meet the performance requirements of Table 1 considering the outage of a long lead time Facility? We hope that the intent is not to require Entities to be able to meet the performance requirements

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	of Table 1 assuming a long lead time Facility out of service. If that is the intent, then we believe that only Contingencies P0-P2 in Table 1 ought to apply to Requirement R2.1.4. Otherwise, Requirement R2.1.4 would require building transmission to triple contingency (N-3) criteria. Contingency P3 requires building transmission to a single contingency plus a generator outage (a double contingency that has the same performance criteria requirements as single contingencies). Since generators are long term lead Facilities that no one that we know of carries spares for, R2.1.4 as written would mean that Contingency P3 becomes two generators out of service with system adjustments followed by another contingency (N-3). This would have the (possibly unintended) consequences of significantly reducing long-term firm ATC since utilities will likely use TRM to account for the potential for long-term outages. If meeting the criteria of Table 1 is the intent of the SDT, then a potential way to address this is to restate R2.1.4 to state that only P0 through P2 (zero and single contingency) apply to R2.1.4.If meeting the performance criteria of Table 1 is the intent of the SDT for R2.1.4, then we also believe that R2.1.4 should also only apply to the EHV and not the HV system. Yes, when a major piece of equipment such as a transformer fails, it could be out for a long period of time; however, a transformer failure is far less probable than an over-head transmission line failure (e.g., a transformer failure is in the range of a once in 50 year event, whereas a transmission line fails probably once a year or once every other year, almost two orders of magnitude difference). A major 500 kV/230 kV autotransformer failure will have a far larger radius of impact than a 230 kV/138 kV autotransformer meant to serve the local area, giving additional support to purchasing a spare transformer for the 500/230 kV auto (EHV system). A small utility with only one or two 230 / 138 kV autos does not have sufficient justification to purchase a spare autotransformer due to the very low failure rate and the much more localized purpose of the transformer. If the intent of the SDT is to meet the performance requirements of Table 1 for R2.1.4, then the standard would essentially cause many small utilities who cannot justify spare autos to plan to serve only load and significantly reduce ATC in the planning horizon. Based on the lesser impact of HV connected autos as compared to EHV connected autos, and if the intent of the SDT is to meet the performance requirements of Table 1 for R2.1.4, then we would recommend that, for auto-transformers, R2.1.4 should only be applicable to EHV connected auto-transformers. R2.8 Please explain the reason for this requirement. The effort required to collect this data is substantial and does not have any benefit to the BES. R2.9 Please explain the reason for this requirement. It seems to cause Entities to develop performance criteria for themselves for Multiple and Extreme Contingencies that are not in Table 1. The effort required to collect this data to compare against any self-imposed criteria is substantial and does not have any benefit to the BES. The requirement will result in inconsistency across North America. There is also no discussion of what happens if a Multiple or Extreme contingency is shown to exceed the Entity's self-imposed criteria, is the Entity then non-compliant? If so, what if the Entity simply changes the self-imposed criteria?

Response: In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference.

Parts 2.3 and 2.4 have been revised to reflect your suggestion.

2.3 The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned

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	generation and Transmission Facilities in service which could impact the study area. **2.4** The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required. Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Transmission Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service such that the outage won't last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its System, or have agreement with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. The Planning Coordinator and/or Transmission Planner will need to decide which pieces of major Equipment in their respective systems would be more vulnerable to long term outage. In Part 2.1.5 when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.
Progress Energy Carolina (PEC)	PEC believes that "R2.1.1. System peak Load for either Year One or year two, and for year five" is unneccesarily prescriptive. PEC recommends eliminating the Year One or year two addition. PEC believes that R2.1.4. concerning an entity's spare equipment strategy is overly conservative. The standard should only require N-2 deep planning and not N-3. PEC believes that for R2.4.1 "a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads" should be clarified to include "as appropriate" clause. Induction motor load modeling should not be required for all dynamic studies. PEC believes that for R2.5.2. The language "For steady state, short circuit, or Stability analysis: the present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area" needs to be made more clear. The important point is that material changes must be modeled if they have occurred. Also the 20MW threshold is far too small to be material. PEC believes that R2.8. and P2.9 are unnecessary and should be removed.

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Response: Requirement R2, part 2.1.1 is intended to require studies for System Peak Load Conditions for 2 of the years in the Near-Term Transmission Planning Horizon: (1) A year five case to identify potential problem that can be addressed if the planned projects proceed as scheduled; (2) A Year One or year two case to identify any potential problems unanticipated in the five-year case, which if not addressed, could impact operations as time progresses. The standard provides flexibility for the Planning Coordinator or Transmission Planner to use past studies to support the current year assessment, and to assess other years in addition to those identified in Requirement R2, part 2.1.1. No change made. Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service such that the outage won't last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its System, or have agreement with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. In Part 2.1.5 when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.4.1 allows the use of an aggregate System Load model which represents the overall dynamic behavior of the Load that could impact the study area. Part 2.4.1 has been revised to provide greater clarity. **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Part 2.5.2 has been revised and included as Part 2.6.2 to address your concerns. The references to a 20 MW threshold have been deleted from the revised standard. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
CPS Energy	As written, is it the intent of Requirement R2.1.4. to escalate the contingencies in Table 1 from "N-1" to "N-2" and "N-2" to N-3" for long lead-time replacement equipment, such as autotransformers and GSUs? If so, we feel that this requirement is

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	overly burdensome that will result in unnecessary expense to the customers. In Requirement R2.4.1., what is the intent of the second sentence if an aggregate system load model is acceptable? We feel that the second sentence should be removed. In Requirement R2.6.2., we feel that statement of the project initiation date has no benefit and should be removed as a requirement. The required in-service date should be adequate. We do not believe that there is any benefit to reliability by documenting the Consequential and Non-Consequential Load Loss data required by Requirements R2.8. and R2.9.
Response: Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service such that the outage won't last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its System, or have agreement with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. In Part 2.4.1, the intent for the second sentence is that if more accurate Load Model is available it should be used. The standard should not inadvertently disallow improved Load modeling. In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
MidAmerican Energy Company	MidAmerican commends the SDT for all its hard work on this standard. MidAmerican offers the following comments on R2: MidAmerican believes that the second sentence of R2.3 as written will result in unnecessary modeling for the required short

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	circuit analysis. MidAmerican recommends that the sentence The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area. MidAmerican recommends that R2.3 be changed by deleting the words any and could and replace with the words materially. In this way, the sentence would read, They analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with generation and Transmission Facilities in service which materially impact the study area. Requirement 2.5 is too confining and is complicated and unnecessary. MidAmerican asks that the requirement be deleted in its entirety. Alternatively, if the SDT does not agree with deleting all of R2.5, then MidAmerican asks that the SDT consider deleting the R2.5.1. MidAmerican believes R2.4 will ensure that analysis is fresh by requiring a certain number of studies be conducted for certain years in the planning horizon. Why add the requirement for no older than 5 calander years? With the R2.4 and the material requirements in R2.5.2 shouldn't that be more than enough to ensure that the analysis is fresh enough to support the assessment?? If R2.5.2 is not deleted, the words and interconnected to the Bulk Electric System should be added behind 20 MW or greater. Requirement 2.6.2 requires the project initiation date. MidAmerican recommends that the SDT delete the requirement to provide this date as an initiation date is not related to system reliability. If the SDT believes it is critical to get this date, then the SDT should define it. Does it mean when engineering starts, when it is decided to proceed, or something else? At a minimum, MidAmerican believes that the SDT should add the word expected behind largest to avoid unnecessary compliance issues for an unexpected event, and clarify that R2.8 and R2.9 are not required for sensitivity cases.

Response: Part 2.3 has been revised to provide greater clarity. However, the SDT declines to make the changes suggested because Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt, and develop a Corrective Action Plan as needed. As such, they are not specifically related to individual new planned Facilities.

> **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

Deleting Part 2.5 would leave no guidance on when past studies can be used to support current Assessment. This can increase work load. Part 2.5 has been revised and included as Part 2.6 as shown.

> **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.
>
> **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required.

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2.7 For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Deseret Generation & Transmission	R2.5.2 For Past studies to be used in the Planning Assessment, the suggestion that the addition of a 20 MW generator would disqualify those past studies is way too restrictive. It should be left up to the Transmission Planner to evaluate the applicabililty of past studies and the two sub bullets should be removed and replace with a general statement about past studies should adequately represent the present system to be used in the Planning Assessment. Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the "largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event" if it is documented? R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.
Response: Part 2.5.2 has been revised and included as Part 2.6.2 to address your concerns. The references to a 20 MW threshold have been deleted from the revised standard. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to	

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	demonstrate that System changes do not impact the performance results in the study area. Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt and is not specifically related to new planned Facilities. Part 2.3 has been revised to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.6 has been modified and included as new Part 2.7. The intent is to allow discretion for the Planning Coordinator or Transmission Planner to correct those deficiencies if they are prevalent (i.e., occur is more than one sensitivity). Part 2.7.2 has also been added to require that the Corrective Action Plan include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary. The intent is to allow discretion for the Planning Coordinator or Transmission Planner to correct those deficiencies if they are prevalent (i.e., occur is more than one sensitivity). **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: **2.7.2** Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary. Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in he new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.
Northeast Utilities	R2 Comment We recommend replacing the phrase prepare with conduct and document in the first sentence. R2.1.1 Comment The requirement to evaluate year one or year two should be removed. This is not consistent with the time horizon identified in R2. R2.1.2 Comment The requirement should be removed. With no description of the system stresses and generator outages to be applied when assessing the off-peak load, it is difficult to imagine any issues which would arise which are not revealed in the peak load evaluation that could not be addressed through generation dispatch adjustments.

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	R2.1.3 Comment - The emphasis on sensitivity testing in the existing section appears misdirected and should be focused on reasonable risk. The assessment should have to include a discussion of reasonable risk. The sensitivity list can be used to select sensitivities to assess risk. Having a requirement to perform one sensitivity study just to meet the requirement of the standard does not add value to the assessment. R2.1.3 Comment - What should be the time duration for the bullet that reads Planned duration or timing of Transmission outages R2.1.4 Priority Comment With respect to spare equipment strategy, this requirement imposes severe testing requirements upon the system. However, there is no discussion on the generation dispatch or system transfers that are to be used for this portion of the assessment. The expectations for changes in system stresses need to be clear as part of the standard. Additionally, this section does not contemplate changing the acceptability of load loss. After experiencing a major contingency such as this, some change in the acceptability of load loss should be expected. The standard needs to allow Non-Consequential load loss for P3 & P6 events when spare equipment strategy is incorporated in the testing. An example of such an event, that non-consequential load loss should be acceptable, would be a long-term outage of one transformer at a station which would be modeled in the base, followed by event P6 testing on initial system condition of a transformer out of service then followed by a 2nd transformer outage. This would be three transformers out at the same station and this could approach Extreme Events Contingency. R2.2 Comment We suggest replacing the phrase a current System peak Load study with a valid System peak Load study in the first sentence. The word current is confusing, as some read the word current to mean today's rather than valid. R2.3 Comment Please provide guidance as to what year should be represented when performing short circuit studies. R2.4.1 Comment ? Change to read: "For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads or an aggregate System Load model which represents the overall dynamic behavior of the Load. R2.5.1 Comment" We suggest deleting this requirement, and incorporating it into R2.5.2. R2.5.2 Comment To incorporate R.2.5.1 into R2.5.2; please modify the section as follows: For steady state, short circuit, or Stability analysis the study shall be less than five calendar years old or less: the present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: The addition/deletion/change of individual generating unit capability determined to be material by the Planning Coordinator or Transmission Planner. [A 20 MW generator is fairly small in a 30,000 MW system and system concerns would already be addressed through the System Impact Study]?An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES determined to be material by the Planning Coordinator or Transmission Planner. R2.6 Priority Comment As written, this section undermines the value of the sensitivity testing. This section should require a corrective action plan to fix problems determined in sensitivity analysis if there is a reasonable risk of occurrence. We suggest making the standard read Provide documentation that explains the reasoning for the sensitivities considered and selected. R2.6 Comment At the end of the second sentence, the phrase in the tables is used. We suggest using more definitive language such as in Table 1.

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	R2.6.2 Comment The phrase Project Initiation Date needs to be defined. It is unclear if this is the date of ground breaking, purchase orders being issued, solution study initiation, etc. Additionally, in the second sentence the phrase as well as an in-service date should be modified to read as well as a target in-service date. R2.6.3 Comment Plans can provide a target in-service year but not an actual in-service year. R2.6.4 Priority Comment There should be a cutoff point when changes occur beyond a certain date. When that date occurs, further changes will be evaluated in the next year's assessment. Otherwise, if a state makes a decision not to site a project a few weeks prior to the end of the assessment period, there will not be sufficient time to incorporate this into that year's assessment and develop corrective actions. R2.8 Comment Largest consequential load loss is not factored into the Planning Assessment and should therefore be deleted. R2.9 Priority Comment We highly recommend that the standard should not allow non-consequential load loss to resolve any violation arising from the planning events in Table 1. Therefore, this requirement should be deleted.
ISO New England, Inc.	R2 Comment We recommend replacing the phrase prepare with conduct and document in the first sentence. R2.1.1 Comment The requirement to evaluate year one or year two should be removed. This is not consistent with the time horizon identified in R2. R2.1.2 Comment The requirement should be removed. With no description of the system stresses and generator outages to be applied when assessing the off-peak load, it is difficult to imagine any issues which would arise which are not revealed in the peak load evaluation that could not be addressed through generation dispatch adjustments. R2.1.3 Comment - The emphasis on sensitivity testing in the existing section appears misdirected and should be focused on reasonable risk. The assessment should have to include a discussion of reasonable risk. The sensitivity list can be used to select sensitivities to assess risk. Having a requirement to perform one sensitivity just to meet the requirement of the standard does not add value to the assessment. R2.1.4 Priority Comment With respect to spare equipment strategy, this requirement imposes severe testing requirements upon the system. However, there is no discussion on the generation dispatch or system transfers that are to be used for this portion of the assessment. The expectations for changes in system stresses need to be clear as part of the standard. Additionally, this section does not contemplate changing the acceptability of load loss. After experiencing a major contingency such as this, some change in the acceptability of load loss should be expected. The standard should consider allowing Non-Consequential load loss for P1 & P2 events. The standard needs to allow Non-Consequential load loss for P3 & P4 events. Why doesn't the standard state (such as a transformer, generator or power electronic device) and not just (such as a transformer). R2.2 Comment We suggest replacing the phrase a current System peak Load study with a valid System peak Load study in the first sentence. The word current is confusing as some read the word current to mean today's rather than valid. R2.3 Comment Please provide guidance as to what year should be represented when performing short circuit studies. R2.4.1 Comment Change to read: For peak System Load levels, a Load model shall be used which appropriately

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	represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads or an aggregate System Load model which represents the overall dynamic behavior of the Load. R2.5.1 Comment? We suggest deleting this requirement, and incorporating it into R2.5.2.R2.5.2 Comment To incorporate R.2.5.1 into R2.5.2; please modify the section as follows: For steady state, short circuit, or Stability analysis the study shall be less than five calendar years old or less: the present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: The addition/deletion/change of individual generating unit capability determined to be material by the Planning Coordinator or Transmission Planner. [A 20 MVA generator is fairly small in a 30,000 MW system and system concerns would already be addressed though the System Impact Study]? An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES determined to be material by the Planning Coordinator or Transmission Planner. R2.6 Priority Comment As written, this section undermines the value of the sensitivity testing. This section should require a corrective action plan to fix problems determined in sensitivity analysis if there is a reasonable risk of occurrence. We suggest making the standard read Provide documentation that explains the reasoning for the sensitivities considered and selected. R2.6 Comment At the end of the second sentence, the phrase in the tables is used. We suggest using more definitive language such as in Table 1. R2.6.2 Comment The phrase Project Initiation Date needs to be defined. It is unclear if this is this the date of ground breaking, purchase orders being issued, solution study initiation, etc. Additionally, in the second sentence the phrase as well as an in-service date should be modified to read as well as a target in-service date. R2.6.3 Comment Plans can provide a target in-service year but not an actual in-service year. R2.6.4 Priority Comment There should be a cutoff point when changes occur beyond a certain date. When that date occurs, further changes will be evaluated in the next year's assessment. Otherwise, if a state makes a decision not to site a project a few weeks prior to the end of the assessment period, there will not be sufficient time to incorporate this into that year's assessment and develop corrective actions. R2.8 Comment Largest consequential load loss is not factored into the Planning Assessment and should therefore be deleted. R2.9 Comment This requirement is unclear. Is this requirement asking for each transmission planner to list their criteria for non-consequential load loss, or is it asking how much non-consequential load loss was being relied upon in the assessment? We recommend that the requirement be modified to require documentation of the maximum amount of non-consequential load loss that was relied upon during the assessment.
Central Maine Power Company	R2 Comment We recommend replacing the phrase prepare with conduct and document in the first sentence. R2.1.1 Comment The requirement to evaluate year one or year two should be removed. This is not consistent with the time horizon identified in R2.

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	R2.1.2 Comment The requirement should be removed. With no description of the system stresses and generator outages to be applied when assessing the off-peak load, it is difficult to imagine any issues which would arise which are not revealed in the peak load evaluation that could not be addressed through generation dispatch adjustments. R2.1.3 Comment - The emphasis on sensitivity testing in the existing section appears misdirected and should be focused on reasonable risk. The assessment should have to include a discussion of reasonable risk. The sensitivity list can be used to select sensitivities to assess risk. Having a requirement to perform one sensitivity just to meet the requirement of the standard does not add value to the assessment. R2.1.4 Priority Comment With respect to spare equipment strategy, this requirement imposes severe testing requirements upon the system. However, there is no discussion on the generation dispatch or system transfers that are to be used for this portion of the assessment. The expectations for changes in system stresses need to be clear as part of the standard. Additionally, this section does not contemplate changing the acceptability of load loss. After experiencing a major contingency such as this, some change in the acceptability of load loss should be expected. The standard should consider allowing Non-Consequential load loss for P1 & P2 events. The standard needs to allow Non-Consequential load loss for P3 & P4 events. Why doesn't the standard state "(such as a transformer, generator or power electronic device)" and not just "(such as a transformer)". What constitutes "spare equipment strategy" Would a strategy that involves out-of-merit dispatch or operational restrictions be considered a valid "spare equipment strategy". If a transformer is lost, could a reconfiguration of transmission constitute a valid "spare equipment strategy"? R2.2 Comment We suggest replacing the phrase a current System peak Load study with a valid System peak Load study in the first sentence. The word current is confusing as some read the word current to mean today's rather than valid. R2.3 Comment Please provide guidance as to what year should be represented when performing short circuit studies. R2.4.1 Comment Change to read: For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads or an aggregate System Load model which represents the overall dynamic behavior of the Load. R2.5.1 Comment We suggest deleting this requirement, and incorporating it into R2.5.2. R2.5.2 Comment To incorporate R.2.5.1 into R2.5.2; please modify the section as follows:For steady state, short circuit, or Stability analysis the study shall be less than five calendar years old or less: the present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: The addition/deletion/change of individual generating unit capability determined to be material by the Planning Coordinator or Transmission Planner. [A 20 MVA generator is fairly small in a 30,000 MW system and system concerns would already be addressed though the System Impact Study]? An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES determined to be material by the Planning Coordinator or Transmission Planner. R2.6 Priority Comment As written, this section undermines the value of the sensitivity testing. This section should require a corrective action plan to fix problems determined in sensitivity analysis if there is a reasonable risk of occurrence. We suggest making the standard read Provide documentation that explains the reasoning for the sensitivities considered and

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	selected. R2.6 Comment At the end of the second sentence, the phrase in the tables is used. We suggest using more definitive language such as in Table 1?. R2.6.2 Comment The phrase Project Initiation Date needs to be defined. It is unclear if this is this the date of ground breaking, purchase orders being issued, solution study initiation, etc. Additionally, in the second sentence the phrase as well as an in-service date should be modified to read as well as a target in-service date?. R2.6.3 Comment Plans can provide a target in-service year but not an actual in-service year. R2.6.4 Priority Comment There should be a cutoff point when changes occur beyond a certain date. When that date occurs, further changes will be evaluated in the next year's assessment. Otherwise, if a state makes a decision not to site a project a few weeks prior to the end of the assessment period, there will not be sufficient time to incorporate this into that year's assessment and develop corrective actions. R2.8 Comment Largest consequential load loss is not factored into the Planning Assessment and should therefore be deleted. R2.9 Comment This requirement is unclear. Is this requirement asking for each transmission planner to list their criteria for non-consequential load loss, or is it asking how much non-consequential load loss was being relied upon in the assessment? We recommend that the requirement be modified to require documentation of the maximum amount of non-consequential load loss that was relied upon during the assessment.

Response: The SDT does not think that in Requirement R2 replacing "prepare" with "conduct and document" would add clarity, since Requirement R2 includes requirement to document assumptions and results. No change made.

The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. No change made. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon.

Mitigation Time Horizon

The time horizons available for mitigating a violation to a requirement include the following:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

Part 2.1.2 requires that the Planning Coordinator and/or Transmission Planner also consider off-peak conditions because the System must be able to meet

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performance requirements over all demand levels. System peak condition may not represent all stressed conditions. For example, during off-peak, that Load is low, and the generation would have to be turned off to achieve Load-resource balance. Turning down resources within a Load area could result in reliability problems. Lowering the Load in areas with many non-dispatchable resources could also pose potential problems. As the System incorporates more and more renewable resources, some of them are non-dispatchable; a standard must be forward looking so the Planning Coordinator and Transmission Planner can identify potential problems as part of the Assessment. No change made.

Part 2.1.3 (now Part 2.1.4) has been rewritten to clarify the intent of the requirement. The requirement does not preclude a discussion of risk.

> **2.1.4** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.
>
> - Real and reactive forecasted Load.
> - Expected transfers.
> - Expected in service dates of new or modified Transmission Facilities.
> - Reactive resource capability.
> - Generation additions, retirements, or other dispatch scenarios.
> - Controllable Loads and Demand Side Management.
> - Duration or timing of planned Transmission outages.

Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service such that the outage won't last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its System, or have agreement with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. The Planning Coordinator and/or Transmission Planner will need to decide which pieces of major Equipment in their respective Systems would be more vulnerable to long term outage. In Part 2.1.5 when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.2 is intended to require a study performed in the current year, as opposed to studied performed in the past years. Part 2.2 has been revised to provide

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	greater clarity. **2.2** The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: For Part 2.3 the decision on the year to be represented in the study is left to the discretion of the Planning Coordinator or Transmission Planner. Part 2.3 only requires it to be either study that was performed during the current year or in the past. For example, this year is 2009 and a study performed in 2009 is a current study, the study can investigate the System in a future year, which is at the discretion of the Planning Coordinator or Transmission Planner performing the study. Part 2.3 has been revised to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. Part 2.4.1 was not changed as proposed because the intent of the last sentence is to allow the use of an aggregated System Load model as an appropriate Load representation. The suggested change could be read to mean that an aggregated System Load model would not appropriately represent the dynamic behavior of Loads. Note that changes were made to Part 2.4.1 based on other stakeholder comments. Parts 2.5 .1 and R2.5.2 (new Parts 2.6.1 and R2.6.2) were not combined. The references to the “20 MW” threshold have been deleted from the revised standard. Part 2.6 has been modified and included as new Part 2.7. The intent is to allow discretion for the Planning Coordinator or Transmission Planner to correct those deficiencies if they are prevalent (i.e., occur is more than one sensitivity). Although not required, the standard does not preclude the Planning Coordinator or Transmission Planner to develop Corrective Action Plans for high risk scenarios. However, if the scenario is high risk, then it should have been included in the base assumptions in the assessment and the Corrective Action Plan would have been required. The end of the second sentence has been changed to refer to Table 1 as suggested. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Requirement R2, part 2.6.3 has been deleted. Part 2.6.4 allows the Planning Coordinator or Transmission Planner to address situations that are beyond its control by utilizing Non-Consequential Load Loss and/or curtailment of Firm Transmission Service, which are normally not permitted. Depending on the urgency of the need, the Corrective Action Plan may be developed outside the normal Assessment cycle at the discretion of the Planning Coordinator or Transmission Planner involved. No change made. Parts 2.8 and R2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.

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Gainesville Regional Utilities	R2.1.1- References a "system peak Load" for each of the referenced years. Some utilities are summer peaking and some are winter peaking and others may have a history of having one or the other in any given year. So can you clarify which peak you are referring to or change to statement to perform studies involving both seasonal peaks? R.2.4.1- I suggest quantifying the reference to the behavior of induction motor loads to single motors greater than 1000 hp or multi motors at one bus totalling more that 2000 hp or so, since smaller induction motors probably will not have any significant impact of the BES. I feel this is best handled as a sensitivity issue determined by the PC who is familiar with this area. R2.5.1- If the system has not had any significant changes of the last ten years, then a study going back to that change should be acceptable for the assessment. R2.5.2- Should the "shall not include" really read as "shall include"? R2.6- The reference to "tables" in line 6 should be "table" since there is only a Table 1 in the standard. R2.6.1-R2.6.3- Question-- Why is the font size of the bullet text smaller that the other bullet segments?

Response: In Requirement R2, part 2.1.1, the selection of the system peak Load conditions is at the discretion of the Planning Coordinator or Transmission Planner. The standard allows for use of past studies to support a current Assessment. Therefore, for an area with both summer and winter peaks, the Planning Coordinator or Transmission Planner can choose to perform summer and winter peak cases on alternate years and the Assessment can rely on, e.g., a summer peak study performed in the current year and a winter peak study performed in the previous year, provided the requirement for use of past year studies is satisfied. No change made.

Part 2.4.1 allows for the use of an aggregate System Load model which represents the overall dynamic behavior of the Load that could impact the study area. So as written, the suggested representation is allowed. Note that changes were made to Part 2.4.1 based on other stakeholder comments.

Part 2.5.1 has been revised and included as Requirement R2, part 2.6.1 to address your concerns.

> **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

In Part 2.5.2 “shall not include” is correct because the intent is that for the past study to be applicable, the present System should not have changed materially compared to that represented in the past study. However, Requirement R2, part 2.5.2 has been revised and included as Requirement R2, part 2.6.2 in the new version to provide greater clarity.

> **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

Part 2.6 (now 2.7) was modified to use the phrase, “in Table 1” rather than “in the tables.”

Part 2.5.1 (now 2.6.1) has been revised as shown.

> **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

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2.6.2 For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. For Part 2.6.1 (now 2.7.1) the format has been corrected. Parts 2.6.2 and 2.6.3 were deleted from the revised standard.	
JEA	R2.1.4 It is not clear if this spare equipment strategy excludes Generator Owner's obligations for their generation plant equipment and only includes Transmission Owner's equipment. It is also not clear what Measurable document is required to back up a position of no vulnerabilities. I recommend that we limit the spare equipment strategy to TO equipment and not include GO equipment which excludes step-up transformers, turbines, generators, rotors, etc.Also, it does seem unreasonable to assess the long-term loss of a transformer to the "Extreme Events" of Table 1 or any other event other than the P3 events unless substituted in the assessment by a more extreme and probable event. An event from P3 alone should be sufficient to expose a weakness of a spare equipment strategy based on historical industry statistics for such likelihood. Propose changing "The analysis shall reflect the Contingencies identified in Table 1..." to "An analysis shall be performed that as a minimum assesses the impact of the long term outage of Transmission Owner equipment under either a P3 event that could occur in the absence of the subject equipment" or a more stressful event as deemed appropriate by the Functional Entity performing the assessment. R2.6.4 First of all, some level of expected Non-consequential load loss is always prudent to balance customer expectations on cost and reliability subject to Local and State Authority's guidance. Second, load development and gneration development are the major drivers for transmission development needs. Generation plans are more dependable and manageable as to timing and impact. Load development is not very dependable and manageable relative to transmission system improvement needs. It is not unusual for new load forecast to either expose a transmission weakness or on the other hand to eradicate a transmission weakness in the Near Term horizon. Without guidance, it could be assumed that affects from load forecast are beyond the control of the Transmission Planner and Transmission Coordinator. In addition, it is not unusual to have the load forecast lead the generation plan by a few years causing a need for Non-Consequential Load Loss until such time the additional generation is in-service providing generation balance to the load area and mitigating the transmission improvement needs. This occurs frequently as generation development lags load development in fast growing communities. Propose establishing a cap on Non-Consequential Load Loss for all Corrective Action Plans where the Table 1 events currently do not allow at all. An additional option for the SDT to consider could be to add an allowance of lag time (maybe 4-5 years) to cover the gap while the generation addition is being developed.
Response: Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Transmission Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service such that the outage won't last into the next planning cycle. However, the major Equipment is not limited to the major Equipment of the Transmission Owner; this standard covers major pieces of pieces of Transmission Equipment without regard to ownership. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its System, or have agreement with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. Requirement R2, part 2.1.5 has been revised to require that the analysis reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.	

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	2.1.5 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. For Part 2.6.4 (now 2.7.5), the SDT declines to set a cap on Non-Consequential Load Loss on situations that are outside the control of the Planning Coordinator or the Transmission Planner. The premise is that the Corrective Action Plan has already been developed, but was not able to be implemented in time. The situation can occur with both unexpected changes in generation, Load pattern or delay in permitting and construction of new Transmission Facilities. In addition, a cap on the allowable Non-Consequential Load Loss may be different for different areas and may not be practical in a Continent-wide standard. No change made.
NorthWestern Corporation NorthWestern Energy (NWE) (NWMT)	Short circuit analysis is a local issue. The reliability of the BES does not depend on the regular assessment of short circuit duty. Therefore, we believe short circuit analysis should be deleted from R2. R2.1.4 needs more clarification as to what constitutes major Transmission equipment. This would require a separate analysis (study) for each transformer (or any long lead-time equipment) for which a spare is not available, which could result in numerous additional cases. Major Transmission equipment could be limited to voltage levels greater than 200 kV. An exception should be made for phase-shifting transformers. As the system changes, with new generation and transmission lines being added, these analyses could become outdated very quickly. If a transformer were to fail, the Planning Department would immediately study the current system with this transformer removed. As stated in R2.4.1, the requirement to include induction motor loads is too prescriptive. At this time, with all of the unknown or estimated variables in the system model, accuracy of the model would not be improved. If a highly industrialized section were to develop within the NWE footprint, induction motor load could be added to the system model. The 20 MW threshold identified as "material change" for generation in R2.5 is too small. A better number for material generation changes would be 100 MW or a limit based on a percentage of the study area's installed generating capacity. Also, an aggregate of 20 MW addition/deletion generation would depend on the location of the individual generators to determine whether the overall system would be affected or not. The statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement. R2.8 should be deleted. It is not necessary for reliability. R2.9 should be deleted. It is not necessary for reliability.
Response: Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt and is not specifically related to new planned Facilities. Requirement R2, part 2.3 has been revised to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned	

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	generation and Transmission Facilities in service which could impact the study area. Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.4.1 is intended to allow the Planning Coordinator and Transmission Planner the discretion in the use of Aggregated System Load models in Stability Studies, if specific models are not available. However, it does not dictate the methodology or the process on how the studies are to be done. No change made. Part 2.5 has been revised and included as requirement R2, part 2.6 as shown. Note that the references to the "20 MW" threshold were deleted from the revised standard. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Parts 2.8 and R2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Requirement R2, part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.
SMUD	R2.1.3 and R2.4.3The sentence, "sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment: ", should be modified by changing the second 'included' to 'considered'. R2.1.4Since there is no NERC reliability standard requirement for a 'spare equipment strategy', what is the standing of a requirement that is based on having one R2.5.2There is no example given for 'Transmission additions/removals' Recommend that the wording of this requirement be made more discretionary with a requirement that the Transmission Planner include language explaining the reasons for using past studies.
Response: Parts 2.1.3 (now Part 2.1.4) and R2.4.3 have been revised. However, the SDT declines to change the work "included" to "considered" because the intent is that if the base case modeled already models the stressed condition, such as 1 in 10 adverse weather Load, even higher Load may not need to be included in the sensitivity study, **2.1.4** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of	

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	changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Real and reactive forecasted Load. • Expected transfers. • Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. • Controllable Loads and Demand Side Management. • Duration or timing of planned Transmission outages. **2.4.3** For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Load level, Load forecast, or dynamic model assumptions. • Expected transfers. • Expected in service dates of new or modified Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. The SDT has included the spare equipment strategy in Part 2.1.4 to ensure that the BES is designed so that it remains reliable even with long lead time Equipment unavailable, consistent with the directive from FERC Order 693. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. The SDT revised Part 2.5.2 (now Part 2.6.2) to remove the "Transmission additions/removals" and "generation changes" language.
Progress Energy Florida, Inc.	Concerning R2.1.4, this sub-requirement is overly burdensome for two primary reasons: a) It amounts to a system-wide N-2 and N-3 analysis, which goes against FERC's policy of separation and distinction between types of events as stated in Paragraph 1788 of Order 693: Under TPL-002-0 the system is not required to be able to withstand another N-1 contingency. That N-1 requirement is a Category C contingency which is addressed by TPL-003-0. b) The requirement to perform system-wide analysis for such a scenario is a significant workload issue, and will take time away from analysis of more probable events. Concerning the issue of material changes in past studies in sub-requirement

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	R2.5.2, PEF objects to the specification of changes in units of 20 MW or greater, due to the fact that a change (or even deletion) of a 20 MW unit in a case modeling a large BES does not truly constitute a material change. The SDT in its response to Question 15 in the comments for draft 2 stated that The SDT did not want to be overly prescriptive when describing the type of changes that could be considered material and has left the text general. PEF suggests that the SDT take its own advice, making the language in R2.5.2 more general in nature and leaving such modeling details to the discretion of the Transmission Owner. In R2.6.2, PEF assumes that the term "project initiation date" is intended to mean the Construction Move-In date. If the term means the first date at which Planners had identified it as a mitigation, PEF would object to this as it would appear to preclude the right to develop superior mitigations, or to cancel a project if it can be demonstrated as no longer needed. Concerning R2.8 and R2.9, PEF strenuously objects to such requirements. These requirements have no bearing on demonstrating the reliability (or lack thereof) of the BES, and therefore should be removed from the Standard.

Response: Part 2.1.4 (now Part 2.1.5) is based on FERC Order 693, Paragraphs 1724 – 1727. Part 2.1.5 is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Part 2.1.5 has been revised to require that the Planning Assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.5.2 has been revised and included as Requirement R2, part 2.6.2 to address your concerns. The revised standard does not include the reference to a "20 MW" threshold.

> **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

Part 2.6 has been revised and included as Requirement R2, part 2.7 in the new version.

> **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

Parts 2.8 and R2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Requirement R2, part 2.9 in he new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only.

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2.9 The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Xcel Energy	R2.1.3 is this indicating that only one of the variations need to be studied? ("in one or more of the following conditions"). Recommend having the planner work with the load to determine what sensitivity studies to perform. R2.1.4 it is unclear as to what should be done with the analysis that incorporates the company's spare equipment strategy. Is this requirement inferring that a company's spare equipment strategy need to ensure that it can still operate to within the requirements for contingencies of Table 1 without the component? R2.2.1 is the intent to have the study for the 10 year horizon or to include any project that is started within the next 10 years and thus the study must be extended to the forecasted completion of the project (conceivably as long as 20 years or more?) R2.6.4 recommend clarifying how situations beyond the control of the TP or PC are determined. It is unclear if this is to imply that if something is outside of the control of the department who conducts the planning studies or if it is outside the control of the registered function's legal entity (i.e. corporation). R2.8 appears to be nonessential information for reliability; for what purpose does this requirement exist? R2.9 - appears to be nonessential information for reliability; for what purpose does this requirement exist?

Response: Part 2.1.3 (now Part 2.1.4) does not preclude the Planning Coordinator or Transmission Planner working with other Functional Entities to develop strategies on performing sensitivity studies. Part 2.1.4 requires that the Planning Coordinator or Transmission Planner perform sensitivity studies for at least one of the variation not already covered in the studies described in Parts 2.1.1 and 2.1.2

Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service such that the outage won't last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its System, or have agreements with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.2.1 has been revised because extending the Planning Horizon beyond 10 years for projects with lead times longer than 10 years is already covered in the definition of Long-Term Transmission Planning Horizon. This allowance is needed to provide planning flexibility, and is at the discretion of the Planning Coordinator or Transmission Planner. For example, if the System is found not to meet performance standards in year 10, but the project to correct the loading cannot be placed in service for 12 years, then the Corrective Action Plan needs to identify the interim solutions before the project can be brought on line.

> **2.2.1** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the

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rationale for why that year was selected. Part 2.6.4 refers to the situations beyond the control of the Transmission Planner or Planning Coordinator as Functional Entities. Parts 2.8 and R2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as requirement R2, part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
New Brunswick System Operator	R2.1.4 Major transmission element needs to be defined. For example, what about sync condenser, or generator step up transformer R2.2 Clearity required. Example: What is meant by "current System peak load" It is not clear what supplemental load loss is. Would load tripped due to undervoltage or SPS as a result of a contingency be considered supplemental load? As a follow up what then is Non-consequential load (provide examples). How would this load be lost? The requirements appear the same regardless of the amount of Non-consequential load loss. Is there any consideration of applying thresholds both on suppmental and non-consequential load loss where these loads are defined as (or applied as) "exceeding xxx amount of MW". Regarding Table 1 b, what does the following mean: "However, Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements." Please clearify the definition of Year One. This definition also does not include Planning coordinator. Was that intentional?
Response: In Part 2.1.4 (now Part 2.1.5), major Transmission Equipment would be those pieces of Equipment, the loss of which can have significant impact on System performance. They are typically the ones listed in the Contingency Events in Table 1. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.2 refers to a "current System peak Load study". This would be a System peak Load study that is performed in the current year. In the Definition Section, Supplemental Load Loss is defined as Load that is disconnected from the network by end-user Equipment responding to post-Contingency System conditions. Because the disconnection is at the discretion of the Load customer, not the Planning Coordinator or Transmission Planner, they cannot be counted on to leave the System. Therefore, the Transmission System cannot be planned as if such Load would disconnect. Part 2.2 has been revised to provide greater clarity. **2.2** The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the	

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	following annual current study, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: A cap on the allowable Non-Consequential Load Loss may be different for different areas and may not be practical in a Continent-wide standard. No change made. See response for Part 2.2 above. The definition has been revised to include Planning Coordinator. **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.
Lafayette Utilities System	R2.5. This basic requirement intends, as we understand it, to require that earlier studies not be used for a current assessment if they are no longer accurate. But the phrasing is potentially confusing, and would be clearer if revised. Since the requirement deals with the use of past studies, we suggest that R2.5.2 be revised to state that the study may be used only if there have been no material changes, so that R2.5 reads in full: R2.5. Past studies may be used to support the Planning Assessment if they meet the following requirements: R2.5.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less. R2.5.2. For steady state, short circuit, or Stability analysis: the study may be used only if there have been no material changes, such as generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater. With respect to footnote 10 to Table 1, we fear that the flexibility suggested by those provisions may be excessive for a planning standard. The ambiguity occasioned by stating emergency actions that can properly be taken in a planning standard can be utilized by those who plan the system in a manner which plans to drop non-consequential loads just as footnote b has been used in the past. If this is intended to raise the bar as stated these provisions do not belong in a planning standard, at least as now stated. It may be appropriate to remove the reference to footnote 10, at least in the Initial System Condition entry in P3, where it suggests that it can be invoked after loss of a single generator, and we request the SDT to review that footnote to assure that it is appropriate in the other entries to which it is applied. In addition to the foregoing, we are concerned that the language of footnote 10 to Table 1 is unclear and subject to at least one interpretation that would seriously undermine reliability. Specifically, the first sentence of footnote 10 permits "[c]urtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch." The reference to an "obligat[ion] to re-dispatch" is ambiguous at best and should be clarified. For example, footnote 10 should not be read as permitting Balancing Authority A to rely on curtailment of firm transmission service coupled with re-dispatch of generation by adjacent Balancing Authority B during a Level 5 TLR event, based on the theory that, if a Level 5 TLR is declared and the Reliability Coordinator assigns to Balancing Authority B an NNL reduction responsibility that compels it to reload its resources, Balancing Authority B is therefore "obligated to re-dispatch" within the meaning of footnote 10. We suspect the intent of the first sentence of footnote 10 was to recognize and give effect to arrangements in which (following the example) Balancing Authority A has made a prior contractual arrangement with

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	Balancing Authority B (or another generation owner) to provide redispatch services when requested by Balancing Authority A. In that circumstance, Balancing Authority A would be allowed to couple the curtailment of firm transmission with redispatch provided by Balancing Authority B (or another generation owner) pursuant to its contractual obligation. We suggest that this limitation be reflected by revising the first sentence of footnote 10 to read as follows: Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources subject to a contractual obligation to provide re-dispatch service to the operator of the system for which the Transmission Planner is responsible, is allowed both as a System adjustment (as identified in the column titled "Initial System Conditions") and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Without the limitation reflected in the foregoing revision, an entity could interpret footnote 10 as allowing it to rely on the redispatch of generation by other systems that may be (in effect) mandated by a Reliability Coordinator during a Level 5 TLR event. That sort of "leaning" on adjacent systems should not be permitted as a System adjustment or corrective action under TPL-001, especially where it imposes uncompensated burdens and costs on the system(s) forced to redispatch under these circumstances.
Response: Part 2.5 has been revised and included as Requirement R2, part 2.6 as shown. Note that the revised standard does not include any reference to the "20 MW" threshold. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Footnote 10 (now footnote 9) was added to address the disjoint between how some parties calculate ATC/AFC when assessing Long Term Firm Transmission Service and the currently proposed TPL-001-1 standard. TPL-001-1 requires Transmission Planners to plan their systems to meet multiple contingency events and some parties assess Long Term Firm Transmission Service on a first Contingency basis. Units obligated to re-dispatch, as contemplated in Footnote 9 are those units which are contractually bound to provide the service as well as those obligated to provide the service under Network Integrated Transmission Service, under FERC's pro forma OATT. Under the pro forma OATT, units designated as network resources receiving NITS are obligated to re-dispatch as requested by the Transmission Provider pursuant to Section 33.2 to maintain reliability. The footnote is worded such that curtailment/re-dispatch cannot result in the loss of firm Load preserves the guidance given by FERC in Order 693 that no single Contingency result in the loss of firm Load. No change made. The SDT has reviewed the application of footnote 10 (now footnote 9) and believes that it is correct. No change made.	
Mississippi Delta Energy Agency	R2.5. This basic requirement intends, as we understand it, to require that earlier studies not be used for a current assessment if they are no longer accurate. But the phrasing is potentially confusing, and would be clearer if revised. Since the requirement deals with the use of past studies, we suggest that R2.5.2 be revised to state that the study may be used only if there have been no material changes, so that R2.5 reads in full:"R2.5. Past studies may be used to support the Planning Assessment if they meet the following requirements: R2.5.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less. R2.5.2. For steady state, short circuit, or Stability analysis: the study may be used only if there have been no material changes, such as generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated

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	addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater. With respect to footnote 10 to Table 1, we fear that the flexibility suggested by those provisions may be excessive for a planning standard. The ambiguity occasioned by stating emergency actions that can properly be taken in a planning standard can be utilized by those who plan the system in a manner which plans to drop non-consequential loads just as footnote b has been used in the past. If this is intended to raise the bar as stated these provisions do not belong in a planning standard, at least as now stated. It may be appropriate to remove the reference to footnote 10, at least in the Initial System Condition entry in P3, where it suggests that it can be invoked after loss of a single generator, and we request the SDT to review that footnote to assure that it is appropriate in the other entries to which it is applied.
Response: Part 2.5 has been revised and included as Requirement R2, part 2.6 as shown. Note that the revised standard does not include any reference to the "20 MW" threshold. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Footnote 10 (now footnote 9) was added to address the disjoint between how some parties calculate ATC/AFC when assessing Long Term Firm Transmission Service and the currently proposed TPL-001-1 standard. TPL-001-1 requires Transmission Planners to plan their systems to meet multiple contingency events and some parties assess Long Term Firm Transmission Service on a first Contingency basis.. Units obligated to re-dispatch, as contemplated in Footnote 9 are those units which are contractually bound to provide the service as well as those obligated to provide the service under Network Integrated Transmission Service, under FERC's pro forma OATT. Under the pro forma OATT, units designated as network resources receiving NITS are obligated to re-dispatch as requested by the Transmission Provider pursuant to Section 33.2 to maintain reliability. The footnote is worded such that curtailment/re-dispatch cannot result in the loss of firm Load preserves the guidance given by FERC in Order 693 that no single Contingency result in the loss of firm Load. No change made.	
Ameren	In R2, The phrase document results should be changed to summarize results. While results will be documented, the Planning Assessment should just include a summary. In R2.1, the reference to requirement R2.6 (at the end of the last line) should be changed to R2.5. In R2.1.3, it is suggested that the studies be referred to as the "base studies" to avoid confusion with the sensitivity studies. Also it is suggested that another phrase be added at the end for clarity. The entire R2.1.3 would then be as follows: For each of the base studies described in Requirements R2.1.1 and R2.1.2, sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment. Sensitivity studies would include changes to: In Requirement R2.1.4, it is suggested that language be added to reflect the possible unavailability of the equipment, such as: When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that

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	the System is expected to experience the possible unavailability of the long lead time equipment. It is not clear how adequate lead times for equipment would be determined. In Requirements R2.3 and R2.4, consider adding a reference to Requirement R2.5 for the past studies. In Requirement R2.4.1, it is suggested that it be reworded to the following: System peak Load for one of the five years, including Load models which appropriately represents the dynamic behavior of Loads, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Load models referenced in R2.4.1 should be confined to the consideration of transient stability study work. With the elimination of the distinction between system and generating plant stability studies, the blanket requirement in R2.5.1 that all stability analyses be five calendar years old or less, regardless of any material changes to the system, would cause needless work to be performed on those plants or areas of the system where no changes are occurring. We suggest adding the following to the end of R2.5.1: unless justification can be provided to demonstrate that the results of an older study are still valid. In Requirement R2.4.3, it is suggested that this sub-requirement be reworded to the following: For each of the base studies described in Requirements R2.4.1 and R2.4.2, sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the base studies shall be included in the Assessment. Sensitivity studies would include changes to: In bullet three of Requirement R2.6.1, would we allow automatic generation tripping for a single (P1) event if it is not consequential? It seems that tripping of generation should be restricted to P2 events 2 or 3 at a minimum. In bullet five of Requirement R2.6.1, is there a maximum duration that operating procedures can be used before a capital project must be included (or completed) in the Corrective Action Plan? In Requirement R2.6.2, it is not clear what constitutes a "project initiation date". Please clarify. Please explain the reason why Requirement R2.8 is needed in the Assessment. Reporting the largest Consequential Load Loss does not impact reliability. Please explain the reason why Requirement R2.9 is needed in the Assessment. Reporting the largest Non-Consequential Load Loss doe not impact reliability. The proposed standard not only raises the bar for system performance requirements, but also raises the bar for reporting and documentation. We need to employ almost as many librarians and technical writers as engineers to develop and keep track of the documentation. Engineers need to spend more time performing the studies and spend less time documenting studies keeping track of documentation for multiple years.

Response: Part 2 has been revised to reflect your suggestion.

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.

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In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made. The SDT reviewed Part 2.1.3 (now Part 2.1.4) and declined to use the term "base study" because "base study" may have different meanings in different parts of the continent, and the term, "studies described in Parts 2.1.1 and 2.1.2" should be sufficient to avoid confusion. No change made. Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Parts 2.3 and 2.4 have been revised to include the reference to the requirements for use of past studies. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. **2.4** The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part2.6. The following studies are required. Part 2.4.1 has been revised to reflect your suggestion. In addition, Part 2.4 concerns only "The Near-Term Transmission Planning Horizon portion of the Stability analysis". Part 2.4.1 carries the same limitation as Part 2.4. **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. The requirement has been revised as suggested. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. The SDT reviewed Part 2.4.3 and declined to use the term "base study" because "base study" may have different meanings in different parts of the continent, and the term, "studies described in Parts 2.4.1 and 2.4.2" should be sufficient to avoid confusion. No change made. Part 2.6 has been revised and included as Requirement, part 2.7 to reflect your suggestion. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: The third bullet in Part 2.6.1 (now 2.7.1) is intended to meet the requirements in Table 1. Generation tripping is allowed at the discretion of the Planning

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Coordinator or Transmission Planner for P1 Events as long as there is no loss of firm Non-Consequential Load. In addition, in the fifth bullet, the duration for use of an operating procedure is also at the discretion of the Planning Coordinator or Transmission Planner because it may not be feasible environmentally to implement Transmission reinforcements in some locations. Project initiation date has been deleted from the requirements. Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Requirement R2, part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Puget Sound Energy, Inc.	Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. The 20 MW threshold identified as material change for generation in R2.5 is too small. The limit should be raised or based on a percentage of the study area's installed generating capacity. R2.7 should be deleted, see comment on R2 above. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event? if it is documented? R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.
Response: Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt and is not specifically related to new planned Facilities. Part 2.3 has been revised to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.	

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Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. The language in Part 2.5.2 that referenced a 20 MW threshold was deleted from the revised standard. The SDT assumes that you meant the comment on short circuit analysis above. The SDT declines to delete the requirement as the SDT believes that it is a necessary part of an overall Planning Assessment. Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed the both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Requirement R2, part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Manitoba Hydro	Requirement Text: R2.1: Reference of past studies should be to R2.5, not R2.6 (typo). R2.1.3: The sensitivity to Planned duration or timing of Transmission Outages should be modified to only include Planned long duration Transmission outages that span multiple seasons, if known. Short duration planned maintenance outages should not be included in a planning assessment. R2.1.4 - The second sentence doesn't read right - the sentence should be changed to read: "The analysis shall reflect the Contingencies identified in Table 1 under the conditions that the System is expected to experience during the unavailability of the long lead time equipment. R2.2.1 - This sub-requirement should be deleted. Why do extra assessments beyond the 10 year period" Any items beyond 10 years will be covered when they fall into the 10 year period. For example, if we assess the 10 year horizon, then the project due to be complete in 12 years will be part of the assessment in 2 years when it is 10 years out. We will have to show every year how our system meets compliance regardless of this extra analysis, so what's the point. Every year we have to show how we comply in the short and long term so what difference does it make when each project is completed as long as we are in compliance or identify Corrective Action Plans (CAPs) along the way. R2.4.1: The statement "a Load model shall be used which appropriately represents the dynamic behavior of Loads is not very crisp. What will appropriate be interpreted to mean by the NERC auditor? Does an MOD standard exist that covers gathering data and validating loads models? This should be a first step. The SDT should add a statement that the application of detailed induction motor modeling can be limited to areas where poor voltage recovery is expected due to a high concentration of such load. The requirement should be modified to require the PC/TP to provide a rationale for the load models used in its specific planning area. R2.5: A Past Study is a definition and should be moved to the definition section. The definition only identifies power changes

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	as possible material changes, but should also include machine control (exciters/governors) changes. We suggest the bulleted list of Material Generation changes be expanded. R2.6.1: Can the SDT clarify how a rate application qualifies as a CAP action? R2.9 - The sentence should refer to maximum Non-Consequential Load Loss not maximum permissible Non-Consequential Load Loss.

Response: In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made.

In Part 2.1.3 (now Part 2.1.4), outages that span multiple seasons are included in the last bullet, "Planned duration or timing of Transmission outages". No change made.

Part 2.1.4 (now Part 2.1.5) has been revised to reflect your suggestion.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.2.1 has been revised because extending the Planning Horizon beyond 10 years for projects with lead times longer than 10 years is already covered in the definition of Long-Term Transmission Planning Horizon. This allowance is needed to provide planning flexibility, and is at the discretion of the Planning Coordinator or Transmission Planner. For example, if the System is found not to meet performance standards in year 10, but the project to correct the loading cannot be placed in service for 12 years, then the Corrective Action Plan needs to identify the interim solutions before the project can be brought on line.

> **2.2.1** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

Part 2.4.1 has been revised to provide greater clarity.

> **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

The SDT declines to move past study to the Definition Section because the Definition, once approved, will apply to all NERC Standards, however, past study is only used in this TPL Standard.

In Part 2.6.1, "rate application" refers to rate incentives to change behavior of end-use customers and can be part of the "actions to achieve required System performance". This is included to allow for non-traditional solutions to achieving required System performance.

Part 2.9 has been deleted.

E.ON U.S.	R2.1.3Change For each of the studies to For at least one of the studies R2.1.1 and R2.1.2 require that 3 studies be performed each year. As written, the requirement indicates that the transmission planner has to perform at least one sensitivity study for the 3 studies required by R2.1.1 and R2.1.2. This means that the transmission planner would also have to perform 3 or more sensitivity studies each year. One sensitivity study for one of the 3 studies required by R2.1.1 and

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	R2.1.2 should suffice. R2.1.4.Delete "The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment. This statement is redundant since R3 requires this analysis for all of R2.1. Including this statement in R2.1.4 and not in R2.1.1 and R2.1.2 makes it appear that this requirement has different performance requirements. R2.4.3R2.4 does not require studies annually. However, if the transmission planner chooses to study a System Peak Load or a System Off-Peak Load condition R2.4.3 requires that the planner also study sensitivity to that same condition in the current year. E.ON U.S. believes it sufficient that the assessment include a sensitivity study for some System Peak Load and some System Off-Peak Load condition.R2.6The third sentence should be modified to include R2.1.4., so that it reads "Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3, R2.1.4 and R2.4.3. The annual studies performed for Category P6 alert the Transmission Planner to the risks of transformer failure. The Transmission Planner is required to design the system to limit those risks. If the delivery time for a piece of equipment is 11 months, then P6 allows Interruption of Firm Transmission Service and Non-Consequential Load Loss. If the delivery time for a piece of equipment is 12 months, then P1 requires that the system be designed for no Interruption of Firm Transmission Service and Non-Consequential Load Loss. This is a significant increase in performance requirements for an event that will most likely not extend beyond to a second System Peak Load period. If R2.1.4 is not included in the requirement the transmission planners would essentially be designing for an Extreme Event, i.e., events which are more severe and have a lower probability of occurrence than Planning Events. R2.6.1Operating Procedures, by NERC definition, require significantly more detail than is appropriate for a Corrective Action Plan. It is not appropriate that Transmission Planners write Operating Procedures to be used by NERC Certified System Operators. E.ON U.S. suggests that Operating Procedures be changed to mitigation plans. R2.6.5 Planning Assessments and System Facilities are not NERC defined terms. Operating Procedures, by NERC definition, require significantly more detail than is appropriate for a Corrective Action Plan. It is not appropriate that Transmission Planners write Operating Procedures to be used by NERC Certified System Operators. E.ON U.S. suggests that Operating Procedures be changed to mitigation plans. R2.8There are no requirements to limit Consequential Load Loss. Impacted customers are typically aware of the customary level of service and have chosen not to pay for extraordinary levels of service. E ON US questions the purpose and benefit of this requirement. While continuity of service to end use customers is an important measure of service reliability for which utilities answer to state authorities, BES reliability requires that the system remain balanced and that local failures not result in cascading BES events NERC standards should, pursuant to FPA Section 215, focus solely on BES reliability

Response: Parts 2.1.3 (now Part 2.1.4) and 2.4.3: The SDT disagrees with changing Parts 2.1.4 and 2.4.3 to requiring sensitivity study for only one System condition because this change potentially could reduce the Assessment to be based on one sensitivity study on one System condition. Since the same sensitivity can have different impacts on System performance under different System conditions, and different System conditions may require different sensitivities to be investigated, such limitation may not be adequate to maintain reliability going forward. No change made.

Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Transmission Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service

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such that the outage won't last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its System, or have agreements with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.6 is not intended for the Planning Coordinator or Transmission Planner to write Operating Procedures, only to reflect the effects or results of the Operating Procedures in its Corrective Action Plan. Mitigation Plan carries a special meaning for Compliance and so may not be appropriate for use in this standard. No change made. The term, "Planning Assessment" is one of several terms proposed for addition to the NERC Glossary of Terms Used in Reliability Standards. "System" and "Facilities" are already approved terms. Part 2.8 is intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed the requirement and agrees that as written it was unclear. Part 2.8 has been revised and included as Requirement R2, part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
LCRA Transmission Services Corporation	In R2.6.2, it is stated that a project initiation date is required as well as an in-service date. What is considered the project initiation date, the point at which the project plan is approved or the time at which construction is to begin? If it is the time at which construction is to begin, then LCRA TSC believes this requirement does not belong in the TPL-001-1 standard as the construction timeframe for a project is developed by groups outside of Planning based on resources and outage availability.
Response: Project initiation date has been deleted from the requirements.	
National Grid	R2 Comment In the first sentence, replace the phrase prepare with conduct and document and in the second sentence replace "This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses" with "The Planning Assessment shall review assumptions of current or past studies and assess the continuing validity of the steady state, short circuit, and stability results. The review of assumptions, supplemental analysis, and updated results shall be documented. R2.1 Comment A. The terms assess and annual study are referenced in the same requirement. It is unclear what constitutes either. Is an annual study required for every area or is an annual assessment required for every area, which may include some supporting study to address changes to the conditions? B. Requirement R2.1 should refer to R2.5 rather than R2.6 R2.1.1 Comment A. Year One and year two do not provide enough time to implement Corrective Action Plans and are better

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	suited for Operations studies. The requirement to evaluate Year One or year two should be removed. B. Is a year 5 study required annually for every area of a system? R2.1.2 Comment ? The requirement should be removed. With no description of the system stresses and generator outages to be applied when assessing the off-peak load, it is difficult to imagine any issues which would arise which are not revealed in the peak load evaluation that could not be addressed through generation dispatch adjustments. Need to define conditions for assessment. R2.1.3 Comment A. The emphasis on sensitivity testing in the existing section appears misdirected and should be focused on the expected accuracy of the assumptions. The assessment should have to include a discussion of accuracy of the assumptions. Having a requirement to perform one more sensitivity not already included is vague and does not add value to the assessment or the standard. B. Planned Transmission Outages are not known in the Planning horizon. Also the release of the outage on any given day is controlled by operations based on the conditions. The conditions are not known for the Planning assessment. The last bullet referring to Planned Transmission Outages should be deleted. C. Delete the phrase "are intended to." It is difficult to measure intent and what is important is whether the system has been stressed, not whether the responsible entity intended to stress the system. D. What is expected from a sensitivity analysis? Is it to change the base case and see how the case responded, is it to create a new base case and rerun all of the events, or is it to change the base case and rerun a select number of events. It is anticipated that the answer will vary based on what is changed. R2.1.4 Priority Comment With respect to spare equipment strategy; this requirement potentially imposes a requirement to plan for three events, which is overly severe. After experiencing a major contingency of a long lead time facility, there should be some change in the acceptability of risk. This change in risk could include an allowance for the loss of non-consequential load or some of the multiple events from Table 1 should be evaluated as Extreme Contingency events. R2.2 Comment We suggest replacing the phrase a current System peak Load study? with a valid System peak Load study in the first sentence. The word current is confusing as some read the word current to mean today's rather than valid. R2.3 Comment A. The requirement to conduct annually isn't consistent with support. We suggest Conducted annually should be replaced with the phrase assessed annually?.B. "Interruption duty" should be changed to "interrupting duty." All terms in the IEEE dictionary related to breaker opening use the word "interrupting," while terms related to loss of supply to customers use the word "interruption." R2.4.1 Comment A. The two sentences are describing an or condition and they should be merged to read: For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads or an aggregate System Load model which represents the overall dynamic behavior of the Load. R2.4.3 Comment - Delete the phrase "are intended to." It is difficult to measure intent and what is important is whether the system has been stressed, not whether the responsible entity intended to stress the system.

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	R2.5 Comment If past studies only support, then a new study is still required. We suggest changing “Past studies may be used to support the Planning Assessment if they meet the following requirements:” to “Past studies may be used to fulfill all or a portion of the Planning Assessment provided they meet the following requirements:” Violation Severity Levels:R2 - There is no VSL associated with R2.5. A VSL should be added, perhaps under Moderate, that "past studies were utilized to fulfill all or a portion of the requirement, but the studies did not meet the requirements in R2.5." R2.5.1 Comment? We suggest deleting this requirement, and incorporating it into R2.5.2.R2.5.2 Comment To incorporate R.2.5.1 into R2.5.2; please modify the section as follows: For steady state, short circuit, or stability analysis the study shall be less than five calendar years old from the date of completion. The present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. A material change does not require the whole study to be redone. It only requires that the affected portion of the study be reassessed. Material generation changes include: The addition/deletion/change of individual generating unit capability determined to be material by the Planning Coordinator or Transmission Planner. “ An aggregated addition/deletion/change to a group of generating units directly connected to the BES at one point of interconnection through one or more transformers and determined to be material by the Planning Coordinator or Transmission Planner. The reference to the step-up transformer may not capture a wind farm that could have transformers to step-up to a collection voltage and transformer that wouldn’t be labeled a GSU to connect to the system. R2.6 Priority Comment A. As written, this section undermines the value of the sensitivity testing. This section should require a corrective action plan to fix problems determined in sensitivity analysis if there is a reasonable risk of occurrence. We suggest making the standard read Provide documentation that explains the reasoning for the sensitivities considered and selected. B. At the end of the second sentence, the phrase in the tables” is used. We suggest using more definitive language such as in Table 1. R2.6.1 Comment -In the last bullet, the reference to "rate application" is unclear. R2.6.2 Comment The phrase Project Initiation Date needs to be defined. It is unclear if this is the date of ground breaking, purchase orders being issued, solution study initiation, etc. Additionally, in the second sentence the phrase as well as an in-service date should be modified to read as well as a target in-service date. R2.6.3 Comment Plans can provide a target in-service year, but not an actual in-service year. R2.6.4 Priority Comment There should be a cutoff point when changes occur beyond a certain date. When that date occurs, further changes will be evaluated in the next year’s assessment. Otherwise, if a state makes a decision not to site a project a few weeks prior to the end of the assessment period, there will not be sufficient time to incorporate this into that year’s assessment and develop corrective actions. R2.7 Comment A. "Interruption duty" should be changed to "interrupting duty." All terms in the IEEE dictionary related to breaker opening use the word "interrupting," while terms related to loss of supply to customers use the word "interruption."B. The requirement would be clearer if it we restructured as follows: "For short circuit analysis, if the short circuit interrupting duty determined in Requirement R2.3 exceeds the Equipment Rating of fault interrupting devices, the Planning Authority . .

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	." R2.8 Comment A. Largest consequential load loss is not factored into the Planning Assessment and should therefore be deleted. B. If it is not deleted, do we have to prepare one number for P1 and a separate number for P2? The phrase any P1 event and any P2 event in Table 1 could also be read as the worst loading for each event within P1 and P2, which could be hundreds of values depending on how many events are analyzed. We recommend that the requirement be modified to require documentation of the maximum amount of consequential load loss that was relied upon during the assessment of the P1 and P2 events.C. If it is not deleted, "shall provide" should be changed to "shall identify" for consistency with R2.9 R2.9 Comment A. Largest consequential load loss is not factored into the Planning Assessment and should therefore be deleted. B. If it is not deleted, this requirement is unclear. Is this requirement asking for each transmission planner to list their criteria for non-consequential load loss, or is it asking how much non-consequential load loss was being relied upon in the assessment? Including the word "permissible" implies the responsible entity must decide how much Non-Consequential Load Loss is allowed. We recommend that the requirement be modified to require documentation of the maximum amount of non-consequential load loss that was relied upon during the assessment of the P1 and P2 events.

Response: The SDT does not think that in Requirement R2 replacing "prepare" with "conduct and document" would add clarity, since Requirement R2 includes requirement to document assumptions and results. No change made.

In the Definition Section, Planning Assessment is defined as "Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies". Therefore, in Part 2.1, an Assessment is an evaluation of System performance based on studies performed. While an Assessment is required annually, it can be based on past studies as long as the requirement for a valid past study is met. As such, all studies used to support the Assessment do not have to be preformed annually. No change made.

In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made.

For Part 2.1.1 Year One and year two are within the Planning Horizon. In the Definition Section, Year One is defined as "The first year that a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the current calendar year". Operating Studies are performed for system conditions within 12 months of the current calendar year. No change made.

Part 2.1.1 is intended to require studies for System Peak Load Conditions for 2 of the years in the Near-Term Transmission Planning Horizon: (1) A Year five case to identify potential problems that can be addressed if the planned projects proceed as scheduled; (2) A Year one or Year two case to identify any potential problems unanticipated in the five-year case, which if not addressed, could impact operations as time progresses. The standard provides flexibility for the Planning Coordinator or Transmission Planner to use past studies to support the current year assessment and to assess other years in addition to those identified in Part 2.1.1. No change made.

Part 2.1.2 requires that the Planning Coordinator and/or Transmission Planner also consider off-peak conditions because the System must be able to meet performance requirements over all demand levels. System peak condition may not represent all stressed conditions. For example, during off-peak, the Load is low and the generation would have to be turned off to achieve Load-resource balance. Turning off resources within a Load area could result in reliability problems. Lowering the Load in areas with many non-dispatchable resources could also pose potential problems. As the System incorporates more and more renewable resources, some of them are non-dispatchable; a standard must be forward looking so the Planning Coordinator and Transmission Planner can identify potential problems. If studies for one of the Load periods are not needed annually, the Planning Coordinator or Transmission Planner can rely on past studies for the

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Planning Assessment. No change made.

Part 2.1.3 (now Part 2.1.4) has been rewritten to clarify the intent of the requirement. The Planning Coordinator or Transmission Planner can include a discussion of accuracy of the assumptions in response to the new Part 2.7.2 on the actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.1.4 For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of planned Transmission outages.

2.7.2 Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

The last Bullet in Part 2.1.3 (now Part 2.1.4) is intended to cover planned outages of Facilities in sensitivity studies if such planned outages are known at the time the planning studies are performed, for example, planned outage of a major Transmission line during construction if the Corrective Action Plan calls for rebuilding of the line to a higher operating voltage. The sensitivity study can cover the "what if" situation where the project start can be delayed or the project may take longer to construct. No change made.

Part 2.1.3 - 'Are intended to' has been deleted.

The SDT declines to make the change as suggested. A Planning Assessment is not the same as a study. As stated in the Definition, a Planning Assessment is a "documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies". As such, a Planning Assessment is based on a number of studies from which to draw conclusions about System performance and to develop Corrective Action Plans where needed. The suggested change would necessarily imply that a study is the same as a Planning Assessment, which is not the intent of Part 2.3.

Part 2.1.4 (now Part 2.1.5) is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Part 2.1.5 has been revised to address some of your concerns. Part 2.1.4 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

2.1.5 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or

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	more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.2 is intended to require a study performed in the current year, as opposed to studies performed in the past years. Part 2.2 has been revised to provide greater clarity. **2.2** The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: Part 2.3 has been revised to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. Part 2.4.1 was not changed as suggested because the intent of the last sentence is to allow the use of an aggregated System Load model as an appropriate Load representation. The suggested change could be read to mean that an aggregated System Load model would not appropriately represent the dynamic behavior of loads. However, Part 2.4.1 has been revised to provide greater clarity. **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Part 2.4.3 has been revised to provide greater clarity, and the phrase, “are intended to” is no longer used. **2.4.3** For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Load level, Load forecast, or dynamic model assumptions. • Expected transfers. • Expected in service dates of new or modified Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. As revised Part 2.1.3 (now Part 2.1.4) requires the use of sensitivity studies to “demonstrate the impact of changes to the basic assumptions used in the model”. To this end the sensitivity studies need only to be able to demonstrate the impact of changes. Typically, a sensitivity study would be a subset of the study already performed. It usually involves comparing the base cases with and without the change under consideration, and rerunning a list of the worst Contingencies. However, each situation is different and the specifics are left to the Planning Coordinator or Transmission Planner who are more familiar with the situation(s) to be

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	investigated. Part 2.5 (now Part 2.6) was not changed because studies, including past studies, are used to support the annual Assessment, and are not used to support current studies. The VSL for Part 2.5 (now Part 2.6) was added as a Lower VSL. R2, Lower VSL: The responsible entity failed to comply with Requirement R2, part 2.9 or Requirement R2, part 2.6. Parts 2.5.1 and 2.5.2 (new Parts 2.6.1 and 2.6.2) were not combined; however, they have been revised to address your concerns. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Part 2.6 has been modified and included as new Part 2.7. The intent is to allow discretion for the Planning Coordinator or Transmission Planner to correct those deficiencies if they are prevalent (i.e., occur is more than one sensitivity). Although not required, the standard does not preclude the Planning Coordinator or Transmission Planner to develop Corrective Action Plans for high risk scenarios. However, if the scenario is high risk, then it should have been included in the base assumptions in the assessment and the Corrective Action Plan would have been required. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Part 2.6 has been modified and included as new Part 2.7 In Part 2.6.1, “rate application” refers to rate incentives to change behavior of end-use customers and can be part of the “actions to achieve required System performance”. This is included to allow for non-traditional solutions to achieving required System performance. Part 2.6.3 - Project initiation date and in service date are no longer used in the requirements. Part 2.6.4 allows the Planning Coordinator or Transmission Planner to utilize Non-Consequential Load Loss and/or curtailment of Firm Transmission Service, which are normally not permitted to address situations that are beyond its control. Depending on the urgency of the need, the Corrective Action Plan may be developed outside the normal Assessment cycle at the discretion of the Planning Coordinator or Transmission Planner involved. Part 2.7 has been revised and included as Requirement R2, part 2.8 to reflect your suggestion. **2.8** For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

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Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed the both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Requirement R2, part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Entergy Services, Inc	The "study area" referred to in R2.3 should be defined. Does it mean external contingency events should be evaluated, or, the effects of internal contingency events on external parties. It should be clarified that generating facilities are not included in R2.1.4. The strategy may include agreements to share spare equipment among facilities, generation owners, and transmission owners. In R2.6.4 what is "prudent"? Who decides what is prudent? Recommend that the word be stricken. R2.6.4 is in conflict with the Implementation Plan. The Implementation plan omits P1 as an event where the bar has been raised but R2.6.4 allows the use of non-consequential load and firm transmission service curtailment. Clearly, the bar has been raised for any event, including P1, which allowed the curtailment of non-consequential load or firm transmission service in the existing standard. In R2.9 is the team requiring that a criteria be set by each Transmission Owner to set a maximum level of non-consequential load loss allowed by that Transmission Owner, or, that the amount of non-consequential load curtailment needed to meet the requirement be documented? What is the rationale for being so prescriptive in requiring specific years to be studied in R2.1.1 Why not allow the TP and/or PC to decide on the three years to be studied in the Near Term?? In the subrequirements of R2.1.3 and R2.4.3, the use of the word timing is unclear. Consider using in service date or “schedule for”. R2.1.4: The spare equipment strategy is too severe. The requirement should take into consideration the probability of occurrence of the events. Losing a transformer followed by the loss of a generator and a second transmission element is very unlikely. Non-consequential load loss should be allowed for this type of analysis. With the elimination of the distinction between system and generating plant stability studies, the blanket requirement in R2.5.1 that all stability analyses be five calendar years old or less, regardless of any material changes to the system, would cause needless work to be performed on those plants or areas of the system where no changes are occurring. Recommend adding the following to the end of R2.5.1: unless justification can be provided to demonstrate that the results of an older study are still valid. In R.2.4.1 it is mentioned that an aggregate System Load model that represents dynamic behavior of the load is acceptable. Does it mean that load at every bus in the study area has to be represented with an aggregate load model? This could be very cumbersome effort and we are not sure whether the software program can handle this magnitude of dynamic data. To help address this, revise Load to be Load that could impact the study area is acceptable. In Requirement R2.6.2, please clarify the definition of "project initiation date". Please explain the reason why Requirement R2.8 is needed in the Assessment and how does reporting the largest

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	Consequential Load Loss impact reliability?? Please explain the reason why Requirement R2.9 is needed in the Assessment and how does reporting the largest Non-Consequential Load Loss impact reliability?? Please clarify the use of the word permissible in the phrase "maximum permissible Non Consequential Load Loss".

Response: In Part 2.3 because the area that can be impacted is not confined to Facilities ownership, the study area should therefore include all Facilities that can reasonably be impacted. Where the study area involves several owners, coordination is required. However, since short circuit analysis is usually a localized issue, the area impacted would not be extensive.

Part 2.1.4 (now Part 2.1.5) refers to "unavailability of major Transmission equipment" without regard to ownership. Also, Part 2.1.5 only requires a spare equipment strategy but does not dictate the details of that strategy. So sharing of spare equipment is allowed. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.6.4 has been revised to address your concerns and the word, "prudent" was removed.

The Implementation Plan has been revised to include certain P1 events where the bar is being raised.

Part 2.1.1 is intended to require studies for System Peak Load Conditions for 2 of the years in the near-term planning horizon: A Year five case to identify potential problem that can be addressed if the planned projects proceed as scheduled. A Year one or Year two case to identify any potential problems unanticipated in the five-year case, which if not addressed, could impact operations as time progresses. The standard provides flexibility for the Planning Coordinator or Transmission Planner to use past studies to support the current year assessment and to assess other years in addition to those identified in Part 2.1.1.

Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only.

> **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.

Part 2.1.3 (now Part 2.1.4) and R2.4.3 have been revised to reflect your suggestion.

> **2.1.4** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

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	• Real and reactive forecasted Load. • Expected transfers. • Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. • Controllable Loads and Demand Side Management. • Duration or timing of planned Transmission outages. **2.4.3** For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Load level, Load forecast, or dynamic model assumptions. • Expected transfers. • Expected in service dates of new or modified Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. Part 2.4.1 has been revised to address your concerns. **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Part 2.5 has been revised and included as Part 2.6. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Part 2.6.2 was removed.
Great River Energy	R 2.1, 2.3, and 2.4 need consistency. 2.1 says "The Near-Term Transmission Planning portion of the Steady State analysis..." 2.3 says "The short circuit portion of the Planning Assessment ... addressing the Near-Term Planning Horizon..." 2.4 says "The Near-Term Transmission Planning portion of the Stability analysis..." These three sentences confuse the order. As I understand the Planning Assessment has two parts, a Near-Term portion and a Long-Term portion. Each of those parts has three components, a Steady state component, a Short Circuit component, and a Stability component. I

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	believe the standard's language should be structured as such. R2.1.3- The last bullet would seem to indicate that planners have the capability of predicting the future. The statement would seem to fit more in an operating standard. A suggested revision would be: Known long-term transmission outages with duration greater than one year R 2.1.4 addresses the spare equipment strategy. What is the scope of this sensitivity? Is the intent to do only a full steady state analysis with regard to long lead time spares? R2.6.2 would seem to be placing the planner again in the capability of predicting the future. Coming up with specific dates based on budgets, projected growth rates, potential permitting issues, and material delivery schedules would make it difficult to define an initiating date and an in-service date. An in-service season and year may be more applicable in a planning study for near-term projects. GRE is not sure why an initiating date is of relevance in an assessment.

Response: In the third posting, the Standard, as proposed, requires steady state, Stability and short circuit analyses for the Near-Term Transmission Planning Horizon; steady state for the Long-Term Transmission Planning Horizon. In the fourth posting, the SDT proposes to add Stability analysis to the Long-Term Transmission Planning Horizon. So the requirements are not the same as you described. However, the Requirements have been revised to provide greater clarity.

> **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.
>
> **2.4** The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part2.6. The following studies are required.

The last Bullet in Part 2.1.3 (now Part 2.1.4) is intended to cover planned outages of Facilities in sensitivity studies if such planned outages are known at the time the planning studies are performed, for example, planned outage of a major Transmission line during construction if the Corrective Action Plan calls for rebuilding of the line to a higher operating voltage. The corresponding sensitivity could simulate unplanned delay starts or unplanned extension of construction period. No change made.

Part 2.1.4 (now Part 2.1.5) is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. As such the analysis is not limited to steady state studies. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Parts 2.6.2 and 2.6.3 have been removed since the definition of Corrective Action Plan already includes "timetable for implementation".

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BC Hydro	Comments: Consider changing the second sentence to read, This Planning Assessment shall use current or past studies, document assumptions, document results and shall cover all analyses needed to clearly demonstrate that the proposed system expansion plan meets all planning criteria and standards. This standard should not limit the studies to only steady state analyses, short circuit analyses and Stability analyses none of which seem to be defined anywhere. In some cases it would be appropriate for planning studies to cover analyses of such phenomenon as electromagnetic transients, sub-synchronous resonance, ferroresonance and harmonics. The fact that Stability is capitalized suggests that it refers to the definition of Stability in the NERC glossary, but that definition reads just, The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances?, but stability analyses (often more properly termed dynamic simulation studies) usually encompass more than simply electromechanical or voltage stability. Usually voltage and frequency excursions are also analyzed and perhaps temporary overcurrent also (eg, assessing temporary overvoltage levels across series capacitor banks).
Response: Even though the other types of studies as identified are important for specific cases, a NERC Standard needs to be applicable continent-wide. The modification could require the inclusion of studies such as EMTP, long-term stability, etc., in the annual Planning Assessment, which is not necessary in all cases. No change made.	
Midwest ISO	Opening Remarks. Specific Comments for Requirement 2:A) Under R2, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R2 only says Long-term Planning. By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: Near-Term and Long-Term Transmission Planning. B) Under R2.1 there is a reference to qualified past studies in R2.6. We believe that this reference should be pointing to R2.5 not R2.6. C) Under R2.1.3 there is ambiguity in the third bullet language new or modified Facilities and we believe that this language should mimic that of R1.1.2 in order to improve this requirement. The third bullet should read: Timing of the installation of new Planned Facilities or changes to existing Facilities. D) Under R2.1.3 there is ambiguity in the fourth bullet language capability and we believe that this language should read: Reactive resource capability (Generator, STATCOM, SVC, other?etc). We believe that this language addition improves this requirement. E) Under R2.1.3 there is ambiguity in the seventh bullet language Transmission outages and we believe that this language should read: Planned duration or timing of specifically scheduled or planned for Transmission outages. This language mimics similar language suggested above in R1.1.1 (letter C on page 3 of 9) F) When a spare equipment strategy does not cover the long lead time unavailability as stated in 2.1.4, will the system be treated as “normal system condition and Table 1 requirements or as having a contingency from which system adjustments are to be made prior to subsequent events. We believe that this task will be burdensome for large entities such as RTOs and we are not clear on the benefit that this requirement brings. For example: If in an RTO system where a party has spare equipment, how can the RTO ensure that a spare part from one asset owner can be made available to other asset owners”

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	G) Under R2.2 a System peak load study is required annually for one of the years in the assessment period. R2.2.1 requires the assessing entity to extend their planning assessment to accommodate any known longer lead time projects that may take longer than ten years to complete. It does not make sense to study the ten year horizon, find a problem in year ten which has a solution that required twelve years to build. For compliance with this standard, you would need to find another solution that can be built within ten years as opposed to the suggested language in R2.2.1 of extending the planning assessment beyond ten years to accommodate the solution that falls outside of the Long-Term Planning Horizon. No project solution greater than 10 years should be acceptable because it falls outside the Long-Term Transmission Planning Horizon. Suggestion to strike sub-requirement R2.2.1 from this standard. H) Under R2.3 the second sentence requires that "The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study year". We suggest changing the language to read: The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with Planned Facilities in service which could impact the study year". The definition of Planned Facilities was suggested to be added in the comment above in R1.1.2 under letter (E). I) Under R2.4 the second sentence requires states The following studies are required. We suggest changing the language to read: The following current studies are required. We believe that this language addition improves this requirement. J) Under R2.4.1 the first sentence leaves to much ambiguity as to who determines whether severity of system peak or off peak as well as whether the system load levels appropriately represents the dynamic behavior of loads. If the monitoring agency wishes to make this determination than it should be explicitly written here in this requirement. If the assessing entity is to make this determination than we offer the following language suggestion that we feel will improve this requirement. "For one of the five years, the more severe System peak or off peak System load level, as judged by the assessing entity, shall be used which in the judgment of the assessing entity appropriately represents the dynamic behavior of Loads including consideration of the behavior of induction motors". K) For R2.4.2, we suggest striking this requirement altogether and add System Off-Peak to R2.4.1 above in R2.4.1 under letter (I). L) Under R2.4.3 there is ambiguity in the third bullet language new or modified Facilities and we believe that this language should mimic that of R1.1.2 in order to improve this requirement. The third bullet should read: Timing of the installation of new Planned Facilities or changes to existing Facilities. M) Under R2.4.3 there is ambiguity in the fourth bullet language capability and we believe that this language should read: Reactive resource capability (Generator, STATCOM, SVC, other etc). We believe that this language addition improves this requirement. N) The sub requirement R2.5.2 states that for steady state, short circuit, or stability analysis; the present System model shall not include any material changes, such as..etc. The present language in this section is vague and requires discretion on the part of both the Transmission Planner and the Planning Coordinator performing the assessment. For example, new transmission enhancements may have been added since the previous System model was developed. In general, such topology enhancements will only improve reliability and would not necessitate re-assessment with a newly updated System

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	model. In addition, any significant generator additions would have been evaluated with a full separate generator interconnection study at which the full reliability of the System would have been taken into consideration. For this reason, we believe the following language for R2.5.2 would improve this requirement: For steady state, short circuit, or Stability analysis: the current System model of the assessed plan year shall not include any changes material to the assessment, as judged by the entity performing the assessment, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study year. Material generation changes could include: O) Under R2.6.1 the fifth bullet regarding the use of Operating Procedures needs to be made clearer. We believe that the following language will improve this requirement: Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan. Operating Procedures may not include Non-Consequential Load Loss when not permitted in Table 1. P) Under R2.6.1 the sixth bullet regarding the use of rate applications, DSM, new technologies or other initiatives can be improved with the following language additions: Use of rate applications, DSM, new technologies or other demand side initiatives can be improved with the following language additions. Q) Under R2.6.2 the language regarding project initiation date is vague. We suggest the following definition to be added to this standard and further added to the NERC Glossary of Terms: Project Initiation Date A date in which Planned Facilities are expected to break ground. R) Under R2.8 please add a coma between the words event and caused. A PC/TP would study multiple P1 and P2 events involving consequential load loss not just the largest. Unless the SDT has a measure in mind for consequential load loss, this requirement should be removed. S) Under R2.9 please strike the word permissible and replace with necessary. It is not clear what the SDT is requesting with this requirement.

Response: The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made.

Mitigation Time Horizon

The time horizons available for mitigating a violation to a requirement include the following:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.

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	• **Operations Assessment** — follow-up evaluations and reporting of real time operations In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made Part 2.1.3 (including the third and seventh bullets) (and now Part 2.1.4) has been revised to provide greater clarity. The SDT declines to change the fourth bullet because adding a partial list of devices that could provide reactive resources may not improve clarity beyond the present description. **2.1.4** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Real and reactive forecasted Load. • Expected transfers. • Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. • Controllable Loads and Demand Side Management. • Duration or timing of planned Transmission outages. Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service such that the outage won't last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its System, or have agreement with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. Perhaps it would help if sharing major Equipment can be part of an operating agreement within entities belonging to the RTO; however, that would be outside the scope of this Standard. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.2.1 has been revised because extending the Planning Horizon beyond 10 years for projects with lead time longer than 10 years is already covered in the definition of Long-Term Transmission Planning Horizon. This allowance is needed to provide planning flexibility, and is at the discretion of the Planning Coordinator or Transmission Planner. For example, if the System is found not to meet performance standard in year 10, but the project to correct the loading cannot be placed in service for 12 years, then the Corrective Action Plan needs to identify the interim solutions before the project can be brought on line. **2.2.1** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the

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	rationale for why that year was selected. Part 2.3 has been revised to reflect your suggestion. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. In Part 2.4.1, the SDT was not able to locate the reference to the comment on the "ambiguity as to who determines whether severity of system peak or off peak". No change made. Part 2.4.1 has been revised to provide greater clarity. However, the SDT declines to modify Part 2.4.1 to require study for "the more severe System peak or off peak System load level" for one of the five years in the Near-Term Transmission Planning Horizon because the System needs to meet performance requirements under all System conditions including peak and off-peak. In addition, the Planning Coordinator or Transmission Planner can rely on past studies as provided in Part 2.5 (Part 2.6 in the new version). For this reason Part 2.4.2 has been retained. **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Part 2.4.3 (including the third bullet) has been revised to provide greater clarity. The SDT declines to change the fourth bullet because adding a partial list of devices that could provide reactive resources may not improve clarity beyond the present description. **2.4.3** For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Load level, Load forecast, or dynamic model assumptions. • Expected transfers. • Expected in service dates of new or modified Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. Part 2.5 has been revised and included as Part 2.6. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Part 2.6.1 has been revised and included as Part 2.7.1 to provide greater clarity. However, the SDT declines to include "Operating Procedures may not include Non-Consequential Load Loss when not permitted in Table 1" because it is redundant. Part 2.6.1 (now Part 2.7.1) is a sub-part of Part 2.6 (now Part 2.7), which

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explicitly requires meeting the performance requirements in Table 1. Parts 2.6.2 and 2.6.3 have been removed since the definition of Corrective Action Plan already includes “timetable for implementation” so a new NERC definition is not required. Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
PJM	In R2, why require a Planning Coordinator AND a Transmission Planner to perform this analysis? Isn’t this a duplication of effort? In R2, I have always heard that dynamics studies are performed to determine Stability. In R2.1, need to update reference to R2.6 from R2.5. In 2.1.1 and R2.1.2, is this annual peak or seasonal peak? Summer peak for summer peaking entities and winter peak for winter peaking entities or both summer and winter peak for all entities. R2.1.1 year one or two studies should be only required as operating studies. By their nature, the upgrades or fixes that could be accomplished in this time frame are limited to short lead time fixes. These analyses are needed to determine how to accommodate construction schedule deviations and near term system issues that may cause issues. Traditional Planning studies will be of no benefit in this timeframe. Change the requirement to be a study for year 3,4 or 5 with updates for material changes that occur when a previous year study is still within this time frame.R2.1.2 and R2.1.1 should be combined and the TP should assess and justify its choice of the critical load scenarios to analyze. Concerned about the extent of variations required in R2.1.3. Like would I have to vary all proposed generator in-service dates? Just a couple? One? Requirements need to be clear or compliance will assume the largest scope possible. Also in R2.1.3, first bullet words should align with the words of R1.1.3. Also in R2.1.3, second bullet words should align with words of R1.1.4 and R1.1.5. Also in R2.1.3, third bullet, modified facilities are not installed, suggest changing -installation to -availability--. Also in R2.1.3, fifth bullet, suggest moving retirements-- up to third bullet and dropping -- Generation additions, retirements, or other-- leaving just dispatch scenarios R2.1.4 should be deleted. There are no NERC requirements on spare equipment availability and this requirement seems like a backhanded way to include such a requirement. R2.2.1 should be reworded because it now requires everyone to extend their studies. Suggest If planned projects will take longer than ten years to complete, the Planning Assessment shall be extended accordingly- R2.4.1 Not sure I understand. The second sentence and the third sentence seem to be in conflict

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	R2.4.2. This requirement has lost significance with the deletion of unit stability. Off-Peak scenarios are critical for unit stability and analysis of pockets of known light load stability sensitivity. This requirement should not be worded to require a general system off-peak stability study since this will not provide useful information. The requirement should be reworded to clarify that the TP should identify its critical off-peak stability sensitivities and provide annual stability analyses that address the system's off peak stability issues.R.2.4.3 should only refer to R2.4.1 since R2.4.2 are sensitivities themselves. In R2.4.3, first bullet, how would load model assumptions be varied? Same comments on bullets here as R2.1.3 above. R2.5.2 is impossible to judge. Material changes needs to be defined. The word could in the sentence before the bullets makes them useless as a definition. By trying to define material changes the SDT has created a situation where, for large interconnection, it would be virtually impossible to use a past study. The addition of a 100 MW generator two states removed from the study area would not be considered material but by the guidelines in this requirement it can be interpreted as such. R2.5.2 Add that retools of past studies that address the local impacts of specific cumulative material changes that occur are sufficient to continue to support current planning assessment. R2.6 has a mixing sigular and plural tenses. What if only one problem is found and therefore only one Corrective Action Plan is needed. Or can one Plan cover all the problems found? Responses to R2.8 and R2.9 would be considered Critical Energy Infrastructure Information (CEII) and that should be noted so it can be protected. R2.8 and 2.9 change to read that the Planning Coordinator will provide its criteria for load loss that is adheared to for all events.

Response: Requirement R2 applies to both the Planning Coordinator and Transmission Planner because the Planning Coordinator may have a larger area than the Transmission Planner. Functional Model Version 3 states that, "Like the Resource Planners and Transmission Planners at the 'local' level, the Planning Coordinator maintains system models and performs the necessary studies to evaluate whether the composite resource and transmission plans of its Resource Planners and Transmission Planners are in compliance with reliability standards". No change made.

Please suggest modifications to more accurately describe "stability" Analyses. No change made.

In the new version, Part.2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made.

For Part 2.1.1, Year One and year two are within the Planning Horizon. In the Definition Section, Year One is defined as "The first year that a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the current calendar year". Operating Studies are performed for system conditions within 12 months of the current calendar year. Part 2.1.1 is intended to require studies for System Peak Load Conditions for 2 of the years in the Near-Term Transmission Planning Horizon: (1) A Year five case to identify potential problem that can be addressed if the planned projects proceed as scheduled; (2) A Year one or year two case to identify any potential problems unanticipated in the five-year case, which if not addressed, could impact operations as time progresses. The standard provides flexibility for the Planning Coordinator or Transmission Planner to use past studies to support the current year assessment and to assess other years in addition to those identified in Part 2.1.1. Part 2.1.2 requires that the Planning Coordinator and/or Transmission Planner also consider off-peak conditions in addition to peak conditions because the System must be able to meet performance requirements over all demand levels. System peak condition may not represent all stressed conditions. For example, during off-peak, the Load is low, and the generation would have to be

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turned off to achieve Load-resource balance. Turning down resources within a Load area could result in reliability problems. Lowering the Load in areas with many non-dispatchable resources could also pose potential problems. As the System incorporates more and more renewable resources, some of them are non-dispatchable; a standard must be forward looking so the Planning Coordinator and Transmission Planner can identify potential problems. If studies for one of the Load periods are not needed annually, the Planning Coordinator or Transmission Planner can rely on past studies for the Planning Assessment.

The bullets under Requirement R1, Part 1.1.3 have been removed from the revised standard, so no effort was made to line up the bullets in Requirement R1, Part 1.1.3 with the first two bullets under Requirement R2, Part 2.1.3. Parts 2.1.3 (now Part 2.1.4) and 2.4.3 and associated bullet lists have been revised to provide greater clarity for the expected changes. "Installation" has been removed from the third bullet. The SDT believes it is appropriate to treat generation change and transmission changes separately and did not move retirements up to the third bullet. The extent of the variations for each item listed is left to the discretion of the Planning Coordinator or Transmission Planner who are more familiar with the system being studied. Load modeling assumptions can be varied by varying, for example, the percentage of motor Load or the customer mix. It is up to the Planning Coordinator or the Transmission Planner to decide how the assumptions would be varied.

2.1.4 For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of planned Transmission outages.

2.4.3 For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Load level, Load forecast, or dynamic model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

Part 2.1.4 (now Part 2.1.5) is based on FERC Order 693, Paragraphs 1724 – 1727. Part 2.1.4 requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or

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can be purchased and be placed in service such that the outage won't last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its System, or have agreement with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. The Planning Coordinator and/or Transmission Planner will need to decide which pieces of major Equipment in their respective systems would be more vulnerable to long term outage. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.2.1 has been revised to reflect your suggestion. **2.2.1** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected. Part 2.4.1 is intended to allow the use of aggregated system Load models if more accurate Load models are not available. Therefore, the second and third sentences are not in conflict. The SDT declines to include Part 2.4.2 in Part 2.4.3 because it is not intended to be a sensitivity study because the System needs to meet performance requirements under all System conditions including peak and off-peak. In addition, the Planning Coordinator or Transmission Planner can rely on past studies as provided in Part 2.5 (Part 2.6 in the new version). For this reason Part 2.4.2 has been retained. Part 2.5 has been revised and included as Part 2.6 as shown. The language referencing "material generation changes" has been removed from the revised standard. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Part 2.6 has been revised and included as Part 2.7 to address your concerns about mixing singular and plural possibilities. . **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Parts 2.8 and R2.9 were intended to contribute to open and transparent Transmission planning for peer review. The standard does not preclude protection of the Critical Energy Infrastructure Information (CEII). The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2

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events in Table 1.	
Brazos Electric Cooperative	In R2.1, end of paragraph i believe you mean Requirement 2.5, not 2.6. In R2.6.2 we believe maintaining a 'project initiation date' serves no purpose and should be deleted. These dates are wildly variable given the nature of each project and the numerous issues that can affect these dates. 2.6.2 and 2.6.3 should be combined to simply require an in-service year/date and allow the owners to work as needed to meet these dates. We think R2.9 should be deleted as it is vague in nature, seems to serve no purpose and would be hard to verify the accuracy of the value in an audit. 2.8 is direct and can be easily detailed for an audit.
Response: In the new version, Part.2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made. Project initiation date and in service date have been removed from the requirements. Parts 2.8 and R2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees with the majority of commenters that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
American Electric Power	AEP agrees with R2.3., but should note that the planning horizon short circuit models are not presently developed in any systematic fashion, since, unlike the development of steady-state (power flow) and stability models that are mandated under MOD-010 and MOD-012, respectively, there are no NERC Standards that mandate the development of short circuit models in a similar fashion. As to R2.4., requiring study of both peak and off-peak conditions in every stability assessment removes the possibility in this regard that stability study scopes may be defined most appropriately by engineering judgment. We believe system load level is often important, but not necessarily more important than any of the other sensitivity variables listed under R2.4.3. We suggest listing system load level along with these and removing R2.4.1. and R2.4.2. The text in R2.4.1., referring to dynamic load modeling, may still be retained somewhere, and since this falls in the category of modeling and data, we suggest including this under R1.1. With regard to R2.5., a 20 MW increase in generation may well be construed as a material generation change, but it is questionable whether a 20 MW decrease would be for transmission planning purposes. Also, the validity of many studies, particularly plant oriented stability studies, may well extend beyond five years if there have been no transmission modifications in the vicinity of the plant or to the plant itself. In these instances, it would seem counter-productive to disqualify a study after five years. The duration of the validity of certain types of past studies is better determined by the occurrence of significant transmission or generation changes. Please note, under R2.6.2., to define project initiation date [Changed sequence to keep in numerical order].

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Response: Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt and is not specifically related to new planned Facilities. However, a NERC-wide data base or models similar to MOD-010 or MOD-012 may be neither desirable nor necessary, since short circuit study concerns localized issues and can be contained within a study area. Part 2.3 has been revised to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. The SDT declines to include Load levels in sensitivity studies in Part 2.4.3 and remove Parts 2.4.1 and 2.4.2. Since Part 2.4.3 would only require studying one or more of the list of sensitivities, this change can result in no Stability study performed for either peak Load or off-peak Load condition in the Near-Term Transmission Planning Horizon. In addition, the standard does not require a new Stability study be performed annually; the Planning Coordinator or Transmission Planner can rely on past studies as provided in Part 2.5 (Part 2.6 in the new version). For this reason no change was made. Part 2.5 has been revised and included as Part 2.6 as shown. The reference to the "20 MW" threshold has been removed from the revised standard. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Project initiation date has been removed from the requirements.	
ITC Holdings	Comments: In R2.1, there is a reference to R2. 6. Based on the posted red-line version, we believe this reference should be changed to R2.5. Should this same reference be included in R2.4?? In R2.3, it is stated that the short circuit analysis should be supported by either current or past studies. Should a reference be added to R2.5? In R2.6 it is stated: Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3 and R2.4.3. While we recognize that this conforms to FERC orders, it would still seem that this statement might be interpreted to mean that CAPs intended to cover a number of sensitivities go beyond standards and be used by interveners to block such CAPs. A revision to the standard to the standard to encourage CAP when needed for numerous sensitivities might be appropriate. R 2.6.4, as written, is very subjective. While we understand the need for R2.6.4, who is the ultimate judge of what situations are beyond the control of the TP or PC responsible for the mitigation plan and if they "are taking prudent actions to resolve the situation" As written, it is the auditor. This will be difficult to prove compliance and might provide significant discrepancies in compliance with standards.

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Response: In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made.	
The reference has been added.	
2.4 The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required:	
Parts 2.3 and 2.4 have been revised to add reference to Part 2.5 (included in the new version as Part 2.6).	
2.3 The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.	
Part 2.6 has been revised and included as Part 2.7. A new Part 2.7.2 has been added to require that the Corrective Action Plan include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.	
2.7 For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:	
2.7.2 Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.	
Part 2.6.4 has been revised and included as Part 2.7.5 to address your concerns. The word "prudent" is no longer used.	
2.7.5 If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.	
Northern Indiana Public Service Company	R2.3: Clarify the requirement. Does the short circuit study examine topology for a single year, the topology in years studied using the steady state models or each year of the near term planning horizon?
Response: Part 2.3 requires that the Assessment of short circuit duty requirements are conducted annually addressing the Near-Term Transmission Planning Horizon. However, the specific methodology or assumptions to be used are left to the discretion of the Planning Coordinator or Transmission Planner.	
Minnesota Power	A) Under R2, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R2 only says Long-term Planning. By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: Near-Term and Long-Term Transmission

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	Plannin?. B) Under R2.1 there is a reference to qualified past studies in R2.6. We believe that this reference should be pointing to R2.5 not R2.6. C) R2.1.4 addresses the spare equipment strategy. What is the scope of this sensitivity? Is the intent only to do a steady state analysis on equipment with long lead time spares D) Under R2.2 a System peak load study is required annually for one of the years in the assessment period. R2.2.1 requires the assessing entity to extend their planning assessment to accommodate any known longer lead time projects that may take longer than ten years to complete. It does not make sense to study the ten year horizon, then find a problem in year ten which has a solution that requires twelve years to build. For compliance with this standard, you would need to find another solution that can be built within ten years as opposed to the suggested language in R2.2.1 of extending the planning assessment beyond ten years to accommodate the solution that falls outside of the Long-Term Planning Horizon. No project solution greater than 10 years should be acceptable because it falls outside the Long-Term Transmission Planning Horizon. Suggestion to strike sub-requirement R2.2.1 from this standard. E) Requirements R2.1, R2.3, and R2.4 are written inconsistently. 2.1 says The Near-Term Transmission Planning portion of the Steady State analysis 2.3 says The short circuit portion of the Planning Assessment addressing the Near-Term Planning Horizon 2.4 says The Near-Term Transmission Planning portion of the Stability Analysis These three sentences confuse the order. As we understand, the Planning assessment has two parts: a Near-Term portion and a Long-Term portion. Each of those parts has three components: a Steady State component, a Short Circuit component, and a Stability component. We suggest the language in the standard should be structured consistently and appropriately as such) Under R2.4.3 there is ambiguity in the third bullet language new or modified Facilities and we believe that this language should mimic that of R1.1.2 in order to improve this requirement. The third bullet should read: Timing of the installation of new Facilities or changes to existing Facilities. G) The sub requirement R2.5.2 states that for steady state, short circuit, or stability analysis; the present System model shall not include any material changes, such as..etc. The present language in this section is vague and requires discretion on the part of both the Transmission Planner and the Planning Coordinator performing the assessment. For example, new transmission enhancements may have been added since the previous System model was developed. In general, such topology enhancements will only improve reliability and would not necessitate re-assessment with a newly updated System model. In addition, any significant generator additions would have been evaluated with a full separate generator interconnection study at which the full reliability of the System would have been taken into consideration. For this reason, we believe the following language for R2.5.2 would improve this requirement: For steady state, short circuit, or Stability analysis: the current System model of the assessed plan year shall not include any changes material to the assessment, as judged by the entity performing the assessment, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study year. Material generation changes could include: H) Modify R2.6.2 to remove the obligation to include the project initiation date. The inclusion of this date would add unnecessary work that is not needed to assure adequate BES reliability In addition, it is not clear whether initiation refers to

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	the commencement of engineering, design, construction, etc.

Response: The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made.

Mitigation Time Horizon

The time horizons available for mitigating a violation to a requirement include the following:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations

In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made.

In Part 2.1.4 (now Part 2.1.5) when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1. Part 2.1.5 is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Transmission equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. It is not intended to limit to steady state analyses only. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.2.1 has been revised because extending the Planning Horizon beyond 10 years for projects with lead time longer than 10 years is already covered in the definition of Long-Term Transmission Planning Horizon. This allowance is needed to provide planning flexibility, and is at the discretion of the Planning Coordinator or Transmission Planner. For example, if the System is found not to meet performance standard in year 10, but the project to correct the loading cannot be placed in service for 12 years, then the Corrective Action Plan needs to identify the interim solutions before the project can be brought on line.

> **2.2.1** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

As written the Planning Assessment consists of 2 parts: Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon, Steady State and Stability Assessments are required for both near-term and long-Term, but short circuit assessment is required only for the near-term. Part 2.3 has been revised

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to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. The 3rd bullet of Part 2.4.3 has been revised. **2.4.3 bullet 3** Expected in service dates of new or modified Facilities Part 2.5.2 has been revised and included as Part 2.6.2 to provide greater clarity. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Project initiation date has been removed from the requirements.	
LADWP	R2.3 There is no value to conduct short circuit analysis on an annual basis. Short circuit contribution is location constrained. Maximum short circuit interrupting duty cannot be determined by any planning cases; so putting this requirement in TPL will cause only confusion and will creat misleading information. If there is a need to develop a standard on how to evaluate maximum short circuit interrupting duty, the more appropriate place would be FAC. R2.1.3 Controllable Loads and DWM: DSM should not be a stand alone item in planning studies because DSM already is imbedded in load forecasts. Not sure what controllable loads are. R2.1.4 Any requirment dealing with spare parts should be handled in TOP, not TPL. TOP is the forum to develop operating procedures,"work-arounds", and so on when the non-availability of spare forced a company to develop temporary mitigations and it would be a mistake to suggest that planners should be able to consider such temporary fixes as acceptable planning solutions.R 2.5.2 The 20 MW threshold, at best, is "noise" for us. We would not be concerned with generation chnages that is 10 times this threshold. What is the rationale for requiring a new study just because there is a change in generation capability? R2.8 and 2.9 What measurements would this required information be measured against? I can't find any and if there is no measurement, it really does not belong. R2.6.2 Project initiation date is hard to define. Is it the date the project is budgeted? or the date the management approved the budget and at what level? or is it the date when engineering design is initiated? For both short term and long term planning horizons, the project in service date should be sufficient. there are too many variables to define "project initiation date" not to mention there is no measurable to benchmark such a requirement.
Response: Parts 2.3 and 2.7 are intended for the Planning Coordinator and/or Transmission Planner to assess whether circuit breakers supporting the BES have the interrupting capability for Faults that they will be expected to interrupt. No change made. Part 2.1.3 (now Part 2.1.4) is intended to cover sensitivity studies, for example, if DSM is imbedded in the Load forecast, the sensitivity study can simulate	

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conditions where not all effects of DSM is realizable, and the Load may be higher than studied . Controllable Load can be part of the local rate incentive program, where the customer Load can be controlled by the Transmission Operator. The bullets are examples, so the Planning Coordinator or Transmission Planner can choose the sensitivity and does not have to study, for example, controllable Load, if the related Load-Serving Entity does not have such a program. Part 2.1.4 (now Part 2.1.5) is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Transmission Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Parts .2.8 and R2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1. Part 2.5.2 (now 2.6.2) has been revised for clarity and the 20 MW threshold has been removed. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Project initiation date has been removed from the requirements.	
Platte River Power Authority	R2.6.2. Expand on the meaning of the "initiation date." R2.8. I don't understand the relevance of this requirement. May your intention be explained differently? R2.9. I don't understand the relevance of this requirement. May your intention be explained differently?
Response: Project initiation date has been removed from the requirements. Parts 2.8 and R2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
MAPPCOR	R2.1.1 Consider calling this Near Term years instead of specifically naming certain years.

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	R2.1.3 eliminate the last bullet. Planned duration or timing of Transmission outages is part of R1.1.1 which already specifies that models will include planned outages of generation and transmission facilities. R2.1.4 the second line is unclear. There is a reference to lead time of one year or more Is the intent for that to mean outage duration of one year or more??? If so, it should be written that way. Also, in the 3rd line, eliminate the words an analysis of (otherwise it would direct one to assess an analysis.) This in essence is an N-3 study. This risk that a TO or GO takes will show up in the operations of the BES. Also some states assess a penalty for equipment that is sitting idle that cost the taxpayers, so you could be penalize for not have spare equipment or if you do have it. R2.2.1 does this mean, for example, that entities may be doing 12 year or 15 year assessments? It should be written to say what it means. R2.4.1 Change to read: For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads or an aggregate System Load model which represents the overall dynamic behavior of the Load. R2.5.1 Suggest deleting this requirement, and incorporating it into R2.5.2. R2.5.2 Incorporate R.2.5.1 into R2.5.2; please modify the section as follows:For steady state, short circuit, or Stability analysis the study shall be less than five calendar years old or less: the latest Transmission Planning Horizon System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: The addition/deletion/change of individual generating unit capability determined to be material by the Planning Coordinator or Transmission Planner. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES determined to be material by the Planning Coordinator or Transmission Planner. R2.6 ? The creation of hard and fast Corrective Action Plans for the LTRA is not a good use of resources. The reason for planning studies is to uncover possible weak spots in the system for some number of years into the future, and then pursue additional studies to examine the issues. Planning studies include many assumptions, and the issues may not even arise on the real system. If they do, there may be many possible remedies. Creating CAPs with milestones and other firm dates for potential problems uncovered in assessments of future years is simply not practical, and the PC (PA) may have little or no influence on what remedy is selected even if a problem appears to be real. R2.6.2 The phrase Project Initiation Date needs to be defined. It is unclear if this is this the date of ground breaking, purchase orders being issued, solution study initiation, etc. Additionally, in the second sentence the phrase as well as an in-service date should be modified to read as well as a target in-service date. R2.6.3 Plans can provide a target in-service year but not an actual in-service year. R2.6.4 recommend clarifying how situations beyond the control of the TP or PC are determined. It is unclear if this is to imply that if something is outside of the control of the department who conducts the planning studies or if it is outside the control of the registered function's legal entity (i.e. corporation). There should be a cutoff point when changes occur beyond a certain date. When that date occurs, further changes will be evaluated in the next year's assessment. Otherwise, if a state makes a decision not to site a project a few weeks prior to the end of the assessment period, there will not be sufficient

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	time to incorporate this into that year's assessment and develop corrective actions. R2.8 appears to be nonessential information for reliability; for what purpose does this requirement exist? R2.9 - appears to be nonessential information for reliability; for what purpose does this requirement exist?

Response: Part 2.1.1 is intended to require studies for System Peak Load Conditions for 2 of the years in the Near-Term Transmission Planning Horizon: (1) A year five case to identify potential problem that can be addressed if the planned projects proceed as scheduled; (2) A Year One or year two case to identify any potential problems unanticipated in the five-year case, which if not addressed, could impact operations as time progresses. The standard provides flexibility for the Planning Coordinator or Transmission Planner to use past studies to support the current year assessment, and to assess other years in addition to those identified in R2.1.1.

The last Bullet in Part 2.1.3 is intended to cover planned outages of Facilities in sensitivity studies if such planned outages are known at the time the planning studies are performed, for example, a planned outage of a major Transmission line during construction if the Corrective Action Plan calls for rebuilding of the line to a higher operating voltage. The corresponding sensitivity could simulate unplanned delay starts or unplanned extension of construction period of the planned project. No change made.

Part 2.1.4 (now Part 2.1.5) is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Transmission equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.2.1 has been revised because extending the Planning Horizon beyond 10 years for projects with lead time longer than 10 years is already covered in the definition of Long-Term Transmission Planning Horizon. This allowance is needed to provide planning flexibility, and is at the discretion of the Planning Coordinator or Transmission Planner. For example, if the System is found not to meet performance standard in year 10, but the project to correct the loading cannot be placed in service for 12 years, then the Corrective Action Plan needs to identify the interim solutions before the project can be brought on line.

> **2.2.1** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

Part 2.4.1 has been modified.

> **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

Part 2.5.1 (now Part 2.6.1) is considered a separate requirement by the SDT and has not been deleted or merged. It has been revised for clarity.

> **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided

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to demonstrate that the results of an older study are still valid. Part 2.5.2 (now Part 2.6.2) has been revised for clarity. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Part 2.6 has been revised and included as Part 2.7 to address your concerns. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Project initiation date has been deleted from the requirements. The requirement for in service date has been deleted. Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees with the majority of the commenters that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in he new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Orlando Utilities Commission	-I think R2.1 has a typo and should reference requirement R2.5, not R2.6. – R2 Does the phrase “System Peak Load” require true system peak be tested, or a peak condition. As an example, FRCC experience a two peak loads, a summer peak that occurs regularl
Response: In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made. System peak Load means the highest Load within the time period that is being evaluated.	
American Transmission Company	We propose the following comments for R2:In sections R2.1.3 and R2.4.3 please explain the reference to expected transfers and how that differs from R1.1.5 interchange. If these are analogous, then change the references to interchange. Modify R2.5.2 second bullet to clarify that this addresses an aggregated addition/deletion/change to a group of generating units directly connected through a shared step-up transformer . . . . Modify R2.6.2 to remove the obligation to include the project initiation date. The inclusion of this date would add unnecessary work that is not needed to assure adequate BES reliability. In addition, it is not clear whether initiation refers to the commencement of engineering, design, construction, etc.ATC agrees that the Transmission Planner should be responsible for a corrective action plan (R 2.6) and its associated sub-requirements, but we do not agree that the Planning

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	Coordinator should also be listed. Unlike a Transmission Planner, a Planning Coordinator does not have the ability or responsibility to implement a corrective action plan. Requirement 2.6 and its associated sub-requirements should be limited to only the Transmission Planner. Remove the R2.8 requirement. The activity of identifying and including the largest Consequential Load Loss caused by any P1 or any P2 events in the Planning Assessment may not assure adequate BES reliability. A P1 or P2 event with the largest Consequential Load Loss could occur at a location on the system that is strong enough to not result in any performance violation. The amount of Consequential Load Loss may not have a relevant correlation to system performance and reliability. Remove the R2.9 requirement. The activity of identifying and including the maximum permissible Non-Consequential Load Loss caused by selected Table 1 Planning Events may not assure adequate BES reliability. The maximum permissible Non-Consequential Load Loss could occur at a location on the system that is strong enough to not result in any performance violation. The maximum amount of Non-Consequential Load Loss may not have a relevant correlation to system performance and reliability. Add R2.10. The obligation to identify and observe applicable steady state voltage and post-Contingency voltage deviations should be a Requirement, rather than performance note a in the Planning Events, Steady State Only section of Table 1. And the obligation to identify and observe applicable transient voltage response limits should be a Requirement, rather than performance note b in the Planning Events, Stability Only section of Table 1. In addition, due to the system limit requirements of FAC-010 and FAC-014 the reference to the PC and TP is unnecessary. We suggest this text: The Planning Assessment shall identify the applicable steady state voltage, post-Contingency voltage deviations, and transient voltage response limits.

Response: Part 1.1.5 has been revised to state "Known commitments for Firm Transmission Service and Interchange" The NERC Glossary of Terms defines Firm Transmission Service as "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption" and Interchange as "Energy transfers that cross Balancing Authority boundaries. "Transfer" can cover more than Firm Transmission Service or Interchange. Parts 2.1.3 and 2.4.3 would cover the sensitivity of changes in expected transfers regardless of the cause.

Part 2.5.2 – The examples in the bullets have been deleted.

Part 2.6.2 - Project initiation date has been deleted from the requirements.

Part 2.6 has been revised and included as Part 2.7 in the new version to address your concerns. The SDT declines to limit the application of Part 2.6 to the Transmission Planner because the Planning Coordinator would be responsible for coordination between Transmission Providers.

> **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees with the majority of the commenters that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new

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version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1. The obligation to identify potential steady state, transient, post-transient and post-Contingency problems is already included in Parts 2.1 through 2.4 and in Part 2.6 (Part 2.7 in the new version). Therefore adding a new Part 2.10 is not needed.	
Turlock Irrigation District	TID expresses concern that the planning extension of R2.2.1 could lead to a scenario where a single members long term project (beyond 10 years) could then require all neighboring members to extend their own planning horizons (similar to a lowest common denominator issue) and face unnecessary technical issues.
Response: Part 2.2.1 has been revised because extending the Planning Horizon beyond 10 years for projects with lead time longer than 10 years is already covered in the definition of Long-Term Transmission Planning Horizon. This allowance is needed to provide planning flexibility, and is at the discretion of the Planning Coordinator or Transmission Planner. For example, if the System is found not to meet performance standard in year 10, but the project to correct the loading cannot be placed in service for 12 years, then the Corrective Action Plan needs to identify the interim solutions before the project can be brought on line. If a neighboring Planning Coordinator or Transmission Planner extends their planning horizon beyond ten years, it may be prudent for the Planning Coordinator or Transmission Planner to similarly extend the associated planning horizon, but it is not necessary for compliance of this standard. Therefore, the Planning Coordinator or Transmission Planner can choose whether to extend the planning horizon beyond 10 years for its own planning area(s) for the purpose of compliance. **2.2.1** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.	
New York Independent System Operator	R2.1.2 - System off-peak is more likely a stability issue than a steady state issue. If system off-peak becomes a steady state issue, it can be mitigated through generation redispatch. Accordingly, it appears that this requirement is not necessary for steady state analysis R2.1.4 - With respect to spare equipment strategy, this requirement potentially imposes a requirement to plan for three events, which is overly severe. As previously stated in R1, the system model should be a model of the projected system, which would include a long term actual forced outage. If this requirement is not referring to actual outages, then it is suggesting an N-1-1-1 analysis, which is a requirement that would require significant additional work with little value added for reliability because such contingencies have a very low probability. Under R2.5 - Past Studies may be used to support the Planning Assessment if they meet the following requirements and the sub-requirement R2.5.2 states that for SS, SC, or stability analysis "the PRESENT (emphasis added) System model shall not include any material changes, such as, . The NYISO interprets this language to mean that past studies may be used to support planning assessments as long as there are no material changes to the LATEST PLANNING HORIZON system model. The Standards Drafting Team should clarify whether this interpretation is correct. The standard should further state whether, if there was a material change such as a 20 MW generator, the past study may be used if the impact of this small change is assessed. Finally, the regional entity should have a process to determine whether changes are material that is

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	similar to the NPCCs process for determining what level of annual transmission review should be conducted each year.

Response: Regarding comment on Part 2.1.2, NERC Standards require that Systems can operate reliably over all demand levels. If steady state problems under off-peak conditions needed to be corrected through re-dispatch and/or switching to reconfigure the System, then a Corrective Action Plan involving re-dispatch and switching will need to be developed to ensure that the plan can be implemented. Since a past study can be used to support a current Assessment in accordance with Part 2.5 (Part 2.6 in the new version), an off-peak study would not have to be performed every year.

In Part 2.1.4 (now Part 2.1.5) when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. Part 2.1.5 is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.5.2 (now 2.6.2) has been revised for clarity. The bullets under 2.5.2 have been removed from the revised standard.

> **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

Duke Energy	R2 Instead of document results the requirement should be to summarize results. While results will be documented, the Planning Assessment should just include a summary. R2.1 What's the value in being able to use qualified past studies if you have to use annual current studies? Strike the words supplemented with and insert the word or. R2.5.2 Suggest deleting the phrase Material generation changes could include: and the two accompanying bullets. A change of 20 MW on a large system may not always be material. R2.8 and R2.9 should be deleted. We don't see a reliability-related need for these requirements. In the sub-requirements of 2.1.3 and 2.4.3, the use of the word timing is unclear. Consider using in service date or schedule for. R2.4.1: It is not clear how much Load a dynamic model must have. Likely, it must still be proven that the analysis software can accommodate every load in the model having a load model that includes induction motor models. To help address this, revise Load to be Load that could impact the study area is acceptable.

Response: Requirement R2 has been revised to provide greater clarity and the word, "summarize" was added in support of your suggestion.

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	R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. In Part 2.1 it is envisioned that not all parts of the studies, on which the Assessment is to be based, can rely on past studies. For example, a study on year five performed during the past year may not be representative of year five in the current year. A past study can still be used if it can be demonstrated that the requirements for use of past studies are met. No change made. 2.5.2 – Both bullets under 2.5.2 have been deleted as suggested Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees with the majority of the commenters that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1. Parts 2.1.3 (now Part 2.1.4) and 2.4.3 have been revised. **2.1.4** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Real and reactive forecasted Load. • Expected transfers. • Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. • Controllable Loads and Demand Side Management. • Duration or timing of planned Transmission outages. **2.4.3** For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Load level, Load forecast, or dynamic model assumptions. • Expected transfers. • Expected in service dates of new or modified Facilities.

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	• Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. Part 2.4.1 has been revised to reflect your suggestion. **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.
Tucson Electric Power Company	Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). In R2.1, we believe the reference for past studies should be Requirement R2.5 not Requirement R2.6. Also, we suggest removing the phrase supplemented with and replacing it with the word or. This phrase indicates that previous studies cannot be a primary source for the assessment, which contradicts section 2.5.Remove the phrase not already included in the studies in R2.1.3. With this phrase included, you cannot use a previous sensitivity study to support the current assessment and Requirement R2.5 allows the use of previous studies if the conditions are met. Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement.Remove the phrase "not already included in the studies" in R2.4.3. With this phrase included, you cannot use a previous sensitivity study to support the current assessment and Requirement R2.5 allows the use of previous studies if the conditions are met. The 20 MW threshold identified as "material change" for generation in R2.5 is too small. The limit should be raised or based on a percentage of the study area'sinstalled generating capacity. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the "largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event" if it is documented? R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.
Response: Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt. Even though the effects of short circuit capability is localized and may be related to new	

Organization	Question 2 Comment
planned Facilities, it is important to BES reliability. Part 2.3 has been revised to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. Part 2.1 requires certain current studies be conducted each year for the Near-Term steady state assessment, which can be supplemented with past studies. The SDT disagrees that the statements are contradictory. No change made. Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.6 (now Part 2.7) has been revised for clarity. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: The material change wording has been deleted from the requirement. . Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Independent Electricity System Operator	1. We think "conduct and document" is more appropriate than "prepare". Suggest to make this change. 2. We understand the reason for introducing the spare equipment strategy in R2.1.4 is to address comments raised on planned and long-term outages. However, this is not the only cause of unavailability of major Transmission equipment for more than 12 months. Construction or line upgrade program may also require certain transmission facilities be taken out of service for a protracted period. We suggest that R2.1.4 be revised to "When an entity's spare equipment strategy or transmission project construction plan could result in the unavailability of".. 3. When would PCs and TPs be expected to perform the analysis referred to in R2.1.4 ? in anticipation of the possibility of unavailability of major transmission equipment of after such unavailability has occurred or is planned?

Organization	Question 2 Comment
	4. R2.3: The first sentence is unclear and the wording can be supported is misleading. We suggest the first sentence be revised to: The short circuit analysis portion of the Planning Assessment addressing the Near-Term Transmission Planning Horizon shall be conducted annually and be supported by current or past studies. Alternatively, language similar to R2.4 may be considered: "The Near-Term Transmission Planning Horizon portion of the short circuit analysis shall be assessed annually and be supported by current or past studies. 5. R2.4 stipulates the details of the study for Near-Term Transmission Planning horizon for the stability analysis. Unlike its steady state analysis counterpart, there is no requirement stipulated for the Long-Term Transmission Planning horizon for the stability analysis. Is this intentional, or do the same conditions apply to the Long-Term stability analysis" 6. R2.6: Suggest to change in the tables to Table 1 at the end of the second sentence. 7. We agree with the VRFs, Mitigation Horizons and Measures. We also agree with the VSLs except R2.5 is not included. However, If R2.5 is meant to be explanatory (to illustrate the conditions under which past studies may be used), then the conditions should be provided in those requirements (e.g. R2.3) that allow for the use of past studies. If, however, these conditions are meant to be requirements, then their VSLs should be developed.

Response: The SDT does not see the proposed language as an improvement. No change made.

In Part 2.1.4 (now Part 2.1.5) when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. Part 2.1.5 is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of equipment will be replaced. If not, its impact of unavailability would need to be assessed. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.3 has been revised to provide greater clarity.

> **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

The SDT added Part 2.5 to address your concern.

> **2.5** The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported by current or past studies.

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Part 2.6 (now Part 2.7) has been changed as suggested. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: The Lower VSL has been revised accordingly. R2, Lower VSL: The responsible entity failed to comply with Requirement R2, part 2.9 or Requirement R2, part 2.6.	
Kansas City Power & Light	R2.1.3 is this indicating that only one of the variations need to be studied? (in one or more of the following conditions). Recommend having the planner work with the load to determine what sensitivity studies to perform. R2.1.4 it is unclear as to what should be done with the analysis that incorporates the company's spare equipment strategy. Is this requirement inferring that a company's spare equipment strategy need to ensure that it can still operate to within the requirements for contingencies of Table 1 without the component? R2.2.1 ? is the intent to have the study for the 10 year horizon or to include any project that is started within the next 10 years and thus the study must be extended to the forecasted completion of the project (conceivably as long as 20 years or more?) R2.5.2 - Remove the word intervening and this requirement must be more specific about what this requirement is trying to communicate and acccomplish. R2.6.4 recommend clarifying how situations beyond the control of the TP or PC are determined. It is unclear if this is to imply that if something is outside of the control of the department who conducts the planning studies or if it is outside the control of the registered function's legal entity (i.e. corporation). R2.8 appears to be nonessential information for reliability; for what purpose does this requirement exist? R2.9 - appears to be nonessential information for reliability; for what purpose does this requirement exist?
Response: Part 2.1.3 (now Part 2.1.4) is intended for the Planning Coordinator or the Transmission Planner to investigate at least one of the conditions listed. Part 2.1.3 has been revised to provide greater clarity. It is expected that there will be coordination between the Planning Coordinator, the Transmission Planner and the other impacted Functional Entities. **2.1.4** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Real and reactive forecasted Load.	

Organization	Question 2 Comment
	• Expected transfers. • Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. • Controllable Loads and Demand Side Management. • Duration or timing of planned Transmission outages. In Part 2.1.4 (now Part 2.1.5) when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will apply. Part 2.1.5 is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of equipment will be replaced. If not, its impact of unavailability would need to be assessed. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.2.1 has been revised because extending the Planning Horizon beyond 10 years for projects with lead time longer than 10 years is already covered in the definition of Long-Term Transmission Planning Horizon. This allowance is needed to provide planning flexibility, and is at the discretion of the Planning Coordinator or Transmission Planner. For example, if the System is found not to meet performance standard in year 10, but the project to correct the loading cannot be placed in service for 12 years, then the Corrective Action Plan needs to identify the interim solutions before the project can be brought on line. **2.2.1** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected. Part 2.5.2 has been revised and included as Part 2.6.2 in the new version to provide greater clarity. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Part 2.6.4 (now 2.7.5) does not prejudge the acceptability of the situation outside the control of the Planning Coordinator or Transmission Planner, which has prevented the implementation of the Corrective Action Plan, provided that the Planning Coordinator or Transmission Planner documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service. Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning

Organization	Question 2 Comment
Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
ReliabilityFirst Corporation	R2- Suggest changing annual Planning Assessment to "annual Planning Assessment Report". Requires short circuit analysis, at present NERC wide common data base for conducting short circuit analysis, does not exist. Short circuit analysis is only performed when there are major system changes and their impact is local. R2.1.1 requires either Year One or year two, and year five. NERC members utilize Models developed by MMWG for the assessment study needs and they are usually lag by one year. R2.1.3 -Suggest changing last bullet to read "Transmission lines, Transformers, Generating unit and Reactive sources that are scheduled for extended outages during the study period should not be included in the Assessment Model." R2.4.1- The requirements in the two sentences seem to contradict each other. R2.4.2 – This does not mention modeling dynamic behavior of loads. R2.5.2 – "could include" is weak and may not be enforceable. Suggest removing all the text after the first paragraph. Does this require any additional studies to demonstrate that the changes do not impact previous conclusions? R2.7 – Short Circuit analysis should not be a part of Performance Requirements". These should be included in "PRC" Standards
Response: Requirement R2 has been revised. **R2.** Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. Part 2.1.1 is intended to require studies for System Peak Load Conditions for 2 of the years in the near-term planning horizon: (1) A year five case to identify potential problem that can be addressed if the planned projects proceed as scheduled; (2) A Year One or year two case to identify any potential problems unanticipated in the five-year case, which if not addressed, could impact operations as time progresses. The standard provides flexibility for the Planning Coordinator or Transmission Planner to use past studies to support the current year assessment, and to assess other years in addition to those identified in Part 2.1.1. Therefore, if the models developed by MMWG lag by one year, it can qualify as a valid past study. Planned outages of generation and Transmission Facilities are included in Part 1.1.1 (included as Part 1.1.2 in the new version). Transmission Facilities covers lines, reactive devices, and other substation equipment. Part 2.1.3 (now Part 2.1.4) is intended to cover sensitivity studies on "what if" scenarios. Part 2.1.4 has been revised to provide greater clarity. **2.1.4** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.	

Organization	Question 2 Comment
	• Real and reactive forecasted Load. • Expected transfers. • Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. • Controllable Loads and Demand Side Management. • Duration or timing of planned Transmission outages. Part 2.4.1 is intended to allow the use of aggregated system Load models if more accurate Load models are not available. Therefore, the second and third sentences are not in conflict. In Part 2.4.1 the SDT specifies the dynamic Load model representation for on peak because the System voltages are generally lower during on peak. The percentage of motor Load, e.g., in air conditioners, could significantly increase reactive power requirements especially when they stall due to low System voltage and can therefore impact dynamic System performance on-peak. However, motor Load would likely not pose the same problem during off-peak as the System voltages are usually higher. So, in Part 2.4.2, it can be left to the discretion of the Planning Coordinator or Transmission Planner whether the dynamic motor Load would need to be represented per the requirement in Part 2.4.1, Part 2.5.2 has been revised and included as Part 2.6.2 in the new version to provide greater clarity. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Part 2.7 is intent to require a Corrective Action Plan if the short circuit duty requirement exceeds the current interrupting duty of the circuit breaker. No change made.

3. Requirement R3 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: Minor wording changes were made to Requirement R3 to clarify that this requirement pertains to the requirements of the studies needed to support the Planning Assessment. Several industry commenters wanted confirmation that Requirement R3 applied to both the Planning Coordinator and the Transmission Planner feeling that the requirement could result in duplication of effort. The SDT directed the commenters to Requirement R6 (now Requirement R7), which provides a mechanism for determining individual and joint responsibilities for performing the required studies for the Planning Assessment. Several clarifying changes were made to the wording of the parts under Requirement R3 to address industry comments.

R3 For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1.

R3.1 Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4.

R3.2 Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, part 3.5.

R3.3 Contingency analyses shall be performed and:

R3.3.2 Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

R3.3.3 Ensure relay loadability limits are respected.

R3.3.4 Simulate the expected automatic operation of existing and planned devices designed to provide Steady State control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

R3.4 Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

R3.4.1 The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

R3.5 Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R3, moderate VSL: The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.

Organization	Question 3 Comment
Northeast Power Coordinating Council	R3.3.2 Traditionally transmission planners have used their judgment about the minimum steady state voltage limitations of generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R3.3.3 " PRC-023 requires relay loadability to be reflected in facility ratings. Therefore this additional requirement is unnecessary and should be deleted. R3.5 ? We recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following:- Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events- It should be clear that an evaluation does not require solution development for all Extreme Events- Change "an evaluation of possible actions" to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered. For Requirements R3.4 and R3.5, what defines "more severe System impacts"?
Response: R3.3.2: The SDT agrees that judgment is used today. There is a project (PRC-024) that will address this issue. The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure that they are being treated within the simulation as they will react in the real world. No change made for this comment. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections. **R3.3.3** Ensure relay loadability limits are respected. R3.5: The SDT disagrees that the standard should mandate corrective actions for extreme events due to the low probability of these events. However, the SDT believes that those extreme events that are expected to produce more serve System impacts should be analyzed to assess the extent of the impacts on the System to provide the Planning Coordinator/Transmission Planner with information to decide, where appropriate, if it is reasonable to provide some corrective actions to reduce the possibility or limit the consequences of an extreme event. The need to identify possible actions addresses an Order 693 directive. Your suggested wording would make identification of possible actions optional. No change made. R3.4 & R3.5: Requirement R3, parts 3.4 and 3.5 require the Planning Coordinator/Transmission Planner to prepare a list of planning event and extreme event Contingencies that, in the Planning Coordinator's and Transmission Planner's judgment, are expected to produce more severe System impacts, and to document the reasons for the Contingencies selected. The documented rationale provided by the Planning Coordinator/Transmission Planner will define what is considered to be the more severe System impacts.	
Transmission Planning	R3.3.1. COMMENT: This would make sense for 3-terminal lines which we are including in contingency files, but for normal 2-terminal lines, very unnecessary. Suggested language at the end would say "Simulation of individual element outages is allowed if it produces an effect more severe that the entire circuit outage". This implies that by modeling individual branch outages would represent more severe conditions than entire circuit outages due to the fact that there would be consequential load loss. R3.4. COMMENT: Table 1 as drafted is very confusing and could be interpreted incorrectly. Recommend revising the header for "Table 1 " Steady State & Stability Performance Extreme Events" Should be changed to "Table 2 - Steady State & Stability Performance Extreme Events" because the expected performance requirements associated with Planning Events could be

Organization	Question 3 Comment
	interpreted to be applicable to Extreme Events as well. Alternatively, the performance requirements at the top of Table 1 need to include a statement that they are applicable to Planning Events only.
Response: R3.3.1: The SDT disagrees with the comment as the intent of Requirement R3, part 3.3.1, consistent with FERC Order 693, is to perform the simulation to reflect how the Protection System will operate in the real System for each Contingency without operator intervention. The requirement does not preclude the Planning Coordinator/Transmission Planner from studying individual elements or other maintenance scenarios. Planning event P2-1 addresses an element outage configuration. Please also see footnote 8. No change made. R3.4: The SDT feels that the table headings are sufficiently clear as stated. No change made.	
SERC Engineering Committee Planning Standards Subcommittee	R3.1:In Requirement R3.1, it is suggested that the word "contingency" be added to describe the lists created in R3.4.: "Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists created in Requirement R3.4. R3.3.1: Recommend that it be clarified that simulation of the more conservative case of a single branch (bus-to-bus) outage is acceptable, as opposed to always simulating the full breaker-to-breaker outage. R3.3.2The requirement needs to be clarified. It is not clear if it is referring to the ability of plants to meet their voltage schedule, or to their ability to stay connected during post contingencies. R3.3.4:In Requirement R3.3.4, it is suggested adding the words "and switched" to capacitors and reactors:"Simulate the expected operation of existing and planned devices designed to provide Steady State control of electrical system quantities. These devices include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.
Response: R3.1: The SDT agrees and has modified Requirement R3, part 3.1 accordingly **R3.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4. R3.3.1: The SDT disagrees with the comment as the intent of Requirement R3, part 3.3.1, consistent with FERC Order 693, is to perform the simulation to reflect how the Protection System will operate in the real System for each Contingency without operator intervention. The requirement does not preclude the Planning Coordinator/Transmission Planner from studying individual elements or other maintenance scenarios. Planning event P2-1 addresses a branch outage configuration. Please also see footnote 8 (now footnote7). No change made. R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.4: The SDT agrees and has revised the wording. **R3.3.4** Simulate the expected automatic operation of existing and planned devices designed to provide Steady State control of electrical system quantities	

Organization	Question 3 Comment
when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.	
Modesto Irrigation District	On page 10 under Section R3.3.3, I believe more specifics on what is meant by "relay loadability" need to be given in regard to the requirement of "identify how loadability is analyzed in the steady state simulation". For example, does the analyst need to state that the maximum loading allowed on any system element is less than or equal to 150% of the element's maximum seasonal rating ? We believe that R3.3.1-R3.3.4 should be bullets under R3.3
Response: R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits, as defined in the relay loadability standard, are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected. R3.3.1-R3.3.4: The SDT disagrees as these are mandatory requirements of the Contingency analyses. Bullets are only used to identify the possible, but not all inclusive, elements of a menu. No change made.	
OPUC	3. Requirement R3 ? Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.Comments:A: R3.3 should be modified to become the requirement to conduct contingency analyses with R3.3.1 thru 4 presented as bullets there-under.
Response: R3.3.1-R3.3.4: The SDT disagrees as these are mandatory requirements of the Contingency analyses. Bullets are only used to identify the possible, but not all inclusive, elements of a menu. No change made.	
Bonneville Power Administration	R3.1 should be clarified. Suggested clarification: R3.1 - "Studies shall be performed to determine whether the BES meets the performance requirements in Table 1. A reduced set of contingencies can be simulated based on a list created in requirement R3.4." As currently drafted, R3.3 is not a requirement. Without the statements in R3.3.1-R3.3.4, R3.3 is simply a phrase. Sub-Sub-Requirements R3.3.1 through R3.3.4 should be bullets under R3.3, with the language in R3.3 modified so that it becomes the requirement to conduct contingency analyses that address the four resulting bullets R3.3.2 is unclear as drafted. The minimum steady state voltage limitation for synchronous generators is not a very meaningful value. All generators with an automatic voltage regulator will maintain the set point voltage until the VAR capability of the generator is exceeded, and then the voltage will deteriorate. Requirement R3.4 also needs to be clarified as follows: R3.4 - "A reduced list of Contingencies can be developed for System Performance evaluation in Requirement R3.1 that includes those Planning Event Contingencies that are expected to produce more severe System impacts based on system performance as required in Table 1. "The Statement at the end of R3.4 and R4.4 says "rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an

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	explanation of why the remaining Contingencies would exhibit better system performance." The statement does not make sense and should be deleted since the contingencies selected are those to produce more sever system performance. R3.5 ? We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingencies than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.

Response: R3.1: The SDT agrees and has modified the requirement.

> **R3.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4.

R3.3:The SDT has modified the wording to provide greater clarity. The SDT disagrees that Requirement R3 parts 3.3.1- 3.3.4 should be bullets as these are mandatory parts of the required contingency analyses. Bullets are only used to identify the possible but not all inclusive elements of a menu. No change made.

> **R3.3** Contingency analyses shall be performed and:

R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world.

> **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

R3.4: The SDT has made a revision to the posted wording of the requirement to add clarity and address your comment.

> **R3.4** Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

R3.4 & R4.4: Several industry commenters have indicated that an explanation of “why the remaining Contingencies would produce less severe System performance” should be deleted since the Contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an “explanation of why the remaining Contingencies would produce less severe System results”.

R3.5: Several industry commenters have indicated that an explanation of “why the remaining Contingencies would produce less severe System performance” should be deleted since the contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an “explanation of why the remaining Contingencies would produce less severe System results”.

> **R3.5** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible

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actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.	
MRO MRO NERC Standards Review Subcommittee	MRO NSRS proposes the following comments for R3.Revise the R3.3.2 text to clarify that subsequent analysis is performed on generators whose voltages are expected to fall below the minimum voltage limits. MRO NSRS suggests this text: "Consider the minimum steady state voltage limitations of all generators and identify how generators with bus voltages below its minimum voltage limits are analyzed in the subsequent steady state simulations. Revise the R3.3.3 text to more clearly relate to the specific requirements in PRC-023. MRO NSRS suggests this text: "Incorporate relay loadability per PRC-023 and identify how relay loadability is analyzed in the steady state simulation.
Response: R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement. **R3.3.3** Ensure relay loadability limits are respected.	
SERC Engineering Committee Dynamics Review Subcommittee (DRS)	R3.3.3 applies to "all Transmission lines. Should this only apply to lines above 230 kV and lines identified as critical below 230 kV" At least this should be limited to BES lines. R3.3.4 says "Simulate the expected operation of existing and planned devices designed to provide Steady State control of electrical system quantities. This should say, "Simulate the expected operation of existing and planned BES devices designed to provide Steady State control of BES electrical system quantities.
Response: R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits, as defined in the relay loadability standard, are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected. R3.3.4: The SDT disagrees as this standard only applies to the BES. No change made.	
SERC Engineering Committee Reliability Review Subcommittee (RRS)	In R3, should the "and" in the first sentence actually be "or"? especially for same footprint? Perhaps the "and" should be replaced by "and/or". Can the PC satisfy this requirement by reviewing studies performed by differing TPs or is separate analysis really required especially when the TP and PC have the same footprint"? In Requirement R3.1, it is suggested that the word "contingency" be added to describe the lists created in R3.4. R3.3.1. Recommend that it be clarified that simulation of the more conservative case of a single branch (bus-to-bus) outage is acceptable, as opposed to always simulating the full breaker-to-breaker outage. R3.3.2The requirement needs to be clarified. It is not clear if it is referring to the ability of plants to meet their voltage schedule, or

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	to their ability to stay connected during post contingencies. Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists created in Requirement R3.4. "R3.3.2"For all generators, studies shall consider the minimum steady state voltage limitations and identify how the generators are analyzed in the steady state simulation. The above wording needs to be changed, as the intent of this sentence is unclear. Is the intent that Transmission Planners need to ensure that generating plants can meet their voltage schedule under Base Case (N-0) conditions? Is this the same as the generator underexcited operation limit?? In R3.3.2, need guidance on how to consider minimum steady state voltage limitations. Is there a NERC team addressing this" R3.3.3"For all Transmission lines, studies shall consider relay loadability and identify how loadability is analyzed in the steady state simulation. The above wording needs to be changed, as the intent of this sentence is unclear. Is the intent that Transmission Planners need to ensure that relay loading limits are included in the facility ratings? Is this the 130% of conductor rating limit?? Revise M3 to include a reference to R6, since the allocation of responsibilities will directly affect the evidence which is to be provided. In the VSL for R3, a severe VSL is listed as failing to meet performance requirement for P0 or P1. We do not understand why a severe VSL would be applied to an all ties closed event which should have little if any problems. We believe that this should be a lower or moderate VSL instead of severe. In R3.3.3 is the relay loadability required for all HV and EHV voltage levels? Previously NERC had required this for 230-kV and above only. This would be massive requirement for our Transmission Lines between 100 and 200-kV. Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists created in Requirement R3.4. ? In Requirement R3.3.4, it is suggested adding the words "and switched" to capacitors and reactors: Simulate the expected operation of existing and planned devices designed to provide Steady State control of electrical system quantities. These devices include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

Response: R3: The SDT believes that the requirement belongs to both the Planning Coordinator and the Transmission Planner. Requirement R7 provides a mechanism for determining individual and joint responsibilities for performing the required studies for the Planning Assessment regardless of whether the Planning Coordinator and Transmission Planner footprints overlap or not. No change made.

R3.1. The SDT agrees and has modified the requirement.

> **R3.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4.

R3.3.1: The SDT disagrees with the comment as the intent of Requirement R3, part 3.3.1, consistent with FERC Order 693, is to perform the simulation to reflect how the Protection System will operate in the real System for each Contingency without operator intervention. The requirement does not preclude the Planning Coordinator/Transmission Planner from studying individual elements or other maintenance scenarios. Planning event P2-1 addresses a branch outage configuration. Please also see footnote 8 (now footnote 7). No change made.

R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage

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limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. There is a project (PRC-024) that will address this issue of minimum steady state voltage limitations. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits, as defined in the relay loadability standard, are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected. M3: The SDT disagrees. Requirement R6 (now Requirement R7) is an overarching requirement that applies to the entire set of analysis required to meet the requirements of the TPL standard and to the Corrective Action Plan developed as part of the assessment. The intent of this requirement is to clarify that TPL requirements can be met through joint or shared analysis. Coordinating and/or joint analysis does not alleviate the responsibility that all entities need to comply with the standard requirements. Therefore, the SDT sees no reason to link Requirement R3 directly to Requirement R6 (now Requirement R7) in the measure or anywhere else. The requirements stand by themselves and do not require such a linkage. No change made. VSL: The SDT disagrees with your assessment. The failure to perform studies to determine the BES meets performance requirement for the P0 and P1 categories is deemed to be severe as these categories represent steady state (no Contingency) and single Contingency (probable) operation and are significant elements of the overall requirement. No change made. R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits, as defined in the relay loadability standard, are respected in the analysis. R3.3.4: The SDT agrees and has revised the wording. **R3.3.4** Simulate the expected automatic operation of existing and planned devices designed to provide Steady State control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.	
FirstEnergy Corp	Specific comments, Requirements of R3:A. R3: For readability revise "computer simulations using models utilizing data" to "computer simulation models utilizing data" B. R3.3.2: The intent of this requirement is not clear. What is the voltage limitation sought? Vmin at the generator terminals, high-side of the GSU, low-side GSU, etc. Also the requirement text "identify how the generators are analyzed in the steady state simulation" does not drive a particular reliability goal. If the objective is to require tripping of units during a contingency simulation that are identified to be below their stated Vmin then the requirement should clearly state that the unit should be tripped and solution resolved. C. R3.3.3: This requirement should be removed as it is redundant with facility rating requirements stated in PRC-023, FAC-008 and FAC-009. D. R3.3.4: For readability we suggest inserting the word "may" in between "devices include".We agree with the stated Measures, VRF, Time-Horizon, Data Retention and VSL of requirement R3
Response: R3: The SDT has revised the wording accordingly.	

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	R3 For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections **R3.3.3** Ensure relay loadability limits are respected. R3.3.4: The STD has added the word "may" in between "devices include". **R3.3.4** Simulate the expected automatic operation of existing and planned devices designed to provide Steady State control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors. Measures, VRF, Time Horizon, Data Retention and VSLs: Thank you for your comment.
TVA System Planning	In R3.3.2, need guidance on how to consider minimum steady state voltage limitations. Is there a NERC team addressing this? It is not clear if it is referring to the ability of plants to meet their voltage schedule, or to their ability to stay connected during post contingencies. In R3, should the "and" in the first sentence actually be "or"? especially for same footprint? Perhaps the "and" should be replaced by "and/or". Can the PC satisfy this requirement by reviewing studies performed by differing TPs or is separate analysis really required especially when the TP and PC have the same footprint? In the VSL for R3, a severe VSL is listed as failing to meet performance requirement for P0 or P1. We do not understand why a severe VSL would be applied to an all ties closed event which should have little if any problems. We believe that this should be a lower or moderate VSL instead of severe. In R3.3.3 is the relay loadability required for all HV and EHV voltage levels? Previously NERC had required this for 230-kV and above only. This would be massive requirement for our TLs between 100 and 200-kV.
Response: R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. There is a project (PRC-024) that will address this issue. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through	

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voltage limitations. Include in the assessment any assumptions made. R3: The SDT believes that the requirement belongs to both the Planning Coordinator and the Transmission Planner regardless of whether the Planning Coordinator and Transmission Planner footprints overlap or not. No change made. VSL: The SDT disagrees with your assessment. The failure to perform studies to determine the BES meets performance requirement for the P0 and P1 categories is deemed to be severe as these categories represent steady state (no Contingency) and single Contingency (probable) operation and are significant elements of the overall requirement. No change made. R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits, as defined in the relay loadability standard, are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected.	
Exelon Transmission Planning	In R3.3.2 it should be clear that the TP / TO is not required to provide whatever voltage that the unit desires and that the intent of this requirement is to ensure that if a generator is going to trip due to low voltage that the simulation will include the generator tripping. 3.3.2 and 3.3.3. are somewhat redundant with 3.3.1 " suggest rewording 3.3.1 to say including transmission lines with respect to relay loadability and generators with respect to minimum operating voltage. If 3.3.3 is targeting the low voltage ride through capability of the wind generators it should be clear.
Response: R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and that they are being treated within the simulation as they will react in the real world (in your comment 3.3.3 referring to low voltage ride through, we assume in our response that you were referring to 3.3.2) **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.2 & R3.3.3: The SDT does not agree that Requirement R3 parts 3.3.1, 3.3.2 and 3.3.3 are somewhat redundant as they require distinctly different simulation actions. No change made. R3.3.3: This requirement is for all generators, not just wind. It is important for the planning models to accurately reflect how the System will actually perform.	
Southern Company	R3.3.3 applies to "all Transmission lines. To be consistent with the relay loadability standard, this should only apply to lines above 230 kV and lines between 100 kV and 230 kV identified as critical. R3.2 and R3.5 are both addressing the Extreme Events. However, R3.2 is referring to R3.5 while R3.5 is referring to R3.2. We suggest deleting the reference back to R3.2 which is in R3.5. A similar situation exists for R3.1 and R3.4. R3 seems to use the words studies and analyses interchangeably. Did the SDT intend for them to be the same? Using one term or the other would be better understood.

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	There are two tables labeled table 1. It would be much clearer to mark them table 1 Planning Events and table 2 Extreme Events.
Response: R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected. R3.1 & R3.4 and R3.2 & R3.5: The SDT has decided to retain the back references for clarity. No change made. R3: The SDT agrees that use of studies and analyses can be confusing. The wording in Requirement R3 has been revised to use studies. **R3** For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. Table 1: Based on Industry feedback, the SDT has decided to have one Table and believes that the headings are sufficiently clear to distinguish between planning and extreme events. No change made.	
United Illuminating	R3.3.2 Comment Traditionally transmission planners have used their judgment about the minimum steady state voltage limitations of generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R3.3.3 Comment ? PRC-023 requires relay loadability to be reflected in facility ratings. Therefore this additional requirement is unnecessary and should be deleted. R3.5 Priority Comment ?We recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following:- Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events- It should be clear that an evaluation does not require solution development for all Extreme Events- Change “an evaluation of possible actions”? to “where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered.
Response: R3.3.2: The SDT agrees that judgment is used today. There is a project (PRC-024) that will address this issue. The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections. **R3.3.3** Ensure relay loadability limits are respected. R3.5: The SDT disagrees that the standard should mandate corrective actions for extreme events due to the low probability of these events. However, SDT believes that those extreme events that are expected to produce more serve System impacts should be analyzed to assess the extent of the impacts on the System to provide the Planning Coordinator/Transmission Planner with information to decide, where appropriate, if it is reasonable to provide some corrective actions to reduce the	

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possibility or limit the consequences of an extreme event. The need to identify possible actions addresses an Order 693 directive. Your suggested wording would make identification of possible actions optional. No change made.	
System Protection and Transmission Planning Department	R3 appears to require redundant studies by TP and PC.If the TP and PC participate in the same studies, would this meet the intent of this requirement? This would include studies that are RRO sponsored, or performed by sub-regional planning groups.
Response: R3: The SDT believes that the requirement belongs to both the Planning Coordinator and the Transmission Planner. Requirement R7 (formerly Requirement R6) provides a mechanism for determining individual and joint responsibilities for performing the required studies for the Planning Assessment regardless of whether the PC and TP footprints overlap or not. No change made.	
PPL Energy Plus	It appears there is a 24 month grace period to allow modeling updates to meet R 3.3.1. This is a good idea since the powerflow computer models may not include the required data and will need to be updated.
Response: Thank you for your comment.	
PacifiCorp Deseret Generation & Transmission SRP Arizona Public Service Co Southern California Edison Company Western Area Power Administration Pacific Gas and Electric Co, Puget Sound Energy, Inc. NV Energy San Diego Gas and Electric Co California ISO Tucson Electric Power Company	As currently drafted, R3.3 is not a requirement. Without the statements in R3.3.1-R3.3.4, R3.3 is simply a phrase. Sub-Sub-Requirements R3.3.1 through R3.3.4 should be bullets under R3.3, with the language in R3.3 modified so that it becomes the requirement to conduct contingency analyses that address the four resulting bullets R3.3.2 is unclear as drafted. The minimum steady state voltage limitation for synchronous generators is not a very meaningful value. All generators with an automotive voltage regulator will maintain the set point voltage until the VAR capability of the generator is exceeded, and then the voltage will deteriorate. R3.5 ? We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingencies than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.
NorthWestern Corporation NorthWestern Energy (NWE)	R3.3 is unclear. Requirements R3.3.1 through R3.3.4 should be bullets under R3.3, with R3.3 modified so that it becomes the

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(NWMT)	requirement to conduct contingency analyses that address the four resulting bullets R3.3.2 is unclear. The minimum steady state voltage limitation for synchronous generators is not a very meaningful value. All generators with an automatic voltage regulator will maintain the set point voltage until the VAR capability of the generator is exceeded, and then the voltage will deteriorate. In R3.3.3 the term "loadability" needs to be defined. R3.5 needs to be modified. It would be better to combine R3.2 with R3.5. The first part of the requirement requires identification of events that produce more severe System impacts. The presumed reason that the other contingencies were not selected is because they were deemed to be less severe or non-credible. In any case, theoretically, there can always be examples of more severe Extreme Contingencies than the one selected for study. This can be achieved by simply choosing events that are even less credible. For example, if the Extreme Contingency studied was a simultaneous loss of 3 transmission lines with the failure of a redundant RAS (SPS), then an event resulting in the simultaneous loss of 4 lines with the failure of 2 sets of redundant RASs would be even more severe. Listing all possible extreme events could result in a limitless list.
Response: R3.3: The SDT has modified the wording to provide greater clarity. The SDT disagrees that Requirement R3, parts 3.3.1- 3.3.4 should be bullets as these are mandatory requirements of the contingency analyses. Bullets are only used to identify the possible but not all inclusive elements of a menu. **R3.3** Contingency analyses shall be performed and: R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.5: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the Contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining Contingencies would produce less severe System results". **R3.5** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.	
Western Area Power Administration	R3.3.3 should be covered in the PRC Standards. While R3.3 is labeled as "Contingency analysis", R3.3.4 is related to Steady State control and therefore should not be within R3.3.
Response: R3.3.3**:** The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections. **R3.3.3** Ensure relay loadability limits are respected. R3.3.4: The SDT disagrees with your comment. The simulation of the expected operation of devices such as phase-shifting transformers, load tap changing transformers, etc., impacts the post-Contingency performance of the System. No change made.	

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Tampa Electric	Consider revising standard for clarity. Subrequirements are not clear as written. Consider moving subrequirements R3.3.1 - R3.3.4 under other requirements for clarification. R3.5 Including an explanation of why remaining contingencies would produce less severe system results could be a limitless effort. Listing all "possible" extreme events seems unrealistic.
Response: The SDT requires more information in order to respond to your request to clarify the standard and sub-requirements. Numerous clarifications have been made to the fourth posting due to specific industry comments. R3.3.1-R3.3.4: The SDT disagrees as these are mandatory requirements of the Contingency analyses. No change made. R3.5: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining contingencies would produce less severe System results". **R3.5** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.	
Florida Reliability Coordinating Council, Inc - Transmission Working Group	R3.3.1 & 3.3.4 " Consider adding language that the entity should not be held responsible for simulating "the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention? on neighboring systems, only on the entity's own system. Also, consider moving R3.3.1 and R3.3.4 under R3.1 as sub-requirements and require that the overall studies take into account the effect of protection systems and control devices in the performance of the BES and it's ability to meet the table 1 requirements. R3.3.1 ? This seems unnecessary for normal 2-terminal lines, consider adding language to the effect of: "Simulation of individual element outages is allowed if it produces an effect more severe than the entire circuit outage". R3.4 - Consider changing the header for table 1 - "Steady State & Stability Performance Extreme Events" to Table 2 - "Steady State & Stability Performance Events". As is, it could be interpreted that the expected performance requirements associated with Planning Events apply to Extreme Events also.
Response: R3.3.1 & R3.3.4: The SDT has determined that it is necessary for the Planning Coordinator and Transmission Planner to coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list created in Requirement R3, part 3.4. Consequently, "the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention" will also apply for the Contingencies on adjacent Systems. The fourth draft of the standard will include this change by adding Requirement R3, part 3.4.1. **R3.4.1** The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.	

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The SDT believes that Requirement R3, parts 3.3.1 and 3.3.4 are separate mandatory requirements and disagrees that they should be moved under Requirement R3, part 3.1. No change made. R3.3.1: The SDT disagrees with the comment as the intent of Requirement R3, part 3.3.1, consistent with FERC Order 693, is to perform the simulation to reflect how the Protection System will operate in the real System for each Contingency without operator intervention. The requirement does not preclude the Planning Coordinator/Transmission Planner from studying individual elements or other maintenance scenarios. Planning event P2-1 addresses an individual outage configuration. Please also see footnote 8. No change made. R3.4 Table 1: Based on Industry feedback, the SDT has decided to have one Table and believes that headings are sufficiently clear. No change made.	
FMPA	R3.1, The criteria in Table 1 do not allow load shedding following a single contingency (e.g., the old footnote "b" was removed). While we agree this ought to be the case for the EHV system, we believe that there are cases where for the HV system, which often acts more like a distribution system, the costs to meet this standard would be prohibitive and unfair to the consumers served by those utilities. For instance, the Florida Keys served by the Florida Keys Electric Coop (FKEC) and Keys Energy Services (KEYS) is connected to the mainland by two 138 kV lines down to Tavernier Key (about 1/3rd the distance from the mainland to Key West). Currently, the system is planned and operated under single contingency to allow non consequential load shedding automatically via Under-Voltage Load Shedding, and to meet thermal limits by manual load shedding, all load shed is in the Florida Keys following the single contingency with no impact to the Bulk Electric System. The standard, as written, would force one of two things: 1) the construction of a third line in this environmentally pristine area at a very high cost that might increase rates to customers in the Florida Keys by 20% for a level of reliability that much of the Keys would not even experience since 2/3rds of the Keys is fed by a radial line with consequential load loss; or 2) separate the two lines such that both are operated radially with resultant consequential load loss, compliant with the standards, but actually causing consumers to have a lower level of reliability. We propose to reinstate footnote "b" for the HV system, allowing non-consequential load loss for lower voltage system that have little to no impact on the Bulk Electric System and limit the elimination of non-consequential load loss to be applicable to only the EHV. Alternatively, but less appealing and more of an administrative challenge would be to establish a Regional Entity administered process for application for exception to this criteria. FERC's Order 693 at paragraph 1794 states that: "(t)he Commission also clarifies that an entity may seek a regional difference to the Reliability Standard from the ERO for case-specific circumstances". We interpret this as meaning the Regional Entity can allow exceptions under certain criteria such as a significant increase in costs to consumers with little discernable benefit as is the case with the Florida Keys. For R3.2, we are at a loss of how a hurricane event can be modeled, and why such an evaluation is needed. Albeit, many contingencies can occur during a hurricane event, it is not likely that multiple contingencies will happen within the same < 1 minute window it takes to go from transient stability conditions to steady state conditions, and then it is unlikely that multiple significant contingency events will occur within the 30 minutes it takes operators to adjust the system to prepare for the next contingency. Therefore, we do not understand the significance of modeling a hurricane event. In addition, a hurricane can have an infinite number of different scenarios and time-lines of contingencies and picking one or two would be a meaningless exercise since an actual hurricane will be completely different than what is modeled. At least an earthquake has a fault line that makes it relatively easier to identify which facilities might be affected, but a hurricane has an infinite number of possibilities. We suggest eliminating hurricanes from extreme events and model potential results of a hurricane, such as loss of a ROW, loss of a substation or plant, and loss of a major load center. R3.3, the list ought to consider contingencies on neighboring systems that could impact the TP's / PC's system (this comment

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	would not carry over to R4.3 since stability is more a protection system / clearing time issue). R3.3.1, the entity should not be held responsible for simulating "the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention" on neighboring systems, only on the Entity's own system. R3.4 and the first part of R3.5 ought to be combined, e.g., both require justification for why a limited set of worst case contingencies are studied for N-1, N-2 and extreme contingencies. The latter part of R3.5 concerning cascading outages for an extreme contingency should become the only requirement of R3.5 (there are currently two requirements embedded within R3.5).
Response: R3.1: To comply with Order 693, the SDT have decided to raise the performance requirements such that Non-Consequential Load loss should not be allowed for P1 events of Table 1. No change made. R3.2: Table 1 extreme events: Requirement R3, part 3.5 requires the Planning Coordinator/Transmission Planner to identify and compile a list of the extreme events that are expected to produce more severe System impacts, along with a rationale for selection of those Contingencies. The wide area extreme events such as item 3.iv are provided as examples and not meant to be a mandatory list of events to be simulated. No change made. R3.3: The SDT assumes that the comment "R3.3, the list ought to consider contingencies on neighboring systems that could impact the TP's / PC's system" actually refers to Requirement R3, part 3.4 where the Contingency list is created. The SDT agrees with your comment and has determined that it is necessary for the Planning Coordinator and Transmission Planner to coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list created in Requirement R3, part 3.4. The fourth draft of the standard will include this change by adding Requirement R3, part 3.4.1. The need to include Contingencies on adjacent Systems will also apply to Stability. **R3.4.1** The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. R3.3.1: The SDT has determined that it is necessary for the Planning Coordinator and Transmission Planner to coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list created in Requirement R3, part 3.4. Consequently, "the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention" will also apply for the Contingencies on adjacent Systems. The fourth draft of the standard will include this change. R3.4 & R3.5: The SDT does not agree that these requirements should be combined. Requirement R3, part 3.4 requires the development of a Contingency list of planning events, and Requirement R3, part 3.5 requires a Contingency list of extreme events - two separate requirements. The SDT agrees that both require that a rationale be provided for stating why the events selected are expected to produce the more severe System impacts. No change made. R3.5: The SDT disagrees and sees no reason to split these out as they would still be essentially the same requirement. No change made.	
CPS Energy	Requirement R3.3.2. needs clarification.
Response: R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through	

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	voltage limitations. Include in the assessment any assumptions made.
MidAmerican Energy Company	MidAmerican commends the SDT for it hard wok on this standard and specifically its R3.3.1 wording. MidAmerican has suggestions for the following parts of R3:" . " R3.3.2 " delete the words "For all generators" at the beginning. It is unnecessary in that later in the requirement it states specifically that the responsible entity is to "identify how the generators are analyzed in the steady state limitation". R3.3.3 " use a similar construction to R3.3.2 but delete the words "For all transmission lines". In other words, replace "For all Transmission lines, studies shall consider relay loadability and identify how loadability is analyzed in the steady state limitations. With "Studies shall consider relay loadability and identify how loadability for transmission lines is analyzed in the steady state simulations. " R3.4 and R3.5 " change "remaining Contingencies" to "remaining unselected Contingencies".
Response: Thank you for your comments. R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits, as defined in the relay loadability standard, are respected in the analysis **R3.3.3** Ensure relay loadability limits are respected.. R3.4 & R3.5: The SDT has revised Requirement R3, parts 3.4 and 3.5 by eliminating the requirement to provide the rationale for the unselected Contingencies. **R3.4** Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. **R3.5** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.	
Northeast Utilities	R3.3.2 Comment - Traditionally transmission planners have used their judgment about the minimum steady state voltage limitations of generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to inclusion of R3.3.2 as a requirement in this standard. R3.3.3 Comment - PRC-023 requires relay loadability to be reflected in facility ratings. Therefore this additional requirement is

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	unnecessary and should be deleted. R3.5 Priority Comment - We recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following:-Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events-It should be clear that an evaluation does not require solution development for all Extreme Events-Change "an evaluation of possible actions"? to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered.
ISO New England, Inc. Central Maine Power Company	R3.3.2 Comment - Traditionally transmission planners have used their judgment about the minimum steady state voltage limitations of generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R3.3.3 Comment - PRC-023 requires relay loadability to be reflected in facility ratings. Therefore this additional requirement is unnecessary and should be deleted. R3.5 Priority Comment -We recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following:- Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events- It should be clear that an evaluation does not require solution development for all Extreme Events- Change "an evaluation of possible actions"? to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered.
Response: R3.3.2: The SDT agrees that judgment is used today. There is a project (PRC-024) that will address this issue. The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections. **R3.3.3** Ensure relay loadability limits are respected. R3.5: extreme events: The SDT disagrees that the standard should mandate corrective actions for extreme events due to the low probability of these events. However, the SDT believes that those extreme events that are expected to produce more serve System impacts should be analyzed to assess the extent of the impacts on the System to provide the Planning Coordinator/Transmission Planner with information to decide, where appropriate, if it is reasonable to provide some corrective actions to reduce the possibility or limit the consequences of an extreme event. No change made.	
JEA	R3. Change wording from "The studies shall be based on computer simulations using models utilizing data provided in Requirement R1." to "The studies shall be based on computer simulations using models that are the best representation of the future planned system and its associated use as provided by Requirement R1. The studies shall detail the effects of all future

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	equipment connectivity and topology arrangements and their associated Protection system responses to Contingency events regardless of model details." R3.3.2. I assume the concern here is on voltage ride through of generators and generator auxillary equipment. Propose changing language from "For all generators..." to"Include analysis of how generator and generator auxillary equipment over and under voltage protection and ride through capability were considered for the post-contingency steady state bus voltage levels." R3.3.3. I assume the concern here is ensuring consideration is given to how system protection relays could respond to post-contingency circuit emergency loadings. Protection systems that could limit the emergency ratings of transmission circuits should be considered in the Facitility Rating standard and therefore not necessary to include in the TPL standard. However, if requirement does remain in the TPL standard, propose changing language from:"For all transmission lines..." to"Include analysis of how implemented relay protection systems and their potential automatic response prior to timely corrective actions are considered for the post-contingency steady state circuit loadings".
Response: The SDT has revised Requirements R1 and R3 to provide greater clarity to the SDT's intent. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions **R3** For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections. **R3.3.3** Ensure relay loadability limits are respected.	
SMUD	R3.5Listing all possible scenarios for studying extreme contingencies will result in a limitless list. Discretion should be given to the transmission planner on the selection of the contingencies without a requirement to list why other extreme contingencies have not been included. R3.3.2:When the word, 'consider' is used, it can be read as a guidance and not a requirement. The requirement is unclear.
Response: R3.5: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the Contingencies selected are those to produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining Contingencies would produce less severe System results".	

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R3.5 Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted. R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.	
Progress Energy Florida, Inc.	Concerning R3.3.1, PEF believes that, in virtually every conceivable scenario, contingency analyses show that analysis of individual elements will reveal overloading or undervoltages, whereas the same event modeled according to protection system design (i.e. simulating the event as the actual "breaker-to-breaker" operation would occur) may not. Analysis of individual elements is therefore a more conservative method for studying the BES. PEF is not opposed to analysis of entire circuit outages; PEF therefore suggests that in addition to the existing language of R3.3.1, an additional sentence be added as follows: "Simulation of the loss of individual elements is acceptable in lieu of simulating the loss of all elements in a protection zone if it produces greater overloads or lower voltages. This approach would allow for more efficient coordination with Transmission Operators as they schedule planned outages or make system adjustments in outage scenarios.
Response: R3.3.1: The SDT disagrees with the comment as the intent of Requirement R3, part 3.3.1, consistent with FERC Order 693, is to perform the simulation to reflect how the Protection System will operate in the real System for each Contingency without operator intervention. The requirement does not preclude the Planning Coordinator/Transmission Planner from studying individual elements or other scenarios. Planning event P2-1 addresses an individual element outage configuration. Please also see footnote 8 (now footnote 7). No change made.	
Xcel Energy	R3.3.3: Relay loadability has no bearing beyond the near term horizon. Loadability is not determined several years out. R3.5 " does this imply that mitigation plans must be implemented" If not, then this is highly subjective and the last sentence of this requirement should be deleted.
Response: R3.3.3: The SDT does not agree with your comment**.** No change made. R3.5: The SDT disagrees that the standard should mandate corrective actions for extreme events due to the low probability of these events. However, the SDT believes that those extreme events that are expected to produce more serve System impacts should be analyzed to assess the extent of the impacts on the System to provide the Planning Coordinator/Transmission Planner with information to decide, where appropriate, if it is reasonable to provide some corrective actions to reduce the possibility or limit the consequences of an extreme event. The need to identify possible actions addresses an Order 693 directive. No change made.	
Ameren	In Requirement R3.1, it is suggested that the word "contingency" be added to describe the lists created in R3.4. Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists created

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	in Requirement R3.4. R3.3.2 -For all generators, studies shall consider the minimum steady state voltage limitations and identify how the generators are analyzed in the steady state simulation. The above wording needs to be changed, as the intent of this sentence is unclear. It is not clear whether Transmission Planners need to ensure that generating plants can meet their voltage schedule under Base Case (N-0) conditions, or whether this would be the same as the generator underexcited operation limit. R3.3.3?For all Transmission lines, studies shall consider relay loadability and identify how loadability is analyzed in the steady state simulation. The above wording needs to be changed, as the intent of this sentence is unclear, whether the intent is that Transmission Planners ensure that relay loading limits are included in the facility ratings, or whether this reflect some rule of thumb, such as 130% of conductor rating. In Requirement R3.3.4, it is suggested adding the words "and switched" to capacitors and reactors: Simulate the expected operation of existing and planned devices designed to provide Steady State control of electrical system quantities. These devices include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.
Response: R3.1: The SDT agrees and has modified the requirement. **R3.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4. R3.3.2: The SDT has changed the wording to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits, as defined in the relay loadability standard, are respected in the analysis **R3.3.3** Ensure relay loadability limits are respected. R3.3.4: The SDT agrees and has revised the wording to read “and switched capacitors and inductors”. **R3.3.4** Simulate the expected automatic operation of existing and planned devices designed to provide Steady State control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.	
Manitoba Hydro	R3.1: The requirement text should be changed to read “studies shall be performed for Planning Events to determine whether the BES meets the performance requirements in Table 1 based on the contingency list of events created in Requirement R3.4. . R3.2: Requirement wording should be similar to R3.4 for consistency. R3.4 & R3.5: The selection of the contingency list is based on the knowledge of the PC/TP. How do you produce “an explanation

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	of why the remaining Contingencies would produce less severe System results. without proving this with a study? If the explanation is "that based on engineering judgment, the remaining contingencies would produce less severe system results" then the explanation is implied and not necessary. VSLs: Under the moderate to severe VSL, the performance requirements currently refer to P2 through P7. We believe this is a typo and should be P1 through P7.
Response: R3.1: The SDT agrees and has modified the requirement. **R3.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4. R3.2: The SDT has revised the requirement. **R3.2** Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, part 3.5. R3.4 & R3.5: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining Contingencies would produce less severe System results". **R3.4** Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. **R3.5** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted. VSL: The VSL matrix is correct. No change made.	
LCRA Transmission Services Corporation	In R3.3.4, what is meant by the term "electrical system quantities"? Quantities is typically an amount and its use here would indicate that a term such as parameters would be better suited.
Response: R3.3.4 Checking a few dictionary definitions: parameter: "an expression, a constant or variable whose value determines the specific form of the expression; one of an independent variable in a set of parametric equations; whereas quantity is defined as: an exact or specified amount or measure; that property by virtue of which is measurable; extent; measure, size, any amount. It appears that "quantities" is the better choice. No change made.	
National Grid	R3 Comment "Planning Assessment" and "shall perform analysis" are contradictory. R3 and its sub-requirements then reference study requirements. If this is an assessment, then the standard shouldn't be requiring a study.R3.1 Comment ? A. It is not clear what should be included in the list related to R3.4. Events P0 through P4 should include analysis of all BES facilities for which the Transmission Planner is responsible. Events P5 and higher should be limited to contingency events

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	that are deemed the most significant by the Transmission Planner. B. R3.1 refers to “lists”. Is R3.4 creating one list or multiple lists” Suggest changing “lists” to “list” R3.2 Comment - Since R3.4 and R3.5 both require the responsible entity to create a list, the words in R3.2 be should be revised to be more similar to the words in R3.1. Suggest changing “Studies shall be performed to assess the impact of the Extreme Events identified in Requirement R3.5. to “Studies shall be performed to assess the impact of the Extreme Events, which are identified by the list created in Requirement R3.5. R3.3.2 Comment “ A. Traditionally transmission planners have used their judgment about the minimum steady state voltage limitations of generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. B. Voltage limitations are for both minimum and maximum. If this requirement is kept, then “minimum” should be deleted. C. Is this requirement really looking at “voltage limits” or generator “reactive capability”? R3.3.3 - This requirement should be deleted. Each reliability issue should be addressed in one standard and relay loadability is addressed in PRC-023. If requirements of PRC-023 are met, the relay loadability does not constitute a limitation. If this requirement is intended to apply to modeling relay characteristics in stability simulations, which is not addressed by PRC-023, then the requirement should be more explicit. However, as written it appears that the intent was to be in-line with Blackout Recommendation 8a which relates to steady-state loadability, which is covered by PRC-023. R3.4 Comment - Table 1 includes both Steady State and Stability events. R3.4 needs to indicate that it only applies to the Steady State portion of the Table. R3.5 Priority Comment ?It is recommended that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences and the requirements are too vague to have auditable value. If the requirement is not deleted, the following is recommended:- Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events. If not, it will be difficult to utilize the results to obtain projects approvals.- It should be clear that an evaluation does not require solution development for all Extreme Events- Change “an evaluation of possible actions”? to “where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered. – The statement “and shall include an explanation of why the remaining Contingencies would produce less severe System results” is too open and should be deleted. Violation Severity Levels:R3.4 Since this is a binary requirement, should this have a Severe VSL? R3.5 Since this is a binary requirement, should this have a Severe VSL?
Response: R3: The SDT agrees that use of studies and analyses can be confusing and has changed the wording to provide greater clarity. **R3** For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, parts 2.1, and 2.2. The studies shall be based on computer simulation models using	

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	data provided in Requirement R1. R3.4: Requirement R3, part 3.4 has been revised to indicate that the Planning Coordinator/Transmission Planner is to produce a Contingency list, of those planning events that are expected to produce more severe results on its portion of the BES. The Planning Coordinator/Transmission Planner is required to identify the Contingency list to be studied and provide the rationale as to why these Contingencies are expected to produce more severe results. There is no requirement to include all BES facilities for P0 to P4. No change made. R3.1: The SDT has changed "lists" to "list". **R3.1** Studies shall be performed for Planning Events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4. R3.2: The SDT has revised the wording of the requirement. **R3.2** Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, part 3.5. R3.3.2: The SDT agrees that judgment is used today. There is a project (PRC-024) that will address this issue. The SDT has changed the wording to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and that they are being treated within the simulation as they will react in the real world. The word minimum was retained as the intent is to address low voltage ride through. No change made. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections. R3.4: Although Table 1 includes both steady state and stability events, Requirement R3 is "for the steady state portion of the Planning Assessment.."; so there is no need for adding further clarification in Requirement R3, part 3.4. No change made. R3.5: The SDT disagrees that the standard should mandate corrective actions for extreme events due to the low probability of these events. However, SDT believes that those extreme events that are expected to produce more serve System impacts should be analyzed to assess the extent of the impacts on the System to provide the PC/TP with information to decide, where appropriate, if it is reasonable to provide some corrective actions to reduce the possibility or limit the consequences of an extreme event. The need to identify possible actions addresses an Order 693 directive. Your suggested wording would make identification of possible actions optional. No change made. Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the Contingencies selected are those to produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining contingencies would produce less severe System results". **R3.4** Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. **R3.5** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed

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to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted. VSLs: The VSLs for Requirement R3, parts 3.4 & 3.5 are required elements of the primary requirement. The VSLs categorize noncompliance with the requirement, "in total" – not with each of the individual parts of the requirement. No change made.	
Entergy Services, Inc	In R3.5 what would constitute "an evaluation of possible actions designed to reduce?" R3 should be broken into two pieces where the near term portion could be a Medium VRF but the long term section should be a Low VRF. Violations occuring in the longer term horizon are subjective and assumptions concerning future plans too broad to justify a Medium VRF. In Requirement R3.1, it is suggested that the word "contingency" be added to describe the lists created in R3.4.
Response: R3.5: In the event that an extreme event causes cascading outages, the "possible actions" would be the possible actions that would reduce the likelihood or mitigate the consequences and adverse impacts of the event". VRF: The SDT believes that all of the steady state responses are equally important. No change made. R3.1: The SDT agrees and has revised the wording. **R3.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4.	
Great River Energy	R3.3.3 The relay loadability section needs better definition. Is this identifying that: if the relay load limit is the most Limiting Element of a transmission line how it would be handled if it is overloaded considering that there may be some margin before opening the line and/orif the line reaches a certain overload level based on a non-Relay Load Limit being the Most Limiting Element that the relay load limit should be analyzed to see if it will actually activate an opening of the transmission line or the planners need to review all of the relays associated with all transmission lines within the model and indicate if loadability is a concern for each contingency analyzed. There are a lot of lines, (probably the majority), that have not defined a relay capability within the rating fields of the model! This would seem to be a FAC-009 issue. As a discussion point on R3.3.3, it would seem that relay loadability should be addressed in FAC-009 and the Model Building process. Putting this burden in the planning assessment will be difficult to determine if the Most Limiting Element within the model is not a relay load limit as those parameters typically are not the Most Limiting Element. Every line in the model may need to be defined as to what its relay loadability is to meet this requirement. Our regional model build reports a Most Limiting Element, a short term emergency level, and a long-term emergency for the three ratings available within the model. It would seem that the long-term emergency field should be replaced with a Relay Load Limit value such that the R3.3.3 would not be as great of a burden on the planner.
BC Hydro	R3.3.3: Consider changing it to read, "Demonstrate that, for all Transmission lines, relay loadability standards are met in accordance with the PRC series of standards"
Response: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections and to	

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ensure relay loadability limits, as defined in the relay loadability standard, are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected.	
Midwest ISO	Opening Remarks. Specific Comments for Requirement 3:A) Under R3, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R3 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning". B) Under R3.1 the "Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the lists created in the Requirement 3.4". We believe that the following language will improve this requirement: Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the more severe contingency lists created in the Requirement 3.4. C) Under R3.3.2 the Midwest ISO generally agrees with FirstEnergy's comments on this. D) Under R3.3.3 the Midwest ISO feels that this sub-requirement is redundant with PRC-023-2 and therefore we feel that this sub-requirement needs to be removed and replaced with our suggested bullet language under R1.1.2 ? Relay Loadability Limitation (see F on page 3 of 9 above) E) Under R3.4 to make this requirement clearer, please add the following language between the words "expected to" in the first sentence: "expected by the assessing entity to" We believe that this language addition improves the clarity of this requirement. The first sentence would then read: Those Planning Event Contingencies in Table 1 that are expected by the assessing entity to produce more severe System impacts shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3.1 created. F) Under R3.5 to make this requirement clearer, please add the following language between the words "expected to" in the first sentence: "expected by the assessing entity to" We believe that this language addition improves the clarity of this requirement. The first sentence would then read: Those Extreme Events in Table 1 that are expected by the assessing entity to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3.2 created.
Response: The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made. **Mitigation Time Horizon** The time horizons available for mitigating a violation to a requirement include the following: • **Long-term Planning** — a planning horizon of one year or longer. • **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.	

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	• **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time. • **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system. • **Operations Assessment** — follow-up evaluations and reporting of real time operations. R3.1: The SDT has modified the requirement. **R3.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4. R3.3.2 The SDT has changed the wording to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections. **R3.3.3** Ensure relay loadability limits are respected. R3.4 & R3.5: The Planning Coordinator/Transmission Planner are the applicable entities for this standard, so adding "by the assessing entity" is redundant. No change made.
PJM	In R3, why require a Planning Coordinator AND a Transmission Planner to perform this analysis? Isn't this a duplication of effort? R3.4 should come before R3.1. You should never reference down in a standard. Please present the items in the order in which they should be performed/considered. R3.5 should come before R3.2. You should never reference down in a standard. Please present the items in the order in which they should be performed/considered. R3.3.2 should be broken into two requirements since two separate tasks need to be performed. R3.3.3 should be broken into two requirements since two separate tasks need to be performed. Also in R3.3.3, analysis of relay loadability will require the inclusion of all relay models 200 kV and above. This information is not presently gathered by the ERAG MMWG for the Eastern Interconnection. To help with compliance, questions R3.3.4 needs more specificity. Maybe define a minimum percentage of total possible contingencies as a bright line whether you have performed enough more severe contingencies. Would expect a number between 10 and 25 percent. R3.4 should be broken into two requirements since two separate tasks need to be performed. To help with compliance questions, R3.3.5 needs more specificity. Maybe define a minimum percentage of total possible contingencies as a bright line whether you have performed enough more severe extreme contingencies. Would expect a number

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	between 10 and 25 percent. R3.5 should be broken into three requirements since three separate tasks need to be performed.
Response: R3: The SDT believes that the requirement belongs to both the Planning Coordinator and the Transmission Planner. No change made. R3.4 & R3.5: The SDT disagrees. No change made. R3.3.2: The SDT sees this as only one requirement to identify how the generators are analyzed. No change made. R3.3.3: The SDT sees this as only one requirement to identify how the relay loadability is analyzed. No change made. R3.3.3: The SDT has clarified the requirement to ensure all relay loadability limits are respected in the analysis. R3.3.4: The number of Contingencies is system specific and any percentage that the SDT would establish would be wrong for some entities. No change made. R3.4: The SDT disagrees as the tasks are related. No change made. R3.3.5: The number of Contingencies is system specific and any percentage that the SDT would establish would be wrong for some entities. No change made R3.5: The SDT disagrees as the tasks are related. No change made.	
Brazos Electric Cooperative	R3.4 and 3.5 give us a concern. Table 1 identifies a number of events that are to be assessed but requiring an explanation of why certain events would produce less severe results seems to be open ended thus making it hard to audit. If all the events in Table 1 are studied or have been studied in the past then what is one supposed to document? we understand this is to allow the planner a certain amount of flexibility in their analysis but it seems counter to the idea of requiring a review of all the events in Table 1. We don't have any suggested wording changes, just passing along a general idea.
Response: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the contingencies selected are those that produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining Contingencies would produce less severe System results".	
American Electric Power	With regard to R3.3.3., please include transformers as relay loadability also applies to transformers.
Response: The SDT has clarified the requirement to ensure relay loadability limits are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected.	
ITC Holdings	Comments: If the SDT feels that a requirement such as R3.3.4 is necessary, it may also be necessary to identify further limitations on the use of the control devices referred to. For example, a manually controlled phase shifter would require a time period, or loading limits, to readjust flows to limit a post-contingency flow if not pre-set in the pre-contingency state. Similarly, a tap-changing transformer also requires an adjust period for voltage control. We suggest adding a statement to this requirement (or somewhere in performance requirements) that "all post-contingency flows/voltages must remain within the applicable facility ratings before,

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	during, and after the use of such control devices.
Response: The SDT has revised the requirement wording to clarify that the intent is to simulate automatic operation of existing and planned devices. **R3.3.4** Simulate the expected automatic operation of existing and planned devices designed to provide Steady State control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.	
Northern Indiana Public Service Company	R3.3.3: Evaluation of loadability should be triggered only for those circuits with new protection settings issued since the last assessment; evaluation of circuits that have not been newly assigned or re-assign protection settings is a misuse of resources.
Response: The SDT has clarified the requirement to ensure all relay loadability limits are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected.	
Minnesota Power	A) Under R3, the Time Horizon of the TPL standards is intended for years one through 10; however, the Time Horizon shown in R3 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning". B) R3.3.3 Is this sub-requirement redundant with PRC-023-2? Is it covered in FAC-009? We believe the SDT should review these standards and if it is a redundant requirement, then this sub-requirement needs to be removed. C) Under R3.4 to make this requirement clearer, please add the following language between the words "expected to" in the first sentence: "expected by the assessing entity to"? We believe that this language addition improves the clarity of this requirement. The first sentence would then read: "Those Planning Event Contingencies in Table 1 that are expected by the assessing entity to produce more severe System impacts shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3.1 created. D) Under R3.5 to make this requirement clearer, please add the following language between the words "expected to" in the first sentence so that the phrase reads: "expected by the assessing entity to"? We believe that this language addition improves the clarity of this requirement. The first sentence would then read: "Those Extreme Events in Table 1 that are expected by the assessing entity to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3.2 created.
Response: The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made. **Mitigation Time Horizon** The time horizons available for mitigating a violation to a requirement include the following:	

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• **Long-term Planning** — a planning horizon of one year or longer. • **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal. • **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time. • **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system. • **Operations Assessment** — follow-up evaluations and reporting of real time operations. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections. **R3.3.3** Ensure relay loadability limits are respected. R3.4& R3.5: The Planning Coordinator/Transmission Planer are the applicable entities, so adding "by the assessing entity" is redundant. No change made.	
LADWP	R3.4 This requirement is very strange. If there is a known planning event that is more severe than those listed in Table 1, it should be so identified in Table 1. It is not fair to ask every planner to search for more severe contingencies without any specifics. R3.4 should be deleted. R3.5 This is similar to R3.4; this requires proving of null set. The only way this requirement can be met is to perform an exhaustive and unlimited list of extreme event, real or imaginery, before a rationale can be rendered. This requirement should be deleted with the exception of the last sentence regarding "cascading outages.
Response: R3.4: Requirement R3.4 has been revised. The intent is not to identify additional Contingencies in addition to the planning events in Table 1, but to identify those Table 1 planning events that are expected to be more severe for your portion of the BES. Based on industry comments, the SDT has deleted the requirement to provide an explanation of "why the remaining Contingencies would produce less severe System performance". **R3.4** Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. R3.4 & R3.5: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the Contingencies selected are those that produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining Contingencies would produce less severe System results". **R3.5** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.	
Platte River Power Authority	R3.3.3. Zone 3 type relay loadability studies (single and multiple contingency analyses) should be performed in the OPERATING HORIZON to provide results flagged for possible problems to the Relay Engineers who will evaluate a relay setting change on an Facility or a modification to a relay setting for a new Facility about to be put in-service. I do not see the value of Zone 3 relay

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	loadability checks in the Planning Horizon.
Response: The SDT does not agree that relay loadability should be limited to the Operating Horizon. The SDT has clarified the requirement to ensure relay loadability limits are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected.	
MAPPCOR	R3.3.2 - Traditionally transmission planners have used their judgment about the minimum steady state voltage limitations of generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R3.3.3 - PRC-023 requires relay loadability to be reflected in facility ratings. Therefore this additional requirement is unnecessary and should be deleted. R3.4 is there a measure for what is a "more severe system impact"? R3.5 Recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following:-Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events-It should be clear that an evaluation does not require solution development for all Extreme Events-Change "an evaluation of possible actions"? to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered.
Response: R3.3.2: The SDT agrees that judgment is used today. There is a project (PRC-024) that will address this issue. The SDT has changed the wording to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections **R3.3.3** Ensure relay loadability limits are respected. R3.4: Requirement R3, part 3.4 requires the Planning Coordinator/Transmission Planner to prepare a list of planning event Contingencies that, in the Planning Coordinator's and Transmission Planner's judgment, are expected to produce more severe System impacts, and to document the rationale for the Contingencies selected. The documented rationale provided by the Planning Coordinator/Transmission Planner will define what is considered to be the more severe System impacts relative to the Contingencies not selected because they are expected to be less severe. No change made. R3.5: The SDT disagrees that the standard should mandate corrective actions for extreme events due to the low probability of these events. However, the SDT believes that those extreme events that are expected to produce more serve System impacts should be analyzed to assess the extent of the impacts on the System to provide the Planning Coordinator/Transmission Planner with information to decide, where appropriate, if it is reasonable to provide some corrective actions to reduce the possibility or limit the consequences of an extreme event. The need to identify possible actions addresses an Order 693 directive. Your suggested wording would	

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make identification of possible actions optional. No change made.	
Orlando Utilities Commission	For Requirement 3.3.1 and 3.3.4 I suggest adding language similar to 3.3.2 and 3.3.3 establishing that "studies shall consider" rather then requiring every simulation precisely recreate this usually minor part of system performance. These devices generally do not respond except for a nearby event, and even then their response is rarely such that it would make the situation "worse". The effect of these devices must be considered, but mandating that every simulation faithfully reproduce the response of every device is not only an efficient way to do this, it actually provides a counter incentive to going above and beyond the standard requirements. Any simulation used to meet this standard that failed to precisely reproduce the performance of this equipment would be a violation of this requirement (as currently written). As such there is no incentive for an entity to include anything but the absolute minimum number of simulations required to meet the standard, since each extra simulation represents an opportunity to miss this requirement. Good planning is based on running a broad range of events against a broad range of conditions and evaluating those responses against a set of performance criteria. This is encouraged by requiring that studies consider the response of equipment to these events rather then mandating their precise reproduction in simulation.
Response: R3.3.1: The SDT disagrees with the comment as the intent of Requirement R3, part 3.3.1, consistent with Order 693, is to perform the simulation to reflect how the Protection System will operate in the real System for each Contingency without operator intervention. No change made. R3.3.4: The SDT disagrees with your comment. The simulation of the expected operation of devices such as phase-shifting transformers, load tap changing transformers ,etc. impacts post-Contingency the performance of the System. No change made.	
American Transmission Company	We propose the following comments for R3.Revise the R3.3.2 text to clarify that subsequent analysis is performed on generators whose voltages are expected to fall below the minimum voltage limits. We suggest this text: Consider the minimum steady state voltage limitations of all generators and identify how generators with bus voltages below its minimum voltage limits are analyzed in the subsequent steady state simulations. Revise the R3.3.3 text to more clearly relate to the specific requirements in PRC-023. We suggest this text: "Incorporate relay loadability per PRC-023 and identify how relay loadability is analyzed in the steady state simulation. Add R3.3.5. The obligation to consider only planned System adjustments that are executable should be a Requirement, rather than performance note "e" in the Planning Events, Steady State & Stability section of Table 1. We suggest this text: "Consider planned System adjustments, such as Transmission configuration changes and redispatch of generation, that are executable within the time duration of the applicable Facility Ratings.
Response: R3.3.2: The SDT has changed the wording to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected.	

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R3.3: The SDT disagrees as such planned System adjustments are considered to be operator corrective actions as opposed to automatic actions considered in Requirement R3, part 3.3. No change made.	
Idaho Power	R3.3.2 is unclear as drafted. The minimum steady state voltage limitation for synchronous generators is not a very meaningful value. All generators with an automatic voltage regulator will maintain the set point voltage until the VAR capability of the generator is exceeded, and then the voltage will deteriorate. R3.5 -The requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study is overly burdensome. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. Listing all possible extreme events could result in a limitless list.
Response: R3.3.2: The SDT has changed the wording to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.5: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the Contingencies selected are those to produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining contingencies would produce less severe System results". **R3.5** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.	
New York Independent System Operator	R3.5. - The Extreme Events testing in Table 1 should be removed from this standard since there is no requirement to develop a Corrective Action Plan to address unacceptable consequences and the requirements are very general or vague. At a minimum, testing should only be required for EHV facilities or facilities specified by the Regional Entity ? for example, NPCC designates facilities that can have consequences outside an area as bulk power system facilities.
Response: R3.5: extreme events: The SDT disagrees that the standard should mandate corrective actions for extreme events due to the low probability of these events. However, SDT believes that those extreme events that are expected to produce more serve System impacts should be analyzed to assess the extent of the impacts on the System to provide the Planning Coordinator/Transmission Planner with information to decide, where appropriate, if it is reasonable to provide some corrective actions to reduce the possibility or limit the consequences of an extreme event. No change made.	
Duke Energy	Revise M3 to include a reference to R6, since the allocation of responsibilities will directly affect the evidence which is to be provided.
Response: M3: The SDT disagrees. Requirement R6 (now Requirement R7) is an overarching requirement that applies to the entire set of analysis required to meet	

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the requirements of the TPL standard and to the Corrective Action Plan developed as part of the assessment. The intent of this requirement is to clarify that TPL requirements can be met through joint or shared analysis. Coordinating and/or joint analysis does not alleviate the responsibility that all entities need to comply with the standard requirements. Therefore, the SDT sees no reason to link Requirement R3 directly to Requirement R6 (now Requirement R7) in the measure or anywhere else. The requirements stand by themselves and do not require such a linkage. No change made	
Independent Electricity System Operator	1. In our opinion, R3 as drafted is rather convoluted as it attempts to cover several objectives. Firstly, we recommend replacing "utilizing data in Requirement R1" with "developed in accordance with Requirement R1" both in the requirement and the VSLs. Secondly, is the main objective of R3 to ensure studies are conducted based on computer simulation utilizing data provided in Requirement R1? Or is it to ensure that this is done, and that all the other objectives are also fulfilled, for example: assessment of system performance (R3.1 and R3.5), conducting the analysis as specified in R3.2 and R3.3, identification of critical Planning Event contingencies (R3.4), etc. If it is the former, then not conducting studies based on computer simulation utilizing data provided in Requirement R1 alone should have a VSL of Severe. If it is the latter, then the requirement should be either: (a) Revised to place all supporting conditions in the subrequirements. As an example, R3 could be revised as follows:R3. The steady state analyses of the Near-Term and Long-Term Planning Assessment as stipulated in R2.1 and R2.2 shall be performed as follows:R3.1. Studies are conducted based on computer simulation utilizing data provided in Requirement R1;R3.2. Studies shall be performed to determine?. (the rest of the existing R3.1) R3.2. The existing R3.3, and so on.This way, not conducting studies based on computer simulation utilizing data provided in Requirement R1 will be "rolled up" to the VSLs for the main requirement, as is currently stated in the VSL table.Or(b) Restructure, if there are multiple main objectives in R3, to clearly have the main objectives in the main requirement, or split it into more than one main requirement.2. Based on the way R3 is written, we agree with the VRF, Time Horizon and Measure. However, we do have a difficulty with the VSL based on our comments above on the requirement, especially on the Moderate VSL for "The Transmission Planner or Planning Coordinator did not base its studies on computer simulations using models utilizing data provided in Requirement R1.
Response: Requirement R3 has been modified. **R3** For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. R3 is a single requirement and the SDT disagrees with the concept of splitting this up into separate requirements. No change made. The moderate VSL has been modified to align with the changes made to the wording of the requirement. **R3, moderate VSL**: The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.	
Kansas City Power & Light	R3.3.3: Relay loadability has no bearing beyond the near term horizon. Loadability is not determined several years out. R3.5 " does this imply that mitigation plans must be implemented" If not, then this is highly subjective and the last sentence of this requirement should be deleted.

Organization	Question 3 Comment
Response: R3.3.3 The SDT does not agree that relay loadability should be limited to the near term horizon. The SDT has clarified the requirement to ensure relay loadability limits, as defined in the relay loadability standard, are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected. R3.5: extreme events: The SDT disagrees that the standard should mandate corrective actions for extreme events due to the low probability of these events. However, SDT believes that those extreme events that are expected to produce more serve System impacts should be analyzed to assess the extent of the impacts on the System to provide the Planning Coordinator/Transmission Planner with information to decide, where appropriate, if it is reasonable to provide some corrective actions to reduce the possibility or limit the consequences of an extreme event.	
ReliabilityFirst Corporation	R3- Throughout this requirement there is a mention of developing a contingency table. It will be nice that such a table is developed under MOD-010 and MOD-012 standard. ERAG can develop such a list as part of their base case development effort. R3.3.3- Suggest changing it to read “For all Transmission lines, studies shall consider relay loadability, if that is the limiting factor for line loading.” R3.3.4 The term “expected operation” is vague. Some of these devices have relays which cause them to automatically respond to system changes, others are controlled by an operator. In both cases, the devices are “expected” to be utilized. Given that operator controlled devices are less certain to be utilized, and may be delayed in being utilized. The expected operation needs to be studied differently for automated devices and those requiring operator interventions.
Response: R3: Requirements R3.4 & R3.5 place the responsibility of creating planning event and extreme event Contingency lists on the applicable entities, the Planning Coordinator and the Transmission Planner as owners, operators or users of the BES. The SDT believes that requirement to develop these Contingency lists of planning and extreme events expected to produce the most severe results, and the rationale for the selection of these events, is best left to the Planning Coordinator/Transmission Planner responsible for its portion of the BES. However, the SDT does not believe that the standard would preclude ERAG from playing a role in the development of these Contingency lists; however, the compliance responsibility will fall to the Planning Coordinator/Transmission Planner. R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected. R3.3.4: The SDT agrees and has added automatic to the requirement. **R3.3.4** Simulate the expected automatic operation of existing and planned devices designed to provide Steady State control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.	

4. Requirement R4 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: The SDT has made numerous clarifying changes to the requirements due to industry comments. In addition, Requirement R4, part 4.3.3 has been added.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1.

4.1 Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, part 4.4.

4.2 Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, part 4.5.

4.3 Contingency analyses shall be performed and:

4.3.2 Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.3 Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers.

4.3.4 Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4 Those planning events in Table 1that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4, part 4.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1 The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5 Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R4, part 4.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

Footnote 2 Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.

R4 VSL	The responsible entity did not identify planning events as described in Requirement R4, part 4.4 or extreme events as	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine that the BES meets the

	described in Requirement R4, part 4.5.	that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, part 4.2 to assess the impact of extreme events. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.	that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, part 4.3.	performance requirements for three or more of the categories (P1 through P7) in Table 1.

Organization	Question 4 Comment
Dominion - Electric Transmission	R4.4 - Dominion believes that creating a master list of all contingencies a planner must take is burdensome and provides no planning value. In addition the contingencies will vary based on the loading configuration and the specific study case. In general, we start out with the very worst contingencies. If these cause hard rotor swings, we know we will probably have to do most of the possible contingencies in the station until we get down to contingencies that do not swing the generator much. But if the swings are light, then that particular load/topology situation probably does not need in-depth exploration. Creating a master list could create unnecessary study. However, we do support a list of the extreme contingencies in R4.5.
Response: Requirement R4, part R4.4 does not require a master list of all possible contingencies. The requirement is to create a list of those Contingencies expected to produce more severe results. There is nothing that prevents you from modifying the list based on simulation results (e.g., hard rotor swings). No change made.	
Northeast Power Coordinating Council	R4.3.2 - Traditionally transmission planners have assumed that generators would ride through low voltages associated with Planning Events which is generally adequate for non-wind generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R4.5 Priority Comment ?We recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following:- Extreme Event performance should be a consideration when developing Corrective Action Plans to

Organization	Question 4 Comment
	address Planning Events- It should be clear that an evaluation does not require solution development for all Extreme Events- Change “an evaluation of possible actions”? to “where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered. For Requirements R4.4 and R4.5, what defines “more severe System impacts”?
Response: R4.3.2: There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should just document your assumptions regarding ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. R4.5: The SDT considers extreme event testing to be an important part of the assessment and therefore will not delete it. The expectation for extreme event testing is that for major problems you will evaluate actions to reduce likelihood or mitigate consequences. The SDT believes the original words express this concept better than your suggested words. No change made. R4.4 and R4.5: The definition of "more severe impacts" is left to the engineering judgment of the Transmission Planner and Planning Coordinator.	
Transmission Planning	R4.3.2. COMMENT: The inability to survive a given low voltage transient is often dependent on motor performance within the generating facility’s auxiliary load distribution system and is not a specific relay setting. Determination of specific generating plant low voltage ride through capability requires extensive modeling of the plant distribution system and is outside the scope of this standard.
Response: R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require extensive modeling of a generating plant's distribution system. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.	
SERC Engineering Committee Planning Standards Subcommittee	R4.1:In Requirement R4.1, it is suggested that the word "contingency" be added to describe the lists created in R4.4?Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists created in Requirement R4.4. R4.4:Regarding Requirement R4.4, it is suggested that a rewording be considered such as described below:? For each category of the Planning Events in Table 1, those Planning Event Contingencies that are expected to produce more severe System impacts shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4.1 shall be created. The rationale for the Contingencies selected for evaluation shall be available as supporting information

Organization	Question 4 Comment
	with an explanation of why the remaining Contingencies would produce less severe System results. R4.3.2:R4.3.2 requires that voltage ride through capability be analyzed. It is not clear what should be analyzed (e.g. auxiliary loads, generator protection, generator capability, etc.) This requirement needs more clarity. Footnote #3:Footnote #3 needs to be revised to include 2LG faults in addition to 3-Phase faults indicating that the SLG criteria is met.
Response: R4.1: The SDT agrees and has added the word "Contingency". **4.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, part 4.4. R4.4: The SDT agrees and has modified the wording similar to your suggested wording, however - due to other stakeholder comments, the phrase requiring an explanation was deleted from the revised standard. **4.4** Those planning events in Table 1that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4, part 4.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require extensive modeling of a generating plant's distribution system. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. Footnote #3 (now footnote #2): The SDT agrees and has modified the wording similar to your suggested wording. **Footnote 2** Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.	
Modesto Irrigation District	Comments: We believe that R4.3.1-R4.3.3 should be bullets under R4.3
Response: R4.3.1-R4.3.3: The SDT disagrees as these are mandatory elements of the Contingency analyses. Bullets are only used to identify the possible, but not all inclusive, elements of a menu. No change made.	
OPUC	4. Requirement R4 ? Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement. Comments: A: R4.3 should be modified to become the requirement to conduct contingency analyses with R4.3.1 thru 3

Organization	Question 4 Comment
	presented as bullets there-under. B: R4.3.2 should clarify whether all relay protection must be modeled
Response: R4.3: The SDT disagrees as these are mandatory requirements of the Contingency analyses. Bullets are only used to identify the possible, but not all inclusive, elements of a menu. However, R4.3 has been modified to read more like a requirement as shown below. **4.3** Contingency analyses shall be performed and: R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require extensive modeling of all relay protection. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.	
Bonneville Power Administration	Requirement R4 should be consistent with R3. Suggested edit for R4. - "For the Stability portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term Transmission Planning Horizon studies in Requirement R2.4. The studies shall be based on computer simulations using models developed from the data provided in Requirement R1." R4.1 should be clarified consistent with comments to R3.1. Suggested clarification for R4.1 - "Studies shall be performed to determine whether the BES meets the performance requirements in Table 1. A reduced set of contingencies can be simulated based on a list created in requirement R4.4." As currently drafted, R4.3 is not a requirement. Without the statements in R4.3.1-R4.3.3, R4.3 is simply a phrase. Sub-Sub-Requirements R4.3.1 through R4.3.3 should be bullets under R4.3, with the language in R4.3 modified so that it becomes the requirement to conduct contingency analyses that address the three resulting bullets. R4.3.2 ? it is not clear what is required to be modeled. Typically a generator may have 10 or more protective relays. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to do that for all generators in the system. Requirement R4.4 also needs to be clarified as follows: R4.4 - "A reduced list of Contingencies can be developed for System Performance evaluation in Requirement R4.1 that includes those Planning Event Contingencies that are expected to produce more severe System impacts based on system performance as required in Table 1. R4.5 ? We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingency than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then

Organization	Question 4 Comment
	simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.

Response: The wording in Requirement R4 has been made identical to that in Requirement R3.

> **R4.** For the Stability portion of the Planning Assessment, as described in Requirement R2, parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1.

R4.1: The intent is to run the contingencies developed in Requirement R4, part 4.4, not a reduced set of them. No change made.

R4.3: The SDT disagrees as these are mandatory elements of the Contingency analyses. Bullets are only used to identify the possible, but not all inclusive, elements of a menu. However, Requirement R4, part 4.3 has been modified to read more like a requirement as shown below.

> **4.3** Contingency analyses shall be performed and:

R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require modeling of all relay protection. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4.3.2 to clarify this.

> **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

R4.4: The intent of Requirement R4, part 4.4 is to identify and develop a list of Contingencies to be run. Your proposed wording does not capture that intent. No change made.

R4.5: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining Contingencies would produce less severe System results".

MRO MRO NERC Standards Review Subcommittee	MRO NSRS proposes the following comments for R4:Add R4.3.3 text include relay loadability in the R4 (Stability) requirements to parallel R3.3.3 in the R3 (Steady State) requirement which would more clearly relate to the specific requirements in PRC-023. MRO NSRS suggests this text: "Incorporate relay loadability per PRC-023 and identify how relay loadability is analyzed in the dynamic simulation. In R4.3.4, MRO NSRS proposes limiting the scope to automatic devices and adding the notion of "including but not limited to". MRO NSRS suggests R4.3.4 text of: "Simulate the expected automatic operation of existing and planned control devices including but not limited to generation exciter control and power system stabilizers, static VAR compensators, power flow controllers, and DC Transmission controllers.

Response: R4.3: The SDT agrees with the general idea and has added Requirement R4, part 4.3.3. However, Requirement R4, part 4.3.3 requires that you "Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers" rather than creating a stability requirement for relay loadability. This requirement is more applicable to stability studies than a relay loadability requirement would be. Relay loadability is more of a steady state

Organization	Question 4 Comment
issue than a dynamic issue. **4.3.3** Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers. R4.3.4: The SDT has added the word "automatic" into Requirement R4, part 4.3.4 such that it now reads as follows: **4.3.4** Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.	
SERC Engineering Committee Reliability Review Subcommittee (RRS)	In R4, should the “and” in the first sentence actually be “or”?” Footnote #3 needs to be revised to include 2LG faults in addition to 3Phase faults indicating that the SLG criteria is met. In Requirement R4.1, it is suggested that the word "contingency" be added to describe the lists created in R4.4”Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists created in Requirement R4.4. ? Regarding Requirement R4.4, it is suggested that a rewording be considered such as the following: For each category of the Planning Events in Table 1, those Planning Event Contingencies that are expected to produce more severe System impacts shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4.1 shall be created. The rationale for the Contingencies selected for evaluation shall be available as supporting information with an explanation of why the remaining Contingencies would produce less severe System results. ? R4.3.2 requires that voltage ride through capability be analyzed. It is not clear what should be analyzed (e.g. auxiliary loads, generator protection, generator capability, etc.) This requirement needs more clarity. ? R4.3.2 ? By in large, the industry does not have the input data or the methods to do this. It would seem necessary to have PRC-024 approved before this can be met. In R4.3.2, need guidance on how to consider minimum steady state voltage limitations.
Response: R4: Requiring the Planning Coordinator AND the Transmission Planner to perform analysis should not result in a duplication of effort. Requirement R6 (now Requirement R7) requires the two entities to agree on their individual and joint responsibilities. The SDT believes that ‘AND’ is the proper word rather than ‘OR’. Using ‘OR’ could be interpreted by one entity as not applying to them. No change made. Footnote #3 (now footnote #2): The SDT agrees and has made the suggested change. **Footnote 2** Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. R4.1: The SDT agrees and has made the suggested change. **4.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, part 4.4.	

Organization	Question 4 Comment
R4.4: The SDT agrees and has made the suggested change however - due to other stakeholder comments, the phrase requiring an explanation was deleted from the revised standard. **4.4** Those planning events in Table 1that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4, part 4.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require modeling of all relay protection. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.	
FirstEnergy Corp	Specific comments, Requirements of R4:A. R4.1: A space is needed between the text "Requirement and R4.4" which are run together in the requirement. B. R4.3.3: For readability we suggest inserting the word "may" in between "devices include". We agree with the stated Measures, VRF, Time-Horizon, Data Retention and VSL of requirement R4
Response: R4.1: The SDT has corrected this problem. **4.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, part 4.4. R4.3.3: The SDT agrees and has made the suggested change. **4.3.4** Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.	
TVA System Planning	In R4, should the “and” in the first sentence actually be “or”? R4.3.2 requires that voltage ride through capability be analyzed. It is not clear what should be analyzed (e.g. auxiliary loads, generator protection, generator capability, etc.) This requirement needs more clarity. By in large, the industry does not have the input data or the methods to do this. It would seem necessary to have PRC-024 approved before this can be met.
Response: R4: Requiring the Planning Coordinator AND the Transmission Planner to perform analysis should not result in a duplication of effort. Requirement R6 (now Requirement R7) requires the two entities to agree on their individual and joint responsibilities. The SDT believes that ‘AND’ is the proper word rather than ‘OR’. Using OR could be interpreted by one entity as not applying to them. No change made. R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require modeling of	

Organization	Question 4 Comment
all relay protection. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.	
Exelon Transmission Planning	See comment in response to question 9 regarding the lack of definition related to the failure of a "single Protection System".
Response: See response to question 9 comment.	
Southern Company	Generating unit stability should be separated from system stability like in previous drafts. R4.2 and R4.5 are both addressing the extreme events. However, R4.2 is referring to R4.5 while R4.5 is referring to R4.2. We suggest deleting the reference back to R4.2 which is in R4.5. A similar situation exists for R4.1 and R4.4.
Response: The majority of the industry believes that there should be no distinction between generating unit stability and System Stability. No change made. R4.2, R4.5, R4.1, R4.4: The SDT does not see any harm in having the cross referencing. No change made.	
United Illuminating Northeast Utilities ISO New England, Inc. Central Maine Power Company	R4.3.2 Priority Comment - Traditionally transmission planners have assumed that generators would ride through low voltages associated with Planning Events which is generally adequate for non-wind generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R4.5 Priority Comment ?We recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following:- Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events- It should be clear that an evaluation does not require solution development for all Extreme Events- Change "an evaluation of possible actions"? to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered.
Response: R4.3.2: There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. R4.5: The SDT considers extreme event testing to be an important part of the assessment and therefore will not delete it. The expectation for extreme event testing is that for major problems you will evaluate actions to reduce likelihood or mitigate consequences. The SDT believes the original words express this concept better	

Organization	Question 4 Comment
than your suggested words. No change made.	
System Protection and Transmission Planning Department	Comments under R1 apply here as well. The requirement to "utiliz[e] data provided in Requirement R1" is redundant with MOD-012, and should be moved to MOD-012. To conform with R1, we suggest a phrase be inserted that requires model data used in Stability Studies used for Annual Assessments be consistent with data submitted under MOD-012.
Response: R4: MOD-012 does not require the data to be used for an assessment of the Transmission System. Therefore, the requirement to utilize data provided under Requirement R1 is needed in this standard. No change made. R4: Because Requirement R1 references the data provided under MOD-012, there is no need for a reference to MOD-012 in Requirement R4. No change made.	
PPL Energy Plus	It should be pointed out that Breaker Failure (i.e. fail to open) and Breaker Fault (internal fault in breaker) are two different events.
Response: Breaker failure and breaker fault are two different events and that is reflected by having two different designations for these events in Table 1 (P2.3 and P4). No change made.	
PacifiCorp Deseret Generation & Transmission SRP Arizona Public Service Co Southern California Edison Company Western Area Power Administration Pacific Gas and Electric Co, Puget Sound Energy, Inc. NV Energy San Diego Gas and Electric Co Tucson Electric Power Company	As currently drafted, R4.3 is not a requirement. Without the statements in R4.3.1-R4.3.3, R4.3 is simply a phrase. Sub-Sub-Requirements R4.3.1 through R4.3.3 should be bullets under R4.3, with the language in R4.3 modified so that it becomes the requirement to conduct contingency analyses that address the three resulting bullets. R4.3.2 - it is not clear what is required to be modeled. Typically a generator may have 10 or more protective relays. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to do that for all generators in the system. R4.5 ? We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingency than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.
NorthWestern Corporation NorthWestern Energy (NWE)	R4.3 is unclear. Requirements R4.3.1 through R4.3.3 should be bullets under R4.3, with R4.3 modified so that it becomes the requirement to conduct contingency analyses that address the three resulting bullets

Organization	Question 4 Comment
(NWMT)	R4.3.2 is unclear. It appears to be a broken sentence. Typically a generator may have 10 or more protective relays. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to do that for all generators in the system. It is our understanding that the voltage ride through standard is not complete at this time. R4.5 needs to be modified. It would be better to combine R4.2 and R4.5. The first part of the requirement requires identification of events that produce more severe System impacts. The presumed reason that the other contingencies were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be examples of more severe Extreme Contingencies than the one selected for study. This can be achieved by simply choosing events that are even less credible. For example, if the Extreme Contingency studied was a simultaneous loss of 3 transmission lines with the failure of redundant RAS (SPS), then an event resulting in the simultaneous loss of 4 lines with the failure of 2 sets of redundant RASs would be even more severe. Listing all possible extreme events could result in a limitless list.
Response: R4.3: The SDT disagrees as these are mandatory elements of the Contingency analyses. Bullets are only used to identify the possible, but not all inclusive, elements of a menu. However, Requirement R4, part 4.3 has been modified to read more like a requirement as shown below. **4.3** Contingency analyses shall be performed and: R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require modeling of all relay protection. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. R4.5: Several industry commenters have indicated that an explanation of “why the remaining Contingencies would produce less severe System performance” should be deleted since the contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an “explanation of why the remaining Contingencies would produce less severe System results”.	
Western Area Power Administration	R4.3.3 need not include the operation of exciters and power system stabilizers as modeling of these parts of a generation system is already covered in Mod-12 & Mod-13 Standards and therefore are inherent in the dynamic analysis conducted using a program such as the GE PSLF or PTI power system simulation programs.
Response: R4.3.3: MOD-012 and MOD-013 do not require the data to be used for an assessment of the Transmission System. Therefore, the requirement to simulate the operation of exciters and stabilizers is needed in this standard. No change made.	
Tampa Electric	Clarification needed on modeling of protection system equipment.
Response: Requirement R4, parts 4.3.1 and 4.3.2 do not require modeling of Protection System equipment. It just requires you to have simulations which include the effect of Protection System equipment operation. You don't have to specifically model a relay to simulate the effect of clearing a fault at 3 cycles. No change made.	

Organization	Question 4 Comment
Florida Reliability Coordinating Council, Inc - Transmission Working Group	R4.3.1 - Please clarify, is the intent of this requirement to have every relay modeled? We suggest clarifying that the intent is that Protection System Equipment would be incorporated into the contingency list, and that modeling the Protection System equipment settings and logic would only be done for Protection Systems that could significantly impact stability response (e.g., out-of-step relaying) as deemed appropriate through engineering judgment, and that the intent would be to do this only for the Region under study and not the entire Interconnection (e.g., studies in Florida should not need to include relays in Canada). R4.4 & R4.5 - Does the intent of allowing this "More severe events" to establish actual study parameter extend between the planned events and extreme events (e.g. if a range of extreme events establishes that planning events performance requirements are met, would a redundant analysis of the planning events still be required)
Response: Requirement R4, part 4.3.1 does not require modeling of Protection System equipment. It just requires you to have simulations which include the effects of Protection System equipment operation. You don't have to specifically model a relay to simulate the effect of clearing a fault at 3 cycles. If you need to model a relay to capture its effect, then model that relay. And certainly engineering judgment should be used to determine which relay effects should be included in the simulations. No change made. R4.4 and R4.5: You can always demonstrate that performance requirements are met by meeting them for a more severe Contingency. It is possible that you could demonstrate that performance requirements are met for planning events by performing extreme events (e.g., using a three-phase fault with stuck breaker Contingency can demonstrate that performance requirements for a single phase fault plus stuck breaker contingency is met). No change made.	
FMPA	R4.2, see comment on R3.3 concerning how to model a hurricane event or other weather event. R4.3, contingency analysis ought to specifically exclude studying contingencies on neighboring systems since stability is more related to protection system and clearing times. R4.3.1, please clarify, is the intent of this requirement to have every distance relay in each Interconnect modeled? We suggest clarifying that the intent is that Protection System Equipment would be incorporated into Facility Ratings and the contingency list, and that modeling the Protection System equipment settings and logic would only be done for Protection Systems that could significantly impact stability response (e.g., out-of-step relaying) as deemed appropriate through engineering judgment, and that the intent would be to do this only for the Region under study and not the entire Interconnection (e.g., studies in Florida should not need to include relay models in Canada). R4.3.2, we assume that the intent of this requirement would be to help establish the magnitude and duration of acceptable post-transient voltage dips, presumable to meet the curve published in the PRC-023 standard under draft. Is this a correct assumption? We assume the drafting team does not expect models to be written for every generator to actually model potential loss of station service due to voltage dips and automatically model potential generator trips. R4.4 and R4.5, see comments on R3.4 and R3.5 about re-arranging these requirements.
Response: R4.2: There are no hurricane events or weather events in the extreme events for stability analysis. No change made. R4.3: The SDT disagrees. There may be some contingencies on external systems which can have a dynamic impact on the system under study. Part 4.4.1 has been added to Requirement R4 to address this possibility.	

Organization	Question 4 Comment
4.4.1 The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. R4.3.1: Requirement R4, part 4.3.1 does not require modeling of Protection System equipment. It just requires you to have simulations which include the effects of Protection System equipment operation. Certainly engineering judgment should be used to determine which relay effects should be included in the simulations. No change made. R4.3.2: The intent of this requirement is to include in the Planning Assessment how voltage ride-through capability is analyzed in your studies. It does not require extensive modeling of a generating plant's distribution system. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the Planning Assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. R4 and R5: The SDT does not agree that the requirements should be re-ordered. No change made.	
MidAmerican Energy Company	MidAmerican commends the SDT for its hard work on this standard. MidAmerican suggests that R4.5 be revised by changing "remaining Contingencies" to "remaining unselected Contingencies.
Response: R4.5: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining Contingencies would produce less severe System results". **4.5** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R4, part 4.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.	
SMUD	R4.3:R4.3.2 - The requirement is unclear. If it is to cover modeling issues, then it should be under MOD series. If it is to cover voltage ride through performance, then performance metrics should be provided. R4.5Listing all possible scenarios for studying extreme contingencies will result in a limitless list. Discretion should be given to the transmission planner on the selection of the contingencies without a requirement to list why other extreme contingencies have not been included.
Response: R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require extensive modeling of a generating plant's distribution system. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this.	

Organization	Question 4 Comment
4.3.2 Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. R4.5: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining Contingencies would produce less severe System results".	
Progress Energy Florida, Inc.	For R4.3.2, PEF assumes that the SDT understands that the extent of analyzing generation voltage ride-through capability does not extend to modeling of individual inductive loads on the Distribution side, as this does not fit the definition of the BES. Motor loads on the Distribution system do have an effect on generation voltage ride-through capability, however, and PEF therefore is perplexed as to what extent the SDT expects concerning analysis for this sub-requirement.
Response: R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require extensive modeling of a generating plant's distribution system. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.	
Xcel Energy	R4.3 - requires very labor intensive and detailed studies to be conducted; there are concerns about being able to accomplish the required studies within the 24 month implementation period; additionally, while there may be some reliability benefit to requiring these studies, have the costs of this requirement been studied?; an alternative could be some sort of phased implementation (x% completed by 24months, etc.) R4.3.3 - to what degree is generator relaying factored into the model/study?
Response: R4.3: The SDT believes that 24 months is sufficient to perform the additional studies. No change made. R4.3.3: Generator relaying is not a part of Requirement R4, part 4.3.3.	
Ameren	In Requirement R4.1, it is suggested that the word "contingency" be added to describe the lists created in R4.4Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists created in Requirement R4.4. Regarding Requirement R4.4, it is suggested that a rewording be considered such as described below:For each category of the Planning Events in Table 1, those Planning Event Contingencies that are expected to produce more severe System impacts shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4.1 shall be created. The rationale for the Contingencies selected for evaluation shall be available as supporting information with an explanation of why the remaining Contingencies would produce less severe System results.

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	R4.3.2 requires that voltage ride through capability be analyzed. It is not clear what should be analyzed. e.g. auxiliary loads, generator protection, generator capability, etc. We would like to see more clarity on this requirement. It seems that the stuck breaker scenarios would always be more severe than the internal breaker failure scenario since they would be clearing in delayed clearing time and thus make P2.3 redundant. Are there is some question on whether P3 contingencies would be necessary for stability analysis. Revise wording in VSL from “categories” to “applicable categories”. e.g. some entities may not have common tower facilities and thus there would be no P7 category contingencies to evaluate. Footnote #3 needs to be revised to include Double-Line-To-Ground faults in addition to Three-Phase faults indicating that the SLG criteria is met.

Response: R4.1: The SDT agrees and has added the word "Contingency".

> **4.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, part 4.4.

R4.4: The SDT agrees and has modified the wording similar to your suggested wording however - due to other stakeholder comments, the phrase requiring an explanation was deleted from the revised standard.

> **4.4** Those planning events in Table 1that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4, part 4.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require extensive modeling of a generating plant's distribution system. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this.

> **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

Stuck breaker comment: A stuck breaker scenario would not always be more severe than an internal breaker fault. Depending on the location of CTs and PTs, an internal fault could take longer to clear.

P3 comment: Fault induced delayed voltage recovery simulations could be more severe in a Load area when a generator is out of service. Therefore, P3 events are applicable to Stability analysis.

VSL: The SDT does not believe it is necessary to add the word "applicable" in front of "categories" in the VSL for Requirement R4. The requirement in Part 4.1 is to study the list (Part 4.4) of "Those planning event Contingencies in Table 1 that are expected to produce more severe System impacts". If you have no applicable events in one of the categories, then just state that in the Planning Assessment. This will not be considered as not performing a study for one of the categories.

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R4 VSL	The responsible entity did not identify planning events as described in Requirement R4, part 4.4 or extreme events as described in Requirement R4, part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, part 4.2 to assess the impact of extreme events. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1.
Footnote #3 (now footnote #2): The SDT agrees and has modified the wording similar to your suggested wording. **Footnote 2** Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.				
Manitoba Hydro	R4.1: The requirement text should be changed to read “studies shall be performed for Planning Events to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists of events created in Requirement R4.4. R4.2: Requirement wording should be similar to R4.4 for consistency. R4.3: We agree that consideration of generator voltage ride through is important. However, we also suggest that frequency ride through capability be analyzed. R4.4 & R4.5: The selection of the contingency list is based on the knowledge of the PC/TP. How do you produce “an explanation of why the remaining Contingencies would produce less severe System results. without proving this with a study” If the explanation is “that based on engineering judgment, the remaining contingencies would produce less severe system results” then the explanation is implied and not necessary.			

Organization	Question 4 Comment
Response: R4.1: The SDT agrees and has changed the wording similar to your suggestion. **4.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, part 4.4. R4.2: The SDT does not understand this comment. No change made. R4.3: Frequency ride-through for generators would only be needed for a limited number of simulations, and therefore the SDT does not see the need to make a general requirement for this. No change made. R4.4 and R4.5: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining Contingencies would produce less severe System results".	
LCRA Transmission Services Corporation	In R4.3.3, what is meant by the term "electrical system quantities"? Quantities is typically an amount and its use here would indicate that a term such as parameters would be better suited.
Response: "Electrical system quantities" are items such as voltage, current, power, etc. The SDT believes the use of this term is appropriate in Requirement R4, part 4.3.3 (now 4.3.4). No change made.	
National Grid	R4 Comment " "Planning Assessment" and "shall perform analysis" are contradictory. R4 and its sub-requirements, then reference study requirements. If this is an assessment, then the standard shouldn't be requiring a study. R4.1 Comment ? A. It is not clear what should be included in the list related to R4.4. Events P0 through P4 should include analysis of all facilities BES facilities for which the Transmission Planner is responsible. Events P5 and higher should be limited to contingency events that are deemed the most significant by the Transmission Planner. B. R4.1 refers to "lists". Is R4.4 creating one list or multiple lists? Suggest changing "lists" to "list" R4.2 Comment - Since R4.4 and R4.5 both require the responsible entity to create a list, the words in R4.2 be should be revised to be more similar to the words in R4.1. Suggest changing "Studies shall be performed to assess the impact of the Extreme Events identified in Requirement R4.5. " to "Studies shall be performed to assess the impact of the Extreme Events, which are identified by the list created in Requirement R4.5. R4.3.2 Priority Comment - Traditionally transmission planners have assumed that generators would ride through low voltages associated with Planning Events which is generally adequate for non-wind generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R4.5 Priority Comment ?It is recommended that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. If the requirement is not deleted, the following is recommended:- Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events. If not, it will be difficult to utilize the results to obtain projects approvals.- It should be clear that an evaluation does not require solution development for all Extreme Events- Change "an evaluation of possible

Organization	Question 4 Comment
	actions"? to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered. - The statement "and shall include an explanation of why the remaining Contingencies would produce less severe System results" is too open and should be deleted. Violation Severity Levels:R4.4 Since this is a binary requirement, should this have a Severe VS? R4.5 Since this is a binary requirement, should this have a Severe VSL?
Response: R4: The SDT does not see a contradiction. Requirement R4 is a study requirement. The assessment requirement for stability is Requirement R2, part 2.4 and requires the use of current or past studies. No change made. R4.1A: The SDT disagrees. P1 - P4 (P0 not applicable to Stability) should be run for those Contingencies expected to produce more severe results. It is not necessary to study faults on every line in the System. No change made. R4.1B: The SDT agrees and has changed "lists" to "list". **4.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, part 4.4. R4.2: The SDT agrees and has changed to your suggested wording. **4.2** Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, part 4.5. R4.3.2: There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. R4.5: The SDT considers extreme event testing to be an important part of the assessment and therefore will not delete it. The expectation for extreme event testing is that for major problems you will evaluate actions to reduce likelihood or mitigate consequences. The SDT believes the original words express this concept better than your suggested words. No change made. R4.4 and R4.5 VSLs: The VSLs are based on taking Requirement R4 as a whole with Requirement R4, parts 4.4 and 4.5 being portions of that whole. The SDT does not think that failing to create a list of Contingencies should be a severe violation. When taking Requirement R4 as a whole, failing to create the list was deemed to be lower violations. No change made.	
Entergy Services, Inc	In R4.5 what would constitute "an evaluation of possible actions designed to reduce?"? R4.3.2 requires that voltage ride through capability be analyzed. It is not clear what should be analyzed (e.g. auxiliary loads, generator protection, generator capability, etc.) This requirement needs more clarity. " R4.3.2 " By in large, the industry does not have the input data or the methods to do this. It would seem necessary to have PRC-024 approved before this can be met.

Organization	Question 4 Comment
Response: R4.5: "An evaluation of actions designed to reduce" means looking for ways to reduce the probability of the event occurring or reducing the magnitude of the consequences of that event. For example, if a three phase fault with a bus differential failing to operate results in the collapse of a large Load area, a possible action would be to add a redundant bus differential relay. This reduces the probability of the event occurring. Or if a three phase fault with a stuck breaker results in a large area of the system pulling out of synchronism, an SPS could be used to trip a generator and keep the rest of the system in synchronism. This would reduce the magnitude of the consequences of the event. The evaluation would be comparing potential solutions and their cost with the consequences of the event to determine the best course of action to take (if any). R4.3.2: There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.	
BC Hydro	Comments: Consider changing R4.3.2 to, “Confirm proper generator performance under anticipated conditions including low voltage ride-through capability” In R4.3.3, change “VAR” to “var”. The IEC has adopted the name var, var (volt ampere reactive power), for the coherent SI unit volt ampere for reactive power. (see: http://www.iec.ch/zone/si/si_elecmag.htm#si_rpo). Is there an overlap between R4.3.3 and the MOD standards? If so, perhaps R4.3.3 should be deleted. If not, perhaps the MOD standard should be expanded to include this. Consider adding R4.3.4, “not simulate any operator intervention”
Response: R4.3.2: The SDT has changed the wording of Requirement R4, part 4.3.2 for additional clarification. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. R4.3.3: The SDT agrees and has changed "VAR" to "var". **4.3.4** Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers. R4.3.3: MOD-012 and MOD-013 do not require the data to be used for an assessment of the Transmission System. Therefore, the requirement to simulate the operation of exciters and stabilizers is needed in this standard. No change made. R4.3.4: The SDT does not think it is necessary to add "not simulate any operator intervention". If operator intervention is appropriate in the time frame of the study, then simulate it. No change made.	
Midwest ISO	Opening Remarks. Specific Comments for Requirement 4:

Organization	Question 4 Comment
	A) Under R4, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R4 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning".
Minnesota Power	Under R4, the Time Horizon of the TPL standards is intended for years one through 10; however, the Time Horizon shown in R4 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning".

Response: The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made.

Mitigation Time Horizon

The time horizons available for mitigating a violation to a requirement include the following:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

PJM	In R4, why require a Planning Coordinator AND a Transmission Planner to perform this analysis? Isn't this a duplication of effort? R4.4 should come before R4.1. You should never reference down in a standard. Please present the items in the order in which they should be performed/considered. Also in R4.1, a space is needed between "Requirement" and -R4.4-. R4.5 should come before R4.2. You should never reference down in a standard. Please present the items in the order in which they should be performed/considered. In R4.2.3, I question whether the existing dynamics models can evaluate voltage ride through. If you are just talking about modeling voltage protection of generators then maybe, but this protection information is presently not collected by the ERAG MMWG for the Eastern Interconnection. R4.4 should be broken into two requirements since two separate tasks need to be performed. R4.5 should be broken into three requirements since three separate tasks need to be performed.

Organization	Question 4 Comment
Response: R4: Requiring the Planning Coordinator AND the Transmission Planner to perform analysis should not result in a duplication of effort. Requirement R6 (now Requirement R7) requires the two entities to agree on their individual and joint responsibilities. No change made. R4.4 & R4.5: The SDT does not believe that re-ordering the requirements serves any purpose. No change made. R4.1: The SDT has revised the requirement. **4.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, part 4.4. R4.2.3: The SDT assumes you meant Requirement R4.3.2: There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. R4.4: The SDT disagrees that this requirement should be broken into two requirements. There are not two independent tasks in the requirement. The tasks are inherently correlated and will be assessed as part of the primary Requirement R4. No change made. R4.5: The SDT disagrees that this requirement should be broken into three requirements. There are not three independent tasks in the requirement. The tasks are inherently correlated and will be assessed as part of the primary Requirement R4. No change made.	
Brazos Electric Cooperative	Same general comment in 4.4 and 4.5 about the requirement to maintain documentation on why certain events would produce less severe results.
Response: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining Contingencies would produce less severe System results".	
American Electric Power	The cross-referencing between R4.1 and R4.4, and between R4.2 and R4.5, seems to add unnecessary complexity and could be eliminated by merging each of these pairs of sub-requirements. Under the event column of Table 1 of the proposed TPL standard, considering entries P3 and P6, the option to apply either SLG or 3-phase fault types should be retained to be consistent with the existing TPL standards, which permit either SLG or 3-phase faults (see existing Table 1, Category B and Category C3). If the SDT decides not to make the requested change, then the SDT should give recognition to the unique characteristics of 765 kV lines where permanent 3-phase faults are virtually non-existent. AEP's 765 kV transmission facilities have been successfully planned and operated with only a SLG fault criterion. Therefore, Table 1 Planning Events P3 and P6 should permit application of SLG faults.
Response: The SDT does not see any harm in having the cross referencing. No change made.	

Organization	Question 4 Comment
Table 1: Requirement R1.3.1 in TPL-002-0a states that simulations should "Be performed and evaluated only for those Category B Contingencies that would produce the more severe System results or impacts." The SDT believes that the intent of the existing TPL standards is to simulate the worst case whether three phase or single-line-to-ground. The new standard is clarifying that three-phase is required for single Contingency events. No change made. Note that AEP may request an entity variance from this part of the standard.	
ITC Holdings	Comments: In R2.5.1, a limitation is identified for stability studies that are used to support the annual assessment be less than five calendar years old. Should this reference be included in R4??
Response: R4: Because the five year limitation is stated in Requirement R2, part 2.5.1, there is no need to repeat it in Requirement R4. No change made.	
LADWP	R4.5 See coments on R3.4 and 3.5
Response: See response to comments for Requirement R3, parts 3.4 and 3.5.	
Platte River Power Authority	R4.3.2. Delete this requirement as it is covered under MOD-013-1, R1.2 for RRO Dynamics Data requirements. When the generator is modeled accordingly the generator's performance will be simulated and analyzed in the stability studies. R4.3.3. Delete this requirement as it is covered under MOD-013-1, R1.2 and R1.3 for RRO Dynamics Data requirements. When the generator is modeled accordingly the generator's performance will be simulated and analyzed in the stability studies.
Response: R4.3.2: The SDT has changed the wording of Requirement R4, part 4.3.2 for additional clarification. This does not require the modeling of generator relays although that is one method that could be used to meet the requirement. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. R4.3.3: MOD-013 does not require the data to be used for an assessment of the Transmission System. Therefore, the requirement to simulate the operation of exciters and stabilizers is needed in this standard. No change made.	
MAPPCOR	R4.3.2 - Traditionally transmission planners have assumed that generators would ride through low voltages associated with Planning Events which is generally adequate for non-wind generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R4.5 -Recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following:-Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events-It should be clear that an evaluation does not require solution development for all Extreme Events-Change “an evaluation of possible actions”? to “where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered.

Organization	Question 4 Comment
Response: R4.3.2: There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. R4.5: The SDT considers extreme event testing to be an important part of the assessment and therefore will not delete it. The expectation for extreme event testing is that for major problems you will evaluate actions to reduce likelihood or mitigate consequences. The SDT believes the original words express this concept better than your suggested words. No change made.	
Orlando Utilities Commission	For Requirement 4.3.1 and 4.3.3 I suggest adding language similar to 3.3.2 and 3.3.3 establishing that "studies shall consider" rather then requiring every simulation precisely recreate this usually minor part of system performance. These devices generally do not respond except for a nearby event, and even then their response is rarely such that it would make the situation "worse". The effect of these devices must be considered, but mandating that every simulation faithfully reproduce the response of every device is not only an efficient way to do this, it actually provides a counter incentive to going above and beyond the standard requirements. Any simulation used to meet this standard that failed to precisely reproduce the performance of this equipment would be a violation of this requirement (as currently written). As such there is no incentive for an entity to include anything but the absolute minimum number of simulations required to meet the standard, since each extra simulation represents an opportunity to miss this requirement. Good planning is based on running a broad range of events against a broad range of conditions and evaluating those responses against a set of performance criteria. This is encouraged by requiring that studies consider the response of equipment to these events rather then mandating their precise reproduction in simulation. Requirement 4.4 and 4.5 establish that only those events that would cause the most severe system impacts should be studied. This is an excellent requirement since it focuses the large resource requirement in performing these studies on the events that will provide the best information. Does the intent of the "More severe events" to establish actual study parameter extend between the planned events (R4.4) and extreme events (R4.5)? Or phrased another way, if an entity selects a proper range of extreme events and establishes that planning event performance requirements are met, could that be used as evidence that R4.4 is met as well, or would R4.4 require the same conditions be reproduced in their less severe configuration.
Response: R4.3.1: The SDT believes you should simulate the removal of System elements that Protection System and other controls would remove, not just consider it. No change made. R4.3.3 (now Part 4.3.4): The SDT has clarified that the devices to be included in the study which provide dynamic control are those that impact the study area. R4.4 and R4.5: You can always demonstrate that performance requirements are met by meeting them for a more severe Contingency. It is possible that you could demonstrate that performance requirements are met for planning events by performing extreme events (e.g., using a three-phase fault with stuck breaker Contingency can demonstrate that performance requirements for a single phase fault plus stuck breaker Contingency is met).	
American Transmission	We propose the following comments for R4:Add R4.3.3 text to include relay loadability in the R4 (Stability) requirements to

Organization	Question 4 Comment
Company	parallel R3.3.3 in the R3 (Steady State) requirement which would more clearly relate to the specific requirements in PRC-023. We suggest this text: "Incorporate relay loadability per PRC-023 and identify how relay loadability is analyzed in the dynamic simulation. In R4.3.4, we propose limiting the scope to automatic devices and adding the notion of "including but not limited to". We suggest R4.3.4 text of: "Simulate the expected automatic operation of existing and planned control devices including but not limited to generation exciter control and power system stabilizers, static VAR compensators, power flow controllers, and DC Transmission controllers. Add R4.3.5. The obligation to consider only planned System adjustments that are executable should be a Requirement, rather than performance note "e" in the Planning Events, Steady State & Stability section of Table 1. We suggest this text that matches R3.3.5: "Consider planned System adjustments, such as Transmission configuration changes and redispatch of generation, that are executable within the time duration of the applicable Facility Ratings.
Response: R4.3.3: The SDT agrees with the general idea and has added Requirement R4, part 4.3.3. However, Requirement R4, part 4.3.3 requires that you "Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers" rather than creating a Stability requirement for relay loadability. This requirement is more applicable to Stability studies than a relay loadability requirement would be. Relay loadability is more of a steady state issue than a dynamic issue. **4.3.3** Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers. R4.3.4: The SDT has made the suggested changes. **4.3.4** Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers. R4.3.5: Header note 'e' gives permission to use System adjustments under certain conditions. This is not a requirement and doesn't need to be included in Requirement R4. No change made.	
Idaho Power	R4.3.2 Generation protection system contain up to a dozen tripping functions functions. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to do that for all generators in the system.R4.5 ? Again I disagree with this requirement. It is the same as R3.5 and overly burdensome.
Response: R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require extensive modeling of all relay protection. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.	

Organization	Question 4 Comment
Duke Energy	Revise M4 to include a reference to R6, since the allocation of responsibilities will directly affect the evidence which is to be provided.
Response: M4: The SDT disagrees. No change made.	
California ISO	As currently drafted, R4.3 is not a requirement. Without the statements in R4.3.1-R4.3.3, R4.3 is simply a phrase. Sub-Sub-Requirements R4.3.1 through R4.3.3 should be bullets under R4.3, with the language in R4.3 modified so that it becomes the requirement to conduct contingency analyses that address the three resulting bullets. R4.3.2 it is not clear what is required to be modeled. Typically a generator may have 10 or more protective relays. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to do that for all generators in the system. R4.5 We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingency than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.

Response: R4.3: The SDT disagrees as these are mandatory elements of the Contingency analyses. Bullets are only used to identify the possible, but not all inclusive, elements of a menu. However, Requirement R4, part 4.3 has been modified to read more like a requirement as shown below.

> **4.3** Contingency analyses shall be performed and:

R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require modeling of all relay protection. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this.

> **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

R4.5: Several industry commenters have indicated that an explanation of “why the remaining Contingencies would produce less severe System performance” should be deleted since the Contingencies selected are those that produce more severe System performance. The SDT agrees and has deleted the requirement for an “explanation of why the remaining Contingencies would produce less severe System results”.

> **4.5** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R4, part 4.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

Organization	Question 4 Comment
Independent Electricity System Operator	. Same comments as in R3, above, except our proposed wording on R4 will read:R4. The Stability analyses of the Near-Term Planning Assessment as stipulated in R2.4.2 shall be performed as follows:. since there are no detailed requirements stipulated for Stability analysis portion for the Long-Term Planning Assessment. However, the main requirement contains a condition for performing the Contingency analyses listed in Table 1. First of all, there are no VSLs for failing to meet this condition. Secondly, this duplicates with some of the subrequirements, e.g. R4.4, R4.5. Suggest to remove this condition from the main requirement. If the main requirement is to be revised in a similar fashion as suggested for R3, then this will become a non-issue. 2. Similar to R3, we agree with the VRF, Time Horizon and Measure for R4. However, we do have the same difficulty with the VSL based on our comments on the convoluted nature of the requirement as indicated above, especially on the Moderate VSL for The Transmission Planner or Planning Coordinator did not base its studies on computer simulations using models utilizing data provided in Requirement R1.
Response: R4: The SDT does not see any need for Requirement R4 to reference back to Requirement R2, part 2.4. No change made. R4 VSL: (1) The VSL for Requirement R4 does cover failing to perform the Contingency analysis in Table 1. Depending on how many Contingency categories are not addressed, the violation could be moderate, high, or severe. No change made. R4 VSL: (2) Requirement R4 provides the general requirement to perform the Contingency analysis in Table 1. The parts like Requirement R4, part 4.4 provide more details on what must be run. There is no duplication. No change made. R4.5: The SDT believes that Requirement R4, part 4.5 is a necessary part. No change made. R4 VSL: The SDT disagrees with this idea. No change made.	
Kansas City Power & Light	R4.3 requires very labor intensive and detailed studies to be conducted; there are concerns about being able to accomplish the required studies within the 24 month implementation period; additionally, while there may be some reliability benefit to requiring these studies have the costs of this reliability increase been studied?; an alternative could be some sort of phased implementation (x% completed by 24months, etc.) R4.3.3 to what degree is generator relaying factored into the model/study?
Response: R4.3: The SDT believes that 24 months is sufficient to perform the additional studies. No change made. R4.3.3: Generator relaying is not a part of Requirement R4, part 4.3.3.	
ReliabilityFirst Corporation	R4.3.2 – Requires simulating generator voltage ride through capability. This may require modeling generator protection schemes to existing Dynamic models. This falls under which again falls under Section 1600 of NERC Rules of Procedure.
Response: R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require modeling of generator protection schemes. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information	

Organization	Question 4 Comment
about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.	

5. Requirement R5 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: In response to industry comments, the SDT has deleted the word 'proxy' in favor of the terminology 'criteria or methodology' in Requirement R5 (now Requirement R6).

R6. Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, any criteria or methodology used in its analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.

Organization	Question 5 Comment
Dominion - Electric Transmission Tucson Electric Power Company	Use of Proxies: There is no requirement that the Planning Coordinator (PC) must use the same proxies as the Transmission Planner (TP). Since differences in proxy assumptions may lead to different study results, R5 should be revised to require the PC and TP to coordinate the use of proxies.
Hydro-Québec TransEnergie (HQT)	There is no requirement that the Planning Coordinator must use the same proxies as the Transmission Planner. Differences in proxy assumptions may lead to different study results. R5 needs to be modified to require coordination of proxies between Planning Coordinators and Transmission Planners.
Response: Criteria or methodologies will be fleshed out in peer review. No change made.	
OPUC	MRO NSRS proposes specifying that the proxy documentation be included in the Planning Assessment and add the rationale for the proxy. MRO NSRS suggests this text: "Each Transmission Planner and Planning Coordinator shall document within the Planning Assessment any proxies used in the analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding. The documentation will consist of the definition of each proxy used and the rationale for the proxies.
Response: The SDT has revised the requirement language to provide greater clarity as to the intent. **R6.** Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, any criteria or methodology used in its analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.	
Bonneville Power Administration	There is no requirement that the Planning Coordinator (PC) must use the same proxies as the Transmission Planner (TP). Since differences in proxy assumptions may lead to different study results, R5 should be revised to require the PC and TP to coordinate the use of proxies. M5 doesn't make any sense. Need to revise this Measure so that it fits the Requirement R5. Also need to revise the Data Retention discussion in Section 1.4 to align with R5. In the VSL associated with R5, we believe that failure to define and document one of the proxies should be a moderate VSL,

Organization	Question 5 Comment
	failure to define and document two proxies should me a high VSL, while failure to define and document three proxies should be a severe VSL. Otherwise failing to document only one proxy would result in a severe VSL.
Response: Criteria or methodologies will be fleshed out in peer review. The SDT has changed the language of Requirement R6 (formerly Requirement R5). **R6.** Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, any criteria or methodology used in its analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding. The SDT does not agree and believes that the Measure appropriately addresses Requirement R6 (formerly Requirement R5). No change made. The SDT does not agree and believes that the Data Retention for this Requirement is in line with accepted Guidelines. No change made. The SDT appreciates your comment on the level of severity for this Requirement but still believes this is the appropriate level to apply. No change made.	
MRO MRO NERC Standards Review Subcommittee	We agree with the stated Requirement, Measure, VRF, Time-Horizon, Data Retention and VSL of requirement R5.
PacifiCorp	None - no concerns identified by the TWG
JEA	PEF does not presently have any concerns with R5.
Central Maine Power Company	We agree with the requirement, the VRF, Time Horizon, Measure and VSLs.
Response: Thank you for your response. However, due to other responses, some changes have been made. Please see the summary response.	
SRP	In R5 the term “proxy” needs to be defined. In addition, an example of a proxy should be given.
Gainesville Regional Utilities	R5:Guidelines for identifying proxies for unstable conditions would be helpful.
Progress Energy Florida, Inc.	The term proxy is unclear. Please provide an example or an explanation of proxy. If this is related to Note “i” in Table 1, it should be so stated. If it is related to assumptions or criteria, please state so.
Xcel Energy	Please clearify "Proxies"
Mississippi Delta Energy Agency	The term proxy is unclear. Please provide an example or an explanation of proxy. Perhaps a different term, such as metric, may better describe this requirement to more people.
Tenaska, Inc.	In R5, what is meant by the term “any proxies”? Please clarify. This comment also pertains to this terms use in the VSL as well.

Organization	Question 5 Comment
Manitoba Hydro	It is unclear as to what is meant by the term “proxy used in the analysis” used in this requirement. Is a “proxy” a “criteria”?
National Grid	Comments: The meaning of the word “proxies” in this context seems uncommon making the requirement unclear. Perhaps “proxies” should be replaced with “criteria” or “criteria or proxies”.
Northern Indiana Public Service Company	What is a proxy as related to transmission planning? The drafting team should not introduce "non-standard" terms in a Standard document.
San Diego Gas and Electric Co	R5. For clarification, please list examples of "proxies" that might be used.
Minnesota Power	an example of proxy may be helpful, not all entities use proxies.
ISO New England, Inc. Western Area Power Administration American Electric Power Great River Energy New York Independent System Operator Modesto Irrigation District Louisiana Energy and Power Authority City Utilities of Springfield, MO Duke Energy New Brunswick System Operator MidAmerican Energy Company	The term proxy is unclear. Please provide an example or an explanation of proxy.
California ISO NorthWestern Corporation NorthWestern Energy (NWE) (NWMT)	The term “proxies” is somewhat confusing; recommend the use of “assumptions” if that is an acceptable substitute.
Independent Electricity System	On page 13 under Section R5, can the term “proxies” be defined and clarified, and examples given, in this context ?

Organization	Question 5 Comment
Operator Northeast Power Coordinating Council	
Kansas City Power & Light	5. Requirement R5 Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.Comments:A: An example should be added for proxy use.
IRC Standards Review Committee	We recommend using an alternate term for proxies such as criteria, guidelines, etc. to clarify what is meant.
Pepco Holdings, Inc. - Affiliates	We recommend that the word “proxies” be changed to “criteria”.
Transmission Planning	5. Requirement R5 Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.Comments:A: An example should be added for proxy use.
TVA System Planning	It is unclear as to what is meant by the term “proxy used in the analysis” used in this requirement. Does this mean Planning Coordinator established practices, thresholds or guidelines used to gauge when simulations suggest an event such as cascading outages occurs? If so the language should state: R5. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, when established practices, thresholds or guidelines identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.
United Illuminating	Please clarify how the term “Proxies” is used in this requirement.
PPL Energy Plus	Please define the term "proxies".
CPS Energy	Comments: It is unclear as to what is meant by the term “proxy used in the analysis” as it is used in this requirement. Does this mean Planning Coordinator established practices, thresholds, or guidelines used to gauge when simulations suggest an event such as cascading outages occurs? If so the language should state: R5. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, when established practices, thresholds or guidelines identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.
Response: The SDT agrees with this comment and has changed the Requirement language to provide clarity as to intent. **R6.** Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, any criteria or methodology used in its analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.	
SERC Engineering Committee	In the VSL associated with R5, we believe that failure to define and document one of the proxies should be a moderate VSL,

Organization	Question 5 Comment
Reliability Review Subcommittee (RRS)	failure to define and document two proxies should me a high VSL, while failure to define and document three proxies should be a severe VSL. Otherwise failing to document only one proxy would result in a severe VSL. The word "proxies" in this context is confusing and subject to various interpretations. Recommend changing the word "proxies" to "criteria. There is no requirement that the Planning Coordinator (PC) must use the same proxies as the Transmission Planner (TP). Since differences in proxy assumptions may lead to different study results, R5 should be revised to require the PC and TP to coordinate the use of proxies.
Response: The SDT appreciates your comment on the level of severity for this Requirement but still believes this is the appropriate level to apply. No change made. The SDT agrees with this comment and has changed the Requirement language to provide clarity as to intent. **R6.** Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, any criteria or methodology used in its analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding. The SDT does not see the need for a requirement to coordinate the use of proxies. No change made.	
FirstEnergy Corp	The determination of a failure to document a single proxy should not be categorized as "severe".
Response: The SDT appreciates your comment on the level of severity for this Requirement but still believes this is the appropriate level to apply. No change made.	
Southern Company	"Proxies" is not defined. We take "proxy" to mean a procedure used to model system response that is outside the capability of system modeling tools used in the analysis. For example, a powerflow model might not be able to model cascading events with built-in capabilities. As a proxy, the engineer would run follow-up studies that would mimic expected system response. Please define the term "proxy".
SMUD	It is unclear as to what is meant by the term "proxy used in the analysis" used in this requirement. Does this mean Planning Coordinator established practices, thresholds or guidelines used to gauge when simulations suggest an event such as cascading outages occurs? If so the language should state: R5. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, when established practices, thresholds or guidelines identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.
Platte River Power Authority	We propose specifying that the proxy documentation be included in the Planning Assessment and add the rationale for the proxy. We suggest this text: "Each Transmission Planner and Planning Coordinator shall document within the Planning Assessment any proxies used in the analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding. The documentation will consist of the definition of each proxy used and the rationale for the proxies.

Organization	Question 5 Comment
Turlock Irrigation District	Comments: It is unclear as to what is meant by the term "proxy used in the analysis" used in this requirement. Does this mean Planning Coordinator established practices, thresholds or guidelines used to gauge when simulations suggest an event such as cascading outages occurs? If so the language should state: R5. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, when established practices, thresholds or guidelines identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.
Response: The SDT agrees with this comment and has changed the Requirement language to provide clarity as to intent. **R6.** Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, any criteria or methodology used in its analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.	
Deseret Generation & Transmission	Please provide a definition of "cascading outages" since the FERC and NERC removed their approval of the definition. Or use the definition of "cascading" found in the NERC Glossary of Terms. This term is also used in R3.5, R4.5, and Table 1.a. without any definition provided. NOTE: On December 27,2007, the Federal Energy Regulatory Commission remanded the definition of" Cascading Outage" to NERC. On February 12, 2008, the NERC Board of Trustees withdrew its November 1, 2006 approval of that definition, without prejudice to the ongoing work of the FACstandards drafting team and the revised standards that are developed through the standardsdevelopment process. Therefore, the definition is no longer in effect. Please provide a definition of "voltage instability" since the NERC Glossary of Terms does not provide one. This term is also used in Table 1.a. without any definition provided. Please provide a definition of "uncontrolled islanding" since the NERC Glossary of Terms does not provide one. This term is also used in Table 1.a. without any definition provided.
Response: The SDT declines to provide definitions for the indicated terms.	
Puget Sound Energy, Inc.	Data Retention: The 5th bullet should refer to "proxies" instead of "studies".
Response: The SDT disagrees with your statement as the studies will reveal the Proxies (now criteria or methodology) used in the Planning Assessment. No change made.	
E.ON U.S.	M5 doesn't make any sense. Need to revise this Measure so that it fits the Requirement R5. Also need to revise the Data Retention discussion in Section 1.4 to align with R5. In the VSL associated with R5, we believe that failure to define and document the proxies should be a moderate VSL.
Response: The SDT does not agree and believes that the Measure appropriately addresses Requirement R6 (formerly Requirement R5). No change made. The SDT does not agree and believes that the Data Retention for this Requirement should be and is identical to the other Requirements. No change made. The SDT appreciates your comment on the level of severity for this Requirement but still believes this is the appropriate level to apply. No change made.	

Organization	Question 5 Comment
Entergy Services, Inc	Under R5, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R5 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning".
ITC Holdings	Under R5, the Time Horizon of the TPL standards is intended for years one through 10; however, the Time Horizon shown in R5 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning".

Response: The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made.

Mitigation Time Horizon

The time horizons available for mitigating a violation to a requirement include the following:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.

Operations Assessment — follow-up evaluations and reporting of real time operations.

Idaho Power	M5 doesn't make any sense. Need to revise this Measure so that it fits the Requirement R5. Also need to revise the Data Retention discussion in Section 1.4 to align with R5.

Response: The SDT does not agree and believes that the Measure appropriately addresses Requirement R6 (formerly Requirement R5). No change made.

6. Requirement R6 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: Requirement R6 (now Requirement R7) is an overarching requirement that applies to the entire set of analysis required to meet the requirements of the TPL standard and to the Corrective Action Plan developed as part of the Planning Assessment. The intent of this requirement is to clarify that while the responsibilities for the TPL requirements are for both the Transmission Planner and Planning Coordinator, the individual tasks may be met through joint or shared analysis. Industry feedback indicates that it is important to minimize duplicative studies to the greatest extent possible. Coordinating and/or joint analysis does not alleviate the responsibility that all entities need to comply with the standard requirements. The SDT has made changes for clarity.

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.

Organization	Question 6 Comment
Northeast Power Coordinating Council United Illuminating Northeast Utilities ISO New England, Inc. Central Maine Power Company	We do not feel that this requirement belongs in this standard and it should be deleted. The standard defines requirements for the assessment not who does what.
Response: The intent of this requirement is to clarify that TPL requirements can be meet through joint or shared analysis. Industry feedback indicates that it is important to minimize duplicative studies to the greatest extent possible. This requirement does not preclude any single entity from performing all the study work required to support an assessment. No change made.	
MRO NERC Standards Review Subcommittee	MRO NSRS is not clear if: 1) Each Transmission Planner is to meet all the requirements including doing all the studies and all Planning coordinators are to meet the requirements including doing all the studies.Or 2) If the Transmission Planner and Planning Coordinator are to work as a team to meet all the requirements including doing all the studies. Either one of them could do various parts of the required studies. For example, maybe the PC could do the stability part so all TP's would not necessarily have to buy that software if they did not need it for other planning purposes.In the first read of this standard, it appears that the intention was number 1, which sounds awfully duplicative. But then take a look at Requirement 6. R6. Each Transmission Planner and Planning Coordinator shall determine and identify individual and joint responsibilities for performing the required studies for the Planning Assessment. [Violation Risk Factor: Low] [Time Horizon: Long-term Planning]After reading R6, it appears that number 2 was intended. Perhaps R6 should be the very first requirement in the standard. The MRO NSRS requests that the NERC SDT clarify the responsibility of the requirements of this standard.

Organization	Question 6 Comment
Response: The requirement specifies that individual and joint responsibilities for performing the required studies be identified. Requirement R6 (now Requirement R7) is an overarching requirement that applies to the entire set of analysis required to meet all the requirements of the TPL. **R7**. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.	
SERC Engineering Committee Reliability Review Subcommittee (RRS)	In absence of these agreements, it is assumed that both Transmission Planners and Planning Coordinators would be responsible for performing the studies. How do the Corrective Action Plans get resolved between these entities if there is no agreement on the study results??Requirements R1, R2, R3, R4 and R5 should all be revised to include a reference to R6 regarding the determination of individual and joint responsibilities for performing the required studies. In the VSL associated with R6, we believe that failure to determine and identify one responsibility should be a moderate VSL, failure to determine and identify two responsibilities should me a high VSL, while failure to determine and identify three responsibilities should be a severe VSL. Otherwise failing to document only one responsibility would result in a severe VSL.
Response: Requirement R6 (now Requirement R7) is an overarching requirement that applies to the entire set of analysis required to meet all the requirements of the TPL and to the corrective action plan developed as part of the assessment. The proposed changes to the VSLs do not conform to Guideline 3 of the FERC VSL order. No change made to the VSL. **R7**. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.	
FirstEnergy Corp	We agree with the stated Requirement, Measure, VRF, Time-Horizon, Data Retention and VSL of requirement R6.
Progress Energy Florida, Inc.	PEF does not presently have any concerns with R6.
American Transmission Company	We agree with the revisions to R6.
Independent Electricity System Operator	We agree with the requirement, the VRF, Time Horizon, Measure and VSLs.
Response: Thank you for your response. However, please see changes indicated in the summary due to other industry comments.	
TVA System Planning	In the VSL associated with R6, we believe that failure to determine and identify one responsibility should be a moderate VSL, failure to determine and identify two responsibilities should me a high VSL, while failure to determine and identify three responsibilities should be a severe VSL. Otherwise failing to document only one responsibility would result in a severe VSL.
Response: The proposed changes to the VSL do not conform to Guideline 3 of the FERC VSL order. No change made	

Organization	Question 6 Comment
Florida Reliability Coordinating Council, Inc - Transmission Working Group	Please clarify that the phrase "individual and joint responsibilities" applies to entities (e.g., the TPs and PCs) and not specific individuals.R6 Please clarify if this requirement is intended for cases where a TP is not a PC and therefore is working "under" a PC? Or if this is intended to apply across neighboring PC's?
FMPA	Please clarify that the phrase "individual and joint responsibilities" applies to entities (e.g., the TPs and PCs) and not specific individuals.
Response: Thank you for pointing out a potential for misinterpretation of the intent of the requirement. The SDT has modified the language. **R7**. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.	
Xcel Energy	Why is this needed if both entities must comply with the standard?At a minimum the requirement should include language to state that the one party must provide to the other with enough notice to comply with a required study if there is a shift or assignment of a responsibility.
Ameren	In absence of these agreements, it is assumed that both Transmission Planners and Planning Coordinators would be responsible for performing the studies. It is not clear how the Corrective Action Plans get resolved between these entities if there is no agreement on the study results.
Duke Energy	Requirements R1, R2, R3, R4 and R5 should all be revised to include a reference to R6 regarding the determination of individual and joint responsibilities for performing the required studies.
Response: Requirement R6 (now Requirement R7) is an overarching requirement that applies to the entire set of analysis to meet all the requirements of the TPL. This includes the corrective action plan developed as part of the assessment. Coordinating and/or joint analysis does not alleviate the responsibility that all entities need to comply with the standard requirements. **R7**. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.	
Midwest ISO	A) Under R6, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R6 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning".
Minnesota Power	Under R6, the Time Horizon of the TPL standards is intended for years one through 10; however, the Time Horizon shown in R6 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning".
Response: The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time	

Organization	Question 6 Comment
frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made. **Mitigation Time Horizon** The time horizons available for mitigating a violation to a requirement include the following: • **Long-term Planning** — a planning horizon of one year or longer. • **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal. • **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time. • **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system. • **Operations Assessment** — follow-up evaluations and reporting of real time operations.	
Brazos Electric Cooperative	is there any other way to identify responsibilities between the parties than having an agreement? R6 seems to indicate an agreement of some sort must be in place. if that is the case then it could simply say an agreement must be in place.
Response: The requirement has been clarified in response to others' comments. The SDT did not want to imply that a separate agreement would be required for the purposes of the assessment. **R7**. Each Planning Coordinator, in conjunction with each of its Transmission Planners shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.	
ITC Holdings	Comments: Should this requirement state that ?The Transmission Planner in conjunction with their Planning Coordinator shall determine and identify individual and joint responsibilities for performing the required studies for the Planning Assessment.
Response: The SDT has modified the language. **R7**. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.	
LADWP	R6: Does this requirement requires authors of the planning assessment report should be identified? If so, can we use plain English like "The authors of the Planning Assessment report shall be identified". If not, please explain what this requirement is all about.
Kansas City Power & Light	Why is this needed if both entities must comply with the standard?At a minimum the requirement should include language to state that the one party must provide to the other with enough notice to comply with a required study if there is a shift or assignment of a responsibility.

Organization	Question 6 Comment
Response: Requirement R6 (now Requirement R7) is an overarching requirement that applies to the entire set of analysis required to meet all the requirements of the TPL and to the corrective action plan developed as part of the assessment. The intent of this requirement is to clarify TPL requirements can be met through joint or shared analysis. Industry feedback indicates that it is important to minimize duplicative studies to the greatest extent possible. Coordinating and/or joint analysis does not alleviate the responsibility that all entities need to comply with the standard requirements. **R7**. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.	
Orlando Utilities Commission	R6: Is this requirement intended for cases where the TP is not also their PC, or is this between adjacent PC's?
Response: The intent of this requirement is to clarify TPL requirements can be meet through joint or shared analysis. Industry feedback indicates that it is important to minimize duplicative studies to the greatest extent possible. The requirement has been clarified in response to others' comments. **R7**. Each Planning Coordinator, in conjunction with each of itsTransmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.	

7. Requirement R7 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: Many commenters feel that the reference to FERC Order 890 is inappropriate, but most do not argue against the importance of sharing Planning Assessment information. There was also concern about the meaning of the phrase "coordinating of analysis of these results", and what was specifically required. The SDT believes sharing of information, understanding the impact on/from neighboring areas, peer review/feedback, and wide area assessment are important to effective Transmission planning. As a result of the comments several revisions have been made to TPL-001-1.

Revisions to Requirement R3, part R3.4 and Requirement R4, part 4.4 will clarify the expectation that Transmission Planner's and Planning Coordinator's analyze Table 1 events outside their System for reliability impacts to understand neighboring System impacts. The revised TPL-001-1 Requirement R8 (formerly Requirement R7) will ensure appropriate information is exchanged between Transmission Planner's and Planning Coordinator's for sharing of information, review, and coordination of plans in conformance with Order 693, paragraph 1755 and 1756 expectations by requiring distribution of Planning Assessments to neighboring Transmission Planners and Planning Coordinators, as well as entities with a reliability-related need. The NERC Rules and Procedures and delegation agreements cover existing TPL-005-0 & TPL-006-0 assessment requirements for regional and inter-regional assessments allowing for retirement of these two standards. The aggregate effect of the above items will be an overlapping assessment of BES reliability from each Transmission Planner area up through each Interconnection.

R8 Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.

R8.1 If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M8 Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient, date, and contents, or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and any functional entity who has indicated a reliability need and has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

R8 VSL	The responsible entity failed to distribute the results of its Planning Assessment to any one of its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

Organization	Question 7 Comment
Northeast Power Coordinating Council United Illuminating Northeast Utilities ISO New England, Inc. National Grid Central Maine Power Company	This standard should not be reiterating FERC Order 890. We do not feel that this requirement belongs in this standard and it should be deleted.
SERC Engineering Committee Planning Standards Subcommittee	FERC Order 890:The reference to FERC Order 890 as it is currently written makes it seem like a suggestion to follow Order 890. If Order 890 explicitly describes this process then the sentence should read “as described in FERC Order 890. If not, this should not be mentioned at all.
Bonneville Power Administration PacifiCorp Deseret Generation & Transmission SRP Arizona Public Service Co Western Area Power Administration Pacific Gas and Electric Co, Puget Sound Energy, Inc. NV Energy Southern California Edison Company San Diego Gas and Electric Co California ISO Tucson Electric Power Company	We believe that references to FERC Orders should not be included in requirements of standards. This comment also applies to M7.

Organization	Question 7 Comment
NorthWestern Corporation NorthWestern Energy (NWE) (NWMT)	In R7 the references to FERC Orders should not be included in requirements of standards. This comment also applies to M7.
Response: The SDT agrees that the standard should not reference Order 890 and the reference has been deleted. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. **M8** Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient, date, and contents, or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and any functional entity who has indicated a reliability need and has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.	
MRO NERC Standards Review Subcommittee	MRO NSRS proposes expanding the scope of entities to consider, limit it to those entities that indicate a reliability need for coordination, and eliminate the direct reference to Order 890. MRO NSRS suggests this text: "Each Planning Coordinator shall establish a list of adjacent Planning Coordinators and any functional entity who has indicated a reliability need, distribute its Planning Assessment results to the listed entities and consider comments on the assumptions and results through an open and transparent peer review process.
Response: The scope of entities has been modified. Each Transmission Planner and Planning Coordinator shall distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. An additional sub-requirement has been added to require that if a recipient of the Planning Assessment results provides documented comments on the results, the respective Transmission Planner or Planning Coordinator shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. **R8.1** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	
SERC Engineering Committee Reliability Review Subcommittee (RRS)	The reference to FERC Order 890 as it is currently written makes it seem like a suggestion to follow Order 890. If Order 890 explicitly describes this process then the sentence should read "as described in FERC Order 890. If not, this should not be mentioned at all. " Requirement R7 describes that the Planning Coordinator is to share Planning Assessments with adjacent Planning Coordinators. Does this need to be expanded for the Transmission Planners to share their Planning Assessments with the Planning Coordinators?? In the VSL associated with R7, we believe that the PC failing to coordinate analysis should be a moderate VSL, the PC failing to distribute should be a high VSL, and failing to do both of these tasks should be a severe VSL.

Organization	Question 7 Comment

Response: The SDT agrees that the standard should not reference Order 890 and the reference has been deleted.

The scope of entities has been modified. Each Transmission Planner and Planning Coordinator shall distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment.

The VSL has been modified to reflect the changes to the requirement. The requirement no longer requires a coordinated analysis. The failure to distribute the results is a High VSL. Failure to respond to comments is a Severe VSL.

R8 Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.

R8 VSL	The Transmission Planner or Planning Coordinator failed to distribute the results of its Planning Assessment to any one of its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	N/A	The Transmission Planner or Planning Coordinator failed to distribute the results of its Planning Assessment to its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	The Transmission Planner or Planning Coordinator failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

FirstEnergy Corp	We agree with the stated Requirement, Measure, VRF, Time-Horizon, Data Retention and VSL of requirement R7.
Progress Energy Florida, Inc.	PEF does not presently have any concerns with R7.

Response: Thank you for your response. However, please note the changes made to Requirement R7, Measure R7, and the Requirement R7 VSL (now Requirement R8) due to a majority of industry commenters indicating that some changes were needed.

IRC Standards Review Committee	Is the PC expected to distribute the TP Planning Assessments as part of its coordination requirement?

Response: The term “coordinating analysis” has been deleted from the requirement and only distribution of assessments by the Transmission Planner and Planning Coordinator is required.

R8 Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.

Organization	Question 7 Comment			
TVA System Planning	In the VSL associated with R7, we believe that the PC failing to coordinate analysis should be a moderate VSL, the PC failing to distribute should be a high VSL, and failing to do both of these tasks should be a severe VSL.			
Response: The VSL has been modified to reflect the changes to the requirement. The requirement no longer requires a coordinated analysis. The failure to distribute the results is a High VSL. Failure to respond to comments is a Severe VSL. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.				
R8 VSL	The Transmission Planner or Planning Coordinator failed to distribute the results of its Planning Assessment to any one of its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	N/A	The Transmission Planner or Planning Coordinator failed to distribute the results of its Planning Assessment to its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	The Transmission Planner or Planning Coordinator failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.
Southern Company	We recommend the following wording for R7.Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among adjacent Planning Coordinators and any functional entity who has indicated a reliability need. Each Planning Coordinator shall coordinate analysis of these results through an open and transparent peer review process such as described in FERC Order 890.			
Response: The SDT agrees and, in addition, the scope of entities has been modified. Each Transmission Planner and Planning Coordinator shall distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. The VSL has been modified to reflect the changes to the requirement. The requirement no longer requires a coordinated analysis. The failure to distribute the results is a High VSL. Failure to respond to comments is a Severe VSL. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.				
R8 VSL	The responsible entity failed to distribute the results of its Planning Assessment to any one of	N/A	The responsible entity failed to distribute the results of its Planning Assessment to its adjacent Transmission	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment

Organization	Question 7 Comment			
	its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.		Planners and Planning Coordinators, respectively in accordance with Requirement R8.	results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.
System Protection and Transmission Planning Department	The phrase "coordinating analysis of these results" seems to indicate potential second-guessing by other entities. We suggest "coordinating REVIEW of these results" may be clearer. The term "such as described in FERC Order 890" allows non-jurisdictional utilities to establish an appropriate process. This is good. However, we still have the same misgivings about the term "such as" used here.			
Manitoba Hydro	It is unclear as to what is meant by “coordinating analysis of these results”? Does this imply an obligation to conduct joint studies or just an obligation to distribute the assessment and respond to feedback? We suggest that the wording “such as described in FERC Order 890” be replaced with “such as may be required by a regulator in its PC/TP area”. The SDT is posing several other questions for industry consideration not related to the specific requirement questions above.			
Response: The SDT agrees that the term “coordinating analysis” is unclear and has modified Requirement R7 (now Requirement R8) to only require distribution of planning assessments. The reference to Order 890 is no longer necessary. However, the SDT does believe it is appropriate to require a response if a recipient of the Planning Assessment results provides documented comments on the results. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.				
PPL Energy Plus	Please continue to mention relevant FERC Orders (such as 890) in the standards since the FERC orders are the source of many of the planning standards. Planners need to acknowledge, respect, and design processes and systems around the FERC rulings.			
MidAmerican Energy Company	MidAmerican commends the SDT for its hard work on this standard. MidAmerican recommends changing R7 by changing “FERC Order 890” to “FERC Order No. 890”.			
Response: The majority of commenters had an opposite opinion of referencing FERC Orders in NERC standards and the reference to Order 890 has been deleted.				
Florida Reliability Coordinating Council, Inc - Transmission Working Group	The requirement as written requires that the results of the assessment are shared on a post assessment basis between entities in a manner similar to the Attachment K process. Please clarify whether:-Is this intended to be the end results? Or does this require the inviting of entities in at the very beginning and facilitating their participation throughout the process? -Is it intended that the process described in order 890 become essentially a NERC Standard that every sentence must be met in the most literal of sense? Or is this referencing the order as a general guideline on what should be expected but not as a literal			

Organization	Question 7 Comment
	checkmark of the process? Consider adding a footnote or other clarifications that failure of others to participate in the process is not a non compliance by the entity inviting them to the process. Otherwise non-responsiveness of a neighboring PC who may not have reliability need to participate and whose participation is beyond the control of the PC that initiated the process could trigger non-compliance.
Entergy Services, Inc	This requirement is addressed through FERC Order No. 890 (9 principles of transmission planning).
Platte River Power Authority	R7. Delete this requirement as it is the responsibility of the Transmission Provider under FERC Order 890.
American Transmission Company	We propose expanding the scope of entities to consider, limit it to those entities that indicate a reliability need for coordination, and eliminate the direct reference to FERC Order 890 and peer review. We suggest this text: "Each Planning Coordinator shall establish a list of adjacent Planning Coordinators and any functional entity who has indicated a reliability need, and distribute its Planning Assessment results to the listed entities and consider comments on the assumptions and results.
Response: The reference to Order 890 created confusion regarding process requirements and the reference has been deleted. The standard now requires each Transmission Planner and Planning Coordinator to distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. In addition, if a recipient of the Planning Assessment results provides documented comments on the results, the respective Transmission Planner or Planning Coordinator shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. This simplifies the process while achieving appropriate involvement of affected entities. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. **R8.1** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	
SMUD	Requirement R7 should end after the words '....who has indicated a reliability need'. R7:The requirement should not invoke another document for compliance. The words, ", coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890', should be deleted. This comment also applies to M7.
Response: The reference to Order 890 created confusion regarding process requirements and the reference has been deleted. The standard now requires each Transmission Planner and Planning Coordinator to distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. In addition, if a recipient of the Planning Assessment results provides documented comments on the results, the respective Transmission Planner or Planning Coordinator shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. This simplifies the process while achieving appropriate involvement of affected entities. Conforming changes have been made to Measure M7 (now M8). **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and	

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Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. **R8.1** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. **M8** Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient, date, and contents, or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and any functional entity who has indicated a reliability need and has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.	
Xcel Energy	Recommend deleting the portion of the requirement that states: "coordinating analysis of these results through an open and transparent review process such as described in FERC Order 890.
LADWP	FERC 890 stands on its own, why should a planning standard refers to a FERC Order? Does this imply that if a FERC Order is not referenced in the planning standard, we can ignor the order?
Independent Electricity System Operator	1. We question the need to mention FERC 890. If this meant to be an example for the US entities, we suggest this to be put into a footnote with indication that it is an example for the US entities only.2. We agree with the requirement, the VRF, Time Horizon, Measure and VSLs.
Response: The reference to Order 890 created confusion regarding process requirements and the reference has been deleted. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.	
Ameren	Requirement R7 describes that the Planning Coordinator is to share Planning Assessments with adjacent Planning Coordinators. It is not clear whether this needs to be expanded for the Transmission Planners to share their Planning Assessments with the Planning Coordinators. The reference to FERC Order 890 as it is currently written makes it seem like a suggestion to follow Order 890. If Order 890 explicitly describes this process then the sentence should read "as described in FERC Order 890. If not, maybe this should not be mentioned at all.
Response: The scope of entities has been modified. Each Transmission Planner and Planning Coordinator shall distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. The reference to Order 890 created confusion regarding process requirements and the reference has been deleted. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.	
Midwest ISO	A) Under R7, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R7 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10

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	and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning". B) The coordination of analysis of results through an open and transparent process is already a FERC requirement thus producing a double jeopardy for those entities that fall under the jurisdiction of FERC Order 890. We recommend striking the following language in the last sentence: ...coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890. C) Under R7 only the Planning Coordinator is required to coordinate the distribution of Planning Assessment results among adjacent PCs and any functional entity who has indicated a reliability need, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890. Should the TP be added to this requirement? We propose the suggested language change: Each Transmission Planner and Planning Coordinator shall coordinate the distribution of Planning Assessment results among adjacent Transmission Planners and Planning Coordinators, respectfully, and to any functional entity who has indicated a reliability need, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890. D) Based on the comments above in (B) and (C), our suggested requirement language is as follows: Each Transmission Planner and Planning Coordinator shall coordinate analysis in support of assessments in accordance with applicable regulatory requirements. Each Planning Coordinator shall distribute its completed planning assessment results among adjacent Planning Coordinators and any functional entity who indicated in writing a reliability related need.

Response: The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. No change made.

Mitigation Time Horizon

The time horizons available for mitigating a violation to a requirement include the following:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

The reference to "coordinating analysis" and Order 890 created confusion regarding process requirements and the requirement has been modified. The standard now requires each Transmission Planner and Planning Coordinator to distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. In addition, if a recipient of the Planning Assessment results provides documented comments on the results, the respective Transmission Planner or Planning Coordinator shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. This simplifies the process while achieving appropriate involvement of affected entities.

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R8 Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. **R8.1** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	
PJM	R7 needs to be broken into two parts. First establish the list of entities that need to get the assessment results. Second would be to coordinate the results as mentioned. Are the results mentioned in R7 different from the Planning Assessment?
Response: The standard now requires each Transmission Planner and Planning Coordinator distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. In addition, if a recipient of the Planning Assessment results provides documented comments on the results, the respective Transmission Planner or Planning Coordinator shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. This simplifies the process while achieving appropriate involvement of affected entities. The reference to "results" in Requirement R7 (now Requirement R8) is to the Planning Assessment results. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. **R8.1** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	
Minnesota Power	Under R7, the Time Horizon of the TPL standards is intended for years one through 10; however, the Time Horizon shown in R7 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning".
Response: The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made. **Mitigation Time Horizon** The time horizons available for mitigating a violation to a requirement include the following: • **Long-term Planning** — a planning horizon of one year or longer. • **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal. • **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time. • **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.	

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• **Operations Assessment** — follow-up evaluations and reporting of real time operations.	
MAPPCOR	Propose expanding the scope of entities to consider, limit it to those entities that indicate a reliability need for coordination, and eliminate the direct reference to Order 890. Suggest this text: "Each Planning Coordinator shall establish a list of adjacent Planning Coordinators and any functional entity who has indicated a reliability need, distribute its Planning Assessment results to the listed entities and consider comments on the assumptions and results through an open and transparent peer review process.
Response: The standard now requires each Transmission Planner and Planning Coordinator distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. The reference to Order 890 created confusion regarding process requirements and the reference has been deleted. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.	
Orlando Utilities Commission	The term "results of the assessment", is this is the final end result that is shared and analyzed? A requirement should not reference an order or another non NERC document. All the requirements and measures for performance should be covered in the standard or through reference to another NERC approved standard. The language used in other standards would be more appropriate and directly auditable. Require that the PC/TP to share assessment and support material with those requesting entities and respond to any of their specific comments. This will insure openness and transparency in a manner and can be directly audited.
Response: The reference to "coordinating analysis" and Order 890 created confusion regarding process requirements and the reference has been deleted. The standard now requires each Transmission Planner and Planning Coordinator distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. In addition, if a recipient of the Planning Assessment results provides documented comments on the results, the respective Transmission Planner or Planning Coordinator shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. This simplifies the process while achieving appropriate involvement of affected entities. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. **R8.1** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	
Turlock Irrigation District	In light of the fact that FERC has determined not to apply the Order No. 890 transmission planning processes requirement to non-public utilities, TID expresses concern over the reference to Order No. 890 in R7. TID recommends that this reference be replaced with a more direct instruction that details what exactly is meant by the requirement of "an open and transparent peer review process. R7 makes reference to the peer review process laid out in FERC Order No. 890. This reference to Order No. 890 is duplicative and vague and must be clarified. The peer review process set forth in Attachment K of Order No. 890, lays out nine different principles (Coordination, Openness, Transparency, Information Exchange, Comparability, Dispute Resolution,

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	Regional Participation, Economic Planning Studies, and Cost Allocation for New Projects). Most of these principles are inapplicable when placed in the context of NERC Reliability Standards. Subjecting NERC members to all of these vague and broad principles without specific guidance as to their application would be a significant burden. TID proposes that the reference to Order No. 890 be removed from R7 and replaced with a provision that expressly details the principles of openness and transparency that are contemplated in R7. Such an express provision would bring clarity to the requirement so that entities subject to R7 would know exactly what they are expected to do to comply with the requirements of R7. As it is now written, the broad reference to Order No. 890 is vague and confusing.TID is also concerned with the fact that the Violation Severity Levels for R7 now appear to run from High to Severe, with the potential of significant penalties being assessed on noncompliant entities. The High and Severe Violation Severity Levels for TLP-001-1 R7 are inappropriate given the already vague and conflicting guidance of R7, especially as R7 merely duplicates the Order No. 890 requirements. Once the reference to Order No. 890 is replaced with a provision that expressly provides specific guidance as to what is meant by the "open and transparent peer review process," the appropriate Violation Severity Level for R7 would be Low to Moderate.

Response: The reference to "coordinating analysis" and Order 890 created confusion regarding process requirements and the reference has been deleted. The standard now requires each Transmission Planner and Planning Coordinator distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. In addition, if a recipient of the Planning Assessment results provides documented comments on the results, the respective Transmission Planner or Planning Coordinator shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. This simplifies the process while achieving appropriate involvement of affected entities.

The VSL's have been modified based on the clarified Requirement R7 (now Requirement R8) for distribution of Planning Assessments, the importance of sharing planning information and being responsive to neighboring entities reliability related concerns.

R8 Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.

R8.1 If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

R8 VSL	The responsible entity failed to distribute the results of its Planning Assessment to any one of its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

New York Independent System	The Standards Drafting Team should clarify the standard as to whether the PC will be expected to distribute the TP Planning

Organization	Question 7 Comment
Operator	Assessments as part of its coordination requirement?
Response: The language has been clarified as to the responsibility of each Transmission Planner and Planning Coordinator. The standard now requires each Transmission Planner and Planning Coordinator distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.	
Kansas City Power & Light	Recommend deleting the portion of the requirement that states: "coordinating analysis of these results through an open and transparent review process such as described in FERC Order 890.
Response: The reference to "coordinating analysis" and Order 890 created confusion regarding process requirements and the reference has been deleted. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.	

8. The SDT changed several definitions in response to industry comments to the second posting. Do you agree with these changes? If not, please clearly indicate which definition you disagree with and provide specific comments.

Summary Consideration: Many of the responders suggested that several of the definitions either be revised or deleted. As a result, the definitions for Supplemental Load Loss, Load Reduction, Planning Events and Extreme Events have been deleted and the definitions for Consequential Load Loss, Non-Consequential Load Loss and Year One have been revised.

In association with the changes in definitions, the SDT has also revised note 'b' and added note 'i' in the header to Table 1.

There were several requests to include comment on Under-frequency (UFLS) and Under-voltage load (UVLS) shedding. UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled Load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. As a result, no change was made.

There were some suggestions to include definitions and distinction between 'planned' and 'proposed'. The SDT tried to address the concepts of planned and proposed in a prior posting. The response from industry strongly discouraged the Standard from delving into the distinction. As a result, no change was made.

There were a couple of suggestions relative to adding back the examples of applications of Bus-tie Breakers or otherwise changing the definition. The SDT removed the statement on Bus-tie Breakers because comments were received to indicate that although the examples were true for most applications, it wasn't universal and examples were provided where Bus-tie Breakers were used between ring buses, etc. As a result, no change was made.

There was a suggestion to change the reference to 'Horizon'. "Horizon" is not something new and the SDT does not agree with changing it. As a result, no was change made.

There were a couple of requests to include new definitions for "cascading outages", "voltage instability", and "uncontrolled islanding". The SDT did not see a reason to define these terms in TPL-001-1. The requesters were invited to draft a SAR if they wanted to pursue having these terms defined. As a result, no change was made.

The following changes were made to definitions as a result of industry comments:

Consequential Load Loss: All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.

Year One: The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.

Header note 'b': Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme event excluding P0.

Header note 'i': The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Organization	Yes or No	Question 8 Comment
Northeast Power Coordinating Council	No	Revise the Load Reduction and Non-Consequential Load Loss definitions as follows.Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions resulting from following a Planning or Extreme Event. Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction. Intended post contingency loss of load (other than Interruptible Load, Supplemental Load or Load Reduction) caused by operator or SPS (RAS) action. (Priority Comment)For Drafting Team consideration: What types of non-interruptible load loss would be considered non-consequential load loss--manual load shedding for example? With this in mind, can the definition be simplified, maybe to read: Non-Consequential Load Loss: Operator action taken to deliberately remove load from service in response to adverse system conditions.
Response: The SDT has deleted the Load Reduction definition. The SDT has simplified the Non-Consequential Load Loss definition and has eliminated the references to Supplemental Load Loss and Load Reduction. The New definition is: **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.		
SERC Engineering Committee Planning Standards Subcommittee	No	Definitions: Revised Definitions are generally better than those from the previous version, but additional clarity could be provided. Load Reduction Please clarify whether this includes both load response and operator initiated action, such as in changes to transformer LTC. Supplemental Load Loss - From a utility perspective, this would be considered as load response. Please clarify how Supplemental Load Loss would be included in the stability analysis. Bus tie breaker A statement in the previous version which listed examples was removed from this version of the definition. The statement was helpful and should be re-inserted. The statement was: Substation configurations such as ring bus, breaker and a half, or double-bus double-breaker do not use bus tie breakers.
Response: The definitions for Load Reduction and Supplemental Load Loss have been deleted. The SDT has simplified the Non-Consequential Load Loss definition and has eliminated the references to Supplemental Load Loss and Load Reduction. The New definition is: **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment. In association with the changes in definitions, the SDT has revised note 'b' and added note 'i' in the header to Table 1.		

Organization	Yes or No	Question 8 Comment
Header note 'b': Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme event excluding P0. **Header note 'i':** The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements. The SDT removed the statement on Bus-tie Breakers because comments were received to indicate that although it was true for most applications, it wasn't universal and examples were provided where Bus-tie Breakers were used between ring buses, etc. No change made.		
Modesto Irrigation District	No	On page 2 under "Definitions of Terms Used in Standard", the red-lined out example used to clarify the definition of "Non-Consequential Load Loss" seems valuable to me, and I think they should not remove it but leave it in.
Response: The SDT has decided that it is inappropriate to include examples within a Standard's definition. The SDT is concerned that an example isn't all inclusive and it will create opportunities for loopholes. No change made.		
Bonneville Power Administration PacifiCorp Deseret Generation & Transmission SRP Xcel Energy Western Area Power Administration Southern California Edison Company San Diego Gas and Electric Co Idaho Power California ISO	No	Clarification is needed on the use of UVLS. Is it acceptable or not. Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss Allowed column is No, is load disconnecetd from the system by UVLS a violation? What about Supplemental Load Loss or UFLS?
Arizona Public Service Co	No	Claification is needed on the use of UVLS. Is it acceptable or not. Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss Allowed column has a No entry, is load disconnecetd from the system by UVLS a violation? What about Supplemental Load Loss or UFLS?

Organization	Yes or No	Question 8 Comment
Pacific Gas and Electric Co,	No	Claification is needed on the use of UVLS. Is it acceptable or not? We understand from the discussion in the webinar that in the proposed TPL-001-1, Table 1, if there is a "no" in the column for allowable load loss, you are still allowed to have UVLS set up to drop the load, but cannot plan on meeting the standard with the load shedding. Therefore, if the Non-Consequential Load Loss Allowed column is No, is load disconnecetd from the system by UVLS a violation, given that you can lose the load but cannot plan on it? Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. What about the treatment of Supplemental Load Loss or UFLS?
Puget Sound Energy, Inc.	No	Claification is needed on the use of UVLS. Is it acceptable or not. Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss Allowed column is No, is load disconnecetd from the system by UVLS a violation? What about Supplemental Load Loss or UFLS?Provide clear explanations of the load definitions.
NV Energy	No	Claification is needed on the use of UVLS. Is it acceptable or not. Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss Allowed column is No, is load disconnecetd from the system by UVLS a violation? What about Supplemental Load Loss or UFLS? We are also wondering how loads that have interruptible rates should be handled.
LADWP	No	UVLS should be an allowed mitigation for multiple contingencies, P3 and above. UVLS is an effective measure against voltage collapse, a system condition that if not mitigated in a timely fashion could lead to cascading events. Saqme with UFLS.
Response: UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. No change made.		
Tucson Electric Power Company	No	Claification is needed on the use of UVLS. Is it acceptable or not? Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss Allowed column is No, is load disconnecetd from the system by UVLS a violation? What about Supplemental Load Loss or UFLS? Year One The use of calendar year is confusing. When does the 12-18 month window begin? We suggest "The year 18 months beyond the present month.
Response: UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. No change made. The definition of Year One has been clarified. **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that		

Organization	Yes or No	Question 8 Comment
begins 12-18 months from the end of the current calendar year.		
MRO NERC Standards Review Subcommittee	No	MRO NSRS suggests the following comments: Add a Consequential Generation Loss definition because both load and generation loss can be considered, but there is only Consequential Load Loss definition. MRO NSRS suggests text of: Consequential Generation Loss: All Generation that is no longer delivered to any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions. Expand the Consequential Load Loss definition to include protection for abnormal operating conditions. MRO NSRS suggests text of: Consequential Load Loss: All Load that is no longer served by any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions. Expand the Load Reduction definition to include consideration of TOP judgment and established protection schemes. MRO NSRS suggests text of: Load Reduction: The reduction of Load that is still connected to the System, but in the judgment of the Transmission Operator or through the previous established Special Protection Systems, Under-Frequency Load Shedding programs, Over-Frequency Load Shedding program, should be reduced to overcome to lower voltage conditions following a Planning or Extreme Event. Modify the Planning Assessment definition to more explicitly apply to the BES and the TPL-001 requirements. MRO NSRS suggests text of: Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies in the BES from the steady state and stability performance requirements set forth in the TPL-001 standard. Modify the Planning Events definition more explicitly apply to the TPL-001 requirements. MRO NSRS suggests text of: Planning Events: Events that are identified in the steady state and stability performance requirements set forth in the TPL-001 standard. Expand the Year One definition to include the PC, refer to the Planning Assessment, and refer to the current calendar year. MRO NSRS suggests text of: Year One: The first year that each Transmission Planner and Planning Coordinator is responsible for conducting a Planning Assessment. This is further defined as the planning window that begins 12-18 months from the current calendar year. MRO NSRS would like to delete the definition of "Year One". This is already being done and adding a planning window opens entities to noncompliance for conditions i.e. Model building outside of entities control.
Response: Requirement R2, part 2.7.1 allows for generation tripping and run-back, so a definition for Consequential Generation Loss is not required. The proposed change to expand Protection System operation to include abnormal operating conditions is too vague and is too broad. In addition it would create an overlap with the definition of Non-Consequential Load because Protection Systems used to protect abnormal operating conditions would include Special Protection System which could be used to trip Non-Consequential Load. No change made. The SDT has deleted the Load Reduction definition. UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled load shedding is allowed. The Standard does not address the		

Organization	Yes or No	Question 8 Comment
acceptability of the tools to be used for any Corrective Action Plan. No change made. As stated in the "Purpose" the Standard establishes Transmission System planning performance for the BES. Repeating that within the Standard creates opportunities for confusion whenever it is not specifically noted. The SDT wants to minimize confusion by not repeating applicability throughout the document. Also the Planning Assessment involves more than remedying identified deficiencies. For example, it may also confirm that there are no deficiencies or it may evaluate the impacts of schedule changes in the Corrective Action Plans. No change made. The definition for Planning Events has been deleted. The SDT believes that a near term study requirement is a necessary part of the standard and that a definition for Year One is a necessary component to achieve that objective. The SDT has received several constructive comments on this and has made revisions to the definition. Although revisions fall short of your suggestion, the SDT hopes that additional clarity will help. The revised definition is: **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.		
SERC Engineering Committee Dynamics Review Subcommittee (DRS)	No	There is a need to add definitions to discriminate between planned and proposed projects. We propose the following definitions: Planned Facilities: Facilities that address the near-term deficiencies and have been approved with a financial commitment. Proposed Facilities: Facilities that address long-term deficiencies for which no commitment is required today since they may change based on future evaluation. We propose the following definitions for events: Planning Events: Events which are listed as Planning in Table 1 in Standard TPL-001-1. Extreme Events: Events which are listed as Extreme in Table 1 in Standard TPL-001-1. Bus-tie Breaker definition still seems somewhat generic and the use of 'configurations' causes uncertainty. We propose the following definition: Bus-tie Breaker: A circuit breaker whose intended purpose is to connect two individual substation buses. The definition of Supplemental Load Loss includes the phrase, "by end-user equipment", which could be understood to mean there are devices at the end-user location that remove this equipment (and conversely, load that is not disconnected "by" end-user equipment cannot be included). Also, the term "post-Contingency" can be confusing because in the case of faults, this phrase is not clear if it means conditions after the fault initiation itself or only after the clearing of the fault. We propose the following definition: Supplemental Load Loss: End-user Load that inherently disconnects from the System as a consequence of (or "in response") to the conditions created by the System event. Load Reduction: A decrease in the amount of connected Load caused by lower voltage conditions following a Planning or Extreme Event.
Response: The SDT tried to address the concepts of planned and proposed in a prior posting. The response from industry strongly discouraged the standard from delving into the distinction. No change made.		

Organization	Yes or No	Question 8 Comment
The definition for planning events has been deleted. The definition for extreme events has been deleted. The definition as proposed by SERC for a Bus-tie Breaker would apply to every breaker in any configuration. The definition in the Standard is trying to limit the application to a connection between configurations of buses, which could include flat buses, ring buses, breaker and a half, etc. The SDT is deliberately using the term configuration to avoid unintentionally excluding a particular configuration. No change made. The definition for Supplemental Load Loss has been deleted. The definition for Load Reduction has been deleted.		
SERC Engineering Committee Reliability Review Subcommittee (RRS)	No	Revised Definitions are generally better than those from the previous version, but additional clarity could be provided. Supplemental Load Loss - From a utility perspective, this would be considered as load response. Please clarify how Supplemental Load Loss would be included in the stability analysis. “Bus tie breaker “ A statement in the previous version which listed examples was removed from this version of the definition. The statement was helpful and should be re-inserted. The statement was: “Substation configurations such as ring bus, breaker and a half, or double-bus double-breaker do not use bus tie breakers. “Extreme Events definition references severity and probability. These terms should be included in the definition of Planning Events. Add a definition of Planned and Proposed facilities. Planned facilities address the near term deficiencies and have been approved with a financial commitment while proposed facilities address long term deficiencies for which no commitment is required today since they may change based on future evaluation. Consequential Load Loss - Is an SPS to trip load qualify as a planned protection system”? Load Reduction - Is this automatic as in a load response or is it operator initiated as in changes to transformer LTC? How would Supplemental Load Loss be included in the stability analysis? Table 1 suggests that it cannot be included to meet steady-state performance. Suggest that the following be added to the definition: Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements. “Where would interruptible load be included in these definitions” Bus-tie Breaker definitions still seems somewhat generic and the use of 'configurations' causes uncertainty. Revise Bus-tie Breaker to read, "A circuit breaker whose intended purpose is to connect two individual substation buses." "Bus-tie" is not capitalized in the Table. “Consequential Load Loss must include load that is lost due to the inherent response of the particular type of load. Some motors, lighting and processes will naturally trip during an event, although not as a result of the protection system. It may have been the intent of the SDT to include this phenomenon in the Supplemental Load Loss defintion. However, this definition includes the phrase, "by end-user equipment", and that makes one think that there are devices at the end-user location that is removing this equipment (and conversely, load that is not disconneted "by" end-user equipment cannot be

Organization	Yes or No	Question 8 Comment
		included). Also, the term "post-Contingency" can be confusing because in the case of faults, this phrase is not clear if it means conditions after the fault initiation itself or only after the clearing of the fault. Revise Supplemental Load Loss to read, "End-user Load that inherently disconnects from the System as a consequence of (or "in response") to the conditions created by the System event." SERC RRS suggests adding back the following to the Bus-tie breaker definition that was contained in Posting #2: ?Substations configurations such as ring bus, breaker and a half, or double bus double breaker protection schemes do not use bus tie breakers?. SERC Members believe that this additional wording helps explain this definition much more clearly. In Posting #2, undervoltage load shed, underfrequency load shed, and Special Protection Schemes were considered to be Non-Consequential Load Loss. Are these now no longer considered to be Non-Consequential Load Loss but instead now considered to be Load Reduction, Supplemental Load Loss, or something else? Should Supplemental Load Loss be further defined as load that is disconnected from the network by end-user equipment responding during duration of the fault as well as to post contingency system conditions? Also the definition of Supplemental Load Loss may benefit from some examples in the definition to further help clarify. The second sentence in the Year One definition is rather confusing. We would suggest changing “calendar year” to “date”. Otherwise it may be interpreted that Year One would begin 12 to 18 months from the end of the current calendar year. Suggest from “beginning”.

Response: The SDT has simplified the Non-Consequential Load Loss definition and has eliminated the references to Supplemental Load Loss and Load Reduction. The New definition is:

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.

In association with the changes in definitions, the SDT has revised note ‘b’ and added note ‘i’ in the header to Table 1.

Header note ‘b’: Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme event excluding P0.

Header note ‘i’: The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

The SDT removed the statement on Bus-tie Breakers because comments were received to indicate that although it was true for most applications, it wasn’t universal and examples were provided where bus tie breakers were used between ring buses, etc. No change made.

The SDT tried to address the concepts of planned and proposed in a prior posting. The response from industry strongly discouraged the standard from delving into the distinction. No change made.

An SPS does not qualify as a planned Protection System because it is not being used “to isolate the fault”, which is a condition of the statement. No change made.

The definition for Load Reduction has been deleted.

Interruptible load is either Consequential Load or Non-Consequential Load which is permitted to be lost for specific events and conditions defined in Table 1. No

Organization	Yes or No	Question 8 Comment
change made. The SDT removed the statement on Bus-tie Breakers because comments were received to indicate that although it was true for most applications, it wasn't universal and examples were provided where bus tie breakers were used between ring buses, etc. No change made. The definition for Supplemental Load Loss has been deleted. Bus-tie Breaker has been capitalized in the Table. The definition for Load Reduction has been deleted. The SDT removed the statement on Bus-tie Breakers because comments were received to indicate that although it was true for most applications, it wasn't universal and examples were provided where bus tie breakers were used between ring buses, etc. No change made. UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. No change made. The SDT has decided that it is inappropriate to include examples within a Standard's definition. The SDT is concerned that an example isn't all inclusive and it will create opportunities for loop holes. The definition for Year One has been revised to add clarity. The revised definition is: **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.		
FirstEnergy Corp	No	A. Supplemental Load Loss: We disagree with newly proposed definition for "Supplemental Load Loss" which is introduced to address some stakeholders concerns related to a Load's response to transient conditions. Table 1 note "b" causes confusion indicating that Supplemental Load Loss is an acceptable consequence of a Planning Event or an Extreme Event but then goes on to say that Supplemental Load Loss can not be relied upon to meet steady state performance requirements. This seems to imply that it is permissible to use Supplemental Load Loss for stability analysis. It is not logical to allow its use in one time frame but not the other. The inclusion of the Supplemental Load Loss definition enters into a power quality issue at the end-user delivery point which is not the focus of the TPL-001-1 standard. FE suggests that this definition be removed. B. Load Reduction: The new proposed definition of "Load Reduction" while technically written correctly may not align with its common use throughout industry. Load Reduction is often thought of as an operator initiated response, rather than a natural system response to a contingency event. If the definition remains, the SDT should consider striking the text "following a Planning or Extreme Event" so that the definition can more generally apply to other areas of the standards if needed. However, as stated in question 9, we believe Load Reduction was inadvertently omitted in note "b" of the Table 1. If so, we would have similar concerns with the occasional use of Load Reduction in that it would be allowed in stability and excluded in steady-state FE suggests that this definition be removed.The "Load Reduction" definitional term brings into question what is an acceptable steady-state load model within the TPL-001-1 standard. The standard provides some prescriptive language in requirement R2.4.1 regarding dynamic stability load models but is silent on steady-state load modeling. Most transmission planners use a conservative approach of simulating constant power loads in the steady-state environment and therefore the "Load Reduction" definition would not apply. However, if a constant impedance load

Organization	Yes or No	Question 8 Comment
		model were used, Load Reduction would be reflected and less conservative outcomes would result. At a minimum, the standard should require the transmission planner to document its load modeling assumptions for steady-state simulations. [See above comment on Question 2 regarding a proposed new R2.1.1 requirement] C. Year One: We continue to oppose the Year One definition developed by the SDT. In our Draft 2 comments, FirstEnergy proposed a Year One definition of "The planning year that begins with the upcoming annual period under study". During the last comment period we indicated:"We believe the attempt to try and delineate between the near-term planning horizon and operational planning horizon is not needed within the TPL standard and that the near-term period should account for the upcoming annual study periods. If not revised, the need for two near-term studies on an annual basis is overly burdensome as many transmission planning organizations perform upcoming annual seasonal assessments for seasonal peak (summer/winter) periods. Requiring an additional two studies near-term does not provide significant benefit. Further reasoning for making the change is the allowance of operating procedures as part of Corrective Action plans. Operating procedures can easily be developed and implemented to mitigate projected performance violations prior to an upcoming seasonal period." The SDT's response from the Draft 2 comment period indicated "The standard does not require that studies are duplicated. If an operating study can be used to demonstrate an assessment for planning purposes, then the operating study would be sufficient."Since "Year One" is defined as "...a planning window that begins 12-18 months from the current calendar year" we would appreciate the SDT reconciling their Draft 2 response to the Year One definition and confirm whether or not it intends that a study of the next occurring seasonal peak period would suffice for meeting one of the current year Near-Term studies as required in requirement R2.1.1.A secondary concern with the Year One definition is its reference to the Transmission Planner with no mention of the Planning Coordinator. D. Planning Assessment: We suggest that the team consider an enhancement to the definition of "Planning Assessment". When read independently within the NERC Glossary of Terms a lay person should have a better understanding of the transmission Planning Assessment and it should set the foundational understanding that a Planning Assessment is not equivalent to a single study but rather a collection of studies. Additionally, the definition should more explicitly apply to the TPL-001-1 intended purpose. We propose a new definition based largely on the verbiage in requirement R2. "Planning Assessment: An annual documented evaluation of future Transmission System performance predicted over a minimum 10-year period, based on new or previously completed simulation studies and the Corrective Action Plans needed to satisfy steady-state, stability and short circuit performance requirements." E. Planning Event: We propose that the definition of "Planning Event" more explicitly apply to the TPL-001-1 standard and read as follows: "Planning Event: A contingency condition evaluated for its steady-state and stability impacts on the BES transmission System, requiring Corrective Action plans to remedy identified deficiencies" F. Consequential Load Loss: We suggest that the definition be revised to more closely align with the text stated in requirement R3.3.1. The proposed definition would read "Consequential Load Loss: All Load that is no longer served by any Transmission Facilities as a result of the removal of all elements that the Protection System and other automatic controls are expected to disconnect for a transmission System Contingency without operator intervention." If our proposed new definition is not acceptable, we suggest that the word "automatically" be added between "being removed" and replace "a planned" with "as designed".

Organization	Yes or No	Question 8 Comment
Response: The definition of Supplemental Load Loss has been deleted from the revised standard. In association with the changes in definitions, the SDT has revised note 'b' and added note 'i' in the header to Table 1. **Header note 'b':** Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme event excluding P0. **Header note 'i':** The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements. The definition for Load Reduction has been deleted. The definition for Year One has been revised to reflect your comment. The revised definition is: **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year. The SDT does not agree with combining the types of studies in the definition of Planning Assessment. No change made. The definition for planning event has been deleted. The definition of Consequential Load Loss has been revised however the SDT did not believe that it was necessary to insert 'automatically' in the definition. The revised definition is: **Consequential Load Loss:** All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault .		
IRC Standards Review Committee New York Independent System Operator	No	The Year One definition is confusing. According to the definition, Year One can start any time between 12 and 18 months from a current calendar year. Is that January 1 of the current calendar year? Further, when does year 2, year 3, etc? start? Is this definition only applicable to the TP?
Progress Energy Carolina (PEC)	No	In this definition: "Year One: The first year that a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the current calendar year" recommend that the '12-18 months' specification be removed. It is confusing.
E.ON U.S.	No	Year One: The calendar year contains 12 months. As written, Year One could start as early as January 2010 (1/1/2009 plus 12 months) or as late as July 2011 (12/31/2009 plus 18 months). E.ON U.S. believes that the statement should be modified to: read " that begins 12-18 months from the beginning of the current calendar year". This would limit the beginning of the current window to be January 2010 or July 2010.
Midwest ISO	No	Year One: At a minimum the SDT needs to address the applicability of this definition to include both the Transmission

Organization	Yes or No	Question 8 Comment
		Planner and Planning Coordinator. The Year One definition needs additional clarification with the current calendar year. According to the definition, Year One can start any time between 12 and 18 months from a current calendar year. Suggested definition for Year One: The first year that each Transmission Planner and Planning Coordinator is responsible for conducting a Planning Assessment. This is further defined as the planning window that begins at least 12-18 months from the end of the current calendar year.
BPA		Definition of terms - Year one: The current draft defines "year one" as "the planning window that begins 12-18 months from the current calendar year". However it's not clear: 1. When this 12-18 months should start to be counted. Is it counted from Jaunuary 1 of this calendar year, or Dec. 31 of this calendar year, or somewhere in the middle of the year depending on the planning entity's choice. 2. Does this calendar year refer to the year when the annual assessment report is submitted, or the calendar year when the annual assessment is started? For example, we may start to work on an annual assessment report in late 2009 but finally complete it in early 2010. In this case which year should be the "current calendar year" for the report? Each year in July BCTC receives a new load forecast, which covers the next 10 years with year 1 starting on April 1 of the next calendar year. If we determine the TPL "year one" by counting 12-18 months from the beginning of this calendar year, we are oke to use this new load forecast. If we determine the TPL year one by counting 12-18 months from the end of this calendar year, the new load forecast for year 1 and year 10 are already out-of-date by the time we receive them. Clarify which year is the "current calendar year" and when is the start of the 12-18 months.
Response: Rather than removing the specification, the SDT has revised the definition to clarify the reference point. The revised definition is: **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.		
TVA System Planning	No	TVA suggests adding back the following to the Bus-tie breaker definition that was contained in Posting #2: Substations configurations such as ring bus, breaker and a half, or double bus double breaker protection schemes do not use bus tie breakers. TVA believes that this additional wording helps explain this definition much more clearly. In Posting #2, undervoltage load shed, underfrequency load shed, and Special Protection Schemes were considered to be Non-Consequential Load Loss. Are these now no longer considered to be Non-Consequential Load Loss but instead now

Organization	Yes or No	Question 8 Comment
		considered to be Load Reduction, Supplemental Load Loss, or something else? Should Supplemental Load Loss be further defined as load that is disconnected from the network by end-user equipment responding during duration of the fault as well as to post contingency system conditions? Also the definition of Supplemental Load Loss may benefit from some examples in the definition to further help clarify. Please clarify how Supplemental Load Loss would be included in the stability analysis. The second sentence in the Year One definition is rather confusing. We would suggest changing “calendar year” to “date”. Otherwise it may be interpreted that Year One would begin 12 to 18 months from the end of the current calendar year. Suggest from “beginning”. Load Reduction ? Please clarify whether this includes both load response and operator initiated action, such as in changes to transformer LTC. Should definition also include that this load is continuing to be served? Consequential Load Loss must include load that is lost due to the inherent response of the particular type of load. Some motors, lighting and processes will naturally trip during an event, although not as a result of the protection system. It may have been the intent of the SDT to include this phenomenon in the Supplemental Load Loss defintion. However, this definition includes the phrase, "by end-user equipment", and that makes one think that there are devices at the end-user location that is removing this equipment (and conversely, load that is not disconneted "by" end-user equipment cannot be included). Also, the term "post-Contingency" can be confusing because in the case of faults, this phrase is not clear if it means conditions after the fault initiation itself or only after the clearing of the fault. Revise Supplemental Load Loss to read, "End-user Load that inherently disconnects from the System as a consequence of (or "in response") to the conditions created by the System event."

Response: The SDT removed the statement on Bus-tie Breakers because comments were received to indicate that although it was true for most applications, it wasn’t universal and examples were provided where bus tie breakers were used between ring buses, etc. No change made.

The definition of Non-Consequential Load Loss has been revised to provide greater clarity.

> **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.

The definition for Supplemental Load Loss has been deleted.

The definition for Year One has been revised to reflect your comment. The revised definition is:

> **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.

The definition for Load Reduction has been deleted.

In association with the changes in definitions, the SDT has revised note ‘b’ and added note ‘h’ in the header to Table 1.

Organization	Yes or No	Question 8 Comment
Header note 'b': Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme event excluding P0. **Header note 'i':** The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements. The definition for Supplemental Load Loss has been deleted.		
Southern Company	No	We disagree with deleting the definition of system stability and generating unit stability. The proposed definition for Year One reads as follows Year One: The first year that a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the current year. Please clarify if this refers to the first "calendar" year when a Transmission Planner becomes responsible for assessments. If so, then add the word "Calendar" so that it reads "Year One: The first calendar year ..... .
Response: The SDT deleted the difference between generator unit Stability and System Stability due to a majority of comments received from industry in a previous posting. No change made. The definition for Year One has been revised to reflect your comment. The revised definition is: **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.		
United Illuminating	No	Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions resulting from a Planning or Extreme Event. Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction. Intended post contingency loss of load (other than Interruptible Load, Supplemental Load or Load Reduction) caused by operator or SPS (RAS) action. (Priority Comment)
Northeast Utilities Central Maine Power Company	No	Refine load loss definitions as follows.Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions resulting from a Planning or Extreme Event. Non-Consequential Load Loss: Intended post contingency loss of load (other than Interruptible Load, Supplemental Load or Load Reduction) caused by operator or SPS (RAS) action. (Priority Comment)
ISO New England, Inc.	No	Refine load loss definitions as follows.Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions resulting from following a Planning or Extreme Event. Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction. Intended post contingency loss of load (other than Interruptible Load, Supplemental Load or Load Reduction) caused by operator or SPS (RAS) action. (Priority Comment)

Organization	Yes or No	Question 8 Comment
Response: The definition for Load Reduction has been deleted. The SDT has simplified the Non-Consequential Load Loss definition and has eliminated the references to Supplemental Load Loss and Load Reduction. The New definition is: **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.		
System Protection and Transmission Planning Department	Yes	We appreciate the effort of the SDT to clarify "Consequential load loss", and think references to this term are clearer in this draft. Proxies?, used in R5, should be defined. See R5 comments for our suggestion.
Response: See response to question 5 comments. The term, "proxies" is not used in the revised standard.		
MidAmerican Energy Company	No	MidAmerican commends the SDT for its hard work on this standard. MidAmerican believes the SDT improved several of the definitions and believes additional changes are needed: For the bus-tie definition, what does "individual substation bus configurations" mean?? The consequential load loss states that it is load that "removed from service by a planned Protection System operation to isolate fault conditions". This implies that a contingency that does not involve a fault could never have consequential load loss. MidAmerican suggests that the words "to isolate fault conditions" be replaced with "in response to a contingency event". Alternatively, consider using the words in R3.3.1 which defines the same information but without referring to fault conditions. The definition of Long-Term Transmission Planning Horizon is confusing because it is not clear which term the words "when required to accommodate any known longer lead time projects that may take longer than ten years to complete" are meant to modify. MidAmerican believes the intent is that these words only apply to the years ten or beyond and not the entire period years six to ten and beyond. Therefore, we recommend that the words be changed by starting a new sentence in the definition and putting it in parentheses "(Years beyond ten years are required to accommodate any known longer lead time projects that may take longer than ten years to complete.) MidAmerican commends the SDT for improving the Year One definition. MidAmerican still believes the Year One definition is too confining. It indicates that the first year is defined as the planning window that begins 12-18 months from the current calendar year. This means if the regional entity provides models during the current calendar year in April, the responsible entity cannot use those models in conducting planning until a year that begins in May of the next year. Why delay the start of Year One? What is gained by this delay? MidAmerican recommends that Year One NOT be a defined term. This definition clarifies a term that does NOT need to be clarified for any reason. MidAmerican believe this is a fix for a problem that does not exist. Does the SDT have evidence of lack of compliance in this regard?? Modify the Planning Assessment definition to more explicitly apply to the BES and the TPL-001 requirements. We suggest text of: Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies in the BES from the steady state and stability performance requirements set forth in

Organization	Yes or No	Question 8 Comment
		the TPL-001 standard. Modify the Planning Events definition more explicitly apply to the TPL-001 requirements. We suggest text of: Planning Events: Events that are identified in the steady state and stability performance requirements set forth in the TPL-001 standard.
Response: Bus configurations could include flat buses, ring buses, breaker and a half, etc. The reference to fault conditions was intentionally used to exclude SPS action. A Contingency without a fault would be an inadvertent or mis-operation, which is not directly addressed by this standard. No change made. The SDT did not recognize a benefit to the proposed wording change for the definition of Long-Term Transmission Planning Horizon. No change made. The SDT believes that a near term study requirement is a necessary part of the standard and that a definition for Year One is a necessary component to achieve that objective. The SDT has received several constructive comments on this and has made revisions to the definition. Although revisions fall short of your suggestion, the SDT hopes that additional clarity will help. The revised definition is: **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year. As stated in the "Purpose" the Standard establishes Transmission System planning performance for the BES. Repeating that within the Standard creates opportunities for confusion whenever it is not specifically noted. The SDT wants to minimize confusion by not repeating applicability throughout the document. Also the Planning Assessment involves more than remedying identified deficiencies. For example, it may also confirm that there are no deficiencies or it may evaluate the impacts of schedule changes in the Corrective Action Plans. No change made. The definition for planning events has been deleted.		
Gainesville Regional Utilities	Yes	But as referenced in question 5, I believe you need a good definition for the following terms; "cascading outages", "voltage instability", and "uncontrolled islanding".
Response: The SDT sees no reason to define "cascading outages", "voltage instability", or "uncontrolled islanding" in TPL-001-1. If Gainsville wishes to pursue, please draft a SAR. No change made.		
Progress Energy Florida, Inc.	No	PEF continues to disagree strenuously with differentiating between Consequential Load Loss and Non-Consequential Load Loss. PEF does not believe that load loss has anything whatsoever to do with demonstrating the robustness of the BES. The approach the SDT is taking with TPL-001-1 is essentially "Feeder Reliability", rather than BES Reliability. Should the SDT decide that they must continue with this approach, PEF will explore options for expressing concern about this at the FERC level. PEF is perplexed by the definition of Supplemental Load Loss. PEF, as a Transmission Owner, considers its "end-user" to be the Distribution System. PEF would therefore use this definition to design Distribution-side controlled load curtailment schemes that essentially qualify as Consequential Load Loss. If this is not the intent of the SDT, PEF suggests that the

Organization	Yes or No	Question 8 Comment
		SDT modify this definition to make its meaning clearer.
Response: The SDT has revised the definitions and notes in the table, which should clarify the reference to the end-user. Pertinent revisions are: **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment. **Header note 'b':** Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme event excluding P0. **Header note 'i':** The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.		
Ameren	No	Extreme Events definition references severity and probability. These terms should be included in the definition of Planning Events. Add a definition of Planned and Proposed facilities. Planned facilities address the near term deficiencies and have been approved with a financial commitment while proposed facilities address long term deficiencies for which no commitment is required today since they may change based on future evaluation. Revised Definitions are generally better than those from the previous version, but additional clarity could be provided. Consequential Load Loss ? Would an SPS to trip load qualify as a planned protection system? Load Reduction ? Please clarify whether this includes both load response and operator initiated action, as in changes to transformer LTC. Supplemental Load Loss - From a utility perspective, this would be considered as load response. Please clarify how Supplemental Load Loss would be included in the stability analysis. Table 1 suggests that it cannot be included to meet steady-state performance. Suggest that the following be added to the definition: Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements.
Response: The definitions for both extreme events and planning events have been deleted. The SDT tried to address the concepts of planned and proposed in a prior posting. The response from industry strongly discouraged the standard from delving into the distinction. No change made. An SPS does not qualify as a planned Protection System because it is not being used "to isolate the fault", which is a condition of the statement. The definition for Load Reduction has been deleted. In association with the changes in definitions, the SDT has revised note 'b' and added note 'i' in the header to Table 1. **Header note 'b':** Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme event excluding P0. **Header note 'i':** The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an		

Organization	Yes or No	Question 8 Comment
event shall not be used to meet steady state performance requirements.		
Manitoba Hydro	No	Consequential Load Loss: the wording "by a planned Protection System operation to isolate fault conditions" is awkward wording. The wording should be changed to "by a Protection System operation designed to isolate fault conditions". Load Reduction: This definition is not needed and load reduction is not prohibited in the standard. It will take some effort to even measure such a load reduction in simulation. Given that there are four load related definitions, the standard would be simplified by deleting this term. Any voltage dependent load will be reduced for a low voltage condition. In steady state (P0), load is normally modeled as constant MVA load so load is constant. In the steady state period after a contingency, transformer taps and voltage control devices will restore voltage, and consequently, any load modeled as voltage dependent will be restored to pre-contingency level. The term is not used anywhere in the requirements of the standard - it is only included in Table 1 Note b in the definition of Non-Consequential Load Loss. We do not think it is needed. Supplemental Load Loss: Why did the drafting team decide to include Supplemental load loss? In Table 1, it is stated under "note b" that Supplemental Load Loss cannot be used to meet steady state performance requirements. Does this imply that it is acceptable for "non-consequential" induction motor load to trip off as a result of undervoltage during the disturbance due to its protection setting? It is possible that this load loss during a stability simulation may avoid the need to add dynamic reactive support. Can the drafting team clarify the intent of the standard or delete Supplemental Load Loss. At minimum, the TP/PA should identify the minimum transient voltage that they are planning the system for. In that way, any load loss for unplanned events that cause lower transient voltages or load loss that occurs at a higher transient voltage wouldn't be a violation. Also, unless the end-user load is modeled in detail, or a proxy is used, the planner will not know if such load exists or would be lost in the simulation.
Response: The definition for Consequential Load Loss has been revised to reflect your comment. The revised definition is: **Consequential Load Loss:** All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault . The definitions for Load Reduction and Supplemental Load Loss have been deleted. In association with the changes in definitions, the SDT has revised note 'b' and added note 'h' in the header to Table 1. **Header note 'b':** Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme event excluding P0. **Header note 'i':** The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.		
National Grid	No	Comments: Can the definitions of the "Planning Horizon" in the FAC, the "Long-term Planning" Time Horizon (italicized and in parentheses next to the Violation Risk Factor), and the "Near-Term" and "Long-Term Transmission Planning" be included in the definitions section to avoid confusion" Refine load loss definitions as follows. Consequential Load Loss: All Load that is no longer served by any Transmission

Organization	Yes or No	Question 8 Comment
		Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. Comment It is not clear if Consequential load includes load that is connected to transmission within an island. Suggest revising the definition to "..load no longer served by the Transmission System (or perhaps by the BES?) as a result of Transmission Facilities being removed?" Load Reduction: Quantity of Load that is reduced due to lower voltage conditions resulting from a Planning or Extreme Event. Comment "Load Reduction" as written is the load remaining after the reduction. This should be rewritten to indicate it is the change in load from the previous value to that still connected. Also, the defined term "Load Reduction" is counter to what most engineers consider to be a load reduction and as written it does not seem necessary to define this term. Most engineers associate Load Reduction as a manual or automatic action by a customer to reduce demand. As defined it appears that Load Reduction refers only to the voltage sensitivity of load which should be captured in the system model if it is necessary to model this effect. Therefore the reference should be changed from "Load Reduction" to "Voltage Sensitive Load Loss". Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction. Comment The definition is indirect. Suggest to revise the definition to be direct by stating "Intended post contingency loss of load (other than Interruptible Load, Supplemental Load or Load Reduction) caused by operator or SPS (RAS) action. Planning Events: Events that require Transmission system performance requirements to be met.Comment - Suggest "Events for which Transmission system performance requirements shall be met". Supplemental Load Loss: Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.Comment - Suggest rewording last phrase to "..responding to System Contingency conditions." - or perhaps just "..responding to System conditions." Year One: The first year that a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the current calendar year. Comment - Suggest rewording second sentence to "This is further defined as beginning 12-18 months from the current calendar year." - This avoids the awkwardness in present draft of seeming to define Year One as a planning window as well as a particular year.

Response: The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made.

Mitigation Time Horizon

The time horizons available for mitigating a violation to a requirement include the following:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.

Organization	Yes or No	Question 8 Comment
• **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system. • **Operations Assessment** — follow-up evaluations and reporting of real time operations. The definition for Consequential Load Loss has been revised to reflect your comment. **Consequential Load Loss:** All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault . The definitions for Load Reduction and Supplemental Load Loss have been deleted. The definition for Planning Event has been deleted. The definition for Year One has been revised to reflect your comment.. The revised definition is: **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.		
Entergy Services, Inc	No	Include a definition of "planned facilities": Facilities that address the near-term deficiencies and have been approved with a financial commitment. In Posting #2, undervoltage load shed, underfrequency load shed, and Special Protection Schemes were considered to be Non-Consequential Load Loss. Are these now no longer considered to be Non-Consequential Load Loss but instead now considered to be Load Reduction, Supplemental Load Loss, or something else?
Response: The SDT tried to address the concepts of planned and proposed in a prior posting. The response from industry strongly discouraged the standard from delving into the distinction. No change made. UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. No change made.		
BC Hydro	No	Comments: In almost all instances, the word "horizon" should be changed to "period" in both the definitions and throughout the standard. The word horizon refers to the end of the period; it literally means, "the limit of one's mental outlook" and the horizon is normally the furthest we can see. A long-term horizon-year study would be a study of conditions expected in the last year of the long-term planning period (often the 10th or 20th year). A long-term horizon-year study would not be expected to refer to a series of studies of each year in the long-term planning period.
Response: The reference to 'Horizon' is not something new and the SDT does not agree with changing it. No change made.		
PJM	No	Planning Events and Extreme Events should refer to the lists in the tables since there is no other way to understand which contingency falls into what definition. The designation is deterministic and somewhat arbitrary but commonly accepted.

Organization	Yes or No	Question 8 Comment
Response: The definitions for planning events and extreme events have been deleted.		
American Electric Power	No	"Load Reduction" does not need to be retained as a defined term; in fact it only appears once in the draft standard at the top of Table 1. In addition, it is well understood that load is sensitive to voltage, so it seems unnecessary to call attention to it. Furthermore, the "Supplemental Load Loss" definition should also be removed. These definitions are not generally relevant to planning studies. Neither steady-state nor stability planning studies should acknowledge or rely on "Supplemental Load Loss" because it is simply unpredictable without detailed load device protection data. In fact, properly set minimum voltage limits should ensure that no appreciable load is tripped by customer equipment response as long as that equipment meets generally accepted equipment and design standards. For the same reason, steady-state planning studies should not rely on "Load Reduction" because the planning function is supposed to ensure that a designated forecasted load can be served under credible contingencies. However, it is okay that stability studies acknowledge and rely on load voltage sensitivity ("Load Reduction"), and in fact this is required due to the nature of the analysis and cannot be otherwise. Therefore, there is no need to call attention to it.Given the above comments, the remaining two load loss definitions should be further clarified, though not changed substantively, to read as noted below. Consequential Load Loss: All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. It excludes Load that is disconnected from the network by load internal protection or end-user equipment responding to post-Contingency System conditions. Also, it excludes Load that remains connected to the System, but that may be reduced due to lower voltage conditions as a consequence of a Planning or Extreme Event.Non-Consequential Load Loss: Any Load loss intentionally caused due to automatic system protective functions such as UVLS, special protection systems, or as the result of operating procedures. Finally, the lettered bullets at the top of Table 1 need to be modified as appropriate to reflect the above comments that load loss due to internal load protection or end-user equipment, what was called "Supplemental Load Loss", should NOT be permitted in complying with either steady-state or stability performance criteria. Load that remains connected to the System, but that may be reduced due to lower voltage, should NOT be permitted in complying with steady-state performance criteria, but should be allowed, by necessity, in complying with stability performance criteria.
Response: The definitions for Load Reduction and Supplemental Load Loss have been deleted. The definitions for Consequential and Non-Consequential Load loss have been revised **Consequential Load Loss:** All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault . **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including		

Organization	Yes or No	Question 8 Comment
Load that is disconnected from the System by end-user equipment. In association with the changes in definitions, the SDT has revised note 'b' and added note 'i' in the header to Table 1. **Header note 'b':** Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme event excluding P0. **Header note 'i':** The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements. UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. No change made.		
Northern Indiana Public Service Company	No	The definitions need clarification, especially if they will be extracted from the standard when approved and included in the NERC Glossary. The SDT should include a Technical Writer to clarify the proposed language.
Response: Thank you for your response.		
Platte River Power Authority	No	Non-Consequential Loss of Load - It is not clear in all the Load Loss definitions where planned load shedding or "controlled interruption of electric supply" belong. However, the NERC Webinar on June 30 was very helpful, and I make the following comment in line with the answer I heard to my question. A "Yes" in the last column of Table 1 means that planned load shedding or "controlled interruption of electric supply" is allowed for that Category of Contingencies. (For a P2.2 Bus Section Fault, SLG, HV, "Yes", one could choose to implement a planned load shedding procedure or scheme to meet system performance requirements.) Planned load shedding may be manual load shedding or automatic actions such as direct load tripping or UVLS for example. Therefore, please add mention of the planned load shedding or the "controlled interruption of electric supply" and list specific examples in the definition for "Non-Consequential Loss of Load."
Response: The SDT has decided that it is inappropriate to include examples within a Standard's definition. The SDT is concerned that an example isn't all inclusive and it will create opportunities for loopholes. No change made. UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. No change made.		
American Transmission Company	No	We suggest the following comments: Add a Consequential Generation Loss definition because both load and generation loss can be considered, but there is only Consequential Load Loss definition. We suggest text of: "Consequential Generation Loss: All Generation that is no longer delivered to any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions.

Organization	Yes or No	Question 8 Comment
		Expand the Consequential Load Loss definition to include protection for abnormal operating conditions. We suggest text of: "Consequential Load Loss: All Load that is no longer served by any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions. Expand the Load Reduction definition to include consideration of TOP judgment and established protection schemes. We suggest text of: "Load Reduction: The reduction of Load that is still connected to the System, but in the judgment of the Transmission Operator or through the previous established Special Protection Systems, Under-frequency Load Shedding programs, Over-frequency Load Shedding program, should be reduced to overcome to lower voltage conditions following a Planning or Extreme Event. Modify the Planning Assessment definition to more explicitly apply to the BES and the TPL-001 requirements. We suggest text of: "Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies in the BES from the steady state and stability performance requirements set forth in the TPL-001 standard. Modify the Planning Events definition to more explicitly apply to the TPL-001 requirements. We suggest text of: "Planning Events: Events that are identified in the steady state and stability performance requirements set forth in the TPL-001 standard. Expand the Year One definition to include the PC, refer to the Planning Assessment, and refer to the current calendar year. We suggest text of: "Year One: The first year that each Transmission Planner and Planning Coordinator is responsible for conducting a Planning Assessment. This is further defined as the planning window that begins 12-18 months from the current calendar year.

Response: Requirement R2, part 2.7.1 allows for generation tripping and run-back, so a definition for Consequential Generation Loss is not required.

The definition for Consequential Load Loss has been revised to provide greater clarity.

> **Consequential Load Loss:** All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault .

The definition for Load Reduction has been deleted.

UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. No change made.

As stated in the "Purpose" the Standard establishes Transmission System planning performance for the BES. Repeating that within the Standard creates opportunities for confusion whenever it is not specifically noted. The SDT wants to minimize confusion by not repeating applicability throughout the document. Also the Planning Assessment involves more than remedying identified deficiencies. For example, it may also confirm that there are no deficiencies or it may evaluate the impacts of schedule changes in the Corrective Action Plans. No change made.

The definition of planning events has been deleted.

Organization	Yes or No	Question 8 Comment
The definition for Year One has been revised to reflect your comment. The revised definition is: **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.		
Duke Energy	No	Bus-tie Breaker definitions still seems somewhat generic and the use of 'configurations' causes uncertainty. Revise Bus-tie Breaker to read, "A circuit breaker whose intended purpose is to connect two individual substation buses." "Bus-tie" is not capitalized in the Table. Consequential Load Loss must include load that is lost due to the inherent response of the particular type of load. Some motors, lighting and processes will naturally trip during an event, although not as a result of the protection system. It may have been the intent of the SDT to include this phenomenon in the Supplemental Load Loss definition. However, this definition includes the phrase, "by end-user equipment", and that makes one think that there are devices at the end-user location that are removing this equipment (and conversely, load that is not disconnected "by" end-user equipment cannot be included). Also, the term "post-Contingency" can be confusing because in the case of faults, this phrase is not clear if it means conditions after the fault initiation itself or only after the clearing of the fault. Revise Supplemental Load Loss to read, "End-user Load that, due to its characteristics, disconnects from the System in response to the conditions created by the System event."
Response: The definition as proposed by Duke Energy for a Bus-tie Breaker would apply to every breaker in any configuration. The definition in the Standard is trying to limit the application to a connection between configurations of buses, which could include flat buses, ring buses, breaker and a half, etc. The SDT is deliberately using the term configuration to avoid unintentionally excluding a particular configuration. No change made. The table has been updated to capitalize the term, “Bus-tie Breaker” where used. The definition for Supplemental Load Loss has been deleted. The definition for Consequential Load Loss has been revised to reflect your comments. The revised definition is: **Consequential Load Loss:** All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault .		
Independent Electricity System Operator	No	Is Year One intended to coincide with a calendar year or can it start in any month of the year? We suggest the following change to the definition. Insert “calendar” before “first” and “within” before “12” and change “from” to “of”. NERC should seek to reinstate a definition of “cascading outages” and create one for “uncontrolled islanding”.
Response: The definition for Year One has been revised to reflect your comment. The revised definition is: **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.		

Organization	Yes or No	Question 8 Comment
The SDT sees no reason to define “cascading outages” or “uncontrolled islanding” in TPL-001-1. If IESO wishes to pursue, please draft a SAR. No change made.		
Kansas City Power & Light	Yes	
Dominion - Electric Transmission	Yes	
Transmission Planning	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
Exelon Transmission Planning	Yes	
Western Area Power Administration	Yes	
Tampa Electric	Yes	
Florida Reliability Coordinating Council, Inc - Transmission Working Group	Yes	Excellent changes
FMPA	Yes	
CPS Energy	Yes	
JEA	Yes	
Brazos Electric Cooperative	Yes	
ITC Holdings	Yes	None

Organization	Yes or No	Question 8 Comment
Minnesota Power	Yes	
Orlando Utilities Commission	Yes	Good Job.
ReliabilityFirst Corporation	Yes No	It would have been nice if a red lined list of these changes is attached to the standard.
Response: Thank you for your response. However, due to other comments, several definitions have been changed as shown above.		

9. Do you agree with the changes in the performance elements and notes in Table 1? If not, please provide specific comments by note number, note alpha character, or performance category. Please note that footnotes 5 and 10 are handled separately in question 10.

Summary Consideration: While many comments were received from industry for this question, the vast majority of them were of a clarifying nature. While there were still a few questions on raising the bar for 300 kV, the actual performance elements now seem to have been honed to a point that is acceptable. The following changes were made due to industry comments:

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.

R5 Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltages may remain outside that level.

Header note 'a': BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur.

Header note 'c': Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

Header note 'f': Facility Ratings shall not be exceeded.

Header note 'k': Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

P4: Loss of multiple elements caused by a stuck breaker [11](non-Bus-tie) attempting to clear a Fault on one of the following: & 6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie) attempting to clear a Fault on the associated bus

P7: Any two adjacent (vertically or horizontally) circuits on common structure

Extreme event 'a': Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency

Extreme event steady state 1: Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.

Extreme event Stability 1: With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.

Footnote 2: Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.

Footnote 3: Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems as defined by the Regional Entity. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruptions of Firm Transmission Service and Non-Consequential Load.

Footnote 7: Opening breaker(s) without a fault on one end of a normally networked Transmission circuit such that the line is now open at that end and possibly serving Load radial from a single source point.

Footnote 10: A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing .

Footnote 11: Excludes circuits that share a common structure or common Right-of-Way for 1 mile or less.

Organization	Yes or No	Question 9 Comment
Northeast Power Coordinating Council	No	For Steady State & Stability: Steady State & Stability: a. Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur. b. Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirementsP5 Priority Comment As written, this requirement is overly severe. This would require the simulation of a “dead” station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. P7 Priority Comment Event 1 - This requirement requires the evaluation of the loss of two circuits on a multiple circuit tower. We recommend that this be modified so that only the loss of two adjacent (vertically or horizontally) circuits need be evaluated. We also recommend that the Planning Coordinator be allowed to evaluate and if appropriate exempt specific locations from this contingency based on acceptable risk. Comments on Extreme Events Table 1- We recommend renumbering the Extreme Events table to be Table 2. Stability Condition 2 Note a - Priority Comment - As written, this requirement is overly severe. This would require the simulation of a “dead” station if only one battery is present (use of NERC Glossary’s Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. Stability Condition 2 Note h “ Eliminate this requirement or change to loss of station following three-phase fault. This note is confusing. Without providing a better defined scenario, it is unclear as to what clearing times should

Organization	Yes or No	Question 9 Comment
		be used in this simulation. Comments on Footnotes " Table 1- We recommend renumbering the Footnotes table to be Table 3. Footnote 1.a.i " Should clarify that this requirement refers to generator units that are connected to the BES system. Footnote 1.a.ii " Contingency Reserve is dependent on the generation on-line. We suggest changing the first sentence to say that you can't lose more than that permissible by the Planning Coordinator. Also change "pull out of synchronism" to "lose synchronism" in this sentence and in the second sentence. (Is "Lose synchronism" a more commonly used term?). Footnote 1.a.i, states "For Planning Event P1: No generating unit or units shall be allowed to pull out of synchronism." There is the potential for this requirement to be taken too far. Does this mean that someone's 4 kW generator at home needs to remain synchronized? Therefore, there needs to be some sort of qualifier on this requirement. Suggested wording: "For Planning Event P1: No generating unit or units greater than 20 MW and directly interconnected at 100 kV or above shall be allowed to lose synchronism. Note that synchronism applies to conventional synchronous generators and may not apply to other generation technology." Footnote 3 " We recommend revising the wording of the last sentence to "A three phase fault study indicating criteria are being met is sufficient evidence that a SLG condition would also meet criteria. Footnote 4 " We recommend that a lower bound be put on the HV electric systems (such as 100 kV), rather than just saying "and lower". As has been commented on in a previous draft, the Drafting Team should also consider not having a prescribed voltage definition of BES, be it called EHV or HV. Studies should determine what facilities should be part of the BES because of their impact on reliability. A proposal is to modify Footnote 4 to replace the phrase "?(EHV) Facilities defined as greater than 300 kV?? with "?(EHV) Facilities defined as having a significant impact on the reliability of the System, generally at voltages greater than 300 kV as determined by the Planning Coordinator?? In using such language, the more stringent requirements could apply to BES/EHV but not globally for Facilities operating at voltages greater than 300 kV. Using this methodology the extra investment required would go towards real improvement of the reliability of the System. EHV and HV should be added to the Definitions of Terms Used in Standard. Footnote 12 We recommend adding an alternative modifier to the end of the sentence, "or for 5 towers or less. This is consistent with NPCC criteria.

Response: NPCC suggested adding the word 'Transmission' to the beginning of header note 'a'. In TPL-001-1, draft 4, the SDT made a change to header note 'a' as suggested by the commenter but modified it to be 'BES Transmission'.

Header note 'a': BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur.

Additionally it is proposed to state in header note "b" that Load Reduction is not an acceptable means to meet steady state performance requirements. Regarding the

Organization	Yes or No	Question 9 Comment
suggested change to header note 'b', no change was made as the standard does not prescribe a particular Load model such as constant power, constant impedance, etc. Depending on the assumptions used by the Transmission Planner, a Load Reduction could occur in the steady state analysis. In response to industry comments on TPL-001-1, draft 2, the SDT clarified that the P5 event is not intended to include an evaluation of individual components of the Protection System. The intent of P5 is to evaluate the failure of a Protection System design, and it is not based on any particular component of that design. Also, please see the Summary Considerations for Question 7 from the second posting comments; specifically item 3 on page 207. The suggested wording change to include 'adjacent' for the P7 planning event is accepted by the SDT and reflected in TPL-001-1, draft 4. The SDT does not accept the proposed provision for the Planning Coordinator to exempt locations for study of the P7 event beyond what is already exempted per footnote 11. **P7:** Any two adjacent (vertically or horizontally) circuits on common structure The suggested change to reference the extreme events as Table 2 was not accepted by the SDT. The team feels sufficient clarity is provided by the division breaks within the table. The table is to be viewed holistically as a single table stating performance requirements and reference notes for the TPL-001-1 standard. Regarding extreme event Stability item 2a, the response to your P5 comment above applies. No changes were made in regard to extreme event 2a. Regarding extreme event Stability item 2h, items 2f through 2h are deleted as this was a mis-interpretation of the existing table and are not required in the Stability timeframe. The suggested change to reference the Footnotes area as Table 3 was not accepted by the SDT. The team feels sufficient clarity is provided by the division breaks within the table. The table is to be viewed holistically as a single table stating performance requirements and reference notes for the TPL-001-1 standard. Footnote 1 has been deleted and moved into Requirement R4, parts 4.1.1 – 4.1.3. The indicated change was not made by the SDT as it was felt that it added no additional clarity. Regarding footnote 1.a.ii the SDT did not accept the proposed wording changes related to loss of synchronism. The change proposed was not substantive and the wording presently used, "pulling out of synchronism", is sufficient. Footnote 1 has been deleted and moved into Requirement R4, parts 4.1.1 – 4.1.3. No change made. Regarding the suggestion for the Planning Coordinator to establish the maximum allowable amount, the SDT has set a maximum and believes that it is the appropriate value. An entity can always set more stringent criteria. No change made. The comment on footnote 1.a.i is redundant and already addressed above. Footnote 1 has been deleted and moved into Requirement R4, parts 4.1.1 – 4.1.3. The SDT accepts the NPCC proposed change for footnote 3 (now footnote 2). **Footnote 2:** Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. Regarding footnote 4 (now footnote 3), the SDT does not accept the proposed change to establish a lower bound on the HV electric System. The lower bound is based on the BES definition established by a Regional Entity organization. While this is generally understood to be 100kV, it may vary throughout the North American footprint. The SDT has however modified footnote 3 for clarity. **Footnote 3:** Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems as defined by the Regional Entity. The designation of EHV and HV is used to distinguish		

Organization	Yes or No	Question 9 Comment
between stated performance criteria allowances for interruptions of Firm Transmission Service and Non-Consequential Load. Regarding footnote 4 (now footnote 3), the commenter suggest that the standard should not prescribe a voltage definition of BES, be it called EHV or HV and that studies are needed to determine BES Facility definitions. The BES definition is defined by the Regional Entity organization and studies are not generally relied upon for BES determination. The additional changes suggested in revising footnote 3 to limit the EHV definition to only those Facilities deemed significant to reliability as determined by the Planning Coordinator was not accepted by the SDT. Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined. The EHV and HV definitions are not being added to the NERC Glossary of Terms based on their limited use within the TPL standard. Regarding footnote 12 (now footnote 11), the 1 mile exception is more precise as span lengths can vary greatly between towers. No change was made.		
Transmission Planning	No	COMMENT: P2-1. Opening of Breaker(s) w/o fault Event: Does the modeling of this event require that the line remains energized up to the breakers" This will require adding a bus at each end with a zero impedance branch connection to "open" representation of breakers. Explicit modeling of a circuit breaker opening would require a substantial modeling effort and would not produce results more adverse than any of the other P2 contingencies. Why is this necessary? Recommend deletion of this planning event. The threshold of higher performance for facilities above 300 kV may wrongly influence decisions on project alternatives in favor of facilities with less stringent requirements. We do not agree that such a threshold is necessary or warranted.
Response: In Draft 3, footnote 8 (now footnote 7) was added to further clarify the need for the P2-1. There is no need to show a line energized up to the breakers that opened. The intent is simply to look for low voltage or thermal problems while supplying Load from one end of a normally networked line. The SDT does not believe the proposed higher performance requirements for the EHV will cause a disincentive for the EHV infrastructure. Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined. No change made.		
SERC Engineering Committee Planning Standards Subcommittee	No	Table 1 titles: The word "Requirements" needs to be added to the Table 1 titles in the existing tables. Table 1 " Steady State & Stability Performance Requirements Planning Events Table 1 " Steady State & Stability Performance Requirements Extreme Events Table 1 " Steady State & Stability Performance Requirements Footnotes (Planning Events and Extreme Events)Steady-state vs. stability analysis: We recommend that Table 1 be split back as was done in the previous draft to handle the 1) steady-state and 2) stability performance requirements. This is needed to provide clarity on which contingencies apply to steady-state and which apply to stability analysis. Table I, P7.1: It would not be likely to lose the two outside circuits on a vertically configured structure and not lose the middle circuit. Change the wording to: "Any two adjacent circuits on a common structure.
Response: The Table 1 title does not include the word requirements since the table is referenced by the requirements of the standard. For example, see		

Organization	Yes or No	Question 9 Comment
Requirements R3, parts 3.1 and 3.4 which require the Transmission Planner to develop Contingency lists for study based on the table performance requirements. The tables were combined for convenience since each Contingency event was the same in each table and based on stakeholder input. The Fault Type column adequately describes what fault type is required for study in the dynamic Stability timeframe. No change made. The suggested wording change to include "adjacent" for the P7 planning event is accepted by the SDT and reflected in Draft 4. **P7:** Any two adjacent (vertically or horizontally) circuits on common structure		
Duke Energy	No	Stability Extreme 2g needs a note like number 12 that excludes short distances. Stability Extreme 2h: Is this meant to be an event initiated by a 3LG fault or is it a catastrophic event that leaves all the elements at a station with a 3LG fault. If it is the former, then 2h needs a note to limit this to locations where actual events could lead to the loss of the entire station. There is no need to study this if there are no protection system events that lead to loss of the whole station (there would be no scenario to model). If 2h is meant to represent some catastrophe that causes all the elements at the site to experience a fault, then some clarification is needed to get consistent studies. Possibly rewrite 2h as, ?Assume all the buses at a single voltage level (one voltage level plus transformers) experience an event that results in a 3LG fault and disables local protection (fault must clear from remote stations or other side of transformer).
Response: The SDT agrees with the proposed addition of a footnote to address a threshold distance for circuits considered for study in loss of common Right-of-Way. The team has set the threshold at 1 mile or more, consistent with footnote 11. Footnote 11 (formerly footnote 12) was revised to account for both the common tower and common Right-of-Way exemption. Footnote 11 has been added to the extreme event Stability 2f and steady-state 2b. **Footnote 11:** Excludes circuits that share a common structure or common Right-of-Way for 1 mile or less Regarding extreme event Stability item 2h, items 2f through 2h are deleted as this was a mis-interpretation of the existing table and are not required in the Stability timeframe.		
Modesto Irrigation District	No	On page 20 under Table 1, why are "SLG" (i.e., single line to ground) type faults still specified when footnote 3 on page 24 indicates that analyzing three phase faults is sufficient ? On page 20 under Table 1 part f, changing "post transient" to "post Contingency" may be confusing to most analysts as post-transient is a well defined term that has been in use for many years, and is even referenced in Table W-1 of the WECC supplemental planning standard TPL - (001 thru 004) " WECC " 1 - CR. On page 20 under Table 1 part g, does that mean that for Planning Event P0 the analyst is not required to simulate a fault with normal clearing without a loss of any system element, in order to demonstrate system stability " On page 24 under Footnote 1 a ii, I would like to suggest that we add the phrase "(unless the relays are equipped with blinders and timers)" right after the phrase "must not pass through relay characteristics". This is because the blinders (i.e., straight line characteristic of a distance relay) and timers can be used to prevent distance relays from tripping when power angle swings cause the apparent impedance the distance relays see to cross into the distance relay's zone of protection.

Organization	Yes or No	Question 9 Comment
Response: When a SLG fault type is specified in Table 1, it is the fault that must be satisfied to meet performance criteria for the referenced planning event. Since 3-phase faults are simpler to simulate, a planner may simulate the 3-phase fault and if performance criteria are met then no further work is needed since the 3-phase fault has a greater BES impact than an SLG fault. However, if the 3-phase screening does not meet performance criteria, then the planner must perform the more labor intensive SLG analysis to determine whether or not performance criteria are being met. Please see footnote 2. The change from post-transient to post-Contingency was made in the last draft since the note refers to a steady-state timeframe. No change made. No stability review for the P0 event is required. Footnote 1 has been deleted and moved to Requirement R4, parts 4.1.1 – 4.1.3 but the indicated change was not made as the SDT does not feel that it would add any clarity.		
Pepco Holdings, Inc. - Affiliates	Yes	PHI does not disagree with the performance elements, but suggests that the table would be improved if a leading sentence were added to the definition section at the beginning of the table.
Response: Without a specific recommendation, the SDT is unable to make a change.		
MRO NERC Standards Review Subcommittee	No	MRO NSRS suggests the following changes:MRO NSRS believes reference to the use of Load Reduction to meet steady state performance requirement was omitted in Planning Events, Steady State and Stability, Item b. MRO NSRS suggests modifying the last sentence in Item b: However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirements. MRO NSRS proposes limiting the scope to automatic devices in Planning Events, Steady State and Stability, Item c. MRO NSRS suggests text of: c. Simulate the removal of all elements that Protection Systems and other Controls are expected to disconnect automatically for each Contingency?. Modify the P3 Category performance criteria to apply only to the loss of two generators because probability of the loss of two base load generators is an order of magnitude higher than the loss of a generator and any other transmission element. MRO NSRS suggests the listing of: the loss of transmission circuit, transformer, shunt device, and single pole of DC line be removed from the P3 Events column. The corresponding events be moved to the P6 Category by “1. Generator” to the listing in the Initial System Condition (Loss of . . .) column. Limit the scope of the simulations in Item 1 of the Extreme Events, Steady State and Stability section to automatic systems and controls. MRO NSRS suggests this text: 1. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect automatically for each Contingency. Clarify the meaning of the loss of multiple circuits in Item 2.a of the Extreme Events, Steady State section by using wording similar to P7. MRO NSRS suggests this text: a. Loss of three or more circuits that share a common structure. Clarify the reference to actual, historical operating experience in Item 3.b of the Extreme Events, Steady State section. MRO NSRS suggests this text: b. Other events based upon actual operating experience that may result in wide area disturbances. Clarify the reference to actual, historical operating experience in Item 2.i of the Extreme Events, Stability State

Organization	Yes or No	Question 9 Comment
		section. MRO NSRS suggests this text that is similar to Steady State, Item 3.b: i. Other events based upon actual operating experience that may result in wide area disturbances. Further clarify the applicable shunt devices in Footnote 7 with this suggested text: 7. Requirements which are applicable to shunt devices, also apply to FACTS devices that are connected to ground, but not instrument voltage transformers or surge arresters.
Response: Regarding the suggested change to header note "b", no change was made as the standard does not prescribe a particular Load model such as constant power, constant impedance, etc. The SDT has added the suggested wording. **Header note 'c':** Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event. The SDT disagrees with the proposed change to the P3 event. The loss of a generator is highly probable and the SDT and other stakeholders support the P3 requirement to meet the P1 criteria for the loss of a generator unit plus the loss of any other P1 element, not just another generator. No change made. The SDT has added the suggested wording. **Extreme event 'a':** Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency The SDT disagrees that the proposed wording of extreme event 2a is needed since the proposed change is not substantive. The SDT disagrees that the proposed wording of extreme event 3b is needed since the proposed change is not substantive. Regarding the suggested change to footnote 7 (now footnote 6), the devices listed are not typically considered in a planning study. The SDT disagrees that the proposed change is needed for clarity. No change made.		
SERC Engineering Committee Dynamics Review Subcommittee (DRS)	No	P5 should not be a Planning Event. PRC Standards address protection system failures. The complexity associated with identifying and simulating such events is unknown and the defense of assumptions made and events simulated will lead to inconsistency in compliance and enforcement. Industry-accepted proxies for such events could be developed that would allow for efficient identification of areas needing further detailed study. Attempting to intermingle protection system operation with BES performance will be nearly impossible to implement given current technologies Stability Extreme 2g needs a note like number 12 that excludes short distances. Stability Extreme 2h: Is this meant to be an event initiated by a 3LG fault or is it a catastrophic event that leaves all the elements at a station with a 3LG fault. If it is the former, then 2h needs a note to limit this to locations where actual events could lead to the loss of the entire station. There is no need to study this if there are no protection system events that lead to loss of the whole station (there would be no scenario to model). If 2h is meant to represent some catastrophe that causes all the elements at the site to experience a fault, then some clarification is needed to get consistent studies. Possibly rewrite 2h as, "Assume all the buses at a single voltage level (one voltage level plus transformers) experience an event that results in a 3LG fault and disables local protection (fault must clear from remote stations or other side of transformer).

Organization	Yes or No	Question 9 Comment
Response: In P5 the event description was changed in Draft 3 to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to normal fault clearing. The SDT agrees with the proposed addition of a footnote to address a threshold distance for circuits considered for study in loss of common Right-of-Way. The team has set the threshold at 1 mile or more, consistent with footnote 12 (now footnote 11). Footnote 11 was revised to account for both the common tower and common Right-of-Way exemption. Footnote 11 has been added to the extreme event Stability 2f and steady-state 2b. **Footnote 11:** Excludes circuits that share a common structure or common Right-of-Way for 1 mile or less Regarding extreme event Stability item 2h, items 2f through 2h are deleted as this was a mis-interpretation of the existing table and are not required in the Stability timeframe.		
SERC Engineering Committee Reliability Review Subcommittee (RRS)	No	"The word "Requirements" needs to be added to the Table 1 titles in the existing tables.oTable 1 ? Steady State & Stability Performance Requirements Planning Events Table 1 ? Steady State & Stability Performance Requirements Extreme Events Table 1 Steady State & Stability Performance Requirements? Footnotes (Planning Events and Extreme Events)? We recommend that Table 1 be split back as was done in the previous draft to handle the 1) steady-state and 2) stability performance requirements. This is needed to provide clarity on which contingencies apply to steady-state and which apply to stability analysis. Table I, P7.1: It would not be likely to lose the two outside circuits on a vertically configured structure and not lose the middle circuit. Change the wording to: Any two adjacent circuits on a common structure. The word "Requirements" needs to be added to the Table 1 titles in the existing tables.oTable 1 Steady State & Stability Performance Requirements Planning Events Table 1 Steady State & Stability Performance Requirements Extreme Events Table 1 Steady State & Stability Performance Requirements? Since it appears that the Table 1 cannot fit on a single page, it is suggested that multiple tables be developed to handle the 1) steady-state and 2) stability performance requirements. Footnotes may be included on a second page if needed. Comments were provided in early versions regarding the issues associated with raising the bar, and it was suggested that the marginal reliability benefits associated with these changes were not worth the marginal costs. We have not seen any significant changes from the earlier performance requirements. The question still remains, are we directing the resources where they need to be allocated to address and improve system reliability? So far the answer is believed to be "No". The existing TPL 002-0 allows for some local load to be dropped for a single contingency event as long as the Bulk system reliability was not impacted. However there is no such allowance any longer for losing such load for a single contingency in the proposed draft. It would be very expensive for SERC Members to fix all such events in several remote areas that would have very little impact on the overall reliability of the SERC Members? bulk system. SERC Members believe that the capital spent for these fixes could be used to better strengthen the overall bulk system in much better ways.

Organization	Yes or No	Question 9 Comment
		P5 should not be a planning event. PRC standards address protection system failures. The complexity associated with identifying and simulating such events is unknown and the defense of assumptions made and events simulated will lead to inconsistency in compliance and enforcement. Industry accepted proxies for such events could be developed that would allow for efficient identification of areas needing further study. Attempting to intermingle protection system operation with BES performance will be nearly impossible to implement given current technologies.
Response: The Table 1 title does not include the word requirements since the table is referenced by the requirements of the standard. For example, see Requirement R3, parts 3.1 and 3.4 which require the Transmission Planner to develop Contingency lists for study based on the table performance requirements. The tables were combined for convenience since each Contingency event was the same in each table and based on stakeholder input. The Fault Type column adequately describes what fault type is required for study in the dynamic Stability timeframe. The suggested wording change to include "adjacent" for the P7 planning event is accepted by the SDT and reflected in Draft 4. **P7:** Any two adjacent (vertically or horizontally) circuits on common structure In regards to proposed change to prohibit Non-Consequential Load shed in response to a single Contingency event. FERC, in Order 693, was clear in paragraph 1794 that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the majority of the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement. The suggestion for multiple tables was not accepted by the SDT. The team feels sufficient clarity is provided by the division breaks within the table. The table is to be viewed holistically as a single table stating performance requirements and reference notes for the TPL-001-1 standard. In P5 the event description was changed in Draft 3 to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to normal fault clearing.		
FirstEnergy Corp	No	A. Note b: Please see comments in our response to Question #8 related to note b and the Supplemental Load definition. B. Note b: We believe the SDT inadvertently allowed the used of Load Reduction to meet Steady State performance requirements. We suggest text of: "However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirements." C. Note b: If our assumption is correct on item B above, we fail to see the need to define two terms Load Reduction and Supplemental Load Loss which are not permitted within the Table 1 performance requirements for steady-state nor mentioned and used within the requirement language. It appears that the Load Reduction and Supplemental Load Loss are permissible within the stability timeframe. It is not understood why it would be valid to account for these in the stability timeframe but not steady-state. D. Note i: What if the TP or PC has no criteria for transient voltage response? The standard should have a requirement that ensures that such a criteria is documented by the entity if it is intended to be used within the TPL-

Organization	Yes or No	Question 9 Comment
		001-1 standard. E. P2-3: It seems that footnote 10 should apply to the EHV criteria stated in the column titled "Interruption of Firm Transmission Service Allowed" since it applies for the P5-1 through P5-5 EHV criterion. F. P5: We agree with the change made in Draft 3 to remove the reference to "single component" of the Protection System. Additionally, the SDT clarified its intended purpose of the P5 event as stated in the Draft 2, Q7 Summary Considerations:"A number of commenters expressed concern related to Planning Event P5 Protection System Failure and the need to evaluate a single component failure of a BES Protection System; particularly a failure of a station battery. The SDT has revised the P5 Planning Event description to remove the reference to single component failure and the event description was changed to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to normal fault clearing. A Protection System failure resulting in loss of the substation (one voltage level plus transformers) would not qualify as a P5 Planning Event since that event is considered an Extreme Event. A Standard Authorization Request (SAR) has been issued for industry comment (1/20/2009 through 2/18/2009) based on work completed by the System Protection and Controls Task Force (SPCTF). The proposed project will address the need for Protection System redundancy, based on an n-1 failure of individual components of the Protection System."It is suggested that a footnote be added the text Protection System as stated in the P5 Event Description. The footnote should read "Failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to normal fault clearing. This contingency is NOT based on failure of any particular single component of the Protection System design." This footnote will help clarify the intent without having to rely on the Comment record established during this standard development project. G. In the Extreme Event table we suggest event identifiers that are similar to those used in the Planning Events table. For Extreme Steady State we suggest ESS1, ESS2-1, ESS2-1... ESS2-5, ESS3-1 and ESS3-2. For the Extreme Stability we suggest ES1, ES2-1...ES2-9. This will provide a short-cut reference for industry when referring to a particular event.

Response:

A) Please see our comments related to the Supplemental Load definition in question 8.

B) Regarding the suggested change to header note “b”, no change was made as the standard does not prescribe a particular Load model such as constant power, constant impedance, etc.

C) Voltage sensitive Load loss is permitted in the transient Stability timeframe as it is common in Stability simulation tools to assume a certain percentage of Load is removed based on motor stalling. To the extent a Transmission Planner accounts for this within their analysis, the standard does not prohibit its use in the Stability timeframe. However, for steady-state thermal and voltage criteria reviews the use of voltage sensitive Load loss is prohibited. The definition of Load reduction has been deleted and the concept has been incorporated in the definition of Non-Consequential Load Loss.

D) The standard drafting team has added new Requirement R5 to explicitly require criteria for transient voltage criteria.

Organization	Yes or No	Question 9 Comment
		R5 Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for their System. For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltages may remain outside that level. E) Footnote 10 (now footnote 9) does not apply since P2-3 is classified as a single Contingency. F) In regards to the P5 event, in response to industry comments on Draft 2, the SDT clarified that the P5 event is not intended to include an evaluation of individual components of the Protection System. The intent of P5 is to evaluate a failure of a Protection System design, and not based on any particular component of the design. Please see the Summary Considerations area of Question 7 from the Draft 2 comments; specifically item 3 on page 207. Since the P5 event description says loss of a single Protection System and not single Protection System device or component, the SDT believes sufficient clarity is inherent in the P5 event description. The proposed footnote was not accepted by the SDT. **G)** Regarding the proposed short-cut references to the extreme events, the SDT disagrees. No change made.
TVA System Planning	No	The existing TPL 002-0 allows for some local load to be dropped for a single contingency event as long as the Bulk system reliability was not impacted. However there is no such allowance any longer for losing such load for a single contingency in the proposed draft. It would be very expensive for TVA to fix all such events in several remote areas that would have very little impact on the overall reliability of the TVA bulk system. TVA believes that the capital spent for these fixes could be used to better strengthen the overall bulk system in much better ways. P5 should not be a planning event. PRC standards address protection system failures. The complexity associated with identifying and simulating such events is unknown and the defense of assumptions made and events simulated will lead to inconsistency in compliance and enforcement. Industry accepted proxies for such events could be developed that would allow for efficient identification of areas needing further study. Attempting to intermingle protection system operation with BES performance will be nearly impossible to implement given current technologies. Stability Extreme 2.g, and Steady State 2.b. both need a note like footnote number 12 that excludes short distances. Suggest footnote #12 be modified to include right-of-way in addition to structures.

Response: In regards to a proposed change to prohibit Non-Consequential Load shed in response to a single Contingency event, FERC, in Order 693, was clear in paragraph 1794 that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the majority of the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement.

In P5 the event description was changed in Draft 3 to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to normal fault clearing.

The SDT agrees with the proposed addition of a footnote to address a threshold distance for circuits considered for study in loss of common Right-of-Way. The SDT has set the threshold at 1 mile or more, consistent with footnote 12 (now footnote 11). Footnote 11 was revised to account for both the common tower and common ROW exemption. Footnote 11 has been added to the extreme event steady-state 2b.

Organization	Yes or No	Question 9 Comment
Footnote 11: Excludes circuits that share a common structure or common Right-of-Way for 1 mile or less		
Exelon Transmission Planning	No	Table 1 comments in general: Even after modification from the previous version, it is still not clear if the "BES Voltage Level" applies to the contingency element voltage leFRCCan overload on a 138 kV line, is non-consequential load loss allowed on the 138 kV system? There is a concern about the lack of definition related to the failure of a "single Protection System" this could be widely interpreted. Would over tripping for line faults fall into this definition?
Response: The BES Voltage Level column applies to the System voltage of the Facilities removed from service by the planning event studied. In the example provided by Exelon, Non-Consequential Load Loss would not be permitted since the outaged facility is at the EHV level. No, over tripping is mis-operation and that does not fall into this definition.		
United Illuminating	No	Steady State & Stability comments as follows: Steady State & Stability: a. Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur. b. Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirements P5 Priority Comment As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. P7 Priority Comment Event 1 - This requirement requires the evaluation of the loss of two circuits on a multiple circuit tower. We recommend that this be modified so that only the loss of two adjacent (vertically or horizontally) circuits need be evaluated. We also recommend that the Planning Coordinator be allowed to evaluate and if appropriate exempt specific locations from this contingency based on acceptable risk. Comments on Extreme Events Table 1- We recommend renumbering the Extreme Events table to be Table 2. Stability Condition 2 Note a - Priority Comment - As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. Stability Condition 2 Note h " Eliminate this requirement or change to loss of station following three phase fault. This note is confusing. Without providing a better defined scenario, it is unclear as to what clearing times should be used in this simulation. Note 1.a.ii " Contingency Reserve is dependent on the generation on-line. We suggest changing the first sentence to say that you can't lose more than that permissible by the Planning Coordinator. Also change "pull out of synchronism" to "lose synchronism" in this sentence and in the second sentence. (Is "Lose synchronism" a more

Organization	Yes or No	Question 9 Comment
		commonly used term?). Note 3 We recommend revising the wording of the last sentence to "A 3 phase fault study indicating criteria are being met is sufficient evidence that a SLG condition would also meet criteria. Note 4 " We recommend that a lower bound be put on the HV electric systems (such as 100 kV), rather than just saying "and lower".
Northeast Utilities	No	Steady State & Stability are as follows:Steady State & Stability: a. Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur. b. Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirements Non-Consequential Load Loss Allowed Comment (priority comment):We highly recommend that the standard as written should not allow non-consequential load loss to resolve any violation arising from the planning events in Table 1 (except when considering spare equipment strategy together with events P3 or P6). We believe that planning for reliable power should discourage load loss mitigation. Therefore, the column for the "Non-Consequential Load Loss Allowed" in Table 1 should all have entries of "No". P5 Priority Comment As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary's Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. P7 Priority Comment Event 1 - This requirement requires the evaluation of the loss of two circuits on a multiple circuit tower. We recommend that this be modified so that only the loss of two adjacent (vertically or horizontally) circuits need be evaluated. We also recommend that the Planning Coordinator be allowed to evaluate and, if appropriate, exempt specific locations from this contingency based on acceptable risk. Comments on Extreme Events Table 1- We recommend renumbering the Extreme Events table to be Table 2. Stability Condition 2 Note a - Priority Comment - As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary's Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. Stability Condition 2 Note h ? Eliminate this requirement or change to loss of station following three-phase fault. This note is confusing. Without providing a better defined scenario, it is unclear as to what clearing times should be used in this simulation. Comments on Footnotes Table 1- We recommend renumbering the Footnotes table to be Table 3. Note 1.a.i " Should clarify that this requirement refers to generator units that are connected to the BES system. Note 1.a.ii " Contingency Reserve is dependent on the generation on-line. We suggest changing the first sentence

Organization	Yes or No	Question 9 Comment
		to say that you can't lose more than that permissible by the Planning Coordinator. Also change "pull out of synchronism" to "lose synchronism" in this sentence and in the second sentence. (Is "Lose synchronism" a more commonly used term?). Note 3 We recommend revising the wording of the last sentence to "A three-phase fault study indicating criteria are being met is sufficient evidence that a SLG fault condition would also meet criteria. Note 4 " We recommend that a lower bound be put on the HV electric systems (such as 100 kV), rather than just saying "and lower".
Central Maine Power Company	No	Steady State & Stability comments as follows:Steady State & Stability: a. Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur. b. Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirements P5 Priority Comment As written, this requirement is overly severe. This would require the simulation of a ?dead? station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. P7 Priority Comment Event 1 - This requirement requires the evaluation of the loss of two circuits on a multiple circuit tower. We recommend that this be modified so that only the loss of two adjacent (vertically or horizontally) circuits need be evaluated. We also recommend that the Planning Coordinator be allowed to evaluate and if appropriate exempt specific locations from this contingency based on acceptable risk. Comments on Extreme Events Table 1- We recommend renumbering the Extreme Events table to be Table 2. Extreme Event Stability Condition 2 Note a - Priority Comment - As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. Extreme Event Stability Condition 2 Note h " Eliminate this requirement or change to loss of station following three phase fault. This note is confusing. Without providing a better defined scenario, it is unclear as to what clearing times should be used in this simulation. Footnote 1.a.ii " Contingency Reserve is dependent on the generation on-line. We suggest changing the first sentence to say that you can't lose more than that permissible by the Planning Coordinator. Also change "pull out of synchronism" to "lose synchronism" in this sentence and in the second sentence. (Is "Lose synchronism" a more commonly used term?). Footnote 1.a.i, states "For Planning Event P1: No generating unit or units shall be allowed to pull out of synchronism." There is the potential for this requirement to be taken too far. Does this mean that someone's 4 kW generator at home needs to remain synchronized" Therefore, there needs to be some sort of qualifier on this

Organization	Yes or No	Question 9 Comment
		requirement. Suggested wording: "For Planning Event P1: No generating unit or units greater than 20 MW and directly interconnected at 100 kV or above shall be allowed to lose synchronism. Note that synchronism applies to conventional synchronous generators and may not apply to other generation technology." Footnote 3 " We recommend revising the wording of the last sentence to "A three phase fault study indicating criteria are being met is sufficient evidence that a SLG condition would also meet criteria. Footnote 4 " We recommend that a lower bound be put on the HV electric systems (such as 100 kV), rather than just saying "and lower". Footnote 12 " We recommend adding an alternative modifier to the end of the sentence, "or for 5 towers or less. This is consistent with NPCC criteria.

Response: The stakeholders suggest adding the word "Transmission" to the beginning of header note "a". Additionally it is proposed to state in header note "b" that Load Reduction is not an acceptable means to meet steady state performance requirements. In Draft 4, the SDT made a change to header note "a" as suggested by the commenter but modified it to be "BES Transmission…". Regarding the suggested change to header note "b", no change was made as the standard does not prescribe a particular Load model such as constant power, constant impedance, etc. However, the load reduction definition has been deleted and incorporated in Non-Consequential Load.

Header note 'a': BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur.

The SDT agrees that Non-Consequential Load Loss should be discouraged, however, many of the events contained in Table 1 are very low probability events where intentionally dropping load to protect the integrity of the remainder of the BES may be an acceptable solution. Throughout the development process, the SDT has reviewed whether to allow Non-Consequential Load Loss for each event within Table 1 and has determined that "Yes" is the appropriate response where it is used within this column. No change made.

In regards to the P5 event, in response to industry comments on Draft 2, the SDT clarified that the P5 event is not intended to include an evaluation of individual components of the Protection System. The intent of P5 is to evaluate a failure of a Protection System design, and is not based on any particular component of the design. Please see the Summary Considerations area of Question 7 from the Draft 2 comments; specifically item 3 on page 207. Since the P5 event description says loss of a single Protection System and not single Protection System device or component, the SDT believes sufficient clarity is inherent in the P5 event description.

The suggested wording change to include "adjacent" for the P7 planning event is accepted by the SDT and reflected in Draft 4. The SDT does not accept the proposed provision for the Planning Coordinator to exempt locations for study of the P7 event beyond what is already exempted per footnote 12 (now footnote 11).

P7: Any two adjacent (vertically or horizontally) circuits on common structure

The suggested change to reference the extreme events as Table 2 was not accepted by the SDT. The team feels sufficient clarity is provided by the division breaks within the table. The table is to be viewed holistically as a single table stating performance requirements and reference notes for the TPL-001-1 standard.

Regarding extreme event Stability item 2a, our response to your P5 comment above applies. No changes were made in regard to the extreme event 2a.

Regarding extreme event Stability item 2h, items 2f through 2h are deleted as this was a mis-interpretation of the existing table and are not required in the Stability timeframe.

The suggested change to reference the Footnotes area as Table 3 was not accepted by the SDT. The team feels sufficient clarity is provided by the division breaks

Organization	Yes or No	Question 9 Comment
		within the table. The table is to be viewed holistically as a single table stating performance requirements and reference notes for the TPL-001-1 standard. Footnote 1 was deleted and moved to Requirement R4, parts 4.1.1 – 4.1.3 but the SDT did not make the suggested change as it felt that it didn't add any additional clarity. Regarding footnote 1.a.ii the SDT did not accept the proposed wording changes related to loss of synchronism. The change proposed was not substantive and the wording presently used, "pulling out of synchronism", is sufficient. No change made. Regarding the suggestion for the Planning Coordinator to establish the maximum allowable amount, the SDT has set a maximum and believes that it is the appropriate value. An entity can always set more stringent criteria. No change made. The comment on footnote 1.a.i is redundant and already addressed above. The SDT accepts the proposed change for footnote 3 (now footnote 2). **Footnote 2:** Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. Regarding footnote 4 (now footnote 3), the SDT does not accept the proposed change to establish a lower bound on the HV electric System. The lower bound is based on the BES definition established by a Regional Entity organization. While this is generally understood to be 100kV, it may vary throughout the North American footprint. The SDT has however modified footnote 3 for clarity. **Footnote 3:** Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems as defined by the Regional Entity. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruptions of Firm Transmission Service and Non-Consequential Load. Regarding footnote 4 (now footnote 3), the commenter suggest that the standard should not prescribe a voltage definition of BES, be it called EHV or HV and that studies are needed to determine BES Facility definitions. The BES definition is defined by the Regional Entity organization and studies are not generally relied upon for BES determination. The additional changes suggested in revising footnote 3 to limit the EHV definition to only those facilities deemed significant to reliability as determined by the Planning Coordinator was not accepted by the SDT. Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined. The EHV and HV definitions are not being added to the NERC Glossary of Terms based on their limited use within the TPL standard. Regarding footnote 12 (now footnote 11), the 1 mile exception is more precise as span lengths can vary greatly between towers. No change was made.
System Protection and Transmission Planning Department	No	The order of scenarios listed in the table should reflect the relative probability of events. Did the SDT intend to order listed contingencies by relative severity? Could it do so" Planning Events - SLG fault simulation should not be required. They should only be performed if more severe than 3-phase faults. A SLG fault with delayed breaker clearing could have more system impact than a 3-phase fault. The "Extreme Events" portion of the table is confusing " partly because the form differs from the Planning Event portion. The difference between contingencies in the Planning portion and the Extreme portion is not clear.

Organization	Yes or No	Question 9 Comment
		Perhaps the Extreme Event portion could be a separate Table. Extreme Events / Stability section - Why specifically require "g. SLG fault on all Transmission lines on a common Right-of-Way. "
Response: The order is not based on probability. When a SLG fault type is specified in Table 1, it is the fault that must be satisfied to meet performance criteria for the referenced planning event. Since 3-phase faults are simpler to simulate a planner may simulate the 3-phase and if performance criteria are met, then no further work is needed since the 3-phase fault has a greater BES impact than a SLG fault. However, if the 3-phase screening does not meet criteria, then the planner must perform the more labor intensive SLG analysis to determine whether or not performance criteria are being met. See footnote 2. The extreme events area of the table has not been reformatted. The SDT believes the table clearly delineates what is required in regards to studies required for stability and those required for steady-state. Regarding the extreme events Stability item "g" retains consistency with what is currently in the approved TPL-004-0 standard as a NERC category D7 event.		
PPL Energy Plus	No	The WECC suggests P4 penalizes EHV and if this is true, please re-write P4 to eliminate the penalty.
Response: In regards to the EHV performance criteria for the P4 event, the EHV performance expectations remain as stated in Draft 3. P4 events pose higher risk and impact to the BES since there is no time for System adjustments for potential multiple Facility outages that can result from a single fault. Since the EHV is considered the backbone of the BES carrying large amounts of power between generation and Load and typically not directly servicing end-user customers the higher performance expectations for the high impact P4 events is warranted.		
Bonneville Power Administration PacifiCorp Deseret Generation & Transmission SRP Southern California Edison Company Western Area Power Administration Pacific Gas and Electric Co, NV Energy San Diego Gas and Electric Co	No	P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements. As such, this is a low probability condition and loss of Non-Consequential load should be allowed for EHV. We disagree with raising the bar for EHV for P4.

Organization	Yes or No	Question 9 Comment
Idaho Power California ISO		
Xcel Energy	No	P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements.
Puget Sound Energy, Inc.	No	P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker).
Response: The SDT has added the introductory text proposed for the P4 "Event" column of the table to bring consistency with the P5 event. In regards to the EHV performance criteria for the P4 event, the EHV performance expectations remain as stated in Draft 3. P4 events pose higher risk and impact to the BES since there is no time for System adjustments for potential multiple Facility outages that can result from a single fault. Since the EHV is considered the backbone of the BES carrying large amounts of power between generation and Load and typically not directly servicing end-user customers the higher performance expectations for the high impact P4 events is warranted.		
Western Area Power Administration	Yes	There is information within the notes that is not required to correctly understand and apply the TPL Standard. Examples are: 1. Note 1.a.i " the 2nd sentence is not needed to say what is not an out-of-step occurrence. 2. Note 9 is not needed to clarify what "internal" means.
Response: The SDT believes the notes provided help clarify the performance criteria stated in Table 1. No changes were made in Draft 4.		
Florida Reliability Coordinating Council, Inc - Transmission Working Group		The table is significantly improved from the prior versions and provides superior clarification over the existing standards. However, please explain why there is a performance difference between P2.3 (breaker failure), P4 (stuck breaker) and P7 (2 circuits on a common tower) for EHV. We recommend consistant critera between P2.3, P4 and P7 that allow curtailment of firm service and loss of non-consequential load.
Response: The SDT appreciates your support in the overall table revisions. In the early stages of standard development, the SDT reviewed the various Contingency classifications for likelihood and impact. Single Contingency events were placed higher in the table than multiple Contingency events. The SDT determined that since the EHV System (300kV and above) was utilized to carry large amounts of power between generation and Load and typically not directly servicing end-user customers, higher performance expectations were appropriate for some higher impact events. The P2.3 (breaker failure) event poses a high risk and impact to the BES since it is a single Contingency event. The SDT raised the performance requirement on the P4 (stuck breaker) event for EHV to parallel that of the P2.3 event. The SDT considered that even though P4 is a multiple event, the design of the substation and Protection System can reduce the impact of events and the SDT believes that the standard should encourage designs that have a positive impact on the System's ability to serve Load. The SDT determined that the performance requirements for the P7 event for EHV should not be raised.		
FMPA	No	Table 1 seems to have lost the requirement to be within Facility Ratings for single and double contingencies (e.g., the change in note "f" of Table 1). Are we missing something? If not, is this change intentional?

Organization	Yes or No	Question 9 Comment
		Footnote 10 does not seem to adequately highlight that Facilities should be within applicable ratings for single and credible double contingencies. The table is significantly improved from the prior versions and provides superior clarification over the existing standards. However, please explain why there is a performance difference between P2.3 (breaker failure), P4 (stuck breaker) and P7 (2 circuits on a common tower) for EHV. Considering the frequency of these events in actual experience, it would seem that 2 circuits on a common tower should have a more restrictive or equal performance to a stuck breaker performance, yet the performance requirements are just the opposite. We recommend allowing curtailment of firm service and loss of non-consequential load for a stuck breaker or failed breaker.
Response: In Table 1, header note "f", the text "Facility Ratings shall not be exceeded" was inadvertently deleted in the Draft 3 standard and has been re-inserted in Draft 4. **Header note 'f':** Facility Ratings shall not be exceeded. Regarding footnote 10 (now footnote 9), the issue was addressed by adding Facility Ratings back in. The SDT appreciates your support in the overall table revisions. In the early stages of standard development, the SDT reviewed the various Contingency classifications for likelihood and impact. Single Contingency events were placed higher in the table than multiple Contingency events. The SDT determined that since the EHV System (300kV and above) was utilized to carry large amounts of power between generation and Load and typically not directly servicing end-user customers, higher performance expectations were appropriate for some higher impact events. The P2.3 (breaker failure) event poses a high risk and impact to the BES since it is a single Contingency event. The SDT raised the performance requirement on the P4 (stuck breaker) event for EHV to parallel that of the P2.3 event. The SDT considered that even though P4 is a multiple event, the design of the substation and Protection System can reduce the impact of events and the SDT believes that the standard should encourage designs that have a positive impact on the System's ability to serve Load. The SDT determined that the performance requirements for the P7 event for EHV should not be raised.		
Progress Energy Carolina (PEC)		PEC prefers having separate tables for steady-state and dynamic analyses. PEC believes the requirements were more clear in that format.
Response: The SDT consolidated the tables following several Draft 2 stakeholder comments to consolidate. The prior separate tables reflected the same planning events and the SDT agreed (although not unanimously) to consolidate for simplification. The column labeled "Fault Type" along with footnote 3 (now footnote 2) provides sufficient information regarding what is needed for the Stability analysis.		
City Utilities of Springfield, MO	No	City Utilities of Springfield, Missouri does not agree with the restrictions placed on the Category P3 contingencies. Since this will simulate a multiple contingency similar to a Category P4, loss of firm transmission service and/or loss of non-consequential load should be allowed. We suggest that the drafting team expand the allowable mitigating measures for a Category P3 to be consistent with a Category P4, where loss of firm transmission service and/or loss of non-consequential load is allowed for HV levels.
Response: The P3 Contingency (loss of a generator unit, followed by System adjustments follow by another N-1) was considered by the SDT as one of the more		

Organization	Yes or No	Question 9 Comment
likely planning events and therefore both the EHV and HV were kept to the more stringent planning performance criteria. No changes made for Draft 4.		
MidAmerican Energy Company	No	MidAmerican commends the SDT for its hard work on this standard. MidAmerican commends the SDT for most of the changes to Table 1. MidAmerican does have a few comments:? MidAmerican suggests that Footnote 11 be added to the sixth item under P4. The note 11 clarifies the meaning of a stuck breaker yet this footnote isn't applied to item 6 under P4 which is a stuck-breaker item. MidAmerican believes that it is confusing having a set of explanations for Extreme Events that are 1 through 3 under Steady State and 1 and 2 under Stability and yet have later footnotes listed that are 1 through 11. MidAmerican suggests that the items 1 through 3 under Steady State and 1 and 2 under Stability for Extreme Events be changed to some other designation such as bullets or letters so that it is easy to see that the numerical footnotes start after these explanations of the extreme events. ? Further clarify the applicable shunt devices in Footnote 7 with the suggested text 7. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground, but not instrument voltage transformers or surge arrestors.
Response: The SDT accepts the proposed change to add a reference to footnote 11 (now footnote 10) on planning event P4.6. The SDT believes that the formatting is correct and sufficiently clear. No change made. Regarding the suggested change to footnote 7 (now footnote 6), the devices listed are not BES Facilities typically considered in a planning study. The SDT disagrees that the proposed change is needed for clarity. No change made.		
JEA	No	Footnote 8 relative to P2.1 seems to imply that all of the single contingency assessments for circuits should include assessment of (1) both ends of the circuit disconnecting as in P1 and (2) either end of the circuit disconnceting as in P2. This results in 3 seperate single contingency assessments for the one circuit. I am not sure of the benefit other than trying to identify a high voltage situation or in the case of tap loads, a thermal loading issue. Recommend changing Footnote 8 to"For circuits with tapped load, a seperate analysis shall be performed for an outage of each end of the circuit where the load is tapped."
Response: The SDT did not change the footnote since there are other conditions that may need to be evaluated for an open ended line such as angular Stability and high voltage.		
NorthWestern Corporation NorthWestern Energy (NWE) (NWMT)	No	P6 on the table seems to be less severe than either P4 or P5, yet it allows loss of Firm Transmission Service and Non-consequential Load which are not allowed for EHV in P4 or P5. Interruption of Firm Transmission Service and Non-Consequential Load Loss should be allowed for P4, P5, and P6. Transmission lines should have the same requirements regardless of the voltage. Also, if not able to model Firm Transmission Service, how will one know if it is interrupted? The column labeled Interruption of Firm Transmission Service Allowed? should be eliminated since it is not a clearly defined test of

Organization	Yes or No	Question 9 Comment
		performance. It is not clear how to use the present definition of "Firm Transmission Service" for a planning horizon study. P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements. As such, this is a low probability condition and loss of Non-Consequential load should be allowed for EHV.
Response: The P6 event is considered a lower impact event since it requires two separate faults to occur. Therefore, interruption of Firm Transmission Service and Non-Consequential Load Loss following the second event is permitted. Conversely, the P4 and P5 events are based on a single fault and an abnormal clearing mode. These events pose higher risk and impact to the BES since there is no time for System adjustments for the multiple Contingency Facility outcomes resulting from a single fault. Therefore, the EHV is held to higher performance criteria. The SDT disagrees with the proposed change. The higher expectation placed on the EHV, and therefore differing requirements for portions of the Transmission System, is due to the EHV being the backbone of the BES carrying large amounts of power between generation and Load and typically not directly servicing end-user customers. The numerous Firm Transmission Service contracts occurring on a short-term basis within the operating horizon are not the focus in TPL-001-1. It is expected that any long-term Firm Transmission Service agreements required for consideration within a Transmission planning horizon will be limited and well known by the responsible entity. This has been further clarified in draft 4 per the revisions made to the Requirement R1 modeling requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The SDT has added the introductory text proposed for the P4 "Event" column of the table to bring consistency with the P5 event. In regards to the EHV performance criteria for the P4 event, the EHV performance expectations remain as stated in Draft 3. P4 events pose higher risk and impact to the BES since there is no time for System adjustments for potential multiple Facility outages that can result from a single fault. Since the EHV is considered the backbone of the BES carrying large amounts of power between generation and Load and typically not directly servicing end-user customers the higher performance expectations for the high impact P4 events is warranted. **P4:** Loss of multiple elements caused by a stuck breaker [11](non-Bus-tie) attempting to clear a Fault on one of the following: & 6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie) attempting to clear a Fault on the associated bus		
SMUD	No	The allowed corrective actions in Table 1 to meet performance standards do not explicitly state how DSM solutions should be treated [there is a potential for 20% of national peak demand to be met by "demand response"] . If it is allowed to be used, and since this is a fairly significant amount, it would help if it is explicitly addressed in Table 1.
Response: The standard does not place a ceiling on DSM that can be utilized. No changes made in Draft 4.		
Progress Energy Florida, Inc.	No	PEF has multiple concerns with Table 1, the most fundamental of these concerns being that the existing Table in the existing TPL Standards is far superior to the new table. PEF suspects that the large blackout/brownout events in the Northeast and West have been the primary impetus behind devising a new Standard that will allegedly

Organization	Yes or No	Question 9 Comment
		improve BES reliability. PEF strongly feels that proper planning, operation and maintenance under existing NERC Standards could have prevented all of the aforementioned events, and thus a new TPL Standard and a new Table 1 is not necessary. PEF's specific concerns with Table 1 as it exists in this 3rd draft of TPL-001-1 are as follows: As a general concern, PEF, as has been stated already, does not believe that organizing a Reliability table according to whether or not loss of Firm Transmission Service or loss of Non-Consequential Load can occur is appropriate. The BES can be demonstrated to be robust and can even be continually improved under the existing TPL Standards. PEF fails to see how FERC's and NERC's desire to eliminate Footnote (b) as stated in the existing TPL Standards has anything to do with the desire to improve the reliability of the BES. Indeed, as TPL-001-1 exists at present, PEF suspects that many Transmission Owners will a) reduce posted ATC values to reduce risk of loss of Firm Transmission Service or b) remove breakers to convert Non-Consequential Load into Consequential Load. Both of these actions fly in the face of what FERC desires for the BES of the future. FERC certainly desires for power markets to open up further and thereby encourage lower energy prices, but at present TPL-001-1 and the accompanying Table 1 is in opposition to enhancing the power marketing industry. In addition, removing breakers is in opposition to reliability and customer service. An additional general concern involves the continued differentiation between HV and EHV. EHV by its very nature carries significantly larger amounts of power than HV, and therefore an EHV event inherently causes a greater disparity between Generation and Load than a HV event, making the loss of Firm Transmission Service or loss of Non-Consequential Load necessary for even a single contingency. Should all utilities be therefore required to make their EHV systems redundant? Such a suggestion is preposterous. Given this fact, and the fact that EHV events hardly ever occur (and, as outlined in the draft Table 1, have never occurred on PEF's system), PEF believes holding EHV to a higher standard is inappropriate, and will result in no more than a negligible reliability improvement at tremendous cost.Based on the above concerns, PEF believes for all event scenarios (P0 P7), analysis according to whether or not loss of Firm Transmission Service or loss of Non-Consequential Load can occur is inappropriate and should be deleted from the Standard. Concerning event P2-1, PEF assumes that "opening of breaker w/o fault" means opening breakers from both sides of the circuit. PEF therefore does not understand the difference between event P2-1 and events P1-1 through P1-4, and therefore suggests deleting P2-1 and combining the remainder of P2 with P1. Given the concerns above, voicing additional concerns about the Footnotes, short of reinstating the existing Footnote (b), is irrelevant.

Response: In regards to proposed change to prohibit Non-Consequential Load shed in response to a single Contingency event, FERC, in Order 693, was clear in paragraph 1794 that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the majority of the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement.

In Draft 3, footnote 8 (now footnote 7) was added to further clarify the need for the P2-1 event. The intent is simply to look for low voltage or thermal problems while supplying Load from one end of a normally networked line. In planning event P1-2, the network line would be opened at both ends and any Load tapped to the

Organization	Yes or No	Question 9 Comment
network line would be dropped. For planning event P2-1 for the same line, the Load would be studied being served from either end of the line.		
ISO New England, Inc.	No	Priority Comment As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. Priority Comment Event 1 - This requirement requires the evaluation of the loss of two circuits on a multiple circuit tower. We recommend that this be modified so that only the loss of two adjacent (vertically or horizontally) circuits need be evaluated. We also recommend that the Planning Coordinator be allowed to evaluate and if appropriate exempt specific locations from this contingency based on acceptable risk. Comments on Extreme Events Table 1- We recommend renumbering the Extreme Events table to be Table 2. Stability Condition 2 Note h Eliminate this requirement or change to loss of station following three phase fault. This note is confusing. Without providing a better defined scenario, it is unclear as to what clearing times should be used in this simulation. Note 1.a.ii Contingency Reserve is dependent on the generation on-line. We suggest changing the first sentence to say that you can't lose more than that permissible by the Planning Coordinator. Also change "pull out of synchronism" to "lose synchronism" in this sentence and in the second sentence. (Is "Lose synchronism" a more commonly used term?). Note 3 We recommend revising the wording of the last sentence to ?A 3 phase fault study indicating criteria are being met is sufficient evidence that a SLG condition would also meet criteria. Note 4 We recommend that a lower bound be put on the HV electric systems (such as 100 kV), rather than just saying "and lower".
Response: In regards to the P5 event, in response to industry comments on Draft 2, the SDT clarified that the P5 event is not intended to include an evaluation of individual components of the Protection System. The intent of P5 is to evaluate a failure of a Protection System design, and not based on any particular component of the design. Please see the Summary Considerations area of Question 7 from the Draft 2 comments; specifically item 3 on page 207. Since the P5 event description says loss of a single Protection System and not single Protection System device or component, the SDT believes sufficient clarity is inherent in the P5 event description. The suggested wording change to include "adjacent" for the P7 planning event is accepted by the SDT and reflected in Draft 4. The SDT does not accept the proposed provision for the Planning Coordinator to exempt locations for study of the P7 event beyond what is already exempted per footnote 12 (now footnote 11).The suggested change to reference the extreme events as Table 2 was not accepted by the SDT. The team feels sufficient clarity is provided by the division breaks within the table. The table is to be viewed holistically as a single table stating performance requirements and reference notes for the TPL-001-1 standard. **P7:** Any two adjacent (vertically or horizontally) circuits on common structure The SDT believes that the table is formatted correctly and is sufficiently clear. No change made. Regarding extreme event Stability item 2h, items 2f through 2h are deleted as this was a mis-interpretation of the existing table and are not required in the Stability timeframe. Regarding footnote 1.a.ii the SDT did not accept the proposed wording changes related to loss of synchronism. The change proposed was not substantive		

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and the wording presently used, "pulling out of synchronism", is sufficient. Footnote 1 was deleted and moved to Requirement R4, parts 4.1.1 – 4.1.3. Regarding the suggestion for the Planning Coordinator to establish the maximum allowable amount, the SDT has set a maximum and believes that it is the appropriate value. An entity can always set more stringent criteria. No change made. The SDT accepts the proposed change for footnote 3 (now footnote 2). **Footnote 2:** Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. Regarding footnote 4 (now footnote 3), the SDT does not accept the proposed change to establish a lower bound on the HV electric System. The lower bound is based on the BES definition established by a Regional Entity organization. While this is generally understood to be 100kV, it may vary throughout the North American footprint. The SDT has however modified footnote 3 to include the text "defined by the applicable BES" to address the concern raised by the commenter. **Footnote 3:** Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems as defined by the Regional Entity. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruptions of Firm Transmission Service and Non-Consequential Load.		
Arizona Public Service Co	No	P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements. As such, this is a low probability condition and loss of Non-Consequential load should be allowed for EHV. We disagree with raising the bar for EHV for P4. We do not agree with Note "i" which requires establishing transient voltage response limits. There is no solid basis for such limits. In the past such limits were used as proxies for VAR margin and are not needed anymore. This will also result into non-uniform criteria throughout the interconnection. If such a limit were to be established, it should be based upon quantifiable reliably impact and should be supported by firm technical basis. Note 1b: Acceptable damping should not be defined by Planning coordinator and should be left to the Transmission Planner. Otherwise it would result into non-uniform criteria for the interconnections.
Response: The SDT has added the introductory text proposed for the P4 "Event" column of the table to bring consistency with the P5 event. In regards to the EHV performance criteria for the P4 event, the EHV performance expectations remain as stated in Draft 3. P4 events pose higher risk and impact to the BES since there is no time for System adjustments for potential multiple Facility outages that can result from a single fault. Since the EHV is considered the backbone of the BES carrying large amounts of power between generation and Load and typically not directly servicing end-user customers the higher performance expectations for the high impact P4 events is warranted. **P4:** Loss of multiple elements caused by a stuck breaker [11](non-Bus-tie) attempting to clear a Fault on one of the following: & 6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie) attempting to clear a Fault on the associated bus The SDT has added a Requirement R5 to explicitly require criteria for transient voltage criteria. **R5** Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for their System. For transient voltage response, the criteria shall at a minimum, specify a voltage level and a		

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		maximum length of time that transient voltages may remain outside that level. In regards to the comment on footnote 1b, as written it's based on the more restrictive criteria of the Planning Coordinator or the Transmission Planner. Since the Planning Coordinator has a wider area purview over the Transmission Planner, it is unclear why the commenter has a concern of Planning Coordinator criteria causing non-uniformity within the Interconnection. With fewer Planning Coordinators being involved there would be less disparity across an Interconnection if the Planning Coordinator's criteria were more restrictive than the Transmission Planner's criteria. No changes were made to this footnote in Draft 4.
Hydro-Québec TransEnergie (HQT)	No	Footnote 4 We recommend that a lower bound be put on the HV electric systems (such as 100 kV), rather than just saying "and lower". As has been commented on in a previous draft, the Drafting Team should also consider not having a prescribed voltage definition of BES, be it called EHV or HV. Studies should determine what facilities should be part of the BES because of their impact on reliability. A proposal is to modify Footnote 4 to replace the phrase "(EHV) Facilities defined as greater than 300 kV" with "(EHV) Facilities defined as having a significant impact on the reliability of the System, generally at voltages greater than 300 kV as determined by the Planning Coordinator"? In using such language, the more stringent requirements could apply to BES/EHV but not globally for Facilities operating at voltages greater than 300 kV. Using this methodology the extra investment required would go towards real improvement of the reliability of the System. EHV and HV should be added to the Definitions of Terms Used in Standard. Footnote 12 We recommend adding an alternative modifier to the end of the sentence, "or for 5 towers or less. This is consistent with NPCC criteria.
Response: Regarding footnote 4 (now footnote 3), the SDT does not accept the proposed change to establish a lower bound on the HV electric System. The lower bound is based on the BES definition established by a Regional Entity organization. While this is generally understood to be 100kV, it may vary throughout the North American footprint. The SDT has however modified footnote 3 to include the text "defined by the applicable BES" to address the concern raised by the commenter. **Footnote 3:** Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems as defined by the Regional Entity. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruptions of Firm Transmission Service and Non-Consequential Load. Regarding footnote 4 (now footnote 3), the commenter suggests that the standard should not prescribe a voltage definition of BES, be it called EHV or HV and that studies are needed to determine BES Facility definitions. The BES definition is defined by the Regional Entity organization and studies are not generally relied upon for BES determination. The additional changes suggested in revising footnote 3 to limit the EHV definition to only those Facilities deemed significant to reliability as determined by the Planning Coordinator was not accepted by the SDT. Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined. The EHV and HV definitions are not being added to the NERC Glossary of Terms based on their limited use within the TPL standard. Regarding footnote 12 (now footnote 11), the 1 mile exception is more precise as span lengths can vary greatly between towers. No change was made.		

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Ameren	No	The word "Requirements" needs to be added to the Table 1 titles in the existing tables.Table 1 Steady State & Stability Performance RequirementsPlanning Events Table 1 Steady State & Stability Performance RequirementsExtreme Events Table 1 Steady State & Stability Performance RequirementsFootnotes (Planning Events and Extreme Events) Since it appears that the Table 1 cannot fit on a single page, it is suggested that multiple tables be developed to handle the 1) steady-state and 2) stability performance requirements. Footnotes may be included on a second page if needed. Comments were provided in early versions regarding the issues associated with raising the bar, and it was suggested that the marginal reliability benefits associated with these changes were not worth the marginal costs. We have not seen any significant changes from the earlier performance requirements. The question still remains, are we directing the resources where they need to be allocated to address and improve system reliability? So far the answer is believed to be "No".
Response: The Table 1 title does not include the word requirements since the table is referenced by the requirements of the standard. For example, see Requirement R3, parts 3.1 and 3.4 which require the Transmission Planner to develop Contingency lists for study based on the table performance requirements. The suggestion for multiple tables was not accepted by the SDT. The team feels sufficient clarity is provided by the division breaks within the table. The table is to be viewed holistically as a single table stating performance requirements and reference notes for the TPL-001-1 standard. Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined.		
Maine Public Advocate	No	P2, P3, P4, and P5 - The change allowing no load shedding or interruption of firm transmission service for the types of events and faults listed will lead to the construction and installation of more transmission plant. These expensive plant additions have not, however, been preceded or justified by any evidence that the reliability of the current system - using current planning standards which allow load shedding and interruption of firm transmission service - is lacking. The August 2003 blackout, to the extent utilities and other industry stakeholders have cited it for this purpose, was not caused by the lack of such planning standards; it was an event that should not have occured and would not have but for the utter failure of First Energy to pay attention to operations and vegetation management. The Joint US/Canada Report makes this clear. These proposed changes are not needed and will cause unreasonable increases in rates that are not justified by the putative increases in reliability.There is currently too much emphasis on reliability and not enough emphasis on costs. Utilities are spurred, of course, by the FERC's ROE incentive. NERC should not allow this incentive to influence the reasonalbeness of any of its standards, particularly this one which can only lead to unneeded redundancy in the high voltage transmission system and resulting higher costs.
Response: FERC, in Order 693, was clear in paragraph 1794 that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the majority of the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement.		

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The P2 events are common failure, single Contingency events therefore the criteria is properly set. Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined.		
Manitoba Hydro	No	Note b should be reworded to ?However, Supplemental Load Loss associated with a P2 through P5 event shall not be used to meet post-contingency steady-state performance requirements. Also we do not see a need for Load Reduction (see Q8 comment) Note b also implies that voltage dependent load is not permitted to be modeled for P0. This in turn means that the model must have all load represented as constant MVA. The load representation can change for categories P1 through P7. Is this the intent of the language? Note e: Are the planned System adjustments and redispatch allowed following all Planning Events if they result in curtailment of Firm Transmission Service? Should Note 10 also be referenced here? Footnote 7 applies to FACTS devices that are connected to ground. It is possible to have an ungrounded FACTS device (eg. Delta connected) or a series connected FACTS device (UPFC, SSSC, etc.). I would recommend deleting "that are connected to ground" so that the note is more general. Series connected FACTS will likely be separated via circuit breakers in a similar way as a transformer or phase shifter. Other series FACTS device, like a TCSC also typically self protect via a bypass breaker and should be considered as a separate element. Extreme Events:Steady State 1: Does the loss of a DC line refer to a bipole line? Steady State 2e: The loss of a large load could result from a Planning Event, perhaps even a P1 or P2 event - likely not an extreme event - compared to the loss of a major load center.
Response: The commenter provides no reasoning for the proposed limitation. No changes made. See our response to your Q8 comment. The standard does not prescribe a particular Load model such as constant power, constant impedance, etc. Footnote 10 (now footnote 9) does not apply globally to the entire table so it should not be reflected on header note “e”. No change made. The phrase “connected to ground” is appropriate since the focus is on shunt devices. No changes made. Loss of a bipolar line is covered as a P7 planning event. The reference to DC Line for the extreme event in question is intended to be loss of two independent single pole DC lines without time for System adjustments between each outage. The SDT has revised the extreme event descriptions for item 1 of steady state and Stability for clarity. **Extreme event steady state 1:** Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments. **Extreme event Stability 1:** With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced		

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out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments. While it is true that large amounts of Load could result from single Contingency planning events, the focus with the extreme event Steady State 2e item is different and intended to cover the complete loss of a major population center or urban area.		
E.ON U.S.		Table 1 Extreme Events CommentsSteady State2.bRight-of-Way should include a reference to footnote 1 2.2.d.Item 2.d. references loss of all generating units at a "station" but Item 3 references generating plants and nuclear power plants. It is unclear whether Item 2.d requires an outage of all generating units connected to a single transmission station (all voltages) or an outage of all generating units at a generating plant (although they may be connected to multiple transmission stations). 2.gRight-of-Way should include a reference to footnote 12. Footnotes12E ON U.S. suggests the definition be expanded to: Exclude circuits that share common structure for 1 mile or less and Transmission lines that share common Right-of-Way for 1 mile or less.
Response: The SDT does not believe a reference to footnote 1 is needed as suggested by the commenter. If the intent was to say a reference to footnote 12 (now footnote 11) as raised by other stakeholders, the SDT agrees with the proposed addition of a footnote to address a threshold distance for circuits considered for study in loss of common Right-of-Way. The team has set the threshold at 1 mile or more, consistent with footnote 11. Footnote 11 was revised to account for both the common tower and common Right-of-Way exemption. Footnote 11 has been added to the extreme event steady-state 2b. **Footnote 11:** Excludes circuits that share a common structure or common Right-of-Way for 1 mile or less Extreme event 2d and 3a are similar in that each covers the loss of all generating units at a single plant location. However, in 3a, two plants are reviewed. In each case, all units are to be outaged regardless of the BES voltage level to which they connect.		
National Grid	No	Steady State & Stability comments are as follows:Steady State & Stability: a. Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur. How does this apply to Steady State testing?b. Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirementsThe second sentence re: Supplemental Load Loss implies need to test without end-user's actions and then assess whether action of separating end-user needs to be taken by Transmission system? B. Event P2-3 and P4 have the same impact; also events P2-4 and P4-6 have the same impact. Can these be consolidated? P5 Priority Comment ? As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. P7 Priority Comment Event 1 - This requirement requires the evaluation of the loss of two circuits on a multiple

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		circuit tower. We recommend that this be modified so that only the loss of two adjacent (vertically or horizontally) circuits need be evaluated. Or allow the Planning Coordinator to evaluate and if appropriate exempt specific locations from this contingency based on acceptable risk. Comments on Extreme Events Table 1- We recommend renumbering the Extreme Events table to be Table 2. Stability Condition 2 Note a - Priority Comment - As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. Stability Condition 2 Note h Eliminate this requirement or change to loss of station following three phase fault. This note is confusing. Without providing a better defined scenario, it is unclear as to what clearing times should be used in this simulation. Note 1.a.i - For Planning Event P1: No generating unit or units shall be allowed to pull out of synchronism." There needs to be some sort of qualifier on this requirement. We suggest the following, "For Planning Event P1: No generating unit or units, directly interconnected at 100 kV or above, shall be allowed to lose synchronism." Note 1.a.ii " Contingency Reserve is dependent on the generation on-line. We suggest changing the first sentence to say that you can't lose more than that permissible by the Planning Coordinator. Also change "pull out of synchronism" to "lose synchronism" in this sentence and in the second sentence. (Is "Lose synchronism" a more commonly used term?). Note 3 We recommend revising the wording of the last sentence to "A 3 phase fault study indicating criteria are being met is sufficient evidence that a SLG condition would also meet criteria. Note 11. Reference is made to Independent Pole Operation (IPO) " Can this be clarified by referencing it as IPO or Independent Pole Trip (IPT) as opposed to single-pole switching. Note 4 ? We recommend that a lower bound be put on the HV electric systems (such as 100 kV), rather than just saying "and lower". Extreme Events:Steady State 3a - loss of two generating plants - This can be considered in two ways - one which results in loss of source (e.g. from fuel, cooling water, or nuke design shutdown) OR the second which could result in loss of stations including lines and breakers (e.g. from wildfires, weather, cyber attack, etc) - which is meant here? Both?

Response: The identification of Transmission voltage instability, cascading outages, and uncontrolled islanding is an appropriate expectation for steady state analysis. Steady state power flow analysis such as P-V or Q-V is suitable for screening, final System reinforcement decisions or operating limits are generally confirmed by more accurate time domain (dynamic) simulation. The TPL-001-1 standard in Requirement R5 requires the Transmission Planner and Planning Coordinator to define and document any criteria used to identify System instability such as cascading events, voltage instability or uncontrolled islanding.

The commenter suggests adding the word "Transmission" to the beginning of header note "a". Additionally it is proposed to state in header note "b" that Load Reduction is not an acceptable means to meet steady state performance requirements. In Draft 4, the SDT made a change to header note "a" as suggested by the

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		commenter but modified it to be "BES Transmission…". Regarding the suggested change to header note "b", no change was made as the standard does not prescribe a particular Load model such as constant power, constant impedance, etc. However, the definition of Load reduction has been deleted as it is now contained within the definition of Non-Consequential Load Loss. The definition for Supplemental Load Loss was deleted and the definition of Non-Consequential Load Loss has been changed to reflect this. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment. The commenter proposes to consolidate planning events P2-3 & P4 as well as P2-4 & P4-6 indicating they will have the same result. Within the steady state timeframe, these events will result in common outcomes; however, considered with the transient Stability timeframe, different outcomes are expected due to the delayed clearing mode of the P4 events. No changes were made by the SDT in this regard. In regards to the P5 event, in response to industry comments on Draft 2, the SDT clarified that the P5 event is not intended to include an evaluation of individual components of the Protection System. The intent of P5 is to evaluate a failure of a Protection System design, and not based on any particular component of the design. Please see the Summary Considerations area of Question 7 from the Draft 2 comments; specifically item 3 on page 207. Since the P5 event description says loss of a single Protection System and not single Protection System device or component, the SDT believes sufficient clarity is inherent in the P5 event description. The suggested wording change to include "adjacent" for the P7 planning event is accepted by the SDT and reflected in Draft 4. The SDT does not accept the proposed provision for the Planning Coordinator to exempt locations for study of the P7 event beyond what is already exempted per footnote 12 (now footnote 11). **Footnote 11:** Excludes circuits that share a common structure or common Right-of-Way for 1 mile or less The suggested change to reference the extreme events as Table 2 was not accepted by the SDT. The team feels sufficient clarity is provided by the division breaks within the table. The table is to be viewed holistically as a single table stating performance requirements and reference notes for the TPL-001-1 standard. Regarding extreme event Stability item 2a, our response to your P5 comment above applies. No changes were made in regard to the extreme event 2a. Regarding extreme event Stability item 2h, items 2f through 2h are deleted as this was a mis-interpretation of the existing table and are not required in the Stability timeframe. The suggested change to reference the Footnotes area as Table 3 was not accepted by the SDT. The team feels sufficient clarity is provided by the division breaks within the table. The table is to be viewed holistically as a single table stating performance requirements and reference notes for the TPL-001-1 standard. Footnote 1 has been deleted and moved to Requirement R4, parts 4.1.1 – 4.1.3. No change was made to the requirement wording as this standard only applies to the BES. Regarding footnote 1.a.ii the SDT did not accept the proposed wording changes related to loss of synchronism. The change proposed was not substantive and that the wording presently used, "pulling out of synchronism", is sufficient. Regarding the suggestion for the Planning Coordinator to establish the maximum allowable amount, the SDT has set a maximum and believes that it is the appropriate value. An entity can always set more stringent criteria. No change made. The comment on footnote 1.a.i is redundant and already addressed above. The SDT accepts the proposed change for footnote 3 (now footnote 2). **Footnote 2:** Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient

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evidence that a SLG condition would also meet the criteria. Footnote 11 (now footnote 10) has been changed to address your concern. **Footnote 10:** A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing Regarding footnote 4 (now footnote 3), the SDT does not accept the proposed change to establish a lower bound on the HV electric System. The lower bound is based on the BES definition established by a Regional Entity organization. While this is generally understood to be 100kV, it may vary throughout the North American footprint. The SDT has however modified footnote 3 to include the text "defined by the applicable BES" to address the concern raised by the commenter. **Footnote 3:** Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems as defined by the Regional Entity. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruptions of Firm Transmission Service and Non-Consequential Load. Regarding footnote 12 (now footnote 11), the 1 mile exception is more precise as span lengths can vary greatly between towers. No change was made. For extreme event 3a, the minimum expectation is the loss of two entire generation plants due to some wide area event as described by the examples in roman numeral i through vi. The planner at its own discretion could simulate removal of Transmission lines, transformers, etc. for the initiating event scenario considered.		
Entergy Services, Inc	No	P2.1 should allow the shedding of load along the line that would be served radially to mitigate overloads or undervoltages on the radial line. Doing so would clearly not result in degradations to the BES but only the local area served by the radial line. P4.5 is an extremely unlikely occurrence and should be equivalent to P4.6. P5 should not be a planning event. PRC standards address Protection systems. The complexity associated with identifying and simulating such events is unknown and the defense of assumptions made and events simulated will lead to inconsistency in compliance and enforcement. Industry accepted proxies for such events could be developed that would allow for efficient identification of areas needing further detailed study. Attempting to intermingle protection system operation with BES performance will be nearly impossible to implement given current technologies. In general, the entire table should be reconciled, one way or another, with MOD standards governing ATC/AFC. If multiple contingencies, protection system failures, breaker failures, and other less likely events must be planned for, then ATC/AFC processes should be equally limited, at least for long term service. Any service granted on a simple N-1 basis should be Conditional Firm. Anything less than interconnection-wide application of more stringent AFC/ATC evaluation processes commensurate with the long term planning standards will result in the shifting of costs and risks from wholesale users to retail rate payers.
Response: FERC, in Order 693, was clear in paragraph 1794 that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the majority of the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement.		

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The likelihood of a bus fault is the same for each. However, the Bus-tie Breaker event (P4.6) has a lower risk simply because there are a limited set of Bus-tie Breakers compared to a entire population of BES breakers that could be in a stuck condition as in the P4.5 situation. No change was made in draft 4. The P5 the event description was changed in Draft 3 to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to normal fault clearing. The comments made on the needed for reconciling the ATC standards are beyond the scope of this project. However, it is expected that conforming changes in other standards that currently reference the existing TPL standards will need to occur.		
Great River Energy	No	Why is the P needed in defining the category? They all have a P. Top note f and i should reference the Planning criteria established by the Planning Coordinator (or the Transmission Owner if more restrictive).The Transmission Owner is typically the one that sets the limits on their facilities. The Planner just works for the Owner.
Response: P is used as shorthand for "planning" event contingency as opposed to an extreme event Contingency. The Transmission Owner would establish the Facility Ratings, however, the Planning Coordinator and Transmission Planner establish the System criteria that must be met. Header notes 'f' and 'l' refer to established System parameters or criteria for voltage. No changes made.		
BC Hydro	No	Comments: Note "d": The term "Normal Clearing" is not well defined. Consider adding a definition in this standard or changing the NERC Glossary definition of "Normal Clearing" to read, "A protection system operates as designed and the fault is cleared in the maximum time that a properly functioning protection system would be expected to take to clear the fault, considering tolerances in normal protection operating times and circuit breaker interrupting times"No generating unit or units totaling more than the Contingency Reserve of the Balancing Authority (or Reserve Sharing Group if applicable) shall be disconnected from the System by a Special Protection System Note "e": Consider changing to, "For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are automatic (ie, implemented by a NERC-certified Special Protection System, SPS) and executable within the time duration applicable to the Facility Ratings. For P1 and P2 events, (a) generation shedding shall be limited to the normal level of Contingency Reserve of the Balancing Authority (or Reserve Sharing Group if applicable) that would be carried in the control area under the system conditions being studied and (b) no manual operator actions should be necessary to ensure Facility Ratings are not exceeded. Note that, in the operating time frame, the operator would immediately take whatever actions and system adjustments are needed to prepare for the next set of possible contingencies". It should be recognized that this will result in a higher transmission planning standard than the previous wording and that should be seen as a desirable outcome of updating the NERC standards since transmission system reliability (or lack of it) is the impetus for the whole Mandatory Reliability Standards (MRS) process. It should also be emphasized that PLANNING standards are necessarily conservative, simple and easy to apply since in the planning time frame all possible circumstances that might be encountered in the operating timeframe cannot be

Organization	Yes or No	Question 9 Comment
		assessed or nothing would ever get built. If operator action is permitted "if such adjustments are executable within the time duration applicable to the Facility Ratings", how will that be measured consistently to ensure the standard is met? One planner might count on five operators having nothing to distract them from adjusting the output levels of 10 plants to reduce the load on a line to below its 10-minute overload rating, whereas another might be more conservative and assume some of the operators may be busy with other things and be more conservative in estimating how much can be accomplished in 10 minutes. If no operator action is permitted, the standard is easily measured and a more secure system results, one of the main objectives of the MRS. The addition of the requirement that criteria are met without operator action is consistent with R3.3.1 that states "[Contingency analysis shall] simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention [emphasis added]". Performance Category P7: Consider changing the first event to, "All circuits on common structures" and consider changing the fault type to 3-phase. Extreme Events (Steady State): Consider changing item 1 to read, "With an initial condition of a single generator, Transmission Circuit, DC Line (one pole), shunt device or transformer forced out of service and prior to System adjustments, a second generator, Transmission Circuit, DC Line (one pole), shunt device or transformer is forced out of service. Extreme Events (Stability): Change item 1 to read, "With an initial condition of a single generator, Transmission Circuit, DC Line (one pole), shunt device or transformer forced out of service and prior to System adjustments, apply a 3" fault on a second generator, Transmission Circuit, DC Line (one pole), shunt device or transformer. Change item 2.g to read, "3" fault on all Transmission lines on a common Right-of-Way. Simultaneous 3" faults on all lines on a common right of way seems more likely (plane crash, avalanche, earth quake, wildfire) than simultaneous SLG faults. Footnote 1: Consider changing Item 1.a.I to read, "For Planning Events P1 and P2: No generating unit or units". And consider adding the following sentence, "No generating unit or units totaling more than the Contingency Reserve of the Balancing Authority (or Reserve Sharing Group if applicable) shall be disconnected from the System by a Special Protection System?. Footnote 8: Consider changing to, "Opening of Breaker(s) w/o fault in category P2 includes the situation in which one end of a normally networked Transmission circuit becomes open-ended, possibly resulting in voltage deviations outside acceptable limits especially at the open end of the line". Using the phrase "Opening of Breaker(s) w/o fault" that is used in the "event" column of category P2 will help people make the connection to the footnote.

Response: The SDT reviewed the existing NERC Glossary of Terms definition for Normal Clearing and found it sufficient for use in the TPL-001-1 standard. No changes were made.

Header note 'e' is not limited to automatic System adjustments. Manual operator initiated System adjustments are permitted so long as the applicable time limited rating is maintained during the adjustment. The proposed change was not accepted by the SDT.

Organization	Yes or No	Question 9 Comment
a) The standard does not place a ceiling on consequential generation tripping. b) Manual operator actions are permitted for all Contingencies. The ratings must always be adhered to. If a Contingency were to cause current flows to exceed a 24-hour Facility Rating but a 4-hour rating was not, then either natural Load reduction or System adjustments must occur within the 4-hour period. The standard permits manual System adjustments. Requirement R3, part 3.3.1 only refers to the initial System reaction to the event that the simulation program must accurately represent. The proposed changes to P7 were not accepted by the SDT. The situation described is covered as an extreme event under Steady State item 2a. The proposed change of "DC Line (one pole)" over the existing text "DC Line" was accepted by the SDT with a slight modification to read single pole. Changes were made to items 1 for both extreme event Steady State and Stability. **Extreme event steady state 1:** Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments. **Extreme event Stability 1:** With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments. Regarding extreme event Stability item 2g, items 2f through 2h were deleted as this was a mis-interpretation of the existing table and are not required in the Stability timeframe. The change proposed is no longer required. The proposed change to footnote 1 was not accepted. Generation tripping by an SPS is permitted. Footnote 8 (now footnote 7) was changed for clarity. **Footnote 7:** Opening breaker(s) without a fault on one end of a normally networked Transmission circuit such that the line is now open at that end and possibly serving Load radial from a single source point.		
IRC Standards Review Committee Midwest ISO Minnesota Power New York Independent System Operator	Yes	The stability studies require significantly more computer time and a more detailed model. The standard should allow the PC/TP to use judgment to manage size and complexity of the study.
Response: The standard permits judgment on choosing those events that are "expected to produce more severe System impacts." See Requirement R3, part 3.4 and Requirement R4, part 4.4. Additionally, in this draft the SDT has removed extreme event Stability items 2f through 2h since this was a mis-interpretation of the existing table and are not required in the Stability timeframe.		
PJM	No	Table 1, Lead in Note I. The industry has not yet reached a consensus on appropriate Transient Voltage Limits.

Organization	Yes or No	Question 9 Comment
		It's not clear that reliability will be enhanced by requiring each entity to establish a Transient Voltage Limit. Table 1 footnote 1 - System stable means: a. Angular Stability:i. For Planning Event P1: No generating unit or units shall be allowed to pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.This is not consistent with Loss of load whereby load can be lost due to a first contingency within contractual arrangements made with the load. This definition should be modified to read -A generator being disconnected from the System by fault clearing action or by a Special Protection System or prior arrangement?- as long as no other cascading outages occur. In Table 1, Extreme Events, Item 3a, i, ii, iii, iv and vi seem like events that would occur over long periods of time not in contingency simulation time frames. They seem more like sensitivities. Table 1 Delete P5 is the preferred option. If not deleted need to clarify that so that related or additional -faults in the vicinity of- are considered. As currently worded it can require all simultaneous N-2 combinations within some number of substation radius for which overtrips could occur. You would have to do all combinations since they are unpredictable. If the SDT means for the relay failure to be located at or very near to the initiating event, then perhaps the combinations are more manageable but still extremely burdensome.
Response: The SDT has added new Requirement R5 to explicitly require criteria for transient voltage criteria. This new requirement allows for the responsible entity to determine the acceptable limit for its System. **R5** Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for their System. For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltages may remain outside that level. The proposed change for "or by prior agreement" was not accepted by the SDT since the addition of footnote 5 (now footnote 4) and the ability to shed Conditional Firm service should adequately cover the situation described. No change made. The intent of extreme event 3 'a' is simply to look at the loss of all units from two separate plants. Items i, ii, iii, iv and vi are merely explanatory to what could initiate this type of event. No change made. The P5 event description was changed in Draft 3 to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a Delayed Clearing mode that may also include additional electrical Facilities being removed when compared to normal fault clearing.		
Brazos Electric Cooperative	No	For the most part Table 1 is acceptable but not entirely. The general 'feel' is that more studies are required. Requiring more studies is not going to provide additional reliability benefit but Brazos does not own many miles of transmission above 300 kV so the impact will be less for us than other larger TOs. We do not see the purpose of studying events where all forms of load loss is allowed. We understand upgrading the transmission system for these events is not required and is unneeded so why study certain events other than to insure that cascading outages don't occur? Without running a full set of studies it is a little hard to determine if Table 1 can be readily assessed or the true value of the additional studies.

Organization	Yes or No	Question 9 Comment
Response: More studies are being required in the sense that sensitivity studies are now required. However, the number of scenarios covered in the planning events and extreme events is comparable to the existing Category A, B, C and D items in use today. For events that permit the loss of Non-Consequential Load, a Transmission Planner could elect to impose stricter criteria on itself than the minimum expectations of the standard. However, the SDT believes an appropriate criterion has been established. Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined. The sensitivity studies are intended to broaden the knowledge of the Transmission Planner. If several sensitivities show a susceptibility to a particular planning event, a Transmission Planner may elect to act and include in their Corrective Action Plans based on the risk and likelihood.		
American Electric Power	No	Consider adding a Planning Event defined to address common mode outages of two generating units. The language could parallel that of P7, substituting “common system” for “common structure”. In the present draft, Planning Events P4 and P5 address single faults that may result in multiple contingencies. Most of these events can be expected to involve either multiple transmission facilities or a mix of generating units and transmission facilities. P7 covers common mode (structure) outages of transmission lines. There are no common mode generator contingencies specified. Define the term “common Right-of-Way” and/or modify the term to “common or adjacent Right(s)-of-Way”. In the absence of a definition, if two lines are built on opposite sides of some geographic boundary (such as a two-lane road) they may legally be completely separate, potentially with no overlap in the agreements between the Transmission Owner and landowners. However, from the standpoint of BES exposure to weather related outages, the lines clearly will simultaneously be exposed to similar conditions. Lines that follow geographically parallel routes for more than a minimum distance and are within some minimum separation should be considered to be on a common Right-of-Way. Suggestion for the minimum parallel distance would be 1 mile (based on footnote 12).
Response: The common mode event described is classified as an extreme event, see item 1 in steady state and Stability. The Transmission Planner could elect to impose a higher criteria on itself and consider a variation of the P3.1 event that would not include a System adjustment between the loss of two units, but it is not required by the standard. No change made. The commenter accurately describes the potential outcome of the P4 and the P5 events. As described above, the Transmission Planner could elect to evaluate the simultaneous loss of two units, but it was not identified by data reviewed by the SDT as being a highly likely event and therefore not included as a planning event. The SDT has made clarifying changes to Footnote 12 (now footnote 11). Footnote 11 has been added to the extreme event steady-state 2b. Extreme event Stability 2f has been deleted. **Footnote 11:** Excludes circuits that share a common structure or common Right-of-Way for 1 mile or less		
LADWP	No	Table 1 continues with discriminatory performance criteria required of 300kV and above facilities. This new "higher" criteria could lead to endless argument and litigations as to who did what to whom if implemented. Currently, all transmission facilities have same performance criteria; the impacts of each new facility are carefully evaluated and mitigations are included as part of the Plan of Service. This new, discriminatory requirement would

Organization	Yes or No	Question 9 Comment
		force everyone with EHV facilities to re-do its palnning studies and mitigate the impacts. Unfortunately, the real world is quite messy. For example, Company A has put in a 500KV line twenty years ago and since then, Companies B, C, and D have put in several underlying 230 kV, 115 kV lines. Is company A on hook now to mitigate all the problems for lines that came in later? Or is it required to re-create the conditions 20 years ago and mitigate only what would have been required. This is a very simplistic example to illustrate potential disagreements that would arise by this discriminatory criteria. If there is any engineering evidence to support this arbitrary requiremnts, it has yet to be presented. As I commented in the past, the last two major cyctme wide cascading event, both in WECC AND THE Eastern Interconnect, were both caused by 230kV systems.
Response: Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined. In the example provided, each company A, B, C and D is responsible for ensuring that criteria is met for its own facilities.		
Platte River Power Authority	No	At the top of Table 1 Planning Events, under "Stability Only:" regarding Note "i": Suggest deleting everything from "established" on to the end. (WECC establishes acceptable limits for transient voltage response.)
Response: The SDT has revised the referenced header note, now header note “k” in draft 4. The note now says both the Transmission Planner’s and the Planning Coordinator’s criteria must be met. **Header note ‘k’:** Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.		
Orlando Utilities Commission	Yes	Comments: The table is significantly improved from the prior versions and provides superior clarification over the existing standards. In areas where an entity is the TSP and the PC, it is obvious that the Firm Service provided by the TSP falls within the performance requirements of the standard regarding curtailment. However if the firm service is provided by another TSP (a different PC) and causes a problem, who is responsible for insuring it does not have to be curtailed. As an example if System A has a firm transmission service agreement that under contingency causes a problem on System C, is system C in violation if the service has to be cut to protect their system, or is System A that granted and is responsible for the service?
Response: We appreciate your support of the TPL-001-1 standard and the revised Table 1. The Planning Coordinator or Transmission Planner is responsible for its portion of the BES and therefore is responsible for insuring there are no performance violations on its System. Further, the origin of the violation and the responsibility for curtailing service is not within the scope of the planning standards as it is an equity issue and not a reliability issue.		
American Transmission Company	No	We suggest the following changes:We believe reference to the use of Load Reduction to meet steady state performance requirement was omitted in Planning Events, Steady State and Stability, Item b. We suggest modifying the last sentence in Item b: However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirements. We propose limiting the scope to automatic devices in Planning Events, Steady State and Stability, Item c. We suggest text of: c. Simulate the removal of all elements that Protection Systems and other Controls are expected

Organization	Yes or No	Question 9 Comment
		to disconnect automatically for each Contingency?. Remove performance note ?e" in the Planning Events, Steady State & Stability section and replace it with R3.3.5 and R4.3.5, as suggested in the comments for R3 and R4. The qualification of allowable planned System adjustments should be a Requirement, rather than a performance note. Remove performance note "a" in the Planning Events, Steady State Only section, and replace it with R2.10, as suggested in the comments for R2. The obligation to identify and observe applicable steady state voltage and post-Contingency voltage deviations should be a Requirement, rather than a performance note. Remove performance note "b" in the Planning Events, Stability Only section and replace it with R2.10, as suggested in the comment for R2. The obligation to identify and observe applicable transient voltage response limits should be a Requirement, rather a performance note. Modify the P3 Category performance criteria to apply only to the loss of two generators because the probability of the loss of two base load generators is an order of magnitude greater than the loss of a generator and any other transmission element. We suggest the listing of: the loss of transmission circuit, transformer, shunt device, and single pole of DC line be removed from the P3 Events column. The corresponding events be moved to the P6 Category by "1. Generator" to the listing in the Initial System Condition (Loss of . . .) column.Limit the scope of the simulations in Item 1 of the Extreme Events, Steady State and Stability section to automatic systems and controls. We suggest this text: "1. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect automatically for each Contingency. Clarify the meaning of the loss of multiple circuits in Item 2.a of the Extreme Events, Steady State section by using wording similar to P7. We suggest this text: "a. Loss of three or more circuits that share a common structure. Clarify the reference to actual, historical operating experience in Item 3.b of the Extreme Events, Steady State section. We suggest this text: "b. Other events based upon actual operating experience that may result in wide area disturbances. Clarify the reference to actual, historical operating experience in Item 2.i of the Extreme Events, Stability State section. We suggest this text that is similar to Steady State, Item 3.b: "i. Other events based upon actual operating experience that may result in wide area disturbances. Further clarify the applicable shunt devices in Footnote 7 with this suggested text: "7. Requirements which are applicable to shunt devices, also apply to FACTS devices that are connected to ground, but not instrument voltage transformers or surge arresters. ATC suggest that following change to Table 1, footnote 4. Existing language:"Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems."Suggested Modification:"Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 100kV through the 300kV Systems."

Organization	Yes or No	Question 9 Comment
Response: Regarding the suggested change to header note "b", no change was made as the standard does not prescribe a particular Load model such as constant power, constant impedance, etc. The proposed change to header note "c" has been made. **Header note 'c':** Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event. The proposed deletion of header note "e" was not accepted. The note is explanatory describing something that is permitted rather than a requirement that shall be followed. The proposed change to move item header note 'e' to the requirements was not accepted. Additionally, under Requirement R3, part 3.1 and Requirement R4, part 4.1 the entire table is tied to a reliability requirement for both steady state and Stability. Regarding comments on header notes "a" and "b" - under Requirement R3, part 3.1 and Requirement R4, part 4.1 the entire table is tied to a reliability requirement for both steady state and Stability. The loss of a generator plus any other N-1 item was viewed as highly likely by the SDT. No change was made to the P3 and P6 events as proposed by the commenter. No change was made to the note as the SDT considered the present wording sufficient to describe the condition. No change was made to the note as the SDT considered the present wording sufficient to describe the condition. The proposed change to footnote 7 (now footnote 6) was not made as the SDT considers the present wording sufficient to describe the condition. The change to footnote 4 (now footnote 3) was not accepted although the SDT did make a clarifying change to the footnote. **Footnote 3:** Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems as defined by the Regional Entity. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruptions of Firm Transmission Service and Non-Consequential Load.		
Omaha Public Power District	No	Header note 'f' under Planning Events: The redline version shows that the sentence "Facility Ratings shall not be exceeded" was removed from the beginning of header note "f" (header note "b" in the previous draft). This sentence needs to be reinserted at the beginning of header note "f". The requirement that Facility Ratings not be exceeded is a core principle of steady-state transmission-system assessment and needs to be explicitly stated somewhere in the standard. If this sentence is not reinserted, it could lead to a situation where different regions come up with different interpretations of the manner in which Facility Ratings need to be respected. Category P2: In the third column of the table, there is a dotted line that appears to be separating two parts of the description for event type P2.3. It appears that this dotted line should be removed. Category P3: In the fifth, sixth, and seventh columns of the table, there is one set of cells for event types P3.1 through P3.4 and another set of cells for event type P3.5. Since these two sets of cells are identical, they can be merged into one set that applies to event types P3.1 through P3.5. This would make the presentation of requirements for Category P3 consistent with that of Category P1. Category P7: Category P7 requires analyzing SLG faults on any two circuits on common structures. Add language to clarify whether SLG faults on both the same and different phases of the two circuits need to be

Organization	Yes or No	Question 9 Comment
		considered or whether it is sufficient to assume that the SLG faults occur on the same phase of the two circuits.
Response: In header note "f", the text "Facility Ratings shall not be exceeded" was inadvertently deleted in the Draft 3 standard and has been re-inserted in Draft 4. The dotted line separator is appropriate and is used to distinguish between the EHV and HV performance criteria of the P2.3 event. The suggested table format change for the P3 event was accepted. The standard does not specify. It's at each Planning Coordinator's or Transmission Planner's discretion.		
Tucson Electric Power Company	No	Clarify use of the term "single contingency" in P2 as P2-2 and P2-3 are labeled as single contingencies but multiple elements are effected. In the past loss of a branch or shunt element has been considered a single contingency but loss of a bus element could involve the loss of multiple branch or shunt elements. P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements. As such, this is a low probability condition and loss of Non-Consequential load should be allowed for EHV. We disagree with raising the bar for EHV for P4.We also disagree with raising the bar for P5. This is a multiple contingency condition and may result in loss of more than 2 elements. We strongly disagree with elimination of load shed (of non-consequential load) for loss of multiple branch or shunt elements >300 kV.
Response: The P2-2 and P2-3 items are considered single Contingency since a single fault occurrence causes the event. While it is true that multiple elements are anticipated to trip, the event is still considered a single Contingency. TPL-001-1 differs from the existing standard in that it is clear that single branch outages that are not reflective of actual Protection Systems and controls design will not be acceptable. If a single fault can result in multiple elements being removed from service they must be simulated accordingly. The SDT has added the introductory text proposed for the P4 "Event" column of the table to bring consistency with the P5 event. In regards to the EHV performance criteria for the P4 event, the EHV performance expectations remain as stated in Draft 3. P4 events pose higher risk and impact to the BES since there is no time for System adjustments for potential multiple Facility outages that can result from a single fault. Since the EHV is considered the backbone of the BES carrying large amounts of power between generation and Load and typically not directly servicing end-user customers the higher performance expectations for the high impact P4 events is warranted. **P4:** Loss of multiple elements caused by a stuck breaker [11](non-Bus-tie) attempting to clear a Fault on one of the following: & 6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie) attempting to clear a Fault on the associated bus Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined. The Implementation Plan is intended to provide sufficient time to shift to the new expectations.		
Independent Electricity System Operator	No	"Single-phase-to-ground" faults should replace all occurrences of "single-line-to-ground" faults.

Organization	Yes or No	Question 9 Comment
		Events in P6 and P7 need more clarity for back to back installation where no DC line exists. In note footnote 11 we propose the following change. 11. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing. We do not agree with the removal of the provision to allow load rejection for 1 and 2 elements out of service under certain defined conditions as indicated in footnote "b" of Table I of the current TPL standards.
Response: The SLG fault description is a commonly understood term. No change was made. For back to back installations, each pole of the converter station would be treated the same as a DC line. No change made. The proposed change for footnote 11 (now footnote 10) was accepted. **Footnote 10:** A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing In regards to proposed change to prohibit Non-Consequential Load shed in response to a single Contingency event, FERC, in Order 693, was clear in paragraph 1794 that interruption of Non-Consequential Load are not permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the majority of the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement.		
ReliabilityFirst Corporation	Yes	The term "stuck breaker" has been mis-understood, and additional text is needed to make it clear. "A stuck breaker is defined as a breaker that failed to open due to a mechanical failure internal to the breaker which prevents it from opening or protection system failures that failed to send a trip signal.
Response: The SDT agrees in part with your response. We concur that a stuck breaker is based on a mechanical failure of a single breaker. However, a Protection System failure could result in different outcomes depending on the design implemented. The SDT has partitioned the prior C6 through C9 contingencies into the P4 and P5 planning events to bring greater focus on this distinction.		
Kansas City Power & Light	Yes	
ReliabilityFirst Corporation	Yes	
Dominion - Electric Transmission	Yes	
Duke Energy	Yes	
ITC Holdings	Yes	None

Organization	Yes or No	Question 9 Comment
New Brunswick System Operator		No comment
Gainesville Regional Utilities	Yes	
CPS Energy	Yes	
Southern Company	Yes	
Tampa Electric	Yes	
Response: Thank you for your response.		

10. The changes to the Table include the addition/revision of footnotes 5 and 10 that address curtailment of Firm Transmission Service and conditional Firm Transmission Service. Do you agree with the footnotes? If not, please provide specific comments.

Summary Consideration: The majority of respondents were positive with their comments on the addition of the two footnotes. A number of clarifying questions were asked and the SDT has attempted to quell those questions with clarifications made to the footnotes. Please note that footnote 5 is now footnote 4 and footnote 10 is now footnote 9.

Footnote 4: Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.

Footnote 9: Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.

Organization	Yes or No	Question 10 Comment
Dominion - Electric Transmission	No	Table 1 Interruption of Firm Transmission Service is not allowed for many of the events listed. Doesn't this imply that firm point-to-point service can't be interrupted even when the service is provided across points that are connected only by a radial facility? If so, does NERC have the authority to determine how transmission service providers calculate firm ATC? Dominion is also concerned that transmission service providers appear subject to "double jeopardy" I.E, NERC fine for violations of applicable reliability standard and FERC sanctions if OATT is violated.
Response: It is the SDT's opinion that the point-to-point service described is in essence; Conditional Firm Service based on the condition that the radial Facility is in service and could thus be interrupted under Footnote 5 (now footnote 4). No change made.		
Transmission Planning	No	It appears that the reference callout to footnote 5 should be placed on every "No" in the "Interruption of Firm Transmission Service column instead of in the header, as was done with reference callouts to footnote 10. In footnote 5 "conditional" should be capitalized since it refers to a specific product defined under the OATT. Also, this only covers the specific condition form of the product, but does not address the specified number of hours form of the product. If the second form of the product is the basis for the service and the transaction is modeled in the case, and curtailment will mitigate an overload, it should also be allowed. Footnote 10 is too long and subjective. There is no purpose in adding the phrase "when coupled with the appropriate re-dispatch of resources obligated to re-dispatch" because if there is an obligation to re-dispatch, it is done, and if there is no obligation to do so, then curtailment is the only alternative " no coupling necessary,

Organization	Yes or No	Question 10 Comment
		therefore, this phrase should be deleted. In addition, the last two sentences end in "must be considered". What is the appropriate amount of "consideration" and what defines whether the consideration is acceptable or not? The last sentence should be a stand alone performance requirement in the Steady State and Stability notes at the top of Table 1 (in the list a through e) and should end in "must be adhered to" instead of "must be considered".Suggested revision:10. Curtailment of firm transmission service is allowed both as a System adjustment (as identified in the column titled "Initial System Conditions") and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load.
Response: Footnote 5 (now footnote 4) is intended to apply to every row in the "Interruption of Firm Transmission Service Allowed" column while Footnote 10 (now footnote 9) does not. The placement of the footnotes is predicated on that premise. No change made. The SDT agrees with the capitalization of the word Conditional and has made the necessary corrections. **Footnote 4:** Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service. Footnote 5 (now footnote 4) states that "When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service…" The word "conditions" is intended to address the 'hours' form of Conditional Firm service in that the hours a service may not be available should be based on System conditions that exist for those hours. No change made. Footnote 10 (now footnote 9) was added to address the disjoint between how some parties calculate ATC/AFC when assessing Long Term Firm Transmission Service and the currently proposed TPL-001-1 standard. TPL-001-1 requires Transmission Planners to plan their systems to meet multiple contingency events and some parties assess Long Term Firm Transmission Service on a first Contingency basis. Units obligated to re-dispatch, as contemplated in Footnote 9 are those units which are contractually bound to provide the service as well as those obligated to provide the service under Network Integrated Transmission Service, under FERC's pro forma OATT. Under the pro forma OATT, units designated as network resources receiving NITS are obligated to re-dispatch as requested by the Transmission Provider pursuant to Section 33.2 to maintain reliability. The footnote is worded such that curtailment/re-dispatch cannot result in the loss of firm Load preserves the guidance given by FERC in Order 693 that no single Contingency result in the loss of firm Load. No change made. Where contractual agreements exist between entities allowing re-dispatch, and the curtailment of Firm Transmission Service associated with that re-dispatch is point-to-point, the point-to-point service curtailment would be allowed. In the case of units otherwise obligated, namely those resources with Network Integrated Transmission Service designated as network resources, curtailment of point-to-point service involving those resources would not be allowed. The SDT believes that applicable Facility Ratings noted throughout the standard cover all Facilities. No change made.		
SERC Engineering Committee Planning Standards Subcommittee	No	Footnote 5:Suggest rewording of footnote 5 to:Curtailment of conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the conditional Firm Transmission Service. Footnote 10: Footnote 10 is definitely an improvement from previous versions. It is suggested that the word "also" be added to the last line:Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of

Organization	Yes or No	Question 10 Comment
		resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled "Initial System Conditions") and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must also be considered.
Ameren	No	Suggest rewording of footnote 5, though we do not use conditional firm service:Curtailment of conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the conditional Firm Transmission Service. Footnote 10 is definitely an improvement from previous versions. It is suggested that the word "also" be added to the last line:Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled "Initial System Conditions") and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner'splanning region are relied upon, Facility Ratings in those regions must also be considered.
Response: The SDT agrees with proposed re-wording of Footnote 5 (now footnote 4) and the additional wording in Footnote 10 (now footnote 9). **Footnote 4:** Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.: **Footnote 9:** Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must should also be respected. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service. Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.		
SERC Engineering Committee Reliability Review Subcommittee	No	Suggest rewording of footnote 5 to: Curtailment of conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the conditional Firm Transmission Service.

Organization	Yes or No	Question 10 Comment
(RRS)		Footnote 10 is definitely an improvement from previous versions. It is suggested that the word "also" be added to the last line: Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled "Initial System Conditions") and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must also be considered.
Response: The SDT agrees with proposed re-wording of Footnote 5 (now footnote 4) and the additional wording in Footnote 10 (now footnote 9). **Footnote 4:** Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service. **Footnote 9:** Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must should also be respected. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service. Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.		
Southern Company	No	Footnote 10 should not be applied to P3. The curtailment of firm service should not be allowed for a unit out / line out contingency.
Response: Footnote 10 (now footnote 9) was added to address the disjoint between how some parties calculate ATC/AFC when assessing Long Term Firm Transmission Service and the currently proposed TPL-001-1 standard. TPL-001-1 requires Transmission Planners to plan their systems to meet multiple contingency events and some parties assess Long Term Firm Transmission Service on a first Contingency basis.. Units obligated to re-dispatch, as contemplated in Footnote 9 are those units which are contractually bound to provide the service as well as those obligated to provide the service under Network Integrated Transmission Service, under FERC's pro forma OATT. Under the pro forma OATT, units designated as network resources receiving NITS are obligated to re-dispatch as requested by the Transmission Provider pursuant to Section 33.2 to maintain reliability. The footnote is worded such that curtailment/re-dispatch cannot result in the loss of firm Load preserves the guidance given by FERC in Order 693 that no single Contingency result in the loss of firm Load. No change made.		
System Protection and Transmission Planning	Yes	These concepts seem too important to relegate to footnotes. Could this discussion of how to handle Firm transactions and redispatch be moved to a more prominent place? Perhaps these concepts should be removed

Organization	Yes or No	Question 10 Comment
Department		from this standard entirely. A more appropriate place for these concepts would be in ATC standards.
Response: While the SDT agrees that these are important concepts, given that the inclusion of all firm use of the BES, including the use created by Firm Transmission Service, is essential to meaningful Transmission Planning Assessments, The SDT therefore does not agree that the concepts can be removed entirely from the TPL standard. Ultimately Transmission planning engineers will be responsible for the study work done and the proposals to ensure each entity meets the requirements in the standard. The SDT believes that the tables will be the central point of reference and thus the most appropriate place for the provisions regarding how firm Transmission use can be handled. No change made.		
Florida Reliability Coordinating Council, Inc - Transmission Working Group	Yes	Excellent additionFootnote 10 is long and subjective. There is no purpose in adding the phrase "when coupled with the appropriate re-dispatch of resources obligated to re-dispatch" because if there is an obligation to re-dispatch, it is done, and if there is no obligation to do so, then curtailment is the only alternative " no coupling necessary. Suggested revision:10. Curtailment of firm transmission service is allowed both as a System adjustment (as identified in the column titled "Initial System Conditions") and as a corrective action, providing those adjustments do not result in the shedding of any firm Load.
Response: Footnote 10 (now footnote 9) was added to address the disjoint between how some parties calculate ATC/AFC when assessing Long Term Firm Transmission Service and the currently proposed TPL-001-1 standard. TPL-001-1 requires Transmission Planners to plan their systems to meet multiple contingency events and some parties assess Long Term Firm Transmission Service on a first Contingency basis.. Units obligated to re-dispatch, as contemplated in Footnote 9 are those units which are contractually bound to provide the service as well as those obligated to provide the service under Network Integrated Transmission Service, under FERC's pro forma OATT. Under the pro forma OATT, units designated as network resources receiving NITS are obligated to re-dispatch as requested by the Transmission Provider pursuant to Section 33.2 to maintain reliability. The footnote is worded such that curtailment/re-dispatch cannot result in the loss of firm Load preserves the guidance given by FERC in Order 693 that no single Contingency result in the loss of firm Load. No change made.		
FMPA	Yes	We disagree with how the performance criteria is applied to different contingencies, but agree that firm transmission can be curtailed post-contingency as a system adjustment, and especially as preparation for the next contingency.
NorthWestern Corporation NorthWestern Energy (NWE) (NWMT)	No	NWE has provided comments above concerning Firm Transmission Service and the foot notes should address the issues that we have raised above.
Progress Energy Florida, Inc.	No	Again, given the fundamental concerns that PEF has stated in previous Questions, PEF sees voicing detailed concerns for these footnotes as irrelevant, short of suggesting the reinstatement of the existing Footnote (b).
Response: The SDT thanks you for your comments.		
Progress Energy Carolina (PEC)	No	PEC believes that Footnote 10 should be clarified. The proposed wording "Where Facilities external to the Transmission Planner'splanning region are relied upon, Facility Ratings in those regions must be considered" is unclear. It is not clear what "relied upon" means. Also, thermal overloads on neighboring systems are generally

Organization	Yes or No	Question 10 Comment
		the neighboring system's responsibility to mitigate.
Response: The intent of Footnote 10 (now footnote 9) is to allow Transmission Planner's to use resources obligated to re-dispatch to meet reliability requirements. However, without due consideration to Facilities external to the Transmission Planner's study area, Facility Ratings could potentially be violated in those areas unbeknownst to the owners of those Facilities. Footnote 10 has been revised for clarity. **Footnote 9:** Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must should also be respected.		
JEA	No	Footnote 10: First of all, the term firm Load is used instead of the term Non-Consequential load. Are these the same? If so, maybe we need to be consistent here. Assuming they are the same and in reference to previous comment on use of Non-Consequential load shedding. :"Propose establishing a cap on Non-Consequential Load Loss for all Corrective Action Plans where the Table 1 events currently do not allow at all. The cap could also be accompanied by an allowance of lag time (maybe 4-5 years)."To be consistent, some level of Non-Consequential load shedding should be allowed where Generation redispatch falls short for a few years until new planned generation is added to the system.
Response: The SDT does not see where any additional clarity would be added by the suggested change. No change made. The SDT has considered establishing a cap on Consequential and Non-Consequential Load Loss. Currently the SDT has elected not to do so, but instead to add reporting requirements in Requirement R2, Part 2.9 for a possible cap in the future. Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must also be adhered to.		
SMUD	No	The allowed corrective actions in Table 1 to meet performance standards do not explicitly state how DSM solutions should be treated [there is a potential for 20% of national peak demand to be met by "demand response"] . If it is allowed to be used, and since this is a fairly significant amount, it would help if it is explicitly addressed in Table 1.
Response: The SDT agrees that DSM initiatives can impact TPL-001-1 assessments. It is the SDT's opinion that DSM initiatives would be reflected in the Load models. No change made.		
Pacific Gas and Electric Co,	Yes	We support the concept. However, we are unclear about the last sentence of Footnote 10, which reads "where

Organization	Yes or No	Question 10 Comment
		Facilities external to the Transmission Planner'splanning region are relied upon, Facility Ratings in those regions must be considered. For resources from areas external to the Transmission Planner'splanning regions, would identification of the need to, for example, increase System Operating Limits into the his/her Transmission Planning Area as part of the Corrective Action Plan be counted as having "considered" the "Facility Ratings in those impacted regions"? Otherwise, it may be difficult for the Transmission Planner to assess and identify all the Facility Ratings that may be impacted in a region external to his/her Transmission Planning Area.
Response: The SDT agrees and has strengthened the language in Footnote 10 (now footnote 9) **Footnote 9:** Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must should also be respected. Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must also be adhered to.		
Manitoba Hydro	Yes	Note 10: The drafting team is to be congratulated for including the ability to curtail Firm Transmission Service as long as generation is available to redispatch to prevent firm load loss. Note 5: Firm transmission service can also be curtailed when the service is conditioned on the element is being available (note 5). It is recommended to add note 10 to contingencies P1 and P2. This would allow for curtailment of Firm Transmission Service via redispatch without dropping load when re-adjusting the system following these single contingency events, or automatically adjusting the system via an SPS action initiated by the P1 or P2 event, consistent with note b of the existing TPL standards. The consequence of not including Note 10 could mean extensive new transmission line construction without any increase in transfer capability. In Note 10, the SDT is assuming that the Firm transmission Service is Network Service to load. Does Note 10 also apply if the Firm Transmission Service is firm point-to-point service?
Response: The SDT agrees that Footnote 10 (now footnote 9) all System adjustments. However, P1 and P2 do not include System Adjustments. While the SDT recognizes that firm service has been granted on radial Facilities it is the SDT's opinion that such service is, in essence, Conditional Firm Service based upon the condition that the radial Facility is in service. No change made. Footnote 10 (now footnote 9) was added to address the disjoint between how some parties calculate ATC/AFC when assessing Long Term Firm Transmission Service and the currently proposed TPL-001-1 standard. TPL-001-1 requires Transmission Planners to plan their systems to meet multiple contingency events and some parties assess Long Term Firm Transmission Service on a first Contingency basis. Units obligated to re-dispatch, as contemplated in Footnote 9 are those units which are contractually bound to provide the service as well as those obligated to provide the service under Network Integrated Transmission Service, under FERC's pro		

Organization	Yes or No	Question 10 Comment
forma OATT. Under the pro forma OATT, units designated as network resources receiving NITS are obligated to re-dispatch as requested by the Transmission Provider pursuant to Section 33.2 to maintain reliability. The footnote is worded such that curtailment/re-dispatch cannot result in the loss of firm Load preserves the guidance given by FERC in Order 693 that no single Contingency result in the loss of firm Load. No change made. Where contractual agreements exist between entities allowing re-dispatch, and the curtailment of Firm Transmission Service associated with that re-dispatch was point-to-point, the point-to-point service curtailment would be allowed. In the case of units otherwise obligated, namely those resources with Network Integrated Transmission Service designated as network resources, curtailment of point-to-point service involving those resources would not be allowed as there is no obligation to do so.		
National Grid Northeast Utilities	Yes	Capitalize "Firm Transmission Service" in footnote 10 and instead of saying firm Load use Firm Demand to be consistent with the NERC Glossary
Northeast Power Coordinating Council	No	Capitalize Firm Transmission Service in footnote 10 and instead of saying firm Load use Firm Demand to be consistent with the NERC Glossary.
Response: The SDT agrees with the proposed changes. **Footnote 9:** Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must should also be respected.: Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must also be adhered to.		
BC Hydro	No	Comments: Consider changing Footnote 10 to read, "Curtailment of firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled ["title" is a noun, not a verb and "titled" is an adjective meaning having a title, esp. of nobility] "Initial System Conditions") and a corrective action provided both are accomplished automatically by a NERC-certified SPS, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.
Response: The SDT agrees with the proposed use of "entitled". **Footnote 9:** Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed		

Organization	Yes or No	Question 10 Comment
		both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must should also be respected. Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must also be adhered to. The SDT respectfully disagree that inclusion of language limiting the use of Footnote 10 (now footnote 9) to only those applications where an SPS is involved would further complicate the application of the footnote and would unduly limit its application. No change made.
San Diego Gas and Electric Co		We agree that TPL-005 and TPL-006 appear to have been adequately covered in the draft TPL-001-1 as currently written. However, we will need to review this assessment after TPL-001-1 is finalized. In addition, there is no place to state our concerns for Section D. so we added it here. We question the "not applicable" entry under Section D 1.1.2. What does it mean when the reset period is not applicable? Does it mean there is no reset period, so all non-compliance in all prior years will be counted as prior violations when considering non-compliance in future years?
Response: The sanctions guidelines developed by the compliance program as part of the ERO start-up process eliminated the use of the concept of the "compliance reset period." The reason the heading "Compliance Monitoring and Reset Time" is still in the standards template is because some Standards Committee members felt that a change to the standard template couldn't be made without having the change go through full due process. Therefore, NERC staff agreed to always put, "Not applicable" under this heading until the next version of the manual is issued. This term will be eliminated in Version 8.		
LADWP	No	The use of the term"Firm Transmission Service" is problematic at best. See my comments on R1. The proper term is "Expected Transfer Level"
Response: Although Firm Transmission Service is a defined term in the NERC Glossary, it is recognized that some planning processes do not designate inter-area transfers as firm or non-firm. Re-dispatch of Designated Network Resources or resources contractually bound to participate in re-dispatch activities would in many cases result in changes in area interchange and thus would still be allowed in Footnote 10 (now footnote 9). Additionally, the proposed standard now requires sensitivities to be included in the Planning Assessment which may include expected transfers. No change made.		
Central Maine Power Company	Yes	
Independent Electricity System Operator	Yes	

Organization	Yes or No	Question 10 Comment
Kansas City Power & Light	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
MRO MRO NERC Standards Review Subcommittee	Yes	N/A
SERC Engineering Committee Dynamics Review Subcommittee (DRS)	Yes	None.
Platte River Power Authority	Yes	
American Transmission Company	Yes	
Idaho Power	Yes	
Minnesota Power	Yes	
Midwest ISO	Yes	
NV Energy	Yes	
PJM	Yes	
Brazos Electric Cooperative	Yes	no comment
American Electric Power	Yes	
ITC Holdings	Yes	Comments: We concur that footnote 10 should not apply to P0, P1 or P2 events.
Entergy Services, Inc	Yes	Units obligated to re-dispatch must include all Network Resources
ISO New England, Inc.	Yes	
New Brunswick System Operator		No comment

Organization	Yes or No	Question 10 Comment
Western Area Power Administration	Yes	
MidAmerican Energy Company	Yes	
Deseret Generation & Transmission	Yes	
Gainesville Regional Utilities	Yes	
Western Area Power Administration	Yes	
Tampa Electric	Yes	
IRC Standards Review Committee	Yes	
TVA System Planning	Yes	
Exelon Transmission Planning	Yes	
United Illuminating	Yes	
FirstEnergy Corp	Yes	We presently agree with the Footnote 5 and text.
Response: Thank you for your response.		

11. The SDT has provided an Implementation Plan as part of this posting. The plan includes the retirement of TPL-005-0 and TPL-006-0. Do you agree with the elements of the Plan? If not, please provide specific comments.

Summary Consideration: There were 3 main comments associated with this question.

Eleven commenters indicated that 60 months is not enough time to build major lines, especially if up to 24 months is needed to do the Planning Assessment and develop a Corrective Action Plan. The SDT considered this issue when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of the comments received from this posting. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. The third draft of TPL-001-1 does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply.

The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control.

Eight commenters indicated that more time is needed before dynamic Load modeling Requirement R2, part 2.4.1 becomes effective. However, Requirement R2, part 2.4.1 does not require a detailed dynamic Load model, only an aggregate System model. The SDT believes that such a model can be developed within the 24 month period before this requirement becomes effective.

Seven commenters raised concerns about the retirement of TPL-005-0 and TPL-006-0, regarding the requirements or lack thereof being placed on the Planning Coordinators and Transmission Planners to provide inputs to the Regional Entities so they can meet their obligations to NERC to prepare regional assessments. The SDT believes that the retirement of TPL-005-0 and TPL 006-0 have been adequately addressed by adding the Requirement R3, part 3.4.1, Requirement R4, part 4.4, and Requirement R8 with part 8.1 in the fourth draft of TPL-001-1 to ensure that Planning Coordinators and Transmission Planners will provide the necessary inputs to the Regions so that the Regions can fulfill their obligations to NERC in accordance with the NERC Rules of Procedure.

Changes were made to the following requirements due to industry comments:

3.4.1 The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.4.1 The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

R8 Each Planning Coordinator and Transmission Planner shall distribute its its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.

8.1 If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Organization	Yes or No	Question 11 Comment
Dominion - Electric Transmission	No	Dominion agrees with the retirement of TPL-005-0 and TPL-006-0. However, Dominion has some concern over the implementation period and believes that 60 months to implement corrective action plans may not be enough. This standard has more stringent requirements ("raising the bar") than the current TPL standards. Having to assess the system for these new standards as well as implementing corrective action plans within 60 months could be difficult to get approval to site and construct new transmission. Dominion suggests that an additional 12 to 24 months be given to allow time for the assessments to determine violations, solicit input from all stakeholders through RTO process (As required by FERC 890) to determine the most appropriate corrective action plans.
Response: The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. The third draft of TPL-001-1 does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control.		
Northeast Power Coordinating Council	No	Please clarify, since R2 through R6 should become effective before results could be distributed to adjacent Planning Coordinators and any functional entity. However, by the wording of the effective date of R1 and R7 it appears R7 becomes effective before R2 to R6. That is, 24 months are allowed by the standard to complete the planning assessments after regulatory approval. The results may not be ready for distribution by the planning coordinator after the first twelve months. As written, the Standard would become effective at different times in different jurisdictions. Requirement R7 requires coordination among adjacent Planning Coordinators and any Functional Entity that has indicated a reliability need. Such coordination cannot be granted until the Standard is effective for all involved jurisdictions. The term "Planning Coordinator" is not defined in the NERC Glossary of Terms used in Reliability Standards and, therefore, this standard should indicate whether this term is the same as the "Planning Authority" defined in the glossary. Otherwise the definition of the Planning Coordinator should be included in the NERC Glossary of Terms used in Reliability Standards. With regard to the many changes/modifications from the previous draft and from the previous TPL standards being replaced by TPL-001-1, another posting of this Standard will be necessary to fully evaluate the impact (on reliability and also cost of implementation) of such changes. The decision to allow the use of all type of RAS or SPS (particularly generator tripping and run-back) as a common practice for single contingency does not "raise the bar" in the planning standard, and should be reviewed. How can higher system performance be required that involves substantial infrastructure investment to prevent

Organization	Yes or No	Question 11 Comment
		events with a very low probability of occurrence, and allow use of a less reliable measure (SPS failure or misoperation having a higher probability of occurrence) to reduce the investment for more probable events?
Response: Distribution of Planning Assessments under Requirement R7 (now Requirement R8) is not limited to Planning Assessment results produced in conformance with the revised standard. Until such results are available, the SDT intended that Planning Assessments produced using the existing standards would be distributed. Planning Coordinator is listed as the new term for Planning Authority in the latest approved version of the Functional Model and is in the latest version of the NERC Glossary of Terms Used in Reliability Standards. No change made. The SDT agrees that another posting is required and has produced a fourth draft. The SDT's intent was to raise the bar where it was practical to do so and not lower the bar in any case. The allowance for the use of SPS and RAS in response to single Contingencies simply reflects the existing practice in many parts of North America. Where this has not been a common practice, individual Regional Entities, Planning Coordinators or Transmission Planners have the latitude to establish more stringent criteria.		
SERC Engineering Committee Planning Standards Subcommittee	No	Construction activities:60 months effective date seems acceptable for planning activities, but may not adequate for all construction activities. Typical times to construct a transmission line in various areas of SERC can range between 7 to 10 years. Accordingly, we recommend the effective date for construction projects be changed to at least 84 months.Dynamic load models:More time is needed for entities to determine the appropriate dynamic load model required by R2.4.1. We recommend at least 36 months before this requirement becomes effective.
Response: The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. The third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control. Requirement R2, part 2.4.1 does not require a detailed dynamic Load model, only an aggregate System model. The SDT believes that such a model can be developed within the 24 month period before this requirement becomes effective.		
Bonneville Power Administration		We agree that TPL-005 and TPL-006 appear to have been adequately covered in the draft TPL-001-1 as currently written. However, we will need to review this assessment after TPL-001-1 is finalized. In addition, there is no place to state our concerns for Section D. so we've added it here. We question the "not applicable" entry under Section D 1.1.2. What does it mean when the reset period is not applicable? Does it mean there is no reset period, so all non-compliance in all prior years will be counted as prior violations when considering non-compliance in future years? OTHER COMMENTS:Would like to see TPL-001-1 more specifically address system performance required for radial load areas served by multiple transmission circuits (unequal capacity) from a single source substation. For

Organization	Yes or No	Question 11 Comment
		example, a radial load served by a single circuit 115-kV line and a single circuit 230-kV line. For a single contingency loss of the 230-kV circuit, cannot serve peak load area demand. Is this situation meant to be covered by Category P1 in TPL-001-1? I don't see anything similar to TPL-002-0a, Category B, Note b under Loss of Demand.
Response: The sanctions guidelines developed by the compliance program as part of the ERO start-up process eliminated the use of the concept of the "compliance reset period." The reason the heading "Compliance Monitoring and Reset Time" is still in the standards template is because some Standards Committee members felt that a change to the standard template couldn't be made without having the change go through full due process. Therefore, NERC staff agreed to always put, "Not applicable" under this heading until the next version of the manual is issued. This term will be eliminated in Version 8. The loss of Load served by a single Transmission line would be considered Consequential Load Loss which is permitted by the TPL-001-1 standard. However, as in your example, if a Load is served by 2 Transmission lines and one of the lines is not sufficient to supply the Load for the loss of the other, then it would be considered Non-Consequential Load Loss which is not permitted.		
MRO MRO NERC Standards Review Subcommittee	No	MRO NSRS offers the following comments.The last paragraph should be removed from the Effective Date section. This paragraph contains requirements and describes compliance procedures, rather than stating effective date details. If any requirements regarding Corrective Action Plans are included, then they should be placed in the R2 section. If descriptions of compliance procedures related to Corrective Action Plan implementation are deemed to be necessary, then they should be placed in NERC procedure documents. This standard should not contain any requirements regarding the implementation of Corrective Action Plans. The implementation of transmission system action plans depends on the actions (e.g. financing, regulatory approval, legal services, engineering, construction, commissioning) of many different entities, other than PCs or TPs. So, PCs and TPs should not be held responsible for the implementation of action plans since they have little or no control over the activities related to implementation. The standard could include requirements that obligate PCs and TPs to develop Corrective Action Plans that are executable (i.e. plans that are based on lead times that provide reasonable assurance that the planned facilities can be placed in service by the time that they are needed) or devise revised Corrective Action Plans when they learn that the actions plans are not expected to be implemented by the intended in-service date. The standard could also include requirements that obligate PCs and TPs to establish and apply project implementation lead time assumptions that are derived from historical experience and the implementation lead time projections from the applicable TOs, GOs, and DPs. Remove or modify the 60 month effective date statement because it's impractical and unreasonable. The effective date for performing analyses and developing subsequent Corrective Action Plans is 24 months. This leaves only 36 months to expect that the more stringent Corrective Action Plans would be implemented. It is improbable that all action plans related to BES facilities, especially above 300 kV could be implemented. Some EHV projects can take 5 to 10 years to implement depending on the size, complexity, and controversial nature of the project. MRO NSRS suggests that the effective date be stated in a more "implementation dependent" rather than a "fixed timeframe" manner. Consider wording such as "tripping of Non-Consequential Load or curtailment of Firm Transmission Service (in accordance with Requirement R2.6.4) is allowed until Corrective Action Plans based on TPL-001-1 analyses are implemented".
Response: The SDT disagrees that the last paragraph of the Effective Date should be removed. No change made.		

Organization	Yes or No	Question 11 Comment
The SDT disagrees with your view that the Corrective Action Plans should not include implementation requirements. A plan has no value unless it is implemented. No change made. The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. The third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply. The SDT considered your suggestion to change the language of Requirement 2.7.5 to make it more "implementation dependent" rather than using a "fixed timeframe" but we do not believe such a change is appropriate because it would make auditing of this requirement difficult.		
SERC Engineering Committee Dynamics Review Subcommittee (DRS)	No	More time is needed for entities to determine the appropriate dynamic load model required by R2.4.1. We recommend at least 36 months before this requirement becomes effective. A 60 month effective date seems acceptable for planning activities, but may not adequate for all construction activities. Typical times to construct a transmission line in various areas of SERC can range between 7 to 10 years. Accordingly, we recommend the effective date for construction projects be changed to at least 84 months.
Response: The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. The third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control.		
SERC Engineering Committee Reliability Review Subcommittee (RRS)	No	60 months after effective date seems generally acceptable for planning activities, but may not adequate for all construction activities. Typical times to construct a transmission line in various areas of SERC can range between 7 to 10 years. Accordingly, we recommend the effective date for construction projects be changed to at least 84 months. More time is needed for entities to determine the appropriate dynamic load model required by R2.4.1. We recommend at least 36 months before this requirement becomes effective. Since breaker duty is a new "raising the bar" issue - should there also be a 5 or more year implementation plan for this as well? Also trying to construct enough facilities within the 5 year implementation period will result in multiple outages at same time - possibly affecting SERC member's bulk reliability during this construction period. Also SERC members are concerned that EHV equipment manufacturers will not be able to meet all the equipment orders that will be required to meet the "raising the bar" requirements. SERC members are also concerned that the costs to meet the new requirements contained in this TPL will amount to many billions of dollars with very little impact overall on the reliability of the Bulk transmission system. "When will the Implementation Plan be removed from the standard after it is officially approved" Will a revised

Organization	Yes or No	Question 11 Comment
		TPL standard need to be prepared to omit this implementation language?? If contingencies in one utility's system results in issues within another utility, who is responsible for studying the contingencies and who would be responsible for documenting the CAP?

Response: The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. This third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply.

The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control.

Requirement R2, part 2.4.1 does not require a detailed dynamic Load model, only an aggregate System model. The SDT believes that such a model can be developed within the 24 month period before this requirement becomes effective.

The SDT does not view the breaker duty requirements as a raising of the bar. While these may be new requirements in NERC Standards, the SDT believes that most entities already follow these practices because they are safety related.

If manufacturers or other service providers can not meet increased demands for equipment and services, that would be an event outside the control of the Planning Coordinator or Transmission Planner. With respect to any additional capital requirements driven by the new standard, the SDT can not speculate regarding the magnitude of such requirements. However, the SDT strongly believes that the revised standard is necessary to ensure an adequate level of reliability for North America's Bulk Electric Systems.

The Implementation Plan is not a part of the Standard per se but will be balloted.

The SDT has modified the language in Requirement R3, part 3.4.1 and Requirement R4, part 4.4.1 as well as Requirement R8 with part 8.1 to clarify the handling of "cross border" Contingencies and performance violations.

3.4.1 The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

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R8 Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.

8.1 If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

TVA System Planning	No	TVA is concerned that the 5 year window for meeting the "raising the bar" requirements is still not adequate. For instance, it typically takes TVA 7 to 10 years to build a new 500-kV transmission line - including time required for such processes as federally mandated NEPA environmental reviews. Strongly suggest increasing this time

Organization	Yes or No	Question 11 Comment
		window to 10 years.Also trying to construct enough facilities within the 5 year implementation period will result in multiple outages at same time - possibly affecting TVA's bulk reliability during this construction period. Also TVA is concerned that EHV equipment manufacturers will not be able to meet all the equipment orders that will be required to meet the "raising the bar" requirements. Thus TVA believes that these additional concerns strengthen the need to have a 10 year implementation period. Since breaker duty is a new "raising the bar" issue - should there also be a 5 year implementation plan for this as well? TVA is also concerned that the costs to meet the new requirements contained in this TPL will amount to between $1 billion to $2 billion with very little impact overall on the reliability of the Bulk transmission system. TVA is also very concerned about the increase in rates that will be required to support these new facilities. When will the Implementation Plan be removed from the standard after it is officially approved? Will a revised TPL standard need to be prepared to omit this implementation language? If contingencies in one utility's system results in issues within another utility, who is responsible for studying the contingencies and who would be responsible for documenting the CAP? More time is needed for entities to determine the appropriate dynamic load model required by R2.4.1. We recommend at least 36 months before this requirement becomes effective.

Response: The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. This third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply.

The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control.

If manufacturers or other service providers can not meet increased demands for equipment and services, that would be an event outside the control of the Planning Coordinator or Transmission Planner.

The SDT does not view the breaker duty requirements as a raising of the bar. While these may be new requirements in NERC Standards, the SDT believes that most entities already follow these practices because they are safety related.

With respect to any additional capital requirements driven by the new standard, the SDT can not speculate regarding the magnitude of such requirements. However, the SDT strongly believes that the revised standard is necessary to ensure an adequate level of reliability for North America's Bulk Electric Systems.

The Implementation Plan is not a part of the Standard per se but it will be balloted.

The SDT has modified the language in Requirement R3, part 3.4.1, Requirement R4, part 4.4.1, and Requirement R8 with part 8.1 to clarify the handling of "cross border" Contingencies and performance violations.

3.4.1 The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that

Organization	Yes or No	Question 11 Comment
Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. **4.4.1** The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. **8.1** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. Requirement R2, part 2.4.1 does not require a detailed dynamic Load model, only an aggregate System model. The SDT believes that such a model can be developed within the 24 month period before this requirement becomes effective.		
FirstEnergy Corp	No	We disagree with the proposed Implementation Plan. The implementation period for the TPL-001-1 transmission planning standard should be limited to the time needed to transition to the new study requirements. The proposed 5-year implementation for the "raise the bar" aspects of this standard delves into project management and review of capital construction progress which should remain outside the scope of this standard. The standard should only consider if an entity has completed the required studies and has developed Corrective Action Plans to ensure performance criteria is being maintained. The last paragraph of the Implementation Plan is not appropriate for the Implementation Plan as it discusses compliance enforcement information. This paragraph should be srtuck.
Response: The SDT disagrees with your view that the Corrective Action Plans should not include implementation requirements. A plan has no value unless it is implemented. No change made. The SDT disagrees that the last paragraph of the Effective Date should be removed. No change made.		
IRC Standards Review Committee	Yes	The 3rd draft states this will be addressed later in the project. Removal of these standards would not affect NERC and the RE's obligations to perform assessments. Will the PC/TP be obligated under NERC Rules of Procedure to provide Assessments to NERC and the Regions upon request?
Midwest ISO	Yes	The 3rd draft states that this will be addressed later in the project. Removal of these standards would not affect NERC and the RE's obligations to perform assessments. Will the PC/TP be obligated under NERC Rules of Procedure to provide Assessments to NERC and the Regions upon request?
New York Independent System Operator		The 3rd draft states the Plan will be addressed later in the project. Removal of these standards would not affect NERC and the RE's obligations to perform assessments. The Standards Drafting Team should clarify whether the PC/TP will be obligated under NERC Rules of Procedure to provide Assessments to NERC and the Regions upon request.
Response: Retirement of TPL-005-0 and TPL 006-0 have been addressed by adding the necessary requirements in the fourth draft of TPL-001-1 to ensure that Planning Coordinators and Transmission Planners will provide the necessary inputs to the Regions so that the Regions can fulfill their obligations to NERC in accordance with the NERC Rules of Procedure. **3.4.1** The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that		

Organization	Yes or No	Question 11 Comment
Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. **4.4.1** The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. **8.1** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.		
Southern Company	No	More time is needed for entities to determine the appropriate dynamic load model required by R2.4.1. We recommend at least 36 months before this requirement becomes effective.Other than that, the SDT has done a good job in allowing time for entities to get into compliance with the requirements where the bar has been raised.
Response: Requirement R2, part 2.4.1 does not require a detailed dynamic Load model, only an aggregate System model. The SDT believes that such a model can be developed within the 24 month period before this requirement becomes effective.		
Lafayette Utilities System	No	Lafayette is in the area which is impacted by Entergy transmission planning. Entergy is one of the few NERC transmission owners which has for some years now relied upon its interpretation of “footnote b” in the previous TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0 as permitting planning for the loss of Non-Consequential Load or interruption of firm transfers as a way of planning and building less transmission than other utilities would have considered themselves obligated to build for reliability. That Entergy interpretation, and the consequent lower investment in transmission planning and construction, has been a matter of some concern among Entergy regulators at both State and Federal levels, as well as Entergy transmission customers, and has been rejected by the SPP, which has been given the authority to develop the base plan for transmission additions on the Entergy system. It was the Entergy rejection of that base plan that most recently led to a day long technical conference among regulators at the recent SEARUC conference in Charleston, SC.The proposed Implementation Plan for TPL-001-1 is drafted to make the new standard, which the proposed Implementation Plan describes as one that “raises the bar in several areas,” effective only after the passage of 60 months from the first day of the first calendar quarter following applicable approval. That time for implementation is also embodied in A.5 of the proposed standard. This time lag is chosen, according to the proposed Implementation Plan, because of the “significant budget, siting, permitting, and construction impacts on many transmission owners. There are significant problems and costs for those whose electric service is dependent upon an inadequate transmission system, which would argue for a lesser period of time to reach compliance. This is especially true when the existing system is planned on an assumption as to the meaning of footnote b which assumption was clearly recognized as being controversial and a minority view. In recent years there have been repeated Entergy TLRs at quite high levels, which have repeatedly required emergency EEA-3s to keep firm load on line. And there has been an ongoing dispute between Entergy and the SPP as to footnote b and whether there should be limits on consequential load to be shed which has led the SPP (as the Entergy ICT) to have a complete base case for Entergy transmission construction already developed which is, by FERC direction, the basis for the Entergy construction plan. In its construction plan, however, Entergy dropped some 20 of the projects in the SPP base plan because of the Entergy view that it could go ahead and plan to drop non-consequential load as a means of remaining in compliance with Standards rather than building the transmission projects that would have been required in accordance with the

Organization	Yes or No	Question 11 Comment
		SPP base plan. While not all of the proposed changes embodied in TPL-001-1 may have been incorporated in the SPP base plan development, certainly the footnote b issues were. The costs of the failure of reliability and congestion resulting from the Entergy failure have been quite high, for Entergy retail customers as well as for others, and will continue to be high so long as there is no obligation to comply. Firm transmission obligations are simply not met while there is no obligation to comply. While it is certainly true that transmission cannot be planned and constructed overnight, it is also true that those who relied upon the minority interpretation of footnote b have been on notice for years both that that interpretation was challenged, and also that it was a minority viewpoint, as NERC itself advised FERC in its response to the NOPR that preceded Order 693.In 2007 FERC directed that NERC clarify the intended meaning of footnote b in its Order 693, and pointed out at that time that the interpretation permitting loss of load was "based largely on the matter of economics, not reliability. Id., P 1792. At that time, only Entergy and NIPSCO (certainly not "many" Transmission Owners" a word that appears twice in the draft Implementation Plan) would even admit to their interpretation of footnote b to weaken the grid. NERC agreed that such an interpretation was incorrect in its filings leading up to Order 693. In its June 26, 2006 Comments of North American Electric Reliability Council and North American Electric Reliability Corporation on Staff Preliminary Assessment, at p. 57-58, NERC noted that load shedding in a single contingency event is not acceptable: "footnote b to TPL-002-0 is intended to provide a limited exception to the general rule for serving load from a radial transmission line and should only be applied in unique circumstances, as described above. NERC recognizes that looped configurations are key to the reliable operation of the interconnection, and to meet reasonable expectations for reliable service to loads. . . . NERC standards, including footnote b, are not intended to endorse or approve planning the interconnection using radial configurations as a preferred method for reliably serving load, nor do NERC standards consider load shedding acceptable for single contingency events. It thus seems strange for NERC, an organization whose very existence was intended to assure the reliability of the grid, to reward those recalcitrant transmission owners who intentionally failed to expend the money and effort that the responsible transmission owners did expend, and at the expense of those who rely on the transmission system to do its basic job. Order 693, P 1794, "strongly discourage[d] an approach that reflects the lowest common denominator. Many of those transmission owners and planners for whom this change constitutes "raising the bar" presumably had plenty of time to consider what their options would be if their interpretation was incorrect, and should be expected to have reserve plans on hand pretty close to being ready to go when the dispute was lost. In the Entergy case, the plan has been in its hands for some time, and the fact that it has chosen to reject the SPP plan based on its own minority interpretation of footnote b is no one's fault but its own. And it certainly does not have to start from scratch to develop the plan; it consciously chose to reject the plan that the ICT developed for it.Lafayette asks that at least as to the changes tied to footnote b interpretation, and other excuses for dropping non-consequential load, the time for compliance be shortened to no more than two years following regulatory approval of the standard. R2.6 already provides for the development of a Corrective Action Plan, and it would not encourage reliability if five years were taken to develop a Corrective Action Plan, as opposed to complying with the standard. Second, Lafayette suggests that, whether or not NERC chooses to stick with its 5-year "lowering of the bar" to permit those entities which may have used a similar interpretation of footnote b to avoid building a sturdy grid, it not try to influence FERC and the courts as to legal questions that may develop during that period. We recognize that the changes made in what will be TPL-001-1 go well beyond the clarification of footnote b, so that for some changes there may be a reason for the 5 year phase in. But whether or not the 5 year phase in is going to be

Organization	Yes or No	Question 11 Comment
		applicable to all of those changes, we suggest that it would be improper to mischaracterize what is being done in a way that appears to have been drafted to influence legal questions that may come up.Specifically, as currently drafted, the descriptive modifier "many" should not be used in describing the entities which had chosen to use the lower bar interpretation of footnote b. While we recognize that a number of commenters have looked to one interpretation or another of footnote b in a few extreme situations, a review of comments does not show other transmission owners who have relied on the extreme interpretation used by Entergy on a systematic basis, And we think it inappropriate for the description in the paragraph beginning at the bottom of p.1 of that draft Implementation Plan to focus on the footnote b issue, as it now does. We suggest a modification which makes the description accurate, and which avoids the kind of misinterpretation which led to the footnote b controversy in the first place. We suggest that that first part of that paragraph be revised to read as follows:TPL-001-1 "raises the bar" in several areas where performance requirements have been changed in the new Standard versus those in existing TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0. Among other things, loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain events, whereas the existing Standards were interpreted by some to allow such actions. As shown in Table 1 of TPL-001-1, the performance requirements associated with the following events represent "raising the bar"??
Louisiana Energy and Power Authority	No	LEPA is in the area which is impacted by Entergy transmission planning. Entergy is one of the few NERC transmission owners which has for some years now relied upon its interpretation of "footnote b" in the previous TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0 as permitting planning for the loss of Non-Consequential Load or interruption of firm transfers as a way of planning and building less transmission than other utilities would have considered themselves obligated to build for reliability. That Entergy interpretation, and the consequent lower investment in transmission planning and construction, has been a matter of some concern among Entergy regulators at both State and Federal levels, as well as Entergy transmission customers, and has been rejected by the SPP, which has been given the authority to develop the base plan for transmission additions on the Entergy system. It was the Entergy rejection of that base plan that most recently led to a day long technical conference among regulators at the recent SEARUC conference in Charleston, SC.The proposed Implementation Plan for TPL-001-1 is drafted to make the new standard, which the proposed Implementation Plan describes as one that "raises the bar in several areas," effective only after the passage of 60 months from the first day of the first calendar quarter following applicable approval. That time for implementation is also embodied in A.5 of the proposed standard. This time lag is chosen, according to the proposed Implementation Plan, because of the "significant budget, siting, permitting, and construction impacts on many transmission owners. There are significant problems and costs for those whose electric service is dependent upon an inadequate transmission system, which would argue for a lesser period of time to reach compliance. This is especially true when the existing system is planned on an assumption as to the meaning of footnote b which assumption was clearly recognized as being controversial and a minority view. In recent years there have been repeated Entergy TLRs at quite high levels, which have repeatedly required emergency EEA-3s to keep firm load on line. And there has been an ongoing dispute between Entergy and the ICT as to footnote b and whether there should be limits on consequential load to be shed which has led the SPP (as the Entergy ICT) to have a complete base case for Entergy transmission construction already developed which is, by FERC direction, the basis for the Entergy construction plan. In its construction plan, however, Entergy dropped some 20 of the projects in the ICT base plan because of the Entergy view that it could go ahead and plan to drop non-consequential load as a means of remaining in compliance with

Organization	Yes or No	Question 11 Comment
		Standards rather than building the transmission projects that would have been required in accordance with the ICT base plan. While not all of the proposed changes embodied in TPL-001-1 may have been incorporated in the SPP base plan development, certainly the footnote b issues were. The costs of the failure of reliability and congestion resulting from the Entergy failure have been quite high, for Entergy retail customers as well as for others, and will continue to be high so long as there is no obligation to comply. Firm transmission obligations are simply not met while there is no obligation to comply. While it is certainly true that transmission cannot be planned and constructed overnight, it is also true that those who relied upon the minority interpretation of footnote b have been on notice for years both that that interpretation was challenged, and also that it was a minority viewpoint, as NERC itself advised FERC in its response to the NOPR that preceded Order 693.In 2007 FERC directed that NERC clarify the intended meaning of footnote b in its Order 693, and pointed out at that time that the interpretation permitting loss of load was "based largely on the matter of economics, not reliability. Id., P 1792. At that time, only Entergy and NIPSCO would even admit to this less reliable interpretation of footnote b. NERC agreed that such an interpretation was incorrect in its filings leading up to Order 693. In its June 26, 2006 Comments of North American Electric Reliability Council and North American Electric Reliability Corporation on Staff Preliminary Assessment, at p. 57-58, NERC noted that load shedding in a single contingency event is not acceptable: "footnote b to TPL-002-0 is intended to provide a limited exception to the general rule for serving load from a radial transmission line and should only be applied in unique circumstances, as described above. NERC recognizes that looped configurations are key to the reliable operation of the interconnection, and to meet reasonable expectations for reliable service to loads. . . . NERC standards, including footnote b, are not intended to endorse or approve planning the interconnection using radial configurations as a preferred method for reliably serving load, nor do NERC standards consider load shedding acceptable for single contingency events. Hence, those recalcitrant transmission owners who intentionally failed to expend the money and effort that the responsible transmission owners did expend, have been rewarded at the expense of those who rely on the transmission system to do its basic job. Order 693, P 1794, "strongly discourage[d] an approach that reflects the lowest common denominator. Many of those transmission owners and planners for whom this change constitutes "raising the bar" presumably had plenty of time to consider what their options would be if their interpretation was incorrect, and should be expected to have reserve plans on hand pretty close to being ready to go when the dispute was lost. In the Entergy case, the plan has been in its hands for some time, and it has chosen to reject the ICT plan based on its own minority interpretation of footnote b. LEPA asks that at least as to the changes tied to footnote b interpretation, and other excuses for dropping non-consequential load, the time for compliance be shortened to no more than two years following regulatory approval of the standard. R2.6 already provides for the development of a Corrective Action Plan, and it would not encourage reliability if five years were taken to develop a Corrective Action Plan, as opposed to complying with the standard. Second, LEPA suggests that, whether or not NERC chooses to stick with its 5-year time period to permit those entities which may have used a similar interpretation of footnote b, it not try to influence FERC and the courts as to legal questions that may develop during that period. We recognize that the changes made in what will be TPL-001-1 go well beyond the clarification of footnote b, so that for some changes there may be a reason for the 5 year phase in. But whether or not the 5 year phase in is going to be applicable to all of those changes, we suggest that it would be improper to mischaracterize what is being done in a way that appears to have been drafted to influence legal questions that may come up.Specifically, as currently drafted, the descriptive modifier "many" should not be

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		used in describing the entities which had chosen to use the lower bar interpretation of footnote b. While we recognize that a number of commenters have looked to one interpretation or another of footnote b in a few extreme situations, a review of comments does not show other transmission owners who have relied on the extreme interpretation used by Entergy on a systematic basis, And we think it inappropriate for the description in the paragraph beginning at the bottom of p.1 of that draft Implementation Plan to focus on the footnote b issue, as it now does. We suggest a modification which makes the description accurate, and which avoids the kind of misinterpretation which led to the footnote b controversy in the first place. We suggest that that first part of that paragraph be revised to read as follows:"TPL-001-1 "raises the bar" in several areas where performance requirements have been changed in the new Standard versus those in existing TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0. Among other things, loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain events, whereas the existing Standards were interpreted by some to allow such actions. As shown in Table 1 of TPL-001-1, the performance requirements associated with the following events represent "raising the bar""?
Mississippi Delta Energy Agency	No	MDEA is in the area which is impacted by Entergy transmission planning. Entergy is one of the few NERC transmission owners which has for some years now relied upon its interpretation of "footnote b" in the previous TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0 as permitting planning for the loss of Non-Consequential Load or interruption of firm transfers as a way of planning and building less transmission than other utilities would have considered themselves obligated to build for reliability. That Entergy interpretation, and the consequent lower investment in transmission planning and construction, has been a matter of some concern among Entergy regulators at both State and Federal levels, as well as Entergy transmission customers, and has been rejected by the SPP, which has been given the authority to develop the base plan for transmission additions on the Entergy system. It was the Entergy rejection of that base plan that most recently led to a day long technical conference among regulators at the recent SEARUC conference in Charleston, SC.The proposed Implementation Plan for TPL-001-1 is drafted to make the new standard, which the proposed Implementation Plan describes as one that "raises the bar in several areas," effective only after the passage of 60 months from the first day of the first calendar quarter following applicable approval. That time for implementation is also embodied in A.5 of the proposed standard. This time lag is chosen, according to the proposed Implementation Plan, because of the "significant budget, siting, permitting, and construction impacts on many transmission owners. There are significant problems and costs for those whose electric service is dependent upon an inadequate transmission system, which would argue for a lesser period of time to reach compliance. This is especially true when the existing system is planned on an assumption as to the meaning of footnote b which assumption was clearly recognized as being controversial and a minority view. In recent years there have been repeated Entergy TLRs at quite high levels, which have repeatedly required emergency EEA-3s to keep firm load on line. And there has been an ongoing dispute between Entergy and the SPP as to footnote b and whether there should be limits on consequential load to be shed which has led the SPP (as the Entergy ICT) to have a complete base case for Entergy transmission construction already developed which is, by FERC direction, the basis for the Entergy construction plan. In its construction plan, however, Entergy dropped some 20 of the projects in the SPP base plan because of the Entergy view that it could go ahead and plan to drop non-consequential load as a means of remaining in compliance with Standards rather than building the transmission projects that would have been required in accordance with the SPP base plan. While not all of the proposed changes embodied in TPL-001-1 may have been incorporated in the

Organization	Yes or No	Question 11 Comment
		SPP base plan development, certainly the footnote b issues were. The costs of the failure of reliability and congestion resulting from the Entergy failure have been quite high, for Entergy retail customers as well as for others, and will continue to be high so long as there is no obligation to comply. Firm transmission obligations are simply not met while there is no obligation to comply. While it is certainly true that transmission cannot be planned and constructed overnight, it is also true that those who relied upon the minority interpretation of footnote b have been on notice for years both that that interpretation was challenged, and also that it was a minority viewpoint, as NERC itself advised FERC in its response to the NOPR that preceded Order 693.In 2007 FERC directed that NERC clarify the intended meaning of footnote b in its Order 693, and pointed out at that time that the interpretation permitting loss of load was "based largely on the matter of economics, not reliability. Id., P 1792. At that time, only Entergy and NIPSCO (certainly not "many" Transmission Owners? a word that appears twice in the draft Implementation Plan) would even admit to their interpretation of footnote b to weaken the grid. NERC agreed that such an interpretation was incorrect in its filings leading up to Order 693. In its June 26, 2006 Comments of North American Electric Reliability Council and North American Electric Reliability Corporation on Staff Preliminary Assessment, at p. 57-58, NERC noted that load shedding in a single contingency event is not acceptable: "footnote b to TPL-002-0 is intended to provide a limited exception to the general rule for serving load from a radial transmission line and should only be applied in unique circumstances, as described above. NERC recognizes that looped configurations are key to the reliable operation of the interconnection, and to meet reasonable expectations for reliable service to loads. . . . NERC standards, including footnote b, are not intended to endorse or approve planning the interconnection using radial configurations as a preferred method for reliably serving load, nor do NERC standards consider load shedding acceptable for single contingency events. It thus seems strange for NERC, an organization whose very existence was intended to assure the reliability of the grid, to reward those recalcitrant transmission owners who intentionally failed to expend the money and effort that the responsible transmission owners did expend, and at the expense of those who rely on the transmission system to do its basic job. Order 693, P 1794, "strongly discourage[d] an approach that reflects the lowest common denominator. Many of those transmission owners and planners for whom this change constitutes "raising the bar" presumably had plenty of time to consider what their options would be if their interpretation was incorrect, and should be expected to have reserve plans on hand pretty close to being ready to go when the dispute was lost. In the Entergy case, the plan has been in its hands for some time, and the fact that it has chosen to reject the SPP plan based on its own minority interpretation of footnote b is no one's fault but its own. And it certainly does not have to start from scratch to develop the plan; it consciously chose to reject the plan that the ICT developed for it.MDEA asks that at least as to the changes tied to footnote b interpretation, and other excuses for dropping non-consequential load, the time for compliance be shortened to no more than two years following regulatory approval of the standard. R2.6 already provides for the development of a Corrective Action Plan, and it would not encourage reliability if five years were taken to develop a Corrective Action Plan, as opposed to complying with the standard. Second, MDEA suggests that, whether or not NERC chooses to stick with its 5-year "lowering of the bar" to permit those entities which may have used a similar interpretation of footnote b to avoid building a sturdy grid, it not try to influence FERC and the courts as to legal questions that may develop during that period. We recognize that the changes made in what will be TPL-001-1 go well beyond the clarification of footnote b, so that for some changes there may be a reason for the 5 year phase in. But whether or not the 5 year phase in is going to be applicable to all of those changes, we suggest that it would be improper to mischaracterize what is being done in a way that

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		appears to have been drafted to influence legal questions that may come up.Specifically, as currently drafted, the descriptive modifier "many" should not be used in describing the entities which had chosen to use the lower bar interpretation of footnote b. While we recognize that a number of commenters have looked to one interpretation or another of footnote b in a few extreme situations, a review of comments does not show other transmission owners who have relied on the extreme interpretation used by Entergy on a systematic basis, And we think it inappropriate for the description in the paragraph beginning at the bottom of p.1 of that draft Implementation Plan to focus on the footnote b issue, as it now does. We suggest a modification which makes the description accurate, and which avoids the kind of misinterpretation which led to the footnote b controversy in the first place. We suggest that that first part of that paragraph be revised to read as follows:TPL-001-1 "raises the bar" in several areas where performance requirements have been changed in the new Standard versus those in existing TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0. Among other things, loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain events, whereas the existing Standards were interpreted by some to allow such actions. As shown in Table 1 of TPL-001-1, the performance requirements associated with the following events represent "raising the bar"??
Response: Thank you for the background which helps the SDT understands your concerns. The SDT believes that this revised Standard has clarified the intent of the old footnote 'b' as well as other areas of the original standard that were open to interpretation. Standards must apply equally to all, so the SDT has chosen what it believes to be a reasonable implementation timeline that balances a wide variety of interests and circumstances. Finally, please note that the Implementation Plan document provided with this posting of the draft Standard is neither a part of the Standard or the Standard Roadmap but will be balloted. Therefore the SDT sees no need to modify the language.		
System Protection and Transmission Planning Department	Yes	We concur with SDT intent to retire TPL-005 and TPL-006. As there is no comment form entry to accept comments on MEASURES, we add one note here, related to "such as" lists - as noted above for R1.1.2, R2.1.4, R2.5.2, R3.3.4, R4.3.3, and R5. As written now, all measures include "such as" lists. We strongly suggest you remove "such as electronic or hard copies" from all measure statements.
Response: Thank you for your response. The SDT believes that examples of evidence "such as electronic or hard copies" help clarify the intent of the measure. Since no other responses requested removal of those words, the SDT will retain them.		
PacifiCorp Deseret Generation & Transmission SRP Southern California Edison Company Western Area Power Administration Pacific Gas and Electric Co, Puget Sound Energy, Inc.		We agree that TPL-005 and TPL-006 appear to have been adequately covered in the draft TPL-001-1 as currently written. However, we will need to review this assessment after TPL-001-1 is finalized. In addition, there is no place to state our concerns for Section D. so we added it here. We question the "not applicable" entry under Section D 1.1.2. What does it mean when the reset period is not applicable? Does it mean there is no reset period, so all non-compliance in all prior years will be counted as prior violations when considering non-compliance in future years?

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California ISO		
NV Energy	No	We agree that TPL-005 and TPL-006 appear to have been adequately covered in the draft TPL-001-1 as currently written. However, we will need to review this assessment after TPL-001-1 is finalized. In addition, there is no place to state our concerns for Section D. so we added it here. We question the "not applicable" entry under Section D 1.1.2. What does it mean when the reset period is not applicable? Does it mean there is no reset period, so all non-compliance in all prior years will be counted as prior violations when considering non-compliance in future years? Why is this changing from an annual reset period in the current standards?
Response: The sanctions guidelines developed by the compliance program as part of the ERO start-up process eliminated the use of the concept of the "compliance reset period." The reason the heading "Compliance Monitoring and Reset Time" is still in the standards template is because some Standards Committee members felt that a change to the standard template couldn't be made without having the change go through full due process. Therefore, NERC staff agreed to always put, "Not applicable" under this heading until the next version of the manual is issued. This term will be eliminated in Version 8.		
Tampa Electric	Yes	Consider having all requirements go into effect at the same time.
Response: The SDT chose a phased approach for establishing effective dates for individual requirements to reflect the broad range of implementation time frames associated with different requirements. Rather than use a least common denominator, which would have led to a new standard that would not be implemented for 60 months, those requirements that needed less time were assigned earlier effective dates. No change made.		
Florida Reliability Coordinating Council, Inc - Transmission Working Group		Overall the plan is an improvement! Allowing for a 60 month phase in of the more restrictive performance requirements is useful, however consider applying the 60 month phase in (or some timeframe) to P1 events for extenuating circumstances, e.g. unable to obtain ROW, etc. Having R1 and R7 going into effect first do raise the concern of what TPL standards are in effect during the time frame. The implementation should also be more specific on what "going into effect" means. Assessments are not a one day event but are a year long effort that culminates in a final "report" that is the assessment. Most NERC standards effect ongoing activities, and the day they go into effect the utilities functions are expected to be compliant. In this case that rationale would require that in the prior year two assessments where performed, one compliant with the current standard and one compliant with then new standard, however we don't believe that was the intent. Perhaps a statement below the paragraph regarding the 60 month implementation plan for Corrective Action Plans to the effect of:"Once effective all future assessments shall upon completion be compliant with this standard. Assessments completed prior to the effective date shall be based on the TPL standards in effect at the time. The standard is not intended to require a retroactively compliant assessment be in effect when the standard becomes active, but instead that the next assessment be compliant with the revised standard"
Response: The SDT believes that extenuating circumstances are covered in Requirement R2, part 2.7.5. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's		

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or Planning Coordinator's control. The SDT recognizes that assessments take a period of time to complete. The date on which the assessment was initiated would determine whether the current TPL standards or the revised TPL-001-1 would govern compliance requirements. No change made.		
FMPA	No	We suggest that the 60 month calendar apply to the HV system as well for all Categories. It is just as difficult, if not more difficult, to build a new 138 kV line in the Florida Keys as it is to build a 300+ kV line. The same time frame should apply to both. Also, as highlighted in the comments above to R2.1.4, P3 essentially causes utilities to build upgrades to N-3 planning criteria which may necessitate significant transmission upgrades if left unchanged. Hence, if left unchanged, P3 ought to have at least 5 years as well. The implementation plan ought to include an "out" for extenuating circumstances, e.g., unable to obtain ROW, etc. For instance, it is doubtful that another line in the Keys could ever get built without significant intervention and utilities that are unable to obtain ROW should not receive sanctions for something outside of their control. Consider changing the effective dates of R1 and R7 to take effect at the same time as R2 through R6 so you do not have to meet two standards during the same time period. Otherwise, clarify how the effective date impacts which version of the standard is to be used in an assessment before a scheduled compliance audit. The implementation should also be more specific on what "going into effect" means. Assessments are not a one day event but are a year long effort that culminates in a final "report" that is the assessment. Most NERC standards effect ongoing activities, and the day they go into effect the utilities functions are expected to be compliant. In this case that rationale would require that in the prior year two assessments were performed, one compliant with the current standard and one compliant with then new standard, however we don't believe that was the intent. Perhaps a statement below the paragraph regarding the 60 month implementation plan for Corrective Action Plans to the effect of:?Once effective all future assessments shall upon completion be compliant with this standard. Assessments completed prior to the effective date shall be based on the TPL standards in effect at the time. The standard is not intended to require a retroactively compliant assessment be in effect when the standard becomes active, but instead that the next assessment be compliant with the revised standard?
Response: The revised standard has raised the bar for certain planning events. In those cases, a 60 month effective date is permitted. The determination as to when the 60 month period applies is related to the Contingency and not the solution. Therefore, if a 138 kV line is proposed as a corrective action for one of the raising the bar events, 60 months would be provided to implement the construction of the 138 kV line. Regarding the impact of spare policies, the SDT does not agree with your premise that solutions to meet this requirement could take at least 5 years. Since the requirement addresses spare transmission equipment, and not generating equipment as your example suggests, one direct solution would be to purchase additional spare transmission equipment. In virtually all cases this could be accomplished in less than 5 years. The SDT believes that extenuating circumstances are covered in Requirement R2, part 2.7.5. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." The SDT chose a phased approach for establishing effective dates for individual requirements to reflect the broad range of implementation time frames associated with		

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different requirements. Rather than use a least common denominator, which would have led to a new standard that would not be implemented for 60 months, those requirements that needed less time were assigned earlier effective dates. No change made. The SDT recognizes that assessments take a period of time to complete. The date on which the assessment was initiated would determine whether the current TPL standards or the revised TPL-001-1 would govern compliance requirements. No change made		
Progress Energy Carolina (PEC)	No	More time than 12 months is needed for modeling the complete effects of Relay Protection Systems and the effects of Relay Loadability. PEC suggests that this period of time be extended to 24 months or longer.
Response: The standard does not require detailed modeling of Relay Protection Systems. It only requires that the impacts of those systems be reflected in the modeling of Contingencies and the evaluation of the resulting System performance. This is no different than the current standards.		
MidAmerican Energy Company	No	MidAmerican commends the SDT for its hard work on this standard. MidAmerican does not support the paragraph that states "Any entity that cannot fully implement its Corrective Action Plan".shall self report itself?? MidAmerican believes that the Energy Policy Act of 2005 does not provide NERC or FERC the authority to require construction of facilities. Therefore, MidAmerican believes that this paragraph should be deleted in its entirety from the implementation plan as requiring responsibility to build facilities or else self report non-compliance. This is in direct contradiction to federal law.
Response: The Corrective Action Plan requirements do not necessarily result in construction of new Facilities, although it is understood that in some cases the only practical solution to a performance violation will require new or upgraded Facilities. Therefore, the SDT does not believe that these requirements contradict federal law and disagrees with your recommendation that the paragraph you mentioned should be removed.		
Northeast Utilities	Yes	Other Comments:Comment 1 Please clarify, since R2 through R6 should become effective before results could be distributed to adjacent Planning Coordinators and any functional entity. However, by the wording of the effective date of R1 and R7 it appears R7 becomes effective before R2 to R6. That is, 24 months are allowed by the standard to complete the planning assessments after regulatory approval. The results may not be ready for distribution by the planning coordinator after the first twelve months. Comment 2 The term "Planning Coordinator" is not defined in the NERC Glossary of Terms used in Reliability Standards and, therefore, this standard should indicate whether this term is the same as the "Planning Authority" defined in the glossary. Otherwise the definition of the Planning Coordinator should be included in the NERC Glossary of Terms used in Reliability Standards.
Progress Energy Florida, Inc.	No	While the Implementation Plan is extremely vague at present, making a specific enforcement date impossible to determine, PEF is concerned that the language at present will not allow enough time for Transmission Owners to prepare for the increased stringency.
Response: The SDT chose a phased approach for establishing effective dates for individual requirements to reflect the broad range of implementation time frames associated with different requirements. Rather than use a least common denominator, which would have led to a new standard that would not be implemented for 60 months, those requirements that needed less time were assigned earlier effective dates. No change made. Planning Coordinator is defined in the latest approved version of the Glossary.		
Hydro-Québec TransEnergie (HQT)	No	With regard to the many changes/modifications from the previous draft and from the previous TPL standards being replaced by TPL-001-1, another posting of this Standard will be necessary to fully evaluate the impact (on

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		reliability and also cost of implementation) of such changes. The decision to allow the use of all type of RAS or SPS (particularly generator tripping and run-back) as a common practice for single contingency does not "raise the bar" in the planning standard, and should be reviewed. How can higher system performance be required that involves substantial infrastructure investment to prevent events with a very low probability of occurrence, and allow use of a less reliable measure (SPS failure or misoperation having a higher probability of occurrence) to reduce the investment for more probable events?
Response: The SDT agrees that another posting is required and has produced a fourth draft. The SDT's intent was to raise the bar where it was practical to do so and not lower the bar in any case. The allowance for the use of SPS and RAS in repose to single contingencies simply reflects the practice in many parts of North America. Where this has not been a common practice, individual Regional Entities, Planning Coordinators or Transmission Planners have the latitude to establish more stringent criteria.		
Ameren	No	At least 36 months would be needed for R1 compliance, should inclusion of explicit modeling of protection system equipment be required in dynamic model representations, and if all breakers would need to be explicitly modeled. More time is needed for entities to determine the appropriate dynamic load model required by R2.4.1. We recommend at least 36 months before this requirement becomes effective. 60 months effective date seems acceptable for planning activities, but may not adequate for all construction activities. Typical times to construct a transmission line in various areas of SERC can range between 7 to 10 years. Accordingly, we recommend the effective date for construction projects be changed to at least 84 months. 12 months appears reasonable for R7.
Response: The standard does not require detailed modeling of Relay Protection Systems or circuit breakers. It only requires that the impacts of those systems be reflected in the modeling of Contingencies and the evaluation of the resulting System performance. This is no different than the current standards. Requirement R2, part 2.4.1 does not require a detailed dynamic Load model, only an aggregate System model. The SDT believes that such a model can be developed within the 24 month period before this requirement becomes effective. The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. The third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control.		
Manitoba Hydro	No	TPL-005-0 is a Regional and Interregional Self-Assessment Reliability Report. Such an assessment is beyond the capability of an individual PC or TP. While the new TPL-001-1 can and should include a requirement on the PC and TP to include in their assessments the interconnections with their adjacent systems, it does not make sense to

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		mandate an individual TP or PC to conduct an interregional assessment. Consequently, TPL-005-0 should be retained and mandated on the regions via the NERC delegation agreements with the regions.
Response: The standard does not require an individual Planning Coordinator or Transmission Planner to conduct an interregional assessment. It would require Planning Coordinators to provide the necessary inputs and work with the Regional Entity to provide a regional assessment that would continue to satisfy NERC's needs. The filing of a Planning Assessment by the Regional Entity is no longer required by a standard because it is covered adequately in NERC's Rules of Procedure.		
Entergy Services, Inc	No	P1 events needs to be correctly classified as "raising the bar": P1 events should be included in the bulleted list of areas where the "bar was raised". The paragraph beginning at the bottom of page 2 of the Implementation Plan clearly states that the bar was raised "because loss of Non-Consequential Load or interruption of firm transfers is no longer allowed". Since P1 events in the existing standard allow this, the revised P1 events should be categorized as a raising of the bar. " Effective date needs to be extended: Additionally, in the areas where the bar has been raised, the effective date needs to be extended to at least 7 years. Siting (environment assessment and permitting, right-of-way acquition, regulatory approvals) alone for many of the facilities likely needed can take 3 years or more in some areas. Likely delays due to litigation and affected stakeholder intervention must be considered. In addition, while the SDT has collected some cursory estimates of the costs which may be passed on to end-use customers, no discussion of the intended or expected increase in reliability has been published. Other considerations that will have an impact on the effective date are construction outages on the bulk transmission system and competition of resources (human and material). " Effect on reliability is not adequately quantified: Since one of the SDTs objectives is to ensure that "requirements set at an appropriate level to ensure reliability,"what reliability metrics are expected to be impacted? By how much? What will the billions of dollars spent on transmission procure in terms of reliability to ratepayers? To what degree would the proposed standard decrease the probability of a blackout? If a blackout were to occur, would the proposed standard tend to decrease or increase the size and magnitude of the event?? More time is needed for entities to determine the appropriate dynamic load model required by R2.4.1. We recommend at least 36 months before this requirement becomes effective. Since breaker duty is a new "raising the bar" issue - should there also be a 5 or more year implementation plan for this as well? If a Transmission Planner has a Corrective Action Plan identified within the accepted time limitations but the facilities identified in the CAP cannot be implemented in time, would the TP be found non-compliant on the TPL-001-1?? If contingencies in one utility's system results in issues within another utility, who is responsible for studying the contingencies and who would be responsible for documenting the CAP?
Response: The SDT disagrees that P1 represents a raising of the bar. While the exiting standard was somewhat unclear about dropping firm Non-Consequential Load for P1 type events, there is little evidence to support that as a widespread practice. Therefore, the revised standard is simply a clarification of the intent of the earlier standards. The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the		

Organization	Yes or No	Question 11 Comment
standard by potentially delaying some corrective actions that could be implemented in 60 months or less. The third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control. With respect to any additional capital requirements driven by the new standard, the SDT can not speculate regarding the magnitude of such requirements. However, the SDT strongly believes that the revised standard is necessary to ensure an adequate level of reliability for North America's Bulk Electric Systems. Requirement R2.4.1 does not require a detailed dynamic Load model, only an aggregate System model. The SDT believes that such a model can be developed within the 24 month period before this requirement becomes effective. The SDT does not view the breaker duty requirements as a raising of the bar. While these may be new requirements in NERC Standards, the SDT believes that most entities already follow these practices because they are safety related. If a Transmission Planner has prepared an acceptable Corrective Action Plan within the required time limits, but the implementation of the plan cannot be completed in time for reasons that are beyond the control of the Transmission Planner, " then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." In such a case, it is the intent of the SDT that the Transmission Planner would be compliant. The SDT has modified the language in Requirement R3, part 3.4.1, Requirement R4, part 4.4.1, and Requirement R8 with part 8.1 to clarify the handling of "cross border" Contingencies and performance violations. **3.4.1** The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. **4.4.1** The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. **8.1** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.		
PJM	No	Removal of these standards will not affect NERC and the Regional Entity's obligations to perform assessments. Will the PC/TP be obligated under NERC Rules of Procedure to provide Assessments to NERC and the Regions upon request?
Response: The standard does not require an individual Planning Coordinator or Transmission Planner to conduct an interregional assessment. The filing of an		

Organization	Yes or No	Question 11 Comment
assessment by the Regional Entity is no longer required by a standard because it is covered adequately in NERC's Rules of Procedure.		
ITC Holdings	Yes	Comments: We generally concur. However, it would appear that there is no incentive to submit a mitigation plan for less than 60 months for the new requirements that raise the bar (those listed as bullet points). If "circumstances are within your control" to mitigate in less than 60 months, why not require it?
Response: While the SDT understands the basis for your suggestion, it would be cumbersome and possibly confusing to change the requirements to apply differently in different circumstances. The SDT believes that peer reviews of the Corrective Action Plan and compliance audits would incent completion of corrective actions as soon as practical. No change made.		
Northern Indiana Public Service Company	No	In A5, text appearing under "Effective Date" is not clear regarding application of the phrase, "(above 300 kV)", for the first and fourth dot points.
Response: For the first dot, the parenthetical "above 300 kV" applies only to P2-2 events. For the fourth dot, the parenthetical applies to all events P4-1 through P4-5		
LADWP	No	Cannot agree to something when this is not final.
Idaho Power	No	I would like to review this after completion of the standard.
Response: The SDT was simply asking whether you agree with the Implementation Plan as written.		
Orlando Utilities Commission	Yes	Overall the plan is excellent! Allowing for a 60 month phase in of the more restrictive performance requirements and an exception for those who need longer to meet them is an equitable and reliable practice. Having R1 and R7 go into effect first though raises the question of what TPL standard is in effect during that time frame? I recommend having the entire standard go into effect at the same time and avoid that issue. There is limited benefit to R1 and R7 going into effect early. The implementation should also be more specific on what "going into effect" means. Assessments are not a one day event but are a year long effort that culminates in a final "report" that is the assessment. Most NERC standards affect ongoing activities, and the day they go into effect the utilities functions are expected to be compliant, this is not however so clear when the "function" is the culmination of a year long effort. Perhaps a statement below the paragraph regarding the 60 month carve out to the effect of: Once this standard becomes effective all future assessments shall be compliant with this standard. Assessments completed prior to the effective date shall be judged by their compliance with TPL standards in effect at the time.
Response: The SDT chose a phased approach for establishing effective dates for individual requirements to reflect the broad range of implementation time frames associated with different requirements. Rather than use a least common denominator, which would have lead to a new standard that would not be implemented for 60 months, those requirements that needed less time were assigned earlier effective dates. The SDT recognizes that assessments take a period of time to complete. The date on which the assessment was initiated would determine whether the current TPL standards or the revised TPL-001-1 would govern compliance requirements.		
American Transmission Company	No	We offer the following comments.The proposed standard implies that the 24 and 60 month periods run in parallel rather than sequentially. As currently proposed, the effective date for performing analyses and developing subsequent Corrective Action Plans is 24 months. If the identification of new needs and action plans take 24 months, then only 36 months would be left to implement the new action plans. It may not be feasible to install some BES facilities, especially above 300 kV in less than 3 years. Some EHV projects can take 5 to 10 years to

Organization	Yes or No	Question 11 Comment
		implement depending on the size, complexity, and controversial nature of the project. We suggest that the effective date be stated in a more "implementation dependent" rather than a "fixed timeframe" manner. Consider wording such as "tripping of Non-Consequential Load or curtailment of Firm Transmission Service (in accordance with Requirement R2.6.4) is allowed until Corrective Action Plans that are based on TPL-001-1 analyses can be implemented".
Response: The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. This third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control. The SDT considered your suggestion to change the language of Requirement R2, part 2.7.5 to make it more "implementation dependent" rather than using a "fixed timeframe" but we do not believe such a change is appropriate because it would make auditing of this requirement difficult.		
Duke Energy	No	Requirements R2 through R6 are proposed to become effective the first day of the first calendar quarter 24 months after applicable regulatory approval, and we agree with that. However, the standard also provides that for 60 months following the first day of the first calendar quarter following applicable regulatory approval, Corrective Action Plans applying to performance elements P2-1, P2-2 (above 300 kV), P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 kV) are allowed to include tripping of Non-Consequential Load or curtailment of Firm Transmission Service (in accordance with Requirement R2.6.4) that would not otherwise be permitted by the requirements of TPL-001-1. Since the first 24 months following regulatory approval will be spent developing and validating new studies and methodologies needed to meet TPL-001-1, that would only leave 36 months to implement corrective actions. We propose that the 60 month clock start with the effective dates of Requirements R2 through R6, to allow sufficient time to implement corrective actions that are determined within the 24 month period, which could include system modifications that require long lead times. Also, the implementation plan contains the following wording regarding retirement of the existing TPL standards: TPL-001-0, TPL-002-0a, TPL-003-0a, and TPL-004-0 are being retired as they are replaced in their entirety by TPL-001-1. TPL-005-0 and TPL-006-0 are being retired because their requirements are adequately covered by the revised TPL-001-1 and NERC's Rules of Procedure, Section 800. TPL-001-1 should not be used as a vehicle for fulfilling any of the TPL-005-0 and 006-0 requirements because of the difference in focus and entities involved. In reality, the new TPL-001-1 does not appear to have incorporated any of the requirements of TPL-005-0 and 006-0. TPL-001-1 appropriately focuses on how PC's and TP's should perform studies and document assessments of their transmission facilities impact on BES reliability. TPL-005-0 and 006-0 focus on assessments of regional and inter-regional BES reliability, including other non-transmission issues as well. The NERC Rules of Procedure and existing FERC Order 890 efforts appear to be sufficient to cover the requirements of TPL-005-0 and 006-0.

Organization	Yes or No	Question 11 Comment
		Therefore, retirement of TPL-005-0 and 006-0 is still appropriate.
Response: The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. This third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control. The SDT believes that this revised standard together with NERC's Rules of Procedure will completely address the regional assessment requirements covered in the existing standards.		
Tucson Electric Power Company		We agree that TPL-005 and TPL-006 appear to have been adequately covered in the draft TPL-001-1 as currently written. However, we will need to review this assessment after TPL-001-1 is finalized. In addition, there is no place to state our concerns for Section D. so we added it here. We question the "not applicable" entry under Section D 1.1.2. What does it mean when the reset period is not applicable? Does it mean there is no reset period, so all non-compliance in all prior years will be counted as prior violations when considering non-compliance in future years? We believe that 60 months is not sufficient to implement the Corrective Action Plan for the "raise the bar" requirements. Siting transmission lines can take longer than this window. We strongly recommend increasing the window to 120 months which is a more realistic estimate of the time required to bring an EHV transmission project from conception to construction.
Response: The sanctions guidelines developed by the compliance program as part of the ERO start-up process eliminated the use of the concept of the "compliance reset period." The reason the heading "Compliance Monitoring and Reset Time" is still in the standards template is because some Standards Committee members felt that a change to the standard template couldn't be made without having the change go through full due process. Therefore, NERC staff agreed to always put, "Not applicable" under this heading until the next version of the manual is issued. This term will be eliminated in Version 8. The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT reconsidered its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. This third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control.		

Organization	Yes or No	Question 11 Comment
Kansas City Power & Light	No	Regional areas may be made up of multiple Planning Coordinators. It is important to maintain an assessment of an entire Regional Reliability Organizations area. TPL-005 and TPL-006 should not be replaced with this proposed TPL-001.
Response: The SDT recognizes that many of the Regional Entities have multiple Planning Coordinators within their boundaries. The filing of an assessment by the Regional Entity is no longer required by a standard because it is covered adequately in NERC's Rules of Procedure.		
ReliabilityFirst Corporation	Yes	
Transmission Planning	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
Exelon Transmission Planning	Yes	
United Illuminating	Yes	
Western Area Power Administration	Yes	
Gainesville Regional Utilities	Yes, Yes	,
ISO New England, Inc.	Yes	
National Grid	Yes	
Brazos Electric Cooperative	Yes	no comment at this time
American Electric Power	Yes	
Minnesota Power	Yes	
Central Maine Power Company	Yes	
Response: Thank you for your response.		

Consideration of Comments on Fourth Draft of Standard TPL-001-1 — Project 2006-02

The Assess Transmission Future Needs Standard Drafting Team thanks all commenters who submitted comments on the fourth draft of the TPL-001-1 standard. This standard was posted for a 30-day public comment period from September 16, 2009 through October 16, 2009. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 67 sets of comments, including comments from more than 180 different people from over 85 companies representing all of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

Due to industry comments, the SDT has made the following clarifying changes;

- Definition: Non-Consequential Load Loss
- Requirement R1, part 1.1.6
- Requirement R2, parts 2.1.3, 2.1.4, 2.1.5, 2.3, 2.4, 2.4.3 bullet #3, 2.5, 2.6.2, 2.7, 2.7.1 bullets #1 and #4, and 2.9
- Requirement R3, parts 3.3, 3.3.2, 3.3.3 and 3.6
- Requirement R4, parts 4.1.2, 4.3, and 4.5
- Requirement R5
- Requirement R6
- Requirement R8
- Measures M1, M6, M7, and M8
- Table 1, Header notes 'b', 'f', and 'g', footnotes 1, 2, 3, 5, and 7
- Data retention for Requirement R1, R3, R5, R6, and R8
- VSLs for Requirements R1 and R8

While the changes cited address the vast majority of comments received, the following minority viewpoints remain:

- Continued concern over the value of the "raising the bar" for EHV Facilities
- Continued concern with excessive study or documentation requirements
- Concerns that the Implementation Plan could be interpreted to require construction (contrary to the Energy Policy Act of 2005)

In addition, several commenters requested that workshops be conducted to explain the details of the new standard. To date, the SDT has conducted 3 webinars and presented the standard at 2 different NERC standards workshops. In addition, the NERC Planning Committee has had 2 presentations and several regional entities requested and received presentations from SDT members. If Regional Entities wish to conduct seminars on the standard, SDT members from that region could be made available as participants in the discussions.

The SDT does not feel that this standard requires field testing prior to ballot. The SDT has not made any substantive or contextual changes with this posting and has determined that this standard is ready to go to ballot.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

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9. The SDT has revised the definitions in response to industry comments to the third posting. Do you agree with these definition changes? If not, please clearly indicate which definition you disagree with and provide specific comments. 193
10. Do you agree with the changes in the performance elements and notes in Table 1? If not, please provide specific comments by note number, note alpha character, or performance category. 212
11. The SDT has provided a revised Implementation Plan as part of this posting. Do you agree with the revisions to the Plan? If not, please provide specific comments. 252
12. Do you believe that this standard is ready to go to ballot? (if 'No' is checked here, the SDT will consider that comments raised on the other questions drove that decision.)267

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Bob Cummings	TIS	X	X		X	X				X	X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Eric M. Mortenson (Chair)	Exelon Energy Delivery		
2.	Mark Byrd (Vice Chair)	Progress Energy Carolinas		
3.	Gary Brownfield	Ameren		
4.	Kenneth A. Donohoo	Oncor Electric Delivery		
5.	Patricia E. Metro	National Rural Electric Cooperative Association		
6.	I. Paul McCurley	National Rural Electric Cooperative Association		
7.	Scott M. Helyer	Tenaska, Inc.		
8.	Israel Melendez	Constellation Energy Commodities Group		
9.	Hari Singh	Siemens Power Technologies International		8
10.	John M. Simonelli	ISO New England, Inc.		2
11.	Digaunto Chatterjee	MISO		2
12.	Steve Corey	New York Independent System Operator		2
13.	Dana Walters	National Grid USA	NPCC	9
14.	Hai Quoc Le	Northeast Power Coordinating Council, Inc.	NPCC	9

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
15. Bill Harm	PJM	RFC	9										
16. Wenchun Zhu	American Transmission Company	MRO	9										
17. Salva R. Andiappan	Midwest Reliability Organization	MRO	9										
18. Hector Sanchez	Florida Power & Light Co.	FRCC	9										
19. Pedro Modia	Midwest Reliability Organization	FRCC	9										
20. W. Perry Stowe	Southern Company Transmission Company	SERC	9										
21. Jay Caspary	Southwest Power Pool	SPP	9										
22. Wesley Woitt	CenterPoint Energy	ERCOT	9										
23. David Franklin	Southern California Edison Company	WECC	9										
24. Branden Sudduth	Western Electricity Coordinating Council	WECC	9										
25. Other Observers and NERC Staff													
2.	Group	Ben Li	SRC of ISO/RTO (Comments submitted by Mark Westendorf of Midwest ISO on behalf of Ben Li)		X								
Additional Member	Additional Organization	Region	Segment Selection										
1. Ben Li	IESO	NPCC	2										
2. Bill Phillips	MISO	MRO	2										
3. Mark Thompson	AESO	WECC	2										
4. Charles Yeung	SPP	SPP	2										
5. Steve Myers	ERCOT	ERCOT	2										
6. Patrick Brown	PJM	RFC	2										
7. James Castle	NYISO	NPCC	2										
3.	Group	Guy Zito	Northeast Power Coordinating Council--RSC										X
Additional Member	Additional Organization	Region	Segment Selection										
1. Ralph Rufrano	New York Power Authority	NPCC	5										
2. Alan Adamson	New York State Reliability Council, LLC	NPCC	10										
3. Gregory Campoli	New York Independent System Operator	NPCC	2										
4. Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2										
5. Kurtis Chong	Independent Electricity System Operator	NPCC	2										

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
6. Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC 1										
7. Saurabh Saksena	National Grid	NPCC 1										
8. Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC 1										
9. Brian D. Evans-Mongeon	Utility Services	NPCC 8										
10. Mike Garton	Dominion Resources Services, Inc.	NPCC 5										
11. Brian L. Gooder	Ontario Power Generation Incorporated	NPCC 5										
12. Kathleen Goodman	ISO - New England	NPCC 2										
13. David Kiguel	Hydro One Networks Inc.	NPCC 1										
14. Michael R. Lombardi	Northeast Utilities	NPCC 1										
15. Randy MacDonald	New Brunswick System Operator	NPCC 2										
16. Greg Mason	Dynegy Generation	NPCC 5										
17. Bruce Metruck	New York Power Authority	NPCC 6										
18. Chris Orzel	FPL Energy/NextEra Energy	NPCC 5										
19. Robert Pellegrini	The United Illuminating Company	NPCC 1										
20. Michael Schiavone	National Grid	NPCC 1										
21. Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC 3										
22. Gerry Dunbar	Northeast Power Coordinating Council	NPCC 10										
23. Lee Pedowicz	Northeast Power Coordinating Council	NPCC 10										
4. Group	Philip R. Kleckley	SERC Planning Standards Subcommittee			X							

Additional Member	Additional Organization	Region	Segment Selection
1. John Sullivan	Ameren Services Co.	SERC	1
2. Charles Long	Entergy	SERC	1
3. Scott Goodwin	Midwest Independent Transmission System Operator	SERC	1
4. James Manning	North Carolina Electric Membership Corporation	SERC	3
5. Jim Kelley	PowerSouth Energy Cooperative	SERC	1
6. Pat Huntley	SERC Reliability Corporation	SERC	10
7. Bob Jones	Southern Company Services, Inc.-Trans	SERC	1
8. David Marler	Tenessee Valley Authority	SERC	1

5. Group	Bob Cummings (Coordinator)	NERC System Protection and Control Subcommittee (SPCS)	X	X		X	X				X	X

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	John L. Ciufo	Hydro One, Inc	NPCC	1
2.	Jonathan Sykes	PG&E	WECC	1
3.	Michael McDonald	Ameren Services Company	SERC	1
4.	William J. Miller	Exelon Corporation	RFC	1
5.	Josh Wooten	Tennessee Valley Authority	SERC	9
6.	Sungsoo Kim	Ontario Power Generation Inc	NPCC	5
7.	Joe T. Uchiyama	U.S. Bureau of Reclamation	WECC	5
8.	Charles W. Rogers	Consumers Energy	RFC	4
9.	Joseph M Burdis	PJM Interconnection, L.L.C.	RFC	2
10.	Jim Ingleson	New York Independent System Operator	NPCC	2
11.	Bryan J Gwyn	National Grid	NPCC	1, 10
12.	Henry G Miller	AEP Service Corp	RFC	1, 10
13.	Richard P. Quest	Xcel Energy	MRO	1, 10
14.	John Mulhausen	Florida Power & Light Co	FRCC	1, 10
15.	Philip Winston	Georgia Power Company	SERC	10, 1
16.	Dean Sikes	Cleco Power LLC	SPP	1, 10
17.	Samuel Francis	Oncor Electric Delivery	ERCOT	1, 10
18.	Baj Agrawal	Arizona Public Service Co	WECC	1, 10
19.	Thomas Wiedman	Wiedman Power System Consulting Ltd		NA
20.	Robert W. Cummings	NERC		NA
21.	Philip J Tatro	NERC		NA

6.	Group	W. R. Schoneck	Florida Power and Light	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Shaffer		FRCC	
2.	Pedro Modia		FRCC	
3.	Carlos Candelaria		FRCC	
4.	Kiko Barredo		FRCC	

7.	Group	Richard Kafka	Pepco Holdings, Inc. - Affiliates PHI	X		X		X	X				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
Additional Member	**Additional Organization**	**Region**	**Segment Selection**										
1. Bill Mitchell	Delmarva Power & Light Co.	RFC	1										
2. John Radman	Potomac Electric Power Co.	RFC	1										
3. Carl Kinsley	Atlantic City Electric	RFC	1										
8.	Group	Rick Foster	SERC Dynamics Review Subcommittee (DRS)	X								X	X
Additional Member	**Additional Organization**	**Region**	**Segment Selection**										
1. John Sullivan	Ameren Services Company	SERC	1										
2. Anthony Williams	Duke Energy Carolinas	SERC	1										
3. Sujit Mandal	Entergy	SERC	1										
4. Venkat Kolluri	Entergy	SERC	1										
5. John O'Connor	Progress Energy Carolinas	SERC	1										
6. Bob Jones	Southern Company Services, Inc. - Trans	SERC	1										
7. Jonathan Glidewell	Southern Company Services, Inc. - Trans	SERC	1										
8. Robbie Bottoms	Tennessee Valley Authority	SERC	1, 9										
9. Tom Cain	Tennessee Valley Authority	SERC	1, 9										
10. Herb Schrayshuen	SERC Reliability Corporation	SERC	10										
11. Carter Edge	SERC Reliability Corporation	SERC	10										
9.	Group	Steve Hill	Modesto Irrigation District Transmission Planning	X		X		X					
Additional Member	**Additional Organization**	**Region**	**Segment Selection**										
1. Spencer Tacke	MID	WECC	NA										
10.	Group	Doug Hohlbaugh	FirstEnergy Corp	X		X	X	X	X				
Additional Member	**Additional Organization**	**Region**	**Segment Selection**										
1. Ed Baznik	FE	RFC	1										
2. John Stephens	FE	RFC	1										
3. Jeff Mackauer	FE	RFC	1										
4. Carl Bridenbaugh	FE	RFC	1										
5. Sam Ciccone	FE		1, 3, 4, 6										

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
11.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Berhanu Tesema	BPA Transmission Planning	WECC	1
2.	Melvin Rodrigues	BPA Transmission Planning	WECC	1
3.	Chuck Matthews	BPA Transmission Planning	WECC	1
4.	Kyle Kohne	BPA Transmission Planning	WECC	1
5.	Larry Furumasu	BPA Transmission Planning	WECC	1

12.	Group	Carol Gerou	NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Neal Balu	WPS Corporation	MRO	3, 4, 5, 6
2.	Terry Bilke	Midwest ISO Inc.	MRO	2
3.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
4.	Ken Goldsmith	Alliant Energy	MRO	4
5.	Alice Murdock	Xcel Energy	MRO	1, 3, 5, 6
6.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
7.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
8.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
9.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
10.	Scott Nickels	Rochester Public Utilties Address	MRO	4
11.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6

13.	Individual	Frank Gaffney, Regulatory Compliance Officer	Florida Municipal Power Agency, and its Member Cities, Lakeland Electric and Fort Pierce Utility Authority	X		X	X	X	X	X			
14.	Individual	Travis Hyde	Oklahoma Gas & Electric	X									
15.	Individual	Hugh Francis	Southern Company	X		X		X					
16.	Individual	Richard	FRCC Transmission Working Group	X		X	X					X	X

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
17.	Individual	Brent Ingebrigtson	E.ON U.S.	X		X		X	X				
18.	Individual	Eric Mortenson	Exelon Transmission Planning	X		X							
19.	Individual	Tom Mielnik	MidAmerican Energy Company	X		X		X	X				
20.	Individual	Pete Jones	Puget Sound Energy, Inc.	X									
21.	Individual	Baj Agrawal	Arizona Public Service Co.	X		X		X					
22.	Individual	Jay Teixeira	ERCOT ISO		X								X
23.	Individual	Milorad Papic	Idaho Power	X									
24.	Individual	James Tucker	Deseret Power	X		X		X					
25.	Individual	Adam Menendez	Portland General Electric Co.	X		X		X	X				
26.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
27.	Individual	Tim Ponseti, VP	TVA System Planning	X									
28.	Individual	Brian Keel	SRP	X									
29.	Individual	Vishal Patel	Southern California Edison (SCE)	X		X		X					
30.	Individual	John Collins	Platte River Power Authority	X		X			X				
31.	Individual	Gordon Rawlings	British Columbia Transmission Corp	X	X								
32.	Individual	James Starling	SCE&G	X		X		X	X				
33.	Individual	Catherine Mathews	NorthWestern Energy	X		X		X					
34.	Individual	Dilip Mahendra	Sacramento Municipal Utility District	X		X	X	X					

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
35.	Individual	Thad Ness	American Electric Power	X		X		X	X				
36.	Individual	Bart White	Progress Energy Florida, Inc.	X		X							
37.	Individual	Terry Huval	Lafayette Utilities System										
38.	Individual	Jessica Rice	NV Energy	X									
39.	Individual	L. Earl Fair	Gainesville Regional Utilities	X		X		X					
40.	Individual	Phuong Tran	Lakeland Electric	X		X		X					
41.	Individual	Michael Ayotte	ITC Holdings	X									
42.	Individual	John Pearson	ISO New England		X								
43.	Individual	Darryl Curtis	Oncor Electric Delivery	X									
44.	Individual	Scott Goodwin	Midwest ISO		X								
45.	Individual	John Sullivan	Ameren	X		X		X	X				
46.	Individual	Saurabh Saksena	National Grid	X		X							
47.	Individual	Robert H. Easton	Western Area Power Adm - RMR	X								X	
48.	Individual	Roger Champagne	Hydro-Québec TransEnergie (HQT)	X									
49.	Individual	Greg Campoli	NYISO		X								
50.	Individual	Chifong Thomas	Pacific Gas and Electric Co.	X		X		X					
51.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
52.	Individual	David M. Conroy	Central Maine Power Company	X									

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
53.	Individual	Paul Rocha	CenterPoint Energy	X									
54.	Individual	Mark Byrd	Progress Energy Carolinas	X		X		X					
55.	Individual	Larry Brusseau	MAPP								X		
56.	Individual	Aaron Staley	Orlando Utilities Commission	X		X		X	X				
57.	Individual	Martin Bauer	US Bureau of Reclamation					X					
58.	Individual	Michael R. Lombardi	Northeast Utilities	X		X		X					
59.	Individual	Alice Murdock	Xcel Energy	X		X		X	X				
60.	Individual	David Wang	San Diego Gas & Electric Co	X									
61.	Individual	Dan Rochester	Independent Electricity System Operator		X								
62.	Individual	Jason Shaver	American Transmission Company	X									
63.	Individual	R. Peter Mackin	Utility System Efficiencies, Inc. (USE)										
64.	Individual	Mark Graham, on behalf of the Power System Planning Department	Tri-State Generation and Transmission Association	X		X		X	X				
65.	Individual	David Bradt	United Illuminating	X									
66.	Individual	John Mayhan	Omaha Public Power District	X		X		X	X				
67.	Individual	Mark Kuras	PJM										

1. **Requirement R1 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.**

Summary Consideration: The SDT has made several clarifying changes to Requirement R1, Measure M1, and to the VSLs for R1 based on industry comments.

Requirement R1, Part 1.1.6 has been clarified to reflect that this requirement may not be exclusively sources supplying load. As an example, Demand Side-Management (DSM) may be used.

The words "within its respective area" have been added after "that it is maintaining System models," to Measure M1 for additional clarification.

The words "responsible entity's" have been added after "OR The" under the Moderate and Severe VSLs for Requirement R1 for additional clarification as well.

R1, Part 1.1.6 - Resources (supply or demand side) required for Load

R3.3.3. Trip Transmission elements when relay loadability limits are exceeded

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, any criteria or methodology used in the analysis to identify System instability for conditions such as Cascading , voltage instability, or uncontrolled islanding.

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within its respective area, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

R1 VSL	The responsible entity's System model failed to represent one of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other	The responsible entity's System model failed to represent three of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1.

		sources, including items represented in the Corrective Action Plan.		

Organization	Comments for Question 1
ERCOT ISO	* This requirement seems to be embedding information that should be contained in the MOD standards. Does this present double jeopardy? This requirement, measurement, and VSL are all about maintaining models a MOD standard revision may need to be included or recommended to allow the focus of the TPL standard to be on transmission planning studies, not modeling. * Requirement 1.1.2 should read “all known outages of generation or transmission facilities with a duration of at least six months as appropriate for the timeframe represented by the particular model” * The moderate VSL category states “the System model did not use” this is confusing as the model does not do anything. It should contain the latest data. We also want to ensure this is not implying that the studies must use the latest data data changes continuously, and a study may never be complete if the data must be continuously updated. * Will any agreements made in R7 override the “each TP and PC” requirement? To clarify this, the requirement could be rephrased: "In accordance to the responsibilities assigned in R7, the responsible Transmission Planners and Planning Coordinators shall maintain System models for performing the studies needed to complete the required Planning Assessments. The models shall contain the latest data consistent with MOD-010 and MOD-012? "
Response: 1. The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has incorporated these additional requirements in the TPL standard with the intent that they will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. As for the double jeopardy comment - From the ERO Rules of Procedure, Appendix 4B- Sanction Guidelines, Section 3.10 Multiple Violations: “Strictly speaking, NERC or the regional entity can determine and levy a separate penalty or sanction, or direct remedial action, upon a violator for each individual violation. However, in instances of multiple violations related to a single act or common incidence of noncompliance, NERC or the regional entity will generally determine and issue a single aggregate penalty, sanction, or remedial action directive bearing reasonable relationship to the aggregate of the related violations. The penalty, sanction, or remedial action will not be that determined individually for the least serious of the violations; it will generally be at least as large or expansive as what would be called for individually for the most serious of the violations.” 2. The SDT does not believe that the proposed language adds any clarity. No change made. 3. The SDT does not believe that the proposed language adds any clarity. No change made. The system models should be updated per MOD-010 & MOD-012. 4. Requirement R7 identifies the individual and joint responsibilities for performing required studies only. The SDT believes that both the Transmission Planner and Planning Coordinator have this modeling responsibility. Therefore the SDT believes that the existing language is adequate and that no changes are required.	
Bonneville Power Administration	: R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change “real and reactive load forecast” to “forecasted demand and power factor” so it is clear that forecasting reactive load is not required.

Organization	Comments for Question 1
	For R1.1.5 we suggest changing the wording from "Known commitments for Firm Transmission Service and Interchange" to "Known commitments for Firm Transmission Service or Interchange". It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.
NorthWestern Energy	As written R1.1.4, "Real and reactive Load forecasts", could mean that both Real and Reactive Load forecasts are required. Since most entities only forecast Real (MW) and apply a power factor for reactive (MVAR), wording could be changed to " forecasted demand and power factor" to clarify that forecasting reactive load is not required. In R1.1.5 Change "Firm Transmission Service and Interchange" to "Firm Transmission Service or Interchange". This way the requirement can be satisfied by either one or the other.
Deseret Power	Comments: R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. For R1.1.5 we suggest changing the wording from "Known commitments for Firm Transmission Service and Interchange" to "Known commitments for Firm Transmission Service or Interchange". It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.
Idaho Power	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. For R1.1.5 I suggest changing the wording from "Known commitments for Firm Transmission Service and Interchange" to "Known commitments for Firm Transmission Service or Interchange". It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.
Modesto Irrigation District Transmission Planning	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. R1.1.5 we suggest changing the wording from "Known commitments for Firm Transmission Service and Interchange" to "Known commitments for Firm Transmission Service or Interchange". It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.
NV Energy	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. For R1.1.5 we suggest changing the wording from "Known commitments for Firm Transmission Service and Interchange" to "Known commitments for Firm Transmission Service or Interchange". It is difficult to distinguish between the two in future cases

Organization	Comments for Question 1
	where not all contractual arrangements are known.
Pacific Gas and Electric Co.	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change “real and reactive load forecast” to “forecasted demand and power factor” so it is clear that forecasting reactive load is not required. For R1.1.5 we suggest changing the wording from “Known commitments for Firm Transmission Service and Interchange” to “Known commitments for Firm Transmission Service or Interchange”. It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.
Puget Sound Energy, Inc.	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change “real and reactive load forecast” to “forecasted demand and power factor” so it is clear that forecasting reactive load is not required. For R1.1.5 we suggest changing the wording from “Known commitments for Firm Transmission Service and Interchange” to “Known commitments for Firm Transmission Service or Interchange”. It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.
San Diego Gas & Electric Co	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change “real and reactive load forecast” to “forecasted demand and power factor” so it is clear that forecasting reactive load is not required. R1.1.5 "firm transmission service agreements" should be removed the from the requirement. Firm transmission service agreements, "known" or otherwise, have no effect on reliable operation of the grid; power will flow where it wants, not where, or how, the firm transmission service agreement may specify. From a reliability perspective this information is of no use.
Southern California Edison (SCE)	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change “real and reactive load forecast” to “forecasted demand and power factor” so it is clear that forecasting reactive load is not required. For R1.1.5 we suggest changing the wording from “Known commitments for Firm Transmission Service and Interchange” to “Known commitments for Firm Transmission Service or Interchange”. It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.
SRP	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change “real and reactive load forecast” to “forecasted demand and power factor” so it is clear that forecasting reactive load is not required. For R1.1.5 we suggest changing the wording from “Known commitments for Firm Transmission Service and Interchange” to “Known commitments for Firm Transmission Service or Interchange”. It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.

Organization	Comments for Question 1
Western Area Power Adm - RMR	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. For R1.1.5, I suggest changing the wording from "Known commitments for Firm Transmission Service and Interchange" to "Known commitments for Firm Transmission Service or Interchange". It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.
Response: 1. Requirement R1, part 1.1.4 states that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast. No change made. 2. The SDT believes that the existing language is adequate and no further change is required. If you do not have any known Firm Transmission Service as an example, then this fact should just be documented.	
Northeast Utilities	[R1.1.6] What is NERC's definition of "Resources required to supply load"?[Add R1.1.7] The standard is referring to requirements for sensitivity and other issues without a reference to base cases. There needs to be some direction provided on the initial conditions used in the assessment. This guidance should include a discussion as to whether or not generator forced outages are to be represented in the base cases. Additionally, the standard is also silent on the treatment of system transfers, both internal and external, as to how they should be modeled in the base cases. For some areas, their current practice is to include heavy system stresses in their base cases. It is unclear if this practice works within the purview of this standard. Therefore, it is recommended that each Region must have a document that defines what constitutes base case conditions.
Response: 1. "Resources required to supply load" is not a NERC defined term. "Facility" is a defined term and does include generators. The SDT has made a clarifying change to Requirement R1, part 1.1.6. **R1, part 1.1.6** - Resources (supply or demand side) required for Load **2.** The SDT believes that "base case conditions" should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested. Please note that Requirement R1, part 1.1.2 includes only known outages of generation with duration of at least 6 months. Requirement R1, part 1.1.5 includes known commitments for Firm Transmission Service and Interchange - while the sensitivity analysis under Requirement R2, parts 2.1.4 and 2.4.3 can include varying expected transfers by a sufficient amount to stress the System. The Standard will leave it up to each Region to further define their own base case documentation if they desire to have such a document.	
Progress Energy Florida, Inc.	As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all appropriate parties to review PEF's previous comments to this effect.
Response: Throughout the drafting process, the SDT has carefully considered your comments as well comments from other industry members.	
American Electric Power	Because the revised transmission planning standard now explicitly references short circuit analysis, we believe that there is a

Organization	Comments for Question 1
	need for a parallel MOD standard to establish requirements for short circuit modeling and for a corresponding reference under R1, just as there are references made in R1 to MOD-010 (power flow models) and MOD-012 (stability models) . We recognize that such a MOD standard will not be addressed as part of this project, but we request that the SDT pass this comment on to NERC Staff.
Response: NERC has committed that it will update the appropriate MOD standards after the TPL revisions are finalized. A note has already been made in the official NERC issues database for a revision to the MOD standards based on the changes to TPL.	
CenterPoint Energy	CenterPoint Energy appreciates the SDT's efforts in revising R1 and generally agrees with the requirement except for verbiage and sub-requirements relating to modeling future transmission system projects, including projects identified in Corrective Action Plans. Specifically, CenterPoint Energy recommends that the SDT revise R1 by deleting the text "including items represented in the Corrective Action Plan" and delete part 1.1.3 in its entirety. Certainly, it is appropriate to model some limited subset of future projects, including projects included in Corrective Action Plans, which are reasonably "firm" or "committed". In previous drafts, the SDT tried to incorporate language to capture that concept but apparently abandoned the idea in response to industry comments. However, it remains true that many future "planned" projects, including projects in Corrective Action Plans, are tentative in nature and have a high degree of uncertainty due to uncertainty in forecasted system conditions. Because of this reality, and the fact that models are intended to be useful for identifying what future projects might be necessary, CenterPoint Energy believes many transmission planning organizations do not and should not model any and all new planned transmission facilities tentatively identified based upon studies and assessments of previous system models. Once the System model is updated with previously contemplated transmission projects, it is problematic to determine in future studies whether or not those projects are still needed, which is contrary to the intent of updating the model. If CenterPoint Energy's recommended changes are made, Transmission Planners and Planning Coordinators would not be precluded from incorporating future projects into their System models in accordance with their established practice but they would not be required to inappropriately model any and all previously contemplated projects.
Response: The SDT believes that the Corrective Action Plans and Requirement R1, part 1.1.3 are being correctly used in this planning standard. Please note that there are a variety of associated actions that can be used to achieve required System performance as noted in Requirement R2, part 2.7.1. The SDT agrees that systems can change over time which will result in some changes for the Corrective Action Plans. The SDT is not trying to "pin down" entities in regards to these plans but to ensure that entities are planning reliable Transmission Systems and have sufficient time to get needed plans in service to continue meeting the TPL 001-1 requirements. The SDT believes that these actions are needed in the planning horizons in order to have a reliable Bulk Electric System. No change made.	
Platte River Power Authority	Change R1.1.5 wording from "...Service and Interchange." to "...Service or Interchange."
Response: The SDT believes that the existing language is adequate and no further change is required. If you do not have any known Firm Transmission Service as an example, then this fact should just be documented.	
ITC Holdings	Comments: These requirements refer to new facilities which would include new generators. ITC requests clarification as to what constitutes a "new generator" that needs to be considered -- those in the queue, those with signed Interconnection Agreements, those under construction... What is the line of demarcation between what is in and what is out?

Organization	Comments for Question 1
	In addition to the above, ITC also requests clarification as to whether or not these requirements apply to new generators, who connect to the network as "Energy Only" resources and, are either, not required to construct facilities needed to meet reliability requirements or are allowed to operate as "Energy Only" until needed facilities are constructed. The CAP for these facilities is that they will be curtailed or other generation will be curtailed should "operating" violations occur. Under market mechanisms, these generators are allowed to operate if their energy prices are lower than other generators whose curtailment eliminates the violation, even though the curtailed generators have paid for the facilities needed to meet reliability requirements. As the standard is written, these requirements imply that all generators must be included in studies. Were we to do so, significant standards violations might result. Does the Transmission Owner have to study all violation scenarios or include all "Energy Only" generators in studies when the CAP is always the same: "Market redispatch". Please clarify study scenario requirements for "Energy Only" resources.
Response: 1. Requirement R1 is a modeling requirement which requires any expected operational Facilities to be modeled based on market and contractual obligations. 2. The SDT believes that the requirements under this standard do include "Energy Only" generators. Please note under Requirement R2, part 2.7.1 that manual and automatic generation runback/tripping is allowed as a response to single or multiple Contingencies to mitigate Steady State performance violations. Also automatic generation tripping is allowed for single and multiple Contingency events to mitigate Stability performance violations.	
FirstEnergy Corp	FirstEnergy believes the draft 4 version of requirement R1 is greatly improved over prior drafts. The team has correctly responded to industry stakeholders and arrived at an appropriate middle ground that should resolve most stakeholder concerns. The changes made in R1.1.2 stating modeling of known outages with a duration of 6-months or more helps clarify a requirement that was previous subjective and open for interpretation. The removal of the previously prescriptive "such as list" is also well received by FirstEnergy.Finally, the addition of the text "known commitments" in regards to Firm Transmission Service and Interchange resolves our prior concerns.
Gainesville Regional Utilities	I like the more simplified approach used in the requirement listing. As far as "using the latest data consistent with MOD-010 & MOD -012 data", I feel that unplanned or unknown system changes between the times when studies are actually ran for the long term planning process should not be an issue for any type of negative interpretation by a compliance auditor. I presently do not have a suggestion on how to guarantee such an understanding. Overall the revisions look good.
Tri-State Generation and Transmission Association	R1 - The changes to R1 seem good.
Response: Thank you for your comments.	
Utility System Efficiencies, Inc. (USE)	For R1.1.5 I suggest changing the wording from "Known commitments for Firm Transmission Service and Interchange" to "Known commitments for Firm Transmission Service or Interchange". It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.
Response: The SDT believes that the existing language is adequate and no further change is required. If you do not have any known Firm Transmission Service as	

Organization	Comments for Question 1
an example, then this fact should just be documented.	
Orlando Utilities Commission	In general I support all the changes from the prior revision. I especially like the clarification that outages of 6 months or longer need attention in planning studies. Several questions on the details: R1 requires the maintenance of system models for the purpose of studies and establishes that these models should be updated with the latest data from various sources. Is this requiring that models should always be current, updated for the slightest change, even between studies? Or just that models are kept up to date in a more practical application such as monthly, quarterly or before their use in a study?R1 states that the model should be "..supplemented by other sources as needed, including items represented in the corrective action plan"? Read in context with the overall requirement this allows for projects that are in the corrective action plan to be added, but does not require that they are, is this the correct understanding? -R1 requires the model to represent Known Commitments for Firm Transmission Service, and also references load forecasts. The application of this requirement seems to be that the model should be based on the load forecast and include the appropriate known firm transmission service for the amount that would be used at that forecast level?
Response: 1. Yes, your understanding is correct. Thank you for your comments. 2. The SDT agrees that the model should be based on the load forecast. The SDT believes that the appropriate known Firm Transmission Service should also be included. Please note that Requirement R1, part 1.1.6 has been clarified to state that supply or demand side can be used for supplying Load. **R1, part 1.1.6** - Resources (supply or demand side) required for Load	
MAPP	1. It would be helpful to identify the relationship expected between the PC and the TP. It looks as if both PC and TP are expected to maintain the same models. We need to avoid duplicated effort. Does the standard really apply to "both", or could it be "either"? 2. Is a Corrective Action Plan being used correctly throughout this standard? It seems like the specifics of a CAP aren't appropriate for future planning years. Planning studies are only estimates of expected system growth, and the apparent problem might turn out to be different, or not exist at all. Will compliance people start going "over the top" examining CAPs? The current practice of summarizing possible problems in future years and identifying possible solutions seems more appropriate than pinning entities down to Corrective Action Plans. Corrective Action Plans seem appropriate only for the Operating horizon.R1 We interpret that "within their respective areas" refers the geographic footprint of the TP or PC transmission system. 3. We propose clarifying that "within their respective area" does not require the inclusion of remote generation or load (metering) buses that are within the declared Balancing Authority area, but may be outside and separate from the TP or PC geographic footprint. 4. M1 We recommend the bolded words be added to M1 to indicate that each responsible entity must provide evidence that "it is maintaining System models within its respective area, using the latest"? What does it mean to have a hardcopy of a system model? 5. R1.1.2 We suggest that this requirement be removed because the "known outage(s)" are only to be included in the models

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	when for P1 events are simulated, as specified in R2.1.3. We suggest that the intent can be more simply handled by stating in R2.1.3 that known outages be simulated along with P1 events for the System peak or Off-Peak conditions when the outages are scheduled to occur. 6. R1.1.3 Add the qualification of "for the years defined in R2". 7. R1.1.6 We interpret that "Resources required" allows the inclusion of fictional generators in the models when they are needed to make future normal system cases solve. If this is not the intended interpretation, then we suggest modifying the wording to make the desired interpretation more clear.
Response: 1. The SDT believes that both the Transmission Planner and Planning Coordinator have this modeling responsibility. Therefore the SDT believes that the existing language is adequate and that no changes are required. 2. The SDT believes that the Corrective Action Plans are being correctly used in this planning standard and is appropriate for all planning years. Please note that there are a variety of associated actions that can be used to achieve required System performance as noted in Requirement R2, part 2.7.1. The SDT agrees that Systems can change over time which will result in some changes for the Corrective Action Plans. The SDT cannot speculate on auditor's actions. The SDT is not trying to "pin down" entities in regards to these plans but to ensure that entities are planning reliable Transmission Systems and have sufficient time to get needed plans in service to continue meeting the TPL-001-1 requirements. The SDT believes that these actions are needed in the planning horizons in order to have a reliable Bulk Electric System. The SDT believes that "within their respective area" does refer to the Transmission Planner's or Planning Coordinator's geographic footprint. 3. The SDT believes agrees that the "within their respective area" terminology excludes remote generation and Load buses since they are not within the Transmission Planner's or Planning Coordinator's geographic footprint. The SDT believes that the existing language is adequate and no further change is required. 4. The SDT agrees that adding "within its respective area" would help clarify this measure. The SDT has modified Measure M1 to include this new language. An example of a hard copy of a System model is having printouts of each individual bus showing Load, Transmission line, generator, capacitors, etc., connected to that bus with associated impedances, ratings, etc. **M1**. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within its respective area, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1 5. The SDT disagrees since multiple outages may be taken during the same time period under Requirement R1, part 1.1.2. The SDT believes that all outages should be modeled to insure the System reliability during the outage duration. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-Contingency. See Requirement R2, part 2.1.3 for additional details concerning studies required with known outages. No change made. 6. The SDT does not believe that the proposed language adds any clarity. No change made. 7. The SDT believes that this requirement includes any fictional generators that may be needed to match up generation and Load. The SDT has made clarifying change to Requirement R1, part 1.1.6. **R1, part 1.1.6** - Resources (supply or demand side) required for Load	
MidAmerican Energy Company	MidAmerican recommends the words in all caps be added to M1 to indicate that each responsible entity must provide evidence

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	that "it is maintaining System models WITHIN ITS RESPECTIVE AREA, using the latest"?
Response: The SDT agrees that adding "within its respective area" would help clarify this measure. The SDT has modified Measure M1 to include this new language. **M1**. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within its respective area, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.	
Florida Power and Light	No entity that we know of provides specific reactive load forecasts. From the auditor's perspective, what is expected and acceptable for System models representing reactive load forecasts? Suggested change: 1.1.4 Real Load forecasts and future reactive Load assumptions? Not all system models can represent all "Known commitments for Firm Transmission Service and Interchange". The SDT needs to add "that are expected to be utilized." to the requirement. 1.1.6 Recommend changing to "Resources expected to supply Load"The requirements seem to imply a difference in certainty between "known" and "planned". Known implies certainty, where planned implies less certainty, as in an assumption. Planned things can change but known things are much less subject to change. The drafting team should clarify the distinction between the two terms or be more specific in the requirement as to what is expected rather than leaving it for interpretation as to meaning and intent.
Response: 1. Requirement R1, part 1.1.4 states that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast. The SDT believes that the existing language is adequate. The SDT believes that all known commitments for Firm Transmission Service and Interchange should be modeled. The SDT does not believe that the proposed language adds any clarity. No change made. 2. The SDT has made clarifying change to Requirement R1, part 1.1.6 based on industry comments. Please note that the word "required" is used in Requirement R1, part 1.1.6. **R1, part 1.1.6** - Resources (supply or demand side) required for Load	
Independent Electricity System Operator	Please explain what is envisaged by the phrase "and shall represent projected System conditions." that is not already covered by the list in Requirement R1, part 1.1. We suggest removing the phrase. We do not have any comments on the, measure, VRF and Time Horizon. Consistent with our comment above, we believe that the 2nd condition under the Severe VSL is (a) vague, and (b) already covered by parts 1.1.1 to 1.1.6. This second condition is not needed.
Response: The goal is for the responsible entity to build a realistic simulation for the System models which may contain items not listed under Requirement R1, part 1.1. The SDT disagrees with the VSL comment and believes that the second condition under the Severe VSL covers additional items under Requirement R1 itself that are not covered under Requirement R1, parts 1.1.1 thru 1.1.6. No change made.	
NYISO	R1 - The NYISO would like to align itself with the comments of the ISO/RTO Council stating that the PC may begin model building using provisions from tariff or agreements such as its Transmission Owners agreement. While the data may be

Organization	Comments for Question 1
	consistent with that provided in Mod 10 and 12, there may not be a direct correlation. We, therefore, also suggest the following wording for R1."Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall reflect data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and/or data that is provided in accordance with tariff or transmission owner agreements. The models may be supplemented by other sources as needed including items represented in the Corrective Action Plan, and shall represent projected System conditions. "R1.1.2 - Outages of less than 12 months are generally coordinated by operations, not planning departments. In reference to system modeling, it doesn't make sense for outages of less than a year. We therefore recommend replacing "duration of at least six months" with duration of 12 months or more. R1.1.5 - Interchange should not be modeled in the base case system representation, unless their neutrality to system reliability has been clearly demonstrated. There are times that economic interchanges between New York and a neighbor may have an impact on one of the transmission systems that may, at times, pose reliability constraints on the operation of the New York system. R1.1.6 - Please define what is included in "resources required to supply load." It is unclear what is included or not included in this requirement. The NPCC definition of "resource" is inclusive.
Response: 1. The SDT believes the existing language is correct and that the suggested changes do not provide additional clarity. No change made. 2. The requirement does not refer to outages occurring within the next 6 months which the SDT agrees would be an operational issue and not a planning issue. The requirement is referring to outages in the planning horizon that have a duration of at least six months. The SDT believes that such outages should be incorporated into the Planning Assessment. No change made. 3. The SDT disagrees and believes that known firm transmission commitments and interchange should be modeled and can affect the transmission system reliability. No change made. 4. "Resources required to supply load" is not a NERC defined term. "Facility" is a defined term and does include generators. The SDT has made a clarifying change to Requirement R1, part 1.1.6. **R1, part 1.1.6** - Resources (supply or demand side) required for Load	
NERC Standards Review Subcommittee	R1 The MRO NSRS interprets that "within their respective areas" refers to the geographic footprint of the TP or PC transmission system. The MRO NSRS proposes clarifying that "within their respective area" does not require the inclusion of remote generation or load (metering) buses that are within the declared Balancing Authority area, but may be outside and separate from the TP or PC geographic footprint. M1 The MRO NSRS recommends that words be added to M1 to indicate that each responsible entity must provide evidence that "it is maintaining System models within its respective area, using the latest"?
Response: 1. The SDT believes agrees that the "within their respective area" terminology excludes remote generation and Load buses since they are not within the Transmission Planner's or Planning Coordinator's geographic footprint. The SDT believes that the existing language is adequate and no further change is required.	

Organization	Comments for Question 1
2. The SDT agrees that adding "within its respective area" would help clarify this measure. The SDT has modified M1 to include this new language. **M1**. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within its respective area, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1	
Central Maine Power Company	R1.1.1 Make this read "Existing Facilities and Resources" so that it will be a lead in to the changes proposed for 1.1.6. R1.1.2 This type of event is sufficiently addressed within the existing testing requirements (P6) and therefore should be eliminated , beyond that such outages are reviewed and approved on an operational basis and should not be included in a planning standard. During known outages for equipment upgrades or repairs there may be some increased exposure to load loss, which should be recognized as an acceptable exposure. In the event that this requirement is maintained please change six months to one year. 1.1.6 Resources may not be exclusively sources supplying load. Therefore the reference should not involve load. The focus should be on changes to resources and "resources required to supply load" should be replaced with "New planned Resources and changes to existing Resources"We suggest NERC develops a definition for "resource" or use the following definition found in NPCC Glossary of Terms, Document A-7: Resource - Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load. ADD 1.2 The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions. The standard must describe base assumptions. M1 It is not practical to retain system model information in a hard copy form. This provision should be dropped. D.1.1.4 Data Retention: The Transmission Planner and the Planning Coordinator may not be using the same software. If both are required to store the data, do they both have to have the software to use the data? Can this be changed to an "or" such that one of them must retain the data and it can be up to them as to who is responsible for data retention.
ISO New England	1. R1.1.1 Make this read "Existing Facilities and Resources" so that it will be a lead in to the changes proposed for 1.1.6. 2. R1.1.2 This type of event is sufficiently addressed within the existing testing requirements (P6) and therefore should be eliminated , beyond that such outages are reviewed and approved on an operational basis and should not be included in a planning standard. During known outages for equipment upgrades or repairs there may be some increased exposure to load loss, which should be recognized as an acceptable exposure. In the event that this requirement is maintained please change six months to one year. 3. 1.1.6.. Resources may not be exclusively sources supplying load. Therefore the reference should not involve load. The focus should be on changes to resources and "resources required to supply load" should be replaced with "New planned Resources and changes to existing Resources"We suggest NERC develops a definition for "resource" or use the following definition found in NPCC Glossary of Terms, Document A-7: Resource Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases

Organization	Comments for Question 1
	from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load. 4. ADD 1.2 The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions. The standard must describe base assumptions. 5. M1It is not practical to retain system model information in a hard copy form. This provision could be dropped. 6. D.1.1.4 Data Retention: The Transmission Planner and the Planning Coordinator may not be using the same software. If both are required to store the data, do they both have to have the software to use the data? Can this be changed to an "or" such that one of them must retain the data and it can be up to them as to who it is.
Response: 1. The SDT believes that the "and Resources" is not needed as a lead in to Requirement R1, part 1.1.6 since both Requirement R1, parts 1.1.1 and 1.1.6 are directly under Requirement R1, part 1.1. No change made. 2. The SDT disagrees since multiple outages may be taken during the same time period under Requirement R1, part 1.1.2, thus this situation may be worse than only having two Contingencies as noted in P6. The SDT believes that all outages should be modeled to ensure the System reliability during the outage duration. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-Contingency. See Requirement R2, part 2.1.3 for additional details concerning studies required with known outages. No change made. 3. The SDT agrees that this requirement may not be exclusively sources supplying Load. As an example, Demand Side-Management (DSM) may be used. The SDT has made clarifying change to Requirement R1, part 1.1.6 based on industry comments. **R1, part 1.1.6** - Resources (supply or demand side) required for Load 4. The SDT believes that the "base case conditions" should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested. 5. Since Measure M1 states that either electronic OR hard copy format is required, the SDT believes that no changes are required since either of the formats is acceptable. 6. The SDT believes that both the Transmission Planner and Planning Coordinator have this responsibility. Therefore the SDT believes that the existing language is adequate and that no changes are required.	
United Illuminating	R1.1.1 Make this read "Existing Facilities and Resources" so that it will be a lead in to the changes proposed for 1.1.6. R1.1.2 This type of event is sufficiently addressed within the existing testing requirements (P6) and therefore should be eliminated , beyond that such outages are reviewed and approved on an operational basis and should not be included in a planning standard. During known outages for equipment upgrades or repairs there may be some increased exposure to load loss, which should be recognized as an acceptable exposure. In the event that this requirement is maintained please change six months to one year. 1.1.6.. Resources may not be exclusively sources supplying load. Therefore the reference should not involve load. The focus should be on changes to resources and "resources required to supply load" should be replaced with "New planned Resources and changes to existing Resources"We suggest NERC develops a definition for "resource" or use the following definition found

Organization	Comments for Question 1
	in NPCC Glossary of Terms, Document A-7: Resource Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load. ADD 1.2 The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions. The standard must describe base assumptions.
Response: 1. The SDT believes that the "and Resources" is not needed as a lead in to Requirement R1, part 1.1.6 since both Requirement R1, parts 1.1.1 and 1.1.6 are directly under Requirement R1, part 1.1. No change made. 2. The SDT disagrees since multiple outages may be taken during the same time period under Requirement R1, part 1.1.2, thus this situation may be worse than only having two Contingencies as noted in P6. The SDT believes that all outages should be modeled to ensure the System reliability during the outage duration. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-Contingency. See Requirement R2, part 2.1.3 for additional details concerning studies required with known outages. No change made. 3. The SDT agrees that this requirement may not be exclusively sources supplying Load. As an example, Demand Side-Management (DSM) may be used. The SDT has made clarifying change to Requirement R1, part 1.1.6 based on industry comments. **R1, part 1.1.6** - Resources (supply or demand side) required for Load 4. The SDT believes that the "base case conditions" should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested.	
Ameren	R1.1.2: Inclusion of outages of generation or transmission facilities with a duration of at least 6 months in the models is too restrictive. An outage duration of 1 month would be more appropriate for inclusion in the seasonal peak and off-peak models. R1.1.5: It is not clear from the wording how Firm Transmission Service and Interchange schedules should be considered, or whether the status quo is adequate. A given generating facility may have transmission service commitments which exceed the facility's generating capability. VSL: Given the annual cycle of collecting, revising and submitting system model data under MOD-010 and MOD-012, there could be a lag of several months between receipt of updated data prior to having this data included in the next round of system models. The TP/PC should not be penalized for this.
Response: 1. The SDT believes that the 6 month outage duration required for modeling outages is sufficient. However a utility may exceed this requirement by having lower outage duration if they choose. The outages should be modeled in the appropriate cases whether the outages occur in the spring, summer, fall, winter, etc. 2. The Standard is requiring the modeling of known commitments for Firm Transmission Service and Interchange schedules as a means of stressing the transmission system pre-contingency. If a given generator is reserving transmission capability beyond the capability of the resources to deliver, then someone must have evaluated the system based on a set of assumptions that identified that the system is capable of delivering the service, which would be consistent with this requirement. 3 The System models should be updated in accordance with MOD-010 & MOD-012. No change made.	

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Xcel Energy	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.
Response: Requirement R1, part 1.1.4 states that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast.	
SERC Planning Standards Subcommittee	R1: MOD-010 and 012 are not directly applicability to the PC. References to other processes (e.g. tariff requirements or transmission owner agreements) that are utilized to provide this data may be desirable, but do not satisfy R1 as presently written.VSL: In the Moderate and Severe VSL, insert "responsible entity's" in front of the term "System model."
SERC Dynamics Review Subcommittee (DRS)	R1: MOD-010 and 012 are not directly applicable to the PC. References to other processes (e.g. tariff requirements or transmission owner agreements) that are utilized to provide this data may be desirable, but do not satisfy R1 as presently written.VSL: In the Moderate and Severe VSL, insert "responsible entity's" in front of the term "System model."

Response: The MOD-010 and MOD-012 standards are not directly applicable to the Planning Coordinator; however the Planning Coordinator has to utilize data provided by others such as that provided in accordance with MOD-010 and -012.

The SDT agrees and will insert this additional wording in the moderate and severe VSLs for Requirement R1.

R1 VSL	The responsible entity's System model failed to represent one of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.	The responsible entity's System model failed to represent three of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1.

Manitoba Hydro	Recommend removing "and shall represent projected System Conditions" from R1. This is already clearly contained in R1.1.1

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	through R1.1.6. If the drafting team knows of other projected system conditions then they should be listed in R1.1. "The System Model did not represent projected System Conditions as described in Requirement R1 should be removed from the severe VSL column. By failing to represent 4 or more of the requirements in 1.1.1 through 1.1.6, projected System Conditions are not represented.
Response: The SDT disagrees and believes that there may need to be additional information contained in the models that is not specifically noted under Requirement R1.1. The goal is for the responsible entity to build a realistic simulation for the System models. The SDT disagrees and believes that the second condition under the Severe VSL covers additional items under Requirement R1 itself that are not covered under Requirement parts 1.1.1 thru 1.1.6.	
Northeast Power Coordinating Council--RSC	1. Requirement 1.1.1: Replace "Existing Facilities" with "Existing Facilities and Resources" so that it will be a lead in to the changes proposed for 1.1.6. 2. Requirement 1.1.2 "Consideration of known outages should not be included in a planning assessment. Such outages are coordinated by operations and are only permitted if the system can be operated reliably, where assumptions may be different than those used in planning assessments. Including this as a requirement effectively means that the system must be designed to withstand three outages. In those cases where safety, or reliability, or both are a concern by long duration outages (e.g., more than one year), temporary Operating Protocols are implemented to mitigate their impact. During known outages for equipment upgrades or repairs there may be some increased exposure to load loss, which should be recognized as an acceptable exposure. If this requirement must be kept, the outages with duration in excess of a year should be considered, rather than those of six months. This type of event is sufficiently addressed within the existing testing requirements (P6) and therefore should be eliminated, beyond that such outages are reviewed and approved on an operational basis and should not be included in a planning standard. Known or "known planned" outages will not necessarily fall in the operations timeframe, and as such may not be subject to approval by operations departments. This is especially so given the fact that the earliest start date for Year One is 12 months beyond the current year. 3. Requirement 1.1.5 Interchange. Interchange usually refers to non-firm short-term economic transactions that often take place between Balancing Authorities to take advantage of their respective resources surplus (i.e. not needed for local reliability.) However, such transactions should not be modeled in the base case system representation, unless their neutrality to system reliability has been clearly demonstrated. For example, economic interchanges between New England and PJM through New York have an impact on the New York transmission system that may, at times, pose reliability constraints on the operation of the New York system. 4. Requirement 1.1.6 what are "resources required to supply load, gens, HVDC, tie lines? Resources may not be exclusively sources supplying load. The focus should be on changes to resources. "Resources required to supply Load" should be replaced with New planned Resources and changes to existing Resources. NPCC suggests NERC develops a definition for "resource" or use the following definition found in NPCC Glossary of Terms, Document A-7: Resource Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load.A

Organization	Comments for Question 1
	5. Requirement 1.2 should be added to address the base assumptions for sensitivity and other issues requirements. 6. For Measure M1: Elaborate on "hard copy format". Does that entail maintaining a hard copy of the system model? It is impractical to retain system model information in a hard copy format. This provision should be dropped.
Response: 1.The SDT believes that the "and Resources" is not needed as a lead in to Requirement R1, part 1.1.6 since both Requirement R1, parts 1.1.1 and 1.1.6 are directly under Requirement R1, part 1.1. 2. The SDT disagrees and believes that all outages should be modeled to ensure System reliability during the outage duration. Since multiple outages may be taken during the same time period under Requirement R1, part 1.1.2, this situation may be worse than only having two Contingencies as noted in P6. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-Contingency. See Requirement R2, part 2.1.3 for additional details concerning studies required with known outages. No change made. 3. The SDT disagrees and believes that known firm Transmission commitments and interchange should be modeled and can affect the Transmission System reliability. No change made. 4. The SDT agrees that this requirement may not be exclusively sources supplying Load. As an example, Demand Side-Management (DSM) may be used. The SDT has made a clarifying change to Requirement R1, part 1.1.6 based on industry comments. **R1, part 1.1.6** - Resources (supply or demand side) required for Load 5. The SDT believes that the "base case conditions" should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested. 6. Since Measure M1 states that either electronic OR hard copy format is required, the SDT believes that no changes are required since either of the formats is acceptable. An example of a hard copy of a System model is having printouts of each individual bus showing Load, Transmission line, generator, capacitors, etc., connected to that bus with associated impedances, ratings, etc.	
Hydro-Québec TransEnergie (HQT)	Requirement 1.1.2 Consideration of known outages should not be included in a planning assessment. Such outages are coordinated by operations and are only permitted if the system can be operated reliably, where assumptions may be different than those used in planning assessments. Including this as a requirement effectively means that the system must be designed to withstand three outages. In those cases where safety, or reliability, or both are a concern by long duration outages (e.g., more than one year), temporary Operating Protocols are implemented to mitigate their impact. If this requirement must be kept, the outages with duration in excess of a year should be considered, rather than those of six months. Requirement 1.1.5 Interchange. Interchange usually refers to non-firm short-term economic transactions that often take place between Balancing Authorities to take advantage of their respective resources surplus (i.e. not needed for local reliability.) However, such transactions should not be modeled in the base case system representation, unless their neutrality to system reliability has been clearly demonstrated. For example, economic interchanges between New England and PJM through New York have an impact on the New York transmission system that may, at times, pose reliability constraints on the operation of the New York system. Requirement 1.1.6 what are "resources required to supply load" " gens, HVDC, tie lines" HQT, as does NPCC, suggests NERC

Organization	Comments for Question 1
	develops a definition for "resource" or use the following definition found in NPCC Glossary of Terms, Document A-7: Resource - Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load.

Response: 1. The SDT disagrees and believes that all outages should be modeled to ensure System reliability during the outage duration. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-Contingency. See Requirement R2, part 2.1.3 for additional details concerning studies required with known outages.

The SDT believes that the 6 month duration is appropriate. No change made.

2. The SDT disagrees and believes that known firm Transmission commitments and interchange should be modeled and can affect the Transmission System reliability. No change made.

3. The SDT agrees that this requirement may not be exclusively sources supplying Load. As an example, Demand Side-Management (DSM) may be used. The SDT has made a clarifying change to Requirement R1, part 1.1.6 based on industry comments.

R1, part 1.1.6 - Resources (supply or demand side) required for Load

Organization	Comments for Question 1
Midwest ISO	Requirement R1: The Planning Coordinator may begin model building using provisions from tariff and/or other agreements such as its Transmission Owners agreement. While the data may be consistent with that provided in Mod 10 and 12, there may not be a direct correlation between the two sets of data. This could become burdensome for a Planning Coordinator to make that correlation between the two. Suggest the following wording for R1.Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall reflect data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and/or data that is provided in accordance with tariff or transmission owner agreements. The models may be supplemented by other sources as needed including items represented in the Corrective Action Plan, and shall represent projected System conditions Requirement R1.1.5: In the Moderate and Severe VSL, insert "responsible entity's" in front of the term "System Models" so it reads as such: "The responsible entity's System model did not"

Response: 1. The SDT does not believe that the proposed language adds any clarity. No change made.

The SDT agrees and will insert this additional wording in the moderate and severe VSLs for Requirement R1.

R1 VSL	The responsible entity's System model failed to represent one of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, parts 1.1.1 through 1.1.6. OR	The responsible entity's System model failed to represent three of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, parts 1.1.1 through 1.1.6. OR

Organization	Comments for Question 1
	The responsible entity's System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan. The responsible entity's System model did not represent projected System conditions as described in Requirement R1.
FRCC Transmission Working Group	Several questions on the details:- R1 requires the maintenance of system models for the purpose of studies and establishes that these models should be updated with the latest data from various sources. Read in context this seems to require that a PA/TP has models, and they are updated either on some sort of regular schedule, for example quarterly or before the start of a study, and use the latest information at the time they are updated. Is this a correct understanding of the requirement? - R1 states that the model should be "..supplemented by other sources as needed, including items represented in the corrective action plan"? Read in context with the overall requirement this allows for projects that are in the corrective action plan to be added to the model as needed, is this the correct understanding? -R1 requires the model to represent "projected system conditions" which include in the list below "Known Commitments for Firm Transmission Service" and "Load Forecast". This seems to require that your known firm transmission service commitments are matched to their corresponding customers load forecast and expected operation profile, relative to load level in the case. Or phrased another way, the model should represent the service and load as they would be expected to operate at the load level in the case. Is this a correct understanding? Comments: With regard to the Moderate Violation Severity Level, what if the entity does not have the "latest" data but the entity did include items in the corrective action plan? Should the "and" between MOD-010 and MOD-012 be an "OR" and have the "AND" be for the High VSL?Not all system models can represent all "Known commitments for Firm Transmission Service and Interchange". The SDT needs to add "that are expected to be utilized." to the requirement. 1.1.6 Recommend changing to "Resources expected to supply Load"

Response: 1. The SDT agrees with your understanding. The System models should be updated in accordance with MOD-010 & MOD-012.

2. Yes, this is the correct understanding. Items from the Corrective Action Plan should be included in the models as noted under Requirement R1.

3. The SDT agrees with your understanding.

4. If the entity does not have the latest data, but did include items in the Corrective Action Plan, then the SDT believes the entity would be in violation of a Moderate Severity level. The SDT believes that the existing language is correct. The SDT believes that all System models should represent all known commitments for Firm Transmission Service and Interchange. The SDT does not believe that the proposed language adds any clarity. No change made.

5 The SDT realizes that this requirement may not be exclusively sources supplying Load. As an example, Demand Side-Management (DSM) may be used. The SDT

Organization	Comments for Question 1
has made a clarifying change to Requirement R1, part 1.1.6 based on industry comments. **R1, part 1.1.6** - Resources (supply or demand side) required for Load	
National Grid	Sub-Requirement 1.1.1: Replace "Existing Facilities" with "Existing Facilities and Resources" so that it will be a lead in to the changes proposed for 1.1.6. Sub-Requirement 1.1.2: This type of event is sufficiently addressed within the existing testing requirements (P6) and therefore should be eliminated, beyond that such outages are reviewed and approved on an operational basis and should not be included in a planning standard. During known outages for equipment upgrades or repairs there may be some increased exposure to load loss, which should be recognized as an acceptable exposure. In the event that this requirement is maintained please change six months to one year. Sub-Requirement 1.1.6: Resources may not be exclusively sources supplying load. Therefore the reference should involve load. The focus should be on changes to resources. "Resources required to supply Load" should be replaced with "New planned Resources and changes to existing Resources"It is suggested that NERC develop a definition for "resource" or use the following definition found in NPCC Glossary of Terms, Document A-7: Resource - Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load. ADD 1.2 The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions. The standard must describe base assumptions. Measure M1: Elaborate on "hard copy format". Does that entail maintaining a hard copy of the system model? It is impractical to retain system model information in a hard copy format. This provision should be dropped.
Response: 1 The SDT believes that the "and Resources" is not needed as a lead in to Requirement R1, part 1.1.6 since both Requirement R1, parts 1.1.1 and 1.1.6 are directly under Requirement R1, part 1.1. 2. The SDT disagrees since multiple outages may be taken during the same time period under Requirement R1, part 1.1.2, thus this situation may be worse than only having two Contingencies as noted in P6. The SDT believes that all outages should be modeled to ensure the System reliability during the outage duration. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-Contingency. See Requirement R2, part 2.1.3 for additional details concerning studies required with known outages. 3. The SDT agrees that this requirement may not be exclusively sources supplying Load. As an example, Demand Side-Management (DSM) may be used. The SDT has made a clarifying change to Requirement R1, part 1.1.6 based on industry comments. **R1, part 1.1.6** - Resources (supply or demand side) required for Load 4 The SDT believes that the "base case conditions" should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested. 5. Since Measure M1 states that either electronic OR hard copy format is required, the SDT believes that no changes are required since either of the formats is acceptable. An example of a hard copy of a System model is having printouts of each individual bus showing Load, Transmission line, generator, capacitors, etc.,	

Organization	Comments for Question 1
connected to that bus with associated impedances, ratings, etc.	
Lakeland Electric	Suggesting language "known planned" outages and in place of "known" outages Suggesting language "real & reactive resources" in place of "Resources" "within its respective area", how about ties?
Response: The SDT does not believe that the proposed language adds any clarity. No change made. The SDT has made clarifying change to Requirement R1, part 1.1.6 based on industry comments since this requirement may not be exclusively sources supplying Load. **R1, part 1.1.6** - Resources (supply or demand side) required for Load Tie Lines should be modeled as required to achieve conformance with the MOD standards.	
Exelon Transmission Planning	The feedback from Round 3 of comments is appreciated, but there is still a concern that the inclusion of known (or "expected") transfers is to be studied as a sensitivity. We believe that the base case should already contain the most likely ("expected") transfer scenario and a sensitivity case would be studied with a less likely transfer scenario. As written it appears that the standard would require that the base case would contain no transfers or some transfer level other than what is "expected". It is suggested the term "Expected transfers" be changed to "Additional transfers beyond base case conditions". The use of this term will provide clarity between what is to be modeled in the basecase and what is to be studied as a sensitivity case. There are a number of overlapping requirements with this standard and other standards in various stages of development, such as voltage stability criteria, protection system redundancy, relay loadability, and protection system contingencies that could cause non-compliance with several standards for a single infraction. Suggest removing overlapping requirements be removed from R6, P5 from Table 1, R3.3.3 and R3.3.1, respectively.
Response: 1. Requirement R1, part 1.1.5 requires that known commitments for Firm Transmission Service and Interchange be modeled. However the sensitivity analysis under Requirement R2, parts 2.1.4 and 2.4.3 require that at least one condition not already in the studies be varied by a sufficient amount in order to stress the System by a measurable change in performance. The SDT does not believe that the proposed language adds any clarity. No change made 2. As for the double jeopardy comment - From the ERO Rules of Procedure, Appendix 4B- Sanction Guidelines, Section 3.10 Multiple Violations: "Strictly speaking, NERC or the regional entity can determine and levy a separate penalty or sanction, or direct remedial action, upon a violator for each individual violation. However, in instances of multiple violations related to a single act or common incidence of noncompliance, NERC or the regional entity will generally determine and issue a single aggregate penalty, sanction, or remedial action directive bearing reasonable relationship to the aggregate of the related violations. The penalty, sanction, or remedial action will not be that determined individually for the least serious of the violations; it will generally be at least as large or expansive as what would be called for individually for the most serious of the violations." 3. The SDT believes that some overlap is necessary but the SDT has tried to minimize this as much as possible. Requirement R6 deals with defining and documenting certain items such as Cascading, voltage instability, and uncontrolled islanding. Note that Requirement R6 has been clarified to remove "outages" from "Cascading outages". P5 is a multiple Contingency caused by loss of a single Protection System. R3.3.1 deals with the removal of elements that the Protection System and other	

Organization	Comments for Question 1
automatic controls are expected to disconnect. However the SDT has clarified the relay loadability issue in Requirement R3, part 3.3.3 by stating how these are handled in the simulations when these limits are exceeded. **R3.3.3**. Trip Transmission elements when relay loadability limits are exceeded **R6**. Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, any criteria or methodology used in the analysis to identify System instability for conditions such as Cascading , voltage instability, or uncontrolled islanding.	
Florida Municipal Power Agency, and its Member Cities	The MOD standards for load forecasts (e.g., MOD-016 through 021) do not require submission of a reactive load forecast from the LSEs and RPs; therefore, why is it expected that the TPs and PCs use a reactive forecast that is not provided? From the auditor's perspective, what is expected and acceptable for System models representing reactive load forecasts? Suggested change: 1.1.4 Real Load forecasts and future reactive Load assumptions? Not all system models can represent all "Known commitments for Firm Transmission Service and Interchange". The SDT needs to add "that are expected to be utilized." to the requirement.
Response: 1. Requirement R1, part 1.1.4 states that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast. The SDT cannot comment on what an auditor may find compliant or non-compliant. No change made. 2. The SDT believes that the existing language is adequate and no further change is required. If you do not have any known Firm Transmission Service as an example, then this fact should just be documented.	
SRC of ISO/RTO	The PC may begin model building using provisions from tariff or agreements such as its Transmission Owners agreement. While the data may be consistent with that provided in MOD 10 and 12, there may not be a direct correllation. The following wording is suggested for R1.R1. Each Transmission Planner and Planner Coordinator shall maintain System Models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall reflect data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and/or data that is provided in accordance with tariff or transmission owner agreements. The models may be supplemented by other sources as needed including items represented in Corrective Action Plans, and shall represent projected System conditions. AESO does not comment on VSLs or VRFs.
Response: 1. The SDT believes that this is adequate as long as the data remains consistent with that provided in MOD-010 and MOD-012.	
US Bureau of Reclamation	The requirement for the model is not clearly stated. Based on the requirement 2, the models must prove the Corrective Action Plan items developed in 2.7.1. The actions in 2.7.1 are developed by the Transmission Planner or Planning Authority ("List System deficiencies and associated actions needed to achieve required System performance"). Requirement 1 however requires that the model "shall represent projected System conditions". Is the intent of the modelling to demonstrate system performance based on changes proposed by the Tranmission Owners and Generator Owners. Or is it the intent to have the Transmission Planner and Planning Authority develop proposals through system studies that the Transmission Owners and Generator Owners must implement?

Organization	Comments for Question 1
Response: Requirement R1 requires that Corrective Action Plans be included in the models. Requirement R1 includes items represented in the Corrective Action Plans along with represented projected System conditions. The intent of the modeling is to ensure that entities are planning reliable Transmission Systems and have sufficient time to get needed plans in service to continue meeting the TPL-001-1 requirements. The SDT believes that these actions are needed in the planning horizons in order to have a reliable Bulk Electric System. No change made.	
Oncor Electric Delivery	The six month limitation of requirement 1.1.2. "Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months." is applicable to near-term and long-term Planning studies, but makes the new TPL-001 standard non-extendible to the near-term operational planning studies (next month, next week, or next day). During near-term operational planning periods, it is essential to include the impacts of ALL known outages in the operational analysis.It should be made clear that the TPL-001 Standard is not applicable to the Operational Planning Horizon. This non-applicability points out the need for a separate (but equal in scope) operational planning analysis standard.There appears to be a lack of clarity related to relay loadability and protection system redundancy. Relay loadability is handled in greater detail (as it should be) under the proposed PRC-023 standard, so any reference here should only be a placeholder. Similarly, the issues of redundancy are being addressed in more detail in a new proposed standard on protection system reliability. 1.1.2 ? The requirement will result in the need to evaluate construction sequence in planning studies. 1.1.6 ? What are "resources required to supply load gens, HVDC, tie lines" NPCC suggests NERC develops a definition for "resource" or use the following definition found in NPCC Glossary of Terms, Document A-7: Resource Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load.1.1.6 Resources are not serving load but are supporting network operations. ADD 1.1.7 The standard is referring to requirements for sensitivity and other issues without a reference to base cases. It is recommended that each Region have a document that defines what constitutes "base case" conditions. M1What does it mean to have a hardcopy of a system model? 1.4 Data Retention: The Transmission Planner and the Planning Coordinator may not be using the same software. If both are required to store the data, are they both required to have identical software to use the data? We recommend that the entities have an option to determine which of the two entities retains the information.
Response: 1. The SDT agrees that this standard does not apply to the operating planning horizon. Please see the NERC TOP standards, as an example, for additional information concerning operational planning. The SDT believes that relay redundancy is best handled in Project 2009-07: Reliability of Protection Systems. However, the SDT has clarified the relay loadability issue in Requirement R3, part 3.3.3 by stating how these are handled in the simulations when these limits are exceeded. **R3.3.3**. Trip Transmission elements when relay loadability limits are exceeded	

Organization	Comments for Question 1
2. The SDT agrees that evaluation of construction sequences would have to be performed in order to successfully model outages as required. 3. The SDT agrees that this requirement may not be exclusively sources supplying Load. As an example, Demand Side-Management (DSM) may be used. The SDT has made a clarifying change to Requirement R1, part 1.1.6 based on industry comments. **R1, part 1.1.6** - Resources (supply or demand side) required for Load 4. The SDT believes that the "base case conditions" should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested. 5. Since Measure M1 states that either electronic OR hard copy format is required, the SDT believes that no changes are required since either of the formats is acceptable. An example of a hard copy of a system model is having printouts of each individual bus showing Load, Transmission line, generator, capacitors, etc., connected to that bus with associated impedances, ratings, etc. 6. The SDT believes that both the Transmission Planner and Planning Coordinator have this responsibility. Therefore, the SDT believes that the existing language is adequate and that no changes are required.	
TIS	The six month limitation of requirement 1.1.2. "Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months." Is is applicable to near-term and long-term Planning studies, but makes the new TPL-001 standard non-extensible to the near-term operational planning studies (next month, next week, or next day). During near-term operational planning periods, it is essential to include the impacts of ALL known outages in the operational analysis.It should be made clear that the TPL-001 Standard is not applicable to the Operational Planning Horizon. This points out the need for a separate (but equal in scope) operational planning analysis standard. There appears to be a double-jeopardy issue related to relay loadability and protection system redundancy. Relay loadability is handled in greater detail (as it should be) under the proposed PRC-023 standard, so any reference here should only be a placeholder. Similarly, the issues of redundancy are being addressed in more detail in a new proposed standard on protection system reliability.
Response: 1. The SDT agrees that this standard does not apply to the operating planning horizon. See the NERC TOP standards, as an example, for additional information concerning operational planning. 2. As for the double jeopardy comment - From the ERO Rules of Procedure, Appendix 4B- Sanction Guidelines, Section 3.10 Multiple Violations: "Strictly speaking, NERC or the regional entity can determine and levy a separate penalty or sanction, or direct remedial action, upon a violator for each individual violation. However, in instances of multiple violations related to a single act or common incidence of noncompliance, NERC or the regional entity will generally determine and issue a single aggregate penalty, sanction, or remedial action directive bearing reasonable relationship to the aggregate of the related violations. The penalty, sanction, or remedial action will not be that determined individually for the least serious of the violations; it will generally be at least as large or expansive as what would be called for individually for the most serious of the violations." 3. The TPL draft is silent on the issue of redundancy. However the SDT has clarified the relay loadability issue in Requirement R3, part 3.3.3 by stating how these are handled in the simulations when these limits are exceeded. **R3.3.3**. Trip Transmission elements when relay loadability limits are exceeded	

Organization	Comments for Question 1
TVA System Planning	TVA agrees with the changes made in R1 - especially the minimum 6 month duration required for outages to be modeled.In R1.1.5, how should partial path transmission service be accounted for in the known commitments for firm transmission service and interchange? VSL: In the Moderate and Severe VSL, insert "responsible entity's" in front of the term "System model" after the "or".

Response: 1. The SDT believes that you should plan for known commitments. Therefore, the part of the partial path that is known should be modeled.

2. The SDT agrees and will insert this additional wording in the moderate and severe VSLs for R1.

R1 VSL	The responsible entity's System model failed to represent one of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.	The responsible entity's System model failed to represent three of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1.

American Transmission Company	We propose the following changes and questions: R1 We interpret that "within their respective areas" refers the geographic footprint of the TP or PC transmission system. We propose clarifying that "within their respective area" does not require the inclusion of remote generation or load (metering) buses that are within the declared Balancing Authority area, but may be outside and separate from the TP or PC geographic footprint. R1.1.2 We suggest that this requirement be removed because the "known outage(s)" are only to be included in the models when P1 events are simulated, as specified in R2.1.3. We suggest that the intent of this requirement can be more simply handled by stating in R2.1.3 that "known outages be simulated along with P1 events for the System peak or Off-Peak conditions when the outages are scheduled to occur". R1.1.3 Add the qualification of "for the years defined in R2". R1.1.6 We interpret that "Resources required" allows the inclusion of fictional generators in the models when they are needed to

Organization	Comments for Question 1
	make future normal system cases solve. If this is not the intended interpretation, then we suggest modifying the wording to make the desired interpretation more clear. M1 " Revise M1 to indicate that each responsible entity must provide evidence with the added qualification, ". . . it is maintaining System models within its respective area, using the latest . . ."
Response: 1. The SDT believes that the "within their respective area" does refer to the Transmission Planner's or Planning Coordinator's geographic footprint. The SDT does not believe that the proposed language adds any clarity. No change made. 2. The SDT disagrees since multiple outages may be taken during the same time period under Requirement R1, part 1.1.2. The SDT believes that all outages should be modeled to ensure the System reliability during the outage duration. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-Contingency. See Requirement R2, part 2.1.3 for additional details concerning studies required with known outages. 3. The requirements in TPL-001-1 are all inter-related so no change is required. 4. The SDT believes that this requirement includes any fictional generators that may be needed to match up generation and Load. The SDT has made a clarifying change to Requirement R1, part 1.1.6. **R1, part 1.1.6** - Resources (supply or demand side) required for Load 5. The SDT agrees that adding "within its respective area" would help clarify this measure. The SDT has modified Measure M1 to include this new language. **M1**. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within its respective area, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.	
PJM	Consider rewording R1.1 to, -Consistent with the desired year and season a system model shall represent-. This removes some ambiguity about what to include in each model. Possible confusion existed about the multitude of models and what needed to be in each of them. These words deal with each model separately.
Response: The SDT does not believe that the proposed language adds any clarity. No change made.	

2. Requirement R2 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: A number of Commenters requested clarification of on the use of past studies (Part 2.6) either as a supplement to or in place of the annual current year studies (in Parts 2.1 through 2.5). Many also requested that the requirements for Part 2.1 (Near-Term steady state studies) and Part 2.2 (Long-Term steady state studies) be changed from "annual current studies, supplemented by qualified past studies" to "annual current study or qualified past studies".

The SDT reviewed Requirement 2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the Near-Term and the Long-Term planning horizon, respectively. While the SDT envisions that the standard is flexible enough to allow the use of qualified past studies, the planning assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for the Near-Term Planning Horizon and one of the years in the Long-Term Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested.

A number of Commenters questioned the need for two distinct study years to support the planning assessment for the Near Term planning horizon, especially in areas with very low Load growth. They requested reducing the requirements for annual current studies to one study to support the Near-Term planning horizon.

The SDT reviewed the requirements and declines to change to one Near-Term study. Load growth may not be the only determination factor for System performance; other examples are addition or retirement of generation. The SDT therefore, believes that, as a minimum to support reliability, Transmission plans are needed for the time frame just after operation planning (Year One or year two), as well as the time frame at the end of the Near-Term (year five) to allow implementation of solutions, which may require longer lead time.

Many Commenters requested clarification of the Load level(s) to be used in an "off-peak" case. One Commenter explained that the NERC glossary defines Off-Peak as those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand and On-Peak as those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of higher electrical demand. Therefore, the Commenters pointed out that Off-peak can be ANY Load level less than peak, and, as such, can be confusing.

The SDT notes that the intent of Parts 2.1.2 and 2.4.2 is to assess those System conditions during periods with lower Load levels than peak when the System may show different potential problems than during periods with peak Load level. For example, during light Load conditions, there may be high voltage problems because of the charging in the lightly loaded lines. There could also be thermal overload problems for areas with more generation than Load. The System could have less damping and could result in potential Stability problems. For this reason, it would not be appropriate to eliminate the

requirement to investigate Off-Peak steady state conditions. At the same time, the standard should not be overly prescriptive; therefore, the exact System Off-Peak Load should be specified by the entity performing the study.

Commenters also questioned the need for Off-Peak studies because the System Off-Peak is more likely a Stability issue than a steady state issue, and if System Off-Peak becomes a steady state issue, it can be mitigated through generation re-dispatch. Three Commenters also suggest moving Part 2.1.2 to Part 2.1.4 and treating it as one of the sensitivity analyses.

Based on the need to assess System conditions during periods of lower Load, the SDT believes that it would not be appropriate to move the studies of Off-Peak Load conditions from Parts 2.1.2 or Part 2.4.2 to be included in the sensitivity studies required in Parts 2.1.4 or 2.4.3. Sensitivity studies only need to cover one of the six conditions included in the bullets, and this may not be the one selected by the entity, resulting in no study of Off-Peak conditions being performed.

Many Commenters suggested clarification that for Part 2.1.3 it must be clear that the reference to outage schedules as listed in Part 1.1.2 (which requires modeling of known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months) must be limited to the planning horizon.

Part 2.1.3 is a sub-part of Part 2.1 which is limited by the Near-Term Transmission Planning Horizon so no change is made.

One Commenter suggested that Part 2.1.3 is not needed if the outages in Part 1.1.2 are properly built into the model. Three Commenters suggested clarifying changes.

Part 2.1.3 codifies studies needed to support the Planning Assessment. The SDT intends for Part 2.1.3 to cover known long duration outages, for example, taking a 230 kV Transmission line out of service to rebuild it to operate at 500 kV. These cases are to simulate System conditions with the Facility in question out of service as Category P0 (or N-0). For the next outage, the System performance will need to meet requirements for Category P1. This is not the same as requirements for Category P6, which assumes that the outage for the first Facility would be of shorter duration than 6 months. To provide greater clarity, Part 2.1.3 has been revised.

Many Commenters expressed concerns that the use of the words and phrases, “credible”, “sufficient”, “stressed” conditions and “measurable change” may be too vague for compliance. Many Commenters also state that to include and define sensitivity cases and simulations in the standard, the base case assumptions to be used in the assessments must also be defined.

The SDT notes that it envisions that “credible”, “sufficient”, “stressed” conditions and “measurable change” are to be defined by the responsible Planning Coordinator or Transmission Planner because each System is different. Likewise, the SDT believes that the “base case conditions”, on which to base the sensitivity cases should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies.

Some Commenters suggested removing the last bulleted item in the list under Part 2.1.4. (Duration or timing of planned Transmission outages).

The SDT declines to remove the last bullet in Part 2.1.4, "Duration or timing of planned Transmission outages" as a potential sensitivity. The intent of this bullet item is to cover unexpected changes in plans, for example, a potential delay in returning a Transmission line back to service after a planned outage of 6 months or more for rebuilding to a higher capacity line. In this case, the System with the equipment in question out of service would be modeled as P0 (or N-0). For the next outage, the System performance will need to meet requirements for Category P1 and not P6.

Many Commenters also asked whether the (bulleted) list of potential sensitivities in Parts 2.1.4 and 2.4.3 should be the same. Many also expressed concern that Part 2.1.4 (as well as Part 1.1.4) seems to require forecasting reactive Load when most entities forecast demand (MW) and apply a power factor(s) to calculate reactive Load.

The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within Parts 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and Stability evaluations, respectively. Part 1.1.4 and Part 2.1.4 state that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast.

Two Commenters would like clarification that the sensitivity findings do not obligate the Planning Coordinator or Transmission Planner to establish Corrective Action Plans.

The SDT notes that Part 2.7 states, in part, that "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. In addition, Part 2.7.2 describes the requirement on Corrective Action Plans to "Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary".

Some Commenters suggested clarifying changes to the first sentence in Parts 2.1.4 and Part 2.4.3 from "impact of changes to the basic assumptions used in the model for the list of items below", to "impact of change to the basic assumptions used in the model". For Part 2.4.3, a number of Commenters also suggested a workshop to clarify some of the requirements.

The SDT modified Parts 2.1.4 and 2.4.3. The SDT agrees that a workshop is a good idea. However, because of differences in each Region/Interconnection, the SDT encourages the Regions to hold workshops on issues specific to the Regions utilizing SDT members as participants in the discussions.

Some Commenters expressed concerns that Part 2.1.5 may require entities to have a spare equipment strategy, about the amount of added work, and that it may be redundant with Categories P2, P3, or P6 in Table 1. One Commenter was concerned that this requirement may be difficult for entities such as the Planning Coordinator, who may not own or manage the Transmission equipment or the spare strategy.

The SDT notes that Part 2.1.5 only requires that the Planning Coordinator and the Transmission Planner plan for the potential unavailability of long lead time major Transmission equipment in accordance with its spare equipment strategy. For example, if an entity's spare equipment strategy is to have a spare transformer on site, then the unavailability of a similar transformer

(due to outages) would be limited to the time it would take to energize the spare transformer. Assuming that this time is no more than that required to return a similar outaged transformer back to service, Part 2.1.5 can be satisfied without performing additional planning studies. If on the other hand, the transformer would have to be purchased, then it would take more than a year to replace. In this case, for Part 2.1.5, P0 should be modeled with the transformer in question out of service. The performance requirements in Table 1 will apply for the next single Contingency. This is not the same as P2 or P6; both of which are events starting from System intact condition as P0. It is also not the same as P3, which covers loss of a generator as the first event, and Part 2.1.5 covers loss of a piece of major Transmission equipment for which there is no spare. In addition, the Planning Coordinator does not have to own or manage the Transmission equipment or the strategies, it only needs to know the strategy and take it into account in selecting the appropriate Contingencies to study and plans for the potential unavailability of long lead time major Transmission equipment. It also does not preclude a Transmission Planner from coordinating its spare equipment strategy with others.

Some Commenters state that the requirement is not clear as to whether a Corrective Action Plan is required for those pieces of long lead time equipment without spares. Others believe that the Corrective Action Plans should allow actions such as, "out of merit dispatch", "operational restrictions", and "System reconfiguration" if the System cannot meet performance requirements without the facility in service.The SDT notes that Part 2.1.5 is part of Requirement 2, for which a Corrective Action Plan would be required. As stated in Part 2.1.5, the corrective actions should, as a minimum, allow reliable operations for categories P0, P1, and P2 during the times when the equipment is expected to be unavailable. The SDT also believes that the concern of allowing actions such as, "out of merit dispatch", "operational restrictions", and "System reconfiguration" to be part of the Corrective Action Plan has already been addressed. These actions are allowed in Part 2.7.1 on Corrective Actions.

One commenter seeks clarification on the study requirements for Part 2.1.5 during the time period in which the spare was put in service and no spare would be in place.

The SDT notes that Part 2.1.5 does not address the specific requirements of an individual plan. Since a Planning Assessment is required annually, the analysis required under Part 2.1.5 is an annual requirement. The answer to the specific example would depend on a variety of factors, including the timing of the failure, the length of time that it would take to replace the spare, your Operation Planning time horizon and the specifics of your individual spare equipment strategy. In addition, to provide greater clarity, the SDT has revised the first sentence of Part 2.1.5.

A number of Commenters suggested that Part 2.3 be modified to state that it is up to the planner to determine the year of study within the Near-Term Transmission Planning Horizon.

The SDT notes that Part 2.3 is silent on the year of study within the Near-Term Transmission Planning Horizon. Therefore, it is up to the Transmission Planner or Planning Coordinator to select the study years most suited to the System in question. In addition, Part 2.3 only requires an annual Planning Assessment, which is to be supported by annual current or qualified past studies.

A number of Commenters asked why there is no requirement stipulating short-circuit analysis for the long-term horizon. Another Commenter asked why there is no requirement for short circuit studies similar to Requirement R3 for steady state studies or Requirement R4 for Stability studies.

The SDT notes that Part 2.3 is for short circuit assessment of the System in general and is more suited for the near-term planning horizon, when Transmission plans are more certain. Lead time to implement a corrective action if found necessary can reasonably be expected to be completed in the near-term time frame. Short circuit study for the longer term planning horizon should be studied on a case by case basis associated with specific project(s). In addition, the SDT does not believe a requirement to cover short circuit studies similar to Requirement R3 or Requirement R4 is required. The SDT's intent was that while the standard requires short circuit results to be included in the assessment, it does not need to address the technical requirements for completing the short circuit study as that may be entity specific.

Some Commenters questioned the need for short circuit studies to be required in this standard since Short circuit analysis is a local issue. The reliability of the BES does not depend on the regular assessment of short circuit duty. In addition, the effects of the failure of over-stressed breakers are already included in the events listed in Table 1: for example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault).

The SDT states that Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt. Even though the effects of short circuit capability are localized and may be related to new planned Facilities, it is important to BES reliability.

A number of Commenters requested that the SDT clarify Part 2.4.1 as to when "Load models considering induction motors" are required. They requested limits or thresholds to provide Load models based on areas that have Stability limits or issues and based on Loads capable of significantly impacting voltage Stability. This is so that areas that don't have large motors or Stability issues should not be required to add unnecessary Load modeling.

The SDT declines to add specifics on Load modeling requirements because such specificity needs to be determined by the entity performing the study. Part 2.4.1 allows the use of "an aggregate System Load model which represents the overall dynamic behavior of the Load". All areas including those that do not have large motors can use an appropriate aggregate System Load model.

One Commenter asked if Part 2.4.2 should include requirements for dynamic Load models, considering the behavior of induction motor Loads.

The SDT reviewed Parts 2.4.1 and 2.4.2. In Part 2.4.1 the SDT specifies the dynamic Load model representation for on peak because the System voltages are generally lower during on peak. The percentage of motor Load, e.g., in air conditioners, could significantly increase reactive power requirements especially when they stall due to low System voltage and can therefore impact dynamic System performance on-peak. However, motor Load would likely not pose the same problem during off-peak as the System voltages are usually higher. So, in Part 2.4.2, it can be left to the discretion of the Planning Coordinator or Transmission Planner whether the dynamic motor Load would need to be represented per the requirement in Part 2.4.1.

Some Commenters requested clarification as to whether the language in Part 2.5 "proposed generation additions and changes" should also include Transmission additions and changes.

The SDT intends for Part 2.5 to require investigation of Stability issues due to addition of generators, not system stability issues in general. The SDT does not believe that, in general, a Stability assessment is needed for the Long-Term Planning Horizon. The System model for that time frame is too uncertain for a meaningful assessment of the System's stability. However, for those situations where a specific generator is planned to be added in that time frame, the SDT believes that it will be appropriate to require that the generator's Stability impact be evaluated.

A number of Commenters request clarification on the phrase "material change", which could impact whether a past study can be used to support a current-year assessment.

The SDT notes that Part 2.6.2 also allows an entity to rely on a past study with a material change if "a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area". Therefore, it is up to the entities performing the study to provide the rationale based on changes, such as Load growth.

Some Commenters requested clarification of the intent of the Corrective Action Plan and whether projects added in the Corrective Action Plan should be modeled in subsequent years when assessing System performances.

The SDT believes that Part 2.7 requires a Corrective Action Plan to be developed "when the analysis indicates an inability of the System to meet the performance requirements in Table 1". Therefore, the intent is to address situations where simulation and the application of currently planned projects and procedures are insufficient to meet the performance requirements. If a project is added to the Corrective Action Plan, it should be included as part of the study assumptions based on the criteria Planning Coordinator's and Transmission Planner's use for inclusion of such planned projects, and clearly identified as an assumption for the annual assessment as required in Requirement R2 until it is in service or shown to be no longer needed. Two Commenters observed that Part 2.7 seems to have lost the reference to lead times for Corrective Action Plan(s) that were present in the existing TPL-001-0, TPL-002-0, and TPL-003-0 standards and requested to include in the standard some indication of when activity needs to start to implement the Corrective Action Plan. The SDT notes that the NERC Glossary of Terms defines Corrective Action Plan as "A list of actions and an associated timetable for implementation to remedy a specific problem. Also, Part 2.7.4 requires that the CAP be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures. By including the timing of needed action and requiring such reviews in subsequent assessments, any deficiencies, if not adequately addressed, will become violations. Therefore, the SDT believes that this concern has been addressed.

A majority of Commenters objected to the inclusion of Part 2.9 because it is not reliability related and does not address a performance oriented issue but is rather an information gathering exercise, and suggested that this requirement be deleted.

The SDT agrees with the Commenters as to the nature of the requirement. The SDT also reviewed FERC Order 693 and observed that it directs the ERO to consider including this effort in the standard development process. The SDT has tried through several postings but industry pushback is still significant that this doesn't belong in a standard. The SDT decided that

this effort should best be continued through a NERC data gathering request. The data gathered can then be used in a future revision of this standard.

The following changes were made to the standard requirements due to industry comments:

Requirement R2, part 2.1.3: P1 events in Table 1 with known outages modeled, as in Requirement R1, part 1.1.2 under those System peak or Off-Peak conditions when known outages are scheduled.

Requirement R2, part 2.1.4: For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

Requirement R2, part 2.1.5: When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Requirement R2, part 2.3: The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

Requirement R2, part 2.4: The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, part2.6. The following studies are required:

Requirement R2, part 2.4.3: For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

Requirement R2, part 2.4.3, bullet #1: Load level, Load forecast, or dynamic Load model assumptions

Requirement R2, part 2.4.3, **bullet #3**: Expected in service dates of new or modified Transmission Facilities

Requirement R2, part 2.5: The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, part 2.6.

Requirement R2, part 2.6.2: For steady state, short circuit, or Stability analysis: the System represented in the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

Requirement R2, part 2.7: For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

Requirement R2, part 2.7.1, bullet #4: Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.

Requirement R2, part 2.9:

Table 1, footnote 1: If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.

Requirement R2, data retention: The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.

Organization	Comments for Question 2
Independent Electricity System Operator	(1) Part 2.1.4: We do not believe the sentence: To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. is necessary or measurable. The first part of 2.1.4 already stipulates sufficient details for the responsible entity to conduct sensitivity analysis including the parameters to be varied. Adding the "how-to conduct" requirement is overly prescriptive and unnecessary, and the condition for "that demonstrate a measurable change in performance" is not measurable. It lacks a definitive target or direction for the responsible entity to determine (a) what conditions need to be attained to demonstrate a measurable change in performance, (b) what constitutes "measurable change in performance", and (c) what follow-up or corrective actions are needed to address the adverse performance as a result of stressing the system beyond the forecast conditions. In our comments on Draft 1, we disagreed with the requirement to conduct sensitivity testing. This is part of the analysis exercise that planners normally perform to help them identify critical parameters/conditions for consideration in planning assessments and in developing remedial plans. Having a reliability requirement to stipulate the details of sensitivity analysis is unnecessary but produces much increased work whose acts are difficult to measure and whose results are not taken any further to arrive at a useful outcome. Once again, we urge the SDT to consider dropping this requirement. (2) Part 2.3 stipulates the short-circuit assessment requirements for the near-term horizon. Unlike its steady-state and stability counterparts, there are no requirements stipulated for short-circuit analysis for the long-term horizon. Is this intentional? If so, we are unable to identify the rationale for this decision. If not, we suggest revising Part 2.3 to: The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the near-term and long-term Transmission Planning Horizons

Organization	Comments for Question 2
	and can be supported by. (3) R2.4.1: We believe that "considering the behavior of induction motors" is not necessary since the wording "a Load model which represents the dynamic behavior" already covers this. (4) In part 2.5, we recommend inserting the text "and Transmission Facilities" after "generation" to be consistent with the wording of part 2.3 (5) As drafted, the VLSs do not address missing certain combinations of parts of Requirement R2. For example, the condition assigning a Low, Moderate or High VSL is the failure of one of the parts listed under these columns. There is no assignment for failing more than one of the listed parts. We propose adding a second condition under the High VSL as follows: OR two or more of parts 2.3, 2.6, 2.8 and 2.9.. Also, part 2.5 is missing from the SEVERE VSL. We recommend including it. As written, it is possible to miss say parts 2.1 and 2.5 and still not be captured under the Severe VSL if that is the intent.
Response: For Part 2.1.4, The SDT envisions that stressed conditions and "measurable change" are to be defined by the responsible Planning Coordinator or Transmission Planner. Part 2.7 states, in part, that "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. In addition, Part 2.7.2 describes the requirement on corrective action plans to "Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary". No change made. Part 2.3 is for short circuit assessment of the System in general and is more suited for the near-term planning horizon, when Transmission plans are more certain. Lead time to implement corrective actions if found necessary can reasonably be expected to be completed in the near-term time frame. Short circuit studies for the longer term planning horizon should be studied on a case by case basis associated with specific project(s). Therefore the SDT declines to make the change as suggested. For Part 2.4.1, the clause "considering the behavior of induction motor Loads" is a clarification of the intent of this Requirement. Therefore, the SDT declines to make the change. Part 2.5 is intended for investigation of Stability issues due to addition of generators. The SDT does not believe that, in general, a Stability assessment is needed for the Long-Term Transmission Planning Horizon. The System model for that time frame is too uncertain for a meaningful assessment of the System's Stability. However, for those situations where a specific generator is planned to be added in that time frame, the SDT believes that it will be appropriate to require that the generator's Stability impact be evaluated. The SDT reviewed the VSL assignments and believes that as written they are as intended. In assigning the VSLs the SDT considers the potential lead time to implement the corrective action as well as the impact of non-compliance. Parts 2.1, 2.2, 2.4, and 2.7 cover the basics of planning activities and the lead time to implement the Corrective Action Plan can be longer than the near term planning horizon. As such, failure to comply with two of more of these parts can severely impact future System reliability. Part 2.5 covers long term Stability analysis, corrective actions would likely involve addition of dynamic voltage support, which can reasonably be expected to be implemented within the near term horizon.	
ERCOT ISO	* Requirement R2 (and throughout the standard) What is meant by "its portion of the BES"? Will any agreements made in R7 override the "each TP and PC" requirement? To clarify this, the requirement could be rephrased: "In accordance to the responsibilities assigned in R7, the responsible Transmission Planners and Planning Coordinators shall prepare?"* Requirement 2.1.3: This is not needed if these outages are properly built into the model.

Organization	Comments for Question 2
	* Requirement 2.1.4: This requirement applies to 2.1.1 and 2.1.2. Why does it omit 2.1.3? Should it be referring to 2.1.3 for P1 contingencies? * How will 2.1.4 be proven? What is the definition of “stress” in this context and what defines “sufficient” stress? What is “measureable change”? What is the expected response to the results of this analysis? For example, if the load forecast must double to “sufficiently” stress the system, is the expectation that facilities should be planned to respond to the stress? * Requirement 2.1.5: Including the spare equipment strategy will be difficult for a PC that doesn’t own or manage the transmission equipment or the strategies. But if this inclusion is only done by a TP, the benefits of coordinating with other TPs may not be realized. * Requirement 2.2: If each entity is responsible to study the System peak Load of its area, but a PC is responsible for multiple TP systems, then what System Peak Load is the PC responsible to study “ a model that includes the non-coincident peaks of all of the TP systems for which it is responsible or the coincident peak demand across the whole system for which the PC is responsible” * Requirements 2.4.1 and 2.4.2: These appear to have inconsistent references to defined terms. Should this be consistent? The NERC glossary states: "Off-Peak: Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand.""On-Peak: Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of higher electrical demand.""System: A combination of generation, transmission, and distribution components."* Requirement 2.6.2: Reads as if a change is being made to an existing study. It is confusing. Possibly restate: "2.6.2 For steady state, short circuit, or stability analysis: previous studies can be used only if a material change to the system has not occurred or if a change that did occur does not impact the study area." * Requirement 2.7: in each case throughout the standard, replace “planning events” with “planning events as defined in Table 1” and “extreme events” with “extreme events as defined in Table 1” * Requirement 2.7.2: It would be good to clearly state here or in 2.1.4 that results from stressing the system do not always need to be resolved.

Response: BES can cover the entire region or Interconnection. “Its portion of the BES” limits the accountability to only the portion for which the Planning Coordinator or Transmission Planner is responsible. Requirement R7 requires that the Planning Coordinator and Transmission Planner’s coordinate and delineate their individual responsibilities within their portions of BES if there are any overlaps. Therefore the SDT declines to make the change.

Part 2.1.3 codifies studies needed to support the Planning Assessment and as such must be retained.

Parts 2.1.1 and 2.1.2 are “normal” System conditions. Part 2.1.3 covers P1 Contingencies with known long duration outage of a Facility included as Category P0. Therefore, the standard does not require sensitivity studies on top of P1 outage events as specified in Part 2.1.3. However, the standard does not preclude applying Part 2.1.4 to Part 2.1.3.

For Part 2.1.4, The SDT envisions that stressed conditions and “measurable change” are to be defined by the responsible Planning Coordinator or Transmission Planner.

For Part 2.1.5, the Planning Coordinator does not have to own or manage the Transmission equipment or the strategies, it only needs to know the strategy and take it

Organization	Comments for Question 2
	into account in selecting the appropriate Contingencies to study. Part 2.1.5 does not require that each entity has a spare equipment strategy; only that it plans for the potential unavailability of long lead time major Transmission equipment. It also does not preclude a Transmission Planner from coordinating its spare equipment strategy with others. For Part 2.2, the intent of the System peak Load case is to model the System conditions at the time of Peak Demand of the System for which an entity is responsible. Therefore, this case should model the coincidental peak of the System. However, the standard does not preclude the Planning Coordinator from also studying System conditions at higher Load levels, such as the non-coincident peak. For Parts 2.4.1 and 2.4.2, the NERC Glossary defines "Peak Demand" as: "1. The highest hourly integrated Net Energy For Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year). 2. The highest instantaneous demand within the Balancing Authority Area." NERC also defines Load as, "An end-use device or customer that receives power from the electric system." The draft Standard uses "System peak Load" to refer to the System conditions when the Load level is at the Peak Demand of the System being studied; and "Off-Peak Load" to refer to those System conditions when the Load level is lower. For assessing System performance, reasonably adverse System conditions should be modeled. Part 2.6.2 is governed by Part 2.6, which states: "Past studies may be used to support the Planning Assessment if they meet the following requirements". Therefore the SDT believes that the proposed change does not add clarity and has already been covered. Furthermore, the proposed change would introduce confusion in Part 2.6.1, which is also governed by Part 2.6. Planning event appears once in Requirement R2: Part 2.7 begins with "For planning events shown in Table 1". The SDT cannot find "extreme events" in requirement R2. Therefore, the SDT was not clear on the issues being raised. Since the language used has the same intent as the proposed change, no change was made. Part 2.7 states, in part, that "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. In addition, Part 2.7.2 describes the requirement on Corrective Action Plans to "Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary". The SDT believes that this concern is covered in the existing draft.
Bonneville Power Administration	: The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies " It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most

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	entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.
Response: The SDT reviewed Requirement 2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the Near-Term and the Long-Term Transmission Planning Horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested. The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within Parts 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and stability evaluations, respectively. **Requirement R2, part 2.4.3**, **bullet #3**: Expected in service dates of new or modified Transmission Facilities Parts 1.1.4 and 2.1.4 state that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast	
Northeast Utilities	[R2.1] The language of this requirement should be revised as follow: The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required: [R2.1.2] Please clarify the load level to be used for "System Off-Peak Load". [R2.1.4] To include and define sensitivity cases and simulations in the standard NERC must also define base cases to be used in the assessments. Refer to comment suggesting the addition of Requirement R1.1.7. [R2.1.5] It is not clear whether a corrective action plan should be developed for this requirement and if we are to develop an action plan should it be temporary and cover only the time period that the major Transmission equipment was unavailable? [R2.2] The language of this requirement should be revised as follow: The long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required: [R2.3] Please provide guidance as to what year should be represented when performing short circuit studies or is it up to the Planner to select a year for the study? [R2.5] There is no guidance on the load level that should be used for the long-term stability study as is required by Requirement R2.2.1 for the Steady State assessment. [R2.9] Why the need to report the largest Consequential Load Loss since the TPL Standard does not limit the amount of Consequential Load that could be allowed? We recommend that this requirement should be deleted.

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Response: The SDT reviewed Requirement 2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the Near-Term and the Long-Term Transmission Planning Horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study will be performed. Therefore, the SDT declines to make the change as suggested. The intent of Part 2.1.2 is to assess those System conditions during periods with lower Load levels than peak when the System may show different potential problems than during periods with peak Load level. For example, during light Load conditions, there may be high voltage problems because of the charging in the lightly loaded lines. There could also be thermal overload problems for areas with more generation than Load. For this reason, it would not be appropriate to eliminate the requirement to investigate Off-Peak steady state or Stability conditions. At the same time, the standard is not intended to be prescriptive; therefore, the exact System Off-Peak Load can be specified by the entity performing the study. For Part 2.1.4, the SDT believes that the "base case conditions", on which to base the sensitivity cases should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested. The Corrective Action Plan is covered in Part 2.7 for planning events shown in Table 1 "when the analysis indicates an inability of the System to meet the performance requirements in Table 1". For Part 2.1.5, the corrective action should, as a minimum, allow reliable operations for categories P0, P1, and P2 during the times when the equipment is expected to be unavailable. For Part 2.2, while the SDT envisions that the standard is flexible enough to allow the use of qualified past studies; the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of basic planning process, the SDT believes that the steady state portion of the studies should be done annually covering one of the years in the Long-Term Transmission Planning Horizon. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire Long-Term Transmission Planning Horizon. Making the change as requested in Part 2.2 can result in no current-year study being performed for the Long-Term Transmission Planning Horizon. Therefore, the SDT declines to make the change as suggested. Part 2.3 is silent on the year of study within the Near-Term Transmission Planning Horizon. Therefore, it is up to the Transmission Planner or Planning Coordinator to select the study years most suited to the System in question. In addition, Part 2.3 only requires an annual Planning Assessment, which is to be supported by annual current or qualified past studies. For Part 2.5, the stressed conditions for Stability are often System specific. The intent is to allow the entity performing the Stability study, which is most knowledgeable about its System, to determine the System conditions, including Load levels, on which to perform the assessment. Part 2.9 has been deleted as suggested.	
Central Maine Power Company	2.1.3 In the event that R1.1.2 is kept it must be clear that the reference to outage schedules as listed in part 1.1.2 must be limited to the Planning Horizon. Table 1 There is confusion in interpretation of the table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to

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	shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading? 2.1 Language should be revised similar to R2.4 as follows: The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required: 2.1.2 Should be moved to the list of sensitivities currently in 2.1.4. (Off-peak needs to be more specifically defined). 2.1.4 Consistent with the suggestion made for section 1.1.2 please remove the last bulleted item in the list under section 2.1.4. Duration or timing of planned Transmission outages. 2.2 The language in 2.2 should be revised to be similar to 2.4 as follows: The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required: 2.3 This should be modified to state that it is up to the Planner to determine the year of study within the Near Term Transmission Planning Horizon. 2.4.2 This should be deleted as it is covered under section 2.4.3. 2.4.3 To define a sensitivity, NERC must define base assumptions. 2.7 We suggest changing the word “run” to “condition” such that it reads “Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity condition in accordance with Requirements R2, parts 2.1.4 and 2.4.3.” 2.9 The requirement to report the largest single consequential load loss under Requirement 2.9 should not be included in the standard. The TPL does not limit the size of the consequential load loss. If it remains, it must be made clear that it be applicable only to Year One or Year Two.
ISO New England	2.1.3: In the event that R1.1.2 is kept it must be clear that the reference to outage schedules as listed in part 1.1.2 must be limited to the Planning Horizon. Table 1 - There is confusion in interpretation of the table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading 2.1 Language should be revised similar to R2.4 as follows: “The Near-Term Transmission Planning Horizon portion of the steady stateanalysis shall be assessed annually and be supported by current or past studies as indicated inRequirement R2, part 2.6. The following studies are required:”2.1.2 Should be moved to the list of sensitivities currently in 2.1.4. (Off-peak needs to be

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	more specifically defined). 2.1.4 Consistent with the suggestion made for section 1.1.2 please remove the last bulleted item in the list under section 2.1.4. "Duration or timing of planned Transmission outages." To define a sensitivity, NERC must define base assumptions. Refer to Comment on Proposal to add an item 1.22.2 The language in 2.2 should be revised to be similar to 2.4 as follows: "The Long-Term Transmission Planning Horizon portion of the steady stateanalysis shall be assessed annually and be supported by current or past studies as indicated inRequirement R2, part 2.6. The following studies are required:"2.3 This should be modified to state that it is up to the Planner to determine the year of study within the Near Term Transmission Planning Horizon. 2.4.2 This should be deleted as it is covered under section 2.4.3. 2.4.3 To define a sensitivity, NERC must define base assumptions. Requirement 2.7 We suggest changing the word "run" to "condition" such that it reads "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity condition in accordance with Requirements R2, parts 2.1.4 and 2.4.3." 2.9: The requirement to report the largest single consequential load loss under Requirement 2.9 should not be included in the standard. The TPL does not limit the size of the consequential load loss. If it remains, it must be made clear that it be applicable only to Year One or Year Two.
United Illuminating	2.1.3: In the event that R1.1.2 is kept it must be clear that the reference to outage schedules as listed in part 1.1.2 must be limited to the Planning Horizon. Table 1 - There is confusion in interpretation of the table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading? 2.1 Language should be revised similar to R2.4 as follows: "The Near-Term Transmission Planning Horizon portion of the steady stateanalysis shall be assessed annually and be supported by current or past studies as indicated inRequirement R2, part 2.6. The following studies are required:"2.1.2 Should be moved to the list of sensitivities currently in 2.1.4. (Off-peak needs to be more specifically defined). 2.1.4 Consistent with the suggestion made for section 1.1.2 please remove the last bulleted item in the list under section 2.1.4. Duration or timing of planned Transmission outages. To define a sensitivity, NERC must define base assumptions. Refer to Comment on Proposal to add an item 1.22.2 The

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	language in 2.2 should be revised to be similar to 2.4 as follows: The Long-Term Transmission Planning Horizon portion of the steady stateanalysis shall be assessed annually and be supported by current or past studies as indicated inRequirement R2, part 2.6. The following studies are required: 2.3 This should be modified to state that it is up to the Planner to determine the year of study within the Near Term Transmission Planning Horizon. 2.4.2 This should be deleted as it is covered under section 2.4.3. 2.4.3 To define a sensitivity, NERC must define base assumptions. Requirement 2.7 We suggest changing the word "run" to "condition" such that it reads "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity condition in accordance with Requirements R2, parts 2.1.4 and 2.4.3." 2.9: The requirement to report the largest single consequential load loss under Requirement 2.9 should not be included in the standard. The TPL does not limit the size of the consequential load loss. If it remains, it must be made clear that it be applicable only to Year One or Year Two.

Response: Part 2.1.3 is a sub-part of Part 2.1 which is limited by the Near-Term Transmission Planning Horizon so no change is made.

The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT's intent.

> **Table 1, footnote 1**: If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.

While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because Near-Term steady state analysis as required in part 2.1 is part of the basic planning process, the SDT believes that the steady portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire Near-Term Transmission Planning Horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested.

The intent of Part 2.1.2 is to support the assessment of those System conditions during periods with lower Load levels than peak when the System may show different potential problems than during periods with peak Load level. For example, during light Load conditions, there may be high voltage problems because of the charging in the lightly loaded lines. There could also be thermal overload problems for areas with more generation than Load. The SDT therefore disagrees that studies of Off-Peak Load should be included in sensitivity studies. Sensitivity studies only need to cover one of the six conditions included in the bullets and may not be the one selected by the entity, resulting in no study of Off-Peak conditions being performed. The exact System Off-Peak Load should be specified by the entity performing the study.

The SDT declines to remove the last bullet in Part 2.1.4, "Duration or timing of planned Transmission outages" as a potential sensitivity. The intent is to cover unexpected changes in plans, for example, a potential delay in returning a Transmission line back to service after a planned outage of 6 months or more for rebuilding to

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	a higher capacity line. In this case, the System with the equipment in question out of service would be modeled as P0 (or N-0). For the next outage, the System performance will need to meet requirements for Category P1 and not P6. For Part 2.1.4, the SDT believes that the "base case conditions", on which to base the sensitivity cases, should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because Long-Term steady state analysis as required in part 2.2 is part of the basic planning process, the SDT believes that the steady state portion of the studies covering one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire Long-Term Transmission Planning Horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested. Part 2.3 is silent on the year of study within the Near-Term Transmission Planning Horizon. Therefore, it is up to the Transmission Planner or Planning Coordinator to select the study years most suited to the System in question. In addition, Part 2.3 only requires an annual Planning Assessment, which is to be supported by annual current or qualified past studies. . The SDT declines to delete part 2.4.2 as it does not believe that Part 2.4.3 covers System conditions at Off-Peak Load level(s) as envisioned. The Sensitivity study only needs to cover one of the six conditions included in the bullets and may not be the one selected by the entity, resulting in no study of Off-Peak conditions. As in Part 2.1.4, for Part 2.4.3, the SDT believes that the "base case conditions" on which to base the sensitivity cases, should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. Part 2.7 has been changed to address your concerns. **Requirement R2, part 2.7**: For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Part 2.9 has been deleted as suggested.
MAPP	2.1.3: It must be clear that the reference to outage schedules as listing in part 1.1.2 must be limited to the Planning Horizon. There is confusion in interpretation of the Table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading? R2.1.4/R2.4.3 The terms "credible" and "measurable change" are ambiguous and not defined. Therefore, we suggest that these terms be defined or more clearly described to avoid the risk of different and possibly contradictory interpretations by TPs, PCs, and auditors.

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	R 2.1.5 - Spare equipment strategy. This appears to be more of a risk analysis than a simulation study requirement. If a simulation is required then it would appear that the PC/TP would need to rerun the entire system intact study with each "major transmission equipment "that is unavailable as a prior outage (i.e. for each generator, HVDC, SVC, XFMR) over the entire study parameters. How would this be evaluated? Is this not covered under P2 already? We also propose replacing the term "major Transmission" with "BES" because BES is a well defined term while "major Transmission" is not. R2.4.1 We recommend that the SDT clarify section 2.4.1 and when load models considering induction motors are required. The clarification should add limits or thresholds to provide load models based on areas that have stability limits or issues and to loads of substation size and having dynamic characteristic capable of significantly impacting voltage stability. Areas that don't have large motors or stability issues should not be required to add unnecessary load modeling. R2.6.2 Change "to demonstrate that System changes do no impact the performance results in the study area" to "to demonstrate that System changes do not significantly impact the performance results in the study area." 2.6.2 As written results in an unrealistic requirement to review every impact minor or large and determine which meets this item and which do not. The recommended change solves this problem. R 2.7 Corrective Action Plan: Is this not already apart of FERC Order 890? The PC may not be able to develop a CAP as they may not be the owners and would have no say about how a problem will be resolved. R 2.8.1 Suggest using a word other than "deficiencies" as it is associated with non-compliance. R2.9 ? We propose that this requirement be removed because annually stating the single, largest expected, Consequential Load Loss due to a P1 or P2 event in the TP or PC system is not needed to provide reliable BES performance or assure open and transparent Transmission planning peer review. In general, standards should not contain requirements that don't improve reliability.

Response: Part 2.1.3 is a sub-part of Part 2.1 which is limited by the Near-Term Transmission Planning Horizon so no change is made.

The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT's intent and it now reads:

> **Table 1, footnote 1**: If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.

For Part 2.1.4, The SDT envisions that credible stressed conditions and "measurable change" are to be defined by the responsible Planning Coordinator or Transmission Planner.

Part 2.1.5 only requires that the Planning Coordinator or Transmission Planner plans for the potential unavailability of long lead time major Transmission equipment in accordance with its spare equipment strategy. For example, if an entity's spare equipment strategy is to have a spare transformer on site, then the unavailability of a

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similar transformer (due to outages) would be limited to the time it would take to energize the spare transformer. Assuming that this time is no more than that required to return a similar outaged transformer back to service, Part 2.1.5 can be satisfied without performing additional planning studies. If on the other hand, the transformer would have to be purchased, then it would take more than a year to replace. In this case, P0 should be modeled with the transformer in question out of service. This is not the same as P2. The SDT declines to replace the term "major Transmission equipment" with "BES equipment" because the intent is to investigate the unavailability of major pieces of equipment in the Transmission System. Transmission is defined in the NERC Glossary as, "An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems". For Part 2.4.1, the SDT declines to add specifics, which includes "limits or thresholds to provide Load models based on areas that have Stability limits or issues and to Loads of substation size and having dynamic characteristic capable of significantly impacting voltage Stability" because such specificity needs to be determined by the entity performing the study. Part 2.4.1 allows the use of "an aggregate System Load model which represents the overall dynamic behavior of the Load". All areas including those that do not have large motors can use an appropriate aggregate System Load model. The SDT declines to make the change suggested in Part 2.6.2 because it did not add more clarity than the existing language. In Part 2.7, the responsibility for developing CAPs lies with both the Planning Coordinator & Transmission Planner regardless of ownership. A FERC Order is not a NERC Standard, and not subject to the NERC audit and enforcement procedures. The SDT declines to change the word "deficiencies" in Part 2.8.1. The SDT believes it is the most appropriate word to capture the SDT intent. Part 2.9 has been deleted as suggested.	
Oncor Electric Delivery	2.1.3: It must be clear that the reference to outage schedules listed in part 1.1.2 must be limited to the Planning Horizon. See the TIS comment tor R1. There is lack of clarity in the interpretation of certain rudiments of Table 1 When the voltage class of the contingency element and the monitored element are different (one is HV and the other is EHV), which voltage class is the allowance for shedding of non-consequential load applied? For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are there allowances to shed load to keep the 345-kV from exceeding its load rating. Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, would there be allowances to shed load to keep the 138-kV from exceeding its load rating 2.1 Language should be revised similar to R2.4 as follows: "The Near-Term Transmission Planning Horizon portion of the steady stateanalysis shall be assessed annually and be supported by current or past studies as indicated inRequirement R2, part 2.6. The following studies are required: 2.1.2 the term "off peak" is an issue. The definition just says less than peak. 2.1.4 Duration or timing of planned Transmission outages. In order to define a "sensitivity", NERC must define a base case. 2.1.5 There should be greater clarity to the fact that this is an assessment only, and not a solution. Actions such as "out of merit dispatch", "operational restrictions", "System reconfiguration" can be part of a Corrective Action Plan if the system cannot meet

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	performance requirements without the facility in service. 2.2 The language in 2.2 should be revised to be similar to 2.4 as follows: The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as indicated inRequirement R2, part 2.6. The following studies are required:2.3 The standard does not indicate a year to study. Is this the discretion of the Transmission Planner? [Review last comment/why doesn't this apply to stability?] 2.4.2 There should be greater clarity to the term "Off peak" Should the Transmission Planner have more discretion in selecting load level. Is there a need for this requirement? 2.4.3 To define a "sensitivity" a base case must be defined for comparison. Requirement 2.7 suggest changing the term "run" to "condition" in "Corrective Action Plan(s) does not need to be developed solely to meet the performance requirements for a single sensitivity run(?) in accordance with Requirements R2, parts 2.1.4 and 2.4.3. 2.7.2 See previous comments on sensitivities. 2.9: The requirement to report the largest single consequential load loss under Requirement 2.9 should not be included in the standard. If it remains, provide greater clarity that there is applicability only to Year One. Furthermore, additional clarification is needed to ensure that the requirement to report consequential load loss (single number) is ONLY for the most severe contingencies studied for the P1 and P2 contingencies. 2.9 ? Why is it necessary to identify the largest consequential load loss if the TPL standard does not limit the size of the consequential load loss?

Response: Part 2.1.3 is a sub-part of Part 2.1 which is limited by the Near-Term Transmission Planning Horizon so no change is made.

The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT's intent and it now reads:

> **Table 1, footnote 1**: If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.

Part 2.1 covers near-term steady state studies and Part 2.4 covers near-term Stability studies. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire Near-Term Transmission Planning Horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested.

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	The intent of Part 2.1.2 is to assess those System conditions during periods with lower Load levels than peak when the System may show different potential problems than during periods with peak Load level. For example, during light Load conditions, there may be high voltage problems because of the charging in the lightly loaded lines. There could also be thermal overload problems for areas with more generation than Load. Since such conditions can be case specific, the standard should not be overly prescriptive; therefore, the exact System Off-Peak Load should be specified by the entity performing the study. The last bullet in Part 2.1.4, "Duration or timing of planned Transmission outages" is intended to cover unexpected changes in plans, for example, a potential delay in returning a Transmission line back to service after a planned outage of 6 months or more for rebuilding to a higher capacity line. The SDT believes that your concern on Part 2.1.5 has already been addressed. Part 2.7.1 Corrective Action can include, among other things: ○ Installation, modification, or removal of Protection Systems or Special Protection Systems ○ Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations. ○ Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations. ○ Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan. ○ Use of rate applications, DSM, new technologies, or other initiatives. For Part 2.2, while the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of basic planning process, the SDT believes that the long-term steady state portion of the studies in Part 2.2 should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire long-term planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested. Part 2.3 is silent on the year of study within the Near-Term Transmission Planning Horizon. Therefore, it is up to the Transmission Planner or Planning Coordinator to select the study years most suited to the System in question. In addition, Part 2.3 only requires an annual Planning Assessment, which is to be supported by annual current or qualified past studies. The NERC glossary states: "Off-Peak: Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand." The intent is to assess those System conditions during periods with lower Load levels than peak when the System may show different potential problems than during periods with peak Load levels. For example, during light Load conditions, there may be high voltage problems because of the charging in the lightly loaded lines. There could also be thermal overload problems for areas with more generation than Load. The exact System Off-Peak Load should be specified by the entity performing the study. For part 2.4.3, the SDT believes that the "base case conditions" should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies involving long-term forecasts. Part 2.7 has been changed to address your concerns. **Requirement R2, part 2.7**: For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: For Part 2.7.2, see the responses above to your other comments.

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Part 2.9 has been deleted as suggested.	
FirstEnergy Corp	A. FirstEnergy disagrees with requirement R2 sub-part 2.1.1 requiring the annual completion of two near-term steady-state studies. We believe that on a yearly basis completion of one near-term study and one long-term study is sufficient to interpolate and extrapolate the results needed to cover the entire planning horizon. The team should keep in mind that the overall assessment will include qualified past studies to supplement the results for a more refined view of anticipated conditions. We request that the team revise the near-term annual study requirements to require completion of only one near-term steady-state study and allow the TP/PC flexibility in choosing the appropriate study year. B. In requirement 2.7.1 the team should consider collapsing the 3rd and 4th bullets into a more succinct single bullet that says "Installation or modification of automatic generation runback/tripping". The use of "manual" generation run-back should be accounted for in an Operating Procedure (5th bulleted item). The additional text on the existing 3rd and 4th bullets discussing "single or multiple contingency" is not needed as the text stated in the parent R2.7 text is sufficient. C. We concur with the team's removal of the overly prescriptive requirements to include "initiation dates" and "in-service dates" from the Corrective Action Plans. However, the team may want to ensure some aspect of timing is identified in the Corrective Action Plans. It is recommended that the team revise the text of sub-part 2.7.1 that precedes the bulleted list to read "List system deficiencies, associated actions needed to achieve required System performance and the timing of when the actions are needed"
Response: For Part 2.1.1, the SDT declines to change to one near-term study because as a minimum to support reliability, Transmission plans are needed for the timeframe just after operation planning (Year One or year two), as well as the timeframe at the end of the near-term (year five) to allow implementation of solutions, which may require longer lead time. The SDT reviewed Requirement R2, part 2.7.1 and found that it is clear as written. The SDT therefore declines to make the change. For Requirement R2, part 2.7.1, the NERC Glossary of Terms defines Corrective Action Plan as "A list of actions and an associated timetable for implementation to remedy a specific problem. Therefore, the suggested change to include "timing" is not needed.	
NERC Standards Review Subcommittee	Add R2.7.1 Item #7 The MRO NSRS proposes the addition of the following bullet item to R2.7.1, "Planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration of the Facility Ratings." because this explains what is allowed to be considered for Corrective Action Plan developments. [After bullet item #7 is added, Note "e" under "Steady State & Stability section of Table 1 should refer to R2.7.1.] R2.9" The MRO NSRS still proposes that this requirement be removed because annually stating the single, largest expected, Consequential Load Loss due to a P1 or P2 event in the TP or PC system is not needed to provide reliable BES performance or assure open and transparent Transmission planning peer review. In general, standards should not contain requirements that don't improve reliability. R2.4.1 The MRO NSRS recommends that the SDT clarify section 2.4.1 and when load models considering induction motors are required. The clarification should add limits or thresholds to provide load models based on areas that have stability limits or issues and to loads of substation size and having dynamic characteristic capable of significantly impacting voltage stability.

Organization	Comments for Question 2
	Areas that don't have large motors or stability issues should not be required to add unnecessary load modeling.
Response: Planned system adjustments could include Operating Plans such as re-dispatch. Requirement R2, part 2.7.1 is a list of examples, so it could include more items than listed, including Note e in Table 1. The SDT declines to make the suggested change. Part 2.9 has been deleted as suggested. For Part 2.4.1, the SDT declines to add specifics, which includes "limits or thresholds to provide Load models based on areas that have Stability limits or issues and to Loads of substation size and having dynamic characteristic capable of significantly impacting voltage Stability" because such specificity needs to be determined by the entity performing the study. Part 2.4.1 allows the use of "an aggregate System Load model which represents the overall dynamic behavior of the Load". Areas that do not have large motors can use an appropriate aggregate System Load model.	
Lakeland Electric	Agree with the changes made to the spare equipment strategy requirement
Response: The SDT thanks you for your comments.	
Progress Energy Florida, Inc.	As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all appropriate parties to review PEF's previous comments to this effect.
Response: Throughout the drafting process, the SDT has carefully considered your comments as well as comments from other industry members.	
Florida Municipal Power Agency, and its Member Cities	As worded, 2.1 now seems to require power flow, short circuit and stability studies be done every year for the Near Term. Is this the intent of the SDT? There are smaller systems that do not require this (e.g., if a smaller system has nothing more change form year to year than a 1.5% load growth, and there is plenty of margin on various SOLs, why is another study needed?). FMPA suggests re-wording to: "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies or by qualified past studies as indicated in Requirement R2, part 2.6" Since 2.2 only has one sub-bullet, 2.2.1 ought to be collapsed into 2.2. We think it would read less confusing as well, see below for suggested phrasing: "The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by a current study of expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected, supplemented with qualified past studies as indicated in Requirement R2, part 2.6. The short circuit studies of 2.3 should not only assess the fault current interrupting capability of breakers, but also circuit switchers and the momentary current carrying capability of other equipment, such as switches and substation bus. We recommend changing the phrase to: "The analysis shall be used to determine whether the fault current is within the momentary current carrying capabilities and/or fault current interrupting capabilities of (Elements or Facilities) using ". Also, for the short circuit study of 2.3 (and 2.8), it is not necessary to study all of the contingencies, just P2. Taking other Facilities out in addition to the fault will only reduce fault current. Auditors may not be aware of that and maybe the standard

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	could say that only P2 needs to be studied to reduce future confusion. In 2.6, “material change” is ambiguous, especially in regards to load growth. How much load growth is allowed before it is “material”? Is the intent of the SDT to have 2.7 apply to all previous bullets in R2? If so, then it could be made clearer by starting 2.7 with “ For the analyses discussed in 2.1 through 2.5, and for the planning events shown in Table 1, when the analyses indicate “? 2.7 seems to have lost the reference to lead times for Corrective Action Plan(s) that were present in the existing TPL-001-0, TPL-002-0 and TPL-003-0 standards, is that the intent of the SDT? Since only two of the years in the near term need to be studied, and one of the year’s in the long term study, there ought to be some method to determine when a Corrective Action Plan is needed, the lead time of that Corrective Action Plan, to give an indication of when activity needs to start to implement the Corrective Action Plan. The Planning Coordinator and Transmission Planner should not be responsible in 2.7 for any repercussion of an entity not implementing the Corrective Action Plan. Bullet 2.7 ought to be reworded to developing the Corrective Action Plan only and not implementation. For instance, 2.7.4 requires review of Corrective Action Plans. If a Corrective Action Plan calls for a major transmission addition, then that addition usually is in the domain of the Transmission Owner. If the Transmission Owner decides not to build the transmission upgrade for a variety of reasons (e.g., budgets, etc.), then the Planning Coordinator and Transmission Planner could end up being in violation of the standards through no fault of their own (e.g., even though curtailment of firm service would then be allowed in 2.7.3, if such curtailment would not solve the problem, e.g., if there is not enough pre-contingency re-dispatch available, then the Planning Coordinator would be in violation).Implementation of the Corrective Action Plan, however, is very important. FMPA suggests that another requirement be added to require Transmission Owners, Generation Owners, Transmission Operators, Generation Operators (latter two if there are operating schemes involved) within the planning area of the Planning Coordinators and Transmission Planners to implement the plan as determined by the Planning Coordinators and Transmission Planners, with another requirement requiring that the entities agree on the Corrective Action Plan. This would mean expanding the applicability of the standard. This new requirement ought to have a VRF of High because not implementing the Corrective Action Plan could have high risks. What is the reliability purpose of 2.9? Is it to identify the largest potential supply / demand mismatch? If so, the largest loss of source, usually about 1000 MW, will overwhelm this number. FMPA does not understand the reliability purpose of providing this number, especially since the power flow models already capture most of this information (e.g., amount of load connected to tap substations or radial feeds). This seems to be an administrative item with no reliability purpose, especially since it only applies to P1 (why does it apply to P1 ? how can there be consequential load loss without a contingency, unless it’s specific to 2.1.5?) and P2.
Response: The SDT reviewed Requirement R2, parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require “annual current year study, supplemented by qualified past studies”. Parts 2.1 and 2.2 cover steady state studies in the Near-Term and the Long-Term planning horizons, respectively. Short circuit studies (Part 2.3), near-term Stability studies (Part 2.4) and long-term Stability studies (Part 2.5) allow the use of current or qualified past studies. Therefore, as drafted the standard only requires annual steady state studies. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for the Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon	

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	should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested. In addition, the two study years are intended to cover both the timeframe just after operation planning (Year One or year two), as well as the timeframe to allow implementation of solutions, which may require a longer lead time. Load growth may not be the only determination factor on System performance; other examples are addition or retirement of generation. The suggested change for Parts 2.2 and 2.2.1 does not provide additional clarity. The SDT declines to make the change. Part 2.3 was changed in the previous posting to include circuit breakers only due to a preponderance of industry comments in draft 3. The SDT declines to make the suggested change. The SDT believe this concern on Part 2.3 is covered. The Transmission Planner or Planning Coordinator can provide an explanation of why the Contingencies selected would produce the more severe conditions. Note that Part 2.3 requires an annual Planning Assessment only. Part 2.6.2 allows an entity to rely on a past study with a material change if "a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area". Therefore, it is up to the entities performing the study to provide the rationale based on changes, such as Load growth. The intent of Part 2.7 is to be applied to all "planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1". The SDT believes that the intent is clear. The SDT declines to make the suggested change. Part 2.7 requires that for all planning events in Table 1, the Planning Assessment includes a Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Also, Part 2.7.4 requires that the CAP be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures. For 2.7.1, the NERC Glossary of Terms defines Corrective Action Plan as "A list of actions and an associated timetable for implementation to remedy a specific problem. Therefore, your concerns have been addressed. The planners' responsibility is to always have a plan that meets the performance requirements during the planning horizon. If the original CAP can't be implemented, the planner must develop an alternate plan to meet the performance requirements. The definition of CAP includes a timing element as per the Glossary. For issues involving inability to implement a CAP, which is beyond the control of the Planning Coordinator or Transmission Planner, such as the example given, the Planning Coordinator or Transmission Planner can rely on Part 2.7.3 in addition to those actions already allowed tomeet performance requirements. Part 2.9 has been deleted to address your concerns.
Gainesville Regional Utilities	Combining 4 TPL standards into 1 standard makes for a situation that you will always be audited on all the covered functional areas instead of part of the functions in a given audit. Example, in 2009, TPL-004 was not part of the audit while the other 3 standards were part of the audit. Of course, you should always be current with all functional assessments. I use one assessment document to cover all the functional areas. I do like the added clarity on the time horizons for various studies. I find R2. part 2.1.5 to create a somewhat clearer focus on spare equipment strategy. But the created task could create a lot of

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	work for a utility depending on its configuration and redundancy.
Response: Combining TPL-001 through -006 into one standard was in response to comments from the industry and FERC Order 693. Part 2.1.5 only requires that the Planning Coordinator or Transmission Planner plans for the potential unavailability of long lead time major Transmission equipment in accordance with its spare equipment strategy. For example, if an entity's spare equipment strategy is to have a spare transformer on site, then the unavailability of a similar transformer (due to outages) would be limited to the time it would take to energize the spare transformer. Assuming that this time is no more than that required to return a similar outaged transformer back in service, Part 2.1.5 can be satisfied without performing additional planning studies. If on the other hand, the transformer would have to be purchased, then it would take more than a year to replace, and studies will likely needed to be done to plan for the potential unavailability.	
ITC Holdings	Comments: R2.1.1 Are two distinct study years necessary if a transmission owner can demonstrate that loads within their footprint have minimal growth over the 5 year period, defined to be less than X% of growth? Since the standard requires a relatively large number of studies to meet performance requirements, an initial set of studies along with studies demonstrating that "CAPs work" seems sufficient during periods of load stagnation. R2.1.4, R2.4.3 & R2.7.1. These requirements refer to new facilities which would include new generators. ITC requests clarification as to what constitutes a "new generator" that needs to be considered -- those in the queue, those with signed Interconnection Agreements, those under construction... What is the line of demarcation between what is in and what is out? In addition to the above, ITC also requests clarification as to whether or not these requirements apply to new generators, who connect to the network as "Energy Only" resources and, are either, not required to construct facilities needed to meet reliability requirements or are allowed to operate as "Energy Only" until needed facilities are constructed. The CAP for these facilities is that they will be curtailed or other generation will be curtailed should "operating" violations occur. Under market mechanisms, these generators are allowed to operate if their energy prices are lower than other generators whose curtailment eliminates the violation, even though the curtailed generators have paid for the facilities needed to meet reliability requirements. As the standard is written, these requirements imply that all generators must be included in studies. Were we to do so, significant standards violations might result. Does the Transmission Owner have to study all violation scenarios or include all "Energy Only" generators in studies when the CAP is always the same: "Market redispatch". Please clarify study scenario requirements for "Energy Only" resources.
Response: For Part 2.1.1, Load growth may not be the only determination factor on system performance; other examples are addition or retirement of generation. The two study years are intended to cover both the time frame just after operation planning (Year One or year two), as well as the time frame to allow implementation of solutions, which may require longer lead time. NERC Standards specify what the requirements are and not how to meet the requirements. The SDT therefore declines to specify how the studies are to be done. The intent of the standard is to allow the Planning Coordinator or the Transmission Planner performing the studies the discretion on the sensitivities (Parts 2.1.4 and 2.4.3) to investigate and the generators to be assumed in the Corrective Action Plan (Part 2.7.1). The SDT believes that the requirements under this draft do include "Energy Only" generators. Please note under Requirement R2, part 2.7.1 that manual and automatic generation runback/tripping is allowed as a response to single or multiple Contingencies to mitigate Steady State performance violations. Also automatic generation tripping is allowed for single and multiple Contingency events to mitigate Stability performance violations	

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Deseret Power	Comments: The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies" It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.
Response: The SDT reviewed Requirement R2, parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for the Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested. The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within Parts 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and Stability evaluations, respectively. **Requirement R2, part 2.4.3**, **bullet #3**: Expected in service dates of new or modified Transmission Facilities Part 1.1.4 and Part 2.1.4 state that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast	
SCE&G	Does R.2.9 refer to customer load only or does it include pumped storage facility pumping loads?
Response: Part 2.9 has been deleted based on industry input.	
Orlando Utilities Commission	I like the clarification of "summarize results" compared to the wording in the prior edition. -It is obvious an attempt has been made to further define when past studies may be used, but I think it is still a bit confusing. Requirement 2.1, 2.2 appear to be saying that current studies must be used, but that additional information can be provided if desired and it meets certain requirements. Sub-Requirements 2.3, 2.4 and 2.5 seem to allow use of past studies that meet the

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	requirements of 2.6 in lieu of new work. If this is the correct understanding then I suggest the following: For 2.1 and 2.2 revise the statement to read "…and be supported by the following annual current studies. The analysis may also include other current and past studies in addition to the required annual current studies listed below. The reference to R2.6 is removed since including it invites confusion over when prior art can be used and if the material is solely supplemental, then there is no reliability advantage to limiting what can be incorporated a supplemental material. R2.6 should also be revised to read "Past studies may be used in lieu of current studies for R2.3, R2.4, R2.6 if they meet the following requirements:" This will insure that it is very obvious in both places when prior art may be used in lieu of new work. -R2.6.2 Consider revising "the study shall not include any material changes" to "the system represented in the study shall not include any material changes". Stating that "the study shall not include material changes" implies changes to the study from the time it was performed to the time it was used, like inserting or removing text, not changes in the underlying transmission system which is what I think you are really targeting. -R2.1.4 and 2.4.3: The statement "sufficient amount to stress the system…credible conditions…demonstrate a measurable change" implies that a sensitivity must meet three general criteria: (I will be using load forecast as an easy example, but obviously there is a range and combination of items that could be used) 1. That it is expected to increase stress, for example increasing the load forecast would general increase stress, where decreasing it would not. 2. That the increase should be substantial, for example growing the load at 2x the expected growth rate vs 1.01x the expected rate. 3. That the change doesn't have to exceed the bounds of credibility. If a 2x or 3x increase doesn't result in a stack of new constraints, it does not mean the sensitivity is inadmissible. Is this a correct understanding? -R2.7: Is the "Corrective Action Plan" intended to document all of an entities planned future reliability related transmission projects and operational procedures? Or is it intended to address situations where simulation and the application of currently planned projects and procedures are insufficient to meet the performance requirements? The next comment is very closely related to this one. -R2.7: If a project is added one year to the "Corrective Action Plan" but then in the subsequent year has been added to the model, resulting in simulation showing no performance violations, should it be removed from the Corrective Action Plan? Or should it be referenced in the plan each year until it is either in service or demonstrated to no longer be required?

Response: The SDT reviewed Requirement R2, parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies should be done annually covering Year One or year two and year five for Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. The remaining requirements for Short circuit studies Part 2.3), near-term stability studies (Part 2.4) and long-term Stability studies (Part 2.5) can then be covered by current or past studies.

The SDT declines to change Part 2.6 to read "Past studies may be used in lieu of current studies for Requirement R2, parts 2.3, 2.4, and 2.6 if they meet the following requirements" because it does not add clarity.

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Part 2.6.2 has been revised to address your concerns. **Requirement R2, part 2.6.2**: For steady state, short circuit, or Stability analysis: the System represented in the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area For Parts 2.1.4 and 2.4.3, the example you gave is a valid example for addressing "the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance". Part 2.7 requires a Corrective Action Plan to be developed "when the analysis indicates an inability of the System to meet the performance requirements in Table 1". Therefore, the intent is to address situations where simulation and the application of currently planned projects and procedures are insufficient to meet the performance requirements. If a project is added to the Corrective Action Plan, it should be included as part of the study assumptions based on that the criteria Planning Coordinator and Transmission Planner use for inclusion of such planned projects, and clearly identified as an assumption for the annual Assessment as required in Requirement R2, until it is in service or shown to be no longer needed.	
TVA System Planning	In R2.1.4 and R2.4.3, TVA is concerned about the use of the words "sufficient" and "measurable" from a compliance standpoint. TVA believes that these words should be deleted or at least better defined to clarify the actual intent from the SDT on what is technically required for these sensitivity studies. TVA agrees with limiting R2.1.5 spare equipment strategy to just the P0, P1, and P2 single contingency categories. In R2.7.3, both Non-Consequential Load Loss and curtailment of Firm Transmission Service can be permitted if situations arise that are beyond the control of the TP or PC. However these actions are not useful for stability related issues. TVA suggests that for stability related issues, if situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the TP or PC is permitted to allow some generation to lose synchronism utilizing out of step relaying or other protection method to correct the situation that would normally not be permitted in Table 1. We appreciate the deletion of the previous requirement on non-Consequential Load Loss from the previous draft of TPL-001-1.R2.9: Recommend that this refers to customer loads only, and not to include utility loads such as pump-storage or compressed air generating plant pumping load.
Response: For Part 2.1.4, The SDT envisions that stressed conditions and "measurable change" are to be defined by the responsible Planning Coordinator or Transmission Planner. For Part 2.7.3, most of the situations that are beyond the control of the Transmission Planner or Planning Coordinator usually involve permitting or long lead time projects. If there is a Stability issue, there should be time to implement a CAP. No change made. Part 2.9 has been deleted in response to industry comments.	
Lafayette Utilities System	LUS is satisfied that the current version resolves the issues we raised as to R2.

Organization	Comments for Question 2
Response: The SDT thanks you for your comments.	
MidAmerican Energy Company	MidAmerican commends the SDT for their hard work on this standard. MidAmerican does have comments about this requirement though. MidAmerican recommends a minor editorial to 2.1.4. The subrequirement states that "To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies, by a sufficient amount to" The subrequirement as written is not clear whether the condition to be varied is to be one not included in the base studies or a condition that is not varied as part of the sensitivity studies. MidAmerican recommends that this subrequirement be changed as follows: "To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions FOR WHICH VARIATION IS not already included in the studies, by a sufficient amount to"? The words in caps are words that MidAmerican suggests are added to this part of requirement 2. MidAmerican recommends that the SDT clarify section 2.4.1 and when load models considering induction motors are required. The clarification should add limits or thresholds to provide load models based on areas that have stability limits or issues and to loads of substation size and having dynamic characteristic capable of significantly impacting system damping. Areas that don't have large motors or stability issues should not be required to add unnecessary load modeling. MidAmerican recommends that the SDT modify 2.6.2 by changing "to demonstrate that System changes do no impact the performance results in the study area" to "to demonstrate that System changes do not SIGNIFICANTLY impact the performance results in the study area." The word that is in all caps is added. 2.6.2 as written results in an unrealistic requirement to review every impact minor or large and determine which meets this item and which do not. The recommended change solves this problem. MidAmerican recommends the data retention for R2 and M2 be revised to change "All" to "The". The word "All" is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: "THE Planning Assessments performed since". The word in all caps is a word suggested to be added.
Response: The SDT declines to make the change because it does not add clarity to the requirement. For Part 2.4.1, the SDT declines to add specifics, which includes "limits or thresholds to provide load models based on areas that have stability limits or issues and to loads of substation size and having dynamic characteristic capable of significantly impacting voltage stability" because such specificity needs to be determined by the entity performing the study. Part 2.4.1 allows the use of "an aggregate System Load model which represents the overall dynamic behavior of the Load". Areas that do not have large motors can use an appropriate aggregate System Load model. The SDT declines to make the change suggested in Part 2.6.2 because it did not add more clarity than the existing language. The SDT has made the suggested change. **Requirement R2, data retention**: The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.	
British Columbia Transmission Corp	none

Organization	Comments for Question 2
Response: The SDT thanks you for your comments.	
SERC Dynamics Review Subcommittee (DRS)	Part 2.1.4 and 2.4.3: delete the word "sufficient." We appreciate the deletion of the previous R2.9 on non-Consequential Load Loss from the previous draft of TPL-001-1.Bullet 1 of R.2.4.3: change "Dynamic Model" to "Dynamic Load Model". Part 2.9: Does this refer to customer loads only, or does it include pump-storage or compressed air generating plant pumping load.We recommend that the expected largest consequential load be limited to customer load, not utility load, i.e., pump-storage.
Response: For Part 2.1.4, The SDT envisions that credible sufficient stressed conditions are to be defined by the responsible Planning Coordinator or Transmission Planner. Bullet 1 of Requirement R2, part 2.4.3: has been revised to address your concerns. **Requirement R2, part 2.4.3, bullet #1:** Load level, Load forecast, or dynamic Load model assumptions Part 2.9 has been deleted in response to industry comments.	
SERC Planning Standards Subcommittee	Part 2.1.4 and 2.4.3: delete the word "sufficient." We appreciate the deletion of the previous R2.9 on non-Consequential Load Loss from the previous draft of TPL-001-1. Part 2.9: Does this refer to customer loads only, or does it include pump-storage or compressed air generating plant pumping load.
Response: The word "sufficient" is needed in Part 2.1.4 and Part 2.4.3 to ensure that the variations made to the assumptions to investigate sensitivity are large enough to be meaningful so they can demonstrate the impacts of the changes. The SDT envisions that credible sufficient stressed conditions are to be defined by the responsible Planning Coordinator or Transmission Planner. As such, the SDT declines to revise Parts 2.1.4 and 2.4.3 as suggested. Part 2.9 has been deleted in response to industry comments.	
CenterPoint Energy	Part 2.2: CenterPoint Energy recommends deleting part 2.2 since studies performed in the Long-Term Transmission Planning Horizon have dubious value for organizations whose longest lead time items take less than five years to construct. Even for organizations requiring longer than five years to build some projects, it should be noted that beyond the five year horizon, generation reserve margins have generally been exhausted, requiring speculation as to the location and size of future generating resources in developing system models. In recognition of this reality, the current set of TPL standards appropriately require that assessments be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may require longer lead time solutions. Part 2.5: Part 2.5 appears to have been added in response to one comment to the 3rd draft. In fact, the commenter did not recommend or propose the requirement found in 2.5, but only asked about the SDT's intent regarding this matter. CenterPoint

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	Energy strongly disagrees that part 2.5 is necessary or advisable and recommends that it be deleted. We wholeheartedly agree that Transmission Planners should consider and selectively study potential stability concerns. However, we believe that Transmission Planners are already considering and selectively studying potential stability concerns, and deleting part 2.5 would not preclude the continuation of these practices. However, we oppose mandating stability analysis in the Long-Term Transmission Planning horizon of proposed generation additions or changes due to the uncertainty of where and how much generation will actually be constructed beyond the five year horizon, particularly since generation can be built much faster than five years and can easily invalidate any such assessment. Part 2.7: CenterPoint Energy recommends that part 2.7 be revised to add a reference to part 3.4 and part 4.4 as follows: For planning events shown in Table 1, selected in accordance with parts 3.4 and 4.4, when the analysis. This recommended change is to prevent possible ambiguity or conflicts between part 2.7 and parts 3.4 and 4.4. Part 2.9: CenterPoint Energy agrees with multiple commenters to the 3rd draft that part 2.9 (previously 2.8) should be deleted. Part 2.9 is an unnecessary reporting requirement that has no actual bearing on reliability. By continuing to insist on R2.9, the SDT seems to have inappropriately ignored industry comments to the previous draft while ironically inserting R2.5 into this draft in response to only one industry comment (which did not actually advocate that R2.5 was necessary). CenterPoint Energy urges the SDT to reconsider its dismissal of industry concerns regarding R2.9.
Response: For Part 2.2, the SDT believes there is value in taking a long range view in planning to assess the general trend. The effort can be useful even taking into consideration the uncertainty surrounding long-term planning studies. Since the Long-Term Transmission Planning Horizon is year 6 – year 10, the Planning Coordinator or Transmission Planner can for example, select year 6 or 7 in the Long-Term Transmission Planning Horizon and then use this study as the past study to supplement the near-term studies in the following year(s). For Part 2.5, The SDT believes it is important to evaluate Stability when the planners are evaluating new generation addition or changes which can be more than 5 years in the future, as required in NERC Standard FAC-001-0. Part 2.7 is the Corrective Action Plan resulting from the Planning Assessment. Part 3.4 covers the requirements for studies supporting the steady state portion of the assessment; and Part 4.4 covers the requirements for studies supporting the Stability portion. The SDT believes that Part 2.7 is clear as is and no change is needed. Part 2.9 has been deleted in response to industry comments.	
Progress Energy Carolinas	PEC believes that the language of R2.5 "proposed generation additions and changes" should be clarified as to whether transmission changes near generators are included or not. PEC believes that the requirement to report the largest single consequential load loss under Requirement 2.9 should not be included in the standard. If it remains, it must be made clear that it be applicable only to Year One, and there should be additional clarification that the requirement to report consequential load loss (single number) is ONLY for the most severe contingencies studied for the P1 and P2 contingencies.
Response: Part 2.5 is intended for investigation of Stability issues due to addition of generators. The SDT does not believe that, in general, a Stability assessment is needed for the Long-Term Transmission Planning Horizon. The System model for that timeframe is too uncertain for a meaningful assessment of the System's Stability. However, for those situations where a specific generator is planned to be added in that timeframe, the SDT believes that it will be appropriate to require that	

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the generator's Stability impact be evaluated. Part 2.9 has been deleted in response to industry comments.	
Portland General Electric Co.	PGE believes that the scope of the studies mandated by this requirement should be limited to elements energized at 200kV and above, elements included in generator interconnection, and elements included in interconnections with other utilities. PGE's 115kV system functions to provide "load service" rather than transmission and does not impact the grid in the same manner as the 230kV and 500kV elements that comprise PGE's transmission system. PGE further believes that the requirement to conduct off-peak studies should focus on the varied generation patterns and impact to recognized transmission paths (for WECC, those identified in the WECC Path Catalog) rather than including the full range of studies that are required for on-peak studies. PGE's transmission system is embedded within the larger regional transmission system of the Bonneville Power Administration, and studies of System Off-Peak Load will not reveal any meaningful data internal to PGE's system. Finally, PGE believes that the wording of R2.6.2 is so restrictive that the entire intent of the subrequirement would be negated. PGE believes that "material changes" is such a broad term that every past study would have to have such changes made to reflect the system as it currently exists. Therefore, a company seeking to use a past study to support its Planning Assessment would have to provide a "technical rationale" showing that the material changes do not impact performance results. An effort to demonstrate a technical rationale in a manner that would satisfy future auditors would in many cases be more burdensome than performing a new study.
Response: NERC Reliability Standards apply to BES elements as defined by each Regional Entity. No change made. The SDT believes that System Off-Peak Load studies are a valuable tool in proper planning. Therefore, your Planning Assessment needs to address the results for your System of an Off-Peak Load study regardless of whether you conduct the studies or you rely on studies done by others. No change made. The SDT does not agree that developing a 'technical rationale' is such an onerous task. One can utilize their professional judgment, point to past studies of similar conditions, etc. The key is to thoroughly explain your decisions. No change made.	
FRCC Transmission Working Group	Please further clarify the definition when past studies may be used. Requirement 2, bullets 2.1, 2.2 appear to say that current studies must be used, but that additional information can be provided if desired and it meets certain requirements. Sub-Requirements 2.3, 2.4 and 2.5 seem to allow use of past studies that meet the requirements of 2.6 in lieu of new work. If this is the correct understanding then I suggest the following:For 2.1 and 2.2 revise the statement to read "and be supported by the following annual current studies. The analysis may also include other current and past studies in addition to the annual current studies listed below. R2Bullet 2.6 should also be revised to read "Past studies may be used in lieu of current studies for Bullets 2.3, 2.4, 2.6 if they meet the following requirements: This will insure that it is very obvious the planner, when they may or may not use prior art in place of new work and it's specified in all places in the standard where this is referenced.For these supplemental or "above and beyond" studies, 2.6 should not be referenced. First of all it makes it confusing, since 2.6 is primarily concerned with prior art being used in lieu of new work. Also if the material is supplemental, then it's supplemental and setting requirements on it will

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	only reduce the material provided not improve the reliability of the system. -2.6.2 Consider revising "the study shall not include any material changes" to "the system represented in the study shall not include any material changes". Stating that "the study shall not include material changes" implies changes to the study from the time it was performed to the time it was used, not changes in the underlying transmission system which is what I think you are really targeting. -2.1.4 and 2.4.3: The statement "sufficient amount to stress the system"credible conditions"demonstrate a measurable change" implies that a sensitivity must meet three general criteria: (I will be using load forecast as an easy example, but obviously there is a range of items that could be used)1. That it is expected to increase stress, for example increasing the load forecast would general increase stress, where decreasing it would not.2. That increases should be substantial, for example growing the load at 2x the expected rate vs 1.01x the expected rate. 3. That the change doesn't have to exceed the bounds of credibility. If a 2x or 3x increase doesn't result in a stack of new constraints, it does not mean the increase has to go to 10x the forecast just to show extensive effects. Is this a correct understanding? , realizing that I'm only referencing load growth for simplicity, it not being the only sensitivity? -2.1.4 and 2.4.3: The first sentence "impact of changes to the basic assumptions used in the model for the list of items below", please consider changing to just "impact of change to the basic assumptions used in the model". Including the "list of items below" implies that all items must be addressed, which seems to conflict with the second sentence which specifically allows one or more. -2.7: Is the "Corrective Action Plan" intended to document all of an entities planned future reliability related transmission projects and operational procedures? Or is it intended to address situations where simulation and the application of currently planned projects and procedures are insufficient to meet the performance requirements? -2.7: If a project is added one year to the "Corrective Action Plan" but then in the subsequent year has been added to the model, resulting in simulation showing no performance violations, should it be removed from the Corrective Action Plan? Or should it be referenced in the plan each year until it is either in service or demonstrated to no longer be required? Comments: With regard to the Lower VSL, is 2.6 considered to be met if only one of two sub-requirements (2.6.1 or 2.6.2) is met? With regard to the Moderate VSL, is 2.8 considered to be met if only one of two sub-requirements (2.8.1 or 2.8.2) is met? Also, since 2.3 depends on 2.6, what happens if an entity does not meet R2.6 because it did not meet one of the sub-requirements of 2.6? With regard to the High and Severe VSL, if any one of the sub-requirements of 2.1, 2.2, 2.4 or 2.7 is not met, is the entire sub-requirement considered not met? (This question is generic throughout all VSL) Also, for the short circuit study of 2.3 (and 2.8), it is not necessary to study all of the contingencies, just P2. Taking other Facilities out in addition to the fault will only reduce fault current. Auditors may not be aware of that and maybe the standard could say that only P2 needs to be studied to reduce future confusion. Is the intent of the SDT to have 2.7 apply to all previous bullets in R2? If so, then it could be made clearer by starting 2.7 with

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	"For the analyses discussed in 2.1 through 2.5, and for the planning events shown in Table 1, when the analyses indicate " 2.7 seems to have lost the reference to lead times for Corrective Action Plan(s) that were present in the existing TPL-001-0, TPL-002-0 and TPL-003-0 standards, is that the intent of the SDT? Since only two of the years in the near term need to be studied, and one of the year's in the long term study, there ought to be some method to determine when a Corrective Action Plan is needed, the lead time of that Corrective Action Plan, to give an indication of when activity needs to start to implement the Corrective Action Plan. The requirement clearly states that "For the steady state portion of the Planning Assessment " it must perform simulations that show generator ride through voltage limitations under 3.3.2. However, ride through limitations are performed through stability simulations not steady state as required by R3. Please provide clarity. Additionally, 3.2 requires studies to be performed to assess the impact of the extreme events. Yet, 3.3 requires analyses shall be performed but does not specify the events intended to study. Suggested language for 3.3 should say "Contingency analyses shall be performed to assess the impact of the extreme events and:" Under 3.3.1 it states that the Planner must simulate the removal of all elements that the Protection System would be expected to disconnect. Language should be included to allow the Planner to provide a rationale to assess more severe system conditions without needing to simulate the effects of Protection Systems. The references within the requirements are very confusing. 3.1 refers to a contingency list created in 3.4 which refers back to 3.1. Similarly 3.2 refers to a contingency list created in 3.5 which refers back to 3.2. These should be combined into one sub-requirement.

Response: The SDT reviewed Requirement R2, parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon.

The SDT declines to make the suggested changes in Parts 2.1, 2.2, and 2.6 because they do not add clarity.

The SDT has revised Part 2.6.2 as suggested.

> **Requirement R2, part 2.6.2**: For steady state, short circuit, or Stability analysis: the System represented in the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

For Parts 2.1.4 and 2.4.3, the example you gave is a valid example for addressing "the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance".

Part 2.1.4 and 2.4.3 have been revised as suggested.

> **Requirement R2, part 2.1.4**: For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

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	Requirement R2, part 2.4.3: For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: Part 2.7 requires a Corrective Action Plan to be developed for "when the analysis indicates an inability of the System to meet the performance requirements in Table 1". Therefore, the intent is to address situations where simulation and the application of currently planned projects and procedures are insufficient to meet the performance requirements. If a project is added to the Corrective Action Plan, it should be included as part of the study assumptions (and clearly identified as such), based on the criteria that the Planning Coordinator and Transmission Planner use for inclusion of such planned projects, for the annual Assessment as required in requirement R2, until it is in service or shown to be no longer needed. For the VSL for Requirement 2, both Parts 2.6.1 and 2.6.2 as well as Parts 2.8.1 and 2.8.2 must be met for the requirements to be met. If an entity relied on a past study, which was not a qualified study in accordance with Part 2.6, then based on the standard, it would not meet the requirement in Part 2.3. The intent is that with regard to the High and Severe VSL, if any one of the sub-requirements of Parts 2.1, 2.2, 2.4, or 2.7 is not met, the entire sub-requirement will be considered not met. The SDT believes this concern on Part 2.3 is covered. The Transmission Planner or Planning Coordinator can provide an explanation for why the Contingencies selected would produce the more severe conditions. Part 2.3 requires annual Planning Assessment only. The intent of Part 2.7 is to be applied to all "planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1". Therefore, a reference to Parts 2.1 through 2.5 is not needed. For 2.7.1, NERC Glossary of Terms defines Corrective Action Plan as "A list of actions and an associated timetable for implementation to remedy a specific problem. Also, Part 2.7.4 requires that the CAP be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures. By including the timing of needed action and requiring such reviews in subsequent Assessments, any deficiencies, if not adequately addressed, will become violations. Therefore, the SDT believes that your concerns have been addressed. Part 3.3.2: Generator protections exist that can result in generator tripping for bus voltage below minimum generator steady state voltage limits. The SDT believes that the voltage ride through test is applicable in post-Contingency steady-state where the planner would know if post-Contingency bus voltage violates generator trip points. If a trip point is violated, Part 3.3.2 would require the planner to trip the generator in the post-Contingency case to assess if performance is met with the generator tripped. No change made. Part 3.2 & Part 3.3: The SDT revised the wording of Part 3.3 as shown below to make it clear that it applies to both planning and extreme events: **Requirement R3, part 3.3**: Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall: Part 3.3.1: The SDT disagrees with the comment as the intent of Requirement R3, part 3.3.1, consistent with Order 693, is to perform the simulation to reflect how the Protection System will operate in the real System for each Contingency without operator intervention. The requirement does not preclude the Planning Coordinator/Transmission Planner from studying more severe scenarios. No change made. Part 3.1/Part 3.4 & Part 3.2/Part 3.5: The SDT does not believe that combining the requirements would provide any significant advantage. No change made.

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American Electric Power	R 2.6.2, as written, may lead to misinterpretation. Following are two alternative suggestions to remedy this issue for the SDT's consideration: 1) "For steady-state, short-circuit, or Stability analysis: the study shall be rendered obsolete by any material changes unless?" or 2) "For steady-state, short-circuit, or Stability analysis: the system shall not include any material changes unless?" While R3 (steady-state studies) covers 2.1 and 2.2 (steady-state assessments), and R4 (stability studies) covers 2.4 and 2.5 (stability assessments), there does not appear to be a corresponding requirement (short circuit studies) to cover 2.3 (short circuit assessments). We recommend that a new requirement be established and numbered to align between existing requirements R3 and R4.
Response: Part 2.6.2 has been revised as suggested. **Requirement R2, part 2.6.2**: For steady state, short circuit, or Stability analysis: the System represented in the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. For Part 2.3, the SDT does not believe a requirement to cover short circuit studies similar to Requirement 3 or Requirement 4 is required. The SDT's intent is for the short circuit study results to be included in the assessment. It does not believe that the standard needs to address the technical requirements for completing the short circuit study as that may be entity specific. Therefore the SDT declines to make the change as suggested.	
NYISO	R2. - The NYISO tariff establishes a biennial "Comprehensive System Planning Process," Compliance with an "Annual Planning Assessment" will therefore be a simple repetition of data reported in the prior year assessment. Please clarify that this is acceptable. We believe that the use of "past studies" provides for this. R2.1 - "Steady state" should be defined upfront with other definitions. In defining "steady state" is "thermal voltage" the primary metric being measured? R2.1.1 - Again want to confirm that due to the NYISO biennial planning cycle, that use of "past studies" will be acceptable. R2.1.2 - Please define what is intended by "off peak." Our reading is that it is ANY load level less than peak. Also, consistent with our comments on the prior draft, system off-peak is more likely a stability issue than a steady state issue. If system off-peak becomes a steady state issue, it can be mitigated through generation redispatch. Accordingly, it appears that this requirement is not necessary for steady state analysis. R2.1.4 - This is just too vague to be a useful requirement. The sentence ? To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. is too subjective to be enforceable. Either definitions of phrases like "sufficient amount" "credible conditions" and "measurable change" are included, or the requirement needs to be written more clearly to state what is actually being required without such high level of subjectivity. Further, we believe that this sentence may not be necessary at all, as the first sentence in 2.1.4 provides sufficient detail to conduct sensitivity analysis without being overly prescriptive. R2.4.3 As much of this language is a repeat of language in 2.1.4, above, our comments there also apply to this section. R2.6 - "Past Studies may be used to support the Planning Assessment if they meet the following requirements" and the sub-

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	requirement R2.6.2 states that for SS, SC, or stability analysis the study shall not include any material changes, such unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. While this is better than the prior draft, the NYISO still would like more clarity on the definition of "material changes." Would the inclusion of a technical rationale satisfy ANY change, regardless of magnitude, in a past study. Or could we just invoke the usage of a statement such as "The NYISO feels this change does not constitute a "material change." to be compliant with this requirement? We recommend that the regional entity should have a process to determine whether changes are material that is similar to the NPCC's process for determining what level of annual transmission review should be conducted each year. Finally, does this only relate to, or is limited to, the LATEST PLANNING HORIZON system model R2.7 Recommend that in the sentence "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity" wording should be changed to "performance requirements for any single sensitivity" R2.7.1 Recommend changing phrase that leads into list to read "Such actions including, but not limited to:" R2.7.2 - Recommend consideration of striking this section. It is not clear how an entity can provide a rational for unnecessary actions. Further, if actions are not necessary, what limit would there be on a rational, so they would seemingly be useless? Finally, it is stated above, corrective action plans should not be required for sensitivity studies. R2.9 There does not seem to relate to any reliability need the NYISO is aware of for this requirement to remain.

Response: Regarding Requirement R2 and Part 2.1.1, the SDT believes that NYISO's current process is inconsistent with Parts 2.1 (covering near-term steady state studies) and 2.2 (covering long-term steady state studies) of the draft Standard. Both Parts 2.1 and 2.2 require an annual current year study. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for the Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon.

For part 2.1, the SDT does not believe a definition for steady state is needed as this is a well understood term. There is no 'primary' metric – see the Table 1 Header Notes for more details.

The intent of Part 2.1.2 is to assess those System conditions during periods with lower Load levels than peak when the System may show different potential problems than during periods with peak Load level. For example, during light Load conditions, there may be high voltage problems because of the charging in the lightly loaded lines. There could also be thermal overload problems for areas with more generation than Load. For this reason, it would be appropriate to investigate Off-Peak steady state conditions to ensure that System performance can meet requirements under all demand levels. At the same time, the standard should not be overly prescriptive; therefore, the exact System Off-Peak Load and System conditions should be specified by the entity performing the study.

For Parts 2.1.4 and 2.4.3, The SDT envisions that credible "sufficient" "stressed" conditions and "measurable change" are to be defined by the responsible Planning Coordinator or Transmission Planner because each System is different and the standard should not be overly prescriptive.

Part 2.6.2 allows an entity to rely on a past study with a material change if "a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area". The intent is to assess system performance based on the latest available information. Therefore, it is up to the entities performing the study to provide the rationale based on changes, such as Load growth, generation or Transmission additions or modifications.

Part 2.7 has been changed to address your concerns.

Requirement R2, part 2.7: For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements

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in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Part 2.7.1 is simply a list and an entity can always do more than what is required in the Standard. No change made. Part 2.7.2 provides for development of a Corrective Action Plan if a number of sensitivity studies result in the same potential problem. For example, if only one sensitivity study results in potential problems or if the probability of occurrences of the sensitivity scenarios is low, then this would be the rationale to state that a Corrective Action Plan would not be necessary. Part 2.9 has been deleted in response to industry comments.	
Xcel Energy	R2.1 The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies" R2.1.5 Does "The Planning Assessment shall reflect" mean that the entity must meet the performance requirements for categories P0,P1,and P2 during the equipment unavailability? R2.9 As commented in the previous draft, we do not believe this requirement contributes anything to improving BES reliability. Therefore, we strongly recommend deleting this requirement.
Response: The SDT reviewed Requirement R2, parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizon, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested. For 2.1.5, your interpretation is correct. Part 2.1.5 requires that the Planning Coordinator or Transmission Planner plans for the potential unavailability of long lead time major Transmission equipment in accordance with its spare equipment strategy. If the spare equipment strategy can result in unavailability of long lead time equipment, the study will need to also be modeled with the piece of equipment out of service as P0. Part 2.9 has been deleted as suggested.	
Ameren	R2.1.3: The wording for this requirement needs clarification. It is suggested that the following language be submitted as a replacement: Known outages of generation or Transmission facilities should be included in the models representing those

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	System peak or Off-peak conditions when outages are scheduled. R2.1.4 and R2.4.3: The phrase “by a sufficient amount” should be modified to “by an amount”. Also, in R2.4.3, “dynamic model assumptions” should be changed to “dynamic load model assumptions.” R2.6.2: Recognition should be made of the fact that cancellation of generation or transmission projects, which may have been included in a previous study, would decrease fault levels, and would reduce or eliminate the need for short circuit analysis. R2.8: Would the Planning Coordinator be required to review, replicate, or validate short circuit studies? We appreciate the deletion of R2.9 from the previous draft of TPL-001-1 and eliminated the reporting of Non-Consequential Load Loss for each of the planning events. In R2.9, it is recommended that the largest Consequential Load Loss not include items such as pumped storage load or other utility load.
Response: Part 2.1.3 covers known long duration outages, for example, taking a 230 kV Transmission line out of service to rebuild it to operate at 500 kV. These cases are to simulate System conditions with the Facility in question out of service as Category P0 (or N-0). For the next outage, the System performance will need to meet requirements for Category P1. For Parts 2.1.4 and 2.4.3, the SDT envisions that “credible”, “sufficient”, “stressed” conditions and “measurable change” are to be defined by the responsible Planning Coordinator or Transmission Planner because each System is different. Part 2.4.3 has been revised as suggested. **Requirement R2, part 2.4.3, bullet #1:** Load level, Load forecast, or dynamic Load model assumptions For Part 2.6.2, the SDT agrees with the expectation concerning short circuit studies. For Part 2.8, as in other parts of this draft standard, the Planning Coordinator is responsible for its portion of the BES. It may delegate the work by agreement, it is, however, still responsible. Part 2.9 has been deleted in response to industry comments.	
Manitoba Hydro	R2.1.4.: The first sentence implies that all sensitivities should be studied. The second sentence refers to one or more. I suggest the following change to the first sentence: "....basic assumptions used in the model." (i.e. delete "for the list of items shown below." from the end of the first sentence.) R2.4.3: The exact same change as above in R2.1.4. R2.1.5: We assume the intent of the standard would be to perform an annual review of the inventory of spare equipment to determine if the spare strategy required updating. For example, if a transformer failed and the spare was moved into position, a new spare would be ordered to replace the failed one. During the period, when no spare was in place, additional assessments would be required to ensure meeting Table 1. Can the drafting team clarify? R2.5: The drafting team modified “material changes” to simply “changes” in R2.5. This does not add clarity. Given that R2.5 is

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	related to Stability Analysis, perhaps "changes" could be modified to "changes that could impact stability or voltage". R2.6: Recommend changing "the study" to "the past study" and "an older study" to "an older past study" to ensure no confusion could result from past and current studies. Can the drafting team explain how a past study can have material changes in R2.6.2? Perhaps R2.6.2 could be deleted. VSL: We would recommend moving R2.8's VSL from Moderate to both High and Severe. R2.8 requires a corrective plan to be developed when the short circuit duty of a circuit breaker is known to be exceeded. This is safety issue and a reliability issue.

Response: In Parts 2.1.4 and 2.4.3, the first sentence has been revised as suggested.

> **Requirement R2, part 2.1.4**: For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:
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> **Requirement R2, part 2.4.3**: For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

Part 2.1.5 does not address the specific requirements of an individual plan. Since a Planning Assessment is required annually, the analysis required under Part 2.1.5 is an annual requirement. The answer to the specific example would depend on a variety of factors, including the timing of the failure, the length of time that it would take to replace the spare, your Operation Planning time horizon and the specifics of your individual spare equipment strategy. The language in Part 2.1.5 states "the impact of this possible unavailability on System performance shall be assessed", which must be completed annually as a part of your Planning Assessment. The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing (Year One) is defined as the planning window that begins 12-18 months from the end of the current calendar year. After the original spare is put to use, if a new spare can be made available before Year One in the next Planning Assessment, the time period during which no spare is available could then be covered in Operation Planning studies. Longer delivery times would impact the spare availability and an appropriate assessment would be expected in Year One by the Transmission Planner. In addition, to provide greater clarity, the SDT has revised the first sentence of Part 2.1.5 to read, "When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed.

> **Requirement R2, part 2.1.5**: When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.5, the SDT declines to make the change as suggested because the suggested change does not add clarity.

The SDT declines to make the change suggested in Part 2.6 because it did not add more clarity than the existing language.

The SDT has revised Part 2.6.2 to provide additional clarity.

> **Requirement R2, part 2.6.2**: For steady state, short circuit, or Stability analysis: the System represented in the study shall not include any material changes

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unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. While the SDT agrees that the short circuit analysis is important, Part 2.8 has been assigned a VSL based on its need to fulfill Requirement R2. Safety is covered in other venues.	
Tri-State Generation and Transmission Association	R2.2 What is an "annual current study"? Would this include previously performed studies that are still applicable?? R2.2. What is "qualified past studies"? We have no definitions for "qualifying" previous work. This might be remedied by inserting the term "qualified" in R2.6.? R2.1.4. Sensitivity cases could add much work to the existing process. However, the standard calls for "at least one" of the listed sensitivity studies to be performed. R2.2.1. The requirement to perform a "current study" assessing expected System peak Load conditions, for one of the years in the Long-Term Transmission Planning Horizon, is extra work if a valid/qualified study is available. If the intention here is to have a valid study for at least one of the years 6 to 10, then perhaps some simple rewording will solve the problem. We ascribe to the concept of requiring annual assessments, but not necessarily requiring repeated analysis if system changes do not warrant restudy. Hyphenate "in-service" R2.6.1 Change "the study shall be five calendar years old or less" to: "the study is five calendar years old or less" R2.6.2 change the phrase "shall not include any material changes" to "does not include any material changes" R2.6.2 it is not clear what is meant by "material changes" - different "Study conditions" or "changes that could cause different results for a particular study"?
Response: In Parts 2.2 & 2.2.1, an "annual current study" is one that must be done in the current assessment cycle. Previously performed studies can be used to supplement the current study, but not in place of it. Because steady state analysis is part of basic planning process, the SDT believes that the steady state portion of the studies covering one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire Long-Term Transmission Planning Horizon. In Part 2.2, the "qualified past studies" are as indicated in Requirement R2, part 2.6. The SDT believes that the existing language is clear and changes are not needed. Part 2.1.4 – There is no question here so the SDT is unable to provide a specific response. For Part 2.6.1, the SDT declines to make the changes as suggested because they do not provide more clarity than the existing language. The SDT has revised Part 2.6.2 to address your concerns. Part 2.6.2 also allows an entity to rely on a past study with a material change if "a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area". Therefore, it is up to the entities performing the study to provide the rationale based on changes, such as load growth. **Requirement R2, part 2.6.2**: For steady state, short circuit, or Stability analysis: the System represented in the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.	
Oklahoma Gas & Electric	R2.4.3 Not positive what this actually requires Transmission Planner to perform. Recommend compliance with requirement be

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	the responsibility of the Transmission Coordinator. R2.9 OG&E has not provided this information in the past. Different sets of load flow models will result in different data results. Do not see any merit with providing information.
Response: Part 2.4.3 is part of Requirement 2, which applies to both the Transmission Planner and the Planning Coordinator for their respective portion of the BES. So, both are responsible for meeting the requirements even though the actual work may be shared or delegated. Part 2.9 has been deleted in response to industry comments.	
Arizona Public Service Co.	R2.6.2: The wording "study shall not include" is confusing since it refers to the past studies.
Response: Part 2.6.2 has been to address your concerns. **Requirement R2, part 2.6.2**: For steady state, short circuit, or Stability analysis: the System represented in the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.	
Hydro-Québec TransEnergie (HQT)	Requirement 2.1 As written, it is not clear. HQT, as does NPCC, suggests revising language as in 2.4 as follows:"The Near-Term Transmission Planning Horizon portion of the steady state" analysis shall be assessed annually and be supported by current or past studies as indicated in? Requirement R2, part 2.6. The following studies are required: Requirement 2.1.2 The use of the term "off peak" is a concern. The definition for this term can be read to say that it is any load level less than peak. This does not provide enough clarity to guide the required assessments. Requirement 2.2 As written, it is not clear. HQT, as does NPCC, suggests revising language in 2.2 as in 2.4 as follows: The Long-Term Transmission Planning Horizon portion of the steady state" analysis shall be assessed annually and be supported by current or past studies as indicated in? Requirement R2, part 2.6. The following studies are required: Requirement 2.7 HQT,as does NPCC, suggests changing the word "run" to "condition" in "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3." Requirement 2.9 It should not be necessary to identify the largest consequential load loss if the TPL standard does not limit the size of the consequential load loss. This requirement should be deleted.
Response: The SDT reviewed Requirement R2, parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizon, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year	

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	study being performed. Therefore, the SDT declines to make the change as suggested. The intent of Part 2.1.2 is to assess those System conditions during periods with lower Load levels than peak when the System may show different potential problems than during periods with peak Load level. For example, during light Load conditions, there may be high voltage problems because of the charging in the lightly loaded lines. There could also be thermal overload problems for areas with more generation than Load. For this reason, it would not be appropriate to eliminate the requirement to investigate Off-Peak steady state or Stability conditions. At the same time, the standard should not be overly prescriptive; therefore, the exact System Off-Peak Load should be specified by the entity performing the study. Part 2.7 has been changed to address your concerns. **Requirement R2, part 2.7**: For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Part 2.9 has been deleted as suggested.
Northeast Power Coordinating Council--RSC	Requirement R2 (second line): "This Planning Assessment shall use current or past studies," should be replaced with "This Planning Assessment shall use current studies or qualified past studies as indicated in Requirement R2, part 2.6," Requirements 2.1, 2.2, 2.3, and 2.4--As written, are not clear. It is suggested to revise the language as follows: "The Near-Term Transmission Planning Horizon portion of the steady stateanalysis shall be assessed annually and be supported by current studies or qualified past studies as indicated in Requirement R2, part 2.6. The following studies are required:"Requirement 2.1.2 The use of the term "off peak" is a concern. The definition for this term is not provided, and can be read to say that it is any load level less than peak. This does not provide enough clarity to guide the required assessments. Requirement 2.1.3: It must be clarified that the reference to outages as listed in Requirement R1, part 1.1.2 must be limited to Planning Horizon. Refer to Requirement 1.1.2 in the response to Question 1. Requirement 2.1.4: Consistent with the suggestion made for Requirment 1.1.2 remove the last bulleted item in the list under Requirement 2.1.4 "Duration or timing of planned Transmission outages." The standard is referring to requirements for sensitivity without a reference to base cases. Refer to Comment on Proposal to add an item 1.2 Requirement 2.1.5: It needs to be clear that this is only an assessment, not a solution. Actions such as out of merit dispatch, operational restrictions, System reconfiguration can be part of a Corrective Action Plan if the System cannot meet performance requirements without the Facility in service. It can be reworded as "an assessment of the impact of this possible unavailability on System performance shall be performed". Requirement 2.3: The requirement does not indicate a year to study. This should be modified to state that it is up to the Planner to determine the year of study within the Near Term Transmission Planning Horizon.

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	Requirement 2.4.2: Same as 2.1.2 Requirement 2.4.3: Refer to the Comment for Question 1 to add a Requirement 1.2 Requirement 2.5: Revise language as follows: be supported by current studies or qualified past studies as indicated in Requirement R2, part 2.6. Requirement 2.7 NPCC suggests changing the word "run" to "condition" so the wording will read Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity condition in accordance with Requirements R2, parts 2.1.4 and 2.4.3. Requirement 2.9 It should not be necessary to identify the largest consequential load loss if the TPL standard does not limit the size of the consequential load loss. This requirement should be deleted. If it remains, it must be made clear that it be applicable only to Year One or Year Two.
National Grid	Requirement R2 (second line): This Planning Assessment shall use current or past studies, should be replaced with "This Planning Assessment shall use current studies or qualified past studies as indicated in Requirement R2, part 2.6," Sub-Requirements 2.1, 2,2, 2,3, and 2.4: Language to be revised to the following:"be supported by current studies or qualified past studies as indicated in Requirement R2, part 2.6. The following studies are required."Sub-Requirement 2.1.2: Definition of "off-peak" not provided and can be read to say that it is any load level less than peak. This does not provide enough clarity to guide the required assessments. Sub-Requirement 2.1.3: It must be clarified that the reference to outages as listed in Requirement R1, part 1.1.2 must be limited to Planning Horizon. Refer to Sub-Requirement 1.1.2 in Question 1.Sub-Requirement 2.1.4: Consistent with the suggestion made for section 1.1.2 please remove the last bulleted item in the list under section 2.1.4. "Duration or timing of planned Transmission outages." The standard is referring to requirements for sensitivity without a reference to base cases. Refer to Comment on Proposal to add an item 1.2 Sub-Requirement 2.1.5: It needs to be clear that this is only an assessment, not a solution. Actions such as out of merit dispatch, operational restrictions, System reconfiguration can be part of a Corrective Action Plan if the System cannot meet performance requirements without the Facility in service. It can be reworded as "an assessment of the impact of this possible unavailability on System performance shall be performed" Sub-Requirement 2.3: The requirement does not indicate a year to study. This should be modified to state that it is up to the Planner to determine the year of study within the Near Term Transmission Planning Horizon. Sub-Requirement 2.4.2: Same as 2.1.2Sub-Requirement 2.4.3: Refer to Comment on Proposal to add an item 1.2 Sub-Requirement 2.5: Revise language as follows:"be supported by current studies or qualified past studies as indicated in Requirement R2, part 2.6. Sub-Requirement 2.7: It is suggested to change the word "run" to "condition" such that it reads "Corrective Action Plan(s) do not

Organization	Comments for Question 2
	need to be developed solely to meet the performance requirements for a single sensitivity condition in accordance with Requirements R2, parts 2.1.4 and 2.4.3." Sub-Requirement 2.7.2: Refer to Comment on Proposal to add an item 1.2 Sub-Requirement 2.9: It should not be necessary to identify the largest consequential load loss if the TPL standard does not limit the size of the consequential load loss. This requirement should be deleted. If it remains, it must be made clear that it be applicable only to Year One or Year Two.

Response: The SDT reviewed Requirement R2, parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizon, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested.

The intent of Parts 2.1.2 and 2.4.2 is to support assessment of those System conditions during periods with lower Load levels than peak when the System may show different potential problems than during periods with peak Load level. For example, during light Load conditions, there may be high voltage problems because of the charging in the lightly loaded lines. There could also be thermal overload problems for areas with more generation than Load. The System could have less damping and could result in potential Stability problems. For this reason, it would not be appropriate to eliminate the requirement to investigate Off-Peak steady state or Stability conditions. At the same time, the standard should not be overly prescriptive; therefore, the exact System Off-Peak Load should be specified by the entity performing the study.

Part 2.1.2 – Off-Peak is a defined term in the NERC Glossary.

Part 2.1.3 is a sub-part of Part 2.1 which is limited by the Near-Term Transmission Planning Horizon so no change is made.

The SDT declines to remove the last bullet in Part 2.1.4, "Duration or timing of planned Transmission outages" as a potential sensitivity. The intent is to cover unexpected changes in plans, for example, a potential delay in returning a Transmission line back to service after a planned outage of 6 months or more for rebuilding to a higher capacity line. In this case, the System with the equipment in question out of service would be modeled as P0 (or N-0), the next outage would be, for example, P1 (N-1), and not covered in P6.

For Part 2.1.4, the SDT believes that the "base case conditions", on which to base the sensitivity cases, should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested.

The SDT believes that your concern on Part 2.1.5 has already been addressed. Part 2.7.1 - Corrective Action can include, among other things:

- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.

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	○ Use of rate applications, DSM, new technologies, or other initiatives. In addition, the first sentence of Part 2.1.5 has been revised. **Requirement R2, part 2.1.5**: When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. The SDT believes that this concern has been addressed. Part 2.3 is silent on the year of study within the Near-Term Transmission Planning Horizon. Therefore, it is up to the Transmission Planner or Planning Coordinator to select the study years most suited to the System in question. In addition, Part 2.3 only requires an annual Planning Assessment, which is to be supported by annual current or qualified past studies. For Part 2.4.3, the SDT believes that the "base case conditions", on which to base the sensitivity cases, should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested. The existing language in Part 2.5 already allows the assessment to be supported by current or past studies. Therefore, the suggested change is not needed. Part 2.7 has been changed to address your concerns. **Requirement R2, part 2.7**: For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: For response to comments on Part 2.7.2, please see previous response to proposal to add Part 1.2. Part 2.9 has been deleted due to industry comments.
Midwest ISO	Requirement R2.1.4: It should be made clear that the sensitivity findings do not obligate the PC or TP to establish Corrective Action Plans to address any needs identified in the sensitivity cases. Also, the use of the following two words "sufficient" and "measurable" are too vague and hard to quantify. This may require an auditor's opinion. Suggest at least removing the word "sufficient" from the requirements. Requirement R2.1.5: This requirement states that we need to perform prior outage analysis for P0, P1 and P2 events for all long-lead time (>1year) components without spares. This seems redundant with P3 and P6 which will answer whether those events are an issue. Need to be clear that loss of load is or is not allowed for these events. P2 still allows for some loss of load. Bottom line is that P2.1.5 seems duplicative. What is intent of requirement? Rather say the P3 and P6 should note if long-lead time items are involved without spares. Also, the Planning Coordinator could have an administrative burden demonstrating compliance with a spare equipment strategy for its entire footprint. Requirement R2.4.3: the use of the following two words "sufficient" and "measurable" are too vague and hard to quantify. This may require an auditor's opinion. Suggest at least removing the word "sufficient" from the requirements.

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	Requirement R2.7.2: As suggested in the comments above for R2.1.4, it should be clarified that corrective actions are not necessary for performance deficiencies identified by sensitivity studies. Request removing this requirement all together. If the SDT agrees to keep this requirement then we offer the following comments: It is not clear how an entity can provide rational for why actions were not necessary. Requirement R2.9: With regards to the largest consequential loss of loads for P1 and P2 events; if no action is required then why require the entities to provide this. Will it matter if 10MW or 100MW is tripped with the line? This is a system design issue which is not addressed by the standards, if this requirement is kept how is an entity expected to demonstrate compliance for this? This requirement is an administrative burden and we propose to remove R2.9 all together considering that there is not a reliability-related need for this information and it is unnecessary.
Response: The SDT believes that your concern on Part 2.1.4 is already covered in the existing draft. The existing Part 2.7 states, in part, that "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, parts 2.1.4 and 2.4.3. In addition, Part 2.7.2 describes the requirement on Corrective Action Plans to "Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary". For Parts 2.1.4 and 2.4.3, The SDT envisions that "credible", "sufficient", "stressed" conditions and "measurable change" are to be defined by the responsible Planning Coordinator or Transmission Planner because each System is different. Part 2.1.5 only requires that the Planning Coordinator or Transmission Planner plans for the potential unavailability of long lead time major Transmission equipment in accordance with its spare equipment strategy. For example, if an entity's spare equipment strategy is to have a spare transformer on site, then the unavailability of a similar transformer (due to outages) would be limited to the time it would take to energize the spare transformer. Assuming that this time is no more than that required to return a similar outaged transformer back in service, Part 2.1.5 can be satisfied without performing additional planning studies. If on the other hand, the transformer would have to be purchased, then it would take more than a year to replace. In this case, for Part 2.1.5, P0 should be modeled with the transformer in question out of service. The performance requirements in Table 1 will apply for the next single Contingency. This is not the same as P2 or P6; both of which are events starting from System intact condition as P0. It is also not the same as P3, which covers loss of a generator as the first event, and Part 2.1.5 covers loss of a piece of major Transmission equipment, for which there is no spare. The words "sufficient" and 'measurable' are needed in Part 2.4.3 to ensure that the variations made to the assumptions to investigate sensitivity are large enough to be meaningful so they can demonstrate the impacts of the changes. The SDT envisions that credible sufficient stressed conditions and measurable changes are to be defined by the responsible Planning Coordinator or Transmission Planner. As such, the SDT declines to revise Parts 2.1.4 and 2.4.3 as suggested. The SDT believes that your concern on Part 2.7 is covered in the existing draft. Part 2.7 states, in part, that "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. In addition, Part 2.7.2 provides for development of a Corrective Action Plan if a number of sensitivity studies result in the same potential problem. For example, if only one sensitivity study results in potential problems or if the probability of occurrences of the sensitivity scenarios is low, then this could be the rationale to state that corrective action plan would not be necessary. Part 2.9 has been deleted as suggested.	
Duke Energy	Reword R2.1 as follows: The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be based on the following annual current studies, supplemented with qualified past studies that meet Requirement R2, part 2.6.

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	The following studies are required: We believe that using a past study for the Long Term Assessment is adequate, as long as the past study meets R2.6. Reword R2.2 as follows: The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be based on the following annual current study or qualified past study that meets Requirement R2, part 2.6. The following study is required: Reword R2.2.1 as follows: System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected. We believe that using past studies for the Near-Term Transmission Planning Horizon portion of the Stability analysis is adequate, as long as the past studies meet R2.6. Reword R2.4 as follows: The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be based on the following annual current studies or qualified past studies that meet Requirement R2, part2.6. The following studies are required: R2.5 Does the phrase "proposed generation additions or changes in that timeframe" refer only to generation changes, or does it also refer to transmission system changes?
Response: The SDT declines to make the change to Part 2.1 as suggested because it does not add more clarity than the existing language. The SDT declines to make this change to Part 2.2 and Part 2.2.1. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire Long-Term Transmission Planning Horizon. Making the change as requested can result in no current-year study for the Long-Term Transmission Planning Horizon being performed. Therefore, the SDT declines to make the change as suggested. The SDT declines to make the change to Part 2.4 as suggested because it does not add more clarity than the existing language. Part 2.5 is intended for investigation of Stability issues due to addition of generators. The SDT does not believe that, in general, a Stability assessment is needed for the Long-Term Transmission Planning Horizon. The System model for that timeframe is too uncertain for a meaningful assessment of the System's Stability. However, for those situations where a specific generator is planned to be added in that timeframe, the SDT believes that it will be appropriate to require that the generator's Stability impact be evaluated.	
NorthWestern Energy	Short circuit analysis is a local issue. The reliability of the BES does not depend on the regular assessment of short circuit duty. Therefore, we believe short circuit analysis should be deleted from R2. The wording in R2.1 is unclear: Are new annual studies required each year or are qualified past studies acceptable if no changes have been made? R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies"

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	Are the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3? Both are for Near-Term studies but for steady state and stability respectively. If they should align, the wording should be modified to be the same. As written R2.1.4, "Real and reactive Load forecasts", could mean that both Real and Reactive Load forecasts are required. Since most entities only forecast Real (MW) and apply a power factor for reactive (MVAR), wording could be changed to " forecasted demand and power factor" to clarify that forecasting reactive load is not required.
Response: Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt. Even though the effects of short circuit capability are localized and may be related to new planned Facilities, it is important to BES reliability. Therefore, the SDT declines to delete the requirement for short circuit analysis from Requirement R2. The SDT reviewed Requirement 2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for the Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested. The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within Parts 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and stability evaluations, respectively. **Requirement R2, part 2.4.3**, **bullet #3**: Expected in service dates of new or modified Transmission Facilities Part 2.1.4 states that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast.	
Sacramento Municipal Utility District	SMUD appreciates the diligence with which the SDT has responded to our earlier comments. SMUD offers the following comments on Draft #4 for the SDT's consideration: R2.1.4: To define a "sensitivity" case, the standard should first define a "base" case. If a sensitivity case is a more conservative scenario analysis than a base case, does an entity need to perform/document a Planning Assessment for both "base" and "sensitivity" or is a Planning Assessment that uses the "Sensitivity" case adequate? R2.1: The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies". R2.1.4 and R2.4.3: The words, "by a sufficient amount" should be removed as it does not provide any more clarity.

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	R2.1.5: The first part of the sentence calls for an analysis of the impact (of modeling the spare equipment strategy). The second part of the sentence that defines the applicable categories to study, starts with the words "The Planning Assessment". Use of the defined words "Planning Assessment", broadens the study to both an impact assessment and providing details of a "Corrective Action Plan". The intent of the requirement should be made clear in the first sentence. R2.4.3: Suggest deleting the words "in the Planning Assessment". Since a corrective action is not required for all sensitivities (see R2.7), use of the defined term in this paragraph can be confusing. R2.6.1: SMUD agrees with allowing a study older than five years to be considered if a technical rationale can be provided. R2.9: The requirement to report the largest single consequential load loss should not be included in the standard. If it remains, it must be made clear that it be applicable only to Year One, and there should be additional clarification that the requirement to report consequential load loss (single number) is ONLY for the most severe contingencies studied for the P1 and P2 contingencies. Table 1 P1.3 and associated Note 5: Is the purpose of the "reference voltage" to determine a valid transformer contingency (thereby, limiting the scope of R2.9)? R2.7 / Table 1, Notes e and i: Note (e) excludes references to load that is allowed to be dropped if it is NOT part of Non-Consequential Load Loss. This note should include such Load (if represented in the load forecast being studied as being part of the Demand Response) if it can be dropped within the time duration applicable to the Facility Ratings. Note (i): Since the definition of Non-CLL would allow interruptible load to be dropped, is note (i) stating that interruptible load cannot be dropped even if it meets the "executable within the time duration' requirement"

Response: For Part 2.1.4, the SDT believes that the "base case conditions" on which to base the sensitivity cases should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. It is also up to the entity performing the study to determine the scenarios to be used for the Planning Assessment.

The SDT reviewed Requirement 2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested.

For Parts 2.1.4 and 2.4.3, The SDT envisions that "credible", "sufficient", "stressed" conditions and "measurable change" are to be defined by the responsible Planning Coordinator or Transmission Planner because each System is different.

Part 2.1.5 is part of Requirement R2, which requires that each Transmission Planner and Planning Coordinator prepare an annual Planning Assessment of its portion of the BES, therefore, the use of Planning Assessment in Part 2.1.5 has not broadened the requirement. The first sentence of Part 2.1.5 has been revised to provide more clarity.

Requirement R2, part 2.1.5: When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of

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one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. For Part 2.4.3, the SDT declines to delete "in the Planning Assessment" as suggested because Part 2.4.3 is part of Requirement R2, which covers the requirement of preparing an annual Planning Assessment. Part 2.9 has been deleted as suggested. Table 1, P1.3 and associated footnote 5: the term "reference voltage" is used in determining if a transformer is classified as EHV or HV for the BES. This classification then ties to footnote 1 in regards to provisions for the interruption of Firm Transmission Service and Non-Consequential Load Loss. For example, if a 345/138 kV transformer is outaged for the event studied the high-voltage (HV) allowances for interruption of Firm Transmission Service and loss of Non-Consequential Load would apply. The 138/66 kV transformer may not be classified as a BES Facility; your regional entity organization definition of the BES should be consulted for an official position. Note (e) in Table 1 refers to "planned System adjustments" and "Transmission configuration changes and re-dispatch of generation" are examples of "planned System adjustments". Table 1 note (i) is intended to clarify that even if it is known that an end-user who implements a more conservative practice than that of the Transmission Planner/Planning Coordinator regarding steady-state voltage criteria and chooses to interrupt its own Load, the end-use Load must still be represented in the steady-state timeframe. The Load tripping is permitted in a Stability review, however, it should be assumed that a customer will react quickly to restore its Load and therefore the standard requires the Load be represented in the steady-state timeframe. Only actions (manual or automatic) taken by the Transmission Planner/Planning Coordinator are permitted for consideration for a steady-state review.	
US Bureau of Reclamation	The conflict is created in Section 2.5 in that only proposed generation additions or changes are assessed in "Long-Term planning Horizon portion of the Stability analysis. This Section should also address proposed transmission facility additoins or changes. Section 2.7 indicates that the Planning Assessment shall include Corrective Action Plan(s) addressing how performance requirements will addressed. This implies that the Corrective Action plans are not proposed generation or transmission additions or changes. If Corrective Action Plan items are developed through Planning Assessments, they should be clarified as proposals for consideration by Generator Owners and Transmission owners in developed future system modifications or additions.
Response: Part 2.5 is intended for investigation of Stability issues due to addition of generators. The SDT does not believe that, in general, a Stability assessment is needed for the Long-Term Transmission Planning Horizon. The System model for that timeframe is too uncertain for a meaningful assessment of the System's Stability. However, for those situations where a specific generator is planned to be added in that timeframe, the SDT believes that it will be appropriate to require that the generator's Stability impact be evaluated. However, the standard does not preclude investigation of addition of other Facilities, such as Transmission Facilities. Part 2.7 does not imply that "the Corrective Action plans are not proposed generation or transmission additions or changes". Part 2.7.2 includes a list of actions that can be included as part of a Corrective Action Plan, which the Transmission Planner and Planning Coordinator are required to prepare.	
TIS	The reference in R2.1.3 to the outage schedules as listing in part R1.1.2 must be recognized as a limitation to the standard to the Planning Horizon. See the TIS comment tor R1.

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	There is confusion in interpretation of the Table 1 When the voltage class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied? For example if a SLG fault is on a 138-kV element or a 345/138-kV autotransformer, are you allowed to shed load to keep a345-kV element from overloading? Conversely, if the fault is on a 345-kV element, are you allowed to shed load to keep a 138-kV from overloading? It should be the voltage level of the overloaded element (not the outaged element) that determines whether or not non-consequential load shedding is allowed. The TIS believes that the requirement to report the largest single consequential load loss under Requirement 2.9 should not be included in the standard. If it remains, it must be made clear that it be applicable only to Year One, and there should be additional clarification that the requirement to report consequential load loss (single number) is ONLY for the most severe contingencies studied for the P1 and P2 contingencies.
Response: Part 2.1.3 is a sub-part of Part 2.1 which is limited by the Near-Term Transmission Planning Horizon so no change is made. The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT's intent and it now reads: **Table 1, footnote 1**: If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. Part 2.9 has been deleted as suggested.	
Idaho Power	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies"?, while R2.1 implies current studies must be used but can be supplemented by past studies. I suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies"? to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies"? It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.
Response: The SDT reviewed Requirement 2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be	

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Modesto Irrigation District Transmission Planning	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads “This Planning Assessment shall use current or past studies”, while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from “The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies” to “The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies” It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change “real and reactive load forecast” to “forecasted demand and power factor” so it is clear that forecasting reactive load is not required.R2.1.4, R2.4.3 "... vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measureable change in performance." Please define measureable. An example would certainly help. This would be a good workshop item to show how to perform. R2.6.2 The previous version defined material change. This current version eliminated the definition of material change, but still indicates the study shall not include any material changes.... This is unclear; please clarify.
Response: The SDT reviewed Requirement R2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require “annual current year study, supplemented by qualified past studies”. Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement	

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NV Energy	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies" It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.
Pacific Gas and Electric Co.	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies"? It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the

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San Diego Gas & Electric Co	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies"? It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.
SRP	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies" It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.
Response: The SDT reviewed Requirement R2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission	

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Puget Sound Energy, Inc.	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies" The wording in R2.1.1 is unclear as to whether two studies are required or only one. Should it read "year one or year two or year 5" as opposed to "year 1 or year 2 and year 5"? The language in 2.3, indicating that short circuit analysis be studied as part a BES transmission planning assessment should not be required. The effects of the failure of over-stressed breakers are already included in the Events listed in Table 1. Examples would include P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). The addition of short circuit analysis study does not add any additional reliability information. It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. R2.9 should be deleted (or not required for local load loss). The SDT indicated in the response to "Consideration of Comments on 3rd Draft of Standard TPL-001-1" that the requirement R2.9 is intended to "contribute to an open and transparent Transmission planning for peer review." And if the "largest Consequential Load Loss" is a local (intra-network) event? Would the documentation of such an event contribute to reliability in any way?
Response: The SDT reviewed Requirement R2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizon, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of	

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Southern California Edison (SCE)	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies"? It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. Additionally, 2.4.2 is inconsistent with 2.4.1 with regards to language. It seems the intent of the Standards Drafting Team was to have the two consistent with each other. Specifically, the quote below, from section 2.4.1, is missing from section 2.4.2 (keeping in mind the word "peak" should be replaced with "Off-Peak"."System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable."

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Response: The SDT reviewed Requirement R2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for the Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested. The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and stability evaluations, respectively. **Requirement R2, part 2.4.3**, **bullet #3**: Expected in service dates of new or modified Transmission Facilities Parts 1.1.4 and 2.1.4 state that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast. In Part 2.4.1, the SDT specifies the dynamic Load model representation for on peak because the System voltages are generally lower during on peak. The percentage of motor Load, e.g., in air conditioners, could significantly increase reactive power requirements especially when they stall due to low System voltage and can therefore impact dynamic System performance on-peak. However, motor Load would likely not pose the same problem during Off-peak as the System voltages are usually higher. So, in Part 2.4.2, it can be left to the discretion of the Planning Coordinator or Transmission Planner whether the dynamic motor Load would need to be represented per the requirement in Part 2.4.1.	
Utility System Efficiencies, Inc. (USE)	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. I suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies"? It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same.
Response: The SDT reviewed Requirement R2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for the Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested.	

Organization	Comments for Question 2
The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and stability evaluations, respectively. **Requirement R2, part 2.4.3**, **bullet #3**: Expected in service dates of new or modified Transmission Facilities	
Western Area Power Adm - RMR	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. I suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies"? It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. In R2.1.5 " the opening statement "When an entity's "spare equipment strategy" Does this imply an auditor would ask for this documentation as part of the review of this new TPL-001? Also " what other Standard requires the "spare equipment strategy"? I'm trying to determine what kind of documentation is required for this Requirement.
Response: The SDT reviewed Requirement R2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizon, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for the Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested. The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and stability evaluations, respectively. **Requirement R2, part 2.4.3**, **bullet #3**: Expected in service dates of new or modified Transmission Facilities Parts 1.1.4 and 2.1.4 state that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast. Part 2.1.5 does not require a spare equipment strategy. It only requires that the Planning Coordinator or Transmission Planner plans for the potential unavailability of long lead time major Transmission equipment in accordance with its spare equipment strategy. For example, if an entity's spare equipment strategy is to have a spare	

Organization	Comments for Question 2
transformer on site, then the unavailability of a similar transformer (due to outages) would be limited to the time it would take to energize the spare transformer. Assuming that this time is no more than that required to return a similar outaged transformer back in service, Part 2.1.5 can be satisfied without performing additional planning study. If on the other hand, the transformer would have to be purchased, then it would take more than a year to replace. In this case, P0 should also be modeled with the transformer in question out of service. The SDT cannot comment on what documentation an auditor would need to support an audit.	
SRC of ISO/RTO	Under 2.1.4- It should be made clear that the sensitivity findings do not obligate the PC or TP to establish Corrective Action Plans to address any needs identified in the sensitivity cases. Specifically, we do not believe the sentence "To accomplish this, the sensitivity analysis in the Planning Assesment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance." is measurable or necessary. The first part of 2.1.4 already stipulates sufficient details for the responsible entity to conduct sensitivity analysis including the parameters to be varied. Adding the "how-to-conduct" requirement is overly prescriptive and unnecessary, and the condition for "that demonstrate a measurable change in performance" is not measurable. It lacks a definitive target or direction for the responsible entity to determine (a) what conditions need to be attained to demonstrate a measurable change in performance, (b) what constitutes "measurable change in performance", and (c) what follow-up or corrective actions are needed to address the adverse performance as a result of stressing the system beyond the forecast conditions. Under 2.1.4 and 2.4.3 "sufficient" and "measurable" are too vague and hard to quantify. This may require an auditor's opinion. Suggest removing at least the word "sufficient" from the requirements. Under 2.3- Some PCs do not perform short circuit analysis. Is it the intent of the SDT to make the analysis standardized over a footprint? Alternatively, this could be a TP only responsibility. Further, Part 2.3 stipulates the short-circuit assessment requirements for the near-term horizon. Unlike its steady-state and stability counterparts, there are no requirements stipulated for short-circuit analysis for the long-term horizon. Is this intentional? If so, we are unable to identify the rationale for this decision. If not, we suggest revising Part 2.3 to: "The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the near-term and long-term Transmission Planning Horizons and can be supported by...". Under 2.7.2, it is not clear how an entity can provide rational for why actions are not necessary. If actions are not necessary, then no rationalizing is needed. Further, as stated above, corrective action plans should not be required for sensitivity studies. R2.7.2 should be struck. We propose to remove R2.9, since there is not a reliability need for this information and it is unnecessary. AESO does not comment on VSLs or VRFs.
Response: For Part 2.1.4, the requirement for Corrective Action Plans to address any needs identified in the sensitivity cases is included in Part 2.7. Part 2.7 states, in part, that “Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. In addition, Part 2.7.2 describes the requirement on Corrective Action Plans to “Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary”. For Parts 2.1.4 and 2.4.3, the SDT envisions that “credible”, “sufficient”, “stressed” conditions and “measurable change” are to be defined by the responsible Planning Coordinator or Transmission Planner because each System is different.	

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Part 2.3 is intended for the Planning Coordinator and Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt. The standard allows the Planning Coordinator and Transmission Planner to coordinate on who would perform short circuit studies. But each is still responsible for meeting the requirements. Part 2.3 is for short circuit assessment of the system in general and is more suited for the Near-Term Transmission Planning Horizon, when Transmission plans are more certain. Lead time to implement corrective action if found necessary can reasonably be expected to be completed in the near-term timeframe. Short circuit study for the longer term planning horizon should be studied on a case by case basis associated with specific project(s). The SDT disagrees that Part 2.7.2 should be struck. Part 2.7.2 provides for development of a Corrective Action Plan if a number of sensitivity studies result in the same potential problem. For example, if only one sensitivity study results in potential problems or if the probability of occurrences of the sensitivity scenarios is low, then this could be the rationale to state that corrective action plan would not be necessary. Part 2.9 has been deleted as suggested.	
Exelon Transmission Planning	We believe that the Table 1 performance criteria should be based on the voltage level of potentially overloaded elements and not based on the voltage level of the element(s) removed from service. If a 100 kV line were overloaded for a 500 kV contingency, it does not make sense to us to treat it differently than if the same overload occurred for a 100 kV contingency since the severity of the event is the same in both cases. The availability of load shedding to reduce overloads on EHV equipment and not for overloads on HV equipment makes sense since typically a greater amount of load would need to be shed to unload an EHV facility than an HV facility. We disagree with the requirement to report the largest amount of consequential load loss. If this information is not used to meet a requirement adding to reliability, it is creating undo burden. If the requirement is kept, it should be made clear as to which case or cases the requirement pertains. The Planning Assessment will contain extremely sensitive information. The threshold that it must be supplied to ANY functional entity is too low. There should be a CEII or other process to ensure that this information is adequately protected.
Response: The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined. Changes were made to footnote 1 to better clarify the SDT's intent and it now reads: **Table 1, footnote 1**: If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. Part 2.9 has been deleted based on industry responses.	
American Transmission Company	We propose the following changes and following questions:New R2.1 We suggest that R2.6 be relocated to the R2.1 position to allow the preferred style of backward references to text that occurs earlier in a document, rather than forward references to text that appears later in a document.

Organization	Comments for Question 2
	R2.1.3 As noted above, we suggest that R1.1.2 be removed and that R2.1.3 be revised to state that "Known outages of generation or Transmission Facilities with a duration of at least six months be simulated along with P1 events for the System peak or Off-Peak conditions when the outages are scheduled to occur." We interpret that simulation of known outages of at least six months should refer only to individual outages with duration of six months or more have to be simulated and not a set of sequential (back-to-back) outages where each individual outage is less than six months, but the composite duration of the set is more than six months. We also interpret that if two or more known outages with duration of at least six months are overlapping that the outage would be simulated as simultaneous for the System peak or Off-Peak conditions when the overlapping outages are scheduled to occur. R2.1.4 The terms of "credible" and "measurable change" are ambiguous and not defined. Therefore, we suggest that these terms be defined or more clearly described to avoid the risk of different and possibly contradictory interpretations by TPs, PCs, and auditors.R2.1.4 bullet items We suggest that the number and description of the bullet items in R2.1.4 match the bullet points in R2.4.3. Otherwise, please explain the reasons for any differences between the bullet items in R2.1.4 and R2.4.3. R2.1.4 bullet #2 & # 5 We suggest that the wording of bulletin #2 be changed to "Expected transfers and other generation dispatch scenarios". This modification would put the transfer and dispatch element, which are complementary, together in the same bullet item, rather than grouping the "generation dispatch" (operating level) element together with the generation capacity elements in bullet item #5. R2.1.4 bullet #7 We propose replacing the adjective "planned" with "known" for consistency with R2.1.3 and any other "known" references in the standard. R2.1.5 We propose replacing the term "major Transmission" with "BES" because BES is a well defined term, while "major Transmission" is not. New R2.3.1 We suggest the addition of new R2.3.1 to emulate the distinction between the requirement to perform a short circuit assessment and conduct required studies or analysis to support the assessment (e.g. R2.1/R2.1.1 and R2.2/R2.2.1). We propose wording such as, "Perform an analysis for at least one year in the Near Term Transmission Planning Horizon." This requirement would set an expectation that an analysis should be conducted to at least one or more years in the near-term planning horizon, rather than imply that an analysis of all five years in the near-term planning horizon must be conducted. R2.4.1 - The terms of "study area" and "represents" are ambiguous and not defined. Therefore, we suggest that these terms be more clearly described to avoid the risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. R2.4.3 The terms of "credible" and "measurable change" are ambiguous and not defined. Therefore, we suggest that these terms be defined or more clearly described to avoid the risk of different and possibly contradictory interpretations by TPs, PCs, and auditors.R2.4.3 bullet items We suggest that the number and description of the bullet items in R2.1.4 match the bullet points in R2.1.4. Otherwise, please explain the reasons for any differences. R2.4.3 bullet #2 & # 5 We suggest that the wording of bulletin #2 be changed to "Expected transfers and other generation dispatch scenarios". This would place these similar items in the same bullet item #2, rather than having the "other generation dispatch" in bullet item #5.

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	R2.4.3 bullet #3 We suggest that the wording of "new or modified Transmission Facilities" to agree with the wording in bulletin #3 of R2.1.4. R2.6 As noted earlier, we suggest that the numbering of this requirement be changing it to R2.1 to avoid the style of forward references. Add R2.7.1 Item #7 - We propose the addition of the following bullet item to R2.7.1 because any requirement in the head notes or foot motes of Table 1 should occur within the body of standard. Item #7 could read, "Planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration of the Facility Ratings." Note "e" in the Planning Events, Steady State & Stability section is stated in the form of a Requirement (e.g. use the verb "shall"), but all requirements should be included in the Requirements section and not introduced (and basically hidden) in the performance notes of Table 1. [After bullet item #7 is added, Note "e" under "Steady State & Stability section of Table 1 should refer to R2.7.1] R2.7.2 " We suggest using the term, "mitigation actions", to more clearly distinguish that this requirement is not asking for the development of "Corrective Action Plans", such as those that are needed for inability to meet base case performance requirements.R2.7.6 We suggest that the wording of R2.7.6 be the same as R.2.8.2. Otherwise, we propose that R2.7.6 and R2.8.2 be revised with wording like, ". . . implementation status of identified Corrective Action Plans for System Facilities and Operating Procedures." to clarify that the identified system facilities and operating procedures refer only to those that were in the previous year's Corrective Action Plans. R2.9 We still propose that this requirement be removed because annually stating the single, largest expected, Consequential Load Loss due to a P1 or P2 event in the TP or PC system is not needed to provide reliable BES performance or assure open and transparent Transmission planning peer review.

Response: The SDT reviewed the order of Parts 2.1 and 2.6 and declines to modify it as suggested because it does not add additional clarity.

Part 2.1.3 covers known long duration outages, for example, taking a 230 kV Transmission line out of service to rebuild it to operate at 500 kV. These cases are to simulate System conditions with the Facility in question out of service as Category P0 (or N-0). For the next outage, the System performance will need to meet requirements for Category P1. This is not the same as requirements for Category P6, which assumes that the outage for the first Facility would be of shorter duration than 6 months. Part 2.1.3 has been revised to read "P1 events in Table 1 with known outages modeled, as in Requirement R1, part 1.1.2 under those System peak or Off-Peak conditions when known outages are scheduled" to provide more clarity. The SDT agrees that if two or more known outages with duration of at least six months are overlapping that the outage should be simulated as simultaneous for the conditions when the overlapping outages are scheduled to occur. This is consistent with the requirement to simulate the System conditions as it is expected to operate.

For Parts 2.1.4 and 2.4.3, the SDT envisions that "credible", "sufficient", "stressed" conditions and "measurable change" are to be defined by the responsible Planning Coordinator or Transmission Planner because each System is different. The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within Parts 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and Stability evaluations, respectively.

Requirement R2, part 2.4.3, **bullet #3**: Expected in service dates of new or modified Transmission Facilities

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	The SDT declines to change the second and fifth bullets in Part 2.4.3 because the existing arrangement will keep the generator scenarios together. Expected transfers are not always associated with generation dispatch. In Part 2.1.4, bullet #7, the SDT declines to replace "planned" with "known" as suggested in "Duration or timing of planned Transmission outages". Part 2.1.4 covers sensitivity scenarios and reflects uncertainty in planning assumptions. The intent of this bullet is to cover unexpected changes in plans, for example, a potential delay in returning a Transmission line back to service after a planned outage of 6 months or more for rebuilding to a higher capacity line. If the outage is "known", then there would not be any need to perform this study as a sensitivity. In Part 2.1.5, the SDT declines to replace the term "major Transmission equipment" with "BES equipment" because the intent is to investigate the unavailability of major pieces of equipment in the Transmission System. Transmission is defined in the NERC Glossary as, "An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems". Part 2.3 is silent on the year of study within the Near-Term Transmission Planning Horizon. Therefore, it is up to the Transmission Planner or Planning Coordinator to select the study years most suited to the System in question. In addition, Part 2.3 only requires an annual Planning Assessment, which is to be supported by annual current or qualified past studies. As such, the SDT believes it is inappropriate to make the change as suggested Part 2.4.1: The SDT believes that the terms of "study area" and "represents" should be defined by the Planning Coordinator or Transmission Planner performing the study, and should be part of the coordination between the entities. For Parts 2.1.4 and 2.4.3, The SDT envisions that "credible", "sufficient", "stressed" conditions and "measurable change" are to be defined by the responsible Planning Coordinator or Transmission Planner because each System is different. The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within Parts 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and stability evaluations, respectively. **Requirement R2, part 2.4.3**, **bullet #3**: Expected in service dates of new or modified Transmission Facilities The SDT declines to change the second and fifth bullets in Part 2.4.3 because the existing arrangement will keep the generator scenarios together. Expected transfers are not always associated with generation dispatch. The SDT reviewed the order of Part 2.1 and Part 2.6 and declines to modify it as suggested because it does not add additional clarity. Note e in Table 1 is a condition for allowance of planned System adjustments, which could include Operating Plans such as re-dispatch. Part 2.7.1 is a list of examples, so it could include more items than listed, including Note e in Table 1. The SDT declines to make the suggested change. Part 2.7.2 provides for development of a Corrective Action Plan if a number of sensitivity studies result in the same potential problem. For example, if only one sensitivity study results in potential problems or if the probability of occurrences of the sensitivity scenarios is low, then this could be the rationale to state that corrective action plan would not be necessary. Part 2.9 has been deleted as suggested.
PJM	R2 should use the term –dynamics analysis- instead of –stability analysis-. A dynamics study is used to determine stability like a power flow study is used to determine overloads or voltage violations. In R2.1.1 is -System peak Load- seasonal peak load or the peaking season of that region? For example, if I'm a summer peaking

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	region, must I do a summer peak study and a winter peak study or just a summer peak study? In R2.1.3, change -for known outages, as modeled in- to –with known outages modeled, as required in-. R2.1.5 should be made clear that only one piece of equipment should be taken out at a time for each sensitivity. No matter what FERC says, this requirement should be deleted because this analysis serves no purpose. If a spare equipment strategy is required, please tell us so in a spare equipment standard, not hidden here in a performance standard. R2.4.3 – Please delete the words -for the list of items shown below- at the end of the first sentence. There is an implication in this sentence, as originally worded, that a sensitivity must be performed for the entire list of sensitivities instead of how it is explained in the second sentence. R2.6.2 – Please reword -the study shall not include any material changes- to –a study with material changes shall not be used- The old sentence sounded like you just exclude the material changes and you are good to go. R2.7.1 – Please change -List System deficiencies- to –List performance deficiencies-. R2.7.1 – 3rd Bullet – I would lump this under Special Protection Systems, also why is runback not allowed for dynamics problems, seems there are some restrictions buried here. R2.7.1 – 6th Bullet – What is a –rate application-? R2.7.2 – This is pushing us to plan the system for scenarios that may never happen. Pushing us to some higher level of reliability will cost significant money. Should the ratepayers be burdened with this excess? I say no, remove this requirement. R2.8.1 – Change -List System deficiencies- to –List short circuit deficiencies-.

Response: The SDT declines to replace "Stability analysis" with "dynamic analysis" because it does not add additional clarity.

The intent of Part 2.1.1 is to assess those System conditions under peak Load conditions when the System is reasonably stressed. It is envisioned that the Planning Coordinator or Transmission Planner will determine the System conditions for its planning studies.

Part 2.1.3 has been revised as suggested.

> **Requirement R2, part 2.1.3**: P1 events in Table 1 with known outages modeled, as in Requirement R1, part 1.1.2 under those System peak or Off-Peak conditions when known outages are scheduled.

Part 2.1.5 only requires that the Planning Coordinator or Transmission Planner plans for the potential unavailability of long lead time major Transmission equipment in accordance with its spare equipment strategy. For example, if an entity's spare equipment strategy is to have a spare transformer on site, then the unavailability of a similar transformer (due to outages) would be limited to the time it would take to energize the spare transformer. Assuming that this time is no more than that required to return a similar outaged transformer back in service, Part 2.1.5 can be satisfied without performing additional planning studies. If on the other hand, the transformer would have to be purchased, then it would take more than a year to replace. In this case, P0 should be modeled with the transformer in question out of service.

Part 2.4.3 has been revised as suggested.

> **Requirement R2, part 2.4.3**: For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of

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	the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: Part 2.6.2 has been revised as suggested. **Requirement R2, part 2.6.2**: For steady state, short circuit, or Stability analysis: the System represented in the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. The SDT declines to revise Part 2.7.1 as suggested because it does not add additional clarity. The SDT declines to combine the third bullet with Special Protection Schemes (SPS) because automatic generation tripping does not always have to be part of an SPS. In any case, this list contains examples only. It is envisioned that run-back would take a longer time period and would not fit in the transient Stability study period. Part 2.7.1, sixth bullet, "rate application" can be regulatory incentives, such as demand response, distributed generation, etc. Part 2.7.2 provides for development of a Corrective Action Plan if a number of sensitivity studies result in the same potential problem. For example, if only one sensitivity study results in potential problems or if the probability of occurrences of the sensitivity scenarios is low, then this could be the rationale to state that corrective action plan would not be necessary. In addition, Part 2.7.1 allows the use of lower cost alternatives, such as operating procedures, among other things to correct potential performance deficiencies identified. The SDT declines to revise Part 2.8.1 because the language as written is clear.

3. Requirement R3 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: The SDT has modified the wording of several parts of Requirement R3 to increase clarity as requested by many industry comments and shown below. Requirement R3, part 3.6 was deleted in response to industry comments as it is not a performance oriented requirement.

Requirement R3, part 3.3: Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

Requirement R3, part 3.3.2: Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

Requirement R3, part 3.3.3: Trip Transmission elements when relay loadability limits are exceeded.

Requirement R3, part 3.5: Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

Requirement R3, part 3.6:

Requirement R3, data retention: The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.

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Independent Electricity System Operator	(1) R3 has become more of a “how to” requirement than a “what” requirement, as illustrated below. (a) Part 3.3 is overly prescriptive. A requirement that says contingency analysis shall be performed which reflect proper operation of all Protection Systems and actions of all automatic devices would suffice. If necessary, some examples such as those listed in Part 3.3.4 may be added as illustration. (b) The parts that ask for creating a list of contingencies and having rationale available as supporting information, in Part 3.4 for example, are overly prescriptive and unnecessary. These are documentation requirements, not reliability requirements. If one asked the question: will reliability be adversely affected if the responsible entity failed to document the list and the rationale for choosing this list? If the answer is no, then they don’t rise up to a reliability standard. To meet the intent of Part 3.4, a simple requirement that asks the responsible entity to demonstrate acceptable system performance for the applicable planning events in Table 1 would suffice. Table 1 already stipulates the events that must be considered in the analysis. We do not see the need to go into such details as “some events are expected to produce more severe impacts”, and the need to ask the planners to

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	create a list of these more impactive contingencies for subsequent evaluation. Similar observation is made for Part 3.5 on the extreme event list and for Part 3.6 for the amount of generation loss, and the rationale. (2) We have no comments on the measure, VRF and Time Horizon. However, there is no VSL for Part 3.6.
Response: R3: The SDT disagrees with the comment. The parts of Requirement R3 specify the components required for a compliant study. No change made. Part 3.4 & Part 3.5: Require the planning entity to identify which Contingencies are chosen to be simulated in the study, and explain why these are chosen. The SDT assumes that the Planning Coordinator/Transmission Planner, applying experience of past studies and knowledge of its System, is in the best position to determine which Contingencies in Table 1 are most relevant, as it is impossible to study all Contingencies especially the multiple Contingency events. No change made. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES. VSL for Part 3.6: The SDT has deleted Part 3.6.	
ERCOT ISO	* Will any agreements made in R7 override the “each TP and PC” requirement? To clarify this, the requirement could be rephrased: "In accordance to the responsibilities assigned in R7, the responsible Transmission Planners and Planning Coordinators shall perform?. "* Section 3.1 and 3.4 appear to be related. Confusing references can be eliminated by combining them and removing 3.4 as follows: "3.1. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES shall be identified and studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1. A list of those Contingencies and the rationale for those Contingencies selected for evaluation shall be available as supporting information".* Similarly, Section 3.2 and 3.5 appear to be related. Confusing references can be eliminated by combining them and removing 3.5: "3.2. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and studies shall be performed to assess the impact of the extreme events. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted A list of the events and the rationale for those Contingencies selected for evaluation shall be available as supporting information."
Response: R7: The agreements required by Requirement R7 are intended to clarify the responsibilities among the Planning Coordinator and Transmission Planner. The SDT believes this is clear in the existing language. No change made. Parts 3.1 & 3.4: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Parts 3.2 & 3.5: The SDT does not believe that combining the requirements provides any significant advantage. No change made.	
Northeast Utilities	[R3.3.2] Traditionally, transmission planners have assumed that generators would ride through low voltages associated with Planning Events, which is generally adequate for non-wind generators. If this standard is going to require its incorporation into the assessments, there should be a MOD standard developed requiring the generator owners to provide the necessary

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	information prior to its inclusion as a requirement in this standard. [R3.3.3] This requirement is already addressed in NERC Standard PRC-023 and reflected in facility ratings and therefore, should be removed from TPL-001-1. [R3.5] This requirement needs clarification as to what is specifically required for the "evaluation of possible actions". Otherwise the following is recommended: It should be clear that an evaluation does not require solution development for all Extreme Events. Change "an evaluation of possible actions" to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered." [R3.6] Why the need to report the amount of "Consequential Generation Loss" since TPL-001-1 does not impose any limit or reliability consequence? We recommend that this requirement be deleted from the standard.
Response: Part 3.3.2: Where test data is not available, the SDT believes that most Transmission Planners/Planning Coordinators currently assume generators ride through low voltage based on extensive field experience. There is a project (Project 2007-09 — Generator Verification) that will provide the required generator data to validate the assumptions. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure that the simulation models the generator response as it will react in the real world. If voltage ride through limits would cause a generator to trip in the real world, the study must determine if the performance requirements are met for the initiating event and subsequent generator trip. No change made for this comment. Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.5: The requirement is to evaluate possible actions which, if implemented, could reduce the likelihood or mitigate the consequences of an extreme event. The SDT believes that what these "possible actions" are should be left to the judgment of the Planning Coordinator/Transmission Planner who has knowledge of their System. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.	
Central Maine Power Company	3.2 Item 3.2 should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. 3.3.2 This requirement is not practical unless a MOD is created so that known minimum generator steady state or ride through voltage limitations are used instead of assumed values. To create a MOD, collect the data, and incorporate the information into the studies will take time, which necessitates the need for an implementation period. Absent accepting this suggestion with respect to creating an MOD, please provide assumed minimum generator steady state or ride through voltage limitations as a standard reference for this analysis. 3.3.3 There appears to be a compliance double-jeopardy issue related to relay loadability. Relay loadability is handled in

Organization	Comments for Question 3
	greater detail (as it should be) under the proposed PRC-023 standard, so any reference here should be deleted. 3.4 It is suggested that this requirement is made a sub-bullet of Requirement 3.1 to keep the related requirements together. 3.5 and 4.5 Both of these requirements need clarification as to what is specifically required for the "evaluation of possible actions." 3.5 It is suggested that this be made a sub-bullet of Requirement 3.2 to keep the related requirements together. 3.6 Item 3.6 should be deleted since there is no limit defined in the standard.
ISO New England	3.2 Item 3.2 should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. 3.3.2 This requirement is not practical unless a MOD is created so that known minimum generator steady state or ride through voltage limitations are used instead of assumed values. To create a MOD, collect the data, and incorporate the information into the studies will take time, which necessitates the need for an implementation period. Absent accepting this suggestion with respect to creating an MOD, please provide assumed minimum generator steady state or ride through voltage limitations as a standard reference for this analysis. 3.3.3 There appears to be a compliance double-jeopardy issue related to relay loadability. Relay loadability is handled in greater detail (as it should be) under the proposed PRC-023 standard, so any reference here should be deleted. 3.4 It is suggested that this requirement is made a sub-bullet of Requirement 3.1 to keep the related requirements together. 3.5 and 4.5 Both of these requirements need clarification as to what is specifically required for the "evaluation of possible actions." 3.5 It is suggested that this be made a sub-bullet of Requirement 3.2 to keep the related requirements together. 3.6 Item 3.6 should be deleted since there is no limit defined in the standard.
United Illuminating	3.2 Item 3.2 should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. 3.3.2 This requirement is not practical unless a MOD is created so that known minimum generator steady state or ride through voltage limitations are used instead of assumed values. To create a MOD, collect the data, and incorporate the information into the studies will take time, which necessitates the need for an implementation period. Absent accepting this suggestion with respect to creating an MOD, please provide assumed minimum generator steady state or ride through voltage limitations as a standard reference for this analysis. 3.3.3 There appears to be a compliance double-jeopardy issue related to relay loadability. Relay loadability is handled in

Organization	Comments for Question 3
	greater detail (as it should be) under the proposed PRC-023 standard, so any reference here should be deleted. 3.4 It is suggested that this requirement is made a sub-bullet of Requirement 3.1 to keep the related requirements together. 3.5 and 4.5 Both of these requirements need clarification as to what is specifically required for the "evaluation of possible actions." 3.5 It is suggested that this be made a sub-bullet of Requirement 3.2 to keep the related requirements together. 3.6 Item 3.6 should be deleted since there is no limit defined in the standard.
Response: Part 3.2: The SDT disagrees and believes there is value in running extreme event analysis to test the robustness of the System. No change made. Part 3.3.2: Where test data is not available, the SDT believes that most Transmission Planners/Planning Coordinators currently assume generators ride through low voltage based on extensive field experience. There is a project (Project 2007-09 — Generator Verification) that will provide the required generator data to validate the assumptions. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure that the simulation models the generator response as it will react in the real world. If voltage ride through limits would cause a generator to trip in the real world, the study must determine if the performance requirements are met for the initiating event and subsequent generator trip. No change made. Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.4: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Parts 3.5 & 4.5 The requirement is to evaluate possible actions which, if implemented, could reduce the likelihood or mitigate the consequences of an extreme event. The SDT believes that what these "possible actions" are should be left to the judgment of the Planning Coordinator/Transmission Planner whose has knowledge of their System. Part 3.5: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.6: Part 3.6: The SDT has deleted part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.	
Florida Municipal Power Agency, and its Member Cities	3.3.1, is the intent of the SDT that extreme events that may cause loading beyond relay trip settings (especially Zone 3) be simulated? There is no need for 3.3.3 since the Facility Ratings should already take this into account (FAC-008, R1.2.1 The scope of equipment addressed shall include, but not be limited to, " relay protective devices, "). This adds unneeded burden to transmission planners in developing evidence for this that already exists elsewhere. In other words, by respecting Facility Ratings, we respect relay loadability.
Response: Part 3.3.1: The intent of the SDT is for the planner to simulate the Protection System operation so that all elements that the Protection System is designed to remove (breaker to breaker) are removed in the simulation for the list of Contingencies the planner has developed in Requirement R3, parts 3.4 (planning events)	

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and 3.5 (extreme events). Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded.	
Oncor Electric Delivery	3.3.2 Do we want to be able to trip gen? 3.3.3 Relay loadability covered in PRC-023 3.6 Why is this information reported if there is no limit or reliability consequence. 3.3.3 This requirement is already addressed in NERC Standard PRC-023 and reflected in the facility's rating and should be removed from TPL-001-1. 3.4 It is strongly suggested that this requirement is made a sub-bullet of Requirement 3.1 to keep the related requirements together. 3.5 and 4.5 Both of these requirements need clarification as to what is specifically required for the "evaluation of possible actions." 3.5 It is strongly suggested that this be made a sub-bullet of Requirement 3.2 to keep the related requirements together. 3.6 It is recommended that the "consequential generation" loss is excluded from the amount documented. [Why?]
Response: Part 3.3.2: In order to ensure performance requirements are met in cases where System conditions could cause a generator to trip, Requirement R3, part 3.3.2 requires that the entity trip a generator at locations where bus voltages in the simulation fall below known or assumed generator steady state or ride through voltage limits. No change made. Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded. Part 3.4: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Parts 3.5 & 4.5 The requirement is to evaluate possible actions which, if implemented, could reduce the likelihood or mitigate the consequences of an extreme event. The SDT believes that what these "possible actions" are should be left to the judgment of the Planning Coordinator/Transmission Planner who has knowledge of their System. Part 3.5: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.	

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FirstEnergy Corp	A. The inclusion of sub-part 3.3.3 of Requirement R3 that reads "Ensure relay loadability limits are respected" is not needed as it is duplicative with standard PRC-023, and indirectly redundant with the facility rating standards FAC-008 and FAC-009. Additionally, the introductory notes of performance Table 1 item "f" is clear that Facility Ratings shall not be exceeded and PRC-023 makes it clear that relay loadability must be accounted for in Facility Ratings. In NERC's three-year assessment, Attachment 2 it clearly indicates that one goal of NERC's standards development work plan is " ...retiring redundant requirements ..." (Please reference page 4, the 6th bullet under plan objectives). To that end, we should not knowingly create redundant requirements that lead to double jeopardy issues for industry stakeholders. If a "belts and suspenders" is the goal here, it's suggested that a footnote be added to item "f" of the introductory notes that would clarify that PRC-023 must be adhered to with regard to Facility ratings. B. If the generator bus is modeled at the generator voltage, then this should be the reference voltage point. If the generator is modeled directly connected to the BES, then the transmission voltage should be the reference voltage. Either way, the reference point should be consistent. In addition, 3.3.2 requires the unit to be tripped. It should be noted that the minimum voltage point may be overly-conservative, since the minimum voltage that a unit can stay on line is MVA output dependent. For base load units, determining a generator minimum voltage should be relatively straightforward, however, peaking and regulating units, not so. Our experience has been that generating units at manned locations generally do not have undervoltage protection or alarms, so FE is not certain how this Requirement to trip those units matches the "real world". C. We suggest the team discontinue the use of "Coordinate with adjacent transmission planners" in regards to sub-part 3.4.1 related to the inclusion of contingencies from adjacent systems. The "coordination" type of requirements creates a need to develop compliance evidence such as e-mail correspondence, meeting minutes etc that serve no real reliability purpose. The requirement should simply be that the TP shall include adjacent System contingencies expected to produce the more severe System impacts on their system. In fact, sub-part 3.4 already includes that language. We suggest the team append the sentence "The planning event contingencies shall include:" to the end of sub-part 3.4 followed by two bullets that indicate 1) events within the TP's system and 2) events on adjacent transmission Systems.
Response: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded. Part 3.3.2: Where test data is not available, the SDT believes that most Transmission Planners/Planning Coordinators currently assume generators ride through low voltage based on extensive field experience. There is a project (Project 2007-09 — Generator Verification) that will provide the required generator data to validate the assumptions. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure that the simulation models the generator response as it will react in the real world. If voltage ride through limits would cause a generator to trip in the real world, the study must determine if the performance requirements are met for the initiating event and subsequent generator trip. No change made. Part 3.4.1: SDT believes that it is necessary for the planner to coordinate with adjacent planners to identify contingencies in adjacent systems that could impact the planners system. No change made.	
Progress Energy Florida, Inc.	As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all

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	appropriate parties to review PEF's previous comments to this effect.
Response: Throughout the drafting process, the SDT has carefully considered your comments as well as comments from other industry members.	
CenterPoint Energy	CenterPoint Energy recommends references to "Long-Term Transmission Planning Horizon" be revised to contain comparable language as in the existing TPL standards that limit Long-Term studies to marginal system conditions requiring longer lead times. See CenterPoint Energy's comments regarding part 2.2 for the rationale behind this recommendation. CenterPoint Energy also recommends deleting part 3.4.1 as being overly prescriptive and difficult to demonstrate in an audit.
Response: Long-Term Transmission Planning Horizon: The SDT believes there is value in taking a long range view in planning to assess the general trend. Since the Long-Term planning horizon is year 6 – year 10, the Planning Coordinator or Transmission Planner can for example, select year 6 in the Long-Term Planning Horizon and then use this study as the past study to supplement the Near-Term year 5 study requirement the following year. No change made. Part 3.4.1: SDT believes that it is necessary for the planner to coordinate with adjacent planners to identify Contingencies in adjacent Systems that could impact the planners System. No change made.	
ITC Holdings	Comments: Assumptions regarding Low Voltage Ride Through (LVRT) capability are risky and not well understood. If the SDT feels this is a critical requirement that merits corrective action then we believe LVRT characteristics for various machine types should be developed through a NERC process. Without such "standards", it will be difficult to justify CAPs based on LVRT assumptions. For example, would the Transmission Owner (TO) or Generator Owner be responsible for the cost of VAR CAPs if an LVRT assumption were violated. Can a TO require an LSE to install automatic load shedding for an LVRT assumption when cascade or local load loss result from an LVRT assumption? In addition, as the SDT has already indicated, the industry is still in a learning curve regarding the dynamic behavior of certain loads. If LVRT capability is considered as a critical requirement, then what about High Voltage Ride Through (HVRT) capability? The violation of HVRT could also cause certain damages to the system. R3.4.1 (contingency list coordination with neighbors) It's unclear as to the "measure" for this requirement. Do you give your neighbor a list of "contingencies" in your area. Should it include all categories (p1 thru p7 for example)? Does your neighbor have to study a cascade situation in his system caused by an outage in your system? Are joint studies merited? More importantly, if an outage in a neighboring system requires a CAP, who's responsible, particularly if the CAP involves the neighboring system. Does the neighbor have to have a CAP, according to this standard, if the violation is in your system, and the CAP is in his? Who pays? Are you putting a study burden on your neighbor when you do this? Do you include additional contingencies to ensure that you do not miss a contingency that might impact your neighbors system to avoid any potential compliance implication on you?
Response: Part 3.3.2: Where test data is not available, the SDT believes that most Transmission Planners/Planning Coordinators currently assume generators ride through low voltage based on extensive field experience. There is a project (Project 2007-09 — Generator Verification) that will provide the required generator data to validate the assumptions. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure that the simulation models the generator response as it will react in the real world. If voltage ride through limits would cause a generator to trip in the real world, the study must determine	

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if the performance requirements are met for the initiating event and subsequent generator trip. No change made. If tripping of a generator results in performance which does not meet the requirements in Table 1, Requirement R2, part 2.6 requires the planner to develop a Corrective Action Plan. The allocation of costs to implement such a plan is beyond the scope of this standard. The SDT has decided not to include a requirement for high voltage ride through. Part 3.4.1: SDT believes that it is necessary for the planner to coordinate with adjacent planners to identify Contingencies in adjacent Systems that could impact the planners System. No change made. The SDT believes that the methodology for determining the appropriate Contingencies in the adjacent Systems is best left to the judgment of each planner. This could include Contingencies from all planning event categories (P1 to P7) if it is judged they could have an impact. Similarly, the neighboring System would select categories in adjacent Systems to study. The requirement does not mandate joint studies. If a performance deficiency is found in the planner's System due to a Contingency in an adjacent System, it is up to the planner in whose System the deficiency exists to develop the CAP. Cost allocation for the CAP is beyond the scope of this standard.	
FRCC Transmission Working Group	Comments: With regard to the Moderate VSL, consider deleting "utilizing data" in order to avoid penalizing twice for failing to meet R1. Please provide clarity to 3.3.2 which states that a Planning Assessment "it must perform simulation that show generator ride through voltage limitation". However, ride through is only performed through stability simulation.The references within the requirements are very confusing. 3.1 refers to a contingency list created in 3.4 which refers back to 3.1. Similarly 3.2 refers to a contingency list created in 3.5 which refers back to 3.2. These should be combined into one requirement bullet. Please provide clarity to 3.3.1. Is the intent of the drafting team that extreme events that may cause loading beyond relay trip settings (zone 3) be simulated?
Response: VSL: Requirement R1 requires you to maintain System models. Requirement R4 requires you to use that model data for your Stability studies. These are two different things requiring two VSLs. No change made. Part 3.3.2: Generators can trip when bus voltage drops below minimum generator steady state voltage limits. The SDT believes that the voltage ride through test is applicable in post-Contingency steady-state where the planner would know if post-contingency bus voltage violates generator trip points. If a trip point is violated, Requirement R3, part 3.3.2 would require the planner to remove the generator in the post-Contingency case to assess if performance is met with the generator removed. No change made. Parts 3.1 & 3.4; 3.2 & 3.5: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.3.1: The intent of the SDT is for the planner to simulate the Protection System operation so that all elements that the Protection System is designed to remove (breaker to breaker) are removed in the simulation for the list of Contingencies the planner has developed in Requirement R3, parts 3.4 (planning events) and 3.5 (extreme events). Requirement R3, Part 3.3 wording has been modified to add to clarify the intent. **Requirement R3, part 3.3**: Contingency analyses for Requirement R3, parts 3.1 & 3.2 shall:	
Gainesville Regional Utilities	Even though I do assess my portion of the BES, I do so, not in an isolated, detached vacuum, but in light of its active connection to the rest of the FRCC Region and how, if at all possible, my small system could in any way be determined at the region level

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	to have any impact in any of the functional areas of the entire region. So the requirements in this section are considered and assessed as "a part of the whole".
Response: As you have not referenced a specific section, the SDT can not provide a response.	
Utility System Efficiencies, Inc. (USE)	For clarity I suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits.
Bonneville Power Administration	For clarity we suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits.
Idaho Power	For clarity we suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits.
NV Energy	For clarity we suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits."
San Diego Gas & Electric Co	For clarity we suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits.
Southern California Edison (SCE)	For clarity we suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits."
SRP	For clarity we suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits."
Western Area Power Adm - RMR	For clarity, I suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits."
Deseret Power	Comments: For clarity we suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits.
Response: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded.	
TVA System Planning	In R3.3.3, TVA believes that relay loadability is already covered in PRC-023. TVA is concerned that including this requirement could result in possible double jeopardy if a utility was found non compliant with PRC-023. Is the SDT proposing that relay

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	loadability be covered for all BES facilities or just those facilities identified in PRC-023?
Response: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded. The SDT intent is that Requirement R3, part 3.3.3 applies to those BES elements where relay loadability limit is defined by PRC-023.	
Modesto Irrigation District Transmission Planning	For clarity we suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits. Also please define relay loadability limit.
Response: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded. R3.3.3: Relay loadability is defined in PRC-023-1.	
MidAmerican Energy Company	MidAmerican commends the SDT for their hard work on this standard. MidAmerican does have comments about this requirement though. MidAmerican recommends the data retention for R3 and M3 be revised to change "All" to "The". The word "All" is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: "THE studies performed in support". The word in all caps is a word suggested to be added.
Response: Data Retention: The SDT agrees with your suggestion. The wording in "data retention" for R3 has been changed. Measure M3 already use the word "the". **Requirement R3, data retention:** The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.	
Progress Energy Carolinas	PEC believes that R3.3.3 "Ensure relay loadability limits are respected" is unnecessary. The requirement to stay within Facility Limits is much more bounding. Several footnote references from Table 1 to the footnotes are incorrect.
Response: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Table1: The SDT has corrected the footnote references.	

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Oklahoma Gas & Electric	R 3.4, R3.5 There appear to be no standards of directions on identifying severe or extreme system impacts. OG&E does not like being held accountable to nebulas standards. Need more specific information.
Response: Parts 3.4 & 3.5: The SDT assumes that the Planning Coordinator/Transmission Planner applying experience of past studies and knowledge of its System is in the best position to determine which Contingencies in Table 1 are most relevant, as it is impossible to study all Contingencies especially the multiple Contingencies. No changes made.	
SRC of ISO/RTO	R3 has become more of a "how to" requirement than a "what" requirement as illustrated below. (a) Part 3.3 is overly prescriptive. A requirement that says contingency analysis shall be performed which reflect proper operation of all Protection Systems and actions of all automatic devices would suffice. If necessary, some examples such as those listed in Part 3.3.4 may be added as illustration. (b) The parts that ask for creating a list of contingencies and having rationale available as supporting information, in Part 3.4 for example, are overly prescriptive and unnecessary. These are documentation requirements, not reliability requirements. If one ask the question: Will reliability be adversely affected if the responsible entity failed to document the list and teh rationale for choosing the list? and the answer is no, then the requirement does not rise up to a reliability standard. To meet the intent of Part 3.4, a simple requirement that asks the responsible entity to demonstrate acceptable system performance for the applicable planning event in Table 1 would suffice. Table 1 already stipulates the event that must be considered in the analysis. We do not see the need to go into such details as "some events are expected to produce more severe impacts...", and the need to ask the planners to create a list of these more impactive contingencies for subsequent evaluation. Similar observation is made for Part 3.5 on the extreme event list and for Part 3.6 for the amount of generation loss, and the rationale. AESO does not comment on VSLs or VRFs>
Response: R3: The SDT disagrees with the comment. The parts of Requirement R3 specify the components required for a compliant study. No change made. Part 3.4 & Part 3.5: Require the planning entity to identify which contingencies are chosen to be simulated in the study, and explain why these are chosen. The SDT assumes that the Planning Coordinator/Transmission Planner, applying experience of past studies and knowledge of its System, is in the best position to determine which Contingencies in Table 1 are most relevant, as it is impossible to study all Contingencies especially the multiple Contingency events. No change made. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES. VSL: The SDT does not understand the reference to AESO.	
Manitoba Hydro	R3.2: Recommend changing “the list” to “the Contingency list” to add clarity and consistency.
Response: Part 3.2: SDT does not believe clarity is improved by adding the word "contingency" to the word "list". No change made.	

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MRO NERC Standards Review Subcommittee	R3.3.1 Revise the wording to add, ". . . including the simulation of transmission circuit loadability protection." The Protection System actions should be included in this requirement regarding proper Protection System simulation, rather than as a separate requirement in R3.3.3. Otherwise there would be in double jeopardy of violating R3.3.1. and R3.3.3 when circuit loadability protection is not properly simulated. R3.3.2 The MRO NSRS suggests that this requirement be removed because it is premature to requirement Transmission Planners to simulate under voltage tripping until the MOD standards require it. If the drafting team does not remove this requirement the MRO NSRS proposes revised wording to qualify which generating units to consider and which voltage limits to simulate, "Trip generating units that are connected to the BES when actual or assumed minimum generator steady state or ride through voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment". The requirement should not apply to all relevant generating units until one of the MOD standards requires all Generator Owners to provide their minimum generating unit voltage limits to the TP and PC. If the wording of R3.3.2 must be different from its counterpart, R4.3.2, then please explain the reasons for any differences. R3.3.3 As noted above, The MRO NSRS suggests that R3.3.3 be removed and this System Protection simulation requirement should be included in R3.3.1, which is the requirement to properly simulate Protection System actions. Add R3.3.5 The MRO NSRS suggests the addition of R3.3.5, "Applicable System Operating Limits for the planning horizon shall not be exceeded." because Note "a" and "b" under "Steady State Only" at the beginning of Table 1 are stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and hidden) in the performance notes of Table 1. [After R3.3.5 is added, Note "a" should be revised and refer to R3.3.5.] Add R3.3.6 The MRO NSRS suggests the addition of R3.3.6, "The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to steady state voltage requirements." because Note "d" under "Steady State Only" at the beginning of Table 1 is stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and hidden) in the performance notes of Table 1. [After R3.3.6 is added, Note "d" should be revised to refer to R3.3.6.] R3.4.1 The MRO NSRS suggests that the word "coordinate" and the reference to the Transmission Planner be removed and offer the following revised text, "the Planning Coordinator shall provide the list of contingencies that are simulated in the adjacent Planning Coordinator area to the respective Planning Coordinator for review and feedback.". Standard Drafting Teams are generally instructed not to use the word "coordinate". The MRO NSRS suggests that this requirement apply to the PC because the PC would share with any affected Transmission Planners. R3.6 The MRO NSRS suggests the wording of this requirement be revised to, "Manual or automatic generation runback or tripping is permitted to meet steady state performance requirements for planning events P1 through P7 in Table 1." because Reliability Standard PRC-015-1 already includes requirements regarding the review and approval of Special Protection Systems. Therefore, the Planning Assessment does not need to duplicate description of the design and intent of the Special Protection System. M3 & R3 Data Retention - The MRO NSRS proposes that the wording in these elements be revised to change "All" to "The". The word "All" is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data

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	retention would read as follows: "The studies performed in support".?
Response: Part 3.3.1: The intent of this requirement is to remove elements that the Protection System would remove to clear a fault (breaker-to-breaker). The Transmission circuit loadability protection could trip un-faulted lines due to the post fault System loadings. Adding the suggested wording "including the simulation of transmission circuit loadability protection." would change the intent of Requirement R3, part 3.1.1. No change made. Part 3.3.2: Where test data is not available, the SDT believes that most Transmission Planners/Planning Coordinators currently assume generators ride through low voltage based on extensive field experience. There is a project (Project 2007-09 — Generator Verification) that will provide the required generator data to validate the assumptions. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure that the simulation models the generator response as it will react in the real world. If voltage ride through limits would cause a generator to trip in the real world, the study must determine if the performance requirements are met for the initiating event and subsequent generator trip. No change made. The SDT added the phrase "or high side of the GSU voltages" to make Requirement R3, part 3.3.2 consistent with Requirement R4, part 4.3.2. Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.3.5 Proposed: The SDT believes that a new requirement is not needed. Requirement R3, part 3.1 states "Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1." Header notes are part of Table 1 and therefore included in Requirement R3. Part 3.3.6 Proposed: The SDT believes that a new requirement is not needed. Requirement R3, part 3.1 states "Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1.". Header notes are part of Table 1 and therefore included in Requirement R3. Part 3.4.1: The SDT believes that it is necessary for the planner to coordinate with adjacent planners to identify Contingencies in adjacent systems that could impact the planners System. Both the Transmission Planner and Planning Coordinator have this responsibility. No change made. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES. Data Retention: The SDT agrees with your suggestion. The wording in "data retention" for Requirement R3 has been changed. Measure M3 already uses the word "the". **Requirement R3, data retention:** The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.	
SERC Dynamics Review Subcommittee (DRS)	R3.3.1: We propose to add "permanently" before "disconnect".
Response: Part 3.3.1: The SDT believes that adding the word "permanently" has no significance for the steady state simulation of fault clearing. No change made.	
MAPP	R3.3.2 - We suggest that this requirement be removed because it is premature to require Transmission Planners to simulate under voltage tripping until the MOD standards require it. If the drafting team does not remove this requirement we propose revised wording to qualify which generating units to consider and which voltage limits to simulate, "Trip generating units that are

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	connected to the BES when actual or assumed minimum generator steady state or ride through voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment". 3.3.3 We suggest that R3.3.3 be removed and this System Protection simulation requirement should be included in R3.3.1, which is the requirement to properly simulate Protection System actions Add R3.3.5 We suggest the addition of R3.3.5, Applicable System Operating Limits for the planning horizon shall not be exceeded. because Note "a" and "b" under "Steady State Only" at the beginning of Table 1 are stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and hidden) in the performance notes of Table 1. [After R3.3.5 is added, Note "a" should be revised and refer to R3.3.5.] Add R3.3.6 We suggest the addition of R3.3.6, ?The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to steady state voltage requirements. because Note "d" under "Steady State Only" at the beginning of Table 1 is stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and hidden) in the performance notes of Table 1. [After R3.3.6 is added, Note "d" should be revised to refer to R3.3.6.] R3.4.1: Remove the Transmission Planner and change "coordinate" to "provide" information to adjacent PC. We are working on other standards to remove "coordinate" and we should avoid it here. Coordinate requires interaction between two entities (or more), so if one does not respond, the other could be found to be non-compliant for something they cannot control.

Response: Part 3.3.2: Where test data is not available, the SDT believes that most Transmission Planners/Planning Coordinators currently assume generators ride through low voltage based on extensive field experience. There is a project (Project 2007-09 — Generator Verification) that will provide the required generator data to validate the assumptions. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure that the simulation models the generator response as it will react in the real world. If voltage ride through limits would cause a generator to trip in the real world, the study must determine if the performance requirements are met for the initiating event and subsequent generator trip. No change made

Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded.

Requirement R3, part 3.3.3: Trip Transmission elements when relay loadability limits are exceeded

The intent of Requirement R3, part 3.3.1 is to remove elements that the Protection System would remove to clear a fault (breaker-to-breaker). The Transmission circuit loadability protection could trip unfaulted lines due to the post fault System loadings. Adding the suggested wording "including the simulation of transmission circuit loadability protection." would change the intent of Requirement R3, part 3.1.1. No change made.

Part 3.3.5 Proposed: The SDT believes that a new requirement is not needed. Requirement R3, part 3.1 states "Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1.". Header notes are part of Table 1 and therefore included in Requirement R3.

Part 3.3.6 Proposed: The SDT believes that a new requirement is not needed. Requirement R3, part 3.1 states "Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1.". Header notes are part of Table 1 and therefore included in Requirement R3.

Part 3.4.1: SDT believes that it is necessary for the planner to coordinate with adjacent planners to identify contingencies in adjacent systems that could impact the

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planners system. Both the Transmission Planner and Planning Coordinator have this responsibility. No change made.	
NYISO	R3.3.3 This requirement is already addressed in NERC Standard PRC-023 and reflected in the facility's rating and should be removed. R3.5. - The Extreme Events testing in Table 1 should be removed from this standard since there is no requirement to develop a Corrective Action Plan to address unacceptable consequences and the requirements are very general or vague. At a minimum, testing should only be required for EHV facilities or facilities specified by the Regional Entity for example, NPCC designates facilities that can have consequences outside an area as bulk power system facilities. If this remains, the NYISO requests that the phrase "evaluation of possible actions" be greatly clarified. R3.6 The NYISO seeks greater clarification of the phrase "consequential generation."
Response: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.5: The SDT believes, and the majority of the industry agrees as seen in the comments, that continuing to study these possible scenarios is a valuable planning exercise. The requirement is to evaluate possible actions which, if implemented, could reduce the likelihood or mitigate the consequences of an extreme event. No change made. Part 3.6: The term "consequential generation" is not used in Requirement R3, part 3.6. The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.	
Xcel Energy	R3.3.3 Xcel does not believe that relay loadability limits is a valid system planning performance criterion because we are unsure how transmission relay loadability settings developed in accordance with PRC-023 can be more limiting than the Facility Ratings. Note that the purpose of PRC-023 standard is "Protective relay settings shall not limit transmission loadability" and it requires that the relay settings be higher than the "highest seasonal Facility Rating of a circuit". If relay settings limit the transmission loadability below its Facility Rating, then it is a violation of PRC-023. Requirements R3.4 and R3.5 appear to be related to and set the limits for R3.1 and R3.2 respectively. Suggest moving both Requirements R3.4 and R3.5 into R3.1 and R3.2, allowing these sub-Requirements (R3.4 and 3.5) to be deleted. R3.3 It is unclear from the wording in R3.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R3.1 and R3.2. Please clarify the wording of R3.3.
Response: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded The SDT agrees that relay loadability limits would exceed Facility ratings except in cases where exceptions to the loadability standard exist.	

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Part 3.4: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.5: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.3: The SDT revised the wording of Part 3.3 as shown below to make it clear that it applies to both planning and extreme events: **Requirement R3, part 3.3**: Contingency analyses for Requirement R3, parts 3.1 & 3.2 shall:	
Sacramento Municipal Utility District	R3.3.3: To implement this requirement, the standard appears to call for one more facility rating which is based on Relay Loadability. Is the intent to also model the protection system actions if this limit is violated? Should such a requirement be moved to the MOD or FAC standard with conformance subject to Note (f) of Table 1 (Facility ratings shall not be exceeded) and R3.3.1 (simulate the removal of all elements that the Protection System and other " are expected to disconnect")?
Response: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.3.1: The intent of this requirement is to remove elements that the Protection System would remove to clear a fault (breaker-to-breaker). The Transmission circuit loadability protection could trip un-faulted lines due to the post fault System loadings. Adding the suggested wording "including the simulation of transmission circuit loadability protection." would change the intent of Requirement R3, part 3.1.1.	
Puget Sound Energy, Inc.	R3.41 requires clarification. With respect to these "Contingencies on adjacent systems," the responsibility of listing and analyzing these events needs to be clarified. Should the event simulation be the responsibility of the "neighboring" system (where the event would occur) or the adjacent system that may feel the impact of this event? Per the developed rationale from R3.4, the neighboring system may determine that a particular event is "less severe" and hence not studied, even though this event may potentially impact a neighbor. Further, for these "Contingencies on adjacent systems" that result in system performance outside one's own operating limits, it is unclear who is responsible for mitigating these contingencies. It is potentially awkward in that one entity may be planning another entity's system improvements.
Response: R3.4.1: The intent is for the Planning Coordinator/ Transmission Planner to include in their Contingency lists Contingencies from adjacent Systems which may impact their System, and to run these Contingencies. The Planning Coordinator/Transmission Planner is responsible for mitigation of performance deficiencies in their System caused by Contingencies on their list, including the Contingencies from adjacent Systems.	
Duke Energy	R3.5 includes the phrase "cascading outages". We believe that the word "cascading" should be the capitalized NERC-defined term "Cascading".
Response: R3.5: The SDT agrees. The phrase "cascading outages" has been changed to "Cascading" to align with the NERC Glossary of Terms. **Requirement R3, part 3.5**: Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be	

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available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.	
Northeast Power Coordinating Council--RSC	Requirement 3.2: This requirement should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. Requirement 3.3.3: This requirement is already addressed in NERC Standard PRC-023 and reflected in the facility's rating and should be removed from TPL-001-1 since the standard already requires observance of facility ratings. Relay Loadability is handled in greater detail (as it should be) under the proposed PRC-023 standard, so no reference should be made in this standard, thereby introducing a double jeopardy issue. Requirement 3.4: It is strongly suggested that this requirement is made a sub-bullet of Requirement 3.1 to keep the related requirements together. Requirements 3.5--This requirement needs clarification as to what is specifically required for the "evaluation of possible actions." The list associated with Requirement 2. part 2.7.1 provides examples of possible actions, and leaving "evaluation" undefined offers the Planning Coordinator and Transmission Planner the leeway to use judgment in making their evaluations. Requirement 3.5 NPCC strongly suggests making this a sub-bullet of Requirement 3.2 to keep the related requirements together.Provide clarification as to what is specifically required for the "evaluation of possible actions". Requirement 3.6 Currently this requirement is not clear, and does not address any reliability issue. Clarification should be added that the "consequential generation" loss be excluded from the amount documented. Without the clarification, the Requirement should be deleted.
Response: Part 3.2: The SDT disagrees and believes there is value in running extreme event analysis to test the robustness of the System. No change made. Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.4: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.5 The requirement is to evaluate possible actions which, if implemented, could reduce the likelihood or mitigate the consequences of an extreme event. The SDT believes that what these "possible actions" are should be left to the judgment of the Planning Coordinator/Transmission Planner who has knowledge of their System. Part 3.5: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.	
Midwest ISO	Requirement R3.6: With regards to the Generation Runback MW reporting; if no action is required then why require the entities

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	to provide this. Will it matter if 10MW or 100MW is part of the generation runback scheme tripped with the line? This is a system design issue which is not addressed by the standards, if this requirement is kept how is an entity expected to demonstrate compliance for this? This requirement is an administrative burden and we propose to remove R3.6 all together considering that there is not a reliability-related need for this information and it is unnecessary.
Response: Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.	
Hydro-Québec TransEnergie (HQT)	Requirements 3.5 and 4.5 Both of these requirements need clarification as to what is specifically required for the "evaluation of possible actions." Requirement 3.3.3 This requirement is already addressed in NERC Standard PRC-023 and reflected in the facility's rating and should be removed from TPL-001-1 since the standard already requires observance of facility ratings. Requirement 3.4 HQT, as does NPCC, strongly suggests making this requirement a sub-bullet of Requirement 3.1 to keep the related requirements together. Requirement 3.5 HQT, as does NPCC, strongly suggests making this a sub-bullet of Requirement 3.2 to keep the related requirements together. Requirement 3.6 ?Currently this requirement is not clear. HQT, as does NPCC, recommends clarification be added that the "consequential generation" loss is excluded from the amount documented.
Response: Part 3.5 The requirement is to evaluate possible actions which, if implemented, could reduce the likelihood or mitigate the consequences of an extreme event. The SDT believes that what these "possible actions" are should be left to the judgment of the Planning Coordinator/Transmission Planner whose has knowledge of their System. Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.4: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.5: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.	
Pacific Gas and Electric Co.	Requirements R3.4 and R3.5 appear to be related to and set the limits for R3.1 and R3.2 respectively. Suggest moving both Requirements R3.4 and R3.5 into R3.1 and R3.2, allowing these sub-Requirements (R3.4 and 3.5) to be deleted. It is unclear from the wording in R3.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R3.1 and R3.2. Please clarify the wording of R3.3.

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	For clarity we suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits.
Response: Part 3.4: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.5: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.3: The SDT revised the wording of Requirement R3, part 3.3 as shown below to make it clear that it applies to both planning and extreme events: **Requirement R3, part 3.3**: Contingency analyses for Requirement R3, parts 3.1 & 3.2 shall: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded	
National Grid	Sub-Requirement 3.2: This requirement should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. Sub-Requirement 3.3.3: Relay Loadability is handled in greater detail (as it should be) under the proposed PRC-023 standard, so no reference should be made in this standard. It indicates a double jeopardy. Sub-Requirement 3.4: It is strongly suggested that this requirement is made a sub-bullet of Requirement 3.1 to keep the related requirements together. Sub-Requirement 3.5: It is strongly suggested that this requirement is made a sub-bullet of Requirement 3.2 to keep the related requirements together. Provide clarification as to what is specifically required for the "evaluation of possible actions." Sub-Requirement 3.6: This requirement does not address any reliability issue should be deleted. If it is to be kept, it is recommended that the "consequential generation" loss be excluded from the amount documented.
Response: Part 3.2: The SDT disagrees and believes there is value in running extreme event analysis to test the robustness of the System. No change made. Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.4: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.5: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.5: The requirement is to evaluate possible actions which, if implemented, could reduce the likelihood or mitigate the consequences of an extreme event. The SDT believes that determining these "possible actions" should be left to the judgment of the Planning Coordinator/Transmission Planner who has knowledge of their	

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System. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.	
Tri-State Generation and Transmission Association	Thank you for removing the requirement to explain why "non-studied contingencies" would produce less severe results." Don't say "R3, part 3.4". Instead, for much easier referencing of sections, just say "R3.4". This applies throughout the entire Standard." R3.5 In the phrase "extreme events in Table 1 that are expected to produce more severe System impacts", the term "extreme events" seems redundant with "more severe". If Extreme Events were capitalized, it would be apparent that the TP should choose more severe events typified by details listed in the Extreme Events section of Table 1.
Response: R3, part 3.4: NERC has directed that the new terminology be adopted for all parts of a requirement. No changes made. R3.5: The SDT disagrees that the suggested changes add clarity. No change made. R3.5: The extreme events are listed in Table 1. Some of these events will have a greater impact than others on a given System. The SDT's expectation is that the planner knows his system and would use judgment to select the extreme events that would have a more severe impact on his System. No change made.	
Ameren	The readability of R3.3 could be improved with the following wording changes:3.3 Contingency analyses shall be performed: 3.3.1 To simulate the removal? 3.3.2 To simulate tripping generators where simulations show? 3.3.3 And results reviewed to ensure relay loadability limits? 3.3.4 To simulate the expected? Requirement R3.3.1 needs to include language regarding the automatic restoration of facilities. The following language is suggested: To simulate the removal of all elements that the Protection System is expected to disconnect and the restoration of all elements that the automatic controls are expected to restore for each Contingency without operator intervention. Requirement R3.6: What is the purpose of this Requirement? We do not see how the reporting of this information adds to system reliability, and believe that this is more of a market issue. For those systems that are planned based on a single contingency, it is believed that numerous generation facilities would be impacted by the N-2 planning events and particularly those involving transmission facilities in the vicinity of power plant switchyards. Documenting manual or automatic generation runback or tripping of generation for the proposed P1 and P2 events is not unreasonable, but it is expected that developing runback or tripping schemes for the proposed P3-P7 events and reporting those contingencies and the amount of generation curtailed on an annual basis is of little value. Further, what information is to be reported for the P6 events for R3.6? As P6 events allow system adjustment following the first contingency (P1 event) to prepare for the second contingency (P1 event), is the runback information to be reported the generation that is to be curtailed after the first event (which should already be reported for the P1 category), after the second

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	event, or after both events? In real-time operations, security constrained economic redispatch continually adjusts generation to maintain transmission facility loadings within ratings anticipating the next single contingency event. Does the Standards Drafting Team intend for the industry to report the amount of curtailed generation in anticipation of the next P1 event?
Response: Part 3.3: The SDT has not adopted your suggested wording, but has made wording revisions to improve clarity as follows: **Requirement R3, part 3.3**: Contingency analyses for Requirement R3, parts 3.1 & 3.2 shall: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded. Part 3.3.1: The reference to "other automatic controls" is intended to include other tripping means such as cross-tripping and not automatic restoration devices. No change made. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.	
Florida Power and Light	The requirement clearly states that "For the steady state portion of the Planning Assessment" it must perform simulations that show generator ride through voltage limitations under 3.3.2. However, ride through limitations are performed through stability simulations not steady state as required by R3. This is confusing as currently drafted, please provide clarity. Additionally, 3.2 requires studies to be performed to assess the impact of the extreme events. Yet, 3.3 requires analyses shall be performed but does not specify the events intended to study. Suggested language for 3.3 should say "Contingency analyses shall be performed to assess the impact of the extreme events and:" Under 3.3.1 it states that the Planner must simulate the removal of all elements that the Protection System would be expected to disconnect. Language should be included to allow the Planner to provide a rationale to assess more severe system conditions without needing to simulate the effects of Protection Systems. This would capture the intent of this requirement.
Response: Part 3.3.2: Generators can trip when bus voltage drops below minimum generator steady state voltage limits. The SDT believes that the voltage ride through test is applicable in post-contingency steady-state where the planner would know if post-Contingency bus voltage violates generator trip points. If a trip point is violated, Requirement R3, part 3.3.2 would require the planner to remove the generator in the post-Contingency case to assess if performance is met with the generator removed. No change made. Part 3.3: The SDT revised the wording of Requirement R3, part 3.3 as shown below to make it clear that it applies to both planning and extreme events: **Requirement R3, part 3.3**: Contingency analyses for Requirement R3, parts 3.1 & 3.2 shall: Part 3.3.1: Consistent with FERC Order 693, the intent of the SDT is for the planner to simulate the Protection System operation so that all elements that the Protection System is designed to remove (breaker to breaker) are removed in the simulation for the list of Contingencies the planner has developed in Requirement R3, parts 3.4 (planning events) and 3.5 (extreme events). The requirement does not preclude the Planning Coordinator/Transmission Planner from studying more severe scenarios. No change made.	

Organization	Comments for Question 3
NorthWestern Energy	The wording in R3.3.3 should be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits. In R3.3.3 The term "loadability" needs to be defined. R3.5 needs to be modified. It would be better to combine R3.2 with R3.5. The first part of the requirement requires identification of events that produce more severe System impacts. The presumed reason that the other contingencies were not selected is because they were deemed to be less severe or non-credible. In any case, theoretically, there can always be examples of more severe Extreme Contingencies than the one selected for study. This can be achieved by simply choosing events that are even less credible. For example, if the Extreme Contingency studied was a simultaneous loss of 3 transmission lines with the failure of a redundant RAS (SPS), then an event resulting in the simultaneous loss of 4 lines with the failure of 2 sets of redundant RASs would be even more severe. Listing all possible extreme events could result in a limitless list.
Response: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.3.3: Relay loadability is defined in NERC Standard PRC-023-1. R3.5: The SDT agrees that there could be an endless list of possible extreme events, The requirement has been written to allow the Planning Coordinator/Transmission Planner to use experience and the knowledge of their System to select relevant extreme events that have some reasonable probability of occurring. The SDT does not believe that combining Requirement R3, part 3.5 with Requirement R3, part 3.2 provides any significant advantage. No change made.	
American Transmission Company	We propose the following changes and questions: R3.3.1 The term of "controls" is ambiguous and not defined, unlike the term, "Protection Systems", which is defined. Therefore, we suggest that this item be defined or more clearly described to avoid the risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. R3.3.1 Add the wording, ". . . including the simulation of transmission circuit loadability protection." to this requirement, rather than have a separate R3.3.3 requirement for recognizing overload protection. Overload protection is simply one of the types of automatic Protection System that may remove one or more elements from service. R3.3.2 - We suggest qualifying which generating units to consider and which voltage limits to simulate with revised wording like, "Trip generating units that are connected to the BES when actual or assumed minimum generator steady state or ride through voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment". The requirement should not apply to all relevant generating units until one of the MOD standards requires all Generator Owners to provide their minimum generating unit voltage limits to the TP and PC. If the wording of R3.3.2 must be different from its counterpart, R4.3.2, then please explain the reasons for any differences. R3.3.3 As noted above, we suggest that R3.3.3 be removed and that this System Protection loadability simulation requirement is included in R3.3.1 because overload protection is simply one type of automatic Protection System actions.

Organization	Comments for Question 3
	Add R3.3.5 We suggest the addition of R3.3.5 because any requirement in the head notes or foot notes of Table 1 should occur within the body of standard. The text of R3.3.5 should read, "Applicable System Operating Limits for the planning horizon shall not be exceeded." Presently, Note "a" and "b" under "Steady State Only" at the beginning of Table 1 are stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and basically hidden) in the performance notes of Table 1. [After R3.3.5 is added, Note "a" should be revised and refer to R3.3.5.] Add R3.3.6 ? We suggest the addition of R3.3.6 because any requirement in the head notes or foot motes of Table 1 should occur within the body of standard. The text of R3.3.6 should read, "The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to steady state voltage requirements." because Note "d" under "Steady State Only" at the beginning of Table 1 is stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and basically hidden) in the performance notes of Table 1. [After R3.3.6 is added, Note "d" should be revised to refer to R3.3.6.] R3.5 - We interpret that R3.5 requires the TP and PC to conduct an evaluation of possible actions to reduce the likelihood or impact of extreme events, which produce the more severe impacts, if cascading outages may occur. Does the drafting team intend for the TP and PC to fulfill this requirement for at least one event in each of the five categories (i.e. 3 steady state and 2 stability) or in each of the 21 categories/sub-categories (i.e. 14 steady state and 7 stability). Also, if the resulting cascading outages do not result in any overloads, under-voltages, voltage collapse, or loss of generator synchronization, then should the evaluation of possible actions to reduce likelihood or impact be required? R3.6 We suggest the wording of this requirement be revised to, "Manual or automatic generation runback or tripping is permitted to meet steady state performance requirements for planning events P1 through P7 in Table 1." because Reliability Standard PRC-015-1 already includes requirements regarding the review and approval of Special Protection Systems. Therefore, the Planning Assessment does not need to duplicate description of the design and intent of the Special Protection System.

Response: Part 3.3.1: The SDT believes that the meaning of "controls" is clear in the context it is used - "Protection Systems and Other automatic controls" (such as a cross-trip scheme) that disconnect elements to clear a fault". No change made.

Part 3.3.1: The intent of this requirement is to remove elements that the Protection System would remove to clear a fault (breaker-to-breaker). The Transmission circuit loadability protection could trip un-faulted lines due to the post fault system loadings. Adding the suggested wording "including the simulation of transmission circuit loadability protection." would change the intent of Requirement R3, part 3.1.1. No change made.

Part 3.3.2: Where test data is not available, the SDT believes that most Transmission Planners/Planning Coordinators currently assume generators ride through low voltage based on extensive field experience. There is a project (Project 2007-09 — Generator Verification) that will provide the required generator data to validate the assumptions. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure that the simulation models the generator response as it will react in the real world. If voltage ride through limits would cause a generator to trip in the real world, the study must determine if the performance requirements are met for the initiating event and subsequent generator trip. No change made.

The phrase "or high side of the GSU voltages" was added to Requirement R3, part 3.3.2 to make the wording in Requirement R3, part 3.3.2 the same as in Requirement R4, part 4.3.2.

Requirement R3, part 3.3.2: Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed

Organization	Comments for Question 3
	minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. Combining Requirement R3, part 3.3.3 with Requirement R3, part 3.3.1 would change the intent of Requirement R3, part 3.3.1. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.3.5 Proposed: The SDT believes that a new requirement is not needed. Requirement R3, part 3.1 states "Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1.". Header notes are part of Table 1 and therefore included in Requirement R3. Part 3.3.6 Proposed: The SDT believes that a new requirement is not needed. Requirement R3, part 3.1 states "Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1." Header notes are part of Table 1 and therefore included in Requirement R3. Part 3.5: Requires the planning entity to identify which contingencies are chosen to be simulated in the study, and explain why these are chosen. The SDT assumes that the Planning Coordinator/Transmission Planner, applying experience of past studies and knowledge of its System, is in the best position to determine which Contingencies in Table 1 are most relevant, as it is impossible to study all Contingencies especially the multiple Contingency events. Requirement R3, part 3.5 requires "an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts" if cascading outages - the trigger for evaluation of possible mitigating actions is cascading outages, not "overloads, under-voltages, voltage collapse, or loss of generator synchronization". No change made. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES. The SDT notes that generator runback or tripping is not prohibited by the standard.
PJM	In R3.3.2, low voltage protection, like practically all generator protection, is not commonly collected, at least by MMWG, and will take a great deal of time and effort to gather. R3.3.3 – Relay loadability should not be evaluated in a performance standard. A separate line rating and protection setting evaluation can determine if relay loadability is exceeded. If kept, this protection information, is not commonly collected, at least by MMWG, and will take a great deal of time and effort to gather. R3.5 – Needs a 3.5.1 similar to 3.4.1. R3.6 needs some words about sending up a red flag is the generation tripped or runback is greater than the largest single contingency. Like –The Reliability Coordinator, Transmission Operator and Balancing Authority must be notified if the planned generation tripped or runback scheme is greater than the largest single contingency.-
Response: Part 3.3.2: Where test data is not available, the SDT believes that most Transmission Planners/Planning Coordinators currently assume generators ride through low voltage based on extensive field experience. There is a project (Project 2007-09 — Generator Verification) that will provide the required generator data to validate the assumptions. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure that the simulation models the generator response as it will react in the real world. If voltage ride through limits would cause a generator to trip in the real world, the study must determine if the performance requirements are met for the initiating event and subsequent generator trip. No change made. Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded.	

Organization	Comments for Question 3
	Requirement R3, part 3.3.3: Trip Transmission elements when relay loadability limits are exceeded Part 3.5.1 Proposed: The SDT has not included a requirement on the Planning Coordinator/ Transmission Planner to coordinate with adjacent Systems to identify extreme Contingencies in these adjacent Systems that would impact the Planning Coordinator/Transmission Planner's System. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.

4. Requirement R4 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: Many commenters expressed concerns that the new "relaying" requirements that were added to draft 4 would essentially require modeling every zone 3 relay in each Interconnection. The requirements do not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then one can either take action according to the generic model results or investigate the characteristics of the relays actually used on that branch.

In response to several commenters, Part 4.1.2 was modified to no longer require tripping of out-of-step generators in the simulations.

Clarifications to the requirements were made as follows:

Requirement R3, part 3.3.2 - Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

Requirement R4, part 4.1.2 - For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

Requirement R4, part 4.3 - Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

Requirement R4, part 4.5 - Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R4, part 4.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

Organization	Comments for Question 4
Independent Electricity System Operator	(1) Part 4.3: Similar comments on Part 3.3 provided under Q3 also apply here. (2) Parts 4.4 and 4.5: similar comments on Parts 3.4 and 3.5 provided under Q3 also apply here.(3) We do not have any comments on the measure, VRF, Time Horizon and VSLs.
SRC of ISO/RTO	1. Part 4.3: Similar comments as for Part 3.3 (i.e. overly prescriptive, etc...) provided under question 3 also apply here. 2. Parts 4.4 and 4.5: Similar comments on Part 3.4 and 3.5 provided under question 3 also apply here.

Organization	Comments for Question 4
	AESO does not comment on VSLs or VRFs.
Response: See response to your comments on Requirement R3, part 3.3. See response to your comments on Requirement R3, parts 3.4 and 3.5.	
ERCOT ISO	* Will any agreements made in R7 override the "each TP and PC" requirement? To clarify this, the requirement could be rephrased: "In accordance to the responsibilities assigned in R7, the responsible Transmission Planners and Planning Coordinators shall perform?. "* Similar to comments provided in R3, Section 4.1 and 4.4 appear to be related. Confusing references can be eliminated by combining them and removing 4.4: "4.1. Those planning events in Table 1that are expected to produce more severe System impacts on its portion of the BES, shall be identified and studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1. A list of those Contingencies and the rationale for those Contingencies selected for evaluation shall be available as supporting information. "* Similarly, Section 4.2 and 4.5 appear to be related. Confusing references can be eliminated by combining them and removing 4.5: "4.2. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and studies shall be performed to assess the impact of the extreme events. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted. A list of those events and the rationale for those Contingencies selected for evaluation shall be available as supporting information. "
Response: The agreements required by Requirement R7 are intended to clarify the responsibilities among the Planning Coordinator and Transmission Planners. The SDT believes this is clear in the existing language. Requirement R4, parts 4.1 & 4.4: The SDT does not believe that combining the requirements serves any purpose. No change made. Requirement R4, parts 4.2 & 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made.	
Northeast Utilities	[R4.1.1] This requirement needs better clarification. Does it mean that a generator that trips on any other condition apart from tripping on out-of-synchronism is acceptable? Example if the generator is not able to ride through a low voltage condition created by a fault. We recommend that this requirement is dropped from TPL-001-1 standard. [R4.1.2] This approach will require a different modeling technique from current practice and will require an implementation period. [R4.3.2] Refer to comment for Requirement R3.3.2. [R4.5] This requirement needs clarification as to what is specifically required for the "evaluation of possible actions". Otherwise the following is recommended:" It should be clear that an evaluation does not require solution development for all Extreme Events" Change "an evaluation of possible actions" to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered."

Organization	Comments for Question 4
Response: Part 4.1.1: The requirement will not be dropped. The requirement states that for event P1, no generating unit shall pull out of synchronism. If the event results in a unit tripping due to fault clearing action or due to an SPS action, this is acceptable. Low voltage ride-through is handled in a separate requirement (Requirement R4, part 4.3.2). Part 4.1.2: Tripping the generator is no longer required. The SDT has modified Requirement R4, part 4.1.2. **Requirement R4, part 4.1.2** - For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities. Part 4.3.2: See response to your comment on Requirement R3, part 3.3.2. Part 4.5: The requirement is to evaluate possible actions which could reduce the likelihood or mitigate the consequences of the event. The standard should not prescribe those actions. It is up to your judgment what those possible actions could be. No change made.	
Central Maine Power Company	4.1.1 This should be revised to only be applicable to generators interconnected to the BES. This may need an implementation period as not all existing units are interconnected in accordance with the standard as proposed. As written this applies to small generators and doesn't necessarily reflect reliability of the network. 20 MW is a recommended generator minimum size. 4.1.2 This will require implementation period. 4.2 Item 4.2 should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. 4.4 It is suggested that this requirement is made a sub-bullet of Requirement 4.1 to keep the related requirements together. 4.5 It is suggested that this requirement is made a sub-bullet of Requirement 4.2 to keep the related requirements together.
ISO New England	4.1.1 This should be revised to only be applicable to generators interconnected to the BES. This may need an implementation period as not all existing units are interconnected in accordance with the standard as proposed. As written this applies to small generators and doesn't necessarily reflect reliability of the network. 20 MW is a recommended generator minimum size. 4.1.2 This will require implementation period. 4.2 Item 4.2 should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. 4.4 It is suggested that this requirement is made a sub-bullet of Requirement 4.1 to keep the related requirements together. 4.5 It is suggested that this requirement is made a sub-bullet of Requirement 4.2 to keep the related requirements together.
United Illuminating	4.1.1 This should be revised to only be applicable to generators interconnected to the BES. This may need an implementation

Organization	Comments for Question 4
	period as not all existing units are interconnected in accordance with the standard as proposed. As written this applies to small generators and doesn't necessarily reflect reliability of the network. 20 MW is a recommended generator minimum size. 4.1.2 This will require implementation period. 4.2 Item 4.2 should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. 4.4 It is suggested that this requirement is made a sub-bullet of Requirement 4.1 to keep the related requirements together. 4.5 It is suggested that this requirement is made a sub-bullet of Requirement 4.2 to keep the related requirements together.
Response: Part 4.1.1: The standard applies only to the BES and therefore, without revision, does not place this requirement on generators not directly connected to the BES. The SDT believes that generators smaller than 20 MW also need to be stable for single Contingencies (P1). No change made. Part 4.1.2: Tripping the generator is no longer required. The SDT has modified Requirement R4, part 4.1.2. **Requirement R4, part 4.1.2** - For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities. Part 4.2: The SDT disagrees and believes there is value in running extreme event analysis. No change made. Part 4.4: The SDT does not believe that combining the requirements serves any purpose. No change made. Part 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made.	
Florida Municipal Power Agency, and its Member Cities	4.1.1, suggest rewording "(a) generator being disconnected from the Bulk Electric System ", system as defined in the Glossary includes distribution, and we do not believe that is the intent of the SDT. 4.1.2, 4.3.1 and 4.3.3 essentially require modeling every Zone 3 (or higher, such as Zone 5) relay in each Interconnection (or at least in the Region under study and adjacent regions) because, in order to simulate the impact of a power swing on a distance relay, one would need to know the characteristics of the distance relay and how long the transient swing remains within that characteristic, which means modeling the relay. Is that the intent of the SDT? If so, FMPA suggests limiting these bullets to Facilities 230 kV and higher.
Response: Part 4.1.1: The standard applies only to the BES and therefore, without revision, does not place this requirement on generators not directly connected to the BES. No change made. Parts 4.1.2, 4.3.1, & 4.3.3: This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. No change made.	

Organization	Comments for Question 4
Xcel Energy	4.3 Does the requirement allow it to be optional as to whether an entity chooses to include generator exciter controls, PSS, etc.? To what degree must a device impact the study area, in order for it to be required to be included in the simulation? Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. R4.3 It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful and unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If it is the intent to require that entities assess both, we suggest including the assessment in the list of sensitivities.
Response: Part 4.3: If generator exciter controls and PSS do not affect the study area, it is not necessary to model them. However, most Transmission Planners will have them in their simulations because these controls are already included in their model. It is up to your judgment as to what control devices have an impact on the study area. Parts 4.4 & 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made. Part 4.3: The Contingency analyses in Requirement R4, part 4.3 refer to the studies in Requirement R4, parts 4.1 and 4.2. However, for additional clarity, Requirement R4, part 4.3 has been modified. **Requirement R4, part 4.3** - Contingency analyses for Requirement R4, parts 4.1 and 4.2 shall : Part 4.3.1: The Standard requires you to study only the events which produce more severe System impacts. If two Systems are swinging apart, then successful high speed reclosing could show a more severe impact. However, if successful reclosing is not expected to produce a more severe impact, you are not required to study it. No change made.	
FirstEnergy Corp	A. The SDT should bring consistency to the text used for sub-part 4.3.2 of R4 and sub-part 3.3.2 of R3. In R4 it indicates "generator bus voltages or high-side of GSU" as the reference voltage point whereas 3.3.2 only indicates "generator bus voltage" as the point of reference. If the generator bus is modeled at the generator voltage, then this should be the reference voltage point. If the generator is modeled directly connected to the BES (no transformer is explicitly modeled), then the transmission voltage should be the reference voltage. B. Requirement R4, sub-part 4.3.2 is well intentioned, but problematic for those performing dynamic simulations. Does a Guide or Practice exist to determine the dynamic undervoltage capability of a synchronous machine? Most excitation systems contain "field forcing" functions to maintain stability through fault conditions (1 second or so of capability), but FE is not aware of any published, readily available quantities or formulas that can be used to determine this highly time dependent function. Application of the steady state minimum voltage is grossly over-conservative. FE questions why low voltage limits should even be considered in dynamic simulations, since the primary concern for generating equipment during events of this nature and duration are metallurgical, not thermal (voltage). C. Requirement R3 sub-part 4.3.3 is troublesome since the modeling detail needed for Protection Systems within traditional stability programs is not available. It is expected that software adjustments will be needed from the software vendors before this

Organization	Comments for Question 4
	requirement can be met. The implementation plan of 24 months may be insufficient in regards to 4.3.3. In draft 3 Progress Energy and Ameren in the Q11 comments indicated that more time is needed for Protection System modeling required by TPL-001-1. The SDT responded "The standard does not require detailed modeling of Relay Protection Systems. It only requires that the impacts of those systems be reflected in the modeling of Contingencies and the evaluation of the resulting System performance. This is no different than the current standards." The inclusion of sub-part 4.3.3 in Draft 4 does not appear to align with this response. Please clarify the intent of 4.3.3 and respond regarding FE's belief that more time is needed for software improvements. D. We suggest the team discontinue the use of "Coordinate with adjacent transmission planners" in regards to sub-part 4.4.1 related to the inclusion of contingencies from adjacent systems. The "coordination" type of requirements creates a need to develop compliance evidence such as e-mail correspondence, meeting minutes etc that serve no real reliability purpose. The requirement should simply be that the TP shall include adjacent contingencies expected to produce the more severe System impacts on their systems. In fact, sub-part 4.4 already includes that language. We suggest the team append the sentence "The planning event contingencies shall include:" to the end of sub-part 4.4 followed by two bullets that indicate 1) events within the TP's system and 2) events on adjacent transmission Systems.
Response: A. Part 4.3.2: To be consistent with Requirement R4, part 4.3.2., Requirement R3, part 3.3.2 has been modified to also allow the use of voltages on the high side of the GSU. The use of voltages on the high side of the GSU allows greater flexibility in applying voltage ride-through capability of generators - some of which are defined on the high side of the GSU. **Requirement R3, part 3.3.2** - Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. B. Part 4.3.2: The purpose of Requirement R4, part 4.3.2 is to take into account the low voltage ride-through capability of generators in the studies. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. No change made. C. Part 4.3.3: This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. Therefore, the SDT does not believe that more time is needed in the Implementation Plan. No change made. D. Part 4.4.1: The SDT strongly disagrees with your suggestion. It is much easier to coordinate with adjacent Transmission Planners for Stability simulations. A requirement to study Contingencies on adjacent Systems creates an enormous burden for Stability simulations which have to take into account substation configurations and relaying times. A much better method is to coordinate with neighbors as to which Contingencies on their System could impact your System and then study only those Contingencies on the neighbor's System. No change made.	
Gainesville Regional Utilities	As generation and transmission elements are added to our small system, we evaluate the stability impact as part of its feasibility and impact studies. After installation and in each year of a critical conditions study at the regional level, our elements are considered in the regional priority listings to determine if any stability issues need additional or continuous evaluation. Again, as a "part of the whole" our elements are considered and our assessment is based on these and other findings. Again, this revision

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	seems to add clarity to this requirement and its parts. Good Job!
Response: Thanks for your comment.	
Progress Energy Florida, Inc.	As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all appropriate parties to review PEF's previous comments to this effect.
Response: Throughout the drafting process, the SDT has carefully considered your comments as well as comments from other industry members.	
CenterPoint Energy	CenterPoint Energy recommends deleting part 4.4.1 as being overly prescriptive and difficult to demonstrate in an audit.
Response: Part 4.4.1: The SDT disagrees that this requirement is prescriptive and difficult to demonstrate compliance. There is a need to consider Contingencies on a neighbor's System which may impact your System. It is much easier to coordinate with adjacent Transmission Planners for Stability simulations than to study them all yourself. A requirement to study Contingencies on adjacent Systems creates an enormous burden for Stability simulations which have to take into account substation configurations and relaying times. A much better method is to coordinate with neighbors as to which Contingencies on their System could impact your System and then study only those Contingencies on the neighbor's System. For the audit you should show documentation where you asked and received these Contingencies from your neighbors. No change made.	
Deseret Power	Comments: Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
Response: Parts 4.4 & 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made. Part 4.3: The Contingency analyses in Requirement R4, part 4.3 refer to the studies in Requirement R4, parts 4.1 and 4.2. However, for additional clarity, Requirement R4, part 4.3 has been modified. **Requirement R4, part 4.3** - Contingency analyses for Requirement R4, parts 4.1 and 4.2 shall : Part 4.3.1: The Standard requires you to study only the events which produce more severe System impacts. If two Systems are swinging apart, then successful high speed reclosing could show a more severe impact. However, if successful reclosing is not expected to produce a more severe impact, you are not required to study it. No change made.	
ITC Holdings	Comments:On R4.3.2:Assumptions regarding Low Voltage Ride Through (LVRT) capability are risky and not well understood. If the SDT feels this is a critical requirement that merits corrective action then we believe LVRT characteristics for various machine types should be developed through a NERC process. Without such "standards", it will be difficult to justify CAPs based on LVRT

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	assumptions. For example, would the Transmission Owner (TO) or Generator Owner be responsible for the cost of VAR CAPs if an LVRT assumption were violated. Can a TO require an LSE to install automatic load shedding for an LVRT assumption when cascade or local load loss result from an LVRT assumption? In addition, as the SDT has already indicated, the industry is still in a learning curve regarding the dynamic behavior of certain loads. If LVRT capability is considered as a critical requirement, then what about High Voltage Ride Through (HVRT) capability? The violation of HVRT could also cause certain damages to the system. R4.4.1 - (contingency list coordination with neighbors) It's unclear as to the "measure" for this requirement. Do you give your neighbor a list of "contingencies" in your area. Should it include all categories (p1 thru p7 for example)? Does your neighbor have to study a cascade situation in his system caused by an outage in your system? Are joint studies merited? More importantly, if an outage in a neighboring system requires a CAP, who's responsible, particularly if the CAP involves the neighboring system. Does the neighbor have to have a CAP, according to this standard, if the violation is in your system, and the CAP is in his? Who pays? Are you putting a study burden on your neighbor when you do this? Do you include additional contingencies to ensure that you do not miss a contingency that might impact your neighbors system to avoid any potential compliance implication on you?
Response: Part 4.3.2: There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. And yes, you can make System improvements based on reasonable assumptions. The SDT does not believe that high voltage ride through of generators has been an issue in past events like low voltage ride through has been. Thus, there is no need to include it in the standard. Part 4.4.1: The intent of the requirement is to give your neighbor a list of Contingencies (P1-P7) for which you have observed an impact to the neighbor's System. Your neighbor will then study those Contingencies. Joint studies are not required. If a Contingency on a neighbor's System causes a problem on your System, you must find a solution and the reverse situation is the same.	
TVA System Planning	For R4.1.2. Suggested change: For planning events P2 through P7: A generator that pulls out of synchronism shall be considered in the simulations and the resulting apparent impedance swings shall not result in the tripping of any Transmission System elements other than the generating unit and its directly connected Facilities." [Since often tripping a out of step generator reduces impedance swings, if the simulation shows acceptable impedance swings and voltage levels without tripping the generator, why would we be required to determine the tripping time and simulate tripping in each of the simulations that we have to run for these event categories? Without the suggested change involving the word "considered", significant extra effort would be required to perform simulations for small generators with no added benefit in achieving the purpose of assuring that impedance swings from generators are not passing through lines on the Bulk Electric System for events P2-P7. 4.3.3. Suggested change: Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers when such devices impact the study area. Without this change, a significant amount of effort would be required (with no added benefit) to evaluate protection systems all over the grid that have little or no impact on the study area.

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	R4.3.1: add "if reclosing is actually used as part of a protection system" to the end of the sentence.
Response: Part 4.1.2: The SDT agrees with the concern and has modified Requirement R4, part 4.1.2. **Requirement R4, part 4.1.2** - For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities Part 4.3.3: This does not necessarily require modeling of specific relays all over the grid. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. Therefore, the SDT does not see a need to add words that specifically limit the simulation of these impacts to the study area. No change made. Part 4.3.1: The requirement is to consider the impact of high speed reclosing. This does not mean that you need to study high speed reclosing if you are not using it. No change made.	
SERC Dynamics Review Subcommittee (DRS)	It is not clear as to the expectations of standard drafting team for dynamic modeling of relays. Parts 4.1.2 and 4.3.3 imply that all transmission relays may need to be explicitly modeled in the dynamic simulations. Is this the team's intent, please clarify? For R4.1.2. Suggested change: Replace word "tripped" with "considered". Reasoning: Since often tripping an out-of-step generator reduces impedance swings, if the simulation shows acceptable impedance swings and voltage levels without tripping the generator, why would we be required to determine the tripping time and simulate tripping in each of the simulations that we have to run for these event categories? Without the suggested change involving the word "considered", significant extra effort would be required to perform simulations for small generators with no added benefit in achieving the purpose of assuring that impedance swings from generators are not passing through lines on the Bulk Electric System for events P2-P7. Part 4.3.1: add "when used as part of a protection system" to the end of the sentence. Part 4.3.3: add "when such devices affect the study area" to the end of the sentence. Part 4.4: place a space between words "Table 1" and "that".
Response: Parts 4.1.2 & 4.3.3: This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. Part 4.1.2: The SDT agrees with the concern and has modified Requirement R4, part 4.1.2. **Requirement R4, part 4.1.2** - For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities Part 4.3.1: The requirement is to consider the impact of high speed reclosing. This does not mean that you need to study high speed reclosing if you are not using it. No change made. Part 4.3.3: As stated above, a generic relay model can be used to meet this requirement. Therefore, the SDT does not see a need to add words that specifically limit the simulation of these impacts to the study area. No change made.	

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Part 4.4: The typo has been corrected.	
SERC Planning Standards Subcommittee	It is not clear as to the expectations of standard drafting team for dynamic modeling of relays. Parts 4.1.2 and 4.3.3 imply that transmission relays may need to be explicitly modeled in the dynamic simulations. Is this the team's intent, please clarify? Part 4.3.1: add "when used as part of a protection system" to the end of the sentence. Part 4.3.3: add "when such devices affect the study area" to the end of the sentence.
Response: Parts 4.1.2 & 4.3.3: This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. Part 4.3.1: The requirement is to consider the impact of high speed reclosing. This does not mean that you need to study high speed reclosing if you are not using it. No change made. Part 4.3.3: As stated above, a generic relay model can be used to meet this requirement. Therefore, the SDT does not see a need to add words that specifically limit the simulation of these impacts to the study area. No change made.	
Ameren	It is not clear as to the expectations of the standard drafting team for dynamic modeling of relays. Requirements 4.1.2 and 4.3.3 imply that transmission relays may need to be explicitly modeled in the dynamic simulations. Is this the team's intent? If so, has the team given consideration to the availability of relay models in the commonly used Power System simulation software programs, and considered the cost and effort required for such implementation versus the expected benefits? Is there any historical experience that would imply that such modeling is crucial to the reliability of the BES? It is suggested that generators that pull out of synchronism be given consideration for their effects on the system, without requiring simulation of generator tripping in R4.1.2. Requirement R4.3.1 needs to include some additional language regarding the automatic restoration of facilities and allowance of high-speed reclosing. The following language is suggested: Simulate the removal of all elements that the Protection System is expected to disconnect and the restoration of all elements that the automatic controls are expected to restore for each Contingency without operator intervention while also considering the impact of successful or unsuccessful high-speed reclosing, if high-speed reclosing is employed. R4.3.3: Suggested wording addition: "for those devices relevant to the study area." A space needs to be added between "Table 1" and "that" in Requirement 4.4.
Response: Parts 4.1.2 & 4.3.3: This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. Part 4.1.2: The SDT agrees with the concern and has modified 4.1.2.	

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Requirement R4, part 4.1.2 - For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities Part 4.3.1: The SDT does not see the need for the standard to specify other automatic controls. No change made. Part 4.3.3: As stated above, a generic relay model can be used to meet this requirement. Therefore, the SDT does not see a need to add words that specifically limit the simulation of these impacts to the study area. No change made. Part 4.4: The typo has been corrected.	
Utility System Efficiencies, Inc. (USE)	It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
Response: Part 4.3: The Contingency analyses in Requirement R4, part 4.3 refer to the studies in Requirement R4, parts 4.1 and 4.2. However, for additional clarity, Requirement R4, part 4.3 has been modified. **Requirement R4, part 4.3** - Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall : Part 4.3.1: The Standard requires you to study only the events which produce more severe System impacts. If two Systems are swinging apart, then successful high speed reclosing could show a more severe impact. However, if successful reclosing is not expected to produce a more severe impact, you are not required to study it.	
MidAmerican Energy Company	MidAmerican commends the SDT for their hard work on this standard. MidAmerican does have comments about this requirement though. MidAmerican urges that the SDT delete 4.1.1 which requires that no generating unit shall pull out of synchronism during a stability analysis. A generating unit pulling out of synchronism does not necessarily result in thermal, voltage, or stability violations and does not necessarily result in cascading, instability, or uncontrolled separation. The loss of synchronism and tripping of a generator is in effect no different than tripping due to mechanical issues such as tube leaks. Present electric grid design that allows tripping for out-of-synchronism is reliable and secure. Adding the requirement that no unit may pull out of synchronism goes well beyond current grid design practices. MidAmerican believes that 4.1.2 and 4.3.3 as written would require responsible entities in the industry to add additional modeling of relaying in dynamic stability models of our system. MidAmerican suggests that 4.3.3 be limited to transient swings on facilities 345 kV and above so as to limit this part of requirement 4 to those situations that are most likely to result in cascading. If the SDT determines not to add such a limitation, MidAmerican asks that the implementation time for R4 to be increased. MidAmerican believes that many responsible entities would need 3 years to add these relaying models to system stability models so that the fourth year additional transmission planning analysis in this respect is conducted. MidAmerican urges that the SDT increase the implementation time for R4 from 2 years to 4 years. (MidAmerican also made this comment under Question 11.)? 4.3.1 indicates that for stability contingency analysis shall be performed to “Simulate the removal of all elements that the

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	Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention while also considering the impact of successful or unsuccessful high speed reclosing." MidAmerican believes that it is over-kill to provide this as a general requirement as written. In such a case, such successful or unsuccessful high speed reclosing analysis conceivably would need to be performed for numerous unnecessary situations given the generally wide spread use of high speed reclosing on transmissions systems. MidAmerican urges the SDT to revise this requirement to only require the study of successful and unsuccessful high speed reclosing where high speed reclosing has been added to resolve a specific stability issue such as a breaker closing angle issue." 4.5 MidAmerican believes that the extreme events that should be studied are the more credible ones. The credible events are those that the planner considers credible when considering both how severe the event is and how likely it is. For example, while a tornado might be the most severe event, its likelihood of hitting key facilities is low. It is more likely to have a severe thunderstorm that hits key facilities but causes less impact on the system. The planner should plan for the severe thunderstorm but perhaps should not plan for the tornado. MidAmerican recommends that 4.5 be revised to indicate that a list of those events that "produce more severe System impacts AND ARE MORE LIKELY" (the words in all caps are suggested words to be added) be studied as being more credible events. Then the purpose of the last sentence in 4.5 is clearer in that possible actions that reduce the likelihood or mitigate the consequences of the events shall be reviewed for those contingencies where likelihood in combination with consequences justify such evaluation. MidAmerican recommends the data retention for R4 and M4 be revised to change "All" to "The". The word "All" is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: "THE studies performed in support". The word in all caps is a word suggested to be added.

Response: Part 4.1.1: The SDT disagrees. A unit's pulling out of synchronism for a normally cleared fault is an indication of a weak Transmission System or insufficient relaying. A corrective action should be developed. No change made.

Parts 4.1.2 & 4.3.3: This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line.

Part 4.3.3: As stated above, a generic relay model can be used to meet this requirement. Therefore, the SDT does not see a need to add words that specifically limit the simulation of these impacts to only high voltage lines. No change made.

Part 4.3.3: Because this requirement does not necessarily require modeling of specific relays (as described directly above), the SDT does not agree that a longer time is needed in the Implementation Plan. No change made.

Part 4.3.1: The SDT disagrees. The requirement is to consider the impact of high speed reclosing. This does not mean that you need to study high speed reclosing if you are not using it. If you are using it, then it should be covered in the studies. No change made.

Part 4.5: The extreme events for Stability analysis cover Contingencies like 3-phase fault with stuck breaker or a 3-phase fault after an element has gone out of service prior to System adjustments. These events are less likely to occur than the Planning Events. The SDT does not see any need to add the suggested qualifier "are more likely" because by definition none of the extreme events are more likely.

The SDT agrees and has made the suggested change.

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TIS	Nowhere in the stability requirements is it necessary for evaluating the loss of all generators in a station; it is included in the steady state requirements. The standard should require examination of all units in a generating station where single line-to-ground faults on generation station buses could cause the clearing of the entire station. Further, single phase faults with delayed clearing (or stuck breaker) are not included. Often, such exclusion of stability analysis for loss of all generators at a station these are things that happen!
Response: The SDT excluded loss of all units at a generating station as an extreme event for Stability. In general there are no Contingencies that could cause this to happen in a Stability time frame of interest. If there are faults or faults with breaker failure which could cause the loss of all generators at a plant, then that event is required to be studied under the other planning or extreme events. Single phase faults with stuck breaker are included in planning event P4.	
Southern Company	Part 4.3.1: add "when used on the system" to the end of the sentence. This is needed to clarify that you don't have to study high speed reclosing if you don't utilize it.
Response: Part 4.3.1: The requirement is to consider the impact of high speed reclosing. This does not mean that you need to study high speed reclosing if you are not using it. No change made.	
Oklahoma Gas & Electric	R4 OG&E believes the Transmission Coordinator be held accountable for R4. The Transmission Coordinator should coordinate this type of study with the Transmission Planner for a regional look of the whole system. For example Southwest Power Pool should coordinate this type of study with the members of the Southwest Power Pool to better examine the entire region of the Southwest Power Pool. We do not see the need to duplicate the work. R4.4 & R4.5 There appear to be no standards of directions on identifying severe or extreme system impacts. OG&E does not like being held accountable to nebulas standards. Need more specific information.
Response: R4: The SDT assumes you meant to say Planning Coordinator rather than Transmission Coordinator (which is not in the Functional Model). Requirement R7 requires the Planning Coordinator and Transmission Planner to work out who will be conducting what studies. Parts 4.4 & 4.5: Use your engineering judgment to determine which Contingencies could produce more severe results. For example, it could be argued that faults close in to generating plants would be more severe than faults two busses away from the plant.	
MAPP	R4.1.1 & R4.1.2 - We propose that these sub-requirements be removed. The generating unit loss of synchronism does not necessary result in a thermal, voltage, or stability violations. R4.3.2 We suggest that this requirement be removed because it is premature to require Transmission Planners to simulate under voltage tripping until the MOD standards require it. If the drafting team does not remove this requirement we propose wording like, "Trip generating units that are connected to the BES when actual or assumed minimum generator transient voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment". The requirement should not apply to all relevant generating units until one of the MOD standards

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	requires all Generator Owners to provide their minimum generating unit voltage limits to the TP and PC. If the wording of R4.3.2 must be different from its counterpart, R3.3.2, then please explain the reasons for any differences. Add R4.3.5 We suggest the addition of R4.3.5, "Applicable System Operating Limits for the planning horizon shall not be exceeded." because Note "a" and "b" under "Stability Only" at the beginning of Table 1 are stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and hidden) in the performance notes of Table 1. [After R4.3.5 is added, Note "a" should revised and refer to R4.3.5.]
Response: Parts 4.1.1 & 4.1.2: The SDT disagrees. A unit's pulling out of synchronism for a normally cleared fault is an indication of a weak Transmission System or insufficient relaying. A corrective action should be developed. The SDT sees no reason to delete Requirement R4, parts 4.1.1 and 4.1.2. Part 4.3.2: The purpose of Requirement R4, part 4.3.2 is to take into account the low voltage ride-through capability of generators in the studies. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. Your proposed wording is not significantly different from the existing wording. No change made. Part 4.3.2: To be consistent with Requirement R4, part 4.3.2, Requirement R3, part 3.3.2 has been modified to also allow the use of voltages on the high side of the GSU. The use of voltages on the high side of the GSU allows greater flexibility in applying voltage ride-through capability of generators - some of which are defined on the high side of the GSU. **Requirement R3, part 3.3.2** - Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. Part 4.3.5: The SDT does not see a need for making these header notes into requirements. These apply more directly as qualifiers for the results of the simulations and therefore, they fit better as header notes to the Table. No change made.	
NERC Standards Review Subcommittee	R4.1.1 & R4.1.2 The MRO NSRS proposes that these sub-requirements be removed. The generating unit loss of synchronism does not necessary result in a thermal, voltage, or stability violations.R4.1.1 - Wording from R4.1.1 about no generating unit pulling out of synchronism should be deleted. The simple loss of synchronism of a unit or even multiple units does not necessarily result in thermal, voltage, or stability. All standards and requirements should demonstrate a reliability related basis. There is no direct reliability or security requirement that prevents a unit from loosing synchronism. The loss of a unit from synchronism is no different than the regular loss of the unit for mechanical reasons, therefore this requirement unnecessarily results in FERC directing utilities to build infrastructure beyond what is needed for system security. R4.1.3 The MRO NSRS proposes that this sub-requirement be removed because there are no NERC power system damping standards. R.4.3.2 The MRO NSRS suggests that this requirement be removed because it is premature to requirement Transmission Planners to simulate under voltage tripping until the MOD standards require it. If the drafting team does not remove this requirement the MRO NSRS proposes wording like, "Trip generating units that are connected to the BES when actual or assumed minimum generator transient voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment". The requirement should not apply to all relevant

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	generating units until one of the MOD standards requires all Generator Owners to provide their minimum generating unit voltage limits to the Transmission Planner and Planning Coordinator. If the wording of R4.3.2 must be different from its counterpart, R3.3.2, then please explain the reasons for any differences. R4.3.3 Every dynamic event simulation involves power system transient swings. What are the size and scope of the transient swings and what is the scope of the system to be examined, to which this requirement is referring? Please reword this requirement to give the industry a better understanding of what is intended. As written R4.3.3, it might be interpreted to require responsible entities to add the modeling of all relaying instead of just pertinent. Perhaps, R4.3.3 should be limited to transient swings on facilities 345 kV and above so as to limit this part of requirement 4 to those situations that are most likely to result in cascading. If the SDT determines not to add such a limitation, the MRO NSRS proposes that the implementation time for R4 to be increased. The MRO NSRS believes that many responsible entities would need 3 years to add these relaying models to system stability models so that the fourth year additional transmission planning analysis in this respect is conducted. The MRO NSRS urges that the SDT increase the implementation time for R4 from 2 years to 4 years. When it may actually respond or triggered. R 4.3.1 This requirement refers to high speed reclosing and the MRO NSRS presumes that this is special high speed reclosing that is completed in several cycles, rather than the normal high speed reclosing that is completed in a number of seconds. The MRO NSRS recommends that the term high speed reclosing be defined for this sub-requirement with an angular stability component. R4.5 - The MRO NSRS believes that the extreme events that should be studied are the more credible ones. The credible events are those that the planner considers credible when considering both how severe the event is and how likely it is. For example, while a tornado might be the most severe event, its likelihood of hitting key facilities is quite low. It is more likely to have a severe thunderstorm that hits key facilities but causes less impact on the system. The planner should plan for the severe thunderstorm but perhaps should not plan for the tornado. The MRO NSRS recommends that 4.5 be revised to indicate that a list of those events that "produce more severe System impacts and are more likely" (the bolded words are suggested words to be added) be studied as being more credible events. Then the purpose of the last sentence in 4.5 is clearer in that possible actions that reduce the likelihood or mitigate the consequences of the events shall be reviewed for those contingencies where likelihood in combination with consequences justify such evaluation.
Response: Parts 4.1.1 & 4.1.2: The SDT disagrees. A unit's pulling out of synchronism for a normally cleared fault is an indication of a weak Transmission System or insufficient relaying. A corrective action should be developed. The SDT sees no reason to delete Requirement R4, parts 4.1.1 and 4.1.2. Part 4.1.3: Requirement R4, part 4.1.3 requires the Planning Coordinator and Transmission Planner to use their engineering judgment on what constitutes acceptable damping. The SDT did not think it appropriate to prescribe what acceptable damping is. Most Planning Coordinator's and Transmission Planner's should already have this kind of criteria for their systems. No change made. Part 4.3.2: The purpose of Requirement R4, part 4.3.2 is to take into account the low voltage ride-through capability of generators in the studies. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. Your proposed	

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wording is not significantly different from the existing wording. No change made. Part 4.3.2: To be consistent with Requirement R4, part 4.3.2., Requirement R3, art 3.3.2 has been modified to also allow the use of voltages on the high side of the GSU. The use of voltages on the high side of the GSU allows greater flexibility in applying voltage ride-through capability of generators - some of which are defined on the high side of the GSU. **Requirement R3, part 3.3.2** - Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. Part 4.3.3: This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. Therefore, the SDT does not believe this should be limited to only high voltage lines. Because this requirement does not necessarily require modeling of specific relays, the SDT also does not agree that a longer time is needed in the Implementation Plan. Part 4.3.1: The SDT believes that there is general understanding in the industry that reclosing that is accomplished in a number of seconds is not high speed reclosing. It is just known as reclosing. High speed reclosing would occur within a second after fault clearing. Part 4.5: The extreme events for Stability analysis cover Contingencies like 3-phase fault with stuck breaker or a 3-phase fault after an element has gone out of service prior to System adjustments. These events are less likely to occur than the planning events. The SDT does not see any need to add the suggested qualifier "are more likely" because by definition none of the extreme events are more likely.	
Sacramento Municipal Utility District	R4.1.1: There appears to be a conflict between what is not allowed for a generator in R4.1.1 and what is allowed in Note (b) of Table 1 (consequential generation loss " which is an undefined term " and hence can be interpreted as one sees fit). R4.3.3: It is unclear what is expected from this requirement. Are Protection personnel to take the results of the transient stability simulation and determine its impact on the Protection System? Or, is it that the Protection System should be properly modeled in stability simulations? If it is the latter, this requirement is already covered by R4.3.1 (simulate the removal of all elements). R4.3.2: If done right, this requirement should be already complied with under R4.3.1. If it needs to be spelled out, a better place may be in the MOD Standards. R4.4 and R4.5: Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3.R4.3.1 appears to require an assessment of both successful and unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both, we suggest including the assessment in the list of sensitivities.
Response: Part 4.1.1: The generation loss referred to in note b is the generation that is disconnected from the System by fault clearing action. This is completely different from a generator pulling out of synchronism. Part 4.3.3: The requirement is to take into account the impact of transient swings. This does not necessarily require modeling of specific relays. Some dynamic	

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simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. Part 4.3.2: Requirement R4, part 4.3.1 requires simulating the removal of elements which must be removed to clear the fault. Requirement R4, part 4.3.2 involves generator low voltage ride-through and tripping the generator when voltages are too low. These are two completely different things. Parts 4.4 & 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made. Part 4.3: The Contingency analyses in Requirement R4, part 4.3 refer to the studies in Requirement R4, parts 4.1 and 4.2. However, for additional clarity, Requirement R4, part 4.3 has been modified. **Requirement R4, part 4.3** - Contingency analyses for Requirement R4, parts 4.1 and 4.2 shall : Part 4.3.1: The Standard requires you to study only the events which produce more severe System impacts. If two Systems are swinging apart, then successful high speed reclosing could show a more severe impact. However, if successful reclosing is not expected to produce a more severe impact, you are not required to study it.	
Manitoba Hydro	R4.1.2: For P2 events, a generator that pulls out of synchronism must be tripped. Tripping of the generator could result in Interruption of Firm Transmission Service unless redispatch is allowed - Footnote 9 should be allowed. R4.1.3 states that “power oscillation shall exhibit acceptable damping as established by the PC and TP”. There is no requirement for the PC or TP to develop criteria for acceptable damping. Requirement R5 or R6 should be expanded to require the PC and TP to establish criteria for acceptable power oscillation damping. R4.2: Recommend changing “the list” to “the Contingency list” to add clarity and consistency.
Response: The SDT agrees and has changed Table 1 so that footnote 9 applies to planning event P2. Part 4.1.3: There doesn't have to be a specific requirement for the Planning Coordinator and Transmission Planner to establish damping criteria. Most should already have such a criteria. No change made. Part R4.2: The SDT does not see any value in adding the word "Contingency" to the word "list". No change made.	
Duke Energy	R4.3.3 must be clarified regarding what method is to be used for assessing the impact of transient swings on Protection System operation. For example, how is this to be included in models, is this referring to a post simulation evaluation comparing results to actual relay settings, etc?? R4.5 includes the phrase “cascading outages”. We believe that the word “cascading” should be the capitalized NERC-defined term “Cascading”.
Response: Part 4.3.3: The requirement is to take into account the impact of transient swings. This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. Part 4.5: The SDT has modified Requirement R4, part 4.5 to use the term "Cascading" rather than "cascading outages."	

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Requirement R4, part 4.5 - Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R4, part 4.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.	
NorthWestern Energy	R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. We suggest moving both R4.4 and R4.5 into R4.1 and R4.2, then R4.4 and R4.5 could be deleted. R4.3 is unclear whether the Contingency analyses need to be performed for all planning events or only the more severe events referenced in R4.1 and R4.2. R4.3 needs clarification. R4.3.1 requires considering the impact of both successful and unsuccessful high-speed reclosing. Since successful reclosing is a much less severe event, it seems unnecessary to assess both. If entities need to assess both, the assessment could be in the list of sensitivities. R4.5 needs to be modified. It would be better to combine R4.2 and R4.5. The first part of the requirement requires identification of events that produce more severe System impacts. The presumed reason that the other contingencies were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be examples of more severe Extreme Contingencies than the one selected for study. This can be achieved by simply choosing events that are even less credible. For example, if the Extreme Contingency studied was a simultaneous loss of 3 transmission lines with the failure of redundant RAS (SPS), then an event resulting in the simultaneous loss of 4 lines with the failure of 2 sets of redundant RASs would be even more severe. Listing all possible extreme events could result in a limitless list.
Response: Parts 4.4 & 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made. Part 4.3: The Contingency analyses in Requirement R4, part 4.3 refer to the studies in Requirement R4, parts 4.1 and 4.2. However, for additional clarity, Requirement R4, part 4.3 has been modified. **Requirement R4, part 4.3** - Contingency analyses for Requirement R4, parts 4.1 and 4.2 shall : Part 4.3.1: The Standard requires you to study only the events which produce more severe System impacts. If two Systems are swinging apart, then successful high speed reclosing could show a more severe impact. However, if successful reclosing is not expected to produce a more severe impact, you are not required to study it. Part 4.5: Requirement R4, Part 4.5 refers to the Contingency events listed in the extreme event Stability section of Table 1. Your example does not fall into the events listed. For this analysis you don't just keep adding more and more outaged elements. You only have to do the ones listed in the Table that would be expected to produce more severe results.	
Northeast Power Coordinating Council--RSC	Requirement 4.1.1: This should be revised to only be applicable to generators interconnected to the BES. This may need an implementation period as not all existing units are interconnected in accordance with the standard as proposed. As written this applies to small generators and doesn't necessarily reflect reliability of the network. 20 MW is a recommended generator minimum size. Requirement 4.1.2: Simulating the tripping of a generator that pulls out of synchronism is presently not modeled and will require

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	an implementation period. Requirement 4.2: This requirement should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. Requirement 4.4 NPCC strongly suggests making this requirement a sub-bullet of Requirement 4.1 to keep the related requirements together. Requirement 4.5 NPCC strongly suggests making this requirement a sub-bullet of Requirement 4.2 to keep the related requirements together. This requirement needs clarification as to what is specifically required for the "evaluation of possible actions." The list associated with Requirement 2. part 2.7.1 provides examples of possible actions, and leaving "evaluation" undefined offers the Planning Coordinator and Transmission Planner the leeway to use judgment in making their evaluations.
Response: Part 4.1.1: The standard applies only to the BES as defined by your Region.. No change made. Part 4.1.2: Tripping the generator is no longer required. The SDT has modified Requirement R4, part 4.1.2. **Requirement R4, part 4.1.2** - For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities. Part 4.2: The SDT disagrees and believes there is value in running extreme event analysis. No change made. Part 4.4: The SDT does not believe that combining the requirements serves any purpose. No change made. Part 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made. The requirement is to evaluate possible actions which could reduce the likelihood or mitigate the consequences of the event. The standard should not prescribe those actions. It is up to your judgment what those possible actions could be.	
Midwest ISO	Requirement R4.3.1: Please consider adding the following language to the end of the sentence "when used as part of a protection system". Requirement R4.3.1: Please consider adding the following language to the end of the sentence "when such devices affect the study area".
Response: Part 4.3.1: The requirement is to consider the impact of high speed reclosing. This does not mean that you need to study high speed reclosing if you are not using it. No change made. Part 4.3.1: High speed reclosing would be considered only for the line you are studying. Therefore, it always impacts the study area. No change made.	
Hydro-Québec TransEnergie	Requirements 3.5 and 4.5 Both of these requirements need clarification as to what is specifically required for the "evaluation of

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(HQT)	possible actions." Requirement 4.4 HQT, as does NPCC, strongly suggests making this requirement a sub-bullet of Requirement 4.1 to keep the related requirements together. Requirement 4.5 HQT, as does NPCC, strongly suggests making this requirement a sub-bullet of Requirement 4.2 to keep the related requirements together.
Response: Part 4.5: "An evaluation of actions designed to reduce" means looking for ways to reduce the probability of the event occurring or reducing the magnitude of the consequences of that event. For example, if a three phase fault with a bus differential failing to operate results in the collapse of a large Load area, a possible action would be to add a redundant bus differential relay. This reduces the probability of the event occurring. Or if a three phase fault with a stuck breaker results in a large area of the System pulling out of synchronism, an SPS could be used to trip a generator and keep the rest of the System in synchronism. This would reduce the magnitude of the consequences of the event. The evaluation would be comparing potential solutions and their cost with the consequences of the event to determine the best course of action to take (if any). Part 4.4: The SDT does not believe that combining the requirements serves any purpose. No change made. Part 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made.	
Bonneville Power Administration	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
Idaho Power	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful and unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
Modesto Irrigation District Transmission Planning	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more

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	severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
NV Energy	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
Pacific Gas and Electric Co.	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
Puget Sound Energy, Inc.	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.41 requires clarification. With respect to these “Contingencies on adjacent systems,” the responsibility of listing and analyzing these events needs to be clarified. Should the event simulation be the responsibility of the “neighboring” system (where the event would occur) or the adjacent system that may feel the impact of this event? Per the developed rationale from R4.4, the neighboring system may determine that a particular event is “less severe” and hence not studied, even though this event may potentially impact a neighbor. Further, for these “Contingencies on adjacent systems” that result in system performance outside one’s own operating limits, it is unclear who is responsible for mitigating these contingencies. It is potentially awkward in that one entity may be planning another entity’s system improvements.
San Diego Gas & Electric Co	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted.

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	It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
Southern California Edison (SCE)	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. t is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
SRP	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
Western Area Power Adm - RMR	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2, respectively. I Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful and unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both.

Response: Parts 4.4 & 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made.

Part 4.3: The Contingency analyses in Requirement R4, part 4.3 refer to the studies in Requirement R4, parts 4.1 and 4.2. However, for additional clarity, Requirement R4, part 4.3 has been modified.

Requirement R4, part 4.3 - Contingency analyses for Requirement R4, parts 4.1 and 4.2 shall :

Part 4.3.1: The Standard requires you to study only the events which produce more severe System impacts. If two Systems are swinging apart, then successful high

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speed reclosing could show a more severe impact. However, if successful reclosing is not expected to produce a more severe impact, you are not required to study it. No change made.	
National Grid	Sub-Requirement 4.1.1: This should be revised to only be applicable to generators interconnected to the BES. This may need an implementation period as not all existing units are interconnected in accordance with the standard as proposed. As written this applies to small generators and doesn't necessarily reflect reliability of the network. 20 MW is a recommended generator minimum size. Sub-Requirement 4.1.2: Simulating the tripping of a generator that pulls out of synchronism is presently not modeled and will require implementation period. Sub-Requirement 4.2: This requirement should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. Sub-Requirement 4.4: It is strongly suggested that this requirement is made a sub-bullet of Requirement 4.1 to keep the related requirements together. Sub-Requirement 4.5: It is strongly suggested that this requirement is made a sub-bullet of Requirement 4.2 to keep the related requirements together. Provide clarification as to what is specifically required for the "evaluation of possible actions."
Response: Part 4.1.1: The standard applies only to the BES as defined by your Region. No change made. Part 4.1.2: Tripping the generator is no longer required. The SDT has modified Requirement R4, part 4.1.2. **Requirement R4, part 4.1.2** - For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities. Part 4.2: The SDT disagrees and believes there is value in running extreme event analysis. No change made. Part 4.4: The SDT does not believe that combining the requirements serves any purpose. No change made. Part 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made. Part 4.5: "An evaluation of actions designed to reduce" means looking for ways to reduce the probability of the event occurring or reducing the magnitude of the consequences of that event. For example, if a three phase fault with a bus differential failing to operate results in the collapse of a large Load area, a possible action would be to add a redundant bus differential relay. This reduces the probability of the event occurring. Or if a three phase fault with a stuck breaker results in a large area of the system pulling out of synchronism, an SPS could be used to trip a generator and keep the rest of the system in synchronism. This would reduce the magnitude of the consequences of the event. The evaluation would be comparing potential solutions and their cost with the consequences of the event to determine the best course of action to take (if any).	
Tri-State Generation and	The standard needs to use the term "Dynamic Stability", not just "Stability", to differentiate between dynamic and voltage stability

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Transmission Association	considerations. R4.1 contains the phrase "based on the Contingency list created in Requirement R4.4". The contingency list is referred to in R4.4 (and R3.4), but is not created there. In R4.3.1 the requirement for additional evaluation of "successful or unsuccessful high speed reclosing" is an additional performance requirement. Whether this refers to the possibility of reclosing mechanism failure, or the effectiveness of reclosing operations (there is some ambiguity here). The reference to high speed reclosing in R4.3.1 is a good addition. For ease in auditing, it should be listed as a separate requirement (or sub-requirement).
Response: The SDT does not see any need to use that term as it does not provide any needed clarity. No change made. Parts 4.1 & 4.4: The Contingency list is created in Requirement R4, part 4.4. The SDT does not understand your comment. Part 4.3.1: The SDT does not see any value in making this a separate requirement. No change made.	
American Transmission Company	We propose the following changes and pose the following questions: R4.1.1 We suggest that there should be some qualification of which generating units are referred to in this requirement. We propose that the requirement say, "No generating unit connected to the BES shall pull out of synchronism." For example, some utilities include smaller generation units that are connected at voltages below 100 kV and even down to distribution voltage in their base cases. R4.1.2 We propose that the wording of this requirement be revised to reflect the same BES qualification of the generating unit that we noted in R4.1.1 above. 4.3.1 This requirement refers to high speed reclosing and we presume that this is special high speed reclosing that is completed in several cycles, rather than the normal high speed reclosing that is completed in a number of seconds. We recommend that the term high speed reclosing be defined for this sub-requirement.R. 4.3.2 We suggest qualifying which generating units to consider and which voltage limits to simulate with revised wording like, "Trip generating units that are connected to the BES when actual or assumed minimum generator transient voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment". The requirement should not apply to all relevant generating units until one of the MOD standards requires all Generator Owners to provide their minimum generating unit voltage limits to the TP and PC. If the wording of R4.3.2 must be different from its counterpart, R3.3.2, then please explain the reasons for any differences. R4.3.3 Every dynamic event simulation involves power system transient swings. What are the size and scope of the transient swings and what is the scope of the system to be examined, to which this requirement is referring? Please reword this requirement to give the industry a better understanding of what is intended. Add R4.3.5 We suggest the addition of R4.3.5, "Applicable System Operating Limits for the planning horizon shall not be exceeded." Note "a" and "b" under "Stability Only" at the beginning of Table 1 are stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and basically

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	hidden) in the performance notes of Table 1. [After R4.3.5 is added, Note "a" should be revised and refer to R4.3.5.] Add R4.3.5 We suggest the addition of R4.3.5, "Applicable System Operating Limits for the planning horizon shall not be exceeded." because Note "a" and "b" under "Steady State Only" at the beginning of Table 1 is stated in the form of a Requirement (e.g. note usage of the verb, "shall") and all Requirements should be clearly included in the body of the standard and not be introduced (and basically hidden) in the performance notes of Table 1. [After R3.3.5 is added, Note "a" should allude to R3.3.5.]
Response: Part 4.1.1: The standard applies only to the BES as defined by your Region. No change made. Part 4.1.2: The standard applies only to the BES as defined by your region. No change made. Part 4.3.1: The SDT believes that there is general understanding in the industry that reclosing that is accomplished in a number of seconds is not high speed reclosing. It is just known as reclosing. High speed reclosing would occur within a second after fault clearing. Part 4.3.2: The purpose of Requirement R4, part 4.3.2 is to take into account the low voltage ride-through capability of generators in the studies. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. Your proposed wording is not significantly different from the existing wording. No change made. Part 4.3.2: To be consistent with Requirement R4, part 4.3.2, Requirement R3, part 3.3.2 has been modified to also allow the use of voltages on the high side of the GSU. The use of voltages on the high side of the GSU allows greater flexibility in applying voltage ride-through capability of generators - some of which are defined on the high side of the GSU. **Requirement R3, part 3.3.2** - Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. Part 4.3.3: The requirement is to take into account the impact of transient swings. This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. Part 4.3.5: The SDT does not see a need for making these header notes into requirements. These apply more directly as qualifiers for the results of the simulations and therefore, they fit better as header notes to the Table.	
American Electric Power	We recommend inserting "unstable" in the requirement language as follows: "Simulate the impact of unstable transient swings on Protection System operation?" Our perception is that the wording of 4.3.3 is almost certain to require the representation of impedance relay characteristics on both ends of all lines in a study area in order to satisfy an audit, and would eventually require representation on both ends of all BES lines as all areas would be studied at some point. This sub-requirement would place a huge burden on transmission planning and protection engineering staff. Experience has shown that tripping of transmission lines or transformers on stable swings is extremely rare. The burden this sub-requirement would cause as presently worded is not commensurate with the expected benefit.
Response: Part 4.3.3: The requirement is to take into account the impact of transient swings. This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a	

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branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. The SDT does not agree to insert the word "unstable" before "transient swings" because some stable swings can get into relay characteristics.	
FRCC Transmission Working Group	With regard to the Moderate VSL, consider deleting “utilizing data” in order to avoid penalizing twice for failing to meet R1. 4.1.1, suggest rewording “(a) generator being disconnected from the Bulk Electric System “, system as defined in the Glossary includes distribution, and we do not believe that is the intent of the SDT. 4.1.2, 4.3.1 and 4.3.3 essentially requirerequires modeling every Zone 3 (or higher, such as Zone 5) relay in each Interconnection (or at least in the Region under study and adjacent regions) because, in order to simulate the impact of a power swing on a distance relay, one would need to know the characteristics of the distance relay and how long the transient swing remains within that characteristic, which means modeling the relay. Is that the intent of the SDT?
Response: Requirement R1 requires you to maintain System models. Requirement R4 requires you to use that model data for your Stability studies. These are two different things requiring two VSLs. No change made. Part 4.1.1: The standard applies only to the BES as defined by your Region. No change made. Parts 4.1.2, 4.3.1, & 4.3.3: This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line.	
E.ON U.S.	With respect to Category P6, a Multiple Contingency event (the overlapping occurrence of two or more single events) allows Non-Consequential Load Loss. The "System adjustments" do not list yet do not exclude Load Shedding. E.ON U.S believes that Load Shedding should be included as an option in similar manner to Curtailment of Firm Transmission Service. If the SDT disagrees with this recommendation, then E.ON U.S. suggests that the SDT clearly state the allowed use of Load Shedding. E.ON U.S. observes that in the case of Extreme Events the SDT provided the following response to a previous comment:Extreme event 2d and 3a are similar in that each covers the loss of all generating units at a single plant location. However, in 3a, two plants are reviewed. In each case, all units are to be outaged regardless of the BES voltage level to which they connect.E.ON U.S. recommends that the word "station" in event 2d to be changed "plant".
Response: In Event P6 the term System adjustments has a reference to footnote 9. This footnote clearly states that System adjustments do not include the shedding of firm Demand. The allowable loss of Non-Consequential Load for event P6 refers to after the second Contingency has occurred. The SDT agrees that there needs to be consistency and has changed the word "plants" to "stations" in extreme event 3a.	
Oncor Electric Delivery	Within “stability requirements” there is no requirement for evaluating the loss of all generators in a station; it is included in the steady state requirements. We recommend that the standard require examination of all units in a generating station where single line-to-ground faults on generation station buses could result in clearing of the entire station. Furthermore, single phase faults with delayed clearing (or stuck breaker) are not included. Often, such exclusion of stability

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	analysis for loss of all generators at a station these are things that happen! 4.1.1 This should be dropped. As written, this applies to small generators and doesn't necessarily reflect reliaiblity of the network. 4.1.2 This is not presently modeled and will require implementation period 4.2 Why do we need to do study extreme events? The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. 4.4 It is strongly suggested that this requirement is made a sub-bullet of Requirement 4.1 to keep the related requirements together. 4.5 It is strongly suggested that this requirement is made a sub-bullet of Requirement 4.2 to keep the related requirements together.
Response: The SDT excluded loss of all units at a generating station as an extreme event for Stability. In general there are no Contingencies that could cause this to happen in a Stability time frame of interest. If there are faults or faults with breaker failure which could cause the loss of all generators at a plant, then that event is required to be studied under the other planning or extreme Events. No change made. Single phase faults with stuck breaker are included in planning event P4. Part 4.1.1: The SDT believes that Part 4.1.1 is required for BES reliability. The standard applies only to the BES as defined by your Region. The SDT believes that all generators directly connected to the BES need to be stable for single Contingencies (P1). No change made. Part 4.1.2: Tripping the generator is no longer required. The SDT has modified Requirement R4, part 4.1.2. **Requirement R4, part 4.1.2** - For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities. Part 4.2: The SDT disagrees and believes there is value in running extreme event analysis. No change made. Part 4.4: The SDT does not believe that combining the requirements serves any purpose. No change made. Part 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made.	
PJM	in R4.1.2 – It should be made clear when the unit should be tripped. Timing is important in dynamics studies. Actual protection made need to be modeled to cover this item completely. In R4.3.3 - This protection information, is not commonly collected, at least by MMWG, and will take a great deal of time and effort to gather. R4.5 – Needs a 4.5.1 similar to 4.4.1.
Response: Part 4.1.2: Tripping the generator is no longer required. The SDT has modified Requirement R4, part 4.1.2. **Requirement R4, part 4.1.2** - For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent	

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	impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities Part 4.3.3: This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. The SDT believes the time allotted in the Implementation Plan is appropriate. Part 4.5: The SDT does not agree that a similar requirement is needed for extreme events. No change made.

5. Requirement R5 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement. (Note – This is a new requirement.)

Summary Consideration: Several commenters expressed concern with potential double jeopardy between this standard and the VAR standards. From the ERO Rules of Procedure, Appendix 4B- Sanction Guidelines, Section 3.10 Multiple Violations: "Strictly speaking, NERC or the regional entity can determine and levy a separate penalty or sanction, or direct remedial action, upon a violator for each individual violation. However, in instances of multiple violations related to a single act or common incidence of noncompliance, NERC or the regional entity will generally determine and issue a single aggregate penalty, sanction, or remedial action directive bearing reasonable relationship to the aggregate of the related violations. The penalty, sanction, or remedial action will not be that determined individually for the least serious of the violations; it will generally be at least as large or expansive as what would be called for individually for the most serious of the violations." The existing VAR standards (VAR-001-1a and VAR-002-1b) address the operational time horizon but do not address the planning horizon. NERC Standards Project 2008-1 is under development and the SAR addresses the planning horizon. As this project moves forward, the Standards Drafting Team for Project 2008-1 will more fully develop the requirements for reactive planning and will evaluate whether those requirements should reside in the TPL standard or the VAR standards.

Several commenters expressed concern that the requirement to develop a transient voltage response criterion was not limited to establishing a low voltage threshold. The SDT clarified that the minimum requirement for establishing a transient voltage response criterion was to establish a low voltage level and the maximum length of time that the transient voltages may remain below that level. To clarify the SDT's intent, the wording of R5 has been modified as follows:

R5. Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level.

Requirement R5 data retention: The documentation specifying the criteria since the last compliance audit in accordance with Requirement R5 and Measure M5.

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Independent Electricity System Operator	(1) We do not have any concern with the requirement as written, but suggest the SDT consider adding "and associated reactive power requirements" after "acceptable System steady state voltage limits" to take care of the concern raised in the recently posted SAR for a new VAR standard. We do not think a new standard is required for stipulating reactive power requirements as they are best addressed in the planning assessment criteria and the SOL/IROL determination requirements. (2) We do not have any comments on the measure, VRF, Time Horizon and VSL.
Response: 1) The SDT declines to add "and associated reactive power requirements". The Voltage and Reactive Planning and Control Project (2008-1) will more	

Organization	Comments for Question 5
fully develop the requirements for reactive planning and will evaluate whether those requirements should reside in the TPL standard or the VAR standards. 2) Thank you.	
MAPP	A voltage criterion is addressed by the VAR standards where they are applicable to TOs and TOPs. Including a voltage requirement in the planning standards appears to be creating a double-jeopardy exposure.
Response: As for the double jeopardy comment - From the ERO Rules of Procedure, Appendix 4B- Sanction Guidelines, Section 3.10 Multiple Violations: "Strictly speaking, NERC or the regional entity can determine and levy a separate penalty or sanction, or direct remedial action, upon a violator for each individual violation. However, in instances of multiple violations related to a single act or common incidence of noncompliance, NERC or the regional entity will generally determine and issue a single aggregate penalty, sanction, or remedial action directive bearing reasonable relationship to the aggregate of the related violations. The penalty, sanction, or remedial action will not be that determined individually for the least serious of the violations; it will generally be at least as large or expansive as what would be called for individually for the most serious of the violations." The existing VAR standards (VAR-001-1a and VAR-002-1b) address the operational time horizon but do not address the planning horizon. NERC Standards Project 2008-1 is under development and the SAR addresses the planning horizon. As this project moves forward, the Standards Drafting Team for Project 2008-1 will more fully develop the requirements for reactive planning and will evaluate whether those requirements should reside in the TPL standard or the VAR standards.	
NERC Standards Review Subcommittee	A. The MRO NSRS recommends the data retention for R5 and M5 be revised to change "All" to "The". The word "All" is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: "The documentation specifying the criteria since". B. This requirement should not include the criterion, "post-Contingency voltage deviation", because this criterion is not used widely enough in the industry to be a well established criterion.
Response: A. The SDT has modified the data retention for Requirement R5 to strike the word "All" and has replaced it with the word "The". **Requirement R5 data retention**: The documentation specifying the criteria since the last compliance audit in accordance with Requirement R5 and Measure M5. B. The SDT believes that the reference to 'post-Contingency voltage deviation' is widely used and is an acceptable reference in the standard. No change made.	
Progress Energy Florida, Inc.	As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all appropriate parties to review PEF's previous comments to this effect.
Response: Throughout the drafting process, the SDT has carefully considered your comments as well comments from other industry members.	
Idaho Power	As worded R5 is unclear. I interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. I suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."

Organization	Comments for Question 5
Bonneville Power Administration	As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
NV Energy	As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
Pacific Gas and Electric Co.	As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
Puget Sound Energy, Inc.	As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
Sacramento Municipal Utility District	As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
San Diego Gas & Electric Co	As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
Southern California Edison (SCE)	As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
SRP	As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum

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	length of time that transient voltage may remain below that level."
Western Area Power Adm - RMR	As worded, R5 is unclear. I interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. I suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
Response: The SDT clarified that the minimum for establishing a transient voltage response criterion was to establish a low voltage level and the maximum length of time that the transient voltages may remain below that level. **R5**. Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level.	
CenterPoint Energy	CenterPoint Energy is not familiar with the phrase "post-Contingency voltage deviations" and recommends that this phrase be deleted. Alternatively, the text should be revised to read "steady state post-contingency voltage limits." Including both phrases is unnecessary and confusing.
American Transmission Company	R5 This requirement should not include the criteria item, "post-Contingency voltage deviation", because this criteria is not used widely enough in the industry to be a well established criteria.
Response: The SDT believes that the term is widely used and believes that it is appropriate for inclusion in this standard. No change made.	
Deseret Power	Comments: As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
Response: The SDT clarified that the minimum for establishing a transient voltage response criterion was to establish a low voltage level and the maximum length of time that the transient voltages may remain below that level. **R5**. Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level.	
Omaha Public Power District	In the first sentence of the requirement text, change "voltage limits" to "voltage".
Response: The SDT believes that the use of "voltage limits" is correct. No change made.	

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TVA System Planning	In the VSL associated with R5, we believe that failure to define and document one of the criteria should be a moderate VSL, failure to define and document two criteria should me a high VSL, while failure to define and document three criteria should be a severe VSL. Otherwise failing to document only one criteria would result in a severe VSL.
Response: The SDT believes that establishing the criteria for acceptable voltage deviations should be a binary VSL. No change made.	
MidAmerican Energy Company	MidAmerican commends the SDT for their hard work on this standard. MidAmerican does have comments about this requirement though. MidAmerican recommends the data retention for R5 and M5 be revised to change "All" to "The". The word "All" is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: "THE documentation specifying the criteria since". The word in all caps is a word suggested to be added.
Response: The SDT has modified the data retention for R5 to strike the word "All" and has replaced it with the word "The". **Requirement R5 data retention**: The documentation specifying the criteria since the last compliance audit in accordance with Requirement R5 and Measure M5.	
NorthWestern Energy	R5 could be interpreted to address both high voltage and low voltage criteria. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level." This way high voltage is definitely excluded.
Modesto Irrigation District Transmission Planning	R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level.
Response: The SDT clarified that the minimum for establishing a transient voltage response criterion was to establish a low voltage level and the maximum length of time that the transient voltages may remain below that level. **R5**. Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level.	
Oklahoma Gas & Electric	R5 OG&E believes the Transmission Coordinator be held accountable for the transient voltage response portion of R5. The Transmission Coordinator should coordinate this type of voltage criteria with the Transmission Planner for a regional look of the whole system. For example Southwest Power Pool should coordinate this type of study with a stakeholder developed voltage criteria within the members of the Southwest Power Pool to better examine the entire region of the Southwest Power Pool. We do not see the need to duplicate the work.
Response: The SDT disagrees that only the transmission coordinator should be responsible for having a transient voltage response. Every planner, whether a	

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Transmission Planner or Planning Coordinator, needs to have a transient voltage response criterion to fully evaluate its portion of the BES.	
Midwest ISO	Requirement R5: Not all Transmission Planners have delta voltage criteria which this requirement will now require them to have. Looks like this requirement is not a one shoe fits all requirement.
Response: The SDT agrees that voltage criteria may not be a "one size fits all" criteria. This requirement requires each Transmission Planner and Planning Coordinator to have criteria for acceptable voltage limits.	
SERC Dynamics Review Subcommittee (DRS)	The content in the severe VSL column should be split among the lower, moderate, and high categories, with failure to include one element as Moderate and two elements as High. It is stated that the Transmission Planner and Planning Coordinator shall have criteria specifying voltage limits, post-contingency voltage deviations, and transient voltage response. How would an nteraction with a third party system be handled? For example a contingency causes a voltage deviation on one system that is within thevoltage deviation criteria, but causes a voltage deviation violation on a neighboring system that has a more stringent criterion.
SERC Planning Standards Subcommittee	The content in the severe VSL column should be split among the lower, moderate, and high categories, with failure to include one element as Moderate and two elements as High. It is stated that the Transmission Planner and Planning Coordinator shall have criteria specifying voltage limits, post-Contingency voltage deviations, and transient voltage response. How would an interaction with a third party system be handled? For example a contingency that occurs on a system that is within their voltage deviation criteria, but causes a voltage deviation violation on a neighboring system that has a more stringent criteria.
Response: The SDT believes that establishing the criteria for acceptable voltage deviations should be a binary VSL. No change made. This standard places the requirement for performance on each entity's portion of the BES (Requirement R2). In addition, Requirement R3, part 3.4.1 and Requirement R4, part 4.4.1 require the coordination of the Contingencies and Requirement R8 requires the distribution of the Planning Assessment. These requirements will ensure that third party impacts are identified.	
Lafayette Utilities System	The modified version resolves the confusion noted by several commenters in the earlier draft.
Response: Thank you.	
US Bureau of Reclamation	The requirement in Table 1 is for Planning Authority and Transmission Planner to establish accceptable voltage deviations and limits. The requirement only indicates the that each shall have a criteria. That does not imply an agreement on a single limit or deviation allowable under a System Steady State post-contingency condition.
Response: The SDT agrees with your statement.	
Progress Energy Carolinas	There appears to be a double-jeopardy issue related to voltage performance criteria related to the VAR Standards. The voltage and var criteria will also be required in VAR-001 and 002.

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TIS	There appears to be a double-jeopardy issue related to voltage performance criteria related to the VAR Standards.
National Grid	Voltage criteria are addressed by the VAR standards. Including a voltage requirement in the planning standards appears to be creating a double-jeopardy exposure. Also, implementing transient voltage criteria will require time.Replace "Each Transmission Planner and Planning Coordinator" with "Each Transmission Planner OR Planning Coordinator".
Northeast Power Coordinating Council--RSC	Voltage criteria are addressed by the VAR standards. Including a voltage requirement in the planning standards appears to be creating a double-jeopardy exposure. Also, implementing transient voltage criteria will require time.Replace "Each Transmission Planner and Planning Coordinator" with "Each Transmission Planner OR Planning Coordinator".
Response: As for the double jeopardy comment - From the ERO Rules of Procedure, Appendix 4B- Sanction Guidelines, Section 3.10 Multiple Violations: "Strictly speaking, NERC or the regional entity can determine and levy a separate penalty or sanction, or direct remedial action, upon a violator for each individual violation. However, in instances of multiple violations related to a single act or common incidence of noncompliance, NERC or the regional entity will generally determine and issue a single aggregate penalty, sanction, or remedial action directive bearing reasonable relationship to the aggregate of the related violations. The penalty, sanction, or remedial action will not be that determined individually for the least serious of the violations; it will generally be at least as large or expansive as what would be called for individually for the most serious of the violations." The existing VAR standards (VAR-001-1a and VAR-002-1b) address the operational time horizon but do not address the planning horizon. NERC Standards Project 2008-1 is under development and the SAR addresses the planning horizon. As this project moves forward, the Standards Drafting Team for Project 2008-1 will more fully develop the requirements for reactive planning and will evaluate whether those requirements should reside in the TPL standard or the VAR standards.	
Gainesville Regional Utilities	Voltage considerations can get lost in the various studies. This requirement brings focus to the voltage component which it rightly deserves.
Response: Thank you.	
Central Maine Power Company	Voltage criteria is addressed by the VAR standards. Including a voltage requirement in the planning standards appears to be creating a double-jeopardy exposure.R5. Change to Read "Each Transmission Planner OR Planning Coordinator " Need time to implement transient voltage criteria.
ISO New England	Voltage criteria is addressed by the VAR standards. Including a voltage requirement in the planning standards appears to be creating a double-jeopardy exposure.R5. Change to Read "Each Transmission Planner OR Planning Coordinator " Need time to implement transient voltage criteria.
United Illuminating	Voltage criteria is addressed by the VAR standards. Including a voltage requirement in the planning standards appears to be creating a double-jeopardy exposure.R5. Change to Read "Each Transmission Planner OR Planning Coordinator " Need time to implement transient voltage criteria.

Organization	Comments for Question 5
Response: As for the double jeopardy comment - From the ERO Rules of Procedure, Appendix 4B- Sanction Guidelines, Section 3.10 Multiple Violations: "Strictly speaking, NERC or the regional entity can determine and levy a separate penalty or sanction, or direct remedial action, upon a violator for each individual violation. However, in instances of multiple violations related to a single act or common incidence of noncompliance, NERC or the regional entity will generally determine and issue a single aggregate penalty, sanction, or remedial action directive bearing reasonable relationship to the aggregate of the related violations. The penalty, sanction, or remedial action will not be that determined individually for the least serious of the violations; it will generally be at least as large or expansive as what would be called for individually for the most serious of the violations." The existing VAR standards (VAR-001-1a and VAR-002-1b) address the operational time horizon but do not address the planning horizon. NERC Standards Project 2008-1 is under development and the SAR addresses the planning horizon. As this project moves forward, the Standards Drafting Team for Project 2008-1 will more fully develop the requirements for reactive planning and will evaluate whether those requirements should reside in the TPL standard or the VAR standards. The implementation Plan allows 24 months before Requirement R5 becomes effective.	
Oncor Electric Delivery	Voltage criteria is addressed within the VAR standards. This appears to be redundant.
Response: The existing VAR standards (VAR-001-1a and VAR-002-1b) address the operational time horizon but do not address the planning horizon. NERC Standards Project 2008-1 is under development and the SAR addresses the planning horizon. As this project moves forward, the Standards Drafting Team for Project 2008-1 will more fully develop the requirements for reactive planning and will evaluate whether those requirements should reside in the TPL standard or the VAR standards to ensure that it is not a redundant requirement.	
American Electric Power	We believe that it is appropriate to eliminate the reference to transient voltage response as it is duplicative and unnecessary. System stability is already better addressed by other performance requirements defined in this standard.
Response: The SDT believes that a criterion should be established for transient voltage response by each Transmission Planner and Planning Coordinator and that it is complementary to the other performance requirements in this standard, not duplicative.	
FirstEnergy Corp	We concur with the inclusion of R5 and the criteria needed for steady-state voltage limits, post-contingency deviations and the transient voltage response for its System. In regards to the transient voltage criteria, its our understanding that the this criteria is for planning purposes only and not intended for operation time horizon evaluations being performed by the TOP.
Response: The SDT agrees that the requirement for criteria for transient voltage responses is for planning studies and does not address operating studies since they are outside the scope of this standard.	
Ameren	With respect to specifying a voltage level and maximum duration for transient voltage response, does it make sense for each Transmission Planner to have their own criteria? Should we be meeting an industry standard such as the ITI (CBEMA) Curve published by the Technical Committee 3 (TC3) of the Information Technology Industry Council (ITI, formerly known as the Computer & Business Equipment manufacturer's Association) and available at www.itic.org? Meeting any of the criteria to be developed for Requirement R5 will depend on the load model assumptions used.It is stated that the Transmission Planner and Planning Coordinator shall have criteria specifying voltage limits, pos-Contingency voltage deviations, and transient voltage response. How would an interaction with a third party be handled, particularly if one entity has more stringent criteria?

Organization	Comments for Question 5
	The content in the severe VSL column should be split among the lower, moderate, and high categories.
Response: The SDT believes that each Transmission Planner and Planning Coordinator should have a criteria and has not placed bounds on how to establish the criteria. This standard places the requirement for performance on each entity's portion of the BES (Requirement R2). In addition, Requirement R3, part 3.4.1 and Requirement R4, part 4.4.1 require the coordination of the Contingencies and Requirement R8 requires the distribution of the Planning Assessment. These requirements will ensure that third party impacts are identified. The SDT believes that establishing the criteria for acceptable voltage deviations should be a binary VSL. No change made.	
PJM	Remove any mention of transient voltage response. Very few entities can perform this type of analysis.
Response: The SDT believes that a criterion should be established for transient voltage response by each Transmission Planner and Planning Coordinator and disagrees with the assertion that very few entities have the capability to complete this type of analysis. No change made.	

6. Requirement R6 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: The SDT has made clarifying changes based on industry comments as follows: **R6**. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, any criteria or methodology used in the analysis to identify System instability for conditions such as Cascading , voltage instability, or uncontrolled islanding**M6**. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of documentation specifying any criteria or methodology used in the analysis to identify System instability that was utilized in preparing the Planning Assessment in accordance with Requirement R6. **Requirement R6, data retention** - The documentation specifying any criteria or methodology utilized in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.

Organization	Comments for Question 6
Progress Energy Florida, Inc.	As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all appropriate parties to review PEF's previous comments to this effect.
Response: Throughout the drafting process, the SDT has carefully considered your comments as well as comments from other industry members.	
Florida Municipal Power Agency, and its Member Cities	FMPA suggests adding the word "potential" into " identify the potential for System instability". The criteria and methodology may be used to determine if further analysis is warranted, e.g., if steady state voltages fall below 0.9 per unit, then do a voltage stability study, or something like that. Going below 0.9 does not mean voltage collapse, but, it may be an indicator to study it; hence, the word "potential".
FRCC Transmission Working Group	For R6 please consider the following revision: "Each TP and PC shall define and document within their planning assessment any criteria or methodology used in their analysis to identify system instability /deleted/ for /deleted/ conditions such as cascading outages, voltage instability, or uncontrolled islanding." As written originally it could be taken to be the methods for determining if you have instability during a cascading outage, rather then the methods for determining if you are at risk for instability like a cascading outage. the word "potential" into "identify the potential for System instability ". The criteria and methodology may be used to determine if further analysis is warranted, e.g., if steady state voltages fall below 0.9 per unit, then duedo a voltage stability study. Going below 0.9 does not mean voltage collapse, but, it may be an indicator to study it; hence, the word "potential".
Response: The SDT disagrees with your suggestion of adding the term 'potential' in Requirement R6. The Standard does not preclude the application of criteria or methodology to determine potential instability. No change made.	
Orlando Utilities Commission	For R6 please consider the following revision: "Each TP and PC shall define and document within their planning assessment any criteria or methodology used in <<their>> analysis to identify system instability //for// conditions such as cascading outages, voltage instability, or uncontrolled islanding." Adding the text in <<>> and deleting the text in ////. As written originally it could

Organization	Comments for Question 6
	be taken to be the methods for determining if you have instability during a cascading outage, rather then the methods for determining if you are at risk for instability like a cascading outage.
Response: The SDT disagrees with your assessment that the language of "… criteria or methodology used in the analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding" is misleading. The System instability applies to the cascading outages, voltage instability, OR uncontrolled islanding, not just to cascading outages. No change made.	
Gainesville Regional Utilities	I believe that this requirement is better defined and documented at the regional level with all involved parties contributing. If consensus is not achievable, then the exception utilities can create their own knowing that they need technically valid references to support their position.
Response: The SDT disagrees as it is better to allow the individual a Transmission Planner or Planning Coordinator to determine this versus the region as the region could be quite varied. The Requirement does not preclude the region from doing as you suggest with coordination in the region. No change made.	
FirstEnergy Corp	If an entity is required to adhere to its Facility Ratings, how is it feasible that a cascade violation would occur? FirstEnergy questions the need for this review based on Table 1 performance requirements and the need to adhere to Facility Ratings.
Response: This may not be an issue in the application of this criteria or methodology for planning events P0 through P7, however, this needs to be available when evaluating System response when applying extreme events.	
Arizona Public Service Co.	It is not clear who this applies to. Is it both TP and PC individually, or one of the two, or both jointly?
Response: The requirement is for both.	
American Electric Power	M6 does not appear to align with the content of R6. M6 needs to be reworded to reference documentation of criteria or methodology rather than studies. Corresponding changes will also need to be made to the corresponding bullet under Data Retention.
Manitoba Hydro	The R6 text does not match the Data Retention 6th bullet text "studies performed". The Retention 6th bullet text should be updated to reflect the R6 text "criteria or methodology used in the analysis to identify System instability".The R6 text does not match the M6 text. The M6 text should be revised as follows: replace "studies utilized in preparing the Planning Assessment" with "criteria and methodology to identify System instability used within its analysis".
Response: The SDT agrees and has changed the language of Measure M6 and also the language for Data Retention. **M6**. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of documentation specifying any criteria or methodology used in the analysis to identify System instability that was utilized in preparing the Planning Assessment in accordance with Requirement R6. **Requirement R6, data retention** - The documentation specifying any criteria or methodology utilized in support of its Planning Assessments since the last	

Organization	Comments for Question 6
compliance audit in accordance with Requirement R6 and Measure M6.	
Ameren	M6: The wording on this measure appears to have been copied from M3 or M4 but is not appropriate since R6 addresses criteria and methodology and not a study.
SERC Dynamics Review Subcommittee (DRS)	M6: The wording on this measure appears to have been copied from M3 or M4 but is not appropriate since R6 addresses criteria and methodology but not a study.
Southern Company	M6: The wording on this measure appears to have been copied from M3 or M4 but is not appropriate since R6 addresses criteria and methodology and not a study. Replace the word "studies" with "criteria or methodology".
TVA System Planning	M6: The wording on this measure appears to have been copied from M3 or M4 but is not appropriate since R6 addresses criteria and methodology and not a study.
SERC Planning Standards Subcommittee	Comments: M6: The wording on this measure appears to have been copied from M3 or M4 but is not appropriate since R6 addresses criteria and methodology and not a study.
Response: The SDT agrees and has changed the language of Measure M6. **M6**. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of documentation specifying any criteria or methodology used in the analysis to identify System instability that was utilized in preparing the Planning Assessment in accordance with Requirement R6.	
MidAmerican Energy Company	MidAmerican commends the SDT for their hard work on this standard. MidAmerican does have comments about this requirement though. MidAmerican recommends the data retention for R6 and M6 be revised to change “All” to “The”. The word “All” is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: “THE studies performed in support”. The word in caps is a word suggested to be added.
NERC Standards Review Subcommittee	The MRO NSRS recommends the data retention for R6 and M6 be revised to change “All” to “The”. The word “All” is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: “The studies performed in support”.
Response: The SDT agrees with your suggestion of changing the “All” to “The” in the data retention section for Requirement R6 and Measure M6. **M6**. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of documentation specifying any criteria or methodology used in the analysis to identify System instability that was utilized in preparing the Planning Assessment in accordance with Requirement R6. **Requirement R6, data retention** - The documentation specifying any criteria or methodology utilized in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.	
Duke Energy	R6 includes the phrase “cascading outages”. We believe that the word “cascading” should be the capitalized NERC-defined

Organization	Comments for Question 6
	term "Cascading".
Response: The SDT agrees with your suggestion of changing "cascading" to Cascading". **R6**. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, any criteria or methodology used in the analysis to identify System instability for conditions such as Cascading , voltage instability, or uncontrolled islanding.	
Oklahoma Gas & Electric	R6 OG&E believes the Transmission Coordinator be held accountable for R6. The Transmission Coordinator should coordinate this type of study/documentation with the Transmission Planner for a regional look of the whole system. For example Southwest Power Pool should coordinate this type of study/documentation with the members of the Southwest Power Pool to better examine the entire region of the Southwest Power Pool. We do not see the need to duplicate the work.
Response: The SDT assumes that you mean Planning Coordinator. The requirement is for both entities.	
Tri-State Generation and Transmission Association	R6 seems OK but check M6. Should this refer to R2 and not R6?
Independent Electricity System Operator	We do not have any comments on the requirement, VRF, Time Horizon and the VSL. However, Measure M6 (which refers to "studies utilized in preparing the Planning Assessment") does not seem to be relevant to Requirement R6, which deals with defining and documenting the criteria and methodology used in the analysis to identify System instability.
Response: The SDT agrees and has changed the language of Measure M6. **M6**. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of documentation specifying any criteria or methodology used in the analysis to identify System instability that was utilized in preparing the Planning Assessment in accordance with Requirement R6.	
MAPP	Suggest removing "Transmission Planner" since the PC performs the assessment.
Response: The SDT disagrees with your comment as both entities should be documenting their criteria.	

7. Requirement R7 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: The SDT modified Measure M7 to clarify the supporting documentation used to establish the individual and joint responsibilities for performing the required studies. The SDT also clarified the data retention associated with Requirement R7. Measure M7 and the data retention associated with Requirement R7 now read:

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

Requirement R7 data retention: The current, in force documentation for the agreement(s) on roles and responsibilities, as well as all such documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

Organization	Comments for Question 7
ERCOT ISO	* Will any agreements made in R7 override the "each TP and PC" requirement? Would it be appropriate to say: "Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies and assessments."* What kind of documentation will be acceptable to demonstrate "each entity's individual and joint responsibilities"?
Response: The SDT sees no additional clarity being provided by your suggested wording. No change made. To address your concerns the SDT has changed Measure M7 to clarify the type of supporting documentation that could be used to establish individual and joint responsibilities for performing the required studies. **M7.** Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.	
American Transmission Company	Revise part of the requirement text to read, ". . . identify each entity's individual and joint responsibilities . . ." to provide better clarity. Perhaps this requirement should be listed at the beginning of the Requirements section, instead being mentioned near the end of this section.
Response: The SDT sees no additional clarity being provided by your suggested wording. No change made. The SDT discussed the change and based on industry input decided not to change the order of the requirements.	

Organization	Comments for Question 7
Progress Energy Florida, Inc.	As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all appropriate parties to review PEF's previous comments to this effect.
Response: Throughout the drafting process, the SDT has carefully considered your comments as well as comments from other industry members.	
CenterPoint Energy	CenterPoint Energy believes R7 relates to matters best addressed through registration, such as JROs or delegation agreements. If other commenters agree, CenterPoint Energy recommends that R7 be deleted.
Response: This requirement was inserted to address industry concern regarding the potential for duplication of work. No change made.	
TVA System Planning	In the VSL associated with R7, we believe that failure to determine and identify one responsibility should be a moderate VSL, failure to determine and identify two responsibilities should me a high VSL, while failure to determine and identify three responsibilities should be a severe VSL. Otherwise failing to document only one responsibility would result in a severe VSL.
Response: The SDT believes that procedurally, Requirement R7 is binary. No change made.	
MidAmerican Energy Company	MidAmerican commends the SDT for their hard work on this standard. MidAmerican does have comments about this requirement though. MidAmerican recommends the data retention for R7 and M7 be revised to delete "All". The word "All" is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: "The current, in force agreement on identified responsibilities, as well as such agreements in force".
NERC Standards Review Subcommittee	The MRO NSRS recommends the data retention for R7 and M7 be revised to delete "All". The word "All" is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: "The current, in force agreement on identified responsibilities, as well as such agreements in force".
Response: The SDT agrees that the proposed change to Measure M7 and the data retention removes the potential for an unintended interpretation. **M7.** Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7. **Requirement R7 data retention:** The current, in force documentation for the agreement(s) on roles and responsibilities, as well as all such documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.	
Tri-State Generation and Transmission Association	R7 - Duties of the Planning Coordinator are being created and changed as we go along, like changing rules of a flag football game as it is played. Is there any requirement that every TP have a PC? As far as we know, the PC was introduced as an additional authority level for regional or inter-utility study work. Previous R7 wording asked PCs and TPs to work together. The present wording implies that every TP must have a PC which is a separate entity, and that PC would dictate study responsibilities. The wording of R4.4.1 seems much better in this regard.

Organization	Comments for Question 7
Response: It does not create the requirement that each Transmission Planner report to a Planning Coordinator, that relationship is defined in the Functional Model This requirement specifies that, if there is a relationship between a Transmission Planner and Planning Coordinator there is no need for duplicate analysis if each entity agrees on the delegation of work. No change made.	
NYISO	R7. - The NYISO requests clarification as to whether the PC will be expected to distribute the TP Planning Assessments as part of its coordination requirement?
Response: This standard does not require the Planning Coordinator to distribute the individual Transmission Planner assessments.	
MAPP	Suggest moving this requirement to the head of the list. It's a basis for the rest of this standard.
Response: The SDT discussed the change and based on industry input decided not to change the order of the requirements.	
Orlando Utilities Commission	The intent is much clearer, thank you for revising this.
Oklahoma Gas & Electric	We agree that it should be clearly stated who does what between the Transmission Planner and the Planning Coordinator. We feel like this will eliminate duplication of work and create a better overall regional examination of the electric grid.
Gainesville Regional Utilities	Looks good.
Response: Thank you.	
Florida Municipal Power Agency, and its Member Cities	The Measure and Data Retention for R7 is ambiguous. While the measure could be interpreted as not requiring a contract, the data retention uses the words "in force agreement" which implies a formal contract, where roles and responsibilities could very well be assigned in regional planning committee minutes and ensuing e-mail correspondence. Suggest changing the words to "Documentation of agreement on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence" in both locations.
Response: The SDT agrees that the proposed changes to Measure M7 and the data retention remove the potential for an unintended interpretation. Measure M7 and the data retention associated with Requirement R7 now read: **M7.** Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7. **Requirement R7 data retention:** The current, in force documentation for the agreement(s) on roles and responsibilities, as well as all such documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.	

8. Requirement R8 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: The SDT believes revisions to Requirement R3, parts 3.4 and Requirement R4, part 4.4 will clarify the expectation that Transmission Planners and Planning Coordinators analyze Table 1 events outside their Systems for reliability impacts. The proposed, new Requirement R8 (old Requirement R7) requirement (below), will ensure appropriate information is exchanged between Transmission Planners and Planning Coordinators for sharing of information, review, and coordination of plans in conformance with Order 693 paragraph 1755 and 1756 expectations. The SDT believes the NERC Rules and Procedures and delegation agreements cover existing TPL-005 & -006 assessment requirements for regional and inter-regional assessments. The aggregate effect of the above items will be an overlapping assessment of BES reliability from each Transmission Planner area up through each Interconnection.

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information.

R8 data retention. Three calendar years of the notices and other documentation employed in accordance with Requirement R8 and Measure M8

R8 VSL	The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners or adjacent Planning Coordinators, and to one functional entity that has a reliability related need and has submitted a written request for the information, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to its adjacent Transmission Planners or adjacent Planning Coordinators, and to any functional entity that has a reliability related need and has submitted a written request for the information, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

Organization	Comments for Question 8
Independent Electricity System Operator	(1) No comments on the requirement, measure, VRF and Time Horizon. 3) VSLs:(a) We do not agree with the Severe VSL condition. In our view, distributing planning assessment results is the intent of the requirement; it is more important to share results than to field questions from recipients of the results. Assigning a Severe VSL for failing Part 8.1 puts the driver at the wrong place.(b) The condition under Low and High seems to be the same. In the Low, failing to distribute the results to ANY ONE of the TPs and PCs means none, which is the same as the condition for High unless the condition under Low really means failing to distribute the results to ONE of the TPs and PCs whereas the High really means failing to distribute the results to two or more of the TPs and PCs. If this is the proper interpretation, then we'd suggest the VSLs be revised as follows:Low: failing to respond to comments within 90 daysHigh: failing to distribute the results to one of the TPs and PCsSevere: failing to distribute the results to two or more of the TPs and PCs.Alternatively, a Moderate can be added to capture the condition for failing to distribute the results to two of the TPs and PCs, while the Severe can become failure to distribute the results to three of the TPs and PCs.

Response: The SDT disagrees because the requirement's focus is on coordination of planning. If questions/concerns are not responded to, coordination of planning is not being accomplished. The VSLs related to failing to distribute results are appropriate. However, the SDT agrees that the Lower VSL is unclear and will make a change to delete the word "any". In addition, the SDT has modified the Lower and High VSL wording to be clearer.

R8 VSL	The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners or adjacent Planning Coordinators, and to one functional entity that has a reliability related need and has submitted a written request for the information, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to its adjacent Transmission Planners or adjacent Planning Coordinators, and to any functional entity that has a reliability related need and has submitted a written request for the information, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

ERCOT ISO	* Will any agreements made in R7 override the "each TP and PC" requirement? To clarify this, the requirement could be rephrased: "In accordance to the responsibilities assigned in R7, the responsible Transmission Planners and Planning Coordinators shall distribute?. "* Include "within the interconnection" such as: "distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners within the interconnection and to any functional entity that indicates a reliability related need for the Planning Assessment results"* Should "reliability related need" be defined? This appears in multiple standards.

Response: No, the agreements made in Requirement R7 pertain to performance of the required studies and will not override the Planning Coordinator and Transmission Planner's responsibilities under Requirement R8 relating to distribution of Planning Assessments.

Organization	Comments for Question 8
The SDT does not believe the suggested language adds any clarity. No change made. A definition is not required. The present wording is in other approved standards and is sufficiently clear based on experience to date. No change made.	
Northeast Utilities	[R8.1] There is no statute of limitation for comments, nor is there a limit on the number of comments. There is also potential conflict with the deadline for completing a study and when comments may be submitted. If this requirement is retained the following is suggested: "Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to the functional entities that the Planning Coordinator recognizes as having a reliability need for the Planning Assessment results".
Response: The SDT disagrees that there should be a statute of limitation for asking questions related to coordination of planning and believes parties will act appropriately. The SDT disagrees that there should be a limit to the number of questions allowed related to coordination of planning and believes parties will act appropriately. The requirement is to distribute the results of the completed Planning Assessments associated with this standard therefore all related supporting studies are complete and there is no potential conflict. The word "indicates" has been changed to "has" to be clearer. This revised wording has the same meaning as the suggested wording and is sufficiently clear. Both the Transmission Planner and Planning Coordinator may be asked for their Planning Assessment by an entity with a reliability related need. Therefore the statement must apply to both the Transmission Planner and Planning Coordinator. **R8**. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information.	
Oncor Electric Delivery	8.1 This requirement should be removed because it appears redundant to FERC 890. (suggest having one statement or the other) However, if it isn't, then the Term "documented" in R8.1 the term documented needs to be defined. Suggest adding the qualifier "written " i.e., "If a recipient of the Planning Assessment results provides "documented written" comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a "documented written" response to that recipient within 90 calendar days of receipt of those comments. The requirement to distribute reports to entities with "need" has very significant CEII implications. This should be tightened to a "bona fide reliability need" for the information, requiring CEII or confidential material handling procedures. R8, 8.1, and Measurement M8 There is no statute of limitation for comments (Suggest clarifying what we mean here assume we are note referring to the NERC Standards Commenting Process), nor is there a limit on the number of comments. There is also potential conflict with the deadline for completing a study and when comments may be submitted (e.g. comments are received the day before the study is to be completed. If this requirement is retained the following is suggested: Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to functional entities that demonstrated a reliability need with concurrence from their planning coordinator for the Planning Assessment results. [I think there are issues still with this language. I think it needs to say "and to the functional entities that the Planning Coordinator recognizes as having a reliability need for the Planning Assessment results."]

Organization	Comments for Question 8
	Compliance 1.4 Data Retention, last bullet - this relates back to Requirements R8, 8.1, and Measurement M8. This seems to be a nuisance requirement to get in trouble for. [Requirement is to keep 3 years of notifications related to R8 & 8.1.]
Response: The SDT seeks to retire the existing TPL-005 & -006 while continuing to meet the purpose of their requirements. FERC Order 693 and 890 each provide expectations and direction to the ERO regarding enhancement of regional coordination and planning. The SDT believes the inclusion of Requirement R8 in the standard and performance of the regional assessments required under NERC delegation agreements will meet these objectives. The present wording is in other approved standards and is sufficiently clear based on experience to date. Bona fide does not add significant clarity. Control of CEII and control of competitive market information per Standards of Conduct are a fundamental expectation of all industry participants and is not required in the standard. The SDT disagrees that there should be a statute of limitation for asking questions related to coordination of planning and believes parties will act appropriately. The SDT also disagrees that there should be a limit to the number of questions allowed related to coordination of planning and believes parties will act appropriately. The requirement is to distribute the results of the completed Planning Assessments associated with this standard therefore all related supporting studies are complete and there is no potential conflict. The SDT agrees the wording is somewhat unclear and will clarify by adding "adjacent" before Transmission Planner. The word "indicates" has been changed to "has" to be clearer. This revised wording has the same meaning as the suggested wording and is sufficiently clear. **R8**. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information. The SDT believes that retaining the documentation for 3 years is consistent with other standards and appropriate for audit purposes. No change made.	
Progress Energy Florida, Inc.	As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all appropriate parties to review PEF's previous comments to this effect.
Response: Throughout the drafting process, the SDT has carefully considered your comments as well as comments from other industry members.	
CenterPoint Energy	CenterPoint Energy believes R8 is over-reaching and recommends deleting it. CenterPoint Energy is particularly concerned about requiring assessments to be distributed to "any functional entity that indicates a reliability related need". There is already a process in place for entities to request and receive the FERC Form 715 submittals of other entities. FERC's process appropriately recognizes and addresses CEII issues and imposes a requirement that the entity demonstrate need for the information and that the industry complies with certain security-related requirements. Beyond CEII matters, transmission planning information can have implications for market entities bidding on congestion rights in competitive energy markets. Therefore, the dissemination of transmission planning information may be governed by the regulatory authority having jurisdiction over the market functions, which is not necessarily FERC in all cases. In any case, given the availability of the FERC 715 process, there is no need for a somewhat duplicative requirement in this standard. Accordingly, CenterPoint Energy recommends that R8 be deleted in its entirety.
Response: Requirement R8 is necessary to ensure that appropriate coordination of planning occurs and supports regional assessments performed under NERC delegation agreements. Control of CEII is a fundamental expectation of all industry participants and the "reliability related need" restriction ensures only appropriate parties must be given	

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planning assessments. Control of competitive market information per Standards of Conduct is a fundamental expectation of all industry participants and the "reliability related need" restriction ensures only appropriate parties must be given planning assessments. The SDT seeks to retire the existing TPL-005 & -006 while continuing to meet the purpose of their requirements. FERC Orders 693 and 890 each provide expectations and direction to the ERO regarding enhancement of regional coordination and planning. The SDT believes the inclusion of Requirement R8 in the standard and performance of the regional assessments required under NERC delegation agreements will meet these objectives. FERC 715 is not adequate to achieve these objectives. No change made.	
Bonneville Power Administration	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
Modesto Irrigation District Transmission Planning	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
NV Energy	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
Pacific Gas and Electric Co.	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
Puget Sound Energy, Inc.	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
Sacramento Municipal Utility District	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
San Diego Gas & Electric Co	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
Southern California Edison (SCE)	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
SRP	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
Utility System Efficiencies, Inc. (USE)	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?

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Western Area Power Adm - RMR	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
Deseret Power	Comments: Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
Response: Yes - The NERC Reliability Functional Model defines the meaning of the term "functional entity".	
SERC Planning Standards Subcommittee	Comments: R8: It is not clear whether the assessment results must be distributed to all parties of interest, or if it would be sufficient to post the assessment at a central location, and distribute information to access the information. Also, FERC Standards of Conduct issues would come into play in assuring that the information is available only to appropriate personnel. R8: It is not clear if the requirement to provide assessment results to adjacent PCs and TPs is required, or only upon a reliability related request.R8: The PC and TP responsibilities should be stated separately for clarity. Part 8.1: It is not clear what the form of the response to the comments should be " would an acknowledgement be sufficient, or would it be necessary to pursue a process of examining comments in detail and revising and reissuing the corresponding assessment"The requirement needs to be revised to make the above points clear.
Response: The standard does not specify the mechanics of distribution of the information, only that it must occur. The method proposed would be acceptable as long as it met Measure M8 and Section 1.4 under compliance monitoring. Control of competitive market information per Standards of Conduct is a fundamental expectation of all industry participants and the "reliability related need" restriction ensures only appropriate parties must be given planning assessments. The SDT agrees and will clarify by adding "adjacent" before Transmission Planner and added wording requiring a written request. The word "indicates" has been changed to "has" to be clearer. **R8**. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information. The standard should not specify the means of providing and responding to comments, but ensures that appropriate communication is initiated. No change made.	
Orlando Utilities Commission	Excellent requirement, thank you for revising this
Response: Thank you.	
Southern Company	For additional clarity in who should receive the assessment, we recommend replacing "indicates" with "has" and adding words to the end of the sentence so that it states the following: "and to any functional entity that has a reliability related need for the Planning Assessment results and provides a written request." For Part 8.1, we do not believe the intent is for casual emails to be documented and formally responded to. And we do not believe that anyone who happens to receive the assessment should be able to comment. Therefore, we recommend the following wording: "If one of the above named entities provides formal written comments on the results, the respective Planning Coordinator or

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	Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments." If these recommendations are accepted, then the wording of M8 would have to change accordingly.
Response: The SDT agrees and will clarify by adding "adjacent" before Transmission Planner and added wording requiring a written request. **R8**. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information. The standard should not specify the means of providing and responding to comments, but ensures that appropriate communication is initiated. The SDT has altered the wording of Requirement R8 to provide clarity and to attempt to alleviate your concern.	
Manitoba Hydro	Is there a need to retain comments and responses to comments for Requirement R8?
Response: Yes, see Measure M8 and the following changes to 1.4 Data Retention. **R8 data retention**. Three calendar years of the notices and other documentation employed in accordance with Requirement R8 and Measure M8	
SCE&G	It is not clear if the requirement to provide assessment results to adjacent Planning Coordinators and Transmission Planners is always required or only upon a reliability related request.
Response: The SDT considers the distribution to Planning Coordinators and Transmission Planners as mandatory and has changed the wording of Requirement R8 to address the wording for other functional entities. **R8**. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information.	
MidAmerican Energy Company	MidAmerican commends the SDT for their hard work on this standard. MidAmerican does have comments about this requirement though. MidAmerican asks that the SDT revise R8 to limit the need to provide the Planning Assessment as follows “adjacent Planning Coordinators and ADJACENT Transmission Planners and to any REGISTERED functional entity”? The words in all caps are words that MidAmerican suggests are added to the requirement to clarify that the word adjacent also applies to Transmission Planners and to clarify that the functional entity must be registered in order for the requirement to provide the Planning Assessment to apply. MidAmerican asks that the low VSL for R8 be revised to delete the word “any” from the requirement so that the requirement will read “The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners”.
Response: The SDT agrees and will clarify by adding "adjacent" before Transmission Planner, but the SDT believes adding “registered” is unnecessary because it is understood that it relates to NERC Reliability Standards. **R8**. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information.	

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The SDT agrees and will make change to delete the word "any".

R8 VSL	The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners or adjacent Planning Coordinators, and to one functional entity that has a reliability related need and has submitted a written request for the information, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to its adjacent Transmission Planners or adjacent Planning Coordinators, and to any functional entity that has a reliability related need and has submitted a written request for the information, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

Progress Energy Carolinas	Need to define "adjacent" Planning Coordinators. Does this mean a neighbor with at least one joint interconnection? The requirement to provide the Planning Assessment "to any functional entity that indicates a reliability related need" should be made subject to applicable confidentiality and CEII provisions.

Response: The SDT believes "adjacent" is an understood term and would apply to any neighbor with a joint Interconnection. No change made.

Control of CEII is a fundamental expectation of all industry participants and the "reliability related need" restriction ensures only appropriate parties must be given planning assessments. No change made.

Tri-State Generation and Transmission Association	R8 - We find that web-site posting would be sufficient distribution if it were not for the need for auditability. Please consider a way to qualify web-posting as an acceptable distribution method.

Response: The standard does not specify the mechanics of distribution of the information, only that it must occur. The method proposed would be acceptable as long as it met Measure M8 and 1.4 under compliance monitoring. No change made.

NYISO	R8- It should be made clear that a TP should not be required to send their assessment to adjacent PCs. Likewise the PCs should not be required to send their assessment to TPs not in their footprint. R8.1: This should not be required until the Assessment is complete and posted. Additionally, this could be an administratively intense task to respond to each and every comment and document that a response is made within 90 days. Is there any room for an extension to this requirement?

Response: The SDT disagrees, the broader communication is necessary to achieve appropriate coordination. No change made.

The requirement is to distribute the results of completed Planning Assessments, then respond to comments. Therefore the assessment is posted and complete before

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comments can be received and responded to. The SDT recognizes this fact and believes 90 days should be sufficient to develop a response. No change made.	
Oklahoma Gas & Electric	R8 OG&E believes the Transmission Coordinator be held accountable for R8 and coordinate this type of data exchange to ensure a regional coordination effort is achieved.
Response: The SDT believes you were referring to Planning Coordinator in your comment. The SDT believes both the Transmission Planner and Planning Coordinator must distribute their assessments to meet the overall intent of Requirement R8 and achieve appropriate coordination. No change made.	
Xcel Energy	R8 Xcel Energy appreciates the language stating "reliability need" however it is unclear as to what constitutes this or who would make that determination. Please clarify so as to avoid future disputes on providing or obtaining the information.
Response: The present wording is in other approved standards and is sufficiently clear based on experience to date. No change made.	
Central Maine Power Company	R8, 8.1, and Measurement M8 This standard should not be used to remedy deficiencies in meeting the coordination requirements of FERC Order 890. Therefore these should be deleted. If this requirement is retained the following is suggested:"Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to the functional entities that the Planning Coordinator and Transmission Planner recognizes as having a reliability need for the Planning Assessment results." Additionally, there is no deadline for comments. There is also potential conflict with the deadline for completing a study and when comments may be submitted (e.g. comments are received the day before the study is to be completed.) These issues must be addressed. 1.4 Data Retention: The last bullet is unnecessary and should be deleted from the standard.
ISO New England	R8, 8.1, and Measurement M8 This standard should not be used to remedy deficiencies in meeting the coordination requirements of FERC Order 890. Therefore these should be deleted. If this requirement is retained the following is suggested: Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to the functional entities that the Planning Coordinator and Transmission Planner recognizes as having a reliability need for the Planning Assessment results. Additionally, there is no statute of limitation for comments. There is also potential conflict with the deadline for completing a study and when comments may be submitted (e.g. comments are received the day before the study is to be completed.) These issues must be addressed. 1.4 Data Retention: The last bullet is unnecessary and should be deleted from the standard.
Response: The SDT seeks to retire the existing TPL-005 & -006 while continuing to meet the purpose of their requirements. FERC Orders 693 and 890 each provide expectations and direction to the ERO regarding enhancement of regional coordination and planning. The SDT believes the inclusion of Requirement R8 in the standard	

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and performance of the regional assessments required under NERC delegation agreements will meet these objectives. No change made. This revised wording has the same meaning as the suggested wording and is sufficiently clear. The SDT disagrees that there should be a statute of limitation for asking questions related to coordination of planning and believes parties will act appropriately. The requirement is to distribute the results of the completed Planning Assessments associated with this standard therefore all related supporting studies are complete and there is no potential conflict. No change made. The SDT believes that data retention is a necessary function as outlined in the guidelines. No change made.	
United Illuminating	R8, 8.1, and Measurement M8 This standard should not be used to remedy deficiencies in meeting the coordination requirements of FERC Order 890. Therefore these should be deleted. If this requirement is retained the following is suggested:"Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to the functional entities that the Planning Coordinator and Transmission Planner recognizes as having a reliability need for the Planning Assessment results." Additionally, there is no statute of limitation for comments. There is also potential conflict with the deadline for completing a study and when comments may be submitted (e.g. comments are received the day before the study is to be completed.) These issues must be addressed. Measures M1:It is not practical to retain system model information in a hard copy form. This provision could be dropped. Compliance: D 1.1.4 Data Retention: The Transmission Planner and the Planning Coordinator may not be using the same software. If both are required to store the data, do they both have to have the software to use the data? Can this be changed to an "or" such that one of them must retain the data and it can be up to them as to who it is. Also, the last bullet is unnecessary and should be deleted from the standard.
Response: The SDT seeks to retire the existing TPL-005 & -006 while continuing to meet the purpose of their requirements. FERC Orders 693 and 890 each provide expectations and direction to the ERO regarding enhancement of regional coordination and planning. The SDT believes the inclusion of Requirement R8 in the standard and performance of the regional assessments required under NERC delegation agreements will meet these objectives. No change made. This revised wording has the same meaning as the suggested wording and is sufficiently clear. No change made. The SDT disagrees that there should be a statute of limitation for asking questions related to coordination of planning and believes parties will act appropriately. No change made. The requirement is to distribute the results of the completed Planning Assessments associated with this standard therefore all related supporting studies are complete and there is no potential conflict. Since Measure M1 states that either electronic OR hard copy format is required, the SDT believes that no changes are required since either of the formats is acceptable. An example of a hard copy of a system model is having printouts of each individual bus showing Load, Transmission line, generator, capacitors, etc., connected to that bus with associated impedances, ratings, etc. The SDT believes that both the Transmission Planner and Planning Coordinator have this responsibility for the data retention. Therefore the SDT believes that the	

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existing language is adequate and that no changes are required. The SDT believes that both should have the necessary software for using the data.	
Ameren	R8: It is not clear whether the assessment results must be distributed to all parties of interest, or if it would be sufficient to post the assessment at a central location, and distribute information to access the information. Also, FERC Standards of Conduct issues would come into play in assuring that the information is available only to appropriate personnel. R8.1: It is not clear what the form of the response to the comments should be " would an acknowledgement be sufficient, or would it be necessary to pursue a process of examining comments in detail and revising and reissuing the corresponding assessment" The audience of those able to provide comments to the assessments should be appropriately limited, and not open to anyone who wishes to comment.
Response: The standard does not specify the mechanics of distribution of the information, only that it must occur. The method proposed would be acceptable as long as it met Measure M8 and Section 1.4 under compliance monitoring. Control of competitive market information per Standards of Conduct is a fundamental expectation of all industry participants and the "reliability related need" restriction ensures only appropriate parties must be given planning assessments. The standard should not specify the means of providing and responding to comments, but ensures that appropriate communication is initiated. The SDT believes that the requirement limiting distribution to adjacent Planning Coordinator/Transmission Planner's and other functional entities with a reliability related need who request it appropriately limits those commenting. No change made.	
SERC Dynamics Review Subcommittee (DRS)	R8: It is not clear whether the assessment results must be distributed to all parties of interest, or if it would be sufficient to post the assessment at a central location, and distribute information to access the information. Also, FERC Standards of Conduct issues would come into play in assuring that the information is available only to appropriate personnel. For additional clarity in who should receive the assessment, we recommend replacing "indicates" with "has" and adding words to the end of the sentence so that it states the following: "and to any functional entity that has a reliability related need for the Planning Assessment results and provides a written request. "R8: The PC and TP responsibilities should be stated separately for clarity. Part 8.1: It is not clear what the form of the response to the comments should be. Would an acknowledgement be sufficient, or would it be necessary to pursue a process of examining comments in detail and revising and reissuing the corresponding assessment? The requirement needs to be revised to make the above point clear.? For Part 8.1, we do not believe the intent is for casual emails to be documented and formally responded to. And we do not believe that anyone who happens to receive the assessment should be able to comment. Therefore, we recommend the following wording: "If one of the above named entities provides formal written comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments." If these recommendations are accepted, then the wording of M8 would have to change accordingly.

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Response: The standard does not specify the mechanics of distribution of the information, only that it must occur. The method proposed would be acceptable as long as it met Measure M8 and Section 1.4 under compliance monitoring. Control of competitive market information per Standards of Conduct is a fundamental expectation of all industry participants and the "reliability related need" restriction ensures only appropriate parties must be given planning assessments. The word "indicates" has been changed to “has” to be clearer. The other revised wording has the same meaning as the suggested wording and is sufficiently clear. **R8**. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information. The standard should not specify the means of providing and responding to comments, but ensures that appropriate communication is initiated. The SDT believes that the requirement limiting distribution to adjacent Planning Coordinator/Transmission Planner's and other functional entities with a reliability related need who request it appropriately limits those commenting. The revised wording has the same meaning as the suggested wording which is sufficiently clear.	
MAPP	R8: Remove Transmission Planners: Each PC shall distribute it Planning Assessment to adjacent PC and to any registered function entity that indicates a reliability need for the Planning Assessment results. R8.1 Remove Transmission Planners from subrequirement.
Response: The SDT believes both the Transmission Planner and Planning Coordinator must distribute their assessments and respond to comments to meet the overall intent of Requirement R8 and achieve appropriate coordination. No change made.	
Midwest ISO	Requirement R8- It should be made clear that a TP should not be required to send their assessment to adjacent PCs. Likewise the PCs should be required to send their assessment to TPs not in their footprint. Please consider the following language change for R8:Each Planning Coordinator shall distribute its planning assessment results to adjacent Planning Coordinators and to any other Planning Coordinators who indicate they have a reliability related need for the planning assessment results. Each Transmission Planner shall distribute its planning assessment results to adjacent Transmission Planner and to any other Transmission Planner who indicates they have a reliability related need for the planning assessment results. Requirement R8.1: This should be clarified such that this requirement is only required on Assessments that are completed and posted as final. If not, this could be an administratively burdensome task for an entity to have to respond to each and every comment and then document that they did respond within 90 days. Please consider the following language changes for R8.1If a recipient of the Planning Assessment’s final results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.
Response: The SDT disagrees with the suggested limitations and believes both the Transmission Planner and Planning Coordinator must distribute their assessments to the applicable entities cited in the requirement to meet the overall intent of Requirement R8 and achieve appropriate coordination. No change made. The Requirement R8 requirement is to distribute Planning Assessment results associated with this standard. Therefore Requirement R8, part 8.1 only requires response to comments on the applicable assessment results. No change in wording is necessary.	

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Northeast Power Coordinating Council--RSC	Requirements R8, 8.1, and Measure M8--There are a number of concerns with these requirements. There needs to be a specified time period upon which comments must be received. As written, there is no sunset on when comments may be made and therefore they must be responded to. Additionally, it is not clear if the 90-day response time may extend beyond the end of the year to maintain and maintain annual compliance. R8 also causes redundancy of distribution of assessments. There is no statute of limitation for comments. There is also potential conflict with the deadline for completing a study and when comments may be submitted (e.g. comments are received the day before the study is to be completed.) These issues must be addressed. This standard should not be used to remedy deficiencies in meeting the requirements of FERC Order 890. Therefore these should be deleted. If this requirement is retained the following revision to Requirement 8 is suggested:"Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to the functional entities that the Planning Coordinator and Transmission Planner recognize as having a reliability need for the Planning Assessment results." Compliance: 1.4 Data Retention: The Transmission Planner and the Planning Coordinator may not be using the same software. If both are required to store the data, do they both have to have the software to use the data? Can this be changed to an "or" such that one of them must retain the data and it can be up to them as to who it is? 1.4 Data Retention, last bullet - this relates back to Requirements R8, 8.1, and Measure M8. "Three calendar years of the notifications" seems to be an unnecessary requirement, and should be deleted. As an alternative to deletion, the implementation of a rolling three calendar years of notifications could be considered.

Response: The SDT disagrees that there should be a statute of limitation for asking questions related to coordination of planning and believes parties will act appropriately. The SDT's intent is that compliance would be judged by whether the comment was responded to in the required 90 days.

The SDT disagrees, this communication is necessary to achieve appropriate coordination.

The SDT disagrees that there should be a statute of limitation for asking questions related to coordination of planning and believes parties will act appropriately. The requirement is to distribute the results of the completed Planning Assessments associated with this standard therefore all related supporting studies are complete and there is no potential conflict.

The SDT seeks to retire the existing TPL-005 & -006 while continuing to meet the purpose of their requirements. FERC Orders 693 and 890 each provide expectations and direction to the ERO regarding enhancement of regional coordination and planning. The SDT believes the inclusion of Requirement R8 in the standard and performance of the regional assessments required under NERC delegation agreements will meet these objectives. No change made.

The SDT agrees the wording could be clearer and will clarify by adding "adjacent" before Transmission Planner. The word "indicates" has been changed to "has" to be clearer. The other revised wording has the same meaning as the suggested wording.

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent

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Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information. The SDT believes that both the Transmission Planner and Planning Coordinator have the responsibility for data retention. Therefore, the SDT believes that the existing language is adequate and that no changes are required. The SDT believes that both should have the necessary software for using the data. The SDT believes that retaining the documentation for 3 years is consistent with other standards and appropriate for audit purposes.	
Hydro-Québec TransEnergie (HQT)	Requirements R8, 8.1, and Measurement M8 There are a number of concerns with these requirements. There needs to be a specified time period upon which comments must be received. As written, there is no sunset on when comments may be made and therefore they must be responded to. Additionally, it is not clear if the 90-day response time may extend beyond the end of the year to maintain and maintain annual compliance. R8 also causes redundancy of distribution of assessments.Suggested revised Requirement R8 to say: Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to functional entities that demonstrated a reliability need with concurrence from their planning coordinator for the Planning Assessment results.
Response: The SDT disagrees that there should be a statute of limitation for asking questions related to coordination of planning and believes parties will act appropriately. The SDT's intent is that compliance would be judged by whether the comment was responded to in the required 90 days. The SDT believes both the Transmission Planner and Planning Coordinator must distribute their assessments to meet the overall intent of Requirement R8 and achieve appropriate coordination. No change made.	
US Bureau of Reclamation	Results of the Planning Assessments should be coordinated with all owner entities who all share in system reliability. Any owner that may choose to implement a Corrective ACtion Plan item should have access to the basis for the need.
Response: The SDT agrees and believes Requirement R8 facilitate the necessary interaction between reliability related entities. No change made.	
TIS	Term “document” in R8.1 the term documented needs to be defined. TIS suggests using the term “written “ i.e., “If a recipient of the Planning Assessment results provides documented written comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented written response to that recipient within 90 calendar days of receipt of those comments. ”The requirement to distribute reports to entities with “need” has very significant CEII implications. This should be tightened to a “bona fide reliability need” for the information, requiring CEII or confidential material handling procedures. Other general comments:1. Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft.
Response: The present wording is in other approved standards and is sufficiently clear based on experience to date. Control of CEII is a fundamental expectation of all industry participants and the "reliability related need" restriction ensures only appropriate parties must be given	

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planning assessments. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the Summary Considerations for Question 10.	
NERC Standards Review Subcommittee	The MRO NSRS asks that the SDT revise R8 to limit the need to provide the Planning Assessment as follows "adjacent Planning Coordinators and adjacent Transmission Planners and to any registered functional entity"? This MRO NSRS suggestion is added to the requirement to clarify that the word adjacent also applies to Transmission Planners and to clarify that the functional entity must be registered in order for the entity to be applicable to the requirement.
Response: The SDT agrees and will clarify by adding "adjacent" before Transmission Planner, but the SDT believes adding "registered" is unnecessary because it is understood as it relates to NERC Reliability Standards. **R8**. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information.	
Florida Power and Light	The requirement to distribute the Planning Assessment should not mandate distribution of a document but should be more flexible and allow for making the Planning Assessment available, such that those entities that need the information can have it readily available. R8 should be modified as follows: Each Planning Coordinator and Transmission Planner shall make available its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.
Response: The SDT believes Requirement R8 must be a standards requirement and ensures communication of information necessary for regional assessments. No change made.	
NorthWestern Energy	The term "functional entity" needs to be defined.
Response: The NERC Reliability Functional Model defines the term "functional entity".	
Gainesville Regional Utilities	The wording could be a little better to indicate that the PC and TP should always get each others planning assessments, but other entities need to indicate a reliability related need to get the same. I suggest making a second sentence and eliminating the word "and".
Response: The SDT agrees that the wording could be a little better and will clarify by adding "adjacent" before Transmission Planner. **R8**. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information.	
National Grid	This standard should not be used to remedy deficiencies in meeting the requirements of FERC Order 890. Therefore these should be deleted.

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	If this requirement is retained the following is suggested: Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to the functional entities that the Planning Coordinator and Transmission Planner recognizes as having a reliability need for the Planning Assessment results. Additionally, there is no statute of limitation for comments. There is also potential conflict with the deadline for completing a study and when comments may be submitted (e.g. comments are received the day before the study is to be completed.) These issues must be addressed. Compliance: 1.4 Data Retention: The Transmission Planner and the Planning Coordinator may not be using the same software. If both are required to store the data, do they both have to have the software to use the data? Can this be changed to an "or" such that one of them must retain the data and it can be up to them as to who is it. 1.4 Data Retention, last bullet - this relates back to Requirements R8, 8.1, and Measurement M8. "Three calendar years of notification" seems to be a nuisance requirement to get in trouble for. This is unnecessary and should be deleted.
Response: The SDT seeks to retire the existing TPL-005 & -006 while continuing to meet the purpose of their requirements. FERC Orders 693 and 890 each provide expectations and direction to the ERO regarding enhancement of regional coordination and planning. The SDT believes the inclusion of Requirement R8 in the standard and performance of the regional assessments required under NERC delegation agreements will meet these objectives. No change made. The SDT agrees and will clarify by adding "adjacent" before Transmission Planner. The word "indicates" has been changed to "has" to be clearer. The other revised wording has the same meaning as the suggested wording which is sufficiently clear. **R8**. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information. The SDT disagrees that there should be a statute of limitation for asking questions related to coordination of planning and believes parties will act appropriately. No change made. The requirement is to distribute the results of the completed Planning Assessments associated with this standard therefore all related supporting studies are complete and there is no potential conflict. The SDT believes that both the Transmission Planner and Planning Coordinator have this responsibility for the data retention. Therefore the SDT believes that the existing language is adequate and that no changes are required. The SDT believes that both should have the necessary software for using the data. No change made. The SDT believes that retaining the documentation for 3 years is consistent with other standards and appropriate for audit purposes.	
TVA System Planning	TVA believes that the TP and PC are unnecessarily duplicating work as shown in R8 and in M8. TVA believes that just the PC should be responsible for this coordination. R8: It is not clear whether the assessment results must be distributed to all parties of interest, or if it would be sufficient to post the assessment at a central location, and distribute information necessary to access the results. Also, FERC Standards of Conduct issues would come into play in assuring that the information is available only to appropriate

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	personnel. R8.1: It is not clear what the form of the response to the comments should be " would an acknowledgement be sufficient, or would it be necessary to pursue a process of examining comments in detail and revising and reissuing the corresponding assessment"
Response: The SDT believes both the Transmission Planner and Planning Coordinator must distribute their assessments to meet the overall intent of Requirement R8 and achieve appropriate coordination. The standard does not specify the mechanics of distribution of the information, only that it must occur. The method proposed would be acceptable as long as it met Measure M8 and Section 1.4 under compliance monitoring. Control of competitive market information per Standards of Conduct is a fundamental expectation of all industry participants and the "reliability related need" restriction ensures only appropriate parties must be given planning assessments. The standard should not specify the means of providing and responding to comments, but ensures that appropriate communication is initiated. No change made.	
SRC of ISO/RTO	Under R8 it should be made clear that a TP should not be required to send their assessment to adjacent PCs and that PCs should not be required to send their assessments to TPs not in their footprint. Under R8.1: If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.This should not be required until the Assessment is final and could be an administrative intense task. The following wording is suggested for R8:R8. Each Planning Coordinator shall distribute its planning assessment results to adjacent Planning Coordinators and to any Planning Coordinator who indicates a reliability related need for the planning assessment results. Each Transmission Planner shall distribute its planning assessment results to adjacent Transmission Planners and to any other Transmission Planner who indicates they have a reliability need for the planning assessment results. R8.1 If a recipient of the Planning Assessment final results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments. AESO does not comment on VSLs or VRFs.
Response: The SDT believes both the Transmission Planner and Planning Coordinator must broadly distribute their assessments to meet the overall intent of Requirement R8 and achieve appropriate coordination. No change made. The requirement is to distribute the results of the completed Planning Assessments associated with this standard therefore all related supporting studies are complete and there is no potential conflict. The SDT recognizes this fact and believes 90 days should be sufficient to develop a response. The SDT disagrees with the suggested limitations and believes both the Transmission Planner and Planning Coordinator must distribute their assessments to the applicable entities cited in the requirement to meet the overall intent of Requirement R8 and achieve appropriate coordination. No change made.	
Pepco Holdings, Inc. - Affiliates	While the SDT has stated in the Description of Current Draft that the issues of TPL-005 and TPL-006 have been addressed. It is not clear to PHI Affiliates that this is true. It is not evident how wide area planning is performed. Requirement 2 states Each

Organization	Comments for Question 8
PHI	Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES.

Response: The SDT seeks to retire the existing TPL-005 & -006 while continuing to meet the purpose of their requirements. FERC Orders 693 and 890 each provide expectations and direction to the ERO regarding enhancement of regional coordination and planning. The SDT believes the inclusion of Requirement R8 in the standard and performance of regional assessments will meet these objectives.

FRCC Transmission Working Group	With regards to the High VSL, what about entities that indicate a reliability related need for the Planning Assessment? Should this be part of the High VSL? Consider changing the requirement to distribute the Planning Assessment to become more flexible and allow for making the Planning Assessment available to those entities that indicates a need. Consider revising as follows:Each Planning Coordinator and Transmission Planner shall make available its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. The definition of "Known Commitments" should explain how that would diferentiate between Planned Commitments

Response: The SDT agrees and will add those with a reliability related need to the Lower and High VSL.

R8 VSL	The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners or adjacent Planning Coordinators, and to one functional entity that has a reliability related need and has submitted a written request for the information, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to its adjacent Transmission Planners or adjacent Planning Coordinators, and to any functional entity that has a reliability related need and has submitted a written request for the information, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

The proposed revised wording is essentially the same as the current wording and does not provide any additional clarity. No change made.

The SDT believes that the existing language regarding known commitments is adequate and no further change is required.

9. The SDT has revised the definitions in response to industry comments to the third posting. Do you agree with these definition changes? If not, please clearly indicate which definition you disagree with and provide specific comments.

Summary Consideration: The SDT received several comments on definitions. The following summarizes the questions and response on the definitions. Planning Assessment: The SDT considered the comment, but feels that a Corrective Action Plan includes the 'do nothing' option, which would address the concern and decided not to change the definition.

Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition.

The SDT believes the exclusion of voltage sensitive load belongs in the Non-Consequential Load Loss definition because it is not Non-Consequential load.

Consequential Load Loss: Due to comments in prior postings, the SDT has elected to define Consequential Load specific to Load that is lost due to a fault. Non-Consequential Load has been defined to be all else, except as noted. That which has been noted is excluded from coverage by the standard. So it is not necessary to include the noted exclusions from the Non-Consequential Load Loss definition in the Consequential Load Loss definition.

Planning Horizon: The only location where planning horizon didn't specify Near-Term or Long-Term was in the 'Purpose'. The SDT didn't feel that this reference needed to be specific or was sufficient to warrant a definition. No changes have been made.

Year One: The SDT believes the definition will capture both a summer and winter peak and is necessary to provide a clear starting point for the planning horizon.

Year One is not considered to be the immediate year following the current year, as suggested by some, because if the study were completed at the end of the year, then there would be no time to implement a Corrective Action Plan. Also, that following year is in the Operational Planning time frame.

The SDT doesn't see a problem with entities having slightly different study periods. This situation exists under the current TPL Standards.

With regards to any possible inconsistencies within the practices of any entity, the SDT believes that the requirements as defined are required for a Planning Assessment. How these requirements are met is beyond the scope of this standard and should be discussed within the responsible entities.

Consequential Generation Loss: Generation run-back and tripping is acceptable. It is up to the Planning Coordinator and the Transmission Planner to determine how many units or cumulative MW may be interrupted due to either a consequential or non-consequential action. Therefore it isn't necessary for the SDT to define Consequential Generation Loss.

Note 'b' has been revised to clarify the issue. Consequential Load Loss as well as generation loss is acceptable as a consequence of any planning or extreme event excluding P0.

Bus-Tie Breaker: The SDT has elected to define a Bus-Tie Breaker. If the SDT were to also define what is not a Bus-Tie Breaker, then anything that was missed would not be defined. To be comprehensive, the SDT has to limit the definition to what a Bus-Tie Breaker is to avoid further complexity.

Steady State: 'Steady State' was changed to 'steady state', so no definition is required.

The following definition was changed for clarity due to industry comments:

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Note 'b': Consequential Load Loss as well as generation loss is acceptable as a consequence of any planning or extreme event excluding P0.

Organization	Yes or No	Comments for Question 9
FRCC Transmission Working Group		Consider the following definition for clarification: Planning Assessment: Documented evaluation of (1) studies of future Transmission System performance and (2) Corrective Action Plans (included in studies) to remedy identified deficiencies. Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, or (2) the response of voltage sensitive Load that is disconnected from the System by end-user equipment.
Response: Planning Assessment: The SDT considered the comment, but feels that a Corrective Action Plan includes the 'do nothing' option, which would address the concern and decided not to change the definition. Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
ERCOT ISO	No	* Planning horizon is not formally defined but used many times throughout the standards. If there is a need to define the Near- and Long-term Transmission Planning Horizons, then the transmission planning horizon itself also should be defined. Additional confusion on this issue is the use of Long-term Planning as a planning horizon of one year or longer, also not formally defined. We finally found this referenced in the NERC Drafting Team guideline, which is not an obvious place to look for a definition. * Year One is only used two times " once to define Near-term Transmission Planning Horizon and once in the TPL standard. If this is not used throughout the NERC standards, it should not be defined. As an alternative, the transmission planning horizon could be formally defined, with Near- and Long-term Transmission Planning Horizons defined as subsets of the main definition. This would eliminate the need for a formal definition of Year One. If Year One stays as a new definition, it seems to be too broad, potentially allowing for omission of a peak season in the study. For example, if Year One is the period 12 to 18 months from the end of 2009, then Year One is currently 2011. Why is the year 2010 not considered to be Year One.*

Organization	Yes or No	Comments for Question 9
		Non-Consequential Load Loss is confusing " due to the base word "consequence". Consequential Load Loss is intended to be a load loss that is a result, or consequence, of the isolation. Non-Consequential Load Loss seems intended to imply it was not a consequence of the isolation. Although the standard attempts to define the term, this definition does not agree with the common English definition of the term. "Non-consequential" (or "Inconsequential") implies that the load loss is unimportant, minor or insignificant. This is the opposite intent of how this term is used in the standard, where it is used to mean the load that it is unacceptable to lose for a particular event. Alternatives could be "Direct Load loss" and "Indirect Load loss" to replace the two concepts that are included as Consequential and Non-Consequential respectively.
Response: Planning Horizon: The only location where planning horizon didn't specify Near-Term or Long-Term was in the 'Purpose'. The SDT didn't feel that this reference needed to be specific or was sufficient to warrant a definition. No changes have been made. Year One: Year One is not considered to be the immediate year following the current year because if the study were completed at the end of the year, then there would be no time to implement a Corrective Action Plan. Also, that following year is in the Operational Planning time frame. No changes have been made. As you have indicated, the terms 'consequential' and 'non-sequential' can be interpreted consistent with the intent of the SDT. Further the use has been accepted by NERC and seems to have been accepted by the industry in the multiple postings to date. By changing 'Non-consequential' (or not-consequential) to 'inconsequential' you have changed the meaning. The SDT is content with the terms and has focused on the clarity of the definition, which also seems to be the focus of the comments from the industry. The SDT has decided to stay with the existing terms rather than changing them as this late date. No changes have been made.		
Northeast Utilities	No	[Comment on Year One Definition] This still defines Year One as both a particular year AND a window. It cannot be both. We suggest rewording the second sentence to read: "This is further defined as the beginning 12-18 months from the end of the current year".
Hydro-Québec TransEnergie (HQT)	No	Definitions " Year One " This still defines Year One as both a particular year AND a window. It cannot be both. Suggest rewording the second sentence to read: "This is further defined as beginning 12-18 months from the end of the current year."
Response: The SDT does not agree that there is an issue and has not changed the definition.		
Platte River Power Authority	No	1. Please make the definition for Non-Consequential Load Loss simple and straightforward. For example, Non-Consequential Load Loss: The planned shedding of firm load.(Note that phrases "firm load" and "firm load shedding" are used frequently in a dozen other standards.) 2. Move the remainder of the sentence about "the response of voltage sensitive Load including...by end-user equipment." from the Non-Consequential Load Loss definition to the Consequential Load Loss definition.
Response: Non-Consequential Load Loss; Due to comments received in earlier postings, the SDT believes that the definition can not be that simple. The SDT believes the exclusion of voltage sensitive load belongs in the Non-Consequential Load Loss definition because it is not Non-Consequential Load. Therefore, any reduction in load due to sensitivity to low voltage would not result in a compliance violation. No change made.		

Organization	Yes or No	Comments for Question 9
To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
NERC Standards Review Subcommittee	No	A. Add a Consequential Generation Loss definition, which would be a complement to the Consequential Load Loss definition. Both consequential load loss and consequential generation loss are referred to in note "b" of the Steady State & Stability section of Table 1, but only consequential load loss is defined. The MRO NSRS suggests text of: Consequential Generation Loss: All Generation that is no longer delivered to any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions. B. The MRO NSRS offers the following comment to one of the proposed definitions of TPL-001. Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss that is the result of the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment. C. Add a Planning Horizon definition. This term is used in this proposed standard, in the FAC-010-2 standard, and possibly in other future standards, but it has not been defined yet. D. The SDT is to be commended for working on the Year one definition, however, concerns exist that if the standard is adopted as written, it is incompatible with the eastern interconnection wide ERAG model process. E. If the SDT intends to change the planning processes and model building processes throughout NERC in this regard, then the SDT should explain the benefits of changing this process and verify that it does not sabotage the normal model building and study process.
Response: A. Generation run-back and tripping is acceptable. It is up to the Planning Coordinator and the Transmission Planner to determine how many units or cumulative MW may be interrupted due to either a consequential or non-consequential action. Therefore it isn't necessary for the SDT to define Consequential Generation Loss. Note 'b' has been revised to clarify the issue. **Note 'b':** Consequential Load Loss as well as generation loss is acceptable as a consequence of any planning or extreme event excluding P0. B. To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment C. The only location where planning horizon didn't specify Near-Term or Long-Term was in the 'Purpose'. The SDT didn't feel that this reference needed to be specific or was sufficient to warrant a definition. No changes have been made. D & E. With regards to any possible inconsistencies within the practices of any entity, the SDT believes that the requirements as defined are required for a Planning		

Organization	Yes or No	Comments for Question 9
Assessment. How these requirements are met is beyond the scope of this standard and should be discussed within the responsible entities.		
MAPP	No	Add a Consequential Generation Loss definition, which would be a complement to the Consequential Load Loss definition. Both consequential load loss and consequential generation loss are referred to in note "b" of the Steady State & Stability section of Table 1, but only consequential load loss is defined. We suggest text of: "Consequential Generation Loss: All Generation that is no longer delivered to any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions. Add a Planning Horizon definition. This term is used in this proposed standard, in the FAC-010-2 standard, and possibly in other future standards, but it has not been defined yet.
Response: Consequential Generation Loss: Generation run-back and tripping is acceptable. It is up to the Planning Coordinator and the Transmission Planner to determine how many units or cumulative MW may be interrupted due to either a consequential or non-consequential action. Therefore it isn't necessary for the SDT to define Consequential Generation Loss. Note 'b' has been revised to clarify the issue. **Note 'b':** Consequential Load Loss as well as generation loss is acceptable as a consequence of any planning or extreme event excluding P0. Planning Horizon: The only location where planning horizon didn't specify Near-Term or Long-Term was in the 'Purpose'. The SDT didn't feel that this reference needed to be specific or was sufficient to warrant a definition. No changes have been made.		
United Illuminating	No	As currently defined "Non-Consequential Load Loss" could allow widespread or cascading motor stall. The language in the definition cannot be this generic. The text is broad enough that it could allow a voltage collapse, the definition is incompatible with Table 1a (BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur). The definition for the non-consequential load loss combined with Table 1 would prohibit any customer from tripping its own load for contingencies that indicate 'no' in the non-consequential load loss column. This is not practical and appears to be an unintended consequence of the change in definition. This requires a change in the definition or the table.We suggest clearly defining exactly what Non-Consequential Load Loss is as "intended post-Contingency loss of load caused by operator or SPS (RAS) action."
Central Maine Power Company	No	As currently defined Non-Consequential Load Loss could allow widespread or cascading motor stall. The language in the definition cannot be this generic. The text is broad enough that it could allow a voltage collapse; the definition is incompatible with Table 1a (BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur). The definition for the non-consequential load loss combined with Table 1 would prohibit any customer from tripping its own load for contingencies that indicate 'no' in the non-consequential load loss column. This is not practical and appears to be an unintended consequence of the change in definition. This requires a change in the definition or the table.We suggest defining Non-

Organization	Yes or No	Comments for Question 9
		Consequential Load Loss as "intended post-Contingency loss of load caused by operator or SPS (RAS) action."
ISO New England	No	As currently defined Non-Consequential Load Loss could allow widespread or cascading motor stall. The language in the definition cannot be this generic. The text is broad enough that it could allow a voltage collapse, the definition is incompatible with Table 1a (BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur). The definition for the non-consequential load loss combined with Table 1 would prohibit any customer from tripping its own load for contingencies that indicate 'no' in the non-consequential load loss column. This is not practical and appears to be unintended consequencetof the change in definition. This requires a change in the definition or the table.We suggest defining Non-Consequential Load Loss as "intended post-Contingency loss of load caused by operator or SPS (RAS) action."
National Grid	No	As currently defined Non-Consequential Load Loss could allow widespread or cascading motor stall. The language in the definition cannot be this generic. The text is broad enough that it could allow a voltage collapse, the definition is incompatible with Table 1a (BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur). The definition for the non-consequential load loss combined with Table 1 would prohibit any customer from tripping its own load for contingencies that indicate 'no' in the non-consequential load loss column. This is not practical and appears to be unintended consequent of the change in definition. This requires a change in the definition or the table.It is suggested to redefine Non-Consequential Load Loss as "intended post-Contingency loss of load caused by operator or SPS (RAS) action."
Response: The SDT added Requirement R5 to require that every Transmission Planner and Planning Coordinator has a voltage criteria. The voltage criteria should prevent the exposure to widespread or cascading motor stall and should limit any potential misinterpretation that the Non-Consequential Load Loss would allow such events. Table 1a (BES Transmission voltage instability, Cascading, and uncontrolled islanding shall not occur) supports Requirement R5 and reinforces the point that the definition for Non-Consequential Load Loss should not be read so broadly as to allow for unacceptable events. The definition for the Non-Consequential Load Loss excludes end-user actions, which disconnect the Load from the system. So Table 1 does not apply to such Load. The proposed definition is too narrow and would only capture anticipated Load losses for predefined conditions. It would not capture unanticipated loss of Load, which still needs to be accounted for within the definition. To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment		
Progress Energy Florida, Inc.	No	As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all appropriate parties to review PEF's previous comments to this effect.
Response: Throughout the drafting process, the SDT has carefully considered your comments as well as comments from other industry members.		

Organization	Yes or No	Comments for Question 9
Deseret Power	No	Comments: The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language follows Non-Interruptible Load loss other than: "Consequential Load Loss" the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment. This version uses the same wording but clarifies that the term "other than" applies to all three things.
Response: Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
Sacramento Municipal Utility District	No	Definition of Non-Consequential Load (Non-CLL): This definition excludes from the "Non-Consequential Load" only the "Interruptible" portion of Demand Response. The last SDT response to a comment on Draft #3 stated that there is no ceiling on the amount of DSM that can be utilitized (see Reference 1 below). Since Demand Response is more than just "Interruptible" demand, it is recommended that the exclusion in the definition for Non-CLL be broadened to include other relevant categories (see Reference 2 below) of Demand Response / DSM that is acceptable. Reference 1: pdf page 310, 337: SDT response related to DSM at http://www.nerc.com/docs/standards/sar/ATFNSDT_third_posting_comment_responses_2009Sept16.pdf Reference 2: http://www.nerc.com/docs/pc/drdtf/DADS_Phase_III_Final_090109.pdf, Figure 3 at pdf page 16, block under Capacity; and, associated definitions in Appendix III at pdf page 46 Use of the defined term "Planning Assessment" throughout the standard: Since the definition includes both performance evaluation (assessment) and corrective action to remedy identified deficiencies, its usage throughout the standard should be reviewed to ensure that it does not mandate corrective actions where the minimum requirement may be calling only for an assessment. The SDT should consider including a definition for "Spare Equipment Strategy". The SDT's comments on "spare equipment strategy" (at pdf page 122 of Consideration of Comments on 3rd Draft) state that it is based on a directive from FERC Order 693. Directives that impact reliability should be translated in to a requirement in a Standard. Even the proposed scope of MOD-010-0 (reference http://www.nerc.com/files/2010-2012_RS-Development-Plan_Volume-I_II.pdf page 223) makes a reference to the strategy, but does not require it.
Response: DSM: The SDT believes that any Load that is interruptible should be so under an agreement or tariff provision, which excludes it from the constraints of the TPL standard. No changes have been made. Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment Planning Assessment: The SDT considered the comment, but feels that a Corrective Action Plan includes the 'do nothing' option, which would address the concern		

Organization	Yes or No	Comments for Question 9
and decided not to change the definition. Spare equipment strategy: The SDT believes that spare equipment strategy can be managed by individual Transmission Owners and that the term does not have to be defined in the Standard. The SDT further believes it has satisfied the intent of the directive of FERC Order 693 by including Requirement R2, part 2.1.5. No changes have been made.		
Midwest ISO	No	Definition Section: The definition for "Bus Tie Breaker" should be revised to clarify whether a breaker in a standard ring bus or breaker and one-half scheme should be considered a "bus tie breaker". Definition Section: We believe that the "Year One" definition changes have clarified what is intended. Definition Section: We suggest having the following definition of Consequential Generation Loss added to the definition section. Consequential Generation Loss - All generation that is no longer connected to the transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.
Response: Bus-Tie Breaker: The SDT has elected to define a Bus-Tie Breaker. If the SDT were to also define what is not a Bus-Tie Breaker, then anything that was missed would not be defined. To be comprehensive, the SDT has to limit the definition to what a Bus-Tie Breaker is to avoid further complexity. No changes have been made. Consequential Generation Loss: Generation run-back and tripping is acceptable. It is up to the Planning Coordinator and the Transmission Planner to determine how many units or cumulative MW may be interrupted due to either a consequential or non-consequential action. Therefore it isn't necessary for the SDT to define Consequential Generation Loss. Note 'b' has been revised to clarify the issue. Consequential Load Loss as well as generation loss is acceptable as a consequence of any planning or extreme event excluding P0. **Note 'b':** Consequential Load Loss as well as generation loss is acceptable as a consequence of any planning or extreme event excluding P0.		
Northeast Power Coordinating Council--RSC	No	Definitions " Year One " This still defines Year One as both a particular year AND a window. It cannot be both. Suggest rewording the second sentence to read: "This is further defined as beginning 12-18 months from the end of the current year." As currently defined Non-Consequential Load Loss could allow widespread or cascading motor stall. The language in the definition cannot be this generic. The text is broad enough that it could allow a voltage collapse. The definition is incompatible with Table 1a (BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur). The definition for the non-consequential load loss combined with Table 1 would prohibit any customer from tripping its own load for contingencies that indicate 'no' in the non-consequential load loss column. This is not practical and appears to be an unintended consequence of the change in definition. This requires a change in the definition or the table.It is suggested to redefine Non-Consequential Load Loss as "intended post-Contingency loss of load caused by operator or SPS (RAS) action."

Organization	Yes or No	Comments for Question 9
Response: Year One: The SDT does not agree that there is an issue and has not changed the definition. No change made. Non-Consequential Load Loss: The SDT added Requirement R5 to require that every Transmission Planner and Planning Coordinator has a voltage criteria. The voltage criteria should prevent the exposure to widespread or cascading motor stall and should limit any potential misinterpretation that the Non-Consequential Load Loss would allow such events. Table 1a (BES Transmission voltage instability, Cascading, and uncontrolled islanding shall not occur) supports Requirement R5 and reinforces the point that the definition for Non-Consequential Load Loss should not be read so broadly as to allow for unacceptable events. The definition for the Non-Consequential Load Loss excludes end-user actions, which disconnect the Load from the system. So Table 1 does not apply to such Load. The proposed definition is too narrow and would only capture anticipated Load losses for predefined conditions. It would not capture unanticipated loss of Load, which still needs to be accounted for within the definition. To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
Gainesville Regional Utilities	No	I still find the Non-Consequential Load Loss definition vague. But, I presently do not have anything better to offer and thus I can live with it.
Response: Thank you for your response.		
SRC of ISO/RTO	No	In note b of the steady state and stability section of Table 1, consequential generation loss is referenced; however, there is no definition of such. A definition of consequential generation loss that is defined similar to "consequential load loss" should be added. The definition for "Bus Tie Breaker" should be revised to clarify whether a breaker in a standard ring bus or breaker and one-half scheme should be considered a "bus tie breaker". "year one" definition changes have clarified what is intended. AESO does not comment on VSLs or VRFs.
Response: Consequential Generation Loss: Generation run-back and tripping is acceptable. It is up to the Planning Coordinator and the Transmission Planner to determine how many units or cumulative MW may be interrupted due to either a consequential or non-consequential action. Therefore it isn't necessary for the SDT to define Consequential Generation Loss. Note 'b' has been revised to clarify the issue. **Note 'b':** Consequential Load Loss as well as generation loss is acceptable as a consequence of any planning or extreme event excluding P0. Bus Tie Breaker: The SDT has elected to define a Bus Tie Breaker. If the SDT were to also define what is not a Bus Tie Breaker, then anything that was missed would not be defined. To be comprehensive the SDT has to limit the definition to what a Bus Tie Breaker is to avoid further complexity.		

Organization	Yes or No	Comments for Question 9
The SDT does not see the difference between what is in the draft and what is proposed and does not agree that there is an issue. No change has been made to the definition.		
TVA System Planning	No	Is the 12-18 months referenced in the Year One definition actually from the start of the TA or the anticipated completion date of the same TA? Suggest revising the Non-Consequential Load Loss definition: Non-Interruptible Load loss other than (1) Consequential Load Loss, (2) the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment, and (3) utility loads such as pump storage loads, compressed air generating pumping loads, and scrubber loads, etc when such loads do not result in tripping of a generating unit.
Response: Year One: Year One begins 12-18 months from the end of the calendar year. No change made. Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment. The SDT interpreted utility loads such as pump storage loads, compressed air generating pumping loads, and scrubber loads as interruptible loads, which don't need to be highlighted separately. As a result, no changes were made to include this list.		
NYISO	No	Question # 9 The SDT has revised the definitions in response to industry comments to the third posting. Do you agree with these definition changes? If not, please clearly indicate which definition you disagree with and provide specific comments. No. Need to define "Steady State" and "Consequential Load" as well as other phrases included throughout the NYISO's response.
Response: 'Steady State' was changed to 'steady state', so no definition is required. No change made. No instances of 'Consequential Load' were identified in the draft standard. All of the references were to 'Consequential Load Loss', which is defined. No change made.		
Oklahoma Gas & Electric	No	R 3.4, R3.5, R4.4 & R4.5 There appear to be no standards of directions on identifying severe or extreme system impacts. This may need to be defined. Extreme events evaluated (last page of Table 1) OG&E needs more specific information on what is defined to be an extreme event before offering support. It appears the number of possible combinations and permutations that could be run make any compressive study overwhelming to perform and would provide very limited benefits. This needs to be clarified.
Response: Extreme event: The SDT agrees that extreme event analysis could be overwhelming if all possible combinations and permutations were evaluated. However that is not the expectation. Requirement R3, part 3.5 of the standard requires only those extreme events "that are expected to produce more severe System Impacts". Therefore this is a judgment call with a corollary expectation that one can provide an explanation of the thoughts behind the judgment for selecting the events.		

Organization	Yes or No	Comments for Question 9
Duke Energy	No	Reword the definition of Non-Consequential Load Loss as follows: Non-Interruptible Load loss other than Consequential Load Loss and other than the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.
Response: Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
Florida Power and Light	No	The definition of "Known Commitments" should explain how that would differentiate between Planned Commitments Planning Assessment definition should be clarified as follows: Planning Assessment: Documented evaluation of (1) studies of future Transmission System performance and (2) Corrective Action Plans (included in studies) to remedy identified deficiencies. Non-Consequential Load Loss definition should be clarified as follows: Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, or (2) the response of voltage sensitive Load that is disconnected from the System by end-user equipment. The SDT should do a search through the document (and Table 1) on “cascading” and capitalize the “C” and delete “outages” where it appears after “Cascading”.
Response: Known Commitments: The SDT believes that the existing language is adequate and no further change is required. If you do not have any known Firm Transmission Service as an example, then this fact should just be documented. Planning Assessment: The SDT considered the comment, but feels that a Corrective Action Plan includes the ‘do nothing’ option, which would address the concern and decided not to change the definition. Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment. The SDT did change, “cascading outages” to “Cascading” throughout the standard as suggested.		
Ameren	No	The definition of Bus-tie Breaker is unclear. This definition needs to be made clearer to remove issues regarding P2 and P5 planning events. We suggest the following additional language: A breaker in a standard breaker-and-a-half or ring bus configuration is not a Bus-tie Breaker. Suggest rewording Non-Consequential Load Loss definition: Non-Interruptible Load loss other than Consequential Load Loss. Non-Consequential Load Loss does not include the response of voltage sensitive

Organization	Yes or No	Comments for Question 9
		Load or Load that is disconnected from the System by end-user equipment.
Response: Bus-Tie Breaker: The SDT has elected to define a Bus-Tie Breaker. If the SDT were to also define what is not a Bus-Tie Breaker, then anything that was missed would not be defined. To be comprehensive the SDT has to limit the definition to what a Bus-Tie Breaker is to avoid further complexity. Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
Arizona Public Service Co.	No	The definition of Non-Consequential Load is confusing. It is not clear whether the response of voltage sensitive load and the load that is disconnected by the end user is included or not included. It is suggested that all items that are excluded be itemized and that there be no ambiguity.
Response: Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
Bonneville Power Administration	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: " Consequential Load Loss " the response of voltage sensitive Load " Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term "other than" applies to all three things.
Idaho Power	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: " Consequential Load Loss " the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term "other than" applies to all three things.
Modesto Irrigation District Transmission Planning	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: " Consequential Load Loss " the response of voltage sensitive Load " Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term "other than" applies to all three things.
NV Energy	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: " Consequential Load Loss " the response of voltage sensitive Load ? Load that is disconnected from the System by end-user

Organization	Yes or No	Comments for Question 9
		equipment.This version uses the same wording but clarifies that the term “other than” applies to all three things.
Pacific Gas and Electric Co.	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: “ Consequential Load Loss “ the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term “other than” applies to all three things.
Puget Sound Energy, Inc.	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: “ Consequential Load Loss “ the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term “other than” applies to all three things.
San Diego Gas & Electric Co	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: “ Consequential Load Loss “ the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.
Southern California Edison (SCE)	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: “ Consequential Load Loss “ the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term “other than” applies to all three things.
SRP	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: “ Consequential Load Loss “ the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term “other than” applies to all three things.
Utility System Efficiencies, Inc. (USE)	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: “ Consequential Load Loss “ the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term “other than” applies to all three things.
Western Area Power Adm - RMR	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies.

Organization	Yes or No	Comments for Question 9
		Suggested revision to the language follows:Non-Interruptible Load loss other than: " Consequential Load Loss " the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term "other than" applies to all three things.
Xcel Energy	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: " Consequential Load Loss " the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term "other than" applies to all three things.
NorthWestern Energy	No	The definition of Non-Consequential Load needs clarification. A possible revision is to list bulleted items in the definition: Non-Interruptible Load loss other than: " Consequential Load Loss " the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.This way "other than" applies to all three bullets.
Response: Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
Omaha Public Power District	No	The definition of Non-Consequential Load Loss is not clear. It's not clear whether "the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment" is considered to be Non-Consequential Load Loss or not. Based on previous drafts, it appears that the SDT's intent is that "the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment" is considered to be a special type of Consequential Load Loss--a type that transmission-planning entities are not allowed to rely upon to meet steady-state performance requirements. Comments on this fourth draft from one commenter seemed to indicate that he was interpreting the definition of Non-Consequential Load Loss to mean that "the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment" is considered to be Non-Consequential Load Loss. Consider breaking the definition of Non-Consequential Load Loss into two or more sentences to prevent misinterpretation and confusion. Also consider including a reference to "the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment" in the definition of Consequential Load Loss if this type of load loss is considered to be a special type of Consequential Load Loss. If this type of load loss is considered to be a special type of Consequential Load Loss, add the following sentence to the end of Note "b" at the top of Table 1: However, see Note "i" for a restriction that applies to steady state performance.
Response: Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		

Organization	Yes or No	Comments for Question 9
The SDT believes the reference to exclude voltage sensitive load belongs in the Non-Consequential Load Loss definition because this is neither Consequential nor Non-Consequential. No change was made to Note 'b' or 'i' for this issue.		
NERC System Protection and Control Subcommittee (SPCS)	No	The Drafting Team should change the definition of Consequential Load Loss to clarify that load lost due to operation of remote backup protection is not Consequential Load Loss. Operation of remote backup protection is not Normal Clearing for a fault.Consequential Load Loss: All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by Normal Clearing initiated by the a Protection System operation designed to isolate the fault.
Response: Consequential Load Loss considering operation of remote backup protection: For the purpose of the Transmission Planning Standard the remote backup protection is still operating to isolate the fault and the SDT is interpreting the subsequent loss of Load to be Consequential Load Loss. No change was made.		
MidAmerican Energy Company	No	The SDT is to be commended for working on the Year One definition, however, MidAmerican continues to be concerned that if the standard is adopted with the Year One definition as written, it is incompatible with the eastern interconnection wide ERAG model process.The definition as currently provided in the draft standard states that Year One of analysis should begin 12-18 months from the end of the current calendar year. This contradicts the time frames that models are currently made available in the MRO as a result of the process for building models through the ERAG. For example, the models developed through the MRO and ERAG model building process in 2009 include cases for the years 2010, 2011, 2015, and 2020. According to the definition of Year One, the 2011 cases in the 2009 series models would be representative of Year One during the 2009 calendar year. However the ERAG models are not provided until late 2009, and some data sets may not be available until early 2010. With this Year One definition, there would be limited or no time where the ERAG model series would include cases representing Year One as defined in the draft standard. MidAmerican urges the SDT to delete the Year One definition altogether. Since the development of regional models are tied to ERAG models and since ERAG model timing is set at the interconnection-wide level, it is likely that nearly all Transmission Planners and Planning Coordinators are working with similar models that are available at similar times. It seems to MidAmerican that this detail on what Year One is can be easily controlled interconnection-wide through the ERAG and which models they provide when.However, if the SDT believes that the Year One definition is necessary, MidAmerican urges the SDT to revised the Year One definition from stating "12-18 months from the end of the current calendar year" to stating "0-18 months from the end of the current calendar year". This revised definition would be at least compatible with the current ERAG process.
Response: Year One: The SDT believes the definition will capture both a summer and winter peak and is necessary to provide a clear starting point for the planning horizon. With regards to any possible inconsistencies within the practices of any entity, the SDT believes that the requirements as defined are required for a Planning Assessment. How these requirements are met is beyond the scope of this standard and should be discussed within the responsible entities. No changes were made.		
Tri-State Generation and Transmission Association	No	The SDT removed definitions of Extreme Events and Load Reduction. We still need to have some scale to differentiate N-1 from less likely but possibly higher impact events. However, we do understand that such a

Organization	Yes or No	Comments for Question 9
		criteria will take some time to develop, and should perhaps be a separate subject addressed by a new SAR. Year One has a flexible definition. It does not seem very intuitive. We can't say whether this is good or bad, although one entity's year one could overlap with another's year two.
Response: The SDT doesn't see a problem with entities having slightly different study periods. This situation exists under the current TPL Standards.		
US Bureau of Reclamation	No	The term "Consequential Load Loss" and "Planning Assessment" contain the terms "Transmission System" and/or "Transmission Facilities". The terms "Transmission System and Transmission Facilities are not defined in the NERC Glossary of Terms. The terms should either be in lower case or a definition added. The Term "Non-Consequential Load Loss" refers to a "Non-Interruptible Load" loss which is other than Consequential Load Loss. There is no mention in the Consequential Load Loss definition of the type of load (interruptible or non-interruptible). This adds confusion to what appears to be the distinction in the differences between the two, that one was the result of a fault and the other was the result of voltage.
Response: Transmission system: The SDT was unable to find a reference to 'Transmission System'. The SDT believes the references to 'Transmission system' were used correctly and no change was made. Transmission Facility: 'Facility' is a defined term in the NERC Glossary. The SDT believes the references to 'Transmission Facilities' are used correctly and no change was made. Non- Interruptible Load: Consequential Load Loss can be either interruptible or Non-Interruptible, so the distinction is not required. Non-Consequential is not a concern if it is interrupting interruptible load, but is a concern if it is inappropriately interrupting Non-Interruptible load. So the definition for Non-Consequential Load Loss is specific to Non-Interruptible load. The SDT disagrees with your statement that the loss of Non-Consequential load is the result of voltage. Load Loss as a result of voltage sensitivity is excluded from Non-Consequential Load Loss by the definition. No changes have been made.		
American Transmission Company	No	We suggest the following changes: Add a Consequential Generation Loss definition, which would be a complement to the Consequential Load Loss definition. Both consequential load loss and consequential generation loss are referred to in note "b" of the Steady State & Stability section of Table 1, but only consequential load loss is defined. We suggest text of: "Consequential Generation Loss: All Generation that is no longer delivered to any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions. Revise the Consequential Load Loss definition to include protection for abnormal operating conditions. We suggest text of: "Consequential Load Loss: All Load that is no longer served by any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions."Revise the Planning Assessment definition to more explicitly apply to the BES and the TPL-001 requirements. We suggest text of: "Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies in the BES from the steady

Organization	Yes or No	Comments for Question 9
		state and stability performance requirements set forth in the TPL-001 standard." Add a Planning Horizon definition. This term is used in this proposed standard, in the FAC-010-2 standard, and possibly in other future standards, but it has not been defined yet.
Response: Consequential Generation Loss: Generation run-back and tripping is acceptable. It is up to the Planning Coordinator and the Transmission Planner to determine how many units or cumulative MW may be interrupted due to either a consequential or non-consequential action. Therefore it isn't necessary for the SDT to define Consequential Generation Loss. Note 'b' has been revised to clarify the issue. Consequential Load Loss as well as generation loss is acceptable as a consequence of any planning or extreme event excluding P0. **Note 'b':** Consequential Load Loss as well as generation loss is acceptable as a consequence of any planning or extreme event excluding P0. Consequential Load Loss: The SDT disagrees with your proposed revision to the definition for Consequential Load Loss because it would provide for the use of an SPS or RAS to trip Consequential Load for an undefined 'abnormal condition', which is not an acceptable definition. No change is made. Applicability to BES: It is stated in the Purpose that the Standard applies to the BES. Therefore, the SDT doesn't see the need to have to repeat that throughout the document. Therefore no change is made. Planning Horizon: The only location where planning horizon didn't specify Near-Term or Long-Term was in the 'Purpose'. The SDT didn't feel that this reference needed to be specific or was sufficient to warrant a definition. No changes have been made.		
SERC Dynamics Review Subcommittee (DRS)	No	With the simplified definition for Bus-tie Breaker, would a breaker in a standard ring bus or breaker-and-a-half scheme be considered a Bus-tie Breaker? Request the definition be revised to clarify as follows: Add this sentence to the end of the definition: "A breaker in a standard breaker"and-a-half or ring bus configuration is not a Bus-tie Breaker. Suggest revising the Non-Consequential Load Loss definition to: Non-Interruptible Load loss other than (1) Consequential Load Loss and (2) the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.
SERC Planning Standards Subcommittee	No	With the simplified definition for Bus-tie Breaker, would a breaker in a standard ring bus or breaker-and-a-half scheme be considered a Bus-tie Breaker? Request the definition be revised to clarify this. Suggest revising the Non-Consequential Load Loss definition: Non-Interruptible Load loss other than (1) Consequential Load Loss and (2) the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.
Response: Bus-Tie Breaker: A breaker in a ring bus or a breaker-and-a half scheme would not be considered Bus-tie breakers. The SDT has elected to define a Bus-Tie Breaker. If the SDT were to also define what is not a Bus-Tie Breaker, then anything that was missed would not be defined. To be comprehensive the SDT has to limit the definition to what a Bus-Tie Breaker is to avoid further complexity. Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss.		

Organization	Yes or No	Comments for Question 9
Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
American Electric Power	Yes	
British Columbia Transmission Corp	Yes	
Exelon Transmission Planning	Yes	
FirstEnergy Corp	Yes	
Florida Municipal Power Agency, and its Member Cities	Yes	
Independent Electricity System Operator	Yes	
Manitoba Hydro	Yes	
Pepco Holdings, Inc. - Affiliates PHI	Yes	
Progress Energy Carolinas	Yes	
SCE&G	Yes	
TIS	Yes	
Orlando Utilities Commission	Yes	I agree, but that is based on not having seen any proposed changes from others that might change my mind.
Lafayette Utilities System	Yes	LUS generally supports the changes to the definitions and the changes to the rest of the standard. We appreciate the efforts of the SDT in responding to the many comments that were filed in response to version 3, and in crafting what appears to LUS to be a reasonable attempt to attain a consensus position, at least as we understand the result.
ITC Holdings	Yes	None

Organization	Yes or No	Comments for Question 9
PJM	Yes	
Response: Thank you.		
Oncor Electric Delivery	Yes	(Motor stall should not be included in this section) The language in the definition cannot be this generic. This becomes open to interpretation in Table 1. Localized load may not be an issue, but the text is broad enough that it could allow a voltage collapse.
Response: Non-Consequential Load Loss: The SDT added Requirement R5 to require that every Transmission Planner and Planning Coordinator has a voltage criteria. The voltage criteria should prevent the exposure to widespread or cascading motor stall and should limit any potential misinterpretation that the Non-Consequential Load Loss would allow such events. Table 1a (BES Transmission voltage instability, Cascading, and uncontrolled islanding shall not occur) supports Requirement R5 and reinforces the point that the definition for Non-Consequential Load Loss should not be read so broadly as to allow for unacceptable events. The definition for the Non-Consequential Load Loss excludes end-user actions, which disconnect the Load from the system. So Table 1 does not apply to such Load. To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
Southern Company	Yes	Suggest revising the Non-Consequential Load Loss definition for additional clarity to the following: Non-Interruptible Load loss other than (1) Consequential Load Loss and (2) the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.
Response: Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		

10. Do you agree with the changes in the performance elements and notes in Table 1? If not, please provide specific comments by note number, note alpha character, or performance category.

Summary Consideration: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. Final edits failed to correctly show footnote renumbering needed for removal of the Draft 3 footnote 1 which was moved to Requirement R4. All references to the prior Draft 3 footnote 1 should have been removed in Draft 4 and the remaining footnote references as shown in Draft 3 should have been decremented by a value of one. In Draft 5, the SDT has corrected the footnote references and the changes made are summarized as follows:

Table Area Reference	Footnote Reference Errors in Draft 4	Comment
Header notes	Yes	For item "j" the footnote reference to footnote "1" is now removed.
Title Row, Planning Events	No	All footnote references were shown correctly in Draft 4. No changes required in Draft 5.
Planning Event P0	No	No footnote references are used in this row in Draft 4. No changes required in Draft 5.
Planning Event P1	No	All footnote references were shown correctly in Draft 4. No changes required in Draft 5.
Planning Event P2	No	All footnote references were shown correctly in Draft 4. No changes required in Draft 5.
Planning Event P3	Yes	Footnote references to "19" should have been "9".
Planning Event P4	Yes	In the column titled "Category" the footnote reference to "101" should have been "10". In the column titled "Interruption of Firm Transmission Service Allowed" the footnote reference to "10" should have been "9."
Planning Event P5	Yes	In the column titled "Interruption of Firm Transmission Service Allowed" the footnote reference to "19" should have been "9".
Planning Event P6	No	All footnote references were shown correctly in Draft 4. No changes required in Draft 5.
Planning Event P7	No	All footnote references were shown correctly in Draft 4. No changes required in Draft 5.
Extreme Events Steady-State 2a & 2b	Yes	Footnote references to "12" should have been "11".

Table Area Reference	Footnote Reference Errors in Draft 4	Comment
Extreme Events Stability 2a, 2b, 2c, 2d	Yes	Footnote references to "11" should have been "10".
Extreme Events Stability 2e	Yes	Footnote references to "11" should have been removed.

A number of commenters indicated that some planning events will result in the same elements being removed from service and sought clarification on whether or not each event required analysis. The SDT acknowledges that different initiating events may result in identical Facilities being removed by protection action. While there may be some overlap in the steady-state timeframe, care must be taken to ensure proper reviews are made in the Stability timeframe where warranted due to delayed clearing modes that may result from the initiating event. For example, a bus fault and a stuck breaker may each clear a bus; however, the stuck breaker will have different reaction times due to the delayed clearing mode and therefore may warrant a review in a Stability environment. The standard allows the Transmission Planner and Planning Coordinator flexibility in using engineering judgment for the Table 1 events it studies for both the steady-state and Stability environments. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission Planner/Planning Coordinator can justify that certain events are duplicative for a given timeframe then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System. Planning event P2-1 was renamed to "Opening of a line section w/o a fault" to better clarify the SDT's intended analysis. This was in response to some commenters who remained confused by the P2-1 event and felt a detailed breaker model may be necessary. The drafting team clarifies here that a detailed breaker model is not needed. Conforming changes were also made to footnote 7 to make clear the intent of this planning event.

The P5 Protection System Failure event description was changed in support of stakeholders who indicated that multiple element outages may not always result from a P5 event and that it may only result in Delayed Fault Clearing of the faulted Transmission element/Facility. The P5 event now states "Failure of a single Protection System that results in Delayed Fault Clearing on one of the following:"

Footnote 9 is now applied to all "No" items for the column "Interruption of Firm Transmission Service Allowed". Footnote 9 clarifies that Firm Transmission Service can be interrupted so long as appropriate re-dispatch of resources are available and obligated to re-dispatch without any firm Load loss and that Facility ratings are maintained.

Some commenters expressed confusion on whether or not an event is classified as an EHV or HV event. This is an important concept to understand as it directly relates to the stated Table 1 criteria for Interruption of Firm Transmission Service and Non-Consequential Load Loss. The event is classified as EHV or HV based on the lowest nominal system voltage level of all the Facilities removed by the event studied and regardless of the fault location. For example, a fault that removes a 345/138kV

transformer is classified as a high-voltage (HV) event and the HV criteria apply. Changes to footnotes 1 and 5 were made to aid understanding in this regard.

Note changes are as follows:

Header note 'f': Applicable Facility Ratings shall not be exceeded.

Header note 'g': System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

Footnote 1 - If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.

Footnote 2 - Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.

Footnote 3 - Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.

Footnote 5 - For non-Generator Step Up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.

Footnote 7 - Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.

In addition, the definition of Non-Consequential Load Loss was revised to provide greater clarity:

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Organization	Yes or No	Comments for Question 10
FRCC Transmission Working Group		Please clearly indicate for P3 and P5 that note 1 and note 9 apply. Consider using a comma, not a note 19 that does not exist. The P2-1 event needs to be clarified with its intent. In the SDT Consideration of Comments to the 3rd DRAFT posting, the response to Transmission Planning clarified that "There is no need to show a line energized up to the

Organization	Yes or No	Comments for Question 10
		breakers that opened. The intent is simply to look for low voltage or thermal problems while supplying Load from one end of a normally networked line." This could be accomplished by adding this to footnote 7 or re-naming the event "Opening of a Line Section w/o fault".
Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The SDT has accepted the commenter's suggestion to better clarify the P2-1 planning event. The Event description in Table 1 for the P2-1 planning event has been re-titled "Opening of a line section w/o a Fault[7]" and the corresponding footnote number 7 has been revised to read as follows: **Footnote 7** - Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.		
SRP	No	: As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.
Response: The SDT agrees that some planning events will result in the same elements being removed from service. However, the similarities may only be valid from a steady-state view point and care must be taken to review the events in the Stability timeframe due to delayed clearing modes that may result from the initiating event. For example, a bus fault and a stuck breaker may each clear a bus; however, the stuck breaker will have different reaction times due to the delayed clearing mode and therefore may warrant a review in a Stability environment. The standard allows the Transmission Planner and Planning Coordinator flexibility in using engineering judgment for the Table 1 events in which it studies for both the steady-state and Stability environments. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission Planner/Planning Coordinator can justify that certain events are duplicative for a given timeframe then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System. At this time the SDT does not plan to conduct a workshop as suggested by the commenter. If Regional Entities wish to conduct seminars on the standard, SDT members from that region could be made available as participants in the discussions. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.		
Northeast Utilities	No	[Comment on Non-Consequential Load Allowed for certain Planning Events] We recommend that the standard as written should not allow non-consequential load loss to be used to resolve violations arising from the planning events in Table 1. We believe that planning for a reliable power system should discourage mitigation by load loss. Therefore, Non-Consequential Load Loss should not be allowed in a future looking system plan.

Organization	Yes or No	Comments for Question 10
		[Comment on Table 1 Item e, under Steady State & Stability] Our understanding here is that we should be able to redispatch after the first contingency (using fast start generation) to secure the system in anticipation of a second contingency and not redispatch to fix first contingency violations. Is this interpretation correct?Further, this standard doesn't specify which units can be adjusted following the contingency. This seems to stress the fact that the standard needs to address the definition of what is a base case. Also, the standard should be clear on whether we can or cannot rely on generation redispatch after the first contingency, i.e., should the failure of a fast start generator to start up be included in the contingency, or is this another level of contingency? [Comments on Footnotes] Footnotes 1, 10, 11, 19 and 101 need to be fixed. They are either mislabeled or do not point to any item.
Response: The SDT disagrees with the commenter's view related to disallowing Non-Consequential Load Loss for any planning event. The SDT believes they have made the appropriate expectations in not permitting its use for some Contingency planning events involving EHV Facilities. A Transmission Planner/Planning Coordinator may implement a more conservative planning approach beyond what TPL-001-1 requires if they believe one is warranted. The standard in Requirement R2, sub-part 2.7.1 (Corrective Action Plans) indicates that generation curtailment, tripping and re-dispatch are permissible Corrective Action Plans for both single and multiple Contingency events. Therefore, the SDT does not agree with Northeast Utilities view in this regard. The standard does not include prescriptive expectations for a "base case" conditions and allows flexibility to the TP/PC in this regard. See requirement R1 for initial model (P0 starting conditions) requirements. Starting of a "fast-start" generation unit appears to be viewed in the context of a Corrective Action solution to a studied planning event. There may situations like this that lend themselves to sensitivity analysis as required by the TPL-001-1 standard. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.		
British Columbia Transmission Corp	No	1. Table 1 event indicates loss of one of the equipment. It appears to be silent on the event classification regarding multiple equipments within the same protection zone. Is this considered as a single contingency or multiple contingencies? Please clarify. 2. Table 1 P5 refers to the event on loss of multiple elements caused by the failure of a single protection system while clearing a fault on one contingency. For systems equipped with dual or redundant protections, is a protection failure still a valid concern? Shouldn't this contingency analysis be excluded from the requirement? Please clarify. 3. Table 1 Extreme Events under Stability section, there is a reference to protection failure during fault clearing. Again for systems equipped with dual or redundant protections the requirement should be reconsidered. Please confirm. 4. Table 1 Extreme Events under both Steady State and Stability sections, there is a reference to loss of transmission lines on a common right-of-way. Please consider adding a Footnote to define the common right-of-way using minimum length similar to the one used for circuits on common structure (Footnote 12).

Organization	Yes or No	Comments for Question 10
		5. Performance Table 1 Footnote Item 1 on definition of angular stability, it states "For Planning Event P1: No generating unit or units shall be allowed to pull out of synchronism." o The requirement of no unit pull out of sync is not clear. Does this apply to small generators connected to distribution or lower voltage class lines? Or this is only applicable to generators connected to BEC (i.e. 100kV and above) without intermediary transmission voltage line connections? 6. Table 1 Footnote Item 6 refers to the "reference voltage" for transformers. What is the purpose of a reference voltage? Is this used to determine a valid transformer contingency? If so, according to the present definition a 3 phase fault on the 138kV side of a 138/66kV transformer is not considered a valid contingency to be assessed. Is this the intent?
Response: 1. The P1 Event is a single Contingency condition. A P1 Event may or may not remove other BES Facilities with it depending on the Protection System design. For example, a fault on a Transmission line (single Contingency) may also remove a BES transformer if no high-side transformer protection device is installed. 2. A P5 Event with a redundant Protection System will be covered by the analogous single Contingency event from a steady-state view. However, even with redundant Protection System designs there may be a delayed clearing mode that may need to be considered with the Stability timeframe. The standard allows the Transmission Planner and Planning Coordinator flexibility in using engineering judgment for the Table 1 events in which it studies for both the steady-state and Stability environments. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission Planner/Planning Coordinator can justify that certain events are duplicative for a given timeframe then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System. 3. See response to item 2. 4. The commenter appears to have referenced a Draft 3 version of the standard. The change requested was included in Draft 4. Footnote 11 in draft 4 reads as follows: "Excludes circuits that share a common structure or common Right-of-Way for 1 mile or less". 5. The commenter appears to have referenced a Draft 3 version of the standard as the former Draft 3 footnote 1 was moved to Requirement R4, part 4.1.1 in draft 4. The applicability of the NERC Reliability Standards unless otherwise stated is the Bulk Electric System and Part 4.1.1 applies only to BES generating units. **6.** The commenter appears to have referenced a Draft 3 version of the standard and the question is related to footnote 5 of the Draft 4 standard. The term "reference voltage" is used in determining if a transformer is classified as EHV or HV for the BES. This classification then ties to footnote 1 in regards to provisions for the interruption of Firm Transmission Service and Non-Consequential Load Loss. For example, if a 345/138 kV TR is outaged for the Event studied, the high-voltage (HV) allowances for interruption of Firm Transmission Service and loss of Non-Consequential Load would apply. The 138/66 kV transformer may not be classified as a BES Facility, your Regional Entity definition of the BES should be consulted for an official position.		
NERC Standards Review Subcommittee	No	A. P3 Modify the P3 Category performance criteria to apply only to the loss of two generators because the probability of the loss of two base load generators is an order of magnitude greater than the loss of a generator and any other transmission element. The MRO NSRS suggests the listing of: the loss of transmission circuit, transformer, shunt device, and single pole of DC line be removed from the P3 Events column. Move the

Organization	Yes or No	Comments for Question 10
		"generator + another element" events to the P6 Category by adding "1. Generator" to the listing in the Initial System Condition (Loss of . . .) column. B. The SDT should be commended for the changes that were made to Table 1. However, the MRO NSRS does recommend a few editorial changes. On page 16 under the Steady State and Stability heading is item d. Simulate Normal Clearing unless otherwise specified. This is also listed as footnote 2 to the table. The MRO NSRS recommends that item d under the Steady State and Stability heading be deleted. C. Why is there a footnote 1 indicator to note j. under Stability only? The MRO NSRS suggests that this footnote 1 indicator be deleted. D. Item i. under Steady State only states that "the response of voltage sensitive Load that is disconnected from the System by end-user equipment" is not to be used to meet steady state requirements. However, the non-consequential load loss says yes meaning it is allowed for some events in the table and non-consequential load loss definition includes the "response of voltage sensitive Load that is disconnected from the System by end-user equipment." This seems to be a direct contradiction. The MRO NSRS suggests that Item i. under steady state only be deleted. E. The MRO NSRS does not understand why there is a footnote 19 indicator for P3 and P5 EHV in the table when no footnote 19 exists. Perhaps the SDT meant footnotes 1 and 9 but The MRO NSRS recommends that this be corrected.F. The MRO NSRS does not understand why there is a footnote 12 indicator for Item 2 a and 2 b. on page 19. Perhaps the SDT meant footnotes 1 and 2 apply but The MRO NSRS recommends that this be corrected.

Response:

A. The SDT disagrees with the proposed adjustment of moving select generator Contingency outages to new planning event designations. The Table 1 planning event order regarding outage probability is somewhat subjective and the SDT believes appropriate expectations were made for generation outages within the P3 event. No changes made.

B. The SDT appreciates the support for changes made. The SDT decided to keep both references to "simulate normal clearing unless otherwise specified". While redundant, we believe it is important information and should aid to ensure industry is aware of the intent.

C. The reference to footnote 1 in Table note "j" should have been deleted in Draft 4. The SDT has fixed a number of footnote reference errors in Draft 5.

D. The Draft 4 definition of Non-Consequential Load Loss confused some stakeholders in that some thought the voltage sensitive Load was "inclusive" to this type of Load. The definition was changed to better clarify the SDT's intent that customer sensitive Load and Load disconnected by the end-user is not included within the definition. With that change the perception of a conflict is now resolved.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

E. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.

Organization	Yes or No	Comments for Question 10
Bonneville Power Administration	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard. Table 1, the second to last column: Please clarify what is meant by "Interruption of Firm Transmission Service." Planning studies do not differentiate firm and non-firm transmission services. Planning studies model a load forecast, a generation dispatch, and the system topography. Interruption of firm transmission service is a commercial issue and is not related to assessing reliability of the system. If an assumed transfer is interrupted in a power flow case due to a contingency, and if no consequential load loss were allowed and all criteria were met, the system would still be exhibiting reliable performance. We believe interruption of firm transmission service should be allowed for all planning events P1 through P5 when assessing the reliability of the transmission system. At a minimum, footnote 9 in Table 1 should apply to all events in category's P1 through P5 that do not allow interruption of firm transmission service.The NERC definition of Firm Transmission Service states "highest quality of service offered to customers under a filed rate schedule that anticipates no planned interruption." Planning events required to be evaluated in Table 1 are unplanned interruptions by nature since they are studied to determine mitigation should they occur unexpectedly. This is inconsistent with the definition Table 1, P1.4, P3.4, P4.4, P5.4, and P6.3: Shunt devices are not required to be in service at all times. It does not make sense to include it in the events column. How would you assess it while several of these devices are not deployed because they are not needed for the conditions studied? Table 1, P1 & P2: What is the rational for having two categories for single contingency? Table 1, P2.1 (Opening of a breaker without a fault): Please clarify what constitutes opening a breaker without a fault mean? Planning for these events will be time consuming (modeling every breaker position open) and expensive to mitigate for events that occur solely due to human error and should be removed for the table. Table 1, P2.2, P2.3, and P2.4: These are not single contingency events and should be moved to P3.
Response: The SDT agrees that some planning events will result in the same elements being removed from service. However, the similarities may only be valid from a steady-state view point and care must be taken to review the events in the Stability timeframe due to delayed clearing modes that may result from the initiating event. For example, a bus fault and a stuck breaker may each clear a bus; however, the stuck breaker will have different reaction times due to the delayed clearing mode and therefore may warrant a review in a Stability environment. The standard allows the Transmission Planner and Planning Coordinator flexibility in using engineering judgment for the Table 1 events in which it studies for both the steady-state and Stability environments. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission		

Organization	Yes or No	Comments for Question 10
Planner/Planning Coordinator can justify that certain events are duplicative for a given timeframe then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System. At this time the SDT does not plan to conduct a workshop as suggested by the commenter. As an alternative, the SDT will ask WECC area SDT member(s) to discuss this matter via appropriate WECC technical committees utilizing SDT members as participants in the discussions. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The SDT agreed with the commenter regarding the Table 1 performance requirements related to the Interruption of Firm Transmission Service. The team has applied footnote 9 to all Events that indicated "No" in this column. The Firm Transmission Service within the context of a planning horizon are long-term service arrangements from one Balancing Authority area to another that should be reflected within the planning model and net-interchange. The standard allows engineering judgment and flexibility to exclude certain Contingencies that may not be pertinent for the conditions studied. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission Planner/Planning Coordinator can justify that certain events not pertinent for a given study then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System. The two Contingency categories are used to delineate between higher ranked P1 single Contingencies and the lower ranked, yet high impact P2 single Contingency events. In P2, the team chose to differentiate between the EHV and HV in regards to performance expectations whereas in P1 the performance requirements for both EHV and HV are the same. The SDT believes the P2.1 event is important for review and it remains in Draft 5. Inadvertent relay operation that trips a breaker(s) is the primary reason forced outage cause for a P2.1 event. The condition could also be a planned (maintenance) event. The P2.1 event has been renamed "opening of a line section w/o a fault" to better align with the team's intent. Additionally, footnote 7 was revised to better clarify the need to study the P2.1 event. Footnote 7 now reads: **Footnote 7** - Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point. The P2.2, P2.3, and P2.4 planning events are less likely yet higher impact single Contingency events. While its true that these events will likely result in multiple elements being disconnected from the System they are classified as single Contingency since they are a common mode event resulting from a single fault with normal Protection System clearing. As stated above, the SDT does not treat the P2 events in the same manner as P1 events and there are unique expectations in performance for P2 events that result in HV element outages versus solely EHV element outages.		
Idaho Power	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. I believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes

Organization	Yes or No	Comments for Question 10
		to ensure accuracy prior to balloting this standard.
Southern California Edison (SCE)	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.
Utility System Efficiencies, Inc. (USE)	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service. Simulations of these outages would then be the same, even though the initiating event is different. I believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any footnote in the document, and some other footnotes seem to be misplaced. I would encourage drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.
Western Area Power Adm - RMR	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. I believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any footnote in the document, and some other footnotes seem to be misplaced.I encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.
Response: The SDT agrees that some planning events will result in the same elements being removed from service. However, the similarities may only be valid from a steady-state view point and care must be taken to review the events in the Stability timeframe due to delayed clearing modes that may result from the initiating event. For example, a bus fault and a stuck breaker may each clear a bus; however, the stuck breaker will have different reaction times due to the delayed clearing mode and therefore may warrant a review in a Stability environment. The standard allows the Transmission Planner and Planning Coordinator flexibility in using engineering judgment for the Table 1 events in which it studies for both the steady-state and Stability environments. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission		

Organization	Yes or No	Comments for Question 10
Planner/Planning Coordinator can justify that certain events are duplicative for a given timeframe then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System. At this time the SDT does not plan to conduct a workshop as suggested by the commenter. As an alternative, the SDT will ask WECC area SDT member(s) to discuss this matter via appropriate WECC technical committees utilizing SDT members as participants in the discussions. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.		
Modesto Irrigation District Transmission Planning	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard. please define "post contingency" and "post transient" Why was the previous version footnote 1 defining "angular stability eliminated?
Response: The SDT agrees that some planning events will result in the same elements being removed from service. However, the similarities may only be valid from a steady-state view point and care must be taken to review the events in the Stability timeframe due to delayed clearing modes that may result from the initiating event. For example, a bus fault and a stuck breaker may each clear a bus; however, the stuck breaker will have different reaction times due to the delayed clearing mode and therefore may warrant a review in a Stability environment. The standard allows the Transmission Planner and Planning Coordinator flexibility in using engineering judgment for the Table 1 events in which it studies for both the steady-state and Stability environments. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission Planner/Planning Coordinator can justify that certain events are duplicative for a given timeframe then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System. At this time the SDT does not plan to conduct a workshop as suggested by the commenter. As an alternative, the SDT will ask WECC area SDT member(s) to discuss this matter via appropriate WECC technical committees utilizing SDT members as participants in the discussions. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The SDT did not receive a substantial appeal from industry to define the terms proposed by the commenter and these terms are widely used and accepted in the industry. The proposed definitions were not added in Draft 5. The prior footnote 1 regarding angular stability was moved into the requirements section of the standard under Requirement R4 per the request of various		

Organization	Yes or No	Comments for Question 10
stakeholders in prior drafts.		
NV Energy	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.
Pacific Gas and Electric Co.	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.
Puget Sound Energy, Inc.	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.
Deseret Power	No	Comments: As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document,

Organization	Yes or No	Comments for Question 10
		and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.
NorthWestern Energy	No	Several outages identified in Categories P2, P4, and P5 seem to result in the same elements being removed from service, even though the initiating event is different. Thus, the same scenario is evaluated more than once. Also, the footnote numbering is not correct. We would like the drafting team to conduct a workshop before this standard goes to ballot to educate the industry on what outages are required to be simulated for which Categories.
Response: The SDT agrees that some planning events will result in the same elements being removed from service. However, the similarities may only be valid from a steady-state view point and care must be taken to review the events in the Stability timeframe due to delayed clearing modes that may result from the initiating event. For example, a bus fault and a stuck breaker may each clear a bus; however, the stuck breaker will have different reaction times due to the delayed clearing mode and therefore may warrant a review in a Stability environment. The standard allows the Transmission Planner and Planning Coordinator flexibility in using engineering judgment for the Table 1 events in which it studies for both the steady-state and Stability environments. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission Planner/Planning Coordinator can justify that certain events are duplicative for a given timeframe then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System. At this time the SDT does not plan to conduct a workshop as suggested by the commenter. If Regional Entities wish to conduct seminars on the standard, SDT members from that region could be made available as participants in the discussions. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.		
Sacramento Municipal Utility District	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. Comments on notes have been provided with associated requirements.
San Diego Gas & Electric Co	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different.
Response: The SDT agrees that some planning events will result in the same elements being removed from service. However, the similarities may only be valid from a steady-state view point and care must be taken to review the events in the Stability timeframe due to delayed clearing modes that may result from the initiating event. For example, a bus fault and a stuck breaker may each clear a bus; however, the stuck breaker will have different reaction times due to the delayed clearing mode and therefore may warrant a review in a Stability environment. The standard allows the Transmission Planner and Planning Coordinator flexibility in using engineering judgment for the Table 1 events in which it studies for both the steady-state and Stability environments. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe		

Organization	Yes or No	Comments for Question 10
System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission Planner/Planning Coordinator can justify that certain events are duplicative for a given timeframe then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System.		
Progress Energy Florida, Inc.	No	As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all appropriate parties to review PEF's previous comments to this effect.
Response: Throughout the drafting process, the SDT has carefully considered your comments as well as comments from other industry members.		
Pepco Holdings, Inc. - Affiliates PHI	No	Category P5 should be more appropriately titled DELAYED CLEARING OR Loss of multiple elements caused by the failure of a single Protection System while clearing a fault on one of the following....A protection system failure does not necessarily lead to loss of multiple power system elements. Sometimes it may just be delayed clearing of the faulted element. The recommended change is based on the SDT's response to comments submitted to Draft #2 of the standard? -A number of commenters expressed concern related to Planning Event P5 "Protection System Failure" and the need to evaluate a single component failure of a BES Protection System; particularly a failure of a station battery. The SDT has revised the P5 Planning Event description to remove the reference to "single component failure" and the event description was changed to match what is stated in the currently approved TPL standards under Category C6 through C9. --The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to normal fault clearing.-- A Protection System failure resulting in loss of the substation (one voltage level plus transformers) would not qualify as a P5 Planning Event since that event is considered an Extreme Event. Also, the phrase "failure of a single Protection System" should be defined. Draft #1 language used the term -single component failure- of a protection system. Based on a number of comments that were received, that term was subsequently replaced with the term -failure of a single Protection System-. To avoid confusion, this term needs to be defined within this standard and / or examples provided. If not, there will be confusion on how to study this category of events. This issue has been raised by numerous commenters throughout the standard development process. That fact that it continues to be expressed through numerous drafts indicates a lack of clarity as to exactly what protection system failures are to be studied.For example - Assume there are two protection systems on a facility (Scheme A and Scheme B). Assume one publishes a clearing time for Scheme A, and a slower clearing time for Scheme B. The TPL standard, as written, could imply that for a P5 failure of a single Protection System (scheme A or B fails) you would study the event assuming the worst case clearing time (i.e., using the slower clearing time for Scheme B.) Is that what is intended? If so, it should be so stated. However, that interpretation assumes the failure of a single Protection System would not effect the operation of the second Protection System. In other words it would not address single component points of failure, which could disable both Scheme A and Scheme B. Suppose both schemes were fed from the same set of CT's, VT's, battery, etc. Since the phrase "single component failure of the protection system" was eliminated, does this mean failure of both schemes due to a single component failure is not required to be studied under the P5 category? The standard must be very clear as to what contingency (i.e., what kind of protection system failure) is

Organization	Yes or No	Comments for Question 10
		to be studied. It should not be silent on this point, nor should it refer to another standard for guidance on what contingencies to study.
Response: The SDT agrees with points raised by the commenter and has changed the event description of the P5 planning event to better clarify the intent of simulating this Contingency. The SDT did not agree with the proposal to add a definition for the phrase "failure of a single Protection System". The SDT believes the description modification in the Event column of Table 1 suffices in this regard. The P5 planning event remains unchanged in the study work intended by the SDT and the description modifications are aimed only at clarifying our intent. The SDT confirms that the intent of P5 is not to study the loss of both Scheme A and Scheme B for the example provided by the commenter and that the expectation would be the study of the slower clearing time scheme (Scheme B).		
Oklahoma Gas & Electric	No	Category P7 OG&E supports as long as footnote 11 is included. Category P6 is an N-2 situation. OG&E does not support the wholesale study of every N-2 combination of contingencies even though one is allowed for the interruption of firm transmission service and non-consequential load loss. Establishing and maintaining operating guides associated with every N-2 set of contingencies is oppressive and would provide limited value. OG&E understands the need for targeted N-2 contingency studies; such as breaker failure. Category P5 Need more specific description of "Protection System failure" before receiving OG&E's support. Category P4 OG&E supports performing studies. OG&E also supports the differentiation between "DHV" and "HV". OG&E does not support developing operating guides for every voltage or overload issue discovered. Category P3 OG&E is concerned about the value of P3. Information about the expected value of performing studies for the category is needed before receiving OG&E support. Category P2 OG&E supports even though there are a few minor issues. Category P1 OG&E supportsOG&E will need every bit of the 60 months time mentioned on page 3 under "Effective Date" to implement all indicated upgrades. There is benefit in hardening the OG&E electrical system for such protection system failures, such as P4 & P5, but it may not be cost effective. Comments Stability AnalysisStability Analysis Recommend Planning Coordinator will be responsible for running the stability analysis to assure NERC compliance. The Planning Coordinator and Transmission Planner should work together to prepare the data.
Response: In P7, footnote 11 remains, thanks for your support. In P6 not every possible combination would be expected to be studied, especially for a Transmission Planner/Planning Coordinator covering a very large geographic footprint. The standard allows engineering judgment and flexibility to exclude certain Contingencies that may not be pertinent for the conditions studied. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission Planner/Planning Coordinator can justify that certain events are not pertinent for a given study then at their discretion they may		

Organization	Yes or No	Comments for Question 10
elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System. Based on feedback from some commenters the SDT made changes to the P5 planning event description as shown in Table 1. The changes are not substantive, do not alter the team's prior intent and aimed at clarification only. Regarding the comments provided on P4. The SDT appreciates the commenter's support in regard to the bifurcated approach of performance expectations related to the BES. The SDT believes all performance deficiencies related to thermal ratings and voltage ratings require corrective actions and the standard provides the Transmission Planner/Planning Coordinator a wide range of alternatives, including but not limited to Operating Procedures. As stated above, the Contingencies studied are expected to be those that have the most severe impact on a particular Facility and not necessarily every possible scenario. The SDT's review of outage events associated with various System conditions revealed that the potential for a generating unit outage being coincident with a variety of other Contingency conditions requires close evaluation. Again, study of some your largest units in combination with other events may suffice to cover the "more severe" conditions for your System and flexibility is afforded to the Transmission Planner to ensure proper coverage without the needed to study each and every combination. We appreciate your support on planning event P1 & P2 expectations. Regarding the proposal for Stability to be covered by the Planning Coordinator. The standard in P7 requires the Transmission Planner and Planning Coordinator to determine and identify individual or joint responsibilities for performing required studies. The Transmission Planner may rely on work being preformed by its Planning Coordinator but each is responsible for showing auditable compliance for the TPL-001-1 study requirements including Stability.		
SERC Planning Standards Subcommittee	No	Comments: Some of the footnote superscripts do not appear to have a corresponding reference in the footnotes, in the case of number 19 at several locations in the Firm Transmission Service column, and number 101 in the P4 cell in the Category column.
Southern Company	Yes	Some of the footnote superscripts do not appear to have a corresponding reference in the footnotes, in the case of number 19 at several locations in the Firm Transmission Service column (should be 9), and number 101 in the P4 cell in the Category column (should be 10). In header note j, the reference to footnote 1 should be removed. In steady state extreme events 2a and 2b, the reference to footnote 12 should be to footnote 11. In stability extreme events 2a through 2e, the reference to footnote 11 should be to footnote 10.
Lafayette Utilities System	Yes	While LUS remains concerned as to the way in which what is now footnote 9 may be followed in operation in areas where there have been historic problems with the old "footnote b", we appreciate the clarifications that have been made, and recognize that this may be the best way to resolve an issue for the industry. Please note that there remains what appears to be a typographical error in Table 1, Category P3, under "Initial System Condition" in that the footnote reference is to footnote 19, which does not exist. The reference was to footnote 10 in v.3 and we assume that the correct reference here is to footnote 9, which used to be footnote 10.
Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT		

Organization	Yes or No	Comments for Question 10
has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.		
US Bureau of Reclamation	No	Consequential Load Loss was defined, however, consequential generator loss was not. It may be easier to define "consequential loss" and let it apply to either.
Response: The SDT does not believe a definition to differentiate between consequential or non-consequential generation loss is needed since generation tripping and re-dispatch is permitted as a corrective action for all planning events as stated in Requirement R2, part 2.7.1.		
Tri-State Generation and Transmission Association	No	Extreme Events detailed at the end of Table 1 should be itemized in the same way as for so-called "Planning Events" at the beginning of Table 1. Steady State Extreme Event 1 would be EP1, Dynamic Stability Extreme Event 1 would be ED1, etc. Also, please use the term Dynamic Stability, not just Stability, as explained above. It would be helpful if descriptions had unique identifiers, for example Dynamic Extreme Event 1 could be called N-1-1. For Dynamic Extreme Event 1, the phrase "With an initial condition" conflicts with the phrase "prior to System adjustments" at the end of the sentence. The term "initial condition" suggests a maintenance outage, or at least an outage that has sustained long enough for the system to have responded/adjusted. Footnote text does not line-up with the body text in the Extreme Event Table. It seems to us that a bus-tie breaker would have the same chance of failure as another breaker. Therefore differentiation is not needed in Table 1.
Response: The SDT recognizes a minority position to label the extreme events in a manner similar to the planning events for a short-hand notation. However, based on lack of a significant majority objection to the extreme event table layout the team determined no changes were needed in this regard. The SDT believes the references to Stability in the extreme events portion of the table are sufficient. No changes made. The SDT does not believe that a conflict exists for extreme event 1 in regards to "With an initial condition" and "prior to system adjustment". No changes made. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The SDT agrees that any breaker has an equal chance for failure due to a fault. However, when lumped together with all the BES line breakers and transformer breakers, the Bus-tie Breaker application is much less prevalent within the BES when considering all beaker fault possibilities. The SDT recognizes that Bus-tie Breaker applications are used to lessen the impact of a bus fault outage (P2.2). Therefore, in regards to meeting the single Contingency breaker fault condition, the SDT felt it was necessary to differentiate between performance expectations between bus-tie and non bus-tie breakers. See P2.3 and P2.4 planning events.		
Omaha Public Power District	No	If "the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment" is considered to be a special type of Consequential Load Loss, add the following sentence to the end

Organization	Yes or No	Comments for Question 10
		of Note "b": However, see Note "i" for a restriction that applies to steady state performance. In Note "g", change "voltage limits" to "voltages". In Note "j", it appears that the reference to Footnote 1 is not needed. For Category P3, should the reference to Footnote 19 in the second column be a reference to Footnote 9? For Categories P3, P4, and P5, in the column labeled "Interruption of Firm Transmission Service Allowed", are the references to Footnotes 19 and 10 needed? For Category P4, should the reference to Footnote 101 in the first column be a reference to Footnote 10? For Category P4, should the reference to Footnote 11 in the third column be a reference to Footnote 10? In Items 2a and 2b of the "Steady State" subsection of the "Extreme Events" section, should the references to Footnote 12 be references to Footnote 11? In Footnote 1, change "loss of Non-Consequential Load" to either "Non-Consequential loss of Load" or "Non-Consequential Load Loss". (The point here is that the adjective "Non-Consequential" applies to the word "loss" rather the word "Load".) In the first sentence of Footnote 2, change "Normal Clearing faults" to "Normal Clearing of faults". In the second sentence of Footnote 2, remove the comma following the word "types". In Footnote 3, change "Non-Consequential Load" to either "Non-Consequential loss of Load" or "Non-Consequential Load Loss". (The point here is that the adjective "Non-Consequential" applies to the word "loss" rather the word "Load".) In the second sentence of Footnote 5, change "generator Step Up" to "Generator Step Up" to be consistent with the rest of the footnote.

Response: Load removed by end-user action or voltage sensitive Load that trips while the Transmission Planner/Planning Coordinator transient voltage criteria is being met is NOT a special case on Consequential Load Loss. No changes made.

The SDT agrees with the proposed change to note "g" in Table 1.

> **Header note 'g'**: System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.

The SDT agrees with the proposed wording change to footnote 1. The SDT also made other changes to footnote 1 for clarity and it now reads:

> **Footnote 1 -** If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load

Organization	Yes or No	Comments for Question 10
Loss. The SDT agrees with the proposed wording change to footnote 2. **Footnote 2** - Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. The SDT agrees with the proposed wording change to footnote 3. The team also made other changes to footnote 3 for clarity and it now reads: **Footnote 3** - Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss. The SDT agrees with the proposed wording change to footnote 5. Footnote 5 now indicates: **Footnote 5** - For non-Generator Step Up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.		
TVA System Planning	No	In Header note j - the reference to footnote #1 should be removed. Are batteries included as part of Protection System for P5 events? P3 reference to footnote #19 under Initial System Condition and for Interruption of Firm Transmission Service Allowed should actually be footnote #9. P5 reference to footnote #19 for Interruption of Firm Transmission Service Allowed should actually be footnote #9. The reference to footnote #101 in the P4 category should actually be to #10. For Steady State notes under Extreme Events, events 2a and 2b should reference footnote #11 instead of #12. For Stability notes, event 2 should refer to footnote #10 instead of #11.In footnote #3, should there be an "or" before "as defined by the Regional Entity"?
Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The P5 event is not a review of individual Protection System components but rather evaluates the loss of a "single Protection System" scheme or design. It is acceptable to simulate that a local (at the same substation) alternate Protection System scheme is still operational when performing a P5 review. The SDT chose this language to align with the SAR titled: Reliability of Protection Systems (Project 2009-7). The SDT believes that the individual component level evaluation of Protection Systems and redundancy requirements should be covered under the PRC standards and has only addressed a single protection scheme failure in the Planning Assessment required for the TPL standard. A Protection System component failure (i.e., battery) that removes multiple Protection System schemes is beyond the P5		

Organization	Yes or No	Comments for Question 10
planning event. Based on feedback from some commenters, the SDT made changes to the P5 planning event description as shown in Table 1. The changes are not substantive, do not alter the team's prior intent, and are aimed at clarification only.		
Arizona Public Service Co.	No	Note a: It would be helpful if there was a clear understanding of what constitutes voltage instability for the purpose of this standard. Is TP expected to have its own criteria for voltage stability? Are the dynamic and angle stabilities intentionally excluded? P3 refers to foot note 19 but there is no foot note 19. P4 refers to foot note 11, but the foot note does not seem to be applicable. Foot notes in second to last column of the table are confusing.
Response: In Requirement R5 the Transmission Planner/Planning Coordinator is expected to have documented its criteria for transient voltage response. It is expected that this criteria would reflect what would be considered voltage instability. Related to the question on dynamic and angle stabilities, the standard provides a requirement for what is considered a stable System in Requirement R4, part 4.1. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.		
Lakeland Electric	No	Recommended the following changes to the HV definition:Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems, per the Regional Entity's BES criteria/definition. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems, per the Regional Entity's BES criteria/definition.
Response: The SDT has retained the same delineation of the Bulk Electric System (EHV and HV) in Draft 5. No changes made.		
Duke Energy	No	Reword Steady State Only: f. as follows: "Applicable Facility Ratings shall not be exceeded." P3 Initial System Conditions footnote should be 9, not 19. Also, P4 footnote should not be 101. Please check all footnote references.
Response: The SDT agrees with the proposed wording change to header note "f" and it now reads: **Header note 'f':** Applicable Facility Ratings shall not be exceeded. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.		

Organization	Yes or No	Comments for Question 10
Ameren	No	Some of the footnote superscripts do not appear to have a corresponding reference in the footnotes, in the case of number 19 at several locations in the Firm Transmission Service column, which should be changed to number 9, and numbers 11 and 101 in the P4 cell in the Category column that should be changed to 10. Table 1 - Steady State and Stability Performance - Planning Events, note c., and Table 1 - Steady State & Stability Performance - Extreme Events, note a. will need to be revised to address the restoration of facilities as described above in comments to Questions 3 and 5. A header is needed on the third page of Table 1 Steady State & Stability Performance. Table 1 Steady State and Stability Performance Extreme Events - Steady State: Superscripts on items 2a and 2b should be 11 rather than 12. Similarly, for the Extreme Events - Stability items 2a through 2f, the superscript should be 10 rather than 11.
Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. As stated in the SDT's response to comments made by Ameren in Question 3, in Requirement R3, part 3.3.1 the reference to "other automatic controls" is intended to include other tripping means such as cross-tripping and not automatic restoration devices. No change made. Ameren comments to Question 5 do not appear pertinent to "automatic restoration" of facilities. No change made. The SDT agrees that an appropriate page header is needed on for each page of the Table and has worked with NERC staff to correct this in Draft 5.		
SERC Dynamics Review Subcommittee (DRS)	No	Some of the footnote superscripts do not appear to have a corresponding reference in the footnotes, in the case of: Table 1 Planning Events P3 superscripts should be 9 and not 19. Table 1 P5 superscript 19 should also be 9. Table 1 Planning Events P4 superscript 101 should be 10, superscript 11 should also be 10. Table 1 Extreme Events steady state items 2A and 2B superscript should be 11, not 12. Table 1 Extreme Events stability items 2A-2F superscript should be 10, not 11. No header on third page of Table 1 Planning Events. Table 1, Planning Events, wherever it says "no" in the "interruptions of firm transmission service" column, generation tripping by fault clearing action should be allowed.
Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The SDT agrees that an appropriate page header is needed on for each page of the Table and has worked with NERC staff to correct this in Draft 5. The SDT agrees with the commenter regarding the suggestion to permit generation re-dispatch when a "No" is indicated in the Table 1 column titled "Interruption of		

Organization	Yes or No	Comments for Question 10
Firm Transmission Service Allowed" and footnote 9 is now reflected on each occurrence.		
SRC of ISO/RTO	No	Table 1 should appear right after the requirements and before the VSLs. AESO does not comment on VSLs or VRFs.
Response: The SDT agrees with the commenter's recommendation to move Table 1 within the standard so that it follows directly after the requirements. This change was made in Draft 5.		
ERCOT ISO	No	The references to the footnotes need commas there are several references to footnote 19 and at least one to footnote 101.
Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.		
MidAmerican Energy Company	No	The SDT should be commended for the changes that were made to Table 1. However, MidAmerican does recommend a few editorial changes. On page 16 under the Steady State and Stability heading is item d. Simulate Normal Clearing unless otherwise specified. This is also listed as footnote 2 to the table. MidAmerican recommends that item d under the Steady State and Stability heading be deleted. Why is there a footnote 1 indicator to note j. under Stability only? MidAmerican suggests that this footnote 1 indicator be deleted.? Item i. under Steady State only states that "the response of voltage sensitive Load that is disconnected form the System by end-user equipment" is not to be used to meet steady state requirements. However, the non-consequential load loss says yes meaning it is allowed for some events in the table and non-consequential load loss definition includes the "response of voltage sensitive Load that is disconnected from the System by end-user equipment." This seems to be a direct contradiction. MidAmerican suggest that Item i. under steady state only be deleted. MidAmerican does not understand why there is a footnote 19 indicator for P3 and P5 EHV in the table when no footnote 19 exists. Perhaps the SDT meant footnotes 1 and 9 but MidAmerican recommends that this be corrected. MidAmerican does not understand why there is a footnote 12 indicator for Item 2 a and 2 b. on page 19. Perhaps the SDT meant footnotes 1 and 2 apply but MidAmerican recommends that this be corrected.
Response: While the SDT agrees that the phrase appears twice, it does not create any confusion or unnecessary redundancy. Footnote 2 is just a more detailed explanation of what needs to be done in Stability studies. No change made. The footnote 1 indication has been deleted as suggested.		

Organization	Yes or No	Comments for Question 10
The definition of Non-Consequential Load Loss has been revised to provide greater clarity as to the SDT's intent. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.		
Xcel Energy	No	There are references to footnote 12 on page 19, and footnote 101 on page 17, yet no such footnotes exist on page 20. Some of the other footnotes seem to be misplaced. Please review and validate all footnote references.
Midwest ISO	No	Table 1 Steady State & Stability Performance Planning Events, Note "b": It states that consequential generation loss is acceptable; however, there is no definition of this in the definition section. We suggest having the following definition of Consequential Generation Loss added to the definition section. Table 1 There appears to be a few typos on P3, P4 and P5 note references because there are no Note 19 nor Note 101. Please clarify this. Table 1 Steady State & Stability Performance Planning Events: We believe that this table should appear right after the requirements but before the VSLs.
Response: It appears the commenter intended to suggest a definition for consequential generation loss but neglected to include its proposed definition. Regardless, the SDT considered the need for such a definition and concluded no definition was needed. No change made. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The SDT agrees with the commenter's recommendation to move Table 1 within the standard so that it follows directly after the requirements. This change was made in Draft 5.		
Florida Municipal Power Agency, and its Member Cities	No	Table 1, under Steady State & Stability, "a" states: "BES Transmission voltage instability, cascading outages and uncontrolled islanding shall not occur." There are small portions of the grid where there may be three long lines feeding a load, and if two of those two lines were lost (P6 for instance), the remaining line would go into voltage collapse losing a few hundred MWs of consequential load with no impact to the BES. FMPA suggests that the wording be appended by: "BES Transmission voltage instability, cascading outages and uncontrolled islanding shall not occur for P0 through P2. BES Transmission voltage instability, cascading outages and uncontrolled islanding causing a supply / demand mismatch of more than the largest single loss of source shall not occur." FMPA does not understand why a bus-tie breaker would be treated differently than another breaker. They both have the same chance of failure.
Response: The SDT considered the proposed change to note "a" but did not accept the proposed change. For the situation described, System adjustments are permitted between the outages of a P6 event to minimize the impact. Additionally, following the second outage the use of an SPS could be used to further minimize		

Organization	Yes or No	Comments for Question 10
the impact and avoid an unstable System condition. The team agrees that any breaker has an equal chance for failure due to a fault. However, when lumped together with all the BES line breakers and transformer breakers, the Bus-tie Breaker application is much less prevalent within the BES when considering all beaker fault possibilities. The SDT recognizes that Bus-tie Breaker applications are used to lessen the impact of a bus fault outage (P2.2). Therefore, in regards to meeting the single Contingency breaker fault condition the SDT felt it was necessary to differentiate between performance expectations between bus-tie and non bus-tie breakers. See P2.3 and P2.4 planning events.		
Manitoba Hydro	No	Table 1:1. When two (or more) footnotes apply simultaneously they should be separated by commas; ot are these typos? 2. The P2 contingency "opening of a breaker without a fault" could be moved up to a P1 contingency. This is a higher probability event then a bus section fault. 3. P4, Event column: The 11 superscript, after the phrase "Loss of multiple elements....", should be a 10. In P3, should 19 be 9? 4. Footnote 9: The drafting team clearly permits generator redispatch coupled with curtailment of firm transmission service for multiple contingencies (P3-P5). We believe generator redispatch is appropriate for P1 and P2 as well. R2.7.1 lists several actions that are permitted to be used as corrective plans including Special Protection Systems, automatic generator tripping or manual generator runback to respond to both single and multiple contingencies. Any loss of generation will require redispatch to ensure emergency generation reserves are replenished and the system is ready for the next contingency. For contingency P1, loss of generator, load will not be lost because there are generation reserves, however redispatch will be required to restore these reserves. Footnote 9 should apply to P1 and P2 contingencies. 5. Footnote 11: This note is a reference for a common tower outage. I think the words "or common Right-of-Way" should be deleted from the sentence. It is obvious that circuits on a common tower must be on a common Right-of-Way. 6. Note b: Consequential generation loss could use a definition similar to consequential and non-consequential load loss to add clarity. The standard as written in R4.1.2 permits cascade tripping of generators due to pulling out of synchronism. Typically this has been defined as instability or cascade tripping and not permitted in the past. 7. Note i: note i implies that any voltage sensitive load or load dropped by end-user equipment shall not be used to meet steady-state performance requirements. However, given that this note is not included under the stability portion, does this mean that voltage sensitive load or load that is dropped by end-user equipment can be used to meet the TC and PC planning criteria established in R5? Induction motors could trip in the stability analysis if the transient voltage is low enough (non-consequential load loss). The R5 criteria will be met as long as the load is manually switched back in and the post-disturbance steady state loading is acceptable. Can the drafting team

Organization	Yes or No	Comments for Question 10
		clarify the intent of Note i?

Response:

1. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.
2. The SDT did not accept the proposed change for the placement of the P2.1 planning event into the P1 group.
3. As noted above, errors in reference to various Table 1 footnotes are recognized by the SDT and have been corrected in Draft 5.
4. The SDT agreed with the commenter and footnote 9 was added to the P1 and P2 events in regard to the column titled "Interruption of Firm Transmission Service Allowed"
5. Common structure may be interpreted as common ROW but Common ROW does not necessarily equate to common structure. Since the wording is 'or', it covers both circumstances. No change made.
6. The SDT does not believe a definition to differentiate between consequential or non-consequential generation loss is needed since generation tripping and re-dispatch is permitted as a corrective action for all planning events as stated in Requirement R2, part 2.7.1.
7. Table 1, note "i" is intended to clarify that even if it is known that an end-user who implements a more conservative practice than that of the Transmission Planner/Planning Coordinator regarding steady-state voltage criteria and chooses to interrupt its own Load, the end-use Load must still be represented in the steady-state timeframe. The Load tripping is permitted in a Stability review, however, it should be assumed that a customer will react quickly to restore its Load and therefore the standard requires the Load be represented in the steady-state timeframe. Only actions (manual or automatic) taken by the Transmission Planner/Planning Coordinator are permitted for consideration for a steady-state review.

NERC System Protection and Control Subcommittee (SPCS)	No	The Drafting Team should modify the P5 Category column in Table 1 to read "P5 Multiple Contingency (Fault plus Protection System failure to operate). "This addition will focus the P5 Category on the overall Protection System failure to operate." The Drafting Team should include requirements in P5 of Table 1 for simulating both single-phase and 3-phase fault types for Protection System failures to operate.P4 and P5 call for simulations with SLG faults. Prolonged clearing times that result from breaker failures or Protection System failures to operate increase the probability that the fault may evolve from single-phase to multi-phase, and that probability further increases in EHV substations due to the closer clearances of bus work and equipment.Whereas Breaker Failure times are more likely to be known and mitigated through Breaker Failure Protection Systems, the clearing times associated with Protection System failures to operate may be much longer, increasing the probability of evolving in to multi-phase faults. The phrase "or a protection system failure" should be removed from items 2a through 2e in the Extreme Event table following Table 1.If the initializing event is the SLG fault, its evolution to a multi-phase fault alone (due to a Protection System failure to operate) should not be considered an Extreme Event for stability analysis.

Response: While the SDT did not accept the proposed P5 description change a change has been made for clarity. Based on feedback from some commenters the

Organization	Yes or No	Comments for Question 10
SDT made changes to the P5 planning event description as shown in Table 1. The changes are not substantive, do not alter the team's prior intent, and are aimed at clarification only. In regards to include both a SLG and 3-phase for the P5 planning event the SDT respectfully disagrees with the commenter. Based on the SDT's review of historical outage data the SDT believes that a SLG event evolving to a 3-phase item is less likely and that 3-phase fault with Protection System failure is appropriately treated with the standard as an extreme event under extreme event Stability item 2a through 2d. No change made.		
Florida Power and Light	No	The P2-1 event needs to be clarified with its intent. In the SDT Consideration of Comments to the 3rd DRAFT posting, the response to Transmission Planning clarified that "There is no need to show a line energized up to the breakers that opened. The intent is simply to look for low voltage or thermal problems while supplying Load from one end of a normally networked line." This could be accomplished by adding this to footnote 7 or re-naming the event "Opening of a Line Section w/o fault".
Response: The SDT agrees with comments in regard to the P2-1 planning event. A relay mis-operation that inadvertently trips a breaker is the primary reason forced outage cause for a P2.1 event. The condition could also be a planned (maintenance) event. P2.1 has been renamed "opening of a line section w/o a fault" to better align with the teams intent. Additionally, footnote 7 was revised to better clarify the need to study the P2.1 event. Footnote 7 now reads: **Footnote 7** - Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.		
MAPP	No	The table needs to match the stated requirements in R3 & R4
Response: The standard explicitly references Table 1 in both Requirements R3 and R4 regarding the need to address the planning events and extreme events from both a steady-state (Requirement R3) and stability (Requirement R4) timeframe. The standard is written in a manner where both the standard requirements and Table 1 work jointly together to describe study expectations. In short, Table 1 is part and parcel to the standard.		
Hydro-Québec TransEnergie (HQT)	No	There is confusion in interpretation of the Table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading? Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft. Other footnotes appear to be mislabeled as well. If Extreme Events are not deleted from the standard, then a different number for the table for Extreme Events should be used. Extreme Events 2a need to define towerline. Add language to replace towerline with structure. Table 1 Footnotes require a close editorial review. There are two number ones, and multiple items pointing to the

Organization	Yes or No	Comments for Question 10
		wrong footnote or footnotes that don't exist (19, 101), etc. Several instances are discussed below but this is not an exhaustive list. Table 1 Steady State & Stability Performance Planning Events - Note (a) this note is placed under "Steady State & Stability" but issues of voltage instability, cascading outages, and uncontrolled islanding apply only to stability. NPCC suggests this note be relocated to "Stability Only." Table 1 Steady State & Stability Performance Planning Events - Note (i) this indicates that one cannot meet steady state requirements by depending on end-user owned equipment. Please clarify the purpose and performance requirement on this note with respect to end-user schemes and possible arrangements already in place to trip end-user equipment. Table 1, P4 footnote reference in Category column needs to change from 101 to 10. Footnote reference in Event column lead-in description needs to change from 11 to 10. Table 1, P5 As written, this requirement replicates a fault causing a loss of station anywhere that there is only one protection system. This is overly severe and would lead to the requirement for fully redundant protection systems at many stations. The use of the term "Protection System" in P5 is unacceptably inconsistent with the NERC definition of Protection System because it does not exclude the battery and its associated series elements. Battery systems should not be included. Table 1, P7 for Event 1 (the loss of two adjacent circuits), this needs to specify if these are the same phase or different phases.Table 1 Steady State & Stability Performance Extreme Events It appears that for Steady state, item 2, that item (a) is encompassed by (b). It if is not, what makes it different? Table 1, footnote #2 typo there is an erroneous comma in the phrase "are the fault types, that must be evaluated." Please remove said comma. Table 1, footnote #3, HQT, as does NPCC, has asked NERC to put a lower bound on the HV but it seems that this remains unaddressed.More stringent performance requirements should be applied to Facilities that represent the backbone of the electric power grid and act as the medium for moving large amounts of power from production to various Load centers, rather than to those Facilities that directly serve end-use Load customers. However, as had been commented in preceding postings, the EHV breakpoint for these more stringent requirements, defined in note 3 of table 1 as "all Facilities greater than 300 kV", is not appropriately defined and should be reviewed. A uniform voltage-level threshold has not been shown to adequately cover all of the different power systems in North America, and significant additional costs will be incurred without proportional or measurable reliability benefits if this definition is not changed.The following is a proposed modification to the EHV definition "all Facilities greater than 300 kV" :"Facilities representing the backbone of the System, generally operating at voltages greater than 300 kV, as determined by the Planning Coordinator and approved by Regional Entity." In using such language, we believe that the extra investment required would go towards real improvement of the reliability of the Interconnected System. Furthermore, HQT believe that untill the BES/BPS definition debate is settled at NERC and FERC level, the proposed definition permits the use of the performance base methodology to determine the BPS element subjected to this standard. The way the standard is actually

Organization	Yes or No	Comments for Question 10
		written, it can be interpreted as 300 kV and above, wheter it is part of BPS or not. HQT believe it is overly prescriptive and leaves no leeway.

Response: The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV Facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT's intent and it now reads:

> **Footnote 1 -** If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.

Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.

The SDT has retained extreme events and believe it is important to review the extreme events for potential Cascading and if identified complete an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the extreme event(s). The SDT retained the same table reference area for extreme events.

The SDT believes that towerline is a commonly understood term and that the use of "structure" over "tower line" is not a substantive change. No change made in Draft 5 in this regard.

As noted above, errors in reference to Table 1 footnotes are recognized by the SDT and have been corrected in Draft 5.

The SDT disagrees with the commenter's view that Table 1 note "a" is not valid for the steady-state timeframe. The standard in Requirement R6 requires a Transmission Planner/Planning Coordinator to define and document, within their Planning Assessment, any criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. A steady-state review is not prohibited by the standard and may be included within the criteria used.

Table 1 note "i" is intended to clarify that even if it is known that an end-user who implements a more conservative practice than that of the Transmission Planner/Planning Coordinator regarding steady-state voltage criteria and chooses to interrupt its own Load, the end-use Load must still be represented in the steady-state timeframe. The Load tripping is permitted in a Stability review, however, it should be assumed that a customer will react quickly to restore its Load and therefore the standard requires the Load be represented in the steady-state timeframe. Only actions (manual or automatic) taken by the Transmission Planner/Planning Coordinator are permitted for consideration for a steady-state review.

As noted above, errors in reference to Table 1 footnotes are recognized by the SDT and have been corrected in Draft 5.

The P5 event is not a review of individual Protection System components but rather evaluates the loss of a "single Protection System" scheme or design. It is acceptable to simulate that a local (at the same substation) alternate Protection System scheme is still operational when performing a P5 review. The SDT chose this language to align with the SAR titled: Reliability of Protection Systems (Project 2009-7). The SDT believes that the individual component level evaluation of Protection Systems and redundancy requirements should be covered under the PRC standards and has only addressed a single protection scheme failure in the Planning Assessment required for the TPL standard. A Protection System component failure (i.e., battery) that removes multiple Protection System schemes is beyond the P5 planning event. Based on feedback from some commenters, the SDT made changes to the P5 planning event description as shown in Table 1. The P5 is now described as shown below. The changes are not substantive, do not alter the team's prior intent and aimed at clarification only.

Organization	Yes or No	Comments for Question 10
The standard does not specify common or different phase for the P7 planning event and is left to the engineering judgment of the Transmission Planner/Planning Coordinator. No change made. Extreme event 2a does not cover 2b when two or more tower lines are contained in the same Right-of-Way. Extreme event item "2a" is 3 or more circuits on the same tower line or structure. Extreme event item "2b" considers loss of multiple Transmission lines located on a different tower line but within the same the same Right-of-Way. The erroneous comma in footnote 2 has been removed as suggested by the commenter. The SDT has retained the same delineation of the Bulk Electric System (EHV and HV) in Draft 5. No changes made.		
National Grid	No	There is confusion in interpretation of the Table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading? Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft. Other footnotes appear to be mislabeled as well. If Extreme Events are not deleted from the standard, then a different number for the table for Extreme Events should be used. Table 1, P5: The use of the term "Protection System" in P5 is unacceptably inconsistent with the NERC definition of Protection System because it does not exclude the battery and its associated series elements. Extreme Events 2a need to define towerline. Add language to replace towerline with structure. Table 1, footnote #3, change Regional Entity to Regional Reliability Organization.
Response: The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV Facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT's intent and it now reads: **Footnote 1 -** If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The SDT has retained extreme events and believe it is important to review the extreme events for potential Cascading and if identified complete an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the extreme event(s). The SDT retained the same table		

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reference area for extreme events. The P5 event is not a review of individual Protection System components but rather evaluates the loss of a "single Protection System" scheme or design. It is acceptable to simulate that a local (at the same substation) alternate Protection System scheme is still operational when performing a P5 review. The SDT chose this language to align with the SAR titled: Reliability of Protection Systems (Project 2009-7). The SDT believes that the individual component level evaluation of Protection Systems and redundancy requirements should be covered under the PRC standards and has only addressed a single protection scheme failure in the Planning Assessment required for the TPL standard. A Protection System component failure (i.e., battery) that removes multiple Protection System schemes is beyond the P5 planning event Based on feedback from some commenters, the SDT made changes to the P5 planning event description as shown in Table 1. The changes are not substantive, do not alter the team's prior intent and aimed at clarification only. The SDT disagrees with the commenter that the P5 event is a misuse of the defined Protection System term. The SDT believes that tower line is a commonly understood term and that the use of "structure" over "tower line" is not a substantive change. No change made in Draft 5 in this regard. The SDT concluded that the use of Regional Entity is not necessary. Other changes have been made to footnote for clarity based on other comments. **Footnote 3** - Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.		
Northeast Power Coordinating Council--RSC	No	There is confusion in interpretation of the Table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading? Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft. Other footnotes appear to be mislabeled as well. If Extreme Events are not deleted from the standard, then a different number for the table for Extreme Events should be used. Extreme Events 2a need to define towerline. Add language to replace towerline with structure. Table 1 Footnotes require a close editorial review. There are two number ones, and multiple items pointing to the wrong footnote or footnotes that don't exist (19, 101), etc. Several instances are discussed below but this is not an exhaustive list. Table 1 Steady State & Stability Performance Planning Events - Note (a) this note is placed under "Steady State & Stability" but issues of voltage instability, cascading outages, and uncontrolled islanding apply only to stability. NPCC suggests this note be relocated to "Stability Only." Table 1 Steady State & Stability Performance Planning Events - Note (i) this indicates that one cannot meet steady state requirements by depending on end-user owned equipment. Please clarify the purpose and performance requirement on this note with respect to end-user schemes and possible arrangements already in

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		place to trip end-user equipment. Table 1, P4 footnote reference in Category column needs to change from 101 to 10. Footnote reference in Event column lead-in description needs to change from 11 to 10. Table 1, P5 As written, this requirement replicates a fault causing a loss of station anywhere that there is only one protection system. This is overly severe and would lead to the requirement for fully redundant protection systems at many stations. The use of the term "Protection System" in P5 is unacceptably inconsistent with the NERC definition of Protection System because it does not exclude the battery and its associated series elements. Battery systems should not be included. Table 1, P7 for Event 1 (the loss of two adjacent circuits), this needs to specify if these are the same phase or different phases. Table 1 Steady State & Stability Performance Extreme EventsIt appears that for Steady state, item 2, that item (a) is encompassed by (b). It if is not, what makes it different? Table 1, footnote #2 typo there is an erroneous comma in the phrase "are the fault types, that must be evaluated." Please remove said comma. Table 1, footnote #3, NPCC has asked NERC to put a lower bound on the HV but it seems that this remains unaddressed.More stringent performance requirements should be applied to Facilities that represent the backbone of the electric power grid and act as the medium for moving large amounts of power from production to various Load centers, rather than to those Facilities that directly serve end-use Load customers. However, as had been commented in preceding postings, the EHV breakpoint for these more stringent requirements, defined in note 3 of table 1 as "all Facilities greater than 300 kV", is not appropriately defined and should be reviewed. A uniform voltage-level threshold has not been shown to adequately cover all of the different power systems in North America, and significant additional costs will be incurred without proportional or measurable reliability benefits if this definition is not changed.The following is a proposed modification to the EHV definition "all Facilities greater than 300 kV"?: "Facilities representing the backbone of the System, generally operating at voltages greater than 300 kV, as determined by the Planning Coordinator and approved by Regional Entity." In using such language, we believe that the extra investment required would go towards real improvement of the reliability of the Interconnected System.

Response: The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV Facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT's intent and it now reads:

> **Footnote 1 -** If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.

Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected

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the footnote references and a detailed explanation of the changes required are summarized in the above Summary Considerations for Question 10. The SDT has retained extreme events and believe it is important to review the extreme events for potential Cascading and if identified complete an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the extreme event(s). The SDT retained the same table reference area for extreme events. The SDT believes that tower line is a commonly understood term and that the use of "structure" over "tower line" is not a substantive change. No change made. As noted above, errors in reference to Table 1 footnotes are recognized by the SDT and have been corrected in Draft 5. The SDT disagrees with the commenter's view that Table 1 note "a" is not valid for the steady-state timeframe. The standard in requirement R6 requires a Transmission Planner/Planning Coordinator to define and document, within their Planning Assessment, any criteria or methodology used in the analysis to identify System instability for conditions such as Cascading outages, voltage instability, or uncontrolled islanding. A steady-state review is not prohibited by the standard and may be included within the criteria used. Table 1 note "i" is intended to clarify that even if it is known that an end-user who implements a more conservative practice than that of the TP/PC regarding steady-state voltage criteria and chooses to interrupt its own Load, the end-use Load must still be represented in the steady-state timeframe. The Load tripping is permitted in a Stability review, however, it should be assumed that a customer will react quickly to restore its Load and therefore the standard requires the Load be represented in the steady-state timeframe. Only actions (manual or automatic) taken by the Transmission Planner/Planning Coordinator are permitted for consideration for a steady-state review. As noted above, errors in reference to Table 1 footnotes are recognized by the SDT and have been corrected in Draft 5. The P5 event is not a review of individual Protection System components but rather evaluates the loss of a "single Protection System" scheme or design. It is acceptable to simulate that a local (at the same substation) alternate Protection System scheme is still operational when performing a P5 review. The SDT chose this language to align with the SAR titled: Reliability of Protection Systems (Project 2009-7). The SDT believes that the individual component level evaluation of Protection Systems and redundancy requirements should be covered under the PRC standards and has only addressed a single protection scheme failure in the Planning Assessment required for the TPL standard. A Protection System component failure (i.e., battery) that removes multiple Protection System schemes is beyond the P5 planning event Based on feedback from some commenters, the SDT made changes to the P5 planning event description as shown in Table 1. The changes are not substantive, do not alter the team's prior intent and aimed at clarification only. The standard does not specify common or different phase for the P7 planning event and is left to the engineering judgment of the Transmission Planner/Planning Coordinator. No changes made. Extreme event 2a does not cover 2b when two or more tower lines are contained in the same Right-of-Way. Extreme event item "2a" is 3 or more circuits on the <u>same tower line or structure.</u> Extreme event item "2b" considers loss of multiple Transmission lines located on a different tower line but within the same the same Right-of-Way. The erroneous comma in footnote 2 has been removed as suggested by the commenter. The SDT has retained the same delineation of the Bulk Electric System (EHV and HV) in Draft 5. No change made.		
ISO New England	No	We generally agree with the table however our issues are as follows:Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft. Other footnotes appear to be mislabeled as well.

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United Illuminating	No	We generally agree with the table however our issues are as follows:Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft. Other footnotes appear to be mislabeled as well. If Extreme Events are not deleted from the standard, then a different number for the table for Extreme Events should be used. There is confusion in interpretation of the Table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading?P5 The use of the term "Protection System" in P5 is unacceptably inconsistent with the NERC definition of Protection System because it does not exclude the battery and its associated series elements. Extreme Events 2a need to define tower line. Add language to replace "tower line" with "structure". Table 1, footnote #3, change Regional Entity to Regional Reliability Organization.
Central Maine Power Company	No	We generally agree with the table, however our issues are as follows:Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft. Other footnotes appear to be mislabeled as well. If Extreme Events are not deleted from the standard, then a different number for the table for Extreme Events should be used. There is confusion in interpretation of the Table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV

Organization	Yes or No	Comments for Question 10
		autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading?P5 The use of the term "Protection System" in P5 is unacceptably inconsistent with the NERC definition of Protection System because it does not exclude the battery and its associated series elements. Extreme Events 2a need to define tower line. Add language to replace "tower line" with "structure". Table 1, footnote #3 change Regional Entity to Regional Reliability Organization.
Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The SDT has retained extreme events and believe it is important to review the extreme events for potential Cascading and if identified complete an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the extreme event(s). The SDT retained the same table reference area for extreme events The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV Facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT's intent and it now reads: **Footnote 1 -** If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. The SDT believes that tower line is a commonly understood term and that the use of "structure" over "tower line" is not a substantive change. No change made in Draft 5 in this regard. The SDT concluded that the use of Regional Entity in footnote 3 is not necessary. No change made to reflect the proposed Regional Reliability Organization as proposed by the commenter. **Footnote 3** - Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.		
American Transmission Company	No	We suggest the following changes:Note "e" in the Planning Events, Steady State & Stability section – After bulletin item #7 is added to R2.7.1 as proposed above, refer to this bulletin item with wording like, ". . . applicable to the Facility Ratings (as noted in R2.7.1).". Note "a" and Note "b" in the Planning Events, Steady State Only section Both of these notes are stated in the form of a Requirement (e.g. use the verb "shall"), but all requirements should be included in the Requirements section and not introduced (hidden) in the performance notes of Table 1. After R3.3.5 is added as proposed above, replace Note "a" and "b" with wording from R3.3.5, "Applicable System

Organization	Yes or No	Comments for Question 10
		Operating Limits for the planning horizon shall not be exceeded, as stated in R3.3.5.". Note "a" and "b" can be combined and replaced with a single Note because the observance of System Operating Limits related to steady state conditions covers both items. Note "d" in the Planning Events, Steady State Only section This note is stated in the form of a Requirement (e.g. use the verb "shall"), but all requirements should be included in the Requirements section and not introduced in the performance notes of Table 1. After R3.3.6 is added as proposed above, replace Note "d" with wording from R3.3.6, The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to steady state voltage requirements, as stated in R3.3.6. Note "a" and Note "b" in the Planning Events, Stability Only section Both of these notes are stated in the form of a Requirement (e.g. use the verb "shall"), but all requirements should be included in the Requirements section and not introduced in the performance notes of Table 1. After R4.3.5 is added as proposed above, replace Note "a" and "b" with wording from R4.3.5, "Applicable System Operating Limits for the planning horizon shall not be exceeded, as stated in R4.3.5.". Note "a" and "b" can be combined and replaced with a single Note because the observance of System Operating Limits related to stability covers both items P3 Modify the P3 Category performance criteria to apply only to the loss of two generators because the probability of the loss of two base load generators is an order of magnitude greater than the loss of a generator and any other transmission element. We suggest the listing of: the loss of transmission circuit, transformer, shunt device, and single pole of DC line be removed from the P3 Events column. Move the "generator + another element" events to the P6 Category by adding "1. Generator" to the listing in the Initial System Condition (Loss of . . .) column. Item 2.a in the Extreme Events, Steady State section Clarify the meaning of the loss of multiple circuits in Item 2.a by using wording similar to P7. We suggest this text: "a. Loss of three or more circuits that share a common tower." Item 3.b of the Extreme Events, Steady State section " Clarify the reference to actual, historical operating experience in Item 3.b. We suggest this text: "b. Other events based upon actual operating experience that may result in wide area disturbances." Item 2.i of the Extreme Events, Stability State section " Clarify the reference to actual, historical operating experience in Item 2.i. We suggest this text that is similar to Steady State, Item 3.b: "i. Other events based upon actual operating experience that may result in wide area disturbances." Extreme Event sections are not updated to reflect the new footnote numbering (for instance Item 2a and Item 2b of the Steady State column). Footnote 6 " Further clarify the applicable shunt devices in Footnote 6 with this suggested text: "6. Requirements

Organization	Yes or No	Comments for Question 10
		which are applicable to shunt devices, also apply to FACTS devices that are connected to ground, but not instrument voltage transformers or surge arresters."

Response: The SDT in ATC's Q2 comments declined to add the suggested 7th bullet to Requirement R2, part 2.7.1. The list in Requirement R2, part 2.7.1 provides examples of potential corrective actions and includes references to the use of generation tripping/runback when used to meet steady-state or Stability performance requirements. The note "e" in Table 1 is a condition for allowance of planned System adjustments, which could include Operating Plans such as re-dispatch and qualifies that the operating actions must be achievable with the timeframe of an applicable ratings. No change made.

The Table 1 performance requirements are tied to the standard through Requirements R3 and R4. For example in Requirement R3, part 3.1 the requirement indicates "Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1..". Header notes are part of Table 1 and therefore included in part 3.1 of requirement R3. No change made.

The proposed Requirement R3, part 3.3.5 was not adopted by the SDT. No change made.

Regarding note "d" comment - the Table 1 performance requirements are tied to the standard through Requirements R3 and R4.

The proposed Requirement R3, part 3.3.6 was not adopted by the SDT. No change made.

There are no notes "a" and "b" in the Stability only section. The correct reference is "j" and "k". The Table 1 performance requirements are tied to the standard through Requirements R3 and R4. No change made.

The SDT disagrees with the proposed adjustment of moving select generator Contingency outages to new planning event designations. The Table 1 planning event order is somewhat subjective and the SDT believes appropriate expectations were made for generation outages within the P3 event. No changes made.

Item 2.a in the Extreme Events, steady-state the language as shown in Draft 4 already indicates the text requested by the commenter. It's possible that an earlier draft of TPL-001-1 was referenced when making the comment. No change required.

Item 3b in the Extreme Events, steady-state the language as shown in Draft 4 already indicates the text requested by the commenter. It's possible that an earlier draft of TPL-001-1 was referenced when making the comment. No change required.

Item 2i in the Extreme Events, Stability language was revised to "2f" in Draft 4 and already indicates the text requested by the commenter. It's possible that an earlier draft of TPL-001-1 was referenced when making the comment. No change required.

Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.

Regarding footnote 6, the SDT believes the footnote is sufficient. Based on lack of support for the proposed change from other stakeholders the SDT determined no change was needed.

Oncor Electric Delivery	Yes	Errata Changes - Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. Other Footnotes appear to be mislabeled as well. There is lack of clarity in the interpretation of Table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from exceeding its load rating? Conversely, if

Organization	Yes or No	Comments for Question 10
		the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from exceeding its load rating? Table I, item "e" ?It doesn't specify which units can be adjusted following the contingency. This seems to be similar to the fact that the standard doesn't address the base case. Should the standard be clear that you can or cannot rely on generation redispatch? Should failure of a fast start generator to start up be included in the contingency, or is this another level of contingency? Table I, non-consequential load loss under no circumstance is it acceptable to shed non-consequential load to address issues in a future looking system plan. Table 1 Steady State & Stability Performance Planning Events - Note (i) this indicates that one cannot meet steady state requirements by depending on end-user owned equipment. Please clarify the purpose and performance requirement on this note with respect to end-user UVLS scheme and possible contractual arrangement already in place to trip end-user equipment. Table 1, P7 for the DCT, are these the same phase? Table 1 Steady State & Stability Performance Extreme EventsSteady state, item 2, isn't (a) covered by (b) Table 1, footnote #3, NPCC has asked NERC to put a lower bound on the HV but it seems that this remains unaddressed. P5 This test is overly severe since it could assume the total protection system failure and the system would have to rely on remote end clearing. Part of the problem seems to be that the battery is part of the protection system. The intent seems to have been to fail part of one system, not the battery. If the battery is to be excluded, then it should be clearly stated. Extreme Events 2a The term "towerline" should be defined. We agree with the SDT that more stringent performance requirements be applied for the Facilities that do not directly serve end-use load but rather represent the backbone of the electric power grid and act as the medium for moving large amounts of power from production to various load centers.However, as HQT commented on previous draft, we strongly believe that the EHV breakpoint for these more stringent requirements, defined in note 3 of table 1 as "all Facilities greater than 300 kV" is not appropriately defined and should be reviewed. The SDT have not demonstrated that a uniform voltage-level threshold could adequately covers all different power system types in North America and we strongly believe that significant, additional costs will be incurred without proportional or measurable reliability benefits if this definition is not changed.We propose to modify EHV definition "all Facilities greater than 300 kV" by the following " Facilities representing the backbone of the System, generally at voltage greater than 300 kV, as determined by the Planning Coordinator and approved by Regional Entity." In using such a language, we believe that the additional investment required would facilitate real improvement of the reliability of the interconnected System.
Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT		

Organization	Yes or No	Comments for Question 10
		has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV Facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT's intent and it now reads: **Footnote 1 -** If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. Regarding the note "e" reference to re-dispatch. The re-dispatch of any generation permissible for re-dispatch having impact on the Transmission Planner/Planning Coordinator area. The SDT believes that the standard is clear in Requirement R2, sub-part 2.7.1 (Corrective Action Plans) that generation curtailment, tripping and re-dispatch are permissible Corrective Action Plans for both single and multiple Contingency events. Starting of a "fast-start" generation unit appears to be viewed in the context of a corrective action solution to a studied planning event. There may situations like this that lend themselves to sensitivity analysis as required by the TPL-001-1 standard. The SDT respectfully disagrees with the commenter's view related to disallowing Non-Consequential Load Loss for any planning event. The SDT believes they have made the appropriate expectations in not permitting its use for some Contingency planning events involving EHV facilities. A Transmission Planner/Planning Coordinator may implement a more conservative planning approach beyond what TPL-001-1 requires if they believe one is warranted. Table 1 note "i" is intended to clarify that even if it is known that an end-user who implements a more conservative practice than that of the TP/PC regarding steady-state voltage criteria and chooses to interrupt its own Load, the end-use Load must still be represented in the steady-state timeframe. The Load tripping is permitted in a Stability review, however, it should be assumed that a customer will react quickly to restore its Load and therefore the standard requires the Load be represented in the steady-state timeframe. Only actions (manual or automatic) taken by the Transmission Planner/Planning Coordinator are permitted for consideration for a steady-state review. Interruptible Load agreements are permissible and the Load dropped through contractual arrangements with the end-user can be reflected in the steady-state analysis. The standard does not specify common or different phase for the P7 planning event and is left to the engineering judgment of the Transmission Planner/Planning Coordinator. No change made. Extreme event 2a does not cover 2b when two or more tower lines are contained in the same Right-of-Way. Extreme event item "2a" is 3 or more circuits on the <u>same tower line or structure.</u> Extreme event item "2b" considers loss of multiple Transmission lines located on a different tower line but within the same the same Right-of-Way. The SDT believes that tower line is a commonly understood term and that the use of "structure" over "tower line" is not a substantive change. No change made in Draft 5 in this regard. The SDT has retained the same delineation of the Bulk Electric System (EHV and HV) in Draft 5. No changes made.
TIS	Yes	Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft. There is confusion in interpretation of the Table 1 When the voltages class of the contingency element and the

Organization	Yes or No	Comments for Question 10
		monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied?. Please see additional comments provided for R2.
Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV Facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT's intent and it now reads: **Footnote 1 -** If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. See the SDT's response to your comments provided for Requirement R2.		
Platte River Power Authority	Yes	If clarity is given for the "Non-Consequential Load Loss Allowed" column of Yes/No that it refers to the planned shedding of firm load. (see my comment on Definition)
Response: See the SDT's response to your comment in Q9.		
American Electric Power	Yes	In Table 1, footnotes 19 and 101 should probably read 9 and 10. Also, we suggest adding table borders in P4 to more clearly align the columns that correspond to Event 6 (similar use of table borders as was done in P2).
Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The SDT has made changes to the table borders for the P4 planning event per your recommendation.		
Orlando Utilities Commission	Yes	Note 2 regarding three phase faults being sufficient evidence for SLG faults is an excellent addition, thank you. For P3 and P5 it should be made clearer that note 1 AND note 9 apply, maybe by using a comma in-between, not a note 19 that I wasn't able to locate. For Note 9, reading the context it applies only to P3, P5 and P6, but not to P1. To apply this to actual study methodology, in responding to a P1 event Note 9 can not be applied when returning the system to a continuous (sustainable) state. However after those adjustments are made if additional adjustments are needed to make the system "secure", that is prepared for the next event in the P3 or P6 contingency, then note 9 can be applied? Is

Organization	Yes or No	Comments for Question 10
		this a correct understanding?
Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. Footnote 9 is now applied to all "No" items for the column "Interruption of Firm Transmission Service Allowed". Footnote 9 clarifies that Firm Transmission Service can be interrupted so long as appropriate re-dispatch of resources are available and obligated to re-dispatch without any firm Load loss and that Facility ratings are maintained. Planning events P0, P1, and P2 now also include footnote 9 and is allowed both as a System adjustment to prepare for the next event and as a corrective action to the event studied. Please refer to the footnote for more details.		
NYISO	Yes	Question #10. Do you agree with the changes in the performance elements and notes in Table 1? If not, please provide specific comments by note number, note alpha character, or performance category. Yes
Exelon Transmission Planning	Yes	
FirstEnergy Corp	Yes	
Gainesville Regional Utilities	Yes	
Independent Electricity System Operator	Yes	
Progress Energy Carolinas	Yes	
SCE&G	Yes	
PJM	Yes	
ITC Holdings	Yes	none
Response: Thank you for your support of the SDT's work.		

11. The SDT has provided a revised Implementation Plan as part of this posting. Do you agree with the revisions to the Plan? If not, please provide specific comments.

Summary Consideration: There were 5 main comments associated with this question.

1. Thirteen commenters requested clarification to better define the 60 month effective date for certain "raising the bar" performance requirements. The SDT believes that the current language in Section A. 5 of the Standard, with a minor change that the SDT will incorporate in the next draft, is clear. That section, as modified, will state that the five year period starts "beginning on the first day of the first calendar quarter following applicable regulatory approval" of the revised standard.

2. Four commenters indicated that 60 months is not enough time to build major lines, especially if up to 24 months is needed to do the Planning Assessment and develop a Corrective Action Plan. The SDT considered this issue when TPL-001-1, draft 3 was prepared, and the SDT again discussed its position in light of the comments received from this posting. The SDT continues to believe that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. The current draft of TPL-001-1 does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.3 would apply.

3. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control.
   Four commenters believe that it is inappropriate or in violation of Energy Policy Act 2005 for the revised standard to require building new facilities and some also question the requirement to self-report inability to meet Corrective Action Plan requirements. The Corrective Action Plan, however, does not require construction of facilities per se and, therefore, the SDT does not believe that the language in the current draft violates the Energy Policy Act of 2005. Other choices available as part of the Corrective Action Plan besides constructing new facilities include use of interruptible Load contracts, implementation of Demand Side Management programs, and the addition of generation. The SDT understands that there may be certain circumstances where the only viable solution to a performance deficiency is to add a new Transmission Facility. This is no different than situations that Transmission Planners have faced under the current TPL standards as well as voluntary criteria that have existed for many years. The SDT also points out that should a Transmission Planner or Planning Coordinator find that they can not meet the performance requirements by the end of the 60 month transition period, they would need to submit a mitigation plan to their Regional Entity. As long as an acceptable mitigation plan is offered, the intent of the SDT is that the reporting entity will not be subject to penalties.

3. Four commenters pointed out a typographical error that reversed the numbering of Requirements R7 and R8 in the Implementation Plan. The implementation plan has been corrected to reflect the SDT's original intent that Requirements R1 and R7 (not Requirement R8) become effective 12 months after approval and Requirements R2 through R6 plus Requirement R8 (not Requirement R7), with the noted exceptions, become effective 24 months after approval.

4. Three commenters asked for clarification of the parenthetical language applicable to Events P1-2 and P1-3. The parenthetical phrase related to P1-2 and P1-3 is intended to limit the application of the 60 calendar month exception to those situations where footnote b of the existing standards was interpreted to mean that controlled interruption of electric supply to local network customers connected to or supplied by the faulted element is permitted. The SDT took this position in recognition of the fact that a significant number of entities interpret footnote 'b' in this manner and, therefore, the revised standard represents a "raising of the bar" for them.

Organization	Yes or No	Comments for Question 11
Lafayette Utilities System		LUS remains concerned as to the length of time permitted for implementation, and believes that it should be shorter, but would not oppose adoption of version 4, as it has now been clarified, if that is the only issue of concern. There may be ways, outside the standard development process, to limit the financial harms caused to others as a result of the failure to meet the clarified standard during the implementation period.
Response: Many industry entities have expressed concern that the stated implementation period may not be sufficient, particularly for major projects. The SDT believes it has struck the right balance between the differing views, and does not plan to shorten the time permitted for implementation as you have suggested.		
FRCC Transmission Working Group		The implementation plan needs to be clarified that during the first year the existing TPL standards are still in effect. As written it appears that only R1 and R8 are in effect and the existing TPL standards are not.Assessments are a year long process and are based on a year or more worth of studies, the study work and assessment are not executed in a single day. R2 through R7 is unclear what "coming into effect means". Please consider adding the following paragraph:"Entities are not required to alter their annual schedule based on the R2-R7 requirements going into place or have duplicate efforts at assessments in the year the old and new standard overlap. Therefore any assessment performed prior to R2-R7 going into effect shall meet R1, R8 and the prior TPL standards; an assessment under the revised standard is not required until the following annual cycle. An assessment performed after R2-R7 are in effect shall meet these new TPL Standard. The date the assessment is "performed" for the purposes of this phase in, shall be determined by the date the entity began formally sharing results with its neighbors under R8." Please clarify the parenthetical for P1-2 and P1-3. Is the intent of this parenthetical referring to Consequential Load Loss that is allowed for P1 events?
Response: The Implementation Plan has been corrected to reflect the SDT's original intent that Requirements R1 and R7 (not Requirement R8) become effective 12		

Organization	Yes or No	Comments for Question 11
months after approval and Requirements R2 through R6 plus Requirement R8 (not Requirement R7), with the noted exceptions, become effective 24 months after approval. The SDT does not believe that a clarification, as you suggested, is needed to cover the one-year period for months 13 through 24. The NERC standards process is clear that an existing standard that is being revised remains in force until the revised standard becomes effective. The SDT has reviewed your suggested addition to the paragraph that addresses the effective date for Requirements R2 through R6 plus Requirement R8. The SDT does not believe that your suggestion provides further clarification and the SDT has determined that no further change is warranted. The parenthetical phrase related to P1-2 and P1-3 is intended to limit the application of the 60 calendar month exception to those situations where footnote b of the existing standards was interpreted to mean that controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element is permitted. The SDT took this position in recognition of the fact that a significant number of entities interpret footnote b in this manner and, therefore, the revised standard represents a "raising of the bar" for them.		
ERCOT ISO	No	* The implementation plan references revisions to the MOD standards. Should the team submit a SAR for the revision of the MOD standards to ensure TPL needs are considered? As stated in the comments for R1 " if the MOD standards are properly updated, there is no need to state MOD requirements in TPL-001.* Definition comments from Question 9 apply to implementation plan.* The Implementation Plan references R1 and R8 to be effective within 12 months of regulatory approval. R8 per the implementation plan state that the responsibilities of the PC and TP will be defined. This appears to be R7 of Draft 4 and the requirement language does not align. Conversely, the Effective Date should be revised to ensure the references to the requirements align properly. As written it states the assessment should be available before the assessment is complete. * During the 24 month transition period, any entity that can prove compliance with the revised TPL-001 should not have to prove compliance to the old TPL-001 through TPL-004. * The SAR should state that TPL-005 and TPL-006 are to be retired. The only place this has been found is within the implementation plan. It is not an intuitive place to find this information.
Response: The SDT referenced revisions to the MOD standards to establish a record of the need to fill a gap in the overall coordination among the Reliability Standards. The SDT does not intend to submit a SAR; rather the expectation is that NERC will take the necessary action to follow through to address this need at the appropriate point in time. See the SDT's response to your definition comments in Question 9. The Implementation Plan has been corrected to reflect the SDT's original intent that Requirements R1 and R7 (not Requirement R8) become effective 12 months after approval and Requirements R2 through R6 plus Requirement R8 (not Requirement R7), with the noted exceptions, become effective 24 months after approval. The SDT disagrees with your comment regarding demonstration of compliance during the 24 month transition period. At any point in time, one and only one set of TPL related requirements will be in force. It is those requirements that the Planning Coordinator and Transmission Planner must comply with and not future requirements that have not yet become effective. The SDT assumes that in your last comment the reference to SAR should have been Standard (or more precisely "Standard Development Roadmap"). (A Supplemental SAR was posted for comment and added to this project that does address the possibility of retiring TPL-005 and TPL-006.) The SDT agrees with your		

Organization	Yes or No	Comments for Question 11
suggestion, and the Roadmap has been modified to state: "TPL-005 & -006 issues are addressed in the fourth draft and those standards will also be replaced by TPL-001-1. (See page 1, last sentence of section titled "Proposed Action Plan and Description of Current Draft:" In addition, the "Version History" has been updated to indicate that requirements from TPL-005-0 and TPL-006-0 have been incorporated into TPL-001-1.		
NERC Standards Review Subcommittee	No	A. In the implementation plan, the provision which indicates if an entity doesn't construct in time that entity has to report itself as noncompliant. This is a violation of the energy policy act. Since FERC can't force an entity to built, this provision should be deleted. B. This standard does not contain any requirements regarding the implementation of the Corrective Action Plans. So, the wording in this section of "Any entity that cannot fully implement . . . ", should be replaced with wording like, "If the Corrective Action Plans to eliminate the need . . . can not be implemented within 60 calendar months . . . then the Transmission Planner and Planning Authority should work with the applicable Transmission Owner (s) and Regional entity(s) to develop mitigation plans for revised Corrective Action Plans until the implementation issue is resolved". C. The proposed standard implies that the 24 month time period (for R2-R7) and 60 month time period (for specific allowances for selected event categories) run in parallel rather than sequentially. As currently proposed, the effective date for performing analyses and developing subsequent Corrective Action Plans is 24 months. If the identification of new needs and action plans take 24 months, then only 36 months would be left to implement the new corrective action plans. It may not be feasible to install some BES facilities, especially above 300 kV, in less than 3 years. Some EHV projects can take 5 to 10 years to implement depending on the size, complexity, and controversial nature of the project. D. The MRO NSRS suggests that the effective date be stated in more "implementation dependent" terms for this "one time" transient period, rather than specific and possibly inappropriate "fixed timeframe" terms. Consider wording such as "tripping of Non-Consequential Load or curtailment of Firm Transmission Service (in accordance with Requirement R2, part 2.7.5) is allowed until Corrective Action Plans that are based on TPL-001-1 analyses can be implemented".
Response: A. The SDT disagrees with your characterization of the Corrective Action Plan. The Corrective Action Plan does not require construction of facilities per se and, therefore, the SDT does not believe that the language in the current draft violates the Energy Policy Act of 2005. Other choices available as part of the Corrective Action Plan besides constructing new facilities include use of interruptible load contracts, implementation of Demand Side management programs, and the addition of generation. The SDT understands that there may be certain circumstances where the only viable solution to a performance deficiency is to add a new transmission facility. This is no different than situations that Transmission Planners have faced under the current TPL standards as well as voluntary criteria that have existed for many years. The SDT also points out that should a Transmission Planner or Planning Coordinator find that they can not meet the performance requirements by the end of the 60 month transition period, they would need to submit a mitigation plan to their Regional Entity. As long as an acceptable mitigation plan is offered, the intent of the SDT is that the reporting entity will not be considered non-compliant nor will penalties be imposed. The SDT has modified the Implementation Plan to clarify the wording. B. The SDT believes that the requirement language is clear that the Corrective Action Plan shall be implemented. In Requirement 2, part 2.7.5 reference is made to "implementation of a Corrective Action Plan," and in Requirement R2, part 2.7.6 there is a requirement to review "implementation status."		

Organization	Yes or No	Comments for Question 11
C. Your interpretation that the 24 month and 60 month time periods run in parallel is correct. The SDT understands that some large projects that are part of the Corrective Action Plan may take more than 60 months to complete. However, the SDT also believes that some time limit must be placed on the Corrective Action Plan and 60 months was chosen to strike a balance between those commenters who requested more time and those who would like to see corrective actions completed sooner. The SDT also provided a procedure for mitigation in those situations where 60 months was insufficient. It is the intent of the SDT that the development of an acceptable mitigation plan will avoid penalties. D. The SDT considered your suggested restatement of effective dates during the transition period. The SDT does not believe that such a change would materially improve the standard language. In fact, your specific example would be problematic because Requirement R2, part 2.7.5 applies universally not just to the transition period.		
Progress Energy Florida, Inc.	No	As PEF is opposed to TPL-001-1 as a whole, we cannot comment on the details of the Implementation Plan, other than to say that given the fundamental inadequacies of TPL-001-1, PEF does not believe the Standard should be implemented at all.Given that the wording of Question 12 appears to imply that any general comments made in the Question 12 comments section would be unwelcome and disregarded, PEF would respectfully like to make the following comments regarding our overall position on TPL-001-1:PEF filed extensive comments for the 1st, 2nd and 3rd drafts of TPL-001-1 and voiced serious concerns about the consequences that Transmission Owners and ratepayers will undoubtedly face if TPL-001-1 were to be implemented. PEF respectfully asks the SDT to review PEFs previous comments, particularly from the perspective of the ratepayers. The average ratepayer in the U.S. is already experiencing high electricity bills based on fuel pass-through charges and electric utilities? needs to raise rates to successfully operate and maintain the system. Furthermore, the ratepayers have not been involved in this Standard drafting process, and indeed have not even been informed at even the most cursory level. PEF has pointed this out in previous comments, and the SDTs response has been inadequate. Given the erroneous approach of Table 1 in TPL-001-1 to gauge reliability based on whether or not firm transmission service or non-consequential load will be curtailed, implementation of the Standard will dramatically increase ratepayers? already-high rates with little or no appreciable reliability improvement. Additionally, Transmission Owners will be forced to reduce ATC in order to prevent compliance violations, thus shutting out Power Marketers and potentially resulting in construction of more new generation than is really needed. Another major conflict that TPL-001-1 will cause is a rift between the FERC/NERC regulatory environment and the various states? Public Service Commissions (PSC). The major transmission projects that TPL-001-1 will mandate (especially those mandated due to the overly burdensome and unnecessary > 300 kV section) will have to be approved for permitting and funding through Determination of Need hearings at the PSC. When questioned by the PSC on the need for such projects, Transmission Owners will be obligated to admit that the projects really aren't needed but for NERC's new TPL-001-1 Standard, which will undoubtedly result in the PSCs denial of approval. PEF also would like to note that the SDT still has not provided sufficient reason for the need to implement a new TPL Standard. PEF and its fellow members in FRCC have historically demonstrated excellent reliability while performing long-term Transmission Planning under the existing TPL Standards. There simply is no practical reason for improvement on the existing Standards. PEF is aware of the history of the drafting of a new TPL

Organization	Yes or No	Comments for Question 11
		Standard, however, having reviewed FERCs direction to NERC in this matter. Regarding this, PEF feels that NERC should have pointed out the likely consequences to merely following FERCs directions in their entirety; instead, NERC formed a SDT which proceeded to draft a new TPL Standard that satisfied each and every direction FERC had given. This approach has resulted in a draft Standard that is much too stringent, not conducive to significant reliability improvement and prohibitively expensive to implement.In conclusion, PEF strenuously opposes TPL-001-1, and feels the implementation of TPL-001-1 is unfair, irresponsible and unnecessary. PEF furthermore feels that it has sufficiently proven this in previous comments, and will continue to seek additional avenues to ensure that said comments are given proper consideration. TPL-001-1 is thus not in a condition to go to ballot, and it would be highly inappropriate to send this Standard to ballot given the major concerns that PEF and numerous other utilities within NERC have raised.
Response: The wording in Question 12 has created confusion among many commenters and was not intended to imply that if you checked the YES box, the SDT would not consider your comments. The SDT is obligated to consider all comments, make changes in the drafts that the SDT, as representatives of the entire industry, believe need to be made and provide responses to all comments. The SDT has carefully considered the PEF comments throughout the drafting process and has made changes to the drafts based on your comments and those received from the other commenters. Throughout the process, the SDT has been attempting to iterate toward a standard that the industry, as a whole, can support. The SDT, FERC, and the majority of the industry (through their comments) support the need to improve the TPL standards.		
Florida Power and Light	No	Do not understand the parenthetical for P1-2 and P1-3. The language is confusing and needs to be clarified. Isn't it referring to Consequential Load Loss that is allowed for P1 events?
Response: The parenthetical phrase related to P1-2 and P1-3 is intended to limit the application of the 60 calendar month exception to those situations where footnote b of the existing standards was interpreted to mean that controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element is permitted. The SDT took this position in recognition of the fact that a significant number of entities interpret footnote b in this manner and, therefore, the revised standard represents a "raising of the bar" for them.		
MidAmerican Energy Company	No	MidAmerican commends the SDT for changes that improved the Implementation Plan, however, MidAmerican does have a comment about the plan. MidAmerican urges the SDT to modify the implementation plan where it is indicated that any "entity which cannot fully implement their Corrective Action Plan to eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for these performance elements by that date shall self report themselves as being unable to meet the performance requirements of the Reliability Standard." This is essentially requiring an entity to self report for failing to build facilities. The Energy Policy Act of 2005 did not give FERC and therefore, NERC, the authority to require construction of electric facilities. Therefore, this implementation plan is implying an authority that is not given to FERC or NERC. This provision of the implementation plan should be completely deleted from the standard, the provision to state that one is non-compliant for this should be deleted from the standard, or there should be a statement that such a requirement is subject to limitations of the Energy Policy Act of 2005. This is a deal-killer for MidAmerican with regard to voting on this standard. MidAmerican believes that 4.1.2 and 4.3.3 as written would require responsible entities in the industry to add

Organization	Yes or No	Comments for Question 11
		additional modeling of relaying in dynamic stability models of our system. MidAmerican suggests that 4.3.3 be limited to transient swings on facilities 345 kV and above so as to limit this part of requirement 4 to those situations that are most likely to result in cascading. If the SDT determines not to add such a limitation, MidAmerican asks that the implementation time for R4 to be increased. MidAmerican believes that many responsible entities would need 3 years to add these relaying models to system stability models so that the fourth year additional transmission planning analysis in this respect is conducted. MidAmerican urges that the SDT increase the implementation time for R4 from 2 years to 4 years. (MidAmerican may this comment in response to Question 4 as well.)
Response: The SDT disagrees with your characterization of the Corrective Action Plan. The Corrective Action Plan does not require construction of facilities per se and, therefore, the SDT does not believe that the language in the current draft violates the Energy Policy Act of 2005. Other choices available as part of the Corrective Action Plan besides constructing new facilities include use of interruptible load contracts, implementation of Demand Side management programs, and the addition of generation. The SDT understands that there may be certain circumstances where the only viable solution to a performance deficiency is to add a new transmission facility. This is no different than situations that Transmission Planners have faced under the current TPL standards as well as voluntary criteria that have existed for many years. The SDT also points out that should a Transmission Planner or Planning Coordinator find that they can not meet the performance requirements by the end of the 60 month transition period, they would need to submit a mitigation plan to their Regional Entity. As long as an acceptable mitigation plan is offered, the intent of the SDT is that the reporting entity will not be considered non-compliant nor will penalties be imposed. The SDT has modified the Implementation Plan to clarify the wording. Requirement R4, parts 4.1.2 and 4.3.3 do not necessarily require modeling of specific relays. Commercially available software includes a generic relay model which can easily be applied to every branch in the simulation. This generic relay includes assumed zone 1, 2, and 3 characteristics based on the branch impedance. If this model shows impedance swings in a branch element, then the Transmission Planner or Planning Coordinator can either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. The SDT agrees that studying the impact of swings should be limited to the study area. However, the SDT does not believe this should be limited to only high voltage lines. Because Requirement R4, part 4.3.3 does not necessarily require modeling of specific relays (as described directly above), the SDT does not agree that a longer time is needed in the Implementation Plan.		
Oklahoma Gas & Electric	No	OG&E will need every bit of the 60 months time mentioned on page 3 under “Effective Date” to implement all indicated upgrades. There is benefit in hardening the OG&E electrical system for such protection system failures, such as P4 & P5, but it may not be cost effective.
Response: Thank you for your comment.		
Manitoba Hydro	No	Requirement R8, as the standard is currently written, doesn't match the language on page 2 of the discussion provided by the drafting team (i.e. related to determining individual and joint assessments). The drafting team should flip Requirements R7 and R8 so that the implementation plan matches the intent or modify the implementation plan.
Response: The implementation plan has been corrected to reflect the SDT’s original intent that Requirements R1 and R7 (not Requirement R8) become effective 12 months after approval and Requirements R2 through R6 plus Requirement R8 (not Requirement R7), with the noted exceptions, become effective 24 months after approval.		

Organization	Yes or No	Comments for Question 11
Bonneville Power Administration	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
Idaho Power	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
Modesto Irrigation District Transmission Planning	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
NV Energy	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
Pacific Gas and Electric Co.	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
Puget Sound Energy, Inc.	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
Sacramento Municipal Utility District	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
San Diego Gas & Electric Co	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
Southern California Edison (SCE)	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
SRP	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five

Organization	Yes or No	Comments for Question 11
		years from the modeled year or five years from the effective date of this standard.
Western Area Power Adm - RMR	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the Effective Date of this standard.
Xcel Energy	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem, or five years from the modeled year, or five years from the effective date of this standard.
Deseret Power	No	Comments: Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
NorthWestern Energy	No	In the Effective Date section, 60 calendar months is allowed for Corrective Action Plans. When does the 60 month period start? From the day the problem is identified? From the modeled year? Or from the effective date of the standard?
Response: The SDT believes that the current language in Section A. 5 of the Standard, with a minor change that the SDT will incorporate in the next draft, is clear. That section, as modified, will state that the five year period begins "on the first day of the first calendar quarter following applicable regulatory approval" of the revised standard.		
MAPP	No	The last part of the Effective Date section deals with the requirement to submit a Corrective Action Plan, and then to submit a mitigation plan to be approved by the Regional Entity and NERC. Failure do get those done would result in the initiation of "settlement proceedings." This means that entities may be found non-compliant for failure to build facilities. That seems to fly in the face of the EPAct of 2005.
Response: The SDT disagrees with your characterization of the Corrective Action Plan. The Corrective Action Plan does not require construction of facilities per se and, therefore, the SDT does not believe that the language in the current draft violates the Energy Policy Act of 2005. Other choices available as part of the Corrective Action Plan besides constructing new facilities include use of interruptible load contracts, implementation of Demand Side management programs, and the addition of generation. The SDT understands that there may be certain circumstances where the only viable solution to a performance deficiency is to add a new transmission facility. This is no different than situations that Transmission Planners have faced under the current TPL standards as well as voluntary criteria that have existed for many years. The SDT also points out that should a Transmission Planner or Planning Coordinator find that they can not meet the performance requirements by the end of the 60 month transition period, they would need to submit a mitigation plan to their Regional Entity. As long as an acceptable mitigation plan is offered, the intent of the SDT is that the reporting entity will not be considered non-compliant nor will penalties be imposed.		
SERC Dynamics Review Subcommittee (DRS)	No	There is a concern about the last paragraph in the Implementation Plan. It is easy to interpret this language to state that the entity is noncompliant if the performance requirements are not completed within 5 years. The concern is that the 5 year window for meeting the "raising the bar" requirements is still not adequate. For

Organization	Yes or No	Comments for Question 11
		instance, it typically takes 7 to 10 years to build a new 500-kV transmission line - including time required for such processes as federally mandated NEPA environmental reviews. We strongly suggest increasing this time window to 10 years.
Response: The SDT understands that some large projects that are part of the Corrective Action Plan may take more than 60 months to complete. However, the SDT also believes that some time limit must be placed on the Corrective Action Plan and 60 months was chosen to strike a balance between those commenters who requested more time and those who would like to see corrective actions completed sooner. The SDT also provided a procedure for mitigation in those situations where 60 months was insufficient. It is the intent of the SDT that the development of an acceptable mitigation plan will avoid penalties.		
TVA System Planning	No	TVA agrees with the inclusion of P1-2 and P1-3 in the 60 month implementation window. However TVA also strongly suggests that all Planning Events be included in the same implementation window where local load was allowed to be dropped in the past in footnotes b and c of the existing TPL standards. In the first bullet under Effective Date, both Non-Consequential Load Loss and curtailment of Firm Transmission Service can be permitted for certain events up to 60 months. However these actions are not useful for stability related issues. TVA suggests that out of step relaying or other protection method be allowed in for stability related issues when situations do arise that are beyond the control of the TP or PC. TVA is very concerned about the last paragraph in the Implementation Plan. TVA interprets this language to state that the entity is basically noncompliant if the mentioned Corrective Action Plans are not implemented within 60 calendar months. Due to the large amount of work that some utilities will have to meet these new requirements, TVA strongly suggests that the utilities be found compliant if the utilities are still putting a good faith effort forward in trying to meet the new standards, such as for constructing a long 500-kV transmission line that may take at least 10 years to construct TVA still believes that since breaker duty was not included in the previous TPL standards, this should also have a 60 month implementation window as well due to this now becoming a new TPL compliance issue. TVA noted this same comment in Posting #3; however, TVA requests that this be reconsidered due to being a new official TPL requirement like the other new requirements have with the 60 month implementation window. TVA is concerned that the 60 calendar month window for meeting the “raising the bar” requirements is still not adequate. For instance, it typically takes TVA 7 to 10 years to build a new 500-kV transmission line - including time required for such processes as federally mandated NEPA environmental reviews. Strongly suggest increasing this time window to 10 years.
Response: The SDT believes that footnote ‘c’ conditions in the current TPL standards are adequately addressed in the revised standard. The SDT disagrees that Non-Consequential Load Loss is not useful for Stability related issues. The tripping of such Load as part of an SPS could be accomplished quickly enough to improve Stability margins. Furthermore, there is nothing in the revised standard that precludes the use of out of step relaying. The SDT believes that your interpretation of the last paragraph of the Implementation Plan is incorrect. Should a Transmission Planner or Planning Coordinator find that they can not meet the performance requirements by the end of the 60 month transition period, they would need to provide a mitigation plan to their Regional		

Organization	Yes or No	Comments for Question 11
Entity. Although the SDT agrees that the breaker duty requirement is new to this revision of the standard, the SDT does not believe that there is a need to allow a 60 month transition period for this requirement to become effective. Replacing over-dutied circuit breakers can often be accomplished within the 24 month period provided by the effective date of the requirement. In those cases where the replacement could take longer, there are other approaches available to mitigate the over-duty condition. The SDT understands that some large projects that are part of the Corrective Action Plan may take more than 60 months to complete. However, the SDT also believes that some time limit must be placed on the Corrective Action Plan and 60 months was chosen to strike a balance between those commenters who requested more time and those who would like to see corrective actions completed sooner.		
Ameren	No	We appreciate that the Standards Drafting Team has proposed delayed effective dates to allow tripping of Non-Consequential Load or curtailment of Firm Transmission Service for a number of categories of contingency events to allow more time to become compliant. However, we do not look forward to having to self-report non-compliance because the industry and the government changed the planning rules in the middle of the game.
Response: Please note that should a Transmission Planner or Planning Coordinator find that they can not meet the performance requirements by the end of the 60 month transition period, they would need to submit a mitigation plan to their Regional Entity. It is the intent of the SDT that the development of an acceptable mitigation plan will avoid penalties.		
FirstEnergy Corp	No	We disagree with the proposed Implementation Plan. The implementation period for the TPL-001-1 transmission planning standard should be limited to the time needed to transition to the new study requirements. The proposed 5-year implementation for the "raise the bar" aspects of this standard delves into project management and review of capital construction progress which should remain outside the scope of this standard. The standard should only consider if an entity has completed the required studies and has developed Corrective Action Plans to ensure performance criteria is being maintained.Implementation of transmission system action plans depends on the actions of many other functional entities, other than PCs or TPs. PCs and TPs should not be held responsible for the implementation of action plans since they have little or no control over the activities related to implementation. For example, an RTO/ISO may act as both the PC and the TP for its transmission owner or transmission operator membership, however, the RTO/ISO should not be subject to compliance sanctions for incomplete projects that it does not have direct responsibility.FirstEnergy suggests that a new TPL standard is required to successfully accomplish the vision and endpoint that this drafting team has in mind. It is our opinion that the TO, TOP, DP and GO are needed as applicable entities to bring to fruition the capital enforcement projects or operating procedures that are identified by the PC/TP. This TPL-001-1 standard should stop at the conclusion of studies, assessments and development of Corrective Action Plans and a new TPL standard should be developed to address implementation of Corrective Action Plans.
Response: The SDT has considered your position and still believes that the requirement to implement the Corrective Action Plan is appropriate. Furthermore, the SDT does not believe that the standard should apply to additional entities beyond the Transmission Planner and Planning Coordinator. In fact, doing so would tend to make implementation of the Corrective Action Plan more difficult by reducing clarity as to who is the responsible entity. Where the Transmission Planner or Planning Coordinator is an RTO, agreements between the RTO and its members, which typically include the entities you describe, require those members to implement plans		

Organization	Yes or No	Comments for Question 11
developed by the RTO. Where the Transmission Planner or Planning Coordinator is not an RTO, in most cases, they are a vertically integrated utility that includes all of the entities that you describe. In other cases, the Transmission Planner and Planning Coordinator can establish agreements with the entities for which they are providing those services to specify responsibilities for implementation of the Corrective Action Plan.		
American Transmission Company	No	We offer the following comments.This standard does not contain any requirements regarding the implementation of the Corrective Action Plans. So, the wording in this section of "Any entity that cannot fully implement . . . ", should be replaced with wording like, "If the Corrective Action Plans to eliminate the need . . . can not be implemented within 60 calendar months . . . then the TP and PA should work with the applicable TO(s) and Re(s) to develop mitigation plans for revised Corrective Action Plans until the implementation issue is resolved". The proposed standard implies that the 24 month time period (for R2-R7) and 60 month time period (for specific allowances for selected event categories) run in parallel rather than sequentially. As currently proposed, the effective date for performing analyses and developing subsequent Corrective Action Plans is 24 months. If the identification of new needs and action plans take 24 months, then only 36 months would be left to implement the new corrective action plans. It may not be feasible to install some BES facilities, especially above 300 kV, in less than 3 years. Some EHV projects can take 5 to 10 years to implement depending on the size, complexity, and controversial nature of the project. We suggest that the effective date be stated in more "implementation dependent" terms for this "one time" transient period, rather than specific and possibly inappropriate "fixed timeframe" terms. Consider wording such as "tripping of Non-Consequential Load or curtailment of Firm Transmission Service (in accordance with Requirement R2, part 2.7.5) is allowed until Corrective Action Plans that are based on TPL-001-1 analyses can be implemented".The "implementation dependent" approach may allow the removal of all or part of the text on implementation exceptions and mitigation procedures that do not appear to be suitable in an Effective Date section.
Response: The SDT believes that the requirement language is clear that the Corrective Action Plan shall be implemented. In Requirement 2, part 2.7.3 reference is made to "implementation of a Corrective Action Plan," and in Requirement R2, part 2.7.4 there is a requirement to review "implementation status." Your interpretation that the 24 month and 60 month time periods run in parallel is correct. The SDT understands that some large projects that are part of the Corrective Action Plan may take more than 60 months to complete. However, the SDT also believes that some time limit must be placed on the Corrective Action Plan and 60 months was chosen to strike a balance between those commenters who requested more time and those who would like to see corrective actions completed sooner. The SDT also provided a procedure to submit a mitigation plan to their Regional Entity where 60 months was insufficient. It is the intent of the SDT that the development of an acceptable mitigation plan will avoid penalties. The SDT has modified the Implementation Plan to clarify the wording. The SDT also considered your suggested restatement of effective dates during the transition period. The SDT does not believe that such a change would materially improve the standard language. In fact, your specific example would be problematic because Requirement R2, part 2.7.5 applies universally not just to the transition period.		
Tri-State Generation and Transmission Association	No	Yes and No. We see some potential problems.12 months after BOT adoption, R1 maintain system models - becomes effective. Why delay Also 12 months after adoption, R8 distribute planning assessment results - becomes effective. As an assessment cannot be distributed before it is completed, this must be coordinated with R2.24 months after BOT adoption R2 Annual Planning Assessment - timing must coordinate with R8 above.

Organization	Yes or No	Comments for Question 11
Response: The SDT attempted to strike a balance between those commenters who requested more time and those who would like to see some requirements become effective earlier. In the case of Requirement R1, the SDT saw little value in making this requirement effective before 12 months. Furthermore, doing so would break the standard effective dates into yet another time period possibly leading to confusion as to which portions of the revised and old standards are in effect. The implementation plan has been corrected to reflect the SDT's original intent that Requirements R1 and R7 (not Requirement R8) become effective 12 months after approval and Requirements R2 through R6 plus Requirements R8 (not Requirement R7), with the noted exceptions, become effective 24 months after approval.		
American Electric Power	Yes	
British Columbia Transmission Corp	Yes	
Central Maine Power Company	Yes	
Exelon Transmission Planning	Yes	
Florida Municipal Power Agency, and its Member Cities	Yes	
Gainesville Regional Utilities	Yes	
Hydro-Québec TransEnergie (HQT)	Yes	
Independent Electricity System Operator	Yes	
ISO New England	Yes	
Northeast Power Coordinating Council--RSC	Yes	
Northeast Utilities	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates PHI	Yes	

Organization	Yes or No	Comments for Question 11
Progress Energy Carolinas	Yes	
SCE&G	Yes	
SERC Planning Standards Subcommittee	Yes	
Southern Company	Yes	
SRC of ISO/RTO	Yes	
TIS	Yes	
United Illuminating	Yes	
US Bureau of Reclamation	Yes	
Utility System Efficiencies, Inc. (USE)	Yes	
ITC Holdings	Yes	none
National Grid	Yes	None.
NYISO	Yes	Question #11 The SDT has provided a revised Implementation Plan as part of this posting. Do you agree with the revisions to the Plan? If not, please provide specific comments. Yes
Response: Thank you for your input.		
Orlando Utilities Commission	Yes	The phasing in of the higher performance criteria is a very reasonable approach. The implementation plan needs to be painfully clear that during the first year the existing TPL standards are still in effect, and that R1 and R8 are in effect in addition. Most NERC standards have one revision take effect on a specific date, make the old version out of date. In this case however if TPL 001 retires the prior standards, then only R1 and R8 would need to be performed in the first year, which I do not believe that is the intent. In addition to this, further clarification may be needed for the application of R2-R7, even if they were to come into effect the first year. Assessments are a year long process and published once a annually. As an example many entities “publish” or finish the Assessment in December, that being the culmination of months of work. If R2-R7 are effective on June 2011 then the intended application seems to be that the assessment in Dec 2011 should comply with the new

Organization	Yes or No	Comments for Question 11
		standard. Is that the intent, or would there need to be a valid assessment based on the new standard available the day the standard is in effect? Maybe phrasing to this effect. "Entities are not required to alter there annual schedule based on the R2-R7 requirements going into place or have duplicate efforts at assessments in the annual period the old and new standard overlap. Any assessment completed (as determined by the date that the entity formally shared results under R8) after the effective date for R2-R7 shall comply with those requirements."
Response: First, it should be noted that the Implementation Plan has been corrected to reflect the SDT's original intent that Requirements R1 and R7 (not Requirement R8) become effective 12 months after approval and Requirements R2 through R6 plus Requirement R8 (not Requirement R7), with the noted exceptions, become effective 24 months after approval. The SDT does not believe that a clarification is needed to cover the one-year period for months 13 through 24 when Requirements R1 and R7 plus the existing standard will be in effect because Requirements R1 and R7 are new requirements that do not replace any requirements in the existing standards. The NERC standards process is clear that an existing standard that is being revised remains in force until replaced by revised standard requirements becomes effective. The SDT believes that sufficient flexibility was provided in the definition of Year One to permit Transmission Planners and Planning Coordinators to maintain their current assessment schedule if they desire. It is the SDT's expectation that any assessment initiated 24 months or more after the effective date of Requirements R2 through R6 plus Requirement R8 would adhere to the revised standard requirements.		
Duke Energy	Yes	Yes, however we don't understand the meaning of this phrase which follows P1-2 and P1-3: "for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element".
Response: The parenthetical phrase related to P1-2 and P1-3 is intended to limit the application of the 60 calendar month exception to those situations where footnote b of the existing standards was interpreted to mean that controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element is permitted. The SDT took this position in recognition of the fact that a significant number of entities interpret footnote b in this manner and, therefore, the revised standard represents a "raising of the bar" for them.		
PJM	No	The timeframe to gather additional protection and dynamic load modeling data is too short. Millions of pieces of new data will need to be collected and validated before valid models will be available. Extend the period to 24 months.
Response: The SDT does not intend that detailed protection and dynamic Load models will be required for all Transmission elements and Loads in the System models used for the assessments. In particular, Requirement R2, part 2.4.1 states that "An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable." Furthermore, there is no explicit requirement in Requirement R1 for representation of protection schemes. To the extent such detail is needed, it would apply to the Stability studies required as part of Requirement R4. Requirements R2 and R4 are already specified to be effective in 24 months following regulatory approval.		

12. Do you believe that this standard is ready to go to ballot? (if 'No' is checked here, the SDT will consider that comments raised on the other questions drove that decision.)

Summary Consideration: The initial response of the majority of the commenters was that this standard is not ready to go to ballot. The reasons for the negative responses included: 1) a desire to have a sample detailed Planning Assessment, 2) concern over the value of the "raising the bar" for EHV Facilities, 3) concern with excessive study or documentation requirements, 4) concern that the Implementation Plan could be interpreted to require construction (contrary to the Energy Policy Act of 2005), and 5) concern that some of the requirements are not clear and contain ambiguous language. The SDT learned that some commenters voted 'No' to ensure that their comments would be reviewed and considered by the SDT. Other commenters stated that this draft was ready to go to ballot and the remaining commenters stated that it was ready for ballot with favorable consideration of the comments provided.

The SDT has responded to all of these concerns in the responses to the comments. The majority of the issues raised about unclear and ambiguous language were clarified without material changes to the draft. The SDT evaluated the comments provided in response to this draft and has determined that the majority of the remaining 'No' votes are because the commenters disagree with the position(s) taken by the SDT and not because the standard is unclear or unenforceable. The issues that were raised about increased performance requirements, increased study requirements, and increased documentation have been vetted by the industry and the SDT through four posting periods over the last 3 years.

The SDT has posted this standard for four posting periods over the last 3 years. In the previous three postings, the SDT has developed more than 1300 pages of comments and responses. The form of the main requirements and sub-parts has changed in response to industry comment, but the substance of the main requirements and sub-parts has not changed substantially in the last two postings.

The SDT has not made any substantive or contextual changes with this posting and has determined that this standard is ready to go to ballot.

Organization	Yes or No	Comments for Question 12
Sacramento Municipal Utility District		The SDT should develop a detailed sample assessment prior to balloting so that the SDT's hard work can be voted on by an informed ballot pool.
Platte River Power Authority	No	No, not until there is some form of common understanding, among the people reading this draft, of how to interpret from Table 1 (Planned and Extreme) all the contingency scenarios that will be required to demonstrate full compliance with the standard. It would be helpful if the Drafting Team spearheaded some workshops to walk us through how this might be done.
Response: The SDT agrees that it is important to have an informed ballot pool; however, the SDT does not plan to develop a sample assessment prior to balloting. The SDT has taken several steps to inform the industry and will continue those outreach efforts.		

Organization	Yes or No	Comments for Question 12
FRCC Transmission Working Group		We the FRCC TWG feel that the standard is very close to ballot, but the drafting team still needs to address several issues raised in the comments before balloting.
CenterPoint Energy	No	CenterPoint Energy is well aware of the diligence of the SDT in preparing this major consolidation and rewrite of the existing TPL standards. CenterPoint Energy believes this latest version is almost ready for ballot. CenterPoint Energy respectfully requests consideration by the SDT of the refinements to this latest draft proposed by CenterPoint Energy.
FirstEnergy Corp	No	FirstEnergy does not believe the proposed TPL-001-1 standard is ready for ballot until our primary concern with the Implementation Plan as identified in our comment to Q11 is addressed. Additionally, our most pressing secondary concern is the modeling required for Protection Systems related to 4.3.3. Finally, we believe the standard is overly burdensome related to the annual near-term study requirements as stated in 2.1.1 as noted by our Q2 comments.
SERC Dynamics Review Subcommittee (DRS)	No	If the revisions recommended above are adopted, the standard would then be ready for ballot. We commend the drafting team for their efforts in preparing this draft standard for ballot.
SERC Planning Standards Subcommittee	No	If the revisions recommended above are adopted, the standard would then be ready for ballot. We commend the drafting team for their efforts in preparing this draft standard for ballot.
Midwest ISO	No	Only if the proposed changes and questions are adequately addressed.
NorthWestern Energy	No	Since the definition section needs to be changed, some wording in the requirements needs to be modified, and the footnote numbering in Table 1 need to be corrected, we believe another draft should be issued before taking this standard to ballot.
US Bureau of Reclamation	No	The definitions require revisions. Additional work is required to clarify Corrective Action plan items, agreement on votlage limits and acceptable deviations, as well as coordination of Planning Assessment results with owner entities.
SRC of ISO/RTO	No	The proposed changes and comments need to be adequately addressed before any ballot.
Independent Electricity System Operator	No	The standard has become overly prescriptive and unnecessary (see our comments under Q2, Q3 and Q4 on Part 2.1.4, Parts 3.3 to 3.6, Parts 4.3 to 4.5. Much work is needed to condense or remove these requirements.
Hydro-Québec TransEnergie (HQT)	No	There are still issues as indicated in the submitted comments that need to be addressed before this standard should go to ballot.
Northeast Power Coordinating	No	There are still issues as indicated in the submitted comments that need to be addressed before this standard

Organization	Yes or No	Comments for Question 12
Council--RSC		should go to ballot.
Orlando Utilities Commission	Yes	I have not seen all the comments of other entities, so there may be some comments that would require the standard be reposted. Assuming I have correctly read the standard, all of my comments would improve the communication of the existing intent, not alter the requirement.
American Electric Power	Yes	The SDT has done an exceptional job working through complex issues and varying perspectives to arrive at this solid draft. This version has significantly improved the standard and has raised the bar where appropriate to do so. With favorable consideration of comments from this round, the revised draft should be ready for ballot.
Duke Energy	Yes	Yes, assuming our comments are addressed effectively.
American Transmission Company	Yes	Yes, if the proposed changes and questions are adequately addressed.
Response: Please see the comment responses for each question to see how the SDT addressed the issues raised in your comments.		
Xcel Energy	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different.
Response: The SDT agrees that some planning events will result in the same elements being removed from service. However, the similarities may only be valid from a steady-state view point and care must be taken to review the events in the Stability timeframe due to delayed clearing modes that may result from the initiating event. For example, a bus fault and a stuck breaker may each clear a bus; however, the stuck breaker will have different reaction times due to the delayed clearing mode and therefore may warrant a review in a Stability environment. The standard allows the Transmission Planner and Planning Coordinator flexibility in using engineering judgment for the Table 1 events in which it studies for both the steady-state and Stability environments. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission Planner/Planning Coordinator can justify that certain events are duplicative for a given timeframe then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System.		
SCE&G	No	As per our comments.
British Columbia Transmission Corp	No	
Florida Power and Light	No	
Manitoba Hydro	No	

Organization	Yes or No	Comments for Question 12
Northeast Utilities	No	
Pepco Holdings, Inc. - Affiliates PHI	No	
Progress Energy Florida, Inc.	No	
United Illuminating	No	
PJM	No	
Bonneville Power Administration	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.
Idaho Power	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, I believe modifications are necessary prior to taking this standard to ballot.
Modesto Irrigation District Transmission Planning	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.
NV Energy	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.
Pacific Gas and Electric Co.	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.
Puget Sound Energy, Inc.	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.
San Diego Gas & Electric Co	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.

Organization	Yes or No	Comments for Question 12
Southern California Edison (SCE)	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.
Utility System Efficiencies, Inc. (USE)	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, I believe additional modifications are necessary prior to taking this standard to ballot.
Western Area Power Adm - RMR	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, I believe modifications are necessary prior to taking this standard to ballot.
Deseret Power	No	Comments: Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.
SRP	No	: Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.
Response: Please see the comment responses for each question to see how the SDT addressed the issues raised in your comments, including the clarifications that the SDT made concerning the Table 1 outages and footnotes.		
Ameren	No	Certainly the proposed assessment and documentation requirements are more comprehensive and the performance standards are more rigorous than the existing TPL-001 through TPL-004 reliability standards. But, by performing the proposed additional required studies and documenting the results, how much additional reliability will be provided to the System? None, but we will be auditably compliant. More planning engineers will need to be hired to perform the studies and develop the assessments, more librarians will need to be hired to keep track of all the paperwork and computer file storage, and more trees will be killed printing the paper to send to all those that need to review the documents and provide comments. Is this the most effective way to improve transmission system reliability from a planning perspective? What measurable benefits are to be accrued for providing an EHV system that would not result in the loss of non-consequential load for P2-2, P2-3, P4 1-5, and P5 1-5 planning events, all of which are rare and infrequent? What is the estimated cost for this incremental "improvement" to cover the System's short-comings? The EHV system is already the most reliable portion of the BES with an availability of approximately 99% and can withstand extreme events without widespread outages.
Response: The SDT believes that the added clarity of the proposed standard is very important to ensure that entities can clearly understand the requirements. Even though EHV outages are less frequent than outages of lower voltage Transmission Facilities, the SDT believes that there should not be Non-Consequential Load Loss		

Organization	Yes or No	Comments for Question 12
for the single Contingencies in P2 and for the failure of a circuit breaker or Protection Systems in the P4 and P5 events.		
ITC Holdings	No	Comments: In addition to our other comments, ITC offers the following feedback. The requirements are rather complex, yet the measures seem extremely simple. Have they been discussed in any detail and are they sufficiently described to insure and understanding of just what is expected (ie., Are the requirements sufficient as measures in and of themselves?) R2.1.5 for example discusses "spare equipment strategy for long-lead time facilities". If I have a 2p.u. xfmr, can I assume it spares all similar category transformers or would I have to study P0,P1 and P2 contingencies if it replaces a 3 p.u. xfmr. If I don't have a spare and can't meet P0,P1 or P2 contingencies without load shedding, do I need a CAP. See also our comments under R3.4.1. We haven't reviewed all requirements and all measures in this fashion but suggest the SDT do so.
Response: The SDT has reviewed the measures and believe that they are sufficient to measure compliance with the requirements. The issues raised about transformer assumptions are System specific and are, therefore, not addressed by the standard. If you do not have a spare for a piece of equipment with a long lead time and your System cannot meet the performance requirements without that piece of equipment, you must have a Corrective Action Plan to address that deficiency. Part 3.4.1: See response to Q3.		
ERCOT ISO	No	ERCOT recognizes that much effort has been put into this standard. However, a lot of effort will be required to ensure documentation for the standard is sufficient, yet the benefit of the additional documentation effort required is marginal. For a standard like this, stating every possible issue and studying every possible scenario is not realistic and potentially will lead to complacency very little planning outside the scope of this standard will be done regardless of the system needs.
Response: The SDT has attempted to clarify areas where the existing standard is ambiguous. In this effort to clarify, the SDT has introduced new areas where documentation is required; however, in most instances, this documentation was already implicitly required. The SDT believes that it has limited the documentation requirements to the minimum required to ensure thorough evaluation of BES reliability. While the SDT has expanded the scenario analysis required with additional study year requirements and sensitivity requirements, the SDT has not developed an exhaustive list of studies or analysis that the planner must conduct. The SDT believes that the requirements contained within the standard are the minimum requirements necessary to evaluate BES reliability, while continuing to give the planner latitude in the portfolio of studies that the planner will conduct.		
NERC System Protection and Control Subcommittee (SPCS)	No	Inclusion of the changes proposed by the System Protection and Control Subcommittee (SPCS) drove the belief that the standard is not ready to go to ballot. Such changes would be substantial enough to invoke another round of comments by the Industry.
Response: Please see the comment responses for each question to see how the SDT addressed the issues raised in your comments. The SDT has not made substantial changes based on the comments.		
Central Maine Power Company	No	It is closer, but there are still some unacceptable issues that need to be addressed.

Organization	Yes or No	Comments for Question 12
ISO New England	No	It is closer, but there are still some unacceptable issues that need to be addressed. The single most important comment is to define the base assumptions for use in studies.
National Grid	No	It is closer, but there are still some unacceptable issues that need to be addressed.
Response: The SDT has made changes based on the comments. Please see the individual comment responses to see how the SDT addressed the issues raised in your comments.		
MAPP	No	MAPPCOR urges the SDT to modify the effective date where it is indicated that any "entity that cannot fully implement its Corrective Action Plan to eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for the above listed performance elements within 60 calendar months of the compliance date for Requirements R2 through R4 shall self report itself as being unable to meet the performance requirements of this Reliability Standard." This is essentially requiring an entity to self report for failing to build facilities. The Energy Policy Act of 2005 did not give FERC and therefore, NERC, the authority to require construction of electric facilities. Therefore, this implementation plan is implying an authority that is not given to FERC or NERC. This provision of the effective date should be completely deleted from the standard, the provision to state that one is non-compliant for this should be deleted from the standard, or there should be a statement that such a requirement is subject to limitations of the Energy Policy Act of 2005.
Response: The SDT has modified the language in the Implementation Plan to address this concern. Additionally, the last paragraph of the effective date section of the standard was eliminated to address this concern.		
NERC Standards Review Subcommittee	No	More discussion is needed pertaining to this standard.
Response: The SDT believes with the clarifications made in Draft 5 that the standard is ready for ballot.		
Portland General Electric Co.	No	PGE believes that this standard should not go to ballot without revisions to restrict the scope of the standard as outlined above.
Response: The SDT has not restricted the standard to Facilities >200 kV, as proposed in your comment to Q2. The Facilities that make up the Bulk Electric System (BES) are defined by each Regional Entity and this standard must address all of the BES Facilities to ensure reliability of the BES.		
NYISO	No	Question #12 Do you believe that this standard is ready to go to ballot? (if "No" is checked here, the SDT will consider that comments raised on the other questions drove that decision.) No. Too many significant questions and key definitions remain unanswered.

Organization	Yes or No	Comments for Question 12
		Table 1 - General comment - Footnotes needs significant clean-up Page 16 Note (a) this note is placed under "Steady State & Stability" but issues of voltage instability, cascading outages, and uncontrolled islanding apply only to stability Note (f) Does this refer to "Normal Ratings"? Please provide clarity. Note (g) "System steady state" should be defined by applicable regional entity. Note (i) indicates that one cannot meet steady state requirements by depending on end-user owned equipment. Please clarify the purpose and performance requirement on this note with respect to end-user schemes and possible arrangements already in place to trip end-user equipment. Page 17 P5 As written, this requirement replicates a fault causing a loss of station anywhere that there is only one protection system. This is overly severe and would lead to the requirement for fully redundant protection systems at many stations. Page 18 P7 for Event 1 (the loss of two adjacent circuits), this needs to specify if these are the same phase or different phasesPage 19How could any system planner reasonably and accurately portray what contingencies might occur from any single or combination of extreme events listed? PAGE 20 Is the one mile exclusion in footnote 14 a contiguous mile, or a total of one mile for the entire length of the lines? (i.e. Are multiple instances of common towers or common rights of way exempt if each instance is less than a mile?)General Comment:The NYISO would like to align itself in supporting the following comment submitted by the NPCC: We agree with the SDT that more stringent performance requirements be applied for Facilities that do not directly serve end-use Load customers but rather represent the backbone of the electric power grid and act as the medium for moving large amounts of power from production to various Load centers.However, as HQT commented on previous draft, we strongly believe that the EHV breakpoint for these more stringent requirements, defined in note 3 of table 1 as "all Facilities greater than 300 kV" is not appropriately defined and should be reviewed. The SDT have not demonstrated that a uniform voltage-level threshold could adequately covers all different power system types in North America and we strongly believe that significant additional costs will be incurred without proportional or measurable reliability benefits if this definition is not changed.We propose to modify EHV definition "all Facilities greater than 300 kV" by the following "Facilities representing the backbone of the System, generally at voltage greater than 300 kV, as determined by the Planning Coordinator and approved by Regional Entity." In using such a language, we believe that the extra investment required would go towards real improvement of the reliability of the interconnected System.

Response: Footnote references were corrected.

The SDT does not agree that Header Note "a" should only apply in the Stability section, since these conditions should not be allowed to occur in any timeframe.

Header Note "f" is not limited to normal ratings. Facility Ratings are defined in the NERC Glossary as: The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility. Since these ratings are time

Organization	Yes or No	Comments for Question 12
dependent, a rating higher than a normal rating can be utilized, as long as Header Note "e" is maintained. Header Note "g" – The SDT believes that it is appropriate for each Transmission Planner and Planning Coordinator to define the acceptable Steady state voltages. Header Note "i" – The purpose of the restriction is to ensure that the planner develops the System so that all of the Load, including voltage sensitive Load, can be served after an event. The P5 event is a Category C event in the existing Table, and the SDT changed the requirement for >300 kV so that Non-Consequential Load Loss is not acceptable. For the P7 event, it is the responsibility of the planner to evaluate the loss of adjacent circuits as the planner believes is appropriate for their System. For footnote 14, the SDT intends to limit the exposure for multiple circuits to less than 1 mile total. It does not matter whether the exposure is contiguous or not. The SDT declines to add "generally" to the requirements that apply to Facilities operated at greater than 300 kV as that would make the requirements unmeasurable.		
Lakeland Electric	No	The effective section needs more clarification:The assessment and supporting studies in accordance with the new standard is not effective until two years after this new standard is approved, however, it is required (R8) that PCs and TPs distribute its planning Assessment and results to adjacent PCs and TPs one year after the standard is effective. Which standard does the SDT intend for the (the old TPL standards or the new TPL standard) PCs and TPs to use to assess their system during the first year after the standard is approved? R2 thru R7 (assessments and studies) becomes effective 2 yrs after regulatory approval. That means that utilities have three years left to build/upgrade the projects identified in the studies/assessment (which was not effective until the 2nd year). Three years might not be enough to build long EHV or HV lines to meet the standard requirement.What happens between year 5 and year 7? After year 5, utilities are not allowed to trip Non-Consequential Load or curtailment of Firm Transmission Service for those specific contingency listed. However, the utilities do not have to self report until year 7 ("60 months of the compliance date for R2 through R4")
Response: A number of commenters pointed out a typographical error that reversed the numbering of Requirements R7 and R8 in the Implementation Plan. The implementation plan has been corrected to reflect the SDT's original intent that Requirements R1 and R7 (not Requirement R8) become effective 12 months after approval and Requirements R2 through R6 plus Requirement R8 (not Requirement R7), with the noted exceptions, become effective 24 months after approval. Changes were made to the Standard and the Implementation Plan document. Consequently, the revised assessment requirements and Requirement R8 are all effective 24 months after applicable regulatory approval. During the one-year period after Requirements R1 and R7 become effective and before the remaining requirements become effective, Transmission Planners and Planning Coordinators should conduct their assessments based on the current requirements. The SDT considered the concerns of a number of commenters as to whether 60 months will be sufficient to complete major projects when TPL-001-1, draft 3 was prepared, and the SDT again discussed its position in light of the comments received from this posting. The SDT continues to believe that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. The current draft of TPL-001-1 does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.3 would apply. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the		

Organization	Yes or No	Comments for Question 12
Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. ….” This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner’s or Planning Coordinator’s control. All parts of the revised standard will be in effect 60 months after applicable regulatory approval, so there are no unique requirements that exist only between year 5 and year 7.		
Tri-State Generation and Transmission Association	No	The SDT needs to look at the Measures section more closely. Please consider: In what jurisdiction could it be developed, and would it be possible to develop estimates of costs to meet the new requirements contained in this draft TPL by Reliability Area, then have utilities examine whether there will be a corresponding increase in Bulk Transmission System reliability?The primary directive of NERC Reliability Standards is to improve system reliability and thus minimize potential cascading of the Bulk Electric System. This developing TPL Standard will provide some needed clarification and perhaps better uniformity of Planning Study work. Any Standard that would move us toward the primary goal should be attended to meticulously. The SDT must endeavor to ensure this standard moves us in that direction and does not simply give us more structure. That said, please use this guiding test as we put final touches on this standard: Will each Requirement decrease the potential of cascading outages and increase service reliability?
Response: Throughout the development process, the SDT has been cognizant of the changes in the requirements and their potential impact on BES reliability. The SDT believes that all of the requirements and their sub-parts contained in this standard address the NERC directive of ensuring Bulk Electric System reliability.		
Oklahoma Gas & Electric	No	This document needs to be cyrstal clear because of compliance requirements. It still needs some work to clarify some definitions and address duplication of work (between the Transmission Planner and Planning Coordinator).
Response: The SDT has worked diligently to make the requirements very clear and unambiguous. See responses to Q9 for changes made to the definitions in this draft. The SDT has written the standard such that each Transmission Planner and each Planning Coordinator is responsible for each requirement and its sub-parts.		
TVA System Planning	No	TVA is very concerned about the tremendous amount of additional work that has been proposed for both the steady state and for stability analysis. TVA believes that there will be very little payoff for these additional studies. TVA is concerned that the costs to meet the new requirements contained in this draft TPL will amount to between $1 billion to $2 billion with very little impact overall on the reliability of the Bulk transmission system. TVA is also very concerned about the increase in customer rates that will be required to support these new facilities.
Response: The SDT has made efforts to ensure that new study requirements in the proposed standard contribute to the completeness of Planning Assessments and remove the ambiguity in the existing standards. The SDT believes that the higher performance requirements are necessary to ensure a reliable BES.		
Gainesville Regional Utilities	Yes	
Oncor Electric Delivery	Yes	

Organization	Yes or No	Comments for Question 12
Progress Energy Carolinas	Yes	
Southern Company	Yes	
TIS	Yes	
Exelon Transmission Planning	Yes	Concern is with the issues raised in Question 2. Performance requirements should be based on the voltage level of the overloaded element.
Response: Please see the comment responses for Q2 to see how the SDT addressed the issues raised in your comments. The SDT disagrees that the voltage level of the overloaded element should be used to determine acceptable performance.		
Lafayette Utilities System	Yes	LUS believes that the current draft of the standard is a significant improvement on the previous draft, and that the standard is ready to go to ballot. While there are elements of the standard which we consider to be short of the ideal, we recognize that this has been a consensus-building process and that the version 4, as explained and clarified, is a compromise which may be the best attainable for the industry at the moment.
Response: Thank you for your comment.		

Consideration of Comments on Initial Ballot — Assess Transmission Future Needs (Project 2006-02)

Summary Consideration: Due to industry comments, the SDT has made a number of changes to the standard as shown below. In making these changes, the SDT has attempted to be responsive to the information provided in the initial ballot comments while continuing to be responsive to the FERC Order 693 directives. Please note that footnote 12 on non-consequential load loss is currently being utilized as a placeholder. The resolution of this issue will be provided in Project 2010-11. When that resolution is reached, the content will be copied to TPL-001-2.

Year One: The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

Requirement R1 - Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes the normal system condition in Table 1.

Requirement R2 - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.

Requirement R2, part 2.1 - The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, part 2.6, as follows:

Requirement R2, part 2.1.4 - For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

Requirement R2, part 2.1.5 - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

Requirement R2, part 2.4.1 - System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

Requirement R2, part 2.4.3 - For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

Requirement R2, part 2.5 - The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, part2.6. The technical rationale for determining material changes shall be documented.

Requirement R3, part 3.3.1 - Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

- Tripping of generators where simulations show generator bus voltages or high side of the Generation Step Up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.
- Tripping of Transmission elements where relay loadability limits are exceeded.

Requirement R3, part 3.5 - Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

Requirement R4, part 4.3.1 - Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

- Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

Requirement R4, part 4.4 - Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

Requirement R4, part 4.5 - Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

Header note 'a': The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

Header note 'b': Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

Header note 'e': Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

P5. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following:

Extreme event 2d. Loss of all generating units at a generating station.

11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.

12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.

13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

M6. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of documentation specifying any criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity who has indicated a reliability need and that functional entity has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

R8 VSL	The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners, one adjacent Planning Coordinator, or to one functional entity that has a reliability related need and that has submitted a written request for the information, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to more than one of its adjacent Transmission Planners, adjacent Planning Coordinators, or functional entities that have a reliability related need and that have submitted a written request for the information, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herbert Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
Kent Kujala	Detroit Edison Company	3	Abstain	Document is overly complex.
Daniel Herring	Detroit Edison Company	4	Abstain	I don't believe this end product from the consolidation of the TPL standards into one standard turned out the way the industry was hoping it would. This standard is long, complex, and difficult to follow.
Response: The standard covers a number of complex issues and problems. The SDT has made every attempt to avoid unnecessary complexity. No change made.				
Paul Rocha	CenterPoint Energy	1	Negative	CenterPoint Energy believes the proposed standard has strayed far from its original intent as indicated in the 2002 Version 1 SAR and that this proposed standard is now overly prescriptive. CenterPoint Energy also will not support the proposed expansion of mandatory, auditable long term planning requirements beyond the requirements found in the existing TPL standards and the intent reflected in the 2002 version 1 SAR. This concern is exacerabated by the expansion of stability studies and corrective action plan requirements applied to the long term planning horizon.
Response: The SDT is providing clarity around all of the requirements consistent with the intent of the existing standards, the approved 2002 SAR, and the approved 2006 Supplemental SAR. No change made.				
Gregory L. Pieper	Xcel Energy	1	Negative	No comment.
Response: Without any specific comments to address, the SDT is unable to further address your concerns. No change made.				
Charles Locke	Kansas City Power & Light Co.	3	Negative	The standards are overly prescriptive and will increase industry costs substantially without materially improving customer service or reliability, and I believe they go significantly beyond the original standard. If the reason for a new standard is to clarify interpretation problems with Table I performance, that should be addressed without all the additional requirements that are added in the new standard.
Thomas Saitta	Kansas City Power & Light Co.	6	Negative	
Response: The SDT is providing clarity around all of the requirements consistent with the intent of the existing standards. The SDT has attempted to balance				

Voter	Entity	Segment	Vote	Comment
reliability versus cost based on responses to comments in previous postings. No change made.				
Saurabh Saksena	National Grid	1	Affirmative	1. An annual study shouldn't be required for all areas. A documented assessment based on past studies should be adequate for some areas. 2. Years 5 and 10 need to be defined. It appears that the difference between Year One and year 5 is only 3 years. 3. In Table 1, event P5 is not clear enough to communicate that it doesn't include the failure of a single element such as a battery, which is included in the NERC glossary definition for a Protection System. 4. Part 2.7.2 should include Runback or tripping of HVDC in the list of possible actions. 5. Parts 2.1.4 & 2.4.3 should be revised from ' ... the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies ....' to ' ... the sensitivity analysis in the Planning Assessment must vary one or more of the following original conditions in the studies ....'. This will provide a reference similar to a Base Case definition as a reference for the sensitivities and will eliminate the implication of infinitely adding one more sensitivity to the list of sensitivities. 6. The implementation window for part 2.4.1needs to be increased from 24 to 36 months.
Michael Schiavone	Niagara Mohawk (National Grid Company)	3	Affirmative	
Response: 1. The intent of the SDT wasn't that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and Part 2.1. **Requirement R2** - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. **Requirement R2, part 2.1.4 -** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: **Requirement R2, part 2.4.3 -** For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:				

Voter	Entity	Segment	Vote	Comment
2. The SDT believes that this concern is alleviated by the revised definition for Year One. **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013. Then Year 5 would be four years after Year One and Year 10 would be nine years after Year One. Using the example in the definition of Year One, Year 5 would be the 12 month period that includes the forecasted peak load period of either 2016 or 2017, respectively, and Year 10 would be 2021 or 2022, respectively. 3. The SDT has changed the text for the P5 event and added a footnote 13 as a result of your (and others') comments to address these concerns. **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following: **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94). 4. The SDT assumes that you meant Requirement R2, Part 2.7.1. As stated, the list is not all inconclusive but a list of possible actions. The SDT agrees that runback or tripping of HVDC would be allowable actions. No change made. 5. The SDT agrees that the current wording may be confusing and has made a change to promote clarity in this area. **Requirement R2** - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. **Requirement R2, part 2.1.4 -** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: **Requirement R2, part 2.4.3 -** For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: 6. The SDT has reviewed similar comments from earlier drafts and believes that the implementation timeframe for this item is appropriate. Without any further specific reasons, the SDT is unable to address your concerns. No change made.				

Voter	Entity	Segment	Vote	Comment
Linda Brown	San Diego Gas & Electric	1	Affirmative	1. The new standard is supposed to be a performance based standard, but goes beyond performance by suggesting solutions (2.7.1). 2. The new standard is an overly wordy and poorly organized version of the original four TPLs. In order to understand a requirement, the reader must jump to different sections in the document. 3. The new standard is poorly written making it confusing. For example, R2.1.1 says "System peak Load for either Year One or year two, and for year five". I think it means, "study the system as it may exists 5 years from now and as it may exist either one year from now, or two years from now." 4. Section R2.1.4 of the new standard requires Real and Reactive forecasted load. This makes no sense. To my knowledge, no one forecasts reactive load. They assume a power factor and using the real power load and the assumed power factor, they calculate the reactive load. 5. The load modeling requirement may take some time to achieve. 6. It asks for sensitivities that assume generation that may never be built. 7. The Corrective Action Plan doesn't define who gets the plan. It just says to make one. 8. The new standard makes requirements out of practices. For example, section 3.3.3 requires relay loading actions to be part of the analysis. Any competent transmission planning engineer does this.

Response: 1. The proposed standard clarifies allowable solutions but doesn't mandate any particular solution without deviating from performance-based requirements. No change made.

2. Without any specific comments to address, the SDT is unable to further address your concerns. No change made.

3. The SDT does not think the requirement is poorly worded nor are there other comments about this particular wording. Your assumption is correct but does not add any additional clarity. No change made.

4. Since the reactive Load is based on a forecast of the real Load, the SDT chose to characterize both real and reactive Loads as forecasts. No change made.

5. The SDT assumes that you are referring to the induction motor Load modeling required for Stability studies. The standard permits an aggregate model assumption that can be applied for a given system that is not substation specific. The SDT believes that 24 months is an adequate time period to accomplish this task. No change made.

6. The SDT has made a change to the requirements to promote clarity in this area. Generation is just one of the examples of what could be studied.

> **Requirement R2** - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.

Voter	Entity	Segment	Vote	Comment
Requirement R2, part 2.1.4 - For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: **Requirement R2, part 2.4.3 -** For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: 7. The Corrective Action Plan isn't delivered separately as it is part of the Planning Assessment. Requirement R8 specifies availability of Planning Assessments. No change made. 8. The SDT wrote the requirements for the proposed standard based on reliability-based needs for a continent-wide standard for transmission planning purposes and have been vetted through multiple industry comment periods. Requirements are often based on existing practices. No change made.				
Dana Cabbell	Southern California Edison Co.	1	Affirmative	1. We recommend moving the EHV and HV definition from the Performance Table footnote to "Definitions of Terms used in Standard" section. 2. While draft 5 of this proposed standard is a substantial improvement over the previous drafts and the existing TPL standards, there are still areas where additional clarity is needed. We believe that a workshop, after FERC approval of the standard, where issues can be discussed and clarified will go a long way towards smooth implementation of this proposed standard. Some of the areas that require additional clarification are: o Application of consequential and non-consequential load and the EHV and HV voltage levels o Discussion on what is needed to study the various Planning Events. One example is P5, which involves "failure of a single protection system." 3. We recommend the following slight modification to the specified subrequirements of R2 to include clarifying references to R3 and R4 as follows: o 2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: o 2.2. The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6:

Voter	Entity	Segment	Vote	Comment
				o 2.4. The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, part 2.6. The following studies are required in accordance with R4: o 2.5. The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported in accordance with R4 by current or past studies as qualified in Requirement R2, part 2.6
Response: 1. The EHV/HV differentiation is not meant to be a definition in that it only applies to this standard. No change made. 2. The SDT has held several webinars on this project and may well hold another before the project is complete. In addition, the SDT has performed numerous outreach activities to regional entities, sub-committees, etc., on the details of the standard. The project has been presented several times at the NERC Standards Workshops. Once the standard is approved by FERC, the SDT ceases to exist. Therefore, any activities subsequent to that approval would be under general NERC jurisdiction. The SDT suggests that you broach this idea with NERC staff. Also, the SDT has clarified P5 in this revision. 2.1 & 2.2 – The SDT feels that the linkage between requirements is properly cited in Requirement R3 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made. 2.4 – Part 2.4 is already part of Requirement R2 so no additional reference is required. No change made. 2.5 - The SDT feels that the linkage between requirements is properly cited in Requirement R4 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made.				
Thomas J. Bradish	RRI Energy	5	Affirmative	I support the WECC position paper on this subject. Namely: 1. While draft 5 of this proposed standard is a substantial improvement over the previous drafts and the existing TPL standards, there are still areas where additional clarity is needed. We believe that a workshop, after FERC approval of the standard, where issues can be discussed and clarified will go a long way towards smooth implementation of this proposed standard. Some of the areas that require additional clarification are: o Application of consequential and non-consequential load and the EHV and HV voltage levels o Discussion on what is needed to study the various Planning Events. One example is P5, which
Scott Kinney	Avista Corp.	1	Affirmative	
Dennis Malone	El Paso Electric Company	1	Affirmative	

Voter	Entity	Segment	Vote	Comment
Richard J. Padilla	Pacific Gas and Electric Company	5	Affirmative	involves "failure of a single protection system." 2. We recommend the following slight modification to the specified subrequirements of R2 to include clarifying references to R3 and R4 as follows: o 2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: o 2.2. The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: o 2.4. The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, part 2.6. The following studies are required in accordance with R4: o 2.5. The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported in accordance with R4 by current or past studies as qualified in Requirement R2, part 2.6
Response: 1. The SDT has held several webinars on this project and may well hold another before the project is complete. In addition, the SDT has performed numerous outreach activities to regional entities, sub-committees, etc., on the details of the standard. The project has been presented several times at the NERC Standards Workshops. Once the standard is approved by FERC, the SDT ceases to exist. Therefore, any activities subsequent to that approval would be under general NERC jurisdiction. The SDT suggests that you broach this idea with NERC staff. 2.1 & 2.2 – The SDT feels that the linkage between requirements is properly cited in Requirement R3 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made. 2.4 – Part 2.4 is already part of Requirement R2 so no additional reference is required. No change made. 2.5 - The SDT feels that the linkage between requirements is properly cited in Requirement R4 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made.				
Chifong L. Thomas	Pacific Gas and Electric Company	1	Affirmative	1. While draft 5 of this proposed standard is a substantial improvement over the previous drafts and the existing TPL standards, there are still areas where additional clarity is needed. We believe that a workshop, after FERC approval of the standard, where issues can be discussed and clarified will go a long way towards smooth implementation of this proposed standard.

Voter	Entity	Segment	Vote	Comment
				Some of the areas that require additional clarification are: o Application of consequential and non-consequential load and the EHV and HV voltage levels o Discussion on what is needed to study the various Planning Events. One example is P5, which involves "failure of a single protection system." 2. We recommend the following slight modification to the specified sub-requirements of R2 to inserting "in accordance with R3" or "in accordance with R4" to clarify references to R3 and R4, respectively, as follows: o 2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: o 2.2. The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: o 2.4. The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, part 2.6. The following studies are required in accordance with R4: o 2.5. The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported in accordance with R4 by current or past studies as qualified in Requirement R2, part 2.6 3. As proposed, Non-Consequential Load Loss is defined as "Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment". As voltage at the fault goes to zero, and voltages in the parts of the system near the fault become very low, some voltage sensitive Loads may be tripped, and, as a result may not "ride through" the fault. Would this types of Load loss be covered under item (2), "the response of voltage sensitive Load" during the transient dynamic study, as long as the TP and PC model these Loads as connected to the system in the post-contingency steady state power flow representation?
Response: 1. The SDT has held several webinars on this project and may well hold another before the project is complete. In addition, the SDT has performed numerous outreach activities to regional entities, sub-committees, etc., on the details of the standard. The project has been presented several times at the NERC Standards Workshops. Once the standard is approved by FERC, the SDT ceases to exist. Therefore, any activities subsequent to that approval would be under				

Voter	Entity	Segment	Vote	Comment
general NERC jurisdiction. The SDT suggests that you broach this idea with NERC staff. 2.1 & 2.2 – The SDT feels that the linkage between requirements is properly cited in Requirement R3 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made. 2.4 – Part 2.4 is already part of Requirement R2 so no additional reference is required. No change made. 2.5 - The SDT feels that the linkage between requirements is properly cited in Requirement R4 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made. Yes, your assumptions are correct.				
Timothy VanBlaricom	California ISO	2	Affirmative	2.1 The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, part 2.6: 2.2 The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, part 2.6:
Response: 2.1 & 2.2 – The SDT feels that the linkage between requirements is properly cited in Requirement R3 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made.				
Paul B. Johnson	American Electric Power	1	Affirmative	AEP appreciates the extensive efforts by the SDT to develop the version of this standard that is presently before the industry for ballot. The proposed version addresses much of the confusion that exists with the current standards that it will replace. The SDT should be commended for having gone to great lengths to explain the interpretation of this revised standard as part of its reply to industry comments. Adherence to this standard should result in a sufficiently reliable system by narrowing the broad interpretations that have been made of the requirements in the existing standards. AEP believes that the SDT has satisfied enough of FERC's concerns so that FERC will approve this standard if passed by the industry. Therefore, AEP supports approval of this standard. AEP would like to make a suggestion that any future revision of TPL-001-1 should place appropriate restrictions on the use of Special Protection Systems as a permanent solution in the Corrective Action Plan. While AEP recognizes that there are acceptable applications of SPS on a permanent basis, we are concerned that in highly interconnected portions of the grid the use of multiple SPS can cause complex interactions that would be difficult to predict and could lead to unintended consequences. AEP also recognizes that an SPS may be the only practical option on an interim basis.
Raj Rana	American Electric Power	3	Affirmative	
Brock Ondayko	AEP Service Corp.	5	Affirmative	
Edward P. Cox	AEP Marketing	6	Affirmative	

Voter	Entity	Segment	Vote	Comment
Response: Thank you for your response. The SDT will enter a comment in the official NERC issues database on your concern about permanent SPS solutions. That will assure that a future drafting team will address your concern.				
George R. Bartlett	Entergy Corporation	1	Affirmative	Entergy appreciates the work of the drafting team and recognizes the challenges associated with complexities of this effort. Entergy is voting "Affirmative" on the proposed standard but would appreciate the SDT consideration of the following comments in any further efforts to improve the standard: 1. The implementation plan is simply too aggressive. Locating and building transmission facilities continues to become more time consuming. Even lower voltage facilities can take 5 to 7 years to navigate through the various technical and regulatory challenges associated with building these facilities. Entergy would propose extending the implementation plan to 7 years for 230 kV and below, and 10 years for above 230 kV where transmission lines must be constructed. While the SDT has the intent that no penalties be imposed where facilities can not be constructed by the end of the implementation plan, we are concerned that ambiguity may exist may lead to issues should enforcement be left to interpret what is "beyond the control of the Transmission Planner or Planning Coordinator" in R2.7.3 2. 2. P5 in the new table is simply not defined to the extent that a consistent analysis method can be applied throughout the industry. While the process of identifying single points of failure will be time consuming and manpower intensive, it is feasible to complete. However, the consequences of those single points of failure can not be defined with consistency across the industry. Consequences of protection system failures are dependent on fault types, initial system conditions, and other factors which are not and can not be tracked in traditional planning tools. The ambiguities associated with P5 will almost certainly lead to additional standards needs and numerous requests for interpretation. Entergy would propose industry standardized proxies be allowed in lieu of detailed analysis of the interface between protection systems and the delivery aspects of the BES. Proxies could be developed to ensure the industry identifies and avoids events which have recently been associated with single points of failure in a protection system. 3. Entergy believes that more clarity is needed in R2.1.4 and R2.7 concerning sensitivity studies. The determination of when sensitivity study results should warrant mitigation should be left to the Transmission Planner and/or Planning Coordinator. The requirement to document the studies and their results will proved transparency and allow for transmission improvements through normal stakeholder and regulatory processes.

Voter	Entity	Segment	Vote	Comment
Response: 1. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility. 2. The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns. **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following: **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94). 3. The SDT did not receive any other comments in this regard and believes that the wording is clear. No change made.				
Robert Martinko	FirstEnergy Energy Delivery	1	Affirmative	FirstEnergy appreciates the dedication of the Assess Transmission and Future Needs Standards Drafting Team commends the group for their hard work to bring the proposed TPL-001-1 standard to industry for consideration. The TPL-001-1 standard provides greater compliance clarity than what presently exists in vague and open for interpretation TPL standards. The project appropriately consolidates six existing TPL standards into a single standard, while driving the industry to needed robust planning reviews. The team has carefully considered the industry feedback during the standards development and made many adjustments to better clarify the requirement language. The team is also commended for the improvements made to the Performance Table describing steady-state and stability performance expectations and creating the distinction between Planning Events and Extreme Events. FirstEnergy is voting to AFFIRM the standard and offers the following suggestions to the standards drafting team for areas of improvement and a more appropriate transition to the TPL-001-1 standard. 1) YearOne Definition: FirstEnergy requests that the team consider a change so that Year One is the planning window that begins 12-18 months from the "start" of the current calendar year, and not
Kevin Querry	FirstEnergy Solutions	3	Affirmative	
Douglas Hohlbaugh	Ohio Edison Company	4	Affirmative	
Kenneth Dresner	FirstEnergy Solutions	5	Affirmative	

Voter	Entity	Segment	Vote	Comment
Mark S Travaglianti	FirstEnergy Solutions	6	Affirmative	from the "end" of the calendar year. This change is needed so that minimal adjustments are needed to the ERAG MMWG model building process, which is the basis for planning models used by many within the Eastern Interconnection. The change would still meet the team's intent of requiring the industry to plan beyond current year load periods which are appropriately considered an operating timeframe in the context of TPL-001-1. If the team does not agree to this change for use in the TPL-001-1 standard, we ask the team to consider adding an Entity Variance that would permit the proposed change within the Eastern Interconnection. 2) Implementation Plan: The 60-month transition, as reflected in the team's Implementation Plan, may not be sufficient time for completion of new transmission facilities that may be needed as part of a Corrective Action Plan. The Implementation Plan calls for a 60-month period that is in parallel to the 24-month transition period for completing new model and study expectations per the TPL-001-1 standard. The proposed standard raises study expectations in a number of areas such as removing load shedding for n-1 conditions, more detailed load modeling regarding induction motor loads, developing and documenting transient voltage criterion, etc. FirstEnergy believes it is more appropriate for the 60-month transition for completed Corrective Action Plans to be sequential to the 24-month transitional items. It will take industry some time to transition to the new model and study expectations and industry should be allotted a full 60 months for the completion of major transmission infrastructure that may be included in Corrective Action Plans. 3) Two Near-Term Studies: FirstEnergy supports a need for "fresh" annual steady-state studies being completed for both the Near-Term and Long-Term planning horizons as reflected in requirement 2.1 which states "... be supported by the following annual current studies ...". However, we continue to stress that the need for two studies in the Near-Term horizon (requirement R2.1.1) creates unnecessary burden on industry resources, especially in light that sensitivity analyses are required for each study year. The focus should be that the Transmission Planner needs to cover the entire planning horizon through past and present (current annual) studies and allow the Transmission Planner more latitude to pick the current annual studies. A single present year study within the Near-term and Long-Term planning horizons, supplemented with past studies should be sufficient to effectively interpolate and extrapolate results to cover the entire planning horizon. To the extent a past study remains a qualified past study (as described in the standard in R2.6) we believe the transmission planner should still have discretion to continue to use those studies as their study time period moves forward.

Response: 1. Based on your comment and those of others, the SDT has revised the definition of Year One.

Year One: The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For

Voter	Entity	Segment	Vote	Comment
example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013. 2. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. 3. The intent of the SDT wasn't that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and part 2.1. **Requirement R2** - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. **Requirement R2, part 2.1 -** The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, part 2.6, as follows:				
William L. Thompson	Dominion Virginia Power	1	Affirmative	o Effective Date - For those raising the bar standards, corrective action plans must be implemented by 60 calendar months. We believe as we have commented previously that for new EHV facilities, this may be difficult to achieve. Our recommendation was to add an additional 24 months to that timeframe. However, they have added Requirement R2.7.3 which allows for situations out of our control to use non-consequential load loss to temporarily resolve violations until the corrective action plans are implemented. Although this does cover us as long as we have a legitimate reason, it does leave to the interpretation of the auditor that the reason is "valid". We therefore still believe more time should be allowed. o Requirement R3.3.2 - Dominion does not agree that the low voltage ride through is a steady-state issue as included in requirement R3.3.2. We foresee demonstrating compliance for this requirement as a difficult if not impossible task hence subjecting the industry to undue non-compliance risk. Furthermore, we believe that low voltage ride through is a dynamic modeling issue covered in requirement R4.3.2. o Assessment time and documentation - Although we do see the need and improvements in the standard, it is clear to Planning that more assessments and documentation will be the end result. It is difficult to determine how much time and resource requirements this will take until we begin implementing the standard. Planning does have a concern that additional resources will be required and have heard this from others in the industry.
Jalal (John) Babik	Dominion Resources, Inc.	3	Affirmative	
Mike Garton	Dominion Resources, Inc.	5	Affirmative	
Louis S Slade	Dominion Resources, Inc.	6	Affirmative	

Voter	Entity	Segment	Vote	Comment
Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility. The SDT voltage ride through is not confined to the dynamic period. There are protection requirements that could result in generator tripping and that must be considered in the steady-state analysis. The SDT has clarified the wording of the requirement. **Requirement R3, part 3.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: • Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. • Tripping of Transmission elements where relay loadability limits are exceeded. The SDT is sensitive to this issue and that is why there is a staggered Implementation Plan. The timeframes are designed to allow entities time to catch up to the new requirements and were derived from a specific question asked of the industry.				
Kim Warren	Independent Electricity System Operator	2	Affirmative	On page 3 of the Implementation Plan it is stated: "For 60 months after the first day of the first calendar quarter following applicable regulatory approval, Corrective Action Plans..." It is unclear how this should be interpreted in those jurisdictions where no regulatory approval is required. For consistency, we recommend the following wording: "For 60 months after the first day of the first calendar quarter following applicable regulatory approval, or, in those jurisdictions where no regulatory approval is required, 60 months after the first day of the first calendar quarter following Board of Trustees adoption, Corrective Action Plans..."
Response: As pointed out in the comment, the wording on page 3 of the Implementation Plan should agree with the wording on page 2. The SDT has made this change. However, due to other comments, the 60 month period has been changed to 84 months. For 84 months after the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required on the first day of the first calendar quarter, 84 months after Board of Trustees adoption, Corrective Action Plans applying to performance elements…				

Voter	Entity	Segment	Vote	Comment
Tom Bowe	PJM Interconnection, L.L.C.	2	Affirmative	PJM is supports the standard because it helps to remove the ambiguity in the existing TPL standards and it promotes actions that will result in an improvement in the reliability of the Bulk Electric System. PJM believes that the draft standard addresses the issues raised in the SAR and by FERC orders 672 and 693. The industry wide webinars conducted during the drafting process were particularly helpful in providing the industry with an additional vehicle to better understand the proposed modifications to the TPL standards and provided an additional avenue for industry feedback to the Standard Drafting Team. While supportive of the standard PJM believes additional clarifying language should be added to the following requirements: R 2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: R 2.1.1. System peak Load for either Year One or year two, and for year five. It should be made clear the intent of the requirement for a "Year One or year two" assessment is to "dovetail" with the operational horizon in order to assess the steady state impact of changes from the system as planned. As currently written, the intent and required depth of the additional "Year One or year two" study is ambiguous.
Response: Part 2.1 is already part of Requirement R2 so no additional reference is required. No change made. Based on your comment and those of others, the SDT has revised the definition of Year One. **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.				
Ronald D. Schellberg	Idaho Power Company	1	Affirmative	Recommend the following slight modification to the specified subrequirements of R2 to include clarifying references to R3 and R4 as follows: o 2.1. ...by the following annual current studies in accordance with R3, ... o 2.2. ...by the following annual current study in accordance with R3, ... o 2.4. ... The following studies are required in accordance with R4: o 2.5. ...and be supported in accordance with R4 by current or past studies ...

Voter	Entity	Segment	Vote	Comment
Response: 2.1 & 2.2 – The SDT feels that the linkage between requirements is properly cited in Requirement R3 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made. 2.4 – Part 2.4 is already part of Requirement R2 so no additional reference is required. No change made. 2.5 - The SDT feels that the linkage between requirements is properly cited in Requirement R4 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made.				
Jason L. Murray	Alberta Electric System Operator	2	Affirmative	While voting affirmative on this standard we agree with the following WECC comments: 1. While draft 5 of this proposed standard is a substantial improvement over the previous drafts and the existing TPL standards, there are still areas where additional clarity is needed. We believe that a workshop, after FERC approval of the standard, where issues can be discussed and clarified will go a long way towards smooth implementation of this proposed standard. Some of the areas that require additional clarification are: o Application of consequential and non-consequential load and the EHV and HV voltage levels o Discussion on what is needed to study the various Planning Events. One example is P5, which involves "failure of a single protection system." 2. We recommend the following slight modification to the specified subrequirements of R2 to include clarifying references to R3 and R4 as follows: o 2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: o 2.2. The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: o 2.4. The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, part 2.6. The following studies are required in accordance with R4: o 2.5. The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported in accordance with R4 by current or past studies as qualified in Requirement R2, part 2.6.

Voter	Entity	Segment	Vote	Comment
				The AESO would also like to add that due to provincial acts, regulations, policies and market structure in Alberta, the AESO and Alberta entities involved in the standards process will consider modifications to this standard when adopting it as an Alberta Reliability Standard. In particular we may need to consider rewording the requirements concerning the use of RAS as mitigation for single and multiple contingencies.
Response: 1. The SDT has held several webinars on this project and may well hold another before the project is complete. In addition, the SDT has performed numerous outreach activities to regional entities, sub-committees, etc., on the details of the standard. The project has been presented several times at the NERC Standards Workshops. Once the standard is approved by FERC, the SDT ceases to exist. Therefore, any activities subsequent to that approval would be under general NERC jurisdiction. The SDT suggests that you broach this idea with NERC staff. 2.1 & 2.2 – The SDT feels that the linkage between requirements is properly cited in Requirement R3 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made. 2.4 – Part 2.4 is already part of Requirement R2 so no additional reference is required. No change made. 2.5 - The SDT feels that the linkage between requirements is properly cited in Requirement R4 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made. Thank you for this information.				
Richard Jones	South Carolina Electric & Gas Co.	5	Negative	"SCE&G appreciates the efforts of the Standard Drafting Team and believes this version of the TPL standard has addressed most of the significant issues found in previous versions. However, SCE&G believes there are several significant issues that need modification or further explanation. 1. SCE&G agrees with other submitted comments that the requirement to complete new transmission construction to meet new performance requirements within 60 months is too short. SCE&G believes that 84 months is more reasonable. 2. SCE&G agrees with comments submitted by Duke Energy that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues, does not provide any real benefit to Bulk Electric System (BES) reliability, and may have unintended negative consequences on reliability and service quality. In many

Voter	Entity	Segment	Vote	Comment
Matt H Bullard	South Carolina Electric & Gas Co.	6	Negative	instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. The standard should continue to allow Transmission Planners to use discretion regarding loss of non-consequential load, such that Transmission Planners, customers, and local regulators jointly control the decision making when BES reliability is not an issue. 3. SCE&G believes there are still different interpretations of Consequential and Non-Consequential Load loss and how each should be applied or not applied. The Standard drafting team should provide several examples in its response to these comments showing how to apply and not apply Consequential and Non-Consequential Load Loss. Without clear examples, SCE&G believes many request for interpretation will be submitted to NERC by the industry."
Response: 1. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1, footnote b order. 2. The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others' concerns in this area. 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. 3. The SDT has clarified the issue of Non-Consequential Load Loss as shown above. Providing examples here of what is Non-Consequential Load Loss versus Consequential Load Loss would have no bearing. The words are what matter and the SDT feels that the clarification provided should alleviate your concern.				
Randi Woodward	Minnesota Power, Inc.	1	Negative	1. Requirement 2 - This requirement states that Stability analyses must be performed as part of the annual Planning Assessments. We would like to see the term "Stability analysis" more clearly defined as there are several different types of stability related analysis that can be performed for power systems including: transient stability, voltage stability and small signal stability. 2. Requirement 2.5 - This requirement states that "Stability analysis shall be assessed to address the impact of proposed generation additions or changes." We would like to see the term "proposed generation" more clearly defined. It is our opinion that only planned generation should be included in the Long-Term Transmission Planning Horizon assessment. In most generation queues there is a very large amount of proposed generation which would be impractical to study. These proposed generation additions are typically included in a System Impact Study which ultimately determines the transmission upgrades required for interconnection. 3. Requirement 2.1.5 - This requirement states that potential impact of the unavailability of major Transmission equipment be assessed annually for equipment (such as transformers) with long

Voter	Entity	Segment	Vote	Comment
				delivery lead times. We believe that it should be acceptable for a Transmission Owner to maintain a spare equipment plan that includes a reliability assessment. This plan would be reviewed and updated annually. We don't believe that a detailed assessment, as part of the Near-Term Transmission Planning Horizon assessment is warranted. 4. Requirement 4.1.2 - This requirement states that apparent impedance swings resulting from generator loss of synchronism shall not result in the tripping of any Transmission System elements. We believe that this requirement, as worded, precludes the use of transmission line out-of-step tripping relays to effectively island or isolate larger blocks of generation that have lost synchronism with the BES. 5. Requirement 4.3.3 - This requirement states that the assessments should simulate the impact of transient swings on Protection System operation. This would imply that detailed models of all transmission protection elements be included in the stability analysis. We believe that this is impractical due to the large number of relays that would need to be modeled. The standard should state that the use of a relay scanning model is an acceptable alternative to using detailed relay models. A scanning model typically monitors the apparent impedance for an established set of transmission lines and flags when the apparent impedances encroach on a classical 3-zone set of distance relay characteristics based on the monitored line impedance.

Response: 1. The SDT intended for the term Stability analysis to include system Stability and unit Stability analyses. These analyses could include all three aspects of Stability that you mentioned. It is left up to the judgment of the Planning Coordinator/Transmission Planner to decide which aspects of Stability may produce more severe results and therefore, must be analyzed. No change made.

2. Each Transmission Planner is governed by rules for when and how proposed generation units will be included in analyses. The current wording of the requirement is to allow for this degree of flexibility to remain part of the planning process. No change made.

3. The SDT has clarified the requirement based on your comments and those of others.

> **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

4. Requirement R4, part 4.1.2 – The SDT agrees that you can't use an out-of-step relay and that the situation you described is a system Stability issue and is considered an application for an SPS which is allowed by the standard. No change made.

5. The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern.

> **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect

Voter	Entity	Segment	Vote	Comment
for each Contingency without operator intervention. The analyses shall include the impact of subsequent: • Successful high speed reclosing and unsuccessful high speed reclosing into a Fault. • Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.				
Robert Pellegrini	United Illuminating Co.	1	Negative	1. Section 2 of the standard requires annual assessment of the system regardless of whether system conditions are essentially unchanged from year to year. This creates unnecessary study work and must be changed in order for UI to support the standard. 2. In Table 1 - Steady State & Stability Performance Planning Events, Category P5 wording for the EHV contingency continues to call for no loss of load in the event of the loss of a single protection system. This requirement as currently worded goes well beyond the intent of the Standard Committee as stated in response to comments as follows: "A Protection System component failure (i.e., battery) that removes multiple Protection System schemes is beyond the P5 planning event". It is UI's opinion that similar language excluding battery system failures should be incorporated into this requirement. 3. UI is concerned that the standard is completely silent regarding base case assumptions and stress levels (loads and interface transfers). The standard should provide some direction or statement of objective regarding base case development and sensitivity testing requirements. For example, the standard should include some statement(s) such as, "base cases(and/or) sensitivity testing must include consideration of reasonable unplanned and planned generation outages". On the other hand UI does not suggest trying to precisely describe the number of generators that should be assumed out of service in this national standard.
Response: 1. The intent of the SDT wasn't that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and part 2.1. **Requirement R2** - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. **Requirement R2, part 2.1 -** The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6, as follows:				

Voter	Entity	Segment	Vote	Comment
2. The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns. **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following: **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94). 3. The SDT is trying to provide guidance without being overly prescriptive. Projected System conditions as well as the types of sensitivities that need to be studied are described. No change made.				
Dan R. Schoenecker	Midwest Reliability Organization	10	Negative	1. Section 2.5 proposed generation is too broad and overly inclusive. It should be replaced with planned or committed. 2. We have a concern that the timeframe of 60-month (5 year) for implementing Corrective Action Plans (CAP), is insufficient. We believe that the implementation timeframe must be extended to seven (7) years. We are aware of Requirement 2.7.3, which covers situations that arise beyond the control of the Transmission Planner (TP) or Planning Coordinator (PC), but believes that the proposed language is ambiguous and maybe problematic for compliance. 3. We believe the spare equipment language doesn't belong in the standard. Whether a Transmission Owner has spare equipment is a risk for that Transmission Owner to evaluate and then take responsibility for the decision. For the Planning Coordinator, inclusion of the spare equipment language would mean that for each Transmission Owner's piece of equipment that cannot be replaced within one year 3 more base cases would need to be run for each season and load level, which may lead to an excessive amount of base case development with little resulting benefit to reliability.
Response: 1. Each Transmission Planner is governed by rules for when and how proposed generation units will be included in analyses. The current wording of the requirement is to allow for this degree of flexibility to remain part of the planning process. No change made. 2. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility. 3. The SDT has clarified the requirement based on your comments and those of others. **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a				

Voter	Entity	Segment	Vote	Comment
lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.				
Roger C Zaklukiewicz	Roger C Zaklukiewicz	8	Negative	1. There does not appear to be a resolution to the issue of BES definition 2. A concern that too many years are required to be studied annually. Are this many studies required especially if there are no substantial transmission infrastructure additions or modifications and virtually no generation resource additions or retirements. 3. At state siting hearings, the Standard has to address the appropriate use of 90/10 or 50/50 peak load forecasts, the requirement to maintain established intra- and inter-transfer limit levels under stressed conditions. Also, more specific requirements regarding appropriate generation dispatches for area studies and large area or regional load flow and voltage studies. 4. Re-think the need or justification for modeling loads dynamically. Simulations of actual system disturbances have represented past actual system responses with a high degree of accuracy.

Response: 1. The SDT does not believe that it needs to define BES. In their March 18th orders, FERC suggested a continent-wide definition of BES. No change made.

2. The intent of the SDT wasn't that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and part 2.1.

> **Requirement R2** - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.
>
> **Requirement R2, part 2.1 -** The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, part 2.6, as follows:

3. The SDT is trying to provide guidance without being overly prescriptive. Projected System conditions as well as the types of sensitivities that need to be studied are described. No change made.

4. Dynamic load modeling is important for correct dynamic simulations. Industry has acknowledged the need for accurate Load modeling and the SDT has codified this need in the proposed standard. No change made.

Voter	Entity	Segment	Vote	Comment
James Tucker	Deseret Power	1	Negative	1. While draft 5 of this proposed standard is a substantial improvement over the previous drafts and the existing TPL standards, there are still areas where additional clarity is needed. We believe that a workshop, after FERC approval of the standard, where issues can be discussed and clarified will go a long way towards smooth implementation of this proposed standard. Some of the areas that require additional clarification are: o Application of consequential and non-consequential load and the EHV and HV voltage levels o Discussion on what is needed to study the various Planning Events. One example is P5, which involves "failure of a single protection system." 2. We recommend the following slight modification to the specified subrequirements of R2 to include clarifying references to R3 and R4 as follows: o 2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: o 2.2. The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: o 2.4. The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, part 2.6. The following studies are required in accordance with R4: o 2.5. The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported in accordance with R4 by current or past studies as qualified in Requirement R2, part 2.6 3. Table 1-P5 Multiple Contingencies (Fault plus Protection System failure to operate) Normal System. There is a significant change in the system normal performance required for EHV systems from the current performance required in TPL-003 (Category C). This TPL-001-1 version does not allow any Non-Consequential load loss (table 1) or firm Demand (note 9) for EHV systems in the event of protection system failure and delayed clearing. This performance requirement would thus preclude use of existing protection systems that rely on remote clearing of interconnected EHV lines or stations if they provide local load service. As written the standard essentially now requires Category B performance rather than Category C performance for multiple contingencies. It is Deseret's opinion

Voter	Entity	Segment	Vote	Comment
				that loss of Non-Consequential load or firm Demand should be allowed for the rare event involving multiple contingencies stated in P5 as long at the load or firm Demand loss is contained and controlled in the local load service area and the event does not impact other interconnected utilities or their loads. 4) Table 1 - Steady State & Stability Performance Planning Events Category P5 (Multiple Contingency (Fault plus Protection System failure to operate). Category P5 requires responsible entities to study the Event titled Failure of a single Protection System that results in Delayed Fault Clearing on one of the following: Generator, Transmission Circuit, Transformer, Shunt Device, or Bus Section. It appears that this requirement is an indication that multiple protection system failure is not allowed under the proposed TPL-001-1. This appears to be a requirement for redundant protection systems for all possible events on all voltage levels of the transmission system. It also appears that this requirement is attempting to define what comprises an adequate protection system. As the draft standard is presently written it appears that multiple protection system failures are not included in this part or any part of the draft TPL-001-1 standard. As written, it is Deseret's view that any multiple protection system failure would be categorized as an Extreme Event under the draft TPL-001-1 standard. Deseret contends that the many and varied issues associated with designing appropriate protection systems should be done in the context of the development of a protection system standard and not in the context of TPL-001-1. In fact, there is currently a proposed standard going through the NERC standards development process which goal is exactly that. If the standards drafting team intends to require responsible entities to have 100% redundant protection systems on all of its BES facilities, Deseret contends that this fact should be stated up front in the standard so that all interested parties may become aware of this requirement and provide informed comment. Deseret believes that it is appropriate to wait until the current protection system redundancy standard under development proceeds through the SAR process and approval system, given that this in an important generic issue that affects the entire industry. Notwithstanding the inappropriateness of raising the protection system issue in the context of a planning standard, Deseret believes that any planning requirement that includes the failure of a single protection system that results in delayed fault clearing must have a very clear definition of the terms "single protection system" and "delayed fault clearing" in or for entities to determine what compliance with the standard requires. The draft TPL-001-1 standard does not have clear definitions of these terms, leaving room for considerable latitude for interpretation by various responsible entities, auditors, and compliance enforcement authorities. Clear, specific, and technically defensible language is needed for these terms.
Response: 1. The SDT has held several webinars on this project and may well hold another before the project is complete. In addition, the SDT has performed numerous outreach activities to regional entities, sub-committees, etc., on the details of the standard. The project has been presented several times at the NERC Standards Workshops. Once the standard is approved by FERC, the SDT ceases to exist. Therefore, any activities subsequent to that approval would be under				

Voter	Entity	Segment	Vote	Comment
general NERC jurisdiction. The SDT suggests that you broach this idea with NERC staff. The SDT feels that the linkage between requirements is properly cited in Requirement R3 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made. Part 2.4 is already part of Requirement R2 so no additional reference is required. No change made. The SDT feels that the linkage between requirements is properly cited in Requirement R4 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made. The SDT agrees that the bar has been raised for the EHV system in that no planned Load shedding (Non-Consequential Load Loss) is permitted for the P5 condition beyond Protection System clearing that responds to the studied P5 event. All Load removed by the Protection System isolating the Fault is Consequential Load Loss for the event. The SAR for this standard recognized FERC orders which indicated a need to "raise the bar" for the industry. The SDT agrees with this premise and is attempting to do this in a reasonable fashion. No change made. The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns. **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following: **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).				
Bernard Pelletier	Hydro-Quebec TransEnergie	1	Negative	The reason for the No vote cast by HQT is that HQT still believe that the EHV and HV threshold defined as a fixed voltage (300 kV) on footnote 3 of Table 1 is too prescriptive, and unnecessary, for NPCC Members using a performance base methodology to determine elements of the BPS. HQT believes that if the 300 kV threshold was introduced as a necessity to reduce the BES portion of the system subject to the Standard in some region with a 100 kV bright line definition of BES so that entities in these regions do not incur prohibitive spending to respect this Standard, there should also be a way to accommodate NPCC Member's use of a performance methodology to determine on which elements to apply the Standards without having entities guessing the way Compliance will be implemented for this Standard in regard to specific voltage threshold. For HQT's system, EHV should correspond to 735 kV since more than half of our 315 kV substations directly supply load. The SDT gave this answer as the rational for choosing the 300 kV threshold when they replied to HQT concerns about the EHV voltage definition as 300 kV and over, in the first posting of the Standard : Â« Systems operated above 300 kV generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers where the energy is then delivered by other Transmission or sub-Transmission Systems to end use customers... Obviously the intent of the SDT when choosing a 300 kV threshold do not correspond to the reality of HQTs system characteristic. HQT agrees with the intent of the SDT to raise the bar in that important Standard but disagree with having to systematically apply the

Voter	Entity	Segment	Vote	Comment
				Standard to all 300 kV and above system. One way to clarify the Standard would be to mentioned in the footnote 3 that :`` In the region where there is a performance base methodology to determine BES element, these BES elements would be subject to the Standard; in other region, the 300 kV threshold would apply.
Response: This standard applies to the BES. If there are areas of your system that are not BES, then the standard doesn't apply to them. This would be true even if those elements are above 300 kV. No change made.				
Donald Gilbert	JEA	5	Negative	Although this proposed standard places additional burden of proof upon JEA's Transmission Planning process, JEA finds the overall direction of the standard requirements prudent. JEA appreciates the allowance of Non-Consequential Load Loss afforded in provision 2.7.3 where documented circumstances outside the control of the TP or PC suffice; however, JEA is concerned that there are some limited prudent cases where consumers, local jurisdictions, and state jurisdictions may find it prudent to plan on some Non-Consequential Load Loss in order to defer building transmission infrastructure (just for the purpose to serve speculative load growth) for the overall benefit of the consumer. Therefore, concerning the prohibition of Non-Consequential Load Loss, JEA proposes the addition to the standard that allows the use of Non-Consequential Load Loss for local area load for planning events where it is not presently allowed. In Â¶1794 of Order 693, FERC stated "Regarding the comments of Entergy and Northern Indiana that the Reliability Standard should allow entities to plan for the loss of firm service for a single contingency, the Commission finds that their comments may be considered through the Reliability Standards development process. However, we strongly discourage an approach that reflects the lowest common denominator." Clearly, FERC did not direct NERC to eliminate "all" use of Non-Consequential Load Loss for single contingencies, but rather stated that its use should be "considered through the Reliability Standards development process". Therefore, the SDT should define "local area" where load loss is allowed and either set limits on how much load can be lost or a reporting requirement to ensure transparency concerning this planning practice. I propose that the standard should define "local area" as the load that is located on a single loop between two BES sources and limit the Non-Consequential Load Loss to the amount of Consequential Load Loss that would occur if the networked loop of load serving stations were sectionalized such that the loop operated as two radial circuits. The Standard could further require the TP or PC to document the results of both simulations with and without the sectionalization of the loop comparing the levels of Non-Consequential Load Loss to the level of Consequential load loss." This approach would clearly not be "a least common denominator approach", but rather a practical manner to allow the balance between transmission expansion costs and the limited risk to the local load within an area.

Voter	Entity	Segment	Vote	Comment
Response: The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area. 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.				
Kirit S. Shah	Ameren Services	1	Negative	Ameren appreciates the diligence and dedication of the Standard Drafting Team and commends the group for their hard work to bring the proposed standard TPL-001-1 to this level. We have seen considerable improvements to the proposed standard from earlier versions and note the positive changes to many of the requirements. We also recognize that the overall language of the standard has improved to enhance its readability and the language and format of the Tables now provides a clear understanding of acceptable System performance for the various Planning Events. However, inasmuch as the proposed Standard has improved, we cannot support the approval of this document at this time. 1. We disagree with the proposed definition of Year One. We believe that Year One should be the planning window that begins 12-18 months from the start of the current calendar year, and not from the end of the calendar year. We believe that following this modification to the definition would require minimal adjustments to the ERAG MMWG model building process, which we all use as the basis for our planning models. Following the proposed definition would require additional models to be built by the MMWG or lead to holes in the model building effort for both the operating and planning horizons. 2. We do not believe that 60 months is a reasonable time period to build transmission facilities to meet the new performance requirements. Building a transmission line in Illinois is estimated to take 7 years (84 months) from the time the project is authorized. Though requirement R2.7.3 is included to address situations beyond the control of the Transmission Planner, it leaves to the interpretation of the auditor whether the appropriate actions are being taken to resolve the issue that would continue to allow dropping of Non-Consequential Load or curtailment of Firm Transmission Service. 3. We have concerns for including induction motor representations in the load models without any study or bench-marking activities to meet the requirements of R2.4.1. Although the proposed standard offers that an aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable (to relieve the burden of trying to develop specific induction motor load representation at each load bus), we believe that the modeled System response will be considerably different compared to the actual System response in some parts of the System which will open up the industry to additional scrutiny, such as the Compliance Inquiry (CIQ) and/or Compliance Violation Investigation (CVI). 4. We do not agree that low voltage ride-through is a steady-state issue as included in requirement

Voter	Entity	Segment	Vote	Comment
				R3.3.2. We believe that low voltage ride-through is a dynamic modeling issue as correctly included in requirement R4.3.2. 5. We have concerns that the dynamics models cannot support the additional data requirements to include actual impedance relay models for all transmission facilities to meet the requirements of R4.1.2 and R4.3.3. In an attempt to relieve our concerns, the SERC presenters indicated that generic PSS/E impedance relay models could be included in the dynamics models. However, we also have concerns for using generic PSS/E impedance relay models as the actual impedance relays may be set differently than the generic PSS/E relay models which will open up the industry to additional scrutiny, such as the Compliance Inquiry (CIQ) and/or Compliance Violation Investigation (CVI).

Response: 1. Based on your comment and those of others, the SDT has revised the definition of Year One.

> **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

2. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility.

3. The SDT assumes that you are referring to the induction motor Load modeling required for Stability studies. The standard permits an aggregate model assumption that can be applied for a given system that is not substation specific. The SDT believes that 24 months is an adequate time period to accomplish this task. Dynamic load modeling is important for correct dynamic simulations. Industry has acknowledged the need for accurate Load modeling and the SDT has codified this need in the proposed standard. No change made.

4. The SDT voltage ride through is not confined to the dynamic period. There are protection requirements that could result in generator tripping and that must be considered in the steady-state analysis. The SDT has clarified the wording of the requirement.

> **Requirement R3, part 3.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:
>
> - Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.
> - Tripping of Transmission elements where relay loadability limits are exceeded.

Voter	Entity	Segment	Vote	Comment
5. 4.3.3 - The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern. **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: • Successful high speed reclosing and unsuccessful high speed reclosing into a Fault. • Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.				
Robert D Smith	Arizona Public Service Co.	1	Negative	APS proposes that the standard allows the use of Non-Consequential Load Loss for local area load for P1 events. The current requirements may pose significant burden without appropriate benefits. As currently written APS does not believe that 60 months is a reasonable time period to build transmission facilities to meet the new performance requirements. Building a transmission line can often take more than 5 years to complete from the time the project is authorized. Though requirement R2.7.3 is included to address situations beyond the control of the Transmission Planner, it leaves to the interpretation of the audit whether the appropriate actions are being taken to resolve the issue. APS proposes that the requirement be changed to 84 months.
Response: The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area. 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility.				
John Tolo	Tucson Electric Power Co.	1	Negative	As currently written it is believed that 60 months is not a reasonable time period to build transmission facilities to meet the new performance requirements. Regional and local planning and review process, permitting, siting, legal challenges, routing, and system path rating process can often take more than 5 years to complete from the time the project is authorized. Category P2 requires responsible entities to study the opening of a line section without a fault. The

Voter	Entity	Segment	Vote	Comment
				standard as written states that the opening of this line section will not result in consequential load loss and no voltage or thermal violations will occur on the BES. This requirement should not be applicable to all HV facilities. From a reliability perspective, a more effective and efficient method would be a bifurcated functional requirement rather than a voltage requirement. This TPL-001-1 version does not allow any Non-Consequential load loss (table 1) or firm Demand (note 9) for EHV systems in the event of protection system failure and delayed clearing. This performance requirement would thus preclude use of existing protection systems that rely on remote clearing of interconnected EHV lines or stations if they provide local load service. Category P5 requires responsible entities to study the Event titled Failure of a single Protection System that results in Delayed Fault Clearing on one of the following: Generator, Transmission Circuit, Transformer, Shunt Device, or Bus Section. It appears that this requirement is an indication that multiple protection system failure is not allowed under the proposed TPL-001-1. This appears to be a requirement for redundant protection systems for all possible events on all voltage levels of the transmission system. It also appears that this requirement is attempting to define what comprises an adequate protection system. Many and varied issues associated with designing appropriate protection systems should be done in the context of the development of a protection system standard and not in the context of TPL-001-1. TPL-001-1 has added requirement 2.1.5 discussing spare equipment and lead times and inclusion in the "Planning Assessment". The standard in this section is not performance based requirement but an activity based requirement as currently stated under R2 2.1.5. The standard should be revised and 2.1.5 removed as it does not directly improve the systems performance requirements nor compliance stated in Table 1.

Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order.

The SDT believes that the addition of footnote 12 (when it is finalized) will address your concern.

The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area.

12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.

The SDT has clarified the requirement based on your comments and those of others.

Requirement R2, part 2.1.5 - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall

Voter	Entity	Segment	Vote	Comment
be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.				
Brandy A Dunn	Western Area Power Administration	1	Negative	As drafted the standard TPL-001-1 has added requirement 2.1.5 discussing spare equipment strategy and lead times and inclusion in the "Planning Assessment". The standard in this section is not a performance based requirement but an activity based requirement as currently stated under R2 2.1.5. We recommend that the standard be revised and 2.1.5 removed as it does not directly improve the systems performance requirements nor compliance stated in Table 1.
Joseph S. Stonecipher	Beaches Energy Services	1	Negative	We believe that requirement 2.1.5 on spare equipment strategy is discriminatory for smaller entities. For many smaller entities, having a spare transformer is not a practical solution and makes far less sense and has significantly more customer rate impacts than for a larger utility. Yes, it may be possible to arrange an agreement with a neighboring entity for use of their spare, but that assumes that the neighboring entity's transformer specifications are similar enough for use as a spare, which may not be the case. Order 693 states at Paragraph 1725: "... the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy". The standard oversteps this direction by not including a consideration of planned outages versus forced outages in requirement 2.1.5, in other words, if an entity has no plans for a long term outage of a transformer, it should be excluded from the assessment of 2.1.5. Such a condition would allow an entity to assess things like gas in oil analysis to predict when a long term outage might be planned, and the flexibility between start and end dates of that planned outage.
Bruce Merrill	Lincoln Electric System	3	Negative	Requirement 2.1.5 should only address known planned outages of major Transmission equipment that has a lead time of one year or more. As currently drafted requirement 2.1.5 does not specify whether it includes both forced outages and planned outages. Requirement 2.1.5 also does not specify that system adjustments are allowed since adjustments are not allowed in categories P0, P1, and P2. Without system adjustments the requirement 2.1.5 would always produce more severe System impacts than the categories P0, P1, and P2 in Table 1. Allowing System adjustments would make requirement 2.1.5 (P1) match category P6, yet requirement 2.1.5 (P2) would still result in more
Dennis Florom	Lincoln Electric System	5	Negative	

Voter	Entity	Segment	Vote	Comment
Eric Ruskamp	Lincoln Electric System	6	Negative	severe System impacts than currently contemplated in the TPL-001-1 Standard. It appears that requirement 2.1.5 would greatly increase the study work by requiring a new base case for each unique Transmission equipment and repeating the associated contingency analysis. Would Correction Action Plans be required for requirement 2.1.5, whereas, they do not need to be developed solely to meet the performance requirements for a single sensitivity?
Response: The SDT has clarified the requirement based on your comments and those of others. **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.				
Elizabeth Howell	ITC Transmission	1	Negative	As written, the balloted standard is a significant advancement over the past planning standards. It raises the bar for the EHV system (>300kV) and is a significant step forward toward the desired improvement in the North American electric grid. The detailed requirements along with the Table 1 performance expectations for Planning Events should result in Corrective Action Plans that improve the electric grid in measurable ways. The additional specifications to insure that load will not be lost, intentionally or otherwise, during relatively routine system outages reinforces the value of reliability standards. While ITC recognizes the significant improvement in the Planning Standard and applauds the Standard Drafting Team (SDT) for constructing this new document, we believe minor changes are still needed to provide clarity to the standard to avoid possible miss-interpretation of the intent of the SDT during compliance audits and the potential for unnecessary duplication of study effort in areas if differences between the studies conditions are relatively small. Minimally, ITC feels additional guidelines need to be supplied for some of the decisions left to engineering judgment, such as in R2.5 where it is clear as to the need for studies of "new" generation, no "minimum" size is indicated. Additional guidelines should be added to the standard and the Reliability Standard Audit Worksheet (RSAW) should be completed prior to balloting the standard. ITC is concerned about the mandatory need for the three distinct studies as required in R2.1 and R2.2 if the differences between the prevalent conditions are projected to be small. For example, if a systems load changes are insignificant between years 1 or 2 and year 5, and other conditions changes such as generation additions, power flow patterns and other are small for the system under study. The same issue may exist between year 5 and years 6 through 10 Under such conditions these studies may not be prudent and necessary to thoroughly evaluate the systems performance. ITC

Voter	Entity	Segment	Vote	Comment
				agrees with the SDT that the three studies make sense and are prudent when a system's conditions are changing. A review of how this section in the standard might be warranted. While a spare equipment strategy is a good idea, R2.1.5, the requirement should be clear to avoid compliance violations for the implications of a major piece of equipment failure with or without spare equipment. Until this is clearer for both Planners and auditors or an RSAW is available, there is a greater likelihood for compliance issues. ITC also has concerns regarding requirements R3.3.2 and R4.3.2 regarding Low Voltage Ride Through (LVRT). Both require tripping of generators when "voltages are less than known or assumed generator low voltage ride through capability". This means the planner either knows the limit or assumes one. For ITC, we only trip for "known" limits, such as those for wind generators. Our policy is to not "assume" LVRT. A concern is if a LVRT is not assumed for all plants will a transmission company be found not compliant. This should be made clearer either in the standard or in an RSAW. For these reasons, ITC is voting no at this time. ITC would like to see the SDT add clarity to the sections identified above or develop a Reliability Standard Audit Worksheet to accompany the standard being ballotted. Please feel free to contact us if you have questions regarding our comments.

Response: The SDT has clarified the requirement wording to address your concern.

> **Requirement R2, part 2.5 -** The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, part2.6. The technical rationale for determining material changes shall be documented.

The intent of the SDT wasn't that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and part 2.1.

> **Requirement R2** - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.

> **Requirement R2, part 2.1 -** The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, part 2.6, as follows:

The SDT has clarified the requirement based on your comments and those of others.

> **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible

Voter	Entity	Segment	Vote	Comment
unavailability of the long lead time equipment The SDT voltage ride through is not confined to the dynamic period. There are protection requirements that could result in generator tripping and that must be considered in the steady-state analysis. The SDT has clarified the wording of the requirement. **Requirement R3, part 3.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: • Tripping of generators where simulations show generator bus voltages or high side of the Generation Step Up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. • Tripping of Transmission elements where relay loadability limits are exceeded. The development of an RSAW is more properly the purview of the Compliance Dept. No change made.				
Jason Shaver	American Transmission Company, LLC	1	Negative	ATC believes that the Standard is moving in the right direction, but has identified the following concern which is preventing us from voting "affirmative". Our concern is that the timeframe of 60-month (5 year) for implementing Corrective Action Plans (CAP), is insufficient. We believe that the implementation timeframe must be extended to seven (7) years. ATC is aware of Requirement 2.7.3, which covers situations that arise beyond the control of the Transmission Planner (TP) or Planning Coordinator (PC), but believes that the proposed language is ambiguous. Clarity needed (R 2.7.3): 1) An auditor could identify many things that could reasonably be within the "control" of a TP or PC but are not covered by NERC standards or a TP / PC's process, procedures or criteria. This wide area of discretion leaves entities open to possible non-compliance violation based on an auditor's perception of what they believe should be in the TP / PC's control. 2) In addition, we believe that the concept of "control" must be limited to an entities compliance obligation as a Transmission Planner and/or Planning Coordinator. In other words entities must be allowed the ability identify situation which fall under its "control" as a Transmission Owner, Transmission Operator, Generator Owner or Generator Operator etc. but is beyond the responsibility of its Transmission Planner or Planning Coordinator functions. . Suggested footnote: A TP or PC is in compliance with this requirement if the situation being documented is not covered in its internal processes, procedures or criteria required for NERC/Regional compliance obligations assigned to the TP or PC functions. Transmission Planners and Planning Coordinators are responsible for the identification of a CAP but it is the Transmission Owner that is ultimately responsible for implementing the CAP.
Gregory J Le Grave	Wisconsin Public Service Corp.	3	Negative	

Voter	Entity	Segment	Vote	Comment
				Additional areas of concern: ATC requested that the SDT re-examine the following concerns which we have been previously identified: 1. R1.1.2 "known outages of at least six months in duration" - The present wording in inconsistent between R1.1.2 and R2.1.3. We suggest that this requirement be removed because the "known outage(s)" are only to be included in the models when P1 events are simulated, as specified in R2.1.3. We suggest that the intent of this requirement can be more simply handled by stating in R2.1.3 that "known outages be simulated along with P1 events for the System peak or Off-Peak conditions when the outages are scheduled to occur". 2. R2.1.4 & R2.4.3 "range of credible conditions that demonstrate a measurable change in performance" - We suggest that the terms "credible" and "measurable" be define or use words that more definitively describe the requirement. 3. Table 1 - Requirements are "buried" in the Performance Table, rather than being included in the Requirement Section - a. Add R2.7.5 - We believe that all requirements should appear in the Requirements section and not be "buried" in the performance tables. We propose the addition of the following bullet item to R2.7.5. It could read, "Planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration of the Facility Ratings." Note "e" in the Planning Events, Steady State & Stability section is stated in the form of a Requirement (e.g. use the verb "shall"), but all requirements should be included in the Requirements section and not introduced (and basically hidden) in the performance notes of Table 1. [After bullet item #7 is added, Note "e" under "Steady State & Stability section of Table 1 should refer to R2.7.5] b. Add R3.3.5 - We believe that all requirements should appear in the Requirements section and not be "buried" in the performance tables. We suggest the addition of R3.3.5. The text of R3.3.5 should read, "Applicable System Operating Limits for the planning horizon shall not be exceeded." Presently, Note "a" and "b" under "Steady State Only" at the beginning of Table 1 are stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and basically hidden) in the performance notes of Table 1. [After R3.3.5 is added, Note "a" should be revised and refer to R3.3.5.] c. Add R3.6 - We believe that all requirements should appear in the Requirements section and not be "buried" in the performance tables. We suggest the addition of R3.3.6. The text of R3.3.6 should read, "The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to steady state voltage requirements." because Note "d" under "Steady State Only" at the beginning of Table 1 is stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly

Voter	Entity	Segment	Vote	Comment
				stated under Requirements and not be introduced (and basically hidden) in the performance notes of Table 1. [After R3.3.6 is added, Note "d" should be revised to refer to R3.3.6.] 4. R2.7.2 - "include actions to resolve performance deficiencies identified in multiple sensitivity studies" - We do not think that mitigation plans should be required for deficiencies found in multiple sensitivity studies because the conditions in some sensitivity studies are more extreme and less likely than base case conditions. Some of the sensitivity study conditions are not credible or plausible enough to warrant the implementation of mitigation measures. What is the interpretation of multiple studies - more than one or a majority of the number that were studied? 5. R3.5 - We interpret that R3.5 requires the TP and PC to conduct an evaluation of possible actions to reduce the likelihood or impact of extreme events, which produce the more severe impacts, if cascading outages may occur. Does the drafting team intend for the TP and PC to fulfill this requirement for at least one event in each of the five categories (i.e. 3 steady state and 2 stability) or in each of the 21 categories/sub-categories (i.e. 14 steady state and 7 stability). Also, if the resulting cascading outages do not result in any overloads, under-voltages, voltage collapse, or loss of generator synchronization, then should the evaluation of possible actions to reduce likelihood or impact still be required?

Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility.

The SDT believes the existing wording is clear and that the suggested wording is equivalent without providing any additional clarity. No change made.

Requirement R2, part 2.1.4 is part of Requirement R2 which mandates that an entity must document all assumptions utilized in the Planning Assessment. No change made.

The suggested change would move header note 'e to new Requirement R2, part 2.7.5 on the premise that it is a buried requirement. The phrasing of header note 'e' does not indicate that it is a mandatory requirement. It is a statement of allowed actions consistent with other notes. No change made.

The SDT does not believe that the items mentioned are buried requirements; rather they are statements of system performance that are better placed in the performance table. Requirements R3 & R4 specifically refer to the table which makes the table part and parcel of the requirements. No change made.

The SDT believes that it is more effective to state this as a header note instead of repeating it multiple times throughout the table. It is not a buried requirement but a description of what is utilized in the simulation. No change made.

Voter	Entity	Segment	Vote	Comment
Requirement R2, part 2.7.2 already states that an entity must supply the rationale for when actions were not necessary so the SDT believes that your concerns have already been addressed. No change made. The requirement states that an entity must supply the rationale for those events selected so the SDT believes that your concern has already been addressed. It provides the necessary guidance while allowing needed flexibility and not being overly prescriptive. No change made.				
Larry E Watt	Lakeland Electric	1	Negative	Below are some proposed changes and requests for clarification concerning the new TPL-001-1 standard. R2.6.2 The phrase "material changes" is not explicitly defined, and it is unclear what changes constitute a "material" change. It is asked that more precise wording or a definition of the word "material change" be provided. R3.3.2 The words "...known or assumed minimum generator steady state or ride through voltage limitations..." could be (and were) read as a series, with "known", "assumed minimum generator steady state", and "ride through voltage limitations" interpreted as three items in the series. For clarity, it is suggested that the standard be rewritten as such: Trip generators where simulations show generator bus voltages or high side of the Generation Step Up (GSU) transformer voltages are less than the known or assumed minimum generator steady state, or the known or assumed ride through voltage limitations. Include in the assessment any assumptions made. Here, the comma separates the two items in the series, with the words "known" and "assumed" modifying each of the items. R4.3.2 Following the changes made to requirement 3.3.2, it is suggested that requirement 4.3.2 be changed to the following: Trip generators where simulations show generator bus voltages or high side of the Generation Step Up (GSU) transformer voltages are less than the known or assumed minimum generator low voltage ride through capability. Include in the assessment any assumptions made. R4.3.3 An issue has been raised as to whether the word "simulate" denotes the modeling of all relays that protect transmission lines and transformers within a power flow/transiant simulator. It is suggested that this word be changed to "assess," to clarify that this requirement does not compel the Planning Coordinator and Transmission Planner to conduct PSS/E simulations to study the above conditions. The revised requirement can read: Assess the impact of transient swings on Protection System operation for Transmission lines and transformers. R4.4.1 There are two concerns with this requirement. The first is that this requirement makes no provision for the adjacent Planning Coordinator (PC) and Transmission Planner (TP) with a System Contingency to notify the PC and TP of the impacted System. Instead, the responsibility falls on the

Voter	Entity	Segment	Vote	Comment
				PC and TP of the impacted System to confer with each of their adjacent PCs and TPs to verify if a contingency on an adjacent System impacts the formers System. Or, it can cause the PC and TP to perform exhaustive contingency analyses (P0-P7) on all adjacent systems to determine which contingency/contingencies can impact their system to include them in their Contingency list. The second is that the term "impact" is not defined. A concern is should a Contingency cause a line on an adjacent System to load from 99% to 101% of its SOL rating, does this 2% constitute an "impact"? Conversely, would a Contingency that causes a significant increase to an adjacent System's line of 5% or more, without violating that line's SOL rating, be considered as having "impacted" the adjacent System? The proposed change to this requirement is: Adjacent Planning Coordinators and adjacent Transmission Planners will coordinate the identification of those Contingencies within their Systems and determine which, if any, impact the adjacent System. Those identified Contingencies may then be added to the adjacent Planning Coordinators and Transmission Planners' Contingency List. With this change, PCs and TPs of both Systems are responsible for coordinating their efforts, and the definition of "impact" is left to the coordinating PCs and TPs to decide. R8 It is unclear whether the adjacent Planning Coordinators and adjacent Transmission Planners must submit a written request for the information, or if the written request applies only to the functional entity that has a reliability related need. If the adjacent Planning Coordinators and adjacent Transmission Planners do not need to submit a written request, should the Planning Assessment be sent to them automatically?

Response: Material change is system specific and difficult to define on a continent-wide basis and is left to engineering judgment with a documented technical rationale as stated in the requirement. No change made.

The SDT does not see any real difference in the suggested wording from what is already there. No change made.

The SDT does not see any real difference in the suggested wording from what is already there. No change made.

The SDT has clarified the requirement to address your concerns.

Requirement R4, part 4.3.1 - Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

- Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual

Voter	Entity	Segment	Vote	Comment
				relay models. Since the requirement is written for each Planning Coordinator and Transmission Planner, it covers the exchange of information on critical Contingencies and their impacts among all Planning Coordinators and Transmission Planners and thus distributes the responsibility and work load. No change made. The SDT does not see any real difference in the suggested wording from what is already there. No change made. The requirement clearly states that the entity must have a reliability-based need for the information so that unauthorized requests won't be made and the request for the information must be in writing. No change made.
Eric Egge	Black Hills Corp	1	Negative	BHC does not believe that 60 months is a reasonable time period to build transmission facilities to meet the new performance requirements. Building a transmission line varies significantly in regional and local planning and review process, permitting, siting, legal challenges, routing, and system path rating process can often take more than 5 years to complete from the time the project is authorized. Though requirement R2.7.3 is included to address situations beyond the control of the Transmission Planner, it leaves to the interpretation of the audit whether the appropriate actions are being taken to resolve the issue that would continue to allow dropping of Non-Consequential Load or curtailment of Firm Transmission Service. As drafted the standard TPL-001-1 has added requirement 2.1.5 discussing spare equipment and lead times and inclusion in the "Planning Assessment". The standard in this section is not performance based requirement but an activity based requirement as currently stated under R2 2.1.5. PacifiCorp recommends that the standard should be revised and 2.1.5 removed as it does not directly improve the systems performance requirements nor compliance stated in Table 1.
Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility. Requirement R2, part 2.7.3 requires an entity to document their actions. Therefore, it is up to the entity to ensure that the documentation sufficiently explains their position. No change made. The SDT has clarified the requirement based on your comments and those of others. **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall				

Voter	Entity	Segment	Vote	Comment
be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.				
Janelle Marriott	Tri-State G & T Association Inc.	3	Negative	Definitions section- Add a definition to this standard, which would revise the definition of "Stability" in the NERC glossary to read: "Stability: Unless qualified specifically as Voltage Stability, the term Stability shall mean the ability of system generators to maintain angular equilibrium, also known as Dynamic stability." Definitions section- The definition for Year One is vague. If the definition is intended to capture both a summer and winter season and is necessary to provide a clear starting point for the planning horizon, then this should be stated explicitly in the definition. We recommend inserting the phrase "12-month" before the phrase "planning window" R2.1 The word "current" can mean either "electrical current" - a physical measure of electron movement, or "at the present time" - most recent or up-to-date. If you must use the term "current" in R2.1, say "current annual studies" rather than "annual current studies". R2.1.4 Part 2.1.4 should be removed from the requirement. The benefits of requiring one or more of these is unclear. Which of the listed conditions does an entity choose? There are no criteria for selection of one of the listed sensitivity topics as most-significant to a particular system. It is not apparent how particular sensitivities would increase BES reliability. If this part is not deleted, we recommend removing the phrase "not already included in the studies". Also, this requirement must state how one could determine validity of chosen sensitivity conditions. R2.1.5 We suggest adding the word "individually" to the end of the first sentence of part R2.1.5: "impact of this possible unavailability on System performance shall be assessed individually." In R2.4.1, it is left to the utility what level of load modeling detail is used. This is good because it gives the utility flexibility to select and use appropriate models. However, is it not clear what behavior of induction motors is targeted here. We recommend deleting the phrase "considering the behavior of induction motor loads", or else please specify what behavior is of concern. Part 2.4.3 should be removed from the requirement. As commented in our response to part 2.1.4, the benefit of requiring one or more of these is unclear - which of the listed conditions does an entity choose? There are no criteria for selection of one of the listed sensitivity topics as most-significant to a particular system. It is not apparent how this would increase BES reliability. If this part is not deleted, we recommend removing the phrase "not already included in the studies". Also, this requirement must state how one could determine validity of chosen sensitivity conditions. R2.6.2 We suggest that 2.6.2 be modified to read: "the System represented in the study has not
Keith V. Carman	Tri-State G & T Association Inc.	1	Negative	

Voter	Entity	Segment	Vote	Comment
				materially changed, or a technical rationale can be given that the changes do not impact performance in the study area." If 2.1.4 and 2.4.3 are removed as we suggest, then this sentence in part 2.7 should be removed: "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirement R2, parts 2.1.4 and 2.4.3." In part 2.7.1, remove the second sentence and all bullets. These are not measurable performance criteria. R3.5 asks for evaluation of actions designed to reduce the likelihood of potential cascading caused by extreme events, but 1) does not require documentation of results, and 2) does not require that the evaluation show that proposed actions would affect or limit cascading. R4.1 Insert "compliance with" in R4.1 text, which will then read "based on the Contingency list created in compliance with Requirement R4, part 4.4." There is no list in part 4.4. Part 4.4 requires a list of more severe contingencies (Table 1 planning events) to be created. R4.1.2 is unrealistic. Utilities implement out-of-step tripping schemes to limit the extent of impacts of such events that cause out-of-step conditions. Some of these occurrences can be mitigated better by tripping transmission elements and not generation. The decision to trip either transmission or generation should not be predetermined in the standard. We recommend that part 4.1.2 be reworked. R4.1.3 Does this preclude the regional reliability organization from choosing to establish damping criteria at some time in the future? R4.3.1 It is unclear whether this refers to the possibility of reclosing system failure, or the impacts of reclosing into a still-faulted system. R4.3.2 This is an admirable goal, and we applaud the SDT's vision. However, modeling all Protection Systems may be beyond the capabilities of presently used dynamic modeling tools. The number of impedance and overcurrent relays that would need to be included for lines and transformers would likely overwhelm these programs. We are concerned that the programs in use may not have the capability to model important relay characteristics such as load encroachment or out-of-step operating characteristics. R4.3.4 The phrase "of electrical system quantities" is unclear and can be removed without changing the intent of the requirement. R6 Remove the "for conditions such as ..." list.

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				Does Table 1, Category P5, require consideration of clearing from all remote terminals and evaluating those time delays assuming no tripping is available locally? Table 1 Extreme Events List- In the Stability section of the Table 1 Extreme Events List, use the term Dynamic Stability, not just Stability - or insert a revised Stability definition as noted above. M8, part 1.4 Simplify by changing "current, in force documentation" to "operative documentation". "Current" is redundant with "in force". Table 1 - Headnotes to Planning Events o Table 1, Headnote b - Delete "or extreme" since this headnote is for Planning Events. o Table 1, Headnote e - You may omit the phrase "For all planning events," since this headnote is for Planning Events. o Table 1, Headnote i - It is unclear what is meant by "end-user equipment associated with an event". o Table 1, Headnote h -We suggest this be moved to a footnote for P0: "Planning Event Category P0 is applicable to steady state only. No Dynamic Stability Analysis is required." o Headnote j - It is not clear why this falls under "Stability Only", and suggest that "dynamic stability" be included with headnote "a" Table 1 - Footnotes o Table 1, Footnote 2 - We suggest this footnote is not needed. R2.3 covers this sufficiently. o Table 1, new footnote- We suggest a footnote be added to the column labeled "Initial System Condition" indicating that "Normal System means all transmission elements are in service and all portions of the BES within the study area are performing within specified operating limits". Table 1 - Planning Events o Event P2 is categorized as 'Single Contingency'; however the listed events would typically result in the loss of more than one element. In other words, Category P2 contingencies are those in which a single system element is removed from service due to one of the listed initiating events. We are concerned because it appears that all events listed for the single-contingency Category P2 are not covered under other multiple-contingency Categories. For example, a faulted Bus Section. o Events P2 and P5 are described in terms of the elements initiating a fault, while the others are in terms of number of elements out-of-service due to a contingency. Event P4 is described in terms of

Voter	Entity	Segment	Vote	Comment
				both - the elements lost and the initiating fault. It would be helpful to have additional notes explaining the apparent inconsistent wording of Planning Events. o The distinction between 'Single Contingency' and 'Multiple Contingency' Category classifications for an event must be clear. Categories A through D have worked well for the industry to this point, and it would be helpful if the transitio

Response: The SDT feels that the current definition fits the intent of the standard. Modifying the definition could have unintended consequences on other standards. No change made.

Based on your comment and those of others, the SDT has revised the definition of Year One.

> **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

The SDT agrees and has made the change.

> **Requirement R2, part 2.1 -** The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, part 2.6, as follows:

The SDT has deleted the suggested phrase.

> **Requirement R2, part 2.1.4 -** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

The SDT has clarified the requirement based on your comments and those of others although the term 'individually' was not added as the SDT did not see that it added any clarity.

> **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment

The SDT has clarified the requirement.

> **Requirement R2, part 2.4.1** - System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the

Voter	Entity	Segment	Vote	Comment
				expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. The SDT has deleted the suggested phrase. **Requirement R2, part 2.4.3 -** For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: The SDT does not see that the suggested change adds clarity. No change made. Parts 2.1.4 or 2.4.3 were not removed so no change is needed here. The listed items are simply that – a list of actions that would be included. This is an allowable and encouraged format for Reliability Standards. No change made. Requirement R3, part 3.5 is part of Requirement R3 which links back to Requirement R2 where the documentation is required. No change made. The SDT believes that the present wording is correct. No change made. Requirement R4, part 4.1.2, deals with a single generator pulling out of synchronism. The situation you described is a system Stability issue and is considered an application for an SPS which is allowed by the standard. No change made. Nothing in this standard precludes a region from adopting an additional requirement in the future. No change made. The SDT modified the language of the requirement to address your concern. **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: • Successful high speed reclosing and unsuccessful high speed reclosing into a Fault. • Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models. The SDT believes that your comment is for requirement R4, part 4.3.3. The SDT has modified the wording of this requirement to address your concern. **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: • Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.

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				• Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models. The SDT does not see any reason to delete the phrase as it is not causing any confusion. No change made. The SDT believes that the present wording is appropriate. No change made. You need to model the way that Protective System is expected to operate; if there is no local backup, then remote clearing will have to be simulated. No change made. All aspects of Stability are to be considered. No change made. The present language is common in many standards and the SDT sees no reason to change it here. There may be a difference between 'current' and 'in force' due to effective dates. No change made. The SDT has made a clarifying change to the note. **Header note 'b':** Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0. The SDT agrees and has modified the note accordingly. **e**. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. End-user equipment is that equipment owned and operated by an end-user over which an entity has no control. No change made. This is simply a matter of preference as the suggested change would not alter the meaning or intent. No change made. The SDT agrees and has deleted header note 'j'. Dynamic stability is covered in the requirements and no reference is needed in the header notes. This footnote is referring to Stability studies and not short circuit analysis. No change made. System normal, or P0, is the starting system condition for the projected study conditions per the model developed in accordance with Requirement R1. The SDT has adjusted Requirement R1 to provide this clarity. **Requirement R1 -** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes the normal system condition in Table 1. The category descriptions are meant to characterize the events. A single event may remove more than one element from service and that has been addressed in Header note 'c'. The SDT does not believe that there are inconsistencies within the table. The P2 category describes single events that may result in multiple

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elements being removed from service. The P2 events differ from the multiple event categories which consider two or more sequential events. No change made. The SDT agrees that the structure of the descriptions are different because they are describing dissimilar types of events but the SDT does not feel that they are inconsistent or causing any confusion. No change made. The change was made since the table is now event based and because the four existing standards were consolidated into one standard. The industry has supported these changes. No change made.				
Fred Frederick	Southern Indiana Gas and Electric Co.	3	Negative	Definitions, Year One - Vectren disagrees with the proposed definition of Year One. Vectren believes that Year One should be the planning window that begins 12-18 months from the start of the current calendar year, and not from the end of the calendar year. Section 5 - Effective Date, the allowance of 60 calendar months for Corrective Action Plan implementation is too short. Recommend this be extended to 84 months to allow for proper planning, budgeting, right-of-way acquisition and construction. R2.4.1 - System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Vectren has concern with this requirement. The concern is that Vectren will be held to strict interpretation of this standard with regard to an actual event occurring that was not exactly reproduced by the Vectren model. R2.7.2 - The term "include actions to resolve performance deficiencies identified in multiple sensitivity studies" causes concern. Mitigation plans should not necessarily be required for deficiencies found in multiple sensitivity studies because the conditions in some sensitivity studies are typically extreme and less likely than base case conditions. Some of the sensitivity study conditions may not be credible or plausible enough to warrant the implementation of mitigation plans. Also, what is the interpretation of multiple studies? Is that more than one, a majority, 2/3 of the number that were studied, or some other number? R2.7.3 - The term “beyond the control of the Transmission Planner or Planning Coordinator” needs to be better defined. An auditor could interpret a situation to be within the “control” of a TP or PC but are not covered by NERC standards or a TP / PC’s process, procedures or criteria. This leaves entities open to possible non-compliance violations based on an auditor’s perception of what they believe should be in the TP / PC’s control. Also, Vectren is not in agreement that Non-Consequential Load Loss should not be allowed for any case. There may be cases, especially future year studies that indicate a need for building transmission infrastructure, to serve speculative load growth. In these cases the consumers, local

Voter	Entity	Segment	Vote	Comment
				jurisdictions, and state jurisdictions may find it a prudent plan to assume some Non-Consequential Load Loss in order to defer building transmission infrastructure. R3.3.3 - Trip Transmission elements when relay loadability limits are exceeded. Vectren has concerns that system models (or software applications) cannot support the requirements of R3.3.3. Another concern is that Vectren will be held to strict interpretation of this standard with regard to an actual event occurring that was not exactly reproduced by the Vectren model. R4.1.3 - For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner. Vectren has concerns with this requirement. What if the PC and the TP cannot reach an agreement in the definition of "acceptable damping"? R4.1.2 - When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities. Vectren has concerns that dynamics models (or software applications) cannot support the requirements of R4.1.2. Another concern is that Vectren will be held to strict interpretation of this standard with regard to an actual event occurring that was not exactly reproduced by the Vectren model. R4.3.3 - Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers. Vectren has concerns that dynamics models (or software applications) cannot support the requirements of R4.3.3. Another concern is that Vectren will be held to strict interpretation of this standard with regard to an actual event occurring that was not exactly reproduced by the Vectren model. Table 1 - Steady State & Stability Performance, Planning Events, k. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner. What if the PC and the TP cannot reach an agreement in the definition of "acceptable limits"? Table 1 - Steady State & Stability Performance, Extreme Events, V. A successful cyber attack. This requirement is too vague. It could be interpreted in any number of ways.

Response: Based on your comment and those of others, the SDT has revised the definition of Year One.

> **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen

Voter	Entity	Segment	Vote	Comment
until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility. 2.4.1 – The SDT has added the word 'expected' to the text to alleviate your concern. Planning models are based on the best information available to the planners at the time of the study and it is well understood that they may not exactly represent actual conditions at any given time. The results of on-going benchmarking and model development activities can be incorporated when those activities yield more representative results. **Requirement R2, part 2.4.1** - System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Requirement R2, part 2.7.2 already states that an entity must supply the rationale for when actions were not necessary so the SDT believes that your concerns have already been addressed. No change made. If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility. No change made. The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area. 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. The expectation of this requirement is that relay tripping would be handled consistent with their PRC-023 expectations. Planning models are based on the best information available to the planners at the time of the study and it is well understood that they may not exactly represent actual conditions at any given time. No change made. Requirement R4, part 4.1.3 does not state that the criteria are set jointly. If such an item became an issue, the SDT believes that it is covered in Requirement R7. No change made. The SDT believes that the necessary tools are readily available. Planning models are based on the best information available to the planners at the time of the study and it is well understood that they may not exactly represent actual conditions at any given time. No change made. The table does not state that the limits are set jointly. If such an item became an issue, the SDT believes that it is covered in Requirement R7. No change made. The event is the loss of two generating stations. A successful cyber attack is simply an example of a cause of the event. No change made.				
Liam Noailles	Xcel Energy, Inc.	5	Negative	Xcel Energy appreciates the hard work of the Standard Drafting Team and commends the group for making substantial improvements in every successive draft of the TPL-001-1 standard to bring it to the proposed version for balloting. However, in as much as the proposed TPL-001-1 standard has

Voter	Entity	Segment	Vote	Comment
Michael Ibold	Xcel Energy, Inc.	3	Negative	improved, we cannot support its approval at this time for the following reasons: 1. Implementation Plan: Xcel Energy does not believe that 60 months is a reasonable time period to build transmission facilities to meet the new "raise-the bar" performance requirements. Building a transmission line in Xcel Energy's service area spanning eight-states (and two RTO's) varies significantly in regional and local planning and review process, regulatory approval process, permitting and routing process, legal challenges, etc. These processes can often take more than 5 years to complete from the time the project is conceived as a proposed solution. Though requirement R2.7.3 is included in the standard to address situations beyond the control of the Transmission Planner, we are concerned that it leaves to the interpretation and judgment of the auditor whether the Transmission Planner is taking appropriate actions to resolve the situation and consequently whether the interim solution of dropping Non-Consequential Load or curtailment of Firm Transmission Service is acceptable. Xcel Energy will be comfortable supporting the standard if the 60 months time-frame is increased to 84 months. 2. Intended Scope of Planning Event P5: Xcel Energy is unsure of what comprises the scope of "Failure of a single Protection System" - does it imply studying the failure to operate of the relay or communication channel utilized in the primary protection scheme for an equipment (e.g. transmission line), or does it also include studying the failure of other single Protection System components such as current/voltage transformer or station battery? Note that the former interpretation will result in delayed clearing of the faulted transmission element only, consistent with operation of the local backup protection (typically zone 2 operation of line distance relays). On the other hand, the failure of current/voltage transformer or station battery could compromise the operation of both primary and local backup protection schemes for the faulted equipment, thus requiring the remote backup protection to clear the fault, which results in longer-duration delayed clearing and the loss of more than one transmission element. In Table 1, characterizing P5 as a multiple contingency event (like P4 or P7) also contributes to the scope confusion. As discussed above, a primary protection relay failure will typically result in the loss of a single (faulted) element only, not the outage of multiple elements (that always occurs in P4 or P7 events). Then, should the P5 event be construed to study the failure of CT/PT and/or station battery which, as discussed above, will typically result in the loss of multiple elements? If yes, isn't the standard implicitly requiring redundant CTs/PTs or station batteries to enable meeting the EHV performance requirement? If no, shouldn't the P5 event description reflect the intended scope more clearly? This may presumably be achieved by modifying P5 to read "Failure of primary protective relay that results in Delayed Fault Clearing on one of the following:" 3. Steady-state Performance of Planning Event P5 versus P1: Assuming that the intent of the P5 event is to study the operation failure of primary protection scheme (failure of the relay or its communication channel), the delayed clearing time associated with local backup protection scheme is
David F. Lemmons	Xcel Energy, Inc.	6	Negative	

Voter	Entity	Segment	Vote	Comment
				only relevant to the stability performance. If the post-contingency outcome for P5 consists of the loss of the faulted transmission element only, can the post-contingency steady state system condition for event P5 be any different than for event P1? We contend that both events will result in the same post-contingency steady-state system condition since the only difference is the normal versus delayed clearing time. If so, should the steady-state performance requirements for event P5 be any different than for event P1? For steady-state analysis, the HV level performance requirements for P5 in Table 1 become contradictory to those for P1. This is another example of why the intended scope of P5 event needs to be specified more clearly. 4. Ambiguities and Inconsistencies: Xcel Energy is providing the following editorial comments for your consideration to improve the consistency and clarity of the standard. Several, but not all, of the ambiguities and/or inconsistencies are confusing enough to qualify as show-stoppers since they prevent the standard's intent and scope to come across clearly. 4.1 Table 1 - Headnotes to Planning Events o Headnote b - At a minimum, delete "or extreme" since it is out of place in this headnote. Consider truncating at "... generation loss is acceptable." since the headnote is by default applicable to all planning events, and P0 exclusion is implicit in the context. o Headnote e - Consider omitting the phrase "For all planning events," since the headnote is by default applicable to all planning events. o Headnote i - Consider re-wording to remove the unintended association of equipment with event being implied at "...by end-user equipment associated with an event...". Suggest deleting the redundant phrase "associated with an event" since the headnote is by default applicable to all planning events. Alternatively, modify to read as follows: "Load loss resulting from an event due to the response of voltage sensitive Load or due to Load that is disconnected from the System by end-user equipment shall not be used to meet steady state performance requirements." o Headnote h - Unlike other headnotes, this does not describe a system performance but offers a clarification on applicability. Therefore, like other clarifications/qualifications, it belongs in the footnotes - suggest changing it to footnote assigned to P0. o Headnote j - It is not clear why this falls under Stability Only, and it also lacks specificity in expected stability performance. Note that the generic 'stable' is an umbrella term that includes all types of system (in)stability including voltage (in)stability, frequency (in)stability and cascading facility outages, not simply angular (in)stability. Considering that headnote 'a' includes most varieties of system (in)stability, we suggest adding "angular instability" in headnote "a" and deleting this

Voter	Entity	Segment	Vote	Comment
				headnote. 4.2 Table 1 - Footnotes Footnote 2 - Suggest deletion of "Unless specified otherwise, simulate normal clearing of faults" since it is redundant with Headnote 'd' for Planning Events and Headnote 'b' for Extreme Events. Alternatively, delete both Headnotes and do not change Footnote 2. 4.3 Table 1 - Planning Events - Column 2 - Initial System Condition - Normal System What are the attributes of Normal System? Is this term intended to be synonymous with "system intact" or N-0 system topology? Is the event P0 intended to be identical to the existing Category A? The intent is not clear and needs to be explicitly stated. We suggest that the first occurrence of the term be modified as follows: "Normal System (all Facilities in service)" to explicitly convey the intent. Note that the qualifier in parenthesis is the verbiage for Category A used in the existing TPL standards. However, we also note that if P0 is intended to be synonymous with "system intact", then it does not appear that the base case system model built as per Requirement R1, part 1.1, will always be compatible with P0 - due to the known outages to be included in the model (part 1.1.2). Does the standard envisage P0 and "system intact" to connote "All Facilities in service minus the known outages"? If so, this must be clearly stated. .4 Table 1 - Planning Events - Column 1 - Category What is the significance of 'Single Contingency' or 'Multiple Contingency' qualifier for an event? Is it intended to characterize the number of elements outaged due to the initiating event, or is it intended to convey the number of equipment failures/faults comprising the initiating event? The NERC glossary definition of Contingency "The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element." does not help remove this ambiguity. Regardless of the chosen interpretation, inconsistency arises for the following events: Event P2 - Wouldn't initiating events P2-2, P2-3 and P2-4 typically result in the loss of more than one element? So qualifying P2 as single contingency appears to correspond with the equipment fault/failure description in the Event column but does not correspond to the total number of elements outaged due to the initiating event. Event P3 - Per the description in the Event column, the events P3-1 to P3-5 result in the loss of one element. So qualifying P3 as a multiple contingency appears to correspond with the total number of elements outaged, after including the (overlapping) prior outage. But the multiple contingency qualification is not consistent with the initiating event description in the Event column. Event P6 - Same comment as P3. Event P1 - Can the loss of only one element be presumed as an outcome of normal clearing of a fault, which appears to be the implicit initiating event here? How about the case of a normally cleared fault on a transformer-terminated line that is not breakered at the transformer end? Or the case of a normally cleared fault on a line-connected shunt reactor that is not breakered to the line? The resulting loss of two elements is not consistent

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				with the event description. And by characterizing the event in terms of loss of one element, it is also inconsistent with headnote c that requires removal of all elements expected to automatically disconnect for each event. 4.5 Table 1 - Planning Events - Column 3 - Event Descriptions for events P1, P3, P6 and P7 are in terms of number of elements (one or multiple) outaged due to the contingency, whereas events P2 and P5 are described in terms of the initiating fault only. The exception is event P4 which is described in terms of both - the elements lost and the initiating fault. Is there a good reason why the event descriptions are not consistently worded? We note that the contingency descriptions in column 2 of the existing Table I are expressed in terms of "Initiating Event(s) and Contingency Element(s)." We think this issue is closely correlated to the previous comment on the apparent lack of consistency between the contingency terminology in column 1 and the event description in column 3.

Response: 1. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility.

2. The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns.

> **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following:
>
> **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

3. A P5 event is different and will not duplicate a P1 event for steady state if the entity does not have fully redundant Protection Systems. No change made.

The SDT agrees and has made a clarifying change.

> **Header note 'b':** Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

The SDT agrees and has modified the note accordingly.

> **Header note 'e'**. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

While technically correct, the suggested change does not create additional clarity and the existing wording doe not cause any confusion in the eyes of the SDT. No change made.

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This is simply a matter of preference as the suggested change would not alter the meaning or intent. No change made. The SDT agrees and has deleted header note 'j'. This is simply a matter of preference. While somewhat duplicative, it may add clarity and hasn't seemed to cause any confusion. No change made. System normal is the starting system condition for the projected study conditions per the model developed in accordance with Requirement R1. The SDT has adjusted Requirement R1 to provide this clarity. **Requirement R1 -** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes the normal system condition in Table 1. The category descriptions are meant to characterize the events. A single event may remove more than one element from service and that has been addressed in Header note 'c'. The SDT does not believe that there are inconsistencies within the table. No change made. The SDT agrees that the structure of the descriptions are different because they are describing dissimilar types of events but the SDT does not feel that they are inconsistent or causing any confusion. No change made.				
Henry Ernst-Jr	Duke Energy Carolina	3	Negative	Duke appreciates the hard work that has been done by the Standard Drafting Team to get the standard to this point. Duke is supportive of the standard as it helps to remove some of the 'grey' in the existing TPL standards, as well as driving actions that will improve the reliability of the Bulk Electric System. However, Duke believes that two areas in the standard need to be improved in order for Duke to vote to approve the standard. 1. Duke does not believe that 60 months is a reasonable time period to build transmission facilities to meet the new performance requirements. In an email to the registered ballot body, Ameren stated " Building a transmission line in Illinois is estimated to take 7 years (84 months) from the time the project is authorized." Duke agrees with the point that Ameren is making that building of a new EHV transmission line can be a very lengthy process. Duke thinks that a more appropriate time frame would be 84 months. 2. Duke believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues, does not provide any real benefit to Bulk Electric System (BES) reliability, and may have unintended negative consequences on reliability. Often, corrective actions to mitigate these events are local in nature and only require minor additional loss of local load to avoid major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. The standard should continue to allow Transmission Planners to use

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				discretion regarding loss of non-consequential load, such that Transmission Planners, customers, and local regulators jointly control the decision making when BES reliability is not an issue. The transparency requirements of the new standard facilitate this type of decision making. In addition, the prohibition on non-consequential load loss for these events creates an incentive for Transmission Planners to remove lines serving load from network (serve the loads radially) so that they are characterized as consequential load. The unintended consequence of the standard would be a reduction in reliability for service to local load.
Response: 1. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. 2. The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area. 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.				
Charles A. Freibert	Louisville Gas and Electric Co.	3	Negative	E.ON U.S. suggests that Extreme Event 2e be clarified by adding: if generating was added in front of station, "Loss of all generating units at a generating station." This would distinguish from a loss of all units at a transmission station. Also, it is consistent with 3a, "Loss of two generating stations ...". E.ON U.S. objects to the modification of P2-1 to only include "Opening of a line section w/o a fault". Footnote 7 indicates that this is to ensure that radial load that would have tripped with a fault can be served. This is a new criteria that opens a line without an actual fault and may result in converting some of these lines to radials to comply with this requirement which could decrease overall reliability.
Charlie Martin	Louisville Gas and Electric Co.	5	Negative	
Daryn Barker	Louisville Gas and Electric Co.	6	Negative	
Response: The SDT assumes that you meant 2d and of so, agrees and has made the change. **Extreme event 2d.** Loss of all generating units at a generating station. This is not a new criterion as this is exactly what was in TPL-002-0, Table 1, Category B "Loss of an Element without a Fault." No change made.				
Luther E. Fair	Gainesville Regional Utilities	1	Negative	Even though I am voting negative on this version of the standard, I want to acknowledge the considerable effort that the SDT has put into developing this change to the NERC Standard TPL-001, Transmission System Planning Performance Requirements. I do consider it, in most part, an improvement to the existing standard, but I feel it falls short by not providing more clarity and less ambiguity. As a very small utility that happens to have chosen a 138 kV loop to circle its city to serve

Voter	Entity	Segment	Vote	Comment
				its citizens, we feel unreasonably burdened at times to accomplish the documentation task at hand. I offer the following as a few examples of concern: GRU believes that requirement 2.1.5 on spare equipment strategy is discriminatory for smaller entities. For many smaller entities, having a spare transformer is not a practical solution and makes far less sense and has significantly more customer rate impacts than for a larger utility. Yes, it may be possible to arrange an agreement with a neighboring entity for use of their spare, but that assumes that the neighboring entity's transformer specifications are similar enough for use as a spare, which may not be the case. Order 693 states at Paragraph 1725: "... the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy". Next, Requirement 3.3.3 as written would require modeling of nearly every phase distance relay, especially when studying extreme events. The requirement ought to have the flexibility afforded in 3.3.2 where the planner can use a conservative assumption and screening methods (e.g., the proposed curves of PRC-024) for relay loadability (e.g., the requirements of PRC-023). Requirement 4.3.1 would also require modeling of nearly every phase distance relay in the Interconnection, again because it applies to extreme events and we will not know ahead of time where the power swings will traverse distance relay characteristics. I look forward to the next generation of this standard's development. L. Earl Fair

Response: The SDT has clarified the requirement based on your comments and those of others.

> **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment

The SDT agrees that a planner should be able to utilize conservative assumptions and screening methods and doesn't believe that there is anything in the requirement that precludes an entity from doing so. The SDT disagrees that the modeling of phase distance relays is required. No change made.

The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern.

> **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:
>
> - Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
> - Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

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• Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.				
Daniel Brotzman	Commonwealth Edison Co.	1	Negative	Exelon is concerned with the use of the term 'Protection System' in Category P5 of the Table 1 performance criteria. 'Protection System' is a defined term in the NERC Glossary (Protection System - Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry). Thus, a potential interpretation of the standard as currently proposed would be that the loss of a station battery is to be included in analysis as a valid single contingency. We understand that the SDT response to previous comments on this issue indicates that the battery contingency was not intended to be part of the P5 contingencies. However, no changes or clarifications were subsequently made to the proposed Standard to clarify the requirements and exclude this interpretation. This leaves open the potential for multiple interpretations of the Standard and creates ambiguity for the functional entities that will have to implement the revised Standard. Additionally, Exelon is concerned that performance criteria in the draft Standard is based on the voltage level of the contingency element rather than the monitored element.
Response: The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns. **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following: **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94). The SDT placed greater emphasis on the facility being removed than the monitored remaining intact Facilities. The outage of an EHV Facility will typically be of greater concern for the potential of transferring power flow to lower voltage parallel paths than the reverse. No change made.				
Pat G. Harrington	BC Hydro and Power Authority	3	Negative	File: NERC_Std_TPL-001_Draft05_Ballot_Comments_BCH20100226.doc A. GENERAL COMMENTS The standard needs to better define the pre- and post-contingency generation dispatch conditions and stipulate that the worst-case combination of possible load levels and generation dispatch must be studied. For example, the portion of a transmission network connecting a "generation-rich" region (ie, a region with much more generating capacity than local load) to the rest of the BES, should be able to operate within normal voltage level limits without overloading any elements under normal system conditions (N-0). If there are intermittent resources like wind parks or run-of-the-river hydro plants that the system is not depending on to supply dependable generating capacity (or at least not to the full nameplate rating of those resources), generation shedding or run-back can be permitted for single-contingencies (N 1 situation). The amount of generation shedding should be limited to the difference between the aggregate maximum generating capacity of the region and the aggregate

Voter	Entity	Segment	Vote	Comment
				dependable generating capacity of the region and there should be further limits defined for generation shedding/run-back as described below. Add the following definitions: o 1. Consequential Generation Loss: All Generation that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault. o 2. Non-Consequential Generation Loss: Dependable Generating Capacity Loss that does not include: (1) Consequential Generation Loss, (2) Generation loss due to low voltage or (3) Generation loss due to protective relays of the generating unit or its step-up transformer. o 3. Dependable Generating Capacity: The level of generating capacity of a plant or unit that the system operator can count on to serve Non-Interruptible Load by virtue of the plant or unit's fuel supply being available to provide that level of generating capacity more than 97% of the time. "EHV" and "HV" need to be defined because they are not defined in the NERC Glossary (NERC Glossary (use "Edit, Find on this page..." and look for "Glossary": http://www.nerc.com/elibrary.php?doc_class=&doc_dept=&submit=Filter) B. SPECIFIC COMMENTS R2, 2.2.1: The system configuration of the last year of the planning period should be studied as well as at least one other year that is most-likely to fail to meet planning criteria with an explanation for why that year is considered the worst case. As it is written, it would be quite acceptable for the TP and/or TC to simply study the year immediately following a major system upgrade with the rationale being that it would likely be the least likely system condition to fail any reliability standards. As it is written, there is no requirement that the rationale provided be logical or reasonable. R2, 2.4: "Stability analysis" does not cover all of the dynamic criteria that need to be met. A more general term, like "Stability and dynamic simulation studies" should be used. "Stability" is defined by NERC as just, "The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances", but the assessments done in what people term "Stability" studies involve more than a check on the electromechanical stability (equilibrium) of the system. Voltage sags and swells, frequency deviations and short term overloading of equipment (eg, transient and dynamic current fluctuations through series capacitors that would provide an indication of the voltage stress across the capacitor dielectric) are usually included in "Stability" studies. R2, 2.4.1: "...for one of the five years" should be changed to "...for the most critical year of the 5 year Near-Term planning period". R2, 2.4.2: This requirement needs to be better defined. Is this requirement meant to demonstrate acceptable system performance during maintenance outages over the daily peak load periods of the off-peak season (ie, summertime for a winter-peaking region) or is this intended to address light-load

Voter	Entity	Segment	Vote	Comment
				issues like over-voltages and frequency deviations? R3, 3.2 The performance requirements for extreme events need to be defined in more detail. The criteria for acceptable system performance for extreme events seems to be only described vaguely in R3 item 3.5. R3, 3.5: Change "Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created" to, "Those extreme events in Table 1 that are expected to produce more severe System impacts most likely to cause Cascading,, equipment damage or pose a significant risk to public or worker safety [needs to be further defined] shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created" Also, simply providing "an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s)" is inadequate. One or more SPSs should be defined and studies should demonstrate that they prevent cascading outages and isolate, in a pre-planned controlled manner, the portion of the system experiencing the extreme event to minimize the extent of the disturbance. If necessary, an SPS should be provided that isolates the control area experiencing the extreme event from the rest of the interconnected system. R4, 4.1.1: Add (referring to the additional text suggested below for Note e of Table 1), "The amount of generating capacity disconnected or "run-back" by a Special Protection Scheme (SPS) shall be limited in accordance with Note e of Table 1". R4, 4.1.2: Add, "Studies shall be conducted to demonstrate that all circuit breakers that may be called upon to trip for an out-of-step condition (180 degrees across the open breaker) are properly rated for this duty considering the worst case voltage on any isolated transmission circuits due to trapped charge." R4, 4.1.3: Acceptable damping should be defined (eg, "studies must show that any oscillations are damped to less than 10% of their initial magnitude within 30 seconds") [or develop a different specific requirement that can be measured]. R4. 4.5" Change "Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R4, part 4.2 created" to, "Those extreme events in Table 1 that are expected to produce more severe System impacts most likely to cause Cascading, equipment damage or pose a significant risk to public or worker safety [needs to be further defined] shall be identified and a list of those events to be evaluated for System performance in Requirement R4, part 4.2 created".

Voter	Entity	Segment	Vote	Comment
				Also, simply providing "an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s)" is inadequate. One or more SPSs should be defined and studies should demonstrate that they prevent cascading outages and isolate, in a pre-planned controlled manner, the portion of the system experiencing the extreme event to minimize the extent of the disturbance. If necessary, an SPS should be provided that isolates the control area experiencing the extreme event. R5 & R6: Shouldn't the Load Serving Entities (LSEs) define system performance criteria instead of the Transmission Planner or the Planning Coordinator? The LSEs have an obligation to their customers and must demonstrate to their regulators that they are providing acceptable system performance and reliability of supply to their customers. The Transmission Planner and Planning Coordinator have less incentive to provide high levels of system performance. Due to regulatory difficulties in getting approvals for transmission system upgrades, there

Response: The standard requires a normal System model, P0, be developed that projects anticipated conditions for the period under study. Any additional stress of the System prior to loss of an element would be handled through sensitivity analysis as required in Requirement R2. In addition, the SDT explored the possibility of placing limits on the amount of generation runback and the industry clearly indicated in comments that they did not support such limits. No change made.

The EHV/HV differentiation is not meant to be a definition in that it only applies to this standard. No change made.

One can always study additional years if so desired. The SDT believes that "rationale" implies logic and reason. No change made.

The SDT intended for the term Stability analysis to include system Stability and unit Stability analyses. These analyses could include all aspects of Stability that you mentioned. It is left up to the judgment of the Planning Coordinator/Transmission Planner to decide which aspects of Stability may produce more severe results and therefore, must be analyzed. No change made.

The critical year can only be determined after reviewing the entire portfolio of current and past studies and is not a pre-determined condition. The SDT expectation is that an entity is building a portfolio over time that covers the entire planning horizon and thus determines any critical periods. No change made.

The requirement was intended to cover all conditions that could occur during Off-Peak periods. No change made.

Requirement R3, part 3.2 contains no performance obligations. It is simply a requirement to assess the impacts. No change made.

The SDT made a clarifying change to the requirement.

> **Requirement R3, part 3.5 -** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

Voter	Entity	Segment	Vote	Comment
Due to the complexity associated with extreme events, the SDT believes it is inappropriate to require any more than a list of possible actions. An SPS could be a solution but it is not the only one. No change made. The SDT explored the possibility of placing limits on the amount of generation runback and the industry clearly indicated in comments that they did not support such limits. No change made. This standard is not intended to address engineering specifications such as proposed here. No change made. There is no single definition; the SDT has left it up to each Planning Coordinator or Transmission Planner to define. No change made. The SDT has made a clarifying change to the requirement. **Requirement R4, part 4.5 -** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted. Due to the complexity associated with extreme events, the SDT believes it is inappropriate to require any more than a list of possible actions. An SPS could be a solution but it is not the only one. No change made. These are System requirements for the BES and properly belong to the Planning Coordinator and Transmission Planner. No change made.				
Paul Shipps	Lakeland Electric	6	Negative	Five years is not enough time in many circumstances to build significant new transmission lines.
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Negative	Our concern is that the timeframe of 60-month (5 year) for implementing Corrective Action Plans (CAP), is insufficient. We believe that the implementation timeframe must be extended to seven (7) years.
Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order.				

Voter	Entity	Segment	Vote	Comment
W. R. Schoneck	Florida Power & Light Co.	3	Negative	FPL Comments on TPL-001-1 Standard FPL believes the Standard requirements need to be clear and unambiguous. The SDT has addressed many of the gray areas of Draft four in their consideration of comments however these comments are not part of the Standard that is currently out for ballot. Incorporating these types of clarifing comments with the use of footnotes in the Standard to help clarify the intent would be a significant improvement for anyone interpreting the Standard including an auditor or investigator. The definition of Year One is an unnecessary departure from the planning practices used in most of the Eastern Interconnection. It is recommended the phrase end of the current calendar year be changed to the current calendar year. This change will allow PAs to begin their near term analysis with either next year or the year after as deemed appropriate. The performance requirements of Table 1 do not allow the loss of non-consequential load for single and multiple contingency events. The disallowance of load loss does not provide any real benefit to the reliability of the BES and is an unnecessary overreach into local quality of service issues that are best addressed by State, Provincial or Municipal authorities. There may be circumstances such as high local transmission costs or local opposition to transmission construction where prohibition of non-consequential load loss represents a poor cost/benefit or quality of life tradeoff. Providing a quantitative cap in non-consequential load loss such as 100 MW may be rationale compromise in the goal of limiting load loss for the more probable outage events. Our preference would be to retain the capability of limited non-consequential load loss. Absent this, the 60 calendar month phase in period described in the Introduction section is too short for transmission facilities rated above 300 kV. Approval and permitting of EHV transmission lines is extremely difficult and time consuming in most parts of the Eastern Interconnection. The phrase any material changes used in requirement R.2.6.2 will effectively cause all Planning Authorities to run all studies every year regardless of minor changes in the model. The overwhelming majority of PAs use a 10 year set of planning models developed annually by Regions or Subregions. These annual sets of planning models will always have some changes. The annual study requirement is especially problematic for Stability and Short circuit studies that require much more engineering time to complete and are mush less likely to have results impacted by minor model changes such as different load forecasts. Uncertainty with audit review of technical rationale documentation will serve to focus Transmission Planning engineering resources on short term compliance to an extent that is counter productive. Requirement 2.5 represents a significant expansion of Stability Studies into the Long Term horizon. In many cases the stability issue in long term scenarios will be with the response of new generating plants to fault scenarios such as a breaker failure event. The protection upgrades needed to mitigate performance issues are easily

Voter	Entity	Segment	Vote	Comment
				accomplished in the short term. The uncertainty of compliance judgement of rationale documentation will force a tremendous amount of unnecessary study work. It is recommend Requirement 2.5 be removed. We concur with the SDT's opinion expressed in the most recent consideration of comments that the individual component level evaluation of protection systems and redundancy requirements should be covered under the PRC standards and that the intent of the protection failure contingencies specified in Table 1 is to simulation the failure of a single protection scheme. The event description for the P5 contingency was revised in draft 5 but it continues to reflect a range of protection component failures that greatly exceed the intent of the SDT. The term Protection System is in direct conflict with the intent of the SDT, as it is defined in the Glossary to include components such as station batteries. The term Protection System should be replaced with Protection Scheme in Table 1. Requirement 4.3.1 can be interpreted to require dynamic simulation analysis of multiple fault event scenarios for transmission lines with high speed reclosing enabled. This additional analysis may be advisable for certain rare special situations but is unnecessary and burdensome as a general requirement for transmission planning contingency analysis. As such, requirement 4.3.1 will discourage application of high speed reclosing. This would be an unfortunate outcome given the benefits of high speed reclosing both for transmission reliability and customer power quality. It is recommended that 4.3.1 be reworded as follows; Simulate the operation of Protection Systems and other automatic controls as they would be expected for each contingency. The SDT has indicated in their responses to previous comments on requirement R4.3.3 that generic relay models could be used for screening purposes. While we agree with this as a practical method, the language of R4.3.3 could be interpreted to require explicit modeling of all protection and controls which is neither practicable nor an effective use of engineering resources. It is recommended that R4.3.3 be deleted.

Response: Based on your comment and those of others, the SDT has revised the definition of Year One.

> **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area.

> 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.

Material change is system specific and difficult to define on a continent-wide basis and is left to engineering judgment with a documented technical rationale as

Voter	Entity	Segment	Vote	Comment

stated in the requirement. No change made.

The SDT has clarified the requirement to address your concern.

> **Requirement R2, part 2.5 -** The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, part2.6. The technical rationale for determining material changes shall be documented.

The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns.

> **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following:
>
> **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern.

> **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:
>
> - Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
> - Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
> - Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.3 - The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern.

> **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:
>
> - Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
> - Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
> - Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

Voter	Entity	Segment	Vote	Comment
Thomas W. Richards	Fort Pierce Utilities Authority	4	Negative	FPUA believes that 5 years is not enough time in many circumstances to build significant new transmission lines. Seven years is a more appropriate lead time for the implementation plan / effective date. FPUA believes that requirement 2.1.5 on spare equipment strategy is discriminatory for smaller entities. For many smaller entities, having a spare transformer is not a practical solution and makes far less sense and has significantly more customer rate impacts than for a larger utility. Order 693 states at Paragraph 1725: "... the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy". The standard oversteps this direction by not including a consideration of planned outages versus forced outages in requirement 2.1.5, in other words, if an entity has no plans for a long term outage of a transformer, it should be excluded from the assessment of 2.1.5. Such a condition would allow an entity to assess things like gas in oil analysis to predict when a long term outage might be planned, and the flexibility between start and end dates of that planned outage. Requirement 3.3.3 as written would require modeling of nearly every phase distance relay, especially when studying extreme events. The requirement ought to have the flexibility afforded in 3.3.2 where the planner can use a conservative assumption (e.g., the proposed curves of PRC-024) for relay loadability (e.g., the requirements of PRC-023). Requirement 4.3.1 would also require modeling of nearly every phase distance relay in the Interconnection, again because it applies to extreme events and we will not know ahead of time where the power swings will traverse distance relay characteristics. FPUA agrees with Ameren's concerns about the ability of the programs to actually be able to model this requirement and FPUA fears that we are setting ourselves up for failure. We suppose that "generic" relays could be modeled to observe what distance relay characteristics are actually crossed by power swings and then, for that simulation, go back and individually model the actual relays for that specific simulation, but, that is a labor intensive process, not to mention the level of effort that would be required to maintain an interconnection wide database of relay settings. FPUA believes that the SDT ought to evaluate the perceived increase in accuracy that is intended with these requirements. It is FPUA's belief that the expected increase in accuracy is lost when considering other simulation inaccuracies that we really cannot improve (e.g., load modeling, load level modeled, dispatch modeled, etc., versus what would happen in an actual event) until much more work is done on improving our understanding of dynamic load behavior, benchmarking the model to actual system events, and possibly improvements on the ability to perform "real-time" stability analyses so that we have more practical operating experience to insert into our planning processes. Let's be practical in understanding the level of accuracy we can reasonably achieve in our simulations and model in accordance with that level of accuracy.

Voter	Entity	Segment	Vote	Comment
Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. The SDT has clarified the requirement based on your comments and those of others. **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment The SDT agrees that a planner should be able to utilize conservative assumptions and screening methods and doesn't believe that there is anything in the requirement that precludes an entity from doing so. No change made. The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern. **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: • Successful high speed reclosing and unsuccessful high speed reclosing into a Fault. • Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.				
Harold Taylor, II	Georgia Transmission Corporation	1	Negative	Georgia Transmission Corporation (GTC) supports the efforts of the study team and believes that their efforts to improve the Standard are moving in the right direction. However, we have identified the following concerns which prevent us from voting "affirmative". 1. GTC echoes ATC's concerns with the use of the word "control" in R2.7.3. (ref. ATC email; From: Shaver, Jason To: Gilbert, Don C. Manager, Electric System Planning ; bp-2006-02_ATFNSDT_TPL_in@nerc.com Sent: Wed Feb 24 09:43:11 2010 Subject: RE: Comments on TPL-001-1, Project 2006-02) An auditor could identify many things that may reasonably be within the "control" of a TP or PC, that are not covered by NERC standards or a TP / PC's process, procedures or criteria. This wide area of discretion leaves entities open to findings of possible non-compliance based solely on an auditor's perception of what he or she believes should be in the TP / PC's control. In addition, the concept of "control" must be limited to an entity's compliance obligation as a Transmission Planner and/or Planning Coordinator. In other words, an entity must be allowed the ability to identify situations which fall under its "control" as a Transmission Owner, Transmission Operator, Generator Owner or Generator Operator etc. but is beyond the responsibility of its

Voter	Entity	Segment	Vote	Comment
				Transmission Planner or Planning Coordinator functions. 2. R2.7.2 - "include actions to resolve performance deficiencies identified in multiple sensitivity studies" - Mitigation plans should not be required for deficiencies found in multiple sensitivity studies because the conditions in some sensitivity studies are more extreme and less likely than base case conditions. Some of the sensitivity study conditions are not credible or plausible enough to warrant the implementation of mitigation measures. It is not clear if the interpretation of multiple studies is more than one or a majority of the number that were studied. 3. Throughout the Standard there are circular references that make the interpretation confusing. We recommend that all references should refer back to previous sections and not to future sections, thereby avoiding circular references. 4. We disagree with the proposed definition of Year One. Year One should be the planning window that begins 12-18 months from the start of the calendar year, and not from the end of the calendar year. This would require minimal adjustments to the ERAG MMWG model building process. The proposed definition would force additional models to be built by the MMWG. 5. We agree with others that the timeframe of 60-month (5 year) for implementing Corrective Action Plans (CAP), is insufficient. We believe that the implementation timeframe must be extended to seven (7) years. GTC is aware of Requirement 2.7.3, which covers situations that arise beyond the control of the Transmission Planner (TP) or Planning Coordinator (PC), but believes that the proposed language is ambiguous. 6. We have concerns for including induction motor representations in the load models without any study or bench-marking activities to meet the requirements of R2.4.1. This information should be supplied by the LSE as part of the MOD standard. We understand that the proposed standard will accept an aggregate system load model which represents the overall dynamic behavior of the load to relieve the burden of trying to develop specific induction motor load representation at each load bus. However this modeled system response will be considerably different compared to the actual system response which will open up the industry to unwarranted scrutiny and possible compliance violation investigations. 7. We disagree with the inclusion of low voltage ride-through in requirement R3.3.2. Low voltage ride-through is a dynamic modeling issue as correctly included in requirement R4.3.2. 8. "EHV" and "HV" need to be defined in the NERC Glossary. 9. Requirement R2.4.2 needs to be better defined. It is not clear if this requirement is meant to demonstrate acceptable system performance during maintenance outages over the daily peak load

Voter	Entity	Segment	Vote	Comment
				periods of the off-peak season or intended to address light-load issues like over-voltages and frequency deviations. 10. A better definition for Consequential Load Loss is needed. The Non-Consequential Load Loss definition conflicts with the Consequential Load Loss definition. The Response of Voltage Sensitive Load exception under the Non-Consequential Load definition is a circular reference. It is not clear whether Voltage Sensitive Load is Consequential Load Loss or Non-Consequential Load Loss. 11. It is not clear if Consequential Load Loss is intended to be limited to: a) Load between two open (breaker/switches) protective devices and b) Protective devices (breakers/switches) for radial load. 12. Requirement R1.1.5 states that the system model shall represent "Known commitments for Firm Transmission Service and Interchange". GTC requests clarification of how to represent "Known commitments" whose collective magnitude can exceed the Load requirements.

Response: 1. If an entity can demonstrate that it has made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility.

2. Requirement R2, part 2.7.2 already states that an entity must supply the rationale for when actions were not necessary so the SDT believes that your concerns have already been addressed. No change made.

3. The SDT has made every attempt to make the standard as easy to follow as possible and believes that all references cited in the standard are correct. No change made.

4. Based on your comment and those of others, the SDT has revised the definition of Year One.

> **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

5. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility.

6. The SDT does not disagree that the Load Serving Entity may provide the initial information but someone needs to be responsible for adapting the model accordingly and that entity has to be the Transmission Planner or Planning Coordinator. No change made.

7. The SDT voltage ride through is not confined to the dynamic period. There are protection requirements that could result in generator tripping and that must be

Voter	Entity	Segment	Vote	Comment
considered in the steady-state analysis. The SDT has clarified the wording of the requirement. **Requirement R3, part 3.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: • Tripping of generators where simulations show generator bus voltages or high side of the Generation Step Up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. • Tripping of Transmission elements where relay loadability limits are exceeded. 8. The EHV/HV differentiation is not meant to be a definition in that it only applies to this standard. No change made. 9. The requirement was intended to cover all conditions that could occur during Off-Peak periods. No change made. 10. The definitions are not in conflict as the definition of Non-Consequential Load Loss specifically states that it doesn't include Consequential Load Loss. The response of Load to voltage is not classified as Consequential or Non-Consequential Load Loss. This standard articulates how voltage sensitive Load should be treated during different time periods of a simulation. No change made. 11. Both examples provided are Consequential Load Loss per the definition. 12. The SDT does not believe that a continent-wide standard should proscribe a single approach. Requirement R1 states that an entity must document its assumptions. No change made.				
Gordon Pietsch	Great River Energy	1	Negative	GRE recommends the following revision to the wording in subrequirement 2.5: "...the impact of proposed generation additions that have made a commitment to interconnect with the Bulk Electric System..." In addition, it appears that the drafting team has inadvertently included additional compliance requirements in the language of Table 1. The net result of this is that these requirements are effectively buried in the Table 1 language. GRE does not take exception to these additional requirements but believes that they should be included in the Requirements section of the Standard. Having the Table 1 language written as it is presents additional risks for non-compliance that would not otherwise be there if these requirements would be included in the Requirements section.
Response: The SDT has clarified this requirement based on industry comments. **Requirement R2, part 2.5 -** The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, part2.6. The technical rationale for determining material changes shall be documented.				

Voter	Entity	Segment	Vote	Comment
Without any specific comments to address, the SDT is unable to further address your concerns. No change made.				
Jacquie Smith	ReliabilityFirst Corporation	10	Negative	In R1.1.6 is OR the proper desciption of resources? Shouldn't this be AND? Resources are both supply AND demand side. Is R4.1.2 too stringent. At the least, shouldn't there be an exception for Special Protection Systems and Remedial Action Schemes to trip for apparent impedance swings? In 4.3.1 shouldn't the analysis be for both successful high speed reclosing and for unsuccessful high speed reclosing, (AND instead of OR) In Measure 8, the mixture of OR and AND is confusing. As presently written, as long as no entity makes a written request for the information they pass the test. Thus, as long as your neighbors do not complain about not receiving the information an entity is compliant. Better wording would be: The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners, or one of its adjacent Planning Coordinators, or to one functional entity ..... The responsible entity failed to distribute the results of its Planning Assessment to two or more of its adjacent Transmission Planners, adjacent Planning Coordinators, functional entity ..... Also, I think failure to distribute results is more severe than failing to respond to comments. Failing to give their neighbors an opportunity to comment is less severe than failing to acknowledge comments. I presume that the documented response to comments can be nothing more than "Thank you for your comments." All of the above are minor compared to this next problem. (I believe this needs to be addressed before we can vote yes.) The level of detail of Planning Assessment results is missing from the requirements. Is a message to your neighbors stating that you have performed a Planning Assessment and everything is OK, enough to meet the requirement, or does it need to be more detailed? The minimum contents of the Planning Assessment results shared with Transmission Planners, Planning Authorities, and other functional entities needs to be clearly stated. Also, the RRO is not a functional entity. As written, can this standard be used as justification for not sending detailed Reliability Assessment information to the ReliabilityFirst? Would requiring sharing with Stakeholders with a reliability need be better than limiting the required sharing to functional entities?
Response: The SDT believes that 'or' is appropriate. This allows for an entity to model supply or demand or both as appropriate. No change made. Requirement R4, part 4.1.2, deals with a single generator pulling out of synchronism. The situation you described is a system Stability issue and is considered an				

Voter	Entity	Segment	Vote	Comment

application for an SPS which is allowed by the standard. No change made.

The SDT has clarified the language of Requirement 4, part 4.3.1, bullet #1 to address your concerns and those of others.

Requirement R4, part 4.3.1 - Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

- Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

Measure M8 had a typo which has been corrected. The remainder of the comment seems to be directed to VSLs and the SDT reviewed the VSLs and has made a clarifying change.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity who has indicated a reliability need and that functional entity has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

R8 VSL	The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners, one adjacent Planning Coordinator, or to one functional entity that has a reliability related need and that has submitted a written request for the information, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to more than one of its adjacent Transmission Planners, adjacent Planning Coordinators, or functional entities that have a reliability related need and that have submitted a written request for the information, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

The definition of Planning Assessment details what must be exchanged. No change made.

Voter	Entity	Segment	Vote	Comment
Any functional entity such as a Regional Entity or Reliability Assurer would qualify which would allow RFC to get the information. No change made.				
Kathleen Goodman	ISO New England, Inc.	2	Negative	ISO New England is submitting a negative vote on the TPL-001 standard, because: 1. Section 2 of the standard requires annual assessment of the system regardless of whether system conditions are essentially unchanged from year to year. This creates unnecessary study work and must be changed in order for ISO NE to support the standard. 2. In Table 1 - Steady State & Stability Performance Planning Events, Category P5 wording for the EHV contingency continues to call for no loss of load in the event of the loss of a single protection system. This requirement as currently worded goes well beyond the intent of the Standard Committee as stated in response to comments as follows: "A Protection System component failure (i.e., battery) that removes multiple Protection System schemes is beyond the P5 planning event". It is ISO New England's opinion that similar language to the comment response should be incorporated into this requirement. 3. ISO New England has additional reservations about the standard that should be addressed in subsequent revisions however items 1 and 2 here must be addressed for ISO New England to support the standard.

Response: 1. The intent of the SDT wasn't that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and part 2.1.

> **Requirement R2** - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.
>
> **Requirement R2, part 2.1 -** The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, part 2.6, as follows:

2. The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns.

> **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following:
>
> **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

3. Without any specific comments to address, the SDT is unable to further address your concerns at this time. No change made.

Voter	Entity	Segment	Vote	Comment
Brian Conroy	Central Maine Power Company	1	Negative	Issues with TPL-001-1 draft 5 in ballot: R 1 & 2 - There is insufficient direction/specification regarding base case development and sensitivity testing. Only "known outage(s) of generation" is specified. R2.1.1 - Year One or year two are operating time frame studies. Year five, particularly with additional load from load growth, is appropriate for system planning. There should not be a requirement for any more than one short-term and one long-term steady-state assessment. 2.1.5 - The 'spare equipment strategy' requirement effectively amounts to a N-1-1 analysis, but without the system adjustment between contingencies. A N-1-1 analysis should be sufficient. R2 - An annual assessment of the system is required regardless of whether system conditions are essentially unchanged from year to year. Note that R2.6 is only for 'support' and are 'supplementation.' This creates unnecessary study work and must be changed in order for ISO NE to support the standard. R2.4.1 - The dynamic load model must consider the behavior of induction motor Loads in the stability assessment. The behavior of customers' induction motor loads is not known. Table 1, Category P5, EHV - loss of load in the event of a fault plus the loss of a protection system, should be allowed. This requirement as currently worded goes well beyond the intent of the Standard Committee as stated in response to comments as follows: "A Protection System component failure (i.e., battery) that removes multiple Protection System schemes is beyond the P5 planning event". The draft standard is too prescriptive in some areas and too open to various interpretations in others.

Response: System normal, or P0, is the starting system condition for the projected study conditions per the model developed in accordance with Requirement R1. Requirement R1 contains more than just 'known outages of generation' that need to be considered. The SDT has adjusted Requirement R1 to provide this clarity. The SDT believes that sufficient direction on sensitivities is in the requirement but the SDT has made a slight clarifying change to the requirement.

> **Requirement R1 -** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes the normal system condition in Table 1.

The SDT has changed the definition of Year One to more clearly show the SDT's intent. The SDT believes that two near-term studies are necessary in order to calibrate the planning assumptions against operations (Year One or year two) and to provide an additional data point for interpolation (Year One or year two and

Voter	Entity	Segment	Vote	Comment
year five). **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013. The SDT has clarified the requirement based on your comments and those of others. **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment An annual Planning Assessment is required but it can be supported by current or past studies. The SDT has clarified Requirement R2, part 2.1 accordingly. **Requirement R2, part 2.1 -** The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, part 2.6, as follows: The SDT has changed Requirement R2, part 2.1 as indicated above to address your concern. 2.4.1 The standard permits an aggregate model assumption that can be applied for a given system that is not substation specific. No change made. The SDT disagrees that Non-Consequential Load Loss should be allowed for EHV. The SDT feels that it was appropriate to raise the bar on situations that would impact the reliability and performance of the System and considered above 300 kV as the backbone of the System and thus needs to be extremely reliable and was an appropriate place for raising of the bar. The SDT has changed the text for the P5 event as a result of comments. **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following: **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).				

Voter	Entity	Segment	Vote	Comment
Lorees Tadros	Omaha Public Power District	1	Negative	It's unclear what the intent of the SDT was in Requirement R6, especially when R6 is considered in conjunction with Measurement M6. R6 includes the phrase "for conditions such as Cascading, voltage instability, or uncontrolled islanding", while M6 does not. R6 and M6 should use parallel language, similar to the way R5 and M5 use parallel language. Additionally, why is "System instability" mentioned in R6 for conditions such as Cascading, voltage instability, or uncontrolled islanding, when in Note "a" at the top of Table 1, the requirement that Cascading, voltage instability, and uncontrolled islanding not occur applies to both steady-state and stability analysis? In Note "f" at the top of Table 1, the word "applicable" was inserted in front of the term "Facility Ratings". The word "applicable" is unnecessary and should be struck. Inclusion of it could lead to certain Planning Coordinators and Transmission Planners interpreting it in ways that were never intended by the SDT. The word "applicable" should also be struck from Footnote 9 of Table 1. A reference to Footnote 9 was added to each occurrence of the word "No" in the second-to-last column of Table 1. This is confusing, because a "No" in this column means that interruption of firm transmission service is not allowed, while Footnote 9 says that curtailment of firm transmission service is allowed. This needs to be clarified.

Response: The SDT agrees and has revised the wording accordingly.

> **M6.** Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of documentation specifying any criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

Requirement R6 is documentation for criteria and methodology for risk exposure to those items. The SDT does not believe it is in conflict with header note 'a'. This is parallel to using thermal ratings to determine if lines become overloaded during the analysis. No change made.

The word 'applicable' is correct as ratings vary over time and the standard must accommodate this situation. No change made.

As a general rule, curtailment is not allowed. The footnote sets out exceptions to that as long as the conditions in the footnote are met. The SDT believes that this is the proper method to present the concept. No change made.

Voter	Entity	Segment	Vote	Comment
Garry Baker	JEA	3	Negative	JEA is concerned that there are some limited prudent cases where consumers, local jurisdictions, and state jurisdictions may find it prudent to plan on some Non-Consequential Load Loss in order to defer building transmission infrastructure for the overall benefit of the consumer. Therefore, JEA proposes the addition to the standard that allows the use of Non-Consequential Load Loss for local area planning.
Brad Chase	Orlando Utilities Commission	1	Negative	OUC appreciates that hard work of the STD and of the industry in reviewing and commenting on these standards. The STD has worked hard to try to address the concerns of the industry. OUC is voting against these standards. The proposed standard raise the bar in terms of study and performance requirements, an increase that will result in a non trivial increase in costs for utilities to meet the standards. The change in the standard did address some ambiguities in the old standard, but also introduced some new ones. Reviewing the new standard against the old OUC finds that our cost and that of our neighbors will increase to meet these standards. However OUC does not believe there will be a real increase in reliability on either the bulk system or at the individual user level due to these increased costs. In the current environment the direction from our customers is to keep rates as low as possible, and from our regulatory agency it is to have as little environmental impact as possible. The customers and regulatory agency do look at outages, but transmission is very rarely a contributor to those outages and funds expended can be better spent elsewhere, like on the distribution system or hurricane hardening, then on studying and constructing redundant transmission facilities that provide little to no increase in the end user's reliability. The standard also reduces the range of circumstances where non-consequential load loss is acceptable. OUC does not generally rely on consequential load loss for these circumstances, but this is a choice made based on feedback from our customers and local regulatory authorities. Consequential load loss, when confined to a limited area, is not a Bulk Electric System reliability issue. It is an issue best addressed locally where the cost in terms of capital facilities, condemnation, environmental impacts, probability of event and severity of event can be evaluated and a decision made that addresses these issues. A miniscule decrease in the risk of an outage would often be desirable to the community due to the subsequent rate increase and the impact of constructing power lines through their wetlands, scenic and urban areas. Since such an outage is not even noticeable at a regional scale, the choice should be left to those impacted, not mandated by NERC.
Richard Kinas	Orlando Utilities Commission	5	Negative	
Ballard Keith Mutters	Orlando Utilities Commission	3	Negative	
Kimberly J. Jones	North Carolina Utilities Commission	9	Negative	The NC Utilities Commission is concerned that the requirement prohibiting loss of non-consequential load for events in Table 1 of TPL-001-1 is an inappropriate overreach into service issues that are more appropriately addressed by state regulatory commissions. This requirement does not provide any benefit to reliability of the bulk electric system and could undermine state efforts to balance

Voter	Entity	Segment	Vote	Comment
				reliability issues with cost of service issues. Requiring remediation by a date certain could frustrate the coordinated siting of new lines with other planned infrastructure upgrades such as highways or bridges. The standard should continue to allow Transmission Planners to use discretion regarding loss of non-consequential load, understanding that state commissions are positioned to force electric utilities to address service quality issues on an expedited basis, should it be necessary and in the public interest.
Response: The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area. 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.				
Mike Laney	Luminant Generation Company LLC	5	Negative	Luminant supports the concept of a more robust transmission planning criteria as described in TPL-001-1, but has serious concerns about the timeline being proposed. The 60-month implementation timeframe associated with the elimination of non-consequential load loss does not have any mechanisms to respect the base level of construction activity already underway in the various NERC regions that may materially impact compliance with a 60-month timeline. In ERCOT, the Public Utility Commission of Texas (PUCT) has mandated the construction of over 4,400 circuit miles of transmission within the next five years to support over 18,000 MW of wind generation. The PUCT Competitive Renewable Energy Zones (CREZs) build out plan requires the ERCOT 345 kV transmission network to be expanded by ~51% (in terms of total circuit miles), necessitating complex coordination of transmission clearances for construction of new lines, making it difficult to economically operate in a secure manner. These new CREZ transmission facilities are scheduled for completion by 2014 (i.e., within the next 5 years). The concurrent implementation of TPL-001-01 will compete with the CREZ build-outs and other on-going transmission upgrades needed to support load growth in the ERCOT region, which has historically experienced higher load growth rates than other parts of the country. Given that these major activities (including CREZ) reflect the most aggressive transmission build out plan in the history of ERCOT and that the implementation of TPL-001-1 will only add to that, Luminant is concerned that adding the implementation of TPL-001-1 on top of these activities will not provide adequate clearance windows to economically or reliably implement this plan within the proposed 60-month implementation window. In light of these concerns, Luminant proposes a 120 month implementation timeline of TPL001-1 for the ERCOT region Additionally, Luminant would like to see safeguards added to TPL-001-1 that acknowledge that each NERC region must complete all of the identified transmission upgrades associated with implementation of TPL-001-1 before NERC regions are required to begin operating with this level of security constraints enforced. Given that it is not possible to operate a NERC region any more securely than it is planned to be operated, this type of safeguard may readily apparent, but explicitly

Voter	Entity	Segment	Vote	Comment
				stating it would still be helpful. With the modifications outlined above, Luminant could support TPL-001-1. Thanks for the opportunity to comment.
Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. The SDT has extended the implementation plan as described above and that Requirement R2, part 2.7.3 provides sufficient latitude for entities to accommodate your concern. No change made.				
Terry Harbour	MidAmerican Energy Co.	1	Negative	MidAmerican find P5 confusing. What analysis is required? Does P5 specify the analysis of individual components of a System Protection system, the entire protection system as a whole, or something else? Do the benefits justify the requirement?
Response: The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns. **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following: **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).				
John Canavan	NorthWestern Energy	1	Negative	NorthWestern Energy Rationale for our Vote NO: Below are NorthWestern's Comments on TPL-001-1 Draft 5: January 6, 2010: While this document has improved slightly with each successive draft, there are still several flaws that persist that NorthWestern finds to be unacceptable: 1. The definition of a Bus-tie Breaker is vague. As a practical matter any breaker could qualify. 2. The definition of Non-Consequential Load Loss doesn't fit its name. 3. The idea of a Planning Assessment (developed throughout the document) is loose enough that it seems always to be asking the Transmission Planner to "do another comprehensive study anyway just to be sure you won't get sanctioned". There were numerous discussions about this, but the Drafting team has not cleaned up the language on this. The original idea was that a TP whose comprehensive study was not rendered unusable by the developments of a single year could perform an Assessment, and reasonably re-use the results of that study for the following year. The language in R2.1 contains the language: "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following current studies, supplemented with qualified past studies as indicated in Requirement R2, part 2.6:" This language

Voter	Entity	Segment	Vote	Comment
				convinces any Transmission Planning person that an annual analytical study complete with power flow simulations is required. This requirement is onerous, since there is a significant waste of manpower and resources involved in conducting such a study when for most years a bi-annual study program would clearly be sufficient. NorthWestern considers that this one issue is worthy of a NO vote based on the excessive nature of the requirement. 4. The language in R2.3 requires a short circuit analysis to be conducted annually. As with our comment 3 above, we find this excessive. This level of vigilance is not commensurate with the potential threat of a situation where fault duty could exceed breaker interrupting capability. 5. The stricter requirements in the table for EHV lines certainly "raise the bar" for these facilities. They are also likely to reduce the enthusiasm for building such facilities. The outcome of this may be unintended consequences that are far more onerous to society that the amount of load loss that is avoided by the standard. It is not clear that this addition to the standard is well reasoned. 6. NorthWestern is concerned about the potential for uneven treatment by various auditors as they follow this standard. While there is some risk of this for any standard, we believe the language in this standard is still weak. 7. The 60 month time limit for implementing Corrective Action Plans may be quite unrealistic in the Montana transmission line environment. It really is not clear what is in the Transmission Planner's "control" in this arena. 8. The definition of "year one" is problematic. Presently the WECC does not produce base cases that are well suited to this choice. We would like to encourage the Drafting Team to work to "tighten up" the language in the standard. This particular standard is so important to the general reliability of the transmission system (BES) that it deserves an extra effort at clarity, conciseness, and thoughtful language to achieve truly beneficial practices in the design of the BES. We believe that a "NO" vote is our best recourse to promote this extra effort. We understand that this standard has been a "long time in the making". That is because it is truly a difficult drafting challenge, not because of a poor effort.
Response: 1. The definition has been iterated several times based on industry comments in the past and seems to have been accepted by the overwhelming majority of the industry to date. No change made. 2. The use of non-consequential is in line with the previously used term 'consequential' and doesn't imply that it isn't important. No change made. 3. The intent of the SDT wasn't that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and part 2.1.				

Voter	Entity	Segment	Vote	Comment
Requirement R2 - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. **Requirement R2, part 2.1 -** The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, part 2.6, as follows: 4. Past studies are allowed as long as they qualify as per Requirement R2, part 2.6 and that should alleviate your concern. No change made. 5. There are many other factors over and above this standard that will determine what entities build in the future. The SDT and many stakeholders believe that it is important to raise the bar for reliability. No change made. 6. The SDT has made every attempt to make this standard clear, unambiguous, and enforceable. Without any specific comments to address, the SDT is unable to further address your concerns. No change made. 7. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. 8. Based on your comment and those of others, the SDT has revised the definition of Year One. **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.				
David H. Boguslawski	Northeast Utilities	1	Negative	NU votes to oppose TPL-001-1 with the following comments: Northeast Utilities (NU) is very appreciative of the effort of the SDT in preparing TPL-001-1. NU believes that this effort has resulted in a new TPL standard that shows improvement over the existing TPL standards. However, there are still some important concerns that NU believes should be addressed prior to the adoption of TPL-001-1. Therefore, in its present state NU can not vote for the acceptance of the draft standard and votes to REJECT the proposed standard (TPL-001-1). NU would like the SDT to re-visit and address the concerns listed below: 1. The use of Non-Consequential Load Loss to mitigate violations arising from certain planning events: NU has objected to this requirement in comments submitted for previous drafts of TPL-001-1. NU believes that Non-Consequential Load Loss should not be considered for P1 to P7 events to achieve the level of reliability needed when planning the electric power system. The amount of load that could be shed is open ended in TPL-001-1 and this will lead to different interpretations which can be detrimental to the stakeholders. To put it simply the standard as currently drafted will lead to

Voter	Entity	Segment	Vote	Comment
				confusion as Transmission Owners, Regional Reliability Organizations, along with state and federal agencies will need to come to agreement on what the standard allows and what it doesn't. Ultimately, a standard that does not have clear measurable criteria will lead to difficulty in developing and obtaining approval for projects to achieve the required level of reliability. If the SDT and NERC believe that allowing the use of Non-Consequential Load Loss for multiple element contingencies (e.g., N-1-1 or P6 planning events) is necessary in achieving system reliability then NERC should specify that the amount should be minimal, such as less than 100 MW. 2. The use of past study reports to satisfy Requirement R2, parts R2.1 and R2.2: The language of Requirement R2, parts R2.1, R2.2 and R2.6 is confusing and will lead to different interpretations from different stakeholders. While Requirements R2.1 and R2.2 indicate that annual studies should be conducted and to be supplemented by past studies, Requirement R2.6 seems to suggest that past studies could be used instead. The SDT's response to NU's comment on this issue supports the assertion that annual studies should always be conducted even if there are no changes in the system conditions and past studies should be used for the years within the assessment period but not called out by the standard. If studies are conducted every year then why the need to use past studies. This creates unnecessary study work and should be changed. 3. Table 1 - Steady State & Stability Performance Planning Events, Category P5 Events: This requirement as currently worded goes well beyond the intent of the Standard Committee as stated in response to comments as follows: "A Protection System component failure (i.e., battery) that removes multiple Protection System schemes is beyond the P5 planning event". It is NU's opinion that similar language to the comment response should be incorporated into this requirement to avoid any confusion. 4. Base case initial conditions: NU believes that a great deal of confusion and uncertainty will be eliminated or reduced if the standard attempts to define the nature of initial base cases that should be used in planning studies. As it stands now this issue is left to interpretation, which can lead to confusion when determining appropriate planning projects to achieve a reliable power system. Depending upon the interpretation of the base case dispatches and the level of interface flows (level of stress) they may reveal reliability violations in the power system. Non-uniformity in developing base cases for an area or region may mask real reliability problems in the system. This is one of the primary weaknesses of the existing TPL standards. 5. Items 1, 2, 3 and 4 are Northeast Utilities primary concerns which should be addressed prior to NU accepting the standard. NU has additional reservations about the standard that should be addressed in subsequent revisions. 6. NU also supports the comments from other transmission owners that 60 months may not be

Voter	Entity	Segment	Vote	Comment
				sufficient to complete construction of transmission facilities.

Response: 1. The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others' concerns in this area.

12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.

2. The intent of the SDT wasn't that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and part 2.1.

Requirement R2 - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.

Requirement R2, part 2.1 - The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, part 2.6, as follows:

3. The SDT has changed the text for the P5 event as a result of your (and others') comments to address these concerns.

P5. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following:

13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

4. The SDT is trying to provide guidance without being overly prescriptive. Projected System conditions as well as the types of sensitivities that need to be studied are described. No change made.

5. Without any specific comments to address, the SDT is unable to further address your concerns. No change made.

6. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. ince problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order.

Henry G. Masti	New York State Electric & Gas Corp.	1	Negative	NYSEG supports the NYISO comments and also offer: The standard requires that dynamic load models be used that take into account induction motor effects. This information is generally not available and therefore it would be unworkable to develop an accurate model. The standard requires relays be modeled into the dynamic simulation. While standard mho, distance, or reactance distance relay model may exist, manufacturer-specific relay models often do not. Since this modeling is generally not available, it would be unworkable to develop an accurate dynamic model to test relay loadabilitiy.

Voter	Entity	Segment	Vote	Comment
Response: The standard permits an aggregate model assumption that can be applied for a given system that is not substation specific so this is not unworkable. No change made. The SDT has clarified Requirement R4, part 4.3.1, bullet #3 to address your concerns. **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: • Successful high speed reclosing and unsuccessful high speed reclosing into a Fault. • Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.				
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Negative	Oklahoma Gas & Electric (OG&E) Comments on Proposed NERC TPL-001-1 1.) OG&E feels that the effective dates of R1 and R7 shall become effective 18 months and not 12 months. Some entities budgeting cycles may not be based on 12 months and expenditures may be required by some to be compliant. 2.) OG&E feels that the effective dates of R2 through R6 shall become effective 30 months and not 24 months. This will allow entities adequate time to budget (personnel & tools), train, and perform the required studies. 3.) As others have mentioned, OG&E would like the 60 months extended to 84 months. 4.) Further examination should be conducted to evaluate the feasibility of performing the stability analysis every two years and not annually. 5.) OG&E has concerns for including induction motor representations in the load models without any study or bench-marking activities to meet the requirements of R2.4.1. 6.) The abbreviations of HV and EHV used in Table 1 shall be defined in the "Definitions of Terms Used in Standard" section. 7.) Although Table 1 has been improved, further work is needed to make Table 1 more intuitive. The notes at the beginning and ending of Table 1 seem awkward within the document.
Response: 1. The SDT believes that 12 months is sufficient. This isn't a completely new requirement – entities should be doing this work now for the existing TPL				

Voter	Entity	Segment	Vote	Comment
standards. No change made. 2. The SDT believes that 24 months is sufficient. This isn't a completely new requirement – entities should be doing this work now for the existing TPL standards. No change made. 3. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. 4. The requirement is for an annual assessment and past studies can be used if qualified as per Requirement R2, part 2.6. No change made. 5. The standard permits an aggregate model assumption that can be applied for a given system that is not substation specific. No change made. 6. The EHV/HV differentiation is not meant to be a definition in that it only applies to this standard. No change made. 7. Without any specific comments to address, the SDT is unable to further address your concerns. No change made.				
Mark Sampson	PacifiCorp	1	Negative	PacifiCorp appreciates the diligence and dedication of the Standard Drafting Team and commends the group for their hard work to bring the proposed standard TPL-001-1 to this level. PacifiCorp believes the overall language of the standard has improved to enhance its readability and the language and format of the Tables now provides some improvement in the understanding of acceptable System performance for the various Planning Events. However, inasmuch as the proposed Standard has improved, we cannot support the approval of this document at this time. The following comments and suggestions are provided in support of a no vote on the TPL-001-1 standard as currently proposed proposed. 1) As currently written our Company does not believe that 60 months is a reasonable time period to build transmission facilities to meet the new performance requirements. Building a transmission line in PacifiCorp's 6 state service areas varies significantly in regional and local planning and review process, permitting, siting, legal challenges, routing, and system path rating process can often take more than 5 years to complete from the time the project is authorized. Though requirement R2.7.3 is included to address situations beyond the control of the Transmission Planner, it leaves to the interpretation of the auditor whether the appropriate actions are being taken to resolve the issue that would continue to allow dropping of Non-Consequential Load or curtailment of Firm Transmission Service. Table 1 - Steady State & Stability Performance Planning Events Category P2 (Single Contingency). Category P2 requires responsible entities to study the opening of a line section without a fault. The standard as written states that the opening of this line section will not result in consequential load
John Apperson	PacifiCorp	3	Negative	
Sandra L. Shaffer	PacifiCorp	5	Negative	
Gregory D Maxfield	PacifiCorp	6	Negative	

Voter	Entity	Segment	Vote	Comment
				loss and no voltage or thermal violations will occur on the BES. . This requirement is applicable to EHV (above 300 kV) and HV (100-300 kV) facilities. PacifiCorp believes that this requirement should not be applicable to all HV facilities. From a reliability perspective, a more effective and efficient method would be a bifurcated functional requirement rather than a voltage requirement. In PacifiCorp's system, and in much of the Western Interconnection, a breaker that opens without a fault in the 115/138 kV system almost never has the potential to cause impacts beyond the local area. In most cases this extremely rare event (the unplanned opening of a breaker without a fault) cannot impact the EHV Bulk Electric System. As such, this requirement (P2-1) is not appropriate at the HV voltage levels. A more appropriate requirement for P2-1 would be to require this performance level only for the EHV portion of the BES and the HV facilities that perform a transmission service in addition to local load service. This should not be a requirement for HV facilities that only provide local load service. 2) Table 1-P5 Multiple Contingencies (Fault plus Protection System failure to operate) Normal System. There is a significant change in the system normal performance required for EHV systems from the current performance required in TPL-003 (Category C). This TPL-001-1 version does not allow any Non-Consequential load loss (table 1) or firm Demand (note 9) for EHV systems in the event of protection system failure and delayed clearing. This performance requirement would thus preclude use of existing protection systems that rely on remote clearing of interconnected EHV lines or stations if they provide local load service. As written the standard essentially now requires Category B performance rather than Category C performance for multiple contingencies. It is PacifiCorp's opinion that loss of Non-Consequential load or firm Demand should be allowed for the rare event involving multiple contingencies stated in P5 as long at the load or firm Demand loss is contained and controlled in the local load service area and the event does not impact other interconnected utilities or their loads. 3) Table 1 - Steady State & Stability Performance Planning Events Category P5 (Multiple Contingency (Fault plus Protection System failure to operate). Category P5 requires responsible entities to study the Event titled Failure of a single Protection System that results in Delayed Fault Clearing on one of the following: Generator, Transmission Circuit, Transformer, Shunt Device, or Bus Section. It appears that this requirement is an indication that multiple protection system failure is not allowed under the proposed TPL-001-1. This appears to be a requirement for redundant protection systems for all possible events on all voltage levels of the transmission system. It also appears that this requirement is attempting to define what comprises an adequate protection system. As the draft standard is presently written it appears that multiple protection system failures are not included in this part or any part of the draft TPL-001-1 standard. As written, it is PacifiCorp's view that any multiple protection system failure would be categorized as an Extreme Event under the draft TPL-001-1

Voter	Entity	Segment	Vote	Comment
				standard. PacifiCorp contends that the many and varied issues associated with designing appropriate protection systems should be done in the context of the development of a protection system standard and not in the context of TPL-001-1. In fact, there is currently a proposed standard going through the NERC standards development process which goal is exactly that. If the standards drafting team intends to require responsible entities to have 100% redundant protection systems on all of its BES facilities, PacifiCorp contends that this fact should be stated up front in the standard so that all interested parties may become aware of this requirement and provide informed comment. PacifiCorp believes that it is appropriate to wait until the current protection system redundancy standard under development proceeds through the SAR process and approval system, given that this in an important generic issue that affects the entire industry. Notwithstanding the inappropriateness of raising the protection system issue in the context of a planning standard, PacifiCorp believes that any planning requirement that includes the failure of a single protection system that results in delayed fault clearing must have a very clear definition of the terms "single protection system" and "delayed fault clearing" in or for entities to determine what compliance with the standard requires. The draft TPL-001-1 standard does not have clear definitions of these terms, leaving room for considerable latitude for interpretation by various responsible entities, auditors, and compliance enforcement authorities. Clear, specific, and technically defensible language is needed for these terms. 4) As drafted the standard TPL-001-1 has added requirement 2.1.5 discussing spare equipment and lead times and inclusion in the "Planning Assessment". The standard in this section is not performance based requirement but an activity based requirement as currently stated under R2 2.1.5. PacifiCorp recommends that the standard should be revised and 2.1.5 removed as it does not directly improve the systems performance requirements nor compliance stated in Table 1.

Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility.

The SDT believes that the addition of footnote 12 (when it is finalized) will address your concern.

The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area.

12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.

The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns.

Voter	Entity	Segment	Vote	Comment
P5. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following: **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94). The SDT has clarified the requirement based on your comments and those of others. **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment				
John C. Collins	Platte River Power Authority	1	Negative	Platte River appreciates the efforts and perseverance of the Drafting Team on this important standard. A "no" vote is cast because the following requirements are not clear and have RISKS for different interpretations that could result in non-compliance. (1) Table 1 Planning Events, column for Initial System Condition. Does "Loss of" refer to a planned outage or forced outage? (2) Table 1, Extreme Events, column for Stability. In Stability Event 1, what is the fault type for the first forced outage? (The second forced outage is specified as 3-phase.) (3) Contingency lists required for Planning Events in Table 1. The required scope of contingency analysis for each Category is not clear. P1. Create a list of Contingencies only for the more severe P1 type, or create lists for each of P1-1 through P1-5 types? P2. Create a list of Contingencies only for the more severe P2 type, or create lists for each of P2-1 through P2-4 types? P3. Create a list of Contingencies only for the more severe P3 type, or create lists for each of P3-1 through P3-5 types? P4. Create a list of Contingencies only for the more severe P4 type, or create lists for each of P4-1 through P4-6 types? P5. Create a list of Contingencies only for the more severe P5 type, or create lists for each of P5-1 through P5-5 types? P6. Create a list of Contingencies only for the more severe P6 type, or create lists for each of P6-1-1 through P6-4-4 types, 16 possible combinations? P7. Create a list of Contingencies only for the more severe P7 type, or create lists for each of P7-1 through P7-2 types? (4) Contingency lists required for Extreme Events in Table 1. The required scope of contingency analysis for each Steady State and Stability columns is not clear. Create a list of Contingencies only for the more severe type, or create lists for each of the "such as" types? (5) Table 1, compare footnotes 1, 3, and 5. Does a P4-3 or P5-3 contingency involving an EHV-HV transformer and causing deficiencies on the EHV allow Non-Consequential Load Loss to correct since

Voter	Entity	Segment	Vote	Comment
				the HV is the lowest voltage and override the "No" in the column for Non-Consequential Load Loss Allowed for EHV? (6) What is a "sufficient amount" and how much is a "measurable change" for sensitivity case stressing? See parts 2.1.4 and 2.4.3. (7) Are the actions associated with single vs. multiple sensitivity studies in part 2.7.2 Corrective Action Plans? (8) Are Long-term stability analyses required only if there are generation additions or changes in the long-term horizon? See part 2.5.
Response: 1. Planned outages of six months or more should be incorporated into the P0 condition as per the requirements. The events cited are forced outages. 2. It doesn't matter what type of Fault creates the first outage condition as it is the second outage that is studied. 3. The SDT believes that an entity only needs a list for those types of events that are more severe for your study area. 4. An entity doesn't need a list for each 'such as'. The rationale for those selected must be documented as stated in the requirements. 5. For an outage of an EHV/HV transformer, performance requirements specified as HV must be met. 6. Requirement R2, part 2.1.4 is part of Requirement R2 which mandates that an entity must document all assumptions utilized in the Planning Assessment. No change made. 7. Requirement R2, part 2.7.2 is for multiple sensitivities. Requirement R2, part 2.7 states that Corrective Action Plans are not required for single sensitivities. 8. Yes, it is required only if there are additions or changes in the long term.				
Christopher L de Graffenried	Consolidated Edison Co. of New York	1	Negative	Reword Table 1 Note (i) as follows: The response of voltage sensitive load that is disconnected from the system by end-user equipment associated with an event shall not be used to meet steady state performance requirements Reword Requirement R 1.1.5 as follows: Known commitments for Firm Transmission Service, and, additionally, other types of transactions provided they have been demonstrated to not violate existing reliability constraints
Nickesha P Carrol	Consolidated Edison Co. of New York	6	Negative	
Peter T Yost	Consolidated Edison Co. of New York	3	Negative	

Voter	Entity	Segment	Vote	Comment
Response: The header note is not just for disconnections by end-user equipment but would also cover the natural response of Load for voltage reduction. The suggested wording changes the intent of the SDT. No change made. The SDT believes that the defined term 'Interchange' covers other transfers as described in your comment. No change made.				
Henry Delk, Jr.	SCE&G	1	Negative	SCE&G appreciates the efforts of the Standard Drafting Team and believes this version of the TPL standard has addressed most of the significant issues found in previous versions. However, SCE&G believes there are several significant issues that need modification or further explanation. 1. SCE&G agrees with other submitted comments that the requirement to complete new transmission construction to meet new performance requirements within 60 months is too short. SCE&G believes that 84 months is more reasonable. 2. SCE&G agrees with comments submitted by Duke Energy that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues, does not provide any real benefit to Bulk Electric System (BES) reliability, and may have unintended negative consequences on reliability and service quality. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. The standard should continue to allow Transmission Planners to use discretion regarding loss of non-consequential load, such that Transmission Planners, customers, and local regulators jointly control the decision making when BES reliability is not an issue. 3. SCE&G believes there are still different interpretations of Consequential and Non-Consequential Load loss and how each should be applied or not applied. The Standard drafting team should provide several examples in its response to these comments showing how to apply and not apply Consequential and Non-Consequential Load Loss. Without clear examples, SCE&G believes many request for interpretation will be submitted to NERC by the industry.
Hubert C. Young	South Carolina Electric & Gas Co.	3	Negative	
Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area. 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. The SDT has clarified the issue of Non-Consequential Load Loss as shown above. Providing examples here of what is Non-Consequential Load Loss versus				

Voter	Entity	Segment	Vote	Comment
Consequential Load Loss would have no bearing on eventual compliance findings. The words are what matter and the SDT feels that the clarification provided should alleviate your concern.				
Charles H Yeung	Southwest Power Pool	2	Negative	SPP recommends the standards drafting team review the IRC SRC comments submitted in Oct 2009 and reassess those concerns.
Response: The SDT addressed the comments of the IRC SRC in its responses to the last posting which were captured in the Consideration of Comments report. Without any new specific comments to address, the SDT is unable to further address your concerns. No change made.				
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Negative	SWTC Comments: The SDT has done a lot of good work in developing the TPL 001 standard. However, I agree with the comments of others and suggest that another draft should be produced before the standard is sent to a ballot. SWTC forsees a problem with manpower and the cost of studies for small entities such as ourselves. This will be an extra burden and costs that will ultimately be borne by the consumer who is already not very happy lately. In part 2.7.1, remove the second sentence and all bullets. These are not measurable performance criteria. EHV" and "HV" need to be defined because they are not defined in the NERC Glossary. R4.3.2 This is an admirable goal, and we applaud the SDT's vision. However, modeling all Protection Systems may be beyond the capabilities of presently used dynamic modeling tools. The number of impedance and overcurrent relays that would need to be included for lines and transformers would likely overwhelm these programs. We are concerned that the programs in use may not have the capability to model important relay characteristics such as load encroachment or out-of-step operating characteristics. R5 & R6: Shouldn't the Load Serving Entities (LSEs) define system performance criteria instead of the Transmission Planner or the Planning Coordinator? The LSEs have an obligation to their customers and must demonstrate to their regulators that they are providing acceptable system performance and reliability of supply to their customers. The Transmission Planner and Planning Coordinator have less incentive to provide high levels of system performance. Due to regulatory difficulties in getting approvals for transmission system upgrades, there may be a tendency on the part of TPs and TCs to avoid proposing transmission upgrades, letting system performance degrade instead by abandoning traditional planning criteria and defining less stringent standards for themselves. R6 Remove the "for conditions such as ..." list.

Voter	Entity	Segment	Vote	Comment
Response: The SDT has clarified Requirement R2 and part 2.1 to make it clearer that qualified past studies can be utilized. **Requirement R2** - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. **Requirement R2, part 2.1 -** The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, part 2.6, as follows: The listed items are simply that – a list of actions that would be included. This is an allowable and encouraged format for Reliability Standards. No change made. The EHV/HV differentiation is not meant to be a definition in that it only applies to this standard. No change made. The SDT believes that your comment is for Requirement R4, part 4.3.3. The SDT has modified the wording of this requirement to address your concern. **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: • Successful high speed reclosing and unsuccessful high speed reclosing into a Fault. • Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models. These are System requirements for the BES and properly belong to the Planning Coordinator and Transmission Planner. No change made.				
Donald S. Watkins	Bonneville Power Administration	1	Negative	The Bonneville Power Administration (BPA) acknowledges and appreciates the hard work and diligence of the Standards Drafting team on such a large effort. BPA respectfully submits the following comments.

Voter	Entity	Segment	Vote	Comment
Rebecca Berdahl	Bonneville Power Administration	3	Negative	1. Requirement R1.1.2: BPA recommends that system models should only represent outages with a duration of one year or more. The planning horizon should not cover an outage less than one year because there is not adequate time for developing and implementing any necessary mitigation plan. Known outages with duration less than one year should be dealt with in the Operations horizon. In addition, the near term steady state studies represent year one or year two and year five as required by R2.1.1. Therefore it is not consistent with the rest of the standard to require modeling outages less than one year. 2. Requirement R3.5: BPA recommends removing the requirement to evaluate possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the extreme events. o This is more stringent than the existing requirement without providing any increased reliability benefit. The new standard already requires a significant increase of study cases and this additional requirement results in an undue study burden on utilities without adding any benefit. o In addition, Table 1, Extreme Events, should be reduced to a more prudent list of possible events to evaluate risks and consequences. It is obvious that several of the events, especially under item 3 (Wide Area Events), would cause cascading and it is not practical to evaluate possible mitigation plans for such extreme events. 3. Table 1: The category P2 Single Contingency should be removed. o Events P2.2, P2.3 and P2.4 should be moved to category P4 since these events are not single contingencies. P2 is a single contingency category, which by definition takes one system component out of service. Bus section faults and bus-tie breaker faults are multiple contingencies since they are events that take multiple system components out of service. o Event P2.1 "opening of a line section w/o a fault" should not be included in the planning standard. At a minimum Event P2.1 should be moved to Category P1 since it is a single contingency and it should allow Interruption of Firm Transmission Service and Non-Consequential Load Loss for the HV ((<300 kV) BES level. Many of the HV (115-kV) lines have taps that serve loads and are designed to remove all elements that the protection system and other automatic controls are expected to disconnect. This is consistent with Requirement 3.3.1 which states "Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention." Inadvertent opening of one end of an HV line section without a fault almost never has the potential to cause impacts beyond the local area, yet has a low probability of occurrence and would be very costly in some cases to mitigate. 4. Footnote 11: BPA recommends removing the reference to common Right-of-Way. This could be mis-interpreted that a common Right-of-Way longer than 1mile should be planned for under Category
Francis J. Halpin	Bonneville Power Administration	5	Negative	
Brenda S. Anderson	Bonneville Power Administration	6	Negative	

Voter	Entity	Segment	Vote	Comment
				P7. The NERC standards only include common Right-of-Way under extreme events and in this footnote. So, it would be consistent with the rest of the standard to remove this reference from the footnote and possibly make a specific reference in the Extreme Events category where it applies. 5. Requirement R2.4.1: BPA agrees with other commenter's concerns that requiring Load models that consider the behavior of induction motor Loads is premature without adequate development and benchmarking efforts. In addition, specific types of models and data required for analysis should not be mentioned here, but should be specified and submitted through the appropriate MOD Standard's. 6. Requirement R4.3.3: BPA agrees with other commenter's concerns regarding simulating the impact of transient swings on Protection System operation for Transmission lines and transformers. It would be an extremely burdensome task to model relay impedance characteristics for all elements with little or no benefit, and it is questionable whether the simulation programs would support this effort.

Response: 1. The time frame is for future outages in the planning horizon and last for at least six months. No change made.

2. The SDT disagrees as this is effectively the same requirement as presently stated in TPL-004. No change made.

The SDT does not agree that these conditions obviously will create Cascading. The SDT reminds the commenter that not all events must be studied. No change made.

3. The category descriptions are meant to characterize the events. A single event may remove more than one element from service and that has been addressed in Header note 'c'. The SDT does not believe that there are inconsistencies within the table. The P2 category describes single events that may result in multiple elements being removed from service. The P2 events differ from the multiple event categories which consider two or more sequential events. No change made.

4. The SDT has revised the footnote to provide additional clarity based on your comment.

> **11.** Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.

5. The standard permits an aggregate model assumption that can be applied for a given system that is not substation specific. No change made.

6. The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern.

> **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:
>
> - Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
> - Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
> - Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual

Voter	Entity	Segment	Vote	Comment
relay models.				
Ralph Frederick Meyer	Empire District Electric Co.	1	Negative	The Empire District Electric Company appreciates the dedication of the Standards Drafting Team Empire cannot support the approval of the proposed standard as written. Empire finds exception to the proposed standards in the following areas: 1) We disagree with the proposed requirement 2.1.5 on spare equipment strategy in that it is discriminatory for smaller entities like Empire. Having a spare transformer is not practical and makes far less sense for a smaller entity but yet has a significant rate impact to our customers. 2) We disagree with requirement 3.3.3 as written would require modeling of nearly every phase distance relay, especially when studying extreme events. The requirement deserves flexibility as allowed in requirement 3.3.2 3) We do not believe 60 months is a reasonable time period to build transmission facilities to meet the new performance requirements. Our suggestion to the drafting team would be some amount of time greater than 7 years (84 months).

Response: The SDT has clarified the requirement based on your comments and those of others.

> **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment

The SDT agrees that a planner should be able to utilize conservative assumptions and screening methods and doesn't believe that there is anything in the requirement that precludes an entity from doing so. No change made.

The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order.

Voter	Entity	Segment	Vote	Comment
Frank Gaffney	Florida Municipal Power Agency	4	Negative	The Florida Municipal Power Agency (FMPA) appreciates the hard work of the SDT, but, we believe there are significant issues that remain with the standard. FMPA believes that 5 years is not enough time to build significant new transmission lines and believes that 7 years is a more appropriate lead time. FMPA believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local quality of service issues and does not provide any real benefit to BES reliability. The standard ought to separate what an entity chooses to do for the benefit of its own customers and the impacts it may on the reliability of the BES. FMPA believes that an entity has the right to choose to utilize the existing footnote "b" in the version 0 standards if that choice does not detrimentally impact the ability to provide transmission service to others. FMPA believes that requirement 2.1.5 on spare equipment strategy is discriminatory to smaller entities. Also, Order 693 at Paragraph 1725 states: "... the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy". The standard oversteps this direction by not including a consideration of planned outages versus forced outages. Requirements 3.3.3 and 4.3.1 would require modeling of nearly every phase distance relay in the Interconnection. It is questionable whether we have the software tools to do so, and this would require a huge level of effort to maintain an interconnection wide database of relay settings for questionable benefit. FMPA believes that the SDT ought to evaluate the perceived increase in accuracy that is intended with these requirements. It is FMPA's belief that the expected increase in accuracy is lost when considering other simulation inaccuracies that we really cannot improve (e.g., load modeling) until much more work is done on improving our understanding of dynamic load behavior and benchmarking the model to actual system events.

Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order.

The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area.

12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.

The SDT has clarified the requirement based on your comments and those of others.

Requirement R2, part 2.1.5 - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a

Voter	Entity	Segment	Vote	Comment
lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment The SDT agrees that a planner should be able to utilize conservative assumptions and screening methods and doesn't believe that there is anything in the requirement that precludes an entity from doing so. No change made. The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern. **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: • Successful high speed reclosing and unsuccessful high speed reclosing into a Fault. • Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.				
Alden Briggs	New Brunswick System Operator	2	Negative	The NBSO applauds the efforts of the Drafting Team on this very important TPL standard. However, we feel that it is not quit ready for acceptance but with a few tweeks and some much needed clarity it would be. NBSO believes the BES versus BPS needs resolution as we much prefer standards that applicable to the bulk power system based on an impact assessment opposed to an arbitrary voltage level. The standard should be more flexible allowing for any trade off between temporarily shedding small amounts of load to recover from a single contingency where the alternative which may force significant transmission upgrades. The standard gives preference to a single line feeding a local area versus two lines, where the loss of one of two under high loading conditions should allow for portions of load to be shed to maintain voltage. The standard considers demand side management as an option but no allowance for instantaneous and temporary load loss that could be required before DSM could be activated. The standard should be clear that if in agreement with a distribution provider some portions of the distribution load (non-consequential load loss) may be shed for a single contingency for undervoltage and underfrequency conditions. The requirements for load models should be clarified so capture dynamic behaviour within reason.

Voter	Entity	Segment	Vote	Comment
				There should be a Q&A guide to allow for examples to clarify the requirements.
Response: The SDT does not believe that it needs to define BES. In its March 18th order, FERC suggested a continent-wide definition of the BES. No change made. The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area. **12.** Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. DSM is permitted because it is pre-arranged with the customer. For transmission systems, DSM is expected to be used in anticipation of the next transmission system Contingency, not in response to the transmission system Contingency. UVLS & UFLS are intended safety nets for operations and should not be relied upon in transmission planning. No change made. The standard permits an aggregate model assumption that can be applied for a given system that is not substation specific. Dynamic load modeling is important for correct dynamic simulations. Industry has acknowledged the need for accurate Load modeling and the SDT has codified this need in the proposed standard. No change made. While a Q&A providing examples may be helpful it would have no official bearing and such an effort is not in the project schedule.				
Gregory Campoli	New York Independent System Operator	2	Negative	The New York Independent System Operator (NYISO) believes this proposed standard is moving in the right direction with the right intentions, and while we truly appreciate the expertise and hard work that the standards drafting team (SDT) has consistently exhibited throughout this lengthy process, we have voted no on the adoption of this balloted version of the proposed NERC Standard TPL-001-1 for the following reasons: 1. The proposed Standard would significantly, and unnecessarily, shift responsibilities away from the Transmission Owner (TO). The proposal would require that for the Bulk Electric System (BES) throughout the New York Control Area (NYCA) the NYISO would annually evaluate: specified contingency events, all corrective action plans, and all spare equipment strategies. As we are not a BES facility owner, we believe that facility specific requirements should stay with facility owners. 2. The proposed Standard requires that Corrective Action Plans are included in each Planning Assessment and states "Such actions may include..." followed by a list of actions. Restricting allowable actions, and excluding runback/tripping of HVDC would have a direct impact on multiple existing facilities in New York and would adversely impact the reliability planning of the NYCA. 3. The proposed Standard would require the PC & TP to assess the impact and probability of the possible unavailability of any piece of equipment with a lead time of one year or more. Such an evaluation of spare equipment strategies would require significant additional resources and data, but

Voter	Entity	Segment	Vote	Comment
				provide no benefit to system reliability, as it is redundant to the existing N-1-1 contingency requirement (P6). 4. The proposed Standard would require an "annual" assessment of the system in order for it to be considered "current." The NYISO has a biennial reliability planning process and does not find it necessary to perform all studies annually in order to be current. We see no reliability benefit to requiring this to be done annually; in fact, dilution of planning efforts and resources is in itself a reliability risk. 5. The proposed Standard lacks a clear definition of the first year of the planning horizon. It is defined as the planning window that begins 12-18 months from the end of the current calendar year. If "Year One" is two calendar years out, what is year two? year five? This ambiguity poses an unacceptable risk to compliance. 6. For steady-state and stability analysis, the proposed Standard creates a limited list of required sensitivities, and may require sensitivities with no useful objective. The Standard should instead provide a list of suggested sensitivities to allow the planning entity to use its judgment to study sensitivities pertinent to its system. Furthermore, in the absence of a definition of base case conditions, it is difficult to determine, from a compliance standpoint, what is a "stressed" system. 7. The proposed Standard requires stability models to represent the dynamic behavior of loads, including the consideration of the behavior of induction motor loads. The NYISO, along with many other systems, has not determined a need to model dynamic loads, and therefore has not benchmarked any such models. The NYISO recommends that prior to this requirement being in place, a modeling standard should exist that is specific to dynamic loads.

Response: 1. Planning the system is the responsibility of the Planning Coordinator and Transmission Planner as per the Functional Model. The Planning Coordinator or Transmission Planner simply needs to account for those strategies and facility specific items that are passed to them by asset owners. No change made.

2. The list is not all inconclusive but a list of possible actions. The SDT agrees that runback or tripping of HVDC would be allowable actions. No change made.

3. The SDT has clarified the requirement based on your comments and those of others.

> **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment

4. The intent of the SDT wasn't that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words

Voter	Entity	Segment	Vote	Comment
may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and part 2.1. **Requirement R2** - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. **Requirement R2, part 2.1 -** The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, part 2.6, as follows: 5. Based on your comment and those of others, the SDT has revised the definition of Year One. **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013. 6. The SDT has made clarifying changes to Requirements R1 and R2, part 2.1.4 to address your concerns. **Requirement R1 -** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes the normal system condition in Table 1. **Requirement R2, part 2.1.4 -** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: 7. The standard permits an aggregate model assumption that can be applied for a given system that is not substation specific. Dynamic load modeling is important for correct dynamic simulations. Industry has acknowledged the need for accurate Load modeling and the SDT has codified this need in the proposed standard. No change made.				

Voter	Entity	Segment	Vote	Comment
Alan Adamson	New York State Reliability Council	10	Negative	The New York State Reliability Council (NYSRC) appreciates the hard work and time the drafting team has devoted during its preparation this standard. The present version represents a significant improvement over the present transmission planning TPL standards. However, the TPL-001-1 standard needs further improvement in several areas before the NYSRC can vote to approve the standard, as follows: 1. The standard requires annual assessment of the system regardless of whether system conditions are essentially unchanged from year to year. This may require unnecessary study work. 2. Testing requirements are rigidly defined in the standard, but specifically what is to be tested is loosely defined. 3. The standard requires analyses of a specific list of sensitivities. Instead, the standard should provide a list of suggested sensitivities and allow the planning entity to use its judgment to study those sensitivities that may be more pertinent to its system. 4. The standard requires stability models to represent the dynamic behavior of loads, considering the behavior of induction motor loads. New York has not modeled dynamic loads, and such modeling has never been benchmarked. For many years, simulations of actual system disturbances have been represented with excellent accuracy, without modeling loads dynamically. 5. The definition of BES (100kv bright line) is uncertain at this time. Therefore, until this definition and its application is resolved, it is not possible to know - without a clarifying provision in the standard - which portion of a system that presently has a performance based methodology, such as the New York State Power System, is subject to the TPL-001-1 standard.

Response: 1. The intent of the SDT wasn't that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and part 2.1.

> **Requirement R2** - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.
>
> **Requirement R2, part 2.1 -** The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, part 2.6, as follows:

2. What needs to be tested is the transmission system that is under the purview of the Planning Coordinator or Transmission Planner.

3. The SDT has made clarifying changes to Requirement R2, part 2.1.4 to address your concerns.

> **Requirement R2, part 2.1.4 -** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to

Voter	Entity	Segment	Vote	Comment
demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: 4. The SDT assumes that you are referring to the induction motor Load modeling required for Stability studies. The standard permits an aggregate model assumption that can be applied for a given system that is not substation specific. Dynamic load modeling is important for correct dynamic simulations. Industry has acknowledged the need for accurate Load modeling and the SDT has codified this need in the proposed standard. No change made. 5. The SDT does not believe that it needs to define BES. In its March 18th orders, FERC suggested a continent-wide definition of BES. No change made.				
James Armke	Austin Energy	1	Negative	The proposed TPL-001-1 Standard needs to be revised regarding the comments submitted by Ameren, Duke, and JEA.
Response: Please see responses to Ameren, Duke, and JEA.				
Silvia P Mitchell	Florida Power & Light Co.	6	Negative	The SDT has addressed many of the gray areas of Draft four in their consideration of comments however these comments are not part of the Standard that is currently out for ballot. Incorporating these type of clarifying comments in the Standard with the use of footnotes to clarify the intent would be a significant improvement for anyone interpreting the Standard including an auditor or investigator. The definition of Year One is an unnecessary departure from the planning practices used in most of the Eastern Interconnection. It is recommended the phrase end of the current calendar year be changed to the current calendar year. This change will allow PAs to begin their near term analysis with either next year or the year after as deemed appropriate. The performance requirements of Table 1 do not allow the loss of non-consequential load for single and multiple contingency events. The disallowance of load loss does not provide any real benefit to the reliability of the BES and is an unnecessary overreach into local quality of service issues that are best addressed by State, Provincial or Municipal authorities. There may be circumstances such as high local transmission costs or local opposition to transmission construction where prohibition of non-consequential load loss represents a poor cost/benefit or quality of life tradeoff. Providing a quantitative cap in non-consequential load loss such as 100 MW may be rationale compromise in the goal of limiting load loss for the more probable outage events. Our preference would be to retain the capability of limited non-consequential load loss. Absent this, the 60 calendar month phase in period described in the Introduction section is too short for transmission facilities rated above 300 kV. Approval and permitting of EHV transmission lines is

Voter	Entity	Segment	Vote	Comment
				extremely difficult and time consuming in most parts of the Eastern Interconnection. The phrase any material changes used in requirement R.2.6.2 will effectively cause all Planning Authorities to run all studies every year regardless of minor changes in the model. The overwhelming majority of PAs use a 10 year set of planning models developed annually by Regions or Subregions. These annual sets of planning models will always have some changes. The annual study requirement is especially problematic for Stability and Short circuit studies that require much more engineering time to complete and are much less likely to have results impacted by minor model changes such as different load forecasts. Uncertainty with audit review of technical rationale documentation will serve to focus Transmission Planning engineering resources on short term compliance to an extent that is counterproductive. Requirement 2.5 represents a significant expansion of Stability Studies into the Long Term horizon. In many cases the stability issue in long term scenarios will be with the response of new generating plants to fault scenarios such as a breaker failure event. The protection upgrades needed to mitigate performance issues are easily accomplished in the short term. The uncertainty of compliance judgment of rationale documentation will force a tremendous amount of unnecessary study work. It is recommend Requirement 2.5 be removed. We concur with the SDT's opinion expressed in the most recent consideration of comments that the individual component level evaluation of protection systems and redundancy requirements should be covered under the PRC standards and that the intent of the protection failure contingencies specified in Table 1 is to simulation the failure of a single protection scheme. The event description for the P5 contingency was revised in draft 5 but it continues to reflect a range of protection component failures that greatly exceed the intent of the SDT. The term Protection System is in direct conflict with the intent of the SDT, as it is defined in the Glossary to include components such as station batteries. The term Protection System should be replaced with Protection Scheme in Table 1. Requirement 4.3.1 can be interpreted to require dynamic simulation analysis of multiple fault event scenarios for transmission lines with high speed reclosing enabled. This additional analysis may be advisable for certain rare special situations but is unnecessary and burdensome as a general requirement for transmission planning contingency analysis. As such, requirement 4.3.1 will discourage application of high speed reclosing. This would be an unfortunate outcome given the benefits of high speed reclosing both for transmission reliability and customer power quality. It is recommended that 4.3.1 be reworded as follows; Simulate the operation of Protection Systems and other automatic controls as they would be expected for each contingency. The SDT has indicated in their responses to previous comments on requirement R4.3.3 that generic relay models could be used for screening purposes. While we agree with this as a practical method,

Voter	Entity	Segment	Vote	Comment
				the language of R4.3.3 could be interpreted to require explicit modeling of all protection and controls which is neither practicable nor an effective use of engineering resources. It is recommended that R4.3.3 be deleted.

Response: The SDT has made every attempt to fully clarify the intent of the requirements in response to official specific comments. Without specific references, the SDT is unable to act on your comment. No change made.

Based on your comment and those of others, the SDT has revised the definition of Year One.

> **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area.

> 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.

The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order.

Material change is system specific and difficult to define on a continent-wide basis and is left to engineering judgment with a documented technical rationale as stated in the requirement. No change made.

The SDT has clarified Requirement R2, part 2.5 to address your concerns.

> **Requirement R2, part 2.5 -** The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, part2.6. The technical rationale for determining material changes shall be documented.

The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns.

> **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following:
>
> **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern.

> **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

Voter	Entity	Segment	Vote	Comment
				• Successful high speed reclosing and unsuccessful high speed reclosing into a Fault. • Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models. 4.3.3 - The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern. **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: • Successful high speed reclosing and unsuccessful high speed reclosing into a Fault. • Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.
Christopher Plantev	Integrys Energy Group, Inc.	4	Negative	The Standard is moving in the right direction, but the following concern is preventing us from voting "affirmative". The timeframe of 60-months (5 year) for implementing Corrective Action Plans (CAP), is insufficient. We believe that the implementation timeframe must be extended to seven (7) years. Requirement 2.7.3, which covers situations that arise beyond the control of the Transmission Planner (TP) or Planning Coordinator (PC), but the proposed language is ambiguous. An auditor could identify many things that could reasonably be within the "control" of a TP or PC but are not covered by NERC standards or a TP / PC's process, procedures or criteria. This discretion leaves entities open to possible non-compliance violation based on an auditor's perception of what they believe should be in the TP / PC's control. In addition, the concept of "control" must be limited to an entities' compliance obligation as a Transmission Planner and/or Planning Coordinator. In other words entities must be allowed the ability identify situations which fall under its "control" as a Transmission Owner, Transmission Operator, Generator Owner or Generator Operator etc. but is beyond the responsibility of its Transmission Planner or Planning Coordinator functions.
Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can				

Voter	Entity	Segment	Vote	Comment
demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility. If an entity can demonstrate that it has made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility.				
Thomas J Trickey	Lakeland Electric	5	Negative	The timeframe of 60-month (5 year) for implementing Corrective Action Plans (CAP), is insufficient, recomend that the implementation timeframe be extended to seven (7) years.
Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order.				
Greg Lange	Public Utility District No. 2 of Grant County	3	Negative	There appears to be many questions about the correct planning long-term horizon. This alone is enough to vote no and ask the drafting team to reconsider that language and their thought process. Grant also has an issue with section 2.1.5. We are struggling with the phrase "major Transmission equipment" and the example of "a transformer". We think it is very important for equipment that is necessary for bulk transfers on the system or one that if lost would cause harm to a neighboring system to be considered in this planning standard. We don't believe a BPS standard should force prescriptive behavior onto an entity, for customer service issues. If the loss of a transformer only impacts local load, this standard should not contemplate or prescribe what the local entity should do. This leaves to much interpretation up to the auditor. The standard could easily become. "You must have spare transformers in inventory to pass compliance with this requirement". Grant is aware that this standard in version zero addressed customer load. Shame on us for not being more proactive and correcting that issue then. We have a new opportunity to correct it now and we would like to see it done. This and all standards should leave local customer service issues alone and concentrate on performance of the major transfers between generation and large load centers. This is not to say that our utilites will choose to leave load off for a year, just that the decision for how to solve this local problem should remain local.
Response: The SDT is unaware of many questions being raised on the long term horizon. Without specific comments, the SDT is unable to address your concern. No change made. The SDT has clarified the requirement based on your comments and those of others.				

Voter	Entity	Segment	Vote	Comment
Requirement R2, part 2.1.5 - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment FERC has been quite clear that this standard needs to address the issue of Non-Consequential Load Loss. The SDT has added footnote 12 to address your concerns. 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.				
Mace Hunter	Lakeland Electric	3	Negative	There are two requirements in this Standard that could be interpreted in many different ways and will greatly complicate dynamic simulation studies. 4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention while also considering the impact of successful or unsuccessful high speed reclosing. 4.3.3. Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers. Most problematic is 4.3.3 which can be interpreted as requiring discrete models of all relays protecting transmission lines and transformers. This is an impossible task. Developing explicit relay models for simulations of even a small subset of BES equipment would be an enormous engineering effort with little or no benefit. The SDT's response to this criticism is, "This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line." There are two problems with this response. First, if the SDT wishes to allow for the use of screening methods then this allowance needs to be part of the Standard language. The Standard development comments and responses have no standing once the Standard is approved by FERC as law. A narrow, strict interpretation of the Standard based on requirement language is to be expected from auditors and investigators. A second problem with the above SDT response is that applicability of generic models is subject to technical challenge. The generic model available within PSS/E sets up circular characteristics for each branch element that are fixed percentages of the branch impedance. These fixed, non adjustable percentages are 46% for zone A, 75% for zone B and 110% for zone C. These generic reaches are significantly smaller than loadability limits allowed under the PRC-023-1. The intent of Requirement 4.3.3 would be better served if reworded as follows; "R4.3.3 Consider the impact of dynamic swings on protection systems and model protection operation where appropriate" Requirement 4.3.1 can be

Voter	Entity	Segment	Vote	Comment
				interpreted to require dynamic simulation analysis of multiple fault event scenarios for transmission lines with high speed reclosing enabled. This additional analysis may be advisable for certain rare special situations but is unnecessary and burdensome as a general requirement for transmission planning contingency analysis. As such, requirement 4.3.1 will discourage application of high speed reclosing. This would be an unfortunate outcome given the benefits of high speed reclosing both for transmission reliability and customer power quality. It is recommended that 4.3.1 be reworded as follows; "4.3.1 Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each contingency."

Response: The SDT has modified the requirement to address your concern.

Requirement R4, part 4.3.1 - Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

- Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern.

Requirement R4, part 4.3.1 - Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

- Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

Voter	Entity	Segment	Vote	Comment
Larry Akens	Tennessee Valley Authority	1	Negative	TVA appreciates the work of the ATFN drafting team over the last several years in drafting this new standard. TVA does have concerns on several issues that need to be corrected as we move forward with this standard. Therefore TVA is voting "Negative" on this proposed standard due to the following issues: 1. TVA believes that the 5 year implementation plan allowed for "Raising the bar" facilities does not allow sufficient time for TVA to construct the required new facilities. TVA average time for constructing a new 500-kV line is approximately 7 to 10 years, given the lead time on ROW and following all NEPA requirements. If the 5 year implementation plan is not increased, TVA is also concerned about the extensive outages that must take in upgrading 500-kV facilities in order to meet the 5 year requirement. This would require multiple 500-kV outages in the same timeframe which could have a detrimental effect on the overall Bulk Electric System reliability during this construction phase. TVA does understand that the team has added language regarding the TP or PC inability to get the projects completed through no fault of its own; however, there is no guarantee that TVA will be found compliant if all the work cannot be accomplished in this time frame. 2. TVA believes that the footnotes b and c that allow for local load drop in the current TPL standards should still be allowed. TVA understands that this is addressed in FERC Order 693; however, the capital improvements to fix many of these issues will have no overall reliability gain for the Bulk Electric System. 3. TVA is concerned that no generating unit shall pull out of synchronism for Planning Event P1, while the standard does allow generator runback/tripping for the same event. TVA believes that this requirement is overly burdensome without providing any material improvement in system reliability. Additionally, R4.1.1 directly conflicts with Table 1, Note a (applicable to both Steady State & Stability) which states "Consequential Load as well as generation loss is acceptable as a consequence of any planning event ... excluding P0." TVA strongly suggests that this loss of synchronism be allowed for P1 or at least add the ability to trip these units for this P1 event by out of step relaying - since other means of tripping the units are allowed - such as thru the use of other actions including Special Protection Schemes as long as the instability does not spread beyond a local area. 4. TVA is concerned with the inclusion of battery failures being included in event P5. P5 states "Multiple Contingency Fault plus Protection System failure to operate". TVA understands that the drafting team believes that batteries are not intended to be included in this event; however, station batteries are presently included in the NERC Glossary definition of "Protection Systems." TVA believes that specific language excluding batteries is required for this P5 event in order to prevent future compliance issues regarding this.
George T. Ballew	Tennessee Valley Authority	5	Negative	
Marjorie S. Parsons	Tennessee Valley Authority	6	Negative	

Voter	Entity	Segment	Vote	Comment
Response: 1. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. 2. The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area. 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. 3. The SDT believes that if an entity has a known condition that identifies a generation unit(s) is prone to trip for a single Contingency event then the entity should proactively trip the unit(s) rather than relying on out-of-step protection to trip the unit. The SDT takes this position because of the concern of the possible detrimental effects of loss of synchronism on the overall reliability of the BES. No change made. 4. The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns. **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following: **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).				
Lee Schuster	Florida Power Corporation	3	Negative	We appreciate the challenging and time-consuming work that has been done by the Standard Drafting Team (SDT) to draft TPL-001-1 according to the specific requests made by FERC in Order 693. We are supportive of planning, constructing, operating and maintaining the most reliable Bulk Electric System (BES) that is reasonably feasible. We believe that collectively the industry has exhibited excellent BES reliability under existing NERC TPL Standards. For this reason and for others detailed below, we will vote "no" on the proposed standard. 1. We do not believe that 60 months is a reasonable time period to build transmission facilities to meet the new performance requirements. This is especially true of EHV projects. Ameren recently stated in an email to the RBB that "[b]uilding a transmission line in Illinois is estimated to take 7 years (84 months) from the time the project is authorized." In our own experience, we have been limited by permitting and local government processes to the extent that even 69 kV, 115 kV and 230 kV line projects are taking longer than 60 months. We therefore agree with Ameren's point that building of a new EHV transmission line can be a very lengthy process. We think that a more
Sam Waters	Progress Energy Carolinas	3	Negative	

Voter	Entity	Segment	Vote	Comment
Wayne Lewis	Progress Energy Carolinas	5	Negative	appropriate time frame would be 84 months, with provisions to limit or waive fines if a Transmission Owner can demonstrate that the implementation process was unavoidably impeded by permitting, environmental or governmental processes. 2. As has been stated in all four commenting periods by Progress as well as certain other registered entities, we believe that the requirement prohibiting loss of non-consequential load for events in Table 1 of TPL-001-1 is an inappropriate overreach by the standard into local load quality of service issues that are already adequately regulated by states' Public Service/Utility Commissions, and does not provide any benefit to BES reliability. The approach of prohibiting the shedding of even a single distribution feeder amounts to feeder reliability rather than BES reliability. This approach, if allowed to be in the Standard, may result in unintended negative results in BES reliability. We therefore appeal to the SDT to discuss this issue with NERC and FERC given the numerous utilities that share this concern. The standard should continue to allow Transmission Planners to use discretion regarding loss of non-consequential load. 3. Requirement R4.1.1 states in part that "for planning event P1: No generating unit shall pull out of synchronism." This requirement is overly burdensome without providing any material improvement in system reliability. Additionally, R4.1.1 directly conflicts with Table 1, Note (a) (applicable to both Steady State & Stability) which states "Consequential Load as well as generation loss is acceptable as a consequence of any planning event ... excluding P0." Clearly, the intent the TPL-001-1 standard is to maintain the integrity and reliability of the overall grid, not any particular element. In other words, throughout the standard it is acceptable to lose any generator, load, line or other element as long as more wide reaching consequences are precluded (i.e., cascading outages, non-consequential load loss, etc. is not allowed). As written, R4.1.1 would not allow the use of out of step protective relaying as a solution to trip an unstable generator for a P1 event. It does allow tripping of the same generator due to "fault clearing action" (such as for a fault on the generator terminals) or "by a Special Protection System". Therefore the loss of the generator itself must be acceptable. The notion that preventing loss of synchronism events is the only acceptable means of also precluding more widespread (and unacceptable) consequences resulting from the effect of stability swings is not valid. For some generating units (particularly small, remotely located units) these other unacceptable consequences may not even occur. Also, other means, such as out of step blocking of transmission lines applied in conjunction with out of step generator tripping, may be an effective solution. Any of these solutions is allowed for events P2 through P7 in requirement R4.1.2. We recommend that Requirement R4.1.1 be deleted and R.4.1.2 be revised to include events P1 through P7. Given the concerns raised above, we respectfully request that the SDT make the suggested improvements to TPL-001-1 and continue the process toward approval of the Standard.

Voter	Entity	Segment	Vote	Comment
Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area. 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. 3. The SDT believes that if an entity has a known condition that identifies a generation unit(s) is prone to trip for a single Contingency event then the entity should proactively trip the unit(s) rather than relying on out-of-step protection to trip the unit. The SDT takes this position because of the concern of the possible detrimental effects of loss of synchronism on the overall reliability of the BES. No change made.				
Jason L Marshall	Midwest ISO, Inc.	2	Negative	We are voting negative for several reasons. 1. We believe Requirement 2, Part 2.1.5 is an administrative requirement that is not consistent with the NERC BOT approved results/performance based standards effort. Furthermore, the additional reliability benefit is not clear to us. 2. We believe that Requirement 2, Part 2.3 should only be implemented when there is another requirement in the PRC standards for Transmission Owners and Generation Owners to supply the necessary protection information. 3. We believe that that Requirement 2, Part 2.4.1 needs to be further clarified that the dynamic behavior of load model is an estimate only based on engineering assumptions. As written now, it is not clear how much deviation is allowed from actual system operation. 4. We believe Requirement 4, Part 4.3.2 should not be implemented until there is a requirement for the Generator Owners/Operators to supply their generator low voltage ride through capability. 5. We believe Requirement 4, Part 4.3.3 should be further refined to clarify that the purpose is to screen zone 3 relay issues. As written now, it appears that zone 3 relays must be modeled in detail because it is not clear that the intent is to only screen potential problems. We are basing our comments on the drafting team's responses to previous comments that they view using generic zone 3 relay models in PSS/E is acceptable.
Response: 1. The SDT disagrees that this is an administrative requirement as it does not state that you must develop a strategy; it states that you must consider the strategy in your planning. Therefore, it has a direct bearing on the reliability of the BES. No change made. 2. This standard describes what must be done and not how to do it. The SDT expects that the information cited could be obtained through several different				

Voter	Entity	Segment	Vote	Comment
mechanisms such as delegation agreements or data requests. No change made. 3. The SDT has added the word 'expected' to the text to alleviate your concern. Planning models are based on the best information available to the planners at the time of the study and it is well understood that they may not exactly represent actual conditions at any given time. The results of on-going benchmarking and model development activities can be incorporated when those activities yield more representative results. **Requirement R2, part 2.4.1** - System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. 4. This standard describes what must be done and not how to do it. The SDT expects that the information cited could be obtained through several different mechanisms such as delegation agreements or data requests. No change made. 5. In the summary considerations in draft 4 of this project, the SDT indicated that generic relay models can be applied. If this model shows impedance swings in a branch element, then one can either take action according to the generic model results or investigate the characteristics of the relays actually used on that branch. In this draft, the SDT has clarified the requirement for the use of generic relay models. **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: • Successful high speed reclosing and unsuccessful high speed reclosing into a Fault. • Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.				
Brenda L Truhe	PPL Electric Utilities Corp.	1	Negative	We are voting 'no' on this ballot as this revision proposes to expand contingency requirements beyond traditional planning levels (example - stuck breaker AND protection failure).
Mark A. Heimbach	PPL Generation LLC	5	Negative	
Response: The SDT agrees that new expectations are contained within the requirements aimed at improving BES reliability. An implementation plan has been created to allow for the industry to comply with the new requirements.				
Terry L. Blackwell	Santee Cooper	1	Negative	We disagree with the proposed definition of Year One. We believe that Year One should be the planning window that begins 12-18 months from the start of the current calendar year, and not from

Voter	Entity	Segment	Vote	Comment
Zack Dusenbury	Santee Cooper	3	Negative	the end of the calendar year. We believe that following this modification to the definition would require minimal adjustments to the ERAG MMWG model building process, which we all use as the basis for our planning models. Following the proposed definition would require additional models to be built by the MMWG or lead to holes in the model building effort for both the operating and planning horizons. SCPSA does not believe that 60 months is a reasonable time period to build transmission facilities to meet the new performance requirements. In an email to the registered ballot body, Ameren stated " Building a transmission line in Illinois is estimated to take 7 years (84 months) from the time the project is authorized." SCPSA agrees with the point that Ameren is making that building of a new EHV transmission line can be a very lengthy process. SCPSA thinks that a more appropriate time frame would be 84 months. SCPSA believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues, does not provide any real benefit to Bulk Electric System (BES) reliability, and may have unintended negative consequences on reliability. Often, corrective actions to mitigate these events are local in nature and only require minor additional loss of local load to avoid major projects. The standard should continue to allow Transmission Planners to use discretion regarding loss of non-consequential load, such that Transmission Planners, customers, and local regulators jointly control the decision making when BES reliability is not an issue. The transparency requirements of the new standard facilitate this type of decision making. In addition, the prohibition on non-consequential load loss for these events creates an incentive for Transmission Planners to remove lines serving load from network (serve the loads radially) so that they are characterized as consequential load. The unintended consequence of the standard would be a reduction in reliability for service to local load.
Suzanne Ritter	Santee Cooper	6	Negative	

Response: Based on your comment and those of others, the SDT has revised the definition of Year One.

> **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order.

The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area.

Voter	Entity	Segment	Vote	Comment
12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.				
Thomas C. Mielnik	MidAmerican Energy Co.	3	Negative	We find P5, Multiple Contingency (Fault plus Protection System failure to operate) to be confusing. What analysis is required for this? Analysis of individual Protection System component failures or something else? Do the benefits justify this requirement?
Response: The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns. **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following: **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).				
Ajay Garg	Hydro One Networks, Inc.	1	Negative	We thank the Standard Drafting Team for their long and dedicated effort to develop this standard. At this time, Hydro One has decided to cast a negative vote with the following comments: 1. Note 3 in Table 1 refers to EHV Facilities (above 300 kV) and HV (300 kV and lower voltage systems) The standards uses this threshold to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss. We suggest the following be added to this note: "In the region(s) or area where there is a performance based methodology in place to determine Bulk Electric System (BES) elements (e.g. NPCC), only the BES portion of the system is subject to the Standard." 2. The Standard repeatedly uses the capitalized term "Firm Transmission Service (FTS)." The NERC Glossary of Terms defines FTS as "The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." We believe that the use of this term and that of "Transmission Service" in TPL-001-1 should be revised as they do not have the same meaning in all jurisdictions. A clarification within the standard will eliminate this confusion. 3. The Effective Date Section in the proposed standard gives a time of 60 months to implement certain Corrective Actions. We believe this Standard should not explicitly define timelines (5 years in this case) for transmission projects. Regulatory approvals for new or modified transmission systems may take a significant time in some jurisdictions. We suggest changing the wording to say that Transmission mitigation measures for the reliability of the Bulk Electric System must be implemented as soon as practical exercising due diligence. Progress of and/or delays associated with critical project(s) impacting BES reliability should be submitted to the respective regions and NERC. We recognize that Requirement 2.7.3 covers situations that arise beyond the control of the Transmission Planner (TP) or Planning Coordinator (PC), but we believe that the proposed 60 months timeline
Michael D. Penstone	Hydro One Networks, Inc.	3	Negative	

Voter	Entity	Segment	Vote	Comment
				should be removed.
Response: This standard applies to the BES. If there are areas of your system that are not BES, then the standard doesn't apply to them. This would be true even if those elements are above 300 kV. No change made. The SDT reviewed the use of Firm Transmission Service and believes that the term is used correctly in the standard. No change made. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility.				
Mark Ringhausen	Old Dominion Electric Coop.	4	Negative	While the SDT has made progress in their changes from the first draft, there are still some areas that need to be clarified. Others are proving more specific comments (PJM) so look for their comments and address.
Response: Please see response to PJM.				

Voter	Entity	Segment	Vote	Comment
Richard Salgo	Sierra Pacific Power Co.	1	Negative	While we greatly appreciate the work of the SDT, and feel that this Standard has achieved significant improvement, there are a number of issues precluding our approval as written: Spare Equipment: need a clarification on what the "assessment" of the impact of equipment availability entails. For instance, is the assessment a simple narrative of the necessary operational mitigation, engineering analysis of the impact, or on the other extreme, is it a full repeat of the NERC study work for all potential permutations of long lead-time equipment? We have difficulty accepting the language regarding the loss of non-consequential load. As written, this creates a disincentive for the implementation of incremental reliability improvements in the network; ie, creation of a parallel path that does not fully provide redundancy to load service would drive a violation of the requirement. Lastly, the treatment of firm transmission service from the standpoint that it cannot be curtailed under various contingencies is problematic. As written, it would appear that the single-contingency loss of a contract transmission path would require continuance of the firm transmission service via some alternate parallel path. Such methodology would require all such paths to have redundancy via parallel transmission or result in dramatic reductions in transfer ratings.

Response: The SDT has clarified the wording of the requirement and believes that this will address your concern.

> **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area.

> 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.

Footnote 9 states the conditions for when Firm Transmission Service may be curtailed. If what you are describing is actually Conditional Firm, then see footnote 4. No change made.

Informal Comments on Assess Transmission Future Needs – Project 2006-02.

The TPL-001-2 standard for Assess Transmission Future Needs (Project 2006-02) Drafting Team thanks all commenters who submitted comments on the fifth draft overview. These standards were posted for a 30-day public comment period from August 3, 2010 through September 2, 2010. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 7 sets of comments, including comments from 77 different people from approximately 69 companies representing 6 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

The SDT has completed the review of the informal comments from industry for Project 2006-02: Assess Transmission Future Needs. Each and every comment was reviewed and considered by the SDT regardless of whether there is a formal written response shown. The majority of the cases where the SDT did not make a change or provide a written response was because the SDT had already responded to the issue or the SDT did not believe that the proposed revision added clarity or otherwise improved the quality of the proposed standard.

The SDT made a number of changes due to the comments received from industry and drafting team discussions arising from those comments as highlighted below:

- Year One definition – deleted 'must'
- Conforming changes to the language in the Effective Date – made language consistent with the Implementation Plan
- Requirement R1 and M1 – changed, ". . . the latest data consistent with . . ." to "data consistent with. . . " and established P0 as normal System condition in Table 1
- Requirement R2, part 2.1.4 – replaced 'performance' with 'System response' and changed last bullet from ". . . planned Transmission outages" to ". . . known Transmission outages"
- Requirement R2, part 2.6.2 – require documentation explaining material changes
- Requirement R2, part 2.7.1 – made it clear that statement is not all inclusive
- Requirement R2, part 2.8.2 – made language consistent with Requirement R2, part 2.7.4
- Requirement R4, part 4.3.1, bullet #1 – added qualifier for high speed reclosing
- Requirement R6 and M6 and data retention for R6 – changed 'any' to 'the'
- Table 1, header note 'i' – deleted 'including Load'
- Table 1, P0 – delete superscript in column 6
- Table 1, P2 – added 'Breaker' to description
- Table 1, P4 – added 'Breaker' to description
- Table 1, P5: added 'non-redundant'
- Table 1, extreme events – Stability: made language consistent with Table 1, P5
- Measure M8 – spelled out the functional entity involved
- Data retention for Requirement R7 – deleted 'all such'
- Changed, "Initial System Conditions" to "Initial Conditions" in column heading of Table 1 and Table 1 Note 9
- Deleted section, "Compliance Monitoring and Reset Timeframe as this is no longer included in the standard template.

The SDT believes that with these changes, the industry concerns have been addressed except for Footnote 12 (content of existing footnote b). Until the issues with footnote 'b' in Project 2010-11: TPL Table 1 are resolved, the SDT will not request the Standards Committee to move the project to the ballot phase. This could mean that Project 2006-02 may sit in limbo for several months pending the outcome of the Project 2010-11 deliberations. So that industry can see what has transpired with regard to their comments on Project 2006-02, the SDT is requesting that the consideration of comments document, along with the redlined version of TPL-001-2 corresponding to those comment responses be posted immediately. In this way, the industry can see what the SDT has decided in response to comments while the content of the comments is still fresh in the minds of the commenters. The SDT encourages anyone reading the posted documents to reach out to members of the SDT for informal discussions of posted documents.

Once Project 2010-11 is resolved, the wording for footnote 'b' will be essentially copied to TPL-001-2. The SDT realizes that this cannot be a simple cut and paste due to format differences between the old standard and the revised TPL-001-2 and will take appropriate actions to make things fit correctly. Once this has been accomplished, the SDT expects to ask the Standards Committee to move Project 2006-02 to the ballot stage.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

1. The SDT has revised the Implementation Plan based on industry comments to the initial ballot. Do you support this change? If you do not support this change, please specify why you disagree and include specific alternative language to resolve your concern. 10

2. The SDT has revised the definition of Year One based on industry comments to the initial ballot. Do you support this change? If you do not support this change, please specify why you disagree and include specific alternative language to resolve your concern. 20

3. The SDT has revised the Requirements language based on industry comments to the initial ballot. Do you support these changes? If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your cncern. 28

3.1 Requirement R2 and Part 2.1 – past studies 36

3.2 Requirement R2, Parts 2.1.4 & 2.4.3 – sensitivity analysis: 47

3.3 Requirement R2, Part 2.4.1 – dynamic load models: 57

3.4 Requirement R2, Part 2.5 – material clarification: 64

4. The SDT has revised the header notes based on industry comments to the initial ballot. If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your concern. 70

5. The SDT has revised the performance table (including the list of extreme events and footnotes) based on industry comments to the initial ballot. If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your concern. 78

6. The SDT has revised the Measures based on industry comments to the initial ballot. If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your concern. 95

7. The SDT has revised the Requirement R8 VSL based on industry comments to the initial ballot. If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your concern. 102

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Mallory Huggins	NERC Staff										
2.	Group	Philip Kleckley	SERC Planning Standards Subcommittee	X		X		X					
3.	Group	Guy Zito	Northeast Power Coordinating Council										X
4.	Group	David Kiguel	Hydro One Networks Inc.	X		X							
5.	Group	Bob Cummings	Transmission Issues Subcommittee										
6.	Group	Robert Jones	SERC Dynamics Review Subcommittee	X									X
7.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee										X
8.	Group	Richard Kafka	Pepco Holdings, Inc - Affiliates	X		X		X	X				
9.	Group	Ben Li	IRC Standards Review Committee		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
10.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				
11.	Individual	Eric Mortenson	Exelon Transmission Planning	X									
12.	Individual	Andy Tillery	Southern Company	X		X							
13.	Individual	Steve Rueckert	Western Electricity Coordinating Council										X
14.	Individual	Jana Van Ness, Director Regulatory Compliance	Arizona Public Service Company	X		X		X					
15.	Individual	Brent.Ingebrigtson@eon-us.com	E.ON U.S.	X		X		X	X				
16.	Individual	Richard Becker	Florida Reliability Coordinating Council, Inc - Transmission Working Group	X	X	X	X						X
17.	Individual	Brandy A. Dunn	Western Area Power Administration	X					X				
18.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
19.	Individual	Ray Mason	ReliabilityFirst										X
20.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
21.	Individual	Catherine Mathews	NorthWestern Energy (NWMT)	X									
22.	Individual	Phuong Tran	Lakeland Electric	X		X		X					
23.	Individual	Tom Duane	PNM	X		X							

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
24.	Individual	Doug Hohlbaugh	FirstEnergy	X		X	X	X	X				
25.	Individual	John Collins	Platte River Power Authority	X		X			X				
26.	Individual	Aaron Staley	Orlando Utilities Commission	X									
27.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
28.	Individual	Randi Woodward	Minnesota Power	X									
29.	Individual	Martin Bauer	US Bureau of Reclamation					X					
30.	Individual	Paul Rocha	CenterPoint Energy	X									
31.	Individual	Tim Ponseti, VP	TVA Transmission Planning & Compliance									X	
32.	Individual	Dan Rochester	Independent Electricity System Operator		X								
33.	Individual	Dilip Mahendra	SMUD	X		X	X	X					
34.	Individual	RoLynda Shumpert	South Carolina and Gas	X		X		X	X				
35.	Individual	Brian Keel	SRP	X									
36.	Individual	Darcy O'Connell	California ISO		X								
37.	Individual	Scott Inglebritson	Seattle City Light	X		X	X	X		X			
38.	Individual	Ean O'Neill	California Energy Commission									X	
39.	Individual	Kathleen Goodman	ISO New England Inc.		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
40.	Individual	Oscar Herrera	Los Angeles Department of Water and Power	X		X		X	X				
41.	Individual	Orlando A Ciniglio	Idaho Power Co	X		X							
42.	Individual	David Bradt	United Illuminating	X		X							
43.	Individual	John Sullivan	Ameren	X		X		X	X				
44.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
45.	Individual	Sergio Garza	LCRA TSC	X									
46.	Individual	Saurabh Saksena	National Grid	X		X							
47.	Individual	Charles Lawrence	American Transmission Company	X									
48.	Individual	Thad Ness	American Electric Power (AEP)	X		X		X	X				
49.	Individual	Bill Middaugh	Tri-State Generation & Transmission	X									
50.	Individual	David Miller	Lakeland Electric	X		X		X					
51.	Individual	Steve Stafford	GTC	X									
52.	Individual	Chifong Thomas	Pacific Gas and Electric Company	X		X		X					
53.	Individual	Michael R. Lombardi	Northeast Utilities	X		X		X					
54.	Individual	Christopher L. de	Consolidated Edison Co. of New York, Inc.	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
		Graffenried											
55.	Individual	Spencer Tacke	Modesto Irrigation District			X	X						
56.	Individual	Alex Rost	NBSO		X								
57.	Individual	Curtis A. Beveridge	Central Maine Power Company	X									
58.	Individual	Darryl Curtis	Oncor Electric Delivery	X									
59.	Individual	Jeffrey McKinney	New York State Electric & Gas Corp	X									
60.	Individual	Bart White	Progress Energy	X		X		X	X				
61.	Group	L Zotter, M Morais, J Billo, J Conto, S Jue, JC Culberson, J Teixeira, G Gnanam, S Myers	ERCOT ISO		X								
62.	Individual	Gary Trent	Tucson Electric Power Company	X		X		X					
63.	Individual	Gregory Campoli	New York Independent System Operator		X								
64.	Individual	Claudiu Cadar	GDS Associates, Inc.	X									
65.	Individual	Terry Harbour	MidAmerican Energy	X									
66.	Individual	Catherine Koch	Puget Sound Energy	X									
67.	Individual	Joe Tarantino	Sacramento Municipal Utility District	X		X	X	X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
68.	Individual	Patrick Farrell	Southern California Edison Company	X		X		X	X				
69.	Individual	John Mayhan	Omaha Public Power District	X		X		X	X				
70.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X				

1. **The SDT has revised the Implementation Plan based on industry comments to the initial ballot. Do you support this change? If you do not support this change, please specify why you disagree and include specific alternative language to resolve your concern.**

Summary Consideration:

The majority of respondents agree with the changes to the Implementation Plan and no further changes to the Implementation Plan are deemed necessary.

The SDT fully realizes that Project 2010-11 (Table 1 - footnote "b") must reach resolution prior to finalizing TPL-001-2 and stated the same in the information attached with the fifth posting of Project 2006-02.

The SDT reviewed the comment on consistency of language in the Implementation Plan and the Roadmap and agrees with the comment. The paragraph under Effective Date in the standard has been changed accordingly.

> For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required on the first day of the first calendar quarter 84 months after Board of Trustees adoption, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-2, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-2:

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered the comments. In many of the cases relating to the comments, the SDT has already responded to similar comments and those responses are quoted here for convenience:

1.1.5 – "The SDT believes that the base cases should include any area interchange that is planned between utilities." In addition, non-firm transactions are not required to be modeled.

2.1.5 – "When a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. This requirement is intended for the Planning Coordinator and/or Transmission Planner to take into account its spare equipment strategy for long lead time Equipment when assessing the performance of its System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Actions such as out of merit dispatch, operational restrictions, System reconfiguration can be part of a Corrective Action Plan if the System cannot meet performance requirements without the Facility in service."

2.3/2.8 – "is intended for the Planning Coordinator and/or Transmission Planner to assess whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt. Even though the effects of short circuit capability are localized and may be related to new planned Facilities, it is important to BES reliability."

3.4.1/4.4.1 – "The SDT has determined that it is necessary for the Planning Coordinator and Transmission Planner to coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list created." In addition, the SDT wants to make it clear that an entity is responsible for corrective actions on its own System.

4.3.1 – "does not require modeling of Protection System equipment. It just requires you to have simulations which include the effects of Protection System equipment operation. You don't have to specifically model a relay to simulate the effect of clearing a fault at 3 cycles. If you need to model a relay to capture its effect, then model that relay. And certainly engineering judgment should be used to determine which relay effects should be included in the simulations."

References to TPL-001-1 are a typo and will be cleaned up. The correct reference, as pointed out, is TPL-001-2.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council Consolidated Edison Co. of New York, Inc	No	Requirement R1 Part 1.1 and following states "System models shall represent:... 1.1.5. Known commitments for firm Transmission Service and Interchange. It was commented during a previous posting that 1.1.5 should be reworded to read: Known commitments for Firm Transmission Service, and, additionally, other types of transactions provided they have been demonstrated to not violate existing reliability constraints. The response was that "The SDT believes that the defined term 'Interchange' covers other transfers as described in your comment. No change made."It is agreed that known Interchanges should be modeled. However, it is imperative that existing reliability constraints not be violated in the process. That is, Interchange relating to economic transactions should not drive planning studies. Reliability related investments should not be driven by congestion related to economic transactions incorporated into planning models. Following is a preferred/revised wording: o 1.1.5. Known commitments for firm Transmission Service and Interchange. Interchange is meant to refer to energy transactions other than firm Transmission Service. While rigorous planning studies have been conducted to permit the uninterrupted implementation of firm Transmission Service without jeopardizing the reliable operation of the Interconnected System, other types of energy transaction only take place whenever system conditions permit them. They are usually of very short duration relative to planning assessment periods (usually spanning for a few hours to a few days) and deemed highly interruptible subject to reliability issues that may arise during operation of the system. In other words, the term Interchange refers to economic transactions that are permitted when the system is secure and there are reasonable reliability margins to effect dispatch changes to lower operating costs. As such, Interchange should not be reflected in system representation meant to assess system reliability in adherence to reliability criteria delineated in documents such as TPL-001.

Organization	Yes or No	Question 1 Comment
GDS Associates, Inc.	No	We disagree with the Implementation Plan and we suggest changes as follows:- The title should read "Implementation Plan for TPL-001-2"- With regards to the Prerequisite Approvals, NERC project #2010-11 still in progress (Table 1, Footnote 'b') must be implemented before this current TPL-001-2 standard gets implemented. However, while the 2010-11 NERC project does not define any of the new terms such as consequential / non-consequential load, the footnote 'b' cannot be just copied into the new standard (see TPL-001-2 standard Table 1, note 12). Note 'b' may further change to reflect the verbiage in the TPL-001-2 standard.- Not sure what is the intent of the last paragraph. While the proposed changes to Table 1, footnote 'b' are quite precise, are we still open a door to those entities that will continue to trip Non-Consequential Load and curtail Firm Transmission Service? If no penalties for such practices while the proposed standard allows a sufficient time frame to correct any deficiencies, then what is the point to all the effort behind the development of a new TPL standard?
SMUD		R2.7.1, last bullet: Please provide specifics on the types of acceptable 'Corrective Actions' covered by 'rate applications and DSM' and the planning horizon for which they are considered acceptable. As an alternative, NERC should develop a process by which what is considered acceptable is published and continuously updated. (With due apologies for not raising this point earlier).
Western Electricity Coordinating Council	Yes	We commend the SDT for its work to continue the improvement on the proposed TPL-001-1. We were not able to find a place to include comment on various requirements not identified in the questions below; therefore, we have included our comments here: Requirement and 2.6 and 2.6.1: A study that is five years old is very likely to be out of date. The entity's BES may have not changed much in five years but the entity cannot be certain whether or not their neighbor's system may have changed. Changes outside the immediate entity's system can impact results of studies within their system. Suggest that two years is a maximum that past studies should be allowed. Requirement 3.4.1 and 4.4.1 require PCs and TPs to coordinate with adjacent PCs and TPs to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. Please clarify whether this means that a PC or TP must coordinate with others to identify contingencies on other Systems that the PC or TP must now include on their Contingency list to simulate and address any performance violations on their own System, or does it mean that the PC or TP must coordinate with others to identify contingencies on their System that the PC or TP must now include on their Contingency list to simulate and address any performance violations on other Systems. In either case, the standard does not seem to clearly state what must be done, or whose responsibility it is to mitigate, if a contingency in one System causes a performance violation in another System. Requirement R4.3.1, bullet point 3 requires the stability analyses to include the impact of subsequent "[t]ripping

Organization	Yes or No	Question 1 Comment
		of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models". As written, this bullet could be interpreted as requiring the inclusion of these relay models in stability data bases. We do not have generic or actual relay models in our dynamics data bases for tripping line faults on lines and transformers represented. We represent actual relay response and tripping times of relays, communications, and breakers to faults in tripping transmission lines and transformers. Requiring the inclusion of generic or actual relay models for all relays that can trip lines and transformers would add a large burden to the development and maintenance of accurate dynamics model files that would add little or no benefit. Please change this bullet to read: "Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on known Protection System response".
Tucson Electric Power Company	Yes	We commend the SDT for its work to continue the improvement on the proposed TPL-001-1. We have included additional comments here since we were not able to find a place to include comments on the following: Requirement R4; Requirement, Parts 2.1.5, 2.3, and 2.8; Requirement 3, Part 3.3.2; and Requirement 4, Parts 4.3.1and Part 4.3.2 Requirement 2, Part 2.1.5:The spare equipment strategy does not improve reliability performance. If an outage of a long lead time piece of equipment occurs, the system should still be able to operate in a reliable manner that meets the performance measures of Categories P3 and P6. If an entity cannot meet its performance requirements under this standard, a capital project is indicated. Spare equipment being available would not mitigate this need it only increases expenses until the item is needed. Requirement 2, Parts 2.3 and 2.8:Short circuit fault duty is a localized phenomena that is mainly impacted by the addition of new generation or transmission facilities. Due to proprietary concerns of generation and transmission interconnection requests, short circuit studies are performed in forums outside the annual Planning Assessment. Normally, these studies will be conducted before the projects can be included in regional base cases. As such, short circuit analysis should not be included in this Standard since it would provided limited benefit. Requirement 3, Part 3.3.2 and Requirement 4, Part 4.3.2Steady state response of dynamic control devices should also be included in the Part 3.3.2. and the list of possible devices included should be removed from Part 3.3.2 and 4.3.2. Section R4.3.1, bullet point 3 requires the stability analyses to include the impact of subsequent "[t]ripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models". As written, this bullet could be interpreted as requiring the inclusion of these relay models in stability data bases. We do not have generic or actual relay models in our dynamics data bases for tripping line faults on lines and transformers represented. We represent actual relay response and tripping times of relays, communications, and breakers to faults in tripping transmission lines and transformers. Requiring

Organization	Yes or No	Question 1 Comment
		the inclusion of generic or actual relay models for all relays that can trip lines and transformers would add a large burden to the development and maintenance of accurate dynamics model files that would add little or no benefit. Please change this bullet to read: “Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on known Protection System response”.
Western Area Power Administration	Yes	The whole bullet point section in the Effective Date section referring to Corrective Action Plans could be deleted and instead captured by Requirement R2.7.3. A seven year grace period is probably not favorable to FERC, and a better solution could be developed to meet industry needs. In R2.7.3, a possible example of "beyond the control of the Transmission Planner" could be that the physics of a significant percentage of induction motors in low inertia air-conditioning loads would tend to pull out for certain N-1 events. This may in significant part occur because such motors may have nearly no dynamic stability margin to withstand such N-1 events as close-in 3-phase faults with normal clearing during peak load conditions. So until the Transmission Planner has been able to institute changes in the industry to address the basic physics of such loads, this Requirement 2.7.3 would permit the use of such "Non-Consequential" Load Loss and curtailment of Firm Transmission Service. In this example, it may take longer than a seven year time period to fix the problem. On the other hand, some examples of Non-Consequential Load Loss could perhaps be mitigated in a shorter timeframe. Provided that an entity has a good technical justification and defined margin for “Non-Consequential” Load Loss or curtailment of Firm Transfers, then it may be acceptable. Requirement R2.7.3 seems to move in this direction. Section R4.3.1, bullet point 3 requires the stability analyses to include the impact of subsequent “[t]ripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models”. As written, this bullet could be interpreted as requiring the inclusion of these relay models in stability data bases. We do not have generic or actual relay models in our dynamics data bases for tripping line faults on lines and transformers represented. We represent actual relay response and tripping times of relays, communications, and breakers to faults in tripping transmission lines and transformers. Requiring the inclusion of generic or actual relay models for all relays that can trip lines and transformers would add a large burden to the development and maintenance of accurate dynamics model files that would add little or no benefit. Please change this bullet to read: “Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on known Protection System response”.
NERC staff	Yes	NERC staff supports the change to allow Corrective Action Plans to include tripping of Non-Consequential Load and curtailment of Firm Transmission Service for 7 years. This seems long, but staff understands the stakeholder concern that it could take that long to plan, site, and construct facilities required for compliance with the standard.
SERC Dynamics Review	Yes	“The comments expressed herein represent a consensus of the views of the above named members of the SERC Engineering Committee Dynamics Review Subcommittee only and should not be construed as the

Organization	Yes or No	Question 1 Comment
Subcommittee		position of SERC Reliability Corporation, its board or its officers."
Lakeland Electric	Yes	Shouldn't the "Implementation Plan for TPL-001-1" document be for TPL-001-2? Also, "TPL-001-1" is referenced throughout the document.
FirstEnergy	Yes	We appreciate the effort of the standard drafting team and the changes reflected in the current draft of the TPL-001-1 standard. The changes are improvements that should move the standard towards greater industry consensus. The extended Implementation Plan aligns with suggestions in FE's prior ballot comments. We support the Implementation Plan change made by the team.
US Bureau of Reclamation	Yes	With exception of the definitions.
TVA Transmission Planning & Compliance	Yes	TVA supports the change from five years to seven years for the implementation plan period.
Independent Electricity System Operator	Yes	We agree with this change. We further suggest that this change and the additional wording: "or in those jurisdictions where no regulatory approval is required on the first day of the first calendar quarter, 84 months after Board of Trustees adoption" be added to P. 3 of the standard that starts with "For 84 calendar months..." to be totally consistent.
Pacific Gas and Electric Company	Yes	We commend the SDT for its work to continue the improvement on the proposed TPL-001-1. We were not able to find a place to include comment on Requirement R3 or R4; therefore, we have included our comments here: Section R4.3.1, bullet point 3 requires the stability analyses to include the impact of subsequent "[t]ripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models". As written, this bullet could be interpreted as requiring the inclusion of these relay models in stability data bases. We do not have generic or actual relay models in our dynamics data bases for tripping line faults on lines and transformers represented. We represent actual relay response and tripping times of relays, communications, and breakers to faults in tripping transmission lines and transformers. Requiring the inclusion of generic or actual relay models for all relays that can trip lines and transformers would add a large burden to the development and maintenance of accurate dynamics model files that would add little or no benefit. Please change this bullet to read: "Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on known Protection System response". Section 3.4.1 and 4.4.1 require PCs and TPs to coordinate with adjacent PCs and TPs to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. Please clarify whether this means 1) that a PC or TP must coordinate with others to identify contingencies on other

Organization	Yes or No	Question 1 Comment
		Systems that the PC or TP must now include on their Contingency list to simulate and address any performance violations on their own System, or 2) that the PC or TP must coordinate with others to identify contingencies on their System that this PC or TP must now include on their Contingency list to simulate and address any performance violations on the other Systems. In either case, the standard does not seem to clearly state what must be done, or whose responsibility it is to develop the corrective action plan, if a contingency in one System causes a performance violation in another System.
Puget Sound Energy Sacramento Municipal Utility District Modesto Irrigation District Los Angeles Department of Water and Power Idaho Power Co California Energy Commission SRP Platte River Power Authority PNM Arizona Public Service Company	Yes	We commend the SDT for its work to continue the improvement on the proposed TPL-001-1. We were not able to find a place to include comment on Requirement R4; therefore, we have included our comments here: Section R4.3.1, bullet point 3 requires the stability analyses to include the impact of subsequent "[t]ripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models". As written, this bullet could be interpreted as requiring the inclusion of these relay models in stability data bases. We do not have generic or actual relay models in our dynamics data bases for tripping line faults on lines and transformers represented. We represent actual relay response and tripping times of relays, communications, and breakers to faults in tripping transmission lines and transformers. Requiring the inclusion of generic or actual relay models for all relays that can trip lines and transformers would add a large burden to the development and maintenance of accurate dynamics model files that would add little or no benefit. Please change this bullet to read: "Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on known Protection System response".
SERC Planning Standards Subcommittee	Yes	
Hydro One Networks Inc.	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
Pepco Holings, Inc - Affiliates	Yes	
IRC Standards Review	Yes	

Organization	Yes or No	Question 1 Comment
Committee		
Bonneville Power Administration	Yes	
Exelon Transmission Planning	Yes	
Southern Company	Yes	
Florida Reliability Coordinating Council, Inc - Transmission Working Group	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
NorthWestern Energy (NWMT)	Yes	
Orlando Utilities Commission	Yes	
Manitoba Hydro	Yes	
Minnesota Power	Yes	
South Carolina and Gas	Yes	
California ISO	Yes	
Seattle City Light	Yes	
ISO New England Inc.	Yes	
United Illuminating	Yes	

Organization	Yes or No	Question 1 Comment
Ameren	Yes	
Xcel Energy	Yes	
Hydro-Quebec TransEnergie	Yes	
National Grid	Yes	
American Transmission Company	Yes	
American Electric Power (AEP)	Yes	
Tri-State Generation & Transmission	Yes	
Lakeland Electric	Yes	
GTC	Yes	
Northeast Utilities	Yes	
NBSO	Yes	
Central Maine Power Company	Yes	
Oncor Electric Delivery	Yes	
New York State Electric & Gas Corp	Yes	
Progress Energy	Yes	
ERCOT ISO	Yes	

Organization	Yes or No	Question 1 Comment
New York Independent System Operator	Yes	
MidAmerican Energy	Yes	
Southern California Edison Company	Yes	

2. The SDT has revised the definition of Year One based on industry comments to the initial ballot. Do you support this change? If you do not support this change, please specify why you disagree and include specific alternative language to resolve your concern.

Summary Consideration:

The majority of respondents agree with the changes to the Year One definition but there was one change made due to industry comments for consistency of terminology.

> **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One ~~must~~ includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One ~~must~~ includes the forecasted peak Load period for either 2012 or 2013.

The SDT acknowledges the concerns expressed by a minority of commenters on ambiguity of wording, embedding the definition in the requirements, and use of operating horizon studies. However, the SDT believes that the definition has been vetted through numerous industry comment periods and that it now represents a reasonable definition for a continent-wide standard while still providing a level of flexibility for the planner.

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered the comments.

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	No	The definition of Year One could be eliminated, and its wording used in place of Year One within the text of the requirement. The proposed definition has now added ambiguity with respect to “year two” and “year five” which are not defined. Year two could be deleted and R.2.1.1 modified as follows: System peak Load representing a point in time 12-24 months and another point in time 48-65 months into the future from the time the study is initiated. Define Year Five as the twelve month period 4 to 6 calendar years from the date of the Planning Assessment.
ISO New England Inc.	No	The definition of Year One could be deleted and used in place of Year One within the text of the requirement. The proposed definition has now added ambiguity with respect to “year two” and “year five” which are not defined. Year two could be deleted and R.2.1.1 modified as follows: System peak Load representing a point in time 12-24 months and another point in time 48-65 months into the future from the time the study is initiated.

Organization	Yes or No	Question 2 Comment
Western Electricity Coordinating Council	No	We recognize that the drafting team made changes to the definition of Year One based on industry comments. However, we believe that the revised language could allow for a situation where an entity could use its next season's operating study as its Year One planning study. For example, if the entity does its study in the fall of 2011, the proposed definition would allow the entity to use its summer 2012 operating study as its Year One study. This is a very short period to address any issued identified. Suggest working into the requirement that Planning Studies must look out at least 12 months beyond when the study is performed. This would still allow for the provision in the current definition example ("if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013) because the entity would be able to use their 2013 Load period, but it would prevent the entity from using the 2012 Load period if they started the assessment late in 2011.
E.ON U.S.	No	Comments: 2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected. E.ON U.S. believes the scope of the 'current study' should be defined. It is not clear whether the scope is the same as outlined in section 2.1.
Florida Reliability Coordinating Council, Inc - Transmission Working Group	No	No, because it is worded to be dependent upon when an assessment is started rather than when the assessment is completed and valid. Assessments don't typically include a "start date". An assessment completed on a calendar date should include (be valid for) the forecasted peak load for a timeframe that begins no more than 24 months from the date that the assessment was completed.
Lakeland Electric	No	"the latest" is not needed from the second sentence of R1, since the sentence already ended with "..shall represent projected System conditions". R1 Part 1.1.2 Suggest adding this clarification at the end "... six months during the period under study". This language addition helps clarify the point that if an outage occurs during the summer and the entity's system peak occurs in the winter, then the system peak Load study case (model) does not have to include this particular outage.
Seattle City Light	No	The definition of Year One is now too flexible and does not meet the intent of the standard. For example, our system peak is generally in January of the year. If I perform TPL studies in November 2011, studying the peak in January 2012 is acceptable according to the new definition. This is only two months from the date of the study. The intent of the TPL standard should be that entities must study and plan for inadequacies found in the studies. A one- or two-month lead time is not adequate to address any problems identified. Year One should be the year containing the first peak 12 months or more from the current date. Otherwise, TPL studies become merely seasonal operational studies, not planning studies. Alternative Language: "For the Planning Assessment started in a given year, Year One should contain the first system peak that occurs twelve months or more after the date

Organization	Yes or No	Question 2 Comment
		of the Planning Assessment."
US Bureau of Reclamation	No	The language implies a requirement. The language "Year One must include the forecasted peak Load period for one of the following two calendar years" is a requirement and not a statement of clarification. If the definition is that "Year One" can also be the period used for forecast peak load, then it should be stated so. It is suggested that either the language in the definition is modified or the language is deleted from the definition and moved to the body of the standard.
United Illuminating	No	Year One should be used within the text of the requirement. Do not have a definition for Year One.
National Grid	No	Year One should be used within the text of the requirement. Do not have a definition for Year One. Year two could be deleted and R.2.1.1 modified as follows: For the Planning Assessment started in a given calendar year, the first year that is studied must include the forecasted peak Load period for one of the following two calendar years. An additional Near-term study must be performed that is four calendar years beyond the first year that is studied.
Tri-State Generation & Transmission	No	Comments: The Year One definition is somewhat clearer now, but there is still some ambiguity. We recommend the removal of the term "Year One, year two, and year five" from R2.1.1. and deletion of the Year One definition (definitions are not required for year two and year five, for instance). The Year One concept can be integrated into the definition of Near-Term Transmission Planning Horizon, which we suggest changing to "The period beginning with the first year following the operating horizon, as determined by the Transmission Planner or Planning Coordinator, through the fifth year." Then, rather than say "Year One, year two, and year five", we can use the phrase "at least one of the first two years of the Near-Term Transmission Planning Horizon, and the fifth year".This will require corresponding changes in R2.1.1 and R2.1.2.
Lakeland Electric	No	While the definition of Year One addresses the time span this year occupies, it does not address when that time span begins. The example which was added to the definition suggests that Year One begins twelve months from the start of the Planning Assessment, but it does not appear to be specifically stated. The following language is recommended: "The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing, beginning twelve months from the planned completion date of the Planning Assessment."
Northeast Utilities Consolidated Edison Co. of New York, Inc.	No	NU does not support the revised definition of Year One as we believe it leads to confusion. Our suggestion is that Year One should be the Peak Load Year after the study is initiated. The subsequent years should be counted from Year One (e.g., a study that is started in year 2010 with peak load in 2011 will have Year One as

Organization	Yes or No	Question 2 Comment
		2011 and Year Two as 2012, etc.).
Modesto Irrigation District	No	The definition as it is in the current standards is fine. The new proposed definition is unclear.
NBSO	No	To avoid confusion, the formal definition for Year One should be eliminated and wording used to describe Year One be placed within the appropriate requirement. For example, R2.1.1 could be re-written to state: System peak Load representing a point in time 12-24 months and another point in time 48-65 months into the future from the time the study is initiated.
Central Maine Power Company New York State Electric & Gas Corp New York Independent System Operator	No	The added clarification to the definition of Year One serves to remove most ambiguity with respect to Year One. However, the revision has added further ambiguity to the terms “year two” and “year five” which are not defined. For the Planning Assessment started in a given calendar year, the first year that is studied must include the forecasted peak Load period for one of the following two calendar years. An additional Near-term study must be performed that is four calendar years beyond the first year that is studied. We recommend defining Year Five as the twelve month period 4 to 6 calendar years from the date of the Planning Assessment. We further recommend revising R2.1.1 as follows: “System peak Load for Year One and for Year Five.”Alternatively, the definition of Year One could be eliminated and described within the text of the requirements.
Tucson Electric Power Company	No	A seasonal reference should be included in the example. Alternative language beginning with the second sentence: For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak load period for the forecasted peak load season that is between 12 and 24 months into the future from the current season. For example, if a Planning Assessment was started in 2011 prior to the forecasted peak season, then Year One must include the forecasted peak load for 2012. If the Planning Assessment was started in 2011 during or after the forecasted peak season, then Year One must include the forecasted peak load for 2013.
GDS Associates, Inc.	No	The definition it seem both incomplete and exhaustive:- If taken out of the planning assessment context, the definition is missing the matter that is supposed to identify. We suggest changing the first sentence such as “The first twelve month period to which the functional entity is responsible for the assessment of Transmission System Planning performance.”- While it will be a burdensome task to define each year that follows Year One, the definition of Year One may include a sentence that define the rule for the following years such as “All of the twelve months period following Year One shall commence immediately after the end of the preceding twelve months period.”- The definition should not include examples.
Pacific Gas and Electric Company		We recognize that the drafting team made changes to the definition of Year One based on industry comments. However, we believe that the revised language could allow for a situation where an entity could use its next season’s operating study as its Year One planning study. For example, if the entity does its study in the fall of

Organization	Yes or No	Question 2 Comment
		2011, the proposed definition would allow the entity to use its summer 2012 operating study as its Year One study. This is a very short period to address any issued identified. Suggest working into the requirement that Planning Studies must look out at least 12 months beyond when the study is performed. This would still allow for the provision in the current definition example ("if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013) because the entity would be able to use their 2013 Load period, but it would prevent the entity from using the 2012 Load period if they started the assessment late in 2011.
NERC staff	Yes	NERC staff supports the revisions to the definition of Year One. However, we believe an associated change should be made where this term is used in part 2.1.1 of Requirement 2 which requires modeling of "System peak Load for either Year One or year two, and for year five." It seems the new definition of Year One would negate the need to refer to year two. NERC staff recommends that part 2.1.1 be changed to "System peak Load for Year One and for year five."
Western Area Power Administration	Yes	Yes, this clarification helps. The drafting team could also define "year five".
FirstEnergy	Yes	The change in the Year One definition provides greater flexibility for the industry and also addresses a prior FE comment during the 1st ballot. We appreciate the team's careful consideration of the industry feedback and support the change.
TVA Transmission Planning & Compliance	Yes	TVA supports the change in the Year One definition - but would suggest that the word "started" should be changed to "completed" since a Planning Assessment may be started in one calendar year and finished in the next calendar year.
SERC Planning Standards Subcommittee	Yes	
Hydro One Networks Inc.	Yes	
SERC Dynamics Review Subcommittee	Yes	
MRO's NERC Standards Review Subcommittee	Yes	

Organization	Yes or No	Question 2 Comment
Pepco Holings, Inc - Affiliates	Yes	
IRC Standards Review Committee	Yes	
Bonneville Power Administration	Yes	
Exelon Transmission Planning	Yes	
Southern Company	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
NorthWestern Energy (NWMT)	Yes	
PNM	Yes	
Platte River Power Authority	Yes	
Orlando Utilities Commission	Yes	
Manitoba Hydro	Yes	
Minnesota Power	Yes	
Independent Electricity System Operator	Yes	
South Carolina and Gas	Yes	

Organization	Yes or No	Question 2 Comment
SRP	Yes	
California ISO	Yes	
California Energy Commission	Yes	
Los Angeles Department of Water and Power	Yes	
Idaho Power Co	Yes	
Ameren	Yes	
Hydro-Quebec TransEnergie	Yes	
LCRA TSC	Yes	
American Transmission Company	Yes	
American Electric Power (AEP)	Yes	
GTC	Yes	
Oncor Electric Delivery	Yes	
Progress Energy	Yes	
ERCOT ISO	Yes	
MidAmerican Energy	Yes	
Puget Sound Energy	Yes	

Organization	Yes or No	Question 2 Comment
Sacramento Municipal Utility District	Yes	
Xcel Energy	Yes	
Southern California Edison Company	Yes	

3.

The SDT has revised the Requirements language based on industry comments to the initial ballot. Do you support these changes? If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your concern.

Summary Consideration:

Due to various industry comments, the SDT made the following clarifying change to Requirement R1:

> **R1**. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use ~~the latest~~ data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes P0 as the normal ~~s~~System condition in Table 1.

The SDT believes that 6 months is the correct number in Requirement R1, Part 1.1.2 because the planner is evaluating longer term periods, and shorter duration outages, which have scheduling flexibility, are addressed by Operations Planning. Outages six months or longer will typically be over the study periods (peak and Off-Peak) addressed in Requirement R2, Part 2.1.3.

Requirement R1, Part 1.1.6 – An issue was raised that resources could be used for export to other areas. The SDT did not make a change to the requirement since exports to other areas are covered in Requirement R1, Part 1.1.5.

The majority of respondents agree with the posted changes to these requirements and no other changes have been made based on stakeholder comments.

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered the comments.

Organization	Yes or No	Question 3 Comment
NERC staff	No	NERC staff suggests that the added sentence in R1 be deleted and “Normal System” in Table 1 be replaced with “No unplanned Element outages.” We have a problem with R1 establishing “normal system condition.” “Normal” is not defined, but the system condition that most people would define as “normal” is the System operating within its limits. There are no checks required on the projected system conditions to guarantee “operation within limits.” Staff realizes that if this were the case, the categories tested would all pass their respective tests. (In other words, the category tests may define operating limits that in turn define “normal” from a planning perspective.) Thus, the added sentence in R1 should be deleted. In Table 1, the use of the term “Normal System” in the column “Initial System Condition” really means “No unplanned Element outages.” All Elements that do not have a planned outage are assumed in-service (for transmission Elements) or available for dispatch (for generators).

Organization	Yes or No	Question 3 Comment
		Contrast the term "Normal System" with categories P3 and P6, which have the loss of an Element (which is unplanned) followed by the loss of a second Element (also unplanned). "Normal System" should be replaced with "No unplanned Element outages."
SERC Planning Standards Subcommittee Southern Company Ameren	No	The definition does not adequately address normal (pre-contingency) operating procedures or system configurations. Language should be added to the requirement (perhaps as R1.1.7) to include normal operating procedures or system configurations in place prior to any contingency occurring.
Bonneville Power Administration	No	Please clarify R1.1.2 to state "Known outage(s) of generation or Transmission Facility(ies) during the Planning Horizon with a duration of of at least six months."
E.ON U.S.	No	In the statement: "the Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list."E.ON U.S. believes that the use of the pronoun "their" in the quoted section above is confusing. "Their" could be read as applying to the adjacent Planning Coordinators and not to the Planning Coordinator to whom the standard applies. E.ON U.S. recommends that the word "their" should be changed to "the Planning Coordinator's and Transmission Planner's" in order to make it clear.
Florida Reliability Coordinating Council, Inc - Transmission Working Group	No	No, Since "the latest" data may become available after the study is complete, a planner may not be able to ever complete a study. Please consider removing "the latest" from the second sentence.
Western Area Power Administration	No	It's difficult to tell whether Requirement R1 is intended to require only one base case or whether it was intended to require creation of separate models for each possible N-0 condition ("normal system condition") under a variety of stressing scenarios. The inserted language does not seem to provide additional clarity. Suggested language may be "This establishes the initial 'Normal System' condition corresponding to category P0 in Table 1." Also, in Requirement R1.1.5, how are the Firm Transmission Service commitments supposed to be modeled in Power Flow Cases? Are they just to be modeled as loads, generation, and control area interchanges? Suppose a POR or POD is not at a generator or load bus. What selection of generation and load would represent the projected system conditions for this Firm Transmission Service commitment?
CenterPoint Energy	No	The SDT did not incorporate CenterPoint Energy's previous comment regarding R1; therefore, CenterPoint Energy's concerns remain.

Organization	Yes or No	Question 3 Comment
United Illuminating National Grid Central Maine Power Company New York State Electric & Gas Corp	No	For R1 Ambiguity regarding base case assumptions, in combination with lack of clarity and clear direction of purpose regarding the sensitivity analysis, undermines the objectives of the standard; R1.1 Part 1.1.2. With respect to known outages, there needs to be greater flexibility in the standards (e.g. more tolerance to non-consequential load shedding or limitations to the contingencies that need to be considered (e.g. P0, P1, & P2)). Regional allowances for load shedding under this condition should be approved. Duration of known outages should be increased from six months to one year; R1.1 Part 1.1.6 Delete "required for Load". Resources may also be used for export to other areas, not just internal load.
ISO New England Inc.	No	R1.1 Part 1.1.2. With respect to known outages, there needs to be greater flexibility in the standards (e.g. more tolerance to non-consequential load shedding or limitations to the contingencies that need to be considered (e.g. P0, P1, & P2)). Regional allowances for load shedding under this condition should be approved. Duration of known outages should be increased from six months to one year; R1.1 Part 1.1.6 Delete "required for Load". Resources may also be used for export to other areas, not just internal load.
American Transmission Company	No	We propose the following changes and questions: R1 - We offer the minor suggestion of replacing the wording of “maintain System models within their respective areas” with “maintain System models of elements that are interconnected to any portion of the BES that is owned or operated by the TP or PC”. This wording would avoid the ambiguity that can occur when a BA that is associated primarily with one TP declares ownership of a bus in another TP’s geographic area, but expects its primary TP to maintain the BA’s model data for the remote generation or load. R1.1.2 - We request a SDT opinion on how two individual outages should be modeled if they are both in excess of six months duration and they overlap by less than six months. Should the overlapping condition only be modeled if the condition is expected to last more than six months?
Tri-State Generation & Transmission	No	We suggest changing the added sentence to “This establishes the Category P0, No Contingency, Initial System Conditions in Table 1.”
Lakeland Electric	No	Consider removing “...the latest...” from R1 and changing R1.1.2 to state “...six months during the period of

Organization	Yes or No	Question 3 Comment
		study."
Northeast Utilities	No	NU believes that the Normal System Conditions as stated in Requirement R1 should establish the base case conditions to be used for the assessment studies. More guidelines for developing base cases should be addressed in the requirements. What the statement in Requirement R1 lacks is the manner of creating generation dispatches and the level of interface flows (level of stress), which are central to any base case to be used to assess the reliability of the electric power network. Depending upon how the base case dispatches and the level of interface flows are created, a study may reveal reliability violations in the power system. This is a weakness of the existing TPL standards. NU, however, will support the idea of developing regional guidelines in regard to the nature of the base cases to be used for the NERC reliability studies. Comment on Requirement R1.1, Part 1.1.2: With respect to known outages NU requests that the six month duration listed by the requirement should be changed to one year duration. Requirement R1.1 Part 1.1.6: The phrase "required for Load" should be deleted as this confuses the issue [since resources may also be used for export to other areas and not just internal load].
NBSO	No	R1 should have some language to state that base case assumptions should be made such that they appropriately stress the system to be tested and are in accordance with good engineering practice.
Tucson Electric Power Company	No	Proposed changes1.1.1 Existing Facilities that will not be changed before the study year 1.1.3 New planned Facilities and planned changes to existing facilities
GDS Associates, Inc.	No	The Time Horizon should be for both Near-Term and Long-Term Planning.
MidAmerican Energy	No	There are concerns over the FERC outstanding March order on TPL and how FERC interprets "normal" or base case conditions and "assuming" an entities primary protection system is out of service and must rely on its backup protection system to operate. This concept combined with the new tables cannot be perpetuated.
Xcel Energy	No	Although we support the change conceptually, we believe the sentence added in R1 needs more specificity to ensure a better correlation to the relevant portions of Table 1. Please make it clear that the system model created as per R1 corresponds to Category P0 by explicitly referring to it. Suggested language is: 'This establishes the "Normal System" initial condition corresponding to category P0 in Table 1.' Further, consider omitting the word "System" in Table 1 Column 2 heading by calling it "Initial Condition" – the redundancy produced by its usage in both heading and entry does not appear to provide any

Organization	Yes or No	Question 3 Comment
		value. Alternative suggested language is: 'This establishes the "Normal" initial system condition corresponding to category P0 in Table 1." This alternative approach envisages changing the Column 2 entries to "Normal" since the word "System" is now retained in the heading.
MRO's NERC Standards Review Subcommittee	Yes	We propose the following changes and questions:R1 - We offer the minor suggestion of replacing the wording of "maintain System models within their respective areas" with "maintain System models of elements that are interconnected to any portion of the BES that is owned or operated by the TP or PC". This wording would avoid the ambiguity that can occur when a BA that is associated primarily with one TP declares ownership of a bus in another TP's geographic area, but expects its primary TP to maintain the BA's model data for the remote generation or load. R1.1.2 - We request the SDT opinion on how two individual outages should be modeled if they are both in excess of six months duration and they overlap by less than six months. Should the overlapping condition only be modeled if the condition is expected to last more than six months?
Northeast Power Coordinating Council	Yes	
Hydro One Networks Inc.	Yes	
Transmission Issues Subcommittee	Yes	
SERC Dynamics Review Subcommittee	Yes	
Pepco Holings, Inc - Affiliates	Yes	
IRC Standards Review Committee	Yes	
Exelon Transmission Planning	Yes	

Organization	Yes or No	Question 3 Comment
Western Electricity Coordinating Council	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
NorthWestern Energy (NWMT)	Yes	
PNM	Yes	
FirstEnergy	Yes	
Platte River Power Authority	Yes	
Orlando Utilities Commission	Yes	
Manitoba Hydro	Yes	
Minnesota Power	Yes	
US Bureau of Reclamation	Yes	
TVA Transmission Planning & Compliance	Yes	
Independent Electricity System Operator	Yes	
South Carolina and Gas	Yes	
SRP	Yes	

Organization	Yes or No	Question 3 Comment
California ISO	Yes	
Seattle City Light	Yes	
California Energy Commission	Yes	
Los Angeles Department of Water and Power	Yes	
Idaho Power Co	Yes	
Hydro-Quebec TransEnergie	Yes	
LCRA TSC	Yes	
American Electric Power (AEP)	Yes	
GTC	Yes	
Pacific Gas and Electric Company	Yes	
Consolidated Edison Co. of New York, Inc.	Yes	
Modesto Irrigation District	Yes	
Oncor Electric Delivery	Yes	
Progress Energy	Yes	
ERCOT ISO	Yes	
New York Independent System	Yes	

Organization	Yes or No	Question 3 Comment
Operator		
Puget Sound Energy	Yes	
Sacramento Municipal Utility District	Yes	
Southern California Edison Company	Yes	

3.1 Requirement R2 and Part 2.1 – past studies

Summary Consideration:

The majority of respondents agree with the changes to these requirements and only the changes to these requirements noted below have been made.

The SDT believes that the supposed inconsistencies mentioned in the language are not inconsistencies at all but necessary qualifiers. No change made.

Based on comments received, the SDT has modified Requirement R2, part 2.6.2 as follows to provide additional clarity:

> **2.6.2** For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. ~~shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.~~ Documentation to support the technical rationale for determining material changes shall be included.

The following change was made to clarify that the list following the statement is not all inclusive:

> **2.7.1** List System deficiencies and the associated actions needed to achieve required System performance. Examples of ~~S~~such actions ~~may~~ include:

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered them. In some of the cases relating to the above comments, the SDT has already responded to similar comments and those responses are quoted here for convenience:

2.1.5 – "When a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. This requirement is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Actions such as out of merit dispatch, operational restrictions, System reconfiguration can be part of a Corrective Action Plan if the System cannot meet performance requirements without the Facility in service."

Organization	Yes or No	Question 4 Comment
Northeast Power Coordinating Council Consolidated Edison Co. of New York, Inc.	No	The revisions made to Requirement R2 Part 2.1 appear to resolve the concern that past studies could not be used to comply with the short-term steady state study requirements. This revision must be carried through to other sections (R2.2, 2.2.1). However, the language of Requirement R2 Part 2.2 still seems to suggest that current annual studies are always required for the long-term steady state assessment to be compliant. This may have been an oversight, for consistency Requirement R2 Part 2.2 should be modified to similarly read as Requirement R2, Part 2.1. Regarding R2.2, the language should be consistent with 2.1. For example, use "current or qualified past studies" instead of "the following annual current study". Revisions made to Requirement R2.1.5 have made it worse than was originally drafted. This would require the PC & TP to study (meaning performing a technical analysis) of the impact and probability of the possible unavailability of any piece of equipment with a lead time of one year or more. Such an evaluation of spare equipment strategies would require significant additional resources and data, but provide no benefit to system reliability, as it is redundant to the existing N-1-1 contingency requirement (P6). R2.7 requires that Corrective Action Plans are included in each Planning Assessment and states “Such actions may include...” followed by a list of actions. Restricting allowable actions, and excluding runback/tripping of HVDC would have a direct impact on multiple existing facilities in New York and would adversely impact the reliability planning of the NYCA. Runback/tripping of HVDC must be added to the list, and also suggest revising to “Such actions may include but not be limited to:”.
Florida Reliability Coordinating Council, Inc - Transmission Working Group	No	No, Please consider removing R.2.6.2. The overwhelming majority of PAs use a 10 year set of planning models developed annually by Regions or Subregions. These annual sets of planning models will always have some changes. The annual study requirement is especially problematic for Stability and Short circuit studies that require much more engineering time to complete and are much less likely to have results impacted by minor model changes such as different load forecasts. Uncertainty with audit review of technical rationale documentation will serve to focus Transmission Planning engineering resources on short term compliance to an extent that is counter productive.
Western Area Power Administration	No	R 2.1.5: The issue in this Requirement is studied in the Operations next-day; next-week; next-month studies required under the TOP Standards; and are also covered by processes such as the Operational Transfer Capability Policy Committee (OTCPC) seasonal study process within the WECC. It would be quite onerous to run a complete power flow simulation on separate base cases for each transformer (or other equipment with long lead time) initially out of service. The revision in language from “Planning Assessment” to “studies” does not clarify that a power flow simulation is not necessarily required for each situation. A valid assessment could include other methods such as using sound technical reasoning to relate the initial out-of-service

Organization	Yes or No	Question 4 Comment
		condition to a condition that has already been studied. This condition may have taken place in previous operational studies. The language in the standard could be improved to make this clarification - perhaps reference R2.6. Additionally, this Requirement still needs further clarification. Currently the scope of equipment applicable to the requirement could be misinterpreted as larger than that contemplated by FERC. The standard as written seems to say that the responsible entity needs to study the spare equipment strategy for all "major transmission equipment" with long lead times. In the directive to include this requirement, FERC used the term "critical facilities". In the NOPR to Order No. 693 they stated, "Critical facilities are those facilities that impact IROLs and deliverability of generation to firm load" (P1081). In Order No. 693 FERC also said, "if an entity's spare equipment strategy for the permanent loss of a transformer is to use a 'hot spare' or to relocate a transformer from another location in a timely manner, the outage of the transformer need not be assessed under peak system conditions" (P1725).Finally, the drafting team could clarify if this requirement applies to radial branches (such as generator step-ups or step-down to load). Such branches may be construed as "critical facilities" but the impediment to deliverability of generation to firm load is consequential to the initial outage.
Lakeland Electric	No	Please consider removing R.2.6.2
Platte River Power Authority	No	I like that you have requirements for qualifying past studies, but Part 2.6.2 is confusing. Please change Part 2.6.2 to read something like: "For steady state, short circuit or Stability analysis: no material changes have occurred to the System represented in the study or, if material changes have occurred, a technical rationale can be provided to explain that the changes do not impact the performance results in the study area."
Orlando Utilities Commission	No	Allowing the use of past studies in lieu of new studies for part or all of an assessment when the underlying system hasn't changed in a signficant change if very prudent. However the wording in 2.6.2 of "unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area" is of concern. By this wording is it intended that the planner must demonstrate that every material change has no impact? In essence doing more work to prove that a study isn't required then the study would take? Or that the planner must essentially have a technical rationale (overarching) for determining when a material change is "material enough" to impact system perofrmance?
Minnesota Power	No	Requirement 2 - This requirement states that Stability analyses be performed as part of the annual Planning Assessments. Minnesota Power would like to see the term "Stability analysis" more clearly defined as there are several different types of stability related analysis that can be performed for power systems including: transient stability, voltage stability and small signal stability.
US Bureau of Reclamation	No	The question is misleading in that R2 also include current studies. The overall structure of the standard

Organization	Yes or No	Question 4 Comment
		could be greatly improved if the standard were segmented into Near Term and Long Term with sub segments for each specific type of analysis to be performed. Second, the standard does not use consistent terms. The Planning Assessment is to include Near Term and Long Term portions which must have steady state analysis, short circuit analysis, and stability analysis (ref. R2). Requirement R 2.1 introduces sensitivity analysis for the Near Term portion, and then refers to the Planning Analysis which is in reality both Near Term and Long Term portions. That implies that sensitivity analysis must be required for both? The standard repeats the requirement for annual stability studies in 2.4 which was already a requirement for Planning Assessments. The requirement 2.1.5 is one the most problematic requirements in this standard. This requirement implies that an entity must have spare equipment and a strategy to employ it. That is beyond the scope of the Energy Policy Act 2005. Spare equipment is not on-line and does not contribute to the reliability of the existing system. The Energy Policy Act of 2005 specifically prohibits the requirement to enhance or modify the system. The use, application, or requirement to have spare equipment violates that prohibition. This section should be removed. In addition, this requirement suffers from an ability to implement. In the first case, the requirement is invoked if the spare equipment strategy could result in unavailability of transmission equipment. How is that determined? There is no nexus to that determination. The unavailability may have already occurred once the transmission equipment has failed. The only way to avoid unavailability if the transmission equipment that fails has a hot stand-by with automatic fail-over. The presence or not of a suitable replacement will still result in unavailability by virtue of the failure o the first piece of transmission equipment. Next problem, who will second guess the owner of the replacement. Where is the requirement to make the replacement strategy available? The standard should focus on system performance with existing equipment to meet current and future loads.
CenterPoint Energy	No	The SDT did not incorporate CenterPoint Energy's previous comments regarding R2; therefore, CenterPoint Energy's concerns remain.
ISO New England Inc. United Illuminating National Grid	No	We can agree with R2.1 however with respect to R2.2 Language should be consistent with 2.1 for example - use "current or qualified past studies" instead of "the following annual current study."
Northeast Utilities	No	The revisions made to Requirement R2 Part 2.1 appear to resolve the concern that past studies could not be used to comply with the short-term steady state study requirements. However, the language of Requirement R2 Part 2.2 still seems to suggest that current annual studies are always required for the long-term steady state assessment to be compliant. This may have been an oversight, for consistency Requirement R2 Part

Organization	Yes or No	Question 4 Comment
		2.2 should be modified to similarly read as Requirement R2, Part 2.1.
Hydro-Quebec TransEnergie	No	Requirement R2 Part 2.2 should be modified to read as 2.1 (not impose current annual studies as the only requirement for assessment)
American Transmission Company	No	R2.1.3 - We offer the minor suggestion of revising R2.1.3 to state, "Known outages of generation or Transmission Facilities with a duration of at least six months be simulated along with P1 events for the System peak or Off-Peak conditions when the outages are scheduled to occur." We interpret that the requirement should only call for the simulation of individual outages with duration of six months or more and not imply the simulation of sequential (back-to-back) outages where each individual outage is less than six months, but the composite duration of the back-to-back outages is more than six months. We also interpret that if two or more known outages with duration of at least six months are overlapping, then the overlapping outage condition would only be simulated for the conditions when the overlapping outages are scheduled to occur if the duration of the overlapping condition is at least six months.
Tri-State Generation & Transmission	No	2.1.5 - Change "shall be performed for" to "shall have been performed for."
Lakeland Electric	No	No, the phrase any material changes used in requirement R.2.6.2 will effectively cause all Planning Authorities to run all studies every year regardless of minor changes in the model. The overwhelming majority of PAs use a 10 year set of planning models developed annually by Regions or Subregions. These annual sets of planning models will always have some changes. The annual study requirement is especially problematic for Stability and Short circuit studies that require much more engineering time to complete and are much less likely to have results impacted by minor model changes such as different load forecasts. Uncertainty with audit review of technical rationale documentation will serve to focus Transmission Planning engineering resources on short term compliance to an extent that is counter productive. Please consider removing R.2.6.2
NBSO	No	NBSO agrees with the language for R2.1, but the language with R2.2 should be changed to be consistent with R2.1. NBSO disagrees with the revisions to R2.1.5. Requiring PAs to study instead of assess the possible unavailability of equipment with a lead time of a year or more will result in significant demand on resources with little impact on system reliability. NBSO also questions what additional value such studies will bring in addition to the N-1-1 requirements (P6).

Organization	Yes or No	Question 4 Comment
Central Maine Power Company New York State Electric & Gas Corp	No	We completely agree with the revision to R2.1, but this revision must be carried through to other sections (R2.2, 2.2.1) and R2.2 language should be consistent with 2.1 for example - use "current or qualified past studies" instead of "the following annual current study". Revisions made to Requirement R2.1.5 have made it worse than as originally drafted. This would require the PC & TP to study, or in other words perform technical analysis of, the impact and probability of the possible unavailability of any piece of equipment with a lead time of one year or more. Such an evaluation of spare equipment strategies would require significant additional resources and data, but provide no benefit to system reliability, as it is redundant to the existing N-1-1 contingency requirement (P6).
Progress Energy	No	While PE does not disagree with the basic premise of 2.1, PE disagrees with the language to the extent that 2.1 is qualified by language in 2.6 and 2.6.2. The issue of managing modeling of case data is already adequately handled in MOD Standards. Furthermore, PE does not feel that the term “material” can be defined with any mutually agreed-upon boundaries, and could be construed to require any and all Transmission Planners and/or Planning Authorities to make multiple revisions of base cases each year. PE therefore appeals to the SDT to remove the language referring to R2 Part 2.6.2 and furthermore appeals for the deletion of R2.6.2. Furthermore, PE appeals to the SDT to modify R2.6.1 to say “For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate the validity of the results of any studies older than five years or any studies using cases containing major modeling differences from other submitted studies.”
ERCOT ISO	No	Previous Comment unaddressed: Requirement 2.1.5: Including the spare equipment strategy will be difficult for a PC that doesn’t own or manage the transmission equipment or the strategies. This requirement should only be applicable to TP. Furthermore, R7 should be deleted and the responsibilities of each entity should be explicitly stated within the specific requirements.
New York Independent System Operator	No	NYISO completely agrees with the revision to R2.1, but this revision must be carried through to other sections (R2.2, 2.2.1). Revisions made to Requirement R2.1.5 have made it worse than as originally drafted. This would require the PC & TP to study, or in other words perform technical analysis of, the impact and probability of the possible unavailability of any piece of equipment with a lead time of one year or more. Such an evaluation of spare equipment strategies would require significant additional resources and data, but provide no benefit to system reliability, as it is redundant to the existing N-1-1 contingency requirement (P6).

Organization	Yes or No	Question 4 Comment
		R2.7 requires that Corrective Action Plans are included in each Planning Assessment and states "Such actions may include..." followed by a list of actions. Restricting allowable actions, and excluding runback/tripping of HVDC would have a direct impact on multiple existing facilities in New York and would adversely impact the reliability planning of the NYCA. Runback/tripping of HVDC must be added to the list.
Xcel Energy	No	Specifically, the phrase "as follows" at the end of Part 2.1 does not appear to be an appropriate lead-in for the sub-parts under 2.1. Please consider re-wording Part 2.1 consistent with Part 2.4 to use the lead-in "The following studies are required:" Why is it essential to use the qualifier "annual" for "current studies" in Part 2.1? Can a study be considered current if it is conducted less frequently than once every year? Note that Parts 2.3, 2.4 and 2.5 do not use the "annual" qualifier, nor does Requirement R2. Recommend deleting this apparently non-essential qualifier in both 2.1 and 2.2 to improve consistency. In Part 2.5, should "annually" be inserted after "shall be assessed" to make it consistent with Parts 2.1, 2.2, 2.3 and 2.4? If the omission is intentional in 2.5, please explain why. To improve semantics and consistency, please modify 2.2.1 as follows to make it consistent with 2.1.1 and 2.4.1 "System peak Load for one of the years in the…" We are unable to appreciate why the wording in Part 2.3 is not consistent with that in Part 2.1, 2.2, 2.4 or 2.5. Note that the semantics of the wording "… (steady state / stability) analysis shall be assessed annually…" can be interpreted to be much different than the semantics of the Part 2.3 wording "The short circuit analysis…. shall be conducted annually …". The former requires the analysis to be *assessed* annually but 2.3 requires the analysis to be *conducted* annually without explicitly requiring it be assessed –- is the usage of "conducted" instead of 'assessed" consistent with the intent? It is unclear why the stipulation to use "current or qualified past studies" needs to be repeated in each of the Parts 2.1, 2.2, 2.3, 2.4 and 2.5 when it is already specified in Requirement R2 at the highest hierarchy level. Suggest eliminating redundant usage by deleting from the parts under R2. In Part 2.6.2, the intent is awkwardly conveyed within the phrase "…the System represented in the study shall not include any material changes unless…". In the context of a *past* study, how can the System represented possibly include any material changes (that would have presumably occurred after the study)? Suggest modifying Part 2.6.2 to read "For steady state, short circuit or Stability analysis: no material changes have occurred in the System represented in the study or, if material changes have occurred, a technical rationale shall be provided to explain why they do not significantly impact the study results." In Parts 2.6.1 and 2.6.2, the lead-in phrase "For steady state, short circuit or Stability analysis:" does not appear to be essential. Even in the absence of this phrase, wouldn't these two attributes of a qualified past study apply (by default) to all types of analysis? Suggest deleting this seemingly redundant phrase in both 2.6.1 and 2.6.2.

Organization	Yes or No	Question 4 Comment
		Perhaps this comment is more persuasive when considered together with the next comment. Recommend moving Part 2.6 to the first part under R2 (Part 2.1) because it defines the qualified past studies which are applicable to all types of analysis (steady state, stability and short circuit) that are detailed in the subsequent parts.
MRO's NERC Standards Review Subcommittee	Yes	R2.1.3 - We offer the minor suggestion of revising R2.1.3 to state, "Known outages of generation or Transmission Facilities with a duration of at least six months be simulated along with P1 events for the System peak or Off-Peak conditions when the outages are scheduled to occur." We interpret that the requirement should only call for the simulation of individual outages with duration of six months or more and not imply the simulation of sequential (back-to-back) outages where each individual outage is less than six months, but the composite duration of the back-to-back outages is more than six months. We also interpret that if two or more known outages with duration of at least six months are overlapping, then the overlapping outage condition would only be simulated for the conditions when the overlapping outages are scheduled to occur if the duration of the overlapping condition is at least six months. R2.1.5 - We offer a major suggestion regarding the phrase "could result in the unavailability of major transmission equipment" because this phrase is ambiguous and not defined. So, there is a significant risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. We proposed adding that the TP and PC "shall provide documentation to support the technical rationale for defining unavailability of major transmission equipment" similar to R2.5.
NERC staff	Yes	NERC staff supports the use of qualified past studies for the Near Term horizon.
American Electric Power (AEP)	Yes	R2, Part 2.1 - idicates that 'qualified' past studies can be utilized. This is an ambiguous term and we suggest the SDT consider the implications.
SERC Planning Standards Subcommittee	Yes	
Hydro One Networks Inc.	Yes	
SERC Dynamics Review Subcommittee	Yes	
Pepco Holings, Inc - Affiliates	Yes	

Organization	Yes or No	Question 4 Comment
IRC Standards Review Committee	Yes	
Bonneville Power Administration	Yes	
Exelon Transmission Planning	Yes	
Southern Company	Yes	
Western Electricity Coordinating Council	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
NorthWestern Energy (NWMT)	Yes	
PNM	Yes	
FirstEnergy	Yes	
Manitoba Hydro	Yes	
TVA Transmission Planning & Compliance	Yes	
Independent Electricity System Operator	Yes	
South Carolina and Gas	Yes	

Organization	Yes or No	Question 4 Comment
SRP	Yes	
California ISO	Yes	
Seattle City Light	Yes	
California Energy Commission	Yes	
Los Angeles Department of Water and Power	Yes	
Idaho Power Co	Yes	
Ameren	Yes	
LCRA TSC	Yes	
GTC	Yes	
Pacific Gas and Electric Company	Yes	
Modesto Irrigation District	Yes	
Oncor Electric Delivery	Yes	
Tucson Electric Power Company	Yes	
GDS Associates, Inc.	Yes	
MidAmerican Energy	Yes	
Puget Sound Energy	Yes	

Organization	Yes or No	Question 4 Comment
Sacramento Municipal Utility District	Yes	
Southern California Edison Company	Yes	

3.2 Requirement R2, Parts 2.1.4 & 2.4.3 – sensitivity analysis:

Summary Consideration:

The SDT intent is that multiple condition sensitivities will be assessed since you are required to run the cases for peak and Off-peak conditions, multiple years, etc. If the problem exists in two or more of these cases, it would be an indication of 'multiple' problems. No change made.

The SDT understands that running sensitivities may require additional work for some entities. The sensitivities studied should be used to compare system response to different conditions to provide a broader perspective for the planner and the SDT believes that this is important enough to justify the additional work.

The SDT has made a clarifying change to the words in Requirement R2, part 2.1.4 based on comments received:

> **2.1.4** For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response~~performance~~:

The SDT has made the language in Requirement R2, part 2.7, bullet 7 consistent with the other parts of the standard as follows:

- List System deficiencies and the associated actions needed to achieve required System performance. Examples of ~~S~~such actions ~~may~~ include:

The majority of respondents agree with the changes to these requirements and only the changes to the requirements noted above have been made in response to stakeholder comments.

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered the comments.

Organization	Yes or No	Question 5 Comment
Northeast Power Coordinating Council Consolidated Edison Co. of New York, Inc.	No	Part 2.1.4, requires an entity to vary one or more conditions to demonstrate a change in performance. If the cases were initially stressed, this may force an entity to simulate conditions with less severe stresses. At this point, there is limited to no value to this additional workload. Having a requirement to test at least one sensitivity as a blanket requirement may not be informative by itself and is more unclear since sensitivities are being required on an undefined base set of conditions. If an entity does a case with a stressed set of assumptions, is it

Organization	Yes or No	Question 5 Comment
		necessary to do a non-stressed case? Additionally, our concern involves wording under 2.1.4 and 2.4.3 that sensitivities are required varying one or more conditions. Subsequently, in requirement 2.7.2 corrective action plans need to be developed to resolve performance deficiencies "only" if identified in multiple conditions or require a rationalization why no corrective action plan is necessary. Multiple conditions sensitivities under 2.1.4 and 2.4.3 are necessary to satisfy requirement 2.7.2. Requirement 2.7.2 adds ambiguity and should be removed. If not, a suggested revision to Requirement 2.7.2 as follows:2.7.2. Corrective Action Plans are not required for performance deficiencies identified in a sensitivity analysis. In general, the scope of this requirement is too broad and non-specific, and only results in undue study burden. Is it necessary for sensitivity analysis to be included in requirements since in accordance with good engineering practices a conservative approach should be used in studies? The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions as commented in issue #3. The standard must describe base assumptions. To define a sensitivity condition, NERC must define base assumptions.
Hydro One Networks Inc.	No	The scope of this requirement is too broad and non-specific and only results in undue study burden.
MRO's NERC Standards Review Subcommittee	No	R2.1.4 & R2.4.3 - We offer a major suggestion regarding the terms of 'credible' and 'measurable change" because these terms are ambiguous and not defined. So, there is a significant risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. We proposed adding that the TP and PC "shall provide documentation to support the technical rationale for determining the range of credible conditions and measurable change in performance" similar to R2.5. R2.1.4 & R2.4.3 bullet items - We offer the minor suggestion that the number and description of the bullet items in R2.1.4 match the bullet points in R2.4.3. Otherwise, please explain the reasons for any differences between the bullet items in R2.1.4 and R2.4.3. R2.1.4 bullet #2 & # 5 - We suggest that the wording in bullet #2 be changed to "Expected transfers and other generation dispatch scenarios". This modification would put the transfer and dispatch element, which are complementary, together in the same bullet item, rather than grouping the 'generation dispatch' (operating level) element together with the generation capacity elements in bullet item #5. R2.1.4 bullet #7 - We offer the minor suggestion that the term "planned" be replaced with "known" to be consistent with R1.1.2 and R2.1.3. Besides the term "planned outage" has a specific meaning in the Reliability Standards that are specific to the Operating horizon. R2.7.2 - With regard to "include actions to resolve performance deficiencies identified in multiple sensitivity

Organization	Yes or No	Question 5 Comment
		studies", we do not think that mitigation plans should be required for deficiencies found in multiple sensitivity studies because the conditions in some sensitivity studies are more extreme and less likely than base case conditions. It's impractical to require corrective actions for longer term horizon sensitivities due to how fast the electric grid changes. We believe sensitivity analyses are valuable to improving the development of mitigation plans to address base case performance limit concerns. Some of the sensitivity study conditions are not credible or plausible enough to warrant the implementation of mitigation measures. What is the interpretation of multiple sensitivity studies - more than one or a majority of the number that were studied?
IRC Standards Review Committee	No	The primary concern involves wording under 2.1.4 and 2.4.3 that sensitivities are required by varying one or more conditions. Subsequently, in requirement 2.7.2 corrective action plans need to be developed to resolve performance deficiencies "only" if identified in multiple conditions or require a rationalization why no corrective action plan is necessary. Multiple conditions sensitivities under 2.1.4 and 2.4.3 are necessary to satisfy requirement 2.7.2. Requirement 2.7.2 adds ambiguity and should be removed. Alternatively, Requirement 2.7.2 could be revised as follows:2.7.2. Corrective Action Plans are not required for performance deficiencies identified in a sensitivity analysis. If a Planning Coordinator includes Corrective Action Plans to resolve performance deficiencies identified in multiple sensitivity analysis, the Planning Coordinator shall provide documentation to support those Plans.
Florida Reliability Coordinating Council, Inc - Transmission Working Group	No	This change does not clarify the required sensitivity analysis. A measureable change in performance is unclear? Instead of a measurable change in performance, a measureable change in contingency response of the Bulk Electric System would be more appropriate. A change in performance implies not meeting one of the performance requirements as specified in Table 1.
Lakeland Electric	No	A "measureable change in performance" can be interpreted as not meeting one of the performance requirements as specified in Table 1 in order for the condition to be selected as a sensitivity. This will cause utilities to perform sensitivity analysis for all system conditions listed in R2.1.4 to determine which one fails to meet one of the performance requirements in Table 1, as one may not be able to tell performance impact until after the studies are performed. Suggested change: "...one of the following conditions by a sufficient amount...system conditions that may demonstrate a measurable change in system response."
Orlando Utilities Commission	No	What is meant by "measurable change in performance"? Is this a measure that the sensistivty should move the system from meeting the performance requirements to not meeting the performance requirements? Or just a measurable change in system response, IE the loading was 45% on this corridor but is now 76%.
US Bureau of Reclamation	No	Sensitivity analysis is not included in R2. This gets back to the structure of the standard. There should a clear indication of the studies that are to be included in the Near-Term and Long-Term portions of the Planning

Organization	Yes or No	Question 5 Comment
		Assessments.
CenterPoint Energy	No	The SDT did not incorporate CenterPoint Energy's previous comments regarding R2; therefore, CenterPoint Energy's concerns remain.
California ISO	No	Requirement 2.7.2 could be revised as follows:2.7.2. Corrective Action Plans are not required for performance deficiencies identified in a sensitivity analysis. If a Planning Coordinator includes Corrective Action Plans to resolve performance deficiencies identified in multiple sensitivity analysis, the Planning Coordinator shall provide documentation to support those Plans.
ISO New England Inc.	No	Part 2.1.4, requires an entity to vary one or more conditions to demonstrate a change in performance. If the cases were initially stressed, this may force an entity to simulate conditions with less severe stresses. At this point, there is limited to no value to this additional workload. Having a requirement to test at least one sensitivity as a blanket requirement may not be informative by itself and is more unclear since sensitivities are being required on an undefined base set of conditions Additionally, our concern involves wording under 2.1.4 and 2.4.3 that sensitivities are required varying one or more conditions. Subsequently, in requirement 2.7.2 corrective action plans need to be developed to resolve performance deficiencies "only" if identified in multiple conditions or require a rationalization why no corrective action plan is necessary. Multiple conditions sensitivities under 2.1.4 and 2.4.3 are necessary to satisfy requirement 2.7.2. Requirement 2.7.2 adds ambiguity and should be removed. Requirement 2.7.2 should be revised as follows:2.7.2. Corrective Action Plans are not required for performance deficiencies identified in a sensitivity analysis.
United Illuminating National Grid	No	If an entity does a stressed set of assumptions do they always need to do a non-stressed case?
Hydro-Quebec TransEnergie	No	It is questionable that sensitivity analysis be included in Requirements since a conservative approach should already be used in studies, in accordance with good engineering practices.
American Transmission Company	No	R2.1.4 & R2.4.3 - We offer a major suggestion regarding the terms of 'credible' and 'measurable change" because these terms are ambiguous and not defined. So, there is a significant risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. We proposed adding that the TP and PC "shall provide documentation to support the technical rationale for determining the range of credible conditions and measurable change in performance" similar to R2.5. R2.1.4 & R2.4.3 bullet items - We offer the minor suggestion that the number and description of the bullet items in R2.1.4 match the bullet points in R2.4.3. Otherwise, please explain the reasons for any differences between

Organization	Yes or No	Question 5 Comment
		the bullet items in R2.1.4 and R2.4.3. R2.1.4 bullet #7 - We offer the minor suggestion that the term “planned” be replaced with “known” to be consistent with R1.1.2 and R2.1.3. Besides the term “planned outage” has a specific meaning in the Reliability Standards that are specific to the Operating horizon. R2.7.2 - With regard to "include actions to resolve performance deficiencies identified in multiple sensitivity studies", we do not think that mitigation plans should be required for deficiencies found in multiple sensitivity studies because the conditions in sensitivity studies are more extreme and less likely than base case conditions. Some sensitivity study conditions are not credible or plausible enough to warrant the implementation of mitigation measures. What is the SDT interpretation of multiple studies - more than one or a majority of the sensitivities that were studied?
Lakeland Electric	No	It is recommended that the phrase “...measureable change in performance...” be changed to “...measurable change in system response...” A change in performance is unclear, and could suggest that a sensitivity study is valid only if the System is stressed to the point that it no longer performs within the criteria established by Table 1. In addition, it is recommended that the following text appear after the last sentence of 2.4.3: “The condition or conditions to be varied shall be left to the discretion of the Transmission Planner or Planning Coordinator, provided they are selected from the list below.”
Northeast Utilities	No	The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions as commented in Question #3. The standard must describe base assumptions. To define a sensitivity condition, NERC must define base assumptions.
Modesto Irrigation District	No	This new requirement will expand the scope of the study work beyond a reasonable extent.
NBSO	No	Base case assumptions should be made such that they appropriately stress the system to be tested and are in accordance with good engineering practice. If the base cases are already stressed, the requirement to study sensitivity cases may result in the study of less severe conditions, and thus require additional time and resources while providing little additional value to the overall assessment.
Central Maine Power Company New York State Electric & Gas	No	These sensitivities need to be considered if not already included in the base case assumptions.

Organization	Yes or No	Question 5 Comment
Corp		
Progress Energy	No	PE does not have concerns in general with either 2.1.4 or 2.4.3. PE does, however, disagree with the wording at the end of the main paragraph of 2.4.3. Whether or not analysis qualifies as sensitivity analysis should not be predicated upon the end results; rather, it should be based upon major case modeling differences. PE therefore recommends that the phrase "...that demonstrate a measurable change in performance" be removed so that the last sentence in the main paragraph read "...by a sufficient amount to stress the System within a range of credible conditions."
ERCOT ISO	No	The stress test requirements should be deleted. The purpose of this proposed Standard is to establish planning performance standards that support reliable operation. This is achieved by imposing performance requirements relative to specific conditions and contingencies. Compliance with the performance metrics within these boundaries is presumably indicative of a reliable system. It is unclear what value is added by stress testing the system in accordance with undefined, vague parameters, as required by Requirements 2.1.4 and 2.4.3. The criteria in the relevant requirements that govern the stress testing are defined by the following ambiguous phrase: 1) "by a sufficient amount"; 2) "range of credible conditions"; and 3) "measurable change of performance". Application of these criteria introduces uncertainty for both the regulated community and the relevant compliance enforcement authorities, which, in turn, creates audit risks for regulated entities. Furthermore, there is no reliability value because the stress test requirements do not establish objective criteria and do not prescribe any actions based on the stress test results. Reliability Standards should set specific obligations that are readily discernible and achievable on a consistent basis. The existing Standard does this by setting specific performance obligations relative to specific conditions and contingencies. Conversely, the stress test requirements introduce ambiguity and uncertainty with no reliability benefit; the only apparent effect is unnecessary audit liability risk for regulated entities. Accordingly, ERCOT believes that these requirements should be deleted.
Tucson Electric Power Company	No	TEP agrees with removing the phrase "not already included in the studies." However, TEP does not understand the purpose of sensitivity studies. TEP is concerned that imposing additional sensitivity studies could lead to requirements that exceed the proposed standards. TEP recommends removing sesnitivity analysis from the standard.
New York Independent System Operator	No	Our concern involves wording under 2.1.4 and 2.4.3 that sensitivities are required varying one or more conditions. Subsequently, in requirement 2.7.2 corrective action plans need to be developed to resolve performance deficiencies "only" if identified in multiple conditions or require a rationalization why no corrective action plan is necessary. Multiple conditions sensitivities under 2.1.4 and 2.4.3 are necessary to satisfy requirement 2.7.2.

Organization	Yes or No	Question 5 Comment
		Requirement 2.7.2 adds ambiguity and should be removed. Requirement 2.7.2 should be revised as follows:2.7.2. Corrective Action Plans are not required for performance deficiencies identified in a sensitivity analysis.
GDS Associates, Inc.	No	The requirements are extremely burdensome. We recommend changing the last sentence of 2.1.4 requirement by removing "by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:" because there are instances where listed conditions may not result in measurable changes in performance (Ex. An increase in load in a well built system may not cause any measurable changes in performance because there is sufficient transmission capacity to serve the load).
SMUD		What is the significance of changing the wording for section R2.1.5 from 'assessed' to 'studied' and 'Planning Assessments' to 'studies'?
Western Area Power Administration	Yes	In Requirement 2.1.4, "Sensitivity Analysis". How much change does it take in any of the modeling assumptions (load, generation, voltage support, topology, etc.) to significantly stress the system within a range of credible condition? As this Requirement relates to R2.7, Would it be necessary to have Corrective Action Plan(s) if needed to meet all the Sensitivity Cases? How many Sensitivities before must have Corrective Action Plan? Also - why is it essential to use the qualifier "annual" for "current studies" in Part 2.1? Can a study be considered current if it is conducted less frequently than once per year? Note that Parts 2.3, 2.4 and 2.5 do not use the "annual" qualifier, nor does Requirement R2. Recommend deleting this apparently non-essential qualifier in both R2.1 and R2.2. We are unable to appreciate why the wording in Part 2.3 is not consistent with that in Part 2.1, 2.2, 2.4 or 2.5. Note that the semantics of the wording "... (steady state / stability) analysis shall be assessed annually..." can be interpreted to be much different than the semantics of the Part 2.3 wording "The short circuit analysis.... shall be conducted annually ...". The former requires the analysis to be *assessed* annually but 2.3 requires the analysis to be *conducted* annually without explicitly requiring it be assessed -- is the usage of "conducted" instead of 'assessed" consistent with the intent? In Part 2.6.2, the intent is awkwardly conveyed within the phrase "...the System represented in the study shall not include any material changes unless...". In the context of a *past* study, how can the System represented possibly include any material changes (that would have presumably occurred after the study)? Suggest modifying Part 2.6.2 to read "For steady state, short circuit or Stability analysis: no material changes have occurred in the System represented in the study or, if material changes have occurred, a technical rationale shall be provided to explain why they do not significantly impact the study results."

Organization	Yes or No	Question 5 Comment
NERC staff	Yes	NERC staff supports removing the phrase “not already included in the studies” from the parts 2.1.4 and 2.4.3 of Requirement R2. We believe that the requirement is more clear and less subject to interpretation without this phrase.
MidAmerican Energy	Yes	R2.1.4 bullet #7 - Replace the adjective “planned” with “known” for consistency with R1.1.2 and R2.1.3.R2.3 Replace “conducted” with “assess” for consistency with R1.1.2 and R2.1.3.R2.4 Replace “current or past studies as qualified” with “current or qualified past studies as indicated” for consistency with R2
SERC Planning Standards Subcommittee	Yes	
SERC Dynamics Review Subcommittee	Yes	
Pepco Holings, Inc - Affiliates	Yes	
Bonneville Power Administration	Yes	
Exelon Transmission Planning	Yes	
Southern Company	Yes	
Western Electricity Coordinating Council	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
NorthWestern Energy (NWMT)	Yes	
PNM	Yes	

Organization	Yes or No	Question 5 Comment
FirstEnergy	Yes	
Platte River Power Authority	Yes	
Manitoba Hydro	Yes	
Minnesota Power	Yes	
TVA Transmission Planning & Compliance	Yes	
Independent Electricity System Operator	Yes	
South Carolina and Gas	Yes	
SRP	Yes	
Seattle City Light	Yes	
California Energy Commission	Yes	
Los Angeles Department of Water and Power	Yes	
Idaho Power Co	Yes	
Ameren	Yes	
LCRA TSC	Yes	
American Electric Power (AEP)	Yes	
Tri-State Generation &	Yes	

Organization	Yes or No	Question 5 Comment
Transmission		
GTC	Yes	
Pacific Gas and Electric Company	Yes	
Oncor Electric Delivery	Yes	
Puget Sound Energy	Yes	
Sacramento Municipal Utility District	Yes	
Xcel Energy	Yes	
Southern California Edison Company	Yes	

3.3 Requirement R2, Part 2.4.1 – dynamic load models:

Summary Consideration:

The majority of respondents agree with the changes to these requirements and no changes to these requirements have been made in response to stakeholder comments.

The SDT does not intend that detailed dynamic Load models will be required for Loads in the System models used for the assessments. In particular, Requirement R2, part 2.4.1 states that an aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

The SDT has placed this requirement in TPL standards because it is not presently covered in MOD standards.

Organization	Yes or No	Question 6 Comment
NERC staff	No	NERC staff understands why the SDT has inserted the word “expected” before “dynamic behavior of Loads,” but we have concerns with this addition. We understand that a PC or TP that models the best current industry understanding of load behavior should not need to worry about compliance if that model does not match actual load response for all possible system conditions. However, we are concerned that this change to part 2.4.1 of Requirement R2 may be too accommodating. If a PC or TP has unrealistic expectations about load behavior, would this permit the use of unrealistic models? While we have struggled to develop an alternative proposal, we hope that the SDT will identify a way to address this concern.
Northeast Power Coordinating Council	No	There is insufficient information and experience regarding dynamic load modeling. It may also be included as a “sensitivity” analysis in 3.2, rather than requiring and expecting accurate representation of a dynamic load model. If this requirement is kept, a modeling standard must be written that is specific to dynamic loads. Change belongs in a modeling standard, not in TPL-001.
Hydro One Networks Inc.	No	There is insufficient information and experience regarding dynamic load modeling. Hence, this should not be a requirement but a guide or an item to be considered to the extent possible. It may also be included as a “sensitivity” analysis in 3.2, rather than requiring and expecting accurate representation of dynamic load model.
Transmission Issues Subcommittee	No	TIS believes that the term “expected” leaves the question as to “whose expectation.” It should be stated as to “expected...by the Transmission Planner.”

Organization	Yes or No	Question 6 Comment
Exelon Transmission Planning	No	There is not an industry consensus around best practices for modeling the dynamic behavior or characteristics of load. It is premature to make this a requirement in an enforceable standard which would be held to this degree of subjective auditing.
Manitoba Hydro	No	The last two sentences "System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable." belong in the MOD standards. They are not required in TPL-001-2.
US Bureau of Reclamation	No	Not included in R2. See response to Question 3.2
CenterPoint Energy	No	The SDT did not incorporate CenterPoint Energy's previous comments regarding R2; therefore, CenterPoint Energy's concerns remain.
Ameren	No	Industry needs guidance regarding how to provide reasonable induction motor representation as opposed to generic models.
Hydro-Quebec TransEnergie	No	There is insufficient data available to accurately model system wide motor loads.
LCRA TSC	No	The first bullet item in Section 3.3.1 should be the same as the second bullet in Section 4.3.1. The wording is somewhat confusing in both. Also, the wording as proposed does not recognize that a high voltage limit could also be violated. Edits to the item as shown below are suggested. Tripping of generators where simulations show generation bus voltages or high side generation step up (GSU) voltages are outside known limits, or assumed to be outside generator steady state limits, or have reached the generator ride through voltage limit. Include in the assessment any assumptions made.
Tri-State Generation & Transmission	No	Rather than specifically call out induction motor loads, we recommend changing the second sentence to "Stability analysis shall include models that represent the expected dynamic behavior of system elements that could impact the study area."
GTC	No	We have concerns for including induction motor representations in the load models without any study or bench-marking activities to meet the requirements of R2.4.1. This information should be supplied by the LSE as part of the MOD standard. We understand that the proposed standard will accept an aggregate system load model which represents the overall dynamic behavior of the load to relieve the burden of trying to develop specific induction motor load representation at each load bus. However this modeled system response will be considerably different compared to the actual system response which will open up the

Organization	Yes or No	Question 6 Comment
		industry to unwarranted scrutiny and possible compliance violation investigations.
Consolidated Edison Co. of New York, Inc.	No	There is insufficient information and experience regarding dynamic load modeling. It may also be included as a "sensitivity" analysis in 3.2, rather than requiring and expecting accurate representation of a dynamic load model. If this requirement is kept, a modeling standard should be written that is specific to dynamic loads. This change belongs in a modeling standard, not in TPL-001.
NBSO	No	By implication, the response of induction motor load would need to be considered when modeling the expected dynamic behaviour of loads that could impact the study area. NBSO suggests re-wording parts of R2.4.1 as follows: System peak load levels shall include a model which represents the expected dynamic behaviour of loads that could impact the study area. An aggregate system load model which represents the overall expected dynamic behaviour of load is acceptable.
Central Maine Power Company New York State Electric & Gas New York Independent System Operator	No	We have not determined a need to model dynamic loads, and therefore have not benchmarked any such models. We recommend that prior to this requirement being in place, a modeling standard should exist that is specific to dynamic loads.
ERCOT ISO	No	ERCOT ISO suggests adding "best available" as a descriptor to load models. Distribution Providers (DPs)/Load Serving Entities (LSEs) are the appropriate NERC functional entities to provide dynamic load data. Accordingly, Planning Coordinators (PCs) and Transmission Planners (TPs) must rely on those entities for that data. Despite reliance on DPs/LSEs for this data, the Standard proposes to impose an obligation on PCs and TPs to include a load model representative of "expected" dynamic behavior. Simply put, PCs and TPs do not have this information and should not be subject to compliance liability risk for an issue that is beyond their control. This change will still accomplish the goal of reflecting dynamic data in the relevant models, while mitigating PC/TP compliance risk by basing their compliance on information that is within their control - i.e. the "best available" information. Based on this change, the language should read - "System peak Load levels shall include best available Load models which represent the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads". This language is also a more accurate reflection of the Consideration of Comments by the Standard Drafting Team after the March 2010 comment period.To address this issue in the most appropriate manner, the Standard should be revised to establish an appropriate process for collection, reporting and use of dynamic data based on assigning obligations to the appropriate functional entities. In essence, DPs/LSEs should be required to collect the data and report it to TPs. Because TP models are the basis for PC models, the dynamic data will be included in PC models as part of the process. However, DPs and TPs should still only be required to use the "best available" data. Continued use of this language will mitigate the liability risk associated with a

Organization	Yes or No	Question 6 Comment
		requirement related to data that is within the control of a third party. Even under a construct where DPs/LSEs are required to collect and report dynamic data, there is no guarantee they will do so and PCs/TPs should not be held accountable in those circumstances. Accordingly, PC/TP compliance risk will be mitigated by use of a "best available" standard.
GDS Associates, Inc.	No	We disagree with the content of this requirement based on several facts:- We believe that the dynamic behavior of the load cannot be accurately estimated beyond current time. We are concern about the effort required to ascertain the dynamic response of the load- The requirement references "Loads that could impact the study area" without specifying how an entity will identify these loads. Perhaps the standard should provide guidelines to determine which loads would impact the study area.
MidAmerican Energy	No	MidAmerican questions if the widespread use of composite load models really provides significant benefits to additional dynamic analyses over generic load conversion assumptions which have been historically used. The use of composite load models may result in more precise individual load models, but no more accurate dynamic simulations. This poorly worded requirement should be deleted in its entirety as providing additional burden without any additional reliability benefits. If the composite load model requirement must be kept, it should be modified to include the following bolded text:"...System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads, but without requiring a detailed load survey be conducted..."
Platte River Power Authority	Yes	For consistency, use the qualifier "expected" in the second sentence of Part 2.4.1 also, such that it reads "...represents the overall expected dynamic behavior..."
Xcel Energy	Yes	For consistency, use the qualifier "expected" in the second sentence of Part 2.4.1 also, such that it reads "…represents the overall *expected* dynamic behavior…"
SERC Planning Standards Subcommittee	Yes	
SERC Dynamics Review Subcommittee	Yes	
MRO's NERC Standards Review Subcommittee	Yes	

Organization	Yes or No	Question 6 Comment
Pepco Holings, Inc - Affiliates	Yes	
IRC Standards Review Committee	Yes	
Bonneville Power Administration	Yes	
Southern Company	Yes	
Western Electricity Coordinating Council	Yes	
Arizona Public Service Company	Yes	
Florida Reliability Coordinating Council, Inc - Transmission Working Group	Yes	
Western Area Power Administration	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
NorthWestern Energy (NWMT)	Yes	
Lakeland Electric	Yes	
PNM	Yes	
FirstEnergy	Yes	
Orlando Utilities Commission	Yes	

Organization	Yes or No	Question 6 Comment
Minnesota Power	Yes	
TVA Transmission Planning & Compliance	Yes	
Independent Electricity System Operator	Yes	
South Carolina and Gas	Yes	
SRP	Yes	
California ISO	Yes	
Seattle City Light	Yes	
California Energy Commission	Yes	
ISO New England Inc.	Yes	
Los Angeles Department of Water and Power	Yes	
Idaho Power Co	Yes	
United Illuminating	Yes	
National Grid	Yes	
American Transmission Company	Yes	
American Electric Power (AEP)	Yes	

Organization	Yes or No	Question 6 Comment
Lakeland Electric	Yes	
Pacific Gas and Electric Company	Yes	
Northeast Utilities	Yes	
Modesto Irrigation District	Yes	
Oncor Electric Delivery	Yes	
Progress Energy	Yes	
Tucson Electric Power Company	Yes	
Puget Sound Energy	Yes	
Sacramento Municipal Utility District	Yes	
Southern California Edison Company	Yes	

3.4 Requirement R2, Part 2.5 – material clarification:

Summary Consideration:

The majority of respondents agree with the changes to these requirements and no changes to these requirements have been made based on stakeholder comments.

The SDT discussed defining 'material change' but did not believe that such a definition was appropriate in a continent-wide standard. With the wide variety in sizes and types of systems, the number of parameters that need to be considered, etc., there are too many variables involved. With the inclusion of Requirement R8 and the sharing of information, there is an opportunity for open discussion on such matters.

The SDT notes that Part 2.6.2 allows an entity to rely on a past study with a material change if "a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area". Therefore, it is up to the entities performing the study to provide the rationale based on changes, such as Load growth.

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered the comments.

Organization	Yes or No	Question 7 Comment
Exelon Transmission Planning	No	The term 'material changes' is subjective. It is very difficult to determine a base case to study combinations of generator additions on a changing transmission network in the 6 to 10 year time period to be used for dynamic simulations. Dynamic studies should be performed whenever new generator interconnections are proposed and it is at that time where meaningful calculations can be performed. The long term six to ten year out dynamic studies for groupings of potential units should be done at a high level, if at all.
Florida Reliability Coordinating Council, Inc - Transmission Working Group	No	This change does not clarify material. Material should be quantified somehow. We recommend changing the phrase "material generation additions or changes" to "generation in the vicinity with additions of changes larger than 200 MW".
Lakeland Electric	No	Please consider removing R2.6.2. The "any material change" language can cause utilities perform studies due to material changes outside of and remote to its system.

Organization	Yes or No	Question 7 Comment
Orlando Utilities Commission	No	I agree with what I think is the intent. The word "Material" is meant to allow for changes in model to occur that are "small" relative to the TP/PC. For example the 400 MW generator that might be built in 10 years by another utility over a hundred miles, several dozen buses and generators away to not force new study work. However as written in 2.5 it requires you to define what a material change is, and could be applied to mean every change must be identified and explained rather then an overarching rationale that would only have you looking for changes that meet the material criteria. But then in 2.6.2 the word material is used with no obligation to explain what material is, only to explain if a material change would not impact the results in a study area. I recommend leaving the term material, but setting a requirement, measure, or definition that requires the TP/PC to define what they consider material specific to their system and circumstance. Since this will by the hetreogenous nature of the grid be different for each it may not be reasonable to pre-define what is reliable. Just as was done with many items in the ATC (MOD) standards, require that it be documented and questions on that rationale be answered. If a specific level of technical oversight is desired, consider requiring that description to be on file with the regional entity and approved by their planning committee. I think the team is heading in a good direction, it's just how the words will be applied that concern me. This may be a case where an Example or two would go a long way towards providing guidance to entities and auditors.
Manitoba Hydro	No	Adding the word “material” does not clarify Part 2.5. The word “material” can be interpreted in many ways and is subjective. In order to have a consistent approach by all TPs, the drafting team should add a definition of the term “material”. One TP may consider a new 200 MW unit as not being material because there are several larger units in the TPs system.
US Bureau of Reclamation	No	The term "material" is arbitrary. It is suggested that a specific value be used to trigger the assessment.
CenterPoint Energy	No	The SDT did not incorporate CenterPoint Energy's previous comments regarding R2; therefore, CenterPoint Energy's concerns remain.
Progress Energy	No	PE agrees in general with the changes made to R2.5. PE disagrees, however, with the language stipulating that current and past studies be qualified by the language in R2.6 Part 2.6.2 (see notes for Question 3.1 regarding recommending changes with regard to R2.6.2).
Tucson Electric Power Company	No	If a material change (generator addition/retirement, new generator models based on unit testing, or transmission line or non-distribution transformer addition) is not planned for the longer-term planning horizon, do the longer-term stability studies need to be performed? TEP's agreement/disagreement with Part 2.4.1 is

Organization	Yes or No	Question 7 Comment
		dependent on the response to this question. If the answer is the studies do not need to be performed, then TEP supports these changes.
GDS Associates, Inc.	No	We are not sure what will be included in these "material generation additions or changes". Perhaps the standard should provide guidelines to determine what are these material changes or additions?
Xcel Energy	No	It appears that the requirement appended at the end of Part 2.5 "…and shall include documentation to support the technical rationale for determining material changes." is duplicative of Part 2.6.2. Please address this apparent redundancy.
NERC staff	Yes	NERC staff supports inserting the word "material" in the reference to assessing the impact of proposed generation. We have some concern that this change leaves this part of the requirement open to interpretation, but we also understand the need to permit some degree of engineering judgment to be applied. It would not be appropriate to require that every potential generation addition be included in the assessment where some proposed additions may by inspection be deemed to be immaterial due to size and/or interconnection location.
IRC Standards Review Committee	Yes	However, the requirement infers that a subjective judgment from a compliance auditor will be required.
Bonneville Power Administration	Yes	It should be noted that if there is more generation proposed in an area than there load and export capability, all proposed material generation additions would not be represented. Determining what future generation additions to include in the Long-Term Transmission Planning Horizon may be based on a non-technical rationale rather than a technical rationale.
Western Area Power Administration	Yes	The drafting team could provide guidance on what is "material". In Part 2.5, should "annually" be inserted after "shall be assessed" to make it consistent with Parts 2.1, 2.2, 2.3 and 2.4? If the omission is intentional in 2.5, please explain why.
Platte River Power Authority	Yes	I like the flexibility you give the PC and TP to define what 'material' means in their 'documentation to support the technical rationale for determining material changes.' In Part 2.5 this rationale will decide whether or not any Long-Term Stability studies are required for the Planning Assessment. And in Part 2.6.2 this rationale will be a factor in qualifying a past study.
Independent Electricity System	Yes	We do not have a concern with this change but we don't think it is necessary. It is not a requirement, and

Organization	Yes or No	Question 7 Comment
Operator		appropriate wording in the Measures can take care of it.
SERC Planning Standards Subcommittee	Yes	
Northeast Power Coordinating Council	Yes	
Hydro One Networks Inc.	Yes	
SERC Dynamics Review Subcommittee	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
Pepco Holings, Inc - Affiliates	Yes	
Southern Company	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
NorthWestern Energy (NWMT)	Yes	
FirstEnergy	Yes	
Minnesota Power	Yes	
TVA Transmission Planning & Compliance	Yes	
South Carolina and Gas	Yes	

Organization	Yes or No	Question 7 Comment
SRP	Yes	
California ISO	Yes	
Seattle City Light	Yes	
California Energy Commission	Yes	
ISO New England Inc.	Yes	
Los Angeles Department of Water and Power	Yes	
Idaho Power Co	Yes	
United Illuminating	Yes	
Ameren	Yes	
Hydro-Quebec TransEnergie	Yes	
LCRA TSC	Yes	
National Grid	Yes	
American Transmission Company	Yes	
American Electric Power (AEP)	Yes	
Tri-State Generation & Transmission	Yes	
Lakeland Electric	Yes	

Organization	Yes or No	Question 7 Comment
GTC	Yes	
Northeast Utilities	Yes	
Consolidated Edison Co. of New York, Inc.	Yes	
NBSO	Yes	
Central Maine Power Company	Yes	
Oncor Electric Delivery	Yes	
New York State Electric & Gas Corp	Yes	
ERCOT ISO	Yes	
New York Independent System Operator	Yes	
MidAmerican Energy	Yes	
Sacramento Municipal Utility District	Yes	
Southern California Edison Company	Yes	

4. The SDT has revised the header notes based on industry comments to the initial ballot. If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your concern.

Summary Consideration:

The SDT clarified the language of header note 'i' as a result of comments received as follows:

i. The response of voltage sensitive Load ~~including Load~~ that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

The majority of respondents agree with the changes to the header notes and no other changes to the header notes have been made based on stakeholder comments.

Requirements cannot be 'hidden' in the Table because the Table is specifically cited in the requirements text and is thus part of the requirements.

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered the comments.

Organization	Yes or No	Question 8 Comment
Northeast Power Coordinating Council	No	Header note (i) in the first Table 1 (p. 10) could imply that voltage-varying load shall not be used to meet steady state performance requirements. Steady state load models in use include voltage-varying loads. The explicit representation of (voltage-dependent) load models is perfectly consistent with the requirements defined in R1 (which calls for a comprehensive representation of system components and their expected operating status in the planning assessment period) and the impetus to the creation of more specific load models in dynamic assessments found Requirement 2.4 of this draft of TPL-001-2. It is a known that depressed voltage conditions cause certain system elements to perform below their rated capacity. For example, capacitors provide less voltage support and voltage controlling transformers are impeded by their finite tap range to direct VAR flow into areas affected by low voltage conditions. Certain load types, on the other hand, provide a self-compensating relief to depressed voltage by naturally decreasing demand in a manner proportional to their characteristics, without operator intervention. Choosing to negate the voltage-dependence of one of these system elements (load, in our case) results in an inaccurate system representation that, in turn, may lead to erroneous assessments of the reliability state of the interconnected system and, potentially, to the implementation of unwarranted system upgrades. This note should be revised

Organization	Yes or No	Question 8 Comment
		to only reference loads which are disconnected due to voltage.
Transmission Issues Subcommittee	No	Delete the word "voltage" from the last header note J concerning Stability Only. All types of transient stability must be observed.
LCRA TSC	No	The third bullet of 4.3.1 requires the addition of relay models for stability studies. This type of analysis is performed today by scripting the tripping of multiple lines due to breaker failure events. The inclusion of relay models into the stability study will result in added complexity and an over reliance on relay models for system stability assessment. The stability assessment should assess stability resulting from the operation of relays as opposed to reliance on a relay model for proper system representations. Assurance of the proper operation of relays results from the analysis performed to set relays not from stability studies. From Section 4.3.1:"Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models." Section 4.5 requires that "The rationale for those Contingencies selected for evaluation shall be available as supporting information." This will have to be developed. Requirement R5 requires the establishment of criteria for transient voltage response of the system. This seems unnecessary given the proposed changes to Table 1. The proposed changes to table 1 seem to make clear the type of system response that is allowable through its specification of what is allowable in terms of interruptions to Firm Transmission and Non-Consequential loads. R5 states: "Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level."
Consolidated Edison Co. of New York, Inc.	No	o Header note (i) in the first Table 1 (p. 10) The explicit representation of (voltage-dependent) load models is perfectly consistent with the requirements defined in R1 (which calls for a comprehensive representation of system components and their expected operating status in the planning assessment period) and the impetus to the creation of more specific load models in dynamic assessments found Requirement 2.4 of this draft of TPL-001-2. It is a known that depressed voltage conditions cause certain system elements to perform below their rated capacity. For example, capacitors provide less voltage support and voltage controlling transformers are impeded by their finite tap range to direct VAR flow into areas affected by low voltage conditions. Certain load types, on the other hand, provide a self-compensating relief to depressed voltage by naturally decreasing demand in a manner proportional to their characteristics, without operator intervention. Choosing to negate the voltage-dependence of one of these system elements (load, in this case) results in an inaccurate system representation that, in turn, may lead to erroneous assessments of the reliability state of the interconnected

Organization	Yes or No	Question 8 Comment
		system and, potentially, to the implementation of unwarranted system upgrades.
Central Maine Power Company New York State Electric & Gas Corp New York Independent System Operator	No	Header note (i) in the first Table 1 could imply that voltage-varying load shall not be used to meet steady state performance requirements. NYISO steady state load models include voltage-varying loads. This note should be revised to only reference loads which are disconnected due to voltage.
MidAmerican Energy	No	The reference to BES should be placed back into Note a in the header above table 1.
Xcel Energy	No	Although we support the revised header notes, we believe that the following additional changes are needed to enhance clarity and improve consistency: We are unable to see the compelling need and/or the value of separating the header notes in three categories. Since the applicability of each header to either one or both steady-state and stability performance is obvious from its respective verbiage, we suggest eliminating the categorization. This will also allow the header notes to be reordered/regrouped as per related functionality, thus improving the Table 1 readability. Following is a suggested re-ordering of header notes: a. Applicable Facility Ratings shall not be exceeded. The System shall remain stable. Cascading and uncontrolled islanding shall not occur. b. Planning event P0 is applicable to steady state only. c. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event except P0. d. The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment as a consequence of any event shall not be used to meet steady state performance requirements. e. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits established by the Planning Coordinator and Transmission Planner. f. Transient voltage response shall be within acceptable limits as established by the Planning Coordinator and Transmission Planner. g. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. h. Simulate the removal of all elements that Protection Systems and other controls are expected

Organization	Yes or No	Question 8 Comment
		to automatically disconnect for each event. Simulate Normal Clearing unless otherwise specified.
MRO's NERC Standards Review Subcommittee American Transmission Company	Yes	We offer the major suggestion that Requirements not be created in the Performance Table and be absent from the Requirement section. Requirements should only be referred to in the Performance Table after they already exist in the Requirement section. a. Notes “f” and “g” under “Steady State Only” section in the Table 1 header create requirements (e.g. use the verb, “shall”) that do not appear in the Requirements section. We suggest adding R3.3.5, which could read, “Applicable System Operating Limits for the planning horizon shall not be exceeded.” [After R3.3.5 is added, Notes “f” and “g” should be revised and refer to R3.3.5.]. b. Note “i” under “Steady State Only” section in the Table 1 header creates a requirement (e.g. use the verb, “shall”) that does not appear in the Requirements section. We suggest adding R3.3.6, which could read, “The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state voltage requirements.” [After R3.3.6 is added, Note “d” should be revised to refer to R3.3.6. c. Note “j” under the “Stability Only” section in the Table 1 header creates a requirement (e.g. use the verb, “shall”) that does not appear in the Requirements section. We suggest adding R4.1.4, which could read, “Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner”. [After R4.1.4 is added, Note “j” should be revised to refer to R4.1.4.]
Western Area Power Administration	Yes	Following is a suggested re-ordering of header notes to replace of the three categories concept - same information: a. Applicable Facility Ratings shall not be exceeded. The System shall remain stable. Cascading and uncontrolled islanding shall not occur. b. Planning event P0 is applicable to steady state only. c. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event except P0. d. The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment as a consequence of any event shall not be used to meet steady state performance requirements. e. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits established by the Planning Coordinator and Transmission Planner. f. Transient voltage response shall be within acceptable limits as established by the Planning Coordinator and Transmission Planner. g. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. h. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event. Simulate Normal Clearing unless otherwise specified.
NERC staff	Yes	NERC staff supports the changes to the header notes in Table 1.

Organization	Yes or No	Question 8 Comment
Florida Reliability Coordinating Council, Inc - Transmission Working Group	Yes	We support the changes to the performance tables.
Platte River Power Authority	Yes	I like the flexibility you give the PC and TP in Requirements R3 and R4 to develop their rationale for the Contingencies they select for evaluation.
Orlando Utilities Commission	Yes	I am assuming you mean the header notes on the performance table
Progress Energy	Yes	PE assumes the term “header notes” is referring to the “Planning Performance Events” at the top of Table 1. If this is the case, PE has no concerns with the present language.
SERC Planning Standards Subcommittee	Yes	
Hydro One Networks Inc.	Yes	
SERC Dynamics Review Subcommittee	Yes	
Pepco Holings, Inc - Affiliates	Yes	
IRC Standards Review Committee	Yes	
Bonneville Power Administration	Yes	
Exelon Transmission Planning	Yes	
Southern Company	Yes	
Western Electricity Coordinating Council	Yes	

Organization	Yes or No	Question 8 Comment
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
NorthWestern Energy (NWMT)	Yes	
Lakeland Electric	Yes	
PNM	Yes	
FirstEnergy	Yes	
Manitoba Hydro	Yes	
Minnesota Power	Yes	
CenterPoint Energy	Yes	
TVA Transmission Planning & Compliance	Yes	
Independent Electricity System Operator	Yes	
South Carolina and Gas	Yes	
SRP	Yes	
California ISO	Yes	
Seattle City Light	Yes	

Organization	Yes or No	Question 8 Comment
California Energy Commission	Yes	
ISO New England Inc.	Yes	
Los Angeles Department of Water and Power	Yes	
Idaho Power Co	Yes	
United Illuminating	Yes	
Ameren	Yes	
Hydro-Quebec TransEnergie	Yes	
National Grid	Yes	
American Electric Power (AEP)	Yes	
Tri-State Generation & Transmission	Yes	
Lakeland Electric	Yes	
GTC	Yes	
Pacific Gas and Electric Company	Yes	
Northeast Utilities	Yes	
Modesto Irrigation District	Yes	
NBSO	Yes	

Organization	Yes or No	Question 8 Comment
Oncor Electric Delivery	Yes	
ERCOT ISO	Yes	
Tucson Electric Power Company	Yes	
GDS Associates, Inc.	Yes	
Puget Sound Energy	Yes	
Sacramento Municipal Utility District	Yes	
Southern California Edison Company	Yes	

5.

The SDT has revised the performance table (including the list of extreme events and footnotes) based on industry comments to the initial ballot. If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your concern.

Summary Consideration:

The SDT has made the following clarifying changes to address concerns raised in the comments:

- P0 – delete superscript 9 in column 6: No[9]
- P5 event description: Delayed Fault -Clearing —due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following:
- Extreme events language for Stability events has been made consistent with P5.
- Added 'Breaker' to the Bus-tie and non-Bus-tie phrases in P2 and P4

No other changes were made to the Performance Table based on stakeholder comments.

The SDT fully realizes that Project 2010-11 must reach resolution prior to finalizing TPL-001-2 and stated same in the information attached with the fifth posting of Project 2006-02.

The SDT has made the language in Requirement R2, part 2.8.2 consistent with that in Requirement R2, part 2.7.4:

> **2.8.2** Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered the comments.

Organization	Yes or No	Question 9 Comment
NERC staff		NERC staff is concerned with P5 and footnote 9 and thus cannot support these changes in their entirety. First, a revision to the Draft 4 definition of P5 should be used in lieu of the current Draft 5 version: "Loss of multiple elements caused by the Fault clearing consistent with failure of a single Protection System while clearing a fault on one of the following: . . ."After reviewing the P5 contingency throughout various drafts of this standard, along with existing Table 1 for TPL-001 through TPL-004, NERC staff's primary concern is that this most recent version is going in the wrong direction by becoming too limiting regarding which Protection System component failures are covered. Draft 5 is an improvement because it removes the reference to loss of

Organization	Yes or No	Question 9 Comment
		multiple elements in Draft 4 (which defined P5 as "Loss of multiple elements caused by the failure of a single Protection System while clearing a fault on one of the following: . . ."). Draft 5 takes a step backward, however, by referring to Delayed Fault Clearing. The advantage of not referring to Delayed Fault Clearing is that for cases where redundant protection systems are provided, the fault clearing may not be delayed even when a single Protection System failure occurs. Ideally, NERC staff believes that P5 should refer to "failure of any component of a Protection System," but NERC staff recognizes that we cannot get there until the term Protection System is redefined and Project 2009-07-Reliability of Protection Systems is underway. Until that change is possible, NERC staff encourages the SDT to use the revised version of P5 proposed above. A second concern is with footnote 9, which is used numerous times in Table 1. System adjustments may be used in two different settings: the first is to address the aftermath of a particular Contingency; the second is to prepare for the next Contingency.Staff suggests that the current footnote 9 have this language added: "Post-Contingency Ccurtailment of Firm Transmission Service to address the simulated contingency, when coupled with ...." Footnote 9 is used in the column labeled "Interruption of Firm Transmission Service Allowed" whenever a "No" is provided. The footnote 9 in this column has to do with System adjustments that address the aftermath of the Contingency that is being simulated. Therefore, no footnote 9 appears appropriate for category P0 (No Contingency). The reference in footnote 9 to no load loss and staying within applicable Facility rating, including those on a neighboring system, is sufficient for addressing the aftermath of the Contingency being simulated. To address next Contingency, an additional footnote is needed in the "Initial System Condition" column for category P3 and category P6. The following is suggested: "System adjustments to prepare for the next Contingency must be completed within 30 minutes." Footnote 9 is used in the column labeled "Initial System Condition" for category P3 and category P6, and these two categories define the loss of an Element "followed by System adjustments" and then followed by the loss of a second Element. It is unclear whether the intent in footnote 9 in these two cases is meant to address the same issue referenced above (i.e. the aftermath of the Contingency being simulated) or whether it is intended to address the next Contingency. Thus, both situations need to be addressed using the suggestions indicated above.
Northeast Power Coordinating Council Consolidated Edison Co. of New York, Inc.		To support the change to P5, other items need to also be modified. In Table 1 - Steady State & Stability Performance Extreme Events (p. 12), in the Stability Section, the language should be made similar to wording in P5. Protection System should be removed and replaced with the words "relay failure". This change should be made for 2a through 2d:2. Local or wide area events affecting the Transmission System such as: a. 3Ã˜ fault on generator with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. b. 3Ã˜ fault on Transmission circuit with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. c. 3Ã˜ fault on transformer with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. d. 3Ã˜ fault on bus section with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing.

Organization	Yes or No	Question 9 Comment
		Note 11 (p. 14) needs clarification as shown: Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for a total of 1 mile or less. There are two tables labeled “Table 1”. Suggest that the extreme events table be renamed “Table 2”.
MRO's NERC Standards Review Subcommittee		We offer the major suggestion that the P3 Category performance criteria be modified to apply only to the loss of two generators. The SDT properly recognizes that generator outages are significantly more probable than line or transformer outages and should be “higher” in the category list. However given the clearly higher probability of generator outages, the probability of the loss of two generators is clearly higher than the loss of a generator and line or the loss of a generator and transformer. Therefore, if the loss of two generators is in the P3 category, then the loss of a generator and line or transformer should be clearly “lower” in the category list. We suggest the listing of: the loss of a generator and some other element (e.g. transmission circuit, transformer, shunt device, and single pole of DC line) be moved to a lower event category, such as the P6 Category by adding “1. Generator” to the listing in the Initial System Condition (Loss of . . .) column. Item 2.a in the Extreme Events, Steady State section - Clarify the meaning of the loss of multiple circuits in Item 2.a by using wording similar to P7. We suggest this text: “a. Loss of three or more circuits that share a common structure.” Footnote 6 - Further clarify the applicable shunt devices in Footnote 6 with this suggested text: “6. Requirements which are applicable to shunt devices, also apply to FACTS devices that are connected to ground, but not instrument voltage transformers or surge arresters.”
Bonneville Power Administration		Table 1, P5 currently requires the study of “[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed”. As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: “Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following”. In Table 1, P2 and P3, the last column “Non-Consequential Load Loss Allowed” where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore the proposed footnote 12 should include a provision to default to the existing footnote “b” in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, “Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial

Organization	Yes or No	Question 9 Comment
		customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers."
Exelon Transmission Planning		Comments: The term 'HV' in the performance table should be defined as 'Bulk Electric System elements up to 300 kV, not simply all elements 'below 300 kV'. Footnote 12 should be clarified to specifically state the requirements before voting takes place. The performance criteria should be based on the voltage level of the element experiencing stress due to the contingency, not based on the voltage level of the outaged element. It does not seem to make sense that the loss of a 500 kV bus would not allow for any non-consequential load shedding unless the bus contained a 500 to 230 kV transformer, in which case additional load shedding would be allowed. If outages on a 230 kV system, such as bus fault with stuck breaker, were to cause overloads on a 500 kV network it is acceptable to shed load, but if the outages were on the 500 kV system originally it would not be acceptable to shed additional load. It seems as if it should be the severity of the situation and the elements involved that would dictate allowable remedial actions and not the initial cause of the disturbance. If, for example, there was a 500 kV contingency outage that caused problems on the 230 kV system there would be a problem that may require load shedding on the 230 kV system. If there were a 230 kV contingency or series of contingencies that caused overloads on the 500 kV system, it would be more difficult to find enough lower voltage load to shed to bring the 500 kV system back to applicable ratings or conditions. The inability to shed non-consequential load could theoretically be resolved by hanging a small EHV / HV transformer on a particular bus, or by tapping a EHV line with an auto transformer.
Southern Company		NO. We wish to make a comment on the stability extreme event table: Changes were made in planning event P5 to narrow the focus to specific relay failures. The same changes are needed for stability extreme event 2a, 2b, 2c, and 2d.
Western Electricity Coordinating Council Arizona Public Service Company PNM SRP California Energy Commission Los Angeles Department of		Table 1, P5 currently requires the study of "[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed". As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: "Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following". In Table 1, P2 and P3, the last column "Non-Consequential Load Loss Allowed" where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential

Organization	Yes or No	Question 9 Comment
Water and Power Pacific Gas and Electric Company Modesto Irrigation District Puget Sound Energy Sacramento Municipal Utility District		Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote "b". This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote "b" in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, "Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers." Timing of this project and project 2010-11 is critical. It would be very difficult to vote to approve the proposed TPL-001-2 prior to knowing the outcome of Project 2010-11 (footnote b issue).
E.ON U.S.		E.ON U.S. believes that Table 1 should be formatted to avoid having the tables split by page breakers. In addition, tables spanning across multiple pages should have headers at the top of each page.
Florida Reliability Coordinating Council, Inc - Transmission Working Group		Footnote 12 performance requirements of Table 1 should allow the loss of non-consequential load for all contingency categories except for P0. The disallowance of load loss does not provide any real benefit to the reliability of the BES and is an unnecessary overreach into local quality of service issues that are best addressed by State, Provincial or Municipal authorities. There may be circumstances such as high local transmission costs or local opposition to transmission construction where prohibition of non-consequential load loss represents a poor cost/benefit or quality of life tradeoff. Having a provision at the regional level that a PA or TP can have a certain amount of non-consequential load loss designed or planned in to its system that would be reasonable if it is acceptable to the RE and does not have an adverse impact on the remaining BES. In lieu of such a RE provision, providing a quantitative cap in non-consequential load loss such as 100 MW may be rationale compromise in the goal of limiting load loss for the more probable outage events. Our preference would be to retain the capability of limited non-consequential load loss. Footnote 9 should also be under consideration as part of Project 2010-11 and should be noted as such for clarification.
Western Area Power Administration		In footnotes 9 and 12, two critical issues are being addressed in large part via these "clarifying" footnotes. These are curtailment of "Firm Transmission Service" (which seems primarily to be a contract/scheduling issue) and the loss of "Non-Consequential Load." Perhaps these issues should receive more attention in the

Organization	Yes or No	Question 9 Comment
		actual requirements. In P5 the term “Protection System” was removed and replaced with “relay”. How are protection system elements other than relays accounted for? In studying a multiple contingency event with a communication system or control circuitry failure would it be necessary demonstrate P1 performance levels? These details could become critical as industry deals with issues such as FERC’s interpretation of TPL-002-0 Requirement R1.3.10 (RM10-6-000). In Table 1 - Extreme Events - Stability - Items 2a-2d, change “Protection System failure” to “relay failure” to be consistent with changes in P5. Table 1, P5 currently requires the study of “[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed”. As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: “Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following”. Footnote 13 - Delete “voltage (#27, #59)” since the under/over voltage relays are not called upon to provide the primary protection for fault clearing on Transmission elements. Suggest modifying Event P4 description to be more consistent with Event P5 description by including Delayed Fault Clearing in the description in lieu of “Loss of multiple elements”. Suggested Event P4 description is: “Delayed Fault Clearing caused by a stuck non Bus-tie Breaker attempting to clear a fault on one of the following:” In Table 1, P2 and P3, the last column “Non-Consequential Load Loss Allowed” where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote “b”. This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote “b” in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, “Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the

Organization	Yes or No	Question 9 Comment
		affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers." Timing of this project and project 2010-11 is critical. It would be very difficult to vote to approve the proposed TPL-001-2 prior to knowing the outcome of Project 2010-11 (footnote b issue).
PacifiCorp		Under Category P2 (Single Contingency) and Normal System Conditions, the performance table indicates that, for both HV and EHV, interruption of firm transmission service and non-consequential load loss are not allowed following the opening of a line section without a fault. This section of the performance table should distinguish between EHV and HV - performance requirements following the opening of a line section without a fault should be the same as those for a bus section fault. As with the bus section fault, interruption of firm transmission service and non-consequential load loss should be allowed for HV.
NorthWestern Energy (NWMT) Idaho Power Co		Table 1, P5 currently requires the study of "[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed". As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: "Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following". In Table 1, P2 and P3, the last column "Non-Consequential Load Loss Allowed" where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote "b". This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote "b" in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, "Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers."

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Lakeland Electric		The performance requirements of Table 1 do not allow the loss of non-consequential load for single and multiple contingency events. The disallowance of load loss does not provide any real benefit to the reliability of the BES and is an unnecessary overreach into local quality of service issues that are best addressed by State, Provincial or Municipal authorities. There may be circumstances such as high local transmission costs or local opposition to transmission construction where prohibition of non-consequential load loss represents a poor cost/benefit or quality of life tradeoff. Having a provision at the regional level that a PA or TP can have a certain amount of non-consequential load loss designed or planned in to its system that would be reasonable if it is acceptable to the RE and does not have an adverse impact on the remaining BES. In lieu of such a RE provision, providing a quantitative cap in non-consequential load loss such as 100 MW may be rationale compromise in the goal of limiting load loss for the more probable outage events. Our preference would be to retain the capability of limited non-consequential load loss. It is our understanding that footnote 9 is under consideration as part of Project 2010-11 and should be noted as such for clarification.
FirstEnergy		Table 1, P5 currently requires the study of "[d]elayed Fault Clearing due to the failure of a relay (footnote 13) protecting the Faulted element to operate as designed". To the extent fully redundant relaying exists with no expected delay in Fault Clearing its understood that the P5 event would not be a concern for the redundant system design. The drafting team has taken appropriate steps within the TPL standard to focus on relaying failures to provide clarity in what is required for P5 planning event.
Platte River Power Authority		No. Table 1, P5 currently requires the study of "[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed". As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: "Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following". In Table 1, P2 and P3, the last column "Non-Consequential Load Loss Allowed" where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote "b". This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote "b" in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, "Note:

Organization	Yes or No	Question 9 Comment
		Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers." Timing of this project and project 2010-11 is critical. It would be very difficult to vote to approve the proposed TPL-001-2 prior to knowing the outcome of Project 2010-11 (footnote b issue). In Table 1 - Planning Events - Suggest changing the description for Events P2-3, P2-4, P4 and P4-6 to use the term 'Bus-tie Breaker' or 'non-Bus-tie Breaker' as applicable. In Table 1 - Extreme Events - Stability - Items 2a-2d, do you mean 'Protection System failure' here, or do you want to change to 'relay failure' to be consistent with changes in P5?
Orlando Utilities Commission		I generally agree with the direction the team has gone. Footnote 9 should also be highlighted as being part of the project 2010-11 discussion just as footnote 12 is.
Manitoba Hydro		In point g, violations are noted in terms of post-Contingency voltage deviations rather than post-Contingency voltage limits. This may lead to confusion, as some utilities evaluate performance based on a post-Contingency voltage deviation criterion while other utilities evaluate performance based on post-Contingency voltage limits. This same comment applies to Requirement R5.Suggested rewording for point g:System steady state voltages and post-Contingency voltages or voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner. Suggested rewording for the first sentence in Requirement R5:Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltages or voltage deviations, and the transient voltage response for its System. Note 12 states that an outstanding issue related to non-consequential load loss is being discussed. This will create a lot of uncertainty. Manitoba Hydro could not support this standard unless the resolution of Note B is known.
CenterPoint Energy		CenterPoint Energy appreciates the effort put forth by the SDT in revising the performance table. The current draft of P5 is preferable to previous versions.
TVA Transmission Planning & Compliance		TVA is concerned about footnote 12 (known as footnote b in existing TPL standards). TVA believes that utilities should be given some freedom in dropping local load in response to N-1 events as long as overall

Organization	Yes or No	Question 9 Comment
		BES reliability is not impacted. Otherwise significant capital improvements will be required that will have no overall reliability gain for the Bulk Electric System. TVA does agree with the revisions made specifically to the P5 event. TVA wishes to make a comment on the stability extreme event table: Changes were made in planning event P5 to narrow the focus to specific relay failures. The same changes are needed for stability extreme event 2a, 2b, 2c, and 2d.
SMUD		For the Western Interconnection, the performance level for a Bus-tie breaker fault under TPL-001-2, Table 1, Item P2-4, Notes (a) and (f), requires no thermal overloads and no cascading. While, FAC-010-2.1, R1.2, R2.5-R2.6, as modified by E1.1, E1.1.7, E1.3, and E1.3.1 requires a different performance level of no cascading. Please explain why this regional variance is not included under TPL-001-2, Item E.
California ISO		We support these changes, although we suggest that the proposed footnote 12 include an interim provision to default to the existing footnote “b” in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, “Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.”
Seattle City Light		Table 1, P5 does not recognize the existence of redundant (or backup) relays. These are an integral part of the protection system design and should be considered in analysis of SLG faults. The TPL standard should encourage redundant, fail-safe systems, not ignore them. In Table 1, P2 and P3, we have a concern about not allowing non-consequential load loss. Project 2010-11 is deciding on this issue, but is not completed (see footnote 12). Should the standard become effective before this project is completed, no non-consequential load loss would be allowed, requiring many transmission additions and reconfigurations. Please change the "NO" in the last column to "YES" until the completion of Project 2010-11.
ISO New England Inc.		We are supportive of the change to P5. However, in making this modification, other items need to also be changed. In Table 1 - Stability, the language should be made similar to wording in P5. Protection System should be removed and replaced with the words “relay failure”. This change should be made for 2a through 2d:2. Local or wide area events affecting the Transmission System such as: a. 3Ã˜ fault on generator with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. b. 3Ã˜ fault on Transmission circuit with

Organization	Yes or No	Question 9 Comment
		stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. c. 3Ã˜ fault on transformer with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. d. 3Ã˜ fault on bus section with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. We also believe that Note 11 needs clarifying wording as shown below:"Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for a total of 1 mile or less"
United Illuminating National Grid Central Maine Power Company New York State Electric & Gas Corp		In Table 1 - Stability, Make language similar to wording in P5. "Protection System" should be removed and replaced with the words "relay failure". This would avoid future interpretation issues about the intent of this requirement (as we understand it) to exclude more severe though less likely failures such as battery systems. This change should be made for 2a through 2d on page 12).In Note 11 (page 14) ADD the wording shown in "quotes" below: Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for "a total of" 1 mile or less.
Hydro-Quebec TransEnergie		In table 1 on page 12 (Stability section), Relay failure should replace Protection System
LCRA TSC		An important footnote to Table 1 is omitted from this proposed revision. This omission prevents adequate evaluation of the footnote. Footnote 12 in Table 1 is no longer applied to P2.1, P2.2, P2.3, P4, and P5. The footnote states: “Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.” The footnote should be removed from the proposed revision until Project 2010-11 is concluded.
American Transmission Company		We offer the major suggestion that the P3 Category performance criteria be modified to apply only to the loss of two generators. The SDT properly recognizes that generator outages are significantly more probable than line or transformer outages and should be “higher” in the category list. However given the clearly higher probability of generator outages, the probability of the loss of two generators is clearly higher than the loss of a generator and line or the loss of a generator and transformer. Therefore, if the loss of two generators is in the P3 category, then the loss of a generator and line or transformer should be clearly “lower” in the category list. We suggest the listing of: the loss of a generator and some other element (e.g. transmission circuit, transformer, shunt device, and single pole of DC line) be moved to a lower event category, such as the P6 Category by adding “1. Generator” to the listing in the Initial System Condition (Loss of . . .) column. We offer the minor suggestion that Item 2.a in the Extreme Events, Steady State section - Clarify the meaning of the loss of multiple circuits in Item 2.a by using wording similar to P7. We suggest this text: “a. Loss of three or more circuits that share a common structure.”

Organization	Yes or No	Question 9 Comment
		We offer the minor suggestion that Footnote 6 - Further clarify the applicable shunt devices in Footnote 6 with this suggested text: "6. Requirements which are applicable to shunt devices, also apply to FACTS devices that are connected to ground, but not instrument voltage transformers or surge arresters." ATC has significant concerns with Q3.2 (R2.1.4 & R2.4.3), Q4 (Table requirements) and Q5 (P3 scope), as noted above. In addition, ATC offers the following suggestions to promote proper Reliability Standard quality and content. (1.) Revise the Planning Assessment definition to more explicitly apply to the BES and the TPL-001 requirements. We suggest text of: "Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies in the BES from the steady state and stability performance requirements set forth in the TPL-001 standard." 2.) R2.1.5 - We propose replacing the term 'major Transmission' with "BES" because BES is a well defined term, while the term 'major Transmission' is not. (3.) Add R2.3.1 - We suggest the addition of a R2.3.1 requirement to emulate the distinction between the requirement to perform a short circuit assessment and conduct required studies or analysis to support the assessment (e.g. R2.1/R2.1.1 and R2.2/R2.2.1). We propose wording such as, "Perform an analysis for at least one year in the Near Term Transmission Planning Horizon." This requirement would set an expectation that an analysis should be conducted to at least one or more years in the near-term planning horizon, rather than imply that an analysis of all five years in the near-term planning horizon must be conducted. 4.) R2.7.4 - We suggest that the wording of R2.7.4 be the same as R.2.8.2. Otherwise, we propose that R2.7.4 and R2.8.2 be revised with wording like, ". . . implementation status of identified Corrective Action Plans for System Facilities and Operating Procedures." to clarify that the identified system facilities and operating procedures refer only to those that were in the previous year's Corrective Action Plans. (5.) R3.3.1 - The term of 'controls' is ambiguous and not defined, unlike the term, 'Protection Systems', which is defined. Therefore, we suggest that this item be defined or more clearly described to avoid the risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. (6.) R3.3., bullet #1 - We suggest qualifying which generating units to consider and which voltage limits to simulate with revised wording like, "Trip generating units that are connected to the BES when actual or assumed minimum generator steady state or ride through voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment". The requirement should not apply to all relevant generating units until one of the MOD standards requires all Generator Owners to provide their minimum generating unit voltage limits to the TP and PC. If the wording of R3.3.1, bullet #1 must be different from its counterpart, R4.3.1, then please explain the reasons for any differences.

Organization	Yes or No	Question 9 Comment
		(7.) R3.4.1 - Compliance with the requirement "to coordinate" is problematic and non-measurable. We suggest replacing it with the requirement "to communicate". 8.) R3.5 - We interpret that R3.5 requires the TP and PC to conduct an evaluation of possible actions to reduce the likelihood or impact of extreme events, which produce the more severe impacts, if cascading outages may occur. Does the drafting team intend for the TP and PC to fulfill this requirement for at least one event in each of the five categories (i.e. 3 steady state and 2 stability) or in each of the 21 categories/sub-categories (i.e. 14 steady state and 7 stability). Also, if the resulting cascading outages do not result in any overloads, under-voltages, voltage collapse, or loss of generator synchronization, then should the evaluation of possible actions to reduce likelihood or impact be required? (9.) R4.1.1 - We suggest that there should be some qualification of which generating units are referred to in this requirement. We propose that the requirement say, "No generating unit connected to the BES shall pull out of synchronism." For example, some utilities include smaller generation units that are connected at voltages below 100 kV and even down to distribution voltage in their base cases. (10.) R4.1.2 - We propose that the wording of this requirement be revised to reflect the same BES qualification of the generating unit that we noted in R4.1.1 above. (11.) R4.3.1 - This requirement refers to high speed reclosing and we presume that this is special high speed reclosing that is completed in several cycles, rather than the normal high speed reclosing that is completed in a number of seconds. We recommend that the term high speed reclosing be more clearly defined for this sub-requirement. (12.) R5 - We propose removing the criteria item, "post-Contingency voltage deviation", because this criterion has not been developed and used widely enough in the industry to be introduced into the standards. (13.) R7 - Revise part of the requirement text to read, ". . . identify each entity's individual and joint responsibilities . . ." to provide better clarity. Perhaps this requirement should be listed at the beginning of the Requirements section, instead being mentioned near the end of this section. (14.) Change the forward referencing to backward referencing. We agree with R2.6, R3.1, R3.5, R4.1, and 4.2. However, we suggest that the requirements be ordered so that all of the references refer back to earlier text, rather later text to be consistent with the rest of this standard and other referencing in this standard (e.g. R2.1.3, R2.1.4, R2.4.3, R3, R3.3, R3.5, R4, R4.3, R4.4, R4.5), as well as other standards.
Tri-State Generation & Transmission		Table 1, P5 does not seem to account for redundant relays in the Protection System to mitigate potential relay failure. We recommend changing the "Event" to "Delayed Fault Clearing due to the failure of a relay to operate as designed, if that is the only relay protecting the Faulted element, for one of the following:" In Table 1, P2 and P3, the last column "Non-Consequential Load Loss Allowed" where the requirement

Organization	Yes or No	Question 9 Comment
		"No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote "b". This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote "b" in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, "Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers." Timing of this project and project 2010-11 is critical. It would be very difficult to vote to approve the proposed TPL-001-2 prior to knowing the outcome of Project 2010-11 (footnote b issue). Second, we are unclear why voltage relays are included in footnote 13 and think they can be removed. Third, in the Extreme Events - Stability section of Table 1, items 2a-2d "Protection System failure" should be changed to "relay failure" to be consistent with Table 1, Category P5.
Lakeland Electric		The performance requirements of Table 1 do not allow the loss of non-consequential load for single and multiple contingency events. The disallowance of load loss does not provide any real benefit to the reliability of the BES and is an unnecessary overreach into local quality of service issues that are best addressed by State, Provincial or Municipal authorities. There may be circumstances such as high local transmission costs or local opposition to transmission construction where prohibition of non-consequential load loss represents a poor cost/benefit or quality of life tradeoff. Having a provision at the regional level that a PA or TP can have a certain amount of non-consequential load loss designed or planned in to its system that would be reasonable if it is acceptable to the RE and does not have an adverse impact on the remaining BES. In lieu of such a RE provision, providing a quantitative cap in non-consequential load loss such as 100 MW may be rationale compromise in the goal of limiting load loss for the more probable outage events. Our preference would be to retain the capability of limited non-consequential load loss.It is our understanding that footnote 9 is under consideration as part of Project 2010-11 and should be noted as such for clarification.
NBSO		For consistency, 'Protection System' should be replaced with 'relay' on Table 1 (p12) Stability Section, items

Organization	Yes or No	Question 9 Comment
		2a-2d.
Progress Energy		PE remains concerned with the present draft of TPL-001-2 regarding the presence or absence of footnotes in particular events. PE believes that, for all events in Table 1 except P0, any "No" designation in the "Non-Consequential Load Loss allowed" column should have Footnote 12 appended to it. Several events do append footnote 12 to a "No" answer, but several do not. PE does not see why certain events should be denied the use of Footnote 12 as long as Footnote 12 is worded in a manner such that the BES will not be adversely affected.PE has additional concerns regarding two Footnotes. Footnote 9 contains language regarding firm transmission service that is very similar to language presently under review in NERC Project 2010-11. PE feels that Footnote 9 should have had a statement at the end similar to that of Footnote 12, such as "Note: Firm Transmission Service is being decided in Project 2010-11. When that project is finalized, the resolution will be copied into Footnote 9." Without such a statement, PE cannot understand why the Firm Transmission language in footnote (b) under Project 2010-11 is being reviewed, while it is apparently no longer being reviewed in Project 2006-02.Footnote 12 contains the following language as a place holder: "Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here." PE has filed substantial comments on the footnote (b) issue in previous drafts, pointing out that disallowance of curtailment of non-consequential load is a local load issue and not a BES concern. PE therefore cannot make any positive determination as to whether the draft Standard, TPL-001-2, and its associated Table 1, will be a viable Standard until the language in Footnote 12 is resolved via Project 2010-11. Given the potential for unresolved and confusing issues regarding the parallel development of Project 2006-02 and 2010-11, PE encourages NERC to resolve all issues within Project 2010-11 before taking the draft Standard TPL-001-2 to ballot in Project 2006-02.
Tucson Electric Power Company		Table 1, P5 currently requires the study of "[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed". As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: "Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following". In Table 1, P2 and P3, the last column "Non-Consequential Load Loss Allowed" where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote "b". This will require immediate redesigns to meet this

Organization	Yes or No	Question 9 Comment
		particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote "b" in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, "Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers." Timing of this project and project 2010-11 is critical. It would be very difficult to vote to approve the proposed TPL-001-2 prior to knowing the outcome of Project 2010-11 (footnote b issue).Non-Consequential Load Loss and curtailment of Firm Transmission Service should be allowed for loss of EHV BES elements for Category P4 and P5 events.
New York Independent System Operator		There are two tables labeled "Table 1". The extreme events table should be renamed "Table 2".
MidAmerican Energy		Voting "no" - Footnote 6 - Further clarify the applicable shunt devices in Footnote 6 with this suggested text: 6. Requirements which are applicable to shunt devices, also apply to FACTS devices that are connected to ground, but not instrument voltage transformers or surge arresters
Southern California Edison Company		SCE supports the revised performance table.
Omaha Public Power District		Why is Footnote 12 used for some occurrences of the word "No" in the last column of Table 1 but not other occurrences of the word "No"?
Hydro One Networks Inc.		No selection boxes in this question. Yes, we support.
SERC Dynamics Review Subcommittee		Yes. The SERC DRS supports the revisions.
Duke Energy		We support the changes.

Organization	Yes or No	Question 9 Comment
South Carolina and Gas		Yes
Xcel Energy		The defined term "Bus-tie Breaker" is not used per se anywhere in the Requirements or in Table 1. Suggest changing the description for Events P2-3, P2-4, P4 and P4-6 to use the term Bus-tie Breaker or non-Bus-tie Breaker, as applicable. Existing P5 event description needs improvement since the phrase "…failure of relay protecting the Faulted element to operate as designed…" reads awkwardly and also includes some superfluous verbiage that can be omitted. For example, isn't "protecting the faulted element" the basic function of every protective relay? Also, isn't "(failure) to operate as designed" inherent in the definition of Delayed Fault Clearing? Suggested P5 event description is: "Delayed Fault Clearing due to the operation failure of a primary protection relay[13] when attempting to clear a fault on one of the following:" Footnote 13 – Delete "voltage (#27, #59)" since the under/over voltage relays are not called upon to provide the primary protection for fault clearing on Transmission elements. In Table 1 – Extreme Events – Stability – Items 2a-2d, change "Protection System failure" to "relay failure" to be consistent with changes in P5. Suggest modifying Event P4 description to be more consistent with Event P5 description by including Delayed Fault Clearing in the description in lieu of "Loss of multiple elements". Suggested Event P4 description is: "Delayed Fault Clearing caused by a stuck non Bus-tie Breaker attempting to clear a fault on one of the following:"

6. The SDT has revised the Measures based on industry comments to the initial ballot. If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your concern.

Summary Consideration:

The SDT has made the following changes due to industry comments:

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using ~~the latest~~ data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, ~~any~~ the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity who has indicated a reliability need and that the ~~functional entity~~ Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

Data retention for R7 - The current, in force documentation for the agreement(s) on roles and responsibilities, as well as ~~all such~~ documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

Conforming changes were made to M6 and the data retention for R6/M6. Conforming changes were made to R1 to eliminate the phrase, "the latest." The majority of respondents agree with the changes to the Measures and no other changes to the Measures have been made based on stakeholder comments.

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered the comments.

Organization	Yes or No	Question 10 Comment

Organization	Yes or No	Question 10 Comment
Florida Reliability Coordinating Council, Inc - Transmission Working Group	No	It appears that there is a disagreement between R8 and M8, regarding public posting. We Agree with M8 posting option.
NorthWestern Energy (NWMT)	No	Measure M6 is too vague. It is unclear how to identify the conditions of Cascading, voltage instability, or uncontrolled islanding. The Glossary of Terms defines Cascading as "The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies." Does the loss of system elements have to extend beyond the Control Area to be considered "Cascading"? Is there a Megawatt threshold that must be satisfied? Is there a time duration involved? Also, "cascading outages" needs to be defined. In addition, "voltage instability" and "uncontrolled islanding" should both be defined.
Lakeland Electric	No	please consider remove "the latest" from M1
Ameren	No	For measurements M3 and M4, there is some question as to what is to be provided as evidence of a study. Would the study results alone provide sufficient evidence, or does the entire powerflow, stability, or short circuit effort need to be documented in a formal study report? There are no measures for the creation and coordination of contingency lists that are to be developed in R3.4, R3.5, R4.4, and R4.5. Are these contingency lists required to be a documented part of the study?
MidAmerican Energy	No	Revise measures to be consistent with requirements. 1. R6 Delete "any". The use of the word any in standards should not be allowed. 2. Revise the Planning Assessment definition to more explicitly apply to the BES and the TPL-001 requirements. We suggest text of: "Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies in the BES from the steady state and stability performance requirements set forth in the TPL-001 standard." 3. R2.1.5 - We propose replacing the term 'major Transmission' with "BES" because BES is a well defined term, while the term, 'major Transmission', is not. 4. Add R2.3.1 - We suggest the addition of a R2.3.1 requirement to emulate the distinction between the requirement to perform a short circuit assessment and conduct required studies or analysis to support the assessment (e.g. R2.1/R2.1.1 and R2.2/R2.2.1). We propose wording such as, "Perform an analysis for at least one year in the Near Term Transmission Planning Horizon." This requirement would set an expectation

Organization	Yes or No	Question 10 Comment
		that an analysis should be conducted to at least one or more years in the near-term planning horizon, rather than imply that an analysis of all five years in the near-term planning horizon must be conducted. 5. R2.7.2 - Delete 2.7.2. With regard to "include actions to resolve performance deficiencies identified in multiple sensitivity studies", mitigation plans should not be required for deficiencies found in multiple sensitivity studies because the conditions in some sensitivity studies are more extreme and less likely than base case conditions. Some of the sensitivity study conditions are not credible. 6. R2.7.4 - We suggest that the wording of R2.7.4 be the same as R.2.8.2. 7. R3.5 - We interpret that R3.5 requires the TP and PC to conduct an evaluation of possible actions to reduce the likelihood or impact of extreme events, which produce the more severe impacts, if cascading outages may occur. Does the drafting team intend for the TP and PC to fulfill this requirement for at least one event in each of the five categories (i.e. 3 steady state and 2 stability) or in each of the 21 categories/sub-categories (i.e. 14 steady state and 7 stability). Also, if the resulting cascading outages do not result in any overloads, under-voltages, voltage collapse, or loss of generator synchronization, then should the evaluation of possible actions to reduce likelihood or impact be required? 8. R4.1.1 - We suggest that there should be some qualification of which generating units are referred to in this requirement. We propose that the requirement say, “No generating unit with a Point of Interconnection connected to the BES shall pull out of synchronism.” For example, some utilities include smaller generation units that are connected at voltages below 100 kV and even down to distribution voltage in their base cases. 9. R4.1.2 - We propose that the wording of this requirement be revised to reflect the same BES qualification of the generating unit that we noted in R4.1.1 above. 10. R4.3.1 - This requirement refers to high speed reclosing and we presume that this is special high speed reclosing that is completed in several cycles, rather than the normal high speed reclosing that is completed in a number of seconds. We recommend that the term high speed reclosing be more clearly defined for this sub-requirement. 11. R.4.3.2 - We suggest qualifying which generating units to consider and which voltage limits to simulate with revised wording like, “Trip generating units that are connected to the BES when actual or assumed minimum generator transient voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment”. The requirement should not apply to all relevant generating units until one of the MOD standards requires all Generator Owners to provide their minimum generating unit voltage limits to the TP and PC. If the wording of R4.3.2 must be different from its counterpart, R3.3.2, then please explain the reasons for any differences. 12. R5 - This requirement should allow the applicable entity (such as the TOP / TO) to define a “Post-Contingency Voltage Deviation” as this criteria is not used widely enough in the industry to be a well

Organization	Yes or No	Question 10 Comment
		established criteria. 13. Revise R8 to limit the need to provide the Planning Assessment as follows “adjacent Planning Coordinators and adjacent Transmission Planners and to any registered functional entity...” 14. Data Retention for R3, R5, R6, & R7 - The MRO NSRS proposes that the wording in these elements be revised to change “All” to “The”. The word “All” is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: “The studies performed in support....”
NERC staff	Yes	NERC staff supports the changes to the Measures.
SERC Planning Standards Subcommittee	Yes	
Northeast Power Coordinating Council	Yes	
Hydro One Networks Inc.	Yes	
SERC Dynamics Review Subcommittee	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
Pepco Holings, Inc - Affiliates	Yes	
IRC Standards Review Committee	Yes	
Exelon Transmission Planning	Yes	
Southern Company	Yes	
Western Area Power	Yes	

Organization	Yes or No	Question 10 Comment
Administration		
PacifiCorp	Yes	
Duke Energy	Yes	
FirstEnergy	Yes	
Platte River Power Authority	Yes	
Orlando Utilities Commission	Yes	
Manitoba Hydro	Yes	
Minnesota Power	Yes	
TVA Transmission Planning & Compliance	Yes	
Independent Electricity System Operator	Yes	
South Carolina and Gas	Yes	
California ISO	Yes	
Seattle City Light	Yes	
ISO New England Inc.	Yes	
Los Angeles Department of Water and Power	Yes	
Idaho Power Co	Yes	

Organization	Yes or No	Question 10 Comment
United Illuminating	Yes	
Hydro-Quebec TransEnergie	Yes	
National Grid	Yes	
American Transmission Company	Yes	
American Electric Power (AEP)	Yes	
Tri-State Generation & Transmission	Yes	
GTC	Yes	
Pacific Gas and Electric Company	Yes	
Northeast Utilities	Yes	
Consolidated Edison Co. of New York, Inc.	Yes	
NBSO	Yes	
Central Maine Power Company	Yes	
Oncor Electric Delivery	Yes	
New York State Electric & Gas Corp	Yes	
Progress Energy	Yes	

Organization	Yes or No	Question 10 Comment
ERCOT ISO	Yes	
Tucson Electric Power Company	Yes	
New York Independent System Operator	Yes	
Xcel Energy	Yes	
Southern California Edison Company	Yes	

7. The SDT has revised the Requirement R8 VSL based on industry comments to the initial ballot. If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your concern.

Summary Consideration:

The SDT made the following clarification due to industry comments:

> **4.3.1, bullet #1**: Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

The VSL was not changed as the majority response was that the industry is in general agreement with the VSL.

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered the comments.

Organization	Yes or No	Question 11 Comment
Northeast Power Coordinating Council Consolidated Edison Co. of New York, Inc.	No	Requirement 8 is an administrative burden to TPs and PCs that adds no value to Bulk Power System reliability. PCs should be including TPs, neighboring PCs and interested parties in its planning processes when developing the Planning Assessments. Therefore, the inclusion of a set of VSLs for Requirement 8 is unnecessary. Should the VSLs for Requirement 8 remain, Requirement 8.1 should be revised to reflect that comments only to the final Assessment (not drafts developed during a process) need a response as follows:If a recipient of the planning assessment final results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments.If Requirement 8 and 8.1 are retained, they should be revised to reflect that comments only to the final Assessment (not drafts developed during a process) need a response and there should be a limit on the comment period as follows:If a recipient of the planning assessment final results provides documented comments on the results within 90 days of receipt, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments. Other comments not addressed by this Comment Form as follows: Section 3.3 - The last sentence of 3.3.1 should be removed. This is addressed in PRC-023. Line ratings are addressed in PRC-023. PRC-023 requires coordination with the Reliability Coordinator. Remove “Tripping of Transmission elements where relay loadability limits are exceeded.” Section 4.3 - High speed reclosing is not defined, and to help eliminate any confusion that it may introduce

Organization	Yes or No	Question 11 Comment
		into the standard it will be worthwhile for the SDT to define this term. Several specific examples from previous comments on sensitivity analysis and guidance for base case assumptions: The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions. The standard must describe base assumptions. To define a sensitivity condition, NERC must define base assumptions. As for allowing con-consequential load loss for Categories P1 through P5, suggest approval at the Regional level, with a concept of allowing it in a "local area" that does not impact BPS reliability. All references to 300 kV in document should be replaced with EHV (for example in the Introduction, Section 5).The first phrase of Note 3 on p. 14 should be revised as follows: "Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as those representing the backbone of the System, generally at voltage greater than 300 kV, and high voltage (HV) Facilities defined as those not representing the backbone of the System, as determined by the Planning Coordinator and approved by Regional Entity."
IRC Standards Review Committee	No	(AESO is not a party to the following comments since its VSLs are set by the Alberta regulatory authority.)Requirement 8 is an administrative burden to TPs and PCs that adds no value to reliability. PCs should be including TPs, neighboring PCs and interested parties in its planning processes when developing the Planning Assessments. Therefore, the inclusion of a set of VSLs for Requirement 8 is unnecessary.Should the SDT decide to leave the VSLs for Requirement 8, Requirement 8.1 should be revised to reflect that comments only to the final Assessment (not drafts developed during a process) need a response as follows: 8.1 If a recipient of the planning assessment final results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments.For a Planning Coordinator (PC) who distributes the Planning Assessment to many different entities (to adjacent PCs, TPs, and other functional entities), a concern regarding the Requirement R8 VSL is that it is overly restrictive to apply a violation for failing to distribute the results of its Planning Assessment to only one PC, TP, or functional entity (and to apply a High VSL for failing to distribute to more than one entity), particularly since an entity's contact is subject to change over time, and since Measure M8 allows for publicly posting the results of its Planning Assessment to its website. Should the SDT decide to include the VSLs for Requirement 8, we would recommend revising to use a percentage approach rather than applying a violation to a Planning

Organization	Yes or No	Question 11 Comment
		Coordinator who fails to provide the results of its Planning Assessment to one PC, TP, or other functional entity (or applying a High VSL for failing to distribute to more than one entity.) Recommend applying a similar percentage approach to the VSLs drafted by NERC Staff for Project #2007-23 VSLs (e.g., for FAC-013-1) to be considered for the TPL-001-2 R8 VSLs. For example, o Lower VSL: The responsible entity failed to provide the Planning Assessment final results to 5% or less of the required entities. o Moderate VSL: The responsible entity failed to provide the Planning Assessment final results to more than 5% up to (and including) 10% of the required entities. o High VSL: The responsible entity failed to provide the Planning Assessment final results to more than 10% up to (and including) 15% of the required entities. o Severe VSL: The responsible entity failed to provide the Planning Assessment final results to more than 15% of the required entities OR [the existing language for the Severe VSL].Explanation: The VSLs were modified for consistency with other standards and VSLs.Reference: Link to VSLs drafted by NERC Staff for Project #2007-23 VSLs (e.g., for FAC-013-1):http://www.nerc.com/docs/standards/sar/Staff_Proposed_VSLs_2010July27.pdf
Southern Company	No	We wish to make a comment on R4.3.1: it appears that this requires stability simulations of both successful and unsuccessful high-speed reclosing for all contingency simulations regardless of whether high-speed reclosing is used on the faulted line. We suggest the following wording be used to replace the first bullet: "Successful high-speed reclosing and unsuccessful high-speed reclosing onto a fault, where such reclosing is applied, and where such additional simulations are deemed appropriate by the PC or TP." Also, we wish to make a comment on footnote #13 of Table 1. 13. Applies to any of the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, & 67), voltage (#27 & 59), directional (#32 & 67), and associated tripping (#86 & 94) relays.
Florida Reliability Coordinating Council, Inc - Transmission Working Group	No	The requirement to distribute the Planning Assessment should be more flexible and allow for making the Planning Assessment available, such that those entities that desire the information can have it readily available. R8 should be modified to replace distribute with "make available:, so the new requirement would read as follows: Each Planning Coordinator and Transmission Planner shall make available its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.
PacifiCorp	No	The language for Requirement R8 is ambiguous with regard to which adjacent entities must request in writing the results of the Planning Assessment. The language should be clarified to read: "Upon request made in

Organization	Yes or No	Question 11 Comment
		writing, each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any other functional entity that has a reliability related need." The Requirement R8 VSL language should also be revised accordingly.
ReliabilityFirst	No	TPL-001-2 Draft 5 is much better than Draft 4.There is still one significant concern, that I do not believe the drafting team adequately addressed. It is unclear as to what "Planning Assessment results" and "results of its Planning Assessment" entail. The Draft 5 response that "Planning Assessment" is a defined term does not fully address this concern. "Planning Assessment results" or "results of its Planning Assessment" is not necessarily the same thing as "Planning Assessment". As written, "Planning Assessment results" or "results of its Planning Assessment" could be anything from a single sentence, to a few brief high level paragraphs, to a detailed and technically complete Planning Assessment. The Standard needs to more clearly state what is required in the report to other entities. Based on the drafting team response in Draft 4, it seems that replacement of "Planning Assessment results" or "results of its Planning Assessment" with the term "Planning Assessment" or "its Planning Assessment" would be appropriate. Violation Severity Levels: R8The failure to provide documented responses to documented comments to "Planning Assessment results" is deemed to be a higher severity level than failing to distribute "results of its Planning Assessment". Failure to distribute denies functional entities an opportunity to comment, and could prevent coordinated planning, and thus should be deemed to be more severe than failing to provide documented responses to documented comments.
Lakeland Electric	No	The requirement to distribute the Planning Assessment should be more flexible and allow for making the Planning Assessment available, such that those entities that desire the information can have it readily available. R8 should be modified as follows: Each Planning Coordinator and Transmission Planner shall make available its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.
Orlando Utilities Commission	No	R8 should require that the PC and TP make available it's planning assessment results when requested, rather then requring the preemptive transmittal. There is no reliablity purpose served by providing unsolicited information.
US Bureau of Reclamation	No	The language implies that the responsible entity may choose to not distribute it is feels the entity making the request does not have a "reliability related need". It is not clear why that distinction is being made?
California ISO	No	Requirement 8 is an administrative burden to TPs and PCs that adds no value to reliability. PCs should be including TPs, neighboring PCs and interested parties in its planning processes when developing the

Organization	Yes or No	Question 11 Comment
		Planning Assessments. Therefore, the inclusion of a set of VSLs for Requirement 8 is unnecessary.Should the SDT decide to leave the VSLs for Requirement 8, Requirement 8.1 should be revised to reflect that comments only to the final Assessment (not drafts developed during a process) need a response as follows: 8.1 If a recipient of the planning assessment final results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments.For a Planning Coordinator (PC) who distributes the Planning Assessment to many different entities (to adjacent PCs, TPs, and other functional entities), a concern regarding the Requirement R8 VSL is that it is overly restrictive to apply a violation for failing to distribute the results of its Planning Assessment to only one PC, TP, or functional entity (and to apply a High VSL for failing to distribute to more than one entity), particularly since an entity's contact is subject to change over time, and since Measure M8 allows for publicly posting the results of its Planning Assessment to its website.Should the SDT decide to include the VSLs for Requirement 8, would recommend revising to use a percentage approach rather than applying a violation to a Planning Coordinator who fails to provide the results of its Planning Assessment to one PC, TP, or other functional entity (or applying a High VSL for failing to distribute to more than one entity.) Recommend applying a similar percentage approach to the VSLs drafted by NERC Staff for Project #2007-23 VSLs (e.g., for FAC-013-1) to be considered for the TPL-001-2 R8 VSLs. For example, o Lower VSL: The responsible entity failed to provide the Planning Assessment final results to 5% or less of the required entities. o Moderate VSL: The responsible entity failed to provide the Planning Assessment final results to more than 5% up to (and including) 10% of the required entities. o High VSL: The responsible entity failed to provide the Planning Assessment final results to more than 10% up to (and including) 15% of the required entities. o Severe VSL: The responsible entity failed to provide the Planning Assessment final results to more than 15% of the required entities OR [the existing language for the Severe VSL].Explanation: The VSLs were modified for consistency with other standards and VSLs.Reference: Link to VSLs drafted by NERC Staff for Project #2007-23 VSLs (e.g., for FAC-013-1):http://www.nerc.com/docs/standards/sar/Staff_Proposed_VSLs_2010July27.pdf
Ameren	No	The sharing issues of requirement R8 are still not clear, therefore the R8 VSL is not clear. It is not clear if the intent of the SDT is for the PC to share the assessments with PCs and TPs are to share the assessments with TPs, or whether the intent is for the TP to share its assessments with its PC. Will posting the assessment to a secure web-site meet the intent of the requirement? Although the comment form is not designed to allow for such, we need to comment on R4.3.1: As written, it appears that this requires stability simulations of both successful and unsuccessful high-speed reclosing for all contingency simulations, regardless of whether high-speed reclosing is actually implemented. A suggested wording change for the first bullet: "Successful high-speed reclosing and unsuccessful high-speed reclosing onto a fault, where such reclosing is applied, and where such additional simulations are deemed appropriate by the PC or TP."

Organization	Yes or No	Question 11 Comment
		Another comment needs to be made regarding the stability extreme event table: Changes were made in planning event P5 to concentrate on specific relay failures. The same changes need to be made for stability extreme events 2a, 2b, 2c, and 2d.The proposed standard will significantly increase the amount of work required to develop more detailed and complex system models, to perform and document the engineering studies to meet the performance requirements, and to develop the assessments necessary for compliance. All of these increased engineering activities are perceived to provide marginal benefit to the reliability of the bulk electric system, but will require significant increases in manpower across the industry. Further, the manpower is presently not available to develop these more detailed models and to perform these studies with any reasonable assuredness. It will be a continuing challenge to the industry to obtain and keep the engineering talent needed to perform these compliance activities for such marginal benefits.
Central Maine Power Company New York State Electric & Gas Corp	No	Requirement 8 is an administrative burden to TPs and PCs that adds no value to reliability. PCs should be including TPs, neighboring PCs and interested parties in its planning processes when developing the Planning Assessments. Therefore, the inclusion of a set of VSLs for Requirement 8 is unnecessary.Furthermore, the requirement lacks a specified time frame to receive comments, thereby implying that TPs and PCs would be required to reply to comments forever following the finalization of a Planning Assessment. The NYISO proposes a limit of six months.Should the SDT decide to leave the VSLs for Requirement 8, Requirement 8.1 should be revised to reflect that comments only to the final Assessment (not drafts developed during a process) need a response as follows:If a recipient of the planning assessment final results provides documented comments on the results within 180 calendar days of the issuance of those final results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments. We also have other comments not addressed by this Comment Form as follows - Section 2.7, Section 3.3, Section 4.3, and overall:Section 2.7 requires that Corrective Action Plans are included in each Planning Assessment and states “Such actions may include...” followed by a list of actions. Restricting allowable actions, and excluding runback/tripping of HVDC would have a direct impact on multiple existing facilities in New York and would adversely impact the reliability planning of the NYCA. Runback/tripping of HVDC must be added to the list. Section 3.3 - We feel that the last sentence of 3.3.1 should be removed. This is handled by PRC-023. Line ratings are addressed by PRC-023. PRC-023 requires coordination with the Reliability Coordinator. Remove “Tripping of Transmission elements where relay loadability limits are exceeded.” Section 4.3 - High speed reclosing is not defined.Overall - We have previously made comments which have not been addressed in the current version of the proposed standard. Support for the standard can at most be limited without addressing comments.

Organization	Yes or No	Question 11 Comment
		We have previously commented on sensitivity analysis and guidance for base case assumptions. Also, extreme event analysis should not be mandated in this standard as no corrective action is required. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required, and there is no requirement for corrective action if anything is identified. The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions. The standard must describe base assumptions. To define a sensitivity condition, NERC must define base assumptions.
New York Independent System Operator	No	Requirement 8 is an administrative burden to TPs and PCs that adds no value to reliability. PCs should be including TPs, neighboring PCs and interested parties in its planning processes when developing the Planning Assessments. Therefore, the inclusion of a set of VSLs for Requirement 8 is unnecessary.Furthermore, the requirement lacks a specified time frame to receive comments, thereby implying that TPs and PCs would be required to reply to comments forever following the finalization of a Planning Assessment. The NYISO proposes a limit of six months.Should the SDT decide to leave the VSLs for Requirement 8, Requirement 8.1 should be revised to reflect that comments only to the final Assessment (not drafts developed during a process) need a response as follows:If a recipient of the planning assessment final results provides documented comments on the results within 180 calendar days of the issuance of those final results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments.
NERC staff	Yes	NERC staff supports the changes to the VSL for Requirement R8.
SERC Planning Standards Subcommittee	Yes	Comments: We wish to make a comment on R4.3.1: it appears that this requires stability simulations of both successful and unsuccessful high-speed reclosing for all contingency simulations regardless of whether high-speed reclosing is used on the faulted line. We suggest the following wording be used to replace the first bullet: “Successful high-speed reclosing and unsuccessful high-speed reclosing onto a fault, where such reclosing is applied, and where such additional simulations are deemed appropriate by the PC or TP.” We wish to make a comment on the stability extreme event table: Changes were made in planning event P5 to narrow the focus to specific relay failures. The same changes are needed for stability extreme event 2a, 2b, 2c, and 2d.
Hydro One Networks Inc.	Yes	Requirement 8 is an administrative burden and adds little or no value to the BPS reliability. Therefore, the inclusion of a set of VSLs for Requirement 8 is unnecessary.
SERC Dynamics Review	Yes	We wish to make a comment on R4.3.1: it appears that this requires stability simulations of both successful

Organization	Yes or No	Question 11 Comment
Subcommittee		and unsuccessful high-speed reclosing for all contingency simulations regardless of whether high-speed reclosing is used on the faulted line. We suggest the following wording be used to replace the first bullet: "Successful high-speed reclosing and unsuccessful high-speed reclosing onto a fault, where such reclosing is applied."We wish to make a comment on the stability extreme event table: Changes were made in planning event P5 to narrow the focus to specific relay failures. The same changes are needed for stability extreme event 2a, 2b, 2c, and 2d.
MRO's NERC Standards Review Subcommittee	Yes	Other Comments:1. How are backup relays handled (TPL-002-0, R1.3.10 & TPL-001-2 R1 & P5)? What does FERC construe as normal system for a protection system. The TPL-001-2 R1 & P5, this standard doesn't appear to address primary protection and how this handled. 2. Revise the Planning Assessment definition to more explicitly apply to the BES and the TPL-001 requirements. We suggest text of: "Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies in the BES from the steady state and stability performance requirements set forth in the TPL-001 standard." 3. R2.1.5 - We propose replacing the term 'major Transmission' with "BES" because BES is a well defined term, while the term, 'major Transmission', is not. 4. Add R2.3.1 - We suggest the addition of a R2.3.1 requirement to emulate the distinction between the requirement to perform a short circuit assessment and conduct required studies or analysis to support the assessment (e.g. R2.1/R2.1.1 and R2.2/R2.2.1). We propose wording such as, "Perform an analysis for at least one year in the Near Term Transmission Planning Horizon." This requirement would set an expectation that an analysis should be conducted to at least one or more years in the near-term planning horizon, rather than imply that an analysis of all five years in the near-term planning horizon must be conducted. 5. R2.7.4 - We suggest that the wording of R2.7.4 be the same as R.2.8.2. Otherwise, we propose that R2.7.4 and R2.8.2 be revised with wording like, ". . . implementation status of identified Corrective Action Plans for System Facilities and Operating Procedures." to clarify that the identified system facilities and operating procedures refer only to those that were in the previous year's Corrective Action Plans. 6. R3.3.1 - The term of 'controls' is ambiguous and not defined, unlike the term, 'Protection Systems', which is defined. Therefore, we suggest that this item be defined or more clearly described to avoid the risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. 7. R3.3.1, bullet #1 - We suggest qualifying which generating units to consider and which voltage limits to simulate with revised wording like, "Trip generating units that are connected to the BES when actual or assumed minimum generator steady state or ride through voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment". The requirement should not apply to all relevant generating units until one of the MOD

Organization	Yes or No	Question 11 Comment
		standards requires all Generator Owners to provide their minimum generating unit voltage limits to the TP and PC. If the wording of R3.3.1 bullet #1 must be different from its counterpart, R4.3.1 bullet #2, then please explain the reasons for any differences. 8. R3.4.1 - Compliance with the requirement "to coordinate" is problematic and non-measureable We suggest replacing it with the requirement "to communicate". 9. R3.5 - We interpret that R3.5 requires the TP and PC to conduct an evaluation of possible actions to reduce the likelihood or impact of extreme events, which produce the more severe impacts, if cascading outages may occur. Does the drafting team intend for the TP and PC to fulfill this requirement for at least one event in each of the five categories (i.e. 3 steady state and 2 stability) or in each of the 21 categories/sub-categories (i.e. 14 steady state and 7 stability). Also, if the resulting cascading outages do not result in any overloads, under-voltages, voltage collapse, or loss of generator synchronization, then should the evaluation of possible actions to reduce likelihood or impact be required? 10. R4.1.1 - We suggest that there should be some qualification of which generating units are referred to in this requirement. We propose that the requirement say, "No generating unit connected to the BES shall pull out of synchronism." For example, some utilities include smaller generation units that are connected at voltages below 100 kV and even down to distribution voltage in their base cases. 11. R4.1.2 - We propose that the wording of this requirement be revised to reflect the same BES qualification of the generating unit that we noted in R4.1.1 above. 12. R4.3.1 - This requirement refers to high speed reclosing and we presume that this is special high speed reclosing that is completed in several cycles, rather than the normal high speed reclosing that is completed in a number of seconds. We recommend that the term high speed reclosing be more clearly defined for this sub-requirement. 13. R5 - This requirement should remove the criterion item, "post-Contingency voltage deviation", because this criterion is not used widely enough in the industry to be well established criterion. 14. R8 - This requirement should be revised to limit the need to provide the Planning Assessment as follows "adjacent Planning Coordinators and adjacent Transmission Planners and to any registered functional entity..." This suggestion is added to the requirement to clarify that the word adjacent also applies to Transmission Planners and to clarify that the functional entity must be registered in order for the entity to be applicable to the requirement.
TVA Transmission Planning & Compliance	Yes	Additional TVA comments:TVA wishes to make a comment on R4.3.1: it appears that this requires stability simulations of both successful and unsuccessful high-speed reclosing for all contingency simulations. Does high speed reclosing occur in less than 60 cycles or 60 seconds? If a utility does not have reclosing on a

Organization	Yes or No	Question 11 Comment
		transmission line - then must the utility still perform stability studies assuming that there is reclosing? TVA suggests the following wording be used to replace the first bullet: "Successful high-speed reclosing and unsuccessful high-speed reclosing onto a fault, where such reclosing is applied, and where such additional simulations are deemed appropriate by the PC or TP." In R4.1.1, TVA is concerned that no generating unit shall pull out of synchronism in a local area only (thus not impacting the overall reliability of the BES) for Planning Event P1, while the standard does allow generator runback/tripping for the same event. Thus the generating unit may be tripped by a special protection scheme - but may not be tripped by an out of step relay. TVA believes that out of step relaying should be allowed for this unit tripping as long as this does not affect the overall reliability of the BES.
South Carolina and Gas	Yes	We wish to make a comment on the revisions to R4.3.1. We believe that the analysis of both successful and unsuccessful high speed reclosing for all cases is not justified and should be left to the discretion of the Transmission Planner.
ISO New England Inc.	Yes	Requirement 8 and 8.1, should be revised to reflect that comments only to the final Assessment (not drafts developed during a process) need a response and there should be a limit on the comment period as follows:If a recipient of the planning assessment final results provides documented comments on the results within 90 days of receipt, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments. We have other comments not addressed by this Comment Form as follows - Sections 2.7, 3.3, 4.3 and overall. R2.7 requires that Corrective Action Plans are included in each Planning Assessment and states "Such actions may include..." followed by a list of actions. Runback/tripping of HVDC should be added to the list. Section 3.3 - We feel that the last sentence of 3.3.1 should be removed. This is handled by PRC-023. Line ratings are addressed by PRC-023. PRC-023 requires coordination with the Reliability Coordinator. Remove "Tripping of Transmission elements where relay loadability limits are exceeded." Section 4.3 - High speed reclosing needs to be defined.
Hydro-Quebec TransEnergie	Yes	o All references to 300 kV in document should be replaced with EHV (In the introduction, section 5) o The first phrase of Note 3 on p 14 should be revised as follows: "Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as those representing the backbone of the System, generally at voltage greater than 300 kV, and high voltage (HV) Facilities defined as those not representing the backbone of the System, as determined by the Planning Coordinator and approved by Regional Entity."

Organization	Yes or No	Question 11 Comment
National Grid	Yes	Other Comments:Section 3.3 - We feel that the last sentence of 3.3.1 should be removed. This is handled by PRC-023. Line ratings are addressed by PRC-023. PRC-023 requires coordination with the Reliability Coordinator. Remove "Tripping of Transmission elements where relay loadability limits are exceeded." Section 4.3 - High speed reclosing is not defined. We have previously commented on sensitivity analysis and guidance for base case assumptions. Also, extreme event analysis should not be mandated in this standard as no corrective action is required.
Tri-State Generation & Transmission	Yes	None regarding R8. The following comments refer to parts of the proposed standard for which no questions are asked.R4, Part 4.1.2: The response to our previous comment indicated that our description was for a system Stability issue. R4 is addressing system Stability and we believe the comment still applies and that it was not answered in the response. We have two issues with 4.1.2: Sometimes out-of-step (loss of generator synchronism) is better mitigated through islanding by tripping transmission rather than by tripping generators; the second point is that the ability of present modeling programs does not include the capability to model all types of impedance relays and their associated OOS blocking and tripping capabilities that are available. R4, Part 4.3.1: The third bullet implies that all impedance relays (and perhaps others) will need to be modeled in the stability databases. We question whether the existing simulation programs can accommodate this large magnitude of data inclusion and whether there is any benefit to BES reliability. Certainly using generic models rather than actual models would be of no benefit. We recommend changing the third bullet to "Evaluation of Protection System behavior when transient power swings are detected or predicted to have impedance characteristics that may approach relay operating characteristics."
Northeast Utilities	Yes	No comments on Question 7.Other Comments: As detailed below, NU has other comments that are not addressed by this Comment Form as follows - Section 3.3, Section 4.3, Non-Consequential Load Loss as referenced in the events Table 1 and studies using extreme event contingencies. Section 3.3 - NU believes that the last sentence of Part 3.3.1 should be removed since this is handled by PRC-023. Line ratings are addressed by PRC-023 which requires coordination with the Reliability Coordinator. NU suggests the removal of the following sentence: "Tripping of Transmission elements where relay loadability limits are exceeded." Section 4.3 - High speed reclosing is not defined and to help eliminate any confusion that it may introduce into the standard it will be worthwhile for the SDT to define this term. Non-Consequential Load Loss - Depending upon the resolution of "Project 2010-11, TPL Table 1, Footnote b" NU may have additional comments regarding this issue. Studies Using Extreme Event Contingencies: The requirements for sensitivity analysis already address issues

Organization	Yes or No	Question 11 Comment
		going beyond what is expected to meet the reliability requirements of the standard. Therefore, requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if a concern is identified.
NBSO	Yes	NBSO suggests considering rewording the VSL so that they address the failure to distribute the final results of planning assessments.
ERCOT ISO	Yes	ADDITIONAL COMMENTS: Short circuit analysis (R2.3 and R2.8) should only be applicable to TPs. Fault duty issues are typically local in nature and it would be an overlap for PCs to perform this same analysis done by the local Transmission Planner. Furthermore, R7 should be deleted and the responsibilities of each entity should be explicitly stated within the specific requirements. Previous Comment Unaddressed : Requirement 2.6.2: Reads as if a change is being made to an existing study. It is confusing. Possibly restate: "2.6.2 For steady state, short circuit, or stability analysis: previous studies can be used only if a material change to the system has not occurred or if a change that did occur does not impact the study area." R4.1.2 - Planning Coordinators do not perform protection coordination nor do they have access to the relay settings information required to do this analysis. This requirement should apply to Transmission Planners only because they perform system protection.The substantive scope of the standard is relative to Long-Term Transmission Planning Horizon and Near-Term Transmission Planning Horizon. The Purpose section is described in terms of the “planning horizon” generally. It may be worthwhile aligning the two to mitigate the potential for any confusion. ERCOT proposes the following revisions to the Purpose section: 3.Purpose: Establish Transmission system planning performance requirements within the relevant planning horizon (i.e. Long-Term or Near-Term) to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies .In addition, the “Time Horizon” for the Standard is “Long-Term Planning”. Obviously, this necessarily encompasses both Long-Term and Near-Term Transmission Planning Horizons. However, the scope of the Long-Term Planning time horizon is not readily apparent. ERCOT recommends appropriate revisions that clearly define the applicable time horizons.
MidAmerican Energy	Yes	

Organization	Yes or No	Question 11 Comment
Southern California Edison Company	Yes	
Pepco Holings, Inc - Affiliates	Yes	
Exelon Transmission Planning	Yes	
Western Area Power Administration	Yes	
Duke Energy	Yes	
NorthWestern Energy (NWMT)	Yes	
FirstEnergy	Yes	
Platte River Power Authority	Yes	
Manitoba Hydro	Yes	
Minnesota Power	Yes	
Independent Electricity System Operator	Yes	
Seattle City Light	Yes	
Los Angeles Department of Water and Power	Yes	
Idaho Power Co	Yes	
American Transmission Company	Yes	

Organization	Yes or No	Question 11 Comment
American Electric Power (AEP)	Yes	
GTC	Yes	
Oncor Electric Delivery	Yes	
Progress Energy	Yes	
Xcel Energy	Yes	
Tucson Electric Power Company	Yes	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Assess Transmission Future Needs and Develop Transmission Plans — Project 2006-02

The Assess Transmission Future Needs and Develop Transmission Plans Drafting Team thanks all commenters who submitted comments on the 6th draft of the TPL-001-2 standard for Assess Transmission Future Needs (Project 2006-02). These standards and associated documents were posted for a 45-day public comment period from April 18, 2011 through May 31, 2011. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 43 sets of comments, including comments from approximately 78 different people and approximately 69 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

No changes were made to the text of any Requirement. The SDT made several changes in response to comments submitted during the formal comment period and successive ballot that ended May 31, 2011.

- The 5th and 6th bullets of the Data Retention section to make the language in the data retention statements consistent with the language in the requirements.
- The third part of the Severe VSL for Requirement R1 to make the language consistent with the requirement.
- The VSL for Requirement R8 to make the language consistent with the language in the requirement.
- The Effective Date section of the Implementation Plan to make the language consistent with the language in the Effective Date section in the proposed TPL-001-2.
- The bullets in Requirement R3, Part 3.3.1 were replaced with numbers because the bullets were inconsistent with NERC's protocol on the use of bullets in Requirements.
- The bullets in Requirement R4, Part 4.3.1 were replaced with numbers because the bullets were inconsistent with NERC's protocol on the use of bullets in Requirements.

The SDT is requesting that this project be moved to the recirculation ballot stage.

All comments submitted may be reviewed in their original format on the standard's project page:

http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

1. The SDT has made revisions to the requirements language of TPL-001-2 based on industry comments and the Quality Review. Do you agree with these changes? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments with clear indications as to which requirement you are commenting on. …..... 10
2. The SDT has made revisions to the VRF and VSL of TPL-001-2 which will be part of a non-binding poll with this posting based on industry comments and the Quality Review. Do you agree with these changes? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. …..... 39
3. If you have any other comments on this Standard that you have not already provided in response to the prior questions, please provide them here. …..... 54

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Charles W. Long	SERC Planning Standards Subcommittee	X									X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Pat Huntley	SERC Reliability Corporation	SERC	10
2.	Bob Jones	Southern Company Services	SERC	1
3.	Darrin Church	Tennessee Valley Authority	SERC	1
4.	Phil Kleckley	South Carolina Electric & Gas Co.	SERC	1
5.	John Sullivan	Ameren Services Co.	SERC	1
6.	Charles Long	Entergy Services, Inc.	SERC	1

2.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1

Group/Individual		Commenter	Organization		Registered Ballot Body Segment									
					1	2	3	4	5	6	7	8	9	10
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1										
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10										
7.	Brian Evans-Mongeon	Utility Services	NPCC	8										
8.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5										
9.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5										
10.	Kathleen Goodman	ISO - New England	NPCC	2										
11.	Chantel Haswell	FPL Group, Inc.	NPCC	5										
12.	David Kiguel	Hydro One Networks Inc.	NPCC	1										
13.	Michael R. Lombardi	Northeast Utilities	NPCC	1										
14.	Randy MacDonald	Nerw Brunswick Power Transmission	NPCC	1										
15.	Bruce Metruck	New York Power Authority	NPCC	6										
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10										
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1										
18.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1										
19.	Saurabh Saksena	National Grid	NPCC	1										
20.	Michael Schiavone	National Grid	NPCC	1										
21.	Wayne Sipperly	New York Power Authority	NPCC	5										
22.	Donald Weaver	New Brunswick System Operator	NPCC	1										
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1										
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3										
3.	Group	Jonathan Hayes	SPP Reliability Standards Development Team		X	X	X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charles Yeung	SPP	SPP	2
2.	John Allen	City Utilities of Springfield	SPP	1, 4
3.	John Fulton	Xcel Energy	SPP	1, 3, 5
4.	Mark Hamilton	Oklahoma Gas & Electric	SPP	1, 3, 5
5.	Michelle Corley	CLECO	SPP	1, 3, 5

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10
6. Nathan McNeil	Midwest Energy	SPP 1, 3										
7. Tony Gott	Associated Electric Coop, Inc	SERC 1, 3, 5										
8. Matt Bordelon	CLECO	SPP 1, 3, 5										
9. Valerie Pinamonti	American Electric Power	SPP 1, 3, 5										
4. Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				
Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1. Berhanu Tesema	BPA, Transmission Planning	WECC	1									
2. Chuck Matthews	BPA, Transmission Planning	WECC	1									
3. Kyle Kohne	BPA, Transmission Planning	WECC	1									
4. Patrick Rochelle	BPA, Transmission Planning	WECC	1									
5. Kendall Rydell	BPA, Transmission Planning	WECC	1									
5. Group	Carol Gerou	MRO's NERC Standards Review Forum										X
Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1. Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6									
2. Chuck Lawrence	American Transmission Company	MRO	1									
3. Tom Webb	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6									
4. Jodi Jenson	Western Area Power Administration	MRO	1, 6									
5. Ken Goldsmith	Alliant Energy	MRO	4									
6. Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6									
7. Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6									
8. Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6									
9. Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6									
10. Scott Nickels	Rochester Public Utilties	MRO	4									
11. Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6									
12. Marie Knox	Midwest ISO Inc.	MRO	2									
13. Lee Kittelson	Otter Tail Power Company	MRO										
14. Scott Bos	Muscatine Power & Water	MRO										

Group/Individual		Commenter	Organization		Registered Ballot Body Segment									
					1	2	3	4	5	6	7	8	9	10
15.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5										
16.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6										
17.	Richard Burt	Minnkota Power Cooperative, Inc.	MRO	1, 3, 5, 6										
6.	Group	Patricia Robertson	BC Hydro		X									
	Additional Member	Additional Organization	Region	Segment Selection										
1.	Venkataramakrishnan Vinnakota	BC Hydro	WECC	2										
2.	Pat Harrington	BC Hydro	WECC	3										
3.	Clement Ma	BC Hydro	WECC	5										
4.	Daniel O'Hearn	BC Hydro	WECC	6										
7.	Group	Ed Davis	Entergy Services		X		X		X	X				
	Additional Member	Additional Organization	Region	Segment Selection										
1.	Stan Jaskot	Entergy Services	SERC	5										
2.	Terry Benoit	Entergy Services	SERC	6										
3.	Joel Plessinger	Entergy Services	SERC	3										
4.	Ed Davis	Entergy Services	SERC	1										
8.	Group	Brandy A. Dunn	Western Area Power Administration		X					X				
	Additional Member	Additional Organization	Region	Segment Selection										
1.	Pete Kinney	Western Area Power Administration	MRO	6										
9.	Group	Sammy Alcaraz	Imperial Irrigation District		X		X	X		X				
	Additional Member	Additional Organization	Region	Segment Selection										
1.	David Barajas		WECC											
2.	Marcela Caballero		WECC											
3.	Tino Zaragoza		WECC	1										
4.	Jesus Alcaraz		WECC	3										
5.	Diana Torres		WECC	4										

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
6. Cathy Bretz			WECC 6										
10.	Group	Bill Middaugh	Tri-State Generation and Transmission Assn., Inc.	X		X		X					
Additional Member		**Additional Organization**	**Region**	**Segment Selection**									
1. Mark Graham		Tri-State G&T	WECC	1									
2. Chris Pink		Tri-State G&T	WECC	1									
11.	Individual	David Kiguel	Hydro One Networks Inc.	X		X							
12.	Individual	Jim Eckelkamp	Progress Energy	X		X		X	X				
13.	Individual	Janet Smith	Arizona Public Service Company	X		X		X	X				
14.	Individual	John Bussman	Associated Electric Cooperative Inc	X		X		X	X				
15.	Individual	Thad Ness	American Electric Power	X		X		X	X				
16.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
17.	Individual	Bernie Pasternack	Transmission Strategies, LLC								X		
18.	Individual	Joe O'Brien	NIPSCO	X		X		X	X				
19.	Individual	Scott Bos	Muscatine Power and Water	X		X		X	X				
20.	Individual	Sunitha Kothapalli	Puget Sound Energy, Inc.	X		X		X					
21.	Individual	Anthony Jablonski	ReliabilityFirst										X

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
22.	Individual	Michael Moltane	ITC	X									
23.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
24.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
25.	Individual	Tony Eddleman	Nebraska Public Power District	X		X		X					
26.	Individual	Robert Casey	Georgia Transmission Corporation	X									
27.	Individual	Jonathan Appelbaum	United Illuminating	X									
28.	Individual	Andrew Z.Pusztai	American Transmission Company, LLC	X									
29.	Individual	Michael Jones	National Grid	X		X							
30.	Individual	Tim E. Ponseti, VP	TVA TP&C	X									
31.	Individual	Michael Falvo	Independent Electricity System Operator		X								
32.	Individual	Alex Rost	NBSO		X								
33.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
34.	Individual	Christine Hasha	Electric Reliability Council of Texas, Inc.		X								
35.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
36.	Individual	Kathleen Goodman	ISO New England Inc.		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
37.	Individual	Claudiu Cadar	GDS Associates, Inc.	X									
38.	Individual	David Thorne	Pepco Holdings Inc	X		X							
39.	Individual	Michael Lombardi	Northeast Utilities	X		X		X					
40.	Individual	Marie Knox	MISO		X								
41.	Individual	Gregory Campoli	New York Independent System Operator		X								
42.	Individual	Kirit Shah	Ameren	X		X		X	X				
43.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X									

1. **The SDT has made revisions to the requirements language of TPL-001-2 based on industry comments and the Quality Review. Do you agree with these changes? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments with clear indications as to which requirement you are commenting on.**

Summary Consideration: Several commenters stated that Requirement R1, Part 1.1.5 should not include interchange because interchange introduces economic considerations into a Reliability Standard. The SDT explained that the requirement is to include known commitments for interchange and therefore the requirement is not for economic purposes, but rather planning to meet obligations.

A number of commenters stated that they believed that there was an inconsistency between Requirement R2, Parts 2.1 and 2.2, since qualified studies were not allowed for the Long-Term Transmission Planning Horizon case. The SDT believes that the requirement to conduct the annual study on one of the study years in the Long-Term Transmission Planning Horizon ensures that the planner conducts a new study annually to evaluate the System improvement needs in the Long-Term Transmission Planning Horizon, even if they utilize qualified past studies for the Near-Term Transmission Planning Horizon cases.

Several commenters stated that they believed that Requirement R2, Part 2.1.5 was ambiguous since it was not clear that the planner did not have to include multiple outages of long lead time components simultaneously. The SDT explained that Requirement R2, Part 2.1.5 does not require simultaneous outages of multiple long lead time components.

Some commenters expressed concerns with Requirement R2, Part 2.4.1 since they were concerned with the ability for planners to adequately model the dynamic behavior of Load. The SDT explained that since it is important to correctly model the characteristics of the Load, it believes that the requirement to represent the dynamic behavior of the Load is needed to ensure BES reliability.

A number of commenters expressed concern that Requirement R7 was administrative and was not required. The SDT explained that it believes that the requirement is necessary to ensure that there are no gaps created between the Transmission Planners and the Planning Coordinators when they determine their individual responsibilities.

Several commenters stated that they had concerns with Requirement R8. These concerns are that the requirements create excessive work and should include time limits on requesting the Planning Assessment, are ambiguous, and should include the ability to post the Planning Assessment. The SDT explained that the requirements are only to distribute the Planning Assessment, which should not require a large amount of work, and the requirements are clear that the planners must distribute to adjacent Transmission Planners and Planning Coordinators and others with a reliability need. The SDT further explained that posting the Planning Assessment could meet the requirement to distribute.

Several commenters stated that they believed that Table 1, P2-1 was inconsistent with Footnote 7. The SDT explained that Footnote 7 was included to clarify that "Opening a line section without a fault" could include, but does not always, creating a radial line section with Load and that the planner must evaluate this situation as a part of P2-1.

A number of commenters expressed concern that Footnote 12 was not appropriate or that this standard should be delayed until FERC approved TPL-002-1 Footnote 'b'. The SDT explained that Footnote 12 was consistent with language in the recent NERC Board of Trustees approved TPL-002-1 Footnote 'b" and that this standard should not be delayed until FERC rules on the other standard.

No changes were made to requirements due to industry comments to question 1. However changes were made to the wording of the Implementation Plan to make it consistent with the language in the Effective Date section of the standard. Also, the language in the data retention section was changed for bullets five and six to make it consistent with the language in the requirements – no changes were made to the timeframe for data retention.

DR, 5th bullet: The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.

DR, 6th bullet: The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.

Organization	Yes / No	Question 1 Comment
Lower Colorado River Authority	Ballot Comment	1. R2 (2.5): The requirement for stability assessment in years 6-10 should be limited for new generation interconnections or for planned major transmission system improvements that have regional impact. The standard should clarify the 'material changes' that would necessitate stability planning assessments and documentation. 2. R8 requirement to distribute all Planning Assessment results to adjacent PCs and TPs are excessive and cumbersome. Regarding R8, LCRA TSC suggests the following language: Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners in accordance with the overseeing Reliability Coordinator requirements. Any functional entity that has a reliability related need and submits a written request for the Planning Assessment results, the Transmission Planner and Planning Coordinator shall provide the latest Planning Assessment results within 30 days of such request.

Organization	Yes / No	Question 1 Comment
Response: For Requirement R2, Part 2.5, the SDT believes it is important to evaluate Stability when the planners are evaluating new generation additions or changes which can be more than 5 years in the future, as required in NERC Standard FAC-001-0. The SDT discussed defining 'material change' but did not believe that such a definition was appropriate in a continent-wide standard. With the wide variety in sizes and types of systems, the number of parameters that need to be considered, etc., there are too many variables involved. No change made. For Requirement R8, the SDT disagrees that the requirement is excessive and cumbersome and did not make the suggested change. In addition, the proposed language would place requirements on the Reliability Coordinators, who are not included in the Applicability for this standard, and they should not be involved in determining the extent of the distribution of the Planning Assessments.		
Florida Municipal Power Agency	Ballot Comment	FMPA has minor comments to help improve the clarity of the standard. R7 is not needed and administrative in nature. Instead is should say that an entity can use as evidence another entity's study, but not in the requirement and rather in the measures. R8 is ambiguous, does the requirement require submitting the Planning Assessment only after receiving a written request, or automatic distribution to neighboring PCs and TPs without a written request, and to others with a reliability related need following a written request? Table 1, under first heading of "Steady State and Stability", bullet c should be removed since it is duplicative of the standard, and not entirely consistent with the standard (e.g., open to interpretation whereas the standard better clarifies how to study protection system operation)
Response: Requirement R7 ensures that there are no gaps between Transmission Planners or the Planning Coordinators that may cause reliability concerns. No change made. Requirement R8 requires the automatic distribution to neighboring Planning Coordinators and Transmission Planners without a written request and to others with a reliability related need following a written request. The SDT believes this is an important considerations and not ambiguous. No change made. Table 1, bullet c under first heading, is not in conflict with the requirements. The SDT decided to include additional details in Table 1 so that it would have the basic information necessary for the planner to develop the simulations for their studies without always referring back to the requirements language. No change made.		
Madison Gas and Electric Co.	Ballot Comment	Please revise the words "System" to "system" or preface with BES System. NERC defines System to include distribution components. Plus this Standard is only applicable to PCs and TPs.

Organization	Yes / No	Question 1 Comment
MidAmerican Energy Co.	Ballot Comment	Resolve the conflict between R2 and other requirements in the TPL standards by replacing the term, "System" with "BES" in various places throughout the standard when the reference should not be to the collective generation, transmission, and distribution systems, which is the definition of the NERC Glossary term, "System". These locations are: R2.1.4, R2.1.5, R2.4.3, R2.6.2, R2.7, R2.7.1, R2.7.4, R2.8.1, R2.8.2, R3.5, R4.5, R5, and R6.
Response: Even though the capitalized term "System" includes distribution components, the SDT believes that its usage within this standard is correct because the Reliability Standards apply only to the BES. Therefore, adding additional qualifiers is not needed. No change made.		
City of Austin dba Austin Energy Lower Colorado River Authority	Ballot Comment	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In our view, a Registered Entity's Board of Directors, local public utility commission, and/or its customers should determine what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote. Regarding R2 (2.5): The value of annually assessing system stability for years 6-10 is questionable. The requirement for stability assessment in years 6-10 should be limited to new generation interconnections or planned major transmission system improvements with regional impact. The standard should clarify the 'material changes' that would necessitate stability planning assessments and documentation. Regarding the R8 requirement to distribute all Planning Assessment results to adjacent Planning Coordinators and Transmission Planners is excessive and cumbersome. Regarding R8, we suggest the following language: Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners in accordance with the requirements of the applicable Reliability Coordinator. Any Registered Entity with a reliability-related need may submit a written request for the Planning Assessment results and the Transmission Planner or Planning Coordinator shall provide the latest Planning Assessment results within 30 days of such request.
Response: The SDT incorporated the language in Footnote 12 that was approved in Project 2010-11 TPL Table 1 Footnote B. For Requirement R2, Part 2.5, the SDT believes it is important to evaluate Stability when the planners are evaluating new generation additions or changes which can be more than 5 years in the future, as required in NERC Standard FAC-001-0. The SDT discussed defining 'material change' but did not believe that such a definition was appropriate in a continent-wide standard. With the wide variety in sizes and types of systems, the number of parameters that need to be considered, etc., there are too many variables involved. No change made.		

Organization	Yes / No	Question 1 Comment
For Requirement R8, the SDT disagrees that the requirement is excessive and cumbersome and did not make the suggested change. In addition, the proposed language would place requirements on the Reliability Coordinators, who are not included in the Applicability for this standard, and they should not be involved in determining the extent of the distribution of the Planning Assessments.		
City of Green Cove Springs City of Vero Beach Fort Pierce Utilities Authority Keys Energy Services	Ballot Comment	R7is not needed and administrative in nature. Instead is should say that an entity can use as evidence another entity's study, but not in the requirement and rather in the measures. R8 is ambiguous, does the requirement require submitting the Planning Assessment only after receiving a written request, or automatic distribution to neighboring PCs and TPs without a written request, and to others with a reliability related need following a written request? Table 1, under first heading of "Steady State and Stability", bullet c should be removed since it is duplicative of the standard, and not entirely consistent with the standard (e.g., open to interpretation whereas the standard better clarifies how to study protection system operation)
Response: Requirement R7 ensures that there are no gaps between Transmission Planners or the Planning Coordinators that may cause reliability concerns. No change made. Requirement R8 requires the automatic distribution to neighboring Planning Coordinators and Transmission Planners without a written request and to others with a reliability related need following a written request. The SDT believes this is an important considerations and not ambiguous. No change made.		
Alberta Electric System Operator	Ballot Comment	With respect to R2, Part 2.7.1 which lists system deficiencies and the associated actions needed to achieve System performance, the 3rd and 4th bullet identify the following actions as being acceptable. :Installation or modification of automatic generation tripping as a response to a single or multiple contingency to mitigate Stability performance violations. :Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations. The current Alberta transmission policy does not allow for the tripping or runback of generation for a single contingency; however for multiple contingencies it is acceptable. The AESO will bring TPL-001-2, with any modifications, through the standard development consultation process in Alberta and ultimately to the Alberta Utilities Commission for approval.
Response: The list in Requirement R2, Part 2.7.1 are examples of actions that are acceptable under the NERC Reliability Standard, however, certain actions may not be acceptable under state, provincial, or other regulatory policies or requirements and are not intended to supersede other regulations or policies.		

Organization	Yes / No	Question 1 Comment
ReliabilityFirst	Yes	1. In requirement 4.3, the high speed recloser time of 1 second is too restrictive. We suggest that the time be expanded to 2 seconds to capture all reclosing operations that might impact stability studies.We interpret the use of bullet points in Requirement 4.3.1 to mean that any one of the statements can be included in the analyses. In this requirement, the use of bullet points should be removed and replaced with language that requires all of the statements to be included in the analyses. We strongly believe that the language needs amended in requirement 4.3.1, such that, we will reconsider our voting position. 2. In Table 1 labeled Steady State and Stability Performance Extreme Events we contend that the change to "relay failure" is unnecessarily limiting. The previous use of Protection system was satisfactory. Protection System is a defined term and encompasses many components that may fail and not just the relay. 3. In table 1 Steady State & Stability Performance Planning Events under P5 "non-redundant" needs to be better defined. We suggest saying in a footnote that two devices do not need to be identical in order to be redundant. Redundant relays or relay schemes need to have the same performance level to be considered redundant but do not need to be identical equipment.
Response: The SDT believes that high speed reclosing is less than one second and has not received other comments that the time should be extended. The SDT believes that the language is clear that any of the three items shall be included in the analyses, if applicable. No change made. Table 1, Extreme Events, Stability Item 2 – The SDT made the language consistent with the language in the Planning Events to ensure that the planner was evaluating Stability based on performance of the System after the failure of a relay to operate and the planner should not address the many component failures that could create different failure modes. No change made. The SDT believes that non-redundant is understood by the industry. No change made.		
Bonneville Power Administration	Yes	1. If current study is performed to assess the system, there is no need to supplement with past studies. o Suggested language for R2.2:- For the planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed and be supported by the following annual current study or qualified past studies as indicated in Requirement R2, Part 2.6 2. Load models should be consistent across the region o Suggested language for R2.4.1:- System peak load for one of the five years. System peak load levels shall include a the latest load model developed by the regional planning coordinator which represents the expected dynamic behavior of loads that could impact the study area, considering the behavior of induction motor loads. 3. R2.5 is redundant and should be deleted. It is already included in R1.1.3 and R2.6.2.4. R3.5: This

Organization	Yes / No	Question 1 Comment
		standard requires mitigating the consequences of extreme events. Requiring potentially very costly mitigation actions for very low probability event is unnecessary burden to utilities. o Suggested language for R3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. Evaluation of the risk, consequences and adverse impacts of the event(s) shall be conducted.
Response: For Requirement R2, Part 2 - If the planner chooses to annually complete current studies to assess the system, the planner is not required to use past studies, but rather is allowed to use information from past studies in lieu of completing additional current studies. No change made. For Requirement R2, Part 2.4.1 – Not all Transmission Planners and Planning Coordinators are under a regional Planning Coordinator. However, for areas with a regional Planning Coordinator, that regional Planning Coordinator may have a requirement for all Transmission Planners and Planning Coordinators in its area utilize the regional Load model. No change made. Requirement R2, Part 2.5 is not redundant since the referenced requirements do not require the planner to assess the impact in the Long-Term Transmission Planning Horizon. The requirement is that the planners assess the impact of proposed material changes and have corrective action plans to resolve concerns from those proposed changes. The planner is not required to implement the corrective action plans unless the proposed material changes occur and the issues remain unresolved. No change made. Requirement R3, Part 3.5 – The SDT does not believe that the suggested language adds clarity and is also concerned that evaluation of possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event are not required by the proposed language. No change made.		
Ameren Services	Ballot Comment	(1) Requirement R2.4.1, which addresses dynamic load modeling, has been a cause for concern because of the lack of guidance regarding reasonable induction motor representation as opposed to generic load models. While it is recognized that the effort to simulate the effects of induction motor loads is important, it is premature to include such modeling as part of the requirements for this standard. (2) For Measurements M3 and M4, there is still some question as to what is to be provided as sufficient evidence of a study. It is not clear whether the study results would be sufficient, or whether the entire powerflow, stability, or short circuit effort needs to be documented in a formal study report. For example, it is not clear whether contingency lists used in performing the study work would need to be retained as part of the documentation. (3) The standard as written is too prescriptive with regard to critical system conditions which are to be modeled. Such conditions would vary considerably for different systems across the continent. (4) Overall,

Organization	Yes / No	Question 1 Comment
		we believe that this standard does not improve the clarity of what is required, and would give additional occasions for disputes between compliance monitors and various registered entities.
Response: For Requirement R2, Part 2.4.1, the SDT believes that there are models available that account for the dynamic nature of the Load. No change made. For Measurements M3 and M4, the planner is required to retain evidence that they completed the tasks required in each sub-part of Requirements R3 & R4. These sub-parts require evidence including steady state power flow, Stability and short circuit. Further, the Contingency lists are specifically required in Requirement R3, Parts 3.4 & 3.5 and Requirement R4, Parts 4.4 & 4.5. No change made. The SDT disagrees that the standard is too restrictive about the system conditions to be evaluated. The SDT believes that this standard is a significant improvement and adds needed clarity to the existing TPL standards. No change made.		
New York State Reliability Council	Ballot Comment	1. In R1.1.5, known commitments for Firm Transmission Service, plus other Interchange that does not violate reliability constraints - it is imperative to model other Interchange after accounting for all existing and planned Firm Transmission Service to ensure that reliability-based transactions are not confused with economic interchange. 2. In R2.2.5, the current requirement language can be interpreted to require evaluation of the simultaneous unavailability of multiple long-lead-time components. Also, as a transformer outage is already evaluated as part of category P6 in Table 1, additional studies should not be required; however, spare equipment strategies could be assessed in the context of the planning assessment. 3. In R2.2, the language in this requirement is materially inconsistent with R2.1, unnecessarily requiring a current study.
Response: The SDT selected known commitments for Firm Transmission Service and Interchange to separate the planning requirements of commitments from the economic transactions. No change made. In Requirement R2, Part 2.1.5, the requirement is for the planner to make an assessment of the loss of long lead time (>1 year) equipment, unless the entity's spare equipment strategy can mitigate the issue in less than one year. Therefore, in those instances, the system will be evaluated against the system with the component out of service (multiple Contingencies). While P6 will simulate the same set of outages, the requirements of P1 and P2 are different than P6. Therefore, the planner needs to make an assessment of their system under the more stringent performance requirements. No change made. Requirement R2, Part 2.1 and 2.2 – The SDT left the requirement to conduct the annual study on one of the study years in the Long-Term Planning Horizon to ensure that the planner would conduct a new study annually to evaluate the System improvement needs in the Long-Term Planning Horizon. No change made.		

Organization	Yes / No	Question 1 Comment
Tennessee Valley Authority	Ballot Comment	1. TVA is concerned about the additional studies, modeling, and projects that must be performed to meet this proposed standard. TVA believes that this amount of work will have little overall improvement on the reliability of the BES. 2. TVA believes that the 7 year implementation plan allowed for "Raising the bar" facilities does not allow sufficient time for TVA to construct the required new facilities. TVA average time for constructing a new 500-kV line can be up to 10 years, given the lead time on ROW and following all NEPA requirements. TVA does understand that the team has language (R2.7.3) regarding the TP or PC inability to get the projects completed through no fault of its own; however, there is no safeguard that the entity will be found non-compliant if all the work cannot be accomplished in this time frame. 3. TVA believes that the footnotes b and c that allow for local load drop in the current TPL standards should still be allowed. TVA understands that this is addressed in FERC Order 693; however, the capital improvements to fix many of these issues will have little overall reliability gain for the Bulk Electric System. TVA believes that this is a local load reliability issue and not a BES concern. 4. TVA is concerned that no generating unit shall pull out of synchronism for Planning Event P1, while the standard does allow generator runback/tripping for the same event. TVA believes that this requirement is overly burdensome without providing any material improvement in system reliability. Does distributed generation have to meet the same requirements for not pulling out of synchronism as a large nuclear unit? 5. The Implementation Plan should include a five-year delay in the effective date for short circuit studies (R2 parts 2.3 and 2.8) since these studies are a new TPL requirement and are not required in the current version 0 standards.
Response: 1) The SDT appreciates the concern about additional work compared to the reliability benefits. The SDT believes that the changes within the proposed standard represent the appropriate work to ensure BES reliability. No change made. 2) The SDT believes that the Implementation Plan gives entities the necessary time to develop and implement Corrective Action Plans. No change made. 3) The SDT incorporated the language in Footnote 12 that was approved in Project 2010-11 TPL Table 1 Footnote B. No change made. 4) The SDT does not believe that any generator should pull out of synchronism for a single Contingency. No change made. 5) While short circuit study requirements may be new in the realm of mandatory enforceable standards, the SDT does not believe that they present a significant "raising of the bar" for industry. The SDT believes that prudent short circuit practices are effectively in place today to ensure safe operation of the equipment.		

Organization	Yes / No	Question 1 Comment
Therefore, no extension in the Implementation Plan was made in regard to short circuit studies.		
Florida Municipal Power Pool	Ballot Comment	A. Spare Equipment, R2.1.5 - The requirement reaches beyond the FERC directive. The directive was: "Accordingly, the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy." So, the directive is only to address planned outage, not unplanned outages. Also note that the applicability to GSUs is ambiguous. "Transmission" is defined as: "An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems." Is the "point of supply" the generator terminal, or the GSU high side terminal? B. Table 1, under first heading of "Steady State Only", bullet i is open to interpretation. Many utilities use steady state P-V analyses to study voltage stability and design UVLS systems in apart around those steady state analyses. Would this bullet essentially eliminate P-V and Q-V studies and the related use of UVLS? C. R7 is not needed and administrative in nature. Instead is should say that an entity can use as evidence another entity's study, but not in the requirement and rather in the measures. D. R8 is ambiguous, does the requirement require submitting the Planning Assessment only after receiving a written request, or automatic distribution to neighboring PCs and TPs without a written request, and to others with a reliability related need following a written request? E. Table 1, under first heading of "Steady State and Stability", bullet c should be removed since it is duplicative of the standard, and not entirely consistent with the standard (e.g., open to interpretation whereas the standard better clarifies how to study protection system operation)
Response: The SDT respectfully disagrees that the Commission directive regarding a spare equipment strategy is limited to planned outages. In Order 693, Par 1725, the Commission states in its discussion "Thus, if an entity's spare equipment strategy for the permanent loss of a transformer is to use a "hot spare" or to relocate a transformer from another location in a timely manner, the outage of the transformer need not be assessed under peak system conditions." The SDT believes FERC clearly intended the spare equipment strategy to cover a catastrophic loss of such long lead-time equipment. Further, the SDT believes it has appropriately limited this review to a small subset of the overall Planning Events – P0, P1, and P2 and for a loss that would be sustained for a year or longer. No change made. Table 1, Steady State and Stability, Item I does not restrict the use of UVLS since it only addresses equipment disconnected by end-user equipment. No change made.		

Organization	Yes / No	Question 1 Comment
Requirement R7 ensures that there are no gaps between Transmission Planners or the Planning Coordinators that may cause reliability concerns. No change made. Requirement R8 requires the automatic distribution to neighboring Planning Coordinators and Transmission Planners without a written request and to others with a reliability related need following a written request. The SDT believes this is an important consideration and not ambiguous. No change made. Table 1, Bullet c under first heading, is not in conflict with the requirements. The SDT decided to include additional details in Table 1 so that it would have the basic information necessary for the planner to develop their simulations for their studies without always referring back to the requirements language. No change made.		
Modesto Irrigation District	Ballot Comment	Both Sections 2.1.4 (seven sensitivities) and 2.4.3 (five sensitivities) require sensitivity studies to be run for all planning events and for all years specified , which increases the number of required studies beyond a reasonable and manageable limit. Also, both Section 2.1.4 and 2.4.3 specify that running studies over "...a range of credible conditions that demonstrate a measurable change in System response (performance)." must be completed, yet using "credible conditions" and also "demonstrating a measurable change in System response (performance)", may be mutually exclusive. "Measurable change in System response (performance)" is open to a broad interpretation, which increases the risk that the auditor may very likely interpret it differently than the utility system planner. The definition of the extreme events that have to be analyzed has been made nebulous, where in the existing standards they are quite specific. Requirement 2.1.5 requires the modeling of the loss of any system element that does not have a back-up or spare available sooner than 1 year, as part of the system normal state. It is not clear why using 1 year of loss of use for a system element is being used as the triggering point requiring further system enhancements. Thank you.
Response: Requirement R2, Part 2.1.4 and Part 2.4.3 do not require an unreasonable amount of sensitivities, since they both state the planner must "vary one or more of the following conditions". No change made. Requirement R2, Parts 2.1.4 and Part 2.4.3 allow the planner to use engineering judgment to determine the sensitivities to be completed. No change made. Requirement R2, Part 2.1.5 uses one year as a typical definition of a long lead time for equipment, so that the planner will assess their system performance without that equipment over peak periods. No change made.		

Organization	Yes / No	Question 1 Comment
Hydro One Networks, Inc.	Ballot Comment	Hydro One Networks is casting a negative vote. Other than a few changes related to Footnotes 9 and 12 of Table 1 and VSLs, the other changes in the proposed draft are minor. The concerns of the industry on several important issues have not been sufficiently addressed in this draft. For detailed comments please refer to our submission through the on-line comment form.
Response: The SDT posted a redline draft against the last posted draft and also posted a redline draft against the previous ballot draft. The SDT addressed important issues that were raised during the first ballot. Please see specific responses to your comments where they were submitted.		
Luminant Energy	Ballot Comment	Our most significant concerns are related to the following: (1) The requirements for Sensitivity Analysis are not stringent enough. (2)Studies should include variations in the duration and timing of transmission outages. "Anticipated" outages should be included in the studies and not just "known" transmission outages. It is our experience that only including "known" outages drastically under represents the actual number of transmission outages. (3) Major equipment outages lasting three or more months, as a result of Spare equipment strategies should be included in studies. The time limit of one year as specified in the Standard is too lax. Specific suggested language: 1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months or any known outage(s) of generation or Transmission Facility(ies) that will extend into the high stress period of the BES. 2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies (as indicated in Requirement R2, Part 2.6, as follows). Qualifying studies shall include the following conditions: Add language between 2.1.3 and 2.1.4 to account for generation limitations due to Ancillary Services. Suggested wording: All planning studies must recognize and make provision for secure delivery of each of the Ancillary Services (eg Operating Reserve). In no case shall these studies double count capacity as being available for congestion management and Ancillary Services unless processes are in place to allow for location specific deployment of these Ancillary Service reserves for congestion management purposes.

Organization	Yes / No	Question 1 Comment
		2.1.4 (bullet 7) Duration and timing of anticipated Transmission outages such as required maintenance activities. 2.1.4 (bullet 8 added) Reasonable variations of anticipated generator availability after accounting for equivalent forced outage rate. 2.1.5 If an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that would cause an outage of three months or more, (such as a transformer) the impact of this outage on System performance shall be studied. 2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: â€¢ Load level, Load forecast, or dynamic Load model assumptions. â€¢ Expected transfers. â€¢ Expected in service dates of new or modified Transmission Facilities. â€¢ Reactive resource capability. â€¢ Generation additions, retirements, or other dispatch scenarios. â€¢ Duration or timing of anticipated Transmission outages such as required maintenance activities. â€¢ Reasonable variations of anticipated generator availability after accounting for equivalent forced outage rate. 2.4.4. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled. 2.4.5 If an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that would cause an outage of three months or more, (such as a transformer) the impact of this outage on System performance shall be studied.
Response: 1) The sensitivities addressed in Requirement R2, Parts 2.1.4 and Part 2.4.3 allow the planner to use engineering judgment to determine the sensitivities to be completed. Since sensitivities are included to ensure that the planner evaluates alternative conditions, it is necessary to allow flexibility to evaluate different types of changes that could occur. No change made. 2) Reliability Standards are the minimum requirements and if conditions warrant, entities may add additional outages to be evaluated in their planning studies.		

Organization	Yes / No	Question 1 Comment
No change made. 3) Requirement R2, Part 2.1.5 uses one year as a typical definition of a long lead time for equipment, so that the planner will assess their system performance without that equipment over peak periods. No change made. For Requirement R2, Part 2.1, the SDT did not add language between Parts 2.1.3 and 2.1.4 to account for generation limitations due to Ancillary Services. The proposed addition assumes a particular market structure and that market structure is not uniform across North America. The "projected System conditions" in Requirement R1 would be violated if an entity double counted its Ancillary Services. No change made. Requirement R2, Part 2.1.4, bullet 7 & 8 are examples of sensitivities and the examples provided would address those contemplated by the SDT. No change made. Requirement R2, Part 2.1.5 uses one year as a typical definition of a long lead time for equipment, so that the planner will assess their system performance without that equipment over peak periods. No change made. Requirement R2, Part 2.4.3 – Since the five conditions for sensitivities have been vetted through six postings, the SDT did not add the two proposed conditions. No change made. Requirement R2, proposed 2.4.4 – Since the known outages are already included in the cases, as required by Requirement R.1, Part 1.1.2, there is not a need to require specific studies that include them – No change made. Requirement R2, proposed Part 2.4.5 – The proposed requirement is already contained in Requirement 2, Part 2.1.5 and does not need to be duplicated here. The SDT has used the typical one year time period to define long lead time for equipment and believes that three months is too short a time period for this requirement. No change made.		
MidAmerican Energy Co.	Ballot Comment	Regarding Requirement 8, there is not a significant risk to the reliability of the BES if an annual Planning Assessment is not distributed to another entity or if a documented response to Planning Assessment comments is not provided within 90 days of a request. Requirement 8 is an administrative requirement that adds little to improve reliability. We recommend that the VRF for Requirement 8 remain "Low", rather than be changed to "Medium".
Response: The SDT believes that sharing the Planning Assessments with adjacent Transmission Planners and Planning Coordinators is an important component of the planning process. The SDT did not change the VRF. The previous change reflects the latest guidelines on the topic.		

Organization	Yes / No	Question 1 Comment
Consolidated Edison Co. of New York	Ballot Comment	Requirement R1.1.5: Delete "and Interchange." The inclusion of other than Firm transactions (e.g. economic transactions in Interchange) in a base power flow case utilized for planning/designing the interconnected system blurs the boundary between reliability issues and purely economic issues. Reliability issues are issues that a Transmission Owner (TO) must address for the purpose of meeting its load demand, and are defined by the application of well established reliability standards and criteria that are based on the electrical characteristics of the interconnected system, but without economic considerations. Instead, economic transactions are types of transactions that a TO may enter into once its load obligations are met, and are evaluated based on economic parameters that are markedly different from the aforementioned reliability criteria (e.g. congestion costs). Modeling all types of transactions in a power flow case without distinction detracts from the accuracy and validity of either assessment (reliability and economic).
Response: Requirement R1, Part 1.5 does not require Interchange for economic purposes. The requirement is to represent "Known commitments". No change made.		
Platte River Power Authority	Ballot Comment	Stability requirements R4.1.2, along with the second and third bullets of R4.3.1, could be misunderstood to require the development of comprehensive relaying models for all Facilities represented in the stability model. These requirements should be made clear that Stability studies are to simulate the effects of relaying (tripping certain Facilities) and not require relaying models to trigger and cause the effects.
Response: The SDT language in Requirement R4, Part 4.3.1 states "The analyses shall include the impact of subsequent" and does not require comprehensive relaying models. However, it does require that the planner take into account the effects of System Protection on System performance. No change made.		
GDS Associates, Inc.	No	1. Footnotea. Footnote should state "Draft 7" instead 2. Requirement R1a. Time Horizon should include both Near-term and Long-term Planning3. Requirement R2a. Time Horizon should include both Near-term and Long-term Planningb. Requirement R2, Part 2.1 o The inclusion of the words "For the Planning Assessment" it seem unnecessary as long as main requirement R2 is only about the Planning Assessment and nothing else. o The term "Qualifying studies" from the last sentence is referring to the qualified past studies, or the annual studies, or both actually? Suggesting adjusting the verbiage so it would not create confusion. o Subpart 2.1.4- Requirement R2, Part 2.1.1 and Part 2.1.2 are referring to system conditions, not studies. The second sentence may be subject of non-objective interpretations and may generate burdensome and

Organization	Yes / No	Question 1 Comment
		unrealistic amount of work. The requirement should state instead "For each of the system conditions described in Requirement R2, Part 2.1.1 and Part 2.1.2, the studies shall include sensitivity cases utilized to demonstrate whether there is any significant impact due to changes on the basic assumptions used in the model. The analysis, by case, may contemplate varying one or more of the following conditions:" o Subpart 2.1.5- We suggest adjusting the time threshold of potential equipment unavailability in order to be consistent with the time frame for the "known Transmission outages". c. Requirement R2, Part 2.2 o The inclusion of the words "For the Planning Assessment" it seem unnecessary as long as main requirement R2 is only about the Planning Assessment and nothing else. o While the Near-Term portion of the Planning Assessment details the premises of the study, the Long-Term is lacking in such thing. d. Requirement R2, Part 2.3 o Although both the steady-state and transient stability studies are required for the Near-Term and Long-Term, the short-circuit study is required only for the Near-Term. This is big disconnect, because there can be stability analyses conducted without a short-circuit assessment. o Breakers should be checked for their breaking capability, as well as to withstand the fault. All other disconnecting equipment, as well as current transformers in particular shall be also verified for their withstand capabilities. The current statement should be replaced with "The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term and Long-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to assess performances of transmission elements affected by a potential increase of short-circuit contributions to fault" e. Requirement R2, Part 2.4 o The inclusion of the words "For the Planning Assessment" it seem unnecessary as long as main requirement R2 is only about the Planning Assessment and nothing else. o Similar with 2.1, the last sentence should read "The studies should include the following conditions:" o Subpart 2.4.1- We believe that the dynamic behavior of the load cannot be accurately estimated beyond current time. We are concerned about the effort required to ascertain the dynamic response of the load. As for the "Loads that could impact the study area" the standard doesn't include any directions in how an entity will identify these loads. Perhaps the standard should provide guidelines to determine which loads would impact the study area. o Subpart 2.4.3- See comments from Subpart 2.1.4f.

Organization	Yes / No	Question 1 Comment
		Requirement R2, Part 2.5 o The inclusion of the words "For the Planning Assessment" it seem unnecessary as long as main requirement R2 is only about the Planning Assessment and nothing else. g. Requirement R2, Part 2.6 o Subpart 2.6.2- We agree with the suggested changes as responding to previous commentsh. Requirement R2, Part 2.7 o Subpart 2.7.1- We disagree with the implemented changes. The standard should not include examples. If needed, a white paper can accompany the standard. We suggest adjusting the last sentence to read “Such actions may include, but are not limited to, the following:” i. Requirement R2, Part 2.8 o This should apply to all disconnecting equipment and CT in particular with respect not only to their interrupting duty, but to their withstand capabilities also. See comment on Part 2.3.4. Table 1a. Footnote 9 o With respect to the Curtailment of Firm Transmission Service we suggest SDT to revise the language in order to be consistent with the Implementation Plan. 5. Measure M1a. This measure it is hard to read. For simplicity, we suggest adjusting this measure to read "Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, and the models reflect the System conditions in accordance with Requirement R1." 6. Measure M7a. The measure encompasses the particular scenario where the parties involved have reached an agreement for performing the required studies. In order to cover situations where the parties have not reach an agreement, the measure should read "Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies all individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7." 7. Compliancea. Data retention o The 5th bullet should read "The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5." o The 6th bullet should read "The documentation specifying the criteria or methodology used to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding since the last compliance audit in accordance with Requirement R6 and Measure M6." o The 7th bullet should be reworded in accordance with suggested changes at M7.

Organization	Yes / No	Question 1 Comment
Response: 1. This is the sixth time that this standard has been posted for comments. The reference to a seventh posting on the web site is because the standard was posted once for informational purposes. No change made. 2. Requirement R1. Per the standards process, the Time Horizon for this standard is Long-term Planning; which includes both the Short-Term and Long-Term Planning Horizon. No change made. 3. Requirement R2, Part 2.1 – "For the Planning Assessment" were added in a previous draft for clarity – No change made. Requirement R2, Part 2.1 – "Qualifying Studies" could be either or both – No change made. Requirement R2, Part 2.1.4 – The requirement is for the planner to have a completed study for each of the conditions in Parts 2.1.1 & 2.1.2. The requirement to complete sensitivity studies has been included to ensure that the planner tests their system by stressing the system beyond what is within their base cases. Since the System conditions vary across North America, the relevant sensitivities are best determined by the planner. The proposed language does not convey the same intent. No change made. Requirement R2, Part 2.1.5 – The SDT determined that the impact of "known outages …" does not directly coorelate to the entity's spare equipment strategy. No change made. c. Requirement R2, Part 2.2 – "For the Planning Assessment" were added in a previous draft for clarity – No change made. Requirement R2, Part 2.2 - The SDT limited the requirements in the Long-Term to allow the planner more latitude in that time frame, while ensuring that the planner conducted a Long-Term assessment of their portion of the BES. No change made. d. Requirement R2, Part 2.3 - A planner may choose to complete a short circuit study in conjunction with its Long-Term Steady Steady State and Stability studies, but the SDT does not believe that the planner should be required to complete a short circuit study in the Long-Term Transmission Planning Horizon. No change made. The SDT agrees that any system element must be able to withstand the stresses that they may be subjected to, however, the standard must ensure BES reliability. Therefore, the SDT limited the requirement to the breakers since they protect other system elements from the fault. No change made. e. Requirement R2, Part 2.4 – "For the Planning Assessment" were added in a previous draft for clarity . The SDT does not believe that replacing the last sentence as proposed adds any additional clarity. No change made. Requirement R2, Part 2.4.1 – The SDT believes that the planner must consider the dynamic behavior of its System Load and develop a representative model, however, the SDT should not dictate "how" the Load should be modeled. Those specific details must be included in the model by the individual planner. No change made. Requirement R2, Part 2.4.3 - The requirement is for the planner to have a completed study for each of the conditions in Parts 2.4.1 & 2.4.2. The requirement to		

Organization	Yes / No	Question 1 Comment
complete sensitivity studies has been included to ensure that the planner tests their system by stressing the system beyond what is within their base cases. Since the System conditions vary across North America, the relevant sensitivities are best determined by the planner. The proposed language does not convey the same intent. No change made. Requirement R2, Part 2.5 – "For the Planning Assessment" were added in a previous draft for clarity – No change made. Requirement R2, Part 2.7.1 – The SDT has included limited examples where we believe that additional clarity is needed. Since the list is clearly marked as "examples", the SDT believes the phrase "but not limited to", is not required. No change made. Requirement R2, Part 2.8 - The SDT agrees that any system element must be able to withstand the stresses that they may be subjected to, however, the standard must ensure BES reliability. Therefore, the SDT limited the requirement to the breakers since they protect other system elements from the fault. No change made. The Implementation Plan has been revised as suggested although the SDT wishes to point out that no dates have been changed. Measure M1 – While the suggested langauage is shorter it does not contain all of the terminology of the matching requirement and thus violates a basic guideline for measures. No change made. 6. Measure 7 – The suggested langauge doesn't change the assumed scenario cited and provides no additional clarity. No change made. 7. Data retention, 5th bullet – The SDT agrees that for consistency the suggested terms should be added so that this bullet matches up with the language of the requirement. DR, 5th bullet: The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5. Data retention, 6th bullet - The SDT agrees that for consistency the suggested terms should be added so that this bullet matches up with the language of the requirement. DR, 6th bullet: The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6. Data retention, 7th bullet – The SDT declined to make the suggested changes to Requirement R7 so no change is necessary for Measure M7.		
United Illuminating ISO New England Inc	No	a. 2.6.2 - What was the intent of this change? The old language seemed to work. The language should not be changed from the previous version. b. For 2.8.2 - Was the phrase changed to reflect modifications of facilities? If so the requirement should be

Organization	Yes / No	Question 1 Comment
		modified to read "Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures with respect to modifications of facilities. Otherwise the requirement is unclear. c. For Section R8.1 - the proposed requirement conflicts with a long standing stakeholder process in our area which posts study results and allows comment within a defined period before studies are finalized. If this section is to be retained then it should be modified to only allow comments on Transmission studies less than one-year old. Requirement 8 and 8.1, should be revised to include a limit on the comment period as follows: If a recipient of the planning assessment final results provides documented comments on the results within 90 days of receipt, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments. d. With respect to Table 1 - We suggest adding an event 6 to P1 to address the contingent loss of back to back HVDC Facilities. If not added to P1 then this event needs to be added somewhere in the standard. e. We don't agree with footnote 7 specifying that only one end of the line should be open for this condition. If the SDT is to keep this concept make P2 event 1 simply say "Opening one end of a line section w/o a fault" and delete the footnote. The existing footnote is unclear due to the use of language such as "possibly".

Response: a. Requirement R2, Part 2.6.2 was revised in response to comments that a "qualified" study may have material changes remote from the area of study and the previous version would not have allowed the use of that study. No change made.

b. Requirement R2, Part 2.8.2 – The added phrase – "of identified System Facilities and Operating Procedures" was added to ensure that it was clear what "implementation status" was referencing. No change made.

c. Requirement R8, Part 8.1 - The SDT does not believe that the requirement conflicts with other stakeholder processes and does not believe that a time limit is required. Beyond responding to the comment, other actions by the planner are at the discretion of the planner. No change made.

d. Table 1, P1 back to back DC - The contingent loss of back to back HVDC facilities is included as a transformer. Footnote 5 states, in part, that "Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. Therefore, the SDT has not explicitly included back-to-back HVDC as a separate Contingency. No change made.

e. Table 1, footnote 7 – The SDT added the footnote to further explain its intent for P2-1 and to ensure that the planner assess the voltage of a load bus that was on a radial line. The word "possibly" was used since having load on a radial is not always the outcome of opening one end of a line section. No change made.

Organization	Yes / No	Question 1 Comment
Northeast Utilities	No	Definition of Terms Used in the StandardThe definitions of "Near-Term Transmission Planning Horizon" and "Year One" have been deleted from the standard, yet they are still used in draft 7. NU is concerned about voting in favor of this standard with these terms being defined by another project without a full discussion of the impact to this proposed standard. NU suggests repeating the definitions in this proposed standard. Requirement R1NU believes that the Normal System Conditions as stated in Requirement R1 should establish the base case conditions to be used for the assessment studies. However, a more detailed guideline for developing base cases should be addressed by the requirements. By just modifying the language of requirement R1 to indicate that "P0" constitutes the initial system conditions does not address this concern in Draft #7. A more detailed guideline for base case development is needed. Requirement R8The wording in requirement R8 needs to be amended to restrict comments to the most recent assessment only, for a limited period (say 3 months) after its release. The current wording appears to offer unlimited opportunity to comment on past assessments, long after their release. Footnote 7It appears there is a discrepancy between Footnote 7 and Event P2-1. Footnote 7 could be eliminated by rewording Event P2-1 as follows: "Opening one end of a line section w/o a fault". Footnote 12NU did not agree with the clarification of Table 1 Footnote B of TPL-002 and did not vote for its approval. Therefore, NU does not agree with the same clarification being applied here for Non-Consequential Load Loss. For reference, below is NU's comment on TPL-002 Table 1, Footnote B:"The revised language of Footnote b suggests that non-consequential demand interruption (load that is not directly served by the elements removed from service as a result of the contingency) could be used to mitigate reliability concerns arising from NERC Category B contingency events (i.e., single element contingencies). This language seems to encourage operational workarounds and adds burdens for operators of the system. NU believes this is not consistent with planning a highly reliable bulk electric system and thus does not support this weaker language". General commentNU believes that a standard should contain statements and requirements that are direct and measurable. TPL-001-2 should not be an exception to this rule. Therefore, statements like "An objective" which appears in Footnotes 9 and 12 shall not be used.
Response: Definitions of Near-Term Transmission Planning Horizon and Year One are now approved NERC Glossary Terms and are no longer needed in this proposed standard. The definitions have been vetted through this process through the 1st six postings of this standard and were approved by the Commission in		

Organization	Yes / No	Question 1 Comment
FAC-013. With the wide variety of system conditions and market structures across North America, the SDT chose not to establish a single set of conditions for a base case. Each planner shall establish their base case that meets their needs and their other regulatory requirements. No change made. Requirement R8, Part 8.1 - The SDT does not believe that a time limit for commenting on a Planning Assessment is required. Beyond responding to the comment, other actions by the planner are at the discretion of the planner. No change made. Table 1, P2-1 – The SDT does not agree that there is a discrepancy between the Contingency and Footnote 7. Footnote 7 was utilized to clarify a specific condition that would need to be evaluated as a part of P2-1. No change made. Footnotes 12 and 9 were translated from the BOT approved language from TPL-002-1, Footnote 'b'.		
Electric Reliability Council of Texas, Inc.	No	ERCOT ISO believes that the revisions do not go far enough in addressing previously submitted comments. As written this standard would require restructuring of the functions in the ERCOT Region because several requirements are being assigned to the PC that are currently performed only by the TPs. It would not provide any reliability benefits to have the ERCOT PC assume these functions. Specifically, the following requirements should be modified: R2.1.5 should be clarified to be applicable to TPs only since the ERCOT PC does not have the information necessary to perform this analysis; R2.3 and R2.8 should be clarified to be applicable to TPs only since the ERCOT PC does not perform this analysis (it is performed by the TPs in ERCOT); R4.1.2 should be clarified to only apply to TPs because the ERCOT PC does not have the modeling information necessary to perform this analysis. Additionally, R2.1.4 and R2.4.3 should be removed because the requirements are subjective and there are no actions prescribed to be taken based on the sensitivity results. The Load model requirement should be removed from R2.4.1 because this would be better addressed in a MOD standard. Alternatively, R2.4.1 should be rewritten as "System peak Load for one of the five years with expected dynamic load models." A concurrent requirement should be incorporated to mandate DSPs and TPs to supply dynamic load model data to the PC to perform the required studies.
Response: Requirement R2, Part 2.1.5 requires that studies be completed based on an entity's spare equipment strategy. The ERCOT Planning Coordinator could utilize Requirement R7 to document the individual and joint responsibilities for these studies and document the outcome of these studies. No change made.		

Organization	Yes / No	Question 1 Comment
Requirement R2, Parts 2.3 and 2.8 – The ERCOT Planning Coordinator could utilize Requirement R7 to document the individual and joint responsibilities for these studies and document the outcome of these studies. No change made. Requirement R4, Part 4.1.2 requires the Transmission Planner and Planning Coordinator to accurately represent the behavior of the system if a generator pulls out of synchronism. Therefore, this information is needed by each Transmission Planner and Planning Coordinator to ensure that the appropriate system response is modeled. No change made. Requirement R2, Parts 2.1.4 and R2.4.3 require the completion of sensitivity studies and allows the planner the discretion on which variables to vary. In addition, Requirement R2, Part 2.7 requires Corrective Action Plans to address issues that are present in multiple sensitivities. The MOD standards only require data to be submitted, and this requirement allows the variation of the forecasted load as one of the possible sensitivities. No change made. Requirement R2, Part 2.4.1 – The SDT believes that the drafted language more clearly explains the requirement than the proposed language. This requirement is for the planner to utilize models that reflect the dynamic nature of the load with an expectation that the planner will obtain the required information in Requirement R1 to determine how it is modeled. No change made.		
Independent Electricity System Operator	No	IESO is generally supportive of the draft of TPL-001-2 as evidenced by our previous AFFIRMATIVE vote during the last ballot. Further, IESO also supported the revisions to Footnote 'b' to Table 1 of the TPL standards under Project 2010-11. That revision was balloted and approved by the ballot pool in February 2011 and filed with FERC for approval in March 2011. The revised footnote has been incorporated into the current draft of TPL-001-2 as Footnotes 9 and 12 but the Commission, by letter to NERC dated May 17, 2011, has requested NERC to provide supplemental information before the revised Footnote 'b' could be approved. In light of FERC's request and the uncertainty regarding the final provisions of these footnotes, coupled with the ongoing work on Project 2010-17 for the revision of the BES definition and development of an Exception Process and the impact that may have, we respectfully suggest that the drafting team delay further work on TPL-001-2 pending FERC's ruling on NERC's petition seeking approval of the transmission planning standards that contain the revised Footnote 'b' to Table 1.
Response: The SDT believes that it is important to continue with the approval of this standard. If FERC directs changes based on TPL-002-1, Footnote 'b', they will be addressed with this project.		
New York Independent System Operator	No	If the following recommended revisions are made to the requirements listed, subject to other unforeseen material changes, NYISO would no longer oppose the approval of this standard. Requirement R2.1.5 The current requirement language can be interpreted to require evaluation of the simultaneous unavailability of multiple long-lead-time components. Also, as a transformer outage is already

Organization	Yes / No	Question 1 Comment
		evaluated as part of category P6 in Table 1, additional studies should not be required, however spare equipment strategies could be ASSESSED in the context of the Planning Assessment. NYISO thus recommends this requirement be revised as follows: R 2.1.5 When an entity's spare equipment strategy could result in the unavailability of a major Transmission component that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed with due regard to categories P0, P1, and P2 identified in Table 1. Requirement R2.2The language in this requirement is materially inconsistent with R2.1, unnecessarily requiring a current study. NYISO requests that R2.2 and the sub-requirement be revised as follows:2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies shall include: 2.2.1. Expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected. Requirement R8.1There is an apparent open ended time frame afforded report recipients in their review of any Planning Assessment. This requirement should apply to only the most recent Planning Assessment. NYISO thus recommends the following language: 8.1. If a recipient of the most recent Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.
Response: Requirement R2, Part 2.1.5 is not the same as P6 – Table 1, however, the analysis for P6 could be utilized, if the results show there will not be load loss. Except for the outages being evaluated under P0, P1, and P2 for individual components out of service without a long term spare, the requirement does not require the evaluation of the simultaneous loss of multiple long lead time components. The SDT believes that the language "with due regard to" is not as clear as the proposed language. No change made. Requirement R2, Part 2.1 and 2.2 – The SDT left the requirement to conduct the annual study on one of the study years in the Long-Term Planning Horizon to ensure that the planner would conduct a new study annually to evaluate the System improvement needs in the Long-Term Planning Horizon. No change made. Requirement R8, Part 8.1 - The SDT does not believe that a time limit for commenting on a Planning Assessment is required. Beyond responding to the comment, other actions by the planner are at the discretion of the planner. No change made.		
NBSO	No	Items that, if not addressed, will likely cause a negative vote from NBSO:R2.2 differs from R2.1, R2.3, R2.4 and R2.5 since R2.2 does not state that the annual assessment of the Long-Term Transmission Planning

Organization	Yes / No	Question 1 Comment
		Horizon portion of the steady state analysis can be supported by qualified past studies. Likely this omission is an oversight, but unresolved it can cause significant burden with little gain in reliability. Individual items that, if not addressed, may not cause NBSO to vote Negative, but in combination may result in a negative vote:The language of requirements R2.1.4 and R2.4.3 allowing the performance of one or more sensitivities appears to be inconsistent with language in R2.7.2 that requires multiple sensitivities to determine if actions to resolve performance deficiencies are necessary. R7 (and M7) seem to indicate that the PC is ultimately responsible for determining the individual and joint responsibilities for performing the required planning assessment studies, with the expectation to consult and come to agreement with its corresponding TPs, but this interpretation is not clear. The correct interpretation of this requirement is important for resolving situations where a PC and TP do not agree on the assignment of responsibilities. Suggested wording: "Each PC shall work in conjunction with each of its TPs to determine and identify..." The language in R8 is unclear. One point of confusion relates to which entity is responsible for sending their Planning assessments to other entities. For example, who does a PC distribute their planning assessments to?:-Adjacent PC? (Seems to be clearly addressed)-TPs within its PC footprint? (Not clearly covered by the language in R8)-TPs adjacent to its PC footprint (Not clear if this is the responsibility of the PC, TP or both)In addition, the language in R8.1 appears to offer unlimited opportunity to request response to comments on any past assessment, long after their release. Providing limits in the langue of R8.1 is recommended in order to avoid unnecessary burden on PCs and TPs for little gain in reliability or constructive stakeholder involvement.
Response: Requirement R2, Part 2.1 and 2.2 – The SDT left the requirement to conduct the annual study on one of the study years in the Long-Term Planning Horizon to ensure that the planner would conduct a new study annually to evaluate the System improvement needs in the Long-Term Planning Horizon. No change made. Requirement R2, Parts 2.1.4 and 2.4.3 are not inconsistent with Requirement R2, Part 2.7.2. With the various requirements, the planners are required to conduct multiple sensitivities. Therefore, Requirement R2, Part 2.7.2 could be used when the results of these multiple sensitivities identify common concerns. No change made. Requirement R7 – The SDT believes that the current language addresses the various arrangements that could exist between the Planning Coordinator and Transmission Planner, better than the proposed language. If agreement is not reached, both the Planning Coordinator and the Transmission Planner would be required individually to perform all of the required studies. No change made.		

Organization	Yes / No	Question 1 Comment
Requirement R8 – Each planner is required to distribute its Planning Assessment to all adjacent planners (Transmission Planners and Planning Coordinators). Requirement R8, Part 8.1 - The SDT does not believe that a time limit for commenting on a Planning Assessment is required. Beyond responding to the comment, other actions by the planner are at the discretion of the planner. No change made.		
Hydro One Networks Inc.	No	Other than a few changes related to Footnotes 9 and 12 of Table 1 and VSLs, the other changes in the April 15, 2011, draft are minor. The concerns of the industry on several important issues have not been sufficiently addressed in this draft (see our response to Question 3).
Response: Please see the response to Question 3.		
Manitoba Hydro	No	-R2.1.4 and R2.4.3: 'Expected transfers' should be replaced with 'Firm Transmission Service and Interchange' to correlate to R1 (R1.1.5 states 'Known commitments for Firm Transmission Service and Interchange' must be represented in system mode
Response: Requirement R2, Parts 2.1.4 and R2, Part 2.4.3 use the more inclusive term - Expected transfers – for sensitivities. The SDT does not want to unnecessarily restrict the transfers that could be evaluated as a part of a sensitivity study. No change made.		
Associated Electric Cooperative Inc	No	R2.4.1:The SDT has put a stronger emphasis on dynamic load behavior in stability studies (FIDVR, induction motor loads, etc) to be included in the peak models. The standard does indicate that "An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable." We feel that this should be clarified to ensure that the current modeling processes address what NERC desires with this requirement. At a minimum, we recommend that a grace period be implemented to account for any regional modeling practices which need time to implement dynamic load behavior per the draft standard. R2.5:It is our understanding that the Long-Term Transmission Planning Horizon does not require the sensitivity analysis which is required in R2.4 for the Near-Term Transmission Planning Horizon for the stability portion of the studies. R2.7:It is our understanding that Corrective Action Plan(s) do not need to be developed for performance violations observed in the sensitivity analysis (steady state and stability) unless the violation is observed in several sensitivities as it is indicated in R2.7.2: "Include actions to resolve performance deficiencies indentified in multiple sensitivity studies or provide rationale for why actions were not necessary". We feel

Organization	Yes / No	Question 1 Comment
		that this needs to be further clarified. R3.3.1:This requirement indicates that steady state analysis should include the effect of ride-through voltage limitations of generating units. We are having difficulty seeing how this is a steady-state issue. Generally one would expect a generator to experience ride-through voltage issues during faults. Per Table 1, P1.1 already require generator outages be taken - wouldn't that cover this issue? We feel that this needs to be further clarified. R3.4.1:This requirement states that "Transmission Planners shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list". We feel that the coordination requirement should be removed from the standard as this will result in a massive increase in workload/time required to perform the TPL studies. AECI has several ties to adjacent Transmission Planners and Planning Coordinators - it will be a very time intensive task to coordinate with all of these parties. If the standard wants to ensure that the Contingencies overlap - we can agree to that, however we feel that the SDT needs to give some firm clarity on how far to go with it (how many buses away, only include ties, etc?). R4.1.2:We would like clarification on what is mean by "apparent impedance swings". R4.3.1:Is the intent of the SDT to require that generic or actual relay models be added to the stability models? We feel that this needs to be further clarified. R8:This requirement states that the Planning Assessments shall be distributed within 90 days of their completion to adjacent Planning Coordinators, Transmission Planners, and functional entities that have a reliability need (3rd Interconnection Customers?). We do not agree with the mandatory requirement of distributing the results of our TPL studies: We consider this information to be CEII We can agree to distribute the results upon request, but do not agree with the 30 day timeframe as more time will be needed to sign applicable Non-Disclosure Agreements, etc.
Response: Requirement R2, Part 2.4.1 – The SDT has allowed flexibility for the planner to determine how to meet this requirement. The implementation plan has allowed at least 24 months for coordination and development of modeling practices. No change made. Requirement R2, Part 2.5 – Sensitivities are not required for years in the Long-Term Transmission Planning Horizon. Requirement R2, Part 2.7 – Your understanding of the need for Corrective Action Plans to address deficiencies identified by sensitivity studies is correct. The SDT believes that the proposed language is clear. No change made.		

Organization	Yes / No	Question 1 Comment
Requirement R3, Part 3.3.1 – Within the steady state analysis, the planner is required to represent the actual state of each generator based on the system response to a contingency and this includes voltage ride-through for generators. Table 1, P1-1 does not address this issue, since it is only a single generator outage and the requirements of Requirement R3, Part 3.3.1 could be a generator out of service (because it doesn't ride-through) as a result of a more severe contingency. No change made. Requirement R3, Part 3.4.1 – The SDT added the requirement to coordinate Contingency lists to ensure that these lists do not omit Contingencies on adjacent systems that may cause performance concerns. The SDT believes that most planners are already considering outages on the fringes of their neighbors system to ensure that they meet the performance requirements. The SDT does not agree that this will be a massive increase in workload for planners. No change made. Requirement R4, Part 4.1.2 – The "apparent impedance swing" is the trajectory of changes in the apparent impedance seen by a distance relay for various system and fault conditions. In the case contemplated in Requirement R4, Part 4.1.2, it is the trajectory seen by the distance relay for the initial fault and the subsequent generator(s) pulling out of synchronism. If that trajectory were to come within the tripping characteristic of the relay for a sufficient length of time, the relay would cause its associated line to trip. No change made. Requirement R4, Part 4.3.1, bullet 3 – The planner may reflect the effects of either generic or actual relay models. No change made. Requirement R8 – The SDT believes that 30 days should be adequate time to get the necessary agreements in place to make the Planning Assessment available. No change made.		
National Grid	No	R2.8.2We recommend this requirement be clarified with the following modification: The Corrective Action Plan shall:2.8.1. List System deficiencies and the associated actions needed to achieve required System performance. 2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of planned modifications to System Facilities and Operating Procedures.
Response: The proposed change of "identified" to "planned modifications to" does not change the proposed requirement or add clarity. No change made.		
Consolidated Edison Co. of NY, Inc.	No	Requirement R1.1.5: Delete "and Interchange." The inclusion of other than Firm transactions (e.g. economic transactions in Interchange) in a base power flow case utilized for planning/designing the interconnected system blurs the boundary between reliability issues and purely economic issues. Reliability issues are issues that a Transmission Owner (TO) must address for the purpose of meeting its load demand, and are defined by the application of well established reliability standards and criteria that are based on the electrical characteristics of the interconnected system, but without economic considerations. Instead, economic transactions are types of transactions that a TO may enter into once its load obligations are met, and are evaluated based on economic parameters that are markedly different from the aforementioned reliability criteria (e.g. congestion costs). Modeling all types of transactions in a power flow

Organization	Yes / No	Question 1 Comment
		case without distinction detracts from the accuracy and validity of either assessment (reliability and economic).
Response: Requirement R1, Part 1.5 does not require Interchange for economic purposes. The requirement is to represent "Known commitments". No change made.		
Nebraska Public Power District	No	The existing TPL-001 through TPL-004 Standards and Requirements are clear and concise. The new merged TPL-001-1 Standard and Requirements is no longer clear and concise. Further, the modification made to allow an SPS to trip a remote generator for an N-1 (TPL-002) type of event is a degradation of system reliability. Transmission system facilities should be added to maintain stability for a new generator interconnection for any N-1 Category B event. An SPS should not be relied upon for a Category B event, an SPS should only be allowed for Category C & D (TPL-003 & TPL-004) type events.
Response: The SDT believes that there is much less ambiguity in the proposed standard than the existing standards. There is no restriction in the existing TPL-002-1 on a planner's ability to utilize an SPS to trip a remote generator for a Category B event and the SDT did not change this. No change made.		
Northeast Power Coordinating Council	No	The wording of Part 1.1.2, "known outages...with a duration of at least 6 months" should be revised to "...at least 1 year". Also for consideration is that "known outages...with a duration of at least 6 months" are dealt with in operational studies rather than planning studies. Any adverse impacts that these outages might have are mitigated by operational decisions rather than planning decisions within a 6 month horizon. Moving this requirement out of the TPL Standard to an operational standard should be considered. Make the wording consistent between 2.1 and 2.2 as it relates to qualified past studies. Specifically:Parts 2.1.2, 2.1.4, 2.1.5The language of requirements 2.1.4 and 2.4.3 allowing the performance of one or moresensitivities appears to be inconsistent with language in 2.7.2. 2.7.2 requires multiplesensitivities to determine if actions to resolve performance deficiencies are necessary.Will varying only one measurable quantity several times in multiple simulationssatisfy multiple sensitivity studies or just one sensitivity study? The numbers and types of required sensitivity studies is unclear, and subject to interpretation by PCs and TPs. The current wording in Part 2.1.5, "spare strategy", appears to be open-ended regarding the number of

Organization	Yes / No	Question 1 Comment
		permutations to be analyzed. It should be restricted to assessing only one piece of equipment being unavailable or outaged at a time. 2.1.5 should be consistent with R2 and 2.1 regarding the use of the terms assessment and studies. As with the preceding comment regarding Part 1.1.2, moving this requirement out of the TPL Standard and to an operational standard should be considered.It is unclear if the last sentence of R2.1.5 allows for the curtailment of firm transmission service before the application of category P0, P1 and P2 events. This last sentence states:"...with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment." The wording in Part 2.2 "be supported by the following annual current study, supplemented with qualified past studies" should be replaced with the similar statement in Part 2.1: "be supported by current annual studies or qualified past studies". Part 2.7.1 lists potential system actions to address System deficiencies. It is suggested that this list be moved to a guideline or white paper. The wording in Part 8.1 needs to be amended to restrict comments to the most recent assessment only. Contingencies on back to back HVDC installations are not mentioned in the standard. The treatment of combined cycle facilities (all units in outage?) needs to be clarified, as well as Footnote 7 of Table 1 requiring clarification. In Table 1, Event 1 of Category P2 and related Footnote 7 are not clear because of the use of the word "possibly". If the intension is to simulate the line end opening condition of tapped lines, this should be clearly stated in the table (without reference to "Opening of a line section" and use of different language in the footnote). From Table 1b: "Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0." Firm Transmission Services Loss is also acceptable and should be added (particularly in P1 loss of a single pole of a DC line for which the transfer is reduced accordingly to the remaining pole capability).
Response: Requirement R1, Part 1.1.2 does not address the outages in the operational time frame. However, if a planner knows that a System component is going to be out of service for more than 6 months, the planner must model the component outage in the appropriate models and evaluate the System to ensure that the System meets the performance requirements of the standard. No change made. Requirement R2, Part 2.1 and 2.2 – The SDT left the requirement to conduct the annual study on one of the study years in the Long-Term Planning Horizon to		

Organization	Yes / No	Question 1 Comment
ensure that the planner would conduct a new study annually to evaluate the System improvement needs in the Long-Term Planning Horizon. No change made. Requirement R2, Part 2.1.4 and 2.4.3 each require two studies on sensitivity cases, but more studies can be performed by the planner. Requirement R2, Part 2.7.2 states that Corrective Action Plans are required (or rationale for why they are not needed) are required if performance deficiency exists in multiple sensitivity studies, not just one study. No change made. Requirement R2, Part 2.1.5 requires the study of each major Transmission equipment outage, consistent with spare equipment strategy, for System normal and P1 and P2 Contingencies. It does not require the study of P1 and P2 Contingencies with more than one major Transmission equipment, except for other equipment that are modeled out as "Known outages" consistent with Requirement R1, Part 1.1.2. No change made. Requirement R2, Part 2.1.5 is a planning requirement to ensure that an entity's spare equipment strategy is considered during the development of the Planning Assessment. The curtailment of Firm Transmission Service (FTS) for the situation outlined would be considered curtailing FTS for Normal System conditions and is not allowed. No change made. Requirement R2, Part 2.1 and 2.2 – The SDT left the requirement to conduct the annual study on one of the study years in the Long-Term Planning Horizon to ensure that the planner would conduct a new study annually to evaluate the System improvement needs in the Long-Term Planning Horizon. No change made. Requirement R2, Part 2.7.1 – The list represents examples, but not an exhaustive list of actions that could make up a Corrective Action Plan. No change made. Requirement R8, Part 8.1 - The SDT does not believe that a time limit for commenting on a Planning Assessment is required. Beyond responding to the comment, other actions by the planner are at the discretion of the planner. No change made. Table 1, P1 {back to back DC - The contingent loss of back to back HVDC facilities is included as a transformer. Footnote 5 states, in part, that "Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. Therefore, the SDT has not explicitly included back-to-back HVDC as a separate Contingency. No change made. Combined cycle generation outages are expected to be modeled in the manner that they would be tripped, per Requirement R3, Part 3.3.1 and Requirement R4, Part 4.3.1. Therefore, if the outage of one generator causes more generation to be lost (via the Protection System or other automatic controls are expected to disconnect), then, the entire amount of generation lost must be modeled for that specific contingency. No change made. Table 1, footnote 7 – The SDT added the footnote to further explain its intent for P2-1 and to ensure that the planner assess the voltage of a load bus that was on a radial line. The word "possibly" was used since having load on a radial is not always the outcome of opening one end of a line section. No change made. Table 1, Top note 1b – The SDT disagrees that Firm Transmission Service (FTS) may be interrupted for all events. The events where the interruption of FTS is not permitted are shown with a "No" in the column titled "Interruption of Firm Transmission Service Allowed", however, footnote 9 clarifies that interruption of Firm Transmission Service can be used as both a corrective action and system adjustment as permitted within Table 1. For the specific issue raised, loss of a single pole of a DC line, to the extent the availability of the DC pole is a condition of the transfer being viable, footnote 4 may also address the commenter's		

Organization	Yes / No	Question 1 Comment
concern. No change made.		
Ameren	No	There were a number of comments made on the previous draft of TPL-001-2 for which there were few, if any, changes made to the latest draft of the standard. Specifically:Requirement R1 does not address normal (pre-contingency) operating procedures or system configurations. Language should be added to the requirement (possibly as an additional Requirement R1.1.7) to include normal operating procedures or system configurations in place prior to any contingency occurring. Requirement R2.4.1, which addresses dynamic load modeling, has been a cause for concern because of the lack of guidance regarding reasonable induction motor representation as opposed to generic load models. While it is recognized that the effort to simulate the effects of induction motor loads is important, it is premature to include such modeling as part of the requirements for this standard. In addition, it appears that only the peak load model in R2.4.1 is required to represent expected dynamic behavior of Load. Such load models, if adopted should represent dynamic behavior of the load for all dynamic studies.
Response: The SDT posted a redline draft against the last posted draft and also posted a redline draft against the previous ballot draft. The SDT addressed many important issues that were raised during the first ballot. The SDT did not include all of the different procedures that are permitted. Normal operation procedures or system configuration may be utilized as long as they are consistent with the way the System would be operated and not inconsistent with the requirements within the standard. Requirement 2, Part 2.4.1 – One focus of dynamic Load model requirement in Part 2.4.1 is "considering the behavior of induction motor Load". The areas of concern for induction motor Load are the Peak Load periods since Fault Induced Delayed Voltage Recovery (FIDVR) is primarily a concern at high Load levels with a high penetration of induction motor Loads. The SDT has spelled out this requirement in the Peak Load studies but did not include the explicit requirement, with focus on induction motor Load, for the other Load periods. Even though the standard doesn't have the explicit requirement for other Load levels, Requirement R1 includes the statement "shall represent projected System conditions", so the planner cannot ignore the dynamic behavior of the Load for those other Load periods. No change made.		
Western Area Power Administration	No	We concur that the standard is an improvement over previous drafts, but we vote "No" to the existing draft and request additional clarifications and/or modified language for a re-circulated vote prior to adoption. The following are areas where we suggest improvement or have questions:Please further define Consequential and/or Non-Consequential Load Loss: Does the Consequential Load Loss definition include underfrequency or undervoltage load shedding installed to protect transmission system reliability? Does the Consequential Load Loss definition include load tripped by a Special Protection System (SPS) or a

Organization	Yes / No	Question 1 Comment
		Remedial Action Scheme (RAS)? Either how underfrequency and undervoltage load shedding or how load shedding by a RAS relates to Consequential Load Loss should be clear in the Consequential and/or Non-Consequential Load Loss definition of the approved version of this NERC standard. Why is Near-Term Tranmission Planning Horizon deleted from the definitions of Terms Used in this Standard, yet it is used throughout the standard? This definition should remain. R1.1.5: How are "known commitments for Firm Transmission Service" to be modeled and tracked in power flow cases? Is it acceptable for Transmission Planners to simply assume what the ultimate sources and ultimate sinks are for each firm transmission service commitment or are Transmission Planners to know exactly which ultimate sources and ultimate sinks are associated with each commitment and to track each one accordingly in each power flow case?Assuming the intent here is reliability based and not marketing based, is the application of Firm Transmission intended to apply to reliability designated 'paths'? Most all Firm Transmission service contracts have caveats for unplanned interruption and such agreements should qualify as "re-dispatch" per Footnote 9? R2.1.5: If a group of utilities were to develop and manage among themselves a coordinated spare equipment program, such that the risk to any one of its participating entities of experiencing a significant unavailability for any major Transmission equipment that has a lead time of one year or more is deemed not significant, then would those utilities still have to do the studies required by R2.1.5 to evaluate the system impact of extended outages of such equipment?Scenario for Clarification: Short of spare equipment for items with a greater than 1 yr lead time, assessment studies are required to include sensitivities and operating plans for sustained loss of these equipment items, as a prior outage. For example, if an EHV facility is lost for more than 1 yr, and firm transmission interruption is not allowed, it appears the only compliant alternative (to a redundant facility) is a redispatch plan that is well documented and accepted by all stakeholders, per Footnote 9. R2.3: Is only the 5-year Near-Term Transmission Planning Horizon case required for the annual short-circuit analysis? R2.4.1: How is the dynamic modeling of induction motor Loads to be developed by the Transmission Planners? Is it acceptable for Transmission Planners to assume the same induction motor modeling as has generally been assumed and applied by most Transmission Planners throughout the Western Interconnection or will the induction motor modeling have to be based upon the type and amount of actual

Organization	Yes / No	Question 1 Comment
		induction motors installed in the system? R2.5: Does NERC have a particular technical rationale about what determines “proposed material generation additions or changes?” R2.6.2: Does NERC have a particular technical rationale about what determines “material changes?” R2.7.3: Please define “beyond the control” under Definition of Terms Used in Standard. This is an important concept. Without NERC definition, this term is highly debatable and should be eliminated. Scenario for Clarification: If the stakeholder rate payers do not approve expenditures for facility improvements required to eliminate non-consequential load loss, is this beyond the control of the Transmission Planner? Rate payers should be able make the ultimate free market choice determination of risk versus cost associated with their reliability. Otherwise market interests (particularly generation) disproportionately pressure excessive reliability based improvements that must be borne by all rate payers. R3.3.1: Please define “relay loadability limit” under Definitions of Terms Used in Standard. This is an extremely important concept. This term has been used quite commonly for decades and is now used in this latest proposed standard. Without NERC definition, this term is highly debatable and should be eliminated. Scenario for Clarification: If PRC-023 is met whereby all “relay loadability limits” are set at least 150% of the highest thermal limiter (0.85 voltage and 30 lagging powerfactor) this sensitivity would justifiably not be needed so long as verification is shown that no element overloaded greater than 150%. R3.1 and R3.4: The interrelation between these two paragraphs needs additional clarification. R3.1 calls for verification via studies that the BES meets Table 1 performance criteria based on the contingency list resulting from R3.4. However, R3.4 states that the contingency list used to meet R3.1 only need include “Those planning events in Table 1, that are expected to produce more severe System impacts on.....the BES” and the associated “rationale” for those chosen contingencies. Is NERC suggesting that the studies do not need to include all contingencies based on Table 1, so long as ample “rationale” is provided? However, the Transmission Planner must provide studies to determine if every contingency of Table 1 meets performance requirements. How are the “more severe” contingencies determined if the Table 1 contingencies are not evaluated comprehensively? It seems R3.4 could be eliminated and the contingencies be based simply on Table 1. Please define “more severe”, relative to less severe under Definitions of Terms Used in Standard, in an effort to help evaluate the suitability of a particular contingency for inclusion on this list. Looking at context, it appears that the purpose of this statement is to ensure that the worst contingencies are studied. Is the intent here simply to allow a given contingency to cover for a less severe or similar contingency and avoid duplicate simulations?

Organization	Yes / No	Question 1 Comment
		R3.4.1 and R4.4.1 Please include and define a reasonable number of contingent buses into adjacent systems that should be considered. No more than 2 are recommended for the standard. R3.5 and R4.5: How many of the "events in Table 1 that are expected to produce more severe system impacts" should the required evaluation identify and evaluate? To what extent should the evaluation focus on the "other" Extreme Events described under items 3.b and 2.f in Table 1, particularly if existing disturbance reports in the Western (or Eastern) Interconnection have recorded and evaluated the occurrence of particular events that have already created cascading? Because the requirement seems to involve a check for Cascading, perhaps some clarity could be provided with respect to the NERC definition of "Cascading." In particular, in the Cascading definition, how widespread is "widespread;" is the phrase "electric service interruption" only about the loss of firm load or could it also be only about the loss of firm generation or only about the loss of firm transmission service or is it about some combination of loss of firm load, loss of firm generation, and loss of firm transmission service; how large an area is meant by the expression "spreading beyond an area predetermined by studies" when the simulations that analyze the initiating Extreme Event will model the entire Western (or Eastern) Interconnection? So how does the study determine that the sequentially spreading service interruption has spread beyond the entire Western (or Eastern) Interconnection that is modeled in the simulation? Or is the term "area" meant to describe only that part of the Western (or Eastern) Interconnection that the Transmission Planner has evaluated for system impacts while ignoring impacts to the rest of the Interconnection? Table 1 - Planning Events, Steady State Only Note i: "The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event" seems to be included as items 2) and 3) under the Non-Consequential Load Loss definition. So, it seems acceptable to use this form of load loss to meet the stability performance requirements. However, the "Steady State Only" note i in Table 1 specifically does not allow its use to meet steady state performance requirements. Therefore, the "Steady State Only" note i in Table 1 should clarify why it seems acceptable to use it to meet stability performance requirements but not to meet steady state performance requirements. Table 1 - Planning Events, Category P2: Category P2 seems to include an unrelated mix of planning events ranging from a seemingly benign event (i.e., opening of a line section without a fault) to what would seem to be much more severe events (i.e., bus section fault or internal breaker fault). A clarification of why these planning events were lumped into the same Category P2 would be helpful to the Transmission Planner. Also, does the language in footnote 7 (i.e., "opening one end of a line section without a fault on a normally networked Transmission circuit ...") mean that P2-1 ("opening of a line section without a fault") should be

Organization	Yes / No	Question 1 Comment
		modeled as an open-ended line section? Table 1 - Planning Events, P2-2 (EHV) and P2-3 (EHV): For each of these planning events, its corresponding "Non-Consequential Load Loss Allowed" column should include a footnote 12 with each of the "No" boxes, similar to that allowed under the seemingly much less severe event P2-1 ("opening of a line section without a fault"). Otherwise, please explain why the seemingly much less severe P2 event (P2-1) has a footnote 12 exception for Non-Consequential Load Loss Allowed but the two seemingly more severe P2 events (P2-2 and P2-3) do not. Table 1 - Planning Events, P4-1 through P4-5 (EHV): For the stuck breaker planning events of P4-1 through P4-5 on the EHV system, their corresponding "Non-Consequential Load Loss Allowed" column should include a footnote 12 with their "No" box, similar to that allowed under the seemingly much less severe N 1 planning events (P1-1 through P1-5). Otherwise, please explain why the seemingly much less severe N 1 events (P1-1 through P1-5) have a footnote 12 exception for Non-Consequential Load Loss Allowed but the seemingly much more severe stuck breaker events (P4-1 through P4-5) do not. Table 1 - Planning Events, P5-1 through P5-5 (EHV): For the relay failure planning events of P5-1 through P5-5 on the EHV system, their corresponding "Non-Consequential Load Loss Allowed" column should include a footnote 12 with their "No" box, similar to that allowed under the seemingly much less severe N 1 events (P1-1 through P1-5). Otherwise, please explain why the seemingly much less severe N 1 events (P1-1 through P1-5) have a footnote 12 exception for Non-Consequential Load Loss Allowed but the seemingly much more severe relay failure events (P5-1 through P5-5) do not.

Response: The definition of Consequential Load Loss does not include underfrequency or undervoltage load shedding, since this Load is not interrupted by the "Protection System operation designed to isolate the fault". No change made.

The definition of Consequential Load Loss does not include Load tripped by a Special Protection System (SPS) or a Remedial Action Scheme (RAS), since this Load is not interrupted by the "Protection System operation designed to isolate the fault". No change made.

The definition of Near-Term Transmission Planning Horizon is now an approved NERC Glossary Term. No change made.

Requirement R1, Part 1.1.5 (Known commitments for Firm Transmission Service and Interchange) is required to ensure that planners consider those transactions that have been committed to and meet the system performance requirements. "How" the planners account for these commitments should be developed by the planner in accordance to all of the regulatory and market rules that apply to them. No change made.

Requirement R2, Part 2.1.5 does not require a planner to study the unavailability of major long lead time equipment if the entity's spare equipment strategy could

Organization	Yes / No	Question 1 Comment
not result in the unavailability of that equipment for one year or more. No change made. Requirement R2, Part 2.3 requires the short circuit analysis only for the years of the Near-Term Transmission Planning Horizon. No change made. RequirementR2, Part 2.4.1 – The SDT believes that the planner must consider the dynamic behavior of its System load and develop a representative model, however, the SDT should not dictate "how" the load should be modeled. No change made. Requirement R2, Part 2.5 does not specify "how" an entity determines that "proposed material generation additions or changes" have occurred. It is up to each entity to develop its technical rationale for its determination. No change made. Requirement R2, Part 2.6.2 does not specify "how" an entity determines that "material changes" have occurred. It is up to each entity to develop its technical rationale for its determination. No change made. Requirement R2, Part 2.7.3 has been included to account that certain Corrective Action Plans may not be able to be implemented due to circumstances that the planner cannot control. The SDT expects that these situations will be limited and that the impact to BES will be limited to interrupting Non-Consequential Load if the Contingency were to occur. Due to the wide variety of circumstances across North America, the SDT did not believe that it was appropriate to articulate the acceptable set of conditions. No change made. Requirement R3, Part 3.3.1 utilizes the term "relay loadability limits" as it is utilized in the PRC standard. No change made. Requirement R3, Parts 3.1 and 3.4 together require the planner to create a list of the "more severe" Contingencies, along with the rationale for "why" those Contingencies were selected, that will be simulated to ensure that the System meets the performance requirements. This language was included to be consistent with the existing TPL standards that do not require the planner to run simulations of all possible Contingencies. No change made. Requirements R3, Part 3.4.1 and Requirement R4 Part 4.4.1 do not include "how" to define the Contingencies in adjacent systems that should be included since it will be variable based on the conditions of the System. It is the responsibility of the planners to coordinate the list of Contingencies to ensure BES reliability. No change made. Requirement R3, Part 3.5 and Requirement R4 Part 4.5 require the planner to identify the "events in Table 1 that are expected to produce more severe system impacts". The number of "events" that should be included in the list are a "how" that the planner must determine. No change made. Table 1, Extreme Events Steady State 3b and Stability 2f are included to ensure that the planner considers "operating experience" when determining the extent of Contingency analysis to conduct for the entity's Extreme Event simulations. The term "widespread" categorizes those events that are more far-reaching than the Local Area events identified in Extreme Events Steady State 2 a-e. No change made. Table 1, Top note 'i' Steady State Only does not apply to Stability studies. Therefore, voltage sensitive Load disconnected by end-user equipment may be used during Stability simulations. The planner should not depend on this voltage sensitive Load being disconnected to meet the performance requirements (steady state after the system transient reaction ends) but this Load should be disconnected from the System for the Stability simulations to accurately represent how the		

Organization	Yes / No	Question 1 Comment
System will respond. No change made. Table 1, P2 contains single Contingency events that have the same performance requirements. No change made. Table 1, P2-1 covers the opening of line section without a fault and Footnote 7 clarifies that the line section may be energized from one end and still serving Load. The expectation is that both situations are evaluated when appropriate. No change made. Table 1 P2-2 (EHV) and P2-3 (EHV) do not allow the exception allowed by Footnote 12. The SDT believes that the EHV system should be planned to handle these single Contingencies without Non-Consequential Load Loss. No change made. Table 1, P4-1 through P4-5 (EHV) does not allow the exception allowed by Footnote 12. The SDT believes that the EHV system should be planned to handle these Contingencies without Non-Consequential Load Loss. No change made. Table 1, P5-1 through P5-5 (EHV) does not allow the exception allowed by Footnote 12. The SDT believes that the EHV system should be planned to handle these Contingencies without Non-Consequential Load Loss. No change made.		
Progress Energy		First, Progress Energy ("PE") notes that many changes to the Requirements language have been appropriate or have improved upon the language of the previous drafts, and PE commends the SDT in this. PE does have concerns, however, with the language in R8 and its corresponding Measure M8, and therefore must select 'no' for Q1 and provide comments. PE disagrees with the language of R8 primarily to the extent that the use of the verb “distribute” with respect to communicating Planning Assessments leads the reader to M8, which lacks language that would provide for the optimal correlation with R8. Regarding the M8 language, PE feels that the term “demonstration of a public posting” is a valid action in demonstrating compliance with R8 and thus should be more clearly described as one of several acceptable methods of distributing Planning Assessments. In addition, given the appropriate concern that NERC and FERC have recently raised regarding Cyber threats and the need for additional Cyber Security measures, PE feels that the public posting language should contain a qualification regarding the security of CEII information. PE thus recommends that an appropriate phrase to use would be “demonstration of a secure public posting”, thereby making clear that a public posting would not be a website accessible to just anyone due to CEII concerns.
Response: Requirement R8 - The SDT agrees that posting is an acceptable method of distributing but the intent of the standard requirement is to ensure that affected parties obtain the Planning Assessment. Measure M8 clarifies that posting is acceptable but not the only way to meet the requirement. While the SDT recognizes that certain planning information is covered by CEII requirements, the responsibility to protect that information already resides with the entity and is therefore not needed within this standard. No change made.		

Organization	Yes / No	Question 1 Comment
SERC Planning Standards Subcommittee	Yes	
SPP Reliability Standards Development Team	Yes	
MRO's NERC Standards Review Forum	Yes	
BC Hydro	Yes	
Entergy Services	Yes	
Imperial Irrigation District	Yes	
Arizona Public Service Company	Yes	
American Electric Power	Yes	
Duke Energy	Yes	
Transmission Strategies, LLC	Yes	
NIPSCO	Yes	
Muscatine Power and Water	Yes	
ITC	Yes	
Tri-State Generation and Transmission Assn., Inc.	Yes	In general, revisions are editorial and seem to have improved the overall document.

Organization	Yes / No	Question 1 Comment
Pepco Holdings Inc	Yes	Pepco Holdings Inc supports the proposed revisions.
Puget Sound Energy, Inc.	Yes	We Appreciate SDTs efforts in bringing clarity to the TPL standards.
South Carolina Electric and Gas	Yes	
Georgia Transmission Corporation	Yes	
American Transmission Company, LLC	Yes	
TVA TP&C	Yes	
Xcel Energy	Yes	
MISO	Yes	
Consumers Energy	Ballot Comment	We agree with the comments of MISO.
Oncor Electric Delivery Company LLC	Yes	
Response: Thank you for your support.		

2. **The SDT has made revisions to the VRF and VSL of TPL-001-2 which will be part of a non-binding poll with this posting based on industry comments and the Quality Review. Do you agree with these changes? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: Comments received were predominantly about individual assessments of whether a VRF or VSL had been assigned correctly and some pointed out what they thought were incorrect interpretations of established guidelines by the SDT. The SDT followed guidelines established by FERC and NERC in these areas and therefore no changes were made in this regard.

In two particular instances, inconsistencies between wording in the requirement and VSL were pointed out and the SDT made the following changes due to those comments:

R1. VSL – Severe (third part): The responsible entity's System model did not use ~~the latest~~ data consistent with ~~the data~~that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.

R8 VSL	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners.

	it was more than 30 days but less than or equal to 40 days following the request	it was more than 40 days but less than or equal to 50 days following the request.	it was more than 50 days but less than or equal to 60 days following the request.	OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

Organization	Yes / No	Question 2 Comment
Consolidated Edison Co. of New York	Ballot Comment	Requirement R1.1.5: Delete “and Interchange.” The inclusion of other than Firm transactions (e.g. economic transactions in Interchange) in a base power flow case utilized for planning/designing the interconnected system blurs the boundary between reliability issues and purely economic issues. Reliability issues are issues that a Transmission Owner (TO) must address for the purpose of meeting its load demand, and are defined by the application of well established reliability standards and criteria that are based on the electrical characteristics of the interconnected system, but without economic considerations. Instead, economic transactions are types of transactions that a TO may enter into once its load obligations are met, and are

Organization	Yes / No	Question 2 Comment
		evaluated based on economic parameters that are markedly different from the aforementioned reliability criteria (e.g. congestion costs). Modeling all types of transactions in a power flow case without distinction detracts from the accuracy and validity of either assessment (reliability and economic).
Response: The SDT selected Known commitments for Firm Transmission Service and Interchange to separate the planning requirements of commitments from the economic transactions. No change made.		
San Diego Gas & Electric	Ballot Comment	The clarity of this standard is getting worse. Our earlier comments did not seem impacting. At this point, we believe the existing TPL-001-0.1, TPL-002-0a, TPL-003-0a and TPL-004-0 provide much better clarify for us to comply with the TPL standards.
Response: The SDT believes that there is much less ambiguity in the proposed standard than the existing standards, based on feedback from previous postings. . No change made.		
Alberta Electric System Operator	Ballot Comment	The AESO casts an abstain vote as the VSLs and VRFs in Alberta are established by provincial authorities.
Response: Thank you for your response.		
Western Electricity Coordinating Council	Ballot Comment	I'm not certain that I agree with changing the VRF for R2 from Medium to High. I understand that it is accordance with the VRF guidelines, but I guess I disagree with the guidelines. I don't believe that any requirement with a planning time frame, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.
Response: The SDT is required to follow the VRF guidelines established by FERC, which apply to both operations and planning on equal footing. No change made.		
Florida Municipal Power Agency	Ballot Comment	FMPA has minor comments to help improve the clarity of the standard. R7 is not needed and administrative in nature. Instead is should say that an entity can use as evidence another entity's study, but not in the requirement and rather in the measures.

Organization	Yes / No	Question 2 Comment
		R8 is ambiguous, does the requirement require submitting the Planning Assessment only after receiving a written request, or automatic distribution to neighboring PCs and TPs without a written request, and to others with a reliability related need following a written request? Table 1, under first heading of "Steady State and Stability", bullet c should be removed since it is duplicative of the standard, and not entirely consistent with the standard (e.g., open to interpretation whereas the standard better clarifies how to study protection system operation)
Keys Energy Services City of Green Cove Springs	Ballot Comment	R7 is not needed and administrative in nature. Instead is should say that an entity can use as evidence another entity's study, but not in the requirement and rather in the measures. R8 is ambiguous, does the requirement require submitting the Planning Assessment only after receiving a written request, or automatic distribution to neighboring PCs and TPs without a written request, and to others with a reliability related need following a written request? Table 1, under first heading of "Steady State and Stability", bullet c should be removed since it is duplicative of the standard, and not entirely consistent with the standard (e.g., open to interpretation whereas the standard better clarifies how to study protection system operation)
Response: Requirement R7 ensures that there are no gaps between Transmission Planners or the Planning Coordinators that may cause reliability concerns. No change made. Requirement R8 requires the automatic distribution to neighboring Planning Coordinators and Transmission Planners without a written request and to others with a reliability related need following a written request. The SDT believes this is an important consideration and not ambiguous. No change made. Table 1, Bullet c under first heading, is not in conflict with the requirements. The SDT decided to include additional details in Table 1 so that it would have the basic information necessary for the planner to develop their simulations for their studies without always referring back to the requirements language. No change made.		
City of Austin dba Austin Energy	Ballot Comment	Previous TPL Standard balloting included the FERC Order that clarified footnote "b" regarding the planned or controlled interruption of electric supply for an N-1 event. In our view, a Registered Entity's Board of Directors, local public utility commission or customers should determine the acceptable level of service and the associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote. Additionally, with respect to R2 (2.5), the value of annually assessing system stability for years 6-10 is

Organization	Yes / No	Question 2 Comment
		questionable. The requirement for stability assessment in years 6-10 should be limited to new generation interconnections or planned major transmission system improvements with regional impact. The standard should clarify the "material changes" that would necessitate stability planning assessments and documentation. Finally, The R8 requirement to distribute all Planning Assessment results to adjacent Planning Coordinators and Transmission Planners is excessive and cumbersome. Regarding R8, we suggest the following language: "Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners in accordance with the requirements of the applicable Reliability Coordinator. Any Registered Entity with a reliability-related need may submit a written request for the Planning Assessment results and the Transmission Planner or Planning Coordinator shall provide the latest Planning Assessment results within 30 days of such request."
Response: Footnotes 12 and 9 were translated from the BOT approved language from TPL-002-1, Footnote 'b'. No change made. For Requirement R2, Part 2.5, the SDT believes it is important to evaluate Stability when the planners are evaluating new generation additions or changes which can be more than 5 years in the future, as required in NERC Standard FAC-001-0. The SDT discussed defining 'material change' but did not believe that such a definition was appropriate in a continent-wide standard. With the wide variety in sizes and types of systems, the number of parameters that need to be considered, etc., there are too many variables involved. No change made. For Requirement R8, the SDT disagrees that the requirement is excessive and cumbersome and did not make the suggested change. In addition, the proposed language would place requirements on the Reliability Coordinators, who are not included in the Applicability for this standard, and they should not be involved in determining the extent of the distribution of the Planning Assessments.		
Southwest Power Pool Regional Entity	Ballot Comment	I'm voting affirmative, but I'd prefer to avoid having VSLs where the only choice is Severe. I'd like to see either some gradation or we should use a different term to clarify that the requirement is either met or not (binary) instead of Severe VSL.
Response: The SDT is required to follow the guidelines established by NERC and FERC. No change made. No change made.		
Arizona Public Service Co.	Ballot Comment	While AZPS generally supports this standard, AZPS cannot support the violation severity levels that are proposed in the recirculation ballot. AZPS believes the time frames set forth in the proposed security levels are unreasonably short (10 days) and should be extended to 30 days between each elevation in severity level. For these reasons, AZPS has changed its vote to "negative."

Organization	Yes / No	Question 2 Comment
Response: The SDT has followed the accepted guidelines for timeframes in the proposed VSLs. The SDT is required to follow the guidelines established by NERC and FERC. . No change made.		
Balancing Authority of Northern California NCR11118	Ballot Comment	SMUD believes believes that the VRF should be Medium, as are the VRFs for the other requirements related to conducting the assessments, rather than High.
Response: The SDT is required to follow the VRF guidelines established by FERC,.. No change made.		
Black Hills Corp	Ballot Comment	Black Hills is voting against the proposed VRF/VSL's based on the fact that the VRF for R2 was changed from Medium to High without any explanation.
Deseret Power	Ballot Comment	R2 was moved from medium to high without reason. Since it is long term it should remain medium.
California ISO	Ballot Comment	The VRF for Requirement R2 was changed from Medium to High without explanation. The other VRF's for assessment requirements continue to have a Medium VRF designation, and for consistency it would be appropriate for Requirement R2 to continue to have a Medium VRF designation.
Bonneville Power Administration	No	The VRF for R2 was changed from Medium to High without any explanation. Since the time horizon for R2 is Long Term Planning, BPA believes that the VRF should be Medium, as are the VRFs for the other requirements related to conducting the assessments, rather than High.
Arizona Public Service Company	No	With regards to R2, it appears that the VRF has changed from Medium to High without any justification; and with the time horizon of long term planning, AZPS believes there is no justification for changing it from Medium to High.
Idaho Power Company	Ballot Comment	The VRF for R2 was changed from Medium to High without any explanation. The time horizon for R2 is Long Term Planning and the Idaho Power believes that the VRF should be Medium, as are the VRFs for the other requirements related to conducting the assessments, rather than High.
Tucson Electric Power Co.	Ballot	This recommendation is based on the fact that the VRF for R2 was changed from Medium to High without any

Organization	Yes / No	Question 2 Comment
	Comment	explanation. The time horizon for R2 is Long Term Planning and it is believed that the VRF should be Medium, as are the VRFs for the other requirements related to conducting the assessments, rather than High.
Response: In the comment form for this posting, the SDT did address this issue as shown below: R2 – The VRF has been changed to High to reflect the importance of the Planning Assessment and to meet the latest guidelines. No change made.		
MidAmerican Energy Co.	Ballot Comment	Regarding Requirement 8, we do not believe that there is significant risk to the reliability of the BES if an annual Planning Assessment is not distributed to another entity or if a documented response to Planning Assessment comments is not provided within 90 days of a request. Requirement 8 is an administrative requirement that adds little to improve reliability. We recommend that the VRF for Requirement 8 remain "Low", rather than be changed to "Medium".
Response: In assigning the VRF for Requirement R8, the SDT is required to follow the guidelines established by NERC and FERC. No change made.		
Independent Electricity System Operator	Ballot Comment	IESO is generally supportive of the draft of TPL-001-2 as evidenced by our previous AFFIRMATIVE vote during the last ballot. Further, IESO also supported the revisions to Footnote 'b' to Table 1 of the TPL standards under Project 2010-11. That revision was balloted and approved by the ballot pool in February 2011 and filed with FERC for approval in March 2011. The revised footnote has been incorporated into the current draft of TPL-001-2 as Footnotes 9 and 12 but the Commission, by letter to NERC dated May 17, 2011, has requested NERC to provide supplemental information before the revised Footnote 'b' could be approved. In light of FERC's request and the uncertainty regarding the final provisions of these footnotes, coupled with the ongoing work on Project 2010-17 for the revision of the BES definition and development of an Exception Process and the impact that may have, we respectfully suggest that the drafting team delay further work on TPL-001-2 pending FERC's ruling on NERC's petition seeking approval of the transmission planning standards that contain the revised Footnote 'b' to Table 1.
Response: The SDT believes that it is important to continue with the approval of this standard. If FERC directs changes based on TPL-002-1, Footnote 'b', they will be addressed with this project.		
Hydro One Networks, Inc.	Ballot	Hydro One Networks is casting a negative vote. Other than a few changes related to Footnotes 9 and 12 of Table 1 and VSLs, the other changes in the proposed draft are minor. The concerns of the industry on several

Organization	Yes / No	Question 2 Comment
	Comment	important issues have not been sufficiently addressed in this draft. For detailed comments please refer to our submission through the on-line comment form.
Response: Please see responses to on-line comments.		
Platte River Power Authority	Ballot Comment	VRF for R2 should be changed back to Medium. VRF for R8 should be changed back to Low.
Response: The SDT is required to follow the VRF guidelines established by NERC and FERC. . No change made.		
American Municipal Power	Ballot Comment	The VSLs appear to have a very low threshold for a SEVERE violation of the individual standard requirements for a planning standard. Please consider the impact of having arbitrarily low thresholds for SEVERE violations. The way the VSLs are set now, an honest interpretation or a small administrative mistake could result in a very high dollar penalty and would be construed as having a high correlation with causing a cascading outage by the media. I think we all just want the appropriate fines or sanctions for a violation and to have minimal fines or sanctions for accidental interpretations or menial paperwork based violations. Please consider another metric or raising the current thresholds.
Response: The SDT is required to follow the VSL guidelines established by NERC and FERC, which apply to both operations and planning on equal footing. No change made.VSL		
Florida Municipal Power Pool	Ballot Comment	A. Spare Equipment, R2.1.5 - The requirement reaches beyond the FERC directive. The directive was: "Accordingly, the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy." So, the directive is only to address planned outage, not unplanned outages. Also note that the applicability to GSUs is ambiguous. "Transmission" is defined as: "An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems." Is the "point of supply" the generator terminal, or the GSU high side terminal? B. Table 1, under first heading of "Steady State Only", bullet i is open to interpretation. Many utilities use steady state P-V analyses to study voltage stability and design UVLS systems in apart around those steady

Organization	Yes / No	Question 2 Comment
		state analyses. Would this bullet essentially eliminate P-V and Q-V studies and the related use of UVLS? C. R7 is not needed and administrative in nature. Instead is should say that an entity can use as evidence another entity's study, but not in the requirement and rather in the measures. D. R8 is ambiguous, does the requirement require submitting the Planning Assessment only after receiving a written request, or automatic distribution to neighboring PCs and TPs without a written request, and to others with a reliability related need following a written request? E. Table 1, under first heading of "Steady State and Stability", bullet c should be removed since it is duplicative of the standard, and not entirely consistent with the standard (e.g., open to interpretation whereas the standard better clarifies how to study protection system operation)
Response: Requirement R2, Part 2.1.5 ensures BES reliability by requiring the planner to assess the system for long lead time items based on the entities' spare equipment strategy. The footnotes in Table 1 clearly define the way transformers are evaluated. No change made. Table 1, Steady State and Stability, Item I does not restrict the use of UVLS since it only addresses equipment disconnected by end-user equipment. No change made. Requirement R7 ensures that there are no gaps between Transmission Planners or the Planning Coordinators that may cause reliability concerns. No change made. Requirement R8 requires the automatic distribution to neighboring Planning Coordinators and Transmission Planners without a written request and to others with a reliability related need following a written request. The SDT believes this is an important consideration and not ambiguous. No change made. Table 1, Bullet c under first heading, is not in conflict with the requirements. The SDT decided to include additional details in Table 1 so that it would have the basic information necessary for the planner to develop their simulations for their studies without always referring back to the requirements language. No change made.		
MRO's NERC Standards Review Forum	No	The NSRF recommends that the VRF for Requirement 8 remain "Low", rather than be changed to "Medium". We do not believe that there is significant risk to the reliability of the BES if an annual Planning Assessment is not distributed to another entities or a documented response to Planning Assessment comments is not provided within 90 days of a request. The findings in an assessment report are not urgent, but address system needs that will emerge over years in the future. In addition, entities with a reliability related need for Planning Assessment information generally have the means to make their own independent planning assessment of adjacent systems or other areas of interest.

Organization	Yes / No	Question 2 Comment
Minnkota Power Coop. Inc.	Ballot Comment	MPC echoes the comments of the MRO NSRS/F
Lincoln Electric System	Ballot Comment	Refer to comments submitted by the MRO NERC Standards Review Subcommittee.
Response: The SDT is required to follow the guidelines established by NERC and FERC.. No change made.		
Tri-State Generation and Transmission Assn., Inc.	No	Many of the sub-requirements of R2 do not warrant high risk VRFs, yet violation of any R2 sub-requirement would result in a "High Risk Factor" violation assessment. We believe that having so many sub-requirements can result in inaccurate overall severity classification. For example, skipping one study defined in R2.1.2 (Planning Assessments) for a particular time frame or load level would probably not result in a direct actual degradation in system performance, but would still result in a High Violation Risk Factor.
Response: The SDT is required to follow the VRF guidelines established by NERC and FERC, which apply to both operations and planning on equal footing.. No change made.		
Muscatine Power and Water	No	MP&W would like to recommend that the VRF for Requirement 8 remain "Low", rather than "Medium." It is our belief that there is not a significant risk to the reliability of the BES if an annual Planning Assessment is not distributed to another entities or a documented response to Planning Assessment comments is not provided within 90 days of a request. This is more administrative in nature. The findings in an assessment report are not urgent, but address system needs that will emerge over years in the future. Additionally, entities with a reliability-related need for Planning Assessment information generally have the ability to perform their own independent planning assessment of adjacent systems or other areas of interest.
American Transmission Company, LLC	No	ATC recommends that the VRF for Requirement 8 remain "Low", rather than be changed to "Medium". ATC does not believe that there is significant risk to the reliability of the BES if an annual Planning Assessment is not distributed to another entities or a documented response to Planning Assessment comments is not provided within 90 days of a request. The findings in an assessment report are not urgent, but address system needs that will emerge over years in the future. In addition, entities with a reliability related need for Planning Assessment information generally have the means to make their own independent planning assessment of adjacent systems or other areas of interest.

Organization	Yes / No	Question 2 Comment
Electric Reliability Council of Texas, Inc.	No	ERCOT ISO believes that the VRF for R8 should be "low". The distribution of the Planning Assessment is administrative in nature, the failure to distribute the Planning Assessment does not necessarily equate to not communicating the content of the assessment, and the consequence of not distributing the Planning Assessment does not immediately impact the reliability of the BES; thus it does not warrant a 'Medium' risk factor.
Response: The SDT is required to follow the VRF guidelines established by NERC and FERC. No change made.		
ReliabilityFirst	No	ReliabilityFirst generally agrees with the Violation Risk Factors (VRFs) but disagrees with the Violation Severity Levels (VSLs) for the following reasons:1. VSL for R1a. Under the last "Severe" VSL, the word "latest" should be removed to be consistent with the language in Requirement 1. This is a violation of the FERC Guideline 3: "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement"2. VSLs for R2a. To be consistent with the language in Requirement 2, suggest modifying the last "Severe" VSL to state "The responsible entity failed to prepare an annual Planning Assessment of its portion of the BES" 3. VSLs for R3a. Under the last VSL under the "High" category, the word "perform" should be replaced with "simulate" to be consistent with the requirement. (e.g. "The responsible entity did not simulate Contingency analysis as described in Requirement R3, Part 3.3.") 4. VSL's for R4a. Under the last VSL under the "High" category, the word "perform" should be replaced with "simulate" to be consistent with the requirement (e.g. "The responsible entity did not simulate Contingency analysis as described in Requirement R4, Part 4.3."). 5. VSLs for R6a. To be consistent with the language in Requirement 6, suggest modifying the "Severe" VSL to state "The responsible entity failed to define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions, as described in Requirement R6." 6. VSLs for R7a. Suggest adding the following language to the end of the "Severe" VSL; "for the Planning Assessment", to be consistent with the requirement. 7. VSL for R8a. Under all four categories of VSLs, any reference to "Planning Assessment" should be changed to "Planning Assessment results" to be consistent with the language in Requirement 8 (or more appropriately, the term "results" should be removed from Requirement 8). This is a violation of the FERC

Organization	Yes / No	Question 2 Comment
		Guideline 3: "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement" b. Under the "Lower" VSL, it is unclear why there is a 30 day timeframe for the first VSL, while the "Moderate", and "High" VSLs have a 10 day timeframe. Based on FERC recommendations, suggest making the timeframe for all four VSL s, 10 day increments. c. VSLs need to be developed to deal with a violation of Part 8.1 (i.e. the PC or TP failed to provide a documented response to that recipient within 90 calendar days of receipt of those comments)

Response: 1. The SDT has corrected the language used as shown:

R1. VSL – Severe (third part): The responsible entity's System model did not use ~~the latest~~ data consistent with ~~the data~~that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.

2. The SDT believes that the wording shown must be taken in context and thus is clear. No change made.

3. & 4. The SDT believes the word 'perform' is consistent with the language used in the requirement. No change made.

5. The SDT sees the suggested change as unecessary and not providing any additional clarity as it is clear that the analysis is part of the Planning Assessment. No change made.

6. The entire standard is about the Planning Assessment and the SDT believes that this is clear in the language used. No change made.

7. The SDT has made the suggested change as shown below:

R8 VSL	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR,	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR,	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR,	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR

Organization	Yes / No	Question 2 Comment			
		The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

7b. The 30 days shown is according to the established guidelines as are the 10 day increments that follow. The SDT is required to follow the guidelines established by NERC and FERC. No change made.e.

7c. VSLs have been developed with regard to Requirement R8, part 8.1 and were shown in the posted version. No change made.

Organization	Yes / No	Question 2 Comment
ITC	No	ITC recommends revising R8 VSLs as follows:Lower VSLThe responsible entity distributed its Planning Assessment to known adjacent Planning Coordinators and known adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request. Moderate VSLsThe responsible entity distributed its Planning Assessment more than 30days but less than 60 days after subsequent requests by adjacent Planning Coordinators or adjacent Transmission Planners who were not sent copies upon completion of the Planning Assessment. OR, The responsible entity distributed its Planning Assessment to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request High VSLs - eliminate this section. i.e., no high VSLs only lower,moderate and severe Severe VSLsThe responsible entity distributed its Planning Assessment to functional entities having a reliability related need, adjacent Transmission Planners and adjacent Planning coordinators who requested the Planning Assessment in writing but it was more than 60 days following the request.
Response: 1. The suggested wording change is not consistent with the language used in the Requirement. Furthermore, the SDT does not believe that the word 'known' is necessary in this regard. No change made. 2. The suggested wording is not consistent with the language used in the requirement. Furthermore, the increment suggested would violate established guidelines. The SDT is required to follow the VSL guidelines established by FERC. No change made. 3. When dealing with incremental times in VSLs, the established guidelines indicate that all 4 types of VSL should be utilized. No change made. 4. The SDT believes the suggested change makes the VSL less clear. No change made.		
Manitoba Hydro	No	-The language "latest data" is used in the Severe VSL for R1, however "latest" was removed from R1 and M1. "Latest" should also be removed from the Severe VSL for consistency.-What is the rationale for changing the preparation of the Planning
Response: The SDT has corrected the language used as shown: **R1. VSL – Severe** (third part): The responsible entity's System model did not use ~~the latest~~ data consistent with ~~the data~~that provided in accordance with the		

Organization	Yes / No	Question 2 Comment
MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.		
National Grid	No	R 2.0 We recommend that the VRF for this Planning Requirement remain at "Medium". The risks associated with Planning Requirements have a longer time horizon for corrective action than, for example, those risks associated with much shorter Operational time frames.
Response: The SDT is required to follow the VRF guidelines established by NERC and FERC. No change made.		
Independent Electricity System Operator	No	See our response to Q1.
Response: See response to Q1.		
Consumers Energy	Ballot Comment	We agree with comments submitted by MISO
MISO	No	Regarding Requirement 8, we do not believe that there is significant risk to the reliability of the BES if an annual Planning Assessment is not distributed to another entity or if a documented response to Planning Assessment comments is not provided within 90 days of a request. Requirement 8 is an administrative requirement that adds little to improve reliability. We recommend that the VRF for Requirement 8 remain "Low", rather than be changed to "Medium".
Response: The SDT is required to follow the VRF guidelines established by NERC and FERC. No change made.		
New York Independent System Operator	No	Requirement 8 is an administrative burden that adds no value to reliability. Comments have been provided on several past drafts highlighting this effect. The revisions made to the VRF and VSL for Requirement 8 further exacerbate this burden. One could conclude from observation of the VSLs and VRFs, that Requirement 8 was the most important requirement of TPL-001-1.Many Planning Coordinators and Transmission Planners have stakeholder processes that govern participation and notification. Further, FERC Order 890 requires stakeholder participation and transparent processes.
Response: The SDT is required to follow the VRF guidelines established by NERC and FERC.. No change made.		

Organization	Yes / No	Question 2 Comment
Ameren	No	The VRF for Requirement R8 should remain Low. There is no significant risk to the reliability of the BES if a Planning Assessment is not distributed to another entity, or if a documented response is not provided within 90 days of a request. The assignment of some VRFs are inconsistent with the importance of the requirements. R2 requires the development of an assessment and it is determined to have a high VRF. However, R3 and R4 require that studies be performed and these studies are determined to have a medium VRF. Performing the studies is essential to developing an assessment and more important to maintaining reliability. If the VRFs for R3 and R4 are correct, then the VRF for R2 should be no higher than medium. The VRF for R5 to develop a steady-state voltage criteria is determined to be medium. However, the VRF for R6 to develop instability criteria is determined to be low. If the VRF for R6 is correct, then the VRF for R5 should also be low.
Response: The SDT is required to follow the VRF guidelines established by NERC and FERC. No change made. The SDT agrees that studies are essential to the Planning Assessment but believes that the Planning Assessments are more than just the studies. For example, under the correct set of circumstances, an entity can use past studies in their Planning Assessment. Therefore, the SDT believes that the VRFs assigned are correct and in adherence with established guidelines. No change made. The SDT believes that having the criteria (Requirement R5) is more important for the reliability of the BES than documenting the methodology (Requirement R6). No change made.		
SERC Planning Standards Subcommittee	Yes	
SPP Reliability Standards Development Team	Yes	
Entergy Services	Yes	
Imperial Irrigation District	Yes	
Progress Energy	Yes	

Organization	Yes / No	Question 2 Comment
American Electric Power	Yes	
Duke Energy	Yes	
Transmission Strategies, LLC	Yes	
NIPSCO	Yes	
Puget Sound Energy, Inc.	Yes	
South Carolina Electric and Gas	Yes	
Georgia Transmission Corporation	Yes	
United Illuminating	Yes	
TVA TP&C	Yes	
ISO New England Inc.	Yes	
GDS Associates, Inc.	Yes	Agree in general.
Pepco Holdings Inc	Yes	
Northeast Utilities	Yes	
Oncor Electric Delivery Company LLC	Yes	
Response: Thank you for your support.		

3. **If you have any other comments on this Standard that you have not already provided in response to the prior questions, please provide them here.**

Summary Consideration: Several commenters stated that the SDT failed to address significant concerns and that only minor changes were made from the prior draft. The SDT believes that some stakeholders based their review on a red-line document of the TPL standard which only describes changes made following the Quality Review (QR) team review of the standard; shown as a red-line document http://www.nerc.com/docs/standards/sar/tpl-001-2_redline_to_last_posted_110415.pdf. A complete and thorough red-line of all changes made from the prior 3/01/10 ballot period to the version posted on the most recent ballot (concluded on 5/31/11) was posted and communicated after the start of the last comment period. A number of changes were made in response to industry feedback prior to the latest ballot. Those changes can be viewed at: http://www.nerc.com/docs/standards/sar/TPL-001-2_Redline_to_last_balloted.pdf.

A number of commenters indicated they cast a negative vote and recommended the SDT delay further work on TPL-001-2 pending FERC's ruling on the revised Footnote 'b' to Table 1 found in the existing TPL standards. The SDT believes concerns in process efficiency related to this project and FERC's on-going review of the revised footnote 'b' should not be the sole reason for a negative vote on the new proposed TPL standard and that an entity's vote should be based on the technical merits of the standard. The SDT has taken care to ensure footnotes 9 and 12 in combination are written consistently with footnote 'b'. The SDT encourages that any negative ballot based solely on FERC's pending ruling on footnote "b" be revisited.

Some commenters stated they find the new standard to be poorly organized and too prescriptively written and that the existing standards are preferred over the proposed TPL-001-2. The SDT and others in industry, as evidenced by the 74% ballot approval, hold a different opinion in regard to the standard. The SDT believes the comments of one stakeholder well articulate its view of the standard: "The SDT, Observers, and the Industry as a whole have put a tremendous amount of thought and work into the development of this latest draft. While nobody should claim that this latest version is perfect, it is far clearer, more in tune with current industry needs, and much improved compared to the existing approved Standards that it will replace." The SDT believes many important improvements in transmission planning are driven by the proposed TPL-001-2 that will further improve reliability of the Bulk Electric System.

A few commenters questioned the term "non-redundant relay" as used in planning event P5 and asked the SDT to clarify a distinction between a "back-up relay" and a "redundant relay" and proposed the SDT provide a definition for the term "non-redundant". The SDT clarifies that redundant means 'duplicate capability resulting in the same outcome.' A redundant relay is not the same as back-up relaying capability which may result in more Facilities being removed for failure of the primary/redundant relay to operate as designed. The SDT believes this concept is widely understood by most in industry and does not see the need for a NERC Glossary Definition.

Several commenters noted that the standard makes use of new capitalized "defined" terms, yet the definitions proposed in previous drafts were removed from the most recent draft of TPL-001-2. The SDT clarified that two previously proposed

definitions that were part of this project were moved to another standard development project – Project 2010-10, titled "FAC Order 729". The two definitions, "Near-Term Transmission Planning Horizon" and "Year One" were approved by the NERC Board of Trustees on January 24, 2011.

Some commenters indicated that the standard' Implementation Plan should be extended to permit a full 5-years implementation of any Corrective Action Plans required due to short circuit studies. The commenters indicate that these studies are not presently covered by a NERC Reliability Standard and they see this as a significant "raising of the bar" as characterized by other new requirements. The SDT clarified that while a short circuit study requirement is new to mandatory enforceable standards, the SDT does not believe the short circuit study requirements present a significant "raising of the bar" for industry and that good utility short circuit practices are already in place to ensure safe operation of equipment. No extension in the Implementation Plan was made in regard to short circuit studies.

Several commenters stated an opinion that Requirement R1, Part 1.1.2 indicating the models maintained by the Transmission Planners should reflect "known outages … with a duration of at least 6 months", are more appropriately dealt with in the operational studies rather than planning studies and that the item should be removed from the standard. The SDT disagrees with the view that outages of 6 months or more should only be reviewed in the operations timeframe. Such an outage could be for an upcoming construction project requiring certain Facilities to be removed from service for long durations of time one or more years in the future and those situations should be evaluated with sufficient lead time to determine any vulnerabilities and development of sufficient Corrective Action Plans as required. The SDT retained the requirement in the standard.

A number of commenters stated that they believed that there was an inconsistency between Requirement R2, Parts 2.1 and 2.2, since qualified past studies were not allowed for the Long-Term Transmission Planning Horizon case. The SDT clarifies that the requirement to conduct a current annual study for one of the study years in the Long-Term Transmission Planning Horizon is intentional to drive earlier identification of potential Transmission performance limitations and earlier development of Corrective Action Plans (CAP). The study results can be used as qualified past studies as they advance to later years, including moving to the Near-Term Transmission Planning Horizon.

Several commenters stated that they believed that Requirement R2, Part 2.1.5 was ambiguous since it was not clear that the planner did not have to include multiple outages of long lead time components simultaneously. The SDT explained that Requirement R2, Part 2.1.5 does not require simultaneous outages of multiple long lead time components.

Some commenters expressed concerns with Requirement R2, Part 2.4.1 since they were concerned with the ability of planners to adequately model the dynamic behavior of Load. The SDT explained that the "aggregate" dynamic Load model may include high-level assumptions on Load profiles for industrial, commercial, and residential Loads that are applied generically across the planning area study based on the planner's engineering judgment and system knowledge. The model is not required to be "bus" specific.

The SDT appreciates the concern raised by multiple commenters in regard to the inclusion of the 2nd bulleted item of Requirement R3, Part 3.3.1 that states the steady-state Contingency analysis should include subsequent "Tripping of

Transmission elements where relay loadability limits are exceeded". The commenters believe this concern is addressed by PRC-023 and should be removed from the standard. The SDT believes the item is warranted and that TPL studies may earlier identify and flag relay setting concerns based on required Long-Term Transmission Planning Horizon studies. Within the TPL standard, such a concern would have a Corrective Action Plan that would address the issue which would also meet the expectations of PRC-023. The SDT sees this as a defense in depth approach.

A number of commenters expressed concern that Requirement R7 was administrative and was not required. The SDT explained that it believes that the requirement is necessary to ensure that there are no gaps created between the Transmission Planners and the Planning Coordinators when they determine their individual responsibilities.

Several commenters stated that they had concerns with Requirement R8. These concerns are that the requirements create excessive work and should include time limits on requesting the Planning Assessment, are ambiguous, and should include the ability to post the Planning Assessment. The SDT explained that the requirements are only to distribute the Planning Assessment, which should not require a large amount of work, and the requirements are clear that the planners must distribute to adjacent Transmission Planners and Planning Coordinators and others with a reliability need. The SDT further explained that posting the Planning Assessment could meet the requirement to distribute.

Several commenters stated that they believed that Table 1, P2-1 was inconsistent with Footnote 7. The SDT explained that Footnote 7 was included to clarify that "Opening a line section without a fault" could include, but does not always, creating a radial line section with Load and that the planner must evaluate this situation as a part of P2-1.

No requirements were changed as a result of comments received. However, two bulleted items were marked as bullets incorrectly and that formatting has been corrected.

3.1.1 Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2 Tripping of Transmission elements where relay loadability limits are exceeded.

4.3.1.1 Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2 Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3 Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

Organization	Yes/ No	Question 3 Comment
James A. Maenner	Ballot Comment	The medium VRF for R8 should remain at low. Not sharing planning assessments with other entities within 90 days doesn't create a serious or imminent threat to the BES.
Response: The change to a Medium VRF resulted from the Quality Review (QR) conducted by the independent QR team prior to the last ballot. This requirement is seen as more than simply an administrative response to a request but rather a proactive step required of the applicable planner to share results of its system assessment which may include and reflect potential system impacts to neighboring systems. The SDT is required to follow the VRF guidelines established by NERC and FERC. No change made.		
San Diego Gas & Electric	Ballot Comment	Clarity of this standard is getting worse. Our earlier comments did not seem impacting. At this point, we believe the existing TPL-001-0.1, TPL-002-0a, TPL-003-0a and TPL-004-0 provide much better clarify for us to comply with the TPL standards.
Response: The SDT respectfully disagrees with your view. According to results of the last ballot, 74% of the ballot poolsupport the proposed standard. The SDT believes the standard clarifies a number of expectations and that appropriate changes have been made to further improve the future planning and review of the Bulk Electric System's ability to reliably serve users of the system. No change made.		
Western Electricity Coordinating Council	Ballot Comment	It is unknown at this time what the outcome of the FERC request for additional infomation related to footnote B will be, but if if results in changes to the language of footnote B, that may change our support for this standard.
Salt River Project	Ballot Comment	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In SRP's view, a Registered Entity's Board of Directors, state Utilities Commission, and/or its customers should determine what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining Affirmative vote.
Public Utility District No. 1 of Chelan County	Ballot Comment	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In our view, board of directors/Public Utility should have the determination what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote.
Snohomish County PUD No. 1	Ballot	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or

Organization	Yes/ No	Question 3 Comment
	Comment	controlled interruption of electric supply for an N-1 situation. In our view, a Registered Entity's Board of Directors, Utility Commission, and/or its customers should determine what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote.
Public Utility District No. 1 of Chelan County	Ballot Comment	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In our view, board of directors/Public Utility should have the determination what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote.
Clark Public Utilities	Ballot Comment	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In our view, the utility's elected board of commissioners should have the determination what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote.
Response: The SDT has taken care to ensure consistency in footnote 12 (and footnote 9) with the prior footnote 'b' revision supported by industry, approved by the NERC Board of Trustees and submitted for regulatory approval. No change made.		
Imperial Irrigation District		Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In our view, board of directors/Public Utility should have the determination what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote. 1. R2 (2.5): The value of assessing system stability for years 6-10 is questionable. Stability studies should be conducted for new generation interconnections or for planned major transmission system improvements that have regional impact. 2. R8 requirement to distribute all Planning Assessment results to adjacent PCs and TPs are excessive and cumbersome. Regarding R8, IID suggest the following languages:Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners in accordance with the overseeing Reliability Coordinator requirements. Any functional entity that has a reliability related need and submits a written request for the Planning Assessment results, the Transmission Planner and Planning Coordinator shall provide the latest Planning Assessment

Organization	Yes/ No	Question 3 Comment
		results within 30 days of such request.
Response: The SDT has taken care to ensure consistency in footnote 12 (and footnote 9) with the prior footnote 'b' revision supported by industry, approved by the NERC Board of Trustees and submitted for regulatory approval. No change made. Regarding Requirement R2, Part 2.5, the SDT believes the requirement as written meets your perspective. For the long-term period, the stability assessment is only required to address "… the impact of proposed material generation additions or changes in that timeframe …". No change made. Regarding Requirement R8, the SDT disagrees that the requirements for distributing assessment results should be based on requirements of the Reliability Coordinator. The Reliability Coordinator is primarily focused on real-time issues/concerns not planning horizon timeframes. The SDT does not see this requirement as overly burdensome as the results could be emailed to multiple entities in a single notification. Additionally, we do not see Requirement R8 as excessive as we believe it is important to communicate assessment results with others in industry whose systems for which they are responsible for may be impacted by the host analysis being communicated. No changes made.		
Gainesville Regional Utilities	Ballot Comment	I do have one point of concern for your consideration; This standard does raise the bar in some areas, most notably for an entity the size of GVL it applies performance requirements for long lead equipment emergency replacement. For example if we don't have the ability to replace a transformer at Parker within a few months of failure, then we would have to demonstrate that we can meet many (but not all) of the same performance criteria without the transformer that we can with the transformer.
Response: The commenter is referring to expectations stated in Requirement R2, Part 2.1.5 related to a spare equipment strategy regarding the potential unavailability of long lead time equipment that could be out of service for a year or more in the absence of a spare replacement. The SDT believes it has appropriately limited the analysis to address Planning Events P0, P1, and P2 as stated in Table 1. No change made.		
Beaches Energy Services	Ballot Comment	My biggest concern is the spare transformer issue. Beaches Energy Services is fine because our Transmission Planner (FMPA) actually run the assessments proposed in the new standard and we have excess transformer capacity; but, I'm concerned for other small entities. Essentially, the requirement will likely be interpreted as requiring us to meet the loss of a Bulk Electric System transformer, plus another contingency (two contingencies) to the same performance criteria as a single contingency, if we don't have a spare. This seems discriminatory to small entities.
Response: The commenter is referring to expectations stated in Requirement R2, Part 2.1.5 related to a spare equipment strategy regarding the potential unavailability of long lead time equipment that could be out of service for a year or more in the absence of a spare replacement. The SDT believes it has appropriately limited the analysis to address Planning Events P0, P1, and P2 as stated in Table 1. Any organization – large or small - meeting functional entity		

Organization	Yes/ No	Question 3 Comment
registration obligations has the potential to impact the Bulk Electric System and their assessments must include appropriate spare equipment strategies. No change made.		
Hydro One Networks, Inc.	Ballot Comment	Hydro One Networks is casting a negative vote. Other than a few changes related to Footnotes 9 and 12 of Table 1 and VSLs, the other changes in the proposed draft are minor. The concerns of the industry on several important issues have not been sufficiently addressed in this draft. For detailed comments please refer to our submission through the on-line comment form.
Response: The SDT believes the commenter's response is based on their review of red-line document of the TPL standard which only describe changes made following the Quality Review (QR) team review of the standard which was conducted prior to the last ballot. That red-line was shown as http://www.nerc.com/docs/standards/sar/tpl-001-2_redline_to_last_posted_110415.pdf. A complete and thorough red-line of the TPL standard showing all changes made from the prior 3/01/10 ballot period to the version posted on the most recent ballot (concluded on 5/31/11) was posted during the last comment/ballot period. A number of changes were made in response to industry feedback prior to the last ballot. Those changes can be viewed at: http://www.nerc.com/docs/standards/sar/TPL-001-2_Redline_to_last_balloted.pdf. The SDT's response to input provided by the on-line comment form is addressed in responses to Q1 and Q2 above. No change made.		
Hydro-Quebec TransEnergie	Ballot Comment	These are the two major concerns : * In Table 1 footnote 3 : Again, the definition of EHV facilities shoud be changed to something like : Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as those representing the backbone of the System, generally at voltage greater than 300 kV, and high voltage (HV) Facilities defined as those not representing the backbone of the System, as determined by the Planning Coordinator and approved by Regional Entity. * In Table 1 b : "Consequential Load Loss as well as generation loss is acceptable as a a consequence of any event excluding P0". We should also add Firm Transmission Services Loss is also acceptable (particularly in P1 Loss of a single pole of a DC line for which the transfer is reduced accordingly to the remaining pole capability). "
Response: In regard to Table 1 footnote 3, the SDT respectfully disagrees and believes the footnote is clear in regards to what subset of Bulk Electric System Facilities are classified as EHV and that the remaining fall to HV Facilities. Anything not deemed Bulk Electric System by a Regional Entity is outside of the scope of footnote 3 and the footnote clarifies that Table 1 sometimes has unique performance requirements depending on the event studied. The SDT believes the categorization is correct. No change made. The SDT disagrees that Firm Transmission Service (FTS) may be interrupted for all events. The events where the interruption of FTS is not permitted are shown with a "No" in the column titled "Interruption of Firm Transmission Service Allowed", however, footnote 9 clarifies that interruption of Firm Transmission Service		

Organization	Yes/ No	Question 3 Comment
can be used as both a corrective action and system adjustment as permitted within Table 1. For the specific issue raised, loss of a single pole of a DC line, to the extent the availability of the DC pole is a condition of the transfer being viable, footnote 4 may also address the commenter's concern. No change made.		
Independent Electricity System Operator	Ballot Comment	IESO is generally supportive of the draft of TPL-001-2 as evidenced by our previous AFFIRMATIVE vote during the last ballot. Further, IESO also supported the revisions to Footnote 'b' to Table 1 of the TPL standards under Project 2010-11. That revision was balloted and approved by the ballot pool in February 2011 and filed with FERC for approval in March 2011. The revised footnote has been incorporated into the current draft of TPL-001-2 as Footnotes 9 and 12 but the Commission, by letter to NERC dated May 17, 2011, has requested NERC to provide supplemental information before the revised Footnote 'b' could be approved. In light of FERC's request and the uncertainty regarding the final provisions of these footnotes, coupled with the ongoing work on Project 2010-17 for the revision of the BES definition and development of an Exception Process and the impact that may have, we respectfully suggest that the drafting team delay further work on TPL-001-2 pending FERC's ruling on NERC's petition seeking approval of the transmission planning standards that contain the revised Footnote 'b' to Table 1.
Response: The SDT believes IESO's concerns in process efficiency related to this project and FERC's on-going review of the prior submittal of a revised footnote 'b' should not be the sole reason for a negative vote on the new proposed TPL standard and that IESO's vote should be based on the technical merits of the standard. The SDT encourages IESO to revisit its negative ballot position during the recirculation ballot. As stated in the comment provided, IESO finds footnotes 9 and 12 to be written consistently with footnote 'b' and if IESO supported footnote 'b', the SDT encourages continued support of the issue in the new proposed TPL-001-2 and doing so shows support of the standard on its technical merits. No change made.		
Lakeland Electric	Ballot Comment	LAK appreciates the hard work of the Standard Drafting team and applauds the significant improvement of clarity of the draft standard. FMPA believes we are almost there, but, there are a number of issues left to resolve. Issues that Cause FMPA to Recommend a Negative Vote A. Spare Equipment, R2.1.5 - The requirement reaches beyond the FERC directive. The directive was: "Accordingly, the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy." So, the directive is only to address planned outage, not unplanned outages. Also note that the applicability to GSUs is ambiguous. "Transmission" is defined as: "An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems." Is the "point of supply" the generator terminal, or the GSU high side terminal?

Organization	Yes/ No	Question 3 Comment
		B. Table 1, under first heading of "Steady State Only", bullet i is open to interpretation. Many utilities use steady state P-V analyses to study voltage stability and design UVLS systems in apart around those steady state analyses. Would this bullet essentially eliminate P-V and Q-V studies and the related use of UVLS?
Response: The SDT respectfully disagrees that the Commission directive regarding a spare equipment strategy is limited to planned outages. In Order 693, Par 1725, the Commission states in its discussion "Thus, if an entity's spare equipment strategy for the permanent loss of a transformer is to use a "hot spare" or to relocate a transformer from another location in a timely manner, the outage of the transformer need not be assessed under peak system conditions." The SDT believes FERC clearly intended the spare equipment strategy to cover a catastrophic loss of such long lead-time equipment. Further, the SDT believes it has appropriately limited this review to a small subset of the overall Planning Events – P0, P1, and P2 and for a loss that would be sustained for a year or longer. No change made. The SDT refers the commenter to footnote 5 in regards to the applicability of GSU transformers. The "point of supply" is irrelevant in regards to planning a Transmission system for potential generation loss. The applicable generation is any unit deemed to be BES generation supply by the applicable regional entity. No change made. The SDT points out that Table 1 header note "i" applies to steady-state only and is intended to prevent any reduction in non-consequential Load due to what the planner believes to be sensitive Load loss that may drop out as voltage declines. It is the understanding of the SDT that most utilities only reflect or account for such reduction in Load in the transient timeframe and that planning decisions based on steady-state analysis would appropriately account for serving the non-consequential Load unless subject to interruption per that studied planning event. The bullet does not eliminate P-V or Q-V studies nor does it prohibit use of UVLS as a mitigating action where non-consequential load interruption is permitted. No change made.		
New Brunswick Power Transmission Corporation	Ballot Comment	Foot Note 12: Rather than requiring planning entities to have a open and transparent planning stakeholder process, which could require significant costs and administration, the foot note should focus on ensuring that affected loads/entities are aware of the possible risks of load loss and alternatives and provide for affected stakeholder feedback
Response: The SDT believes the open and transparent stakeholder process described by footnote 12 provides an efficient platform for which the affected end-users and other registered entities would be made aware of instances where non-consequential Load loss is being considered as a Corrective Action Plan and provides the best opportunity for feedback. The process envisioned is already in place in various areas across the various Interconnections in which the NERC Reliability Standards are enforceable. No change made.		
Powerex Corp.	Ballot Comment	Powerex has submitted a negative ballot for Draft #6 of Standard TPL-001 because Powerex has concerns regarding Footnotes 9 and 4 that need to be addressed. Details of our concerns are summarized below.

Organization	Yes/ No	Question 3 Comment
		Background: The work that transmission planners do to ensure Firm Transmission Service is tremendously important for the reliability of the Bulk Electric System and forms a key part of the foundation upon which system operators and energy market participants interact. As a Purchasing-Selling Entity, Powerex is primarily concerned about Footnote 9 that conditions when interruption of Firm Transmission Service may allowed. We believe that the goals of maintaining system reliability and enhancing market participation will both be best served if the conditions for interrupting Firm Transmission Service become clear and unambiguous in the TPL-001-2 Standard. In our experience, Transmission Providers have different interpretations of the TPL-001 Performance Table and because of latitude previously granted by Footnote B have different perspectives of when Interuptions of Firm Transfers is acceptable. Below we describe the two interpretations using the language of the proposed TPL-001 standard. Interpretation #1: Following loss of the most critical transmission element under stressed conditions, the transmission provider plans to supply the forecast peak loads and Firm Transmission Service indefinitely. o Typically this is achieved by assuming that the System Operators would, within a few minutes of the P1 Single Contingency, curtail all non-firm transmission service and then arm Special Protection Schemes that could result in Interruption of Firm Transmission Service or Non-Consequential Load Loss in the event of a P6 Multiple contingency. Interpretation #2: Following loss of the most critical transmission element under stressed conditions, the transmission provider plans to supply the forecast peak loads indefinitely but may curtail all Firm Transmission Service within 20 minutes if required. o Typically this occurs on systems where there are no Special Protection Schemes to address P6 Multiple contingencies, consequently, the transmission planners assume that curtailment of all non-firm AND as much Firm Transmission Service as required will occur within ~20 minutes of the P1 Single Contingency because the Operators must prepare their transmission system to withstand the next worst contingency. Currently, Purchasing-Selling Entities must plan for situations where they could see their Firm Transmission Service on certain paths curtailed within 20 minutes of a P1 contingency. The less stringent interpretation of the TPL-001 Performance Table that allowed a P1 contingency to change into a P6 contingency within the same operating hour, has resulted in situations where the Firm Transmission Service for inter-regional transfers face significantly greater risks of interruption than the Firm Transmission Service provided to local Load Serving Entities. Powerex recommends that the Standards Drafting Team revise TPL-001 such that all Transmission Planners will know that they should plan for Firm Transmission Service to be sustained indefinitely following P1 contingencies. Specific Comments on TPL-001-2: Footnote 9: Deviation from the Approved Footnote B Powerex believes that the Footnote B, as approved by the NERC Board of Trustees on February 17, 2011, is more stringent than the previous Footnote B and will have the effect of ensuring that Firm Transmission Service can be sustained indefinitely following P1 contingencies. The key difference of the proposed Footnote 9 is that it adds

Organization	Yes/ No	Question 3 Comment
		the phrase "as a System adjustment" to the approved version of Footnote B. We believe this addition would cause the practice of curtailing Firm Transmission Service within 20 minutes of P1 contingencies to continue. Consequently, we recommend that the proposed Footnote 9 maintain the approved wording as follows: Footnote 9: An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed (deletion)[as] a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch.... For consistency, Table 1 should also be modified to remove the Footnote 9 reference from the Initial Condition Column for the P3-Multiple Contingency and P6 Multiple Contingency Categories. Footnote 9: Clarity on what is meant by "Resources obligated to re-dispatch" It is unclear to many parties what is meant by an obligation to re-dispatch. Some interpret this as a right to direct the Source to curtail energy scheduled on Firm Transmission Service. Our belief is that "an obligation to re-dispatch" should correspond to a formal agreement with a Generation Owner, located on the load side of a transmission constraint, to resupply the load that had been receiving energy from a remote source before the Firm Transmission Service was curtailed. Consequently, we recommend that Footnote 9 be revised as follows: Footnote 9: ..... a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch [to ensure uninterrupted energy supply to the Load-Serving Entity(ies)], where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss.... Footnote 4: Conditional Firm Transmission Service Footnote 4: "Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service." In a sense, offering conditional firm transmission service is analogous to selling land in a known flood plane - this can be a perfectly acceptable option provided all parties involved in current and future transactions can quantify the risks and manage them appropriately. There needs to be coordination between the planners, operators and marketers to ensure that the conditions that could lead to curtailment of Conditional Firm Transmission Service are understood and the associated risks properly managed. We are concerned that in the absence of coordination, specifically additional requirements included in the BAL and INT standards, energy that is scheduled on conditional firm could actually be marketed as firm and as a result the counterparties to some transactions may not be aware of the curtailment risks they could face.
Response: Footnote 9 - The SDT believes that footnote 9 appropriately allows interruption of Firm Transmission Service as both a corrective action to the initial event studied and as a permissible intermediate "system adjustment" when evaluating a multiple Contingency event such as P3 or P6. The key is that there must		

Organization	Yes/ No	Question 3 Comment
be no loss of Load and the planner must be able to show that the curtailment is supported by a valid re-dispatch of generation that would be "obligated to re-dispatch." Therefore, the planner cannot simply re-dispatch units outside the area of control for the transmission system for which it is reviewing – the re-dispatch must be valid and realistic. The commenter indicates an opinion that footnote 9 introduces a difference from the revised footnote 'b' because footnote 9 is applied to multiple Contingency planning events P3 and P6 as an intermediate step – system adjustment. However, the SDT believes that footnote 'b' is consistent as it does not explicitly distinguish between the two – corrective action or system adjustment following the single Contingency event that may precede a multiple Contingency event. No change made. Footnote 4 – The SDT agrees with the commenter that the specifics of Conditional Firm Transmission service including the potential/rights for curtailments need to be well understood by all parties involved but the SDT has not identified any BES reliability gaps. No change made.		
Tucson Electric Power Co.	Ballot Comment	The definition for Near Term Planning Horizon was deleted, but the formal term is used in other sections such as R2.2.1. There should be a linkage to MOD standard (e.g. 028, 029 & 030) definitions such as 13 months, etc.
Response: Two previously proposed definitions that were part of this project were moved to another standard development project – Project 2010-10 titled "FAC Order 729". The two definitions, "Near-term Transmission Planning Horizon" and "Year One" were approved by the Board of Trustees on January 24, 2011.		
Western Area Power Administration	Ballot Comment	Standard is improved over previous drafts, but would like to see further changes. Please see suggestions and comments provided on the Official Comment Form.
Response: Please see the SDT's response to your suggestions in Question 1.		
SERC Planning Standards Subcommittee		R1 does not seem to address issues where data errors have been introduced into the latest model data. Also, R1 and its VSL may be interpreted to exclude the use of past studies. The Implementation Plan should include a five-year delay in the effective date for short circuit studies (R2 parts 2.3 and 2.8) since these studies are not required in the current version 0 standards. The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Response: Requirement R1 of the new TPL standard requires the Transmission Planner and Planning Coordinator to maintain System models within its		

Organization	Yes/ No	Question 3 Comment
respective area of responsibility. The requirement indicates that information received via MOD-010 and MOD-012 shall be "supplemented by other sources as needed" and to the extent errors and omissions were either discovered by, or brought to the attention of, the Transmission Planner or Planning Coordinator Requirement R1 establishes an expectation that these "other sources" would be utilized to accurately "represent the project System conditions" being studied. No change made. Requirement R1 is applicable to models used for both current and past studies. No change made. Implementation Plan, Short Circuit Studies – While short circuit study requirements may be new in the realm of mandatory enforceable standards, the SDT does not believe that they present a significant "raising of the bar" for industry. The SDT believes that prudent short circuit practices are effectively in place today to ensure safe operation of the equipment. Therefore, no extension in the Implementation Plan was made in regard to short circuit studies.		
SPP Reliability Standards Development Team		A5 It would seem that 84 months wouldn't be universally attainable due to different system configurations, terrain, geography, and permitting issues that are required to complete a corrective action plan. In 2.4.1 we would like to see better clarity on what an Aggregate system load model is and how granular it should be. If the answer is a very detailed representation of the load system then it may take a longer time to implement. In section 2.7 we would to see clarification on the sensitivity analysis. Is this in reference to seasonal models and differences in fuel availability? We need more detail on how this is to be done so that it won't be left up to interpretation. We would like for clarification of the planning assessment and who is performing which tasks. We would also like to utilize a regional assessment due to limited resources. Under which criteria should the assessment fall under the regional entity or the individual companies? In section 3.4.1 this type of coordination could be difficult due to other adjacent entities on different schedules and some possibly couldn't have the amount of detail to incorporate into another's processes. We know this is generally covered in coordination of real time operations and wonder if it is appropriate to require this type of coordination in the long term process. Is there already an operational standard that covers this? Would it be better to address this in the operational standards? PC's between regions are already coordinating for long term studies. Should this standard fall more on the back of the PC's rather than the TP Can we get a bright line definition of what apparent impedance swings means? R4.3.1 will the detailed amount of data then be incorporated back into the NERC modeling processes and create a more detailed model with better accuracy?

Organization	Yes/ No	Question 3 Comment
		R8 We do not agree that we should provide the assessment to every adjacent PC and TP. We do agree however that if requested by these entities we would provide the assessment. We don't mind sharing information with requestors but would like a longer duration than 30 days due to the fact that we would like to know what type of "reliability need" any entity would have considering that some of the information could be considered CEII. Non disclosure agreements may be needed in order to provide this information.

Response: Effective Date (A5) – The SDT believes the 7 year (84 month) transition to areas where the standard significantly raises planning expectations over the existing standard is more than sufficient for the vast majority of the continent and for most Corrective Action Plans. To the extent additional time is required an entity would need to submit a timely mitigation plan with its Regional Entity organization. No change made.

The "aggregate" dynamic Load model may include high-level assumptions on Load profiles for industrial, commercial, and residential Loads that are applied generically across the planning area study based on the planner's engineering judgment and system knowledge. The model is not required to be "bus" specific. No change made.

In Requirement R2, Part 2.7, it is stated that a Corrective Action Plan is not required solely for a "single sensitivity study". The standard envisions a portfolio of sensitivity analyses being established for a planning area and the standard does not require Corrective Action Plans for single sensitivity results that may have placed the system in a greater stressed analysis (i.e., heavy system transfers) for its initial (P0) sensitivity model over other models that did not identify performance criteria violations for the same Contingency event studied. No change made.

If a Regional Entity acts as your "Planning Coordinator" then tasks between the Planning Coordinator and Transmission Planner are to be defined as part of Requirement R7. The standard does not prohibit the use of valid studies performed by 3rd parties for a given planning area. No change made.

In regards to Requirement R3, Part 3.4.1, the SDT envisions that knowledge of the applicable Contingencies on neighboring systems would develop over time and be discovered with the results being distributed in Requirement R8. The SDT believes that this is an important improvement to the planning timeframe analysis and that system information learned in the operations environment should most certainly be considered to the extent it improves the robustness of the Planning Assessment. No change made.

Both the registered Transmission Planner and Planning Coordinator have functional entity responsibility for Transmission system planning as defined by NERC's Functional Model. The SDT believes the new TPL-001-2 is appropriately aimed at both throughout the standard. Additionally, Requirement R7 should address the commenter's concern and if greater responsibility can be agreed upon for the Planning Coordinator for a particular area of the continent the standard would not prohibit such a determination. No change made.

The "apparent impedance swing" is the trajectory of changes in the apparent impedance seen by a distance relay for various system and fault conditions. In the case contemplated in Requirement R4, Part 4.1.2, it is the trajectory seen by the distance relay for the initial fault and the subsequent generator(s) pulling out of synchronism. If that trajectory were to come within the tripping characteristic of the relay for a sufficient length of time, the relay would cause its associated line

Organization	Yes/ No	Question 3 Comment
to trip. No change made. This standard does not address the studies performed by NERC or its model building practices. The SDT and (based on the recent ballot approval of 74%) the majority of industry support Requirement R8 – no change made.		
MRO's NERC Standards Review Forum		The NSRF recommends that the term, "System" be replaced with "BES" in various places throughout the standard when the reference should not be to the collective generation, transmission, and distribution systems, which is the definition of the NERC Glossary term, "System". These locations are: R2.1.4, R2.1.5, R2.4.3, R2.6.2, R2.7, R2.7.1, R2.7.4, R2.8.1, R2.8.2, R3.5, R4.5, R5, and R6
Muscatine Power and Water		MP&W recommends that the term "System" be replaced with "BES" in various places throughout the standard when the reference should not be to the collective generation, transmission, and distribution systems. This is the current definition of the NERC Glossary term "System". The locations where "System" can be found in the Standard are: R2.1.4, R2.1.5, R2.4.3, R2.6.2, R2.7, R2.7.1, R2.7.4, R2.8.1, R2.8.2, R3.5, R4.5, R5, and R6.
Response: Even though the capitalized term "System" includes distribution components, the SDT believes that its usage within this standard is correct because the Reliability Standards apply only to the BES. Therefore, adding additional qualifiers is not needed. No change made.		
BC Hydro		BC Hydro agrees with merging the standards together into one and we feel the new version brings further clarity to the annual planning assessment. BC Hydro would vote Affirmative for bringing clarity, however we do not believe the rewording in Footnote 9 is clear which is why we are voting Negative. Footnote B, as approved by the NERC Board of Trustees on February 17, 2011 was reworded as Foot Note 9 in the proposed TPL 001-2 draft 7 amendment. This rewording still does not clearly define what impact the proposed revision would have on the curtailment of firm transfers in the regional entities.
Response: The equivalent of the revised footnote 'b' as approved by the NERC Board of Trustees on February 17, 2011 is addressed by the combination of two footnotes – footnote 9 and footnote 12 – in the new proposed TPL-001-2 standard. The SDT believes that footnote 9 appropriately allows interruption of Firm Transmission Service as both a corrective action to the initial event studied and as a permissible intermediate "system adjustment" when evaluating a multiple Contingency event such as P3 or P6. The reliance on the interruption of Firm Transmission Service in the Planning Horizon is limited in two ways. First, there must be no planned use of firm Load shedding and second, the planner must be able to demonstrate that the curtailment is supported by a valid re-dispatch of generation that would be "obligated to re-dispatch." Therefore, the planner cannot simply re-dispatch units outside the area of control for the transmission system for which it is reviewing – the re-dispatch must be valid and realistic. No change made.		

Organization	Yes/ No	Question 3 Comment
Entergy Services		Footnote 12 to Table 1 concerning non-consequential load loss should be clarified. The existing language will result in difficulties in proving compliance. Suggested language would be:"Planned or controlled interruption of Demand supplied by Transmission Facilities made temporarily radial as a result of a P1 or P2 event and where the location of the planned loss of Demand is limited to those Transmission Facilities made radial.
Response: The SDT in a separate standards development project - Project 2010-11 TPL Table 1 Order – attempted the radial concept described by the commenter in its revision of footnote 'b' as used in the existing set of TPL standards. The proposed "radial" footnote 'b' was presented for industry ballot from 05/17/10 through 05/27/10 and failed at 63.8%. Following an industry technical conference, the SDT continued to work on footnote 'b' and a revised version was approved by the NERC Board of Trustees on February 17, 2011. The combination of footnotes 9 and 12 consistently apply the industry approved revised footnote 'b' in the new standard. No change made.		
Tri-State Generation and Transmission Assn., Inc.		R1.1 to "System models used for Steady State and Stability Analysis shall represent:" Much of what is in R1.1 is unnecessary for Short Circuit studies. In contrast, there are items not mentioned in R1.1 that are necessary for short circuit studies. R2.1.4 requires sensitivity analysis to study "a range of credible conditions that demonstrate a measurable change". How will the required actions in R2.1.4 be documented or measured, and what is accomplished by performing sensitivity analysis in the context of a system performance assessment? In R2.3, change the first sentence to read "The short circuit analysis portion of the Planning Assessment shall be conducted annually, using one of the cases described in 2.1.1, addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6." There appears to be no reason to perform short circuit studies for all three Near-Term Transmission Planning Horizon cases. R2.4.3 requires sensitivity analysis to study "a range of credible conditions that demonstrate a measurable change". How will the required actions in R2.4.3 be documented or measured, and what is accomplished by performing sensitivity analysis in the context of a system performance assessment? R2.7.1 remove the last bullet. We believe these programs are already factored into the load forecast, as they are associated with resource scheduling and planning load serving, and not transmission planning. In particular, DSM measures would fall under R2.4.1, and the term "new technologies, or other initiatives" The language of Requirement 3 unnecessarily repeats the language of R1 and R2. As now written, R3 states "For the steady state portion of the Planning Assessment, each Transmission Planner and Planning

Organization	Yes/ No	Question 3 Comment
		Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1." R3 We recommend that the introductory language in Requirement R3 be changed to read "The studies in Requirement R2, Parts 2.1, and 2.2 shall be performed using models as defined in Requirement R1 in accordance with the following criteria." We believe that Requirements 3.1 and 3.4 should be combined into R3.1, eliminating R3.4. It is redundant to have Requirement 3.1 say "perform R3.4". We recommend that R3.4 be deleted and that R3.1 be replaced with:R3.1 Planning event studies shall be performed in accordance with "Table 1 - Steady State & Stability Performance Planning Events;" and shall be based on a supportable Contingency list. Comment: The content of 3.4.1 was intentionally omitted as it is redundant with R7. Also, the language "...more severe System impacts..." was intentionally omitted as it could be subject to a wide range of interpretations.Similarly, we recommend that R3.5 be deleted and that R3.2 be replaced with:R3.2 Extreme event studies shall be performed in accordance with "Table 1 - Steady State & Stability Extreme Events;" and shall be based on a supportable Contingency list. We recommend the following new requirement be inserted after the revised R3.2 language:Should the extreme event studies identify potential Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted. Comment: As before, the language "...more severe System impacts..." was intentionally omitted as it could be subject to a wide range of interpretations. We recommend removing the second bullet of R3.3.1, "Tripping of Transmission elements where relay loadability limits are exceeded" for the following reasons:1. There is currently no tool to model relay loadability characteristics in Steady State analysis. 2. Requirement R3.3.1 would require inclusion of relay models in modeling data that are not currently provided. MOD-012 does not require impedance or overcurrent relay models to be submitted.3. In Requirement 3.3.1, the second bullet, it is impossible to model complete and accurate relay loadability using present-day steady state simulation tools. At best an individual point could be chosen to model relays based on a selected power factor. We recommend changing the opening text of Requirement R.3.3.2 to say "Simulate the expected automatic or manual operation..." Subrequirement R4.1.2 represents a tremendous increase in dynamic modeling complexity. Modeling relay

Organization	Yes/ No	Question 3 Comment
		action during apparent impedance swings would require inclusion of impedance relay models in modeling data that are not required to be submitted in MOD-012. If such modeling is necessary, then the corresponding data requirements need to be addressed in MOD standards. We believe that Requirements 4.1 and 4.4 should be combined into R4.1 as shown below and R4.4 should be deleted. It is redundant to have Requirement 4.1 say "perform R4.4." We recommend R4.1 language be revised to read as follows:R4.1 Planning event studies shall be performed in accordance with "Table 1 - Steady State & Stability Performance Planning Events;" and shall be based on a supportable Contingency list.Comment: The content of 4.4.1 should be omitted as it is redundant with R7. Also, the language "...more severe System impacts..." should be omitted as it could be subject to a wide range of interpretations. Similarly, R4.5 should be deleted and R4.2 should be replaced with:R4.2 Extreme event studies shall be performed in accordance with "Table 1 - Steady State & Stability Extreme Events;" and shall be based on a supportable Contingency list. We recommend the following new requirement be inserted after the revised R4.2:Should the extreme event studies identify potential Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the even(s) shall be conducted. Comment: As before, the language "...more severe System impacts..." was intentionally omitted as it could be subject to a wide range of interpretations. Clarify the first bullet in Requirement R4, part 4.3.1 by changing it to "High-speed (less than 1 second) reclosing, where the fault has cleared, and high-speed reclosing into the permanent fault , but in each case only if high-speed reclosing is utilized". In Requirement R4, part 4.3.1, third bullet, it is impossible to model complete and accurate relay loadability using present-day steady state simulation tools. Existing applications do have impedance relay models, but these models do not model many relay capabilities- for example, non-circular protection regions and load-encroachment. We recommend removing this bullet. The comment statement we made above referring to R4.1.2 also applies to R4.3.1. MOD-012 does not require reclosing relay model data to be submitted. If such modeling is necessary, then the corresponding data requirements need to be addressed in MOD standards. Furthermore, there is not a standard built-in reclosing relay model in current stability simulation tools. Comments regarding Table 1-We assume the headnote i. to Table 1 - "The response of voltage sensitive Load..." - means that studies must not rely on end-user load tripping to meet the performance requirements defined in TPL-001-2 but that it should be modeled (when known) so that its occurrence would be evident.

Organization	Yes/ No	Question 3 Comment
		We don't see the need to apply Footnote 12 to only certain contingency categories or certain events in categories. Recommend putting the footnote in the column header just as with Footnotes 1, 2, 3, and 4.Recommend changing "utilized" in Measurement M3 to "performed."Recommend changing "utilized" in Measurement M4 to "performed."Modify Measurement M7 to "Each Planning Coordinator shall provide dated documentation on roles and responsibilities of its Transmission Planners, such as..." The deleted phrase, "in conjunction with each of its Transmission Planners," appears to be unnecessary.

Response: Requirement R1, Part 1.1 – The SDT believes that the planners must have the general information in Requirement R1, Part 1.1 in order to conduct the necessary studies for steady state, stability, and short circuit. The requirement states that the planner shall maintain System models, not to have a single model that covers all three categories. The SDT believes that the planner will need the items in Requirement R1, Part 1.1 to develop the smaller set of items that are necessary for their short circuit models. No change made.

Requirement R2, Part 2.1.4 – This item requires the planner to show evidence of one or more sensitivity studies which show appreciable change from the prior projected (P0) system condition (pre-sensitivity adjustment). Measurable changes for the revised P0 system condition could be evidenced by line or transformer flows, voltages, a change in dispatch, load increase, etc., assuming the change places additional stress on a portion of the system being reviewed for the sensitivity studied. The sensitivity analysis is important for the applicable entity to better understand their system's vulnerability to alternate "base (P0)" conditions. The intent is to develop a portfolio of potential credible conditions so that the planner better understands potential vulnerabilities. In the Corrective Action Plans (CAP) area of the standard, Requirement R2, Part 2.7, a CAP may be required if a Planning Event shows performance criteria concerns for one or more sensitivity scenarios. No change made.

Requirement R2, Part 2.3 – The standard states that the planner shall maintain System models, not to have a single model that covers all three categories - for steady state, stability, and short circuit. It is common within many organizations that separate models are maintained for short circuit analysis since they require breaker configuration details not contained within steady-state load flows. Additionally, short circuit models may not have end-use Load represented but rather emphasis is on system topology, impedance, generation dispatch, fault location etc. No change made.

Requirement R2, Part 2.4.3 – same response as Requirement R2, Part 2.1.4 above.

Requirement R2, Part 2.7.1 – The SDT disagrees that the last bulleted item which includes use of a rate application or DSM program would be inclusive to the forecasted Load within the model studied. No change made.

Requirement R3 – The SDT clarifies that Requirement R2 refers to an "annual assessment" which collectively includes current or past studies, Corrective Action Plans, etc. required for steady-state, stability, and short circuit analysis. Requirement R3 deals with a portion of the overall assessment and is focused on the

Organization	Yes/ No	Question 3 Comment
steady-state "study" requirements for the Near-Term and Long-Term Transmission Planning Horizons. No change made. Requirement R3, Part 3.1 – The SDT did not receive any significant industry objection to having Parts 3.1 and 3.4 separated. The proposed change is based on a formatting and style preference and does not address a reliability gap in the standard. No change made. Requirement R3, Part 3.2 – The SDT did not receive any significant industry objection to having Parts 3.2 and 3.5 separated. The proposed change is based on a formatting and style preference and does not address a reliability gap in the standard. No change made. Requirement R3, Part 3.4.1 and Requirement R7 are uniquely different and not redundant as suggested by the commenter. No change made. Requirement R3, Part 3.5 (proposed new 3.2 by commenter) – The commenter finds the term "more severe System impacts" too open to interpretation and suggests a focus on Cascading conditions. The SDT believes the requirement is clear as written and that the statement "more severe System impacts" is used to describe the latitude in engineering judgment afforded to the planner in developing its extreme Contingency list. Action is only required on the subset of items that show the potential for Cascading. No change made. Requirement R3, Part 3.3.1, bullet 2 – this does not require an "automatic" modeling feature but rather it could be further subsequent manual analysis performed as needed for a given Planning Event. For example, if a line flow shows >150% loading the planner may need to trip the circuit to see if a stable condition results and what performance criteria issues may be present. To the extent this could be automated through programming the planner may do so at their discretion. No change made. For similar reasons stated in the response to Requirement R3, Part 3.5, the SDT does not find the phrase "more severe System impacts" as vague and open to interpretation. No change made. Requirement R3, Part 3.3.1 - The SDT language does not require comprehensive relaying models. No change made. Requirement R3, Part 3.3.2 - The SDT does not believe the proposed wording changes provide any clarity and finds the item clear as stated. No change made. Requirement R4, Part 4.1.2 – The "apparent impedance swing" is the trajectory of changes in the apparent impedance seen by a distance relay for various system and Fault conditions. In the case contemplated in Requirement R4, Part 4.1.2, it is the trajectory seen by the distance relay for the initial Fault and the subsequent generator(s) pulling out of synchronism. If that trajectory were to come within the tripping characteristic of the relay for a sufficient length of time, the relay would cause its associated line to trip. With that explanation, the SDT does not believe the modeling requirements are overly complex or difficult to achieve. No change		

Organization	Yes/ No	Question 3 Comment
made. Requirement R4, Parts 4.1 and 4.4 - The SDT did not receive any significant industry objection to having Parts 4.1 and 4.4 separated. The proposed change is based on a formatting and style preference and does not address a reliability gap in the standard. No change made. Requirement R4, Part 4.5 - the SDT does not believe the proposed wording changes are warranted and finds the item clear as stated. No change made. Requirement R4, Part 4.3.1, first bullet – the SDT does not believe the proposed wording changes are warranted and finds the item clear as stated. No change made. Requirement R4, Part 4.3.1, third bullet – The SDT language in Requirement R4, Part 4.3.1 states "The analyses shall include the impact of subsequent" and does not require comprehensive relaying models. However, it does require that the planner take into account the effects of System Protection on System performance. No change made. Table 1 header note "i" – The SDT notes that this item only applies to steady-state load flow analysis and no assumed shedding of non-consequential sensitive Load is permitted for the steady-state analysis unless it is to be intentionally dropped as part of a Corrective Action Plan where warranted. No change made.		
Hydro One Networks Inc.		A. Regarding Requirement 1.1.2, assessment of "known outages... with a duration of at least 6 months", are dealt with in the operational studies rather than planning studies. In addition, any adverse impact that these outages might have, are mitigated by operational decisions rather than "planning" decisions within a 6-month horizon. It is suggested to move this requirement out of TPL standards and instead include it a relevant operational standards. B. The statement in R 2.1.4, "must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response", leaves room for very different interpretations by PCs and TPs as to the number and type of required sensitivity studies. Are all interpretations, based on the engineering judgment of the PC and TP, acceptable? C. The language of R 2.1.4 and 2.4.3 allowing to perform one or more sensitivities appears to be inconsistent with the language in R 2.7.2 which requires multiple sensitivities to determine if actions to resolve performance deficiencies are necessary. Will varying only one measurable quantity several times in multiple simulations constitute multiple sensitivity studies or one sensitivity study?

Organization	Yes/ No	Question 3 Comment
		D. The language of Requirement 2.1.5, "spare strategy", appears to be open-ended regarding the number of permutations to be analyzed. It is suggested to move this requirement out of TPL standard and instead have this issue dealt with in the operational standards. E. In R 2.2, the statement "be supported by the following annual current study, supplemented with qualified past studies" should be replaced with a similar statement in R 2.1 which says: "be supported by current annual studies or qualified past studies". F. In R 4.1.1, "For planning event P1: No generating unit shall pull out of synchronism" is too restrictive. In many cases a P1 event may result in instability of a small nearby generator without a significant impact on the reliability of BES. The same requirement states that "A generator being disconnected from the System ... by a Special Protection System is not considered pulling out of synchronism". If rejection of ANY generator by SPS is acceptable, why should instability of a small generator, resulting in its disconnection by its protection without a severe impact on the system, be unacceptable in all circumstances? If this requirement is unchanged, it dictates the addition of an SPS (Generation Rejection) for any unit that might go unstable without any benefit for the reliability of the BES. G. In Table 1, Event 1 of Category P2 and related Footnote 7 (simulation of LEO condition) are not clear (concern with the use of the word "possibly"). If the intension is to simulate LEO condition of tapped lines, this should be clearly stated in the table (without reference to "Opening of a line section" and use of different language in the footnote).

Response: A: The SDT disagrees with the view that outages of 6-months or more should only be reviewed in the operations timeframe. Such an outage could be for an upcoming construction project requiring certain facilities to be removed from service for long durations of time and those situations should be evaluated with sufficient lead time to determine any vulnerabilities and development of sufficient Corrective Action Plans as required. No change made.

B. The standard does not mandate the number of sensitivity analyses performed nor the number of adjustments made and engineering judgment of the Transmission Planner and Planning Coordinator is acceptable. No change made.

C. Requirement R2, Parts 2.1.4 and 2.4.3 are not inconsistent with Requirement R2, Part 2.7.2. With the various requirements, the planners are required to conduct multiple sensitivities. Therefore, Requirement R2, Part 2.7.2 could be used when the results of these multiple sensitivities identify common concerns. The situation described ~~would~~ could be considered multiple sensitivity studies, if the multiple simulations represent more than one of the studies in Requirement R2, Part 2.1.1 and 2.1.2 or Requirement R2, Part 2.4.1 and 2.4.2. No change made.

D. The spare equipment strategy is an important planning aspect to better assist operations. The SDT disagrees that the number of permutations is open-ended. The evaluation is simply a new P0 condition starting with a long lead-time (one year or more) facility removed from service followed by an analysis

Organization	Yes/ No	Question 3 Comment
covering the P0, P1 and P2 studies. No change made. E. The requirement for an annual current steady-state study in the Long-term Transmission Planning Horizon is intentional to drive earlier identification of potential transmission performance limitations and earlier development of Corrective Action Plans. The study results can be used as qualified studies as they advance to later years, including moving to the Near-Term Transmission Planning Horizon. No change made. F. The SDT respectfully disagrees with the commenter. For a P1 single Contingency event, the SDT believes, and a majority of industry stakeholders find it reasonable, that no Bulk Electric System (BES) generation unit be pulled out of synchronism due to the P1 event studied. If the "small" nearby unit is served below threshold kV and MW size limitations set by your Regional Entity to qualify as a BES unit, the unit would not be within scope of the standard. No change made. G. Table 1, footnote 7 – The SDT added the footnote to further explain its intent for P2-1 and to ensure that the planner assess the voltage of a load bus that was on a radial line. The word "possibly" was used since having load on a radial is not always the outcome of opening one end of a line section. No change made.		
Arizona Public Service Company		AZPS would like to reiterate its "Affirmative" voting recommendation with regard to the proposed revisions to the Standard. AZPS erroneously entered a "Negative" Standard vote for one of its voting segments.
Transmission Strategies, LLC		The SDT, Observers, and the Industry as a whole have put a tremendous amount of thought and work into the development of this latest draft. While nobody should claim that this latest version is perfect, it is far clearer, more in tune with current industry needs, and much improved compared to the existing approved Standards that it will replace.
Response: Thank you for your support.		
NIPSCO		1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. This is a little confusing to me. Does this mean the outage must last at least six months?Or does this mean at least model outages that last six months or more. If it is the latter then, I'm not sure that is stringent enough.There may be known critical outages occurring over peak that do not last 6 months. If non-consequential load loss is not allowed for loss of one element, then what about the next contingency? Couldn't that result in having to interrupt Firm service? Is that okay as a corrective action plan in the outage coordination horizon?Does this apply to both near-term and long-term planning? If so, we probably need to model additional unplanned potential outages on top of n-1 conditions.

Organization	Yes/ No	Question 3 Comment
		Lastly. in section 2.1.4 should there be a category for high/low wind conditions?
Response: Requirement R1, Part 1.1.2 is related to known existing conditions or known future conditions of facilities being removed from service; i.e., a construction project that requires an existing facility to be de-energized for a period of 6-months or more. This requirement should not be confused with hypothetical situations that could result in an extended loss of a facility. Those situations are the intended purpose of a sound spare equipment strategy. The standard only requires analysis of known or planned outages of 6-months or greater to be included within a P0 system condition. The planner could review shorter duration planned outages as part of its sensitivity analysis portfolio. No change made. The SDT does not believe there is a need to account for a high/low wind condition situation. The intended purpose of this suggested condition within the sensitivity portfolio is not clear. No change made.		
ReliabilityFirst		1. Requirement 8 and 8.1 uses the language of "Planning Assessment results". This language is not defined in the section of the standard that defines the terms of use. For consistency "Planning Assessment results" should be replaced with "Planning Assessment". 2. Requirement 2.1.5 has statements that are ambiguous. What is considered major transmission equipment? What is an entity's "spare equipment strategy"? The requirement is not clear as to how many power flow models are required (one per piece of "major transmission equipment" without a spare, or one model with every piece of "major transmission equipment" without a spare being out of service)? As written, if an entity has no "spare equipment strategy" they could be exempt from this requirement. 3. We interpret the use of bullet points in Requirement 3.3.1 to mean that either one of the statements can be chosen. This requirement should be written where all the bulleted statements are included in the analyses.
Response: 1. The SDT sees no reliability reason or clarity for the change suggested. No change made. 2. Requirement R2, Part 2.1.5 is intended to analyze the removal of a single piece of long lead time equipment (one year or more) to the extent there is no existing spare equipment strategy to provide a means of returning to service (in a less than one year) a comparable replacement. If this condition exists, then the facility (single element) in question must be removed in the model to establish a new P0 system condition and studies must then be run for P0, P1, and P2 for the new system scenario. The spare equipment strategy must be reviewed for the entity's system exposure to catastrophic failures resulting in the long lead-time facility outages, however, only one facility must be removed at a time if the condition exists for multiple facilities. A Transmission Planner may have no spare equipment strategy if they are able to demonstrate they are not responsible for any facilities which they believe could place them in a "long lead-time" scenario. No change made.		

Organization	Yes/ No	Question 3 Comment
3. The bulleted items of Requirement R3, Part 3.3.1 were meant to be inclusive. This means that the use of bullets here was incorrect and the items should be numbered elements. This same change was made to Requirement R4, Part 4.3.1. **3.3.1.1** Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. **3.3.1.2** Tripping of Transmission elements where relay loadability limits are exceeded. **4.3.1.1** Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized. **4.3.1.2** Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. **4.3.1.3** Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.		
ITC		ITC COMMENTS on TPL-001 voteITC will reluctantly vote to approve the draft standard. While we have concerns, we are voting to approve this standard because we believe the positive elements outweigh the portions of the draft standard that we object to. It is important that the improved requirements that effectively "raise the bar" over the existing standard should become effective sooner rather than later. A negative vote, which might cause a further delay in implementation of the standard, would be the least desirable outcome. However, we still believe that the VSL that would find that an entity had committed a "severe" violation for failure to distribute its planning assessment to an adjacent Transmission Planner or Planning Coordinator has the potential to overly punish a simple error in oversight. We would agree that willfully withholding an assessment from a neighbor or a valid requestor justifies a severe violation but an administrative or clerical oversight does not. For example, it might escape our attention that an entity, particularly a smaller one, registers as a TP or TP. As far as we know, there is no requirement that a registrant, or even one who de-registers, must notify an "adjacent" TP or PC of their change in status. As written, the standard requires you be found in "severe" violation, even if that new entity fails to notify you of their change in status. You would still be in severe violation even if they later ask for your planning assessment. Even if the standard passes, we request that this VSL be fixed to make the distinction between an administrative error and willful neglect. Our response to question 2 offers a suggested method to do this.
Response: Requirement R8 is an important aspect of the new TPL-001-2 standard to communicate results with neighboring systems and those demonstrating a reliability need. The SDT notes that the VSL Guidelines require a Severe VSL for each and every requirement but encourages graded (multiple level) VSLs where		

Organization	Yes/ No	Question 3 Comment
possible. In regard to Requirement R8, the SDT has established four VSLs. It is noted that an entity can be up to 120 days (~ 4 months) late in its delivery of the information and remain in the Lower VSL category before being exposed to the Severe VSL category. The 10 day increment in the other VSL categories, above the 120 day Lower VSL, conforms to NERC's VSL Guidelines. See the response to your suggested VSL changes in Question 2, however, it is noted that no changes were made to the Requirement R8 VSLs. No change made.		
South Carolina Electric and Gas		R1 does not seem to address errors in data that have been introduced in the latest model data. In addition, R1 and its VSL may be interpreted to exclude the use of past studies. The Implementation Plan should include a five year delay in the effective date for short circuit studies for parts 2.3 and 2.8 of R2 because these studies are not required in the current Version 0 standards.
Response: Requirement R1 of the new TPL-001-2 standard requires the Transmission Planner and Planning Coordinator to maintain System models within its respective area of responsibility. The requirement indicates that information received via MOD-010 and MOD-012 shall be "supplemented by other sources as needed" and to the extent errors and omissions were to be discovered by, or brought to the attention of, the Transmission Planner or Planning Coordinator Requirement R1 establishes an expectation that these "other sources" would be utilized to accurately "represent the project System conditions" being studied. No change made. Requirement R1 is applicable to models used for both current and past studies. No change made. Implementation Plan, Short Circuit Studies – While short circuit study requirements may be new in the realm of mandatory enforceable standards, the SDT does not believe that they present a significant "raising of the bar" for industry. The SDT believes that prudent short circuit practices are effectively in place today to ensure safe operation of the equipment. Therefore, no extension in the Implementation Plan was made in regard to short circuit studies.		
Manitoba Hydro		-Why was the Near Team Transmission Planning Horizon definition moved to the Glossary prior to TPL-001-2 approval?- The definition of Non-Consequential Load Loss should not contain '(2) the response of voltage sensitive Load' because voltage sensitive
Response: Two previously proposed definitions that were part of this project were moved to another standard development project – Project 2010-10 titled "FAC Order 729". The two definitions, "Near-term Transmission Planning Horizon" and "Year One" were approved by the Board of Trustees on January 24, 2011. The statement related to the "Non-Consequential Load Loss" definition is incomplete. No change made.		

Organization	Yes/ No	Question 3 Comment
National Grid		R 1.1.2 We recommend the known facility outage duration be defined as facility outage durations lasting at least twelve months. R 1.1. (page 4) System models shall represent: 1.1.1. Existing Facilities 1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six twelve months. 1.1.3 ..... R 2.1.4 We recommend that this requirement be eliminated. We do not see the value of this additional analysis when the number, type and severity of the sensitivity tests are not well defined. These tests are then used to define Corrective Action Plans in cases only where multiple tests show performance deficiencies. R 2.1.5 Spare equipment strategies are typically designed to prevent long outages (possibility a year or more) of equipment with very long lead times. Any such strategy “could” result in these long outages depending upon the number of failures that may be postulated.This requirement is misleading and we thus recommend it be eliminated. R 2.2 We recommend the language for R 2.2 should be consistent with 2.1 for example - use "current or qualified past studies" instead of "the following annual current study." R 2.6.2 We recommend that the wording of this requirement remain unchanged. R 2.7.1 This portion of the requirement provides a list of “acceptable” Corrective Action Plans. It provides equal weight to infrastructure reinforcements and Special Protection Systems as means to mitigate violations resulting form single or multiple contingencies at both the EHV and HV levels.National Grid’s position is that a national standard should not endorse the use of Special Protection Systems as corrective actions to mitigate single contingency violations.Local Northeast Planning Criteria indicates that special protection systems (SPS) shall be used judiciously and may be used to provide protection for infrequent contingencies, or for temporary conditions that may exist such as project delays, unusual combinations of system demand and equipment outages or availability, or specific equipment maintenance outages. A SPS may also be applied to preserve system integrity in the event of severe facility outages and extreme contingencies. The decision to employ a SPS shall take into account the complexity of the scheme and the consequences of correct or incorrect operation as well as its benefits. We are further of the opinion that specific methods of correcting system performance deficiencies should not be specified in a National Standard. We thus recommend that the Corrective Action List be eliminated from this requirement as illustrated below. 2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. R 2.7.2 We feel that this requirement and requirement R 2.1.4 adds ambiguity to the process as we have

Organization	Yes/ No	Question 3 Comment
		indicated above. We thus recommend that this requirement be eliminated. R 3.3.1 We feel that the last sentence of 3.3.1 should be removed. This is handled by PRC-023. Line ratings are addressed by PRC-023. PRC-023 requires coordination with the Reliability Coordinator. Remove "Tripping of Transmission elements where relay loadability limits are exceeded" Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall: 3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: o Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R 3.4.1 We would recommend the following addition as a clarification to the required information exchange: 3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. 3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their respective Systems are included in the Contingency list. R 8.1 National Grid's concern regarding this requirement stems from the apparent open ended time frame afforded report recipients in their review of the Planning Assessment. This has the potential to stall the review process. National Grid thus recommends that any recipient of the Planning Assessments be given a specific time period for their response as indicated in R 8.1 below. R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, and adjacent Transmission Planners, within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of sucha request. [Violation Risk Factor: LowMedium] [Time Horizon: Long-term Planning] 8.1. The recipient of the Planning Assessment results shall provides documented final comments on the results within 90 calendar days of receipt of the Planning Assessment. The respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. Table 1 Steady State & Stability Performance Planning Events (Page10). The event description for

Organization	Yes/ No	Question 3 Comment
		Category P2 Event 1. along with the accompanying footnote 7 (Page 14) creates some confusion for multi-terminal lines. We recommend that Footnote 7 be eliminated and the event description be changed as follows: Category Initial Conditions Event P2 Normal System 1. Opening of a single load interrupting device at one terminal of a line without a fault. Table 1 (Planning Events and Extreme Events) Footnote 12 (Page 14).We are concerned that additional stakeholder process indicated in Footnote 12 has the potential to stall the Planning Assessment review process. We recommend that reference to this new process be eliminated from the Footnote.Our additional, concerns with Footnote 12 are addressed in comments originally provided by ISO-NE. We agree with their following comments : The following language for Footnote 12 is proposed:"Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems."If Footnote 12 in Table 1 must be retained, the following language is proposed: "An objective of the planning process shall be to minimize the likelihood and magnitude of interruption of Demand, (excluding Interruptible Demand or Demand-Side Management), following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: a. Interruptible Demand or Demand-Side Managementb. Circumstances where the uses of Demand interruption not directly interrupted by the contingency are documentedc. Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than Interruptible Demand or Demand Side Management)"
Response: Requirement R1, Part 1.1.2 – The SDT and a majority of industry stakeholder support the 6-month period stated in the requirement. No change made. Requirement R1, Part 1.1 – Same comment as above. No change made. Requirement R2, Part 2.1.4 – Requirement R2, Parts 2.1.4 and 2.4.3 are not inconsistent with Requirement R2, Part 2.7.2. With the various requirements, the planners are required to conduct multiple sensitivities. Therefore, Requirement R2, Part 2.7.2 could be used when the results of these multiple sensitivities identify common concerns. No change made. Requirement R2, Part 2.1.5 is intended to analyze the removal of a single piece of long lead time equipment (one year or more) to the extent there is no existing		

Organization	Yes/ No	Question 3 Comment
		spare equipment strategy to provide a means of returning to service (in less than one year) a comparable replacement. If this condition exists, then the facility (single element) in question must be removed in the model to establish a new P0 system condition and studies must then be run for P0, P1, and P2 for the new system scenario. The spare equipment strategy must be reviewed for the entity's system exposure to catastrophic failures resulting in the long lead-time facility outages, however, only one facility must be removed at a time if the condition exists for multiple facilities. A Transmission Planner may have no spare equipment strategy if they are able to demonstrate they are not responsible for any facilities which they believe could place them in a "long lead-time" scenario. No change made. Requirement R2, Part 2.2 - The requirement for an annual current steady-state study in the Long-Term Transmission Planning Horizon is intentional to drive earlier identification of potential Transmission performance limitations and earlier development of Corrective Action Plans. The study results can be used as qualified studies as they advance to later years, including moving to the Near-Term Transmission Planning Horizon. No change made. Requirement R2, Part 2.6 – The changes made to this requirement in the last draft were essentially style changes and the most substantive change is the introduction of documentation required to support the technical rationale for determining whether or not material changes have occurred. This was a recommendation made by the Quality Review process and agreed to by the SDT. No change made. Requirement R2, R2.7.1 – The SDT respectfully disagrees that actions that could be part of a Corrective Action Plan (CAP) should be eliminated. In regard to the concern of allowing SPS within the CAP, this view is not shared across the continent-wide footprint and National Grid and its Regional Entity always have the ability to go above and beyond the requirements of a NERC standard if they believe such action is warranted. No change made. Requirement R2, Part 2.7.2 - Requirement R2, Parts 2.1.4 and 2.4.3 are not inconsistent with Requirement R2, Part 2.7.2. With the various requirements, the planners are required to conduct multiple sensitivities. Therefore, Requirement R2, Part 2.7.2 could be used when the results of these multiple sensitivities identify common concerns. No change made. Requirement R3, Part 3.3.1 – The SDT appreciates the concern raised; however, it believes the subsequent tripping of "Transmission elements where relay loadability limits are exceeded" is warranted. The TPL studies may earlier identify and flag relay setting concerns based on required Long-Term Transmission Planning Horizon studies. Within the TPL standard, such a concern would have a Corrective Action Plan that would address the issue which would also meet the expectations of PRC-023. The SDT sees this as a defense in depth approach. No change made. Requirement R3, Part 3.4.1 – The additional information suggested was not implemented as it did not add to reliability or clarify the issue beyond the present wording. No change made. Requirement R8, Part 8.1 – The SDT does not see a reliability related need for the suggestion and believes a response regarding a Planning Assessment is warranted no matter when raised by the reviewing party. No change made.

Organization	Yes/ No	Question 3 Comment
Table 1, footnote 7 – The SDT added the footnote to further explain its intent for P2-1 and to ensure that the planner assess the voltage of a load bus that was on a radial line. The word "possibly" was used since having load on a radial is not always the outcome of opening one end of a line section. No change made. Table 1, Footnote 12 – The SDT believes the stakeholder process provides a level of transparency needed when an entity intends to utilize provisions offered by footnote 12 (and footnote 9). No change made.		
TVA TP&C		TVA - has following comments:TVA is concerned about footnote 12 (known as footnote b in existing TPL standards). TVA believes that utilities should be given some freedom in dropping local load in response to N-1 events as long as overall BES reliability is not impacted. Otherwise significant capital improvements will be required that will have no overall reliability gain for the Bulk Electric System. In R4.1.1, TVA is concerned that no generating unit (including distributed generation) shall pull out of synchronism in a local area only (thus not impacting the overall reliability of the BES) for Planning Event P1, while the standard does allow generator runback/tripping for the same event. Thus the generating unit may be tripped by a special protection scheme - but may not be tripped by an out of step relay. TVA believes that out of step relaying should be allowed for this unit tripping as long as this does not affect the overall reliability of the BES. Table 1 contains both planning events and extreme events. Suggest labeling the planning events as Table 1 and the extreme events as Table 2 to help reduce confusion. VSL for R1 does not seem to address issues where data errors have been introduced into the latest model data. Also, R1 and its VSL may be interpreted to exclude the use of past models. The Implementation Plan should include a five-year delay in the effective date for short circuit studies (R2 parts 2.3 and 2.8) since these studies are a new TPL requirement and are not required in the current version 0 standards.
Response: The SDT has taken care to ensure consistency in footnote 12 (and footnote 9) with the prior footnote 'b' revision supported by industry, approved by the NERC Board of Trustees, and submitted for regulatory approval. No change made. Requirement R4, Part 4.1.1 - The SDT respectfully disagrees with the commenter. For a P1 single Contingency event, the SDT believes, and a majority of industry stakeholders find it reasonable, that no Bulk Electric System (BES) generation unit be pulled out of synchronism due to the P1 event studied. If the "small" nearby unit is served below threshold kV and MW size limitations set by the Regional Entity to qualify as a BES unit, the unit would not be within scope of the standard. No change made.		

Organization	Yes/ No	Question 3 Comment
Desire for Two Tables – This has been vetted within industry in prior comment/ballot periods. The majority of stakeholders support the current format. No change made. Requirement R1 VSL – The requirement indicates that supplied data may have to be supplemented as appropriate. The SDT believes that this covers correcting any data errors. The SDT sees no reason why the current language invalidates the use of past models as long as they meet the requirements. No change made. While short circuit study requirements may be new in the realm of mandatory enforceable standards, the SDT does not believe that they present a significant "raising of the bar" for industry. The SDT believes that prudent short circuit practices are effectively in place today to ensure safe operation of the equipment. Therefore, no extension in the Implementation Plan was made in regard to short circuit studies.		
Independent Electricity System Operator		See our response to Q1.
Response: See response to Q1.		
NBSO		Items that, if not addressed, will likely cause a negative vote from NBSO: NBSO believes that R1.1.2 is more appropriately addressed in the operational timeframe. Perhaps more appropriate alternatives could include:-only considering planned outages with durations of one year or more (in-line with typical planning timeframes), or -requiring that facilities with planned outages lasting over the complete duration of time period being studied be modeled out of service. R2.1.5 may significantly increase the demands of the planning assessments with little gain in reliability. Depending on interpretation, R2.1.5 could exponentially increase the work load of the annual planning assessment. NBSO interprets the intent of R2.1.5 to require that entities have, review and evaluate their spare equipment strategies. Perhaps the assessment of a spare equipment strategy would be more appropriately addressed in a separate standard. Further, categories P0, P1 and P2 do not reference footnote 9 in the Initial Condition column. NBSO is unclear if the last sentence of R2.1.5 allows for the curtailment of firm transmission service under the N-1 conditions before the application of category P0, P1 and P2 events. This last sentence states:"...with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment." Table 1, note b should be modified to allow for the loss of Firm Transmission Service. This addresses cases where Firm Transmission Service is lost in direct consequence to the event (e.g. loss of one DC pole, an

Organization	Yes/ No	Question 3 Comment
		interface comprised of a single line, a bus fault that clears multiple lines in an interface, etc...) Individual items that, if not addressed, may not cause NBSO to vote Negative, but in combination may result in a negative vote:The definitions of “near-term transmission planning horizon” and “year one” have been removed from the standard, yet they are still used in draft 7. Further, the definition of these terms is being filed as part of another project. NBSO is concerned with endorsing a standard based on terms whose definitions may change independently of this project. For R7, NBSO is concerned that one entity may be found noncompliant should another entity fail to meet their agreed upon responsibilities. For example, a PC may be relying on the results from a TP’s studies to complete its own planning assessment, but the TP did not meet their responsibilities. In this case, the PC should not be found non-compliant for an incomplete planning assessment due to the failure of the TP to meet their responsibilities.Contingencies on back to back HVDC facilities are not addressed in the standard.

Response: Requirement R1, Part 1.1.2 - The SDT disagrees with the view that outages of 6 months or more should only be reviewed in the operations timeframe. Such an outage could be for an upcoming construction project requiring certain facilities to be removed from service for long durations of time and those situations should be evaluated with sufficient lead time to determine any vulnerabilities and development of sufficient Corrective Action Plans as required. No change made.

Requirement R2, Part 2.1.5 is intended to analyze the removal of a single piece of long lead time equipment (one year or more) to the extent there is no existing spare equipment strategy to provide a means of returning to service (in a less than one year) a comparable replacement. If this condition exists, then the facility (single element) in question must be removed in the model to establish a new P0 system condition and studies must then be run for P0, P1, and P2 for the new system scenario. The spare equipment strategy must be reviewed for the entity’s system exposure to catastrophic failures resulting in the long lead-time facility outages, however, only one facility must be removed at a time if the condition exists for multiple facilities. A Transmission Planner may have no spare equipment strategy if they are able to demonstrate they are not responsible for any facilities which they believe could place them in a “long lead-time” scenario. No change made.

Requirement R2, Part 2.1.5 & Footnote 9 – Footnote 9 is not applicable to the Initial Condition (Pre-contingency) of P0, P1, and P2 even with a long lead-time device out of service. No change made.

Table 1, footnote ‘b’ - The SDT believes the concern should be addressed by footnote 4, Conditional Firm Transmission Service. No change made.

Removal of Definitions - Two previously proposed definitions that were part of this project were moved to another standard development project – Project 2010-10 titled “FAC Order 729”. The two definitions, “Near-Term Transmission Planning Horizon” and “Year One” were approved by the Board of Trustees on January 24, 2011.

Requirement R7 – The SDT disagrees, having documented clear lines of responsibility should protect against the concern raised. No change made.

Organization	Yes/ No	Question 3 Comment
Back to Back HVDC – The contingent loss of back to back HVDC facilities is included as a transformer. Footnote 5 states, in part, that "Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. Therefore, the SDT has not explicitly included back-to-back HVDC as a separate Contingency. No change made.		
Xcel Energy		Effective Date: The effective date section seems to imply that Non-Consequential Load Loss will not be permitted after the 84 month implementation period. We do not believe that was the drafting team's intent and request that it be modified. Footnote # 12 in Table 1, in particular, seems to support our assumption that the team did not intend to disallow it. For reference, the footnote states:"12. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to address BES performance requirements. When Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss is documented, including alternatives evaluated; and where the utilization of Non-Consequential Load Loss is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments." However, if it was the drafting team's intent to not allow Non-consequential Load Loss after the 84 month implementation period, we disagree and ask the team to reconsider. Particularly for rural areas, in some cases, this will be the only action possible. R2.1.4: a) We would like to see clarification on the term "sensitivity analysis". Is this in reference to seasonal models and differences in fuel availability? We would like more detail on how this is to be done so that it won't be left up to interpretation. b) We would like the drafting team to consider stratification of the tasks needed to perform a Planning Assessment. In our opinion, having both the TP and PC do exactly the same study produces tremendous and unnecessary duplication. Without stratification, the TPL-001 standard will continue to perpetuate the same paradigm used in the existing TPL-001 through TPL-004 standards. The NERC Functional Model makes a clear distinction between PC and TP functions/responsibilities. It is not clear why that distinction is not leveraged in the new TPL-001 standard. This will be particularly troublesome in areas where an ISO or RTO is the Planning Coordinator. In order for the RTO/ISO, as the PC, to be able to do their Planning Assessment, the Transmission Planners would have to provide a lot of detailed input data. So, in effect, both the PC and TP would be performing their assessment from the same data. It would make more sense if the RTO (as the PC) performed the required studies on the 500-345 kV network and the TP performed the required studies on everything below 230 KV.

Organization	Yes/ No	Question 3 Comment
		We also recommend the allowance for utilization of a regional assessment, instead of performing your own, due to individual entity resource constraints. R2.4.1: We would like to see better clarity on what an Aggregate system load model is and how granular it should be. If the intent is for the model to contain a very detailed representation of the load system, then it may take a longer time to implement. R3.4.1: a) This type of coordination could be difficult due to other adjacent entities on different schedules and some may not have the amount of detail to incorporate into another's processes. We know this is generally covered in coordination of real time operations and wonder if it is appropriate to require this type of coordination in the long term process. Is there already an operational standard that covers this? Would it be better to address this in the operational standards? We would like the roles of the coordinators vs. the planners to be clarified in order to ensure that no work is being duplicated. b) PC's between regions, such as RTOs, are already coordinating for long term studies. In these cases, we feel the PC should alone be responsible for the requirements, rather than also the TPs. c) Can we get a clear definition of what apparent impedance swings means? We interpret it as rotor angle stability. R4.3.1: We would like to see that the detailed data is incorporated back into the NERC modeling processes and create a more detailed model with better accuracy. R8: We do not agree with the requirement to provide the assessment to every adjacent PC and TP because we fail to see the reliability benefit in doing so. However, we do agree that the PC and TP should be required to provide the assessment to any of these entities, if requested. Additionally, for entities that make such requests, we would like to have 90 days instead of 30 to respond. In many cases a non-disclosure agreement will have to be executed due to CEII classification of some information, and this can take several months.
Response: Effective Date - The SDT believes the Effective Date section is sufficiently clear. The use of Non-Consequential Load Loss while discouraged by the standard is permitted when justified and presented in a transparent manner to other stakeholders (footnote 12). No change made. Sensitivity Analysis – This analysis should be viewed as a modified study of the Peak or off-peak studies required in Requirement R2, Parts 2.1.1 and 2.1.2. The SDT believes the examples provided in the bulleted list of Requirement R2, Part 2.1.4 are sufficiently clear as examples of what could be modified to create the sensitivity model. No change made.		

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Delineation of tasks between Transmission Planner and Planning Coordinator – The issue raised is addressed by Requirement R7. No change made. Regional Assessments – The standard does not prohibit the use of valid studies performed by 3rd parties for use in the assessment results. No change made. Requirement R2, Part 2.4.1 - The "aggregate" dynamic Load model may include high-level assumptions on Load profiles for industrial, commercial, and residential Loads that are applied generically across the planning area study based on the planner's engineering judgment and system knowledge. The model is not required to be "bus" specific. No change made. Requirement R3, Part 3.4.1 - The SDT envisions that knowledge of the applicable Contingencies on neighboring systems would develop over time and be discovered with the results being distributed in Requirement R8. The SDT believes that this is an important improvement to the planning timeframe analysis and that system information learned in the operations environment should most certainly be considered to the extent it improves the robustness of the planning assessment. No change made. Planning Coordinator responsibility – NERC's Functional Model clearly places Transmission planning responsibility both on the Transmission Planner and Planning Coordinator. Requirement R7 should help alleviate any overlap concerns in responsibility. No change made. Apparent Impedance Swings - The "apparent impedance swing" is the trajectory of changes in the apparent impedance seen by a distance relay for various system and Fault conditions. In the case contemplated in Requirement R4, Part 4.1.2, it is the trajectory seen by the distance relay for the initial Fault and the subsequent generator(s) pulling out of synchronism. If that trajectory were to come within the tripping characteristic of the relay for a sufficient length of time, the relay would cause its associated line to trip. No change made. NERC Modeling Process – The standard does not govern NERC actions as they are not a registered entity. To the extent NERC pulls information from a model building process such as MMWG (ERAG) then the models used by NERC will likely contain the information desired. No change made. Requirement R8 – The SDT and a majority of industry support Requirement R8. No change made.		
ISO New England Inc.		We feel previous comments have largely been ignored by the Standards Drafting Team leading to a lack of support for the standard. Overall the standard should be more precise in its language. The following comments are provided for serious consideration with respect to revisions:Comments: From Section A.3 - the introduction please strike the word "probable" as shown below Purpose: Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies This is deterministic contingency testing and this word introduces probability into the standard where it does not belong. For R1.1 Part 1.1.2. With respect to known outages, there needs to be greater flexibility in the standards (e.g. more tolerance to non-consequential load shedding or limitations to the contingencies that need to be

Organization	Yes/ No	Question 3 Comment
		considered (e.g. P0, P1, & P2)). Regional allowances for load shedding under this condition should be acceptable. Duration of known outages should be increased from six months to one year. For R1.1 Part 1.1.6 Delete "required for Load". Resources may also be used for export to other areas, not just internal load. REMOVE INTERCHANGE from 1.1.5 - Definition of Interchange - The inclusion of Interchange requires designing for non-Firm service.In the NERC Glossary of Terms Used the term Interchange is defined as "Energy transfers that cross Balancing Authority boundaries." It is meant to refer to energy transaction other than firm Transmission Service. While rigorous planning studies have been conducted to permit the uninterrupted implementation of firm Transmission Service without jeopardizing the reliable operation of the Interconnected System, other types of energy transaction only take place whenever system conditions permit them. They are usually of very short duration relative to planning assessment periods (usually spanning for a few hours to a few days) and are deemed highly interruptible and subject to reliability issues that may arise during operation of the system. In other words, the term Interchange refers to economic transactions that are permitted when the system is secure and there are reasonable reliability margins to effect dispatch changes to lower operating costs. As such, Interchange should not be reflected in system representation meant to assess system reliability under TPL-001. Part 2.1.4, requires an entity to vary one or more conditions to demonstrate a change in performance. If the cases were initially stressed, this may force an entity to simulate conditions with less severe stresses. At this point, there is limited or no value to this additional workload. Having a requirement to test at least one sensitivity as a blanket requirement may not be informative by itself and is more unclear since sensitivities are being required on an undefined base set of conditions. Additionally, our concern involves wording under 2.1.4 and 2.4.3 that sensitivities are required varying one or more conditions. Subsequently, in requirement 2.7.2 corrective action plans need to be developed to resolve performance deficiencies "only" if identified in multiple conditions or require a rationalization why no corrective action plan is necessary. Multiple condition sensitivities under 2.1.4 and 2.4.3 are necessary to satisfy requirement 2.7.2. Requirement 2.7.2 adds ambiguity and should be removed or revised as follows: 2.7.2. Corrective Action Plans are not required for performance deficiencies identified in a sensitivity analysis. We agree with R2.1 however with respect to R2.2 Language should be consistent with 2.1 for example - use "current or qualified past studies" instead of "the following annual current study." For 2.7.1 - We don't believe this list provides value nor should it be included in the standard. Section 3.3 - We feel that the last sentence of 3.3.1 should be removed. This is handled by PRC-023. Line

Organization	Yes/ No	Question 3 Comment
		ratings are addressed by PRC-023. PRC-023 requires coordination with the Reliability Coordinator. Remove "Tripping of Transmission elements where relay loadability limits are exceeded." In Table 1 - The fault descriptions must be clear. They must use "3-phase", "single-phase-to ground", or "2-phases-to ground" in the descriptions of a fault rather than SLG (a line is not a phase in electrical terms--single line to ground is not precise enough). In Table 1 - Where two elements are affected by a fault it must be clear whether the requirement is for a single-phase-to ground fault, or a 2-phase-to ground fault. They are different faults that will have different dynamic responses. For Table 1- add a footnote for the term generator to address the treatment of Combined Cycle Generators - "In addition to evaluating the loss of a single generator, the loss of all interrelated generators shall also be considered as a single contingency." Operating experience has shown that trips of the entire CC facility often occur even on facilities that claim the combined cycle generators are independent. Where a category involves an initial condition representing the loss of a facility followed by an event represeting the loss of a facility such as P3, the standard must be clear as to the amount of time assumed between faults. An assumption may be 30 minutes, but the standard must not leave this unsaid. This clarity must be provided in the Table 1 Notes.In addition, the standard must be clear on the allowable re-adjustments between contingencies such as P3, or better, must be clearly limit the permissible re-adjustments. For example, it is not realistic to assume an unlimited amount of re-dispatch between faults-e.g. the allowable re-adjustment should be limited to actions that can be effectively implemented in less than 30 minutes, such as a, b, c, d, ..., and the amount of generation re-dispatch must not exceed the amount of future planned contingency reserve, or similar language. This clarity must be derivable from the Table 1 Notes.
Response: A.3 Purpose Statement – While admittedly "probable" is somewhat in the eye of the beholder the intent is that Bulk Electric System (BES) should operate reliably for the more "probable" or "credible" Contingencies, i.e., Planning Events (Table 1), and that the BES reliability performance expectation is lower for the less "probable" extreme events. The SDT does not see this statement as defining the standard as probabilistic Contingency planning and agrees that the standard is deterministic planning. No change made. Requirement R2, Part 1.1.2 – The SDT disagrees that the duration of known outages should be increased from 6 months to one year. The intent is to ensure review of an upcoming construction project requiring certain facilities to be removed from service for long durations of time and those situations should be evaluated with sufficient lead time to determine any vulnerabilities and development of sufficient Corrective Action Plans (CAP) as required. The SDT believes it is		

Organization	Yes/ No	Question 3 Comment
appropriate to study all planning events for the projected system and not limit it to just P0, P1. or P2. Load shedding could be part of a "temporary" CAP when justified by the use of footnote 12. No change made. Requirement R1, Part 1.1.6 - The SDT does not believe the phrase "required for Load" is confusing. Without the statement, in theory, one could have a model with lots of supply resources but none which are dispatched to serve the Load. The term Load does not depict whether it is located internal or external to the Transmission system footprint. No change made. Requirement R1, Part 1.1.5 – Both firm and non-firm transfers of power should be modeled to the extent they are "known commitments" in the Planning Horizon. The short duration transactions described would likely not be known and therefore should not be included in a planning model. No change made. Requirement R2, Part 2.1.4 – the commenter has missed the key phrase "… by a sufficient amount to stress the System …". So, by definition of the requirement the sensitivity analysis is not intended to lower the overall stress of the system being analyzed. Additionally, Requirement R2, Parts 2.1.4 and 2.4.3 are not inconsistent with Requirement R2, Part 2.7.2. With the various requirements, the planners are required to conduct multiple sensitivities. Therefore, Requirement R2, Part 2.7.2 could be used when the results of these multiple sensitivities identify common concerns. No change made. Requirement R2, Part 2.2 - The requirement for an annual current steady-state study in the Long-Term Transmission Planning Horizon is intentional to drive earlier identification of potential transmission performance limitations and earlier development of Corrective Action Plans (CAPs). The study results can be used as qualified studies as they advance to later years, including moving to the Near-Term Transmission Planning Horizon. No change made. Requirement R2, R2.7.1 – The SDT respectfully disagrees that example actions that could be part of a Corrective Action Plan (CAP) should be eliminated. If an entity takes issue with the use of one of the stated items as part of a CAP, they are always free to go above and beyond the requirements of a NERC standard if they believe such action is warranted. No change made. Requirement R3, Part 3.3.1 – The SDT appreciates the concern raised; however, it believes the subsequent tripping of "Transmission elements where relay loadability limits are exceeded" is warranted. The TPL studies may earlier identify and flag relay setting concerns based on required Long-Term Transmission Planning Horizon studies. Within the TPL standard, such a concern would have a CAP that would address the issue which would also meet the expectations of PRC-023. The SDT sees this as a defense in depth approach. No change made. Fault Types – Only single line to ground (SLG) and three-phase (3PH) fault types are covered by the standard. See Table 1, footnote 2 for further information on fault types and standard expectations. No change made. Combined Cycle Plants – If the planner believes it is appropriate to model the tripping of the combined cycle generation as a set then they should do so. Recall, in planning assessments, you are analyzing Contingency events based on electrical Faults and the SDT reminds the commenter that adherence to introductory Table 1 note "c" is required. Additionally, to the extent the combined cycle units deliver their power via a common GSU transformer the loss of the GSU should also address the concern. No change made. System Adjustments – The timing between events which are not common mode events (P3, P6) is not defined by the standard. Engineering judgment should		

Organization	Yes/ No	Question 3 Comment
prevail and if the planner believes a susceptibility to an N-2 event of quick duration places their system at risk then the use of automatic controls should be considered. The only qualifier on System adjustments is that Facility Ratings must be adhered to during the adjustment. So, if you are adhering to a 30-minute Emergency Rating, but are exceeding a 24-hour Emergency Rating then the adjustment must be completed within the time limitation of the rating. No change made.		
Northeast Utilities		The following previous comments that were filed by NU were not addressed by the SDT in the current draft. For NU to support the standard these comments should be addressed or reasons should be provided why they have not been addressed. Repeated below are NU's comments that were filed for the previous draft. Requirement R1, Part 1.1.2 NU requests that the six month duration stated by Requirement R1, Part 1.1.2 should be modified to one year duration to eliminate outages that occur within the "operational planning timeframe". Requirement R1, Part 1.1.6The phrase "required for Load" should be deleted as this confuses the issue.Requirement R2, Part 2.2The language of Requirement R2 Part 2.2 seems to suggest that current annual studies are always required for the long-term steady state assessment. This may have been an oversight, for consistency Requirement R2 Part 2.2 should be modified to similarly read as Requirement R2, Part 2.1. Requirement R2, Parts 2.1.4 & 2.4.31) The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions. The standard must describe base assumptions. To define a sensitivity condition, NERC must define base assumptions. 2) Requirement R2, Part 2.1.4 and Part 2.4.3 should clarify what is meant by multiple sensitivity studies and one sensitivity study. Will varying only one measurable quantity several times in multiple simulations constitute multiple sensitivity studies or one sensitivity study? Requirement R3, Part 3.3.1NU feels that the last sentence of Requirement R3, Part 3.3.1 should be removed since this is handled by PRC-023. Line ratings are addressed by PRC-023 which requires coordination with the Reliability Coordinator. NU suggests the removal of the following sentence: "Tripping of Transmission elements where relay loadability limits are exceeded."
Response: Requirement R1, Part 1.1.2 - The SDT disagrees with the view that outages of 6 months or more should only be reviewed in the operations timeframe. Such an outage could be for an upcoming construction project requiring certain Facilities to be removed from service for a long durations of time and those situations should be evaluated with sufficient lead time to determine any vulnerabilities and development of sufficient Corrective Action Plans as required. The		

Organization	Yes/ No	Question 3 Comment
review of known and planned construction items should not be delayed until the operations timeframe. No change made. Requirement R1, Part 1.1.6 - The SDT does not believe the phrase "required for Load" is confusing. Without the statement, in theory, one could have a model with lots of supply resources but none which are dispatched to serve the load. No change made. Requirement R2, Part 2.2 - The requirement for an annual current steady-state study in the Long-term Transmission Planning Horizon is intentional to drive earlier identification of potential Transmission performance limitations and earlier development of Corrective Action Plans (CAP). The study results can be used as qualified studies as they advance to later years, including moving to the Near-Term Transmission Planning Horizon. No change made. Requirement R2, Parts 2.1.4 & 2.4.3 – The "base case" assumption is described in Requirement R1 by the fact that the P0 model "shall represent the projected System conditions" for the study period. That essentially establishes the "base case" condition. The sensitivity analysis in Requirement R2, Part 2.1.4 is intended to address some potential "what if" conditions that the planner should consider as an alternate base P0 condition. The SDT believes Requirement R2, Part 2.1.4 provides sufficient detail and clarity of the intended purpose of a sensitivity study and defers to engineering judgment in how the alternate base (sensitivity) model is established. Varying one variable multiple times would cover multiple sensitivities. For example, one may vary the Load modeled. If the base condition is a 50/50 forecast model, one sensitivity may be an 80/20 forecast, while yet another is a 90/10 forecast model. No change made. Requirement R3, Part 3.3.1 – The SDT appreciates the concern raised; however, it believes the subsequent tripping of "Transmission elements where relay loadability limits are exceeded" is warranted. The TPL studies may earlier identify and flag relay setting concerns based on required Long-Term Transmission Planning Horizon studies. Within the TPL standard, such a concern would have a CAP that would address the issue which would also meet the expectations of PRC-023. The SDT sees this as a defense in depth approach. No change made.		
MISO		Overall, we remain concerned that the revisions to the TPL standard are not on balance an improvement to the original. The document is not well organized topically, making it more difficult to navigate and understand. If the primary improvements sought in requirements for reliability planning were to increase system performance levels (no loss of firm demand) for certain multiple contingency events, and to ensure more stressed system sensitivities are analyzed, this can be accomplished in a much simpler revision. We do not believe that this standard as written improves the clarity of what is required, and therefore provides an opportunity for greater disputes between compliance monitors and applicable entities, and this is not a positive outcome. We also believe that the standard is too prescriptive as to what critical system conditions must be modeled, as these conditions vary considerably from system to system and within large systems. Table 1-Steady State and Stability Performance Planning Events, Category P5, now includes "non-redundant" relay in the Event column. What is meant by non-redundant relay? It is unclear if the SDT's intent is to provide distinction between a back-up relay and a redundant relay. We recommend that the SDT provide a definition for the term "non-redundant".

Organization	Yes/ No	Question 3 Comment
Consumers Energy	Ballot Comment	We agree with comments submitted by MISO
Response: The SDT and others in industry hold a different opinion in regards to the standard. The SDT refers you to the comments provided by Transmission Strategies, LLC which well articulates what it believe is the opinion of many in industry evidenced by the 74% approval during the last ballot. Transmission Strategies, LLC states "The SDT, Observers, and the Industry as a whole have put a tremendous amount of thought and work into the development of this latest draft. While nobody should claim that this latest version is perfect, it is far clearer, more in tune with current industry needs, and much improved compared to the existing approved Standards that it will replace". No change made. Redundant Relay – Redundant means duplicate capability resulting in the same outcome. The redundant relay is not the same as a back-up relaying capability which may result in more Facilities being removed for failure of the primary/redundant relay to operate as designed. The SDT believes this concept is widely understood by most in industry and does not see the need for a NERC Glossary Definition. No change made.		
New York Independent System Operator		Requirement R2.4.1The NYISO, along with many other systems, has not determined a need to model dynamic loads, and therefore has not benchmarked any such models. The NYISO recommends that prior to the implementation of this requirement a modeling standard should exist that is specific to dynamic loads, including as assessment for the need for dynamic load models.
Response: Requirement 2, Part 2.4.1 – One focus of the dynamic Load model requirement in Requirement R2, Part 2.4.1 is "considering the behavior of induction motor load". The areas of concern for induction motor load are the Peak load periods since Fault Induced Delayed Voltage Recovery (FIDVR) is primarily a concern at a high load levels with a high penetration of induction motor loads. The SDT has spelled out this requirement in the Peak Load studies but did not include the explicit requirement, with focus on induction motor load, for the other load periods. Even though the standard doesn't have the explicit requirement for other load levels, Requirement R1 includes the statement "shall represent projected System conditions", so the planner cannot ignore the dynamic behavior of the load for those other load periods. No change made.		
Ameren		With respect to Requirement R8, will posting the assessment to a secure web site meet the intent of the requirement? What are the Planning Assessment results identified in R8, and how are they different from the Planning Assessment? It appears that the language for R8 is inconsistent with the VSL for R8. The revised language for the VSL for R8 has removed the word "results". For Measurements M3 and M4, there is still some question as to what is to be provided as sufficient evidence of a study. It is not clear whether the study results would be sufficient, or whether the entire powerflow,

Organization	Yes/ No	Question 3 Comment
		stability, or short circuit effort needs to be documented in a formal study report. For example, it is not clear whether contingency lists used in performing the study work would need to be retained as part of the documentation. The items listed as 4.1.1 through 4.1.3 are not requirements but are performance criteria and should be included in the Table 1 only, consistent with the other performance criteria. Overall, we believe that this standard does not improve the clarity of what is required, and would give additional occasions for disputes between compliance monitors and various registered entities. The standard as written is too prescriptive with regard to critical system conditions which are to be modeled. Such conditions would vary considerably for different systems across the continent.
Response: Requirement R8 – Posting results to a secure website with adequate communication that the results are available for review would suffice for Requirement R8. The "Planning Assessment" and "Planning Assessment results" are one and the same. No change made. Measures M3 and M4 – The evidence could be a combination of summary documented results, the power flow case itself, the Contingency lists, output files showing evidence of the Contingency analysis being performed, etc. No change made. The SDT believes the items in Requirement R4, Parts 4.1.1 through 4.1.3 are properly located. The standard is the sum of the parts – requirements and the Table and the location of the highlighted items is not critical to the desired outcome. No change made. Clarity of the standard - The SDT and others in industry hold a different opinion in regard to the standard. The SDT refers you to the comments provided by Transmission Strategies, LLC which well articulates what it believes is the opinion of many in industry evidenced by the 74% approval during the last ballot. Transmission Strategies, LLC states "The SDT, Observers, and the Industry as a whole have put a tremendous amount of thought and work into the development of this latest draft. While nobody should claim that this latest version is perfect, it is far clearer, more in tune with current industry needs, and much improved compared to the existing approved Standards that it will replace". No change made.		

Exhibit E

Mapping Document

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Mapping Document

Project 2006-02 Assess Transmission Future Needs

Mapping document showing the translation of TPL-001-2 – System Performance Under Normal (No Contingency) Conditions (Category A); TPL-002—1b – System Performance Following Loss of a Single Bulk Electric System (BES) Element (Category B); TPL-003-1a – System Performance Following Loss of Two or More Bulk Electric System Elements (Category C); TPL-004-1 – System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D); TPL-005-0 – Regional and Interregional Self-Assessment Reliability Reports; and TPL-006-0.1 – Data From the Regional Reliability Organization Needed to Assess Reliability.

Standard TPL-001-1 – System Performance Under Normal (No Contingency) Conditions (Category A)		
Requirement in Approved Standard	Translation to New Standard or Other Action	Description (as needed)
R1	TPL-001-2, R1 & R2 TPL-001-2, Table 1 – P0	Requirement R1 sets P0 in Table 1 as the normal system condition.
R1.1	TPL-001-2, R2.1 TPL-001-2, R2.2	Requirement R2.1 is for near-term and Requirement R2.2 is for long-term
R1.2	TPL-001-2, R2.1 TPL-001-2, R2.2	Requirement R2.1 is for near-term and Requirement R2.2 is for long-term
R1.3	TPL-001-2, R2.3 TPL-001-2, R2.4	Requirement R2.3 is for near-term and Requirement R2.4 is for long-term
R1.3.1	TPL-001-2, R2.1.1 TPL-001-2, R2.1.2 TPL-001-2, R2.2.1 TPL-001-2, R1	Requirements R2.1.1 & 2.1.1 are for near-term and Requirement R2.2.1 is for long-term. These new requirements are more stringent than the existing as they require annual assessments regardless of whether the system has changed or not. Requirement R1 is for System models.
R1.3.2	TPL-001-2, R2.1.1 & R2.1.2 TPL-001-2, R2.2.1	Requirements R2.1.1 & R2.1.2 are for near-term and Requirement R2.2 is for long-term.
R1.3.3	TPL-001-2, R2.2.1	This requirement is more stringent than the existing requirement in that it requires a long-term assessment regardless of system conditions.
R1.3.4	TPL-001-2, R1	Normal (pre-contingency) operating procedures, if required, are a part of a Corrective Action Plan and therefore, are required to be included in the System model.

R1.3.5	TPL-001-2, R1.1.5	
R1.3.6	TPL-001-2, R1 & R2.1.1 TPL-001-2, R1 & R2.1.2 TPL-001-2, R2.1.4	Requirements R1, R2.1.1, & R2.1.2 set up the base requirements and Requirement 2.1.4 requires sensitivity analysis to demonstrate the impact of changes to the basic assumptions used in the model.
R1.3.7	TPL-001-2, R1 TPL-001-2, Table 1	Requirement R1 sets P0 in Table 1 as the normal system condition.
R1.3.8	TPL-001-2, R1.1.1 TPL-001-2, R1.1.3	
R1.3.9	TPL-001-2, R1.1.4	Requirement R1.1.4 requires that Reactive Power forecasts are utilized and that performance is met for same.
R1.4	TPL-001-2, R1 &R1.1.3	
R2	N/A	Introductory sentence
R2.1	TPL-001-2, R2.7	
R2.1.1	TPL-001-2, R2.7	Requirement 2.7 requires the development of a Corrective Action Plan which includes a schedule for implementation.
R2.1.2	TPL-001-2, R2.7	Requirement 2.7 requires the development of a Corrective Action Plan which includes a schedule for implementation.
R2.1.3	TPL-001-2, R2.7	Requirement 2.7 requires the development of a Corrective Action Plan which includes a schedule for implementation.
R2.2	TPL-001-2, R1	
R3	TPL-001-2, R2 TPL-001-2, R8	Requirement R2 requires the documentation of the assumptions and summarized results. The revised Requirement R8 is more stringent than the existing requirement in that it includes other Planning Coordinators and Transmission Planners as well as functional entities having a reliability-based need.

Standard TPL-002—1b – System Performance Following Loss of a Single Bulk Electric System (BES) Element (Category B)		
Requirement in Approved	Translation to	Description (as needed)

Standard	New Standard or Other Action	
R1	TPL-001-2, R1, R2, R3.1, & R4.1 TPL-001-2, Table 1 – P1 & P2-1	
R1.1.	TPL-001-2, R2.1 TPL-001-2, R2.2	Requirement R2.1 is for near-term and Requirement R2.2 is for long-term.
R1.2	TPL-001-2, R2.1 & 2.4 TPL-001-2, R2.2 & 2.5	Requirements R2.1 & R2.4 are for near-term and Requirements R2.2 & R2.5 are for long-term.
R1.3.	TPL-001-2, R3 TPL-001-2, R4	Requirement R3 is for steady-state. Requirement R4 is for stability.
R1.3.1	TPL-001-2, R3.4 TPL-001-2, R4.4	Requirement R3.4 is for steady-state and Requirement R4.4 is for stability.
R1.3.2	TPL-001-2, R2.1 & R2.4 TPL-001-2, R2.2 & R2.5 TPL-001-2, R1	Requirements R2.1 & R2.4 are for near-term. Requirement R2.2 is for long-term. Requirement R1 is for System models.
R1.3.3	TPL-001-2, R2.1.1, R2.1.2, R2.4.1, & R2.4.2 TPL-001-2, R2.2.1 & R2.5	Requirements R2.1.1, R2.1.2, R2.4.1 & R2.4.2 are for near-term and Requirements R2.2.1 & R2.5 are for long-term. These new requirements are more stringent than the existing as they require annual assessments regardless of whether the system has changed or not.
R1.3.4	TPL-001-2, R2.2.1 TPL-001-2, R2.5	These requirements are more stringent than the existing requirement in that it requires a long-term assessment regardless of system conditions.
R1.3.5	TPL-001-2, R1.1.5	
R1.3.6	TPL-001-2, R1, R2.1.1 & R2.4.1 TPL-001-2, R1, R2.1.2 & R2.4.2 TPL-001-2, R2.1.4	Requirements R1, R2.1.1, R2.1.2, R2.4.1, & R2.4.2 set up the base requirements and Requirement 2.1.4 requires sensitivity analysis to demonstrate the impact of changes to the basic assumptions used in the model.

R1.3.7	TPL-001-2, R3.1 & R4.1 TPL-001-2, Table 1 – P1 & P2-1	
R1.3.8	TPL-001-2, R1.1.1 TPL-001-2, R1.1.3	
R1.3.9	TPL-001-2, R1.1.4	Requirement R1.1.4 requires that Reactive Power forecasts are utilized and that performance is met for same.
R1.3.10	TPL-001-2, R1.1.1, R1.1.3, R3.3.1, & R4.3.1 TPL-001-2, Table 1 – header note 'c', P-4, & P-5	Requirements R3.3.1, R4.3.1, and header note 'c' require the removal of elements that protection systems are expected to disconnect. Requirements R1.1.1 & R1.1.3 require that existing and planned facilities are modeled. Table 1, P-4, P-5, & extreme events require that backup or redundant systems are included.
R1.3.11	TPL-001-2, R3.3.2 & R4.3.2	Requirements R3.3.2 and R4.3.2 require the simulation of expected automatic operation of existing and planned control devices.
R1.3.12	TPL-001-2, R1.1.2 TPL-001-2, R2.1.3	
R1.4	TPL-001-2, R1 & R1.1.3	
R1.5	TPL-001-2, R3.1 & R4.1 TPL-001-2, Table 1 – P1 & P2-1	
R2	N/A	Introductory sentence
R2.1	TPL-001-2, R2.7	
R2.1.1	TPL-001-2, R2.7	Requirement 2.7 requires the development of a Corrective Action Plan which includes a schedule for implementation.
R2.1.2	TPL-001-2, R2.7	Requirement 2.7 requires the development of a Corrective Action Plan which includes a schedule for implementation.
R2.1.3	TPL-001-2, R2.7	Requirement 2.7 requires the development of a Corrective Action Plan which includes a schedule for implementation.
R2.2	TPL-001-2, R1	
R3	TPL-001-2, R2 &	Requirement R2 requires the documentation of

	R8	the assumptions and summarized results. Requirement R8 is more stringent than the existing requirement in that it includes other Planning Coordinators and Transmission Planners as well as functional entities having a reliability-based need.
Standard TPL-003-1a – System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)		
Requirement in Approved Standard	Translation to New Standard or Other Action	Description (as needed)
R1	TPL-001-2, R1, R2, R3.1, and R4.1 TPL-001-2, Table 1 – P2-2, P2-3, P2-4, P3 through P7	
R1.1	TPL-001-2, R2.1 TPL-001-2, R2.2	Requirement R2.1 is for near-term and Requirement R2.2 is for long-term.
R1.2	TPL-001-2, R2.1 & R2.4 TPL-001-2, R2.2 & R2.5	Requirements R2.1 & R2.4 are for near-term and Requirements R2.2 & R2.5 are for long-term
R1.3	TPL-001-2, R3 TPL-001-2, R4	Requirement R3 is for steady-state and Requirement R4 is for stability.
R1.3.1	TPL-001-2, R3.4 TPL-001-2, R4.4	Requirement R3.4 is for steady-state and Requirement R4.4 is for stability.
R1.3.2	TPL-001-2, R2.1 &R2.4 TPL-001-2, R2.2 & R2.5 TPL-001-2, R1	Requirements R2.1 & R2.4 are for near-term. Requirements R2.2 & R2.5 are for long-term. Requirement R1 is for System models.
R1.3.3	TPL-001-2, R2.1.1, R2.1.2, R2.4.1, & R2.4.2 TPL-001-2, R2.2.1 & R2.5	Requirements R2.1.1, 2.1.2, R2.4.1, & R2.4.2 are for near-term and Requirements R2.2.1 & R2.5 are for long-term. These new requirements are more stringent than the existing as they require annual assessments regardless of whether the system has changed or not.

R1.3.4	TPL-001-2, R2.2.1 TPL-001-2, R2.5	These new requirements are more stringent than the existing requirement in that it requires a long-term assessment regardless of system conditions.
R1.3.5	TPL-001-2, R1.1.5	
R1.3.6	TPL-001-2, R1, R2.1.1, & R2.4.1 TPL-001-2, R1, R2.1.2, & R2.4.2 TPL-001-2, R2.1.4	Requirements R1, R2.1.1, R2.1.2, R2.4.1, & R2.4.2 set up the base requirements and Requirement 2.1.4 requires sensitivity analysis to demonstrate the impact of changes to the basic assumptions used in the model.
R1.3.7	TPL-001-2, R3.1 & R4.1 TPL-001-2, Table 1 – P2-2, P2-3, P2-4, P3 through P7	
R1.3.8	TPL-001-2, R1.1.1 TPL-001-2, R1.1.3	
R1.3.9	TPL-001-2, R1.1.4	Requirement R1.1.4 requires that Reactive Power forecasts are utilized and that performance is met for same.
R1.3.10	TPL-001-2, R1.1.1, R1.1.3, R3.3.1, & R4.3.1 TPL-001-2, Table 1 – header note 'c', P-4 & P-5	Requirements R3.3.1, R4.3.1, and header note 'c' require the removal of elements that protection systems are expected to disconnect. Requirements R1.1.1 & R1.1.3 require that existing and planned facilities are modeled. Table 1, P-4 & P-5, require that backup or redundant systems are included.
R1.3.11	TPL-001-2, R3.3.2 & R4.3.2	Requirements R3.3.2 and R4.3.2 require the simulation of expected automatic operation of existing and planned control devices.
R1.3.12	TPL-001-2, R1.1.2 TPL-001-2, R2.1.3	
R1.4	TPL-001-2, R1 & R1.1.3	
R1.5	TPL-001-2, R3.1 & R4.1 TPL-001-2, Table 1 – P2-2, P2-3,	

	P2-4, P3 through P7	
R2	N/A	Introductory sentence
R2.1	TPL-001-2, R2.7	
R2.1.1	TPL-001-2, R2.7	Requirement 2.7 requires the development of a Corrective Action Plan which includes a schedule for implementation.
R2.1.2	TPL-001-2, R2.7	Requirement 2.7 requires the development of a Corrective Action Plan which includes a schedule for implementation.
R2.1.3	TPL-001-2, R2.7	Requirement 2.7 requires the development of a Corrective Action Plan which includes a schedule for implementation.
R2.2	TPL-001-2, R1	
R3	TPL-001-2, R2 & R8	Requirement R2 requires the documentation of the assumptions and summarized results. Requirement R8 is more stringent than the existing requirement in that it includes other Planning Coordinators and Transmission Planners as well as functional entities having a reliability-based need.
Standard TPL-004-1 – System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)		
Requirement in Approved Standard	Translation to New Standard or Other Action	Description (as needed)
R1	TPL-001-2, R1, R2, R3.5, & R4.5 TPL-001-2, Table 1 – Steady State & Stability Performance Extreme Events	
R1.1	TPL-001-2, R2.1	
R1.2	TPL-001-2, R2.1 & R2.4	
R1.3	TPL-001-2, R3 TPL-001-2, R4	Requirement R3 is for steady-state and requirement R4 is for stability.

R1.3.1	TPL-001-2, R3.5 & R4.5	
R1.3.2	TPL-001-2, R2.1 & R2.4 TPL-001-2, R1	Requirements R2.1 & R2.4 are for near-term. Requirement R1 is for System models.
R1.3.3	TPL-001-2, R2.1.1, R2.1.2, R2.4.1, & R2.4.2	These new requirements are more stringent than the existing as they require annual assessments regardless of whether the system has changed or not.
R1.3.4	TPL-001-2, R1.1.5	
R1.3.5	TPL-001-2, R1.1.1 TPL-001-2, R1.1.3	
R1.3.6	TPL-001-2, R1.1.4	Requirement R1.1.4 requires that Reactive Power forecasts are utilized and that performance is met for same.
R1.3.7	TPL-001-2, R1.1.1, R1.1.3, R3.3.1, & R4.3.1 TPL-001-2, Table 1 – Extreme Events header note 'a' & extreme events	Requirements R3.3.1, R4.3.1, and Extreme Events header note 'a' require the removal of elements that protection systems are expected to disconnect. Requirements R1.1.1 & R1.1.3 require that existing and planned facilities are modeled. Table 1, extreme events require that backup or redundant systems are included.
R1.3.8	TPL-001-2, R3.3.2 & R4.3.2	Requirements R3.3.2 and R4.3.2 require the simulation of expected automatic operation of existing and planned control devices.
R1.3.9	TPL-001-2, R1.1.2 TPL-001-2, R2.1.3	
R1.4	TPL-001-2, Table 1 – Steady State & Stability Performance Extreme Events	
R2	TPL-001-2, R2 & R8	Requirement R2 requires the documentation of the assumptions and summarized results. Requirement R8 is more stringent than the

		existing requirement in that it includes other Planning Coordinators and Transmission Planners as well as functional entities having a reliability-based need.
Standard TPL-005-0 – Regional and Interregional Self-Assessment Reliability Reports		
Requirement in Approved Standard	Translation to New Standard or Other Action	Description (as needed)
R1	ERO Rules of Procedure, Section 803	
R1.1	ERO Rules of Procedure, Section 803	
R1.1.1	ERO Rules of Procedure, Section 803	
R1.1.2	ERO Rules of Procedure, Section 803	
R1.1.3	ERO Rules of Procedure, Section 803	
R1.2	ERO Rules of Procedure, Section 803	
R1.3	ERO Rules of Procedure, Section 803	
R1.4	ERO Rules of Procedure, Section 803	
R2	ERO Rules of Procedure, Section 803	
R3	ERO Rules of Procedure, Section 803	
R3.1	ERO Rules of Procedure,	

	Section 803	
R3.2	ERO Rules of Procedure, Section 803	
R3.3	ERO Rules of Procedure, Section 803	
R3.4	ERO Rules of Procedure, Section 803	
R3.5	ERO Rules of Procedure, Section 803	
R3.6	ERO Rules of Procedure, Section 803	
Standard TPL-006-0.1 – Data From the Regional Reliability Organization Needed to Assess Reliability		
Requirement in Approved Standard	Translation to New Standard or Other Action	Description (as needed)
R1	ERO Rules of Procedure, Section 804	
R1.1	ERO Rules of Procedure, Section 804	
R1.2	ERO Rules of Procedure, Section 804	
R1.3	ERO Rules of Procedure, Section 804	
R1.4	ERO Rules of Procedure, Section 804	
R1.5	ERO Rules of Procedure, Section 804	
R1.6	ERO Rules of Procedure,	

	Section 804	
R1.7	ERO Rules of Procedure, Section 804	

Exhibit F

Complete Development record of the proposed TPL-001-2 Reliability Standard

Project 2006-02
Assess Transmission Future Needs and Develop Transmission Plans

Related Files

Status:
The NERC Board of Trustees adopted the TPL-001-2 standard on August 4, 2011. The Implementation Plan for TPL-001-2 will retire TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1 at midnight the day before TPL-001-2 becomes effective as they are replaced in their entirety by TPL-001-2 (subject to regulatory approval). The Implementation Plan also calls for retiring TPL-005-0 and TPL-006-0.1 at that time (subject to regulatory approval) because the Requirements are either covered by the revised TPL-001-2 or by Section 800 of NERC's Rules of Procedure.

Purpose/Industry Need:
The revisions to the following standards would improve technical clarity and address concerns identified by stakeholders and FERC:

- TPL-001 — System Performance under Normal Conditions
- TPL-002 — System Performance Following Loss of a Single BES Element
- TPL-003 — System Performance Following Loss of Two or More BES Elements
- TPL-004 — System Performance Following Extreme BES Events
- TPL-005 — Regional and Interregional Self-Assessment Reliability Reports
- TPL-006 — Data from the Regional Reliability Organization Needed to Assess Reliability

The final SAR is to establish a standard for assessing and planning the transmission systems in North America. The transmission system must be assessed and planned to ensure that it performs its intended functions in providing reliable delivery of power for the future needs of customers.

Draft	Action	Dates	Results	Consideration of Comments
Draft 8 TPL-001-2 Clean**(94)** | Redline to last posting**(95)** **Implementation Plan** Clean**(92)** | Redline**(93)** New Definitions for Approval**(91)** VRFs and VSLs for	Recirculation Ballot>> Info**(96)**	7/13/11 - 7/22/11 (closed)	Summary**(99)** Full Record**(98)** Ballot Comments**(97)**	

Draft	Action	Dates	Results	Consideration of Comments
Draft 8 TPL-001-2 Clean**(94)** | Redline to last posting**(95)** **Implementation Plan** Clean**(92)** | Redline**(93)** New Definitions for Approval**(91)** VRFs and VSLs for TPL-001-2**(90)** **Supporting Materials:** TPL-001-1**(89)** TPL-002-1b**(88)** TPL-003-1a**(87)** TPL-004-1**(86)** TPL-005-0**(85)** TPL-006-0.1**(84)**	Recirculation Ballot>> Info**(96)**	7/13/11 - 7/22/11 (closed)	Summary**(99)** Full Record**(98)** Ballot Comments**(97)**	
Draft 7 TPL-001-2 — Transmission System Planning Performance Requirements Clean**(74)** | Redline to last posting **(75)**|TPL-001-2 Redline to last balloted**(76)** Implementation Plan**(73)** **Supporting Materials:** Comment Form**(72)** TPL-001-1**(71)** TPL-002-1b**(70)** TPL-003-1a**(69)** TPL-004-1**(68)** TPL-005-0**(67)** TPL-006-0.1**(66)**	Join ballot pool>>	4/18/11 - 5/18/11 (closed)	Summary**(82)** Full Record**(81)** Non-Binding Results**(80)**	Consideration of Comments**(83)**
	Successive Ballot and Non-Binding Poll>> Info**(78)**	5/18/11 - 5/31/11 (closed)		
	30-day Formal Comment Period Submit Comments>> Info**(77)**	4/18/11 - 5/31/11 (closed)	Comments Received**(79)**	

Draft 6 TPL-001-2 — Transmission System Planning Performance Requirements Clean**(63)** | Redline to last posting**(64)**	Info**(65)**			
Draft 5 TPL-001-2 — Transmission System Planning Performance Requirements Clean**(58)** | Redline**(59)** Implementation Plan Clean**(56)** | Redline**(57)** **Supporting Materials:** Comment Form (Word)**(55)**	30-day Informal Comment Period Submit Comments>> Info**(60)**	08/03/10 - 09/02/10	Comments Received**(61)**	Consideration of Comments**(62)**
TPL-001-1 — Transmission System Planning Performance Requirements Clean**(48)** | Redline**(49)** Implementation Plan Clean**(46)** | Redline**(47)** **Supporting Materials:** Issues Database**(45)** VRF and VSL Documentation**(44)**	Initial Ballot Vote>> | Info**(51)**	02/19/10 - 03/01/10 (closed)	Summary**(53)** Full Record**(52)**	Consideration of Comments**(54)**
	Pre-ballot Review Join>> | Info**(50)**	01/20/10 - 02/19/10 (closed)		

Draft 4 TPL-001-1 — Transmission System Planning Performance Requirements Clean**(39)** | Redline to last posting**(40)** **Supporting Materials:** Comment Form (Word)**(38)** Implementation Plan Clean**(36)** **|** Redline**(37)**	Comment Period Info**(41)** Submit Comments>>	09/16/09 - 10/16/09 (closed)	Comments Received**(42)**	Consideration of Comments**(43)**
Draft 3 TPL-001-1 — Transmission System Planning Performance Requirements Clean**(31)** | Redline to last posting**(32)** **Supporting Materials:** Comment Form (Word)**(30)** Implementation Plan**(29)**	Comment Period Info**(33)** Submit Comments>>	05/26/09 - 07/09/09 (closed)	Comments Received**(34)**	Consideration of Comments**(35)**
Draft 2 TPL-001-1 — Transmission System Planning Performance Requirements Clean**(24)** | Redline to last posting**(25)** **Supporting Materials:** Comment Form (Word)**(23)**	Comment Period Info**(26)** Submit Comments>>	08/14/08 - 9/29/08 (closed)	Comments Received**(27)**	Consideration of Comments**(28)**

Industry WebEx and Conference Call to Provide Overview of First Draft of TPL-001-1 — Transmission System Planning Performance Requirements Info**(22)**		October 10, 2007		
Draft 1 TPL-001-1 — Transmission System Planning Performance Requirements Clean**(17)**	Comment Period Info**(19)** Submit Comments**(18)**	09/12/07 - 10/26/07 (closed)	Comments Received**(20)**	Response to Comments**(21)**
ATFN Supplemental SAR Supplemental SAR Version 2**(16)** Redline to 1st Posting**(15)**				
ATFN Supplemental SAR Supplemental SAR Version 1**(10)**	Comment Period Info**(12)** Submit Comments**(11)**	02/15/07 - 03/16/07 (closed)	Comments Received**(13)**	Consideration of Comments**(14)**
Final SAR**(9)**				
Assess Transmission Future Needs SAR Drafting Team Draft SAR Version 3**(7)**	Submit Nomination**(8)**	November 18, 2005 (closed)		
Draft SAR Version 2**(4)**		05/05/04 - 06/05/04 (closed)	Comments Received**(5)**	Consideration of Comments**(6)**
Draft SAR Version 1**(1)**		04/02/02 - 05/03/02 (closed)	Comments Received**(2)**	Consideration of Comments**(3)**

Standard Authorization Request (SAR) Form

Title of Proposed Standard:	Assess Transmission Future Needs and Develop Transmission Plans
Request Date:	March 6, 2002
Authorized for Posting:	March 20, 2002
SAR ID# :	TRNS_NDS_&_PLNS_01_01

SAR Requestor Information		**SAR Type** (Put an 'x' in front of one of these selections)	
Name:	Jim Byrd	X	New Standard
Primary Contact:	Jim Byrd		Revision to existing Standard
Telephone: Fax:	214-743-6870 972-263-6710		Withdrawal of existing Standard
e-mail:	jbyrd@txu.com		Emergency Action

Purpose/Industry Need (Provide one or two sentences)

To establish a standard for assessing and planning the transmission systems in North America.
The transmission system must be assessed and planned to ensure that it performs its intended functions in providing reliable delivery of power for the future needs of customers.

Brief Description (A few sentences or a paragraph)

Requirements shall be established for assessing transmission system performance under a variety of system conditions including system normal conditions, abnormal conditions, and extreme system conditions. Requirements shall be established for a plan, including a definition of the planning horizon, to address these conditions to ensure that the interconnected transmission systems perform their intended functions and to prevent severe adverse effects such as uncontrolled or cascading interruption of network operation. The plan may utilize operating, construction, market solutions or other components to address these conditions.

Reliability Functions

The Standard will Apply to the Following Functions *(Put an 'X' in front of each one that applies)*		
X	Reliability Authority	Ensures the reliability of the bulk transmission system within its Security Authority Area. This is the highest reliability authority.
	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time
	Interchange Authority	Authorizes valid and balanced Interchange Schedules
X	Planning Authority	Plans the bulk electric system
	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
X	Transmission Owner	Owns transmission facilities
	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
	Distribution Provider	Provides and operates the "wires" between the transmission system and the customer
	Generator	Owns and operates generation unit(s) or runs a market for generation products that performs the functions of supplying energy and Interconnected Operations Services
	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required.
	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

Reliability and Market Interface Principles

Applicable Reliability Principles *(Put an 'x in front of all that apply)*	
X	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.
	2. The frequency of interconnected bulk electric systems shall be controlled within defined limits through the balancing of electric supply and demand
X	3. Information necessary for planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably
	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented
	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems
X	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions
X	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis

Does the proposed Standard comply with all of the following Market Interface Principles? *(Enter 'yes' or 'no')*	YES
1. Interconnected The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy	
2. An Organization Standard shall not give any market participant an unfair competitive advantage	
3. An Organization Standard shall neither mandate nor prohibit any specific market structure	
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard	
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards	

Assess Transmission Future Needs and Develop Transmission Plans

SAR Commenter Information			
Name	David H. McMillan		
Organization	Calpine		
Telephone	713-830-8710	Fax	713-830-2001
E-mail	dmcmillan@calpine.com		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?
☒ Yes ☐ No

Look at the SAR called: Assess Transmission Future Needs and Develop Transmission Plans:
Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No
☐ Yes ☒ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☒ The scope of the SAR should be reduced to eliminate: any aspect that goes beyond establishing specific reliability criteria to be incorporated into the Transmission Planning activity and product.
Other comments: The "Generator" reliability function should be checked as being impacted since generators are defined as an integral component of the bulk power transmission system being planned.

SAR Commenter Information			
Name	Bill Carr		
Organization	Dynegy, Inc.		
Telephone	713-7657-8723	Fax	713-767-5986
E-mail	bill.carr@dynegy.com		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

Look at the SAR called: Assess Transmission Future Needs and Develop Transmission Plans:
Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☐ The scope of the SAR should be reduced to eliminate:

Other comments: The purpose/industry need section should start with: The purpose of this standard is to ensure that a consistent, uniformly applied standard is developed .. ..

SAR Commenter Information			
Name	John Anderson and John Hughes		
Organization Electricity Consumers Resource Council (ELCON)			
Telephone	202-682-1390	Fax	202-289-6370
E-mail	jhughes@elcon.org/janderson@elcon.org		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed:

The actual drafting of these 11 SARs is premature. Every "reliability" standard also is a "commercial" standard. There must be very detailed coordination with the organization that will establish "commercial" standards (NAESB). Such coordination has not even begun. The scope, procedures, process and practices of such coordination must be clearly specified and agreed to before the drafting of the SARs begins.

Look at the SAR called: Assess Transmission Future Needs and Develop Transmission Plans:
Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No
☐ Yes ☒ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☒ The scope of the SAR should be reduced to eliminate: The establishment of this SAR is premature. All commercial implications of the SAR should be identified and mitigated prior to the drafting.

SAR Commenter Information			
Name	Phil Park		
Organization	Powerex		
Telephone	604 891 5020	Fax	604 895 7012
E-mail	phil.park@powerex.com		

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed:

I have a general comment to preface my comments on the individual SARs. To me, what we are calling a "core reliability requirements" are simply technical specifications for things we believe the industry cannot adequately address through commercial negotiations between individual players or things too small to bother with by one on one negotiations. Core reliability requirements do not include business practices. These technical specification should ensure that they do not prohibit worthwhile commercial negotiations. With this definition, all core reliability requirements have commercial elements. I can accept this and this should not inhibit us from setting a technical specification (core reliability requirement) where one makes sense. However, we must avoid setting one whenever we can, simply because we can. This latter approach will inhibit valuable commercial activity. If the reliability standards become so encompassing that they threaten commercial activity, we will simply end up focusing on including exemptions, waivers, and differences such that the standard has limited applicability.

In many cases in my comments below I have not indicated whether or not the proposed standard is required. This can only be determined after we have rationalized the details of each of the SARs. The answer to this question should be an outcome of the process, not an input to it.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☐ No
☐ Yes ☒ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate: The description should be revised as follows: "Requirements shall be established to ensure that interconnected transmission systems are planned such that they can reliably perform their intended functions over a wide range of system conditions." The phase "while continuing to operate reliably within equipment and electric system thermal, voltage, and statbility limits" should be transferred to SAR #2 addressing facility ratings, operating limits, and transfer capabilities.

Other comments: *Assessment of future needs and development of transmission plans is highly related to commercial processes. As in other markets, information needs to be collected to assess future ability of the market participants to respond to market requirements. This SAR should be coordinated with business practices for the industry.*

The phase I am recommending be moved to SAR #2, which appears to encompass standards presently covered by Planning Standards I.A (Table 1) and I.D, is the major component that makes this SAR a core reliability requirement. My rationale for moving this to SAR #2 is included in the comment form for that SAR.

SAR Commenter Information			
Name	MAAC Region		
Organization	MAAC		
Telephone	610-666-8854	Fax	610-666-2297
E-mail	dicapram@pjm.com		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed:

MAAC questions the need for standards concerning 'Design' of Protection systems, Physical connection, Coordinate Interchange, and Analysis of disturbances.

"Design" issues are commercial issues not reliability issues.
The Transmission Operators will define Interconnection Agreements.
Coordination of Interchange can be a subset of "Coordinate Operations"
Disturbance analysis will be address by regulators

Most of these are good business practices or good utility practice but not core reliability standards.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No
☐ Yes ☒ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:

Other comments:

The substance of this SAR should focus on defining 'uniform study conditions' and on ensuring that all interregional analyses use those conditions.

Must ensure that the SAR does NOT become a mandate "to use the same load flow Tool" (which would be a violation of the Market principles).

SAR Commenter Information			
Name	Mike Miller		
Organization	Southern Company		
Telephone	205 257 7755	Fax	6663
E-mail	mbmiller@southernco.com		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: The "Assess Transmission future needs and develop transmission plans" SAR does not state a requirement to plan the system so that it can be operated within operating limits. I feel that this terminology (operating limits or other term such as Operating Security Limits) should be common among all SARs. The system must be planned so that it can be operated reliably. Using this terminology in all SARs would provide the appropriate link among them.

Without knowing the details that will be included in the standards as described by these SARs, it is difficult to make an assessment on the completeness of this set of SARs. I feel that there should be a SAR that requires LSEs, distribution providers, and generators to respond to requests that will have the effect of operating the system within Operating Limits.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is

☒ The scope of the SAR should be expanded to include: Planning must be coordinated to optimize not only transmission but generation as well. The left alone process of disjointing generation and transmission is creating a non-steady state electrical system. The criteria for designing a system must include defined measurements adopted by all. This brief description does not provide sufficient detail to ensure reliability is planned. The planning criteria must address defined transmission planning for transfer usage as well as specific load service usage in other words interconnection as well as intraconnection. The need to define roles, responsibilities and authority must be developed between Federal (RTO) characteristics and functions and transmission owners.

☐ The scope of the SAR should be reduced to eliminate:

Other comments: Transmission Operator and perhaps Distribution Provider should be added to the list of applicable functions.

SAR Commenter Information			
Name	Alan Johnson		
Organization	Mirant Americas Energy Marketing		
Telephone	678-579-3108	Fax	678-579-5760
E-mail	alan.r.johnson@mirant.com		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed:

There may not be a need for the following two standards: i) Define (Physical) Connection Requirements; and ii) Monitor and Analyze Disturbances, Events, and Conditions.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☒ The scope of the SAR should be reduced to eliminate: Reference to standardization of the solution set for the transmission plan (see Brief Description section). Mirant is concerned that the standard goes beyond assessment and planning of the bulk transmission system, delving into definition of the methods for meeting the plan. Per the *Market Interface Principles* (principle 4), the standard should not inhibit commercial/market solutions.

Other comments:

Mirant believes that the standard should not apply to the Transmission Owner function, consistent with the *Functional Model*.

April 23, 2002

SRP Comments on NERC 11 SAR sent out on April 2, 2002.

All 11 SAR's (this group of 10 plus the one sent out earlier) don't contain enough information to make the kind of judgments requested on the forms. Therefore the forms are not filled out.

We recommend all the SAR's be advanced to the next step to develop the specific standards and associated measurements for each standard so that we can evaluate and comment on them.

All of these SAR's are needed for reliable planning and operation of the bulk electric transmission system and meet the principle requirements.

Comments on the White paper:

1. The paper fails to state what standards are supposed to be. This seems so basic; one has to assume that those drafting the white paper want to redefine the definition contained in the Organizational Standards Manual. This leads to a lot of confusion and is not the place to do that.

2. The Planning Standards were written in a different time period than the Operating Policies with different objectives. Thus they are different and that should be recognized. For instance the development of a Planning Functional model has absolutely nothing to do with whether control areas exist or not and whether companies have restructured or not. The statement about control areas may be true for the Operating Policies but it is not try for the Planning Standards.

   The Planning Standards (Templates) were written to meet the definition of a standard in the Organizational Standards Manual, to meet at least one of the Reliability Principles, to comply with all the Market Interface Principles and to contain the compliance administration elements. This is very different than what is contained in the Operating Policies. The Planning Standards need to go through the new process so that both the Operating elements and Planning elements of the Organizational Standards are consistent, are not duplicative and are needed for reliability.

3. The term " core reliability requirement" is used in the white paper but is never mentioned in the Organizational Standards Manual. Using an undefined term is very misleading and should be avoided.

4. The paper in several places address "what performance must be achieved". As noted above, an Organizational Standard can be broader than that and this write up is misleading.

5. The process has been lengthened because of the multiple posting of the SAR's. NERC has a body of reliability requirements written up into Compliance Templates. With very little effort these could be written up into SAR's that would provide sufficient detail for NERC to evaluate them. It is very hard to comprehend why one does not use this work to expedite the process. Instead SAR's are sent out with insufficient information. The process is long enough. We should be looking for all ways possible to speed it up.

Comments on the SAR write-up:

1. The SAR write-up only contains the purpose and brief description of a standard. Where is the Standard? I thought that is what the SAR is for?

2. The descriptions are in most cases extremely vague. The write-ups contain words like "such as" or "as defined in the standard". These are big enough to cover a MAC truck. Once again there is insufficient information to make a good judgment.

April 29, 2002

Guy V. Zito
Manager, Planning
Northeast Power Coordinating Council
1515 Broadway Floor 43
New York, NY 10036

RE: NEPOOL Compliance Working Group (NCWG) comments pertaining to the 10 Standard Authorization Requests (SARs) posted for open comment

The NCWG has reviewed the 10 SARs posted for open comment and has agreed they are core standards, which serve a purpose in support of reliability.

Standard Title:
Prepare for and Respond to Abnormal or Emergency Conditions
Prepare for and Respond to Blackout or Island Conditions
Coordinate Interchange
Coordinate Operations
Monitor and Analyze Disturbances, Events and Conditions
Operate Within Limits – Monitor and Assess Short-term Transmission
Define (Physical) Connection Requirements
Design, Install, and Coordinate Control Protection Systems
Assess Transmission Future Needs and Develop Transmission Plans
Determine Facility Ratings, Operating Limits, and Transfer Capabilities

We do not agree that the **SAR Type** is a new standard. We suggest that at a minimum the SAR should indicate the existing standard and whether or not it will be withdrawn when the revised standard is adopted. We suggest that NERC stop the open process of reviewing existing policies and standards if these Organizational Standards will replace them. NERC should clearly indicate that one purpose of the Organizational Standards Process is to replace existing standards.

Sincerely,
Daniel L. Stosick

Chairman, NEPOOL Compliance Working Group
C/o ISO New England, Inc.
One Sullivan Road
Holyoke MA 01040-2841

Cc: NEPOOL Compliance Working Group
CP9 Working Group
Paul Shortly
Richard Burke
Richard Kowalski

SAR Commenter Information			
Name	Robert D. Smith		
Organization	Arizona Public Service		
Telephone	(602) 250-1144	Fax	(602) 250-1155
E-mail	robert.smith@aps.com		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No
☒ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:
Other comments: We do not believe that transmission plans should utilize market solutions as solutions to identify problems.

SAR Commenter Information			
Name	Mr. Charles Moser (Northborough, MA) and Mr. Ronald Halsey (Syracuse, NY)		
Organization National Grid USA			
Telephone	508 421 7600 315 428 3181	Fax	508 421 7520 315 428 5615
E-mail	charles.moser@us.ngrid.com ronald.halsey@us.ngrid.com		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: These standards as written delve much too deeply into the details of "HOW" and "WHAT" AND "WHEN". They instead should stick to the idea of developing an umbrella of BROAD PERFORMANCE BASED CRITERIA standards that establish the basis for the creation of Region specific standards that will meet the intent of the NERC standard.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☐ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☒ The scope of the SAR should be reduced to eliminate:

Other comments: The standard should define the transmission system performance basis upon which any planning or assessment efforts would be measured. We do not need a standard on HOW to assess or plan our systems. We need a broad based standard that will define the required transmission system performance levels based on an established and demonstrated need for such performance levels rather than on an abstract concept of "reliability".

SAR Commenter Information			
Name	Vern Colbert		
Organization	Dominion Virginia Power		
Telephone	(804) 273-3399	Fax	(804) 273-2405
E-mail	vern_colbert@dom.com		
Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid? ☒ Yes ☐ No			

SAR Commenter Information			
Name	Greg Gideon		
Organization	TXU Energy		
Telephone	214-875-9483	Fax	214-875-9246
e-mail	ggideon1@txu.com		
Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid? ☒ Yes ☐ No			

SAR Commenter Information			
Name	Paul Rocha		
Organization	Reliant Energy HL&P		
Telephone	713-207-2768	Fax	713-207-2281
e-mail	paul-rocha@reliantenergy.com		

Reliant Energy HL&P ("HL&P") files these comments regarding the ten Standard Authorization Requests (SARs) discussed below. Please note that HL&P is the regulated electric utility operating in and around the area of Houston, Texas, within the ERCOT region. HL&P does not represent Reliant Resources, the unregulated energy services company operating in various areas of North America and Europe. Reliant Energy expects to spin off Reliant Resources later this year. In anticipation of the pending separation, HL&P and Reliant Resources are operating in large part as two separate companies. It is HL&P's understanding that Reliant Resources may separately provide comments regarding these SARs.

HL&P agrees that there is a need for a standard for assessing transmission future needs and developing transmission plans. We support ERCOT's comments, which either have or will soon be filed, regarding the appropriate scope and characteristics of such standards. However, we believe a prospective NERC planning standard should apply to interstate and international electric systems only, and should not apply to intrastate electric systems such as ERCOT, as explained more fully below.

The assessment of need and development of transmission plans should strive for an appropriate balance between ensuring reliability, maintaining reasonable transmission rates, mitigating congestion costs, and avoiding unnecessary landowner impact. For intrastate transmission systems such as ERCOT, HL&P believes that the appropriate place to balance these objectives is within the intrastate region itself, since the ERCOT organization, and the standards it develops, are subject to state commission review and approval. That same state commission (the Public Utility Commission of Texas) also has rate-setting and line certification authority, and thus is uniquely positioned to balance the conflicting objectives involved in transmission system planning. However, for interstate and international regions, it may be appropriate for NERC to develop a transmission planning standard. Recognizing that NERC does not have rate-setting or line certification authority, NERC should guard against establishing one-dimensional standards that fail to take into account all the dimensions that guide the transmission planning process.

SAR Commenter Information			
Name	Brant Eldridge		
Organization	ECAR		
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E-mail	brante@ecar.org		

ECAR has conducted a survey of its member companies regarding the eleven SARs, which NERC has initiated to-date. We recognize that the comment period for the first SAR issued ("Balance Resources and Demand") has already closed. However, considering that the first SAR was issued earlier than the other ten primarily just to get the process started, and further considering that all 11 SARs are viewed by NERC as a possible complete set of Organization Standards (re: the "White Paper"), ECAR believes that comments on the first SAR should still be considered along with those on the other ten.

11 of the 18 ECAR Full Members, along with two Associate Members, submitted responses to the SAR survey. Some of the responses were submitted using the NERC "SAR Comment Form", while others were contained in narrative e-mails, and one was faxed to us. Therefore, a complete set of the ECAR member company responses will be sent to the Standards Process Manager at NERC via Fed Ex to arrive at NERC by May 3rd. The Fed Ex package will include a copy of this e-mail. FYI, NERC may also receive some of the ECAR member company responses directly from the companies. Some of the individual company responses will be identical to what will be in the Fed Ex package and some will contain more detailed comments.

The ECAR member company responses contain numerous and wide-ranging comments about the need for each of the 11 proposed Organization Standards, as well as comments regarding the scope and applicability of the SARs. As your review of these responses will show, there is general ECAR consensus – but not unanimity -- that the 11 SARs as a set cover the scope of performance needed to ensure reliability of the interconnected North American bulk power systems. Some ECAR members feel that there are performance areas not covered in the proposed set of Organization Standards, and they have provided what they think is missing. Others believe that some of the proposed Organization Standards are not needed, and they explain why they feel that way. Numerous comments were directed at the scope and applicability of the SARs. Several ECAR companies questioned the inclusion of the "Distribution Provider" function in the applicability section of the SARs, believing that NERC should stick to its traditional focus on the bulk power systems and stay out of the distribution arena.

The recent call for nominees to serve on SAR Drafting Teams is the appropriate next step. ECAR believes that all 11 SARs need to be refined to reflect industry comments and then posted again for another round of industry comments. Before proceeding into actual development of Organization Standards based on these 11 SARs, NERC must have clear industry consensus on the need for each of the Organization Standards outlined in the 11 SARs, as well as consensus on the scope and applicability of those SARs.

If the wide-ranging comments received from ECAR members are any indication, there is still some serious work to be done to achieve the needed clear industry consensus on how to proceed.

East Kentucky Power Cooperative (General Comment)

EKPC believes our present standards are adequate and therefore is not in favor of developing a new set of standards. We also believe the new process should be revised to provide for a screening committee to evaluate proposed standards before they are presented to all NERC members for comment. However, given that we are going to develop new standards with this process, EKPC endorses all eleven of the SARs. Thanks, Paul Atchison.

LG&E Energy (General Comment)

LG&E agrees there is a need for the eleven proposed organization standards. However, we do see a disconnect with their development and operating procedures/protocols of RTO's. Where will this coordination take place to ensure consistency, eliminate redundancy, and application particularly since there will most likely be more than 1 RTO at the time of issuance?

VECTRON – Southern Indiana Gas & Electric (General Comment)

The NERC Proposed Organization Standards appear to me to cover the scope of performance needed to insure reliability of the interconnected grid. The scope of the SARs as proposed, also, look fine to me.

Dayton Power & Light (General Comment)

We are okay with the 11 proposed Standards.

American Electric Power (General Comment)

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American Electric Power is providing the following comments on the 10 most recent Standard Authorization Requests (SARs) to ECAR as input to the formulation of ECAR's response to NERC. AEP looks forward to working with ECAR and NERC as well as other market participants to ensure the continued reliability of the electrical system.

Clearly the electricity industry has been exceptionally dynamic and fluid in recent years and is going through many changes. While changes can be positive, it is incumbent on the industry to ensure that changes, which are adopted result in enhanced reliability and a better market environment. With this in mind, we envision that there are actually three interrelated but separable processes with respect to the development of standards.

First, the relevant standards need to be identified. Over recent months this has been referred to as defining "what" the standard is.

Second, there need to be decisions about "how" these standards are to be achieved.

Third, choices have to be made as to how these standards will be implemented.

The resultant standards, when implemented and operational, will potentially affect production, consumption and investment decisions. By necessity, the standards, including how they are achieved and implemented, are closely related to the design of the market and the separation of functions among market

participants and service providers. For this reason, we encourage discussion and even preliminary definition of what core reliability standards are needed. However, we strongly urge restraint with respect to the other two aspects of the process - defining how the standards will be achieved as well as how they will be implemented. In our opinion, the latter two processes are highly integrated with the process of market design and implementation as well as market operation; the development of RTOs; and the definition of the NERC/NAESB interface.

Given that closure on many of the market design issues is expected in the near future, we see little risk in delaying the latter two processes - how the standards are achieved and implemented-- until such time as clarity is achieved on Standard Market Design (SMD) and RTO formation. Moreover, since the NERC/NAESB interface will likely impact decisions on how standards will be achieved as well as how they will be implemented, it seems logical to wait until that interface has been defined.

We think it would be beneficial for NERC to recognize that nothing is gained by deciding how the standards will be achieved (including implementation) at this stage of the debate on Standard Market Design and the RTO development process. We would prefer to see the SAR process simply make the threshold determination as to whether any of the proposed standards are needed, and then put on hold the actual development of those standards that are needed until the critical market development activities described above are closer to completion. AEP is reviewing the SARs with particular emphasis on their scope, both individually and collectively, and we plan to provide appropriate comments to NERC by May 3.

Consumers Energy (General Comment)

Consumers Energy opposes all 10 of the SARs on their present form. We understand that it is too late to vote on the 11th SAR.

The concern that we have is that there is only limited ability to prevent new requirements from being incorporated with the old, standard reliability requirements. The SAR descriptions sound good because they espouse the old, tried and true reliability concepts that we have known and loved from the past. If there was an effective way to limit the resulting practices to those traditional values, I would be the first to support them. Unfortunately, we are not voting here on codification of the current practices. We, instead, are voting to develop a set of practices that will include the currently unknown and possibly oppressive, unacceptable set of future requirements. This vote has nothing to do with the tried and true practices from the past. Its about accepting an unknown set of requirements on faith and trust ... that none of the practice developers will be out to do us harm.

The standard argument here is that the SARs are only scope setting documents and that we will still have a change to shape and to vote on the actual standards when they go through the final approval stage. If we believe this argument, we are totally ignoring the lessons from the past. There is no guarantee that ECAR will have any personnel involved in the development of the final practices. It is unclear how many people will be involved in the drafting of the practices nor how they will be selected.

The biggest single concern is what the final product will look like and how it will be voted on. I would make a modest wager that it will consist of a handful of standard practices that we all could accept (and in fact would insist upon) along with three practices that are new and totally unacceptable. We will be faced with the proposition that we must vote on the "package" of practices where we must accept the bad ones to get the good ones. I can find no reference to a line item voting procedure.

The solution to this problem is to suggest a provision in all ten SARs that the final package of practices will not include any policies that are not already in the NERC approved set of policies and standards. Consumers Energy could then support all ten SARs.

C.V. Waits

Duquesne Light Company (General Comment)

OPERATIONS AND ASSET MANAGEMENT
System Operations
Transmission Business

TO: Brant Eldridge
FROM: J. F. Rosser
DATE: May 8, 2002
SUBJECT: NERC "Organizational Standards"

In response to your memo of April 19, 2002, Duquesne Light Company presents the following comments concerning the eleven "Standard Authorization Request" (SAR) Forms. Generally, the proposed standards seem to simply restate today's standards and label them as "new" Organizational Standards. Specifically, the proposed SAR titled "Balance Resources and Demand" is really a restatement of the current Disturbance Control Measure, CPS1, CPS2 and a new Frequency Response Measurement. This SAR, as represented at the CRC meeting, was to provide an example of how other SARs should be composed.

1. The purpose of the standard is stated as; Maintain scheduled Frequency within an Interconnection.

2. The Industry need includes Arrest Sudden frequency changes; Prevent Time error; Prevent Operation of Underfrequency Relays, prevent line loading limits violations, minimize inadvertant interchange.

3. Standards include; a measurement (FRM) to ensure automatic throttle controls are available to arrest frequency changes, a measurement (CPM1) to ensure adequate generation control regulation to maintain scheduled frequency, a measurement (CPM2) to ensure unscheduled power flows do not occur which could cause transmission operating limit violations, a measurement (DCM) to ensure scheduled frequency is maintained after a disturbance.

It is evident that this SAR's Title, Purpose, Need and Measures are inconsistent with each other, mixing frequency schedules and inadvertant accumulations with transmission loading violations and time error. Also, certain "Needs" and "Standards" are inconsistent with the NERC BOT decision to not pursue the development of business practices (i.e., minimization of inadvertant accumulations, timer error accumulations, etc. are equity issues and not related to reliability concerns).

Furthermore, suggested are measures that better relate to other Standards. For example, transmission limit violations fit better into "Monitor and Assess Short Term Transmission Reliability" – operate within limits. When considered under that alternate standard, this measurement may not survive because other measurements may be deemed more appropriate.

Look at the SAR from a purely technical approach. In doing so, Duquesne Light suggests that the title of the Standard "Balance Resources and Load" should be rewritten to be "Maintain Scheduled Frequency".

The Purpose of Standards would be to maintain Interconnection frequency within acceptable limits.

The Industry Need would be to prevent damage to customer equipment and to prevent unstable operations related to disturbances.

The Standard should include a description of acceptable frequency along with a technical defense of the standard including standard generator limits, motor limits, etc.. See ECAR Document #3, Appendix 1, (attached) as an example.

The Standard should include adherence to accepted industry practices such as the installation of underfrequency relays, automatic governor control requirements, etc. including the operation of this equipment within limits specified within the standard.

Measures and Requirements may include:

1. a measurement similar to CPS1
2. annual audit of underfrequency load shedding equipment, levels, and set points
3. annual audit of the status and condition of automatic governor controls
4. monitoring of frequency excursions related to disturbance conditions (Security Coordinator)
5. Coordination of interchange schedules

Measurements should not include:

1. DCM because it duplicates CPM1 and is not frequency sensitive
2. CPM2 because it purports to protect against transmission loading violations related to SAR #6

If NERC would consider business practices, the ECAR Inadvertant Settlement Process could be incorporated into the standard with a longer range target of replacing energy banks with a pay as you go policy, possible tied to adders ($/MWH) related to system frequency deviations from schedule. Otherwise, NAESB would develop these business practices.

The following are Duquesne's comments on the other 10 proposed SARs.

1. Assess Transmission Future Needs & Develop Transmission Plans – Appropriate
2. Determine Facility Ratings, Operating Limits and Transfer Capabilities – Appropriate
3. Design, Install, Coordinate Control and Protection Systems – Appropriate
   Standard should be expanded to include coordination between Transmission Owners, Transmission Operators, etc.
4. Define (Physical) Connection Requirements – Inappropriate as a stand alone SAR
   This SAR should be included in SARs #2, #3, #6, #7, #8, #9, #10, #11
5. Previously reviewed
6. Operate Within Limits – Monitor & Assess – Inappropriate as a stand alone SAR, but should be incorporated with SAR #8. Coordinated operations are required to ensure limits are not violated.
7. Coordinate Interchange – Inappropriate as a stand alone SAR. Should be part of SAR #5.
8. See review of SAR #6.

9., 10., and 11. Should be incorporated into SAR #6/#8 and/or #5 as modified by DLC

In conclusion, Duquesne Light applauds the NERC SAR initiative. NERC must, however, take care to not simply allow this initiative to be a restatement of existing standards

and application of performance measurements that miss the target. Care must be taken to identify the exact technical need/purpose (quantifiable) for each performance standard, ensuring that each performance measurement ties precisely with a stated need/purpose in support of the standard (e.g., A Standard whose purpose is to maintain frequency should not be tied to a need to limit unscheduled power flows that can cause operating limit violations but should be tied to general turbine-generator requirements).

cc: ECAR Executive Board
ECAR Coordination Review Committee
ECAR Market Interface Committee

SAR Commenter Information			
Name	David L. Hart		
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No
☒ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:

Other comments: The SAR seems broad enough to enable it to include planning associated with IPPs. This should definitely be considered in the further development of this Standard.

SAR Commenter Information			
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

What is missing from the NERC set of SARs?

1. Load forecasting, generation capacity, and capacity margin analysis.
2. Generation operating requirements:
    a. Voltage schedule produced and followed
    b. Voltage control kept on automatic
    c. Generator controls with a 5% or less droop
    d. Speed control (frequency) on automatic
    e. Record the times and reasons when speed control, voltage control, or voltage schedule were not on automatic.
3. Reliable construction and maintenance standards for transmission lines, transmission substations, and generation substations.
4. Control Area tie-line tripping for conditions of:
    a. Under frequency
    b. Overload
    c. Instability
    d. Voltage collapse

Note that item #4 was not included in the old NERC Reliability Standards. We did not have the technical ability to properly manage these conditions for at least the first twenty years of NERC. We now have the technical ability to predict and operate at the **points of no recovery** for these conditions and should not do so, to:

a. Reduce the number of **Control Areas Blacked Out** by a major disturbance to the interconnected grid.
b. Make **Safe Unit Shut Down Power** from neighboring control areas much more available.
c. Make **Unit Restart Power** much more available from neighboring control areas.
d. Make **Load Restoration Power** much more available from neighboring control areas.
e. **Reduce Dependence** on questionable black start plans.
f. **Never disconnect a control area** from the interconnected grid, unnecessarily.

All that is needed at this time for this item #4 is that the five ECAR technical panels involved (OP, TSPP, TFP, GFP, PP) develop a set of guides for these four conditions for which tie lines should be tripped. Then, any control area that would like to obtain the six advantages listed above, would have a solid well thought out set of guides to start from. (I would be glad to help any of the technical panels with the details. Lew Gray)

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

SAR Commenter Information			
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

Other comments: The Standard should also apply to the Transmission Provider function since the source fo much of the congestion management/ TLR related data will be obtained from this functional area.

SAR Commenter Information			
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

General Comments:

1) Even though the Standards drafting committee is to be fairly small (8 or 9, I believe), there needs to be a committee VOTING process for deciding on the final proposed wording or a Standard.

2) There needs to be a formal face to face forum for reviewing SARs after the drafting committee has done its work. Some have proposed the current Standing Committee meeting as this forum. As long as the meetings match up with the Standards development timeline, this would be OK.

3) We also support the submittal of the actual Standards Development process through the SAR process. The current process was developed without any "due process" or formal approval process prior to the BOT adoption.

4) We still believe that there are too many Segments in the NERC process.

5) The new NERC standards development should be completed and receive ANSI approval before development begins on the new standards contemplated by these SARS. Proceeding with SARS before the new standards process is in place ensures that significant re-work will be required.

6) The industry is already stretched very thin supporting the many NERC and FERC initiatives. The number of SARs proposed at one time is excessive. Also, there will be inevitable overlaps and conflicts between the various SAR drafting groups. Only 1 or 2 SARs should move forward at one time.

7) The time provided to review and comment on such a large number of SARs was insufficient to do a thorough review and provide accurate and complete comments.

The "Assess Transmission future needs and develop transmission plans" SAR does not state a requirement to plan the system so that it can be operated within operating limits. We feel that this terminology (operating limits or other term such as Operating Security Limits) should be common among all SARs. The system must be planned so that it can be opearated reliably. Using this terminology in all SARs would provide the appropriate link among them.

Without knowing the details that will be included in the standards as described by these SARs, it is difficult to make an assessment on the completeness of this set of SARs. We feel that there should be a SAR that requires LSEs, distribution providers, and generators to respond to requests that will have the effect of operating the system within Operating Limits.

Maintenance requirements should cover transmission equipment other than just protection and control equipment.

A lot of vital requirements of existing policies are not included in any of the proposed SARS, i.e., time error correction, inadvertent, etc.

The main power equipment design, installation, and maintenance requirements are not adequately addressed in these SARs (i.e. circuit breakers, transformers, transmission lines, etc.). Should also address transmission line right-of-way maintenance.

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed:

It appears that some of the SARS overlap and cover some of the same areas, such as "Prepare For and Respond to Emergency Conditions", "Prepare for and Respjond to Blackout or Island conditions", and "Monitor and Analyze Disturbances, Events, and Conditions". These could all fall under a single Emergency Operations SAR. "Coordinate Interchange" should also fall under "Coordinate Operations". In addition, the SARS are intended to define standards for core reliability functions, i.e., "who to do". Some of the SARS really describe processes (i.e., "how to do it") rather than define standards, such as the SAR on "Determine Facility Ratings, Operating Limits and Transfer Limits". There are others that may need to be combined-it is suggested that a remapping of policies to specific SARS should be done.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☐ The scope of the SAR should be reduced to eliminate:

Other comments: For the Applicable Functions, TSP, T-owner, and T-operator could all apply. We question whether RA should be applicable. Was the RA inclusion possibly a holdover from when the Planning Authority was not developed?

The scope of this SAR seems rather large, perhaps it could be divided into more manageable pieces.

SAR Commenter Information		
Name	Charles Yeung	
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: Core organization standards for reliability must be specific and offer measurable boundary conditions to achieve reliability objectives. Additionally, these standards should not presume that procedural requirements to achieve reliability objectives are included as part of a core reliability standard. Procedures may be necessary for entities to follow to meet NERC Organization Standards requirements. Most procedures meant to achieve reliability objectives contain impacts on the operations of the marketplace. The inextricable link between the reliability needs and the market needs makes the development of reliability-driven procedures impossible to do in a NERC reliability - focused process. If NERC proceeds to develop the core organization standards for reliability, there must be close coordination with entities, such as NAESB and RTOs, that will develop market-driven procedures so that a proper procedure can be developed to meet both reliability objectives and commercial needs.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☒ No

☐ Yes ☐ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☒ The scope of the SAR should be reduced to eliminate: any reference to criteria to be determined by boundary conditions established outside a measurable or quantifiable standard. A core standard for reliability should be specific and measurable. This SAR proposes that a standard be "a plan" that encompasses normal, abnormal, and extreme system conditions and not define what those conditions are. The plan is a solution - not a measurable standard. As stated in the SAR, "..the plan may utilize operating, construction, and market solutions..", there are numerous possible methods to facilitate the reliability need this SAR suggests. These methods revolve around market operations and should be developed in a process that considers all market interests and weigh those against a measurable reliability need. The proposed standard should be focused on the measurable and definable boundary conditions for "normal, abnormal, and extreme system conditions."

SAR Commenter Information			
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

The proposed set of 11 Standards are described in very generic terms with few details. Therefore it is not possible to assess whether or not the set of these 11 organization standards is complete with respect to some or all areas of power system performance from reliability perspective. For example, there should be a standard for Power System Model (power flow, short circuit, dynamics, EMTP) Development along with corresponding Data Verification requirements. Is model building and data verification encompassed by the presently proposed set of standards? If so, there should be a separate stand-alone standard for it, because most, if not all, reliability and marketing decisions for performance and use of the transmission system are based on the analyses using this data. Providing timely, verified, and appropriate data should be the responsibility of all the users of the transmission system.

There also should be a standard for wide-area coordinated system planning. Is wide-area coordinated planning addressed by the proposed standards? While some level of coordination in planning and operation exists today, this level of coordination needs to be increased. Again, an RTO should facilitate coordination among its members and neighbors, but a standard for wide-area (beyond the boundaries of transmission owning entity, RRO, or RTO) planning would ensure that it is done on a regular and consistent basis.

Much effort (several man-years) was expended in the recent development of the NERC Planning Standards. It would seem that the main emphasis of those standards is still relevant. While we are not sure whether or not or how those standards would be used in this SAR process, we believe that at the very least, they should be used as starting points from which new standards can be developed that can wrap around the NERC Functional Model.

Not being involved in this process from the beginning, I am not sure what was considered in determining which existing standards belong in the proposed set of 11 as a separate standard. It would appear that Coordinate Interchange (SAR#7) and Coordinate Operations (SAR#8) could be combined into one Organizational Standard as could Prepare for and Respond to Abnormal or Emergency Conditions (SAR# 10) and Prepare for and Respond to Blackout or Island Conditions (SAR#11). Similarly, it appears that the proposed SAR#2, Determine Facility Ratings, Operating Limits, and Transfer Capabilities should be separated into three SARs.

Either in these Standards or The NERC Functional Model, a clear definition of who is ultimately responsible for compliance with the standard is required. For example, which entity assumes the ultimate responsibility for long term system planning? Is it ISO, RTO, ITC, Transmission Owner or Transmission Provider? As the function definition of the Planning Authority has not been defined yet, it is not certain that it would provide an answer to this question. In any case, responsible entities should be very clearly defined for compliance with each proposed standard or the new standards.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is

☒ The scope of the SAR should be expanded to include: More details to judge whether or not all reliability related activities are covered or not.

☐ The scope of the SAR should be reduced to eliminate:

Other comments: The purpose and description is too general. This standard may require to be split into two or more SARs.

SAR Commenter Information			
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid? ☒ Yes ☐ No			
Is there a reliability-related need for an Organization Standard to be developed on this topic? ☒ Yes ☐ No ☒ Yes ☐ No The scope of the SAR is fine as it is			

SAR Commenter Information			
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☐ The scope of the SAR should be reduced to eliminate:

Other comments: This high level SAR is ok, as is. More detail must be added in future SAR iterations/postings to provide expectations to those entities/individuals involved with planning and/or assessing the performance of the bulk power transmission system under varying conditions.

SAR Commenter Information			
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: The SARs do not seem to address requirements for data (network models, generator and load models) needed for static and dynamic studies in the Operating and Planning horizones.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No
☐ Yes ☒ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:

Other comments: The sentences that refer to 'plan' to 'address these conditions' should be modified to incorporate the following concept;

When studies show that the system may not meet the performance requirements established for various conditions, plans shall be developed to address such situations, and studies shall demonstrate that when the plans are implemented the system will meet the established performance requirements.

SAR Commenter Information		
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

N/A

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed:

Entergy believes there are three "core reliability" Organization Standards needed that constitute "what" is needed for reliability:

1) Balance Resources and Demand,
2) Operate Within Thermal, Voltage and Stability Limits, and
3) Coordinate Operations.

All the other eight SARs, including other processes like TLR, constitute "how" these three "core reliability" Organization Standards are met. The remaining eight SARs do not rise to the level of "core reliability" Organization Standards. These eight should be developed as processes, either by the industry within the three Organization Standards or by individual industry owners/participants. For instance, the E-Tag system was developed by the industry, facilitated by NERC, and is one part of the process for meeting the intent of "Coordinate Interchange", which itself is a process under "Balance Resources and Demand" and/or "Coordinate Operations". The existing TLR process was developed by the industry to assist industry participants meet the core Organization Standard "Operate Within Limits - Monitor and Assess Short-Term Transmission".

Others of the SARs should be developed by individuals but do not themselves rise to the level of "core reliability" Organization Standard. For instance, every system operator should have plans for recovering from blackout or islanding conditions, "Prepare for and Respond to Blackout or Island Conditions". However, we believe these processes should be developed by individual operators, unique to their own systems, and are not core Organization Standards.
Further comments on the individual SARs are included below for your consideration.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☒ No
☐ Yes ☒ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:

Other comments:

This SAR is really a requirement to establish a "process" for assessing and planning the transmission system. We view the contents of this SAR to be one of the "how"s for meeting the renamed Organization Standard "Operate Within Limits - Monitor and Assess Short-Term Transmission" . As such, this SAR does not rise to the level of "core reliability" Organization Standard.

The industry currently has in place regional processes for assessing and planning the power system under a variety of normal, abnormal, and extreme system conditions. The process should be continued, updated if necessary, and participation in the process should be a required activity by all industry participants.

SAR Commenter Information			
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American Electric Power (AEP) appreciates the opportunity to comment on the 10 most recent Standard Authorization Requests (SARs) and looks forward to working with NERC and other market participants to ensure the continued reliability of the electrical system.
Clearly the electricity industry has been exceptionally dynamic and fluid in recent years and is going through many changes. While changes can be positive, it is incumbent on the industry to ensure that changes, which are adopted result in enhanced reliability and a better market environment. With this in mind, we envision that there are actually three interrelated but separable processes with respect to the development of standards.

? First, the relevant standards need to be identified. Over recent months this has been referred to as defining "what" the standard is.
? Second, there need to be decisions about "how" these standards are to be achieved.
? Third, choices have to be made as to how these standards will be implemented.

The resultant standards, when implemented and operational, will potentially affect production, consumption and investment decisions. By necessity, the standards, including how they are achieved and implemented, are closely related to the design of the market and the separation of functions among market participants and service providers. For this reason, we encourage discussion and even preliminary definition of what core reliability standards are needed. However, we strongly urge restraint with respect to the other two aspects of the process – defining how the standards will be achieved as well as how they will be implemented. In our opinion, the latter two processes are highly integrated with the process of market design and implementation as well as market operation; the development of RTOs; and the definition of the NERC/NAESB interface.

Given that closure on many of the market design issues is expected in the near future, we see little risk in delaying the latter two processes – how the standards are achieved and implemented - until such time as clarity is achieved on Standard Market Design (SMD) and RTO formation. Moreover, since the NERC/NAESB interface will likely impact decisions on how standards will be achieved as well as how they will be implemented, it seems logical to wait until that interface has been defined.

We would prefer to see the SAR process simply make the threshold determination as to whether each of the proposed standards are needed, and then put on hold the actual development of those standards that are needed until the critical market development activities described above are closer to completion. Only at that point in time, will it be known whether the proposed standards cover the scope of performance needed to ensure reliability of the interconnected North American Grid. In the interim, AEP looks forward to continue working with NERC, NAESB and other market participants to develop and implement the appropriate standards.

Other comments: It is unclear to AEP what the intent was of this SAR . This SAR appears to have both market and reliability implications. As such, before moving forward to develop this SAR, AEP requests a further clarification of the specific intent. To the extent that this SAR is transitioning an existing standard from the old world to the new world (Functional Model), then the standard should not go beyond the original scope. Consistent with our general comments, once the clarity is achieved on Standard Market Design and RTO formations, then this standard should be revisited and reevaluated.

SAR Commenter Information			
Name	Ed Kirschner		
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: General comment on entire set of SAR's and the overall process: Based on the short descriptions and the broad scope of most of these SAR's, it appears that these SAR's will encompass many of the existing planning and operating templates developed during the NERC pilot program. Experience obtained during the pilot program showed that many of the planning templates and some of the operating templates were difficult to interpret and even more difficult to measure for compliance, let alone determine exactly who the templates applied. Based on the scope descriptions given for each SAR, it appears these SAR's are written to encompass those same templates. Hopefully, the final standards will be written such that each standard is clear and concise as to how exactly the entity must comply for different levels of compliance and exactly which entities must comply for each measure of each standard. With the benefit of experience of the pilot program, Cinergy would like to suggest that since several of the measures in the existing templates are difficult if not impossible to actually measure for compliance, that some of these proposed standards or portions thereof not be developed into standards but instead be written as "good engineering practices". These "practices" could be used in the certification process for the various functions in the NERC Functional model such as Reliability Authority, Planning Authority, etc. We will try to indicate on each SAR, those portions that should be written as "practices". In the event that all eleven of these SAR's are approved to move forward, then the list should be prioritized and developed somewhat consecutively instead of simultaneously. We have already observed how difficult it is to stay abreast of the templates developed during the pilot as far as providing meaningful comments and review due to the sheer volume of documents distributed for review. Although there are only eleven SAR's, each SAR encompasses multiple measures, which will need to be defined in order to specify how each part is to be measured for compliance and to define what entities must comply for each part. Also since technical experts will be required to assist in the development of these standards, there will be a burden on resources if all of these are developed simultaneously since many of the standards could involve some of the same experts. The priority of developing each standard should be based on industry consensus of what are the major problems/issues that are threatening the reliability of the transmission grid today. Standards should be written so that performance can be measured as it affects overall grid reliability vs trying to measure practices or procedures.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☒ No

☐ Yes ☒ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☒ The scope of the SAR should be reduced to eliminate: entire standard

Other comments: This SAR should be developed as a "practice" to be used in the certification process for Planning Authorities and Reliability Authorities. Experience with the existing templates and NERC Table 1A shows how difficult it is to not only determining how to comply with this standard but to actually measure it for compliance. It is difficult if not impossible to determine if events will result in "cascading" - usually engineering judgment is used. It is also not practical to investigate every possible extreme or abnormal system condition to check for "cascading" - again engineering judgment is used. All of these factors makes measuring an entity for compliance very difficult if not impossible. Based on the ongoing development of RTO's and the open stakeholder process proposed for future planning studies, it does not appear that lack of planning will be an issue.

SAR Commenter Information			
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: Frequency control and processes standardized to speedy determine what are the problems contributing to poor frequency. What is considered "poor frequency"? Some SARs do not include critical participants that should be included.

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: The scopes of these SARs range from small details to broad areas of responsibilities and overlap in many areas. It would seem that a top down approached would make better sense.

None

SAR Commenter Information			
Name	Peter Burke (submitting comments provided by numerous ATC contributors)		
Organization American Transmission Company			
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: (1) ATC applauds the effort of the SAR's to acknowledge the dismantling of the vertically integrated utilities. However, some care needs to be given to defining the separated groups. For example, it is not always clear what is meant by Planning Group, Transmission Owner, Transmission Service Provider, and Transmission Operator, whether some groups are included in others, and whether there should or shouldn't be that inclusion. For each of the SAR's, there was some lack of confidence that the correct complying entities had been identified.

(2) Perhaps buried within the SAR's is a modeling component that will surface in the details, but none of these SAR's will accomplish their intent without credible models from which to do analysis.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is

☒ The scope of the SAR should be expanded to include: SAR #8 includes coordinated "planning". This language should be added here so that the Assessing and Planning of the Transmission System is coordinated. If modeling isn't addressed in the details it should be.

☐ The scope of the SAR should be reduced to eliminate:

Other comments: (1) It is not clear how market solutions would fit in providing reliable delivery of power for the future needs of customers. Market solutions could provide an interm solution to transmission constraints but they should not be used in planning future transmission needs.

Maybe the transmission service provider (TSP) should have some responsibility within this area as it relates to providing adequate transmission service to the market. If the TSP identifies a bottleneck on the transmission system creating problems transferring energy across the system, that should be included in future plans to try to eliminate that bottleneck.

The transmission operator, if not the same as the transmission owner, should have some responsibility in making sure the transmission owner knows about future improvements needed to improve it's system from an operational perspective.

(2) NERC should ensure that the standards defined within this SAR include a definition of how the planning model is created. Is there any way to come up with a standard for what gets included in the future models? For example, roll-over rights for transmission service, proposed generation facilities, proposed transmission facilities that require state approval and/or signficant right-of-way acquisition.

SAR Commenter Information			
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: SARs should be developed that cover Operator Personnel and Training and Telecommunications reliability.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No
☒ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:

Other comments: The SAR should also apply to the following organizations because of their involvement in the planning process: Transmission Service Provider, Transmission Operator, Distribution Provider, Generator, Purchasing-Selling Entitiy, and Load-Serving Entity.

SAR Commenter Information			
Name	David Little		
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Is there a reliability-related need for an Organization Standard to be developed on this topic? ☒ Yes ☐ No ☒ Yes ☐ No The scope of the SAR is fine as it is			

SAR Commenter Information			
Name	Art Giardino		
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: Too soon to proceed

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☒ No
☐ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:

Other comments: Resources should not be expended on this SAR until FERC has specifyed the organization responsible for wholesale electric standards development.

SAR Commenter Information		
Name	Compliance Subcommittee	
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: A lot of vital requirements of existing policies are not included in any of the proposed SARS, i.e., time error correction, inadvertent, etc.

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: It appears that some of the SARS overlap and cover some of the same areas, such as "Prepare For and Respond to Emergency Conditions", "Prepare for and Respond to Blackout or Island conditions", and "Monitor and Analyze Disturbances, Events, and Conditions". These could all fall under a single Emergency Operations SAR. "Coordinate Interchange" should also fall under "Coordinate Operations". In addition, the SARS are intended to define standards for core reliability functions, i.e., "what to do". Some of the SARS really describe processes (i.e., "how to do it") rather than define standards, such as the SAR on "Determine Facility Ratings, Operating Limits and Transfer Limits". There are others that may need to be combined - it is suggested that a re-mapping of Policies to specific SARs should be done.

None

SAR Commenter Information	
Name OPWG	
Organization SERC (Contact = Nancy Fallon)	
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid? ☐ Yes ☒ No If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: The "Assess Transmission future needs and develop transmission plans" SAR does not state a requirement to plan the system so that it can be operated within operating limits. We feel that this terminology (operating limits or other term such as Operating Security Limits) should be common among all SARs. The system must be planned so that it can be opearated reliably. Using this terminology in all SARs would provide the appropriate link among them. Without knowing the details that will be included in the standards as described by these SARs, it is difficult to make an assessment on the completeness of this set of SARs. We feel that there should be a SAR that requires LSEs, distribution providers, and generators to respond to requests that will have the effect of operating the system within Operating Limits.	
None	

SAR Commenter Information		
Name	Planning Standards Working Group (PSWG)	
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?
☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: Maintenance requirements should cover transmission equipment other than just protection and control equipment.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No
☒ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:
Other comments: For the Applicable Functions, TSP, T-owner, and T-operator could all apply. We question whether RA should be applicable. Was the RA inclusion possibly a holdover from when the Planning Authority was not developed?

The scope of this SAR seems rather large, perhaps it could be divided into more manageable pieces.

SAR Commenter Information			
Name	Gary Won and Don Tench Comments submitted on behalf of the Independent Electricity Market Operator (IMO)		
Organization	Independent Electricity Market Operator (IMO)		
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No - see comments

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed:

Comments:

The proposed standards appear to provide the necessary coverage to ensure a reliable interconnected North American grid. A thorough review will need to be done to ensure that no necessary and significant performance requirement is missed that is in the current Operating Policies and Planning Standards. While the proposed SARs may cover the scope of performance needed, we have several concerns with the overall set at this stage of implementation;

1. The 'White Paper on NERC's set of Organizational Standards", dated April 11, 2002, clearly articulates a direction with which we agree. The paper proposes that 'these standards will define ***what*** performance must be achieved, without providing restrictive measures on ***how*** to achieve that performance'. This direction arose following industry experience with the very large set of current planning and operating standards and recognition by the industry that the current standards, in many areas, are too prescriptive of the 'how'. By focusing the industry on meeting less meaningful standards, the goal of maintaining reliability is actually put at risk. It is our belief that the proposed set of standards still focuses too much on the 'how', to the potential detriment of the overall objective.
2. Perhaps the most important aspect of a set of organization standards is to define to whom and to what the standards apply. The NERC Functional Model does a good job of providing a framework to define to whom the standards apply. However, what the standards apply to is left almost entirely open. What the standards apply to is variously described in the proposed SARs as the; transmission system, interconnected transmission system, network, power system, bulk electricity system and those facilities which affect reliability, among others. The white paper again provides valuable insight by defining the objective in terms of the 'interconnected electric systems in North America', however, this too is subject to individual interpretation. A definition of what the standards apply to, in terms of scope, is perhaps more important than the individual SARs. As such, I suggest that this scope needs to be developed through the SAR process. This needs to be addressed in a global fashion rather than relying on the development of a different scope for each SAR.
3. The proposed SARs deviate from the white paper direction to focus on reliability and delve into areas which are potentially outside of their scope such as; equipment damage, data sharing, procedures and studies. To the extent that these areas are performance related, the need is understood. However the development of past standards has shown that these areas often become part of a standard when they are really only one method of how a given level of performance can be achieved.
4. The 'High Level Map of Old Doc's to new Doc's' proposed by SAC (attached at the end of this package) provides a mapping of existing NERC planning and operating standards into the proposed new SARs. Each of the broad areas defined by the existing standards must be judged carefully against the 'White Paper' principles before even being included in the mapping. It is our belief that many will not pass this test.
5. The language of the proposed set of SARs struggle (understandably) to recognize the industry changes facing open electricity markets. Often they reflect a historic utility perspective including distinctions between 'planning' and 'operating' and emphasis on elements of 'pro forma' tariffs, which may no longer be relevant. To the maximum extent possible, the SARs must be developed to be independent of organizational and regulatory structures as well as respecting Regional and international differences. In our view, performance based standards are the best way to recognize this diversity.

We are very supportive of the goals NERC has set and would be glad to discuss further or participate more directly in their development.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No
☐ Yes ☒ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☒ The scope of the SAR should be reduced to eliminate:
The SAR must be rigorously tested against the White Paper requirements to specify what performance must be achieved rather than how to achieve that performance. For example, in what way is a standard for 'planning the transmission systems' a performance standard? Wouldn't such a standard be considered one means of determining whether a performance standard based on system behaviour (both present and future) is met?
Other comments: The Standard description implies that there should be a single transmission expansion plan. It reads as if there is or must be a single coordinated and minimum cost plan (same theme in the Planning Authority proposal currently being circulated for comment). In a market environment, there may be a need for multiple plans since the viability and timing of various generator projects (and the system enhancements that may be required for deliverability of their output) will be dictated by commercial rather than system adequacy considerations. Similarly the timing of merchant transmission projects will reflect commercial rather than system security considerations

A minimum set of criteria for assessing the acceptability of plans is needed. The NPCC A-2 (see www.npcc.org) document covers the aspects of ensuring against significant (disagree with the use of "extreme" in the SAR), adverse impacts over a wide area. Market systems also need criteria to determine when to initiate or order plans, or trigger some regulatory backstop if expansion plans are deemed to be insufficient to meet needs. (Must also define what minimum need is).

SAR Commenter Information	
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: The promulgation for comment of these SARs is premature. The industry "standard making process" is in a transition phase and it is overly burdensome to devote resources at this time. Once legislation or FERC firmly determines which entiy(ies) is responsible for standards it will make sense to move forward with said entity.

Even if NERC wants to cover reliability standards, almost all standards have a reliability and commercial impact; thereby, necessitating developing a single process that incorporates both commercial and reliability aspects of standards development. The current NERC process risks being changed soon, discounts commercial aspects, and is not part of a finalized overall industry process.

Waiting a short while to move forward on a new standards setting process is acceptable and prudent given that NERC standards are currently in place and the industry can continue to use these standards until the new process and standards setting organization(s) are firmly set.

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: The promulgation for comment of these SARs is premature. The industry "standard making process" is in a transition phase and it is overly burdensome to devote resources at this time. Once legislation or FERC firmly determines which entiy(ies) is responsible for standards it will make sense to move forward with said entity.

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Waiting a short while to move forward on a new standards setting process is acceptable and prudent given that NERC standards are currently in place and the industry can continue to use these standards until the new process and standards setting organization(s) are firmly set.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☒ No

☐ Yes ☐ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☐ The scope of the SAR should be reduced to eliminate:

Other comments: The promulgation for comment of these SARs is premature. The industry "standard making process" is in a transition phase and it is overly burdensome to devote resources at this time. Once legislation or FERC firmly determines which entiy(ies) is responsible for standards it will make sense to move forward with said entity.

Even if NERC wants to cover reliability standards, almost all standards have a reliability and commercial impact; thereby, necessitating developing a single process that incorporates both commercial and reliability aspects of standards development. The current NERC process risks being changed soon, discounts commercial aspects, and is not part of a finalized overall industry process.

Waiting a short while to move forward on a new standards setting process is acceptable and prudent given that NERC standards are currently in place and the industry can continue to use these standards until the new process and standards setting organization(s) are firmly set.

SAR Commenter Information		
Name	R. Scott Henry, Chairman	
Organization	Interconnected Operations Services Subcommittee, NERC	
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: The IOS Subcommittee appreciates the opportunity of submitting comments on the ten SAR's posted by NERC. The IOS Subcommittee found the white paper most instructive in explaining the intent of this initial posting. Generally, the SAR's posted outline the topics for a reasonable first set of organization standards. Since much work is still to be done in developing the details of the SAR's and the related organization standards, a definitive statement on the comprehensive nature of these SAR's is premature at this point. The IOS Subcommittee does note that interconnected operations services are important components of several of the SAR's. NERC's IOS work, summarized in the IOS Reference Document in the NERC Operating Manual, has been substantive in identifying the minimum necessary components of interconnected operations services. Addressing more than simply the need to balance energy, the IOS work stresses the importance of responsive capabilities and controls necessary to achieve reliable bulk electric operation. The IOS Subcommittee recommends that the drafting of the proposed standards considers the IOS Reference Document and that IOS expertise be considered an essential competency of the standard drafting team.

In its discussion of these SAR's, the IOS Subcommittee identified three fundamental policy issues needing resolution prior to detailed work on development of these standards. First, the SAR's generally propose that the organization standards would apply to Service Functions contained in the Reliability Model, and they do not propose addressing the role of generators, loads, and others in provision and delivery of IOS's. The SAR's implicitly assume that the roles of others will be addressed through contracts. While the IOS Subcommittee does not necessarily disagree with this assumption (no consensus has been reached either way), there is a need to further explore the potential applicability of aspects of the proposed standard to others. This issue requires further debate and may serve as a critical precedent for the scope of other Organization Standards. Second, the "Assess Transmission Future Needs and Develop Transmission Plans" SAR proposes a standard to develop plans. None of the SAR's identifies who has the obligation to implement the plan. A plan without assignment or accountability for implementation is likely to provide no fruitful results. Third, the proposed standards and associated measures and criteria should not be any more restrictive than is necessary for a reliable bulk electric system. Market mechanisms for the provision of IOS should not be unnecessarily constrained. Market design is evolving rapidly, including for example, the ability to provide real time balancing services through bid-based mechanisms.

The IOS Subcommittee offers its assistance to the Standards Requestor(s) as further work is invested in development of these organization standards.

SAR Commenter Information	
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid? ☒ Yes ☐ No	
Is there a reliability-related need for an Organization Standard to be developed on this topic? ☐ Yes ☒ No ☐ Yes ☐ No The scope of the SAR is fine as it is ☐ The scope of the SAR should be expanded to include: ☐ The scope of the SAR should be reduced to eliminate: **Other comments:** This is an ongoing function that will be coordinated by RTOs with transmission owners and market participants. Every RTO will have or already has a planning protocol on how long term transmission plans are developed. A standard is not needed to make this function occur. For those entities not in an RTO, a similar process will exist to develop long term transmission plans.	

SAR Commenter Information			
Name	Kent Saathoff		
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This SAR and the other posted SARs provide an appropriate framework for transitioning existing NERC Operating Policies and Planning Standards into new, NERC Organization Standards. Multiple compliance measures may be defined and developed for each of the eleven proposed Organization Standards. The Organization Standards and related compliance measures should focus on what functions must be performed for reliability, on who is responsible for each compliance measure for each required function and not, on how the compliance measure is achieved. The compliance measure must be measurable or demonstrable to ensure compliance.

Sound planning is the foundation for a reliable transmission system. Therefore a standard for defining transmission planning requirements is appropriate.

ERCOT believes the following issues should be considered in the development of this standard:

· The assessment leading to a transmission plan may be the most important aspect of this standard. Operational challenges must be identified, coordinated and remedial action plans made. Facility solutions usually require a longer time frame than the operating requirements allow.

· Incorporate a reasonable planning horizon - Sound planning must be based on reasonably accurate forecasts of future load and generation patterns. In the new competitive generation markets it is not possible to perform meaningful forecasts more than five years out. Attempting to do so is not a good use of scarce resources.

· Allowance of Remedial Action Plans (RAP) and Special Protection Schemes (SPS)– Major transmission construction that may be the preferred long-term answer to transmission reliability usually has a long lead-time. There should be provisions for the interim use of RAP and SPS in meeting the planning standard.

· Recognition of Regional differences - All standards should make allowance for reasonable differing regional requirements. Requirements may vary due to differences in climate, predominate generation type, transmission design standards, availability of interruptible load and market rules.

· FACTS devices are emerging as feasible solutions to transmission improvements. They should be considered in the development of standards for transmission planning and facility ratings (may include in SAR ID# FACILITY_RATINGS_01_01 as well).

SAR Commenter Information			
Name	Ronald Gunderson		
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?
☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: We did not have adequate time to be sure all reliability areas are covered by these SARs.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No
☐ Yes ☒ No The scope of the SAR is fine as it is
☒ The scope of the SAR should be expanded to include: 1) a requirement to provide assessments at all demand levels 2) Transmission Service Providers should be included in the list of functions.

☒ The scope of the SAR should be reduced to eliminate: This standard should only apply to long-term planning functions. A parallel standard is required for operational planning.

SAR Commenter Information			
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Organization	Exelon Corporation		
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed:

The reliability policies, or "Organization Standards", must be specific and limited to standards based on the NERC-defined seven reliability principles and five market interface principles and not go beyond these areas. In addition, the NERC Organization Standards process must be coordinated with the process that will be established by FERC to develop busines practice standards.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☒ No

☐ Yes ☐ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☐ The scope of the SAR should be reduced to eliminate:

Other comments: A SAR is not needed for a transmission expanision plan, since it includes "market solutions". Market solutions are outside NERC's scope with respect to the development of reliability policies or "Organization Standards".

SAR Commenter Information			
Name	Carter B. Edge		
Organization	Southeastern Power Administration		
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E-mail	cartere@sepa.doe.gov		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: Time Error Corrections; Inadvertant Interchange

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

SAR Commenter Information			
Name	Warren Schaefer		
Organization	Dairyland Power Cooperative		
Telephone	608/787-1252	Fax	608/787/1327
E-mail	wjs@dairynet.com		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: We are not sure from the brief scope that is provided with each SAR that all the NERC Planning Standards and Operating Policies are covered.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is

☒ The scope of the SAR should be expanded to include: 1) a requirement to provide assessments at all demand levels 2) Transmission Service Providers should be included in the list of functions.

☒ The scope of the SAR should be reduced to eliminate: This standard should only apply to long-term planning functions. A parallel standard is required for operational planning.

Other comments: This is a reliability standard and should not include Market functions

SAR Commenter Information			
Name	Mike Miller		
Organization	Southern Company		
Telephone	205 257 7755	Fax	6663
E-mail	mbmiller@southernco.com		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: The "Assess Transmission future needs and develop transmission plans" SAR does not state a requirement to plan the system so that it can be operated within operating limits. I feel that this terminology (operating limits or other term such as Operating Security Limits) should be common among all SARs. The system must be planned so that it can be operated reliably. Using this terminology in all SARs would provide the appropriate link among them.

Without knowing the details that will be included in the standards as described by these SARs, it is difficult to make an assessment on the completeness of this set of SARs. I feel that there should be a SAR that requires LSEs, distribution providers, and generators to respond to requests that will have the effect of operating the system within Operating Limits.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is

☒ The scope of the SAR should be expanded to include: Planning must be coordinated to optimize not only transmission but generation as well. The left alone process of disjointing generation and transmission is creating a non-steady state electrical system. The criteria for designing a system must include defined measurements adopted by all. This brief description does not provide sufficient detail to ensure reliability is planned. The planning criteria must address defined transmission planning for transfer usage as well as specific load service usage in other words interconnection as well as intraconnection. The need to define roles, responsibilities and authority must be developed between Federal (RTO) characteristics and functions and transmission owners.

☐ The scope of the SAR should be reduced to eliminate:

Other comments: Transmission Operator and perhaps Distribution Provider should be added to the list of applicable functions.

SAR Commenter Information			
Name	Jim Griffith		
Organization	Bulk Power Operations Southern Company		
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E-mail	jsgriffi@southernco.com		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: Frequency control and processes standardized to speedy determine what are the problems contributing to poor frequency. What is considered "poor frequency"? Some SARs do not include critical participants that should be included.

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: The scopes of these SARs range from small details to broad areas of responsibilities and overlap in many areas. It would seem that a top down approached would make better sense.

None

SAR Commenter Information		
Name	Southern Company	
Organization		
Telephone	(205) *257-4222*	Fax (205) *257-1040*
E-mail	DGPIATT@southernco.com	

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

The new Organizational Standards must include the "How's" as well as the "What's" to just maintain the current level of reliability for the electric transmission system. The current NERC Planning Standards and Operating Policies, in general, document the body of good utility practice that provides that currently level of reliability seen in North America. If only the Standards ("What's") were published without the Measures ("How's") the new document will be woefully inadequate. The planning, design, construction, operation and maintenance of the electric transmission system are a very refined process of applied scientific principles and technology. The current proposed Organizational Standards create a level of ambiguity that will not adequately ensure the reliability of the grid is maintained at the levels seen today. Southern Company suggests that NERC consider withdrawing the entire proposed set of standards and reconsider its process for developing reliability standards. When posting standards for comment, NERC should consider a longer comment period. Thirty days is too short due to the amount of corporate coordination and information gathering required to submit meaningful responses.

With respect to the scope of reliability standards, the development of all reliability standards should be within the general context of ensuring that the grid is protected from uncontrolled or cascading interruption of network operation. None of the proposed SAR's fully addresses these basic operational requirements, although certain aspects of these requirements are contained within some of the SAR's. Therefore, it is recommended that NERC prepare an initial standard that establishes the minimum reliability requirements needed to prevent severe adverse events from occurring on our transmission system, i.e. uncontrolled or cascading interruption of network operation. This pivotal standard - call it "MINIMAL OPERATIONAL REQUIREMENTS" - would address such basic reliability considerations such as

- No operator should knowingly operate in a manner that inappropriately affects the reliability of another entity
- No operator should allow operation of the system in such a manner that inappropriately risks cascading outage of the network or violates an operating security limit.
- No operator should allow operations that violate safety standards established by the National Electric Safety Code, ANSI Standards, IEEE, etc….
- No operator should allow operations outside established equipment ratings
- Etc.

These may or may not represent the appropriate set of minimal reliability considerations, and are offered for illustrative purposes only. Once this pivotal standard has been established and fully vetted, all future SAR's can be developed within the context of these basic requirements. If it were deemed necessary to increase or adjust these pre-established minimum levels, the pending adjustments would need to be fully vetted in both the commercial and the reliability forums.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No the scope of the SAR is fine as it is

☒ The scope of the SAR should be expanded to include:

The scope of this SAR is poorly written and does not adequately represent or convey the transmission planning functional responsibilities. A better way to phrase the purpose could be:

To establish a standard for evaluating the performance of the transmission system to ensure that appropriate levels of functionality and reliability are achieved in both the short-term and long-term time frames.

☐ The scope of the SAR should be reduced to eliminate:

Other comments:

The "Brief Description", once again, is poorly written and does not represent transmission planning in general.

The I.A. Planning Standard is a very functional standard with the exception of S3.M3 and should be

followed very closely as a template to the developing the scope of this SAR.

SAR Commenter Information			
Name	Jon. Loresch		
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: responsibility for maintaining adequate operating reserves and reactive support. (Perhaps to be included in SAR on "Balancing Resources and Demand"?); responsibility for assessing and defining what are adequate operating reserves and reactive support. (Perhaps to be included in SAR on "Developing Transmission Plans"?)

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is

☒ The scope of the SAR should be expanded to include: responsibility for assessing and defining what are adequate operating reserves and reactive support.

☐ The scope of the SAR should be reduced to eliminate:

Other comments: Load and Generator entities are just as integral as Transmission Owners to the planning of the system. This should incorporate the responsibilities of all entities to provide information necessary for assessment.

SAR Commenter Information			
Name	Ray Morella		
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No
☒ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:

Other comments: Standard requirements that establish a consistant and reliable measure to evaluate the transmission system must be developed and maintained to insure that the transmision system can perform safely and reliably. Requirements that address normal, abnormal, and extreme conditions need to be defined. Standard protocol need to be enforced that addresses future operating conditions of the transmission system that will ensure that events such as uncontrolled seperation or cascading does not occure during any single contingency.

SAR Commenter Information			
Name	Scott Helyer		
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: On SAR ID# PHYSCAL_CON_REQ_01_01, it appears that specifying requirements for operating limits and AGC go beyond the Physical Connection Requirements. We need to ensure that this Standard would not overlap another reliability standard on operating limits and that we do not create a reliability requirement that AGC is needed for all generators when the market should decide which generators require AGC. Writing a standard that indicates how AGC should be provided if a generator wishes to provide such a service would be acceptable.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

SAR Commenter Information			
Name	Kenneth A. Githens		
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: Several of the SAR's contain market related issues. These should be delayed until FERC final ruling on Standardized Transmission Service and Wholesale Electric Market Design

The scope of the SAR should be reduced to eliminate: This SAR proposes "the plan may utililize operating, construction, market solutions or other components to address these conditions." Market solutions requires this standard be developed by a process that take into account market along with reliability interests.

SAR Commenter Information			
Name	Chifong Thomas		
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: We need to add flexibility to allow for Regional differences in all the SAR's. We also need application criteria to provide guidance on when SPS should be applied as permanent measures and when it should be applied as temporary measures to mitigate potential system problems.

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

SAR Commenter Information			
Name	Vahid Madani		
Organization	WECC Remedial Action Scheme Reliability Task Force		
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: Application criteria for SPS (or Remedial Action Scchemes) should be included. SPS, thought may be considered as some form of protection and control measure, is applied for many different purposes which may be systems related and not necessary equipment protection related. Clear criteria are needed for consistant application of SPS (RAS) and when SPS (RAS) could be considered as an alternative to mitigate for system deficiencies. Planning criteria need to provide guidance on when SPS should be applied as permanent measures and when it should be applied as temporary measures to mitigate potential system problems. Special Protection Schemes, Protection Schemes and Control Schemes should all be treated separately.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☐ No The scope of the SAR is fine as it is

☒ The scope of the SAR should be expanded to include:

1) Planning criteria should be expanded to include maintainability of the system. Simple mitigation measures such as removing equipment out of service during lightly loaded and off-peak hours, to make system adjustments and to allow equipment protection against high voltage conditions may not be considered practical since it may crate N-1 operating conditions. Also, possible overall system deficiencies for interconnected systems may not allow such prudent practices such as removing equipment from service.

2) Establish a separate SAR for implementation of various types of SPS - Identify criteria for application of each type such as:
Overload mitigation, Adaptive overload mitigation schemes, UFLS, UVLS, stability related schemes, etc.

3) Develop a plan to address operating issues for interconnected grids systems where SPS is used systematically to mitigate against many different types of system deficiencies within a Region, operating in a coordinated manner with multiple mitigation measures simultaneously operating in parallel creates increased potential for cascading outages following an un-planned outage.

SAR Commenter Information			
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: See individual SAR comments.

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: See individual SAR comments.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is

☒ The scope of the SAR should be expanded to include: More detail is needed about what is required in order to write this standard.

☒ The scope of the SAR should be reduced to eliminate: Developing plans. The SAR should only address the creation of Planning Standards - Plan Development is a compliance issue.

Other comments: As written, this SAR does not set a standard, but rather seems to try to assign responsibility for setting the standard.

SAR Commenter Information			
Name	Mr Paul Tremblay, Mr. Mike Penstone, and Mr Ajay Garg		
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

The design of Bulk Electric System is complex and its performance depends upon a variety of factors including but not limited to, designs, configurations, designs, technologies, operating practices, etc. The proposed standards should focus upon required performance objectives and methods of measuring success or failure(ie. PERFORMANCE BASED CRITERIA standards) rather than prescribing the means to achieve these objectives.

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed:

As above, standards should not prescribe processes nor means of achieving an outcome. This has been done, effectively, by NPCC for over 25 years.

NERC standards should facilitate in the establishment of Region/RTO/Area specific standards that will meet the NERC performance standard.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☒ No

☐ Yes ☐ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☒ The scope of the SAR should be reduced to eliminate:

SAR Commenter Information			
Name	Marv Landauer		
Organization BPA			
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: I do not think it is appropriate at this point in the process to define the Reliability Functions that are associated with the Standard and cast them in concrete (which Maureen has indicated is the case). As the standards are drafted. issues may come up that need to be includeded that will require coverage by other reliability functions. If they are defined early in the porcess, they should be subject to revision later as necessary.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☐ The scope of the SAR should be reduced to eliminate:

Other comments: The description should be modified to only include "performance under a variety of PLAUSIBLE system conditions". Why aren't the load and generator functions involved in this standard? Aren't they the ones the system is built for? As I mentioned above, I believe that making the connection between Reliability Functions and the SAR should be deferred until later in the process.

SAR Commenter Information			
Name	Francis J Halpin		
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No
☒ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:
Other comments: Drafting team should rely heavily upon existing NERC Reliability Criteria in the development of this standard.

Should include Generator and LSE to the list of functional entities to which this standard would apply. Generators and loads are both key factors in the planning process for future transmission needs and should therefore be subject to the requirements of this standard.

SAR Commenter Information	
Name Edward Stoneburg	
Organization Illinois Power Company	
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E-mail edward_stoneburg@illinoispower.com	

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: There is inadequate detail provided to allow a determination of whether the proposed set of Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American Grid. The answer to this question will depend upon the specifics included in each SAR. Detailed SARs must be developed and recirculated before any work begins on development of detailed Organization Standards. These SAR's should be specific about the WHAT of what is the reliability requirement and WHO is obligated to comply (but does not necessarily need detail as to HOW and should not set commercial practices as to HOW to comply) .

Illinois Power suggests the following approach to developing an adequately detailed SAR:

1) For each Function, determine what are the necessary standards to which the provider of that function should be held to in order to ensure reliability. This should not be a wholesale transfer of existing NERC Operating Procedures and Planning Standards into Organization Standards.

2) Consideration should be given to having Standards that apply clearly for each Function rather than multiple Functions being addressed within topical Standards. In that way a Balancing Authority, for example, would only need to be concerned with one Standard, not sorting through multiple standards to figure out what applies to them. Much easier for training their people, keeping track of changes, etc.

3) Each SAR should clearly identify specific and measurable requirements. This aspect is key and should not be left to the later development work, nor should the Standard Writers have authority to expand the specific, measurable reliability requirements without coming through the SAR process.

Should NERC decide to proceed based upon the information submitted for comment, Illinois Power has provided specific comments on each SAR.

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: See above

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☐ No **THE INTENT OF THIS STANDARD IS UNCLEAR SUCH THAT WE CANNOT DETERMINE IF THERE IS A NEED**

☐ Yes ☒ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☒ The scope of the SAR should be reduced to eliminate: Reliability Authorities: In reviewing a Reliabilty Authorities responsibilities, it does not appear to Illinois Power that the RA has any responsibility to assess FUTURE needs or develop FUTURE plans, and therefore would not be subject to this Standard

Other comments: There is inadequate detail in the SAR to determine if the scope of the SAR is appropriate and adequate. A standard in this area should focus on the minimum frequency of assessment and the definition of normal, abnormal, and extreme conditions that must be studied. The creation of a plan should not be a measurable standard as implied in this SAR. Nor should the Standard require specific operating, construction, or market solutions. It should only define the reliability requirements

SAR Commenter Information			
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: Flexibility allowing for Regional differences in all the SAR's.

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: Further comments on SAR's will clarify some of our thoughts.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

SAR Commenter Information			
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: A separate Standard should be developed related to operational planning requirements. In your proposed SARs, the operational planning function is included in SAR 1 along with the new facility planning function. Although there are a lot of similar activities requiring similar tools in either function the criteria system consideration and level of detail involved is quite different. Therefore they should be two Separate SARs to address the Standards requirement relative to these activities. Further discussed in SAR1 comments

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: SAR 7 "Coordinate Interchange" as written seems to reference the function of creating transactions which is a Business Standard. This SAR to reference the reliability requirements of interchange should be related to SCHEDULED Transactions and the data and monitoring requirements associated with this activity. This is further discussed in SAR7.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☐ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☒ The scope of the SAR should be reduced to eliminate: functionality related to assessing transmission performance and relate only to planning future transmission expansion.

Other comments: This SAR's Purpose/Industry Need should be modified in the following way:

the Purpose statement should have the word "assessing" removed so it addresses a planning function only.

The Industry Need comment should be changed to the following "The transmission system must be planned to ensure the reliable delivery of energy and power to meet the needs of customers. A reliable supply of electricity is essential to ensure the safety and economic viability of modern North American society."

Transmission Service Provider should also be included in the list of complying functions.

SAR Commenter Information			
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No
☒ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:

Other comments: These comments apply to the complete set of Proposed Organization Standards. Among the set of SARs, the references to "Reliability Function(s) That Would Need to Comply With This Standard" is not consistent. Ensure the "Function Definitions" from The NERC Functional Model are used consistently throughout. All of the "Reliability Principle(s)" should be listed first to ensure the reader knows what all of them are. In the SAR form they are referred to as "Reliability and Market Interface Principles". It appears that the term "interconnected bulk electric systems" is not consistently used.

The Brief Description refers to "or other components to address these conditions." The vagueness is problematic as was discovered in the crafting of the original NERC Planning Standards.

SAR Commenter Information			
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: Need to add standards covering Reliability Authority responsibilities and authority; and Telecommunications.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☒ The scope of the SAR should be reduced to eliminate: market solutions" in the last sentence of the Brief Description.

Assess Transmission Future Needs and Develop Transmission Plans SAR

Consideration of Industry Comments on SAR Version 1
(SAR Originally Posted for Comment 4/02/02 – 5/03/02)

Background:

Version 1 of the **"Assess Transmission Future Needs and Develop Transmission Plans"** SAR was an abbreviated SAR, which included an "Industry Need" statement and a brief description of the proposed standard, but did not include a detailed description. The purpose of this first posting was to collect feedback from the industry on the following questions:

- Is there a reliability-related need for this SAR?

If there is such a need, how should the scope of the SAR be changed?
- The scope of the SAR is fine as is
- The scope of the SAR should be reduced to eliminate……
- The scope of the SAR should be expanded to include…..

In January 2004, the Standards Authorization Committee (SAC) appointed a Drafting Team (DT) to address industry answers and comments to the questions posed. The DT was also charged with refining the SAR and drafting a detailed description of the proposed standard in preparation for the 2nd posting of the SAR.

This document contains the DT responses to the first set of comments on the original SAR. Because almost 2 years have elapsed since the comments were collected, some have become dated and no longer apply to the present situation. Thus, the DT has not addressed each and every comment, but rather only those that are still timely and represent a general consensus from industry.

Please note that the original comments from industry respondents are shown as underlined text, while the SAR DT responses are shown in yellow highlight.

Question: *"Is there a Reliability-Related Need for this SAR?*

Development of this SAR is not needed or is premature.
Industry comments were overwhelmingly in favor of a standard on transmission assessment and planning, so the SAR DT feels we should proceed with the preparation of a final SAR to be posted for industry comment.

Question: *"Scope of this SAR Should be Reduced to Eliminate ……."*

Standard should not go beyond assessment & planning of the bulk transmission system.
We agree. The DT feels that this SAR as presently written does not go beyond assessment and planning of the bulk transmission system.

Standard should not apply to intrastate systems.
These standards are being drafted to apply to ALL North American bulk electric systems.

Market solutions are outside NERC's scope with respect to development of reliability policies.
Agreed. The present SAR does not require transmission plans to facilitate market operation -- instead, the emphasis is on ensuring reliability.

Definition of "what" core reliability standards are needed is encouraged. However, "how" they are achieved and implemented should not be included at this time, until there is clarity on SMD & RTO formation, and NERC/NAESB interface is defined.
We agree. Industry responses to postings of other SARs and standards indicate that it is widely felt that NERC standards should concentrate on "what" the requirements are, not "how" to achieve them.

SAR should only address creation of Planning Standards. Plan Development is a compliance issue.
The Standard will not tell people "how" to achieve the solutions, but only require that they have a Plan. This is in accordance with the Functional Model, which requires that each Planning Authority have a documented Plan to address inadequacies identified in a transmission needs assessment.

SAR should only define the reliability requirements, not specific solutions.
Agreed.

Eliminate the function relating to "assessing" transmission performance. Only "plan" future transmission expansion.
Assessment of the transmission system is needed to identify anticipated deficiencies that proper planning will correct. Thus, the SAR DT feels that both "assessment" and "planning" are essential components of this SAR.

Standard should only apply to the long-term planning function. Should be a parallel standard for operational planning.
We agree. The standard will only address long term planning, which is defined in the Functional Model as 1 year and beyond.

Standard must not become a mandate for all to use the same load flow model.
Agreed.

Question: *"Scope of this SAR Should be Expanded to Include ……."*

Scope should be expanded to include generation as well.
The SAR DT understands this requirement to "include" generation to mean developing transmission plans that include (as inputs to the transmission adequacy assessment) resources, adequacy plans and load forecasts of LSE's . According to the Functional Model, the Planning Authority must develop an integrated plan from both Transmission Planners and Resource Planners. We agree generation should be included; however, we do not believe that there should be a single standard that integrates resource adequacy planning and transmission adequacy planning. This standard should address only transmission adequacy planning. Separate RA standards may be developed, applicable to different entities; e.g., transmission standards for TOs, resource standards for LSEs .

NERC should guard against establishing a one-dimensional standard that fails to take into account all dimensions that guide the planning process.
Agreed.

SAR should include a requirement to plan the system so that it can be operated within operating limits .
The SAR DT believes that complying with a properly-designed planning standard will result in a system that can be operated within operating limits.

Scope should include planning associated with IPPs
See our response to the comment above that the "scope should be expanded to include generation as well".

NERC should ensure that the standards defined include a definition of how the planning model is created.
The SAR DT has attempted to address this issue in the proposed SAR.

Standard should be specific and measurable and define what "normal", "extreme", and "abnormal" system conditions are.
Agreed. The DT has deleted these terms from the SAR and instead has included a requirement that the standard use the contingency events identified in Table 1 of existing Planning Standard I.A.

Minimum set of criteria for assessing acceptability of plans is needed.
The SAR DT believes the proposed SAR establishes minimum system performance standards, but does not direct how to meet those standards. For a Plan to be acceptable, anticipated system performance under the Plan must meet the minimum criteria established by the standard.

May be a need for multiple expansion plans because of timing of generator projects that are dictated by commercial rather than system adequacy considerations.
The SAR DT does not envision that the standard will address commercial or market issues. However, the standard will require documentation and disclosure of generation assumptions used to develop the Transmission Plan.

Must define what minimum need is. Some regulatory backstop is needed if expansion plans are deemed insufficient to meet needs.
The DT feels that the SAR as written will result in a standard that defines the minimum need.

SAR should identify who has obligation to implement transmission plans.
The Functional Model identifies which functions have the responsibility to implement transmission plans. The SAR DT (in the Comment Form posted with Version 2 of the SAR) has asked for industry guidance on the monitoring of implementation plans.

Must use a reasonable planning horizon (less than or equal to 5 years).
The DT believes that the SAR as written will result in a standard that requires the use of a reasonable planning horizon.

Provision for interim use of Remedial Action Plans (RAP) & Special Protection Schemes (SPS) is needed.
The SAR DT feels that the standard will neither require nor preclude the use of RAP or SPS for either interim or permanent use to meet the reliability criteria contained in the standard.

Regional differences should be recognized.
Agreed. The SAR DT has asked for industry input to identify such differences. See the Comment Form posted with the SAR – V2.

Requirement to provide assessment at all demand levels should be added.
The SAR DT has developed language to consider the variability of load in the development of the standard.

Responsibility for assessing and defining adequate operating reserves and reactive support should be added.
The SAR DT believes operating reserves is an operational issue that should be addressed by operating standards. However, voltage support and reactive power will be addressed in this standard.

Planning criteria should be expanded to include maintainability of system.
The SAR DT has asked for industry input on this issue. Refer to the Comment Form posted with the SAR – V2.

When studies indicate that the system may not meet performance requirements, plans should be developed to address the situation and studies should demonstrate that implemented plans meet requirements.
We agree.

Core standard for reliability should be specific & measurable.
Agreed.

"Miscellaneous Comments"

Technical specifications should ensure that they do not prohibit worthwhile commercial negotiations or commercial activity.
Agreed.

Must have coordination with operating procedures and protocols of RTOs.
The standard will be applicable to all functional responsibilities included in the Functional Model.

Must be close coordination with NAESB and RTOs to meet both reliability objectives and commercial needs.
The standard will define reliability criteria without precluding or dictating viable commercial solutions.

Measuring for compliance is extremely difficult. It is also difficult to determine if events will result in "cascading outages".
We believe the standard will clarify and explicitly state the requirements for compliance. Agreed that a clearer definition of "cascading outages" is needed, and the definition is being developed.

SAR will not accomplish its intent without credible models from which to do analysis.
Agreed.

SAR seems large – divide it up?
The SAR does cover a large scope, but the DT feels that dividing the SAR and standard is premature at this point.

Scope of SAR is poorly written. It does not convey transmission planning responsibilities.
Scope is being revised to add more details and become clearer.

Separate SAR should be established for implementation of SPS. Develop plans to address operational issues for interconnected grids where SPS is needed to mitigate against system deficiencies.
There is a separate SAR that addresses Protection Systems. To the extent that SPS affects transmission assessment and planning, some aspects of SPS may be addressed in this SAR.

SAR does not set standard, but tries to assign responsibility for setting standard.
As envisioned, this SAR will address BOTH the standard and the responsibility.

END OF INDUSTRY COMMENTS/DT RESPONSES FOR SAR – V1

When completed, email to: gerry.cauley@nerc.net

Standard Authorization Request Form

Title of Proposed Standard	Assess Transmission Future Needs and Develop Transmission Plans
Request Date	May 01, 2004

SAR Requestor Information		**SAR Type** (Put an 'x' in front of one of these selections)	
Name	Paul Rocha	☒	New Standard
Primary Contact	Paul Rocha	☐	Revision to existing Standard
Telephone Fax	(713) 207-2768	☐	Withdrawal of existing Standard
E-mail	paul.rocha@centerpointenergy.com	☐	Urgent Action

Purpose/Industry Need (Provide one or two sentences)

To establish a standard for assessing and planning the transmission systems in North America. The transmission system must be assessed and planned to ensure that it performs its intended functions in providing reliable delivery of power for the future needs of customers.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies by double clicking the grey boxes.)*		
☒	Reliability Authority	Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest reliability authority.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules
☒	Planning Authority	Plans the bulk electric system
☐	Resource Planner	Develops a long-term (>1year) plan for the resource adequacy of specific loads within a Planning Authority area.
☒	Transmission Planner	Develops a long-term (>1 year) plan for the reliability of transmission systems within its portion of the Planning Authority area.
☐	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
☒	Transmission Owner	Owns transmission facilities
☐	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
☐	Distribution Provider	Provides and operates the “wires” between the transmission system and the customer
☐	Generator Owner	Owns and maintains generation unit(s)
☐	Generator Operator	Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services
☐	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required
☐	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.
☐	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check boxes for all that apply by double clicking the grey boxes.)*	
☒	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box by double clicking the grey area.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft, modify, or withdraw a Standard based on this description.)

The Standard shall establish requirements for assessing the performance of planned bulk electric transmission systems and the requirements for documenting a plan to remedy any inadequacies identified in the process of conducting such assessments.

The scope of such assessments and plans is for a planning horizon of one year or more. The scope *does not* include the operating horizon less than one year. While the planning horizon is intended to provide for facility additions, there is no intent to exclude appropriate operating procedures from the transmission plan.

The planning horizon must be long enough to permit timely implementation of viable solutions to remedy the potential inadequacies found. Assessments should cover a planning horizon of at least 5 years. The horizon may be longer than 5 years, based on regulatory or legislative requirements, or on the judgment of the Transmission Planner or Planning Authority.

The Standard shall identify reliability requirements, but shall not specify *how* to achieve such requirements. These requirements shall apply to Transmission Planners and to Planning Authorities.

The applicable portions of the following existing NERC Planning Standards will be used as the starting point in drafting these requirements:

- I.A Transmission Systems
- I.B Reliability Assessment
- I.D Voltage Support & Reactive Power
- II.A System Data
- II.D Actual and Forecast Demands

The Standard shall require that system models be developed, maintained and shared in a manner consistent with the Functional Model. Included will be requirements that each Planning Authority and Transmission Planner document and disclose the methodology used for incorporating planned generation assets in the model, as well as how such generation is dispatched. While methodologies and assumptions must be documented, the Standard will *not* prescribe specific tools to be used in the performance assessment of the planned systems.

The Standard will identify the various planning functions that are responsible for compliance with the standard criteria. The assignment of compliance responsibility will be consistent with the Functional Model.

This Standard will *not* include requirements for:

- Resource Planning (i.e., assessing or ensuring the availability of adequate generation resources to serve load).
- Planning generation additions to remedy any generation resource inadequacies.
- Mitigation plans to relieve congestion due to economy transfers of generation resources.

However, the Standard should neither preclude nor require the consideration of generation or load (demand side management) or operating procedures as alternatives to transmission reinforcement/reconfiguration when developing solutions to potential transmission inadequacies.

While the Standard should start from and closely align with the existing Planning Standards I.A, .B, .D, II.A,.D, the system conditions to be studied or assessed may need to be better defined or clarified. For example, the Standard should clarify that the requirement to assess the performance at ***all*** demand levels does not mean that a multitude of transmission models need to be created for every possible demand level, only that a representative sample covering critical operating conditions needs to be modeled in accordance with regionally-defined criteria.

Other examples of areas that should be considered for clarification in the Standard include:

- The Standard should provide a clearer definition of "cascading outages".*

  *Existing Planning Standard I.A definition: "Cascading is the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies"

- The Standard should take into account the variability of load due to factors such as weather and time of day.

- The Standard should allow for the development and use of probabilistic planning methods. The minimum requirements of probabilistic methods are the contingencies as described in Table 1 of existing Planning Standard I.A.. There should be NERC approval of acceptable levels of risk.

- Existing Planning Standard S1, S2, S3, S4 and Table I.A Category A, B, C, D should be clarified on the issue of how a planned outage should be used in an assessment.

- Performance requirements for Category C events shall be re-evaluated. For example, for certain Category C events, such as #2, #3 and #9 events, consider removing references to "Applicable Ratings" to clarify that the performance requirement is "No Cascading Outages are Allowed".

- The Standard should include requirements to ensure that the maximum available short circuit current is within the ratings of transmission facilities.

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation
FACILITY_RATINGS_01_01	*"Determine Facility Ratings, Operating Limits and Transfer Capabilities".* The Planning Standard will use some data collected within the "Facility Ratings" SAR. The Draft "Facility Ratings" Standard, Section 603, establishes some guidelines for the planning function to set operating limits based on Table 1 of the existing Planning Standard I.A.
OPER_WITHN_LMTS_01_01	*"Operate Within Interconnection Reliability Operating Limits".* This Planning Standard needs to establish future planning criteria such that the bulk electric power system can be operated within operating limits.

Regional Differences

Region	Explanation
ECAR	
ERCOT	
FRCC	
MAAC	
MAIN	
MAPP	
NPCC	
SERC	
SPP	
WECC	

Related NERC Operating Policies or Planning Standards

ID	Explanation
Planning Std. I.A	Transmission Systems: Plan within ratings, avoid cascading outages, uncontrolled system separation, and voltage and transient instability.
Planning Std. I.B	Reliability Assessment
Planning Std. I.D	Voltage Support & Reactive Power
Planning Std. II.A	System Data
Planning Std. II.D	Actual & Forecast Demands

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E-mail this form between May 5 and June 5, 2004 to: sarcomm@nerc.com with "Comments" in the subject line.

If you have any questions about this Standards Draft Comment Form, please contact the Director of Standards – Gerry Cauley at 609-452-8060.

Background:

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If there is such a need, how should the scope of the SAR be changed?

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- The scope of the SAR should be expanded to include…..
- The scope of the SAR should be reduced to eliminate……

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Most of the industry respondents indicated that there is indeed a reliability-related need to develop a standard to address transmission assessment and planning issues. Comments were received from many different sources, including individuals, small and large utilities, groups of utilities, and Regional Councils. The SAR DT considered the comments submitted by each industry participant, and revised the SAR to conform to the changes that were technically sound and appeared to represent a consensus of participants.

The revised SAR (Version 2) is posted on the NERC web site given in the blue box at the top of this form. Also posted is a Consideration of Comments document, in which the DT has responded to the original industry comments from 2002. You can find Version 1 of the SAR and industry comments on this version at the same web location.

Please review Version 2 of the SAR and complete this Comment Form to let the SAR DT know if you agree or disagree with the SAR DT's assessment that this SAR is ready to be developed into a Standard.

Commenter Information (For Individual Commenters)

Name: Karl Kohlrus

Organization: City Water, Light & Power

Industry Segment #: 5

Telephone: (217)-321-1391

E-mail: kkohlrus@cwlp.com

Key to Industry Segment #'s:

1 – Trans. Owners
2 – RTO's, ISO's, RRC's
3 – LSE's
4 – TDU's
5 - Generators
6 - Brokers, Aggregators, and Marketers
7 - Large Electricity End Users
8 - Small Electricity Users
9 - Federal, State, and Provincial Regulatory or other Govt. Entities

STD Commenter Information (For Groups Submitting Group Comments)

Name of Group:	**Group Chair:** **Chair Phone:** **Chair Email:**

List of Group Participants that Support These Comments:

Name	Company	Industry Segment #

Please Review Version 2 of the SAR and Answer the Following Questions

Insert a "check' mark in the appropriate boxes by double-clicking the gray areas.

1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

   (a). Do you believe that the events in Categories B, C & D are classified correctly?

   ☒ Yes

   ☐ No

   ☐ Comments:

   (b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

   (c) Which of the following approaches do you favor regarding Table 1 of existing Planning Standard I.A?:

   ☒ Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events.

   Please explain your choice:

   ☒ Create a new category between C and D with performance characteristics between that of the present Categories C and D.

   Please explain your choice

   Multiple contingencies have lower and varying probabilities of occurrence.

   ☐ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

   Please explain your choice:

   ☐ Comments:

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

   ☐ Yes

   ☒ No

   ☐ Comments:

3. If your answer to question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan?

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

   The SAR drafting team believes that it is impractical to exhaustively test for every contingency described in each category plus every conceivable planned outage. Should the requirement to consider planned outages in addition to each Category A through D contingency remain part of this planning standard?

   ☐ Yes (consider planned outages in all Categories A through D).

   ☒ Yes (consider planned outages in some Categories only).

   Please specify which Categories: B and some C.

   ☐ No

   ☐ Comments:

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

   ☒ Comments:

   WECC has asked the NERC PC for waivers for some of the Category C requirements.

6. Do you have any other comments on the SAR?

   ☐ Comments:

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Please review Version 2 of the SAR and complete this Comment Form to let the SAR DT know if you agree or disagree with the SAR DT's assessment that this SAR is ready to be developed into a Standard.

Commenter Information (For Individual Commenters)
Name: William J. Smith
Organization: Allegheny Power
Industry Segment #: 1
Telephone: (724) 838-6552
E-mail: wsmith1@alleghenypower.com

Key to Industry Segment #'s:

1 – Trans. Owners
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Insert a "check' mark in the appropriate boxes by double-clicking the gray areas.

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   (a). Do you believe that the events in Categories B, C & D are classified correctly?

   ☒ Yes

   ☐ No

   ☐ Comments:

   (b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

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   Please explain your choice:

   ☐ Create a new category between C and D with performance characteristics between that of the present Categories C and D.

   Please explain your choice

   ☐ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

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   ☐ Yes (consider planned outages in all Categories A through D).

   ☒ Yes (consider planned outages in some Categories only).

   Please specify which Categories:

   ☐ No

   ☒ Comments: Allegheny Power feels that it is practical to consider planned outages in categories A and B.

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

   ☐ Comments:

6. Do you have any other comments on the SAR?

   ☒ Comments: Under "Detailed Description" the second and third paragraphs are unclear and appear to be conflicting. The first of those paragraphs specifies that the "scope of such assessments and plans is for a planning horizon of one year or more". The second of those paragraphs specifies, "Assessments should cover a planning horizon of at least 5 years". This appears to be a conflict. It may be that the term "planning horizon" is being used differently in these two paragraphs. It is unclear to us what is the intention of the first of those two paragraphs is.

   Also under "Detailed Description on page SAR-5, the paragraph starting "While the Standard should start from…" has a problem with it's second sentence. The sentence "For example…" does really apply to the first sentence. We recommend that this paragraph be changed as follows:

   > While the Standard should start from and closely align with the existing Planning Standards I.A, .B, .D, II.A,.D, the system conditions to be studied or assessed may need to be better defined or clarified.
   >
   > Examples of areas that should be considered for clarification in the Standard include:

- The Standard should clarify that the requirement to assess the performance at all demand levels does not mean that a multitude of transmission models need to be created for every possible demand level, only that a representative sample covering critical operating conditions needs to be modeled in accordance with regionally-defined criteria.
- The Standard should provide a clearer definition of "cascading outages".*

And so on.

Also in that bulleted list, the existing 5th bullet item, "Performance requirements for Category C events shall be re-evaluated. For example, for certain Category C events , such as #2, #3 and #9 events, consider removing references to "Applicable Ratings" to clarify that the performance requirement is "no Cascading Outages are Allowed" doesn't appear necessary. "No Cascading Outages" is already part of Table I for these events. Removing "Applicable Ratings" would not add to the clarity.

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Most of the industry respondents indicated that there is indeed a reliability-related need to develop a standard to address transmission assessment and planning issues. Comments were received from many different sources, including individuals, small and large utilities, groups of utilities, and Regional Councils. The SAR DT considered the comments submitted by each industry participant, and revised the SAR to conform to the changes that were technically sound and appeared to represent a consensus of participants.

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Please review Version 2 of the SAR and complete this Comment Form to let the SAR DT know if you agree or disagree with the SAR DT's assessment that this SAR is ready to be developed into a Standard.

Commenter Information (For Individual Commenters)
Name: Tom Mielnik Organization: MidAmerican Energy Company Industry Segment #:3 Telephone: 563-333-8129 E-mail: tcmielnik@midamerican.com

Key to Industry Segment #'s:

1 – Trans. Owners
2 – RTO's, ISO's, RRC's
3 – LSE's
4 – TDU's
5 - Generators
6 - Brokers, Aggregators, and Marketers
7 - Large Electricity End Users
8 - Small Electricity Users
9 - Federal, State, and Provincial Regulatory or other Govt. Entities

STD Commenter Information (For Groups Submitting Group Comments)		
Name of Group:	**Group Chair:** **Chair Email:**	**Chair Phone:**

List of Group Participants that Support These Comments:

Name	Company	Industry Segment #

Please Review Version 2 of the SAR and Answer the Following Questions

Insert a "check' mark in the appropriate boxes by double-clicking the gray areas.

1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

   (a). Do you believe that the events in Categories B, C & D are classified correctly?

   ☐ Yes

   ☒ No

   ☐ Comments:

   (b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

   MidAmerican Energy believes the interconnected transmission system should be planned, designed, and constructed to withstand high probability events and to withstand low probability events with significant negative consequences. MidAmerican believes it is a waste of the ratepayers' money to plan, design, and construct the interconnected transmission system for low probability events without significant negative consequences.

   MidAmerican Energy would reclassify certain low probability events such as Category C1 events, C2 events, certain Category C3 events (two transformers, transmission circuit plus a transformer, two transmission circuits, DC line plus a transformer, DC line plus a transmission circuit, and two DC lines), C6 events, C7 events, C8 events, and C9 events to a new category between C and D with performance characteristics between that of the present Categories C and D. MidAmerican Energy would require that the interconnected transmission system be planned, designed, and constructed to protect for instability, cascading, and uncontrolled separation for the low probability events in the new sub-category.

   MidAmerican Energy believes the following information supports this new reclassification by demonstrating that the events that MidAmerican recommends for reclassification are the low probability Category C events. MidAmerican recognizes that published outage data are subject to interpretation, potential inaccuracy, and change through time; however, MidAmerican believes that MidAmerican operating experience with transmission element outages supports the statistical summary provided in the following table.

345 kV Outage Data				
Contingency	Outage Rate, occ./year	Duration, hours	Probability	Relative Likelihood
Generator B1	9	81	0.08321918	1
Two generators C3	1.5	40.5	0.00693493	12
Bipolar DC line * (Similar to B4)	1.41	21	0.00338014	24
Line * B2	0.8065	18	0.00165719	50
Transformer B3	0.0642	157	0.00115062	72
Bipolar DC Line * + Generator (Sim. to 1 Pole DC line + gen. C3)	0.1478	16.68	0.00028143	296
Line * + Generator C3	0.0820	14.7	0.00013760	605
Generator + Transformer C3	0.0157	53.4	0.00009571	870
Common tower * C5	0.007	113	0.00009030	922
Breaker Failure- Insulation Breakdown C2 RECLASSIFY THIS EVENT	0.001423	163	0.00002647	3,144
Bipolar DC line *+Bipolar DC line * (Sim. to Two 1 Pole DC lines - C3) RECLASSIFY THIS EVENT	0.009532	10.5	0.00001143	7,281
Stuck breaker C6-C9 RECLASSIFY THIS EVENT	0.00635	4	0.00000290	28,696
Line * + Line * (independent) C3 RECLASSIFY THIS EVENT	0.00267	9	0.00000275	30,262
Line * + Transformer C3 RECLASSIFY THIS EVENT	0.0010	16.1	0.00000184	45,228
Two transformers C3 RECLASSIFY THIS EVENT	0.00014774	78.5	0.00000132	63,045
Bus Section** RECLASSIFY THIS EVENT	0.0023	4.7	0.00000123	67,438

* Per 100 mile-year.

** Based upon 230 kV data.

References

1. MAPP-CSRWG, "MAPP Bulk transmission system outage report", June 2001.
2. C. R. Heising, et al, "Final report on high voltage circuit breaker reliability data for use in substation and system studies – report on behalf of WG 13.06, in Proceedings of CIGRE Conference, Paris, 1994.
3. R. Billinton, A. A. Chowdhury, "Generating unit models using the Canadian Electricity database", CEA Transactions, Volume 23, 1984.
4. R. N. Allan, "Concepts of data for assessing the reliability of composite systems", IEEE Tutorial Course on Reliability Assessment of Composite Generation and Transmission Systems, Course Text 90EH0311-1-PWR.

Contact info:

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Davenport, Iowa 52801
(563)333-8129
tcmielnik@midamerican.com

(c) Which of the following approaches do you favor regarding Table 1 of existing Planning Standard I.A?:

☐ Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events.

Please explain your choice:

☒ Create a new category between C and D with performance characteristics between that of the present Categories C and D.

Please explain your choice

The approach that results in the most appropriate transmission system design is the one recommended by MidAmerican Energy. Improvements should be planned for those Category C events that are high probability events regardless of the consequences. Planners should also review all Category C events for instability, cascading, and uncontrolled separation. Improvements should be planned for those Category C events (both high probability and low probability events) which have significant consequences, that is, that result in instability, cascading, and uncontrolled separation. It is MidAmerican's belief that the intent of the drafting team that originally developed the existing NERC Planning Standards was to require the NERC member to plan to protect for instability, cascading, and uncontrolled separation for Category C events.

MidAmerican believes reclassifying less likely Category C events as Category D events will result in planners ignoring low-probability contingencies that result in significant consequences: cascading, uncontrolled separation, and instability.

MidAmerican believes that allowing for "good cause exceptions" is also not the preferable approach. MidAmerican believes that the events listed by MidAmerican for reclassification are much less likely than the other Category C events generally throughout NERC. This means that these events should be reclassified in general throughout NERC and not just in certain "good cause exceptions". (Although, it should be noted that MidAmerican does support regional differences where appropriate.) Besides, there are issues associated with the development and utilization of a process for approving "good cause exceptions".

☐ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

Please explain your choice:

☐ Comments:

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

   ☐ Yes

   ☒ No

   ☒ Comments: MidAmerican Energy believes that this standard should not include requirements for reporting on the progress or status of implementing the plans developed in accordance with this standard. There are too many conditions beyond the control of the NERC member for this to be a part of a standard requiring compliance review. Complex environmental, regulatory, and political issues prevent many transmission facilities from being constructed or being constructed in a scheduled manner. The Not-In-My-Back-Yard philosophy has hit even the rural areas so that there is no part of the NERC area where a NERC member can confidently predict completion of transmission system improvements in plans. Further, conditions can change even during a year to such an extent that compliance review for implementation from one year to the next is problematic. Further, regulatory oversight provides for appropriate review of plan implementation anyway. MidAmerican urges that the SAR drafting team not pursue this well-meaning but problematic approach.

3. If your answer to question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan?

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

   The SAR drafting team believes that it is impractical to exhaustively test for every contingency described in each category plus every conceivable planned outage. Should the requirement to consider planned outages in addition to each Category A through D contingency remain part of this planning standard?

   ☐ Yes (consider planned outages in all Categories A through D).

   ☐ Yes (consider planned outages in some Categories only).

   Please specify which Categories:

   ☒ No

   ☒ Comments:

   Planned Outages can be scheduled and analyzed in advance in the operating horizon (less than one year). Therefore, it should not be necessary to require that "systems must be capable of meeting Category C requirements while accommodating the planned outage of any bulk electric equipment..." Planned outages should be studied in advance by the requesting control area and be reviewed by the governing Reliability Coordinator to determine if overloads could occur. If studies show that overloads could occur, the planned outage should be deferred or operating guides prepared which would be used in the event a contingency does occur.

There is no need to plan or build facilities to meet Planning Standard 1.A when Planned Outages can be accommodated within the frame work of existing guidelines and procedures. Studies conducted for the operating horizon are not the subject of this standard.

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

   ☐ Comments:

6. Do you have any other comments on the SAR?

   ☒ Comments:

   a. MidAmerican Energy urges the SAR drafting team to add Category C#1, #6, #7 and #8 events to the second from last paragraph in the SAR which describes considering removing references to "Applicable Ratings" to clarify the performance requirement for certain Category C events.

   b. MidAmerican Energy urges the SAR drafting team to direct the Standard Drafting Team to remove references to "Applicable Ratings" from all events listed in the second to last paragraph because information is readily available which demonstrates that the listed events are much less likely than other Category C events.

   c. MidAmerican Energy urges the SAR drafting team to add the following words to the third paragraph from the end to more clearly explain the SAR drafting team's position with regard to planned outages:

   "In particular, it is incorrect to have a requirement to exhaustively test for every contingency described in each category plus every conceivable planning outage.

   Planned Outages can be scheduled and analyzed in advance in the operating horizon (less than one year). Therefore, it should not be necessary to require that "systems must be capable of meeting Category C requirements while accommodating the planned outage of any bulk electric equipment..." Planned outages should be studied in advance by the requesting control area and be reviewed by the governing Reliability Coordinator to determine if overloads could occur. If studies show that overloads could occur, the planned outage should be deferred or operating guides prepared which would be used in the event a contingency does occur.

   There is no need to plan or build facilities to meet Planning Standard 1.A when Planned Outages can be accommodated within the frame work of existing guidelines and procedures. Studies conducted for the operating horizon are not the subject of this standard.

   Therefore, the SAR drafting team directs the standard drafting team to delete the requirement for the prior planned outage from the standard given that known planned outages must be included in studies that are conducted during the operating horizon which are not the subject of this standard but which are required in accordance with NERC Standard 200, "Operate Within Interconnection Reliability Operating Limits Standard" and NERC Standard 600, "Determine Facility Ratings, Operating Limits, and Transfer Capabilities".

   d. MidAmerican Energy urges the SAR drafting team to include the following statement in the SAR:

   "The Standard should clarify how breaker failure events (Category C2, C6, C7, C8, and C9 events) are to be considered given that operating a breaker with disconnects open or eliminating a breaker are technically acceptable mitigation schemes for such events. Such mitigation schemes actually result in less reliable system designs and system operating configurations. Thus including Applicable Ratings in the Standard for these lower probability breaker failure events can send the wrong reliability signals to NERC members."

This paragraph reflects another reason why breaker failure events should be reclassified such that Applicable Ratings is no longer considered a requirement for these low probability events.

e. MidAmerican Energy urges the SAR drafting team to consider not reclassifying any of the Category C events to Category D but instead deleting the Applicable Rating requirements from the lower probability Category C events. MidAmerican believes that the performance requirements for lower probability Category C events should be to protect for cascading, instability, and uncontrolled separation. It is MidAmerican's belief that this was the intent of the drafting team that originally developed the existing NERC Planning Standards.

f. MidAmerican Energy is concerned that the SAR does not provide for the coordination of the requirements of the planning standards in NERC Standard 500, "Assess Transmission Future Needs and Develop Transmission Plans", with the NERC Operating Standards provided in NERC Standard 600, "Determine Facility Ratings, Operating Limits, and Transfer Capabilities." The criteria that are proposed as a starting point for 500 in this SAR (events from Categories A through D) differ from the criteria that are included in the latest draft of NERC Standard 600 (Categories A and B). If these approaches are continued, then studies run for the operating horizon will differ significantly from studies run for the planning horizon. These differences in studies will carry over to the calculation of quantities used to offer transmission service, that is, Total Transfer Capacity and Available Transmission Capacity. If NERC does not coordinate these two standards, there will be a discontinuity in TTC and ATCs when the Planning Horizon begins and the Operating Horizon ends or from one day less than one year to one year. MidAmerican urges the SAR drafting team to consider this discontinuity and coordinate the SAR for 500 with the Standard that is being written for 600. If a discontinuity between criteria is allowed to continue in the SAR for Standard 500, the SAR drafting team should have a clear explanation for all market participants as to the reason for the discontinuity and how that should be dealt with by the elements of the NERC Functional Model.

g. In general, MidAmerican Energy supports the six bullets that the SAR drafting team has provided on page SAR-5 with the amendments and additions described above in our comments. These bullets add needed details to the SAR.

Note – This form is to comment on **Version 2** of the **"Assess Transmission Future Needs and Develop Transmission Plans"** SAR.

The latest version of this SAR (TRNS_NDS_&_PLNS_01_02) is posted on the Standards web site at: http://www.nerc.com/~filez/standards/Assess-Transmission-Future-Needs.html

E-mail this form between May 1 and May 31, 2004 to: sarcomm@nerc.com with "Comments" in the subject line.

If you have any questions about this Standards Draft Comment Form, please contact the Director of Standards – Gerry Cauley at 609-452-8060.

Background:

Version 1 of the **"Assess Transmission Future Needs and Develop Transmission Plans"** SAR was posted for a 30-day public comment period between April 2 and May 3, 2002. This first version was an abbreviated SAR, which included an "Industry Need" statement and a brief description of the proposed standard, but did not include a detailed description. The purpose of this first posting was to collect feedback from the industry on the following questions:

- Is there a reliability-related need for an Organization Standard to be developed on this topic?

If there is such a need, how should the scope of the SAR be changed?

- The scope of the SAR is fine as is
- The scope of the SAR should be expanded to include…..
- The scope of the SAR should be reduced to eliminate……

In January 2004, the Standards Authorization Committee (SAC) appointed a Drafting Team (DT) to address industry answers and comments to the questions posed. The DT was also charged with refining the SAR and drafting a detailed description of the proposed standard in preparation for the 2nd posting of the SAR.

Most of the industry respondents indicated that there is indeed a reliability-related need to develop a standard to address transmission assessment and planning issues. Comments were received from many different sources, including individuals, small and large utilities, groups of utilities, and Regional Councils. The SAR DT considered the comments submitted by each industry participant, and revised the SAR to conform to the changes that were technically sound and appeared to represent a consensus of participants.

The revised SAR (Version 2) is posted on the NERC web site given in the blue box at the top of this form. Also posted is a Consideration of Comments document, in which the DT has responded to the original industry comments from 2002. You can find Version 1 of the SAR and industry comments on this version at the same web location.

Please review Version 2 of the SAR and complete this Comment Form to let the SAR DT know if you agree or disagree with the SAR DT's assessment that this SAR is ready to be developed into a Standard.

Commenter Information (For Individual Commenters)
Name:
Organization:
Industry Segment #:
Telephone:
E-mail:

Key to Industry Segment #'s:

1 – Trans. Owners
2 – RTO's, ISO's, RRC's
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6 - Brokers, Aggregators, and Marketers
7 - Large Electricity End Users
8 - Small Electricity Users
9 - Federal, State, and Provincial Regulatory or other Govt. Entities

STD Commenter Information (For Groups Submitting Group Comments)	
Name of Group: MAPP Planning Standards Development Working Group	**Group Chair:** Tom Mielnik **Chair Phone:** 563-333-8129 **Chair Email:** tcmielnik@midamerican.com

List of Group Participants that Support These Comments:

Name	Company	Industry Segment #
Tom Mielnik	MEC	2
Delyn Helm	GRE	2
David Jacobson	MH	2
Dennis Kimm	MEC	2
Dean Schiro	XEL	2
Jason Weiers	OTP	2
Steve Sanders	WAPA	2

Please Review Version 2 of the SAR and Answer the Following Questions

Insert a "check' mark in the appropriate boxes by double-clicking the gray areas.

1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

   (a). Do you believe that the events in Categories B, C & D are classified correctly?

   ☐ Yes

   ☐ No

☒ Comments: The definition of applicable ratings needs to be clarified. The SAR DT should also indicate if it is feasible to have different applicable ratings for different categories of events.

The SAR DT should review the history of the original classification. This review should include all classes. If outage statistics are used to classify events, how many years of data are appropriate? If the data window is too small, the results will be skewed. Moreover, is it appropriate to use outage data for all these categories of events? Outage data over a long period of time may provide insight into equipment performance, but is it appropriate to reflect weather related contingency events – the data may not reflect the effect of a once in a 100 year storm?

(b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

MAPP would reclassify certain low probability events such as Category C1 events, C2 events, certain Category C3 events (two transformers, transmission circuit plus a transformer, two transmission circuits, DC line plus a transformer, DC line plus a transmission circuit, and two DC lines), C6 events, C7 events, C8 events, and C9 events to either a new category between C and D with performance characteristics between that of the present Categories C and D or to Category D. MAPP would require that the interconnected transmission system be planned, designed, and constructed to protect for instability, cascading, and uncontrolled separation for the low probability events in the new sub-category. Regions should develop procedures for determining that systems are properly protected for instability, cascading and uncontrolled separation.

MAPP believes the following information supports this new reclassification by demonstrating that the events that MAPP recommends for reclassification are the low probability Category C events. MAPP recognizes that published outage data are subject to interpretation, potential inaccuracy, and change through time; however, MAPP believes that MAPP operating experience with transmission element outages supports the statistical summary provided in the following table.

345 kV Outage Data				
Contingency	Outage Rate, occ./year	Duration, hours	Probability	Relative Likelihood
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Line * B2	0.8065	18	0.00165719	50
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Generator + Transformer C3	0.0157	53.4	0.00009571	870
Common tower * C5	0.007	113	0.00009030	922
Breaker Failure- Insulation Breakdown C2 RECLASSIFY THIS EVENT	0.001423	163	0.00002647	3,144
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Bus Section** RECLASSIFY THIS EVENT	0.0023	4.7	0.00000123	67,438

* Per 100 mile-year.

** Based upon 230 kV data.

References

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3. R. Billinton, A. A. Chowdhury, "Generating unit models using the Canadian Electricity database", CEA Transactions, Volume 23, 1984.
4. R. N. Allan, "Concepts of data for assessing the reliability of composite systems", IEEE Tutorial Course on Reliability Assessment of Composite Generation and Transmission Systems, Course Text 90EH0311-1-PWR.

Contact info:

Tom Mielnik, Chair
MAPP Planning Standards Development Working Group
MidAmerican Energy Company
106 East Second Street
Davenport, Iowa 52801
(563)333-8129
tcmielnik@midamerican.com

(c) Which of the following approaches do you favor regarding Table 1 of existing Planning Standard I.A?:

☒ Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events.

If the events are low probability, then some should be considered for moving to Cat D.

Please explain your choice:

☒ Create a new category between C and D with performance characteristics between that of the present Categories C and D.

Please explain your choice

Improvements should be planned for those Category C events that are high probability events regardless of the consequences. Planners should also review all Category C events for instability, cascading, and uncontrolled separation. Improvements should be planned for those Category C events (both high probability and low probability events) which have significant consequences, that is, that result in instability, cascading, and uncontrolled separation.

MAPP believes that allowing for "good cause exceptions" is not the preferable approach. MAPP believes that the events listed by MAPP for reclassification are much less likely than the other Category C events generally throughout NERC. This means that these events should be reclassified in general throughout NERC and not just in certain "good cause exceptions". (Although, it should be noted that MAPP does support regional differences where appropriate.) Besides, there are issues associated with the development and utilization of a process for approving "good cause exceptions".

☐ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

Please explain your choice:

☐ Comments:

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

☐ Yes

☐ No

☒ Comments: Requirements for reporting on the progress or status of implementing the plans should be left to the regions and appropriate regulatory bodies. The MAPP Regional Transmission Committee currently has a regional planning process for compliance for implementing transmission plans.

3. If your answer to question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan?

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

   The SAR drafting team believes that it is impractical to exhaustively test for every contingency described in each category plus every conceivable planned outage. Should the requirement to consider planned outages in addition to each Category A through D contingency remain part of this planning standard?

   ☐ Yes (consider planned outages in all Categories A through D).

   ☐ Yes (consider planned outages in some Categories only).

   Please specify which Categories:

   ☒ No

   ☒ Comments:

   Planned Outages can be scheduled and analyzed in advance in the operating horizon (less than one year). Therefore, it should not be necessary to require that "systems must be capable of meeting Category C requirements while accommodating the planned outage of any bulk electric equipment..." Planned outages should be studied in advance by the requesting control area and be reviewed by the governing Reliability Coordinator to determine if overloads could occur. If studies show that overloads could occur, the planned outage should be deferred or operating guides prepared which would be used in the event a contingency does occur.

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

   ☐ Comments:

6. Do you have any other comments on the SAR?

   ☒ Comments:

   a. MAPP urges the SAR drafting team clarify the meaning of the term "Applicable Ratings" and determine if it is possible to have different A/Rs for different categories.

   b. MAPP urges the SAR drafting team to add words to the third paragraph from the end to more clearly explain the SAR drafting team's position with regard to prior planned outages.

c. MAPP is concerned that the SAR does not provide for the coordination of the requirements of the planning standards in NERC Standard 500, "Assess Transmission Future Needs and Develop Transmission Plans", with the NERC Operating Standards provided in NERC Standard 600, "Determine Facility Ratings, Operating Limits, and Transfer Capabilities." The criteria that are proposed as a starting point for 500 in this SAR (events from Categories A through D) differ from the criteria that are included in the latest draft of NERC Standard 600 (Categories A and B). If these approaches are continued, then studies run for the operating horizon will differ significantly from studies run for the planning horizon. These differences in studies will carry over to the calculation of quantities used to offer transmission service, that is, Total Transfer Capacity and Available Transmission Capacity. If NERC does not coordinate these two standards, there will be a discontinuity in TTC and ATCs when the Planning Horizon begins and the Operating Horizon ends or from one day less than one year to one year. MAPP urges the SAR drafting team to consider this discontinuity and coordinate the SAR for 500 with the Standard that is being written for 600. If a discontinuity between criteria is allowed to continue in the SAR for Standard 500, the SAR drafting team should have a clear explanation for all market participants as to the reason for the discontinuity and how that should be dealt with by the elements of the NERC Functional Model.

d. MAPP notes that Standard 600, "Determine Facility Ratings, Operating Limits, and Transfer Capabilities" has been drafted to do away with the references to Categories A through D. The criteria are just listed in the standard. MAPP asks that the SAR drafting team require that the standard drafting team for Standard 500 also eliminate the category references to be consistent with the Standard 600 approach.

e. MAPP is concerned that the SAR does not limit manual or automatic readjustments for certain lower probability or low consequence events. MAPP urges that the SAR drafting team add additional provisions to require the drafting team to consider which manual and automatic readjustments are allowed and when in meeting the criteria that is included in the standards.

f. MAPP is concerned that there is no provision for recognizing the variability of generation in the SAR. MAPP asks the SAR drafting team add another bullet to the SAR which states, "The Standard should take into account the variability of generation due to factors such as weather and time of day."

g. MAPP is concerned that there is no reference in the SAR to the need to handle firm contracts that may roll-over in the futures. Plans developed for the transmission system must recognize that the transmission system must have sufficient capacity to handle roll-overs. MAPP urges the SAR drafting team to include an appropriate description of the requirement for the plans with regard to roll-overs.

h. MAPP asks that the SAR drafting team add a bullet to the SAR that requires that the Standard drafting team to consider the development of reactive power margin and transfer power margin standards which expand beyond existing NERC Standard I.D.

i. In general, MAPP supports the six bullets that the SAR drafting team has provided on page SAR-5 with the amendments and additions described above in our comments. These bullets add needed details to the SAR.

Note – This form is to comment on **Version 2** of the **"Assess Transmission Future Needs and Develop Transmission Plans"** SAR.

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E-mail this form between May 5 and June 5, 2004 to: sarcomm@nerc.com with "Comments" in the subject line.

If you have any questions about this Standards Draft Comment Form, please contact the Director of Standards – Gerry Cauley at 609-452-8060.

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If there is such a need, how should the scope of the SAR be changed?

- The scope of the SAR is fine as is
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- The scope of the SAR should be reduced to eliminate……

In January 2004, the Standards Authorization Committee (SAC) appointed a Drafting Team (DT) to address industry answers and comments to the questions posed. The DT was also charged with refining the SAR and drafting a detailed description of the proposed standard in preparation for the 2nd posting of the SAR.

Most of the industry respondents indicated that there is indeed a reliability-related need to develop a standard to address transmission assessment and planning issues. Comments were received from many different sources, including individuals, small and large utilities, groups of utilities, and Regional Councils. The SAR DT considered the comments submitted by each industry participant, and revised the SAR to conform to the changes that were technically sound and appeared to represent a consensus of participants.

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Please review Version 2 of the SAR and complete this Comment Form to let the SAR DT know if you agree or disagree with the SAR DT's assessment that this SAR is ready to be developed into a Standard.

Commenter Information (For Individual Commenters)
Name: John Horakh – May 27, 2004
Organization: MAAC
Industry Segment #: 2
Telephone: 609-625-6014
E-mail:john.horakh@conectiv.com

Key to Industry Segment #'s:

1 – Trans. Owners
2 – RTO's, ISO's, RRC's
3 – LSE's
4 – TDU's
5 - Generators
6 - Brokers, Aggregators, and Marketers
7 - Large Electricity End Users
8 - Small Electricity Users
9 - Federal, State, and Provincial Regulatory or other Govt. Entities

STD Commenter Information (For Groups Submitting Group Comments)	
Name of Group:	**Group Chair:** **Chair Phone:** **Chair Email:**

List of Group Participants that Support These Comments:

Name	Company	Industry Segment #

Please Review Version 2 of the SAR and Answer the Following Questions

Insert a "check' mark in the appropriate boxes by double-clicking the gray areas.

1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

   (a). Do you believe that the events in Categories B, C & D are classified correctly?

   X☐ Yes, but see comments below

   ☐ No

   X☐ Comments: Categories B, C and D should be renamed as follows –

   Category B – High Probability Contingency Event

   Category C – Medium Probability Contingency Event

   Category D – Low Probability Contingency Event

   The difference in the categories should NOT be stated in terms of how many elements are out of service, but rather should be stated in terms of the PROBABILITY of the initiating event that occurs. The difference in the categories is in the "stress" the system is allowed to experience and in the "fix" required. For B, a high probability event, stress should be low and the only fix allowed is system reinforcement. For D, a low probability event, severe system stress is allowed, and system reinforcement is not mandated. C is somewhere in between, a medium probability, with medium system stress permitted, and some loss of load and/or curtailment of transfers allowed in lieu of system reinforcement. Table I can then be simplified by removing the column labeled "Elements Out of Service", because it is unnecessary and not relative. Actually, the columns labeled "Thermal Limits", "Voltage Limits", "System Stable" and "Cascading Outages" can be eliminated too, because they are the same for each Category A, B and C (but notes for each column should be retained).

   (b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

   (c) Which of the following approaches do you favor regarding Table 1 of existing Planning Standard I.A?:

   ☐ Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events.

   Please explain your choice:

   ☐ Create a new category between C and D with performance characteristics between that of the present Categories C and D.

   Please explain your choice

☐ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

Please explain your choice:

X☐ Comments: NONE OF THE ABOVE. Keep the three categories, but rename them as in 1.a. above. Adding an additional category would introduce too much confusion in planning the system. Assuming that the contingencies in B, C and D are already in their correct probability categories, no changes need to be made. If someone could prove that a contingency in B is Low Probability the same as the contingencies in D, that contingency could be moved.

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

X☐ Yes

☐ No

X☐ Comments: Reporting should be on a "delay" basis. Known delays to the plan should be reported, along with the reason for the delay and use of alternate solutions.

3. If your answer to question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan? See answer to 2. Above.

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

The SAR drafting team believes that it is impractical to exhaustively test for every contingency described in each category plus every conceivable planned outage. Should the requirement to consider planned outages in addition to each Category A through D contingency remain part of this planning standard?

☐ Yes (consider planned outages in all Categories A through D).

X☐ Yes (consider planned outages in some Categories only).

Please specify which Categories: Categories A and B, which are high probability and therefore could easily occur during a planned outage.

☐ No

☐ Comments:

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

☐ Comments:

6. Do you have any other comments on the SAR?

☐ Comments:

Note – This form is to comment on **Version 2** of the **"Assess Transmission Future Needs and Develop Transmission Plans"** SAR.

The latest version of this SAR (TRNS_NDS_&_PLNS_01_02) is posted on the Standards web site at: http://www.nerc.com/~filez/standards/Assess-Transmission-Future-Needs.html

E-mail this form between May 5 and June 5, 2004 to: sarcomm@nerc.com with "Comments" in the subject line.

If you have any questions about this Standards Draft Comment Form, please contact the Director of Standards – Gerry Cauley at 609-452-8060.

Background:

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- Is there a reliability-related need for an Organization Standard to be developed on this topic?

If there is such a need, how should the scope of the SAR be changed?

- The scope of the SAR is fine as is
- The scope of the SAR should be expanded to include…..
- The scope of the SAR should be reduced to eliminate……

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Commenter Information (For Individual Commenters)
Name:
Organization:
Industry Segment #:
Telephone:
E-mail:

Key to Industry Segment #'s:

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2 – RTO's, ISO's, RRC's
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7 - Large Electricity End Users
8 - Small Electricity Users
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STD Commenter Information (For Groups Submitting Group Comments)	
Name of Group: SERC EC Planning Standards Subcommittee	**Group Chair:** Bob Jones **Chair Phone:** (205) 257-6148 **Chair Email:** rajones@southernco.com

List of Group Participants that Support These Comments:

Name	Company	Industry Segment #
Darrell Pace	Alabama Electric Cooperative, Inc	1
Brian D. Moss	Duke Power Company	1
Kham Vongkhamchanh	Entergy Services, Inc.	1
Clay Young	South Carolina Electric & Gas Company	3
Arthur E. (Art) Brown	South Carolina Public Service Authority	1
Bob Jones	Southern Company Services, Inc.	1
Byron Stewart	Tennessee Valley Authority	1
Pat Huntley	SERC Staff	2

Please Review Version 2 of the SAR and Answer the Following Questions

Insert a "check' mark in the appropriate boxes by double-clicking the gray areas.

1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

   (a). Do you believe that the events in Categories B, C & D are classified correctly?

   X Yes

   ☐ No

   X Comments: The SERC PSS believes that Category C events are more likely to occur than Category D events and should require higher performance expectations.

   (b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

   (c) Which of the following approaches do you favor regarding Table 1 of existing Planning Standard I.A?:

   ☐ Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events.

   Please explain your choice:

   ☐ Create a new category between C and D with performance characteristics between that of the present Categories C and D.

   Please explain your choice

   ☐ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

   Please explain your choice:

   X Comments: The SERC PSS agrees that low consequence Category C events should be considered compliant. However, as we interpret Table I, a Category C event that results in low consequences (e.g. no cascading) is already considered compliant since entities can drop load or curtail firm transfers to return to applicable thermal or voltage ratings.

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

   ☐ Yes

   X No

☐ Comments:

3. If your answer to question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan?

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

   The SAR drafting team believes that it is impractical to exhaustively test for every contingency described in each category plus every conceivable planned outage. Should the requirement to consider planned outages in addition to each Category A through D contingency remain part of this planning standard?

   ☐ Yes (consider planned outages in all Categories A through D).

   ☐ Yes (consider planned outages in some Categories only).

   Please specify which Categories:

   ☐ No

   X Comments: The SERC PSS agrees that the requirement to consider planned outages in addition to each Category A and B contingency remain part of this planning standard. The SERC PSS could not reach consensus on the requirement to consider planned outages in addition to each Category C and D contingency. However, the SERC PSS does agree that exhaustive testing for every contingency described in each category is not required. The I.A compliance templates state that they must "Be performed and evaluated only for those Category [B, C, and D] contingencies that would produce the more severe system results or impacts."

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain. No

   ☐ Comments:

6. Do you have any other comments on the SAR?

   X Comments: The SERC PSS agrees that the Standard should provide a clearer definition of "cascading outages." In addition the SERC PSS recommends that the Standard provide a clearer definition of what is meant by "system stable."

   The SERC PSS agrees that the Standard should not address resource planning, however the standard should include requirements for LSEs to provide forecast resource data required to develop power flow models as required in the current II.D standards. Accordingly, this standard should also apply to LSEs.

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Most of the industry respondents indicated that there is indeed a reliability-related need to develop a standard to address transmission assessment and planning issues. Comments were received from many different sources, including individuals, small and large utilities, groups of utilities, and Regional Councils. The SAR DT considered the comments submitted by each industry participant, and revised the SAR to conform to the changes that were technically sound and appeared to represent a consensus of participants.

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Please review Version 2 of the SAR and complete this Comment Form to let the SAR DT know if you agree or disagree with the SAR DT's assessment that this SAR is ready to be developed into a Standard.

Commenter Information (For Individual Commenters)
Name: Robert Snow Organization: Robert Snow Industry Segment #: 8 Telephone: 973 763 0832 E-mail: familysnow@aol.com

Key to Industry Segment #'s:

- **1 – Trans. Owners**
- **2 – RTO's, ISO's, RRC's**
- **3 – LSE's**
- **4 – TDU's**
- **5 - Generators**
- 6 - Brokers, Aggregators, and Marketers
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STD Commenter Information (For Groups Submitting Group Comments)	
Name of Group:	**Group Chair:** **Chair Phone:** **Chair Email:**

List of Group Participants that Support These Comments:

Name	Company	Industry Segment #

Please Review Version 2 of the SAR and Answer the Following Questions

Insert a "check' mark in the appropriate boxes by double-clicking the gray areas.

1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

   (a). Do you believe that the events in Categories B, C & D are classified correctly?

   ☒ Yes

   ☐ No

   ☐ Comments: **Without a rigorous Probabilistic Risk Analysis, moving any of these events to a category D event is bad practice. All of the events have occurred at one time or another, especially circuit breaker and bus faults. Moving them to a category D essentially removes them from requiring action to mitigate/solve the impact on reliability.**

   (b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

   (c) Which of the following approaches do you favor regarding Table 1 of existing Planning Standard I.A?:

   ☐ Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events.

   Please explain your choice:

   ☐ Create a new category between C and D with performance characteristics between that of the present Categories C and D.

   Please explain your choice

   ☐ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

   Please explain your choice:

   ☐ Comments:

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

   ☒ Yes

   ☐ No

☒ Comments: Developing plans without a follow up program is a waste of time and money. One of the most telling comments form the August Blackout report was that a number of the items were the same as in other blackouts.

3. If your answer to question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan? When there is a significant change in the assumptions, the plan needs to be re-studied and revised as appropriate. The SAR must require such re-studies. Any plan is only as good as its assumptions. Whenever there is a significant change in the assumptions, the plan needs to be revised to account for the change. Having a plan that assumes there will be specific generation projects is worthless when those specific projects are changed, cancelled or if other generation retires.

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

   The SAR drafting team believes that it is impractical to exhaustively test for every contingency described in each category plus every conceivable planned outage. Should the requirement to consider planned outages in addition to each Category A through D contingency remain part of this planning standard?

   ☐ Yes (consider planned outages in all Categories A through D).

   ☒ Yes (consider planned outages in some Categories only).

Please specify which Categories: Categories A through C should be considered. Category D does not require action so the analysis with outages does not add anything. Most planning software allows the sue of scripts to run multiple analysis without intervention. The state of modern computers is such that the added testing is not significant. Also, for most systems, this type of analysis is performed to define which load levels and generation dispatch would allow the maintenance (the problem in reverse).

   ☐ No

   ☐ Comments:

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

   ☒ Comments: Each region has their own requirements.

6. Do you have any other comments on the SAR?

   ☒ Comments:

Second Paragraph: Replace the second sentence with "The planning horizon is intended to provide for facility additions. Operating procedures shall not be used as a substitute for good system design and shall only be applicable during maintenance outages and while facilities are being constructed." (The original language would allow what was identified as the root cause of the Italian blackout. Namely, an operating procedure that had to be executed within 15 minutes. The operator had to call another area and ask for them to perform an operating procedure. The procedure was underway but

did not happen fast enough to avoid the next line to trip. Operating procedures should never be a long term substitute for constructing facilities needed to assure reliability.)

Third Paragraph: While some of the information about generation additions and load growth are considered reliable for five (5) years, a long-term study of approximately ten (10) years is necessary to identify global issues such as import limitations to a region that would require projects that have traditionally taken more than five (5) years. Suggest, "Assessments shall cover a detailed planning horizon consistent with available information but no less than five (5) years. The five year horizon shall include load growth, new internal and external firm generation, generation retirements/failures, uncontrollable loop flows, reliance on external generation (identify both firm and market), topology changes, and firm transactions. A longer term study using a variety of scenarios that are expected to cover the most likely long term activity, shall be conducted to identify projects that take longer than five years to implement."

Fourth Paragraph: The standards should apply to transmission owners, transmission operators, transmission planners, anyone who is connecting facilities to the transmission system, control areas, and reliability coordinators.

Fifth Paragraph: Add the following after the bullets. "In addition to the above, the standard shall provide requirements on methodology of forecasting and normalizing load. This would include methods of determining the normalized load over a large geographic area with different weather patterns and norms. The "normalized" load should not be the load associated with the median weather over a summer or winter period but the load level that will provide sufficient reliability to supply all firm load obligations. Each region shall provide a definition as to what is sufficient reliability. The definition shall clearly define the risk that is being assumed in terms similar to the LOLE for lack of generation. In addition to the above two risk variables, a methodology shall be identified to quantify the risk of not being able to deliver the difference between the local load and generation. This is essentially the ability of the transmission system to respond to different generation dispatch patterns."

Sixth Paragraph: Replace the last phrase in the last sentence with "while the standard will not prescribe specific tools, it shall identify methodologies to validate and procedures to operate the tools so that the identified outcomes from the analysis are not dependent on the tool or the way the tool was used or initialized."

Under the section of "Other Examples …"

3rd Bullet: Add a sentence after the first sentence "The probabilistic methodology shall not ignore specific cases that would result in significant load dump or cascading outrages. Each region shall identify how to resolve such outages." The last sentence "Acceptable levels of risk in terms of maximum consequential and programmatic load dump and maximum durations for the outages shall be defined."

5th bullet: Clarify that the "applicable ratings" for multiple events should be consistent with supplying firm load and firm transactions until the outages are repaired or switching mitigates the overloads. For example, one applicable rating would be the short time rating of equipment that was stressed when a transformer failed. However, there must be a method of supplying the load pocket for the duration to repair/replace the transformer that does not involve long term rotating blackouts. Just achieving "no cascading outages" is not sufficient.

New section: The subject of assuring the generation is deliverable to the load should be added. This should not be vague but should be defined by a specific set of tests and the expected range of results. In doing these tests, reliance on capacity assigned to other regions should be limited to amounts identified and accepted by adjacent regions. For example, if a region is assuming it will have net purchases from adjacent regions, the other regions must show a net sale.

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Commenter Information (For Individual Commenters)
Name: Kirit S. Shah
Organization: Ameren
Industry Segment #: 1
Telephone: (314) 554-3542
E-mail: kshah@ameren.com

Key to Industry Segment #'s:

1 – Trans. Owners
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Insert a "check' mark in the appropriate boxes by double-clicking the gray areas.

1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

   (a). Do you believe that the events in Categories B, C & D are classified correctly?

   ☐ Yes

   ☒ No

   ☐ Comments:

   (b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

   All category C outages that have a direct impact on serving load because of the system configuration (straight bus or tapped load) should be reclassified, including C-1, C-2, C-5, and C-9 to provide more latitude. For category C events, we should be more concerned that the system holds together and not that the local load may be at risk for these multiple contingency events.

   (c) Which of the following approaches do you favor regarding Table 1 of existing Planning Standard I.A?:

   ☒ Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events.

   Please explain your choice: Reclassify C-1,C-2, and C-9 to category D (less probable events).

   C-3 (line and a generator combination) should be reclassified as category B event (more probable than other C-3 events. Also, why is a loss of a tower line with two circuits category C (C-5) while loss of a tower line with 3 circuits is category D (D-6), though a probability of loss of a tower line may be the same ? We may want to be consistent in categorizing the event – loss of a multi-circuit tower line.

   ☐ Create a new category between C and D with performance characteristics between that of the present Categories C and D.

   Please explain your choice

   ☐ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

   Please explain your choice:

   ☐ Comments:

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

☒ Yes

☐ No

☒ Comments: The requirement should not be onerous.

3. If your answer to question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan?

   (i) Annual update with a short note to document changes.
   (ii) Smaller projects (cap bank addition, change of terminal equipment like switches, wavetrap, or CT) may be combined as a group in such reporting to avoid providing a long list of updates.

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

   The SAR drafting team believes that it is impractical to exhaustively test for every contingency described in each category plus every conceivable planned outage. Should the requirement to consider planned outages in addition to each Category A through D contingency remain part of this planning standard?

   ☐ Yes (consider planned outages in all Categories A through D).

   ☐ Yes (consider planned outages in some Categories only).

   Please specify which Categories:

   ☒ No

   ☒ Comments: (i) Is the issue planning the system or granting the outage? Local load may be exposed for granting a maintenance/construction outage, but the system should not be at risk.

   (ii) If the system is planned with category C requirements, in most cases it should meet category A and B requirements during a planned outage. To meet requirements of categories A and B during planned outage should be adequate.

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

   ☐ Comments:

6. Do you have any other comments on the SAR?

   ☒ Comments:

   A. We believe that for planning of robust transmission system, the Standard should include (1) some incremental transfer capability requirement in addition to what is "projected" or modeled in the base case, (2) a combination of a line and a generator outage should be included in category B.

   B. Page SAR-4, Paragraph 2, last phrase states that " …there is no intent to exclude appropriate operating procedures…". What is "appropriate"? Could generation redispatch be an appropriate operating procedure? If yes, what level of redispatch is appropriate?

The standard should include definition of "appropriateness" of operating procedures so that they are developed and applied on an uniform and consistent basis.

C. Page SAR-4, Paragraph 4: Should the requirements be applied to Transmission Owners also?

D. Page SAR-4, Paragraph 6, Why document and disclose of methodology limited to planned generation only? What about planned transmission and interchange? Is it because there is more uncertainty for speculative generation than transmission? What about differences in modeling details require for different type of analyses, such as thermal or voltage, regional or local? It is our experience that more detailed representation (lower voltage facilities) is required for voltage analysis than thermal analysis. Perhaps the standard should state that additional detail may need to be added to the model to adequately represent the system for specific studies.

E. Page SAR-5, Paragraph 1: If generation is considered in lieu of transmission reinforcement, the system must be able to withstand the loss of that generation plus another single contingency. The reason for this is that generation can be on or off due to economic and other factors after its installation, while transmission is almost always "on".

F. Other example of areas that should be considered for clarification is :

The "projected level of transfers" defined in the Standard – what does this include? Should it include/consider all transmission reservations including roll-over-rights?

G. SAR-5, Bullet #1: In addition to the definition of "cascading outages" , clarification is needed for identification of a cascading state. For example, we are not sure that assumption of some percent overload, say 125% of emergency rating, is a good proxy for cascading.

H. Page SAR-5, Bullet# 3: the second statement states that "The minimum requirements of probabilistic methods are the contingencies as described in Table 1 of existing Planning Standard I.A. " Does this mean that probability should be assigned to at least all of the contingencies included in Table I.A.?

I. Page SAR-5, Bullet #3: We believe that defining acceptable levels of risk will be a major undertaking. Isn't the level of risk is dependent upon the entity and/or perception? Using a deterministic methodology in the planning horizon for single contingency provides a margin to handle many multiple unplanned facility outages or unforeseen system conditions in operating horizon.

J. Page SAR-5, Bullet# 4: Planned outages for maintenance or construction are generally managed in the operating horizon, and are granted only during specific load levels (off-peak), generation patterns, and interchange patterns when the transmission system is not expected to be fully utilized. We agree that clarification should be provided on how this information should be used in an assessment. However, as the scope of planning assessments is for the planning horizon of one year or more (SAR-4, paragraph 2) and not the operating horizon, we do not believe that the requirement for planning for maintenance outages should be included in planning assessments.

K. Page SAR-5, Bullet# 5: We agree that some of the contingency categories should be reviewed. See our response to Item 1 C.

L. Page SAR-5, Bullet# 6: We assume that short circuit current refers to fault duty or interrupting current.

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If you have any questions about this Standards Draft Comment Form, please contact the Director of Standards – Gerry Cauley at 609-452-8060.

Background:

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- Is there a reliability-related need for an Organization Standard to be developed on this topic?

If there is such a need, how should the scope of the SAR be changed?

- The scope of the SAR is fine as is
- The scope of the SAR should be expanded to include…..
- The scope of the SAR should be reduced to eliminate……

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Please review Version 2 of the SAR and complete this Comment Form to let the SAR DT know if you agree or disagree with the SAR DT's assessment that this SAR is ready to be developed into a Standard.

Commenter Information (For Individual Commenters)
Name: Jim Useldinger Organization: Kansas City Power & Light Industry Segment #: 1 Telephone: 816-654-1212 E-mail: jim.useldinger@kcpl.com

Key to Industry Segment #'s:

1 – Trans. Owners
2 – RTO's, ISO's, RRC's
3 – LSE's
4 – TDU's
5 - Generators
6 - Brokers, Aggregators, and Marketers
7 - Large Electricity End Users
8 - Small Electricity Users
9 - Federal, State, and Provincial Regulatory or other Govt. Entities

STD Commenter Information (For Groups Submitting Group Comments)		
Name of Group:	**Group Chair:** **Chair Email:**	**Chair Phone:**

List of Group Participants that Support These Comments:

Name	Company	Industry Segment #

Please Review Version 2 of the SAR and Answer the Following Questions

Insert a "check' mark in the appropriate boxes by double-clicking the gray areas.

1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

   (a). Do you believe that the events in Categories B, C & D are classified correctly?

   ☒ Yes

   ☐ No

   ☐ Comments:

   (b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

   (c) Which of the following approaches do you favor regarding Table 1 of existing Planning Standard I.A?:

   ☐ Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events.

   Please explain your choice:

   ☐ Create a new category between C and D with performance characteristics between that of the present Categories C and D.

   Please explain your choice

   ☒ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

   Please explain your choice: KCP&L supports the recommendation that the Standard should allow for the development and use of probabilistic planning methods in reliability assessment.

   ☒ Comments: KCP&L does not support any reclassification of the existing Category's. The probability of occurrence of some contingencies may, in actuality, be very low. However, this should not diminish the importance of their assessment in the Category that they are currently found.

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

   ☒ Yes

   ☐ No

☒ Comments:

KCP&L supports a requirement for reporting the status of implementing the mitigation plans. On a regional basis, mitigation plans should be reported by the Transmission Planner, as a minimum, on an annual basis through the regional model building process and assessed through the regional assessment studies performed by the Regional Reliability Coordinator.

3. If your answer to question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan?

   Any out-of-cycle changes to the mitigation plan should be reported to the Reliability Coordinator and re-evaluated on an as-needed basis. Coordinated planning between other regions and entities will be critical.

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

   The SAR drafting team believes that it is impractical to exhaustively test for every contingency described in each category plus every conceivable planned outage. Should the requirement to consider planned outages in addition to each Category A through D contingency remain part of this planning standard?

   ☐ Yes (consider planned outages in all Categories A through D).

   ☐ Yes (consider planned outages in some Categories only).

   Please specify which Categories:

   ☒ No

   ☐ Comments:

   Planned outages are typically short-term (less than 1 year) and should be considered in the operating horizon. A planned outage is typically allowed during system load conditions when they will have minimal impact on the system.

   KCP&L would prefer to clarify the existing Category B contingency that states "Loss of an element without a fault" be listed as the B5 contingency on the Table. Then, in Category C under Contingency 3, the revised wording should read "3. Category B (B1, B2, B3, B4, or B5) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, B4, or B5) contingency. This will allow for the first contingency to include a planned outage (B5 without a fault) as well as a contingency with one of the fault conditions described in B1, B2, B3, and B4.

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

   ☒ Comments:

   KCP&L is aware of neighboring regional council differences in classification of Category B and C contingencies between SPP and MAPP.

6. Do you have any other comments on the SAR?

☒ Comments:

In regards to developing accurate regional models, all known firm transmission service including rollover provisions for all firm transmission service should be included in the base case models.

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Please review Version 2 of the SAR and complete this Comment Form to let the SAR DT know if you agree or disagree with the SAR DT's assessment that this SAR is ready to be developed into a Standard.

Commenter Information (For Individual Commenters)
Name: Donald D. Taylor, PE, NSPE Organization: Westar Energy, Inc. Industry Segment #: 1 Telephone: 785-575-6430 E-mail: Don_Taylor@wr.com

Key to Industry Segment #'s:

1 – Trans. Owners
2 – RTO's, ISO's, RRC's
3 – LSE's
4 – TDU's
5 - Generators
6 - Brokers, Aggregators, and Marketers
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STD Commenter Information (For Groups Submitting Group Comments)		
Name of Group:	**Group Chair:** **Chair Email:**	**Chair Phone:**

List of Group Participants that Support These Comments:

Name	Company	Industry Segment #

Please Review Version 2 of the SAR and Answer the Following Questions

Insert a "check' mark in the appropriate boxes by double-clicking the gray areas.

1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

   (a). Do you believe that the events in Categories B, C & D are classified correctly?

   ☒ Yes

   ☐ No

   ☒ Comments: "Loss of single component without a fault" should become Category B5 and be included in the listing of items in category C3.

   (b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

   (c) Which of the following approaches do you favor regarding Table 1 of existing Planning Standard I.A?:

   ☐ Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events.

   Please explain your choice:

   ☐ Create a new category between C and D with performance characteristics between that of the present Categories C and D.

   Please explain your choice

   ☒ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

   Please explain your choice: Once an analysis has been performed, a subsequent "assessment" can easily dismiss low consequence events. However, low probability with high consequence should not be granted an exception. The initial premise of the Planning Standards did not contemplate probabilistic or Monte Carlo analysis.

   ☒ Comments: "Good Cause Exception" must be carefully defined before entities are allowed to shield high consequence events regardless of probability of occurence.

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

   ☒ Yes

   ☐ No

☐ Comments: Having a "plan" that is not implemented is of no value.

3. If your answer to question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan?

   In the annual process to update power flow models, there are necessarily changes to the load forecast, use of the interconnected network, and financial constraints which must be taken into account. Reporting to the Regional Reliability Organization should include a discussion of substantive changes and reasons behind them. There should not be a judgment made by the RRO that the explanation is "adequate" so long as the explanation is made. The changes are critical information that must be taken into account when evaluating transmission service requests. Reporting should not be more frequent than the model-building cycle.

   Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

   The SAR drafting team believes that it is impractical to exhaustively test for every contingency described in each category plus every conceivable planned outage. Should the requirement to consider planned outages in addition to each Category A through D contingency remain part of this planning standard?

   ☒ Yes (consider planned outages in all Categories A through D).

   ☐ Yes (consider planned outages in some Categories only).

   Please specify which Categories: Categories A through C.

   ☐ No

   ☒ Comments: The notion of including maintenance outages is to ensure that system restorations correctly evaluate single elements that would be removed in groups under a breaker-to-breaker outage analysis. The intent should not be to have any single element out for maintenance AND withstand the next contingency and should be stated as such.

4. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

   ☒ Comments: Yes. MAPP categorizes some contingencies differently.

5. Do you have any other comments on the SAR?

   ☒ Comments: How will this SAR integrate with the Version 0 Standards?

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Commenter Information (For Individual Commenters)
Name: Ed Davis
Organization: Entergy Services, Inc
Industry Segment #: 1 – Trans. Owner
Telephone: 504-310-5884
E-mail: edavis@entergy.com

Key to Industry Segment #'s:

1 – Trans. Owners
2 – RTO's, ISO's, RRC's
3 – LSE's
4 – TDU's
5 - Generators
6 - Brokers, Aggregators, and Marketers
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List of Group Participants that Support These Comments:

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Please Review Version 2 of the SAR and Answer the Following Questions

Insert a "check' mark in the appropriate boxes by double-clicking the gray areas.

1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

   (a). Do you believe that the events in Categories B, C & D are classified correctly?

   ☒ Yes

   ☐ No

   ☒ Comments:

   - Entergy believes that Category C events are more likely to occur than Category D events and should require higher performance expectations.

   (b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

   (c) Which of the following approaches do you favor regarding Table 1 of existing Planning Standard I.A?:

   ☐ Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events.

   Please explain your choice:

   ☐ Create a new category between C and D with performance characteristics between that of the present Categories C and D.

   Please explain your choice

   ☐ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

   Please explain your choice:

   ☒ Comments:

   - Entergy agrees that low consequence Category C events should be considered compliant. However, as we interpret Table I, a Category C

event that results in low consequences (e.g. no cascading) is already considered compliant since entities can drop load or curtail firm transfers to return to applicable thermal or voltage ratings.

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

   ☐ Yes

   ☒ No

   ☐ Comments:

3. If your answer to question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan?

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

   The SAR drafting team believes that it is impractical to exhaustively test for every contingency described in each category plus every conceivable planned outage. Should the requirement to consider planned outages in addition to each Category A through D contingency remain part of this planning standard?

   ☐ Yes (consider planned outages in all Categories A through D).

   ☒ Yes (consider planned outages in some Categories only).

   Please specify which Categories:

   ☐ No

   ☒ Comments:

   - It is not necessary to include planned maintenance outages in addition to Category A (no contingencies) because Category A plus planned outages equals Category B (single contingency). Therefore inclusion of maintenance outages in Category A is superfluous. The current standards do not require planned outages with Category A for that very reason.

Maintenance outages should be considered for only Category B and C contingencies.

Category D recognizes that cascading will occur in conjunction with the contingencies, so adding on more planned outages seems unnecessary, especially since Category D outages are very low probability events.

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

   ☐ Comments:

6. Do you have any other comments on the SAR?

   ☒ Comments:

   - Entergy agrees the standard should not address resource planning. However, the standard should include requirements for the LSEs to provide forecast resource data required to develop power flow models. Accordingly, this standard should also apply to LSEs.

   - In addition, the standard should require the Transmission Planner to document and describe the methodology used to plan the transmission system around the generation dispatch assumptions used by the Transmission Planner to meet the LSE load when and if the LSE provided resources do not equal the LSE provided load.

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Commenter Information (For Individual Commenters)
Name: K. Bachor, Dir. of Transmission Services S. Wallace, Dir. of System Operations Organization: Seminole Electric Cooperative Industry Segment #: 4 Telephone: (813) 963-0994 E-mail:

Key to Industry Segment #'s:

1 – Trans. Owners
2 – RTO's, ISO's, RRC's
3 – LSE's
4 – TDU's
5 - Generators
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   (a). Do you believe that the events in Categories B, C & D are classified correctly?

   ☐ Yes

   ☐ No

   ☐ Comments:

   (b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

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   Please explain your choice:

   ☐ Comments:

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   ☐ Yes

   ☐ No

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4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

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   ☐ Yes (consider planned outages in some Categories only).

   Please specify which Categories:

   ☐ No

   ☐ Comments:

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

   X Comments:

   In Florida, with the state requirements for the siting of facilities, the planning horizon should be adjusted from 5 YRS to 8 YRS. The 5 YR horizon is too short for some major transmission line projects and/or studies of transmission interconnections/upgrades for base load central station generating facilities.

6. Do you have any other comments on the SAR?

   X Comments:

   - SAR Paragraph 6: " … the Standard shall require that system models be developed, maintained …"
     it is recommended that these models be "region-wide" system models that are developed utilizing a documented, consistent, region-wide criteria
   - SAR Paragraph 10: " … a representative sample covering critical operating conditions …"
     It is recommended that this standard include specific requirements; such as, at what load levels and how many different load levels is intended by this part of the SAR. A suggestion would be 100% and 80%, and perhaps the 60% load level.
   - SAR Paragraph 11 Bullet 4: Many grid operations difficulties occur when a line is scheduled out for maintenance. If this SAR is going to address required N-2 planning assessments, then it must be clear and specific regarding the conditions when N-2 assessments are appropriate and the specific criteria for N-2 assessments.

Additional Comments:

- The SAR should define specific planning voltage criteria for consistency between transmission owners/providers. Voltage Criteria should be specifically defined for normal condition and N-1 conditions and can be specified differently for:
    - Bulk power - non-load serving buses
    - Meshed/Looped - load serving buses
    - Radial - load serving buses
- The SAR should require joint transmission planning - at a minimum, joint transmission planning should be required between transmission service providers and their network service customers.

Note – This form is to comment on **Version 2** of the **"Assess Transmission Future Needs and Develop Transmission Plans"** SAR.

The latest version of this SAR (TRNS_NDS_&_PLNS_01_02) is posted on the Standards web site at: http://www.nerc.com/~filez/standards/Assess-Transmission-Future-Needs.html

E-mail this form between May 1 and May 31, 2004 to: sarcomm@nerc.com with "Comments" in the subject line.

If you have any questions about this Standards Draft Comment Form, please contact the Director of Standards – Gerry Cauley at 609-452-8060.

Background:

Version 1 of the **"Assess Transmission Future Needs and Develop Transmission Plans"** SAR was posted for a 30-day public comment period between April 2 and May 3, 2002. This first version was an abbreviated SAR, which included an "Industry Need" statement and a brief description of the proposed standard, but did not include a detailed description. The purpose of this first posting was to collect feedback from the industry on the following questions:

- Is there a reliability-related need for an Organization Standard to be developed on this topic?

If there is such a need, how should the scope of the SAR be changed?

- The scope of the SAR is fine as is
- The scope of the SAR should be expanded to include…..
- The scope of the SAR should be reduced to eliminate……

In January 2004, the Standards Authorization Committee (SAC) appointed a Drafting Team (DT) to address industry answers and comments to the questions posed. The DT was also charged with refining the SAR and drafting a detailed description of the proposed standard in preparation for the 2nd posting of the SAR.

Most of the industry respondents indicated that there is indeed a reliability-related need to develop a standard to address transmission assessment and planning issues. Comments were received from many different sources, including individuals, small and large utilities, groups of utilities, and Regional Councils. The SAR DT considered the comments submitted by each industry participant, and revised the SAR to conform to the changes that were technically sound and appeared to represent a consensus of participants.

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Please review Version 2 of the SAR and complete this Comment Form to let the SAR DT know if you agree or disagree with the SAR DT's assessment that this SAR is ready to be developed into a Standard.

Commenter Information (For Individual Commenters)
Name: Alan Adamson Organization: New York State Reliability Council Industry Segment # 2 Telephone: (518) 355-1937 E-mail: aadamson@nycap.rr.com

Key to Industry Segment #'s:

1 – Trans. Owners
2 – RTO's, ISO's, RRC's
3 – LSE's
4 – TDU's
5 - Generators
6 - Brokers, Aggregators, and Marketers
7 - Large Electricity End Users
8 - Small Electricity Users
9 - Federal, State, and Provincial Regulatory or other Govt. Entities

STD Commenter Information (For Groups Submitting Group Comments)	
Name of Group:	**Group Chair:** **Chair Phone:** **Chair Email:**

List of Group Participants that Support These Comments:

Name	**Company**	**Industry Segment #**

Please Review Version 2 of the SAR and Answer the Following Questions

General Comment: It is the New York State Reliability Council's (NYSRC) position that NERC should not weaken existing criteria, including the NERC Planning Standards listed in the SAR as the starting point to be used in drafting a new standard. Therefore, with the advent of the Version 0 standards, we believe that there is no longer a need for this SAR. The comments in the "Consideration of Industry Comments" paper indicate that comments received in 2002 on SAR Version 1 were in favor of a standard on transmission assessment and planning, which was the SAR DT's reason for preparing this SAR. However, the Version 0 standards development process will now provide a transmission planning standard, without requiring the preparation of this new SAR. The comments below support our position that the existing Planning Standards should not be weakened.

Insert a "check' mark in the appropriate boxes by double-clicking the gray areas.

1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

   (a). Do you believe that the events in Categories B, C & D are classified correctly?

   ☒ Yes

   ☐ No

   ☐ Comments:

   (b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

   (c) Which of the following approaches do you favor regarding Table 1 of existing Planning Standard I.A?:

   ☐ Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events.

   Please explain your choice:

   ☐ Create a new category between C and D with performance characteristics between that of the present Categories C and D.

   Please explain your choice

   ☐ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

   NYSRC Comment: In accordance with the NERC process for developing reliability standards, an entity may include a Regional Difference as part of the NERC standard if there is such a condition. Therefore, there is no need for the standard to include "good cause exceptions".

Please explain your choice:

☒ **NYSRC Comments:** Any of the above three choices would weaken the present NERC standards. Therefore, as answered in (a) above, there should be no changes to Categories B, C, and D as they now exist in the present Planning Standards.

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

   ☒ Yes

   ☐ No

   ☐ Comments:

3. If your answer to question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan?

   NYSRC Response: Updated transmission plans should be reported along with compliance assessments as required.

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

   The SAR drafting team believes that it is impractical to exhaustively test for every contingency described in each category plus every conceivable planned outage. Should the requirement to consider planned outages in addition to each Category A through D contingency remain part of this planning standard?

   ☒ Yes (consider planned outages in all Categories A through D).

   ☐ Yes (consider planned outages in some Categories only).

   Please specify which Categories:

   ☐ No

   ☒ **NYSRC Comment:** Again, the existing standards should not be weakened.

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

   ☒ **NYSRC Comments:** It is the NYSRC's position that (1) NERC specifies minimum standards, (2) a Region may establish more stringent standards for its members separate from the NERC standards, and (3) it is unnecessary to include these more stringent standards within the framework of the NERC standards.

6. Do you have any other comments on the SAR?

   ☒ **NYSRC Comments:** As stated above, it is the NYSRC's position that there is no need to develop this SAR. However, despite this position, if the DT has sufficient support to go forward with a new standard, we have the following additional comments:

1. SAR-4: Third paragraph – insert "and plans" after "Assessments". The last sentence is not needed. A Region or other entity may have more stringent requirements than NERC – therefore, such a statement is not needed.
2. Fifth paragraph – define "applicable portion". List the specific standards and measurements that are intended to be used as the starting point.
3. Bottom of page - We agree that a transmission planning standard should not include Resource Planning requirements. However, the NYSRC strongly believes that NERC should develop a separate Resource Planning Standard.
4. SAR-5: first bullet – replace "provide" with "consider".
5. Third bullet – Is the probabilistic method referred to here considered a replacement for the NERC Criteria or a supplement to NERC Criteria? NERC should not allow such a method as a substitute for NERC criteria. I am not aware that NERC has completed an analysis to evaluate and compare the level of reliability of probabilistic criteria with NERC criteria. Such an evaluation would be needed.
6. Fifth bullet – This should be removed. This would be a weakening of the criteria.
7. The relationship with the Version 0 standards should recognized in the SAR, including the mechanism of how this "Version 1" standard would replace Version 0.

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If you have any questions about this Standards Draft Comment Form, please contact the Director of Standards – Gerry Cauley at 609-452-8060.

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- Is there a reliability-related need for an Organization Standard to be developed on this topic?

If there is such a need, how should the scope of the SAR be changed?

- The scope of the SAR is fine as is
- The scope of the SAR should be expanded to include…..
- The scope of the SAR should be reduced to eliminate……

In January 2004, the Standards Authorization Committee (SAC) appointed a Drafting Team (DT) to address industry answers and comments to the questions posed. The DT was also charged with refining the SAR and drafting a detailed description of the proposed standard in preparation for the 2nd posting of the SAR.

Most of the industry respondents indicated that there is indeed a reliability-related need to develop a standard to address transmission assessment and planning issues. Comments were received from many different sources, including individuals, small and large utilities, groups of utilities, and Regional Councils. The SAR DT considered the comments submitted by each industry participant, and revised the SAR to conform to the changes that were technically sound and appeared to represent a consensus of participants.

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Please review Version 2 of the SAR and complete this Comment Form to let the SAR DT know if you agree or disagree with the SAR DT's assessment that this SAR is ready to be developed into a Standard.

Commenter Information (For Individual Commenters)
Name:
Organization:
Industry Segment #:
Telephone:
E-mail:

Key to Industry Segment #'s:

1 – Trans. Owners
2 – RTO's, ISO's, RRC's
3 – LSE's
4 – TDU's
5 - Generators
6 - Brokers, Aggregators, and Marketers
7 - Large Electricity End Users
8 - Small Electricity Users
9 - Federal, State, and Provincial Regulatory or other Govt. Entities

STD Commenter Information (For Groups Submitting Group Comments)	
Name of Group: NPCC, CP9 Reliability Standards Working Group	Group Chair: Guy Zito Chair Phone:212-840-1047 Chair Email: gzito@npcc.org

List of Group Participants that Support These Comments:		
Name	**Company**	**Industry Segment #**
Roger Champagne	*TransEnergie (Quebec)*	*1*
Ralph Rufrano	*New York Power Authority*	*1*
David Kiguel	*Hydro One Netwoks (Ontario)*	*1*
David Little	*Nova Scotia Power*	*1*
Kathleen Goodman	*ISO New England*	*2*
Dan Stosick	*ISO New England*	*2*
Peter Lebro	*US National Grid*	*1*
James Pratico	*New York ISO*	*2*
Larry Eng	*Niagara Mohawk*	*1*
Khaqan Khan	*The Independent Electricity Market Operator IMO, Ontario*	*2*
Alan Adamson	*New York State Reliability Council*	*2*
Guy Zito, John Mosier, Brian Hogue (Staff)	*Northeast Power Coordinating Council*	*2*

Please Review Version 2 of the SAR and Answer the Following Questions

Insert a "check' mark in the appropriate boxes by double-clicking the gray areas.

General Comment: It is the opinion of the Northeast Power Coordinating Council's CP9 working group participating members that the existing NERC criteria should not be weakened, including the NERC Planning Standards listed in the SAR as the starting point to be used in drafting a new standard. The comments below support our position that the existing Planning Standards should not be weakened.

1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in

Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

(a). Do you believe that the events in Categories B, C & D are classified correctly?

☒ Yes

☐ No

☐ Comments:

(b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

(c) Which of the following approaches do you favor regarding Table 1 of existing Planning Standard I.A?:

☐ Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events.

Please explain your choice:

☐ Create a new category between C and D with performance characteristics between that of the present Categories C and D.

Please explain your choice

☐ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

Please explain your choice:

☒ Comments:

NPCC believes that the relationship between the concept of the Version 0 Standards and all the developing Version 1 Standards needs to be consistent. The reliability attributes of the Version 0 standards must be "carried through and into" the Version 1 Standards and there needs to be coordination to ensure this occurs.

NPCC suggests leaving the categories as listed. Choice of any of the above would result in a weakened standard. We suggest no changes be made to Categories B, C, and D as they presently exist in the Planning Standards

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

☒ Yes

☐ No

☐ Comments:

3. If your answer to question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan?

In the northeast, the NPCC Annual Transmission Reviews address this and in addition NPCC keeps a "Major Projects List" to "track" BPS additions and modifications and includes transmission, generation and other major equipment identified as a BPS element.

NPCC suggests that the resultant NERC standard not be overly prescriptive in requirements for reporting progress/status on the standard and flexibility be afforded to allow various documentation and processes already in place to achieve compliance, and also we suggest it be done annually.

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

   The SAR drafting team believes that it is impractical to exhaustively test for every contingency described in each category plus every conceivable planned outage. Should the requirement to consider planned outages in addition to each Category A through D contingency remain part of this planning standard?

   ☐ Yes (consider planned outages in all Categories A through D).

   ☒ Yes (consider planned outages in some Categories only).

   Please specify which Categories:

   ☐ No

   ☒ Comments: We reiterate that the existing standards should not be weakened and request that the SAR be clarified to remove ambiguity regarding what is meant by "considering" a planned outage. Planned outages at present are considered however this is deemed an Operational Planning issue and is conducted so as to set Operational Limits for those conditions on a pre-contingency basis to allow for N-1 conditions.

   This particular SAR will ultimately result in a "planning" Reliability Standard. The wording, as it has been phrased, infers that the system must be planned, designed and built to N-2 standards (i.e. a line out for maintenance on top of a circuit element outage). Treatment of planned outages should be considered to some extent and NPCC suggests the drafting team receive direction from the SAC regarding planned outages. NPCC suggests that planned outages should be considered only in categories in A through C.

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

   ☐ Comments:

6. Do you have any other comments on the SAR?

   ☒ Comments:

   NPCC also would like to submit its definition of Bulk Power System, as follows, and would like it to be considered as a "building block" for the NERC BES definition.

– **Bulk Power System-BPS-(or BES in NERC documents) — The interconnected electrical systems within northeastern North America comprising generation and transmission facilities on which faults or disturbances can have a significant adverse impact outside of the local area. In this context, local areas are determined by the Council members.**

– NPCC suggests that any discussion and resultant determination of a definition for Cascading Outage be fully coordinated with the STDs 200 and 600. NPCC had submitted a suggested definition for the last posting of STD 200;

  Cascading Outage- "The uncontrolled successive loss of Bulk Electric System elements that propagate beyond a defined area (Balancing Area's) boundaries."

Also NPCC recognizes that Resource Planning is not covered in the proposed Standard because it is considered as being handled by market mechanisms that are/will be in place or perhaps addressed in a separate standard. Therefore, NPCC assumes that the generation and load information required to perform the planning studies are provided as described in section II.A of the existing Planning Standards. If not, sections II.B, II.E and III of the existing Planning Standards should also be used as the starting point in drafting of the reliability requirements.

– NPCC is not in favor of removing references to "Applicable Ratings" as is suggested on SAR-5 fifth bullet. Despite the fact that the performance requirement would be "No Cascading Outages are Allowed", the "Applicable Ratings" should always be respected.

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Commenter Information (For Individual Commenters)
Name: Ken Githens Organization: Allegheny Energy Supply Industry Segment #: 5 Telephone: 412-858-1635 E-mail: kgithen@alleghenyenergy.com

Key to Industry Segment #'s:

1 – Trans. Owners
2 – RTO's, ISO's, RRC's
3 – LSE's
4 – TDU's
5 - Generators
6 - Brokers, Aggregators, and Marketers
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STD Commenter Information (For Groups Submitting Group Comments)		
Name of Group:	**Group Chair:** **Chair Email:**	**Chair Phone:**

List of Group Participants that Support These Comments:

Name	Company	Industry Segment #

Please Review Version 2 of the SAR and Answer the Following Questions

Insert a "check' mark in the appropriate boxes by double-clicking the gray areas.

1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

   (a). Do you believe that the events in Categories B, C & D are classified correctly?

   ☒ Yes

   ☐ No

   ☐ Comments:

   (b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

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   Please explain your choice:

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   Please explain your choice

   ☐ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

   Please explain your choice:

   ☐ Comments:

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

   ☐ Yes

   ☒ No

   ☒ Comments: However, major facility additions, delayed additions, or deletions that effect the reliability of the system could be included as part of the regional form 715 base case yearly filings and listed as changes from last year's cases. This would allow older cases to easily be updated and used.

3. If your answer to question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan?

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

   The SAR drafting team believes that it is impractical to exhaustively test for every contingency described in each category plus every conceivable planned outage. Should the requirement to consider planned outages in addition to each Category A through D contingency remain part of this planning standard?

   ☐ Yes (consider planned outages in all Categories A through D).

   ☐ Yes (consider planned outages in some Categories only).

   Please specify which Categories:

   ☒ No

   ☒ Comments: I would modify C-3 since it has the same effect as or similar to a C-3 event to include (line out followed by a category B event).

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

   ☐ Comments:

6. Do you have any other comments on the SAR?

   ☐ Comments:

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9 - Federal, State, and Provincial Regulatory or other Govt. Entities

STD Commenter Information (For Groups Submitting Group Comments)		
Name of Group: TVA Transmission Planning Department	**Group Chair:** **Chair Email:**	**Chair Phone:**

List of Group Participants that Support These Comments:

Name	Company	Industry Segment #
David Till	TVA	9
David Marler	TVA	9
Brenda Eberhart	TVA	9
Darrin Church	TVA	9
Byron Stewart	TVA	9
William Tiller	TVA	9

Please Review Version 2 of the SAR and Answer the Following Questions

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1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

   (a). Do you believe that the events in Categories B, C & D are classified correctly?

   ☒ Yes

   ☐ No

   ☐ Comments:

   (b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

   (c) Which of the following approaches do you favor regarding Table 1 of existing Planning Standard I.A?:

   ☐ Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events.

   Please explain your choice:

   ☐ Create a new category between C and D with performance characteristics between that of the present Categories C and D.

   Please explain your choice

   ☒ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

   Please explain your choice:

   This approach allows documentation of an assessment of low consequence to substitute for the expenditure of an unwarranted solution, but maintains the integrity of the event probability assessment. Since others may have different ideas of what is low probability, this approach would be best with sufficient justification of low probability.

   ☐ Comments:

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

   ☐ Yes

☒ No

☒ Comments:

This reporting would constitute a logistical burden counterproductive to the total planning effort.

3. If your answer to question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan?

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

   The SAR drafting team believes that it is impractical to exhaustively test for every contingency described in each category plus every conceivable planned outage. Should the requirement to consider planned outages in addition to each Category A through D contingency remain part of this planning standard?

   ☐ Yes (consider planned outages in all Categories A through D).

   ☐ Yes (consider planned outages in some Categories only).

   Please specify which Categories:

   ☐ No

   ☒ Comments: Everyone in the group agreed that planned outages should be considered, but the group didn't agree on which categories to apply. About half believed they should be applied to all categories while the other half believed only A and B categories should have planned outages studied for the one year and beyond horizon.

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

   ☐ Comments:

6. Do you have any other comments on the SAR?

   ☐ Comments:

Note – This form is to comment on **Version 2** of the **"Assess Transmission Future Needs and Develop Transmission Plans"** SAR.

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E-mail this form between May 5 and June 5, 2004 to: sarcomm@nerc.com with "Comments" in the subject line.

If you have any questions about this Standards Draft Comment Form, please contact the Director of Standards – Gerry Cauley at 609-452-8060.

Background:

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- Is there a reliability-related need for an Organization Standard to be developed on this topic?

If there is such a need, how should the scope of the SAR be changed?

- The scope of the SAR is fine as is
- The scope of the SAR should be expanded to include…..
- The scope of the SAR should be reduced to eliminate……

In January 2004, the Standards Authorization Committee (SAC) appointed a Drafting Team (DT) to address industry answers and comments to the questions posed. The DT was also charged with refining the SAR and drafting a detailed description of the proposed standard in preparation for the 2nd posting of the SAR.

Most of the industry respondents indicated that there is indeed a reliability-related need to develop a standard to address transmission assessment and planning issues. Comments were received from many different sources, including individuals, small and large utilities, groups of utilities, and Regional Councils. The SAR DT considered the comments submitted by each industry participant, and revised the SAR to conform to the changes that were technically sound and appeared to represent a consensus of participants.

The revised SAR (Version 2) is posted on the NERC web site given in the blue box at the top of this form. Also posted is a Consideration of Comments document, in which the DT has responded to the original industry comments from 2002. You can find Version 1 of the SAR and industry comments on this version at the same web location.

Please review Version 2 of the SAR and complete this Comment Form to let the SAR DT know if you agree or disagree with the SAR DT's assessment that this SAR is ready to be developed into a Standard.

Commenter Information (For Individual Commenters)	
Name:	Kathleen Goodman
Organization:	ISO New England Inc.
Industry Segment #:	2
Telephone:	(413) 535-4111
E-mail:	kgoodman@iso-ne.com

Key to Industry Segment #'s:

1 – Trans. Owners
2 – RTO's, ISO's, RRC's
3 – LSE's
4 – TDU's
5 - Generators
6 - Brokers, Aggregators, and Marketers
7 - Large Electricity End Users
8 - Small Electricity Users
9 - Federal, State, and Provincial Regulatory or other Govt. Entities

STD Commenter Information (For Groups Submitting Group Comments)	
Name of Group:	Group Chair: Chair Phone: Chair Email:

List of Group Participants that Support These Comments:		
Name	Company	Industry Segment #

Please Review Version 2 of the SAR and Answer the Following Questions

Insert a "check' mark in the appropriate boxes by double-clicking the gray areas.

General Comment: It is the opinion of the Northeast Power Coordinating Council's CP9 working group participating members that the existing NERC criteria should not be weakened, including the NERC Planning Standards listed in the SAR as the starting point to be used in drafting a new standard. The comments below support our position that the existing Planning Standards should not be weakened.

1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

(a). Do you believe that the events in Categories B, C & D are classified correctly?

☒ Yes

☐ No

☐ Comments:

(b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

(c) Which of the following approaches do you favor regarding Table 1 of existing Planning Standard I.A?:

☐ Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events.

Please explain your choice:

☐ Create a new category between C and D with performance characteristics between that of the present Categories C and D.

Please explain your choice

☐ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

Please explain your choice:

☒ Comments:

ISO-NE believes that the relationship between the concept of the Version 0 Standards and all the developing Version 1 Standards needs to be consistent. The reliability attributes of the Version 0 Standards must be "carried through and into" the Version 1 Standards; there needs to be coordination to ensure this occurs.

ISO-NE suggests leaving the categories as listed. Choice of any of the above would result in a weakened standard. We suggest no changes be made to Categories B, C, and D as they presently exist in the Planning Standards.

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

☒ Yes

☐ No

☐ Comments:

3. If your answer to question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan?

In the northeast, the NPCC Annual Transmission Reviews address this and, in addition, NPCC keeps a "Major Projects List" to "track" BPS additions and modifications and includes transmission, generation and other major equipment identified as a BPS element.

ISO-NE suggests that the resultant NERC Standard not be overly prescriptive in requirements for reporting progress/status on the standard and flexibility be afforded to allow various documentation and processes already in place to achieve compliance; we also suggest it be done annually.

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

   The SAR drafting team believes that it is impractical to exhaustively test for every contingency described in each category plus every conceivable planned outage. Should the requirement to consider planned outages in addition to each Category A through D contingency remain part of this planning standard?

   ☐ Yes (consider planned outages in all Categories A through D).

   ☒ Yes (consider planned outages in some Categories only).

   Please specify which Categories:

   ☐ No

   ☒ Comments: We reiterate that the existing Standards should not be weakened and request that the SAR be clarified to remove ambiguity regarding what is meant by "considering" a planned outage. Planned outages, at present, are considered, however this is deemed an Operational Planning issue and is conducted so as to set Operational Limits for those conditions on a pre-contingency basis to allow for N-1 conditions.

   This particular SAR will ultimately result in a "planning" Reliability Standard. The wording, as it has been phrased, infers that the system must be planned, designed and built to N-2 standards (i.e. a line out for maintenance on top of a circuit element outage). Treatment of planned outages should be considered to some extent and NPCC suggests the drafting team receive direction from the SAC regarding planned outages. NPCC suggests that planned outages should be considered only in categories A through C.

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

   ☐ Comments:

6. Do you have any other comments on the SAR?

   ☒ Comments:

   ISO-NE would like to submit the NPCC definition of Bulk Power System, as follows, and would like it to be considered as a "building block" for the NERC BES definition.

– **Bulk Power System-BPS-(or BES in NERC documents) — The interconnected electrical systems within {northeastern} North America comprising generation and transmission facilities on which faults or disturbances can have a significant adverse impact outside of the local area. In this context, local areas are determined by the Council members.**

– ISO-NE strongly suggests that any discussion and resultant determination of a definition for Cascading Outage be fully coordinated with the STDs 200 and 600. ISO-NE and NPCC had submitted a suggested definition for the last posting of STD 200;

Cascading Outage - "The uncontrolled successive loss of Bulk Electric System elements that propagate beyond a defined area (Balancing Area's) boundaries."

Recognizing that Resource Planning is not covered in the proposed Standard because it is considered as being handled by market mechanisms that are/will be in place or perhaps addressed in a separate standard, may we assume that the generation and load information required to perform the planning studies are provided as described in Section II.A of the existing Planning Standards?. If not, Sections II.B, II.E and III of the existing Planning Standards should also be used as the starting point in drafting of the reliability requirements.

– ISO-NE does not support removing references to "Applicable Ratings" as is suggested on SAR-5 fifth bullet. Despite the fact that the performance requirement would be "No Cascading Outages are Allowed," the "Applicable Ratings" should always be respected.

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If there is such a need, how should the scope of the SAR be changed?

- The scope of the SAR is fine as is
- The scope of the SAR should be expanded to include…..
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Most of the industry respondents indicated that there is indeed a reliability-related need to develop a standard to address transmission assessment and planning issues. Comments were received from many different sources, including individuals, small and large utilities, groups of utilities, and Regional Councils. The SAR DT considered the comments submitted by each industry participant, and revised the SAR to conform to the changes that were technically sound and appeared to represent a consensus of participants.

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Please review Version 2 of the SAR and complete this Comment Form to let the SAR DT know if you agree or disagree with the SAR DT's assessment that this SAR is ready to be developed into a Standard.

Commenter Information (For Individual Commenters)
Name: Khaqan Khan **Organization:** Independent Electricity Market Operator **Industry Segment #:** 2 **Telephone:** 905-855-6288 **E-mail:** khaqan.khan@theIMO.com

Key to Industry Segment #'s:

1 – Trans. Owners
2 – RTO's, ISO's, RRC's
3 – LSE's
4 – TDU's
5 - Generators
6 - Brokers, Aggregators, and Marketers
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9 - Federal, State, and Provincial Regulatory or other Govt. Entities

STD Commenter Information (For Groups Submitting Group Comments)	
Name of Group:	**Group Chair:** **Chair Phone:** **Chair Email:**

List of Group Participants that Support These Comments:

Name	Company	Industry Segment #

Please Review Version 2 of the SAR and Answer the Following Questions

Insert a "check' mark in the appropriate boxes by double-clicking the gray areas.

1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

   (a). Do you believe that the events in Categories B, C & D are classified correctly?

   ☒ Yes

   ☐ No

   ☐ Comments:

   (b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

   (c) Which of the following approaches do you favor regarding Table 1 of existing Planning Standard I.A?:

   ☐ Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events.

   Please explain your choice:

   ☐ Create a new category between C and D with performance characteristics between that of the present Categories C and D.

   Please explain your choice

   ☐ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

   Please explain your choice:

   ☒ Comments: Any inclusion of above mentioned options [re: under item (c)] may result in deteriorated standard. Therefore, for purposes of continued goals of reliability, it is our suggestion that no changes should be made in categories B, C and D (as they presently exist in the Planning Standards).

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

   ☒ Yes

   ☐ No

☐ Comments:

3. If your answer to question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan?

   Comments: In the Northeast, the NPCC Annual Transmission Reviews address this and in addition NPCC keeps a "Major Projects List" to "track" BPS additions and modifications and includes transmission, generation and other major equipment identified as a BPS element.

   We also suggest that the resultant NERC standard not be overly prescriptive in requirements for reporting progress/status on the standard and flexibility be afforded to allow various documentation and processes already in place to achieve compliance, and moreover, we suggest that this be done annually.

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

   The SAR drafting team believes that it is impractical to exhaustively test for every contingency described in each category plus every conceivable planned outage. Should the requirement to consider planned outages in addition to each Category A through D contingency remain part of this planning standard?

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   ☒ Comments: We reiterate that the existing standards should not be weakened and request that the SAR be clarified to remove ambiguity regarding what is meant by "considering" a planned outage. Planned outages are considered however this is deemed an Operational Planning issue and is conducted so as to set Operational Limits for those conditions on a pre-contingency basis to allow for N-1 conditions.

   This particular SAR will ultimately result in a planning standard. The wording, as it has been phrased, infers that the system must be planned, designed and built to N-2 standards (i.e. a line out for maintenance on top of a circuit element outage). Treatment of planned outages should be considered to some extent and NPCC suggests the drafting team receive direction from the SAC regarding planned outages. We also concur with the NPCC/CP9 suggestion that planned outages should be considered only in categories in A through C.

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

   ☐ Comments:

6. Do you have any other comments on the SAR?

☒ Comments:

(1) We also resubmit our earlier suggested definition as given in the comments for the last(3rd) posted version of STD 200;

Cascading Outage- "The uncontrolled successive loss of Bulk Electric System elements that propagate beyond a defined area (Balancing Area's) boundaries"

(2) The IMO also supports the comments submitted by ISO/RTO Council- Standards Review Committee as well as the CP-9/NPCC Group

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Please review Version 2 of the SAR and complete this Comment Form to let the SAR DT know if you agree or disagree with the SAR DT's assessment that this SAR is ready to be developed into a Standard.

Commenter Information (For Individual Commenters)
Name:
Organization:
Industry Segment #:
Telephone:
E-mail:

Key to Industry Segment #'s:

1 – Trans. Owners
2 – RTO's, ISO's, RRC's
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4 – TDU's
5 - Generators
6 - Brokers, Aggregators, and Marketers
7 - Large Electricity End Users
8 - Small Electricity Users
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STD Commenter Information (For Groups Submitting Group Comments)	
Name of Group: **SPP's Transmission Working Group**	**Group Chair:** Ronnie Frizzell **Chair Phone:** (501) 570-2433 **Chair Email:** rfrizzell@aecc.com

List of Group Participants that Support These Comments:

Name	Company	Industry Segment #
Ronnie Frizzell*	Arkansas Electric Cooperative Corp.	4
Noman Williams*	Sunflower Electric Power Cooperative	1
Don Taylor*	Westar Energy	1
Jim Useldinger*	Kansas City Power & Light	1
John Fulton*	Southwestern Public Service	1
Matt McGee*	American Electric Power	1
Sam McGarrah*	Empire District Electric	1
Mitch Williams*	Western Farmers Electric Cooperative	1
John Chiles*	ETEC	4
Mak Nagle	Entergy	1
Jim Kistner	Associated Electric Cooperative, Inc.	1
Alex Lau*	Southwest Power Pool	2
Phil Crissup*	Oklahoma Gas & Electric	1
Howard Conus*	City Utilities of Springfield, Mo	1
Alan Myers*	Aquila Networks	1
David Sargent*	Southwestern Power Administration	1

Please Review Version 2 of the SAR and Answer the Following Questions

Insert a "check' mark in the appropriate boxes by double-clicking the gray areas.

1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

   (a). Do you believe that the events in Categories B, C & D are classified correctly?

   ☒ Yes

   ☐ No

   ☐ Comments:

   (b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

   (c) Which of the following approaches do you favor regarding Table 1 of existing Planning Standard I.A?:

   ☐ Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events.

   Please explain your choice:

   ☐ Create a new category between C and D with performance characteristics between that of the present Categories C and D.

   Please explain your choice

   ☒ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

   Please explain your choice: SPP would like to see a definition of "good cause exceptions" at a minimum.

   ☒ Comments: SPP encourages the development of probabilistic techniques to assess reliability but caution needs to be exercised prior to implementation to ensure support from all stakeholders.

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

   ☒ Yes

   ☐ No

   ☒ Comments: SPP supports this reporting requirement, but notes that this burden should not be imposed more frequently than annually.

3. If your answer to question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan? Although SPP is implementing a 2 year planning cycle, project updates are collected on an annual basis. To ensure compliance with reliability criteria, mitigation reviews are also provided on an annual basis consistent with the annual model building process. Updates due to new "out of cycle" projects or significant scope/timing changes associated with major projects in the approved regional expansion plan and its assessments are evaluated on an as-needed basis. Coordinated planning and model building using consistent definitions with neighboring regions/entities will be critical. Efforts should be undertaken to put data collection, modeling building and transmission assessment processes for neighboring regions/entities on the same cycles.

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

   The SAR drafting team believes that it is impractical to exhaustively test for every contingency described in each category plus every conceivable planned outage. Should the requirement to consider planned outages in addition to each Category A through D contingency remain part of this planning standard?

   ☐ Yes (consider planned outages in all Categories A through D).

   ☒ Yes (consider planned outages in some Categories only).

   Please specify which Categories: C.3. needs to be modified to address N-1-1 concerns. Category B (B1, B2, B3 or B4, including loss of an element without a fault) or in the alternative create Category B5 to Loss of an element without a fault. The later is preferred.

   ☐ No

   ☒ Comments: Planned outages are typically not evaluated more than one year in advance and are not scheduled during peak load conditions. However, the existing Planning Standard 1.A is problematic in that it requires the system to be designed to accommodate planned outages during peak load conditions.

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

   ☒ Comments: SPP is aware of differences between SPP and the neighboring regions of ERCOT, MAPP and WECC.

6. Do you have any other comments on the SAR?

   ☒ Comments: Implementation of this SAR needs to be coordinated with the activities of the Version 0 Standards Drafting Team.

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Commenter Information (For Individual Commenters)

Name: Peter Burke [on behalf of ATC's David Smith]

Organization: American Transmission Company

Industry Segment #: 1

Telephone: 262-506-6863

E-mail: PBurke@atcllc.com

Key to Industry Segment #'s:

1 – Trans. Owners
2 – RTO's, ISO's, RRC's
3 – LSE's
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5 - Generators
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Name of Group:	Group Chair: Chair Email:	Chair Phone:
List of Group Participants that Support These Comments:		
Name	Company	Industry Segment #

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   (a). Do you believe that the events in Categories B, C & D are classified correctly?

   ☒ Yes

   ☐ No

   ☐ Comments:

(b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

(c) Which of the following approaches do you favor regarding Table 1 of existing Planning Standard I.A?:

☐ Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events.

Please explain your choice:

☐ Create a new category between C and D with performance characteristics between that of the present Categories C and D.

Please explain your choice

☒ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

Please explain your choice:

The outage listed in the existing categories are reasonable but, because we don't know all the specific details about a certain part of the system, there should be some mechanism to consider exceptions.

☐ Comments:

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

☐ Yes

☒ No

☐ Comments:

While an entity should be implementing plans to maintain or improve the reliability required by the standards, having to report on the implementation could become quite complicated. Plans are often changing to meet changing system conditions, sometimes so much so that what seemed reasonable to do last year is replaced by entirely new plans.

3. If your answer to question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan?

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

   The SAR drafting team believes that it is impractical to exhaustively test for every contingency described in each category plus every conceivable planned outage. Should the requirement to consider planned outages in addition to each Category A through D contingency remain part of this planning standard?

   ☐ Yes (consider planned outages in all Categories A through D).

   ☐ Yes (consider planned outages in some Categories only).

   Please specify which Categories:

   ☒ No

   ☐ Comments: *Planning the system should consider the need for planned outages but should not require the capability to plan outages at peak system loads.*

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

   ☐ Comments:

6. Do you have any other comments on the SAR?

   ☐ Comments:

   P SAR-3, Market Interface principles, question 5 – Depending on the level of public exposure of the load flow and stability models, generation cost data and stability parameter data may be deemed by some entities as confidential market information.

   P SAR-4, II.A System Data – Needs to consider the difficulties, particularly for stand-alone transmission companies, in obtaining resource information so models can balance load and resources.

   P SAR-5, third bullet – This may also go back to question 1 in this document but the statement, "There should be NERC approval of acceptable levels of risk" needs to be better defined. For example does this mean that a utility can't decide to increase the operating temperature of a line conductor without NERC approval?

   The SAR drafting team seems to have its arms around the issues and seems ready to proceed to Standard development.

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Most of the industry respondents indicated that there is indeed a reliability-related need to develop a standard to address transmission assessment and planning issues. Comments were received from many different sources, including individuals, small and large utilities, groups of utilities, and Regional Councils. The SAR DT considered the comments submitted by each industry participant, and revised the SAR to conform to the changes that were technically sound and appeared to represent a consensus of participants.

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Please review Version 2 of the SAR and complete this Comment Form to let the SAR DT know if you agree or disagree with the SAR DT's assessment that this SAR is ready to be developed into a Standard.

Commenter Information (For Individual Commenters)	Key to Industry Segment #'s: **1 – Trans. Owners** **2 – RTO's, ISO's, RRC's** **3 – LSE's** **4 – TDU's** **5 - Generators** 6 - Brokers, Aggregators, and Marketers **7 - Large Electricity End Users** **8 - Small Electricity Users** 9 - Federal, State, and Provincial Regulatory or other Govt. Entities
Name: Bill Bojorquez Organization: ERCOT Industry Segment #:2 Telephone: (512) 248-3036 E-mail: bbojorquez@ercot.com	

Please Review Version 2 of the SAR and Answer the Following Questions

Insert a "check' mark in the appropriate boxes by double-clicking the gray areas.

1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

(a). Do you believe that the events in Categories B, C & D are classified correctly?

☒ Yes

☐ No

☐ Comments:

(b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

(c) Which of the following approaches do you favor regarding Table 1 of existing Planning Standard I.A?:

☐ Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events.

Please explain your choice:

☐ Create a new category between C and D with performance characteristics between that of the present Categories C and D.

Please explain your choice

☐ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

Please explain your choice:

☒ Comments:

We suggest no changes be made to Categories B, C, and D as they presently exist in the Planning Standards. Choice of any of the above would result in a weakened standard and degraded reliability throughout NERC member systems.

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

☒ Yes

☐ No

☐ Comments:

3. If your answer to question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan?

Periodic Transmission Reviews to address changes in plans and tracking lists of BPS additions and modifications (that would include transmission, generation and other major equipment identified as a BPS element).

The resultant NERC standard should not be overly prescriptive in requirements for reporting progress/status on the standard. Flexibility should allow for the various documentation and processes already in place to achieve compliance.

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

   The SAR drafting team believes that it is impractical to exhaustively test for every contingency described in each category plus every conceivable planned outage. Should the requirement to consider planned outages in addition to each Category A through D contingency remain part of this planning standard?

   ☒ Yes (consider planned outages in all Categories A through D).

   ☐ Yes (consider planned outages in some Categories only).

   Please specify which Categories:

   ☐ No

   ☒ Comments*: The existing standards should not be weakened*

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

   ☐ Comments:

6. Do you have any other comments on the SAR?

   ☒ Comments:

   Determination of a definition for Cascading Outage should be coordinated with the STDs 200 and 600.

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STD Commenter Information (For Groups Submitting Group Comments)	
Name of Group: *Southern Company Services, Inc*	**Group Chair:** *Marc Butts* **Chair Phone:** 205-257-4839 **Chair Email:** mmbutts@southernco.com

List of Group Participants that Support These Comments:

Name	Company	Industry Segment #
Rod Hardiman	*Southern Company Services*	1
Jonathan Glidewell	*Southern Company Services*	1
Bobby Jones	*Southern Company Services*	1
Bill Pope	*Gulf Power Company*	3
Marc Butts	*Southern Company Services*	1

Please Review Version 2 of the SAR and Answer the Following Questions

Insert a "check' mark in the appropriate boxes by double-clicking the gray areas.

1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

   (a). Do you believe that the events in Categories B, C & D are classified correctly?

   ☒ Yes

   ☐ No

☒ Comments: **Category C events are more likely to occur than Category D events and should require higher performance expectations.**

(b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

(c) Which of the following approaches do you favor regarding Table 1 of existing Planning Standard I.A?:

☐ Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events.

Please explain your choice:

☐ Create a new category between C and D with performance characteristics between that of the present Categories C and D.

Please explain your choice

☐ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

Please explain your choice:

☒ Comments: **Since the events are currently categorized correctly, 1.b and 1.c are not applicable. Low consequence Category C events should be considered compliant. However, as we interpret Table I, a Category C event that results in low consequences (e.g. no cascading) is already considered compliant since entities can drop load or curtail firm transfers to return to applicable thermal or voltage ratings.**

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

☐ Yes

☒ No

☐ Comments: **Too burdensome for the perceived benefits.**

3. If your answer to question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan?

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

   The SAR drafting team believes that it is impractical to exhaustively test for every contingency described in each category plus every conceivable planned outage. Should the requirement to consider planned outages in addition to each Category A through D contingency remain part of this planning standard?

   ☐ Yes (consider planned outages in all Categories A through D).

   ☒ Yes (consider planned outages in some Categories only).

   Please specify which Categories: **Categories A and B only.**

   ☐ No

   ☒ Comments: **The requirement to consider planned outages in addition to each Category A and B contingency should remain part of this planning standard. We agree with the SAR drafting team that exhaustive testing for every contingency described and every load level in each category is not practical.**

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

   ☒ Comments: **Not aware of any at this time. However, Regional Differences could develop and each request for a Regional Difference should be considered individually.**

6. Do you have any other comments on the SAR?

   ☒ Comments:

   In general, the NERC Standards need to have a common definition across the board for any definition used in a Standard. For example, the definition for "Cascading Outages" needs to be coordinated with the Standards Drafting Team (SDT) for the "Determine Facility Ratings, Operating Limits, and Transfer Capability" standard.

   Southern agrees that the Standard should provide a clearer definition of "cascading outages." We suggest that the following be considered:
   Cascading — the uncontrolled successive loss of system elements triggered by contingencies which results in widespread electric service interruption 1) that drops 1000 MW of load or more or 2) that crosses control area boundaries.
   In addition Southern recommends that the Standard provide a clearer definition of what is meant by "system stable." We suggest that the following be considered:

   System stable — For Category A and B simulations, system stable means that no generating units pull out of synchronism. For Category C events, system stable means that if units pull out of synchronism, 1) the resulting impedance swings are not out into the transmission system and 2) the total amount of generation lost because of out-of-step tripping does not exceed the control area operating reserve level.

The standard should include requirements for LSEs to provide forecast resource data as required in the current II.D standards, to facilitate development of power flow models. Accordingly, this standard should also apply to LSEs.

On page 4 of the SAR, bottom half of the page; there is a paragraph that discusses how the Transmission Planner should document generation dispatch. Comment: In relation to the methodology being used for incorporating planned generation assets in the model and how generation is dispatched, the type of each generating unit, the primary fuel type for each generating unit, and a dispatch order of the generating units should be required. In addition, a general description of the dispatch methodology used for the system should also be required. However, no cost information should be required.

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STD Commenter Information (For Groups Submitting Group Comments)

Name of Group:	**Group Chair:** Ben Morris **Chair Phone:** 415-973-7687 **Chair Email:** bem8@pge.com
Western Electricity Coordinating Council	

List of Group Participants that Support These Comments:

Name	Company	Industry Segment #
Baj Agrawal	*Arizona Public Service*	*1*
Phil Park	*British Columbia Transmission Corporation*	*2*
Jeff Miller	*California Independent System Operator*	*2*
Ron Schellberg	*Idaho Power Company*	*1*
Rahn Sorensen	*Nevada Power Company*	*1*
Ben Morris	*Pacific Gas and Electric Company*	*1*
Rick Padilla	*Pacific Gas and Electric Company*	*5*
Chifong Thomas	*Pacific Gas &Electric Company.*	*1*
Dilip Mahendra	*Sacramento Municipal Utility District*	*1*
Brian K. Keel	*Salt River Project*	*1*
Dana Cabbell	*Southern California Edison*	*1*
Mohan Kondragunta	*Southern California Edison*	*1*
John D. Martinsen	*Snohomish County PUD*	*4*

Please Review Version 2 of the SAR and Answer the Following Questions

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   (a). Do you believe that the events in Categories B, C & D are classified correctly?

   ☐ Yes

   ☒ No

   ☒ Comments:

   The Categories should be based on the probability of occurrence of the initiating events. A review of Table I (Standard IA) shows that the contingencies in the same Categories seem to have very different probabilities of occurrence. As such, a new category should be defined between Category C and Category D. The more probable Category D events and the less probable Category C events should be placed in this new category and not be allowed to cascade.

   (b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

   WECC supports moving C.2 and C.9 to a new Category between the current C and D Categories. WECC Planning Standards do not support reclassification of C.3.

   (c) Which of the following approaches do you favor regarding Table 1 of existing Planning Standard I.A?:

   ☐ Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events.

   Please explain your choice:

   ☒ Create a new category between C and D with performance characteristics between that of the present Categories C and D.

   Please explain your choice

   A no-cascading performance requirement is needed for this new category.

   There are Category C events, which have a very low probability of occurrence. Such events, even if they occurred should not lead to cascading, even though local facility ratings or voltage limits may be exceeded. Very often, the solution for such low probability contingencies would be to install a relay system to interrupt load or generation. The probability of relay misoperation to prevent potential problems resulting from the contingency may be higher than the probability of the contingency itself. Thus the impact on the users of the grid may not be significantly reduced. Nevertheless, the system reliability would be better served if we can add a category for such low probability contingencies (which would not result in cascading), and the risk of which is acceptable.

   ☐ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

Please explain your choice:

☐ Comments:

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

☐ Yes

☒ No

☒ Comments:
Since many of the transmission plans are dependent upon factors such as, resource plans, local load projections, new technology, permitting, to name a few, it would not be meaningful to report on the status of implementation of a transmission plan. In any case, if a potential transmission problem is not solved, it will show up again in subsequent years, so there will be pressure to solve it. This continuous "certification" would ensure that any potential transmission problem, once identified, would not be left unsolved even without NERC requiring status reports on implementation.

3. If your answer to question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan?

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

The SAR drafting team believes that it is impractical to exhaustively test for every contingency described in each category plus every conceivable planned outage. Should the requirement to consider planned outages in addition to each Category A through D contingency remain part of this planning standard?

☐ Yes (consider planned outages in all Categories A through D).

☒ Yes (consider planned outages in some Categories only).

Please specify which Categories: A, B, and C (except C-3)

☐ No

☒ Comments:
All contingencies where a single point of failure could cause facilities to be lost should be tested for compliance with the standards even under planned maintenance conditions. However, it should never be necessary to exhaustively test every possible combination of outages. Those contingencies that are clearly not critical outages should not have to be simulated.

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

☒ Comments:

The existing NERC Standard C-9 (and C-2 for bus sectionalizing breakers) as it applies to WECC should be modified so that thermal limit and voltage limit violations are allowed for bus sectionalizing breaker failures. This is because bus sectionalizing breaker failure is a relatively low probability event. Use of a bus sectionalizing breaker should be encouraged because it reduces the impact of a disturbance to a portion of the load only. Without the proposed modification there is no incentive to use the sectionalizing breaker. However, under no conditions should system instability or cascading outages be allowed for bus sectionalizing breaker failures.

6. Do you have any other comments on the SAR?

– ☒ Comments:

1. On Page SAR-5 of the draft SAR, the third bullet states: "The Standard should allow for the development and use of probabilistic planning methods. The minimum requirements of probabilistic methods are the contingencies as described in Table 1 of existing Planning Standard I.A. There should be NERC approval of acceptable levels of risk."

   The Standard should also allow for the use of Probabilistic Criteria. In WECC, Probabilistic Planning refers to the application of fixed planning standards to a given problem to determine the probable or expected load not served. Probabilistic Criteria is used to refer to adjusting the performance category based on the probability of the event for a specific facility. The performance category can move up or down depending on actual or planned performance. Therefore, Table 1 would be the starting point for making probabilistic criteria adjustments. Probabilistic adjusted criteria would be the basis for Probabilistic Planning.

   For example, the NERC Planning Standards should follow what WECC is doing with regard to listing disturbances as a guide, but say that other disturbances with the same probability should be included. List the probability ranges (outages per year), Category B: >= 0.33, Category C: 0.33 to 0.033; Category D1 (no cascading): 0.033 to .0033, Category D2: < .0033.

   The standard should allow for changes in the required performance for given disturbances if a probability in another range has been established for a given disturbance.

   WECC recommends that the approval of acceptable levels of risk be at the regional level.

   NERC should require that the regional councils specify voltage dip and minimum frequency standards. NERC should not set the standards.

2. Page SAR-4 states that the Standard would not include requirements for Resource Planning. In order to develop any meaningful standard the resource part of the power system should be addressed by including standards for the modeling of existing resources, planned retirement of resources, and planned resources in the next 5 to 10 years time frame. This information will be necessary in order to assess whether future system can or can not meet the reliability standards.

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Commenter Information (For Individual Commenters)

Name: Mark J. Kuras

Organization: MAAC

Industry Segment #: 2

Telephone: 610-666-8924

E-mail: kuras@pjm.com

Key to Industry Segment #'s:

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   (a). Do you believe that the events in Categories B, C & D are classified correctly?

   X Yes

   No

   X Comments: **I believe that an in depth investigation of the probability of each possible contingency occurring be investigated by NERC to determine each contingency's relative probability and those results used to re-rank the contingency list, if necessary.**

   (b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

   (c) Which of the following approaches do you favor regarding Table 1 of existing Planning Standard I.A?:

   ☐ Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events.

   Please explain your choice:

   X Create a new category between C and D with performance characteristics between that of the present Categories C and D.

   Please explain your choice

   This is the best choice of the ones mentioned here but see my answer to 1.(b) above for another approach. This approach allows for some levels of performance between C and D such as restricting the performance to "no cascading or system instability" for some C and maybe even D events.

   ☐ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

   Please explain your choice:

   ☐ Comments:

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

   X Yes

☐ No

☐ Comments: **It's one thing to develop plans and another to follow through on them. PJM can offer suggestions on how this tracking could be accomplished.**

3. If your answer to question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan?

   A plan is a plan at that point in time. Plans change. Periodic checks of implementation of plans can uncover these plan changes that should be allowed.

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

   The SAR drafting team believes that it is impractical to exhaustively test for every contingency described in each category plus every conceivable planned outage. Should the requirement to consider planned outages in addition to each Category A through D contingency remain part of this planning standard?

   X Yes (consider planned outages in all Categories A through D).

   ☐ Yes (consider planned outages in some Categories only).

   Please specify which Categories:

   ☐ No

   ☐ Comments: **Contingencies don't only happen when all lines are in service. Outages should be modeled during all types of contingency evaluation. This may be a fairly daunting task but this evaluation will help the system operators be prepared for the reality of operating the system in a less than ideal state. Possible ways to select lines to outage may be to look at lines with high unscheduled outage rates, lines close to sources of contamination, lines through areas that have historically had vegetation contact problems, and especially lines that when outaged can cause operating problems.**

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

   ☐ Comments:

6. Do you have any other comments on the SAR?

   ☐ Comments:

Note – This form is to comment on **Version 2** of the **"Assess Transmission Future Needs and Develop Transmission Plans"** SAR.

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E-mail this form between May 5 and June 5, 2004 to: sarcomm@nerc.com with "Comments" in the subject line.

If you have any questions about this Standards Draft Comment Form, please contact the Director of Standards – Gerry Cauley at 609-452-8060.

Background:

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If there is such a need, how should the scope of the SAR be changed?

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- The scope of the SAR should be expanded to include…..
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In January 2004, the Standards Authorization Committee (SAC) appointed a Drafting Team (DT) to address industry answers and comments to the questions posed. The DT was also charged with refining the SAR and drafting a detailed description of the proposed standard in preparation for the 2nd posting of the SAR.

Most of the industry respondents indicated that there is indeed a reliability-related need to develop a standard to address transmission assessment and planning issues. Comments were received from many different sources, including individuals, small and large utilities, groups of utilities, and Regional Councils. The SAR DT considered the comments submitted by each industry participant, and revised the SAR to conform to the changes that were technically sound and appeared to represent a consensus of participants.

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Please review Version 2 of the SAR and complete this Comment Form to let the SAR DT know if you agree or disagree with the SAR DT's assessment that this SAR is ready to be developed into a Standard.

Commenter Information (For Individual Commenters)
Name: Marv Landauer Organization: BPA Industry Segment #: 1 Telephone: 503-230-4105 E-mail: mjlandauer@bpa.gov

Key to Industry Segment #'s:

1 – Trans. Owners
2 – RTO's, ISO's, RRC's
3 – LSE's
4 – TDU's
5 - Generators
6 - Brokers, Aggregators, and Marketers
7 - Large Electricity End Users
8 - Small Electricity Users
9 - Federal, State, and Provincial Regulatory or other Govt. Entities

STD Commenter Information (For Groups Submitting Group Comments)		
Name of Group: Internal BPA review group	**Group Chair:** **Chair Email:**	**Chair Phone:**

List of Group Participants that Support These Comments:

Name	Company	Industry Segment #
Paul Arnold	BPA	1
Rebecca Berdahl	BPA	1
Mark Bond	BPA	1
Gordon Comegys	BPA	1
Angela DeClerk	BPA	1
Don Gold	BPA	1
Kyle Kohne	BPA	1
Mike Kreipe	BPA	1
Chuck Matthews	BPA	1
Bill Mittelstadt	BPA	1
James Murphy	BPA	1
Melvin Rodrigues	BPA	1
Mike Viles	BPA	1
Paul Ferron	BPA	1

Please Review Version 2 of the SAR and Answer the Following Questions

Insert a "check' mark in the appropriate boxes by double-clicking the gray areas.

1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

   (a). Do you believe that the events in Categories B, C & D are classified correctly?

   ☐ Yes

   x☐x No

   ☐ Comments:

   (b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

Outage categories C1, C2 and C9 do not appear to be classified correctly as verified by the attached outage probability data. There is consistency between the categories except that C1, C2 and C9 outages have a much lower probability of occurrence that the other Category C outages.

(c) Which of the following approaches do you favor regarding Table 1 of existing Planning Standard I.A?:

☐ Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events.

Please explain your choice:

x☐x Create a new category between C and D with performance characteristics between that of the present Categories C and D.

Please explain your choice

The C2 (with respect to a bus section breaker failure) and the C9 outages should be in this new category. Although these outages have extremely low probability, they should not cause cascading. This is especially true of C2, which is a single contingency failure of a bus section breaker. Therefore we favor adding a new category between Level C and D (or moving these two outages to Level D) with performance requirements of no cascading and system stable but with no requirement to be within applicable ratings.

☐ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

Please explain your choice:

☐ Comments:

Although this is not our preferred choice, allowing the use of "good cause exceptions" (which

we assume is the same as probabilistic methods which could move contingencies to a lower performance level although this is inconsistent with other statements in the SAR) to verify exceptions to the present categories would also be acceptable. For the C2 example, showing that these events statistically occur every 1200-1300 years and would not cause cascading problems on the system should provide enough evidence that a lower performance level is appropriate.

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

   x☐x Yes

   ☐ No

   ☐ Comments:

A plan without a requirement to update progress on implementing the plan has little value. This is essential for an effective standard. This should not be an extensive reporting procedure and could easily be met during the subsequent compliance report.

3. If your answer to question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan?

Once a transmission plan is identified in a compliance report, progress on that project should be reported in subsequent compliance reports. If system conditions change, this should be described along with the consequences to the proposed plans. If project need goes away, the project can be cancelled. However, if the project need still exists and the responsible entity has not implemented a plan to correct the deficiency, it should be listed as non-compliant. Legitimate problems with regulatory and siting issues should be acceptable reasons for project delay.

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

   The SAR drafting team believes that it is impractical to exhaustively test for every contingency described in each category plus every conceivable planned outage. Should the requirement to consider planned outages in addition to each Category A through D contingency remain part of this planning standard?

   ☐ Yes (consider planned outages in all Categories A through D).

   ☐ Yes (consider planned outages in some Categories only).

   Please specify which Categories:

   x☐x No

   ☐ Comments:

This requirement should be addressed in operational planning studies (less than one year). This standard is not appropriate for Transmission Planning studies except possibly as a tool to measure or compare the robustness or availability of transmission plans. This is not an item that should require any compliance action.

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

   x☐x Comments:

Although WECC has several requirements in its standards that are more stringent than the existing NERC criteria, it also has two standards that are less stringent (C2 and C9). Depending on the resolution of question #1 above, C2 and C9 may be a regional difference.

WECC has a formal Probabilistic Planning process that allows adjustment of performance levels of contingencies in either direction. As this SAR states that the existing NERC Table I is the minimum criteria for probabilistic methods, this will be a regional difference for WECC. This is discussed more in Item #6 below.

6. Do you have any other comments on the SAR?

   x☐x Comments:

Probabilistic Planning Methods: The handling of probabilistic criteria in the SAR seems quite convoluted, i.e. it can only be used to increase performance levels AND has to be approved by NERC. This is not the way probabilistic planning should work.

WECC presently has a process (Seven Step Reliability Performance Evaluation) to allow changes in performance requirements (both up and down) for specific outages based on rigorous analysis and monitoring actual performance. It is mostly applicable to requirements beyond the NERC criteria (such as outages of adjacent circuits on separate towers). Use of these methods should be allowed with approval of affected regions. This process should allow for movement below Table 1, i.e. moving Category C outage to Category D. One way to resolve this would be to replace the word "minimum" in the SAR to "starting".

Applicable Ratings: There is a need to tighten up the methodology for Applicable Ratings to ensure that compliance with this standard is measurable. We assume that this will take place in the Determine Facility Ratings Standard although we are concerned about how this is progressing.

Transition to Operating Standards: The Planning Standards include multi-layered requirements for different types of outages, i.e., Level B single contingencies, Level C and D multiple contingencies. Compliance with these requirements is to be defined and monitored via the new Reliability Standards. However, once the system moves into the Operational timeframe (one year or less), Policy 2 presently requires meeting N-1 contingencies only with no requirements for Levels C and D. The transition between planning and operations needs further exploration.

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Please review Version 2 of the SAR and complete this Comment Form to let the SAR DT know if you agree or disagree with the SAR DT's assessment that this SAR is ready to be developed into a Standard.

Commenter Information (For Individual Commenters)
Name: Neil Brausen, Jeff Billinton, Bob Chow Organization: Alberta Electric System Operator (AESO) Industry Segment #: 2 Telephone: 403-539-2531 E-mail: bob.chow@aeso.ca

Key to Industry Segment #'s:

1 – Trans. Owners
2 – RTO's, ISO's, RRC's
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STD Commenter Information (For Groups Submitting Group Comments)		
Name of Group:	Group Chair: Chair Email:	Chair Phone:
List of Group Participants that Support These Comments:		
Name	Company	Industry Segment #

Please Review Version 2 of the SAR and Answer the Following Questions

Insert a "check' mark in the appropriate boxes by double-clicking the gray areas.

1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

   (a). Do you believe that the events in Categories B, C & D are classified correctly?

   ☒ Yes

   ☐ No

   ☒ Comments:

Generally the B and C events are classified correctly. However, there is a need to reconsider the grouping of the D events on some consistent basis (e.g. such as using outage frequency as a determinant). There should also be some means to include double-circuit lines and buses as B events if their probability of outage is comparable to that of other category B contingencies.

(b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

(c) Which of the following approaches do you favor regarding Table 1 of existing Planning Standard I.A?:

☐ Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events.

Please explain your choice:

☒ Create a new category between C and D with performance characteristics between that of the present Categories C and D.

Please explain your choice

There are D contingencies that are probable although rare (e.g. loss of multiple circuits on separate tower lines on a common right-of-way). These contingencies may result in loss of load or generation but should not allow cascading. Other D contingencies such as loss of all lines on a multi-line corridor or the loss of a complete station would be difficult to contain. These events should be treated differently than the former.

☐ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

Please explain your choice:

☐ Comments:

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

☐ Yes

☒ No

☒ Comments:

It is not clear to whom the reporting would go to and how it would be used. Normally, reporting would be required for the regulatory process in the affected jurisdiction. The scope of that reporting would not be limited to reliability only but also other aspects of the transmission plan (e.g. customer connections, efficiency improvements, etc).

3. If your answer to question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan?

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

   The SAR drafting team believes that it is impractical to exhaustively test for every contingency described in each category plus every conceivable planned outage. Should the requirement to consider planned outages in addition to each Category A through D contingency remain part of this planning standard?

   ☐ Yes (consider planned outages in all Categories A through D).

   ☒ Yes (consider planned outages in some Categories only).

   Please specify which Categories: A to C

   ☐ No

   ☒ Comments:

   A need to clarify what constitutes the "normal" condition when a facility (transmission or generation) is on a long duration planned outage (is it a day, a week, etc). The A to C contingency categories can then be applied to the "normal" condition as defined. The testing requirement could perhaps be stated in a way that leaves it to the judgement of the planning authority as to the critical combinations of outages that need to be tested.

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

   ☐ Comments:

6. Do you have any other comments on the SAR?

   ☒ Comments:

   The basis of probabilistic planning, in our view, is to make planning decisions based on the metrics, such frequency, duration and impact, derived from probabilistic assessments. This is usually difficult to do in planning the bulk portion of the transmission system, since outage events are rare but their impact is significant (like multiplying infinity and zero). The categorization of contingencies in Table 1 using outage frequency as a determinant is a step in applying probabilistic techniques in this Standard but it is not probabilistic planning in its true sense. The

SAR development team should clarify what it intends with regard to "the use of probabilistic planning methods".

We believe that the assumptions made for the amount, type and location of future supply are important considerations in assessing the future needs of transmission systems. The SAR drafting team should consider this forecast requirement in developing this Standard. Similarly, there is difficulty in separating planning for reliability and planning for overall system efficiency and economy, and the Standard must be clear on this differentiation.

The SAR drafting team should clarify through rules, tests, definitions, etc. the portion of an entity's transmission system that shall be planned under the full NERC Standard and what portion may be exempted.

There should be a clear distinction between the appropriate use and application of RAS (or SPS) and "safety nets".

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Organization:
Industry Segment #:
Telephone:
E-mail:

Key to Industry Segment #'s:

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STD Commenter Information (For Groups Submitting Group Comments)	
Name of Group: ISO/RTO Council Standards Review Committee	**Group Chair:** Karl Tammar **Chair Phone:** 518-356-6205 **Chair Email:** ktammar@nyiso.com

List of Group Participants that Support These Comments:

Name	Company	Industry Segment #
Dale McMaster	AESO	2
Ed Riley	CAISO	2
Sam Jones	ERCOT	2
Don Tench	IMO	2
Peter Brandien	ISO-NE	2
Bill Phillips	MISO	2
Karl Tammar	NYISO	2
Bruce Balmat	PJM	2
Carl Monroe	SPP	2

Please Review Version 2 of the SAR and Answer the Following Questions

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(a). Do you believe that the events in Categories B, C & D are classified correctly?

☒ Yes

☐ No

☐ Comments:

(b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

(c) Which of the following approaches do you favor regarding Table 1 of existing Planning Standard I.A?:

☐ Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events.

Please explain your choice:

☐ Create a new category between C and D with performance characteristics between that of the present Categories C and D.

Please explain your choice

☐ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

Please explain your choice:

☒ Comments:

We suggest no changes be made to Categories B, C, and D as they presently exist in the Planning Standards. Choice of any of the above would result in a weakened and degraded reliability standard throughout NERC member systems.

.

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

   ☒ Yes

   ☐ No

   ☐ Comments:

3. If your answer to question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan?

Periodic Transmission Reviews to address changes in plans and tracking lists of BPS additions and modifications (that would include transmission, generation and other major equipment identified as a BPS element).

The resultant NERC standard should not be overly prescriptive in requirements for reporting progress/status on the standard. Flexibility should allow for the various documentation and processes already in place to achieve compliance.

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

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   ☒ Yes (consider planned outages in all Categories A through D).

   ☐ Yes (consider planned outages in some Categories only).

   Please specify which Categories:

   ☐ No

   ☒ Comments*: The existing standards should not be weakened*

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

   ☐ Comments:

6. Do you have any other comments on the SAR?

   ☒ Comments:

   Determining a definition for Cascading Outage should be coordinated with the STDs 200 and 600.

   This standard should make it abundantly clear that it applies to both internal and external systems, that is the system under study and adjacent systems, or the entire interconnection if appropriate.

   Seasonal and weather related variability should be considered in studies.

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STD Commenter Information (For Groups Submitting Group Comments)	
Name of Group: Southern Co. Generation & Energy Marketing (SCGEM)	Group Chair: Roman Carter Chair Phone:205.257.6027 Chair Email:jrcarter@southernco.com

List of Group Participants that Support These Comments:		
Name	**Company**	**Industry Segment #**
Roman Carter	**SCGEM**	**6**
Joel Dison	*SCGEM*	*6*
Lucius Burris	*SCGEM*	*6*
Tony Reed	*SCGEM*	*6*
Lloyd Barnes	*SCGEM*	*6*
Clifford Shepard	**SCGEM**	**6**

Please Review Version 2 of the SAR and Answer the Following Questions

Insert a "check' mark in the appropriate boxes by double-clicking the gray areas.

1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

   (a). Do you believe that the events in Categories B, C & D are classified correctly?

   ☒ Yes

   ☐ No

☒ Comments: Category C events are more likely to occur than Category D events and should require higher performance expectations.

(b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

(c) Which of the following approaches do you favor regarding Table 1 of existing Planning Standard I.A?:

☐ Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events.

Please explain your choice:

☐ Create a new category between C and D with performance characteristics between that of the present Categories C and D.

Please explain your choice

☐ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

Please explain your choice:

☒ Comments: Since the events are currently categorized correctly, 1.b and 1.c are not applicable.

Low consequence Category C events should be considered compliant. However, as we interpret Table I, a Category C event that results in low consequences (e.g. no cascading) is already considered compliant since entities can drop load or curtail firm transfers to return to applicable thermal or voltage ratings.

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

☐ Yes

☒ No

☐ Comments: Too burdensome for the perceived benefits.

3. If your answer to question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan?

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

   The SAR drafting team believes that it is impractical to exhaustively test for every contingency described in each category plus every conceivable planned outage. Should the requirement to consider planned outages in addition to each Category A through D contingency remain part of this planning standard?

   ☐ Yes (consider planned outages in all Categories A through D).

   ☒ Yes (consider planned outages in some Categories only).

   Please specify which Categories: **Categories A and B only.**

   ☐ No

   ☒ Comments: The requirement to consider planned outages in addition to each Category A and B contingency should remain part of this planning standard. We agree with the SAR drafting team that exhaustive testing for every contingency described and every load level in each category is not practical.

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

   ☒ Comments: Not aware of any at this time. However, Regional Differences could develop and each request for a Regional Difference should be considered individually.

6. Do you have any other comments on the SAR?

   ☒ Comments:

   Southern agrees that the Standard should provide a clearer definition of "cascading outages". We suggest that the following be considered: The uncontrolled successive loss of system elements triggered by contingencies which results in widespread electric service interruption 1) that drops 1000 mw of load or more or 2) that crosses control area boundaries.

   In addition, Southern recommends that the Standard provide a clearer definition of what is meant by "system stable". We suggest that the following be considered: For category A and B simulations, system stable means that no generating units pull out of synchronism. For Category C events, system stable means that if units pull out of synchronism, 1) the resulting impedance swings are not out into the transmission system and 2) the total amount of generation lost because of out-of-step tripping does not exceed the control area operating reserve level.

   In general, the NERC Standards need to have a common definition across the board for any definition used in a Standard. For example, the definition for "Cascading Outages" needs to be coordinated with the Standards Drafting Team (SDT) for the "Determine Facility Ratings, Operating Limits, and Transfer Capability" standard.

   It would also be beneficial to the generation sector if the SDT for this new Planning Standard could summarize the differences between the existing Planning Standards I.A, I.B, I.D, II.A, and II.D and the new Planning Standard as it is being developed. This would gauge the potential impact to the plants. The main concerns have been 1) how to address regional differences (primarily related to

Category C events), 2) how to differentiate Table I's application to the Planning world versus the Operations world, and 3) how to state the requirements more clearly.

The standard should include requirements for LSEs to provide forecast resource data required to develop power flow models as required in the current II.D standards. Accordingly, this standard should also apply to LSEs.

In relation to the methodology being used for incorporating planned generation assets in the model and how generation is dispatched, the type of each generating unit, the primary fuel type for each generating unit, and a dispatch order of the generating units should be required. In addition, a general description of the dispatch methodology used for the system should also be required. However, no cost information should be required.

Note – This form is to comment on **Version 2** of the **"Assess Transmission Future Needs and Develop Transmission Plans"** SAR.

The latest version of this SAR (TRNS_NDS_&_PLNS_01_02) is posted on the Standards web site at: http://www.nerc.com/~filez/standards/Assess-Transmission-Future-Needs.html

E-mail this form between May 1 and May 31, 2004 to: sarcomm@nerc.com with "Comments" in the subject line.

If you have any questions about this Standards Draft Comment Form, please contact the Director of Standards – Gerry Cauley at 609-452-8060.

Background:

Version 1 of the **"Assess Transmission Future Needs and Develop Transmission Plans"** SAR was posted for a 30-day public comment period between April 2 and May 3, 2002. This first version was an abbreviated SAR, which included an "Industry Need" statement and a brief description of the proposed standard, but did not include a detailed description. The purpose of this first posting was to collect feedback from the industry on the following questions:

- Is there a reliability-related need for an Organization Standard to be developed on this topic?

If there is such a need, how should the scope of the SAR be changed?

- The scope of the SAR is fine as is
- The scope of the SAR should be expanded to include…..
- The scope of the SAR should be reduced to eliminate……

In January 2004, the Standards Authorization Committee (SAC) appointed a Drafting Team (DT) to address industry answers and comments to the questions posed. The DT was also charged with refining the SAR and drafting a detailed description of the proposed standard in preparation for the 2nd posting of the SAR.

Most of the industry respondents indicated that there is indeed a reliability-related need to develop a standard to address transmission assessment and planning issues. Comments were received from many different sources, including individuals, small and large utilities, groups of utilities, and Regional Councils. The SAR DT considered the comments submitted by each industry participant, and revised the SAR to conform to the changes that were technically sound and appeared to represent a consensus of participants.

The revised SAR (Version 2) is posted on the NERC web site given in the blue box at the top of this form. Also posted is a Consideration of Comments document, in which the DT has responded to the original industry comments from 2002. You can find Version 1 of the SAR and industry comments on this version at the same web location.

Please review Version 2 of the SAR and complete this Comment Form to let the SAR DT know if you agree or disagree with the SAR DT's assessment that this SAR is ready to be developed into a Standard.

Commenter Information (For Individual Commenters)
Name: Raj Rana - Coordinator
Organization: AEP
Industry Segment #:1,3,5,6
Telephone: 614-716-2359
E-mail: raj_rana@AEP.com

Key to Industry Segment #'s:

1 – Trans. Owners
2 – RTO's, ISO's, RRC's
3 – LSE's
4 – TDU's
5 - Generators
6 - Brokers, Aggregators, and Marketers
7 - Large Electricity End Users
8 - Small Electricity Users
9 - Federal, State, and Provincial Regulatory or other Govt. Entities

STD Commenter Information (For Groups Submitting Group Comments)	
Name of Group:	**Group Chair:** **Chair Phone:** **Chair Email:**

List of Group Participants that Support These Comments:

Name	Company	Industry Segment #

Please Review Version 2 of the SAR and Answer the Following Questions

Insert a "check' mark in the appropriate boxes by double-clicking the gray areas.

1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

   (a). Do you believe that the events in Categories B, C & D are classified correctly?

   ☐ Yes

   ☐ No

   X Comments: Need to see outage probability data in order to answer definitively.

   (b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

   Based on good data, the probabilities of exiting C and D events could be estimated. The events could then be grouped into higher probability events (Category C) and lower probability events (Category D). AEP would be able to provide some outage data to support this analysis. Contact Ali Al-Fayez, Manager – Transmission Asset Performance (614 552-1649)

   (c) Which of the following approaches do you favor regarding Table 1 of existing Planning Standard I.A?:

   X Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events.

   Please explain your choice: Four categories are sufficient and generally understood by the industry. Specific changes that are supported by outage probabilities can be made, as appropriate, by moving Category C tests to Category D.

   ☐ Create a new category between C and D with performance characteristics between that of the present Categories C and D.

   Please explain your choice

   ☐ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

   Please explain your choice:

   X☐ Comments: "Good cause exceptions" can always be considered, but this approach should not be institutionalized.

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

X Yes

☐ No

X Comments: The reporting requirements should not be burdensome, but they are needed to ensure a minimum level of accountability.

3. If your answer to question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan?
A simple narrative explanation should be provided that explains what factors have eliminated the need for the transmission modification/addition or changed its timing. In cases where a modified solution has been developed, the Transmission Planner should demonstrate the effectiveness of the modified approach and compare to the original approach.

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

   The SAR drafting team believes that it is impractical to exhaustively test for every contingency described in each category plus every conceivable planned outage. Should the requirement to consider planned outages in addition to each Category A through D contingency remain part of this planning standard?

   ☐ Yes (consider planned outages in all Categories A through D).

   X Yes (consider planned outages in some Categories only).

   Please specify which Categories: B, C and D

   ☐ No

   X Comments: For Categories where planned maintenance is considered, it should only be necessary to test the most significant planned outages, not all possible planned outages.

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

   No

   ☐ Comments:

6. Do you have any other comments on the SAR?
No

   ☐ Comments:

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Telephone:
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9 - Federal, State, and Provincial Regulatory or other Govt. Entities

STD Commenter Information (For Groups Submitting Group Comments)	
Name of Group:	**Group Chair:** **Chair Phone:** **Chair Email:**

List of Group Participants that Support These Comments:

Name	**Company**	**Industry Segment #**
Robert W. Pierce	**Duke Energy**	**1**

Please Review Version 2 of the SAR and Answer the Following Questions

Insert a "check' mark in the appropriate boxes by double-clicking the gray areas.

1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

   (a). Do you believe that the events in Categories B, C & D are classified correctly?

   ☒ Yes

   ☐ No

   ☐ Comments:

   (b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

   (c) Which of the following approaches do you favor regarding Table 1 of existing Planning Standard I.A?:

   ☐ Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events.

   Please explain your choice:

   ☐ Create a new category between C and D with performance characteristics between that of the present Categories C and D.

   Please explain your choice

   ☒ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

   Please explain your choice: Allow the flexibility for reasonable exceptions to the general categories based on frequency of occurrence. This may mean the possibility of a particular contingency moving up or down in category. This allowance permits appropriate exercise of engineering judgment in the planning process.

   ☐ Comments:

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

   ☐ Yes

   ☒ No

☐ Comments:

3. If your answer to question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan?

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

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   ☐ Yes (consider planned outages in all Categories A through D).

   ☐ Yes (consider planned outages in some Categories only).

   Please specify which Categories:

   ☒ No

   ☒ Comments: The first priority should be to clarify the requirements of the I.A table. Utilities/ regions are interpreting the table differently. What was the original basis for the contingency categories and required response in the table? Clarify whether the original intent was to perform thermal, voltage and stability screens for all categories and the frequency at which the screenings were intended to performed.

   It is impractical to expect all screenings of all categories on a frequent basis. It may be appropriate to state that the table is for general guidance and that transmission owners may determine frequency at which studies should be performed based on load growth, system loading and significance of changes to the system.

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

   ☐ Comments:

6. Do you have any other comments on the SAR?

   ☒ Comments: Resource planning cannot be excluded from the standard. Guidance should be provided on incorporation of resource data from all LSE's and how resource deficiencies in outyear models should be handled (e.g. model fictitious generation with no reactive capability to ensure sufficient reactive resources are planned for if power is purchased from off system in the future). The increasingly frequent changes in resource designations are causing greater uncertainty in performance of planning for reliable system operation.

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8 - Small Electricity Users
9 - Federal, State, and Provincial Regulatory or other Govt. Entities

STD Commenter Information (For Groups Submitting Group Comments)	
Name of Group:	**Group Chair:** Peter Mackin **Chair Phone:** 916-631-3212 **Chair Email:** pmackin@navigantconsulting.com

List of Group Participants that Support These Comments:

Name	Company	Industry Segment #
Peter Krzykos	Arizona Public Service	1
Chifong Thomas	Pacific Gas and Electric Co.	1
Peter Mackin	Transmission Agency of Northern California (TANC)	1
Matthew Stoltz	Basin Electric Power Cooperative	1
Bob Easton	Western Area Power Administration	1
Charles Russell	Salt River Project	1
Joe Seabrook	Puget Sound Energy	1, 3, and 5

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   (a). Do you believe that the events in Categories B, C & D are classified correctly?

   ☐ Yes

   ☒ No

☒ Comments:

The Categories should be based on probability of occurrence of the initiating events. A review of Table I (Standard IA) show that the contingencies in the same Categories seem to have very different probabilities of occurrence.

Category D needs to be split into two categories, the more probable Category D events should not be allowed to cascade. For example, the new no cascading category should include:

loss of 2 units at a plant

loss of adjacent lines in a right of way

loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker

There is no defined performance level for 3 phase fault, stuck breaker, and loss of one line.

(b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

See A. For support, see the NERC/WECC Planning Standards

(c) Which of the following approaches do you favor regarding Table 1 of existing Planning Standard I.A?:

☐ Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events.

Please explain your choice:

☒ Create a new category between C and D with performance characteristics between that of the present Categories C and D.

Please explain your choice

A no-cascading performance requirement is needed.

There are Category C events, which have a very low probability of occurrence. Such events, even if occurred should not lead to cascading, even though local facility ratings or voltage limits may be exceeded. Very often, the solution for such low probability contingencies would be to install relay system to interrupt load or generation. The probability of relay misoperation to prevent potential problems resulting from the contingency may be higher than the probability of the contingency itself. In this case, the system reliability would be better serve if we can add a category for such low probability contingencies (which would not result in cascading), and the risk of which is acceptable.

☐ Keep the same categories as now exist, but allow for "good cause exceptions" upon a showing of low probability of occurrence (and low consequence) of specific Category C events.

Please explain your choice:

☐ Comments:

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

☐ Yes

☒ No

☒ Comments:

Since many of the transmission plans are dependent upon factors such as, resource plans, local load projections, new technology, permitting, to name a few, it would not be meaningful to report on the status of implementation of a transmission plan. In any case, if a potential transmission problem is not solved, it will show up again in subsequent years, so there will be pressure to solve it. This continuous "certification" would ensure that any potential transmission problem, once identified, would not be left unsolved even without NERC requiring status reports on implementation.

3. If your answer to question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan?

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

The SAR drafting team believes that it is impractical to exhaustively test for every contingency described in each category plus every conceivable planned outage. Should the requirement to consider planned outages in addition to each Category A through D contingency remain part of this planning standard?

☐ Yes (consider planned outages in all Categories A through D).

☒ Yes (consider planned outages in some Categories only).

Please specify which Categories: A, B, and C (except C-3)

☐ No

☒ Comments: All contingencies where a single point of failure could cause facilities to be lost should be tested for compliance with the standards even under planned maintenance conditions. However, it should never be necessary to exhaustively test every possible combination of outages. Those contingencies that are clearly not critical outages should not have to be simulated.

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

☒ Comments: The existing NERC Standard C-9 (and C-2 for bus sectionalizing breakers) as it applies to WECC should be modified so that thermal limit and voltage limit violations are allowed for bus sectionalizing breaker failures. However, under no conditions should system instability or cascading outages be allowed for bus sectionalizing breaker failures.

6. Do you have any other comments on the SAR?

– ☒ Comments: On Page SAR-5 of the draft SAR, the third bullet states: "The Standard should allow for the development and use of probabilistic planning methods. The minimum requirements of probabilistic methods are the contingencies as described in Table 1 of existing Planning Standard I.A. There should be NERC approval of acceptable levels of risk."

–

It appears to us that as written, the standard that flows from this SAR can only allow the probabilistic planning methods to make the standard more, not less, stringent than the existing Standard IA. This is not the way probabilistic planning methods should work. This statement also does not make sense when you read the next sentence, "There should be NERC approval of acceptable levels of risk." If the standard can only be more stringent, then there is no need for NERC to approve the level of risk, or even the probability of occurrence of the contingency. One way to resolve this issue would be to change the word "minimum" to "starting".

The NERC Planning Standards should follow what WECC is doing with regard to listing disturbances as a guide, but say that other disturbances with the same probability should be included. List the probability ranges (outages per year), Category B: >= 0.33, Category C: 0.33 to 0.033; Category D1 (no cascading): 0.033 to .0033, Category D2: < .0033.

The standard should allow for changes in the required performance for given disturbances if a probability in another range has been established for a given disturbance.

NERC should specify voltage dip and minimum frequency standards similar to WECC (i.e., the voltage dip and minimum frequency should be within Applicable Ratings). We are not proposing that NERC set fixed values for these standards that would be the same throughout the ten NERC Regions.

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Note: Questions refer to the 6 questions posed to industry on the SAR Comment Form, posted with SAR Version 2. Some of the question statements listed in this Table of Contents have been abbreviated or paraphrased from their original form. Question statements are shown in their entirety in the body of this document.

BACKGROUND

The Standard 500 **S**tandard **A**uthorization **R**equest **(SAR)**, "Assess Transmission Future Needs and Develop Transmission Plans", was posted for a second public comment period from May 5 through June 5, 2004. The SAR Drafting Team (DT) asked industry participants to provide feedback on the revisions made to the SAR through a special Comment Form posted with the SAR (Version 2).

The SAR (Version 2) Comment Form posed 6 questions, some of which were multi-part. There was a total of 28 sets of comments returned, with 121 individuals responding. The industry comments can be viewed in their original format at:

ftp://www.nerc.com/pub/sys/all_updl/standards/sar/TRNS_NDS_&_PLNS_DT_01_02_Comments.pdf

The Standard 500: "Assess Transmission Future Needs and Develop Transmission Plans" SAR Drafting Team met and considered each of the sets of responses to the questions posed with the SAR (Version 2) Comment Form. The questions were aimed at gathering feedback on the changes made (or proposed to be made) to the SAR.

In consideration of these industry comments, the SAR DT drafted a third version of the SAR for consideration by the Standards Authorization Committee (SAC). The SAR (Version 3), if accepted by the SAC, will serve as specifications for a Standards Drafting Team to draft the new Standard 500. The Standards Drafting Team will have access to all industry comments made on the SAR (Version 2), and well as the SAR DT's consideration of these comments.

FORMAT OF THIS DOCUMENT

In this document, comments from industry participants are shown under each question, along with the SAR Drafting Team's summary of results and consideration of the comments, provided in blue text immediately under each question.

In most cases, a single response has been provided to show how the comments were considered. In some cases, the SAR DT provided a short note to indicate how a unique comment was considered.

At the end of this document there is an Industry Commenter Key listing each entity, industry segment (e.g., Transmission Owner, Generator, ISO, etc.) and the individual names of those responding via the SAR Comment Form.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give EVERY comment serious consideration in this process! If you feel there has been an error or omission, you can contact John Twitchell in the NERC office. John can be reached at 609-452-8060 or at John.Twitchell@nerc.net. Or you can contact this SAR's DT's Facilitator, Margaret Stambach at 518-384-1062 or at mr.stambach@ieee.org.

QUESTION 1(A): DO YOU BELIEVE THAT THE EVENTS IN TABLE I OF EXISTING PLANNING STANDARD I.A ARE CLASSIFIED CORRECTLY?

Question in its entirety:

1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

(a). Do you believe that the events in Categories B, C & D are classified correctly? Comments?

SUMMARY:

YES (entities)	21	NO (entities)	5
YES (individuals)	76	NO (individuals)	42
	NO definitive answer	1 (1 entity, 1 individual) - AEP	

Consideration by the SAR DT:

The SAR DT is recommending a review of existing Table I, including the likelihood, duration and impact of events, as well as the definition of applicable ratings (A/R). This review may result in a re-classification of Table I events for the new Standard. The review may also result in other changes, such as addition or deletion of categories, events or performance requirements, use of probabilistic planning methods, or re-naming of categories based on event probability ranges.

Entities responding YES to Question 1(a) – the events in Table I are classified correctly:

AES, AESO, ALLEGHENY, ATC, CWLP, DUKE, ENTERGY, ERCOT, IMO, ISONE, ISO/RTO, KCPL, MAAC/Horakh, MAAC/Kuras, NPCC, NYSRC, R.Snow, SCGEM, SERC, SOUTHERNCO, SPP, TVA, WESTAR (21 entities, 76 individuals).

SOME ENTITIES RESPONDING YES TO QUESTION 1 (a) [THE EVENTS ARE CLASSIFIED CORRECTLY] HAD THE FOLLOWING ADDITIONAL COMMENTS:	
AESO:	Generally the B and C events are classified correctly. However, there is a need to reconsider the grouping of the D events on some consistent basis (e.g. such as using outage frequency as a determinant). There should also be some means to include double-circuit lines and buses as B events if their probability of outage is comparable to that of other category B contingencies.
ENTERGY, SERC, SOUTHERNCO, SCGEM:	Entities listed believe that Category C events are more likely to occur than Category D events and should require higher performance expectations.
MAAC/Horakh	Categories B, C and D should be renamed as follows – Category B – High Probability Contingency Event

	Category C – Medium Probability Contingency Event Category D – Low Probability Contingency Event The difference in the categories should NOT be stated in terms of how many elements are out of service, but rather should be stated in terms of the PROBABILITY of the initiating event that occurs. The difference in the categories is in the "stress" the system is allowed to experience and in the "fix" required. For B, a high probability event, stress should be low and the only fix allowed is system reinforcement. For D, a low probability event, severe system stress is allowed, and system reinforcement is not mandated. C is somewhere in between, a medium probability, with medium system stress permitted, and some loss of load and/or curtailment of transfers allowed in lieu of system reinforcement. Table I can then be simplified by removing the column labeled "Elements Out of Service", because it is unnecessary and not relative. Actually, the columns labeled "Thermal Limits", "Voltage Limits", "System Stable" and "Cascading Outages" can be eliminated too, because they are the same for each Category A, B and C (but notes for each column should be retained).
MAAC/Kuras:	I believe that an in depth investigation of the probability of each possible contingency occurring be investigated by NERC to determine each contingency's relative probability and those results used to re-rank the contingency list, if necessary.
R.Snow:	Without a rigorous Probabilistic Risk Analysis, moving any of these events to a category D event is bad practice. All of the events have occurred at one time or another, especially circuit breaker and bus faults. Moving them to a category D essentially removes them from requiring action to mitigate/solve the impact on reliability.
WESTAR**:**	"Loss of single component without a fault" should become Category B5 and be included in the listing of items in category C3 *{See similar comments: SPP comment under Question 4, Choice (2) and KCPL comment under Question 4, Choice (3)}.*

QUESTION 1(B): IF YOUR ANSWER TO THE ABOVE QUESTION IS NO, HOW WOULD YOU RE-CLASSIFY THE EVENTS?

Question in its entirety:

1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

(a). Do you believe that the events in Categories B, C & D are classified correctly?

(b). If your answer to (a) is No, how would you re-classify the events? If you have data to support your answer, please provide contact information for the individual responsible for the data.

SUMMARY: 5 entities (42 individuals) answered NO to Question 1(a) and therefore responded to Question 1(b).

Also included in this section are two miscellaneous comments on whether events are classified correctly: one comment from AEP, who had no definitive answer to Question 1(a), and one comment from MAPP, who answered NO to Question 1(a).

Consideration by the SAR DT:

The SAR DT is recommending a review of existing Table I, including the likelihood, duration and impact of events, as well as the definition of applicable ratings (A/R). This review may result in a re-classification of Table I events for the new Standard. The review may also result in other changes, such as addition or deletion of categories, events or performance requirements, use of probabilistic planning methods, or re-naming of categories based on event probability ranges.

Entities responding NO to Question 1(a) – the events in Table I are NOT classified correctly:

AMEREN, BPA, MAPP, MEC and WECC (WECC-1 plus WECC-2). (5 entities, 42 individuals)

ENTITIES RESPONDING TO QUESTION 1(b) [i.e., ENTITIES RESPONDING NO TO QUESTION 1(a) - THE EVENTS ARE NOT CLASSIFIED CORRECTLY]	
Ameren	All category C outages that have a direct impact on serving load because of the system configuration (straight bus or tapped load) should be reclassified, including C-1, C-2, C-5, and C-9 to provide more latitude. For category C events, we should be more concerned that the system holds together and not that the local load may be at risk for these multiple contingency events.
BPA	Outage categories C1, C2 and C9 do not appear to be classified correctly as verified by the attached *outage probability data.* There is consistency between the categories except that C1, C2 and C9 outages have a much lower probability of occurrence than the other Category C outages. ***{See Attached Companion Document: Excel File – "BPAdata". Or contact: Marv Landauer, (503) 230-4105, mjlandauer@bpa.gov}***
MAPP & MEC	MAPP and MEC would reclassify certain low probability events such as Category C1 events, C2 events, certain Category C3 events (two transformers, transmission circuit plus a transformer, two transmission circuits, DC line plus a transformer, DC line plus a transmission circuit, and two DC lines), C6 events, C7 events, C8 events, and C9 events to either a new

	category between C and D with performance characteristics between that of the present Categories C and D or to Category D. *[MEC supports creating a new category between C & D].* MAPP and MEC would require that the interconnected transmission system be planned, designed, and constructed to protect for instability, cascading, and uncontrolled separation for the low probability events in the new sub-category. Regions should develop procedures for determining that systems are properly protected for instability, cascading and uncontrolled separation. MAPP & MEC believe the attached *outage probability data* supports this new reclassification by demonstrating that the events that MAPP & MEC recommend for reclassification are the low probability Category C events. ***{See Attached Companion Document: Word File – "MAPP-MECdata". Or contact: Tom Mielnik, (563) 333-8129, tcmielnik@midamerican.com}***
MEC	MidAmerican Energy believes the interconnected transmission system should be planned, designed, and constructed to withstand high probability events and to withstand low probability events with significant negative consequences. MidAmerican believes it is a waste of the ratepayers' money to plan, design, and construct the interconnected transmission system for low probability events without significant negative consequences.
WECC-1 & WECC-2	The Categories should be based on the probability of occurrence of the initiating events. A review of Table I (Standard I.A) shows that the contingencies in the same Categories seem to have very different probabilities of occurrence.
WECC-1	Category D needs to be split into two categories, the more probable Category D events should not be allowed to cascade. For example, the new "No Cascading" category should include: Loss of 2 units at a plant Loss of adjacent lines in a right of way Loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker. There is no defined performance level for 3 phase fault, stuck breaker, and loss of one line. For support of this position, see the NERC/WECC Planning Standards
WECC-2	A new category should be defined between Category C and Category D. The more probable Category D events and the less probable Category C events should be placed in this new category and not be allowed to cascade. This WECC group supports moving C.2 and C.9 to a new Category between the current C and D Categories. WECC Planning Standards do not support reclassification of C.3.

MISCELLANEOUS COMMENTS ON WHETHER EVENTS ARE CLASSIFIED CORRECTLY	
AEP	Need to see outage probability data in order to answer definitively. Based on good data, the probabilities of existing C and D events could be estimated. The events could then be grouped into higher probability events

	(Category C) and lower probability events (Category D). AEP would be able to provide some outage data to support this analysis. ***{Contact Ali Al-Fayez, Manager – Transmission Asset Performance (614 552-1649)}***
MAPP:	The definition of applicable ratings needs to be clarified. The SAR DT should also indicate if it is feasible to have different applicable ratings for different categories of events. The SAR DT should review the history of the original classification. This review should include all classes. If outage statistics are used to classify events, how many years of data are appropriate? If the data window is too small, the results will be skewed. Moreover, is it appropriate to use outage data for all these categories of events? Outage data over a long period of time may provide insight into equipment performance, but is it appropriate to reflect weather related contingency events – the data may not reflect the effect of a once in a 100 year storm? **Consideration by the SAR DT:** *The SAR DT is recommending that the new Standard clarify ambiguities in performance requirements, specifically cascading outages and A/R. We are also recommending the new Standard clarify that different ratings may be applicable to different categories of events, and perhaps to different types of events within a category (specified by entities in accordance with STD 600).*

QUESTION 1(C): WHICH APPROACH DO YOU FAVOR?: (1) KEEP THE SAME CATEGORIES AND RE-CLASSIFY CERTAIN EVENTS AS CATEGORY D, (2) CREATE A NEW CATEGORY BETWEEN C & D, (3) KEEP THE SAME CATEGORIES AND ALLOW FOR GOOD CAUSE EXCEPTIONS.

Question in its entirety:

1. Some members of the SAR drafting team believe that certain Category C events, as defined in Table 1 of existing Planning Standard I.A, are much less likely to occur than other events in Category C. It is felt that certain specific Cat. C events could be re-classified as Cat. D upon showing a low probability of occurrence (and low consequence) of these events.

(c). Which of the following approaches do you favor regarding Table 1 of existing Planning standard I.A?
(1) Keep the same categories as now exist and re-classify the low probability (and low consequence) events as Category D events. Please explain your choice.
(2) Create a new category between C and D with performance characteristics between that of the present categories C and D. Please explain your choice.
(3) Keep the same categories as now exist, but allow for "good cause exceptions" upon showing a low probability of occurrence (and low consequence) of specific Category C events. Please explain your choice.

SUMMARY:

Entities supporting Choice (1)	4 (9 individuals)
Entities supporting Choice (2)	7 (46 individuals)
Entities supporting Choice (3)	6 (24 individuals)
Entities supporting NONE of the choices	11 (44 individuals)

Consideration by the SAR DT:

The SAR DT is recommending a review of existing Table I, including the likelihood, duration and impact of events, as well as the definition of applicable ratings (A/R). This review may result in a re-classification of Table I events for the new Standard. The review may also result in other changes, such as addition or deletion of categories, events or performance requirements, use of probabilistic planning methods, or re-naming of categories based on event probability ranges.

Since there was no clear consensus on how to address re-classification of events, the SAR DT feels that a thorough review of existing Table I will assure that events are properly classified for the new Standard.

Entities supporting Choice (1) – keep same categories and re-classify certain events as Cat. D

AEP, AMEREN, CWLP, MAPP (4 entities, 9 individuals)

ENTITIES SUPPORTING CHOICE (1) – KEEP SAME CATEGORIES AND RE-CLASSIFY CERTAIN EVENTS AS CATEGORY D	
AEP	Four categories are sufficient and generally understood by the industry. Specific changes that are supported by outage probabilities can be made, as appropriate, by moving Category C tests to Category D.
AMEREN	Reclassify C-1,C-2, and C-9 to category D (less probable events). C-3 (line and a generator combination) should be reclassified as category B event (more probable than other C-3 events. Also, why is a loss of a tower line with two circuits category C (C-5) while loss of a tower line with 3 circuits is category D (D-6), though a probability of loss of a tower line may be the same ? We may want to be consistent in categorizing the event – loss of a multi-circuit tower line.
CWLP	(No explanation given.)
MAPP	If the events are low probability, then some should be considered for moving to C or D.
MISCELLANEOUS COMMENT ON CHOICE (1) – KEEP SAME CATEGORIES & RE-CLASSIFY CERTAIN EVENTS AS CATEGORY D	
MEC	MidAmerican does NOT support this choice, since MEC believes that reclassifying less likely Category C events as Category D events will result in planners ignoring low-probability contingencies that result in significant consequences: cascading, uncontrolled separation, and instability.

Entities supporting Choice (2) – create new category between C & D.

AESO, BPA, CWLP, MAAC/Kuras, MAPP, MEC, WECC (WECC-1 plus WECC-2). (7 entities, 46 individuals)

ENTITIES SUPPORTING CHOICE (2) – CREATE A NEW CATEGORY BETWEEN C & D	
AESO	There are D contingencies that are probable although rare (e.g. loss of multiple circuits on separate tower lines on a common right-of-way). These contingencies may result in loss of load or generation but should not allow cascading. Other D contingencies such as loss of all lines on a multi-line corridor or the loss of a complete station would be difficult to contain. These events should be treated differently than the former.
BPA	The C2 (with respect to a bus section breaker failure) and the C9 outages should be in this new category. Although these outages have extremely low probability, they should not cause cascading. This is especially true of C2, which is a single contingency failure of a bus section breaker. Therefore we favor adding a new category between Level C and D (or moving these two outages to Level D) with performance requirements of no cascading and system stable but with no requirement to be within applicable ratings. ***[See similar comment from WECC-2 under Question 5, Regional Differences]***

CWLP	Multiple contingencies have lower and varying probabilities of occurrence.
MAAC/Kuras	This is the best choice of the ones mentioned here but see my comment in 1.(a) above for another approach. This approach allows for some levels of performance between C and D such as restricting the performance to "no cascading or system instability" for some C and maybe even D events.
MAPP & MEC	Improvements should be planned for those Category C events that are high probability events regardless of the consequences. Planners should also review all Category C events for instability, cascading, and uncontrolled separation. Improvements should be planned for those Category C events (both high probability and low probability events) which have significant consequences, that is, that result in instability, cascading, and uncontrolled separation.
MEC	The approach that results in the most appropriate transmission system design is the one recommended by MEC. It is MEC's belief that the intent of the drafting team that originally developed the existing NERC Planning Standards was to require the NERC member to plan to protect for instability, cascading, and uncontrolled separation for Category C events.
WECC-1 & WECC-2	A "No Cascading" performance requirement is needed for this new category. There are Category C events, which have a very low probability of occurrence. Such events, even if they occurred, should not lead to cascading, even though local facility ratings or voltage limits may be exceeded. Very often, the solution for such low probability contingencies would be to install a relay system to interrupt load or generation. The probability of relay misoperation to prevent potential problems resulting from the contingency may be higher than the probability of the contingency itself. Thus the impact on the users of the grid may not be significantly reduced. Nevertheless, the system reliability would be better served if we can add a category for such low probability contingencies (which would not result in cascading), and the risk of which is acceptable.

Entities supporting Choice (3) – keep same categories and allow for good cause exceptions.

ATC, BPA, DUKE, KCPL, SPP, TVA, WESTAR. (6 entities, 24 individuals).

{Note: BPA not counted in this choice. BPA counted in Choice (2) "New Category", since that is their preferred choice}

ENTITIES SUPPORTING CHOICE (3) – KEEP SAME CATEGORIES AND ALLOW FOR GOOD CAUSE EXCEPTIONS	
ATC	The outages listed in the existing categories are reasonable but, because we don't know all the specific details about a certain part of the system, there should be some mechanism to consider exceptions.
BPA	Although this is not our preferred choice, allowing the use of "good cause exceptions" (which we assume is the same as probabilistic methods which could move contingencies to a lower performance level although this is inconsistent with other statements in the SAR) to verify exceptions to the present categories would also be acceptable. For the C2 example, showing that these events statistically occur every 1200-1300 years and would not cause cascading problems on the system should provide enough evidence that a lower performance level is appropriate.

DUKE	Allow the flexibility for reasonable exceptions to the general categories based on frequency of occurrence. This may mean the possibility of a particular contingency moving up or down in category. This allowance permits appropriate exercise of engineering judgment in the planning process.
KCPL	KCPL supports the recommendation that the Standard should allow for the development and use of probabilistic planning methods in reliability assessment. However, KCP&L does not support any reclassification of the existing Categories. The probability of occurrence of some contingencies may, in actuality, be very low. However, this should not diminish the importance of their assessment in the Category that they are currently found.
SPP	SPP would like to see a definition of "good cause exceptions" at a minimum. SPP encourages the development of probabilistic techniques to assess reliability but caution needs to be exercised prior to implementation to ensure support from all stakeholders.
TVA	This "good cause exception" approach allows documentation of an assessment of low consequence to substitute for the expenditure of an unwarranted solution, but maintains the integrity of the event probability assessment. Since others may have different ideas of what is low probability, this approach would be best with sufficient justification of low probability.
WESTAR	Once an analysis has been performed, a subsequent "assessment" can easily dismiss low consequence events. However, low probability with high consequence should not be granted an exception. The initial premise of the Planning Standards did not contemplate probabilistic or Monte Carlo analysis. "Good Cause Exception" must be carefully defined before entities are allowed to shield high consequence events regardless of probability of occurrence.
MISCELLANEOUS COMMENTS ON CHOICE (3) - KEEP SAME CATEGORIES & ALLOW FOR GOOD CAUSE EXCEPTIONS	
AEP	"Good cause exceptions" can always be considered, but this approach should not be institutionalized.
MAPP & MEC	MAPP & MEC believe that allowing for "good cause exceptions" is not the preferable approach. We believe that the events listed by MAPP & MEC for reclassification are much less likely than the other Category C events generally throughout NERC. This means that these events should be reclassified in general throughout NERC and not just in certain "good cause exceptions". (Although, it should be noted that MAPP & MEC do support Regional Differences where appropriate.) Besides, there are issues associated with the development and utilization of a process for approving "good cause exceptions".
NYSRC	In accordance with the NERC process for developing reliability standards, an entity may include a Regional Difference as part of the NERC standard if there is such a condition. Therefore, there is no need for the standard to include "good cause exceptions".

Entities supporting NONE of the 3 choices:

ENTERGY, ERCOT, IMO, ISONE, ISO/RTO, MAAC/Horakh, NPCC, NYSRC, SCGEM, SERC, SOUTHERNCO, (11 entities, 44 individuals).

ENTITIES SUPPORTING NONE OF THE CHOICES - NO CHANGES TO CATEGORIES/EVENTS	
ENTERGY, SCGEM, SERC, SOUTHERNCO	Since the events are currently categorized correctly, above Questions 1 (b) and 1 (c) are not applicable. Entities listed agree that low consequence Category C events should be considered compliant. However, as we interpret Table I, a Category C event that results in low consequences (e.g. no cascading) is already considered compliant since entities can drop load or curtail firm transfers to return to applicable thermal or voltage ratings.
ERCOT, IMO, ISONE, ISO/RTO, NPCC, NYSRC	Any of the above three choices would weaken the present NERC standards. All entities listed take the position that there should be No Changes to Categories B, C, and D as they now exist in the present Planning Standards.
MAAC/Horakh	NONE OF THE ABOVE. Keep the three categories, but rename them as in 1.a. above. Adding an additional category would introduce too much confusion in planning the system. Assuming that the contingencies in B, C and D are already in their correct probability categories, no changes need to be made. If someone could prove that a contingency in B is Low Probability the same as the contingencies in D, that contingency could be moved.

QUESTION 2: DO YOU BELIEVE THE STANDARD SHOULD REQUIRE REPORTING ON *IMPLEMENTING* THE TRANSMISSION PLANS?

Question in its entirety:

2. Do you believe the standard should include requirements for reporting on the progress or status of *implementing* the plans developed in accordance with this standard?

SUMMARY:

YES (entities)	13	NO (entities)	13
YES (individuals)	60	NO (individuals)	53
	NO definitive answer	1 (1 entity, 7 individuals) - MAPP	

Consideration by the SAR DT:

There was no clear consensus on whether reporting on the progress or status of implementing the plans should be included in the Standard. This SAR Drafting Team is recommending that the new Standard address requirements for reporting (perhaps to the Regions) on the progress or status of implementing the plans, but such requirements should not impose undue burdens upon transmission entities.

Any such reporting requirements shall be consistent with the Resource & Transmission Adequacy's RTATF Recommendation #2: "Among other items, the new Reliability Standards should clearly define the key elements of an acceptable mitigation plan to achieve compliance with the standard(s) and a general process to ensure implementation of the mitigation plan".

Entities responding YES to Question 2 – the standard SHOULD require implementation reporting.

AEP, AMEREN, BPA, IMO, ISONE, ISO/RTO, ERCOT, KCPL, MAAC/Horakh, MAAC/Kuras, NPCC, NYSRC, R.Snow, SPP, WESTAR (13 entities, 60 individuals)

SOME ENTITIES RESPONDING YES TO QUESTION 2 [THE STANDARD SHOULD REQUIRE IMPLEMENTATION REPORTING] HAD THE FOLLOWING ADDITIONAL COMMENTS:	
AEP	The reporting requirements should not be burdensome, but they are needed to ensure a minimum level of accountability.
AMEREN	The reporting requirement should not be onerous.
BPA	A plan without a requirement to update progress on implementing the plan has little value. This is essential for an effective standard. This should not be an extensive reporting procedure and could easily be met during the subsequent compliance report.
KCPL	KCP&L supports a requirement for reporting the status of implementing the mitigation plans. On a regional basis, mitigation plans should be reported by the Transmission Planner, as a minimum, on an annual basis through the regional model building process and assessed through the regional

	assessment studies performed by the Regional Reliability Coordinator.
MAAC/Kuras	It's one thing to develop plans and another to follow through on them. PJM can offer suggestions on how this tracking could be accomplished.
R.Snow	Developing plans without a follow up program is a waste of time and money. One of the most telling comments from the August Blackout report was that a number of the items were the same as in other blackouts.
SPP	SPP supports this reporting requirement, but notes that this burden should not be imposed more frequently than annually.
WESTAR	Having a "plan" that is not implemented is of no value.

Entities responding NO to Question 2 – the standard SHOULD NOT require implementation reporting.

AES, AESO, ALLEGHENY, ATC, CWLP, DUKE, ENTERGY, MEC, SCGEM, SERC, SOUTHERNCO, TVA, WECC-1, WECC-2 (13 entities, 53 individuals)

SOME ENTITIES RESPONDING NO TO QUESTION 2 [THE STANDARD <u>SHOULD NOT</u> REQUIRE IMPLEMENTATION REPORTING] HAD THE FOLLOWING ADDITIONAL COMMENTS:	
AES	AES does not favor an implementation report. However, major facility additions, delayed additions, or deletions that effect the reliability of the system could be included as part of the regional form 715 base case yearly filings and listed as changes from last year's cases. This would allow older cases to easily be updated and used.
AESO	It is not clear to whom the reporting would go to and how it would be used. Normally, reporting would be required for the regulatory process in the affected jurisdiction. The scope of that reporting would not be limited to reliability only but also other aspects of the transmission plan (e.g. customer connections, efficiency improvements, etc).
ATC	While an entity should be implementing plans to maintain or improve the reliability required by the standards, having to report on the implementation could become quite complicated. Plans are often changing to meet changing system conditions, sometimes so much so that what seemed reasonable to do last year is replaced by entirely new plans.
MEC	MidAmerican Energy believes that this standard should not include requirements for reporting on the progress or status of implementing the plans developed in accordance with this standard. There are too many conditions beyond the control of the NERC member for this to be a part of a standard requiring compliance review. Complex environmental, regulatory, and political issues prevent many transmission facilities from being constructed or being constructed in a scheduled manner. The Not-In-My-Back-Yard philosophy has hit even the rural areas so that there is no part of the NERC area where a NERC member can confidently predict completion of transmission system improvements in plans. Further, conditions can change even during a year to such an extent that compliance review for implementation from one year to the next is problematic. Further, regulatory oversight provides for appropriate review of plan implementation anyway. MidAmerican urges that the SAR drafting team not pursue this well-meaning but problematic approach.

SCGEM, SOUTHERNCO	Too burdensome for the perceived benefits.
TVA	This reporting would constitute a logistical burden counterproductive to the total planning effort.
WECC-1 & WECC-2	Since many of the transmission plans are dependent upon factors such as, resource plans, local load projections, new technology, permitting, to name a few, it would not be meaningful to report on the status of implementation of a transmission plan. In any case, if a potential transmission problem is not solved, it will show up again in subsequent years, so there will be pressure to solve it. This continuous "certification" would ensure that any potential transmission problem, once identified, would not be left unsolved even without NERC requiring status reports on implementation.

MISCELLANEOUS COMMENT ON WHETHER THE STANDARD SHOULD REQUIRE IMPLEMENTATION REPORTING (Neither Yes/No Box Checked)	
MAPP	Requirements for reporting on the progress or status of implementing the plans should be left to the regions and appropriate regulatory bodies. The MAPP Regional Transmission Committee currently has a regional planning process for compliance for implementing transmission plans.

QUESTION 3: IF YOUR ANSWER TO *QUESTION 2* IS YES, HOW WOULD YOU PROPOSE ACCOUNTING FOR CHANGES IN A TRANSMISSION PLAN?

Question in its entirety:

3. If your answer to Question 2 is Yes, given that transmission plans change over time as modeling assumptions, systems and plans change, how would you propose accounting for changes in a Transmission Plan?

SUMMARY: 13 entities (60 individuals) answered YES to Question 2 and therefore responded to Question 3.

Consideration by the SAR DT:

There was no clear consensus on whether reporting on the progress or status of implementing the plans should be included in the Standard. This SAR Drafting Team is recommending that the new Standard address requirements for reporting (perhaps to the Regions) on the progress or status of implementing the plans, but such requirements should not impose undue burdens upon transmission entities.

Any such reporting requirements shall be consistent with the Resource & Transmission Adequacy's RTATF Recommendation #2: "Among other items, the new Reliability Standards should clearly define the key elements of an acceptable mitigation plan to achieve compliance with the standard(s) and a general process to ensure implementation of the mitigation plan".

Entities responding YES to Question 2 (The standard SHOULD require implementation reporting) and therefore responding to Question 3 (How would you account for changes in a Transmission Plan?).

AEP, AMEREN, BPA, ERCOT, IMO, ISONE, ISO/RTO, KCPL, MAAC/Horakh, MAAC/Kuras, NPCC, NYSRC, R.Snow, SPP, WESTAR (13 entities, 60 individuals)

ENTITIES RESPONDING TO QUESTION 3 – HOW WOULD YOU PROPOSE ACCOUNTING FOR CHANGES IN A TRANSMISSION PLAN? [i.e., ENTITIES RESPONDING YES TO QUESTION 2 - THE STANDARD SHOULD REQUIRE IMPLEMENTATION REPORTING]:	
AEP	A simple narrative explanation should be provided that explains what factors have eliminated the need for the transmission modification/addition or changed its timing. In cases where a modified solution has been developed, the Transmission Planner should demonstrate the effectiveness of the modified approach and compare to the original approach.
AMEREN	Provide the following: (i) Annual update with a short note to document changes. (ii) Smaller projects (cap bank addition, change of terminal equipment like switches, wavetrap, or CT) may be combined as a group in such reporting to avoid providing a long list of updates.
BPA	Once a transmission plan is identified in a compliance report, progress on that project should be reported in subsequent compliance reports. If system conditions change, this should be described along with the consequences to the proposed plans. If project need goes away, the project can be canceled.

	However, if the project need still exists and the responsible entity has not implemented a plan to correct the deficiency, it should be listed as non-compliant. Legitimate problems with regulatory and siting issues should be acceptable reasons for project delay.
ERCOT, IMO, ISONE, ISO/RTO, NPCC	All entities listed favor periodic transmission reviews to address changes in plans. In the northeast, the NPCC Annual Transmission Reviews address this and in addition NPCC keeps a "Major Projects List" to "track" BPS additions and modifications and includes transmission, generation and other major equipment identified as a BPS element. The entities suggest that the resultant NERC standard not be overly prescriptive in requirements for reporting progress/status on the standard and flexibility be afforded to allow various documentation and processes already in place to achieve compliance. They suggest it be done annually.
KCPL	Any out-of-cycle changes to the mitigation plan should be reported to the Reliability Coordinator and re-evaluated on an as-needed basis. Coordinated planning between other regions and entities will be critical.
MAAC/Horakh	Reporting should be on a "delay" basis. Known delays to the plan should be reported, along with the reason for the delay and use of alternate solutions.
MAAC/Kuras	A plan is a plan at that point in time. Plans change. Periodic checks of implementation of plans can uncover these plan changes that should be allowed.
NYSRC	Updated transmission plans should be reported along with compliance assessments as required.
R. Snow	When there is a significant change in the assumptions, the plan needs to be re-studied and revised as appropriate. The SAR must require such re-studies. Any plan is only as good as its assumptions. Whenever there is a significant change in the assumptions, the plan needs to be revised to account for the change. Having a plan that assumes there will be specific generation projects is worthless when those specific projects are changed, canceled or if other generation retires.
SPP	Although SPP is implementing a 2 year planning cycle, project updates are collected on an annual basis. To ensure compliance with reliability criteria, mitigation reviews are also provided on an annual basis consistent with the annual model building process. Updates due to new "out of cycle" projects or significant scope/timing changes associated with major projects in the approved regional expansion plan and its assessments are evaluated on an as-needed basis. Coordinated planning and model building using consistent definitions with neighboring regions/entities will be critical. Efforts should be undertaken to put data collection, modeling building and transmission assessment processes for neighboring regions/entities on the same cycles.
WESTAR	In the annual process to update power flow models, there are necessarily changes to the load forecast, use of the interconnected network, and financial constraints which must be taken into account. Reporting to the Regional Reliability Organization should include a discussion of substantive changes and reasons behind them. There should not be a judgment made by the RRO that the explanation is "adequate" so long as the explanation is made. The changes are critical information that must be taken into account when evaluating transmission service requests. Reporting should not be more frequent than the model-building cycle.

QUESTION 4: SHOULD THE REQUIREMENT TO CONSIDER PLANNED OUTAGES IN ADDITION TO EACH CONTINGENCY REMAIN PART OF THIS PLANNING STANDARD?

Question in its entirety:

4. Existing Planning Standard I.A requires: *"The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed".*

The SAR drafting team believes that it is impractical to exhaustively test for every contingency described in each category plus every conceivable planned outage. Should the requirement to consider planned outages in addition to each Category A through D contingency remain part of this planning standard?
(1) Yes, consider planned outages in all Categories A through D.
(2) Yes, consider planned outages in some Categories only – Please specify which Categories.
(3) No, do not consider planned outages in addition to each contingency in any Category.

SUMMARY:

Entities supporting Choice (1)	6 (16 individuals)
Entities supporting Choice (2)	15 (76 individuals)
Entities supporting Choice (3)	8 (27 individuals)

Miscellaneous Comment (No choice selected) – 1 entity (2 individuals) - Seminole

Consideration by the SAR DT:

The SAR Drafting Team believes there is confusion surrounding the planned outage requirement in Table I of the existing standard. The SAR DT is recommending that the new Planning Standard clarify the issue of how a planned outage should be used in a planning assessment.

The new Standard should specify whether the planned outage requirement should be retained for Categories B and C. If retained, the requirement should be clarified in such a way that it can be practically implemented. In particular, the Transmission Planner should not be required to exhaustively test their systems for every conceivable planned (including maintenance) outage in addition to every conceivable Category B and C contingency.

The new Standard should clarify that the planned outage requirement does not apply to Categories A and D.

Entities supporting Choice (1) – consider planned outages in ALL Categories A through D.

ERCOT, ISO/RTO, NYSRC, MAAC/Kuras, TVA (half of group), WESTAR (6 entities, 16 individuals)

ENTITIES SUPPORTING CHOICE (1) – CONSIDER PLANNED OUTAGES IN ALL CATEGORIES A THROUGH D	
ERCOT, ISO/RTO, NYSRC	Again, the existing standards should not be weakened.

MAAC/Kuras	Contingencies don't only happen when all lines are in service. Outages should be modeled during all types of contingency evaluation. This may be a fairly daunting task but this evaluation will help the system operators be prepared for the reality of operating the system in a less than ideal state. Possible ways to select lines to outage may be to look at lines with high unscheduled outage rates, lines close to sources of contamination, lines through areas that have historically had vegetation contact problems, and especially lines that when outaged can cause operating problems.
TVA	**{Half of group}.** Everyone in the group agreed that planned outages should be considered, but the group didn't agree on which categories to apply. About half believed they should be applied to all categories while the other half believed only A and B categories should have planned outages studied for the one year and beyond horizon.
WESTAR	The notion of including maintenance outages is to ensure that system restorations correctly evaluate single elements that would be removed in groups under a breaker-to-breaker outage analysis. The intent should not be to have any single element out for maintenance AND withstand the next contingency and should be stated as such.

Entities supporting Choice (2) – consider planned outages in SOME Categories only.

AEP, AESO, ALLEGHENY, CWLP, ENTERGY, IMO, ISONE, MAAC/Horakh, NPCC, R. Snow, SCGEM, SERC, SOUTHERNCO, SPP, TVA (half of group), WECC (WECC-1 plus WECC-2). (15 entities, 76 individuals)

ENTITIES SUPPORTING CHOICE (2) – CONSIDER PLANNED OUTAGES IN <u>SOME</u> CATEGORIES.	
AEP	**{B, C & D only}.** For Categories where planned maintenance is considered, it should only be necessary to test the most significant planned outages, not all possible planned outages.
AESO	**{A, B & C only}.** There is a need to clarify what constitutes the "normal" condition when a facility (transmission or generation) is on a long duration planned outage (is it a day, a week, etc). The A to C contingency categories can then be applied to the "normal" condition as defined. The testing requirement could perhaps be stated in a way that leaves it to the judgment of the Planning Authority as to the critical combinations of outages that need to be tested.
ALLEGHENY	**{A & B only}.** Allegheny Power feels that it is practical to consider planned outages in categories A and B.
CWLP	**{B and some C}.** No further comments.
ENTERGY	**{B & C only}.** It is not necessary to include planned maintenance outages in addition to Category A (no contingencies) because Category A plus planned outages equals Category B (single contingency). Therefore inclusion of maintenance outages in Category A is superfluous. The current standards do not require planned outages with Category A for that very reason. Maintenance outages should be considered for only Category B and C contingencies. Category D recognizes that cascading will occur in conjunction with the contingencies, so adding on more planned outages seems unnecessary,

	especially since Category D outages are very low probability events.
IMO, ISONE, NPCC	**{A, B & C only}.** We reiterate that the existing standards should not be weakened and request that the SAR be clarified to remove ambiguity regarding what is meant by "considering" a planned outage. Planned outages at present are considered however this is deemed an Operational Planning issue and is conducted so as to set Operational Limits for those conditions on a pre-contingency basis to allow for N-1 conditions. This particular SAR will ultimately result in a "planning" Reliability Standard. The wording, as it has been phrased, infers that the system must be planned, designed and built to N-2 standards (i.e. a line out for maintenance on top of a circuit element outage). Treatment of planned outages should be considered to some extent and the listed entities suggest the drafting team receive direction from the SAC regarding planned outages. The listed entities suggest that planned outages should be considered only in categories in A through C.
MAAC/Horakh	**{A & B only}.** Consider planned outages in Categories A & B only, since these categories are high probability and therefore could easily occur during a planned outage.
R.Snow	**{A, B & C only}.** Categories A through C should be considered. Category D does not require action so the analysis with outages does not add anything. Most planning software allows the sue of scripts to run multiple analysis without intervention. The state of modern computers is such that the added testing is not significant. Also, for most systems, this type of analysis is performed to define which load levels and generation dispatch would allow the maintenance (the problem in reverse).
SCGEM, SOUTHERNCO	**{A & B only}.** The requirement to consider planned outages in addition to each Category A and B contingency should remain part of this planning standard. We agree with the SAR drafting team that exhaustive testing for every contingency described and every load level in each category is not practical.
SERC	**{A & B only}.** The SERC PSS agrees that the requirement to consider planned outages in addition to each Category A and B contingency remain part of this planning standard. The SERC PSS could not reach consensus on the requirement to consider planned outages in addition to each Category C and D contingency. However, the SERC PSS does agree that exhaustive testing for every contingency described in each category is not required. The I.A compliance templates state that they must *"Be performed and evaluated only for those Category [B, C, and D] contingencies that would produce the more severe system results or impacts."*
SPP	**{B & C only}.** C.3. needs to be modified to address N-1-1 concerns. Category B (B1, B2, B3 or B4, including loss of an element without a fault) or in the alternative create Category B5 to Loss of an element without a fault. The latter is preferred. *[See similar comments - KCPL comment under Question 4 Choice (3) below, and Westar comment under Question 1(a) above]* Planned outages are typically not evaluated more than one year in advance and are not scheduled during peak load conditions. However, the existing Planning Standard 1.A is problematic in that it requires the system to be designed to accommodate planned outages during peak load conditions.
TVA	**{A & B only – half of group}.** Everyone in the group agreed that planned

	outages should be considered, but the group didn't agree on which categories to apply. About half believed they should be applied to all categories while the other half believed only A and B categories should have planned outages studied for the one year and beyond horizon.
WECC-1 & WECC-2	**{A, B & C (except C-3)}.** All contingencies where a single point of failure could cause facilities to be lost should be tested for compliance with the standards even under planned maintenance conditions. However, it should never be necessary to exhaustively test every possible combination of outages. Those contingencies that are clearly not critical outages should not have to be simulated.

Entities supporting Choice (3) – do NOT consider planned outages in addition to each contingency in any Category.

AES, AMEREN, ATC, BPA, DUKE, KCPL, MAPP, MEC (8 entities, 27 individuals)

ENTITIES SUPPORTING CHOICE (3) – DO NOT CONSIDER PLANNED OUTAGES IN ADDITION TO EACH CONTINGENCY IN ANY CATEGORY.	
AES	I would modify C-3 since it has the same effect as or similar to a C-3 event to include (line out followed by a category B event).
AMEREN	Is the issue planning the system or granting the outage? Local load may be exposed for granting a maintenance/construction outage, but the system should not be at risk. If the system is planned with category C requirements, in most cases it should meet category A and B requirements during a planned outage. To meet requirements of categories A and B during planned outage should be adequate. Planned outages for maintenance or construction are generally managed in the operating horizon, and are granted only during specific load levels (off-peak), generation patterns, and interchange patterns when the transmission system is not expected to be fully utilized. We agree that clarification should be provided on how this information should be used in an assessment. However, as the scope of planning assessments is for the planning horizon of one year or more (SAR-4, paragraph 2) and not the operating horizon, we do not believe that the requirement for planning for maintenance outages should be included in planning assessments.
ATC	Planning the system should consider the need for planned outages but should not require the capability to plan outages at peak system loads.
BPA	This requirement should be addressed in operational planning studies (less than one year). This standard is not appropriate for Transmission Planning studies except possibly as a tool to measure or compare the robustness or availability of transmission plans. This is not an item that should require any compliance action.
DUKE	The first priority should be to clarify the requirements of the I.A table. Utilities/ regions are interpreting the table differently. What was the original basis for the contingency categories and required response in the table? Clarify whether the original intent was to perform thermal, voltage and stability screens for all categories and the frequency at which the screenings were intended to performed. It is impractical to expect all screenings of all categories on a frequent basis. It may be appropriate to state that the table is for general guidance and that

	transmission owners may determine frequency at which studies should be performed based on load growth, system loading and significance of changes to the system.
KCPL	Planned outages are typically short-term (less than 1 year) and should be considered in the operating horizon. A planned outage is typically allowed during system load conditions when they will have minimal impact on the system. KCPL would prefer to clarify the existing Category B contingency that states "Loss of an element without a fault" be listed as the B5 contingency on the Table. Then, in Category C under Contingency 3, the revised wording should read "3. Category B (B1, B2, B3, B4, or B5) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, B4, or B5) contingency. This will allow for the first contingency to include a planned outage (B5 without a fault) as well as a contingency with one of the fault conditions described in B1, B2, B3, and B4. {*See similar comments - Westar comment under Question 1(a) and SPP comment under Question 4, Choice (2).*}
MAPP & MECC	Planned Outages can be scheduled and analyzed in advance in the operating horizon (less than one year). Therefore, it should not be necessary to require that "systems must be capable of meeting Category C requirements while accommodating the planned outage of any bulk electric equipment..." Planned outages should be studied in advance by the requesting control area and be reviewed by the governing Reliability Coordinator to determine if overloads could occur. If studies show that overloads could occur, the planned outage should be deferred or operating guides prepared which would be used in the event a contingency does occur.
MEC	There is no need to plan or build facilities to meet Planning Standard 1.A when Planned Outages can be accommodated within the frame work of existing guidelines and procedures. Studies conducted for the operating horizon are not the subject of this standard.

MISCELLANEOUS COMMENT ON CONSIDERING PLANNED OUTAGES – (No Choice Selected)	
SEMINOLE	Many grid operations difficulties occur when a line is scheduled out for maintenance. If this SAR is going to address required N-2 planning assessments, then it must be clear and specific regarding the conditions when N-2 assessments are appropriate and the specific criteria for N-2 assessments.

QUESTION 5: ARE YOU AWARE OF ANY REGIONAL OR INTERCONNECTION DIFFERENCES IN REQUIREMENTS FOR ASSESSING AND PLANNING TRANSMISSION SYSTEMS IN NORTH AMERICA?

Question in its entirety:

5. Are you aware of any Regional or Interconnection differences in the requirements for assessing and planning transmission systems in North America? If so, please list and explain.

SUMMARY: 10 entities (68 individuals) responded to this question and gave examples of Regional/Interconnection differences.

Consideration by the SAR DT:

The SAR Drafting Team considered each comment individually, as shown in the table below.

Entities responding to Question 5 – are you aware of any Regional/Interconnection differences?

BPA, CWLP, KCPL, NYSRC, SCGEM, SEMINOLE, SOUTHERNCO, SPP, R, Snow, WECC (WECC-1 plus WECC-2), WESTAR. (10 entities, 68 individuals)

ENTITIES RESPONDING TO QUESTION (5) – ARE YOU AWARE OF ANY REGONAL/INTERCONNECTION DIFFERENCES?	
BPA	Although WECC has several requirements in its standards that are more stringent than the existing NERC criteria, it also has two standards that are less stringent (C2 and C9). Depending on the resolution of question #1 above, C2 and C9 may be a regional difference. WECC has a formal Probabilistic Planning process that allows adjustment of performance levels of contingencies in either direction. As this SAR states that the existing NERC Table I is the minimum criteria for probabilistic methods, this will be a regional difference for WECC. This is discussed more in our comments on the SAR document. **Consideration by the SAR DT** *The present SAR no longer states that existing Table I is the minimum criteria for probabilistic methods, only that Table I should be used as a starting point for a review of the existing standard. Thus, probabilistic planning could allow for adjustment of performance requirements in either direction.* *The SAR DT is recommending that the review of the existing standard include the likelihood, duration and impact of events, as well as the definition of applicable ratings (A/R). This review may result in a re-classification of Table I events for the new Standard. The review may also result in other changes, such as addition or deletion of categories, events or performance requirements, use of probabilistic planning methods, or re-naming of categories based on event probability ranges.* *Since there was no clear consensus on how to address re-classification of events, the SAR DT feels that a thorough review of existing Table I will assure that events are properly classified for the new Standard.* *If differences in the classification of events or performance requirements remain after the draft Standard is posted, please provide your specific*

	comments at that time
CWLP	WECC has asked the NERC PC for waivers for some of the Category C requirements. **Consideration by the SAR DT** *See the SAR DT response to WECC-1 & WECC-2 in this table.*
KCPL	KCPL is aware of neighboring regional council differences in classification of Category B and C contingencies between SPP and MAPP. **Consideration by the SAR DT** *The SAR DT is recommending a review of existing Table I, which may result in a re-classification of Table I events for the new Standard. The review may also result in other changes, such as addition or deletion of categories, events or performance requirements, use of probabilistic planning methods, or re-naming of categories based on event probability ranges.* *Since there was no clear consensus on how to address re-classification of events, the SAR DT feels that a thorough review of existing Table I will assure that events are properly classified for the new Standard.* *If differences in the classification of Category B and C contingencies remain after the draft Standard is posted, please provide your specific comments at that time.*
NYSRC	It is the NYSRC's position that (1) NERC specifies minimum standards, (2) a Region may establish more stringent standards for its members separate from the NERC standards, and (3) it is unnecessary to include these more stringent standards within the framework of the NERC standards. **Consideration by the SAR DT** *The SAR DT agrees with this position.*
SCGEM, SOUTHERNCO	Not aware of any at this time. However, Regional Differences could develop and each request for a Regional Difference should be considered individually. **Consideration by the SAR DT** *The SAR DT agrees with this position.*
SEMINOLE	In Florida, with the state requirements for the siting of facilities, the planning horizon should be adjusted from 5 YRS to 8 YRS. The 5 YR horizon is too short for some major transmission line projects and/or studies of transmission interconnections/upgrades for base load central station generating facilities. **Consideration by the SAR DT** *The present SAR provides for a planning horizon of 5 years or more.*
SPP	SPP is aware of differences between SPP and the neighboring regions of ERCOT, MAPP and WECC. **Consideration by the SAR DT** *If differences remain after the draft Standard is posted, please provide your specific comments at that time.*
R. Snow	Each region has their own requirements.

	Consideration by the SAR DT *Each Region has the right to request Regional differences for approval as part of the Standard.*
WECC-1 & WECC-2	The existing NERC Standard C-9 (and C-2 for bus sectionalizing breakers) as it applies to WECC should be modified so that thermal limit and voltage limit violations are allowed for bus sectionalizing breaker failures. This is because bus sectionalizing breaker failure is a relatively low probability event. Use of a bus sectionalizing breaker should be encouraged because it reduces the impact of a disturbance to a portion of the load only. Without the proposed modification there is no incentive to use the sectionalizing breaker. However, under no conditions should system instability or cascading outages be allowed for bus sectionalizing breaker failures. **Consideration by the SAR DT** *The SAR DT is recommending a review of existing Table I, including the likelihood, duration and impact of events, as well as the definition of applicable ratings (A/R). This review may result in a re-classification of Table I events for the new Standard. The review may also result in other changes, such as addition or deletion of categories, events or performance requirements, use of probabilistic planning methods, or re-naming of categories based on event probability ranges.* *Since there was no clear consensus on how to address re-classification of events, the SAR DT feels that a thorough review of existing Table I will assure that events are properly classified for the new Standard.* *If differences in the classification of events or performance requirements remain after the draft Standard is posted, please provide your specific comments at that time.*
WESTAR	Yes. MAPP categorizes some contingencies differently. **Consideration by the SAR DT** *The SAR DT is recommending a review of existing Table I, which may result in a re-classification of Table I events for the new Standard. The review may also result in other changes, such as addition or deletion of categories, events or performance requirements, use of probabilistic planning methods, or re-naming of categories based on event probability ranges.* *Since there was no clear consensus on how to address re-classification of events, the SAR DT feels that a thorough review of existing Table I will assure that events are properly classified for the new Standard.* *If differences in the categorization of events remain after the draft Standard is posted, please provide your specific comments at that time.*

QUESTION 6: DO YOU HAVE ANY OTHER COMMENTS ON THE SAR (V2)?

Question in its entirety:

6. Do you have any other comments on Version 2 of the SAR? Please list and explain.

SUMMARY: Most of the 28 entities (121 individuals) responded to this question and provided additional comments on the SAR (Version 2).

Consideration by the SAR DT:

The SAR Drafting Team considered each comment individually, as shown in the tables below.

The additional comments were divided into the following headings:

- *General – Is there a need for this SAR? How will this SAR fit in with the new Version 0 Standards? Will the existing standards be weakened?*
- *Scope of Standard*
- *Planning Horizon*
- *Use of Operating Procedures*
- *Transition Between Operating & Planning Standards*
- *Functions to Which the Standard Applies*
- *Applicable Portions of Existing Standards*
- *System Models*
- *Resource Planning*
- *Use of Generation or Load as Solutions*
- *Formatting of the SAR*
- *Demand Levels for Modeling*
- *Definition of Terms*
- *Variability of Load & Generation*
- *Probabilistic Planning Methods*
- *Planned Outages*
- *Applicable Ratings*
- *Short Circuit Current*
- *Other Areas that Should be Added or Clarified*

GENERAL COMMENTS ON THE SAR (VERSION 2)

ATC	The SAR drafting team seems to have its arms around the issues and seems ready to proceed to Standard development. **Consideration by the SAR DT** *The SAR DT agrees with this position and appreciates the vote of confidence.* On p. 3 of the SAR, Market Interface Principles, Question 5 stating that the Standard will not require public disclosure of commercially sensitive information: Depending on the level of public exposure of the load flow and stability models, generation cost data and stability parameter data may be deemed by some entities as confidential market information. **Consideration by the SAR DT** *This SAR does not establish the level of public exposure of data. The Standard Drafting Team will determine these requirements. Please submit your comments at the time of the draft Standard posting.*
IMO, ISONE, NPCC	The entities listed believe that the relationship between the concept of the Version 0 Standards and all the developing Version 1 Standards needs to be consistent. The reliability attributes of the Version 0 standards must be "carried through and into" the Version 1 Standards and there needs to be coordination to ensure this occurs. **Consideration by the SAR DT** *There will certainly be changes between V0 and the developing V1 Standards (V1 will be a revision of V0) but these changes must be approved by the industry, thus assuring carry-through and acceptance of reliability attributes.*
IMO, ISONE, NPCC, NYSRC	It is the opinion of NYSRC, ISONE, IMO, and the Northeast Power Coordinating Council's CP9 working group participating members that the existing NERC criteria should not be weakened, including the NERC Planning Standards listed in the SAR as the starting point to be used in drafting a new standard. Our comments support our position that the existing Planning Standards should not be weakened. **Consideration by the SAR DT** *The majority of industry comments have indicated that this SAR is needed to consider content changes in existing Standards. There will be changes between the Version 0 standards (existing standards with formatting changes) and the developing Version 1 standards (V1 will be a revision of V0), but these changes must be approved by the Industry.* *All parties will have an opportunity to participate in the Standard drafting process, including commenting on the draft Standard. Concerns that changes made may weaken the Standard should be brought up at that time.*
NYSRC	<u>With the advent of the Version 0 standards, we believe that there is no longer a need for this SAR.</u> The comments in the "Consideration of Industry Comments" paper indicate that comments received in 2002 on SAR Version 1 were in favor of a standard on transmission assessment and planning, which was the SAR DT's reason for preparing this SAR. However, the Version 0

	standards development process will now provide a transmission planning standard, without requiring the preparation of this new SAR. Despite this position, if the DT does get sufficient support to go forward with a new standard, NYSRC has additional comments, as shown below. **Consideration by the SAR DT** *Version 0 Standards are intended to re-format the existing Standards without changing content, using Functional Model terminology. The majority of industry comments have indicated that this SAR is indeed required to consider content changes in existing Standards.* The relationship with the Version 0 standards should be recognized in the SAR, including the mechanism of how this "Version 1" standard would replace Version 0. **Consideration by the SAR DT** *Version 0 Standards are intended to re-format existing Standards without changing content, using Functional Model terminology. The present SAR uses these existing approved Standards as a starting point to consider content changes for a new Planning Standard. There will be changes between V0 and the developing V1 standards (V1 will be a revision of V0), but these changes must be approved by the Industry.*
SPP	Implementation of this SAR needs to be coordinated with the activities of the Version 0 Standards Drafting Team. **Consideration by the SAR DT** *See our response to NYSRC above.*
WESTAR	How will this SAR integrate with Version 0 Standards? **Consideration by the SAR DT** *Version 0 Standards are intended to re-format the existing Standards without changing content, using Functional Model terminology. The present SAR uses these existing approved Standards as a starting point to consider content changes for a new Planning Standard.*

COMMENTS ON SCOPE OF STANDARD

AESO	The SAR drafting team should clarify through rules, tests, definitions, etc. the portion of an entity's transmission system that shall be planned under the full NERC Standard and what portion may be exempted. **Consideration by the SAR DT** *All NERC Standards apply to the bulk electric power system.* *The SAR DT felt that the definition of "bulk transmission" is an issue too large to be handled by one DT alone, and should be defined at a higher level. Accordingly, the SAR DT referred this issue to the NERC Director of Standards.*
IMO, ISO/RTO	This standard should make it abundantly clear that it applies to both internal and external systems, that is the system under study and adjacent systems, or the entire interconnection if appropriate. **Consideration by the SAR DT** *The SAR DT agrees with this position. If the commenter believes the Standard does not sufficiently address this issue, we encourage the commenter to provide specific language to address this concern when a draft Standard is posted.*
SEMINOLE	The SAR should require joint transmission planning - at a minimum, joint transmission planning should be required between transmission service providers and their network service customers. **Consideration by the SAR DT** *Based on industry feedback to the first posting (V1) of the SAR, this present SAR indicates the Standard will identify reliability performance requirements, but not specify how to achieve such requirements. Joint planning is one way to achieve the reliability requirements, and is neither precluded nor required by this SAR.*

COMMENTS ON THE PLANNING HORIZON

ALLEGHENY	This paragraph and the next **(the 2nd & 3rd paragraphs of posted SAR-Version 2)** are unclear and appear to be conflicting. This first paragraphs specifies that the "scope of such assessments and plans is for a planning horizon of one year or more". The next paragraph specifies, "Assessments should cover a planning horizon of at least 5 years". This appears to be a conflict. It may be that the term "planning horizon" is being used differently in these two paragraphs. It is unclear to us what is the intention of the first of these two paragraphs. **Consideration by the SAR DT** *As a result of your comment, the present SAR has been clarified to indicate that the planning period starts at one year and extends to 5 years or more.*
NYSRC	**From SAR Version 2:** "……..The planning horizon must be long enough to permit timely implementation of viable solutions to remedy the potential inadequacies found. Assessments should cover a planning horizon of at least 5 years. The horizon may be longer than 5 years, based on regulatory or legislative requirements, or on the judgment of the Transmission Planner or Planning Authority……" In paragraph above, 2nd sentence, insert "and plans" after "Assessments". The last sentence is not needed. A Region or other entity may have more stringent requirements than NERC – therefore, such a statement is not needed. **Consideration by the SAR DT** *The SAR DT agrees and accepts your first comment for inclusion in the revised SAR. The SAR DT decided to retain the last sentence in the referenced paragraph to clarify the requirement about the planning horizon.*
R. Snow	While some of the information about generation additions and load growth are considered reliable for five (5) years, a long-term study of approximately ten (10) years is necessary to identify global issues such as import limitations to a region that would require projects that have traditionally taken more than five (5) years. Suggest the following wording: *"Assessments shall cover a detailed planning horizon consistent with available information but no less than five (5) years. The five year horizon shall include load growth, new internal and external firm generation, generation retirements/failures, uncontrollable loop flows, reliance on external generation (identify both firm and market), topology changes, and firm transactions. A longer term study using a variety of scenarios that are expected to cover the most likely long term activity, shall be conducted to identify projects that take longer than five years to implement."* **Consideration by the SAR DT** *The SAR DT considered your alternative wording to be overly prescriptive. However, in the present SAR, the wording has been changed to clarify that the planning horizon extends to 5 years or more.*
SEMINOLE	In Florida, with the state requirements for the siting of facilities, the planning horizon should be adjusted from 5 YRS to 8 YRS. The 5 YR horizon is too short for some major transmission line projects and/or studies of transmission interconnections/upgrades for base load central station generating facilities. **Consideration by the SAR DT** *In the present SAR, the wording has been changed to clarify that the planning*

	horizon extends to 5 years or more.

COMMENTS ON USE OF OPERATING PROCEDURES

AMEREN	" …there is no intent to exclude appropriate operating procedures…". What is "appropriate"? Could generation redispatch be an appropriate operating procedure? If yes, what level of redispatch is appropriate? The standard should include a definition of "appropriateness" of operating procedures so that they are developed and applied on a uniform and consistent basis. **Consideration by the SAR DT** *The SAR DT believes it to be problematic to produce an exhaustive list of all appropriate operating procedures. Furthermore, industry feedback to the first posting (V1) of the SAR indicated a strong industry preference for the Standard not to specify how to achieve the reliability requirements. However, if you believe the draft Standard, when posted, does not sufficiently address this issue, please submit your comments at that time.*
MAPP	MAPP is concerned that the SAR does not limit manual or automatic readjustments for certain lower probability or low consequence events. MAPP urges that the SAR drafting team add additional provisions to require the drafting team to consider which manual and automatic readjustments are allowed and when in meeting the criteria that is included in the standards. **Consideration by the SAR DT** *See the SAR DT response to AMEREN, above.*
R. Snow	***From SAR Version 2:*** "……..While the planning horizon is intended to provide for facility additions, there is no intent to exclude appropriate operating procedures from the transmission plan……..." Replace this sentence with "The planning horizon is intended to provide for facility additions. Operating procedures shall not be used as a substitute for good system design and shall only be applicable during maintenance outages and while facilities are being constructed." *[The original language would allow what was identified as the root cause of the Italian blackout. Namely, an operating procedure that had to be executed within 15 minutes. The operator had to call another area and ask them to perform an operating procedure. The procedure was underway but did not happen fast enough to avoid the next line trip. Operating procedures should never be a long term substitute for constructing facilities needed to assure reliability.]* **Consideration by the SAR DT** *Industry feedback to the first posting (V1) of the SAR indicated a strong industry preference for the Standard not to specify how to achieve the reliability requirements. Therefore, the SAR DT did not accept your suggestion. However, when the draft Standard is posted, feel free to submit your comments at that time.*

COMMENTS ON TRANSITION BETWEEN PLANNING & OPERATING STANDARDS

BPA	*Transition to Operating Standards:* The Planning Standards include multi-layered requirements for different types of outages, i.e., Level B single contingencies, Level C and D multiple contingencies. Compliance with these requirements is to be defined and monitored via the new Reliability Standards. However, once the system moves into the Operational timeframe (one year or less), Policy 2 presently requires meeting N-1 contingencies only with no requirements for Levels C and D. The transition between planning and operations needs further exploration. **Consideration by the SAR DT** *As a result of your comment and others, the present SAR has been revised to require that the new Standard consider the transition between operating and planning standards. In particular, the new Planning Standard will be coordinated with other standards, such as Standard 600, "Determine Facility Ratings, Operating Limits and Transfer Capabilities", which also applies to operations.*
MAPP & MEC	MAPP & MEC are concerned that the SAR does not provide for the coordination of the requirements of the planning standards in NERC Standard 500, "Assess Transmission Future Needs and Develop Transmission Plans", with the NERC Operating Standards provided in NERC Standard 600, "Determine Facility Ratings, Operating Limits, and Transfer Capabilities." The criteria that are proposed as a starting point for 500 in this SAR (events from Categories A through D) differ from the criteria that are included in the latest draft of NERC Standard 600 (Categories A and B). If these approaches are continued, then studies run for the operating horizon will differ significantly from studies run for the planning horizon. These differences in studies will carry over to the calculation of quantities used to offer transmission service, that is, Total Transfer Capacity and Available Transmission Capacity. If NERC does not coordinate these two standards, there will be a discontinuity in TTC and ATCs when the Planning Horizon begins and the Operating Horizon ends or from one day less than one year to one year. MAPP & MEC urge the SAR drafting team to consider this discontinuity and coordinate the SAR for 500 with the Standard that is being written for 600. If a discontinuity between criteria is allowed to continue in the SAR for Standard 500, the SAR drafting team should have a clear explanation for all market participants as to the reason for the discontinuity and how that should be dealt with by the elements of the NERC Functional Model. **Consideration by the SAR DT** *See the SAR DT's response to BPA above.*

COMMENTS ON FUNCTIONS TO WHICH THE STANDARD APPLIES

AMEREN	**From SAR Version 2:** "…….The Standard shall identify reliability requirements, but shall not specify how to achieve such requirements. These requirements shall apply to Transmission Planners and to Planning Authorities……..." Should the requirements be applied to Transmission Owners also? **Consideration by the SAR DT** *Yes. After reviewing your comment, we deleted the last sentence of the referenced paragraph, since page 2 of the SAR already lists TO as a function to which the Standard applies.*
R. Snow	The standards should apply to Transmission Owners, Transmission Operators, Transmission Planners, anyone who is connecting facilities to the transmission system, control areas, and reliability coordinators. ***Consideration by the SAR DT*** *After reviewing your comment, we deleted the last sentence of the referenced paragraph. On SAR page 2 is a list of functions to which the Standard applies. The functions listed are: RA, PA, TP, TO, LSE. This list is consistent with the Functional Model.*

COMMENTS ON APPLICABLE PORTIONS OF EXISTING STANDARD

NYSRC	***From SAR Version 2:*** "……The applicable portions of the following existing NERC Planning Standards will be used as the starting point in drafting these requirements: • I.A Transmission Systems • I.B Reliability Assessment • I.D Voltage Support & Reactive Power • II.A System Data • II.D Actual and Forecast Demands……." Define "applicable portion". List the specific standards and measurements that are intended to be used as the starting point. ***Consideration by the SAR DT*** *The SAR DT believes this level of specificity is not needed in a SAR. If this concern is not addressed in the posted draft Standard, please feel free to submit your comments at that time.*
R. Snow	***From SAR Version 2:*** "……The applicable portions of the following existing NERC Planning Standards will be used as the starting point in drafting these requirements: • I.A Transmission Systems • I.B Reliability Assessment • I.D Voltage Support & Reactive Power • II.A System Data • II.D Actual and Forecast Demands……." Add the following after the bullets. *"In addition to the above, the standard shall provide requirements on methodology of forecasting and normalizing load. This would include methods of determining the normalized load over a large geographic area with different weather patterns and norms. The "normalized" load should not be the load associated with the median weather over a summer or winter period but the load level that will provide sufficient reliability to supply all firm load obligations. Each region shall provide a definition as to what is sufficient reliability. The definition shall clearly define the risk that is being assumed in terms similar to the LOLE for lack of generation. In addition to the above two risk variables, a methodology shall be identified to quantify the risk of not being able to deliver the difference between the local load and generation. This is essentially the ability of the transmission system to respond to different generation dispatch patterns."* ***Consideration by the SAR DT*** *The SAR DT believes this level of specificity is not needed in a SAR. If these concerns are not addressed in the posted draft Standard, please feel free to submit your comments at that time.*
SCGEM	It would also be beneficial to the generation sector if the SDT for this new Planning Standard could summarize the differences between the existing Planning Standards I.A, I.B, I.D, II.A, and II.D and the new Planning Standard as it is being developed. This would gauge the potential impact to the plants. The main concerns have been 1) how to address regional differences (primarily related to Category C events), 2) how to differentiate Table I's application to the Planning world versus the Operations world, and 3) how to state the requirements more clearly. ***Consideration by the SAR DT*** *Since the revised Standard has not yet been drafted, the summary you*

	requested cannot be provided at this time. This summary comparison will be addressed in the Implementation Document that accompanies the new Standard.
SEMINOLE	The SAR should define specific planning voltage criteria for consistency between transmission owners/providers. Voltage Criteria should be specifically defined for normal condition and N-1 conditions and can be specified differently for: • Bulk power - non-load serving buses • Meshed/Looped - load serving buses • Radial - load serving buses ***Consideration by the SAR DT*** *The SAR DT believes this level of specificity is not needed in a SAR. If this concern is not addressed in the posted draft Standard, please feel free to submit your comments at that time.*

COMMENTS ON SYSTEM MODELS

AESO	We believe that the assumptions made for the amount, type and location of future supply are important considerations in assessing the future needs of transmission systems. The SAR drafting team should consider this forecast requirement in developing this Standard. Similarly, there is difficulty in separating planning for reliability and planning for overall system efficiency and economy, and the Standard must be clear on this differentiation. ***Consideration by the SAR DT*** *The SAR DT believes the present SAR addresses most of these concerns. With regard to your last concern, the SAR DT believes there is not always a clear differentiation between reliability, efficiency & economy considerations. However, NERC standards primarily focus on reliability and do not directly address efficiency & economy considerations. If you have specific suggestions after the draft Standard is posted, please comment at that time.*
AMEREN	We believe that for planning of robust transmission systems, the Standard should include (1) some incremental transfer capability requirement in addition to what is "projected" or modeled in the base case, (2) a combination of a line and a generator outage should be included in category B. ***Consideration by the SAR DT*** *With regard to (1) the SAR requires each Planning Authority and Transmission Planner to document the methodology for incorporating planned generation assets in the model. In response to your comment, the present SAR has been revised to specify that the methodology for incorporating planned generation assets (including transfers) must be documented. However, the SAR DT believes any specific incremental transfer capability requirement in the new Standard would be overly prescriptive.* *With regard to (2), the Standard Drafting Team will be reviewing the likelihood, duration and impact of events, as well as performance requirements of the existing Table I Categories. If this issue is still a concern when the draft Standard is posted, please submit your comments at that time.*
AMEREN	Why document and disclose methodologies limited to planned generation only? What about planned transmission and interchange? Is it because there is more uncertainty for speculative generation than transmission? What about differences in modeling details required for different type of analyses, such as thermal or voltage, regional or local? It is our experience that more detailed representation (lower voltage facilities) is required for voltage analysis than thermal analysis. Perhaps the standard should state that additional detail may need to be added to the model to adequately represent the system for specific studies. ***Consideration by the SAR DT*** *In response to your comment, the present SAR has been revised to require documentation of modeling assumptions, including generation modeling assumptions. The SAR DT highlighted generation assumptions because the SAR DT believes such assumptions are particularly important. Furthermore, given unbundling of generation resources from transmission in some areas, we believe there is considerable additional uncertainty in these assumptions,*

	both with regard to new generating units and dispatch of new and existing units.
ATC	New standard needs to consider the difficulties, particularly for stand-alone transmission companies, in obtaining resource information so models can balance load and resources. ***Consideration by the SAR DT*** *The present SAR does indicate that the Standard shall require that system models be developed, maintained and shared in a manner consistent with the Functional Model. The SAR also states that the Standard shall consider a requirement for LSEs to provide forecast resource data for input to the models. If the commenter has specific suggestions to further address this concern, please provide specific suggestions when the draft Standard is posted.*
KCPL	In regards to developing accurate regional models, all known firm transmission service, including rollover provisions for all firm transmission service, should be included in the base case models. ***Consideration by the SAR DT*** *The SAR DT believes this provision does not need to be in the SAR for the new Standard. Rollover provisions for firm transmission service is a FERC tariff issue that does not apply to entities outside of FERC's jurisdiction. Therefore, the SAR DT believes this provision would be overly prescriptive.*
MAPP	MAPP is concerned that there is no reference in the SAR to the need to handle firm contracts that may roll-over in the futures. Plans developed for the transmission system must recognize that the transmission system must have sufficient capacity to handle roll-overs. MAPP urges the SAR drafting team to include an appropriate description of the requirement for the plans with regard to roll-overs. ***Consideration by the SAR DT*** *The SAR DT believes this provision does not need to be in the SAR for the new Standard. Rollover provisions for firm transmission service is a FERC tariff issue that does not apply to entities outside of FERC's jurisdiction. Therefore, the SAR DT believes this provision would be overly prescriptive.*
R. Snow	**From SAR Version 2:** "……..The Standard shall require that system models be developed, maintained and shared in a manner consistent with the Functional Model. Included will be requirements that each Planning Authority and Transmission Planner document and disclose the methodology used for incorporating planned generation assets in the model, as well as how such generation is dispatched. While methodologies and assumptions must be documented, the Standard will not prescribe specific tools to be used in the performance assessment of the planned systems……" Replace the last sentence with *"while the standard will not prescribe specific tools, it shall identify methodologies to validate and procedures to operate the tools so that the identified outcomes from the analysis are not dependent on the tool or the way the tool was used or initialized."* ***Consideration by the SAR DT*** *Industry feedback to the first posting (V1) of the SAR indicated a strong industry preference for the Standard not to specify how to achieve the*

	reliability requirements. Therefore, the SAR DT did not accept your suggestion.
SCGEM, SOUTHERNCO	In relation to the methodology being used for incorporating planned generation assets in the model and how generation is dispatched: the type of each generating unit, the primary fuel type for each generating unit, and a dispatch order of the generating units should be required. In addition, a general description of the dispatch methodology used for the system should also be required. However, no cost information should be required. ***Consideration by the SAR DT*** *The SAR DT believes the referenced language addresses this concern by requiring system model sharing and documentation of generation modeling assumptions. The SAR DT agrees with the commenter that cost data should not be required because it would violate Market Interface Principle 5 (see SAR p. 3) which prohibits requiring the public disclosure of commercially-sensitive information.*
SEMINOLE	It is recommended that these models be "region-wide" system models that are developed utilizing a documented, consistent, region-wide criteria. ***Consideration by the SAR DT*** *The SAR DT believes this provision would be overly prescriptive.*

COMMENTS ON RESOURCE PLANNING

DUKE	Resource planning cannot be excluded from the standard. Guidance should be provided on incorporation of resource data from all LSE's and how resource deficiencies in outyear models should be handled (e.g. model fictitious generation with no reactive capability to ensure sufficient reactive resources are planned for if power is purchased from off system in the future). The increasingly frequent changes in resource designations are causing greater uncertainty in performance of planning for reliable system operation. ***Consideration by the SAR DT*** *The SAR DT agrees that generation resource modeling is an important data requirement for transmission assessment and planning. However, the SAR distinguishes resource information as an input to transmission planning studies from a requirement to assess and ensure the adequacy of generation resources (i.e., resource planning).* *The SAR DT believes it is an open issue as to what level of specificity the Standard should require for model building. If this issue is still a concern when the draft Standard is posted, please submit your comments at that time.* *Note: Whether to check the Resource Planning box on page. 2 of the SAR (as a function to which the Standard applies) has been deferred to the NERC Director of Standards.*
ENTERGY, SCGEM, SERC, SOUTHERNCO	Entities agree the Standard should not address resource planning. However, the Standard should include requirements for the LSEs to provide forecast resource data required to develop power flow models as required in the current II.D Standards. Accordingly, this new Standard should also apply to LSEs. (Thus, entities believe the "LSE" box on p.2 of SAR should be checked as an applicable function). ***Consideration by the SAR DT*** *The SAR DT believes commenters have raised a valid point. The SAR DT believes it is an open issue as to what level of specificity the Standard should require for model building. Therefore, the present SAR has been revised to indicate that the Standard shall consider a requirement for the Load Serving Entities to provide forecast resource data.* *Note: LSE box on page 2 of the SAR has also been checked.*
ENTERGY	In addition, the Standard should require the Transmission Planner to document and describe the methodology used to plan the transmission system around the generation dispatch assumptions used by the Transmission Planner to meet the LSE load when and if the LSE provided resources do not equal the LSE provided load. ***Consideration by the SAR DT*** *The SAR DT believes it is an open issue as to what level of specificity the Standard should require for model building. If this issue is still a concern when the draft Standard is posted, please submit your comments at that time.*
IMO, ISONE, NPCC	The entities listed recognize that Resource Planning is not covered in the proposed Standard because it is considered as being handled by market

	mechanisms that are/will be in place or perhaps addressed in a separate standard. Therefore, we assume that the generation and load information required to perform the planning studies are provided as described in section II.A of the existing Planning Standards. If not, sections II.B, II.E and III of the existing Planning Standards should also be used as the starting point in drafting of the reliability requirements. ***Consideration by the SAR DT*** *The SAR DT believes it is an open issue as to what level of specificity the Standard should require for model building. If this issue is still a concern when the draft Standard is posted, please submit your comments at that time.*
NYSRC	We agree that a transmission planning standard should not include Resource Planning requirements. However, the NYSRC strongly believes that NERC should develop a separate Resource Planning Standard. ***Consideration by the SAR DT*** *The Resource and Transmission Adequacy Task Force (RTATF) proposed and NERC accepted that a Resource Adequacy SAR should be developed.*
WECC-2	In order to develop any meaningful standard, the resource part of the power system should be addressed by including standards for the modeling of existing resources, planned retirement of resources, and planned resources in the next 5 to 10 years time frame. This information will be necessary in order to assess whether future systems can or can not meet the reliability standards. ***Consideration by the SAR DT*** *The SAR DT believes the present SAR as written addresses this concern. Specifically, the SAR requires the documentation and sharing of system models, including the methodology of incorporating planned generation assets in the model as well as how such generation is dispatched.*

COMMENT ON USE OF GENERATION OR LOAD AS SOLUTIONS

AMEREN	If generation is considered in lieu of transmission reinforcement, the system must be able to withstand the loss of that generation plus another single contingency. The reason for this is that generation can be on or off due to economic and other factors after its installation, while transmission is almost always "on". ***Consideration by the SAR DT*** *The SAR DT agrees with this position. The loss of a generating unit plus another single contingency is already an event against which transmission systems must be tested in the existing Standards, and the present SAR provides for the new Standard to use the existing Standards as a starting point. If this issue is still a concern when the draft Standard is posted, please submit your comments at that time.*

COMMENT ON SAR FORMATTING

ALLEGHENY	***From SAR Version 2:*** "……..While the Standard should start from and closely align with the existing Planning Standards I.A, .B, .D, II.A,.D, the system conditions to be studied or assessed may need to be better defined or clarified. For example, the Standard should clarify that the requirement to assess the performance at **all** demand levels does not mean that a multitude of transmission models need to be created for every possible demand level, only that a representative sample covering critical operating conditions needs to be modeled in accordance with regionally-defined criteria……..." This paragraph starting "While the Standard should start from…" has a problem with it's second sentence. The sentence "For example…" does not really apply to the first sentence. We recommend that this paragraph be changed as follows: *"While the Standard should start from and closely align with the existing Planning Standards I.A, .B, .D, II.A,.D, the system conditions to be studied or assessed may need to be better defined or clarified.* *Examples of areas that should be considered for clarification in the Standard include:* *The Standard should clarify that the requirement to assess the performance at ALL demand levels does not mean that a multitude of transmission models need to be created for every possible demand level, only that a representative sample covering critical operating conditions needs to be modeled in accordance with regionally-defined criteria.* *The Standard should provide a clearer definition of "cascading outages".** *And so on".* ***Consideration by the SAR DT*** *In response to your comment, we have revised the SAR to reflect the new formatting.*

COMMENT ON DEMAND LEVELS FOR MODELING

SEMINOLE	***From SAR Version 2:*** "……For example, the Standard should clarify that the requirement to assess the performance at **all** demand levels does not mean that a multitude of transmission models need to be created for every possible demand level, only that a representative sample covering critical operating conditions needs to be modeled in accordance with regionally-defined criteria……..." Regarding " … a representative sample covering critical operating conditions …" It is recommended that this standard include specific requirements; such as, at what load levels and how many different load levels is intended by this part of the SAR. A suggestion would be 100% and 80%, and perhaps the 60% load level. ***Consideration by the SAR DT*** *The SAR DT considered your suggestions for specific load levels to be overly prescriptive.*

COMMENTS ON DEFINITION OF TERMS

AMEREN	In addition to the definition of "cascading outages" , clarification is needed for identification of a cascading state. For example, we are not sure that assumption of some percent overload, say 125% of emergency rating, is a good proxy for cascading. ***Consideration by the SAR DT*** *The SAR DT agrees that a clearer definition of cascading outages (including what constitutes a cascading state) must be provided in the new Standard, and be fully coordinated with the definition in other new Standards. The present SAR has been revised accordingly.*
ERCOT, IMO, ISONE, ISO/RTO, NPCC	All entities listed suggest that the definition for Cascading Outage be fully coordinated with the STDs 200 and 600. ***Consideration by the SAR DT*** *The SAR DT agrees with this position. The SAR DT believes a clearer definition of cascading outages must be provided in the new Standard, and be fully coordinated with the definition in other new Standards. The SAR has been revised accordingly.*
IMO, ISONE, NPCC	NPCC has submitted a suggested definition of "cascading outage" in the comments for the last posting of STD 200, which is endorsed by the other entities listed: *Cascading Outage- "The uncontrolled successive loss of Bulk Electric System elements that propagate beyond a defined area (Balancing Area's) boundaries.""* ***Consideration by the SAR DT*** *The SAR DT agrees that a clearer definition of cascading outages must be provided in the new Standard, and be fully coordinated with the definition in other new Standards. Your specific suggestion is inconsistent with the definition in the latest version of STD 600. Please provide additional comments and suggestions when the draft Standard is posted.*
IMO, ISONE, NPCC	NPCC would also like to submit a proposed definition of Bulk Power System, as follows, and would like it to be considered as a "building block" for the NERC BES (Bulk Electric System) definition. The definition is endorsed by the other listed entities: *Bulk Power System-BPS-(or BES in NERC documents) — "The interconnected electrical systems within northeastern North America comprising generation and transmission facilities on which faults or disturbances can have a significant adverse impact outside of the local area. In this context, local areas are determined by the Council members."* ***Consideration by the SAR DT*** *The SAR DT feels that the definition of "bulk transmission" is an issue too large to be handled by one Drafting Team alone, and should be defined at a higher level. Accordingly, the SAR DT referred this issue to the NERC Director of Standards.*
NYSRC	***From SAR Version 2:*** "…….The Standard should provide a clearer definition of "cascading

	outages"……". Replace "provide" with "consider". ***Consideration by the SAR DT*** *The SAR DT retained the word "provide", since we believe a clearer definition of cascading outages must be provided in the new Standard, and be fully coordinated with the definition used in other developing Standards.* *The present SAR has been revised to require that definitions be coordinated and consistent with other Standards being drafted by NERC.*
SERC	The SERC PSS agrees that the Standard should provide a clearer definition of "cascading outages." In addition the SERC PSS recommends that the Standard provide a clearer definition of what is meant by "system stable." ***Consideration by the SAR DT*** *The SAR DT agrees, and the SAR has been revised to recommend that the new Standard provide a clearer definition of "system stable".*
SCGEM, SOUTHERNCO	In general, the NERC Standards need to have a common definition across the board for any definition used in a Standard. For example, the definition for "Cascading Outages" needs to be coordinated with the Standards Drafting Team (SDT) for the "Determine Facility Ratings, Operating Limits, and Transfer Capability" standard (STD 600). ***Consideration by the SAR DT*** *The SAR DT agrees with this position. The SAR DT believes a clearer definition of cascading outages must be provided in the new Standard, and be fully coordinated with the definition in other new Standards. The SAR has been revised accordingly.*
SCGEM, SOUTHERNCO	Southern agrees that the Standard should provide a clearer definition of "cascading outages." We suggest that the following be considered: *Cascading — "The uncontrolled successive loss of system elements triggered by contingencies which results in widespread electric service interruption 1) that drops 1000 MW of load or more or 2) that crosses control area boundaries."* In addition, Southern recommends that the Standard provide a clearer definition of what is meant by "system stable." We suggest that the following be considered: *System stable — "For Category A and B simulations, system stable means that no generating units pull out of synchronism. For Category C events, system stable means that if units pull out of synchronism, 1) the resulting impedance swings are not out into the transmission system and 2) the total amount of generation lost because of out-of-step tripping does not exceed the control area operating reserve level."* ***Consideration by the SAR DT*** *The SAR DT will pass these suggested definitions along to the Standard Drafting Team for consideration.*

COMMENTS ON VARIABILITY OF GENERATION & LOAD

IMO, ISO/RTO	Seasonal and weather related variability should be considered in studies. ***Consideration by the SAR DT*** *The SAR DT agrees with this position. We believe the present SAR as written takes into account seasonal and weather-related variations.*
MAPP	MAPP is concerned that there is no provision for recognizing the variability of generation in the SAR. MAPP asks the SAR drafting team to add another bullet to the SAR which states, "The Standard should take into account the variability of generation due to factors such as weather and time of day." ***Consideration by the SAR DT*** *The SAR DT agrees with this position. We have not added a bullet to the SAR, but rather have revised the existing bullet to take your suggestion into account.*

COMMENTS ON PROBABILISTIC PLANNING METHODS

AESO	The basis of probabilistic planning, in our view, is to make planning decisions based on the metrics, such frequency, duration and impact, derived from probabilistic assessments. This is usually difficult to do in planning the bulk portion of the transmission system, since outage events are rare but their impact is significant (like multiplying infinity and zero). The categorization of contingencies in Table 1 using outage frequency as a determinant is a step in applying probabilistic techniques in this Standard but it is not probabilistic planning in its true sense. The SAR development team should clarify what it intends with regard to "the use of probabilistic planning methods". ***Consideration by the SAR DT*** *In response to your comment, the SAR DT has revised the present SAR to clarify our intent with regard to probabilistic planning methods.*
AMEREN	**From SAR Version 2:** "……..The Standard should allow for the development and use of probabilistic planning methods. The minimum requirements of probabilistic methods are the contingencies as described in Table 1 of existing Planning Standard I.A.. There should be NERC approval of acceptable levels of risk……." The second sentence about "The minimum requirements of probabilistic methods …. Does this mean that probability should be assigned to at least all of the contingencies included in Table I.A.? AMEREN believes that defining acceptable levels of risk will be a major undertaking. Isn't the level of risk dependent upon the entity and/or perception? Using a deterministic methodology in the planning horizon for single contingency provides a margin to handle many multiple unplanned facility outages or unforeseen system conditions in the operating horizon. ***Consideration by the SAR DT*** *The SAR DT is recommending the continued use of deterministic criteria in the Standard, but is also recommending probabilistic planning methods as an alternative or augmentation to the deterministic criteria. The SAR DT believes probabilistic planning methods are another way of defining acceptable levels of risk. For example, the existing deterministic criteria considers all line outages to be the same level of risk, but a probabilistic method may differentiate transmission line outages by length of line. The SAR DT has revised the present SAR to clarify this point in response to your comment.*
ATC	**From SAR Version 2:** "……..The Standard should allow for the development and use of probabilistic planning methods. The minimum requirements of probabilistic methods are the contingencies as described in Table 1 of existing Planning Standard I.A.. There should be NERC approval of acceptable levels of risk……." This may also go back to question 1 in the Comment Form, but the statement, "There should be NERC approval of acceptable levels of risk" needs to be better defined. For example does this mean that a utility can't decide to increase the operating temperature of a line conductor without NERC approval? ***Consideration by the SAR DT*** *The SAR DT agrees that the sentence concerning NERC approval was unclear. The SAR DT has removed the referenced sentence and added*

	wording to clarify our intent regarding the "use of probabilistic planning methods".
BPA	The handling of probabilistic criteria in the SAR seems quite convoluted, i.e. it can only be used to *increase* performance levels AND has to be approved by NERC. This is not the way probabilistic planning should work. WECC presently has a process (Seven Step Reliability Performance Evaluation) to allow changes in performance requirements (both up and down) for specific outages based on rigorous analysis and monitoring actual performance. It is mostly applicable to requirements beyond the NERC criteria (such as outages of adjacent circuits on separate towers). Use of these methods should be allowed with approval of affected regions. This process should allow for movement below Table 1, i.e. moving Category C outage to Category D. One way to resolve this would be to replace the word "minimum" in the SAR to "starting". ***Consideration by the SAR DT*** *In response to your comment, the SAR DT has added wording to clarify our intent regarding the "use of probabilistic planning methods". Specifically, there is no longer reference to "minimum criteria", but rather a recommendation that the existing Standards be used as a "starting point", allowing movement above or below existing Table I. The reference to NERC approval has also been removed.*
NYSRC	Is the probabilistic method referred to here considered a replacement for the NERC Criteria or a supplement to NERC Criteria? NERC should not allow such a method as a substitute for NERC criteria. I am not aware that NERC has completed an analysis to evaluate and compare the level of reliability of probabilistic criteria with NERC criteria. Such an evaluation would be needed. ***Consideration by the SAR DT*** *The SAR DT is recommending the continued use of deterministic criteria in the Standard, but is also recommending probabilistic planning methods as an alternative or augmentation to the deterministic criteria. The SAR DT has revised the present SAR to clarify this point in response to your comment.*
R. Snow	**From SAR Version 2:** "……..The Standard should allow for the development and use of probabilistic planning methods. The minimum requirements of probabilistic methods are the contingencies as described in Table 1 of existing Planning Standard I.A.. There should be NERC approval of acceptable levels of risk……." Add a sentence after the first sentence *"The probabilistic methodology shall not ignore specific cases that would result in significant load dump or cascading outages. Each region shall identify how to resolve such outages." The last sentence "Acceptable levels of risk in terms of maximum consequential and programmatic load dump and maximum durations for the outages shall be defined."* ***Consideration by the SAR DT*** *The SAR DT believes this level of specificity is not needed in a SAR. However, the SAR DT appreciates your comment, and has revised the present SAR to clarify the potential application of probabilistic planning methods. If this issue is still a concern when the Standard is posted, feel free to submit your comments at that time.*

WECC-1	It appears to us that as written, the standard that flows from this SAR can only allow the probabilistic planning methods to make the standard more, not less, stringent than the existing Standard IA. This is not the way probabilistic planning methods should work. This statement also does not make sense when you read the next sentence, "There should be NERC approval of acceptable levels of risk." If the standard can only be more stringent, then there is no need for NERC to approve the level of risk, or even the probability of occurrence of the contingency. One way to resolve this issue would be to change the word "minimum" to "starting". ***Consideration by the SAR DT*** *In response to your comment, the SAR DT has added wording to clarify our intent regarding the "use of probabilistic planning methods". Specifically, there is no longer reference to "minimum criteria", but rather a recommendation that the existing Standards be used as a "starting point", allowing movement above or below existing Table I. The reference to NERC approval has also been removed.*
WECC-2	The Standard should also allow for the use of Probabilistic Criteria. In WECC, Probabilistic Planning refers to the application of fixed planning standards to a given problem to determine the probable or expected load not served. Probabilistic Criteria is used to refer to adjusting the performance category based on the probability of the event for a specific facility. The performance category can move up or down depending on actual or planned performance. Therefore, Table 1 would be the starting point for making probabilistic criteria adjustments. Probabilistic adjusted criteria would be the basis for Probabilistic Planning. ***Consideration by the SAR DT*** *See the SAR DT's response to WECC-1 and BPA above.*
WECC-1 & WECC-2	The NERC Planning Standards should follow what WECC is doing with regard to listing disturbances as a guide, but say that other disturbances with the same probability should be included. List the probability ranges (outages per year), Category B: >= 0.33, Category C: 0.33 to 0.033; Category D1 (no cascading): 0.033 to .0033, Category D2: < .0033. The standard should allow for changes in the required performance for given disturbances if a probability in another range has been established for a given disturbance. NERC should require that the Regional Councils specify voltage dip and minimum frequency standards similar to WECC (i.e., the voltage dip and minimum frequency should be within Applicable Ratings). We are not proposing that NERC set fixed values for these standards that would be the same throughout the ten NERC Regions. NERC should not set the standards. WECC recommends that the approval of acceptable levels of risk be at the regional level. ***Consideration by the SAR DT*** *In response to your comment, the SAR DT has added wording to clarify our intent regarding the "use of probabilistic planning methods".*

	The SAR DT believes the existing Standard allows Regions to apply voltage dip and voltage stability Regional requirements under the "voltage limits" section of Table I. The SAR DT believes that frequency standards are outside the scope of Transmission Planning for most Regions, and has not included frequency standards in the NERC SAR. This does not preclude Regions where frequency standards have transmission adequacy implications from developing their own standards.

COMMENTS ON PLANNED OUTAGES

AMEREN	We do not believe that the requirement for planning for maintenance outages should be included in planning assessments. See AMEREN's response/comments to Question 4 in this document. ***Consideration by the SAR DT*** *In reviewing industry responses, there was no clear consensus on the issue of including planned outages in planning assessments. See the SAR DT's response to MAPP below. We believe the revised wording in the present SAR adequately addresses these concerns.*
MAPP	MAPP urges the SAR drafting team to add words under this bullet to more clearly explain the SAR drafting team's position with regard to prior planned outages. ***Consideration by the SAR DT*** *The SAR DT believes there is confusion surrounding the planned outage requirement in the existing standard. The SAR DT is recommending that the new Standard specify whether to retain this requirement for Categories B and C. If retained, the Standard should clarify the requirement in such a way that the requirement can be practically implemented.* *In particular, the SAR DT has revised the present SAR to clarify that transmission entities are not required to exhaustively test their systems for every conceivable planned (including maintenance) outage in addition to every conceivable Category B and C contingency. The SAR DT has also revised the SAR to delete the planned outage requirement for Categories A and D.*
MEC	MEC urges the SAR drafting team to add the following words to this bullet to more clearly explain the SAR drafting team's position with regard to planned outages: *"In particular, it is incorrect to have a requirement to exhaustively test for every contingency described in each category plus every conceivable planned outage.* *Planned Outages can be scheduled and analyzed in advance in the operating horizon (less than one year). Therefore, it should not be necessary to require that "systems must be capable of meeting Category C requirements while accommodating the planned outage of any bulk electric equipment..." Planned outages should be studied in advance by the requesting control area and be reviewed by the governing Reliability Coordinator to determine if overloads could occur. If studies show that overloads could occur, the planned outage should be deferred or operating guides prepared which would be used in the event a contingency does occur.* *There is no need to plan or build facilities to meet Planning Standard 1.A when Planned Outages can be accommodated within the frame work of existing guidelines and procedures. Studies conducted for the operating horizon are not the subject of this standard.* *Therefore, the SAR drafting team directs the standard drafting team to delete the requirement for the prior planned outage from the standard given that known planned outages must be included in studies that are conducted during the operating horizon which are not the subject of this standard but which are required in accordance with NERC Standard 200, "Operate Within Interconnection Reliability Operating Limits Standard" and NERC Standard 600, "Determine Facility Ratings, Operating Limits, and Transfer Capabilities".*

	Note: The above suggested wording is similar to the MAPP/MEC comment for Question 4, and the SAR DT is offering a similar consideration: ***Consideration by the SAR DT*** *See the SAR DT's response to MAPP above. We believe the revised wording in the present SAR adequately addresses these concerns.*
SEMINOLE	Many grid operations difficulties occur when a line is scheduled out for maintenance. If this SAR is going to address required N-2 planning assessments, then it must be clear and specific regarding the conditions when N-2 assessments are appropriate and the specific criteria for N-2 assessments. ***Consideration by the SAR DT*** *See the SAR DT's response to MAPP above. We believe the revised wording in the present SAR adequately addresses these concerns*

COMMENTS ON APPLICABLE RATINGS

ALLEGHENY	**From SAR- Version 2:** "…….Performance requirements for Category C events shall be re-evaluated. For example, for certain Category C events, such as #2, #3 and #9 events, consider removing references to "Applicable Ratings" to clarify that the performance requirement is "No Cascading Outages are Allowed"……". This bullet does not appear necessary. "No Cascading Outages" is already part of Table I for these events. Removing "Applicable Ratings" would not add to the clarity. ***Consideration by the SAR DT*** *The wording in the present SAR was revised to remove the referenced language.* *The SAR DT is recommending that the Standard DT conduct a review to determine whether the events in existing Table I are classified correctly. In conducting its review of the likelihood of events and acceptable performance requirements, the Standard DT should clarify ambiguities in performance requirements, specifically cascading outages and Applicable Ratings (A/R).* *For example, the Standard should clarify tests used for considering cascading, such as divergent power flow, overload limits post contingency, voltage magnitudes, etc. The Standard should also clarify that different ratings may be applicable to different categories of events and perhaps to different types of events with a category (specified by entities in accordance with STD 600).*
AMEREN	We agree that some of the contingency categories should be reviewed. See AMEREN's comment for Question 1 (c) in this document – approach (1): keep same categories but re-classify certain events as Category D. ***Consideration by the SAR DT*** *See the SAR DT's global consideration of your Question 1(c) comment.*
BPA	Applicable Ratings: There is a need to tighten up the methodology for Applicable Ratings to ensure that compliance with this standard is measurable. We assume that this will take place in the Determine Facility Ratings Standard although we are concerned about how this is progressing. ***Consideration by the SAR DT*** *The SAR DT is recommending that Applicable Ratings (A/R) be clarified by the Standard DT and the Standard DT will evaluate your comment at that time.*
IMO, ISONE, NPCC	We are not in favor of removing references to "Applicable Ratings". Despite the fact that the performance requirement would be "No Cascading Outages are Allowed", the "Applicable Ratings" should always be respected. ***Consideration by the SAR DT*** *The SAR DT is recommending that Applicable Ratings (A/R) be clarified by the Standard DT and the Standard DT will evaluate your comment at that time.*

MAPP	MAPP urges the SAR drafting team to clarify the meaning of the term "Applicable Ratings" and determine if it is possible to have different A/Rs for different categories. ***Consideration by the SAR DT*** *The SAR DT is recommending that Applicable Ratings (A/R) be clarified by the Standard DT and the Standard DT will evaluate your comment at that time.*
MEC	**From SAR- Version 2:** "……..Performance requirements for Category C events shall be re-evaluated. For example, for certain Category C events, such as #2, #3 and #9 events, consider removing references to "Applicable Ratings" to clarify that the performance requirement is "No Cascading Outages are Allowed"……". MEC urges the SAR drafting team to add Category C#1, #6, #7 and #8 events to the bullet above, to clarify the performance requirement for certain Category C events. ***Consideration by the SAR DT*** *The wording concerning A/R has been revised in the present SAR.* *There was no clear consensus from industry that the events in Categories B, C and D in Table I should be or should not be re-classified. The SAR DT is recommending that the Standard DT conduct a review to evaluate whether the events are classified correctly.* *All parties will have an opportunity to participate in the Standard drafting process, including commenting on the draft Standard. Specific concerns should be brought up at that time.*
MEC	MEC urges the SAR drafting team to direct the Standard Drafting Team to remove references to "Applicable Ratings" from all events listed (see MEC comment above), since information is readily available which demonstrates that the listed events are much less likely than other Category C events. ***Consideration by the SAR DT*** *The SAR DT is recommending that Applicable Ratings (A/R) be clarified by the Standard DT and the Standard DT will evaluate your comment at that time.*
MEC	MEC urges the SAR drafting team to include the following statement in the SAR: "The Standard should clarify how breaker failure events (Category C2, C6, C7, C8, and C9 events) are to be considered given that operating a breaker with disconnects open or eliminating a breaker are technically acceptable mitigation schemes for such events. Such mitigation schemes actually result in less reliable system designs and system operating configurations. Thus including Applicable Ratings in the Standard for these lower probability breaker failure events can send the wrong reliability signals to NERC members." This statement reflects another reason why breaker failure events should be reclassified such that Applicable Ratings is no longer considered a requirement for these low probability events. ***Consideration by the SAR DT*** *See the SAR DT's consideration of MEC's first comment above.*

MEC	MEC urges the SAR drafting team to consider NOT reclassifying any of the Category C events to Category D but instead deleting the Applicable Rating requirements from the lower probability Category C events. MEC believes that the performance requirements for lower probability Category C events should be to protect for cascading, instability, and uncontrolled separation. It is MEC's belief that this was the intent of the drafting team that originally developed the existing NERC Planning Standards. ***Consideration by the SAR DT*** *See the SAR DT's consideration of MEC's first comment above.*
NYSRC	**From SAR- Version 2:** "……..Performance requirements for Category C events shall be re-evaluated. For example, for certain Category C events, such as #2, #3 and #9 events, consider removing references to "Applicable Ratings" to clarify that the performance requirement is "No Cascading Outages are Allowed"…….". The above bullet should be removed. This would be a weakening of the criteria. ***Consideration by the SAR DT*** *There was no clear consensus from industry that the events in Categories B, C and D in Table I should be or should not be re-classified. The SAR DT is recommending that the Standard DT conduct a review to evaluate whether the events are classified correctly.* *All parties will have an opportunity to participate in the Standard drafting process, including commenting on the draft Standard. Concerns that changes made may weaken the Standard should be brought up at that time.*
R. Snow	Clarify that the "applicable ratings" for multiple events should be consistent with supplying firm load and firm transactions until the outages are repaired or switching mitigates the overloads. For example, one applicable rating would be the short time rating of equipment that was stressed when a transformer failed. However, there must be a method of supplying the load pocket for the duration to repair/replace the transformer that does not involve long term rotating blackouts. Just achieving "no cascading outages" is not sufficient. ***Consideration by the SAR DT*** *The SAR DT is recommending that Applicable Ratings (A/R) be clarified by the Standard DT and the Standard DT will evaluate your comment at that time.*

COMMENT ON SHORT CIRCUIT CURRENT

AMEREN	We assume that short circuit current refers to fault duty or interrupting current. ***Consideration by the SAR DT*** *Fault duty and interrupting current refer to the ratings of transmission facilities. The short circuit current is compared to these ratings.*

COMMENTS ON OTHER AREAS THAT SHOULD BE ADDED OR CLARIFIED

AESO	There should be a clear distinction between the appropriate use and application of RAS (or SPS) and "safety nets". ***Consideration by the SAR DT*** *Based on industry comments on the first posting (V1) of the SAR, there was a strong preference not to specify how to achieve reliability performance requirements. Therefore, the SAR does not specifically address these issues/distinctions.*
AMEREN	The "projected level of transfers" defined in the Standard – what does this include? Should it include/consider all transmission reservations including roll-over-rights? ***Consideration by the SAR DT*** *The present SAR has been revised to specify that system models must be developed and shared, including documenting the methodology for incorporating planned generation assets (including transfers) in the model. The projected levels of transfers are determined by each Transmission Planner, and these may include rollover provisions as appropriate.* *Note: See KCPL & MAPP comments under the "System Models" table in this document, and the SAR DT's consideration of those comments.*
MAPP	MAPP asks that the SAR drafting team add a bullet to the SAR that requires that the Standard drafting team consider the development of reactive power margin and transfer power margin standards which expand beyond existing NERC Standard I.D. ***Consideration by the SAR DT*** *The NERC Planning Committee is reviewing Regional reactive power and voltage control practices. Their findings may need to be incorporated into the new Planning Standard (STD 500) when this review is completed. Standard 600 addresses system operating limits and transfer capability. Whereas this SAR DT did not attempt to duplicate these efforts, the present SAR does not preclude the Standard Drafting Team from further refining reactive power margins and/or power transfer margins.* *In the present SAR, a bullet has been added that the Standard address requirements on reactive planning, with specific reference to steady state and transient voltage stability criteria.*
MAPP	MAPP notes that Standard 600, "Determine Facility Ratings, Operating Limits, and Transfer Capabilities" has been drafted to do away with the references to Categories A through D. The criteria are just listed in the standard. MAPP asks that the SAR drafting team require that the standard drafting team for Standard 500 also eliminate the category references to be consistent with the Standard 600 approach. ***Consideration by the SAR DT*** *This SAR 500 DT does not believe that Standard 500 necessarily has to have*

	the same format as Standard 600. However, we have revised the present Standard 500 SAR to provide for coordination between the two Standards.
MAPP & MEC	In general, MAPP and MEC support the six bullets that the SAR drafting team has provided on page SAR-5 (of SAR-Version 2) with the amendments and additions described above in our comments. These bullets add needed details to the SAR. ***Consideration by the SAR DT*** *The present SAR has been revised to reflect appropriate details.*
R. Snow	New section: The subject of assuring that generation is deliverable to the load should be added. This should not be vague but should be defined by a specific set of tests and the expected range of results. In doing these tests, reliance on capacity assigned to other regions should be limited to amounts identified and accepted by adjacent regions. For example, if a region is assuming it will have net purchases from adjacent regions, the other regions must show a net sale. ***Consideration by the SAR DT*** *The NERC Planning Committee is tackling this deliverability issue, as identified by the Resource and Transmission Adequacy Task Force (RTATF). This new Transmission Planning Standard (STD 500) may need to be revised in the future to reflect integration with Resource Adequacy Standards.*

INDUSTRY COMMENTER KEY

TOTAL ENTITIES COMMENTING; 28

TOTAL INDIVIDUALS COMMENTING 121

AEP: AEP Service Corp, Raj Rana

AES: Allegheny Energy Supply (Generator), Ken Githens

AESO: Alberta Electric System Operator (ISO), Neil Brausen, group chair. Includes:

Neil Brausen, Jeff Billinton, Bob Chow

ALLEGHENY: Allegheny Power (Transmission Owner), William J. Smith

AMEREN: Ameren (Transmission Owner), Kirit Shah

ATC: American Transmission Company (Transmission Owner), Peter Burke (on behalf of ATC's David Smith).

BPA: Bonneville Power Administration (Transmission Owner), Marv Landauer, group chair. Includes:

Paul Arnold, Rebecca Berdahl, Mark Bond, Gordon Comegys, Angela DeClerk, Don Gold, Kyle Kohne, Mike Kreipe, Chuck Matthews, Bill Mittlestadt, James Murphy, Melvin Rodrigues, Mike Viles, Paul Ferron

CWLP: City Water, Light & Power (Illinois- Generator), Karl Kohlrus

DUKE: Duke Energy (Transmission Owner), Thomas Pruitt, Robert W. Pierce

ENTERGY: Entergy Services, Inc (Transmission Owner), Ed Davis

ERCOT: Electric Reliability Council of Texas, Bill Bojorquez

IMO: Independent Electricity Market Operator; Khaqan Khan

ISONE: ISO New England, Kathleen Goodman

ISO/RTO: ISO/RTO Council Standards Review Committee, Karl Tammar (NYISO), group chair. Includes:

AESO, Dale McMaster
CAISO, Ed Riley
ERCOT, Sam Jones
IMO, Don Tench
ISO-NE, Peter Brandien
MISO, Bill Phillips
NYISO, Karl Tammar
PJM, Bruce Balmat
SPP, Carl Monroe

KCPL: Kansas City Power & Light (Transmission Owner), Jim Useldinger

MAAC/Horakh: Mid-Atlantic Area Council, John Horakh
MAAC/Kuras: Mid-Atlantic Area Council, Mark J. Kuras

MAPP: Mid-Continent Area Power Pool, Tom Mielnik (MEC), group chair. Includes:

MidAmerican Energy Company (MEC), Tom Mielnik, Dennis Kimm
Great River Energy (GRE), Delyn Helm
MH, David Jacobson
XEL, Dean Schiro
Otter Tail Power (OTP), Jason Weiers
Western Area Power Administration, Steve Sanders

MEC: MidAmerican Energy Company (Load Serving Entity), Tom Mielnik

NPCC: Northeast Power Coordinating Council, Guy Zito (NPCC), group chair. Includes:

TransEnergie (Quebec), Roger Champagne
New York Power Authority, Ralph Rufrano
Hydro One Networks (Ontario), David Kiguel
Nova Scotia Power, David Little
ISO New England, Kathleen Goodman, Dan Stosick
US National Grid, Peter Lebro
New York ISO, James Practico
Niagara Mohawk, Larry Eng
Independent Electricity Market Operator, Ontario, Khaquan Khan
New York State Reliability Council, Alan Adamson
NPCC, Guy Zito, John Mosier, Briam Hogue (satff)

NYSRC: New York State Reliability Council, Alan Adamson

R.Snow: Robert Snow, Individual Commenter (Small Electricity User).

SCGEM: Southern Company Generation & Energy Marketing (Brokers, Aggregators, Marketers), Roman Carter, group chair. Includes:

Roman Carter, Joel Dison, Lucius Burris, Tony Reed, Lloyd Barnes, Clifford Shepard.

SEMINOLE: Seminole Electric Coop.(TDU), K. Bachor & S. Wallace

SERC: Southeastern Electric Reliability Council, Bob Jones (Southern Company Services), group chair. Includes:

Alabama Electric Coop., Darrell Pace
Duke Power, Brian Moss
Entergy Services, Kham Vongkhamchanh
South Carolina Electric & Gas, Clay Young
South Carolina Public Service Authority, Arthur Brown
Southern Company Services, Bob Jones
Tennessee Valley Authority, Byron Stewart
SERC Staff, Pat Huntley

SOUTHERNCO: Southern Company Services, Inc. (Transmission Owner), Marc Butts, group chair. Includes:

Rod Hardiman,, Jonathan Gildewell, Bobby Jones, Marc Butts
Bill Pope – Gulf Power (Load Serving Entity)

SPP: Southwest Power Pool – Transmission Working Group, Ronnie Frizzell, group chair. Includes:

Arkansas Electric Coop Corp., Ronnie Frizzell
Sunflower Electric Power Coop., Norman Williams
Westar Energy, Donald Taylor
Kansas City Power & Light, Jim Useldinger
Southwestern Public Service, John Fulton
American Electric Power, Matt McGee
Empire District Electric, Sam McGarrah
Western Farmers Electric Coop., Mitch Williams
ETEC, John Chiles
Entergy, Mak Nagle
Associated Electric Coop., Inc., Jim Kistner
Southwest Power Pool, Alex Lau
Oklahoma Gas & Electric, Phil Crissup
City Utilities of Springfield, MO, Howard Conus
Aquila Networks, Alan Myers
Southwestern Power Administration, David Sargent

TVA: Tennesse Valley Authority (Government Entity). Includes:

David Till, David Marler, Brenda Eberhart, Darrin Church, Byron Stewart, William Tiller

WECC-1: Western Electricity Coordinating Council, Peter Mackin (TANC), group chair. Includes:

Arizona Public Service, Peter Krzykos
Pacific Gas & Electric, Chifong Thomas
Transmission Agency of Northern California (TANC), Peter Mackin
Basin Electric Power Coop, Matthew Stoltz
Western Area Power Administration, Bob Easton
Salt River Project, Charles Russell
Puget Sound Energy, Joe Seabrook

WECC-2: Western Electricity Coordinating Council, Ben Morris (PG&E), group chair. Includes:

Arizona Public Service, Baj Agrawal
British Columbia Transmission Corp., Phil Park
California ISO, Jeff Miller
Idaho Power, Ron Schellberg
Nevada Power, Rahn Sorensen
Pacific Gas & Electric, Ben Morris, Rick Padilla, Chifong Thomas
Sacramento Municipal Utility District, Dilip Mahendra
Salt River Project, Brian Keel
Southern California Edison, Dana Cabbell, Mohan Kondragunta
Snohomish County PUD, John Martinsen

WESTAR: Westar Energy, Inc. (Transmission Owner), Donald Taylor

When completed, email to: gerry.cauley@nerc.net

Standard Authorization Request Form

Title of Proposed Standard	Assess Transmission Future Needs and Develop Transmission Plans
Request Date	May 01, 2004

SAR Requestor Information		**SAR Type** (Put an 'x' in front of one of these selections)	
Name	Paul Rocha	☒	New Standard
Primary Contact	Paul Rocha	☐	Revision to existing Standard
Telephone Fax	(713) 207-2768	☐	Withdrawal of existing Standard
E-mail	paul.rocha@centerpointenergy.com	☐	Urgent Action

Purpose/Industry Need (Provide one or two sentences)

To establish a standard for assessing and planning the transmission systems in North America. The transmission system must be assessed and planned to ensure that it performs its intended functions in providing reliable delivery of power for the future needs of customers.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies by double clicking the grey boxes.)*		
☒	Reliability Authority	Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest reliability authority.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules
☒	Planning Authority	Plans the bulk electric system
☐	Resource Planner	Develops a long-term (>1year) plan for the resource adequacy of specific loads within a Planning Authority area.
☒	Transmission Planner	Develops a long-term (>1 year) plan for the reliability of transmission systems within its portion of the Planning Authority area.
☐	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
☒	Transmission Owner	Owns transmission facilities
☐	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
☐	Distribution Provider	Provides and operates the “wires” between the transmission system and the customer
☐	Generator Owner	Owns and maintains generation unit(s)
☐	Generator Operator	Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services
☐	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required
☐	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.
☒	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check boxes for all that apply by double clicking the grey boxes.)*	
☒	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box by double clicking the grey area.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft, modify, or withdraw a Standard based on this description.)

The Standard shall establish requirements for assessing the performance of planned bulk electric transmission systems and the requirements for documenting plans to remedy any inadequacies identified in the process of conducting such assessments.

The scope of such assessments and plans is for a future planning period (planning horizon) starting at one year and extending to five years or more.

The planning horizon must be long enough to permit timely implementation of viable solutions to remedy the potential inadequacies found. Planning horizons beyond 5 years may be needed to meet regulatory or legislative requirements, or may be based on the judgment of the Transmission Planner or Planning Authority.

The scope *does not* include the operating horizon less than one year. While the planning horizon is intended to provide sufficient time for facility additions, there is no intent to exclude appropriate operating procedures as options to correct potential transmission inadequacies. Such procedures should also be included in the Transmission Plan.

The Standard will consider the transition from the operating horizon to the planning horizon. In particular, the Standard will assure consistency between reliability requirements set forth in the Standards for Planning (for example, this Standard 500, "Assess Transmission Future Needs and Develop Transmission Plans") and similar criteria required by other Standards (such as Standard 600, "Determine Facility Ratings, Operating Limits and Transfer Capabilities"), which also apply in operations.

In addition, the Standard shall explain the relationship between the reliability requirements for operations and those for planning, so that differences are better understood.

The Standard shall identify reliability performance requirements, but shall not specify *how* to achieve such performance requirements.

The applicable portions of the following existing NERC Planning Standards will be used as the starting point in drafting these requirements:

- I.A Transmission Systems
- I.B Reliability Assessment
- I.D Voltage Support & Reactive Power
- II.A System Data
- II.D Actual and Forecast Demands

The Standard shall require that system models be developed, maintained and shared in a manner consistent with the Functional Model and appropriate information-sharing policies. Included will be requirements that each Planning Authority and Transmission Planner document modeling assumptions, including the methodology used for incorporating planned generation assets (including transfers) in the model, as well as how such generation is dispatched. The Standard shall consider a requirement for Load Serving Entities (LSEs) to provide forecast resource data for input to the models.

While methodologies and assumptions must be documented, the Standard will *not* prescribe specific tools to be used in the performance assessment of the planned systems.

The Standard will identify the various planning functions that are responsible for compliance with the standard criteria. The assignment of compliance responsibility will be consistent with the Functional Model.

This Standard will *not* include requirements for:

- Resource Planning (i.e., assessing or ensuring the availability of adequate aggregate generation resources to serve aggregate load).

- Planning generation additions to remedy any aggregate generation resource inadequacies.

- Developing Transmission Plans to mitigate congestion due to economy transfers of generation resources.

However, the Standard should neither preclude nor require the consideration of generation or load (demand side management) as alternatives to transmission reinforcement/reconfiguration when developing solutions to potential transmission inadequacies.

While the Standard should start from and closely align with the existing Planning Standards I.A, I.B, I.D, II.A, and II.D, the system conditions to be studied or assessed may need to be better defined or clarified.

Examples of areas that should be considered for clarification in the Standard include:

- The Standard should clarify that the requirement to assess the performance at *all* demand levels does not mean that a multitude of transmission models need to be created for every possible demand level, only that a representative sample covering critical operating conditions needs to be modeled in accordance with regionally-defined criteria.

- The Standard should provide a clearer definition of "cascading outages", including what constitutes a cascading state. The Standard should also consider providing a clearer definition of "system stable". These definitions must be coordinated and consistent with definitions in other new Standards being drafted by NERC, such as Standards 200 and 600.

- The Standard should take into account the variability of generation, including unit maintenance outages, weather and time of day. Variability of load due to factors such as weather and time of day should also be considered.

- The Standard should continue to use deterministic criteria. The criteria embodied in Table 1 of existing Planning Standard I.A shall be used as a starting point. Following a review of the likelihood, duration, impact of events, and definition of applicable ratings (A/R) in existing Table I, a re-classification of Table I events should be considered, as necessary, for inclusion in the new Standard.

  Other changes should be considered for incorporation into the new Standard. Such changes could include:

  (1) Addition or deletion of categories/events/performance requirements.
  (2) Use of probabilistic planning methods.
  (3) Re-definition of categories (e.g., categories determined by event probability levels or ranges).
  (4) Differences in requirements for an event based on a range of event probabilities (for example, recognize that longer lines have a greater probability of outage than shorter lines).

(5) An alternative table, similar to Table I of existing Planning Standard I.A, except allowing for probabilistic planning criteria.
(6) Provision for a specific facility with an abnormal outage probability to have different performance requirements.

The list above is intended to be illustrative and not exhaustive or mutually exclusive. As allowed by the Standards Development Process, Regions may submit Regional Differences.

- Existing Planning Standard S1, S2, S3, S4 and Table I, Categories A, B, C, and D should be clarified on the issue of how a planned outage should be used in an assessment.

  The Standard should specify whether the planned outage requirement should be retained for Categories B and C. If retained, the requirement should be clarified in such a way that it can be practically implemented. In particular, the Transmission Planner should not be required to exhaustively test its system for every conceivable planned outage (including maintenance outages) in addition to every conceivable Category B and C contingency. The Standard should clarify that the planned outage requirement does not apply to Categories A and D.

- The Standard should address and rectify ambiguities in performance requirements, specifically cascading outages and applicable ratings (A/R). This applies to all Categories, especially Category C.
  For example, the Standard should clarify tests used for considering cascading, such as divergent power flow, post-contingency overload limits, voltage magnitudes, etc. The Standard should also clarify that different ratings may be applicable to different categories of events and perhaps different types of events within a category (specified by entities in accordance with Standard 600).

- The Standard should include requirements to ensure that the maximum available short circuit current does not exceed facility owner specifications.

- The Standard should also address requirements on reactive planning with specific reference to steady state and transient voltage stability criteria.

- The Standard should address requirements for reporting (perhaps to the Regions) on the progress or status of implementing the plans developed in accordance with the Standard. However, any such reporting requirements should be consistent with the Resource & Transmission Adequacy Task Force Recommendation #2, and should not impose undue burdens upon transmission entities

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation
FACILITY_RATINGS_01_01	*"Determine Facility Ratings, Operating Limits and Transfer Capabilities".* The Planning Standard will use some data collected within the "Facility Ratings" SAR. The Draft "Facility Ratings" Standard, Section 603, establishes some guidelines for the planning function to set operating limits based on Table 1 of the existing Planning Standard I.A.
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MAAC	
MAIN	
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SERC	
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Related NERC Operating Policies or Planning Standards

ID	Explanation
Planning Std. I.A	Transmission Systems: Plan within ratings, avoid cascading outages, uncontrolled system separation, and voltage and transient instability.
Planning Std. I.B	Reliability Assessment
Planning Std. I.D	Voltage Support & Reactive Power
Planning Std. II.A	System Data
Planning Std. II.D	Actual & Forecast Demands

MAPP & MEC believe the following information supports our proposed new reclassification by demonstrating that the events that MAPP & MEC recommend for reclassification are the low probability Category C events. MAPP & MEC recognize that published outage data are subject to interpretation, potential inaccuracy, and change through time; however, we believe that MAPP & MEC operating experience with transmission element outages supports the statistical summary provided in the following table.

Contact info:
Tom Mielnik, Chair
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106 East Second Street
Davenport, Iowa 52801
(563)333-8129
tcmielnik@midamerican.com

345 kV Outage Data				
Contingency	Outage Rate, occ./year	Duration, hours	Probability	Relative Likelihood
Generator B1	9	81	0.08321918	1
Two generators C3	1.5	40.5	0.00693493	12
Bipolar DC line * (Similar to B4)	1.41	21	0.00338014	24
Line * B2	0.8065	18	0.00165719	50
Transformer B3	0.0642	157	0.00115062	72
Bipolar DC Line * + Generator (Sim. to 1 Pole DC line + gen. C3)	0.1478	16.68	0.00028143	296
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Generator + Transformer C3	0.0157	53.4	0.00009571	870
Common tower * C5	0.007	113	0.00009030	922
Breaker Failure- Insulation Breakdown C2 RECLASSIFY THIS EVENT	0.001423	163	0.00002647	3,144
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Stuck breaker C6-C9 RECLASSIFY THIS EVENT	0.00635	4	0.00000290	28,696
Line * + Line * (independent) C3 RECLASSIFY THIS EVENT	0.00267	9	0.00000275	30,262
Line * + Transformer C3 RECLASSIFY THIS EVENT	0.0010	16.1	0.00000184	45,228
Two transformers C3 RECLASSIFY THIS EVENT	0.00014774	78.5	0.00000132	63,045
Bus Section** RECLASSIFY THIS EVENT	0.0023	4.7	0.00000123	67,438

* Per 100 mile-year.
** Based upon 230 kV data.

References

1. **MAPP-CSRWG, "MAPP Bulk transmission system outage report", June 2001.**
2. **C. R. Heising, et al, "Final report on high voltage circuit breaker reliability data for use in substation and system studies – report on behalf of WG 13.06, in Proceedings of CIGRE Conference, Paris, 1994.**
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BPA Data

Category	Contingencies	Outages per year	Source of Data
B1	Generator	4	NW Federal system is mostly hydro generation in remote locations and these outages are usually of little consequence to the power system. These outage data are based on three thermal plants located in load areas. Due to the small size of this sample, they may not be very useful. These outages average 109 hour duration.
B2	Transmission Circuit	0.97	BPA data for 225 lines 200-kV through 550-kV, 1985-2003 data (19 years), average length 50.5 miles, outages with duration greater than 1 minute only. Five hour average duration.
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B4	Single Pole DC Line	9	BPA data for PDCI, 845 miles (one line only). 8.99 outages per year with total annual outage time of 170 hours. Not including terminal outages. 19 hour average duration.
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C2	Breaker internal fault	0.00079	1994 CIGRE Brochure 83: data for 230 and 500-kV breakers: insulation breakdown.
C2	Breaker fails to open	0.00569	1994 CIGRE Brochure 83: data for 230 and 500-kV breakers: failure to open.
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C3	Two Line Independent	0.00110	Calculated based on single contingency rate indicated above: 1 outage per year with duration of 5 hours
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C6, C7, C8, C9	Protection failure	0.11969	BPA Data for 115 stations with voltages 230 through 500-kV, 17.8 years of data, resulted in 245 events of preotection failure.
C6	SLG Fault Generator with protection failure	0.47875	Generator single contingency outage rate from above multiplied by protection failure rate (0.11969)
C7	SLG Fault Transmission circuit with protection failure	0.11490	Transmission line single contingency outage rate from above multiplied by protection failure rate (0.11969)
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C9	Bus section fault with protection failure	0.00088	Bus fault outage rate from above multiplied by protection failure rate (0.11969)

Data provided by Marv Landauer based on outage data collected by BPA.

Assess Transmission Planning Future Needs and Develop Transmission Plans-Standard Drafting Team Nomination Form

Please return this form to sarcomm@nerc.com by November 18, 2005. For questions, please contact Mark Ladrow at 609-452-8060 or mark.ladrow@nerc.net.

Please note this Standard drafting team will likely meet initially in mid-December, 2005 to review comments posted on the SAR and to begin drafting the proposed standards. The SAC has directed the drafting team to consider the reduced scope necessitated by the adoption of the current reliability standards and to specifically delineate this reduction in scope during its first public posting. The team will meet as necessary to finalize the scope of standard development activity and to draft the standard(s). The meeting schedule has not been determined yet. It is expected the teams will meet several times in 2006. **All candidates should be prepared to participate actively at these meetings.**

Proposed Standard: Assess Transmission Future Needs and Develop Transmission Plans. The SAR is provided at: SAR LINK
Name: Organization: Address: Office Telephone: Mobile Telephone: Fax: Email:
Please briefly describe your experience and qualifications to serve on the Assess Transmission Future Needs and Develop Transmission Plans Standard Drafting Team. Candidates should have expertise in one or more of the following areas: transmission operations; transmission planning; or regulatory or legal experience related to any of the listed areas. Previous experience working on or applying NERC standards is beneficial, but not a requirement.

I represent the following NERC Reliability Region(s) (check all that apply):	I represent the following Industry Segment (check one):	
☐ ERCOT	☐	1 - Transmission Owners
☐ ECAR	☐	2 - RTOs, ISOs, Regional Reliability Councils
☐ FRCC	☐	3 - Load-serving Entities
☐ MAAC	☐	4 - Transmission-dependent Utilities
☐ MAIN	☐	5 - Electric Generators
☐ MAPP	☐	6 - Electricity Brokers, Aggregators, and Marketers
☐ NPCC	☐	7 - Large Electricity End Users
☐ SERC	☐	8 - Small Electricity End Users
☐ SPP	☐	9 - Federal, State, and Provincial Regulatory or other Government Entities
☐ WECC		
☐ Not Applicable		

Which of the following Function(s)[1] do you have expertise or responsibilities:

☐ Reliability Authority	☐ Transmission Service Provider
☐ Balancing Authority	☐ Transmission Owner
☐ Interchange Authority	☐ Load Serving Entity
☐ Planning Authority	☐ Distribution Provider
☐ Transmission Operator	☐ Purchasing-selling Entity
☐ Generator Operator	☐ Generator Owner
☐ Transmission Planner	☐ Resource Planner
	☐ Market Operator

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group.

[1] These functions are defined in the NERC Functional Model, which is downloadable from the NERC website.

Name: Organization:	Office Telephone: Email:
Name: Organization:	Office Telephone: Email:

When completed, email to: gerry.cauley@nerc.net

Standard Authorization Request Form

Title of Proposed Standard	Assess Transmission Future Needs and Develop Transmission Plans
Request Date	May 01, 2004
Revised: April 30, 2006	

SAR Requestor Information	**SAR Type** (Put an 'x' in front of one of these selections)	
Name Paul Rocha	☒	New Standard
Primary Contact Paul Rocha	☐	Revision to existing Standard
Telephone (713) 207-2768 Fax	☐	Withdrawal of existing Standard
E-mail paul.rocha@centerpointenergy.com	☐	Urgent Action

Purpose/Industry Need (Provide one or two sentences)

To establish a standard for assessing and planning the transmission systems in North America. The transmission system must be assessed and planned to ensure that it performs its intended functions in providing reliable delivery of power for the future needs of customers.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies by double clicking the grey boxes.)*		
☒	Reliability Authority	Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest reliability authority.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules
☒	Planning Authority	Plans the bulk electric system
☐	Resource Planner	Develops a long-term (>1year) plan for the resource adequacy of specific loads within a Planning Authority area.
☒	Transmission Planner	Develops a long-term (>1 year) plan for the reliability of transmission systems within its portion of the Planning Authority area.
☐	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
☒	Transmission Owner	Owns transmission facilities
☐	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
☐	Distribution Provider	Provides and operates the “wires” between the transmission system and the customer
☐	Generator Owner	Owns and maintains generation unit(s)
☐	Generator Operator	Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services
☐	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required
☐	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.
☒	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check boxes for all that apply by double clicking the grey boxes.)*	
☒	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box by double clicking the grey area.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft, modify, or withdraw a Standard based on this description.)

The Standard shall establish requirements, where requirements don't exist, and verify and clarify the existing reliability standards for assessing the performance of planned bulk electric transmission systems and the requirements for documenting plans to remedy any inadequacies identified in the process of conducting such assessments.

The scope of such assessments and plans is for a future planning period (planning horizon) starting beyond the operating horizon and extending to five years or more.

The planning horizon must be long enough to permit timely implementation of viable solutions to remedy the potential inadequacies found. Planning horizons beyond 5 years may be needed to meet regulatory or legislative requirements, or may be based on the judgment of the Transmission Planner or Planning Authority.

The scope *does not* include the operating horizon, typically less than one year. While the planning horizon is intended to provide sufficient time for facility additions, there is no intent to exclude appropriate operating procedures as options to correct potential transmission inadequacies. Such procedures should also be included in the Transmission Plan.

The Standard will address the transition from the operating horizon to the planning horizon. In particular, the Standard will assure consistency between reliability requirements set forth in the Standards for Planning (for example,,TPL-001 through TPL-004) and similar criteria required by other Standards (such as FAC-008-1 through FAC-013-1 standards, "Determine Facility Ratings, Operating Limits and Transfer Capabilities"), which also apply in operations.

In addition, the Standard shall address the relationship between the reliability requirements for operations and those for planning, so that differences are better understood.

The Standard shall identify reliability performance requirements, but shall not specify *how* to achieve such performance requirements.

The existing NERC Reliability Standards TPL-001-0 through TPL-004-0 will be used as the starting point in drafting these requirements.. Included will be requirements that each Planning Authority and Transmission Planner document modeling assumptions, including the methodology used for incorporating planned generation assets (including transfers) in the model, as well as how such generation is dispatched. The Standard may address a requirement for Load Serving Entities (LSEs) to provide forecast resource data for input to the models.

While methodologies and assumptions must be documented, the Standard will *not* prescribe specific tools to be used in the performance assessment of the planned systems.

This Standard will *not* include requirements for:

- Resource Planning (i.e., assessing or ensuring the availability of adequate aggregate generation resources to serve aggregate load).
- Planning generation additions to remedy any aggregate generation resource inadequacies.
- Developing Transmission Plans to mitigate congestion due to economy transfers of generation resources.

However, the Standard should neither preclude nor require the consideration of generation or load (demand side management) as alternatives to transmission reinforcement/reconfiguration when developing solutions to potential transmission inadequacies.

While the Standard should start from and closely align with the existing Reliability Standards TPL-001-0 through TPL-004-0, the system conditions to be studied or assessed may need to be better defined or clarified.

Examples of areas that should be considered for clarification in the Standard include:

- The Standard should clarify that the requirement to assess the performance at *all* demand levels does not mean that a multitude of transmission models need to be created for every possible demand level, only that a representative sample covering critical operating conditions needs to be modeled in accordance with appropriate criteria. (TPL-001-0 through TPL-004-0)
- The Standard should provide a clearer definition of "cascading outages", including what constitutes a cascading state. The Standard should also consider providing a clearer definition of "system stable". (TPL-001-0 through TPL-004-0)

These definitions must be coordinated and consistent with definitions in other new Standards either being drafted or recently approved by NERC, such as Standards FAC-008-1 through FAC-013-1 (Determine Facility Ratings) and IRO-007-1 through IRO-013-1 (Operate within Interconnection Reliability Operating Limits) .

- The Standard should take into account the variability of generation, including unit maintenance outages, weather and time of day. Variability of load due to factors such as weather and time of day should also be considered. (TPL-001-0 through TPL-004-0)
- The Standard should continue to use deterministic criteria. The criteria embodied in Table 1 of existing Reliability Standards TPL-001-0 through TPL-004-0 shall be used as a starting point. Following a review of the likelihood, duration, impact of events, and definition of applicable ratings in existing Table I, a reclassification of Table I events should be considered, as necessary, for inclusion in the new Standard.

Other changes should be considered for incorporation into the new Standard. Such changes could include:

1) Addition or deletion of categories/events/performance requirements.
2) Use of probabilistic planning methods.
3) Re-definition of categories (e.g., categories determined by event probability levels or ranges).
4) Differences in requirements for an event based on a range of event probabilities (for example, recognize that longer lines have a greater probability of outage than shorter lines).
5) An alternative table, similar to Table I of existing Reliability Standards TPL-001-0 through TPL-004-0, except allowing for probabilistic planning criteria.
6) Provision for a specific facility with an abnormal outage probability to have different performance requirements.

The list above is intended to be illustrative and not exhaustive or mutually exclusive. As allowed by the Standards Development Process, Regions may submit Regional Differences.

- Existing Reliability Standard TPL-001-0 through TPL-004-0 and Table I, Categories A, B, C, and D should be clarified on the issue of how a planned outage should be used in an assessment. The Standard should specify whether the planned outage requirement should be retained for Categories B and C. If retained, the requirement should be clarified in such a way that it can be practically implemented. In particular, the Transmission Planner should not be required to exhaustively test its system for every conceivable planned outage (including maintenance outages) in addition to every conceivable Category B and C contingency. The Standard should clarify that the planned outage requirement does not apply to Categories A and D.
- The Standard should address and rectify ambiguities in performance requirements, specifically cascading outages and applicable ratings. This applies to all Categories, especially Category C. For example, the Standard should clarify tests used for considering cascading, such as divergent power flow, post-contingency overload limits, voltage magnitudes, etc. The Standard should also clarify that different ratings may be applicable to different categories of events and perhaps different types of events within a category (specified by entities in accordance with (IRO-007-1 through IRO-013-1 (Operate within Interconnection Reliability Operating Limits)).

- The Standard should include requirements to ensure that the maximum available short circuit current does not exceed facility owner specifications.
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Data provided by Marv Landauer based on outage data collected by BPA.

Standard Authorization Request Form

Title of Proposed Project:	Revisions to TPL-001 through TPL-006, Transmission System Performance and Assessment (This SAR is intended to supplement the SAR for Assess Transmission Future Needs and Develop Transmission Plans dated April 30, 2006 in support of Standards Project 2006-02.)
Request Date	January 17, 2007

SAR Requestor Information		**SAR Type** (*Check a box for each one that applies.*)	
Name	Assess Transmission Future Needs Standard Drafting Team	☐	New Standard
Primary Contact	Robert Millard – Vice Chair, ATFNSDT	☒	Revision to existing Standards
Telephone Fax	(708) 588-9886 none	☒	Withdrawal of existing Standard (possible)
E-mail	bob.millard@rfirst.org	☐	Urgent Action

Purpose (Describe the purpose of the standard — what the standard will achieve in support of reliability.)

This SAR is intended to supplement the SAR for Assess Transmission Future Needs and Develop Transmission Plans dated April 30, 2006 in support of Standards Project 2006-02.

The revisions to the following standards would improve technical clarity and address concerns identified by stakeholders and FERC:

TPL-001 — System Performance under Normal Conditions
TPL-002 — System Performance Following Loss of a Single BES Element
TPL-003 — System Performance Following Loss of Two or More BES Elements
TPL-004 — System Performance Following Extreme BES Events
TPL-005 — Regional and Interregional Self-Assessment Reliability Reports
TPL-006 — Data from the Regional Reliability Organization Needed to Assess Reliability

Revisions to TPL-001 through TPL-004 are already underway (Assess Transmission Future Needs and Develop Transmission Plans Standard Drafting Team) with the primary focus to clarify the associated Table 1, Transmission System Standards – Normal and Emergency Conditions, used to identify the criteria for system assessments. The expansion of the work already underway with TPL-001 through TPL-004 will focus on the general improvements to the standard identified through the attached *Appendix A: Reliability Standard Review Guidelines* and the FERC and stakeholder concerns identified in the attached *Appendix B: TPL-001 through TPL-006 Technical Issues List*.

TPL-005 and TPL-006, which require regional and inter-regional assessments based on the system performance requirements stated in TPL-001 through TPL-004, need to be modified or retired to address the "fill-in-the blank" components and establish requirements within the standards or through a contractual arrangement as to which entity should perform and provide the subject assessment and data. If these requirements are addressed through the delegation agreements each Region has with the Electric Reliability Organization (ERO), TPL-005 and TPL-006 could be retired.

The purpose of modifying this set of standards is to:

1. Provide an adequate level of reliability for the North American bulk power systems — ensure each of the standards is complete and the requirements are set at an appropriate level to ensure reliability.
2. Ensure each of the standards is enforceable as a mandatory reliability standard with financial penalties — the applicability to bulk power system owners, operators, and users, and as appropriate particular classes of facilities, is clearly defined; the purpose, requirements, and measures are results-focused and unambiguous; the consequences of violating the requirements are clear.
3. Make general improvements using the Reliability Standard Review Guidelines and consider the items mentioned in the Technical Issues Lists prepared by the NERC staff which attempt to capture comments from the:
    - FERC NOPR (Docket #RM06-16-00 dated October 20, 2006) ,
    - FERC staff report dated May 11, 2006 concerning NERC standards submitted with ERO application,
    - Version 0 and Phase 3&4 standards development (see note 1),
    - Violations Risk Factors (VRF) drafting team (see note 1),
    - Regional Fill-in-the-Blank Team (RRSWG — a NERC working group involved

with regional standards development), and

- Draft SAR for Planning Authority

The SDT should also consider any other issues that were not completely captured but were stated or referenced in the above materials.

Note 1: Comments received from the industry during public postings of the TPL subject matter were sometimes outside the work being posted or outside the drafting team's scope and were not reflected in the drafting of the final work product. These should now be considered by this SDT.

Industry Need (Provide a detailed statement justifying the need for the proposed standard, along with any supporting documentation.)

The six standards in this set are all Version 0 standards. As the ERO begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. The Version 0 standards and recent updates were put in place as a temporary starting point to start-up the ERO and begin enforcement of mandatory standards. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 translation and any subsequent standards development that have implications to the TPL standards.

Brief Description: (Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.)

The proposed work effort will address three main issues:

1. Conformance to the new rules and regulations brought about by Section 215 of the Federal Power Act and the creation of the ERO,
2. Supplement the approved work of the existing ATFNSDT to include the necessary revisions to TPL-005 & TPL-006, and
3. Address technical issues raised by FERC and industry stakeholders.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☒	Resource Planner	Develops a (>one year) plan for the resource adequacy of its specific loads within its portion of a Planning Coordinator area.
☒	Transmission Planner	Develops a (>one year) plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generating facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☒	Load-Serving Entity	Secures energy and transmission service (and related reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft a standard based on this description.)

This SAR expands on the work already underway with the Assess Transmission Future Needs and Develop Transmission Plans Standard Drafting Team, by requiring that TPL-001 through TPL-006 be upgraded in accordance with the Reliability Standards Development Plan 2007–2009. These revisions include the following:

This SAR will be appended to the already approved SAR for Assess Transmission Future Needs and Develop Transmission Plans and will include modifications to all of the following standards:

TPL-001 — System Performance under Normal Conditions
TPL-002 — System Performance Following Loss of a Single BES Element
TPL-003 — System Performance Following Loss of Two or More BES Elements
TPL-004 — System Performance Following Extreme BES Events
TPL-005 — Regional and Interregional Self-Assessment Reliability Reports
TPL-006 — Data from the Regional Reliability Organization Needed to Assess Reliability

The revisions would improve technical clarity and address concerns identified by stakeholders and FERC. The drafting team will focus on the general improvements to the standards and use as a starting point for the expanded work the subject matter identified in *Appendix A: Reliability Standard Review Guidelines* and the FERC and stakeholder concerns identified in *Appendix B: TPL-001 through TPL-006 Technical Issues List*.

The expanded scope also will include elimination of the 'fill-in-the-blank' elements of TPL-005 and TPL-006, which require regional and inter-regional assessments based on the system performance requirements stated in TPL-001 through TPL-004. The standards need to be modified or retired to address the "fill-in-the blank" components. If the 'fill-in-the-blank' requirements are addressed through the contractual arrangements each Region has with the ERO, TPL-005 and TPL-006 could be retired.

The drafting team must ensure that there is consistency in the requirements across the set of TPL standards

The overall development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards, using the attached, Reliability Standard Review Guidelines. In addition, the drafting team will need to make conforming changes to standards impacted by changes made to these six standards.

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

Regional Differences

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Appendix A: Reliability Standard Review Guidelines

Applicability
Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose
Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements
Does this reliability standard state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability
Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations
Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness
Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?

Consequences for Noncompliance

In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, are the consequences of violating a standard clearly known to the responsible entities?

Clear Language
Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality
Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements
In general, requirements for entities to have 'capabilities' (this would include facilities for communication, agreements with other entities, etc.), should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to 'maintain' their capabilities.

Consistent Terminology
To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a 'unique' definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the 'verb list' from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

This is a requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A requirement that is administrative in nature;

Or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

Time Horizon

The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

Violation Severity Levels

The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. ('Violation severity levels' replaces the existing 'levels of non-compliance.') The violation severity levels may be applied for each requirement or combined to cover multiple requirements, as long as it is clear which requirements are included.

The violation severity levels should be based on the following definitions:

- **Lower: mostly compliant with minor exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
- **Moderate: mostly compliant with significant exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.

- **High: marginal performance or results** — the responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: 70% to 84% compliant.
- **Severe: poor performance or results** — the responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.

Compliance Monitor
Replace, 'Regional Reliability Organization' with 'Regional Entity'

Fill-in-the-blank Requirements
Do not include any 'fill-in-the-blank' requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard – then require another entity to comply with those requirements.

Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in under-frequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.

Requirements for Regional Reliability Organization
Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.

Effective Dates
Must be 1st day of 1st quarter after entities are expected to be compliant – must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply. If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan.

Associated Documents
If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, 'Associated Documents'.

Appendix B: TPL-001 through TPL-006 Technical Issues List

Excerpted from NERC Reliability Standards Development Plan: 2007 - 2009

TPL-001
FERC NOPR

- Require that critical system conditions be determined by conducting sensitivity studies; *(Not necessarily "cook book" but what are the processes someone reasonably skilled in the art would follow.)*
- Require that system conditions and contingencies assessed be reviewed by neighboring systems; *(Looking for coordination with neighboring systems)*
- Modify Requirement R1.3 to substitute the reference to regional reliability organization with Regional Entity;
- Require consideration of planned outages of critical equipment; and
- Modify footnote (a): footnote (a) to Table 1 requires clarification. The NERC Transmission Issues Subcommittee (TIS) 325 recommended that footnote (a) be modified to state explicitly that emergency ratings apply to Category B and C (contingency conditions) and not to Category A (system intact). The Commission proposes that footnote (a) be modified in the revised Reliability Standard as recommended by TIS and that the normal facility rating be in accordance with Reliability Standard FAC-008-1 and normal voltages be in accordance with Reliability Standard VAR-001-1.

FERC Staff Report

- Only for normal
- Doesn't consider planned outages
- Clarify footnote 'a' & 'b' in table
- Stress system during simulations
- Include sensitivity studies
- Include extreme events

Version 0 Industry Comments

- Several semantic issues
- Clarify timing for submittal of corrective plan
- Clarify use of applicable ratings in Table 1, note 'a'
- Need to address deliverability to load
- Define critical system conditions
- Allow for engineering judgment in setting conditions for power flow
- Do planned facilities include just those under construction?
- Need to include multiple time frames
- What is a major load center?
- Table 1 – C.5 goes beyond double circuit outage criteria
- Table 1, items 6, 7, 8 & 9 need footnote stating that they do not apply to generator breaker failure
- Table 1, note 'b' – clarify when to curtail firm deliveries

Phase III/IV Comments

- Add a requirement to verify that there are sufficient reactive resources
- Add a requirement to identify where UVLS should be installed

Violation Risk Factors (VRF) Drafting Team Comment

- R1 – time horizon should be long-term planning

Comment from Draft SAR on Planning Authority

- Provide clarity where the Planning Authority is mentioned

TPL-002:
FERC NOPR

- Require that critical system conditions be determined in the same manner as we propose to require for TPL-001-0;
- Require the inclusion of the reliability impact of the entities' existing spare equipment strategy; *(Only looking for consideration of spare equipment that has a long lead time such as a transformer)*
- Explicitly require all generators to ride through the same set of Category B and C contingencies as required for wind generators in Order No. 661; *(Document explicit definition of ride through capability for generators)*
- Require documentation of load models used in system studies and supporting rationale for their use;
- Clarify the phrase "permit operating steps necessary to maintain system control;" and
- Clarify footnote (b): modify footnote (b) to state that load shedding for a single contingency is not permitted except in very special circumstances where such interruption is limited to the firm load associated with the failure (consequential load loss).330 For purposes of clarity, the Commission proposes to require that the phrase "to prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers" be deleted from footnote (b). This statement is more appropriate for Category C events and is already captured by footnote (c) to Table 1, which is applicable to Category C events.

FERC staff report

- Only includes loss of single element
- NERC TIS Report recommendations not addressed

Version 0 Industry Comments

- Define critical system conditions
- Clarify timing for corrective plan
- Address deliverability of generation to load
- Clarify applicable ratings in Table 1, note 'a'
- Don't include generation runback or re-dispatch
- Must study all contingencies and multiple demand levels & time frames
- Don't include planning outage
- Single terminals are not included

Phase III/IV comments

- Add a requirement to verify that there are sufficient reactive resources
- Add a requirement to identify where UVLS should be installed

VRF comments

- Time horizon should be long-term planning and R2.2 – redundant with R1.3.8

Comment from draft SAR on Planning Authority

- Provide clarity where the Planning Authority is mentioned

TPL-003:
FERC NOPR

- Require that critical system conditions be determined by conducting sensitivity studies (as elaborated in our discussion of TPL-001-0);
- Clarify footnote c: modify footnote (c) to provide specificity regarding the use of the term "controlled interruption" of load.
- Require the applicable entities to define and document the proxies necessary to simulate cascading outages; and
- Tailor the purpose statement to reflect the specific goal of the Reliability, as discussed above.

FERC Staff Report

- Same as TPL-001 & 002

Version 0 Industry Comments

- Same as TPL-001 & 002
- TO should provide plan of action
- Don't base penalties on low probability, low consequence events
- Use NERC Compliance Reporting Process
- Clearly identify outages

Phase III/IV Comments

- Add a requirement to verify that there are sufficient reactive resources
- Add a requirement to identify where UVLS should be installed

VRF Comment

- Time horizon should be long-term planning
- R2 – lack of consistency with TPL-001 & TPL-002
- R2.1 - lack of consistency with TPL-001
- R2.1.1 - lack of consistency with TPL-001 & TPL-004
- R2.1.2 - lack of consistency with TPL-001 & TPL-005
- R2.1.3 - lack of consistency with TPL-001 & TPL-006
- R2.2 - lack of consistency with TPL-001 & TPL-007

Comment from Draft SAR on Planning Authority

- Provide clarity where the Planning Authority is mentioned

TPL-004:
FERC NOPR

- Require that critical system conditions be determined in the same manner as proposed for TPL-001-0;
- Require the identification of options for reducing the probability or impacts of extreme events that cause cascading;
- Require that, in determining the range of extreme events to be assessed, the contingency list of Category D be expanded to include recent events; and
- Tailor the purpose statement to reflect the specific goal of the Reliability Standard.

FERC Staff Report

- Need to reduce the probability of loss of multiple elements and mitigating impact
- Share assessments
- Need to be more severe than weather
- Same as TPL-001

Version 0 Industry Comments

- Same as TPL-001
- Perform analysis on credible contingency
- R1.3.9 – remove from extreme events
- TO should determine which events to study

Phase III/IV Comments

- Add a requirement to verify that there are sufficient reactive resources
- Add a requirement to identify where UVLS should be installed

Comment from Draft SAR on Planning Authority

- Provide clarity where the Planning Authority is mentioned

TPL-005:

FERC NOPR

- Commission will not propose any action on TPL-005-0, as it applies only to regional reliability organizations.
- The term and extent of assessment, as well as the study years, are not appropriately defined; the process for determining load levels needs to be standardized; and local area networks and system adjustments need to be specifically defined.

Regional Fill-in-the-Blank Team Comments

- New SAR needed

Version 0 Industry Comments

- Define fuel adequacy
- An RRO can't make a mandatory request for another RRO to perform a study

TPL-006:
FERC NOPR

- Commission will not propose any action on TPL-006-0, as it applies only to regional reliability organizations.

Comment Form — SAR to Supplement the SAR for Assess Transmission Future Needs and Develop Transmission Plans

Please use this form to submit comments on the proposed SAR to Supplement the SAR for Assess Transmission Future Needs and Develop Transmission Plans. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "TPL Supplement SAR" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowoski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, or ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 – Regional Reliability Organizations, or Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This SAR is intended to supplement the already-approved SAR for Assess Transmission Future Needs and Develop Transmission Plans dated April 30, 2006. The Assess Transmission Future Needs and Develop Transmission Plans SAR includes revisions to TPL-001 through TPL-004 with the primary focus to clarify the associated Table 1, Transmission System Standards – Normal and Emergency Conditions, used to identify the criteria for system assessments.

The supplementary SAR would expand the scope or the original SAR to include TPL-005 and TPL-006 and upgrade the entire set of standards (TPL-001 through TPL-006) to conform to the latest version of the Reliability Standards Procedure Development and the ERO Rules of Procedure.

TPL-005 and TPL-006, which require regional and inter-regional assessments based on the system performance requirements stated in TPL-001 through TPL-004, need to be modified or retired to address the "fill-in-the blank" components and establish requirements within the standards or through a contractual arrangement as to which entity should perform and provide the subject assessment and data. If these requirements are addressed through the delegation agreements each Region has with the Electric Reliability Organization (ERO), TPL-005 and TPL-006 could be retired.

The intent is to comprehensively address all necessary revisions to the entire set of TPL Standards:

TPL-001 — System Performance under Normal Conditions
TPL-002 — System Performance Following Loss of a Single BES Element
TPL-003 — System Performance Following Loss of Two or More BES Elements
TPL-004 — System Performance Following Extreme BES Events
TPL-005 — Regional and Interregional Self-Assessment Reliability Reports
TPL-006 — Data from the Regional Reliability Organization Needed to Assess Reliability

Please review the SAR and then answer the questions on the following page. Please submit the completed form by e-mail to sarcomm@nerc.com with the words "TPL Supplement SAR" in the subject line by **March 16, 2007**.

You do not have to answer all questions.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you believe that there is a reliability-related need to provide additional detail, including specific issues for consideration, to the requirements in this set of standards as proposed in this supplemental SAR?

   ☐ Yes

   ☐ No

   Comments:

2. Do you agree with the expanded scope of the proposed project as set forth in this supplemental SAR? (The scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high-quality, enforceable, and technically sufficient bulk power system reliability standards. Please consider these items as non-mandatory and only for consideration by the drafting team.)

   ☐ Yes

   ☐ No

   Comments:

3. Do you think that there are any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the April 30, 2006 version of the original SAR and this supplemental SAR?

   ☐ Yes

   ☐ No

   Comments:

Maureen E. Long
Standards Process Manager

February 15, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement: Three 30-day Comment Periods Open

The Standards Committee (SC) announces the following standards actions:

SAR to Amend the Assess Transmission Future Needs and Develop Transmission Plans SAR Posted for 30-day Comment Period February 15–March 16, 2007

The SAR to amend the already-approved SAR for Assess Transmission Future Needs and Develop Transmission Plans (Project 2006-02) proposes to add TPL-005-0 and TPL-006-0 to the list of transmission planning standards currently addressed (TPL-001 through TPL-004), to consider issues raised by FERC and stakeholders regarding this set of standards, and to bring the entire set of standards into conformance with the ERO Rules of Procedure and the latest version of the Reliability Standards Development Procedure. Please use the comment form to provide comments on this SAR amendment.

First Standard (MOD-001-1) in the Series of ATC/TTC/AFC Revisions Posted for 30-day Comment Period February 15–March 16, 2007

The first standard modified under Project 2006-07, MOD-001-1 — ATC and AFC Calculation Methodologies, requires the Transmission Service Provider to document and use a single methodology for calculating ATC or AFC. The drafting team is soliciting comments on the proposed requirements before developing the measures and compliance elements. Please use the comment form to provide comments on this draft standard's proposed requirements.

Second Draft of SAR for Backup Facilities Posted for 30-day Comment Period February 15–March 16, 2007

The SAR for Project 2006-04 proposes modifying EOP-008-0 — Plans for Loss of Control Center Functionality. The revisions to EOP-008 focus on ensuring the continuation of functionality needed for reliable system operation regardless of the manner in which it is achieved. The modifications will consider issues raised by FERC and stakeholders about this standard, and will bring the standard into conformance with the ERO Rules of Procedure and the latest version of the Reliability Standards Development Procedure. Please use the comment form to provide comments on this SAR.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

116-390 Village Boulevard, Princeton, New Jersey 08540-5721
Phone: 609.452.8060 ▪ Fax: 609.452.9550 ▪ www.nerc.com

Comment Form — SAR to Supplement the SAR for Assess Transmission Future Needs and Develop Transmission Plans

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	James H. Sorrels, Jr.	
Organization:	AEP	
Telephone:	(614) 716-2370	
E-mail:	jhsorrels@aep.com	
NERC Region		**Registered Ballot Body Segment**
☒ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, or ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
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☐ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
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Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

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TPL-003 — System Performance Following Loss of Two or More BES Elements
TPL-004 — System Performance Following Extreme BES Events
TPL-005 — Regional and Interregional Self-Assessment Reliability Reports
TPL-006 — Data from the Regional Reliability Organization Needed to Assess Reliability

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Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

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   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the expanded scope of the proposed project as set forth in this supplemental SAR? (The scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high-quality, enforceable, and technically sufficient bulk power system reliability standards. Please consider these items as non-mandatory and only for consideration by the drafting team.)

   ☒ Yes

   ☐ No

   Comments: Considering the current scope, the Std DT should be encouraged to consider a major re-write of TPL-001 thru TPL-006, possibly including a restructuring into a single standard rather than the present multiple standards.

3. Do you think that there are any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the April 30, 2006 version of the original SAR and this supplemental SAR?

   ☐ Yes

   ☒ No

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Steve Myers	
Organization:	ERCOT	
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E-mail:	smyers@ercot.com	
NERC Region		**Registered Ballot Body Segment**
☒ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs, or ISOs
☐ **MRO**	☐	3 — Load-serving Entities
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   ☒ Yes

   ☐ No

   Comments: I recommend that you clarify that these lists of items in Appendix B are topics to consider, not topics that must be included. Also, I recommend that any standards requirements that are evident as Good Utility Practice or procedural in nature be retired as requirements, but retained in the form of reference documents, operating guidelines, or some other similar form that will be available to any industry participant that wishes to use them.

2. Do you agree with the expanded scope of the proposed project as set forth in this supplemental SAR? (The scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high-quality, enforceable, and technically sufficient bulk power system reliability standards. Please consider these items as non-mandatory and only for consideration by the drafting team.)

   ☒ Yes

   ☐ No

   Comments: Please also see my response to Question #1.

3. Do you think that there are any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the April 30, 2006 version of the original SAR and this supplemental SAR?

   ☐ Yes

   ☒ No

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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Organization:	Exelon	
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E-mail:	eric.mortenson@exeloncorp.com	
NERC Region		**Registered Ballot Body Segment**
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   ☒ Yes

   ☐ No

   Comments: I believe that most of the additional information contained in the draft 'supplemental' SAR is valuable and will assist the SDT in addressing the various stakeholder concerns. I am concerned with conflicting information addressed below.

   I am not familiar with the concept of a supplemental SAR and am not sure if there are going to be two SARs now, or if this new effort supercedes the existing SAR. This is especially a concern when there appear to be differences between them regarding functional applicabilities and principles, as well as the expansion of scope.

   I understand the Standards Development Procedure to require the original SAR to be modified, when it states, "If the standard drafting team determines it is necessary to expand the scope of the standard ot to modify the scope in a way that is no longer consistent with the scope defined in the SAR, then the drafting team may initiate or recommend another requestor initiate a new SAR (Step 1) to develop the expanded or modified scope. At no time will a drafting team develop a standard that is not within the scope ot the SAR that was authorized for development."

2. Do you agree with the expanded scope of the proposed project as set forth in this supplemental SAR? (The scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high-quality, enforceable, and technically sufficient bulk power system reliability standards. Please consider these items as non-mandatory and only for consideration by the drafting team.)

   ☐ Yes

   ☒ No

   Comments: The approved SAR is of type 'New Standard' while the supplemental SAR type is not, but rather, 'Revision to existing Standards' as well as, 'Withdraw of existing Standard (possible)'.

   Regarding the Reliability Function Applicabilities, the supplemental SAR does not include the Reliability Authority or the Planning Authority which were included in the approved SAR, and the supplemental SAR includes the Resource Planner and Generation Owner functions, which are not included in the approved SAR. I believe that the Planning Authority needs to be addressed in terms of the FERC NOPR discussion, summarized on pages B3 and B4 of the supplemental SAR.

   The supplemental SAR includes item 7 in the Applicable Reliability Principles, while the approved SAR does not.

If there are going to be two SARs then I believe that the supplemental SAR should include the previously approved SAR in the 'Related SARs' section on page 7.

The concise summaries of the Version 0 Industry comments are appreciated, but these should be made more clear in that these will probably become key to any actual changes to planning contingencies. For example, it is not clear what, 'Address deliverability of generation to load' means. Also, does, 'Don't include generation runback or redispatch' mean that this shouldn't be addressed or that the standard should be worded to specifically not include them. Other terms such as, 'Don't include planning outage', and 'single terminals are not included' should also be more thoroughly described.

3. Do you think that there are any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the April 30, 2006 version of the original SAR and this supplemental SAR?

   ☐ Yes

   ☐ No

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
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   ☐ No

   Comments:

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   ☒ Yes

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Kathleen Goodman	
Organization:	ISO New England	
Telephone:	(413) 535-4111	
E-mail:	kgoodman@iso-ne.com	
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You do not have to answer all questions.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you believe that there is a reliability-related need to provide additional detail, including specific issues for consideration, to the requirements in this set of standards as proposed in this supplemental SAR?

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the expanded scope of the proposed project as set forth in this supplemental SAR? (The scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high-quality, enforceable, and technically sufficient bulk power system reliability standards. Please consider these items as non-mandatory and only for consideration by the drafting team.)

   ☐ Yes

   ☒ No

   Comments: We do not support a long-term planning standards applying to RCs. The NERC functional model is very clear that RCs are operational entities. Is the intent to replace RRO with RC for the fill-in-the-blank standards? That would be an inappropriate solution. A more appropriate solution would be to consider replacing the RRO with the planning coordinator.

   We also do not understand how a transmission planning standard could apply to the additional functional entities: Transmission Owner and Generator Owner.

3. Do you think that there are any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the April 30, 2006 version of the original SAR and this supplemental SAR?

   ☐ Yes

   ☒ No

   Comments:

Comment Form — SAR to Supplement the SAR for Assess Transmission Future Needs and Develop Transmission Plans

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Brian Thumm	
Organization:	ITC Transmission	
Telephone:	248.374.7846	
E-mail:	bthumm@itctransco.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, or ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
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☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
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☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 – Regional Reliability Organizations, or Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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1. Do you believe that there is a reliability-related need to provide additional detail, including specific issues for consideration, to the requirements in this set of standards as proposed in this supplemental SAR?

   ☒ Yes

   ☐ No

   Comments: The original SAR did a good job of capturing many of the reliability improvements necessary to the TPL Standards. Now that additional information is available from the various stakeholder groups and drafting teams, it is clear that additional reliability-related improvements to the Standards can be made. It is not clear how to quantify the additional improvement the supplemental SAR will make to the existing Standard Drafting effort, but certqainly there are additional reliability improvements to be made to each of the subject Standards.

2. Do you agree with the expanded scope of the proposed project as set forth in this supplemental SAR? (The scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high-quality, enforceable, and technically sufficient bulk power system reliability standards. Please consider these items as non-mandatory and only for consideration by the drafting team.)

   ☐ Yes

   ☒ No

   Comments: Standard Drafting Teams should not be responding so heavily to comments made by FERC in a NOPR. The NOPR is just that … "Proposed." There may be additional changes required as a result of the final Rule. The final Rule may even negate some of the proposed changes made in the NOPR. If the drafting team thinks that FERC hit on a good idea for improvement, then it would be appropriate for inclusion in the Standard, but simply to make changes to a Standard because an idea surfaced in a Proposed Rule is premature.

3. Do you think that there are any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the April 30, 2006 version of the original SAR and this supplemental SAR?

   ☐ Yes

   ☒ No

   Comments:

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Michael Gammon	
Organization:	Kansas City Power & Light	
Telephone:	816-654-1242	
E-mail:	mike.gammon@kcpl.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, or ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
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☐ **WECC**	☐	8 — Small Electricity End Users
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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   ☒ Yes

   ☐ No

   Comments:

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   ☒ Yes

   ☐ No

   Comments:

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   ☐ Yes

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Ron Mazur	
Organization:	Manitoba Hydro	
Telephone:	(204) 474-3113	
E-mail:	rwmazur@hydro.mb.ca	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, or ISOs
☒ **MRO**	☒	3 — Load-serving Entities
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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1. Do you believe that there is a reliability-related need to provide additional detail, including specific issues for consideration, to the requirements in this set of standards as proposed in this supplemental SAR?

   ☒ Yes

   ☐ No

   Comments: Manitoba Hydro believes the planning standards should ensure that complete and consistent assessments are conducted by the responsible entities.

2. Do you agree with the expanded scope of the proposed project as set forth in this supplemental SAR? (The scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high-quality, enforceable, and technically sufficient bulk power system reliability standards. Please consider these items as non-mandatory and only for consideration by the drafting team.)

   ☒ Yes

   ☐ No

   Comments: Manitoba Hydro agrees in principle with the expanded scope, but believes that this scope should be a part of the Standards Development Procedures manual so all stakeholdrs have a voice in the requirements in Appendix A. We have some concern that the SAR gives the drafting team the power to add additional improvements beyond the SAR as this provides an opportunity for SDT members to forward specific owner agendas.

3. Do you think that there are any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the April 30, 2006 version of the original SAR and this supplemental SAR?

   ☒ Yes

   ☐ No

   Comments: The SAR should considering adding a requirements to the standards to mandate tests for robustness by doing sensitivity to critical system paramenters such as lload growth rate, load power factor, etc.to provide insight into the margin between the operating point and unacceptable performance. There should also be a specific requirement to assess reactive power adequacy, voltage stability and system damping.

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Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
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	☐	10 – Regional Reliability Organizations, or Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: Midwest ISO Stakeholders' Standards Collaboration Participants

Lead Contact: **Jason Marshall**

Contact Organization: **MISO**

Contact Segment: **2**

Contact Telephone: **317-249-5494**

Contact E-mail: **jmarshall@midwestiso.org**

Additional Member Name	Additional Member Organization	Region*	Segment*
Jim Cyrulewski	JDRJC Associates	RFC	8

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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   ☒ Yes

   ☐ No

   Comments: As the standards are written now, all of the requirements apply to both the Transmission Planner and Planning Authority. The NERC Functional Model Version 3 replaced the Planning Authority with the Planning Coordinator . The standards should reflect this change as well as the division of responsibilities between Transmission Planner and Planning Coordinator in the functional model.

   Additionally, they should seek to clarify the relationship between Transmission Planner and Planning Coordinator. How many transmission planners can their be per Planning Coordinator. Can there be overlapping Planning Coordinators?

2. Do you agree with the expanded scope of the proposed project as set forth in this supplemental SAR? (The scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high-quality, enforceable, and technically sufficient bulk power system reliability standards. Please consider these items as non-mandatory and only for consideration by the drafting team.)

   ☐ Yes

   ☒ No

   Comments: We do not support a long-term planning standards applying to RCs. The NERC functional model is very clear that RCs are operational entities. Is the intent to replace RRO with RC for the fill-in-the-blank standards? That would be an inappropriate solution. A more appropriate solution would be to consider replacing the RRO with the planning coordinator.

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   ☐ Yes

   ☒ No

   Comments:

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Organization:		
Telephone:		
E-mail:		
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Group Comments (Complete this page if comments are from a group.)

Group Name: Midwest Reliability Organization (MRO)

Lead Contact: **David Rudolph**

Contact Organization: **MRO for Group (MidAmerican for Contact)**

Contact Segment: **10**

Contact Telephone: **701-355-5722**

Contact E-mail: **drudolph@bepc.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
Neal Balu	WPSR	MRO	10
Terry Bilke	MISO	MRO	10
Al Boesch	NPPD	MRO	10
Robert Coish, Chair	MHEB	MRO	10
Carol Gerou	MP	MRO	10
Ken Goldsmith	ALT	MRO	10
Todd Gosnell	OPPD	MRO	10
Jim Haigh	WAPA	MRO	10
Pam Oreschnik	XCEL	MRO	10
Dick Pursley	GRE	MRO	10
Dave Rudolph	BEPC	MRO	10
Eric Ruskamp	LES	MRO	10
Mike Brytowski, Secretary	MRO	MRO	10
27 Additional MRO Members	Not Named Above	MRO	10

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   ☒ Yes

   ☐ No

   Comments:

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   ☐ Yes

   ☒ No

   Comments:

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Group Comments (Complete this page if comments are from a group.)

Group Name: NPCC CP9 Working Group

Lead Contact: **Guy V. Zito**

Contact Organization: **Northeast Power Coordinating Council**

Contact Segment: **10**

Contact Telephone: **212-840-1070**

Contact E-mail: **gzito@npcc.org**

Additional Member Name	Additional Member Organization	Region*	Segment*
Ralph Rufrano	New York Power Authority	NPCC	1
Ed Thompson	ConEdison	NPCC	1
Al Adamson	New York Power Authority	NPCC	2
Kathleen Goodman	ISO-New England	NPCC	2
Roger Champagne	TransEnergie HydroQuebec	NPCC	1
Ron Falsetti	The IESO	NPCC	2
Murale Gopinathan	Northeast Utilities	NPCC	1
Greg Campoli	New York ISO	NPCC	2
Randy Macdonald	New Brunswick System Operator	NPCC	2
Guy Zito	Northeast Power Coordinating Council	NPCC	10

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Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you believe that there is a reliability-related need to provide additional detail, including specific issues for consideration, to the requirements in this set of standards as proposed in this supplemental SAR?

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the expanded scope of the proposed project as set forth in this supplemental SAR? (The scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high-quality, enforceable, and technically sufficient bulk power system reliability standards. Please consider these items as non-mandatory and only for consideration by the drafting team.)

   ☒ Yes

   ☐ No

   Comments:

3. Do you think that there are any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the April 30, 2006 version of the original SAR and this supplemental SAR?

   ☐ Yes

   ☒ No

   Comments:

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Michael Calimano	
Organization:	New York Independent System Operator	
Telephone:	518-356-6129	
E-mail:	mcalimano@nyiso.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs, or ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
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☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
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	☐	10 – Regional Reliability Organizations, or Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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   Comments:

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   ☐ Yes

   ☒ No

   Comments: It is unclear as to what obligations the RC, TO, and GO would have in a long-term planning standard. The NERC functional model is very clear that RCs are operational entities. The RC, TO, GO ,should not have a direct obligation in the process, but should be a resource for input into the process.

3. Do you think that there are any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the April 30, 2006 version of the original SAR and this supplemental SAR?

   ☐ Yes

   ☒ No

   Comments:

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Mark Ringhausen	
Organization:	ODEC	
Telephone:	804-290-2194	
E-mail:	mringhausen@odec.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, or ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☒	4 — Transmission-dependent Utilities
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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1. Do you believe that there is a reliability-related need to provide additional detail, including specific issues for consideration, to the requirements in this set of standards as proposed in this supplemental SAR?

   ☒ Yes

   ☐ No

   Comments: The planning of the transmission system is critical to the reliability of the transmission system. Additional details provided to all stakeholders are crucial to ensure that transmission is built in a timley manner to protect the relability of the system. Also, by making the process and information available to all stakeholders, you ensure that everyone's interest is heard in the process and not just the large transmission owner/operators, but all users of the transmission system. The assumptions used in the evaluation process must be vetted by all stakeholders as they are the critical drivers on what transmission is needed and when it is needed.

2. Do you agree with the expanded scope of the proposed project as set forth in this supplemental SAR? (The scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high-quality, enforceable, and technically sufficient bulk power system reliability standards. Please consider these items as non-mandatory and only for consideration by the drafting team.)

   ☐ Yes

   ☒ No

   Comments: These are transmission planning standards and as such, should only apply to TPs, not RP, TO and GO entities. Certainly, information must be provided from the TOs and GOs on their facilities to be able to run the planning studies, but the MOd standards should cover this obligation. And RC are operating entities and not planning entities.

3. Do you think that there are any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the April 30, 2006 version of the original SAR and this supplemental SAR?

   ☐ Yes

   ☒ No

   Comments: This should be more than enough to try to get into these transmission planning standards.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Linda Brown	
Organization:	San Diego Gas and Electric	
Telephone:	858-654-6477	
E-mail:	LPBrown@semprautilities.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, or ISOs
☐ **MRO**	☐	3 — Load-serving Entities
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Contact Segment:

Contact Telephone:

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Additional Member Name	Additional Member Organization	Region*	Segment*

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   Comments:

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   ☒ Yes

   ☐ No

   Comments:

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   ☒ Yes

   ☐ No

   Comments:

   SDG&E believes that there are additional revisions that need to be incorporated into this set of standards.

   The Supplemental SAR dated January 17, 2007, has an Appendix B that summarizes issues to be resolved in this new set of standards. Those issues are a collection of comments from FERC NOPR, FERC Staff Report, Industrial comments on version 0, Phase III/IV, etc.

   In order to develop a set of reliability standards for transmission planners, SDG&E believes there are a few more issues to be addressed and/or clarified in this set of standards.

   1. Critical System Conditions

   These "Critical System Conditions" are referring to system conditions to be studied for the transmission planning. Typically, entities deem several system conditions as critical on the basis of accumulative institutional knowledge.

However, in recent FERC NOPR, FERC directs industry to conduct sensitivity studies to identify these critical system conditions and document the sensitivity studies. The sensitivity factors in FERC's direction include load power factors, generation retirements, generation dispatch, transaction patterns, controllable loads, demand side management, transmission outages.

As those will result in extensive scope of study, we would like to see this set of standards clearly answer following questions:

a. How often do we required to perform such sensitivity studies to identify critical system conditions?
b. Do we check those sensitivity factors one by one to find the worst, or do we define the worst combination as the critical? Or
c. Do we continue to leave the "critical system conditions" determination to study performer's discretion?

2. Contingencies
In Appendix B of the latest Supplementary SAR for TPL standards, comments and modification requests were summarized. Contingencies for planning studies is one of critical elements. This can be split into three issues and SDG&E provides following comments for each of them:

a. Study all contingencies
One of the comments suggests to study "all contingencies". Clearly, "All contingencies" need to be clarified. The additional workload incurred due to the dismissal of planners' accumulative institutional knowledge may be unreasonable.
b. Study non-common mode contingencies
The issue regarding reasonable workload also applies to the "non-common mode" contingencies. The non-common mode refers to combination of unrelated elements, say one 230 kV line in CFE (Mexico) and other 230 kV line in Alberta, Canada, as one contingency. This too needs clarification.
c. Study event-based contingencies
Evaluating the impact of "event-based" contingencies makes sense. However, translating an event, such as an earthquake, into a list of elements to be taken out for power flow and stability computer simulation, will need clear guidelines.

3. "Identification of options for reducing the probability or impacts of extreme events that cause cascading"
This is a direct quote of FERC's directed modification in its NOPR.

a. If the impacts only need to be identified with conceptual methods, how do we maintain "consistency" among entities?
b. If FERC intends to request the entities to identify the probability/impacts with quantitative methods, then there is a long list of issues to be addressed before a transmission planner could in reality perform such an analysis:
- How to define "cascading" in system simulation analysis.
- Reasonable and feasible probabilistic variables need to be defined. For instance, in addition to the equipment failure as probabilistic variable, other probabilistic variables need to be considered to meet FERC's direction, such as hurricanes, fires, earthquakes, lightening, flooding, landslides and even an airplane falling into a critical substation, and so on.
- Regional efforts need to be taken to develop a probabilistic methodology and probabilistic database that can be applied uniformly so entities can be treated equally.

- Regional efforts need to be taken to guide selection and/or development of probabilistic analysis software tools. Such tools have to be ready for transmission planners to use and derive quantified solutions.

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Organization:		
Telephone:		
E-mail:		
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Group Comments (Complete this page if comments are from a group.)

Group Name: IRC Standards Review Committee

Lead Contact: **Charles Yeung**

Contact Organization: **SPP**

Contact Segment: **2**

Contact Telephone: **832-724-6142**

Contact E-mail: **cyeung@spp.org**

Additional Member Name	Additional Member Organization	Region*	Segment*
Alicia Daugherty	PJM	RFC	2
Mike Calamino	NYISO	NPCC	2
Ron Falsetti	IESO	NPCC	2
Matt Goldberg	ISO-NE	NPCC	2
Brent Kingsford	CAISO	WECC	2
Anita Lee	AESO	WECC	2
Steve Myers	ERCOT	ERCOT	2
William Phillips	MISO	RFC+	2
		MRO+	
		SERC	

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   ☐ No

   Comments:

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   ☐ Yes

   ☒ No

   Comments: We do not support a long-term planning standards applying to RCs. The NERC functional model is very clear that RCs are operational entities. Is the intent to replace RRO with RC for the fill-in-the-blank standards? That would be an inappropriate solution. A more appropriate solution would be to consider replacing the RRO with the planning coordinator.

   We also do not understand how a transmission planning standard could apply to the additional functional entities: Transmission Owner and Generator Owner.

3. Do you think that there are any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the April 30, 2006 version of the original SAR and this supplemental SAR?

   ☐ Yes

   ☒ No

   Comments:

Consideration of Comments on 1st Posting of SAR to Supplement the Assess Transmission Future Needs SAR

The Supplemental Assess Transmission Future Needs SAR Drafting Team thanks all commenters who submitted comments on the Supplemental Assess Transmission Future Needs SAR. This SAR was posted for a 30-day public comment period from February 15 through March 16, 2007. The requesters asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 16 sets of comments, including comments from 42 different people associated with more than 37 companies or organizations representing 8 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received, the drafting team is recommending that the Standards Committee approve the Supplemental SAR to be moved forward to the standards drafting stage of the process.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easy to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Assess-Transmission-Future-Needs.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

No changes were made to the SAR based on received comments. The only changes that were made to the SAR at this time were to add references and appropriate supporting material to address the FERC Order 693 and to update the attachment to reflect the latest version of the Standard Review Guidelines.

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
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10 – Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	James H. Sorrels, Jr.	AEP	✓				✓	✓				
2.	Anita Lee (G1)	AESO		✓								
3.	Ken Goldsmith (G3)	ALT										✓
4.	Dave Rudolph (G3)	BEPC										✓
5.	Brent Kingsford (G1)	CAISO		✓								
6.	Ed Thompson (G2)	ConEdison										✓
7.	Steve Myers (G1) (I)	ERCOT		✓								
8.	Eric Mortenson	Exelon										
9.	Dick Pursley (G3)	GRE										✓
10.	Roger Champagne	HQT	✓									
11.	Ron Falsetti (G1) (G2) (I)	IESO		✓								
12.	Kathleen Goodman (G2) (I)	ISO-NE										✓
13.	Matt Goldberg (G1)	ISO-NE		✓								
14.	Brian Thumm	ITC Transmission	✓									
15.	Jim Cyrulewski	JDRJC Associates								✓		
16.	Michael Gammon	KCPL	✓									
17.	Eric Ruskamp (G3)	LES										✓
18.	Robert Coish, Chair (G3)	Manitoba Hydro										✓
19.	Ron Mazur	Manitoba Hydro	✓		✓		✓	✓				
20.	David Rudolph (G3)	MidAmerican										✓
21.	Jason Marshall	MISO		✓								
22.	Terry Bilke (G3)	MISO										✓
23.	William Phillips (G1)	MISO		✓								
24.	Carol Gerou (G3)	MP										✓
25.	Mike Brytowski (G3)	MRO										✓

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
26.	Randy Macdonald (G2)	New Brunswick System Opeartor		✓								✓
27.	Murale Gopinathan (G2)	Northeast Utilities										✓
28.	Guy V. Zito (G2)	NPCC										✓
29.	Al Boesch (G3)	NPPD										✓
30.	Greg Campoli (G2)	NY ISO										✓
31.	Mike Calamino (G1) (I)	NYISO		✓								
32.	Ralph Rufrano (G2)	NYPA										✓
33.	Al Adamson (G2)	NYSRC										✓
34.	Mark Ringhausen	Old Dominion Electric Coop.				✓						
35.	Todd Gosnell (G3)	OPPD										✓
36.	Alicia Daugherty (G1)	PJM		✓								
37.	Linda Brown	San Diego Gas and Electric	✓									
38.	Charles Yeung (G1)	SPP		✓								
39.	Roger Champagne (G2)	TransEnergie HydroQuebec										✓
40.	Jim Haigh (G3)	WAPA										✓
41.	Neal Balu (G3)	WPSR										✓
42.	Pam Oreschnik (G3)	XCEL										✓

Legend:

- G1 - IRC Standards Review Committee
- G2 – NPCC CP9 Working Group
- G3 – MRO
- I – Individual comments were submitted in addition to comments submitted as part of a group

Index to Questions, Comments, and Responses

1. Do you believe that there is a reliability-related need to provide additional detail, including specific issues for consideration, to the requirements in this set of standards as proposed in this supplemental SAR? 5

2. Do you agree with the expanded scope of the proposed project as set forth in this supplemental SAR? 8

3. Do you think that there are any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the April 30, 2006 version of the original SAR and this supplemental SAR?.....12

1. **Do you believe that there is a reliability-related need to provide additional detail, including specific issues for consideration, to the requirements in this set of standards as proposed in this supplemental SAR?**

Summary Consideration: All respondents agreed with the statement. The affirmative responses that included comments mainly dealt with procedural issues as opposed to content. The SAR DT believes that we have answered those concerns in the provided responses and that no additional changes to the SAR are required.

Question #1			
Commenter	**Yes**	**No**	**Comment**
Exelon	☑		I believe that most of the additional information contained in the draft 'supplemental' SAR is valuable and will assist the SDT in addressing the various stakeholder concerns. I am concerned with conflicting information addressed below. I am not familiar with the concept of a supplemental SAR and am not sure if there are going to be two SARs now, or if this new effort supercedes the existing SAR. This is especially a concern when there appear to be differences between them regarding functional applicabilities and principles, as well as the expansion of scope. I understand the Standards Development Procedure to require the original SAR to be modified, when it states, "If the standard drafting team determines it is necessary to expand the scope of the standard ot to modify the scope in a way that is no longer consistent with the scope defined in the SAR, then the drafting team may initiate or recommend another requestor initiate a new SAR (Step 1) to develop the expanded or modified scope. At no time will a drafting team develop a standard that is not within the scope ot the SAR that was authorized for development."
Response: The SDT recognized that the scope of the original SAR needed to be broadened to encompass changes in the industry since the approval of the original SAR. We decided to use the concept of a supplement rather than completely re-writing the original SAR. These are not intended to be two distinct SARs. The Supplemental SAR is intended to be a true supplement to the original SAR in every sense of the word.			
ODEC	☑		The planning of the transmission system is critical to the reliability of the transmission system. Additional details provided to all stakeholders are crucial to ensure that transmission is built in a timley manner to protect the relability of the system. Also, by making the process and information available to all stakeholders, you ensure that everyone's interest is heard in the process and not just the large transmission owner/operators, but all users of the transmission system. The assumptions used in the evaluation process must be vetted by all stakeholders as they are the critical drivers on what transmission is needed and when it is needed.
Response: Stakeholders will receive their opportunity to vet the assumptions used in the evaluation process during comment			

Question #1			
Commenter	**Yes**	**No**	**Comment**
and balloting of the standards.			
ERCOT	☑		I recommend that you clarify that these lists of items in Appendix B are topics to consider, not topics that must be included. Also, I recommend that any standards requirements that are evident as Good Utility Practice or procedural in nature be retired as requirements, but retained in the form of reference documents, operating guidelines, or some other similar form that will be available to any industry participant that wishes to use them.
Response: The following excerpt is from point #3 of the Supplemental SAR Purpose Statement – "…***consider*** the items mentioned in the Technical Issues Lists prepared by the NERC staff…" (emphasis added). The intent was always to consider the issues and not to make them necessarily mandatory changes. The comment on good utility practice and procedural requirements will be passed on to the SDT. Please note that Appendix B as it was included in the Supplemental SAR was prepared prior to the final FERC Order. Directions included with that Order must be specifically addressed in the standards drafting process.			
MISO	☑		As the standards are written now, all of the requirements apply to both the Transmission Planner and Planning Authority. The NERC Functional Model Version 3 replaced the Planning Authority with the Planning Coordinator . The standards should reflect this change as well as the division of responsibilities between Transmission Planner and Planning Coordinator in the functional model. Additionally, they should seek to clarify the relationship between Transmission Planner and Planning Coordinator. How many transmission planners can their be per Planning Coordinator. Can there be overlapping Planning Coordinators?
Response: Functional Model v3 will be used as the reference. Your comment and questions will be passed on to the SDT.			
ITC Transmission	☑		The original SAR did a good job of capturing many of the reliability improvements necessary to the TPL Standards. Now that additional information is available from the various stakeholder groups and drafting teams, it is clear that additional reliability-related improvements to the Standards can be made. It is not clear how to quantify the additional improvement the supplemental SAR will make to the existing Standard Drafting effort, but certainly there are additional reliability improvements to be made to each of the subject Standards.
Response: Agreed.			
Manitoba Hydro	☑		Manitoba Hydro believes the planning standards should ensure that complete and consistent assessments are conducted by the responsible entities.
Response: Agreed.			
AEP	☑		

Question #1			
Commenter	**Yes**	**No**	**Comment**
HQT	☑		
IESO	☑		
ISO New England	☑		
KCPL	☑		
MRO	☑		
NPCC CP9 Working Group	☑		
NYISO	☑		
San Diego Gas & Electric	☑		
IRC Standards Review Committee	☑		

2. Do you agree with the expanded scope of the proposed project as set forth in this supplemental SAR? (The scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high-quality, enforceable, and technically sufficient bulk power system reliability standards. Please consider these items as non-mandatory and only for consideration by the drafting team.)

Summary Consideration: The majority of respondents agreed to the proposition. The negative opinions ranged from procedural matters to items that dealt with providing the SDT with sufficient flexibility to do their job or issues that are more appropriately addressed at the standards drafting stage. In particular, there was concern that some of the applicable entities checked on the supplementary SAR were not appropriate. The SAR DT felt that the Transmission Owner & Generator Owner might potentially provide data that could come into play for some of the requirements in TPL-005 & 006. The SAR DT wanted to provide maximum flexibility to the SDT so these entities as well as the Reliability Coordinator were included. However they are only for consideration and not mandatory. The SAR DT believes that we have addressed these concerns in the responses provided and that no additional changes to the SAR are required.

Question #2			
Commenter	**Yes**	**No**	**Comment**
Exelon		☑	The approved SAR is of type 'New Standard' while the supplemental SAR type is not, but rather, 'Revision to existing Standards' as well as, 'Withdraw of existing Standard (possible)'. Regarding the Reliability Function Applicabilities, the supplemental SAR does not include the Reliability Authority or the Planning Authority which were included in the approved SAR, and the supplemental SAR includes the Resource Planner and Generation Owner functions, which are not included in the approved SAR. I believe that the Planning Authority needs to be addressed in terms of the FERC NOPR discussion, summarized on pages B3 and B4 of the supplemental SAR. The supplemental SAR includes item 7 in the Applicable Reliability Principles, while the approved SAR does not. If there are going to be two SARs then I believe that the supplemental SAR should include the previously approved SAR in the 'Related SARs' section on page 7. The concise summaries of the Version 0 Industry comments are appreciated, but these should be made more clear in that these will probably become key to any actual changes to planning contingencies. For example, it is not clear what, 'Address deliverability of generation to load' means. Also, does, 'Don't include generation runback or redispatch'

Question #2			
Commenter	**Yes**	**No**	**Comment**
			mean that this shouldn't be addressed or that the standard should be worded to specifically not include them. Other terms such as, 'Don't include planning outage', and 'single terminals are not included' should also be more thoroughly described.
Response: The SDT recognized that the scope of the original SAR needed to be broadened to encompass changes in the industry since the approval of the original SAR. We decided to use the concept of a supplement rather than completely re-writing the original SAR. These are not intended to be two distinct SARs. The Supplemental SAR is intended to be a true supplement to the original SAR in every sense of the word. The full text of all comments referenced in the Supplemental SAR Appendix B has been made available to the SDT so that there should be no confusion as to the intent or meaning of the comment.			
ODEC		☑	These are transmission planning standards and as such, should only apply to TPs, not RP, TO and GO entities. Certainly, information must be provided from the TOs and GOs on their facilities to be able to run the planning studies, but the MOd standards should cover this obligation. And RC are operating entities and not planning entities.
Response: The SAR DT felt that the TO & GO might potentially provide data that could come into play for some of the requirements in TPL-005 & 006. The SAR DT wanted to provide maximum flexibility to the SDT so these entities as well as the RC were included. However they are only for consideration and not mandatory. Your comments will be passed on to the SDT.			
ISO New England		☑	We do not support a long-term planning standards applying to RCs. The NERC functional model is very clear that RCs are operational entities. Is the intent to replace RRO with RC for the fill-in-the-blank standards? That would be an inappropriate solution. A more appropriate solution would be to consider replacing the RRO with the planning coordinator. We also do not understand how a transmission planning standard could apply to the additional functional entities: Transmission Owner and Generator Owner.
Response: The SAR DT felt that the TO & GO might potentially provide data that could come into play for some of the requirements in TPL-005 & 006. The SAR DT wanted to provide maximum flexibility to the SDT so these entities as well as the RC were included. However they are only for consideration and not mandatory. Your comments will be passed on to the SDT.			
MISO		☑	We do not support a long-term planning standards applying to RCs. The NERC functional model is very clear that RCs are operational entities. Is the intent to replace RRO with RC for the fill-in-the-blank standards? That would be an inappropriate solution. A more appropriate solution would be to consider replacing the RRO with the planning coordinator.
Response: The SAR DT felt that the TO & GO might potentially provide data that could come into play for some of the			

Question #2			
Commenter	**Yes**	**No**	**Comment**
requirements in TPL-005 & 006. The SAR DT wanted to provide maximum flexibility to the SDT so these entities as well as the RC were included. However they are only for consideration and not mandatory. Your comments will be passed on to the SDT.			
NYISO		☑	It is unclear as to what obligations the RC, TO, and GO would have in a long-term planning standard. The NERC functional model is very clear that RCs are operational entities. The RC, TO, GO ,should not have a direct obligation in the process, but should be a resource for input into the process.
Response: The SAR DT felt that the TO & GO might potentially provide data that could come into play for some of the requirements in TPL-005 & 006. The SAR DT wanted to provide maximum flexibility to the SDT so these entities as well as the RC were included. However they are only for consideration and not mandatory. Your comments will be passed on to the SDT.			
IRC Standards Review Committee		☑	We do not support a long-term planning standards applying to RCs. The NERC functional model is very clear that RCs are operational entities. Is the intent to replace RRO with RC for the fill-in-the-blank standards? That would be an inappropriate solution. A more appropriate solution would be to consider replacing the RRO with the planning coordinator. We also do not understand how a transmission planning standard could apply to the additional functional entities: Transmission Owner and Generator Owner.
Response: The SAR DT felt that the TO & GO might potentially provide data that could come into play for some of the requirements in TPL-005 & 006. The SAR DT wanted to provide maximum flexibility to the SDT so these entities as well as the RC were included. However they are only for consideration and not mandatory. Your comments will be passed on to the SDT.			
ITC Transmission		☑	Standard Drafting Teams should not be responding so heavily to comments made by FERC in a NOPR. The NOPR is just that … "Proposed." There may be additional changes required as a result of the final Rule. The final Rule may even negate some of the proposed changes made in the NOPR. If the drafting team thinks that FERC hit on a good idea for improvement, then it would be appropriate for inclusion in the Standard, but simply to make changes to a Standard because an idea surfaced in a Proposed Rule is premature.
Response: The following excerpt is from point #3 of the Supplemental SAR Purpose Statement – "…*consider* the items mentioned in the Technical Issues Lists prepared by the NERC staff…" (emphasis added). The intent was always to consider the issues and not to make them necessarily mandatory changes. Directions included with the FERC Final Order must be specifically addressed in the standards drafting process.			
AEP	☑		Considering the current scope, the Std DT should be encouraged to consider a major re-write of TPL-001 thru TPL-006, possibly including a restructuring into a single standard

Question #2			
Commenter	**Yes**	**No**	**Comment**
			rather than the present multiple standards.
Response: We agree with the general concept and the SDT will be provided with this option**.**			
Manitoba Hydro	☑		Manitoba Hydro agrees in principle with the expanded scope, but believes that this scope should be a part of the Standards Development Procedures manual so all stakeholders have a voice in the requirements in Appendix A. We have some concern that the SAR gives the drafting team the power to add additional improvements beyond the SAR as this provides an opportunity for SDT members to forward specific owner agendas.
Response: The material in Appendix A is excerpted from the Reliability Standards Development Work Plan 2007 – 2009 that was reviewed and approved by the Standards Committee. As stated, it represents general guidelines and not mandatory changes for the revision of existing standards. Stakeholders will receive their opportunity to vet the assumptions used in the evaluation process during comment and balloting of the standards**.**			
ERCOT	☑		Please also see my response to Question #1.
Response: Please see the response to your comment on question #1.			
HQT	☑		
IESO	☑		
KCPL	☑		
MRO	☑		
NPCC CP9 Working Group	☑		
San Diego Gas & Electric	☑		

3. Do you think that there are any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the April 30, 2006 version of the original SAR and this supplemental SAR?

Summary Consideration: Only two respondents suggested revisions. In both cases the comments are more appropriately addressed at the standards drafting stage. The SAR DT believes that we have satisfactorily addressed the expressed concerns with the provided responses and that no additional changes to the SAR are required.

Question #3			
Commenter	**Yes**	**No**	**Comment**
Manitoba Hydro	☑		The SAR should considering adding a requirements to the standards to mandate tests for robustness by doing sensitivity to critical system paramenters such as load growth rate, load power factor, etc., to provide insight into the margin between the operating point and unacceptable performance. There should also be a specific requirement to assess reactive power adequacy, voltage stability and system damping.
Response: The SAR DT is aware of the interest in these items. The scope of both the original and supplemental SARs allows these items to be incorporated in the standards drafting process. We will pass your comments on to the SDT.			
San Diego Gas & Electric	☑		SDG&E believes that there are additional revisions that need to be incorporated into this set of standards. The Supplemental SAR dated January 17, 2007, has an Appendix B that summarizes issues to be resolved in this new set of standards. Those issues are a collection of comments from FERC NOPR, FERC Staff Report, Industrial comments on version 0, Phase III/IV, etc. In order to develop a set of reliability standards for transmission planners, SDG&E believes there are a few more issues to be addressed and/or clarified in this set of standards. 1. Critical System Conditions These "Critical System Conditions" are referring to system conditions to be studied for the transmission planning. Typically, entities deem several system conditions as critical on the basis of accumulative institutional knowledge. However, in recent FERC NOPR, FERC directs industry to conduct sensitivity studies to identify these critical system conditions and document the sensitivity studies. The sensitivity factors in FERC's direction include load power factors, generation

Question #3			
Commenter	**Yes**	**No**	**Comment**
			retirements, generation dispatch, transaction patterns, controllable loads, demand side management, transmission outages. As those will result in extensive scope of study, we would like to see this set of standards clearly answer following questions: a. How often do we required to perform such sensitivity studies to identify critical system conditions? b. Do we check those sensitivity factors one by one to find the worst, or do we define the worst combination as the critical? Or c. Do we continue to leave the "critical system conditions" determination to study performer's discretion? 2. Contingencies In Appendix B of the latest Supplementary SAR for TPL standards, comments and modification requests were summarized. Contingencies for planning studies is one of critical elements. This can be split into three issues and SDG&E provides following comments for each of them: a. Study all contingencies One of the comments suggests to study "all contingencies". Clearly, "All contingencies" need to be clarified. The additional workload incurred due to the dismissal of planners' accumulative institutional knowledge may be unreasonable. b. Study non-common mode contingencies The issue regarding reasonable workload also applies to the "non-common mode" contingencies. The non-common mode refers to combination of unrelated elements, say one 230 kV line in CFE (Mexico) and other 230 kV line in Alberta, Canada, as one contingency. This too needs clarification. c. Study event-based contingencies Evaluating the impact of "event-based" contingencies makes sense. However, translating an event, such as an earthquake, into a list of elements to be taken out for power flow and stability computer simulation, will need clear guidelines. 3. "Identification of options for reducing the probability or impacts of extreme events that cause cascading" This is a direct quote of FERC's directed modification in its NOPR.

Question #3			
Commenter	**Yes**	**No**	**Comment**
			a. If the impacts only need to be identified with conceptual methods, how do we maintain "consistency" among entities? b. If FERC intends to request the entities to identify the probability/impacts with quantitative methods, then there is a long list of issues to be addressed before a transmission planner could in reality perform such an analysis: • How to define "cascading" in system simulation analysis. • Reasonable and feasible probabilistic variables need to be defined. For instance, in addition to the equipment failure as probabilistic variable, other probabilistic variables need to be considered to meet FERC's direction, such as hurricanes, fires, earthquakes, lightening, flooding, landslides and even an airplane falling into a critical substation, and so on. • Regional efforts need to be taken to develop a probabilistic methodology and probabilistic database that can be applied uniformly so entities can be treated equally. • Regional efforts need to be taken to guide selection and/or development of probabilistic analysis software tools. Such tools have to be ready for transmission planners to use and derive quantified solutions.
Response: The following excerpt is from point #3 of the Supplemental SAR Purpose Statement – "…***consider*** the items mentioned in the Technical Issues Lists prepared by the NERC staff…" (emphasis added). The intent was always to consider the issues and not to make them necessarily mandatory changes. Directions included with the FERC Final Order must be specifically addressed in the standards drafting process. The Supplemental SAR was intended to be a true supplement to the original SAR in every sense of the word. The SAR DT is aware of the interest in these items. The scope of both the original and supplemental SARs allows these items to be incorporated in the standards drafting process. We will pass your comments on to the SDT. We refer the commenter to the NERC web site for previous meeting notes and comments concerning related issues.			
ODEC		☑	This should be more than enough to try to get into these transmission planning standards.
Response: Most stakeholders who commented seemed to agree with you.			
MISO		☑	
MRO		☑	
NPCC CP9 Working Group		☑	
NYISO		☑	

Question #3			
Commenter	**Yes**	**No**	**Comment**
IRC Standards Review Committee		☑	
AEP		☑	
ERCOT		☑	
HQT		☑	
IESO		☑	
ISO New England		☑	
ITC Transmission		☑	
KCPL		☑	

1/17/07 Standard Authorization Request Form

Title of Proposed Project: Revisions to TPL-001 through TPL-006, Transmission System Performance and Assessment (This SAR is intended to supplement the SAR for Assess Transmission Future Needs and Develop Transmission Plans dated 4/30/06 in support of Standards Project 2006-02.)	
Request Date	January 17, 2007
Revised	April 5, 2006

SAR Requestor Information	**SAR Type** (*Check a box for each one that applies.*)	
Name Assess Transmission Future Needs Standard Drafting Team	☐	New Standard
Primary Contact Robert Millard – Vice-Chair, ATFNSDT	☒	Revision to existing Standards
Telephone (708) 588-9886 Fax none	☒	Withdrawal of existing Standard (possible)
E-mail bob.millard@rfirst.org	☐	Urgent Action

Purpose (Describe the purpose of the standard — what the standard will achieve in support of reliability.)

This SAR is intended to supplement the SAR for Assess Transmission Future Needs and Develop Transmission Plans dated 4/30/06 in support of Standards Project 2006-02.

The revisions to the following standards would improve technical clarity and address concerns identified by stakeholders and FERC:

TPL-001 — System Performance under Normal Conditions
TPL-002 — System Performance Following Loss of a Single BES Element
TPL-003 — System Performance Following Loss of Two or More BES Elements
TPL-004 — System Performance Following Extreme BES Events
TPL-005 — Regional and Interregional Self-Assessment Reliability Reports
TPL-006 — Data from the Regional Reliability Organization Needed to Assess Reliability

Revisions to TPL-001 through TPL-004 are already underway (Assess Transmission Future Needs and Develop Transmission Plans Standard Drafting Team) with the primary focus to clarify the associated Table 1, Transmission System Standards – Normal and Emergency Conditions, used to identify the criteria for system assessments. The expansion of the work already underway with TPL-001 through TPL-004 will focus on the general improvements to the standard identified through the attached *Appendix A: Reliability Standard Review Guidelines* and the FERC and stakeholder concerns identified in the attached *Appendix B: TPL-001 through TPL-006 Technical Issues List*.

TPL-005 and TPL-006, which require regional and inter-regional assessments based on the system performance requirements stated in TPL-001 through TPL-004, need to be modified or retired to address the "fill-in-the blank" components and establish requirements within the standards or through a contractual arrangement as to which entity should perform and provide the subject assessment and data. If these requirements are addressed through the delegation agreements each Region has with the Electric Reliability Organization (ERO), TPL-005 and TPL-006 could be retired.

The purpose of modifying this set of standards is to:

1. Provide an adequate level of reliability for the North American bulk power systems — ensure each of the standards is complete and the requirements are set at an appropriate level to ensure reliability.
2. Ensure each of the standards is enforceable as a mandatory reliability standard with financial penalties — the applicability to bulk power system owners, operators, and users, and as appropriate particular classes of facilities, is clearly defined; the purpose, requirements, and measures are results-focused and unambiguous; the consequences of violating the requirements are clear.
3. Make general improvements using the Reliability Standard Review Guidelines and consider the items mentioned in the Technical Issues Lists prepared by the NERC staff which attempt to capture comments from the:
    - FERC NOPR (Docket # RM06-16-00 dated October 20, 2006) ,
    - FERC staff report dated May 11, 2006 concerning NERC standards submitted with ERO application,

- Version 0 and Phase 3&4 standards development (see note 1),
- Violations Risk Factors (VRF) drafting team (see note 1),
- Regional Fill-in-the-Blank Team (RRSWG – a NERC working group involved with regional standards development), and
- Draft SAR for Planning Authority

The SDT should also consider any other issues that were not completely captured but were stated or referenced in the above materials.

Directions extracted from FERC Order 693, 890 and other applicable orders and any possible future subsequent revisions will be addressed by the SDT.

Note 1: Comments received from the industry during public postings of the TPL subject matter were sometimes outside the work being posted or outside the drafting team's scope and were not reflected in the drafting of the final work product. These should now be considered by this SDT.

Industry Need (Provide a detailed statement justifying the need for the proposed standard, along with any supporting documentation.)

The six standards in this set are all Version 0 standards. As the ERO begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. The Version 0 standards and recent updates were put in place as a temporary starting point to start-up the ERO and begin enforcement of mandatory standards. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 translation and any subsequent standards development that have implications to the TPL standards.

Brief Description: (Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.)

The proposed work effort will address three main issues:

1. Conformance to the new rules and regulations brought about by Section 215 of the Federal Power Act and the creation of the ERO,
2. Supplement the approved work of the existing ATFNSDT to include the necessary revisions to TPL-005 & TPL-006, and
3. Address technical issues raised by FERC and industry stakeholders.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☒	Resource Planner	Develops a (>one year) plan for the resource adequacy of its specific loads within its portion of a Planning Coordinator area.
☒	Transmission Planner	Develops a (>one year) plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generating facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☒	Load-Serving Entity	Secures energy and transmission service (and related reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft a standard based on this description.)

This SAR expands on the work already underway with the Assess Transmission Future Needs and Develop Transmission Plans Standard Drafting Team, by requiring that TPL-001 through TPL-006 be upgraded in accordance with the Reliability Standards Development Plan 2007 – 2009. These revisions include the following:

This SAR will be appended to the already approved SAR for Assess Transmission Future Needs and Develop Transmission Plans and will include modifications to all of the following standards:

TPL-001 — System Performance under Normal Conditions
TPL-002 — System Performance Following Loss of a Single BES Element
TPL-003 — System Performance Following Loss of Two or More BES Elements
TPL-004 — System Performance Following Extreme BES Events
TPL-005 — Regional and Interregional Self-Assessment Reliability Reports
TPL-006 — Data from the Regional Reliability Organization Needed to Assess Reliability

The revisions would improve technical clarity and address concerns identified by stakeholders and FERC. The drafting team will focus on the general improvements to the standards and use as a starting point for the expanded work the subject matter identified in *Appendix A: Reliability Standard Review Guidelines* and the FERC and stakeholder concerns identified in *Appendix B: TPL-001 through TPL-006 Technical Issues List*.

The expanded scope also will include elimination of the 'fill-in-the-blank' elements of TPL-005 and TPL-006, which require regional and inter-regional assessments based on the system performance requirements stated in TPL-001 through TPL-004. The standards need to be modified or retired to address the "fill-in-the blank" components. If the 'fill-in-the-blank' requirements are addressed through the contractual arrangements each Region has with the ERO, TPL-005 and TPL-006 could be retired.

The drafting team must ensure that there is consistency in the requirements across the set of TPL standards

The overall development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards, using the attached, Reliability Standard Review Guidelines. In addition, the drafting team will need to make conforming changes to standards impacted by changes made to these six standards.

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

Regional Differences

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Appendix A: Reliability Standard Review Guidelines

Applicability
Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose
Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements
Does this reliability standard state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability
Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations
Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness
Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?

Consequences for Noncompliance

In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, are the consequences of violating a standard clearly known to the responsible entities?

Clear Language
Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality
Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements
In general, requirements for entities to have 'capabilities' (this would include facilities for communication, agreements with other entities, etc.), should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to 'maintain' their capabilities.

Consistent Terminology
To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a 'unique' definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the 'verb list' from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

This is a requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A requirement that is administrative in nature;

Or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

~~Mitigation~~ Time Horizon

The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

Violation Severity Levels

The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. ('Violation severity levels' replaces the existing 'levels of non-compliance.') The violation severity levels may be applied for each requirement ~~or~~ and may be combined to cover multiple requirements, as long as it is clear which requirements are included and that all requirements are included.

The violation severity levels should be based on the following definitions:

- **Lower: mostly compliant with minor exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
- **Moderate: mostly compliant with significant exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.

- **High: marginal performance or results** — the responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: 70% to 84% compliant.
- **Severe: poor performance or results** — the responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.

Compliance Monitor

Replace, 'Regional Reliability Organization' with '~~Electric Reliability Organization'~~Regional Entity

~~Bulk Electric System~~

~~Replace, 'Bulk Electric System' with 'bulk power system'~~

Fill-in-the-blank Requirements

Do not include any 'fill-in-the-blank' requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard – then require another entity to comply with those requirements.

Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in under-frequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.

Requirements for Regional Reliability Organization

Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.

Effective Dates

Must be 1st day of 1st quarter after entities are expected to be compliant – must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply. If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan.

Associated Documents

If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, 'Associated Documents'.

Appendix B: TPL-001 through TPL-006 Technical Issues List

Excerpted from NERC Reliability Standards Development Plan: 2007 - 2009

TPL-001
FERC NOPR

- Require that critical system conditions be determined by conducting sensitivity studies; *(Not necessarily "cook book" but what are the processes someone reasonably skilled in the art would follow.)*
- Require that system conditions and contingencies assessed be reviewed by neighboring systems; *(Looking for coordination with neighboring systems)*
- Modify Requirement R1.3 to substitute the reference to regional reliability organization with Regional Entity;
- Require consideration of planned outages of critical equipment; and
- Modify footnote (a): footnote (a) to Table 1 requires clarification. The NERC Transmission Issues Subcommittee (TIS) 325 recommended that footnote (a) be modified to state explicitly that emergency ratings apply to Category B and C (contingency conditions) and not to Category A (system intact). The Commission proposes that footnote (a) be modified in the revised Reliability Standard as recommended by TIS and that the normal facility rating be in accordance with Reliability Standard FAC-008-1 and normal voltages be in accordance with Reliability Standard VAR-001-1.

FERC Staff Report

- Only for normal
- Doesn't consider planned outages
- Clarify footnote 'a' & 'b' in table
- Stress system during simulations
- Include sensitivity studies
- Include extreme events

Version 0 Industry Comments

- Several semantic issues
- Clarify timing for submittal of corrective plan
- Clarify use of applicable ratings in Table 1, note 'a'
- Need to address deliverability to load
- Define critical system conditions
- Allow for engineering judgment in setting conditions for power flow
- Do planned facilities include just those under construction?
- Need to include multiple time frames
- What is a major load center?
- Table 1 – C.5 goes beyond double circuit outage criteria
- Table 1, items 6, 7, 8 & 9 need footnote stating that they do not apply to generator breaker failure
- Table 1, note 'b' – clarify when to curtail firm deliveries

Phase III/IV Comments

- Add a requirement to verify that there are sufficient reactive resources
- Add a requirement to identify where UVLS should be installed

Violation Risk Factors (VRF) Drafting Team Comment

- R1 – time horizon should be long-term planning

Comment from Draft SAR on Planning Authority

- Provide clarity where the Planning Authority is mentioned

TPL-002:
FERC NOPR

- Require that critical system conditions be determined in the same manner as we propose to require for TPL-001-0;
- Require the inclusion of the reliability impact of the entities' existing spare equipment strategy; *(Only looking for consideration of spare equipment that has a long lead time such as a transformer)*
- Explicitly require all generators to ride through the same set of Category B and C contingencies as required for wind generators in Order No. 661; *(Document explicit definition of ride through capability for generators)*
- Require documentation of load models used in system studies and supporting rationale for their use;
- Clarify the phrase "permit operating steps necessary to maintain system control;" and
- Clarify footnote (b): modify footnote (b) to state that load shedding for a single contingency is not permitted except in very special circumstances where such interruption is limited to the firm load associated with the failure (consequential load loss).330 For purposes of clarity, the Commission proposes to require that the phrase "to prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers" be deleted from footnote (b). This statement is more appropriate for Category C events and is already captured by footnote (c) to Table 1, which is applicable to Category C events.

FERC staff report

- Only includes loss of single element
- NERC TIS Report recommendations not addressed

Version 0 Industry Comments

- Define critical system conditions
- Clarify timing for corrective plan
- Address deliverability of generation to load
- Clarify applicable ratings in Table 1, note 'a'
- Don't include generation runback or re-dispatch
- Must study all contingencies and multiple demand levels & time frames
- Don't include planning outage
- Single terminals are not included

Phase III/IV comments

- Add a requirement to verify that there are sufficient reactive resources
- Add a requirement to identify where UVLS should be installed

VRF comments

- Time horizon should be long-term planning and R2.2 – redundant with R1.3.8

Comment from draft SAR on Planning Authority

- Provide clarity where the Planning Authority is mentioned

TPL-003:
FERC NOPR

- Require that critical system conditions be determined by conducting sensitivity studies (as elaborated in our discussion of TPL-001-0);
- Clarify footnote c: modify footnote (c) to provide specificity regarding the use of the term "controlled interruption" of load.
- Require the applicable entities to define and document the proxies necessary to simulate cascading outages; and
- Tailor the purpose statement to reflect the specific goal of the Reliability, as discussed above.

FERC Staff Report

- Same as TPL-001 & 002

Version 0 Industry Comments

- Same as TPL-001 & 002
- TO should provide plan of action
- Don't base penalties on low probability, low consequence events
- Use NERC Compliance Reporting Process
- Clearly identify outages

Phase III/IV Comments

- Add a requirement to verify that there are sufficient reactive resources
- Add a requirement to identify where UVLS should be installed

VRF Comment

- Time horizon should be long-term planning
- R2 – lack of consistency with TPL-001 & TPL-002
- R2.1 - lack of consistency with TPL-001
- R2.1.1 - lack of consistency with TPL-001 & TPL-004
- R2.1.2 - lack of consistency with TPL-001 & TPL-005
- R2.1.3 - lack of consistency with TPL-001 & TPL-006
- R2.2 - lack of consistency with TPL-001 & TPL-007

Comment from Draft SAR on Planning Authority

- Provide clarity where the Planning Authority is mentioned

TPL-004:
FERC NOPR

- Require that critical system conditions be determined in the same manner as proposed for TPL-001-0;
- Require the identification of options for reducing the probability or impacts of extreme events that cause cascading;
- Require that, in determining the range of extreme events to be assessed, the contingency list of Category D be expanded to include recent events; and
- Tailor the purpose statement to reflect the specific goal of the Reliability Standard.

FERC Staff Report

- Need to reduce the probability of loss of multiple elements and mitigating impact
- Share assessments
- Need to be more severe than weather
- Same as TPL-001

Version 0 Industry Comments

- Same as TPL-001
- Perform analysis on credible contingency
- R1.3.9 – remove from extreme events
- TO should determine which events to study

Phase III/IV Comments

- Add a requirement to verify that there are sufficient reactive resources
- Add a requirement to identify where UVLS should be installed

Comment from Draft SAR on Planning Authority

- Provide clarity where the Planning Authority is mentioned

TPL-005:

FERC NOPR

- Commission will not propose any action on TPL-005-0, as it applies only to regional reliability organizations.
- The term and extent of assessment, as well as the study years, are not appropriately defined; the process for determining load levels needs to be standardized; and local area networks and system adjustments need to be specifically defined.

Regional Fill-in-the-Blank Team Comments

- New SAR needed

Version 0 Industry Comments

- Define fuel adequacy
- An RRO can't make a mandatory request for another RRO to perform a study

TPL-006:
FERC NOPR

- Commission will not propose any action on TPL-006-0, as it applies only to regional reliability organizations.

Excerpts from FERC Order 693
TPL Standards

TPL-001-0

1770. Accordingly, the Commission approves Reliability Standard TPL-001-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to TPL-001-0 through the Reliability Standards development process that:

(1) requires that critical system conditions and study years be determined by conducting sensitivity studies with due consideration of the range of factors outlined above;
(2) requires a peer review of planning assessments with neighboring entities;
(3) modifies Requirement R1.3 to substitute the reference to regional reliability organization with Regional Entity;
(4) requires assessments of outages of critical long lead time equipment, consistent with the entity's spare equipment strategy and
(5) address the concerns regarding footnote (a) of Table 1, including the applicability of emergency ratings and consistency of normal ratings and voltages with values obtained from other Reliability Standards and the concerns raised by International Transmission in regard to the footnotes in Table 1.

TPL-002-0

1797. Accordingly, the Commission approves Reliability Standard TPL-002-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to TPL-002-0 through the Reliability Standards development process that:

(1) requires that critical system conditions be determined in the same manner as we propose to require for TPL-001-0;
(2) requires assessments of planned outages of long lead time critical equipment consistent with the entity's spare equipment strategy;
(3) requires all generators to ride through the same set of Category B and C contingencies as required by wind generators in Order No. 661, or to simulate those generators that cannot ride through as tripping;
(4) requires documentation of load models used in system studies and supporting rationale for their use;
(5) clarifies the phrase "permit operating steps necessary to maintain system control" in footnote (a) and the use of emergency ratings and
(6) clarifies footnote (b) in regard to load loss following a single contingency, specifying the amount and duration of consequential load loss and system adjustments permitted after the first contingency to return the system to a normal operating state, as discussed above.

TPL-003-0

1825. Accordingly, the Commission approves Reliability Standard TPL-003-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to TPL-003-0 through the Reliability Standards development process that:

(1) requires that critical system conditions be determined in the same manner as we propose to require for TPL-001-0;
(2) modifies footnote (c) to Table 1 to clarify the term "controlled load interruption;"
(3) requires applicable entities to define and document the proxies necessary to simulate cascading outages and
(4) tailors the purpose statement to reflect the specific goal of the Reliability Standard.

TPL-004-0

1836. Accordingly, the Commission approves Reliability Standard TPL-004-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to TPL-004-0 through the Reliability Standards development process that:

(1) requires that critical system conditions be determined in the same manner as proposed for TPL-001-0;
(2) requires the identification of options for reducing the probability or impacts of extreme events that cause cascading;
(3) requires that, in determining the range of extreme events to be assessed, the contingency list of Category D be expanded to include recent events and
(4) tailors the purpose statement to reflect the specific goal of the Reliability Standard.

TPL-005-0

1840. Consistent with our discussion in the Common Issues section above, we will not approve or remand TPL-005-0 until we receive additional information from the ERO.

1841. In Order No. 890, the Commission stated that there will be a series of technical conferences and regional meetings to obtain industry input to achieving the goal of regional planning. The Commission encourages the ERO to monitor those proceedings and use the results as input to the Reliability Standards development process in revising Reliability Standard TPL-005-0 to address regional planning and related processes.

TPL-006-0

1845. Consistent with our discussion in the Common Issues section above, the Commission will not approve or remand TPL-006-0.

1/17/07 Standard Authorization Request Form

Title of Proposed Project: Revisions to TPL-001 through TPL-006, Transmission System Performance and Assessment (This SAR is intended to supplement the SAR for Assess Transmission Future Needs and Develop Transmission Plans dated 4/30/06 in support of Standards Project 2006-02.)	
Request Date	January 17, 2007
Revised	April 5, 2006

SAR Requestor Information	**SAR Type** (*Check a box for each one that applies.*)	
Name Assess Transmission Future Needs Standard Drafting Team	☐	New Standard
Primary Contact Robert Millard – Vice-Chair, ATFNSDT	☒	Revision to existing Standards
Telephone (708) 588-9886 Fax none	☒	Withdrawal of existing Standard (possible)
E-mail bob.millard@rfirst.org	☐	Urgent Action

Purpose (Describe the purpose of the standard — what the standard will achieve in support of reliability.)

This SAR is intended to supplement the SAR for Assess Transmission Future Needs and Develop Transmission Plans dated 4/30/06 in support of Standards Project 2006-02.

The revisions to the following standards would improve technical clarity and address concerns identified by stakeholders and FERC:

TPL-001 — System Performance under Normal Conditions
TPL-002 — System Performance Following Loss of a Single BES Element
TPL-003 — System Performance Following Loss of Two or More BES Elements
TPL-004 — System Performance Following Extreme BES Events
TPL-005 — Regional and Interregional Self-Assessment Reliability Reports
TPL-006 — Data from the Regional Reliability Organization Needed to Assess Reliability

Revisions to TPL-001 through TPL-004 are already underway (Assess Transmission Future Needs and Develop Transmission Plans Standard Drafting Team) with the primary focus to clarify the associated Table 1, Transmission System Standards – Normal and Emergency Conditions, used to identify the criteria for system assessments. The expansion of the work already underway with TPL-001 through TPL-004 will focus on the general improvements to the standard identified through the attached *Appendix A: Reliability Standard Review Guidelines* and the FERC and stakeholder concerns identified in the attached *Appendix B: TPL-001 through TPL-006 Technical Issues List*.

TPL-005 and TPL-006, which require regional and inter-regional assessments based on the system performance requirements stated in TPL-001 through TPL-004, need to be modified or retired to address the "fill-in-the blank" components and establish requirements within the standards or through a contractual arrangement as to which entity should perform and provide the subject assessment and data. If these requirements are addressed through the delegation agreements each Region has with the Electric Reliability Organization (ERO), TPL-005 and TPL-006 could be retired.

The purpose of modifying this set of standards is to:

1. Provide an adequate level of reliability for the North American bulk power systems — ensure each of the standards is complete and the requirements are set at an appropriate level to ensure reliability.
2. Ensure each of the standards is enforceable as a mandatory reliability standard with financial penalties — the applicability to bulk power system owners, operators, and users, and as appropriate particular classes of facilities, is clearly defined; the purpose, requirements, and measures are results-focused and unambiguous; the consequences of violating the requirements are clear.
3. Make general improvements using the Reliability Standard Review Guidelines and consider the items mentioned in the Technical Issues Lists prepared by the NERC staff which attempt to capture comments from the:
    - FERC NOPR (Docket # RM06-16-00 dated October 20, 2006) ,
    - FERC staff report dated May 11, 2006 concerning NERC standards submitted with ERO application,

- Version 0 and Phase 3&4 standards development (see note 1),
- Violations Risk Factors (VRF) drafting team (see note 1),
- Regional Fill-in-the-Blank Team (RRSWG – a NERC working group involved with regional standards development), and
- Draft SAR for Planning Authority

The SDT should also consider any other issues that were not completely captured but were stated or referenced in the above materials.

Directions extracted from FERC Order 693, 890 and other applicable orders and any possible future subsequent revisions will be addressed by the SDT.

Note 1: Comments received from the industry during public postings of the TPL subject matter were sometimes outside the work being posted or outside the drafting team's scope and were not reflected in the drafting of the final work product. These should now be considered by this SDT.

Industry Need (Provide a detailed statement justifying the need for the proposed standard, along with any supporting documentation.)

The six standards in this set are all Version 0 standards. As the ERO begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. The Version 0 standards and recent updates were put in place as a temporary starting point to start-up the ERO and begin enforcement of mandatory standards. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 translation and any subsequent standards development that have implications to the TPL standards.

Brief Description: (Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.)

The proposed work effort will address three main issues:

1. Conformance to the new rules and regulations brought about by Section 215 of the Federal Power Act and the creation of the ERO,
2. Supplement the approved work of the existing ATFNSDT to include the necessary revisions to TPL-005 & TPL-006, and
3. Address technical issues raised by FERC and industry stakeholders.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☒	Resource Planner	Develops a (>one year) plan for the resource adequacy of its specific loads within its portion of a Planning Coordinator area.
☒	Transmission Planner	Develops a (>one year) plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generating facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☒	Load-Serving Entity	Secures energy and transmission service (and related reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft a standard based on this description.)

This SAR expands on the work already underway with the Assess Transmission Future Needs and Develop Transmission Plans Standard Drafting Team, by requiring that TPL-001 through TPL-006 be upgraded in accordance with the Reliability Standards Development Plan 2007 – 2009. These revisions include the following:

This SAR will be appended to the already approved SAR for Assess Transmission Future Needs and Develop Transmission Plans and will include modifications to all of the following standards:

TPL-001 — System Performance under Normal Conditions
TPL-002 — System Performance Following Loss of a Single BES Element
TPL-003 — System Performance Following Loss of Two or More BES Elements
TPL-004 — System Performance Following Extreme BES Events
TPL-005 — Regional and Interregional Self-Assessment Reliability Reports
TPL-006 — Data from the Regional Reliability Organization Needed to Assess Reliability

The revisions would improve technical clarity and address concerns identified by stakeholders and FERC. The drafting team will focus on the general improvements to the standards and use as a starting point for the expanded work the subject matter identified in *Appendix A: Reliability Standard Review Guidelines* and the FERC and stakeholder concerns identified in *Appendix B: TPL-001 through TPL-006 Technical Issues List*.

The expanded scope also will include elimination of the 'fill-in-the-blank' elements of TPL-005 and TPL-006, which require regional and inter-regional assessments based on the system performance requirements stated in TPL-001 through TPL-004. The standards need to be modified or retired to address the "fill-in-the blank" components. If the 'fill-in-the-blank' requirements are addressed through the contractual arrangements each Region has with the ERO, TPL-005 and TPL-006 could be retired.

The drafting team must ensure that there is consistency in the requirements across the set of TPL standards

The overall development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards, using the attached, Reliability Standard Review Guidelines. In addition, the drafting team will need to make conforming changes to standards impacted by changes made to these six standards.

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

Regional Differences

Region	Explanation
ERCOT	
FRCC	
MRO	
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SERC	
RFC	
SPP	
WECC	

Appendix A: Reliability Standard Review Guidelines

Applicability
Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose
Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements
Does this reliability standard state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability
Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations
Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness
Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?

Consequences for Noncompliance

In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, are the consequences of violating a standard clearly known to the responsible entities?

Clear Language
Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality
Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements
In general, requirements for entities to have 'capabilities' (this would include facilities for communication, agreements with other entities, etc.), should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to 'maintain' their capabilities.

Consistent Terminology
To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a 'unique' definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the 'verb list' from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

This is a requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A requirement that is administrative in nature;

Or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

Time Horizon

The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

Violation Severity Levels

The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. ('Violation severity levels' replaces the existing 'levels of non-compliance.') The violation severity levels may be applied for each requirement and may be combined to cover multiple requirements, as long as it is clear which requirements are included and that all requirements are included.

The violation severity levels should be based on the following definitions:

- **Lower: mostly compliant with minor exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
- **Moderate: mostly compliant with significant exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.

- **High: marginal performance or results** — the responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: 70% to 84% compliant.
- **Severe: poor performance or results** — the responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.

Compliance Monitor
Replace, 'Regional Reliability Organization' with 'Regional Entity

Fill-in-the-blank Requirements
Do not include any 'fill-in-the-blank' requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard – then require another entity to comply with those requirements.

Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in under-frequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.

Requirements for Regional Reliability Organization
Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.

Effective Dates
Must be 1st day of 1st quarter after entities are expected to be compliant – must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply. If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan.

Associated Documents
If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, 'Associated Documents'.

Appendix B: TPL-001 through TPL-006 Technical Issues List

Excerpted from NERC Reliability Standards Development Plan: 2007 - 2009

TPL-001
FERC NOPR

- Require that critical system conditions be determined by conducting sensitivity studies; *(Not necessarily "cook book" but what are the processes someone reasonably skilled in the art would follow.)*
- Require that system conditions and contingencies assessed be reviewed by neighboring systems; *(Looking for coordination with neighboring systems)*
- Modify Requirement R1.3 to substitute the reference to regional reliability organization with Regional Entity;
- Require consideration of planned outages of critical equipment; and
- Modify footnote (a): footnote (a) to Table 1 requires clarification. The NERC Transmission Issues Subcommittee (TIS) 325 recommended that footnote (a) be modified to state explicitly that emergency ratings apply to Category B and C (contingency conditions) and not to Category A (system intact). The Commission proposes that footnote (a) be modified in the revised Reliability Standard as recommended by TIS and that the normal facility rating be in accordance with Reliability Standard FAC-008-1 and normal voltages be in accordance with Reliability Standard VAR-001-1.

FERC Staff Report

- Only for normal
- Doesn't consider planned outages
- Clarify footnote 'a' & 'b' in table
- Stress system during simulations
- Include sensitivity studies
- Include extreme events

Version 0 Industry Comments

- Several semantic issues
- Clarify timing for submittal of corrective plan
- Clarify use of applicable ratings in Table 1, note 'a'
- Need to address deliverability to load
- Define critical system conditions
- Allow for engineering judgment in setting conditions for power flow
- Do planned facilities include just those under construction?
- Need to include multiple time frames
- What is a major load center?
- Table 1 – C.5 goes beyond double circuit outage criteria
- Table 1, items 6, 7, 8 & 9 need footnote stating that they do not apply to generator breaker failure
- Table 1, note 'b' – clarify when to curtail firm deliveries

Phase III/IV Comments

- Add a requirement to verify that there are sufficient reactive resources
- Add a requirement to identify where UVLS should be installed

Violation Risk Factors (VRF) Drafting Team Comment

- R1 – time horizon should be long-term planning

Comment from Draft SAR on Planning Authority

- Provide clarity where the Planning Authority is mentioned

TPL-002:
FERC NOPR

- Require that critical system conditions be determined in the same manner as we propose to require for TPL-001-0;
- Require the inclusion of the reliability impact of the entities' existing spare equipment strategy; *(Only looking for consideration of spare equipment that has a long lead time such as a transformer)*
- Explicitly require all generators to ride through the same set of Category B and C contingencies as required for wind generators in Order No. 661; *(Document explicit definition of ride through capability for generators)*
- Require documentation of load models used in system studies and supporting rationale for their use;
- Clarify the phrase "permit operating steps necessary to maintain system control;" and
- Clarify footnote (b): modify footnote (b) to state that load shedding for a single contingency is not permitted except in very special circumstances where such interruption is limited to the firm load associated with the failure (consequential load loss).330 For purposes of clarity, the Commission proposes to require that the phrase "to prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers" be deleted from footnote (b). This statement is more appropriate for Category C events and is already captured by footnote (c) to Table 1, which is applicable to Category C events.

FERC staff report

- Only includes loss of single element
- NERC TIS Report recommendations not addressed

Version 0 Industry Comments

- Define critical system conditions
- Clarify timing for corrective plan
- Address deliverability of generation to load
- Clarify applicable ratings in Table 1, note 'a'
- Don't include generation runback or re-dispatch
- Must study all contingencies and multiple demand levels & time frames
- Don't include planning outage
- Single terminals are not included

Phase III/IV comments

- Add a requirement to verify that there are sufficient reactive resources
- Add a requirement to identify where UVLS should be installed

VRF comments

- Time horizon should be long-term planning and R2.2 – redundant with R1.3.8

Comment from draft SAR on Planning Authority

- Provide clarity where the Planning Authority is mentioned

TPL-003:
FERC NOPR

- Require that critical system conditions be determined by conducting sensitivity studies (as elaborated in our discussion of TPL-001-0);
- Clarify footnote c: modify footnote (c) to provide specificity regarding the use of the term "controlled interruption" of load.
- Require the applicable entities to define and document the proxies necessary to simulate cascading outages; and
- Tailor the purpose statement to reflect the specific goal of the Reliability, as discussed above.

FERC Staff Report

- Same as TPL-001 & 002

Version 0 Industry Comments

- Same as TPL-001 & 002
- TO should provide plan of action
- Don't base penalties on low probability, low consequence events
- Use NERC Compliance Reporting Process
- Clearly identify outages

Phase III/IV Comments

- Add a requirement to verify that there are sufficient reactive resources
- Add a requirement to identify where UVLS should be installed

VRF Comment

- Time horizon should be long-term planning
- R2 – lack of consistency with TPL-001 & TPL-002
- R2.1 - lack of consistency with TPL-001
- R2.1.1 - lack of consistency with TPL-001 & TPL-004
- R2.1.2 - lack of consistency with TPL-001 & TPL-005
- R2.1.3 - lack of consistency with TPL-001 & TPL-006
- R2.2 - lack of consistency with TPL-001 & TPL-007

Comment from Draft SAR on Planning Authority

- Provide clarity where the Planning Authority is mentioned

TPL-004:
FERC NOPR

- Require that critical system conditions be determined in the same manner as proposed for TPL-001-0;
- Require the identification of options for reducing the probability or impacts of extreme events that cause cascading;
- Require that, in determining the range of extreme events to be assessed, the contingency list of Category D be expanded to include recent events; and
- Tailor the purpose statement to reflect the specific goal of the Reliability Standard.

FERC Staff Report

- Need to reduce the probability of loss of multiple elements and mitigating impact
- Share assessments
- Need to be more severe than weather
- Same as TPL-001

Version 0 Industry Comments

- Same as TPL-001
- Perform analysis on credible contingency
- R1.3.9 – remove from extreme events
- TO should determine which events to study

Phase III/IV Comments

- Add a requirement to verify that there are sufficient reactive resources
- Add a requirement to identify where UVLS should be installed

Comment from Draft SAR on Planning Authority

- Provide clarity where the Planning Authority is mentioned

TPL-005:

FERC NOPR

- Commission will not propose any action on TPL-005-0, as it applies only to regional reliability organizations.
- The term and extent of assessment, as well as the study years, are not appropriately defined; the process for determining load levels needs to be standardized; and local area networks and system adjustments need to be specifically defined.

Regional Fill-in-the-Blank Team Comments

- New SAR needed

Version 0 Industry Comments

- Define fuel adequacy
- An RRO can't make a mandatory request for another RRO to perform a study

TPL-006:
FERC NOPR

- Commission will not propose any action on TPL-006-0, as it applies only to regional reliability organizations.

Excerpts from FERC Order 693
TPL Standards

TPL-001-0

1770. Accordingly, the Commission approves Reliability Standard TPL-001-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to TPL-001-0 through the Reliability Standards development process that:

(1) requires that critical system conditions and study years be determined by conducting sensitivity studies with due consideration of the range of factors outlined above;
(2) requires a peer review of planning assessments with neighboring entities;
(3) modifies Requirement R1.3 to substitute the reference to regional reliability organization with Regional Entity;
(4) requires assessments of outages of critical long lead time equipment, consistent with the entity's spare equipment strategy and
(5) address the concerns regarding footnote (a) of Table 1, including the applicability of emergency ratings and consistency of normal ratings and voltages with values obtained from other Reliability Standards and the concerns raised by International Transmission in regard to the footnotes in Table 1.

TPL-002-0

1797. Accordingly, the Commission approves Reliability Standard TPL-002-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to TPL-002-0 through the Reliability Standards development process that:

(1) requires that critical system conditions be determined in the same manner as we propose to require for TPL-001-0;
(2) requires assessments of planned outages of long lead time critical equipment consistent with the entity's spare equipment strategy;
(3) requires all generators to ride through the same set of Category B and C contingencies as required by wind generators in Order No. 661, or to simulate those generators that cannot ride through as tripping;
(4) requires documentation of load models used in system studies and supporting rationale for their use;
(5) clarifies the phrase "permit operating steps necessary to maintain system control" in footnote (a) and the use of emergency ratings and
(6) clarifies footnote (b) in regard to load loss following a single contingency, specifying the amount and duration of consequential load loss and system adjustments permitted after the first contingency to return the system to a normal operating state, as discussed above.

TPL-003-0

1825. Accordingly, the Commission approves Reliability Standard TPL-003-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to TPL-003-0 through the Reliability Standards development process that:

(1) requires that critical system conditions be determined in the same manner as we propose to require for TPL-001-0;
(2) modifies footnote (c) to Table 1 to clarify the term "controlled load interruption;"
(3) requires applicable entities to define and document the proxies necessary to simulate cascading outages and
(4) tailors the purpose statement to reflect the specific goal of the Reliability Standard.

TPL-004-0

1836. Accordingly, the Commission approves Reliability Standard TPL-004-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to TPL-004-0 through the Reliability Standards development process that:

(1) requires that critical system conditions be determined in the same manner as proposed for TPL-001-0;
(2) requires the identification of options for reducing the probability or impacts of extreme events that cause cascading;
(3) requires that, in determining the range of extreme events to be assessed, the contingency list of Category D be expanded to include recent events and
(4) tailors the purpose statement to reflect the specific goal of the Reliability Standard.

TPL-005-0

1840. Consistent with our discussion in the Common Issues section above, we will not approve or remand TPL-005-0 until we receive additional information from the ERO.

1841. In Order No. 890, the Commission stated that there will be a series of technical conferences and regional meetings to obtain industry input to achieving the goal of regional planning. The Commission encourages the ERO to monitor those proceedings and use the results as input to the Reliability Standards development process in revising Reliability Standard TPL-005-0 to address regional planning and related processes.

TPL-006-0

1845. Consistent with our discussion in the Common Issues section above, the Commission will not approve or remand TPL-006-0.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Version 1 of SAR posted for comment from April 2, 2002 through May 3, 2002.
2. Version 2 of SAR posted for comment from May 5, 2004 through June 5, 2004.
3. Version 3 of SAR posted on November 18, 2005.
4. SAR approved on April 30, 2006.
5. Version 1 of Supplemental SAR posted for comment from February 15, 2007 through March 16, 2007.
6. Version 2 of Supplemental SAR posted on April 9, 2007.
7. Version 1 of revised standard(s) posted for comment on September 17, 2007.

Proposed Action Plan and Description of Current Draft:

The SDT has established an aggressive schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 2Q08. The current draft is the first iteration of the revision of existing standards TPL-001 through TPL-006 and includes one revised standard, TPL-001-1, replacing TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. TPL-005 & -006 will be addressed later in the project. Violation Risk Factors, Time Horizons, Measures, Compliance and Implementation Plans will be included in subsequent postings.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Respond to comments from first posting of standard(s) and submit revision 1 of the standard(s).	4Q2007
2. Respond to comments from second posting of standard(s) and submit revision 2 of the standard(s).	4Q2007
3. Submit revision 3 of the standard(s) for balloting.	4Q2007
4. Submit standard(s) for recirculation balloting.	2Q2008
5. Submit standard(s) to BOT.	2Q2008
6.	
7.	

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Base Case: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect Facility Ratings.

Consequential Load Loss: Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.

Extreme Events: Events which are more severe than Planning Events and have a low probability of occurrence.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond.

Near-Term Transmission Planning Horizon: Transmission planning period that covers Years One through five.

Non-Consequential Load Loss: Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.

Planning Assessment: Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.

Planning Events: Events which require Transmission system performance requirements to be met.

Plant Stability Study: Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.

System Stability Study: Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.

Year One: The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-1**

3. **Purpose:** Establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

   4.1.3. Resource Planner.

   4.1.4. Load-Serving Entity.

   4.1.5. Transmission Owner.

   4.1.6. Generator Owner.

5. **Effective Date:** TBD

B. Requirements

R1. Each Resource Planner, Transmission Planner, Transmission Owner, Generator Owner, and Load-Serving Entity shall each provide its respective Planning Coordinator with the following modeling information required for System performance studies upon request (within 30 calendar days) : *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R1.1. Load forecasts adhering, at a minimum, to the following criteria:

R1.1.1. Use of expected Load mix based on the actual or expected aggregate mix of industrial, commercial, and residential Loads.

R1.1.2. Based on normal weather patterns as agreed to by the Planning Coordinator(s) and the Transmission Planner(s) for the area(s) of their responsibility.

R1.1.3. Identification of Demand Side Management (DSM) Load reductions consistent with operational requirements.

R1.2. Load models with supporting rationale that include power factor data based on historical System performance, validated by measurement during stressed System conditions, or documented Transmission planning area requirements.

R1.3. Firm transfers/Interchange Schedules and resources required to supply Load for each Balancing Authority.

R1.4. Known planned outages and long-term outages for Transmission and generation equipment including protective relays with consideration given to spare equipment strategy.

R1.5. Planned Facilities defined in accordance with the documented criteria of the Planning Coordinator, including but not limited to: Transmission Lines, generators, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies.

R2. Each Transmission Planner and Planning Coordinator shall conduct and document the results of its annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, and shall cover steady state analyses, short circuit analyses, and Stability analyses including both System and plant Stability. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R2.1. The steady state portion of the Near-Term Transmission Planning Horizon Planning Assessment shall address all five years of the assessment period and be supported at a minimum by the following annual current studies,, supplemented with qualified past studies as shown in Requirement R2.6:

R2.1.1. System peak Load for either Year One or year two, and year five.

R2.1.2. System Off-Peak Load for one of the five years.

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation with the rationale for the selected sensitivity(ies) shall be supplied:

R.2.1.3.1. Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.

R.2.1.3.2. Modification of expected transfers.

R.2.1.3.3. Unavailability of long lead time facilities.

R.2.1.3.4. Variability and outages of reactive resources.

R.2.1.3.5. Generation additions, retirements, or other dispatch scenarios.

R.2.1.3.6. Decreased effectiveness of controllable Loads and Demand Side Management.

R.2.1.3.7. Modification of planned Transmission outages.

R2.2. For the steady state portion of the Long-Term Transmission Planning Horizon Planning Assessment, at a minimum, a current System peak Load study is required annually for one of the years in the assessment period to support the annual Planning Assessment.

R2.2.1. To accommodate any known longer lead time projects that may take longer than ten years to complete, the Planning Assessment shall be extended accordingly.

R2.3. The short circuit portion of the Planning Assessment shall be conducted annually and supported by current or past studies.

R2.3.1. A current study shall be performed if changes in the BES result in increased fault currents such as resource additions and other Facility changes that result in reductions in impedance.

R2.4. The System Stability portion of the Near-Term Transmission Planning Horizon Planning Assessment shall address all five years of the assessment period, and be supported by current or past studies. The following studies are required:

R2.4.1. System peak Load for one of the five years. For peak System Load levels, the Load model shall include the dynamic effects of induction motor Loads.

R2.4.2. System Off-Peak Load for one of the five years.

R2.4.3. Sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run with documentation provided explaining the rationale for the selected sensitivity(ies):

R.2.4.3.1. Variations in Load model assumptions.
R.2.4.3.2. Expected simultaneous transfers including non-firm transfers.
R.2.4.3.3. Unavailability of long lead time facilities.
R.2.4.3.4. Reactive dispatch of generators and other reactive power devices.
R.2.4.3.5. Generation additions, retirements, or other dispatch scenarios.

R2.5. The plant Stability portion of the Planning Assessment shall be analyzed consistent with Requirement R4.6 with studies for the year when the following occur:

R2.5.1. New generator(s) are added or generation modifications are made such as increasing generation capability, replacing the exciter or addition of a power System stabilizer.

R2.5.2. Material changes in the electrical vicinity of existing generation are made such as the addition or removal of a Transmission Line at or near the point of Interconnection.

R2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

R2.6.1. For steady state analysis: if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market structure changes.

R2.6.2. For short circuit analysis: if the study is less than five years old and no material changes have occurred to the System in the intervening period.

R2.6.3. For plant and System Stability analysis: until material changes in the System make the study no longer valid. Material changes in the system include the addition of a Transmission Line or a generator.

R2.7. For Planning Events shown in Table 1 – Steady State Performance and Table 2 – Stability Performance, when the analysis indicates an inability of the System to meet the performance requirements in the tables, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed over time but shall meet the performance requirements in the tables. Such plans shall:

R2.7.1. Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.

R.2.7.1.1. For the Near-Term Transmission Planning Horizon, include both a project initiation date as well as an in-service date.

R.2.7.1.2. For the Long-Term Transmission Planning Horizon, provide an in-service year..

R2.7.2. Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables.

R2.7.3. Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'

R2.7.4. Not remove committed projects without documentation to show that the revised plan meets the performance requirements.

R2.7.5. Be reviewed in subsequent annual Planning Assessments as to implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to contingencies in Table 1 – Steady State Performance. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R3.1. Studies shall determine whether the BES meets the performance requirements in Table 1 – Steady State Performance.

R3.2. Contingency analyses shall simulate the removal of all elements including those that System protection is expected to disconnect for each Contingency without operator intervention.

R3.2.1. For all generators, studies shall consider the minimum steady state voltage limitations of all generators and identify how the generators are treated in the steady state simulation.

R3.2.2. For all Transmission lines, studies shall consider relay loadability and identify how loadability is treated in the steady state simulation.

R3.3. For Steady State studies:

R3.3.1. Performance criteria for System normal conditions and for Planning Events in Table 1 – Steady State Performance shall be met.

R3.3.2. Evaluations shall be performed for single Contingencies (identified in Table 1 – Steady State Performance).

R.3.3.2.1. Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment.

R.3.3.2.2. Following single Contingency events, System adjustments other than shedding of firm Load or curtailment of firm transfers are permitted to meet performance requirements provided these adjustments can be accomplished within the time period allowed by the applicable time limited ratings.

R3.3.3. Those Planning Event Contingencies in Table 1 – Steady State Performance not covered in Requirement R3.3.2 that are expected to produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results.

R3.4. Those Extreme Events in Table 1 – Steady State Performance that are expected to produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. If the Extreme Events analysis concludes there are Cascading Outages caused by the occurrence of Extreme Events, an evaluation of implementing a change designed to reduce or mitigate the likelihood of such consequences shall be conducted.

R3.5. Manual and automatic generation run-back is allowed as a response to single and multiple Contingencies as long as Facility Ratings are not exceeded.

R3.6. Manual and automatic generation tripping is allowed for multiple Contingencies and for single Contingencies only in situations that meet all of the following conditions:

R3.6.1. TBD

Note: WECC has informed the SDT that it will be submitting an Interconnection-wide regional variance to allow for manual and automatic generation tripping for single Contingencies. The regional variance will be justified based on physical System differences in the western Interconnection. WECC is developing a white paper to support this position. The actual text of the regional variance will be included in the next posting of this standard.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2.4

and Requirement R2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 2 – Stability Performance. The studies shall cover both System Stability and plant Stability. The following requirements apply to both System Stability and plant Stability studies unless otherwise noted. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R4.1. Studies to meet the performance requirements in Table 2 – Stability Performance shall use computer Stability simulations that analyze the response of the BES.

R4.2. Contingency analyses shall simulate the removal of all elements including those that System protection is expected to disconnect for each Contingency without operator intervention.

R4.3. Studies shall consider the voltage ride through capability of all generators and identify how the generators are treated in the simulation.

R4.4. Studies shall identify any planned upgrades (including protection and control modifications) needed to meet the performance requirements of the Planning Events of Table 2 – Stability Performance and validate their effectiveness.

R4.5. For the System Stability study:

R4.5.1. At a minimum, those Planning Event Contingencies in Table 2 – Stability Performance that would produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information with an explanation of why the remaining Contingencies would produce less severe System results.

R4.5.2. At a minimum, those Extreme Events in Table 2 – Stability Performance that would produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. If the Extreme Events analysis concludes there are Cascading Outages, an evaluation of implementing a change designed to reduce or mitigate the likelihood of such consequences shall be conducted.

R4.6. For the Plant Stability studies:

R4.6.1. Shall be performed for individual generating units 20 MW or greater directly connected through a step-up transformer to the BES and for generating units at the same location which total 75 MW or greater, directly connected through their step-up transformer(s) to the BES.

R4.6.2. Shall be performed for changes in the real power output of a generating unit by more than 10% of the existing capability or more than 20 MW whichever is greater.

R4.6.3. Shall be performed and evaluated for those Planning Events that would produce more severe System impacts and the rationale for the Contingencies selected for evaluation shall be available as supporting

information and shall include an explanation of why the remaining Contingencies would produce less severe System results. The identified Contingencies, at a minimum, shall be evaluated.

R4.6.4. Shall meet Performance requirements for Planning Events in Table 2 – Stability Performance.

R5. Each Transmission Planner and Planning Coordinator shall determine and identify individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R6. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among affected entities, coordinating analysis of these results through an open and transparent peer review process. *[Violation Risk Factor: TBD] [Time Horizon: TBD]* This distribution shall include:

R6.1. Transmission Planners within the Planning Coordinator's area

R6.2. Transmission Planners of neighboring impacted areas

R6.3. Planning Coordinators of neighboring areas

Table 1 – Steady State Performance

Performance Requirements

For all Planning Events:

- Equipment Ratings shall not be exceeded.
- System steady state voltages and post-transient voltage deviation shall be within acceptable limits established by the Planning Coordinator (or Transmission Planner if more restrictive.)
- Voltage instability, cascading outages, and uncontrolled islanding shall not occur.
- Consequential Load loss is allowed for all cases shown.
- Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency.
- Simulate Normal Clearing unless otherwise specified.

Planning Events			
#	**Event**	**Interruption of Firm Transfer Allowed (does not result in loss of Load)**	**Non-Consequential Load Loss Allowed**
P1 (single Contingency)	Loss of: 1. A generator 2. A Transmission circuit 3. A transformer 4. A shunt device (including FACTS devices)	No	No
P2 (single Contingency)	Loss of: 1. Bus section above 300 kV 2. Non-bus tie breaker (above 300 kV) due to internal fault 3. Single pole of a DC line	Yes, if transfer is dependent on the outaged DC line No otherwise	No
P3 (multiple Contingency)	Loss of either a generator, Transmission circuit, a transformer with low side voltage rating above 300 kV, or a bus and a stuck non-bus tie breaker (above 300 kV)	Yes, if transfer is dependent on the outaged DC line No otherwise	No
P4 (multiple Contingency)	1. Loss of a generator followed by a System adjustment followed by the loss of a generator. 2. Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line 3. Loss of a generator followed by a System adjustment followed by the loss of a Transmission circuit 4. Loss of a generator followed by a System adjustment followed by the	Yes, if transfer is dependent on the outaged DC line No otherwise	No

	loss of a transformer		
P5 (multiple Contingency)	Above 300 kV, the loss of: 1. A Transmission circuit followed by a System adjustment followed by the loss of another Transmission circuit 2. A Transmission circuit followed by a System adjustment followed by the loss of a transformer with low side voltage rating above 300 kV 3. A transformer with low side voltage rating above 300 kV followed by a System adjustment followed by the loss of another transformer	Yes	No
P6 (single Contingency)	Loss of: 1. A bus tie breaker due to internal fault 2. A bipolar DC line or an asynchronous tie line 3. A non-bus tie breaker (below 300 kV) due to internal fault 4. A bus section below 300 kV	Yes	Yes
P7 (multiple Contingency)	Loss of: 1. A bus section above 300 kV and a stuck bus tie breaker 2. Either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (below 300 kV)	Yes	Yes
P8 (multiple Contingency)	Below 300 kV, the loss of: 1. A Transmission circuit followed by a System adjustment followed by the loss of another Transmission circuit 2. A Transmission circuit followed by a System adjustment followed by the loss of a transformer 3. A transformer followed by a System adjustment followed by the loss of another transformer	Yes	Yes
P9 (multiple Contingency)	1. Loss of any two circuits on a common structure (excluding where multiple circuits share a common structure for no more than one mile) 2. Loss of a generator followed by a System adjustment followed by the loss of a monopolar or bipolar DC line, or an asynchronous tie line 3. Loss of a DC line (monopolar or bipolar) or asynchronous tie followed by a System adjustment followed by the loss of a second DC line (monopolar or bipolar) or asynchronous tie 4. Loss of a DC line (monopolar or bipolar) or asynchronous tie followed by a System adjustment followed by the loss of a Transmission circuit	Yes	Yes

	5. Loss of a transformer followed by a System adjustment followed by the loss of a DC line (monopolar or bipolar) or asynchronous tie line 6. Loss of a transformer followed by a System adjustment with a spare transformer available followed by the loss of another transformer		

Extreme Events

Evaluation Requirements

For all Extreme Events:

1. See Requirement R3.4
2. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency.
3. Simulate Normal Clearing unless otherwise specified.

Extreme Event Descriptions

1. Loss of a single generator, Transmission circuit, DC line, or transformer forced out of service followed by another single generator, Transmission circuit, DC line, or transformer forced out of service prior to System adjustments.

2. Local area events affecting the Transmission System such as:
   a. Loss of tower line with three or more circuits
   b. Loss of all Transmission lines on a common right-of-way
   c. Loss of switching station or substation (loss of one voltage level plus transformers)
   d. Loss of all generating units at a station
   e. Loss of a large Load or major Load center

3. Wide area events affecting the Transmission System such as:
   a. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation
   b. A successful cyber attack
   c. Regulation that restricts or eliminates the use of a river or lake or other body of water as the cooling source for generation
   d. Shutdown of a nuclear power plant(s) and other facilities a day or more prior to a hurricane, tornado or wildfire, or for other common causes
   e. Regulation that restricts or eliminates the use of a river or lake or other body of water as the cooling source for generation
   f. Shutdown of a nuclear power plant(s) and other facilities a day or more prior to a hurricane, tornado or wildfire, or for other common causes such as problems with similarly designed plants
   g. The loss of older Transmission lines which may not be constructed to meet an entity's present radial ice or wind loading requirements, while the newer or stronger Transmission lines remain in service
   h. Other events based upon operating experience

Table 2 – Stability Performance Table

Performance Requirements

For all Planning Events:

- The System shall be stable[1]
- Dynamic voltages shall be within acceptable limits established by the Planning Coordinator or Transmission Planner (if more restrictive)
- Uncontrolled islanding and Cascading Outages shall not occur
- Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency.
- Simulate Normal Clearing unless otherwise specified.

Planning Events			
#	**Initial Condition**	**Event**	**Non-Consequential Load Loss Allowed**
P1 (single Contingency)	System normal	Single Line Ground (SLG) fault on, a 3-Phase (3Ø) fault on, or an unexpected loss without a fault of (whichever is worst): 1. A generator 2. A Transmission circuit 3. A transformer	No
P2 (single Contingency)	System normal	1. SLG fault on bus section above 300 kV 2. SLG internal fault in non-bus tie breaker (above 300 kV) 3. A single pole block of a DC line	No
P3 (multiple Contingency)	System normal	SLG fault on either a generator, Transmission circuit, a transformer, or a bus and a stuck[2] non-bus tie breaker (above 300 kV)	No
P4 (multiple Contingency)	A single generator out of service followed by System adjustments	1. Apply a P1.1 Contingency. 2. Apply a P2.3 Contingency. 3. Apply a P1.2 Contingency. 4. Apply a P1.3 Contingency.	No
P5 (multiple Contingency)	A Transmission circuit above 300 kV out of service followed by System adjustments	1. Apply a P1.2 Contingency. 2. Apply a P1.3 Contingency.	No

	A transformer with low side voltage rating above 300 kV out of service followed by System adjustments	3. Apply a P1.3 Contingency.	
P6 (single Contingency)	System normal	1. SLG internal fault in bus tie breaker 2. A bipolar block of a DC line 3. SLG internal fault in non-bus tie breaker (below 300 kV) 4. SLG fault on bus section (below 300 kV)	Yes
P7 (multiple Contingency)	System normal	1. SLG fault on a bus section above 300 kV and a stuck bus tie breaker 2. SLG fault on either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (below 300 kV)	Yes
P8 (multiple Contingency)	A Transmission circuit below 300 kV out of service followed by System adjustments A transformer with low side voltage rating below 300 kV out of service followed by System adjustments	1. Apply a P1.2 Contingency. 2. Apply a P1.3 Contingency. 3. Apply a P1.3 Contingency.	Yes
P9 (multiple Contingency)	System normal A single generator out of service followed by System adjustments A DC circuit out of service followed by	1. SLG fault on each circuit of any two circuits on a common structure (excluding events where multiple circuits share a common structure for no more than one mile). 2. Apply a P6.2 Contingency. 3. Apply a P2.3 Contingency. 4. Apply a P1.2 Contingency.	Yes

	System adjustments A transformer out of service followed by System adjustments A spare transformer inserted to replace an outaged transformer followed by System adjustments	5. Apply a P2.3 Contingency. 6. Apply a P1.3 Contingency.	

Extreme Events

Evaluation Requirements

For all Extreme Events:

- See Requirement R4.5.2 in the text
- Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency.
- Simulate Normal Clearing unless otherwise specified.

1. 3Ø fault on generator with stuck breaker
2. 3Ø fault on Transmission circuit with stuck breaker
3. 3Ø fault on transformer with stuck breaker
4. 3Ø fault on bus section with stuck breaker
5. 3Ø internal fault in breaker
6. 3Ø fault on two or more circuits on a common structure
7. SLG or 3Ø fault on all Transmission lines on a common right-of-way
8. 3Ø fault on switching station or substation (loss of one voltage level plus transformers)
9. 3Ø fault with loss of all generating units at a station

Notes:

1. System stable means:
   a. Angular stability:
      i. For Planning Events P1 and P3.2: No generating unit or units shall be allowed to pull out of synchronism. A generator being disconnected from the system by fault clearing action or by a Special Protection Scheme is not considered pulling out of synchronism.
      ii. For all other Planning Events: No generating unit or units totaling more than the contingency reserve (spinning reserve) of the Balancing Authority shall be allowed to pull out of synchronism. Generators that pull out of synchronism must have out-of-step protection and the resulting apparent impedance swings must not pass through relay characteristics that would result in the tripping of

any transmission system elements other than the generating unit and its direct connection facilities.

iii. For all Planning Events: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator or Transmission Planner (if more restrictive).

b. General: Unplanned islanding of portions of the system shall not occur for Planning Events.

2. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) breaker, only one pole is assumed to remain closed.

C. Measures

M1. To be supplied at a later date.

E. Regional Variances

1. WECC Interconnection-wide waiver is under development (see Requirement R3.6.2).

Version History

Version	Date	Action	Change Tracking
1		Revision of TPL-001-0 as per Project 2006-02; includes merging requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-1	Not employed due to scope of revision

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☐Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☐Agree. ☐Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.

- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☐
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☐
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☐
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☐
Comment:

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☐
Comment:

[1] System adjustment can be manual or automatic

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☐ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☐ No ☐
Comment:

Maureen E. Long
Standards Process Manager

September 12, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement: Comment Period Opens

The Standards Committee (SC) announces the following standards actions:

First Draft of TPL-001-1 — Transmission System Planning Performance Requirements Posted for 45-day Comment Period

The first draft of TPL-001-1 — Transmission System Planning Performance Requirements is posted for a 45-day comment period from September 12 though October 26, 2007. The purpose of the proposed standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

The proposed standard consolidates, clarifies, and expands on the requirements that had been in TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0, and includes several new definitions.

Note that the drafting team will hold a WebEx and Conference Call on Wednesday, October 10 from 1 p.m. to 4 p.m. EDT to present and discuss the proposed requirements in TPL-001-1. The purpose of this call is to provide stakeholders with an overview of the proposed requirements, to highlight the areas where the proposed requirements differ from the requirements in the existing TPL-001-0 through TPL-004-0, and to provide stakeholders with the opportunity to ask questions about the proposed requirements.

Please use this comment form to provide comments on the first draft of this standard.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	William Quaintance	
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Telephone:	919-856-3310	
E-mail:	william.quaintance@us.abb.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☒ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment: Agree but delete "or node". It is unnecessary.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: See Q6. Also, from your definition above, a better term would be "directly-connected load loss". This is clear and to the point.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: Most people will think of inconsequential, which often means irrelevant, unimportant, or insignificant. But what you are trying to define is the opposite: load loss that is significant, important, and needs to be**	

prevented. Also, whatever you call it, your examples (UVLS, UFLS, SPS) should be expanded to include unintentional and uncontrolled load loss due to low voltage, high current, impedance relays, etc.	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☐Do not agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment: Agree but adjust language. You are saying "require requirements to be met". Duh. Even if you took out one of them and said "requirements must be met", this is also redundant. The definition of "requirement" is that it is required. How about "Events for which there are strict transmission performance standards that must be met." This may also be slightly redundant, but not as much as the original.**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: I don't see any reason to differentiate between "Plant Stability" and "System Stability". These are not commonly separated. A better differentiation would be between generator (or angular) stability and load (or voltage) stability. These are usually independently studied and indendently occurring.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: See Q9.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment: Agree but delete "annual". Unnecessarily restrictive. Aren't there non-annual studies for which the definition of "year one" is important?**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of

variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: No. However, as long as we're talking about it, NERC should set a standard for the definition of the "peak load" to be planned for. Some utilities use the 50% probability peak load. Some use 90%. A big difference that will result in a big difference in how they are prepared for the peak load days. The sensitivity section is not sufficient to address this.
Also, outages of reactive resources should be (and are) in the list of contingencies, not sensitivities.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment: Absolutely.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: First of all, you are not exactly requiring that DSM be considered or analyzed. You have simply listed it as one of the possible solutions. And you should mention the possibility of "integrated plan" in the standard itself. Since DSM is simply optional, let the planners figure out themselves how to consider DSM.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☒
Comment: Any area where there might possibly be an impact. I.e., engineering judgement.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment: Yes, it helps when considering other issues in the same area. You would know whether or not you can count on a project going in.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment: It's kind of obvious. If you require a solution to begin with, then if that solution is removed, another solution must be planned. However, if the removed project

is not directly related to the study or problem at hand, then engineering judgement will be needed as to whether or not to repeat the study.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☐Do not agree.	Loss of load is not usually considered by tranmission planners. In power flow studies, they look at flows and voltages versus limits. In stability studies, they are looking for angles, speeds, and voltages that stabilize at good values, possibly with temporary excursions less than some limits. How should all these be converted to a loss of load value? Normally we ensure no loss of load <because> we meet thermal, voltage, and stability requirements. Maybe you are saying that planners should not use load tripping as a solution for these violations?
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit	☐Agree. ☐Do not	

followed by System adjustment[1] followed by loss of another Transmission circuit	agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☒

Comment: When talking about breaker outages, I see no reason to differentiate between "non-bus tie" and "bus tie" breakers. Are bus tie breakers inherently more reliable? If the effect on the system due to a tie breaker outage is very bad, then this should be fixed. All other contingencies seem to be slotted based on probability. Shouldn't breakers? Maybe bus tie breakers are weak points in the transmission system that need to be improved.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☒

Comment: Table 1 P3 is a little hard to read/understand. The second column should start out something like "A stuck breaker following the outage of any 1 of the following:" However, P3 will be completely redundant with P2 because, in power flow analysis, there is no difference between a breaker internal fault and a stuck breaker following an external fault. The final outaged equipment is the same. This will cause extra unnecessary work.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	For Table 1 P4, rewrite it to read "Loss of a generator followed by a System adjustment followed by the loss of any one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. A shunt device 5. Single pole of DC line." This structure is easier to read and understand. The order should be like this to match P1. Shunt devices should be included. P3 should be structured similarly.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: Yes, this is the purpose of HVDC. It carries the power your want, no more, no less. Both the good and bad of parallel flows are avoided.

[1] System adjustment can be manual or automatic

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment: Yes, I like this. You can maintain them to be as similar as possible, while still containing the requisite differences.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: I don't see any reason to differentiate between "Plant Stability" and "System Stability". These are not commonly separated, and this distinction is not standard in the industry. You should not be inventing a distinction that doesn't exist. A better differentiation would be between generator (or angular) stability and load (or voltage) stability. These are usually independently studied and independently occurring.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: No. Good idea. A whole plant may be out because of a shortage of cooling water, but this is an orderly shutdown, not a sudden event. It is only appropriate for steady-state.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment: Yes, but the impact on the models and studies is unknown. Some testing needs to be done with full Eastern and Western Interconnection models to see how they handle motor models at every load. I've performed numerous studies where loads in an entire utility or state have been converted to a large % of motors, and the effect can be shocking. The programs (PSS/E and PSLF) may completely bog down if this is done for a whole interconnection. Many stability problems will be found. We definitely need to transition to this, but with care.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: For multiple, only automatic schemes. For single, only automatic schemes if the loss of MW is shown to be acceptable.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment: Every single event will eventually require preparing for the next event. But we cannot plan for every next event. Only specific single and multiple contingencies should be planned for, all flows must be within an established rating of some kind (continuous, 12-hour, 4-hour, 15-min, whatever), and the idea of the "next event" should not be included in a planning standard.

Now maybe there should be a limit as to how short the time of a rating can be in Planning. For example, planning to a 15-min rating is a bad idea. That rating can be used by operators in emergencies, but planners need to do something better. A minimum should be set (e.g. 1 hour rating). I guess if a company wants to use a 15-min rating and then AUTOMATICALLY transition to a 1-hour or 12-hour rating with runback or something else, that is reasonable.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☒
Comment: No. Following a single contingency, all flows must be within some kind of established rating. After that, runback can be used to get under a longer-term rating.

For multiple contingencies, some type of cross-tripping is OK, but runback is too slow and unreliable.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☒
Comment: It makes the system too complex and less reliable. Single contingencies need to be handled without any fancy controls.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: They could be used in the short term until a permanent fix is available. Limit to <5 years.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: In Table 2 P3, more clarification is needed for "above 300 kV". For generators, does that mean those whose POI is >300kV? For transformers, is it the secondary voltage? Also, is the footnote referencing correct?

"A transformer with low side rating above 300 kV" is confusing for transformers with 3 windings. What's the low-side rating of a 500/345/13.8 kV transformer? You should say "a secondary voltage rating above 300 kV" and define "secondary voltage rating" as the second highest voltage rating. This is standard nomenclature. Also, I assume you know that there aren't very many of these. The possibilities are 765/500, 500/345, and 765/345. The first two are uncommon, and the 3rd is only common in AEP and HQ.

In P3, does the 300 kV limit apply to the transmission circuits as well? It is hard to tell.

In R1, you say "Each … shall each …" Delete the second "each", which is redundant. Also delete "required for system performance studies". These words are not part of the requirement. They are part of the justification for the requirement.

Table 1, Extreme Event Descriptions, 3d and 3f are almost identical.

Table 1, P9-1, rewrite as "… (excluding circuits that share common structures for one mile or less)". P9-1 uses "structure" whereas Extreme 2a uses "tower". Make consistent.

P9-2 monopolar is already covered under P4-2.

For all of the multiple contingencies with System Adjustment in the middle, group them together something like this (for those with the same requirements):

"Outage of any one of the following:

1.
2.
3.
4.

followed by System Adjustments followed by outage of any one of the following:

a.
b.
c.
d."

This is easier to understand than separately writing each possible combination of 2.

Overall, the structures of the Tables needs to be made clearer and more consistent. But the ideas are good.

The transition is going to be critical for some of the standards that may require significantly more study work and significant capital investments in transmission infrastructure.

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Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

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The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment: However this could be very subjective.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☒Agree. ☐Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.

- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒
Comment: We beklieve that only the worst case would need to be addressed for stability purposes.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒

Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒
Comment:

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment: However, the question as to what is considered committed versus proposed. There are variuos step in the approval process for our company and we are not sure which approval would be considered committed.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that

performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

[1] System adjustment can be manual or automatic

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☒
Comment: Agree with the statement above as to the timefram regarding stability.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment: However, getting all the modleing data is not easy and may take some time.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Whatever the generator is capable of.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare

for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

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Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: We do not have the capability to have automatic runback at this time. However if an entity does have the capability to perform automatic runback than it should be allowed to prevent overloads. That would be the purpose.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: no comment

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: no comment

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: Based on the p1 to P9 events one would have to model a breaker to breaker instaed of bus to bus. This would be a large undertaking and it seems that it would be more conservative to have a bus to bus model.

Question on P4 - does this apply to all generators on a system or is ther a MW limit to the size of the generator.

P5 Does this mean running N-2 for the 300 KV for all seven cases that would be required. This could take a large amount of computer run time.

We are stating that this change to the standard is not warrented. However, if all these changes are implemented what used to take approximately 1 month to assess will now take approximately 4 months and we are not that big of a system. I assume that the time and manpower to perform all the contingencies has been considered.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
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Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*
			2

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R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☐Do not agree.
Q1. **Comment: Due to the length of this questionnaire and the different regional approaches to how IRC members meet the TPL requirements, indiividual ISO RTOs have chosen to respond separately. Collectively the IRC SRC provides comments in #43 of this questionnaire.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☐Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☐Do not agree.
Q6. **Comment:**	

Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☐Do not agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.

- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☐
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☐
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in

conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☐
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☐
Comment:

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL

standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the

[1] System adjustment can be manual or automatic

steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected

Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☐ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: The Alberta Electric System Operator (AESO) supports the comments from WECC with the exception of Question #19 where the AESO agrees with the proposed requirement R2.7.4 by the SDT.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Wesley O. Davis	
Organization:	Alcoa Power Generating, Inc	
Telephone:	(704)787-1392	
E-mail:	Wesley.Davis@alcoa.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☒	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

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Yes ☐ No ☐
Comment:

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Yes ☐ No ☐
Comment:

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Comment:

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Yes ☐ No ☐
Comment:

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Yes ☒ No ☒

Comment: NERC is revising the Transmission Planning Standards beginning with TPL-001. Alcoa agrees with NERC's approach to revising TPL-001 wherein NERC is consolidating duplicative Standards to promote consistent requirements of the planning process and thus improving reliability. Also, Alcoa agrees that new studies should not result in inadvertent negative impacts on the system especially when such studies have not taken into account the negative impact on an adjacent system.

However, Alcoa believes that the current draft of the TPL fails to address FERC Order 890's requirements of an open and transparent Planning Process. Such a process provides Market Participants an equal opportunity for consideration in the Planning Assessments for contingency impact on transmission availability. (See FERC Order 890 ¶¶ 140, 207, 212, 323, 327, 337). Alcoa also believes that the current draft of the TPL fails to address and incorporate FERC Order 890's new requirement that transmission providers coordinate "…ATC calculations with their neighboring systems."

For example, while Planning Assessments may indicate no NERC Compliance violations where the Table 1 and Table 2 Requirements are met, Market Participants are harmed and not provided protection from unequal treatment of their circumstance. This problem occurs when an analysis of a contingency event results in no IROL or SOL (all facilities remain within established ratings), but resultant transmission constraints cause reductions of ATC and subsequent market impact. As part of the System Planning Process, this is unacceptable, and, as a minimum, this type of situation must be included as a scenario reviewed in the required sensitivity analysis under the NERC TPL-001-1 Standard.

The impact of such practices by large transmission providers on the ATC of smaller transmission providers can be significant. For instance, small transmission providers similar to Alcoa that operate non base-load resources such as hydropower, peaking units or wind power can easily see their ATC's reduced when sensitivity analyses are not performed under TPL-001-1. Alcoa believes that such sensitivity analyses should be a requirement.

Alcoa believes that for consistency with the provisions of Order 890, NERC must re-visit not only the Planning Assessment implications on transmission availability but also couple this review with the revision of the NERC Modeling Data and Assessment Standards (MOD). Alcoa recommends that the MOD and TPL Standards be addressed in similar fashion to:

1) Incorporate the intent of Order 890 requirements of an "Open and transparent Regional Planning Process to provide non-discriminatory planning" for ALL Market Participants

2) Assure that the revised MOD and TPL Standards fully address implications of burdens on the Bulk Electric System (BES) related to transmission availability for contingencies in the Planning Process.

FERC Order 890 ¶ 523 - Coordinate planning with interconnected systems. In addition to preparing a system plan for its own control area on an open and nondiscriminatory basis, each Transmission Provider will be required to coordinate with interconnected systems to (1) share system plans to ensure that they are simultaneously feasible and otherwise use consistent assumptions and data and (2) identify system enhancements that could relieve congestion or integrate new resources. (Emphasis added).

3) Sensitivity Analysis should include the potential impact on transmission availability and/or reductions in ATC on adjacent systems. Where ATC on an interface is reduced for a single contingency (N-1 planning, mitigation options must be provided). (This may require a threshold level of ATC reduction where a percentage reduction would be specified as acceptable on the N-1 basis, and a greater reduction than that threshold would be considered a Standard's Violation).

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☐

Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☐

Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for	☐Agree.	

stability) above 300 kV	☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☐
Comment:

[1] System adjustment can be manual or automatic

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☐ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☐ No ☐
Comment:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	William J. Smith	
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☒Agree. ☐Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.

- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: Scenario analysis should be based on the unique aspect of the particular Transmission zone. Transmission Planners should work to select the best scenarios related to the specific system and adequately describe the selection process..

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: Providing examples would be helpful but specifically stating the required thresholds are transmission system dependent. Providing some methodologies to follow may be prudent such as forecast levels like 90/10; 80/20; or 50/50.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: No sensistivity needed for long term assessment.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in

conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: It should be included if there are specific mandated or approved DSM programs in place during the study period.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: Study area should be at least two buses beyond deficiency and plan elements.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment: There needs to be a clear definition developed for committed and proposed projects and those definitions need to be included in the definition section of the standard.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
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Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	
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[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance

requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an

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assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Should not be limited

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency

outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: This could be permitted provided the run back will allow for the ability to prepare for the next operational contingency and not affect load.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: The use of these system should be limited and not used as a preferred solution and also be approved by a stringent review process through the RTO & RE.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: The system should remain stable, reliable, allow for operational preparation for the next contingency and failure of the RAS/SPS should not lead to a cascading event.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☒
Comment: General Comments:

1). We believe the 300kV cutoff should not be used. It should be based on the definition of a Backbone Facility. The 300kV and above standards should only apply to backbone facilities that are used to provide overall energy transfer and ties to other systems and not facilities that provide load serving purposes. Backbone facilites should be specifically defined and accepted as Backbone facilities through RTO and RE review and acceptance.

2). Planning Scenarios should be forced to include a market based scenario under the Planning Authority obligation which should include long range market projections for generation dispatch, significant energy price changes due to environmental issues or fuels, and market impact of large transmission reinforcements.

3). It should be noted in the process that additional planning resource additions (maybe as much as 30%) will be required to met these new study requirements since they are much more expansive than the existing requirements.

4). These standards could require substantial (millions) upgrades to the system to meet the proposed changes. These are primarily due to the 300kV and above standard revisions and the non-consequential load drop criteria adjustments.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment: Yes, we agree that the "base case" is a power flow model and is the starting point of the analysis. What we are concerned with are the assumptions that go into the development of the "base case". The season, time of day, load level, generation dispatch assumptions, facilities in service, and interchange assumptions (all based on best available data) are just a small subset of the issues that need to be addressed in the development of the base case. We have concerns that so-called "stressed cases" proposed in the standard for compliance testing may in reality be contingency cases, from which additional compliance performance testing would be required.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment: A better name for this would be "direct load loss". The definition should include load served by the faulted element but not directly connected to the faulted element.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Most planning events have a low probability of occurrence. It appears that the SDT is trying to make a distinction that these extreme events would have a lower probability of occurrence than planning events. Consideration should be given to adding the performance requirements with the definition.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.

Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment: It is suggested that another definition be added for "operations planning horizon".**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment: A better name for this would be "indirect load loss".**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: We do not agree that the planning assessment should include asset conditions and age. The age of equipment, if it is well maintained, has little impact on reliability. If NERC wants a standard to deal with age and maintenance of equipment, then it should develop a separate standard for asset management and not overburden TPL-001-1 with such issues.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Consideration should be given to adding the performance requirements in the definition.**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: It seems that the SDT is trying to divide the stability issues between plant (local) and system. As the system load representation and its damping characteristics affect both plant and system stability, it is difficult to separate plant versus system stability studies. The focus of the studies may be only slightly different, depending on the location, type, and duration of the fault conditions assumed.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: See comments above in the response to Q9. Specific inclusion of voltage (load) stability seems to be missing from the definition. Also, angular stability is mentioned only as part of the definition for System Stability Study and not Plant Stability Study. It would seem that this item would be part of both types of study.**	
Q11. **Year One:** The first year that a Transmission Planner is	☒Agree.

responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: For the purposes of compliance, we believe that the existing requirement R1 in Standard TPL-001-0 adequately defines the sensitivities that need to be covered in a valid assessment, and no additional clarification is necessary. Deterministic tests of a limited number of system conditions require the application of engineering judgement to evaluate the complex multi-variable problems involved in planning analyses. We all agree that performing contingency analyses on a single snapshot of expected system conditions is not adequate to plan the transmission system, but planning is not a cookbook exercise, and neither is an engineering assessment of planning activities demonstrating required system performance. Further, we believe that a test of incremental transfer capability determined from some of the sensitivity cases needs to be added to the standard and would go a long way to address how much margin exists in the transmission system to handle the unknown or previously undefined variables.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: There is no need to build a multitude of sensitivity cases to assess the reliability of the system. The sensitivity issues should be handled on an individual system basis by the local transmission planners as applicable to the study system. Conditions that are considered as "stressed" for one area may require all facilities to be in service in another area. Powerflow cases utilizing a number of the items listed under R2.1.3 or R2.4.3 could be produced for in-house study work, but such work should not be required as part of standards compliance. The standard should not be dictating what types of sensitivities should be investigated or considered for all parts of the transmission system.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒
Comment: The biggest problem with performing stability analysis is getting the stability cases to match up with the powerflow cases, and only a limited number of stability cases are developed each year. Further, for those systems that are planned in excess of the NERC Standards regarding stability (3-L-G or 2-L-G vs. 1-L-G as in the Standard), there are no benefits to performing additional sensitivity studies to demonstrate compliance with this standard.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: There are more unknowns in the longer-term studies than in the near-term studies, which would indicate that more sensitivity studies would need to be performed and not less. However, it is more reasonable to suggest that if near-term sensitivity studies show a problem in a particular part of the system, then similar sensitivity studies need to be performed in the longer-term analyses.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or

Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☒
Comment: If DSM can be implemented in the required operating time, we have no objections to using DSM as the planned mitigation to relieve overloads or low system voltages for multiple contingency conditions, but not as a long-term solution for single contingency conditions. However, from our experience, we believe that developing enough DSM in the required time at specific locations in the system will be difficult, and that plain load-shedding would be required to supplement the DSM to achieve the desired performance.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒
Comment: This proposed requirement is unnecessary and a waste of time. Keep in mind this is a planning assessment and not a facilities study. Further, such a requirement implies a distrust of the transmission planners to develop valid corrective action plans to meet the requirements of the TPL standard.

For more complex system facility additions, it would be inconceivable that a Transmission Planner or Owner or Planning Coordinator would proceed without performing powerflow simulations to determine the efficacy of the system addition. But these studies would be perfromed over time considering the best available information and latest standards performance requirements.

The majority of transmission projects consist of the upgrading of terminal equipment or conductor on one or more branches. The only significant change that such upgrade work would produce in a powerflow model would be that the branch ratings would change. It is not necessary to rerun powerflow simulations for such cases, as it can be determined by inspection whether the upgrade work would be sufficient to move the facility rating above the expected normal or contingency flow.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: We understand that there are differences between committed and proposed projects in an RTO environment where there is cost sharing for facility upgrades. From a NERC Standards compliance perspective, however, we do not see a need to differentiate between proposed and committed projects in the corrective action plan, as

long as either properly addresses the required performance issue. We are not sure why there is a need to develop or maintain information on committed projects. This tracking is not needed to meet the existing TPL standards. Compliance requirements should be kept separate from administrative data requests. What is the perceived need to track committed projects that has not been presented here? Is this another example of distrust for transmission owners to build the proper facilities to create a more robust system?

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒

Comment: As stated above, we are not sure why there is a need to develop or maintain information on committed projects. This tracking is not required in the existing TPL standards. As long as the revised corrective action plan meets the reliability performance requirements, what difference does it make if a committed project is cancelled or changed to a proposed project from a compliance perspective? We need to keep compliance requirements separate from administrative data requests or survey responses.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus	☒Agree.	No significant material change identified.

section (SLG for stability) above 300 kV	☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Load pockets supplied by a single EHV substation with only two supplies would not meet this proposed requirement, whereas the existing TPL-003-0 standard would allow the dropping of load for the multiple outage event. A significant material change to build new facilities would be needed to meet the new requirement.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	No opinion as we do not have any transformers with the low side voltages rated above 300 kV. Transmission owners with transformers meeting this requirement should be consulted to determine if a material change would be required.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	No opinion as we do not have any transformers with the low side voltages rated above 300 kV. Transmission owners with transformers meeting this requirement should be consulted to determine if a material change would be required.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☒

Comment: This part of the proposed standard language is confusing. From our perspective, the failure of any 300 kV or above non-bus-tie circuit breaker should not result in the non-consequential loss of load. Further, EHV circuit breakers failing as a result of internal faults are extremely rare, bus-ties or not. Also, it is not clear what would be considered a non-bus tie breaker for ring bus and breaker-and-a-half bus configurations. It would seem that performance requirements for EHV bus-tie breakers (and not non-bus-tie breakers) should be distinguished from other breakers.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: The loss of two or more elements at any EHV substation at time of peak would likely result in loss of non-consequential load. If the intent of the proposed standard is to encourage the development of ring bus or breaker-and-a-half bus arrangements at the EHV level, we would concur where it is physically possible and makes for good engineering practice. However, we must remind the SDT that there are some existing facilities that cannot be converted practically or economically from their present straight bus configuration because of physical limitations. A significant material change, potentially several million dollars per substation, would be required to retrofit facilities, where possible. It would appear that performance requirements for EHV bus-tie breakers (and not non-bus-tie breakers) should be distinguished from other breakers.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	The outage of any two generators should not result in any non-consequential loss of load.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	The outage of a generator and any other element should not result in any non-consequential loss of load.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	The outage of a generator and any other element should not result in any non-consequential loss of load.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	The outage of a generator and any other element should not result in any non-consequential loss of load.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☒

[1] System adjustment can be manual or automatic

Comment: If the system cannot withstand the outage of the single element (AC or DC) without curtailment of the transfer, then the transaction should not be considered as firm.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☒
Comment: We understand the need to clarify the different requirements in the steady-state vs. the stability analyses. However, for each contingency category we expect to see both the steady-state requirements and the corresponding stability requirements in the same table. We believe that it would be better to recombine the steady-state and stability tables and present the information in a landscape format.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment: We appreciate the SDT concern for performing repeated plant stability studies without any change in plant/machine characteristics. However, as the system load representation and its damping characteristics affect both plant and system stability, it is difficult to separate plant versus system stability studies. On some systems in which load and generation are tightly coupled, the focus of plant or system stability studies may differ only slightly with the location and duration of applied fault events. As such, the scope and manner of conducting System Stability study work under Requirement R2.4. for such portions of the interconnected system is not clear. Differences between Plant Stability Studies and System Stability Studies need to be made more clear.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐
Comment: A good test of the robustness of the interconnected system is its ability to handle import plus heavy inrush conditions, such as might occur with loss of a large plant. While the probability of such random events would be very low, the possibility still exists that intentional sabotage could result in such an event.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load

model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☒
Comment: Dynamic studies of peak load conditions should include the effects of induction motors, and particularly in areas where traditional load models have indicated a problem. Unfortunately, there is a lack of data to support the amount and characteristics of the detailed induction load models in many areas. In addition to the consideration of the dynamic effects of induction motor loads, the effects of static capacitor banks installed at both distribution and transmission voltage levels would need to be considered as well. The industry would be looking to NERC for some guidance as to how this data should be developed and maintained for models in future years.

Note that meeting such a requirement would necessitate a significant increase in the dynamic data needed to represent the system. Also, maintenance of such load model data would need to be considered. Load characteristics valid for a near term model might not be valid for future years. Also, summer peak load, winter peak load, and off-peak load characteristics would differ.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: No adjustment of firm (network resource) generation should be allowed for the long-term mitigation of a single contingency. Allowing post-contingency shifts of firm generation as a long-term mitigation of a single contingency event is short-sighted and would not produce a robust system that is required to handle more than single contingency events. Redispatch of firm generation may be required in the near-term as an interim operating guide or procedure until the limiting transmission element can be uprated or other system reinforcement is in place. Generation redispatch should also be allowed to prepare for the next single contingency. For responding to multiple contingencies, redispatch of firm generation should be allowed in the mitigation plan provided that the redispatch can be accomplished in the required operating time and the contingency overloads are not overly severe (indicating possible cascading). Firm generation should also be tripped to quickly mitigate contingencies involving multiple generation outlet transmission circuits. Non-firm (energy only) generation can be tripped or redispatched for any contingency event as needed to keep facility loadings within ratings.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☐ No ☒
Comment: The runback of firm generation should only be allowed as a valid interim operating procedure until a system reinforcement would be installed to uprate or unload the limiting facility. The use of the runback scheme should not be allowed as the long-term solution to a single contingency event. As mentioned above in the response to Q35, non-firm (energy only) generation should be tripped or redispatched for any contingency event as needed to keep facility loadings within ratings.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☒
Comment: No generation runbacks should be allowed as long-term solutions for single contingency conditions.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: Yes, but only as interim operating procedures until the limiting facilities can be uprated or unloaded. SPS or RAS should be allowed to trip non-firm (energy only) generation to keep facility loadings within ratings.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: SPS and RAS should be used only as interim operating procedures to mitigate single contingency events until the limiting facilities can be uprated or unloaded. SPS and RAS should be allowed to trip non-firm (energy only) generation as needed to keep facility loadings within ratings.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: RAS and SPS should be allowed only as an interim operating procedure to mitigate single contingency conditions or to mitigate multiple contingency events on a long-term basis. The RAS or SPS must be effective in mitigating the contingencies and can be implemented within the required operating time.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment: The proposed standard, as well as the existing standards, makes no distinction between firm (network resource) and non-firm (energy only) generation. The standard should clearly state that the standard does not apply to non-firm generation.

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: Much of the language under R1 appears to be redundant with model data requirements as listed in Reliability Standard MOD-010 and MOD-011. Such information would typically be used to produce an annual series of powerflow cases. Instead of supplying such information in a piecemeal manner to the Planning Coordinator as a separate annual effort, the Planning Coordinator should make use of the most recent set of powerflow models. This requirement, as written, could cause a needless duplication of work effort.

It is not clear what is meant by 'stressed System conditions' in Requirement R1.2. Does this mean higher than predicted load, lower than expected reactive resources, or other meaning? It is also not clear what is covered by 'load models' in the same requirement.

It is not clear how expected transfers are to be modified in Requirement R2.1.3.2. Possibilities include higher or lower in the same transfer direction, turn transfer directions around so that importers become exporters, the inclusion of non-firm transfers that can be cut, or change import/export directions. There should be some basis for the sensitivity change.

It is not clear how planned transmission outages are to be modified in Requirement R2.1.3.7. Possibilities include modification of the outage duration, or modifications involving more or less facilities. Since outages are scheduled in the operations planning horizon, based on the best information available at the time of the outage request, it is questionable whether they should not be included in standards that apply to planning in years 1-5 or year 6-10 and beyond.

Requirement R2.2.1. should be deleted. Uncertainties involved with studies looking at system conditions out to ten years in the future would preclude the need to extend a Planning Assessment beyond the ten year period. Any corrective actions needed to resolve problems found during study of long-term system conditions could be noted in the Planning Assessment without the need to extend beyond ten years.

In Requirement R2.3, the scope of the study work involving the short circuit portion of the Planning Assessment is not clear. It is not clear whether the study work should be based on three-phase faults only, three-phase and single-phase faults, or whether classical representation or more a more detailed representation should be utilized.

We assume that Requirement R2.4.3.5 would require only known generation additions, retirements, or other dispatch scenarios, and that those performing the planning scenarios would not speculate on unkown generation additions and retirements.

A market structure change in Requirement R2.6.1 would not constitute a material change in an area with an abundance of low cost base load generation that was always on before the market change and would still be on after the market change.

Under Requirement R2.6.3., Plant and System Stability analyses are considered valid until material changes in the System invalidate previous study work. Here, material changes in the system include addition of a transmission line or generator. Addition of a transmission line or generator would only have an impact on stability of generators near the new facility installation. This is not clear from the wording of the standard, which would appear to require restudy of all generators if a transmission line or generator is added anywhere on the system.

What would be the duration of interim operating procedures in Requirement R2.7?

Requirement R.2.7.1.1. states that a project initiation date should be included in the Corrective Action Plan for each project, as well as an in-service date. A project initiation date may be of use to the particular project design engineering staff, but is of little use in planning the system. Keep in mind that this is a Planning Assessment and not a data request.

The wording of Requirements R3.2 and R4.2 appear to require taking all transmission elements as contingencies, plus modeling contingencies which would remove all elements automatically via System protection equipment. Based on comments from the SDT, the inclusion of all single elements in the set of contingencies to be considered is not intended as part of these requirements. Please verify this in writing.

The wording of Requirement R3.2.1., dealing with generator minimum voltage limitations, is vague with respect to what is required. It is not clear who would determine the minimum steady-state voltage limitations for all generators, and for what conditions. Note that it may be difficult to obtain some information from IPP generating facilities.

Requirement R3.2.2. appears redundant with requirement R1.2.1 of FAC-008-1, which deals with Facility Ratings. Relay load limits are one component already considered in establishing facility ratings.

Requirement R3.3.2.1., which deals with the amount and duration of Consequential Load loss, cannot be addressed adequately. Because an outage might be caused by a

transitory event with quick restoration of the outaged facility, or be caused by extensive damage requiring lengthy repairs, there would be no single value for expected duration for any given outage event in the planning horizon. Therefore, this requirement should be removed from TPL-001-1.

Requirement R3.3.2.2, describing permissible actions following single contingency events to meet performance requrirements, should be removed from TPL-001-1. System adjustments following single contingencies should not be permitted to meet system performance requirements. For similar reasons, Requirement R3.5, describing generator adjustments permissible as responses to single and multiple contingencies, should be modified to remove the reference to single contingencies.

What additional single contingencies would there be that should be considered in Requirement R3.3.3?

Consequential generation loss needs to be considered in Requirement R3.6 for those generators directly connected (through transformation) to transmission lines.

Interconnection requirements establish that generators must have low-voltage ride through capability. It is not clear how is the transmission planner performing the studies would be able to consider this capability in Requirement R4.3.

In Requirement R6, there is no longer a requirement to send the Planning Assessment and Corrective Plan to the regional entities, but to the Reliability Coordinators instead. Why has this change been made? RTOs should not be involved in assessing compliance.

In reference to Table 1, bullet point #3, it is not clear how voltage instability, cascading outages, or uncontrolled islanding would be determined under steady state conditions.

Under Table 1, P1, cutting of firm transfers is not permitted as a response to a single contingency. However, it is not clear whether, in preparation for a subsequent contingency, reduction in firm transfers would be permitted. Reduction in firm transfers should be permissible in this instance.

In Table 1, for contingency categories P5 and P8, how would loss of a transmission circuit above 300 kV followed by loss of a transmission circuit below 300 kV be handled?

Under the Extreme Event Description section of Table 1, note that item 3e. is a duplicate of item 3c. One of these can be deleted. Also, for items 3d. and 3f. the notation regarding early shutdown of nuclear facilities for tornadoes is not realistic. The current state of the art of weather prediction does not permit adequate forecasting of tornadoes a day or more ahead of time which might be a cause for concern for a particular nuclear facility.

With respect to Table 2, contingency types P5 and P8, it would seem that events should include the same items as shown for contingency type P4.

In Table 2, for contingency types P1, P3, P4, P5, P8, and P9, clarification is needed as to whether distribution transformers (138-69 kV or 138-34.5 kV, for example) would be included in the events, or whether the transformers mentioned would be restricted to transmission transformers.

For the various stability scenarios, note that Consequential Load Loss would be a function of how System protection equipment is set up for particular scenarios. Delayed clearing time/Zone 2 clearing times could result in load dropped that would not have been dropped for events cleared in primary clearing time.

In Table 2, Note 1 ii., is it the intent of the drafting team to require dynamic model representation of relaying equipment?

General comments:

We are not sure that a wholesale replacement of the existing standards TPL-001-0 through TPL-004-0 is required. We agree that additional clarification is needed for some items, and particularly for the study assumptions that go into the development of models to be used for the performance testing, but we do not agree that the proposed replacement standard provides that necessary clarification. Further, we believe that the replacement standard relies too much on the accompanying tables. More text needs to be included in the standard regarding the system performance requirements.

There is a lot of subjectivity involved in developing the study assumptions that need to be considered in the sensitivity models for study. How can we be sure that one or more of the sensitivity requirements in R2.1.3 stated for consideration are of the same level of importance by both auditors and those performing the studies? We are interested to see what the measures for all the requirements of the standard will be when they are developed.

Additional planning standard requirements for the EHV system to meet all N-2 conditions without dropping some load will require significant material changes, where feasible. We do not believe that the significant additional costs required for compliance would produce tangible benefits and a corresponding significant improvement in system reliability. What is the justification for the separate treatment for the EHV (>300 kV) facilities? One obvious effect of such requirements is to create a bias against any straight bus configuration for facilities above 300 kV. As stated in response to Question 25, there are existing facilities which cannot be converted from their present configuration. For those facilities which could be upgraded, an implementation period of several years would be needed to meet such requirements.

Meeting the requirements of this standard should not be a full time job. There are many more planning activities that need to be performed other than simulation testing to demonstrate compliance. The existing TPL standards require a significant manpower effort to perform the required studies and develop the planning assessment and corrective action plan. We are concerned that the replacement standard, as proposed, will create an even greater burden on the transmission owners without a commensurate benefit to the system reliability.

It is not within NERC's or ERO's scope of responsibility to address load loss. The focus of the standard should be on the system capabilities and not how much local load is dropped for a substation outage in a defined service area. A few reports showing the resultant bus voltages and facility loadings on a percentage basis for all single and a the more severe multiple contingency events, including operator or automatic mitigation procedures, should be adequate to demonstrate compliance.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☒ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
☒ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

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Phil Cox	AEP	RFC, ERCOT, SPP	5,6

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the

rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment: Consider replacing"computer" with "model".**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment: Consider replacing "Consequential" with better wording (no specific suggestion to offer at this time).**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.

Q6. **Comment: Consider replacing "Non-Consequential" with better wording (no specific suggestion to offer at this time).**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☐Do not agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☒ No ☐
Comment: Consider requiring a minumum of two sensitivity cases.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: Consider requiring that the most severe sensitivity cases be included in the studies as determined by the entities conducting the studies.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☐
Comment: We concur with the use of sensitivity studies, but object to the requirement on what sensitivities to include. The flexibility to determine if sensitivity studies are appropriate, and the flexibility to choose what parameters are appropriate to study for sensitivity should be left open. R2.4.3 as written is restrictive to certain sensitivities and should not be.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☒
Comment: Consider requiring the same sensitivity analysis that is conducted under the near-term studies.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2

will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: Consider requiring that problem contingencies be simulated on base case that models the lower load level that would result with the DSM implemented.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: Consider limiting study area to immediately adjacent systems.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☒
Comment: Consider adding clear definition of "proposed" and "committed" projects (definition may impact response to this question).

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	Consider adding clear definition of "system adjustments", including the amount of time permited to implement prior to the loss of the second facility.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	Consider adding clear definition of "system adjustments", including the amount of time permited to implement prior to the loss of the second facility.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	Consider adding clear definition of "system adjustments", including the amount of time permited to implement prior to the loss of the second facility.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: Consider adding clear definition of "bus tie breaker" and "non-bus tie breaker".

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment: Consider adding clear definition of "bus tie breaker" and "non-bus tie breaker".

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

[1] System adjustment can be manual or automatic

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐
Comment: Extreme Event #9 in Table 2 has 3-phase fault and loss of all generating units at a station. Was this left in by mistake? This type of scenario could conceivably lead to low interconnection frequency or cascading due to consequent transmission overloading or low voltage, and could be studied by dynamic simulation. There have been a number of just such generation loss events as this in the past.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: The statements of fact in the question may be true for some study areas, but not necessarily for all. Requiring this type of load representation when it might not be appropriate to the study is excessively burdensome. This is a judgment better left to those conducting the studies. The percentage of load to be so represented, the extent of the study area over which to apply induction machine representations, and the specific modeling parameters are all judgements just as important as whether or not to

include this type of representation. There is a limit as to how far a standard can replace engineering judgment and that limit is reached here.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: The existing TPL standards imply that generator tripping is not permissible in connection with Category B events in that footnote b does not mention it, whereas it is mentioned in connection with Category C events in footnote c. Generation is a system resource and should be protected against the more common single contingency transmission events. We agree with the status quo on this issue being maintained in the new standard, with the provision for regional variance in R3.6. The provision for manual and automatic runback in R3.5 is okay. We also agree with manual adjustments remaining acceptable in response to any contingencies in the new standard consistent with C3 in existing TPL-003.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment: Question: Why would a runback scheme be needed to move from an emergency state to a normal state when that could be accomplished by regular redispatch?

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Ensure that the scheme is enabled to automatically runback for the problem conditions.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: As long as they are automatic.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Should be allowed as long as they have been approved by the applicable Regional Reliability Organization.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: They include redundancy and their failure does not result in cascading.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: (1) Consider clarifying system performance requirements that would be applicable during (a) the first two minutes after the system disturbance when slow-acting automatic system adjustments (such as the operation of motor-operated-air-break switches that are relayed to sectionalize the faulted segment of a multi-terminal circuit; the changing of taps on tap-changing-under-load transformers; the switching of capacitor banks; etc.) would not allowed to be considered, (b) the next three minutes (two to five minutes after the system disturbance) when these slow-acting automatic system adjustments would be allowed to be considered, (c) the next twenty-five minutes (five to thirty minutes after the system disturbance) when manual system

adjustments would be allowed to be considered, and (d) the time period beyond thirty minutes after the system disturbance when no system adjustments of any kind would be allowed to be considered.

(2) Consider clarifying which functional entity is expected to provide what information specified in this standard, especially in requirement 1.

(3) Consider clarifying the need for functional entities to provide competitive sensitive information such as planned outages.

(4)The system stability study documentation requirements R2.4 and R4.5 do not specify a level on the scope of studies or indicate the extent of coverage across a system required for acceptability. A reasonable scope of such studies might include studies of a system nature in association with dynamic devices, or voltage collapse or cascading scenarios, but what else would be required? Or, how much more stability study documentation beyond what is necessary to comply with TPL-001 through 004 would be required? Specific comments regarding R2.4 are as follows: what does "address" all five years mean? How much of the system do you need to study (for example, do you need to apply faults at every bus)? Again, you wouldn't know how much studying needs to be done before this requirement is satisfied. In R2.4.1 and R2.4.2, depending upon the study at hand, some other load condition such as shoulder peak may be more appropriate. Why should you be required to do peak and off-peak cases in such an instance? In R2.4.3 you are forced into doing at least one of the sensitivity studies listed (i.e., "to reflect one or more of the following conditions..."). Is this intentional? Depending upon the study at hand, none of these may be worthwhile doing, and there may be some other parameter that would be better looked at for sensitivity purposes. Existing TPL-001 through 004, Table 1, Category C3 requires any combination of generator, transmission line, transformer, or HVDC pole block in succession. The new standard excludes several of these combinations from being required in P4, P5, P8 and P9. Is this an intentional exclusion? If so, why? The standard should state explicitly that existing generation does not need to be studied unless R2.5.1 or R2.5.2 apply.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **[Due Date in bold]**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☒	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☒ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. The SDT has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the SDT are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890 and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The SDT did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. The SDT organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The SDT determined that the requirements and analysis for Steady State are different from those for stability. As such, the SDT separated the analysis requirements and created two performance requirement tables.

The SDT recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The SDT has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The SDT has not addressed Measures, Risk Factors, Violation Severity Factors or Time Horizons at this time. These will be addressed when the SDT has better defined the requirements of the standard.

For questions where you agree with the SDT, please state that you agree and if available, please provide supporting documentation. If you disagree with the SDT, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you

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believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the SDT would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the SDT is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: This should not be a defined term in the Glossary, instead there should be a Standard written that provides the industry with the requirements for completing a Base Case Study. This is the first step in completing the Transmission Studies required in TPL-001. There is no guarantee that the rules used by the transmission planners for the base case studies are done in a reliable manner. The Standard needs to be expanded to insure oversight by the compliance monitors to ensure that the base case is sound from a reliability perspective. Also, both reliability and transparency require that the results of the base case study along with the assumptions used to develop the study must be shared with responsible entities within contiguous areas of the BES, not just with contiguous Planning Coordinators and Transmission Planners. To insure consistent results, the Standard should require that a properly conducted Base Case Study be based on agreed rules for conducting such studies within each interconnection and use of consistent data/assumptions by other entities in the region; otherwise, the results of each PC's and TP's planning horizon studies and the operation planning studies will be brought into question.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment: This definition will help define what cascading outage is. There is**	

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confusion in the industry and FERC as to "what is a cascading outage." The planning process needs to address this confusion and define exactly what a cascading outage consists. Some want a cascading outage to be when loads beyond the primary or secondary protection equipment are dropped.	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: The definition is needed; however, this term is dependent on a clear definition of Planning Events, which does not exist.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment: This definition is needed to eliminate the confusion that exists in the industry.**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers Years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment: This definition is needed to eliminate the confusion that exists in the industry.**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: This definition should go beyond just saying "Load loss other than Consequential Load Loss." Recommend adding the following: " . . . including Load Loss that occurs through planned manual (Transmission Operator, Distribution Provider, and so on) operation or planned automatic operation of load shedding equipment such as under-frequency load shedding devices or Special Protection Systems."**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. Comment: This is too general. Just about any kind of review will qualify as a Planning Assessment. Suggested definition: "Documented evaluation of future Bulk Electric System needs by the use of performance studies such as NERC Steady State Transmission Studies or Plant Stability Studies conducted in accordance with the NERC Reliability Standards."	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: What are "performance requirements?" This is too general a statement to be of value for writing specific standards.**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Insert "electric generating" prior to "plant" for clarity. It is unclear as to the intent of this statement. The Standard should require the Transmission Planner to consider contingencies in the vicinity of a particular electric generation plant. However,**	

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the ultimate goal of the "Stability Study" is to determine the stability of the BES and not just the "electric generation plant." It is recommended that this be rewritten to make clear the intent of this statement.	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment: This is a very clear definition that can be used in Standards. The author did a good job of using defined terms in this definition.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits **their** annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: There is a term in the Glossary that is "Operation Plan;" however, there is not a term defining Operations Planning. It is recommended that the SDT drop the last sentence and define the term Operations Planning for the Glossary. Change "their" to "its."**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions", FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The SDT has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity (ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

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Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The term Base Case should not be used in this manner. The conditions of the Base Case Study should be in a Standard to insure that all sensitivity cases are covered.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☒ No ☐

Comment: The Standard should indicate a list that says "the list will include but not be limited to:" and then list the minimum necessary to adequately cover the changes in the study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐

Comment: This is absolutely necessary; it will help with the operational planning that will be needed next. In addition, it will help to determine the amount of study uncertainty that the Transmission Planner believes will be in the plan. This is very important for the Year One.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year 6 and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: The sensitivity study of year 6 and beyond is of little value. The uncertainty (standard deviations) in the input assumptions used to complete the studies for 6 years and longer are so large it would not provide useful answers to make sound decisions regarding the need to build, remove, or improve BES facilities.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will

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be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If Yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐

Comment: This is a conditional Yes. The Resource Planner or Transmission Planner must provide assurance that the specific "Demand" reduction that is incorporated into the scenario analyses will actually be reduced through either customer action or direct load shedding by the Balancing Authority. This type of controllable "Demand" does exist, but it is rare that planners and operators actually have such resources in their portfolios to help with System Deficiencies.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐

Comment: This is necessary to insure the planners did not accidentally take the system and the future operation of the system from the frying pan into the fire.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐

Comment: While it is good to know the difference, it should be made clear in the Standard that if a project is listed as committed, it may be changed the next year to proposed project. Definitions for "committed" and "proposed" are needed to ensure consistent data/assumptions within each region.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance

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requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐

Comment: It may be necessary, as a band-aid-type substitute, to replace a committed project with a Remedial Action Scheme (RAS)/Special Protection Systems in lieu of new facilities. Whatever the revised plan, it must be shown to meet the performance requirements.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable BES that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the SDT attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The SDT is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the SDT to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL Standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	**Note to APPA members – Please examine closely and give us specific comments on Q20 – Q29. If you disagree we need to know.**
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by	☒Agree. ☐Do not agree.	

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loss of another Transmission circuit		
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

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Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards - P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

[1] System adjustment can be manual or automatic

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Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐

Comment: This has been needed for some time.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐

Comment: This is a conditional Yes. If the plant design was such that a fault at the plant could remove all units, then all units should be considered. However, if the plant design is such that the likelihood of all plants going down at one time is improbable, then the SDT's approach is very reliable.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐

Comment: The SDT is correct to include the effects of induction motors in simulating the loads. Voltage issues are and will continue to become more critical in the operation of the BES as time goes by. It will be a big help to planners and operators to know the impacts of such loads.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: I do not understand the question. Is this dealing with voltage adjustment or power adjustment?

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control.

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The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment: However, it should be pointed out that RAS are band-aid solutions to building needed BES infrastructure. Experience has shown that an interconnection can have so many RAS that one RAS will counter another RAS designed for another problem in the interconnection. This problem requires additional study by a NERC task force.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐

Comment: Care must be taken to insure runbacks of one event will not cancel the effects of other runback plans in the same interconnections.

The SDT has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐

Comment: As the SDT has said under certain situations.

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Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: See Question 36.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: Maintain system stability and prevent the loss of load.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐
Comment: The WECC will probably have a couple.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: The Standards are a great start in getting a set of requirements in place that will provide a planning methodology that will be transparent to the Functional entities in the interconnections and will produce results that will permit reliable planning and operations of the BES.

Requirement 5 is a start at attempting to share the results of the planning studies with the correct entities. However, because this is such an important part of reliable planning, this requirement should be rewritten to be much more definitive and comprehensive. It is recommended the SDT review the FAC-014 Standard where this Standard deals with who is to receive the methodology for calculating SOLs. The SDT needs to insure that the Transmission Planners and Planning Coordinators share their Near-Term Planning Horizon Studies with the Transmission Operators (Operation Planners) and the appropriate Regional Entity Planning Committees and Operating Committees.

It is also recommended that the SDT remove all Requirements that are subjective and cannot be measured. For example, who must the Transmission Planner share information

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with? Requirement R5.2 states that information must be shared with Transmission Planners of neighboring impacted areas. A Compliance Monitor cannot determine if a neighbor is being impacted. In fact, from an enforcement perspective, if the involved parties must go before a Judge, who will determine if someone is impacted or not?

In addition, the assumptions the Transmission Planners and Planning Coordinators use to conduct the Studies are not required to be shared or posted. As an example, in some parts of the BES Transmission Planners and Planning Coordinators use Flowgate Methodology to study the BES, while others use Rated System Paths, and still others use Area Interchange (Network Methodology).

This standard needs to be modified to respond to several requests from Order 890 and Order 693. These Orders request that through the Standards, information be made available, posted, and shared with the appropriate reliability functions. This information includes the results of Planning Horizon Studies, Operating Horizon Studies, and eventually the determination of Available Transfer Capabilities. This information also includes, but is not necessarily limited to: how do the planners treat the "counter flows" in their studies, what are the generation and transmission planned outage schedules used in the planning studies, how are Network Loads and Network Facilities treated in planning studies; and how do the planners treat Grandfathered Transmission and Grandfathered Power and Energy Contracts in the planning studies?

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Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

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The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☐Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☐Agree. ☐Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.

- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☐
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☐
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☐
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☐
Comment:

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☐
Comment:

[1] System adjustment can be manual or automatic

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

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Yes ☐ No ☐
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Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

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Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐

Comment: R 2.5.1 and R 4.6 require plant stability studies for all generators greater than 20 MVA for changes in excitation system or PSS addition. Generally plant stability is a problem only for large plants with large generators. Changes in the excitation system of a small generator or PSS addition does not significantly impact the plant stability. In fact, in most cases it improves the plant stability. When an excitation system or a PSS is commissioned in the field, part of the commissioning tests ensure that turbine-generator is stable and that the performance of the excitation system and PSS are acceptable. If an excitation system change or PSS addition is causing a plant stability problem in simulation, it is generally a data issue and can be best handled in MOD standards. Requiring stability studies to be redone does not in any way contribute to the system reliability. There are hundreds of old generators in the US which are going through excitation system retrofits in a given year. Requiring a stability study for each change would add additional study burden without any value to the system. This is unnecessary work with little consequence on the system performance or reliability.

Note: We have additional comments on these standards but they have been covered by comments from WECC. We fully support all of those comments.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs and ISOs
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	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

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Kendall Rydell	BPA, Transmission Planning	WECC	1
Kyle Kohne	BPA, Transmission Planning	WECC	1
Melvin Rodrigues	BPA, Transmission Planning	WECC	1

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The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

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To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☒Do not agree.
Q1. **Comment: Support comments submitted by WECC.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☒Do not agree.
Q2. **Comment: Support comments submitted by WECC. The definition needs to consider loads that are tripped sympathetically that may not be directly connected to the element that is removed from service for fault clearing.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☒Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: Support comments submitted by WECC.**	

Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☒Do not agree.
Q7. **Comment: Support comments submitted by WECC.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Support comments submitted by WECC. Plant Stability is a subset of System Stability.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.

- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: Support comments submitted by WECC. Required sensitivities are different for different areas of the system and for the conditions being studied. The TP or PA are the most familiar with the system and would be the best one's to determine the required sensitivities.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: Support comments submitted by WECC.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☒
Comment: Support comments submitted by WECC.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or

Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☒
Comment: Support comments submitted by WECC. There is a concern with using DSM as a corrective action if it is not directly controlled by the utility and the benefits do not materialize as planned.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒
Comment: Support comments submitted by WECC.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: Support comments submitted by WECC. Also, one reason not to differentiate between committed and proposed projects is that regardless of whether a project is committed or not in a future case, the committment to implement a Corrective Action Plan becomes mandatory as time moves closer to the need date due to required system performance.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: See response to Q18.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	Support comments submitted by WECC.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Support comments submitted by WECC.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	Support comments submitted by WECC.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	Support comments submitted by WECC.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: Support comments submitted by WECC. The probability of loss of a breaker due to an internal fault is low and does not warrent precluding loss of load for this event.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: Support comments submitted by WECC.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

[1] System adjustment can be manual or automatic

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☒
Comment: Support comments submitted by WECC.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☒
Comment: Support comments sent by WECC. There is a link between transient stability and steady state performance for a given event since they model serial time frames for the event.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: Support comments sent by WECC.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Support comments sent by WECC..

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☒
Comment: Support comments sent by WECC.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Support comments sent by WECC.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Support comments sent by WECC.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Support comments sent by WECC.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: Support comments sent by WECC.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐
Comment: Support comments sent by WECC.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☒ No ☐
Comment: Support comments sent by WECC.

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: Support comments sent by WECC. In addition,BPA has the following comments:

1. R2.3.1 - The way the requirement is written sounds like the short circuit study should be run after changes are made to the BES. The study needs to be done sufficiently in advance to allow for needed equipment replacements as a result of the study. Also, "current" in the first senetence should be changed because it is confusing whether it refers to "present" or "amps".

2. There needs to be better definition what is meant by "bus tie breaker". It is assumed this includes both bus tie breakers between a main and auxiliary bus, as well as bus sectionalizing breakers between two main bus sections.

3. In general the table seems unnecessarily complex. It would appear to make more sense to group events by performance as done in the previous Table 1. Also, in general the resulting events for the element contingencies in the table should be compared and like events grouped together since they would be are modeled the same and show the same performance in powerflow studies.

5. P9.1 - It is recommended to exclude multiple circuits sharing a common structure for no more than three miles, rather than one mile. Our analysis shows river crossing systems can be up to three miles and it is impractical to plan for common corridor outages of up to this distance.

6. Planning event P9.6 is the same as P8.3 with the only difference being the restoration time.

7. Regarding extreme event descriptions:
- Item 3.a is not a Transmission Planning, but is relevent for Resource Adequacy.

- Item 3.b is an operational issue not relevent to Transmission Planning. Successful cyber attack would need to be defined. Also, how would the consequences of a successful cyber attack be predicted?
- Regarding item 3.c, generation capabilities should already be modeled in base cases within the planning horizon.
- Items 3.d through 3.f are not relevent to Transmission Planning. These are Resource Adequacy issues within a short term operational horizon.
- Items 3.e and 3.f appear redundant to items 3.c and 3.d.
- Item 3.g is not really a planning issue. The system should be designed to meet required performance for selected contingencies regardless of age or maintenance pratices.
- In general, the extreme events layed out in the previous Table 1 is a much more practical approach to planning the transmission system.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	David Albers	
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E-mail:	dalbers@brazoselectric.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☒ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

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To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

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Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
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Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☒Agree. ☐Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment: Some discussion of what 'documented' means is needed each time it is mentioned. Is this some form of written report at all times or are 'saved' cases with contingency analysis sufficient at certain times or is it just a means to show that an 'assessment' was performed in some fashion.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment: Planners do not 'submit' their studies to ERCOT for evaluation or other. Certain projects are submitted to the group for review and comment but not all studies are submitted as normal pratice in all cases. It may be better to use 'create their base cases' or simply 'performs their annual studies' instead of 'submit their annual studies'**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the

rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: More descretion should be allowed by the TO or planner in deciding the number of cases.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: Again, descretion should be allowed by the TO when selecting the criteria.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: Longer term studies should be performed in the broadest sense, the cases are difficult to create accurately and a greater range of sensitivities do not improve the results.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒

Comment: If DSM is not viable due to market failings, then its inclusion in any CAPs provides an inaccurate soltion to achieve the required system performance.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐

Comment: It is difficult to understand what is meant by 'retested'. The evaluation of a CAP includes testing the recommended option to see how it performs and to insure that it does not create other problems. We assume this is what is meant by retested. In our evaluation we insure that it does not negatively impact all other facilities in the BES and if so what extent and if it is managable. We do not always create a separate 'study area' each time for each system improvement.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒

Comment: What is the difference? We assume committed means you have begun work on the project and can no longer stop. It would seem this would need to be defined more clearly and it is probably different for each project or entity. Why is this differentiation even needed?

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒

Comment: This seems like more documention is needed however if the new CAP analysis will suffice for documentation regarding removal of the 'committed project' then this is acceptable. However, that kind of makes having such a thing as a 'committed project' fairly useless if you can change it. This appears to just be more unnecessary documention.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to

clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	need a definition of generator. The entire train, largest unit at a site or other.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	need definition of system adjustment
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	see above

[1] System adjustment can be manual or automatic

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment: However, acquiring load data may be difficult if not impossible and would require increased manpower. A more reasonable approach is to vary the load data to see the effects instead of wasting effort on load surveys.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Can be including in a RAP or SPS with a long term CAP.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Taken directly from the ERCOT operating Guides for RAPs and SPSs:
Any RAP must meet the following requirements:
a. Coordinated and approved with the owners and operators of facilities included in the RAP.
b. Use is limited to the time required to construct replacement Transmission Facilities. However, the RAP will remain in effect, if replacement Transmission Facilities have been determined by the Control Area Authority to be impractical.
c. Complies with all applicable ERCOT and NERC requirements.
d. ERCOT develops and posts a methodology to include the RAP in the Total Transfer Capability (TTC) calculations, if appropriate.
e. Clearly defines and documents operator actions.
f. Includes the option for the transmission operator to override the procedures if the RAP will not improve system reliability.
g. Operators must be trained in RAP implementation.
For SPSs
13. Special Protection Systems (SPS) are protective relay systems designed to detect abnormal ERCOT System conditions and take pre-planned corrective action (other than the isolation of faulted elements) to provide acceptable ERCOT System performance. SPS actions include among others, changes in demand, generation, or system configuration to maintain system stability, acceptable voltages, or acceptable Facility loadings. An SPS does not include underfrequency or undervoltage load shedding. A Type 1 SPS is any SPS that has wide-area impact and specifically includes any SPS that a) is designed to alter generation output or otherwise constrain generation or imports over DC Ties, or b) is designed to open 345 kV transmission lines or other lines that interconnect TDSPs and impact transfer limits. Any SPS that has only local-area impact and involves only the Facilities of the owner-TDSP is a Type 2 SPS. The determination of whether an SPS is Type 1 or Type 2 will be made by ERCOT upon receipt of a description of the SPS from the SPS owner. Any SPS, whether Type 1 or Type 2, shall meet all requirements of NERC Standards relating to SPSs, and shall additionally meet the following ERCOT requirements:
- The SPS owner shall coordinate design and implementation of the SPS with the owners and operators of Facilities included in the SPS, including but not limited to Generation Resources and HVDC ties.
- The SPS shall be automatically armed when appropriate.
- The SPS shall not operate unnecessarily. To avoid unnecessary SPS operation, the SPS owner may provide a real-time status indication to the owner of any Generation Resource controlled by the SPS to show when the flow on one or more of the SPS's monitored facilities exceeds 90% of the flow necessary to arm the SPS. The cost necessary to provide such status indication shall be allocated as agreed by the SPS owner and the Generation Resource owner.
- The status indication of any automatic or manual arming of the SPS shall be provided as SCADA alarm inputs to the owners of any facility(ies) controlled by the SPS..
- When a Transmission Operator (TO) removes a SPS from service, the TO shall immediately notify ERCOT operations. ERCOT shall modify its reliability constraints to recognize the unavailability of the SPS and notify the Market. When a SPS is returned to service, the TO shall immediately notify ERCOT operations. ERCOT shall modify its reliability constraints to recognize the availability of the SPS.
14. The owner(s) of an existing, modified, or proposed SPS shall submit documentation of the SPS to ERCOT for review and compilation into an ERCOT SPS database. The documentation shall detail the design, operation, functional testing, and coordination of the SPS with other protection and control systems.

- ERCOT shall conduct a review of each proposed SPS and each proposed modification to an existing SPS. Additionally, it shall conduct a review of each existing SPS every five years, or sooner as required by changes in system conditions. Each review shall proceed according to a process and timetable documented in ERCOT Procedures and posted on the ERCOT website.
- For a proposed Type 1 SPS, the review must be completed before the SPS is placed in service, unless ERCOT specifically determines that exemption of the proposed SPS from the review completion requirement is warranted. The timing of placing the SPS into service must be coordinated with and approved by ERCOT. The implementation schedule must be confirmed through submission of a Service Request to ERCOT.
- For a proposed Type 2 SPS, the SPS may be placed into service before completion of the ERCOT review, with advanced prior notice to ERCOT in the form of a Service Request. The timing of placing the SPS into service must be coordinated with and approved by ERCOT. Existing SPSs that have already undergone at least one review shall remain in service during any subsequent review, and proposed modifications to existing SPSs may be implemented, upon notice to ERCOT, and approval of ERCOT before completion of the required ERCOT review.
- The process and schedule for placing an SPS into service must be consistent with documented ERCOT Procedures. The schedule must be coordinated among ERCOT and the owners of any facility(ies) controlled by the SPS, and shall provide sufficient time to perform any necessary testing prior to its being placed in service.
- An ERCOT SPS review shall verify that the SPS complies with ERCOT and NERC criteria and guides. The review shall evaluate and document the consequences of failure of a single component of the SPS, which would result in failure of the SPS to operate when required. The review shall also evaluate and document the consequences of misoperation, incorrect operation, or unintended operation of an SPS, when considered by itself, and without any other system contingency. If deficiencies are identified, a plan to correct the deficiencies shall be developed and implemented. The current review results shall be kept on file and supplied to NERC on request within thirty (30) days.
- As part of the ERCOT review and unless judged to be unnecessary by ERCOT, the appropriate ROS working groups such as the Steady State Working Group, the Dynamics Working Group, and/or the System Protection Working Group shall review the SPS and report any comments, questions, or issues to ERCOT for resolution. ERCOT may work with the owner(s) of facilities controlled by the SPS as necessary to address all issues.
- ERCOT shall develop a methodology to include the SPS in the Commercially Significant Constraint (CSC) limit calculations, if appropriate.
- ERCOT's review shall provide an opportunity for and include consideration of comments submitted by Market Participants affected by the SPS.

15. SPS owners shall notify ERCOT of all SPS operations. Documentation of SPS failures or misoperations shall be provided to ERCOT using the Relay Misoperation Report located in Section 6 of these Operating Guides. ERCOT shall conduct an analysis of all SPS operations, misoperations, and failures. If deficiencies are identified, a plan to correct the deficiencies shall be developed and implemented.
16. For each SPS, the owner shall either identify a preferred exit strategy or explain why no exit strategy is needed to ERCOT. This shall take place according to a timetable documented in ERCOT Procedures and posted on the ERCOT website. Once an exit strategy is complete and a SPS is no longer needed, the owner of an existing SPS shall notify ERCOT, using a Service Request, whenever the SPS is to be permanently disabled, and shall do so according to a timetable coordinated with and approved by ERCOT and the owners of all facilities controlled by the SPS

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: see above

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: In R1.1.1. it appears the data that is being requested requires some amount of survey to determine the mix. This data would require a great deal of manpower and provide little more benefit than simply varying the data for comparison. However it does say in R1 upon request so does this allow the Planning Coordinator the descretion as needed on this type data?

R1.2, What is 'supporting rationale' and 'validated' mean? What are "stressed" System conditions? It appears (from 2.1.3) that stressed means various sensitivities.

R1.4, define 'long-term', generation outages are considered confidential information in ERCOT and thus are not available to all TOs, see next comment

R1.5 somewhere (perhaps in R1) the language should include "its respective portions of the data" or something to that effect meaning that a TO should not be held accountable for a GOs data. R1 appears to read that each entity shall provide the requested data. This seems to be intuitive BUT there are GOs that feel the data responsibility for the entire system belongs to the TOs and this leads to delays in getting accurate information if its uncertain as to who provides what data.

In R2 the language indicates the TP and PC shall each perform studies. There should be some clarity here. Also, it indicates that each shall assess "its portion of the BES". This needs to be clarified as well, obviously contingencies on other portions of the BES may cause issues within different portions. again, what constitutes documentation?

R2.1 it appears from the wording (shall "address" all five years) that the planning assessment must be done on all five years but 2.1.1 appears to state only 2 years are required. Please clarify.

R2.1.3 this seems to indicate that the studies mentioned in 2.1.1 and 2.1.2 should be "stressed" by the conditions listed below or just by one of them. We assume this means using only one is acceptable with proper documentation. Is that correct? Further, the sensitivities are ambiguous. How does one justify higher load levels or even know what they are without input from other TOs or the PC? How does one even guess at the other variables? what is meant by 'long lead time facility'? IF this only means for a TOs "portion of the BES" then it makes more sense but are these even valuable considering the wide range of data. The only variable that can be adjusted with any accuracy is the generation and ERCOT maintains the confidential data in this area. We assume R2.1 to mean you need to assess two peak summer cases, one off peak and then look at varying generation patterns on those cases. This appears to be the latitude given. Is this correct?

R2.2.1 are generation additions considered a "project"? If this means that a case must be created and assessed by all TOs for a known generation addition that is 12 years out, then this will lead to unnecessary studies. We assume this to mean, in the case of a generation addition, that the connecting TO should make an assessment once the PC considers this new addition to be valid for study. Is that correct?

R2.3 what is meant by "past studies" and how long must these be kept? Or is this at the TOs discretion?

R2.3.1 how does one know if the changes will result in increased fault currents until studies are done? This implies that studies SHALL be done for just about ANY change to the BES. There must be discretion allowed here. The word "shall" does not afford any discretion.

R2.4 the same comments for R2.1. apply here concerning years of study and defining 'stressed'. Additionally this type study seems to provide better results when done for the BES which would require input from all TOs thus a study based only on "its portion of the BES" would not have as much value unless you are referring to generation additions and localized studies.

R2.5.1 does not allow any discretion, for any and all all modifications, additions, etc…a study shall be performed. This is not needed in all cases.

R2.5.2 Wording such as "material changes" and "vicinity" are ambiguous terms without discretion being allowed the planner. Voltage level Line changes, amount of generation, something needs to be added to clarify.

R2.6.1 again, what are material changes? Topology changes and generation changes happen monthly, weekly. Are studies to be invalidated for each 'material change'?

R2.6.3 who determines if the study is no longer valid? The TO, PC or the agreement of both?

R2.7.1 what is a 'project initiation date' and why is this needed?

R2.7.2 Projects are added to cases after an analysis has been performed to see if the project is an acceptable alternative. In that analysis the project is 'retested' to see if it is effective. This is assume to be acceptable for the definition of 'retesting'.

R2.7.3 unsure what 'committed' means regarding projects nor understand the need to have this documented anywhere.

R3.2.2 what is 'relay loadability' and where would you note how it is supposed to be treated?

R3.3.1 how is this different than R3.1?

R3.3.2.1 why is there a need to know how much non-consequential load loss exists for each contingency and how can one predict the length of time this will last?

R3.3.2.2 Do we need to document the 'system adjustment' for each contingency?

R3.3.3 what is a severe impact and what is one that is less severe?

R3.4 what is the difference to 3.3.3? The definition given in the NERC Glossary from May of 2007 of Cascading Outage is still vague, it appears to allow the TP or PC the discretion to determine it based on studies. Is this the intent?

R3.5 what is the time limit for run-back?

R4.4 how can TPs identify what generation upgrades are needed (protection and control modifications)?

R4.5.2 whats the difference between this and 4.5.1?

R4.6 the generation levels could be too low for the studies to be useful, perhaps voltage levels should also be added or allow for TP/PC discretion.

R4.6.3 seems to allow some TP discretion in deciding which planning events are more severe but how does one know that without studies?

R5 this seems to have no direction for either party.

R6 is ambiguous

Table 1
terms such as voltage instability, cascading outage and uncontrolled islanding should be defined or allowed to be defined by the PC. If consequential load loss is allowed for all cases then why even mention it? Isn't this like saying if the line trips, it will be out of service? why would one want to document this amount, perhaps for some sort of ranking?
Planning events
what is a 'system adjustment'? if this means to manually redispatch the BES for each condition then these studies shown under P4 will take so long to complete that they will be invalid by the time they are done. In ERCOT, the economics of redispatch are not known to the TP thus this is done by the PC. an automatic computer simulated redispatch will possibly not have the same results. Define 'generator' for is this a single unit, the whole train, the largest unit or other?
For P6 events and above, if consequential load loss and non consequential are allowed, they why study these events? Do TPs plan and build transmission to eliminate the overloads for these events or just study them so that the results are known? Studying every possible event or combination does not make the studies better or provide a

higher insight to areas of concern. A number of the combinations have a low probability of occuring and performing the studies and analizing the results will be a manpower burden and provide no better clarity on needs of the system.

Table 2
The number of events to consider seems excessive although this is not our area of expertise. If each of these is to be run for each 'material change' in the BES then this list is excessive without more leeway or guidance provided.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: For the reasons discussed below, we do not agree with the proposed definition. To address our concerns and address the FERC staff concern regarding ambiguity, the proposed definition could be made acceptable to us by modifying it as follows:** **Load that is no longer served because it either (a) was supplied (wholly or partly) by an element(s) of a radial system or local network that was removed from service due to fault clearing action, was disconnected by controlled interruption to avoid overload of remaining elements of a radial system or local network, or protection or SPS/RAS mis-operation or (b) has dropped out or been tripped during a transient stability period, including an automatic reclosing period, due to a fault on the radial system or local network, including on branches not directly supplying the load.** **We also offer the following alternative:** **Resultant loss or controlled interruption of customers supplied by a radial system or local network, due to a fault on or loss of a facility in the radial system or local network.** **The definition proposed by the SDT removes the second sentence of footnote (b), as directed by FERC, and replaces the first sentence of footnote (b) with a new definition. We agree with the removal of the second sentence of footnote (b). However, we have a concern with this**	

definition replacing the first sentence of footnote (b). We believe that the existing first sentence is a more appropriate definition of consequential load loss and that the proposed definition is more stringent and will have unacceptable impacts on reliability and/or add transmission costs that cannot be justified.

The coining of the term "Consequential Load Loss" has been a significant improvement in terminology compared to our reference to footnote (b). However, FERC only used this phase descriptively and did not order NERC to reconsider what would be acceptable consequential load loss (i.e. revise the first sentence of footnote (b)). The definition appears to be based on an interpretation of the new term rather than defining what this term was coined to describe.

Order 693 requires that footnote (b) be clarified to not allow loss of firm load or firm transfers - i.e. delete the second sentence. Order 693 then refers to the remaining first sentence as consequential load loss. Order 693 does not address issues regarding whether this should further be restricted to only radial lines, not permitting load loss for outages on local networks. Nothing in the NOPR or the staff paper implies otherwise.

The staff paper discusses potential ambiguity regarding which single contingencies load interruption is permitted for. The definition attempts to address this by referring to "directly connected" load. However, this is now ambiguous as "directly connected" might be interpreted to mean only the facility that the load is physically connected to and excluding any upstream facility.

BCTC submits that the upstream facilities need to include both radial facilities and local networks. NERC has stated that looped configurations are key for reliable operation. We consider looped configurations and local networks to be the same thing. The proposed definition will make it more difficult to transition from a radial supply to a looped configuration. For radial loads connected by a single radial line, when the load exceeds the line capacity, the transmission owner has alternatives of upgrading the line, adding a second circuit, or converting to a local network by providing a loop from another supply. With the addition of a second circuit or conversion to local network, controlled load interruption may be necessary for loss of one circuit to avoid overload of the second line. Without the option of controlled load interruption, these alternatives will not provide N-1 capability for all loads they supply without addition of a third circuit. This will lead to a economic preference to upgrading of the existing circuit to meet criteria, thereby perpetuating the single radial line configuration. Other alternatives could include splitting the load between the lines or operating with one line out of service so that a single contingency does not overload the facilities remaining in service. However, the addition of a second circuit with controlled load interruption will provide a more reliable load serve than any of these alternatives, because under N-1 more load will remain continuously on line. We expect that the proposed definition will provide greater assurrance that existing local networks with N-1 capability will continue to have N-1 capability. However, we have concluded that the definition will introduce an additional unacceptable barrier to transition

from N-0 to N-1 supply and that this barrier is not acceptable. We believe that this barrier would be a more significant issue for improving the reliability of supply to all customers than the current situation of permitting some controlled load interruption on local networks. **Another issue that arises if local networks are excluded is load response during transient periods. Customers can connect voltage sensitive loads, such as large motors, on long weak systems. During the transient stability period, voltages can dip to below the ride through capability of the load. The fault need not be on the circuit directly supplying the customer, but may be downstream or on another branch facility. Automatic reclosing is often employed to shorten restoration times, but with the consequence of worsening the transient period. Customers have options to install different types of motors, motor controls, local voltage support to mitigate impacts of transient voltage swings, or simply restart motors following the disturbance. If transmission systems are required to ensure no loss of load during transient stability periods for external faults, a first course of action may be to remove automatic reclosing, which will reduce reliability. Alternatively, customer load connections may be denied or additional transmission circuits may be required, which can be costly compared to the customer load options.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Alternative wording proposed:** **Events which have a low probability of occurrence and are typically more severe than Planning Events.** **Explanation: The primary consideration is the probability of occurrence. We do not exclude events simply because they are more severe.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: See comments on Consequential Load Loss. Propose the following definition to clarify situations for which NCLL is acceptable:** **Load loss other than Consequential Load Loss to avoid cascading, voltage**	

stability, or blackout of the BES. For example, load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage load shedding, under-frequency load shedding, or SPS/RAS.	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Need to insert the word "supported", as below, and further refine, to clarify that the Planning Assessment is not just studies, but includes evaluation of contingencies to be run, sensitivities to consider, etc.** **Documented evaluation of future BES needs, measures to mitigate adverse reliability impacts, and assessments of residual impacts, supported by the use of performance studies ....**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: One problem with this definition is that it assumes that the Transmission Planner submits annual studies. We need definitions for Operating Horizon and Planning Horizon. Then:** **Year One: The first year of the Planning Horizon.**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of

variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☒ No ☒
Comment: The number of sensitivity cases should be tied to the number of resource plans and range of possible load growth forecast.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: Should be tied to the data provided under R1.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☒
Comment: Long term needs to address sensitivities since it usually takes more than five years to contruct new transmission lines.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: DSM should be a load reduction.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: The Assessment should state how the study area was determined, including input from adjacent Planning Coordinators. WECC has processes for coordination of planning information so that Planning Coordinators are informed of plans in other areas.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☒
Comment: We have a larger concern. If a project is Committed and is proceeding with construction, why would a transmission planner not consider this is in planning studies. Showing that a committed project is not needed and removing it from the plans, does not necessarily remove it from the future system. In addition to showing that the revised plan meets the performance requirements, the planner needs to include documentation to show that the Committed project has been cancelled.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	Do not agree based on SDT definition for Consequential and Non-Consequential Load Loss. Will agree subject to proposed revisions to definitions of Consequential and Non-Consequential Load loss.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Do not agree based on SDT definitions. Also do not agree for first outage being a forced outage. Will agree subject to above revisions to definitions of Consequential and Non-Consequential Load loss for the first outage being a planned outage but not a forced outage. To meet this requirement for forced outages, estimate that this change could cost $3 to 5 Billion.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer	☐Agree. ☒Do not agree.	Same comments as for Q21. We do not foresee any cost due to this standard at this time because we do not have any transformers with low side voltage rating above 300 kV.

with low side voltage rating above 300 kV		
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	Same comments as for Q21/22. Furthermore, a double transformer loss forced outage has a very low probability as transformers are very reliable. A more practical approach would be to use single phase transfomers and provide a spare phase.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: Do not agree due to definitions of Consequential and Non-Consequential Load Loss. Can agree subject to the proposed revised definitions to address loss of load during the transient stability period. System is already planned to meet this requirement based on the first sentence of footnote (b).

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: Do not agree due to definitions of Consequential and Non-Consequential Load Loss. Can agree subject to the proposed revised definitions to address loss of load during the transient stability period. System is already planned to meet this requirement based on the first sentence of footnote (b).

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	Do not agree due to the definition for Consequential Load Loss. Definition needs to include local networks for this contingency to be acceptable.
Q27. P4-2: Loss of a generator followed by a System adjustment followed	☐Agree. ☒Do not agree.	similar to Q26.

[1] System adjustment can be manual or automatic

by the loss of a monopolar DC line		
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	Similar to Q26.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	Similar to Q26.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☒
Comment: Disagree with this unless AC lines are treated the same. There should be no distinction between AC and DC lines.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☒
Comment: Disagree with the assumption that steady state and stability analysis are different and should be separated. There are only minor differences between the tables and the reasons are not apparent. The separate tables appears to be unnecessary and is confusing, especially the same contingency numbering for both tables. Any contingency that must be studied in the stability period should also be considered in the post transient steady state period. Request that the SDT provide an explanation of their assumption.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: Plant stability is a Generator Interconnection study, addressed by FAC-001. By including this requirement in TPL, costs may be transferred. TPL-001 need not distinguish between system stability and plant stability. For Planning Assessments, these are the same thing. Plant stability arises when doing generator interconnection.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Stability should be treated the same as steady state. If there is a common mode event that could cause the loss of all generating units at a plant, all relevant simulations should be done. If a common mode contingency of all units at a generating plant is not relevant for stability, then it is not relevant as an extreme event for steady state either. However, operation with all units at a plant off line may be relevant as a sensitivity case for Planning Events. The Transmission Planner needs some lattitude to determine what needs to be considered under Extreme Events and the standards should not be overly perscriptive.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: No restrictions on adjustments that are practical and can be achieved within the timeframe required.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency

ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☐ No ☒
Comment: We do not accept R3.5, which does not limit runback to contingencies based on thermal limits, only that Facility Ratings are not exceeded. If an SOL is based on voltage stability (which is often studied in the post disturbance steady state), Facility Ratings may not be exceeded but runback may not be fast enough to avoid voltage instability. Furthermore, runback for single contingencies should be subject to any conditions that might apply to generator tripping for single contingencies.. See response to Question 39.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☒
Comment: See our response to Question 36. In addition, since this runback is effectively a RAS/SPS with respect to protecting the transmission system from cascading, it must meet all the reliability requirements of a RAS.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: RAS should be permitted when the system performance conforms with the performance requirements laid out in the tables. Generator tripping should be permitted for single contingency events.

R3.6 proposes to limit generator tripping for single contingencies except for certain conditions which are not listed. Without knowing what these conditions might be, we find ourselves speculating on what might be proposed. On the 10 October 2007 conference call, it was suggested that there are concerns regarding generator reserves and loss of reactive capability. We have some observations regarding these concerns. With respect to reserves, some concerns would also apply to runback, since units on runback could not also be on AGC and could not be reallocated to AGC until the transmission contingency is returned to service. There was also a concern regarding tripping of steam units and the delay in bringing them back on line. This is a resource adequacy issue that should be addressed with the customer, not a transmission reliability issue. Regarding the loss of reactive capability, this would be addressed by the post mitigation plan studies to demonstrate that the reactive reserves meet the requirements, whatever they are determined to be. We would generally expect that the reduction in MW transfers would reduce the need for reactive support, so the new condition might not require the reactive support. Nevertheless, the post mitigation

studies will address this. Therefore, we conclude that these concerns are not applicable to transmission planning standards.

BCTC plans and operates a transmission system that interconnects generation comprised of about 90% hydroelectric. Often the extreme generation patterns for which we consider generator tripping occur for a limited time period during the year at off peak. These would be during high runoff and/or light local load periods. For these conditions, there is typically plenty of other generation that can be used as reserves for generator tripping. BCTC currently strives to avoid use of RAS for N-1, especially on the 500 kV transmission system. However, for example, if avoiding generator tripping were to trigger the need for hundreds of km of 500 kV transmission line for an off peak operating condition or a low capacity factor or intermittent resource, we would likely consider RAS, especially for transmission radial to the generator. In the lower voltage systems we often have consequential loss of small generators and consider generator tripping for radial lines and local networks. In most cases, this generator loss is addressed through sensitivity studies and discussions with generator owners and transmission customers with respect to the costs they are willing to incur and what is required by Resource Planners to meet their planning criteria. Operating reserves requirements are also a consideration. Any loss of generation due to tripping or ramping that is less than the amount lost due to consequential loss should be acceptable without question.

In summary, we would be prepared to review and comment on a proposal from the SDT on limitations on generator tripping. BCTC suggests that the SDT list the limitations rather than the permitted conditions and that these limitations should also apply to generator ramping.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: See Q39. Also, WECC RAS Reliability requirements must be met for new systems.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐
Comment: WECC may require a regional difference for generator tripping depending on the conditions imposed in R3.6.1. Other regional variances would not necessarily be in the context of regional difference as defined in the Standards Manual, but rather exceptions for long weak systems for which it is not economic to meet criteria applicable to tightly interconnected systems.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment:

1. We have some questions of clarification for the Standards Drafting Team, that may resolve some of our concerns. (i) Is it the intention of NERC that the more stringent performance requirements in this standard would be applicable for determining System Operating Limits before Transmission Owners are able to implement Corrective Action Plans? The BCTC system is part of the western interconnection and BCTC is a member of WECC. WECC members apply a principle that Planning Standards are also applicable for determining System Operating Limits. If the answer to this question is "no", then BCTC may be able to support some aspects of raising the bar, with the understanding that SOLs would be determined based on the performance standards that the system is planned to. (ii) Has the Standards Drafting Team considered how Transmission Planners will address discrepancies between Corrective Action Plans for this standard and the reality of what can be constructed due to regulatory approvals, siting problems, financing issues, etc.? For example, is it the intention that Transmission Planners should continue to study Corrective Action Plans to meet an N-1-1 Planning Event (e.g. P5-1) without generator tripping when the practical situation is that we may be fortunate to be able to build to meet N-1 with some generator tripping? We are concerned that if we cannot meet the performance requirement for P5-1 due to delay or denial, continuing to assess Corrective Action Plans to meet P5-1 does not provide much useful information compared to planning to meet a doable target. Item 2 below provides a proposal to address this.

2. There is always the possibility that a regulator may deny funding for a Corrective Action Plan or approve funding for a Corrective Action Plan that does not fully meet the performance standards, a siting process may delay or block a Corrective Action Plan, or some other process may frustrate the ability follow through with a Corrective Action Plan to meet NERC performance standards. To avoid the need for a Transmission Planner to continue to study Corrective Action Plans that cannot be implemented, we suggest adding the following Requirement R2.7.6: The Planning Assessment is not required to include a Corrective Action Plan and address the subsequent requirements (of R2.7) in cases that (a) an applicable regulatory agency has ordered that a Corrective Action Plan is not to proceed or that an alternative Corrective Action Plan that does not meet the performance standards is to be implement or (b) the Transmission Planner has documented evidence indicating that such an outcome is likely to occur. Other Requirements for Five and Ten year Assessments may also be exempted depending on the regulatory order. The Planning Assessment will include evidence of the order.

3. R3.3.3, R3.4, R4.5.1, R4.5.2 - A rationale for the selected contingencies should be sufficient. It should not be necessary to explain why the remaining contingencies would produce a less severe result.

4. Table 2, P1 should include shunt devices.

5. A definition or reference to a definition for Firm Load and Firm Transfers is required. The present situation is that these terms are "defined" as those loads and transfers that can be supplied while meeting Category B requirements. In other words, the standards

define the terms. The commercial uses of firm and non-firm may not be applicable and they actually mean non-recallable and recallable service, not directly related to system performance, but incorporating aspects of reservation times.

6. Extreme Events of Tables 1 and 2 should not be subject to the same study requirements as Planning Events. Table 1 Extreme Events need not be studied for both the Near Term and Long Term Horizon (ref. R3.4, R3, R2.1 and R2.2) and for all five years of the Near-Term Horizon (ref R3.4, R3, R2.1). Table 2 Extreme Events should not be required for all five years of the Near-Term Transmission Planning Horizon (ref. R4 and R2.4). When conditions warrant, only a single assessment representing a selected reasonable plannning horizon should be required, and an update required only when past studies are no longer representative. We are concerned that many of the proposed Table 1 Extreme Events (Item 3. a, c, d, e, f) are resource adequacy issues (we also observe that c and e appear to be identical). Transmission Planning Assessments of these events should be initiated at the request of Resource Planners. It should not be necessary for Transmission Planners to initiate and maintain current studies of these Extreme Events. We suggest that Extreme Events be removed from R3 and R4 and addressed in a separate Requirement.

7. The Purpose of this standard should be restated as: Establish requirements for Planning Assessments, including Corrective Action Plans, to be conducted over range of forecast conditions based on system planning performance requirements. Explanation: This revised wording more accurately describes the content of the standard. The Requirements of this standard are to perform Studies and Assessments. The performance tables are referenced by the Requirements and are supporting to the Requirements, but are not a "capital R" Requirement.

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Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
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Group Comments (Complete this page if comments are from a group.)

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Contact Organization:

Contact Segment:

Contact Telephone:

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Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment: It is a fair description for an initial base case.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment: Agree with the definition**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Add specificity in this definition. Suggest the following wording: Outage of two or more elements from service with lower probability of occurrence than Planning Events**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment: Agree with the definition**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment: Agree with the definition**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: Add Remedial Action Schemes (RAS) after "Systems"**	
Q7. **Planning Assessment:** Documented evaluation of future	☒Agree.

Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Do not agree.
Q7. **Comment: Agree with the definition**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Needs clarity. Suggest the following wording: Outage of power system elements such as shown in Tables 1 and 2 that need to be considered and simulated to assess Transmission System Performance**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Definition is not clear. Suggest the following wording: Study of an individual generating plant's capability to remain in synchronism and exhibit damping of the generating units' power oscillations for various contingencies in the vicinity of the plant**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: This definition is for a stable system. Study is performed to determine whether system is stable or not. Suggest the following wording: Study of the system or portions of the system to assess the system's performance in terms of angular stability, power oscillations and voltage limits during dynamic simulation**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: Suggest a shorter definition: Planning window beginning next calendar year**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The

standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: The TP or PA is the best to determine the number and type of sensitivities that are more applicable to their system.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: Let the TP or PA decide the type of stressing needed for a particular case

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒
Comment: Although we concur with the sensitivity analysis but the TP should determine what sensitivities are more appropriate for their system. Sensitivities should not be scripted in the Standard.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: Agree. The Standard should state that sensitivity studies are not required but the TP or PA could use sensitivities if desired.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This

Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: We agree to include DSM among a mix of solutions to a system problem. However, the difficulty is that DSM is unpredictable when needed. Another issue is how much DSM is actually under the control of the Transmission Operator.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: We agree that the system should be retested with the corrective measures to ensure that the defficiency has been cured and that there are no inadvertant negative impacts. Regarding Study Area, it is not a defined term, and it could vary depending on the size of the project or nature of the disturbance being evaluated.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: The understanding about "committed" projects vary from TP to TP. Also projects that are proposed today become committed in the planning horizon. Similarly, committed projects drop out due to variety of reasons. In terms of system studies, both committed and proposed projects are modeled and evaluated in the same system. How do we distinguish between the two?

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment: We agree that committed projects should not be removed from the revised plan. These are supposed to be included in the planning studies which determine the system performance in the first place.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	Loss of bus section is Category C for which the current NERC criteria allows controlled loss of load. The NERC system has been designed with this criteria. To create a more stringent standard would require to build hundreds of miles of new transmission lines to bring the existing system to NERC compliance. What are the potential benefits of this stringent criteria? Also, what is the reasoning behind selecting 300 kV as a cut off level?
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	This event also falls under Category C for which the current NERC criteria allows controlled loss of load. Clear net benefits should be demonstrated to justify adapting to a new stringent criteria.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer	☐Agree. ☒Do not agree.	This event also falls under Category C for which the current NERC criteria allows controlled loss of load. Clear net benefits should be demonstrated to justify adapting to a new stringent criteria.

with low side voltage rating above 300 kV		
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	This event also falls under Category C for which the current NERC criteria allows controlled loss of load. Clear net benefits should be demonstrated to justify adapting to a new stringent criteria.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: Same response as for Q21

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: Do not agree for loss of a bus, or loss of a stuck non-bus tie breaker for the reasons as in the response to Q21.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	Non consequential loss of load should not be permitted for this type of event. Loss of a generator has higher probability and longer duration than many other contingencies. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise has higher probability than other multiple contingency events.

[1] System adjustment can be manual or automatic

Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	Agree that non consequential loss of load should not be permitted due to higher probability of generator outage.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	Same reason as in Q26.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☐Do not agree.	Same reason as in Q26.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: In addition, the interruptible and other negotiated transactions should also be allowed.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment: Agree that the two analysis should be treated separately.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: Plant stability studies are a subset of system stability studies in which loss of a generator is already evaluated to meet performance requirements. In specific situations, sensitivity analysis can be done as deemed appropriate by the TP to address a particular system problem.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within

the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐
Comment: It will be cosistent with the performance requirements under Steady State conditions. Also, loss of entire generating station is possible for a variety of reasons such as, loss of all lines emanating from the station, loss of the gas pipeline feeding the plant, etc.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment: The requirement to include motor load should be extended to other load levels as appropriate.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Maunal such as tripping the generators, automatic such as AVR, excitation systems, stabilizer, and governor adjustments

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment: Agree

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: 1. Run back of generation should not result in tripping of firm load, 2. Power flow should be within the applicable ratings, 3. Frequency should be within the allowable limits

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: Agree

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: RAS or SPS should generally be regarded as a stop gap measure before transmission expansion or reinforcement becomes available. It should not be used as a substitute for transmission facilities.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: 1. RAS or SPS must be simple and manageable. 2. Nnumber of contingencies triggering a RAS or SPS should be very limited (4 allowed by CAISO). 3. RAS or SPS should generally monitor only local facilities that are either directly connected to the plant or one bus away.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐
Comment: ISO relies upon tripping of generators to meet single contingency performance requirements. ISO also relies upon planned and controlled load shedding for the proposed Planning Events P4 and P5.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment: Not aware of any

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐

Comment:

First, and as a general matter, the TPL-001 standard needs to accurately reflect the roles of PA'S and TP'S in areas with organized competitive markets and where the PA'S and TP'S are not vertically integrated utilities. In those areas, the TPL standard should recognize that compliance with the standard is achieved through the publication of a Plan that identifies system needs – and leaves open to the marketplace the specific mix of resources that investors construct to meet those needs. As a result, the Plan need not be, and should not be, prescriptive as to the resource mix that must be achieved. It is important for plans to be equally open to generation, demand response and transmission and not be presecriptive to the actual resource mix. Further, not all organized competitive markets have a mechanism in place to develop an integrated resource and transmission plan to meet future needs. Some markets conduct forecast assessment, thereby providing signals to market participants to make investment decisions.

Similarly, reflecting the divested nature of the industry in areas operated by ISOs and RTOs, the modeling standards should be reviewed to make sure that asset owners (e.g., generator owners and transmission owners) are required to give information in the level of detail and granularity that will allow PA's and TP's to develop plans and models consistent with these standards.

As highlighted in question 16, DSM should be considered an acceptable solution to system needs. However, DSM is generally considered in meeting resource requirements rather than as one of means to relieve transmission constraints. In planning studies, loads that are identified as DSM type (contracted or potential) are modeled as firm loads for reliability assessment. We would therefore seek the SDT’s suggestion on how specifically DSM should be explicitly modeled or used to aid in achieving transmission reliability in the planning horizon. Further, the drafting team must consider whether DSM providers are covered in the Compliance Registry and how the NERC Standards should obligate them to provide the requisite information to PA'ss and TP's so that they are fully taken into account.

Finally, the standards need to be improved to better distinguish the responsibility of Planning Authorities versus Transmission Planners. Currently, the Standard refers to both entities as carrying out the requirements. This appears to be reundant.

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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
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Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: Firm transaction obligations are not used throughout all regions in NERC. Change "including firm transaction obligations" to "including firm transaction obligations where applicable."**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	

Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☐Do not agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.

- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: The number and type of sensitivity studies should be left to the judgement of Transmission Planners. Having too many prescriptive requirements results in concentrating on meeting the requirements rather than on formulating the most effective and efficient improvements.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: See comment to Q12.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒
Comment: The number and type of sensitivity studies should be left to the judgement of Transmission Planners.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System

deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒
Comment: CenterPoint Energy is not aware of DSM ever being identified as an effective option to correct a transmission system deficiency. If such an application of DSM was identified and implemented, load growth would quickly negate the DSM impact, and other measures would have to be taken.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☒
Comment: Many problems identified in future studies and associated transmission improvements are fictitious due to the speculative nature of predicting load and generation growth. Requiring exhaustive studies to determine the full impact of fictitious transmission projects is unnecessarily prescriptive and burdensome, and provides little, if any, value in identifying and solving real transmission problems.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: This is overly prescriptive. Allow each Transmission Plannner to determine the best way to handle planned projects.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this

draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	The forced outage of two independent lines has a low probability of occurrence and should be considered an improbable event with non-consequential load loss permitted.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: The loss of a non-bus tie breaker due to an internal fault has a low probability of occurence and should be considered an improbable event with non-consequential load loss permitted. However, the loss of any breaker, whether by internal fault, external flashover, or stuck breaker, should not result in a cascading failure.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: The loss of either a generator, a Transmission cirucit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV) has a low probability of occurrence and should be considered an extreme event with non-consequential load loss permitted.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	CenterPoint Energy believes the assumption that this is a high probability event is incorrect. Furthermore, an absolute requirement prohibiting non-consequential loss of load has economic and landowner impacts that cannot be ignored.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	CenterPoint Energy believes the assumption that this is a high probability event is incorrect. Furthermore, an absolute requirement prohibiting non-consequential loss of load has economic and landowner impacts that cannot be ignored.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	CenterPoint Energy believes the assumption that this is a high probability event is incorrect. Furthermore, an absolute requirement prohibiting non-consequential loss of load has economic and landowner impacts that cannot be ignored.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☒Do not agree.	CenterPoint Energy believes the assumption that this is a high probability event is incorrect. Furthermore, an absolute requirement

[1] System adjustment can be manual or automatic

		prohibiting non-consequential loss of load has economic and landowner impacts that cannot be ignored.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment: Separating the stability requirements into a second table improved the clarity.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: CenterPoint Energy does not see the distinction between system stability and plant stability studies as defined in the draft standard. Meeting the performance requirements set in R4.5 should suffice for all stability studies. The requirements in R4.6 seem overly prescriptive and could potentially result in numerous studies being required that would have very little positive effect on transmission systems throughout the country.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: CenterPoint Energy agrees with the SDT's assessment.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: CenterPoint Energy includes the dynamic effects of induction motor loads in stability studies. However, this requirement is overly prescriptive since some utilities may not need to include the dynamic effects of induction motors and should not be required to do so.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☒ No ☐
Comment: FPA section 215(i)(2) "does not authorize the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services." However, adherence to TPL-001-1 as currently drafted, will require, de facto, the construction of additional transmission facilities. CenterPoint Energy believes this standard goes far beyond the legislative intent of mandatory reliability standards and will result in construction of transmission capacity in order to remain compliant.

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment:

TPL-001-1 focuses solely on reliability to the exclusion of economic cost/benefits, prudent avoidance, and landowner impacts, which have been the hallmarks of good utility practice that have governed transmission planning and construction for decades. FPA section 215(i)(2) "does not authorize the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services." However, adherence to TPL-001-1 as currently drafted, will require, de facto, the construction of additional transmission facilities. CenterPoint Energy believes this standard excludes proven, historical good utility practice to reach far beyond what is intended by the FPA.

TPL-001-1 contains an excessive number of requirements (over 50). The SDT should consider the removal or modification of the following unnecessary, redundant or overly prescriptive requirements:

R1.1. This is a modeling requirement and should be incorporated into the modeling (MOD) standards. Remove or modify this requirement to eliminate any redundancy with existing modeling standards. If certain subrequirements of R1.1 of TPL-001 are not currently requirements in a MOD standard, it should be questioned, then, whether or not these specific subrequirements are actually needed in ANY standard.

R2.1.3 and R2.4.3 should be removed because they introduce new, vague requirements.

R2.2. Analysis beyond five years has little value due to the speculative nature of predicting load and generation growth. Furthermore, ERCOT does not annually create Long-Term Planning Horizon cases because ERCOT does not believe it is necessary. This requirement should be removed.

R2.5 and R4.6. These requirements are overly prescriptive and unnecessary for the reasons stated in the response to Q32. They should be removed.

R2.7.1 through 2.7.5. Requiring Corrective Action Plans that address how performance requirements will be met is reasonable; however, these standard requirements are overly prescriptive and unnecessary. R2.7.1 through R2.7.5 would result in the development, documentation and explanation of fictitious solutions to fictitious problems. They should be removed.

R3.3.2.1. The requirement to identify consequential load loss for single contingencies in the Planning Assessment is unnecessary and burdensome and should be removed.

R5. The roles of the Transmission Planner and Planning Coordinator are already addressed in the approved NERC definitions and further described in the approved NERC Reliability Functional Model. This requirement is unnecessary and should be removed.

Table 1 and Table 2 - P4, P5, P8, and P9. Including all combinations of two components (generator, Transmission circuit, transformer, monopolar DC line) with generation adjustments is impractical and overly burdensome. For multiple contingencies, CenterPoint Energy recommends including only two-circuit tower lines and the two components (generator, Transmission circuit, transformer, monopolar DC line) that would be cleared by a breaker failure (i.e., stuck breaker).

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1 Version 1 of SAR posted for comment from April 2, 2002 through May 3, 2002.
2 Version 2 of SAR posted for comment from May 5, 2004 through June 5, 2004.
3 Version 3 of SAR posted on November 18, 2005.
4 SAR approved on April 30, 2006.
5 Version 1 of Supplemental SAR posted for comment from February 15, 2007 through March 16, 2007.
6 Version 2 of Supplemental SAR posted on April 9, 2007.
7 Version 1 of revised standard(s) posted for comment on September 17, 2007.

Proposed Action Plan and Description of Current Draft:

The SDT has established an aggressive schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 2Q08. The current draft is the first iteration of the revision of existing standards TPL-001 through TPL-006 and includes one revised standard, TPL-001-1, replacing TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. TPL-005 & -006 will be addressed later in the project. Violation Risk Factors, Time Horizons, Measures, Compliance and Implementation Plans will be included in subsequent postings.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Respond to comments from first posting of standard(s) and submit revision 1 of the standard(s).	4Q2007
2. Respond to comments from second posting of standard(s) and submit revision 2 of the standard(s).	4Q2007
3. Submit revision 3 of the standard(s) for balloting.	4Q2007
4. Submit standard(s) for recirculation balloting.	2Q2008
5. Submit standard(s) to BOT.	2Q2008
6.	
7.	

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Base Case: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch, including firm transaction obligations where applicable, assumed to supply the connected Load. The models also reflect Facility Ratings.

Consequential Load Loss: Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.

Extreme Events: Events which are more severe than Planning Events and have a low probability of occurrence.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond.

Near-Term Transmission Planning Horizon: Transmission planning period that covers Years One through five.

Non-Consequential Load Loss: Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.

Planning Assessment: Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.

Planning Events: Events which require Transmission system performance requirements to be met.

Plant Stability Study: Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.

System Stability Study: Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.

Year One: The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies.

A. Introduction

1. Title: Transmission System Planning Performance Requirements

2. Number: TPL-001-1

3. Purpose: Establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. Applicability:

4.1. Functional Entity

4.1.1. Planning Coordinator.

4.1.2. Transmission Planner.

4.1.3. Resource Planner.

4.1.4. Load-Serving Entity.

4.1.5. Transmission Owner.

4.1.6. Generator Owner.

5. Effective Date: TBD

B. Requirements

R1. Each Resource Planner, Transmission Planner, Transmission Owner, Generator Owner, and Load-Serving Entity shall each provide its respective Planning Coordinator with the following modeling information required for System performance studies upon request (within 30 calendar days) : *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

~~**R1.1.** Load forecasts adhering, at a minimum, to the following criteria:~~

~~**R1.1.1.** Use of expected Load mix based on the actual or expected aggregate mix of industrial, commercial, and residential Loads.~~

~~**R1.1.2.** Based on normal weather patterns as agreed to by the Planning Coordinator(s) and the Transmission Planner(s) for the area(s) of their responsibility.~~

~~**R1.1.3.** Identification of Demand Side Management (DSM) Load reductions consistent with operational requirements.~~

R1.2. Load models with supporting rationale that include power factor data based on historical System performance, validated by measurement during stressed System conditions, or documented Transmission planning area requirements.

R1.3. Firm transfers/Interchange Schedules and resources required to supply Load for each Balancing Authority.

R1.4. Known planned outages and long-term outages for Transmission and generation equipment including protective relays with consideration given to spare equipment strategy.

R1.5. Planned Facilities defined in accordance with the documented criteria of the Planning Coordinator, including but not limited to: Transmission Lines, generators, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies.

R2. Each Transmission Planner and Planning Coordinator shall conduct and document the results of its annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, and shall cover steady state analyses, short circuit analyses, and Stability analyses including both System and plant Stability. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R2.1. The steady state portion of the Near-Term Transmission Planning Horizon Planning Assessment shall address all five years of the assessment period and be supported at a minimum by the following annual current studies,, supplemented with qualified past studies as shown in Requirement R2.6:

R2.1.1. System peak Load for either Year One or year two, and year five.

R2.1.2. System Off-Peak Load for one of the five years.

~~**R2.1.3.** For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation with the rationale for the selected sensitivity(ies) shall be supplied:~~

~~**R.2.1.3.1.** Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.~~

~~**R.2.1.3.2.** Modification of expected transfers.~~

~~**R.2.1.3.3.** Unavailability of long lead time facilities.~~

~~**R.2.1.3.4.** Variability and outages of reactive resources.~~

~~**R.2.1.3.5.** Generation additions, retirements, or other dispatch scenarios.~~

~~**R.2.1.3.6.** Decreased effectiveness of controllable Loads and Demand Side Management.~~

~~**R.2.1.3.7.** Modification of planned Transmission outages.~~

~~**R2.2.** For the steady state portion of the Long-Term Transmission Planning Horizon Planning Assessment, at a minimum, a current System peak Load study is required annually for one of the years in the assessment period to support the annual Planning Assessment.~~

~~**R2.2.1.** To accommodate any known longer lead time projects that may take longer than ten years to complete, the Planning Assessment shall be extended accordingly.~~

R2.3. The short circuit portion of the Planning Assessment shall be conducted annually and supported by current or past studies.

R2.3.1. A current study shall be performed if changes in the BES result in increased fault currents such as resource additions and other Facility changes that result in reductions in impedance.

R2.4. The System Stability portion of the Near-Term Transmission Planning Horizon Planning Assessment shall address all five years of the assessment period, and be supported by current or past studies. The following studies are required:

R2.4.1. System peak Load for one of the five years. For peak System Load levels, the Load model shall include the dynamic effects of induction motor Loads.

R2.4.2. System Off-Peak Load for one of the five years.

~~**R2.4.3.** Sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run with documentation provided explaining the rationale for the selected sensitivity(ies):~~

~~**R.2.4.3.1.** Variations in Load model assumptions.~~
~~**R.2.4.3.2.** Expected simultaneous transfers including non-firm transfers.~~
~~**R.2.4.3.3.** Unavailability of long lead time facilities.~~
~~**R.2.4.3.4.** Reactive dispatch of generators and other reactive power devices.~~
~~**R.2.4.3.5.** Generation additions, retirements, or other dispatch scenarios.~~

~~**R2.5.** The plant Stability portion of the Planning Assessment shall be analyzed consistent with Requirement R4.6 with studies for the year when the following occur:~~

~~**R2.5.1.** New generator(s) are added or generation modifications are made such as increasing generation capability, replacing the exciter or addition of a power System stabilizer.~~

~~**R2.5.2.** Material changes in the electrical vicinity of existing generation are made such as the addition or removal of a Transmission Line at or near the point of Interconnection.~~

R2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

R2.6.1. For steady state analysis: if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market structure changes.

R2.6.2. For short circuit analysis: if the study is less than five years old and no material changes have occurred to the System in the intervening period.

R2.6.3. For plant and System Stability analysis: until material changes in the System make the study no longer valid. Material changes in the system include the addition of a Transmission Line or a generator.

R2.7. For Planning Events shown in Table 1 – Steady State Performance and Table 2 – Stability Performance, when the analysis indicates an inability of the System to meet the performance requirements in the tables, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed over time but shall meet the performance requirements in the tables. Such plans shall:

~~**R2.7.1.** Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~

~~**R.2.7.1.1.** For the Near-Term Transmission Planning Horizon, include both a project initiation date as well as an in-service date.~~

~~**R.2.7.1.2.** For the Long-Term Transmission Planning Horizon, provide an in-service year..~~

~~**R2.7.2.** Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables.~~

~~**R2.7.3.** Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~

~~**R2.7.4.** Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~

~~**R2.7.5.** Be reviewed in subsequent annual Planning Assessments as to implementation status of identified System Facilities and Operating Procedures.~~

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to contingencies in Table 1 – Steady State Performance. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R3.1. Studies shall determine whether the BES meets the performance requirements in Table 1 – Steady State Performance.

R3.2. Contingency analyses shall simulate the removal of all elements including those that System protection is expected to disconnect for each Contingency without operator intervention.

R3.2.1. For all generators, studies shall consider the minimum steady state voltage limitations of all generators and identify how the generators are treated in the steady state simulation.

R3.2.2. For all Transmission lines, studies shall consider relay loadability and identify how loadability is treated in the steady state simulation.

R3.3. For Steady State studies:

R3.3.1. Performance criteria for System normal conditions and for Planning Events in Table 1 – Steady State Performance shall be met.

R3.3.2. Evaluations shall be performed for single Contingencies (identified in Table 1 – Steady State Performance).

~~**R.3.3.2.1.** Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment.~~

R.3.3.2.2. Following single Contingency events, System adjustments other than shedding of firm Load or curtailment of firm transfers are permitted to meet performance requirements provided these adjustments can be accomplished within the time period allowed by the applicable time limited ratings.

R3.3.3. Those Planning Event Contingencies in Table 1 – Steady State Performance not covered in Requirement R3.3.2 that are expected to produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results.

R3.4. Those Extreme Events in Table 1 – Steady State Performance that are expected to produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. If the Extreme Events analysis concludes there are Cascading Outages caused by the occurrence of Extreme Events, an evaluation of implementing a change designed to reduce or mitigate the likelihood of such consequences shall be conducted.

R3.5. Manual and automatic generation run-back is allowed as a response to single and multiple Contingencies as long as Facility Ratings are not exceeded.

R3.6. Manual and automatic generation tripping is allowed for multiple Contingencies and for single Contingencies only in situations that meet all of the following conditions:

R3.6.1. TBD

Note: WECC has informed the SDT that it will be submitting an Interconnection-wide regional variance to allow for manual and automatic generation tripping for single Contingencies. The regional variance will be justified based on physical System differences in the western Interconnection. WECC is developing a white paper to support this position. The actual text of the regional variance will be included in the next posting of this standard.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2.4

and Requirement R2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 2 – Stability Performance. The studies shall cover both System Stability and plant Stability. The following requirements apply to both System Stability and plant Stability studies unless otherwise noted. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R4.1. Studies to meet the performance requirements in Table 2 – Stability Performance shall use computer Stability simulations that analyze the response of the BES.

R4.2. Contingency analyses shall simulate the removal of all elements including those that System protection is expected to disconnect for each Contingency without operator intervention.

R4.3. Studies shall consider the voltage ride through capability of all generators and identify how the generators are treated in the simulation.

R4.4. Studies shall identify any planned upgrades (including protection and control modifications) needed to meet the performance requirements of the Planning Events of Table 2 – Stability Performance and validate their effectiveness.

R4.5. For the System Stability study:

R4.5.1. At a minimum, those Planning Event Contingencies in Table 2 – Stability Performance that would produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information with an explanation of why the remaining Contingencies would produce less severe System results.

R4.5.2. At a minimum, those Extreme Events in Table 2 – Stability Performance that would produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. If the Extreme Events analysis concludes there are Cascading Outages, an evaluation of implementing a change designed to reduce or mitigate the likelihood of such consequences shall be conducted.

~~**R4.6.** For the Plant Stability studies:~~

~~**R4.6.1.** Shall be performed for individual generating units 20 MW or greater directly connected through a step-up transformer to the BES and for generating units at the same location which total 75 MW or greater, directly connected through their step-up transformer(s) to the BES.~~

~~**R4.6.2.** Shall be performed for changes in the real power output of a generating unit by more than 10% of the existing capability or more than 20 MW whichever is greater.~~

~~**R4.6.3.** Shall be performed and evaluated for those Planning Events that would produce more severe System impacts and the rationale for the Contingencies selected for evaluation shall be available as supporting~~

~~information and shall include an explanation of why the remaining Contingencies would produce less severe System results. The identified Contingencies, at a minimum, shall be evaluated.~~

~~**R4.6.4.** Shall meet Performance requirements for Planning Events in Table 2 – Stability Performance.~~

~~**R5.** Each Transmission Planner and Planning Coordinator shall determine and identify individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*~~

R6. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among affected entities, coordinating analysis of these results through an open and transparent peer review process. *[Violation Risk Factor: TBD] [Time Horizon: TBD]* This distribution shall include:

R6.1. Transmission Planners within the Planning Coordinator's area

R6.2. Transmission Planners of neighboring impacted areas

R6.3. Planning Coordinators of neighboring areas

Table 1 – Steady State Performance

Performance Requirements For all Planning Events: • Equipment Ratings shall not be exceeded. • System steady state voltages and post-transient voltage deviation shall be within acceptable limits established by the Planning Coordinator (or Transmission Planner if more restrictive.) • Voltage instability, cascading outages, and uncontrolled islanding shall not occur. • Consequential Load loss is allowed for all cases shown. • Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency. • Simulate Normal Clearing unless otherwise specified.			
Planning Events			
#	**Event**	**Interruption of Firm Transfer Allowed (does not result in loss of Load)**	**Non-Consequential Load Loss Allowed**
P1 (single Contingency)	Loss of: 1. A generator 2. A Transmission circuit 3. A transformer 4. A shunt device (including FACTS devices)	No	No
P2 (single Contingency)	Loss of: 1. Bus section above 300 kV 2. Non-bus tie breaker (above 300 kV) due to internal fault 3. Single pole of a DC line	Yes, if transfer is dependent on the outaged DC line No otherwise	No
P3 (multiple Contingency)	Loss of either a generator, Transmission circuit, a transformer with low side voltage rating above 300 kV, or a bus and a stuck non-bus tie breaker (above 300 kV)	Yes, if transfer is dependent on the outaged DC line No otherwise	No
P4 (multiple Contingency)	1. Loss of a generator followed by a System adjustment followed by the loss of a generator. 2. Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line 3. Loss of a generator followed by a System adjustment followed by the loss of a Transmission circuit 4. Loss of a generator followed by a System adjustment followed by the	Yes, if transfer is dependent on the outaged DC line No otherwise	No

	loss of a transformer		
P5 (multiple Contingency)	Above 300 kV, the loss of: 1. A Transmission circuit followed by a System adjustment followed by the loss of another Transmission circuit 2. A Transmission circuit followed by a System adjustment followed by the loss of a transformer with low side voltage rating above 300 kV 3. A transformer with low side voltage rating above 300 kV followed by a System adjustment followed by the loss of another transformer	Yes	No
P6 (single Contingency)	Loss of: 1. A bus tie breaker due to internal fault 2. A bipolar DC line or an asynchronous tie line 3. A non-bus tie breaker (below 300 kV) due to internal fault 4. A bus section below 300 kV	Yes	Yes
P7 (multiple Contingency)	Loss of: 1. A bus section above 300 kV and a stuck bus tie breaker 2. Either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (below 300 kV)	Yes	Yes
P8 (multiple Contingency)	Below 300 kV, the loss of: 1. A Transmission circuit followed by a System adjustment followed by the loss of another Transmission circuit 2. A Transmission circuit followed by a System adjustment followed by the loss of a transformer 3. A transformer followed by a System adjustment followed by the loss of another transformer	Yes	Yes
P9 (multiple Contingency)	1. Loss of any two circuits on a common structure (excluding where multiple circuits share a common structure for no more than one mile) 2. Loss of a generator followed by a System adjustment followed by the loss of a monopolar or bipolar DC line, or an asynchronous tie line 3. Loss of a DC line (monopolar or bipolar) or asynchronous tie followed by a System adjustment followed by the loss of a second DC line (monopolar or bipolar) or asynchronous tie 4. Loss of a DC line (monopolar or bipolar) or asynchronous tie followed by a System adjustment followed by the loss of a Transmission circuit	Yes	Yes

	5. Loss of a transformer followed by a System adjustment followed by the loss of a DC line (monopolar or bipolar) or asynchronous tie line 6. Loss of a transformer followed by a System adjustment with a spare transformer available followed by the loss of another transformer		

Extreme Events

Evaluation Requirements For all Extreme Events: 1. See Requirement R3.4 2. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency. 3. Simulate Normal Clearing unless otherwise specified.

Extreme Event Descriptions

1. Loss of a single generator, Transmission circuit, DC line, or transformer forced out of service followed by another single generator, Transmission circuit, DC line, or transformer forced out of service prior to System adjustments. **2.** Local area events affecting the Transmission System such as: a. Loss of tower line with three or more circuits b. Loss of all Transmission lines on a common right-of-way c. Loss of switching station or substation (loss of one voltage level plus transformers) d. Loss of all generating units at a station e. Loss of a large Load or major Load center **3.** Wide area events affecting the Transmission System such as: a. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation b. A successful cyber attack c. Regulation that restricts or eliminates the use of a river or lake or other body of water as the cooling source for generation d. Shutdown of a nuclear power plant(s) and other facilities a day or more prior to a hurricane, tornado or wildfire, or for other common causes e. Regulation that restricts or eliminates the use of a river or lake or other body of water as the cooling source for generation f. Shutdown of a nuclear power plant(s) and other facilities a day or more prior to a hurricane, tornado or wildfire, or for other common causes such as problems with similarly designed plants g. The loss of older Transmission lines which may not be constructed to meet an entity's present radial ice or wind loading requirements, while the newer or stronger Transmission lines remain in service h. Other events based upon operating experience

Table 2 – Stability Performance Table

Performance Requirements For all Planning Events: • The System shall be stable[1] • Dynamic voltages shall be within acceptable limits established by the Planning Coordinator or Transmission Planner (if more restrictive) • Uncontrolled islanding and Cascading Outages shall not occur • Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency. • Simulate Normal Clearing unless otherwise specified.			
Planning Events			
#	**Initial Condition**	**Event**	**Non-Consequential Load Loss Allowed**
P1 (single Contingency)	System normal	Single Line Ground (SLG) fault on, a 3 Phase (3Ø) fault on, or an unexpected loss without a fault of (whichever is worst): 1. A generator 2. A Transmission circuit 3. A transformer	No
P2 (single Contingency)	System normal	1. SLG fault on bus section above 300 kV 2. SLG internal fault in non-bus tie breaker (above 300 kV) 3. A single pole block of a DC line	No
P3 (multiple Contingency)	System normal	SLG fault on either a generator, Transmission circuit, a transformer, or a bus and a stuck[2] non-bus tie breaker (above 300 kV)	No
P4 (multiple Contingency)	A single generator out of service followed by System adjustments	1. Apply a P1.1 Contingency. 2. Apply a P2.3 Contingency. 3. Apply a P1.2 Contingency. 4. Apply a P1.3 Contingency.	No
P5 (multiple Contingency)	A Transmission circuit above 300 kV out of service followed by System adjustments	1. Apply a P1.2 Contingency. 2. Apply a P1.3 Contingency.	No

	A transformer with low side voltage rating above 300 kV out of service followed by System adjustments	3. Apply a P1.3 Contingency.	
P6 (single Contingency)	System normal	1. SLG internal fault in bus tie breaker 2. A bipolar block of a DC line 3. SLG internal fault in non-bus tie breaker (below 300 kV) 4. SLG fault on bus section (below 300 kV)	Yes
P7 (multiple Contingency)	System normal	1. SLG fault on a bus section above 300 kV and a stuck bus tie breaker 2. SLG fault on either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (below 300 kV)	Yes
P8 (multiple Contingency)	A Transmission circuit below 300 kV out of service followed by System adjustments A transformer with low side voltage rating below 300 kV out of service followed by System adjustments	1. Apply a P1.2 Contingency. 2. Apply a P1.3 Contingency. 3. Apply a P1.3 Contingency.	Yes
P9 (multiple Contingency)	System normal A single generator out of service followed by System adjustments A DC circuit out of service followed by	1. SLG fault on each circuit of any two circuits on a common structure (excluding events where multiple circuits share a common structure for no more than one mile). 2. Apply a P6.2 Contingency. 3. Apply a P2.3 Contingency. 4. Apply a P1.2 Contingency.	Yes

	System adjustments A transformer out of service followed by System adjustments A spare transformer inserted to replace an outaged transformer followed by System adjustments	5. Apply a P2.3 Contingency. 6. Apply a P1.3 Contingency.	
Extreme Events			
Evaluation Requirements For all Extreme Events: • See Requirement R4.5.2 in the text • Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency. • Simulate Normal Clearing unless otherwise specified.			
1. 3Ø fault on generator with stuck breaker 2. 3Ø fault on Transmission circuit with stuck breaker 3. 3Ø fault on transformer with stuck breaker 4. 3Ø fault on bus section with stuck breaker 5. 3Ø internal fault in breaker 6. 3Ø fault on two or more circuits on a common structure 7. SLG or 3Ø fault on all Transmission lines on a common right-of-way 8. 3Ø fault on switching station or substation (loss of one voltage level plus transformers) 9. 3Ø fault with loss of all generating units at a station			

Notes:

1. System stable means:

a. Angular stability:

i. For Planning Events P1 and P3.2: No generating unit or units shall be allowed to pull out of synchronism. A generator being disconnected from the system by fault clearing action or by a Special Protection Scheme is not considered pulling out of synchronism.

ii. For all other Planning Events: No generating unit or units totaling more than the contingency reserve (spinning reserve) of the Balancing Authority shall be allowed to pull out of synchronism. Generators that pull out of synchronism must have out-of-step protection and the resulting apparent impedance swings must not pass through relay characteristics that would result in the tripping of

any transmission system elements other than the generating unit and its direct connection facilities.

iii. For all Planning Events: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator or Transmission Planner (if more restrictive).

b. General: Unplanned islanding of portions of the system shall not occur for Planning Events.

2. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) breaker, only one pole is assumed to remain closed.

C. Measures

M1. To be supplied at a later date.

E. Regional Variances

1. WECC Interconnection-wide waiver is under development (see Requirement R3.6.2).

Version History

Version	Date	Action	Change Tracking
1		Revision of TPL-001-0 as per Project 2006-02; includes merging requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-1	Not employed due to scope of revision

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: There are a few undefined terms in this definition: "Transmission System" and "interconnected Transmission System". The definition needs to specifically identify what should be modeled and in a manner consistent with other NERC definitions. The definition refers to Facility ratings rather than the general reference to FAC-008 & FAC-009**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Modify to "Events which are more severe,but have a lower probability of occurrence, than Planning Events".**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☒Do not agree.
Q4. **Comment: "A Planning Assessment period that covers years six through ten", is sufficient for the standard." Suggest changing the name to Long-Term Planning Assessment.**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment: Suggest changing the name to Near-Term Planning Assessment, and introduce the description the same was as above.**	
Q6. **Non-Consequential Load Loss:** Load loss other than	☒Agree.

Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Eliminate "capital" from the definition. It is not defined or consistently applicable to the standard. Reference to vague "other factors, such as asset conditions and age" should be removed from this standard; there are no consistent definitions or industry standards on which to base this requirement, nor does it appear to be a necessary addition to the standard.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Propose, "Events for which Transmission performance requirements must be met".**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: See comment on Q9; proposed modification, "Study of the System or portions of the System to determine whether plant and system angular Stability is maintained, power oscillations are damped, and voltages during the dynamic simulation stay within acceptable perfomance limits.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: Modify to, "The first year that a Tranmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner completes its annual studies."**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement to mitigate consequences of problems highlighted as a result of one of the sensitivities.

Suggest modification to, "…sensitivity testing that stresses the System shall be considered, and documentation with the rationale for the sensitivity testing shall be supplied. The sensitivity case(s) may include one or more of the following conditions:"

2.1.3.3 should refer only to planned facilities that may be delayed. 2.1.3.4 - "variability" is too vague for a standard; the standard needs to be more specific as to the intent. 2.1.3.7 should be consistent with 1.4. These comments also apply to 2.4.3.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement to mitigate consequences of problems highlighted as a result of one of the sensitivities.

Reasonably stressed conditions are dependent upon the study area under review and the standard is not likely to be able to be crafted to provide sufficent and consistent direction. However, it might be helpful if the standard clarified whether the base case should include any unplanned generator outages or whether, aside from potential sensitivities, unplanned generator outages are considered only through P1, P3 or P4 Contingencies. If the standard addresses unplanned generator outages only through P1, P3 and P4, then it is recommended that a mandatory sensitivity analysis, with required mitigation, include various potential combinations of a reasonable amount of unplanned outages. The combinations should be based on the part of the system that is under study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment: The standard is unclear whether or not it mandates the requirement to mitigate consequences of problems highlighted as a result of one of the sensitivities.

Suggest modification to, "…sensitivity testing that stresses the System should be considered. Sensitivity case(s) might include among the following conditions:" 2.4.3 shold mimic 2.1.3 except in regard to load models.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: There is no need for sensitivity analysis.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: DSM should be included to the extent that its performance is sufficiently and consistently understood. The standard does not use the term "optimal" Therefore, the Drafting Team appears to be interpreting the Standard to require a vertically-integrated Planner to produce a so-called optimal-mix of resources plan. This would be an incorrect assumption and is not required. In areas with independent planners and competitive wholesale markets, it is sufficent to identify system needs and produce a plan that identifies regulated transmission solutions in the event that market-based resources (such as DSM) do not address those identified needs. Therefore, while DSM can be as effective a resource as generation, per Commission Orders,

in areas with ISOs/RTOs and a competitive wholesale market, the NERC Standard cannot prescribe the development so-called optimized (as is suggesgted by the Drafting Team) resource-mix plans, as identified by a central planner.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: The study area should be based upon planning expertise and knowledge of the system, giving due consideration to external impacts.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment: They should be viewed differently in the Near-Term. However, these should be defined terms.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment: It is unclear as to what the commited project is being removed from. Suggested language "…removed from the plan…".

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Given the low probability of extended overlapping outages of overhead facilities, systems have been designed assuming that load shedding following the loss of a second transmission line is permissible. Eliminating any allowance for load shedding for this condition may require significant system expansion and cost to to customers. However, it would be reasonable to consider establishing an upper bound to the amount of load that could be shed for these purposes.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	Should also consider the initial loss of a transformer, followed by the loss of a Transmission circuit. This should state a transformer with a "high-side" rating above 300 kV.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	This should state a transformer with a "high-side" rating above 300 kV.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of 2 additional generators.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a monopolar DC line
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a Transmission circuit
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a transformer

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm

[1] System adjustment can be manual or automatic

transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: This should also apply to firm transfers via single or double ac facilities as well. In either case, the transfer could be linked to dedicated facilities.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Difficult to envision how such an event would occur.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: This requirement is too specific and limited. Induction motors are only one component of a complex load model. Complex load models are not always necessary, nor are they always the most conservative, depending on the analysis that is being conducted. Where complex load models are required, they should be considered; this may involve use of complex motor and lighting loads or polynomial load representations

with or without frequency dependence. This question also suggests the need for an industry standard regarding transient voltage recovery.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Manual or automatic adjustments should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment. Manual system adjustment should be allowed in between the multiple Contingencies described in P5, provided that the adjustment can be made between contingencies using short-term reserves (10-30 minute).

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment: Generation runback should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐

Comment: However, this should only be allowed where failure of an automatic runback that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: Only allowed where the failure of an SPS that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Only allowed where SPS failure would not have significant adverse impact on the Bulk Electric System; non-Consequential loss of load should be allowed up to an amount potentially specified in the standard.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: System must remain stable with acceptable voltages and all equipment within applicable emergency limits.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☒
Comment: Unsure due to ambiguities in the standard. Depending upon the final standard, New England may need exceptions for existing facilities or allowance for a transition period to develop a compliance plan.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: There should be a "P0" standard that applies to system performance without any contingencies.

Standard should be clear that stabiltiy analysis is not required for Long-Term Planning Assessment.

R.1.1 Load forecasts should be addressed in MOD standards, not TPL.

R 1.4 This should only refer to known long-term outages, not planned outages. Delete "including protective relays"; this is addressed through other provisions.

R.2.1 Shorten "Near-Term Transmission Planning Horizon Planning Assessment" to "Near-Term Planning Assessment".

R 2.2 Shorten "Long-Term Transmission Planning Horizon Planning Assessment" to "Long-Term Planning Assessment".

R2.1, 2.2, 2.3 & 2.4 – The initial paragraph should have identical language regarding 'annual', and 'current or past' aspects.

R2.1.1 There should not be a requirement to look at years one and two; a 5 year study should be sufficient. If there has been an ongoing 5 year study, there should be no major unexpected problems occurring in years 1 and 2. Studies of earlier years should only be required if an unanticipated event occurred that had not been considered in prior studies. The TPL should not address shorter term "Operating Studies" or operating issues.

R 2.2.1 Modify to "If any known projects have a lead time that is longer than ten years, the Planning Assessment shall be extended accordingly."

R 2.6 Steady-state, short circuit, and stability analysis should be required no more than every 5 years unless there is a significant change the system.

R 2.6.1 Remove reference to "market structure changes". The purpose of it's inclusion is unclear.

R 2.7.1.1 Project initiation date should be deleted. If it is retainted, it needs to be defined.

R 2.7.3 Committed and Proposed projects should be defined.

R 3.2.1/R 4.3 - What is the intent of this requirement? There should probably be an MOD associated with Generator Owner requirement to provide related generator protection/ limiter data or other plant information.

R 3.4/R 4.5.2 Remove the requirement to implement changes to reduce or mitigate the likelihood of such consequences of Extreme Events. This may not be reasonable or achieveable.

R 3.2 Sectionalizing schemes shall be considered when reflecting the post-contingent system.

R 3.2.2 - Propose deleting this. Line ratings should already take relay loadability into account.

R 3.3.2.1 - Proposed deleting "expected duration". This would be dependent upon the damage to the element due to the iniating event and other factors.

R 3.3.2.2 - The requirements of this section do not match P6.

R 3.3.3 - Change introductory language to read "Those multiple Contingencies that are…"

R 3.5 - Generation tripping should be allowed as well as generation run-back. In addition, all performance requirements shall be met, rather than just meeting facility rating requirements. Suggested lanague "Manual and automatic generation run-back and/or generation tripping is allowed as a response to single and multiple Contingencies as long as the performance requirements of this standard are met." If these changes are accepted, R 3.6 can be deleted.

R 4 and R 4.1 - The language should be made similar to R 3 and R 3.1.

Suggest bringing language similar R4.4 into the R 3, the steady state section.

R 4.2 - High speed automatic reclosing schemes shall be considered.

R 6.3 - Change to read "Planning Coordinators of neighboring impacted areas".

Table 1 3 b and c Extreme Event descriptions are vague concepts that cannot be practically simulated. 3 d and e are not reasonable or practically useful to simulate.

Table 1, P8 - Language needs to be clarifed as to how the 300 kV threshold is to be treated for transformers. Is this for the high side, low side, or both sides? P5 is much clearer.

Table 2 - Clarification needs to be made that the faults being simulated are permanent faults. This can be addressed under the "Performance Requirements" portion at the beginning of the table, or modify each fault description.

Table 2 P9. Recommend that this be changed to require that faults should be on different phases of each of two adjacent transmission circuits on a multiple circuit transmission tower

Table 1, P9(6) and Table 2 P9 - It is unclear as to what is meant by "A spare transformer inserted to replace an outaged transformer followed by System adjustments". Unclear as to what is to be tested.

General comment - Transmission System is used throughout the document and is an undefined term

The New England Transmission Owners and ISO New England transmission planners met several times to discuss the proposed standard and develop consensus comments based on our experience. The preceding comments are what was developed.

Attached to the e-mail sending these comments is the September 12 Draft 1 TPL-001-1 Reliability Standard in Word format, red-lined with changes to the posted standard which are intended to reflect all of the comments above. This document was maintained by Central Maine Power Company during the course of the New England transmission planner discussions, and any variance (though none are expected) in not intended.
It is expected that this red-lined TPL document will be helpful to the ATFN SDT in reviewing our comments.

Standard Development Roadmap, red-lined with New England Transmission Planners' comments

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Version 1 of SAR posted for comment from April 2, 2002 through May 3, 2002.
2. Version 2 of SAR posted for comment from May 5, 2004 through June 5, 2004.
3. Version 3 of SAR posted on November 18, 2005.
4. SAR approved on April 30, 2006.
5. Version 1 of Supplemental SAR posted for comment from February 15, 2007 through March 16, 2007.
6. Version 2 of Supplemental SAR posted on April 9, 2007.
7. Version 1 of revised standard(s) posted for comment on September 17, 2007.

Proposed Action Plan and Description of Current Draft:

The SDT has established an aggressive schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 2Q08. The current draft is the first iteration of the revision of existing standards TPL-001 through TPL-006 and includes one revised standard, TPL-001-1, replacing TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. TPL-005 & -006 will be addressed later in the project. Violation Risk Factors, Time Horizons, Measures, Compliance and Implementation Plans will be included in subsequent postings.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Respond to comments from first posting of standard(s) and submit revision 1 of the standard(s).	4Q2007
2. Respond to comments from second posting of standard(s) and submit revision 2 of the standard(s).	4Q2007
3. Submit revision 3 of the standard(s) for balloting.	4Q2007
4. Submit standard(s) for recirculation balloting.	2Q2008
5. Submit standard(s) to BOT.	2Q2008
6.	
7.	

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Base Case: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect Facility Ratings.

Consequential Load Loss: Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.

Extreme Events: Events which are more severe, and have a lower probability of occurrence, than Planning Events~~ and have a low probability of occurrence~~.

Long-Term ~~Transmission~~ Planning ~~Horizon~~Assessment: ~~Transmission~~ A ~~p~~Planning Assessment period that covers years six through ten or beyond.

Near-Term ~~Transmission~~ Planning ~~Horizon~~Assessment: ~~Transmission~~ A ~~P~~planning Assessment period that covers Years One through five.

Non-Consequential Load Loss: Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.

Planning Assessment: Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including ~~capital~~ reinforcements and operating procedures~~ and other factors, such as asset conditions and age~~.

Planning Events: Events ~~which require~~for which~~-~~ Transmission system performance requirements ~~to be~~must be met.

~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~

System Stability Study: Study of the System or portions of the System to ~~ensure that~~determine whether plant and system angular Stability is maintained, ~~inter-area~~ power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.

Year One: The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner ~~submits~~completes ~~their~~ its annual studies.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-1**

3. **Purpose:** Establish Transmission System planning performance requirements ~~within the planning horizon~~ to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of ~~probable~~ possible Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator

   4.1.2. Transmission Planner

   4.1.3. Resource Planner

   4.1.4. Load-Serving Entity

   4.1.5. Transmission Owner

   4.1.6. Generator Owner

5. **Effective Date:** TBD

B. Requirements

R1. **Modeling Requirements**

Each Resource Planner, Transmission Planner, Transmission Owner, Generator Owner, and Load-Serving Entity shall each provide its respective Planning Coordinator with the following modeling information that is required for System performance studies upon request (within 30 calendar days): *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

~~**R1.1.**~~Load forecasts and Load models adhering, at a minimum, to the requirements of MOD-011 and MOD-013.~~following criteria:~~

~~**R1.2.0.**Use of expected Load mix based on the actual or expected aggregate mix of industrial, commercial, and residential Loads.~~

~~**R1.3.0.**Based on normal weather patterns as agreed to by the Planning Coordinator(s) and the Transmission Planner(s) for the area(s) of their responsibility.~~

~~**R1.4.0.**Identification of Demand Side Management (DSM) Load reductions consistent with operational requirements.~~

~~**R1.2.**~~**R1.1.** ~~Load models with supporting rationale that include power factor data that may be based on historical System performance, validated by measurement during stressed System conditions, or documented Transmission planning area requirements.~~

~~**R1.3.**~~**R1.2.** Firm transfers/Interchange Schedules and resources required to supply Load for each Balancing Authority.

~~R1.4.~~R1.3. Known ~~planned outages and~~ long-term outages for Transmission and generation equipment ~~including protective relays~~ with consideration given to spare equipment ~~strategy~~.

~~R1.5.~~R1.4. Planned Facilities defined in accordance with the documented criteria of the Planning Coordinator, including but not limited to: Transmission Lines, generators, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies.

R2. Assessment and Corrective Plan Requirements

Each Transmission Planner and Planning Coordinator shall conduct and document the results of its annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, and shall cover steady state analyses, short circuit analyses, and Stability analyses ~~including both System and plant Stability~~.
[Violation Risk Factor: TBD] [Time Horizon: TBD]

R2.1. The steady state portion of the Near-Term ~~Transmission Planning Horizon~~ Planning Assessment shall ~~address all five years of the assessment period and~~ be conducted annually and supported ~~at a minimum~~ by ~~the following annual~~ current studies ~~, supplemented with qualified~~or past studies as ~~shown~~ indicated in Requirement R2.5~~6~~:

R2.1.1. System P~~p~~eak ~~Load~~ Demand for year five; and either Year One or year two if a significant unexpected change in the System occurs~~, and year five~~.

R2.1.2. System Off-Peak Load for one of the five years.

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity ~~case(s)~~testing that stresses the System ~~with sensitivities that reflect one or more of the following conditions~~ shall be ~~run~~ considered, and documentation with the rationale for the ~~selected~~ sensitivity ~~(ies)~~testing shall be supplied.~~:~~ The sensitivity case(s) may include one or more of the following conditions:

R.2.1.3.1. Higher or lower Load forecasts from the Base Case with variability of Load~~/demand~~ and Load power factors due to season, weather, or time of day.

R.2.1.3.2. Modification of expected transfers.

R.2.1.3.3. Unavailability of planned long lead time facilities.

R.2.1.3.4. ~~Variability and o~~Outages of reactive resources.

R.2.1.3.5. Generation additions, retirements, or other dispatch scenarios.

R.2.1.3.6. Decreased effectiveness of controllable Loads and Demand Side Management.

R.2.1.3.7. A change in known long-term outages for Transmission and generation equipment, per R1.3.~~Modification of planned Transmission outages~~.

R2.2. ~~For the steady state portion of the Long-Term Transmission Planning Horizon Planning Assessment, at a minimum, a current System peak Load study is required annually for one of the years in the assessment period to support the annual Planning Assessment.~~ The steady state portion of the Long-Term Planning Assessment shall be conducted annually and supported by a System peak Load study or a past study as indicated in Requirement R2.5:

R2.2.1. If ~~To accommodate~~ any known ~~longer lead time~~ projects ~~that may take~~ have a lead time longer than ten years to complete, then the Planning Assessment shall be extended accordingly.

R2.3. The short circuit portion of the Planning Assessment shall be conducted annually and ~~shall be~~ supported by a current study or a past study as indicated in Requirement R2.5:~~ies~~.

R2.3.1. A current study shall be performed if changes in the BES result in increased fault currents such as resource additions and other facility changes that result in reductions in impedance.

R2.4. ~~The System Stability portion of the Near-Term Transmission Planning Horizon Planning Assessment shall address all five years of the assessment period and be supported by current or past studies. The following studies are required:~~ The System Stability portion of the Near-Term Planning Assessment shall be conducted annually and supported by current studies or past studies as indicated in Requirement R2.5:

R2.4.1. System ~~P~~peak ~~Load~~ Demand for one of the five years. ~~For peak System Load levels, the Load model shall include the dynamic effects of induction motor Loads.~~

R2.4.2. System Off-Peak Load for one of the five years.

R2.4.3. Sensitivity ~~case(s)~~testing that stresses the System ~~to reflect one or more of the following conditions~~ shall be ~~run~~ considered, and ~~with~~ documentation with ~~provided explaining~~ the rationale for the ~~selected~~ sensitivity testing shall be supplied~~(ies)~~. The sensitivity case(s) may include one or more of the following conditions:

R.2.4.3.1. Higher or lower Load forecasts from the Base Case with variability of Load and Load power factors due to season, weather, or time of day.

R.2.4.3.2. Modification of expected transfers.

R.2.4.3.3. Unavailability of planned long lead time facilities.

R.2.4.3.4. Outages of reactive resources.

R.2.4.3.5. Generation additions, retirements, or other dispatch scenarios.

R.2.4.3.6. Decreased effectiveness of controllable Loads and Demand Side Management.

R.2.4.3.7. A change in known long-term outages for Transmission and generation equipment, per R1.3.

~~R.2.4.3.1.~~R.2.4.3.8. -Variations in Load model assumptions.

~~R.2.5.0.0. Expected simultaneous transfers including non-firm transfers.~~

~~R.2.6.0.0. Unavailability of long lead time facilities.~~

~~R.2.7.0.0. Reactive dispatch of generators and other reactive power devices.~~

~~R.2.8.0.0. Generation additions, retirements, or other dispatch scenarios.~~

~~R2.9.The plant Stability portion of the Planning Assessment shall be analyzed consistent with Requirement R4.6 with studies for the year when the following occur:~~

~~R2.10.0.New generator(s) are added or generation modifications are made such as increasing generation capability, replacing the exciter or addition of a power System stabilizer.~~

~~R2.11.0.Material changes in the electrical vicinity of existing generation are made such as the addition or removal of a Transmission Line at or near the point of Interconnection.~~

~~R2.6.~~R2.5. Past studies may be used to support the Planning Assessment if they meet the following requirements:

~~R2.6.1.~~R2.5.1. For steady state analysis: if the study is less than ~~three~~ five years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals~~, and market structure changes~~.

~~R2.6.2.~~R2.5.2. For short circuit analysis: if the study is less than five years old and no material changes have occurred to the System in the intervening period.

~~R2.6.3.~~R2.5.3. For ~~plant and~~ System Stability analysis: until material changes in the System make the study no longer valid. Material changes in the system include the addition of a Transmission Line or a generator.

~~R2.7.~~R2.6. For Planning Events shown in Table 1 – Steady State Performance and Table 2 – Stability Performance, when the analysis indicates an inability of the System to meet the performance requirements in the tables, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans that are ~~allowed~~ made over time ~~but~~ shall meet the performance requirements in the tables. Such plans shall:

~~R2.7.1.~~R2.6.1. Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission projects and/or other changes ~~generation improvements, DSM, new technologies~~, or Operating Procedures including the duration of interim Operating Procedures.

R.2.6.1.1. For the Near-Term ~~Transmission~~ Planning ~~Horizon~~Assessment, ~~include both a project initiation date as well as an~~provide an in-service date.

R.2.6.1.2. For the Long-Term ~~Transmission~~ Planning ~~Horizon~~Assessment, provide an in-service year.

~~R2.7.2.~~R2.6.2. Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables.

~~R2.7.3.~~R2.6.3. Include documentation of the criteria for determining committed and proposed projects with all projects identified as either 'committed' or 'proposed.'

~~R2.7.4.~~R2.6.4. Not remove committed projects without documentation to show that the revised plan meets the performance requirements.

~~R2.7.5.~~R2.6.5. Be reviewed in subsequent annual Planning Assessments as to implementation status of identified System Facilities and Operating Procedures.

R3. Steady State Analysis Requirements

For the steady state portion of the Near-Term and Long-Term Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the ~~Near-Term and Long-Term Transmission Planning Horizon~~ studies in Requirement R2.1 and Requirement R2.2. The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to contingencies in Table 1 – Steady State Performance. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R3.1. Studies shall determine whether the BES meets the performance requirements in Table 1 – Steady State Performance.

R3.2. Contingency analyses shall simulate the removal of all elements ~~including those~~which ~~that~~ Protection Systems ~~protection is~~are expected to disconnect for each Contingency without operator intervention, and shall simulate automatic sectionalizing schemes.

~~R3.2.1.For all generators, studies shall consider the minimum steady state voltage limitations of all generators and identify how the generators are treated in the steady state simulation.~~

~~R3.2.2.For all Transmission lines, studies shall consider relay loadability and identify how loadability is treated in the steady state simulation.~~

R3.3. Studies shall identify any planned upgrades (including protection and control modifications) needed to meet the performance requirements of the Planning Events of Table 1 – Steady State Performance and validate their effectiveness.

~~R3.3.~~R3.4. For s~~S~~teady s~~S~~tate studies:

~~R3.3.1.~~R3.4.1. Performance ~~criteria~~ requirements for System normal conditions and for Planning Events in Table 1 – Steady State Performance shall be met.

~~R3.3.2.~~R3.4.2. Evaluations shall be performed for single Contingencies (identified in Table 1 – Steady State Performance).

~~R.3.3.2.1.~~R.3.4.2.1. Consequential Load loss (expected maximum demand~~ and expected duration~~) following a single Contingency shall be identified in the Planning Assessment.

~~R.3.3.2.2.~~R.3.4.2.2. Following single Contingency events, System adjustments other than shedding of firm Load [this is inconsistent with Table 1 event P6] or curtailment of firm transfers[DMC1] are permitted to meet performance requirements provided these adjustments can be accomplished within the time period allowed by the applicable time limited ratings.

~~R3.3.3.~~R3.4.3. Those ~~Planning Event Contingencies in Table 1 – Steady State Performance not covered in Requirement R3.3.2~~multiple Contingencies that are expected to produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results

~~R3.4.~~R3.5. Those Extreme Events in Table 1 – Steady State Performance that are expected to produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. ~~If the Extreme Events analysis concludes there are Cascading Outages caused by the occurrence of Extreme Events, an evaluation of implementing a change designed to reduce or mitigate the likelihood of such consequences shall be conducted.~~

~~R3.5.~~R3.6. Manual and automatic generation run-back and/or generation tripping is allowed as a response to single and multiple Contingencies as long as ~~Facility Ratings are not exceeded~~the performance requirements of this standard are met.~~.~~

~~R4.0.Manual and automatic generation tripping is allowed for multiple Contingencies and for single Contingencies only in situations that meet all of the following conditions:~~

~~R5.0.0.TBD~~

~~Note: WECC has informed the SDT that it will be submitting an Interconnection-wide regional variance to allow for manual and automatic generation tripping for single Contingencies. The regional variance will be justified based on physical System differences in the western Interconnection. WECC is developing a white paper to support this position. The actual text of the regional variance will be included in the next posting of this standard.~~

R4. Stability Analysis Requirements

For the Stability portion of the Near-Term Planning Assessment, ~~as described in Requirement R2.4 and Requirement R2.5,~~ each Transmission Planner and Planning Coordinator shall perform the ~~Contingency~~ analysi~~e~~s for the studies as described in Requirement R2.4. The studies shall be based on computer dynamic simulations that

analyze BES System response to contingencies listed in Table 2 – Stability Performance. ~~The studies shall cover both System Stability and plant Stability. The following requirements apply to both System Stability and plant Stability studies unless otherwise noted.~~ *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R4.1. Studies shall determine whether the BES meets~~to meet~~ the performance requirements in Table 2 – Stability Performance~~ shall use computer Stability simulations that analyze the response of the BES~~.

R4.2. Contingency analyses shall simulate the removal of all elements ~~including~~ which ~~those that~~ Protection Systems ~~protection is~~are expected to disconnect for each Contingency without operator intervention, and shall simulate automatic reclosing schemes.

~~**R7.3.**Studies shall consider the voltage ride through capability of all generators and identify how the generators are treated in the simulation.~~

~~**R4.4.**~~**R4.3.** Studies shall identify any planned upgrades (including protection and control modifications) needed to meet the performance requirements of the Planning Events of Table 2 – Stability Performance and validate their effectiveness.

~~**R4.5.**~~**R4.4.** For the System Stability S~~s~~tudy:

~~**R4.5.1.**~~**R4.4.1.** ~~At a minimum,~~T ~~t~~hose Planning Events ~~Contingencies~~ in Table 2 – Stability Performance that ~~would~~ are expected to produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results.

~~**R4.5.2.**~~**R4.4.2.** ~~At a minimum,~~T ~~t~~hose Extreme Events in Table 2 – Stability Performance that are expected to ~~would~~ produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. ~~If the Extreme Events analysis concludes there are Cascading Outages, an evaluation of implementing a change designed to reduce or mitigate the likelihood of such consequences shall be conducted.~~

~~**R8.**For the Plant Stability studies:~~

~~**R9.**Shall be performed for individual generating units 20 MW or greater directly connected through a step-up transformer to the BES and for generating units at the same location which total 75 MW or greater, directly connected through their step-up transformer(s) to the BES.~~

~~**R10.**Shall be performed for changes in the real power output of a generating unit by more than 10% of the existing capability or more than 20 MW whichever is greater.~~

~~**R11.**Shall be performed and evaluated for those Planning Events that would produce more severe System impacts shall be identified and the rationale for the Contingencies~~

~~selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. The identified Contingencies, at a minimum, shall be evaluated.~~

~~**R12.** Shall meet Performance requirements for Planning Events in Table 2 – Stability Performance.~~

R5. Each Transmission Planner and Planning Coordinator shall determine and identify individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R6. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among affected entities, coordinating analysis of these results through an open and transparent peer review process. *[Violation Risk Factor: TBD] [Time Horizon: TBD]* This distribution shall include:

R6.1. Transmission Planners within the Planning Coordinator's area

R6.2. Transmission Planners of neighboring impacted areas

R6.3. Planning Coordinators of neighboring impacted areas

Table 1 – Steady State Performance

Performance Requirements

For all Planning Events:

- Equipment Ratings shall not be exceeded
- System steady state voltages and post-transient voltage deviation shall be within acceptable limits established by the Planning Coordinator (or Transmission Planner if more restrictive)
- Voltage instability, cascading outages, and uncontrolled islanding shall not occur
- Consequential Load loss is allowed for all cases shown.
- Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency.
- Simulate Normal Clearing unless otherwise specified.

Planning Events			
#	**Event**	**Interruption of Firm Transfer Allowed (does not result in loss of Load)**	**Non-Consequential Load Loss Allowed**
P0	All transmission facilities in service	No	No
P1 (single Contingency)	Loss of: **1.** A generator **2.** A Transmission circuit **3.** A transformer 4. A shunt device (including FACTS devices)	Yes, if transfer is dependent on the outaged element No otherwise	No
P2 (single Contingency)	Loss of: 1. Bus section above 300kV 2. ~~Non-bus tie b~~Breaker (above 300kV) due to internal fault ~~3.~~Single pole of a DC line 3.	Yes, if transfer is dependent on the outaged ~~DC line~~element No otherwise	No
P3 (multiple Contingency)	Loss of either a: 1. A generator, 2. A Transmission circuit, 3. A~~a~~ transformer with low side voltage rating above 300 kV, or 4. A~~a~~ bus; **and** -a stuck ~~non-bus tie~~ breaker (above 300kV)	Yes, if transfer is dependent on the outaged ~~DC line~~element No otherwise	No
P4 (multiple Contingency)	1. Loss of a generator followed by a System adjustment followed by the loss of a generator. 2. Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line 3. Loss of a generator followed by a System adjustment followed by the loss of a Transmission circuit	Yes, if transfer is dependent on the outaged ~~DC line~~element No otherwise	~~No~~Yes

	4. Loss of a generator followed by a System adjustment followed by the loss of a transformer		
P5 (multiple Contingency)	Above 300kV, the loss of: 1. A Transmission circuit followed by a System adjustment followed by the loss of another Transmission circuit 2. A Transmission circuit followed by a System adjustment followed by the loss of a transformer with low side voltage rating above 300 kV **3.** A transformer with low side voltage rating above 300 kV followed by a System adjustment followed by the loss of another transformer	Yes	~~No~~Yes
P6 (single Contingency)	Loss of: 1. A ~~bus tie~~ breaker due to internal fault 2. A bipolar DC line or an asynchronous ~~tie line~~interconnection 3. A ~~non-bus tie~~ breaker (below 300kV) due to internal fault 4. A bus section below 300kV	Yes	Yes
P7 (multiple Contingency)	Loss of: 1. A bus section above 300kV and a stuck ~~bus tie~~ breaker 2. Either a generator, a Transmission circuit, a transformer, or a bus and a stuck ~~non-bus tie~~ breaker (below 300kV)	Yes	Yes
P8 (multiple Contingency)	Below 300kV, the loss of: 1. A Transmission circuit followed by a System adjustment followed by the loss of another Transmission circuit 2. A Transmission circuit followed by a System adjustment followed by the loss of a transformer 3. A transformer followed by a System adjustment followed by the loss of another transformer	Yes	Yes
P9 (multiple Contingency)	1. Loss of any two circuits on a common structure (excluding where multiple circuits share a common structure for no more than one mile) 2. Loss of a generator followed by a System adjustment followed by the loss of a monopolar or bipolar DC line, or an asynchronous ~~tie line~~interconnection 3. Loss of a DC line (monopolar or bipolar) or asynchronous ~~tie~~ interconnection followed by a System adjustment followed by the loss of a second DC line (monopolar or bipolar) or asynchronous ~~tie~~ interconnection 4. Loss of a DC line (monopolar or bipolar) or asynchronous ~~tie~~ interconnection followed by a System	Yes	Yes

	adjustment followed by the loss of a Transmission circuit 5. Loss of a transformer followed by a System adjustment followed by the loss of a DC line (monopolar or bipolar) or asynchronous ~~tie line~~interconnection 6. Loss of a transformer followed by a System adjustment with a spare transformer available followed by the loss of another transformer		

Extreme Events

Evaluation Requirements

For all Extreme Events:

1. See Requirement R3.5~~4~~
2. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency.
3. Simulate Normal Clearing unless otherwise specified.

Extreme Event Descriptions

1. Loss of a single generator, Transmission circuit, DC line, or transformer forced out of service followed by another single generator, Transmission circuit, DC line, or transformer forced out of service prior to System adjustments.

2. Local area events affecting the Transmission System such as:

- **a.** Loss of tower line with three or more circuits
- b. Loss of all Transmission lines on a common right-of-way
- c. Loss of switching station or substation (loss of one voltage level plus transformers)
- d. Loss of all generating units at a station
- **e.** Loss of a large Load or major Load center

3. Wide area events affecting the Transmission System such as:

- a. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation
- ~~b.A successful cyber attack~~
- ~~c.Regulation that restricts or eliminates the use of a river or lake or other body of water as the cooling source for generation~~
- ~~d.Shutdown of a nuclear power plant(s) and other facilities a day or more prior to a hurricane, tornado or wildfire, or for other common causes~~
- ~~e.Regulation that restricts or eliminates the use of a river or lake or other body of water as the cooling source for generation~~
- ~~f.~~b. Shutdown of a nuclear power plant(s) and other facilities a day or more prior to a hurricane, tornado or wildfire, or for other common causes such as problems with similarly designed plants
- ~~g.~~c. The loss of older Transmission lines which may not be constructed to meet an entity's present radial ice or wind loading requirements, while the newer or stronger Transmission lines remain in service
- ~~h.~~d. Other events based upon operating experience

Table 2 – Stability Performance Table

Performance Requirements

For all Planning Events:

- The System shall be stable[1]
- Dynamic voltages shall be within acceptable limits established by the Planning Coordinator or Transmission Planner (if more restrictive)
- Uncontrolled islanding and Cascading Outages shall not occur
- Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency.
- Simulate permanent Faults with Normal Clearing unless otherwise specified.

Planning Events			
#	**Initial Condition**	**Event**	**Non-Consequential Load Loss Allowed**
P1 (single Contingency)	System normal	Single Line Ground (SLG) fault on, a 3-Phase (3Ø) fault on, or an unexpected loss without a fault of (whichever is worst): 1. A generator 2. A Transmission circuit ~~3.~~3. A transformer	No
P2 (single Contingency)	System normal	1. SLG fault on bus section above 300kV 2. SLG internal fault in ~~non-bus tie~~ breaker (above 300kV) 3. A single pole block of a DC line	No
P3 (multiple Contingency)	System normal	SLG fault on either a 1. A generator, 2. A Transmission circuit, 3. A~~a~~ transformer, or 4. A~~a~~ bus **and** a stuck[2] ~~non-bus tie~~ breaker (above 300kV)[DMC2]	No
P4 (multiple Contingency)	A single generator out of service followed by System adjustments	1. Apply a P1.1 Contingency. 2. Apply a P2.3 Contingency. 3. Apply a P1.2 Contingency. 4. Apply a P1.3 Contingency.	No
P5 (multiple Contingency)	A Transmission circuit above 300 kV out of service followed by System adjustments A transformer with low side voltage rating above 300 kV	1. Apply a P1.2 Contingency. 2. Apply a P1.3 Contingency. 3. Apply a P1.3 Contingency.[DMC3]	No

	out of service followed by System adjustments		
P6 (single Contingency)	System normal	1. SLG internal fault in ~~bus tie~~ breaker 2. A bipolar block of a DC line ~~1.~~3. SLG internal fault in ~~non-bus tie~~ breaker (below 300kV) 4. SLG fault on bus section (below 300kV)	Yes
P7 (multiple Contingency)	System normal	1. SLG fault on a bus section above 300kV and a stuck ~~bus tie~~ breaker 2. SLG fault on either a generator, a Transmission circuit, a transformer, or a bus and a stuck ~~non-bus tie~~ breaker (below 300kV)	Yes
P8 (multiple Contingency)	A Transmission circuit below 300 kV out of service followed by System adjustments A transformer with low side voltage rating below 300 kV out of service followed by System adjustments	1. Apply a P1.2 Contingency. 2. Apply a P1.3 Contingency. 3. Apply a P1.3 Contingency. [DMC4]	Yes
P9 (multiple Contingency)	System normal A single generator out of service followed by System adjustments A DC circuit out of service followed by System adjustments A transformer out of service followed by System adjustments	1. SLG fault on each circuit of ~~any~~ two adjacent circuits on a common structure (excluding events where multiple circuits share a common structure for no more than one mile). 2. Apply a P6.2 Contingency. 3. Apply a P2.3 Contingency. 4. Apply a P1.2 Contingency. 5. Apply a P2.3 Contingency.	Yes

	A spare transformer inserted to replace an outaged transformer followed by System adjustments	6. Apply a P1.3 Contingency. [DMC5]	

Extreme Events

Evaluation Requirements

For all Extreme Events:

- See Requirement R4.~~5~~4.2 in the text
- Simulate the removal of all elements that Protection Systems ~~protection~~ and controls are expected to disconnect for each Contingency.
- Simulate Normal Clearing unless otherwise specified.

Extreme Event Descriptions

1. 3Ø fault on generator with stuck breaker
2. 3Ø fault on Transmission circuit with stuck breaker
3. 3Ø fault on transformer with stuck breaker
4. 3Ø fault on bus section with stuck breaker
5. 3Ø internal fault in breaker
6. 3Ø fault on two or more circuits on a common structure
7. SLG or 3Ø fault on all Transmission lines on a common right-of-way
8. 3Ø fault on switching station or substation (loss of one voltage level plus transformers)
9. 3Ø fault with loss of all generating units at a station

Notes:

1. System stable means:
   a. Angular stability:
      i. For Planning Events P1 and P3.2: No generating unit or units shall be allowed to pull out of synchronism. A generator being disconnected from the system by fault clearing action or by a Special Protection ~~Scheme~~ System is not considered pulling out of synchronism.
      ii. For all other Planning Events: No generating unit or units totaling more than the contingency reserve (spinning reserve) of the Balancing Authority shall be allowed to pull out of synchronism. Generators that pull out of synchronism must have ~~out-of-step protection and the~~ resulting apparent impedance swings ~~must~~ that do not pass through relay characteristics that would result in the tripping of any T~~t~~ransmission system elements other than the generating unit and its direct connection facilities.

iii. For all Planning Events: Power oscillations shall exhibit acceptable damping~~ as established by the Planning Coordinator or Transmission Planner (if more restrictive)~~.

b. General: Unplanned islanding of portions of the system shall not occur for Planning Events.

2. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) breaker, only one pole is assumed to remain closed.

~~3.~~C. Measures

M1. To be supplied at a later date.

E. Regional Variances

1. WECC Interconnection-wide waiver is under development (see Requirement R3.6.2).

Version History

Version	Date	Action	Change Tracking
1		Revision of TPL-001-0 as per Project 2006-02; includes merging requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-1	Not employed due to scope of revision

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☒ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: The manner in which the forecasted bus load is determined needs to be defined with clear and consistent assumptions and methodologies such that the results of transmission studies are reasonably valid throughout the entire planning horizon.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	

Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☐Do not agree.
Q7. **Comment: : Definition should be more clearly defined. Documented evaluation of future Bulk Electric System needs based on the performance requirements as defined for NERC Steady State Transmission Studies or Plant Stability Studies conducted in accordance with the NERC Reliability Standards or more restrictive local area criteria.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Minimum performance requirements need to be clearly defined.**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the

rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☒ No ☐
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☒ No ☐
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐

Comment: : Controllable demand that will be available to both the planner and operator must be well defined and readily available when called upon including operating procedures.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐

Comment: : Corrective action plans must be appropriately modeled in order to verify that implementing the plans results in a BES that will perform based on the applicable NERC Reliability Standards or more restrictive local area criteria.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐

Comment: : Definitions of both “committed” and “proposed” are needed.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐

Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to “raise the bar.” Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☐Do not agree.	Would like to see more explanation for the these scenarios.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

[1] System adjustment can be manual or automatic

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency

ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: Requirement R3.2: Contingency analyses representing only the removal of elements that System protection is expected to automatically disconnect which includes Consequential Load Loss is a reduction in reliability. Excluding the contingency analyses between all elements including those with manually operated switches will result in lowering existing reliability standards and ultimately limit the load restoration capabilities of the BES. Minimum performance standards should be adhered to for all applicable contingencies including outages of elements that may be switched both automatically and manually taking into account controlled load curtailment that is allowed.
Requirement R3.3.2.1: The expected duration of Consequential Load Loss was noted to be required in a Planning Assessment following a single Contingency without any indication as to the assumed cause of the outage. The basis for such estimations of time needs to be defined such that these assessments are developed on a consistent basis.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Karl Kohlrus	
Organization:	City Water, Light & Power - Springfield, Illinois	
Telephone:	217-321-1391	
E-mail:	karl.kohlrus@cwlp.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☒	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

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Q1. **Comment: This should not be a defined term in the Glossary, instead there should be a Standard that provides the industry with the requirements for completing a Base Case Study.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment: This could be load lost which is on a radial line or load served by facilites which do not have fault-interrupting breakers.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: More needs to be added here, especially to define the phrase "low probability of occurrence". Does this refer to N-1, N-2, N-3 etc.? We have a 300 foot long interconnection line between two substations. In this case even N-1 has a low probability of occurrence. This N-1 event has a much lower probability of occurrence than an N-2 event which involves generator outages. We also have an N-1 SPS event which hasn't occurred in 25 years.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	

Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: This definition should go beyond just saying "Load loss other than Consequential Load Loss." Recommend adding the following: " . . . including Load Loss that occurs through planned manual (Transmission Operator, Distribution Provider, and so-on) operation or planned automatic operation of load shedding equipment such as under-frequency Load shedding devices or Special Protection Systems."**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: This definition is too vague. A Planning Assessment should cover the Near-Term or Long-Term Planning Horizon and include Base Case and Contingency Analysis according to NERC Standards.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: This statement is too general. Performance Requirements are not defined.**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Insert "Generating" prior to "Plant" for clarity.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☐Do not agree.
Q10. **Comment:**	
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- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☒ No ☐
Comment: The term Base Case should not be used in this manner. The conditions of the Base Case Study should be in a Standard to insure that all sensitivity cases are covered.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☒ No ☐
Comment: The Standard should indicate a list which says "the list will include but not be limited to:" then list the minimum changes necessary to adequately cover the changes in the study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒
Comment: The requirement for sensitivity studies multiplies the study efforts. It will be burdensome especially when interregional studies are performed. It is better to have quality than quantity.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒
Comment: DSM is not always available and is usually not available without operator action. Therefore, asuming it is alwasys available could give a false sense of security. The system could collapse before DSM is able to be implemented..

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: The system should be retested with new facilities in place to ensure that no new problems arise with the addition of new facilities.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment: "Committed" and "proposed" projects need to be defined.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed	☒Agree. ☐Do not agree.	

by System adjustment followed by loss of another transformer		

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	

[1] System adjustment can be manual or automatic

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐
Comment: If there is any single contingency event that could take out an entire plant, it should be studied.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment: However, low voltage often causes motors and air conditioner compressors to trip, significantly reducing peak loads.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Dispatching quick start units such as combustion turbines or diesels, Contingency Reserve Sharing Group response, redispatch, adjust reactive resources as necessary.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Coordination with neighboring systems is essential when considering generation redispatch.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☒
Comment: SPS use should be limited and SPS's should be of a temporary nature. A mitigation plan with a timeframe for implementation should accompany all SPS's and RAS's.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: See above.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: Maintain system stability, prevent loss of load and prevent cascading outages.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☐ No ☐
Comment: The Standards are a great start in getting a set of requirements in place that will provide a planning methodology that will be transparent to the Functional entities in the interconnections and will produce results that will permit reliable planning and operations of the BES.
The SDY should remove all Requirements that are subjective and can't be measured.
The assumptions the Transmission Planners and Planning Coordinators use to conduct the studies should be posted.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Blake Williams	
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☒ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: Firm transaction obligations are not used throughout all regions in NERC. Change "including firm transaction obligations" to "including firm transaction obligations where applicable."**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	

Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☐Do not agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.

- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: The number of sensitivity studies should be at the discretion of Transmission Planners.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: The type of sensitivty studies should be at the discretion of Transmission Planners.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒
Comment: The number and type of sensitivity studies should be at the discretion of Transmission Planners.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☒
Comment: We concur with not requiring sensitivity studies for the Long Term Assessment.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in

conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒
Comment: Performance of the DSM is not necessarily controlled by the Transmission Owner and cannot be considered "firm". Therefore, use of DSM should be optional, but not mandated.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒
Comment: Should be conducted for Near Term Planning Assessment only with the study area determined at the discretion of the Transmission Planners.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: The treatment of each project should be at the dscretion of the Transmission Planners.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: The treatment of each project should be at the discretion of the Transmission Planners.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
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Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: Should be determined at the discretion of the Transmission Planners.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: Should be determined at the discretion of the Transmission Planners.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	Should be determined at the discretion of the Transmission Planners.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	Should be determined at the discretion of the Transmission Planners.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☒Do not agree.	Should be determined at the discretion of the Transmission Planners.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

[1] System adjustment can be manual or automatic

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☒
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment:

R1.1. This is a modeling requirement and should be incorporated into the modeling (MOD) standards. Remove or modify this requirement to eliminate any redundancy with existing modeling standards. If certain subrequirements of R1.1 of TPL-001 are not currently requirements in a MOD standard, it should be questioned, then, whether or not these specific subrequirements are actually needed in ANY standard.

R2.2. ERCOT does not study the Long-Term Planning Horizon because ERCOT does not believe it is necessary. Remove or modify to state "as applicable by region."

R2.7.1.1 Duration of projects vary between Transmission Owners and statement of the project initiation date has no value to reliability.

R3.3.2 Relay loadability is considered as an MLSE component to the circuit rating as identified in MOD-008 and MOD-009.

R3.3.2.1. The requirement to identify consequential load loss for single contingencies in the Planning Assessment is unnecessary and burdensome and should be removed.

R3.6 Automatic generation tripping should be allowed for radial-connected wind resources.

Table 1 - P6.1, P6.3, and P6.4 These events are triggered by a single credible event and should not allow for loss of Non-Consequential Load.

Table 1 - P9.1 Loss of double-circuit tower lines are triggered by a single credible event and should not allow for loss of Non-Consequential Load.

Table 1 and Table 2 - P4, P5, P8, and P9. Including all combinations of two components (generator, Transmission circuit, transformer) with generation adjustments is impractical and overly burdensome. For multiple contingencies, include only double-circuit tower lines and the two components (generator, Transmission circuit, transformer) that would be cleared by breaker failure.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☒ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☒	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

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Ashwani Vaswani	Dominion - Electric Transmission Load Planning	SERC	1
Mehdi Shakibafar	Dominion - Electric Transmission Interconnection Planning	SERC	1
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Al MacDonald	Dominion - Electric Transmission Operations Planning	SERC	1

William Bigdely	Dominion - Electric Transmission Load Planning	SERC	1
Ronnie Bailey	Dominion Manager - Electric Transmission Planning	SERC	1

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than	☒Agree.

Planning Events and have a low probability of occurrence.	☒Do not agree.
Q3. **Comment: To make this "crisp", it is suggested that this definition be extended as "Events which .....occurrence. The Transmission system performance requirements do not apply to extreme events".**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☒Do not agree.
Q7. **Comment: Suggest to change "...by the use of performance studies that cover....." to "...by the use of past or current performance studies that cover.....".**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the	☒Agree. ☐Do not agree.

study publication are assumed to be conducted under the auspices of Operations Planning.	
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: Transmission Planning engineers have good engineering judgment and need to have some flexibility in selecting the variables that need to be studied.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: Transmission Planning engineers have good engineering judgment and need to have some flexibility in selecting the variables that need to be studied.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒

Comment: Not all the items listed under "B. Sensitivity Studies" may be applicable to stability analysis and also depends on type of stability analysis (Plant/System; angular/voltage). For instance, in some locations stability margins are wide. In such cases, practical experience has shown that such sensitivity analysis is unnecessary. Therefore, this should be applied as applicable, at the engineering judgment of the planning engineers rather than be required by the Standards. In summary, R2.4.3 should be eliminated entirely.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: We concur that no sensitivity studies should be required for the LT planning horizon.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: An appropriate level of DSM should be included in studies.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒
Comment: In the normal course of business, a planner out of necessity will need to check to see if the proposed improvements will actually fix the problem. The prospect of making a multi-million dollar mistake is sufficient incentive to insure this study occurs without the additional burden of creating an audit trail to meet a NERC standard.

Requirements for what study area should be used and documentation of the process are not necessary. If, per chance, a study is not performed immediately, the next set of studies will show the deficiencies, if any.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐

Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒

Comment: We are of the opinion that committed projects could be removed without documentation. Once a project is removed, the next set of studies will show the deficiencies, if any.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for	☐Agree.	Usually, this type of outage will not involve non-consequential load loss,

stability) above 300 kV	☒Do not agree.	however, there may be specific situations where local non-consequential load loss could be justified. This is consistent with how transmission systems have been designed for many years and approved by State commissions. Transmission Owners need to have some flexibility to balance grid reliability vs. cost to the ratepayer. In some instances, the expense required to eliminate all local non-consequential load loss cannot always be justified if there is no significant improvement in wide area bulk power system reliability. In other words, making the standards more stringent by "raising the bar" is not going to result in a dramatic improvement in system reliability. Even the best designed systems are susceptible to human error. Dominion has at least 5 years of transmission outage data clearly illustrating that any resulting loss of load (both consequential and non-consequential) has had an average duration of only 4-7 customer-minutes per year. Going forward, the emphasis and focus should be on planning and operating the bulk electric system so as to confine any transmission outages to the immediate, local area, and not allow the cascading of outages beyond control area boundaries.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	See comment for Question 20 above.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	See comment for Question 20 above.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment	☐Agree. ☒Do not agree.	See comment for Question 20 above.

followed by loss of another transformer		

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: See comment for Question 20 above.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: See comment for Question 20 above.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	Dominion agrees with these proposed standards as they are relatively higher probability events and reflect very closely to the Company's internal planning criteria.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	Although we do not have any DC lines, Dominion agrees with these proposed standards as they are relatively higher probability events and reflect very closely to the Company's internal planning criteria.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	Dominion agrees with these proposed standards as they are relatively higher probability events and reflect very closely to the Company's internal planning criteria.
Q29. P4-4: Loss of a generator followed by System adjustment followed	☒Agree. ☐Do not agree.	Dominion agrees with these proposed standards as they are relatively higher probability events and reflect very

[1] System adjustment can be manual or automatic

by loss of a transformer with low side voltage rating above 300 kV		closely to the Company's internal planning criteria.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment: Not applicable since Dominion has no DC lines

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: More clarification is needed to distinguish the difference in studies performed for plant stability vs. system stability. For example, is a system study mainly a study of inter-area (i.e. - small signal) oscillations?

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: It is unlikely that all units at a plant would trip simultaneously within a short time frame (20 second or so) for which stability simulations are performed.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☒
Comment: The dynamic effects of induction motor load at peak load conditions should be studied only on a limited/selected basis and should not be required for the entire system as a routine study practice. The following are examples where such an effort might be warranted:

(a) where slow voltage recovery has been actually observed in the field following a fault clearance
(b) where steady state analysis (P-V & Q-V curves) indicates a possible voltage collapse scenario for stressed system conditions
(c) for a non-convergent (or very difficult to solve) power-flow case for stressed system conditions while solving for a contingency scenario

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: For a single contingency, no generation adjustment should be allowed. For multiple transmission element contingencies, generation reduction (automatic or manual runback) may be allowed. Unit trip should only be allowed if a unit becomes unstable.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☐ No ☒
Comment: For a single contingency, no generation adjustment should be allowed. For multiple transmission element contingencies, generation reduction (automatic or manual runback) may be allowed. Unit trip should only be allowed if a unit becomes unstable.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☒
Comment: For a single contingency, no generation adjustment should be allowed. For multiple transmission element contingencies, generation reduction (automatic or manual runback) may be allowed. Unit trip should only be allowed if a unit becomes unstable.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: For single contingency events, a SPS scheme should not result in loss of load.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☒ No ☐
Comment: Current planning criteria are approved by State commissions. It is unlikely that the commissions would agree that rate payers should incur the significant cost increases required to meet more stringent planning criteria (i.e. - "raising the bar") when the corresponding improvements in transmission system reliability cannot be quantified.

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment:

GENERAL COMMENTS:

(1) Making the standards more stringent by "raising the bar" is not going to result in a dramatic improvement in system reliability. Even the best designed systems are susceptible to human error. Dominion has at least 5 years of transmission outage data clearly illustrating that any resulting loss of load (both consequential and non-consequential) has had an average duration of only 4-7 customer-minutes per year. Going forward, the emphasis and focus should be on planning and operating the bulk electric system so as to confine any transmission outages to the immediate, local area, and not allow the cascading of outages beyond control area boundaries.

(2) Although we are unable to put specific numbers on the impact of "raising the bar "with respect to non-consequential load loss, it will be enormous. Increased staffing levels may be required, and we would likely incur significant increased transmission maintenance and construction costs. It is likely that State commissions everywhere (not just Virginia) would agree that rate payers should not incur the significant cost increases required to meet more stringent planning criteria (i.e. - "raising the bar") when the corresponding improvements in transmission system reliability cannot be quantified.

SPECIFIC COMMENTS PERTAINING TO REFERENCED SECTIONS OF THE STANDARD:

(1) The last block in Category C of Table 1 of the existing standards deals with protection system failure. We interpreted this as, among other things, having a fault beyond the first-zone coverage of the primary protection scheme with the carrier equipment failure resulting in a second-zone trip of the faulted line (even though only one element will be lost). The second-zone trip time is generally in the range of 30-35 cycles. This may be critical from the stability aspect. The proposed Table 2 of TPL-001-1 is silent about this. Is there a reason why this requirement was left out?

(2) The requirement R4.6.2 may cause some confusion due to the last part "….whichever is greater". It is suggested that the entire wording for this requirement be replaced as listed below to avoid any misunderstanding.

"Shall be performed for changes in the real power output of a generating unit if either of the following applies:
(a) the increase is more than 10 % of the existing capacity (regardless of the amount of MW increase)
(b) the increase is more than 20 MW (regardless of the % increase).

Something to think about regarding a cut-off limit of 10% or 20 MW:

We had a unit with 800 MW existing capacity and the request was to increase it by 15 MW making the total new capacity of 815 MW. The requested increase was less than 10% of the existing capacity and also less than 20 MW, meaning the plant stability study is not required. However, we found that the increase of 15 MW made the plant unstable and we had to come up with a solution (and we did). This example warrants to include something like…. "However, in cases where a stability margin is known (or estimated) to

be slim, stability study should be performed regardless of the % or MW amount of increase (this leads to defining "Stability Margin").

(3) Table I, bullet 3 states that "Voltage Instability, cascading outages and uncontrolled islanding shall not occur." There is no definition for "voltage instability" anywhere in the proposed standard.

(4) R.3.3.2.1. states "Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment." This requirement creates significant unnecessary work without adding any value to system reliability.

(5) Extreme Event Description 3.d. states: "Shutdown of a nuclear power plant(s) and other facilities a day or more prior to a hurricane, tornado or wildfire, or for other common causes." It would appear that day ahead planning for a tornado is not possible, or applicable, for inclusion in this listing.

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Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☐	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

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The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: It is unclear what is meant by "mis-operation". The SDT also needs to address load lost during the transient time frame (e.g. load dropout due to low voltages as a result of a fault) that may not be directly connected to the element removed from service.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	

Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☐Do not agree.
Q7. **Comment: We have a concern with what will be considered acceptable documentation, particularly as it relates to asset conditions and age. Delete the word "needs" and the phrase "such as asset conditions and age". When measures are developed it should be made clear what will constitute an acceptable Planning Assessment.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Delete the term "the effect on the System of." The reference to "System" causes confusion with the term "System Stability Study.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: Need to provide an example to clarify what this means.**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the

rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: The entity performing the studies has the best system specific knowledge to select the appropriate sensitivities that needs to be evaluated. When Measures are developed, they should provide planners with the flexibility to perform appropriate sensitivity studies.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: The sensitivities are best selected by those most familiar with the specific system.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☒
Comment: Sensitivity studies can be useful, but they should only be requried for System Stability Studies. Due to the intensive nature of the studies, the planning engineer should have flexibility to determine appropriate sensitivities to analyze.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: Agreed, sensitivity studies should not be required for the Long-Term.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new

technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: DSM should be carefully included based upon consideration of the particular DSM measures available and the uncertainty associated with each.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: New studies should be performed, but the study conditions should be determined based upon the judgment of the planner.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: Even committed projects may not be built due to a variety of circumstances. Either type of project can be deferred or cancelled for a variety of reasons, including circumstances beyond the transmission planner's control.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: The annual assessment will show that the revised plan meets performance requirements.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to

clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Allow indirect (Non-Consequential) loss of load for events involving short duration outages, such as typical line outages that do not result in cascading outages.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	Allow indirect (Non-Consequential) loss of load for events involving short duration outages, such as typical line outages that do not result in cascading outages.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	Allow indirect (Non-Consequential) loss of load for events involving short duration outages that do not result in cascading outages.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: Depends upon the definition of non-bus tie breaker. By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with	☒Agree. ☐Do not agree.	Table in TPL-001-1 doesn't include the last part of P4-4 (low side voltage rating above 300 kV). We assume the inclusion of 300kV here in the comment

[1] System adjustment can be manual or automatic

low side voltage rating above 300 kV		form is in error.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☒
Comment: DC and AC line contingencies should have the same requirements.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: We agree with the basis laid out (in the question) by the SDT.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: In general, it is a good practice for System Stabilty studies of seasonal load conditions to include the effects of induction motors. However, there is currently a lack

of data to support the amount and characteristics of detailed induction load models in many areas. Prior to making this a requirement, the industry needs guidance as to how this data should be developed, shared and maintained for near-term and long-term models. A long term transition period is required to incorporate motor models into dynamics studies.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: This question is not clear. Manual and automatic adjustments should be allowed for single and multiple contingencies as long as Performance Requirements are met.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment: We see this as an acceptable form of manual or automatic redispatch, which should be allowed as a cost beneficial way of operating the system in a reliable manner, as long as it can be accomplished within the time frame before emergency ratings are exceeded.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☒
Comment: Runback should not be used if the disturbance caused you to exceed emergency ratings (i.e. thermal overload).

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: RAS and SPS are economical solutions that planners ought to be able to use.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: You should not have any wide area cascading if the RAS or SPS fails to operate as expected, or operates when it shouldn't.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: See response to Q36 and Q37 above. No additional conditions beyond meeting the performance requirements.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☐ No ☒
Comment:

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☒ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☒	1 — Transmission Owners
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Group Comments (Complete this page if comments are from a group.)

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Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: Why define a term that is used only once in the document (R.2.1.2.1) and is, by definition, applicable to a[ny] specific point in time.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: I agree with the definiton except for "or mis-operation". The requirements do not, and should not, include mis-operation of protection schemes. We would never finish a study of all potential mis-operations.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: I disagree with the phrase "and have a low probability of occurance". All the Planning Events, except possibly a generator outage (P1.1), have a low probability of occurance.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such	☒Agree. ☐Do not

as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: I agree that Asset Managers need to consider asset condition and age in their spare equipment and replacement strategies but the impact of these factors is beyond the scope of a deterministic Planning Assessment.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Recommend: Events to be simulated is studies (listed in Tables 1 and 2 of TPL-001) which must be documented with Corrective Action Plans when performance requirements of TPL-001 are not met.**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☐Do not agree.
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Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: "studies" should be replaced with "Planning Assessemt", the Planning Assessement is the documention (of past and current studies) submitted for review. Note: the definiton in Q11 does not match TPL-001.**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be

developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☒ No ☐
Comment: The proposed requirements P2, P3 and P4 significantly increase system performance. I agree with the requirements but I do not think it is appropropriate to layer extreme load, extreme transfers and other sensitivities on top of these. The analsysis of any Senistivities should be under the umbrella of Extreme Events or limited to meeting the P1 requirements.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒
Comment: Stability studies are a labor intensive task. Off-peak studies (with max plant gen) is severe enough.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☐
Comment: I agree with the approach.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes

all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒
Comment: DSM and generation improvements should be excluded. What is a "generation improvement"? New technologies could apply to anything, does the SDT mean "new Transmission technologies"?

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒
Comment: Re-testing is part of the normal study process of developing the Corrective Action Plan (CAP). Most CAP should be developed in the Long-Term horizon. The next annual study and all subsequent studies provide sufficient review without developing another set of cases and additional testing in the initial assessment.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: MISO has spent years on trying to make a distinction. If this remains, then "Committed Project" must be defined.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: Our planning process includes documentation of the need, acceleration, delay, or elimination of all projects. As worded, I do not need to document the delay of a Committed project.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-

0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Outage of two 345 kV circuits can create local area issues that result in loss of load but do not affect the integrity of the BES.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	Outage of two 345 kV circuit and a transformer can create local area issues that result in loss of load but do not affect the integrity of the BES.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of	☐Agree. ☒Do not agree.	Outage of two 345 kV transformers can create local area issues that result in loss of load but do not affect the integrity of the BES.

another transformer		

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: EHV station configurations are either ring-bus or breaker and one-half. Breaker failure protection isolates two EHV Facilites which may cause local area issues without affecting the BES.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: This event needs to be reworded. Does the stuck non-bus tie breaker condition only apply to the bus fault or to all faults? Does (above 300 kV) only apply to the stuck non-bus tie breaker or is this limited to faults on facilities above 300 kV?

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed	☒Agree. ☐Do not agree.	

[1] System adjustment can be manual or automatic

by loss of a transformer		

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment: No opinion, we do not operate DC

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment: Yes but the distinction is not clear in the defintions. A Plant Stability Study would typically be done as part of the Generatior Interconnection Request and have all units in the area at maximum output. Is the System Stability Study done on the Base Case or is generation maximized within some area(s)?

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: I agree with the SDTs conclusion.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: I agree that this is an issue but I do not have sufficient data to accurately simulate the condition. This is also complicated by dynamic behavior of distribution capacitors which are not modeled.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: single - none

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☐ No ☒

Comment: I do not agree that the system has to be returned to a "normal state" after a single contingency. The system can continue to be operated in the "emergency state" as long as the next contingency does not cause flows above emergency ratings.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☐

Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment:
R1.4 "including protective relays with consideration given to spare equipment strategy" I do not understand the intent of this phrase or what it adds to the requirement.

R2.6.1 "and market structure changes" What is this, does it require a definition?

R2.7.1.1 What is the project initiation date; the date approval is sought, received, materials are ordered, construction begins? Many projects are upgrades or replacements that this will be meaningless. Don't you really only want multiyear projects?

R2.7.2 The initial study process will incorporate testing. This will require the creation of additional cases and additonal testing prior to the Planning Assessment submittal. Most projects should be identified during the Long Range time frame. Inclusion of the project in the next years base cases and subsequent testing should be adequate.

R2.7.3 Define a "Committed Project". MISO has spent years on this.

R2.7.4 Changes in timing of all projects should be documented in the Planning Assessment. Why would you document Committed Projects that are removed but not any delays or accelerations?

R3 Sensitivity studies (if retained) should have less stringent performance requirements than the other cases required by R2.1.

R3.3.2.1 Unless this is limited to above 300 kV, many hours will be spent for naught. The lower voltage systems often have tapped loads that will trip with the line. The time required to restore will vary on the fault location, and time for switching, sometimes remote and sometimes manual. I do not see the need for or the benefit of this requirement. Please explain.

P3 Event is poorly worded, see response to Q25.

P6.1 above 300 kV, below 300 kV or all? The tables need to be reviewed to make sure that the voltage applicability is clearly stated.

P9.6 Why is this a requirement? It should be much less severe than any of the prior requirements.

Extreme Event 9 (3ph fault with loss of all generating units at a station) is in conflict with Q33 which says it was not included). Am I missing something?

Other, it appears that we are not required to study the outage of a transmission line or transformer followed by the outage of a generator. Was this overlooked, or did I miss it? Would system adjustment be allowed?

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☒ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

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To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

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Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: Further examination is needed to determine how to correctly treat loads served downstream from the faulted element, but not directly connected.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: The statement would be clearer if "low" were changed to "lower".**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	

Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Should also include validation of reactive power supplies.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
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Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.

- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☐
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☐
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment: Planners should use appropriate sensitivity cases.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in

conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☐
Comment:

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL

standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the

[1] System adjustment can be manual or automatic

steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected

Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment: As long as the system would be within normal ratings after runback.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☐ No ☐
Comment:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Charles W. Long or Doug Powell	
Organization:	Entergy Services, Inc.	
Telephone:	601-969-2324 or 504-576-3584	
E-mail:	clong1@entergy.com or rpowel1@entergy.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: Delete "mis-operation". For purposes of planning, all consequential load loss should reflect intended fault clearing actions and not unintended fault clearing actions (i.e., mis-operations). Include load loss due to UVLS & SPS in consequential load loss category.** **Consider using the terms in the existing standard; "Planned Load Loss" and "Unplanned Load Loss" in lieu of Consequential and Non-consequential as they may be easier to define with each Transmission Owner/Planning Authority responsible for defining the terms considering the impact on the Bulk Electric System.** **If the terms remain as proposed, the definition needs further clarification for consequential and non-consequential loads. For example, loads entirely dependent on the faulted element but not directly connected should also be defined to be consequential loads.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Revise to, "Events which are beyond the normal scope of Planning Events and have a lower probability of occurrence."**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.

Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: We recommend to treat load losses due to UVLS & SPS as examples of consequential load loss (refer to question 2).**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Remove "and other factors, such as asset conditions and age" from definition. The terms "age" and "condition" are subjective and the age of equipment, if it is well maintained, has little impact on reliability.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Delete the term "the effect on the System of." The reference to "System" causes confusion with the term "System Stability Study."** **Section R4.6 should identify the Generator Owner as the applicable party for doing the Plant Stability Studies.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: The last sentence in the above definition was not included in the definition listed in the draft standard. Consider deleting the last**	

sentence or providing additional examples.

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The appropriate studies that should be done by each applicable entity is highly dependent on the transmission system being studied. Being too prescriptive may cause irrelevant studies to be completed while diverting resources and attention from sensitivity studes that the entity most familiar with the transmission system believes could result in more meaningful analysis. The Committee should not lose sight of the importance of good engineering judgment exercised by those most familiar with the characteristics of the particular system. While appropriate sensitivity analyses are beneficial in evaluating system performance, it should be clearly stated that projects and/or mitigation plans are left to the discretion of the Transmission Planners.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: Should be left to Transmission Planners discretion and good engineering judgement. (see response to Q12)

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒

Comment: The new requirements for stability studies, including but not limited to the sensitivity studies, will result in a tremendous increase in workload. Because stability studies are so much more time intensive that steady state analysis and because they require personnel with a highly specialized skill set, the number of stability studies required should be increaed only as determined necesssary to evaluate worst-case contingencies. It would seem that the sensitivity analyses as well as many of the multiple contingency analyses could be done for steady state and only worst cases analyzed again by dynamic studies.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐

Comment: DSM should be considered, but it should be done prudently and in accordance with the contracts that govern the specific DSM program and only in cases where the Transmission Owner has direct load control. Transmission Owners should be allowed to include UVLS and SPS systems as a part of their Corrective Action Plans.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: Study area should be determined on a case by case basis by the Transmission Planner. SEAMS agreements and other regional planning coordination activities should provide for adequate cooperation.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment: Committed projects should be tested for effectiveness, however, the effectiveness of Proposed projects, as they are subject to change, should not require the same level of documentation as committed projects.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus	☒Agree.	Table 1 does not specify "SLG"

section (SLG for stability) above 300 kV	☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	N-1-1 requires an increase in investment that will place an undue cost burden on all customers for low probability events. See comments to Q43.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	N-1-1 requires an increase in investment that will place an undue cost burden on all customers for low probability events. See comments to Q43.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	N-1-1 requires an increase in investment that will place an undue cost burden on all customers for low probability events. See comments to Q43.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: N-1-1 requires an increase in investment that will place an undue cost burden on all customers for low probability events.
See comments to Q43.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: N-1-1 requires an increase in investment that will place an undue cost burden on all customers for low probability events.
See comments to Q43..

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	This would require an increase in investment that will place an undue cost burden on all customers for low probability events. It does not appear that there has been any meaningful balancing of the potential benefits against the significant increase in cost that will be required. See comments to Q43.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	This would require an increase in investment that will place an undue cost burden on all customers for low probability events. It does not appear that there has been any meaningful balancing of the potential benefits agains the significant increase in cost that will be required. See comments to Q43.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	This would require an increase in investment that will place an undue cost burden on all customers for low probability events. It does not appear that there has been any meaningful balancing of the potential benefits against the significant increase in cost that will be required. See comments to Q43.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	This would require an increase in investment that will place an undue cost burden on all customers for low probability events. It does not appear that there has been any meaningful blancing of the potential benefits against the significant increase in cost that will be required See comments to Q43.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

[1] System adjustment can be manual or automatic

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☒
Comment: Why are only DC lines exempt for this requirement? Consider exemptions for AC transmission elements as well.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment: This approach clarifies the types of stability studies/simulations to be performed. The performance criteria/guidelines are more explicit under the proposed Standard.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment: See response to Q9

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: This question conflicts with Table 2 item 9. However, we feel it is not necessary to simulate loss of all units at a station. The Transmission Planner or Planning Authority should have the discretion to consider the appropriate number of units to be tripped based on station design, relay design, etc.

Since there is no specific question related to R3.4 that requires an evaluation be conducted of implementing a change designed to reduce or mitigate the likelihood of such consequences. More specific direction should be provided in this regard.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: In general this is a good practice. Dynamic studies of seasonal load conditions should include the effects of induction motors, and particularly in areas where

traditional load models have indicated a problem. Unfortunately, there is a lack of data to support the amount and characteristics of the detailed induction load models in many areas. In addition to the consideration of the dynamic effects of induction motor loads, the effects of static capacitor banks installed at distribution voltage levels would need to be considered as well. Prior to making this a requirement in the reliability standards, the industry needs guidance as to how this data should be developed and maintained for models in future years. This should be a business practice and thus removed from the standard. While we agree that each entity should appropriately model their loads, it would seem appropriate for the MMWG to address the issues of induction motor load modeling.

Note that meeting such a requirement would necessitate a significant increase in the dynamic data needed to represent the system. Maintenance of such load model data would require significant resources. Load characteristics valid for a near term model might not be valid for future years.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: This question is not clear and more explanation should be provided, such as, whether the adjustments are pre or post contingency, whether the contingency involves faults etc. Does this question pertain to plant or system stability?

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☒
Comment: The question is not clear. Generation runback schemes are acceptable as long as emergency ratings are not violated. Runbacks should not be used to restore an element to within emergency ratings.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: RAS or SPS may be allowed for single contingencies when they aid in meeting System Performance requirements. RAS and SPS should not be used to restore an element to within emergency ratings.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: RAS or SPS may be allowed for single contingencies when they aid in meeting System Performance requirements. RAS and SPS should not be used to restore an element to within emergency ratings.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: Following a contingency, power flows on lines should be within their emergency ratings, voltages should be at adequate levels and system should be stable.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment:

Significant Increase in Study Activity Workload on Transmission Planners

The increase in both steady state and dynamic studies required to ensure compliance with the proposed standards will result in increased costs and staff additions. The more specific format and additional requirements of the "Corrective Action Plan" require the TP to provide a significant amount of documentation for each deficiency identified by the studies. Also, R3.2 requires that the studies simulate the protection scheme for all events. The current software tools cannot automate these studies for bus faults and breaker failure events, requiring each scenario to be studied manually. Additionally, experienced staff capable of performing analyses as described in the proposed standard have become increasingly difficult to find and retain and the talent pool of people with these skills has recently become depleted to alarming levels.

Implementation Plan

Given the intent of the proposed standard to encourage large scale investment in the EHV system, full implementation will take years, perhaps decades. Acquirement of right-of-way for new EHV lines has become increasingly difficult in recent years and increasingly expensive due to the environmental and social issues associated with new Transmission. Legal, regulatory, and other difficult issues often take several years to navigate, even for 115kV lines. The Implementation Plan timeframe, if set too short, would be unduly burdensome on Transmission Owners, extraordinarily expensive, and possibly unachievable. The proposed implementation plan should include provisions for those cases where viable solutions simply can not be implemented in time due to circumstances beyond the control of Transmission owners. We recommend a minimum of 15 years for the transition.

Design and Construction Constraints

Even if right-of-way and other legal and regulatory hurdles are cleared, and the capital funding for such a tremendous level of investment was not an issue, the other resources required to actually construct the projects are equally difficult and costly to secure. Raw material prices on commodities like copper and steel have skyrocketed in recent years. Additionally, the skilled labor and Engineering resources are constrained with labor rates almost keeping up with other resource costs. Overall project costs have more than doubled over the last 7-10 years. Recent press releases concerning new generation being planned and then scrapped due to the rapid escalation of project costs are public evidence of this. The inflationary mark-up is impossible to estimate but much less will be built with the same capital investment than is currently envisioned due to the competition for both human and material resources.

Cost-Benefit Analysis

It will be extremely expensive, requiring unprecedented levels of capital investment in Transmission facilities, to become compliant with a proposed standard without any evidence that such increased requirements are justified. Before the standard comes to official vote, it would be prudent for a cost-benefit analysis to be performed to

determine if the reliability improvements justify the huge expenditures certain under the proposed standard. A clear understanding of the reliability benefits and economic costs to customers is critical prior to final action on the proposed standard. While tightening standards will result in a more secure system, overbuilding the system at a significant cost to withstand more severe but less likely contingencies may not be in the public interest. Additionally, it is unclear whether the propose standard is in conflict with section 215 of the Energy Policy Act of 2005.

System Adjustment Clarification

The term "System Adjustment" as outlined in the tables should be better defined. The use of generation for redispatch may have nuances which preclude or otherwise limit their use for studies. Perhaps some clearer guidelines on what is allowed such as committing units, de-committing units, firm and non-firm use, etc. would facilitate transparency and coordination between Transmission Planners.

Transmission Service Evaluation

Another concern is that the proposed standard appears to be inconsistent with the current requirements for evaluating firm transmission service, generally based on an N-1 standard. To the extent this standard is adopted as proposed, the new standard would also need to be incorporated into the standards against which new transmission service is granted.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☒ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☒	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment: It is a fair description for an initial base case.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment: Agree with the definition**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Add specificity in this definition. Suggest the following wording: Outage of two or more elements from service with lower probability of occurrence than Planning Events**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment: Agree with the definition**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment: Agree with the definition**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: Add Remedial Action Schemes (RAS) after "Systems" Amend sentence beginning "For example, Load loss that "directly"**	

occurs……	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☐Do not agree.
Q7. **Comment: Agree with the definition**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Needs clarity. Suggest the following wording: Outage of power system elements such as shown in Tables 1 and 2 that need to be considered and simulated to assess Transmission System Performance**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Definition is not clear. Suggest the following wording: Study of an individual generating plant's capability to remain in synchronism and exhibit damping of the generating units' power oscillations for various contingencies in the vicinity of the plant**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: This definition is for a stable system. Study is performed to determine whether system is stable or not. Suggest the following wording: Study of the system or portions of the system to assess the system's performance in terms of angular stability, power oscillations and voltage limits during dynamic simulation**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: Suggest a shorter definition: Planning window beginning next calendar year**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: The TP or PA is the best to determine the number and type of sensitivities that are more applicable to their system.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: Let the TP or PA decide the type of stressing needed for a particular case

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒
Comment: Although we concur with the sensitivity analysis,the TP should determine what sensitivities are more appropriate for their system. Sensitivities should not be scripted in the Standard.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: Agree. The Standard should state that sensitivity studies are not required but the TP or PA could use sensitivities if desired.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: We agree that the system should be retested with the corrective measures to ensure that the defficiency has been cured and that there are no inadvertant negative impacts. Regarding Study Area, it is not a defined term, and it could vary depending on the size of the project or nature of the disturbance being evaluated.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: The definition of "committed" projects varies from TP to TP. Also projects that are proposed today become committed in the planning horizon. Similarly, committed projects drop out due to variety of reasons. In terms of system studies, both committed and proposed projects are modeled and evaluated in the same system. How do we distinguish between the two?

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment: We agree that committed projects should not be removed from the revised plan. These are supposed to be included in the planning studies which determine the system performance in the first place.

The definition of "committed" projects varies from TP to TP so this would require a standard definition.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	This event falls under Category C for which controlled loss of load is allowed. Clear net benefits should be demonstrated to justify adapting to a new stringent criteria.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	We will comment on this at a later date
Q23. P5-3: For facilities	☐Agree.	We will comment on this at a later date

above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: Same response as for Q21, and
What is the definition of non-bus tie breaker? Doesn't it just refer to line, transformer, and generation breakers?

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: Do not agree for loss of a bus, or loss of a stuck non-bus tie breaker for the reasons as in the response to Q21.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	Non consequential loss of load should not be permitted for this type of event. Loss of a generator has higher probability and longer duration than many other contingencies. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Q27. P4-2: Loss of a	☒Agree.	Agree that non consequential loss of

[1] System adjustment can be manual or automatic

generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Do not agree.	load should not be permitted due to higher probability of generator outage.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	Same reason as in Q26.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☐Do not agree.	Same reason as in Q26.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: In addition, the interruptible and other negotiated transactions should also be allowed.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment: Agree that the two analysis should be treated separately.
It is not clearly defined what is steady state and what is stability. For example are Voltage Stability (PV analysis) studies steady state or stability? Also what are the differences between System Stability and Plant Stability? Are stability studies only required for the near term planning horizon?.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment: Agree with this additional analysis

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐
Comment: It will be consistent with the performance requirements under Steady State conditions. Also, loss of entire generating station is possible for a variety of reasons such as, loss of all lines emanating from the station, loss of the gas pipeline feeding the plant, etc.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment: The requirement to include motor load should be extended to other load levels as appropriate.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Manual such as tripping the generators, automatic such as AVR, excitation systems, stabilizer, and governor adjustments.
From a Planning perspective, you would not want to allow for manual tripping in the time frame of a stability study.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment: Agree

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: 1. Run back of generation should not result in tripping of firm load, 2. Power flow should be within the applicable ratings, 3. Frequency should be within the allowable limits

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: Agree

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: RAS or SPS should generally be regarded as a stop gap measure before transmission expansion or reinforcement becomes available. It should not be used as a substitute for transmission facilities.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: 1. RAS or SPS must be simple and manageable. 2. Number of contingencies triggering a RAS or SPS should be very limited (4 allowed by CAISO). 3. RAS or SPS should generally monitor only local facilities that are either directly connected to the plant or one bus away.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐
Comment: ISO relies upon tripping of generators to meet single contingency performance requirements. ISO also relies upon planned and controlled load shedding for the proposed Planning Events P4 and P5.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment: Not aware of any

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☐ No ☒

Comment:

R1.1.1 - Are percentage of load that is industrial, commercial, and residential needed?

R1.2 - The wording is confusing. If the power factor is based on historical measured values, does it have to be during contingency (stressed)?

R1.5 - "Planned Facilities defined in accordance with the documented criteria of the Planning Coordinator" - what is meant by this?

R2.1.1, R2.1.2, R2.1.3.1 - are all studies to be run using all the contingencies defined in Table 1 - Steady State Performance?

R2.6.1, R2.6.2, R2.6.3 - past studies will never be able to be used if the addition of a transmission line makes them invalid!

R3.2.1 - What is meant by "minimum steady state voltage limitations of all generators"?

R3.2.2 - Relay "loadability"?? What is meant by this? Sounds unreasonable for steady state studies as facility rating should reflect limitations of relay equipments such as CT"s.

General comment: If this proposed standard is approved, since it contains requirements that are more restrictive than current standards, there will need to be a transition period to allow transmission to be built to allow systems to meet the new requirements.

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Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☐Agree. ☒Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment: 'Other factors' such as condition and age should not be required, but may be utilized if these factors are an integral component of the study.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Wording should be changed to allow for engineering judgment to determine which contingencies are applied. There may be instances where contingencies outside of the immediate vicinity of the plant may be significant to its stability. Suggest replacing the word 'System' with 'Transmission System'.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment: Suggest replacing 'System' with 'Transmission System'.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: The required changes should not be specified because they may not impact a particular transmission system based upon its geographic location within the interconnection. Required changes should be determined by the entity performing the study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: DSM should be directly controllable with accurate information as the the magnitude and location. System stability should not be dependent on the operation of DSM.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: The study area should be at least the size of the original study area. Some engineering judgment is required to determine the subset of studies. Next year's study would include the full set of screenings for the future additions.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☒Do not agree.	We do not agree with disallowing non-consequential load loss for these scenarios for the peak load conditions. These are very low probability contingencies, and some non-consequential load loss should be allowed at peak load. We would agree that it would be reasonable to dis-allow non-consequential load loss for these contingencies at a lower load level, such as 75% of peak load.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☒Do not agree.	We do not agree with disallowing non-consequential load loss for these scenarios for the peak load conditions. These are very low probability contingencies, and some non-consequential load loss should be allowed at peak load. We would agree that it would be reasonable to dis-allow non-consequential load loss for these contingencies at a lower load level, such as 75% of peak load.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☒Do not agree.	We do not agree with disallowing non-consequential load loss for these scenarios for the peak load conditions. These are very low probability contingencies, and some non-consequential load loss should be allowed at peak load. We would agree that it would be reasonable to dis-allow non-consequential load loss for these contingencies at a lower load level, such as 75% of peak load.
Q23. P5-3: For facilities	☒Agree.	We do not agree with disallowing non-

above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Do not agree.	consequential load loss for these scenarios for the peak load conditions. These are very low probability contingencies, and some non-consequential load loss should be allowed at peak load. We would agree that it would be reasonable to dis-allow non-consequential load loss for these contingencies at a lower load level, such as 75% of peak load.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: P6 allows for non-consequential load loss for a bus tie breaker, which has the same probability of failure as a non-bus tie breaker.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☒
Comment: We do not agree with disallowing non-consequential load loss for these scenarios for the peak load conditions. These are very low probability contingencies, and some non-consequential load loss should be allowed at peak load. We would agree that it would be reasonable to dis-allow non-consequential load loss for these contingencies at a lower load level, such as 75% of peak load.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a	☒Agree.	

[1] System adjustment can be manual or automatic

System adjustment followed by the loss of a monopolar DC line	☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☒
Comment: This is more pertinent to longer term voltage stability, so the load model should be developed and available for these types of studies.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Generator MW and Mvar output adjustments should be allowed, both manual and automatic.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment: An automated run-back scheme should be allowed but not required for these scenarios - an operator should be able to manually adjust unit output.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Run-back schemes should be allowed for certain single contingencies that can result in unit outlet constraints. Not all emergency ratings are thermal - some are relay or stability limits. In these instances, generator run-back should not be allowed.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: There should be more specific requirements for the long-range studies. The P requirements should be run on the long range case but corrective action plans need only be proposed and not committed.

R3.3.2.1 appears to require consequential load loss identification including peak demand and duration. however there is no requirement addressing the use of this information. Why is this required?

R3.3.3 should be clarified. It is our interpretation that not each of the P contingencies be studied if sufficient rationale is provided to determine the most critical. It would seem that each of the planning category events would need to be addressed.

What is the expectation regarding sensitivity analysis in R2.1.3 and R.2.4.3 if there are no performance requirements defined?

It should be clear in the performance tables that the 'event column' contingencies are logically 'or' events.

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Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

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*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: We suggest that the team remove "or misoperation" from the definition. This could suggest that an overtrip of protection equipment could result in consequential load loss.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment: The definition is OK, but we question its use in the standard. Many of the items listed as extreme events are not considered events. For example, high river temperature is not really an event, it is a condition. The resulting event might be the shut-down of multiple generators.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding,	☐Agree. ☒Do not agree.

or Special Protection Systems.	
Q6. **Comment: We suggest eliminating the reference to Special Protection Systems (SPS). Some SPSs could result in tripping of load in association with a fault. By specifically listing SPSs here, it could imply that if that situation occurs, it would not be considered consequential load drop.**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: We suggest replacing "performance studies" with "past or present studies or information".**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: We ask that the SDT reword the definition to include reference to the planning events in Table 1 and 2 of this standard. This definition should be specific to this standard and not be included in the NERC glossary.**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: We believe that this definition is not needed. The Plant Stability Study is similar to the System Stability Study.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: Although we agree with the concept, the definition is confusing. We suggest simplifying the definition to "The first 12 month period that begins one year and one day from the completion of the study."**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: We suggest that the SDT reword the standard to allow the Transmission Owner additional latitude as to which stress conditions to study. We suggest modifying R2.4.3 to indicate sensitivities "such as those listed below" be studied. That way the standard would be providing examples but would not dictate specific sensitivity studies that should be performed.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment: Although we concur with the use of sensitivity analysis in dynamic studies, the standard should not dictate the specific sensitivities studies to be performed.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: Yes, we concur with this approach and sensitivity analysis should not be required.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒
Comment: We do not feel that the standard should specify, limit, or suggest methods for mitigating system performance deficiencies. We suggest rewording R2.7.1 by ending the first sentence after the words "System performance". The items currently described could be moved to a reference document which could include DSM and other mitigation methods.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: Although we agree with the concept of retesting, the standard should reference that a re-study is only required in the vicinity or portion of the system affected by new facility additions. Determination of the study area should be left to the Transmission Planner's judgement.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: Unless there is an industry agreed upon distinction and definition between "committed" and "proposed" projects, we do not agree that they should be introduced in this standard.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the

performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: Unless there is an industry agreed upon distinction and definition between "committed" and "proposed" projects, we do not agree that they should be introduced in this standard.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused soley by the first contingency.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System	☐Agree. ☒Do not agree.	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused

adjustment followed by loss of a transformer with low side voltage rating above 300 kV		soley by the first contingency.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused soley by the first contingency.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: The tables' use of internal faults and stuck breaker faults is confusing since they have the same result.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: The wording of P3-1 is unclear. We suggest rewording to say "Fault on a generator, line, transformer, or bus and a stuck breaker when the fault is being cleared". We agree with the concept of not dropping load for an EHV stuck breaker with the exception of the bus fault item. We do not believe that it is very realistic to postulate a bus fault along with a stuck breaker and believe that it is a very low probability event.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for

[1] System adjustment can be manual or automatic

		problems caused soley by the first contingency.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused soley by the first contingency.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused soley by the first contingency.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused soley by the first contingency.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☒
Comment: While we agree that steady-state and stability are different situations, in general we believe that the tables are confusing, overly worded, and should be combined. The initiating events are the same regardless of steady-state or stability so there should be no reason not to combine the tables as was done in the previous standards.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: We do not see the difference between plant stability and system stability. Both are based on anuglar stability of machines connected to the system and therefore, they should be treated the same.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: We do not believe that this condition should be required to be tested using stability analysis of extreme events. This is due to the fact that these events should be required to be studied using steady state analysis, and stability analysis results would not add value.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment: We agree with this concept but believe that enforcing it would be very difficult. There are no standards on modeling induction motor load, be it type of models, percentage of load that is motor load, or percentage of large vs small motors.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: As long as thermal, voltage, and stability requirements are met, either automatic or manual runback of the unit should be allowed. Tripping of the unit should be allowed also if the particular unit(s) can be restarted within some relatively short time - say one hour. With this requirement, it appears that only CTs and hydro units would be allowed to be tripped.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency

outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment: As long as thermal, voltage, and stability requirements are met, either automatic or manual runback of the unit should be allowed. Tripping of the unit should be allowed also if the particular unit(s) can be restarted within some relatively short time - say one hour. With this requirement, it appears that only CTs and hydro units would be allowed to be tripped.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Yes, only if the Transmission Owner has documented short term ratings that would not be exceeded during the runback.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: As long as thermal, voltage, and stability requirements are met, RAS or SPS should be allowed provided it does not shed load for a single contingency event.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: As long as thermal, voltage, and stability requirements are met, RAS or SPS should be allowed provided it does not shed load for a single contingency event.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: As long as thermal, voltage, and stability requirements are met, RAS or SPS should be allowed provided it does not shed load for a single contingency event, and only if the Transmission Owner has documented short term ratings that would not be exceeded during the runback.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment:
- R1. Load flow model submittal is redundant with various MOD standards and should not be required by this standard. To the extent any new requirements are introduced, we suggest that existing MOD standards be revised or new MOD standards be created as needed.

- R2 Organization of this requirement could be improved by grouping by Near Term and Long Term and then by steady state, short circuit, and stability requirements.

- R2.1 Too many annual studies are being required by this standard for the Near Term. We suggest limiting the current study year requirement be limited to one Near Term study. As written, it appears that this requirement forces a study for each of the 5 years, however the requirement should to be able to assess the entire 5 year period but not study each year.

- R2.1.1: As written, 2 studies are needed to meet this Near Term assessment requirement. It should be left up to the TO to determine the appropriate year in the short and long term periods. It's particularly odd given the fact that the TO could select year six for the Long Term study which would end up giving him back to back year 5 and 6 studies. The requirement should be to study one year in the 1 to 5 and one year in the 6 to 10 year periods.

- R2.2: This wording is very confusing. We are assuming that it means that you must continuously have to have a study that is less than one year old for the year 6 to 10 period. If so, wording needs to be clarified.

- R2.4.1: The idea of modeling induction motor loads is good in concept, be we question the practicality for an auditor to enforce. To date, a definitive way to model induction motor load does not exist. For example, what is the right mix for percent of load to be motor load or percent of large vs small induction motors.

- R2.6.1: Unless "material change" is specifically defined, the requirement is ambiquous and difficult to enforce consistently. What constitutes a "topology" change?

- R2.6.2: Same comment as R2.6.1 above, material change needs to be defined.

- R2.6.3. Same comment as R2.6.1 above, material change needs to be defined.

- R.2.7.1.1: We don't think it is reasonable nor necessary for the TO to provide an initiation date. No one should care when it was initiated as long as it is in service by the time it is needed.

- R2.7.1.2. Requiring an in-service year for the long-term may not be feasible for the initial study assessment. Based on the number of issues that could occur in the long-term horizon it may take a TP another 6 months to a year of more detailed area studies study to find the optimal solution(s) to resolve multiple system deficiences. In the long-term, only a list of SOLs problems along with year problem is initially anticipated should be required.

- R3.2.1: We suggest the following rewording "R3.2.1. Studies shall include the minimum steady state voltage limitations for all generators, and generators shall be simulated to trip for voltage below the minimum steady state limitation."

- R3.2.2: This is unnecessary in this standard. This is already addressed in the FAC standards dealing with equipment rating. Additionally, the proposed PRC-023 relay loadability standard addresses this concern. Alternatively, reword the requirement to say "if a relay is expected to trip because of an overload then the resulting facility shall be simulated in addition to the initiating event".

- R3.3.3. How do you know which events beyond single contingencies result in producing "more severe" impacts without running all? Either you test or you don't. We suggest some type of cyclical expectation for testing each of the less probable Planning Events, i.e. every three years each must be covered etc.the most critical

- R3.4 Same comment as R3.3.3, you need to test each to understand which produces the most severe impact. We suggest some type of cyclical expectation for testing each of the Extreme Events. The frequency of testing should be less often that the items covered in R3.3.3. It appears the only expectation is to consider some type of change to reduce or mitigate potential Cascade for Extreme Events. It should be clearly written that there in no mandatory expectation to remove the Cascade risk that may be associated with an Extreme Event.

- R4.5.1. Same comment as R3.3.3 (Steady-State) applies for this Stability requirement.

- R4.5.2. Same comment as R3.4 (Steady-State) applies for this Stability requirement.

- R4.6.1. We agree with the requirement but the SDT should assure consistency with data submittal requirements in the MOD standards.

PERFORMANCE TABLES - General
1. In general, we feel the tables are overly complicated and difficult to follow. We suggest the SDT give consideration to merging the proposed tables back together to a single performance table. We also question why the team chose to leave the NERC A, B, C, D concept. The concept of Planning Events could reflect that NERC A, B & C categories must be met for Planning Events and that Category D are Extreme Events. Drastic deviation from the historical NERC performance classifications will require significant re-write of existing TP planning criteria documentation.

2. 300kV Level - It is confusing how the 300kV level requirements are placed within the tables. We suggest separate columns for performance requirements for 300kV and higher and below 300kV. This way, the same Planning Event could easily be reference on the same line and the expectations for each system level could be more readily determined.

TABLE 1 - Steady-State Performance Table

1. We suggest that the "Initial Condition" column that is included in Table 2 - Stability Performance Table - also be added to Table 1. This would allow each to have the same look and feel, and would cut down on the lengthy wording such as: "Loss of a generator followed by System adjustment followed by loss of a generator"

2. Bullet 1 - "Equipment Ratings should not be exceeded." It is not clear which equipment rating would be the applicable rating.

3. Bullet 3 - "Voltage instability, cascading outages and uncontrolled islanding shall not occur". These terms require a definition to ensure consistent interpretation and application from an auditor.

4. It is not clear why stuck breaker items are distinguished from an internal breaker fault. Each will create the same resulting system condition.

5. Why are non-bus tie breakers treated separate from other breakers?

6: P2: Why is a stuck breaker listed as a single contingency?

7. P8: What about a transformer followed by a line outage? Why not just simply list the components and say any combination of the two.

8. P9: "Loss of a transformer followed by a System adjustment with a spare transformer available followed by the loss of another transformer." It is not clear why this is needed? Wouldn't the spare be a possible mitigation of the initial contingency?

9. Extreme Event Descriptions:

A) For item 1, it’s understood that for the N-2 items listed, the "extreme" aspect is that the second event occurs without system adjustment. However, we question whether a two generators simultaneously out should be considered an extreme condition.

B) We agree with the items listed in item 2 as they line-up well with the prior category D events from the existing TPL standards performance table.

C) Many of the classifications listed in item 3 are subjective and can not be tested. We propose that these items should not be requirements.

TABLE 2 - Stability Performance Table

1. With regard to Table 2, much of the proposed testing required for stability are not necessary from a reliability standpoint. Some test items are included that are not, at least in the eastern interconnection, going to impact stability any worse than the relatively simpler requirements of the present standards. By testing single phase local faults in conjunction with a stuck breaker and remote faults with back up clearing for each line emanating from a power plant, you'll cover 99% of your stability issues. Also, this table does not adress relay scheme failures (back up clearing) that were covered in the present standard and which can have a significant impact on the stability of a unit/system.

2. Under the "Event Column", it is inconvenient to need to look back and forth on the table to reference other events, the items should be written in full text. For example, under P4 it is indicated that the "Initial Condition" is a single generator out and the "Event Column" indicates apply "P1.2 Contingency, P1.3 Contingency, etc." These items should be written out so that the user of the Table does not need to flip back and forth to see what the referenced contingencies entail.

3. Regarding P1, why require dynamic analysis for an unexpected loss of the listed equipment without a fault? The fault iniated outage will always be worse.

4. As stated above for Table 1, It is not clear why stuck breaker items are distinguished from an internal breaker fault. Each will create the same resulting system condition.

5.: P5, P8, P9: The analysis suggested to run these multiple contingencies in dynamics would be extremely time consuming and produce little value. We suggest that the steady-state anlysis be used to screen those contingencies which show the potential to cause system cascade and then run dynamic analysis on those items.

6. As stated for Table 1 above, "Loss of a transformer followed by a System adjustment with a spare transformer available followed by the loss of another transformer." It is not clear why this is needed? Wouldn't the spare be a possible mitigation of the initial contingency?

7. In the Notes section shown under Table 2, for item "ii", we are not sure this could be accomplished as our relay models are not reflected in our data set used for dynamics simulation analysis. Two separate and unique software tools house the data and we believe this to be common among most companies.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Hector Sanchez	
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☒ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*
Marty Mennes	Florida Power & Light Company	**FRCC**	Transmission
W. R. Schoneck	Florida Power & Light Company	FRCC	LSE
R. A. Birch	Florida Power & Light Company	FRCC	GO
A. L. Barredo	Florida Power & Light Company	FRCC	LSE
C. Candelaria	Florida Power & Light Company	FRCC	LSE
J. W. Shaffer	Florida Power & Light Company	FRCC	LSE

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance

requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: "Computer" is not appropriate. Replace with "Data model" or "Database model". The last sentence is not clear as to what type of ratings (i.e., normal, short-term emergency, long-term emergency, etc.). Suggest removing sentence completely or rewording as follows: "... in accordance with the documented methodologies required by FAC-008 for each Transmission Owner and Generator Owner."**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: Need to clarify what constitues an element (e.g., breaker-to-breaker, line segment to line segment, transformer or capacitor bank)**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Suggest reword as follows: "Events which are more severe and have a lower probability of occurrence than planning events."**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	

Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: Reword as follows: "Firm load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems, excluding curtailments, DSM, and voltage reduction."**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Last part of the last sentence should be removed "… and other factors, such as asset conditions and age" does not make sense for planning studies. Equipment condition and age are maintenance issues not transmission planning issues.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: There should be no distinction between Plant Stability and System Stability. All stability studies must meet the Performance Requirements for Planning Events in Table 2 - Stability Performance. If there were different Performance Requirements then the distinction would be warranted.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: Dynamic voltage ratings do not add value and are only an approximation for modeling limitations. The definition should not address performance and should only seek to define the term. Reword as follows: "Study of the System or portions of the System to assess angular Stability and inter-area power oscillations."**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the	☐Agree. ☒Do not

Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	agree.
Q11. **Comment: The last sentence of this definition is not included in the Standard. Reword as follows: "The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner performs their annual studies and submits the results to the RRO."**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: Not all Regions' sensitivity concerns are the same.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: The Transmission Planner needs the flexibility to define what are considered "reasonably stressed" cases for their respective systems. This would not a be a proper application of a one size fits all definition.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒

Comment: The standards require near term base case cases to be studied for a broad range of planning and extreme events. The sensitivity analysis requirements contained R.2.4.3. will essentially require every dynamic simulation to be run at least twice regardless of whether or not there is any engineering insight to be gained. While improved understanding may result from sensitivity analysis of certain key event scenarios, the overall benefits of the sensitivity study requirements contained in section R.2.4.3 do not justify the huge increase in engineering effort to conduct and document these simulations.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: There should be no sensitivity studies/analyses for the Long-Term Transmission System Planning Horizon.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐

Comment: If DSM is included as part of an integrated Corrective Action plan, then the impact of DSM should be included by specifying the location and expected quantity of DSM that will mitigate a system deficiency. The use of DSM, whether exclusively or in conjunction with other measures, is an acceptable operating procedure for use in a Corrective Action Plan, as long as the Transmission Owner demonstrates availability and accuracy of DSM data and its viability as an operating procedure for each applicable scenario.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the

changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒
Comment: Incremental benefits do not justify the magnitude of additional studies. Corrective Action plans should be tested, but not as a new study with all of the Corrective Action Plans included simultaneously. The proposed language is inferior to the existing language (TPL-002-0 R2) and suggest replacing with language from TPL-002-0 R2.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: All projects should be called "Planned" projects. There is no distinction in a model between committed and proposed projects that would treat them differently. They are either in the model or not in the model. This sub-requirement does not follow the major requirement wording in R2.7 ".....Such plans shall:" The intent of Requirements R2.7.3 and R2.7.4 should be combined and added into R2.7.1.1. Rather than adding the addtional requirement to document a criteria, the requirement should be that in the Near-Term Planning Horizon, projects cannot be removed (or modified) without demonstrating that the revised plan meets performance criteria. Suggested wording for R2.7.1.1. "Transmission and generation improvement projects for the Near-Term Transmission Planning Horizon, shall have in-service dates provided (to whom?), and shall not have in-service dates changed, or be removed from planning models, without documentation to show that the revised plan meets performance requirements."

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: All projects should be called "Planned" projects. Additionally, see response to question 18.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	This loss is currently distinguished from other single contingencies because of its lower probability of occurrence and a more stringent performance requirement than currently exists is not warranted.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Systems have been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis. In addition, by not allowing loss of non-consequential load, the system may remain in a less secure state or condition.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	Systems have been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis. In addition, by not allowing loss of non-consequential load, the system may remain in a less secure state or condition.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	Systems have been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis. In addition, by not allowing loss of non-consequential load, the system may remain in a less secure state or condition.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: This loss is currently distinguished from other single contingencies because of its lower probability of occurrence and a more stringent performance requirement than currently exists is not warranted.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: Systems have been designed such that Multiple Contingency events (N-2) above 300 kV may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis. In addition, by not allowing loss of non-consequential load, the system may remain in a less secure state or condition. This new category P3-1 is essentially a replacement for Category C5-9 except the only protection element failure to be considered is the failure of a circuit breaker to open. This definition eliminates the need to examine failure of the relay to operate which in many cases has a more serious impact on grid reliability.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	Systems should be planned such that the loss of a generator, followed by System adjustment, followed by the loss of another generator would not result in Non-consequential Load Loss, and equipment ratings would not be exceeded etc. However, the initial state of the system must be clarified in all performance table scenarios (including P4-1).If the Base Case contained known planned outages of generating units, as implied by the requirement R1.4, then the standard performance requirements could be interpreted to require planning for all G-1-1-1 events.
Q27. P4-2: Loss of a generator followed by a	☐Agree.	Systems should be planned such that the loss of a generator, followed by

[1] System adjustment can be manual or automatic

System adjustment followed by the loss of a monopolar DC line	☒Do not agree.	System adjustment, followed by the loss of another generator would not result in Non-consequential Load Loss, and equipment ratings would not be exceeded etc. However, the initial state of the system must be clarified in all performance table scenarios (including P4-1).If the Base Case contained known planned outages of generating units, as implied by the requirement R1.4, then the standard performance requirements could be interpreted to require planning for all G-1-1-1 events.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	Systems should be planned such that the loss of a generator, followed by System adjustment, followed by the loss of another generator would not result in Non-consequential Load Loss, and equipment ratings would not be exceeded etc. However, the initial state of the system must be clarified in all performance table scenarios (including P4-1).If the Base Case contained known planned outages of generating units, as implied by the requirement R1.4, then the standard performance requirements could be interpreted to require planning for all G-1-1-1 events.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	Systems should be planned such that the loss of a generator, followed by System adjustment, followed by the loss of another generator would not result in Non-consequential Load Loss, and equipment ratings would not be exceeded etc. However, the initial state of the system must be clarified in all performance table scenarios (including P4-1).If the Base Case contained known planned outages of generating units, as implied by the requirement R1.4, then the standard performance requirements could be interpreted to require planning for all G-1-1-1 events.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☒

Comment: The proposed standard does not distinguish between asynchronous DC ties and the more common parallel connected DC tie. With an asynchronous DC tie, the transfer is lost with the tie. With a parallel DC tie, the transfer will be shifted to the parallel AC system, therefore, AC lines should have the same performance criteria as DC lines.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☒

Comment: The separation of steady state and dynamic response analysis requirements into two tables (with different contingencies) is inferior to the analysis requirements outlined in Table 1 of the existing TPL Standard. The structure of Table 1 reinforces the requirement for grid stability and maintaining the grid within applicable limits for Category B and C contingencies. Dynamic simulations of Category B and C contingencies that demonstrate grid stability should be followed up with post transient power flow analysis to assess voltage and thermal limits.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒

Comment: There should be no such distinction. All stability studies must meet the Performance Requirements for Planning Events in Table 2 - Stability Performance. If there were different Performance Requirements then the distinction may be warranted. However system stability studies should be sufficient and not warrant additional work.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒

Comment: The question does not match what is included the Extreme Events section of Table 2. Loss of all generating units at a plant should be considered in the Steady State Performance - Extreme Events but not in the Stability Performance - Extreme Events because of the very low probability of the event ocurring within the timeframe of the Stability simulation. Therefore, the performance requirement number 9 for Extreme Events in Table 2 - Stability Performance should be deleted.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load

model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: The issue of delayed voltage recovery is a special phenomenon that can occur in some large urban areas under peak conditions. The modeling of the delayed voltage recovery response is considerably more complex than simply representing induction motor effects. The scope of the delayed voltage recovery issue is extremely limited and its effect on the grid is generally self correcting due to automatic disconnection of the affected air conditioners. While improvements in the accuracy of load models used for the study of grid dynamic response are desireable, this area is not suitable for compliance enforcement. Requirements for specific types of load models are not appropriate in the TPL standard.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Manual and automatic adjustment (increase or decrease) of Var output and manual and automatic tripping or reduction of overall MW output of generators should be allowed.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: At a minimum the emergency ratings should allow sufficient time for the runback scheme to operate reliably.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: The performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. If the proposed TPL standard is adopted the contingency references in PRC-012-0 would need to be updated.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: The performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. If the proposed TPL standard is adopted the contingency references in PRC-012-0 would need to be updated.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: The performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. If the proposed TPL standard is adopted the contingency references in PRC-012-0 would need to be updated.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment: No, if the comments to the above questions are incorporated. The FRCC system is a peninsular system having only one interface with the rest of the interconnected NERC system, and has historically demonstrated exceptionally high reliability with no events in recent history cascading beyond the FRCC system. The adequacy of the existing TPL standards as they apply to the FRCC System have been extensively documented.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐

Comment: General Comment: NERC Standards TPL 001-0 through TPL 004-0 are approved standards that only required modifications pursuant to FERC Order 693. In this proposed draft standard TPL 001-1 the Standard Drafting Team (SDT) has far exceeded the recommendations suggested by FERC in that Order as well as created unnecessary confusion. FPL believes that the SDT's decision to combine NERC Standards TPL 001-0 through TPL 004-0 into one standard was not a specific requirement by FERC Order 693 and may not have been a good decision by the STD, therefore it should be reconsidered after reviewing all of the comments. At a minimun, the team should somehow clearly demonstrate changes in the standard's wording and required performance levels as compared to the existing standards. The new proposed draft of TPL-001 creates unnecessary confusion and interpretation of new ambiguous language, which is inconsistant with the stated objectives, instead of providing clarity to the standards. As an example of how to provide additional clarity, the existing standards have unnecessary redundancy in the tables, for example, it would have been nice to clean up (clarify) the tables such that the table for TPL-001 would only contain the performance criteria for Category A, with footnotes only applicable to that category, clarified as directed by FERC in Order 693. Similarly, TPL-002 would only contain performance criteria for Category B, and so on.

In addition to combining the standards, the SDT has significantly changed contingency specifications and required performance levels. In many cases the changes represent a very significant increase in required performance standards that will require unjustified major capital expenditures and/or reductions in ATC. This also could have an adverse impact on commercial transactions. In other cases, the performance criteria are not clearly defined, such as the timing between multiple contingencies, and the level of readiness of the system after Planning Events. The benefits from the additional performance requirements have not been identified in the proposed standard. Is there a planned phased in approachto move from the existing standard to the new proposed standards. If so, what is it?

Finally, the SDT has chosen to eliminate the footnotes in the current standards, contrary to the direction of FERC in Order 693 to "clarify" the footnotes. The purpose of the footnotes is to further explain terms in the tables, provide guidance in interpreting the expected performance criteria, and specify any exceptions to the criteria. Footnotes also serve the purpose of keeping the standard concise by eliminating repetitiveness.

Specific comments on the Draft Standard
Performance Criteria
The performance requirements table should clearly define what the initial state of the system is assumed to be before any Planning Events, and what the state of the system is assumed to be after the Planning Event. For example, P1 (single contingency) events: assuming that the system is to be compliant, the state of the system prior to the event must be "secure" such that the event could occur and there is no interruption of firm transfer or loss of load, Equipment Ratings are not exceeded, System steady state voltages and post-transient voltage deviation are within acceptable limits. However, the system is not as it was before the event. The system could be described as "normal" but perhaps not "secure". If the requirement is that the system must also be "secure" after the event, then the standard must clarify what is allowed for "system adjustments" after the first Planning event to prepare for the next. FERC Order 693 directed the ERO to modify the second sentence of footnote (b) to clarify that manual system adjustments other than shedding of firm load or curtailment of firm transfers are permitted to return the system to a normal operating state after the first contingency. However, in order to bring the system to a secure state, as is necessary for the second contingency of a

category C3 or C5 event, footnote (c) allows curtailment of firm transfers, and FERC Order 693 only required footnote (c) to be clarify the term "controlled load interruption", leaving the curtailment language intact. The implication of this interpretation is critical to peninsular Florida. The Category B loss of one 500 kV line from Florida to Georgia is sustainable, such that the system is "normal" after the event. However, in order to be prepared for the next contingency, (the loss of the second 500 kV line), firm transfers must be curtailed. (Interruption of Firm Transfer) Without the ability to curtail firm transfers, a "super-firm" priority of service is created, which is unjustified.

Comments on New Performance Tables:
The draft TPL standard represents a major change in the Table 1 contingency definitions and required performance levels.

Table 1 Contingencies C1 and C2 are being moved to the single contingency category. While C1 and C2 represent single element outages, their probability of occurrence is much lower than the other Category B contingencies and they do not belong in the single contingency performance requirements group.

Footnote (b) which permits, as a limited exception in unique circumstances with a sound rational basis, some localized load reduction for single contingencies, has been removed. This is a very significant change for some utilities. Footnote (c) which permits load shedding and curtailment of firm transfers has been removed from C1, C2 and most of C3. This is a very significant increase in required performance level that is not justified.

The "applicable rating" for loading and voltages in Table 1 has been removed so that essentially, the same ratings and voltage restrictions apply to both B and C contingencies. Some utilities plan to a normal rating for single contingencies but will allow a higher short term rating for Category C events. This practice will apparently be disallowed.

Several new Category D "extreme events" have been added which greatly expand the scope and complexity of Category D studies. These are (1) any two unrelated single element outages and (3) wide area events a. through h. These represent a major increase in the scope of Category D studies and probably a doubling of required SWG studies.
The fault with protection element failure categories D1 through D4 have been substantially changed to eliminate analysis of relay failure contingencies. The philosophy contained in the existing TPL-004 standard is that faults with a protection failure should be evaluated whether that failure is a circuit breaker, relay or CT; the proposed standard restricts the analysis to breaker failure.

300 kV Threshold Performance Level
The TPL-001-1 draft sets a threshold of higher performance to facilities above 300 kV than previously established in the existing standard. We do not agree that such a threshold is necessary or warranted nor have they been justified. Requirements which are more stringent for these facilities may wrongly influence decisions on project alternatives in favor of facilities with less stringent requirements.

DC Line Performance Requirement
The TPL-001-1 draft sets a lower performance requirement for the loss of a single pole of a DC line than in the existing standard by allowing interruption of firm transfer if the transfer is deemed to be dependent on the outaged line. Firm transfers are also dependent upon AC lines. The proposed standard does not distinguish between

asynchronous DC ties and the more common parallel connected DC tie. With an asynchronous DC tie, the transfer is lost with the tie. With a parallel DC tie, the transfer will be shifted to the parallel AC system and should have the same performance requirements. We do not agree that such an exception for DC lines is necessary or warranted. The decision in selecting DC vs. AC in transmission lines has traditionally been based on the break-even cost and performance of the two alternatives. The lower performance requirement may wrongly influence decisions on project alternatives in favor of DC facilities with less stringent requirements.

Distinction Between Committed and Proposed Projects:
Models cannot discern the difference between a "committed" project, and a "proposed" project in a performance analysis. The standard should instead set criteria for when models can be relied upon for planning purposes such that changes to the future plan will not have an impact on reliability. The intent of Requirements R2.7.3 and R2.7.4 should be combined and added into R2.7.1.1. Rather than adding the additional requirement to document a criteria, the requirement should be that in the Near-Term Planning Horizon, projects cannot be removed (or modified) without demonstrating that the revised plan meets performance criteria. In addition, the requirement in R2.7.1.1 to supply a "project initiation date" is ambiguous. What will constitute "project initiation" …construction start date? …Engineering complete date? …Land procurement date? Funds allocated date (budgeted)? Suggested wording for R2.7.1.1. "Transmission and generation improvement projects for the Near-Term Transmission Planning Horizon, shall have in-service dates provided, and shall not have in-service dates changed, or be removed from planning models, without documentation to show that the revised plan meets performance requirements." In addition to the concerns mentioned above, how are delays in meeting project in-service dates, which are not in the direct control of the Transmission Owner, caused by siting and Right of Way difficulties (public outcry, exercising eminent domain, court process, etc) addressed? The standard needs to have provisions to recognize these types of issues allowing a Transmission Owner to be compliant as long as he is using due diligence to overcome these types of delays.

Analysis of Relay Protection Failures:
This draft of the TPL standard ignores studies required for analysis of relay protection failures. There is a widespread misconception that studying breaker failure scenarios covers for relay protection failures. This is a false assumption. Typical delayed clearing for a stuck breaker is in the order of 8 to 20 cycles. This is accomplished by the local relay system sensing the stuck breaker and tripping the adjacent elements. However in the case of a protective relay failure the fault must usually be cleared remotely by tripping all lines connected to the station. Typical delays for a relay failure can easily be greater than 30 cycles. Where as breaker failure action just trips a couple of adjoining elements and leaves the rest of the station intact. A typical example of this difference is to assume a bus fault. For breaker failure, all bus breakers except the stuck one would trip. The breaker failure relay scheme then would time out and trip the adjoining breaker and the remote end of the adjoining line would trip. This could all happen in less than 20 cycles. Now consider a bus fault with the differential relay failed. The local relays don't sense the fault because they have failed, nor does the local breaker failure scheme activate because no local detection has occurred. The only way to clear this fault is to trip all lines from the remote terminals. This may take 30 cycles or more. With breaker failure, the bus and one line trips in about 20 cycles. With relay failure, all lines trip remotely isolating the substation in about 30 cycles. Both scenarios must be studied with relay failure being the worse case. Generally, different solutions are required to address relay failure verses breaker failure.

Load Modeling Requirements:
The proposed TPL Standard contains numerous references to load modeling. The goal of improving and verifying the load model is worthwhile but is not appropriate for the TPL standards. Assessment of load model accuracy is best accomplished through detailed analysis of grid disturbance events. The main difficulties in accomplishing this are (1) grid events that significant reduce transmission voltages throughout a load area are infrequently occurring and (2) the process of Recreating the event through simulation studies is extremely complex and time consuming. While these efforts should be encouraged they should remain a RRO prerogative.

R1.1.1 Use of expected Load mix based on the actual or expected aggregate mix of industrial, commercial, and residential Loads. – This requirement is not justified as the load model may be developed through disturbance analysis rather than load type synthesis by customer class. Some LSE's may have great difficulties in creating load forecasts based on customer class. Load forecasting requirements are adequately addressed in the existing MOD standards and do not belong in the proposed TPL standard.

R1.2. Load models with supporting rationale that include power factor data that may be based on historical System performance, validated by measurement during stressed System conditions, or documented Transmission planning area requirements. This requirement is not appropriate fot the TPL standarsds.

R2.4.1. System peak Load for one of the five years. For peak System Load levels, the Load model shall include the dynamic effects of induction motor Loads.

Specific types of load models should not be required in this standard.

Short Circuit Requirements: The new TPL standard also contains numerous references to short circuit analysis, which are new requirements that expand the TPL standards, but without specific testing or performance criteria. Evidence that short circuit studies have been performed is currently required in the existing FAC-002-0 Standard. Since the primary concern is the appropriate sizing of equipment and the prevention of equipment damage as opposed to overall grid reliability, we do not see the need for a set of requirements within the proposed TPL standard for short circuit studies.

Given the aforementioned issues, we believe the proposed TPL standard is inferior to the existing Board approved TPL Standards, creates unnecessary confusion, and will require many iterations of industry comment and revision. As an intermediate approach, we would strongly urge the Standard Drafting Team that the existing TPL standards be modified to respond to FERC Order 693 directives, clarify any ambiguities, and not pursue the proposed new standard any further. This would bring a much needed part of the Reliability Standards into the framework of mandatory enforcement and provide guidance on this longer term effort to improve the TPL standards.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: **FRCC**

Lead Contact: **Vicente Ordax**

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Earl Fair	Gainesville Regional Utilities	FRCC	1
Keith Mutters	Orlando Utilities Commission	FRCC	3
Donald Gilbert	JEA	FRCC	5
Gary Brinkworth	City of Tallahassee	FRCC	1
C. Martin Mennes	Florida Power & Light Company	FRCC	1
Robert A. Birch	Florida Power & Light Company	FRCC	5
John W. Shaffer	Florida Power & Light Company	FRCC	3
Ronald L. Donahey	Tampa Electric Company	FRCC	3
A. L. Barredo	Florida Power & Light Company	FRCC	3
Lee Schuster	Progress Energy Florida	FRCC	3
Bart White	Progress Energy Florida	FRCC	3
Paul Elwing	Lakeland Electric	FRCC	5
Richard Gilbert	Lakeland Electric	FRCC	3
Larry E. Watt	Lakeland Electric	FRCC	1
Paul Shipps	Lakeland Electric	FRCC	6
Thomas J. Szelistowski	Tampa Electric Company	FRCC	1
Fred McNeill	Florida Reliability Coordinating Council	FRCC	10
Ted E. Hobson	JEA	FRCC	1
Gary Baker	JEA	FRCC	3

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the

rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: "Computer" is not appropriate. Replace with "Data model" or "Database model". The last sentence is not clear as to what type of ratings (i.e., normal, short-term emergency, long-term emergency, etc.). Suggest removing sentence completely or rewording as follows: "... in accordance with the documented methodologies required by FAC-008 for each Transmission Owner and Generator Owner."**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: Need to clarify what constitues an element (e.g., breaker-to-breaker, line segment to line segment, transformer or capacitor bank)**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Reword as follows: "Events which are more severe and have a lower probability of occurrence than planning events."**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☒Do not agree.
Q4. **Comment: The definition does not have a reference year when the counting starts. Add the following to the end of the sentence: "... from the current study year."**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree.

	☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: Reword as follows: "Firm load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems, excluding (arranged or contracted) curtailments, DSM, and voltage reduction."**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Last part of the last sentence should be removed "... and other factors, such as asset conditions and age" does not make sense for planning studies. Equipment condition and age are maintenance issues not transmission planning issues.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: There should be no distinction between Plant Stability and System Stability. All stability studies must meet the Performance Requirements for Planning Events in Table 2 - Stability Performance. If there were different Performance Requirements then the distinction would be warranted.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: Dynamic voltage ratings are most often used as a proxy for lack of relay models or other modeling limitations. The definition should not address performance and should only seek to define the term. Reword as follows: "Study of the System or portions of the System to assess angular Stability and inter-area power oscillations."**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the	☐Agree. ☒Do not agree.

study publication are assumed to be conducted under the auspices of Operations Planning.	
Q11. **Comment: The last sentence of this definition is not included in the Standard and should be deleted.**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: Not all Regions' concerns are the same and therefore each Region should determine which sensitivities are appropriate.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: The Transmission Planner needs the flexibility to define what are considered "reasonably stressed" cases for their respective systems. This would not a be a proper application of a one size fits all definition.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒

Comment: The standards require near term base case cases to be studied for a broad range of planning and extreme events. The sensitivity analysis requirements contained R.2.4.3. will essentially require every dynamic simulation to be run at least twice regardless of whether or not there is any engineering insight to be gained. While improved understanding may result from sensitivity analysis of certain key event scenarios, the overall benefits of the sensitivity study requirements contained in section R.2.4.3 do not justify the huge increase in engineering effort to conduct and document these simulations with minimum to no increase in reliability.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: If DSM is included as part of an integrated Corrective Action plan, then the impact of DSM should be included by specifying the location and expected quantity of DSM that will mitigate a system deficiency. Should be permitted only if the tariff allows it and the magnitude is appropriately identified at each load bus. DSM response is limited to transmission provider's territorial customers. The use of DSM, whether exclusively or in conjunction with other measures, is an acceptable operating procedure for use in a Corrective Action Plan, as long as the Transmission Owner demonstrates availability and accuracy of DSM data and its viability as an operating procedure for each applicable scenario.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒

Comment: Incremental benefits do not justify the magnitude of additional studies. Corrective Action plans should be tested, but not as a new study with all of the Corrective Action Plans included simultaneously. Suggest replacing with language from TPL-002-0 R2..

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒

Comment: All projects should be called "Planned" projects. There is no distinction in a model between committed and proposed projects that would treat them differently. The standard should instead set criteria for when models can be relied upon for planning purposes such that changes to the future plan will not have an impact on reliability. The intent of Requirements R2.7.3 and R2.7.4 should be combined and added into R2.7.1.1. Rather than adding the additional requirement to document a criteria, the requirement should be that in the Near-Term Planning Horizon, projects cannot be removed (or modified) without demonstrating that the revised plan meets performance criteria. In addition, the requirement in R2.7.1.1 to supply a "project initiation date" is ambiguous. What will constitute "project initiation" …construction start date? …Engineering complete date? …Land procurement date? Funds allocated date (budgeted)? Suggested wording for R2.7.1.1. "Transmission and generation improvement projects for the Near-Term Transmission Planning Horizon, shall have in-service dates provided, and shall not have in-service dates changed, or be removed from planning models, without documentation to show that the revised plan meets performance requirements."

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒

Comment: See response to question 18.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	This loss is currently distinguished from other single contingencies because of its lower probability of occurrence and a more stringent performance requirement than currently exists is not warranted.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Systems have been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	Systems have been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	Systems have been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒

Comment: This loss is currently distinguished from other single contingencies because of its lower probability of occurrence and a more stringent performance requirement than currently exists is not warranted.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒

Comment: This new category P3-1 is essentially a replacement for Category C5-9 except the only protection element failure to be considered is the failure of a circuit breaker to open. This definition eliminates the need to examine failure of the relay to operate which in many cases has a more serious impact on grid reliability.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	Systems should be planned such that the loss of a generator, followed by System adjustment, followed by the loss of another generator would not result in Non-consequential Load Loss, and equipment ratings would not be exceeded etc. However, the initial state of the system must be clarified in all performance table scenarios (including P4-1).If the Base Case contained known planned outages of generating units, as implied by the requirement R1.4, then the standard performance requirements could be interpreted to require planning for all G-1-1-1 events.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	Systems should be planned such that the loss of a generator, followed by System adjustment, followed by the loss of a monopolar DC line would not result in Non-consequential Load Loss, and equipment ratings would not be exceeded etc. However, the initial state of the system must be clarified in all performance table scenarios (including P4-2).If the Base Case contained known planned outages of generating units, as implied by the requirement R1.4, then the standard

[1] System adjustment can be manual or automatic

		performance requirements could be interpreted to require planning for all G-1-1 L-1 events.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	Systems should be planned such that the loss of a generator, followed by System adjustment, followed by the loss of a transmission circuit would not result in Non-consequential Load Loss, and equipment ratings would not be exceeded etc. However, the initial state of the system must be clarified in all performance table scenarios (including P4-3).If the Base Case contained known planned outages of generating units, as implied by the requirement R1.4, then the standard performance requirements could be interpreted to require planning for all G-1-1 L-1 events.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☒Do not agree.	Systems should be planned such that the loss of a generator, followed by System adjustment, followed by the loss of a transformer would not result in Non-consequential Load Loss, and equipment ratings would not be exceeded etc. However, the initial state of the system must be clarified in all performance table scenarios (including P4-4).If the Base Case contained known planned outages of generating units, as implied by the requirement R1.4, then the standard performance requirements could be interpreted to require planning for all G-1-1 T-1 events.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☒

Comment: DC and AC lines should not be treated differently. System response is similar for the loss of an AC line versus the loss of a parallel connected DC tie. For the loss of a parallel DC tie the transfer is shifted to the parallel AC system in the same manner as a loss of an AC line. The decision in selecting DC vs. AC in transmission lines has traditionally been based on the break-even cost and performance of the two alternatives. The lower performance requirement may wrongly influence decisions on project alternatives in favor of DC facilities with less stringent requirements. Therefore, AC lines should have the same performance criteria as DC lines.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☒

Comment: There are two points of view for this question. One view is that having the persformance requirement for steady state and dynamics on two separate tables is a good idea. It makes it easier to identify the performance requirements for steady state and dynamics. The other view is that separation of these requirements into two tables is not necessary because the existing tables are clear and FERC Order 693 only required the footnotes to be clarified not to redevelop the tables. The structure of existing Table 1 reinforces the requirement for grid stability and maintaining the grid within applicable limits.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒

Comment: There should be no such distinction. All stability studies must meet the Performance Requirements for Planning Events in Table 2 - Stability Performance. If there were different Performance Requirements then the distinction may be warranted. However system stability studies should be sufficient and not warrant additional work.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒

Comment: The question does not match what is included the Extreme Events section of Table 2. The draft proposed TPL standard DOES include the loss of all generating units as Extreme Event 9 in Table 2. We agree that it is highly unlikely that all units at a plant would trip simultaneously. The preceding Extreme Event (8. Loss of a switching station - one voltage level) will in most cases adequately represent generating plant outages .

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒

Comment: The modeling of the delayed voltage recovery response that has been observed in some large urban areas during periods of high air conditioning usage is considerably more complex than simply representing induction motor effects. The scope of the delayed voltage recovery issue is extremely limited and its effect on the grid is generally self correcting due to the automatic disconnection of the affected air conditioners. Requirements for specific types of load models are not appropriate in the TPL standard.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Manual and automatic adjustment (increase or decrease) of Var output and manual and automatic tripping or reduction of overall MW output of generators should be allowed.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: At a minimum the emergency ratings should allow sufficient time for the runback scheme to operate reliably.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: The performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. If the proposed TPL standard is adopted the contingency references in PRC-012-0 would need to be updated.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: The performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. If the proposed TPL standard is adopted the contingency references in PRC-012-0 would need to be updated.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: The performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. If the proposed TPL standard is adopted the contingency references in PRC-012-0 would need to be updated.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment: No, if the comments to the above questions are incorporated. The FRCC system is a peninsular system having only one interface with the rest of the interconnected NERC system, and has historically demonstrated exceptionally high reliability with no events in recent history cascading beyond the FRCC system. The adequacy of the existing TPL standards as they apply to the FRCC System have been extensively documented.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: General Comment:

The SDT has significantly changed contingency specifications and required performance levels. In many cases the changes represent a very significant increase in required performance standards that will require unnecessary major capital expenditures and/or reductions in ATC which will have an adverse impact on commerce. Neither of these outcomes is desirable.

Specific comments on the Draft Standard
Performance Criteria

The performance requirements table should clearly define what the initial state of the system is assumed to be before any Planning Events, and what the state of the system is assumed to be after the Planning Event. For example, P1 (single contingency) events: assuming that the system is to be compliant, the state of the system prior to the event must be "secure" such that the event could occur and there is no interruption of firm transfer or loss of load, Equipment Ratings are not exceeded, System steady state voltages and post-transient voltage deviation are within acceptable limits. However, the system is not as it was before the event. The system could be described as "normal" but perhaps not "secure". If the requirement is that the system must also be "secure" after the event, then the standard must clarify what is allowed for "system adjustments" after the first Planning event to prepare for the next. FERC Order 693 directed the ERO to modify the second sentence of footnote (b) to clarify that manual system adjustments other than shedding of firm load or curtailment of firm transfers are permitted to return the system to a normal operating state after the first contingency. However, in order to bring the system to a secure state, as is necessary for the second contingency of a category C3 or C5 event, footnote (c) allows curtailment of firm transfers, and FERC Order 693 only required footnote (c) to be clarify the term "controlled load interruption", leaving the curtailment language intact. The implication of this interpretation is critical to peninsular Florida. The Category B loss of one 500 kV line from Florida to Georgia is sustainable, such that the system is "normal" after the event. However, in order to be prepared for the next contingency, (the loss of the second 500 kV line), firm transfers must be curtailed. (Interruption of Firm Transfer) Without the ability to curtail firm transfers, a "super-firm" priority of transmission service is created for non-native load customers.

Comments on New Performance Tables:
The draft TPL standard represents a major change in the Table 1 contingency definitions and required performance levels.

Table 1 Contingencies C1 and C2 are being moved to the single contingency category. While C1 and C2 represent single element outages, their probability of occurrence is much lower than the other Category B contingencies and they do not belong in the single contingency performance requirements group.

Footnote (b) which permits, as a limited exception in unique circumstances with a sound rational basis, some localized load reduction for single contingencies, has been removed. This is a very significant change for some utilities and this limited exception should be maintained. Footnote (b) was worked on extensive and achieved industry consensus at one time defining the maximum amount of load that could be shed at 100 MW. Footnote (c) which permits load shedding and curtailment of firm transfers has been removed from C1, C2 and most of C3. This is a very significant increase in required performance level that is not justified.

It is not clear what is meant by the phrase "Equipment Ratings" found in the performance requirements of Table 1. Utilities have different equipment ratings such as normal, long term, short term and emergency ratings. It is not clear that these type of ratings will be permitted in the proposed standard.

Several new Category D "extreme events" have been added which greatly expand the scope and complexity of Category D studies. These are (1) any two unrelated single element outages and (3) wide area events a. through h. These represent a major increase in the scope of Category D studies and probably a doubling of required stability studies.

Analysis of Relay Protection Failures:
The fault with protection element failures have been substantially changed to eliminate analysis of relay failure contingencies. The philosophy contained in the existing standards is that faults with a protection failure should be evaluated whether that failure is a circuit breaker, relay or CT; the proposed standard does not require the analysis of any protection failure. This draft of the TPL standard ignores studies required for analysis of relay protection failures. There is a widespread misconception that studying breaker failure scenarios covers for relay protection failures. This is a false assumption. Typical delayed clearing for a stuck breaker is in the order of 8 to 20 cycles. This is accomplished by the local relay system sensing the stuck breaker and tripping the adjacent elements. However in the case of a protective relay failure the fault must usually be cleared remotely by tripping all lines connected to the station. Typical delays for a relay failure can easily be greater than 30 cycles. Where as breaker failure action just trips a couple of adjoining elements and leaves the rest of the station intact. A typical example of this difference is to assume a bus fault. For breaker failure, all bus breakers except the stuck one would trip. The breaker failure relay scheme then would time out and trip the adjoining breaker and the remote end of the adjoining line would trip. This could all happen in less than 20 cycles. Now consider a bus fault with the differential relay failed. The local relays don't sense the fault because they have failed, nor does the local breaker failure scheme activate because no local detection has occurred. The only way to clear this fault is to trip all lines from the remote terminals. This may take 30 cycles or more. With breaker failure, the bus and one line trips in about 20 cycles. With relay failure, all lines trip remotely isolating the substation in about 30 cycles. Both scenarios must be studied with relay failure being the worse case. Generally, different solutions are required to address relay failure verses breaker failure.

300 kV Threshold Performance Level
The TPL-001-1 draft sets a threshold of higher performance to facilities above 300 kV than previously established in the existing standard. We do not agree that such a threshold is necessary or warranted. Requirements which are more stringent for these facilities may wrongly influence decisions on project alternatives in favor of facilities with less stringent requirements.

Load Modeling Requirements:
The proposed TPL Standard contains numerous references to load modeling. These modeling requirements should be addressed in the MOD Standards. The goal of improving and verifying the load model is worthwhile but is not appropriate for the TPL standards. Assessment of load model accuracy is best accomplished through detailed analysis of grid disturbance events. The main difficulties in accomplishing this are (1) grid events that significant reduce transmission voltages throughout a load area are infrequently occurring and (2) the process of Recreating the event through simulation studies is extremely complex and time consuming. While these efforts should be encouraged they should remain a RRO prerogative.

* R1.1.1 Use of expected Load mix based on the actual or expected aggregate mix of industrial, commercial, and residential Loads. – This requirement is not justified as the load model may be developed through disturbance analysis rather than load type synthesis by customer class. Some LSE’s may have great difficulties in creating load forecasts based on customer class. Load forecasting requirements are adequately addressed in the existing MOD standards and do not belong in the proposed TPL standard.

* R1.2. Load models with supporting rationale that include power factor data that may be based on historical System performance, validated by measurement during stressed System conditions, or documented Transmission planning area requirements. This requirement is not appropriate for the TPL standards.

* R2.4.1. System peak Load for one of the five years. For peak System Load levels, the Load model shall include the dynamic effects of induction motor Loads. Prescribing specific types of load models in this standard is not appropriate because system topology and load make up may be unique from area to area.

Short Circuit Requirements: The new TPL standard also contains numerous references to short circuit analysis, which are new requirements that expand the TPL standards, but without specific testing or performance criteria. These performance criteria are better suited in the FAC Standards since evidence that short circuit studies have been performed is currently required in the existing FAC-002-0 Standard. Since the primary concern is the appropriate sizing of equipment and the prevention of equipment damage as opposed to overall grid reliability, we do not see the need for a set of requirements within the proposed TPL standard for short circuit studies.

Table 2 Angular Stability Notes: The requirement of generation loss not exceeding BA spinning reserve requirement (1.a.ii.) is an unjustified increase in required performance level from the existing TPL Standard which require the grid response to be stable and within applicable ratings. The portion of the notes requiring generator out-of-step protection are inappropriate and unwarranted. First, the simulation result may show the generator being tripped by backup distance or loss of field protection which may be acceptable to the generator owner. Second, the requirement for impedance swings not causing other transmission elements to trip is inappropriate and in conflict with manufacturer recommendations and prevailing practice for generator out of step protection. Most generator out of step relays are set to trip on the "way out" so as to limit phase angle difference across the opening contacts. With this practice, one can not prevent transmission line tripping due to zone 1 pickup without installing out of step blocking should the swing impedance passes through zone 1 relay. Out of step blocking of zone 1 relays is a bad idea as it opens the door to prolonged asynchronous connection of generators.

Circuit Breaker Contingencies: The proposed TPL standard separates circuit breaker related contingencies based on the intended use of the circuit breaker. If the circuit breaker is used to connect busses together (i.e. bus tie breaker) a lower level of performance is required than for other uses and configurations. The existing TPL standards have the contingency events and required level of performance appropriately ordered based on the probability of occurrence. We are not aware of different failure rates for bus ties breakers as opposed to the general circuit breaker population. The proposed standard requires an unjustified higher level of performance for non bus tie breakers and would encourage the use of low cost switching station arrangements such as single breaker/single bus which are less reliable.

Need to clarify the performance requirements that apply to sensitivity studies. These requirements should not be the same.

A.3. - Suggest replacing the word "probable" with "credible" for consistency with the white paper from the Operating Limit Definitions Task Force.

R2.1 - It is not clear how the requirement to address all 5 years can be accomplished when the annual studies do not require all 5 years to be studied. Is the planner expected to study the other years also, but that the required set of cases does not link to each of the 5 years?

R2.2.1 - This requirement creates compliance concerns. Therefore, it is suggested that the SDT clarify that the Long Term Assessment is not required beyond 10 years.

R2.7.3 - The term "proposed" may not be a good choice here ... especially since that's not a term used in other reliability assessments .... should another term be chosen or perhaps this definition could be matched up with work being done now on classification of resources for RAS.

Steady State Performance Table:

P1 - If the transmission line outaged is the facility defined by contract as being the only contract path for the firm transfer, then the firm transfer will be interrupted. P1 should be clarified that this is acceptable.

P3 - Are these elements meant to be combined into a multiple contingency or considered separately (since they are listed with commas)? Or is this meant to be one of the 3 elements listed first AND the stuck breaker? Not clear the way this is worded. Or maybe the structure needs to be different in the sentence (like bullets for the first 3 that would make the "and" stick out more).

NERC Standards TPL 001-0 through TPL 004-0 are approved standards that only required modifications pursuant to FERC Order 693. In this proposed draft standard TPL 001-1 the Standard Drafting Team (SDT) has far exceeded the recommendations suggested by FERC in that Order. The proposed draft standard is a large change in the magnitude of the performance requirements from the exiting TPL Standards. The SDT needs to consider how this proposed standard will be implemented in this new mandatory compliance environment and ensure that reasonable compliance measures can be developed from the proposed standard.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: The base case is also a representation of firm transactions through a BES, generation resources, and models reactive components.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: This definition implies that load that is lost past the directly connected load is allowed. Therefore the definition should be changed to include radially connected load and load that is radialized as a result of a contingency or mis-operation.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: All events on the BES have a low probability of occurrence. Extreme events are those events that have a high consequence to the BES if they were to occur.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such	☐Agree. ☒Do not

as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	agree.
Q6. **Comment: Suggest a change in title to Indirect Load Loss**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Asset conditions and age should not be included in the definition. Equipment replacement, in general, is dependent on performance, not age.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Performance requirements should be added to the definition.**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: The first sentence in not necessary. A Planner may use the base case to further assess a problem in the current year. The definition should begin with "The next planning year following current annual studies".**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the

requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: Sensitivity analyses should not be prescribed. In one system there may be various sensitivites based on region, generation location, number of long range projects, etc. The Planner should provide a summary of the critical sensitivities and documentation supporting their definitionis.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: See comment to Q12.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: The sensitivities should be determined by the Planner. As part of the development of long range projects, sensitivity analyses should be performed.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system

deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒
Comment: DSM should not be a requirement in considering Corrective Action Plans. Because DSM cannot be counted on or controlled, its use as a Corrective Action Plan should not be assumed.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒
Comment: This is the essence of planning. All entities should ensure that Corrective Action Plans address the identified constraints and work within the BES infrastructure. It is not clear what the intent of "new" studies is. Since the evaluation of Corrective Action Plans is part of the planning process, what new studies is this requirement referring to. The determination of the study area should be by the Planner.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment: They are inherently treated differently. "Committed" projects are a part of the base assumptions in the base case, while "proposed" projects are evaluated until a point where corporate commitment has been made.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: See responses to Q17 and Q18.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to

clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	No change from current standards.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	This requirement appears unreasonable for a network system and, particularly, for a series of events. This requirement would be well above current reliability standards. The requirement would also result in higher investment costs for the utilities.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	Not applicable to our existing system
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	Not applicable to our existing system

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: The standard needs to clearly define a non-bus tie breaker. It is also not clear whether the focus of the standard is the kV level or the equipment type. A material change to build new facilities would be needed to meet this new requirement.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: A material change to build new facilities would be needed to meet this new requirement.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	

[1] System adjustment can be manual or automatic

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Special Protection Schemes should be allowed for single and multiple contingencies.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Generation curtailment should allow the system to operate within the facility capabilities and should not put the generator at risk of violating its NERC requirements during curtailment.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: None.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: PRC Standards

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment:
R1.4: The planning assessment is to identify the needs of the BES. A spare equipment strategy should support the needs of the BES, not vice versa. Long-term outages need to be defined.

R2.2.1 Not clear on the purpose of this requirement. Is the concern that the Planner perform a ten year analysis even when the in - service years are outside of the current ten-year planning horizon? The extension period should be defined.

R3.2 Current models do not have the capability of performing the assessments necessary to meet this requirement.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
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Q1. **Comment: There are a two undefined terms in this definition: "Transmission System" and "interconnected Transmission System". The definition needs to specifically identify what should be modeled applicable to the subject area and in a manner consistent with other NERC definitions. The definition refers to Facility ratings rather than the general reference to FAC-008 & FAC-009**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☒Do not agree.
Q2. **Comment: ``directly-connected`` load loss would be more clear**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Modify to "Events which are more severe,but have a lower probability of occurrence, than Planning Events".**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such	☒Agree. ☒Do not

as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	agree.
Q6. **Comment: A better name for this would be "indirect load loss".**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Eliminate "capital" from the definition. It is not defined or consistently applicable to the standard. Reference too vague "other factors, such as asset conditions and age" should be removed from this standard; there are no consistent definitions or industry standards on which to base this requirement, nor does it appear to be a necessary addition to the standard.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Propose, "Events for which Transmission performance requirements must be met".**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: See comment on Q9; proposed modification, "Study of the System or portions of the System to determine whether system angular Stability is maintained, power oscillations are damped, and voltages during the dynamic simulation stay within acceptable perfomance limits.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☒Do not agree.
Q11. **Comment: Modify to, "The first year that a Tranmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner completes and communicates its annual studies."**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement to develop action plans in accordance with consequences of problems highlighted as a result of one of the sensitivity case study.

Suggest modification to, "…sensitivity testing that stresses the System shall be considered, and documentation with the rationale for the sensitivity testing shall be supplied. The sensitivity case(s) may include one or more of the following conditions:"

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement to develop action plans in accordance with consequences of problems highlighted as a result of one of the sensitivity case study.

Reasonably stressed conditions are dependent upon the study area under review and the standard is not likely to be able to be crafted to provide sufficent and consistent direction. However, it might be helpful if the standard clarified whether the base case should include any unplanned generator outages or whether, aside from potential sensitivities, unplanned generator outages are considered only through P1, P3 or P4 Contingencies. If the standard addresses unplanned generator outages only through P1, P3 and P4, then it is recommended that a mandatory sensitivity analysis, with required mitigation, include various potential combinations of a reasonable amount of unplanned outages. The combinations should be based on the part of the system that is under study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment: The standard is unclear whether or not it mandates the requirement to develop action plans in accordance with the consequences of problems highlighted as a result of one of the sensitivity case study.

Suggest modification to, "…sensitivity testing that stresses the System should be considered. Sensitivity case(s) might include among the following conditions:" 2.4.3 shold mimic 2.1.3 except in regard to load models.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: There is no need for sensitivity analysis.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: DSM should be included to the extent that its performance is sufficiently and consistently understood. The standard does not use the term "optimal" Therefore, the Drafting Team appears to be interpreting the Standard to require a vertically-integrated Planner to produce a so-called optimal-mix of resources plan. This would be an incorrect assumption and is not required. In areas with independent planners and competitive wholesale markets, it is sufficent to identify system needs and produce a plan that identifies regulated transmission solutions in the event that market-based resources (such as DSM) do not address those identified needs. Therefore, while DSM can be as effective a resource as generation, per Commission Orders, in areas with ISOs/RTOs and a competitive wholesale market, the NERC Standard cannot prescribe the development so-called optimized (as is suggested by the Drafting Team) resource-mix plans, as identified by a central planner.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: The study area should be based upon planning expertise and knowledge of the system, giving due consideration to external impacts.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment: They should be viewed differently in the Near-Term.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment: It is unclear as to what the committed project is being removed from. Suggested language "…removed from the plan…".

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☒Do not agree.	The term "bus section" needs to be clarified. Some examples should be given showing actual diagram of substation layout.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Given the low probability of extended overlapping outages of overhead facilities, systems have been designed assuming that load shedding following the loss of a second transmission line is permissible. Eliminating any allowance for load shedding for this condition may require significant system expansion and cost to to customers.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐

Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of 2 additional generators.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a monopolar DC line
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a Transmission circuit
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a transformer

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐

[1] System adjustment can be manual or automatic

Comment: This should also apply to firm transfers via single or double ac facilities as well. In either case, the transfer could be linked to dedicated facilities.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☒
Comment: The contingency studied are the same and as a result should be combined into one table. Only the performance might be different.
We understand the need to clarify the different requirements in the steadystate vs. the stability analyses. However, for each contingency category we expect to see both the steady-state requirements and the corresponding stability requirements in the same table. We believe that it would be better to recombine the steady-state and stability tables and present the information in a landscape format.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Difficult to envision how such an event would occur.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: This requirement is too specific and limited. Induction motors are only one component of a complex load model. Complex load models are not always necessary, nor are they always the most conservative, depending on the analysis that is being conducted. Where complex load models are required, they should be considered; this may involve use of complex motor and lighting loads or polynomial load representations

with or without frequency dependence. This question also suggests the need for an industry standard regarding transient voltage recovery.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Manual or automatic adjustments should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment. Manual system adjustment should be allowed in between the multiple Contingencies described in P5, provided that the adjustment can be made between contingencies using short-term reserves (10-30 minute).

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment: Generation runback should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐

Comment: However, this should only be allowed where failure of an automatic runback that is not functionally redundant would not have significant adverse impact on the Bulk Power System.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: A SPS may be used to provide protection for infrequent contingencies, or for temporary conditions that may exist such as project delays, unusual combinations of system demand and equipment outages or availability, or specific equipment maintenance outages. An SPS may also be applied to preserve system integrity in the event of severe facility outages and extreme contingencies. The decision to employ an SPS shall take into account the complexity of the scheme and the consequences of correct or incorrect operation as well as its benefits.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: See response to Q38.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: System must remain stable with acceptable voltages and all equipment within applicable emergency limits.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☒
Comment: Until section R3.6.1 is finalized, we will be unable to determine whether a regional variance is required.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment:
We think that the proposed fusion of previous TPL-001 to TPL-004 and the addition of more specific contingencies involves too much change at once. It would have been better to make specific change to each individual standards. That way, it would have been more practical to evaluate the impact of the proposed changes.

A major concept before evaluating the impact of a standard is to know on what system it will be applied to. In the tables, the notion of a voltage treshold (>300 kV) is introduced. It is our interpretation that the standard as drafted applies only to BPS elements part of that treshold (>300 kV) and not every ">300 kV" element. The SDT should indicate if they have the same interpretation as ours.

We reiterate our comment that it would be preferable to have only one table that would include both steady state and stability contingencies with their respective expected performance.

There might be some protection standards that would need to be developped/clarified before some proposed changes in this standard.

The SDT has made an effort to define Base Case, yet has not used the term in the standard. At a minimum, Base Case should be referred to in sections 2.1.1, 2.1.2

R.1.1 Load forecasts should be addressed in MOD standards, not TPL.

R 1.4 This should only refer to known long-term outages, not planned outages. Delete "including protective relays"; this is addressed through other provisions.

R2.1, 2.2, 2.3 & 2.4 – The initial paragraph should have identical language regarding 'annual', and 'current or past' aspects.

R2.1 There should not be a requirement to look at years one and two; a 5 year study should be sufficient. If there has been an ongoing 5 year study, there should be no major unexpected problems occurring in years 1 and 2. Studies of earlier years should only be required if an unanticipated event occurred that had not been considered in prior studies. The TPL should not address shorter term "Operating Studies" or operating issues.

R 2.2.1 Modify to "If any known projects have a lead time that is longer than ten years, the Planning Assessment shall be extended accordingly."

R 2.6.1 Remove reference to "market structure changes". The purpose of its inclusion is unclear.

R 2.7.1.1 Project initiation date should be deleted. If it is retained, it needs to be defined.

R 3.2.1/R 4.3 - What is the intent of this requirement? There should probably be an MOD associated with Generator Owner requirement to provide related generator protection/ limiter data or other plant information.

R 3.4/R 4.5.2 Remove the requirement to implement changes to reduce or mitigate the likelihood of such consequences of Extreme Events. This may not be reasonable or achieveable.

R 3.2 Sectionalizing schemes shall be considered when reflecting the post-contingent system.

R 3.3.2.1 - Proposed deleting "expected duration". This would be dependent upon the damage to the element due to the iniating event and other factors.

R 3.3.3 - Change introductory language to read "Those multiple Contingencies that are…"

R 3.5 - Generation tripping should be allowed as well as generation run-back. In addition, all performance requirements shall be met, rather than just meeting facility rating requirements. Suggested language "Manual and automatic generation run-back and/or generation tripping is allowed as a response to single and multiple Contingencies as long as the performance requirements of this standard are met." If these changes are accepted, R 3.6 can be deleted.

R 4 and R 4.1 - The language should be made similar to R 3 and R 3.1.

Suggest bringing language similar R4.4 into the R 3, the steady state section.

R 4.2 - High speed automatic reclosing schemes shall be considered.

R 6.2 - Change to read "Transmission Planners of neighboring areas".

Table 1 3 b and c Extreme Event descriptions are vague concepts that cannot be practically simulated. 3 d and e are not reasonable or practically useful to simulate.

Table 1, P8 - Language needs to be clarifed as to how the 300 kV threshold is to be treated for transformers. Is this for the high side, low side, or both sides? P5 is much clearer.

Table 2 P9. Recommend that this be changed to require that faults should be on different phases of each of two adjacent transmission circuits on a multiple circuit transmission tower

Table 1, P9(6) and Table 2 P9 - It is unclear as to what is meant by "A spare transformer inserted to replace an outaged transformer followed by System adjustments". Unclear as to what is to be tested.

General comment - Transmission System is used throughout the document and is an undefined term, both "Transmission" and "System" are defined NERC terms. We recommend that the SDT use the term "System" to replace "Transmission System". System is defined as "A combination of generation, transmission, and distribution components".

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment: The proposed definition fairly reflects the starting point system model used for planning and operations studies.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment: This is the same understanding of the IESO.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: We offer alternative wording to more accurately reflect the lower probability of extreme contingencies than their Planning counterparts, as follows:** **Events which are more severe and have a lower probability of occurrence than Planning Events.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment: Consistent with the IESO's understanding.**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment: Same as above.**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs	☐Agree.

through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Do not agree.
Q6. **Comment: Suggest to either stop at "automatic operations" or to include other examples since the list is not exhaustive, for example: load that drops out due to unacceptable voltage levels (not tripped intentionally by UVLS.**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☒Do not agree.
Q7. **Comment: The definition covers too much detail on the "how" part, and the "documented" qualifier doesn't seem to be required. Suggest to change it to: Evaluation of future Bulk Electric System needs to meet forecast demand under the assumed system conditions for the time frame studied.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Linking it to Transmission system performance requirements presents "loop around" argument. Suggest to change it to: Events which need to be considered and simulated in planning assessments to evaluate Transmission system performance.**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Suggest to replace "Contingencies" with "Planning events", and change the definition as follows:** **Study of an individual generating plant's capability to remain in synchronism and exhibit damping of the generating units' power oscillation for various Planning events.** **Note that "in the vicinity of the plant" is removed to not restrict simulations of events only in the vicinity of the plants as experience has shown that an event remote from the plant could also subject the plant to lose synchronism and/or oscillate without acceptable damping.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: This definition contains requirements that the system must exhibit acceptable performance. The study itself is a tool to assess how the system behaves when subject to Planning events. Suggest to change it to:** **Study of the System or portions of the System to assess the System's performance in the domain of angular Stability, inter-area oscillations and voltage profile during dynamic simulation.**	

Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: Not sure why we need this definition. The standard can simply be worded such that a Transmission Planner is responsible for assessing system needs for time frame beyond the current year. Introducing Operations Planning creates confusion as it is unclear whether this term describes a function or an entity in the context of the proposed definition. Further, the sentence "Analysis conducted for time horizon within the current year from the study publication are assumed to be conducted under the auspices of Operations Planning" is (a) confusing time frame wise, (b) invites debates on the role and responsibility for a term that is not defined in NERC standard or the Functional Model, and (c) is perceived to be prescriptive in organizational setup/responsibility allocation (e.g. why can't a transmission planner conduct operational planning studies?).**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: We do not support introducing sensitivity testing as requirements in the standard, let alone specifying the number of sensitivity cases that need to be developed.

In general, there are two interpretations of sensitivity testing - the type to assist in scoping out planning studies and the type to test the stretched capability of the proposed plans. In the first case, sensitivity testing is conducted to assist in identifying restricting parameters/phenomena, critical faults, and scoping out the conditions that need to be assessed, etc. As such, the scenarios to be included in sensitivity testing vary from one Transmission Planner to another depending on local needs and system characteristics, and even from one study to another for the same area to be assessed. The scope of sensitivity testing is therefore difficult to pin down.

In the second case, while variations such as percentage of forecast peak demand can be picked as a common parameter for sensitivity testing, the follow-on actions, or inactions, after obtaining the test results would be at the sole discretion of the Transmission Planner unless they are specifically addressed by reliability standards. Requiring a Transmission Planner to conduct sensitivity testing, and even to require it to study a specific number of cases case may put a Transmission Planner in a quandary. For example, if sensitivity testing for a case with 5% higher than forecast peak load shows that the system needs a new 500 kV line in a certain area, should the Transmission Planner propose the new line? If so, what are the reliability and economic justifications when it is clearly demonstrated that the line is needed only if the load for that studied time frame turns out to be 5% higher than forecast? If the answer is yes (to propose adding the line), then why don't we simply require that all planning studies assume a condition that is more conservative than that forecast, and stipulate these conditions in the standard accordingly? If not, will the Transmission Planner be criticized for not taking proactive action to manage the potential risk?

Similarly, a Transmission Planner is faced with a much wider study scope if it is required to study the condition assuming one or more major transmission facility is unavailable due to forced outages. These scenarios are more aptly addressed in operations planning or near operations time frame when transmission facility and other system conditions become more predictable. Studies conducted well in advance of real time already rely on many enabling assumptions. Introducing a requirement for sensitivity testing and with specific number of test cases would render the study task difficult to manage, and may put the Transmission Planner in a quandary dealing with the test results. If the standard should require a Transmission Planner to study up to one transmission facility out of service, then this requirement should be clearly stipulated.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a “reasonably stressed” case?

Yes ☐ No ☒
Comment: See comments above. Also, the term "reasonably stressed" is not measurable.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒
Comment: For similar reasons stated in Q13, above.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: We agree, but this raised a question on why did the SDT introduce a requirement for sensitivity testing for year one to year 5 studies but not the year 6 and beyond studies. Wouldn't the degree of uncertainty be higher in the longer time frame?

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒

Comment: No, the amount DSM is, in some established markets, a market-arranged quantity that depends on both the offered price and the discretion of the LSE or load customer at the time such a price signal presents itself. The resultant amount of DSM that can actually be realized when needed is unpredictable.

This requirement also brings up a broader issue. Requirement 2 generally applies to Planning Coordinator and Transmission Planner, there is no distinction made as to which sub-requirements apply to which entity. In some markets, the Transmission Planner is responsible for assessing future needs for transmission facility only. It does not have the authority to even suggest a corrective plan that involves generation improvement or DSM. The way R2 and its sub-requirements is written is more suited for an integrated planning process, which may not exist in some places/developed markets.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: We feel that having the requirement to retest the conditions which show a performance deficiency, but now with the proposed corrective measures, would suffice. To illustrate or require "how a study area should be determined" would be micro-managing, and the term "a study area" is not defined anywhere in the standard and is subject to different interpretation. For example, does it mean the physical area of study or does it mean the various areas in the study that need to be explored. We are therefore unable to offer any view as to "how a study area should be determined".

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☒
Comment: Yes, the distinction should be made as committed projects have a higher degree of certainty to be available for the period under study, whereas a proposed project is one that is supported by the assessment but the commitment to proceed is not yet secured. However, we do not see the need (a) to establish criteria for committed projects and proposed projects, and (b) to distinguish between the criteria between them. If the standard should require a TP to assess both scenarios - with and without proposed projects, then this should be clearly stipulated.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☒
Comment: We agree that committed projects should not be removed from the revised plan. But we question the need for this sub-requirement which calls for: "Revisions to the Corrective Action Plans are allowed over time but shall meet the performance requirements.." Committed projects are normally included in the planning studies for which the performance is assessed. Deficiency, if identified, will have a corrective plans developed. We do not understand the need to remove or revise the committed plan in this context.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	We agree, since the loss of a bus is a single contingency. This is a criterion already adopted by the IESO and other members in the NPCC region, for which non-consequential loss of load is not permitted.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☒Do not agree.	The sequence of events is too general that under some condition, it contradicts with the loss of 2 circuits on the same tower for which non-consequential loss of load is permitted. If the sequence of events is specified such that the two transmission circuits that can be lost are unrelated, then non-consequential loss of load should generally not be allowed following system adjustments after the loss of the first transmission circuit.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☒Do not agree.	Similar reason as above. In this case, the first transmission may also remove a transformer from service if they are in the same protection zone. The next contingency can be the loss of the companion transformer, without a fault on the transformer itself but not on the transmission circuit. If the transmission circuit and the transformer are unrelated, then we would agree that non-consequential loss of load should not be allowed.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☒Do not agree.	Similar reason as above.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: Agree. In general, non-consequential loss of load should not be permitted for any single contingencies.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment: See reason stated for Q24, above.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	The loss of a generator is different from the loss of a transmission facility. The former usually does not result in changes to the system topology nor system operating limits. While loss of 2 generators may result in resource deficiency, the decision to shed load would only be made when operating reserve cannot be replenished after the first contingency, and when the second contingency would result in violation of any SOLs or IROLs or BAL standards for which adjustment cannot be made within the required time line.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	Same reason as above except in this case, the loss of a monopolar dc line could interrupt import. Again, it is a resource issue, not a transmission reliability issue.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission	☒Agree. ☐Do not agree.	Similar reason as above. In this case, while the second contingency is the loss of a transmission circuit, the first contingency (loss of a generator) has

[1] System adjustment can be manual or automatic

circuit		not changed the system topology. Hence, the system condition after having been adjusted following the first contingency should in essence be similar to the all transmission facilities in service condition for which the non-consequential loss of load performance for single contingencies is expected.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	Similar reason as above.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☒
Comment: Whether or not interruption of firm transfers should be allowed is more a business arrangement issue than a transmission reliability issue. Usually, delivery over a DC line, either as an import or access to internal or external resources, is factored into the resource integration plan to support meeting demand and energy transfers. The commitment for firm transfers may be made on the reliance of this delivery. However, the contingent loss of any resources including import is assessed in determining the amount and terms of firm transfers to a third part. This is a business and resource allocation issue, not a transmission reliability issue.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☒
Comment: We agree that the performance requirements for steady state analysis differ from those for stability analysis, but not the contingency requirements. While the specification of, for example, a line to ground fault on a single facility does not mean much to a steady state analysis, and in fact the loss of a single facility is all that it matters, the system is subject to the same type of contingency regardless of the type of analysis to be performed and hence the same contingency needs to be tested in both steady-state and dynamic simulations.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☒
Comment: We agree that both plant stability and system stability have to be studied and that both must exhibit acceptable performance to deem a testing acceptable. The performance requirements for the two could be different, but not the contingency set that must be tested.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐
Comment: Consistent with our comments provided under Q31, while the performance requirements may be different, there should be no distinction made to the type of contingencies that need to be applied to steady state testing and stability testing. An entire generating station may be lost due to various possible reasons: lost of right of way of transmission lines emanating from the generating station; generic protective relaying problems which cause all relays to operate due to a common cause or common mode event.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment: Dynamic testing should assess response of moving equipment including induction motor loads.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Automatic adjustments should include AVR, excitation system, stabilizer and governor, all of which have pre-determined settings. These adjustments should be allowed for any type of contingencies. Manual adjustments that should or can be made other than removal of the generating units from service could include manual switching of transmission and adjustment to Phase Angle Regulators for so long that these actions are documented as applicable operating procedures.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to

maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment: Generation rejection and runback are not uncommon to be employed as special protection systems (SPS) to achieve a stable state and/or reduce transmission loading to within pre-determined levels. SPSs, when employed, are designed to operate in order to meet performance requirements following specific contingencies or when specific system conditions are present. As such, when a contingency occurs or when the conditions should arise for which the SPS (in this case, generation runback) is designed to operate, such actions should be simulated.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Please see our response to Q36 for the rationale for allowing the runback scheme to operate. The conditions that need to be met in order to allow the scheme to operate depends specifically on what that SPS (runback scheme) is designed for. Some schemes are designed to operate upon detecting the opening of specific transmission lines, others are designed to operate upon detection of circuit loading reaching a particular threshold. There is no universal rule as to the conditions that must be met for a runback scheme to operate. The use of runback scheme is similar to using special operating procedure, such as cross tripping, operator instructions to open a circuit, etc. There might be design requirements to ensure the scheme meet certain performance criteria. However, these should be covered in the standards for special protection system. In TPL-001, the requirement would be to include simulation of the runback scheme operation only as the conditions that would prompt the scheme to operate occur, and a requirement to include SPS misoperation, i.e., failure to operate and operate when not initiated, as a contingency.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: SPS and RAS should be allowed for single contingencies. However, a more fundamental requirement is that the SPS (and RAS) should generally be regarded as a stop gap measure before planned transmission expansion or reinforcement becomes available. SPS should in general not be used as a substitute for transmission facilities.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Please see comments provided under Q38, above, regarding the use of SPS not as a substitute for transmission facilities. In addition, there should be requirements to simulate failure of SPS operation as a contingency in addition to the initiating single contingency. In cases where an SPS is intended to achieve acceptable stability performance which can affect interconnection reliability, the SPS should be classified as BES impactive and as such, redundancy may be required. When redundancy is provided, simulation of SPS failing to operate may be waived.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: As indicated in the comments provided under Q38 and Q39, the conditions to simulate operation of the RAS and SPS would depend on the conditions they are designed to protect. We do not believe such conditions can be generalized.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment:

(1) Pertaining to Q1 to Q11: we do not see the need to define this many terms for this standard. Many of the terms are easily understood and have been used in transmission planning for years that the majority of planners in the industry know what they mean. For example: base case, extreme contingencies (these are in fact listed in the table),

planning assessment, planning event, etc. Furthermore, the terms plant stability and system stability are also well understood to mean "machine synchronism" and "system oscillation/damping".

Among the proposed definitions, only the following terms need to be defined to add clarity:

a. Consequential (and non-consequential) loss of load
b. Long-term vs near-term (suggest to change it to short-term) planning horizons

(2) We do not see the need to use the term RAS (Remedial Action Scheme). The term SPS (Special Protection System) is common used in the industry to generally mean any protection scheme that is designed to initiate actions to control flows, voltage, generation runback or high speed rejection, switching of shunt devices, cross-tripping in response to some pre-determined parameters such as loss of a circuit or some threshold voltage or line flow level. Introducing the term RAS would be confusing to suggest that they do not equate to or are not a part of the SPS.

(3) We interpret the requirement stipulated in R1.1.1 is intended to enable more accurate simulations of load response - both in steady state and dynamic analyses. However, we do not support having this level of granularity (eg: industrial, commercial, residential etc.) stipulated in a planning assessment standard as similar requirements already exist in several MOD standards that deal with forecasted load and modeling. We suggest the mix of load detailed requirements be addressed in the latter set of standards. Similarly, R1.2 is best addressed in the MOD standards. Specific to R1.2, we do not agree with the requirement to provide supporting rationale that include power factor data based on historical System performance, validated by measurement during stressed System conditions, or documented Transmission planning area requirements. Load forecast data already provides projected mix of real and reactive demands and type of load.

(4) R1.4 and R2.1.3 require outages be considered in the planning process. We suggest the SDT clearly stipulate that only known planned long term outages (with a minimum duration to be defined) need to be considered. This suggests is made on the basis that:

- Only known outages should be modeled. The need to model unknown outages would render study scope to be too wide to manage
- Only planned outages should be modeled for the same reason.
- Only known planned outages > a certain period should be modeled since it would be unrealistic and unmanageable to model and propose planning solutions to system constraints that appear to last less than, say, 2 weeks. As a general practice, many planners apply a 4 week period as the minimum for inclusion in planning assessment.

Without narrowing the scope, planning assessment will be an enormous task and difficult to manage.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name: Brian F. Thumm		
Organization: ITC Holdings		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment: Firm obligations may possibly include obligations beyond "firm transactions" which most likely means grandfathered transactions and TSRs as you have written it. The planning base cases should have sufficient margins to cover uncertainties as well as "firm transactions". The ATCTDT has "drafts" in place which require that TRM and CBM be included in transmission planning studies for both the near-term and long-term planning horizons. While they are drafts at this stage, consideration should be given to including their requirements in your drafts.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment: Suggest a change in terminology to "direct".**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment: R3.4 implies that "extreme events" will be studied as per the table. The definition seems functionally correct as applied to the standard but somewhat confusing. The existing wording implies that a mitigation plan should be developed if studies show that "extreme events" might cause cascading. If the mitigation plan is a true requirement, saying it is not a planning event can be confusing. "Extreme events are more severe than Planning Events, have a low probability of occurrence and only require___?????_____ in the event of cascade."**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.

Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment: May want to change the terminology as some may interpret this to mean load that is not important and can routinely be shed for any contingency. Suggest 'direct load loss' and 'indirect load loss'. Potential Definition: Load that is not intended to be lost for normal fault clearing or during mis-operation but could be lost either by design, such as under frequency relaying, SPS or backup breaker clearing, or thru manual operator action.**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☐Do not agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☐Do not agree.
Q11. **Comment: Adding a statement specifying that this is at least ??? number of months into the future may be prudent.**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☒ No ☐
Comment: The standard should provide a minimum number of sensitivity cases that should be developed and should include at least a higher load forecast (90/10 vs. 50/50) and a higher generator unavailiablity (LOLE - 1 in 10).

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☒ No ☐
Comment: "Modification of expected transfers" should include unexpected loopflow caused by 3rd parties where applicable. In addition to the obvious impacts on system margins, loopflows have been identified as a major reason that FTR feasibility is hard to predict.

Also, see answer to Q12 above.

Some level of flexibility for some of the stressed cases should be left to the individual Planning areas as they would know typical load/stresses seen by their systems that should be studied and solutions identified for problems.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment: Both peak and off-peak models have been historically used for stability analysis and should continue to be used. The need for additional sensitivity studies should be left to the discreton of the Transmission Planner.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: We believe that both near-term and long-term studies should include sensitivity studies. Near-term studies may produce either operating solutions and more limited transmission solutions. It is just as or more important in a standard like this one to also do sensitivity analysis for the 6-10 year and beyond period. This is necessary to provide the needed advance notice for long-lead time alternatives to problems which are uncovered. Focusing on the next 5 years limits alternatives that can be implemented.

In fact, it makes sense to perform more sensitivity analysis on the longer term as assumptions become less probable the further out into the future you get. If a problem is identified in one snapshot 10 years out it may be less relevant than if it shows up in several varying snapshots 10 years out into the future. The use of sensitivity studies for the 6-10+ year horizon will hopefully have the effect of minimizing the use of band-aid type approaches to identified problems.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: DSM alternatives should focus on existing contractual relationships only. DSM is an alternative to “capacity solutions” and you have to give weight to how well you can count on it during capacity emergencies. Will the load be there to cut? How

certain are you (contractually) that the load will be shed voluntarily when called upon to do so?

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: Without further study once a "solution" has been proposed how can one be sure it will work and not create "other" issues? The area of study should be developed using good engineering judgment with input from any neighboring parties that might be impacted.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: All projects should naturally become committed projects at some point prior to the need date. The time frame should be dependant on the scale and voltage class of the project.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment: We agree.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	Should also consider no or limited loss of load for facilities 100 kV and above.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	Should also consider no or limited loss of Non-consequential load for facilities 100 kV and above. This should be no loss for load levels where the TO would expect to perform system maintenance.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	Should also consider no or limited loss of non-consequential load for facilities 100 kV and above. No loss should be allowed for load levels at which the TO would plan to perform maintenance. Also system adjustment should consider time required for adjustment verses the ratings utilized.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	Should also consider no or limited loss of non-consequential load for facilities 100 kV and above. No loss should be allowed for load levels at which the TO would plan to perform maintenance. Also system adjustment should consider time required for adjust.ment verses the facility ratings utilized.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: Loss of non-consequential load should not be permited, however this should also apply to other breakers across the system including bus tie breakers.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment: Should also consider no loss of non-consequential load for facilities 100 kV and above and this should also apply to other breakers across the system including bus tie breakers.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	Also use of system adjustment should consider time required to complete adjustment.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	Also use of system adjustment should consider time required to complete adjustment.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	Also use of system adjustment should consider time required to complete adjustment. Ability for generation adjustment should include the time required for unit startup if applicable.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	Also use of system adjustment should consider time required to complete adjustment. Ability for generation adjustment should include the time required for unit startup if applicable.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐

[1] System adjustment can be manual or automatic

Comment: However, the owners of the firm transfers may not agree. If they don't, a system impact study needs to be part of the assessment IF THE OWNERS OF THE FIRM TRANSFERS DO NOT AGREE. It must be clear to the original TSR requester that this was truly conditional on the DC line being in service. If it was granted without telling them this, then the interruption of firm transfers should NOT be permitted.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment: We agree but consideration should be given to the amount of work needed by entities to meet these requirements. Full scale annual stability studies may not be needed. If possible, criteria should be developed as to when stability studies need to be repeated (if at all) and to what level (i.e. every bus on the system or just the generator busses or somewhere in between).

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment: See response to Q31.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: If it is not probable, then why study it. Realistic probabilities need to be established and defined for study.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment: However this will require the Load Serving Entities provide specific data for each bus on the system which may not be in the direct control of the entity performing the studies. The standard should be written with this understanding in mind. Failure of a LSE to provide such data should not cause a penalty to be imposed on a Transmission Provider.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: There should be no change in generation for single contingencies. An approved SPS in those areas that use them might be an exception however system damage for failure to operate should not be allowed beyond the station with the SPS. Also, loss of load should not be allowed for failure to operate. An automated adjustment for multiple contingencies is not unrealistic.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☒
Comment: We believe that the BES should be able to operate for N-1 events without reliance on operating schemes. Assuming that some areas allow this, there should be criteria to evaluate the consequences of 2nd contingencies occurring during the runback. In addition, short-time ratings need to be confirmed which limit the time for runback. The system is at risk until the runback is completed and this risk must be evaluated and REQUIRED in the planning assessment.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☒
Comment: We wouldn't agree to this without knowing what you mean by limited use. RAS or SPS as a common practice does not "raise the bar" in planning standard. An RAS or SPS should be allowable as a temporary measure to allow one to meet the standard and two to protect the components of the BES. When used in this capacity, a plan should be being either developed or implemented such that the RAS or SPS can be removed from service.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Temporary in nature.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: This should be limited to the time until a physical solution is possible (i.e., a temporary solution).

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment: Variances should not be a reason to change the standard (lower the bar).

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: A modeling issue that we would like to see standardized is the modeling of generation resources when the load exceeds or is very near the installed reserve level (low generation reserve margin). This would occur in future years when new resources are unknown or not announced yet. It is a concern of ours because we are an independent transmission company and are not always apprised of new resources. We also have a concern with some models which "assume" where new generation would be located or fake generation has been added to meet the load requirements. This can produce distorted transmission assessments because the generation location assumption is not firm. We would prefer to see generation scaling, or an assumption that the power

will be imported or a combination of scaling and imports. Assuming 100% generator availability is also not a good assumption just to balance load and generation.

Other modeling issues:

1. Should not rely on a single generator being dispatched (redispatched) to solve a problem.

2. Using a single generator for redispatch should not be an acceptable corrective action (i.e. rely on a generator that might not be there or may take an extended period to start up).

3. Sensitivities for both the planning horizons should consider load forecast error and variability. You shouldn't just stick with one assumption, such as a 50/50 probability of occurrence. The system needs to be able to operate to loads exceeding 50/50 probability of occurance.

We would also like to see additional requirements be put on "corrective action" solutions to reliability violations resulting from planning assessments. Any corrective action should be restudied to insure that it does not cause other reliability problems for system conditions other than those for which the corrective action is intended to resolve. For example, if redispatch under a transmission outage condition is acceptable, it should not cause any additional reliability violations for the next contingency.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☒ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☐Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☐Agree. ☐Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☐Do not agree.
Q9. **Comment:**	
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Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.

- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: Transmission Planners when developing system improvement options should identify their system specific sensitivity cases that best assesses the robustness of the options under consideration. Project evaluation is not addressed in the NERC standards and performing sensitivity assessments that only lead to operational remedies consistent with the standards, are best performed within the operational horizon where information and assumptions are more certain than within the planning horizon.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: Transmission Planners when developing system improvement options should identify their system specific "reasonable stressed" cases including opportunities for additional economic margins that best assesses the economic benefits of the options under consideration. Project evaluation is not addressed in the NERC standards and performing assessments on "reasonable stressed" cases that only lead to operational remedies consistent with the standards, are best performed within the operational horizon where information and assumptions are more certain than within the planning horizon.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☐
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☐
Comment:

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to

obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☐

Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	I do agree that long term plans should be implemented with the goal to eliminate non-consequential load shedding as a response to this failure mode. However, it may be more beneficial for investing in system improvements to reach this state of robustness where there may be a few years or seasons of potential exposure for utilizing non-consequential load shedding. This should be prudent utility practice as long as post-contingency response is executed within the time frame allowed by the facility emergency ratings and load shedding is limited to TP's contracted or tarrif loads.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☒Do not agree.	See comment on P4-3

[1] System adjustment can be manual or automatic

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☐ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment:
In reference to the use of Non-consequential load shedding under single contingency events: I do agree that long term plans should be implemented with the goal to eliminate non-consequential load shedding as a response to this failure mode. However, it may be more beneficial for investing in system improvements to reach this state of robustness where there may be a few years (or seasons) of potential exposure for utilizing non-consequential load shedding. This should be prudent utility practice as long as post-contingency response is executed within the time frame allowed by the facility emergency ratings and load shedding is limited to Transmission Provider's contracted or tarrif loads.

For example, adding or upgrading transmission facilities into a load area where future generation additions are planned to be in-service within the short term horizon (mitigating thermal or voltage violations assessed under P1 and P4-1 through P4-4) would not be the best investment for the overall economic benefit of the bulk electric system.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Harold G. Wyble	
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☒ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment: Suggest changing "low" to "lower".**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☒Agree. ☐Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment: Suggest adding "Bulk Electric" before "System".**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment: Suggest adding "Bulk Electric" before "System".**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.

- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: N-1 and N-2 analyses should identify any additional sensitivity cases that need to be studied. This standard should not specify the number and type of sensitivities to be studied.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: Transmission Planner has best knowledge of conditions that create greatest stress on local transmission system.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒
Comment: Dynamic studies should be performed when new generation or transformers are added to the system. Should be performed on a periodic basis, not annually.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: Long term planning horizon has significantly greater uncertainty in future conditions and sensitivity studies are unlikely to contribute to reliability because of this.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in

conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: Only for DSM that is contractually "firm" and which can demonstrate mitigation performance (comparable to generation resource) as related to the transmission system.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: Corrective Action Plans taken by a transmission operator should not burden any of its' directly interconnected transmission operators. Study area should include at least all transmission operators directly interconnected to the transmission operator who took the initial corrective action. It may be appropriate to use the entire RTO/ISO/RRO as study area.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: Corrective Action Plans must demonstrate performance based on the expected system configuration. Committed projects can be changed or discontinued before completion.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this

draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: No Non-Consequential loss of load for N-1 event.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment: Must recognize that there may be Consequential loss of load.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	Need voltage limit in Table 1.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐

[1] System adjustment can be manual or automatic

Comment: "Firm" capacity dependent on DC line is similar reliability as a generator.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Agree it is difficult to develop scenario where all units trip simultaneously in stability timeframe.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: Transmission operators are required to maintain reactive reserve requirements.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Generation redispatch should not be allowed for N-1 events. Generation redispatch is appropriate for multiple contingencies. Appropriate SPS and generation runback schemes should be allowed, where the system is designed with those schemes.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency

ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☐ No ☒
Comment: All generators must have "firm" transmission outlet capacity for their nameplate rating. This means delivery of full output under N-1 conditions. A generator that must reduce output for N-1 is not "firm" generation capacity.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☒
Comment: All generators must have "firm" transmission outlet capacity.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☒
Comment: Tripping generation for single contingency other than GSU failure or fault is unacceptable.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: RAS/SPS should not limit generation output for N-1 conditions.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: RAS/SPS should not limit generation output for N-1 conditions.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☒ No ☐
Comment: In the past, Missouri Public Service Commission Staff have required KCPL to demonstrate that generators have "firm" transmission outlet capacity.

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☐ No ☒
Comment: It is redundant to require provision of modeling data in this Standard. This is covered in Standards MOD 10, 12, 16-25.

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Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☒ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

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1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
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3) Address the issues raised by FERC Order 693, 890, and other applicable orders
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The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☒Agree. ☐Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.

- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☐
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☐
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☐
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☐
Comment:

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☐
Comment:

[1] System adjustment can be manual or automatic

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment:

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Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

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Yes ☐ No ☐
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Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

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Yes ☐ No ☐
Comment:

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Comment:

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Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐

Comment: The Planning Authority/Transmission Planner should use valid acceptable assessments to plan their systems to operate and supply customer demand and Firm Transmission Service. If the Planning Authority/Transmission Planner determines other methods (such as operational guides) to resolve system overloads for "N-1 Contingency", the operational guides should be limited to only native network facilities that are in direct control and ownership of the Planning Authority/Transmission Planner. Operational guides should be considered only as short term solution to resolve the overloads and shall be used in all studies and approval for transmission service requests. If the operational guide do not completely resolve the overload or restricts access to transmission service, then the Planning Authority/Transmission Planner shall determine facilities to be constructed to resolve the overloaded or restricted facility.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
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Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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R5 – Coordination requirements

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The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: A basecase is a representation of the interconnected power system network at a given instant of time which correctly models an expected network topology in sufficient details (transmission lines, shunt and series compensations, transformers, breakers, phase-shifting transformers, etc.) , the forecasted loads, and a dispatch of connected generations that would achieve load-generation balance to allow a numerical solution without violation of any reliability standards. The resultant flows on the transmission lines are dictated by the Kirchhoff's laws, not laws of commerce, and therefore, cannot be interpreted as either firm or non-firm commercial transactions. A basecase is just a starting point from which transmission planners can make use of to further stress the portion of the systems that are of interests, to properly evaluate the robustness and reliability of the system and to determine line (non-thermal) ratings or network expansions, as needed.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: The existing standards does not allow load loss for N-1 contingency unless the load is a radial load of the outage element. This new definition appears an attempt to weaken the requirement by broadening it to anything "directly connected" to an element that is removed from service. While it may be argued that probably only radially connected loads fit this definition, this new definition will lead to more creative interpretation of the word "consequential" and leads all of us down unintended consequence. A radial load is a very specific and clearly defined technical term and should not be changed to a new term that is less precise.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree.

	☒Do not agree.
Q3. **Comment: Extreme events for transmission planning should be defined as anything more than N-2. The proposed definition is subjective and not precise. There are examples in this standard as to how this definition can be mis-construed, e.g., cyber attack, wild-fire, hurricanes, etc. These are extreme events that belong in emergency planning, not transmission planning.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☒Do not agree.
Q4. **Comment: The objection is not so much about the definition as about what comes after the definition. This standard proposed to include operating and market studies (calling them sensitivities) in the "nera-term" planning studies. It appears that the SDT believes this would be easier to justify if the sensitivities is limited to near-term and not long-term, hence the motivation for breaking the planning horizon. But this is mis-guided; operating studies belongs in operating standards. They should be addressed appropriately in the TOP for operating scenarios and Market related studies should be addressed in MOD, for example. There are no benefits to include these in transmission palnning studies and therefore no need to break up the planning horizon.**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☐Agree. ☒Do not agree.
Q5. **Comment: See my comment above; the only part about the definition that I would retain is to require each of the first five years in a typical ten-year plan be studied instead of just picking one or two years out of the first five years.**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: See my comment on the Consequential load loss. Why introduce two new and less precise definitions to replace one existing clearly defined definition? Radial load is precise and clearly defined to transmission planners.**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: The assessment of asset conditions and age of equipment belongs in maintenance practices, not a transmission planning issue. Similarly, Operating procedures is an operating matter, not planning studies. They have their own standards that could and should address any issue the SDT may have in mind. Using transmission planning as a catch-all is a wrong headed approach.**	

Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: The term Event has such a broad connotation that it can be misused by layperson. In fact, it is already misused in this standard as evidenced by including events such as cyber attacks, hurricans, tonados, etc as transmission planning events. These events belongs in "emergency" planning, not transmission planning.**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: When performing transient stablity studies using either PSSE or PSLF, loss of synchronism and oscillation damping are automatically part of the performance evaluation; it is not a separate study and should not be classifed as a separate study. In the context of transmission planning, unless someone on the SDT use programs that do not have transient stability package similar to PSSE and PSLF, or has a completely different understanding on the meaning of loss of synchronism and/or damping, there is no need to introduce two new terms to explain a very well understood and established single term known as "transient stability" .**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: This comment should be taken together with the comment on Plant stability and I would recommend not to creat new terms and go back to use well established engineering terms like Transient Stability Study which covers synchronism, damping, voltage limits, angular stability, etc. There are many text books that could be used to support this.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment: very good clarification!**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be

developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: the FERC orders are market focused, not reliability focused; to the extent that these orders require sensitivity studies as outlined in this proposed standards, they belongs in operating studies and real time market studies, not transmission planning studies which are to meet reliability based criteria.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: A "reasnably stressed" case in transmission planning is whether or not the transmission system is stressed. To stress a transmission system, the key parameter to monitor are the line flows. Line flows are dictated by network topology and physics of electricity and very much depends on the objectives of each study, i.e., it is case by case. Standard should focus on what criteria shall be complied, not how to comply. This proposed standard is so prescriptive on how to comply that it reads like a tutorial.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒

Comment: This standard is mixing operational studies with planning studies. The suggested sensitivities in this proposed standards are what operating studies would and should address. It adds no value to the transmission planning by requiring sensitivities in transmission planning just for the sake of it. In addition, performing operating studies more than one year ahead, generally, is quite useless as a general requirement.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: This applies to both long- and near- term, the type of sensitivities proposed here do not belong in transmission planning studies.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒

Comment: We should be very careful about using DSM as Corrective Action for transmission problem. What this would lead to is to have a "built-in" transmission problem which would require DSM as the de facto rolling brown-outs or black-outs. DSM should be part of the resource and load forecasting consideration; transmission planning should design tranmission that can properly serve the forecasted loads with the expected resources; not to "live with" or include transmission contraints that rely on DSM as a solution. If the industry truly wants to use DSM as mitigation for transmission deficiencies, let's do it as a deliberate action, not an unintended consequence.
"System deficiencies" may be corrected with an integrated approach as suggested, but "transmission deficiencies" are solved by transmission improvement. The classic example is Path 15 in WSCC/WECC. The transmssion deficiency of PAth15 was well known for many years (like since '80s) and in the "pre-deregulated" dates, the deficiency was indeed managed by an integrated approach when the utility can operate its assets integrally. Then de-regulation happened and the integrated approach became unbundled and impossible resulted in numerous brown-outs and black-outs in California in 2000-01 until a third transmission line is added. Transmission deficiencies, if not mitigated, will significantly affect the accessibility to transmission services, a key concern of ferc 890.

As for new technology, just how the SDT proposes to define what constitutes a new technology? And how to measure for compliance against such a requirement? Hopefully, this is just another case of overly prescriptive standard.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒

Comment: This is a redundant and unnecessary requirement. How can one come up with a corrective action plan if it has not been demonstrated the plan can mitigate the problem? And if the corrective plan has been able to demonstrate that it can mitigate the problem, why repeat the study again.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: Seems like every company would have its own definition of committed vs propsoed project.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: All this does is create more bureaucratic tracking and paper pushing. People probably won't classify anything as committed until concrete has been poured just so not to have to deal with all these paperwork.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☐Do not agree.	There is a fundamental fatal flaw in having different reliability requirements using an arbitrary separation of the connected bulk electrical systems into above 300kV and below 300kV. The

		standard should be re-draft without this separation and comments be solicitated at that time. These questions are fundamentally unfair without first settling whether or not it is wise to arbitrary separate the bulk system into two different classes. This is like asking someone "Did you hit your spouse today?"
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☐Do not agree.	ditto
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	ditto
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	ditto

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: Don't understand why there is such an obsession with bus tie breakers? Is this a common practice in the East? I am not aware of any issue in WECC, let alone at above 300kV systems.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: ditto

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	This is N-2 and load loss should be permitted. As for whether or not this is a high probability event, there should be an objective measure (such as 1 in 5, 1 in 50, or 1 in 100, etc.) as to what constitute high probability, i.e., are there any outage history that would support any of the contention here that these are high probablity events? It is a mistake to arbitrary injecting "subjective" probability into a deterministic based reliability standard unless the industry is ready to move into 100% probabilistic based reliability standards.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	ditto
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	ditto
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	ditto

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

[1] System adjustment can be manual or automatic

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☒
Comment: If the transfer is on a line experiencing outage, then the transfer is interrupted. Whether or not the transfer is firm is inmaterial. Whether or not it is on the dc or ac line is also inmaterial.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☐
Comment: There is no vote needed here because even under the current standards, the performance requirements for steady state and stability are clearly separated. So what is being added?

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: See my comment on the definition of Plant Stability. Unless the standard drafting team has something completely different from the common understanding of loss of synchronism and so on, transient stability covers both the so called Plant Stability and System Stability Studies.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Loss of a plant as an extreme contingency has been on the book forever and it has never been interpreted as exempted from stability simulation (at least not in WECC) if this secenario is chosen as an extreme event. However, there is no mandatory requirement that loss of all generating units at a plant must be studies for every generating plant. If the design of a generating plant, such as use of redundancy, separate control console/rooms, etc., are such that all unit tripping simultaneously is unlikely, then it should not be requried to be studied just because all the units are inside the fence.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment: This is a qualified yes to the extent that accurate induction motor models are available and the overall load modeling (non-induction motor loads) allow such analysis. Otherwise, focusing only on induction

motors would not provide added information than what is being performed today. The current WECC requriement concerning induction motor modeling should be deemed adequate to meet this requirement.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Whatever is needed to bring the system into balance.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment: Generator runback is allowed under the current standards, why single this out? Hopefully this is not a sign of equating generator runback with generator tripping as the title of this section might suggested. Generator runback is not and should not be classified as an SPS!
It is critical to keep as many units on line as possible post contingency. In many instances, use of generator runback would avoid the need to trip a unit if that was the only way to reduce the generations to return to load-generation balances.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐

Comment: It was never disallowed under the current standards.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☐
Comment: no comment

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐
Comment: Too many to be listed with the separation above and below 300kV being the worst one that will undermine the overall reliability of the electric system in North America. Another major omission in this proposed standard is the complete lack of recognition of the importance of post-transient requirements. Mixing commercial (firm or non-firm transsactions, etc.) and reliability in transmission planning criteria would be in conflicts with WECC rules and practices.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: This proposed standard is very tutorial in nature and far too prescriptive for a standard. A standard should be about what are the criteria and measurables, not about how to meet the criteria.
This propsoed standard should also recognized that it is just a part of many standards being formulated by NERC, know its boundary as transmission planning standard, and not try to be an all encompassing standard for every facit of the power system. Do what we do best as transmission planner and not try to take over others like marketer, operator, generators, etc.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☒ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

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A. New Definitions

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Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment: Should read "Computer model representation of..."**	
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Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment: Define "low probability of occurrence"**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
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Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☐Agree. ☐Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment: "Documented evaluation of future Bulk Electric System performance conducted through performance studies..."**	
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Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
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Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

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- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
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- Variability and outages of Reactive Resources.

- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: There are two questions asked and the response is yes to both. In the ERCOT region, load flow cases are not currently availbale for years 6-10 and this limits the long-term study activity that Transmsion Owners and Transmission Planners can acarry out. As currently proposed (R2.2) is appropriate.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in

conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: The question is not clear regarding "study area"; however, re-testing with corrective action / system improvement(s) in place is a must. The re-test must consider the same simulations that idenitifed the initial deficiency.

In addition, in the re-test, the action/ system inprovement must be considered as a Planning Event itself (i.e., if the initial test showed a specific contingency causing a deficiency, then a physical connection of the system improvement to the identified continegncy should be avoided or minimized - minimize the creation of extreme events.). In other words, planning solutions should be long-term and a system "fix" for the present should not result in a system problem in the foreseeable future.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐

[1] System adjustment can be manual or automatic

Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to

maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☐ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☒
Comment: Only until plans are implemented to address a single continegcy-identified deficiency. In general, plans should always be developed to exit SPS or RAS when economically feasible

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Short-term with exit plans; Loss of significant generation or load resulting from SPS /RAS action

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: Systems must have a balance between security and dependabiliyt. System must be reviewed annually or as system conditions change.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐
Comment: See ERCOT Planning Criteria. Also, through the regional coordinators, NERC recently conducted a survey of transmision planners/owners regarding use of more stringent criteria used in their own systems. The std. drafting team should include a review of the survey results and incorporate into this NERC std as necessary.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: The NERC PC and OC are currently working on a definiton that defines "adequate levels of reliability". The SDT should take this definition into consideration and ensure it is applied in the proposed NERC Std. revision. Along the same lines, if this has not been done yet, the SDT needs to consider the NERC "Reliability Criteria and Operating Limits Concepts" white paper and incorporate applicable elemetns of that white paper to the propsoed NERC Std. revision accordingly. It would not make sense for these (the propsoed NERC std. and the noted white paper to be inconsistent or at opposite ends in terms of what is expected of a reliability-based planned transmission system).

other editorial comments:
1. R1. Delete one of the "each"

2. R1. Should state that data submittals should be "in accordance with regional procedures or process". This will eliminate the region getting data in all sorts of formats.

3. Table 1 - the allowance of loosing "consequential load" should be evaluated based on options to provide temporary emergency back-up support as well as size of load, for example. Structure failures can take an extended period of time to restore and can have significant impacts on a raial load that does not have remote or distribution back-up support. This performance requirment of transmisssion radial-supplied loads should be left to regions or to transmission owners/planners for their own areas based on specific area needs (type and size of load, back-up availbailiyt, etc.).

4. Table 1 - How does NERC define a "transmission circuit"? Does it include a sinlge transmission line as well as a double circuit transmission line?

5. Other than the probability of occurrence, what is the difference between a structure failure of a single circuit and a structure failure on a double circuit configuration? Why is a double circuit not considered a single contingency?

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Ron Mazur	
Organization:	Manitoba Hydro	
Telephone:	204 474 3113	
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☒ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

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Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment: If load losses due to stuck breaker and back-up breaker operations (which would frequently result in the loss of two or more network transmission elements) are not going to be qualified as "Consequential", where should they be placed? MH cannot visualize them as "Non-Consequential", as defined in Q6. Either another "load" category must be developed for these loads, or they should remain as "Consequential".** **In addition, Consequential Load Loss should include the concept of local area load loss to cover a scenario of islanding with a UFLS in the island, or a small network served at the end of a radial line.Can the SDT comment on why this Local Area defined in the existing TPL stds has been removed?**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Change to "Events which are more severe than Planning Events and have a lower probability of occurrence than Planning Events."**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not

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Q5. **Comment:**	
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Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☐Do not agree.
Q7. **Comment: A planning assessment should include performance studies.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: The definition of a planned event should relate to the probablity of occurance. Table shows single contingency planned events and multiple contingency planned events. Why has the SDT gone away from the existing categories of events which sorted the events into categories with different levels probability.**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
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Q11. **Comment:**	

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The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

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- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: Sensitivity analysis that could be considered will vary from region to region or subregion to subregion.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☒ No ☐
Comment: R.2.1.3.2: clarify the intent of modification of expected transfers. Does this apply to firm transfers only, or does it also encompass non-firm transfers? Should this encompass simultaneous non-firm transfers? Planning for non-firm falls into an economic study of cost/benefit and not a relibility requirement.
R2.1.3.3: There is little value in identifying the impact of unavailability of planned facilities. From a reliability perspective, these facilities are required to meet performance requirements. Near term SOLs and IROLs will insure reliability if the facility is late.
R.2.1.3.4: This requirement should be removed and outages of reactive resources should be included in the Table 1 contingencies (assuming the intent is to investigate robustness to voltage instability).
R.2.1.3.5: This requirement should be removed as this is covered, or should be, by the facility connection standard(s).
R.2.1.3.6: This requirement should be removed as this is covered by requirement R2.1.3.1. There is no need to list "decreased effectiveness of controllable loads or DSM" as this is already covered by sensitivity to forecast load and power factor - this will cause confusion.
R.2.1.3.7: Modification of planned Transmission outages should be deleted. The need to assess outages in the planning horizon is questionable, so assessing sensitivity to timing of these outages is of very little value. Furthernmore, this standard already covers prior outages in its other requirements.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐

Comment: R2.4.3.1: This requirement should include variation in load power factor, as this has a significant impact on transient performance.
R2.4.3.3: There is little value in identifying the impact of unavailability of planned facilities. From a reliability perspective, these facilities are required to meet performance requirements. Near term SOLs and IROLs will insure reliability if the facility is late.
R.2.4.3.4: This requirement should be removed and dispatch of reactive power devices should be included in the Table 2 contingencies (assuming the intent is to investigate robustness to voltage instability).
R.2.4.3.5: This requirement should be removed as this is covered, or should be, by the facility connection standard(s).

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: The models for Long-Term Transmission System Planning Horizon typically contain such uncertainty that the base planning is a sensitivity study itself. Sensitivity studies in these years would be a waste of time. The long term analysis should be used to indicate trends such as a reduction in transfer capability, reduction in damping, etc, but not necessarily seek mitigation of such trends.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒

Comment: DSM and generation improvements should be removed from Requirement R2.7.1, as they should not be mandated by a NERC standard are not in the tool box of the transmission planner.
DSM may already be in the load forecast and sensitivities to load forecast variations are included in near term planning horizon sensitivity analysis. Additional DSM shouldn't be part of transmission planners mitigation

plan. If the corrective plan is too expensive the load serving entity could consider DSM and revise their forecast in the next planning cycle.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐

Comment: At some point the corrective action plan should be tested to verify the plan meets the performance requirements. The way the standard is written is that the transmission plan should be perfect for the entire planning horizon for all sensitivities tested. Any issues should be immediately addressed. The standard does not allow any time to develop a corrective plan through an open and transparent process. Based on the NERC definition, a Corrective Action Plan is the list of actions and an associated timetable for implementation to remedy a specific problem. A Corrective Action Plan could mean that load forecasts at the station will be verified, facility ratings verified and alternatives to fix the identified problem to be determined before the next Planning Assessment. Standard R2.7 seems to be mixing the idea of a Corrective Action Plan with the original TPL idea of determining corrective plans to achieve required performance. A corrective plan wil be the end goal of a Corrective Action Plan.
Furthermore, corrective action plans should not be requierd to address issues raised by sensitivity studies. Corrective action plans are developed to meet base case needs which are based on expected load forecasts, transfers, etc. Sensitivity studies are done to measure the robustness of the base case plan. It should be left up to the Planner to decide if the corrective action plan is adequate based on the likelihood of the scenario studied, even if the sensitivity analysis shows some performance violations.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐

Comment: However, since each planner is allowed to define the criteria, there will be no consistency as to what is included in the base case models.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒

Comment: The standard does not allow any time to develop a corrective plan through an open and transparent process. Based on the NERC definition, a Corrective Action Plan is the list of actions and an associated timetable for implementation to remedy a specific problem. A Corrective Action Plan could mean that load forecasts at the station will be verified, facility ratings verified and alternatives to fix the identified problem to be determined before the next Planning Assessment. This standard seems to be mixing the idea of a Corrective Action Plan with the original TPL idea of determining corrective plans to achieve required performance. A corrective plan wil be the end goal of a Corrective Action Plan.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-

0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	With the caveat that if the loss of load is localized, it is acceptable. Raising the bar will result in a cost increase for owners and users of the transmission system. What evidence does the SDT have to show this is justified.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed	☒Agree. ☐Do not agree.	

by System adjustment followed by loss of another transformer		

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☐
Comment: Until the SDT should defines a non-bus tie breaker this is impossible to answer.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: The SDT seems fixated on loss of load. The existing std for this type of event allowed for loss of load and firm transfer could be adjusted. While MH could rationalize that load should not be interrupted, we could not agree that firm transfer can not be reduced. This would amount to n-2 planning to maintain a firm transfer that is backed up by reserves. The requirement to maintain firm transfer will cost MH and the industry millions of dollars with no reliability benefit - a show stopper.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	With the caveat that firm transfer is included in the adjustment, otherwise there is a hugh cost with minimal reliability benefit. A further comment is what rationale was applied by the SDT to come up with these combinations of events? is there a statistical basis? the vible combinations of multiple contigency events should be left to the experience of the transmission planner.
Q27. P4-2: Loss of a generator followed by a	☒Agree.	With the caveat that firm transfer is included in the adjustment, otherwise

[1] System adjustment can be manual or automatic

System adjustment followed by the loss of a monopolar DC line	☐Do not agree.	there is a hugh cost with minimal reliability benefit.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	With the caveat that firm transfer is included in the adjustment, otherwise there is a hugh cost with minimal reliability benefit.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	With the caveat that firm transfer is included in the adjustment, otherwise there is a hugh cost with minimal reliability benefit.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: MH agrees that reduction of firm transfer to readjust the system after a contingency should be allowed for all events. The requirement to maintain firm transfer is a more stringent requirement that in the existing standard. The need to maintain firm transfer amounts to N-2 planning with no reliability benefit. Reduction in firm transfer is not equivalent to loss of load as the transfer is backed up by reserves. MH could not accept a standard mandating that firm transfer can not be interrupted.

MH also recommends P2-3 be moved into the P1 bucket as loss of a single pole of a dc line is similar to loss of a generator or transmission circuit.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment: Yes but the definition of contingencies in table 1 and table 2 should be identical

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: The need to assess Plant Stability should be removed from this standard. The generator connection standard and the proforma tariff interconnection process ensure the plant stability meets performance requirements. Furthermore, the System Assessment provides an overall assessment of the integrated system performance, which includes the impact of the plant. The requirement for plant stability studies appears to be redundant and would be a waste of assessment resources.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐

Comment: Isn't 2.d such an event? In a breaker-and-1/3 or 1/2 generating station, if one station bus is off-line for maintenance, faulting the other bus will kill the station, or at least cause a major disruption with individual generators connected to other stations by separated lines. That is certainly worthy of consideration as a feasible "extreme" event Further, the same low likeihood argument could be applied for the majority of extreme events in Table 2.The emphasis should be on what the response is for extreme events rather than the likelihood of the event. .

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐

Comment: R2.4.1 should be clarified to limit a requirement for detailed modeling (for example, dynamic effects of induction motors loads) to local areas where the planner expects a local emerging voltage recovery issue.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: 1) Reducing or increasing generation while keeping the units on-line or by bringing additional units on line. The amount of generation change should be limited to that amount that can be accomplished within the allowed readjustment period. Due consideration should be given to start up time and ramp rates of the units.
2) Generator tripping should be added to requirement R3.5 in addition to runback. Generator tripping is used extensively in regions where remote generation is delivered via long transmission.
3) Adjustment of firm transfer must be allowed for single and multiple contingency events. MH could not accept the revised standard that removed this existing requirement.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency

outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment: Generator tripping should be added in addition to runback. Generator tripping is used extensively in regions where remote generation is delivered via long transmission There will be a large cost penalty to construct transmisison to remote generation if generator tripping is not allowed. Since the amount of tripping is covered by operating eserves, there is no impact on reliability. Generator tripping should be an option for the planner in the standard as opposed to a regional difference or the need to install an SPS. .

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐

Comment: I see no problem in using a runback scheme to prevent thermal overloads. Most emergency ratings are based on 30 minute values to allow for operator action. An automatic runback could be accomplished in 5-15 minutes depending on the ramp rate of the generator. The runback scheme may allow higher emergency ratings depending on the rating methodology. At no point would emergency ratings be exceeded and at the end, loading would be within normal values.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐

Comment: MH sees no reason to limit the application of SPSs. The SPS is a viable planning option that allows large savings in cost in stability limited system where there is no need to increase thermal capability.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: An automatic runback should be accomplished in 5-15 minutes depending on the ramp rate of the generator. The runback scheme may allow higher emergency ratings depending on the rating methodology. At no point would emergency ratings be exceeded and at the end, loading would be within normal values. Generator tripping should be allowed. Generator tripping is used extensively in regions where remote generation is delivered via long transmission. MH sees no reason to limit the application of SPSs. The SPS is a viable planning option that allows large savings in cost in stability limited system where there is no need to increase thermal capability. .

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: 1) Reducing or increasing generation while keeping the units on-line or by bringing additional units on line. The amount of generation change should be limited to that amount that can be accomplished within the allowed readjustment period. Due consideration should be given to start up time and ramp rates of the units.
2) Generator tripping should be added to requirement R3.5 in addition to runback. Generator tripping is used extensively in regions where remote generation is delivered via long transmission.
3) Capacitor and reactor switching - The number of capacitors and reactors, which may be switched, should be limited to those which could be switched during the allowed readjustment period.
4) Adjustment of load tap changers (LTCs) to the extent possible within the allowed readjustment period.
5) Adjustment of phase shifters to the extent possible within the allowed readjustment period.
6) An increase or decrease to the flow on HVDC facilities to the extent possible within the allowed readjustment period.
7) Transmission reconfiguration - Automatic tripping of transmission lines or transformers to the extent possible within the allowed readjustment period.
8) Automatic tripping of interruptible load or curtailment of or redispatching of Firm Transmission Service to the extent possible within the allowed readjustment period.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☒
Comment: MH does not like the idea of a long transition period. Either NERC adopts the concept of generation rejection or the MRO will need to submit a regional variation. I much prefer the planned loss of generation via an SPS rather than via out-of-step tripping as proposed in the Table 2. In certain areas of the MRO that are stability limited because of long lines to bring generation at the energy source (such as mine mouth plants, hydro plants, etc.) to the load, generation rejection is used to return from an emergency state to a normal state. If generation rejection is not allowed in these cases, extraordinary cost and extraordinary negative environmental impacts will result. As an example, removing one SPS will require new 500 kV transmission between Winnipeg and Minneapolis at a cost of $1 billion to MRO utilities.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: MH would prefer that many of the categories in the existing Table 1 be retained. The SDT has resort the contingency buckets with no explanation as to how this was done. can the SDT provide statistical outage date to justify the changes. MH is not convinced the SDT has addressed the few confusioning issues in Table 1.

R1: MH does not believe R1 is required in this standard. The modelling standards should cover the requirement of the data owners to provide data to the PC.
Further this data needs to be provided to the TP as well.

R1.4: requires planned outage data to be provided to planners. I do not believe this is a requirement for planning. It is not economic to add facilities to accommodate future planned outages. Secondly, the Table 1 multiple contingencies already mandate that planners consider the impacts of an outage with system adjustment followed by testing for the next contingency.

R1.5: requires the PC to define "planned facilities" which should be included in the model. This will lead to inconsistency in what is modelled, as experience has shown that there will be a wide range of assumptions in the definition. This standard should offer a definition for stakeholder debate. The SDT should clarify what is intended by including Protection System Equipment and control devices.

R2.1: It is not necessary to assess all five years of the near term planning horizon – year one, three and five will be more than sufficient. What is the reliability benefit driving the SDT to mandate each of the first five years be assessed?

R2.1.2 and R2.4.2 -- It is important to assess off peak loads with high simultaneous transfers as this is the period where extensive economic interchange occurs, and transient stability issues arise as less uneconomic peak units are off, leaving the load to be supplied by remote generation with reduced local reactive supply, voltage and damping control.

R2.2: The long term assessment should also include an off peak case with simultaneous transfers to provide some indication if the system performance is expected to degrade.

R2.3: The short circuit study is a design issue that would more appropriately covered by a FAC standard. MH recommends it be removed from the Planning standard.

R2.6.1: Why would a past study be invalidated if there is a change in market structure? It would seem that the operation of any market would have to respect reliability criteria.

R.3.3.2.2: Curtailment of firm transfers is allowed as a system adjustment in the existing standard. This ability must be retained in the new standard. Curtailment of a firm transaction is not equivalent to curtailment of load, but is more comparable to runback/tripping of generators. Both are events that can be backed up by contingency reserves and do not result in consequential load loss. Disallowing firm transfer curtailment will result in numerous violations of the performance requirements and result in a requirement to build millions of dollars of transmission. MH can not accept a standard which mandates that firm transfers can not be curtialed following a contingency.

R3.3.3: If rationale for the contingencies selected for evaluation is available then this rationale will state why the selected contingencies are expected to be the most severe. The requirement does not need to state "and shall include an explanation of why the remaining Contingencies would produce less severe System resuts".This is redundant.

R3.4 and R4.5.2: Evaluating a change designed to mitigate the consequences of an exteme event can require significant work. Since there is no requirement to implement corrective plans for extreme events, what is the purpose of this evaluation?

R3.5: Generator tripping should be added in addition to runback. Generator tripping is used extensively in regions where remote generation is delivered via long transmission.

R6: Requires distribution of results and "coordinating analysis of these results through an open and transparent process". Can the SDT clarify what the intent is? As written, it implies the PC/TP just shares assessment results with neighbours. There should be a requirement to conduct joint assessments on inter-regional transfer capability. The assessments should also be provided to the Regional Entities/NERC.

Table 1 -Steady State Performance

MH requests the SDT to provide rationale for how the planning events where resorted from the existing Table 1 Categories to the proposed Planned events.

Performance Requirements: As this is a steady state table, how does one assess if voltage instability, cascading outages or islanding occurs? "Simulate Normal Clearing unless otherwise specified." should be deleted from this Steady State Performance table.

This table should have an Initial Condition column as well as an Event column, as in Table 2. The wording of event descriptions in Table 1 should follow the wording of similar event descriptions in Table 2.

Event: What is a non-bus tie breaker? Is this any breaker that is not a bus tie breaker?

Interruption of Firm Transfer Allowed: Interruption of firm transfer should be allowed following a single contingency – this is a change from the existing standard where system adjustment after a Cat B event could include reduction of firm transfer. Similar to generation tripping/runback, the loss of a firm transaction does not result in Consequential load loss as it is backed up by contingency reserve.

P6-2: What is the justification for classifing a bipolar DC line loss as a single contingency? The existing standard classifies this event as a Cat C multiple contingency event.

P6-3: Why is a breaker internal fault classified as a single contingency? One would assume such a fault would be cleared by backup protection resulting in the loss of multiple elements.

P9-1: Is there any justification for the selection of one mile? Would the fact that there is line shielding be justification for increasing this length? A more reasonable selection could be 5% of the length of the longer of the two circuits.

P9-2: A monopolar DC line loss may be covered in P4-2 (and no non-consequential load loss is allowed). Does loss of a monopolar DC line refer to loss of a single pole of a bipolar line or a bipolar dc line? Can the PC/TP choose between the loss of a monopolar DC line and the loss of a bipolar DC line?

P9-3, P9-4 and P9-5: When the DC line loss is bipolar, the event should be moved to the extreme event category. Does loss of a monopolar DC line refer to loss of a single pole of a bipolar line or a bipolar dc line? Can the PC/TP choose between the loss of a monopolar DC line and the loss of a bipolar DC line?

Exteme Events Evaluation Requirements 3: This should be removed as this is the Steady State Performance table.

Extreme Event Descriptions: How did the SDT determine what events should be classified as extreme events? Was statistical data analyzed?

Extreme Event 1: In the existing TPL standards, the simultaneous loss of two elements was considered a Cat C multiple element event. What is the SDT rational for the change?

Extreme Event 2c: Why is the loss of a single large load an Extreme Event?

Extreme Event 3f: This is a repeat of Extreme Event 3d.

Extreme Event 3g: What is the rationale for distinguishing between old vs. new design for the loss of multiple lines due to icing? Is the SDT implying that new lines must be desined to prevent multiple line loss due to icing?

Table 2 - Stability Performance Table

Performance Requirements: The MRO adds 1/2 to 1 cycle to the Normal Clearing time during simluations as an additional safety margin. The SDT should consider enforcing this practice.

Event: What is a non-bus tie breaker? Is this any breaker that is not a bus tie breaker?

P1: There should be a P1-4 event for a shunt device (ie. "4. A shunt device (including FACTS devices)").

P6-2: What is the justification for classifing a bipolar DC line loss as a single contingency? The existing standard classifies this event as a Cat C multiple contingency event.

P6-3: Why is a breaker internal fault classified as a single contingency? One would assume such a fault would be cleared by backup protection resulting in the loss of multiple elements.

P9-1: Is there any justification for the selection of one mile? Would the fact that there is line shielding be justification for increasing this length? A more reasonable selection could be 5% of the length of the longer of the two circuits.

P9-3: This contingency should be classified as an Extreme Event since statistically, the outage duration of a dc circuit (assume you mean a bipole) is less than 2 hours for MH bipoles, so the probability of a second outage is very low. .

P9-6: Isn't this the same as P1-3? If the outaged tranformer is replaced by a spare transformer, this restores the system to a normal state prior to the event ("Apply a P1.3 Contingency."). What is the point?

Note 1.a.i.: Planning Event P3.2 does not exist.

Note 1.a.ii: This definition of angular stability should be deleted and the definition in Note 1.a.i. should apply to all Planning Events. The system should not be considered to be angular stable when generators are pulling out of synchronism.

Note 1.a.iii.: This standard should define a minimum damping factor and allow the PC/TP to have a more restrictive damping requirement if they choose to.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
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	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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Background

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To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment: MEAG believes that deleting the term "mis-operation" as some may have suggested, would significantly narrow the definition of Consequential Load Loss, which in turn would unreasonably increase the amount of load that is Non-Consequential. The Non-consequestial load loss, which is not allowed in P1-P5. For example, if mis-operation is deleted from the definition and we consider a relay mis-operation where a breaker fails to clear a fault, then any additional load interrupted by the back-up to the failed breaker/relay is Non-Consequential Load (and the standard appears to be violated since only a single transmission circuit was faulted and Non-Consequential Load was lost).**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: A number of the non-extreme events also have a low probability. Recommend change the word to "lower." The definition for "Extreme Events" should reference Table 1.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not

	agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Bulk Electric System deficiencies rather than needs should be evaluated. We do not agree that the planning assessment should include asset conditions and age. This is a preventive maintenace issue. The age of equipment, if it is well maintained, has little impact on reliability.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Change to: "Events that are simulated or assessed to test the transmission system to ensure that performance requirements are met."**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment: Change " the System" to "local area of the Bulk Electric System." It also need a definition for "plant."**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment: Change "System or portions of the system" to "Bulk Electric System's components associated with the Transmission Planer."**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment: The last sentence in the above definition was not included in the definition listed in the draft standard, nor should it be.**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity

studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The entity performing the studies should be allowed to determine the appropriate number of cases that need to be evaluated. Different utilities have different input assumptions, therefore the selection of sensitivities to study are different. For example, some utility needs to study the water availability for its hydro units, while other utility needs to evalauate the sensitivity of gas availability.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: The standard may offer guidance but what constitutes a "reasonably stressed" case will vary from Transmission Planner to Transmission Planner. Therefore, it should be left to the discretion of the entity performing the study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐

Comment: The entity performing the studies should be allowed to determine the appropriate sensitivity studies that need to be evaluated. An alternate approach is to include pre-existing system conditions that additionally stress the system during the contingencies under study so as to verify that stability is preserved under conditions that go beyond those envisioned for the contingency. Stability studies are more time consuming than conventional power flow studies. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: We concur with the current approach.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: DSM should be included if it is a tool made available to the TP for this purpose, but only to the extent that it is available for curtailment by the System Operator and without the option to buy through and remain in service.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: Re-testing should be required only where the correction may impact network flows. The study area should be determined by the TP. The TP has the most knowledge of how the system responds to changes and should be allowed to choose the study area based on the prudent utility practice.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: The goal is to meet the system performance requirements outlined in the standard. Whether a project is proposed or committed is not relevant.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: See response to Q18.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	see Q20 above.
Q22. P5-2: For facilities above 300 kV, loss of a	☐Agree.	see Q20 above.

Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	see Q20 above.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: See response to Q20.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: See response to Q20.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed	☐Agree. ☐Do not agree.	

[1] System adjustment can be manual or automatic

by the loss of a monopolar DC line		
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒

Comment: Generator protection is designed to trip only those units required. In addition, it is the magnitude of generation tripped rather than the number of units tripped that is of the greatest significance to the stability of the grid.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒

Comment: Dynamic studies of seasonal load conditions should include the effects of induction motors, and particularly in areas where traditional load models have indicated a problem. Unfortunately, there is a lack of data to support the amount and characteristics of the detailed induction load models in many areas. In addition to the consideration of the dynamic effects of induction motor loads, the effects of static capacitor banks installed at distribution voltage levels would need to be considered as well. Prior to making this a requirement in the reliability standards, the industry needs guidance as to how this data should be developed and maintained for models in future years.

Note that meeting such a requirement would necessitate a significant increase in the dynamic data needed to represent the system. Maintenance of such load model data would require significant resources. Load characteristics valid for a near term model might not be valid for future years. Also, summer peak load, winter peak load, and off-peak load characteristics would differ.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Adjustments that should be allowed are those that can be performed in time to prevent the system from failing to meet performance requirements. These adjustments may include automatic voltage regulator action, governor action, generator runback, and generator tripping.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency

ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: The generator runback scheme should complete its action within the time allowed by the emergency ratings of elements that exceed their normal thermal ratings.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: RAS or SPS should meet the same criteria as any protection system.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: The conditions required by SPS standards (PRC).

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐
Comment: Facilities rating methodology are different from region to region and company to company.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐

Comment: To the extent that the new standard is more stringent, additional time should be allowed to implement the corrective action plan, with fines suspended until reasonable time has passed to allow implementation. I.E., If the solution is 20 miles of new 500 kV T/L, then allowing fines to the short-term horizon is unreasonable – building 20 miles of 500 kV T/L is not possible in 2 or 3 years.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs and ISOs
☒ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☐	5 — Electric Generators
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Group Comments (Complete this page if comments are from a group.)

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Jim Cyrulewski, P.E.	JDRJC Associates	RFC	8
Joseph DePoorter	Madison Gas & Electric	MRO	4

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Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: Midwest ISO suggests this definition be changed to "Direct Load Loss", as "Consequential Load Loss" may include elements that are not directly connected to the faulted element.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Extreme Events are clearly described on Table 1. Change definition from "low probability of occurrence to "lower probability of occurrence".**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs	☐Agree.

through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Do not agree.
Q6. **Comment: Midwest ISO suggests this definition be changed to "Indirect Load Loss", as "Non-Consequential Load Loss" may be confusing regarding the cause-and-effect relationship between a faulted element and subsequent loss of load.**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☐Do not agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: The words "Bulk Electric" should be added before "System".**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: The words "Bulk Electric" should be added before both occurences of "System".**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the

requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: Requirements 2.1.3 and 2.4.3 call for sensitivity cases that stress the system, with documentation as to the rationale for why a particular sensitivity was selected. Midwest ISO believes that the standard must balance clarity and specificity with flexibility and discretion. If the standard is too prescriptive in the system conditions to be evaluated, sensitivity studies that reflect critical system conditions that experience dictates are appropriate for a given system could be construed as being outside of the standards. Such a determination could make the regulatory approvals of facilties needed for reliability purposes difficult or impossible to obtain. Midwest ISO believes hat the language in the existing standard TPL-001-0, R1.3.2, which states that "PA and TP assessments shall cover critical system conditions and study years as deemed appropriate by the responsible entity" provides the proper balance of these issues.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: This appears to be a case of expecting that "one size fits all" in requiring that certain scenarios be evaluated. Since the goal here is to improve reliability, it makes more sense to have transmission planners identify appropriate sentivities for area under study. The appropriate sensitivity is likely to vary depending on the portion of system being studied.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒

Comment: Use of sensitivities should not be required for Stability analysis, but the Standard should rather allow sensitivities at the discretion of the planning engineer. Due to the computationally intensive nature of these studies, a study rotation would be appropriate. For example, one year would be peak base case, next year off-peak case, and following year a sensitivity case. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: Long-term planning horizon studies are typically based on a number of assumptions regarding future conditions and uncertainties. While testing various load conditions, generator operation assumptions, and power interchange variables may be useful for modeling expected economic value, such analysis does not contribute to reliability.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☒
Comment: Yes, DSM should be considered in transmission studies, but should be limited to firmly contracted DSM resources that are demonstrably applicable for transmission capacity mitigation. DSM is better compared to supply-side resources as they are evaluated for reserve margin contribution. No, the challenge in considering DSM, is that Transmission Planners are not aware of DSM potential on the system and it must be communicated to them for consideration.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒
Comment: Sufficient analysis, including re-testing, must have been performed in creating the Corrective Action Plans. Requiring demonstration by the transmission planner that this is the basis of the Plans is superfluous.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: The current Corrective Action Plan should show the performance of the system with the best information available. These Plans will change year by year as conditions change and new information becomes available. Requiring that Plan projects from previous years may not be modified "without documentation" adds a additional unneeded paperwork.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not	No indirect (non-consequential) loss of load for single contingency events, else operator is in SOL precontingency without

	agree.	such planning.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Allow indirect (Non-Consequential) loss of load for events involving short duration outages, such as typical line outages.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	Do not allow indirect (Non-Consequential) loss of load for events involving long duration outages, such as transformer outages. (Tranformer outage could occur first).
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	Do not allow indirect (Non-Consequential) loss of load for events involving long duration outages, such as transformer outages.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: No indirect (Non-Consequential) loss of load for outage of single EHV element.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment: With the clarification that direct (Consequential) loss of load is associated with all outage elements: both SLG element and stuck breaker element.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	Note - No voltage limit for generator and transformer per Table 1, P4-4

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: The key word in this question is "dependent". Transfer is "firm" if DC line is in service.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

[1] System adjustment can be manual or automatic

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☒
Comment: Yes, we agree that appropriate induction motor loads should be modeled. No, it is not be practical to model all induction motor loads. There needs to be size and location considerations. Data is not readily available today.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Generation redispatch should not be performed for single contingencies. Generation redispatch is appropriate for multiple contingencies. Appropriate SPS and generation runback schemes should be allowed, where the system is designed with those schemes.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☒
Comment: Yes, where the transmission system is designed with these schemes. No, in general when there is no designed SPS or runback for the generator.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☒
Comment: No, this should be the exception, not the rule. Yes, there are mine mouth plants with DC outlet lines, which must be runback if the DC line trips. There are also generators which used to serve large on site loads. The large loads are gone (plants retired) and generator outlet is limited. There are also some generators which have known contingent outlet limits and the generators are OK with runback, if the contingency occurs.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: The use of SPS/RAS may be the appropriate transmission system design. If it is economic to mitigate the SPS, then upgrades should be made.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: SPS may be used if it maintains similar level of system reliability and security as transmission upgrades.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: The Midwest ISO appreciates the opportunity to offer the following recommendations:

1. Requirements for providing modeling data in R1. are redundant with the exising requirements of MOD-010-0, MOD-012-0, and MOD-016-0 through MOD-025-1. Adding these requirements to the TPL Standard is unnecessary and may create confusion.

2. The Standard does not address the return of direct (consequential) load loss following a contingent event. How long of an outage event acceptable?

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: **Midwest Reliability Organization (MRO)**

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Contact Segment: **10**

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Terry Bilke	MISO	MRO	10
Robert Coish	MHEB	MRO	10
Carol Gerou	MP	MRO	10
Jim Haigh	WAPA	MRO	10
Ken Goldsmith	ALTW	MRO	10
Tom Mielnik	MEC	MRO	10
Pam Oreschnick	XCEL	MRO	10
Dave Rudolph	BEPC	MRO	10
Eric Ruskamp	LES	MRO	10
Michael Brytowski	MRO	MRO	10
David Jacobson	MHEB	MRO	10
Ron Mazur	MHEB	MRO	10
27 additional MRO members	not mentioned above	MRO	10

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: The MRO could not agree on the correct definition.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Low probability of occurrence should be in reference to something to be more meaningful. The MRO suggests that the definition be changed to state "lower probability of occurrence than Planning Events."**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	

Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: This definition is too general. It could be interpreted that the performance studies include resource planning rather than transmission system planning, as well as, asset management. Asset management issues should be beyond the scope of this transmission planning standard. Asset management is an engineering discipline that would require a separate standard or standards and is still a developing activity, for example, there is no industry-wide practice for studying aging issues of transmission equipment while there are industry-wide practices for steady-state, stability, and short circuit modeling and planning of transmission systems. The MRO suggests that the word transmission be added to the definition when referring to needs, performance, and reinforcements and that references to asset management be deleted. Here is a proposed definition "Documented evalution of future Bulk Electric System TRANSMISSION needs by the use of TRANSMISSION SYSTEM performance studies that cover a range of assumptions regarding TRANSMISSION system conditions, time frames, future plans including TRANSMISSION IMPROVEMENTS and operating procedures and other factors." The words in all caps were added or inserted to replace the Drafting Team's original words.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: The words "Bulk Electric" should be added before "System".**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: The words "Bulk Electric" should be added before both occurences of "System".**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The Drafting Team has provided the appropriate level of detail by indicating that one or more of the following conditions are to be used. However, the MRO notes that R.2.1.3.1 should be changed to match R.2.4.3.1, that is, R.2.1.3. 1 should be changed to state "Variations in Load model assumptions."

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: This is unnecessary micro-management of the planning process. The MRO recommends that the Drafting Team proceed with the high-level requirement as provided with the minor changes recommended by the MRO in other parts of this comment form.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒

Comment: The MRO is okay with requiring the sensitivity studies but is concerned with the R.2.4.3.2 requirement as written in that it unnecessarily requires that the sensitivity studies to "simultaneous transfer" to include "non-firm transfers". The MRO recommends that this be changed to match R.2.1.3.2 "Modification of expected TRANSFERS." The MRO also questions the wording of R.2.4.3.4 which provides a more limiting

description of the sensitivity to reactive. The MRO recommends that the wording of this requirement be changed to match R.2.1.3.4, "Variability and outages of reactive resources."

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: The models for Long-Term Transmission System Planning Horizon typically contain such uncertainy that the base planning is a sensitivity study iteself. The MRO believes that sensitivity studies in these years would be a waste of time.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒

Comment: DSM should already be in the load forecast and sensitivities to the load forecast variations are included in the near term planning horizon sensitivity analysis. Additional DSM shouldn't be part of the transmission planner's corrective plan. Additional DSM can be considered in the next planning cycle.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒

Comment: The MRO is concerned with this requirement particularly since the standard indicates that System Assessment shall be conducted each year while studies are not required each year. MRO members typically conduct this exercise at the time that studies are originally conducted with regard to improvements. By requiring a new study with improvements (some of which were justified in past studies) demonstrating that these improvements work essentially results in the Transmission Owner needing to clear a new unfair hurdle for improvements. This results in a requirement which will result in wide-spread non-compliance. The SDT

should clarify that this requirement can be met by past studies. The MRO recommends that R2.7.2 be removed because it is redundant since development of the corrective action plan will have included these studies.

At some point the corrective action plan should be tested to verify the plan meets the performance requirements. The way the standard is written is that the transmission plan should be perfect for the entire planning horizon for all sensitivities tested. Any issues should be immediately addressed. The standard does not allow any time to develop the corrective plan through an open and transparent process. Based on the Nerc definition, a Corrective Action Plan is the list of actions and an associated timetable for implementation to remedy a specific problem. A Corrective Action Plan could mean that load forecasts at the station will be verified, facility ratings verified and alternatives to fix the identified problem to be determined before the next Planning Assessment. Standard R2.7 seems to be mixing the idea of a Corrective Action Plan with the original TPL idea of determining corrective plans to achieve required performance. A corrective plan wil be the end goal of a Corrective Action Plan.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐

Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒

Comment: The MRO disagrees with this requirement. This is an unnecessary requirement since each year Corrective Action Plans must meet the system performance requirements.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this change to customers. Alternatively, the SDT should define a level (such as 1000 MW) of non-consequential load that is acceptable for such low probability events.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this change to customers. Alternatively, the SDT should define a level (such as 1000 MW) of non-consequential load that is acceptable for such low probability events.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this change to customers. Alternatively, the SDT should define a level (such as 1000 MW) of non-consequential load that is acceptable for such low probability events.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this change to customers. Alternatively, the SDT should define a level (such as 1000 MW) of non-

		consequential load that is acceptable for such low probability events.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this change to customers. Alternatively, the SDT should define a level of non-consequential load that is acceptable for such low probability events such as 1000 MW.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this change to customers. Alternatively, the SDT should define a level of non-consequential load that is acceptable for such low probability events such as 1000 MW.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	The monopolar DC line words should be revised to "a single pole of a DC line".
Q28. P4-3: Loss of a generator followed by System adjustment followed	☒Agree. ☐Do not agree.	

[1] System adjustment can be manual or automatic

by loss of a Transmission circuit		
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: The MRO questions why interruptions of firm transfers are not allowed in other cases since load dropping is allowed for these cases.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment: The MRO commends the SDT in separating the two tables. The single table for both types of studies has generated confusion in the industry.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: The MRO sees the need for plant stability study requirements somewhere in NERC standards although adding this requirement into this study requires a rehash of the plant stability studies that are conducted throughout ten years or more in an annual assessment. This seems to be an unnecessary duplication. The MRO recommends that this requirement be deleted from this standard and that the SDT recommend to the NERC SAC that this requirement be covered by the appropriate future SAR.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐
Comment: In a breaker-and-1/3 or breaker-and-1/2 generating station, if one station bus is off-line for maintenance, faulting the other bus will kill the station, or at least cause major disruption with individual generators connected to other stations by separated lines or AC separated DC converter transformers via isolated station bays. That is certainly worthy of consideration as a feasible "extreme" event.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment: The MRO agrees that R2.4.1 should provide for the inclusion of dynamic behavior of induction motor loads, however, recommends that there should be a limitation on only requiring such behavior where significant such as large motor loads over a certain MW amount. As written, it could be interpreted that the Transmission Planner is non-compliant if all induction motors are not represented.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Here are the adjustments that the MRO believes the MRO systems are presently designed to meet and what an MRO Augmentation Drafting Team is proposing to require its members to follow for Category B and C events: 1. Generation adjustments - Reducing or increasing generation while keeping the units on-line or by bringing additional units on line. The amount of generation change is limited to that amount that can be accomplished within the allowed readjustment period. Due consideration shall be given to start up time and ramp rates of the units. 2. Generation rejection to the extent possible within the allowed readjustment period. Generation rejection shall not exceed the normal operating reserve of the generation reserve sharing pool to which the MRO Member belongs or of the MRO Member itself if the MRO Member self-provides generation reserves.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment:
Generally, the historical MRO practices and requirements have been to require that following a single contingency the loading of facilities are to be maintained within emergency ratings. Adjustments are allowed to move the system from conditions within emergency ratings to conditions within normal ratings. However, in a limited number of cases, the use of Special Protection Systems are used to initiate fast generation run back, generation rejection, or automatic tripping of a remote transmission facility to get below a longer term emergency rating (30 minutes or longer.) In some cases, these involve parts of the network where remote generation is connected to load where the costs of not using the SPS would involve substantial increased investments and environmental impacts.

Requirement 3.5 needs more clarification. What rating should not be exceeded?

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: The MRO believes the MRO systems are presently designed to meet system performance, in some cases, with the use of SPS to initiate fast generation runback, generation rejection, and automatic tripping of a remote transmission facility for a single contingency event. The fast generation runback or generation rejection should not exceed the normal operating reserve of the generation reserve sharing pool to which the planner belongs or of the planner itself if the planner self-provides generation reserves.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: SPS are often used in the MRO area to avoid unnecessary expenditures and environmental impacts. SPS are sometimes used to prevent instability. The SPS may intiate fast generation run back, automatic generation rejection, or automatic tripping of a facility for a remote event. The MRO notes that the scheme must be automatic, fast acting, consistent with short term equipment ratings. The MRO notes the folowing general conditions for adjustments, that perhaps would be useful in designing performance requirements for allowable system adjustments in addition to the description in Question 39: 1. Generation adjustments - Reducing or increasing generation while keeping the units on-line or by bringing additional units on line. The amount of generation change is limited to that amount that can be accomplished within the allowed readjustment period. Due consideration shall be given to start up time and ramp rates of the units. 2. Capacitor and reactor switching - The number of capacitors and reactors, which may be switched, is limited to those which could be switched during the allowed readjustment period. This includes those capacitors and reactors that would be switched by automatic controls within the same period. 3. Adjustment of load tap changers (LTCs) to the extent possible within the allowed readjustment period. This includes both LTCs which would automatically adjust and those under operator control which could be adjusted within the readjustment period.
4. Adjustment of phase shifters to the extent possible within the allowed readjustment period.
5. An increase or decrease to the flow on HVDC facilities to the extent possible within the allowed readjustment period. 6. Transmission reconfiguration - Automatic tripping of transmission lines or transformers to the extent possible within the allowed readjustment period. 7. Automatic tripping of interruptible load or curtailment of or pre-determined redispatching of Firm Transmission Service to the extent possible within the allowed readjustment period.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐
Comment: If the SDT proceeds with an approach that does not allow generation rejection for contingencies, the MRO will need to submit a regional difference. In certain areas of the MRO that are stability limited because of long lines to bring generation at the energy source (such as mine mouth plants, hydro plants, etc.) to the load, generation rejection is used to return from an emergency state to a normal state. If generation rejection is not allowed in these cases, extraordinary cost and extraordinary negative environmental impacts will result.

As an example, if one particular SPS is removed, new 500 kV transmission will be required between Winnipeg and Minneapolis at a cost of $1billion to the customers of MRO utilities.
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Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐

Comment: The MRO commends the SDT on the difficult task of rewriting some of the most important NERC standards: the TPL standards. The MRO has a number of comments and suggestions.

1. Load modeling data in R1.1 and R1.2 do not belong in the TPL standards. It should be provided for in the MOD standards which provide the numerous load model data requirements. At a minimum, R1.2 should be revised to only require documentation of stressed system conditions. It is unnecessary and micro management to provide for "measurement during stressed System conditions". Further, it is unusual standards drafting to provide for a measurement of load in an assessment standard.

2. R1.4 should be revised to separate "known planned outages" from the rest of the requirement in separate sentences. This is because the reference to spare equipment outages does not have any bearing on the "known planned outages" requirement. Further the consideration of spare equipment strategy is not explained enough to understand what is required here. Further it is not clear as to what equipment must have consideration of spare equipment. The MRO recommends that R1.4 be rewritten as follows: "Known planned outages. Long-term forced outages for transformers with low-side voltages of 100 kV and above and generator step-up transformers should be identified where lack of spare transformers could result in outages of the transformers over the annual peak demand hour."

3. It is unreasonable for R1.5 to provide that planned facilities that are included in System Assessments include circuit breakers, and protection system equipment. These two items should be dropped from R1.5 since these are engineering details that are typically not available at the time that the System Assessment is made.

4. R.2.1.1 - The system peak load study requirements for studies for two of the near-term period seems to be excessive. The MRO recommends that only one year in the near-term period be required.

5. R2.6 should be deleted. The MRO believes that R2.1 and R2.4 are sufficient in describing when current studies are required. R2.6 will result in unnecessary restudy of the system. Alternatively, if R2.6 is kept, then the requirement should be a performance requirement, that as long as material changes do not require restudy then restudy is not required. The Transmission Planner and Planning Coordinator could be required to document why restudy is not required. Material changes should be expanded to refer to only those "significant" transmission line additions or generator additions.

6. R2.71 should be revised to delete "including the duration of interim Operating Procedures" or else the SDT should explain what is meant by this with additional information about what interim Operating Procedures are.

7. R2.7.1.1. should be revised to delete the requirement for project initiation date. This information is not typically available at the time of performing a System Assessment since this is detailed engineering information not pertinent to planning.

8. R2.7.5 should be deleted. The MRO believes the such detailed review of the status of the installation of projects to be beyond the scope of the TPL standard. Since NERC has no authority to require the installation of facilities, how does NERC have authority to require a review of the status of such facilities?

9. R3.2.1 and R3.2.2 seem unnecessary details that are micro-management of the planning process. Both requirements could be met by the transmission planner and planning coordinator with general statements of little value. Also, relay loadability is included in facility ratings and does not need to be covered in TPL.

10. In Table 1, "a shunt device (including FACTS devices)" is too general. Arresters and potential devices for metering and relaying are shunt devices. This should be changed to a specific listing such as: transmission capacitors (100 kV and above), transmission reactors (100 kV and above), …" and whatever other devices that the SDT intends to be included here.

11. In Table 1, Single pole of DC line should be moved to P1.

12. In both tables, "monopolar DC line" should be replaced with a "single pole of a DC line".

13. The revised tables are confusing in descriptions of various outages particularly since the interconnected transmission system has been planned for the past decade using the previous Table I. The SDT should limit its changes to Table I to a limited number of changes that have been known to cause issues in the past rather than raising the bar in a number of cases.

14. The Extreme Event descriptions in Table 1 should be revised to provide definitions of local area and wide area. 3 d. (3f.) and 3 c. (3 e.) are duplicates and should be combined. Wide area events as listed are such unusual events, which are difficult to analyze or model. The requirement should provide that the number of these wide area events to be studied is limited to a minimum of one.

15. The MRO does not believe that contingency reserve is necessarily synonymous with spinning reserve. The SDT should clarify note ii to Table 2.

16. The SDT should clarify the wording in the tables to better explain the events which are either above or below 300 kV. For example, in P5 change 1. IS IT "A Transmission circuit followed by a System adjustment above 300 kV followed by the loss of another Transmission circuit above 300 kV." or is it "A Transmission circuit followed by another Transmission circuit resulting in impacts on 300 kV facilities"?

P5 3. should be revised to say, "A transformer with a low side voltage rating above 300 kV followed by a System adjustment followed by the loss of another transformer with low side voltage rating above 300 kV." or is it "A transformer followed by the loss of another transformer resulting in impacts on 300 kV facilities."

17. R2.1.3 - R2.1.3 reguires sensitivity studies that involve many potential scenarios that would be difficult to create in a Planning Assessment. Planners can not model the unknown and to assume the unknown may be a difficult task to complete. Instead of "shall be run and", the language should be "shall be considered based on current knowledge of system including"

18. Extreme events description for common right-of-way should be defined. Does this include line crossing points? Suggest exclusion for corridors one mile or less similar to P9.1.

19. The language description of the even should be substantially the same between Table 1 and Table 2. Table 2 format is a bit cleaner with initial condition and event separated. Table 1 should follow this format.

20. The loss of a shunt device (e.g. SVC) should be added to Table 2 (P1.4).

21. Note 1ai. to Table 2 refers to event P3.2 which doesn't exist in the Table 2.

22. Note 1aii. to Table 2 allows generating units to "cascade trip" for certain events that were this would not be allowed in the existing TPL standards. The MRO recommends that the more of the events be listed in 1ai. so as to at least maintain reliability.

23. Note 1aiii talks about acceptable damping. NERC should have a standard requiring development and documentation of damping criteria by the planning coordinator.

24. P9 should be changed from referring to a monopolar or bipolar dc line to a single pole of a DC line.

THE FOLLOWING ARE RON MAZUR'S COMMENTS.

25. The MRO does not believe R1 is required in this standard. The modelling standards should cover the requirement of the data owners to provide data to the PC. Further this data needs to be provided to the TP as well.

26. R1.4: requires planned outage data to be provided to planners. The MRO does not believe this is a requirement for planning. It is not economic to add facilities to accommodate future planned outages. Secondly, the Table 1 multiple contingencies already mandate that planners consider the impacts of an outage with system adjustment followed by testing for the next contingency.

27. R1.5: requires the PC to define “planned facilities” which should be included in the model. This will lead to inconsistency what is modelled, as experience has shown that there will be a wide range of assumptions in the definition. This standard should offer a definition for stakeholder debate. The SDT should clarify what is intended by including Protection System Equipment and control devices.

28. R2: The SDT should define the elements of an acceptable assessment in more detail.

29. The MRO recommends that the need to assess Plant Stability be removed from this standard. The generator connection standard and the proforma tariff interconnection process ensure the plant stability meets performance requirements. The System Assessment provides an overall assessment of the integrated system performance, which includes the impact of the plant. This requirement appears to be redundant.

30. R2.1: It is important to assess off peak loads with high simultaneous transfers as this is the period where extensive economic interchange occurs, and transient stability issues arise as less uneconomic peak units are off, leaving the load to be supplied by remote generation with reduced local reactive supply, voltage and damping control.

31. R2.1.3: The requirement for sensitivity cases is excellent. The SDT should consider:
R.2.1.3.1: separate real MW load variation and Power Factor variation
R.2.1.3.2: clarify the intent of modification of expected transfers. Does this apply to firm transfers only, or does it also encompass non-firm transfers.
..R.2.1.3.4: Instead of a sensitivity, the reactive devices should be included in the Table 1 &2 contingencies. If the intent is to investigate robustness to voltage instability, the SDT should clarify.
R.2.1.3.5: Generation additions/retirements should be removed as this is covered, or should be, by the interconnection standards. The SDT should clarify.the need for generation additions/retirement.

32. R2.2: The long term assessment should also include an off peak case with simultaneous transfers to provide some indication if the system performance is expected to degrade.

33. R2.3: The short circuit study is not a reliability assessment issue but a design issue that is more appropriately covered by a Facility Rating Standard. The time required to conduct and report on this analysis in an assessment is better spent on more contingency or sensitivity analysis.

34..R2.4: Similar to the comment on R2.1,. It is important to assess off peak loads with high simultaneous transfers as this is the period where extensive economic interchange occurs, and transient stability issues arise as less uneconomic peak units are off, leaving the load to be supplied by remote generation with reduced local reactive supply, voltage and damping control.

35. R2.4.1: Should be clarified to limit the detailed modeling to local areas where the planner expects an emerging voltage recovery issue due to unusually high concentration of induction motor load. This is a local issue, and a bulk system reliability issue that is imposed system wide. The MRO believes this should be moved to the sensitivity case requirements R2.4.3.

36. R2.4.3: Sensitivity Case requirements should mirror the steady state comments, subject to the suggestion provided above for R2.1.3. That is:
..R.2.4.3.1: should also include power factor variation (actually a separate requirement) as in the stability world, the dynamic modelling of load has a significant influence in meeting transient performance requirements.
R.2.4.3.2: I agree it should simultaneous non-firm transfers. This should be applied to the steady state sensitivity as well (see R.2.1.3.2).
..R.2.4.3.3: delete
..R.2.4.3.4: Needs to be clarified. See R.2.1.3.4.
. R.2.4.3.5: see R.2.1.3.5

37. R2.5: Plant stability analysis should be deleted.

38. R2.6.1: Nowhere else in the standard is there a requirement to assess reliability impacts of market structure changes, so why would a study become invalidated if there is a change in market structure. It would seem to me that the operation of any market would have to respect the reliability criteria.

39. R2.7: Corrective Action Plans: Is the intent that corrective action plans also address issues raised by the sensitivity studies. The MRO argument would be that it should not

be mandated. The plans are developed to meet base case needs which are based on expected load forecasts, transfers, etc. Sensitivity studies are done to measure the robustness of the base case plan. It should be left up to the Planner to decide if the plan is adequate based on the likelihood of the scenario studied, even if the sensitivity analysis shows some performance violations.

40 Also, if rationale is provided for contingencies selected as they are expected to be most severe, then by default those not selected are less severe. Why is there a requirement to explain why you did not select a contingency.

41. R3.4: Requires extra analysis compared to TPL-004-0. Developing mitigation for extreme events can require significant work. Since there is no requirement to implement corrective plans for extreme events, what is the purpose?

42. R3.5: Generator tripping should be added in addition to runback. Generator tripping is used extensively in regions where remote generation is delivered via long transmission. Generator tripping should be an available option for the planner to use as opposed to requiring justification as a regional difference.

43. R4: The requirement to assess Plant stability is redundant as this is assessed as part of the generator interconnection. It should be deleted.

44. R4.5.2: The MRO disagrees on the need to define mitigation for extreme events.

45. R4.6: Should be deleted.

46. R6: Requires distribution of results and "coordinating analysis of these results through an open and transparent process". Can the SDT clarify what the intent is? As written, it implies the PC/TP just shares assessment results with neighbours. The MRO believes there should be a requirement to conduct joint assessments on inter-regional transfer capability.

47. Table 1
Performance Requirements:

- As this is a steady state table, how does one assess if voltage instability, cascading outages or islanding occurs?
- Generator tripping for single contingencies should be added to the allowable actions.
- How did the SDT classify which event was single contingency vs. multiple contingency vs. extreme? Was statistical data analysed?
- What is a non-bus tie breaker? Is this any breaker that is not a bus tie breaker?
- Event P2-3 should be relocated to the P1 event category.
- What is the SDT rationale for defining bus faults >300 k as single contingency events? Is there any statistical dat to warrant this extra requirement? Now a Cat C? Since little load is served off >300 kV it may be a moot point.
- P6 single contingency: What is the justification for classify P6-2, a bipolar dc loss as a single contingency? The existing standard classifies this event as a Cat C multiple contingency event?
- P6-3: Why is a breaker fault classified as a single contingency? One would assume such a fault would be cleared by backup protection resulting in the loss of multiple elements?
- P9-1; Is there any justification for selection of one mile? Can it be two miles? More? Why not no more than 5% of line length? Would the fact that there is line shielding be justification for increased length?

48. Extreme Events

- Event 3.g: what is the rationale for distinguishing between old vs. new design for the loss of multiple lines due to icing? Is the SDT implying that new lines must be designed to prevent multiple line loss due to icing?

49. Table 2 Stability Performance

- MRO Comments on Table one for the same contingencies should also be applied here.

50. P6-2 should be a multiple contingency, as it is in the existing TPL standards.

51. P9-3: should be an extreme event.

52. P9-6: Please clarify the requirement to indicate that it relates to long lead times.

53. The definition for Angular Stability should be modified to allow planned tripping of a generator following a line trip. Why are generators allowed to pull out of synchronism for other planning events? This is cascading. The SDT should clarify if they are refering to local or regional damping modes in 1.a.iii.

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Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☒ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☒Agree. ☐Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.

- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☐
Comment: Leave it open so it can be driven by local issues including those not in the standards. i.e. Running near term criteria on the long term horizon, additional contingencies beyond currently required, etc. as appropriate for the area.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☐
Comment: Leave it open so it can be driven by local issues including those not in the standards. i.e. Running near term criteria on the long term horizon, additional contingencies beyond currently required, etc. as appropriate for the area.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☐
Comment: If reasonable and appropriate and allow for local issues including those not in the standards..

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: Local issues may drive a different approach

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in

conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: We do not have DSM but I could see where it could be used to relieve overloads or low voltage.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☒
Comment: Large enough to ensure negative impacts will not occur. This could best be covered in regional studies. (See Q43 Comment #3)

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☐Do not agree.	See Q43 Comment #5.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☐Do not agree.	See Q43 Comment #5.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	See Q43 Comment #5.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	See Q43 Comment #5.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☐
Comment: See Q43 Comment #5.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance

requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☐
Comment: See Q43 Comment #5.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☐Do not agree.	See Q43 Comment #5.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	See Q43 Comment #5.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☐Do not agree.	See Q43 Comment #5.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☐Do not agree.	See Q43 Comment #5.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment: See Q43 Comment #5.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an

[1] System adjustment can be manual or automatic

assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Unless there is a reasonable reason to expect all the units to trip.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment: We have not seen this on our system based on the review of digital fault recorders (DFR). The difficulty with including induction motors is getting reasonable data from customers about their motors so they can be adequately modeled. (We did ask our consultant to include motor effect in our coordination study since the motors could act as a weak source.)

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Whatever the local entity sees as appropriate and is reasonable versus the cost of fixing the problem. (See Q43 Comment #3)

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Reasonable and workable.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: As long as they work and are reasonable - none. (See Q43 Comment #3)

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: Reasonable and workable. (See Q43 Comment #3)

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐

Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: Muscatine Power & Water (MPW) is a municipal utility with approximately 33 miles of 161 kV lines (2 lines) and 33 miles of 69 kV lines with three – 161/69 kV substations and seven – 69/13.8 kV substations. The service territory is approximately 24 square miles. Our last system peak was 149.9 MW on July 29, 1999 with a more recent peak of 146.9 MW on July 17, 2006 with generating capacity of approximately 253 MW from four units. The main problem we have is keeping up with the standards changes with our limited resources. We would suggest:

1. It was good to see the definitions section. We would also suggest including all acronyms including those in common use. Acronyms have become so common and they are now being reused to mean different things to different groups that for new people, multitasking individuals, or those not dedicated to a specific standard acronyms add confusion. Where possible, we would suggest using existing terms and, if appropriate, preferably already defined or have them defined in IEEE standard #100 dictionary.

2. Can you address adequate documentation? I'm not looking for detail formats or requirements but more minimum requirements and suggested layout etc. One of the problems I have during audits is how much documentation to provide without going over board. More is not good considering time requirements. Our goal is to make it easy for us and the auditors. We met the standard but have we proved it. Being a small utility with little impact on the bulk system how much should we provide?

3. In our region the MAPP Design Review Subcommittee (DRS) and in some cases the Subregional Planning Groups (SPGs) review new and proposed changes to facilities. In many cases they would have to approve any RAS or SPS and thus provide a peer review/reasonable and workable check.

4. R.2.6.1 - Being a small utility we are concerned about the planning study must be less than 3 years old. We budget for studies every three years but adjust that based on whether material changes have occurred to the system. Our last cycle was 6 years only because our load hasn't been growing and we still haven't hit our peak of 1999. Since we are dependent on consultants, we also have a concern for how long it can take for them to complete the study. Since we are small the bigger customer gets the attention. We do use the same criteria for near and long term planning horizons. We also participate in MAPP and ITWG studies for the annual and bulk system review and since our issues in studies are more local rather than the bulk transmission system. How should/could the sensitivity studies be covered for us at the regional level?

5. 300 kV and above questions: MPW is a small utility that doesn’t have any facilities above 161 kV or any DC lines. I can see requiring more stringent performance for EHV

and possibly lower voltage facilities in some cases, however, whether to allow the loss of Non-Consequential load should be left to local entities to decide since the cost of the "corrective action" could exceed the cost of the load loss and put undo burden on the customers. Depending on the type of load the customer may not want/be willing to pay for the extra reliability. If ordered, how will the cost be recovered? The cost should be recovered by the users not just the local customers.

Thanks for the opportunity to comment!

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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
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Contact Organization:

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Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: There are a few undefined terms in this definition: "Transmission System" and "interconnected Transmission System". The definition needs to specifically identify what should be modeled and in a manner consistent with other NERC definitions. The definition refers to Facility ratings rather than the general reference to FAC-008 & FAC-009**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Modify to "Events which are more severe,but have a lower probability of occurrence, than Planning Events".**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☒Do not agree.
Q4. **Comment: "Transmission planning period that covers years six through ten", is sufficient for the standard."**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such	☒Agree. ☐Do not

as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Eliminate "capital" from the definition. Suggest changing wording to "Documented evaluation of future Bulk Electric System needs by use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including reinforcements and operating procedures. The corrective action plans may consider factors such as asset conditions and age."**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Propose, "Events for which Transmission performance requirements must be met".**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: A Plant Stability Study should be a part of a System Stability Study. The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: See comment on Q9; proposed modification, "Study of the System or portions of the System to determine whether unit and system angular Stability is maintained, power oscillations are damped, and voltages during the dynamic simulation stay within acceptable perfomance limits.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: Modify to, "The first year that a Tranmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner completes its annual studies."**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement to develop action plans for problems highlighted as a result of one of the sensitivities.

Suggest modification to, "…sensitivity testing that stresses the System shall be considered, and documentation with the rationale for the sensitivity testing shall be supplied. The sensitivity case(s) may include one or more of the following conditions:"

2.1.3.3 should refer only to planned facilities that may be delayed. 2.1.3.4 - "variability" is too vague for a standard; the standard needs to be more specific as to the intent. 2.1.3.7 should be consistent with 1.4. These comments also apply to 2.4.3.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement to develop action plans for problems highlighted as a result of one of the sensitivities.

Reasonably stressed conditions are dependent upon the study area under review and the standard is not likely to be able to be crafted to provide sufficent and consistent direction. However, it might be helpful if the standard clarified whether the base case should include any unplanned generator outages or whether, aside from potential

sensitivities, unplanned generator outages are considered only through P1, P3 or P4 Contingencies. If the standard addresses unplanned generator outages only through P1, P3 and P4, then it is recommended that a mandatory sensitivity analysis, with required mitigation, include various potential combinations of a reasonable amount of unplanned outages. The combinations should be based on the part of the system that is under study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment: The standard is unclear whether or not it mandates the requirement to devleop action plans for problems highlighted as a result of one of the sensitivities.

Suggest modification to, "…sensitivity testing that stresses the System should be considered. Sensitivity case(s) might include among the following conditions:" 2.4.3 shold mimic 2.1.3 except in regard to load models.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: There is no need for sensitivity analysis.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: DSM should be included to the extent that its performance is sufficiently and consistently understood. The standard does not use the term "optimal" Therefore, the Drafting Team appears to be interpreting the Standard to require a vertically-integrated Planner to produce a so-called optimal-mix of resources plan. This would be an incorrect assumption and is not required. In areas with independent planners and competitive wholesale markets, it is sufficent to identify system needs and produce a plan that identifies regulated transmission solutions in the event that market-based resources (such as DSM) do not address those identified needs. Therefore, while DSM can be as effective a resource as generation, per Commission Orders, in areas with ISOs/RTOs and a competitive wholesale market, the NERC Standard cannot prescribe the development so-called optimized (as is suggesgted by the Drafting Team) resource-mix plans, as identified by a central planner.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: The study area should be based upon planning expertise and knowledge of the system, giving due consideration to external impacts.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment: They should be viewed differently in the Near-Term. However, these should be defined terms.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment: It is unclear as to what the commited project is being removed from. Suggested language "…removed from the plan…".

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that

performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	Should also consider the initial loss of a transformer, followed by the loss of a Transmission circuit. This should state a transformer with a "high-side" rating above 300 kV.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	This should state a transformer with a "high-side" rating above 300 kV.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	If mitigation plans are required that are based on studies that already include unplanned generator outages, then some load loss may be reasonable following the subsequent loss of 2 additional generators.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	If mitigation plans are required that are based on studies that already include unplanned generator outages, then some load loss may be reasonable following the subsequent loss of an additional generator and a monopolar DC line
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	If mitigation plans are required that are based on studies that already include unplanned generator outages, then some load loss may be reasonable following the subsequent loss of an additional generator and a Transmission circuit
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☒Do not agree.	If mitigation plans are required that are based on studies that already include unplanned generator outages, then some load loss may be reasonable following the subsequent loss of an additional generator and a transformer

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐

[1] System adjustment can be manual or automatic

Comment: This should also apply to firm transfers via single or double circuit ac facilities as well. In either case, the transfer could be linked to dedicated facilities.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: As defined in R2.5, a Plant Stability Study should be a part of a System Stability Study. The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Difficult to envision how such an event would occur.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: This requirement is too specific and limited. Induction motors are only one component of a complex load model. Complex load models are not always necessary, nor are they always the most conservative, depending on the analysis that is being conducted. Where complex load models are required, they should be considered; this may involve use of complex motor and lighting loads or polynomial load representations with or without frequency dependence. This question also suggests the need for an industry standard regarding transient voltage recovery.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Manual or automatic adjustments should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment. Manual system adjustment should be allowed in between the multiple Contingencies described in P5, provided that the adjustment can be made between contingencies using short-term reserves (10-30 minute).

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment: Generation runback should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐

Comment: However, this should only be allowed where failure of an automatic runback that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: Only allowed where the failure of an SPS that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Only allowed where SPS failure would not have significant adverse impact on the Bulk Electric System; non-Consequential loss of load should be allowed up to an amount potentially specified in the standard.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: System must remain stable with acceptable voltages and all equipment within applicable emergency limits.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment: We're not aware of any at this time. However, future modifications of the standard may highlight a need for regional variances.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: There should be a "P0" standard that applies to system performance without any contingencies.

Standard should be clear that stabiltiy analysis is not required for Long-Term Planning Assessment.

R.1.1 Load forecasts should be addressed in MOD standards, not TPL.

R 1.4 This should only refer to known long-term outages, not planned outages. Delete "including protective relays"; this is addressed through other provisions.

R.2.1 Shorten "Near-Term Transmission Planning Horizon Planning Assessment" to "Near-Term Planning Assessment".

R 2.2 Shorten "Long-Term Transmission Planning Horizon Planning Assessment" to "Long-Term Planning Assessment".

R2.1, 2.2, 2.3 & 2.4 – The initial paragraph should have identical language regarding 'annual', and 'current or past' aspects.

R2.1.1 There should not be a requirement to look at years one and two; a 5 year study should be sufficient. If there has been an ongoing 5 year study, there should be no major unexpected problems occurring in years 1 and 2. Studies of earlier years should only be required if an unanticipated event occurred that had not been considered in prior studies. The TPL should not address shorter term "Operating Studies" or operating issues.

R 2.2.1 Modify to "If any known projects have a lead time that is longer than ten years, the Planning Assessment shall be extended accordingly."

R 2.6 Steady-state, short circuit, and stability analysis should be required no more than every 5 years unless there is a significant change the system.

R 2.6.1 Remove reference to "market structure changes". The purpose of it's inclusion is unclear.

R 2.7.1.1 Project initiation date should be deleted. If it is retainted, it needs to be defined.

R 2.7.3 Committed and Proposed projects should be defined.

R 3.2.1/R 4.3 - What is the intent of this requirement? There should probably be an MOD associated with Generator Owner requirement to provide related generator protection/ limiter data or other plant information.

R 3.4/R 4.5.2 Remove the requirement to implement changes to reduce or mitigate the likelihood of such consequences of Extreme Events. This may not be reasonable or achieveable.

R 3.2 Sectionalizing schemes shall be considered when reflecting the post-contingent system.

R 3.2.2 - Propose deleting this. Line ratings should already take relay loadability into account.

R 3.3.2.1 - Propose deleting "expected duration". This would be dependent upon the damage to the element due to the iniating event and other factors.

R 3.3.2.2 - The requirements of this section do not match P6.

R 3.3.3 - Change introductory language to read "Those multiple Contingencies that are…"

R 3.5 - Generation tripping should be allowed as well as generation run-back. In addition, all performance requirements shall be met, rather than just meeting facility rating requirements. Suggested lanague "Manual and automatic generation run-back and/or generation tripping is allowed as a response to single and multiple Contingencies as long as the performance requirements of this standard are met." If these changes are accepted, R 3.6 can be deleted.

R 4 and R 4.1 - The language should be made similar to R 3 and R 3.1.

Suggest bringing language similar to R4.4 into R 3, the steady state section.

R 4.2 - High speed automatic reclosing schemes shall be considered.

R 6.3 - Change to read "Planning Coordinators of neighboring impacted areas".

Table 1 3 b and c Extreme Event descriptions are vague concepts that cannot be practically simulated. 3 d and e are not reasonable or practically useful to simulate.

Table 1, P8 - Language needs to be clarifed as to how the 300 kV threshold is to be treated for transformers. Is this for the high side, low side, or both sides? P5 is much clearer.

Table 2 - Clarification needs to be made that the faults being simulated are permanent faults. This can be addressed under the "Performance Requirements" portion at the beginning of the table, or modify each fault description.

Table 2 P9. Recommend that this be changed to require that faults should be on different phases of each of two adjacent transmission circuits on a multiple circuit transmission tower

Table 1, P9(6) and Table 2 P9 - It is unclear as to what is meant by "A spare transformer inserted to replace an outaged transformer followed by System adjustments". Unclear as to what is to be tested.

General comment - Transmission System is used throughout the document and is an undefined term

For any of the items when the standards may become more stringent, try to recognize that there is going to need to be a transition plan to meet compliance.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	NERC Transmission Issues Subcommittee	
Organization:	NERC	
Telephone:		
E-mail:	TIS@nerc.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☒ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

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Additional Member Name	Additional Member Organization	Region*	Segment*
See attached TIS Roster			

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment: The definition should differentiate between powerflow and dynamics base cases**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment: MISOPERATION has to be qualified as being a misoperaiton on the system element that trips**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: The use of the term Extreme should be limited to those events that are truly extreme. A single line-to-ground fault with delayed clearing (for whatever reason) may require remote clearing of the fault, and trips multiple system elements, without time between elements being outaged. Such events are far too common occurrences to call them extreme.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs	☒Agree.

through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☐Do not agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Should not be limited to contingencies in the vicinity of the plant. Remove the terms "in the vicinity of the plant." Engineering judgement can then be used without having to define "vicinity." Plant instability can be caused by system events many (sometimes hundreds of) miles away. Plants were shaken off line in British Columbia due to the tripping of units in Arizona in June 2004.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The

standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☒
Comment: Since the long-term planning is completely couched in uncertainty, at least some generalized sensitivities should be required.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2

will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☒
Comment: Yes, if it can be counted on for relieving transmission constraints. Some DSM contracts do not allow for interruption for anything other than resource adequacy events, or have time-based or economics-based implementation limitations.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: All Corrective Action Plans should be tested on an interconnection-wide basis to screen for potential adverse impacts throughout the interconnection, not just the TOs area.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☒
Comment: No concensus in TIS after extensive disucussion, but it will be discussed further.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☒
Comment: Any revision to the Corrective Action Plan should be tested to ensure that the revised plan meets the precribed performance requirments. Documentation of that testing is appropriate.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar."

Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	Loss of a bus section is a single contingency. Non-consequential load loss should not be allowed.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	This becomes a differentiation between an event and a contingency - if there is time to adjust the system, it is really two events. Non-consequential load loss based on the first event is hard to fathom. Loss of load following the second event is either consequential to the second event (even if load was isolated by the first event) or non-consequential to the second event.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	See Q 21 Comment
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment	☐Agree. ☐Do not agree.	See Q 21 Comment

followed by loss of another transformer		

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: By its very nature, the event described is a breaker failure and the fault will typically need to be cleared by the next set of breakers, often remotely. Tripping out to the backup protection breakers typically can cause significant Consequential load loss. That should not be misconstrued as non-consequential load loss. Non-consequential load loss beyond that is unaceptable.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment: See comment to Q24.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a	☒Agree.	

[1] System adjustment can be manual or automatic

generator followed by System adjustment followed by loss of a transformer	☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment: TIS will discuss this in further review of the standards developement

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment: Although there are many simularities, separation of the testing requirements makes the standard far more understandable.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment: Planning Coordinators should study plant stability at the time of interconnection, and it should be reviewed for significant system or plant modifications that may impact the plant's stability.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐
Comment: Simultaneous loss of the entire generating stations have occurred on 4 occasions in the last 3 years, with simultaneous losses ranging from 1,100 MW to over 3,700 MW. It is imporatant to understand the stability implications to the system and other plants.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major

factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment: If such known phenomena are not properly modeled, how can the resultant study results be expected to be correct and a proper prediction of future system behavior. The modeling shortcomings of the Western Interconnection prior to the August 1996 western blackout showed no potential stability problems for the events that occurred; the system proved otherwise.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: If system adjustments are allowed between events in steady state analysis, manual and automatic adjustments should both be allowed. However, in stability analysis, only automatic adjustments capabilities that are actually in place should be used.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment: This is simply a recognition that the system operators will take action to return the system to a stable and secure operating posture following an event.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that

must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: This is simply a recognition that the system operators will take action to return the system to a stable and secure operating posture following an event. This is also common practice in generator protection/controls for generators with multiple GSUs for loss of one of the GSUs.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: No special conditions required as long as the RAS or SPS are tested to meet the performance requirements.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐
Comment: There may be some in the application of RAS or SPS for N-1 contingencies.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment:

TIS Additional Comments to First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

October 26, 2007

1. In definition of "CONSEQUENTIAL LOAD," misoperations need to be defined better or removed, i.e. inadvertent tripping of elements due to protection system failure, including inadvertent SPS operation, may cause loss of load NOT connected to the element tripped off. In context of the definition, it appears that the misoperation should be on the protection system for the element that is tripped. {PARTLY COVERED}
2. Even when post-contingency voltage remains within prescribed limits, some voltage-sensitive customer load could still be dropped off due to their inherent sensitivity to allowed changes in voltage. Should such cases be considered as dropping non-consequential load or are the performance requirements met as long as post-contingency voltage stays within the prescribed limits? Such load losses can rarely be predicted by steady state analysis unless the loads and their distinct characteristics are explicitly modeled, but may be detectible in dynamic analysis since it is often the first swing voltage excursion that trips such loads.
3. Assuming the standard is passed, especially if the bar is raised, there should be some reasonable implementation period specified to allow entities that do not meet the standard's requirements presently and time to implement changes to become compliant.
4. Why is there a 300 kV threshold? Is there evidence that increasing the redundancy of the high voltage network will provide the largest reliability benefits?
5. Need to specifically define when it is OK to use "permanent" SPSs to meet performance requirements following the first contingency, i.e. separating a balance island should be OK. It is OK to utilize temporary SPS while the permanent corrective measure is being put in place.
6. Need to define, perhaps in the list of definitions, what is the "bus-tie breaker." Differentiation of center breakers in breaker-and-one-half schemes is a crucial item not to be subject to interpretation and possible confusion.
7. Need to clarify that "stuck breaker", regardless of whether cause by protection system failure, breaker failure to operate, or a slow breaker, is de-facto delayed clearance and causes additional contingency (ies).
8. Firm Transfer Cell for P3 does not make sense.
9. Need to strengthen the notion, in the bullets at the top of Table 1, that the assessment should also cover n-0 or "normal state (seems to be adequately covered in the body of the standard, but does not jump out from the Table 1 bullets at the head of the table.)
10. Include SHUNT DEVICES in P3–P9 planning contingencies. The same comment is applicable for stability table.

11. Need to clearly specify what documentation would be required to fulfill the standard's requirements for assessing extreme contingencies.
12. Replace "all" in the Extreme Events subheading with a more appropriate term.
13. Replace "all" in the table for Extreme Events for both Steady State and Stability tables with a more appropriate term to manage documentation requirements.
14. Use different designations for planned and extreme events in steady state and stability tables, e.g. PS and ES for steady state and PD and ED for stability (D for dynamic).
15. Throughout the tables, do not refer to "internal" breaker faults but use breaker fault instead. Faults can occur internal to the breaker, flashed bushings, or a fault (on or within) a free-standing CT associated with the breaker.
16. Modify bullet 5 in the Stability Table to include SPS failures to read:

    > "Simulate the removal of all elements that Protection Systems, SPS or RAS systems, and controls are expected to disconnect for each Contingency."

    If an SPS or RAS is expected to operate for a contingency, it must be modeled as such for that contingency study.
17. In R1.2 need to add "for the period analyzed" and defined what "stressed" conditions means.
18. In R 2.1.3.7 need to insert "long-term" in front of "transmission outages." There is also a need to clarify/describe/define what long-term transmission outage is.
19. There are concerns, particularly for NON-vertically integrated TPs, about need of including Plant Stability requirements.
20. Define what "material" change is in R2.5.2.
21. Presumably the standard will be stamped with a CEII designation
22. Additional granularity should be included showing the correlation between Requirements and their applicability to any of the Functional Model Entities cited in the Standard.

23. Obligations to study and share results of the following should be clear in the TPL Standards:
    - Analysis of impacts on your system for contingencies outside of your system footprint.
    - Analysis of impacts on other systems for contingencies within your system. The owners of the other systems should be notified of your findings and joint analysis should be done if warranted.
    - Powerflow and stability analysis of contingencies that have interconnection-wide impacts. This may best be accomplished through modifications to existing standard TPL-005.

Transmission Issues Subcommittee

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: There are a few undefined terms in this definition: "Transmission System" and "interconnected Transmission System". The definition needs to specifically identify what should be modeled and in a manner consistent with other NERC definitions. The definition refers to Facility ratings rather than the general reference to FAC-008 & FAC-009**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Modify to "Events which are more severe,but have a lower probability of occurrence, than Planning Events".**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☒Do not agree.
Q4. **Comment: "Transmission planning period that covers years six through ten", is sufficient for the standard." Suggest changing the name to Long-Term Planning Assessment.**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment: Suggest changing the name to Near-Term Planning Assessment.**	
Q6. **Non-Consequential Load Loss:** Load loss other than	☒Agree.

Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Eliminate "capital" from the definition. It is not defined or consistently applicable to the standard. Reference to vague "other factors, such as asset conditions and age" should be removed from this standard; there are no consistent definitions or industry standards on which to base this requirement, nor does it appear to be a necessary addition to the standard.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Propose, "Events for which Transmission performance requirements must be met".**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: See comment on Q9; proposed modification, "Study of the System or portions of the System to determine whether unit and system angular Stability is maintained, power oscillations are damped, and voltages during the dynamic simulation stay within acceptable perfomance limits.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: Modify to, "The first year that a Tranmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner completes its annual studies."**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement to develop action plans for problems highlighted as a result of one of the sensitivities.

Suggest modification to, "…sensitivity testing that stresses the System shall be considered, and documentation with the rationale for the sensitivity testing shall be supplied. The sensitivity case(s) may include one or more of the following conditions:"

2.1.3.3 should refer only to planned facilities that may be delayed. 2.1.3.4 - "variability" is too vague for a standard; the standard needs to be more specific as to the intent. 2.1.3.7 should be consistent with 1.4. These comments also apply to 2.4.3.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement develop action plans for problems highlighted as a result of one of the sensitivities.

Reasonably stressed conditions are dependent upon the study area under review and the standard is not likely to be able to be crafted to provide sufficent and consistent direction. However, it might be helpful if the standard clarified whether the base case should include any unplanned generator outages or whether, aside from potential sensitivities, unplanned generator outages are considered only through P1, P3 or P4 Contingencies. If the standard addresses unplanned generator outages only through P1, P3 and P4, then it is recommended that a mandatory sensitivity analysis, with required mitigation, include various potential combinations of a reasonable amount of unplanned outages. The combinations should be based on the part of the system that is under study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment: The standard is unclear whether or not it mandates the requirement to devleop action plans for problems highlighted as a result of one of the sensitivities.

Suggest modification to, "…sensitivity testing that stresses the System should be considered. Sensitivity case(s) might include among the following conditions:" 2.4.3 should mimic 2.1.3 except in regard to load models.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: There is no need for sensitivity analysis.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: DSM should be included to the extent that its performance is sufficiently and consistently understood. The standard does not use the term "optimal" Therefore, the Drafting Team appears to be interpreting the Standard to require a vertically-integrated Planner to produce a so-called optimal-mix of resources plan. This would be an incorrect assumption and is not required. In areas with independent planners and competitive wholesale markets, it is sufficent to identify system needs and produce a plan that identifies regulated transmission solutions in the event that market-based resources (such as DSM) do not address those identified needs. Therefore, while DSM can be as effective a resource as generation, per Commission Orders,

in areas with ISOs/RTOs and a competitive wholesale market, the NERC Standard cannot prescribe the development so-called optimized (as is suggesgted by the Drafting Team) resource-mix plans, as identified by a central planner.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: The study area should be based upon planning expertise and knowledge of the system, giving due consideration to external impacts.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment: They should be viewed differently in the Near-Term. However, these should be defined terms.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment: It is unclear as to what the commited project is being removed from. Suggested language "…removed from the plan…".

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Given the low probability of extended overlapping outages of overhead facilities, systems have been designed assuming that load shedding following the loss of a second transmission line is permissible. Eliminating any allowance for load shedding for this condition may require significant system expansion and cost to to customers. However, it would be reasonable to consider establishing an upper bound to the amount of load that could be shed for these purposes.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	Should also consider the initial loss of a transformer, followed by the loss of a Transmission circuit. This should state a transformer with a "high-side" rating above 300 kV.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	This should state a transformer with a "high-side" rating above 300 kV.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of 2 additional generators.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a monopolar DC line
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a Transmission circuit
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a transformer

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm

[1] System adjustment can be manual or automatic

transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: This should also apply to firm transfers via single or double ac facilities as well. In either case, the transfer could be linked to dedicated facilities.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Difficult to envision how such an event would occur.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: This requirement is too specific and limited. Induction motors are only one component of a complex load model. Complex load models are not always necessary, nor are they always the most conservative, depending on the analysis that is being conducted. Where complex load models are required, they should be considered; this may involve use of complex motor and lighting loads or polynomial load representations

with or without frequency dependence. This question also suggests the need for an industry standard regarding transient voltage recovery.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Manual or automatic adjustments should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment. Manual system adjustment should be allowed in between the multiple Contingencies described in P5, provided that the adjustment can be made between contingencies using short-term reserves (10-30 minute).

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment: Generation runback should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐

Comment: However, this should only be allowed where failure of an automatic runback that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: Only allowed where the failure of an SPS that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Only allowed where SPS failure would not have significant adverse impact on the Bulk Electric System; non-Consequential loss of load should be allowed up to an amount potentially specified in the standard.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: System must remain stable with acceptable voltages and all equipment within applicable emergency limits.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☒
Comment: Unsure due to ambiguities in the standard. Depending upon the final standard, New England may need exceptions for existing facilities or allowance for a transition period to develop a compliance plan.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: There should be a "P0" standard that applies to system performance without any contingencies.

Standard should be clear that stabiltiy analysis is not required for Long-Term Planning Assessment.

R.1.1 Load forecasts should be addressed in MOD standards, not TPL.

R 1.4 This should only refer to known long-term outages, not planned outages. Delete "including protective relays"; this is addressed through other provisions.

R.2.1 Shorten "Near-Term Transmission Planning Horizon Planning Assessment" to "Near-Term Planning Assessment".

R 2.2 Shorten "Long-Term Transmission Planning Horizon Planning Assessment" to "Long-Term Planning Assessment".

R2.1, 2.2, 2.3 & 2.4 – The initial paragraph should have identical language regarding 'annual', and 'current or past' aspects.

R2.1.1 There should not be a requirement to look at years one and two; a 5 year study should be sufficient. If there has been an ongoing 5 year study, there should be no major unexpected problems occurring in years 1 and 2. Studies of earlier years should only be required if an unanticipated event occurred that had not been considered in prior studies. The TPL should not address shorter term "Operating Studies" or operating issues.

R 2.2.1 Modify to "If any known projects have a lead time that is longer than ten years, the Planning Assessment shall be extended accordingly."

R 2.6 Steady-state, short circuit, and stability analysis should be required no more than every 5 years unless there is a significant change the system.

R 2.6.1 Remove reference to "market structure changes". The purpose of it's inclusion is unclear.

R 2.7.1.1 Project initiation date should be deleted. If it is retainted, it needs to be defined.

R 2.7.3 Committed and Proposed projects should be defined.

R 3.2.1/R 4.3 - What is the intent of this requirement? There should probably be an MOD associated with Generator Owner requirement to provide related generator protection/ limiter data or other plant information.

R 3.4/R 4.5.2 Remove the requirement to implement changes to reduce or mitigate the likelihood of such consequences of Extreme Events. This may not be reasonable or achieveable.

R 3.2 Sectionalizing schemes shall be considered when reflecting the post-contingent system.

R 3.2.2 - Propose deleting this. Line ratings should already take relay loadability into account.

R 3.3.2.1 - Proposed deleting "expected duration". This would be dependent upon the damage to the element due to the iniating event and other factors.

R 3.3.2.2 - The requirements of this section do not match P6.

R 3.3.3 - Change introductory language to read "Those multiple Contingencies that are…"

R 3.5 - Generation tripping should be allowed as well as generation run-back. In addition, all performance requirements shall be met, rather than just meeting facility rating requirements. Suggested lanague "Manual and automatic generation run-back and/or generation tripping is allowed as a response to single and multiple Contingencies as long as the performance requirements of this standard are met." If these changes are accepted, R 3.6 can be deleted.

R 4 and R 4.1 - The language should be made similar to R 3 and R 3.1.

Suggest bringing language similar R4.4 into the R 3, the steady state section.

R 4.2 - High speed automatic reclosing schemes shall be considered.

R 6.3 - Change to read "Planning Coordinators of neighboring impacted areas".

Table 1 3 b and c Extreme Event descriptions are vague concepts that cannot be practically simulated. 3 d and e are not reasonable or practically useful to simulate.

Table 1, P8 - Language needs to be clarifed as to how the 300 kV threshold is to be treated for transformers. Is this for the high side, low side, or both sides? P5 is much clearer.

Table 2 - Clarification needs to be made that the faults being simulated are permanent faults. This can be addressed under the "Performance Requirements" portion at the beginning of the table, or modify each fault description.

Table 2 P9. Recommend that this be changed to require that faults should be on different phases of each of two adjacent transmission circuits on a multiple circuit transmission tower

Table 1, P9(6) and Table 2 P9 - It is unclear as to what is meant by "A spare transformer inserted to replace an outaged transformer followed by System adjustments". Unclear as to what is to be tested.

General comment - Transmission System is used throughout the document and is an undefined term

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Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **[Due Date in bold]**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☒ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☒	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
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Group Comments (Complete this page if comments are from a group.)

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Lead Contact:

Contact Organization:

Contact Segment:

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Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

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The SDT did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. The SDT organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The SDT determined that the requirements and analysis for Steady State are different from those for stability. As such, the SDT separated the analysis requirements and created two performance requirement tables.

The SDT recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The SDT has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The SDT has not addressed Measures, Risk Factors, Violation Severity Factors or Time Horizons at this time. These will be addressed when the SDT has better defined the requirements of the standard.

For questions where you agree with the SDT, please state that you agree and if available, please provide supporting documentation. If you disagree with the SDT, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you

believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the SDT would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the SDT is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒ Agree. ☐ Do not agree.
Q1. **Comment: NYISO Agrees**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒ Agree. ☐ Do not agree.
Q2. **Comment: NYISO Agrees**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐ Agree. ☒ Do not agree.
Q3. **Comment: An alternate wording is suggested.** **Events which are more severe and have a lower probability of occurrence than Planning Events.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒ Agree. ☐ Do not agree.
Q4. **Comment: NYISO Agrees ~~long-term period should start at five years.~~**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers Years One through five.	☒ Agree.

	☐ Do not agree.
Q5. **Comment:** **NYISO Agrees**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐ Agree. ☒ Do not agree.
Q6. **Comment:** ~~An element(s) that is removed from service due to fault clearing action or mis-operation may be the cause of the low voltage or frequency. Loss of load in that case should be considered a consequence of the element being removed.~~ Suggest that examples not be listed or a more exhaustive list be developed.	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐ Agree. ☒ Do not agree.
Q7. **Comment:** **The word "Documented" is unnecessary. Suggest simplifying the definition to: Evaluation of future BPS needs to meet forecast demand under the assumed system conditions for the time frame studied.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐ Agree. ☒ Do not agree.
Q8. **Comment:** **Circular logic. Suggest: Events which need to be considered in planning assessments to evaluate Transmission system performance.**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐ Agree. ☒ Do not agree.
Q9. **Comment:** **"Contingencies" should be replaced with "Planning Events". "in the vicinity of the plant" is too restrictive.** **Suggest: Study of an individual generating plant's capability to remain in synchronism with damping power oscillation for various Planning Events.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐ Agree. ☒ Do not agree.
Q10. **Comment:** **The study is an assessment.** **Suggest: Study of the System or portions of the System to assess the System's performance in the domain of angular stability, inter-area oscillations and voltage profile during dynamic simulation.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒ Agree. ☐ Do not agree.
Q11. **Comment:** **NYISO Agrees**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions", FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The SDT has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: ——NYISO does not support the introduction of sensitivity testing in the Planning Standards as a requirement. Sensitivity testing should be dictated by the local needs and system characteristics. The nature of planning studies incorporates assumptions that would make sensitivity analysis difficult to interpret.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: ——See comment to Q12. Additionally, what is the definition of "reasonably stressed"?

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒
Comment: ——See comments to Q12 & Q13.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year 6 and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: ——NYISO does not agree with the requirement of sensitivity studies in the near-term or long-term.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If Yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐

Comment: ——NYISO suggests that the impact included in studies should consider past performance of DSM participants.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency

response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: **NYISO Agrees**

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment: **NYISO Agrees**

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment: **NYISO Agrees**

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable BES that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the SDT attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The SDT is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the SDT to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL Standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	**NYISO Agrees**
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	We are assuming the second circuit is un-related to the first. If that is not the intent then it contracts the loss of multiple related circuits (same tower or protection zone) for which non-consequential load loss is allowed.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	Same comment as with Q21.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	Same comment as with Q21.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: **NYISO Agrees**

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements

for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment: **NYISO Agrees**

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	**NYISO Agrees**
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	**NYISO Agrees**
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	**NYISO Agrees**
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	**NYISO Agrees**

The performance requirement for the following event may be considered less stringent than the existing TPL Standards - P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: NYISO agrees from a reliability aspect.

[1] System adjustment can be manual or automatic

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☒
Comment: Only the difference between steady-state and stability analysis should be the performance requirements. The list of contingencies should be identical regardless of the type of analysis.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment: NYISO agrees with the concept of splitting plant and system stability studies, but only in the area of performance requirements. The studied contingencies should be identical.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Examples of loss of entire generation station: Complete loss of right-of-way exiting facility, simultaneous relay operations due to common cause or mode.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment: **NYISO Agrees**

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: ———Automatic: Pre-determined ranges of AVR, excitation system, stabilizer and governor. Manual: switching and PAR adjustments covered by applicable operating procedures

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment: ———What is the difference between a SPS and RAS? Would not one term be sufficient? SPSs should not be considered a permanent solution. They should only be used as a stop gap before a permanent solution can be implemented.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐

Comment: ———Testing scenarios will have to be developed on a case by case basis depending on the design of the SPS. There is not universal rule that can be made for these unique cases.

The SDT has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: ———As stated previously SPSs shold only be a temporary solution used to protect elements prior to a permanent solution implementation.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: ———Must be temporary, approved by the NYSRC, tested annually with evidence of preventive maintenance submitted annually.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: ———This would be dependent on the characteristics of each unique protection scheme.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☐ No ☒

Comment:

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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
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Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: The term "mis-operation" introduces ambiguity into the definition, and should be deleted. The definition needs further clarification for consequential and non-consequential loads. For example, loads served downstream from the faulted element but not directly connected should also be considered to be consequential loads.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: A number of the non-extreme events also have a low probability. Recommend change the word to "lower." The definition for "Extreme Events" should reference Table 1.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such	☒Agree. ☐Do not

as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☐Do not agree.
Q7. **Comment: Generally, we agree but would request NERC to clarify accounting for asset conditions and age within planning assessments. Wouldn't these already be taken into account in the FAC-008 & FAC-009 ratings?**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Change to: "Events that are simulated or assessed to test the transmission system to ensure that performance requirements are met."**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: This definition could use further clarification to eliminate inconsistencies in how it may be interpretted. Operations planning horizons may typically be 13 to 18 months from the current date due to the reality that transmission upgrades to address operational performance issues may not be able to be implemented inside this period. Some may assume a 24-36 month operations planning window. Based on this assumption, Year 1 could start anywhere from 13 months from the current date to as much as 37 months from the current date.**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of

variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: There should be a stakeholder process for all entities (all Load-Serving Entities and Transmission Customers) involved or impacted within the defined area to provide input to determine which sensitivity cases are to be performed and the appropriate number of cases that need to be evaluated. Not every sensitivity case should be required for every system.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: The standard should offer guidance but what constitutes a "reasonably stressed" case should be left to a stakeholder process as noted in Q12 with some discretion of the entity performing the study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐

Comment: The entity performing the studies should be allowed to determine the appropriate sensitivity studies that need to be evaluated with a stakeholder process for those impacted by these studies as noted above. An alternate approach is to include pre-existing system conditions that additionally stress the system during the contingencies under study so as to verify that stability is preserved under conditions that go beyond those envisioned for the contingency. Stability studies are more time consuming than conventional power flow studies. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☒

Comment: Some sensitivity analysis in the long term years should be done (90/10 load with higher than expected transfers and/or delayed baseload generation) so that higher voltage issues are adequately tested to identify long lead time upgrades, in a similar manner as was done to justify the backbone projects that have been identified in the PJM Interconnection. A stakeholder process should be used by the entity performing the study to complile input on impacted LSEs and other Transmission Customers.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐

Comment: It should be included if it is a tool made available to the TP for this purpose, but only to the extent that it is considered firm.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐

Comment: Re-testing should be required particularly where the correction may impact network flows. The study area should be discussed within a stakeholder process to the TP may compile input from network customers or LSEs that might be affected by the analysis.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment: Projects that are underway (i.e. being built) and are not subject to be potentially delayed and are absolutely needed for reliability should be differentiated between those that are not. Perhaps definitions for each of these terms should be considered for clarification.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	Although this is a relatively low probability event, we do agree that it should be assessed given the widespread effects. It may not justify the need for a network upgrade but at least deserves consideration for an operating or corrective action procedure should the event occur. Also, given this analysis might be new for some TPs, consideration

		should be given to a transition period after the start of this type of assessment.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	We do agree that given the widespread effects of these facilities above 300 kV that these should be subjected to more rigorous assessments.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	We do agree that given the widespread effects of these facilities above 300 kV that these should be subjected to more rigorous assessments.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	We do agree that given the widespread effects of these facilities above 300 kV that these should be subjected to more rigorous assessments.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: see response for Q20.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment: see response for Q20.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	In the case of generating capacity replacement, some guidance as to allowable system adjustments might be needed for clarification. Is calling on contingency reserves from a Reserve Sharing Group immediately prior to internal redispatch of available resources OK? What about Network Customer generation not at maximum output but available for redispatch ? What about transmission reconfiguration, cutting firm purchases (pro-rata or in entirety) acceptable?
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	N/A
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	See reply to Q26.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	See reply to Q26.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment: Not applicable/

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

[1] System adjustment can be manual or automatic

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Generator protection is designed to trip only those units required. In addition, it is the magnitude of generation tripped rather than the number of units tripped that is of the greatest significance to the stability of the grid.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: Dynamic studies of seasonal load conditions should include the effects of induction motors, and particularly in areas where traditional load models have indicated a problem. Unfortunately, there is a lack of data to support the amount and characteristics of the detailed induction load models in many areas. In addition to the consideration of the dynamic effects of induction motor loads, the effects of static capacitor banks installed at distribution voltage levels would need to be considered as well. Prior to making this a requirement in the reliability standards, the industry needs guidance as to how this data should be developed and maintained for models in future years.

Note that meeting such a requirement would necessitate a significant increase in the dynamic data needed to represent the system. Maintenance of such load model data would require significant resources. Load characteristics valid for a near term model might not be valid for future years. Also, summer peak load, winter peak load, and off-peak load characteristics would differ.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Adjustments that should be allowed are those that can be performed in time to prevent the system from failing to meet performance requirements. These adjustments may include automatic voltage regulator action, governor action, generator runback, and generator tripping.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: The generator runback scheme should complete its action within the time allowed by the emergency ratings of elements that exceed their normal thermal ratings.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: RAS or SPS should meet the same criteria as any protection system.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: The conditions required by SPS standards (PRC).

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☒ No ☐
Comment: Modeling data requirements in R1 applicable to many entities may be either redundant with the MOD submittals or may be conflict for entities that are required to submit this data to Transmission Providers to comply with deadlines in their Tarffs. In addition, data submitted by entities named may be confidential so this issue will have to be addressed among those submitting and receiving needed data.

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: Planning Coordinator: The definition of Planning Coordinator should be kept within this document rather than relying on the NERC Functional Model as we believe that this entity has an important role in insuring coordination of transmission and resource plans.

Coordination:
During the teleconference, one issue brought up was the matter of external contingencies being tested as a part of a TP's analysis. The reply was that this issue will be addressed outside this draft standard (TPL-005 and TPL-006) or would be accounted for in the coordination efforts among Transmission Planners. NCEMC is of the opinion that Requirements R5 and R6 need further details to insure adequate anlysis between and among Transmission Planners having varying local planning criteria so that Seams Issues are addressed that are not currently being address in regional and inter-regional studies. To the extent possible, timing of studies should be required to insure coordination between regional and inter-regional groups.

Significant Increase in Study Activity Workload on Transmission Planners:
The increase in both steady state and dynamic studies required to ensure compliance with the proposed standards will result in increased costs and staff additions. The addition of the "Corrective Action Plan" requires the TP to provide a significant amount of documentation for each deficiency identified by the studies. Also, R3.2 requires that the studies simulate the protection scheme for all events. The current software tools cannot automate these studies for bus faults and breaker failure events, requiring each scenario to be studied manually. Additionally, experienced staff capable of performing analyses as described in the proposed standard have become increasingly difficult to find and retain and the talent pool of people with these skills has recently become depleted to alarming levels.

Implementation Plan:
Given the intent of the proposed standard to encourage large scale investment in the EHV system, full implementation will take years, perhaps decades. Acquirement of right-of-way for new EHV lines has become increasingly difficult in recent years and inreasingly expensive. Legal, regulatory, and other difficult issues often take several years to navigate, even for 115kV lines. The Implementation Plan timeframe, if set too short, would be unduly burdensome on Transmission Owners forcing them to be less dicretionary with funds than would be prudent. The proposed implementation plan should include provisions for those cases where viable solutions simply can not be implemented in time due to circumstances beyond the control of Transmission owners. A reasonable period for transition is order.

Design and Construction Constraints:
Even if right-of-way and other legal and regulatory hurdles are cleared, and the capital funding for such a tremendous level of investment was not an issue, the other resources required to actually construct the projects are equally difficult and costly to secure. Raw material prices on comodities like copper and steel have skyrocketed in recent years. Additionally, the skilled labor and Engineering resources are constrained with labor rates almost keeping up with other resource costs. Overall project costs have more than doubled over the last 7-10 years. Recent press releases concerning new generation being planned and then scrapped due to the rapid escalation of project costs are public evidence of this. The inflationary mark-up is impossible to estimate but much less will be built with the same capital investment than is currently envisioned.

Cost-Benefit Analysis:
The proposed standard will be exceedingly expensive to become compliant with unprecedented levels of capital investment in Transmission facilities. Before the standard comes to official vote, it would be prudent for a cost-benefit analysis to be performed to determine if the reliability improvements truly justify the huge expenditures certain under the proposed standard. Additionally, as many jurisdictional rate structures share the cost of such investments between retail and wholesale customers, cost-benefit analyses should be completed for both retail and wholesale customers.

System Adjustment Clarification:
It has already been noted earlier but deserves repeating here: The term "System Adjustment" as outlined in the tables should be better defined. The use of generation for redispatch may have nuances which preclude or otherwise limit their use for studies. Perhaps some clearer guidelines on what is allowed would facilitate transparency and coordination between Transmission Planners.

Transmission Service Evaluation:
A major concern is that the proposed standard appears to be disjointed from the requirements for selling firm Transmission Service. The increase in reliability gained from the proposed standard would, in some regions, quickly be eroded by new firm sales if those sales are based on the historical N-1 ATC requirements. The proposed standard must be applied to long-term firm transmission service requests if Transmission reliability is to be truly enhanced. If the standard is not applied to Transmission Service evaluation, reliability levels for the different classes of firm customers will diverge.

Stakeholder Process:
As a Transmission-Dependent Utility and Network Customer within 3 different Balancing Autorities with one being a Regional Transmission Organization, NCEMC cannot stress

enough the need for a Stakeholder Process for coordination Transmission Planning that may impact Load-Serving Entities and other entities involved. It is critical to address reliability needs of all taking transmission service today and in years to come.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Denise Roeder	
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

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To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☐Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☐Agree. ☐Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.

- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☐
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☐
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☐
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☐
Comment:

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☐
Comment:

[1] System adjustment can be manual or automatic

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☐ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐

Comment: Much of the language in R1 is redundant, because the MOD standards already address what data are required for modeling purposes. Including data requirements here, as well as in the MOD standards, will introduce the possibility of inconsistencies between the two as well as unnecessary duplication of work for entities providing the data. If any changes need to be made to what data are collected or to whom it is provided, those changes should be made in the MOD standards, not by adding data requirements to this standard.

As for most every standard written, some consideration should be given to the cost of meeting the more stringent requirements proposed for this standard. While it might be possible to make incremental improvements in reliability, it may not be cost-effective, particularly given the low probability of some of the events addressed in the standard. Before stakeholders are asked to vote on this standard, a cost-benefit analysis should be performed to provide what would be an otherwise missing, but very important piece, of information about whether the costs of complying with the requirements of this standard are justified based on the reliability improvements that would be achieved.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Rick White	
Organization:	Northeast Utilities	
Telephone:	860-665-2572	
E-mail:	whitefb@nu.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
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Q1. **Comment: There are a few undefined terms in this definition: "Transmission System" and "interconnected Transmission System". The definition needs to specifically identify what should be modeled and in a manner consistent with other NERC definitions. The definition refers to Facility ratings rather than the general reference to FAC-008 & FAC-009**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Modify to "Events which are more severe,but have a lower probability of occurrence, than Planning Events".**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☒Do not agree.
Q4. **Comment: "Transmission planning period that covers years six through ten", is sufficient for the standard." Suggest changing the name to Long-Term Planning Assessment.**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment: Suggest changing the name to Near-Term Planning Assessment.**	
Q6. **Non-Consequential Load Loss:** Load loss other than	☒Agree.

Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Eliminate "capital" from the definition. It is not defined or consistently applicable to the standard. Reference to vague "other factors, such as asset conditions and age" should be removed from this standard; there are no consistent definitions or industry standards on which to base this requirement, nor does it appear to be a necessary addition to the standard.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Propose, "Events for which Transmission performance requirements must be met".**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: See comment on Q9; proposed modification, "Study of the System or portions of the System to determine whether unit and system angular Stability is maintained, power oscillations are damped, and voltages during the dynamic simulation stay within acceptable perfomance limits.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: Modify to, "The first year that a Tranmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner completes its annual studies."**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement to develop action plans for problems highlighted as a result of one of the sensitivities.

Suggest modification to, "…sensitivity testing that stresses the System shall be considered, and documentation with the rationale for the sensitivity testing shall be supplied. The sensitivity case(s) may include one or more of the following conditions:"

2.1.3.3 should refer only to planned facilities that may be delayed. 2.1.3.4 - "variability" is too vague for a standard; the standard needs to be more specific as to the intent. 2.1.3.7 should be consistent with 1.4. These comments also apply to 2.4.3.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement develop action plans for problems highlighted as a result of one of the sensitivities.

Reasonably stressed conditions are dependent upon the study area under review and the standard is not likely to be able to be crafted to provide sufficent and consistent direction. However, it might be helpful if the standard clarified whether the base case should include any unplanned generator outages or whether, aside from potential sensitivities, unplanned generator outages are considered only through P1, P3 or P4 Contingencies. If the standard addresses unplanned generator outages only through P1, P3 and P4, then it is recommended that a mandatory sensitivity analysis, with required mitigation, include various potential combinations of a reasonable amount of unplanned outages. The combinations should be based on the part of the system that is under study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment: The standard is unclear whether or not it mandates the requirement to devleop action plans for problems highlighted as a result of one of the sensitivities.

Suggest modification to, "…sensitivity testing that stresses the System should be considered. Sensitivity case(s) might include among the following conditions:" 2.4.3 should mimic 2.1.3 except in regard to load models.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: There is no need for sensitivity analysis.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: DSM should be included to the extent that its performance is sufficiently and consistently understood. The standard does not use the term "optimal" Therefore, the Drafting Team appears to be interpreting the Standard to require a vertically-integrated Planner to produce a so-called optimal-mix of resources plan. This would be an incorrect assumption and is not required. In areas with independent planners and competitive wholesale markets, it is sufficent to identify system needs and produce a plan that identifies regulated transmission solutions in the event that market-based resources (such as DSM) do not address those identified needs. Therefore, while DSM can be as effective a resource as generation, per Commission Orders,

in areas with ISOs/RTOs and a competitive wholesale market, the NERC Standard cannot prescribe the development so-called optimized (as is suggesgted by the Drafting Team) resource-mix plans, as identified by a central planner.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: The study area should be based upon planning expertise and knowledge of the system, giving due consideration to external impacts.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment: They should be viewed differently in the Near-Term. However, these should be defined terms.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment: It is unclear as to what the commited project is being removed from. Suggested language "…removed from the plan…".

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Given the low probability of extended overlapping outages of overhead facilities, systems have been designed assuming that load shedding following the loss of a second transmission line is permissible. Eliminating any allowance for load shedding for this condition may require significant system expansion and cost to to customers. However, it would be reasonable to consider establishing an upper bound to the amount of load that could be shed for these purposes.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	Should also consider the initial loss of a transformer, followed by the loss of a Transmission circuit. This should state a transformer with a "high-side" rating above 300 kV.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	This should state a transformer with a "high-side" rating above 300 kV.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of 2 additional generators.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a monopolar DC line
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a Transmission circuit
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a transformer

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm

[1] System adjustment can be manual or automatic

transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: This should also apply to firm transfers via single or double ac facilities as well. In either case, the transfer could be linked to dedicated facilities.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Difficult to envision how such an event would occur.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: This requirement is too specific and limited. Induction motors are only one component of a complex load model. Complex load models are not always necessary, nor are they always the most conservative, depending on the analysis that is being conducted. Where complex load models are required, they should be considered; this may involve use of complex motor and lighting loads or polynomial load representations

with or without frequency dependence. This question also suggests the need for an industry standard regarding transient voltage recovery.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Manual or automatic adjustments should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment. Manual system adjustment should be allowed in between the multiple Contingencies described in P5, provided that the adjustment can be made between contingencies using short-term reserves (10-30 minute).

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment: Generation runback should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐

Comment: However, this should only be allowed where failure of an automatic runback that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: It is not recommended that an SPS be used in this situation, that over time, the proliferation of SPSs may degrade system reliability and unduly complicate system operations. If allowed an SPS should only be used where the failure of the SPS that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Only allowed where SPS failure would not have significant adverse impact on the Bulk Electric System; non-Consequential loss of load should be allowed up to an amount potentially specified in the standard.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: System must remain stable with acceptable voltages and all equipment within applicable emergency limits.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☒
Comment: Unsure due to ambiguities in the standard. Depending upon the final standard, New England may need exceptions for existing facilities or allowance for a transition period to develop a compliance plan.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: There should be a "P0" standard that applies to system performance without any contingencies.

Standard should be clear that stabiltiy analysis is not required for Long-Term Planning Assessment.

R.1.1 Load forecasts should be addressed in MOD standards, not TPL.

R 1.4 This should only refer to known long-term outages, not planned outages. Delete "including protective relays"; this is addressed through other provisions.

R.2.1 Shorten "Near-Term Transmission Planning Horizon Planning Assessment" to "Near-Term Planning Assessment".

R 2.2 Shorten "Long-Term Transmission Planning Horizon Planning Assessment" to "Long-Term Planning Assessment".

R2.1, 2.2, 2.3 & 2.4 – The initial paragraph should have identical language regarding 'annual', and 'current or past' aspects.

R2.1.1 There should not be a requirement to look at years one and two; a 5 year study should be sufficient. If there has been an ongoing 5 year study, there should be no major unexpected problems occurring in years 1 and 2. Studies of earlier years should only be required if an unanticipated event occurred that had not been considered in prior studies. The TPL should not address shorter term "Operating Studies" or operating issues.

R 2.2.1 Modify to "If any known projects have a lead time that is longer than ten years, the Planning Assessment shall be extended accordingly."

R 2.6 Steady-state, short circuit, and stability analysis should be required no more than every 5 years unless there is a significant change the system.

R 2.6.1 Remove reference to "market structure changes". The purpose of it's inclusion is unclear.

R 2.7.1.1 Project initiation date should be deleted. If it is retainted, it needs to be defined.

R 2.7.3 Committed and Proposed projects should be defined.

R 3.2.1/R 4.3 - What is the intent of this requirement? There should probably be an MOD associated with Generator Owner requirement to provide related generator protection/ limiter data or other plant information.

R 3.4/R 4.5.2 Remove the requirement to implement changes to reduce or mitigate the likelihood of such consequences of Extreme Events. This may not be reasonable or achieveable.

R 3.2 Sectionalizing schemes shall be considered when reflecting the post-contingent system.

R 3.2.2 - Propose deleting this. Line ratings should already take relay loadability into account.

R 3.3.2.1 - Proposed deleting "expected duration". This would be dependent upon the damage to the element due to the iniating event and other factors.

R 3.3.2.2 - The requirements of this section do not match P6.

R 3.3.3 - Change introductory language to read "Those multiple Contingencies that are…"

R 3.5 - Generation tripping should be allowed as well as generation run-back. In addition, all performance requirements shall be met, rather than just meeting facility rating requirements. Suggested lanague "Manual and automatic generation run-back and/or generation tripping is allowed as a response to single and multiple Contingencies as long as the performance requirements of this standard are met." If these changes are accepted, R 3.6 can be deleted.

R 4 and R 4.1 - The language should be made similar to R 3 and R 3.1.

Suggest bringing language similar R4.4 into the R 3, the steady state section.

R 4.2 - High speed automatic reclosing schemes shall be considered.

R 6.3 - Change to read "Planning Coordinators of neighboring impacted areas".

Table 1 3 b and c Extreme Event descriptions are vague concepts that cannot be practically simulated. 3 d and e are not reasonable or practically useful to simulate.

Table 1, P8 - Language needs to be clarifed as to how the 300 kV threshold is to be treated for transformers. Is this for the high side, low side, or both sides? P5 is much clearer.

Table 2 - Clarification needs to be made that the faults being simulated are permanent faults. This can be addressed under the "Performance Requirements" portion at the beginning of the table, or modify each fault description.

Table 2 P9. Recommend that this be changed to require that faults should be on different phases of each of two adjacent transmission circuits on a multiple circuit transmission tower

Table 1, P9(6) and Table 2 P9 - It is unclear as to what is meant by "A spare transformer inserted to replace an outaged transformer followed by System adjustments". Unclear as to what is to be tested.

General comment - Transmission System is used throughout the document and is an undefined term

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment: NWE recommends the words "and may include non-firm transactions" after the words "firm transaction obligations".**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☒Do not agree.
Q6. **Comment: Include the words "not directly connected" before period of first sentence; and what does "load loss" mean?**	
Q7. **Planning Assessment:** Documented evaluation of future	☒Agree.

Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Do not agree.
Q7. **Comment: Insert before performance studies the words "current or past that is known to be valid".**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: System stability studies covers this definition.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.

- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: The current list is too prescriptive as many may not apply to a specific TP, yet they would be required to study it.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: Each TP's stressed conditions vary, making a list that is applicable to all will not achieve the desired purpose.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☒
Comment: The TP should have the ability to determine the sensitivity to use.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☒
Comment: However, the TP should have the abiltiy to determine the sensitivity to use.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of

Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒
Comment: The word "including" should be "may include", mandating what should be studied is not appropriate. Also, including DSM in the list presumes the balancing area is deficient in generation, which may not always be the case.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: R2.7.2 does not refer to "how a study area should be determined". This added statement should be eliminated.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: No, there are no clear guidelines on how to make this distinction.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: Same problem as Q18; but it isn't clear what level of documentation is needed.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material

changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: Non-consequential load loss should be permitted for this contingency.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: Non-consequential load loss should be permitted for this contingency.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.

[1] System adjustment can be manual or automatic

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: Plant stability is an artifical distinction and is a subset of transient stability.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☒
Comment: If such a standard is constructed, it should be based on a common mode of failure mechanism.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: All adjustments should be allowed as long as they are realistic and achievable in the time frame required and consistent with other study parameters. Also, if a RAS (or special protection system) is the adjustment and if cascading could result from the event, then redundancy should be required.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Yes, (1) if the failure of the runback scheme results in cascading, then it should not be allowed; (2) the power flow should be within the time-limited equipment ratings; and (3) the frequency should be within allowable limits.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐

Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: RAS or SPS should not be allowed for non three phase single line faults. If cascading could result from the failure of the RAS to operate properly, then redundancy should be required.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: RAS or SPS should meet performance requirements including reserve requirements.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐
Comment: WECC allows N-1 generator tripping, and the transmission systems have been designed around this criteria. Moving away from this criteria is not necessary, and for critical N-1 events, redundancy is in place.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☒ No ☐
Comment: Eliminating the N-1 RAS in the West could cause problems for utilities in the West with local jurisdictional cost recovery.

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☐ No ☒
Comment:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☒	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: **NPCC RSC, Regional Standards Committee**

Lead Contact: **Guy V. Zito**

Contact Organization: **Northeast Power Coordinating Council**

Contact Segment: **10**

Contact Telephone: **212-840-1070**

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Additional Member Name	Additional Member Organization	Region*	Segment*
Al Adamson	New York State Reliability Council	**NPCC**	10
David Kiguel	Hydro One Networks	NPCC	1
Donald Nelson	MA Dept of Public Utilities	NPCC	9
Edwin Thompson	ConEd	NPCC	1
Greg Campoli	New York ISO	NPCC	2
Kathleen Goodman	ISO New England	NPCC	2
Michael Gildea	Constellation Energy	NPCC	6
Michael Ranalli	Ngrid US	NPCC	1
Murale Gopinathan	Northeast Utilities	NPCC	1
Ralph Rufrano	New York Power Authority	NPCC	1
Randy MacDonald	New Brunswick System Operator	NPCC	2
Roger Champagne	HydroQuebec TransEnergie	NPCC	1
Biju Gopi	The IESO, Ontario	NPCC	2
Sylvain Clermont	HydroQuebec TransEnergie	NPCC	1
Reza Rizvi	Northeast Power Coordinating Council	NPCC	10
Guy V. Zito	Northeast Power Coordinating Council	NPCC	10

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the

rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: There are a two undefined terms in this definition: "Transmission System" and "interconnected Transmission System". The definition needs to specifically identify what should be modeled applicable to the subject area and in a manner consistent with other NERC definitions. The definition refers to Facility ratings rather than the general reference to FAC-008 & FAC-009**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Modify to "Events which are more severe,but have a lower probability of occurrence, than Planning Events".**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	

Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Eliminate "capital" from the definition. It is not defined or consistently applicable to the standard. Reference too vague "other factors, such as asset conditions and age" should be removed from this standard; there are no consistent definitions or industry standards on which to base this requirement, nor does it appear to be a necessary addition to the standard.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Propose, "Events for which Transmission performance requirements must be met".**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: See comment on Q9; proposed modification, "Study of the System or portions of the System to determine whether system angular Stability is maintained, power oscillations are damped, and voltages during the dynamic simulation stay within acceptable perfomance limits even if unit instability exists.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☒Do not agree.
Q11. **Comment: Modify to, "The first year that a Tranmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner**	

completes and communicates its annual studies."

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement to develop action plans in accordance with consequences of problems highlighted as a result of one of the sensitivities.

Suggest modification to, "…sensitivity testing that stresses the System shall be considered, and documentation with the rationale for the sensitivity testing shall be supplied. The sensitivity case(s) may include one or more of the following conditions:"

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement to develop action plans in accordance with consequences of problems highlighted as a result of one of the sensitivities.

Reasonably stressed conditions are dependent upon the study area under review and the standard is not likely to be able to be crafted to provide sufficent and consistent direction. However, it might be helpful if the standard

clarified whether the base case should include any unplanned generator outages or whether, aside from potential sensitivities, unplanned generator outages are considered only through P1, P3 or P4 Contingencies. If the standard addresses unplanned generator outages only through P1, P3 and P4, then it is recommended that a mandatory sensitivity analysis, with required mitigation, include various potential combinations of a reasonable amount of unplanned outages. The combinations should be based on the part of the system that is under study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment: The standard is unclear whether or not it mandates the requirement to develop action plans in accordance with the consequences of problems highlighted as a result of one of the sensitivities.

Suggest modification to, "…sensitivity testing that stresses the System should be considered. Sensitivity case(s) might include among the following conditions:" 2.4.3 shold mimic 2.1.3 except in regard to load models.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: There is no need for sensitivity analysis.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: DSM should be included to the extent that its performance is sufficiently and consistently understood. The standard does not use the term "optimal" Therefore, the Drafting Team appears to be interpreting the Standard to require a vertically-integrated Planner to produce a so-called optimal-mix of resources plan. This would be an incorrect assumption and is not required. In areas with independent planners and competitive wholesale markets, it is sufficent to identify system needs and produce a plan that identifies regulated transmission solutions in the event that market-based resources (such as DSM) do not address those identified needs. Therefore, while DSM can be as effective a resource as generation, per Commission Orders, in areas with ISOs/RTOs and a competitive wholesale market, the NERC Standard cannot prescribe the

development so-called optimized (as is suggested by the Drafting Team) resource-mix plans, as identified by a central planner.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: The study area should be based upon planning expertise and knowledge of the system, giving due consideration to external impacts.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment: They should be viewed differently in the Near-Term.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment: It is unclear as to what the committed project is being removed from. Suggested language "…removed from the plan…".

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

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The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL

standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Given the low probability of extended overlapping outages of overhead facilities, systems have been designed assuming that load shedding following the loss of a second transmission line is permissible. Eliminating any allowance for load shedding for this condition may require significant system expansion and cost to to customers.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐

Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of 2 additional generators.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a monopolar DC line
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a Transmission circuit
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a transformer

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

[1] System adjustment can be manual or automatic

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: This should also apply to firm transfers via single or double ac facilities as well. In either case, the transfer could be linked to dedicated facilities.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☒
Comment: The contingency studied are the same and as a result should be combined into one table.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Difficult to envision how such an event would occur.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: This requirement is too specific and limited. Induction motors are only one component of a complex load model. Complex load models are not always necessary, nor are they always the most conservative, depending on the analysis that is being conducted. Where complex load models are required, they should be considered; this may involve use of complex motor and lighting loads or polynomial load representations with or without frequency dependence. This question also suggests the need for an industry standard regarding transient voltage recovery.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Manual or automatic adjustments should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment. Manual system adjustment should be allowed in between the multiple Contingencies described in P5, provided that the adjustment can be made between contingencies using short-term reserves (10-30 minute).

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment: Generation runback should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐

Comment: However, this should only be allowed where failure of an automatic runback that is not functionally redundant would not have significant adverse impact on the Bulk Power System.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: A SPS may be used to provide protection for infrequent contingencies, or for temporary conditions that may exist such as project delays, unusual combinations of system demand and equipment outages or availability, or specific equipment maintenance outages. An SPS may also be applied to preserve system integrity in the event of severe facility outages and extreme contingencies. The decision to employ an SPS shall take into account the complexity of the scheme and the consequences of correct or incorrect operation as well as its benefits.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: See response to Q38.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: System must remain stable with acceptable voltages and all equipment within applicable emergency limits.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☒
Comment: Until section R3.6.1 is finalized, we will be unable to determine whether a regional variance is required.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment:

The SDT has made an effort to define Base Case, yet has not used the term in the standard. At a minimum, Base Case should be referred to in sections 2.1.1, 2.1.2

Standard should be clear that stabiltiy analysis is not required for Long-Term Planning Assessment.

R.1.1 Load forecasts should be addressed in MOD standards, not TPL.

R 1.4 This should only refer to known long-term outages, not planned outages. Delete "including protective relays"; this is addressed through other provisions.

R2.1, 2.2, 2.3 & 2.4 – The initial paragraph should have identical language regarding 'annual', and 'current or past' aspects.

R2.1 There should not be a requirement to look at years one and two; a 5 year study should be sufficient. If there has been an ongoing 5 year study, there should be no major unexpected problems occurring in years 1 and 2. Studies of earlier years should only be required if an unanticipated event occurred that had not been considered in prior studies. The TPL should not address shorter term "Operating Studies" or operating issues.

R 2.2.1 Modify to "If any known projects have a lead time that is longer than ten years, the Planning Assessment shall be extended accordingly."

R 2.6.1 Remove reference to "market structure changes". The purpose of its inclusion is unclear.

R 2.7.1.1 Project initiation date should be deleted. If it is retained, it needs to be defined.

R 3.2.1/R 4.3 - What is the intent of this requirement? There should probably be an MOD associated with Generator Owner requirement to provide related generator protection/ limiter data or other plant information.

R 3.4/R 4.5.2 Remove the requirement to implement changes to reduce or mitigate the likelihood of such consequences of Extreme Events. This may not be reasonable or achieveable.

R 3.2 Sectionalizing schemes shall be considered when reflecting the post-contingent system.

R 3.3.2.1 - Proposed deleting "expected duration". This would be dependent upon the damage to the element due to the iniating event and other factors.

R 3.3.3 - Change introductory language to read "Those multiple Contingencies that are…"

R 3.5 - Generation tripping should be allowed as well as generation run-back. In addition, all performance requirements shall be met, rather than just meeting facility rating requirements. Suggested language "Manual and automatic generation run-back and/or generation tripping is allowed as a response to single and multiple Contingencies as long as the performance requirements of this standard are met." If these changes are accepted, R 3.6 can be deleted.

R 4 and R 4.1 - The language should be made similar to R 3 and R 3.1.

Suggest bringing language similar R4.4 into the R 3, the steady state section.

R 4.2 - High speed automatic reclosing schemes shall be considered.

R 6.2 - Change to read "Transmission Planners of neighboring areas".

Table 1 3 b and c Extreme Event descriptions are vague concepts that cannot be practically simulated. 3 d and e are not reasonable or practically useful to simulate.

Table 1, P8 - Language needs to be clarifed as to how the 300 kV threshold is to be treated for transformers. Is this for the high side, low side, or both sides? P5 is much clearer.

Table 2 P9. Recommend that this be changed to require that faults should be on different phases of each of two adjacent transmission circuits on a multiple circuit transmission tower

Table 1, P9(6) and Table 2 P9 - It is unclear as to what is meant by "A spare transformer inserted to replace an outaged transformer followed by System adjustments". Unclear as to what is to be tested.

General comment - Transmission System is used throughout the document and is an undefined term, both "Transmission" and "System" are defined NERC terms. We recommend that the SDT use the term "System" to replace "Transmission System". System is defined as "A combination of generation, transmission, and distribution components".

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: There are a few undefined terms in this definition: "Transmission System" and "interconnected Transmission System". The definition needs to specifically identify what should be modeled and in a manner consistent with other NERC definitions. The definition refers to Facility ratings rather than the general reference to FAC-008 & FAC-009**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Modify to "Events which are more severe,but have a lower probability of occurrence, than Planning Events".**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☒Do not agree.
Q4. **Comment: "Transmission planning period that covers years six through ten", is sufficient for the standard." Suggest changing the name to Long-Term Planning Assessment.**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment: Suggest changing the name to Near-Term Planning Assessment.**	
Q6. **Non-Consequential Load Loss:** Load loss other than	☒Agree.

Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Eliminate "capital" from the definition. It is not defined or consistently applicable to the standard. Reference to vague "other factors, such as asset conditions and age" should be removed from this standard; there are no consistent definitions or industry standards on which to base this requirement, nor does it appear to be a necessary addition to the standard.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Propose, "Events for which Transmission performance requirements must be met".**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: See comment on Q9; proposed modification, "Study of the System or portions of the System to determine whether unit and system angular Stability is maintained, power oscillations are damped, and voltages during the dynamic simulation stay within acceptable perfomance limits.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: Modify to, "The first year that a Tranmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner completes its annual studies."**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement to develop action plans for problems highlighted as a result of one of the sensitivities.

Suggest modification to, "…sensitivity testing that stresses the System shall be considered, and documentation with the rationale for the sensitivity testing shall be supplied. The sensitivity case(s) may include one or more of the following conditions:"

2.1.3.3 should refer only to planned facilities that may be delayed. 2.1.3.4 - "variability" is too vague for a standard; the standard needs to be more specific as to the intent. 2.1.3.7 should be consistent with 1.4. These comments also apply to 2.4.3.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement develop action plans for problems highlighted as a result of one of the sensitivities.

Reasonably stressed conditions are dependent upon the study area under review and the standard is not likely to be able to be crafted to provide sufficent and consistent direction. However, it might be helpful if the standard clarified whether the base case should include any unplanned generator outages or whether, aside from potential sensitivities, unplanned generator outages are considered only through P1, P3 or P4 Contingencies. If the standard addresses unplanned generator outages only through P1, P3 and P4, then it is recommended that a mandatory sensitivity analysis, with required mitigation, include various potential combinations of a reasonable amount of unplanned outages. The combinations should be based on the part of the system that is under study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment: The standard is unclear whether or not it mandates the requirement to devleop action plans for problems highlighted as a result of one of the sensitivities.

Suggest modification to, "…sensitivity testing that stresses the System should be considered. Sensitivity case(s) might include among the following conditions:" 2.4.3 shold mimic 2.1.3 except in regard to load models.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: There is no need for sensitivity analysis.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: DSM should be included to the extent that its performance is sufficiently and consistently understood. The standard does not use the term "optimal" Therefore, the Drafting Team appears to be interpreting the Standard to require a vertically-integrated Planner to produce a so-called optimal-mix of resources plan. This would be an incorrect assumption and is not required. In areas with independent planners and competitive wholesale markets, it is sufficent to identify system needs and produce a plan that identifies regulated transmission solutions in the event that market-based resources (such as DSM) do not address those identified needs. Therefore, while DSM can be as effective a resource as generation, per Commission Orders,

in areas with ISOs/RTOs and a competitive wholesale market, the NERC Standard cannot prescribe the development so-called optimized (as is suggesgted by the Drafting Team) resource-mix plans, as identified by a central planner.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: The study area should be based upon planning expertise and knowledge of the system, giving due consideration to external impacts.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment: They should be viewed differently in the Near-Term. However, these should be defined terms.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment: It is unclear as to what the commited project is being removed from. Suggested language "…removed from the plan…".

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Given the low probability of extended overlapping outages of overhead facilities, systems have been designed assuming that load shedding following the loss of a second transmission line is permissible. Eliminating any allowance for load shedding for this condition may require significant system expansion and cost to to customers. However, it would be reasonable to consider establishing an upper bound to the amount of load that could be shed for these purposes.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	Should also consider the initial loss of a transformer, followed by the loss of a Transmission circuit. This should state a transformer with a "high-side" rating above 300 kV.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	This should state a transformer with a "high-side" rating above 300 kV.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of 2 additional generators.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a monopolar DC line
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a Transmission circuit
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a transformer

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm

[1] System adjustment can be manual or automatic

transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: This should also apply to firm transfers via single or double ac facilities as well. In either case, the transfer could be linked to dedicated facilities.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Difficult to envision how such an event would occur.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: This requirement is too specific and limited. Induction motors are only one component of a complex load model. Complex load models are not always necessary, nor are they always the most conservative, depending on the analysis that is being conducted. Where complex load models are required, they should be considered; this may involve use of complex motor and lighting loads or polynomial load representations

with or without frequency dependence. This question also suggests the need for an industry standard regarding transient voltage recovery.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Manual or automatic adjustments should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment. Manual system adjustment should be allowed in between the multiple Contingencies described in P5, provided that the adjustment can be made between contingencies using short-term reserves (10-30 minute).

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment: Generation runback should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐

Comment: However, this should only be allowed where failure of an automatic runback that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: Only allowed where the failure of an SPS that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Only allowed where SPS failure would not have significant adverse impact on the Bulk Electric System; non-Consequential loss of load should be allowed up to an amount potentially specified in the standard.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: System must remain stable with acceptable voltages and all equipment within applicable emergency limits.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☒
Comment: Unsure due to ambiguities in the standard. Depending upon the final standard, New England may need exceptions for existing facilities or allowance for a transition period to develop a compliance plan.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: There should be a "P0" standard that applies to system performance without any contingencies.

Standard should be clear that stabiltiy analysis is not required for Long-Term Planning Assessment.

R.1.1 Load forecasts should be addressed in MOD standards, not TPL.

R 1.4 This should only refer to known long-term outages, not planned outages. Delete "including protective relays"; this is addressed through other provisions.

R.2.1 Shorten "Near-Term Transmission Planning Horizon Planning Assessment" to "Near-Term Planning Assessment".

R 2.2 Shorten "Long-Term Transmission Planning Horizon Planning Assessment" to "Long-Term Planning Assessment".

R2.1, 2.2, 2.3 & 2.4 – The initial paragraph should have identical language regarding 'annual', and 'current or past' aspects.

R2.1.1 There should not be a requirement to look at years one and two; a 5 year study should be sufficient. If there has been an ongoing 5 year study, there should be no major unexpected problems occurring in years 1 and 2. Studies of earlier years should only be required if an unanticipated event occurred that had not been considered in prior studies. The TPL should not address shorter term "Operating Studies" or operating issues.

R 2.2.1 Modify to "If any known projects have a lead time that is longer than ten years, the Planning Assessment shall be extended accordingly."

R 2.6 Steady-state, short circuit, and stability analysis should be required no more than every 5 years unless there is a significant change the system.

R 2.6.1 Remove reference to "market structure changes". The purpose of it's inclusion is unclear.

R 2.7.1.1 Project initiation date should be deleted. If it is retainted, it needs to be defined.

R 2.7.3 Committed and Proposed projects should be defined.

R 3.2.1/R 4.3 - What is the intent of this requirement? There should probably be an MOD associated with Generator Owner requirement to provide related generator protection/ limiter data or other plant information.

R 3.4/R 4.5.2 Remove the requirement to implement changes to reduce or mitigate the likelihood of such consequences of Extreme Events. This may not be reasonable or achieveable.

R 3.2 Sectionalizing schemes shall be considered when reflecting the post-contingent system.

R 3.2.2 - Propose deleting this. Line ratings should already take relay loadability into account.

R 3.3.2.1 - Proposed deleting "expected duration". This would be dependent upon the damage to the element due to the iniating event and other factors.

R 3.3.2.2 - The requirements of this section do not match P6.

R 3.3.3 - Change introductory language to read "Those multiple Contingencies that are…"

R 3.5 - Generation tripping should be allowed as well as generation run-back. In addition, all performance requirements shall be met, rather than just meeting facility rating requirements. Suggested lanague "Manual and automatic generation run-back and/or generation tripping is allowed as a response to single and multiple Contingencies as long as the performance requirements of this standard are met." If these changes are accepted, R 3.6 can be deleted.

R 4 and R 4.1 - The language should be made similar to R 3 and R 3.1.

Suggest bringing language similar R4.4 into the R 3, the steady state section.

R 4.2 - High speed automatic reclosing schemes shall be considered.

R 6.3 - Change to read "Planning Coordinators of neighboring impacted areas".

Table 1 3 b and c Extreme Event descriptions are vague concepts that cannot be practically simulated. 3 d and e are not reasonable or practically useful to simulate.

Table 1, P8 - Language needs to be clarifed as to how the 300 kV threshold is to be treated for transformers. Is this for the high side, low side, or both sides? P5 is much clearer.

Table 2 - Clarification needs to be made that the faults being simulated are permanent faults. This can be addressed under the "Performance Requirements" portion at the beginning of the table, or modify each fault description.

Table 2 P9. Recommend that this be changed to require that faults should be on different phases of each of two adjacent transmission circuits on a multiple circuit transmission tower

Table 1, P9(6) and Table 2 P9 - It is unclear as to what is meant by "A spare transformer inserted to replace an outaged transformer followed by System adjustments". Unclear as to what is to be tested.

General comment - Transmission System is used throughout the document and is an undefined term

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☒ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☐Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☐Agree. ☐Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.

- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☐
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☐
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☐
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☐
Comment:

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☐
Comment:

[1] System adjustment can be manual or automatic

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☐ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐

Comment: The terms Bus Tie Breaker and Non-Bus Tie Breaker used in Tables 1 and 2 are not well defined. To prevent misinterpretation of the standard, include diagrams that point out examples of bus tie breakers and non-bus tie breakers for each of the following bus schemes: 1) Single bus 2) Ring bus 3) Breaker and a half 4) Double bus double breaker.

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Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **[Due Date in bold]**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☒ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☒	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
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Group Comments (Complete this page if comments are from a group.)

Group Name: **PJM Planning**

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Mahendra Patel		RFC	2
Paul McGlynn		RFC	2
Mohamed Osman		RFC	2
Chuck Liebold		RFC	2
Leanne Harrison		RFC	2
Susan McGill		RFC	2

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

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The SDT did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. The SDT organized the new standard in the following sections:

R1 – Modeling requirements
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The SDT determined that the requirements and analysis for Steady State are different from those for stability. As such, the SDT separated the analysis requirements and created two performance requirement tables.

The SDT recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The SDT has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The SDT has not addressed Measures, Risk Factors, Violation Severity Factors or Time Horizons at this time. These will be addressed when the SDT has better defined the requirements of the standard.

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believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the SDT would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the SDT is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☒Do not agree.
Q1. **Comment: Also FAC-010**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☒Do not agree.
Q2. **Comment: Need to tighten definition example- load that trips in sympathy with fault (motor trips as a direct result but not in protection zone)**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☒Do not agree.
Q3. **Comment: Agree with concept but need better definition**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers Years One through five.	☒Agree. ☒Do not agree.
Q5. **Comment: Near Term should cover years two through five. Planning should not study year one because Operation Planning does and one year is too short of a period to mitigate**	

on a permanent basis.	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☒Do not agree.
Q6. **Comment: Non-Consequential Load Loss should not include load loss due to manual, UVLS and UFLS.**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☐Do not agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☒Do not agree.
Q10. **Comment: Does "inter-area oscillations are damped" imply that you also have to do frequency domain analysis? (Because some industry experts would claim that without small signal analysis you cannot ensure that inter-area oscillations are damped.)**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions", FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The SDT has

included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☒ No ☒
Comment: **At the least, it should provide a measure that indicates that you meet the requirement. Need to modify 2.4.3 to specify what if any performance requirement need to be met.**

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☒ No ☒
Comment: **Again, 'reasonable' is a very subjective term. Refer to comments on question 12**

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☒
Comment: **Yes, however, clear direction is needed. Specific wording that defines if you have done enough, and met the compliance requirements.**

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year 6 and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☒
Comment: **PJM agrees that no sensitivity analysis is required for long term period**

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If Yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☒

Comment: **Yes- DSM should be modeled consistent with how it is expected to be operated based on contractual/operating relationships.**

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☒

Comment: **Yes – At a minimum the system conditions and / or contingency that identified the system deficiency should be evaluated to determine that it has corrected the issue. The extent of the study area needs to be consistent with the size / complexity of the corrective action plan.**

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☒

Comment: **We agree that there needs to be a differentiation between committed and proposed projects. Proposed projects, particularly generation interconnections and their associated network upgrades need to be identified as a group so that they can be removed from cases if the proposed generation interconnection does not move forward.**

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐

Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable BES that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the SDT attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The SDT is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the SDT to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL Standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	**Should be a 3 phase fault not a single line to ground fault.**
Q21. P5-1: For facilities	☒Agree.	

above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: Agree with performance requirement

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards - P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: yes

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

[1] System adjustment can be manual or automatic

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No☐
Comment: **Yes, but should model the true clearing times of each individual unit. Also the standard should clearly state that system reinforcement should not be required for this extreme events.**

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: **No. This is good in theory but is impractical to implement with the large interconnected systems that span large geographical areas.**

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: **Adjustments should be allowed consistent the time periods being studied.**

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Yes ☒ No ☒
Comment. **Yes- At a minimum the emergency rating needs to be coordinated with the SPS timing.**

The SDT has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

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Yes ☒ No ☐
Comment:
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Yes ☐ No ☒
Comment:

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Yes ☒ No ☐
Comment: Yes.

- Delayed clearing due to primary relay system communication failure
- Bus Contingencies should not be included for sensitivity/stressed case
- Sensitivity case should not be included for long term study
- Need to clearly define number of studies required for Load Flow/Stability and what performance criteria must be met.
    - Peak Case
    - Off Peak
    - Sensitivity

- Need to allow SPS operation after a first contingency, system readjustment and a "second " first contingency.
- SPSs can include generation tripping

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☐Do not agree.
Q1. **Comment:**	
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Q2. **Comment:**	
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Q3. **Comment:**	
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Q4. **Comment:**	
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Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☐Do not agree.
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frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
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Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☐Do not agree.
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Q11. **Comment:**	

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The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

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- Unavailability of long lead time facilities.
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- Generation additions, retirements, or other dispatch scenarios.

- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☐
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☐
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

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Yes ☐ No ☐
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☐
Comment:

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☐
Comment:

[1] System adjustment can be manual or automatic

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☐ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐

Comment: 1) P5 and P8 in Tables 1 and 2 – If you keep the "300 kV bar" for distinction between P5 and P8, then please make an exception for P5 to be "Yes" on Non-Consequential Load Loss where load pockets (a.k.a. local load-serving areas) are concerned because "system adjustments" might not be possible to avoid the need for Non-Consequential Load Loss after the loss of another line into the load pocket.

Example - A city, which is a type of load pocket, is served by three transmission lines. If one of the lines into the city is removed from service for maintenance, "system adjustments" within the city might not be possible to prevent steady-state voltages from dropping below an acceptable limit after loss of a second line into the city. If during such an "N-1Line-N1Line" Planning Event the city voltages become extremely low, then shedding of some of the city's load should be allowed, i.e. Non-Consequential Load Loss, for all voltages 100 kV and above. In this example, when one line into the city is removed from service, the TOP could either arm an SPS or RAS for automatic load shedding, or alert the operators to possible implementation of an Operating Procedure for manual load shedding. The city, along with its TO and other authorities, may decide by their own wishes to "raise the bar" and add facilities to maintain acceptable voltages for the worst "N-1Line-1Line" affecting only its local area. However, a facility addition type of solution, driven by a "No" for Non-Consequential Load Loss in P5, should not be mandated.

"Controlled interruption of electric supply to customers (load shedding)" should be allowed for all voltages 100 kV and above as Footnote (c) in TPL-003 allows. Consistent with this request to allow load shedding for this type of disturbance for all voltages 100 kV and above, FERC Order No. 693 in Paragraph 1825 regarding TPL-003 for Category C disturbances (including "N-1Line-1Line") does not ask for "controlled load interruption" to be eliminated, but rather FERC directed the ERO to modify footnote (c) to Table 1 to clarify the term "controlled load interruption". And please note FAC-010-1, R2.5 – "Planned or controlled interruption…(load shedding)…" for TPL-003 conflicts with "No" for Non-Consequential Load Loss in P5 of Draft TPL.

2) Proposed revision to R3.5 – "Manual and automatic generation runback and generator tripping are allowed as a response to single and multiple contingencies as long as Facility Ratings are not exceeded and the result of the generator action, such as location and ramp-up speed of the AGC unit(s) responding to the generation trip or runback, loss of reactive resource, impact on reserves, and restart time of tripped unit(s), meets the performance requirements."

Planning and Operations need flexibility to coordinate with the requirements of Engineering who established the Facility Ratings. It should not matter which method of generation redispatch is employed if all impacts of tripping vs. running back a generator are properly considered and performance requirements are met. The time period for a particular Emergency Rating might require faster generation redispatch than a runback or set of runbacks are capable of providing. Therefore, it may be necessary to trip one 100 MW unit rather than runback several units for a total of 100 MW.

No need for R3.6 with above revision to R3.5.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Mark Byrd	
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Telephone:	919-546-7937	
E-mail:	mark.byrd@pgnmail.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☒ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

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frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment: Planning assessments should not include asset conditions and age.**	
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- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

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Yes ☐ No ☒
Comment: This should be system specific.

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Yes ☐ No ☒
Comment: This should be system specific.

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Yes ☒ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: Sensitivities should not be required for Long-Term.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

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deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: State regulatory requirements mandate that we consider DSM alternatives. The DSM contracts would have to adequately support the intended use.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: There are separate regional processes for coordination with neighboring utilities.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: Are projects are proposed until they are completed.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment: We always should be able to show that we meet performance requirements.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	It is absolutely necessary, however, to allow interruption of firm transfers as a System adjustment. To do otherwise would cause extremely large expenditures for very low probability independent events.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	It is absolutely necessary, however, to allow interruption of firm transfers as a System adjustment. To do otherwise would cause extremely large expenditures for very low probability independent events.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	It is absolutely necessary, however, to allow interruption of firm transfers as a System adjustment. To do otherwise would cause extremely large expenditures for very low probability independent events.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance

requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: This is a very low probability multiple contingency and would cost an extreme sum of money to remedy. Need to clarify whether or not the stuck breaker was connected with loss of element.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☒
Comment: DC and AC lines should be treated comparably.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of

[1] System adjustment can be manual or automatic

Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: Don't need to differentiate between plant and system. These are not usually separated. It would be better to separate angular stability and voltage stability. They are studied independently

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment: This needs to be done but we currently don't have sufficient data and tools to properly perform the analysis. More interconnection-wide testing and data collection needs to be performed. We will need to transition into these studies over time.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Both manual and automatic adjustments should be allowed.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: If the rating is a 2 hour rating then the adjustment should be complete within 2 hours.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒

Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment:

1. In R4.6 and other locations, the generator exemption of 20 MW should be increased to 75 MVA.

2. Need to define bus-tie breaker. Is center breaker in a breaker and a half scheme a bus-tie breaker?

3. Need to continue to allow interruptions to firm transfers. This is essentially allowing redispatch and is an economically sensible solution to low probability high impact multiple contingencies.

4. Need to clarify if the "stuck breaker" is associated with the first event in multiple event contingencies or does one have to choose a breaker not involved with the first event. Note that a breaker cannot be "stuck" if there is no demand to trip. Therefore, a stuck breaker that is not adjacent to the first event will not have a demand to trip.

5. Need to distinguish what the difference is between a "stuck breaker" and a "[loss of breaker due to] internal fault". The specific meaning could make the difference in the clearing time selected for stability studies (normal clearing time versus delayed clearing time).

6. In the Table 2 (for stability) the last bullet under Planning events says to "simulate normal clearing times unless otherwise specified". Does this mean that "stuck breaker" events should be simulated with normal clearing times? Note that in the real world, internally faulted breakers may clear in either normal or delayed clearing time, depending on the relaying and CT configuration.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☒ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☒Agree. ☐Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.

- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: PEF concurs with the draft standard's approach with regard to Q15 that sensitivities should not be required for years six through ten.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐

Comment: The use of DSM, whether exclusively or in conjunction with other measures, is an acceptable operating procedure for use in a Corrective Action Plan, as long as the Transmission Owner demonstrates availability and accuracy of DSM data and its viability as an operating procedure for each applicable scenario.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒
Comment: Each Corrective Action Plan as stated in the original assessments should be trusted as effective, provided the Transmission Owner can demonstrate with its own internal assessments the effectiveness of each Corrective Action Plan.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: This differentiation is meaningless when modeling projects in cases for planning analysis. The standard should instead set criteria for when models can be relied upon for planning purposes such that changes to the future plan will not have an impact on reliability.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

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The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	This single contingency event has a very low probability of occurrence, and thus a more stringent performance requirement than currently exists is not warranted.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration. Furthermore, the greater-than-300 kV Bulk Electric System has been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis, placing particular importance on confining the event to a single area (i.e., not resulting in a cascading outage). Past assessments as well as actual events have demonstrated that by not allowing loss of non-consequential load, the Bulk Electric System may actually remain in a less secure state or condition, i.e. in more danger of experiencing cascading outages.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration. Furthermore, the greater-than-300 kV Bulk Electric System has been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis, placing particular

		importance on confining the event to a single area (i.e., not resulting in a cascading outage). Past assessments as well as actual events have demonstrated that by not allowing loss of non-consequential load, the Bulk Electric System may actually remain in a less secure state or condition, i.e. in more danger of experiencing cascading outages.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration. Furthermore, the greater-than-300 kV Bulk Electric System has been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis, placing particular importance on confining the event to a single area (i.e., not resulting in a cascading outage). Past assessments as well as actual events have demonstrated that by not allowing loss of non-consequential load, the Bulk Electric System may actually remain in a less secure state or condition, i.e. in more danger of experiencing cascading outages.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: This single contingency event has a very low probability of occurrence, and thus a more stringent performance requirement than currently exists is not warranted.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒

Comment: The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration. Furthermore, the greater-than-300 kV Bulk Electric System has been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis, placing particular importance on confining the event to a single area (i.e., not resulting in a cascading outage). Past assessments as well as actual events have demonstrated that by not allowing loss of non-consequential load, the Bulk Electric System may actually remain in a less secure state or condition, i.e. in more danger of experiencing cascading outages. In addition, it should be noted that the technical specifications of this category contain a major oversight. This new Category P3-1 is essentially a replacement for the existing Categories C5-9, except that the only protection element failure being considered is the failure of a circuit breaker to open. This definition eliminates the need to examine failure of the relay to operate, which in many cases has a more serious impact on grid reliability.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration. Specifically, the sudden loss of a large generator followed soon thereafter by the loss of a second generator would often result in such a large generation-to-load mismatch that Non-Consequential Loss of Load would be inevitable. It is clear, however, that the Bulk Electric System should be planned such that any generator can be maintained (offline) and the system can be operated to the contingency of another generator. This is accomplished in the Security Constrained unit commitment process. However, if the intent of this requirement is that the system should be planned such that there can be no Non-Consequential Load Loss for the loss of a second generator (after System adjustment), then the requirement is too stringent in that the planner would essentially have to plan for 3 generator contingencies. Finally, the probability of an event should not

[1] System adjustment can be manual or automatic

		be the primary factor determining whether or not Non-Consequential Loss of Load is permitted, but rather the presence or absence of cascading for the event.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration, provided that the Non-Consequential Loss of Load is confined to a single control area (i.e., not resulting in a cascading outage). Furthermore, the frequency of an event should not be the primary factor determining whether or not Non-Consequential Loss of Load is permitted, but rather the presence or absence of cascading for the event. Existing Category C requirements are adequate for this type of event.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration, provided that the Non-Consequential Loss of Load is confined to a single control area (i.e., not resulting in a cascading outage). Furthermore, the frequency of an event should not be the primary factor determining whether or not Non-Consequential Loss of Load is permitted, but rather the presence or absence of cascading for the event. Existing Category C requirements are adequate for this type of event.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration, provided that the Non-Consequential Loss of Load is confined to a single control area (i.e., not resulting in a cascading outage). Furthermore, the frequency of an event should not be the primary factor determining whether or not Non-Consequential Loss of Load is permitted, but rather the presence or absence of cascading for the event. Existing Category C requirements are

		adequate for this type of event.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☒

Comment: The proposed standard does not distinguish between asynchronous DC ties and the more common parallel connected DC tie. With an asynchronous DC tie, the transfer is lost with the tie. With a parallel DC tie, the transfer will be shifted to the parallel AC system and should have the same performance requirements.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☒

Comment: The separation of steady state and dynamic response analysis requirements into two tables (with different contingencies) is unnecessary, and is inferior to the analysis requirements outlined in Table 1 of the existing TPL Standard. The structure of the existing Table 1 reinforces the requirement for grid stability and maintaining the grid within applicable limits for Category B and C contingencies. Dynamic simulations of Category B and C contingencies that demonstrate grid stability should be followed up with post transient power flow analysis to assess voltage and thermal limits.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒

Comment: There should be no such distinction. All stability studies must meet the Performance Requirements for "Planning Events in Table 2 - Stability Performance". If there were different Performance Requirements then the distinction may be warranted. If the format for "Planning Events in Table 2 - Stability Performance" remains in its existing state, however, system stability studies are sufficient and performing studies under the guise of Plant Stability would constitute additional work with no incremental benefit.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒

Comment: Analysis of this condition should not be required in stability analysis of extreme events due to the fact that no stability simulation (e.g., SLG or 3-phase faults) can be conceived for the Bulk Electric System that would result in simulataneous tripping of all units at a plant.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒

Comment: Requiring detailed modeling of every induction motor on the Bulk Electric System for stability analysis is onerous. Specifically, obtaining a complete set of data for existing induction motors would be infeasible, as would tracking future installations of induction motors. The benefits of such an effort are significantly outweighed by the logistical difficulties. To address the technical merits, the modeling of the delayed voltage recovery response that has been observed in some large urban areas during periods of high air conditioning usage is considerably more complex than can be addressed by simply representing induction motor effects. The scope of the delayed voltage recovery issue is extremely limited and its effect on the grid is generally self correcting due to automatic disconnection of the affected air conditioners. Requirements for specific types of load models are not appropriate in the TPL standard.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Provided events are confined to a single area (i.e., no cascading outages), manual and automatic adjustment (increase or decrease) of Var output and manual and automatic tripping or reduction of overall output of generators should be allowed.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Provided events are confined to a single area (i.e., no cascading outages), automatic runback of generators should be allowed.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: This requirement is addressed in PRC-005 and these requirements should not be addressed again in this Standard. However, the use of RAS or SPS should be allowed as necessary for any single contingency event, provided that such use does not result in cascading outages. It should be noted that the performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. Revision of the existing TPL standards will require updating of the contingency references in PRC-012-0.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: The use of RAS or SPS should be allowed as necessary for any single contingency event, provided that such use does not result in cascading outages. It should be noted that the performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. Revision of the existing TPL standards will require updating of the contingency references in PRC-012-0.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: The use of RAS or SPS should be allowed as necessary for any single contingency event, provided that such use does not result in cascading outages. It should be noted that the performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. Revision of the existing TPL standards will require updating of the contingency references in PRC-012-0.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment: No, but PEF reserves the right to apply for variances based on the completed version of this or any other standard.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: General Comments

NERC Standards TPL 001-0 through TPL 004-0 are approved standards that only required modifications pursuant to FERC Order 693. In this proposed draft standard TPL 001-1, the Standard Drafting Team (SDT) has far exceeded the recommendations suggested by FERC in the Order and has created unnecessary confusion. We disagree with the SDT's decision to combine NERC Standards TPL 001-0 through TPL 004-0 into one standard. Some changes to the existing TPL Standards may be warranted. One particular improvement would be clarifying the tables such that the table for TPL-001, for example, would only contain the performance criteria for Category A, with footnotes only applicable to that category, clarified as directed by FERC in Order 693. Similarly, TPL-002 would only contain performance criteria for Category B, and so on.

In addition to combining the standards, the SDT has significantly changed contingency specifications and required performance levels. In many cases the changes represent a very significant increase in required performance standards that will result in the following:

a) major capital expenditures, some of which will be of a magnitude unprecedented for the Bulk Electric System. Many of these projects would be constructed to mitigate one single low-probability event. The ratepayers, upon discovery of this necessity and realization that these significant expenditures will be passed on to them in their rates, will certainly object to these efforts and will question the wisdom of NERC's mandating change on such a massive scale without the knowledge or input of the public. The SDT stated in its continent-wide conference call on October 10, 2007 that the intent of many of the objectives contained in the proposed TPL-001-1 was to "raise the bar" for electric utilities. We would like to know specifically what this means. The phrase "raise the bar" is vague and overused in North American vernacular in general, and it is particularly irresponsible to use such vagaries when proposing standards which will result in unaffordable upgrades to the North American Bulk Electric System.

b) reductions in ATC. To be compliant with the more stringent requirements of TPL-001-1, Transmission Operators would in many cases be forced to reduce ATC in order to decrease transmission flows to a point at which corrective actions may be taken without the result of cascading. This is diametrically in opposition to one of the key objectives of deregulation and comparable treatment for all entities engaged in transactions on the Bulk Electric System.

c) Reduced Reliability. The elimination of footnote (b) will result in many outage scenarios for which loss of Non Consequential Load is presently unavoidable, but subsequently prohibited. For some scenarios, Transmission Owners may seek to avoid the excessive cost of a project by simply removing breakers from substations, thereby

increasing the range of the initial breaker-to-breaker operation and essentially converting the disallowed Non Consequential Load to Consequential Load. This is obviously an undesirable option and in opposition to fundamental principles of reliability, but might be rendered necessary due to the increased requirements of TPL-001-1.

d) Inability to react to issues of non-compliance. The dynamic nature of planning analysis is such that, from one annual planning cycle to the next, the constantly changing load and generation forecasts invariably result in emerging transmission projects unforeseen in previous cycles. With the increased stringency of TPL-001-1, reacting to these emerging needs in time to demonstrate compliance will be impossible, and thus non-compliance is seen as an inevitability. To further clarify, the major transmission projects that TPL-001-1 would necessitate would be of a magnitude such that extensive engineering, land acquisition and involvement with regulatory and governmental agencies would be required, which could result in project lead times of 10 years or more. Not only would a lengthy transition period be needed for TPL-001-1, but upon the Standard's effective date the ability to implement all future projects would need to be given special consideration in light of these challenges.

In other cases, the performance criteria are not clearly defined, such as the timing between multiple contingencies, and the level of readiness of the system before and after Planning Events.

Finally, the SDT has chosen to eliminate the footnotes in the current standards, contrary to the direction of FERC in Order 693 to "clarify" the footnotes. The purpose of the footnotes is to further explain terms in the tables, provide guidance in interpreting the expected performance criteria, and specify any exceptions to the criteria. Footnotes also serve the purpose of keeping the standard concise by eliminating repetitiveness.

Specific comments on the Draft Standard

Performance Criteria
The performance requirements table should clearly define what the initial state of the system is assumed to be before any Planning Events, and what the state of the system is assumed to be after the Planning Event. For example, P1 (single contingency) events: assuming that the system is to be compliant, the state of the system prior to the event must be "secure" such that the event could occur and there is no interruption of firm transfer or loss of load, Equipment Ratings are not exceeded, System steady state voltages and post-transient voltage deviation are within acceptable limits. However, the system is not as it was before the event. The system could be described as "normal" but perhaps not "secure". If the requirement is that the system must also be "secure" after the event, then the standard must clarify what is allowed for "system adjustments" after the first Planning event to prepare for the next. FERC Order 693 directed the ERO to modify the second sentence of footnote (b) to clarify that manual system adjustments other than shedding of firm load or curtailment of firm transfers are permitted to return the system to a normal operating state after the first contingency. However, in order to bring the system to a secure state, as is necessary for the second contingency of a category C3 or C5 event, footnote (c) allows curtailment of firm transfers, and FERC Order 693 only required footnote (c) to be clarify the term "controlled load interruption", leaving the curtailment language intact. The implication of this interpretation is critical to peninsular Florida. The Category B loss of one 500 kV line from Florida to Georgia is sustainable, such that the system is "normal" after the event. However, in order to be

prepared for the next contingency, (the loss of the second 500 kV line), firm transfers must be curtailed (Interruption of Firm Transfer). Without the ability to curtail firm transfers, a "super-firm" priority of transmission service is created for non-native load customers, and thus comparable treatment no longer exists.

Comments on New Performance Tables:
The draft TPL standard represents a major change in the Table 1 contingency definitions and required performance levels.

Table 1 Contingencies C1 and C2 are being moved to the single contingency category. While C1 and C2 represent single element outages, their probability of occurrence is much lower than the other Category B contingencies and they do not belong in the single contingency performance requirements group.

Footnote (b) which permits, as a limited exception in unique circumstances with a sound rational basis, some localized load reduction for single contingencies, has been removed. This is a very significant change for some utilities. Footnote (c) which permits load shedding and curtailment of firm transfers has been removed from C1, C2 and most of C3. This is a very significant increase in required performance level that is not justified.

The "applicable rating" for loading and voltages in Table 1 has been removed so that essentially, the same ratings and voltage restrictions apply to both B and C contingencies. Some utilities plan to a normal rating for single contingencies but will allow a higher short term rating for Category C events. This practice appears to be either disallowed or inadequately described in TPL-001-1. Transmission Owners should allowed to base ratings on manufacturer specifications or other reasonable criteria using sound engineering judgment.

Several new Category D "extreme events" have been added which greatly expand the scope and complexity of Category D studies. These are (1) any two unrelated single element outages and (2) wide area events a. through h. These represent a major increase in the scope of Category D studies and probably a doubling of required SWG studies.
It should be note that the existing Categories D1 through D4 have been substantially changed to eliminate analysis of relay failure contingencies. The philosophy contained in the existing TPL-004 standard is that faults with a protection failure should be evaluated whether that failure is a circuit breaker, relay or CT; the proposed standard restricts the analysis to breaker failure.

300 kV Threshold Performance Level
The TPL-001-1 draft sets a threshold of higher performance to facilities above 300 kV than previously established in the existing standard. We do not agree that such a threshold is necessary or warranted. Requirements which are more stringent for these facilities may wrongly influence decisions on project alternatives in favor of facilities with less stringent requirements. Additionally, facilities above 300 kV naturally tend to transport larger amounts of power. The loss of single or multiple facilities above 300 kV generally results in an immediate generation-to-load mismatch too great to avoid either curtailment of firm transactions or loss of Non Consequential Load, or both. Singling out facilities above 300 kV for more stringent requirements is therefore clearly unreasonable.

DC Line Performance Requirement

The TPL-001-1 draft sets a lower performance requirement for the loss of a single pole of a DC line than in the existing standard by allowing interruption of firm transfer if the transfer is deemed to be dependent on the outaged line. Firm transfers are also dependent upon AC lines. The proposed standard does not distinguish between asynchronous DC ties and the more common parallel connected DC tie. With an asynchronous DC tie, the transfer is lost with the tie. With a parallel DC tie, the transfer will be shifted to the parallel AC system and should have the same performance requirements. We do not agree that such an exception for DC lines is necessary or warranted. The decision in selecting DC vs. AC in transmission lines has traditionally been based on the break-even cost and performance of the two alternatives. The lower performance requirement may wrongly influence decisions on project alternatives in favor of DC facilities with less stringent requirements.

Distinction Between Committed and Proposed Projects:
Models cannot discern the difference between a "committed" project, and a "proposed" project in a performance analysis. The standard should instead set criteria for when models can be relied upon for planning purposes such that changes to the future plan will not have an impact on reliability. The intent of Requirements R2.7.3 and R2.7.4 should be combined and added into R2.7.1.1. Rather than adding the additional requirement to document a criteria, the requirement should be that in the Near-Term Planning Horizon, projects cannot be removed (or modified) without demonstrating that the revised plan meets performance criteria. In addition, the requirement in R2.7.1.1 to supply a "project initiation date" is ambiguous. What will constitute "project initiation" …construction start date? …Engineering complete date? …Land procurement date? Funds allocated date (budgeted)? Suggested wording for R2.7.1.1. "Transmission and generation improvement projects for the Near-Term Transmission Planning Horizon, shall have in-service dates provided, and shall not have in-service dates changed, or be removed from planning models, without documentation to show that the revised plan meets performance requirements."

Load Modeling Requirements:
The proposed TPL Standard contains numerous references to load modeling. The goal of improving and verifying the load model is worthwhile but is not appropriate for the TPL standards. Assessment of load model accuracy is best accomplished through detailed analysis of grid disturbance events. The main difficulties in accomplishing this are (1) grid events that significant reduce transmission voltages throughout a load area are infrequently occurring and (2) the process of recreating the event through simulation studies is extremely complex and time consuming. While these efforts should be encouraged they should remain a RRO prerogative. A few concerns not previously addressed by comments to Questions 1-42 include the following:

R1.1.1 Use of expected Load mix - based on the actual or expected aggregate mix of industrial, commercial, and residential Loads. – This requirement is not justified as the load model may be developed through disturbance analysis rather than load type synthesis by customer class. Some Load Serving Entities may have great difficulty in creating load forecasts based on customer class. Load forecasting requirements are adequately addressed in the existing MOD standards and do not belong in the proposed TPL standard.

R1.2. Load models with supporting rationale - that include power factor data that may be based on historical System performance, validated by measurement during stressed

System conditions, or documented Transmission planning area requirements. This requirement is not appropriate for the TPL standards.

R.3.3.2.1. Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment. – this Requirement in its present wording could be construed to mean that the precise amount of load between breakers should be specified and reevaluated with every assessment. This would unnecessary and burdensome, and we therefore seek clarification of this Requirement or its removal altogether.

Requirements for studies using Sensitivity cases: R2.4.3 appears to place equal importance on base cases and sensitivity cases with regard to the need to implement projects or Corrective Action Plans. Terms in TPL-001-1 using forms of the word "sensitivity" need to be clearly defined by the SDT. Additionally, the SDT needs to clarify its intent regarding required action based on results from sensitivity studies. We do not agree that results from sensitivity studies should be given equal standing with results from base scenarios, and we would particularly object to any insinuation that projects would need to be implemented to mitigate violations seen in a sensitivity involving speculative non-firm transfers.

Short Circuit Requirements: The new TPL standard also contains numerous references to short circuit analysis, which are new requirements that expand the TPL standards, but without specific testing or performance criteria. Evidence that short circuit studies have been performed is currently required in the existing FAC-002-0 Standard. Since the primary concern is the appropriate sizing of equipment and the prevention of equipment damage as opposed to overall grid reliability, we do not see the need for a set of requirements within the proposed TPL standard for short circuit studies.

FRCC Specifics: One final specific issue concerns the topography and performance history of the Bulk Electric System in our particular region (FRCC). The FRCC system is a peninsular system having only one interface with the rest of the interconnected NERC system, and has historically demonstrated exceptionally high reliability with no events in recent history cascading beyond the FRCC system. While other areas of the NERC system may require some increased stringency in the TPL standards, PE feels that the adequacy of the existing TPL standards as they apply to the FRCC System has been extensively documented.

Conclusion

In conclusion, we believe that TPL-001-1 is unnecessary and burdensome. In particular, the elimination of footnote (b) will deny Transmission Owners and Transmission Operators the right to curtail Non Consequential Load in order to restore the Bulk Electric System. This elimination has absolutely nothing to do with the reliability of the Bulk Electric System; rather, it places the reduction of Customer Minutes of Interruption (CMI) ahead of reliability. Essentially, the emphasis of TPL-001-1 is inappropriately placed on the reliability of distribution feeders rather than the reliability of the Bulk Electric System. The fundamental objective of the existing TPL Standards has been to protect the reliability of the Bulk Electric System, and we believe all future TPL Standards should do the same.

Given the aforementioned issues, we believe the proposed TPL standard is inferior to the existing Board approved TPL Standards, creates unnecessary confusion, and will require many iterations of industry comment and revision. As an intermediate approach, we would strongly urge the Standard Drafting Team that the existing TPL standards be modified to respond to FERC Order 693 directives, clarify any ambiguities, and that the proposed new standard not be pursued any further.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☒	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: To add clarity, the terms "power flow" and "dyanamic" should be included in the definition above. It seems that the defintion may be more detailed than needed without these two terms.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: Should the above definition contain a statement that the load is not intentionally lost, since non-consequential load loss is intentional?**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.

Q6. **Comment: Recommend adding that this load loss is "intentional".**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Recommend adding power flow and dynamic analyses to this definition. Short circuit analyses should not be included.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: I don't believe that this is really the definition of "planning events". This defintion should describe generally what the planning events are, not that they must meet performance requirements.**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☒ No ☐
Comment: A minimum of at least one or two that contain certain scenarios chosen from the list should be required.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: A list of suggestions is sufficient. The flexibility to use different stresses on different systems is needed.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☐
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: The study area should be determined by the Transmission Planner and Planning Coordinator.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to

obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☐

Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

[1] System adjustment can be manual or automatic

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in

response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☐ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: The requirements for the use of SPS and RAS should be contained in a separate standard. That standard should dictate when the RAS and SPS can be used. The planning studies would then simulate those conditions.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☐ No ☐
Comment: The requirement for short circuit studies (mentioned in R2 and included in all of R2.3) should be removed from this standard. Relay and protection engineers use a different type of software (Aspen and CAPE) for different reasons (to calculate phase and ground faults and perform relay coordination studies). Those types of studies should not be included in this standard and are totally separate from performing power flow and dynamics studies.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Jonathan Sykes	
Organization:	SRP	
Telephone:	602-236-6442	
E-mail:	jonathan.sykes@srpnet.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment: Reword to: Transmission planning period that covers years six or beyond.**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☐Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that	☐Agree.

cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Do not agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

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- Modification of expected transfers.
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- Variability and outages of Reactive Resources.

- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☐
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☐
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☐

Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☐
Comment:

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	The time to adjust the system needs to be provided (when does a N-1-1 become a N-2?). If the cause of the outage is transient (temporary) the operator needs some time to test and restore the element (could be minutes up to several hours). If the element is lost indefinitly, the operator will need some minimum time to adjust the system. If this time is not available prior to the next N-1 then the standard should allow Non-Consequetial Loss of Load.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	same as Q21
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	same as Q21

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance

requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	The time to adjust the system needs to be provided (when does a N-1-1 become a N-2?). If the cause of the outage is transient (temporary) the operator needs some time to test and restore the element (could be minutes up to several hours). If the element is lost indefinitly, the operator will need some minimum time to adjust the system. If this time is not available prior to the next N-1 then the standard should allow Non-Consequetial Loss of Load. Some distinction needs to be made the amount of generation connected at a single point on the BES. a wind farm might have many small generators connected to the BES with an aggregate total of 300Mw or more. This requirement will should only apply to generating sources that might be connected to the BES through a single transformer (i.e. wind farm) with minimum agregate total of 300MW (for N-1).
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	same as Q26.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission	☐Agree. ☒Do not agree.	same as Q26.

[1] System adjustment can be manual or automatic

circuit		
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	same as Q26.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load

model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: The loss of transmission line (N-1) may require Gen drop to prevent instability or violation. Studies will need to be performed that study the congestion of generation and transmission cooridors and loss of various elements.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: As long as Non-Consequential Loss of Load is not a solution for single contingencies (N-1).

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Non-Consequential Loss of Load should not be allowed for single contingencies (N-1) and the system must remain stable with no violations.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: Non-Consequential Loss of Load should not be allowed for single contingencies (N-1) and the system must remain stable with no violations.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: The SDT should be commended for very good work at identifying many different issues of the TPL standards. However, TPL-001-1 should take into account the consequences of a Security-Based or Dependability-Based Misoperation (and failure) of the Protection System.

1) A Security-Based Misoperation of the Protection System may remove additional elements of the BES and could be listed in the table under "multiple contingency".

2) A Dependability-Based Misoperation (or Failure) of a non-redundant Protection System could cause long time delays in clearing faults and clear a large area of BES around the faulted Element. This type of failure may not provide local tripping or breaker failure initiation and remote Protection Systems would need to operate to isolate

the fault or disturbance. Often the operation of the remote Protection Systems would cause long time delays in isolating faults and disturbances.

a) The BES should be studied and those elements need to be identified where Dependability-Based Misoperations (or failures) would prevent meeting the performance requirements of Table 1 (Steady State) or Table 2 (Stability). This type of Misoperation (or Failure) will have to be included in the Tables.

For example, some parts of the BES may be able to survive long time delayed clearing of faults caused by Dependability-Based Protection System Misoperations (or failures) and still meet the performance requirements of the tables. But other parts of the BES may experience cascading outages for this same scenario. One solution to minimize the consequences of Dependability-Based Misoperations (or failures) is to install redundant Protection Systems. The redundant Protection Systems would reduce the possibility of a single Dependability-Based Misoperation (or failure) from affecting the isolation of faults and disturbances.

In addition, the TPL-001 standard will need definitions of Security-Based Misoperation and Dependability-Based Misoperation. The following definitions are used for PRC-004-WECC-1:

Security-Based Misoperation: The incorrect operation of a Protection System or RAS for faults or disturbances outside the intended zone of protection. Security is a component of reliability and is the measure of a device's certainty not to operate falsely.

Dependability-Based Misoperation: Any of the following:

☐ The absence of a Protection System or RAS operation when intended

☐ A Protection System or RAS equipment failure is alarmed or indicated to operating personnel.

☐ A Protection System or RAS equipment failure is discovered.

Dependability is a component of reliability and is the measure of a device's certainty to operate when required.

PROTECTION SYSTEM MISOPERATIONS

Operational Scenario

Security-Based Misoperation
Dependability-Based Misoperation
Breaker Fail

Jonathan Sykes

SALT RIVER PROJECT

10/04/07

CASE 1 – Security-Based Misoperation of the Protection System

1. Fault Occurs on Line #1
2. Relays on Line #1 Operate

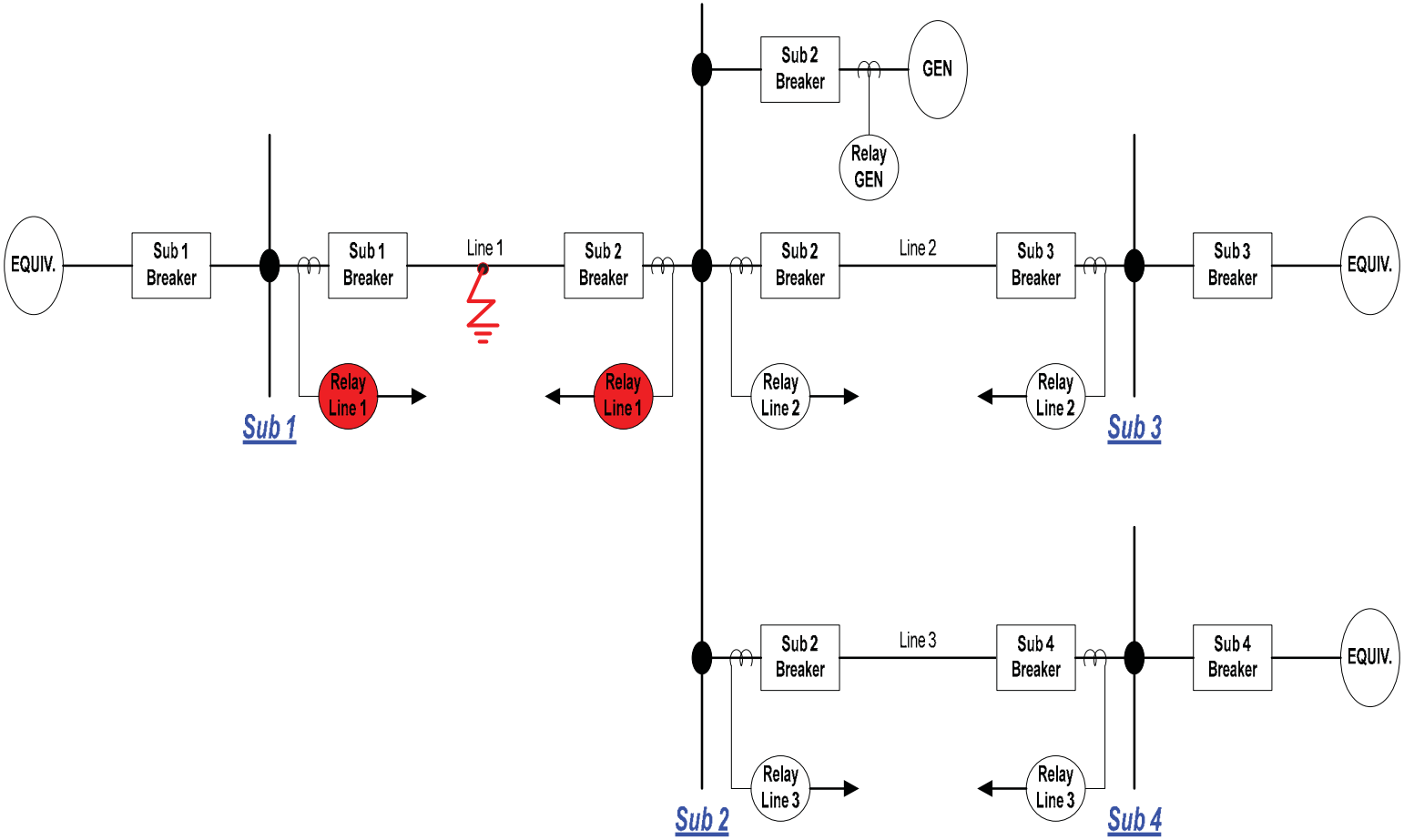

Simplified System One Line

CASE 1 – Security-Based Misoperation of the Protection System

1. Fault Occurs on Line #1
2. Relays on Line #1 Operate
3. Relay at Sub #3 on Line #2 Misoperates
4. Breakers operate and isolate Line #1
5. Breakers operate and isolate Line #2

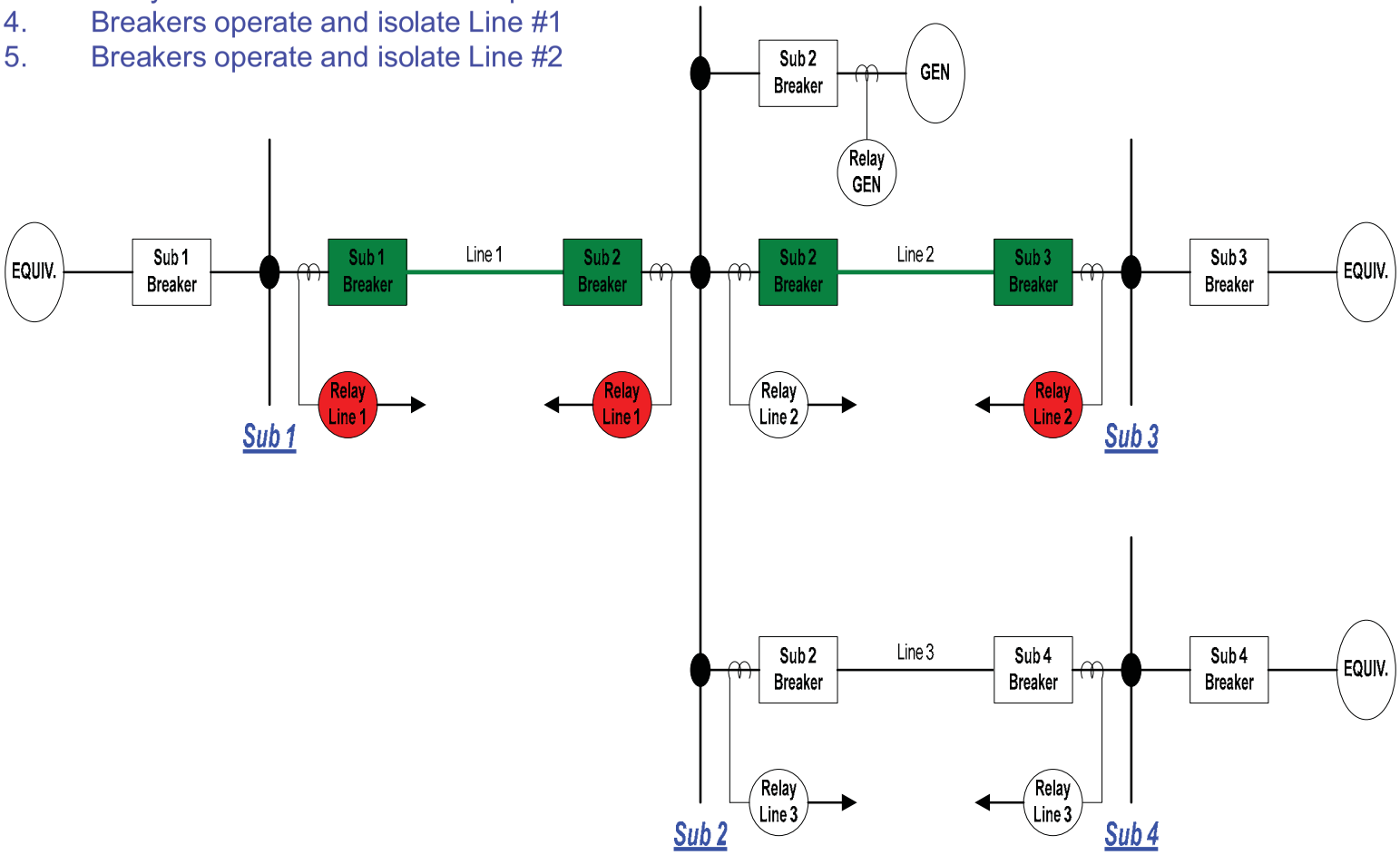

Simplified System One Line

CASE 2 – Dependability-Based Misoperation of the Protection System

1. Fault Occurs on Line #1
2. Relays at Sub #1 Operate and Open Breaker at Sub #1
3. Relays at Sub #2 **DO NOT** Operate and **DO NOT** initiate Breaker Fail

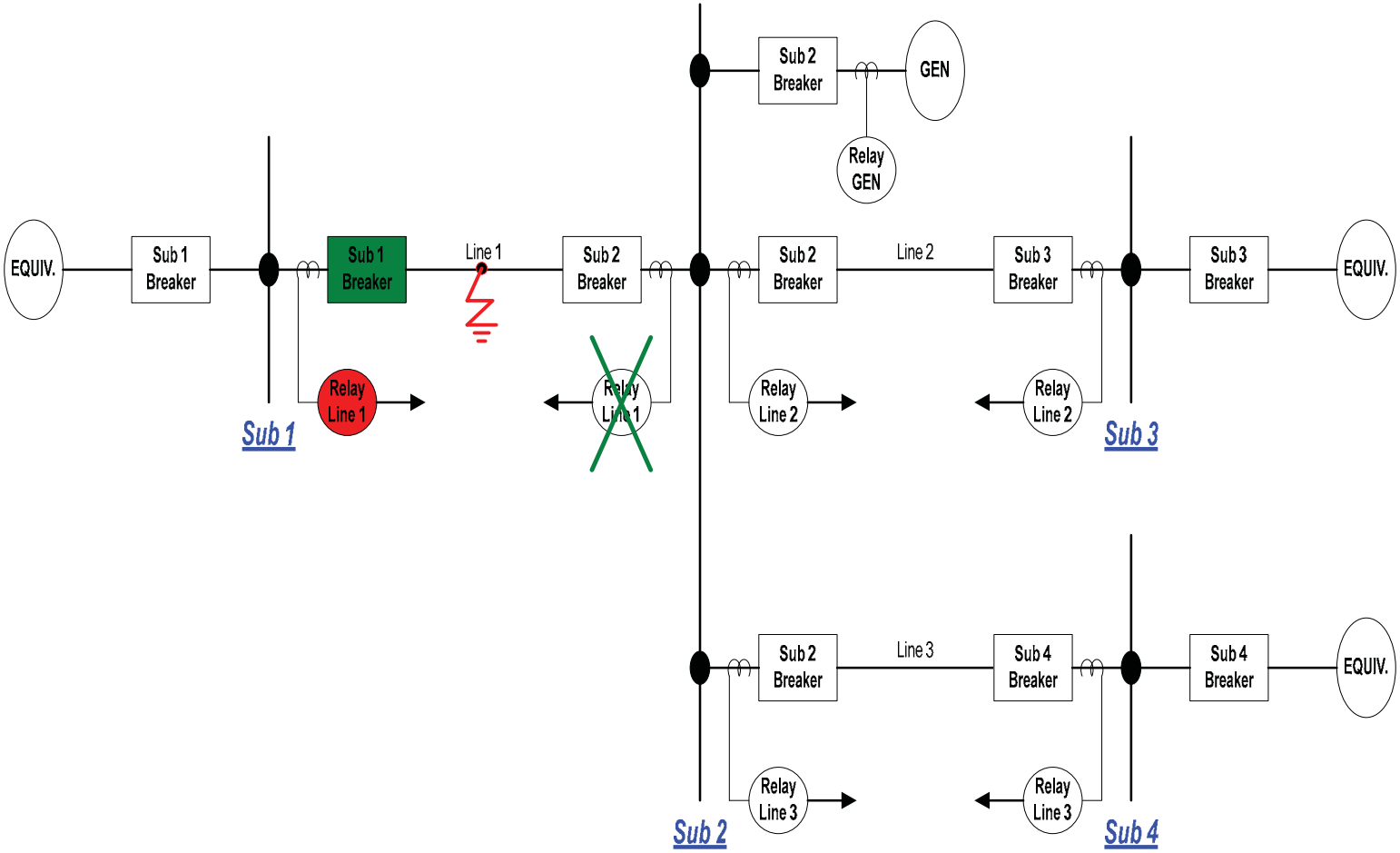

Simplified System One Line

CASE 2 – Dependability-Based Misoperation of the Protection System

1. Fault Occurs on Line #1
2. Relays at Sub #1 Operate and Open Breaker at Sub #1
3. Relays at Sub #2 **DO NOT** Operate and **DO NOT** initiate Breaker Fail
4. Remote relaying operates with long time delays
5. Breakers on various lines Operate and de-energize Sub #2, Line #1, Line #2, Line #3, and GEN

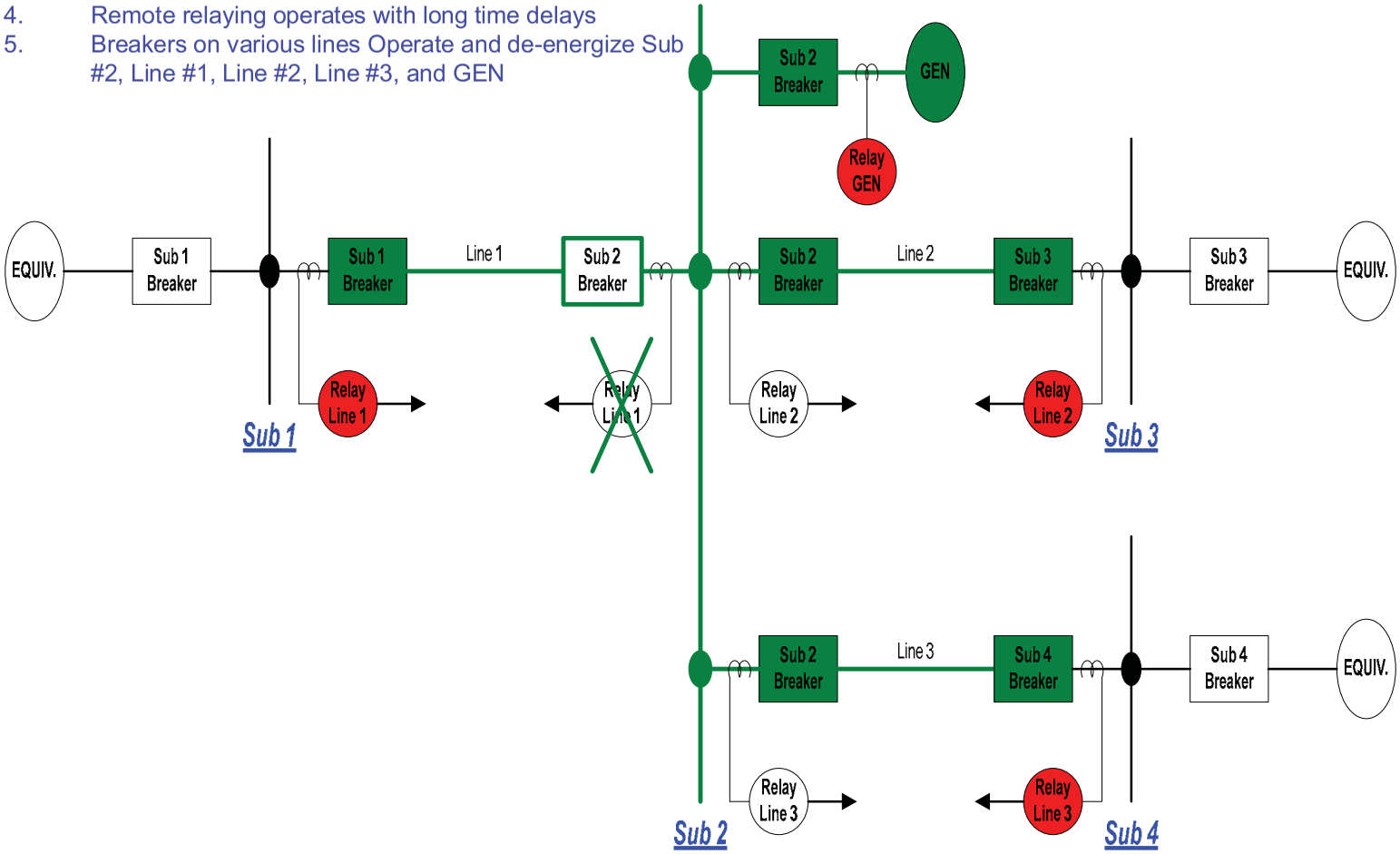

Simplified System One Line

CASE 3 – Breaker Fail

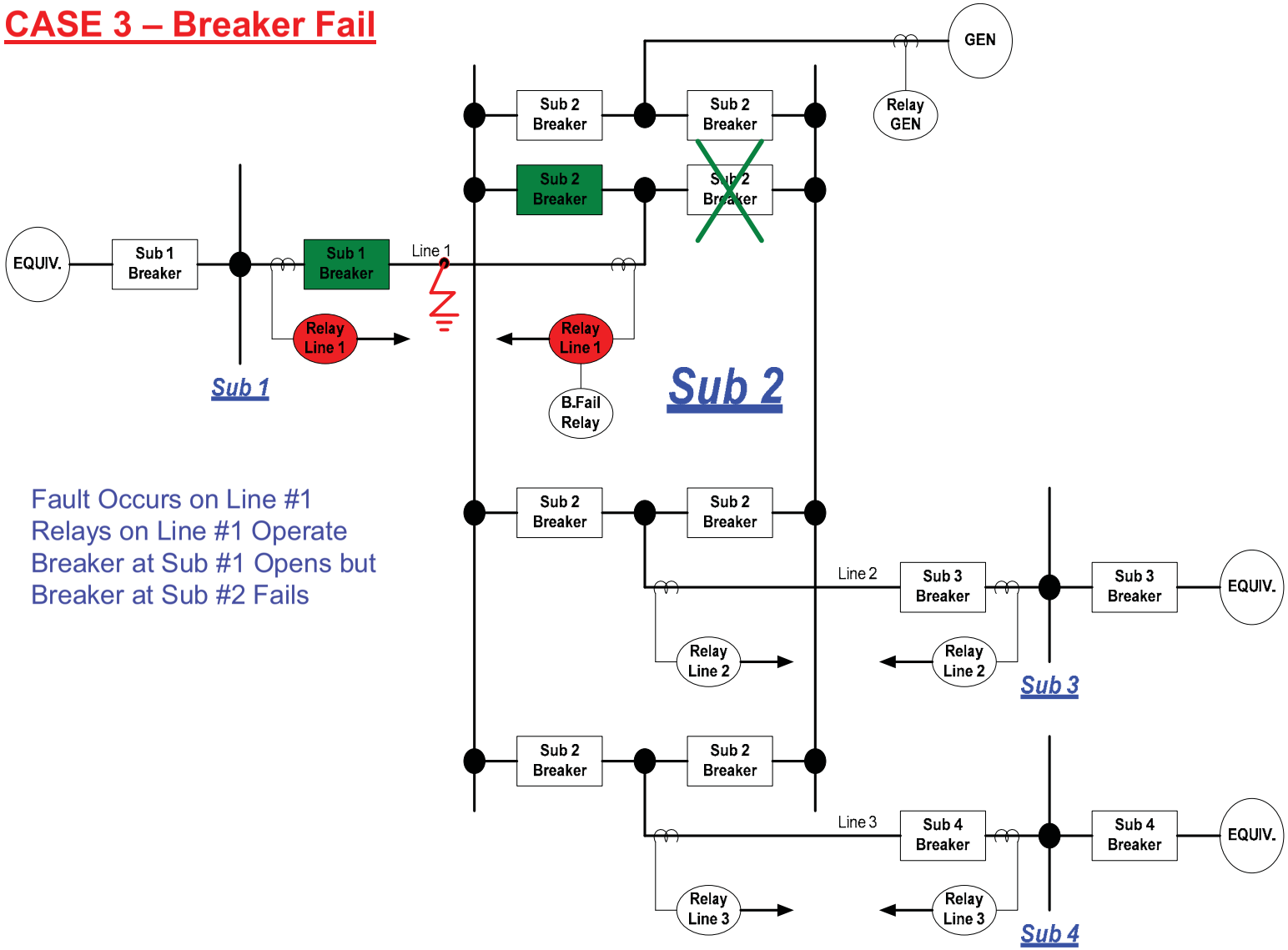

1. Fault Occurs on Line #1
2. Relays on Line #1 Operate
3. Breaker at Sub #1 Opens but Breaker at Sub #2 Fails

Simplified System One Line

(Note: Sub #2 has more detail)

CASE 3 – Breaker Fail

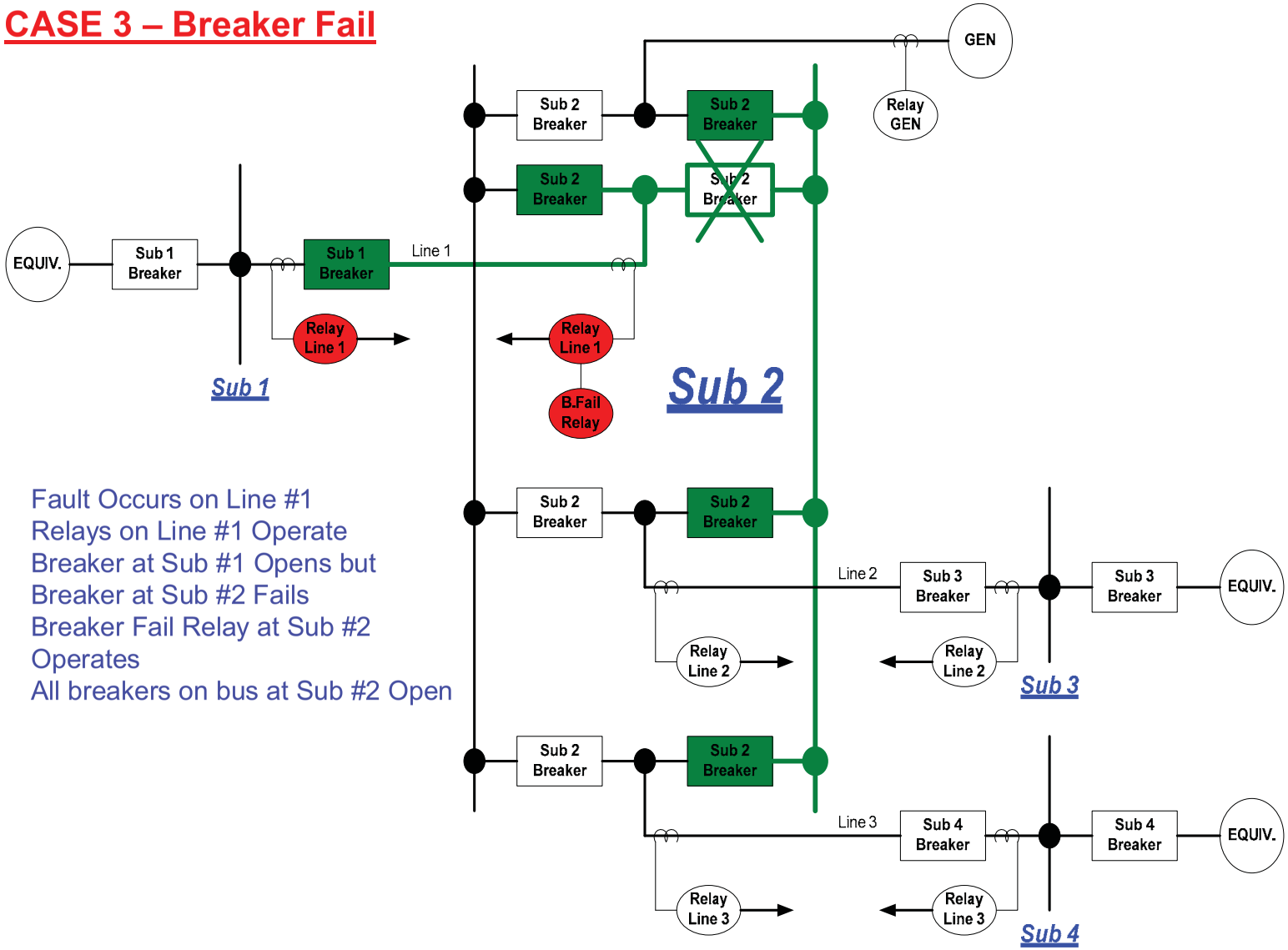

1. Fault Occurs on Line #1
2. Relays on Line #1 Operate
3. Breaker at Sub #1 Opens but Breaker at Sub #2 Fails
4. Breaker Fail Relay at Sub #2 Operates
5. All breakers on bus at Sub #2 Open

Simplified System One Line

(Note: Sub #2 has more detail)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Jonathan Sykes	
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment: Reword to: Transmission planning period that covers years six or beyond.**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☐Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that	☐Agree.

cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Do not agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.

- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☐
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☐
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☐

Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☐
Comment:

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	The time to adjust the system needs to be provided (when does a N-1-1 become a N-2?). If the cause of the outage is transient (temporary) the operator needs some time to test and restore the element (could be minutes up to several hours). If the element is lost indefinitly, the operator will need some minimum time to adjust the system. If this time is not available prior to the next N-1 then the standard should allow Non-Consequetial Loss of Load.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	same as Q21
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	same as Q21

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance

requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	The time to adjust the system needs to be provided (when does a N-1-1 become a N-2?). If the cause of the outage is transient (temporary) the operator needs some time to test and restore the element (could be minutes up to several hours). If the element is lost indefinitly, the operator will need some minimum time to adjust the system. If this time is not available prior to the next N-1 then the standard should allow Non-Consequetial Loss of Load. Some distinction needs to be made the amount of generation connected at a single point on the BES. a wind farm might have many small generators connected to the BES with an aggregate total of 300Mw or more. This requirement will should only apply to generating sources that might be connected to the BES through a single transformer (i.e. wind farm) with minimum agregate total of 300MW (for N-1).
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	same as Q26.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission	☐Agree. ☒Do not agree.	same as Q26.

[1] System adjustment can be manual or automatic

circuit		
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	same as Q26.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load

model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: The loss of transmission line (N-1) may require Gen drop to prevent instability or violation. Studies will need to be performed that study the congestion of generation and transmission cooridors and loss of various elements.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: As long as Non-Consequential Loss of Load is not a solution for single contingencies (N-1).

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Non-Consequential Loss of Load should not be allowed for single contingencies (N-1) and the system must remain stable with no violations.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: Non-Consequential Loss of Load should not be allowed for single contingencies (N-1) and the system must remain stable with no violations.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: The SDT should be commended for very good work at identifying many different issues of the TPL standards. However, TPL-001-1 should take into account the consequences of a Security-Based or Dependability-Based Misoperation (and failure) of the Protection System.

1) A Security-Based Misoperation of the Protection System may remove additional elements of the BES and could be listed in the table under "multiple contingency".

2) A Dependability-Based Misoperation (or Failure) of a non-redundant Protection System could cause long time delays in clearing faults and clear a large area of BES around the faulted Element. This type of failure may not provide local tripping or breaker failure initiation and remote Protection Systems would need to operate to isolate

the fault or disturbance. Often the operation of the remote Protection Systems would cause long time delays in isolating faults and disturbances.

a) The BES should be studied and those elements need to be identified where Dependability-Based Misoperations (or failures) would prevent meeting the performance requirements of Table 1 (Steady State) or Table 2 (Stability). This type of Misoperation (or Failure) will have to be included in the Tables.

For example, some parts of the BES may be able to survive long time delayed clearing of faults caused by Dependability-Based Protection System Misoperations (or failures) and still meet the performance requirements of the tables. But other parts of the BES may experience cascading outages for this same scenario. One solution to minimize the consequences of Dependability-Based Misoperations (or failures) is to install redundant Protection Systems. The redundant Protection Systems would reduce the possibility of a single Dependability-Based Misoperation (or failure) from affecting the isolation of faults and disturbances.

In addition, the TPL-001 standard will need definitions of Security-Based Misoperation and Dependability-Based Misoperation. The following definitions are used for PRC-004-WECC-1:

Security-Based Misoperation: The incorrect operation of a Protection System or RAS for faults or disturbances outside the intended zone of protection. Security is a component of reliability and is the measure of a device's certainty not to operate falsely.

Dependability-Based Misoperation: Any of the following:

☐ The absence of a Protection System or RAS operation when intended

☐ A Protection System or RAS equipment failure is alarmed or indicated to operating personnel.

☐ A Protection System or RAS equipment failure is discovered.

Dependability is a component of reliability and is the measure of a device's certainty to operate when required.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☒ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

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Frank Caston	Santee Cooper	SERC	01
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James M. Jackson	Santee Cooper	SERC	01

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment: Delete the phrase "and reactive resources." It is redundant.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: The term "mis-operation" introduces ambiguity into the definition, and should be deleted. The definition needs further clarification for consequential and non-consequential loads. For example, loads served downstream from the faulted element but not directly connected should also be considered to be consequential loads. A better name for this would be "direct load loss".**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: A number of the non-extreme events also have a low probability. Recommend change the word to "lower."**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment: It is suggested that another definition be added for "operations planning horizon".**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs	☐Agree.

through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Do not agree.
Q6. **Comment: A better name for this would be indirect load loss.**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Bulk Electric System deficiencies rather than needs should be evaluated. We do not agree that the planning assessment should include asset conditions and age. The age of equipment, if it is well maintained, has little impact on reliability. The term "and other factors" should be better defined or deleted.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Change to: "Events that are simulated or assessed to test the transmission system to ensure that performance requirements are met."**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: The definition should end at the semi-colon. The remaining part of the definition should be moved to the definition of "System Stability Study."**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: see Q9 above.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment: The last sentence in the above definition was not included in the definition listed in the draft standard, nor should it be.**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: These factors vary between areas and regions. In addition the TP should be allowed to assess an alternate sensitivity if they can document that it is more appropriate,

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: The standard may offer guidance but what constitutes a "reasonably stressed" case should be left to the discretion of the entity performing the study, since they are the best judge of what stresses the system.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐

Comment: The entity performing the studies should be allowed to determine the appropriate sensitivity studies that need to be evaluated. An alternate approach is to include pre-existing system conditions that additionally stress the system during the contingencies under study so as to verify that stability is preserved under conditions that go beyond those envisioned for the contingency. Stability studies are more time consuming than conventional power flow studies. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: We concur with the current approach.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: It should be included if it is a tool made available to the TP for this purpose, but only to the extent that it is considered controllable and quantifiable resource.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒
Comment: Re-testing should be required only where the correction may impact network flows. The study area should be determined by the TP. The TP has the most knowledge of how the system responds to changes. The majority of transmission projects consist of the upgrading of terminal equipement or conductor on one or more branches. The only significant change that such upgrade work would change in a powerflow model would be that of the branch (facility) ratings would change. It is not necessary to rerun powerflow simulations for such cases, as it can be determined by inspections whether the upgrade work would be sufficient to move the facility rating above the expected normal or contingency flow.

We agree that the Planning process should ensure that corrective actions for a particular defeciency do not lead to other deficiencies. However, the process for ensuring this is not necessarly The development of new study cases which include facilities comprising the corrective action plan and the suscetesting is not needed.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒

Comment: The goal is to meet the system performance requirements outlined in the standard. Whether a project is proposed or committed is irrelevant. R2.7.3 should be deleted.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒

Comment: The goal is to meet the system performance requirements outlined in the standard. Whether a project is proposed or committed is irrelevant. R2.7.4 should be deleted.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	We do not agree with the concept of non-consequential load loss. To maintain system reliability, the disconnect of any load should be allowed.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another	☐Agree. ☒Do not agree.	We do not agree with the concept of non-consequential load loss. To maintain system reliability, the disconnect of any load should be allowed.By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a

Transmission circuit		problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**

Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	The event should be tested for ensuring or maintaining reliability of the BES, however direct load loss should be allowed.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	Same comment as question #26.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	Same comment as question #26.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☒Do not agree.	Same comment as question #26.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☒
Comment: AC and DC contingency events should be treated the same.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

[1] System adjustment can be manual or automatic

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: The transmission planner should have discretion to consider the appropriate number of units to be tripped based on the station design, and/or relay design.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: The characterisitics of detailed induction load are generally lacking to properly model induction loads. Load modeling should be left to the judgement of the TP.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Any adjustments should be allowed that protects the reliability of the BES.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Generator runback schemes should be able to be implemented before emergency thermal rating time limits are exceeded.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: There should be no stability impacts, and system security must be maintained. RAS or SPS should meet the same criteria as any protection system.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: There should be no stability impacts, and system security must be maintained. The requirements are outlined in PRC-015,016, and 017.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment: The proposed standard as well as the existing standards, makes no distinction between firm (network resource) and non-firm (energy only) generation. The standards should clearly state that the standard does not apply to non-firm generation.

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: Transmission Planners are currently able to maintain adequate levels of reliability using the existing TPL-001 thru TPL-004 standards. While incremental improvements can be made, it is not evident that prescribing more stringent planning requirements will result in significant reliability improvements.

Table 1 in the column titled "Interruption of Firm Transfer Allowed," does it pertain to point-to-point only, or does it also apply to network loads? Please explain how this provision is consistent with the requirement to re-dispatch to address system constraints.

There are no explicit performance requirements for normal system performance.

Requirement R1.1.2 refers to "normal weather patterns as agreed to by the Planning Coordinator(s) and the Transmission Planner(s)…" The standard and the ERAG MMWG need to be made consistent.

Requirement R2.3 There are no performance requirements for Short Circuit Studies.

Requirement R2.7.1.1 specifies a "project initiation date". This information is not needed for system reliability purposes.

Requirement R3.2. There should be some flexibility for simulation of planning events. For certain areas of the BES, the resulting configuration after operator intervention could be more severe than the removal of all elements. For example, the operation of a transmission line with one end open may be more severe than opening both ends of the line. This respresents actual operation in order to restore service to stations on the line.

Requirement R3.3.2.1 requires an evaluation for "Consequential Load loss (expected maximum demand and expected duration). Load loss is not an ERO responsibility.

Requirement R3.3.2.2 does not permit the "shedding of firm Load or curtailment of firm transfers". This is not an ERO responsibility.

Requirement R3.6 states "Manual and automatic generation tripping is allowed for multiple Contingencies and for single Contingencies only in situations that meet all of the following conditions: TBD. Generators should be allowed to trip for single and multiple contingencies as long as Facility Ratings are not exceeded. In addition, generators should be allowed to trip for any condition that imperils the generator. System performance should be the criteria, not generator operating state.

Requirement R4.2 states "Contingency analyses shall simulate the removal of all elements including those that the System protection is expected to disconnect for each Contingency without operator intervention." Delete "including those".

Requirement R4.6.1 states that Plant Stability studies "Shall be performed for individual generating units 20 MW or greater…" Does this mean that studies must be performed for all units? Many plants have "sister units" that are essentially the same. This requirement seems to be excessive.

The R1 requirements should be deleted from this standard and should remain on the MOD standards. (MOD-010, MOD-012, and MOD-018)

Requirement R4.6.2 states that Plant Stability studies "Shall be performed for changes in the real power output of a generating unit by more than 10% of the existing capability or more than 20 MW whichever is greater." The meaning of this wording is unclear.

Requirement R4.6.3 states that Plant Stability studies "Shall be performed and evaluated for those Planning Events that would produce more severe System impacts and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. The identified Contingencies, at a minimum, shall be evaluated." The use of "evaluation/evaluated is unclear. Is an evaluation the same as performing a study? If not, what does it mean to select a contingency for evaluation?

The standard needs to define or describe the difference between a "bus" and a "bus section".

Table I, P3, P7.2, P9.6 and Table 2, P7 need some punctuation for clarification.
Table I, P9.6 and Table 2, P9, why study replacing an outaged transformer with a spare?

The use of the terms "bus", "non-tie bus", and "bus section" are not clear. In P7-2 what is meant by the phrase or a bus and a stuck non-bus tie breaker ? Does this imply a bus or a bus section? How would you model this?

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☒ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: What is meant by directly connected? Local area network load is allowed to be shed in Saskatchewan. The Saskatchewan Regulatory Jurisdiction has no plans to change this unless there is technical evidence to justify the increase in reliability.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Suggest that the definition be changed to state "lower probability of occurrence than Planning Events."**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding,	☐Agree. ☒Do not agree.

or Special Protection Systems.	
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: What is the intent "and other factors, such as asset condition and age"? Seems to broad and outside the scope of NERC. Remove it.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: Unnecessary micro-management of the planning process in the Saskatchewan Regulatory Jurisdiction.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance

including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒
Comment:

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material

changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	The SDT should justify that the benefit to customers of this increased reliability justifies the cost.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: The SDT should justify that the benefit to customers of this increased reliability justifies the cost.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: The SDT should justify that the benefit to customers of this increased reliability justifies the cost.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	Local area network load is allowed to be shed in Saskatchewan. The Saskatchewan Regulatory Jurisdiction has no plans to change this unless there is technical evidence to justify the increase in reliability. The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	Local area network load is allowed to be shed in Saskatchewan. The Saskatchewan Regulatory Jurisdiction has no plans to change this unless there is technical evidence to justify the increase in reliability. The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	Local area network load is allowed to be shed in Saskatchewan. The Saskatchewan Regulatory Jurisdiction has no plans to change this unless there is technical evidence to justify the increase in reliability. The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above	☐Agree. ☐Do not agree.	

[1] System adjustment can be manual or automatic

300 kV		

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: Why is this concept not applied to AC tie-lines between systems, whether single or multiple? In Saskatchewan's case there is very little difference.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: What is the purpose of requiring this event or any other extreme event to be studied? We see little benefit in this. In the Saskatchewan context we accept the risk and consequences for extreme events as there is usually very little justification for the increase in reliability versus the economic cost. Saskatchewan plans and designs its system to fail safe in those events and restores the system thereafter.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: The amount of generation change should be limited to the amount that can be accomplished within the allowed readjustment period. Due consideration should be given to start up time and ramp rates of the units. Generation rejection should not exceed the normal operating reserve.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment:
Several generation run back or generation rejection schemes are used in Saskatchewan to restore facility loading to with normal ratings. The costs of not using these schemes would involve substantial increased investments and environmental impacts unacceptable in the Saskatchewan Regulatory Jurisdiction. Conditions are

determined on a case by case basis. However, the generation runback or generation rejection scheme should not exceed the normal operating reserve.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Delegate this issue to the Planning Coordinators.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: Delegate this issue to the Planning Coordinators.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☐ No ☐
Comment: Saskatchewan commends the SDT for taking on this difficult and important task. We wish you good fortune.

Local area network load is allowed to be shed in Saskatchewan for single contingencies, and the interruption of firm transfers are allowed over our DC tie and AC tie-lines. The Saskatchewan Regulatory Jurisdiction has no plans to change this unless there is technical evidence to justify the increase in reliability versus the cost.

Also for P9-1, is there any justification for the selection of one mile? If there is none the development of exemption criterion should be delegated to the Planning Coordinator. It is not what Saskatchewan has used in designing its system, and it is going to involve a significant capital outlay for Saskatchewan with questionable reliability benefits.

Saskatchewan will not support the default value of 1 mile unless there is a technical study (including reliability benefit versus cost) to support it as opposed to any other distance.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Scott Inglebritson	
Organization:	Seattle City Light	
Telephone:	206-684-3491	
E-mail:	scott.inglebritson@seattle.gov	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☒	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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Background

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A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

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Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☒Agree. ☐Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: List specific types of failures or direct us to a specific table which describes planning events.**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☒Do not agree.
Q9. **Comment: "...in the vicinity of the plant..." needs to be more specific. How far away must we study?**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☒Do not agree.
Q11. **Comment: Base cases are developed and studied for seasons, not calendar years. Can the the Year One reference be changed to "the year beginning at the next Winter season" instead of the specific "...next calendar year"?**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: Sensitivity studies should be performed at a level higher than LSE or BA. It seems more appropriate for a RC or RRO to determine regional contingencies.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☒ No ☐
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: Conditions six years or more in the future are unpredictable and sensitivity studies would provide results of limited usefulness.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance

including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: Sensitivity studies should be adequate to determine the study area. Starting at the corrective facility, work out bus by bus, determining sensitivity to the facility's loss. Boundaries of the study area would be defined at buses where loss sesitivity is (for example) 1% or less.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: Since compliance with performance guidelines is mandated, aren't all projects defined in the corrective action plans "committed" projects? Proposed projects in the context of Requirement 2.7 should only exist in the studies to determine which remedial solution(s) comprise the Corrective Action Plan.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment: To agree with the comment in Q18, the requirement should read "Corrective Action Plans shall not be modified without documentation to show that the revised plan meets the performance requirements."

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Loss of two major HV elements can drive our region into undervoltage conditions, forcing us to shed non-consequential load per UVLS standard requirements.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	Same as Q21, loss of elements of this size may initiate UVLS.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	Same as Q21.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: Adequacy of HV supply is outside of our control but may have a detrimental effect on our system. We should not be required to supplement the existing high-voltage infrastructure when it is the responsibility of the transmission owner. If the intent of this requirement is to prevent downstream load loss caused by a fault in the 300kV beloning to the transmission owner, then we agree. We must be able to shed load when our supply is cut.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: As in Q24. Certain combinations in the HV supply system will force us to shed load.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	

[1] System adjustment can be manual or automatic

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: Otherwise, we need reserve transfer capacity equal to the total of the firm transfers, which is not very cost effective!

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Any adjustment required to respond to a contingency should be allowed, unless it adversely impacts the regional system.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Runback should be allowed to prevent a possible cascading outage which might result from the thermal overload, but only to that level needed to protect the equipment, to address the contingency, or to prepare for the next contingency. If the runback level is lower than the normal rating, it should be shown that this runback will not harm the stability of the system.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐

Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: All RAS or SPS schemes should be evaluated to determine the impact on the interconnected system. Actions that derate transfer paths should not be allowed unless essential to protecting equipment or anticipating the next contingency.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: Actions should be intended to address contingency, prevent damage, or prepare for next contingency.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: The additional studies required by this proposed standards are going to put a burden on our utility. We do not have the additional human resources available to perform so much additional work. Also, the stipulation that no "non-consequential load" loss may occur will put a financial burden on our utility. We have always planned assuming that we would able to be shed residential load in case of an emergency caused by a N-2 event or regional outage beyond our control.

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Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
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Group Comments (Complete this page if comments are from a group.)

Group Name: **SERC EC Dynamics Review Subcommittee (DRS)**

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Anthony Williams	Duke Energy Carolinas	SERC	1
Sujit Mandal	Entergy	SERC	1
John O'Connor	Progress Energy Carolinas	SERC	1
Bob Jones	Southern Company Services, Inc. - Trans	SERC	1
Lee Taylor	Southern Company Services, Inc. - Trans	SERC	1
Tom Cain	Tennessee Valley Authority	SERC	1

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Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: Add the following to the end of the definition: "or unintentional load lost as a direct result of the event (e.g. load dropout due to low voltages as a result of a fault)."**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: A number of the non-extreme events also have a low probability. Recommend change the word to "lower." The definition for "Extreme Events" should reference Table 1.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs	☒Agree.

through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Delete the word "needs" and the phrase "such as asset conditions and age." We do not agree that the planning assessment should include asset conditions and age. The age of equipment, if it is well maintained, has little impact on reliability.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Delete the term "the effect on the System of." The reference to "System" causes confusion with the term "System Stability Study."**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the

requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: The entity performing the studies has the best system specific knowledge to select the appropriate sensitivities that needs to be evaluated.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: The entity performing the studies has the best system specific knowledge to determine what constitutes a reasonable stressed case.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment: Use of sensitivity studies is appropriate only for System Stability Studies.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: We agree that sensitivity studies should not be required for the Long-Term..

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2

will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☐
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☐
Comment:

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost. It would be helpful if "bus tie breaker" was defined (e.g. is the middle breaker in a breaker and a half scheme considered a bus tie breaker?).

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

[1] System adjustment can be manual or automatic

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☒
Comment: DC and AC contingency events should be treated the same.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: This question conflicts with Table 2 Extreme Event 9. However, we feel it is not necessary to simulate loss of all units at a station because simultaneous loss of all units is unlikely.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☒
Comment: In general this is a good practice. Dynamic studies of seasonal load conditions should include the effects of induction motors, and particularly in areas where traditional load models have indicated a problem. Unfortunately, there is a lack of data to support the amount and characteristics of the detailed induction load models in many areas. In addition to the consideration of the dynamic effects of induction motor loads, the effects of static capacitor banks installed at distribution voltage levels would need to be considered as well. Prior to making this a requirement in the reliability standards, the industry needs guidance as to how this data should be developed and maintained for models in future years. A long term transition period is required to incorporate motor models into dynamics studies.

Note that meeting such a requirement would necessitate a significant increase in the dynamic data needed to represent the system. Maintenance of such load model data would require significant resources. Load characteristics valid for a near term model might not be valid for future years.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Manual and automatic adjustments should be allowed for single and multiple contingencies as long as performance requirements are met.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☒
Comment: The question is not clear. Generation runback schemes are acceptable as long as emergency ratings are not violated. Runback schemes should not be used to restore an element to within emergency ratings.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: no limitations

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: no additional conditions except meeting performance requirements.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: In the Stability Performance Table, under contingency P8 with a line out add a generator contingency. and with a transformer out add a generator and a line contingency.

In the Stability table change the Extreme events numbering to E1, E2, etc.

In R4.6 and other locations, the generator exemption of 20 MW should be increased to 75 MVA.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: **SERC EC Planning Standards Subcommittee**

Lead Contact: **Travis Sykes**

Contact Organization: **Tennessee Valley Authority**

Contact Segment: **1**

Contact Telephone: **423-751-4162**

Contact E-mail: **tssykes@tva.gov**

Additional Member Name	Additional Member Organization	Region*	Segment*
Darrell Pace	Alabama Electric Coooperative	**SERC**	1
John Sullivan	Ameren	SERC	1
Charles Long	Entergy	SERC	1
David Weekley	MEAG Power	SERC	1
Allen McKee	Midwest ISO (MISO)	SERC, MRO, RFC	2
Pat Huntley	SERC Reliability Corp	SERC	10
Phil Kleckley	SC Electric and Gas	SERC	3
Bob Jones	Southern Company Services	SERC	1

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the

rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: The term "mis-operation" introduces ambiguity into the definition, and should be deleted. The definition needs further clarification for consequential and non-consequential loads. For example, loads served downstream from the faulted element but not directly connected should also be considered to be consequential loads.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: A number of the non-extreme events also have a low probability. Recommend change the word to "lower." The definition for "Extreme Events" should reference Table 1.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	

Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Bulk Electric System deficiencies rather than needs should be evaluated. We do not agree that the planning assessment should include asset conditions and age. The age of equipment, if it is well maintained, has little impact on reliability.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Change to: "Events that are simulated or assessed to test the transmission system to ensure that performance requirements are met."**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment: Change "System" to "Bulk Electric System." Need a definition for "plant."**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment: Change "System" to "Bulk Electric System."**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment: The last sentence in the above definition was not included in the definition listed in the draft standard, nor should it be.**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: The entity performing the studies should be allowed to determine the appropriate number of cases that need to be evaluated.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: The standard may offer guidance but what constitutes a "reasonably stressed" case should be left to the discretion of the entity performing the study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment: The entity performing the studies should be allowed to determine the appropriate sensitivity studies that need to be evaluated. An alternate approach is to include pre-existing system conditions that additionally stress the system during the contingencies under study so as to verify that stability is preserved under conditions that go beyond those envisioned for the contingency. Stability studies are more time consuming than conventional power flow studies. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: We concur with the current approach.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: It should be included if it is a tool made available to the TP for this purpose, but only to the extent that it is considered firm.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: Re-testing should be required only where the correction may impact network flows. The study area should be determined by the TP. The TP has the most knowledge of how the system responds to changes.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: The goal is to meet the system performance requirements outlined in the standard. Whether a project is proposed or committed is irrelevant.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: see answer to Q18.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	see Q20 above.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	see Q20 above.
Q23. P5-3: For facilities	☐Agree.	see Q20 above.

above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: see Q20 above.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: see Q20 above.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	

[1] System adjustment can be manual or automatic

Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Generator protection is designed to trip only those units required. In addition, it is the magnitude of generation tripped rather than the number of units tripped that is of the greatest significance to the stability of the grid.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒

Comment: Dynamic studies of seasonal load conditions should include the effects of induction motors, and particularly in areas where traditional load models have indicated a problem. Unfortunately, there is a lack of data to support the amount and characteristics of the detailed induction load models in many areas. In addition to the consideration of the dynamic effects of induction motor loads, the effects of static capacitor banks installed at distribution voltage levels would need to be considered as well. Prior to making this a requirement in the reliability standards, the industry needs guidance as to how this data should be developed and maintained for models in future years.

Note that meeting such a requirement would necessitate a significant increase in the dynamic data needed to represent the system. Maintenance of such load model data would require significant resources. Load characteristics valid for a near term model might not be valid for future years. Also, summer peak load, winter peak load, and off-peak load characteristics would differ.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Adjustments that should be allowed are those that can be performed in time to prevent the system from failing to meet performance requirements. These adjustments may include automatic voltage regulator action, governor action, generator runback, and generator tripping.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that

must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: The generator runback scheme should complete its action within the time allowed by the emergency ratings of elements that exceed their normal thermal ratings.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: RAS or SPS should meet the same criteria as any protection system.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: The conditions required by SPS standards (PRC).

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: Significant Increase in Study Activity Workload on Transmission Planners: The increase in both steady state and dynamic studies required to ensure compliance with the proposed standards will result in increased costs and staff additions. The addition of the "Corrective Action Plan" requires the TP to provide a significant amount of documentation for each deficiency identified by the studies. Also, R3.2 requires that the studies simulate the protection scheme for all events. The current software tools cannot automate these studies for bus faults and breaker failure events, requiring each scenario to be studied manually. Additionally, experienced staff capable of performing analyses

as described in the proposed standard have become increasingly difficult to find and retain and the talent pool of people with these skills has recently become depleted to alarming levels.

Implementation Plan:
Given the intent of the proposed standard to encourage large scale investment in the EHV system, full implementation will take years, perhaps decades. Acquirement of right-of-way for new EHV lines has become increasingly difficult in recent years and inreasingly expensive. Legal, regulatory, and other difficult issues often take several years to navigate, even for 115kV lines. The Implementation Plan timeframe, if set too short, would be unduly burdensome on Transmission Owners forcing them to be less dicretionary with funds than would be prudent. The proposed implementation plan should include provisions for those cases where viable solutions simply can not be implemented in time due to circumstances beyond the control of Transmission owners. We recommend a minimum of 15 years for the transition.

Design and Construction Constraints:
Even if right-of-way and other legal and regulatory hurdles are cleared, and the capital funding for such a tremendous level of investment was not an issue, the other resources required to actually construct the projects are equally difficult and costly to secure. Raw material prices on comodities like copper and steel have skyrocketed in recent years. Additionally, the skilled labor and Engineering resources are constrained with labor rates almost keeping up with other resource costs. Overall project costs have more than doubled over the last 7-10 years. Recent press releases concerning new generation being planned and then scrapped due to the rapid escalation of project costs are public evidence of this. The inflationary mark-up is impossible to estimate but much less will be built with the same capital investment than is currently envisioned.

Cost-Benefit Analysis:
The proposed standard will be exceedingly expensive to become compliant with unprecedented levels of capital investment in Transmission facilities. Before the standard comes to official vote, it would be prudent for a cost-benefit analysis to be performed to determine if the reliability improvements truly justify the huge expenditures certain under the proposed standard. Additionally, as many jurisdictional rate structures share the cost of such investments between retail and wholesale customers, cost-benefit analyses should be completed for both retail and wholesale customers.

System Adjustment Clarification:
The term "System Adjustment" as outlined in the tables should be better defined. The use of generation for redispatch may have nuances which preclude or otherwise limit their use for studies. Perhaps some clearer guidelines on what is allowed would facilitate transparency and coordination between Transmission Planners.

Transmission Service Evaluation:
A major concern is that the proposed standard appears to be disjointed from the requirements for selling firm Transmission Service. The increase in reliability gained from the proposed standard would, in some regions, quickly be eroded by new firm sales if those sales are based on the historical N-1 ATC requirements. The proposed standard must be applied to long-term firm transmission service requests if Transmission reliability is to be truly enhanced. If the standard is not applied to Transmission Service evaluation, reliability levels for the different classes of firm customers will diverge.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: **SERC EC Reliability Review Subcommittee (RRS) and SERC OC Operations Planning Subcommittee (OPS)**

Lead Contact: **James E. (Jim) Peterson, RRS Chair**

Contact Organization: **South Carolina Public Service Authority**

Contact Segment: **1**

Contact Telephone: **(843) 761-8000 x5201**

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Additional Member Name	Additional Member Organization	Region*	Segment*
Curtis Stepanek	Ameren	**SERC**	1
Brian D. Moss	Duke Energy Carolinas	SERC	1
Kham Vongkhamchanh	Entergy	SERC	1
Ken Wofford	Georgia Transmission Corp.	SERC	1
Denise Roeder	NC Municipal Power Agency #1	SERC	3
Al McMeekin	SC Electric & Gas Company	SERC	1
Clay Young	SC Electric & Gas Company	SERC	3
Rod Hardiman	Southern Company Services, Inc. - Trans	SERC	1
Ian Grant	Tennessee Valley Authority	SERC	1
Marjorie Parsons	Tennessee Valley Authority	SERC	1
Carter Edge	SERC Reliability Corporation	SERC	10
Maria Haney	SERC Reliability Corporation	SERC	10
Eugene Warnecke	Ameren	SERC	1
Chris Bradley	Big Rivers Electric Corporation	SERC	1
Jerry Tang	Municipal Electric Authority of Georgia	SERC	1
Phil Creech	Progress Energy Carolinas	SERC	1
Doug McLaughlin	Southern Company Services, Inc. - Trans	SERC	1
Michael Clements	Tennessee Valley Authority	SERC	1

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the

rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment: Delete the phrase "and reactive resources."**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: The term "mis-operation" introduces ambiguity into the definition, and should be deleted. The definition needs further clarification for consequential and non-consequential loads. For example, loads served downstream from the faulted element but not directly connected should also be considered to be consequential loads. A better name for this would be "Planned Load Loss."**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: A number of the non-extreme events also have a low probability. Recommend change the word to "lower."**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment: It is suggested that another definition be added for**	

"operations planning horizon".	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: A better name for this would be "Unplanned Load Loss". Load loss that occurs from UFLS, UVLS, load shedding or SPS should be moved to Planned Load Loss. Unplanned load loss would be all other load loss other than planned.**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Bulk Electric System deficiencies rather than needs should be evaluated. We do not agree that the planning assessment should include asset conditions and age. The age of equipment, if it is well maintained, has little impact on reliability. The term "and other factors" should be better defined or deleted.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Change to: "Events that are simulated or assessed to test the transmission system to ensure that performance requirements are met."**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: The definition should end at the semi-colon. The remaining part of the definition should be moved to the definition of "System Stability Study."**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: see Q9 above.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment: The last sentence in the above definition was not included in the definition listed in the draft standard, nor should it be.**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: These factors vary between areas and regions. In addition the TP should be allowed to assess an alternate sensitivity if they can document that it is more appropriate,

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: The standard may offer guidance but what constitutes a "reasonably stressed" case should be left to the discretion of the entity performing the study, since they are the best judge of what stresses the system.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐

Comment: The entity performing the studies should be allowed to determine the appropriate sensitivity studies that need to be evaluated. An alternate approach is to include pre-existing system conditions that additionally stress the system during the contingencies under study so as to verify that stability is preserved under conditions that go beyond those envisioned for the contingency. Stability studies are more time consuming than conventional power flow studies. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: We concur with the current approach.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: It should be included if it is a tool made available to the TP for this purpose, but only to the extent that it is considered firm.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒
Comment: Re-testing should be required only where the correction may impact network flows. The study area should be determined by the TP. The TP has the most knowledge of how the system responds to changes.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: The goal is to meet the system performance requirements outlined in the standard. Whether a project is proposed or committed is irrelevant. R2.7.3 should be deleted.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒

Comment: The goal is to meet the system performance requirements outlined in the standard. Whether a project is proposed or committed is irrelevant. R2.7.4 should be deleted.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Q22. P5-2: For facilities above 300 kV, loss of a	☐Agree.	By not allowing non-consequential load loss, utilities will incur significant

Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Do not agree.	expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	It is agreed that this event should be tested for maintaining reliability of the BES, however planned load loss should be allowed.
Q27. P4-2: Loss of a	☐Agree.	same comment as for Q26.

[1] System adjustment can be manual or automatic

generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	same comment as for Q26.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☒Do not agree.	same comment as for Q26.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☒
Comment: DC and AC contingency events should be treated the same. The question is somewhat obscure.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒

Comment: It is not necessary to simulate loss of all units at a station. The Transmission Planner or Planning Authority should have the discretion to consider the appropriate number of units to be tripped based on station design, relay design, etc.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: There is a lack of data to support the amount and characteristics of the detailed induction load models in many areas. Transmission planners should be able to use the latest information and techniques.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Any adjustments should be allowed that protects the reliability of the BES.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that

must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: RAS or SPS should meet the same criteria as any protection system.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: The requirements are outlined in PRC-015, 016, and 017.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment: Not currently aware of any.

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment:
Cost-Benefit Analysis:

Transmission Providers are currently able to maintain adequate levels of reliability using existing standards. While incremental improvements can be made, it is not evident that prescribing more stringent planning requirements will necessarily result in signifcant reliability improvements.

The proposed standard will be exceedingly expensive to become compliant with unprecedented levels of capital investment in Transmission facilities. Before the standard comes to official vote, it would be prudent for a cost-benefit analysis to be performed to determine if the reliability improvements truly justify the huge expenditures under the proposed standard.

In Table 1 in the column titled "Interruption of Firm Transfer Allowed," does it pertain to point-to-point only, or does it also apply to network loads? Please explain how this provision is consistient with the requirement to re-dispatch to address system constraints.

The terms "Consequential Load Loss" and "Non-consequential Load Loss" should be deleted and Table 1 should be modified to discuss "Planned Load Loss" and "Unplanned Load Loss". It should not matter if the load is directly connected to the failed facility or downstream and served by the failed facility. If the plan to protect the interconnected grid is to disconnect those loads using a manual process or an automatic scheme, then it should be allowed.

The R1 requirements should be deleted from this standard and should remain in the MOD standards.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: **Transmission Planning**

Lead Contact: **Philip Kleckley**

Contact Organization: **South Carolina Electric & Gas**

Contact Segment: **3**

Contact Telephone: **803-217-2045**

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Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: "Consequential Load Loss" should be termed "Intentional or Planned Load Loss". Not only should direct connected load loss be included, but loads served by or downstream from the faulted element, that is not directly connected to the faulted element, should also be included.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.

Q6. **Comment: This term is not needed. See comments on "Consequential Load Loss/Intentional Load Loss".**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Bulk Electric System deficiencies rather than needs should be evaluated.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Prefer alternate language, "Events for which Transmission system performance requirements must be met."**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: The standard may offer guidance but the entity performing the sensitivity studies should be able to determine the number of cases required.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: The standard may offer guidance but what constitutes a "reasonably stressed" case should be left to the discretion of the entity performing the study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒
Comment: Stability studies examine generator and system responses to specific conditions. Because the exact system conditions can not be determined in advance, the sensitivity analysis may not be very useful. In addition, stability studies are more time consuming than conventional power flow studies. A preferred approach is to include pre-existing system conditions that additionally stress the system during the contingencies under study so as to verify that stability is preserved under conditions that go beyond those envisioned for the contingency.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This

Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: It should be included if it is a tool made available to the TP for this purpose, but only to the extent it is considered firm.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: Re-testing should be required only where the correction may impact network flows. The study area should be determined by the TP.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: The goal is to meet the system performace requirements outlined in the standard. Whethter a project is proposed or committed is irrelevant.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: See answer to question #18.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the

requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	SCE&G does not agree with the concept of non-consequential load loss. To maintain system reliability, the disconnect of any load should be allowed. If not allowed, unprecedented new transmission costs will be required. These costs will be for local area improvements and will NOT result in increased transfer capabilities for markets.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	See answer to #20.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	See answer to #20.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment	☐Agree. ☒Do not agree.	See answer to #20.

followed by loss of another transformer		

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: See answer to #20.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: See answer to #20.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	Planned load loss should be allowed.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	Planned load loss should be allowed.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	Planned load loss should be allowed.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above	☐Agree. ☒Do not agree.	Planned load loss should be allowed.

[1] System adjustment can be manual or automatic

300 kV		

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☒
Comment: General there should be no difference between AC and DC; however, the answer to this question depends on the contractual arrangements associated with the transfer.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Generator protection is designed to trip only those units required. In addition, it is the magnitude of generation tripped rather than the number of units tripped that is of the greatest significance to the stability of the grid.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒

Comment: There should be an attempt to represent the dynamic behavior of induction motor loads in the generic system load representations. However, the state of induction motor load modeling is not adequate to permit discrete induction motor load models.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Adjustments that should be allowed are those that can be performed in time to prevent the system from failing to meet performance requirements. These adjustments may include automatic voltage regulator action, governor action, and generator runback.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: The generator runback scheme should complete its action within the time allowed by the emergency ratings of elements that exceed their normal thermal ratings.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: A RAS or SPS should be allowed for single contingencies if its failure or misoperation can be compensated for during the time allowed by the emergency ratings of the elements that exceed their normal thermal ratings.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: RAS or SPS should meet the same criteria as any protection system.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: The conditions required by SPS Reliability Standards.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: General Comment. Cost/Benefit analyses should be conducted on each change in a standard or new standard.

Requirement 7.2 will require a 2 bus outage test on the SCE&G transmission system. Most of our busses are straight busses and a stuck line-terminal breaker will result in a clearing of the connected bus (and all facilities connected to that bus). Our read of this requirement is that we must design the system to accommodate a stuck breaker event (outaging all connected facilities) while a different bus (and all of its connected facilities) is already outaged. This is a significant leap in the required performance of our system and will result in tremendous unwarranted costs and years of new local area transmission construction.

Requirement R1.1.2 refers to "normal weather patterns as agreed to by the Planning Coordinator(s) and the Transmission Planner(s)…" The ERAG MMWG considers normal weather to be such that the weather affected load to be that which has a 50%

probability of, plus or minus. The standard and the ERAG MMWG need to be made consistent.

Requirement R2.7.1.1 specifies a "project initiation date". This information is not needed for system reliability purposes.

Requirement R3.3.2.1 requires an evaluation for "Consequential Load loss (expected maximum demand and expected duration). Load loss is not an ERO responsibility.

Requirement R3.3.2.2 does not permit the "shedding of firm Load or curtailment of firm transfers". This is not an ERO responsibility.

Requirement R3.6 states "Manual and automatic generation tripping is allowed for multiple Contingencies and for single Contingencies only in situations that meet all of the following conditions: TBD. Generators should be allowed to trip for single and multiple contingencies as long as Facility Ratings are not exceeded. In addition, generators should be allowed to trip for any condition that imperils the generator. System performance should be the criteria, not generator operating state.

Requirement R4.2 states "Contingency analyses shall simulate the removal of all elements including those that the System protection is expected to disconnect for each Contingency without operator intervention." Delete "including those".

Requirement 4.6.1 states that Plant Stability studies "Shall be performed for individual generating units 20 MW or greater…" Does this mean that studies must be performed for all units? Many plants have "sister units" that are essentially the same. This requirement seems to be excessive.

Requirement 4.6.2 states that Plant Stability studies "Shall be performed for changes in the real power output of a generating unit by more than 10% of the existing capability or more than 20 MW whichever is greater." The meaning of this wording is unclear.

Requirement 4.6.3 states that Plant Stability studies "Shall be performed and evaluated for those Planning Events that would produce more severe System impacts and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. The identified Contingencies, at a minimum, shall be evaluated." The use of "evaluation/evaluated is unclear. Is an evaluation the same as performing a study? If not, what does it mean to select a contingency for evaluation?

The standard needs to define or describe the difference between a "bus" and a "bus section" and ensure that the use of these terms in the standard are as intended.

Table I, P3, P7.2, P9.6 and Table 2, P7 need some punctuation for clarification.
Table I, P9.6 and Table 2, P9, why study replacing an outaged transformer with a spare?

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

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J. T. Wood	Southern Company - Transmission	SERC	1
Jim Viikinsalo	Southern Company - Transmission	SERC	1
Keith Calhoun	Southern Company - Transmission	SERC	1
Shih-Min Hsu	Southern Company - Transmission	SERC	1
Tom Sims	Southern Company - Transmission	SERC	1
Gary Gorham	Southern Company - Transmission	SERC	1
Dave Slovensky	Southern Company - Transmission	SERC	1
Jeremy Bennett	Southern Company - Transmission	SERC	1
Bob Jones	Southern Company - Transmission	SERC	1
Bill Botters	Southern Company - Transmission	SERC	1
Mike Bartlett	Southern Company - Transmission	SERC	1
Maryanne Mujica	Southern Company - Transmission	SERC	1
Lee Taylor	Southern Company -	SERC	1

	Transmission		
Perry Stowe	Southern Company - Transmission	SERC	1
Rod Hardiman	Southern Company - Transmission	SERC	1
Doug McLaughlin	Southern Company - Transmission	SERC	1
Randy Castello	Southern Company - Transmission	SERC	1
John Ciza	Southern Company - Generation	SERC	1
Chuck Chakravarthi	Southern Company - Transmission	SERC	1
Tom Higgins	Southern Company - Generation	SERC	5
Terry Crawley	Southern Company - Generation	SERC	5
Roger Green	Southern Company - Generation	SERC	5
Roman Carter	Southern Company - Transmission	SERC	1

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing

TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the	☐Agree. ☒Do not agree.

connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	
Q1. **Comment: As stated the definition does not appear to allow for equivalenced system representation since it refers to "each bus on the interconnected Transmission System". The words "as represented in the model" should be added after "interconnected Transmission System" or another sentence should be added stating that equivalenced system representation is acceptable. A definition of a dynamics base case should also be considered.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: This definition only relates to load that is "directly connected" to the specific element being removed. It does not allow for any load that may be or becomes radially connected through another branch that is not part of the facility removed. It does not make sense to not allow the loss of load that is actually electrically radial to the facility being outaged. The definition may work better as "Load that is no longer served because it is directly connected to or radially served through an element(s) that is removed from service due to fault clearing action." The word "mis-operation" is not needed in this definition because none of the contingency events use this term.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Recommend modifying the definition to read: "Events which are more severe than Planning events that are evaluated as required by TPL-001-1 Tables 1 and 2, in part, to identify potential Cascading Outages.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment: No Additional Comments.**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment: No Additional Comments.**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment: Agree assuming the change in Q2 is made.**	
Q7. **Planning Assessment:** Documented evaluation of future	☐Agree.

Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Do not agree.
Q7. **Comment: The term "needs" should be replaced by a term that more aptly describes what is being evaluated. The definition should be ended after the word "assumptions." We do not agree that the planning assessment should include asset conditions and age. The age of equipment, if it is well maintained, has little impact on reliability.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Change to, "Events that are simulated or assessed to test the transmission system to ensure that performance requirements are met as defined in TPL-001-1 Tables 1 and 2."**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment: No Additional Comments.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment: No Additional Comments.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: The last sentence in the above definition was not included in the definition listed in the draft standard, nor should it be.**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: This should not be a "one shoe fits all" exercise. It appears that at least one of these items listed is required even though they may not be the most appropriate ones for all entities. There should be the ability to perform other sensitivity analysis instead of these as long as the "rationale" is provided for the choice. The entity should be allowed to determine the appropriate sensitivity cases.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment:

See comment above. [This should not be a "one shoe fits all" exercise. It appears that at least one of these items listed is required even though they may not be the most appropriate ones for all entities. There should be the ability to perform other sensitivity analysis instead of these as long as the "rationale" is provided for the choice. The entity should be allowed to determine the appropriate sensitivity cases.]

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐

Comment: Some sensitivity analysis is reasonable.

Other comments:

1. The wording regarding transfer sensitivity for stability analysis should be the same as the wording used in steady state analysis "modification of expected transfers".

2. The list of sensitivities may not be the most appropriate for all entities. There should be the ability to perform other sensitivity analsysis instead of these as long as the "rationale" is provided for the choice.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment:

Yes, we concur with this approach.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒

Comment: It should not be a requirement that DSM be considered but DSM should be one of the allowable alternatives. The way the present standard is written, it is unclear whether "all" of the named items (except operating procedures with the "or" statement) are required to be considered or whether only one or more of the items need to be included. It is suggested that the following statement replace the word "including" in line two of R2.7.1: "that may include one or more of the following:". This should clarify that all of the items are not required to be in the action plan for compliance.

It also is not clear what the phrase "including the duration of interim Operating Procedure" means. Does this mean how many years you would anticipate using the Operating Procedure or does it mean how long it takes to "repair" the cause of the outage that necessitated the use of the Operating Procedure? Assuming that the meaning is the second one, the requirement to document the "mean time to repair" is new and there does not seem to be a very useful purpose for this requirement. As long as the system performance standards are met and the system is prepared for the next outage, what is the purpose of recording and documenting the length of time that you anticpate it to take to fix the problem? This is variable at best and does not provide useful information.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the

changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☒
Comment:
A properly conducted study should determine that the recommended Corrective Action Plan actually solves the problem and does not cause other problems. If not, it is not a Corrective Action Plan. What appears to be intended here is whether the combination of Corrective Action Plans interact with each other and create additional problems. In the conference call Mr. Odom stated that it was not the intent for "all" the corrective plans be put back into the cases and all of the simulations be redone but only look at local area analysis. If that is the case, what is necessary to be in compliance with R2.7.2 and what type of documentation is required? This is very unclear.

The study area should be determined by the TP. The TP has the most knowledge of how the system responds to changes.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment:
This requirement does not appear to have any major benefit, particularly coupled with R2.7.4 discussed in Q19. The standards require that an assessment be done every year and that the system must meet performance requirements or a Corrective Action Plan be developed. Therefore, if a project has been previously specified as a "committed" project, removing it and or replacing it with something else must also meet performance requirements under this standard or a violation occurs. Also, this performance of the system with the "committed" Corrective Action Plan" removed or modified must be documented. Therefore, requirement R2.7.4 is automatically met and is superfluous in the standard and should be removed. There is no benefit from the distinction between a project definition of "committed" and "proposed".

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment:
See comments for Q18. [This requirement does not appear to have any major benefit, particularly coupled with R2.7.4 discussed in Q19. The standards require that an assessment be done every year and that the system must meet performance requirements or a Corrective Action Plan be developed. Therefore, if a project has been previously specified as a "committed" project, removing it and or replacing it with something else must also meet performance requirements under this standard or a violation occurs. Also, this performance of the system with the "committed" Corrective Action Plan" removed or modified must be documented. Therefore, requirement R2.7.4 is automatically met and is superfluous in the standard and should be removed. There is no benefit from the distinction between a project definition of "committed" and "proposed".]

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar."

Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	By not allowing non-consequential load loss, utilities will incur significant expenditures. The marginal increase in reliability for this low probability event does not justify the huge costs involved.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	This is a very significant change in the performance requirements in this reliability standard. It involves facilities from 345 kV through 764kV which carry significant amounts of power. These also are facilities that require significant lead time to construct in the Southern Balancing Authority with estimates up to 7-10 years in the state of Georgia. If a performance problem is detected under these new requirements, it could take that long to come into compliance and at a very significant cost if a new major 500kV line is required. These facilities can run as much as $4.0 million a mile or more in urban areas. We understand that a few areas of the country presently have this requirement but most do not. In the areas where the requirement has not been in place, the reliability of the system has been acceptable to the local Public Service Commissions that have governed

		the service to Retail customers. There has been no evidence presented that there is a need for an increase in reliability, particulary at the extensive time delay and expense possible from this particular requirement. An adoption of this standard without such evidence can only be considered arbitrary and capricious at best. Increased reliability is, in general, a worthy goal where it is cost effective. It may be appropriate to adopt this type of reliability requirement for areas that deem the resulting reliability increase to be cost effective for their customers. But it is inappropriate to "require" everyone else to be forced to live under this arbitrarily developed expansion of reliability requirements.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	See comments for Q21. [This is a very significant change in the performance requirements in this reliability standard. It involves facilities from 345 kV through 764kV which carry significant amounts of power. These also are facilities that require significant lead time to construct in the Southern Balancing Authority with estimates up to 7-10 years in the state of Georgia. If a performance problem is detected under these new requirements, it could take that long to come into compliance and at a very significant cost if a new major 500kV line is required. These facilities can run as much as $4.0 million a mile or more in urban areas. We understand that a few areas of the country presently have this requirement but most do not. In the areas where the requirement has not been in place, the reliability of the system has been acceptable to the local Public Service Commissions that have governed the service to Retail customers. There has been no evidence presented that there is a need for an increase in reliability, particulary at the extensive time delay and expense possible from this particular requirement. An adoption of this standard without such evidence can only be considered arbitrary and capricious at best. Increased reliability is, in general, a worthy goal where it is cost effective. It

		may be appropriate to adopt this type of reliability requirement for areas that deem the resulting reliability increase to be cost effective for their customers. But it is inappropriate to "require" everyone else to be forced to live under this arbitrarily developed expansion of reliability requirements.]
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	See comments for Q21. [This is a very significant change in the performance requirements in this reliability standard. It involves facilities from 345 kV through 764kV which carry significant amounts of power. These also are facilities that require significant lead time to construct in the Southern Balancing Authority with estimates up to 7-10 years in the state of Georgia. If a performance problem is detected under these new requirements, it could take that long to come into compliance and at a very significant cost if a new major 500kV line is required. These facilities can run as much as $4.0 million a mile or more in urban areas. We understand that a few areas of the country presently have this requirement but most do not. In the areas where the requirement has not been in place, the reliability of the system has been acceptable to the local Public Service Commissions that have governed the service to Retail customers. There has been no evidence presented that there is a need for an increase in reliability, particulary at the extensive time delay and expense possible from this particular requirement. An adoption of this standard without such evidence can only be considered arbitrary and capricious at best. Increased reliability is, in general, a worthy goal where it is cost effective. It may be appropriate to adopt this type of reliability requirement for areas that deem the resulting reliability increase to be cost effective for their customers. But it is inappropriate to "require" everyone else to be forced to live under this arbitrarily developed expansion of reliability requirements.]

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒

Comment: By not allowing non-consequential load loss, utilities will incur significant expenditures. The marginal increase in reliability for this low probability event does not justify the huge costs involved.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒

Comment: By not allowing non-consequential load loss, utilities will incur significant expenditures. The marginal increase in reliability for this low probability event does not justify the huge costs involved.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	These are relatively higher probability events and the increase in performance requirements is justified.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	See comment for Q26 [These are relatively higher probability events and the increase in performance requirements is justified.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	See comment for Q26 [These are relatively higher probability events and the increase in performance requirements is justified.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	See comment for Q26 [These are relatively higher probability events and the increase in performance requirements is justified.

[1] System adjustment can be manual or automatic

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☒
Comment: Why should the reliability level for a transaction on a DC line be different from a transaction over AC? Also, when the transfer over DC is removed, the load it was serving still has to be picked up in the AC network because load cannot be dropped. Therefore, this places a burden on the AC network to serve additional load. If you allow transfers over DC to be interrupted, you should also allow the interruption of transfers over AC for the same events.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:
No Additional Comments.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:
No Additional Comments.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment:
No Additional Comments.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load

model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment: No Additional Comments.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Automatic generator tripping should be allowed for single contingency events and for multiple contingency events.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment: No Additional Comments.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Yes, as long as no emergency ratings are violated.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: RAS and SPS should be defined such that they may only be used for low probability events.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Generator tripping or runback and reconfiguration should be allowed for lower probability single contingency events such as bus faults; we suggest that SPS not be used for events that are more likely to occur.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: If an SPS is used to solve a single contingency problem, then full redundancy should be required. Generator tripping or runback and reconfiguration should be allowed for lower probability single contingency events such as bus faults; we suggest that SPS not be used for events that are more likely to occur.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment: Not at this time.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment: No Additional Comments.

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: See Below:

REQUIREMENTS:

1. The standard is not clear on whether corrective action plans are required for performance failures during the sensitivity analysis required for both steady-state and stability studies. In the phone conference John Odom stated that it was not the intent of the Drafting team to require that facililities be constructed for these conditions. The standard should be made clear on this point.

2. The Load Forecast section (R1.1) is new and is a duplicate of the requirements in the MOD standards and is unclear as written. Having similar requirements in multiple

standards creates the possiblility of conflicting requirements for the industry. If there are different requirements necessary, the MOD standards should be modified and not introduce a new section to the TPL standards.

3. R1.1.1 is unclear in what is intended by the "actual or expected aggregate mix of industrial, commercial, and residential load". Does the word "aggregrate" mean that the split between customer classes should be at the Balancing Authority level or at each load bus represented in the model. In many cases this could place a requirement for substantial load research on the the industry which may take a substantial amount of time and expense to accomplish. The use of the phrase "actual or expected" indicates an expectation that it be based on research and not general industry averages as may be more practical in some cases.

4. The wording in section R1.2 is very unclear. Is the intent to allow for three different methods for obtaining power factor models, i.e. historical system performance, validated by measurements during stressed System conditions, or documented Transmission planning area requirements? The other understanding is that the historical System performance is only measured during stressed System conditions. If this is the intent, what is the definition of stressed system conditions that is intended? Is this just heavy loadings, such as peak times, or is it during sytem disturbances? This is not clear. We suggest that the following words be used instead: "Load models validated by measurement during load levels typically studied or documented Transmission planning area requirements."

5. Requirement R1.4 should be qualified as only the outages within the Planning Horizon. There is no need to include protective relays because outages of relays in the Planning Horizon would not be known. We suggest the following words: "Known planned outages within the Planning Horizon and long-term outages greater than one year within the Planning Horizon for Transmission and generation equipment with consideration given to spare equipment strategy."

6. R1.5: If this places a requirement on the PC to define what constitutes "planned facilities", then this should be explicitly stated as a requirement.

7. R2.1 allows Assessments to be supplemented with "qualified" past studies which are defined in R2.6. R2.6.1 specifies these to be less than three years old for steady-state analysis and certain changes could not have occurred in the "System". There should be some qualification to the definition of "System" to include "the vicinity" of the area under evaluation. We would surmise that there always be some change in topology in the Eastern Interconnect which would preclude the use of past studies. Note that the "in the vicinity of" wording is used with the plant stability studies already. Also, is the intent with the "less than" to eliminate the use of studies three years old? Similar comments can be made for R2.6.2 and R 2.6.3.

8. R2.1 The wording/structure is confusing. The "Planning Assessment shall address all five years", but this does not require all five years be studied. It appears that the minimum study requirements would be two peak studies (years 1 or 2 & 5), one off peak study (any year), and one senstitivity case for each. Is this a correct reading?

9. In R.2.1.3.1 it is unclear what is intended. The study can be for higher or lower load "forecasts" with a different load power factor due to season, weather, or time of day. If you are looking at different seasons, weather, or time of day you will have a different load forecast. Is the intent to require the studies to model different seasons or times of

day that will generate different power factors or is it to focus on higher or lower loads, i.e. is it a load forecast exercise or a power factor exercise? Can we look at Spring conditions and have it qualify for this requirement even though the loads are consistent with my Base Case load forecast?

10. Requirement R2.1.3.3 lists "unavailability of long lead time facilities" as one of the sensitivity(ies) that should be evaluated. It is unclear whether this refers to the construction of projects with long lead times or for replacement of failed equipment that have long lead times for obtaining replacements. One of the drafting team members suggested it was the latter understanding that was intended. We suggest that the language be changed to "Delayed restoration to service of failed facilities with long lead times for repair". This may clarify the intent of the requirement.

11. R2.1.3.7 should be modified to read "Modification of planned long term Transmission outages."

12. R2.3.1 Does "current study" refer to an updated study or is this referring to some type of short-circuit analysis? It appears that analysis is required only every five years unless changes in the BES occur. Is this a correct reading?

13. R2.4: Need to clarify that "address all five years of the assessment period" does not necessarily require that each year must be studied individually. A study of one year could cover all 5 years if it is the worst case.

14. R2.4.3.2 Is the purpose of including non-firm transfers to identify generation limits? Please clarify that the intent is not to require constraints associated with non-firm transfers to be addressed.

15. R2.5.2: The addition of a transmission line always helps plant stability. Therefore, this should not be included as a change requiring a new study.

16. R2.7.1.1 requires that the action plan include a project initiation date as well as the in-service date. The project "initiation date" is not defined and can be interpreted as being when you thought up the project, when you started spending money on design, or when you actually started construction. As long as you have the in-service date when the project is needed, we do not see any major benefit from recording and documenting an "initiation" date. The length of time that it requires to complete a project is extremely variable based on many conditions so we're not sure what benefit, if any, will be gained by recording and documenting the initiation date. It may be impossible for someone not familiar with the legal, regulatory, etc. requirements in a given area to judge whether the timing is appropriate or not. This requirement should be eliminated.

17. R2.7.5 calls for the review of the implementation status of facilities. This imposes a large documentation requirement which has no benefit in reliability. We suggest making this requirement on an "as requested" basis.

18. Requirements 3.2 and 4.2: Delete the words "including those" so that it reads "the removal of all elements that System protection is expected...". As currently written, it sounds like you are going to remove more elements than the protection will remove.

19. R3.2 requires that the contingency analysis shall simulate the removal of all elements including those that System protection is expected to disconnect for each contingency without operator intervention. At present most steady state analysis uses

single "element" contingency with element defined as transmission lines or transformers as defined in the Power Flow cases. In a significant number of cases these individual "lines" are part of a larger "protection control group" (PCG). that would remove multiple elements encompased by the breakers in the PCG The present load flow tools (PSS/E) do not have features that will allow this type of analysis in an automated manner. To facilitate this change in required analysis, program modification will be needed or additional programs written. For an example with a line from bus A to B and then B to C with breakers at A and C and load at B, the outage of either A to B or B to C with load service remaining at Bus B may produce a more stringent condition than removing A to B to C. It appears that the new requirement is requiring the A to B to C analysis instead of the more stringent A to B or B to C.

20. Requirement R3.2.1 is unclear. Generators generally have both a high and a low voltage limitation on the terminal voltage related to station service reqirements. Most load flow representations for generators tend to hold the voltage on the high side of the GSU instead of the low side. Is this requirement attempting to say that the voltage limitations on the generator terminals must be considered or is it something else? This should be made clear in the requirement.

21. R3.3.2.1 requires that the amount of "consequential Load loss following a single Contingency shall be identified and the anticipated duration be recorded". This is an arbitrary requirement that will require significant time and effort to document and will provide no useful information from a planning perspective. Also the inclusion of an "expected" duration is more arbitrary than the actual amount of load. The time required to restore the facilities is a pure guess at best since it will vary substantially based on circumstances and conditions. Since we are also required to remove all elements that the protection control group (PCG) will open instead of just a single "power flow model" line, some of the load may be restored during switching action for tapped loads and some may not. This creates an additonal confusion of what is required to be recorded in terms of duration and load reduction. We see no benefit from identifying and documenting either the amount of consequential load lost or the estimated duration that would justify the time and effort required.

22. R3.3.2.2 This states that curtailments of firm transfers are not permissible following single contingency events to meet the performance criteria. Please clarify whether "firm transfers" refers to firm point to point service only, or if firm network service is also included. Said another way, is the curtailment of a network resource permissible following single contingency events to meet the performance criteria? If not, please clarify how redispatch service as required by Order 890 should be considered. If curtailment of a network resource is permited, please clarify why curtailment of PTP would be held to a higher standard. Also, please clarify whether R3.3.2.2 applies to P6. Lastly, please clarify how Conditional Firm Service (CFS) as required by Order 890 should be considered in meeting R3.3.2.2. CFS allows the curtailment of "firm" PTP transfers. This appears to be in conflict with the performance criteria.

23. Requirement R3.6 is not clear. It could be interpreted as generator tripping allowed for multiple contingencies only for the situations that meet the "to be determined" conditions. Generator tripping should always be allowed for multiple contingencies.

24. R4.5 and R4.6: We suggest dropping the words "For the" in each of these.

25. R4.6.1: Plant stability studies should not be required for generating units as small as 20 MW. The threshhold should be 100 MW or greater.

26. R4.6.3: The last sentence "The identified Contingencies, at a minimum, shall be evaluated" is redundant because the requirement already says "shall be performed and evaluated" The last sentence should therefore be deleted.

TABLE 1 - STEADY STATE PERFORMANCE:

27. In Table 1 in the column titled "Interruption of Firm Transfer Allowed," does it pertain to point-to-point only, or does it also apply to network loads? Please explain how this provision is consistient with the requirement to re-dispatch to address system constraints.

28. Steady state table, extreme event description, section 3: Items d and f are operating issues and therefore should not be included in the table. Also, items c and d are identical. Items d and f are identical.

29. Steady state table: Add the requirement to study n-0 to the table so it will be complete. Call it P0.

30. Steady state table and stability table: Change the heading which now says "For all Planning Events" to say "The following performance requirements must be met for the Planning events evaluated in addition to the requirements given in the columns"

31. Steady state table: For the event in P3, it is not clear what the "above 300 kV" applies to. Is it only the transformer? Or it it also the transmission circuit and generator? Also, the third column mentions DC when there is no DC in the event.

32. The event description in P3 is confusing. Please consider rewording in the 1,2,3 format of the other event descriptions. The term "non-bus tie breaker" is confusing. Please consider using "breaker (excluding bus ties)". Also, above 300 kV, most construction is either ring bus or breaker and a half. Please considered deleting the bus outage contingency. Lastly, please clarify how redispatch and CFS should be considered in the context of P3 and P4, in which the curtailment of firm transfers is not permissible to meet the performance criteria.

33. Steady state table: For transformers below 300 kV, P9.6 is no different from P8.3. We suggest adding the clarification of "above 300 kV" for P9.6.

34. Steady state table Extreme Event:
3.b "A successful cyber attack" needs to be clarified. What should the contingency be?
3.g Add the words "As applicable" to the beginning.
3.h This should be changed to "Other events as deemed appropriate by the PC based upon operating experience". Otherwise there will be no end to the contingencies that must be studied.

35. Several events in the tables use the term "internal fault" for a breaker. The SDT needs to explain what is intended by this term.

36. Steady State Performance Requirement, Table 1, Performance Levels P1-P4, should allow for the interruption of firm transfers if the transfer is dependent upon on the outaged equipment (whether AC or DC) to provide an electrical path specified in the transfer. Therefore, the current verbiage used for the outage of a DC Line should be applied to all levels and state, “Yes, if transfer is dependent on the outaged equipment to provide an electrical path for service”

37. Steady state and stability tables: in the Extreme Events section heading, the word "all" implies that all events must be evaluated when this is not the intent. Either make the heading "For Extreme events" or make it "For all Extreme Events evaluated".

TABLE 2 - STABILITY PERFORMANCE TABLE:

38. Stability table, note 1.a.i: P3.2 should be P2.3.

39. Several events in the tables use the term "internal fault" for a breaker. The SDT needs to explain what is intended by this term.

40. In event P7.2, does the "below 300 kV" apply to the generator, transmission circuit, transformer, and bus as well as to the stuck breaker? Or does it apply only to the stuck breaker?

41. The event description in P3 is confusing. Please consider rewording in the 1,2,3 format of the other event descriptions. The term "non-bus tie breaker" is confusing. Please consider using "breaker (excluding bus ties)". Also, above 300 kV, most construction is either ring bus or breaker and a half. Please considered deleting the bus outage contingency. Lastly, please clarify how redispatch and CFS should be considered in the context of P3 and P4, in which the curtailment of firm transfers is not permissible to meet the performance criteria.

42. Steady state table and stability table: Change the heading which now says "For all Planning Events" to say "The following performance requirements must be met for the Planning events evaluated in addition to the requirements given in the columns"

43. Steady state and stability tables: in the Extreme Events section heading, the word "all" implies that all events must be evaluated when this is not the intent. Either make the heading "For Extreme events" or make it "For all Extreme Events evaluated".

44. Stability table, footnote 1.a.ii. After "out-of-step protection", add the words "or some other means to trip the generator for this condition".

GENERAL:

45. The overall level of documentation required by this standard is excessive.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☒ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☒ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☒	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☒ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: Using consequential and non-consequential seem to be misleading. Perhaps using "direct" and "indirect". Also, mis-operation needs some more explanation and to why it should be included here.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: I think most people understand, but in this new world we need to put some more specificity around the words "low probability".**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: See Q2 answer.**	

Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: May be best to stop the definition after the word assumptions and cover the details as part of the requirements in the standard itself.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Not convinced that this study needs to be differentiated from a System Stability Study.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment: A generator's loss of synchronism and oscillation issues will be seen in this study.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☒ No ☐
Comment: The question may be misleading as number of sensitivity cases is not the issue. Enough studies should be conducted to appropriately define the boundaries of how the system will perform. The standard identifies various issues that may be used as sensitivity cases, but the list may or may not be all inclusive. The team should ask the industry whether any other sensitivities should be included in the standard.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☒ No ☐
Comment: However, what is meant by "reasonably stressed".

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☒
Comment: Any analysis that is performed needs to include some sort of sensitivity analysis. In fact, the sensitivity analysis may yield more information that is helpful in making decisions today than sensitivities performed on a near term study. A way of conducting a sensitivity analysis for long term studies may be to require long term studies to be performed for several years instead of only the one year that is required in the 6-10 year horizon.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system

deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: While DSM may, or may not, be manually operated, it is critical to understand the impacts of DSM and whether different ways of implementing DSM are of value.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: The study area should be the same as in the original study unless the Corrective Action Plans require changes/additions outside of the original study area. If chagnes/additions are made outisde the original area, then the study area must be expanded to include, at a minimum, the area that includes the new changes/additions.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: Add after the word "requirements" the following: "without the committed projects."

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the

requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	May need to consider using 500 kV as some transmission providers serve load off of the 345 kV system which could be triggered by this event.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	See comment in Q20.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	See comment in Q20.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	See comment in Q20.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: Why should we distinquish between a bustie breaker and a non-bus tie breaker? Also, 300 kV may be too low. This is really an issue that should be driven by the customers.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: This is really an issue that should be driven by the customers.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	This is really an issue that should be driven by the customers
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	This is really an issue that should be driven by the customers
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	This is really an issue that should be driven by the customers
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	This is really an issue that should be driven by the customers

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

[1] System adjustment can be manual or automatic

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☒
Comment: The same set of contingency tests need to be applied to in both steady state and stability studies. The performance levels may need to be characterized a little differently, but at the end of the day we are trying maintain a reliable system for the same initiating event both in a stability timeframe and a steady state timeframe.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: It is not clear that there is any difference between the two studies.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Only on a case by case basis where a common mode/single point of failure can be identified that results in the loss of an entire plant.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Any adjustment(manual, automatic, runback, tripping) should be allowed as long as the performance requirements are achieved as described in standard after the adjustments have been made.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: So long as the performance requirements are met then this is not an issue.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: The system, following the use of an RAS or SPS in response to a single contingency, shall meet the performance requirements.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: The system, following the use of an RAS or SPS in response to a single contingency, shall meet the performance requirements.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: The proposed standard contains a number of areas that need further definition, more explanation, or more specificity.

For example, requirement R1 should be rewritten as follows to make it clear who has responsibility for each requirement AND sub-requirement as the standard as written could be read to imply that Transimssion Owners and Generation Owners have to supply a load forecast to the Planning Coordinator:

R1. Each Resource Planner, Transmission Planner, Transmission Owner, Generator Owner, and Load-Serving Entity shall each provide, as specified below, its respective Planning Coordinator with the following modeling information required for System performance studies upon request (within 30 calendar days) : [Violation Risk Factor: TBD] [Time Horizon: TBD]

R1.1. Each Load Serving Entity shall provide the Planning Coordinator load forecasts adhering, at a minimum, to the following criteria:
R1.1.1. Use of expected Load mix based on the actual or expected aggregate mix of industrial, commercial, and residential Loads.
R1.1.2. Based on normal weather patterns as agreed to by the Planning Coordinator(s) and the Transmission Planner(s) for the area(s) of their responsibility.
R1.1.3. Identification of Demand Side Management (DSM) Load reductions consistent with operational requirements.

R1.2. Each Load Serving Entity shall provide the Planning Coordinator load models with supporting rationale that include power factor data based on historical System performance, validated by measurement during stressed System conditions, or documented Transmission planning area requirements.
R1.3. Each Load-Serving Entity shall provide the Planning Coordinator the Firm transfers/Interchange Schedules and resources required to supply Load for each Balancing Authority.
R1.4. Each Transmission Owner and Generation Owner shall provide the Planning Coordinator with known planned outages and long-term outages for Transmission and Generation equipment including protective relays with consideration given to spare equipment strategy.
R1.5. Each Transmission Owner, Generation Owner, Resource Planner, and Transimssion Planner shall provide known planned Facilities defined in accordance with the documented criteria of the Planning Coordinator, including but not limited to: Transmission Lines, generators, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies.

The above is an example and I apologize for the poor pagination. However, the drafting team should look at each requirement/sub-requirement and specifiy precisely to which entity the requirement/sub-requirement applies.

Other comments/concerns/questions with the proposed standard:

Does requirement R2 mean that you you could have two assessments: one performed by the Transmission Planner and one performed by the Planning Coordinator? This could result in two assessments of the same facilities which may or may not be desired.

In Requirement 2.5.1, what is meant by increasing generation? Is there a minimum amount of increased generation or is it any increase?

In Requirements 2.5.2, 2.6.1, 2.6.2, and 2.6.3, what is meant by "material"? This needs more definition wherever the word "material" is used throughout the standard.

In Requirements 2.6.1, 2.6.2, and 2.6.3, the word System and system are both used. Whose System or system needs to be defined. Does that include neighboring system(s)?

In Requirement 2.7.3, "committed" and "proposed" need to be defined.

In Requirement 2.7.5, what needs to happen as a result of such review? Is something supposed to happen in the Corrective Action Plans depending on the implemenation status of identified System Facilities and Operating Procedures?

In R3, what is "normal" performance (n-0)? Should this be a defined term?

In R3.2.1 and 3.2.2, why are these issues covered in a TPL standard as it seems to be more applicable to the Facility Ratings standards or the MOD10, 11, 12, and 13 standards? The TPL standard should probably reference these other standards for issues associated with ratings.

In R3.3.2, the reference to "single contingency" should reference the category (P1, P@, P#, etc.) in Table 1.

In R3.3.2.2, the term "firm transfers" needs to be defined.

In R3.3.3 and R3.4, reference is made to "expected to produce more servere System impacts." How does somebody determine what extreme events that are "expected to produce more servere System impacts?"

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	David Till	
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: We recommend that the terms consequential and non-consequential be changed to direct and indirect. Also, the term should be better defined. We recommend that the definition be "loads that have been de-energized by fault-clearing action or loads that are lost even though the system performance remains within acceptable limits."**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: A number of the planning events also have a low probability. The definition for "Extreme Events" should reference Table 1.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding,	☐Agree. ☒Do not agree.

or Special Protection Systems.	
Q6. **Comment: See comment for Q2. We recommend that this term is defined as "load loss other than consequential load loss".**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Use of the word "deficiencies" instead of "needs" provides better consistency throughout the standard. We do not agree that the planning assessment should directly include asset conditions and age. Asset condition should be part of the ratings process. The age of equipment, if it is well maintained, has little impact on reliability.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: The last sentence in the above definition was not included in the definition listed in the draft standard, nor should it be.**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the

requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: The entity performing the studies should be allowed to determine the appropriate number of cases that need to be evaluated.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: The standard may offer guidance but what constitutes a "reasonably stressed" case should be left to the discretion of the entity performing the study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment: Consideration should be given to the fact that stability studies are more time consuming than conventional power flow studies. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This

Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐

Comment: It should be included if it is a tool made available to the TP for this purpose, but only to the extent that it is considered firm. However, the standards should not determine which type of fix a utility should use to meet system requirements.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐

Comment: Re-testing should be required only where the correction may impact network flows. For example, a transmission line re-sag or CT ratio change to increase a facility rating should not require re-testing. The study area should be determined by the TP or PC as appropriate. The TP or PC has the most knowledge of how the system responds to changes.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐

Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐

Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to

clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	By not allowing non-consequential load loss, utilities will incur significant expenditures to construct a transmission solution for some extremely low probability events with low consequence. Each utility should have the flexibility to base action on probability and consequence. Load shed by UVLS or other means should remain an option to maintain reliability if probability is extremely low, but the high consequence of an event determines that a solution is necessary.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	See Q20.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage	☐Agree. ☒Do not agree.	See Q20.

rating above 300 kV		
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	See Q20.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: See Q20.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: See Q20.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	It is agreed that this event should be tested for maintaining reliability of the BES, however planned load loss should be allowed.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	It is agreed that this event should be tested for maintaining reliability of the BES, however planned load loss should be allowed.
Q28. P4-3: Loss of a generator followed by System adjustment followed	☐Agree. ☒Do not agree.	It is agreed that this event should be tested for maintaining reliability of the BES, however planned load loss should

[1] System adjustment can be manual or automatic

by loss of a Transmission circuit		be allowed.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	It is agreed that this event should be tested for maintaining reliability of the BES, however planned load loss should be allowed.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: There are also conditions where this interruption should be allowed for a single AC tie line.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: This question conflicts with Table 2 Extreme Event #9.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load

model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment: Dynamic studies of seasonal load conditions should include the effects of induction motors, and particularly in areas where traditional load models have indicated a problem. Unfortunately, there is a lack of data to support the amount and characteristics of the detailed induction load models in many areas. In addition to the consideration of the dynamic effects of induction motor loads, the effects of static capacitor banks installed at distribution voltage levels would need to be considered as well. Prior to making this a requirement in the reliability standards, the industry needs guidance as to how this data should be developed and maintained for models in future years. Also, the existing software capability is extremely limited in the ability to study the effects of motor loads.

Note that meeting such a requirement would necessitate a significant increase in the dynamic data needed to represent the system. Maintenance of such load model data would require significant resources. Load characteristics valid for a near term model might not be valid for future years. Also, summer peak load, winter peak load, and off-peak load characteristics would differ.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Any adjustments should be allowed that protects the reliability of the BES.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the

disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: The generator runback scheme should complete its action within the time allowed by the emergency ratings of elements that exceed their normal thermal ratings.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☒
Comment: TVA does not allow generator tripping for a single contingency. However, we recognize that there are certain instances for which this makes practical and economic sense.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: RAS or SPS should meet the same criteria as any protection system.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: The conditions required by SPS standards (PRC).

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: Requirement R1 does not belong in this standard. These requirements are covered by MOD standards.

Spare equipment strategy should be covered as a sensitivity study, but not included in the base case.

R2.1.1 should not be so prescriptive as to which years of 1-5 are studied.

The wording for R2.1.3 and R2.4.3 should be consistent.

Consideration should be given to the specific phases which are faulted in the simultaneous faults for P9 of the stability table. The results can be much different if the simultaneous faults occur on the same phase or different phases.

More guidance should be given for the term "Interruption of Firm Transfer Allowed" in Table 1. Firm transfer is not defined in the NERC glossary. The type of transmission service should be outlined here.

R2.7.1.1 - The project initiation date is not relevant in a reliability standard.

Extreme Event Descriptions
2. a. and b. should include mileage threshholds.
3. e. The term "large load" is vague and should be clarified.
   d. and f. are duplicates.
   c. and e. are duplicates.

Minimum generator voltage data required for R3.2.1 will be require extensive and costly generator testing and analysis to provide data necessary for transmission system studies.

R3.3.2.1 is an operational issue rather than a planning issue.

The addition of the “Corrective Action Plan” requires the TP to provide a significant amount of documentation for each deficiency identified by the studies.

Also, R3.2 requires that the studies simulate the protection scheme for all events. The current software tools cannot automate these studies for bus faults and breaker failure events, requiring each scenario to be studied manually.

The planning event designations are confusing because both the steady-state and stability tables have events P1-P9. A different designation should be used for one of the tables.

In R4.6 and other locations, the individual generator exemption of 20 MW should be increased to 75 MVA.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: There are a few undefined terms in this definition: "Transmission System" and "interconnected Transmission System". The definition needs to specifically identify what should be modeled and in a manner consistent with other NERC definitions. The definition refers to Facility ratings rather than the general reference to FAC-008 & FAC-009**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Modify to "Events which are more severe,but have a lower probability of occurrence, than Planning Events".**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☒Do not agree.
Q4. **Comment: "Transmission planning period that covers years six through ten", is sufficient for the standard." Suggest changing the name to Long-Term Planning Assessment.**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment: Suggest changing the name to Near-Term Planning Assessment.**	
Q6. **Non-Consequential Load Loss:** Load loss other than	☒Agree.

Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Eliminate "capital" from the definition. It is not defined or consistently applicable to the standard. Reference to vague "other factors, such as asset conditions and age" should be removed from this standard; there are no consistent definitions or industry standards on which to base this requirement, nor does it appear to be a necessary addition to the standard.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Propose, "Events for which Transmission performance requirements must be met".**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: See comment on Q9; proposed modification, "Study of the System or portions of the System to determine whether unit and system angular Stability is maintained, power oscillations are damped, and voltages during the dynamic simulation stay within acceptable perfomance limits.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: Modify to, "The first year that a Tranmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner completes its annual studies."**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement to develop action plans for problems highlighted as a result of one of the sensitivities.

Suggest modification to, "…sensitivity testing that stresses the System shall be considered, and documentation with the rationale for the sensitivity testing shall be supplied. The sensitivity case(s) may include one or more of the following conditions:"

2.1.3.3 should refer only to planned facilities that may be delayed. 2.1.3.4 - "variability" is too vague for a standard; the standard needs to be more specific as to the intent. 2.1.3.7 should be consistent with 1.4. These comments also apply to 2.4.3.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement develop action plans for problems highlighted as a result of one of the sensitivities.

Reasonably stressed conditions are dependent upon the study area under review and the standard is not likely to be able to be crafted to provide sufficent and consistent direction. However, it might be helpful if the standard clarified whether the base case should include any unplanned generator outages or whether, aside from potential sensitivities, unplanned generator outages are considered only through P1, P3 or P4 Contingencies. If the standard addresses unplanned generator outages only through P1, P3 and P4, then it is recommended that a mandatory sensitivity analysis, with required mitigation, include various potential combinations of a reasonable amount of unplanned outages. The combinations should be based on the part of the system that is under study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment: The standard is unclear whether or not it mandates the requirement to devleop action plans for problems highlighted as a result of one of the sensitivities.

Suggest modification to, "…sensitivity testing that stresses the System should be considered. Sensitivity case(s) might include among the following conditions:" 2.4.3 shold mimic 2.1.3 except in regard to load models.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: There is no need for sensitivity analysis.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: DSM should be included to the extent that its performance is sufficiently and consistently understood. The standard does not use the term "optimal" Therefore, the Drafting Team appears to be interpreting the Standard to require a vertically-integrated Planner to produce a so-called optimal-mix of resources plan. This would be an incorrect assumption and is not required. In areas with independent planners and competitive wholesale markets, it is sufficent to identify system needs and produce a plan that identifies regulated transmission solutions in the event that market-based resources (such as DSM) do not address those identified needs. Therefore, while DSM can be as effective a resource as generation, per Commission Orders,

in areas with ISOs/RTOs and a competitive wholesale market, the NERC Standard cannot prescribe the development so-called optimized (as is suggesgted by the Drafting Team) resource-mix plans, as identified by a central planner.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: The study area should be based upon planning expertise and knowledge of the system, giving due consideration to external impacts.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment: They should be viewed differently in the Near-Term. However, these should be defined terms.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment: It is unclear as to what the commited project is being removed from. Suggested language "…removed from the plan…".

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Given the low probability of extended overlapping outages of overhead facilities, systems have been designed assuming that load shedding following the loss of a second transmission line is permissible. Eliminating any allowance for load shedding for this condition may require significant system expansion and cost to to customers. However, it would be reasonable to consider establishing an upper bound to the amount of load that could be shed for these purposes.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	Should also consider the initial loss of a transformer, followed by the loss of a Transmission circuit. This should state a transformer with a "high-side" rating above 300 kV.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	This should state a transformer with a "high-side" rating above 300 kV.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of 2 additional generators.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a monopolar DC line
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a Transmission circuit
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a transformer

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm

[1] System adjustment can be manual or automatic

transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: This should also apply to firm transfers via single or double ac facilities as well. In either case, the transfer could be linked to dedicated facilities.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Difficult to envision how such an event would occur.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: This requirement is too specific and limited. Induction motors are only one component of a complex load model. Complex load models are not always necessary, nor are they always the most conservative, depending on the analysis that is being conducted. Where complex load models are required, they should be considered; this may involve use of complex motor and lighting loads or polynomial load representations

with or without frequency dependence. This question also suggests the need for an industry standard regarding transient voltage recovery.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Manual or automatic adjustments should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment. Manual system adjustment should be allowed in between the multiple Contingencies described in P5, provided that the adjustment can be made between contingencies using short-term reserves (10-30 minute).

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment: Generation runback should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐

Comment: However, this should only be allowed where failure of an automatic runback that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: Only allowed where the failure of an SPS that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Only allowed where SPS failure would not have significant adverse impact on the Bulk Electric System; non-Consequential loss of load should be allowed up to an amount potentially specified in the standard.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: System must remain stable with acceptable voltages and all equipment within applicable emergency limits.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☒
Comment: Unsure due to ambiguities in the standard. Depending upon the final standard, New England may need exceptions for existing facilities or allowance for a transition period to develop a compliance plan.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: There should be a "P0" standard that applies to system performance without any contingencies.

Standard should be clear that stabiltiy analysis is not required for Long-Term Planning Assessment.

R.1.1 Load forecasts should be addressed in MOD standards, not TPL.

R 1.4 This should only refer to known long-term outages, not planned outages. Delete "including protective relays"; this is addressed through other provisions.

R.2.1 Shorten "Near-Term Transmission Planning Horizon Planning Assessment" to "Near-Term Planning Assessment".

R 2.2 Shorten "Long-Term Transmission Planning Horizon Planning Assessment" to "Long-Term Planning Assessment".

R2.1, 2.2, 2.3 & 2.4 – The initial paragraph should have identical language regarding 'annual', and 'current or past' aspects.

R2.1.1 There should not be a requirement to look at years one and two; a 5 year study should be sufficient. If there has been an ongoing 5 year study, there should be no major unexpected problems occurring in years 1 and 2. Studies of earlier years should only be required if an unanticipated event occurred that had not been considered in prior studies. The TPL should not address shorter term "Operating Studies" or operating issues.

R 2.2.1 Modify to "If any known projects have a lead time that is longer than ten years, the Planning Assessment shall be extended accordingly."

R 2.6 Steady-state, short circuit, and stability analysis should be required no more than every 5 years unless there is a significant change the system.

R 2.6.1 Remove reference to "market structure changes". The purpose of it's inclusion is unclear.

R 2.7.1.1 Project initiation date should be deleted. If it is retainted, it needs to be defined.

R 2.7.3 Committed and Proposed projects should be defined.

R 3.2.1/R 4.3 - What is the intent of this requirement? There should probably be an MOD associated with Generator Owner requirement to provide related generator protection/ limiter data or other plant information.

R 3.4/R 4.5.2 Remove the requirement to implement changes to reduce or mitigate the likelihood of such consequences of Extreme Events. This may not be reasonable or achieveable.

R 3.2 Sectionalizing schemes shall be considered when reflecting the post-contingent system.

R 3.2.2 - Propose deleting this. Line ratings should already take relay loadability into account.

R 3.3.2.1 - Proposed deleting "expected duration". This would be dependent upon the damage to the element due to the iniating event and other factors.

R 3.3.2.2 - The requirements of this section do not match P6.

R 3.3.3 - Change introductory language to read "Those multiple Contingencies that are…"

R 3.5 - Generation tripping should be allowed as well as generation run-back. In addition, all performance requirements shall be met, rather than just meeting facility rating requirements. Suggested lanague "Manual and automatic generation run-back and/or generation tripping is allowed as a response to single and multiple Contingencies as long as the performance requirements of this standard are met." If these changes are accepted, R 3.6 can be deleted.

R 4 and R 4.1 - The language should be made similar to R 3 and R 3.1.

Suggest bringing language similar R4.4 into the R 3, the steady state section.

R 4.2 - High speed automatic reclosing schemes shall be considered.

R 6.3 - Change to read "Planning Coordinators of neighboring impacted areas".

Table 1 3 b and c Extreme Event descriptions are vague concepts that cannot be practically simulated. 3 d and e are not reasonable or practically useful to simulate.

Table 1, P8 - Language needs to be clarifed as to how the 300 kV threshold is to be treated for transformers. Is this for the high side, low side, or both sides? P5 is much clearer.

Table 2 - Clarification needs to be made that the faults being simulated are permanent faults. This can be addressed under the "Performance Requirements" portion at the beginning of the table, or modify each fault description.

Table 2 P9. Recommend that this be changed to require that faults should be on different phases of each of two adjacent transmission circuits on a multiple circuit transmission tower

Table 1, P9(6) and Table 2 P9 - It is unclear as to what is meant by "A spare transformer inserted to replace an outaged transformer followed by System adjustments". Unclear as to what is to be tested.

General comment - Transmission System is used throughout the document and is an undefined term

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Mark Graham	
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E-mail:	mgraham@tristategt.org	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☒Do not agree.
Q1. **Comment: same as WECC group comments**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☒Do not agree.
Q2. **Comment: same as WECC group comments**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☒Do not agree.
Q3. **Comment: same as WECC group comments.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: same as WECC group comments**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☒Agree. ☒Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment: same as WECC group comments**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Plant stability should be called Station stability. The term "plant" is reserved for aggregates such as total coal plant or total peaking plant, meaning all generating units in that category.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.

- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: same as WECC group comments

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: same as WECC group comments

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒
Comment: Sensitivity studies are most often used to determine operating relationships of a system - sensitivity to generation patterns is deliverability analysis; sensitivity to load growth is margin analysis. Sensitivity analysis should not be required explicitly. The criteria should be stated in terms of load margins, deliverability, and capability to withstand generator or transaction forced outages. The TP can use sensitivity studies or other reasonable methods to assess reliability

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☒
Comment: It is just as important for long range plans of service to provide acceptable operation as it is for near-term facility plans. To specify different criteria for different time periods seems unreasonable.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or

Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒
Comment: DSM should not be considered except as a load forecast variable. Rather, the load forecast probability index should be prescribed (specific probability of exceedance)

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒
Comment: same as WECC group comments

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: same as WECC group comments

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: R2.7.4 calls for change monitoring. If documentation of changes is required, just say so. Do not restrict changes.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

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changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	same as WECC group comments
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	same as WECC group comments
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	same as WECC group comments
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	same as WECC group comments

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: same as WECC group comments

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: same as WECC group comments

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	same as WECC group comments
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	same as WECC group comments
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	same as WECC group comments
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	same as WECC group comments

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☒
Comment: same as WECC group comments

E. Stability

[1] System adjustment can be manual or automatic

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☒
Comment: same as WECC group comments

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: same as WECC group comments

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: same as WECC group comments

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☒
Comment: same as WECC group comments

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: same as WECC group comments

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: same as WECC group comments

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: same as WECC group comments

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: same as WECC group comments

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐

Comment: same as WECC group comments

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☒ No ☐
Comment: same as WECC group comments

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: R1 and R2 address some Load Forecast issues, but are not exhaustive specifications of what Load Forecast range to use in studies. There needs to be some mention of exceedance probability (ExPr) in Load Forecast criteria. For example, we use a forecast with a low ExPr in our studies because we are concerned that, if the system was planned for 50% ExPr (a lower forecast), actual deviation from that forecast might result in load at certain locations exceeding operating margins built into the interconnected transmission system designed to serve only the 50% ExPr forecast load.

Load Specifications in R2.4 are ambiguous for the reasons stated above.

Maximum study ages in R2.6.1 and R2.6.2 seem arbitrary. The time limit does not seem to add anything to the criteria if no material changes have occurred. If spot checks of the most critical areas indicated no criteria violations, there should be no reason to rerun studies. To correct this problem, we suggest using the term "assessment" rather than "study". For most people, "study" implies detailed modeling and simulation analyses summarized in a report, whereas "assessment" implies a reasonable, systematic evaluation of a system which does not necessarily include detailed analysis for the entire system.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☒Do not agree.
Q1. **Comment: A Base Case can only represent the amount of transactions required to serve connected load modeled in the case (local load?). A Path Rating case (developed to represent maximum transfers on a path) would not be considered a base case under this definition. WECC develops base cases to study high power transfers under stressed conditions. Such high power transfers necessarily include both firm and non-firm transaction obligations. Therefore, a base case that represents firm transactions to support "connected load" only, cannot be used to support studies of maximum possible power transfer and is of limited value in WECC. We agree that the above definition is one definition of a base case, but we feel that it can not be the only definition or the limiting definition. We suggest that wording be included that reflects the concept of modeling forecasted or above forecasted load levels if desired, and both firm and non-firm transactions if necessary to model anticipated maximum transfers and represent stressed system conditions as well.** **The definition should refer to the base case as a Computer Simulation Model of the power system, not a Computer Representation of the transmission system, since it is used within a computer program and represents load and generation in addition to transmission. References to "the generation dispatch and firm transaction obligations to supply the connected load" should be removed.** **A base case is a starting case for any condition that needs to be studied, not just a firm transactions case. Firm obligations across the transmission system are many times independent of a specific load service obligation.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☒Do not agree.

Q2. **Comment: Agree with the definition in concept. However, the wording makes the definition seem unrealistic. There are many examples where a certain amount of voltage sensitive load or motor drives sensitive to angle changes are dropped due to normally cleared electrical faults on the transmission system. These loads are not directly connected to the element being removed from service. This type of sympathetic loss of load is unique to the individual customer load. The design of these loads is not under the control of the utilities when it comes to ability to ride through normally cleared faults. We suggest that this definition be modified to include the loss of sensitive load that is not directly connected to the element being removed.** **We propose the following the definition : Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation, and because of sympathetic tripping associated with normal clearing or mis-operation. Load that is lost because it trips due to low voltages experienced during and immediately following the fault (4-6 cycles?) is also considered consequential load loss. We believe this additional recognition is needed because load lost due to low fault voltages is unavoidable and should not result in a standard violation.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☒Do not agree.
Q3. **Comment: Please add the phrase "two or more elements out of service" to the definition from the previous definition in Table I.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: Please add "or Remedial Action schemes" to the end of the definition. FERC Order 693, paragraph 1773 states (6)"clarifies footnote (b) to Table 1 to allow no firm load or firm transactions to be interrupted except for consequential load loss." There needs to be a distinction made between Interruptible Load and Firm Demand.**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions	☒Agree. ☒Do not agree.

and age.	
Q7. **Comment: As identified by the modifications above, we believe the definition should be changed to read, "Documented evaluation of future Bulk Electric System needs by the use of performance studies (steady state and dynamic) that cover a range of reasonable or expected assumptions regarding system conditions, applicable time frames, and future plans; including capital reinforcements and operating procedures, SPS/RAS, and other factors (such as asset conditions and age)."**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Plant Stability seems to be a subset of System Stability. Introducing a new term can cause confusion.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: The TP or PA is the most familiar with the system and so would be the best to determine the sensitivities that are more applicable to their particular system. The Standard should not be overly prescriptive. The Standard can make suggestions or list potential sensitivities but let the TP or PA determine those variables to study and the reasonable range of the sensitivities.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: No, as in the response for Question #12. The TP is the best to determine the type of stressing needed for a particular case. This is very evident in the type of cases used for studies in the different parts of the NERC regions.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☒
Comment: We concur with the use of sensitivities as long as the TPs are allowed to determine the sensitivities that are the more appropriate for their systems and not have the sensitivities scripted in the Standard.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: We agree with this conclusion. The Standard language should state that sensitivities are not required in Long-Term Transmission System Planning Horizon but the TP could use sensitivities if desired.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system

deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☒

Comment: It is unclear whether "DSM" in this question refers to reduction in load or increases in distributed resources, or if the resources are directly controllable by the transmission operator. DSM could be used in the mix of solutions that are used to determine the optimal solution for a transmission issue. However, we have concerns about the use of DSM, that is not under the direct control of the Transmission Operator as a stand alone transmission system solution. Please remember the overstated returns from DSM in the last decade that did not materialize. If these overstated values had been used as a transmission system enhancement, then the system would have been compromised with emergency operating solution until the effective transmission enhancements could be realized.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒

Comment: No, this is too onerous. We recognize that, when planning the system and developing a Corrective Action Plan, the transmission planner would have added the potential projects individually (or in small groups) into a case to re-test the system performance. Hoever, R2.7.2 seems to require that all potential projects be added back into the case simultaneously for retesting. There could be many different alternative solutions for each potential problem identified in the different study years without having the base solution first determined for a nearer term case. There can be many combinations of potential solutions for cases further into the future that satisfy the condition being studied. For example, a voltage problem can be solved by the addition of capacitors, completing a bus tie, adding a short line, operating procedure, changing generation dispatch, etc. Even assuming that one set of solutions are picked so the verification study can be performed, logistically this demonstration may be too close to the assessment in the following year. Instead of retesting the potential projects in the Corrective Action Plan on the original base case, it may be better to test them in the base cases prepared for following year's study. Any potential problem that is unresolved will show up again in the following year's assessment. Therefore, a separate demonstration using an "older" case may not be an efficient use of the TPs' and PAs' time and resources.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒

Comment: The definition of these terms can be vastly different across all TPs. How would this be effectively monitored for compliance with such different definitions? Also,

each TO's criteria to go from a proposed project to a committed project can change over time due to other needs and requirements.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒

Comment: The requirement is similar to the question posed in Question 17. What is the documentation that proves this is needed?

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds

		of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds

		of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒

Comment: We disagree that non-consequential loss of load should not be permitted for this contingency event. We believe that planned and controlled interruption of non-consequential load should be permitted for loss of a non-bus tie breaker (above 300 kV). Losing a non-bus tie breaker could result in simultaneous loss of two or more elements, depending on the bus configuration. Allowing planned and controlled disconnection of some load in the areas would not only prevent cascading and instability (which could result in uncontrolled loss of a larger amount of load), but also enables faster load restoration. Losing a breaker due to an internal fault is a low probability event. To meet this requirement as proposed would require severe pre-contingency curtailment of power transfers, that could impact commerce and/or construction of large number of transmission facilities with the attendant environmental impacts and increased cost to customers.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒

Comment: We disagree that non-consequential loss of load should not be permitted for this contingency event. We believe that planned and controlled interruption of non-consequential load should be permitted for loss of either a generator, a transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV). This contingency event could result in simultaneous loss of two or more elements, depending on the bus configuration. Allowing planned and controlled disconnection of some load in the areas would not only prevent cascading and instability (which could result in uncontrolled loss of a larger amount of load), but also enables faster load restoration. These contingencies are low-probability events. To meet this requirement as proposed would require severe pre-contingency curtailment of power transfers, that could impact commerce and/or construction of a large number of transmission facilities with the attendant environmental impacts and increased cost to customers.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping

[1] System adjustment can be manual or automatic

		outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☒

Comment: We agree with the question asked. In addition, transactions that can be interrupted due to the loss of a DC line should not be limited to the firm transactions, that are dependent on the DC line. It should also include interruptible transactions and other transactions made available through negotiated agreements on both AC and DC lines.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☒

Comment: We agree with the question asked. In addition, because of the time sequence from the start of the fault, through fault clearing and transient dynamic period, the post-transient period to the steady state post-contingency period, there needs to be clear links between the performance requirements in the transient

dynamic time period and the steady state time period. For example, if generator dropping or controlled load interruption is allowed in the transient dynamic period, it should also be allowed in the steady state time period that follows. Otherwise, it would put the Transmission Planners and the Planning Authorities in an untenable situation because, once a generator or load is dropped in the first few cycles after the disturbance; it cannot be required to be on line in the minutes that immediately follow.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒

Comment: It appears that Plant Stability Study is a subset of System Stability Study. R4.6.2 states these shall be performed for changes in real power output of a generating unit by more than 10%. Then it states they shall be performed for planning events. R4.5 already covers any contingencies that are an issue and the system already needs to meet some level of performance for loss of the generator. It seems that a change in generation would already be analyzed from a system standpoint as stated in R2.4.3. It appears that material changes to existing generators should be reflected in modeling requirements elsewhere.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒

Comment: We agree with the SDT that simultaneous 3-phase fault on all generating units in a plant is improbable and effort should be better spent studying more probable events. In any case, this Extreme Event is to be considered in the Steady State Table, and stability cases can be run if it is shown to be needed in the power flow study results. We are, however, confused by this question. This question states that the SDT did not include the requirement to consider loss of all generators at a plant in the stability, yet the Extreme Event in the stability table shows in No. 9, "3Ø fault with loss of all generating units at a station".

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☒

Comment: The requirement to include motor load should be extended to other load level periods and not be limited to peak load period only. However, to capture slow voltage recover phenomena, especially in areas of high penetration of refrigerated air conditioning load (e.g. 50% to 60%), would require modeling down to the distribution system voltage level and explicitly representing shunt capacitors and various induction motor types (e.g. equivalents for single phase motors). If the requirement is not extended, dynamic simulations will likely differ significantly from observed system events. We recommend a phase-in period so that the requirement for use of load models should only include regionally accepted load models for which data are available. This requirement can be extended or modified as the Region in which the entities reside adopts new load modeling guidelines.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: All adjustments should be allowed as long as they are realistic and achievable in the time frame required and consistent with other study parameters. For example, automatic adjustments would be required for correction of a stability problem, but manual adjustment should be allowed for correction of a thermal problem if there is no instability problem.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Yes. Agree. Conditions for generation run back for N-1: 1) Run back of generation cannot result in tripping of firm load, 2) power flow should be within the time-limited equipment ratings, 3) frequency should be within allowable limits.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐

Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Based on the interpretation of the above question, we are providing two responses to this question. The first responds to the limitations placed on RAS, regardless of what action the RAS initiates. The second response specifically addresses RAS that trips generation.

Response 1: RAS should be allowed for single contingency events. Any sort of RAS should be permitted, but there should be a review of the RAS. If the local entities agree to the RAS, it should be allowed. This addresses cost vs. benefit balance. Entities affected should be the ones that determine the best solution for their situation.

Response 2: Generation tripping can be used for single contingency if such application can be demonstrated through transmission planning studies that:

- The generation tripping is planned and controlled ("planned and controlled" means a pre-planned action(s) based on predetermined system conditions that take corrective measure(s) to maintain acceptable system performance).
- The generation tripping does not result in non-consequential load loss.
- System frequency should be within allowable limits.
- System voltage dip and deviation should be within allowable limits.
- The generator owner(s) agrees to the tripping as planned.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: System adjustment involves operator intervention that would be beyond the time frame of RAS operation. Therefore, if a unit is already dropped during RAS or SPS action, it should be assumed to be off-line during system adjustment period.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐

Comment: Yes. WECC allows tripping of generators to meet single contingency performance requirements. WECC also allows planned and controlled load shedding for the proposed Planning Events P2-1, P2-2, P3, P4 and P5, although we agree with the proposed requirements for P4 due to the higher probability of occurrence. If the standard does not allow for non-consequential load shedding of 300 kV and above for P5 scenarios, WECC will develop a regional variance".

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☒ No ☐

Comment: 1) FERC Order 693, Paragraph 1825 regarding TPL-003, Category C – The Commission directed the ERO to modify footnote (c) to Table 1 to clarify the term “controlled load interruption” rather than eliminate its applicability to this performance requirement. 2) FAC-010-1, R2.3 – “…planned or controlled interruption…” This conflicts with “No” for non-consequential load loss allowed in draft TPL.

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐

Comment: 1. R1.3 requires the provision of firm transfer/Interchange Schedules and resources required to supply load for each Balancing Authority. It may not be possible to have reasonably accurate information on firm transfers and Interchange Schedules for years into the future. Within WECC, we develop base cases that represent reasonably stressed conditions that model power flows stressing various paths. Therefore, within WECC, we design the system to operate at levels that can support all sorts of commerce, including the effects of loop flow, and firm and non-firm contracts, in addition to other possibilities. It would be difficult to develop information from this mixture that includes only firm transactions for such future base cases. In addition, WECC does not allow operations at levels not previously studied. Therefore, an exercise to determine firm transaction/schedules would produce information that will be of little value to support reliability in WECC.

2. R2.7.1.2 requires identification of system deficiencies and accociated corrective action for the Long Term Transmission Planning Horizon. This requirement needs to tie to the lead times to implement the corrective action(s). For example, if a 500 kV transmission line is needed to correct a deficiency that surfaces in the tenth year, then this requirement is reasonable. However, if the deficiency is on a low voltage system, that can be resolved with short lead-time projects (such as installing a small capacitor bank) then this requirement would seem to be too prescriptive.

3. R1.5 requires providing modeling information as part of R1 on a number of transmission planned facilities, including circuit breakers. Since circuit breakers are part of a transmission line, we are not sure how a circuit breaker would be modeled separately, as required.

4. R3.2.1 requires that "studies shall consider the minimum steady state voltage limitations of all generators". Since generators (as well as other facilities) have both high and low voltage limits, the standard should require consideration of both high and low voltage limits.

5. In R.3.2.2, please provide a reference for relay loadability.

6. R.3.3.2.1. requires that Consequential Load loss (expected maximum demand and expected duration) following a single contingency shall be identified in the Planning Assessment. We suggest deleting this requirement. By definition, consequential load loss following a contingency can not be avoided and should not be considered an impact on the operation of the BES. It should be part of local service reliability between an entity and its local regulatory agency or contractual relationship between individual parties and not in a NERC Standard governing the operation of a BES.

7. Proposed revision to R3.5 – "Manual and automatic generation runback and generator tripping are allowed as a response to single and multiple contingencies as long as Facility Ratings are not exceeded and the result of the generator action, such as loss of reactive resource, impact on reserves, and restart time of tripped unit(s), meets the performance requirements in the tables."

Example for the need for flexibility in the selection of generation runback and/or tripping to meet the requirements of R3.5 – The time period for a particular Emergency Rating

might require faster generation redispatch than a runback or set of runbacks are capable of providing. Therefore, it may be necessary to trip one 100 MW unit rather than runback several units for a total of 100 MW. Planning and Operations need flexibility to coordinate with the requirements of Engineering who established the Facility Ratings.

No need for R3.6 with above revision to R3.5.

8. Performance standard "P5" (Q.21- 23) does not allow for the use of load shedding (safety nets) required by some utilities to protect against cascading outages if a transmission line is already out of service and a forced outage of another major element occurs. "System adjustments" might not be possible in a load pocket or local load-serving area to prevent "non-consequential load loss" after loss of a second transmission line to the load-serving area. The use of load shedding for such rare events is an established practice and least cost alternative that does not unreasonably compromise reliability of the WECC system. It is also an acceptable and necessary tradeoff from over burdening customers with additional expensive transmission lines and permitting risk in the West where remote generation resources have historically required power to be carried over long distances.

The tradeoffs between economics (building hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation versus load shedding schemes) and the impact of these rare events should be under the purview of local and state jurisdictions, as long as impacts do not result in cascading events outside of the affected jurisdiction. As long as interconnected reliability or neighboring system operation is not negatively impacted, customer interruption size and frequency should be left to the Transmission Providers discretion and to the jurisdiction of state regulators. The amount of load to be shed and its frequency is primarily an issue for state jurisdiction because it is a matter of the cost/benefit associated with customer service regardless of the voltage level problem. In general, incidences of non-consequential loss of customer load events related to contingencies on the back-bone transmission system are rare when compared to other causes of customer outages. Assuming interruptions to customer service are significant, the state regulators and other related constituents will ultimately be responsible for approving any transmission line facilities or generation additions needed to assure reliability.

Implementing an immediate change to this current established practice is not rational or technically feasible due to the long and arduous regulatory and permitting processes that are required to construct new transmission facilities or new load-side generation. Implementation of the standard as written would take many years. At a minimum, even if it is determined that Congress's intent was to create stricter standards, a phase-in period must be included to allow utilities time to obtain necessary permits, regulatory approval and cost recovery to meet the stricter standards.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: **WECC Committees and Subgroups**

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Scott Inglebritson	Seattle City Light	WECC	1,3,4,5
Chad Bowman, PE	Public Utility District #1 of Chelan	WECC	4
Casey Hashimoto	Turlock Irrigation District	WECC	3
Fred Young	Northern California Power Agency	WECC	4
Scott A. Waples	Avista Corporation	WECC	1
Matthew Stoltz	Basin Electric Power Cooperative	WECC	1
Juan C. Sandoval, P.E.	Imperial Irrigation District	WECC	1
Baj Agrawal	Arizona Public Service Co.	WECC	1
Rich Salgo	Sierra Pacific Resources	WECC	1
Brian Whalen	Sierra Pacific Resources	WECC	1
Javier Esparza	Imperial Irrigation District	WECC	1
Milorad Papic	Idaho Power Co.	WECC	1
David Larsen	Transmission Agency of Northern California	WECC	1
Xavier Baldwin	City of Burbank Water & Power	WECC	9
Dana Cabbell	Southern California Edison Co.	WECC	1
Henryk A. Olstowski	Imperial Irrigation District	WECC	5
David Angell	Idaho Power	WECC	1
Charles E. Matthews	Bonneville Power	WECC	1

	Administration		
Mark Graham	Tri-State Generation and Transmission Association	WECC	1

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please

include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☒Do not agree.
Q1. **Comment: A Base Case can only represent the amount of transactions required to serve connected load modeled in the case (local load?). A Path Rating case (developed to represent maximum transfers on a path) would not be considered a base case under this definition. WECC develops base cases to study high power transfers under stressed conditions. Such high power transfers necessarily include both firm and non-firm transaction obligations. Therefore, a base case that represents firm transactions to support "connected load" only, cannot be used to support studies of maximum possible power transfer and is of limited value in WECC. We agree that the above definition is one definition of a base case, but we feel that it can not be the only definition or the limiting definition. We suggest that wording be included that reflects the concept of modeling forecasted or above forecasted load levels if desired, and both firm and non-firm transactions if necessary to model anticipated maximum transfers and represent stressed system conditions as well.** **The definition should refer to the base case as a Computer Simulation Model of the power system, not a Computer Representation of the transmission system, since it is used within a computer program and represents load and generation in addition to transmission. References to "the generation dispatch and firm transaction obligations to supply the connected load" should be removed.** **A base case is a starting case for any condition that needs to be studied,**	

not just a firm transactions case. Firm obligations across the transmission system are many times independent of a specific load service obligation.	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☒Do not agree.
Q2. **Comment: Agree with the definition in concept. However, the wording makes the definition seem unrealistic. There are many examples where a certain amount of voltage sensitive load or motor drives sensitive to angle changes are dropped due to normally cleared electrical faults on the transmission system. These loads are not directly connected to the element being removed from service. This type of sympathetic loss of load is unique to the individual customer load. The design of these loads is not under the control of the utilities when it comes to ability to ride through normally cleared faults. We suggest that this definition be modified to include the loss of sensitive load that is not directly connected to the element being removed.** **We propose the following the definition : Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation, and because of sympathetic tripping associated with normal clearing or mis-operation. Load that is lost because it trips due to low voltages experienced during and immediately following the fault (4-6 cycles?) is also considered consequential load loss. We believe this additional recognition is needed because load lost due to low fault voltages is unavoidable and should not result in a standard violation.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☒Do not agree.
Q3. **Comment: Please add the phrase "two or more elements out of service" to the definition from the previous definition in Table I.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: Please add "or Remedial Action schemes" to the end of the definition. FERC Order 693, paragraph 1773 states (6)"clarifies footnote (b) to Table 1 to allow no firm load or firm transactions to be interrupted except for consequential load loss." There needs to be a distinction made**	

between Interruptible Load and Firm Demand.	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☒Do not agree.
Q7. **Comment: As identified by the modifications above, we believe the definition should be changed to read, "Documented evaluation of future Bulk Electric System needs by the use of performance studies (steady state and dynamic) that cover a range of reasonable or expected assumptions regarding system conditions, applicable time frames, and future plans; including capital reinforcements and operating procedures, SPS/RAS, and other factors (such as asset conditions and age)."**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Plant Stability seems to be a subset of System Stability. Introducing a new term can cause confusion.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the

requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The TP or PA is the most familiar with the system and so would be the best to determine the sensitivities that are more applicable to their particular system. The Standard should not be overly prescriptive. The Standard can make suggestions or list potential sensitivities but let the TP or PA determine those variables to study and the reasonable range of the sensitivities.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: No, as in the response for Question #12. The TP is the best to determine the type of stressing needed for a particular case. This is very evident in the type of cases used for studies in the different parts of the NERC regions.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☒

Comment: We concur with the use of sensitivities as long as the TPs are allowed to determine the sensitivities that are the more appropriate for their systems and not have the sensitivities scripted in the Standard.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: We agree with this conclusion. The Standard language should state that sensitivities are not required in Long-Term Transmission System Planning Horizon but the TP could use sensitivities if desired.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☒

Comment: It is unclear whether "DSM" in this question refers to reduction in load or increases in distributed resources, or if the resources are directly controllable by the transmission operator. DSM could be used in the mix of solutions that are used to determine the optimal solution for a transmission issue. However, we have concerns about the use of DSM, that is not under the direct control of the Transmission Operator as a stand alone transmission system solution. Please remember the overstated returns from DSM in the last decade that did not materialize. If these overstated values had been used as a transmission system enhancement, then the system would have been compromised with emergency operating solution until the effective transmission enhancements could be realized.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒

Comment: No, this is too onerous. We recognize that, when planning the system and developing a Corrective Action Plan, the transmission planner would have added the potential projects individually (or in small groups) into a case to re-test the system performance. Hoever, R2.7.2 seems to require that all potential projects be added back into the case simultaneously for retesting. There could be many different alternative solutions for each potential problem identified in the different study years without having the base solution first determined for a nearer term case. There can be many combinations of potential solutions for cases further into the future that satisfy the condition being studied. For example, a voltage problem can be solved by the addition of capacitors, completing a bus tie, adding a short line, operating procedure, changing generation dispatch, etc. Even assuming that one set of solutions are picked so the verification study can be performed, logistically this demonstration may be too close to the assessment in the following year. Instead of retesting the potential projects in the Corrective Action Plan on the original base case, it may be better to test them in the base cases prepared for following year's study. Any potential problem that is unresolved will show up again in the following year's assessment. Therefore, a separate demonstration using an "older" case may not be an efficient use of the TPs' and PAs' time and resources.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: The definition of these terms can be vastly different across all TPs. How would this be effectively monitored for compliance with such different definitions? Also, each TO's criteria to go from a proposed project to a committed project can change over time due to other needs and requirements.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: The requirement is similar to the question posed in Question 17. What is the documentation that proves this is needed?

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the

		SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the

adjustment followed by loss of a transformer with low side voltage rating above 300 kV		SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒

Comment: We disagree that non-consequential loss of load should not be permitted for this contingency event. We believe that planned and controlled interruption of non-consequential load should be permitted for loss of a non-bus tie breaker (above 300 kV). Losing a non-bus tie breaker could result in simultaneous loss of two or more elements, depending on the bus configuration. Allowing planned and controlled disconnection of some load in the areas would not only prevent cascading and instability (which could result in uncontrolled loss of a larger amount of load), but also enables faster load restoration. Losing a breaker due to an internal fault is a low probability event. To meet this requirement as proposed would require severe pre-contingency curtailment of power transfers, that could impact commerce and/or construction of large number of transmission facilities with the attendant environmental impacts and increased cost to customers.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒

Comment: We disagree that non-consequential loss of load should not be permitted for this contingency event. We believe that planned and controlled interruption of non-consequential load should be permitted for loss of either a generator, a transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV). This contingency event could result in simultaneous loss of two or more elements, depending on the bus configuration. Allowing planned and controlled disconnection of some load in the areas would not only prevent cascading and instability (which could result in uncontrolled loss of a larger amount of load), but also enables faster load restoration. These contingencies are low-probability events. To meet this requirement as proposed would require severe pre-contingency curtailment of power transfers, that could impact commerce and/or construction of a large number of transmission facilities with the attendant environmental impacts and increased cost to customers.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have

[1] System adjustment can be manual or automatic

		higher probability than other multiple contingency events.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☒

Comment: We agree with the question asked. In addition, transactions that can be interrupted due to the loss of a DC line should not be limited to the firm transactions, that are dependent on the DC line. It should also include interruptible transactions and other transactions made available through negotiated agreements on both AC and DC lines.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an

assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☒

Comment: We agree with the question asked. In addition, because of the time sequence from the start of the fault, through fault clearing and transient dynamic period, the post-transient period to the steady state post-contingency period, there needs to be clear links between the performance requirements in the transient dynamic time period and the steady state time period. For example, if generator dropping or controlled load interruption is allowed in the transient dynamic period, it should also be allowed in the steady state time period that follows. Otherwise, it would put the Transmission Planners and the Planning Authorities in an untenable situation because, once a generator or load is dropped in the first few cycles after the disturbance; it cannot be required to be on line in the minutes that immediately follow.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒

Comment: It appears that Plant Stability Study is a subset of System Stability Study. R4.6.2 states these shall be performed for changes in real power output of a generating unit by more than 10%. Then it states they shall be performed for planning events. R4.5 already covers any contingencies that are an issue and the system already needs to meet some level of performance for loss of the generator. It seems that a change in generation would already be analyzed from a system standpoint as stated in R2.4.3. It appears that material changes to existing generators should be reflected in modeling requirements elsewhere.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒

Comment: We agree with the SDT that simultaneous 3-phase fault on all generating units in a plant is improbable and effort should be better spent studying more probable events. In any case, this Extreme Event is to be considered in the Steady State Table, and stability cases can be run if it is shown to be needed in the power flow study results. We are, however, confused by this question. This question states that the SDT did not include the requirement to consider loss of all generators at a plant in the stability, yet the Extreme Event in the stability table shows in No. 9, "3Ø fault with loss of all generating units at a station".

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☒

Comment: The requirement to include motor load should be extended to other load level periods and not be limited to peak load period only. However, to capture slow voltage recover phenomena, especially in areas of high penetration of refrigerated air conditioning load (e.g. 50% to 60%), would require modeling down to the distribution system voltage level and explicitly representing shunt capacitors and various induction motor types (e.g. equivalents for single phase motors). If the requirement is not extended, dynamic simulations will likely differ significantly from observed system events. We recommend a phase-in period so that the requirement for

use of load models should only include regionally accepted load models for which data are available. This requirement can be extended or modified as the Region in which the entities reside adopts new load modeling guidelines.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: All adjustments should be allowed as long as they are realistic and achievable in the time frame required and consistent with other study parameters. For example, automatic adjustments would be required for correction of a stability problem, but manual adjustment should be allowed for correction of a thermal problem if there is no instability problem.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Yes. Agree. Conditions for generation run back for N-1: 1) Run back of generation cannot result in tripping of firm load, 2) power flow should be within the time-limited equipment ratings, 3) frequency should be within allowable limits.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Based on the interpretation of the above question, we are providing two responses to this question. The first responds to the limitations placed on RAS, regardless of what action the RAS initiates. The second response specifically addresses RAS that trips generation.

Response 1: RAS should be allowed for single contingency events. Any sort of RAS should be permitted, but there should be a review of the RAS. If the local entities agree to the RAS, it should be allowed. This addresses cost vs. benefit balance. Entities affected should be the ones that determine the best solution for their situation.

Response 2: Generation tripping can be used for single contingency if such application can be demonstrated through transmission planning studies that:

- The generation tripping is planned and controlled ("planned and controlled" means a pre-planned action(s) based on predetermined system conditions that take corrective measure(s) to maintain acceptable system performance).
- The generation tripping does not result in non-consequential load loss.
- System frequency should be within allowable limits.
- System voltage dip and deviation should be within allowable limits.
- The generator owner(s) agrees to the tripping as planned.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: System adjustment involves operator intervention that would be beyond the time frame of RAS operation. Therefore, if a unit is already dropped during RAS or SPS action, it should be assumed to be off-line during system adjustment period.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐
Comment: Yes. WECC allows tripping of generators to meet single contingency performance requirements. WECC also allows planned and controlled load shedding for the proposed Planning Events P2-1, P2-2, P3, P4 and P5, although we agree with the proposed requirements for P4 due to the higher probability of occurrence. If the standard does not allow for non-consequential load shedding of 300 kV and above for P5 scenarios, WECC will develop a regional variance".

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☒ No ☐
Comment: 1) FERC Order 693, Paragraph 1825 regarding TPL-003, Category C – The Commission directed the ERO to modify footnote (c) to Table 1 to clarify the term "controlled load interruption" rather than eliminate its applicability to this performance requirement. 2) FAC-010-1, R2.3 – "…planned or controlled interruption…" This conflicts with "No" for non-consequential load loss allowed in draft TPL.

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: 1. R1.3 requires the provision of firm transfer/Interchange Schedules and resources required to supply load for each Balancing Authority. It may not be possible to have reasonably accurate information on firm transfers and Interchange Schedules for years into the future. Within WECC, we develop base cases that represent reasonably stressed conditions that model power flows stressing various paths. Therefore, within WECC, we design the system to operate at levels that can support all sorts of commerce, including the effects of loop flow, and firm and non-firm contracts, in addition to other possibilities. It would be difficult to develop information from this mixture that includes only firm transactions for such future base cases. In addition, WECC does not allow operations at levels not previously studied. Therefore, an exercise to determine firm transaction/schedules would produce information that will be of little value to support reliability in WECC.

2. R2.7.1.2 requires identification of system deficiencies and accociated corrective action for the Long Term Transmission Planning Horizon. This requirement needs to tie to the lead times to implement the corrective action(s). For example, if a 500 kV transmission line is needed to correct a deficiency that surfaces in the tenth year, then this requirement is reasonable. However, if the deficiency is on a low voltage system, that can be resolved with short lead-time projects (such as installing a small capacitor bank) then this requirement would seem to be too prescriptive.

3. R1.5 requires providing modeling information as part of R1 on a number of transmission planned facilities, including circuit breakers. Since circuit breakers are part of a transmission line, we are not sure how a circuit breaker would be modeled separately, as required.

4. R3.2.1 requires that "studies shall consider the minimum steady state voltage limitations of all generators". Since generators (as well as other facilities) have both high and low voltage limits, the standard should require consideration of both high and low voltage limits.

5. In R.3.2.2, please provide a reference for relay loadability.

6. R.3.3.2.1. requires that Consequential Load loss (expected maximum demand and expected duration) following a single contingency shall be identified in the Planning Assessment. We suggest deleting this requirement. By definition, consequential load loss following a contingency can not be avoided and should not be considered an impact on the operation of the BES. It should be part of local service reliability between an entity and its local regulatory agency or contractual relationship between individual parties and not in a NERC Standard governing the operation of a BES.

7. Proposed revision to R3.5 – "Manual and automatic generation runback and generator tripping are allowed as a response to single and multiple contingencies as long

as Facility Ratings are not exceeded and the result of the generator action, such as loss of reactive resource, impact on reserves, and restart time of tripped unit(s), meets the performance requirements in the tables."

Example for the need for flexibility in the selection of generation runback and/or tripping to meet the requirements of R3.5 – The time period for a particular Emergency Rating might require faster generation redispatch than a runback or set of runbacks are capable of providing. Therefore, it may be necessary to trip one 100 MW unit rather than runback several units for a total of 100 MW. Planning and Operations need flexibility to coordinate with the requirements of Engineering who established the Facility Ratings.

No need for R3.6 with above revision to R3.5.

8. Performance standard "P5" (Q.21- 23) does not allow for the use of load shedding (safety nets) required by some utilities to protect against cascading outages if a transmission line is already out of service and a forced outage of another major element occurs. "System adjustments" might not be possible in a load pocket or local load-serving area to prevent "non-consequential load loss" after loss of a second transmission line to the load-serving area. The use of load shedding for such rare events is an established practice and least cost alternative that does not unreasonably compromise reliability of the WECC system. It is also an acceptable and necessary tradeoff from over burdening customers with additional expensive transmission lines and permitting risk in the West where remote generation resources have historically required power to be carried over long distances.

The tradeoffs between economics (building hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation versus load shedding schemes) and the impact of these rare events should be under the purview of local and state jurisdictions, as long as impacts do not result in cascading events outside of the affected jurisdiction. As long as interconnected reliability or neighboring system operation is not negatively impacted, customer interruption size and frequency should be left to the Transmission Providers discretion and to the jurisdiction of state regulators. The amount of load to be shed and its frequency is primarily an issue for state jurisdiction because it is a matter of the cost/benefit associated with customer service regardless of the voltage level problem. In general, incidences of non-consequential loss of customer load events related to contingencies on the back-bone transmission system are rare when compared to other causes of customer outages. Assuming interruptions to customer service are significant, the state regulators and other related constituents will ultimately be responsible for approving any transmission line facilities or generation additions needed to assure reliability.

Implementing an immediate change to this current established practice is not rational or technically feasible due to the long and arduous regulatory and permitting processes that are required to construct new transmission facilities or new load-side generation. Implementation of the standard as written would take many years. At a minimum, even if it is determined that Congress's intent was to create stricter standards, a phase-in period must be included to allow utilities time to obtain necessary permits, regulatory approval and cost recovery to meet the stricter standards.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: **WECC Committees and Subcommittees**

Lead Contact: **Steve Rueckert**

Contact Organization: **WECC**

Contact Segment: **10**

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Additional Member Name	Additional Member Organization	Region*	Segment*
Spencer Tacke	Modesto Irrigation District	**WECC**	1
Robert Temple	Western Area Power Administration	WECC	9
Greg Lange	Grant County PUD	WECC	3
Dennis Malone	El Paso Electric Company	WECC	1
Garry Chinn	Metropolitan Water District of Southern California	WECC	1,7
Dilip Mahendra	Sacramento Municipal Utility District	WECC	1
Kevin Dasso	Pacific Gas and Electric	WECC	3
Jim Filippi	Pacific Gas and Electric	WECC	1
Laurence Chaset	CPUC	WECC	9
Robert Jenkins	PG&E	WECC	3
Mark Ziering	California Public Utility Commission	WECC	9
Ben Morris	Pacific Gas and Electric	WECC	1
Chifong Thomas	PG&E	WECC	1
Chuck Stigers	Northwestern Energy	WECC	1
James Tucker	Deseret Power	WECC	1
Kristine Buchholz	Pacific Gas and Electric	WECC	1
Robert Mathews	Pacific Gas and Electric	WECC	1
Gary DeShazo	California ISO	WECC	2
Bob Smith	Arizona Public Service	WECC	1

Les Pereira	NCPA	WECC	4

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the

rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☒Do not agree.
Q1. **Comment: A Base Case can only represent the amount of transactions required to serve connected load modeled in the case (local load?). A Path Rating case (developed to represent maximum transfers on a path) would not be considered a base case under this definition. WECC develops base cases to study high power transfers under stressed conditions. Such high power transfers necessarily include both firm and non-firm transaction obligations. Therefore, a base case that represents firm transactions to support "connected load" only, cannot be used to support studies of maximum possible power transfer and is of limited value in WECC. We agree that the above definition is one definition of a base case, but we feel that it can not be the only definition or the limiting definition. We suggest that wording be included that reflects the concept of modeling forecasted or above forecasted load levels if desired, and both firm and non-firm transactions if necessary to model anticipated maximum transfers and represent stressed system conditions as well.** **The definition should refer to the base case as a Computer Simulation Model of the power system, not a Computer Representation of the transmission system, since it is used within a computer program and represents load and generation in addition to transmission. References to "the generation dispatch and firm transaction obligations to supply the connected load" should be removed.** **A base case is a starting case for any condition that needs to be studied, not just a firm transactions case. Firm obligations across the transmission system are many times independent of a specific load service obligation.**	
Q2. **Consequential Load Loss:** Load that is no longer served	☒Agree.

because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Do not agree.
Q2. **Comment: Agree with the definition in concept. However, the wording makes the definition seem unrealistic. There are many examples where a certain amount of voltage sensitive load or motor drives sensitive to angle changes are dropped due to normally cleared electrical faults on the transmission system. These loads are not directly connected to the element being removed from service. This type of sympathetic loss of load is unique to the individual customer load. The design of these loads is not under the control of the utilities when it comes to ability to ride through normally cleared faults. We suggest that this definition be modified to include the loss of sensitive load that is not directly connected to the element being removed.** **We propose the following the definition : Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation, and because of sympathetic tripping associated with normal clearing or mis-operation. Load that is lost because it trips due to low voltages experienced during and immediately following the fault (4-6 cycles?) is also considered consequential load loss. We believe this additional recognition is needed because load lost due to low fault voltages is unavoidable and should not result in a standard violation.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☒Do not agree.
Q3. **Comment: Please add the phrase "two or more elements out of service" to the definition from the previous definition in Table I.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: Please add "or Remedial Action schemes" to the end of the definition. FERC Order 693, paragraph 1773 states (6)"clarifies footnote (b) to Table 1 to allow no firm load or firm transactions to be interrupted except for consequential load loss." There needs to be a distinction made between Interruptible Load and Firm Demand.**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that	☒Agree.

cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Do not agree.
Q7. **Comment: As identified by the modifications above, we believe the definition should be changed to read, "Documented evaluation of future Bulk Electric System needs by the use of performance studies (steady state and dynamic) that cover a range of reasonable or expected assumptions regarding system conditions, applicable time frames, and future plans; including capital reinforcements and operating procedures, SPS/RAS, and other factors (such as asset conditions and age)."**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Plant Stability seems to be a subset of System Stability. Introducing a new term can cause confusion.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the

rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The TP or PA is the most familiar with the system and so would be the best to determine the sensitivities that are more applicable to their particular system. The Standard should not be overly prescriptive. The Standard can make suggestions or list potential sensitivities but let the TP or PA determine those variables to study and the reasonable range of the sensitivities.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: No, as in the response for Question #12. The TP is the best to determine the type of stressing needed for a particular case. This is very evident in the type of cases used for studies in the different parts of the NERC regions.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☒

Comment: We concur with the use of sensitivities as long as the TPs are allowed to determine the sensitivities that are the more appropriate for their systems and not have the sensitivities scripted in the Standard.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: We agree with this conclusion. The Standard language should state that sensitivities are not required in Long-Term Transmission System Planning Horizon but the TP could use sensitivities if desired.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes

all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☒

Comment: It is unclear whether "DSM" in this question refers to reduction in load or increases in distributed resources, or if the resources are directly controllable by the transmission operator. DSM could be used in the mix of solutions that are used to determine the optimal solution for a transmission issue. However, we have concerns about the use of DSM, that is not under the direct control of the Transmission Operator as a stand alone transmission system solution. Please remember the overstated returns from DSM in the last decade that did not materialize. If these overstated values had been used as a transmission system enhancement, then the system would have been compromised with emergency operating solution until the effective transmission enhancements could be realized.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒

Comment: No, this is too onerous. We recognize that, when planning the system and developing a Corrective Action Plan, the transmission planner would have added the potential projects individually (or in small groups) into a case to re-test the system performance. Hoever, R2.7.2 seems to require that all potential projects be added back into the case simultaneously for retesting. There could be many different alternative solutions for each potential problem identified in the different study years without having the base solution first determined for a nearer term case. There can be many combinations of potential solutions for cases further into the future that satisfy the condition being studied. For example, a voltage problem can be solved by the addition of capacitors, completing a bus tie, adding a short line, operating procedure, changing generation dispatch, etc. Even assuming that one set of solutions are picked so the verification study can be performed, logistically this demonstration may be too close to the assessment in the following year. Instead of retesting the potential projects in the Corrective Action Plan on the original base case, it may be better to test them in the base cases prepared for following year's study. Any potential problem that is unresolved will show up again in the following year's assessment. Therefore, a separate demonstration using an "older" case may not be an efficient use of the TPs' and PAs' time and resources.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: The definition of these terms can be vastly different across all TPs. How would this be effectively monitored for compliance with such different definitions? Also, each TO's criteria to go from a proposed project to a committed project can change over time due to other needs and requirements.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: The requirement is similar to the question posed in Question 17. What is the documentation that proves this is needed?

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as

		proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as

		proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒

Comment: We disagree that non-consequential loss of load should not be permitted for this contingency event. We believe that planned and controlled interruption of non-consequential load should be permitted for loss of a non-bus tie breaker (above 300 kV). Losing a non-bus tie breaker could result in simultaneous loss of two or more elements, depending on the bus configuration. Allowing planned and controlled disconnection of some load in the areas would not only prevent cascading and instability (which could result in uncontrolled loss of a larger amount of load), but also enables faster load restoration. Losing a breaker due to an internal fault is a low probability event. To meet this requirement as proposed would require severe pre-contingency curtailment of power transfers, that could impact commerce and/or construction of large number of transmission facilities with the attendant environmental impacts and increased cost to customers.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒

Comment: We disagree that non-consequential loss of load should not be permitted for this contingency event. We believe that planned and controlled interruption of non-consequential load should be permitted for loss of either a generator, a transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV). This contingency event could result in simultaneous loss of two or more elements, depending on the bus configuration. Allowing planned and controlled disconnection of some load in the areas would not only prevent cascading and instability (which could result in uncontrolled loss of a larger amount of load), but also enables faster load restoration. These contingencies are low-probability events. To meet this requirement as proposed would require severe pre-contingency curtailment of power transfers, that could impact commerce and/or construction of a large number of transmission facilities with the attendant environmental impacts and increased cost to customers.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Q27. P4-2: Loss of a generator followed by a System adjustment followed	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability

[1] System adjustment can be manual or automatic

by the loss of a monopolar DC line		and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☒

Comment: We agree with the question asked. In addition, transactions that can be interrupted due to the loss of a DC line should not be limited to the firm transactions, that are dependent on the DC line. It should also include interruptible transactions and other transactions made available through negotiated agreements on both AC and DC lines.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☒

Comment: We agree with the question asked. In addition, because of the time sequence from the start of the fault, through fault clearing and transient dynamic period, the post-transient period to the steady state post-contingency period, there needs to be clear links between the performance requirements in the transient dynamic time period and the steady state time period. For example, if generator dropping or controlled load interruption is allowed in the transient dynamic period, it should also be allowed in the steady state time period that follows. Otherwise, it would put the Transmission Planners and the Planning Authorities in an untenable situation because, once a generator or load is dropped in the first few cycles after the disturbance; it cannot be required to be on line in the minutes that immediately follow.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒

Comment: It appears that Plant Stability Study is a subset of System Stability Study. R4.6.2 states these shall be performed for changes in real power output of a generating unit by more than 10%. Then it states they shall be performed for planning events. R4.5 already covers any contingencies that are an issue and the system already needs to meet some level of performance for loss of the generator. It seems that a change in generation would already be analyzed from a system standpoint as stated in R2.4.3. It appears that material changes to existing generators should be reflected in modeling requirements elsewhere.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒

Comment: We agree with the SDT that simultaneous 3-phase fault on all generating units in a plant is improbable and effort should be better spent studying more probable events. In any case, this Extreme Event is to be considered in the Steady State Table, and stability cases can be run if it is shown to be needed in the power flow study results. We are, however, confused by this question. This question states that the SDT did not include the requirement to consider loss of all generators at a plant in the stability, yet the Extreme Event in the stability table shows in No. 9, "3Ø fault with loss of all generating units at a station".

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☒

Comment: The requirement to include motor load should be extended to other load level periods and not be limited to peak load period only. However, to capture slow voltage recover phenomena, especially in areas of high penetration of refrigerated air conditioning load (e.g. 50% to 60%), would require modeling down to the distribution system voltage level and explicitly representing shunt capacitors and various induction motor types (e.g. equivalents for single phase motors). If the requirement is not extended, dynamic simulations will likely differ significantly from observed system events. We recommend a phase-in period so that the requirement for use of load models should only include regionally accepted load models for which data are available. This requirement can be extended or modified as the Region in which the entities reside adopts new load modeling guidelines.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: All adjustments should be allowed as long as they are realistic and achievable in the time frame required and consistent with other study parameters. For example, automatic adjustments would be required for correction of a stability problem, but manual adjustment should be allowed for correction of a thermal problem if there is no instability problem.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Yes. Agree. Conditions for generation run back for N-1: 1) Run back of generation cannot result in tripping of firm load, 2) power flow should be within the time-limited equipment ratings, 3) frequency should be within allowable limits.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Based on the interpretation of the above question, we are providing two responses to this question. The first responds to the limitations placed on RAS, regardless of what action the RAS initiates. The second response specifically addresses RAS that trips generation.

Response 1: RAS should be allowed for single contingency events. Any sort of RAS should be permitted, but there should be a review of the RAS. If the local entities agree to the RAS, it should be allowed. This addresses cost vs. benefit balance. Entities affected should be the ones that determine the best solution for their situation.

Response 2: Generation tripping can be used for single contingency if such application can be demonstrated through transmission planning studies that:

- The generation tripping is planned and controlled ("planned and controlled" means a pre-planned action(s) based on predetermined system conditions that take corrective measure(s) to maintain acceptable system performance).
- The generation tripping does not result in non-consequential load loss.
- System frequency should be within allowable limits.
- System voltage dip and deviation should be within allowable limits.
- The generator owner(s) agrees to the tripping as planned.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: System adjustment involves operator intervention that would be beyond the time frame of RAS operation. Therefore, if a unit is already dropped during RAS or SPS action, it should be assumed to be off-line during system adjustment period.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐
Comment: Yes. WECC allows tripping of generators to meet single contingency performance requirements. WECC also allows planned and controlled load shedding for the proposed Planning Events P2-1, P2-2, P3, P4 and P5, although we agree with the proposed requirements for P4 due to the higher probability of occurrence. If the standard does not allow for non-consequential load shedding of 300 kV and above for P5 scenarios, WECC will develop a regional variance".

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☒ No ☐
Comment: 1) FERC Order 693, Paragraph 1825 regarding TPL-003, Category C – The Commission directed the ERO to modify footnote (c) to Table 1 to clarify the term “controlled load interruption” rather than

eliminate its applicability to this performance requirement. 2) FAC-010-1, R2.3 – "…planned or controlled interruption…" This conflicts with "No" for non-consequential load loss allowed in draft TPL.

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐

Comment: 1. R1.3 requires the provision of firm transfer/Interchange Schedules and resources required to supply load for each Balancing Authority. It may not be possible to have reasonably accurate information on firm transfers and Interchange Schedules for years into the future. Within WECC, we develop base cases that represent reasonably stressed conditions that model power flows stressing various paths. Therefore, within WECC, we design the system to operate at levels that can support all sorts of commerce, including the effects of loop flow, and firm and non-firm contracts, in addition to other possibilities. It would be difficult to develop information from this mixture that includes only firm transactions for such future base cases. In addition, WECC does not allow operations at levels not previously studied. Therefore, an exercise to determine firm transaction/schedules would produce information that will be of little value to support reliability in WECC.

2. R2.7.1.2 requires identification of system deficiencies and accociated corrective action for the Long Term Transmission Planning Horizon. This requirement needs to tie to the lead times to implement the corrective action(s). For example, if a 500 kV transmission line is needed to correct a deficiency that surfaces in the tenth year, then this requirement is reasonable. However, if the deficiency is on a low voltage system, that can be resolved with short lead-time projects (such as installing a small capacitor bank) then this requirement would seem to be too prescriptive.

3. R1.5 requires providing modeling information as part of R1 on a number of transmission planned facilities, including circuit breakers. Since circuit breakers are part of a transmission line, we are not sure how a circuit breaker would be modeled separately, as required.

4. R3.2.1 requires that "studies shall consider the minimum steady state voltage limitations of all generators". Since generators (as well as other facilities) have both high and low voltage limits, the standard should require consideration of both high and low voltage limits.

5. In R.3.2.2, please provide a reference for relay loadability.

6. R.3.3.2.1. requires that Consequential Load loss (expected maximum demand and expected duration) following a single contingency shall be identified in the Planning Assessment. We suggest deleting this requirement. By definition, consequential load loss following a contingency can not be avoided and should not be considered an impact on the operation of the BES. It should be part of local service reliability between an entity and its local regulatory agency or contractual relationship between individual parties and not in a NERC Standard governing the operation of a BES.

7. Proposed revision to R3.5 – "Manual and automatic generation runback and generator tripping are allowed as a response to single and multiple contingencies as long as Facility Ratings are not exceeded and the result of the generator action, such as loss of reactive resource, impact on reserves, and restart time of tripped unit(s), meets the performance requirements in the tables."

Example for the need for flexibility in the selection of generation runback and/or tripping to meet the requirements of R3.5 – The time period for a particular Emergency Rating might require faster generation redispatch than a runback or set of runbacks are capable of providing. Therefore, it may be necessary to trip one 100 MW unit rather than runback several units for a total of 100 MW. Planning and Operations need flexibility to coordinate with the requirements of Engineering who established the Facility Ratings.

No need for R3.6 with above revision to R3.5.

8. Performance standard "P5" (Q.21- 23) does not allow for the use of load shedding (safety nets) required by some utilities to protect against cascading outages if a transmission line is already out of service and a forced outage of another major element occurs. "System adjustments" might not be possible in a load pocket or local load-serving area to prevent "non-consequential load loss" after loss of a second transmission line to the load-serving area. The use of load shedding for such rare events is an established practice and least cost alternative that does not unreasonably compromise reliability of the WECC system. It is also an acceptable and necessary tradeoff from over burdening customers with additional expensive transmission lines and permitting risk in the West where remote generation resources have historically required power to be carried over long distances.

The tradeoffs between economics (building hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation versus load shedding schemes) and the impact of these rare events should be under the purview of local and state jurisdictions, as long as impacts do not result in cascading events outside of the affected jurisdiction. As long as interconnected reliability or neighboring system operation is not negatively impacted, customer interruption size and frequency should be left to the Transmission Providers discretion and to the jurisdiction of state regulators. The amount of load to be shed and its frequency is primarily an issue for state jurisdiction because it is a matter of the cost/benefit associated with customer service regardless of the voltage level problem. In general, incidences of non-consequential loss of customer load events related to contingencies on the back-bone transmission system are rare when compared to other causes of customer outages. Assuming interruptions to customer service are significant, the state regulators and other related constituents will ultimately be responsible for approving any transmission line facilities or generation additions needed to assure reliability.

Implementing an immediate change to this current established practice is not rational or technically feasible due to the long and arduous regulatory and permitting processes that are required to construct new transmission facilities or new load-side generation. Implementation of the standard as written would take many years. At a minimum, even if it is determined that Congress's intent was to create stricter standards, a phase-in period must be included to allow utilities time to obtain necessary permits, regulatory approval and cost recovery to meet the stricter standards.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

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Kevin Conway	GCPD	WECC	4
Alan Roth	Calpine	WECC	5
Thomas Green	Public Service Co. of Colorado (XCEL)	WECC	1
Brian Keel	Salt River Project	WECC	1
Bill Hosie	TransCanada Energy	WECC	4
Robert Kondziolka	SRP	WECC	1
Tom Duane	Public Service Company of New Mexico	WECC	1,3
Dan Lyons	Aquila	WECC	1
John Collins	Platte River Power	WECC	1

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the

rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☒Do not agree.
Q1. **Comment: A Base Case can only represent the amount of transactions required to serve connected load modeled in the case (local load?). A Path Rating case (developed to represent maximum transfers on a path) would not be considered a base case under this definition. WECC develops base cases to study high power transfers under stressed conditions. Such high power transfers necessarily include both firm and non-firm transaction obligations. Therefore, a base case that represents firm transactions to support "connected load" only, cannot be used to support studies of maximum possible power transfer and is of limited value in WECC. We agree that the above definition is one definition of a base case, but we feel that it can not be the only definition or the limiting definition. We suggest that wording be included that reflects the concept of modeling forecasted or above forecasted load levels if desired, and both firm and non-firm transactions if necessary to model anticipated maximum transfers and represent stressed system conditions as well.** **The definition should refer to the base case as a Computer Simulation Model of the power system, not a Computer Representation of the transmission system, since it is used within a computer program and represents load and generation in addition to transmission. References to "the generation dispatch and firm transaction obligations to supply the connected load" should be removed.** **A base case is a starting case for any condition that needs to be studied, not just a firm transactions case. Firm obligations across the transmission system are many times independent of a specific load service obligation.**	
Q2. **Consequential Load Loss:** Load that is no longer served	☒Agree.

because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Do not agree.
Q2. **Comment: Agree with the definition in concept. However, the wording makes the definition seem unrealistic. There are many examples where a certain amount of voltage sensitive load or motor drives sensitive to angle changes are dropped due to normally cleared electrical faults on the transmission system. These loads are not directly connected to the element being removed from service. This type of sympathetic loss of load is unique to the individual customer load. The design of these loads is not under the control of the utilities when it comes to ability to ride through normally cleared faults. We suggest that this definition be modified to include the loss of sensitive load that is not directly connected to the element being removed.** **We propose the following the definition : Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation, and because of sympathetic tripping associated with normal clearing or mis-operation. Load that is lost because it trips due to low voltages experienced during and immediately following the fault (4-6 cycles?) is also considered consequential load loss. We believe this additional recognition is needed because load lost due to low fault voltages is unavoidable and should not result in a standard violation.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☒Do not agree.
Q3. **Comment: Please add the phrase "two or more elements out of service" to the definition from the previous definition in Table I.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: Please add "or Remedial Action schemes" to the end of the definition. FERC Order 693, paragraph 1773 states (6)"clarifies footnote (b) to Table 1 to allow no firm load or firm transactions to be interrupted except for consequential load loss." There needs to be a distinction made between Interruptible Load and Firm Demand.**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that	☒Agree.

cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Do not agree.
Q7. **Comment: As identified by the modifications above, we believe the definition should be changed to read, "Documented evaluation of future Bulk Electric System needs by the use of performance studies (steady state and dynamic) that cover a range of reasonable or expected assumptions regarding system conditions, applicable time frames, and future plans; including capital reinforcements and operating procedures, SPS/RAS, and other factors (such as asset conditions and age)."**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Plant Stability seems to be a subset of System Stability. Introducing a new term can cause confusion.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the

rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The TP or PA is the most familiar with the system and so would be the best to determine the sensitivities that are more applicable to their particular system. The Standard should not be overly prescriptive. The Standard can make suggestions or list potential sensitivities but let the TP or PA determine those variables to study and the reasonable range of the sensitivities.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: No, as in the response for Question #12. The TP is the best to determine the type of stressing needed for a particular case. This is very evident in the type of cases used for studies in the different parts of the NERC regions.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☒

Comment: We concur with the use of sensitivities as long as the TPs are allowed to determine the sensitivities that are the more appropriate for their systems and not have the sensitivities scripted in the Standard.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: We agree with this conclusion. The Standard language should state that sensitivities are not required in Long-Term Transmission System Planning Horizon but the TP could use sensitivities if desired.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes

all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☒

Comment: It is unclear whether "DSM" in this question refers to reduction in load or increases in distributed resources, or if the resources are directly controllable by the transmission operator. DSM could be used in the mix of solutions that are used to determine the optimal solution for a transmission issue. However, we have concerns about the use of DSM, that is not under the direct control of the Transmission Operator as a stand alone transmission system solution. Please remember the overstated returns from DSM in the last decade that did not materialize. If these overstated values had been used as a transmission system enhancement, then the system would have been compromised with emergency operating solution until the effective transmission enhancements could be realized.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒

Comment: No, this is too onerous. We recognize that, when planning the system and developing a Corrective Action Plan, the transmission planner would have added the potential projects individually (or in small groups) into a case to re-test the system performance. Hoever, R2.7.2 seems to require that all potential projects be added back into the case simultaneously for retesting. There could be many different alternative solutions for each potential problem identified in the different study years without having the base solution first determined for a nearer term case. There can be many combinations of potential solutions for cases further into the future that satisfy the condition being studied. For example, a voltage problem can be solved by the addition of capacitors, completing a bus tie, adding a short line, operating procedure, changing generation dispatch, etc. Even assuming that one set of solutions are picked so the verification study can be performed, logistically this demonstration may be too close to the assessment in the following year. Instead of retesting the potential projects in the Corrective Action Plan on the original base case, it may be better to test them in the base cases prepared for following year's study. Any potential problem that is unresolved will show up again in the following year's assessment. Therefore, a separate demonstration using an "older" case may not be an efficient use of the TPs' and PAs' time and resources.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: The definition of these terms can be vastly different across all TPs. How would this be effectively monitored for compliance with such different definitions? Also, each TO's criteria to go from a proposed project to a committed project can change over time due to other needs and requirements.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: The requirement is similar to the question posed in Question 17. What is the documentation that proves this is needed?

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as

		proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as

		proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒

Comment: We disagree that non-consequential loss of load should not be permitted for this contingency event. We believe that planned and controlled interruption of non-consequential load should be permitted for loss of a non-bus tie breaker (above 300 kV). Losing a non-bus tie breaker could result in simultaneous loss of two or more elements, depending on the bus configuration. Allowing planned and controlled disconnection of some load in the areas would not only prevent cascading and instability (which could result in uncontrolled loss of a larger amount of load), but also enables faster load restoration. Losing a breaker due to an internal fault is a low probability event. To meet this requirement as proposed would require severe pre-contingency curtailment of power transfers, that could impact commerce and/or construction of large number of transmission facilities with the attendant environmental impacts and increased cost to customers.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒

Comment: We disagree that non-consequential loss of load should not be permitted for this contingency event. We believe that planned and controlled interruption of non-consequential load should be permitted for loss of either a generator, a transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV). This contingency event could result in simultaneous loss of two or more elements, depending on the bus configuration. Allowing planned and controlled disconnection of some load in the areas would not only prevent cascading and instability (which could result in uncontrolled loss of a larger amount of load), but also enables faster load restoration. These contingencies are low-probability events. To meet this requirement as proposed would require severe pre-contingency curtailment of power transfers, that could impact commerce and/or construction of a large number of transmission facilities with the attendant environmental impacts and increased cost to customers.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Q27. P4-2: Loss of a generator followed by a System adjustment followed	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability

[1] System adjustment can be manual or automatic

by the loss of a monopolar DC line		and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☒

Comment: We agree with the question asked. In addition, transactions that can be interrupted due to the loss of a DC line should not be limited to the firm transactions, that are dependent on the DC line. It should also include interruptible transactions and other transactions made available through negotiated agreements on both AC and DC lines.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☒

Comment: We agree with the question asked. In addition, because of the time sequence from the start of the fault, through fault clearing and transient dynamic period, the post-transient period to the steady state post-contingency period, there needs to be clear links between the performance requirements in the transient dynamic time period and the steady state time period. For example, if generator dropping or controlled load interruption is allowed in the transient dynamic period, it should also be allowed in the steady state time period that follows. Otherwise, it would put the Transmission Planners and the Planning Authorities in an untenable situation because, once a generator or load is dropped in the first few cycles after the disturbance; it cannot be required to be on line in the minutes that immediately follow.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒

Comment: It appears that Plant Stability Study is a subset of System Stability Study. R4.6.2 states these shall be performed for changes in real power output of a generating unit by more than 10%. Then it states they shall be performed for planning events. R4.5 already covers any contingencies that are an issue and the system already needs to meet some level of performance for loss of the generator. It seems that a change in generation would already be analyzed from a system standpoint as stated in R2.4.3. It appears that material changes to existing generators should be reflected in modeling requirements elsewhere.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒

Comment: We agree with the SDT that simultaneous 3-phase fault on all generating units in a plant is improbable and effort should be better spent studying more probable events. In any case, this Extreme Event is to be considered in the Steady State Table, and stability cases can be run if it is shown to be needed in the power flow study results. We are, however, confused by this question. This question states that the SDT did not include the requirement to consider loss of all generators at a plant in the stability, yet the Extreme Event in the stability table shows in No. 9, "3Ø fault with loss of all generating units at a station".

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☒

Comment: The requirement to include motor load should be extended to other load level periods and not be limited to peak load period only. However, to capture slow voltage recover phenomena, especially in areas of high penetration of refrigerated air conditioning load (e.g. 50% to 60%), would require modeling down to the distribution system voltage level and explicitly representing shunt capacitors and various induction motor types (e.g. equivalents for single phase motors). If the requirement is not extended, dynamic simulations will likely differ significantly from observed system events. We recommend a phase-in period so that the requirement for use of load models should only include regionally accepted load models for which data are available. This requirement can be extended or modified as the Region in which the entities reside adopts new load modeling guidelines.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: All adjustments should be allowed as long as they are realistic and achievable in the time frame required and consistent with other study parameters. For example, automatic adjustments would be required for correction of a stability problem, but manual adjustment should be allowed for correction of a thermal problem if there is no instability problem.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Yes. Agree. Conditions for generation run back for N-1: 1) Run back of generation cannot result in tripping of firm load, 2) power flow should be within the time-limited equipment ratings, 3) frequency should be within allowable limits.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Based on the interpretation of the above question, we are providing two responses to this question. The first responds to the limitations placed on RAS, regardless of what action the RAS initiates. The second response specifically addresses RAS that trips generation.

Response 1: RAS should be allowed for single contingency events. Any sort of RAS should be permitted, but there should be a review of the RAS. If the local entities agree to the RAS, it should be allowed. This addresses cost vs. benefit balance. Entities affected should be the ones that determine the best solution for their situation.

Response 2: Generation tripping can be used for single contingency if such application can be demonstrated through transmission planning studies that:

- The generation tripping is planned and controlled ("planned and controlled" means a pre-planned action(s) based on predetermined system conditions that take corrective measure(s) to maintain acceptable system performance).
- The generation tripping does not result in non-consequential load loss.
- System frequency should be within allowable limits.
- System voltage dip and deviation should be within allowable limits.
- The generator owner(s) agrees to the tripping as planned.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: System adjustment involves operator intervention that would be beyond the time frame of RAS operation. Therefore, if a unit is already dropped during RAS or SPS action, it should be assumed to be off-line during system adjustment period.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐
Comment: Yes. WECC allows tripping of generators to meet single contingency performance requirements. WECC also allows planned and controlled load shedding for the proposed Planning Events P2-1, P2-2, P3, P4 and P5, although we agree with the proposed requirements for P4 due to the higher probability of occurrence. If the standard does not allow for non-consequential load shedding of 300 kV and above for P5 scenarios, WECC will develop a regional variance".

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☒ No ☐
Comment: 1) FERC Order 693, Paragraph 1825 regarding TPL-003, Category C – The Commission directed the ERO to modify footnote (c) to Table 1 to clarify the term “controlled load interruption” rather than

eliminate its applicability to this performance requirement. 2) FAC-010-1, R2.3 – "…planned or controlled interruption…" This conflicts with "No" for non-consequential load loss allowed in draft TPL.

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐

Comment: 1. R1.3 requires the provision of firm transfer/Interchange Schedules and resources required to supply load for each Balancing Authority. It may not be possible to have reasonably accurate information on firm transfers and Interchange Schedules for years into the future. Within WECC, we develop base cases that represent reasonably stressed conditions that model power flows stressing various paths. Therefore, within WECC, we design the system to operate at levels that can support all sorts of commerce, including the effects of loop flow, and firm and non-firm contracts, in addition to other possibilities. It would be difficult to develop information from this mixture that includes only firm transactions for such future base cases. In addition, WECC does not allow operations at levels not previously studied. Therefore, an exercise to determine firm transaction/schedules would produce information that will be of little value to support reliability in WECC.

2. R2.7.1.2 requires identification of system deficiencies and accociated corrective action for the Long Term Transmission Planning Horizon. This requirement needs to tie to the lead times to implement the corrective action(s). For example, if a 500 kV transmission line is needed to correct a deficiency that surfaces in the tenth year, then this requirement is reasonable. However, if the deficiency is on a low voltage system, that can be resolved with short lead-time projects (such as installing a small capacitor bank) then this requirement would seem to be too prescriptive.

3. R1.5 requires providing modeling information as part of R1 on a number of transmission planned facilities, including circuit breakers. Since circuit breakers are part of a transmission line, we are not sure how a circuit breaker would be modeled separately, as required.

4. R3.2.1 requires that "studies shall consider the minimum steady state voltage limitations of all generators". Since generators (as well as other facilities) have both high and low voltage limits, the standard should require consideration of both high and low voltage limits.

5. In R.3.2.2, please provide a reference for relay loadability.

6. R.3.3.2.1. requires that Consequential Load loss (expected maximum demand and expected duration) following a single contingency shall be identified in the Planning Assessment. We suggest deleting this requirement. By definition, consequential load loss following a contingency can not be avoided and should not be considered an impact on the operation of the BES. It should be part of local service reliability between an entity and its local regulatory agency or contractual relationship between individual parties and not in a NERC Standard governing the operation of a BES.

7. Proposed revision to R3.5 – "Manual and automatic generation runback and generator tripping are allowed as a response to single and multiple contingencies as long as Facility Ratings are not exceeded and the result of the generator action, such as loss of reactive resource, impact on reserves, and restart time of tripped unit(s), meets the performance requirements in the tables."

Example for the need for flexibility in the selection of generation runback and/or tripping to meet the requirements of R3.5 – The time period for a particular Emergency Rating might require faster generation redispatch than a runback or set of runbacks are capable of providing. Therefore, it may be necessary to trip one 100 MW unit rather than runback several units for a total of 100 MW. Planning and Operations need flexibility to coordinate with the requirements of Engineering who established the Facility Ratings.

No need for R3.6 with above revision to R3.5.

8. Performance standard "P5" (Q.21- 23) does not allow for the use of load shedding (safety nets) required by some utilities to protect against cascading outages if a transmission line is already out of service and a forced outage of another major element occurs. "System adjustments" might not be possible in a load pocket or local load-serving area to prevent "non-consequential load loss" after loss of a second transmission line to the load-serving area. The use of load shedding for such rare events is an established practice and least cost alternative that does not unreasonably compromise reliability of the WECC system. It is also an acceptable and necessary tradeoff from over burdening customers with additional expensive transmission lines and permitting risk in the West where remote generation resources have historically required power to be carried over long distances.

The tradeoffs between economics (building hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation versus load shedding schemes) and the impact of these rare events should be under the purview of local and state jurisdictions, as long as impacts do not result in cascading events outside of the affected jurisdiction. As long as interconnected reliability or neighboring system operation is not negatively impacted, customer interruption size and frequency should be left to the Transmission Providers discretion and to the jurisdiction of state regulators. The amount of load to be shed and its frequency is primarily an issue for state jurisdiction because it is a matter of the cost/benefit associated with customer service regardless of the voltage level problem. In general, incidences of non-consequential loss of customer load events related to contingencies on the back-bone transmission system are rare when compared to other causes of customer outages. Assuming interruptions to customer service are significant, the state regulators and other related constituents will ultimately be responsible for approving any transmission line facilities or generation additions needed to assure reliability.

Implementing an immediate change to this current established practice is not rational or technically feasible due to the long and arduous regulatory and permitting processes that are required to construct new transmission facilities or new load-side generation. Implementation of the standard as written would take many years. At a minimum, even if it is determined that Congress's intent was to create stricter standards, a phase-in period must be included to allow utilities time to obtain necessary permits, regulatory approval and cost recovery to meet the stricter standards.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☒ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☒	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: By definition, Extreme Events are not Planning Events. However, only the definition Planning Events has a requirement to meeting performance requirements. I believe Extreme Events also have performance requirements under R3.4 and its definition should reflect this.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☐Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	

Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☐Do not agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: This definition mixes the use of the word "plant" and "generator" which have two different meanings. Suggest re-naming as Generator Stability Study and allow the study of multiple generators at a single site as a plant. The use of "generator" vs. "plant" should also be consistent throughout the standard.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: Suggest replacing the words "annual studies" with "Planning Assessment".**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the

rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☐
Comment: Sensitivity cases do not consider/mention new transmission facilities additions. Although the Transmission Planner should have the ability to determine appropriate sensitivities, system performance based on the delay of new transmission facilities should be considered (may be covered under R2.1.3.3 but could be more explicit).

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: The Transmission Planner should have the ability to determine appropriate sensitivities based on changes to the assumptions within the study. However, those sensitivities should be developed in an open transmission planning process consistent with the transmission planning principles within FERC Order 890.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: The standard should require long-term sensitivity studies to the extent that the open transmission planning process within FERC Order 890 identifies the need for the sensitivities.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: The effect of DSM should be considered in corrective action plans to the extent that DSM can reduce overall load growth and change the timing of new transmission facilities.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: It is difficult to fully prescribe a methodology to define a "study area". It is most appropriate for the Transmission Planning to develop study areas based on and consistent with the transmission planning principles within Order 890.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☒
Comment: If the standard makes a differentiation between "committed" and "proposed" projects, definitions for each, within the standard itself, are necessary. Within the context of R2.7, it is not clear what impact the differentiation between "committed" and "proposed" has on the requirement itself. R2.7 requires Corrective Action Plans to address deficiencies within the performance analysis of the events in Table 1 and Table 2. A fundamental underpinning of R2.7 should be that Corrective Action Plans are developed consistent with the transmission planning principles of Order 890.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment: As stated in response to Q18, it is unclear why the differentiation between "committed" and "proposed" is actually necessary. The standard must allow flexibility, so that the evolution of a Corrective Action Plan can occur within the context of the transmission planning principles of FERC Order 890.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	It is not clear why the standard has established 300 kV as the differentiation point between allowing non-consequential load loss and not allowing it. The standard has established different planning requirements for different voltage levels without establishing why the differentiation is necessary. While transmission facilities over 300 kV in some areas of the country may be considered the "backbone", it is not universally applicable; in some areas, 230 kV and even 138 kV represent the "backbone" of the transmission system. The standard should not bisect the transmission system and apply two

		different planning requirements without clearly establishing why the differentiation is necessary. Additionally, Table 1 needs to clarify the use of the term "Firm Transfers" and the interruption of "Firm Transfers" as an acceptable response to an event. "Firm transfers" is not a standard transmission service offering under the ProForma OATT. The standard must be consistent with service types defined under the ProForma OATT. Suggest that the phrasse "Firm Transfers" be replaced with "Firm Transmission Service consisting of Point-to-Point and Network Integration Transmission Service"
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	See response to Q20.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	See response to Q20
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	See response to Q20

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☐
Comment: See response to Q20

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☐
Comment: See response to Q20

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	It is inappropriate to rely on Non-consequential loss of load as an ultimate Corrective Action Plan for this event. However, non-consequential load loss can provide interim relief until such time as the Corrective Action Plan is actually constructed and in-service.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	See response to Q26.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	See response to Q26.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	See response to Q26.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment:

[1] System adjustment can be manual or automatic

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are

permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: The use of RAS or SPS should not constitute a long-term Corrective Action Plan to address deficiencies. The use of RAS and SPS should be limited to that period of time necessary to place facilities in-service to address the deficiency.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: The use of RAS or SPS should not constitute a long-term Corrective Action Plan to address deficiencies. The use of RAS and SPS should be limited to that period of time necessary to implement expansion of facilities to address the deficiency.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: The use of RAS or SPS should not constitute a long-term Corrective Action Plan to address deficiencies. The use of RAS and SPS should be limited to that period of time necessary to implement expansion of facilities to address the deficiency.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: The use of RAS or SPS should not constitute a long-term Corrective Action Plan to address deficiencies. The use of RAS and SPS should be limited to that period of time necessary to implement expansion of facilities to address the deficiency.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: Within R1.1.2, the Planning Coordinator and the Transmission Planner is required to define what constitutes "normal weather patterns" for the purpose of establishing load forecasts. However, the PC and/or TP are not the appropriate entities to establish "normal weather patterns"; the LSEs, who actually develop load forecasts and have the expertise, are the appropriate entities to establish normal weather patterns. Additionally, this requirement should consider requiring the 50/50 probability load forecast from the LSEs.

Consideration of Comments — 1st Draft of TPL-001-1 — Transmission System Planning Performance Requirements

The Assess Transmission Future Needs Standards Drafting Team thanks all commenters who submitted comments on the first draft of the standard. This standard was posted for a 30-day public comment period from September 12, 2007 through October 26, 2007. The drafting team asked stakeholders to provide feedback on the standard through a special Standard Comment Form. There were more than 80 sets of comments, including comments from 236 different people from more than 80 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received, the drafting team is recommending a second posting of the revised standard.

Definitions and the following requirements have been changed due to industry comment as specifically cited in the responses:

Definitions

- Base Case - the SDT removed "Base Case" as a defined term.
- Bus-tie Breaker – the SDT added a definition.
- Consequential Load Loss – the SDT reworded the definition to better clarify that this is Load loss that occurs when the source to that Load is lost or Load that is lost due to the Load's transient response to the event being studied and to eliminate confusion regarding references to concepts such as fault clearing action, mis-operation, or radial Load.
- Extreme Events – the SDT revised the definition to clarify that Extreme Events have a "lower probability of occurrence than Planning Events."
- Long-Term Transmission Planning Horizon - the SDT revised the definition to clarify when the horizon may extend beyond ten years
- Non-Consequential Load Loss - the SDT revised the definition to improve its clarity and to specify that this is non-interruptible load
- Planning Assessment - the SDT revised the definition to be more succinct, to eliminate the description of the possible range of assumptions, and to clarify that the assessment is an evaluation of Transmission System performance (not needs) and Corrective Action Plans associated with identified deficiencies.
- Planning Coordinator – the SDT added the definition from the Functional Model.
- Plant Stability Study - the SDT replaced the word, "plant" with the term, "generating unit," and modified the wording to improve its clarity.
- System Stability Study - the SDT revised the definition to add further clarity
- Year One - the SDT modified the definition to clarify that Year One is the first year that requires assessment, not study, and to clarify that the planning window begins 12 to 18 months from the completion of the previous assessment.

Sensitivity Studies

The need to conduct sensitivity studies was a directive in FERC Order 693 paragraphs 1694,1704, and 1706. The revised standard provides guidance on what needs to be included in sensitivity studies while not being totally prescriptive.

- Requirement R2.1.3 and Requirement R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies.
- Requirement R2.1.4 and Requirement R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system.
- Requirement R2.4.3 was modified to stipulate that the entity shall provide rational for why sensitivity on the list were or were not included in the sensitivity studies and that the entity may consider additional sensitivities that are appropriate for its own System.
- Requirement R.2.4.3.2 (related to stability analysis) was changed to use the same phrase as used in R.2.1.3.2 (related to steady state analysis) "Modification of expected transfers"
- Requirement R.2.4.3.4 (related to stability analysis) was changed to use the same phrase as used in R.2.1.3.4 (related to steady state analysis) "Variability and outages of reactive resources."
- A new requirement, now numbered as Requirement R2.7.2, has been added to clarify that the sensitivity studies do not in themselves establish the need for a corrective action but the entity must explain how the sensitivities affected the Corrective Action Plan.

Corrective Action Plans

Requirements for corrective action plans have been modified to clarify that these do not need to be developed solely to meet performance requirements for sensitivities and to eliminate subrequirements that distinguished between “committed” and “proposed” projects. The standard now refers to “actions” needed to achieve required System performance without trying to distinguish between “committed” and “proposed” projects. The following adjustments were made to the list of elements that must be included in Corrective Action Plans:

- Sub-requirement R2.7.1 was modified to clarify that there are many options that can be used to achieve required system performance when studies show system deficiencies, including DSM.
- Sub-requirement R2.7.2 to perform re-test has been removed. The purpose of the Corrective Action Plan is to list the actions that are needed to meet performance requirements. The studies, current, and/or past as appropriate, as well as the extent of the size of the study area, are performed to support compliance and demonstrate that the requirements are met. The standard assumes that the actions were developed and verified using the current and past studies that were used to uncover deficiencies and confirm adherence to the performance requirements.
- Sub-requirement R2.7.3 to document the criteria for determining committed and proposed projects and to identify each project as either committed or proposed has been deleted.
- Sub-requirement R2.7.4 that included language restricting the removal of committed projects has been deleted.

- A new Sub-requirement R2.7.2 has been added that requires a description of the consideration of sensitivity studies was applied to the actions needed to achieve system performance

Performance Requirements

- The SDT modified the performance requirements relative to Non-Consequential Loss of Load and revised Tables 1 & 2 to add greater detail and provide for more situations where it is acceptable to lose Non-Consequential Load.
- The second draft proposes that no Non-Consequential Load may be tripped for the loss of a 300 kV (or higher) bus section for a first contingency event.
- The second draft proposes permitting the loss of Non-Consequential Load to meet the Transmission performance requirements for events where there are two independent overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. (See Performance Table Planning Event P6.)
- The second draft proposes allowing load shedding as an acceptable system adjustment action for the entire BES following the loss of the second Transmission outage.
- Moved P2-3 into the P1 category as loss of a single pole of a dc line is similar to loss of a generator or transmission circuit.
- Clarified the distinction between Generating Unit Stability Study and System Stability Study by adding a definition of Generating Unit Stability Study and modifying the definition of System Stability Study – and making modifications to R2.5.
- Removed Extreme Event #9 from Stability Analyses for Extreme Events (3-phase fault and loss of all generating units at a station). The events which remove all of a generating unit from the System occur over a longer period of time which is more applicable in the steady state analyses. These are Extreme Events which are relevant for steady state but not for Stability analyses.
- Modified R2.4.1 to recognize the difficulty of obtaining accurate dynamic Load models including induction motors.
- Modified Requirement R 3.6 (now R3.5) of the steady state portion of the Planning Assessment to specify the conditions under which manual and automatic generation runback and tripping can be used to meet single and multiple Contingency performance requirements and to make it clear that all Facilities must always remain within applicable thermal and voltage ratings.

Generation Run Back and Tripping

- Added R3.5.2 and R3.5.3 to clarify that manual or automatic generation run-back is allowed as a response to single and multiple Contingencies as long as all Facilities shall be operating within their Facility Ratings and as long as a sustainable, stable, operating condition is maintained.
- Modified Requirement R 3.5 to specify the conditions under which automatic (or manual) generation runback can be used to meet single (or multiple) contingency performance requirements and to make it clear that all facilities must always remain within applicable thermal and voltage ratings.
- Modified R3.5 to allow the use of SPS/RAS for single or multiple Contingencies with limitations described in Requirements R3.5.1 through R3.5.3.

Modeling

- A new requirement was added (to replace R1.4) to perform the tests outlined in the performance requirements table and demonstrate that thermal and voltage limits are met, however, all manual and/or automatic actions are allowed (within time constrained ratings) including curtailing firm transfers and controlled shedding of Non-Consequential firm Load.

- In addition, both performance tables have been changed.

Some other major changes included:

- Created a new requirement concerning short circuit analysis.
- Created a requirement to document proxies for instability, cascading outages and uncontrolled islanding.
- Changed requirements to clarify the actions allowed to prepare for the next Contingency.
- Changed requirements to clarify that Facility Ratings may be different for, and a function of, different durations

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Assess-Transmission-Future-Needs.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	William Quaintance	ABB Grid Systems Consulting										
2.	John Bussman	AECI	✓									
3.	Anita Lee	AESO		✓								
4.	Darrell Pace (G11)	Alabama Electric Coooperative	✓									
5.	Wesley O. Davis	Alcoa Power Generating, Inc.	✓		✓		✓		✓			
6.	William J. Smith	Allegheny Power	✓									
7.	Ken Goldsmith (G9)	ALTW										
8.	Rick Foster (G12)	Ameren										
9.	John Sullivan (G11)	Ameren	✓									
10.	Curtis Stepanek (G14)	Ameren	✓									
11.	Eugene Warnecke (G14)	Ameren	✓									
12.	John E. Sullivan	Ameren Services	✓									
13.	Thad K. Ness (G2)	American Electric Power	✓		✓		✓	✓				
14.	Takis Laios (G2)	American Electric Power	✓									
15.	Jon Riley (G2)	American Electric Power	✓									
16.	Rob O'Keefe (G2)	American Electric Power	✓									
17.	Navin Bhatt (G2)	American Electric Power	✓									
18.	Scott Rainbolt (G2)	American Electric Power	✓									
19.	Omar Hellalat (G2)	American Electric Power	✓									
20.	Roger Bentz (G2)	American Electric Power	✓									
21.	Vance Beauregard (G2)	American Electric Power	✓									
22.	Phil Cox (G2)	American Electric Power					✓	✓				
23.	E. Nick Henery (G4)	APPA			✓	✓						
24.	Allen Mosher (G4)	APPA			✓	✓						
25.	Baj Agrawal	Arizona Public Service Co.	✓		✓		✓					

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
26.	Jason Shaver	ATC	✓									
27.	Phil Park	BCTC		✓								
28.	Dave Rudolph (G9)	BEPC										
29.	Chris Bradley (G14)	Big Rivers Electric Corporation	✓									
30.	Chuck Matthews (G3)	BPA Transmission	✓									
31.	Berhanu Tesema (G3)	BPA Transmission	✓									
32.	Kendall Rydell (G3)	BPA Transmission	✓									
33.	Kyle Kohne (G3)	BPA Transmission	✓									
34.	Melvin Rodrigues (G3)	BPA Transmission	✓									
35.	David Albers	Brazos Electric Cooperative	✓									
36.	Charles Cumpton	California ISO		✓								
37.	Paul Rocha (see attachment)	CenterPoint Energy	✓									
38.	David M Conroy (see attachment)	Central Maine Power Company	✓									
39.	Gary Brinkworth (G7)	City of Tallahassee	✓									
40.	Jeff Knottek	City Utilities/Springfield	✓		✓							
41.	Karl Kohlrus (G8)	City Water, Light & Power (IL)					✓					
42.	Karl E. Kohlrus	City Water, Light and Power			✓	✓	✓					
43.	Edwin Thompson (G10)	ConEd										
44.	Michael Gildea (G10)	Constellation Energy										
45.	Blake Williams	CPS Energy	✓									
46.	John K. Loftis, Jr. (G1)	Dominion VA Power	✓									
47.	Kirit Doshi (G1)	Dominion VA Power	✓									
48.	Graig Crider (G1)	Dominion VA Power	✓									
49.	Solomon Yirga (G1)	Dominion VA Power	✓									
50.	Nelson Burks (G1)	Dominion VA Power	✓									
51.	Ashwani Vaswani (G1)	Dominion VA Power	✓									
52.	Mehdi Shakibafar (G1)	Dominion VA Power	✓									
53.	Abdur Masood (G1)	Dominion VA Power	✓									
54.	Thanh Nguyen (G1)	Dominion VA Power	✓									
55.	Ed Broasdale (G1)	Dominion VA Power	✓									

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
56.	Al MacDonald (G1)	Dominion VA Power	✓									
57.	William Bigdely (G1)	Dominion VA Power	✓									
58.	Ronnie Bailey (G1)	Dominion VA Power	✓									
59.	Greg Rowland	Duke Energy	✓		✓							
60.	Anthony Williams (G12)	Duke Energy Carolinas										
61.	Brian D. Moss (G14)	Duke Energy Carolinas	✓									
62.	Keith Yocum	E ON US										
63.	Larry Rodriguez	Entegra Power					✓	✓				
64.	Sujit Mandal (G12)	Entergy										
65.	Charles Long (G11)	Entergy	✓									
66.	Kham Vongkhamchanh (G14)	Entergy	✓									
67.	Charles W. Long	Entergy Services, Inc.	✓		✓		✓					
68.	Doug Powell	Entergy Services, Inc.	✓		✓		✓					
69.	H. Steven Myers	ERCOT ISO		✓								
70.	Eric Mortenson	Exelon	✓		✓							
71.	Doug Hohlbaugh (G5)	FirstEnergy Corporation	✓		✓		✓	✓				
72.	John Stephens (G5)	FirstEnergy Corporation	✓		✓		✓	✓				
73.	Dave Folk (G5)	FirstEnergy Corporation	✓		✓		✓	✓				
74.	Sam Ciccone (G5)	FirstEnergy Corporation	✓		✓		✓	✓				
75.	W. R. Schoneck (G7)	Florida Power & Light Company			✓							
76.	C. Martin Mennes (G7)	Florida Power & Light Company	✓									
77.	Robert A. Birch (G7)	Florida Power & Light Company					✓					
78.	John W. Shaffer (G7)	Florida Power & Light Company			✓							
79.	A. L. Barredo (G7)	Florida Power & Light Company			✓							
80.	Hector Sanchez (G6)	Florida Power and Light	✓		✓		✓					
81.	Marty Mennes (G6)	Florida Power and Light	✓		✓		✓					
82.	W. R. Schoneck (G6)	Florida Power and Light	✓		✓		✓					
83.	R. A. Birch (G6)	Florida Power and Light	✓		✓		✓					
84.	A. L. Barredo (G6)	Florida Power and Light	✓		✓		✓					
85.	C. Candelaria (G6)	Florida Power and Light	✓		✓		✓					
86.	J. W. Shaffer (G6)	Florida Power and Light	✓		✓		✓					

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
87.	Fred McNeill (G7)	Florida Reliability Coordinating Council										✓
88.	Vicente Ordax (G7)	FRCC										✓
89.	Earl Fair (G7)	Gainesville Regional Utilities	✓									
90.	Angela Battle	Georgia Transmission Corp	✓									
91.	Ken Wofford (G14)	Georgia Transmission Corp.	✓									
92.	David Kiguel (G10)	Hydro One Networks										
93.	Roger Champagne (G10)	HydroQuebec TransEnergie										
94.	Sylvain Clermont (G10)	HydroQuebec TransEnergie										
95.	Roger Champagne	Hydro-Québec TransÉnergie	✓									
96.	Ron Falsetti	IESO		✓								
97.	Kathleen Goodman (G10)	ISO New England										
98.	Brian F. Thumm	ITC Holdings										
99.	Jim Cyrulewski (G8)	JDRJC Associates								✓		
100.	Donald Gilbert (G7)	JEA					✓					
101.	Ted E. Hobson (G7)	JEA	✓									
102.	Gary Baker (G7)	JEA			✓							
103.	Don Gilbert	JEA	✓		✓		✓					
104.	Harold G. Wyble	Kansas City Power and Light	✓									
105.	Tim Wu	LADWP	✓		✓		✓					
106.	Scotty Touchette	Lafayette Utilities System	✓		✓		✓					
107.	Paul Elwing (G7)	Lakeland Electric					✓					
108.	Richard Gilbert (G7)	Lakeland Electric			✓							
109.	Larry E. Watt (G7)	Lakeland Electric	✓									
110.	Paul Shipps (G7)	Lakeland Electric						✓				
111.	Sergio Garza	LCRA TSC	✓									
112.	Eric Ruskamp (G9)	LES										
113.	Donald Nelson (G10)	MA Dept of Public Utilities										
114.	Joseph DePoorter (G8)	Madison Gas & Electric				✓						
115.	Ron Mazur	Manitoba Hydro	✓		✓		✓	✓				
116.	Jerry Tang (G14)	MEAG	✓									
117.	David Weekley (G11)	MEAG Power	✓									

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
118.	Robert Coish (G9)	MHEB										
119.	David Jacobson (G9)	MHEB										
120.	Ron Mazur (G9)	MHEB										
121.	Allen McKee (G11)	Midwest ISO (MISO)		✓								
122.	Allen McKee (G8)	Midwest ISO, Inc.		✓								
123.	Carol Gerou (G9)	Minnesota Power										
124.	Terry Bilke (G9)	MISO										
125.	Tom Mielnik (G9)	MRO		✓								
126.	Michael Brytowski (G9)	MRO										
127.	Jerry Tang	Municipal Electric Authority of Georgia	✓									
128.	Lewis Ross	Muscatine Power and Water	✓		✓		✓			✓		
129.	Carol Sedewitz	National Grid	✓									
130.	Denise Roeder (G14)	NC Municipal Power Agency #1			✓							
131.	James R. Manning	NCEMC			✓	✓	✓					
132.	Robert S. Beadle	NCEMC			✓	✓	✓					
133.	Denise Roeder	NCMPA			✓							
134.	Bob Cummings	NERC Transmission Issues Subc.										
135.	Randy MacDonald (G10)	New Brunswick System Operator										
136.	Kathleen Goodman	New England ISO		✓								
137.	Walter A. Pfuntner	New York ISO		✓								
138.	Greg Campoli (G10)	New York ISO										
139.	Ralph Rufrano (G10)	New York Power Authority										
140.	Al Adamson (G10)	New York State Reliability Council										
141.	Michael Ranalli (G10)	Ngrid US										
142.	Reza Rizvi (G10)	Northeast Power Coordinating Council										
143.	Rick White	Northeast Utilities	✓									
144.	Murale Gopinathan (G10)	Northeast Utilities										
145.	John Leland	Northwestern Energy	✓									
146.	Guy V. Zito (G10)	NPCC										✓
147.	Gregory Sullivan	Nstar Electric and Gas Corp.	✓		✓							
148.	John P. Mayhan	OPPD	✓		✓			✓				
149.	Keith Mutters (G7)	Orlando Utilities Commission			✓							

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
150.	Ganesh Velummylum (G17)	PJM (ISO/RTO)		✓								
151.	John Collins	Platte River Power Authority	✓									
152.	Mark Byrd	Progress Energy Carolinas	✓		✓		✓	✓				
153.	John O'Connor (G12)	Progress Energy Carolinas										
154.	Phil Creech (G14)	Progress Energy Carolinas	✓									
155.	Lee Schuster (G7)	Progress Energy Florida			✓							
156.	Bart White (G7)	Progress Energy Florida			✓							
157.	Bart White	Progress Energy Florida, Inc.	✓		✓		✓	✓				
158.	Jeffrey Mitchell	ReliabilityFirst Corp.										✓
159.	Mark Kuras (G17)	RFC		✓								
160.	Mahendra Patel (G17)	RFC		✓								
161.	Paul McGlynn (G17)	RFC		✓								
162.	Mohamed Osman (G17)	RFC		✓								
163.	Chuck Liebold (G17)	RFC		✓								
164.	Leanne Harrison (G17)	RFC		✓								
165.	Susan McGill (G17)	RFC		✓								
166.	Terry Blackwell (G13)	Santee Cooper	✓		✓		✓	✓				
167.	James Peterson (G13)	Santee Cooper	✓									
168.	Shawn T. Abrams (G13)	Santee Cooper	✓									
169.	Vicky Budreau (G13)	Santee Cooper	✓									
170.	Art Brown (G13)	Santee Cooper	✓									
171.	William Gaither (G13)	Santee Cooper	✓									
172.	Glenn Stephens (G13)	Santee Cooper	✓									
173.	Rene' Free (G13)	Santee Cooper	✓									
174.	Frank Caston (G13)	Santee Cooper	✓									
175.	Rick Thornton (G13)	Santee Cooper	✓									
176.	James M. Jackson (G13)	Santee Cooper	✓									
177.	Wayne Guttormson	SASK Power	✓		✓		✓	✓				

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
178.	Al McMeekin (G14)	SC Electric & Gas Company	✓									
179.	Clay Young (G14)	SC Electric & Gas Company			✓							
180.	Phil Kleckley (G11)	SC Electric and Gas			✓							
181.	Scott Inglebritson	Seattle City Light	✓		✓	✓	✓					
182.	Sharma Kolluri (G12)	SERC EC DRS	✓									
183.	Travis Sykes (G11)	SERC EC PSS	✓									
184.	Pat Huntley (G11)	SERC Reliability Corp										✓
185.	Carter Edge (G14)	SERC Reliability Corporation										✓
186.	Maria Haney (G14)	SERC Reliability Corporation										✓
187.	Jim Peterson (G14)	SERC RRS OPS	✓									
188.	Philip R. Kleckley	South Carolina Electric & Gas	✓		✓		✓					
189.	John Ciza (G15)	Southern Company - Generation	✓									
190.	Tom Higgins (G15)	Southern Company - Generation					✓					
191.	Terry Crawley (G15)	Southern Company - Generation					✓					
192.	Roman Carter (G15)	Southern Company - Generation	✓									
193.	Marc Butts (G15)	Southern Company - Transmission	✓									
194.	J. T. Wood (G15)	Southern Company - Transmission	✓									
195.	Jim Viikinsalo (G15)	Southern Company - Transmission	✓									
196.	Keith Calhoun (G15)	Southern Company - Transmission	✓									
197.	Shih-Min Hsu (G15)	Southern Company - Transmission	✓									
198.	Tom Sims (G15)	Southern Company - Transmission	✓									
199.	Gary Gorham (G15)	Southern Company - Transmission	✓									
200.	Dave Slovensky (G15)	Southern Company - Transmission	✓									
201.	Jeremy Bennett (G15)	Southern Company - Transmission	✓									
202.	Bob Jones (G15)	Southern Company - Transmission	✓									
203.	Bill Botters (G15)	Southern Company - Transmission	✓									
204.	Mike Bartlett (G15)	Southern Company - Transmission	✓									
205.	Maryanne Mujica (G15)	Southern Company - Transmission	✓									
206.	Lee Taylor (G15)	Southern Company -	✓									

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
		Transmission										
207.	Perry Stowe (G15)	Southern Company - Transmission	✓									
208.	Rod Hardiman (G15)	Southern Company - Transmission	✓									
209.	Doug McLaughlin (G15)	Southern Company - Transmission	✓									
210.	Randy Castello (G15)	Southern Company - Transmission	✓									
211.	Chuck Chakravarthi (G15)	Southern Company - Transmission	✓									
212.	Roger Green (G15)	Southern Company - Transmission					✓					
213.	Bob Jones (G11)	Southern Company Services	✓									
214.	Jim Busbin (G15)	Southern Company Services, Inc.	✓									
215.	Bob Jones (G12)	Southern Company Services, Inc. - Trans										
216.	Lee Taylor (G12)	Southern Company Services, Inc. - Trans										
217.	Rod Hardiman (G14)	Southern Company Services, Inc. - Trans	✓									
218.	Doug McLaughlin (G14)	Southern Company Services, Inc. - Trans	✓									
219.	Jonathan Sykes	SRP	✓									
220.	Ronald L. Donahey	Tampa Electric Company			✓							
221.	Thomas J. Szelistowski (G7)	Tampa Electric Company	✓									
222.	Scott Helyer	Tenaska, Inc.					✓					
223.	Tom Cain (G12)	Tennessee Valley Authority										
224.	Ian Grant (G14)	Tennessee Valley Authority	✓									
225.	Marjorie Parsons (G14)	Tennessee Valley Authority	✓									
226.	Michael Clements (G14)	Tennessee Valley Authority	✓									
227.	David Till	Tennessee Valley Authority	✓									
228.	Biju Gopi (G10)	The IESO, Ontario										
229.	Alex Boutsioulis	The United Illuminating Company	✓									
230.	Mark Graham	Tri-State G&T										
231.	Gary Trent	Tucson Electric Power Company	✓									
232.	Jim Haigh (G9)	WAPA										
233.	Steve Rueckert (G16)	WECC Committees and Subgroups										✓
234.	Christopher Plante	Wisconsin Public Service Corp			✓	✓	✓					

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
235	Neal Balu (G9)	WPS			✓		✓	✓				
236	Pam Oreschnick (G9)	XCEL										

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group
G1 – Dominion Virginia Power
G2 – American Electric Power
G3 – BPA Transmission
G4 – American Public Power Association
G5 – FirstEnergy Corporation
G6 – Florida Power & Light Company
G7 – FRCC
G8 – Midwest ISO, Inc. (MISO)
G9 – Midwest Reliability Organization (MRO)
G10 – NPCC RCG
G11 – SERC EC PSS
G12 – SERC EC DRS
G13 – Santee Cooper
G14 – SERC RRS OPS
G15 – Southern Company Services, Inc.
G16 – WECC Committees and Subgroups
G17 – PJM (ISO/RTO)

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A) New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

1) **Q1. Base Case: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.**

Summary Response: After reviewing the comments to this proposed definition and the use of the term "base case" in the standard, the SDT determined that "Base Case" does not need to be a defined term.

Organization	Q1. **Comment**	Agree.	Don't agree.
AECC	Neutral. This is a little wordy but I don't have a better answer.		
ABB	Agree but delete "or node". It is unnecessary.	X	
AEP	Consider replacing"computer" with "model".	X	
ATC	We agree with the definition given in the draft standard date Sep-12, 2007. The last sentence is not consistent with the definition given in the draft standard.		X
CenterPoint CPS Energy	Firm transaction obligations are not used throughout all regions in NERC. Change "including firm transaction obligations" to "including firm transaction obligations where applicable."		X
E ON US	Why define a term that is used only once in the document (R.2.1.2.1) and is, by definition, applicable to a[ny] specific point in time.		X
FPL & FRCC	"Computer" is not appropriate. Replace with "Data model" or "Database model". The last sentence is not clear as to what type of ratings (i.e., normal, short-term emergency, long-term emergency, etc.). Suggest removing sentence completely or rewording as follows: "... in accordance with the documented methodologies required by FAC-008 for each Transmission Owner and Generator Owner."		X
Georgia Transm. Corp	The base case is also a representation of firm transactions through a BES, generation resources, and models reactive components.		X
LADWP	A basecase is a representation of the interconnected power system network at a given instant of time which correctly models an expected network topology in sufficient details (transmission lines, shunt and series compensations, transformers, breakers, phase-shifting transformers, etc.) , the forecasted loads, and a dispatch of connected generations that would achieve load-generation balance to allow a numerical solution without violation of any reliability standards. The resultant flows on the transmission lines are dictated by the Kirchhoff's laws, not laws of commerce, and therefore, cannot		X

Organization	Q1. **Comment**	Agree.	Don't agree.
	be interpreted as either firm or non-firm commercial transactions. A basecase is just a starting point from which transmission planners can make use of to further stress the portion of the systems that are of interests, to properly evaluate the robustness and reliability of the system and to determine line (non-thermal) ratings or network expansions, as needed.		
Northwestern Energy	NWE recommends the words "and may include non-firm transactions" after the words "firm transaction obligations".	X	
NERC TIS	The definition should differentiate between powerflow and dynamics base cases.	X	
LCRA	Should read "Computer model representation of…"	X	
PJM	Also FAC-010.	X	X
Santee Cooper	Delete the phrase "and reactive resources." It is redundant.	X	
SERC RRS OPS	Delete the phrase "and reactive resources."	X	
RFC	To add clarity, the terms "power flow" and "dyanamic" should be included in the definition above. It seems that the defintion may be more detailed than needed without these two terms.		X
Southern Transmission	As stated the definition does not appear to allow for equivalenced system representation since it refers to "each bus on the interconnected Transmission System". The words "as represented in the model" should be added after "interconnected Transmission System" or another sentence should be added stating that equivalenced system representation is acceptable. A definition of a dynamics base case should also be considered.		X
Response: Definition of "base case" has been deleted. Therefore concern is no longer applicable.			
City Water Light and Power	This should not be a defined term in the Glossary, instead there should be a Standard that provides the industry with the requirements for completing a Base Case Study.		X
Response: Definition of "base case" has been deleted, as suggested. However, the SDT believes this standard contains requirements for planning reliable transmission systems, including performing appropriate studies.			
APPA	This should not be a defined term in the Glossary, instead there should be a Standard written that provides the industry with the requirements for completing a Base Case Study. This is the first step in completing the Transmission Studies required in TPL-001. There is no guarantee that the rules used by the transmission planners for the base case studies are done in a reliable manner. The Standard needs to be expanded to insure oversight by the compliance monitors to ensure that the base case is sound from a reliability perspective. Also, both reliability and transparency require that the results of the base case study along with the assumptions used to develop the study must be shared with responsible entities within contiguous areas of the BES, not just with contiguous Planning Coordinators and Transmission Planners. To insure consistent results, the Standard should require that a properly conducted Base Case Study be based on agreed rules for conducting such studies within each		X

Organization	Q1. **Comment**	Agree.	Don't agree.
	interconnection and use of consistent data/assumptions by other entities in the region; otherwise, the results of each PC's and TP's planning horizon studies and the operation planning studies will be brought into question.		
Response: Definition of "base case" has been deleted, as suggested. However, the SDT believes this standard contains requirements for planning reliable transmission systems, including performing appropriate studies. The remainder of APPA's comments is not responsive to Q1 and will be addressed in response to Q43.			
Central Maine Power HQTE National Grid New England ISO NU NPCC RCWS NSTAR United Illuminating	There are a few undefined terms in this definition: "Transmission System" and "interconnected Transmission System". The definition needs to specifically identify what should be modeled and in a manner consistent with other NERC definitions. The definition refers to Facility ratings rather than the general reference to FAC-008 & FAC-009		X
Response: Definition of "base case" has been deleted. However, "Transmission System" is not intended as a new term. "Transmission" and "System" are defined in the NERC Glossary of Terms.			
City Utilities/Springfield	The manner in which the forecasted bus load is determined needs to be defined with clear and consistent assumptions and methodologies such that the results of transmission studies are reasonably valid throughout the entire planning horizon.		X
Response: The SDT believes the additional requirements are too prescriptive for this standard but, if appropriate, may be further detailed in MOD standards, which could be further modified through submittal of a SAR if necessary.			
WECC BPA TSGT TEP	A Base Case can only represent the amount of transactions required to serve connected load modeled in the case (local load?). A Path Rating case (developed to represent maximum transfers on a path) would not be considered a base case under this definition. WECC develops base cases to study high power transfers under stressed conditions. Such high power transfers necessarily include both firm and non-firm transaction obligations. Therefore, a base case that represents firm transactions to support "connected load" only, cannot be used to support studies of maximum possible power transfer and is of limited value in WECC. We agree that the above definition is one definition of a base case, but we feel that it can not be the only definition or the limiting definition. We suggest that wording be included that reflects the concept of modeling forecasted or above forecasted load levels if desired, and both firm and non-firm transactions if necessary to model anticipated maximum transfers and represent stressed system conditions as well. The definition should refer to the base case as a Computer Simulation Model of the power system, not a Computer Representation of the transmission system, since it is used within a computer program and represents load and generation in addition to	X	X

Organization	Q1. **Comment**	Agree.	Don't agree.
	transmission. References to "the generation dispatch and firm transaction obligations to supply the connected load" should be removed. A base case is a starting case for any condition that needs to be studied, not just a firm transactions case. Firm obligations across the transmission system are many times independent of a specific load service obligation.		
Response: Definition of "base case" has been deleted. However, the SDT believes some of these issues, particularly relating to the need to study variations from base case conditions, are addressed by Requirement 2.1.3.			
Ameren	Yes, we agree that the "base case" is a power flow model and is the starting point of the analysis. What we are concerned with are the assumptions that go into the development of the "base case". The season, time of day, load level, generation dispatch assumptions, facilities in service, and interchange assumptions (all based on best available data) are just a small subset of the issues that need to be addressed in the development of the base case. We have concerns that so-called "stressed cases" proposed in the standard for compliance testing may in reality be contingency cases, from which additional compliance performance testing would be required.	X	
Response: Definition of "base case" has been deleted. Furthermore, the term "stressed cases" is no longer used in the revised draft.			
ITC	Firm obligations may possibly include obligations beyond "firm transactions" which most likely means grandfathered transactions and TSRs as you have written it. The planning base cases should have sufficient margins to cover uncertainties as well as "firm transactions". The ATCTDT has "drafts" in place which require that TRM and CBM be included in transmission planning studies for both the near-term and long-term planning horizons. While they are drafts at this stage, consideration should be given to including their requirements in your drafts.	X	
Response: Definition of "base case" has been deleted. The SDT appreciates your comments on TRM and CBM; however, these issues will be covered by a separate drafting team.			
Allegheny Power		X	
New York ISO		X	
NCEMC		X	
Manitoba Hydro		X	
MEAG Power		X	
MISO		X	
SaskPower		X	
Seattle City Light		X	
SERC EC DRS		X	
SERC EC PSS		X	
MRO		X	
Muscatine P&W		X	

Organization	Q1. **Comment**	Agree.	Don't agree.
AECI	No comment.	X	
Brazos Electric	No comment.	X	
Dominion	No comment.	X	
ERCOT ISO	It is a fair description for an initial base case.	X	
IESO	The proposed definition fairly reflects the starting point system model used for planning and operations studies.	X	
Duke Energy		X	
KCPL		X	
LUS		X	
Entegra		X	
Entergy		X	
Exelon		X	
FirstEnergy		X	
Progress–Carolinas		X	
Progress–Florida		X	
SCANA		X	
Tenaska		X	
TVA		X	
BCTC		X	
CAISO	It is a fair description for an initial base case.	X	
WPSC		X	
Response:	Thank you. Please see the Summary Response.		

2) Q2. Consequential Load Loss: Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.

Summary Response: The SDT reworded the definition to better clarify that Consequential Load Loss is Load loss that occurs when the source to that Load is lost or Load that is lost due to the Load's transient response to the event being studied. Also the SDT revised this definition as follows to eliminate confusion regarding references to concepts such as fault clearing action, mis-operation, or radial Load:

Consequential Load Loss: Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.

Commenter	Q2. **Comment**	Agree.	Don't agree.
ABB	See Q6. Also, from your definition above, a better term would be "directly-connected load loss". This is clear and to the point.		X
Response: The SDT revised this definition to include Load that is no longer connected to a source as a result of the event being studied. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the Load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.			
AECC	My primary concern with TPL-001-1 is that the problems with footnote B of Table 1 in the current TPL standards have merely been given a different dress and makeup and are now being passed off in the definitions of Consequential Load Loss and Non-Consequential Load Loss. I hope this is not the intent and that my concern is a matter of education. None the less, my first impression leads me to the interpretation above. I will attempt to explain. My concern is based in the methodology used to conduct studies and as a result how the consequential and non-consequential definitions will apply. Specifically the use of a breaker to breaker (BtB) contingency methodology verses an element by element (EtE) methodology. By EtE an element is defined as any switchable device either manual or automatic.		X

Commenter	Q2. **Comment**	Agree.	Don't agree.
	BtB may be useful and may have a place in some system analysis but it only gives a very limited view of the impacts and does not take into account the corresponding operational actions that will take place as a result of a fault event. BtB also does not provide for impacts that might occur during system reconfiguration due to maintenance. EtE provides a much more comprehensive evaluation of the impacts that might be seen on a system and in my opinion is a best practice as opposed to BtB. My concern was raised when during the drafting teams webex on October 11, I heard comments made by the drafting team that "the system should be studied as it is operated". If this comment was intended to mean that events should be studied beyond their initial response then fine otherwise the comment should be clarified. Without clarification, statements like this can be interrupted to mean and only reinforce the mentality that BtB or other inadequate study methods are adequate and can continue to be used. What has all this to do with consequential vs. non-consequesntial load loss? I am getting there. If BtB analysis is permissiable then I disagree with the definitions of consequential and non-consequential load loss. Here is why: It is understandable that a load being normally served (prior to an event) by a radial (meaning one source) will be lost if an event occurs that removes the source. This to me is consequential load. On the other hand, if a load is being served from a transmission line with sources and breakers at both ends (networked) and the line experiences a fault, how is the load on the faulted line classified? Before you jump to an answer, let me explain why I asked. If a fault occurs on a section of the line then obviously both breakers should operate to clear the fault and the load would be removed from the system. This is what is mimicked in breaker to breaker analysis. The problem is that breaker to breaker analysis stops there and some may argue that this is adequate and that the load lost is consequential. I beg to differ. In reality the transmission line will be sectionalized to restore service to the load and isolate the faulted portion of the line. A new steady state condition results one or two radials replacing the faulted transmission line. The impacts of which would be captured if EtE analysis occurs. Because the load is served after the event it should not be classified as consequential. The load being served by resulting radials would not be classified as consequential until the next fault event occurred. Because the system can be sectionalized by switchable devices to establish the new steady state is one reason why switchable devices need to be added to the definition of element.		

Commenter	Q2. **Comment**	Agree.	Don't agree.
	It can be expected from the examples above that the resulting radial(s) serving the load may create greater impacts on the system than the original networked line. The load in this case is not consequential. This is what happens in actual operations, this is what needs to be studied, and the standard needs to ensure that the BES maintains the ability to adequately serve the load following such an event. Having the capability to serve load following the isolation of a faulted section of line is one of the reasons why the networked system was developed in the first place. Another example of radial configuration of networked lines occurs during maintenance. A section of line is taken out of service and ALL load is still served. In this case the load is not consequential because no fault has occurred and again the impacts may be greater than the original networked line. Again these impacts can only be determined by studying the system on an EtE basis. Today's world often forgets that serving load is the reason the BES exist. The BES therefore should be capable of adequately serving the load not only under normal operating conditions and the most common contingency conditions but also under the resulting steady state configuration following a contingency. The BES should be planned in a manner that addresses these contingencies and not in a manner that just seeks to do enough to be able to report compliance. In conclusion, I offer the following recommendations: #1: The definition of Element in the NERC Glossary should be modified to: 1. Include switchable devices either manual or automatic. 2. Clearly define what constitutes an element Suggested modification: Element = Any switchable electrical device (either automatic or manual) with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more elements. The last sentence was struck because you can't define something using the term you are trying to define. #2: The definition of consequential load loss needs further clarification. Consider replacing "due to fault clearing action or misopertion" with "as a result of new steady state conditions following a Planning or Extreme Event."		

Commenter	Q2. **Comment**	Agree.	Don't agree.
	#3: The definition of Planning Events should not be limited to the initial event such as breaker opening for a fault but should include any and all actions taken to sectionalize so that at the end of a Planning Event you have a system that is in steady state and serving as much load as possible. Suggestion: Planning Events = Events which remove one or more Elements and require Transmission system performance requirements to be met. This definition includes the initial event and any after event actions that result in the system returning to a steady state condition and preventing as serving as much Consequential load as possible. #4: The standard should include the expectation that the BES will be studied at some level (at least n-1) using EtE methodology.		
Response: One of the drivers for developing the definitions for Consequential Load and the use of some entities of BtB methodology referred to in your comments were concerns expressed in interviews by NERC TIS and FERC.. The interviews revealed that some planners were running simulations of single contingency by removing "elements" modeled in the simulation, e.g. impedance data from one bus number to another. This removed "element" did not even necessarily represent a real life switchable system element and this is reflected in requirements R3.2 and R4.2 of the Standard. The concept of Consequential Load was needed to clarify that under certain circumstances the standard allows for load to be dropped following the first contingency. As you indicated the planner must consider how the system can be switched and reconfigured to the point that loadings can be returned to within acceptable limits. The SDT has revised the definition to provide more clarity.			
PJM	Need to tighten definition example- load that trips in sympathy with fault (motor trips as a direct result but not in protection zone)	X	X
Response: The SDT revised the definition to better clarify what constitutes Consequential Load Loss in response to various comments.			
ATC	Voltage sensitive load loss (not due to operator action or UVLS) in response to a disturbance should constitute consequential load loss. Loss (drop) of voltage sensitive load must be included in this definition --- it is not non-consequential loss of load.		X
Response: The SDT revised this definition to include Load that is lost as a result of the Load's response to the transient conditions of the event. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when			

Commenter	Q2. **Comment**	Agree.	Don't agree.
Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.			
E ON US	I agree with the definiton except for "or mis-operation". The requirements do not, and should not, include mis-operation of protection schemes. We would never finish a study of all potential mis-operations.		X
Response: The SDT revised this definition to exclude any information that could be confusing, including the mention of misoperations. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.			
BCTC	For the reasons discussed below, we do not agree with the proposed definition. To address our concerns and address the FERC staff concern regarding ambiguity, the proposed definition could be made acceptable to us by modifying it as follows: Load that is no longer served because it either (a) was supplied (wholly or partly) by an element(s) of a radial system or local network that was removed from service due to fault clearing action, was disconnected by controlled interruption to avoid overload of remaining elements of a radial system or local network, or protection or SPS/RAS mis-operation or (b) has dropped out or been tripped during a transient stability period, including an automatic reclosing period, due to a fault on the radial system or local network, including on branches not directly supplying the load. We also offer the following alternative: Resultant loss or controlled interruption of customers supplied by a radial system or local network, due to a fault on or loss of a facility in the radial system or local network. The definition proposed by the SDT removes the second sentence of footnote (b), as directed by FERC, and replaces the first sentence of footnote (b) with a new definition. We agree with the removal of the second sentence of footnote (b). However, we have a concern with this definition replacing the first sentence of footnote (b). We believe that the existing first sentence is a more appropriate definition of consequential load loss and that the proposed definition is more stringent and will have unacceptable impacts on reliability and/or add transmission costs that cannot be justified.		X

Commenter	Q2. **Comment**	Agree.	Don't agree.
	The coining of the term "Consequential Load Loss" has been a significant improvement in terminology compared to our reference to footnote (b). However, FERC only used this phase descriptively and did not order NERC to reconsider what would be acceptable consequential load loss (i.e. revise the first sentence of footnote (b)). The definition appears to be based on an interpretation of the new term rather than defining what this term was coined to describe. Order 693 requires that footnote (b) be clarified to not allow loss of firm load or firm transfers - i.e. delete the second sentence. Order 693 then refers to the remaining first sentence as consequential load loss. Order 693 does not address issues regarding whether this should further be restricted to only radial lines, not permitting load loss for outages on local networks. Nothing in the NOPR or the staff paper implies otherwise. The staff paper discusses potential ambiguity regarding which single contingencies load interruption is permitted for. The definition attempts to address this by referring to "directly connected" load. However, this is now ambiguous as "directly connected" might be interpreted to mean only the facility that the load is physically connected to and excluding any upstream facility. BCTC submits that the upstream facilities need to include both radial facilities and local networks. NERC has stated that looped configurations are key for reliable operation. We consider looped configurations and local networks to be the same thing. The proposed definition will make it more difficult to transition from a radial supply to a looped configuration. For radial loads connected by a single radial line, when the load exceeds the line capacity, the transmission owner has alternatives of upgrading the line, adding a second circuit, or converting to a local network by providing a loop from another supply. With the addition of a second circuit or conversion to local network, controlled load interruption may be necessary for loss of one circuit to avoid overload of the second line. Without the option of controlled load interruption, these alternatives will not provide N-1 capability for all loads they supply without addition of a third circuit. This will lead to a economic preference to upgrading of the existing circuit to meet criteria, thereby perpetuating the single radial line configuration. Other alternatives could include splitting the load between the lines or operating with one line out of service so that a single contingency does not overload the facilities remaining in service. However, the addition of a second circuit with controlled load interruption will provide a more reliable load serve than any of these		

Commenter	Q2. **Comment**	Agree.	Don't agree.
	alternatives, because under N-1 more load will remain continuously on line. We expect that the proposed definition will provide greater assurance that existing local networks with N-1 capability will continue to have N-1 capability. However, we have concluded that the definition will introduce an additional unacceptable barrier to transition from N-0 to N-1 supply and that this barrier is not acceptable. We believe that this barrier would be a more significant issue for improving the reliability of supply to all customers than the current situation of permitting some controlled load interruption on local networks. Another issue that arises if local networks are excluded is load response during transient periods. Customers can connect voltage sensitive loads, such as large motors, on long weak systems. During the transient stability period, voltages can dip to below the ride through capability of the load. The fault need not be on the circuit directly supplying the customer, but may be downstream or on another branch facility. Automatic reclosing is often employed to shorten restoration times, but with the consequence of worsening the transient period. Customers have options to install different types of motors, motor controls, local voltage support to mitigate impacts of transient voltage swings, or simply restart motors following the disturbance. If transmission systems are required to ensure no loss of load during transient stability periods for external faults, a first course of action may be to remove automatic reclosing, which will reduce reliability. Alternatively, customer load connections may be denied or additional transmission circuits may be required, which can be costly compared to the customer load options.		
City Water Light and Power	This could be load lost which is on a radial line or load served by facilites which do not have fault-interrupting breakers.	X	
Duke Energy	It is unclear what is meant by "mis-operation". The SDT also needs to address load lost during the transient time frame (e.g. load dropout due to low voltages as a result of a fault) that may not be directly connected to the element removed from service.		X
Entegra	Further examination is needed to determine how to correctly treat loads served downstream from the faulted element, but not directly connected.		X
Georgia Transm. Corp	This definition implies that load that is lost past the directly connected load is allowed. Therefore the definition should be changed to include radially connected load and load that is radialized as a result of a contingency or mis-operation.		X
LADWP	The existing standards do not allow load loss for N-1 contingency unless the load is a radial load of the outage element. This new definition appears an attempt to weaken the requirement by broadening it to anything "directly connected" to an element that is removed from service. While it may be argued that probably only radially connected loads fit this definition, this new definition will lead to more creative		X

Commenter	Q2. **Comment**	Agree.	Don't agree.
	interpretation of the word "consequential" and leads all of us down unintended consequence. A radial load is a very specific and clearly defined technical term and should not be changed to a new term that is less precise.		
MRO	The MRO could not agree on the correct definition.		X
Santee Cooper	The term "mis-operation" introduces ambiguity into the definition, and should be deleted. The definition needs further clarification for consequential and non-consequential loads. For example, loads served downstream from the faulted element but not directly connected should also be considered to be consequential loads. A better name for this would be "direct load loss".		X
FirstEnergy	We suggest that the team remove "or misoperation" from the definition. This could suggest that an overtrip of protection equipment could result in consequential load loss.		X
NCEMC SERC EC PSS	The term "mis-operation" introduces ambiguity into the definition, and should be deleted. The definition needs further clarification for consequential and non-consequential loads. For example, loads served downstream from the faulted element but not directly connected should also be considered to be consequential loads.		X
NERC TIS	MISOPERATION has to be qualified as being a misoperaiton on the system element that trips.	X	
RFC	Should the above definition contain a statement that the load is not intentionally lost, since non-consequential load loss is intentional?		X
SERC EC DRS	Add the following to the end of the definition: "or unintentional load lost as a direct result of the event (e.g. load dropout due to low voltages as a result of a fault)."		X
Southern Transmission	This definition only relates to load that is "directly connected" to the specific element being removed. It does not allow for any load that may be or becomes radially connected through another branch that is not part of the facility removed. It does not make sense to not allow the loss of load that is actually electrically radial to the facility being outaged. The definition may work better as "Load that is no longer served because it is directly connected to or radially served through an element(s) that is removed from service due to fault clearing action." The word "mis-operation" is not needed in this definition because none of the contingency events use this term.		X
BPA	Support comments submitted by WECC. The definition needs to consider loads that are tripped sympathetically that may not be directly connected to the element that is removed from service for fault clearing.	X	X
WECC TSGT TEP	Agree with the definition in concept. However, the wording makes the definition seem unrealistic. There are many examples where a certain amount of voltage sensitive load or motor drives sensitive to angle changes are dropped due to normally cleared electrical faults on the transmission system. These loads are not directly connected to the element being removed from service. This type of sympathetic loss of load is	X	X

Commenter	Q2. **Comment**	Agree.	Don't agree.
	unique to the individual customer load. The design of these loads is not under the control of the utilities when it comes to ability to ride through normally cleared faults. We suggest that this definition be modified to include the loss of sensitive load that is not directly connected to the element being removed. We propose the following the definition : Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation, and because of sympathetic tripping associated with normal clearing or mis-operation. Load that is lost because it trips due to low voltages experienced during and immediately following the fault (4-6 cycles?) is also considered consequential load loss. We believe this additional recognition is needed because load lost due to low fault voltages is unavoidable and should not result in a standard violation.		
Response: The SDT reworded the definition to better clarify that Consequential Load Loss is Load loss that occurs when the source to that Load is lost or Load that is lost due to the Load's transient response to event being studied. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.			
AEP	Consider replacing "Consequential" with better wording (no specific suggestion to offer at this time).	X	
Ameren	A better name for this would be "direct load loss". The definition should include load served by the faulted element but not directly connected to the faulted element.	X	
SERC RRS OPS	The term "mis-operation" introduces ambiguity into the definition, and should be deleted. The definition needs further clarification for consequential and non-consequential loads. For example, loads served downstream from the faulted element but not directly connected should also be considered to be consequential loads. A better name for this would be "Planned Load Loss."		X
Entergy	Delete "mis-operation". For purposes of planning, all consequential load loss should reflect intended fault clearing actions and not unintended fault clearing actions (i.e., mis-operations). Include load loss due to UVLS & SPS in consequential load loss category. Consider using the terms in the existing standard; "Planned Load Loss" and "Unplanned Load Loss" in lieu of Consequential and Non-consequential as they may be		X

Commenter	Q2. **Comment**	Agree.	Don't agree.
	easier to define with each Transmission Owner/Planning Authority responsible for defining the terms considering the impact on the Bulk Electric System. If the terms remain as proposed, the definition needs further clarification for consequential and non-consequential loads. For example, loads entirely dependent on the faulted element but not directly connected should also be defined to be consequential loads.		
HQTE	``directly-connected`` load loss would be more clear	X	X
ITC	Suggest a change in terminology to "direct".	X	
MEAG Power	MEAG believes that deleting the term "mis-operation" as some may have suggested, would significantly narrow the definition of Consequential Load Loss, which in turn would unreasonably increase the amount of load that is Non-Consequential. The Non-consequential load loss, which is not allowed in P1-P5. For example, if mis-operation is deleted from the definition and we consider a relay mis-operation where a breaker fails to clear a fault, then any additional load interrupted by the back-up to the failed breaker/relay is Non-Consequential Load (and the standard appears to be violated since only a single transmission circuit was faulted and Non-Consequential Load was lost).	X	
MISO	Midwest ISO suggests this definition be changed to "Direct Load Loss", as "Consequential Load Loss" may include elements that are not directly connected to the faulted element.		X
SCANA	"Consequential Load Loss" should be termed "Intentional or Planned Load Loss". Not only should direct connected load loss be included, but loads served by or downstream from the faulted element, that is not directly connected to the faulted element, should also be included.		X
Tenaska	Using consequential and non-consequential seem to be misleading. Perhaps using "direct" and "indirect". Also, mis-operation needs some more explanation and to why it should be included here.		X
TVA	We recommend that the terms consequential and non-consequential be changed to direct and indirect. Also, the term should be better defined. We recommend that the definition be "loads that have been de-energized by fault-clearing action or loads that are lost even though the system performance remains within acceptable limits."		X

Response: The SDT reworded the definition to better clarify that Consequential Load Loss is Load loss that occurs when the source to that Load is lost or Load that is lost due to the Load's transient response to the event being studied. The SDT is concerned that the use of alternative terms might be confusing. Among other things, the terms used in the proposed standard are consistent with terms used by FERC.

Consequential Load Loss: Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's

Commenter	Q2. **Comment**	Agree.	Don't agree.
response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements**.**			
FPL FRCC	Need to clarify what constitues an element (e.g., breaker-to-breaker, line segment to line segment, transformer or capacitor bank)		X
Response: "Element" has been removed.			
SaskPower	What is meant by directly connected? Local area network load is allowed to be shed in Saskatchewan. The Saskatchewan Regulatory Jurisdiction has no plans to change this unless there is technical evidence to justify the increase in reliability.		X
Response: The SDT reworded the definition to better clarify that Consequential Load Loss is Load loss that occurs when the source to that Load is lost or Load that is lost due to the Load's transient response to the event being studied.. Without knowing under what conditions network Load can be shed in Saskatchewan, the SDT does not know whether the proposed standard would cause a change in Saskatchewan's practices or reliability. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements**.**			
Manitoba Hydro	If load losses due to stuck breaker and back-up breaker operations (which would frequently result in the loss of two or more network transmission elements) are not going to be qualified as "Consequential", where should they be placed? MH cannot visualize them as "Non-Consequential", as defined in Q6. Either another "load" category must be developed for these loads, or they should remain as "Consequential". In addition, Consequential Load Loss should include the concept of local area load loss to cover a scenario of islanding with a UFLS in the island, or a small network served at the end of a radial line.Can the SDT comment on why this Local Area defined in the existing TPL stds has been removed?	X	
Response: The SDT reworded the definition to better clarify that Consequential Load Loss is Load loss that occurs when the source to that Load is lost or Load that is lost due to the Load's transient response to the event being studied. However, Load losses associated with a stuck breaker would be considered consequential if they were the result of the initiating event. UFLS activation should not occur on a single Contingency event and would not be considered consequential. A radial Load is directly connected since it has no other source post event and would be consequential. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due~~			

Commenter	Q2. **Comment**	Agree.	Don't agree.
~~to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements**.**			
APPA	This definition will help define what cascading outage is. There is confusion in the industry and FERC as to "what is a cascading outage." The planning process needs to address this confusion and define exactly what a cascading outage consists. Some want a cascading outage to be when loads beyond the primary or secondary protection equipment are dropped.	X	
Response: The SDT agrees that additional clarification is needed regarding cascading outages. FERC is currently working on modifying this definition. However, the definition of cascading outages is a separate issue from the definition of Consequential Load Loss.			
ERCOT ISO	Agree with the definition.	X	
Northwestern Energy		X	
CAISO	Agree with the definition	X	
CenterPoint		X	
Central Maine Power		X	
City Utilities/Springfield		X	
CPS Energy		X	
Allegheny Power		X	
Exelon		X	
Brazos Electric		X	
LCRA		X	
IESO	This is the same understanding of the IESO.	X	
KCPL		X	
LUS		X	
Muscatine P&W		X	
National Grid		X	
New England ISO		X	
New York ISO		X	
NU		X	
NPCC RCWS		X	
Nstar		X	
Progress–Carolinas		X	
Progress–Florida		X	
Seattle City Light		X	
Dominion		X	

Commenter	Q2. **Comment**	Agree.	Don't agree.
United Illuminating		X	
WPSC		X	
Response: Thank you. Please see the Summary Response.			

3) Q3. Extreme Events: Events which are more severe than Planning Events and have a low probability of occurrence.

Summary Response: Industry comments were mixed, with some commenters agreeing with the proposed definition and others disagreeing. Among the disagreeing commenters, several noted that a more accurate characterization of Extreme Events would be that Extreme Events have a "lower probability of occurrence than Planning Events" because even Planning Events have a low probability of occurrence. Based on the comments, the SDT revised this definition as follows:

Extreme Events: Events which are more severe and have a lower probability of occurrence than Planning Events ~~and have a low probability of occurrence~~.

Commenter	Q3. **Comment**	Agree.	Don't agree.
Ameren	Most planning events have a low probability of occurrence. It appears that the SDT is trying to make a distinction that these Extreme Events would have a lower probability of occurrence than planning events. Consideration should be given to adding the performance requirements with the definition.		X
ITC	R3.4 implies that "Extreme Events" will be studied as per the table. The definition seems functionally correct as applied to the standard but somewhat confusing. The existing wording implies that a mitigation plan should be developed if studies show that "Extreme Events" might cause cascading. If the mitigation plan is a true requirement, saying it is not a planning event can be confusing. "Extreme Events are more severe than Planning Events, have a low probability of occurrence and only require___?????_____ in the event of cascade."	X	
WPSC	By definition, Extreme Events are not Planning Events. However, only the definition Planning Events has a requirement to meeting performance requirements. I believe Extreme Events also have performance requirements under R3.4 and its definition should reflect this.		X
Response: The SDT revised this definition in response to various comments. However, the SDT disagrees that performance requirements should be included in the definition as is proposed in the comment. **Extreme Events**: Events which are more severe and have a lower probability of occurrence than Planning Events ~~and have a low probability of occurrence~~.			
ATC Central Maine Power	Suggest "Events which are more severe and have a lower probability of occurrence than the Planning Events"		X
AECC	This is too vague. The old Table 1 did a better job of defining Extreme Events.		X
City Water Light and Power	More needs to be added here, especially to define the phrase "low probability of occurrence". Does this refer to N-1, N-2, N-3 etc.? We have a 300 foot long interconnection line between two substations. In this case even N-1 has a low probability of occurrence. This N-1 event has a much lower probability of occurrence than an N-2 event which involves generator outages. We also have an N-1 SPS event		X

Commenter	Q3. **Comment**	Agree.	Don't agree.
	which hasn't occurred in 25 years.		
E ON US	I disagree with the phrase "and have a low probability of occurance". All the Planning Events, except possibly a generator outage (P1.1), have a low probability of occurance.		X
ERCOT ISO CAISO	Add specificity in this definition. Suggest the following wording: Outage of two or more elements from service with lower probability of occurrence than Planning Events.		X
BCTC	Alternative wording proposed: Events which have a low probability of occurrence and are typically more severe than Planning Events. Explanation: The primary consideration is the probability of occurrence. We do not exclude events simply because they are more severe.		X
Entegra	The statement would be clearer if "low" were changed to "lower".		X
MEAG Power NCEMC Santee Cooper SERC EC DRS SERC EC PSS SERC RRS OPS TVA	A number of the non-Extreme Events also have a low probability. Recommend change the word to "lower." The definition for "Extreme Events" should reference Table 1.		X
MISO	Extreme Events are clearly described on Table 1. Change definition from "low probability of occurrence to "lower probability of occurrence".		X
MRO	Low probability of occurrence should be in reference to something to be more meaningful. The MRO suggests that the definition be changed to state "lower probability of occurrence than Planning Events."		X
Entergy	Revise to, "Events which are beyond the normal scope of Planning Events and have a lower probability of occurrence."		X
KCPL	Suggest changing "low" to "lower".	X	
LCRA	Define "low probability of occurrence"	X	
National Grid New England ISO Sask Power United Illuminating	Modify to "Events which are more severe,but have a lower probability of occurrence, than Planning Events".		X
FPL FRCC HQTE IESO	Suggest reword as follows: "Events which are more severe and have a lower probability of occurrence than planning events."		X

Commenter	Q3. **Comment**	Agree.	Don't agree.
Manitoba Hydro NYISO NU NPCC RCWS NSTAR			
PJM	Agree with concept but need better definition	X	X
Southern Transmission	Recommend modifying the definition to read: "Events which are more severe than Planning events that are evaluated as required by TPL-001-1 Tables 1 and 2, in part, to identify potential Cascading Outages.		X
Tenaska	I think most people understand, but in this new world we need to put some more specificity around the words "low probability".		X
Response: The SDT revised this definition in response to various comments. **Extreme Events**: Events which are more severe and have a lower probability of occurrence than Planning Events ~~and have a low probability of occurrence~~			
APPA	The definition is needed; however, this term is dependent on a clear definition of Planning Events, which does not exist.		X
Response: The SDT revised the definition of Planning Events in response to comments received for Q8 with the intent of adding more clarity to this definition. **Planning Events:** Events ~~which~~ that require Transmission system performance requirements to be met.			
Georgia Transm. Corp	All events on the BES have a low probability of occurrence. Extreme Events are those events that have a high consequence to the BES if they were to occur.		X
Response: The SDT revised this definition in response to various comments. Specifically, in response to the recommendation of several commenters, the SDT revised the definition of Extreme Events to indicate these events have a lower probability of occurrence than Planning Events. However, the consequence is determined by simulating these lower probability events. Therefore, the SDT believes it would be inappropriate to define the consequence. **Extreme Events**: Events which are more severe and have a lower probability of occurrence than Planning Events ~~and have a low probability of occurrence~~			
LADWP	Extreme Events for transmission planning should be defined as anything more than N-2. The proposed definition is subjective and not precise. There are examples in this standard as to how this definition can be mis-construed, e.g., cyber attack, wild-fire, hurricanes, etc. These are Extreme Events that belong in emergency planning, not transmission planning.		X
Response: The SDT revised this definition in response to various comments. Specifically, in response to the recommendation of several commenters, the SDT revised the definition of Extreme Events to indicate these events have a lower probability of occurrence than Planning Events. The SDT also modified the standard to clarify Extreme Events.			

Commenter	Q3. **Comment**	Agree.	Don't agree.
Extreme Events: Events which are more severe and have a lower probability of occurrence than Planning Events ~~and have a low probability of occurrence~~			
NERC TIS	The use of the term Extreme should be limited to those events that are truly extreme. A single line-to-ground fault with delayed clearing (for whatever reason) may require remote clearing of the fault, and trips multiple system elements, without time between elements being outaged. Such events are far too common occurrences to call them extreme.		X
Response: The SDT revised this definition in response to various comments. The SDT also modified the performance tables in response to various comments. **Extreme Events**: Events which are more severe and have a lower probability of occurrence than Planning Events ~~and have a low probability of occurrence~~			
WECC BPA TSGT TEP	Please add the phrase "two or more elements out of service" to the definition from the previous definition in Table I.	X	X
Response: The SDT revised this definition in response to various comments. However, the SDT believes the suggested phrase would be imprecise for the standard as currently drafted because some Extreme Events do not necessarily involve "two or more elements out of service". For example, one type of "extreme event" is loss of a large Load or major Load center, which might possibly occur without two or more elements out of service. **Extreme Events**: Events which are more severe and have a lower probability of occurrence than Planning Events ~~and have a low probability of occurrence~~			
Dominion	To make this "crisp", it is suggested that this definition be extended as "Events which …..occurrence. The Transmission system performance requirements do not apply to Extreme Events".	X	
Response: The SDT revised this definition in response to various comments. However, the SDT is concerned that the language proposed in this comment may cause confusion because requirement R3.4 applies to Extreme Events. **Extreme Events**: Events which are more severe and have a lower probability of occurrence than Planning Events ~~and have a low probability of occurrence~~			
FirstEnergy	The definition is OK, but we question its use in the standard. Many of the items listed as Extreme Events are not considered events. For example, high river temperature is not really an event, it is a condition. The resulting event might be the shut-down of multiple generators.	X	
Response: The SDT revised this definition in response to various comments. The SDT also modified the standard to clarify Extreme Events. **Extreme Events**: Events which are more severe and have a lower probability of occurrence than Planning Events ~~and have a low probability~~			

Commenter	Q3. **Comment**	Agree.	Don't agree.
~~of occurrence~~			
ABB		X	
Allegheny Power		X	
AEP		X	
Brazos Electric		X	
CenterPoint		X	
City Utilities/Springfield		X	
CPS Energy		X	
Exelon		X	
Duke Energy		X	
LUS		X	
Muscatine P&W		X	
Northwestern Energy		X	
Progress–Carolinas		X	
Progress–Florida		X	
RFC		X	
SCANA		X	
Seattle City Light		X	
AECI	However this could be very subjective.	X	
Response: Thank you. Please see the Summary Response.			

4) Q4. Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond.

Summary Response: Most commenters agreed with the proposed definition, but a few commenters raised issues about the use of the term "beyond". Therefore, the SDT revised the definition as follows to clarify when the horizon may extend beyond ten years:

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Commenter	Q4. **Comment**	Agree.	Don't agree.
Central Maine Power NU NSTAR United Illuminating	"A Planning Assessment period that covers years six through ten", is sufficient for the standard." Suggest changing the name to Long-Term Planning Assessment.		X
Response: The SDT believes the term "or beyond" after "years Six through Ten" is necessary for the proposed standard as currently drafted to agree with Requirement R2.2.1, which requires a planning horizon beyond ten years if necessary. Moreover, the use of the phrase "planning horizon" in this definition is intended to indicate the period of time applicable to the assessment.			
FRCC	The definition does not have a reference year when the counting starts. Add the following to the end of the sentence: "… from the current study year."		X
Response: The SDT concurs that a reference year when the counting starts is necessary. The SDT proposed Year One as the reference year when the counting starts.			
AECC	With the time it takes to get transmission planned, approved and built the 10 year time frame is too short. Six to ten year studies are fine but longer term studies need to be performed occasionally. If the requirement remains vague and says 6 to 10 years then what will happen is only 6 year studies. Coupled with the 1 to 5 years in the Near Term Horizon then you potentially set up a situation where you could have a 5 and a 6 year study done. This defeats the purpose of what the intent of the defintion should be. I suggest that 1, 2, 5, 10, 15 year studies be required.		X
Response: The SDT believes the definition should clarify the intent that assessments will cover ten years and may extend beyond ten years if necessary (see Requirement R2.2.1). This definition was revised for additional clarity. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.			
LADWP	The objection is not so much about the definition as about what comes after the definition. This standard proposed to include operating and market studies (calling them sensitivities) in the "near-term" planning studies. It appears that the SDT believes this would be easier to justify if the sensitivities is limited to near-term and		X

Commenter	Q4. **Comment**	Agree.	Don't agree.
	not long-term, hence the motivation for breaking the planning horizon. But this is misguided; operating studies belongs in operating standards. They should be addressed appropriately in the TOP for operating scenarios and Market related studies should be addressed in MOD, for example. There are no benefits to include these in transmission planning studies and therefore no need to break up the planning horizon.		
Response: The SDT disagrees and believes sensitivity studies should be performed in the planning horizon. Furthermore, the requirement for sensitivity studies is responsive to FERC Order 693.			
National Grid New England ISO	"Transmission planning period that covers years six through ten", is sufficient for the standard."		X
SRP	Reword to: Transmission planning period that covers years six or beyond.	X	
Response: The SDT believes the definition should clarify the intent that assessments will cover ten years and may extend beyond ten years if necessary (see Requirement R2.2.1). This definition has been revised for additional clarity. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.			
ABB		X	
ATC		X	
Brazos Electric		X	
City Water Light and Power		X	
Dominion		X	
E ON US		X	
ERCOT ISO		X	
Northwestern Energy		X	
AECI		X	
Allegheny Power		X	
AEP		X	
APPA	This definition is needed to eliminate the confusion that exists in the industry.	X	
BPA		X	
BCTC		X	
CAISO	Agree with the definition	X	
CenterPoint		X	
City Utilities/Springfield		X	
CPS Energy		X	
Duke Energy		X	
Entegra		X	
Entergy		X	
Exelon		X	

Commenter	Q4. **Comment**	Agree.	Don't agree.
FirstEnergy		X	
FPL		X	
Georgia Transm. Corp		X	
HQTE		X	
IESO	Consistent with the IESO's understanding.	X	
ITC		X	
KCPL		X	
LUS		X	
LCRA		X	
Manitoba Hydro		X	
MEAG Power		X	
MISO		X	
MRO		X	
Muscatine P&W		X	
NERC TIS		X	
New York ISO		X	
NCEMC		X	
NPCC RCWS		X	
Progress–Carolinas		X	
Progress–Florida		X	
RFC		X	
Santee Cooper		X	
SaskPower		X	
Seattle City Light		X	
SERC EC DRS		X	
SERC EC PSS		X	
SERC RRS OPS		X	
SCANA		X	
Southern Transmission	No Additional Comments.	X	
Tenaska		X	
TVA		X	
TSGT		X	
TEP		X	
WECC		X	
Response: Thank you. Please see the Summary Response.			

5) Q5. Near-Term Transmission Planning Horizon: Transmission planning period that covers years one through five.

Summary Response: The majority of the commenters agreed with the proposed definition; therefore, the SDT did not modify the definition.

Commenter	Q5. **Comment**	Agree.	Don't agree.
AECC	I agree with the definition but I don't think studies should necessarily be required for all of the years 1 through 5. Years 1 and 2 probably need to be required because of they are sometimes used as the basis for the development of seasonal models and studies used in the opertional horizon in many Open Access Tariffs.	X	
Response: The minimum requirements for the near term are identified under Requirement R2.1. Past studies can also be included as identified in Requirement R2.6.			
Ameren Santee Cooper SERC RRS OPS	It is suggested that another definition be added for "operations planning horizon".		
Response: The reference to Operations Planning in Q11 was erroneous. The term "operations planning horizon" is not defined because it is not used in the standard.			
LADWP	See my comment above; the only part about the definition that I would retain is to require each of the first five years in a typical ten-year plan be studied instead of just picking one or two years out of the first five years.		X
Response: LADWP's comment does not appear to be directed solely at Q5. In addition, the SDT disagrees with the proposed modification of the requirement.			
Central Maine Power	Suggest changing the name to Near-Term Planning Assessment, and introduce the description the same was as above.	X	
New England ISO NU NSTAR United Illuminating	Suggest changing the name to Near-Term Planning Assessment.	X	
Response: The use of the phrase "planning horizon" in this definition is intended to indicate the period of time applicable to the assessment.			
ABB		X	
ATC		X	
Brazos Electric		X	
City Water Light and Power		X	
Dominion		X	
E ON US		X	
ERCOT ISO	Agree with definition.	X	
Northwestern Energy		X	
AECI		X	
AESO		X	

Commenter	Q5. **Comment**	Agree.	Don't agree.
Allegheny Power		X	
AEP		X	
APPA	This definition is needed to eliminate the confusion that exists in the industry.	X	
BPA		X	
BCTC		X	
CAISO	Agree with the definition	X	
CenterPoint		X	
City Utilities/Springfield		X	
CPS Energy		X	
Duke Energy		X	
Entegra		X	
Entergy		X	
Exelon		X	
FirstEnergy		X	
FPL		X	
FRCC		X	
Georgia Transm. Corp		X	
HQTE		X	
IESO	Same as above.	X	
ITC		X	
KCPL		X	
LUS		X	
LCRA		X	
Manitoba Hydro		X	
MEAG Power		X	
MISO		X	
MRO		X	
Muscatine P&W		X	
National Grid		X	
NERC TIS		X	
New York ISO		X	
NCEMC		X	
NPCC RCWS		X	
Progress–Carolinas		X	
Progress–Florida		X	
RFC		X	
SaskPower		X	

Commenter	Q5. **Comment**	Agree.	Don't agree.
Seattle City Light		X	
SERC EC DRS		X	
SERC EC PSS		X	
SCANA		X	
Southern Transmission	No Additional Comments.	X	
Tenaska		X	
TVA		X	
TSGT		X	
TEP		X	
WECC		X	
Response: Thank you.			

6) **Q6. Non-Consequential Load Loss: Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.**

Summary Response: Based on comments, the SDT revised this definition to specify that this is non-interruptible load as follows to add further clarity:

Non-Consequential Load Loss: ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.

Commenter	Q6. **Comment**	Agree.	Don't agree.
AECC	See my comments on Consequential Load Loss. The definition is too vague to just say "load loss other than Consequential Load Loss". The defintion should be clear and examples should not be used to make the definition. This is a bad habit that NERC has which leads the industry to establish status quo based on the examples and not the definition itself. It sounds like Consequential Load Loss is being tied to short circuit fault events and Non-Consequential Load Loss is being tied to events other than short circuit fault events. Remember that undervoltage, underfrequency and SPS are still triggered by "faults". If that is the intent then say it. Don't put forth a vague definition and then try to justify its meaning by an example.		X
IESO	Suggest to either stop at "automatic operations" or to include other examples since the list is not exhaustive, for example: load that drops out due to unacceptable voltage levels (not tripped intentionally by UVLS.		X
New York ISO	Suggest that examples not be listed or a more exhaustive list be developed.		X
Response: See responses to Q2. The SDT revised the definitions of Consequential Load Loss and Non-Consequential Load Loss in response to various comments. However, the SDT believes that the examples add clarity, even if not exhaustive. **Non-Consequential Load Loss:** ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.			
PJM	Non-Consequential Load Loss should not include load loss due to manual, UVLS and UFLS.	X	X
Response: The SDT believes that Load loss that occurs from manual action, UVLS, or UFLS is not a direct consequence of the event being studied and is in fact the type of distinction the SDT intended to make. The SDT believes that Consequential Load Loss is Load loss that			

Commenter	Q6. **Comment**	Agree.	Don't agree.
occurs when the source to that Load is lost or Load that is lost due to the Load's response to a transient condition of the event being studied. All other Load that is lost is non-consequential.			
ABB	Most people will think of inconsequential, which often means irrelevant, unimportant, or insignificant. But what you are trying to define is the opposite: load loss that is significant, important, and needs to be prevented. Also, whatever you call it, your examples (UVLS, UFLS, SPS) should be expanded to include unintentional and uncontrolled load loss due to low voltage, high current, impedance relays, etc.		X
Ameren Santee Cooper	A better name for this would be "indirect load loss".		
Georgia Transm. Corp HQTE	Suggest a change in title to Indirect Load Loss		X
MISO	Midwest ISO suggests this definition be changed to "Indirect Load Loss", as "Non-Consequential Load Loss" may be confusing regarding the cause-and-effect relationship between a faulted element and subsequent loss of load.		X
SERC RRS OPS	A better name for this would be "Unplanned Load Loss". Load loss that occurs from UFLS, UVLS, load shedding or SPS should be moved to Planned Load Loss. Unplanned load loss would be all other load loss other than planned.		X
TVA	See comment for Q2. We recommend that this term is defined as "load loss other than consequential load loss".		X
ITC	May want to change the terminology as some may interpret this to mean load that is not important and can routinely be shed for any contingency. Suggest 'direct load loss' and 'indirect load loss'. Potential Definition: Load that is not intended to be lost for normal fault clearing or during mis-operation but could be lost either by design, such as under frequency relaying, SPS or backup breaker clearing, or thru manual operator action.	X	
Response: See responses to Q2. The SDT revised this definition in response to various comments. However, the SDT is concerned that the use of alternative terms might be confusing. Among other things, the terms used in the proposed standard are consistent with terms used by FERC. Moreover, in response to SERC's comment, the SDT believes that Load loss that occurs from UFLS, UVLS, Load shedding or SPS is not a direct consequence of the event being studied and is in fact the type of distinction the SDT intended to make. **Non-Consequential Load Loss:** ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.			
ATC	Reference to SPS must be excluded from this definition. We recommend that the SDT address what System Elements and/or Load may be tripped by an SPS for each Planning Event in the performance table after N-1-1 scenarios for P3-P5 events.		X

Commenter	Q6. **Comment**	Agree.	Don't agree.
FirstEnergy	We suggest eliminating the reference to Special Protection Systems (SPS). Some SPSs could result in tripping of load in association with a fault. By specifically listing SPSs here, it could imply that if that situation occurs, it would not be considered consequential load drop.		X
Response: The SDT believes that Load loss that occurs from an SPS is not a direct consequence of the event being studied and is in fact the type of distinction the SDT intended to make. FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load Loss.			
City Water Light and Power APPA	This definition should go beyond just saying "Load loss other than Consequential Load Loss." Recommend adding the following: " . . . including Load Loss that occurs through planned manual (Transmission Operator, Distribution Provider, and so-on) operation or planned automatic operation of load shedding equipment such as under-frequency Load shedding devices or Special Protection Systems."		X
Response: See responses to Q2. The SDT revised this definition in response to various comments. **Non-Consequential Load Loss:** ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.			
CAISO	Add Remedial Action Schemes (RAS) after "Systems"		X
ERCOT ISO	Add Remedial Action Schemes (RAS) after "Systems" Amend sentence beginning "For example, Load loss that "directly" occurs…		X
Response: The NERC Glossary of Terms clarifies that the terms "Special Protection System" and "Remedial Action Scheme" can be used interchangeably.			
BCTC	See comments on Consequential Load Loss. Propose the following definition to clarify situations for which NCLL is acceptable: Load loss other than Consequential Load Loss to avoid cascading, voltage stability, or blackout of the BES. For example, load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage load shedding, under-frequency load shedding, or SPS/RAS.		X
SCANA	This term is not needed. See comments on "Consequential Load Loss/Intentional Load Loss".		X
Response: See responses to Q2. The SDT revised this definition in response to various comments. However, the SDT is concerned that the use of alternative terms might be confusing. Among other things, the terms used in the proposed standard are consistent with terms used by FERC. **Non-Consequential Load Loss:** ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual~~			

Commenter	Q6. **Comment**	Agree.	Don't agree.
~~(operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.			
Entergy	We recommend to treat load losses due to UVLS & SPS as examples of consequential load loss (refer to question 2).		X
Response: The SDT believes that Load loss that occurs from an SPS or UVLS is not a direct consequence of the event being studied and is in fact the type of distinction the SDT intended to make. FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load Loss			
FPL FRCC	Reword as follows: "Firm load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems, excluding curtailments, DSM, and voltage reduction."		X
Response: The SDT revised this definition in response to various comments. However, the SDT ddisagrees with curtailments, DSM, and voltage reduction as these are real-time operating actions that must be taken pre-Contingency and are unrelated to Consequential Load Loss and Non-Consequential Load Loss. **Non-Consequential Load Loss:** ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.			
LADWP	See my comment on the Consequential load loss. Why introduce two new and less precise definitions to replace one existing clearly defined definition? Radial load is precise and clearly defined to transmission planners.		X
Response: See responses to Q2. The SDT revised the definitions of Consequential Load Loss and Non-Consequential Load Loss in response to various comments. However, radial Load is not sufficiently precise and is itself confusing if left as the sole explanation. **Non-Consequential Load Loss:** ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.			
Tenaska	See Q2 answer.		X
Response: Please refer to the SDT reply to Q2 comments.			
TSGT	same as WECC group comments		X
BPA	Support comments submitted by WECC.		X
WECC	Please add "or Remedial Action schemes" to the end of the definition. FERC Order		X

Commenter	Q6. **Comment**	Agree.	Don't agree.
TEP	693, paragraph 1773 states (6)"clarifies footnote (b) to Table 1 to allow no firm load or firm transactions to be interrupted except for consequential load loss." There needs to be a distinction made between Interruptible Load and Firm Demand.		
Response: The SDT revised this definition in response to various comments. However, the NERC Glossary of Terms clarifies that the terms "Special Protection System" and "Remedial Action Scheme" can be used interchangeably. **Non-Consequential Load Loss:** ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.			
SaskPower			X
Response: The SDT revised this definition in response to various comments. **Non-Consequential Load Loss:** ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.			
Northwestern Energy	Include the words "not directly connected" before period of first sentence; and what does "load loss" mean?	X	X
Response: See responses to Q2. The SDT revised this definition in response to various comments. However, the SDT is concerned that the use of alternative terms might be confusing. Moreover, the SDT believes the term "Load loss" is largely self-explanatory and is further clarified by the examples provided in the definition. **Non-Consequential Load Loss:** ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.			
AEP	Consider replacing "Non-Consequential" with better wording (no specific suggestion to offer at this time).	X	
RFC	Recommend adding that this load loss is "intentional".	X	
Response: See responses to Q2. The SDT revised this definition in response to various comments. However, the SDT is concerned that the use of alternative terms might be confusing. **Non-Consequential Load Loss:** ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection~~			

Commenter	Q6. **Comment**	Agree.	Don't agree.
~~Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.			
AECI		X	
Allegheny Power		X	
Brazos Electric		X	
CenterPoint		X	
Central Maine Power		X	
City Utilities/Springfield		X	
CPS Energy		X	
Duke Energy		X	
Entegra		X	
Exelon		X	
Dominion		X	
E ON US		X	
KCPL		X	
LUS		X	
LCRA		X	
Manitoba Hydro		X	
MEAG Power		X	
MRO		X	
Muscatine P&W		X	
National Grid		X	
New England ISO		X	
NCEMC		X	
NCMPA		X	
NU		X	
NPCC RCWS		X	
Nstar		X	
Progress–Carolinas		X	
Progress–Florida		X	
Seattle City Light		X	
SERC EC DRS		X	
SERC EC PSS		X	
Southern Transmission	Agree assuming the change in Q2 is made.	X	
United Illuminating		X	
WPSC		X	

Commenter	Q6. **Comment**	Agree.	Don't agree.
Response: Thank you. Please see the Summary Response.			

7) **Q7. Planning Assessment: Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.**

Summary Response: Based on the comments, the SDT revised this definition to be more succinct and eliminate the description of the possible range of assumptions. The definition was also modified to clarify that the assessment is an evaluation of Transmission System performance (not needs) and Corrective Action Plans associated with identified deficiencies.

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~

Commenter	Q7. **Comment**	Agree.	Don't agree.
AECC	Planning assessments shouldn't be limited to the future. Sometimes an assessment needs to be made to benchmark and validate models. Strike: future		X
Response: The SDT revised this definition in response to various comments. However, the purpose of the standard is to assess future transmission needs. Other standards are related to benchmarking and validating models. **Planning Assessment:** Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~			
City Water Light and Power	This definition is too vague. A Planning Assessment should cover the Near-Term or Long-Term Planning Horizon and include Base Case and Contingency Analysis according to NERC Standards.		X
Response: Based on the comments, the SDT revised this definition to be more succinct. Other requirements explain the horizon and conditions required to be studied and should not be included in the definition. **Planning Assessment:** Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~			
APPA	This is too general. Just about any kind of review will qualify as a Planning Assessment. Suggested definition: "Documented evaluation of future Bulk Electric System needs by the use of performance studies such as NERC Steady State Transmission Studies or Plant Stability Studies conducted in accordance with the NERC Reliability Standards."		X
BCTC	Need to insert the word "supported", as below, and further refine, to clarify that the Planning Assessment is not just studies, but includes evaluation of contingencies to be run, sensitivities to consider, etc.		X

Commenter	Q7. **Comment**	Agree.	Don't agree.
	Documented evaluation of future BES needs, measures to mitigate adverse reliability impacts, and assessments of residual impacts, supported by the use of performance studies ….		
City Utilities/Springfield	Definition should be more clearly defined. Documented evaluation of future Bulk Electric System needs based on the performance requirements as defined for NERC Steady State Transmission Studies or Plant Stability Studies conducted in accordance with the NERC Reliability Standards or more restrictive local area criteria.		
Tenaska	May be best to stop the definition after the word assumptions and cover the details as part of the requirements in the standard itself.		X
Response: Based on the comments, the SDT revised this definition to be more succinct and eliminate the description of the possible range of assumptions. The definition was also modified to clarify that the assessment is an evaluation of Transmission System performance (not needs) and Corrective Action Plans associated with identified deficiencies. **Planning Assessment:** Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~			
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating	Eliminate "capital" from the definition. It is not defined or consistently applicable to the standard. Reference to vague "other factors, such as asset conditions and age" should be removed from this standard; there are no consistent definitions or industry standards on which to base this requirement, nor does it appear to be a necessary addition to the standard.		X
Entergy	Remove "and other factors, such as asset conditions and age" from definition. The terms "age" and "condition" are subjective and the age of equipment, if it is well maintained, has little impact on reliability.		X
Exelon	'Other factors' such as condition and age should not be required, but may be utilized if these factors are an integral component of the study.		X
FPL FRCC	Last part of the last sentence should be removed "… and other factors, such as asset conditions and age" does not make sense for planning studies. Equipment condition and age are maintenance issues not transmission planning issues.		X
Georgia Transm. Corp	Asset conditions and age should not be included in the definition. Equipment replacement, in general, is dependent on performance, not age.		X
LADWP	The assessment of asset conditions and age of equipment belongs in maintenance practices, not a transmission planning issue. Similarly, Operating procedures is an operating matter, not planning studies. They have their own standards that could and		X

Commenter	Q7. **Comment**	Agree.	Don't agree.
	should address any issue the SDT may have in mind. Using transmission planning as a catch-all is a wrong headed approach.		
MEAG Power	Bulk Electric System deficiencies rather than needs should be evaluated. We do not agree that the planning assessment should include asset conditions and age. This is a preventive maintenace issue. The age of equipment, if it is well maintained, has little impact on reliability.		X
NCEMC	Generally, we agree but would request NERC to clarify accounting for asset conditions and age within planning assessments. Wouldn't these already be taken into account in the FAC-008 & FAC-009 ratings?	X	
Progress–Carolinas	Planning assessments should not include asset conditions and age.	X	X
Santee Cooper SERC EC PSS SERC RRS OPS	Bulk Electric System deficiencies rather than needs should be evaluated. We do not agree that the planning assessment should include asset conditions and age. The age of equipment, if it is well maintained, has little impact on reliability. The term "and other factors" should be better defined or deleted.		X
SaskPower	What is the intent "and other factors, such as asset condition and age"? Seems to broad and outside the scope of NERC. Remove it.		X
SERC EC DRS	Delete the word "needs" and the phrase "such as asset conditions and age." We do not agree that the planning assessment should include asset conditions and age. The age of equipment, if it is well maintained, has little impact on reliability.		X
Southern Transmission	The term "needs" should be replaced by a term that more aptly describes what is being evaluated. The definition should be ended after the word "assumptions." We do not agree that the planning assessment should include asset conditions and age. The age of equipment, if it is well maintained, has little impact on reliability.		X
TVA	Use of the word "deficiencies" instead of "needs" provides better consistency throughout the standard. We do not agree that the planning assessment should directly include asset conditions and age. Asset condition should be part of the ratings process. The age of equipment, if it is well maintained, has little impact on reliability.		X
Ameren	We do not agree that the planning assessment should include asset conditions and age. The age of equipment, if it is well maintained, has little impact on reliability. If NERC wants a standard to deal with age and maintenance of equipment, then it should develop a separate standard for asset management and not overburden TPL-001-1 with such issues.		X
ATC	We do not agree that "asset conditions and age" belongs in this definition. Furthermore, these factors are not addressed in any requirement.		X
E ON US	I agree that Asset Managers need to consider asset condition and age in their spare equipment and replacement strategies but the impact of these factors is beyond the scope of a deterministic Planning Assessment.		X
Entegra	Should also include validation of reactive power supplies.		X

Commenter	Q7. **Comment**	Agree.	Don't agree.
Response: Based on the comments, the SDT revised this definition to be more succinct and eliminate the description of the possible range of assumptions. **Planning Assessment:** Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~			
FirstEnergy	We suggest replacing "performance studies" with "past or present studies or information".		X
Response: The requirements define the studies that qualify for use in assessments and are not part of the definition.			
LCRA	"Documented evaluation of future Bulk Electric System performance conducted through performance studies…"		
Response: Based on the comments, the SDT revised this definition to be more succinct and eliminate the description of the possible range of assumptions. The definition was also modified to clarify that the assessment is an evaluation of Transmission System performance (not needs) and Corrective Action Plans associated with identified deficiencies. The requirements define the studies that qualify for use in assessments and are not part of the definition. **Planning Assessment:** Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~			
MRO	This definition is too general. It could be interpreted that the performance studies include resource planning rather than transmission system planning, as well as, asset management. Asset management issues should be beyond the scope of this transmission planning standard. Asset management is an engineering discipline that would require a separate standard or standards and is still a developing activity, for example, there is no industry-wide practice for studying aging issues of transmission equipment while there are industry-wide practices for steady-state, stability, and short circuit modeling and planning of transmission systems. The MRO suggests that the word transmission be added to the definition when referring to needs, performance, and reinforcements and that references to asset management be deleted. Here is a proposed definition "Documented evalution of future Bulk Electric System TRANSMISSION needs by the use of TRANSMISSION SYSTEM performance studies that cover a range of assumptions regarding TRANSMISSION system conditions, time frames, future plans including TRANSMISSION IMPROVEMENTS and operating procedures and other factors." The words in all caps were added or inserted to replace the Drafting Team's original words.		X
Dominion	Suggest to change "…by the use of performance studies that cover……" to "…by the use of past or current performance studies that cover……".	X	X
Northwestern Energy	Insert before performance studies the words "current or past that is known to be	X	X

Commenter	Q7. **Comment**	Agree.	Don't agree.
	valid".		
WECC BPA TEP TSGT	As identified by the modifications above, we believe the definition should be changed to read, "Documented evaluation of future Bulk Electric System needs by the use of performance studies (steady state and dynamic) that cover a range of reasonable or expected assumptions regarding system conditions, applicable time frames, and future plans; including capital reinforcements and operating procedures, SPS/RAS, and other factors (such as asset conditions and age)."	X	X
Response: Based on the comments, the SDT revised this definition to be more succinct and eliminate the description of the possible range of assumptions. The definition was also modified to clarify that the assessment is an evaluation of Transmission System performance (not needs) and Corrective Action Plans associated with identified deficiencies. The requirements define the studies that qualify for use in assessments and are not part of the definition. **Planning Assessment:** Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~			
New York ISO	The word "Documented" is unnecessary. Suggest simplifying the definition to: Evaluation of future BPS needs to meet forecast demand under the assumed system conditions for the time frame studied.		X
Response: Documentation is required as proof that evaluation was performed and guidance is provided as to the content of the documentation.			
RFC	Recommend adding power flow and dynamic analyses to this definition. Short circuit analyses should not be included.		
Response: Based on the comments, the SDT revised this definition to be more succinct and eliminate the description of the possible range of assumptions. Requirements define the studies that must be performed. **Planning Assessment:** Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~			
SCANA	Bulk Electric System deficiencies rather than needs should be evaluated.		X
Response: The definition was modified to clarify that the assessment is an evaluation of Transmission System performance (not needs) and Corrective Action Plans associated with identified deficiencies.			
IESO	The definition covers too much detail on the "how" part, and the "documented" qualifier doesn't seem to be required. Suggest to change it to: Evaluation of future Bulk Electric System needs to meet forecast demand under the assumed system conditions for the time frame studied.	X	X
Response: Based on the comments, the SDT revised this definition to be more succinct and eliminate the description of the possible range of assumptions. The definition was also modified to clarify that the assessment is an evaluation of Transmission System performance (not needs) and Corrective Action Plans associated with identified deficiencies. The requirements define the studies that qualify for use in			

Commenter	Q7. **Comment**	Agree.	Don't agree.
assessments and are not part of the definition. Documentation is required as proof that evaluation was performed and guidance is provided as to the content of the documentation. **Planning Assessment:** Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~			
Brazos Electric	Some discussion of what 'documented' means is needed each time it is mentioned. Is this some form of written report at all times or are 'saved' cases with contingency analysis sufficient at certain times or is it just a means to show that an 'assessment' was performed in some fashion.	X	
Response: Documentation is required as proof that evaluation was performed and guidance is provided as to the content of the documentation. Documentation requirements are contained in the standard itself. For example, Requirement R2.7.3 requires documentation of the criteria for determining committed and proposed projects. More clarity may be provided through the subsequent development of compliance measures and auditor worksheets.			
Duke Energy	We have a concern with what will be considered acceptable documentation, particularly as it relates to asset conditions and age. Delete the word "needs" and the phrase "such as asset conditions and age". When measures are developed it should be made clear what will constitute an acceptable Planning Assessment.	X	
Response: The SDT revised this definition in response to various comments. Documentation requirements are contained in the standard itself. For example, Requirement R2.7.3 requires documentation of the criteria for determining committed and proposed projects. More clarity may be provided through the subsequent development of compliance measures and auditor worksheets. **Planning Assessment:** Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~			
ABB		X	
AECI		X	
Allegheny Power		X	
AEP		X	
CenterPoint		X	
CPS Energy		X	
ERCOT ISO CAISO	Agree with the definition.	X	
ITC		X	
KCPL		X	
LUS		X	
Manitoba Hydro	A planning assessment should include performance studies.	X	

Commenter	Q7. **Comment**	Agree.	Don't agree.
MISO		X	
Muscatine P&W		X	
NERC TIS		X	
Progress–Florida		X	
Seattle City Light		X	
Response: Thank you. Please see the Summary Response.			

8) Q8. Planning Events: Events which require Transmission system performance requirements to be met.

Summary Response: The majority of the commenters agreed with the proposed definition; therefore, the SDT did not modify the definition.

Commenter	Q8. **Comment**	Agree.	Don't agree.
AECC	The definition is too vague and does not go far enough to distinguish it from something like and operational event, which only addresses the intial system response and does carry through to the resulting system following the event and subsequent steps that may be taken. Suggest: Planning Events = Events which remove one or more Elements and require Transmission system performance requirements to be met. This definition includes the initial event and any after event actions that result in the system returning to a steady state condition and preventing as serving as much Consequential load as possible.		
Ameren	Consideration should be given to adding the performance requirements in the definition.		X
ATC			X
APPA	What are "performance requirements?" This is too general a statement to be of value for writing specific standards.		X
City Water Light and Power	This statement is too general. Performance Requirements are not defined.		X
City Utilities/Springfield	Minimum performance requirements need to be clearly defined.		X
Georgia Transm. Corp	Performance requirements should be added to the definition.		X
E ON US	Recommend: Events to be simulated is studies (listed in Tables 1 and 2 of TPL-001) which must be documented with Corrective Action Plans when performance requirements of TPL-001 are not met.		X
ERCOT ISO	Needs clarity. Suggest the following wording: Outage of power system elements such as shown in Tables 1 and 2 that need to be considered and simulated to assess Transmission System Performance.		X
CAISO	Needs clarity. Suggest the following wording: Outage of power system elements such as shown in Tables 1 and 2 that need to be considered and simulated to assess Transmission System Performance		X
Central Maine Power HQTE National Grid New England ISO NU NPCC RCWS NSTAR United Illuminating	Propose, "Events for which Transmission performance requirements must be met".		X

Commenter	Q8. **Comment**	Agree.	Don't agree.
LADWP	The term Event has such a broad connotation that it can be misused by layperson. In fact, it is already misused in this standard as evidenced by including events such as cyber attacks, hurricans, tonados, etc as transmission planning events. These events belongs in "emergency" planning, not transmission planning.		X
Southern Transmission	Change to, "Events that are simulated or assessed to test the transmission system to ensure that performance requirements are met as defined in TPL-001-1 Tables 1 and 2."		X
MEAG Power NCEMC Santee Cooper SERC EC PSS SERC RRS OPS	Change to: "Events that are simulated or assessed to test the transmission system to ensure that performance requirements are met."		X
SCANA	Prefer alternate language, "Events for which Transmission system performance requirements must be met."		X
Response: The majority of the commenters agreed with the proposed definition; therefore, the SDT did not modify the definition.			
FirstEnergy	We ask that the SDT reword the definition to include reference to the planning events in Table 1 and 2 of this standard. This definition should be specific to this standard and not be included in the NERC glossary.		X
Response: The majority of the commenters agreed with the proposed definition; therefore, the SDT did not modify the definition. Moreover, the SDT believes the definition should be included in the NERC Glossary of Terms to provide common industry terminology.			
IESO NYISO	Linking it to Transmission system performance requirements presents "loop around" argument. Suggest to change it to: Events which need to be considered and simulated in planning assessments to evaluate Transmission system performance.		X
Response: The majority of the commenters agreed with the proposed definition; therefore, the SDT did not modify the definition. Moreover, the proposed revision would not suffice because Extreme Events must also be considered and simulated in planning assessments.			
Manitoba Hydro	The definition of a planned event should relate to the probablity of occurance. Table shows single contingency planned events and multiple contingency planned events. Why has the SDT gone away from the existing categories of events which sorted the events into categories with different levels probability.		X
Response: The majority of the commenters agreed with the proposed definition; therefore, the SDT did not modify the definition. In response to this specific comment, Planning events were considered to have sufficiently high probability of occurrence as to require planned corrective actions - hence the term Planning Event. However, Planning Events have still been sorted into categories with different performance requirements corresponding to different levels of probability and consequence.			
RFC	I don't believe that this is really the definition of "planning events". This defintion should describe generally what the planning events are, not that they must meet performance requirements.		X
Response: The majority of the commenters agreed with the proposed definition; therefore, the SDT did not modify the definition. The SDT believes that a general description of what the planning events are includes the fact that these are the types of events for which performance			

Commenter	Q8. **Comment**	Agree.	Don't agree.
requirements must be met.			
Seattle City Light	List specific types of failures or direct us to a specific table which describes planning events.		X
Response: The majority of the commenters agreed with the proposed definition; therefore, the SDT did not modify the definition. The SDT believes a definition should be established that does not reference a particular part of the standard.			
ABB	Agree but adjust language. You are saying "require requirements to be met". Duh. Even if you took out one of them and said "requirements must be met", this is also redundant. The definition of "requirement" is that it is required. How about "Events for which there are strict transmission performance standards that must be met." This may also be slightly redundant, but not as much as the original.	X	
Response: The majority of the commenters agreed with the proposed definition; therefore, the SDT did not modify the definition. We believe the language, with respect to the use of require and requirements, is correct, and the suggested language does not offer substantive improvement.			
Northwestern Energy		X	
AECI		X	
Allegheny Power		X	
AEP		X	
BPA		X	
BCTC		X	
Brazos Electric		X	
CenterPoint		X	
CPS Energy		X	
Duke Energy		X	
Entegra		X	
Entergy		X	
Exelon		X	
CPS Energy		X	
FPL		X	
FRCC		X	
Dominion		X	
ITC		X	
KCPL		X	
LCRA		X	
LUS		X	
MISO		X	
MRO		X	
Muscatine P&W		X	

Commenter	Q8. **Comment**	Agree.	Don't agree.
NERC TIS		X	
Progress–Carolinas		X	
Progress–Florida		X	
SaskPower		X	
SERC EC DRS		X	
Tenaska		X	
TVA		X	
TSGT		X	
TEP		X	
WECC		X	
Response: Thank you.			

9) **Q9. Plant Stability Study: Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.**

Summary Response: Based on the responses to Q32 the SDT believes the majority of comments have been addressed. Please refer to responses to Q32 and the revised definition for additional clarification. The SDT revised this definition as follows to further clarify intent:

Generating Unit Stability Study: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations.

~~**Plant Stability Study**: Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~

Commenter	Q9. **Comment**	Agree.	Don't agree.
ABB	I don't see any reason to differentiate between "Plant Stability" and "System Stability". These are not commonly separated. A better differentiation would be between generator (or angular) stability and load (or voltage) stability. These are usually independently studied and independently occurring.		X
Ameren	It seems that the SDT is trying to divide the stability issues between plant (local) and system. As the system load representation and its damping characteristics affect both plant and system stability, it is difficult to separate plant versus system stability studies. The focus of the studies may be only slightly different, depending on the location, type, and duration of the fault conditions assumed.		X
Central Maine Power NPCC RCWS	A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.		X
FirstEnergy	We believe that this definition is not needed. The Plant Stability Study is similar to the System Stability Study.		X
FPL FRCC	There should be no distinction between Plant Stability and System Stability. All stability studies must meet the Performance Requirements for Planning Events in Table 2 - Stability Performance. If there were different Performance Requirements then the distinction would be warranted.		X
HQTE National Grid New England ISO NU	A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.		X

Commenter	Q9. **Comment**	Agree.	Don't agree.
NSTAR United Illuminating			
BPA	Support comments submitted by WECC. Plant Stability is a subset of System Stability.		X
WECC	Plant Stability seems to be a subset of System Stability. Introducing a new term can cause confusion.		X
Progress–Carolinas	Don't need to differentiate between plant and system. These are not usually separated. It would be better to separate angular stability and voltage stability. They are studied independently.		X
Tenaska	Not convinced that this study needs to be differentiated from a System Stability Study.		X
TEP	Plant Stability seems to be a subset of System Stability. Introducing a new term can cause confusion.		X

Response: The SDT revised this definition in response to various comments. The SDT believes that it is important to maintain the distinction between Plant and System Stability studies. Based on the responses to Q32 the SDT believes the majority of comments have been addressed. Please refer to responses to Q32 and the revised definition for additional clarification.

Generating Unit Stability Study: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations.

~~Plant Stability Study: **Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.**~~

ATC	Suggest eliminating the sentence after the semi-colon -- the defined term Stability implies what is addressed in the second sentence and is also noted as a performance requirement in footnote 1.a.i to the Stability Performance Table. We also suggest that reference to "in the vicinity" be replaced by "that affect the plant Stability".		X
Santee Cooper SERC RRS OPS	The definition should end at the semi-colon. The remaining part of the definition should be moved to the definition of "System Stability Study."		X

Response: The SDT revised this definition in response to various comments, although much of the sentence after the semi-colon has been retained for clarity regarding generating unit performance. Based on the responses to Q32 the SDT believes the majority of comments have been addressed. Please refer to responses to Q32 and the revised definition for additional clarification.

Generating Unit Stability Study: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations.

Commenter	Q9. **Comment**	Agree.	Don't agree.
~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
City Water Light and Power	Insert "Generating" prior to "Plant" for clarity.		X
APPA	Insert "electric generating" prior to "plant" for clarity. It is unclear as to the intent of this statement. The Standard should require the Transmission Planner to consider contingencies in the vicinity of a particular electric generation plant. However, the ultimate goal of the "Stability Study" is to determine the stability of the BES and not just the "electric generation plant." It is recommended that this be rewritten to make clear the intent of this statement.		X
WPSC	This definition mixes the use of the word "plant" and "generator" which have two different meanings. Suggest re-naming as Generator Stability Study and allow the study of multiple generators at a single site as a plant. The use of "generator" vs. "plant" should also be consistent throughout the standard.		X
Response: The term "plant" has been deleted and the term "generating unit" is being used in the description of the type of study required. The new definition is for a "Generating Unit Stability Study". The SDT made these changes in response to various comments. Please refer to responses to Q32 and the revised definition for additional clarification. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations.			
~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
ERCOT ISO CAISO	Definition is not clear. Suggest the following wording: Study of an individual generating plant's capability to remain in synchronism and exhibit damping of the generating units' power oscillations for various contingencies in the vicinity of the plant.		X
IESO	Suggest to replace "Contingencies" with "Planning events", and change the definition as follows: Study of an individual generating plant's capability to remain in synchronism and exhibit damping of the generating units' power oscillation for various Planning events. Note that "in the vicinity of the plant" is removed to not restrict simulations of events only in the vicinity of the plants as experience has shown that an event remote from the plant could also subject the plant to lose synchronism and/or oscillate without		X

Commenter	Q9. **Comment**	Agree.	Don't agree.
	acceptable damping.		
New York ISO	"Contingencies" should be replaced with "Planning Events". "in the vicinity of the plant" is too restrictive. Suggest: Study of an individual generating plant's capability to remain in synchronism with damping power oscillation for various Planning Events.		X
Response: The SDT revised this definition in response to various comments. The new definition further clarifies the SDT's intent regarding the "vicinity" that must be considered, although additional buses further away can be studied if desired. Please refer to responses to Q32 and the revised definition for additional clarification. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
Northwestern Energy	System stability studies covers this definition.		X
Response: The SDT believes that it is important to maintain the distinction between Plant and System Stability studies. The SDT revised this definition in response to various comments. Based on the responses to Q32 the SDT believes the majority of comments have been addressed. Please refer to responses to Q32 and the revised definition for additional clarification. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
Duke Energy	Delete the term "the effect on the System of." The reference to "System" causes confusion with the term "System Stability Study.		X
Entergy	Delete the term "the effect on the System of." The reference to "System" causes confusion with the term "System Stability Study." Section R4.6 should identify the Generator Owner as the applicable party for doing the Plant Stability Studies.		X
Response: The reference to the "system" has been deleted from the new definition. SDT revised this definition in response to various comments. Based on the responses to Q32 the SDT believes the majority of comments have been addressed. However, the SDT disagrees			

Commenter	Q9. **Comment**	Agree.	Don't agree.
that the Generator Owner is the applicable party responsible for performing Generating Unit Stability Studies for the purpose of assessing and planning the transmission system, as contemplated by this standard. Please refer to responses to Q32 and the revised definition for additional clarification. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
Exelon	Wording should be changed to allow for engineering judgment to determine which contingencies are applied. There may be instances where contingencies outside of the immediate vicinity of the plant may be significant to its stability. Suggest replacing the word 'System' with 'Transmission System'.		X
NERC TIS	Should not be limited to contingencies in the vicinity of the plant. Remove the terms "in the vicinity of the plant." Engineering judgement can then be used without having to define "vicinity." Plant instability can be caused by system events many (sometimes hundreds of) miles away. Plants were shaken off line in British Columbia due to the tripping of units in Arizona in June 2004.		X
Seattle City Light	"…in the vicinity of the plant…" needs to be more specific. How far away must we study?	X	X
Response: The SDT revised this definition in response to various comments. The new definition further clarifies the SDT's intent regarding the "vicinity" that must be considered, although additional buses further away can be studied if desired. Based on the responses to Q32 the SDT believes the majority of comments have been addressed. Please refer to responses to Q32 and the revised definition for additional clarification. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
LADWP	When performing transient stablity studies using either PSSE or PSLF, loss of synchronism and oscillation damping are automatically part of the performance evaluation; it is not a separate study and should not be classifed as a separate study. In the context of transmission planning, unless someone on the SDT use programs		X

Commenter	Q9. **Comment**	Agree.	Don't agree.
	that do not have transient stability package similar to PSSE and PSLF, or has a completely different understanding on the meaning of loss of synchronism and/or damping, there is no need to introduce two new terms to explain a very well understood and established single term known as "transient stability" .		
Response: The SDT believes that it is important to retain the terms to maintain clarity. The SDT revised this definition in response to various comments. However, few if any other commenters expressed concerns about verbiage relating to loss of synchronism and damping of power oscillations. Therefore, this verbiage remained relatively unchanged. Based on the responses to Q32 the SDT believes the majority of comments have been addressed. Please refer to responses to Q32 and the revised definition for additional clarification. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
SERC EC DRS	Delete the term "the effect on the System of." The reference to "System" causes confusion with the term "System Stability Study."		X
Response: The SDT revised the definition in response to various comments to eliminate the reference to the "system". Based on the responses to Q32 the SDT believes the majority of comments have been addressed. Please refer to responses to Q32 and the revised definition for additional clarification. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
TSGT	Plant stability should be called Station stability. The term "plant" is reserved for aggregates such as total coal plant or total peaking plant, meaning all generating units in that category.		X
Response: The SDT revised the definition to be more general with respect to closely-coupled generating units. Please refer to responses to Q32 and the revised definition for additional clarification. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power			

Commenter	Q9. **Comment**	Agree.	Don't agree.
oscillations. ~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
KCPL	Suggest adding "Bulk Electric" before "System".	X	
Manitoba Hydro MISO MRO	The words "Bulk Electric" should be added before "System".		X
MEAG Power SERC EC PSS	Change " the System" to "local area of the Bulk Electric System." It also need a definition for "plant."	X	
Response: The SDT revised the definition in response to various comments and clarified that the study focuses on an individual generating unit's or electrically closely-coupled generating units' Stability. Please refer to responses to Q32 and the revised definition for additional clarification. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
AECI		X	
Allegheny Power		X	
AEP		X	
BCTC		X	
Brazos Electric		X	
CenterPoint		X	
City Utilities/Springfield		X	
CPS Energy		X	
Entegra		X	
Georgia Transm. Corp		X	
ITC		X	
LCRA		X	
LUS		X	
Muscatine P&W		X	
NCEMC		X	
Progress–Florida		X	

Commenter	Q9. **Comment**	Agree.	Don't agree.
SCANA		X	
Southern Transmission	No Additional Comments.	X	
TVA		X	
Response: Thank you. Please see the Summary Response.			

10) Q10. System Stability Study: Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.

Summary Response: Based on the comments, the SDT revised this definition as follows to add further clarity:

System Stability Study: ~~Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.~~ Study that focuses on portions of the System, which may include many generating units, to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.

Commenter	Q10. **Comment**	Agree.	Don't agree.
Ameren	See comments above in the response to Q9. Specific inclusion of voltage (load) stability seems to be missing from the definition. Also, angular stability is mentioned only as part of the definition for System Stability Study and not Plant Stability Study. It would seem that this item would be part of both types of study.		X
PJM	Does "inter-area oscillations are damped" imply that you also have to do frequency domain analysis? (Because some industry experts would claim that without small signal analysis you cannot ensure that inter-area oscillations are damped.)	X	X
Response: The SDT revised this definition in response to various comments. Based on the responses to Q32 the SDT believes the majority of comments have been addressed. Please refer to responses to Q32 and the revised definition for additional clarification. **System Stability Study:** ~~Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.~~ Study that focuses on portions of the System, which may include many generating units, to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.			
ABB	See Q9.		X
Santee Cooper	see Q9 above.		X
SERC RRS OPS	see Q9 above.		X
Response: See response for Q9.			
ATC	Truncate the definition to "……ensure that Stability is maintained." Note that we suggest that "angular" be deleted so that the definition is comprehensive and it includes both voltage and angular stability. Suggest moving the performance attributes in the definition (after the comma) as footnotes to the Stability Performance Table.		X
Response: The SDT believes that it is important to retain the terms to maintain clarity. Please refer to responses to Q32 and the revised definition for additional clarification.			
ERCOT ISO	This definition is for a stable system. Study is performed to determine whether system		X

Commenter	Q10. **Comment**	Agree.	Don't agree.
CAISO IESO	is stable or not. Suggest the following wording: Study of the system or portions of the system to assess the system's performance in terms of angular stability, power oscillations and voltage limits during dynamic simulation.		
New York ISO	The study is an assessment. Suggest: Study of the System or portions of the System to assess the System's performance in the domain of angular stability, inter-area oscillations and voltage profile during dynamic simulation.		X
Response: The SDT revised this definition to reflect that the study is for portions of the system. The applicable portions of the System still must be studied and the wording was modified to describe that the study determines whether the System remains stable, not that it ensures stability is maintained. Please refer to responses to Q32 and the revised definition for additional clarification. **System Stability Study:** ~~Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.~~ Study that focuses on portions of the System, which may include many generating units, to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.			
Central Maine Power HQTE National Grid New England ISO NU NPCC RCWS NSTAR United Illuminating	See comment on Q9; proposed modification, "Study of the System or portions of the System to determine whether plant and system angular Stability is maintained, power oscillations are damped, and voltages during the dynamic simulation stay within acceptable perfomance limits.		X
Progress–Carolinas	Don't need to differentiate between plant and system. These are not usually separated. It would be better to separate angular stability and voltage stability. They are studied independently.		X
Response: The SDT believes that it is important to maintain the distinction between Generating Unit (formerly Plant) and System Stability studies. Please refer to responses to Q32 and the revised definition for additional clarification.			
FPL FRCC	Dynamic voltage ratings do not add value and are only an approximation for modeling limitations. The definition should not address performance and should only seek to define the term. Reword as follows: "Study of the System or portions of the System to assess angular Stability and inter-area power oscillations."		X
Response: The SDT believes that it is important to retain the information explaining the purpose of the study. Please refer to responses to Q32 and the revised definition for additional clarification.			
LADWP	This comment should be taken together with the comment on Plant stability and I would recommend not to create new terms and go back to use well established engineering terms like Transient Stability Study which covers synchronism, damping,		X

Commenter	Q10. **Comment**	Agree.	Don't agree.
	voltage limits, angular stability, etc. There are many text books that could be used to support this.		
Response: The SDT believes that it is important to retain the terms to maintain clarity. Please refer to responses to Q32 and the revised definition for additional clarification.			
Exelon	Suggest replacing 'System' with 'Transmission System'.	X	
KCPL	Suggest adding "Bulk Electric" before "System".	X	
Manitoba Hydro MISO MRO	The words "Bulk Electric" should be added before both occurances of "System".		X
SERC EC PSS	Change "System" to "Bulk Electric System."	X	
MEAG Power	Change "System or portions of the system" to "Bulk Electric System's components associated with the Transmission Planer."	X	
Response: The SDT believes the reference to the "System" correctly describes the scope of the study. Please refer to responses to Q32 and the revised definition for additional clarification.			
APPA	This is a very clear definition that can be used in Standards. The author did a good job of using defined terms in this definition.		
Northwestern Energy		X	
AECI		X	
Allegheny Power		X	
AEP		X	
BPA		X	
BCTC		X	
Brazos Electric		X	
CenterPoint		X	
City Utilities/Springfield		X	
CPS Energy		X	
Duke Energy		X	
Entegra		X	
Entergy		X	
Dominion		X	
FirstEnergy		X	
Georgia Transm. Corp		X	
ITC		X	
LCRA		X	
LUS		X	
Muscatine P&W		X	
NCEMC		X	

Commenter	Q10. **Comment**	Agree.	Don't agree.
NERC TIS		X	
Progress–Florida		X	
Seattle City Light		X	
SERC EC DRS		X	
SCANA		X	
Southern Transmission	No Additional Comments.	X	
Tenaska	A generator's loss of synchronism and oscillation issues will be seen in this study.	X	
TVA		X	
TSGT		X	
TEP		X	
WECC		X	
Response: Thank you. Please see the Summary Response.			

11) Q11. Year One: The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.

Summary Response: Based on the comments, the SDT modified the definition to clarify that Year One is the first year that requires assessment, not study; and that the planning window begins 12 to 18 months from the completion of the previous assessment. The change reflects the variability in the timing of assessments among different Transmission Planners.

Year One: The first year that a Transmission Planner is responsible for ~~studying~~ assessing. This is further defined as the planning window that begins ~~the next calendar year from the time the Transmission Planner submits their annual studies~~ 12-18 months from the completion of the previous annual Planning Assessment.

Commenter	Q11. **Comment**	Agree.	Don't agree.
ABB	Agree but delete "annual". Unnecessarily restrictive. Aren't there non-annual studies for which the definition of "year one" is important?	X	
E ON US	"studies" should be replaced with "Planning Assessment", the Planning Assessment is the documentation (of past and current studies) submitted for review. Note: the definition in Q11 does not match TPL-001.		X
WPSC	Suggest replacing the words "annual studies" with "Planning Assessment".		X
ATC	The definition here is not consistent with what is in the posted standard (the last sentence is extra) -- we agree with the definition in the posted standard.		X
Entergy	The last sentence in the above definition was not included in the definition listed in the draft standard. Consider deleting the last sentence or providing additional examples.		X
FPL	The last sentence of this definition is not included in the Standard. Reword as follows: "The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner performs their annual studies and submits the results to the RRO."		X
FRCC	The last sentence of this definition is not included in the Standard and should be deleted.		X
MEAG Power Santee Cooper SERC EC PSS SERC RRS OPS Southern Transmission TVA	The last sentence in the above definition was not included in the definition listed in the draft standard, nor should it be.	X	
Response: In the course of reviewing comments, the SDT realized that the definition of Year One in the draft standard varied from the definition of Year One in Q11 of the comment form. The SDT revised this definition in response to various comments.			

Commenter	Q11. **Comment**	Agree.	Don't agree.
Year One: The first year that a Transmission Planner is responsible for ~~studying~~ assessing. This is further defined as the planning window that begins ~~the next calendar year from the time the Transmission Planner submits their annual studies~~ 12-18 months from the completion of the previous annual Planning Assessment.			
AECC	Year One should be the first year following the current year. The first sentence defines year one just fine. Lose the last two sentences. Completely disagree with the last sentence. Studies are not necessarily conducted on calender year basis and the study publication is irrelevant. This is a planning standard and not an opertions standard. Operational vs planning are driven by the horizon time frame and not a study publication date.		X
ERCOT ISO CAISO	Suggest a shorter definition: Planning window beginning next calendar year.		X
Central Maine Power	Modify to, "The first year that a Tranmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner completes its annual studies."		X
Duke Energy	Need to provide an example to clarify what this means.		X
FirstEnergy	Although we agree with the concept, the definition is confusing. We suggest simplifying the definition to "The first 12 month period that begins one year and one day from the completion of the study."		X
Georgia Transm. Corp	The first sentence in not necessary. A Planner may use the base case to further assess a problem in the current year. The definition should begin with "The next planning year following current annual studies".		X
HQTE National Grid New England ISO NU NPCC RCWS NSTAR United Illuminating	Modify to, "The first year that a Tranmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner completes and communicates its annual studies."	X	X
NCEMC	This definition could use further clarification to eliminate inconsistencies in how it may be interpreted. Operations planning horizons may typically be 13 to 18 months from the current date due to the reality that transmission upgrades to address operational performance issues may not be able to be implemented inside this period. Some may assume a 24-36 month operations planning window. Based on this assumption, Year 1 could start anywhere from 13 months from the current date to as much as 37 months from the current date.		X
Brazos Electric	Planners do not 'submit' their studies to ERCOT for evaluation or other. Certain projects are submitted to the group for review and comment but not all studies are	X	

Commenter	Q11. **Comment**	Agree.	Don't agree.
	submitted as normal pratice in all cases. It may be better to use 'create their base cases' or simply 'performs their annual studies' instead of 'submit their annual studies'		
Response: The SDT revised this definition in response to various comments. **Year One:** The first year that a Transmission Planner is responsible for ~~studying~~ assessing. This is further defined as the planning window that begins ~~the next calendar year from the time the Transmission Planner submits their annual studies~~ 12-18 months from the completion of the previous annual Planning Assessment.			
APPA	There is a term in the Glossary that is "Operation Plan;" however, there is not a term defining Operations Planning. It is recommended that the SDT drop the last sentence and define the term Operations Planning for the Glossary. Change "their" to "its."		X
BCTC	One problem with this definition is that it assumes that the Transmission Planner submits annual studies. We need definitions for Operating Horizon and Planning Horizon. Then: Year One: The first year of the Planning Horizon.		X
IESO	Not sure why we need this definition. The standard can simply be worded such that a Transmission Planner is responsible for assessing system needs for time frame beyond the current year. Introducing Operations Planning creates confusion as it is unclear whether this term describes a function or an entity in the context of the proposed definition. Further, the sentence "Analysis conducted for time horizon within the current year from the study publication are assumed to be conducted under the auspices of Operations Planning" is (a) confusing time frame wise, (b) invites debates on the role and responsibility for a term that is not defined in NERC standard or the Functional Model, and (c) is perceived to be prescriptive in organizational setup/responsibility allocation (e.g. why can't a transmission planner conduct operational planning studies?).		X
Response: In the course of reviewing comments, the SDT realized that the definition of Year One in the draft standard varied from the definition of Year One in Question 11 of the comment form. The term "Operations Planning" was used in Q11 but not in the draft standard. Therefore, the SDT revised the definition of Year One in response to various comments but will not introduce a definition for Operations Planning. **Year One:** The first year that a Transmission Planner is responsible for ~~studying~~ assessing. This is further defined as the planning window that begins ~~the next calendar year from the time the Transmission Planner submits their annual studies~~ 12-18 months from the completion of the previous annual Planning Assessment.			
ITC	Adding a statement specifying that this is at least ??? number of months into the future may be prudent.		
Response: The SDT revised this definition in response to various comments. However, in the course of considering this definition and reviewing comments, the SDT believes that the start of Year One will not be a fixed point in time for all Transmission Planners. For example, see NCEMC's comment.			

Commenter	Q11. **Comment**	Agree.	Don't agree.
Year One: The first year that a Transmission Planner is responsible for ~~studying~~ assessing. This is further defined as the planning window that begins ~~the next calendar year from the time the Transmission Planner submits their annual studies~~ 12-18 months from the completion of the previous annual Planning Assessment.			
Seattle City Light	Base cases are developed and studied for seasons, not calendar years. Can the Year One reference be changed to "the year beginning at the next Winter season" instead of the specific "…next calendar year"?	X	X
Response: The SDT revised this definition in response to various comments. However, the SDT has members from a wide variety of NERC regions. In the course of discussing how to define Year One, the team found that practices vary across different regions. For example, many southern regions concentrate on summer peak seasons while others, such as Seattle City Light, may concentrate on winter seasons. The modified definition is intended to accommodate such regional variation. **Year One:** The first year that a Transmission Planner is responsible for ~~studying~~ assessing. This is further defined as the planning window that begins ~~the next calendar year from the time the Transmission Planner submits their annual studies~~ 12-18 months from the completion of the previous annual Planning Assessment.			
Northwestern Energy		X	
AECI		X	
Allegheny Power		X	
AEP		X	
Ameren		X	
BPA		X	
CenterPoint		X	
City Utilities/Springfield		X	
CPS Energy		X	
Dominion		X	
Entegra		X	
Exelon		X	
KCPL		X	
LUS		X	
LADWP	very good clarification!	X	
LCRA		X	
Manitoba Hydro		X	
MISO		X	
MRO		X	
Muscatine P&W		X	
NERC TIS		X	
New York ISO		X	

Commenter	Q11. **Comment**	Agree.	Don't agree.
Progress–Carolinas		X	
Progress–Florida		X	
RFC		X	
SaskPower		X	
SERC EC DRS		X	
SCANA		X	
Tenaska		X	
TSGT		X	
TEP		X	
WECC		X	
Response: Thank you**.** Please see the Summary Response.			

B) Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

12) Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Summary Response: The SDT believes that there is a need to perform sensitivity studies and to set a minimum level of sensitivities to be considered. To achieve that, the SDT is providing some guidance on what could be included in the sensitivity studies without being too prescriptive. Requirement R2.1.3 and Requirement R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.1.4 and Requirement R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system.

The following requirements were changed due to industry comments:

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:
R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:
R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

R2.7.2. ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.

Question 12			
Commenter	**Yes**	**No**	**Comment**
ABB		☑	No. However, as long as we're talking about it, NERC should set a standard for the definition of the "peak load" to be planned for. Some utilities use the 50% probability peak load. Some use 90%. A big difference that will result in a big difference in how they are prepared for the peak load days. The sensitivity section is not sufficient to address this. Also, outages of reactive resources should be (and are) in the list of contingencies, not sensitivities.
Response: The standard does not prescribe what percentage of Load needs to be studied. The peak Load to be planned for is defined by the individual entity. The consideration of a higher or lower probability of peak Load is only one of the sensitivity conditions listed in R2.1.3.			

Question 12			
Commenter	**Yes**	**No**	**Comment**
R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:			
Ameren		☑	For the purposes of compliance, we believe that the existing requirement R1 in Standard TPL-001-0 adequately defines the sensitivities that need to be covered in a valid assessment, and no additional clarification is necessary. Deterministic tests of a limited number of system conditions require the application of engineering judgment to evaluate the complex multi-variable problems involved in planning analyses. We all agree that performing contingency analyses on a single snapshot of expected system conditions is not adequate to plan the transmission system, but planning is not a cookbook exercise, and neither is an engineering assessment of planning activities demonstrating required system performance. Further, we believe that a test of incremental transfer capability determined from some of the sensitivity cases needs to be added to the standard and would go a long way to address how much margin exists in the transmission system to handle the unknown or previously undefined variables.
Response: The SDT believes that there is a need to perform sensitivity studies and to set a minimum level of sensitivities to be considered. To achieve that, the SDT is providing some guidance on what could be included in the sensitivity studies without being too prescriptive. R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. Further the standard is not intended to address how much margin exists in the Transmission System to handle the unknown or previously undefined variables, but to provide base line performance requirements. The entity can provide as much margin as it feels is appropriate. R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.			
AEP	☑		Consider requiring a minimum of two sensitivity cases.
Allegheny Power		☑	Scenario analysis should be based on the unique aspect of the particular Transmission zone. Transmission Planners should work to select the best scenarios related to the specific system and adequately describe the selection process.

Question 12			
Commenter	**Yes**	**No**	**Comment**
APPA		☑	The term Base Case should not be used in this manner. The conditions of the Base Case Study should not be in a Standard to insure that all instability cases are covered.
City Water Light and Power	☑		The term Base Case should not be used in this manner. The conditions of the Base Case Study should be in a Standard to insure that all sensitivity cases are covered.
BCTC	☑	☑	The number of sensitivity cases should be tied to the number of resource plans and range of possible load growth forecast.
Brazos Electric		☑	More descretion should be allowed by the TO or planner in deciding the number of cases.
CenterPoint		☑	The number and type of sensitivity studies should be left to the judgement of Transmission Planners. Having too many prescriptive requirements results in concentrating on meeting the requirements rather than on formulating the most effective and efficient improvements.
CPS Energy		☑	The number of sensitivity studies should be at the discretion of Transmission Planners.
Dominion		☑	Transmission Planning engineers have good engineering judgment and need to have some flexibility in selecting the variables that need to be studied.
Duke Energy		☑	The entity performing the studies has the best system specific knowledge to select the appropriate sensitivities that needs to be evaluated. When Measures are developed, they should provide planners with the flexibility to perform appropriate sensitivity studies.
Entergy		☑	The appropriate studies that should be done by each applicable entity is highly dependent on the transmission system being studied. Being too prescriptive may cause irrelevant studies to be completed while diverting resources and attention from sensitivity studes that the entity most familiar with the transmission system believes could result in more meaningful analysis. The Committee should not lose sight of the importance of good engineering judgment exercised by those most familiar with the characteristics of the particular system. While appropriate sensitivity analyses are beneficial in evaluating system performance, it should be clearly stated that projects and/or mitigation plans are left to the discretion of the Transmission Planners.
ERCOT ISO CAISO		☑	The TP or PA is the best to determine the number and type of sensitivities that are more applicable to their system.
FirstEnergy		☑	We suggest that the SDT reword the standard to allow the Transmission Owner additional latitude as to which stress conditions to study. We suggest modifying R2.4.3 to indicate sensitivities "such as those listed below" be studied. That way the standard would be providing examples but would not dictate specific sensitivity studies that should be performed.
FPL		☑	Not all Regions' sensitivity concerns are the same.
FRCC		☑	Not all Regions' concerns are the same and therefore each Region should determine which sensitivities are appropriate.
Georgia Transm.		☑	Sensitivity analyses should not be prescribed. In one system there may be various sensitivites based on region, generation location, number of long range projects, etc. The Planner should provide a summary of the critical sensitivities and documentation supporting their definitionis.

Question 12			
Commenter	**Yes**	**No**	**Comment**
IESO		☑	We do not support introducing sensitivity testing as requirements in the standard, let alone specifying the number of sensitivity cases that need to be developed. In general, there are two interpretations of sensitivity testing - the type to assist in scoping out planning studies and the type to test the stretched capability of the proposed plans. In the first case, sensitivity testing is conducted to assist in identifying restricting parameters/phenomena, critical faults, and scoping out the conditions that need to be assessed, etc. As such, the scenarios to be included in sensitivity testing vary from one Transmission Planner to another depending on local needs and system characteristics, and even from one study to another for the same area to be assessed. The scope of sensitivity testing is therefore difficult to pin down. In the second case, while variations such as percentage of forecast peak demand can be picked as a common parameter for sensitivity testing, the follow-on actions, or inactions, after obtaining the test results would be at the sole discretion of the Transmission Planner unless they are specifically addressed by reliability standards. Requiring a Transmission Planner to conduct sensitivity testing, and even to require it to study a specific number of cases case may put a Transmission Planner in a quandary. For example, if sensitivity testing for a case with 5% higher than forecast peak load shows that the system needs a new 500 kV line in a certain area, should the Transmission Planner propose the new line? If so, what are the reliability and economic justifications when it is clearly demonstrated that the line is needed only if the load for that studied time frame turns out to be 5% higher than forecast? If the answer is yes (to propose adding the line), then why don't we simply require that all planning studies assume a condition that is more conservative than that forecast, and stipulate these conditions in the standard accordingly? If not, will the Transmission Planner be criticized for not taking proactive action to manage the potential risk? Similarly, a Transmission Planner is faced with a much wider study scope if it is required to study the condition assuming one or more major transmission facility is unavailable due to forced outages. These scenarios are more aptly addressed in operations planning or near operations time frame when transmission facility and other system conditions become more predictable. Studies conducted well in advance of real time already rely on many enabling assumptions. Introducing a requirement for sensitivity testing and with specific number of test cases would render the study task difficult to manage, and may put the Transmission Planner in a quandary dealing with the test results. If the standard should require a Transmission Planner to study up to one transmission facility out of service, then this requirement should be clearly stipulated.
ITC	☑		The standard should provide a minimum number of sensitivity cases that should be developed and should include at least a higher load forecast (90/10 vs. 50/50) and a higher generator unavailiablity (LOLE - 1 in 10).
KCPL		☑	N-1 and N-2 analyses should identify any additional sensitivity cases that need to be studied. This

Question 12			
Commenter	**Yes**	**No**	**Comment**
			standard should not specify the number and type of sensitivities to be studied.
LADWP		☑	the FERC orders are market focused, not reliability focused; to the extent that these orders require sensitivity studies as outlined in this proposed standards, they belongs in operating studies and real time market studies, not transmission planning studies which are to meet reliability based criteria.
Manitoba Hydro		☑	Sensitivity analysis that could be considered will vary from region to region or subregion to subregion.
MEAG Power		☑	The entity performing the studies should be allowed to determine the appropriate number of cases that need to be evaluated. Different utilities have different input assumptions, therefore the selection of sensitivities to study are different. For example, some utility needs to study the water availability for its hydro units, while other utility needs to evalauate the sensitivity of gas availability.
MISO		☑	Requirements 2.1.3 and 2.4.3 call for sensitivity cases that stress the system, with documentation as to the rationale for why a particular sensitivity was selected. Midwest ISO believes that the standard must balance clarity and specificity with flexibility and discretion. If the standard is too prescriptive in the system conditions to be evaluated, sensitivity studies that reflect critical system conditions that experience dictates are appropriate for a given system could be construed as being outside of the standards. Such a determination could make the regulatory approvals of facilties needed for reliability purposes difficult or impossible to obtain. Midwest ISO believes hat the language in the existing standard TPL-001-0, R1.3.2, which states that "PA and TP assessments shall cover critical system conditions and study years as deemed appropriate by the responsible entity" provides the proper balance of these issues.
Muscatine P&W			Leave it open so it can be driven by local issues including those not in the standards. i.e. Running near term criteria on the long term horizon, additional contingencies beyond currently required, etc. as appropriate for the area.
New York ISO		☑	NYISO does not support the introduction of sensitivity testing in the Planning Standards as a requirement. Sensitivity testing should be dictated by the local needs and system characteristics. The nature of planning studies incorporates assumptions that would make sensitivity analysis difficult to interpret.
NCEMC		☑	There should be a stakeholder process for all entities (all Load-Serving Entities and Transmission Customers) involved or impacted within the defined area to provide input to determine which sensitivity cases are to be performed and the appropriate number of cases that need to be evaluated. Not every sensitivity case should be required for every system.
Northwestern Energy		☑	The current list is too prescriptive as many may not apply to a specific TP, yet they would be required to study it.
Progress–Carolinas		☑	This should be system specific.
ReliabilityFirst	☑		A minimum of at least one or two that contain certain scenarios chosen from the list should be required.

Question 12			
Commenter	**Yes**	**No**	**Comment**
Santee Cooper		☑	These factors vary between areas and regions. In addition the TP should be allowed to assess an alternate sensitivity if they can document that it is more appropriate,
SERC EC DRS		☑	The entity performing the studies has the best system specific knowledge to select the appropriate sensitivities that needs to be evaluated.
SERC EC PSS		☑	The entity performing the studies should be allowed to determine the appropriate number of cases that need to be evaluated.
SERC RRS OPS		☑	These factors vary between areas and regions. In addition the TP should be allowed to assess an alternate sensitivity if they can document that it is more appropriate,
SCE&G		☑	The standard may offer guidance but the entity performing the sensitivity studies should be able to determine the number of cases required.
Southern Transm.		☑	This should not be a "one shoe fits all" exercise. It appears that at least one of these items listed is required even though they may not be the most appropriate ones for all entities. There should be the ability to perform other sensitivity analysis instead of these as long as the "rationale" is provided for the choice. The entity should be allowed to determine the appropriate sensitivity cases.
Tenaska	☑		The question may be misleading as number of sensitivity cases is not the issue. Enough studies should be conducted to appropriately define the boundaries of how the system will perform. The standard identifies various issues that may be used as sensitivity cases, but the list may or may not be all inclusive. The team should ask the industry whether any other sensitivities should be included in the standard.
TVA		☑	The entity performing the studies should be allowed to determine the appropriate number of cases that need to be evaluated.
TEP		☑	The TP or PA is the most familiar with the system and so would be the best to determine the sensitivities that are more applicable to their particular system. The Standard should not be overly prescriptive. The Standard can make suggestions or list potential sensitivities but let the TP or PA determine those variables to study and the reasonable range of the sensitivities.
WPS			Sensitivity cases do not consider/mention new transmission facilities additions. Although the Transmission Planner should have the ability to determine appropriate sensitivities, system performance based on the delay of new transmission facilities should be considered (may be covered under R2.1.3.3 but could be more explicit).

Response: The SDT believes that there is a need to perform sensitivity studies and to set a minimum level of sensitivities to be considered. To achieve that, the SDT is providing some guidance on what could be included in the sensitivity studies without being too prescriptive. R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system.

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:

R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission

Question 12			
Commenter	**Yes**	**No**	**Comment**
Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.			
E ON US	☑		The proposed requirements P2, P3 and P4 significantly increase system performance. I agree with the requirements but I do not think it is appropropriate to layer extreme load, extreme transfers and other sensitivities on top of these. The analsysis of any Senistivities should be under the umbrella of Extreme Events or limited to meeting the P1 requirements.
HQTE NPCC RCS		☑	The standard is unclear whether or not it mandates the requirement to develop action plans in accordance with consequences of problems highlighted as a result of one of the sensitivity case study. Suggest modification to, "…sensitivity testing that stresses the System shall be considered, and documentation with the rationale for the sensitivity testing shall be supplied. The sensitivity case(s) may include one or more of the following conditions:"
JEA		☑	Transmission Planners when developing system improvement options should identify their system specific sensitivity cases that best assesses the robustness of the options under consideration. Project evaluation is not addressed in the NERC standards and performing sensitivity assessments that only lead to operational remedies consistent with the standards, are best performed within the operational horizon where information and assumptions are more certain than within the planning horizon.
PJM	☑	☑	At the least, it should provide a measure that indicates that you meet the requirement. Need to modify 2.4.3 to specify what if any performance requirement needs to be met.
Central Maine Power National Grid New England ISO NU NSTAR United Illuminating		☑	The standard is unclear whether or not it mandates the requirement to develop action plans for problems highlighted as a result of one of the sensitivities. Suggest modification to, "…sensitivity testing that stresses the System shall be considered, and documentation with the rationale for the sensitivity testing shall be supplied. The sensitivity case(s) may include one or more of the following conditions:" 2.1.3.3 should refer only to planned facilities that may be delayed. 2.1.3.4 - "variability" is too vague for a standard; the standard needs to be more specific as to the intent. 2.1.3.7 should be consistent with 1.4. These comments also apply to 2.4.3.
Response: The standard requires that deficiencies identified from the results of the current studies need to be addressed via Corrective			

Question 12			
Commenter	**Yes**	**No**	**Comment**
Actions Plan while leaving it to the entity's discretion to decide which deficiencies, if any, identified through sensitivity studies should be addressed by the Corrective Action Plan. Requirement R2.7.2 has been modified to make it clear that the entity must explain changes, if any, to the Corrective Action Plans as a result of considering the sensitivity studies. In addition, the SDT believes that there is a need to perform sensitivity studies and to set a minimum level of sensitivities to be considered. To achieve that, the SDT is providing some guidance on what could be included in the sensitivity studies without being too prescriptive. R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. R2.**7.2.** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.			
MRO		☑	The Drafting Team has provided the appropriate level of detail by indicating that one or more of the following conditions are to be used. However, the MRO notes that R.2.1.3.1 should be changed to match R.2.4.3.1, that is, R.2.1.3. 1 should be changed to state "Variations in Load model assumptions."
Response: The SDT disagrees. The wording in Requirement R.2.4.3.1 is stability related and refers to device characteristics such as motor load as mentioned in Requirement R2.4.1. The wording in Requirement R.2.1.3. 1 refers to "demand" load for steady statae studies.			
Seattle City		☑	Sensitivity studies should be performed at a level higher than LSE or BA. It seems more appropriate for a RC or RRO to determine regional contingencies.
Response: Requirement R2 in the standard states that Planning Assessments, including the sensitivity studies, should be performed by the TP or PC.			
WECC BPA		☑	The TP or PA is the most familiar with the system and so would be the best to determine the sensitivities that are more applicable to their particular system. The Standard should not be overly

Question 12			
Commenter	**Yes**	**No**	**Comment**
TSGT			prescriptive. The Standard can make suggestions or list potential sensitivities but let the TP or PA determine those variables to study and the reasonable range of the sensitivities.
Response: Requirement R2 in the standard states that Planning Assessments, including the sensitivity studies, should be performed by the TP or PC. The SDT believes that there is a need to perform sensitivity studies and to set a minimum level of sensitivities to be considered. To achieve that, the SDT is providing some guidance on what could be included in the sensitivity studies without being too prescriptive. Requirement R2.1.3 and Requirement R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.1.4 and Requirement R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.			
AECC		☑	
AECI		☑	
Exelon		☑	
LCRA		☑	
NERC TIS		☑	
Progress–Florida		☑	
SaskPower		☑	
ATC	☑		
City Utilities/Springfield	☑		
Response: Thank you. Please see the Summary Response.			

13) Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Summary Response: The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. In either case the entity must document the technical rationale for why each was selected. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance.

In addition a new requirement, now numbered as Requirement R2.7.2, has been added to clarify that the sensitivity studies do not in themselves establish the need for a corrective action but the entity must explain how the sensitivities affected the Corrective Action Plan.

Note: The words "reasonably stressed" are only used in the question and do not reference any particular requirement in the standard; therefore, no definition is required.

The following requirements were changed due to industry comments:

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:
R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.
R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:
R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.
R2.7.2. ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.

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Commenter	**Yes**	**No**	**Comment**
Ameren		☑	There is no need to build a multitude of sensitivity cases to assess the reliability of the system. The sensitivity issues should be handled on an individual system basis by the local transmission planners as applicable to the study system. Conditions that are considered as "stressed" for one area may require all facilities to be in service in another area. Power flow cases utilizing a number of the

Question 13			
Commenter	**Yes**	**No**	**Comment**
			items listed under R2.1.3 or R2.4.3 could be produced for in-house study work, but such work should not be required as part of standards compliance. The standard should not be dictating what types of sensitivities should be investigated or considered for all parts of the transmission system.
AEP		☑	Consider requiring that the most severe sensitivity cases be included in the studies as determined by the entities conducting the studies.
Brazos Electric		☑	Again, descretion should be allowed by the TO when selecting the criteria.
CenterPoint		☑	See comment to Q12.
Dominion		☑	Transmission Planning engineers have good engineering judgment and need to have some flexibility in selecting the variables that need to be studied.
CPS Energy		☑	The type of sensitivty studies should be at the discretion of Transmission Planners.
Duke Energy		☑	The sensitivities are best selected by those most familiar with the specific system.
Entergy		☑	Should be left to Transmission Planners discretion and good engineering judgement. (see response to Q12)
Exelon		☑	The required changes should not be specified because they may not impact a particular transmission system based upon its geographic location within the interconnection. Required changes should be determined by the entity performing the study.
ERCOT ISO CAISO		☑	Let the TP or PA decide the type of stressing needed for a particular case.
FPL FRCC		☑	The Transmission Planner needs the flexibility to define what are considered "reasonably stressed" cases for their respective systems. This would not a be a proper application of a one size fits all definition.
Georgia Transm.		☑	See comment to Q12.
IESO		☑	See comments above. Also, the term "reasonably stressed" is not measurable.
KCPL		☑	Transmission Planner has best knowledge of conditions that create greatest stress on local transmission system.
LADWP		☑	A "reasnably stressed" case in transmission planning is whether or not the transmission system is stressed. To stress a transmission system, the key parameter to monitor are the line flows. Line flows are dictated by network topology and physics of electricity and very much depends on the objectives of each study, i.e., it is case by case. Standard should focus on what criteria shall be complied, not how to comply. This proposed standard is so prescriptive on how to comply that it reads like a tutorial.
MEAG Power		☑	The standard may offer guidance but what constitutes a "reasonably stressed" case will vary from Transmission Planner to Transmission Planner. Therefore, it should be left to the discretion of the entity performing the study.

Question 13			
Commenter	**Yes**	**No**	**Comment**
MISO		☑	This appears to be a case of expecting that "one size fits all" in requiring that certain scenarios be evaluated. Since the goal here is to improve reliability, it makes more sense to have transmission planners identify appropriate sentivities for area under study. The appropriate sensitivity is likely to vary depending on the portion of system being studied.
Muscatine P&W			Leave it open so it can be driven by local issues including those not in the standards. i.e. Running near term criteria on the long term horizon, additional contingencies beyond currently required, etc. as appropriate for the area.
NCEMC		☑	The standard should offer guidance but what constitutes a "reasonably stressed" case should be left to a stakeholder process as noted in Q12 with some discretion of the entity performing the study.
Northwestern Energy		☑	Each TP's stressed conditions vary, making a list that is applicable to all will not achieve the desired purpose.
Progress–Carolinas		☑	This should be system specific.
Santee Cooper		☑	The standard may offer guidance but what constitutes a "reasonably stressed" case should be left to the discretion of the entity performing the study, since they are the best judge of what stresses the system.
SERC EC DRS		☑	The entity performing the studies has the best system specific knowledge to determine what constitutes a reasonable stressed case.
SERC EC PSS		☑	The standard may offer guidance but what constitutes a "reasonably stressed" case should be left to the discretion of the entity performing the study.
SERC RRS OPS		☑	The standard may offer guidance but what constitutes a "reasonably stressed" case should be left to the discretion of the entity performing the study, since they are the best judge of what stresses the system.
SCE&G		☑	The standard may offer guidance but what constitutes a "reasonably stressed" case should be left to the discretion of the entity performing the study.
Southern Transm.		☑	See comment above. [This should not be a "one shoe fits all" exercise. It appears that at least one of these items listed is required even though they may not be the most appropriate ones for all entities. There should be the ability to perform other sensitivity analysis instead of these as long as the "rationale" is provided for the choice. The entity should be allowed to determine the appropriate sensitivity cases.]
TEP		☑	No, as in the response for Question #12. The TP is the best to determine the type of stressing needed for a particular case. This is very evident in the type of cases used for studies in the different parts of the NERC regions.
TVA		☑	The standard may offer guidance but what constitutes a "reasonably stressed" case should be left to the discretion of the entity performing the study.
Response: The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own			

Question 13			
Commenter	**Yes**	**No**	**Comment**
system. In either case the entity must document the technical rationale for why each was selected. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance. Note: The words "reasonably stressed" are only used in the question and do not reference any particular requirement in the standard; therefore, no definition is required. **R2.1.3.** For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.1.4.** In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. **R2.4.3.** For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: **R2.4.4.** In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. .			
Allegheny Power		☑	Providing examples would be helpful but specifically stating the required thresholds are transmission system dependent. Providing some methodologies to follow may be prudent such as forecast levels like 90/10; 80/20; or 50/50.
BCTC		☑	Should be tied to the data provided under R1.
Response: The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. In either case the entity must document the technical rationale for why each was selected. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance. **R2.1.3.** For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.1.4.** In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. **R2.4.3.** For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected~~			

Question 13			
Commenter	**Yes**	**No**	**Comment**
~~sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: **R2.4.4.** In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.			
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating		☑	The standard is unclear whether or not it mandates the requirement to mitigate consequences of problems highlighted as a result of one of the sensitivities. Reasonably stressed conditions are dependent upon the study area under review and the standard is not likely to be able to be crafted to provide sufficent and consistent direction. However, it might be helpful if the standard clarified whether the base case should include any unplanned generator outages or whether, aside from potential sensitivities, unplanned generator outages are considered only through P1, P3 or P4 Contingencies. If the standard addresses unplanned generator outages only through P1, P3 and P4, then it is recommended that a mandatory sensitivity analysis, with required mitigation, include various potential combinations of a reasonable amount of unplanned outages. The combinations should be based on the part of the system that is under study.
Response: A new requirement, now numbered as Requirement R2.7.2, has been added to clarify that the sensitivity studies do not in themselves establish the need for a corrective action but the entity must explain how the sensitivities affected the Corrective Action Plan. Requirement R1.4 of the standard requires that long term planned outages are part of the base studies. The performance table provides for specific contingency conditions. The entity may elect to run additional sensitivity studies for even more unplanned outages as stated in Requirement R2.1.4 and document its rationale for doing so. Note: The words "reasonably stressed" are only used in the question and do not reference any particular requirement in the standard; therefore, no definition is required. **R2.**7.2. ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.			
JEA		☑	Transmission Planners when developing system improvement options should identify their system specific "reasonable stressed" cases including opportunities for additional economic margins that best assesses the economic benefits of the options under consideration. Project evaluation is not addressed in the NERC standards and performing assessments on "reasonable stressed" cases that only lead to operational remedies consistent with the standards, are best performed within the operational horizon where information and assumptions are more certain than within the planning horizon.

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Commenter	**Yes**	**No**	**Comment**
Response: Reliability Standards set the minimum performance requirements and any margins can be set /established and implemented by the entity. The standard covers reliability performance issues and not market or economic performance issues. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. In either case the entity must document the technical rationale for why each was selected. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance. Note: The words "reasonably stressed" are only used in the question and do not reference any particular requirement in the standard; therefore, no definition is required. **R2.1.3.** For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.1.4.** In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. **R2.4.3.** For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: **R2.4.4.** In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.			
ITC	☑		"Modification of expected transfers" should include unexpected loopflow caused by 3rd parties where applicable. In addition to the obvious impacts on system margins, loopflows have been identified as a major reason that FTR feasibility is hard to predict. Also, see answer to Q12 above. Some level of flexibility for some of the stressed cases should be left to the individual Planning areas as they would know typical load/stresses seen by their systems that should be studied and solutions identified for problems.
MRO		☑	This is unnecessary micro-management of the planning process. The MRO recommends that the Drafting Team proceed with the high-level requirement as provided with the minor changes recommended by the MRO in other parts of this comment form.
ReliabilityFirst		☑	A list of suggestions is sufficient. The flexibility to use different stresses on different systems is

Question 13			
Commenter	**Yes**	**No**	**Comment**
			needed.
SaskPower		☑	Unnecessary micro-management of the planning process in the Saskatchewan Regulatory Jurisdiction.
WECC BPA TSGT		☑	No, as in the response for Question #12. The TP is the best to determine the type of stressing needed for a particular case. This is very evident in the type of cases used for studies in the different parts of the NERC regions.

Response: The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 and Requirement R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.1.4 and Requirement R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. In either case the entity must document the technical rationale for why each was selected.

In addition a new requirement, now numbered as R2.7.2, has been added to clarify that the sensitivity studies do not in themselves establish the need for a corrective action but the entity must explain how the sensitivities affected the Corrective Action Plan.

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:
R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.
R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:
R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

New York ISO		☑	See comment to Q12. Additionally, what is the definition of "reasonably stressed"?

Response: The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 and Requirement R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.1.4 and Requirement R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. In either case the entity must document the technical rationale for why each was selected. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance.

In addition a new requirement, now numbered as Requirement R2.7.2, has been added to clarify that the sensitivity studies do not in themselves establish the need for a Corrective Action but the entity must explain how the sensitivities affected the Corrective Action Plan.

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Commenter	Yes	No	Comment
Note: The words "reasonably stressed" are only used in the question and do not reference any particular requirement in the standard; therefore, no definition is required. **R2.1.3.** For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.1.4.** In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. **R2.4.3.** For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: **R2.4.4.** In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. **R2.7.2.** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.			
WPS		☑	The Transmission Planner should have the ability to determine appropriate sensitivities based on changes to the assumptions within the study. However, those sensitivities should be developed in an open transmission planning process consistent with the transmission planning principles within FERC Order 890.

Response: The SDT agrees. Nothing in the standard precludes an open process.

The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 and Requirement R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.1.4 and Requirement R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. In either case the entity must document the technical rationale for why each was selected.

In addition a new requirement, now numbered as Requirement R2.7.2, has been added to clarify that the sensitivity studies do not in themselves establish the need for a Corrective Action but the entity must explain how the sensitivities affected the Corrective Action Plan.

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:

Question 13			
Commenter	**Yes**	**No**	**Comment**
R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. **R2.4.3.** For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: **R2.4.4.** In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. R2.**7.2.** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.			
ABB		☑	
AECC		☑	
AECI		☑	
E ON US		☑	
FirstEnergy		☑	
LCRA		☑	
NERC TIS		☑	
Progress–Florida		☑	
Response: Thank you.			
PJM	☑	☑	Again, 'reasonable' is a very subjective term. Refer to comments on question 12
Tenaska	☑		However, what is meant by "reasonably stressed".
Response: Note: The words "reasonably stressed" are only used in the question and do not reference any particular requirement in the standard; therefore, no definition is required.			
APPA	☑		The Standard should indicate a list that says "the list will include but not be limited to:" and then list the minimum necessary to adequately cover the changes in the study.
City Water Power and Light	☑		The Standard should indicate a list which says "the list will include but not be limited to:" then list the minimum changes necessary to adequately cover the changes in the study.
Response: The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 and Requirement R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.1.4 and Requirement R2.4.4 have been added to specifically state that the entity may consider			

Question 13			
Commenter	**Yes**	**No**	**Comment**
additional sensitivities that are appropriate for its own system. In either case the entity must document the technical rationale for why each was selected. **R2.1.3.** For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.1.4.** In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. **R2.4.3.** For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: **R2.4.4.** In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.			
Manitoba Hydro	☑		R.2.1.3.2: clarify the intent of modification of expected transfers. Does this apply to firm transfers only, or does it also encompass non-firm transfers? Should this encompass simultaneous non-firm transfers? Planning for non-firm falls into an economic study of cost/benefit and not a relibility requirement. R2.1.3.3: There is little value in identifying the impact of unavailability of planned facilities. From a reliability perspective, these facilities are required to meet performance requirements. Near term SOLs and IROLs will insure reliability if the facility is late. R.2.1.3.4: This requirement should be removed and outages of reactive resources should be included in the Table 1 contingencies (assuming the intent is to investigate robustness to voltage instability). R.2.1.3.5: This requirement should be removed as this is covered, or should be, by the facility connection standard(s). R.2.1.3.6: This requirement should be removed as this is covered by requirement R2.1.3.1. There is no need to list "decreased effectiveness of controllable loads or DSM" as this is already covered by sensitivity to forecast load and power factor - this will cause confusion. R.2.1.3.7: Modification of planned Transmission outages should be deleted. The need to assess outages in the planning horizon is questionable, so assessing sensitivity to timing of these outages is of very little value. Furthermore, this standard already covers prior outages in its other requirements.
Response: The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 and Requirement R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.1.4 and Requirement R2.4.4 have been added to specifically state that the entity may consider			

Question 13			
Commenter	**Yes**	**No**	**Comment**

additional sensitivities that are appropriate for its own system. In either case the entity must document the technical rationale for why each was selected.

In addition a new requirement, now numbered as Requirement R2.7.2, has been added to clarify that the sensitivity studies do not in themselves establish the need for a Corrective Action but the entity must explain how the sensitivities affected the Corrective Action Plan.

It is the planning entity's decision to establish and document which transfers under Requirement R2.1.3.2 are more significant to study system responses.

The intent of Requirement R2.1.3.3 is for the planning entity to determine the need for alternative plans in the event that previously planned facilities are not installed on time.

Requirement R2.1.3.4 (variability and outages of reactive resources) provides for more unusual or unexpected combination of situations. The contingencies listed in Table 1 usually consider more specific conditions in that the reactive resources are typically connected to circuits or bus sections which are included in Table 1.

Requirement R2.1.3.5 (generation additions, retirements, or other dispatch scenarios) covers future conditions that might exist (such as location, size, numger of facilities) after known connections are made. The FAC standards only consider the initial conditions for known facilities when an entity is requesting connection to the system. Requirement R2.1.3.5 covers the on-going conditions that exist after that connection is made. In addition the requirement covers dispatch scenarios which are not part of the FAC standards.

Requirement R2.1.3.1 is intended to cover all load before any adjustments. This can vary on its own. Requirement R2.1.3.6 covers only a portion of that load and can vary independent of the load forecast. The standard is not just addressing the "net" load but its components.

Requirement R2.1.3.7 parallels Requirement R2.1.3.3 in that "planned" outage durations may vary. It is the entity's responsibility to determene the actions necessaruy to handle extended outages.

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:
R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.
R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:
R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for

Question 13			
Commenter	**Yes**	**No**	**Comment**
why each was selected shall be supplied. **R2.7.2.** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.			
ATC	☑		
City Utilities/Springfield	☑		
Seattle City	☑		
Response: Thank you. Please see the Summary Response.			

14) Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Summary Response: The need to conduct sensitivity analysis was a directive in FERC Order 693 paragraphs 1694,1704, and 1706. The commenters generally agree with the concept of considering sensitivities for near-term Stability analysis. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3.1 provides the flexibility to allow the planning entity to decide how a variation in Load on the entity(ies) System should best be studied. Requirement R2.4.3 has been modified to require documentation of the rationale for why each of the listed sensitivities was or was not selected for running studies. Requirement R2.4.4 has been added to specifically state that the entity may consider additional sensitivities that are deemed appropriate for its own System and document the rationale for selecting each of them.

R2.1.3.1. Higher or lower Load than forecast~~s~~ed ~~from the Base Case~~ with variability of Load/demand and Load power factors due to season, weather, or time of day.
R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:
R2.4.3.2. ~~Expected simultaneous transfers including non-firm~~ Modification of expected transfers**.**
R2.4.3.4. ~~Reactive dispatch of generators and other reactive power devices~~ Variability and outages of reactive resources.
R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

Question 14			
Commenter	**Yes**	**No**	**Comment**
Ameren		☑	The biggest problem with performing stability analysis is getting the stability cases to match up with the power flow cases, and only a limited number of stability cases are developed each year. Further, for those systems that are planned in excess of the NERC Standards regarding stability (3-L-G or 2-L-G vs. 1-L-G as in the Standard), there are no benefits to performing additional sensitivity studies to demonstrate compliance with this standard.
City Water Power and Light		☑	The requirement for sensitivity studies multiplies the study efforts. It will be burdensome especially when interregional studies are performed. It is better to have quality than quantity.
Dominion		☑	Not all the items listed under "B. Sensitivity Studies" may be applicable to stability analysis and also depends on type of stability analysis (Plant/System; angular/voltage). For instance, in some locations stability margins are wide. In such cases, practical experience has shown that such sensitivity analysis is unnecessary. Therefore, this should be applied as applicable, at the engineering judgment of the planning engineers rather than be required by the Standards. In summary, R2.4.3 should be eliminated entirely.
E ON US		☑	Stability studies are a labor intensive task. Off-peak studies (with max plant gen) is severe enough.
SCE&G		☑	Stability studies examine generator and system responses to specific conditions. Because the exact system conditions can not be determined in advance, the sensitivity analysis may not be very

Question 14			
Commenter	**Yes**	**No**	**Comment**
			useful. In addition, stability studies are more time consuming than conventional power flow studies. A preferred approach is to include pre-existing system conditions that additionally stress the system during the contingencies under study so as to verify that stability is preserved under conditions that go beyond those envisioned for the contingency.
TSGT		☑	Sensitivity studies are most often used to determine operating relationships of a system - sensitivity to generation patterns is deliverability analysis; sensitivity to load growth is margin analysis. Sensitivity analysis should not be required explicitly. The criteria should be stated in terms of load margins, deliverability, and capability to withstand generator or transaction forced outages. The TP can use sensitivity studies or other reasonable methods to assess reliability
TVA	☑		Consideration should be given to the fact that stability studies are more time consuming than conventional power flow studies. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.
FirstEnergy	☑		Although we concur with the use of sensitivity analysis in dynamic studies, the standard should not dictate the specific sensitivities studies to be performed.
LADWP	☑		This standard is mixing operational studies with planning studies. The suggested sensitivities in this proposed standards are what operating studies would and should address. It adds no value to the transmission planning by requiring sensitivities in transmission planning just for the sake of it. In addition, performing operating studies more than one year ahead, generally, is quite useless as a general requirement.
Manitoba Hydro	☑		R2.4.3.1: This requirement should include variation in load power factor, as this has a significant impact on transient performance. R2.4.3.3: There is little value in identifying the impact of unavailability of planned facilities. From a reliability perspective, these facilities are required to meet performance requirements. Near term SOLs and IROLs will insure reliability if the facility is late. R.2.4.3.4: This requirement should be removed and dispatch of reactive power devices should be included in the Table 2 contingencies (assuming the intent is to investigate robustness to voltage instability). R.2.4.3.5: This requirement should be removed as this is covered, or should be, by the facility connection standard(s).

Response: The need to conduct sensitivity analysis was a directive in FERC Order 693 paragraphs 1694,1704, and 1706. The SDT agrees with you that dynamic analysis is generally more labor intensive than steady state analysis. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. The SDT has modified Requirement R2.4.3 to stipulate that the entity shall provide rational for why sensitivity on the list were or were not included in the sensitivity studies and that the entity may consider additional sensitivities that are appropriate for its own System.

R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected~~

Question 14			
Commenter	**Yes**	**No**	**Comment**
~~sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:			
AEP			We concur with the use of sensitivity studies, but object to the requirement on what sensitivities to include. The flexibility to determine if sensitivity studies are appropriate, and the flexibility to choose what parameters are appropriate to study for sensitivity should be left open. R2.4.3 as written is restrictive to certain sensitivities and should not be.
CenterPoint		☑	The number and type of sensitivity studies should be left to the judgement of Transmission Planners.
CPS Energy		☑	The number and type of sensitivity studies should be at the discretion of Transmission Planners.
Duke Energy	☑	☑	Sensitivity studies can be useful, but they should only be requried for System Stability Studies. Due to the intensive nature of the studies, the planning engineer should have flexibility to determine appropriate sensitivities to analyze.
ERCOT ISO CAISO		☑	Although we concur with the sensitivity analysis,the TP should determine what sensitivities are more appropriate for their system. Sensitivities should not be scripted in the Standard.
ITC	☑		Both peak and off-peak models have been historically used for stability analysis and should continue to be used. The need for additional sensitivity studies should be left to the discreton of the Transmission Planner.
MEAG Power	☑		The entity performing the studies should be allowed to determine the appropriate sensitivity studies that need to be evaluated. An alternate approach is to include pre-existing system conditions that additionally stress the system during the contingencies under study so as to verify that stability is preserved under conditions that go beyond those envisioned for the contingency. Stability studies are more time consuming than conventional power flow studies. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.
MISO		☑	Use of sensitivities should not be required for Stability analysis, but the Standard should rather allow sensitivities at the discretion of the planning engineer. Due to the computationally intensive nature of these studies, a study rotation would be appropriate. For example, one year would be peak base case, next year off-peak case, and following year a sensitivity case. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.
NCEMC	☑		The entity performing the studies should be allowed to determine the appropriate sensitivity studies that need to be evaluated with a stakeholder process for those impacted by these studies as noted above. An alternate approach is to include pre-existing system conditions that additionally stress the system during the contingencies under study so as to verify that stability is preserved under conditions that go beyond those envisioned for the contingency. Stability studies are more time consuming than conventional power flow studies. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.

Question 14			
Commenter	**Yes**	**No**	**Comment**
Northwestern Energy	☑	☑	The TP should have the ability to determine the sensitivity to use.
Santee Cooper	☑		The entity performing the studies should be allowed to determine the appropriate sensitivity studies that need to be evaluated. An alternate approach is to include pre-existing system conditions that additionally stress the system during the contingencies under study so as to verify that stability is preserved under conditions that go beyond those envisioned for the contingency. Stability studies are more time consuming than conventional power flow studies. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.
SERC EC PSS SERC RRS OPS	☑		The entity performing the studies should be allowed to determine the appropriate sensitivity studies that need to be evaluated. An alternate approach is to include pre-existing system conditions that additionally stress the system during the contingencies under study so as to verify that stability is preserved under conditions that go beyond those envisioned for the contingency. Stability studies are more time consuming than conventional power flow studies. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.
AECI		☑	We believe that only the worst case would need to be addressed for stability purposes.
WECC BPA TEP	☑	☑	We concur with the use of sensitivities as long as the TPs are allowed to determine the sensitivities that are the more appropriate for their systems and not have the sensitivities scripted in the Standard.
Muscatine P&W	☑		If reasonable and appropriate and allow for local issues including those not in the standards..
Response: The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. The SDT has modified Requirement R2.4.3 to stipulate that the entity shall provide rational for why sensitivity on the list were or were not included in the sensitivity studies and that the entity may consider additional sensitivities that are appropriate for its own system. **R2.4.3**. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied**:**			
Entergy		☑	The new requirements for stability studies, including but not limited to the sensitivity studies, will result in a tremendous increase in workload. Because stability studies are so much more time intensive that steady state analysis and because they require personnel with a highly specialized skill set, the number of stability studies required should be increaed only as determined necesssary to evaluate worst-case contingencies. It would seem that the sensitivity analyses as well as many of the multiple contingency analyses could be done for steady state and only worst cases analyzed again by dynamic studies.
FPL FRCC		☑	The standards require near term base case cases to be studied for a broad range of planning and Extreme Events. The sensitivity analysis requirements contained R.2.4.3. will essentially require every dynamic simulation to be run at least twice regardless of whether or not there is any

Question 14			
Commenter	**Yes**	**No**	**Comment**
			engineering insight to be gained. While improved understanding may result from sensitivity analysis of certain key event scenarios, the overall benefits of the sensitivity study requirements contained in section R.2.4.3 do not justify the huge increase in engineering effort to conduct and document these simulations.
Response: The SDT agrees with you that dynamic analysis is generally more labor intensive then steady state analysis. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. The SDT has modified Requirement R2.4.3 to stipulate that the entity shall provide rational for why sensitivity on the list were or were not included in the sensitivity studies and that the entity may consider additional sensitivities that are appropriate for its own System. **R2.4.3**. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied**:**			
KCPL		☑	Dynamic studies should be performed when new generation or transformers are added to the system. Should be performed on a periodic basis, not annually.
Response: The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. The SDT has modified Requirement R2.4.3 to stipulate that the entity shall provide the rational for why sensitivities on the list were or were not included in the sensitivity studies and that the entity may consider additional sensitivities that are appropriate for its own System. The standard allows that the Planning Assessment can be supported by current or past studies. While an assessment is to be done annually, there is no intent to rerun the same studies "annually" unless the standard specifically requires such. Studies you mentioned can be used to support the assessment and be retained as "past" studies as appropriate. **R2.4.3**. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:			
MRO		☑	The MRO is okay with requiring the sensitivity studies but is concerned with the R.2.4.3.2 requirement as written in that it unnecessarily requires that the sensitivity studies to "simultaneous transfer" to include "non-firm transfers". The MRO recommends that this be changed to match R.2.1.3.2 "Modification of expected TRANSFERS." The MRO also questions the wording of R.2.4.3.4 which provides a more limiting description of the sensitivity to reactive. The MRO recommends that the wording of this requirement be changed to match R.2.1.3.4, "Variability and outages of reactive resources."
Response: Requirements R2.4.3.2 and R2.4.3.4 have both been revised to match with R2.1.3.2 and R2.1.3.4 respectively. **R2.4.3.2**. ~~Expected simultaneous transfers including non-firm~~ Modification of expected transfers. **R2.4.3.4**. ~~Reactive dispatch of generators and other reactive power devices~~ Variability and outages of reactive resources.			
LCRA		☑	

Question 14			
Commenter	**Yes**	**No**	**Comment**
IESO		☑	For similar reasons stated in Q13, above.
New York ISO		☑	See comments to Q12 & Q13.
Response: Thank you.			
PJM	☑	☑	Yes, however, clear direction is needed. Specific wording that defines if you have done enough, and met the compliance requirements.
Response: The need to conduct sensitivity analysis was a directive in FERC order 693 paragraphs 1694,1704, and 1706. The SDT agrees with you that dynamic analysis is generally more labor intensive then steady state analysis. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. The SDT have modified Requirement R2.4.3 to stipulate that the entity shall provide rationale for why sensitivities on the list were or were not included in the sensitivity studies and that the entity may consider additional sensitivities that are appropriate for its own System. The standard requires that deficiencies identified from the results of the current studies need to be addressed via Corrective Actions Plan while leaving at the entity 's discretion to decide which deficiencies, if any, identified through sensitivity studies should be addressed by the Corrective Action Plan. **R2.4.3.** For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:			
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating	☑		The standard is unclear whether or not it mandates the requirement to mitigate consequences of problems highlighted as a result of one of the sensitivities. Suggest modification to, "…sensitivity testing that stresses the System should be considered. Sensitivity case(s) might include among the following conditions:" 2.4.3 shold mimic 2.1.3 except in regard to load models.
Response: The standard requires that deficiencies identified from the results of the current studies need to be addressed via Corrective Actions Plan while leaving at entity's discretion to decide which deficiencies, if any, identified through sensitivity studies should be addressed by the Corrective Action Plan. The SDT has modified wording of Requirement R2.4.3 to be consistent with Requirement R2.1.3 as you suggested. **R2.4.3**. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied**:**			
SERC EC DRS	☑		Use of sensitivity studies is appropriate only for System Stability Studies.
Response: Thank you**.**			

Question 14			
Commenter	**Yes**	**No**	**Comment**
Southern Transm.	☑		Some sensitivity analysis is reasonable. Other comments: 1. The wording regarding transfer sensitivity for stability analysis should be the same as the wording used in steady state analysis "modification of expected transfers". 2. The list of sensitivities may not be the most appropriate for all entities. There should be the ability to perform other sensitivity analsysis instead of these as long as the "rationale" is provided for the choice.
Response: The SDT has modified the standard so that R2.1.3.2 and R2.4.3.2 are worded consistently. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. The SDT has modified requirement R2.4.3 to stipulate that the entity shall provide rational for why sensitivity on the list were or were not included in the sensitivity studies and that the entity may consider additional sensitivities that are appropriate for its own system. **R2.4.3.2**. ~~Expected simultaneous transfers including non-firm~~ Modification of expected transfers.			
ABB	☑		Absolutely**.**
Allegheny Power	☑		
APPA	☑		This is absolutely necessary; it will help with the operational planning that will be needed next. In addition, it will help to determine the amount of study uncertainty that the Transmission Planner believes will be in the plan. This is very important for the Year One.
ATC	☑		
BCTC	☑		
Brazos Electric	☑		
City Utilities/Springfield	☑		
Entegra	☑		Planners should use appropriate sensitivity cases.
Exelon	☑		
Georgia Transm.	☑		
JEA	☑		
NERC TIS	☑		
Progress–Carolinas	☑		
Progress–Florida	☑		

Question 14			
Commenter	**Yes**	**No**	**Comment**
Seattle City	☑		
Tenaska	☑		
WPS	☑		
Response: Thank you. Please see the Summary Response.			

15) Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Summary Response: Commenters generally agreed that sensitivities are not needed in long-term planning horizon studies since the studies are typically based on a number of assumptions regarding future conditions and uncertainties. Sensitivities of uncertain models could result in even more uncertain and probably unrealistic conditions, the use of which may cloud the actual trends. Closer in years tend to be more certain and applying sensitivities is necessary to ensure that unexpected conditions would not significantly affect reliability. The standard does not preclude entities from performing long term sensitivity studies which may even provide some basis for the base models used for analysis.

Question 15			
Commenter	**Yes**	**No**	**Comment**
AECC		☑	In the long range the confidence in some variables such as load growth may become fuzzy. Sensitivity analysis let you gauge the impacts that variences in a particular variable may have. I don't think it should be performed for every study but occasional study to maintain sanity is appropiate.
Response: Because the assumptions for the longer term are fuzzy, the SDT did not feel that it was appropriate to require prescriptive sensitivities since such studies could result in an even more distorted model. The SDT felt that the entity should determine if such sensitivities are appropriate knowing their own unique circumstances			
Northwestern Energy		☑	However, the TP should have the ability to determine the sensitivity to use.
Response: The TP can always perform and use sensitivities in addition to those required in the standard.			
AEP		☑	Consider requiring the same sensitivity analysis that is conducted under the near-term studies.
NERC TIS		☑	Since the long-term planning is completely couched in uncertainty, at least some generalized sensitivities should be required.
NCEMC		☑	Some sensitivity analysis in the long term years should be done (90/10 load with higher than expected transfers and/or delayed baseload generation) so that higher voltage issues are adequately tested to identify long lead time upgrades, in a similar manner as was done to justify the backbone projects that have been identified in the PJM Interconnection. A stakeholder process should be used by the entity performing the study to compile input on impacted LSEs and other Transmission Customers.
Response: Commenters generally agreed that sensitivities are not needed in long-term planning horizon studies since the studies are typically based on a number of assumptions regarding future conditions and uncertainties. The standard does not preclude entities from performing long term sensitivity studies which may even provide some basis for the base models used for analysis.			
BCTC	☑	☑	Long term needs to address sensitivities since it usually takes more than five years to contruct new transmission lines.
ITC	☑		We believe that both near-term and long-term studies should include sensitivity studies. Near-term studies may produce either operating solutions and more limited transmission solutions. It is just as or more important in a standard like this one to also do sensitivity analysis for the 6-10 year and

Question 15			
Commenter	**Yes**	**No**	**Comment**
			beyond period. This is necessary to provide the needed advance notice for long-lead time alternatives to problems which are uncovered. Focusing on the next 5 years limits alternatives that can be implemented. In fact, it makes sense to perform more sensitivity analysis on the longer term as assumptions become less probable the further out into the future you get. If a problem is identified in one snapshot 10 years out it may be less relevant than if it shows up in several varying snapshots 10 years out into the future. The use of sensitivity studies for the 6-10+ year horizon will hopefully have the effect of minimizing the use of band-aid type approaches to identified problems.
Tenaska		☑	Any analysis that is performed needs to include some sort of sensitivity analysis. In fact, the sensitivity analysis may yield more information that is helpful in making decisions today than sensitivities performed on a near term study. A way of conducting a sensitivity analysis for long term studies may be to require long term studies to be performed for several years instead of only the one year that is required in the 6-10 year horizon.
Response: Commenters generally agreed that sensitivities are not needed in long-term planning horizon studies since the studies are typically based on a number of assumptions regarding future conditions and uncertainties. The standard does not preclude entities from performing long term sensitivity studies which may provide some basis for the base models used for analysis nor does it preclude studying multiple years if more critical trends are detected.			
TSGT		☑	It is just as important for long range plans of service to provide acceptable operation as it is for near-term facility plans. To specify different criteria for different time periods seems unreasonable.
Response: Commenters generally agreed that sensitivities are not needed in long-term planning horizon studies since the studies are typically based on a number of assumptions regarding future conditions and uncertainties. This is not the same for the near-term. The SDT feels that the level of uncertainty for the two time period justifies a different approach. In any case, the standard does not preclude entities from performing long term sensitivity studies.			
ERCOT ISO CAISO WECC	☑		Agree. The Standard should state that sensitivity studies are not required but the TP or PA could use sensitivities if desired.
TEP	☑		We agree with this conclusion. The Standard language should state that sensitivities are not required in Long-Term Transmission System Planning Horizon but the TP could use sensitivities if desired.
Response: The SDT feels the standard reflects your comment. The standard does not preclude the entity from using sesitivities if more critical trends are detected.			
Georgia Transm.	☑		The sensitivities should be determined by the Planner. As part of the development of long range projects, sensitivity analyses should be performed.
Response: The SDT feels the standard reflects your comment in that even though the standard does not require sensitivities, it does not preclude the entity from using sesitivities if desired. Commenters generally agreed that sensitivities are not needed in long-term planning horizon studies since the studies are typically based on a number of assumptions regarding future conditions and uncertainties.			
Ameren	☑		There are more unknowns in the longer-term studies than in the near-term studies, which would

Question 15			
Commenter	**Yes**	**No**	**Comment**
			indicate that more sensitivity studies would need to be performed and not less. However, it is more reasonable to suggest that if near-term sensitivity studies show a problem in a particular part of the system, then similar sensitivity studies need to be performed in the longer-term analyses.
IESO	☑		We agree, but this raised a question on why did the SDT introduce a requirement for sensitivity testing for year one to year 5 studies but not the year 6 and beyond studies. Wouldn't the degree of uncertainty be higher in the longer time frame?
Response: Commenters generally agreed that sensitivities are not needed in long-term planning horizon studies since the studies are typically based on a number of assumptions regarding future conditions and uncertainties. Closer in years tend to be more certain and applying sensitivities is necessary to ensure that unexpected conditions would not significantly affect reliability. The standard does not preclude entities from performing long term sensitivity studies which may even provide some basis for the base models used for analysis.			
LADWP	☑		This applies to both long- and near- term, the type of sensitivities proposed here do not belong in transmission planning studies.
Response: The SDT felt that it is necessary for planners to consider certain factors that clearly could impact system responses to contingencies. The standard, sub requirements for R2.1 and R2.4, has been modified to require that the planner document why or why not the listed factors were used in the assessment. In addition the standard does not preclude entities from performing long term sensitivity studies which may provide some basis for the base models used for analysis nor does it preclude studying multiple years if more critical trends are detected.			
Muscatine P&W	☑		Local issues may drive a different approach
Response: The SDT feels the standard reflects your comment in that even though the standard does not require sensitivities, it does not preclude the entity from using sesitivities if desired, such as local issues as you suggest.			
New York ISO	☑		NYISO does not agree with the requirement of sensitivity studies in the near-term or long-term.
Response: Commenters generally agreed that sensitivities are not needed in long-term planning horizon studies since the studies are typically based on a number of assumptions regarding future conditions and uncertainties. Closer in years tend to be more certain and applying sensitivities is necessary to ensure that unexpected conditions would not significantly affect reliability.			
WPS	☑		The standard should require long-term sensitivity studies to the extent that the open transmission planning process within FERC Order 890 identifies the need for the sensitivities.
Response: Commenters generally agreed that sensitivities are not needed in long-term planning horizon studies since the studies are typically based on a number of assumptions regarding future conditions and uncertainties. In addition the SDT feels that such sensitivities were not required by the Order. The standard does not preclude entities from performing long term sensitivity studies which may provide some basis for the base models used for analysis nor does it preclude studying multiple years if more critical trends are detected.			
Brazos Electric	☑		Longer term studies should be performed in the broadest sense, the cases are difficult to create accurately and a greater range of sensitivities do not improve the results.
City Water Power and Light	☑		
Dominion	☑		We concur that no sensitivity studies should be required for the LT planning horizon.
E ON US			I agree with the approach.

Question 15			
Commenter	**Yes**	**No**	**Comment**
AECI	☑		
Allegheny Power	☑		No sensistivity needed for long term assessment.
APPA	☑		The sensitivity study of year 6 and beyond is of little value. The uncertainty (standard deviations) in the input assumptions used to complete the studies for 6 years and longer are so large it would not provide useful answers to make sound decisions regarding the need to build, remove, or improve BES facilities.
ATC	☑		
BPA	☑		
CenterPoint	☑		
Central Maine Power	☑		There is no need for sensitivity analysis.
City Utilities/Springfield	☑		
CPS Energy	☑	☑	We concur with not requiring sensitivity studies for the Long Term Assessment.
Duke Energy	☑		Agreed, sensitivity studies should not be required for the Long-Term.
Entergy	☑		
Exelon	☑		
FirstEnergy	☑		Yes, we concur with this approach and sensitivity analysis should not be required.
FPL	☑		There should be no sensitivity studies/analyses for the Long-Term Transmission System Planning Horizon.
FRCC	☑		
HQTE	☑		There is no need for sensitivity analysis.
JEA	☑		
KCPL	☑		Long term planning horizon has significantly greater uncertainty in future conditions and sensitivity studies are unlikely to contribute to reliability because of this.
LCRA	☑		There are two questions asked and the response is yes to both. In the ERCOT region, load flow cases are not currently availbale for years 6-10 and this limits the long-term study activity that Transmsion Owners and Transmission Planners can acarry out. As currently proposed (R2.2) is appropriate.
Manitoba Hydro	☑		The models for Long-Term Transmission System Planning Horizon typically contain such uncertainty that the base planning is a sensitivity study itself. Sensitivity studies in these years would be a waste of time. The long term analysis should be used to indicate trends such as a reduction in transfer capability, reduction in damping, etc, but not necessarily seek mitigation of such trends.

Question 15			
Commenter	**Yes**	**No**	**Comment**
MEAG Power	☑		We concur with the current approach.
MISO	☑		Long-term planning horizon studies are typically based on a number of assumptions regarding future conditions and uncertainties. While testing various load conditions, generator operation assumptions, and power interchange variables may be useful for modeling expected economic value, such analysis does not contribute to reliability.
MRO	☑		The models for Long-Term Transmission System Planning Horizon typically contain such uncertainy that the base planning is a sensitivity study iteself. The MRO believes that sensitivity studies in these years would be a waste of time.
National Grid	☑		There is no need for sensitivity analysis.
New England ISO	☑		There is no need for sensitivity analysis.
NCMPA			
NU	☑		There is no need for sensitivity analysis.
NPCC RCS	☑		There is no need for sensitivity analysis.
Nstar	☑		There is no need for sensitivity analysis.
PJM	☑	☑	PJM agrees that no sensitivity analysis is required for long term period
Progress–Carolinas	☑		Sensitivities should not be required for Long-Term
Progress–Florida	☑		PEF concurs with the draft standard's approach with regard to Q15 that sensitivities should not be required for years six through ten.
ReliabilityFirst	☑		
Santee Cooper	☑		We concur with the current approach.
SaskPower	☑		
Seattle City	☑		Conditions six years or more in the future are unpredictable and sensitivity studies would provide results of limited usefulness.
SERC EC DRS	☑		We agree that sensitivity studies should not be required for the Long-Term..
SERC EC PSS	☑		We concur with the current approach.
SERC RRS OPS	☑		We concur with the current approach.
SCE&G	☑		
Southern Transm.	☑		Yes, we concur with this approach.
TVA	☑		

Question 15			
Commenter	**Yes**	**No**	**Comment**
United Illuminating	☑		There is no need for sensitivity analysis.
Response: Thank you.			

C) Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

16) Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Summary Response: DSM refers to reduction in the net Load that could be used to mitigate generation deficiency or Transmission overload. DSM could be invoked pre-Contingency or as a part of automatic or manual System adjustment post-Contingency. The use of DSM is optional and entities do not have to include DSM in the Corrective Action Plan. However, if DSM is included in the Corrective Action Plan, the entity that included it must justify the DSM amount and associated uncertainties. If an entity can show that DSM is effective, the standard does not bar them from using it.

The following requirement was changed due to industry comments:

R2.7.1 - ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.

Q16			
Commenter	**Yes**	**No**	**Comment**
AECC		☑	Yes - DSM impact should be included if it is known and can be treated the same a generation as far a dependibility, capability, and its known impacts. No - most DSM on our system is already figured into the load.
Response: The SDT provided DSM as a possible action. The entity may choose to use this option or provide additional actions to improve System response.			
Ameren	☑	☑	If DSM can be implemented in the required operating time, we have no objections to using DSM as the planned mitigation to relieve overloads or low system voltages for multiple contingency conditions, but not as a long-term solution for single contingency conditions. However, from our experience, we believe that developing enough DSM in the required time at specific locations in the

Q16			
Commenter	**Yes**	**No**	**Comment**
			system will be difficult, and that plain load-shedding would be required to supplement the DSM to achieve the desired performance.
BPA	☑	☑	Support comments submitted by WECC. There is a concern with using DSM as a corrective action if it is not directly controlled by the utility and the benefits do not materialize as planned.
Brazos Electric		☑	If DSM is not viable due to market failings, then its inclusion in any CAPs provides an inaccurate soltion to achieve the required system performance.
City Water Power and Light		☑	DSM is not always available and is usually not available without operator action. Therefore, asuming it is alwasys available could give a false sense of security. The system could collapse before DSM is able to be implemented.
Georgia Transm.		☑	DSM should not be a requirement in considering Corrective Action Plans. Because DSM cannot be counted on or controlled, its use as a Corrective Action Plan should not be assumed.
MISO	☑	☑	Yes, DSM should be considered in transmission studies, but should be limited to firmly contracted DSM resources that are demonstrably applicable for transmission capacity mitigation. DSM is better compared to supply-side resources as they are evaluated for reserve margin contribution. No, the challenge in considering DSM, is that Transmission Planners are not aware of DSM potential on the system and it must be communicated to them for consideration.
WECC TEP		☑	It is unclear whether "DSM" in this question refers to reduction in load or increases in distributed resources, or if the resources are directly controllable by the transmission operator. DSM could be used in the mix of solutions that are used to determine the optimal solution for a transmission issue. However, we have concerns about the use of DSM, that is not under the direct control of the Transmission Operator as a stand alone transmission system solution. Please remember the overstated returns from DSM in the last decade that did not materialize. If these overstated values had been used as a transmission system enhancement, then the system would have been compromised with emergency operating solution until the effective transmission enhancements could be realized.
Response: DSM refers to reduction in net Load. The standard does allow for consideration of DSM but other factors may disallow inclusion of DSM in the Corrective Action Plan. The amount and uncertainty of DSM needs to be justified by the entity when it is included in their Correction Action Plan. If an entity can show that DSM is effective, the standard does not bar them from using it.			
E ON US		☑	DSM and generation improvements should be excluded. What is a "generation improvement"? New technologies could apply to anything, does the SDT mean "new Transmission technologies"?
Response: DSM refers to reduction in net Load. The standard does allow for consideration of DSM but other factors may disallow the use of DSM as a corrective action. The amount and uncertainty of DSM needs to be justified by the entity when it is included in their Corrective Action Plan. If an entity can show that DSM is effective, the standard does not bar them from using it. The term "generation improvements" means any change or modification to a generator which results in an increase in generation output and/or reactive support. New technologies include any technology that is not currently in use on the electric power System that helps improve efficiency (i.e., energy storage/production technologies, low sag conductors, solid state interrupters, etc.)			
Northwestern Energy		☑	The word "including" should be "may include", mandating what should be studied is not appropriate.

Q16			
Commenter	**Yes**	**No**	**Comment**
			Also, including DSM in the list presumes the balancing area is deficient in generation, which may not always be the case.
Response: The use of DSM is optional. Requirement R2.7.1 has been modified based on your comments to use "may include" instead of "including". DSM typically has been used to compensate for generation deficiency but it can also be used to reduce transmission loading for special conditions and may provide a justifiable corrective action. The standard does allow for the use of DSM but other factors may disallow the use of DSM as a corrective action. **R2.7.1** - ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.			
CenterPoint		☑	CenterPoint Energy is not aware of DSM ever being identified as an effective option to correct a transmission system deficiency. If such an application of DSM was identified and implemented, load growth would quickly negate the DSM impact, and other measures would have to be taken.
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating	☑		DSM should be included to the extent that its performance is sufficiently and consistently understood. The standard does not use the term "optimal" Therefore, the Drafting Team appears to be interpreting the Standard to require a vertically-integrated Planner to produce a so-called optimal-mix of resources plan. This would be an incorrect assumption and is not required. In areas with independent planners and competitive wholesale markets, it is sufficent to identify system needs and produce a plan that identifies regulated transmission solutions in the event that market-based resources (such as DSM) do not address those identified needs. Therefore, while DSM can be as effective a resource as generation, per Commission Orders, in areas with ISOs/RTOs and a competitive wholesale market, the NERC Standard cannot prescribe the development so-called optimized (as is suggesgted by the Drafting Team) resource-mix plans, as identified by a central planner.
NERC TIS	☑	☑	Yes, if it can be counted on for relieving transmission constraints. Some DSM contracts do not allow for interruption for anything other than resource adequacy events, or have time-based or economics-based implementation limitations.
New York ISO	☑		NYISO suggests that the impact included in studies should consider past performance of DSM participants.
Response: The standard does allow for consideration of DSM but other factors may disallow the use of DSM as a corrective action. The amount and uncertainty of DSM needs to be justified by the entity when it is included in their Corrective Action Plan.			
CPS Energy		☑	Performance of the DSM is not necessarily controlled by the Transmission Owner and cannot be considered "firm". Therefore, use of DSM should be optional, but not mandated.
Response: The use of DSM is optional. Requirement R2.7.1 has been modified based on your comments to use "may include" instead of "including". If an entity can show that DSM is effective, the standard should not bar them from using it.			

Q16			
Commenter	**Yes**	**No**	**Comment**
R2.7.1 - ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.			
FirstEnergy		☑	We do not feel that the standard should specify, limit, or suggest methods for mitigating system performance deficiencies. We suggest rewording R2.7.1 by ending the first sentence after the words "System performance". The items currently described could be moved to a reference document which could include DSM and other mitigation methods.
Response: The use of DSM is optional. Requirement R2.7.1 has been modified based on your comments to use "may include" instead of "including". The SDT feels it is more useful to include examples of what the Corrective Action Plan may include. The list of examples should help minimize questions regarding what is valid as a corrective action. **R2.7.1** - ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.			
IESO		☑	No, the amount DSM is, in some established markets, a market-arranged quantity that depends on both the offered price and the discretion of the LSE or load customer at the time such a price signal presents itself. The resultant amount of DSM that can actually be realized when needed is unpredictable. This requirement also brings up a broader issue. Requirement 2 generally applies to Planning Coordinator and Transmission Planner, there is no distinction made as to which sub-requirements apply to which entity. In some markets, the Transmission Planner is responsible for assessing future needs for transmission facility only. It does not have the authority to even suggest a corrective plan that involves generation improvement or DSM. The way R2 and its sub-requirements is written is more suited for an integrated planning process, which may not exist in some places/developed markets.
Response: The use of DSM is optional. Requirement R2.7.1 has been modified based on your comments to use "may include" instead of "including". The standard does allow for consideration of DSM but other factors may disallow inclusion of DSM in the Corrective Action Plan. The amount and uncertainty of DSM needs to be justified by the entity when it is included in their Correction Action Plan. The standard is applicable not only to the Transmission Planner but also to the Planning Coordinator and the Resources Planner. These entities are expected to establish relationships to provide for intergrated analysis and resultant Corrective Action Plan which may include generation, transmission and DSM components. **R2.7.1** - ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including~~			

Q16			
Commenter	**Yes**	**No**	**Comment**
~~Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.			
LADWP		☑	We should be very careful about using DSM as Corrective Action for transmission problem. What this would lead to is to have a "built-in" transmission problem which would require DSM as the de facto rolling brown-outs or black-outs. DSM should be part of the resource and load forecasting consideration; transmission planning should design tranmission that can properly serve the forecasted loads with the expected resources; not to "live with" or include transmission contraints that rely on DSM as a solution. If the industry truly wants to use DSM as mitigation for transmission deficiencies, let's do it as a deliberate action, not an unintended consequence. "System deficiencies" may be corrected with an integrated approach as suggested, but "transmission deficiencies" are solved by transmission improvement. The classic example is Path 15 in WSCC/WECC. The transmssion deficiency of PAth15 was well known for many years (like since '80s) and in the "pre-deregulated" dates, the deficiency was indeed managed by an integrated approach when the utility can operate its assets integrally. Then de-regulation happened and the integrated approach became unbundled and impossible resulted in numerous brown-outs and black-outs in California in 2000-01 until a third transmission line is added. Transmission deficiencies, if not mitigated, will significantly affect the accessibility to transmission services, a key concern of ferc 890. As for new technology, just how the SDT proposes to define what constitutes a new technology? And how to measure for compliance against such a requirement? Hopefully, this is just another case of overly prescriptive standard.
Response: DSM refers to reduction in net Load. The standard does allow for consideration of DSM but other factors may disallow the use of DSM as a corrective action. The amount and uncertainty of DSM needs to be justified by the entity when it is included in their correction action plan. New technologies include any technology that is not currently in general use, or is in the development stages, on the electric power system that helps improve efficiency (i.e. energy storage/production technologies, low sag conductors, solid state interrupters, etc.)			
Manitoba Hydro		☑	DSM and generation improvements should be removed from Requirement R2.7.1, as they should not be mandated by a NERC standard are not in the tool box of the transmission planner. DSM may already be in the load forecast and sensitivities to load forecast variations are included in near term planning horizon sensitivity analysis. Additional DSM shouldn't be part of transmission planners mitigation plan. If the corrective plan is too expensive the load serving entity could consider DSM and revise their forecast in the next planning cycle.
MRO		☑	DSM should already be in the load forecast and sensitivities to the load forecast variations are included in the near term planning horizon sensitivity analysis. Additional DSM shouldn't be part of the transmission planner's corrective plan. Additional DSM can be considered in the next planning

Q16			
Commenter	**Yes**	**No**	**Comment**
			cycle.
Response: The use of DSM is optional. Requirement R2.7.1 has been modified based on your comments to use "may include" instead of "including". DSM refers to reduction in net load that could be used to compensate for a generation deficiency or to reduce transmission overloads. If an entity can show that DSM is effective, the standard should not bar them from using it. **R2.7.1** - ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.			
Southern Transm.		☑	It should not be a requirement that DSM be considered but DSM should be one of the allowable alternatives. The way the present standard is written, it is unclear whether "all" of the named items (except operating procedures with the "or" statement) are required to be considered or whether only one or more of the items need to be included. It is suggested that the following statement replace the word "including" in line two of R2.7.1: "that may include one or more of the following:". This should clarify that all of the items are not required to be in the action plan for compliance. It also is not clear what the phrase "including the duration of interim Operating Procedure" means. Does this mean how many years you would anticipate using the Operating Procedure or does it mean how long it takes to "repair" the cause of the outage that necessitated the use of the Operating Procedure? Assuming that the meaning is the second one, the requirement to document the "mean time to repair" is new and there does not seem to be a very useful purpose for this requirement. As long as the system performance standards are met and the system is prepared for the next outage, what is the purpose of recording and documenting the length of time that you anticpate it to take to fix the problem? This is variable at best and does not provide useful information.
Response: The use of DSM is optional. Requirement R2.7.1 has been modified based on your comments to use "may include" instead of "including". DSM refers to reduction in net load that could be used to compensate for a generation deficiency or to reduce transmission overloads. If an entity can show that DSM is effective, the standard should not bar them from using it. Your first interpretaion is correct (how many years you expect to use the procedure). **R2.7.1** - ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.			
TSGT		☑	DSM should not be considered except as a load forecast variable. Rather, the load forecast probability index should be prescribed (specific probability of exceedance)

Q16			
Commenter	**Yes**	**No**	**Comment**
Response: The use of DSM is optional. If an entity can show that DSM is effective, the standard should not bar them from using it. The use of DSM is optional. Requirement R2.7.1 has been modified based on your comments to use "may include" instead of "including". DSM refers to reduction in net load that could be used to compensate for a generation deficiency or to reduce transmission overloads. **R2.7.1** - ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.			
AECI		☑	
LCRA		☑	
SaskPower		☑	
Seattle City		☑	
Response: Thank you for your response.			
AEP	☑		Consider requiring that problem contingencies be simulated on base case that models the lower load level that would result with the DSM implemented.
Response: The standard does allow for consideration of DSM which is effectively the situation you are describing.			
APPA	☑		This is a conditional Yes. The Resource Planner or Transmission Planner must provide assurance that the specific "Demand" reduction that is incorporated into the scenario analyses will actually be reduced through either customer action or direct load shedding by the Balancing Authority. This type of controllable "Demand" does exist, but it is rare that planners and operators actually have such resources in their portfolios to help with System Deficiencies.
Response: The use of DSM is optional. If an entity can show that DSM is effective, the standard should not bar them from using it. The amount and uncertainty of DSM needs to be justified by the entity when it is included in their Corrective Action Plan.			
ITC	☑		DSM alternatives should focus on existing contractual relationships only. DSM is an alternative to "capacity solutions" and you have to give weight to how well you can count on it during capacity emergencies. Will the load be there to cut? How certain are you (contractually) that the load will be shed voluntarily when called upon to do so?
Response: The use of DSM is optional. If an entity can show that DSM is effective, the standard should not bar them from using it. The standard does allow for consideration of DSM but other factors may disallow the use of DSM as a corrective action. The amount and uncertainty of DSM needs to be justified by the entity when it is included in their Corrective Action Plan.			
KCPL	☑		Only for DSM that is contractually "firm" and which can demonstrate mitigation performance (comparable to generation resource) as related to the transmission system.
MEAG Power	☑		DSM should be included if it is a tool made available to the TP for this purpose, but only to the extent that it is available for curtailment by the System Operator and without the option to buy through and remain in service.

Q16			
Commenter	**Yes**	**No**	**Comment**
Response: The use of DSM is optional. The standard does allow for consideration of DSM but other factors may disallow inclusion of DSM in the Corrective Action Plan. If an entity can show that DSM is effective, the standard does not bar them from using it.			
NCEMC	☑		It should be included if it is a tool made available to the TP for this purpose, but only to the extent that it is considered firm.
Santee Cooper	☑		It should be included if it is a tool made available to the TP for this purpose, but only to the extent that it is considered controllable and quantifiable resource.
SERC EC PSS SERC RRS OPS SCE&G	☑		It should be included if it is a tool made available to the TP for this purpose, but only to the extent that it is considered firm.
TVA	☑		It should be included if it is a tool made available to the TP for this purpose, but only to the extent that it is considered firm. However, the standards should not determine which type of fix a utility should use to meet system requirements.
Response: The use of DSM is optional. If an entity can show that DSM is effective, the standard should not bar them from using it.			
ABB	☑		First of all, you are not exactly requiring that DSM be considered or analyzed. You have simply listed it as one of the possible solutions. And you should mention the possibility of "integrated plan" in the standard itself. Since DSM is simply optional, let the planners figure out themselves how to consider DSM.
Allegheny Power	☑		It should be included if there are specific mandated or approved DSM programs in place during the study period.
ATC	☑		
BCTC	☑		DSM should be a load reduction.
CAISO	☑		We agree to include DSM among a mix of solutions to a system problem. However, the difficulty is that DSM is unpredictable when needed. Another issue is how much DSM is actually under the control of the Transmission Operator.
City Utilities/Springfield	☑		Controllable demand that will be available to both the planner and operator must be well defined and readily available when called upon including operating procedures.
Dominion	☑		An appropriate level of DSM should be included in studies.
Duke Energy	☑		DSM should be carefully included based upon consideration of the particular DSM measures available and the uncertainty associated with each.
Entegra	☑		
Entergy	☑		DSM should be considered, but it should be done prudently and in accordance with the contracts that govern the specific DSM program and only in cases where the Transmission Owner has direct load control. Transmission Owners should be allowed to include UVLS and SPS systems as a part of their Corrective Action Plans.
ERCOT ISO	☑		

Q16			
Commenter	**Yes**	**No**	**Comment**
Exelon	☑		DSM should be directly controllable with accurate information as the the magnitude and location. System stability should not be dependent on the operation of DSM.
FPL FRCC	☑		If DSM is included as part of an integrated Corrective Action plan, then the impact of DSM should be included by specifying the location and expected quantity of DSM that will mitigate a system deficiency. The use of DSM, whether exclusively or in conjunction with other measures, is an acceptable operating procedure for use in a Corrective Action Plan, as long as the Transmission Owner demonstrates availability and accuracy of DSM data and its viability as an operating procedure for each applicable scenario.
Muscatine P&W	☑		We do not have DSM but I could see where it could be used to relieve overloads or low voltage.
PJM	☑	☑	Yes- DSM should be modeled consistent with how it is expected to be operated based on contractual/operating relationships.
Progress–Carolinas	☑		State regulatory requirements mandate that we consider DSM alternatives. The DSM contracts would have to adequately support the intended use.
Progress–Florida	☑		The use of DSM, whether exclusively or in conjunction with other measures, is an acceptable operating procedure for use in a Corrective Action Plan, as long as the Transmission Owner demonstrates availability and accuracy of DSM data and its viability as an operating procedure for each applicable scenario.
Tenaska	☑		While DSM may, or may not, be manually operated, it is critical to understand the impacts of DSM and whether different ways of implementing DSM are of value.
WPS	☑		The effect of DSM should be considered in corrective action plans to the extent that DSM can reduce overall load growth and change the timing of new transmission facilities.
Response: Thank you. DSM refers to reduction in net Load. The use of DSM is optional. If an entity can show that DSM is effective, the standard does not bar them from using it. The standard does allow for consideration of DSM but other factors may disallow the use of DSM as a corrective action. The amount and uncertainty of DSM needs to be justified by the entity when it is included in their Corrective Action Plan.			

17) Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Summary Response: The specific requirement to perform re-test has been removed. The purpose of the Corrective Action Plan is to list the actions that are needed to meet performance requirements. The studies, current, and/or past as appropriate, as well as the extent of the size of the study area, are performed to support compliance and demonstrate that the requirements are met. The standard assumes that the actions were developed and verified using the current and past studies that were used to uncover deficiencies and confirm adherence to the performance requirements.

The following requirement was deleted due to industry comments:

R2.7.2 ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~

Q17			
Commenter	**Yes**	**No**	**Comment**
AECC		☑	A new study should not be required. The impact of "fix" should be evaluated as part of determining it as a viable solution.
Response: The SDT agrees with your comment and has revised the requirements to agree with your comment. **R2.7.2** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~			
Ameren		☑	This proposed requirement is unnecessary and a waste of time. Keep in mind this is a planning assessment and not a facilities study. Further, such a requirement implies a distrust of the transmission planners to develop valid corrective action plans to meet the requirements of the TPL standard. For more complex system facility additions, it would be inconceivable that a Transmission Planner or Owner or Planning Coordinator would proceed without performing power flow simulations to determine the efficacy of the system addition. But these studies would be performed over time considering the best available information and latest standards performance requirements. The majority of transmission projects consist of the upgrading of terminal equipment or conductor on one or more branches. The only significant change that such upgrade work would produce in a power flow model would be that the branch ratings would change. It is not necessary to rerun power flow simulations for such cases, as it can be determined by inspection whether the upgrade

Q17			
Commenter	**Yes**	**No**	**Comment**
			work would be sufficient to move the facility rating above the expected normal or contingency flow.
Response: The purpose of the Corrective Action Plan is to list the actions that are needed to meet performance requirements. The studies are performed to support compliance and demonstrate that the requirements are met. The specific requirement to re-test has been removed. **R2.7.2** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ The SDT has removed the Requirement R2.7.2 but kept the orignal R2.7.5 requirement, which was re-numbered as Requirement R2.7.3, (subsequent annual assessments report on the status of Corrective Action Plans).			
Dominion		☑	In the normal course of business, a planner out of necessity will need to check to see if the proposed improvements will actually fix the problem. The prospect of making a multi-million dollar mistake is sufficient incentive to insure this study occurs without the additional burden of creating an audit trail to meet a NERC standard. Requirements for what study area should be used and documentation of the process are not necessary. If, per chance, a study is not performed immediately, the next set of studies will show the deficiencies, if any.
Response: The intent is to ensure that for a specific problem the Corrective Action Plan is checked to the extent that the Corrective Action Plan does not cause any additional problems. The SDT has removed the Requirement R2.7.2 but kept the orignal 2.7.5 requirement, which was re-numbered as Requirement R2.7.3, (subsequent annual assessments report on the status of Corrective Action Plans). **R2.7.2** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~			
E ON US		☑	Re-testing is part of the normal study process of developing the Corrective Action Plan (CAP). Most CAP should be developed in the Long-Term horizon. The next annual study and all subsequent studies provide sufficient review without developing another set of cases and additional testing in the initial assessment.
Response: The intent of the standard is to develop a Corrective Action Plan that will create a system capable of meeting system performance requirements. The intent of the standard is to provide verification at the time the Corrective Action Plan is developed and not wait a year to perform the verification. This is critical to ensure that plans are coordinated between entities. The SDT has removed the Requirement R2.7.2 but kept the orignal 2.7.5 requirement, which was re-numbered as Requirement R2.7.3, (subsequent annual assessments report on the status of Corrective Action Plans). **R2.7.2** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~			
Brazos Electric	☑		It is difficult to understand what is meant by 'retested'. The evaluation of a CAP includes testing the recommended option to see how it performs and to insure that it does not create other problems. We assume this is what is meant by retested. In our evaluation we insure that it does not negatively impact all other facilities in the BES and if so what extent and if it is managable. We do not always create a separate 'study area' each time for each system improvement.

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Commenter	**Yes**	**No**	**Comment**
CenterPoint	☑	☑	Many problems identified in future studies and associated transmission improvements are fictitious due to the speculative nature of predicting load and generation growth. Requiring exhaustive studies to determine the full impact of fictitious transmission projects is unnecessarily prescriptive and burdensome, and provides little, if any, value in identifying and solving real transmission problems.
CPS Energy		☑	Should be conducted for Near Term Planning Assessment only with the study area determined at the discretion of the Transmission Planners.
FPL FRCC		☑	Incremental benefits do not justify the magnitude of additional studies. Corrective Action plans should be tested, but not as a new study with all of the Corrective Action Plans included simultaneously. The proposed language is inferior to the existing language (TPL-002-0 R2) and suggest replacing with language from TPL-002-0 R2.
Georgia Transm.		☑	This is the essence of planning. All entities should ensure that Corrective Action Plans address the identified constraints and work within the BES infrastructure. It is not clear what the intent of "new" studies is. Since the evaluation of Corrective Action Plans is part of the planning process, what new studies is this requirement referring to. The determination of the study area should be by the Planner.
LADWP		☑	This is a redundant and unnecessary requirement. How can one come up with a corrective action plan if it has not been demonstrated the plan can mitigate the problem? And if the corrective plan has been able to demonstrate that it can mitigate the problem, why repeat the study again.
Manitoba Hydro	☑		At some point the corrective action plan should be tested to verify the plan meets the performance requirements. The way the standard is written is that the transmission plan should be perfect for the entire planning horizon for all sensitivities tested. Any issues should be immediately addressed. The standard does not allow any time to develop a corrective plan through an open and transparent process. Based on the NERC definition, a Corrective Action Plan is the list of actions and an associated timetable for implementation to remedy a specific problem. A Corrective Action Plan could mean that load forecasts at the station will be verified, facility ratings verified and alternatives to fix the identified problem to be determined before the next Planning Assessment. Standard R2.7 seems to be mixing the idea of a Corrective Action Plan with the original TPL idea of determining corrective plans to achieve required performance. A corrective plan wil be the end goal of a Corrective Action Plan. Furthermore, corrective action plans should not be requierd to address issues raised by sensitivity studies. Corrective action plans are developed to meet base case needs which are based on expected load forecasts, transfers, etc. Sensitivity studies are done to measure the robustness of the base case plan. It should be left up to the Planner to decide if the corrective action plan is adequate based on the likelihood of the scenario studied, even if the sensitivity analysis shows some performance violations.
MISO		☑	Sufficient analysis, including re-testing, must have been performed in creating the Corrective Action Plans. Requiring demonstration by the transmission planner that this is the basis of the Plans is superfluous.

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Commenter	**Yes**	**No**	**Comment**
MRO		☑	The MRO is concerned with this requirement particularly since the standard indicates that System Assessment shall be conducted each year while studies are not required each year. MRO members typically conduct this exercise at the time that studies are originally conducted with regard to improvements. By requiring a new study with improvements (some of which were justified in past studies) demonstrating that these improvements work essentially results in the Transmission Owner needing to clear a new unfair hurdle for improvements. This results in a requirement which will result in wide-spread non-compliance. The SDT should clarify that this requirement can be met by past studies. The MRO recommends that R2.7.2 be removed because it is redundant since development of the corrective action plan will have included these studies. At some point the corrective action plan should be tested to verify the plan meets the performance requirements. The way the standard is written is that the transmission plan should be perfect for the entire planning horizon for all sensitivities tested. Any issues should be immediately addressed. The standard does not allow any time to develop the corrective plan through an open and transparent process. Based on the Nerc definition, a Corrective Action Plan is the list of actions and an associated timetable for implementation to remedy a specific problem. A Corrective Action Plan could mean that load forecasts at the station will be verified, facility ratings verified and alternatives to fix the identified problem to be determined before the next Planning Assessment. Standard R2.7 seems to be mixing the idea of a Corrective Action Plan with the original TPL idea of determining corrective plans to achieve required performance. A corrective plan wil be the end goal of a Corrective Action Plan.
PJM	☑	☑	Yes – At a minimum the system conditions and / or contingency that identified the system deficiency should be evaluated to determine that it has corrected the issue. The extent of the study area needs to be consistent with the size / complexity of the corrective action plan.
Progress–Florida		☑	Each Corrective Action Plan as stated in the original assessments should be trusted as effective, provided the Transmission Owner can demonstrate with its own internal assessments the effectiveness of each Corrective Action Plan.
Santee Cooper		☑	Re-testing should be required only where the correction may impact network flows. The study area should be determined by the TP. The TP has the most knowledge of how the system responds to changes. The majority of transmission projects consist of the upgrading of terminal equipement or conductor on one or more branches. The only significant change that such upgrade work would change in a powerflow model would be that of the branch (facility) ratings would change. It is not necessary to rerun powerflow simulations for such cases, as it can be determined by inspections whether the upgrade work would be sufficient to move the facility rating above the expected normal or contingency flow. We agree that the Planning process should ensure that corrective actions for a particular defeciency do not lead to other deficiencies. However, the process for ensuring this is not necessarly The

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Commenter	**Yes**	**No**	**Comment**
			development of new study cases which include facilities comprising the corrective action plan and the suscetesting is not needed.
Southern Transm.	☑	☑	A properly conducted study should determine that the recommended Corrective Action Plan actually solves the problem and does not cause other problems. If not, it is not a Corrective Action Plan. What appears to be intended here is whether the combination of Corrective Action Plans interact with each other and create additional problems. In the conference call Mr. Odom stated that it was not the intent for "all" the corrective plans be put back into the cases and all of the simulations be redone but only look at local area analysis. If that is the case, what is necessary to be in compliance with R2.7.2 and what type of documentation is required? This is very unclear. The study area should be determined by the TP. The TP has the most knowledge of how the system responds to changes
WECC BPA TSGT TEP		☑	No, this is too onerous. We recognize that, when planning the system and developing a Corrective Action Plan, the transmission planner would have added the potential projects individually (or in small groups) into a case to re-test the system performance. Hoever, R2.7.2 seems to require that all potential projects be added back into the case simultaneously for retesting. There could be many different alternative solutions for each potential problem identified in the different study years without having the base solution first determined for a nearer term case. There can be many combinations of potential solutions for cases further into the future that satisfy the condition being studied. For example, a voltage problem can be solved by the addition of capacitors, completing a bus tie, adding a short line, operating procedure, changing generation dispatch, etc. Even assuming that one set of solutions are picked so the verification study can be performed, logistically this demonstration may be too close to the assessment in the following year. Instead of retesting the potential projects in the Corrective Action Plan on the original base case, it may be better to test them in the base cases prepared for following year's study. Any potential problem that is unresolved will show up again in the following year's assessment. Therefore, a separate demonstration using an "older" case may not be an efficient use of the TPs' and PAs' time and resources.
WPS	☑	☑	It is difficult to fully prescribe a methodology to define a "study area". It is most appropriate for the Transmission Planning to develop study areas based on and consistent with the transmission planning principles within Order 890.

Response: The intent of the standard is to develop a corrective action plan that will create a system capable of meeting system performance requirements. The standard assumes that the actions were developed and verified using the current and past studies that were used to uncover deficiencies and confirm adherence to the performance requirements. The SDT has removed Requirement R2.7.2 but kept the orignal 2.7.5 requirement, which was re-numbered as Requirement R2.7.3, (subsequent annual assessments report on the status of Corrective Action Plans).

R2.7.2 ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance~~

Q17			
Commenter	**Yes**	**No**	**Comment**
~~requirements in the tables~~			
ABB	☑	☑	Any area where there might possibly be an impact. I.e., engineering judgement.
Muscatine P&W		☑	Large enough to ensure negative impacts will not occur. This could best be covered in regional studies. (See Q43 Comment #3)
Response: The specific requirement to perform re-test has been removed. The purpose of the Corrective Action Plan is to list the actions that are needed to meet performance requirements. The studies, current and/or past as appropriate as well as the extent of the size of the study area, are performed to support compliance and demonstrate that the requirements are met.			
R2.7.2 ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~			
AECI		☑	
SaskPower		☑	
Response: Thank you for your response.			
Alcoa	☑		NERC is revising the Transmission Planning Standards beginning with TPL-001. Alcoa agrees with NERC's approach to revising TPL-001 wherein NERC is consolidating duplicative Standards to promote consistent requirements of the planning process and thus improving reliability. Also, Alcoa agrees that new studies should not result in inadvertent negative impacts on the system especially when such studies have not taken into account the negative impact on an adjacent system. However, Alcoa believes that the current draft of the TPL fails to address FERC Order 890's requirements of an open and transparent Planning Process. Such a process provides Market Participants an equal opportunity for consideration in the Planning Assessments for contingency impact on transmission availability. (See FERC Order 890 ¶¶ 140, 207, 212, 323, 327, 337). Alcoa also believes that the current draft of the TPL fails to address and incorporate FERC Order 890's new requirement that transmission providers coordinate "…ATC calculations with their neighboring systems." For example, while Planning Assessments may indicate no NERC Compliance violations where the Table 1 and Table 2 Requirements are met, Market Participants are harmed and not provided protection from unequal treatment of their circumstance. This problem occurs when an analysis of a contingency event results in no IROL or SOL (all facilities remain within established ratings), but resultant transmission constraints cause reductions of ATC and subsequent market impact. As part of the System Planning Process, this is unacceptable, and, as a minimum, this type of situation must be included as a scenario reviewed in the required sensitivity analysis under the NERC TPL-001-1 Standard. The impact of such practices by large transmission providers on the ATC of smaller transmission

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Commenter	**Yes**	**No**	**Comment**
			providers can be significant. For instance, small transmission providers similar to Alcoa that operate non base-load resources such as hydropower, peaking units or wind power can easily see their ATC's reduced when sensitivity analyses are not performed under TPL-001-1. Alcoa believes that such sensitivity analyses should be a requirement. Alcoa believes that for consistency with the provisions of Order 890, NERC must re-visit not only the Planning Assessment implications on transmission availability but also couple this review with the revision of the NERC Modeling Data and Assessment Standards (MOD). Alcoa recommends that the MOD and TPL Standards be addressed in similar fashion to: 1) Incorporate the intent of Order 890 requirements of an "Open and transparent Regional Planning Process to provide non-discriminatory planning" for ALL Market Participants 2) Assure that the revised MOD and TPL Standards fully address implications of burdens on the Bulk Electric System (BES) related to transmission availability for contingencies in the Planning Process. FERC Order 890 ¶ 523 - Coordinate planning with interconnected systems. In addition to preparing a system plan for its own control area on an open and nondiscriminatory basis, each Transmission Provider will be required to coordinate with interconnected systems to (1) share system plans to ensure that they are simultaneously feasible and otherwise use consistent assumptions and data and (2) identify system enhancements that could relieve congestion or integrate new resources. (Emphasis added). 3) Sensitivity Analysis should include the potential impact on transmission availability and/or reductions in ATC on adjacent systems. Where ATC on an interface is reduced for a single contingency (N-1 planning, mitigation options must be provided). (This may require a threshold level of ATC reduction where a percentage reduction would be specified as acceptable on the N-1 basis, and a greater reduction than that threshold would be considered a Standard's Violation).
Response: The purpose of this standard is to develop corrective actions that can eliminate system performance deficiencies. The standard does not judge if the action listed is the only or the best action to be taken on an economic or market basis. It is the responsibility of the entity to resolve such issues and conform to FERC Order 890.			
AEP	☑		Consider limiting study area to immediately adjacent systems.
Allegheny Power	☑		Study area should be at least two buses beyond deficiency and plan elements.
BCTC	☑		The Assessment should state how the study area was determined, including input from adjacent Planning Coordinators. WECC has processes for coordination of planning information so that Planning Coordinators are informed of plans in other areas.

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Commenter	**Yes**	**No**	**Comment**
Entergy	☑		Study area should be determined on a case by case basis by the Transmission Planner. SEAMS agreements and other regional planning coordination activities should provide for adequate cooperation.
Exelon	☑		The study area should be at least the size of the original study area. Some engineering judgment is required to determine the subset of studies. Next year's study would include the full set of screenings for the future additions.
IESO	☑		We feel that having the requirement to retest the conditions which show a performance deficiency, but now with the proposed corrective measures, would suffice. To illustrate or require "how a study area should be determined" would be micro-managing, and the term "a study area" is not defined anywhere in the standard and is subject to different interpretation. For example, does it mean the physical area of study or does it mean the various areas in the study that need to be explored. We are therefore unable to offer any view as to "how a study area should be determined".
ITC	☑		Without further study once a “solution” has been proposed how can one be sure it will work and not create “other” issues? The area of study should be developed using good engineering judgment with input from any neighboring parties that might be impacted.
KCPL	☑		Corrective Action Plans taken by a transmission operator should not burden any of its' directly interconnected transmission operators. Study area should include at least all transmission operators directly interconnected to the transmission operator who took the initial corrective action. It may be appropriate to use the entire RTO/ISO/RRO as study area.
LCRA	☑		The question is not clear regarding "study area"; however, re-testing with corrective action / system improvement(s) in place is a must. The re-test must consider the same simulations that identified the initial deficiency. In addition, in the re-test, the action/ system improvement must be considered as a Planning Event itself (i.e., if the initial test showed a specific contingency causing a deficiency, then a physical connection of the system improvement to the identified contingency should be avoided or minimized - minimize the creation of Extreme Events.). In other words, planning solutions should be long-term and a system "fix" for the present should not result in a system problem in the foreseeable future.
MEAG Power	☑		Re-testing should be required only where the correction may impact network flows. The study area should be determined by the TP. The TP has the most knowledge of how the system responds to changes and should be allowed to choose the study area based on the prudent utility practice.
NCEMC	☑		Re-testing should be required particularly where the correction may impact network flows. The study area should be discussed within a stakeholder process to the TP may compile input from network customers or LSEs that might be affected by the analysis.
Northwestern Energy	☑		R2.7.2 does not refer to "how a study area should be determined". This added statement should be eliminated.
Progress–Carolinas	☑		There are separate regional processes for coordination with neighboring utilities.

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Commenter	**Yes**	**No**	**Comment**
ReliabilityFirst	☑		The study area should be determined by the Transmission Planner and Planning Coordinator.
Seattle City	☑		Sensitivity studies should be adequate to determine the study area. Starting at the corrective facility, work out bus by bus, determining sensitivity to the facility's loss. Boundaries of the study area would be defined at buses where loss sesitivity is (for example) 1% or less.
SERC EC PSS SERC RRS OPS SCE&G TVA	☑		Re-testing should be required only where the correction may impact network flows. The study area should be determined by the TP. The TP has the most knowledge of how the system responds to changes.
Tenaska	☑		The study area should be the same as in the original study unless the Corrective Action Plans require changes/additions outside of the original study area. If chagnes/additions are made outisde the original area, then the study area must be expanded to include, at a minimum, the area that includes the new changes/additions.
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating	☑		The study area should be based upon planning expertise and knowledge of the system, giving due consideration to external impacts.
City Water Power and Light	☑		The system should be retested with new facilities in place to ensure that no new problems arise with the addition of new facilities.
Response: Based on industry comment, the SDT has removed Requirement R2.7.2 but kept the orignal 2.7.5 requirement, which was re-numbered as Requirement R2.7.3, (subsequent annual assessments report on the status of Corrective Action Plans). **R2.7.2** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~			
FirstEnergy	☑		Although we agree with the concept of retesting, the standard should reference that a re-study is only required in the vicinity or portion of the system affected by new facility additions. Determination of the study area should be left to the Transmission Planner's judgment.
Response: The SDT has removed the specific requirement to perform re-testing with the understanding that the purpose of the Corrective Action Plan is to list the actions that are needed to meet performance requirements. The studies, current and/or past as appropriate as well as the extent of the size of the study area, are performed to support compliance and demonstrate that the requirements are met. The standard assumes that the actions were developed and verified using the current and past studies that were used to uncover deficiencies and confirm adherence to the performance requirements. **R2.7.2** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance~~			

Q17			
Commenter	**Yes**	**No**	**Comment**
~~requirements in the tables~~			
NERC TIS	☑		All Corrective Action Plans should be tested on an interconnection-wide basis to screen for potential adverse impacts throughout the interconnection, not just the TOs area.
Response: Please see Requirement R8 for the coordination and peer review requirements.			
APPA	☑		This is necessary to insure the planners did not accidentally take the system and the future operation of the system from the frying pan into the fire.
ATC	☑		
City Utilities/Springfield	☑		Corrective action plans must be appropriately modeled in order to verify that implementing the plans results in a BES that will perform based on the applicable NERC Reliability Standards or more restrictive local area criteria.
Duke Energy	☑		New studies should be performed, but the study conditions should be determined based upon the judgment of the planner.
ERCOT ISO CAISO	☑		We agree that the system should be retested with the corrective measures to ensure that the defficiency has been cured and that there are no inadvertant negative impacts. Regarding Study Area, it is not a defined term, and it could vary depending on the size of the project or nature of the disturbance being evaluated.
New York ISO	☑		NYISO Agrees
Response: Thank you but due to the preponderance of industry response to this question, this requirement has been deleted.			

18) Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Summary Response: Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted the original Requirement R2.7.2 through Requirement R2.7.4. A new Requirement R2.7.2 has been added. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions".

The following requirements were changed due to industry comments:

R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.
R2.7.2. ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.
R2.7.3. ~~Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~
R2.7.4. ~~Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~

Q18			
Commenter	**Yes**	**No**	**Comment**
Ameren		☑	We understand that there are differences between committed and proposed projects in an RTO environment where there is cost sharing for facility upgrades. From a NERC Standards compliance perspective, however, we do not see a need to differentiate between proposed and committed projects in the corrective action plan, as long as either properly addresses the required performance issue. We are not sure why there is a need to develop or maintain information on committed projects. This tracking is not needed to meet the existing TPL standards. Compliance requirements should be kept separate from administrative data requests. What is the perceived need to track committed projects that has not been presented here? Is this another example of distrust for transmission owners to build the proper facilities to create a more robust system?
Brazos Electric		☑	What is the difference? We assume committed means you have begun work on the project and can no longer stop. It would seem this would need to be defined more clearly and it is probably different for each project or entity. Why is this differentiation even needed?
Response: The SDT agrees with your comment that from a planning perspective, there is no benefit in trying to distinguish between "committed" and "proposed". Therefore, the SDT has modified Requirement R2.7.1 and deleted the original Requirement R2.7.2 through Requirement R2.7.4 to reflect "actions" needed to achieve required System performance without trying to distinguish between committed and			

Q18			
Commenter	**Yes**	**No**	**Comment**
proposed projects. **R2.7.1.** ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. **R2.7.2.** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1. **R2.7.3.** ~~Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~ **R2.7.4.** ~~Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~			
AECI	☑		However, the question as to what is considered committed versus proposed. There are variuos step in the approval process for our company and we are not sure which approval would be considered committed.
AEP		☑	Consider adding clear definition of "proposed" and "committed" projects (definition may impact response to this question).
Allegheny Power	☑		There needs to be a clear definition developed for committed and proposed projects and those definitions need to be included in the definition section of the standard.
APPA	☑		While it is good to know the difference, it should be made clear in the Standard that if a project is listed as committed, it may be changed the next year to proposed project. Definitions for "committed" and "proposed" are needed to ensure consistent data/assumptions within each region.
BPA		☑	Support comments submitted by WECC. Also, one reason not to differentiate between committed and proposed projects is that regardless of whether a project is committed or not in a future case, the committment to implement a Corrective Action Plan becomes mandatory as time moves closer to the need date due to required system performance.
WECC TSGT TEP		☑	The definition of these terms can be vastly different across all TPs. How would this be effectively monitored for compliance with such different definitions? Also, each TO's criteria to go from a proposed project to a committed project can change over time due to other needs and requirements.
Central Maine Power National Grid New England ISO NU NPCC RCS NSTAR	☑		They should be viewed differently in the Near-Term. However, these should be defined terms.

Q18			
Commenter	**Yes**	**No**	**Comment**
United Illuminating			
City Utilities/Springfield	☑		Definitions of both “committed” and “proposed” are needed.
City Water Power and Light	☑		"Committed" and "proposed" projects need to be defined.
CPS Energy		☑	The treatment of each project should be at the dscretion of the Transmission Planners.
Duke Energy		☑	Even committed projects may not be built due to a variety of circumstances. Either type of project can be deferred or cancelled for a variety of reasons, including circumstances beyond the transmission planner's control.
Entergy	☑		Committed projects should be tested for effectiveness, however, the effectiveness of Proposed projects, as they are subject to change, should not require the same level of documentation as committed projects.
Georgia Transm.	☑		They are inherently treated differently. "Committed" projects are a part of the base assumptions in the base case, while "proposed" projects are evaluated until a point where corporate commitment has been made.
HQTE	☑		They should be viewed differently in the Near-Term.
E ON US		☑	MISO has spent years on trying to make a distinction. If this remains, then "Committed Project" must be defined.
ERCOT ISO CAISO		☑	The definition of "committed" projects varies from TP to TP. Also projects that are proposed today become committed in the planning horizon. Similarly, committed projects drop out due to variety of reasons. In terms of system studies, both committed and proposed projects are modeled and evaluated in the same system. How do we distinguish between the two?
FirstEnergy		☑	Unless there is an industry agreed upon distinction and definition between "committed" and "proposed" projects, we do not agree that they should be introduced in this standard.
FPL FRCC		☑	All projects should be called "Planned" projects. There is no distinction in a model between committed and proposed projects that would treat them differently. They are either in the model or not in the model. This sub-requirement does not follow the major requirement wording in R2.7 ".....Such plans shall:" The intent of Requirements R2.7.3 and R2.7.4 should be combined and added into R2.7.1.1. Rather than adding the addtional requirement to document a criteria, the requirement should be that in the Near-Term Planning Horizon, projects cannot be removed (or modified) without demonstrating that the revised plan meets performance criteria. Suggested wording for R2.7.1.1. “Transmission and generation improvement projects for the Near-Term Transmission Planning Horizon, shall have in-service dates provided (to whom?), and shall not have in-service dates changed, or be removed from planning models, without documentation to show that the revised plan meets performance requirements.”
IESO	☑	☑	Yes, the distinction should be made as committed projects have a higher degree of certainty to be available for the period under study, whereas a proposed project is one that is supported by the

Q18			
Commenter	**Yes**	**No**	**Comment**
			assessment but the commitment to proceed is not yet secured. However, we do not see the need (a) to establish criteria for committed projects and proposed projects, and (b) to distinguish between the criteria between them. If the standard should require a TP to assess both scenarios - with and without proposed projects, then this should be clearly stipulated.
ITC		☑	All projects should naturally become committed projects at some point prior to the need date. The time frame should be dependant on the scale and voltage class of the project.
LADWP		☑	Seems like every company would have its own definition of committed vs propsoed project.
Manitoba Hydro	☑		However, since each planner is allowed to define the criteria, there will be no consistency as to what is included in the base case models.
NCEMC	☑		Projects that are underway (i.e. being built) and are not subject to be potentially delayed and are absolutely needed for reliability should be differentiated between those that are not. Perhaps definitions for each of these terms should be considered for clarification.
NERC TIS	☑	☑	No concensus in TIS after extensive disucussion, but it will be discussed further.
Northwestern Energy		☑	No, there are no clear guidelines on how to make this distinction.
PJM	☑	☑	We agree that there needs to be a differentiation between committed and proposed projects. Proposed projects, particularly generation interconnections and their associated network upgrades need to be identified as a group so that they can be removed from cases if the proposed generation interconnection does not move forward.
Progress–Carolinas		☑	Are projects are proposed until they are completed.
Progress–Florida		☑	This differentiation is meaningless when modeling projects in cases for planning analysis. The standard should instead set criteria for when models can be relied upon for planning purposes such that changes to the future plan will not have an impact on reliability.
Seattle City		☑	Since compliance with performance guidelines is mandated, aren't all projects defined in the corrective action plans "committed" projects? Proposed projects in the context of Requirement 2.7 should only exist in the studies to determine which remedial solution(s) comprise the Corrective Action Plan.
Southern Transm.		☑	This requirement does not appear to have any major benefit, particularly coupled with R2.7.4 discussed in Q19. The standards require that an assessment be done every year and that the system must meet performance requirements or a Corrective Action Plan be developed. Therefore, if a project has been previously specified as a "committed" project, removing it and or replacing it with something else must also meet performance requirements under this standard or a violation occurs. Also, this performance of the system with the "committed" Corrective Action Plan" removed or modified must be documented. Therefore, requirement R2.7.4 is automatically met and is superfluous in the standard and should be removed. There is no benefit from the distinction between a project definition of "committed" and "proposed".
WPS	☑	☑	If the standard makes a differentiation between "committed" and "proposed" projects, definitions for

Q18			
Commenter	**Yes**	**No**	**Comment**
			each, within the standard itself, are necessary. Within the context of R2.7, it is not clear what impact the differentiation between "committed" and "proposed" has on the requirement itself. R2.7 requires Corrective Action Plans to address deficiencies within the performance analysis of the events in Table 1 and Table 2. A fundamental underpinning of R2.7 should be that Corrective Action Plans are developed consistent with the transmission planning principles of Order 890.
Response: The SDT agrees that if the standard is going to include "committed" and "proposed", they will need to be defined. However, the SDT agrees that it will be very difficult to develop definitions of "committed" and "proposed" that are applicable for the entire NERC footprint. Therefore, the SDT has modified Requirement R2.7.1 and deleted the original Requirement R2.7.2 through Requirement R2.7.4 to reflect "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. **R2.7.1.** ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. **R2.7.2.** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1. **R2.7.3.** ~~Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~ **R2.7.4**. ~~Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~			
MEAG Power		☑	The goal is to meet the system performance requirements outlined in the standard. Whether a project is proposed or committed is not relevant.
Santee Cooper SERC EC PSS SERC RRS OPS SCE&G		☑	The goal is to meet the system performance requirements outlined in the standard. Whether a project is proposed or committed is irrelevant. R2.7.3 should be deleted.
Response: The SDT agrees with your comment and has modified Requirement R2.7.1 and deleted the original Requirements R2.7.2 through R2.7.4 to reflect "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. **R2.7.1.** ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.			

Q18			
Commenter	**Yes**	**No**	**Comment**
R2.7.2. ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1. **R2.7.3.** ~~Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~ **R2.7.4**. ~~Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~			
ABB	☑		Yes, it helps when considering other issues in the same area. You would know whether or not you can count on a project going in.
AECC	☑		not only should a distinction be made but committed projects should be further classified as committed and under construction. There is a difference between a project be committed and actually being built. This difference can be many years. It would also be nice to know projects that are in the conceptual stage. This allow other stakeholders to share their thoughts and collaborate on projects of mutual interest before a project reaches the committed stage. Once a project is committed it is very difficult to make modifications.
ATC	☑		
BCTC	☑		
Dominion	☑		
Entegra	☑		
Exelon	☑		
KCPL	☑		
LCRA	☑		
MISO	☑		
MRO	☑		
Muscatine P&W	☑		
New York ISO	☑		NYISO Agrees
ReliabilityFirst	☑		
SaskPower	☑		
Tenaska	☑		
TVA	☑		

Q18			
Commenter	Yes	No	Comment
Response: Thank you but due to the majority of industry response to this question, the requirements have been changed as indicated in the summary.			

19) Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Summary Response: Commenters generally agreed that "committed" plans are difficult to define and may have a different meaning for many entities. In addition, even considering the generally accepted understanding of what "committed" plans means would still lead to the fact that such plans could change up until the plan is actually implemented. Therefore the SDT has modified Requirement R2.7.1 and deleted the original Requirement R2.7.2 through Requirement R2.7.4 to require only the Corrective Action Plan and goes on to state what is intended by the word "actions".

The following requirements were changed due to industry comments:

R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.
R2.7.2. ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.
R2.7.3. ~~Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~
R2.7.4. ~~Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~

Q19			
Commenter	**Yes**	**No**	**Comment**
Ameren		☑	As stated above, we are not sure why there is a need to develop or maintain information on committed projects. This tracking is not required in the existing TPL standards. As long as the revised corrective action plan meets the reliability performance requirements, what difference does it make if a committed project is cancelled or changed to a proposed project from a compliance perspective? We need to keep compliance requirements separate from administrative data requests or survey responses.

Response: The SDT agrees with your comment and has modified Requirement R2.7.1 and deleted the original Requirement R2.7.2 through Requirement R2.7.4 to require only the Corrective Action Plan and indicates what is intended by the word "actions". The SDT feels that documenting the assessment and making it available to others will by its very nature provide all the information necessary to understand which plans changed and the basis for the new plans.

R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating~~

Q19			
Commenter	**Yes**	**No**	**Comment**
~~Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. **R2.7.2.** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1. **R2.7.3.** ~~Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~ **R2.7.4.** ~~Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~			
Brazos Electric		☑	This seems like more documention is needed however if the new CAP analysis will suffice for documentation regarding removal of the 'committed project' then this is acceptable. However, that kind of makes having such a thing as a 'committed project' fairly useless if you can change it. This appears to just be more unnecessary documention.
Dominion		☑	We are of the opinion that committed projects could be removed without documentation. Once a project is removed, the next set of studies will show the deficiencies, if any.
Response: The SDT agrees with your comment that "committed" plans can change. The SDT has modified Requirement R2.7.1 and deleted the original Requirement R2.7.2 through Requirement R2.7.4 to require only the Corrective Action Plan and indicates what is intended by the word "actions". The SDT feels that documenting the assessment and making it available to others will by its very nature provide all the information necessary to understand which plans changed and the basis for the new plans. **R2.7.1.** ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. **R2.7.2.** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1. **R2.7.3.** ~~Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~ **R2.7.4.** ~~Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~			
E ON US		☑	Our planning process includes documentation of the need, acceleration, delay, or elimination of all projects. As worded, I do not need to document the delay of a Committed project.
Northwestern Energy		☑	Same problem as Q18; but it isn't clear what level of documentation is needed.
BPA		☑	See response to Q18.

Q19			
Commenter	**Yes**	**No**	**Comment**
CenterPoint		☑	This is overly prescriptive. Allow each Transmission Planner to determine the best way to handle planned projects.
CPS Energy		☑	The treatment of each project should be at the discretion of the Transmission Planners.
Duke Energy		☑	The annual assessment will show that the revised plan meets performance requirements.
FirstEnergy		☑	Unless there is an industry agreed upon distinction and definition between "committed" and "proposed" projects, we do not agree that they should be introduced in this standard.
Georgia Transm.		☑	See responses to Q17 and Q18.
KCPL		☑	Corrective Action Plans must demonstrate performance based on the expected system configuration. Committed projects can be changed or discontinued before completion.
LADWP		☑	All this does is create more bureaucratic tracking and paper pushing. People probably won't classify anything as committed until concrete has been poured just so not to have to deal with all these paperwork.
Manitoba Hydro		☑	The standard does not allow any time to develop a corrective plan through an open and transparent process. Based on the NERC definition, a Corrective Action Plan is the list of actions and an associated timetable for implementation to remedy a specific problem. A Corrective Action Plan could mean that load forecasts at the station will be verified, facility ratings verified and alternatives to fix the identified problem to be determined before the next Planning Assessment. This standard seems to be mixing the idea of a Corrective Action Plan with the original TPL idea of determining corrective plans to achieve required performance. A corrective plan wil be the end goal of a Corrective Action Plan.
MEAG Power		☑	See response to Q18.
MISO			The current Corrective Action Plan should show the performance of the system with the best information available. These Plans will change year by year as conditions change and new information becomes available. Requiring that Plan projects from previous years may not be modified "without documentation" adds a additional unneeded paperwork.
MRO		☑	The MRO disagrees with this requirement. This is an unnecessary requirement since each year Corrective Action Plans must meet the system performance requirements.
Santee Cooper SERC EC PSS SERC RRC OPS SCE&G		☑	The goal is to meet the system performance requirements outlined in the standard. Whether a project is proposed or committed is irrelevant. R2.7.4 should be deleted.
Southern Transm.		☑	See comments for Q18. [This requirement does not appear to have any major benefit, particularly coupled with R2.7.4 discussed in Q19. The standards require that an assessment be done every year and that the system must meet performance requirements or a Corrective Action Plan be developed. Therefore, if a project has been previously specified as a "committed" project, removing it and or replacing it with something else must also meet performance requirements under this

Q19			
Commenter	**Yes**	**No**	**Comment**
			standard or a violation occurs. Also, this performance of the system with the "committed" Corrective Action Plan" removed or modified must be documented. Therefore, requirement R2.7.4 is automatically met and is superfluous in the standard and should be removed. There is no benefit from the distinction between a project definition of "committed" and "proposed".]
Tenaska		☑	Add after the word "requirements" the following: "without the committed projects."
TSGT		☑	R2.7.4 calls for change monitoring. If documentation of changes is required, just say so. Do not restrict changes.
WECC TEP		☑	The requirement is similar to the question posed in Question 17. What is the documentation that proves this is needed?
SaskPower		☑	
BCTC	☑	☑	We have a larger concern. If a project is Committed and is proceeding with construction, why would a transmission planner not consider this is in planning studies. Showing that a committed project is not needed and removing it from the plans, does not necessarily remove it from the future system. In addition to showing that the revised plan meets the performance requirements, the planner needs to include documentation to show that the Committed project has been cancelled.
IESO	☑	☑	We agree that committed projects should not be removed from the revised plan. But we question the need for this sub-requirement which calls for: "Revisions to the Corrective Action Plans are allowed over time but shall meet the performance requirements.." Committed projects are normally included in the planning studies for which the performance is assessed. Deficiency, if identified, will have a corrective plans developed. We do not understand the need to remove or revise the committed plan in this context.
NERC TIS	☑	☑	Any revision to the Corrective Action Plan should be tested to ensure that the revised plan meets the precribed performance requirements. Documentation of that testing is appropriate.
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating	☑		It is unclear as to what the commited project is being removed from. Suggested language "…removed from the plan…".
ERCOT ISO CAISO	☑		We agree that committed projects should not be removed from the revised plan. These are supposed to be included in the planning studies which determine the system performance in the first place. The definition of "committed" projects varies from TP to TP so this would require a standard definition.

Q19			
Commenter	**Yes**	**No**	**Comment**
Seattle City	☑		To agree with the comment in Q18, the requirement should read "Corrective Action Plans shall not be modified without documentation to show that the revised plan meets the performance requirements."

Response: Based on your comment and the comment of others that state that "committed" plans could change up until the plan is exercised, the SDT has modified Requirement R2.7.1 and deleted the original Requirement R2.7.2 through Requirement R2.7.4 to require only the Corrective Action Plan and indicates what is intended by the word "actions". The SDT feels that documenting the assessment and making it available to others will by its very nature provide all the information necessary to understand which plans changed and the basis for the new plans.

R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.
R2.7.2. ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.
R2.7.3. ~~Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~
R2.7.4. ~~Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~

FPL		☑	All projects should be called "Planned" projects. Additionally, see response to question 18.
FRCC		☑	See response to question 18.

Response: Although the comment suggests referring to all plans as "planned", the comment of others that stated that "committed" plans ("planned" in your case) could change up until the plan is exercised; the SDT has modified Requirement R2.7.1 and deleted the original Requirement R2.7.2 through Requirement R2.7.4 to require only the Corrective Action Plan and indicates what is intended by the word "actions". The SDT feels that documenting the assessment and making it available to others will by its very nature provide all the information necessary to understand which plans changed and the basis for the new plans.

R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.
R2.7.2. ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list

Q19			
Commenter	**Yes**	**No**	**Comment**
of actions developed in accordance with Requirement R2.7.1. **R2.7.3.** ~~Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~ **R2.7.4.** ~~Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~			
ABB	☑		It's kind of obvious. If you require a solution to begin with, then if that solution is removed, another solution must be planned. However, if the removed project is not directly related to the study or problem at hand, then engineering judgment will be needed as to whether or not to repeat the study.
AECC	☑		It should also show the justification for the revision. This is especially true if transmission service is going to be sold using models that contain committed projects. If a plan is revised I would hope the revision would meet the performance requirements better than the project it replaces.
AECI	☑		
Allegheny Power	☑		
AEP	☑		
APPA	☑		It may be necessary, as a band-aid-type substitute, to replace a committed project with a Remedial Action Scheme (RAS)/Special Protection Systems in lieu of new facilities. Whatever the revised plan, it must be shown to meet the performance requirements.
ATC	☑		
City Water Power and Light	☑		
City Utilities/Springfield	☑		
Entegra	☑		
Entergy	☑		
Exelon	☑		
ITC	☑		We agree.
LCRA	☑		
Muscatine P&W	☑		
New York ISO	☑		NYISO Agrees
NCEMC	☑		
PJM	☑		
Progress–Carolinas	☑		We always should be able to show that we meet performance requirements.

Q19			
Commenter	**Yes**	**No**	**Comment**
Progress–Florida	☑		
TVA	☑		
WPS	☑		As stated in response to Q18, it is unclear why the differentiation between "committed" and "proposed" is actually necessary. The standard must allow flexibility, so that the evolution of a Corrective Action Plan can occur within the context of the transmission planning principles of FERC Order 890.
Response: Thank you but due to the majority of industry response to this question, the requirements have been changed			

D) Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

20) Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV

Summary Response: The SDT has considered industry comments and has incorporated changes in the definition of Consequential Load Loss. The SDT has also revised Tables 1 & 2 to add greater detail and provide for more situations where it is acceptable to lose Non-Consequential Load. However, the SDT did not feel that any change needed to be made to this requirement. Note: P2-1 from the original draft is now P2-2 in the revision.

Many of the responders have asked the question why the distinction for bus sections above 300 kV. The SDT has prepared the following response.

The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission Systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT believed the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated above 300 kV generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers where the energy is then delivered by other Transmission or sub-Transmission Systems to end-use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability.

When EHV Systems are compromised, the large volumes of power they serve can place a severe amount of stress on parallel EHV or lower voltage paths. For example, if a large EHV transformer experiences a catastrophic failure, not only are other systems Facilities required to carry more Load but the System is also exposed to other N-1 conditions for long periods of time while awaiting a replacement or repair of the failed equipment. Large generation sources are typically connected at EHV levels and maintenance of the EHV transmission lines within the vicinity of large generation plants must often be coordinated during scheduled unit outages, resulting again in multiple Facility outages over extended periods of time.

Therefore, it was the conclusion of the SDT in Draft 1 to propose greater reliability and operational flexibility through more stringent performance requirements when considering certain N-1 and N-1-1 Contingency events of EHV Systems. Throughout the industry, substation arrangements at EHV levels reflect the importance of these systems as the designs often consist of the more flexible and reliable ring-bus, breaker-and–a-half or double bus-double breaker protection schemes as compared to the simpler, lower cost single bus arrangements that are commonly found on lower voltage systems.

The feedback received from the industry was divided related to the SDT's emphasis placed on a higher expectation for the 300 kV and higher systems. Some commenters questioned the importance and the high costs that may be needed to mitigate existing system designs. Others agreed with the SDT's approach and indicated that the impact to their systems would be minimal. Some commenters even questioned why the more stringent approach was not applied to the entire 100 kV and higher systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission System.

Q20			
Commenter	**Agree**	**Disagree**	**Comment**
ABB			Loss of load is not usually considered by tranmission planners. In power flow studies, they look at flows and voltages versus limits. In stability studies, they are looking for angles, speeds, and voltages that stabilize at good values, possibly with temporary excursions less than some limits. How should all these be converted to a loss of load value? Normally we ensure no loss of load <because> we meet thermal, voltage, and stability requirements. Maybe you are saying that planners should not use load tripping as a solution for these violations?
Response: Tripping of Load can be used as an operating tool to maintain or restore a System to acceptable performance. The standard needs to quantify whether this action is acceptable from a planning perspective and, if so, then it needs to quantify the acceptable situations and limits. This second draft is proposing that no Non-Consequential Load may be tripped for the loss of a 300 kV (or higher) bus section for a first contingency event. (See Table 1)			
LADWP			There is a fundamental fatal flaw in having different reliability requirements using an arbitrary separation of the connected bulk electrical systems into above 300kV and below 300kV. The standard should be re-draft without this separation and comments be solicited at that time. These questions are fundamentally unfair without first settling whether or not it is wise to arbitrary separate the bulk system into two different classes. This is like asking someone "Did you hit your spouse today?"
Response: Draft 2 has been modified for 300 kV and higher systems regarding N-1-1 conditions: Based on industry feedback the SDT has made changes in proposed Draft 2 requirements related to two independent overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. Draft 2 now permits the loss of Non-Consequential Load to meet the Transmission performance requirements for these types of events. Please refer to performance tables Planning Event P6. It is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission for the less probable, but greater risk single Contingency events. Please refer to performance tables Planning Event P2 and note that bus section faults and internal breaker faults (non-bus tie) associated with above 300 kV Facilities are held to a higher performance standard than those operated at 300 kV or below. Please see also summary response.			
Muscatine P&W			See Q43 Comment #5.
Response: See Q43 response.			
Dominion		☑	Usually, this type of outage will not involve non-consequential load loss,

Q20			
Commenter	**Agree**	**Disagree**	**Comment**
			however, there may be specific situations where local non-consequential load loss could be justified. This is consistent with how transmission systems have been designed for many years and approved by State commissions. Transmission Owners need to have some flexibility to balance grid reliability vs. cost to the ratepayer. In some instances, the expense required to eliminate all local non-consequential load loss cannot always be justified if there is no significant improvement in wide area bulk power system reliability. In other words, making the standards more stringent by "raising the bar" is not going to result in a dramatic improvement in system reliability. Even the best designed systems are susceptible to human error. Dominion has at least 5 years of transmission outage data clearly illustrating that any resulting loss of load (both consequential and non-consequential) has had an average duration of only 4-7 customer-minutes per year. Going forward, the emphasis and focus should be on planning and operating the bulk electric system so as to confine any transmission outages to the immediate, local area, and not allow the cascading of outages beyond control area boundaries.
Response: The SDT agrees that typically systems are designed such that Non-Consequential Load won't be lost, which should minimize the exposure to non-compliance for most companies. The SDT agrees that the focus of the standard needs to be on network performance and has added greater detail to Tables 1 & 2 which address the comment. The standard is a planning document; so although the SDT agrees that operating the BES is an important issue, it is not the focus of this standard.			
Northwestern Energy		☑	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
Response: Consequential and Non-Consequential Load Loss involves Transmission System actions not customer equipment response to system performance, which in some cases may be within a tolerable system bandwidth, but not within the customer set points. The standard anticipates that the system will be designed to meet the expected Load, which implies that customer tripping of its own Load should not be the focus in planning studies. This has been addressed in the definition of Consequential Load Loss.			
BCTC		☑	Do not agree based on SDT definition for Consequential and Non-Consequential Load Loss. Will agree subject to proposed revisions to definitions of Consequential and Non-Consequential Load loss.
Response: The SDT has considered industry comments and has incorporated changes in the definition of Consequential Load Loss which should address your concerns.			
CAISO		☑	Loss of bus section is Category C for which the current NERC criteria allows controlled loss of load. The NERC system has been designed with this criteria. To create a more stringent standard would require to build hundreds of miles of new transmission lines to bring the existing system to NERC compliance. What are the potential benefits of this stringent criteria? Also, what is the

Q20			
Commenter	**Agree**	**Disagree**	**Comment**
			reasoning behind selecting 300 kV as a cut off level?
Tenaska		☑	May need to consider using 500 kV as some transmission providers serve load off of the 345 kV system which could be triggered by this event.
Response: It is not clear if the comment is referring to Consequential or Non-Consequential Load, but greater detail has been added to Tables 1 & 2, which should address your comment.			
Exelon	☑	☑	We do not agree with disallowing non-consequential load loss for these scenarios for the peak load conditions. These are very low probability contingencies, and some non-consequential load loss should be allowed at peak load. We would agree that it would be reasonable to dis-allow non-consequential load loss for these contingencies at a lower load level, such as 75% of peak load.
MEAG Power		☑	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
FPL FRCC		☑	This loss is currently distinguished from other single contingencies because of its lower probability of occurrence and a more stringent performance requirement than currently exists is not warranted.
MRO		☑	This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this change to customers. Alternatively, the SDT should define a level (such as 1000 MW) of non-consequential load that is acceptable for such low probability events.
Progress–Florida		☑	This single contingency event has a very low probability of occurrence, and thus a more stringent performance requirement than currently exists is not warranted.
NCEMC	☑		Although this is a relatively low probability event, we do agree that it should be assessed given the widespread effects. It may not justify the need for a network upgrade but at least deserves consideration for an operating or corrective action procedure should the event occur. Also, given this analysis might be new for some TPs, consideration should be given to a transition period after the start of this type of assessment.
Santee Cooper		☑	We do not agree with the concept of non-consequential load loss. To maintain system reliability, the disconnect of any load should be allowed.
SCE&G		☑	SCE&G does not agree with the concept of non-consequential load loss. To maintain system reliability, the disconnect of any load should be allowed. If not allowed, unprecedented new transmission costs will be required. These costs will be for local area improvements and will NOT result in increased

Q20			
Commenter	**Agree**	**Disagree**	**Comment**
			transfer capabilities for markets.
SaskPower		☑	The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
SERC EC DRS SERC EC PSS SERC RRS OPS		☑	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Southern Transm.		☑	By not allowing non-consequential load loss, utilities will incur significant expenditures. The marginal increase in reliability for this low probability event does not justify the huge costs involved.
Response: To address your concern, the SDT will consider a transition policy as part of the implementation plan to allow for Transmission Owners to respond to requirements that involve raising the bar. The implementation plan will be developed for a subsequent posting. As a first step the SDT has added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose non-consequential load.			
TEP		☑	R1 and R2 address some Load Forecast issues, but are not exhaustive specifications of what Load Forecast range to use in studies. There needs to be some mention of exceedance probability (ExPr) in Load Forecast criteria. For example, we use a forecast with a low ExPr in our studies because we are concerned that, if the system was planned for 50% ExPr (a lower forecast), actual deviation from that forecast might result in load at certain locations exceeding operating margins built into the interconnected transmission system designed to serve only the 50% ExPr forecast load. Load Specifications in R2.4 are ambiguous for the reasons stated above. Maximum study ages in R2.6.1 and R2.6.2 seem arbitrary. The time limit does not seem to add anything to the criteria if no material changes have occurred. If spot checks of the most critical areas indicated no criteria violations, there should be no reason to rerun studies. To correct this problem, we suggest using the term "assessment" rather than "study". For most people, "study" implies detailed modeling and simulation analyses summarized in a report, whereas "assessment" implies a reasonable, systematic evaluation of a system which does not necessarily include detailed analysis for the entire system.
Response: The SDT has made several changes to the referenced sections. The SDT agrees that "assessment" and "study" have different implications and reflected that in this revision.			
WECC BPA TSGT		☑	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with

Q20			
Commenter	**Agree**	**Disagree**	**Comment**
			the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Response: It is not clear if the comment is referring to consequential or non-consequential load, but greater detail has been added to Tables 1 & 2, which provides for more situations where it is acceptable to lose load and may address part of the comment. The following response is provided to the issue raised relative to the 300 kV cut-off. Draft 2 Changes for 300 kV and higher systems regarding N-1-1 conditions**:** Based on industry feedback the SDT has made changes in proposed Draft 2 requirements related to two independent overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. Draft 2 now permits the loss of Non-Consequential Load to meet the Transmission performance requirements for these types of events. Please refer to performance tables Planning Event P6. It is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission for the less probable, but greater risk single Contingency events. Please refer to performance tables Planning Event P2 and note that bus section faults and internal breaker faults (non-bus tie) associated with above 300 kV facilities are held to a higher performance standard than those operated at 300 kV or below. Please see also summary response.			
WPS		☑	It is not clear why the standard has established 300 kV as the differentiation point between allowing non-consequential load loss and not allowing it. The standard has established different planning requirements for different voltage levels without establishing why the differentiation is necessary. While transmission facilities over 300 kV in some areas of the country may be considered the "backbone", it is not universally applicable; in some areas, 230 kV and even 138 kV represent the "backbone" of the transmission system. The standard should not bisect the transmission system and apply two different planning requirements without clearly establishing why the differentiation is necessary.

Q20			
Commenter	**Agree**	**Disagree**	**Comment**
			Additionally, Table 1 needs to clarify the use of the term "Firm Transfers" and the interruption of "Firm Transfers" as an acceptable response to an event. "Firm transfers" is not a standard transmission service offering under the ProForma OATT. The standard must be consistent with service types defined under the ProForma OATT. Suggest that the phrasse "Firm Transfers" be replaced with "Firm Transmission Service consisting of Point-to-Point and Network Integration Transmission Service"
Response: The following response is provided to the issue raised relative to the 300 kV cut-off. Draft 2 Changes for 300 kV and higher systems regarding N-1-1 conditions**:** Based on industry feedback the SDT has made changes in proposed Draft 2 requirements related to two independent overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. Draft 2 now permits the loss of Non-Consequential Load to meet the Transmission performance requirements for these types of events. Please refer to performance tables Planning Event P6. It is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission for the less probable, but greater risk single Contingency events. Please refer to performance tables Planning Event P2 and note that bus section faults and internal breaker faults (non-bus tie) associated with above 300 kV facilities are held to a higher performance standard than those operated at 300 kV or below. Please see also summary response. With regards to 'Firm Transfers', 'Firm Transmission Service' is now referenced in the Tables.			
Entergy	☑		Table 1 does not specify "SLG"
PJM	☑		Should be a 3 phase fault not a single line to ground fault.
Response: The tables have been revised and Table 2 differentiates between SLG and 3 phase faults.			
HQTE	☑		The term "bus section" needs to be clarified. Some examples should be given showing actual diagram of substation layout.
Response: The SDT discussed the definition of a 'bus section', but elected not to include a definition or examples in the standard.			
ITC	☑		Should also consider no or limited loss of load for facilities 100 kV and above.
Response: ITC may elect to apply the greater than 300 kV requirement to Facilities greater than 100kV for their own use. However, the SDT feels application to the greater than 300 kV is more appropriate for the requirements in this standard.			
Manitoba Hydro	☑		With the caveat that if the loss of load is localized, it is acceptable. Raising the bar will result in a cost increase for owners and users of the transmission system. What evidence does the SDT have to show this is justified.

Q20			
Commenter	**Agree**	**Disagree**	**Comment**
Response: The ATFNSDT has added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose load.			
AECC	☑		neither should consequential load be lost for any n-1 faults on the 300 kv system and higher.
AECI	☑		
Allegheny Power	☑		
AEP	☑		
APPA	☑		Note to APPA members – Please examine closely and give us specific comments on Q20 – Q29. If you disagree we need to know.
ATC	☑		
Ameren	☑		No significant material change identified.
CenterPoint	☑		
Central Maine Power	☑		
City Utilities/Springfield	☑		
CPS Energy	☑		
Duke Energy	☑		
Entegra	☑		
Brazos Electric	☑		
City Water Power and Light	☑		
E ON US	☑		
ERCOT ISO	☑		
FirstEnergy	☑		
Georgia Transm.	☑		No change from current standards.
IESO	☑		We agree, since the loss of a bus is a single contingency. This is a criterion already adopted by the IESO and other members in the NPCC region, for which non-consequential loss of load is not permitted.
ISO/RTO	☑		
KCPL	☑		
LCRA	☑		

Q20			
Commenter	**Agree**	**Disagree**	**Comment**
MISO	☑		No indirect (non-consequential) loss of load for single contingency events, else operator is in SOL pre-contingency without such planning.
National Grid	☑		
NERC TIS	☑		Loss of a bus section is a single contingency. Non-consequential load loss should not be allowed.
New England ISO	☑		
New York ISO	☑		
NU	☑		
NPCC RCS	☑		
Nstar	☑		
PRPA	☑		
Progress–Carolinas	☑		
Seattle City	☑		
SRP	☑		
United Illuminating	☑		
Response: Thank you.			

21) Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit

Summary Response: Based on industry feedback, the SDT has made changes in proposed Draft 2 requirements related to two independent overlapping single Contingencies (N-1-1) involving two Transmission Facilities operated at a voltage level above 300 kV. Draft 2 now permits the loss of Non-Consequential Load to meet the Transmission performance requirements for these types of events. Please refer to performance tables Planning Event P6.

It is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission for the less probable, but greater risk single Contingency events. Please refer to performance tables Planning Event P2 and note that bus section faults and internal breaker faults (non-bus tie) associated with above 300 kV Facilities are held to a higher performance standard than those operated at 300 kV or below.

Q21			
Commenter	**Agree**	**Disagree**	**Comment**
Muscatine P&W			See Q43 Comment #5.
Response: See responses for Q43.			
Ameren		☑	Load pockets supplied by a single EHV substation with only two supplies would not meet this proposed requirement, whereas the existing TPL-003-0 standard would allow the dropping of load for the multiple outage event. A significant material change to build new facilities would be needed to meet the new requirement.
AEP	☑		Consider adding clear definition of "system adjustments", including the amount of time permited to implement prior to the loss of the second facility.
CenterPoint		☑	The forced outage of two independent lines has a low probability of occurrence and should be considered an improbable event with non-consequential load loss permitted.
Central Maine Power HQTE New England ISO NU NPCC RCS NSTAR United Illuminating		☑	Given the low probability of extended overlapping outages of overhead facilities, systems have been designed assuming that load shedding following the loss of a second transmission line is permissible. Eliminating any allowance for load shedding for this condition may require significant system expansion and cost to to customers. However, it would be reasonable to consider establishing an upper bound to the amount of load that could be shed for these purposes.
E ON US		☑	Outage of two 345 kV circuits can create local area issues that result in loss of load but do not affect the integrity of the BES.
ERCOT ISO CAISO		☑	This event falls under Category C for which controlled loss of load is allowed. Clear net benefits should be demonstrated to justify adapting to a new stringent criteria.
Duke Energy		☑	Allow indirect (Non-Consequential) loss of load for events involving short duration outages, such as typical line outages that do not result in cascading outages.
Entergy		☑	N-1-1 requires an increase in investment that will place an undue cost burden on all customers for low probability events.

Q21			
Commenter	**Agree**	**Disagree**	**Comment**
			See comments to Q43.
Exelon	☑	☑	We do not agree with disallowing non-consequential load loss for these scenarios for the peak load conditions. These are very low probability contingencies, and some non-consequential load loss should be allowed at peak load. We would agree that it would be reasonable to dis-allow non-consequential load loss for these contingencies at a lower load level, such as 75% of peak load.
FirstEnergy		☑	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused soley by the first contingency.
FPL FRCC		☑	Systems have been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis. In addition, by not allowing loss of non-consequential load, the system may remain in a less secure state or condition.
Georgia Transm.		☑	This requirement appears unreasonable for a network system and, particularly, for a series of events. This requirement would be well above current reliability standards. The requirement would also result in higher investment costs for the utilities.
MISO		☑	Allow indirect (Non-Consequential) loss of load for events involving short duration outages, such as typical line outages.
MRO		☑	This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this change to customers. Alternatively, the SDT should define a level (such as 1000 MW) of non-consequential load that is acceptable for such low probability events.
Progress–Carolinas	☑		It is absolutely necessary, however, to allow interruption of firm transfers as a System adjustment. To do otherwise would cause extremely large expenditures for very low probability independent events.
Progress–Florida		☑	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration. Furthermore, the greater-than-300 kV Bulk Electric System has been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis, placing particular importance on confining the event to a single area (i.e., not resulting in a cascading outage). Past assessments as well as actual events have demonstrated that by not allowing loss of non-consequential load, the Bulk Electric System may actually remain in a less secure state or condition, i.e. in more danger of experiencing cascading outages.
Santee Cooper		☑	We do not agree with the concept of non-consequential load loss. To maintain system reliability, the disconnect of any load should be allowed. By not allowing non-consequential load loss,

Q21			
Commenter	**Agree**	**Disagree**	**Comment**
			utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Seattle City		☑	Loss of two major HV elements can drive our region into undervoltage conditions, forcing us to shed non-consequential load per UVLS standard requirements. Loss of two major HV elements can drive our region into undervoltage conditions, forcing us to shed non-consequential load per UVLS standard requirements.
SERC EC DRS SERC EC PSS SERC RRS OPS SCE&G		☑	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Southern Transm.		☑	This is a very significant change in the performance requirements in this reliability standard. It involves facilities from 345 kV through 764kV which carry significant amounts of power. These also are facilities that require significant lead time to construct in the Southern Balancing Authority with estimates up to 7-10 years in the state of Georgia. If a performance problem is detected under these new requirements, it could take that long to come into compliance and at a very significant cost if a new major 500kV line is required. These facilities can run as much as $4.0 million a mile or more in urban areas. We understand that a few areas of the country presently have this requirement but most do not. In the areas where the requirement has not been in place, the reliability of the system has been acceptable to the local Public Service Commissions that have governed the service to Retail customers. There has been no evidence presented that there is a need for an increase in reliability, particulary at the extensive time delay and expense possible from this particular requirement. An adoption of this standard without such evidence can only be considered arbitrary and capricious at best. Increased reliability is, in general, a worthy goal where it is cost effective. It may be appropriate to adopt this type of reliability requirement for areas that deem the resulting reliability increase to be cost effective for their customers. But it is inappropriate to "require" everyone else to be forced to live under this arbitrarily developed expansion of reliability requirements.
TVA		☑	By not allowing non-consequential load loss, utilities will incur significant expenditures to construct a transmission solution for some extremely low probability events with low consequence. Each utility should have the flexibility to base action on probability and consequence. Load shed by UVLS or other means should remain an option to maintain reliability if probability is extremely low, but the high consequence of an event determines that a solution is necessary.
Response: The SDT has added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose load.			
Dominion		☑	See comment for Question 20 above.
Response: See response to question 20.			
Northwestern Energy		☑	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this

Q21			
Commenter	**Agree**	**Disagree**	**Comment**
			requirement and to correct it would be costly.
Response: Consequential and Non-Consequential Load Loss involves Transmission System actions not customer equipment response to system performance, which in some cases may be within a tolerable system bandwidth, but not within the customer set points. The standard anticipates that the System will be designed to meet the expected Load, which implies that customer tripping of its own Load should not be a consideration in planning studies. This has been addressed in the definition of Consequential Load Loss.			
BCTC		☑	Do not agree based on SDT definitions. Also do not agree for first outage being a forced outage. Will agree subject to above revisions to definitions of Consequential and Non-Consequential Load loss for the first outage being a planned outage but not a forced outage. To meet this requirement for forced outages, estimate that this change could cost $3 to 5 Billion.
Response: The SDT has considered industry comments and has incorporated changes in the definition of Consequential Load Loss, which should address your concerns.			
CPS Energy		☑	Should be determined at the discretion of the Transmission Planners.
Response: The standard needs to provide some consistency and needs to define the desired level of System reliability, which will provide a level playing field and will provide guidance and support for the Transmission Planners as they deal with external entities.			
MEAG Power		☑	See Q20 above.
Response: See response to question 20.			
SRP		☑	The time to adjust the system needs to be provided (when does a N-1-1 become a N-2?). If the cause of the outage is transient (temporary) the operator needs some time to test and restore the element (could be minutes up to several hours). If the element is lost indefinitly, the operator will need some minimum time to adjust the system. If this time is not available prior to the next N-1 then the standard should allow Non-Consequetial Loss of Load.
Response: The time the operators have will depend on their time dependent ratings that they have to work with. Many users have a 30 minute rating.			
SaskPower		☑	The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Response: The SDT has added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose load, which should reduce the increased cost exposure.			
Tenaska		☑	See comment in Q20.
Response: See response to question 20.			
WECC BPA TSGT TEP		☑	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance?

Q21			
Commenter	**Agree**	**Disagree**	**Comment**
			Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Response: Draft 2 Changes for 300 kV and higher systems regarding N-1-1 conditions**:** Based on industry feedback the SDT has made changes in proposed Draft 2 requirements related to two independent overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. Draft 2 now permits the loss of Non-Consequential Load to meet the Transmission performance requirements for these types of events. Please refer to performance tables Planning Event P6. It is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission for the less probable, but greater risk single Contingency events. Please refer to performance tables Planning Event P2 and note that bus section faults and internal breaker faults (non-bus tie) associated with above 300 kV facilities are held to a higher performance standard than those operated at 300 kV or below. Please see also summary response. With regards to 'Firm Transfers', 'Firm Transmission Service' is now referenced in the Tables.			
WPS		☑	See response to Q20.
Response: See response to question 20.			
IESO	☑	☑	The sequence of events is too general that under some condition, it contradicts with the loss of 2 circuits on the same tower for which non-consequential loss of load is permitted. If the sequence of events is specified such that the two transmission circuits that can be lost are unrelated, then non-consequential loss of load should generally not be allowed following system adjustments after the loss of the first transmission circuit.
Response: Thank you but due to the majority of industry response to this question, the requirement has been changed.			
ITC	☑		Should also consider no or limited loss of Non-consequential load for facilities 100 kV and above. This should be no loss for load levels where the TO would expect to perform system maintenance.
Response: ITC may elect to apply the greater than 300 kV requirement to facilities greater than 100kV for their own use. However, the ATFNSDT feels application to the greater than 300 kV is more appropriate for the requirements in this standard.			
New York ISO	☑		We are assuming the second circuit is un-related to the first. If that is not the intent then it contracts the loss of multiple related circuits (same tower or protection zone) for which non-consequential load loss is allowed.
NCEMC	☑		We do agree that given the widespread effects of these facilities above 300 kV that these should be subjected to more rigorous assessments.

Q21			
Commenter	**Agree**	**Disagree**	**Comment**
AECC	☑		neither should consequential load be lost for any n-1 faults on the 300 kv system and higher.
AECI	☑		
Allegheny Power	☑		
APPA	☑		
ATC	☑		
Brazos Electric	☑		
City Utilities/Springfield	☑		
City Water Power and Light	☑		
Entegra	☑		
ISO/RTO	☑		
KCPL	☑		
LCRA	☑		
Manitoba Hydro	☑		
National Grid	☑		
NERC TIS	☑		This becomes a differentiation between an event and a contingency - if there is time to adjust the system, it is really two events. Non-consequential load loss based on the first event is hard to fathom. Loss of load following the second event is either consequential to the second event (even if load was isolated by the first event) or non-consequential to the second event.
PJM	☑		
Response: Thank you but due to the majority of industry response to this question, the requirement has been changed			

22) Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV

Summary Response: Draft 2 Changes for 300 kV and higher systems regarding N-1-1 conditions**:**

Based on industry feedback the SDT has made changes in proposed Draft 2 requirements related to two overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. Draft 2 now permits the loss of Non-Consequential Load to meet the Transmission performance requirements for these types of events. Please refer to performance tables Planning Event P6.

It is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission for the less probable, but greater risk single Contingency events. Please refer to performance tables Planning Event P2 and note that bus section faults and internal breaker faults (non-bus tie) associated with above 300 kV facilities are held to a higher performance standard than those operated at 300 kV or below.

Why the distinction for above 300 kV Transmission?

The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission Systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT felt the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability.

When EHV systems are compromised, the large volumes of power served by them can place a severe amount of stress on parallel EHV or lower voltage paths. For example, if a large EHV transformer experiences a catastrophic failure, not only are other systems Facilities required to carry more load but the system is also exposed to other N-1 conditions for long periods of time while awaiting a replacement or repair of the failed equipment. Large generation sources are typically connected at EHV levels and maintenance of the EHV Transmission lines within the vicinity of larges generation plants must often be coordinated during scheduled unit outages, resulting again in multiple Facility outages over extended periods of time.

Therefore, it was the conclusion of the SDT in Draft 1 to propose greater reliability and operational flexibility through more stringent performance requirements when considering certain N-1 and N-1-1 Contingency events of EHV systems. Throughout the industry substation arrangements at EHV levels reflect the importance of these systems as the designs often consist of the more expensive ring-bus, breaker-and –a-half or double bus-double breaker protection schemes as opposed to the more simplistic and lesser cost single bus arrangements that are commonly found on lower voltage systems.

The feedback received from industry was divided related to SDT's emphasis placed on a higher expectation for the 300 kV and higher systems. Some commenter's questioned the importance and the high costs that may be needed to mitigate existing system designs.

Others agreed with the SDT's approach and indicated that the impact to their systems would be minimal. Some commenter's even questioned why the more stringent approach was not applied to the entire 100kV and higher systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV transmission system.

Q22			
Commenter	**Agree**	**Disagree**	**Comment**
Muscatine P&W			See Q43 Comment #5.
Response: See Q43 response.			
Dominion		☑	See comment for Question 20 above.
MEAG Power		☑	See Q20 above.
Tenaska		☑	See comment in Q20.
TVA		☑	See Q20.
WPS		☑	See response to Q20.
Response: See response to Q20.			
E ON US		☑	Outage of two 345 kV circuit and a transformer can create local area issues that result in loss of load but do not affect the integrity of the BES.
Response: The condition you describe appears to be more stringent then the outage the SDT was asking industry to consider; N-1-1 involving a line and transformers where each are operated at a voltage level above 300 kV. However, based on industry feedback the SDT has made changes in proposed requirements for two overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. We have adjusted our approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response area for additional information.			
Northwestern Energy		☑	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
Response: Please see the proposed Glossary Definition for Non-Consequential Load. The proposed definition for Consequential Load clarifies that losing a motor due to motor contactor action is considered to be the loss of Consequential Load.			
BCTC		☑	Same comments as for Q21. We do not foresee any cost due to this standard at this time because we do not have any transformers with low side voltage rating above 300 kV.
CAISO		☑	This event also falls under Category C for which the current NERC criteria allows controlled loss of load. Clear net benefits should be demonstrated to justify adapting to a new stringent criteria.
MRO		☑	This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this

Q22			
Commenter	**Agree**	**Disagree**	**Comment**
			change to customers. Alternatively, the SDT should define a level (such as 1000 MW) of non-consequential load that is acceptable for such low probability events.
Santee Cooper SERC EC DRS SERC EC PSS SERC RRS OPS SCE&G		☑	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
SaskPower		☑	The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Southern Transm.		☑	See comments for Q21. [This is a very significant change in the performance requirements in this reliability standard. It involves facilities from 345 kV through 764kV which carry significant amounts of power. These also are facilities that require significant lead time to construct in the Southern Balancing Authority with estimates up to 7-10 years in the state of Georgia. If a performance problem is detected under these new requirements, it could take that long to come into compliance and at a very significant cost if a new major 500kV line is required. These facilities can run as much as $4.0 million a mile or more in urban areas. We understand that a few areas of the country presently have this requirement but most do not. In the areas where the requirement has not been in place, the reliability of the system has been acceptable to the local Public Service Commissions that have governed the service to Retail customers. There has been no evidence presented that there is a need for an increase in reliability, particulary at the extensive time delay and expense possible from this particular requirement. An adoption of this standard without such evidence can only be considered arbitrary and capricious at best. Increased reliability is, in general, a worthy goal where it is cost effective. It may be appropriate to adopt this type of reliability requirement for areas that deem the resulting reliability increase to be cost effective for their customers. But it is inappropriate to "require" everyone else to be forced to live under this arbitrarily developed expansion of reliability requirements.]
NCEMC	☑		We do agree that given the widespread effects of these facilities above 300 kV that these should be subjected to more rigorous assessments.
Progress–Carolinas	☑		It is absolutely necessary, however, to allow interruption of firm transfers as a System adjustment. To do otherwise would cause extremely large expenditures for very low probability independent events.
WECC BPA TSGT TEP		☑	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance?

Q22			
Commenter	**Agree**	**Disagree**	**Comment**
			Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Response: Based on industry feedback the SDT has made changes in proposed requirements for two overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. We have adjusted our approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
Central Maine Power United Illuminating		☑	Should also consider the initial loss of a transformer, followed by the loss of a Transmission circuit. This should state a transformer with a "high-side" rating above 300 kV.
Response: The SDT agrees that it previously missed the situation described and have accounted for this sequence of events in our new Planning Event P6. Also, notes have been added to the bottom of the performance table to clarify the EHV transformer versus other BES transformers.			
Duke Energy		☑	Allow indirect (Non-Consequential) loss of load for events involving short duration outages, such as typical line outages that do not result in cascading outages.
Response: The specific outage considered involves a circuit and a transformer. An unplanned EHV transformer outage will likely be a long duration outage that needs to be reviewed with other N-1 events and should require a higher level of expected reliability. However, based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. We have adjusted our approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
Entergy		☑	N-1-1 requires an increase in investment that will place an undue cost burden on all customers for low probability events. See comments to Q43.
Response: Your concern related to increased cost is shared with others. Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. We have adjusted our approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information. See response to Q43.			
FirstEnergy		☑	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused soley by the first contingency.
Response: The SDT appreciates your support that Non-Consequential Load dropping would not be permissible following the first Contingency event. However, from a planning viewpoint, the SDT also believes that it should not be permissible to drop Load as part of adjusting the System to prepare for the second on the EHV System. The FERC directed this approach in Order 693, see discussion in paragraphs 1782 and			

Q22			
Commenter	**Agree**	**Disagree**	**Comment**
1796. Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. We have adjusted our approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
FPL FRCC		☑	Systems have been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis. In addition, by not allowing loss of non-consequential load, the system may remain in a less secure state or condition.
Progress–Florida		☑	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration. Furthermore, the greater-than-300 kV Bulk Electric System has been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis, placing particular importance on confining the event to a single area (i.e., not resulting in a cascading outage). Past assessments as well as actual events have demonstrated that by not allowing loss of non-consequential load, the Bulk Electric System may actually remain in a less secure state or condition, i.e. in more danger of experiencing cascading outages.
Response: The events considered are not simultaneous N-2, but intended to be N-1-1 with system adjustments allowed in between the outages. Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. We have adjusted our approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
NERC TIS	☑		See Q 21 Comment
New York ISO	☑		Same comment as with Q21.
SRP		☑	Same as Q21.
Seattle City		☑	Same as Q21, loss of elements of this size may initiate UVLS.
Response: See response to Q21.			
Exelon	☑	☑	We do not agree with disallowing non-consequential load loss for these scenarios for the peak load conditions. These are very low probability contingencies, and some non-consequential load

Q22			
Commenter	**Agree**	**Disagree**	**Comment**
			loss should be allowed at peak load. We would agree that it would be reasonable to dis-allow non-consequential load loss for these contingencies at a lower load level, such as 75% of peak load.
Response: Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. We have adjusted our approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information. The lower (non-peak) Load study that you reference is a good suggestion that could be adopted as an internal company criteria for assessing maintenance flexibility.			
IESO	☑	☑	Similar reason as above. In this case, the first transmission may also remove a transformer from service if they are in the same protection zone. The next contingency can be the loss of the companion transformer, without a fault on the transformer itself but not on the transmission circuit. If the transmission circuit and the transformer are unrelated, then we would agree that non-consequential loss of load should not be allowed.
Response: The intent of this event is to cover two unrelated single Contingency Transmission outages that are non-generator outages. They are to be viewed as an N-1, with system adjustments, followed by the second N-1. The standard will require that Contingency events be modeled to reflect actual removal of all elements within the protection zone. Therefore a single (N-1) Contingency could result in multiple Facilities being removed from service. The N-1-1 event should accurately reflect all Facilities that would be removed from service. Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. We have adjusted our approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
ITC	☑		Should also consider no or limited loss of non-consequential load for facilities 100 kV and above. No loss should be allowed for load levels at which the TO would plan to perform maintenance. Also system adjustment should consider time required for adjustment verses the ratings utilized.
Response: Based on industry feedback, the SDT has made adjustments to the expected Transmission System performance to N-1-1 events. The entire BES is treated the same now for these outage scenarios and the loss of Non-Consequential Load is now permitted. Please refer to performance tables, Planning Event P6. See the above Summary Response for additional information.			
AEP	☑		Consider adding clear definition of "system adjustments", including the amount of time permited to implement prior to the loss of the second facility.
Response: Non-Consequential Load Loss is not permitted for the first N-1 event as part of the permissible system adjustments that can be made to return the system to a "new" normal operating state. The time permitted is based on the time dependent emergency Facility Ratings of the affected Transmission equipment. Following the loss of the second Transmission outage, Load shed is considered an allowable system			

Q22			
Commenter	**Agree**	**Disagree**	**Comment**
adjustment action for the entire BES. This is a change in Draft 2 of the TPL-001-1. Please see performance tables, Planning Event P6 for additional information.			
MISO	☑		Do not allow indirect (Non-Consequential) loss of load for events involving long duration outages, such as transformer outages. (Transformer outage could occur first).
Response: While some SDT members agree with your approach, others on the SDT do not as well many of the industry comments to our Draft 1 standard. The standard does require sensitivity studies and unavailability of long lead time Facilities to be included in the sensitivity study area. Additionally, a TO will be required to notify their PC for long-term Transmission outages with consideration to spare equipment strategy. This would result in a new initial study system (N-0) and performance requirements for other Contingencies would be required subsequent to the long-term outage item.			
National Grid New England ISO NU NPCC RCS NSTAR	☑		Should also consider the initial loss of a transformer, followed by the loss of a Transmission circuit. This should state a transformer with a "high-side" rating above 300 kV.
Response: The SDT agrees that it previously missed the situation described and have accounted for this sequence of events in new Planning Event P6. Also, notes have been added to the bottom of the performance table to clarify the EHV transformer versus other BES transformers.			
Progress–Carolinas	☑		It is absolutely necessary, however, to allow interruption of firm transfers as a System adjustment. To do otherwise would cause extremely large expenditures for very low probability independent events.
Response: The SDT has adjusted the tables in the second revision.			
Ameren			No opinion as we do not have any transformers with the low side voltages rated above 300 kV. Transmission owners with transformers meeting this requirement should be consulted to determine if a material change would be required.
ERCOT ISO			We will comment on this at a later date.
Georgia Transm.			Not applicable to our existing system.
AECC	☑		neither should consequential load be lost for any n-1 faults on the 300 kv system and higher.
AECI	☑		
Allegheny Power	☑		
APPA	☑		
ATC	☑		
Brazos Electric	☑		
City Water Power and Light	☑		
City Utilities/Springfield	☑		

Q22			
Commenter	**Agree**	**Disagree**	**Comment**
Entegra	☑		
HQTE	☑		
ISO/RTO	☑		
KCPL	☑		
LCRA	☑		
Manitoba Hydro	☑		
PJM	☑		
Response: Thank you but due to the majority of industry response to this question, the requirement has been changed			

23) Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer

Summary Response: Draft 2 Changes for 300 kV and higher systems regarding N-1-1 conditions:

Based on industry feedback the SDT has made changes in proposed Draft 2 requirements related to two independent overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. Draft 2 now permits the loss of Non-Consequential Load to meet the Transmission performance requirements for these types of events. Please refer to performance tables Planning Event P6.

It is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission for the less probable, but greater risk single Contingency events. Please refer to performance tables Planning Event P2 and note that bus section faults and internal breaker faults (non-bus tie) associated with above 300 kV Facilities are held to a higher performance standard than those operated at 300 kV or below.

Why the distinction for above 300 kV Transmission?

The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission Systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT felt the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability.

When EHV systems are compromised, the large volumes of power served by them can place a severe amount of stress on parallel EHV or lower voltage paths. For example, if a large EHV transformer experiences a catastrophic failure, not only are other systems Facilities required to carry more Load but the System is also exposed to other N-1 conditions for long periods of time while awaiting a replacement or repair of the failed equipment. Large generation sources are typically connected at EHV levels and maintenance of the EHV Transmission lines within the vicinity of larges generation plants must often be coordinated during scheduled unit outages, resulting again in multiple Facility outages over extended periods of time.

Therefore, it was the conclusion of the SDT in Draft 1 to propose greater reliability and operational flexibility through more stringent performance requirements when considering certain N-1 and N-1-1 Contingency events of EHV systems. Throughout the industry substation arrangements at EHV levels reflect the importance of these systems as the designs often consist of the more expensive ring-bus, breaker-and–a-half or double bus-double breaker protection schemes as opposed to the more simplistic and lesser cost single bus arrangements that are commonly found on lower voltage systems.

The feedback received from industry was divided related to the SDT's emphasis placed on a higher expectation for the 300 kV and higher systems. Some commenters questioned the importance and the high costs that may be needed to mitigate existing system designs.

Others agreed with the SDT's approach and indicated that the impact to their systems would be minimal. Some commenters even questioned why the more stringent approach was not applied to the entire 100kV and higher systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission system.

Q23			
Commenter	**Agree**	**Disagree**	**Comment**
Muscatine P&W			See Q43 Comment #5.
Response: See Q43 response.			
NERC TIS			See Q 21 Comment
SRP		☑	Same as Q21.
Seattle City		☑	Same as Q21.
New York ISO	☑		Same comment as with Q21.
Response: See Q21 response.			
Dominion		☑	See comment for Question 20 above.
MEAG Power		☑	See Q20 above.
Tenaska		☑	See comment in Q20.
TVA		☑	See Q20.
WPS		☑	See response to Q20.
Response: See Q20 response.			
E ON US		☑	Outage of two 345 kV transformers can create local area issues that result in loss of load but do not affect the integrity of the BES.
Response: The condition you describe appears to be more stringent then the outage the SDT was asking industry to consider; N-1-1 involving a line and transformers where each are operated at a voltage level above 300 kV. However, based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. The SDT has adjusted its approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
Northwestern Energy		☑	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
Response: Please see the proposed Glossary Definition for Non-Consequential Load. The proposed definition for Consequential Load clarifies that losing a motor due to motor contactor action is considered to be the loss of Consequential Load.			
BCTC		☑	Same comments as for Q21/22. Furthermore, a double transformer loss forced outage has a very low probability as transformers are very reliable. A more practical approach would be to

Q23			
Commenter	**Agree**	**Disagree**	**Comment**
			use single phase transfomers and provide a spare phase.
CAISO		☑	This event also falls under Category C for which the current NERC criteria allows controlled loss of load. Clear net benefits should be demonstrated to justify adapting to a new stringent criteria.
MRO		☑	This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this change to customers. Alternatively, the SDT should define a level (such as 1000 MW) of non-consequential load that is acceptable for such low probability events.
Santee Cooper SERC EC DRS SERC EC PSS SERC RRS OPS SCE&G		☑	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
SaskPower		☑	The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Southern Transm.		☑	See comments for Q21. [This is a very significant change in the performance requirements in this reliability standard. It involves facilities from 345 kV through 764kV which carry significant amounts of power. These also are facilities that require significant lead time to construct in the Southern Balancing Authority with estimates up to 7-10 years in the state of Georgia. If a performance problem is detected under these new requirements, it could take that long to come into compliance and at a very significant cost if a new major 500kV line is required. These facilities can run as much as $4.0 million a mile or more in urban areas. We understand that a few areas of the country presently have this requirement but most do not. In the areas where the requirement has not been in place, the reliability of the system has been acceptable to the local Public Service Commissions that have governed the service to Retail customers. There has been no evidence presented that there is a need for an increase in reliability, particulary at the extensive time delay and expense possible from this particular requirement. An adoption of this standard without such evidence can only be considered arbitrary and capricious at best. Increased reliability is, in general, a worthy goal where it is cost effective. It may be appropriate to adopt this type of reliability requirement for areas that deem the resulting reliability increase to be cost effective for their customers. But it is inappropriate to "require" everyone else to be forced to live under this arbitrarily developed expansion of reliability requirements.]
WECC BPA TSGT TEP		☑	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for

Q23			
Commenter	**Agree**	**Disagree**	**Comment**
			compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
ITC	☑		Should also consider no or limited loss of non-consequential load for facilities 100 kV and above. No loss should be allowed for load levels at which the TO would plan to perform maintenance. Also system adjustment should consider time required for adjust.ment verses the facility ratings utilized.
NCEMC	☑		We do agree that given the widespread effects of these facilities above 300 kV that these should be subjected to more rigorous assessments.
Progress–Carolinas	☑		It is absolutely necessary, however, to allow interruption of firm transfers as a System adjustment. To do otherwise would cause extremely large expenditures for very low probability independent events.
Response: Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. The SDT has adjusted its approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
Duke Energy		☑	Allow indirect (Non-Consequential) loss of load for events involving short duration outages that do not result in cascading outages.
Response: The specific outage considered involves a circuit and a transformer. An unplanned EHV transformer outage will likely be a long duration outage that needs to be reviewed with other N-1 events and should require a higher level of expected reliability. However, based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. The SDT has adjusted its approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
Entergy		☑	N-1-1 requires an increase in investment that will place an undue cost burden on all customers for low probability events. See comments to Q43.
Response: Your concern related to increased cost is shared with others. Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. The SDT has adjusted its approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information. See response to Q43.			
FirstEnergy		☑	Shedding load could be part of the system adjustment in preparation for the next possible

Q23			
Commenter	**Agree**	**Disagree**	**Comment**
			contingency but load drop would not be acceptable for problems caused soley by the first contingency.
Response: We appreciate your support that Non-Consequential Load dropping would not be permissible following the first Contingency event. However, from a planning viewpoint, the SDT also believes that it should not be permissible to drop Load as part of adjusting the system to prepare for the second on the EHV system. The FERC directed this approach in Order 693, see discussion in paragraphs 1782 and 1796. Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. The SDT has adjusted its approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
FPL FRCC		☑	Systems have been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis. In addition, by not allowing loss of non-consequential load, the system may remain in a less secure state or condition.
Progress–Florida		☑	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration. Furthermore, the greater-than-300 kV Bulk Electric System has been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis, placing particular importance on confining the event to a single area (i.e., not resulting in a cascading outage). Past assessments as well as actual events have demonstrated that by not allowing loss of non-consequential load, the Bulk Electric System may actually remain in a less secure state or condition, i.e. in more danger of experiencing cascading outages.
Response: The events considered are not simultaneous N-2, but intended to be N-1-1 with system adjustments allowed in between the outages. Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. The SDT has adjusted its approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
Central Maine Power National Grid New England ISO NU NSTAR		☑	This should state a transformer with a "high-side" rating above 300 kV.

Q23			
Commenter	**Agree**	**Disagree**	**Comment**
United Illuminating			
Response: The SDT agrees that it previously missed the situation described and have accounted for this sequence of events in new Planning Event P6. Also, notes have been added to the bottom of the Performance table to clarify the EHV transformer versus other BES transformers.			
Exelon	☑	☑	We do not agree with disallowing non-consequential load loss for these scenarios for the peak load conditions. These are very low probability contingencies, and some non-consequential load loss should be allowed at peak load. We would agree that it would be reasonable to dis-allow non-consequential load loss for these contingencies at a lower load level, such as 75% of peak load.
Response: Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. The SDT has adjusted its approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information. The lower (non-peak) Load study that you reference is a good suggestion that could be adopted as an internal company criterion for assessing maintenance flexibility.			
IESO	☑	☑	Similar reason as above.
Response: The intent of this event is to cover two unrelated single Contingency Transmission outages that are non-generator outages. They are to be viewed as an N-1, with system adjustments, followed by the second N-1. The standard will require that Contingency events be modeled to reflect actual removal of all elements within the protection zone. Therefore a single (N-1) Contingency could result in multiple Facilities being removed from service. The N-1-1 event should accurately reflect all Facilities that would be removed from service. Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. The SDT has adjusted its approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
AEP	☑		Consider adding clear definition of "system adjustments", including the amount of time permited to implement prior to the loss of the second facility.
Response: The time permitted is based on the time dependent emergency Facility Ratings of the affected Transmission equipment. Planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings.			
MISO	☑		Do not allow indirect (Non-Consequential) loss of load for events involving long duration outages, such as transformer outages.
Response: While some SDT members agree with your approach, others on the SDT do not as well many of the industry comments to our Draft 1 standard. The standard does require sensitivity studies and unavailability of long lead time Facilities to be included in the sensitivity study area. Additionally, a TO will be required to notify their PC for long-term Transmission outages with consideration to spare equipment strategy. This would result in a new initial study system (N-0) and performance requirements for other Contingencies would be required subsequent to the long-term outage item.			

Q23			
Commenter	**Agree**	**Disagree**	**Comment**
Ameren			No opinion as we do not have any transformers with the low side voltages rated above 300 kV. Transmission owners with transformers meeting this requirement should be consulted to determine if a material change would be required.
ERCOT ISO			We will comment on this at a later date.
AECC	☑		neither should consequential load be lost for any n-1 faults on the 300 kv system and higher.
AECI	☑		
Allegheny Power	☑		
APPA	☑		
ATC	☑		
Brazos Electric	☑		
City Water Power and Light	☑		
City Utilities/Springfield	☑		
Entegra	☑		
Georgia Transm.	☑		Not applicable to our existing system.
HQTE	☑		
ISO/RTO	☑		
KCPL	☑		
LCRA	☑		
Manitoba Hydro	☑		
NPCC RCS	☑		
PJM	☑		
Response: Thank you but due to the majority of industry response to this question, the requirement has been changed			

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

24) Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Summary Response: A majority of the commenters indicated that a definition for "bus-tie breaker" as well as clarification of the Tables is needed. Based on the comments from the industry, the drafting team has proposed a definition for bus–tie breakers, incorporated changes to the definition of Consequential Load and added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose Non-Consequential Load. However, the SDT felt that this was one situation where the bar should be raised and no change was made to this event.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)

Consequential Load Loss: Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.

Q24			
Commenter	**Agree**	**Disagree**	**Comment**
Manitoba Hydro			Until the SDT should defines a non-bus tie breaker this is impossible to answer.
ERCOT ISO CAISO		☑	Same response as for Q21, and What is the definition of non-bus tie breaker? Doesn't it just refer to line, transformer, and generation breakers?
Response: The SDT has accordingly proposed a definition for bus-tie breaker.			
Muscatine P&W			See Q43 Comment #5.
Response: Please see response to Q43.			
Dominion		☑	See comment for Question 20 above.
MEAG Power		☑	See Q20 above.
TVA		☑	See Q20.
WPS		☑	See response to Q20.
Response: Please see response to Q20.			
E ON US		☑	EHV station configurations are either ring-bus or breaker and one-half. Breaker failure protection isolates two EHV Facilites which may cause local area issues without affecting the BES.

Q24			
Commenter	**Agree**	**Disagree**	**Comment**
Northwestern Energy		☑	Non-consequential load loss should be permitted for this contingency.
Duke Energy		☑	Depends upon the definition of non-bus tie breaker. By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence.
Entergy		☑	N-1-1 requires an increase in investment that will place an undue cost burden on all customers for low probability events. See comments to Q43.
FPL FRCC		☑	This loss is currently distinguished from other single contingencies because of its lower probability of occurrence and a more stringent performance requirement than currently exists is not warranted.
Progress–Florida		☑	This single contingency event has a very low probability of occurrence, and thus a more stringent performance requirement than currently exists is not warranted.
SaskPower		☑	The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Response: Based on industry feedback the SDT has made changes in Draft 2 on requirements related to two independent overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. However, it is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission for the less probable, but greater risk single Contingency events. Please refer to performance tables Planning Event P2 and note that bus section faults and internal breaker faults (non-bus tie) associated with above 300 kV Facilities are held to a higher performance standard than those operated at 300 kV or below. Although not unanimous, the majority of the SDT felt the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering contingencies of two EHV Facilities due to one Event. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. Please see also summary response to Q22.			
BCTC		☑	Do not agree due to definitions of Consequential and Non-Consequential Load Loss. Can agree subject to the proposed revised definitions to address loss of load during the transient stability period. System is already planned to meet this requirement based on the first sentence of footnote (b).
Response: The drafting team has considered industry comments and has incorporated changes in the definition of Consequential Load Loss. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet			

Q24			
Commenter	**Agree**	**Disagree**	**Comment**
steady state performance requirements.			
CenterPoint		☑	The loss of a non-bus tie breaker due to an internal fault has a low probability of occurrence and should be considered an improbable event with non-consequential load loss permitted. However, the loss of any breaker, whether by internal fault, external flashover, or stuck breaker, should not result in a cascading failure.
CPS Energy		☑	Should be determined at the discretion of the Transmission Planners.
PJM	☑		Agree with performance requirement. The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?
Response: The SDT has added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose Non-Consequential Load.			
Exelon		☑	P6 allows for non-consequential load loss for a bus tie breaker, which has the same probability of failure as a non-bus tie breaker.
Response: In Draft 1, P6 is for loss of Bus-tie Breaker below 300 kV. This initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT felt the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering contingencies of two EHV Facilities due to one Event. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. Please see also summary response to Q22.			
Georgia Transm.		☑	The standard needs to clearly define a non-bus tie breaker. It is also not clear whether the focus of the standard is the kV level or the equipment type. A material change to build new facilities would be needed to meet this new requirement.
Response: The drafting team has considered industry comments and has incorporated changes in the definition of Consequential Load Loss. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.			

Q24			
Commenter	**Agree**	**Disagree**	**Comment**
This initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT felt the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering contingencies of two EHV Facilities due to one Event. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. Please see also summary response to Q22.			
LADWP		☑	Don't understand why there is such an obsession with bus tie breakers? Is this a common practice in the East? I am not aware of any issue in WECC, let alone at above 300 kV systems.
Response: For straight buses, loss of a Bus-tie Breaker could remove from service multiple bus sections simultaneously resulting in loss of all elements connecting to the impacted bus sections. However, Bus-tie Breakers also have lower probability of outage. The reason for providing performance requirements for Bus-tie Breakers that are different from the performance requirements for non-Bus-tie Breakers is to encourage the installation of Bus-tie Breakers in straight busses.			
MRO		☑	This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this change to customers. Alternatively, the SDT should define a level of non-consequential load that is acceptable for such low probability events such as 1000 MW.
Response: The SDT will consider interim Operating Procedures to allow for Transmission Owners to respond and guidelines that may allow quantifiable and limited exposure to loss of Non-Consequential Load. This may include, for example, providing for defined exclusions during construction of new Facilties. This initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT felt the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering contingencies of two EHV Facilities due to one Event. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. Please see also summary response to Q22.			
Seattle City		☑	Adequacy of HV supply is outside of our control but may have a detrimental effect on our system. We should not be required to supplement the existing high-voltage infrastructure when it is the

Q24			
Commenter	**Agree**	**Disagree**	**Comment**
			responsibility of the transmission owner. If the intent of this requirement is to prevent downstream load loss caused by a fault in the 300kV beloning to the transmission owner, then we agree. We must be able to shed load when our supply is cut.
Response: The treatment of Transmission infrastructure costs is outside the scope of the NERC reliability standards. The SDT will consider interim Operating Procedures to allow for Transmission Owners to respond and guidelines that may allow quantifiable and limited exposure to loss of Non-Consequential Load. This may include, for example, providing for defined exclusions during construction of new facilties.			
Santee Cooper SERC EC DRS SERC EC PSS SERC RRS OPS SCE&G Southern Transm.		☑	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost. It would be helpful if "bus tie breaker" was defined (e.g. is the middle breaker in a breaker and a half scheme considered a bus tie breaker?).
Response: The SDT will consider interim Operating Procedures to allow for Transmission Owners to respond and guidelines that may allow quantifiable and limited exposure to loss of Non-Consequential Load. This may include, for example, providing for defined exclusions during construction of new facilties. The drafting team has considered industry comments and has incorporated changes in the definition of Consequential Load Loss. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.			
Tenaska		☑	Why should we distinquish between a bustie breaker and a non-bus tie breaker? Also, 300 kV may be too low. This is really an issue that should be driven by the customers.
ABB	☑	☑	When talking about breaker outages, I see no reason to differentiate between "non-bus tie" and "bus tie" breakers. Are bus tie breakers inherently more reliable? If the effect on the system due to a tie breaker outage is very bad, then this should be fixed. All other contingencies seem to be slotted based on probability. Shouldn't breakers? Maybe bus tie breakers are weak points in the transmission system that need to be improved.
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR	☑		It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

Q24			
Commenter	**Agree**	**Disagree**	**Comment**
United Illuminating			
ITC	☑		Loss of non-consequential load should not be permitted, however this should also apply to other breakers across the system including bus tie breakers.
Response: Depending on the bus configuration loss of a Bus-tie Breaker could remove from service multiple bus sections simultaneously resulting in loss of all elements connecting to the impacted bus sections. However, Bus-tie Breakers also have lower probability of outage. The reason for providing performance requirements for Bus-tie Breakers that are different from the performance requirements for non-Bus-tie Breakers is to encourage the installation of Bus-tie Breakers in straight busses.			
WECC BPA TSGT TEP		☑	We disagree that non-consequential loss of load should not be permitted for this contingency event. We believe that planned and controlled interruption of non-consequential load should be permitted for loss of a non-bus tie breaker (above 300 kV). Losing a non-bus tie breaker could result in simultaneous loss of two or more elements, depending on the bus configuration. Allowing planned and controlled disconnection of some load in the areas would not only prevent cascading and instability (which could result in uncontrolled loss of a larger amount of load), but also enables faster load restoration. Losing a breaker due to an internal fault is a low probability event. To meet this requirement as proposed would require severe pre-contingency curtailment of power transfers, that could impact commerce and/or construction of large number of transmission facilities with the attendant environmental impacts and increased cost to customers
Response: The SDT will consider interim Operating Procedures to allow for Transmission Owners to respond and guidelines that may allow quantifiable and limited exposure to loss of Non-Consequential Load. This may include, for example, providing for defined exclusions during construction of new facilties.			
Ameren	☑	☑	This part of the proposed standard language is confusing. From our perspective, the failure of any 300 kV or above non-bus-tie circuit breaker should not result in the non-consequential loss of load. Further, EHV circuit breakers failing as a result of internal faults are extremely rare, bus-ties or not. Also, it is not clear what would be considered a non-bus tie breaker for ring bus and breaker-and-a-half bus configurations. It would seem that performance requirements for EHV bus-tie breakers (and not non-bus-tie breakers) should be distinguished from other breakers.
Response: Depending on the bus configuration loss of a Bus-tie Breaker could remove from service multiple bus sections simultaneously resulting in loss of all elements connecting to the impacted bus sections. However, Bus-tie Breakers also have lower probability of outage. The reason for providing performance requirements for Bus-tie Breakers that are different from the performance requirements for non-Bus-tie Breakers is to encourage the installation of Bus-tie Breakers in straight busses. In response to industry comments, the SDT has accordingly proposed a definition for Bus-tie Breaker. **Bus-tie Breaker:** A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)			
AEP	☑		Consider adding clear definition of "bus tie breaker" and "non-bus tie breaker".
Response: In response to industry comments, the SDT has accordingly proposed a definition for Bus-tie Breaker.			

Q24			
Commenter	**Agree**	**Disagree**	**Comment**
Bus-tie Breaker: A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)			
FirstEnergy	☑		The tables' use of internal faults and stuck breaker faults is confusing since they have the same result.
Response: The probability of loss of a breaker due to the breaker internal fault would be higher than loss of a Transmission element coupled with a stuck breaker associated with the faulted element. Tables 1 and 2 have been modified to provide greater clarity.			
NERC TIS	☑		By its very nature, the event described is a breaker failure and the fault will typically need to be cleared by the next set of breakers, often remotely. Tripping out to the backup protection breakers typically can cause significant Consequential load loss. That should not be misconstrued as non-consequential load loss. Non-consequential load loss beyond that is unacceptable.
Response: Whether tripping of additional Facilities by backup protection will lead to more Consequential Load Loss will depend on whether any Load is connected directly to such Facilities. In the second draft the SDT has modified the definition of Consequential Load Loss. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.			
AECC	☑		neither should consequential load be lost for any n-1 faults on the 300 kv system and higher.
AECI	☑		
Allegheny Power	☑		
APPA	☑		
ATC	☑		
Brazos Electric	☑		
City Water Power and Light	☑		
City Utilities/Springfield	☑		
IESO	☑		Agree. In general, non-consequential loss of load should not be permitted for any single contingencies.
Entegra	☑		
ISO/RTO	☑		
KCPL	☑		No Non-Consequential loss of load for N-1 event.

Q24			
Commenter	**Agree**	**Disagree**	**Comment**
LCRA	☑		
MISO	☑		No indirect (Non-Consequential) loss of load for outage of single EHV element.
New York ISO	☑		
NCEMC	☑		See response for Q20.
Progress–Carolinas	☑		
Response: Thank you.			

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

25) Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Summary Response: A majority of the commenters indicated that a definition for "Bus-tie Breaker" as well as clarification of the Tables is needed. Based on the comments from the industry, the drafting team has proposed a definition for Bus–tie Breakers, incorporated changes to the definition of Consequential Load and added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose Non-Consequential Load. The SDT has re-categorized the table to try to clarify what was meant but no changes have been made to this requirement as a result of industry comments.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)

Consequential Load Loss: Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.

Q25			
Commenter	**Agree**	**Disagree**	**Comment**
Muscatine P&W			See Q43 Comment #5.
Response: Please see response to Question 43 #5.			
Ameren		☑	The loss of two or more elements at any EHV substation at time of peak would likely result in loss of non-consequential load. If the intent of the proposed standard is to encourage the development of ring bus or breaker-and-a-half bus arrangements at the EHV level, we would concur where it is physically possible and makes for good engineering practice. However, we must remind the SDT that there are some existing facilities that cannot be converted practically or economically from their present straight bus configuration because of physical limitations. A significant material change, potentially several million dollars per substation, would be required to retrofit facilities, where possible. It would appear that performance requirements for EHV bus-tie breakers (and not non-bus-tie breakers) should be distinguished from other breakers.
Duke Energy		☑	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence.
Entergy		☑	N-1-1 requires an increase in investment that will place an undue cost burden on all customers

Q25			
Commenter	**Agree**	**Disagree**	**Comment**
			for low probability events. See comments to Q43..
SaskPower		☑	The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Santee Cooper SERC EC DRS SERC EC PSS SERC RRS OPS SCE&G Southern Transm.		☑	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Northwestern Energy		☑	Non-consequential load loss should be permitted for this contingency.
Response: Based on industry feedback the SDT has made changes in Draft 2 on requirements related to two independent overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. However, it is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission. Although not unanimous, the majority of the SDT felt the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering Contingencies of two EHV facilities due to one Event. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. Please see also summary response to Q22.			
Dominion		☑	See comment for Question 20 above.
MEAG Power		☑	See Q20 above.
TVA		☑	See Q20.
WPS			See response to Q20.
NCEMC	☑		See response for Q20.
Response: Please see response to Q20.			
E ON US		☑	This event needs to be reworded. Does the stuck non-bus tie breaker condition only apply to the bus fault or to all faults? Does (above 300 kV) only apply to the stuck non-bus tie breaker or is this limited to faults on facilities above 300 kV?
Response: The stuck non-Bus tie Breaker condition applies to all faults listed in P3 in Tables 1 and 2. The ATFNSDT has added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose non-consequential firm load.			
ERCOT ISO CAISO		☑	Do not agree for loss of a bus, or loss of a stuck non-bus tie breaker for the reasons as in the response to Q21.
Response: Please see response to Q21.			
BCTC		☑	Do not agree due to definitions of Consequential and Non-Consequential Load Loss. Can agree subject to the proposed revised definitions to address loss of load during the transient stability

Q25			
Commenter	**Agree**	**Disagree**	**Comment**
			period. System is already planned to meet this requirement based on the first sentence of footnote (b).
MISO	☑		With the clarification that direct (Consequential) loss of load is associated with all outage elements: both SLG element and stuck breaker element.
Response: The drafting team has considered industry comments and has incorporated changes in the definition of Consequential Load Loss. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.			
CenterPoint		☑	The loss of either a generator, a Transmission cirucit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV) has a low probability of occurrence and should be considered an extreme event with non-consequential load loss permitted.
CPS Energy		☑	Should be determined at the discretion of the Transmission Planners.
FirstEnergy		☑	The wording of P3-1 is unclear. We suggest rewording to say "Fault on a generator, line, transformer, or bus and a stuck breaker when the fault is being cleared". We agree with the concept of not dropping load for an EHV stuck breaker with the exception of the bus fault item. We do not believe that it is very realistic to postulate a bus fault along with a stuck breaker and believe that it is a very low probability event.
Response: The SDT has added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose Non-Consequential Load.			
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating		☑	It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.
Response: For straight buses, loss of a Bus-tie Breaker could remove from service multiple bus sections simultaneously resulting in loss of all elements connecting to the impacted bus sections. However, Bus-tie Breakers also have lower probability of outage. The reason for providing performance requirements for Bus-tie Breakers that are different from the performance requirements for non-Bus-tie Breakers so as to encourage the installation of Bus-tie Breakers in straight busses.			
FPL		☑	Systems have been designed such that Multiple Contingency events (N-2) above 300 kV may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis. In

Q25			
Commenter	**Agree**	**Disagree**	**Comment**
			addition, by not allowing loss of non-consequential load, the system may remain in a less secure state or condition. This new category P3-1 is essentially a replacement for Category C5-9 except the only protection element failure to be considered is the failure of a circuit breaker to open. This definition eliminates the need to examine failure of the relay to operate which in many cases has a more serious impact on grid reliability.
FRCC		☑	This new category P3-1 is essentially a replacement for Category C5-9 except the only protection element failure to be considered is the failure of a circuit breaker to open. This definition eliminates the need to examine failure of the relay to operate which in many cases has a more serious impact on grid reliability.
Response: The SDT has added greater detail to Tables 1 & 2, which provides separately for events that involve stuck breakers and protection system failure.			
Georgia Transm.		☑	A material change to build new facilities would be needed to meet this new requirement.
MRO		☑	This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this change to customers. Alternatively, the SDT should define a level of non-consequential load that is acceptable for such low probability events such as 1000 MW.
WECC BPA TSGT TEP		☑	We disagree that non-consequential loss of load should not be permitted for this contingency event. We believe that planned and controlled interruption of non-consequential load should be permitted for loss of either a generator, a transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV). This contingency event could result in simultaneous loss of two or more elements, depending on the bus configuration. Allowing planned and controlled disconnection of some load in the areas would not only prevent cascading and instability (which could result in uncontrolled loss of a larger amount of load), but also enables faster load restoration. These contingencies are low-probability events. To meet this requirement as proposed would require severe pre-contingency curtailment of power transfers, that could impact commerce and/or construction of a large number of transmission facilities with the attendant environmental impacts and increased cost to customers.
Response: The SDT has re-categorized the table to try to clarify what was meant but no changes have been made to this requirement as a result of industry comments.			
LADWP		☑	Ditto (24)
Seattle City		☑	As in Q24. Certain combinations in the HV supply system will force us to shed load.
NERC TIS	☑		See comment to Q24.
Response: Please see response to Q24.			
Manitoba Hydro		☑	The SDT seems fixated on loss of load. The existing std for this type of event allowed for loss of load and firm transfer could be adjusted. While MH could rationalize that load should not be

Q25			
Commenter	**Agree**	**Disagree**	**Comment**
			interrupted, we could not agree that firm transfer can not be reduced. This would amount to n-2 planning to maintain a firm transfer that is backed up by reserves. The requirement to maintain firm transfer will cost MH and the industry millions of dollars with no reliability benefit - a show stopper.
Tenaska		☑	This is really an issue that should be driven by the customers.
Exelon	☑	☑	We do not agree with disallowing non-consequential load loss for these scenarios for the peak load conditions. These are very low probability contingencies, and some non-consequential load loss should be allowed at peak load. We would agree that it would be reasonable to dis-allow non-consequential load loss for these contingencies at a lower load level, such as 75% of peak load.
Response: The SDT must address FERC Order 693. FERC has jurisdiction over firm Transmission service. FERC allows the use of "equally or more efficient or effective approach" and Non-Consequential Load is being used as a proxy for firm Transmission service.			
Progress–Carolinas		☑	This is a very low probability multiple contingency and would cost an extreme sum of money to remedy. Need to clarify whether or not the stuck breaker was connected with loss of element.
Response: The SDT has re-categorized the table to try to clarify what was meant but no changes have been made to this requirement as a result of industry comments. The SDT has added greater detail to Tables 1 & 2 to provide more clarity.			
Progress–Florida		☑	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration. Furthermore, the greater-than-300 kV Bulk Electric System has been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis, placing particular importance on confining the event to a single area (i.e., not resulting in a cascading outage). Past assessments as well as actual events have demonstrated that by not allowing loss of non-consequential load, the Bulk Electric System may actually remain in a less secure state or condition, i.e. in more danger of experiencing cascading outages. In addition, it should be noted that the technical specifications of this category contain a major oversight. This new Category P3-1 is essentially a replacement for the existing Categories C5-9, except that the only protection element failure being considered is the failure of a circuit breaker to open. This definition eliminates the need to examine failure of the relay to operate, which in many cases has a more serious impact on grid reliability.
Response: The SDT must address FERC Order 693. FERC has jurisdiction over firm Transmission service. FERC allows the use of "equally or more efficient or effective approach" and Non-Consequential Load is being used as a proxy for firm Transmission service. The SDT has added greater detail to Tables 1 & 2, which provides for events that involve stuck breakers and protection system failure.			
ABB	☑	☑	Table 1 P3 is a little hard to read/understand. The second column should start out something like "A stuck breaker following the outage of any 1 of the following:" However, P3 will be completely redundant with P2 because, in power flow analysis, there is no difference between a breaker internal fault and a stuck breaker following an external fault. The final outaged equipment is the

Q25			
Commenter	**Agree**	**Disagree**	**Comment**
			same. This will cause extra unnecessary work.
Response: The SDT has added greater detail to Tables 1 & 2.			
AEP	☑		Consider adding clear definition of "bus tie breaker" and "non-bus tie breaker".
Response: The SDT has accordingly proposed a definition for Bus-tie Breaker. **Bus-tie Breaker:** A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)			
ITC	☑		Should also consider no loss of non-consequential load for facilities 100 kV and above and this should also apply to other breakers across the system including bus tie breakers.
Response: The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission Systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT felt the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering single events that can result in Contingencies of two EHV Facilities. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. Loss of Facilities below 300 kV is not expected to have the same impact. Please see also summary response to Q22.			
AECC	☑		neither should consequential load be lost for any n-1 faults on the 300 kv system and higher.
AECI	☑		
Allegheny Power	☑		
APPA	☑		
ATC	☑		
Brazos Electric	☑		
City Water Power and Light	☑		
City Utilities/Springfield	☑		
Entegra	☑		
IESO	☑		See reason stated for Q24, above.
ISO/RTO	☑		
KCPL	☑		Must recognize that there may be Consequential loss of load.

Q25			
Commenter	**Agree**	**Disagree**	**Comment**
LCRA	☑		
New York ISO	☑		
PJM	☑		
Response: Thank you.			

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

26) Q26. P4-1: Loss of a Generator followed by System adjustment[2] followed by loss of another Generator

Summary Response: The SDT notes that FERC's direction with regard to Non-Consequential firm Load and the TPL standards is stated in paragraph 1795 of FERC Order No. 693 as follows: "Based on the record before us, we believe that the transmission planning Reliability Standard should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency." Paragraph 1795 also states, "Therefore, the ERO should modify the sentence to indicate that manual system adjustments, except for shedding firm load or curtailment of firm transfers, are permitted after the first contingency to bring the system back to a normal operating state." These statements which indicate that loss of Non-Consequential firm Load and interruption of firm Transmission service should not be permitted for a single Contingency are meant to apply to Facilities covered by reliability standards regardless of voltage, economics, or rate recovery issues.

These events are on higher voltage facilities on the BES. Therefore, the SDT has drafted the standard to not permit loss of Non-Consequential Load or interruption of firm Transmission service for the loss of a generator followed by System adjustment followed by the loss of another generator. The majority of the commenters in response to the first posting of the standard agreed with the SDT's approach in this regard.

Issues of cost recovery are beyond the scope of the standard.

Q26			
Commenter	**Agree**	**Disagree**	**Comment**
Muscatine P&W			See Q43 Comment #5.
Response: Please see Q43 #5 response.			
City Utilities/Springfield			Would like to see more explanation for the these scenarios.
ABB	☑		For Table 1 P4, rewrite it to read "Loss of a generator followed by a System adjustment followed by the loss of any one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. A shunt device

[2] System adjustment can be manual or automatic

Q26			
Commenter	**Agree**	**Disagree**	**Comment**
			5. Single pole of DC line." This structure is easier to read and understand. The order should be like this to match P1. Shunt devices should be included. P3 should be structured similarly.
Response: The SDT has changed the performance table and language to clarify the specific scenarios. The SDT will be seeking comments on the new performance table.			
Brazos Electric		☑	Need a definition of generator. The entire train, largest unit at a site or other.
Response: The SDT has made changes to the performance table and language to define what is included in an individual generator outage**.**			
Northwestern Energy		☑	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
Response: The SDT has revised the proposed definition of Consequential Load Loss in the second draft. Per the SDT proposed definition, losing a motor due to motor contactor action is not considered Non-Consequential or Consequential Loss of Load. The SDT has made changes to the definition of Consequential Load Loss to clarify how this incident is to be treated with regard to system performance. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements. With regard to the comment on cost, this requirement is consistent with FERC Order No. 693 and the SDT believes this is a more probable event than other events and therefore, the System should be designed per this requirement.			
BCTC		☑	Do not agree due to the definition for Consequential Load Loss. Definition needs to include local networks for this contingency to be acceptable.
Response: See responses to Question 2 and 6.			
CenterPoint		☑	CenterPoint Energy believes the assumption that this is a high probability event is incorrect. Furthermore, an absolute requirement prohibiting non-consequential loss of load has economic and landowner impacts that cannot be ignored.
Response: The majority of commenters in response to the first posting of the draft standard agreed with this approach. With regard to the commenter's second comment, the SDT notes that in Order 693 FERC directs NERC to prohibit loss of Non-Consequential firm Load for a single Contingency and therefore the SDT believes that this is an appropriate requirement for the standard. FERC's direction is meant to apply to BES Facilities covered by reliability standards regardless of land-use, voltage, economics, or rate recovery issues. Issues of land-use, economics, and cost recovery are beyond the scope of the SDT. The majority of commenters in response to the first posting of			

Q26			
Commenter	**Agree**	**Disagree**	**Comment**
the draft standard agreed with this approach. See also the SDT's summary response.			
Central Maine Power New England ISO NU NPCC RCS NSTAR United Illuminating		☑	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of 2 additional generators.
National Grid		☑	If mitigation plans are required that are based on studies that already include unplanned generator outages, then some load loss may be reasonable following the subsequent loss of 2 additional generators.
FPL FRCC		☑	Systems should be planned such that the loss of a generator, followed by System adjustment, followed by the loss of another generator would not result in Non-consequential Load Loss, and equipment ratings would not be exceeded etc. However, the initial state of the system must be clarified in all performance table scenarios (including P4-1).If the Base Case contained known planned outages of generating units, as implied by the requirement R1.4, then the standard performance requirements could be interpreted to require planning for all G-1-1-1 events.
Response: The SDT agrees that the draft standard could reasonably be interpreted that if a major generating outage lasts more than 1 year that the System still needs to be able to meet G-1, System adjustment and then, a 2nd G-1 without the loss of any Non-Consequential Load. This interpretation would require new construction to meet any G-1 + G-1 + G-1, because there would be a violation of the standard if any plant outage occurred and was not available over the peak period during the planning horizon. The SDT believes this is beyond most present planning across NERC. Therefore, the SDT has made a change to the proposed standard to develop a new requirement to replace R1.4 in the modeling section. The new requirement will be to perform the tests outlined in the performance requirements table and demonstrate that thermal and voltage limits are met, however, all manual and/or automatic actions are allowed (within time constrained ratings) including curtailing firm transfers and controlled shedding of Non-Consequential firm Load.			
CPS Energy		☑	Should be determined at the discretion of the Transmission Planners.
Entergy		☑	This would require an increase in investment that will place an undue cost burden on all customers for low probability events. It does not appear that there has been any meaningful balancing of the potential benefits against the significant increase in cost that will be required. See comments to Q43.
LADWP		☑	This is N-2 and load loss should be permitted. As for whether or not this is a high probability event, there should be an objective measure (such as 1 in 5, 1 in 50, or 1 in 100, etc.) as to what constitute high probability, i.e., are there any outage history that would support any of the contention here that these are high probablity events? It is a mistake to arbitrary injecting "subjective" probability into a deterministic based reliability standard unless the industry is ready to move into 100% probabilistic based reliability standards.
Response: The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by another generator outage is higher than an event involving a single transmission line. The SDT notes that in Order 693 FERC directs NERC to prohibit loss of Non-Consequential firm Load for a single Contingency and therefore the SDT believes that this is an			

Q26			
Commenter	**Agree**	**Disagree**	**Comment**
appropriate requirement for the standard. The majority of commenters in response to the first posting of the draft standard agreed with this approach. See also the SDT's summary response.			
FirstEnergy		☑	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused soley by the first contingency.
Response: The SDT notes that in Order 693 FERC directs NERC to prohibit Non-Consequential loss of Load for a single Contingency in the planning horizon whether it is to meet the System performance after the outage or to prepare for the next Contingency and therefore the SDT believes that this is an appropriate requirement for the standard. The majority of commenters in response to the first posting of the draft standard agreed with this approach. See also the SDT's summary response. The SDT notes that when operating the System, the System Operator may have to drop Non-Consequential loss of Load as a last resort to maintain the reliability of the interconnected network. This would typically be for operating situations with more than a single prior outage for the Contingency event.			
Progress–Florida		☑	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration. Specifically, the sudden loss of a large generator followed soon thereafter by the loss of a second generator would often result in such a large generation-to-load mismatch that Non-Consequential Loss of Load would be inevitable. It is clear, however, that the Bulk Electric System should be planned such that any generator can be maintained (offline) and the system can be operated to the contingency of another generator. This is accomplished in the Security Constrained unit commitment process. However, if the intent of this requirement is that the system should be planned such that there can be no Non-Consequential Load Loss for the loss of a second generator (after System adjustment), then the requirement is too stringent in that the planner would essentially have to plan for 3 generator contingencies. Finally, the probability of an event should not be the primary factor determining whether or not Non-Consequential Loss of Load is permitted, but rather the presence or absence of cascading for the event.
Response: The SDT agrees that the draft standard could reasonably be interpreted that if a major generating outage lasts more than 1 year that the System still needs to be able to meet G-1, System adjustment and then, a 2nd G-1 without the loss of any Non-Consequential Load. This interpretation would require new construction to meet any G-1 + G-1 + G-1, because there would be a violation of the standard if any plant outage occurred and was not available over the peak period during the planning horizon. The SDT believes this is beyond most present planning across NERC. Therefore, the SDT has made a change to the proposed standard to develop a new requirement to replace R1.4 in the modeling section. The new requirement will be to perform the tests outlined in the performance requirements table and demonstrate that thermal and voltage limits are met, however, all manual and/or automatic actions are allowed (within time constrained ratings) including curtailing firm transfers and controlled shedding of Non-Consequential firm Load. The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by another generator outage is higher than an event involving a single transmission line. The SDT notes that in Order 693 FERC directs NERC to prohibit loss of Non-Consequential firm Load for a single Contingency and therefore the SDT believes that this is an appropriate requirement for the standard. The majority of commenters in response to the first posting of the draft standard agreed with this approach. See also the SDT's summary response.			

Q26			
Commenter	**Agree**	**Disagree**	**Comment**
SRP		☑	The time to adjust the system needs to be provided (when does a N-1-1 become a N-2?). If the cause of the outage is transient (temporary) the operator needs some time to test and restore the element (could be minutes up to several hours). If the element is lost indefinitly, the operator will need some minimum time to adjust the system. If this time is not available prior to the next N-1 then the standard should allow Non-Consequetial Loss of Load. Some distinction needs to be made the amount of generation connected at a single point on the BES. a wind farm might have many small generators connected to the BES with an aggregate total of 300Mw or more. This requirement will should only apply to generating sources that might be connected to the BES through a single transformer (i.e. wind farm) with minimum agregate total of 300 MW (for N-1).
Response: The SDT believes that the time to adjust that is used in planning needs to be consistent with the time periods for which the Facility Ratings are designed. This time to adjust is different for different types of Facilities, as well as, for individual Facilities. The SDT has clarified this point in the standard but does not provide a specific time to be used for planning across NERC. The SDT has made changes to the performance table and language to define what is included in an individual generator outage. Treatment of wind farm in modeling and analysis needs to be addressed in MOD-010 through MOD-013.			
Santee Cooper		☑	The event should be tested for ensuring or maintaining reliability of the BES, however direct load loss should be allowed.
SERC RRS OPS TVA		☑	It is agreed that this event should be tested for maintaining reliability of the BES, however planned load loss should be allowed.
SCE&G		☑	Planned load loss should be allowed.
Response: The SDT agrees that Consequential (direct) Load Loss should be allowed but disagrees that planned loss of Non-Consequential firm Load should be allowed. The standard has been drafted to allow Consequential direct Load Loss for this event but not Non-Consequential Load Loss for this Contingency event. The SDT has outage data for representative facilities which shows that the probability of an event involving one generator outage followed by another generator outage is higher than an event involving a single Transmission line. The SDT notes that in Order 693 FERC directs NERC to prohibit loss of Non-Consequential firm Load for a single Contingency and therefore the SDT believes that this is an appropriate requirement for the standard. The majority of commenters in response to the first posting of the draft standard agreed with this approach. See also the SDT's summary response.			
SaskPower		☑	Local area network load is allowed to be shed in Saskatchewan. The Saskatchewan Regulatory Jurisdiction has no plans to change this unless there is technical evidence to justify the increase in reliability. The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Response: The SDT is required to address FERC Order 693 and cannot default to lowest common denominator. This issue is beyond the scope of the Standard Drafting Team and needs to be addressed at the NERC level. However, an Entity can request an "Entity Variance" in accordance with the NERC Reliability Standards Development Procedure (Page 27).			
Tenaska	☑		This is really an issue that should be driven by the customers
Response: FERC Order No. 693 and the Energy Policy Act of 2005 has driven changes embodied by this question.			

Q26			
Commenter	**Agree**	**Disagree**	**Comment**
HQTE	☑		Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of 2 additional generators.
Response: FERC Order 693 indicates that only Consequential Load Loss should be allowed while Non-Consequential Load loss should not. See also the SDT's summary response.			
IESO	☑		The loss of a generator is different from the loss of a transmission facility. The former usually does not result in changes to the system topology nor system operating limits. While loss of 2 generators may result in resource deficiency, the decision to shed load would only be made when operating reserve cannot be replenished after the first contingency, and when the second contingency would result in violation of any SOLs or IROLs or BAL standards for which adjustment cannot be made within the required time line.
Response: The SDT agrees with the comment, although that is not the reason for the proposed changes. FERC Order 693 indicates that only consequential load loss should be allowed while non-consequential load loss should not. See also the SDT's summary response.			
ITC	☑		Also use of system adjustment should consider time required to complete adjustment.
Response: The SDT agrees and has proposed changes to the tables to clarify.			
Manitoba Hydro	☑		With the caveat that firm transfer is included in the adjustment, otherwise there is a huge cost with minimal reliability benefit. A further comment is what rationale was applied by the SDT to come up with these combinations of events? is there a statistical basis? the viable combinations of multiple contingency events should be left to the experience of the transmission planner.
Response: FERC Order 693 indicates that firm transfers are not to be curtailed either to meet the System performance for a single Contingency or to prepare for the next Contingency. This is the basis for not allowing firm transfer. See also the SDT's summary response and Order 693, Paragraph 1796 for additional FERC clarification with regard to prohibiting curtailment of firm transfers after a single Contingency. The combinations of events were chosen drawing on the experience of members of the SDT. If there are any additional events that should be added to the tables, please provide specific suggestions during the next comment period.			
NCEMC	☑		In the case of generating capacity replacement, some guidance as to allowable system adjustments might be needed for clarification. Is calling on contingency reserves from a Reserve Sharing Group immediately prior to internal redispatch of available resources OK? What about Network Customer generation not at maximum output but available for redispatch ? What about transmission reconfiguration, cutting firm purchases (pro-rata or in entirety) acceptable?
Response: The SDT agrees with the comment and the SDT has proposed changes to clarify what System adjustments are allowed.			
WPS	☑		It is inappropriate to rely on Non-consequential loss of load as an ultimate Corrective Action Plan for this event. However, non-consequential load loss can provide interim relief until such time as the Corrective Action Plan is actually constructed and in-service.
Response: The SDT agrees with this comment and has proposed an interim relief provision for the standard.			
Ameren	☑		The outage of any two generators should not result in any non-consequential loss of load.

Q26			
Commenter	**Agree**	**Disagree**	**Comment**
AECC	☑		neither should consequential load be lost. The system should operate to all performance criteria for loss of any one generator station (all units).
AECI	☑		
Allegheny Power	☑		
AEP	☑		
APPA	☑		
ATC	☑		
APS			
BPA	☑		
City Water Power and Light	☑		
Dominion	☑		Dominion agrees with these proposed standards as they are relatively higher probability events and reflect very closely to the Company's internal planning criteria.
Duke Energy	☑		
Entegra	☑		
E ON US	☑		
ERCOT ISO CAISO	☑		Non consequential loss of load should not be permitted for this type of event. Loss of a generator has higher probability and longer duration than many other contingencies. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Exelon	☑		
Georgia Transm.	☑		
ISO/RTO	☑		
KCPL	☑		
LCRA	☑		
MEAG Power	☑		
MISO	☑		
MRO	☑		
NERC TIS	☑		

Q26			
Commenter	**Agree**	**Disagree**	**Comment**
New York ISO	☑		
PJM	☑		
Progress–Carolinas	☑		
Seattle City	☑		
SERC EC DRS	☑		
SERC EC PSS	☑		
Southern Transm.	☑		These are relatively higher probability events and the increase in performance requirements is justified.
WECC TSGT TEP	☑		We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Response: Thank you.			

27) Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line

Summary Response: The SDT notes that FERC's direction with regard to Non-Consequential firm Load and the TPL standards is stated in paragraph 1795 of FERC Order No. 693 as follows: "Based on the record before us, we believe that the transmission planning Reliability Standard should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency." Paragraph 1795 also states, "Therefore, the ERO should modify the sentence to indicate that manual system adjustments, except for shedding firm load or curtailment of firm transfers, are permitted after the first contingency to bring the system back to a normal operating state." These statements which indicate that loss of Non-Consequential firm Load and interruption of firm Transmission service should not be permitted for a single Contingency are meant to apply to Facilities covered by reliability standards regardless of voltage, economics, or rate recovery issues.

These events are on higher voltage facilities on the BES. The probability of the outage of one generator followed by the outage of another generator is higher than the probability of a single Transmission line outage. Therefore, the SDT has drafted the standard to not permit loss of Non-Consequential Load or interruption of firm Transmission service for the loss of a generator followed by System adjustment followed by the loss of another generator. The majority of the commenters in response to the first posting of the standard agreed with the SDT's approach in this regard.

Issues of cost recovery are beyond the scope of the standard.

Q27			
Commenter	**Agree**	**Disagree**	**Comment**
Muscatine P&W			See Q43 Comment #5.
Response: Please see response to Q43 #5.			
Northwestern Energy		☑	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
BCTC		☑	Similar to Q26.
Central Maine Power New England ISO NU NSTAR United Illuminating		☑	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a monopolar DC line
National Grid		☑	If mitigation plans are required that are based on studies that already include unplanned generator outages, then some load loss may be reasonable following the subsequent loss of an additional generator and a monopolar DC line
FirstEnergy		☑	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused soley by the first contingency.
FPL FRCC		☑	Systems should be planned such that the loss of a generator, followed by System adjustment, followed by the loss of another generator would not result in Non-consequential Load Loss, and

Q27			
Commenter	**Agree**	**Disagree**	**Comment**
			equipment ratings would not be exceeded etc. However, the initial state of the system must be clarified in all performance table scenarios (including P4-1).If the Base Case contained known planned outages of generating units, as implied by the requirement R1.4, then the standard performance requirements could be interpreted to require planning for all G-1-1-1 events.
LADWP		☑	Ditto (26)
SRP		☑	Same as Q26.
Santee Cooper SERC RRS OPS		☑	Same comment as question #26.
SaskPower		☑	Local area network load is allowed to be shed in Saskatchewan. The Saskatchewan Regulatory Jurisdiction has no plans to change this unless there is technical evidence to justify the increase in reliability. The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
HQTE	☑		Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a monopolar DC line
IESO	☑		Same reason as above except in this case, the loss of a monopolar dc line could interrupt import. Again, it is a resource issue, not a transmission reliability issue.
ITC	☑		Also use of system adjustment should consider time required to complete adjustment.
Manitoba Hydro	☑		With the caveat that firm transfer is included in the adjustment, otherwise there is a hugh cost with minimal reliability benefit.
Tenaska	☑		This is really an issue that should be driven by the customers
Response: Please see response to #26.			
CenterPoint		☑	CenterPoint Energy believes the assumption that this is a high probability event is incorrect. Furthermore, an absolute requirement prohibiting non-consequential loss of load has economic and landowner impacts that cannot be ignored.
Response: The SDT disagrees with the commenter's first statement. The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by a DC line is within an order of magnitude of an event involving a single Transmission line. With regard to the commenter's second comment, the SDT notes that in Order 693 FERC directs NERC to prohibit loss of Non-Consequential firm Load for a single Contingency and therefore the SDT believes that this is an appropriate requirement for the standard. FERC's direction is meant to apply to BES Facilities covered by reliability standards regardless of land-use, voltage, economics, or rate recovery issues. Issues of land-use, economics, and cost recovery are not to be addressed by the SDT as being beyond the scope of the SDT. The majority of commenters in response to the first posting of the draft standard agreed with this approach. See also the SDT's summary response.			
Entergy		☑	This would require an increase in investment that will place an undue cost burden on all customers for low probability events. It does not appear that there has been any meaningful balancing of the potential benefits agains the significant increase in cost that will be required.

Q27			
Commenter	**Agree**	**Disagree**	**Comment**
			See comments to Q43.
Response: The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by a DC line is within an order of magnitude of an event involving a single Transmission line. With regard to the commenter's second comment, the SDT notes that in Order 693 FERC directs NERC to prohibit loss of Non-Consequential firm Load for a single Contingency and therefore the SDT believes that this is an appropriate requirement for the standard. FERC's direction is meant to apply to BES Facilities covered by reliability standards regardless of land-use, voltage, economics, or rate recovery issues. Issues of land-use, economics, and cost recovery are not to be addressed by the SDT as being beyond the scope of the SDT. The majority of commenters in response to the first posting of the draft standard agreed with this approach. See also the SDT's summary response.			
Progress–Florida		☑	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration, provided that the Non-Consequential Loss of Load is confined to a single control area (i.e., not resulting in a cascading outage). Furthermore, the frequency of an event should not be the primary factor determining whether or not Non-Consequential Loss of Load is permitted, but rather the presence or absence of cascading for the event. Existing Category C requirements are adequate for this type of event.
Response: The SDT agrees that the draft standard could reasonably be interpreted that if a major generating outage lasts more than 1 year that the System still needs to be able to meet G-1, System adjustment and then, a 2nd G-1 without the loss of any Non-Consequential Load. This interpretation would require new construction to meet any G-1 + G-1 + G-1, because there would be a violation of the standard if any plant outage occurred and was not available over the peak period during the planning horizon. The SDT believes this is beyond most present planning across NERC. Therefore, the SDT has made a change to the proposed standard to develop a new requirement to replace R1.4 in the modeling section. The new requirement will be to perform the tests outlined in the performance requirements table and demonstrate that thermal and voltage limits are met, however, all manual and/or automatic actions are allowed (within time constrained ratings) including curtailing firm transfers and controlled shedding of Non-Consequential firm Load. The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by a DC line is within an order of magnitude of an event involving a single Transmission line. With regard to the commenter's second comment, the SDT notes that in Order 693 FERC directs NERC to prohibit loss of Non-Consequential firm Load for a single Contingency and therefore the SDT believes that this is an appropriate requirement for the standard. FERC's direction is meant to apply to BES Facilities covered by reliability standards regardless of land-use, voltage, economics, or rate recovery issues. Issues of land-use, economics, and cost recovery are not to be addressed by the SDT as being beyond the scope of the SDT. The majority of commenters in response to the first posting of the draft standard agreed with this approach. See also the SDT's summary response.			
SCE&G		☑	Planned load loss should be allowed.
TVA		☑	It is agreed that this event should be tested for maintaining reliability of the BES, however planned load loss should be allowed.
Response: The SDT agrees that Consequential (direct) Load Loss should be allowed but disagrees that planned loss of Non-Consequential firm Load should be allowed. The standard has been drafted to allow Consequential direct Load Loss for this event but not Non-Consequential Load Loss for this Contingency event. The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by a DC line outage is within an order of magnitude than an event involving a single Transmission line. The SDT notes that in Order 693 FERC directs NERC to prohibit loss of Non-Consequential firm Load for a single Contingency and			

Q27			
Commenter	**Agree**	**Disagree**	**Comment**
therefore the SDT believes that this is an appropriate requirement for the standard. The majority of commenters in response to the first posting of the draft standard agreed with this approach. See also the SDT's summary response.			
MRO	☑		The monopolar DC line words should be revised to "a single pole of a DC line".
Response: The SDT agrees and has made appropriate changes to the tables.			
NPCC RCS	☑		Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a monopolar DC line
Response: See summary response.			
ABB	☑		
Ameren	☑		The outage of a generator and any other element should not result in any non-consequential loss of load.
AECC	☑		neither should consequential load be lost. The system should operate to all performance criteria for loss of any one generator station (all units).
AECI	☑		AECI
Allegheny Power	☑		Allegheny Power
AEP	☑		AEP
APPA	☑		APPA
ATC	☑		ATC
BPA	☑		BPA
Brazos Electric	☑		
City Water Power and Light	☑		
Dominion	☑		Although we do not have any DC lines, Dominion agrees with these proposed standards as they are relatively higher probability events and reflect very closely to the Company's internal planning criteria.
Duke Energy	☑		
Entegra	☑		
ERCOT ISO CAISO	☑		Agree that non consequential loss of load should not be permitted due to higher probability of generator outage.
Exelon	☑		
Georgia Transm.	☑		

Q27			
Commenter	**Agree**	**Disagree**	**Comment**
ISO/RTO	☑		
KCPL	☑		
LCRA	☑		
MEAG Power	☑		
MISO	☑		
NERC TIS	☑		
New York ISO	☑		
PJM	☑		
Progress–Carolinas	☑		
Seattle City	☑		
SERC EC DRS	☑		
SERC EC PSS	☑		
Southern Transm.	☑		See comment for Q26 [These are relatively higher probability events and the increase in performance requirements is justified.
WECC TSGT TEP	☑		We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
WPS	☑		See response to Q26.
Response: Thank you.			

28) Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit

Summary Response: The SDT notes that FERC's direction with regard to Non-Consequential firm Load and the TPL standards is provided in paragraph 1795 of FERC Order No. 693 which indicates that loss of Non-Consequential firm Load and interruption of firm Transmission service should not be permitted for a single Contingency regardless of voltage, economics, or rate recovery issues. Also see summary response to question 26.

These events are on higher voltage facilities on the BES. The probability of the outage of one generator followed by the loss of a Transmission line is within an order of magnitude of a single Transmission line outage. Therefore, the SDT has drafted the standard to not permit loss of Non-Consequential firm Load or interruption of firm Transmission service for the loss of a generator followed by System adjustment followed by the loss of a Transmission line. Issues of land-use, economics, and cost recovery are beyond the scope of the standard.

The majority of the commenters in response to the first posting of the standard agreed with the SDT's approach in this regard.

Q28			
Commenter	**Agree**	**Disagree**	**Comment**
Muscatine P&W			See Q43 Comment #5.
Response: Please see response to Q43 #5.			
Brazos Electric		☑	Need definition of system adjustment.
Response: The SDT agrees that system adjustment needed to be clarified. The SDT has made clarifying changes to the tables.			
Northwestern Energy		☑	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
BCTC		☑	Similar to Q26.
Central Maine Power New England ISO NU NSTAR United Illuminating		☑	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a Transmission circuit
National Grid		☑	If mitigation plans are required that are based on studies that already include unplanned generator outages, then some load loss may be reasonable following the subsequent loss of an additional generator and a Transmission circuit
FirstEnergy		☑	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused soley by the first contingency.
FPL FRCC		☑	Systems should be planned such that the loss of a generator, followed by System adjustment, followed by the loss of another generator would not result in Non-consequential Load Loss, and equipment ratings would not be exceeded etc. However, the initial state of the system must be

Q28			
Commenter	**Agree**	**Disagree**	**Comment**
			clarified in all performance table scenarios (including P4-1).If the Base Case contained known planned outages of generating units, as implied by the requirement R1.4, then the standard performance requirements could be interpreted to require planning for all G-1-1-1 events.
LADWP		☑	Ditto (26)
SRP		☑	Same as Q26.
SaskPower		☑	Local area network load is allowed to be shed in Saskatchewan. The Saskatchewan Regulatory Jurisdiction has no plans to change this unless there is technical evidence to justify the increase in reliability. The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
HQTE	☑		Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a Transmission circuit.
IESO	☑		Similar reason as above. In this case, while the second contingency is the loss of a transmission circuit, the first contingency (loss of a generator) has not changed the system topology. Hence, the system condition after having been adjusted following the first contingency should in essence be similar to the all transmission facilities in service condition for which the non-consequential loss of load performance for single contingencies is expected.
ITC	☑		Also use of system adjustment should consider time required to complete adjustment. Ability for generation adjustment should include the time required for unit startup if applicable.
Manitoba Hydro	☑		With the caveat that firm transfer is included in the adjustment, otherwise there is a hugh cost with minimal reliability benefit.
Tenaska	☑		This is really an issue that should be driven by the customers
Response: See response to #26.			
CenterPoint		☑	CenterPoint Energy believes the assumption that this is a high probability event is incorrect. Furthermore, an absolute requirement prohibiting non-consequential loss of load has economic and landowner impacts that cannot be ignored.
Response: The SDT disagrees with the commenter's first statement. The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by a Transmission line is within an order of magnitude of an event involving a single Transmission line. With regard to the commenter's second comment, see the summary response with regard to FERC Order No. 693.			
CPS Energy		☑	Should be determined at the discretion of the Transmission Planners.
Entergy		☑	This would require an increase in investment that will place an undue cost burden on all customers for low probability events. It does not appear that there has been any meaningful balancing of the potential benefits against the significant increase in cost that will be required. See comments to Q43.
Response: The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage			

Q28			
Commenter	**Agree**	**Disagree**	**Comment**
followed by a Transmission line is within an order of magnitude of an event involving a single Transmission line. With regard to the commenter's second comment, see the summary response with regard to FERC Order No. 693.			
JEA		☑	I do agree that long term plans should be implemented with the goal to eliminate non-consequential load shedding as a response to this failure mode. However, it may be more beneficial for investing in system improvements to reach this state of robustness where there may be a few years or seasons of potential exposure for utilizing non-consequential load shedding. This should be prudent utility practice as long as post-contingency response is executed within the time frame allowed by the facility emergency ratings and load shedding is limited to TP's contracted or tariff loads.
Response: SDT agrees that sufficient time must be provided for transition and will provide for that in the implementation plan for the standard. With regard to other comments, see summary response.			
Progress–Florida		☑	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration, provided that the Non-Consequential Loss of Load is confined to a single control area (i.e., not resulting in a cascading outage). Furthermore, the frequency of an event should not be the primary factor determining whether or not Non-Consequential Loss of Load is permitted, but rather the presence or absence of cascading for the event. Existing Category C requirements are adequate for this type of event.
Response: The SDT agrees that the draft standard could reasonably be interpreted that if a major generating outage lasts more than 1 year that the System still needs to be able to meet G-1, System adjustment and then, a 2nd G-1 without the loss of any Non-Consequential Load. This interpretation would require new construction to meet any G-1 + G-1 + G-1, because there would be a violation of the standard if any plant outage occurred and was not available over the peak period during the planning horizon. The SDT believes this is beyond most present planning across NERC. Therefore, the SDT has made a change to the proposed standard to develop a new requirement to replace R1.4 in the modeling section. The new requirement will be to perform the tests outlined in the performance requirements table and demonstrate that thermal and voltage limits are met, however, all manual and/or automatic actions are allowed (within time constrained ratings) including curtailing firm transfers and controlled shedding of Non-Consequential firm Load. The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by a Transmission line is within an order of magnitude of an event involving a single Transmission line. With regard to the commenter's second comment, see the summary response with regard to FERC Order No. 693.			
Santee Cooper SERC RRS OPS		☑	Same comment as question #26.
SCE&G		☑	Planned load loss should be allowed.
TVA		☑	It is agreed that this event should be tested for maintaining reliability of the BES, however planned load loss should be allowed.
Response: The SDT agrees that Consequential (direct) Load Loss should be allowed but disagrees that planned loss of Non-Consequential firm Load should be allowed. The standard has been drafted to allow Consequential direct Load Loss for this event but not Non-Consequential Load Loss for this Contingency event. The SDT has outage data for representative Facilities which show that the probability of an event			

Q28			
Commenter	**Agree**	**Disagree**	**Comment**
involving one generator outage followed by a DC line outage is within an order of magnitude than an event involving a single Transmission line. Also, see the summary response with regard to FERC Order No. 693.			
IESO	☑		Similar reason as above. In this case, while the second contingency is the loss of a transmission circuit, the first contingency (loss of a generator) has not changed the system topology. Hence, the system condition after having been adjusted following the first contingency should in essence be similar to the all transmission facilities in service condition for which the non-consequential loss of load performance for single contingencies is expected.
ITC	☑		Also use of system adjustment should consider time required to complete adjustment. Ability for generation adjustment should include the time required for unit startup if applicable.
Manitoba Hydro	☑		With the caveat that firm transfer is included in the adjustment, otherwise there is a hugh cost with minimal reliability benefit.
NPCC RCS	☑		Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a Transmission circuit
Response: Please see response to Q27.			
ABB	☑		
Ameren	☑		The outage of a generator and any other element should not result in any non-consequential loss of load.
AECC	☑		neither should consequential load be lost. The system should operate to all performance criteria for loss of any one generator station (all units).
AECI	☑		
Allegheny Power	☑		
AEP	☑		
APPA	☑		
ATC	☑		
BPA	☑		
CAISO	☑		Same reason as in Q26.
City Water Power and Light	☑		
Dominion	☑		Dominion agrees with these proposed standards as they are relatively higher probability events and reflect very closely to the Company's internal planning criteria.
Duke Energy	☑		
Entegra	☑		

Q28			
Commenter	**Agree**	**Disagree**	**Comment**
E ON US	☑		
ERCOT ISO	☑		Same reason as in Q26.
Exelon	☑		
Georgia Transm.	☑		
ISO/RTO	☑		
KCPL	☑		
LCRA	☑		
MEAG Power	☑		
MISO	☑		
MRO	☑		
NERC TIS	☑		
New York ISO	☑		
NCEMC	☑		See reply to Q26.
PJM	☑		
Progress–Carolinas	☑		
Seattle City	☑		
SERC EC DRS	☑		
SERC EC PSS	☑		
Southern Transm.	☑		See comment for Q26 [These are relatively higher probability events and the increase in performance requirements is justified.
WECC TSGT TEP	☑		We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
WPS	☑		See response to Q26.
Response: Thank you.			

29) Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer

Summary Response: The SDT notes that FERC's direction with regard to Non-Consequential firm Load and the TPL standards is provided in paragraph 1795 of FERC Order No. 693 which indicates that loss of Non-Consequential firm Load and interruption of firm Transmission service should not be permitted for a single Contingency regardless of voltage, economics, or rate recovery issues. See summary response to Q26.

These events are on higher voltage facilities on the BES. The probability of the outage of one generator followed by the loss of a transformer is within an order of magnitude of a single Transmission line outage. Therefore, the SDT has drafted the standard to not permit loss of Non-Consequential firm Load or interruption of firm Transmission service for the loss of a generator followed by System adjustment followed by the loss of a transformer. The majority of the commenters in response to the first posting of the standard agreed with the SDT's approach in this regard.

Q29			
Commenter	**Agree**	**Disagree**	**Comment**
Muscatine P&W			See Q43 Comment #5.
Response: Please see response to Q43 #5.			
Brazos Electric		☑	See above.
Northwestern Energy		☑	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
BCTC		☑	Similar to Q26.
Central Maine Power New England ISO NU NSTAR United Illuminating		☑	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a transformer
National Grid		☑	If mitigation plans are required that are based on studies that already include unplanned generator outages, then some load loss may be reasonable following the subsequent loss of an additional generator and a transformer
FirstEnergy		☑	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused soley by the first contingency.
FPL FRCC		☑	Systems should be planned such that the loss of a generator, followed by System adjustment, followed by the loss of another generator would not result in Non-consequential Load Loss, and equipment ratings would not be exceeded etc. However, the initial state of the system must be clarified in all performance table scenarios (including P4-1).If the Base Case contained known planned outages of generating units, as implied by the requirement R1.4, then the standard performance requirements could be interpreted to require planning for all G-1-1-1 events.

Q29			
Commenter	**Agree**	**Disagree**	**Comment**
JEA		☑	See comment on P4-3.
LADWP		☑	Ditto (26)
SRP		☑	Same as Q26.
Santee Cooper SERC RRS OPS		☑	Same comment as question #26.
HQTE	☑		Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a transformer.
IESO	☑		Similar reason as above.
ITC	☑		Also use of system adjustment should consider time required to complete adjustment. Ability for generation adjustment should include the time required for unit startup if applicable.
Manitoba Hydro	☑		With the caveat that firm transfer is included in the adjustment, otherwise there is a hugh cost with minimal reliability benefit.
Tenaska	☑		This is really an issue that should be driven by the customers
Response: Please see response to Q26.			
CenterPoint		☑	CenterPoint Energy believes the assumption that this is a high probability event is incorrect. Furthermore, an absolute requirement prohibiting non-consequential loss of load has economic and landowner impacts that cannot be ignored.
Response: The SDT disagrees with the commenter's first statement. The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by a transformer is within an order of magnitude of an event involving a single Transmission line. With regard to the commenter's second comment, see summary response.			
CPS Energy		☑	Should be determined at the discretion of the Transmission Planners.
Entergy		☑	This would require an increase in investment that will place an undue cost burden on all customers for low probability events. It does not appear that there has been any meaningful blancing of the potential benefits against the significant increase in cost that will be required See comments to Q43.
Response: The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by a transformer is within an order of magnitude of an event involving a single Transmission line. With regard to the commenter's second comment, see summary response			
Progress–Florida		☑	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration, provided that the Non-Consequential Loss of Load is confined to a single control area (i.e., not resulting in a cascading outage). Furthermore, the frequency of an event should not be the primary factor determining whether or not Non-Consequential Loss of Load is permitted, but rather the presence or absence of cascading for the event. Existing Category C requirements are adequate for this

Q29			
Commenter	**Agree**	**Disagree**	**Comment**
			type of event.
NPCC RCS	☑		Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a transformer
Response: Please see response to Q27.			
SCE&G		☑	Planned load loss should be allowed.
TVA		☑	It is agreed that this event should be tested for maintaining reliability of the BES, however planned load loss should be allowed.
Response: The SDT agrees that Consequential (direct) Load Loss should be allowed but disagrees that planned loss of Non-Consequential firm Load should be allowed. The standard has been drafted to allow Consequential direct Load Loss for this event but not Non-Consequential Load Loss for this Contingency event. The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by a DC line outage is within an order of magnitude than an event involving a single Transmission line. Also, see the summary response with regard to FERC Order No. 693.			
Duke Energy	☑		Table in TPL-001-1 doesn't include the last part of P4-4 (low side voltage rating above 300 kV). We assume the inclusion of 300kV here in the comment form is in error.
Response: The SDT notes that the original comment form was in error as described in your comment. The SDT noticed the error and revised the comment form and reposted it to correct the error.			
MISO	☑		Note - No voltage limit for generator and transformer per Table 1, P4-4
KCPL	☑		Need voltage limit in Table 1.
Response: The SDT disagrees because voltage limits differ from system to system.			
ABB	☑		
Ameren	☑		The outage of a generator and any other element should not result in any non-consequential loss of load.
AECC	☑		neither should consequential load be lost. The system should operate to all performance criteria for loss of any one generator station (all units).
AECI	☑		
Allegheny Power	☑		
AEP	☑		
APPA	☑		
ATC	☑		
BPA	☑		
City Water Power and Light	☑		

Q29			
Commenter	**Agree**	**Disagree**	**Comment**
Dominion	☑		Dominion agrees with these proposed standards as they are relatively higher probability events and reflect very closely to the Company's internal planning criteria.
E ON US	☑		
Entegra	☑		
ERCOT ISO CAISO	☑		Same reason as in Q26.
Exelon	☑		
Georgia Transm.	☑		
ISO/RTO	☑		
LCRA	☑		
MEAG Power	☑		
MRO	☑		
NERC TIS	☑		
New York ISO	☑		
NCEMC	☑		See reply to Q26.
PJM	☑		
Progress–Carolinas	☑		
Seattle City	☑		
SERC EC DRS	☑		
SERC EC PSS	☑		
Southern Transm.	☑		See comment for Q26 [These are relatively higher probability events and the increase in performance requirements is justified.
WECC TSGT TEP	☑		We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
WPS	☑		See response to Q26.
Response: Thank you.			

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

30) Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Summary Response: Some commenters that agreed with curtailing firm transfers that are dependent on a DC line when the DC line is outaged indicated that such curtailment should apply to AC lines as well. Also, some of these parties indicated concern that other transfers such as interruptible transfers should be also allowed. The SDT did not make a change in response to these comments because many of the transfers over DC lines are automatically curtailed when the DC line is outaged and because the ability to interrupt other transfers such as non-firm transfers are already provided for in the standard.

Q30			
Commenter	**Agree**	**Disagree**	**Comment**
Muscatine P&W			See Q43 Comment #5.
Response: The SDT does not see how Muscatine Power and Water's Comment #5 to Q43 relates to this question. The SDT does not make any change to the standard with regard to Q30 as a result of this comment.			
Ameren		☑	If the system cannot withstand the outage of the single element (AC or DC) without curtailment of the transfer, then the transaction should not be considered as firm.
AECC		☑	
BCTC		☑	Disagree with this unless AC lines are treated the same. There should be no distinction between AC and DC lines.
Duke Energy		☑	DC and AC line contingencies should have the same requirements.
Entergy	☑	☑	Why are only DC lines exempt for this requirement? Consider exemptions for AC transmission elements as well.
FPL		☑	The proposed standard does not distinguish between asynchronous DC ties and the more common parallel connected DC tie. With an asynchronous DC tie, the transfer is lost with the tie. With a parallel DC tie, the transfer will be shifted to the parallel AC system, therefore, AC lines should have the same performance criteria as DC lines.
FRCC		☑	DC and AC lines should not be treated differently. System response is similar for the loss of an AC line versus the loss of a parallel connected DC tie. For the loss of a parallel DC tie the transfer is shifted to the parallel AC system in the same manner as a loss of an AC line. The decision in selecting DC vs. AC in transmission lines has traditionally been based on the break-even cost and performance of the two alternatives. The lower performance requirement may wrongly influence decisions on project alternatives in favor of DC facilities with less stringent requirements. Therefore, AC lines should have the same performance criteria as DC lines.
Progress–Carolinas		☑	DC and AC lines should be treated comparably.

Q30			
Commenter	**Agree**	**Disagree**	**Comment**
Santee Cooper		☑	AC and DC contingency events should be treated the same.
SaskPower	☑		Why is this concept not applied to AC tie-lines between systems, whether single or multiple? In Saskatchewan's case there is very little difference.
SERC EC DRS		☑	DC and AC contingency events should be treated the same.
SERC RRS OPS		☑	DC and AC contingency events should be treated the same. The question is somewhat obscure.
SCE&G		☑	General there should be no difference between AC and DC; however, the answer to this question depends on the contractual arrangements associated with the transfer.
Southern Transm.		☑	Why should the reliability level for a transaction on a DC line be different from a transaction over AC? Also, when the transfer over DC is removed, the load it was serving still has to be picked up in the AC network because load cannot be dropped. Therefore, this places a burden on the AC network to serve additional load. If you allow transfers over DC to be interrupted, you should also allow the interruption of transfers over AC for the same events.
LADWP		☑	If the transfer is on a line experiencing outage, then the transfer is interrupted. Whether or not the transfer is firm is immaterial. Whether or not it is on the dc or ac line is also immaterial.
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating	☑		This should also apply to firm transfers via single or double ac facilities as well. In either case, the transfer could be linked to dedicated facilities.
ITC	☑		However, the owners of the firm transfers may not agree. If they don't, a system impact study needs to be part of the assessment IF THE OWNERS OF THE FIRM TRANSFERS DO NOT AGREE. It must be clear to the original TSR requester that this was truly conditional on the DC line being in service. If it was granted without telling them this, then the interruption of firm transfers should NOT be permitted.
TVA	☑		There are also conditions where this interruption should be allowed for a single AC tie line.
Response: The SDT did not make a change in response to your comment because many of the transfers over DC lines are automatically curtailed when the DC line is outaged.			
IESO		☑	Whether or not interruption of firm transfers should be allowed is more a business arrangement issue than a transmission reliability issue. Usually, delivery over a DC line, either as an import or access to internal or external resources, is factored into the resource integration plan to support meeting demand and energy transfers. The commitment for firm transfers may be made on the reliance of this delivery. However, the contingent loss of any resources including import is assessed in determining the amount and terms of firm transfers to a third part. This is a business

Q30			
Commenter	**Agree**	**Disagree**	**Comment**
			and resource allocation issue, not a transmission reliability issue.
Response: While it is true that there are business issues associated with the subject of this question, the SDT disagrees with the commenter with regard to the relevance for reliability. How firm transfers will be treated in the standard will have significant impact on Transmission System reliability across NERC. The SDT has not directly made any changes to the standard as a result of this comment but has considered this comment in deciding how to proceed with firm transfers in the standard.			
Progress–Florida		☑	The proposed standard does not distinguish between asynchronous DC ties and the more common parallel connected DC tie. With an asynchronous DC tie, the transfer is lost with the tie. With a parallel DC tie, the transfer will be shifted to the parallel AC system and should have the same performance requirements.
Response: The SDT deleted the reference to asynchronous DC ties in the tables.			
WECC BPA TSGT TEP	☑	☑	We agree with the question asked. In addition, transactions that can be interrupted due to the loss of a DC line should not be limited to the firm transactions, that are dependent on the DC line. It should also include interruptible transactions and other transactions made available through negotiated agreements on both AC and DC lines.
Response: The SDT did not make a change in response to your comment because many of the transfers over DC lines are automatically curtailed when the DC line is outaged and because the ability to interrupt other transfers such as non-firm transfers are already provided for in the standard**.**			
Manitoba Hydro	☑		MH agrees that reduction of firm transfer to readjust the system after a contingency should be allowed for all events. The requirement to maintain firm transfer is a more stringent requirement that in the existing standard. The need to maintain firm transfer amounts to N-2 planning with no reliability benefit. Reduction in firm transfer is not equivalent to loss of load as the transfer is backed up by reserves. MH could not accept a standard mandating that firm transfer can not be interrupted. MH also recommends P2-3 be moved into the P1 bucket as loss of a single pole of a dc line is similar to loss of a generator or transmission circuit.
Response: The SDT does not agree with your first comment on the need to allow reduction of firm transfer for all events since changes have been made to the standard to comply with FERC Order No. 693 which does not allow curtailment of firm transfer or dropping Non-Consequential Load for single Contingencies. The SDT agrees with your second comment and has made the change in the tables.			
MRO	☑		The MRO questions why interruptions of firm transfers are not allowed in other cases since load dropping is allowed for these cases.
Response: The SDT did not make a change in response to your comment because the ability to interrupt other transactions, such as interruptibles, is already provided for in the standard.			
ABB	☑		Yes, this is the purpose of HVDC. It carries the power your want, no more, no less. Both the good and bad of parallel flows are avoided.
Brazos Electric	☑		

Q30			
Commenter	**Agree**	**Disagree**	**Comment**
City Water Power and Light	☑		
Dominion			Not applicable since Dominion has no DC lines.
E ON US			No opinion, we do not operate DC.
ERCOT ISO CAISO	☑		In addition, the interruptible and other negotiated transactions should also be allowed.
Northwestern Energy	☑		
AECI	☑		
Allegheny Power	☑		
AEP	☑		
APPA	☑		
Exelon	☑		
FirstEnergy	☑		
ISO/RTO	☑		
KCPL	☑		"Firm" capacity dependent on DC line is similar reliability as a generator.
MISO	☑		The key word in this question is "dependent". Transfer is "firm" if DC line is in service.
NERC TIS			TIS will discuss this in further review of the standards development.
New York ISO	☑		NYISO agrees from a reliability aspect.
NCEMC	☑		Not applicable.
PJM	☑		
Seattle City	☑		Otherwise, we need reserve transfer capacity equal to the total of the firm transfers, which is not very cost effective!
Tenaska	☑		
WPS	☑		
Response: Thank you.			

E) Stability

31) Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Summary Response: Some respondents thought that the Contingencies are the same for steady state and Stability or should be made the same with only one table. Some respondents thought that having two tables was confusing while others thought it improved clarity. The large majority agreed that separating Stability from steady state was the appropriate approach. The SDT will continue to have Stability and steady state analysis separate with two tables.

Q31			
Commenter	**Yes**	**No**	**Comment**
Ameren		☑	We understand the need to clarify the different requirements in the steady- state vs. the stability analyses. However, for each contingency category we expect to see both the steady-state requirements and the corresponding stability requirements in the same table. We believe that it would be better to recombine the steady-state and stability tables and present the information in a landscape format.
Response: The Contingencies are different in the extreme category. Therefore, it will be less clear to have only one table which includes both. The SDT decided to keep two tables.			
BCTC		☑	Disagree with the assumption that steady state and stability analysis are different and should be separated. There are only minor differences between the tables and the reasons are not apparent. The separate tables appear to be unnecessary and is confusing, especially the same contingency numbering for both tables. Any contingency that must be studied in the stability period should also be considered in the post transient steady state period. Request that the SDT provide an explanation of their assumption.
FPL		☑	The separation of steady state and dynamic response analysis requirements into two tables (with different contingencies) is inferior to the analysis requirements outlined in Table 1 of the existing TPL Standard. The structure of Table 1 reinforces the requirement for grid stability and maintaining the grid within applicable limits for Category B and C contingencies. Dynamic simulations of Category B and C contingencies that demonstrate grid stability should be followed up with post transient power flow analysis to assess voltage and thermal limits.
FRCC		☑	There are two points of view for this question. One view is that having the performance requirement for steady state and dynamics on two separate tables is a good idea. It makes it easier to identify the performance requirements for steady state and dynamics. The other view is that separation of these requirements into two tables is not necessary because the existing tables are clear and FERC Order 693 only required the footnotes to be clarified not to redevelop the tables. The structure of existing Table 1 reinforces the requirement for grid stability and maintaining the grid within

Q31			
Commenter	**Yes**	**No**	**Comment**
			applicable limits.
HQTE		☑	The contingency studied are the same and as a result should be combined into one table. Only the performance might be different. We understand the need to clarify the different requirements in the steady state vs. the stability analyses. However, for each contingency category we expect to see both the steady-state requirements and the corresponding stability requirements in the same table. We believe that it would be better to recombine the steady-state and stability tables and present the information in a landscape format.
LADWP			There is no vote needed here because even under the current standards, the performance requirements for steady state and stability are clearly separated. So what is being added?
IESO	☑	☑	We agree that the performance requirements for steady state analysis differ from those for stability analysis, but not the contingency requirements. While the specification of, for example, a line to ground fault on a single facility does not mean much to a steady state analysis, and in fact the loss of a single facility is all that it matters, the system is subject to the same type of contingency regardless of the type of analysis to be performed and hence the same contingency needs to be tested in both steady-state and dynamic simulations.
Response: The SDT decided to separate steady state from Stability because the models used in the two analyses are different and the Contingencies required are different. Therefore, the SDT decided to keep two tables.			
FirstEnergy		☑	While we agree that steady-state and stability are different situations, in general we believe that the tables are confusing, overly worded, and should be combined. The initiating events are the same regardless of steady-state or stability so there should be no reason not to combine the tables as was done in the previous standards.
Response: The initiating events are different in the extreme category. Therefore, it will be less clear to have only one table. The SDT decided to keep two tables.			
New England ISO		☑	Only the difference between steady-state and stability analysis should be the performance requirements. The list of contingencies should be identical regardless of the type of analysis.
NPCC RCS		☑	The contingency studied are the same and as a result should be combined into one table.
Manitoba Hydro	☑		Yes but the definition of contingencies in table 1 and table 2 should be identical.
Progress–Florida		☑	The separation of steady state and dynamic response analysis requirements into two tables (with different contingencies) is unnecessary, and is inferior to the analysis requirements outlined in Table 1 of the existing TPL Standard. The structure of the existing Table 1 reinforces the requirement for grid stability and maintaining the grid within applicable limits for Category B and C contingencies. Dynamic simulations of Category B and C contingencies that demonstrate grid stability should be followed up with post transient power flow analysis to assess voltage and thermal limits.
Tenaska		☑	The same set of contingency tests need to be applied to in both steady state and stability studies. The performance levels may need to be characterized a little differently, but at the end of the day we

Q31			
Commenter	**Yes**	**No**	**Comment**
			are trying maintain a reliable system for the same initiating event both in a stability timeframe and a steady state timeframe.
Response: The SDT believes that some contingencies are only appropriate for steady state analysis and not for stability. The SDT believes that two tables are clearer than having only one.			
BPA	☑	☑	Support comments sent by WECC. There is a link between transient stability and steady state performance for a given event since they model serial time frames for the event.
WECC TSGT TEP	☑	☑	We agree with the question asked. In addition, because of the time sequence from the start of the fault, through fault clearing and transient dynamic period, the post-transient period to the steady state post-contingency period, there needs to be clear links between the performance requirements in the transient dynamic time period and the steady state time period. For example, if generator dropping or controlled load interruption is allowed in the transient dynamic period, it should also be allowed in the steady state time period that follows. Otherwise, it would put the Transmission Planners and the Planning Authorities in an untenable situation because, once a generator or load is dropped in the first few cycles after the disturbance; it cannot be required to be on line in the minutes that immediately follow.
Response: The SDT agrees that there should be a clear link between performance requirements in the transient period and the steady state period. We believe the standard as written provides this.			
ERCOT ISO	☑		Agree that the two analyses should be treated separately. It is not clearly defined what is steady state and what is stability. For example, are Voltage Stability (PV analysis) studies steady state or stability? Also what are the differences between System Stability and Plant Stability? Are stability studies only required for the near term planning horizon?
Response: Generally, most parties did not express confusion over the issues that are raised by this question. The SDT believes the general industry understanding is as follows: • Voltage Stability (PV analysis) is considered to be a steady state study. • Generating Unit Stability focuses on an individual generating unit or electrically closely-coupled generating units at maximum power and is concerned with Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of Interconnection or one bus away from that point. System Stability studies focus on portions of the System, which may include many generating units possibly at maximum power with Contingencies in that area of the System. System studies would also include Contingencies in large Load areas (using Load models with induction motors properly represented) which could result in fast voltage collapse. • System Stability studies are only required in the Near-Term Planning Horizon. Generating Unit Stability studies could be required for the Long-Term Planning Horizon if the commercial operation date of the plant is in the long term.			
ITC	☑		We agree but consideration should be given to the amount of work needed by entities to meet these requirements. Full scale annual stability studies may not be needed. If possible, criteria should be developed as to when stability studies need to be repeated (if at all) and to what level (i.e. every bus on the system or just the generator busses or somewhere in between).
Response: Full scale annual Stability studies are not necessarily required by the standard. Allowance is made for the use of past studies in the current year assessment.			

Q31			
Commenter	**Yes**	**No**	**Comment**
ABB	☑		Yes, I like this. You can maintain them to be as similar as possible, while still containing the requisite differences.
AECC	☑		
AECI	☑		
Allegheny Power	☑		
AEP	☑		
APPA	☑		
ATC	☑		
Brazos Electric	☑		
City Water Power and Light	☑		
CAISO	☑		Agree that the two analysis should be treated separately.
CenterPoint	☑		Separating the stability requirements into a second table improved the clarity.
Central Maine Power	☑		
CPS Energy	☑		
Duke Energy	☑		
Entergy	☑		This approach clarifies the types of stability studies/simulations to be performed. The performance criteria/guidelines are more explicit under the proposed Standard.
Exelon	☑		
Dominion	☑		
E ON US	☑		
Georgia Transm.	☑		
ISO/RTO	☑		
KCPL	☑		
LCRA	☑		
MEAG Power	☑		
MISO	☑		

Q31			
Commenter	**Yes**	**No**	**Comment**
MRO	☑		The MRO commends the SDT in separating the two tables. The single table for both types of studies has generated confusion in the industry.
Muscatine P&W	☑		
National Grid	☑		
NERC TIS	☑		Although there are many similarities, separation of the testing requirements makes the standard far more understandable.
New York ISO	☑		
NCEMC	☑		
NU	☑		
Nstar	☑		
PJM	☑		
Progress–Carolinas	☑		
ReliabilityFirst	☑		
Santee Cooper	☑		
SaskPower	☑		
Seattle City	☑		
SERC EC DRS	☑		
SERC EC PSS	☑		
SERC RRS OPS	☑		
SCE&G	☑		
Southern Transm.	☑		
TVA	☑		
United Illuminating	☑		
WPS	☑		
Northwestern Energy	☑		
Response: Thank you.			

32) Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Summary Response: The respondents were divided on this question. Most of the negative opinions expressed a view that there is no material distinction between plant and System Stability, with some indicating that the analysis and requirements are the same for both types of studies. Others also suggested that plant Stability is simply a subset of System Stability. In response to these comments, the SDT modified the standard to clarify the distinction between Generating Unit and System Stability.

The following items were changed due to industry comments:

Generating Unit Stability Study: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations.

~~**Plant Stability Study**: Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~

System Stability Study: ~~Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.~~ Study that focuses on portions of the System, which may include many generating units, to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.

R2.5. The ~~plant~~ Generating Unit Stability analysis portion of the Planning Assessment shall be analyzed consistent with Requirement ~~R4.6~~ R5.6 with studies for the year when the following changes that could affect Stability margins occur:

Q32			
Commenter	**Yes**	**No**	**Comment**
ABB		☑	I don't see any reason to differentiate between "Plant Stability" and "System Stability". These are not commonly separated, and this distinction is not standard in the industry. You should not be inventing a distinction that doesn't exist. A better differentiation would be between generator (or angular) stability and load (or voltage) stability. These are usually independently studied and independently occurring.
CenterPoint		☑	CenterPoint Energy does not see the distinction between system stability and plant stability studies as defined in the draft standard. Meeting the performance requirements set in R4.5 should suffice for all stability studies. The requirements in R4.6 seem overly prescriptive and could potentially result in numerous studies being required that would have very little positive effect on transmission systems throughout the country.
FirstEnergy		☑	We do not see the difference between plant stability and system stability. Both are based on anuglar stability of machines connected to the system and therefore, they should be treated the same.

Q32			
Commenter	**Yes**	**No**	**Comment**
Progress–Carolinas		☑	Don't need to differentiate between plant and system. These are not usually separated. It would be better to separate angular stability and voltage stability. They are studied independently.
Tenaska		☑	It is not clear that there is any difference between the two studies.

Response: See summary response. To make the distinction clearer, the SDT has modified the definitions as well as R 2.5. The SDT also believes that specificity in R 2.5 will reduce the burden of performing the Stability studies necessary to ensure a reliable BES.

Generating Unit Stability Study: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations.

~~**Plant Stability Study**: Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~

System Stability Study: ~~Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.~~ Study that focuses on portions of the System, which may include many generating units, to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.

R2.5. The ~~plant~~ Generating Unit Stability analysis portion of the Planning Assessment shall be analyzed consistent with Requirement ~~R4.6~~ R5.6 with studies for the year when the following changes that could affect Stability margins occur:

CAISO		☑	Plant stability studies are a subset of system stability studies in which loss of a generator is already evaluated to meet performance requirements. In specific situations, sensitivity analysis can be done as deemed appropriate by the TP to address a particular system problem.
Central Maine Power HQTE New England ISO NU NPCC RCS NSTAR United Illuminating		☑	A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.
National Grid		☑	As defined in R2.5, a Plant Stability Study should be a part of a System Stability Study. The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.
Northwestern Energy		☑	Plant stability is an artificial distinction and is a subset of transient stability.
LADWP		☑	See my comment on the definition of Plant Stability. Unless the standard drafting team has something completely different from the common understanding of loss of synchronism and so on,

Q32			
Commenter	**Yes**	**No**	**Comment**
			transient stability covers both the so called Plant Stability and System Stability Studies.
Response: The SDT agrees that Generating Unit Stability studies can be viewed as a subset of System Stability studies. The requirements specific to Generating Unit Stability (Requirements R 2.5 and R 4.6 (now R 5.6)) reflect that view. The SDT believes that the specific focus on Generating Unit Stability in Requirement R 2.5 will reduce the burden of performing the Stability studies necessary to ensure a reliable BES.			
FPL FRCC		☑	There should be no such distinction. All stability studies must meet the Performance Requirements for Planning Events in Table 2 - Stability Performance. If there were different Performance Requirements then the distinction may be warranted. However system stability studies should be sufficient and not warrant additional work.
Progress–Florida		☑	There should be no such distinction. All stability studies must meet the Performance Requirements for "Planning Events in Table 2 - Stability Performance". If there were different Performance Requirements then the distinction may be warranted. If the format for "Planning Events in Table 2 - Stability Performance" remains in its existing state, however, system stability studies are sufficient and performing studies under the guise of Plant Stability would constitute additional work with no incremental benefit.
Response: See summary response concerning the distinction between Generating Unit and System Stability as described in Requirements R 2.4 and R 2.5 as well as Requirements R 4.5 and R 4.6 (now Requirements R 5.5 and R 5.6). To make the distinction clearer, the SDT has modified the definitions as well as Requirements R 2.5. The SDT also believes that specificity in Requirements R 2.5 will reduce the burden of performing the stability studies necessary to ensure a reliable BES. In addition, the required Contingencies for Generating Unit Stability studies are different than the Contingencies for System Stability studies. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study**: Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~ **System Stability Study**: ~~Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.~~ Study that focuses on portions of the System, which may include many generating units, to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits. **R2.5**. The ~~plant~~ Generating Unit Stability analysis portion of the Planning Assessment shall be analyzed consistent with Requirement ~~R4.6~~ R5.6 with studies for the year when the following changes that could affect Stability margins occur:			
Dominion		☑	More clarification is needed to distinguish the difference in studies performed for plant stability vs. system stability. For example, is a system study mainly a study of inter-area (i.e. - small signal) oscillations?

Q32			
Commenter	**Yes**	**No**	**Comment**
Response: To make the distinction clearer, the SDT has modified the definitions as well as Requirement R 2.5. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study**: Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~ **System Stability Study**: ~~Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.~~ Study that focuses on portions of the System, which may include many generating units, to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits. **R2.5**. The ~~plant~~ Generating Unit Stability analysis portion of the Planning Assessment shall be analyzed consistent with Requirement ~~R4.6~~ R5.6 with studies for the year when the following changes that could affect Stability margins occur:			
BCTC		☑	Plant stability is a Generator Interconnection study, addressed by FAC-001. By including this requirement in TPL, costs may be transferred. TPL-001 need not distinguish between system stability and plant stability. For Planning Assessments, these are the same thing. Plant stability arises when doing generator interconnection.
Response: The SDT has considered your comments and believes that FAC-001, as currently written does not ensure that Generating Unit Stability studies are performed or that specific performance requirements are met. The SDT also believes that the distinction between Generating Unit and System Stability as described in Requirements R 2.4 and R 2.5 as well as Requirements R 4.5 and R 4.6 (now R 5.5 and R 5.6) is warranted. The SDT believes that specificity in Requirement R 2.5 will reduce the burden of performing the Stability studies necessary to ensure a reliable BES.			
Manitoba Hydro		☑	The need to assess Plant Stability should be removed from this standard. The generator connection standard and the proforma tariff interconnection process ensure the plant stability meets performance requirements. Furthermore, the System Assessment provides an overall assessment of the integrated system performance, which includes the impact of the plant. The requirement for plant stability studies appears to be redundant and would be a waste of assessment resources.
Response: The SDT has considered your comments and believes that neither FAC-001, as currently written, nor the pro forma tariff, ensures that Generating Unit Stability studies are performed or that specific performance requirements are met. Furthermore, not all entities within North America are subject to FERC's OATT.			
MRO		☑	The MRO sees the need for plant stability study requirements somewhere in NERC standards although adding this requirement into this study requires a rehash of the plant stability studies that are conducted throughout ten years or more in an annual assessment. This seems to be an unnecessary duplication. The MRO recommends that this requirement be deleted from this standard and that the

Q32			
Commenter	**Yes**	**No**	**Comment**
			SDT recommend to the NERC SAC that this requirement be covered by the appropriate future SAR.
Response: The SDT believes that the draft requirements do not lead to duplicative studies. If the studies that you reference meet the requirements of TPL-001-1, those studies would in fact satisfy the requirements and additional studies would not be necessary. Furthermore, we believe Requirement R2.5 will reduce the number of studies required because it only requires restudy for generator additions or material changes to the System near the generator.			
WECC BPA TSGT TEP		☑	It appears that Plant Stability Study is a subset of System Stability Study. R4.6.2 states these shall be performed for changes in real power output of a generating unit by more than 10%. Then it states they shall be performed for planning events. R4.5 already covers any contingencies that are an issue and the system already needs to meet some level of performance for loss of the generator. It seems that a change in generation would already be analyzed from a system standpoint as stated in R2.4.3. It appears that material changes to existing generators should be reflected in modeling requirements elsewhere.
Response: The SDT agrees that Generating Unit Stability studies can be viewed as a subset of System Stability studies. The requirements specific to Generating Unit Stability (Requirements R 2.5 and R 4.6 (now R 5.6)) reflect that view. The SDT believes that the specific focus on Generating Unit stability in Requirement R 2.5 will reduce the burden of performing the Stability studies necessary to ensure a reliable BES. To be clear, the 10 % change in generation capability (captured in Requirement R 5.6.2) is what drives the need for a revised study.			
CPS Energy		☑	
Response: Thank you.			
IESO	☑	☑	We agree that both plant stability and system stability have to be studied and that both must exhibit acceptable performance to deem a testing acceptable. The performance requirements for the two could be different, but not the contingency set that must be tested.
Response: The SDT believes that extreme event Contingencies are not required for Generating Unit stability studies.			
Ameren	☑		We appreciate the SDT concern for performing repeated plant stability studies without any change in plant/machine characteristics. However, as the system load representation and its damping characteristics affect both plant and system stability, it is difficult to separate plant versus system stability studies. On some systems in which load and generation are tightly coupled, the focus of plant or system stability studies may differ only slightly with the location and duration of applied fault events. As such, the scope and manner of conducting System Stability study work under Requirement R2.4. for such portions of the interconnected system is not clear. Differences between Plant Stability Studies and System Stability Studies need to be made more clear.
Response: The SDT recognizes that the specific studies required to satisfy the Generating Unit and System Stability requirements will be System specific. In that regard, for some Systems there may be little or no distinction and a single set of studies could satisfy all Stability requirements.			
City Water Power and Light	☑		Yes but the distinction is not clear in the definitions. A Plant Stability Study would typically be done as part of the Generator Interconnection Request and have all units in the area at maximum output. Is the System Stability Study done on the Base Case or is generation maximized within some area(s)?

Q32			
Commenter	**Yes**	**No**	**Comment**
Response: To make the distinction clearer, the SDT has modified the definitions as well as Requirement R 2.5 Also, as indicated in Requirement R 2.4, the System Stability studies should be run using base cases (peak and off-peak) as well as various sensitivity cases (Requirement R2.4.3). **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study**: Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~ **System Stability Study**: ~~Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.~~ Study that focuses on portions of the System, which may include many generating units, to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits. **R2.5**. The ~~plant~~ Generating Unit Stability analysis portion of the Planning Assessment shall be analyzed consistent with Requirement ~~R4.6~~ R5.6 with studies for the year when the following changes that could affect Stability margins occur:			
New York ISO	☑		NYISO agrees with the concept of splitting plant and system stability studies, but only in the area of performance requirements. The studied contingencies should be identical.
Response: The SDT believes that the selection of study Contingencies is System specific. Although it is not required, for some Systems it may be appropriate to use the same Contingency set for Generating Unit and System Stability studies.			
AECI	☑		
Allegheny Power	☑		
AEP	☑		
APPA	☑		This has been needed for some time.
ATC	☑		
Brazos Electric	☑		
E ON US	☑		
ERCOT ISO	☑		Agree with this additional analysis.
Duke Energy	☑		
Entergy	☑		See response to Q9

Q32			
Commenter	**Yes**	**No**	**Comment**
Exelon	☑		
Georgia Transm.	☑		
ISO/RTO	☑		
ITC	☑		See response to Q31.
KCPL	☑		
LCRA	☑		
MEAG Power	☑		
MISO	☑		
Muscatine P&W	☑		
NERC TIS	☑		Planning Coordinators should study plant stability at the time of interconnection, and it should be reviewed for significant system or plant modifications that may impact the plant's stability.
NCEMC	☑		
PJM	☑		
ReliabilityFirst	☑		
Santee Cooper	☑		
Seattle City	☑		
SERC EC DRS	☑		
SERC EC PSS	☑		
SERC RRS OPS	☑		
SCE&G	☑		
Southern Transm.	☑		
TVA	☑		
WPS	☑		
Response: Thank you. Please see the Summary Response.			

33) Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of Extreme Events? If not, please explain.

Summary Response: The majority of commenter's agree with excluding the loss of all generating units at a plant in the Stability analysis of Extreme Events. The SDT agrees with not including this condition in Table 2. Nevertheless any TP or PC could study this Contingency if they believe such a study is warranted.

Q33			
Commenter	**Yes**	**No**	**Comment**
ABB		☑	No. Good idea. A whole plant may be out because of a shortage of cooling water, but this is an orderly shutdown, not a sudden event. It is only appropriate for steady-state.
Brazos Electric		☑	
Dominion		☑	It is unlikely that all units at a plant would trip simultaneously within a short time frame (20 second or so) for which stability simulations are performed.
E ON US		☑	I agree with the SDT's conclusion.
AECI		☑	Agree with the statement above as to the time frame regarding stability.
CenterPoint		☑	CenterPoint Energy agrees with the SDT's assessment.
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating		☑	Difficult to envision how such an event would occur.
CPS Energy		☑	
Duke Energy		☑	We agree with the basis laid out (in the question) by the SDT.
FirstEnergy		☑	We do not believe that this condition should be required to be tested using stability analysis of Extreme Events. This is due to the fact that these events should be required to be studied using steady state analysis, and stability analysis results would not add value.
Georgia Transm.		☑	
ITC		☑	If it is not probable, then why study it. Realistic probabilities need to be established and defined for study.

Q33			
Commenter	**Yes**	**No**	**Comment**
KCPL		☑	Agree it is difficult to develop scenario where all units trip simultaneously in stability timeframe.
Muscatine P&W		☑	Unless there is a reasonable reason to expect all the units to trip.
Progress–Carolinas		☑	
Progress–Florida		☑	Analysis of this condition should not be required in stability analysis of Extreme Events due to the fact that no stability simulation (e.g., SLG or 3-phase faults) can be conceived for the Bulk Electric System that would result in simultaneous tripping of all units at a plant.
SERC EC DRS		☑	This question conflicts with Table 2 Extreme Event 9. However, we feel it is not necessary to simulate loss of all units at a station because simultaneous loss of all units is unlikely.
SERC RRS OPS		☑	It is not necessary to simulate loss of all units at a station. The Transmission Planner or Planning Authority should have the discretion to consider the appropriate number of units to be tripped based on station design, relay design, etc.
Southern Transm.		☑	
Response: Thank you.			
BCTC		☑	Stability should be treated the same as steady state. If there is a common mode event that could cause the loss of all generating units at a plant, all relevant simulations should be done. If a common mode contingency of all units at a generating plant is not relevant for stability, then it is not relevant as an extreme event for steady state either. However, operation with all units at a plant off line may be relevant as a sensitivity case for Planning Events. The Transmission Planner needs some lattitude to determine what needs to be considered under Extreme Events and the standards should not be overly prescriptive.
Response: The SDT disagrees with this point of view. There are Extreme Events which are relevant for steady state but not for Stability analyses.			
Entergy		☑	This question conflicts with Table 2 item 9. However, we feel it is not necessary to simulate loss of all units at a station. The Transmission Planner or Planning Authority should have the discretion to consider the appropriate number of units to be tripped based on station design, relay design, etc. Since there is no specific question related to R3.4 that requires an evaluation be conducted of implementing a change designed to reduce or mitigate the likelihood of such consequences. More specific direction should be provided in this regard.
LADWP		☑	Loss of a plant as an extreme contingency has been on the book forever and it has never been interpreted as exempted from stability simulation (at least not in WECC) if this scenario is chosen as an extreme event. However, there is no mandatory requirement that loss of all generating units at a plant must be studies for every generating plant. If the design of a generating plant, such as use of redundancy, separate control console/rooms, etc., are such that all unit tripping simultaneously is unlikely, then it should not be required to be studied just because all the units are inside the fence.
Response: The SDT agrees that the removal of the Requirement to consider the loss of all generating units at a plant in Stability analysis,			

Q33			
Commenter	**Yes**	**No**	**Comment**
from the Extreme Events of Table 2 does not preclude the Planner from performing this study. The language in R3.4. allows the TP or PC to evaluate the risks versus the costs of implementing mitigation or a reduction of the possibility of that Contingency.			
FPL FRCC		☑	The question does not match what is included the Extreme Events section of Table 2. Loss of all generating units at a plant should be considered in the Steady State Performance - Extreme Events but not in the Stability Performance - Extreme Events because of the very low probability of the event occurring within the timeframe of the Stability simulation. Therefore, the performance requirement number 9 for Extreme Events in Table 2 - Stability Performance should be deleted.
Response: The SDT agrees and has removed the Contingency from Table 2.			
MEAG Power NCEMC SERC EC PSS SCE&G		☑	Generator protection is designed to trip only those units required. In addition, it is the magnitude of generation tripped rather than the number of units tripped that is of the greatest significance to the stability of the grid.
Response: The SDT agrees that the magnitude of the generation being tripped is significant and should be studied when applicable. The SDT agrees that the removal of the Requirement to consider the loss of all generating units at a plant in Stability analysis from the Extreme Events of Table 2 does not preclude the Transmission Planner or Planning Coordinator from performing this study.			
New York ISO		☑	Examples of loss of entire generation station: Complete loss of right-of-way exiting facility, simultaneous relay operations due to common cause or mode.
Response: Your examples may be applicable to a site in your area and if you desire, you can continue to study steady state and Stability but the removal of this note from the Table does not stop the TP or PC from performing the stability studies if desired.			
Santee Cooper		☑	The transmission planner should have discretion to consider the appropriate number of units to be tripped based on the station design, and/or relay design.
Response: The SDT agrees that the removal of the Requirement, to consider the loss of all generating units at a plant in Stability analysis, from the Extreme Events of Table 2 does not preclude the Transmission Planner or Planning Coordinator from performing this study.			
SaskPower		☑	What is the purpose of requiring this event or any other extreme event to be studied? We see little benefit in this. In the Saskatchewan context we accept the risk and consequences for Extreme Events as there is usually very little justification for the increase in reliability versus the economic cost. Saskatchewan plans and designs its system to fail safe in those events and restores the system thereafter.
Response: The SDT agrees with your comment and that is the reason Question 33 was asked of the industry.			
Tenaska		☑	Only on a case by case basis where a common mode/single point of failure can be identified that results in the loss of an entire plant.
Response: The SDT agrees with your statement.			
TVA		☑	This question conflicts with Table 2 Extreme Event #9.
Response: The SDT agrees that this is in conflict with Table #2 Extreme Event #9 and that is why the SDT has now removed it from the Table.			
WECC		☑	We agree with the SDT that simultaneous 3-phase fault on all generating units in a plant is

Q33			
Commenter	**Yes**	**No**	**Comment**
BPA TSGT TEP			improbable and effort should be better spent studying more probable events. In any case, this Extreme Event is to be considered in the Steady State Table, and stability cases can be run if it is shown to be needed in the power flow study results. We are, however, confused by this question. This question states that the SDT did not include the requirement to consider loss of all generators at a plant in the stability, yet the Extreme Event in the stability table shows in No. 9, "3Ø fault with loss of all generating units at a station".
Response: The SDT agrees with your comment and apologizes for the confusion from the wording of the Question. The Contingency has been removed from the Table.			
Northwestern Energy	☑	☑	If such a standard is constructed, it should be based on a common mode of failure mechanism.
Response: The SDT agrees in removing this from the Table #2. However, the Standard language does not preclude a Transmission Planner or Planning Coordinator from studying this, if applicable. The Standard will allow the TP or PC to perform the study without it being a Requirement.			
AEP	☑		Extreme Event #9 in Table 2 has 3-phase fault and loss of all generating units at a station. Was this left in by mistake? This type of scenario could conceivably lead to low interconnection frequency or cascading due to consequent transmission overloading or low voltage, and could be studied by dynamic simulation. There have been a number of just such generation loss events as this in the past.
Response: The SDT did not leave the 3-phase fault in by mistake; it was intentional and follows with the other Requirements in the Table. Rather, Question 33 was phrased incorrectly in stating that this requirement had been removed from the Table. However, by not having this listed in the Requirements does not preclude the Transmission Planner or Planning Coordinator from studying this condition if applicable to their system.			
APPA	☑		This is a conditional Yes. If the plant design was such that a fault at the plant could remove all units, then all units should be considered. However, if the plant design is such that the likelihood of all plants going down at one time is improbable, then the SDT's approach is very reliable.
Response: The proposed removal of note #9 in the Table will not preclude Transmission Planners or Planning Coordinators from studying this condition if applicable.			
IESO	☑		Consistent with our comments provided under Q31, while the performance requirements may be different, there should be no distinction made to the type of contingencies that need to be applied to steady state testing and stability testing. An entire generating station may be lost due to various possible reasons: lost of right of way of transmission lines emanating from the generating station; generic protective relaying problems which cause all relays to operate due to a common cause or common mode event.
Manitoba Hydro	☑		Isn't 2.d such an event? In a breaker-and-1/3 or 1/2 generating station, if one station bus is off-line for maintenance, faulting the other bus will kill the station, or at least cause a major disruption with individual generators connected to other stations by separated lines. That is certainly worthy of consideration as a feasible "extreme" event Further, the same low likeihood argument could be applied for the majority of Extreme Events in Table 2.The emphasis should be on what the response is for Extreme Events rather than the likelihood of the event.

Q33			
Commenter	**Yes**	**No**	**Comment**
Response: The SDT and the majority of the industry do not think that this should be required in Stability analysis for Extreme Events. The events which remove all of a generating unit from the System occur over a longer period of time which is more applicable in the steady state analyses. These are Extreme Events which are relevant for steady state but not for Stability analyses.			
MRO	☑		In a breaker-and-1/3 or breaker-and-1/2 generating station, if one station bus is off-line for maintenance, faulting the other bus will kill the station, or at least cause major disruption with individual generators connected to other stations by separated lines or AC separated DC converter transformers via isolated station bays. That is certainly worthy of consideration as a feasible "extreme" event.
Response: The SDT and the majority of the industry do not think that this should be required in Stability analysis for Extreme Events. The events which occur to remove all of a plant from the system occur over a longer preiod of time which is more applicable in the steady state analyses.			
NERC TIS	☑		Simultaneous loss of the entire generating stations have occurred on 4 occasions in the last 3 years, with simultaneous losses ranging from 1,100 MW to over 3,700 MW. It is important to understand the stability implications to the system and other plants.
Response: The SDT and the majority of the Industry do not think that this should be required in Stability analysis for Extreme Events. The SDT does not believe these events would result in the loss of all generation in a Stability timeframe.			
PJM	☑		Yes, but should model the true clearing times of each individual unit. Also the standard should clearly state that system reinforcement should not be required for this Extreme Events.
Response: The SDT and the majority of the industry do not think that this should be required in Stability analysis. However, by not having it listed in the Requirements does not preclude a Transmission Planner or Planning Coordinator from studying this particular condition. Also, refer to the language of current standard Requirement R5.5.4 which addresses the reinforcement logic.			
Allegheny Power	☑		
Ameren	☑		A good test of the robustness of the interconnected system is its ability to handle import plus heavy inrush conditions, such as might occur with loss of a large plant. While the probability of such random events would be very low, the possibility still exists that intentional sabotage could result in such an event.
ATC	☑		
Response: The loss of a large gas pipeline into a region is not the same as a 3 phase fault at the generator bus location. If the gas line were ruptured, the units would be shut down over a period of minutes, not in a stability time frame. The E3.a in Table 1 is for steady state analysis.			
City Water Power and Light	☑		If there is any single contingency event that could take out an entire plant, it should be studied.
ERCOT ISO CAISO	☑		It will be consistent with the performance requirements under Steady State conditions. Also, loss of entire generating station is possible for a variety of reasons such as, loss of all lines emanating from the station, loss of the gas pipeline feeding the plant, etc.
Response: The loss of a large pipeline would not result in the sudden shutdown of all units within a stability timeframe. The shutdown occurs over tens of minutes.			

Q33			
Commenter	**Yes**	**No**	**Comment**
AECC	☑		It should also be considered in steady state analysis.
Exelon	☑		
ISO/RTO	☑		
LCRA	☑		
MISO	☑		
Seattle City	☑		
WPS	☑		
Response: Thank you.			

34) Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Summary Response: There is consensus that slow voltage recovery is an observed phenomenon that requires study and potential corrective action. However, nearly all responders noted the difficulty of obtaining accurate dynamic Load models. Based on the responses, the study of this phenomenon is in its relative infancy. Most responders are looking for guidelines for these studies whether they answered 'yes' or 'no'. The Transmission Issues Subcommittee (TIS) is forming a working group (TIS WG) to write a technical white paper on this issue. The SDT has recommended that this group include guidelines for load models in their white paper.

Based on industry comments, the SDT believes that this is such an important issue that a Requirement should be in place. As such Requirement R2.4.1 was changed. It will be up to those performing the studies to document their dynamic Load models.

R2.4.1. System peak Load for one of the five years. For peak System Load levels, ~~the~~ a Load model shall ~~include the dynamic effects~~ be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads.

Q34			
Commenter	**Yes**	**No**	**Comment**
E ON US		☑	I agree that this is an issue but I do not have sufficient data to accurately simulate the condition. This is also complicated by dynamic behavior of distribution capacitors which are not modeled.
SERC RRS OPS		☑	There is a lack of data to support the amount and characteristics of the detailed induction load models in many areas. Transmission planners should be able to use the latest information and techniques.
SCE&G		☑	There should be an attempt to represent the dynamic behavior of induction motor loads in the generic system load representations. However, the state of induction motor load modeling is not adequate to permit discrete induction motor load models.
AEP		☑	The statements of fact in the question may be true for some study areas, but not necessarily for all. Requiring this type of load representation when it might not be appropriate to the study is excessively burdensome. This is a judgment better left to those conducting the studies. The percentage of load to be so represented, the extent of the study area over which to apply induction machine representations, and the specific modeling parameters are all judgments just as important as whether or not to include this type of representation. There is a limit as to how far a standard can replace engineering judgment and that limit is reached here.
CenterPoint		☑	CenterPoint Energy includes the dynamic effects of induction motor loads in stability studies. However, this requirement is overly prescriptive since some utilities may not need to include the dynamic effects of induction motors and should not be required to do so.
Central Maine Power National Grid New England ISO		☑	This requirement is too specific and limited. Induction motors are only one component of a complex load model. Complex load models are not always necessary, nor are they always the most conservative, depending on the analysis that is being conducted. Where complex load models are

Q34			
Commenter	**Yes**	**No**	**Comment**
NU NPCC RCS NSTAR United Illuminating			required, they should be considered; this may involve use of complex motor and lighting loads or polynomial load representations with or without frequency dependence. This question also suggests the need for an industry standard regarding transient voltage recovery.
Duke Energy		☑	In general, it is a good practice for System Stability studies of seasonal load conditions to include the effects of induction motors. However, there is currently a lack of data to support the amount and characteristics of detailed induction load models in many areas. Prior to making this a requirement, the industry needs guidance as to how this data should be developed, shared and maintained for near-term and long-term models. A long term transition period is required to incorporate motor models into dynamics studies.
Entergy		☑	In general this is a good practice. Dynamic studies of seasonal load conditions should include the effects of induction motors, and particularly in areas where traditional load models have indicated a problem. Unfortunately, there is a lack of data to support the amount and characteristics of the detailed induction load models in many areas. In addition to the consideration of the dynamic effects of induction motor loads, the effects of static capacitor banks installed at distribution voltage levels would need to be considered as well. Prior to making this a requirement in the reliability standards, the industry needs guidance as to how this data should be developed and maintained for models in future years. This should be a business practice and thus removed from the standard. While we agree that each entity should appropriately model their loads, it would seem appropriate for the MMWG to address the issues of induction motor load modeling. Note that meeting such a requirement would necessitate a significant increase in the dynamic data needed to represent the system. Maintenance of such load model data would require significant resources. Load characteristics valid for a near term model might not be valid for future years.
FPL FRCC		☑	The issue of delayed voltage recovery is a special phenomenon that can occur in some large urban areas under peak conditions. The modeling of the delayed voltage recovery response is considerably more complex than simply representing induction motor effects. The scope of the delayed voltage recovery issue is extremely limited and its effect on the grid is generally self correcting due to automatic disconnection of the affected air conditioners. While improvements in the accuracy of load models used for the study of grid dynamic response are desirable, this area is not suitable for compliance enforcement. Requirements for specific types of load models are not appropriate in the TPL standard.
KCPL		☑	Transmission operators are required to maintain reactive reserve requirements.
MEAG Power NCEMC SERC EC DRS SERC EC PSS TVA		☑	Dynamic studies of seasonal load conditions should include the effects of induction motors, and particularly in areas where traditional load models have indicated a problem. Unfortunately, there is a lack of data to support the amount and characteristics of the detailed induction load models in many areas. In addition to the consideration of the dynamic effects of induction motor loads, the effects of static capacitor banks installed at distribution voltage levels would need to be considered as

Q34			
Commenter	**Yes**	**No**	**Comment**
			well. Prior to making this a requirement in the reliability standards, the industry needs guidance as to how this data should be developed and maintained for models in future years. Note that meeting such a requirement would necessitate a significant increase in the dynamic data needed to represent the system. Maintenance of such load model data would require significant resources. Load characteristics valid for a near term model might not be valid for future years. Also, summer peak load, winter peak load, and off-peak load characteristics would differ.
Muscatine P&W			We have not seen this on our system based on the review of digital fault recorders (DFR). The difficulty with including induction motors is getting reasonable data from customers about their motors so they can be adequately modeled. (We did ask our consultant to include motor effect in our coordination study since the motors could act as a weak source.)
PJM		☑	No. This is good in theory but is impractical to implement with the large interconnected systems that span large geographical areas.
Progress–Florida		☑	Requiring detailed modeling of every induction motor on the Bulk Electric System for stability analysis is onerous. Specifically, obtaining a complete set of data for existing induction motors would be infeasible, as would tracking future installations of induction motors. The benefits of such an effort are significantly outweighed by the logistical difficulties. To address the technical merits, the modeling of the delayed voltage recovery response that has been observed in some large urban areas during periods of high air conditioning usage is considerably more complex than can be addressed by simply representing induction motor effects. The scope of the delayed voltage recovery issue is extremely limited and its effect on the grid is generally self correcting due to automatic disconnection of the affected air conditioners. Requirements for specific types of load models are not appropriate in the TPL standard.
Santee Cooper		☑	The characteristics of detailed induction load are generally lacking to properly model induction loads. Load modeling should be left to the judgment of the TP.
Response: See the summary response, The SDT has recommended that the TIS WG writing the white paper on this phenomenon review your suggestions and comments.			
CPS Energy		☑	
Response: See summary response.			
AECC		☑	if someone want to study the effect of large motor load then fine but it should not be a requirement of a standard
Response: The SDT has received comments regarding the technical merits to include such behavior when appropriate. The SDT feels that proposing this requirement could potentially result in System studies that indicate System response that would meet the performance requirements when in fact the response may fall short.			
Ameren	☑	☑	Dynamic studies of peak load conditions should include the effects of induction motors, and particularly in areas where traditional load models have indicated a problem. Unfortunately, there is a lack of data to support the amount and characteristics of the detailed induction load models in

Q34			
Commenter	**Yes**	**No**	**Comment**
			many areas. In addition to the consideration of the dynamic effects of induction motor loads, the effects of static capacitor banks installed at both distribution and transmission voltage levels would need to be considered as well. The industry would be looking to NERC for some guidance as to how this data should be developed and maintained for models in future years. Note that meeting such a requirement would necessitate a significant increase in the dynamic data needed to represent the system. Also, maintenance of such load model data would need to be considered. Load characteristics valid for a near term model might not be valid for future years. Also, summer peak load, winter peak load, and off-peak load characteristics would differ.
Dominion	☑	☑	The dynamic effects of induction motor load at peak load conditions should be studied only on a limited/selected basis and should not be required for the entire system as a routine study practice. The following are examples where such an effort might be warranted: (a) where slow voltage recovery has been actually observed in the field following a fault clearance (b) where steady state analysis (P-V & Q-V curves) indicates a possible voltage collapse scenario for stressed system conditions (c) for a non-convergent (or very difficult to solve) power-flow case for stressed system conditions while solving for a contingency scenario.
Exelon	☑	☑	This is more pertinent to longer term voltage stability, so the load model should be developed and available for these types of studies.
WECC TSGT TEP BPA	☑	☑	The requirement to include motor load should be extended to other load level periods and not be limited to peak load period only. However, to capture slow voltage recover phenomena, especially in areas of high penetration of refrigerated air conditioning load (e.g. 50% to 60%), would require modeling down to the distribution system voltage level and explicitly representing shunt capacitors and various induction motor types (e.g. equivalents for single phase motors). If the requirement is not extended, dynamic simulations will likely differ significantly from observed system events. We recommend a phase-in period so that the requirement for use of load models should only include regionally accepted load models for which data are available. This requirement can be extended or modified as the Region in which the entities reside adopts new load modeling guidelines.
Brazos Electric	☑		However, acquiring load data may be difficult if not impossible and would require increased manpower. A more reasonable approach is to vary the load data to see the effects instead of wasting effort on load surveys.
City Water Power and Light	☑		However, low voltage often causes motors and air conditioner compressors to trip, significantly reducing peak loads.
ERCOT ISO CAISO	☑		The requirement to include motor load should be extended to other load levels as appropriate.
FirstEnergy	☑		We agree with this concept but believe that enforcing it would be very difficult. There are no standards on modeling induction motor load, be it type of models, percentage of load that is motor

Q34			
Commenter	**Yes**	**No**	**Comment**
			load, or percentage of large vs small motors.
HQTE	☑		This requirement is too specific and limited. Induction motors are only one component of a complex load model. Complex load models are not always necessary, nor are they always the most conservative, depending on the analysis that is being conducted. Where complex load models are required, they should be considered; this may involve use of complex motor and lighting loads or polynomial load representations with or without frequency dependence. This question also suggests the need for an industry standard regarding transient voltage recovery.
IESO	☑		Dynamic testing should assess response of moving equipment including induction motor loads.
ITC	☑		However this will require the Load Serving Entities provide specific data for each bus on the system which may not be in the direct control of the entity performing the studies. The standard should be written with this understanding in mind. Failure of a LSE to provide such data should not cause a penalty to be imposed on a Transmission Provider.
LADWP	☑		This is a qualified yes to the extent that accurate induction motor models are available and the overall load modeling (non-induction motor loads) allow such analysis. Otherwise, focusing only on induction motors would not provide added information than what is being performed today. The current WECC requirement concerning induction motor modeling should be deemed adequate to meet this requirement.
Manitoba Hydro	☑		R2.4.1 should be clarified to limit a requirement for detailed modeling (for example, dynamic effects of induction motors loads) to local areas where the planner expects a local emerging voltage recovery issue.
MISO	☑		Yes, we agree that appropriate induction motor loads should be modeled. No, it is not be practical to model all induction motor loads. There needs to be size and location considerations. Data is not readily available today.
MRO	☑		The MRO agrees that R2.4.1 should provide for the inclusion of dynamic behavior of induction motor loads, however, recommends that there should be a limitation on only requiring such behavior where significant such as large motor loads over a certain MW amount. As written, it could be interpreted that the Transmission Planner is non-compliant if all induction motors are not represented.
Progress–Carolinas	☑		This needs to be done but we currently don't have sufficient data and tools to properly perform the analysis. More interconnection-wide testing and data collection needs to be performed. We will need to transition into these studies over time.
ABB	☑		Yes, but the impact on the models and studies is unknown. Some testing needs to be done with full Eastern and Western Interconnection models to see how they handle motor models at every load. I've performed numerous studies where loads in an entire utility or state have been converted to a large % of motors, and the effect can be shocking. The programs (PSS/E and PSLF) may completely bog down if this is done for a whole interconnection. Many stability problems will be found. We definitely need to transition to this, but with care.
Northwestern Energy	☑		

Q34			
Commenter	**Yes**	**No**	**Comment**
AECI	☑		However, getting all the modeling data is not easy and may take some time.
Allegheny Power	☑		
APPA	☑		The SDT is correct to include the effects of induction motors in simulating the loads. Voltage issues are and will continue to become more critical in the operation of the BES as time goes by. It will be a big help to planners and operators to know the impacts of such loads.
ATC	☑		
BCTC	☑		
Georgia Transm.	☑		
ISO/RTO	☑		
LCRA	☑		
NERC TIS	☑		If such known phenomena are not properly modeled, how can the resultant study results be expected to be correct and a proper prediction of future system behavior. The modeling shortcomings of the Western Interconnection prior to the August 1996 western blackout showed no potential stability problems for the events that occurred; the system proved otherwise.
New York ISO	☑		
SaskPower	☑		
Seattle City	☑		
Southern Transm.	☑		
WPS	☑		
Response: See the summary response, The SDT has recommended that the TIS WG writing the white paper on this phenomenon review your suggestions and comments.			

35) Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Summary Response: Most responders said or implied that all adjustments should be allowed for both single and multiple Contingencies. Some respondents further clarify their response by adding the adjustments must be achieved within a specific timeframe such as meeting performance requirements or the ability to keep the generator on-line. A small number of responders replied that no adjustments should be allowed for single Contingencies but then agreed that adjustments may be allowed for multiple Contingencies.

The SDT has modified Requirement R 3.6 (now R3.5) of the steady state portion of the Planning Assessment to specify the conditions under which manual and automatic generation runback and tripping can be used to meet single and multiple Contingency performance requirements and to make it clear that all Facilities must always remain within applicable thermal and voltage ratings.

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:

Q35	
Commenter	**Comment**
ABB	For multiple, only automatic schemes. For single, only automatic schemes if the loss of MW is shown to be acceptable.
Ameren	No adjustment of firm (network resource) generation should be allowed for the long-term mitigation of a single contingency. Allowing post-contingency shifts of firm generation as a long-term mitigation of a single contingency event is short-sighted and would not produce a robust system that is required to handle more than single contingency events. Redispatch of firm generation may be required in the near-term as an interim operating guide or procedure until the limiting transmission element can be uprated or other system reinforcement is in place. Generation redispatch should also be allowed to prepare for the next single contingency. For responding to multiple contingencies, redispatch of firm generation should be allowed in the mitigation plan provided that the redispatch can be accomplished in the required operating time and the contingency overloads are not overly severe (indicating possible cascading). Firm generation should also be tripped to quickly mitigate contingencies involving multiple generation outlet transmission circuits. Non-firm (energy only) generation can be tripped or redispatched for any contingency event as needed to keep facility loadings within ratings.
City Water Power and Light	Dispatching quick start units such as combustion turbines or diesels, Contingency Reserve Sharing Group response, redispatch, adjust reactive resources as necessary.
Dominion	For a single contingency, no generation adjustment should be allowed. For multiple transmission element contingencies, generation reduction (automatic or manual runback) may be allowed. Unit trip should only be allowed if a unit becomes unstable.
E ON US	single – none
ERCOT ISO CAISO	Manual such as tripping the generators, automatic such as AVR, excitation systems, stabilizer, and governor adjustments. From a Planning perspective, you would not want to allow for manual tripping in the time frame of a stability study.

Q35	
Commenter	**Comment**
BCTC	No restrictions on adjustments that are practical and can be achieved within the timeframe required.
Northwestern Energy	All adjustments should be allowed as long as they are realistic and achievable in the time frame required and consistent with other study parameters. Also, if a RAS (or special protection system) is the adjustment and if cascading could result from the event, then redundancy should be required.
MEAG Power NCEMC SERC EC PSS SCE&G	Adjustments that should be allowed are those that can be performed in time to prevent the system from failing to meet performance requirements. These adjustments may include automatic voltage regulator action, governor action, generator runback, and generator tripping.
AECI	Whatever the generator is capable of.
Allegheny Power	Should not be limited.
AEP	The existing TPL standards imply that generator tripping is not permissible in connection with Category B events in that footnote b does not mention it, whereas it is mentioned in connection with Category C events in footnote c. Generation is a system resource and should be protected against the more common single contingency transmission events. We agree with the status quo on this issue being maintained in the new standard, with the provision for regional variance in R3.6. The provision for manual and automatic runback in R3.5 is okay. We also agree with manual adjustments remaining acceptable in response to any contingencies in the new standard consistent with C3 in existing TPL-003.
Central Maine Power HQTE National Grid New England ISO NU NPCC PCS NSTAR United Illuminating	Manual or automatic adjustments should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment. Manual system adjustment should be allowed in between the multiple Contingencies described in P5, provided that the adjustment can be made between contingencies using short-term reserves (10-30 minute).
Duke Energy	This question is not clear. Manual and automatic adjustments should be allowed for single and multiple contingencies as long as Performance Requirements are met.
Exelon	Generator MW and Mvar output adjustments should be allowed, both manual and automatic.
FirstEnergy	As long as thermal, voltage, and stability requirements are met, either automatic or manual runback of the unit should be allowed. Tripping of the unit should be allowed also if the particular unit(s) can be restarted within some relatively short time - say one hour. With this requirement, it appears that only CTs and hydro units would be allowed to be tripped.
FPL FRCC	Manual and automatic adjustment (increase or decrease) of Var output and manual and automatic tripping or reduction of overall MW output of generators should be allowed.
Georgia Transm.	Special Protection Schemes should be allowed for single and multiple contingencies.
IESO	Automatic adjustments should include AVR, excitation system, stabilizer and governor, all of which have pre-determined settings. These adjustments should be allowed for any type of contingencies. Manual adjustments that should or can be made other than removal of the generating units from service could include manual switching of

Q35	
Commenter	**Comment**
	transmission and adjustment to Phase Angle Regulators for so long that these actions are documented as applicable operating procedures.
ITC	There should be no change in generation for single contingencies. An approved SPS in those areas that use them might be an exception however system damage for failure to operate should not be allowed beyond the station with the SPS. Also, loss of load should not be allowed for failure to operate. An automated adjustment for multiple contingencies is not unrealistic.
KCPL	Generation redispatch should not be allowed for N-1 events. Generation redispatch is appropriate for multiple contingencies. Appropriate SPS and generation runback schemes should be allowed, where the system is designed with those schemes.
LADWP	Whatever is needed to bring the system into balance.
Manitoba Hydro	1) Reducing or increasing generation while keeping the units on-line or by bringing additional units on line. The amount of generation change should be limited to that amount that can be accomplished within the allowed readjustment period. Due consideration should be given to start up time and ramp rates of the units. 2) Generator tripping should be added to requirement R3.5 in addition to runback. Generator tripping is used extensively in regions where remote generation is delivered via long transmission. 3) Adjustment of firm transfer must be allowed for single and multiple contingency events. MH could not accept the revised standard that removed this existing requirement.
MISO	Generation redispatch should not be performed for single contingencies. Generation redispatch is appropriate for multiple contingencies. Appropriate SPS and generation runback schemes should be allowed, where the system is designed with those schemes.
MRO	Here are the adjustments that the MRO believes the MRO systems are presently designed to meet and what an MRO Augmentation Drafting Team is proposing to require its members to follow for Category B and C events: 1. Generation adjustments - Reducing or increasing generation while keeping the units on-line or by bringing additional units on line. The amount of generation change is limited to that amount that can be accomplished within the allowed readjustment period. Due consideration shall be given to start up time and ramp rates of the units. 2. Generation rejection to the extent possible within the allowed readjustment period. Generation rejection shall not exceed the normal operating reserve of the generation reserve sharing pool to which the MRO Member belongs or of the MRO Member itself if the MRO Member self-provides generation reserves.
Muscatine P&W	Whatever the local entity sees as appropriate and is reasonable versus the cost of fixing the problem. (See Q43 Comment #3)
NERC TIS	If system adjustments are allowed between events in steady state analysis, manual and automatic adjustments should both be allowed. However, in stability analysis, only automatic adjustments capabilities that are actually in place should be used.
New York ISO	Automatic: Pre-determined ranges of AVR, excitation system, stabilizer and governor. Manual: switching and PAR adjustments covered by applicable operating procedures.
PJM	Adjustments should be allowed consistent the time periods being studied.
Progress–Carolinas	Both manual and automatic adjustments should be allowed.

Q35	
Commenter	**Comment**
Progress–Florida	Provided events are confined to a single area (i.e., no cascading outages), manual and automatic adjustment (increase or decrease) of Var output and manual and automatic tripping or reduction of overall output of generators should be allowed
Santee Cooper SERC RRS OPS TVA	Any adjustments should be allowed that protects the reliability of the BES.
SaskPower	The amount of generation change should be limited to the amount that can be accomplished within the allowed readjustment period. Due consideration should be given to start up time and ramp rates of the units. Generation rejection should not exceed the normal operating reserve.
Seattle City	Any adjustment required to respond to a contingency should be allowed, unless it adversely impacts the regional system.
SERC EC DRS	Manual and automatic adjustments should be allowed for single and multiple contingencies as long as performance requirements are met.
SERC EC PSS SCE&G	Adjustments that should be allowed are those that can be performed in time to prevent the system from failing to meet performance requirements. These adjustments may include automatic voltage regulator action, governor action, generator runback, and generator tripping.
Southern Transm.	Automatic generator tripping should be allowed for single contingency events and for multiple contingency events.
Tenaska	Any adjustment(manual, automatic, runback, tripping) should be allowed as long as the performance requirements are achieved as described in standard after the adjustments have been made.
WECC BPA TSGT TEP	All adjustments should be allowed as long as they are realistic and achievable in the time frame required and consistent with other study parameters. For example, automatic adjustments would be required for correction of a stability problem, but manual adjustment should be allowed for correction of a thermal problem if there is no instability problem.
AECC	any that are realistic, can be accomplished in the appropriate timeframe and are within the capability of the units
Response: Based on the majority of industry responses, the SDT has modified Requirement R 3.6 (now R 3.5) to specify conditions under which manual and automatic generation runback and tripping can be used to meet single and multiple Contingency performance requirements for the steady state portion of the Planning Assessment. **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:	
APPA	I do not understand the question. Is this dealing with voltage adjustment or power adjustment?
Response: Generation runback deals with a machine's power adjustment.	
Entergy	This question is not clear and more explanation should be provided, such as, whether the adjustments are pre or post contingency, whether the contingency involves faults etc. Does this question pertain to plant or system stability?
Response: Adjustments are post-Contingency. Based on the majority of industry responses, the SDT has modified Requirement R 3.6 (now R 3.5) to specify conditions under which manual and automatic generation runback and tripping can be used to meet single and multiple Contingency performance requirements for the steady state portion of the Planning Assessment.	

Q35	
Commenter	**Comment**
R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:	

F) Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

36) Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Summary Response: The overwhelming majority of respondents believe that generator runback should be allowed for single Contingencies. One respondent thought that runback of firm generation should only be allowed as an interim Operating Procedure until System reinforcements are installed. Another thought that a generator that must reduce output for N-1 is not "firm" generation capacity. Another cautioned that runback may not be fast enough to avoid voltage instability. The draft standard will continue to allow manual or automatic generation run-back as a response to single and multiple Contingencies as long as all Facilities shall be operating within their Facility Ratings and as long as a sustainable, stable, operating condition is maintained.

The following requirements have been added due to industry comments:

R3.5.2. Such action would not violate safety, equipment, regulatory or statutory requirements.
R3.5.3. A sustainable, stable, operating condition is maintained.

Q36			
Commenter	**Yes**	**No**	**Comment**
Ameren		☑	The runback of firm generation should only be allowed as a valid interim operating procedure until a system reinforcement would be installed to uprate or unload the limiting facility. The use of the runback scheme should not be allowed as the long-term solution to a single contingency event. As mentioned above in the response to Q35, non-firm (energy only) generation should be tripped or redispatched for any contingency event as needed to keep facility loadings within ratings.
Response: The SDT and the majority of the industry do not agree that generation runback should be used only as a temporary solution.			
Dominion		☑	For a single contingency, no generation adjustment should be allowed. For multiple transmission element contingencies, generation reduction (automatic or manual runback) may be allowed. Unit

Q36			
Commenter	**Yes**	**No**	**Comment**
			trip should only be allowed if a unit becomes unstable.
Response: The SDT and the majority of the industry agree that the use of generation runback should be allowed for single Contingencies.			
AECC		☑	Generation runback should only be permitted if there are no impacts to area interchange and firm transactions are not altered.
Response: The allowable impact to firm transactions is specified in the performance tables. The use of generation runback is only allowed if the performance requirements are met.			
E ON US		☑	I do not agree that the system has to be returned to a "normal state" after a single contingency. The system can continue to be operated in the "emergency state" as long as the next contingency does not cause flows above emergency ratings.
Response: The SDT agrees that the System can be operated in an emergency state as long as the next Contingency does not cause flows above emergency ratings. However, this does not preclude the use of runback to get flows back within normal ratings.			
BCTC		☑	We do not accept R3.5, which does not limit runback to contingencies based on thermal limits, only that Facility Ratings are not exceeded. If an SOL is based on voltage stability (which is often studied in the post disturbance steady state), Facility Ratings may not be exceeded but runback may not be fast enough to avoid voltage instability. Furthermore, runback for single contingencies should be subject to any conditions that might apply to generator tripping for single contingencies. See response to Question 39.
Response: Requirement R3.5 now has two additional qualifiers on the use of generator runback other than Facilities must be within Facility Ratings: **R3.5.2**. Such action would not violate safety, equipment, regulatory or statutory requirements. **R3.5.3**. A sustainable, stable, operating condition is maintained.			
KCPL		☑	All generators must have "firm" transmission outlet capacity for their nameplate rating. This means delivery of full output under N-1 conditions. A generator that must reduce output for N-1 is not "firm" generation capacity.
Response: The SDT believes that if an n-1 Contingency results in flows within emergency ratings, then the generator has firm Transmission outlet capacity even if it must be backed down to get the System back within normal ratings.			
MISO	☑	☑	Yes, where the transmission system is designed with these schemes. No, in general when there is no designed SPS or runback for the generator.
Response: The SDT believes that runback should be allowed both for existing schemes and for new schemes.			
ABB	☑		Every single event will eventually require preparing for the next event. But we cannot plan for every next event. Only specific single and multiple contingencies should be planned for, all flows must be within an established rating of some kind (continuous, 12-hour, 4-hour, 15-min, whatever), and the idea of the "next event" should not be included in a planning standard. Now maybe there should be a limit as to how short the time of a rating can be in Planning. For example, planning to a 15-min rating is a bad idea. That rating can be used by operators in emergencies, but planners need to do something better. A minimum should be set (e.g. 1 hour

Q36			
Commenter	**Yes**	**No**	**Comment**
			rating). I guess if a company wants to use a 15-min rating and then AUTOMATICALLY transition to a 1-hour or 12-hour rating with runback or something else, that is reasonable.
Response: The SDT considered minimum time duration for the emergency ratings used in planning. However, the SDT decided this would be too restrictive.			
AEP	☑		Question: Why would a runback scheme be needed to move from an emergency state to a normal state when that could be accomplished by regular redispatch?
Response: If regular redispatch can adjust the System following a single Contingency in preparation for the next Contingency in the time frame required by emergency ratings, then no automatic runback is needed.			
APPA	☑		However, it should be pointed out that RAS are band-aid solutions to building needed BES infrastructure. Experience has shown that an interconnection can have so many RAS that one RAS will counter another RAS designed for another problem in the interconnection. This problem requires additional study by a NERC task force.
Response: The SDT and the majority of the industry do not agree that automatic generation runback (by use of an RAS) should be used only as a temporary (or band-aid) solution.			
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating	☑		Generation runback should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment
Response: The SDT agrees.			
Exelon	☑		An automated run-back scheme should be allowed but not required for these scenarios - an operator should be able to manually adjust unit output.
Response: If an operator can adjust the system following a single contingency in preparation for the next contingency in the time frame required by emergency ratings, then no automatic runback is needed.			
FirstEnergy	☑		As long as thermal, voltage, and stability requirements are met, either automatic or manual runback of the unit should be allowed. Tripping of the unit should be allowed also if the particular unit(s) can be restarted within some relatively short time - say one hour. With this requirement, it appears that only CTs and hydro units would be allowed to be tripped.
Response: The SDT agrees that automatic or manual runback should be allowed. We do not agree that only CTs and hydro units could be tripped by SPS.			
Manitoba Hydro	☑		Generator tripping should be added in addition to runback. Generator tripping is used extensively in regions where remote generation is delivered via long transmission There will be a large cost penalty to construct transmisison to remote generation if generator tripping is not allowed. Since the amount of tripping is covered by operating eserves, there is no impact on reliability. Generator tripping should be an option for the planner in the standard as opposed to a regional difference or the need to

Q36			
Commenter	**Yes**	**No**	**Comment**
			install an SPS.
Response: The SDT agrees that generator tripping should be allowed for single and multiple Contingencies (See R 3.5)			
New York ISO	☑		What is the difference between a SPS and RAS? Would not one term be sufficient? SPSs should not be considered a permanent solution. They should only be used as a stop gap before a permanent solution can be implemented.
Response: SPS and RAS are synonymous terms. The SDT and the majority of the industry do not agree that SPS should be used only as a temporary solution.			
ERCOT ISO	☑		Agree
Northwestern Energy	☑		
AECI	☑		
Allegheny Power	☑		
ATC	☑		
BPA	☑		
Brazos Electric	☑		
CAISO	☑		Agree
CenterPoint	☑		
City Water Power and Light	☑		
City Utilities/Springfield	☑		
CPS Energy	☑		
Duke Energy	☑		We see this as an acceptable form of manual or automatic redispatch, which should be allowed as a cost beneficial way of operating the system in a reliable manner, as long as it can be accomplished within the time frame before emergency ratings are exceeded.
Entegra	☑		As long as the system would be within normal ratings after runback.
Entergy	☑		
FPL	☑		
FRCC	☑		
Georgia Transm.	☑		
IESO	☑		Generation rejection and runback are not uncommon to be employed as special protection systems (SPS) to achieve a stable state and/or reduce transmission loading to within pre-determined levels.

Q36			
Commenter	**Yes**	**No**	**Comment**
			SPSs, when employed, are designed to operate in order to meet performance requirements following specific contingencies or when specific system conditions are present. As such, when a contingency occurs or when the conditions should arise for which the SPS (in this case, generation runback) is designed to operate, such actions should be simulated.
ISO/RTO	☑		
ITC	☑		
LADWP	☑		Generator runback is allowed under the current standards, why single this out? Hopefully this is not a sign of equating generator runback with generator tripping as the title of this section might suggested. Generator runback is not and should not be classified as an SPS! It is critical to keep as many units on line as possible post contingency. In many instances, use of generator runback would avoid the need to trip a unit if that was the only way to reduce the generations to return to load-generation balances.
MEAG Power	☑		
MRO	☑		
Muscatine P&W	☑		
NERC TIS	☑		This is simply a recognition that the system operators will take action to return the system to a stable and secure operating posture following an event.
NCEMC	☑		
PJM	☑		
Progress–Carolinas	☑		
Progress–Florida	☑		
SRP	☑		
Santee Cooper	☑		
SaskPower	☑		
Seattle City	☑		
SERC EC DRS	☑		
SERC EC PSS	☑		
SERC RRS OPS	☑		
SCE&G	☑		

Q36			
Commenter	**Yes**	**No**	**Comment**
Southern Transm.	☑		
Tenaska	☑		
TVA	☑		
TSGT	☑		
TEP	☑		
WECC	☑		
WPS	☑		
Response: Thank you. Please see the Summary Response.			

37) Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Summary Response: Respondents appeared to overwhelmingly favor allowance of automatic generation runback to prevent thermal overloads. However, as some respondents indicated the question was not clear and a number indicated that Requirement R 3.5 could be made clearer. Many respondents suggested various conditions be added to the requirements. The SDT has modified Requirement R 3.5 to specify the conditions under which automatic (or manual) generation runback can be used to meet single (or multiple) contingency performance requirements and to make it clear that all facilities must always remain within applicable thermal and voltage ratings.

The following requirement was changed due to industry comments:

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:

Q37			
Commenter	**Yes**	**No**	**Comment**
Dominion		☑	For a single contingency, no generation adjustment should be allowed. For multiple transmission element contingencies, generation reduction (automatic or manual runback) may be allowed. Unit trip should only be allowed if a unit becomes unstable.
Duke Energy		☑	Runback should not be used if the disturbance caused you to exceed emergency ratings (i.e. thermal overload).
Ameren		☑	No generation runbacks should be allowed as long-term solutions for single contingency conditions.
Entergy	☑	☑	The question is not clear. Generation runback schemes are acceptable as long as emergency ratings are not violated. Runbacks should not be used to restore an element to within emergency ratings.
MISO	☑	☑	No, this should be the exception, not the rule. Yes, there are mine mouth plants with DC outlet lines, which must be runback if the DC line trips. There are also generators which used to serve large on site loads. The large loads are gone (plants retired) and generator outlet is limited. There are also some generators which have known contingent outlet limits and the generators are OK with runback, if the contingency occurs.
AECI	☑		We do not have the capability to have automatic runback at this time. However if an entity does have the capability to perform automatic runback than it should be allowed to prevent overloads. That would be the purpose.
Progress–Florida	☑		Provided events are confined to a single area (i.e., no cascading outages), automatic runback of generators should be allowed.
SERC EC DRS		☑	The question is not clear. Generation runback schemes are acceptable as long as emergency ratings are not violated. Runback schemes should not be used to restore an element to within emergency ratings.

Q37			
Commenter	**Yes**	**No**	**Comment**
Response: Industry comments strongly support allowing for the use of generator runback for single Contingencies. Generation runback will be permitted for all Contingencies, and the SDT has modified the standard language accordingly (See Requirement R 3.5). **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:			
ITC		☑	We believe that the BES should be able to operate for N-1 events without reliance on operating schemes. Assuming that some areas allow this, there should be criteria to evaluate the consequences of 2nd contingencies occurring during the runback. In addition, short-time ratings need to be confirmed which limit the time for runback. The system is at risk until the runback is completed and this risk must be evaluated and REQUIRED in the planning assessment.
Response: Industry comments strongly support allowing for the use of generator runback to prevent thermal overloads. The SDT has modified the standard language to clarify this view, including the requirement to remain within Facility Ratings during the course of the runback.			
KCPL		☑	All generators must have "firm" transmission outlet capacity.
Response: Industry comments strongly support allowing for the use of generator runback to prevent thermal overloads. The SDT has modified the standard language to clarify this view.			
ABB	☑	☑	No. Following a single contingency, all flows must be within some kind of established rating. After that, runback can be used to get under a longer-term rating. For multiple contingencies, some type of cross-tripping is OK, but runback is too slow and unreliable.
AECC		☑	Implementing an automatic runback scheme will only mask the impacts of the event. You want to know what happens when an event occurs not set up some psuedo fix that takes place before you know what the problem is.
Response: Industry comments strongly support allowing for the use of generator runback for single contingencies. The SDT has modified the standard language accordingly.			
BCTC	☑	☑	See our response to Question 36. In addition, since this runback is effectively a RAS/SPS with respect to protecting the transmission system from cascading, it must meet all the reliability requirements of a RAS.
Response: The SDT agrees that an automatic generation runback scheme is an SPS, and it must meet the applicable reliability requirements.			
PJM	☑	☑	Yes. At a minimum the emergency rating needs to be coordinated with the SPS timing.
Brazos Electric	☑		Can be including in a RAP or SPS with a long term CAP.
City Water Power and Light	☑		Coordination with neighboring systems is essential when considering generation redispatch.
ERCOT ISO CAISO	☑		1. Run back of generation should not result in tripping of firm load, 2. Power flow should be within the applicable ratings, 3. Frequency should be within the allowable limits
WECC	☑		Yes. Agree. Conditions for generation run back for N-1: 1) Run back of generation cannot result in

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Commenter	**Yes**	**No**	**Comment**
BPA TSGT TEP			tripping of firm load, 2) power flow should be within the time-limited equipment ratings, 3) frequency should be within allowable limits.
Northwestern Energy	☑		Yes, (1) if the failure of the runback scheme results in cascading, then it should not be allowed; (2) the power flow should be within the time-limited equipment ratings; and (3) the frequency should be within allowable limits.
Allegheny Power	☑		This could be permitted provided the run back will allow for the ability to prepare for the next operational contingency and not affect load.
AEP	☑		Ensure that the scheme is enabled to automatically runback for the problem conditions.
APPA	☑		Care must be taken to insure runbacks of one event will not cancel the effects of other runback plans in the same interconnections.
Central Maine Power HQTE National Grid NU NPCC RCS New England ISO NSTAR United Illuminating	☑		However, this should only be allowed where failure of an automatic runback that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.
Exelon	☑		Run-back schemes should be allowed for certain single contingencies that can result in unit outlet constraints. Not all emergency ratings are thermal - some are relay or stability limits. In these instances, generator run-back should not be allowed.
FirstEnergy	☑		Yes, only if the Transmission Owner has documented short term ratings that would not be exceeded during the runback.
FPL FRCC	☑		At a minimum the emergency ratings should allow sufficient time for the runback scheme to operate reliably
Georgia Transm.	☑		Generation curtailment should allow the system to operate within the facility capabilities and should not put the generator at risk of violating its NERC requirements during curtailment.
IESO	☑		Please see our response to Q36 for the rationale for allowing the runback scheme to operate. The conditions that need to be met in order to allow the scheme to operate depends specifically on what that SPS (runback scheme) is designed for. Some schemes are designed to operate upon detecting the opening of specific transmission lines, others are designed to operate upon detection of circuit loading reaching a particular threshold. There is no universal rule as to the conditions that must be met for a runback scheme to operate. The use of runback scheme is similar to using special operating procedure, such as cross tripping, operator instructions to open a circuit, etc. There might be design requirements to ensure the scheme meet certain performance criteria. However, these should be covered in the standards for special protection system. In TPL-001, the requirement would be to include simulation of the runback scheme operation only as the conditions that would prompt the

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Commenter	**Yes**	**No**	**Comment**
			scheme to operate occur, and a requirement to include SPS misoperation, i.e., failure to operate and operate when not initiated, as a contingency.
Manitoba Hydro	☑		I see no problem in using a runback scheme to prevent thermal overloads. Most emergency ratings are based on 30 minute values to allow for operator action. An automatic runback could be accomplished in 5-15 minutes depending on the ramp rate of the generator. The runback scheme may allow higher emergency ratings depending on the rating methodology. At no point would emergency ratings be exceeded and at the end, loading would be within normal values.
MEAG Power NCEMC SERC EC PSS SCE&G TVA	☑		The generator runback scheme should complete its action within the time allowed by the emergency ratings of elements that exceed their normal thermal ratings.
NERC TIS	☑		This is simply a recognition that the system operators will take action to return the system to a stable and secure operating posture following an event. This is also common practice in generator protection/controls for generators with multiple GSUs for loss of one of the GSUs.
New York ISO	☑		Testing scenarios will have to be developed on a case by case basis depending on the design of the SPS. There is not universal rule that can be made for these unique cases.
Progress–Carolinas	☑		If the rating is a 2 hour rating then the adjustment should be complete within 2 hours.
SRP	☑		The loss of transmission line (N-1) may require Gen drop to prevent instability or violation. Studies will need to be performed that study the congestion of generation and transmission corridors and loss of various elements.
Santee Cooper	☑		Generator runback schemes should be able to be implemented before emergency thermal rating time limits are exceeded.
SaskPower	☑		Several generation run back or generation rejection schemes are used in Saskatchewan to restore facility loading to with normal ratings. The costs of not using these schemes would involve substantial increased investments and environmental impacts unacceptable in the Saskatchewan Regulatory Jurisdiction. Conditions are determined on a case by case basis. However, the generation runback or generation rejection scheme should not exceed the normal operating reserve.
Seattle City	☑		Runback should be allowed to prevent a possible cascading outage which might result from the thermal overload, but only to that level needed to protect the equipment, to address the contingency, or to prepare for the next contingency. If the runback level is lower than the normal rating, it should be shown that this runback will not harm the stability of the system.
Southern Transm.	☑		Yes, as long as no emergency ratings are violated.
Tenaska	☑		So long as the performance requirements are met then this is not an issue.
Response: The SDT agrees with your comments.			
MRO	☑		Generally, the historical MRO practices and requirements have been to require that following a single

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Commenter	**Yes**	**No**	**Comment**
			contingency the loading of facilities are to be maintained within emergency ratings. Adjustments are allowed to move the system from conditions within emergency ratings to conditions within normal ratings. However, in a limited number of cases, the use of Special Protection Systems are used to initiate fast generation run back, generation rejection, or automatic tripping of a remote transmission facility to get below a longer term emergency rating (30 minutes or longer.) In some cases, these involve parts of the network where remote generation is connected to load where the costs of not using the SPS would involve substantial increased investments and environmental impacts. Requirement 3.5 needs more clarification. What rating should not be exceeded?
Response: The SDT agrees with your comment and has modified the language of R 3.5 for clarity. **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:			
LADWP	☑		It was never disallowed under the current standards.
Response: The SDT believes that the current standards are silent on the use of SPS such as automatic generation runback. The standard language has been modified to explicitly identify the conditions under which an SPS may be used (See Requirement R 3.5). **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:			
WPS	☑		The use of RAS or SPS should not constitute a long-term Corrective Action Plan to address deficiencies. The use of RAS and SPS should be limited to that period of time necessary to place facilities in-service to address the deficiency.
Response: Industry comments do not support the use of runback only as an interim measure. Accordingly, the current draft standard language does not impose such a limitation on the use of SPS.			
ATC	☑		
CenterPoint	☑		
CPS Energy	☑		
ISO/RTO	☑		
Muscatine P&W	☑		Reasonable and workable.
SERC RRS OPS	☑		
Response: Thank you. Please see the Summary Response.			

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

38) Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Summary Response: From the survey of industry responses regarding automatic readjustment of generation using SPS/RAS, the industry agrees that SPS/RAS may be allowed for single Contingencies. As a result, the SDT has modified the language in the standard such that it will allow the use of SPS/RAS for single or multiple Contingencies.

The following requirements have been changed due to industry comments:

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:
R3.5.1. All Facilities shall be operating within their Facility Ratings.
R3.5.2. Such action would not violate safety, equipment, regulatory or statutory requirements.
R3.5.3. A sustainable, stable, operating condition is maintained

Q38			
Commenter	**Yes**	**No**	**Comment**
ABB		☑	It makes the system too complex and less reliable. Single contingencies need to be handled without any fancy controls.
KCPL		☑	Tripping generation for single contingency other than GSU failure or fault is unacceptable.
LCRA		☑	Only until plans are implemented to address a single contingency-identified deficiency. In general, plans should always be developed to exit SPS or RAS when economically feasible
Central Maine Power National Grid New England ISO NSTAR United Illuminating	☑		Only allowed where the failure of an SPS that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.
NU	☑		It is not recommended that an SPS be used in this situation, that over time, the proliferation of SPSs may degrade system reliability and unduly complicate system operations. If allowed an SPS should only be used where the failure of the SPS that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.
NPCC RCS	☑		A SPS may be used to provide protection for infrequent contingencies, or for temporary conditions that may exist such as project delays, unusual combinations of system demand and equipment outages or availability, or specific equipment maintenance outages. An SPS may also be applied to preserve system integrity in the event of severe facility outages and extreme contingencies. The decision to employ an SPS shall take into account the complexity of the scheme and the consequences of correct or incorrect operation as well as its benefits.

Q38			
Commenter	**Yes**	**No**	**Comment**
SCE&G	☑		A RAS or SPS should be allowed for single contingencies if its failure or misoperation can be compensated for during the time allowed by the emergency ratings of the elements that exceed their normal thermal ratings.
Response: The Industry response to this question has prompted the SDT to change the language to allow SPS/RAS for single or multiple Contingencies. The standard language now lists qualifiers of the use of SPS/RAS, listed in Requirements R3.5.1, R3.5.2 and R3.5.3. **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met: **R3.5.1**. All Facilities shall be operating within their Facility Ratings. **R3.5.2**. Such action would not violate safety, equipment, regulatory or statutory requirements. **R3.5.3**. A sustainable, stable, operating condition is maintained			
City Water Power and Light		☑	SPS use should be limited and SPSs should be of a temporary nature. A mitigation plan with a timeframe for implementation should accompany all SPSs and RASs.
ITC		☑	We wouldn't agree to this without knowing what you mean by limited use. RAS or SPS as a common practice does not "raise the bar" in planning standard. An RAS or SPS should be allowable as a temporary measure to allow one to meet the standard and two to protect the components of the BES. When used in this capacity, a plan should be being either developed or implemented such that the RAS or SPS can be removed from service.
Response: The overall Industry response prompted the SDT to not include the qualifier about temporary use of SPS/RAS.			
CPS Energy		☑	
Response: See summary response.			
AECC		☑	this question is not clear. are you asking if the SPS/RAS be studied as a contingency or if the SPS/RAS is a viable solution for impacts caused by a contintgency. In either case SPS/RAS impacts and effectiveness needs to be evaluated. Especially if they are used as a mitigation for contingency impacts. It should be knownif the SPS/RAS is effective for the model being studied and if not another mitigation should be determined
Response: The SDT is attempting to explicitly state under what conditions a SPS/RAS can be used to mitigate undesirable System response to single Contingency events. The current standards are silent on this issue.			
Ameren	☑		Yes, but only as interim operating procedures until the limiting facilities can be uprated or unloaded. SPS or RAS should be allowed to trip non-firm (energy only) generation to keep facility loadings within ratings.
Response: The overall response from the Industry prompted the SDT to change the language in the Standard to allow SPS/RAS for all single and multiple contingencies with the qualifiers of Requirements R3.5.1, R3.5.2 and R3.5.3. The Standard does not differentiate performance for different generation types. **R3.5.** Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:			

Q38			
Commenter	**Yes**	**No**	**Comment**
R3.5.1. All Facilities shall be operating within their Facility Ratings. **R3.5.2**. Such action would not violate safety, equipment, regulatory or statutory requirements. **R3.5.3.** A sustainable, stable, operating condition is maintained			
Progress–Florida	☑		This requirement is addressed in PRC-005 and these requirements should not be addressed again in this Standard. However, the use of RAS or SPS should be allowed as necessary for any single contingency event, provided that such use does not result in cascading outages. It should be noted that the performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. Revision of the existing TPL standards will require updating of the contingency references in PRC-012-0.
Response: The conditions for the use and application of SPS/RAS are addressed in the TPL Standards. The SDT does not agree that the PRC Standards addresses the use of SPS/RAS.			
Southern Transm.	☑		RAS and SPS should be defined such that they may only be used for low probability events.
Response: The overall response from the Industry prompted the SDT to change the language in the Standard to allow SPS/RAS for all single and multiple contingencies with the qualifiers of Requirements R3.5.1, R3.5.2, and R3.5.3. There are no qualifications of the use of SPS/RAS based on the probability of the contingency. **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met: **R3.5.1**. All Facilities shall be operating within their Facility Ratings. **R3.5.2**. Such action would not violate safety, equipment, regulatory or statutory requirements. **R3.5.3**. A sustainable, stable, operating condition is maintained			
IESO	☑		SPS and RAS should be allowed for single contingencies. However, a more fundamental requirement is that the SPS (and RAS) should generally be regarded as a stop gap measure before planned transmission expansion or reinforcement becomes available. SPS should in general not be used as a substitute for transmission facilities.
New York ISO	☑		As stated previously SPSs should only be a temporary solution used to protect elements prior to a permanent solution implementation.
WPS	☑		The use of RAS or SPS should not constitute a long-term Corrective Action Plan to address deficiencies. The use of RAS and SPS should be limited to that period of time necessary to implement expansion of facilities to address the deficiency.
Response: The overall Industry response prompted the SDT to allow the use of SPS/RAS as a permanent Corrective Action measure and not just as a temporary measure.			
Brazos Electric	☑		
Dominion	☑		
ERCOT ISO	☑		Agree

Q38			
Commenter	**Yes**	**No**	**Comment**
Northwestern Energy	☑		
AECI	☑		
Allegheny Power	☑		
AEP	☑		As long as they are automatic.
APPA	☑		As the SDT has said under certain situations.
ATC	☑		
APS			
BPA	☑		
BCTC	☑		
CAISO	☑		Agree
CenterPoint	☑		
Duke Energy	☑		RAS and SPS are economical solutions that planners ought to be able to use.
Entergy	☑		RAS or SPS may be allowed for single contingencies when they aid in meeting System Performance requirements. RAS and SPS should not be used to restore an element to within emergency ratings.
Exelon	☑		
FirstEnergy	☑		As long as thermal, voltage, and stability requirements are met, RAS or SPS should be allowed provided it does not shed load for a single contingency event.
FPL FRCC	☑		The performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. If the proposed TPL standard is adopted the contingency references in PRC-012-0 would need to be updated.
Georgia Transm.	☑		
HQTE	☑		A SPS may be used to provide protection for infrequent contingencies, or for temporary conditions that may exist such as project delays, unusual combinations of system demand and equipment outages or availability, or specific equipment maintenance outages. An SPS may also be applied to preserve system integrity in the event of severe facility outages and extreme contingencies. The decision to employ an SPS shall take into account the complexity of the scheme and the consequences of correct or incorrect operation as well as its benefits.
ISO/RTO	☑		
Manitoba Hydro	☑		MH sees no reason to limit the application of SPSs. The SPS is a viable planning option that allows large savings in cost in stability limited system where there is no need to increase thermal capability.
MEAG Power	☑		

Q38			
Commenter	**Yes**	**No**	**Comment**
MISO	☑		
MRO	☑		
Muscatine P&W	☑		
NERC TIS	☑		
NCEMC	☑		
PJM	☑		
Progress–Carolinas	☑		
SRP	☑		As long as Non-Consequential Loss of Load is not a solution for single contingencies (N-1).
Santee Cooper	☑		
SaskPower	☑		
Seattle City	☑		
SERC EC DRS	☑		
SERC EC PSS	☑		
SERC RRS OPS	☑		
Tenaska	☑		
TVA	☑		TVA does not allow generator tripping for a single contingency. However, we recognize that there are certain instances for which this makes practical and economic sense.
TSGT	☑		
TEP	☑		
WECC	☑		
Response: Thank you. Please see the Summary Response.			

39) Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Summary Response: Requirement R3.5 has been written such that it allows RAS or SPS for single or multiply Contingencies with limitations described in Requirements R3.5.1 through R3.5.3. Requirement R3.5.2 allows for "regulatory or statutory requirements" that may prohibit or limit the use of RAS or SPS.

In addition, most responders said, or implied, that the failure of SPS/RAS schemes should be studied. Most said that the failure of the schemes should not cause cascade, with some suggesting that there shouldn't be any Non-Consequential Load Loss. The SDT believes that failure of SPS should not be used to establish requirements in the TPL-001-1 standard. Instead, this standard sets requirements when SPS can be used, and relies on the relevant PRC standards to set the requirements for studies and designs to implement the SPS. In response to those that commented regarding existing RRO standards becoming more stringent than the resulting North American standards, there are provisions to allow for regions to have and implement more restrictive standards.

Q39	
Commenter	**Comment**
ABB	They could be used in the short term until a permanent fix is available. Limit to <5 years.
Ameren	SPS and RAS should be used only as interim operating procedures to mitigate single contingency events until the limiting facilities can be uprated or unloaded. SPS and RAS should be allowed to trip non-firm (energy only) generation as needed to keep facility loadings within ratings.
Northwestern Energy	RAS or SPS should not be allowed for non three phase single line faults. If cascading could result from the failure of the RAS to operate properly, then redundancy should be required.
HQTE	See response to Q38.
ITC	Temporary in nature.
KCPL	RAS/SPS should not limit generation output for N-1 conditions.
LCRA	Short-term with exit plans; Loss of significant generation or load resulting from SPS /RAS action.
Manitoba Hydro	An automatic runback should be accomplished in 5-15 minutes depending on the ramp rate of the generator. The runback scheme may allow higher emergency ratings depending on the rating methodology. At no point would emergency ratings be exceeded and at the end, loading would be within normal values. Generator tripping should be allowed. Generator tripping is used extensively in regions where remote generation is delivered via long transmission. MH sees no reason to limit the application of SPSs. The SPS is a viable planning option that allows large savings in cost in stability limited system where there is no need to increase thermal capability.
MRO	The MRO believes the MRO systems are presently designed to meet system performance, in some cases, with the use of SPS to initiate fast generation runback, generation rejection, and automatic tripping of a remote transmission facility for a single contingency event. The fast generation runback or generation rejection should not exceed the normal operating reserve of the generation reserve sharing pool to which the planner belongs or of the planner itself if the planner self-provides generation reserves.

Q39	
Commenter	**Comment**
New York ISO	Must be temporary, approved by the NYSRC, tested annually with evidence of preventive maintenance submitted annually.
NPCC RCS	See response to Q38.
Southern Transm.	Generator tripping or runback and reconfiguration should be allowed for lower probability single contingency events such as bus faults; we suggest that SPS not be used for events that are more likely to occur.
WPS	The use of RAS or SPS should not constitute a long-term Corrective Action Plan to address deficiencies. The use of RAS and SPS should be limited to that period of time necessary to implement expansion of facilities to address the deficiency.
Response: Your suggestion was seriously considered but restrictions were limited to those sub-requirements of Requirement R3.5.	
Brazos Electric City Water Power and Light	Taken directly from the ERCOT operating Guides for RAPs and SPSs: Any RAP must meet the following requirements: a. Coordinated and approved with the owners and operators of facilities included in the RAP. b. Use is limited to the time required to construct replacement Transmission Facilities. However, the RAP will remain in effect, if replacement Transmission Facilities have been determined by the Control Area Authority to be impractical. c. Complies with all applicable ERCOT and NERC requirements. d. ERCOT develops and posts a methodology to include the RAP in the Total Transfer Capability (TTC) calculations, if appropriate. e. Clearly defines and documents operator actions. f. Includes the option for the transmission operator to override the procedures if the RAP will not improve system reliability. g. Operators must be trained in RAP implementation. For SPSs 13. Special Protection Systems (SPS) are protective relay systems designed to detect abnormal ERCOT System conditions and take pre-planned corrective action (other than the isolation of faulted elements) to provide acceptable ERCOT System performance. SPS actions include among others, changes in demand, generation, or system configuration to maintain system stability, acceptable voltages, or acceptable Facility loadings. An SPS does not include underfrequency or undervoltage load shedding. A Type 1 SPS is any SPS that has wide-area impact and specifically includes any SPS that a) is designed to alter generation output or otherwise constrain generation or imports over DC Ties, or b) is designed to open 345 kV transmission lines or other lines that interconnect TDSPs and impact transfer limits. Any SPS that has only local-area impact and involves only the Facilities of the owner-TDSP is a Type 2 SPS. The determination of whether an SPS is Type 1 or Type 2 will be made by ERCOT upon receipt of a description of the SPS from the SPS owner. Any SPS, whether Type 1 or Type 2, shall meet all requirements of NERC Standards relating to SPSs, and shall additionally meet the following ERCOT requirements: • The SPS owner shall coordinate design and implementation of the SPS with the owners and operators of Facilities included in the SPS, including but not limited to Generation Resources and HVDC ties. • The SPS shall be automatically armed when appropriate. • The SPS shall not operate unnecessarily. To avoid unnecessary SPS operation, the SPS owner may provide a

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Commenter	**Comment**
	real-time status indication to the owner of any Generation Resource controlled by the SPS to show when the flow on one or more of the SPS's monitored facilities exceeds 90% of the flow necessary to arm the SPS. The cost necessary to provide such status indication shall be allocated as agreed by the SPS owner and the Generation Resource owner. • The status indication of any automatic or manual arming of the SPS shall be provided as SCADA alarm inputs to the owners of any facility(ies) controlled by the SPS.. • When a Transmission Operator (TO) removes a SPS from service, the TO shall immediately notify ERCOT operations. ERCOT shall modify its reliability constraints to recognize the unavailability of the SPS and notify the Market. When a SPS is returned to service, the TO shall immediately notify ERCOT operations. ERCOT shall modify its reliability constraints to recognize the availability of the SPS. 14. The owner(s) of an existing, modified, or proposed SPS shall submit documentation of the SPS to ERCOT for review and compilation into an ERCOT SPS database. The documentation shall detail the design, operation, functional testing, and coordination of the SPS with other protection and control systems. • ERCOT shall conduct a review of each proposed SPS and each proposed modification to an existing SPS. Additionally, it shall conduct a review of each existing SPS every five years, or sooner as required by changes in system conditions. Each review shall proceed according to a process and timetable documented in ERCOT Procedures and posted on the ERCOT website. • For a proposed Type 1 SPS, the review must be completed before the SPS is placed in service, unless ERCOT specifically determines that exemption of the proposed SPS from the review completion requirement is warranted. The timing of placing the SPS into service must be coordinated with and approved by ERCOT. The implementation schedule must be confirmed through submission of a Service Request to ERCOT. • For a proposed Type 2 SPS, the SPS may be placed into service before completion of the ERCOT review, with advanced prior notice to ERCOT in the form of a Service Request. The timing of placing the SPS into service must be coordinated with and approved by ERCOT. Existing SPSs that have already undergone at least one review shall remain in service during any subsequent review, and proposed modifications to existing SPSs may be implemented, upon notice to ERCOT, and approval of ERCOT before completion of the required ERCOT review. • The process and schedule for placing an SPS into service must be consistent with documented ERCOT Procedures. The schedule must be coordinated among ERCOT and the owners of any facility(ies) controlled by the SPS, and shall provide sufficient time to perform any necessary testing prior to its being placed in service. • An ERCOT SPS review shall verify that the SPS complies with ERCOT and NERC criteria and guides. The review shall evaluate and document the consequences of failure of a single component of the SPS, which would result in failure of the SPS to operate when required. The review shall also evaluate and document the consequences of misoperation, incorrect operation, or unintended operation of an SPS, when considered by itself, and without any other system contingency. If deficiencies are identified, a plan to correct the deficiencies shall be developed and implemented. The current review results shall be kept on file and supplied to NERC on request within thirty (30) days. • As part of the ERCOT review and unless judged to be unnecessary by ERCOT, the appropriate ROS working groups such as the Steady State Working Group, the Dynamics Working Group, and/or the System Protection Working Group shall review the SPS and report any comments, questions, or issues to ERCOT for resolution. ERCOT may work

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Commenter	**Comment**
	with the owner(s) of facilities controlled by the SPS as necessary to address all issues. • ERCOT shall develop a methodology to include the SPS in the Commercially Significant Constraint (CSC) limit calculations, if appropriate. • ERCOT's review shall provide an opportunity for and include consideration of comments submitted by Market Participants affected by the SPS. 15. SPS owners shall notify ERCOT of all SPS operations. Documentation of SPS failures or misoperations shall be provided to ERCOT using the Relay Misoperation Report located in Section 6 of these Operating Guides. ERCOT shall conduct an analysis of all SPS operations, misoperations, and failures. If deficiencies are identified, a plan to correct the deficiencies shall be developed and implemented. 16. For each SPS, the owner shall either identify a preferred exit strategy or explain why no exit strategy is needed to ERCOT. This shall take place according to a timetable documented in ERCOT Procedures and posted on the ERCOT website. Once an exit strategy is complete and a SPS is no longer needed, the owner of an existing SPS shall notify ERCOT, using a Service Request, whenever the SPS is to be permanently disabled, and shall do so according to a timetable coordinated with and approved by ERCOT and the owners of all facilities controlled by the SPS
Response: The SDT anticipates that ERCOT will be able to maintain the existing requirements that you suggest. Requirement R3.5.2 allows for "regulatory or statutory requirements" which may limit RAS or SPS.	
Dominion	For single contingency events, a SPS scheme should not result in loss of load.
Response: Non-Consequential Load Loss is not allowed for single Contingency events.	
ERCOT ISO CAISO	RAS or SPS should generally be regarded as a stop gap measure before transmission expansion or reinforcement becomes available. It should not be used as a substitute for transmission facilities.
Response: Your suggestion was seriously considered but restrictions were limited to those sub-requirements of Requirement R3.5. The SDT anticipates that ERCOT will be able to maintain the existing requirements that you suggest. Requirement R3.5.2 allows for "regulatory or statutory requirements" which may limit RAS or SPS.	
Allegheny Power	The use of these system should be limited and not used as a preferred solution and also be approved by a stringent review process through the RTO & RE.
AEP	Should be allowed as long as they have been approved by the applicable Regional Reliability Organization.
APPA	See Question 36.
BCTC	RAS should be permitted when the system performance conforms with the performance requirements laid out in the tables. Generator tripping should be permitted for single contingency events. R3.6 proposes to limit generator tripping for single contingencies except for certain conditions which are not listed. Without knowing what these conditions might be, we find ourselves speculating on what might be proposed. On the 10 October 2007 conference call, it was suggested that there are concerns regarding generator reserves and loss of reactive capability. We have some observations regarding these concerns. With respect to reserves, some concerns would also apply to runback, since units on runback could not also be on AGC and could not be reallocated to AGC until the transmission contingency is returned to service. There was also a concern regarding tripping of steam units and the delay in bringing them back on line. This is a resource adequacy issue that should be addressed with the customer, not a transmission reliability issue. Regarding the loss of reactive capability, this would be addressed by

Q39	
Commenter	**Comment**
	the post mitigation plan studies to demonstrate that the reactive reserves meet the requirements, whatever they are determined to be. We would generally expect that the reduction in MW transfers would reduce the need for reactive support, so the new condition might not require the reactive support. Nevertheless, the post mitigation studies will address this. Therefore, we conclude that these concerns are not applicable to transmission planning standards. BCTC plans and operates a transmission system that interconnects generation comprised of about 90% hydroelectric. Often the extreme generation patterns for which we consider generator tripping occur for a limited time period during the year at off peak. These would be during high runoff and/or light local load periods. For these conditions, there is typically plenty of other generation that can be used as reserves for generator tripping. BCTC currently strives to avoid use of RAS for N-1, especially on the 500 kV transmission system. However, for example, if avoiding generator tripping were to trigger the need for hundreds of km of 500 kV transmission line for an off peak operating condition or a low capacity factor or intermittent resource, we would likely consider RAS, especially for transmission radial to the generator. In the lower voltage systems we often have consequential loss of small generators and consider generator tripping for radial lines and local networks. In most cases, this generator loss is addressed through sensitivity studies and discussions with generator owners and transmission customers with respect to the costs they are willing to incur and what is required by Resource Planners to meet their planning criteria. Operating reserves requirements are also a consideration. Any loss of generation due to tripping or ramping that is less than the amount lost due to consequential loss should be acceptable without question. In summary, we would be prepared to review and comment on a proposal from the SDT on limitations on generator tripping. BCTC suggests that the SDT list the limitations rather than the permitted conditions and that these limitations should also apply to generator ramping.
Georgia Transm. SERC EC DRS	None.
Muscatine P&W	As long as they work and are reasonable - none. (See Q43 Comment #3)
MISO	The use of SPS/RAS may be the appropriate transmission system design. If it is economic to mitigate the SPS, then upgrades should be made.
Response: See the summary response.	
Central Maine Power National Grid New England ISO NU NSTAR United Illuminating	Only allowed where SPS failure would not have significant adverse impact on the Bulk Electric System; non-Consequential loss of load should be allowed up to an amount potentially specified in the standard.
Response: See the summary response. As to your suggestion on Non-Consequential Loss of Load, it is prohibited for single Contingencies and is not prohibited for multiple Contingencies.	
Duke Energy	You should not have any wide area cascading if the RAS or SPS fails to operate as expected, or operates when it shouldn't.

Q39	
Commenter	**Comment**
Response: See the summary response: PRC standards address SPS failure.	
Entergy	RAS or SPS may be allowed for single contingencies when they aid in meeting System Performance requirements. RAS and SPS should not be used to restore an element to within emergency ratings.
Response: See the summary response. Requirement R3.5.1 restricts RAS/SPS such that facility ratings must be honored at all times.	
FirstEnergy	As long as thermal, voltage, and stability requirements are met, RAS or SPS should be allowed provided it does not shed load for a single contingency event.
Response: See the summary response. Non-Consequential Load Loss is not permitted for single Contingency events.	
FPL FRCC	The performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. If the proposed TPL standard is adopted the contingency references in PRC-012-0 would need to be updated.
Response: See Requirement R3.5. There are no longer any limitations on the use of SPS as long as they meet this criteria.	
IESO	Please see comments provided under Q38, above, regarding the use of SPS not as a substitute for transmission facilities. In addition, there should be requirements to simulate failure of SPS operation as a contingency in addition to the initiating single contingency. In cases where an SPS is intended to achieve acceptable stability performance which can affect interconnection reliability, the SPS should be classified as BES impactive and as such, redundancy may be required. When redundancy is provided, simulation of SPS failing to operate may be waived.
Response: Your suggestions were considered but the only limitations to RAS/SPS are those listed as sub-requirements of Requirement R3.5. PRC standards address SPS failure.	
MEAG Power NCEMC SERC EC PSS SERC RRS OPS SCE&G TVA	RAS or SPS should meet the same criteria as any protection system.
Response: See summary response as regards to planning standards. The PRC standards for SPS will be maintained as you have suggested.	
Progress–Florida	The use of RAS or SPS should be allowed as necessary for any single contingency event, provided that such use does not result in cascading outages. It should be noted that the performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. Revision of the existing TPL standards will require updating of the contingency references in PRC-012-0.
Response: The SDT agrees that the PRC standards address performance and may need to be updated.	
ReliabilityFirst	The requirements for the use of SPS and RAS should be contained in a separate standard. That standard should dictate when the RAS and SPS can be used. The planning studies would then simulate those conditions.
Response: This was considered but the consensus was to keep requirements in TPL-001-1. RAS/SPS is allowed as per Requirement R3.5 and its sub-requirements.	
SRP	Non-Consequential Loss of Load should not be allowed for single contingencies (N-1) and the system must remain stable with no violations.
Response: The SDT agrees and Non-Consequential Load Loss is not permitted.	
Santee Cooper	There should be no stability impacts, and system security must be maintained. RAS or SPS should meet the same criteria as any protection system.

Q39	
Commenter	**Comment**
Response: See the summary response. The PRC standards address protection system criteria.	
SaskPower	Delegate this issue to the Planning Coordinators.
Response: See the summary response. The PC is just one of many applicable functional entities.	
Seattle City	All RAS or SPS schemes should be evaluated to determine the impact on the interconnected system. Actions that derate transfer paths should not be allowed unless essential to protecting equipment or anticipating the next contingency.
Response: See the summary response. The SDT expects that all SPS/RAS will still be subject to the regional scrutiny that you have suggested.	
AECC	See comment to Q38.
Response: See response to Q38.	
Tenaska	The system, following the use of an RAS or SPS in response to a single contingency, shall meet the performance requirements.
Response: The standard allows for RAS/SPS as per Requirement R3.5 but these types of corrective actions are expected to meet the performance requirements as per the tables.	
WECC BPA TSGT TEP	Based on the interpretation of the above question, we are providing two responses to this question. The first responds to the limitations placed on RAS, regardless of what action the RAS initiates. The second response specifically addresses RAS that trips generation. Response 1: RAS should be allowed for single contingency events. Any sort of RAS should be permitted, but there should be a review of the RAS. If the local entities agree to the RAS, it should be allowed. This addresses cost vs. benefit balance. Entities affected should be the ones that determine the best solution for their situation. Response 2: Generation tripping can be used for single contingency if such application can be demonstrated through transmission planning studies that: • The generation tripping is planned and controlled ("planned and controlled" means a pre-planned action(s) based on predetermined system conditions that take corrective measure(s) to maintain acceptable system performance). • The generation tripping does not result in non-consequential load loss. • System frequency should be within allowable limits. • System voltage dip and deviation should be within allowable limits. • The generator owner(s) agrees to the tripping as planned.
Response: Requirement R3.5 allows for the use of SPS and RAS and Requirement R3.5.2 would allow for the kinds of review that you're suggesting.	

40) 40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Summary Response: There was a wide variety of responses that described the conditions that should be met when an RAS or SPS is applied but the majority of the responses can be characterized as follows:

- Requirements for SPS are outlined in the PRC standards
- Maintain System Stability
- Prevent cascading
- Prevent loss of load
- Should be used as a short-term mitigation solution

Other suggestions include:

- Non-Consequential Loss of Load should not be allowed for single Contingencies (N-1)
- Allow to prepare for next Contingency
- If an SPS is used to solve a single Contingency problem, then full redundancy should be required.
- Generator tripping or runback and reconfiguration should be allowed for lower probability single Contingency events such as bus faults.
- SPS not be used for events that are more likely to occur.
- Should not constitute a long-term Corrective Action Plan to address deficiencies.

The SDT has modified Requirement R3.6 (now Requirement R3.5) to specify the conditions under which manual and automatic generation runback and tripping can be used to meet single and multiple Contingency performance requirements and to make it clear that all Facilities must always remain within applicable thermal and voltage ratings.

The following requirements have been changed due to industry comments:

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:

R3.5.1. All Facilities shall be operating within their Facility Ratings.

R3.5.2. Such action would not violate safety, equipment, regulatory or statutory requirements.

R3.5.3. A sustainable, stable, operating condition is maintained.

Q40	
Commenter	**Comment**
Ameren	RAS and SPS should be allowed only as an interim operating procedure to mitigate single contingency conditions or to mitigate multiple contingency events on a long-term basis. The RAS or SPS must be effective in mitigating the contingencies and can be implemented within the required operating time.
Response: Industry comments do not support the use of runback only as an interim measure. The current draft standard language does not	

Q40	
Commenter	**Comment**
impose such a limitation on the use of SPS.	
Brazos Electric	See above.
BCTC	See Q39. Also, WECC RAS Reliability requirements must be met for new systems.
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating	System must remain stable with acceptable voltages and all equipment within applicable emergency limits.
Duke Energy	See response to Q36 and Q37 above. No additional conditions beyond meeting the performance requirements.
Entergy	Following a contingency, power flows on lines should be within their emergency ratings, voltages should be at adequate levels and system should be stable.
FirstEnergy	As long as thermal, voltage, and stability requirements are met, RAS or SPS should be allowed provided it does not shed load for a single contingency event, and only if the Transmission Owner has documented short term ratings that would not be exceeded during the runback.
JEA	RAS/SPS should not limit generation output for N-1 conditions.
Manitoba Hydro	1) Reducing or increasing generation while keeping the units on-line or by bringing additional units on line. The amount of generation change should be limited to that amount that can be accomplished within the allowed readjustment period. Due consideration should be given to start up time and ramp rates of the units. 2) Generator tripping should be added to requirement R3.5 in addition to runback. Generator tripping is used extensively in regions where remote generation is delivered via long transmission. 3) Capacitor and reactor switching - The number of capacitors and reactors, which may be switched, should be limited to those which could be switched during the allowed readjustment period. 4) Adjustment of load tap changers (LTCs) to the extent possible within the allowed readjustment period. 5) Adjustment of phase shifters to the extent possible within the allowed readjustment period. 6) An increase or decrease to the flow on HVDC facilities to the extent possible within the allowed readjustment period. 7) Transmission reconfiguration - Automatic tripping of transmission lines or transformers to the extent possible within the allowed readjustment period. 8) Automatic tripping of interruptible load or curtailment of or redispatching of Firm Transmission Service to the extent possible within the allowed readjustment period.
MISO	SPS may be used if it maintains similar level of system reliability and security as transmission upgrades.
MRO	SPS are often used in the MRO area to avoid unnecessary expenditures and environmental impacts. SPS are sometimes used to prevent instability. The SPS may initiate fast generation run back, automatic generation rejection, or automatic tripping of a facility for a remote event. The MRO notes that the scheme must be automatic, fast acting, consistent with short term equipment ratings. The MRO notes the following general conditions for adjustments, that

Q40	
Commenter	**Comment**
	perhaps would be useful in designing performance requirements for allowable system adjustments in addition to the description in Question 39: 1. Generation adjustments - Reducing or increasing generation while keeping the units on-line or by bringing additional units on line. The amount of generation change is limited to that amount that can be accomplished within the allowed readjustment period. Due consideration shall be given to start up time and ramp rates of the units. 2. Capacitor and reactor switching - The number of capacitors and reactors, which may be switched, is limited to those which could be switched during the allowed readjustment period. This includes those capacitors and reactors that would be switched by automatic controls within the same period. 3. Adjustment of load tap changers (LTCs) to the extent possible within the allowed readjustment period. This includes both LTCs which would automatically adjust and those under operator control which could be adjusted within the readjustment period. 4. Adjustment of phase shifters to the extent possible within the allowed readjustment period. 5. An increase or decrease to the flow on HVDC facilities to the extent possible within the allowed readjustment period. 6. Transmission reconfiguration - Automatic tripping of transmission lines or transformers to the extent possible within the allowed readjustment period. 7. Automatic tripping of interruptible load or curtailment of or pre-determined redispatching of Firm Transmission Service to the extent possible within the allowed readjustment period.
Muscatine P&W	Reasonable and workable. (See Q43 Comment #3)
NERC TIS	No special conditions required as long as the RAS or SPS are tested to meet the performance requirements.
Seattle City	Actions should be intended to address contingency, prevent damage, or prepare for next contingency.
SERC EC DRS	No additional conditions except meeting performance requirements.
Southern Transm.	If an SPS is used to solve a single contingency problem, then full redundancy should be required. Generator tripping or runback and reconfiguration should be allowed for lower probability single contingency events such as bus faults; we suggest that SPS not be used for events that are more likely to occur.
Tenaska	The system, following the use of an RAS or SPS in response to a single contingency, shall meet the performance requirements.
WECC BPA TSGT TEP	System adjustment involves operator intervention that would be beyond the time frame of RAS operation. Therefore, if a unit is already dropped during RAS or SPS action, it should be assumed to be off-line during system adjustment period.

Response: Based on the majority of industry responses, the SDT has modified Requirement R3.6 (now Requirement R3.5) to specify conditions under which manual and automatic generation runback and tripping can be used to meet single and multiple Contingency performance requirements for the steady state portion of the Planning Assessment.

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:

Q40	
Commenter	**Comment**
R3.5.1. All Facilities shall be operating within their Facility Ratings. **R3.5.2.** Such action would not violate safety, equipment, regulatory or statutory requirements. **R3.5.3**. A sustainable, stable, operating condition is maintained.	
City Water Power and Light	Maintain system stability, prevent loss of load and prevent cascading outages.
Response: The SDT agrees with your comment and has modified Requirement R3.6 (now Requirement R3.5) to specify conditions under which manual and automatic generation runback and tripping can be used to meet single and multiple contingency performance requirements. **R3.5.** Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met: **R3.5.1.** All Facilities shall be operating within their Facility Ratings. **R3.5.2.** Such action would not violate safety, equipment, regulatory or statutory requirements. **R3.5.3**. A sustainable, stable, operating condition is maintained.	
ERCOT ISO CAISO	1. RAS or SPS must be simple and manageable. 2. Number of contingencies triggering a RAS or SPS should be very limited (4 allowed by CAISO). 3. RAS or SPS should generally monitor only local facilities that are either directly connected to the plant or one bus away.
Response: The SDT agrees with your comment in (1) and believes this is covered in the requirements of the PRC standards. Based on the majority of industry responses, the SDT has modified Requirement R3.6 (now Requirement R3.5) to specify conditions under which manual and automatic generation runback and tripping can be used to meet single and multiple Contingency performance requirements for the steady state portion of the Planning Assessment. Applying additional requirements needs to be done as a regional difference. **R3.5.** Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met: **R3.5.1.** All Facilities shall be operating within their Facility Ratings. **R3.5.2.** Such action would not violate safety, equipment, regulatory or statutory requirements. **R3.5.3**. A sustainable, stable, operating condition is maintained.	
Northwestern Energy	RAS or SPS should meet performance requirements including reserve requirements.
Allegheny Power	The system should remain stable, reliable, allow for operational preparation for the next contingency and failure of the RAS/SPS should not lead to a cascading event.
AEP	They include redundancy and their failure does not result in cascading.
APPA	Maintain system stability and prevent the loss of load.
SRP	Non-Consequential Loss of Load should not be allowed for single contingencies (N-1) and the system must remain

Q40	
Commenter	**Comment**
	stable with no violations.
Response: The SDT agrees.	
FPL FRCC	The performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. If the proposed TPL standard is adopted the contingency references in PRC-012-0 would need to be updated.
Progress–Florida	The use of RAS or SPS should be allowed as necessary for any single contingency event, provided that such use does not result in cascading outages. It should be noted that the performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. Revision of the existing TPL standards will require updating of the contingency references in PRC-012-0.
Georgia Transm.	PRC Standards
MEAG Power NCEMC SERC EC PSS TVA	The conditions required by SPS standards (PRC).
Santee Cooper	There should be no stability impacts, and system security must be maintained. The requirements are outlined in PRC-015,016, and 017.
SERC RRS OPS	The requirements are outlined in PRC-015, 016, and 017.
SCE&G	The conditions required by SPS Reliability Standards.
Response: The SDT has considered your comments and concludes that the PRC standards describe the performance requirements for SPS but do not specify how the SPS requirements are applied to the Planning Assessment	
IESO	As indicated in the comments provided under Q38 and Q39, the conditions to simulate operation of the RAS and SPS would depend on the conditions they are designed to protect. We do not believe such conditions can be generalized.
ITC	This should be limited to the time until a physical solution is possible (i.e., a temporary solution).
WPS	The use of RAS or SPS should not constitute a long-term Corrective Action Plan to address deficiencies. The use of RAS and SPS should be limited to that period of time necessary to implement expansion of facilities to address the deficiency.
Response: Industry comments do not support the use of runback only as an interim measure. The current draft standard language does not impose such a limitation on the use of SPS.	
LCRA	Systems must have a balance between security and dependability. System must be reviewed annually or as system conditions change.
New York ISO	This would be dependent on the characteristics of each unique protection scheme.
Response: The SDT agrees with your comment and believes this is covered in the requirements of the PRC standards.	
Progress–Florida	The use of RAS or SPS should be allowed as necessary for any single contingency event, provided that such use does not result in cascading outages. It should be noted that the performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. Revision of the existing TPL standards will require updating of the contingency references in PRC-012-0.
Response: Please see Requirement R3.5. The use of SPS is allowed for generation tripping or runback as long as the criteria is met	
AECC	See response to Q38.
Response: See response to Q38.	

Q40	
Commenter	**Comment**
SaskPower	Delegate this issue to the Planning Coordinators.
Response: The SDT believes that it should be a coordinated effort between the Planning Coordinator and the Transmission Planner.	

G) General Questions

41) Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Summary Response: Few comments were received indicating that regional variances would be required although some pointed out that variances may be required depending on the final version of the standard. The standard has been modified with respect to the issue of generation tripping and that should reduce or eliminate the stated level of concern and may make a regional variance unnecessary.

The following requirement was changed due to industry comments:

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~iesy~~ ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:

Q41			
Commenter	**Yes**	**No**	**Comment**
ABB		☑	
Brazos Electric		☑	
Dominion		☑	
E ON US		☑	
AECI		☑	
Allegheny Power		☑	
AEP		☑	
CenterPoint		☑	
CPS Energy		☑	
Duke Energy		☑	
Entegra			
Entergy		☑	
FirstEnergy		☑	
FPL FRCC		☑	No, if the comments to the above questions are incorporated. The FRCC system is a peninsular system having only one interface with the rest of the interconnected NERC system, and has historically demonstrated exceptionally high reliability with no events in recent history cascading beyond the FRCC system. The adequacy of the existing TPL standards as they apply to the FRCC System have been extensively documented.

Q41			
Commenter	**Yes**	**No**	**Comment**
Georgia Transm.		☑	
IESO		☑	
ITC		☑	Variances should not be a reason to change the standard (lower the bar).
KCPL		☑	
MISO		☑	
National Grid		☑	We're not aware of any at this time. However, future modifications of the standard may highlight a need for regional variances.
New York ISO		☑	
PJM		☑	
Progress–Florida		☑	No, but PEF reserves the right to apply for variances based on the completed version of this or any other standard.
Santee Cooper		☑	
SERC EC DRS		☑	
SERC RRS OPS		☑	
SCE&G		☑	
Southern Transm.		☑	
Tenaska		☑	
TVA		☑	
WPS		☑	
Central Maine Power New England ISO NU NSTAR United Illuminating	☑	☑	Unsure due to ambiguities in the standard. Depending upon the final standard, New England may need exceptions for existing facilities or allowance for a transition period to develop a compliance plan.
HQTE NPCC RCS	☑	☑	Until section R3.6.1 is finalized, we will be unable to determine whether a regional variance is required.
Response: Few comments were received indicating that regional variances would be required although some pointed out that variances may be required depending on the final version of the standard.			
Manitoba Hydro	☑	☑	MH does not like the idea of a long transition period. Either NERC adopts the concept of generation rejection or the MRO will need to submit a regional variation. I much prefer the planned loss of generation via an SPS rather than via out-of-step tripping as proposed in the Table 2. In certain

Q41			
Commenter	**Yes**	**No**	**Comment**
			areas of the MRO that are stability limited because of long lines to bring generation at the energy source (such as mine mouth plants, hydro plants, etc.) to the load, generation rejection is used to return from an emergency state to a normal state. If generation rejection is not allowed in these cases, extraordinary cost and extraordinary negative environmental impacts will result. As an example, removing one SPS will require new 500 kV transmission between Winnipeg and Minneapolis at a cost of $1 billion to MRO utilities.
BCTC	☑		WECC may require a regional difference for generator tripping depending on the conditions imposed in R3.6.1. Other regional variances would not necessarily be in the context of regional difference as defined in the Standards Manual, but rather exceptions for long weak systems for which it is not economic to meet criteria applicable to tightly interconnected systems.
ERCOT ISO CAISO	☑		ISO relies upon tripping of generators to meet single contingency performance requirements. ISO also relies upon planned and controlled load shedding for the proposed Planning Events P4 and P5.
LADWP	☑		Too many to be listed with the separation above and below 300kV being the worst one that will undermine the overall reliability of the electric system in North America. Another major omission in this proposed standard is the complete lack of recognition of the importance of post-transient requirements. Mixing commercial (firm or non-firm transactions, etc.) and reliability in transmission planning criteria would be in conflicts with WECC rules and practices.
MRO	☑		If the SDT proceeds with an approach that does not allow generation rejection for contingencies, the MRO will need to submit a regional difference. In certain areas of the MRO that are stability limited because of long lines to bring generation at the energy source (such as mine mouth plants, hydro plants, etc.) to the load, generation rejection is used to return from an emergency state to a normal state. If generation rejection is not allowed in these cases, extraordinary cost and extraordinary negative environmental impacts will result. As an example, if one particular SPS is removed, new 500 kV transmission will be required between Winnipeg and Minneapolis at a cost of $1billion to the customers of MRO utilities.
NERC TIS	☑		There may be some in the application of RAS or SPS for N-1 contingencies.
Northwestern Energy	☑		WECC allows N-1 generator tripping, and the transmission systems have been designed around this criteria. Moving away from this criteria is not necessary, and for critical N-1 events, redundancy is in place.
WECC BPA TSGT TEP	☑		Yes. WECC allows tripping of generators to meet single contingency performance requirements. WECC also allows planned and controlled load shedding for the proposed Planning Events P2-1, P2-2, P3, P4 and P5, although we agree with the proposed requirements for P4 due to the higher probability of occurrence. If the standard does not allow for non-consequential load shedding of 300 kV and above for P5 scenarios, WECC will develop a regional variance".
Response: The standard has been modified with respect to the issue of generation tripping that should reduce the stated level of concern and may make a regional variance unnecessary.			

Q41			
Commenter	**Yes**	**No**	**Comment**
R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~iesy~~ ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met**:**			
LCRA	☑		See ERCOT Planning Criteria. Also, through the regional coordinators, NERC recently conducted a survey of transmission planners/owners regarding use of more stringent criteria used in their own systems. The std. drafting team should include a review of the survey results and incorporate into this NERC std as necessary.
Response: The SDT will review the survey.			
MEAG Power	☑		Facilities rating methodology are different from region to region and company to company.
Response: Ratings methodologies are not covered in this standard.			
AECC	☑		I am more concerned about the regions performing studies consistently than identifying regional variences. My company sits stradle the Southwest Power Pool and SERC. There are considerable difference between the two when it comes to study criteria, assumptions, and how studies are performed. These differences have led to situations where it is near impossible to get models and perform studies near the seams that produce results in which you can have confidence and are comparable. The Southwest Power Pool and its members do a very good job of analyzing and evaluating their region. SPP has criteria that specifically requires EtE analysis and the process used to develop their Transmission Expansion Plan contains treatment of SPS/RAS schemes as mitigations.
Response: The SDT recognizes the regional differences that can exist. However, resolution of all regional variances is outside the scope of the SDT.			
APPA	☑		The WECC will probably have a couple.
ATC	☑		
City Water Power and Light	☑		
ISO/RTO	☑		
PRPA	☑		
Progress–Carolinas	☑		
Response: Thank you.			

42) Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Summary Response: Few comments were received indicating conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement. A few potential issues were identified in areas of the standard that have been modified in the second posting. These areas will need to be re-assessed based on the specific revisions made.

The following requirements were changed due to industry comment:

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~iesy~~ ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:

R9. Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information.

R10. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information.

R11. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information.

R12. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information.

R13. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information.

R14. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to Transmission Lines, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies, within ninety days of a request for such information.

Q42			
Commenter	**Yes**	**No**	**Comment**
ABB		☑	

Q42			
Commenter	**Yes**	**No**	**Comment**
AECC		☑	
Ameren		☑	The proposed standard, as well as the existing standards, makes no distinction between firm (network resource) and non-firm (energy only) generation. The standard should clearly state that the standard does not apply to non-firm generation.
City Water Power and Light		☑	
E ON US		☑	
ERCOT ISO		☑	Not aware of any.
AECI		☑	
Allegheny Power		☑	
AEP		☑	
APPA		☑	
BCTC		☑	
CAISO		☑	Not aware of any
Central Maine Power		☑	
CPS Energy		☑	
Duke Energy		☑	
FirstEnergy		☑	
FPL		☑	
FRCC		☑	
Georgia Transm.		☑	
HQTE		☑	
IESO		☑	
ITC		☑	
Manitoba Hydro		☑	
MISO		☑	
MRO		☑	

Q42			
Commenter	**Yes**	**No**	**Comment**
National Grid		☑	
New England ISO		☑	
New York ISO		☑	
NU		☑	
NPCC RCS		☑	
Nstar		☑	
PJM		☑	
Progress–Carolinas		☑	
Progress–Florida		☑	
SERC EC DRS		☑	
SERC RRS OPS		☑	Not currently aware of any.
SCE&G		☑	
Southern Transm.		☑	
Tenaska		☑	
United Illuminating		☑	
Santee Cooper		☑	The proposed standard as well as the existing standards, makes no distinction between firm (network resource) and non-firm (energy only) generation. The standards should clearly state that the standard does not apply to non-firm generation.
WPS		☑	
Response: Thank You. The SDT is not aware that the proposed requirements conflict with the tariff provisions of firm versus non-firm Transmission and no specific conflict was provided in the comments.			
WECC BPA TSGT TEP	☑		1) FERC Order 693, Paragraph 1825 regarding TPL-003, Category C – The Commission directed the ERO to modify footnote (c) to Table 1 to clarify the term "controlled load interruption" rather than eliminate its applicability to this performance requirement. 2) FAC-010-1, R2.3 – "…planned or controlled interruption…" This conflicts with "No" for non-consequential load loss allowed in draft TPL.
Response: The SDT believes the draft standard does not conflict with FERC Order 693. Paragraph 1794 specifically prohibits loss of Non-Consequential Load for a single Contingency. The SDT has modified the standard for consistency with FAC-010-1, R2.3. Alternatively, to the extent a conflict still exists, FAC-010-1 would need to be revised to comply with the FERC Order.			
CenterPoint	☑		FPA section 215(i)(2) "does not authorize the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for

Q42			
Commenter	**Yes**	**No**	**Comment**
			adequacy or safety of electric facilities or services." However, adherence to TPL-001-1 as currently drafted, will require, de facto, the construction of additional transmission facilities. CenterPoint Energy believes this standard goes far beyond the legislative intent of mandatory reliability standards and will result in construction of transmission capacity in order to remain compliant.
Dominion	☑		Current planning criteria are approved by State commissions. It is unlikely that the commissions would agree that rate payers should incur the significant cost increases required to meet more stringent planning criteria (i.e. - "raising the bar") when the corresponding improvements in transmission system reliability cannot be quantified.
Response: The SDT's understanding is that the ERO believes it has the authority to set performance requirements for reliability.			
KCPL	☑		In the past, Missouri Public Service Commission Staff have required KCPL to demonstrate that generators have "firm" transmission outlet capacity.
Response: The SDT does not believe that the proposed requirements conflict with the stated MO PSC requirement.			
NCEMC	☑		Modeling data requirements in R1 applicable to many entities may be either redundant with the MOD submittals or may be conflict for entities that are required to submit this data to Transmission Providers to comply with deadlines in their Tarffs. In addition, data submitted by entities named may be confidential so this issue will have to be addressed among those submitting and receiving needed data.
Response: The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. The SDT agrees that there may be situations where confidentiality issues will have to be addressed. **R9.** Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information. **R10.** Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information. **R11.** Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information. **R12.** Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information.			

Q42			
Commenter	**Yes**	**No**	**Comment**
R13. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information. **R14.** Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to Transmission Lines, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies, within ninety days of a request for such information.			
Northwestern Energy	☑		Eliminating the N-1 RAS in the West could cause problems for utilities in the West with local jurisdictional cost recovery.
Response: The standard has been modified with respect to the issue of application of RAS/SPS that should reduce the stated level of concern and remove any conflict. **R3.5.** Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~iesy~~ ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met**:**			
ATC	☑		
ISO/RTO	☑		
Response: The SDT believes the referenced requirement is necessary to ensure an appropriate balance between reliability requirements and right-of-way considerations.			

43) Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Summary Response: Several of the commenters reinforced or embellished the comments they submitted in prior questions. Although the SDT has provided responses to all comments submitted as part of this question, more detailed responses and summaries are provided in the prior questions.

However, several comments were received that were different from other prior comments. The SDT has made many changes to requirements based on comments submitted just for Question #43. Some of the major changes are:

1. Created a new requirement concerning short circuit analysis
2. Created a requirement to document proxies for instability, cascading outages and uncontrolled islanding
3. Changed requirements to clarify the actions allowed to prepare for the next Contingency
4. Changed requirements to clarify that Facility Ratings may be different for, and a function of, different durations
5. Added a definition for Bus-tie Breaker.

Other less significant changes were made by the SDT based on the remaining few comments. These are detailed in the responses to the individual comments below.

The following requirements were changed as a result of industry comments:

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)

Consequential Load Loss: Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.

Non-Consequential Load Loss: ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.

R1. ~~Each Resource Planner, Transmission Planner, Transmission Owner, Generator Owner, and Load-Serving Entity shall each provide its respective Planning Coordinator with the following modeling information required for System performance studies upon request (within 30 calendar days) :~~ Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to

complete their Planning Assessment. The models shall use data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources.

R2.1. ~~The steady state portion of~~ The Near-Term Transmission Planning Horizon ~~Planning Assessment~~ portion of the steady state analysis shall ~~address all five years of the assessment period~~ be assessed annually and be supported at a minimum by the following annual current studies, supplemented with qualified past studies as ~~shown~~ indicated in Requirement R2.6:

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:

R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

R2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually and supported by current or past studies.

R2.4 The ~~System Stability portion of the~~ Near-Term Transmission Planning Horizon portion of the Stability analysis ~~Planning Assessment~~ shall be assessed annually ~~address all five years of the assessment period,~~ and be supported by current or past studies. The following studies are required ~~annually~~:

R2.4.1. System peak Load for one of the five years. For peak System Load levels, ~~the~~a Load model shall ~~include the dynamic effects~~ be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads.

R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:

R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

R2.5. The ~~plant~~Generating Unit Stability analysis portion of the Planning Assessment shall be analyzed consistent with Requirement ~~R4.6~~ R5.6 with studies for the year when the following changes that could affect stability margins occur:

R2.5.1. New generator(s) are added or generation modifications are made such as ~~increasing~~changes in generation capability or replacing the exciter ~~or addition of a power System stabilizer~~

R2.5.2. Material Transmission System changes ~~in the electrical vicinity of existing generation are made~~ are made at or near the point of Interconnection of existing Generation such as the ~~addition or~~ removal of a Transmission Line ~~at or near the point of Interconnection~~ or the addition of a new substation in one of the Transmission Lines connected to the plant.

R2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

R2.6.1. For steady state, short circuit, or System Stability analysis: ~~if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market structure changes~~ the study shall be five calendar years old or less.

R2.6.2. For steady state, short circuit ~~analysis~~, Generating Plant Stability, or System Stability analysis: ~~if the study is less than five years old and no material changes have occurred to the System in the intervening period.~~ the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area.
R2.6.3. ~~For plant and System Stability analysis: until material changes in the System make the study no longer valid. Material changes in the system include the addition of a Transmission Line or a generator.~~

R2.7 - For Planning Events shown in Table 1 – Steady State Performance and Table 2 – Stability Performance, when the analysis indicates an inability of the System to meet the performance requirements in the tables, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed ~~over time~~ in subsequent assessments but the System shall continue to meet the performance requirements in the tables. ~~Such plans shall:~~ Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities**.**

R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.

R2.7.2. ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.

R3.3.2.2. Following single Contingency events, ~~System adjustments other than shedding of firm Load or curtailment of firm transfers are permitted to meet performance requirements provided these adjustments can be accomplished within the time period allowed by the applicable time limited ratings.~~ Transmission configuration changes and redispatch of generation are allowed provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits.

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~ if the following conditions are met:

R3.5.1. All Facilities shall be operating within their Facility Ratings.

R3.5.2. Such action would not violate safety, equipment, regulatory or statutory requirements**.**

R3.5.3. A sustainable, stable, operating condition is maintained.

R5.2. Contingency analyses shall simulate the removal of all elements including those that System protection and other automatic controls are ~~is~~ expected to disconnect for each Contingency without operator intervention**.**

R5.5.2 Performance shall meet the requirements for Planning Events in Table 2 – Stability Performance**.**

R5.5.3. Automatic generation tripping is allowed to mitigate Stability violations if the following conditions are met:

R6. For the short circuit portion of the Planning Assessment, as described in Requirement R2.3, each Transmission Planner and Planning Coordinator shall assess the short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties.

R8. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~affected entities~~ neighboring systems, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890.

R9. Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information.

R10. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information.

R11. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information.

R12. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information.

R13. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information.

R14. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to Transmission Lines, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies, within ninety days of a request for such information.

Q43			
Commenter	**Yes**	**No**	**Comment**
ABB	☑		1. In Table 2 P3, more clarification is needed for "above 300 kV". For generators, does that mean those whose POI is >300kV? For transformers, is it the secondary voltage? Also, is the footnote referencing correct? "A transformer with low side rating above 300 kV" is confusing for transformers with 3 windings. What's the low-side rating of a 500/345/13.8 kV transformer? You should say "a secondary voltage rating above 300 kV" and define "secondary voltage rating" as the second highest voltage rating. This is standard nomenclature. Also, I assume you know that there aren't very many of these. The possibilities are 765/500, 500/345, and 765/345. The first two are uncommon, and the 3rd is only common in AEP and HQ. 2. In P3, does the 300 kV limit apply to the transmission circuits as well? It is hard to tell. 3. In R1, you say "Each … shall each …" Delete the second "each", which is redundant. Also delete "required for system performance studies". These words are not part of the requirement. They are part of the justification for the requirement. 4. Table 1, Extreme Event Descriptions, 3d and 3f are almost identical. 5. Table 1, P9-1, rewrite as "… (excluding circuits that share common structures for one mile or less)". P9-1 uses "structure" whereas Extreme 2a uses "tower". Make consistent. 6. P9-2 monopolar is already covered under P4-2. 7. For all of the multiple contingencies with System Adjustment in the middle, group them together something like this (for those with the same requirements): "Outage of any one of the following: 1.

Q43			
Commenter	**Yes**	**No**	**Comment**
			2. 3. 4. followed by System Adjustments followed by outage of any one of the following: a. b. c. d." This is easier to understand than separately writing each possible combination of 2. 8. Overall, the structures of the Tables needs to be made clearer and more consistent. But the ideas are good. 9. The transition is going to be critical for some of the standards that may require significantly more study work and significant capital investments in transmission infrastructure.

Response: 1. The SDT has added a footnote reference to the BES Elements Out of Service column to provide clarity on this issue. The note excludes tertiary windings.
2. The 300 kV threshold also applies to transmission circuits. The SDT has added greater detail to Tables 1 & 2.
3. The SDT has modified Requirement R1 (first draft) as Requirements R9 – R14 and the comment is addressed in the re-write.

R9. Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information.

R10. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information.

R11. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information.

R12. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information.

Q43			
Commenter	**Yes**	**No**	**Comment**
R13. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information. **R14.** Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to Transmission Lines, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies, within ninety days of a request for such information. 4. The Extreme Event descriptions have been revised in Tables 1 and 2 to clear up this wording. 5. P9-1 (P7-1 in second draft) is intended to include all structures in a tower line. Extreme Event 2a refers to a tower line. So they are consistent. 6. The SDT has revised Tables 1 and 2 so that this only shows up in one place now, P7. 7. The SDT has revised the tables as requested. 8. The SDT has revised Tables 1 and 2 as requested. 9 - This will be addressed later in the Implementation Plan.			
AECC	☑		I am not sure what is meant by "not the least common denominator" in the background section. One long time goal of NERC has been to raise the bar and not settle for the status quo which I support. If by this phrase the drafting team is looking to minimize loopholes, remove waffle factor, and eliminate some of the innovative interpretations of requirements then I am in agreement. However, if the drafting team is thinking that the least common denominator is a level of system study that should be performed and that studies should only be performed at some higher level then I disagree and consider this attitude as contradictory to the long term goal of raising the bar. If NERC is serious about reliability then we must get this standard right. Planning is where reliability starts. If reliability is not planned for adequately and built into the system it can not be expected that the future holds much promise for a reliable system. Reliability will not happen on its own. Industry best practices should take precedence over attempts to water down the standards in order to maintain status quo. Do any of the requirements under R1 conflict or repeat any of the requirements set for in any of the other NERC standards, especially some of the MOD and FAC standards? if so R1 should be modified, sections deleted, or reference the appropriate standard. I would like to thank the drafting team for taking on such a formitable task.
Response: The SDT felt that none of the current requirements should be weakened. The SDT felt that it is necessary to develop more stringent requirements where appropriate but not be limited by the fact that companies may need to reinforce their Systems to meet the new requirements.			

Q43			
Commenter	**Yes**	**No**	**Comment**
The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.			
Ameren	☑		1. Much of the language under R1 appears to be redundant with model data requirements as listed in Reliability Standard MOD-010 and MOD-011. Such information would typically be used to produce an annual series of powerflow cases. Instead of supplying such information in a piecemeal manner to the Planning Coordinator as a separate annual effort, the Planning Coordinator should make use of the most recent set of powerflow models. This requirement, as written, could cause a needless duplication of work effort. 2. It is not clear what is meant by 'stressed System conditions' in Requirement R1.2. Does this mean higher than predicted load, lower than expected reactive resources, or other meaning? It is also not clear what is covered by 'load models' in the same requirement. 3. It is not clear how expected transfers are to be modified in Requirement R2.1.3.2. Possibilities include higher or lower in the same transfer direction, turn transfer directions around so that importers become exporters, the inclusion of non-firm transfers that can be cut, or change import/export directions. There should be some basis for the sensitivity change. 4. It is not clear how planned transmission outages are to be modified in Requirement R2.1.3.7. Possibilities include modification of the outage duration, or modifications involving more or less facilities. Since outages are scheduled in the operations planning horizon, based on the best information available at the time of the outage request, it is questionable whether they should not be included in standards that apply to planning in years 1-5 or year 6-10 and beyond. 5. Requirement R2.2.1. should be deleted. Uncertainties involved with studies looking at system conditions out to ten years in the future would preclude the need to extend a Planning Assessment beyond the ten year period. Any corrective actions needed to resolve problems found during study of long-term system conditions could be noted in the Planning Assessment without the need to extend beyond ten years. 6. In Requirement R2.3, the scope of the study work involving the short circuit portion of the Planning Assessment is not clear. It is not clear whether the study work should be based on three-phase faults only, three-phase and single-phase faults, or whether classical representation or more a more detailed representation should be utilized. 7. We assume that Requirement R2.4.3.5 would require only known generation additions,

Q43			
Commenter	**Yes**	**No**	**Comment**
			retirements, or other dispatch scenarios, and that those performing the planning scenarios would not speculate on unkown generation additions and retirements. 8. A market structure change in Requirement R2.6.1 would not constitute a material change in an area with an abundance of low cost base load generation that was always on before the market change and would still be on after the market change. 9. Under Requirement R2.6.3., Plant and System Stability analyses are considered valid until material changes in the System invalidate previous study work. Here, material changes in the system include addition of a transmission line or generator. Addition of a transmission line or generator would only have an impact on stability of generators near the new facility installation. This is not clear from the wording of the standard, which would appear to require restudy of all generators if a transmission line or generator is added anywhere on the system. 10. What would be the duration of interim operating procedures in Requirement R2.7? 11. Requirement R.2.7.1.1. states that a project initiation date should be included in the Corrective Action Plan for each project, as well as an in-service date. A project initiation date may be of use to the particular project design engineering staff, but is of little use in planning the system. Keep in mind that this is a Planning Assessment and not a data request. 12. The wording of Requirements R3.2 and R4.2 appear to require taking all transmission elements as contingencies, plus modeling contingencies which would remove all elements automatically via System protection equipment. Based on comments from the SDT, the inclusion of all single elements in the set of contingencies to be considered is not intended as part of these requirements. Please verify this in writing. 13. The wording of Requirement R3.2.1., dealing with generator minimum voltage limitations, is vague with respect to what is required. It is not clear who would determine the minimum steady-state voltage limitations for all generators, and for what conditions. Note that it may be difficult to obtain some information from IPP generating facilities. 14. Requirement R3.2.2. appears redundant with requirement R1.2.1 of FAC-008-1, which deals with Facility Ratings. Relay load limits are one component already considered in establishing facility ratings. 15. Requirement R3.3.2.1., which deals with the amount and duration of Consequential Load loss, cannot be addressed adequately. Because an outage might be caused by a transitory event with

Q43			
Commenter	**Yes**	**No**	**Comment**
			quick restoration of the outaged facility, or be caused by extensive damage requiring lengthy repairs, there would be no single value for expected duration for any given outage event in the planning horizon. Therefore, this requirement should be removed from TPL-001-1. 16. Requirement R3.3.2.2, describing permissible actions following single contingency events to meet performance requrirements, should be removed from TPL-001-1. System adjustments following single contingencies should not be permitted to meet system performance requirements. For similar reasons, Requirement R3.5, describing generator adjustments permissible as responses to single and multiple contingencies, should be modified to remove the reference to single contingencies. 17. What additional single contingencies would there be that should be considered in Requirement R3.3.3? 18. Consequential generation loss needs to be considered in Requirement R3.6 for those generators directly connected (through transformation) to transmission lines. 19. Interconnection requirements establish that generators must have low-voltage ride through capability. It is not clear how is the transmission planner performing the studies would be able to consider this capability in Requirement R4.3. 20. In Requirement R6, there is no longer a requirement to send the Planning Assessment and Corrective Plan to the regional entities, but to the Reliability Coordinators instead. Why has this change been made? RTOs should not be involved in assessing compliance. 21. In reference to Table 1, bullet point #3, it is not clear how voltage instability, cascading outages, or uncontrolled islanding would be determined under steady state conditions. 22. Under Table 1, P1, cutting of firm transfers is not permitted as a response to a single contingency. However, it is not clear whether, in preparation for a subsequent contingency, reduction in firm transfers would be permitted. Reduction in firm transfers should be permissible in this instance. 23. In Table 1, for contingency categories P5 and P8, how would loss of a transmission circuit above 300 kV followed by loss of a transmission circuit below 300 kV be handled? 24. Under the Extreme Event Description section of Table 1, note that item 3e. is a duplicate of item 3c. One of these can be deleted. Also, for items 3d. and 3f. the notation regarding early shutdown of nuclear facilities for tornadoes is not realistic. The current state of the art of weather prediction

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Commenter	**Yes**	**No**	**Comment**
			does not permit adequate forecasting of tornadoes a day or more ahead of time which might be a cause for concern for a particular nuclear facility. 25. With respect to Table 2, contingency types P5 and P8, it would seem that events should include the same items as shown for contingency type P4. 26. In Table 2, for contingency types P1, P3, P4, P5, P8, and P9, clarification is needed as to whether distribution transformers (138-69 kV or 138-34.5 kV, for example) would be included in the events, or whether the transformers mentioned would be restricted to transmission transformers. 27. For the various stability scenarios, note that Consequential Load Loss would be a function of how System protection equipment is set up for particular scenarios. Delayed clearing time/Zone 2 clearing times could result in load dropped that would not have been dropped for events cleared in primary clearing time. 28. In Table 2, Note 1 ii., is it the intent of the drafting team to require dynamic model representation of relaying equipment? General comments: 29. We are not sure that a wholesale replacement of the existing standards TPL-001-0 through TPL-004-0 is required. We agree that additional clarification is needed for some items, and particularly for the study assumptions that go into the development of models to be used for the performance testing, but we do not agree that the proposed replacement standard provides that necessary clarification. Further, we believe that the replacement standard relies too much on the accompanying tables. More text needs to be included in the standard regarding the system performance requirements. 30. There is a lot of subjectivity involved in developing the study assumptions that need to be considered in the sensitivity models for study. How can we be sure that one or more of the sensitivity requirements in R2.1.3 stated for consideration are of the same level of importance by both auditors and those performing the studies? We are interested to see what the measures for all the requirements of the standard will be when they are developed. 31. Additional planning standard requirements for the EHV system to meet all N-2 conditions without dropping some load will require significant material changes, where feasible. We do not believe that the significant additional costs required for compliance would produce tangible benefits and a corresponding significant improvement in system reliability. What is the justification for the separate

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Commenter	**Yes**	**No**	**Comment**
			treatment for the EHV (>300 kV) facilities? One obvious effect of such requirements is to create a bias against any straight bus configuration for facilities above 300 kV. As stated in response to Question 25, there are existing facilities which cannot be converted from their present configuration. For those facilities which could be upgraded, an implementation period of several years would be needed to meet such requirements. 32. Meeting the requirements of this standard should not be a full time job. There are many more planning activities that need to be performed other than simulation testing to demonstrate compliance. The existing TPL standards require a significant manpower effort to perform the required studies and develop the planning assessment and corrective action plan. We are concerned that the replacement standard, as proposed, will create an even greater burden on the transmission owners without a commensurate benefit to the system reliability. 33. It is not within NERC's or ERO's scope of responsibility to address load loss. The focus of the standard should be on the system capabilities and not how much local load is dropped for a substation outage in a defined service area. A few reports showing the resultant bus voltages and facility loadings on a percentage basis for all single and a the more severe multiple contingency events, including operator or automatic mitigation procedures, should be adequate to demonstrate compliance.

Response: 1. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.
2. The SDT agrees with your concerns and has revised this requirement (now Requirement R9). The terms "stressed System conditions" and "load models" have been removed.

R9. Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information.

3. The SDT is providing some guidance under Requirement R2.1.3 on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. It is the entity's decision to establish and document which transfers are more significant to study System responses. The sensitivity studies do not in themselves establish the need for a plan, only the areas of the System for which the analysis is needed.

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:

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Commenter	**Yes**	**No**	**Comment**
			4. The SDT is providing some guidance under Requirement R2.1.3 on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. It is the entity's decision to establish and document if there are any "planned" outages such as a multi-year Transmission right-of-way rebuilds where outage durations may vary. It is the entity's responsibility to determene the actions necessary to handle extended outages and which are more significant to study System responses. 5. The SDT felt that this wording was appropriate based on comments by FERC in their orders concerning long lead time projects. 6. R2.3 - The studies should be based on the individual TO's practices which are assumed to be in agreement with good utility practice. An annual assessment of the results of these studies is required. 7. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.4.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.4.4 has been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. In either case the entity must document the reason for running or not running cases for the items listed. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance. It is the entity's decision to establish and document if it needs to consider future additions and retirements. It is the entity's responsibility to determene the actions necessary to handle such items and which are more significant to study System responses. **R2.4.3**. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: **R2.4.4**. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. 8. The SDT removed market changes from the requirement (see Requirement R2.6.2) **R2.6.2**. For steady state, short circuit, Generating Plant Stability, or System Stability analysis: the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. 9. The SDT added wording to Requirement R2.6.2 to clarify this concern. 10. The "interim Operating Procedure" was deleted in response to Industry requests for more clarification as being an unnecessary modification of the more general term "Operating Procedure" that is already a defined term in the NERC Glossary.

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Commenter	**Yes**	**No**	**Comment**

11. Requirement R8 (old Requirement R6)which focuses on the distribution of the Planning Assessment results to affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old Requirement R6). Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. The SDT believes that initiation dates are required for near-term Corrective Action Plans to give an indication that the Corrective Action Plans can be implemented in time.

12. In Requirement R3.2 and Requirement R4.2, the SDT revised the event descriptions to provide clarity on simulations in response to FERC Order 693. For example, Requirement R3.2 would require modeling breaker-to-breaker outages rather than modeling bus-to-bus outages in a study.

13. Generator high and low voltage limits are part of the constraints and are considered part of Facility Ratings in FAC-008. FAC-009 provides that the information be provided by the Generator Owner.

14. R3.2.2 - While FAC-008-1 generally addresses this issue, the SDT felt that the relay loadability issue needed to be specifically addressed to ensure its impact was not inadvertently ommitted from Contingency analysis.

15. R3.3.2.1 - FERC required documentation of Consequential Load loss in Order 693, paragraph 1795, (not Non-Consequential) and duration should be based on best judgment for the common cause of the event.

16. R3.3.2.2 has been changed to clarify the concern.

R3.3.2.2 – Following single Contingency events, ~~System adjustments other than shedding of firm Load or curtailment of firm transfers are permitted to meet performance requirements provided these adjustments can be accomplished within the time period allowed by the applicable time limited ratings.~~ Transmission configuration changes and redispatch of generation are allowed provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits.

17. The requirement refers to everything over and above single Contingencies.

18. Requirement R3.6 was completely re-written in Requirement R3.5.

R3.5 Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:

19. The SDT feels that planning studies should be of sufficient scope to cover this situation.

20. R6 (first draft) - does not specify any action by the Reliability Coordinator - the Planning Coordinator coordinates distribution. This action

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Commenter	Yes	No	Comment
			does not involve assessing compliance but involves peer review and coordination of analysis. 21. In the steady state time frame, voltage instability can occur typically during high power transfer and/or peak demand periods. Voltage instability can be assessed using a long-term Stability program. However, it can also be assessed using a power flow program that simulates governor action. There are a number of IEEE papers (e.g., G. Morison, B. Gao, and P. Kundur, "Voltage stability analysis using static and dynamic approaches," IEEE Transactions on Power Systems, vol. 8, no. 3, pp. 1159 – 1171, August 1993) that can provide suggestions on the methodology. Cascading outages and uncontrolled islanding can also occur, for example, when the Transmission Facilities Load beyond the corresponding relay trip settings. This could cause uncontrolled tripping of Transmission Facilities beyond those required to clear the fault. Even though these events are rare, the Transmission Planner should be aware of their possibility when performing studies. 22. The SDT has replaced the term "firm transfer" with "firm transmission service" in Tables 1 and 2. 23. Loss of a Transmission circuit above 300 kV followed by loss of a Transmission circuit below 300 kV would be treated the same as loss of Facilities below 300 kV. 24. The SDT has revised Tables 1 and 2. Items 3d and 3f are meant to capture shutting down of a nuclear power plant as a result, not in anticipation, of events such as tornadoes. 25. Table 2 has been revised so that the elements are now the same. 26. See footnote 2 and 3 in Table 2 for clarification. 27. The SDT agrees. The Load lost as a result of the event specified can be different for different Contingency scenarios (i.e., normal versus delayed clearing). 28. This should already be in your models. 29. TPL-001-1 is based on the existing TPL standards and is not a wholesale replacement but an aggregate of TPL-001 through -004, but does contain new elements and clarifying language. FERC Order 693 asked the SDT to consider combining the 4 standards. Please provide any comments on specific elements needing additional clarification in future responses in the standard development process. 30. Measures will be added later in the process. 31. The SDT felt that it was appropriate to raise the bar on situations that would impact the reliability and performance of the System and considered above 300 kV as the backbone of the System and thus needs to be extremely reliable and was an appropriate place for raising of the bar. Implementation Plan will be supplied with a later draft.

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Commenter	**Yes**	**No**	**Comment**
32. Resources and expenditures versus adequate level of reliability are being given due consideration throughout the process and will ultimately be determined by the industry through the ballot process. 33. FERC has jurisdiction over firm Transmission service. FERC allows the use of "equally or more efficient or effective approach" and firm Load is being used as a proxy for firm Transmission service.			
Brazos Electric	☑		1. In R1.1.1. it appears the data that is being requested requires some amount of survey to determine the mix. This data would require a great deal of manpower and provide little more benefit than simply varying the data for comparison. However it does say in R1 upon request so does this allow the Planning Coordinator the descretion as needed on this type data? 2. R1.2, What is 'supporting rationale' and 'validated' mean? What are "stressed" System conditions? It appears (from 2.1.3) that stressed means various sensitivities. 3. R1.4, define 'long-term', generation outages are considered confidential information in ERCOT and thus are not available to all TOs, see next comment 4. R1.5 somewhere (perhaps in R1) the language should include "its respective portions of the data" or something to that effect meaning that a TO should not be held accountable for a GOs data. R1 appears to read that each entity shall provide the requested data. This seems to be intuitive BUT there are GOs that feel the data responsibility for the entire system belongs to the TOs and this leads to delays in getting accurate information if its uncertain as to who provides what data. 5. In R2 the language indicates the TP and PC shall each perform studies. There should be some clarity here. Also, it indicates that each shall assess "its portion of the BES". This needs to be clarified as well, obviously contingencies on other portions of the BES may cause issues within different portions. again, what constitutes documentation? 6. R2.1 it appears from the wording (shall "address" all five years) that the planning assessment must be done on all five years but 2.1.1 appears to state only 2 years are required. Please clarify. 7. R2.1.3 this seems to indicate that the studies mentioned in 2.1.1 and 2.1.2 should be "stressed" by the conditions listed below or just by one of them. We assume this means using only one is acceptable with proper documentation. Is that correct? Further, the sensitivities are ambiguous. How does one justify higher load levels or even know what they are without input from other TOs or the PC? How does one even guess at the other variables? what is meant by 'long lead time facility'? IF this only means for a TOs "portion of the BES" then it makes more sense but are these even valuable considering the wide range of data. The only variable that can be adjusted with any accuracy is the generation and ERCOT maintains the confidential data in this area. We assume R2.1 to mean you

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Commenter	**Yes**	**No**	**Comment**
			need to assess two peak summer cases, one off peak and then look at varying generation patterns on those cases. This appears to be the latitude given. Is this correct? 8. R2.2.1 are generation additions considered a "project"? If this means that a case must be created and assessed by all TOs for a known generation addition that is 12 years out, then this will lead to unnecessary studies. We assume this to mean, in the case of a generation addition, that the connecting TO should make an assessment once the PC considers this new addition to be valid for study. Is that correct? 9. R2.3 what is meant by "past studies" and how long must these be kept? Or is this at the TOs discretion? 10. R2.3.1 how does one know if the changes will result in increased fault currents until studies are done? This implies that studies SHALL be done for just about ANY change to the BES. There must be discretion allowed here. The word "shall" does not afford any discretion. 11. R2.4 the same comments for R2.1. apply here concerning years of study and defining 'stressed'. Additionally this type study seems to provide better results when done for the BES which would require input from all TOs thus a study based only on "its portion of the BES" would not have as much value unless you are referring to generation additions and localized studies. 12. R2.5.1 does not allow any discretion, for any and all all modifications, additions, etc…a study shall be performed. This is not needed in all cases. 13. R2.5.2 Wording such as "material changes" and "vicinity" are ambiguous terms without discretion being allowed the planner. Voltage level Line changes, amount of generation, something needs to be added to clarify. 14. R2.6.1 again, what are material changes? Topology changes and generation changes happen monthly, weekly. Are studies to be invalidated for each 'material change'? 15. R2.6.3 who determines if the study is no longer valid? The TO, PC or the agreement of both? 16. R2.7.1 what is a 'project initiation date' and why is this needed? 17. R2.7.2 Projects are added to cases after an analysis has been performed to see if the project is an acceptable alternative. In that analysis the project is 'retested' to see if it is effective. This is assume to be acceptable for the definition of 'retesting'.

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Commenter	**Yes**	**No**	**Comment**
			18. R2.7.3 unsure what 'committed' means regarding projects nor understand the need to have this documented anywhere. 19. R3.2.2 what is 'relay loadability' and where would you note how it is supposed to be treated? 20. R3.3.1 how is this different than R3.1? 21. R3.3.2.1 why is there a need to know how much non-consequential load loss exists for each contingency and how can one predict the length of time this will last? 22. R3.3.2.2 Do we need to document the 'system adjustment' for each contingency? 23. R3.3.3 what is a severe impact and what is one that is less severe? 24. R3.4 what is the difference to 3.3.3? The definition given in the NERC Glossary from May of 2007 of Cascading Outage is still vague, it appears to allow the TP or PC the discretion to determine it based on studies. Is this the intent? 25. R3.5 what is the time limit for run-back? 26. R4.4 how can TPs identify what generation upgrades are needed (protection and control modifications)? 27. R4.5.2 whats the difference between this and 4.5.1? 28. R4.6 the generation levels could be too low for the studies to be useful, perhaps voltage levels should also be added or allow for TP/PC discretion. 29. R4.6.3 seems to allow some TP discretion in deciding which planning events are more severe but how does one know that without studies? 30. R5 this seems to have no direction for either party. 31. R6 is ambiguous Table 1 32. terms such as voltage instability, cascading outage and uncontrolled islanding should be defined

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Commenter	**Yes**	**No**	**Comment**
			or allowed to be defined by the PC. If consequential load loss is allowed for all cases then why even mention it? Isn't this like saying if the line trips, it will be out of service? why would one want to document this amount, perhaps for some sort of ranking? Planning events 33. what is a 'system adjustment'? if this means to manually redispatch the BES for each condition then these studies shown under P4 will take so long to complete that they will be invalid by the time they are done. In ERCOT, the economics of redispatch are not known to the TP thus this is done by the PC. an automatic computer simulated redispatch will possibly not have the same results. Define 'generator' for is this a single unit, the whole train, the largest unit or other? 34. For P6 events and above, if consequential load loss and non consequential are allowed, they why study these events? Do TPs plan and build transmission to eliminate the overloads for these events or just study them so that the results are known? Studying every possible event or combination does not make the studies better or provide a higher insight to areas of concern. A number of the combinations have a low probability of occuring and performing the studies and analizing the results will be a manpower burden and provide no better clarity on needs of the system. Table 2 35. The number of events to consider seems excessive although this is not our area of expertise. If each of these is to be run for each 'material change' in the BES then this list is excessive without more leeway or guidance provided.

Response: 1. The SDT believes that models must reflect the expected Load mix of industrial, commercial and residential Loads to appropriately reflect the behavior of the System.

2. The SDT agrees with your concerns and has revised this requirement (now Requirement R9). The terms "stressed System conditions", "validated", and "supporting rationale" have been removed.

3. The SDT has revised this requirement based on industry comments to clarify intent and to be responsive to FERC Order 693, paragraph 1725. Further, it is not the intent of the standard to require consideration of confidential information that is not available.

4. The standard has been revised to identify specific entities responsible for providing the required information.
5. The extent of coordination between the TP and PC can vary depending on many factors such as whether you are part of an ISO/RTO, vertically integrated Investor Owned Utility, or Transmission only company. The Functional Model envisions that planning entities will not only need to use overlapping models to simulate how the System will respond to Contingencies, but they will also be layered to provide for more locally focused studies as well as more global studies. Planning Coordinators need input from the planners doing the local studies to complete their overall studies. Planners need to coordinate their activities and sort out which entity will be detailing its studies to what extent. Documentation of entity studies needs to demonstrate that the System response to Contingencies and any Corrective Action Plan has been screened so as to meet the performance requirements stated in the standard, such as not exceeding applicable voltages and ratings.

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Commenter	**Yes**	**No**	**Comment**
6. Requirement R2 states that the "Planning Assessment shall use current or past studies …." The Planning Assessment is to cover the five year period but the entity is only required to run a limited number of studies. It is the responsibility of the entity to determine if past studies can demonstrate that the performance requirements are met. If past studies in conjunction with the required studies do not demonstrate that the system can meet the performance needed, the entity will need to run additional current studies that demonstrate it can meet the requirements. Requirement R2.1.1 is in reference to Requirement R2.1 which states that the Planning Assessment "be supported at a minimum by the following annual current studies, supplemented with qualified past studies as indicated in Requirement R2.6:" To further clarify, the SDT has deleted the "all five years" language. 7. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.1.4 has been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own System. In either case the entity must document the reason for running or not running cases for the items listed. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance. It is the entity's decision to establish and document which senstiviyies are more significant to study System responses. The sensitivity studies do not in themselves establish the need for a plan, only the areas of the system for which the analysis is needed. **R2.1.3.** For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.1.4**. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. 8. Known generation additions are considered a project and must be studied if the lead times are longer than 10 years. 9. R2.3 - See Requirement R.2.6.2 where this is defined. 10. The SDT has revised the wording of R2.3 to try to clarify that short circuit analysis must be conducted annually but that past studies as defined in Requirement R2.6.2 may be used as appropriate. R2.3 The short circuit analysis portion of the Planning Assessment shall be conducted annually and supported by current or past s 11. Requirement R2.4 has been re-worded to clarify this situation. **R2.4** The ~~System Stability portion of the~~ Near-Term Transmission Planning Horizon portion of the Stability analysis ~~Planning Assessment~~ shall be assessed annually ~~address all five years of the assessment period,~~ and be supported by current or past studies. The following studies are required ~~annually~~:			

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Commenter	**Yes**	**No**	**Comment**

12. See Requirement R5.6.2 which provides the bounds you are looking for.

13. and 14. This wording is intentional to allow the planner some discretion.

15. The SDT has revised Requirement R2.6.3 as the new requirement R2.6.2 to clarify this concern.

R2.6.2 For steady state, short circuit ~~analysis~~, Generating Plant Stability, or System Stability analysis: ~~if the study is less than five years old and no material changes have occurred to the System in the intervening period.~~ the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area.

16. Requirement R8 (old requirement R6) which focuses on the distribution of the Planning Assessment results among affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old requirement R6). Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. Typically the date would indicate when significant resources will begin to be employed This covers any project proposed for the near term. The SDT believes that initiation dates are required for near-term Corrective Action Plans to give an indication that the Corrective Action Plans can be implemented in time.

17. The specific requirement to perform re-test has been removed. The purpose of the Corrective Action Plan is to list the actions that are needed to meet performance requirements. The studies, current and/or past as appropriate as well as the extent of the size of the study area, are performed to support compliance and demonstrate that the requirements are met.

18. Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted Requirements R2.7.2 through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions".

R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.

19. R3.2.2 - The SDT used the term "relay loadability" to describe the maximum Transmission line loading on a specific circuit that is permitted before line relays might see the Load current as a fault and trip the circuit. In those cases where the relay loadability limit is lower than the circuits thermal or Stability rating, the relay loadability limit should be applied as the benchmark for meeting the performance requirements.

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Commenter	**Yes**	**No**	**Comment**
20. Requirement R3.1 requires studies to be performed. Requirement R3.3.1 requires that the results meet the requirements of the standard. 21. R3.3.2.1 - FERC required documentation of Consequential Load loss in Order 693, paragraph 1795, (not Non-Consequential) and duration should be based on best judgment for the common cause of the event. 22. Yes. 23. The intent is to allow the Transmission Planner flexibility for deciding which multiple Contingency Planning Events are run during its annual studies. The standard leaves the classification of "severity" to the engineering judgement of the Transmission Planner based on experience of the System, past study results, input from operations staff, etc. The Transmission Planner will need to explain why others would be known to be less severe. For example a N-1-1 involving two non-related and distant Facilities could be excluded by the TP if desired. 24. Requirement R3.4 covers Extreme Events, Requirement R3.3.3 covers Planning Events. The SDT did not propose a new definition for cascading outage or cascading. 25. The use of the defined term 'Facility Ratings' dictates the time limit. 26. The outcome of the assessment should identify the actions required. 27. In new Requirement R5.5.2, clarification has been provided to differentiate the events. **R5.5.2**. Performance shall meet the requirements for Planning Events in Table 2 – Stability Performance. 28. Those values are based on Large Generator Interconnection Procedures as approved by FERC. 29. It does allow some discretion but good engineering judgement is assumed and you must document your rationale. 30. This requirement assumes that the two parties will react in a professional manner to resolve any differences. 31. The new Requirement R8 clarifies this. **R8**. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~affected entities~~ neighboring systems, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890. 32. In general, new definitions are proposed along with the proposed standard, and will be included in the Glossary of Terms upon approval of			

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Commenter	**Yes**	**No**	**Comment**
the standard. Definitions for Cascading and Stability are included in the NERC Glossary. Further uncontrolled islanding, while not defined, is a common term that is well understood. The SDT does not propose to improve the definitions for Cascading and Stability or propose a new definition for cascading outages and uncontrolled islanding. There are a number of IEEE papers (e.g., P. Kundur, J. Paserba, V. Ajjarapu, G. Anderson, A. Bose, C. Canizares, N. Hatziargyriou, D. Hill, A. Stankovic, C. Taylor, T. V. Custem, V. Vittal, "Definition and Classification of Power System Stability", IEEE Transactions on Power Systems, vol. 19, no. 2, pp. 1387 – 1401, May 2004) that provide descriptions for voltage instability. The requirement concerning Consequential Load is to address FERC Order 693, which directs that the ERO, among other things, to clarify footnote (b) in regard to Load loss following a single Contingency, specifying the amount and duration of Consequential Load Loss and System adjustments that are permitted after the first Contingency to return the System to a normal operating state. 33. The term "System adjustment" is used in the existing TPL Standards, and is intended to have the same meaning in the proposed TPL standard, and includes both manual and automatic actions. 34. For P6 and more severe Events, loss of Consequential and Non-Consequential Load is allowed. The events will still need to be studied to ensure that System reliability and security is maintained and that any outage would not result in unacceptable System performance, such as, cascading, instability and uncontrolled separation. 35. The SDT understands the potential work load increases. Requirement R3.3.3 requires evaluation of only those Planning Events (involving multiple Contingencies) that are expected to produce more severe System impacts.			
City Water Power and Light	☑		The Standards are a great start in getting a set of requirements in place that will provide a planning methodology that will be transparent to the Functional entities in the interconnections and will produce results that will permit reliable planning and operations of the BES. The SDY should remove all Requirements that are subjective and can't be measured. The assumptions the Transmission Planners and Planning Coordinators use to conduct the studies should be posted.
Response: The SDT has endeavored to draft Requirements that are objective and measurable. Since this comment did not include specific Requirements that the commenter proposes should be deleted, the comment relating to removal of subjective, unmeasurable Requirements is unactionable. The SDT believes the comment relating to posting assumptions implies that the standard should not have study assumption Requirements but should only require that assumptions be posted. The SDT is unclear where assumptions would be "posted" but in any event if study assumption Requirements were removed, then the SDT believes there would be little or no value in having study assumptions "posted".			
Dominion	☑		GENERAL COMMENTS: (1) Making the standards more stringent by "raising the bar" is not going to result in a dramatic improvement in system reliability. Even the best designed systems are susceptible to human error. Dominion has at least 5 years of transmission outage data clearly illustrating that any resulting loss of load (both consequential and non-consequential) has had an average duration of only 4-7 customer-minutes per year. Going forward, the emphasis and focus should be on planning and

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Commenter	**Yes**	**No**	**Comment**
			operating the bulk electric system so as to confine any transmission outages to the immediate, local area, and not allow the cascading of outages beyond control area boundaries. (2) Although we are unable to put specific numbers on the impact of "raising the bar "with respect to non-consequential load loss, it will be enormous. Increased staffing levels may be required, and we would likely incur significant increased transmission maintenance and construction costs. It is likely that State commissions everywhere (not just Virginia) would agree that rate payers should not incur the significant cost increases required to meet more stringent planning criteria (i.e. - "raising the bar") when the corresponding improvements in transmission system reliability cannot be quantified. SPECIFIC COMMENTS PERTAINING TO REFERENCED SECTIONS OF THE STANDARD: (1) The last block in Category C of Table 1 of the existing standards deals with protection system failure. We interpreted this as, among other things, having a fault beyond the first-zone coverage of the primary protection scheme with the carrier equipment failure resulting in a second-zone trip of the faulted line (even though only one element will be lost). The second-zone trip time is generally in the range of 30-35 cycles. This may be critical from the stability aspect. The proposed Table 2 of TPL-001-1 is silent about this. Is there a reason why this requirement was left out? (2) The requirement R4.6.2 may cause some confusion due to the last part "….whichever is greater". It is suggested that the entire wording for this requirement be replaced as listed below to avoid any misunderstanding. "Shall be performed for changes in the real power output of a generating unit if either of the following applies: (a) the increase is more than 10 % of the existing capacity (regardless of the amount of MW increase) (b) the increase is more than 20 MW (regardless of the % increase). Something to think about regarding a cut-off limit of 10% or 20 MW: We had a unit with 800 MW existing capacity and the request was to increase it by 15 MW making the total new capacity of 815 MW. The requested increase was less than 10% of the existing capacity and also less than 20 MW, meaning the plant stability study is not required. However, we found that the increase of 15 MW made the plant unstable and we had to come up with a solution (and we did). This example warrants to include something like…. "However, in cases where a stability margin is known (or estimated) to be slim, stability study should be performed regardless of the % or MW

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Commenter	**Yes**	**No**	**Comment**
			amount of increase (this leads to defining "Stability Margin"). (3) Table I, bullet 3 states that "Voltage Instability, cascading outages and uncontrolled islanding shall not occur." There is no definition for "voltage instability" anywhere in the proposed standard. (4) R.3.3.2.1. states "Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment." This requirement creates significant unnecessary work without adding any value to system reliability. (5) Extreme Event Description 3.d. states: "Shutdown of a nuclear power plant(s) and other facilities a day or more prior to a hurricane, tornado or wildfire, or for other common causes." It would appear that day ahead planning for a tornado is not possible, or applicable, for inclusion in this listing.
Response: Specific 1. The SDT agrees with your concern and is working on a solution for a future draft. 2. The wording was lifted from FERC and has not been changed. 3. There are a number of IEEE papers (e.g., P. Kundur, J. Paserba, V. Ajjarapu, G. Anderson, A. Bose, C. Canizares, N. Hatziargyriou, D. Hill, A. Stankovic, C. Taylor, T. V. Custem, V. Vittal, "Definition and Classification of Power System Stability", IEEE Transactions on Power Systems, vol. 19, no. 2, pp. 1387 – 1401, May 2004) that provide descriptions of voltage instability. 4. FERC required documentation of Consequential Load loss in Order 693, paragraph 1795, (not Non-consequential) and duration should be based on best judgment for the common cause of the event. 5. Extreme Events notes have been changed to address this concern.			
E ON US	☑		1. R1.4 "including protective relays with consideration given to spare equipment strategy" I do not understand the intent of this phrase or what it adds to the requirement. 2. R2.6.1 "and market structure changes" What is this, does it require a definition? 3. R2.7.1.1 What is the project initiation date; the date approval is sought, received, materials are ordered, construction begins? Many projects are upgrades or replacements that this will be meaningless. Don't you really only want multiyear projects? 4. R2.7.2 The initial study process will incorporate testing. This will require the creation of additional cases and additonal testing prior to the Planning Assessment submittal. Most projects should be identified during the Long Range time frame. Inclusion of the project in the next years base cases and subsequent testing should be adequate. 5. R2.7.3 Define a "Committed Project". MISO has spent years on this. 6. R2.7.4 Changes in timing of all projects should be documented in the Planning Assessment. Why would you document Committed Projects that are removed but not any delays or accelerations?

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Commenter	**Yes**	**No**	**Comment**
			7. R3 Sensitivity studies (if retained) should have less stringent performance requirements than the other cases required by R2.1. 8. R3.3.2.1 Unless this is limited to above 300 kV, many hours will be spent for naught. The lower voltage systems often have tapped loads that will trip with the line. The time required to restore will vary on the fault location, and time for switching, sometimes remote and sometimes manual. I do not see the need for or the benefit of this requirement. Please explain. 9. P3 Event is poorly worded, see response to Q25. 10. P6.1 above 300 kV, below 300 kV or all? The tables need to be reviewed to make sure that the voltage applicability is clearly stated. 11. P9.6 Why is this a requirement? It should be much less severe than any of the prior requirements. 12. Extreme Event 9 (3ph fault with loss of all generating units at a station) is in conflict with Q33 which says it was not included). Am I missing something? 13. Other, it appears that we are not required to study the outage of a transmission line or transformer followed by the outage of a generator. Was this overlooked, or did I miss it? Would system adjustment be allowed?

Response: 1. The SDT has revised this requirement based on industry comments to clarify intent and to be responsive to FERC Order 693, paragraph 1725.
2. R2.6.1 - The change must be "material" as stated in the standard meaning it must have an impact on the study results or may only make some results invalid and not relevant.
3. Requirement R8 (old requirement R6) which focuses on the distribution of the Planning Assessment results among affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old requirement R6). Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. Typically the date would indicate when significant resources will begin to be employed. This covers any project proposed for the near term. The SDT believes that initiation dates are required for near-term Corrective Action Plans to give an indication that the Corrective Action Plans can be implemented in time
4. Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted Requirements R2.7.2 through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions".

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Commenter	**Yes**	**No**	**Comment**
R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. 5. Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted Requirements R2.7.2 through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions". 6. Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted Requirements R2.7.2 through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions". 7. The SDT is providing some guidance under Requirement R2.1.3 on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. It is the entity's decision to establish and document which transfers are more significant to study system responses. The sensitivity studies do not in themselves establish the need for a plan, only the areas of the system for which the analysis is needed. **R2.1.3**. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: 8. R3.3.2.1 - FERC required documentation of Consequential Load loss in Order 693, paragraph 1795, (not Non-Consequential) and duration should be based on best judgment for the common cause of the event. 9. Please see response to comments on Q25. 10. The SDT has revised Tables 1 and 2 to provide more clarity. 11. P9.6 was to address FERC directive in Order 693 to consider spare equipment strategy. The SDT has revised Tables 1 and 2 to remove P9.6 and included this consideration in R11 of the second draft of the standard to address this issue. 12. In Q33 the SDT posted a question to the industry to request guidance on whether simultaneous tripping of all generating units in a power plant should be included in the Extreme Events in Table 2 (on Stability Studies). 13. Tables 1 and 2 have been revised to address your comments. P3 is meant to cover the combination of overlapping outages regardless of the sequence in which the outages occur.			
ERCOT ISO	☑		1. R1.1.1 - Are percentage of load that is industrial, commercial, and residential needed? 2. R1.2 - The wording is confusing. If the power factor is based on historical measured values, does it have to be during contingency (stressed)? 3. R1.5 - "Planned Facilities defined in accordance with the documented criteria of the Planning Coordinator" - what is meant by this?

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Commenter	**Yes**	**No**	**Comment**
			4. R2.1.1, R2.1.2, R2.1.3.1 - are all studies to be run using all the contingencies defined in Table 1 - Steady State Performance? 5. R2.6.1, R2.6.2, R2.6.3 - past studies will never be able to be used if the addition of a transmission line makes them invalid! 6. R3.2.1 - What is meant by "minimum steady state voltage limitations of all generators"? 7. R3.2.2 - Relay "loadability"?? What is meant by this? Sounds unreasonable for steady state studies as facility rating should reflect limitations of relay equipments such as CT"s. 8. General comment: If this proposed standard is approved, since it contains requirements that are more restrictive than current standards, there will need to be a transition period to allow transmission to be built to allow systems to meet the new requirements.

Response: 1. The SDT believes that models must reflect the expected Load mix of industrial, commercial and residential Loads to correctly reflect the behavior of the System.
2. The SDT has revised this requirement based on industry comments to clarify intent.
3. The referenced verbiage has been deleted from the revised standard
4. Regarding Requirements R2.1.1 and R2.1.2, Requirement R2 states that the "Planning Assessment shall use current or past studies …." The Planning Assessment is to cover the five year period but the entity is only required to run a limited number of studies. It is the responsibility of the entity to determine if past studies can demonstrate that the performance requirements are met. If past studies in conjunction with the required studies do not demonstrate that the System can meet the performance needed, the entity will need to run additional current studies that demonstrate it can meet the requirements.
Regarding Requirement R2.1.3.1, the SDT is providing some guidance under Requirement R2.1.3 on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. It is the entity's decision to establish and document which transfers are more significant to study System responses. The sensitivity studies do not in themselves establish the need for a plan, only the areas of the system the analysis is needed.

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:

5. R2.6.1, R2.6.2, R2.6.3 - The change must be "material" as stated in the standard meaning it must have an impact on the study results or may only make some results invalid and not relevant.
6. R3.2.1 - Generator high and low voltage limits are part of the constraints and are considered part of Facility Ratings in FAC-008. FAC-009 provides that the information be provided by the Generator Owner.

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Commenter	**Yes**	**No**	**Comment**
7. R3.2.2 - The SDT used the term "relay loadability" to describe the maximum Transmission line loading on a specific circuit that is permitted before line relays might see the Load current as a fault and trip the circuit. In those cases where the relay loadability limit is lower than the circuit's thermal or stability rating, the relay loadability limit should be applied as the benchmark for meeting the performance requirements. The SDT believes that equipment ratings, such as CT ratings, should also be reflected, but not necessarily as part of the "relay loadability" limit. 8. The SDT agrees and that will be addressed in the future			
AECI	☑		1. Based on the p1 to P9 events one would have to model a breaker to breaker instead of bus to bus. This would be a large undertaking and it seems that it would be more conservative to have a bus to bus model. 2. Question on P4 - does this apply to all generators on a system or is there a MW limit to the size of the generator. 3. P5 Does this mean running N-2 for the 300 KV for all seven cases that would be required. This could take a large amount of computer run time. 4. We are stating that this change to the standard is not warranted. However, if all these changes are implemented what used to take approximately 1 month to assess will now take approximately 4 months and we are not that big of a system. I assume that the time and manpower to perform all the contingencies has been considered.
Response: 1. The SDT revised the event descriptions to provide clarity on simulations in response to FERC Order 693. Depending on the configuration, modeling bus-to-bus outages in a study is not necessarily more conservative than modeling breaker-to-breaker outages. The SDT understands the potential increases in work load. The draft standard allows the use of past studies to meet the current year assessment and study requirements. 2. The intent is that the standard would apply to all Facilities (including generators) that are represented in the transmission planning simulation. 3. Requirement R3.3.3 requires evaluation of only those Planning Events (involving multiple Contingencies) that are expected to produce more severe System impacts. 4. The SDT understands the potential increases in work load. The draft standard allows the use of past studies to meet the current year assessment and study requirements.			
Allegheny Power	☑		General Comments: 1). We believe the 300 kV cutoff should not be used. It should be based on the definition of a Backbone Facility. The 300 kV and above standards should only apply to backbone facilities that are used to provide overall energy transfer and ties to other systems and not facilities that provide load serving purposes. Backbone facilites should be specifically defined and accepted as Backbone facilities through RTO and RE review and acceptance.

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Commenter	**Yes**	**No**	**Comment**
			2). Planning Scenarios should be forced to include a market based scenario under the Planning Authority obligation which should include long range market projections for generation dispatch, significant energy price changes due to environmental issues or fuels, and market impact of large transmission reinforcements. 3). It should be noted in the process that additional planning resource additions (maybe as much as 30%) will be required to met these new study requirements since they are much more expansive than the existing requirements. 4). These standards could require substantial (millions) upgrades to the system to meet the proposed changes. These are primarily due to the 300 kV and above standard revisions and the non-consequential load drop criteria adjustments.
Response: 1. The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission Systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT believed that the 300 kV and higher Systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many Systems in the various Interconnections and that the more stringent requirements were appropriate when considering Contingencies of two EHV Facilities due to one Event. Systems operated at these voltage levels generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers the energy is delivered by the other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. **2.** Marketing and economics are beyond the scope of the SDT. This is a reliability based standard. 3. Resources and expenditures versus adequate level of reliability are being given due consideration throughout the process and will ultimately be determined by the industry through the ballot process. 4. Resources and expenditures versus adequate level of reliability are being given due consideration throughout the process and will ultimately be determined by the industry through the ballot process.			
AEP	☑		(1) Consider clarifying system performance requirements that would be applicable during (a) the first two minutes after the system disturbance when slow-acting automatic system adjustments (such as the operation of motor-operated-air-break switches that are relayed to sectionalize the faulted segment of a multi-terminal circuit; the changing of taps on tap-changing-under-load transformers; the switching of capacitor banks; etc.) would not allowed to be considered, (b) the next three minutes (two to five minutes after the system disturbance) when these slow-acting automatic system adjustments would be allowed to be considered, (c) the next twenty-five minutes (five to thirty minutes after the system disturbance) when manual system adjustments would be allowed to be considered, and (d) the time period beyond thirty minutes after the system disturbance when no system adjustments of any kind would be allowed to be considered. (2) Consider clarifying which functional entity is expected to provide what information specified in this standard, especially in requirement 1.

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Commenter	**Yes**	**No**	**Comment**
			(3) Consider clarifying the need for functional entities to provide competitive sensitive information such as planned outages. (4)The system stability study documentation requirements R2.4 and R4.5 do not specify a level on the scope of studies or indicate the extent of coverage across a system required for acceptability. A reasonable scope of such studies might include studies of a system nature in association with dynamic devices, or voltage collapse or cascading scenarios, but what else would be required? Or, how much more stability study documentation beyond what is necessary to comply with TPL-001 through 004 would be required? Specific comments regarding R2.4 are as follows: what does "address" all five years mean? How much of the system do you need to study (for example, do you need to apply faults at every bus)? Again, you wouldn't know how much studying needs to be done before this requirement is satisfied. In R2.4.1 and R2.4.2, depending upon the study at hand, some other load condition such as shoulder peak may be more appropriate. Why should you be required to do peak and off-peak cases in such an instance? In R2.4.3 you are forced into doing at least one of the sensitivity studies listed (i.e., "to reflect one or more of the following conditions..."). Is this intentional? Depending upon the study at hand, none of these may be worthwhile doing, and there may be some other parameter that would be better looked at for sensitivity purposes. Existing TPL-001 through 004, Table 1, Category C3 requires any combination of generator, transmission line, transformer, or HVDC pole block in succession. The new standard excludes several of these combinations from being required in P4, P5, P8 and P9. Is this an intentional exclusion? If so, why? The standard should state explicitly that existing generation does not need to be studied unless R2.5.1 or R2.5.2 apply.
Response: 1. NERC Standards are to specify the requirements, which must be met and not "how" they are met. The System adjustments that can take place during various time periods are different in different systems, and should be based on agreements and coordinated among the entities performing the studies. 2. The SDT does not believe it is necessary to be so prescriptive but only requires that accurate data be provided in order to build accurate models. 3. Commercially sensitive and confidential information is covered by existing rules and regulations and can't be altered by the SDT. 4. Address means that you must cover all 5 years in the assessment. Good engineering judgement must be applied. The requirements are minimal and one can always do additional studies. Yes, this is intentional but good engineering judgement may imply that you need to do more than one sensitivity. The SDT has interpreted C3 as described in the tables. The SDT feels that the conditions are properly identified.			
APPA	☑		The Standards are a great start in getting a set of requirements in place that will provide a planning methodology that will be transparent to the Functional entities in the interconnections and will produce results that will permit reliable planning and operations of the BES. 1. Requirement 5 is a start at attempting to share the results of the planning studies with the correct entities. However, because this is such an important part of reliable planning, this requirement

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Commenter	**Yes**	**No**	**Comment**
			should be rewritten to be much more definitive and comprehensive. It is recommended the SDT review the FAC-014 Standard where this Standard deals with who is to receive the methodology for calculating SOLs. The SDT needs to insure that the Transmission Planners and Planning Coordinators share their Near-Term Planning Horizon Studies with the Transmission Operators (Operation Planners) and the appropriate Regional Entity Planning Committees and Operating Committees. 2. It is also recommended that the SDT remove all Requirements that are subjective and cannot be measured. For example, who must the Transmission Planner share information with? Requirement R5.2 states that information must be shared with Transmission Planners of neighboring impacted areas. A Compliance Monitor cannot determine if a neighbor is being impacted. In fact, from an enforcement perspective, if the involved parties must go before a Judge, who will determine if someone is impacted or not? 3. In addition, the assumptions the Transmission Planners and Planning Coordinators use to conduct the Studies are not required to be shared or posted. As an example, in some parts of the BES Transmission Planners and Planning Coordinators use Flowgate Methodology to study the BES, while others use Rated System Paths, and still others use Area Interchange (Network Methodology). 4. This standard needs to be modified to respond to several requests from Order 890 and Order 693. These Orders request that through the Standards, information be made available, posted, and shared with the appropriate reliability functions. This information includes the results of Planning Horizon Studies, Operating Horizon Studies, and eventually the determination of Available Transfer Capabilities. This information also includes, but is not necessarily limited to: how do the planners treat the "counter flows" in their studies, what are the generation and transmission planned outage schedules used in the planning studies, how are Network Loads and Network Facilities treated in planning studies; and how do the planners treat Grandfathered Transmission and Grandfathered Power and Energy Contracts in the planning studies?
Response: 1. The SDT assumes that this is actually referring to Requirement R6. This requirement has been re-written as Requirement R8 and ties back to FERC Order 890 for distribution. **R8**. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~affected entities~~ neighboring systems, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890. 2. The SDT has attempted to not add subjective requirements. However, as measures are developed in a subsequent release, the SDT will review all requirements for subjectivity. 3. Documentation is required in your assement to decribe that you have met the requirements. 4. Information will be shared as required in various orders and regulations as shown in the new Requirement R8 for example.			
ATC	☑		Following are additional comments on the proposed standard.

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Commenter	**Yes**	**No**	**Comment**
			1. R1 Each sub-requirement (R1.1 to R1.5) should specify which Functional Entity (of those listed in R1) is responsible for providing the modeling data. For example, while logically it appears that R1.1 is applicable to the LSE only, it may be argued that parts of it may be applicable to the Transmission Planner also. 2. R1.1.3 We do not agree with identifying the DSM load reduction "consistent with operational requirements" for the purpose of modeling Load in planning studies. This is because DSM is typically employed either for Capacity deficiencies, but not for operations needs. 3. R1.3 "Firm transfers/Interchange Schedules and….." Should say either firm transfers or interchange schedules but not both since they are not equivalent. If the intent here is to model each Balancing Authority's Firm resources and Firm "commitments" needed to supply the Firm Load, then we suggest using the term Firm Commitments defined as the Native Load plus Firm Transmission Service plus LTTRs. 4. Firm Transfer -- Either define this term or use the existing NERC Glossary term Firm Transmission Service instead. Alternatively, use the term Firm Commitments defined as the Native Load plus Firm Transmission Service and LTTRs. Further, in Table 1, the "Interruption of Firm Transfer Allowed" performance requirement should be clarified/reworded to indicate if firm transfer was intended to comprise both firm point-to-point and network transmission service. If so, then curtailment of firm point-to-point transmission service should be permitted for all events P1-P4. Alternatively, the performance requirement could be changed to "Generation Redispatch Allowed". Given the future Day 3 MISO market structure, standards that refer to Generation Redispatch must include Demand Response. 5. R1.4 We believe that each Reliability Coordinator (RC) already receives the planned outage information from all TOs and GOs and maintains it in the Outage Scheduler. Can the Planning Coordinator obtain this information from the RC's operating in its footprint? 6. R1.5 The Transmission Planner is also very likely to have a documented criteria for planned (committed? see R2.7.3) facilities, so this requirement should say TP/PC instead of only PC. What standard will require the TP to have criteria? There should be a separate requirement that applies to the Generator Owner and includes specifics, such as reporting contemplated additions, modifications, and retirements. 7. R2.1.3.1 It is not clear what additional "variability of Load/demand and Load power factors due

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Commenter	**Yes**	**No**	**Comment**
			to season, weather, or time of day" over and above what is modeled in the seasonal base case is expected here. For example, what additional load variability can be studied in a summer peak base case which already represents the system snapshot of a hot (weather) summer (season) mid-afternoon (time of day) loading condition? 8. R2.5.2 Please provide more examples of what would comprise "material changes" that trigger a plant stability study (besides the addition/removal of transmission line). Would it be better to say electrical proxmity (to capture the concept of electrically "close" instead of electrical vicinity? 9. R2.6.1 to R2.6.3 Should all "material changes" trigger a new study? Shouldn't a new study be done only for those changes that are expected to have an adverse impact on system performance? For example, adding a transmission line outlet at a generating station will rarely have an adverse impact on plant stability. Suggest that these requirements specify the need for a new study to support the planning assessment only when changes "that have an adverse material impact on system performance" have occured. 10. R2.7.1.1 It is unclear what is the need/benefit of including a the project initiation date; the project in-service date should be enough in a corrective action plan. Suggest deletion of project initiation date from the requirement. 11. R2.7.3 What is the difference between "committed projects" referred here versus the "planned facilities" referred to in R1.5? Please explain distinction between committed, planned and proposed projects/facilties. 12. R2.7.4 "Not remove committed projects……" Note that a committed project may not get cancelled but can very likely be deferred --- how should deferred projects be handled? 13. R.3 Per this requirement, the BES should be analyzed for normal (N-0) performance. However, Table 1 does not include the corresponding performance requirements. Further, R3.1 refers to studies for evaluating performance requirements in Table 1. Shouldn't Table 1 include normal system performance requirements? 14. System Adjustment -- What automatic/manual actions comprise this term? It will be helpful if the standard explicitly states which post-event system adjustments are acceptable/permitted to meet performance requirements for single contingency events (P1, P2 or P6) versus which pre-event system adjustments (specifically load shedding) are allowed/permitted to prepare for the next contingency (after the N-1 contingency has occurred) in multiple contingency events (P3-P5, P7-P9). This distinction does not appear to be addressed by requirement R3.3.2.2 in the draft

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Commenter	**Yes**	**No**	**Comment**
			standard. 15. R3.3.2.2 is inconsistent with the Planning Events in Table 1. While the requirement states that shedding firm load and curtailing firm transfers are not permitted for single contingencies, these are allowed for event P6 in Table 1. Further, although the requirement implies that these two types of system adjustments are permitted for multiple contingencies, at least one of them is not allowed for the multiple contingency events P3, P4 and P5 in Table 1. 16. System Adjustment Duration -- What is the allowable time for completion of system adjustment? Requirement R3.3.2.2 states that it is the time period allowed by the Transmission Owner's applicable time-limited (emergency) equipment rating. However, R3.3.2.2 is only applicable to single contingency events -- that is, events P1, P2, P6 in Table 1. Shouldn't this concept of allowable system adjustment duration apply uniformly to all Planning Events P1-P9 in Table 1? 17. R3.5 allows generation runback for single and multiple contingencies -- that is, for ALL planning events P1-P9. It appears that this requirement lends itself to be included as another bullet item in the Performance Requirements at the top of Table 1. In fact, why not define what comprises System Adjustment (see comment above) and then tabulate the system adjustments that are (not) permitted for each planning event within Table 1? 18. System Stability studies: The standard must clearly define what types of stability analyses fall under this umbrella term. While it is generally understood that this includes angular stability analysis, which is the only one that is explicitly mentioned in the Table 2 footnotes, the standard does not indicate whether dynamic voltage stability analysis or small-signal stability analysis are also expected to be done as part of system stability studies. 19. Requirement R2 and its sub-requirements are intended to address all aspects of Planning Assessment. However, it is unclear which requirement(s) in the draft standard cover the scope of R1.3.12 in the existing TPL-002 and TPL-003 standards, which requires "Include the planned (including maintenance) outages of any bulk electric equipment at those demand levels for which planned (including maintenance) outages are performed. Further, we are unsure if the direction provided in FERC Order 693 paragraphs 1724 and 1786 with respect to planned (maintenance) outages have been adequately and clearly addressed in the draft standard. Can the SDT point us to the specific requirements that address the above issues? 20. We recommend that the SDT give consideration to acknowledging or addressing the directives in FERC Order 890 for performing transmission system loss analysis and economic assessments --

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Commenter	**Yes**	**No**	**Comment**
			can they be considered within the scope of reliability assessments? EDITORIAL COMMENTS 21. R4.5.1 and R4.5.2 -- It appears that the intent of these sub-requirements within R4.5 for System Stability study is very similar to the intent of R3.3.3 and R3.4 for Steady State studies. If so, then why have different heirarchical numbering for the latter case? Suggest changing R3.3.3 and R3.4 to sub-requirements R3.4.1 and R3.4.2 respectively within R3.4 for Steady State study. Table 1 22. Event P3 -- The performance requirement in column 3 "Interruption of firm transfer allowed" should be simply "NO" (outaged dc line performance is not applicable). 23. Event P5.3 -- Clarify if the "loss of another transformer" is intended to be the loss of a transformer with low-side voltage >300kV or *any* transformer in the BES. 24. Event P9.1 -- Is the one mile intended to be one *contiguous* mile? If so, recommend inserting the qualifier "contiguous" to claridy the intent. 25. Event P9.6 -- The contingency description is very confusing regarding the role of spare transfomer. Is spare transformer part of the system adjustment? Please reword to clarify the intent. 26. Extreme Event Descriptions -- Items 3e and 3f are repetitions of items 3c and 3d. Delete any one pair. Item 3h is too vague --- either provide more specificity or delete it. Table 2 27. Extreme Events - Evaluation Requirements -- Inclusion of item 9 (3-ph fault with loss of all generating units at a station) in the table is inconsistent with Q.33. 28. Having both bullets at the beginning of the table and footnotes at the end of the table, which deal with similar subject matter, tends to be confusing and should be addressed. 29. The different types of Stability analysis (steady state voltage stability, dynamic voltage stability, dynamic generator unit angular stability, and dynamic inter-area power oscillation stability) be clearly and concisely stated in one location and the perfomance requirements for each type of stability should be more clearly stated in appropriate locations.

Response: 1. The standard has been revised (see Requirements R9 through R13) to identify specific entities responsible for providing the required information.

R9. Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including

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Commenter	Yes	No	Comment
the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information. **R10**. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information. **R11**. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information. **R12**. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information. **R13**. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information 2. The SDT has determined that DSM is included in MOD and is no longer explicitly included here. 3. The SDT understands your concern and has modified the requirement (now Requirement R10) to clarify intent. The intent is to include modeling information for firm Transmission service data, Interchange Schedules, and resources required to serve Load. 4. The SDT agrees with your comment concerning the ambiguity of the term "Firm Transfer". The revised requirement (now Requirement R10) and revised Table 1 use the existing NERC Glossary Term Firm Transmission Service, as you suggested. However, the SDT does not agree that curtailment of Firm Transmission Service should be permitted for events P1-P4. 5. Few commenters raised this concern, so the SDT is uncertain whether the necessary information could be obtained from the RC in all regions. The ultimate source of the information is the TO and the GO. In the revised standard, this requirement has been separated into two requirements to clarify the intent for transmission equipment planned outages and long-term outages (Requirement R11) and generation equipment planned outages and long-term outages (Requirement R12). If the TO and GO provide the necessary information to the RC in a given region, it is possible that the TO and GO could arrange for the RC to provide the information to the PC to demonstrate compliance with the requirements or, alternatively, send the information to both the PC and RC. 6. The SDT has modified the standard based on various comments. The phrase "in accordance with the documented criteria of the Planning Coordinator" has been deleted. This requirement has been further revised and separated into two requirements applicable to the Resource Planner and Transmission Planner, respectively. 7. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.1.4 has been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. In either case the entity must document the reason for running or not running cases for the items listed. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance. It is the entity's decision to establish and document which senstivities are more significant to study System responses. The sensitivity studies do not in themselves establish the need for a plan, only the areas of the System for which the analysis is needed. For example an entity's base case Load level may be modeled as a 50/50 Load level which represents what the entity considers normal peak weather conditions. A sensitivity to that may be a 90/10 Load level case which represents extreme weather conditions.			

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Commenter	**Yes**	**No**	**Comment**
			R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.1.4**. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. 8. Requirement R2.5.2 was changed for clarification. **R2.5.2** Material Transmission System changes ~~in the electrical vicinity of existing generation are made~~ are made at or near the point of Interconnection of existing Generation such as the ~~addition or~~ removal of a Transmission Line ~~at or near the point of Interconnection~~ or the addition of a new substation in one of the Transmission Lines connected to the plant. 9. R2.6.1 – R2.6.3 – Requirement R2.6.2 was changed for clarification. **R2.6.2** For steady state, short circuit ~~analysis~~, Generating Plant Stability, or System Stability analysis: ~~if the study is less than five years old and no material changes have occurred to the System in the intervening period.~~ the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. 10. Requirement R8 (old requirement R6) which focuses on the distribution of the Planning Assessment results among affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old requirement R6). Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. Typically the date would indicate when significant resources will begin to be employed. This covers any project proposed for the near term. The SDT believes that initiation dates are required for near-term Corrective Action Plans to give an indication that the Corrective Action Plans can be implemented in time. 11. Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted Requirements R2.7.2 through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions". **R2.7.1.** ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.

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Commenter	**Yes**	**No**	**Comment**
12. Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and Requirements deleted R2.7.2 through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions". 13. The SDT has revised Table 1 to include N-0. 14. The term "System adjustment" is used in the existing TPL Standards, and is intended to have the same meaning in the proposed TPL standard, and includes both manual and automatic actions. 15. The SDT has made extensive changes to the tables to address these concerns. 16. and 17. The use of the defined term 'Facility Ratings' includes time elements which accommodate your concern. 18. You must perform any Stability analysis that is required to meet the performance requirements. 19. Requirement R11 contains this language. 20. The scope of the SAR and standard being prepared is only related to reliability assessments. 21. The SDT attempted to make Steady State and Stability identical but this was not always possible. 22. The SDT believes that the reference to the outaged DC line is appropriate. 23, 24, 26, and 27. P5.3 is intended to be the loss of a second transformer with low-side voltage >300 kV. P9.6 was to address the FERC directive in Order 693 to consider spare equipment strategy. In Q33 the SDT posted a question to the industry to request guidance on whether simultaneous tripping of all generating units in a power plant should be included the Extreme Events in Table 2 (on Stability Studies). The SDT has revised Tables 1 and 2 and included this consideration in Requirement R11 of the second draft of the standard to address this issue. Tables 1 and 2 have also been revised to address your comments on P3 and P9.1, the repeated Extreme Event Items 3c – 3f and Item 3h. For P9.1 (P7.1 in the second draft), the SDT did not change the table to include "contiguous" for the 1 mile (or less) exclusion because the standard does not limit the number of instances where two circuits can share a common tower only that each exclusion applies to a length of one mile or less. 25. The SDT agrees and has eliminated that requirement. 28. Editorial change made to alleviate confusion. 29. You must perform any Stability analysis that is required to meet the performance requirements.			
APS	☑		R 2.5.1 and R 4.6 require plant stability studies for all generators greater than 20 MVA for changes in excitation system or PSS addition. Generally plant stability is a problem only for large plants with large generators. Changes in the excitation system of a small generator or PSS addition does not significantly impact the plant stability. In fact, in most cases it improves the plant stability. When an excitation system or a PSS is commissioned in the field, part of the commissioning tests ensure that turbine-generator is stable and that the performance of the excitation system and PSS are acceptable. If an excitation system change or PSS addition is causing a plant stability problem in simulation, it is generally a data issue and can be best handled in MOD standards. Requiring stability studies to be redone does not in any way contribute to the system reliability. There are hundreds of old generators in the US which are going through excitation system retrofits in a given year. Requiring a stability study for each change would add additional study burden without any value to the system. This is unnecessary work with little consequence on the system performance or reliability.

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Commenter	**Yes**	**No**	**Comment**
			Note: We have additional comments on these standards but they have been covered by comments from WECC. We fully support all of those comments.
Response: Those values are based on Large Generator Interconnection Procedures as approved by FERC. Unit controls are an integral part of the power system and must be analyzed when changes are made.			
BPA	☑		Support comments sent by WECC. In addition,BPA has the following comments: 1. R2.3.1 - The way the requirement is written sounds like the short circuit study should be run after changes are made to the BES. The study needs to be done sufficiently in advance to allow for needed equipment replacements as a result of the study. Also, "current" in the first senetence should be changed because it is confusing whether it refers to "present" or "amps". 2. There needs to be better definition what is meant by "bus tie breaker". It is assumed this includes both bus tie breakers between a main and auxiliary bus, as well as bus sectionalizing breakers between two main bus sections. 3. In general the table seems unnecessarily complex. It would appear to make more sense to group events by performance as done in the previous Table 1. Also, in general the resulting events for the element contingencies in the table should be compared and like events grouped together since they would be are modeled the same and show the same performance in powerflow studies. 5. P9.1 - It is recommended to exclude multiple circuits sharing a common structure for no more than three miles, rather than one mile. Our analysis shows river crossing systems can be up to three miles and it is impractical to plan for common corridor outages of up to this distance. 6. Planning event P9.6 is the same as P8.3 with the only difference being the restoration time. 7. Regarding extreme event descriptions: - Item 3.a is not a Transmission Planning, but is relevent for Resource Adequacy. - Item 3.b is an operational issue not relevent to Transmission Planning. Successful cyber attack would need to be defined. Also, how would the consequences of a successful cyber attack be predicted? - Regarding item 3.c, generation capabilities should already be modeled in base cases within the planning horizon. - Items 3.d through 3.f are not relevent to Transmission Planning. These are Resource Adequacy issues within a short term operational horizon. - Items 3.e and 3.f appear redundant to items 3.c and 3.d. - Item 3.g is not really a planning issue. The system should be designed to meet required

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Commenter	**Yes**	**No**	**Comment**
			performance for selected contingencies regardless of age or maintenance pratices. - In general, the Extreme Events layed out in the previous Table 1 is a much more practical approach to planning the transmission system.
Response: 1. Requirement R2.3.1 has been deleted. In Requirement R2.3, the wording has been revised to be clear that an annual assessment is required and what studies may be used. Requirement R2.6 provides further detail about which past short circuit studies may be used. Requirement R4 explains the conditions that the studies should analyze. 2. The SDT has included a proposed definition of a Bus-tie Breaker in the second draft. **Bus-tie Breaker:** A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.) 3. Tables 1 and 2 have been revised to provide greater clarity. 5. The SDT notes that distances greater than a mile present comparability issues with regard to other situations such as bay crossings, harbor crossings, and other longer spans. The SDT has not revised the requirement as a result in the interest of maintaining comparability without opening the waiver up to other situations. 6. The SDT has deleted P9.6. 7. With regard the Items 3.e and 3.f appearing to be redundant to items 3.c and 3.d., the SDT agrees and has made the appropriate changes to the standard. With regard to the other comments about the Extreme Events, the SDT notes that in Order No. 693, paragraph 1834, the FERC gave examples of Extreme Events that the FERC would expect to see in the revised standard. These examples are consistent with the items that the SDT included in the standard as examples of Extreme Events to be considered. For example paragraph 1834 include "(1) loss of a large gas pipeline into a region or multiple regions that have significant gas-fired Generation; (2) a successful cyber attack; (3) regulation that restricts or eliminates the use of a river or lake or other body of water as the cooling source for generation; (4) tornado or wildfire, or other event and (5) the loss of older transmission lines, which may not be constructed to meet an entity's present radial ice loading requirements…" In paragraph 1834, the FERC directs NERC to expand the list of events with examples such as those described in the paragraph. The SDT believes that the Extreme Event items that the commenter has raised concerns about are consistent with the list of examples provided in paragraph 1834. Further, the SDT notes that while the commenter is correct that some of these events have traditionally been treated as deliverability issues, nonetheless they will dramatically impact the reliability of the interconnected network and are logical Extreme Events for which the probability and consequences should be evaluated when considering ways to make the Transmission System more robust with Operating Procedures and/or System improvements that are reasonable in cost in comparison to the probability and consequences of the Extreme Event. The SDT did not change the standard with regard to these comments.			
BCTC	☑		1. We have some questions of clarification for the Standards Drafting Team, that may resolve some of our concerns. (i) Is it the intention of NERC that the more stringent performance requirements in this standard would be applicable for determining System Operating Limits before Transmission Owners are able to implement Corrective Action Plans? The BCTC system is part of the western interconnection and BCTC is a member of WECC. WECC members apply a principle that Planning Standards are also applicable for determining System Operating Limits. If the answer to this

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Commenter	**Yes**	**No**	**Comment**
			question is "no", then BCTC may be able to support some aspects of raising the bar, with the understanding that SOLs would be determined based on the performance standards that the system is planned to. (ii) Has the Standards Drafting Team considered how Transmission Planners will address discrepancies between Corrective Action Plans for this standard and the reality of what can be constructed due to regulatory approvals, siting problems, financing issues, etc.? For example, is it the intention that Transmission Planners should continue to study Corrective Action Plans to meet an N-1-1 Planning Event (e.g. P5-1) without generator tripping when the practical situation is that we may be fortunate to be able to build to meet N-1 with some generator tripping? We are concerned that if we cannot meet the performance requirement for P5-1 due to delay or denial, continuing to assess Corrective Action Plans to meet P5-1 does not provide much useful information compared to planning to meet a doable target. Item 2 below provides a proposal to address this. 2. There is always the possibility that a regulator may deny funding for a Corrective Action Plan or approve funding for a Corrective Action Plan that does not fully meet the performance standards, a siting process may delay or block a Corrective Action Plan, or some other process may frustrate the ability follow through with a Corrective Action Plan to meet NERC performance standards. To avoid the need for a Transmission Planner to continue to study Corrective Action Plans that cannot be implemented, we suggest adding the following Requirement R2.7.6: The Planning Assessment is not required to include a Corrective Action Plan and address the subsequent requirements (of R2.7) in cases that (a) an applicable regulatory agency has ordered that a Corrective Action Plan is not to proceed or that an alternative Corrective Action Plan that does not meet the performance standards is to be implement or (b) the Transmission Planner has documented evidence indicating that such an outcome is likely to occur. Other Requirements for Five and Ten year Assessments may also be exempted depending on the regulatory order. The Planning Assessment will include evidence of the order. 3. R3.3.3, R3.4, R4.5.1, R4.5.2 - A rationale for the selected contingencies should be sufficient. It should not be necessary to explain why the remaining contingencies would produce a less severe result. 4. Table 2, P1 should include shunt devices. 5. A definition or reference to a definition for Firm Load and Firm Transfers is required. The present situation is that these terms are "defined" as those loads and transfers that can be supplied while meeting Category B requirements. In other words, the standards define the terms. The commercial uses of firm and non-firm may not be applicable and they actually mean non-recallable and recallable service, not directly related to system performance, but incorporating aspects of

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Commenter	**Yes**	**No**	**Comment**
			reservation times. 6. Extreme Events of Tables 1 and 2 should not be subject to the same study requirements as Planning Events. Table 1 Extreme Events need not be studied for both the Near Term and Long Term Horizon (ref. R3.4, R3, R2.1 and R2.2) and for all five years of the Near-Term Horizon (ref R3.4, R3, R2.1). Table 2 Extreme Events should not be required for all five years of the Near-Term Transmission Planning Horizon (ref. R4 and R2.4). When conditions warrant, only a single assessment representing a selected reasonable planning horizon should be required, and an update required only when past studies are no longer representative. We are concerned that many of the proposed Table 1 Extreme Events (Item 3. a, c, d, e, f) are resource adequacy issues (we also observe that c and e appear to be identical). Transmission Planning Assessments of these events should be initiated at the request of Resource Planners. It should not be necessary for Transmission Planners to initiate and maintain current studies of these Extreme Events. We suggest that Extreme Events be removed from R3 and R4 and addressed in a separate Requirement. 7. The Purpose of this standard should be restated as: Establish requirements for Planning Assessments, including Corrective Action Plans, to be conducted over range of forecast conditions based on system planning performance requirements. Explanation: This revised wording more accurately describes the content of the standard. The Requirements of this standard are to perform Studies and Assessments. The performance tables are referenced by the Requirements and are supporting to the Requirements, but are not a "capital R" Requirement.

Response: 1. NERC, in its response to FERC's NOPR on the FAC-010, FAC-011, and FAC-014 standards, committed to revising the FAC and ATC standards when there is consensus on the TPL standards.
The intent of the Corrective Action Plan is to establish a doable set of actions that are to meet the performance requirements. Senstivitiy studies have been specifially added to the standard to allow the planner to assess the impact of corrective actions being delayed. It is the entity's responsibility to assess these impacts and adjust the next set of actions planned to meet performance. The standard also requires that the assessment cover more than the ten year period if the entity deems it necessary to accommodate any long range projects that may take years to complete due to ROW acquisition, hearings, etc. In addition, generation tripping for single Contingencies has been added back into the standard and the N-1-1 performance requirement has been revised to allow generator tripping and Non-Consequential Load dropping.
2. The SDT does not believe that it is necessary to add the words concerning regulatory delays or denials. The intent of the Corrective Action Plan is to establish a plausible set of actions that, when implemented, achieve the performance requirements. Senstivitiy studies have been specifially added to the standard to allow the planner to assess the impact of modification to or delay of a corrective action plan.
It is the entity's responsibility to assess the impacts of a modification or implemetation delay and adjust the next set of corrective actions or modify the proposed plan to meet the performance requirement as prescribed in the standard.
The standard also requires that the assessment cover more than the ten year period if the entity deems it necessary to accommodate any long range projects that may take years to complete due to ROW acquisition, hearings, etc.
3. The SDT believes that it is necessary as part of a complete documentation set explaining why and what was done.

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Commenter	**Yes**	**No**	**Comment**
4. This was added as requested. 5. In reviewing this comment, the SDT noted that Firm Demand and Interruptible Load are defined in the NERC Glossary. The SDT believes Load that is not Interruptible Load as defined in the NERC Glossary best fits the intention of the requirements pertaining to Firm Load in the TPL standard. Therefore, the SDT modified the references to Firm Load to refer instead to non-Interruptible Load in the TPL standard. With this change, Firm Load does not need to be defined in this standard. 6. The SDT agrees with the comment that Extreme Events should not be subject to the same study requirements as Planning Events; however, the SDT proposes to resolve the issue by clarifying the study requirements in the table and the text without removing the Extreme Events from Requirements R3 and R4 and addressing Extreme Events in a separate Requirement. With regard to the comments about resource adequacy issues, as noted in the BPA 7 answer, these events that have been traditionally considered resource adequacy issues are included as Extreme Events to be consistent with FERC Order No. 693 and because such events could dramatically impact the reliability of the interconnected network. As a result, the Transmission Planner/Planning Coordinator should investigate these Extreme Events regardless of whether the Resource Planner considers them to be an issue or not. In this way, the Transmission Planner/Planning Coordinater considers ways to make the Transmission System more robust with Operating Procedures and/or System improvements that are reasonable in cost in comparison to the probability and consequences of the Extreme Event. The SDT did not change the standard with regard to these comments. 7. Since most commenters did not express concern with the Purpose language, the SDT felt that no change was necessary.			
CAISO	☑		1. First, and as a general matter, the TPL-001 standard needs to accurately reflect the roles of PA'S and TP'S in areas with organized competitive markets and where the PA'S and TP'S are not vertically integrated utilities. In those areas, the TPL standard should recognize that compliance with the standard is achieved through the publication of a Plan that identifies system needs – and leaves open to the marketplace the specific mix of resources that investors construct to meet those needs. As a result, the Plan need not be, and should not be, prescriptive as to the resource mix that must be achieved. It is important for plans to be equally open to generation, demand response and transmission and not be presecriptive to the actual resource mix. Further, not all organized competitive markets have a mechanism in place to develop an integrated resource and transmission plan to meet future needs. Some markets conduct forecast assessment, thereby providing signals to market participants to make investment decisions. 2. Similarly, reflecting the divested nature of the industry in areas operated by ISOs and RTOs, the modeling standards should be reviewed to make sure that asset owners (e.g., generator owners and transmission owners) are required to give information in the level of detail and granularity that will allow PA's and TP's to develop plans and models consistent with these standards. 3. As highlighted in question 16, DSM should be considered an acceptable solution to system needs. However, DSM is generally considered in meeting resource requirements rather than as one of means to relieve transmission constraints. In planning studies, loads that are identified as DSM type (contracted or potential) are modeled as firm loads for reliability assessment. We would therefore seek the SDT's suggestion on how specifically DSM should be explicitly modeled or used to aid in

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Commenter	**Yes**	**No**	**Comment**
			achieving transmission reliability in the planning horizon. Further, the drafting team must consider whether DSM providers are covered in the Compliance Registry and how the NERC Standards should obligate them to provide the requisite information to PA'ss and TP's so that they are fully taken into account. 4. Finally, the standards need to be improved to better distinguish the responsibility of Planning Authorities versus Transmission Planners. Currently, the Standard refers to both entities as carrying out the requirements. This appears to be reundant.
Response: 1. The SDT believe that the standard is not prescriptive in the way described in the comments. 2. Comment is beyond the scope of the standard under development and should be addressed through proposed changes to the appropriate MOD standards. 3. The use of DSM is optional. Requirement R2.7.1 has been modified based on comments received to use "may include" instead of "including". The standard does allow for consideration of DSM but other factors may disallow inclusion of DSM in the Corrective Action Plan. The amount and uncertainty of DSM needs to be justified by the entity which includes it in its Correction Action Plan. **R2.7.1**. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. The standard is applicable not only to the Transmission Planner but also to the Planning Coordinator and the Resources Planner. These entities are expected to establish relationships to provide for intergrated analysis and resultant Corrective Action Plan which may include generation, transmission and DSM components. 4. Requirement R2 specifies that each entity is responsible for "its" portion of the BES. Even so there will likely be overlap and joint responsibility in some instances as identified in Requirement R5.			
CenterPoint	☑		1. TPL-001-1 focuses solely on reliability to the exclusion of economic cost/benefits, prudent avoidance, and landowner impacts, which have been the hallmarks of good utility practice that have governed transmission planning and construction for decades. FPA section 215(i)(2) "does not authorize the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services." However, adherence to TPL-001-1 as currently drafted, will require, de facto, the construction of additional transmission facilities. CenterPoint Energy believes this standard excludes proven, historical good utility practice to reach far beyond what is intended by the FPA. TPL-001-1 contains an excessive number of requirements (over 50). The SDT should consider the removal or modification of the following unnecessary, redundant or overly prescriptive

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Commenter	**Yes**	**No**	**Comment**
			requirements: 2. R1.1. This is a modeling requirement and should be incorporated into the modeling (MOD) standards. Remove or modify this requirement to eliminate any redundancy with existing modeling standards. If certain subrequirements of R1.1 of TPL-001 are not currently requirements in a MOD standard, it should be questioned, then, whether or not these specific subrequirements are actually needed in ANY standard. 3. R2.1.3 and R2.4.3 should be removed because they introduce new, vague requirements. 4. R2.2. Analysis beyond five years has little value due to the speculative nature of predicting load and generation growth. Furthermore, ERCOT does not annually create Long-Term Planning Horizon cases because ERCOT does not believe it is necessary. This requirement should be removed. 5. R2.5 and R4.6. These requirements are overly prescriptive and unnecessary for the reasons stated in the response to Q32. They should be removed. 6. R2.7.1 through 2.7.5. Requiring Corrective Action Plans that address how performance requirements will be met is reasonable; however, these standard requirements are overly prescriptive and unnecessary. R2.7.1 through R2.7.5 would result in the development, documentation and explanation of fictitious solutions to fictitious problems. They should be removed. 7. R3.3.2.1. The requirement to identify consequential load loss for single contingencies in the Planning Assessment is unnecessary and burdensome and should be removed. 8. R5. The roles of the Transmission Planner and Planning Coordinator are already addressed in the approved NERC definitions and further described in the approved NERC Reliability Functional Model. This requirement is unnecessary and should be removed. 9. Table 1 and Table 2 - P4, P5, P8, and P9. Including all combinations of two components (generator, Transmission circuit, transformer, monopolar DC line) with generation adjustments is impractical and overly burdensome. For multiple contingencies, CenterPoint Energy recommends including only two-circuit tower lines and the two components (generator, Transmission circuit, transformer, monopolar DC line) that would be cleared by a breaker failure (i.e., stuck breaker).
Response: 1. The SDT's understanding is that the ERO has the authority to set performance requirements for reliability. 2. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD			

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Commenter	**Yes**	**No**	**Comment**
standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. 3. The SDT feels it is appropriate to set a minimum level of sensitivity cases to be looked at. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. The SDT has modified Requirements R2.1.3 and R2.4.3 to clearly stipulate that the entity shall provide rational for why sensitivities on the list were or were not included in the sensitivity studies and that the entity may consider additional sensitivities that are appropriate for its own system. The Standard requires that deficiencies identified from the results of the current studies need to be addressed via Corrective Actions Plans while leaving it at the entity's discretion to decide which deficiencies, if any, identified through sensitivity studies should be addressed by the Corrective Action Plan. **R2.1.3**. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.4.3**. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: 4. The SDT feels that this requirement is appropriate based on its understanding of planning practices throughout North America. This is also mentioned in FERC Order 693. 5. See response to Q32. 6. After careful consideration, the SDT agrees that if the Corrective Action Plan is going to include "committed" and "proposed" projects, they will need to be defined. However, the SDT agrees that it will be very difficult to develop definitions of "committed" and "proposed" that are applicable for the entire NERC footprint. Therefore, the SDT has modified Requirement R2.7.1 and deleted the original Requirements R2.7.2 through R2.7.4 to reflect "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. **R2.7.1**. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. 7. FERC required documentation of Consequential Load loss in Order 693, paragraph 1795, (not Non-Consequential) and duration should be based on best judgment for the common cause of the event. 8. The Functional Model is intended as a guide and aid in drafting reliability standards. Nothing stated in the Functional Model is enforceable in and of itself. Only requirements in approved reliability standards, which may mirror the Functional Model assuming that industry consensus is received on the subject matter, are enforceable.			

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Commenter	**Yes**	**No**	**Comment**
9. The analyses of the combinations of two components are required by the existing TPL standards. The SDT understands the concerns in the potential increase in work load. Requirement R3.3.3 requires evaluation of only those Planning Events (involving multiple Contingencies) that are expected to produce more severe System impacts.			
HQTE	☑		1. We think that the proposed fusion of previous TPL-001 to TPL-004 and the addition of more specific contingencies involves too much change at once. It would have been better to make specific change to each individual standards. That way, it would have been more practical to evaluate the impact of the proposed changes. 2. A major concept before evaluating the impact of a standard is to know on what system it will be applied to. In the tables, the notion of a voltage treshold (>300 kV) is introduced. It is our interpretation that the standard as drafted applies only to BPS elements part of that treshold (>300 kV) and not every ">300 kV" element. The SDT should indicate if they have the same interpretation as ours. 3. We reiterate our comment that it would be preferable to have only one table that would include both steady state and stability contingencies with their respective expected performance. 4. There might be some protection standards that would need to be developped/clarified before some proposed changes in this standard. 5. The SDT has made an effort to define Base Case, yet has not used the term in the standard. At a minimum, Base Case should be referred to in sections 2.1.1, 2.1.2 In addition to the comments from Central Maine Power.
Response: 1. Much of the wording and underlying concepts are the same for the four standards today – the major difference being that each refers to normal, single, multiple or extreme Contingencies. All four use the same table. Merging them into one standard has simply eliminated much of the duplication and brought together the smaller portions of each standard that were different. Past experience has shown that since the four are so closely related that a change in one has a tendency to reflect a change in another – merging the four together helps keep all the changes and relationships in a single point of view. Commenters in general have supported the concept of merging the four standards together. In addition, Paragraph 1692 of Order 693 "directs the ERO to consider integrating Reliability Standards TPL-001-0 through TPL-004-0 into a single Reliability Standard through the Reliability Standards development process". In addition this Order, in conjuction with Order 890, enurmerate attributes of planning standards that the FERC feels should be incorporated into the consolidated standard. SDT believes that the first draft of the standard is consistent with Orders 693 and 890 without being unduley burdensome. 2. As proposed, the standard is intended to apply to all BES (not BPS) Facilities, but for some events the performance requirements are different for Facilities above and below 300 kV. When EHV Systems are compromised, the large volumes of power served by them can place a severe amount of stress on parallel EHV or lower voltage paths. For example, if a large EHV transformer experiences a catastrophic failure			

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Commenter	**Yes**	**No**	**Comment**
not only are other System Facilities required to carry more Load but the System is also exposed to other N-1 conditions for long periods of time while awaiting a replacement or repair of the failed equipment. Large generation sources are typically connected at EHV levels and maintenance of the EHV transmission lines within the vicinity of large generation plants must often be coordinated during scheduled unit outages, resulting again in multiple Facility outages over extended periods of time. 3. The majority of commenters support the development of the two tables as opposed to the single table in the existing TPL standards. Further, the SDT believes that the two tables provide the ability to clarify issues associated with Stability performance and evaluation requirements versus steady-state performance and evaluation requirements. Based on industry feedback, the SDT has completely reformatted the performance tables in Draft 2 of the TPL-001-1 standard. The new format more closely mimics the existing approved TPL standard Table 1, with enhancements we feel the industry will find valuable. 4. Since the SDT is considering specific references to items such as SPS, the SDT will need to address any direct effect on other standards. The SDT encourages the commenter to provide comments on any specific instances where such a clarification or change may be needed. In addition there is a standard under development that will be addressing integration of all Protective Systems. That team will be coordinating with the TPL team. 5. Base Case has been deleted as suggested.			
NPCC RCS	☑		The SDT has made an effort to define Base Case, yet has not used the term in the standard. At a minimum, Base Case should be referred to in sections 2.1.1, 2.1.2 In addition to the comments by Central Maine Power.
Response: After reviewing the comments to this proposed definition and the use of the term "base case" in the standard, the SDT determined that "Base Case" does not need to be a defined term.			
Central Maine Power National Grid New England ISO NU NSTAR United Illuminating	☑		1. There should be a "P0" standard that applies to system performance without any contingencies. 2. Standard should be clear that stabiltiy analysis is not required for Long-Term Planning Assessment. 3. R.1.1 Load forecasts should be addressed in MOD standards, not TPL. 4. R 1.4 This should only refer to known long-term outages, not planned outages. Delete "including protective relays"; this is addressed through other provisions. 5. R.2.1 Shorten "Near-Term Transmission Planning Horizon Planning Assessment" to "Near-Term Planning Assessment". 6. R 2.2 Shorten "Long-Term Transmission Planning Horizon Planning Assessment" to "Long-Term Planning Assessment". 7. R2.1, 2.2, 2.3 & 2.4 – The initial paragraph should have identical language regarding 'annual', and 'current or past' aspects.

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Commenter	**Yes**	**No**	**Comment**
			8. R2.1.1 There should not be a requirement to look at years one and two; a 5 year study should be sufficient. If there has been an ongoing 5 year study, there should be no major unexpected problems occurring in years 1 and 2. Studies of earlier years should only be required if an unanticipated event occurred that had not been considered in prior studies. The TPL should not address shorter term "Operating Studies" or operating issues. 9. R 2.2.1 Modify to "If any known projects have a lead time that is longer than ten years, the Planning Assessment shall be extended accordingly." 10. R 2.6 Steady-state, short circuit, and stability analysis should be required no more than every 5 years unless there is a significant change the system. 11. R 2.6.1 Remove reference to "market structure changes". The purpose of it's inclusion is unclear. 12. R 2.7.1.1 Project initiation date should be deleted. If it is retainted, it needs to be defined. 13. R 2.7.3 Committed and Proposed projects should be defined. 14. R 3.2.1/R 4.3 - What is the intent of this requirement? There should probably be an MOD associated with Generator Owner requirement to provide related generator protection/ limiter data or other plant information. 15. R 3.4/R 4.5.2 Remove the requirement to implement changes to reduce or mitigate the likelihood of such consequences of Extreme Events. This may not be reasonable or achieveable. 16. R 3.2 Sectionalizing schemes shall be considered when reflecting the post-contingent system. 17. R 3.2.2 - Propose deleting this. Line ratings should already take relay loadability into account. 18. R 3.3.2.1 - Proposed deleting "expected duration". This would be dependent upon the damage to the element due to the iniating event and other factors. 19. R 3.3.2.2 - The requirements of this section do not match P6. 20. R 3.3.3 - Change introductory language to read "Those multiple Contingencies that are…"

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Commenter	**Yes**	**No**	**Comment**
			21. R 3.5 - Generation tripping should be allowed as well as generation run-back. In addition, all performance requirements shall be met, rather than just meeting facility rating requirements. Suggested lanague "Manual and automatic generation run-back and/or generation tripping is allowed as a response to single and multiple Contingencies as long as the performance requirements of this standard are met." If these changes are accepted, R 3.6 can be deleted. 22. R 4 and R 4.1 - The language should be made similar to R 3 and R 3.1. 23. Suggest bringing language similar R4.4 into the R 3, the steady state section. 24. R 4.2 - High speed automatic reclosing schemes shall be considered. 25. R 6.3 - Change to read "Planning Coordinators of neighboring impacted areas". 26. Table 1 3 b and c Extreme Event descriptions are vague concepts that cannot be practically simulated. 3 d and e are not reasonable or practically useful to simulate. 27. Table 1, P8 - Language needs to be clarifed as to how the 300 kV threshold is to be treated for transformers. Is this for the high side, low side, or both sides? P5 is much clearer. 28. Table 2 - Clarification needs to be made that the faults being simulated are permanent faults. This can be addressed under the "Performance Requirements" portion at the beginning of the table, or modify each fault description. 29. Table 2 P9. Recommend that this be changed to require that faults should be on different phases of each of two adjacent transmission circuits on a multiple circuit transmission tower 30. Table 1, P9(6) and Table 2 P9 - It is unclear as to what is meant by "A spare transformer inserted to replace an outaged transformer followed by System adjustments". Unclear as to what is to be tested. 31. General comment - Transmission System is used throughout the document and is an undefined term The New England Transmission Owners and ISO New England transmission planners met several times to discuss the proposed standard and develop consensus comments based on our experience. The preceding comments are what was developed.

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Commenter	**Yes**	**No**	**Comment**
			Attached to the e-mail sending these comments is the September 12 Draft 1 TPL-001-1 Reliability Standard in Word format, red-lined with changes to the posted standard which are intended to reflect all of the comments above. This document was maintained by Central Maine Power Company during the course of the New England transmission planner discussions, and any variance (though none are expected) in not intended. It is expected that this red-lined TPL document will be helpful to the ATFN SDT in reviewing our comments.

Response: 1. The SDT concurs for the steady state performance requirements and has added a P0 Planning Event at the top of Table 1 to address the N-0 (existing Category A) condition. However, "normal System" is already included as part of the description of the initial System conditions associated with the fault for the stability study. Therefore, it is not necessary to include P0 in Table 2.
2. The SDT agrees. The requirement only specifies Near-Term.
3. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.
4. The SDT has revised this requirement based on industry comments to clarify intent and to be responsive to FERC Order 693, paragraph 1725.
5. The intent of the suggestion was adopted.
6. The intent of the suggestion was adopted.
7. Identical language was not used; the same words were used in a different order and context. Requirement R2 and the following four sub-requirements each address a slightly different aspect of what studies are to be run. Requirement R2 only mentions current and past in general terms since more specifics are provided in the sub-requirements. Requirement R2.1 makes reference to "annual current" studies to emphasize the fact that the Requirements R2.1.1 and R2.1.2 require specific studies be run each and every calendar year. Requirements R2.2 is consistent with Requirement R2.1.1 in that it requires a specific run each and every calendar year. Requirement R2.3 does not require specific run every year but allows for current or past to support the Assessment; this is also true for Requirement R2.4.
8. Requirement R2.1.1 requires you to study years one "or" two and five. The SDT feels that requirement to run a peak load study for two of the years in the Near-Term Horizon is a minimum required for an adequate Planning Assessment. The SDT felt that the Year One or two study should provide operations with the best information to transition to the Operating Horizon. The year five planning study is the first near term study from the long term set. Five years is a short time if unexpected new facilities are required. Areas with faster growth should appreciate the extra studies.
Requirement R2 includes a statement which states that "Planning Assessment shall use current or past studies." Requirement R2.1 allows for the Planning Assessment to be "...supplemented with qualified past studies…" If you have past studies which are applicable, the standard allows for such.
9. The SDT believes that the present draft language captures the same concept.
10. The SDT agrees with your recommendation and has revised Requirement R.2.6.1 to show a five year shelf-life.

R2.6.1. For steady state, short circuit, or System Stability analysis: ~~if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market~~

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Commenter	**Yes**	**No**	**Comment**
~~structure changes~~ the study shall be five calendar years old or less. 11. The SDT concern was that such structure changes could potentially affect dispatch scenarios, or even transfers being modeled – both of which are sensitivities. 12. Requirement R8 (old Requirement R6) which focuses on the distribution of the Planning Assessment results among affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old Requirement R6) Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. Typically the date would indicate when significant resources will begin to be employed. This covers any project proposed for the near term. The SDT continues to believe that providing the expected project intiation date of System improvements provides useful information to neighboring entities. The SDT believes that initiation dates are required for near-term corrective action plans to give an indication that the corrective action plans can be implemented in time. 13. After careful consideration, the SDT agrees that if the standard is going to include "committed" and "proposed", they will need to be defined. However, the SDT agrees that it will be very difficult to develop definitions of "committed" and "proposed" that are applicable for the entire continent. Therefore, based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted Requirements R2.7.2 through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between "committed" and "proposed" projects. It also lists examples of what is intended by the word "actions". **R2.7.1**. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. R6.2.2 - Whereas the SDT agrees that the suggested re-phrasing has merit, the proposed rephrasing is potentially problematic because "Long-Term Planning Assessment" is not a defined term. 14. The intent is that what is modelled is true to real-life expectations. Changes to MOD are not within scope. 15. The SDT feels that this is an appropriate requirement based on understanding of existing practice within North America. 16. That was the intent of this requirement. 17. The SDT has received numerous comments in support of these requirements. Requirement R3.2.2 is included to provide clarity on simulations in response to FERC Order 693. Relay Loadability is included to be clear that this factor must be taken into account in the planning studies. The SDT has not made changes in response to this comment. 18. The requirement concerning Consequential Load is to address FERC Order 693, which directs the ERO, among other things, to clarify footnote (b) in regard to Load loss following a single Contingency, specifying the amount and duration of Consequential Load Loss and System adjustments that are permitted after the first Contingency to return the System to a normal operating state. 19. Requirement R3.3.2.2 was changed to correct this discrepancy.			

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Commenter	**Yes**	**No**	**Comment**
R3.3.2.2 Following single Contingency events, ~~System adjustments other than shedding of firm Load or curtailment of firm transfers are permitted to meet performance requirements provided these adjustments can be accomplished within the time period allowed by the applicable time limited ratings.~~ Transmission configuration changes and redispatch of generation are allowed provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits. 20. The reference to Table 1 will need to be included because Requirement R3.3.3 applies only to Steady State performance to distinguish this requirement from those in Requirements R4.5.1 and R4.5.2, which apply to Stability Performance. 21. The SDT agrees and has changed Requirement R3.5 **R3.5** Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met: **R3.5.1**. All Facilities shall be operating within their Facility Ratings. **R3.5.2**. Such action would not violate safety, equipment, regulatory or statutory requirements. **R3.5.3**. A sustainable, stable, operating condition is maintained 22. The SDT attempted to make this language similar to the extent possible. 23. The SDT believes that Requirement R2.7 covers this matter for Steady State but will discuss this matter further for subsequent drafts. 24. The intent of this requirement is to model the system as it would be operated and high speed reclosing would therefore be included. 25. The SDT believes that your comment has already been addressed by the words "affected entities" (now directly adjacent Transmission Planner) in Requirement R8 (old Requirement R6). Impacted is difficult to measure. In addition, the purpose of the "peer review" is to help ensure that a Corrective Action Plan is inclusive and some potentially impacted areas are not overlooked. 26. As noted in the BPA 7 answer, these events are included as Extreme Events to be consistent with FERC Order No. 693 and because such events could dramatically impact the reliability of the interconnected network. 27. The SDT agrees that the language for P8 needs to be clarified with regard to the 300 kV threshold. As a result, the SDT has made changes to the standard to clarify the 300 kV threshold. 28. The SDT agrees and has changed the standard to clarify that the faults being simulated are permanent faults. 29. The SDT has made the recommended change in P7. 30. This item was deleted. 31. Transmission is a defined term in the NERC Glossary as is System.			
City Utilities/Springfield	☑		Requirement R3.2: Contingency analyses representing only the removal of elements that System protection is expected to automatically disconnect which includes Consequential Load Loss is a reduction in reliability. Excluding the contingency analyses between all elements including those with manually operated switches will result in lowering existing reliability standards and ultimately limit the load restoration capabilities of the BES. Minimum performance standards should be adhered to for all applicable contingencies including outages of elements that may be switched both automatically and manually taking into account controlled load curtailment that is allowed. Requirement R3.3.2.1: The expected duration of Consequential Load Loss was noted to be required in a Planning Assessment following a single Contingency without any indication as to the assumed

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Commenter	**Yes**	**No**	**Comment**
			cause of the outage. The basis for such estimations of time needs to be defined such that these assessments are developed on a consistent basis.
Response: 1. One of the drivers for assessing the System performance based on removing all elements that System Protection is expected to disconnect (breaker-to-breaker) upon clearing the fault is to address concerns expressed in interviews by NERC TIS and FERC. The premise is that the assessment must examine all phases after a fault occurs. This includes the initial response of the System immediately after the fault clears, as well as after any existing or planned switching actions, such as the ones to which the commenter refers. 2. The proposed TPL-001-1 standard does not place limits on the amount of Consequential Load Loss or the outage duration. In Requirement R.3.3.2.1 the Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment. The SDT believes it is necessary to obtain this data to evaluate the future need for and establish a basis to define maximum amounts of Consequential Load Loss that would be allowed.			
CPS Energy	☑		1. R1.1. This is a modeling requirement and should be incorporated into the modeling (MOD) standards. Remove or modify this requirement to eliminate any redundancy with existing modeling standards. If certain subrequirements of R1.1 of TPL-001 are not currently requirements in a MOD standard, it should be questioned, then, whether or not these specific subrequirements are actually needed in ANY standard. 2. R2.2. ERCOT does not study the Long-Term Planning Horizon because ERCOT does not believe it is necessary. Remove or modify to state "as applicable by region." 3. R2.7.1.1 Duration of projects vary between Transmission Owners and statement of the project initiation date has no value to reliability. 4. R3.3.2 Relay loadability is considered as an MLSE component to the circuit rating as identified in MOD-008 and MOD-009. 5. R3.3.2.1. The requirement to identify consequential load loss for single contingencies in the Planning Assessment is unnecessary and burdensome and should be removed. 6. R3.6 Automatic generation tripping should be allowed for radial-connected wind resources. 7. Table 1 - P6.1, P6.3, and P6.4 These events are triggered by a single credible event and should not allow for loss of Non-Consequential Load. 8. Table 1 - P9.1 Loss of double-circuit tower lines are triggered by a single credible event and should not allow for loss of Non-Consequential Load. 9. Table 1 and Table 2 - P4, P5, P8, and P9. Including all combinations of two components (generator, Transmission circuit, transformer) with generation adjustments is impractical and overly

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Commenter	**Yes**	**No**	**Comment**
			burdensome. For multiple contingencies, include only double-circuit tower lines and the two components (generator, Transmission circuit, transformer) that would be cleared by breaker failure.

Response: 1. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.
2. The SDT believes that the purpose of the long term horizon is to uncover any unexpected trends that might appear after the first five years. Although planning may not be performed as stated in the draft standard, the standard does provide a level of confidence that unusual or unexpected trends or events could always affect the current planning process and allows for planners to propose potentially long term economic solutions that could not be envisioned in the shorter term.
3. Requirement R8 (old Requirement R6) which focuses on the distribution of the Planning Assessment results among affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old Requirement R6) Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. Typically the date would indicate when significant resources will begin to be employed. This covers any project proposed for the near term. The SDT continues to believe that providing the expected project intiation date of System improvements provides useful information to neighboring entities. The SDT believes that initiation dates are required for near-term corrective action plans to give an indication that the corrective action plans can be implemented in time.
4. The SDT has received numerous comments in support of these requirements. Requirement R3.2.2 is included to provide clarity on simulations in response to FERC Order 693. Relay Loadability is included to be clear that this factor must be taken into account in the planning studies. The SDT has not made changes in response to this comment.
5. The requirement concerning Consequential Load is to address FERC Order 693, which directs the ERO, among other things, to clarify footnote (b) in regard to Load loss following a single Contingency, specifying the amount and duration of Consequential Load Loss and System adjustments that are permitted after the first Contingency to return the System to a normal operating state.
6. The SDT has made a change to allow for tripping under certain conditions.

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:
R3.5.1. All Facilities shall be operating within their Facility Ratings.
R3.5.2. Such action would not violate safety, equipment, regulatory or statutory requirements.
R3.5.3. A sustainable, stable, operating condition is maintained.

7. These events are on lower voltage facilities on the BES. The probability of the outage of one breaker or a bus section is much lower than the probability of a single Transmission line outage. Therefore, the SDT has drafted the standard to permit loss of Non-consequential firm Load or interruption of firm Transmission service for the loss of a lower voltage breaker or lower voltage bus section. The majority of the commenters in response to the first posting of the standard agreed with the SDT's approach in this regard.
8. This event is a lower probability event, for example the probability of the outage of one common tower event is much lower than the probability of a single Transmission line outage. Therefore, the SDT has drafted the standard to permit loss of Non-Consequential firm Load

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Commenter	**Yes**	**No**	**Comment**
or interruption of firm Transmission service for the loss of a common tower event. The majority of the commenters in response to the first posting of the standard agreed with the SDT's approach in this regard. 9. The analyses of the combinations of two components are required by the existing TPL standards. The SDT understands the concerns in the potential increase in work load. Requirement R3.3.3 requires evaluation of only those Planning Events (involving multiple Contingencies) that are expected to produce more severe System impacts.			
Entergy	☑		1. Significant Increase in Study Activity Workload on Transmission Planners The increase in both steady state and dynamic studies required to ensure compliance with the proposed standards will result in increased costs and staff additions. The more specific format and additional requirements of the "Corrective Action Plan" require the TP to provide a significant amount of documentation for each deficiency identified by the studies. Also, R3.2 requires that the studies simulate the protection scheme for all events. The current software tools cannot automate these studies for bus faults and breaker failure events, requiring each scenario to be studied manually. Additionally, experienced staff capable of performing analyses as described in the proposed standard have become increasingly difficult to find and retain and the talent pool of people with these skills has recently become depleted to alarming levels. 2. Implementation Plan Given the intent of the proposed standard to encourage large scale investment in the EHV system, full implementation will take years, perhaps decades. Acquirement of right-of-way for new EHV lines has become increasingly difficult in recent years and increasingly expensive due to the environmental and social issues associated with new Transmission. Legal, regulatory, and other difficult issues often take several years to navigate, even for 115kV lines. The Implementation Plan timeframe, if set too short, would be unduly burdensome on Transmission Owners, extraordinarily expensive, and possibly unachievable. The proposed implementation plan should include provisions for those cases where viable solutions simply can not be implemented in time due to circumstances beyond the control of Transmission owners. We recommend a minimum of 15 years for the transition. 3. Design and Construction Constraints Even if right-of-way and other legal and regulatory hurdles are cleared, and the capital funding for such a tremendous level of investment was not an issue, the other resources required to actually construct the projects are equally difficult and costly to secure. Raw material prices on commodities like copper and steel have skyrocketed in recent years. Additionally, the skilled labor and Engineering resources are constrained with labor rates almost keeping up with other resource costs. Overall project costs have more than doubled over the last 7-10 years. Recent press releases concerning new generation being planned and then scrapped due to the rapid escalation of project costs are public evidence of this. The inflationary mark-up is impossible to estimate but much less will be built with the same capital investment than is currently envisioned due to the competition for both human and material resources.

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Commenter	**Yes**	**No**	**Comment**
			4. Cost-Benefit Analysis It will be extremely expensive, requiring unprecedented levels of capital investment in Transmission facilities, to become compliant with a proposed standard without any evidence that such increased requirements are justified. Before the standard comes to official vote, it would be prudent for a cost-benefit analysis to be performed to determine if the reliability improvements justify the huge expenditures certain under the proposed standard. A clear understanding of the reliability benefits and economic costs to customers is critical prior to final action on the proposed standard. While tightening standards will result in a more secure system, overbuilding the system at a significant cost to withstand more severe but less likely contingencies may not be in the public interest. Additionally, it is unclear whether the propose standard is in conflict with section 215 of the Energy Policy Act of 2005. 5. System Adjustment Clarification The term "System Adjustment" as outlined in the tables should be better defined. The use of generation for redispatch may have nuances which preclude or otherwise limit their use for studies. Perhaps some clearer guidelines on what is allowed such as committing units, de-committing units, firm and non-firm use, etc. would facilitate transparency and coordination between Transmission Planners. 6. Transmission Service Evaluation Another concern is that the proposed standard appears to be inconsistent with the current requirements for evaluating firm transmission service, generally based on an N-1 standard. To the extent this standard is adopted as proposed, the new standard would also need to be incorporated into the standards against which new transmission service is granted.
Response: 1. Much of the work that the commenter sites as additional is something that is required by the current approved standards. For example, Requirement R3.2 requires that the planner not just "outage" each power flow model element but reflect outage conditions that truly exists in the real world, e.g., a fault on a three terminal circuit should be modeled as three power flow elements being removed from the case to reflect actual operation. The concepts of "re-testing" and "committed" projects have been removed from the Corrective Action Plan so that only the value added concept of listing the actions necessary to achieve the desired level of system performance remains. Although sensitivity cases are now specifically required, they were considered by many utilities to determine the level of risk that remained after the addition of the proposed reinforcement projects. 2. The SDT understands that there are extended transitionary issues associated with responsible entities becoming compliant with the new standard. The SDT plans to draft an extended implementation plan to accommodate such issues. The plan will be provided for the third posting of the standard. 3. The SDT is unsure of the intent of the comment. While it is becoming increasingly difficult to build new Facilities, the fact is not in itself a valid reason for not complying with the performance requirements of this standard. The responsible entity is required to annually assess the compliance with the performance requirements and to have a Corrective Action Plan when the assessment indicates an inability to meet the			

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Commenter	**Yes**	**No**	**Comment**
performance requirements. A Corrective Action Plan does not necessarily result in building new Facilities. If it is impossible to correct the failure then a mitigation plan should be submitted for approval. 4. The SDT shares your concern on the benefits and cost to meet the proposed increase in some requirements. The SDT and a large number of commenters felt that the proposed changes in requirements were reasonable and will help improve reliability. The SDT is including in the next draft, a schedule for compliance in the Implementation Plan which should give some time for entities to become compliant with the new requirements. The TPL standard is not a standard "to build"; it is a standard to plan for System reliability. The individual entities have the option of deciding how best to meet the growing load and associated reliability needs. 5. The Transmission performance tables have been modified to bring clarity to the Contingencies required for performance studies and when Non-Consequential Load Loss is permitted to meet requirements. The use of manual or automatic System adjustments to revise System topology as well as generation redispatch is always permitted so long as the actions can be performed while adhering to Facility Ratings. 6. The provisions for an entity to grant Transmission service in the US is part of the entity's OATT and is beyond the scope of this standard.			
Exelon	☑		1. There should be more specific requirements for the long-range studies. The P requirements should be run on the long range case but corrective action plans need only be proposed and not committed. 2. R3.3.2.1 appears to require consequential load loss identification including peak demand and duration. however there is no requirement addressing the use of this information. Why is this required? 3. R3.3.3 should be clarified. It is our interpretation that not each of the P contingencies be studied if sufficient rationale is provided to determine the most critical. It would seem that each of the planning category events would need to be addressed. 4. What is the expectation regarding sensitivity analysis in R2.1.3 and R.2.4.3 if there are no performance requirements defined? 5. It should be clear in the performance tables that the 'event column' contingencies are logically 'or' events.
Response: 1. The performance requirements apply to both the "near-term" and the "long-term"assessments. Compliance with the performance requirements should be documented through assessments and a Corrective Action Plan. The SDT has modified the requirements in the new draft to remove the phrase "committed projects." 2. The requirement concerning Consequential Load is to address FERC Order 693, which directs the ERO, among other things, to clarify footnote (b) in regard to Load loss following a single Contingency, specifying the amount and duration of Consequential Load Loss and System adjustments that are permitted after the first Contingency to return the System to a normal operating state. 3. Requirement R3.3.3 requires evaluation of only those Planning Events (involving multiple Contingencies) that are expected to produce more severe System impacts. Requirement R3.3.3 also requires that the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. 4. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirements			

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Commenter	**Yes**	**No**	**Comment**
R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirements R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own System. The sensitivity studies do not in themselves establish the need for a plan, only the areas of the System for which the analysis is needed. **R2.1.3.** For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.1.4**. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. **R2.4.3**. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: **R2.4.4.** In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. 5. The SDT has made changes to clarify the table.			
FirstEnergy	☑		1. - R1. Load flow model submittal is redundant with various MOD standards and should not be required by this standard. To the extent any new requirements are introduced, we suggest that existing MOD standards be revised or new MOD standards be created as needed. 2. - R2 Organization of this requirement could be improved by grouping by Near Term and Long Term and then by steady state, short circuit, and stability requirements. 3. - R2.1 Too many annual studies are being required by this standard for the Near Term. We suggest limiting the current study year requirement be limited to one Near Term study. As written, it appears that this requirement forces a study for each of the 5 years, however the requirement should to be able to assess the entire 5 year period but not study each year. 4. - R2.1.1: As written, 2 studies are needed to meet this Near Term assessment requirement. It should be left up to the TO to determine the appropriate year in the short and long term periods. It's particularly odd given the fact that the TO could select year six for the Long Term study which would end up giving him back to back year 5 and 6 studies. The requirement should be to study one year in

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Commenter	**Yes**	**No**	**Comment**
			the 1 to 5 and one year in the 6 to 10 year periods. 5. - R2.2: This wording is very confusing. We are assuming that it means that you must continuously have to have a study that is less than one year old for the year 6 to 10 period. If so, wording needs to be clarified. 6. - R2.4.1: The idea of modeling induction motor loads is good in concept, be we question the practicality for an auditor to enforce. To date, a definitive way to model induction motor load does not exist. For example, what is the right mix for percent of load to be motor load or percent of large vs small induction motors. 7. - R2.6.1: Unless "material change" is specifically defined, the requirement is ambiquous and difficult to enforce consistently. What constitutes a "topology" change? 8. - R2.6.2: Same comment as R2.6.1 above, material change needs to be defined. 9. - R2.6.3. Same comment as R2.6.1 above, material change needs to be defined. 10. - R.2.7.1.1: We don't think it is reasonable nor necessary for the TO to provide an initiation date. No one should care when it was initiated as long as it is in service by the time it is needed. 11. - R2.7.1.2. Requiring an in-service year for the long-term may not be feasible for the initial study assessment. Based on the number of issues that could occur in the long-term horizon it may take a TP another 6 months to a year of more detailed area studies study to find the optimal solution(s) to resolve multiple system deficiences. In the long-term, only a list of SOLs problems along with year problem is initially anticipated should be required. 12. - R3.2.1: We suggest the following rewording "R3.2.1. Studies shall include the minimum steady state voltage limitations for all generators, and generators shall be simulated to trip for voltage below the minimum steady state limitation." 13. - R3.2.2: This is unnecessary in this standard. This is already addressed in the FAC standards dealing with equipment rating. Additionally, the proposed PRC-023 relay loadability standard addresses this concern. Alternatively, reword the requirement to say "if a relay is expected to trip because of an overload then the resulting facility shall be simulated in addition to the initiating event". 14. - R3.3.3. How do you know which events beyond single contingencies result in producing "more

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Commenter	**Yes**	**No**	**Comment**
			severe" impacts without running all? Either you test or you don't. We suggest some type of cyclical expectation for testing each of the less probable Planning Events, i.e. every three years each must be covered etc.the most critical 15. - R3.4 Same comment as R3.3.3, you need to test each to understand which produces the most severe impact. We suggest some type of cyclical expectation for testing each of the Extreme Events. The frequency of testing should be less often that the items covered in R3.3.3. It appears the only expectation is to consider some type of change to reduce or mitigate potential Cascade for Extreme Events. It should be clearly written that there in no mandatory expectation to remove the Cascade risk that may be associated with an Extreme Event. 16. - R4.5.1. Same comment as R3.3.3 (Steady-State) applies for this Stability requirement. 17. - R4.5.2. Same comment as R3.4 (Steady-State) applies for this Stability requirement. 18. - R4.6.1. We agree with the requirement but the SDT should assure consistency with data submittal requirements in the MOD standards. PERFORMANCE TABLES - General 19. In general, we feel the tables are overly complicated and difficult to follow. We suggest the SDT give consideration to merging the proposed tables back together to a single performance table. We also question why the team chose to leave the NERC A, B, C, D concept. The concept of Planning Events could reflect that NERC A, B & C categories must be met for Planning Events and that Category D are Extreme Events. Drastic deviation from the historical NERC performance classifications will require significant re-write of existing TP planning criteria documentation. 20. 300kV Level - It is confusing how the 300kV level requirements are placed within the tables. We suggest separate columns for performance requirements for 300kV and higher and below 300kV. This way, the same Planning Event could easily be reference on the same line and the expectations for each system level could be more readily determined. TABLE 1 - Steady-State Performance Table 21. We suggest that the "Initial Condition" column that is included in Table 2 - Stability Performance Table - also be added to Table 1. This would allow each to have the same look and feel, and would cut down on the lengthy wording such as: "Loss of a generator followed by System adjustment followed by loss of a generator" 22. Bullet 1 - "Equipment Ratings should not be exceeded." It is not clear which equipment rating

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Commenter	**Yes**	**No**	**Comment**
			would be the applicable rating. 23. Bullet 3 - "Voltage instability, cascading outages and uncontrolled islanding shall not occur". These terms require a definition to ensure consistent interpretation and application from an auditor. 24. It is not clear why stuck breaker items are distinguished from an internal breaker fault. Each will create the same resulting system condition. 25. Why are non-bus tie breakers treated separate from other breakers? 26: P2: Why is a stuck breaker listed as a single contingency? 27. P8: What about a transformer followed by a line outage? Why not just simply list the components and say any combination of the two. 28. P9: "Loss of a transformer followed by a System adjustment with a spare transformer available followed by the loss of another transformer." It is not clear why this is needed? Wouldn't the spare be a possible mitigation of the initial contingency? Extreme Event Descriptions: 29) For item 1, it's understood that for the N-2 items listed, the "extreme" aspect is that the second event occurs without system adjustment. However, we question whether a two generators simultaneously out should be considered an extreme condition. 30) We agree with the items listed in item 2 as they line-up well with the prior category D events from the existing TPL standards performance table. 31) Many of the classifications listed in item 3 are subjective and can not be tested. We propose that these items should not be requirements. TABLE 2 - Stability Performance Table 32. With regard to Table 2, much of the proposed testing required for stability are not necessary from a reliability standpoint. Some test items are included that are not, at least in the eastern interconnection, going to impact stability any worse than the relatively simpler requirements of the present standards. By testing single phase local faults in conjunction with a stuck breaker and remote faults with back up clearing for each line emanating from a power plant, you'll cover 99% of your stability issues. Also, this table does not adress relay scheme failures (back up clearing) that were

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Commenter	**Yes**	**No**	**Comment**
			covered in the present standard and which can have a significant impact on the stability of a unit/system. 33. Under the "Event Column", it is inconvenient to need to look back and forth on the table to reference other events, the items should be written in full text. For example, under P4 it is indicated that the "Initial Condition" is a single generator out and the "Event Column" indicates apply "P1.2 Contingency, P1.3 Contingency, etc." These items should be written out so that the user of the Table does not need to flip back and forth to see what the referenced contingencies entail. 34. Regarding P1, why require dynamic analysis for an unexpected loss of the listed equipment without a fault? The fault iniated outage will always be worse. 35. As stated above for Table 1, It is not clear why stuck breaker items are distinguished from an internal breaker fault. Each will create the same resulting system condition. 36. P5, P8, P9: The analysis suggested to run these multiple contingencies in dynamics would be extremely time consuming and produce little value. We suggest that the steady-state anlysis be used to screen those contingencies which show the potential to cause system cascade and then run dynamic analysis on those items. 37. As stated for Table 1 above, "Loss of a transformer followed by a System adjustment with a spare transformer available followed by the loss of another transformer." It is not clear why this is needed? Wouldn't the spare be a possible mitigation of the initial contingency? 38. In the Notes section shown under Table 2, for item "ii", we are not sure this could be accomplished as our relay models are not reflected in our data set used for dynamics simulation analysis. Two separate and unique software tools house the data and we believe this to be common among most companies.

Response: 1. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.
2. Changing the order or sequence of the specific requirements has been discussed by the SDT but the decision was to retain the current sequence to avoid more confusion among the commenters. The benefit of changing the sequence did not outweigh the benefit of continuity at this point. The commenter is welcome to make a specific proposal for change in the next round of comments.
3. Requirement R2.1 does not require a study for each of the five years. The Planning Assessment shall cover the five year period. Requirements R2.1.1, R2.1.2, and R2.1.3 cover peak loading, off-peak loading, and sensitivities. The SDT feels that the requirement to run a peak load study for two of the years in the Near-Term Horizon is a minimum required for an adequate Planning Assessment. The SDT felt that

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Commenter	**Yes**	**No**	**Comment**
in Requirement R2.1.1 the Year One or two study should provide operations with the best information to transition to the operating horizon. The year five planning study is the first near term study from the long term set. Five years is a short time if unexpected new facilities are required. Requirement R2 includes a statement which states that "Planning Assessment shall use current or past studies." R2.1 allows for the Planning Assessment to be "…supplemented with qualified past studies…" If you have past studies which are applicable, the standard allows for such. 4. The SDT feels that the requirement to run a peak load study for two of the years in the Near-Term Horizon is a minimum required for an adequate Planning Assessment. The SDT felt that in Requirement R2.1.1 the Year One or two study should provide operations with the best information to transition to the operating horizon. The year five planning study is the first near term study from the long term set. Five years is a short time if unexpected new facilities are required. Requirement R2 includes a statement which states that "Planning Assessment shall use current or past studies." R2.1 allows for the Planning Assessment to be "…supplemented with qualified past studies…" If you have past studies which are applicable, the standard allows for such. 5. The intent of Requirement R2.2 is to study one year in the five year period each year. The timing of annual planning studies may mean that the most recent study is slightly over one year old in some years. Over time, the entity should have a portfolio of studies for the long term period as the basis to confirm the assessment of the period. 6. The SDT has softened the wording of Requirement R2.4.1 to address this issue. **R2.4.1**. System peak Load for one of the five years. For peak System Load levels, ~~the~~a Load model shall ~~include the dynamic effects~~ be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. 7, 8, and 9. The SDT agrees this is difficult and has modified the requirement to add some clarity. Most of the studies now have a backstop age of five years where they are no longer useable. **R2.6.** Past studies may be used to support the Planning Assessment if they meet the following requirements: **R2.6.1**. For steady state, short circuit, or System Stability analysis: ~~if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market structure changes~~ the study shall be five calendar years old or less. **R2.6.2**. For steady state, short circuit ~~analysis~~, Generating Plant Stability, or System Stability analysis: ~~if the study is less than five years old and no material changes have occurred to the System in the intervening period.~~ the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. **R2.6.3**. ~~For plant and System Stability analysis: until material changes in the System make the study no longer valid. Material changes in the system include the addition of a Transmission Line or a generator.~~ 10. Requirement R8 (old Requirement R6) which focuses on the distribution of the Planning Assessment results among affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old Requirement R6) Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. Typically the date would indicate when significant resources will begin to be employed. This covers any project proposed for the near term. The SDT			

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Commenter	Yes	No	Comment
			continues to believe that providing the expected project intiation date of System improvements provides useful information to neighboring entities. The SDT believes that initiation dates are required for near-term corrective action plans to give an indication that the corrective action plans can be implemented in time. 11. Requirement R8 (old Requirement R6) which focuses on the distribution of the Planning Assessment results among affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old Requirement R6) Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. Typically the date would indicate when significant resources will begin to be employed. This covers any project proposed for the near term. The SDT continues to believe that by providing the expected project intiation date of System improvements provides useful information to neighboring entities. The SDT believes that initiation dates are required for near-term corrective action plans to give an indication that the corrective action plans can be implemented in time. 12. Requirement R3.2.1 was meant to allow the Planning Coordinator and the Transmission Planner the discretion on the treatment of the generators that may exceed their maximum or minimum voltage limits. 13. The SDT has received numerous comments in support of these requirements. Requirement R3.2.2 is included to provide clarity on simulations in response to FERC Order 693. Relay Loadability is included to be clear that this factor must be taken into account in the planning studies. In addition, Requirement R.3.2.2 only requires the studies to consider relay loadability and identify how loadability is treated in the steady state simulation, not to study relay loadibility. The SDT has not made changes in response to this comment. 14, 15, 16, and 17. The SDT believes it is appropriate for the Transmission Provider/Planning Coordinator to decide how to determine the events that result in the "more severe" impacts. The SDT believes that the standard as written is clear and does not indicate a "mandatory expectation to remove the Cascade risk" for Extreme Events. For example, Requirement R3.3.1 indicates that performance criteria shall be met only for System normal conditions and for Planning Events in Table 1. Requirement R3.3.1 does not include the requirement that the performance criteria be met for Extreme Events. 18. The SDT has added requirements R9 through R13. **R9.** Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information. **R10**. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information. **R11**. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information. **R12**. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information. **R13**. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each

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Commenter	Yes	No	Comment
year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information 19 and 20. The majority of commenters support the development of the two tables as opposed to the single table in the existing TPL standards. Further, the SDT believes that the two tables provide the ability to clarify issues associated with Stability performance and evaluation requirements versus steady-state performance and evaluation requirements. These issues were expressed by commenters during the development of the SAR that initiated the re-write of the TPL standards. By the same token, comments were expressed during the development of the SAR about the need to consider significantly changing the classification of outages to these categories and even to consider eliminating the categories. The SDT took the approach of eliminating the categories in order to concentrate on defining the performance requirements individually for each event as appropriate. The SDT does not see a need at this time to revert to the previous classifications. The SDT has made changes to the tables to clarify the performance and evaluation requirements as the SDT agrees with the commenter that further clarification from the standard issued in the first comment period was required. The SDT agrees with the commenter concerning the need for clarification of the 300 kV performance requirements and, as a result, made changes to the standard intended to accomplish this purpose. 21. The SDT has implemented the suggestion to add an initial condition column to Table 1. 22. The SDT notes that Equipment Ratings are covered in the FAC standards and are set by the Transmission Owner. The SDT does not see the need to add any further requirements with regard to Equipment Ratings. 23. Definitions for cascading and stability are included in the NERC Glossary. Further uncontrolled islanding, while not defined, is a common term that is well understood. The SDT does not propose to improve the definitions for Cascading and Stability or propose a new definition for cascading outages and uncontrolled islanding. The SDT believes that while it may be helpful to either develop a voltage instability definition or else specify performance requirements for voltage instability, there are not generally accepted performance requirements for voltage instability across NERC making it difficult for the SDT to write a voltage instability performance requirement at this time. For example, it has been found that an acceptable margin for voltage Stability varies bus to bus and therefore, is not suitable for a general instability requirement on a PV curve or alternative. There are a number of IEEE papers (e.g., P. Kundur, J. Paserba, V. Ajjarapu, G. Anderson, A. Bose, C. Canizares, N. Hatziargyriou, D. Hill, A. Stankovic, C. Taylor, T. V. Custem, V. Vittal, "Definition and Classification of Power System Stability", IEEE Transactions on Power Systems, vol. 19, no. 2, pp. 1387 – 1401, May 2004) that provide descriptions of voltage instability. It is important to understand what events are being modeled even when conducting steady state studies so as to ensure that studies are being conducted recognizing the FERC indicated in paragraph 1707 of Order No. 693 that planning assessment "faithfully duplicate what will happen in the actual power system and not a generic listing of outages." As a result, the SDT is not proposing to make changes to the standard in response to this comment. 24. The SDT feels that the resulting conditions are not the same. Stuck breaker is described in the notes in the tables. An internal fault is a single Contingency but a stuck breaker is not. 25. The reason for separate treatment of Non-Bus-tie Breaker and Bus-tie Breaker is that there are different System consequences for the 2. 26. The SDT agrees that a stuck breaker is not a single Contingency. It requires a fault-initiated Contingency followed by the failure of the breaker or the System Protection to operate properly. As a result, the stuck breaker is a lower probability Contingency. The SDT has changed the identification of the outage in the table. 27. The SDT agrees with this suggestion and has made the change to the table. 28. P9.6 was an attempt to include outages involving long lead time equipment considering spare equipment strategies in the table as			

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Commenter	**Yes**	**No**	**Comment**
directed by the FERC in Order No. 693. The SDT has deleted P9.6 and included this consideration in Requirement R11 of the second draft of the standard to address this issue. 29. Whether two generators out without System adjustment in between is an event which severely stresses the System would depend on the individual System under study; the SDT believes it is appropriate to not include this as a Planning Event and therefore has not revised the table as suggested. 30. Thanks for the support. 31. With regard to the comments about the Extreme Events in Item 3, the SDT notes that in Order No. 693, paragraph 1834, the FERC gave examples of Extreme Events and Item 3 is consistent with paragraph 1834 in the FERC order. See the response to BPA 7 for more details. Further, the SDT notes that these events dramatically impact the reliability of the interconnected network and are logical extreme events for which the probability and consequences should be evaluated when considering ways to make the transmission system more robust with operating procedures and/or system improvements that are reasonable in cost in comparison to the probability and consequences of the extreme event. The SDT did not change the standard with regard to these comments about Extreme Events in Item 3. 32. The SDT believes that all Stability requirements are necessary for reliability based on an understanding of current practices within North America. Protection systems will be addressed in subsequent versions. 33. The SDT has completely re-formatted the tables due to industry comments. 34. The SDT agrees and has made the change to the table. 35. The SDT feels that the resulting conditions are not the same. Stuck breaker is described in the notes in the tables. An internal fault is a single Contingency but a stuck breaker is not. 36. The SDT believes that Requirement R5.5.1 provides the distinction you are looking for. 37. Spare terminology has been deleted. 38. The intent of the note is the system must meet performance and that the loss of any generator is not greater than your Contingency reserve. You can simulate relay models using other techniques.			
FPL	☑		1. General Comment: NERC Standards TPL 001-0 through TPL 004-0 are approved standards that only required modifications pursuant to FERC Order 693. In this proposed draft standard TPL 001-1 the Standard Drafting Team (SDT) has far exceeded the recommendations suggested by FERC in that Order as well as created unnecessary confusion. FPL believes that the SDT's decision to combine NERC Standards TPL 001-0 through TPL 004-0 into one standard was not a specific requirement by FERC Order 693 and may not have been a good decision by the STD, therefore it should be reconsidered after reviewing all of the comments. At a minimun, the team should somehow clearly demonstrate changes in the standard's wording and required performance levels as compared to the existing standards. The new proposed draft of TPL-001 creates unnecessary confusion and interpretation of new ambiguous language, which is inconsistant with the stated objectives, instead of providing clarity to the standards. As an example of how to provide additional clarity, the existing standards have unnecessary redundancy in the tables, for example, it would have been nice to clean up (clarify) the tables such that the table for TPL-001 would only contain the performance criteria for Category A, with footnotes only applicable to that category, clarified as directed by FERC in Order 693. Similarly, TPL-002 would only contain performance criteria for Category B, and so on.

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Commenter	**Yes**	**No**	**Comment**
			2. In addition to combining the standards, the SDT has significantly changed contingency specifications and required performance levels. In many cases the changes represent a very significant increase in required performance standards that will require unjustified major capital expenditures and/or reductions in ATC. This also could have an adverse impact on commercial transactions. In other cases, the performance criteria are not clearly defined, such as the timing between multiple contingencies, and the level of readiness of the system after Planning Events. The benefits from the additional performance requirements have not been identified in the proposed standard. Is there a planned phased in approachto move from the existing standard to the new proposed standards. If so, what is it? 3. Finally, the SDT has chosen to eliminate the footnotes in the current standards, contrary to the direction of FERC in Order 693 to "clarify" the footnotes. The purpose of the footnotes is to further explain terms in the tables, provide guidance in interpreting the expected performance criteria, and specify any exceptions to the criteria. Footnotes also serve the purpose of keeping the standard concise by eliminating repetitiveness. Specific comments on the Draft Standard Performance Criteria 4. The performance requirements table should clearly define what the initial state of the system is assumed to be before any Planning Events, and what the state of the system is assumed to be after the Planning Event. For example, P1 (single contingency) events: assuming that the system is to be compliant, the state of the system prior to the event must be "secure" such that the event could occur and there is no interruption of firm transfer or loss of load, Equipment Ratings are not exceeded, System steady state voltages and post-transient voltage deviation are within acceptable limits. However, the system is not as it was before the event. The system could be described as "normal" but perhaps not "secure". If the requirement is that the system must also be "secure" after the event, then the standard must clarify what is allowed for "system adjustments" after the first Planning event to prepare for the next. FERC Order 693 directed the ERO to modify the second sentence of footnote (b) to clarify that manual system adjustments other than shedding of firm load or curtailment of firm transfers are permitted to return the system to a normal operating state after the first contingency. However, in order to bring the system to a secure state, as is necessary for the second contingency of a category C3 or C5 event, footnote (c) allows curtailment of firm transfers, and FERC Order 693 only required footnote (c) to be clarify the term "controlled load interruption", leaving the curtailment language intact. The implication of this interpretation is critical to peninsular Florida. The Category B loss of one 500 kV line from Florida to Georgia is sustainable, such that the system is "normal" after the event. However, in order to be prepared for the next contingency, (the loss of the second 500 kV line), firm transfers must be curtailed. (Interruption of Firm Transfer) Without the ability to curtail firm transfers, a "super-firm" priority of service is created,

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Commenter	**Yes**	**No**	**Comment**
			which is unjustified. Comments on New Performance Tables: 5. The draft TPL standard represents a major change in the Table 1 contingency definitions and required performance levels. 6. Table 1 Contingencies C1 and C2 are being moved to the single contingency category. While C1 and C2 represent single element outages, their probability of occurrence is much lower than the other Category B contingencies and they do not belong in the single contingency performance requirements group. 7. Footnote (b) which permits, as a limited exception in unique circumstances with a sound rational basis, some localized load reduction for single contingencies, has been removed. This is a very significant change for some utilities. Footnote (c) which permits load shedding and curtailment of firm transfers has been removed from C1, C2 and most of C3. This is a very significant increase in required performance level that is not justified. 8. The "applicable rating" for loading and voltages in Table 1 has been removed so that essentially, the same ratings and voltage restrictions apply to both B and C contingencies. Some utilities plan to a normal rating for single contingencies but will allow a higher short term rating for Category C events. This practice will apparently be disallowed. 9. Several new Category D "Extreme Events" have been added which greatly expand the scope and complexity of Category D studies. These are (1) any two unrelated single element outages and (3) wide area events a. through h. These represent a major increase in the scope of Category D studies and probably a doubling of required SWG studies. The fault with protection element failure categories D1 through D4 have been substantially changed to eliminate analysis of relay failure contingencies. The philosophy contained in the existing TPL-004 standard is that faults with a protection failure should be evaluated whether that failure is a circuit breaker, relay or CT; the proposed standard restricts the analysis to breaker failure. 300 kV Threshold Performance Level 10. The TPL-001-1 draft sets a threshold of higher performance to facilities above 300 kV than previously established in the existing standard. We do not agree that such a threshold is necessary or warranted nor have they been justified. Requirements which are more stringent for these facilities may wrongly influence decisions on project alternatives in favor of facilities with less stringent requirements.

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Commenter	**Yes**	**No**	**Comment**
			DC Line Performance Requirement 11. The TPL-001-1 draft sets a lower performance requirement for the loss of a single pole of a DC line than in the existing standard by allowing interruption of firm transfer if the transfer is deemed to be dependent on the outaged line. Firm transfers are also dependent upon AC lines. The proposed standard does not distinguish between asynchronous DC ties and the more common parallel connected DC tie. With an asynchronous DC tie, the transfer is lost with the tie. With a parallel DC tie, the transfer will be shifted to the parallel AC system and should have the same performance requirements. We do not agree that such an exception for DC lines is necessary or warranted. The decision in selecting DC vs. AC in transmission lines has traditionally been based on the break-even cost and performance of the two alternatives. The lower performance requirement may wrongly influence decisions on project alternatives in favor of DC facilities with less stringent requirements. Distinction Between Committed and Proposed Projects: 12. Models cannot discern the difference between a "committed" project, and a "proposed" project in a performance analysis. The standard should instead set criteria for when models can be relied upon for planning purposes such that changes to the future plan will not have an impact on reliability. The intent of Requirements R2.7.3 and R2.7.4 should be combined and added into R2.7.1.1. Rather than adding the additional requirement to document a criteria, the requirement should be that in the Near-Term Planning Horizon, projects cannot be removed (or modified) without demonstrating that the revised plan meets performance criteria. In addition, the requirement in R2.7.1.1 to supply a "project initiation date" is ambiguous. What will constitute "project initiation" …construction start date? …Engineering complete date? …Land procurement date? Funds allocated date (budgeted)? Suggested wording for R2.7.1.1. "Transmission and generation improvement projects for the Near-Term Transmission Planning Horizon, shall have in-service dates provided, and shall not have in-service dates changed, or be removed from planning models, without documentation to show that the revised plan meets performance requirements." In addition to the concerns mentioned above, how are delays in meeting project in-service dates, which are not in the direct control of the Transmission Owner, caused by siting and Right of Way difficulties (public outcry, exercising eminent domain, court process, etc) addressed? The standard needs to have provisions to recognize these types of issues allowing a Transmission Owner to be compliant as long as he is using due diligence to overcome these types of delays. Analysis of Relay Protection Failures: 13. This draft of the TPL standard ignores studies required for analysis of relay protection failures. There is a widespread misconception that studying breaker failure scenarios covers for relay protection failures. This is a false assumption. Typical delayed clearing for a stuck breaker is in the order of 8 to 20 cycles. This is accomplished by the local relay system sensing the stuck breaker and tripping the adjacent elements. However in the case of a protective relay failure the fault must

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Commenter	**Yes**	**No**	**Comment**
			usually be cleared remotely by tripping all lines connected to the station. Typical delays for a relay failure can easily be greater than 30 cycles. Where as breaker failure action just trips a couple of adjoining elements and leaves the rest of the station intact. A typical example of this difference is to assume a bus fault. For breaker failure, all bus breakers except the stuck one would trip. The breaker failure relay scheme then would time out and trip the adjoining breaker and the remote end of the adjoining line would trip. This could all happen in less than 20 cycles. Now consider a bus fault with the differential relay failed. The local relays don't sense the fault because they have failed, nor does the local breaker failure scheme activate because no local detection has occurred. The only way to clear this fault is to trip all lines from the remote terminals. This may take 30 cycles or more. With breaker failure, the bus and one line trips in about 20 cycles. With relay failure, all lines trip remotely isolating the substation in about 30 cycles. Both scenarios must be studied with relay failure being the worse case. Generally, different solutions are required to address relay failure verses breaker failure. Load Modeling Requirements: 14. The proposed TPL Standard contains numerous references to load modeling. The goal of improving and verifying the load model is worthwhile but is not appropriate for the TPL standards. Assessment of load model accuracy is best accomplished through detailed analysis of grid disturbance events. The main difficulties in accomplishing this are (1) grid events that significant reduce transmission voltages throughout a load area are infrequently occurring and (2) the process of Recreating the event through simulation studies is extremely complex and time consuming. While these efforts should be encouraged they should remain a RRO prerogative. 15. R1.1.1 Use of expected Load mix based on the actual or expected aggregate mix of industrial, commercial, and residential Loads. – This requirement is not justified as the load model may be developed through disturbance analysis rather than load type synthesis by customer class. Some LSE's may have great difficulties in creating load forecasts based on customer class. Load forecasting requirements are adequately addressed in the existing MOD standards and do not belong in the proposed TPL standard. 16. R1.2. Load models with supporting rationale that include power factor data that may be based on historical System performance, validated by measurement during stressed System conditions, or documented Transmission planning area requirements. This requirement is not appropriate fot the TPL standarsds. 17. R2.4.1. System peak Load for one of the five years. For peak System Load levels, the Load model shall include the dynamic effects of induction motor Loads.

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Commenter	**Yes**	**No**	**Comment**
			18. Specific types of load models should not be required in this standard. 19. Short Circuit Requirements: The new TPL standard also contains numerous references to short circuit analysis, which are new requirements that expand the TPL standards, but without specific testing or performance criteria. Evidence that short circuit studies have been performed is currently required in the existing FAC-002-0 Standard. Since the primary concern is the appropriate sizing of equipment and the prevention of equipment damage as opposed to overall grid reliability, we do not see the need for a set of requirements within the proposed TPL standard for short circuit studies. 20. Given the aforementioned issues, we believe the proposed TPL standard is inferior to the existing Board approved TPL Standards, creates unnecessary confusion, and will require many iterations of industry comment and revision. As an intermediate approach, we would strongly urge the Standard Drafting Team that the existing TPL standards be modified to respond to FERC Order 693 directives, clarify any ambiguities, and not pursue the proposed new standard any further. This would bring a much needed part of the Reliability Standards into the framework of mandatory enforcement and provide guidance on this longer term effort to improve the TPL standards.

Response: 1. The SDT must not only consider directives made in the FERC Orders, but it must also consider the direction given in the two associated SARs. Much of the wording and format in the current standards is repetitive. They all share the same performance table. Historically many have commented that because of the duplication in wording and format that the four should be merged together so that consistency would follow. It would also be easier to find and see the differences for each level of contingency. The SDT will continue to minimize repetitive language, simplify tables, minimize the number of notes, etc.
Commenters in general have supported the concept of merging the four standards together. In addition, Paragraph 1692 of order 693 "directs the ERO to consider integrating Reliability Standards TPL-001-0 through TPL-004-0 into a single Reliability Standard through the Reliability Standards development process". In addition, this order, in conjuction with 890, enurmerates attributes of planning standards that the FERC feels should be incorporated into the consolidated standard. SDT believes that the first draft of the standard is consistent with orders 693 and 890 without being unduly burdensome.
2. The SDT understands that there are extended transition issues associated with responsible entities becoming compliant with the new standard. The SDT plans to draft an implementation plan to accommodate such issues. The plan will be included in the third posting of the standard.
3. The requirement concerning Consequential Load Loss is to address FERC Order 693, which directs the ERO, among other things, to clarify footnote (b) in regard to Load loss following a single Contingency, specifying the amount and duration of Consequential Load Loss and System adjustments that are permitted after the first Contingency to return the System to a normal operating state. In regard to your comment regarding the general use of footnotes, the SDT agrees that notes can add clarity and we have included footnotes where useful in the newly formatted tables.
4. The SDT agrees with the comment that the initial conditions must be clarified in Table 1. Therefore, the SDT has made changes to add an initial condition column to Table 1. The SDT agrees that the System must remain secure after an event and therefore has clarified the standard by adding words to cover this requirement.
Further, the SDT agrees that the overlapping single Contingencies in C3 or the multiple circuit tower Contingency of C5 in the existing TPL

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Commenter	Yes	No	Comment
			standards are much lower probability but given that the performance requirements are only raised on these events for facilities above 300 kV, the SDT does not believe that the proposed changes are unreasonable especially since the changes are consistent with FERC Order No. 693. Please see the SDT responses to Question 22 for more details. 5. The SDT agrees with the comment and believes that this is consistent with FERC Order No. 693. 6. The SDT agrees that C1 and C2 in the existing TPL standards are much lower probability but given that the performance requirements are only raised on C1 and C2 events for facilities above 300 kV, the SDT does not believe that the proposed changes are unreasonable especially since the changes are consistent with FERC Order No. 693. Please see the SDT responses to Question 22 for more details. 7. The SDT has added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose Load. 8. The SDT has referenced Facility Ratings in general terms in Requirements R3.3.2.3 and R3.6.1 to provide flexibility with time based ratings. 9. The SDT has reviewed and revised Extreme Events in Tables 1 & 2. 10. The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission Systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT felt the 300 kV and higher Systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. When EHV Systems are compromised, the large volumes of power served by them can place a severe amount of stress on parallel EHV or lower voltage paths. For example, if a large EHV transformer experiences a catastrophic failure not only are other System Facilities required to carry more Load but the System is also exposed to other N-1 conditions for long periods of time while awaiting a replacement or repair of the failed equipment. Large generation sources are typically connected at EHV levels and maintenance of the EHV Transmission lines within the vicinity of larges generation plants must often be coordinated during scheduled unit outages, resulting again in multiple Facility outages over extended periods of time. Therefore, it was the conclusion of the SDT in Draft 1 to propose greater reliability and operational flexibility through more stringent performance requirements when considering certain N-1 and N-1-1 Contingency events of EHV Systems. Throughout the industry substation arrangements at EHV levels reflect the importance of these Systems as the designs often consist of the more expensive ring-bus, breaker-and –a-half or double bus-double breaker protection schemes as opposed to the more simplistic and lesser cost single bus arrangements that are commonly found on lower voltage systems. The feedback received from industry was divided related to the SDT's emphasis placed on a higher expectation for the 300 kV and higher Systems. Some commenter's questioned the importance and the high costs that may be needed to mitigate existing System designs. Others agreed with the SDT's approach and indicated that the impact to their Systems would be minimal. Some commenters even questioned why the more stringent approach was not applied to the entire 100 kV and higher Systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission System. 11. As a controllable element, a DC terminal can carry more load than it might otherwise based on an impedance split in an all AC System. With most DC providing asynchronous DC ties, the SDT has elected to allow interruption of service. 12. Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted Requirements R2.7.2

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Commenter	**Yes**	**No**	**Comment**
through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions". The SDT continues to believe that by providing the expected project intiation date of System improvements provides useful information to neighboring entities however the region defines "initiation". **R2.7.1**. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. 13. Protection system failures are being studied and will be covered in a future version. 14. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. 15. The SDT believes that models must reflect the expected Load mix of industrial, commercial and residential Loads to correctly reflect the behavior of the System. 16. The SDT has revised this requirement based on industry comments to clarify the intent that Load data be based on expected or historical System performance. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. 17 & 18. The SDT believes that the dynamic effects of induction motors must be considered. The standard does not specify the details of how to model induction motors. Therefore, the SDT believes the standard includes the necessary requirement without being overly prescriptive. 19. Your reference to FAC-002 only addresses the study of a specific request for Interconnection. The TPL draft addresses on-going System changes and increases in available fault current due to the additions of circuits and resources, as listed in the Corrective Action Plan. Short circuit studies help determine appropriate equipment sizing and setting of protective relays. Such studies will help provide for a complete Corrective Action Plan, i.e., the installation of a transformer to resolve a System performance deficiency may require the installation of additional circuit breakers. FERC also noted the need to include this analysis to cover such conditions. 20. The SDT believes that the present course of drafting the four standards as one standard with a revised table of "Contingencies" is the best solution to addressing all FERC directives, following the SARs, considering past comments and providing a single standard outlining the fundamental planning analysis.			
FRCC	☑		General Comment: 1. The SDT has significantly changed contingency specifications and required performance levels. In many cases the changes represent a very significant increase in required performance standards that will require unnecessary major capital expenditures and/or reductions in ATC which will have an

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Commenter	**Yes**	**No**	**Comment**
			adverse impact on commerce. Neither of these outcomes is desirable. Specific comments on the Draft Standard Performance Criteria 2. The performance requirements table should clearly define what the initial state of the system is assumed to be before any Planning Events, and what the state of the system is assumed to be after the Planning Event. For example, P1 (single contingency) events: assuming that the system is to be compliant, the state of the system prior to the event must be "secure" such that the event could occur and there is no interruption of firm transfer or loss of load, Equipment Ratings are not exceeded, System steady state voltages and post-transient voltage deviation are within acceptable limits. However, the system is not as it was before the event. The system could be described as "normal" but perhaps not "secure". If the requirement is that the system must also be "secure" after the event, then the standard must clarify what is allowed for "system adjustments" after the first Planning event to prepare for the next. FERC Order 693 directed the ERO to modify the second sentence of footnote (b) to clarify that manual system adjustments other than shedding of firm load or curtailment of firm transfers are permitted to return the system to a normal operating state after the first contingency. However, in order to bring the system to a secure state, as is necessary for the second contingency of a category C3 or C5 event, footnote (c) allows curtailment of firm transfers, and FERC Order 693 only required footnote (c) to be clarify the term "controlled load interruption", leaving the curtailment language intact. The implication of this interpretation is critical to peninsular Florida. The Category B loss of one 500 kV line from Florida to Georgia is sustainable, such that the system is "normal" after the event. However, in order to be prepared for the next contingency, (the loss of the second 500 kV line), firm transfers must be curtailed. (Interruption of Firm Transfer) Without the ability to curtail firm transfers, a "super-firm" priority of transmission service is created for non-native load customers. Comments on New Performance Tables: The draft TPL standard represents a major change in the Table 1 contingency definitions and required performance levels. 3. Table 1 Contingencies C1 and C2 are being moved to the single contingency category. While C1 and C2 represent single element outages, their probability of occurrence is much lower than the other Category B contingencies and they do not belong in the single contingency performance requirements group. 4. Footnote (b) which permits, as a limited exception in unique circumstances with a sound rational basis, some localized load reduction for single contingencies, has been removed. This is a

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Commenter	**Yes**	**No**	**Comment**
			very significant change for some utilities and this limited exception should be maintained. Footnote (b) was worked on extensive and achieved industry consensus at one time defining the maximum amount of load that could be shed at 100 MW. Footnote (c) which permits load shedding and curtailment of firm transfers has been removed from C1, C2 and most of C3. This is a very significant increase in required performance level that is not justified. 5. It is not clear what is meant by the phrase "Equipment Ratings" found in the performance requirements of Table 1. Utilities have different equipment ratings such as normal, long term, short term and emergency ratings. It is not clear that these type of ratings will be permitted in the proposed standard. 6. Several new Category D "extreme events" have been added which greatly expand the scope and complexity of Category D studies. These are (1) any two unrelated single element outages and (3) wide area events a. through h. These represent a major increase in the scope of Category D studies and probably a doubling of required stability studies. Analysis of Relay Protection Failures: 7. The fault with protection element failures have been substantially changed to eliminate analysis of relay failure contingencies. The philosophy contained in the existing standards is that faults with a protection failure should be evaluated whether that failure is a circuit breaker, relay or CT; the proposed standard does not require the analysis of any protection failure. This draft of the TPL standard ignores studies required for analysis of relay protection failures. There is a widespread misconception that studying breaker failure scenarios covers for relay protection failures. This is a false assumption. Typical delayed clearing for a stuck breaker is in the order of 8 to 20 cycles. This is accomplished by the local relay system sensing the stuck breaker and tripping the adjacent elements. However in the case of a protective relay failure the fault must usually be cleared remotely by tripping all lines connected to the station. Typical delays for a relay failure can easily be greater than 30 cycles. Where as breaker failure action just trips a couple of adjoining elements and leaves the rest of the station intact. A typical example of this difference is to assume a bus fault. For breaker failure, all bus breakers except the stuck one would trip. The breaker failure relay scheme then would time out and trip the adjoining breaker and the remote end of the adjoining line would trip. This could all happen in less than 20 cycles. Now consider a bus fault with the differential relay failed. The local relays don't sense the fault because they have failed, nor does the local breaker failure scheme activate because no local detection has occurred. The only way to clear this fault is to trip all lines from the remote terminals. This may take 30 cycles or more. With breaker failure, the bus and one line trips in about 20 cycles. With relay failure, all lines trip remotely isolating the substation in about 30 cycles. Both scenarios must be studied with relay failure being the worse case. Generally, different solutions are required to

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Commenter	**Yes**	**No**	**Comment**
			address relay failure verses breaker failure. 300 kV Threshold Performance Level 8. The TPL-001-1 draft sets a threshold of higher performance to facilities above 300 kV than previously established in the existing standard. We do not agree that such a threshold is necessary or warranted. Requirements which are more stringent for these facilities may wrongly influence decisions on project alternatives in favor of facilities with less stringent requirements. Load Modeling Requirements: 9. The proposed TPL Standard contains numerous references to load modeling. These modeling requirements should be addressed in the MOD Standards. The goal of improving and verifying the load model is worthwhile but is not appropriate for the TPL standards. Assessment of load model accuracy is best accomplished through detailed analysis of grid disturbance events. The main difficulties in accomplishing this are (1) grid events that significant reduce transmission voltages throughout a load area are infrequently occurring and (2) the process of Recreating the event through simulation studies is extremely complex and time consuming. While these efforts should be encouraged they should remain a RRO prerogative. * R1.1.1 Use of expected Load mix based on the actual or expected aggregate mix of industrial, commercial, and residential Loads. – This requirement is not justified as the load model may be developed through disturbance analysis rather than load type synthesis by customer class. Some LSE's may have great difficulties in creating load forecasts based on customer class. Load forecasting requirements are adequately addressed in the existing MOD standards and do not belong in the proposed TPL standard. * R1.2. Load models with supporting rationale that include power factor data that may be based on historical System performance, validated by measurement during stressed System conditions, or documented Transmission planning area requirements. This requirement is not appropriate for the TPL standards. 10. * R2.4.1. System peak Load for one of the five years. For peak System Load levels, the Load model shall include the dynamic effects of induction motor Loads. Prescribing specific types of load models in this standard is not appropriate because system topology and load make up may be unique from area to area. 11. Short Circuit Requirements: The new TPL standard also contains numerous references to short circuit analysis, which are new requirements that expand the TPL standards, but without specific testing or performance criteria. These performance criteria are better suited in the FAC

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Commenter	**Yes**	**No**	**Comment**
			Standards since evidence that short circuit studies have been performed is currently required in the existing FAC-002-0 Standard. Since the primary concern is the appropriate sizing of equipment and the prevention of equipment damage as opposed to overall grid reliability, we do not see the need for a set of requirements within the proposed TPL standard for short circuit studies. 12. Table 2 Angular Stability Notes: The requirement of generation loss not exceeding BA spinning reserve requirement (1.a.ii.) is an unjustified increase in required performance level from the existing TPL Standard which require the grid response to be stable and within applicable ratings. The portion of the notes requiring generator out-of-step protection are inappropriate and unwarranted. First, the simulation result may show the generator being tripped by backup distance or loss of field protection which may be acceptable to the generator owner. Second, the requirement for impedance swings not causing other transmission elements to trip is inappropriate and in conflict with manufacturer recommendations and prevailing practice for generator out of step protection. Most generator out of step relays are set to trip on the "way out" so as to limit phase angle difference across the opening contacts. With this practice, one can not prevent transmission line tripping due to zone 1 pickup without installing out of step blocking should the swing impedance passes through zone 1 relay. Out of step blocking of zone 1 relays is a bad idea as it opens the door to prolonged asynchronous connection of generators. 13. Circuit Breaker Contingencies: The proposed TPL standard separates circuit breaker related contingencies based on the intended use of the circuit breaker. If the circuit breaker is used to connect busses together (i.e. bus tie breaker) a lower level of performance is required than for other uses and configurations. The existing TPL standards have the contingency events and required level of performance appropriately ordered based on the probability of occurrence. We are not aware of different failure rates for bus ties breakers as opposed to the general circuit breaker population. The proposed standard requires an unjustified higher level of performance for non bus tie breakers and would encourage the use of low cost switching station arrangements such as single breaker/single bus which are less reliable. 14. Need to clarify the performance requirements that apply to sensitivity studies. These requirements should not be the same. 15. A.3. - Suggest replacing the word "probable" with "credible" for consistency with the white paper from the Operating Limit Definitions Task Force. 16. R2.1 - It is not clear how the requirement to address all 5 years can be accomplished when the annual studies do not require all 5 years to be studied. Is the planner expected to study the

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Commenter	**Yes**	**No**	**Comment**
			other years also, but that the required set of cases does not link to each of the 5 years? 17. R2.2.1 - This requirement creates compliance concerns. Therefore, it is suggested that the SDT clarify that the Long Term Assessment is not required beyond 10 years. 18. R2.7.3 - The term "proposed" may not be a good choice here ... especially since that's not a term used in other reliability assessments .... should another term be chosen or perhaps this definition could be matched up with work being done now on classification of resources for RAS. Steady State Performance Table: 19. P1 - If the transmission line outaged is the facility defined by contract as being the only contract path for the firm transfer, then the firm transfer will be interrupted. P1 should be clarified that this is acceptable. 20. P3 - Are these elements meant to be combined into a multiple contingency or considered separately (since they are listed with commas)? Or is this meant to be one of the 3 elements listed first AND the stuck breaker? Not clear the way this is worded. Or maybe the structure needs to be different in the sentence (like bullets for the first 3 that would make the "and" stick out more). 21. NERC Standards TPL 001-0 through TPL 004-0 are approved standards that only required modifications pursuant to FERC Order 693. In this proposed draft standard TPL 001-1 the Standard Drafting Team (SDT) has far exceeded the recommendations suggested by FERC in that Order. The proposed draft standard is a large change in the magnitude of the performance requirements from the exiting TPL Standards. The SDT needs to consider how this proposed standard will be implemented in this new mandatory compliance environment and ensure that reasonable compliance measures can be developed from the proposed standard.

Response: 1. The SDT recognizes that it has it has raised the bar on performance in some areas. The SDT realizes that this will have an impact and is working on an Implementation Plan that will address some of the concerns. This is a performance based reliability standard and does not and should not consider economics. FERC Order 693 clearly states the FERC position on Non-Consequential Load loss. The SDT has made numerous changes to the tables in an attempt to provide further clarity as to what needs to be done to achieve performance.
2. An Initial Conditions column has been added to the tables.
3. The SDT studied available data and practices and determined that these Contingencies do belong in the single Contingency performance group.
4. Local Load pockets are recognized as a problem and the SDT will address them in a future revision.
5. Equipment Ratings is a defined term in the NERC Glossary.
6. The SDT was responding to FERC Order 693 in the details for Extreme Events.

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Commenter	**Yes**	**No**	**Comment**
7. The SDT is still working on the Protection System elements of the standard and will provide more detail in a future revision. 8. The SDT feels that 300 kV and above represents the backbone of the BES and as such warrants more stringent criteria. 9. The SDT feels that the current MOD standards do not cover all of the modeling requirements for a planner. Therefore, the specific areas found lacking are described in the TPL standard. Once the MOD standards are revised appropriately, these requirements can be deleted from TPL. The SDT has re-written these requirements and they are now numbered Requirement R9 through R13. 10. The SDT feels that the Load model used in the study should represent actual conditions as accurately as possible. It has been shown during the reconstruction of the events of the August 14, 2003 blackout in the Northeast that the Load model was critical. One of the recommendations involved developing better Load models. 11. Short circuit studies are required as part of the Interconnection process. The TPL draft addresses on-going System changes and increases in available fault current due to the additions of circuits and resources, as listed in the Corrective Action Plan. Short circuit studies help determine appropriate equipment sizing and setting of protective relays. Such studies will help provide for a complete Corrective Action Plan, i.e., the installation of a transformer to resolve a System performance deficiency may require the installation of additional circuit breakers. FERC also noted the need to include this analysis to cover such conditions. 12. The note on spinning reserve has been corrected. The existing standard does not define what it means for the grid response to be stable. The SDT has attempted to do that with the footnote you referenced. The SDT believes that an excessive amount of generation pulling out of synchronism and tripping is not a stable grid response. Therefore, we have limited the amount which can trip to the amount of the Contingency reserve of the Balancing Authority. If a generator pulls out of synchronism, the SDT believes there should be some means to trip the generator from the grid. Otherwise, the generator could be damaged and the quality of power on the grid suffers. The footnote has been modified to require that the generator must have "out-of-step protection or some other means to trip the generator". The requirement for impedance swings to not cause the tripping of other Transmission elements is most appropriate. A stable response of the grid would not include losing additional Transmission elements. Out of step blocking on lines is not allowed as a solution. The requirement is for the impedance swing not to pass through relay characteristics which would result in tripping Transmission elements. This requires the system to be improved so that the impedance swings do not go out on the Transmission System. 13. Based on the available outage data, the SDT has decided that bus tie breakers are less likely to be exposed to stuck breaker opportunities 14. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirements R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirements R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own System. The sensitivity studies do not in themselves establish the need for a plan, only the areas of the System the analysis is needed. **R2.1.3.** For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.1.4**. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.			

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Commenter	**Yes**	**No**	**Comment**
R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. 15. The SDT feels that 'probable' is a better choice of words here and the majority of commenters have supported the SDT decision on how the purpose is stated 16. The SDT believes that a planner will be able to aggregate current and past studies in a portfolio or archive that will fulfill the requirement. 17. The SDT believes that the requirement as written is clear that studies longer than 10 years are only required if the known lead time of critical projects is longer than 10 years. The standard as written does not mandate a study longer than 10 years out but recognizes that a 15 year out study conducted to adress anticipated long lead time projects can be used to fufill the requirement of "Long-Term Planning Horizon". Paragraph 1692 of order 693 "directs the ERO to consider integrating Reliability Standards TPL-001-0 through TPL-004-0 into a single Reliability Standard through the Reliability Standards development process". In addition this order, in conjuction with 890, enumerates attributes of planning standards that the FERC feels should be incorporated into the consolidated standard. SDT believes that the first draft of the standard is consistent with orders 693 and 890 without being unduly burdensome. The SDT is cognizant that reasonal compliance measures and an achievable implemetation plan need to be developed as part of the standard development process. 18. The indicated language has been deleted from the second revision. 19. P1 - If service to Load by contract can be interrupted for defined conditions, then the SDT does not view this as firm. 20. The SDT has re-formatted the tables to clear up any confusion on this item. 21. The SDT followed the suggestion of FERC in Order 693 to consolidate the 4 standards into 1 if possible.			
Georgia Transm.	☑		R1.4: The planning assessment is to identify the needs of the BES. A spare equipment strategy should support the needs of the BES, not vice versa. Long-term outages need to be defined. R2.2.1 Not clear on the purpose of this requirement. Is the concern that the Planner perform a ten year analysis even when the in - service years are outside of the current ten-year planning horizon? The extension period should be defined. R3.2 Current models do not have the capability of performing the assessments necessary to meet this requirement.
Response: 1. The SDT has revised this requirement based on industry comments to clarify intent and to be responsive to FERC Order 693, paragraph 1725. 2. The SDT believes that the requirement as written is clear that studies longer than 10 years are only required if the known lead time of critical projects is longer than 10 years. The standard as written does not mandate a study longer than 10 years out but recognizes that a 15 year out study conducted to adress anticipated long lead time projects can be used to fufill the requirement of "Long-Term Planning Horizon".			

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Commenter	**Yes**	**No**	**Comment**
3. The SDT feels strongly that the assessment should be based on study of the System as it is expected to perform. The requirement that "Contingency analyses shall simulate the removal of all elements including those that System protection is expected to disconnect for each Contingency without operator intervention" is consistent with that philosophy. A Contingency modeling methodology that reflects how real Systems would operate will need to be constructed if it doesn't already exist.			
IESO	☑		(1) Pertaining to Q1 to Q11: we do not see the need to define this many terms for this standard. Many of the terms are easily understood and have been used in transmission planning for years that the majority of planners in the industry know what they mean. For example: base case, extreme contingencies (these are in fact listed in the table), planning assessment, planning event, etc. Furthermore, the terms plant stability and system stability are also well understood to mean "machine synchronism" and "system oscillation/damping". Among the proposed definitions, only the following terms need to be defined to add clarity: a. Consequential (and non-consequential) loss of load b. Long-term vs near-term (suggest to change it to short-term) planning horizons (2) We do not see the need to use the term RAS (Remedial Action Scheme). The term SPS (Special Protection System) is common used in the industry to generally mean any protection scheme that is designed to initiate actions to control flows, voltage, generation runback or high speed rejection, switching of shunt devices, cross-tripping in response to some pre-determined parameters such as loss of a circuit or some threshold voltage or line flow level. Introducing the term RAS would be confusing to suggest that they do not equate to or are not a part of the SPS. (3) We interpret the requirement stipulated in R1.1.1 is intended to enable more accurate simulations of load response - both in steady state and dynamic analyses. However, we do not support having this level of granularity (eg: industrial, commercial, residential etc.) stipulated in a planning assessment standard as similar requirements already exist in several MOD standards that deal with forecasted load and modeling. We suggest the mix of load detailed requirements be addressed in the latter set of standards. Similarly, R1.2 is best addressed in the MOD standards. Specific to R1.2, we do not agree with the requirement to provide supporting rationale that include power factor data based on historical System performance, validated by measurement during stressed System conditions, or documented Transmission planning area requirements. Load forecast data already provides projected mix of real and reactive demands and type of load. (4) R1.4 and R2.1.3 require outages be considered in the planning process. We suggest the SDT clearly stipulate that only known planned long term outages (with a minimum duration to be defined) need to be considered. This suggests is made on the basis that:

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Commenter	**Yes**	**No**	**Comment**
			- Only known outages should be modeled. The need to model unknown outages would render study scope to be too wide to manage - Only planned outages should be modeled for the same reason. - Only known planned outages > a certain period should be modeled since it would be unrealistic and unmanageable to model and propose planning solutions to system constraints that appear to last less than, say, 2 weeks. As a general practice, many planners apply a 4 week period as the minimum for inclusion in planning assessment. Without narrowing the scope, planning assessment will be an enormous task and difficult to manage.
Response: 1. The SDT deleted the Base Case definition in response to various comments. However, few if any other commenters suggested deleting the other terms proposed in this comment and several suggestions were received from various commenters to include additional definitions. Furthermore, various comments indicated lack of a consensus understanding of the Stability terms, prompting the SDT to retain and clarify the initially proposed definitions. 2. RAS and SPS are interchangeable terms as per the NERC Glossary. 3. The SDT believes that models must reflect the expected Load mix of industrial, commercial and residential Loads to correctly reflect the behavior of the System. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. 4. The SDT intent was for the planner to model known planned outages. Sensitivities may be needed to confirm how much affect the duration of the known outage may have on the assessment. Requirement R1.4 which applies to the whole standard calls for "Known planned outages…"			
ISO/RTO	☑		
Response: Thank you.			
ITC	☑		1. A modeling issue that we would like to see standardized is the modeling of generation resources when the load exceeds or is very near the installed reserve level (low generation reserve margin). This would occur in future years when new resources are unknown or not announced yet. It is a concern of ours because we are an independent transmission company and are not always apprised of new resources. We also have a concern with some models which "assume" where new generation would be located or fake generation has been added to meet the load requirements. This can produce distorted transmission assessments because the generation location assumption is not firm. We would prefer to see generation scaling, or an assumption that the power will be imported or a combination of scaling and imports. Assuming 100% generator availability is also not a good assumption just to balance load and generation. Other modeling issues:

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Commenter	**Yes**	**No**	**Comment**
			2. Should not rely on a single generator being dispatched (redispatched) to solve a problem. 2. Using a single generator for redispatch should not be an acceptable corrective action (i.e. rely on a generator that might not be there or may take an extended period to start up). 3. Sensitivities for both the planning horizons should consider load forecast error and variability. You shouldn't just stick with one assumption, such as a 50/50 probability of occurrence. The system needs to be able to operate to loads exceeding 50/50 probability of occurance. 4. We would also like to see additional requirements be put on "corrective action" solutions to reliability violations resulting from planning assessments. Any corrective action should be restudied to insure that it does not cause other reliability problems for system conditions other than those for which the corrective action is intended to resolve. For example, if redispatch under a transmission outage condition is acceptable, it should not cause any additional reliability violations for the next contingency.
Response: 1. NERC Standards are to specify the requirements, which must be met and not "how" they are met. Whether a single generator can be used in a Corrective Action Plan would depend on whether the resultant Transmission System can meet the other requirements of NERC Reliability Standards. Therefore, when a single generator is used in a Corrective Action Plan, the System must also demonstrate that it can meet System performance requirements for loss of that generator. 2. NERC Standards are to specify the requirements, which must be met and not "how" they are met. Whether a single generator can be used in a Corrective Action Plan would depend on whether the resultant Transmission System can meet the other requirements of NERC Reliability Standards. Therefore, when a single generator is used in a Corrective Action Plan, the System must also demonstrate that it can meet System performance requirements for loss of that generator. If the generator is not yet on line, then additional sensitivity studies should be performed to cover the assumption that it may not be available. 3. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Due to the nature of future analysis, the SDT did not draft specific language to mandate Load growth be a sensitivity analysis for future assessments. Industry feedback is that future assessments already include a variation in projected Load growth. The standard does not preclude any entity from performing studies for any planning horizon that envolve a wide range of sensitivities. The specific requirement to perform re-test has been removed. 4. The SDT believes that as part of obtaining the appropriate corrective action, the solution is tested as part of the study to make sure it meets the performance requirements.			
JEA	☑		In reference to the use of Non-consequential load shedding under single contingency events: I do agree that long term plans should be implemented with the goal to eliminate non-consequential load shedding as a response to this failure mode. However, it may be more beneficial for investing in system improvements to reach this state of robustness where there may be a few years (or seasons) of potential exposure for utilizing non-consequential load shedding. This should be prudent utility practice as long as post-contingency response is executed within the time frame allowed by the

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Commenter	**Yes**	**No**	**Comment**
			facility emergency ratings and load shedding is limited to Transmission Provider's contracted or tarrif loads. For example, adding or upgrading transmission facilities into a load area where future generation additions are planned to be in-service within the short term horizon (mitigating thermal or voltage violations assessed under P1 and P4-1 through P4-4) would not be the best investment for the overall economic benefit of the bulk electric system.
Response: Draft 2 Changes for 300 kV and higher systems regarding N-1-1 conditions: Based on industry feedback the SDT has made changes in proposed Draft 2 requirements related to independent overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. Draft 2 now permits the loss of Non-Consequential Load to meet the Transmission performance requirements for these types of events. Please refer to performance tables Planning Event P6. It is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission for the less probable, but greater risk single Contingency events. Please refer to performance tables Planning Event P2 and note that bus section faults and internal breaker faults (non-Bus Tie) associated with above 300 kV Facilities are held to a higher performance standard than those operated at 300 kV or below.			
KCPL	☑		It is redundant to require provision of modeling data in this Standard. This is covered in Standards MOD 10, 12, 16-25.
Response: The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.			
LUS	☑		The Planning Authority/Transmission Planner should use valid acceptable assessments to plan their systems to operate and supply customer demand and Firm Transmission Service. If the Planning Authority/Transmission Planner determines other methods (such as operational guides) to resolve system overloads for "N-1 Contingency", the operational guides should be limited to only native network facilities that are in direct control and ownership of the Planning Authority/Transmission Planner. Operational guides should be considered only as short term solution to resolve the overloads and shall be used in all studies and approval for transmission service requests. If the operational guide do not completely resolve the overload or restricts access to transmission service, then the Planning Authority/Transmission Planner shall determine facilities to be constructed to resolve the overloaded or restricted facility.
Response: NERC Standards are to specify the requirements, which must be met and not "how" they are met. The draft standard does not preclude the use of operating solutions.			
LADWP	☑		This proposed standard is very tutorial in nature and far too prescriptive for a standard. A standard should be about what are the criteria and measurables, not about how to meet the criteria. This propsoed standard should also recognized that it is just a part of many standards being formulated by NERC, know its boundary as transmission planning standard, and not try to be an all

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Commenter	**Yes**	**No**	**Comment**
			encompassing standard for every facit of the power system. Do what we do best as transmission planner and not try to take over others like marketer, operator, generators, etc.
Response: The goal of the SDT is to provide more information but not be too prescriptive.			
LCRA	☑		1. The NERC PC and OC are currently working on a definiton that defines "adequate levels of reliability". The SDT should take this definition into consideration and ensure it is applied in the proposed NERC Std. revision. Along the same lines, if this has not been done yet, the SDT needs to consider the NERC "Reliability Criteria and Operating Limits Concepts" white paper and incorporate applicable elemetns of that white paper to the propsoed NERC Std. revision accordingly. It would not make sense for these (the propsoed NERC std. and the noted white paper to be inconsistent or at opposite ends in terms of what is expected of a reliability-based planned transmission system). other editorial comments: 2. R1. Delete one of the "each" 3. R1. Should state that data submittals should be "in accordance with regional procedures or process". This will eliminate the region getting data in all sorts of formats. 4. Table 1 - the allowance of loosing "consequential load" should be evaluated based on options to provide temporary emergency back-up support as well as size of load, for example. Structure failures can take an extended period of time to restore and can have significant impacts on a raial load that does not have remote or distribution back-up support. This performance requirment of transmisssion radial-supplied loads should be left to regions or to transmission owners/planners for their own areas based on specific area needs (type and size of load, back-up availbailiyt, etc.). 5. Table 1 - How does NERC define a "transmission circuit"? Does it include a sinlge transmission line as well as a double circuit transmission line? 6. Other than the probability of occurrence, what is the difference between a structure failure of a single circuit and a structure failure on a double circuit configuration? Why is a double circuit not considered a single contingency?
Response: 1. The SDT has reviewed the definition of adequate level of reliability and has included it in its deliberations. The SDT has reviewed the "Reliability Concepts" white paper and find that the document is largely consistent with the current standard as written by the SDT. One notable difference is that the white paper seems to indicate that the Transmission System is designed and operated so that cusomers should only be interrupted that are directly connected to the outaged element for events including Transmission line or transformer faults, breaker or switch failures, or generator trips. (See page 11 of the white paper.) If the SDT were to use this approach then SDT should not allow Non-Consequential Load Loss for P6.1 and P6.3, even though these breakers are below 300 kV.			

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Commenter	**Yes**	**No**	**Comment**
As indicated in the responses to other comments, the SDT has taken the position that the probability of the outage of one breaker is much lower than the probability of a single Transmission line outage. Therefore, the SDT has drafted the standard to permit loss of Non-Consequential firm Load or interruption of firm Transmission service for the loss of a lower voltage breaker. (The SDT does not permit the loss of Non-Consequential firm Load or interruption of firm Transmisssion service for the loss of a breaker above 300 kV.) The majority of the commenters in response to the first posting of the standard agreed with the SDT's approach in this regard. 2. Editorial change was made. 3. The SDT has revised this requirement based on industry comments to specify only that modeling data must be exchanged and allows entities to develop their own formats. It is beyond the scope of the standard to specify the process for data exchange. 4. The standard allows for loss of Consequential Load and does not address restoration requirements. 5. and 6. The Tables treat circuits differently if they share a common tower and they define the maximum length that a double circuit can still be treated as independent circuits as one mile.			
Manitoba Hydro	☑		1. MH would prefer that many of the categories in the existing Table 1 be retained. The SDT has resort the contingency buckets with no explanation as to how this was done. can the SDT provide statistical outage date to justify the changes. MH is not convinced the SDT has addressed the few confusioning issues in Table 1. 2. R1: MH does not believe R1 is required in this standard. The modelling standards should cover the requirement of the data owners to provide data to the PC. Further this data needs to be provided to the TP as well. 3. R1.4: requires planned outage data to be provided to planners. I do not believe this is a requirement for planning. It is not economic to add facilities to accommodate future planned outages. Secondly, the Table 1 multiple contingencies already mandate that planners consider the impacts of an outage with system adjustment followed by testing for the next contingency. 4. R1.5: requires the PC to define "planned facilities" which should be included in the model. This will lead to inconsistency in what is modelled, as experience has shown that there will be a wide range of assumptions in the definition. This standard should offer a definition for stakeholder debate. The SDT should clarify what is intended by including Protection System Equipment and control devices. 5. R2.1: It is not necessary to assess all five years of the near term planning horizon – year one, three and five will be more than sufficient. What is the reliability benefit driving the SDT to mandate each of the first five years be assessed? 6. R2.1.2 and R2.4.2 -- It is important to assess off peak loads with high simultaneous transfers as this is the period where extensive economic interchange occurs, and transient stability issues arise as less uneconomic peak units are off, leaving the load to be supplied by remote generation with reduced local reactive supply, voltage and damping control.

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Commenter	**Yes**	**No**	**Comment**
			7. R2.2: The long term assessment should also include an off peak case with simultaneous transfers to provide some indication if the system performance is expected to degrade. 8. R2.3: The short circuit study is a design issue that would more appropriately covered by a FAC standard. MH recommends it be removed from the Planning standard. 9. R2.6.1: Why would a past study be invalidated if there is a change in market structure? It would seem that the operation of any market would have to respect reliability criteria. 10. R.3.3.2.2: Curtailment of firm transfers is allowed as a system adjustment in the existing standard. This ability must be retained in the new standard. Curtailment of a firm transaction is not equivalent to curtailment of load, but is more comparable to runback/tripping of generators. Both are events that can be backed up by contingency reserves and do not result in consequential load loss. Disallowing firm transfer curtailment will result in numerous violations of the performance requirements and result in a requirement to build millions of dollars of transmission. MH can not accept a standard which mandates that firm transfers can not be curtialed following a contingency. 11. R3.3.3: If rationale for the contingencies selected for evaluation is available then this rationale will state why the selected contingencies are expected to be the most severe. The requirement does not need to state "and shall include an explanation of why the remaining Contingencies would produce less severe System resuts".This is redundant. 12. R3.4 and R4.5.2: Evaluating a change designed to mitigate the consequences of an exteme event can require significant work. Since there is no requirement to implement corrective plans for Extreme Events, what is the purpose of this evaluation? 13. R3.5: Generator tripping should be added in addition to runback. Generator tripping is used extensively in regions where remote generation is delivered via long transmission. 14. R6: Requires distribution of results and “coordinating analysis of these results through an open and transparent process”. Can the SDT clarify what the intent is? As written, it implies the PC/TP just shares assessment results with neighbours. There should be a requirement to conduct joint assessments on inter-regional transfer capability. The assessments should also be provided to the Regional Entities/NERC. Table 1 -Steady State Performance

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Commenter	**Yes**	**No**	**Comment**
			15. MH requests the SDT to provide rationale for how the planning events where resorted from the existing Table 1 Categories to the proposed Planned events. 16. Performance Requirements: As this is a steady state table, how does one assess if voltage instability, cascading outages or islanding occurs? "Simulate Normal Clearing unless otherwise specified." should be deleted from this Steady State Performance table. 17. This table should have an Initial Condition column as well as an Event column, as in Table 2. The wording of event descriptions in Table 1 should follow the wording of similar event descriptions in Table 2. 18. Event: What is a non-bus tie breaker? Is this any breaker that is not a bus tie breaker? 19. Interruption of Firm Transfer Allowed: Interruption of firm transfer should be allowed following a single contingency – this is a change from the existing standard where system adjustment after a Cat B event could include reduction of firm transfer. Similar to generation tripping/runback, the loss of a firm transaction does not result in Consequential load loss as it is backed up by contingency reserve. 20. P6-2: What is the justification for classifing a bipolar DC line loss as a single contingency? The existing standard classifies this event as a Cat C multiple contingency event. 21. P6-3: Why is a breaker internal fault classified as a single contingency? One would assume such a fault would be cleared by backup protection resulting in the loss of multiple elements. 22. P9-1: Is there any justification for the selection of one mile? Would the fact that there is line shielding be justification for increasing this length? A more reasonable selection could be 5% of the length of the longer of the two circuits. 23. P9-2: A monopolar DC line loss may be covered in P4-2 (and no non-consequential load loss is allowed). Does loss of a monopolar DC line refer to loss of a single pole of a bipolar line or a bipolar dc line? Can the PC/TP choose between the loss of a monopolar DC line and the loss of a bipolar DC line? 24. P9-3, P9-4 and P9-5: When the DC line loss is bipolar, the event should be moved to the extreme event category. Does loss of a monopolar DC line refer to loss of a single pole of a bipolar line or a bipolar dc line? Can the PC/TP choose between the loss of a monopolar DC line and the loss of a bipolar DC line?

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Commenter	**Yes**	**No**	**Comment**
			25. Exteme Events Evaluation Requirements 3: This should be removed as this is the Steady State Performance table. 26. Extreme Event Descriptions: How did the SDT determine what events should be classified as Extreme Events? Was statistical data analyzed? 27. Extreme Event 1: In the existing TPL standards, the simultaneous loss of two elements was considered a Cat C multiple element event. What is the SDT rational for the change? 28. Extreme Event 2c: Why is the loss of a single large load an Extreme Event? 29. Extreme Event 3f: This is a repeat of Extreme Event 3d. 30. Extreme Event 3g: What is the rationale for distinguishing between old vs. new design for the loss of multiple lines due to icing? Is the SDT implying that new lines must be desined to prevent multiple line loss due to icing? Table 2 - Stability Performance Table 31. Performance Requirements: The MRO adds 1/2 to 1 cycle to the Normal Clearing time during simluations as an additional safety margin. The SDT should consider enforcing this practice. 32. Event: What is a non-bus tie breaker? Is this any breaker that is not a bus tie breaker? 33. P1: There should be a P1-4 event for a shunt device (ie. "4. A shunt device (including FACTS devices)"). 34. P6-2: What is the justification for classifing a bipolar DC line loss as a single contingency? The existing standard classifies this event as a Cat C multiple contingency event. 35. P6-3: Why is a breaker internal fault classified as a single contingency? One would assume such a fault would be cleared by backup protection resulting in the loss of multiple elements. 36. P9-1: Is there any justification for the selection of one mile? Would the fact that there is line shielding be justification for increasing this length? A more reasonable selection could be 5% of the length of the longer of the two circuits. 37. P9-3: This contingency should be classified as an Extreme Event since statistically, the outage

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Commenter	**Yes**	**No**	**Comment**
			duration of a dc circuit (assume you mean a bipole) is less than 2 hours for MH bipoles, so the probability of a second outage is very low. . 38. P9-6: Isn't this the same as P1-3? If the outaged tranformer is replaced by a spare transformer, this restores the system to a normal state prior to the event ("Apply a P1.3 Contingency."). What is the point? 39. Note 1.a.i.: Planning Event P3.2 does not exist. 40. Note 1.a.ii: This definition of angular stability should be deleted and the definition in Note 1.a.i. should apply to all Planning Events. The system should not be considered to be angular stable when generators are pulling out of synchronism. 41. Note 1.a.iii.: This standard should define a minimum damping factor and allow the PC/TP to have a more restrictive damping requirement if they choose to.

Response: 1. The SDT looked at available historical, statistical data and used that data for guidance in re-ordering the table.
2. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.
3. Planned outages that are long-term need to be provided to the planners in order for them to appropriately represent the topology of the system. This does not imply that one must build in order to accommodate a planned outage and to be responsive to FERC Order 693, paragraph 1725.
4. The referenced verbiage has been deleted from the revised standard.
5. Assessement does not mean that studies have to be run for each of the years, only for Year One or two and five for peak load and for any one of the 5 years for off-peak load. If no changes occurred between the years the assessment will be very simple. However, if the required Corrective Action Plan is delayed, or there is a long planned or forced outage to a major generation or Transmision Facility, or it is believed that some of the sensitivities may have to be addressed, etc., there may be a need to assess each of the years.
6. Agree if that is the case for your System. Each entity is responsible for demonstrating the appropriateness of the assumptions used in the current studies. To some entities this case may be their base case and others it may be a sensitivity case.
7. Requirement R2.2 requires as a minimum a peak load study for one of the 5 years in the Long-term horizon. This does not preclude any entity from running more studies, including for off-peak load conditions.
8. Actions listed in the Corrective Action Plan will more often than not result in higher fault, requiring the installation of even more additional equipment to accommodate the higher fault duty. This requirements ensures that the "entire" effect of the corrective action is captured in the plan. In addition by considering the "entire" effect of a proposed corrective action the entity may find it more economically to propose another action. Therefore, the SDT feels that this should be part of the Planning Assesment.
9. R2.6.1 - The SDT has revised R2.6.1 to delete the reference to market structure.

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Commenter	**Yes**	**No**	**Comment**
R2.6.1. For steady state, short circuit, or System Stability analysis: ~~if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market structure changes~~ the study shall be five calendar years old or less. 10. Curtailment of firm transfers is allowed for some specific Contingencies in compliance with FERC Order 693. 11. R3.3.3 - The SDT recognizes some may consider these words redundant. However, it should be noted that many commenters have asked for the SDT to add words to make other requirements perfectly clear. Since these words do not hurt the requirement and may help some to better understand the requirement, the SDT has not deleted these words. 12. As noted in Requirements R3.4 and R5.7.6, there is an expectation that facilities are designed to reduce or mitigate the likelihood of Extreme Event situations that expose the System to cascading events. 13. This has been added. **R3.5** Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met: 14. R6 - By meeting this requirement for "coordinating analysis of these results through an open and transparent process", the SDT meant a stakeholder process that was set up to meet the requirements of FERC Order No. 890 with regard to an Attachment K filing of a Transmission Provider's Transmission Planning Process. The SDT has made a change to clarify this requirement (see R8 in draft 2). **R8**. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~affected entities~~ neighboring systems, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890. 15. The SDT reviewed each planning event considering the likelihood of the event, the potential outcome of the event and the directives from FERC concerning loss of Non-Consequential Load and determined the expected performance for each event. Then, the SDT re-ordered the events and grouped them by the type of outage and the expected outcomes. Performance requirements: 16. The SDT has reviewed and revised Tables 1 & 2. In the steady state time frame, voltage instability can occur typically during high power transfer and/or peak demand periods. Voltage instability can be assessed using a long-term Stability program. However, it can also be assessed using a power flow program that simulates governor action. There are a number of IEEE papers (e.g., G. Morison, B. Gao, and P. Kundur, "Voltage stability analysis using static and dynamic approaches," IEEE Transactions on Power Systems, vol. 8, no. 3, pp. 1159 – 1171, August 1993) that can provide suggestions on the methodology. Cascading outages and uncontrolled islanding can also occur, for example, when the Transmission Facilities load beyond the corresponding relay trip settings. This could cause uncontrolled tripping of Transmission Facilities beyond those required to clear the fault. Even though these events are rare, the Transmission Planner should be aware of their possibility when performing studies. The SDT did not change Table 1 to remove "Normal Clearing" because depending on the bus configuration, delayed clearing would result in removing more Facilities from service than normal clearing in the steady state post-Contingency period. 17. The SDT has revised Tables 1 & 2 accordingly.			

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Commenter	**Yes**	**No**	**Comment**
18. The SDT has accordingly proposed a definition for Bus-tie Breaker. **Bus-tie Breaker:** A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.) 19. The SDT has reviewed and revised Tables 1 & 2. "Firm Transfer" has been replaced with "Firm Transmission Service". 20. P6.2 - The SDT has reviewed and revised Tables 1 & 2. 21. P6.3 - It is true that multiple elements are impacted, but it is still a single Contingency event. 22. P9.1 - The one mile allows for some measurable physical constraints to building separate lines in all locations, but limits the exposure to a fixed length, which is universally applicable. A percentage doesn't provide the same limitation and consistency. 23. It refers to the loss of a monopolar DC line or one pole of a bipolar DC line. 24. P9.3, P9.4, and P9.5 - The SDT feels that the loss of a bipolar DC line is a multiple Contingency Planning Event. The tables have been revised to provide clarity. 25. Extreme Events 3 - The SDT has revised Extreme Events in Tables 1 & 2 and to comply with FERC Order 693. 26. Extreme Event Descriptions - The analysis of Extreme Events is an effort to assess potential impact of plausible but unlikely events. The selection of events is deterministic, not probabilistic. The SDT also notes that in Order No. 693, paragraph 1834, the FERC gave examples of Extreme Events that the FERC would expect to see in the revised standard. These examples are consistent with the items that the SDT included in the standard as examples of Extreme Events to be considered. For example, paragraph 1834 includes "(1) loss of a large gas pipeline into a region or multiple regions that have significant gas-fired Generation; (2) a successful cyber attack; (3) regulation that restricts or eliminates the use of a river or lake or other body of water as the cooling source for generation; (4) tornado or wildfire, or other event and (5) the loss of older transmission lines, which may not be constructed to meet an entity's present radial ice loading requirements…" In paragraph 1834, the FERC directs NERC to expand the list of events with examples such as those described in the paragraph. 27. Extreme Event 1 - In the existing Table 1 the non-simultaneous loss of two unrelated elements with System adjustment in between is in Category C3, the simultaneous loss of two circuits on a common structure is in Category C5. In the proposed standard Table 1, Extreme Event 1 covers loss of two unrelated elements with no System adjustment in between. If the reference is to a single Contingency, then the focus should be on the Contingency rather than the number of elements affected by the Contingency. 28. Extreme Event 2c - Event 2c is the loss of a station. Event 2e is the loss of Load. The loss of a single large Load or major Load center assumes that multiple events need to occur to realize this level of impact. 29. Extreme Event 3f - The SDT has reviewed and revised Tables 1 & 2. 30. Extreme Event 3g - The issue reflects the exposure during a period where an entity is taking older lines out of service to rebuild them to newer design standards. 31. The SDT has reviewed this requirement and has determined that at this time this is not appropriate for a North American standard. 32. The SDT has provided a definition of a Bus-tie Breaker. 33. Shunt devices have been added to the table. 34. This is now listed as a multiple Contingency (P7). 35. The table has been re-done to emphasize that you need to study events and not just single pieces of equipment. 36. One mile was based on the SDT's review and understanding of existing conditions. 37. The SDT has revised the table (P6) to make it clear that this is for a single pole.			

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Commenter	**Yes**	**No**	**Comment**
38. The language referring to a spare transformer has been deleted form the table. 39. Editorial error has been corrected. 40. The SDT has reviewed the definition of angular Stability and feels that it is appropriate. 41. The SDT has reviewed this requirement and has determined that at this time this is not appropriate for a North American standard.			
MEAG Power	☑		To the extent that the new standard is more stringent, additional time should be allowed to implement the corrective action plan, with fines suspended until reasonable time has passed to allow implementation. I.E., If the solution is 20 miles of new 500 kV T/L, then allowing fines to the short-term horizon is unreasonable – building 20 miles of 500 kV T/L is not possible in 2 or 3 years.
Response: The SDT understands that there are extended transitionary issues associated with responsible entities becoming compliant with the new standard. The SDT plans to draft an extended implementation plan to accommodate such issues. The plan will be provided for the third posting of the standard.			
MISO	☑		The Midwest ISO appreciates the opportunity to offer the following recommendations: 1. Requirements for providing modeling data in R1. are redundant with the exising requirements of MOD-010-0, MOD-012-0, and MOD-016-0 through MOD-025-1. Adding these requirements to the TPL Standard is unnecessary and may create confusion. 2. The Standard does not address the return of direct (consequential) load loss following a contingent event. How long of an outage event acceptable?
Response: 1. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. 2. The proposed TPL-001-1 standard does not place a limit on the amount of Consequential Load Loss or the outage duration. In Requirement R3.3.2.1 the Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment. The SDT believes it is first necessary to obtain data on these items to allow comparison of similar sized Systems and it drives transparancey to expected outcomes.			
MRO	☑		The MRO commends the SDT on the difficult task of rewriting some of the most important NERC standards: the TPL standards. The MRO has a number of comments and suggestions. 1. Load modeling data in R1.1 and R1.2 do not belong in the TPL standards. It should be provided for in the MOD standards which provide the numerous load model data requirements. At a minimum, R1.2 should be revised to only require documentation of stressed system conditions. It is unnecessary and micro management to provide for "measurement during stressed System conditions". Further, it is unusual standards drafting to provide for a measurement of load in an assessment standard. 2. R1.4 should be revised to separate "known planned outages" from the rest of the requirement in

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Commenter	**Yes**	**No**	**Comment**
			separate sentences. This is because the reference to spare equipment outages does not have any bearing on the "known planned outages" requirement. Further the consideration of spare equipment strategy is not explained enough to understand what is required here. Further it is not clear as to what equipment must have consideration of spare equipment. The MRO recommends that R1.4 be rewritten as follows: "Known planned outages. Long-term forced outages for transformers with low-side voltages of 100 kV and above and generator step-up transformers should be identified where lack of spare transformers could result in outages of the transformers over the annual peak demand hour." 3. It is unreasonable for R1.5 to provide that planned facilities that are included in System Assessments include circuit breakers, and protection system equipment. These two items should be dropped from R1.5 since these are engineering details that are typically not available at the time that the System Assessment is made. 4. R.2.1.1 - The system peak load study requirements for studies for two of the near-term period seems to be excessive. The MRO recommends that only one year in the near-term period be required. 5. R2.6 should be deleted. The MRO believes that R2.1 and R2.4 are sufficient in describing when current studies are required. R2.6 will result in unnecessary restudy of the system. Alternatively, if R2.6 is kept, then the requirement should be a performance requirement, that as long as material changes do not require restudy then restudy is not required. The Transmission Planner and Planning Coordinator could be required to document why restudy is not required. Material changes should be expanded to refer to only those "significant" transmission line additions or generator additions. 6. R2.71 should be revised to delete "including the duration of interim Operating Procedures" or else the SDT should explain what is meant by this with additional information about what interim Operating Procedures are. 7. R2.7.1.1. should be revised to delete the requirement for project initiation date. This information is not typically available at the time of performing a System Assessment since this is detailed engineering information not pertinent to planning. 8. R2.7.5 should be deleted. The MRO believes the such detailed review of the status of the installation of projects to be beyond the scope of the TPL standard. Since NERC has no authority to require the installation of facilities, how does NERC have authority to require a review of the status of such facilities?

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Commenter	**Yes**	**No**	**Comment**
			9. R3.2.1 and R3.2.2 seem unnecessary details that are micro-management of the planning process. Both requirements could be met by the transmission planner and planning coordinator with general statements of little value. Also, relay loadability is included in facility ratings and does not need to be covered in TPL. 10. In Table 1, "a shunt device (including FACTS devices)" is too general. Arresters and potential devices for metering and relaying are shunt devices. This should be changed to a specific listing such as: transmission capacitors (100 kV and above), transmission reactors (100 kV and above), …" and whatever other devices that the SDT intends to be included here. 11. In Table 1, Single pole of DC line should be moved to P1. 12. In both tables, "monopolar DC line" should be replaced with a "single pole of a DC line". 13. The revised tables are confusing in descriptions of various outages particularly since the interconnected transmission system has been planned for the past decade using the previous Table I. The SDT should limit its changes to Table I to a limited number of changes that have been known to cause issues in the past rather than raising the bar in a number of cases. 14. The Extreme Event descriptions in Table 1 should be revised to provide definitions of local area and wide area. 3 d. (3f.) and 3 c. (3 e.) are duplicates and should be combined. Wide area events as listed are such unusual events, which are difficult to analyze or model. The requirement should provide that the number of these wide area events to be studied is limited to a minimum of one. 15. The MRO does not believe that contingency reserve is necessarily synonymous with spinning reserve. The SDT should clarify note ii to Table 2. 16. The SDT should clarify the wording in the tables to better explain the events which are either above or below 300 kV. For example, in P5 change 1. IS IT "A Transmission circuit followed by a System adjustment above 300 kV followed by the loss of another Transmission circuit above 300 kV." or is it "A Transmission circuit followed by another Transmission circuit resulting in impacts on 300 kV facilities"? P5 3. should be revised to say, "A transformer with a low side voltage rating above 300 kV followed by a System adjustment followed by the loss of another transformer with low side voltage rating above 300 kV." or is it "A transformer followed by the loss of another transformer resulting in impacts on 300 kV facilities."

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Commenter	**Yes**	**No**	**Comment**
			17. R2.1.3 - R2.1.3 reguires sensitivity studies that involve many potential scenarios that would be difficult to create in a Planning Assessment. Planners can not model the unknown and to assume the unknown may be a difficult task to complete. Instead of "shall be run and", the language should be "shall be considered based on current knowledge of system including" 18. Extreme Events description for common right-of-way should be defined. Does this include line crossing points? Suggest exclusion for corridors one mile or less similar to P9.1. 19. The language description of the even should be substantially the same between Table 1 and Table 2. Table 2 format is a bit cleaner with initial condition and event separated. Table 1 should follow this format. 20. The loss of a shunt device (e.g. SVC) should be added to Table 2 (P1.4). 21. Note 1ai. to Table 2 refers to event P3.2 which doesn't exist in the Table 2. 22. Note 1aii. to Table 2 allows generating units to "cascade trip" for certain events that were this would not be allowed in the existing TPL standards. The MRO recommends that the more of the events be listed in 1ai. so as to at least maintain reliability. 23. Note 1aiii talks about acceptable damping. NERC should have a standard requiring development and documentation of damping criteria by the planning coordinator. 24. P9 should be changed from referring to a monopolar or bipolar dc line to a single pole of a DC line. THE FOLLOWING ARE RON MAZUR'S COMMENTS. 25. The MRO does not believe R1 is required in this standard. The modelling standards should cover the requirement of the data owners to provide data to the PC. Further this data needs to be provided to the TP as well. 26. R1.4: requires planned outage data to be provided to planners. The MRO does not believe this is a requirement for planning. It is not economic to add facilities to accommodate future planned outages. Secondly, the Table 1 multiple contingencies already mandate that planners consider the

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Commenter	**Yes**	**No**	**Comment**
			impacts of an outage with system adjustment followed by testing for the next contingency. 27. R1.5: requires the PC to define "planned facilities" which should be included in the model. This will lead to inconsistency what is modelled, as experience has shown that there will be a wide range of assumptions in the definition. This standard should offer a definition for stakeholder debate. The SDT should clarify what is intended by including Protection System Equipment and control devices. 28. R2: The SDT should define the elements of an acceptable assessment in more detail. 29. The MRO recommends that the need to assess Plant Stability be removed from this standard. The generator connection standard and the proforma tariff interconnection process ensure the plant stability meets performance requirements. The System Assessment provides an overall assessment of the integrated system performance, which includes the impact of the plant. This requirement appears to be redundant. 30. R2.1: It is important to assess off peak loads with high simultaneous transfers as this is the period where extensive economic interchange occurs, and transient stability issues arise as less uneconomic peak units are off, leaving the load to be supplied by remote generation with reduced local reactive supply, voltage and damping control. 31. R2.1.3: The requirement for sensitivity cases is excellent. The SDT should consider: R.2.1.3.1: separate real MW load variation and Power Factor variation R.2.1.3.2: clarify the intent of modification of expected transfers. Does this apply to firm transfers only, or does it also encompass non-firm transfers. ..R.2.1.3.4: Instead of a sensitivity, the reactive devices should be included in the Table 1 &2 contingencies. If the intent is to investigate robustness to voltage instability, the SDT should clarify. R.2.1.3.5: Generation additions/retirements should be removed as this is covered, or should be, by the interconnection standards. The SDT should clarify.the need for generation additions/retirement. 32. R2.2: The long term assessment should also include an off peak case with simultaneous transfers to provide some indication if the system performance is expected to degrade. 33. R2.3: The short circuit study is not a reliability assessment issue but a design issue that is more appropriately covered by a Facility Rating Standard. The time required to conduct and report on this analysis in an assessment is better spent on more contingency or sensitivity analysis. 34..R2.4: Similar to the comment on R2.1,. It is important to assess off peak loads with high simultaneous transfers as this is the period where extensive economic interchange occurs, and

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Commenter	**Yes**	**No**	**Comment**
			transient stability issues arise as less uneconomic peak units are off, leaving the load to be supplied by remote generation with reduced local reactive supply, voltage and damping control. 35. R2.4.1: Should be clarified to limit the detailed modeling to local areas where the planner expects an emerging voltage recovery issue due to unusually high concentration of induction motor load. This is a local issue, and a bulk system reliability issue that is imposed system wide. The MRO believes this should be moved to the sensitivity case requirements R2.4.3. 36. R2.4.3: Sensitivity Case requirements should mirror the steady state comments, subject to the suggestion provided above for R2.1.3. That is: ..R.2.4.3.1: should also include power factor variation (actually a separate requirement) as in the stability world, the dynamic modelling of load has a significant influence in meeting transient performance requirements. R.2.4.3.2: I agree it should simultaneous non-firm transfers. This should be applied to the steady state sensitivity as well (see R.2.1.3.2). ..R.2.4.3.3: delete ..R.2.4.3.4: Needs to be clarified. See R.2.1.3.4. . R.2.4.3.5: see R.2.1.3.5 37. R2.5: Plant stability analysis should be deleted. 38. R2.6.1: Nowhere else in the standard is there a requirement to assess reliability impacts of market structure changes, so why would a study become invalidated if there is a change in market structure. It would seem to me that the operation of any market would have to respect the reliability criteria. 39. R2.7: Corrective Action Plans: Is the intent that corrective action plans also address issues raised by the sensitivity studies. The MRO argument would be that it should not be mandated. The plans are developed to meet base case needs which are based on expected load forecasts, transfers, etc. Sensitivity studies are done to measure the robustness of the base case plan. It should be left up to the Planner to decide if the plan is adequate based on the likelihood of the scenario studied, even if the sensitivity analysis shows some performance violations. 40 Also, if rationale is provided for contingencies selected as they are expected to be most severe, then by default those not selected are less severe. Why is there a requirement to explain why you did not select a contingency. 41. R3.4: Requires extra analysis compared to TPL-004-0. Developing mitigation for Extreme Events

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Commenter	**Yes**	**No**	**Comment**
			can require significant work. Since there is no requirement to implement corrective plans for Extreme Events, what is the purpose? 42. R3.5: Generator tripping should be added in addition to runback. Generator tripping is used extensively in regions where remote generation is delivered via long transmission. Generator tripping should be an available option for the planner to use as opposed to requiring justification as a regional difference. 43. R4: The requirement to assess Plant stability is redundant as this is assessed as part of the generator interconnection. It should be deleted. 44. R4.5.2: The MRO disagrees on the need to define mitigation for Extreme Events. 45. R4.6: Should be deleted. 46. R6: Requires distribution of results and "coordinating analysis of these results through an open and transparent process". Can the SDT clarify what the intent is? As written, it implies the PC/TP just shares assessment results with neighbours. The MRO believes there should be a requirement to conduct joint assessments on inter-regional transfer capability. 47. Table 1 Performance Requirements: • As this is a steady state table, how does one assess if voltage instability, cascading outages or islanding occurs? • Generator tripping for single contingencies should be added to the allowable actions. • How did the SDT classify which event was single contingency vs. multiple contingency vs. extreme? Was statistical data analysed? • What is a non-bus tie breaker? Is this any breaker that is not a bus tie breaker? • Event P2-3 should be relocated to the P1 event category. • What is the SDT rationale for defining bus faults >300 k as single contingency events? Is there any statistical dat to warrant this extra requirement? Now a Cat C? Since little load is served off >300 kV it may be a moot point. • P6 single contingency: What is the justification for classify P6-2, a bipolar dc loss as a single contingency? The existing standard classifies this event as a Cat C multiple contingency event? • P6-3: Why is a breaker fault classified as a single contingency? One would assume such a fault would be cleared by backup protection resulting in the loss of multiple elements? • P9-1; Is there any justification for selection of one mile? Can it be two miles? More? Why not no more than 5% of line length? Would the fact that there is line shielding be justification for

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Commenter	**Yes**	**No**	**Comment**
			increased length? 48. Extreme Events • Event 3.g: what is the rationale for distinguishing between old vs. new design for the loss of multiple lines due to icing? Is the SDT implying that new lines must be designed to prevent multiple line loss due to icing? 49. Table 2 Stability Performance • MRO Comments on Table one for the same contingencies should also be applied here. 50. P6-2 should be a multiple contingency, as it is in the existing TPL standards. 51. P9-3: should be an extreme event. 52. P9-6: Please clarify the requirement to indicate that it relates to long lead times. 53. The definition for Angular Stability should be modified to allow planned tripping of a generator following a line trip. Why are generators allowed to pull out of synchronism for other planning events? This is cascading. The SDT should clarify if they are refering to local or regional damping modes in 1.a.iii.

Response: 1. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.
2. The SDT has revised this requirement based on industry comments to clarify the intent that *known* planned outages and long-term outages for Transmission equipment, including the impact of spare equipment strategy, be considered, and to be responsive to FERC Order 693, paragraph 1725.
3. The SDT does not agree. The SDT believes circuit breakers and protective equipment should be considered when developing criteria since these can affect System performance.
4. The SDT feels that requirement to run a peak load study for two of the years in the Near-Term Horizon is a minimum required for an adequate Planning Assessment. The SDT felt that the Year One or two study should provide operations with the best information to transition to the operating horizon. The year five planning study is the first near term study from the long term set. Five years is a short time if unexpected new facilities are required.
5. R2.6 - The SDT has revised this requirement in response to the numerous comments received.

R2.6.1. For steady state, short circuit, or System Stability analysis: ~~if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market~~

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~~structure changes~~ the study shall be five calendar years old or less. **R2.6.2**. For steady state, short circuit ~~analysis~~, Generating Plant Stability, or System Stability analysis: ~~if the study is less than five years old and no material changes have occurred to the System in the intervening period.~~ the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. **R2.6.3**. ~~For plant and System Stability analysis: until material changes in the System make the study no longer valid. Material changes in the system include the addition of a Transmission Line or a generator.~~ 6. Interim Operating Procedure is required to ensure that the all the performance requriements in Table 1 and Table 2 are met. It could include SPSs, pre-Contingency interruption of non-firm Loads, uneconomic generation dispatch, etc. The SDT recgnizes that this is a temporary measure until a permanent solution is put in place and that is why its duration is required. 7. Requirement R8 (old Requirement R6) which focuses on the distribution of the Planning Assessment results among affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old Requirement R6) Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. Typically the date would indicate when significant resources will begin to be employed. This covers any project proposed for the near term. The SDT continues to believe that by providing the expected project intiation date of System improvements provides useful information to neighboring entities. The SDT believes that initiation dates are required for near-term corrective action plans to give an indication that the corrective action plans can be implemented in time. 8. The standard requires that the identified future deficiencies be addressed by the Corrective Action Plan. The standard does not prescribe what this plan should be but entities have to demonstrate that the Corrective Action Plan or its alternatives will in fact be implemented in time to address the identified deficiencies. If the parts or all of the Corrective Action Plan turns out to be unrealistic due to something like a regulatory order, you still need to meet the performance requirements and a revised or new Corrective Action Plan that meets the performance requirements will need to be developed. The determination of when to update the Corrective Action Plan is based on good engineering judgment. 9. R3.2.1 & R3.2.2 - The SDT has received numerous comments in support of these requirements. Requirements R3.2.1 and R3.2.2 are included to provide clarity on simulations in response to FERC Order 693. Relay Loadability is included to provide the connection between facility ratings and planning studies. The SDT has not made changes in response to this comment. 10. The SDT has revised the table references to shunt Contingency events and removed the paranthetical reference to FACTS devices. The SDT believes it is more appropriate to leave the event more general based on the difficulty of maintaining an up to date reference to emerging technologies. 11. The SDT concurs with your observation. We have made several changes to the performance table organization based on industry input. The single pole DC outage is now reflected as a P1 Planning Event. 12. The SDT concurs with your feedback and the suggested change has been made in Tables 1 and 2. 13. The SDT has completely reformatted the performance tables in Draft 2 of the TPL-001-1 standard. The new format more closely mimics the existing approved TPL standard Table 1, with enhancements the SDT feels the industry will find valuable. The SDT has responded to industry comments regarding higher performance requirements for Facilities above 300 kV and has adjusted requirements for N-1-1 non-generator outages to permit Non-Consequential Load shed post-Contingency following the second event. The SDT has retained a higher			

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Commenter	**Yes**	**No**	**Comment**
expectation for certain N-1 Contingencies occuring on the EHV System. See the Summary Considerations in Q20 through Q23 for additional information. The SDT believes that this approach is consistent with FERC Order 693. 14. The SDT has revised the Extreme Event references and has removed the duplications you reference. The reference to local and wide area events has been retained as we did not receive a significant amount of comments opposing its use and it seems to be generally understood that local are extreme Contingencies eminating from a single location (substation, plant or ROW), whereas the wide area tend to cover a much larger landscape due to a natural disaster or cyber attack. The TP is given flexibility in which Extreme Events it wishes to cover, see Requirement R3.4. 15. The SDT agrees and has revised the note accordingly. 16. The SDT has completely reformatted the performance tables in Draft 2 of the TPL-001-1 standard based on feedback from the industry and input from SDT members. The new format more closely mimics the existing approved TPL standard Table 1, with enhancements the SDT feels the industry will find valuable. The SDT believes the new format will more closely meet your needs. 17. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirements R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirements R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. The sensitivity studies do not in themselves establish the need for a plan, only the areas of the system for which the analysis is needed. **R2.1.3.** For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.1.4**. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. **R2.4.3**. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: **R2.4.4**. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. P5.3 - The table format has been revised for clarity. We have added notes at the end of each table to clarify when a transformer is considered EHV (above 300 kV) or a BES transformer below the EHV level. 18. Tables 1 and 2 have been revised to bring greater clarity. 19. The SDT revised the performance Tables 1 and 2 for clarity based on industry feedback. The SDT has included the initial condition column in each and the events correlate one to one in both tables.			

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Commenter	**Yes**	**No**	**Comment**
20. The single Contingency loss of a shunt device is now included as Planning Event P1.4 in Tables 1 and 2. 21. The SDT has corrected the problem in Table 2. 22. The SDT believes that we are not reducing the reliability of the System as compared to the existing standards. 23. The SDT has reviewed this requirement and has determined that at this time this is not appropriate for a North American standard. 24. Tables 1 and 2 have been revised to include a variety of new improvements. The reference to monopolar is now "single pole of a DC line". The SDT has however retained a bipolar DC line outage; see Planning Event P7.2. 25. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. 26. The SDT has revised this requirement based on industry comments to clarify the intent that *known* planned outages and long-term outages for Transmission equipment, including the impact of spare equipment strategy, be considered, and to be responsive to FERC Order 693, paragraph 1725. 27. The requirement for the PC to define planned Facilities has been deleted from the revised standard. The SDT did not receive many requests for additional clarification of Protection System equipment and control devices and therefore did not revise the standard to address this concern. 28. The SDT has modified the assessment language dealing with steady state analysis in Requirement R2.1 to better define those requirements along with adding Requirement R2.1.4 to allow any additional sensitivities to be run that may be deemed necessary. In addition, Requirement R2.2 has been revised to specifically address steady state analysis: Requirements R2.4 and R2.5 have had many changes to better address the Stability portion of the assessment, Requirement R2.6 better details what past studies may be used in the Planning Assessment, and Requirement R2.7 better addresses Corrective Action Plans and System deficiencies. The SDT believes that all these changes result in better defined portions of the Planning Assessment. **R2.1**. ~~The steady state portion of~~ The Near-Term Transmission Planning Horizon ~~Planning Assessment~~ portion of the steady state analysis shall ~~address all five years of the assessment period~~ be assessed annually and be supported at a minimum by the following annual current studies, supplemented with qualified past studies as ~~shown~~ indicated in Requirement R2.6: **R2.1.4**. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. **R2.7**. For Planning Events shown in Table 1 – Steady State Performance and Table 2 – Stability Performance, when the analysis indicates an inability of the System to meet the performance requirements in the tables, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed ~~over time~~ in subsequent assessments but the System shall continue to meet the performance requirements in the tables. ~~Such plans shall:~~ Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities. The Corrective Action Plan shall: 29. The SDT has reviewed the need for Plant Stability and has concluded that it is appropriate to include it in this standard. It also felt that			

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Commenter	Yes	No	Comment
			this was responsive to FERC Order 693. 30. Requirement R2.2 requires as a minimum a peak load study for one of the 5 years in the Near-Term Horizon. This does not preclude any entity from running more studies, including for off-peak load conditions. 31. The standard is providing some guidance on what needs to be included in sensitivity studies without being totally prescriptive. In response to some comments, the standard was modified to clarify the language to state that at least one of the sensitivities listed in Requirements R2.1.3 and R2.4.3 should be studied and reasons be given for not studying the other ones. Furthermore, the standard also allows for entities to study sensitivity not included on the list that are more appropriate for their respective systems. 32. R2.2 - The Draft 2 version remains unchanged in regard to your comment. There was no overwhelming response from industry that compelled the SDT to make the change proposed. The standard requires off-peak analysis for near-term. In the long-term Requirement R2.2 states "…at a minimum, a current System peak Load study is required annually." This requirement is to capture long lead-time events for peak-Load periods. The peak system is typically the more troublesome period for most planners as Loads are higher and Facility Ratings are lower. Your concern is valid that in the off-peak, transfers across a system can be elevated and it is expected that if a particular System is subject to heavy transfers that a prudent Transmission planner would cover such situations based on their own identified need through sensitivity studies. Howver, such off-peak anlysis is not mandated by the standard for the Long-Term Planning Horizon. 33. R2.3 - The SDT respectfully disagrees and believes that the requirement for short circuit analysis is an improvement and covers a gap in the existing Transmission planning standards. It is essesntial that as System changes are introduced that increase the strength of the System and result in increase short-circuit fault currents, that the Transmission planner not simply look at steady-state Facility Ratings but also consider the short-circuit as well. Having steady-state, short-circuit and Stability in a single cohesive standard ensures that the Transmission planning engineer is evaluating all aspects of proposed changes to the System. 34. R2.4 - The Draft 2 version remains unchanged in regard to your comment. There was no overwhelming response from industry that compelled the SDT to make the change proposed. The standard requires off-peak analysis for near-term. In the long-term Requirement R2.2 states "…at a minimum, a current System peak Load study is required annually." This requirement is to capture long lead-time events for peak-Load periods. The peak system is typically the more troublesome period for most planners as Loads are higher and Facility Ratings are lower. Your concern is valid that in the off-peak, transfers across a system can be elevated and it is expected that if a particular System is subject to heavy transfers that a prudent Transmission planner would cover such situations based on their own identified need through sensitivity studies. Howver, such off-peak anlysis is not mandated by the standard for the Long-Term Planning Horizon. 35. The SDT feels that the Load model used in the study should represent actual conditions as accurately as possible. It has been shown during the reconstruction of the events of the August 14, 2003 blackout in the Northeast that the Load model was critical. One of the recommendations involved developing better Load models. 36. To the degree possible, the SDT has revised the standard to better align steady state and stability sensitivity lists. 37. The SDT has reviewed the need for Plant Stability and has concluded that it is appropriate to include it in this standard. It also felt that this was responsive to FERC Order 693. 38. R2.6.1 - The SDT agrees with your view and references to market structure changes have been removed in Draft 2. 39. Agree. Addressing or not addressing deficiencies discovered as a result of runing sensitivity studies is at the discretion of individual entities. The language of the standard was be modified to clarify this. 40. In developing a rationale why a selected Contingency is the most severe will require some sort of comparison to other Contingencies. In doing so the explanation required in the standard is already addressed. 41. The SDT feels that the current TPL-004 provides limited value to improve System reliability. Performing studies and not even considering

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Commenter	**Yes**	**No**	**Comment**
possible corrective actions (as is the case with the current standard), may result in over looking relatively inexpensive corrective actions which could significantly help improve reliability. It is appropriate to add another requirement to help improve reliability System development. The purpose of the requirement is to assess the risk of cascading outages or a catastrophic event, develop corrective actions and actually implement such actions if it is reasonable, for example installing a SPS. This is also consistent with Paragraph 1833 in FERC Order 693, which directs NERC to modify TPL-004-0 to identify options for reducing the probability or impacts of extreme events that cause cascading. 42. This has been added. **R3.5** Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met: 43. The SDT has reviewed the need for Plant Stability and has concluded that it is appropriate to include it in this standard. It also felt that this was responsive to FERC Order 693. 44. The SDT has reviewed this requirement and has determined that at this time this is appropriate for a North American standard. 45. The SDT has reviewed the need for Plant Stability and has concluded that it is appropriate to include it in this standard. It also felt that this was responsive to FERC Order 693. 46. R6 - By meeting the requirement for "coordinating analysis of these results through an open and transparent process", the SDT meant a stakeholder process that was set up to meet the requirements of FERC Order No. 890 with regard to an Attachment K filing of a Transmission Provider's Transmission Planning Process. The SDT has made a change to clarify this requirement. (see R8 in draft 2) **R8**. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~affected entities~~ neighboring systems, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890. 47. Performance requirements: The Draft 2 version includes a new Requirement (R6) which indicates that each TP must define and document proxies used in simulation studies to identify System instability for conditions such as cascading outages. voltage instability, or uncontrolled islanding. In the steady state time frame, voltage instability can occur typically during high power transfer and/or peak demand periods. Voltage instability can be assessed using a long-term Stability program. However, it can also be assessed using a power flow program that simulates governor action. There are a number of IEEE papers (e.g., G. Morison, B. Gao, and P. Kundur, "Voltage stability analysis using static and dynamic approaches," IEEE Transactions on Power Systems, vol. 8, no. 3, pp. 1159 – 1171, August 1993) that can provide suggestions on the methodology. Cascading outages and uncontrolled islanding can also occur in the steady state time frame, for example, when the Transmission Facilities load beyond the corresponding relay trip settings. This could cause uncontrolled tripping of Transmission Facilities beyond those required to clear the fault. Even though these events are rare, the Transmission Planner should be aware of their possibility when performing studies. **R6**. For the short circuit portion of the Planning Assessment, as described in Requirement R2.3, each Transmission Planner and Planning Coordinator shall assess the short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties.			

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The SDT agreed to make this change, Requirement R3.5 of the second draft of the standard now allows genration tripping for single Contingencies. **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~iesy~~ ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met: To address the directive from FERC in Order 693, the SDT classifies Contingencies by events instead of by the number of Transmission elements lost. One event, for example loss of a breaker, can remove from service upon fault clearing all elements connecting to the breaker. Statistical data available from regional databases were analyzed in developing the draft standard. A Bus-tie Breaker is often used in straight bus substation layouts to sectionalize an otherwise long continuous bus into smaller sections. The SDT has proposed a definition of a Bus-tie Breaker in the second draft. **Bus-tie Breaker:** A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.) Tables 1 and 2 have been revised and Event P2-3 has is now shown as Planning Event P1.5, and loss of a bipolar DC line has been reclassified as a multiple Contingency event. The SDT recognizes that bus section faults can and often do trip multiple Transmission Facilities. The Planning Event P2 defines single Contingency events that are somewhat lower probability than those in P1 but often result in higher consequence impacts due to loss of multiple Transmission elements for the single electrical fault. In more reliable station designs (ring, breaker and a half,etc) this type of condition is minimized. The new TPL Draft 2 continues to emphasize a higher expectation of performance for bus section faults and other P2 events on the Transmission System above 300 kV. See Summary Response for questions Q20 through Q23 for more details on the team's rationale for continuing to seek this level of reliability improvement. The SDT concurs with your view and has made the change. A bipolar dc loss is no longer a single Contingency Planning Event. You are correct in describing the outcome – multiple Facility outages. However, the SDT is describing an internal fault of a breaker, not a stuck breaker condition. Therefore the SDT is treating these as a single Contingency event. The SDT agrees that these are lower probability events than the "typical single Contingency" events but they pose greater risks. The SDT has separated the single Contingencies as P1 and P2 based on their probabilities of occurrence. Also, allowable responses to the P2 events differ from those for the P1 events. It is noted that stuck breaker events are treated separately as P4 Planning Events. The choice of one mile was based on a review of various regional practices. 48. The reference to this item has been removed and more general weather conditions resulting in extreme Contingency conditions are assessed in the Extreme Events area. 49. See comments for Table 1.			

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50. The SDT agrees and has revised the table accordingly. 51. The SDT has reviewed this requirement and has determined that at this time this is appropriate for a North American standard. 52. The SDT has removed the terminology referring to spare transformers. 53. The SDT has reviewed the issue and revised Requirement R5.5.3 to provide clarification. **R5.5.3**. Automatic generation tripping is allowed to mitigate Stability violations if the following conditions are met:			
Muscatine P&W	☑		Muscatine Power & Water (MPW) is a municipal utility with approximately 33 miles of 161 kV lines (2 lines) and 33 miles of 69 kV lines with three – 161/69 kV substations and seven – 69/13.8 kV substations. The service territory is approximately 24 square miles. Our last system peak was 149.9 MW on July 29, 1999 with a more recent peak of 146.9 MW on July 17, 2006 with generating capacity of approximately 253 MW from four units. The main problem we have is keeping up with the standards changes with our limited resources. We would suggest: 1. It was good to see the definitions section. We would also suggest including all acronyms including those in common use. Acronyms have become so common and they are now being reused to mean different things to different groups that for new people, multitasking individuals, or those not dedicated to a specific standard acronyms add confusion. Where possible, we would suggest using existing terms and, if appropriate, preferably already defined or have them defined in IEEE standard #100 dictionary. 2. Can you address adequate documentation? I'm not looking for detail formats or requirements but more minimum requirements and suggested layout etc. One of the problems I have during audits is how much documentation to provide without going over board. More is not good considering time requirements. Our goal is to make it easy for us and the auditors. We met the standard but have we proved it. Being a small utility with little impact on the bulk system how much should we provide? 3. In our region the MAPP Design Review Subcommittee (DRS) and in some cases the Subregional Planning Groups (SPGs) review new and proposed changes to facilities. In many cases they would have to approve any RAS or SPS and thus provide a peer review/reasonable and workable check. 4. R.2.6.1 - Being a small utility we are concerned about the planning study must be less than 3 years old. We budget for studies every three years but adjust that based on whether material changes have occurred to the system. Our last cycle was 6 years only because our load hasn't been growing and we still haven't hit our peak of 1999. Since we are dependent on consultants, we also have a concern for how long it can take for them to complete the study. Since we are small the bigger customer gets the attention. We do use the same criteria for near and long term planning horizons. We also participate in MAPP and ITWG studies for the annual and bulk system review and

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Commenter	**Yes**	**No**	**Comment**
			since our issues in studies are more local rather than the bulk transmission system. How should/could the sensitivity studies be covered for us at the regional level? 5. 300 kV and above questions: MPW is a small utility that doesn't have any facilities above 161 kV or any DC lines. I can see requiring more stringent performance for EHV and possibly lower voltage facilities in some cases, however, whether to allow the loss of Non-Consequential load should be left to local entities to decide since the cost of the "corrective action" could exceed the cost of the load loss and put undo burden on the customers. Depending on the type of load the customer may not want/be willing to pay for the extra reliability. If ordered, how will the cost be recovered? The cost should be recovered by the users not just the local customers. Thanks for the opportunity to comment!
Response: 1. The proposed definitions in the draft standard will be incorporated into the Glossary of Terms when the standard is approved. We believe it is better to have the terms listed in the NERC Glossary of Terms rather than pointing to the IEEE standard since the NERC Glossary is more readily available for use in the reliability standards environment. We have reduced the number of definitions in Draft 2 to try and have a more pointed impact where a definitional term is most needed. 2. Your concern is a compliance matter and not directly related to the reliability requirements. Although not yet available in Draft 2, the SDT will be adding compliance measures in a future draft. If the measures do not clearly address your concern please raise a more specific question related to the appropriate requirements/measures. 3. Thank you for your comment. 4. R2.6.1 - The SDT has revised R2.6.1 to allow the use of past studies that are 5 calendar years old or less. **R2.6.1**. For steady state, short circuit, or System Stability analysis: ~~if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market structure changes~~ the study shall be five calendar years old or less. 5. The SDT has added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose Load. With regards to the loss of Load, the standards don't address cost recovery.			
NERC TIS	☑		1. In definition of "CONSEQUENTIAL LOAD," misoperations need to be defined better or removed, i.e. inadvertent tripping of elements due to protection system failure, including inadvertent SPS operation, may cause loss of load NOT connected to the element tripped off. In context of the definition, it appears that the misoperation should be on the protection system for the element that is tripped. {PARTLY COVERED} 2. Even when post-contingency voltage remains within prescribed limits, some voltage-sensitive customer load could still be dropped off due to their inherent sensitivity to allowed changes in voltage. Should such cases be considered as dropping non-consequential load or are the performance requirements met as long as post-contingency voltage stays within the prescribed limits? Such load losses can rarely be predicted by steady state analysis unless the

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Commenter	**Yes**	**No**	**Comment**
			loads and their distinct characteristics are explicitly modeled, but may be detectible in dynamic analysis since it is often the first swing voltage excursion that trips such loads. 3. Assuming the standard is passed, especially if the bar is raised, there should be some reasonable implementation period specified to allow entities that do not meet the standard's requirements presently and time to implement changes to become compliant. 4. Why is there a 300 kV threshold? Is there evidence that increasing the redundancy of the high voltage network will provide the largest reliability benefits? 5. Need to specifically define when it is OK to use "permanent" SPSs to meet performance requirements following the first contingency, i.e. separating a balance island should be OK. It is OK to utilize temporary SPS while the permanent corrective measure is being put in place. 6. Need to define, perhaps in the list of definitions, what is the "bus-tie breaker." Differentiation of center breakers in breaker-and-one-half schemes is a crucial item not to be subject to interpretation and possible confusion. 7. Need to clarify that "stuck breaker", regardless of whether cause by protection system failure, breaker failure to operate, or a slow breaker, is de-facto delayed clearance and causes additional contingency (ies). 8. Firm Transfer Cell for P3 does not make sense. 9. Need to strengthen the notion, in the bullets at the top of Table 1, that the assessment should also cover n-0 or "normal state (seems to be adequately covered in the body of the standard, but does not jump out from the Table 1 bullets at the head of the table.) 10. Include SHUNT DEVICES in P3–P9 planning contingencies. The same comment is applicable for stability table. 11. Need to clearly specify what documentation would be required to fulfill the standard's requirements for assessing extreme contingencies. 12. Replace "all" in the Extreme Events subheading with a more appropriate term. 13. Replace "all" in the table for Extreme Events for both Steady State and Stability tables with a more appropriate term to manage documentation requirements. 14. Use different designations for planned and extreme events in steady state and stability tables, e.g. PS and ES for steady state and PD and ED for stability (D for dynamic). 15. Throughout the tables, do not refer to "internal" breaker faults but use breaker fault instead. Faults can occur internal to the breaker, flashed bushings, or a fault (on or within) a free-

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Commenter	**Yes**	**No**	**Comment**
			standing CT associated with the breaker. 16. Modify bullet 5 in the Stability Table to include SPS failures to read: "Simulate the removal of all elements that Protection Systems, SPS or RAS systems, and controls are expected to disconnect for each Contingency." If an SPS or RAS is expected to operate for a contingency, it must be modeled as such for that contingency study. 17. In R1.2 need to add "for the period analyzed" and defined what "stressed" conditions means. 18. In R 2.1.3.7 need to insert "long-term" in front of "transmission outages." There is also a need to clarify/describe/define what long-term transmission outage is. 19. There are concerns, particularly for NON-vertically integrated TPs, about need of including Plant Stability requirements. 20. Define what "material" change is in R2.5.2. 21. Presumably the standard will be stamped with a CEII designation 22. Additional granularity should be included showing the correlation between Requirements and their applicability to any of the Functional Model Entities cited in the Standard. 23. Obligations to study and share results of the following should be clear in the TPL Standards: • Analysis of impacts on your system for contingencies outside of your system footprint. • Analysis of impacts on other systems for contingencies within your system. The owners of the other systems should be notified of your findings and joint analysis should be done if warranted. • Powerflow and stability analysis of contingencies that have interconnection-wide impacts. This may best be accomplished through modifications to existing standard TPL-005.

Response: 1. The SDT revised this definition in response to various comments.

Consequential Load Loss: Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet

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steady state performance requirements. 2. The SDT revised this definition in response to various comments. The SDT believes the revised definition addresses the concern expressed in this comment. **Non-Consequential Load Loss:** ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss. 3. The SDT is sensitive to need for an implementation policy to allow for Transmission Owners to respond to requirements that involve raising the bar, but an implementation plan was not developed for this posting. The SDT anticipates developing an implementation plan in response to the next posting. 4. The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT felt the 300 kV and higher Systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. When EHV Systems are compromised, the large volumes of power served by them can place a severe amount of stress on parallel EHV or lower voltage paths. For example, if large EHV transformers experiences a catastrophic failure, not only are other System Facilities required to carry more Load but the System is also exposed to other N-1 conditions for long periods of time while awaiting a replacement or repair of the failed equipment. Large generation sources are typically connected at EHV levels and maintenance of the EHV Transmission lines within the vicinity of larges generation plants must often be coordinated during scheduled unit outages, resulting again in multiple Facility outages over extended periods of time. Therefore, it was the conclusion of the SDT in Draft 1 to propose greater reliability and operational flexibility through more stringent performance requirements when considering certain N-1 and N-1-1 Contingency events of EHV Systems. Throughout the industry substation arrangements at EHV levels reflect the importance of these Systems as the designs often consist of the more expensive ring-bus, breaker-and –a-half or double bus-double breaker protection schemes as opposed to the more simplistic and lesser cost single bus arrangements that are commonly found on lower voltage Systems. The feedback received from industry was divided related to the SDT's emphasis placed on a higher expectation for the 300 kV and higher Systems. Some commenter's questioned the importance and the high costs that may be needed to mitigate existing System designs. Others agreed with the SDT's approach and indicated that the impact to their Systems would be minimal. Some commenter's even questioned why the more stringent approach was not applied to the entire 100kV and higher Systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission System.			

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Commenter	Yes	No	Comment
5. The SDT has revised requirements to include changes related to the allowable use of SPSs related to N-1 events. See new Requirement R3.5 of the Draft 2 TPL-001 standard which indicates SPSs are permitted for automatic generation runback or tripping following a single contingency event. **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~iesy~~ ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met: 6. The SDT has proposed a definition for bus-tie breaker in the second draft. **Bus-tie Breaker:** A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.) 7. Tables 1 and 2 have been revised to provide greater clarity. The SDT has accounted for both stuck breaker and Protection System failures as two unique Planning Events. See performance table requirements for Planning Events P4 and P5. 8. The SDT concurs and changes have been made to the performance Tables 1 and 2. The SDT has completely reformatted the performance tables in Draft 2 of the TPL-001-1 standard. The new format more closely mimics the existing approved TPL standard Table 1, with enhancements we feel the industry will find valuable. 9. The SDT concurs and has added a P0 Planning Event at the top of Table 1 to address the N-0 (existing Category A) condition. 10. The SDT has modified the tables to include shunt devices where appropriate. 11. Changes were made to simplify and clarify Extreme Event expectations. Please refer to both performance tables and Requirements R3.4 (steady-state) and R5.5.4 (Stability). 12. The statement has been revised to say "For all Extreme Events considered". 13. The statement has been revised to say "For all Extreme Events considered". 14. The Planning Events for steady-state and Stability now correlate one-for-one, so the SDT does not feel a need to distinguish each uniquely. The Extreme Events are not presently listed in a tabular format with the formality of the Planning Events. This is somewhat intentional to draw greater emphasis and focus to the Planning Events. If you feel changes are needed in our presentation of the Extreme Events within the performance tables, the SDT would be open to a suggested format from TIS. 15. Tables 1 and 2 have been revised to explain "internal breaker fault" (see Note 5 in Table 1 and Note 4 in Table 2). With this change the term "internal breaker fault" was retained. 16. The SDT believes that SPS/RAS is included in Protection Systems as defined in the NERC Glossary. 17. The SDT has revised the data and modeling requirements based on industry comments to clarify intent. **R9.** Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information. **R10**. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission			

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Commenter	**Yes**	**No**	**Comment**
planning horizon, within ninety days of a request for such information. **R11.** Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information. **R12**. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information. **R13**. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information 18. Since this requirement is relating to sensitivity, it is up to the entity to determine if it is appropriate to reduce the length of or increase the length of the "planned outage" that it has considered in its base case studies. 19. The SDT has reviewed the need for Plant Stability and has concluded that it is appropriate to include it in this standard. It also felt that this was responsive to FERC Order 693. 20. The SDT has changed the wording to provide clarity. **R2.5.2**. Material Transmission System changes ~~in the electrical vicinity of existing generation are made~~ are made at or near the point of Interconnection of existing Generation such as the ~~addition or~~ removal of a Transmission Line ~~at or near the point of Interconnection~~ or the addition of a new substation in one of the Transmission Lines connected to the plant. 21. The Standard is public information. Individual reports may need to be reviewed by the individual entity to ensure compliance with CEII. 22. References to entities have been added. 23. R6 requires "coordinating analysis of these results through an open and transparent process". By this requirement the SDT meant a stakeholder process that was set up to meet the requirements of FERC Order No. 890 with regard to an Attachment K filing of a Transmission Provider's Transmission Planning Process. The SDT has made a change to clarify this requirement (see R8 in draft 2). **R8**. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~affected entities~~ neighboring systems, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890.			
NCEMC	☑		1. Planning Coordinator: The definition of Planning Coordinator should be kept within this document rather than relying on the NERC Functional Model as we believe that this entity has an important role in insuring coordination of transmission and resource plans. Coordination: 2. During the teleconference, one issue brought up was the matter of external contingencies being

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			tested as a part of a TP's analysis. The reply was that this issue will be addressed outside this draft standard (TPL-005 and TPL-006) or would be accounted for in the coordination efforts among Transmission Planners. NCEMC is of the opinion that Requirements R5 and R6 need further details to insure adequate anlysis between and among Transmission Planners having varying local planning criteria so that Seams Issues are addressed that are not currently being address in regional and inter-regional studies. To the extent possible, timing of studies should be required to insure coordination between regional and inter-regional groups. Significant Increase in Study Activity Workload on Transmission Planners: 3. The increase in both steady state and dynamic studies required to ensure compliance with the proposed standards will result in increased costs and staff additions. The addition of the "Corrective Action Plan" requires the TP to provide a significant amount of documentation for each deficiency identified by the studies. Also, R3.2 requires that the studies simulate the protection scheme for all events. The current software tools cannot automate these studies for bus faults and breaker failure events, requiring each scenario to be studied manually. Additionally, experienced staff capable of performing analyses as described in the proposed standard have become increasingly difficult to find and retain and the talent pool of people with these skills has recently become depleted to alarming levels. Implementation Plan: 4. Given the intent of the proposed standard to encourage large scale investment in the EHV system, full implementation will take years, perhaps decades. Acquirement of right-of-way for new EHV lines has become increasingly difficult in recent years and inreasingly expensive. Legal, regulatory, and other difficult issues often take several years to navigate, even for 115kV lines. The Implementation Plan timeframe, if set too short, would be unduly burdensome on Transmission Owners forcing them to be less dicretionary with funds than would be prudent. The proposed implementation plan should include provisions for those cases where viable solutions simply can not be implemented in time due to circumstances beyond the control of Transmission owners. A reasonable period for transition is order. Design and Construction Constraints: 5. Even if right-of-way and other legal and regulatory hurdles are cleared, and the capital funding for such a tremendous level of investment was not an issue, the other resources required to actually construct the projects are equally difficult and costly to secure. Raw material prices on comodities like copper and steel have skyrocketed in recent years. Additionally, the skilled labor and Engineering resources are constrained with labor rates almost keeping up with other resource costs. Overall project costs have more than doubled over the last 7-10 years. Recent press releases concerning new generation being planned and then scrapped due to the rapid escalation of project

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			costs are public evidence of this. The inflationary mark-up is impossible to estimate but much less will be built with the same capital investment than is currently envisioned. Cost-Benefit Analysis: 6. The proposed standard will be exceedingly expensive to become compliant with unprecedented levels of capital investment in Transmission facilities. Before the standard comes to official vote, it would be prudent for a cost-benefit analysis to be performed to determine if the reliability improvements truly justify the huge expenditures certain under the proposed standard. Additionally, as many jurisdictional rate structures share the cost of such investments between retail and wholesale customers, cost-benefit analyses should be completed for both retail and wholesale customers. System Adjustment Clarification: 7. It has already been noted earlier but deserves repeating here: The term "System Adjustment" as outlined in the tables should be better defined. The use of generation for redispatch may have nuances which preclude or otherwise limit their use for studies. Perhaps some clearer guidelines on what is allowed would facilitate transparency and coordination between Transmission Planners. Transmission Service Evaluation: 8. A major concern is that the proposed standard appears to be disjointed from the requirements for selling firm Transmission Service. The increase in reliability gained from the proposed standard would, in some regions, quickly be eroded by new firm sales if those sales are based on the historical N-1 ATC requirements. The proposed standard must be applied to long-term firm transmission service requests if Transmission reliability is to be truly enhanced. If the standard is not applied to Transmission Service evaluation, reliability levels for the different classes of firm customers will diverge. Stakeholder Process: 9. As a Transmission-Dependent Utility and Network Customer within 3 different Balancing Autorities with one being a Regional Transmission Organization, NCEMC cannot stress enough the need for a Stakeholder Process for coordination Transmission Planning that may impact Load-Serving Entities and other entities involved. It is critical to address reliability needs of all taking transmission service today and in years to come.
Response: 1. The SDT modified the definition and the definition will be approved with the standard and added to the Glossary of Terms Used in Reliability Standards. 2. R5 (R7 in second draft) requires the determination of the entities responsible for the portion of the studies. R6 (R8 in second draft) requires "coordinating analysis of these results through an open and transparent process". By this requirement the SDT meant a stakeholder process that was set up to meet the requirements of FERC Order No. 890 with regard to an Attachment K filing of a Transmission Provider's			

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Transmission Planning Process. In addition, NERC Standards are to specify the requirements, which must be met and not "how" they are met. The SDT has made a change to clarify this requirement (see R8 in draft 2). **R8**. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~affected entities~~ neighboring systems, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890. 3. The SDT understands the potential increases in work load. The draft standard allows the use of past studies to meet the current year assessment and study requirements. Requirement R3.2 does not require study of the protective scheme for all events, only that "Contingency analyses shall simulate the removal of all elements including those that System protection is expected to disconnect for each Contingency without operator intervention". For example, the requirement is that the outage simulation should be from breaker to breaker. In addition, Requirement R.3.2.2 only requires the studies consider relay loadability and identify how loadability is treated in the steady state simulation, not to study relay loadibility. 4. The SDT understands that there are extended transitionary issues associated with responsible entities becoming compliant with the new standard. The SDT plans to draft an extended implementation plan to accommodate such issues. The plan will be provided for the third posting of the standard. 5. The SDT understands that there are extended transitionary issues associated with responsible entities becoming compliant with the new standard. The SDT plans to draft an extended implementation plan to accommodate such issues. The plan will be provided for the third posting of the standard. 6. Cost issues are outside the scope of NERC reliability standards. 7. The Transmission performance tables have been modified to bring clarity to the Contingencies required for performance studies and when Non-Consequential Load Loss is permitted to meet requirements. The use of manual or automatic System adjustments to revise System topology as well as generation redispatch is always permitted so long as the actions can be performed while adhering to Facility Ratings. 8. Any requests for long-term Transmission service need to be studied in accordance with peformance requirements. 9. This draft standard addresses the requirement for coordination of studies in an open and transparent process (see Requirement R8 in draft 2).			
NCMPA	☑		Much of the language in R1 is redundant, because the MOD standards already address what data are required for modeling purposes. Including data requirements here, as well as in the MOD standards, will introduce the possibility of inconsistencies between the two as well as unnecessary duplication of work for entities providing the data. If any changes need to be made to what data are collected or to whom it is provided, those changes should be made in the MOD standards, not by adding data requirements to this standard. As for most every standard written, some consideration should be given to the cost of meeting the more stringent requirements proposed for this standard. While it might be possible to make incremental improvements in reliability, it may not be cost-effective, particularly given the low probability of some of the events addressed in the standard. Before stakeholders are asked to vote on this standard, a cost-benefit analysis should be performed to provide what would be an otherwise missing, but very important piece, of information about whether the costs of complying with the

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Commenter	**Yes**	**No**	**Comment**
			requirements of this standard are justified based on the reliability improvements that would be achieved.
Response: 1. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. 2. The treatment of Transmission infrastructure costs is outside the scope of the NERC reliability standards.			
OPPD	☑		The terms Bus Tie Breaker and Non-Bus Tie Breaker used in Tables 1 and 2 are not well defined. To prevent misinterpretation of the standard, include diagrams that point out examples of bus tie breakers and non-bus tie breakers for each of the following bus schemes: 1) Single bus 2) Ring bus 3) Breaker and a half 4) Double bus double breaker.
Response: The SDT has proposed a definition for Bus-tie Breaker in the second draft. **Bus-tie Breaker:** A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)			
PJM	☑		1. Delayed clearing due to primary relay system communication failure 2. Bus Contingencies should not be included for sensitivity/stressed case 3. Sensitivity case should not be included for long term study 4. Need to clearly define number of studies required for Load Flow/Stability and what performance criteria must be met. • Peak Case • Off Peak • Sensitivity 5. Need to allow SPS operation after a first contingency, system readjustment and a "second " first contingency. 6. SPSs can include generation tripping
Response: 1. The SDT does not understand the question and therefore can't respond. 2. Bus Contingencies are just one type of sensitivity that could be included but is not mandated. 3. Sensitivities are not required for long-term. 4. The SDT believes that the number of studies is clearly defined. 5 and 6. The SDT agrees that SPS can include generation tripping. The SDT has modified the requirements to allow SPS for single and multiple Contingencies (See Requirement R 3.5). **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:			

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PRPA	☑		1) P5 and P8 in Tables 1 and 2 – If you keep the "300 kV bar" for distinction between P5 and P8, then please make an exception for P5 to be "Yes" on Non-Consequential Load Loss where load pockets (a.k.a. local load-serving areas) are concerned because "system adjustments" might not be possible to avoid the need for Non-Consequential Load Loss after the loss of another line into the load pocket. Example - A city, which is a type of load pocket, is served by three transmission lines. If one of the lines into the city is removed from service for maintenance, "system adjustments" within the city might not be possible to prevent steady-state voltages from dropping below an acceptable limit after loss of a second line into the city. If during such an "N-1Line-N1Line" Planning Event the city voltages become extremely low, then shedding of some of the city's load should be allowed, i.e. Non-Consequential Load Loss, for all voltages 100 kV and above. In this example, when one line into the city is removed from service, the TOP could either arm an SPS or RAS for automatic load shedding, or alert the operators to possible implementation of an Operating Procedure for manual load shedding. The city, along with its TO and other authorities, may decide by their own wishes to "raise the bar" and add facilities to maintain acceptable voltages for the worst "N-1Line-1Line" affecting only its local area. However, a facility addition type of solution, driven by a "No" for Non-Consequential Load Loss in P5, should not be mandated. "Controlled interruption of electric supply to customers (load shedding)" should be allowed for all voltages 100 kV and above as Footnote (c) in TPL-003 allows. Consistent with this request to allow load shedding for this type of disturbance for all voltages 100 kV and above, FERC Order No. 693 in Paragraph 1825 regarding TPL-003 for Category C disturbances (including "N-1Line-1Line") does not ask for "controlled load interruption" to be eliminated, but rather FERC directed the ERO to modify footnote (c) to Table 1 to clarify the term "controlled load interruption". And please note FAC-010-1, R2.5 – "Planned or controlled interruption…(load shedding)…" for TPL-003 conflicts with "No" for Non-Consequential Load Loss in P5 of Draft TPL. 2) Proposed revision to R3.5 – "Manual and automatic generation runback and generator tripping are allowed as a response to single and multiple contingencies as long as Facility Ratings are not exceeded and the result of the generator action, such as location and ramp-up speed of the AGC unit(s) responding to the generation trip or runback, loss of reactive resource, impact on reserves, and restart time of tripped unit(s), meets the performance requirements." Planning and Operations need flexibility to coordinate with the requirements of Engineering who established the Facility Ratings. It should not matter which method of generation redispatch is employed if all impacts of tripping vs. running back a generator are properly considered and performance requirements are met. The time period for a particular Emergency Rating might require

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			faster generation redispatch than a runback or set of runbacks are capable of providing. Therefore, it may be necessary to trip one 100 MW unit rather than runback several units for a total of 100 MW. No need for R3.6 with above revision to R3.5.
Response: 1. The SDT has completely reformatted the performance tables in Draft 2 of the TPL-001-1 standard. The new format more closely mimics the existing approved TPL standard Table 1, with enhancements we feel the industry will find valuable. The SDT has responded to industry comments regarding higher performance requirements for facilities above 300 kV and have adjusted requirements for N-1-1 non-generator outages to permit Non-Consequential Load shed post-Contingency following the second event. We have retained a higher expectation for certain N-1 Contingencies occuring on the EHV System. See the Summary Response in Q20 through Q23 for additional information. 2. The SDT agrees that SPS can include generation tripping. The SDT has modified the requirements to allow SPS for single and multiple Contingencies (See Requirement R 3.5). **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:			
Progress–Carolinas	☑		1. In R4.6 and other locations, the generator exemption of 20 MW should be increased to 75 MVA. 2. Need to define bus-tie breaker. Is center breaker in a breaker and a half scheme a bus-tie breaker? 3. Need to continue to allow interruptions to firm transfers. This is essentially allowing redispatch and is an economically sensible solution to low probability high impact multiple contingencies. 4. Need to clarify if the "stuck breaker" is associated with the first event in multiple event contingencies or does one have to choose a breaker not involved with the first event. Note that a breaker cannot be "stuck" if there is no demand to trip. Therefore, a stuck breaker that is not adjacent to the first event will not have a demand to trip. 5. Need to distinguish what the difference is between a "stuck breaker" and a "[loss of breaker due to] internal fault". The specific meaning could make the difference in the clearing time selected for stability studies (normal clearing time versus delayed clearing time). 6. In the Table 2 (for stability) the last bullet under Planning events says to "simulate normal clearing times unless otherwise specified". Does this mean that "stuck breaker" events should be simulated with normal clearing times? Note that in the real world, internally faulted breakers may clear in either normal or delayed clearing time, depending on the relaying and CT configuration.
Response: 1. The limits cited are consistent with the registry criteria, Large Generator Interconnection Procedures, and FERC Orders. 2. No, a center breaker in a breaker and a half scheme is not considered a Bus-tie Breaker. The SDT has proposed a definition for Bus-tie			

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Breaker in the second draft. **Bus-tie Breaker:** A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.) 1. Tables 1 and 2 have been revised to replace "firm transfer" with "firm Transmission service". 2. The SDT agrees and appreciates the feedback. The SDT has re-worked the tables, and believes the wording used for stuck breaker will satisfy your concern. Please see Planning Event P4 in each performance table. 3. Tables 1 and 2 have been revised to provide clarity. Please see Planning Events P2.1 and P2.3. 6. The sentence "simulate normal clearing times unless otherwise specified" refers to the events sepcified in the Tables. A stuck breaker would have clearing time that is "otherwise specified". The intent is to simulate "real world" events using the clearing times appropriate for the specific fault and breaker/Protective System configuration.			
Progress–Florida	☑		General Comments 1. NERC Standards TPL 001-0 through TPL 004-0 are approved standards that only required modifications pursuant to FERC Order 693. In this proposed draft standard TPL 001-1, the Standard Drafting Team (SDT) has far exceeded the recommendations suggested by FERC in the Order and has created unnecessary confusion. We disagree with the SDT's decision to combine NERC Standards TPL 001-0 through TPL 004-0 into one standard. Some changes to the existing TPL Standards may be warranted. One particular improvement would be clarifying the tables such that the table for TPL-001, for example, would only contain the performance criteria for Category A, with footnotes only applicable to that category, clarified as directed by FERC in Order 693. Similarly, TPL-002 would only contain performance criteria for Category B, and so on. In addition to combining the standards, the SDT has significantly changed contingency specifications and required performance levels. In many cases the changes represent a very significant increase in required performance standards that will result in the following: a) major capital expenditures, some of which will be of a magnitude unprecedented for the Bulk Electric System. Many of these projects would be constructed to mitigate one single low-probability event. The ratepayers, upon discovery of this necessity and realization that these significant expenditures will be passed on to them in their rates, will certainly object to these efforts and will question the wisdom of NERC's mandating change on such a massive scale without the knowledge or input of the public. The SDT stated in its continent-wide conference call on October 10, 2007 that the intent of many of the objectives contained in the proposed TPL-001-1 was to "raise the bar" for electric utilities. We would like to know specifically what this means. The phrase "raise the bar" is vague and overused in North American vernacular in general, and it is particularly irresponsible to use such vagaries when proposing standards which will result in unaffordable upgrades to the North

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Commenter	**Yes**	**No**	**Comment**
			American Bulk Electric System. b) reductions in ATC. To be compliant with the more stringent requirements of TPL-001-1, Transmission Operators would in many cases be forced to reduce ATC in order to decrease transmission flows to a point at which corrective actions may be taken without the result of cascading. This is diametrically in opposition to one of the key objectives of deregulation and comparable treatment for all entities engaged in transactions on the Bulk Electric System. c) Reduced Reliability. The elimination of footnote (b) will result in many outage scenarios for which loss of Non Consequential Load is presently unavoidable, but subsequently prohibited. For some scenarios, Transmission Owners may seek to avoid the excessive cost of a project by simply removing breakers from substations, thereby increasing the range of the initial breaker-to-breaker operation and essentially converting the disallowed Non Consequential Load to Consequential Load. This is obviously an undesirable option and in opposition to fundamental principles of reliability, but might be rendered necessary due to the increased requirements of TPL-001-1. d) Inability to react to issues of non-compliance. The dynamic nature of planning analysis is such that, from one annual planning cycle to the next, the constantly changing load and generation forecasts invariably result in emerging transmission projects unforeseen in previous cycles. With the increased stringency of TPL-001-1, reacting to these emerging needs in time to demonstrate compliance will be impossible, and thus non-compliance is seen as an inevitability. To further clarify, the major transmission projects that TPL-001-1 would necessitate would be of a magnitude such that extensive engineering, land acquisition and involvement with regulatory and governmental agencies would be required, which could result in project lead times of 10 years or more. Not only would a lengthy transition period be needed for TPL-001-1, but upon the Standard's effective date the ability to implement all future projects would need to be given special consideration in light of these challenges. In other cases, the performance criteria are not clearly defined, such as the timing between multiple contingencies, and the level of readiness of the system before and after Planning Events. Finally, the SDT has chosen to eliminate the footnotes in the current standards, contrary to the direction of FERC in Order 693 to "clarify" the footnotes. The purpose of the footnotes is to further explain terms in the tables, provide guidance in interpreting the expected performance criteria, and specify any exceptions to the criteria. Footnotes also serve the purpose of keeping the standard concise by eliminating repetitiveness.

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			Specific comments on the Draft Standard Performance Criteria 2. The performance requirements table should clearly define what the initial state of the system is assumed to be before any Planning Events, and what the state of the system is assumed to be after the Planning Event. For example, P1 (single contingency) events: assuming that the system is to be compliant, the state of the system prior to the event must be "secure" such that the event could occur and there is no interruption of firm transfer or loss of load, Equipment Ratings are not exceeded, System steady state voltages and post-transient voltage deviation are within acceptable limits. However, the system is not as it was before the event. The system could be described as "normal" but perhaps not "secure". If the requirement is that the system must also be "secure" after the event, then the standard must clarify what is allowed for "system adjustments" after the first Planning event to prepare for the next. FERC Order 693 directed the ERO to modify the second sentence of footnote (b) to clarify that manual system adjustments other than shedding of firm load or curtailment of firm transfers are permitted to return the system to a normal operating state after the first contingency. However, in order to bring the system to a secure state, as is necessary for the second contingency of a category C3 or C5 event, footnote (c) allows curtailment of firm transfers, and FERC Order 693 only required footnote (c) to be clarify the term "controlled load interruption", leaving the curtailment language intact. The implication of this interpretation is critical to peninsular Florida. The Category B loss of one 500 kV line from Florida to Georgia is sustainable, such that the system is "normal" after the event. However, in order to be prepared for the next contingency, (the loss of the second 500 kV line), firm transfers must be curtailed (Interruption of Firm Transfer). Without the ability to curtail firm transfers, a "super-firm" priority of transmission service is created for non-native load customers, and thus comparable treatment no longer exists. Comments on New Performance Tables: The draft TPL standard represents a major change in the Table 1 contingency definitions and required performance levels. 3. Table 1 Contingencies C1 and C2 are being moved to the single contingency category. While C1 and C2 represent single element outages, their probability of occurrence is much lower than the other Category B contingencies and they do not belong in the single contingency performance requirements group. 4. Footnote (b) which permits, as a limited exception in unique circumstances with a sound rational basis, some localized load reduction for single contingencies, has been removed. This is a very significant change for some utilities. Footnote (c) which permits load shedding and curtailment of

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			firm transfers has been removed from C1, C2 and most of C3. This is a very significant increase in required performance level that is not justified. 5. The "applicable rating" for loading and voltages in Table 1 has been removed so that essentially, the same ratings and voltage restrictions apply to both B and C contingencies. Some utilities plan to a normal rating for single contingencies but will allow a higher short term rating for Category C events. This practice appears to be either disallowed or inadequately described in TPL-001-1. Transmission Owners should allowed to base ratings on manufacturer specifications or other reasonable criteria using sound engineering judgment. 6. Several new Category D "Extreme Events" have been added which greatly expand the scope and complexity of Category D studies. These are (1) any two unrelated single element outages and (2) wide area events a. through h. These represent a major increase in the scope of Category D studies and probably a doubling of required SWG studies. It should be note that the existing Categories D1 through D4 have been substantially changed to eliminate analysis of relay failure contingencies. The philosophy contained in the existing TPL-004 standard is that faults with a protection failure should be evaluated whether that failure is a circuit breaker, relay or CT; the proposed standard restricts the analysis to breaker failure. 300 kV Threshold Performance Level 7. The TPL-001-1 draft sets a threshold of higher performance to facilities above 300 kV than previously established in the existing standard. We do not agree that such a threshold is necessary or warranted. Requirements which are more stringent for these facilities may wrongly influence decisions on project alternatives in favor of facilities with less stringent requirements. Additionally, facilities above 300 kV naturally tend to transport larger amounts of power. The loss of single or multiple facilities above 300 kV generally results in an immediate generation-to-load mismatch too great to avoid either curtailment of firm transactions or loss of Non Consequential Load, or both. Singling out facilities above 300 kV for more stringent requirements is therefore clearly unreasonable. DC Line Performance Requirement 8. The TPL-001-1 draft sets a lower performance requirement for the loss of a single pole of a DC line than in the existing standard by allowing interruption of firm transfer if the transfer is deemed to be dependent on the outaged line. Firm transfers are also dependent upon AC lines. The proposed standard does not distinguish between asynchronous DC ties and the more common parallel connected DC tie. With an asynchronous DC tie, the transfer is lost with the tie. With a parallel DC tie, the transfer will be shifted to the parallel AC system and should have the same performance requirements. We do not agree that such an exception for DC lines is necessary or warranted. The decision in selecting DC vs. AC in transmission lines has traditionally been based on the break-even

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Commenter	**Yes**	**No**	**Comment**
			cost and performance of the two alternatives. The lower performance requirement may wrongly influence decisions on project alternatives in favor of DC facilities with less stringent requirements. Distinction Between Committed and Proposed Projects: 9. Models cannot discern the difference between a "committed" project, and a "proposed" project in a performance analysis. The standard should instead set criteria for when models can be relied upon for planning purposes such that changes to the future plan will not have an impact on reliability. The intent of Requirements R2.7.3 and R2.7.4 should be combined and added into R2.7.1.1. Rather than adding the additional requirement to document a criteria, the requirement should be that in the Near-Term Planning Horizon, projects cannot be removed (or modified) without demonstrating that the revised plan meets performance criteria. In addition, the requirement in R2.7.1.1 to supply a "project initiation date" is ambiguous. What will constitute "project initiation" …construction start date? …Engineering complete date? …Land procurement date? Funds allocated date (budgeted)? Suggested wording for R2.7.1.1. "Transmission and generation improvement projects for the Near-Term Transmission Planning Horizon, shall have in-service dates provided, and shall not have in-service dates changed, or be removed from planning models, without documentation to show that the revised plan meets performance requirements." Load Modeling Requirements: 10. The proposed TPL Standard contains numerous references to load modeling. The goal of improving and verifying the load model is worthwhile but is not appropriate for the TPL standards. Assessment of load model accuracy is best accomplished through detailed analysis of grid disturbance events. The main difficulties in accomplishing this are (1) grid events that significant reduce transmission voltages throughout a load area are infrequently occurring and (2) the process of recreating the event through simulation studies is extremely complex and time consuming. While these efforts should be encouraged they should remain a RRO prerogative. A few concerns not previously addressed by comments to Questions 1-42 include the following: R1.1.1 Use of expected Load mix - based on the actual or expected aggregate mix of industrial, commercial, and residential Loads. – This requirement is not justified as the load model may be developed through disturbance analysis rather than load type synthesis by customer class. Some Load Serving Entities may have great difficulty in creating load forecasts based on customer class. Load forecasting requirements are adequately addressed in the existing MOD standards and do not belong in the proposed TPL standard. R1.2. Load models with supporting rationale - that include power factor data that may be based on historical System performance, validated by measurement during stressed System conditions, or

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			documented Transmission planning area requirements. This requirement is not appropriate for the TPL standards. 11. R.3.3.2.1. Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment. – this Requirement in its present wording could be construed to mean that the precise amount of load between breakers should be specified and reevaluated with every assessment. This would unnecessary and burdensome, and we therefore seek clarification of this Requirement or its removal altogether. 12. Requirements for studies using Sensitivity cases: R2.4.3 appears to place equal importance on base cases and sensitivity cases with regard to the need to implement projects or Corrective Action Plans. Terms in TPL-001-1 using forms of the word "sensitivity" need to be clearly defined by the SDT. Additionally, the SDT needs to clarify its intent regarding required action based on results from sensitivity studies. We do not agree that results from sensitivity studies should be given equal standing with results from base scenarios, and we would particularly object to any insinuation that projects would need to be implemented to mitigate violations seen in a sensitivity involving speculative non-firm transfers. 13. Short Circuit Requirements: The new TPL standard also contains numerous references to short circuit analysis, which are new requirements that expand the TPL standards, but without specific testing or performance criteria. Evidence that short circuit studies have been performed is currently required in the existing FAC-002-0 Standard. Since the primary concern is the appropriate sizing of equipment and the prevention of equipment damage as opposed to overall grid reliability, we do not see the need for a set of requirements within the proposed TPL standard for short circuit studies. FRCC Specifics: One final specific issue concerns the topography and performance history of the Bulk Electric System in our particular region (FRCC). The FRCC system is a peninsular system having only one interface with the rest of the interconnected NERC system, and has historically demonstrated exceptionally high reliability with no events in recent history cascading beyond the FRCC system. While other areas of the NERC system may require some increased stringency in the TPL standards, PE feels that the adequacy of the existing TPL standards as they apply to the FRCC System has been extensively documented. Conclusion In conclusion, we believe that TPL-001-1 is unnecessary and burdensome. In particular, the

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Commenter	**Yes**	**No**	**Comment**
			elimination of footnote (b) will deny Transmission Owners and Transmission Operators the right to curtail Non Consequential Load in order to restore the Bulk Electric System. This elimination has absolutely nothing to do with the reliability of the Bulk Electric System; rather, it places the reduction of Customer Minutes of Interruption (CMI) ahead of reliability. Essentially, the emphasis of TPL-001-1 is inappropriately placed on the reliability of distribution feeders rather than the reliability of the Bulk Electric System. The fundamental objective of the existing TPL Standards has been to protect the reliability of the Bulk Electric System, and we believe all future TPL Standards should do the same. Given the aforementioned issues, we believe the proposed TPL standard is inferior to the existing Board approved TPL Standards, creates unnecessary confusion, and will require many iterations of industry comment and revision. As an intermediate approach, we would strongly urge the Standard Drafting Team that the existing TPL standards be modified to respond to FERC Order 693 directives, clarify any ambiguities, and that the proposed new standard not be pursued any further.

Response: 1. The SDT followed the suggestion of FERC in Order 693 to consolidate the 4 standards into 1 if possible. The SDT recognizes that it has it has raised the bar on performance in some areas and has done that due to criticisms and suggestions from various parties. The SDT realizes that this will have an impact and is working on an Implementation Plan that will address some of the concerns. This is a performance based reliability standard and does not and should not consider economics. The SDT has made numerous changes to the tables in an attempt to provide further clarity as to what needs to be done to achieve performance.
2. An Initial Conditions column has been added to the tables. The SDT has also changes several requirements in the tables to allow for more instances of where Load can be dropped.
3. The SDT studied available data and practices and determined that these Contingencies do belong in the single Contingency performance group.
4. Local Load pockets are recognized as a problem and the SDT will address them in a future revision.
5. The use of the defined term Facility Ratings was intentional to answer problems such as described here.
6. The SDT was responding to FERC Order 693 in the details for Extreme Events.
7. The SDT feels that 300 kV and above represents the backbone of the BES and as such warrants more stringent criteria.
8. This is the only comment received on this issue so no changes were made to the second revision of the standard. However, the SDT will continue to review the performance table in subsequent revisions.
9. This verbiage has been removed from the standard.
10. The SDT feels that the current MOD standards do not cover all of the modeling requirements for a planner. Therefore, the specific areas found lacking are described in the TPL standard. Once the MOD standards are revised appropriately, these requirements can be deleted from TPL. The SDT has re-written these requirements and they are now numbered Requirement R9 through R13.
11. R3.3.2.1 - FERC required documentation of Consequential Load loss in Order 693, paragraph 1795, (not Non-Consequential) and duration should be based on best judgment for the common cause of the event.
12. Addressing or not addressing deficiencies discovered as a result of runing sensitivity studies is at the discretion of individual entities. The language of the standard has been changed to require that the entity document why or why not the results of the sensitivities have affected the Corrective Action Plan.

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13. Short circuit studies are required as part of the Interconnection process. The TPL draft addresses on-going System changes and increases in available fault current due to the additions of circuits and resources, as listed in the Corrective Action Plan. Short circuit studies help determine appropriate equipment sizing and setting of protective relays. Such studies will help provide for a complete Corrective Action Plan, i.e., the installation of a transformer to resolve a System performance deficiency may require the installation of additional circuit breakers. FERC also noted the need to include this analysis to cover such conditions. The SDT has thoroughly considered the comments of all reponders. We believe that the revised draft of TPL-001-1 places the proper focus on BES reliability and the BES' mission to serve all firm Load under an appropriate range of Contingency events. Furthermore, the SDT believes that the current draft does in fact respond to the FERC Order 693 directives.			
ReliabilityFirst	☑		The requirement for short circuit studies (mentioned in R2 and included in all of R2.3) should be removed from this standard. Relay and protection engineers use a different type of software (Aspen and CAPE) for different reasons (to calculate phase and ground faults and perform relay coordination studies). Those types of studies should not be included in this standard and are totally separate from performing power flow and dynamics studies.
Response: The SDT believes that it is appropriate to include an assessment of the results of short circuit studies in the assessment of the reliability of the Transmission system. The standard does not specify requirements related to software or specific requirements of the studies.			
SRP	☑		The SDT should be commended for very good work at identifying many different issues of the TPL standards. However, TPL-001-1 should take into account the consequences of a Security-Based or Dependability-Based Misoperation (and failure) of the Protection System. 1) A Security-Based Misoperation of the Protection System may remove additional elements of the BES and could be listed in the table under "multiple contingency". 2) A Dependability-Based Misoperation (or Failure) of a non-redundant Protection System could cause long time delays in clearing faults and clear a large area of BES around the faulted Element. This type of failure may not provide local tripping or breaker failure initiation and remote Protection Systems would need to operate to isolate the fault or disturbance. Often the operation of the remote Protection Systems would cause long time delays in isolating faults and disturbances. a) The BES should be studied and those elements need to be identified where Dependability-Based Misoperations (or failures) would prevent meeting the performance requirements of Table 1 (Steady State) or Table 2 (Stability). This type of Misoperation (or Failure) will have to be included in the Tables. For example, some parts of the BES may be able to survive long time delayed clearing of faults caused by Dependability-Based Protection System Misoperations (or failures) and still meet the performance requirements of the tables. But other parts of the BES may experience cascading outages for this same scenario. One solution to minimize the consequences of Dependability-Based Misoperations (or failures) is to install redundant Protection Systems. The redundant Protection Systems would reduce the possibility of a single Dependability-Based Misoperation (or failure) from

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Commenter	**Yes**	**No**	**Comment**
			affecting the isolation of faults and disturbances. In addition, the TPL-001 standard will need definitions of Security-Based Misoperation and Dependability-Based Misoperation. The following definitions are used for PRC-004-WECC-1: Security-Based Misoperation: The incorrect operation of a Protection System or RAS for faults or disturbances outside the intended zone of protection. Security is a component of reliability and is the measure of a device's certainty not to operate falsely. Dependability-Based Misoperation: Any of the following ▪ The absence of a Protection System or RAS operation when intended ▪ A Protection System or RAS equipment failure is alarmed or indicated to operating personnel. ▪ A Protection System or RAS equipment failure is discovered. Dependability is a component of reliability and is the measure of a device's certainty to operate when required.
Response: To date, the SDT has done the following: Tables 1 and 2 have been revised. A Contingency involving the failure in the Protection System has been added as P5 in Tables 1 and 2. Also 2a-2d were added in the Table 2 Extreme Events. The SDT is continuing discussion on Protection System issues and will be making additional changes as appropriate in future versions.			
Santee Cooper	☑		1. Transmission Planners are currently able to maintain adequate levels of reliability using the existing TPL-001 thru TPL-004 standards. While incremental improvements can be made, it is not evident that prescribing more stringent planning requirements will result in significant reliability improvements. 2. Table 1 in the column titled "Interruption of Firm Transfer Allowed," does it pertain to point-to-point only, or does it also apply to network loads? Please explain how this provision is consistent with the requirement to re-dispatch to address system constraints. 3. There are no explicit performance requirements for normal system performance. 4. Requirement R1.1.2 refers to "normal weather patterns as agreed to by the Planning Coordinator(s) and the Transmission Planner(s)…" The standard and the ERAG MMWG need to be made consistent. 5. Requirement R2.3 There are no performance requirements for Short Circuit Studies. 6. Requirement R2.7.1.1 specifies a "project initiation date". This information is not needed for system reliability purposes.

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Commenter	**Yes**	**No**	**Comment**
			7. Requirement R3.2. There should be some flexibility for simulation of planning events. For certain areas of the BES, the resulting configuration after operator intervention could be more severe than the removal of all elements. For example, the operation of a transmission line with one end open may be more severe than opening both ends of the line. This respresents actual operation in order to restore service to stations on the line. 8. Requirement R3.3.2.1 requires an evaluation for "Consequential Load loss (expected maximum demand and expected duration). Load loss is not an ERO responsibility. 9.Requirement R3.3.2.2 does not permit the "shedding of firm Load or curtailment of firm transfers". This is not an ERO responsibility. 10. Requirement R3.6 states "Manual and automatic generation tripping is allowed for multiple Contingencies and for single Contingencies only in situations that meet all of the following conditions: TBD. Generators should be allowed to trip for single and multiple contingencies as long as Facility Ratings are not exceeded. In addition, generators should be allowed to trip for any condition that imperils the generator. System performance should be the criteria, not generator operating state. 11. Requirement R4.2 states "Contingency analyses shall simulate the removal of all elements including those that the System protection is expected to disconnect for each Contingency without operator intervention." Delete "including those". 12. Requirement R4.6.1 states that Plant Stability studies "Shall be performed for individual generating units 20 MW or greater…" Does this mean that studies must be performed for all units? Many plants have "sister units" that are essentially the same. This requirement seems to be excessive. 13. The R1 requirements should be deleted from this standard and should remain on the MOD standards. (MOD-010, MOD-012, and MOD-018) 14. Requirement R4.6.2 states that Plant Stability studies "Shall be performed for changes in the real power output of a generating unit by more than 10% of the existing capability or more than 20 MW whichever is greater." The meaning of this wording is unclear. 15. Requirement R4.6.3 states that Plant Stability studies "Shall be performed and evaluated for those Planning Events that would produce more severe System impacts and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. The

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Commenter	**Yes**	**No**	**Comment**
			identified Contingencies, at a minimum, shall be evaluated." The use of "evaluation/evaluated is unclear. Is an evaluation the same as performing a study? If not, what does it mean to select a contingency for evaluation? 16. The standard needs to define or describe the difference between a "bus" and a "bus section". 17. Table I, P3, P7.2, P9.6 and Table 2, P7 need some punctuation for clarification. Table I, P9.6 and Table 2, P9, why study replacing an outaged transformer with a spare? 18. The use of the terms "bus", "non-tie bus", and "bus section" are not clear. In P7-2 what is meant by the phrase or a bus and a stuck non-bus tie breaker ? Does this imply a bus or a bus section? How would you model this?

Response: 1. The SDT believes that more stringent planning ("raising the bar") is appropriate in some areas of the standard and will improve reliability.
2. The term "firm transfer" in Tables 1 and 2 has been replaced with "firm Transmission service".
3. Table 1 has been revised to include normal System performance requirements.
4. This requirement has been eliminated in response to various industry comments.
5. Short circuit duty is a Facilitiy Rating, and Facility Ratings shall not be exceeded.
6. The SDT agrees that this information is not required to meet reliability standards. It was specifically added as an additional piece of information in the Planning Assessment to allow some level of peer review within the NERC community and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them.
7. R3.2 - The SDT has added a line end open condition in P2.
8. R3.3.2.1 - FERC has jurisdiction over firm Transmission service. FERC allows the use of "equally or more efficient or effective approach" and firm Load is being used as a proxy for firm Transmission service.
9. This requirement is consistent with FERC Order 693.
10. The SDT agrees that SPS can include generation tripping. The SDT has modified the requirements to allow SPS for single and multiple Contingencies (See Requirement R 3.5).

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:

11. The SDT feels that the wording is equivalent.
12. The answer is yes it does.
13. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.

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Commenter	**Yes**	**No**	**Comment**
14. The SDT feels that the wording is clear as stated. 15. Evaluation is based on good professional judgment and knowledge of the System. It is not the same as a study. 16. "Bus section" is in the existing TPL standards; the SDT is not proposing to change its meaning. The SDT considered but has decided not to include a definition for "bus section". 17. Tables 1 and 2 have been revised. P9.6 has been deleted and replaced with a reference in Requirement R11 in the second draft. **R11**. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information. 18. The SDT has included a definition for Bus-tie Breaker. The SDT has clarified the event description for P7-2 (now P-4 in the second draft). **Bus-tie Breaker:** A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)			
SaskPower	☑		Saskatchewan commends the SDT for taking on this difficult and important task. We wish you good fortune. 1. Local area network load is allowed to be shed in Saskatchewan for single contingencies, and the interruption of firm transfers are allowed over our DC tie and AC tie-lines. The Saskatchewan Regulatory Jurisdiction has no plans to change this unless there is technical evidence to justify the increase in reliability versus the cost. 2. Also for P9-1, is there any justification for the selection of one mile? If there is none the development of exemption criterion should be delegated to the Planning Coordinator. It is not what Saskatchewan has used in designing its system, and it is going to involve a significant capital outlay for Saskatchewan with questionable reliability benefits. Saskatchewan will not support the default value of 1 mile unless there is a technical study (including reliability benefit versus cost) to support it as opposed to any other distance.
Response: 1. The SDT is required to address FERC Order 693 and cannot default to lowest common denominator. This issue is beyond the scope of the SDT and needs to be addressed at the NERC level. However, an Entity can request an "Entity Variance" in accordance with the NERC Reliability Standards Development Procedure (Page 27). **2.** The one mile allows for some measurable physical constraints to building separate lines in all locations, but limits the exposure to a fixed length, which is universally applicable. SaskPower can request an "Entity Variance" in accordance with the NERC Reliability Standards Development Procedure (Page 27).			
Seattle City	☑		The additional studies required by this proposed standards are going to put a burden on our utility. We do not have the additional human resources available to perform so much additional work. Also, the stipulation that no "non-consequential load" loss may occur will put a financial burden on our utility. We have always planned assuming that we would able to be shed residential load in case of

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Commenter	**Yes**	**No**	**Comment**
			an emergency caused by a N-2 event or regional outage beyond our control.
Response: The SDT believes that more stringent planning ("raising the bar") is appropriate in some areas of the standard and will improve reliability.			
SERC EC DRS	☑		1.In the Stability Performance Table, under contingency P8 with a line out add a generator contingency. and with a transformer out add a generator and a line contingency. 2. In the Stability table change the Extreme Events numbering to E1, E2, etc. 3. In R4.6 and other locations, the generator exemption of 20 MW should be increased to 75 MVA.
Response: 1. The transformer – line combination has been added. The SDT does not feel that the other cited events are a legitimate combination. If you have specific data to indicate otherwise, please provide it. 2. The SDT made changes to the format of Extreme Events. 3. This is consistent with FERC Order 693, the Large generator Interconnection procedures, and the registry criteria.			
SERC EC PSS	☑		Significant Increase in Study Activity Workload on Transmission Planners: 1. The increase in both steady state and dynamic studies required to ensure compliance with the proposed standards will result in increased costs and staff additions. The addition of the "Corrective Action Plan" requires the TP to provide a significant amount of documentation for each deficiency identified by the studies. Also, R3.2 requires that the studies simulate the protection scheme for all events. The current software tools cannot automate these studies for bus faults and breaker failure events, requiring each scenario to be studied manually. Additionally, experienced staff capable of performing analyses as described in the proposed standard have become increasingly difficult to find and retain and the talent pool of people with these skills has recently become depleted to alarming levels. Implementation Plan: 2. Given the intent of the proposed standard to encourage large scale investment in the EHV system, full implementation will take years, perhaps decades. Acquirement of right-of-way for new EHV lines has become increasingly difficult in recent years and inreasingly expensive. Legal, regulatory, and other difficult issues often take several years to navigate, even for 115kV lines. The Implementation Plan timeframe, if set too short, would be unduly burdensome on Transmission Owners forcing them to be less dicretionary with funds than would be prudent. The proposed implementation plan should include provisions for those cases where viable solutions simply can not be implemented in time due to circumstances beyond the control of Transmission owners. We recommend a minimum of 15 years for the transition. Design and Construction Constraints: 3. Even if right-of-way and other legal and regulatory hurdles are cleared, and the capital funding for such a tremendous level of investment was not an issue, the other resources required to actually

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Commenter	**Yes**	**No**	**Comment**
			construct the projects are equally difficult and costly to secure. Raw material prices on comodities like copper and steel have skyrocketed in recent years. Additionally, the skilled labor and Engineering resources are constrained with labor rates almost keeping up with other resource costs. Overall project costs have more than doubled over the last 7-10 years. Recent press releases concerning new generation being planned and then scrapped due to the rapid escalation of project costs are public evidence of this. The inflationary mark-up is impossible to estimate but much less will be built with the same capital investment than is currently envisioned. Cost-Benefit Analysis: 4. The proposed standard will be exceedingly expensive to become compliant with unprecedented levels of capital investment in Transmission facilities. Before the standard comes to official vote, it would be prudent for a cost-benefit analysis to be performed to determine if the reliability improvements truly justify the huge expenditures certain under the proposed standard. Additionally, as many jurisdictional rate structures share the cost of such investments between retail and wholesale customers, cost-benefit analyses should be completed for both retail and wholesale customers. System Adjustment Clarification: 5. The term "System Adjustment" as outlined in the tables should be better defined. The use of generation for redispatch may have nuances which preclude or otherwise limit their use for studies. Perhaps some clearer guidelines on what is allowed would facilitate transparency and coordination between Transmission Planners. Transmission Service Evaluation: 6. A major concern is that the proposed standard appears to be disjointed from the requirements for selling firm Transmission Service. The increase in reliability gained from the proposed standard would, in some regions, quickly be eroded by new firm sales if those sales are based on the historical N-1 ATC requirements. The proposed standard must be applied to long-term firm transmission service requests if Transmission reliability is to be truly enhanced. If the standard is not applied to Transmission Service evaluation, reliability levels for the different classes of firm customers will diverge.
Response: 1. The SDT understands the potential increases in work load. The draft standard allows the use of past studies to meet the current year assessment and study requirements. Requirement R3.2 does not require study of the protective scheme for all events, only that "Contingency analyses shall simulate the removal of all elements including those that System protection is expected to disconnect for each Contingency without operator intervention". For example, the requirement is that the outage simulation should be from breaker to breaker. In addition, Requirement R.3.2.2 only requires the studies consider relay loadability and identify how loadability is treated in the steady state simulation, not to study relay loadibility. 2. The SDT understands that there are extended transitionary issues associated with responsible entities becoming compliant with the new			

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Commenter	**Yes**	**No**	**Comment**
standard. The SDT plans to draft an extended implementation plan to accommodate such issues. The plan will be provided for the third posting of the standard. 3. The SDT understands that there are extended transitionary issues associated with responsible entities becoming compliant with the new standard. The SDT plans to draft an extended implementation plan to accommodate such issues. The plan will be provided for the third posting of the standard. Cost issues are outside the scope of NERC reliability standards. 4. The treatment of Transmission infrastructure costs is outside the scope of the NERC reliability standards. 5. The Transmission performance tables have been modified to bring clarity to the Contingencies required for performance studies and when Non-Consequential Load Loss is permitted to meet requirements. The use of manual or automatic System adjustments to revise System topology as well as generation redispatch is always permitted so long as the actions can be performed while adhering to Facility Ratings. 6. The SDT plans to draft an implementation plan. This implementation plan will address, among other issues, the other standards, which will need to be brought into alignment with this standard. The plan will be provided for the third posting of the standard.			
SERC RRS OPS	☑		Cost-Benefit Analysis: 1. Transmission Providers are currently able to maintain adequate levels of reliability using existing standards. While incremental improvements can be made, it is not evident that prescribing more stringent planning requirements will necessarily result in significant reliability improvements. 2. The proposed standard will be exceedingly expensive to become compliant with unprecedented levels of capital investment in Transmission facilities. Before the standard comes to official vote, it would be prudent for a cost-benefit analysis to be performed to determine if the reliability improvements truly justify the huge expenditures under the proposed standard. 3. In Table 1 in the column titled "Interruption of Firm Transfer Allowed," does it pertain to point-to-point only, or does it also apply to network loads? Please explain how this provision is consistient with the requirement to re-dispatch to address system constraints. 4. The terms "Consequential Load Loss" and "Non-consequential Load Loss" should be deleted and Table 1 should be modified to discuss "Planned Load Loss" and "Unplanned Load Loss". It should not matter if the load is directly connected to the failed facility or downstream and served by the failed facility. If the plan to protect the interconnected grid is to disconnect those loads using a manual process or an automatic scheme, then it should be allowed. 5. The R1 requirements should be deleted from this standard and should remain in the MOD standards.
Response: 1. The SDT believes that more stringent planning ("raising the bar") is appropriate in some areas of the standard and will improve reliability. 2. Any changes in the new draft Standard have been carefully weighed and discussed by the SDT. The SDT does not believe that a formal cost benefit analysis is required. However, if you have cost data which you would be willing to supply to the SDT, we will take it under			

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Commenter	**Yes**	**No**	**Comment**
consideration. 3. Tables 1 and 2 have been revised to replace the term "firm transfer" with "firm Transmission service". 4. The SDT feels that the terms are being used consistent with FERC Order 693. 5. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.			
SCE&G	☑		General Comment. 1. Cost/Benefit analyses should be conducted on each change in a standard or new standard. 2. Requirement 7.2 will require a 2 bus outage test on the SCE&G transmission system. Most of our busses are straight busses and a stuck line-terminal breaker will result in a clearing of the connected bus (and all facilities connected to that bus). Our read of this requirement is that we must design the system to accommodate a stuck breaker event (outaging all connected facilities) while a different bus (and all of its connected facilities) is already outaged. This is a significant leap in the required performance of our system and will result in tremendous unwarranted costs and years of new local area transmission construction. 3. Requirement R1.1.2 refers to "normal weather patterns as agreed to by the Planning Coordinator(s) and the Transmission Planner(s)…" The ERAG MMWG considers normal weather to be such that the weather affected load to be that which has a 50% probability of, plus or minus. The standard and the ERAG MMWG need to be made consistent. 4. Requirement R2.7.1.1 specifies a "project initiation date". This information is not needed for system reliability purposes. 5. Requirement R3.3.2.1 requires an evaluation for "Consequential Load loss (expected maximum demand and expected duration). Load loss is not an ERO responsibility. 6. Requirement R3.3.2.2 does not permit the "shedding of firm Load or curtailment of firm transfers". This is not an ERO responsibility. 7. Requirement R3.6 states "Manual and automatic generation tripping is allowed for multiple Contingencies and for single Contingencies only in situations that meet all of the following conditions: TBD. Generators should be allowed to trip for single and multiple contingencies as long as Facility Ratings are not exceeded. In addition, generators should be allowed to trip for any condition that imperils the generator. System performance should be the criteria, not generator operating state.

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Commenter	**Yes**	**No**	**Comment**
			8. Requirement R4.2 states "Contingency analyses shall simulate the removal of all elements including those that the System protection is expected to disconnect for each Contingency without operator intervention." Delete "including those". 9. Requirement 4.6.1 states that Plant Stability studies "Shall be performed for individual generating units 20 MW or greater…" Does this mean that studies must be performed for all units? Many plants have "sister units" that are essentially the same. This requirement seems to be excessive. 10. Requirement 4.6.2 states that Plant Stability studies "Shall be performed for changes in the real power output of a generating unit by more than 10% of the existing capability or more than 20 MW whichever is greater." The meaning of this wording is unclear. 11. Requirement 4.6.3 states that Plant Stability studies "Shall be performed and evaluated for those Planning Events that would produce more severe System impacts and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. The identified Contingencies, at a minimum, shall be evaluated." The use of "evaluation/evaluated is unclear. Is an evaluation the same as performing a study? If not, what does it mean to select a contingency for evaluation? 12. The standard needs to define or describe the difference between a "bus" and a "bus section" and ensure that the use of these terms in the standard are as intended. 13. Table I, P3, P7.2, P9.6 and Table 2, P7 need some punctuation for clarification. 14. Table I, P9.6 and Table 2, P9, why study replacing an outaged transformer with a spare?

Response: 1. Any changes in the new draft Standard have been carefully weighed and discussed by the SDT. The SDT does not believe that a formal cost benefit analysis is required. However, if you have cost data which you would be willing to supply to the SDT, we will take it under consideration.
2. The SDT feels that this requirement is appropriate for a North American standard. The eventual Implementation Plan will address the timeframe for compliance.
3. This requirement has been eliminated in response to various industry comments.
4. The SDT agrees that this information is not required to meet reliability standards. It was specifically added as an additional piece of information in the Planning Assessment to allow some level of peer review within the NERC community and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them.
5. The SDT disagrees. FERC Order 693, Paragraph 1794 specifically prohibits loss of Non-Consequential Load for a single Contingency. Furthermore, FERC required documentation of Consequential Load loss in Order 693, paragraph 1795.
6. R3.3.2.2 - R3.3.2.2 has been revised and the phrase "shedding of firm Load or curtailment of firm transfers" has been deleted.

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Commenter	**Yes**	**No**	**Comment**
R3.3.2.2. Following single Contingency events, ~~System adjustments other than shedding of firm Load or curtailment of firm transfers are permitted to meet performance requirements provided these adjustments can be accomplished within the time period allowed by the applicable time limited ratings.~~ Transmission configuration changes and redispatch of generation are allowed provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits. 7. The SDT agrees that generation tripping can be included. The SDT has modified the requirements (See Requirement R 3.5). **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met: 8. The SDT feels that the wording is equivalent and no changes are necessary. 9. and 10. This is consistent with FERC Order 693, the Large generator Interconnection procedures, and the registry criteria. 11. Evaluation is based on good professional judgment and knowledge of the System. It is not the same as a study. 12. The SDT considered but decided against adding a definition because the term "Bus Section" is in the existing TPL Standards and its meaning is generally understood. 13. Tables 1 and 2 have been revised. 14. P9.6 has been deleted and replaced with a reference in Requirement R11 in the second draft. **R11**. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information.			
Southern Transm.	☑		REQUIREMENTS: 1. The standard is not clear on whether corrective action plans are required for performance failures during the sensitivity analysis required for both steady-state and stability studies. In the phone conference John Odom stated that it was not the intent of the Drafting team to require that facililities be constructed for these conditions. The standard should be made clear on this point. 2. The Load Forecast section (R1.1) is new and is a duplicate of the requirements in the MOD standards and is unclear as written. Having similar requirements in multiple standards creates the possiblility of conflicting requirements for the industry. If there are different requirements necessary, the MOD standards should be modified and not introduce a new section to the TPL standards. 3. R1.1.1 is unclear in what is intended by the "actual or expected aggregate mix of industrial, commercial, and residential load". Does the word "aggregrate" mean that the split between customer classes should be at the Balancing Authority level or at each load bus represented in the model. In many cases this could place a requirement for substantial load research on the the industry which may take a substantial amount of time and expense to accomplish. The use of the phrase "actual or

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Commenter	**Yes**	**No**	**Comment**
			expected" indicates an expectation that it be based on research and not general industry averages as may be more practical in some cases. 4. The wording in section R1.2 is very unclear. Is the intent to allow for three different methods for obtaining power factor models, i.e. historical system performance, validated by measurements during stressed System conditions, or documented Transmission planning area requirements? The other understanding is that the historical System performance is only measured during stressed System conditions. If this is the intent, what is the definition of stressed system conditions that is intended? Is this just heavy loadings, such as peak times, or is it during sytem disturbances? This is not clear. We suggest that the following words be used instead: "Load models validated by measurement during load levels typically studied or documented Transmission planning area requirements." 5. Requirement R1.4 should be qualified as only the outages within the Planning Horizon. There is no need to include protective relays because outages of relays in the Planning Horizon would not be known. We suggest the following words: "Known planned outages within the Planning Horizon and long-term outages greater than one year within the Planning Horizon for Transmission and generation equipment with consideration given to spare equipment strategy." 6. R1.5: If this places a requirement on the PC to define what constitutes "planned facilities", then this should be explicitly stated as a requirement. 7. R2.1 allows Assessments to be supplemented with "qualified" past studies which are defined in R2.6. R2.6.1 specifies these to be less than three years old for steady-state analysis and certain changes could not have occurred in the "System". There should be some qualification to the definition of "System" to include "the vicinity" of the area under evaluation. We would surmise that there always be some change in topology in the Eastern Interconnect which would preclude the use of past studies. Note that the "in the vicinity of" wording is used with the plant stability studies already. Also, is the intent with the "less than" to eliminate the use of studies three years old? Similar comments can be made for R2.6.2 and R 2.6.3. 8. R2.1 The wording/structure is confusing. The "Planning Assessment shall address all five years", but this does not require all five years be studied. It appears that the minimum study requirements would be two peak studies (years 1 or 2 & 5), one off peak study (any year), and one senstitivity case for each. Is this a correct reading? 9. In R.2.1.3.1 it is unclear what is intended. The study can be for higher or lower load "forecasts" with a different load power factor due to season, weather, or time of day. If you are looking at different seasons, weather, or time of day you will have a different load forecast. Is the intent to

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			require the studies to model different seasons or times of day that will generate different power factors or is it to focus on higher or lower loads, i.e. is it a load forecast exercise or a power factor exercise? Can we look at Spring conditions and have it qualify for this requirement even though the loads are consistent with my Base Case load forecast? 10. Requirement R2.1.3.3 lists "unavailability of long lead time facilities" as one of the sensitivity(ies) that should be evaluated. It is unclear whether this refers to the construction of projects with long lead times or for replacement of failed equipment that have long lead times for obtaining replacements. One of the drafting team members suggested it was the latter understanding that was intended. We suggest that the language be changed to "Delayed restoration to service of failed facilities with long lead times for repair". This may clarify the intent of the requirement. 11. R2.1.3.7 should be modified to read "Modification of planned long term Transmission outages." 12. R2.3.1 Does "current study" refer to an updated study or is this referring to some type of short-circuit analysis? It appears that analysis is required only every five years unless changes in the BES occur. Is this a correct reading? 13. R2.4: Need to clarify that "address all five years of the assessment period" does not necessarily require that each year must be studied individually. A study of one year could cover all 5 years if it is the worst case. 14. R2.4.3.2 Is the purpose of including non-firm transfers to identify generation limits? Please clarify that the intent is not to require constraints associated with non-firm transfers to be addressed. 15. R2.5.2: The addition of a transmission line always helps plant stability. Therefore, this should not be included as a change requiring a new study. 16. R2.7.1.1 requires that the action plan include a project initiation date as well as the in-service date. The project "initiation date" is not defined and can be interpreted as being when you thought up the project, when you started spending money on design, or when you actually started construction. As long as you have the in-service date when the project is needed, we do not see any major benefit from recording and documenting an "initiation" date. The length of time that it requires to complete a project is extremely variable based on many conditions so we're not sure what benefit, if any, will be gained by recording and documenting the initiation date. It may be impossible for someone not familiar with the legal, regulatory, etc. requirements in a given area to judge whether the timing is appropriate or not. This requirement should be eliminated.

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			17. R2.7.5 calls for the review of the implementation status of facilities. This imposes a large documentation requirement which has no benefit in reliability. We suggest making this requirement on an "as requested" basis. 18. Requirements 3.2 and 4.2: Delete the words "including those" so that it reads "the removal of all elements that System protection is expected...". As currently written, it sounds like you are going to remove more elements than the protection will remove. 19. R3.2 requires that the contingency analysis shall simulate the removal of all elements including those that System protection is expected to disconnect for each contingency without operator intervention. At present most steady state analysis uses single "element" contingency with element defined as transmission lines or transformers as defined in the Power Flow cases. In a significant number of cases these individual "lines" are part of a larger "protection control group" (PCG). that would remove multiple elements encompased by the breakers in the PCG The present load flow tools (PSS/E) do not have features that will allow this type of analysis in an automated manner. To facilitate this change in required analysis, program modification will be needed or additional programs written. For an example with a line from bus A to B and then B to C with breakers at A and C and load at B, the outage of either A to B or B to C with load service remaining at Bus B may produce a more stringent condition than removing A to B to C. It appears that the new requirement is requiring the A to B to C analysis instead of the more stringent A to B or B to C. 20. Requirement R3.2.1 is unclear. Generators generally have both a high and a low voltage limitation on the terminal voltage related to station service reqirements. Most load flow representations for generators tend to hold the voltage on the high side of the GSU instead of the low side. Is this requirement attempting to say that the voltage limitations on the generator terminals must be considered or is it something else? This should be made clear in the requirement. 21. R3.3.2.1 requires that the amount of "consequential Load loss following a single Contingency shall be identified and the anticipated duration be recorded". This is an arbitrary requirement that will require significant time and effort to document and will provide no useful information from a planning perspective. Also the inclusion of an "expected" duration is more arbitrary than the actual amount of load. The time required to restore the facilities is a pure guess at best since it will vary substantially based on circumstances and conditions. Since we are also required to remove all elements that the protection control group (PCG) will open instead of just a single "power flow model" line, some of the load may be restored during switching action for tapped loads and some may not. This creates an additonal confusion of what is required to be recorded in terms of duration and load reduction. We see no benefit from identifying and documenting either the amount of consequential

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Commenter	**Yes**	**No**	**Comment**
			load lost or the estimated duration that would justify the time and effort required. 22. R3.3.2.2 This states that curtailments of firm transfers are not permissible following single contingency events to meet the performance criteria. Please clarify whether "firm transfers" refers to firm point to point service only, or if firm network service is also included. Said another way, is the curtailment of a network resource permissible following single contingency events to meet the performance criteria? If not, please clarify how redispatch service as required by Order 890 should be considered. If curtailment of a network resource is permited, please clarify why curtailment of PTP would be held to a higher standard. Also, please clarify whether R3.3.2.2 applies to P6. Lastly, please clarify how Conditional Firm Service (CFS) as required by Order 890 should be considered in meeting R3.3.2.2. CFS allows the curtailment of "firm" PTP transfers. This appears to be in conflict with the performance criteria. 23. Requirement R3.6 is not clear. It could be interpreted as generator tripping allowed for multiple contingencies only for the situations that meet the "to be determined" conditions. Generator tripping should always be allowed for multiple contingencies. 24. R4.5 and R4.6: We suggest dropping the words "For the" in each of these. 25. R4.6.1: Plant stability studies should not be required for generating units as small as 20 MW. The threshhold should be 100 MW or greater. 26. R4.6.3: The last sentence "The identified Contingencies, at a minimum, shall be evaluated" is redundant because the requirement already says "shall be performed and evaluated" The last sentence should therefore be deleted. TABLE 1 - STEADY STATE PERFORMANCE: 27. In Table 1 in the column titled "Interruption of Firm Transfer Allowed," does it pertain to point-to-point only, or does it also apply to network loads? Please explain how this provision is consistient with the requirement to re-dispatch to address system constraints. 28. Steady state table, extreme event description, section 3: Items d and f are operating issues and therefore should not be included in the table. Also, items c and d are identical. Items d and f are identical. 29. Steady state table: Add the requirement to study n-0 to the table so it will be complete. Call it P0.

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			30. Steady state table and stability table: Change the heading which now says "For all Planning Events" to say "The following performance requirements must be met for the Planning events evaluated in addition to the requirements given in the columns" 31. Steady state table: For the event in P3, it is not clear what the "above 300 kV" applies to. Is it only the transformer? Or it it also the transmission circuit and generator? Also, the third column mentions DC when there is no DC in the event. 32. The event description in P3 is confusing. Please consider rewording in the 1,2,3 format of the other event descriptions. The term "non-bus tie breaker" is confusing. Please consider using "breaker (excluding bus ties)". Also, above 300 kV, most construction is either ring bus or breaker and a half. Please considered deleting the bus outage contingency. Lastly, please clarify how redispatch and CFS should be considered in the context of P3 and P4, in which the curtailment of firm transfers is not permissible to meet the performance criteria. 33. Steady state table: For transformers below 300 kV, P9.6 is no different from P8.3. We suggest adding the clarification of "above 300 kV" for P9.6. 34. Steady state table Extreme Event: 3.b "A successful cyber attack" needs to be clarified. What should the contingency be? 3.g Add the words "As applicable" to the beginning. 3.h This should be changed to "Other events as deemed appropriate by the PC based upon operating experience". Otherwise there will be no end to the contingencies that must be studied. 35. Several events in the tables use the term "internal fault" for a breaker. The SDT needs to explain what is intended by this term. 36. Steady State Performance Requirement, Table 1, Performance Levels P1-P4, should allow for the interruption of firm transfers if the transfer is dependent upon on the outaged equipment (whether AC or DC) to provide an electrical path specified in the transfer. Therefore, the current verbiage used for the outage of a DC Line should be applied to all levels and state, “Yes, if transfer is dependent on the outaged equipment to provide an electrical path for service” 37. Steady state and stability tables: in the Extreme Events section heading, the word "all" implies that all events must be evaluated when this is not the intent. Either make the heading "For Extreme Events" or make it "For all Extreme Events evaluated".

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			TABLE 2 - STABILITY PERFORMANCE TABLE: 38. Stability table, note 1.a.i: P3.2 should be P2.3. 39. Several events in the tables use the term "internal fault" for a breaker. The SDT needs to explain what is intended by this term. 40. In event P7.2, does the "below 300 kV" apply to the generator, transmission circuit, transformer, and bus as well as to the stuck breaker? Or does it apply only to the stuck breaker? 41. The event description in P3 is confusing. Please consider rewording in the 1,2,3 format of the other event descriptions. The term "non-bus tie breaker" is confusing. Please consider using "breaker (excluding bus ties)". Also, above 300 kV, most construction is either ring bus or breaker and a half. Please considered deleting the bus outage contingency. Lastly, please clarify how redispatch and CFS should be considered in the context of P3 and P4, in which the curtailment of firm transfers is not permissible to meet the performance criteria. 42. Steady state table and stability table: Change the heading which now says "For all Planning Events" to say "The following performance requirements must be met for the Planning events evaluated in addition to the requirements given in the columns" 43. Steady state and stability tables: in the Extreme Events section heading, the word "all" implies that all events must be evaluated when this is not the intent. Either make the heading "For Extreme Events" or make it "For all Extreme Events evaluated". 44. Stability table, footnote 1.a.ii. After "out-of-step protection", add the words "or some other means to trip the generator for this condition". GENERAL: 45. The overall level of documentation required by this standard is excessive.
Response: 1. The SDT is providing some guidance under Requirement R2.1.3 on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. It is the entity's decision to establish and document which transfers are more significant to study System responses. Requirement R 2.7.2 has been added to require a description of how and why the list of actions was modified and/or expanded as a result of the inclusion of the sensitivities selected. The SDT fells that the standards are clear that the sensitivity studies do not in themselves establish the need for a plan, only the areas of the System for which the analysis is needed.			

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R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.7.2**. ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1. 2. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. 3. The terms "actual" and "aggregate" have been deleted. However, the SDT believes the term "expected" allows for flexibility in determining the necessary modeling information. 4. The SDT's initial attempt was to allow any of the three methods listed for obtaining power factor models. The SDT has removed Requirement R1.2 from the draft and replaced it with a new Requirement R9 in the revised draft to have the Distribution Provider provide real and reactive Load forecast data based on expected or historical system performance. **R9.** Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information. 5. The SDT has revised this requirement based on industry comments to delete the reference to "protective relays" and to clarify the intent that *known* planned outages and long-term outages for Transmission equipment, including the impact of spare equipment strategy, be considered, and to be responsive to FERC Order 693, paragraph 1725. 6. The referenced verbiage has been deleted from the revised standard. 7. The intent of the requirements was to put an upper bound on the shelf life of the study and bracket the applicability of the study such that, if changes were made that may effect results of the previous studies, they shouldn't be used. The SDT agrees with your comment and clarified the wording in Requirements R 2.6.1, 2.6.2, and 2.6.3. **R2.6.1**. For steady state, short circuit, or System Stability analysis: ~~if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market structure changes~~ the study shall be five calendar years old or less. **R2.6.2**. For steady state, short circuit ~~analysis~~, Generating Plant Stability, or System Stability analysis: ~~if the study is less than five years old and no material changes have occurred to the System in the intervening period.~~ the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study			

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area.

R2.6.3. ~~For plant and System Stability analysis: until material changes in the System make the study no longer valid. Material changes in the system include the addition of a Transmission Line or a generator~~

8. You are correct. The standard does not require that all 5 years be studied. The standard only requires that the assessment address the five year period. Section 2 provides guidance as to the minimum number of current studies required to produce a meaningful assessment without being totally prescriptive. It is the responsibility of the entity to determine if past studies, in conjunction current studies, sufficiently demonstrate that the performance requirements are met. If past studies in conjunction with the required current studies are not sufficient to demonstrate that the system can meet the performance needed, the entity will need to run additional current studies that demonstrate it can meet the requirements.
9. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3.1 provides the flexibility to allow the planning entity to decide how a variation in load on the entity(ies) system should best be studied. Requirement R2.4.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.4.4 has been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own System. In either case the entity must document the reason for running or not running cases for the items listed. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance. It is the entity's decision to establish and document if it needs to consider future additions and retirements. It is the entity's responsibility to determine the actions necessary to handle such items and which are more significant to study system responses.

R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:

R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

10. The SDT is providing guidance regarding the sensitivity studies while not being totally prescriptive. Requirement R2.1.3.3 provides the flexibility to allow the planning entity(ies) to elect the type of long lead time project that should be included in the analysis. It can be either a long lead time from replacement for failed equipment or a long lead time associated with constructing a new facility. Requirement R2.4.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.4.4 has been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own System. In either case the entity must document the reason for running or not running cases for the items listed. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance. It is the entity's decision to establish and document if it needs to consider future additions and retirements. It is the entity's responsibility to determene the actions necessary to handle such items and which are more significant to study system responses.
11. Since this requirement is relating to sensitivity, it is up to the entity to determine if it is appropriate to reduce the length of or increase

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Commenter	**Yes**	**No**	**Comment**
the length of the "planned outage" that it has considered in its base case studies. 12. In the standard, "current study" is intended to refer to an updated study (i.e., as opposed to a "past study"). The SDT received comments that "current" study could be misconstrued in reference to short circuit "current" (amperes) versus the intended meaning. The SDT revised the standard in an attempt to clarify the intent. A current study will need to be performed as part of the annual Assessment if there are changes warranting one. Until such time as a BES change occurs, studies have to be refreshed at least every five years. 13. The use of the terms "shall address" is trying to convey that message, the requirements detail the studies needed. 14. R2.4.3.2 - Non-firm transfers are included in Requirement R2.4.3.2 to be investigated as sensitivity. The second draft of the proposed standard clarifies in Requirement R2.7 that the corrective actions do not need to be developed solely to meet the performance requirements for sensitivities. **R2.7** - For Planning Events shown in Table 1 – Steady State Performance and Table 2 – Stability Performance, when the analysis indicates an inability of the System to meet the performance requirements in the tables, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed ~~over time~~ in subsequent assessments but the System shall continue to meet the performance requirements in the tables. ~~Such plans shall:~~ Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities. 15. The language was changed to reflect this comment. **R2.5.2**. Material Transmission System changes ~~in the electrical vicinity of existing generation are made~~ are made at or near the point of Interconnection of existing Generation such as the ~~addition or~~ removal of a Transmission Line ~~at or near the point of Interconnection~~ or the addition of a new substation in one of the Transmission Lines connected to the plant. 16. Requirement R8 (old Requirement R6) which focuses on the distribution of the Planning Assessment results among affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old Requirement R6). Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. Typically the date would indicate when significant resources will begin to be employed. This covers any project proposed for the near term. The SDT continues to believe that by providing the expected project intiation date of System improvements provides useful information to neighboring entities. The SDT believes that initiation dates are required for near-term corrective action plans to give an indication that the corrective action plans can be implemented in time. 17. The SDT does not percieve this as an onerous report requirement. The intent is that a list of proposed upgrades be reviewed and modified on a periodic basis. The intent of making the information available is to notify parties that may be impacted by a particular project of a change in the implementation of the project. 18. Based on industry comments, the language referenced in this comment was retained but modified in revised Requirement R5.2 to clarify intent. **R5.2**. Contingency analyses shall simulate the removal of all elements including those that System protection and other automatic controls are ~~is~~ expected to disconnect for each Contingency without operator intervention.			

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19. There may also be the case where the outage of A to C overloads a parallel circuit whereas having the C to B line is service does not overload the parallel circuit. The outage of the A to C line by automatic interruption is the more realistic outage because of the interrupting devices on the ends of the line. Both conditions are now covered in Table 1 and Table 2.
20. Most commenters did not express confusion over this requirement, so it was not modified. Requirement R3.2.1 is intended to address all voltage limitations applicable to generators, which could include nuclear plant operating voltage limits, generator terminal voltage limitations, and station service voltage limitations, for example.
21. R3.3.2.1 - The requirement concerning Consequential Load is to address FERC Order 693, which directs the ERO, among other things, to clarify footnote (b) in regard to Load loss following a single Contingency, specifying the amount and duration of Consequential Load Loss and System adjustments that are permitted after the first Contingency to return the System to a normal operating state.
22. The SDT has revised this requirement accordingly. The SDT does not feel that this standard distinguishes between PTP and network service. P6 has been revised and now shows as P2 in the revised table and shows a separation for performance above and below 300 kV. The SDT is still studying CFS and results will be shown in future revisions.

R3.3.2.2. Following single Contingency events, ~~System adjustments other than shedding of firm Load or curtailment of firm transfers are permitted to meet performance requirements provided these adjustments can be accomplished within the time period allowed by the applicable time limited ratings.~~ Transmission configuration changes and redispatch of generation are allowed provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits.

23. The SDT has modified the requirements for single and multiple Contingencies (See Requirement R 3.5).

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:

24. The SDT feels the wording is equivalent and no change was made.
25. This is consistent with FERC Order 693, the Large generator Interconnection procedures, and the registry criteria.
26. The SDT has made this correction.
27. Tables 1 and 2 have been revised to replace the term "firm transfer" with "firm Transmission service".
28. The SDT revised the Extreme Events accordingly.
29. Table 1 has been revised to include N-0.
30. The SDT made a change to the heading.
31. A footnote reference has been added for clarity.
32. Tables 1 and 2 have been revised to provide clarity. The term "Firm Transfer" has been replaced with "Firm Transmission Service". In addition, the SDT has proposed a definition for Bus-tie Breaker in the second draft.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)

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Commenter	**Yes**	**No**	**Comment**
33. Tables 1 and 2 have been revised. P9.6 has been deleted and replaced with a reference in Requirement R11 in the second draft. **R11**. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information. 34. Tables 1 and 2 have been revised. The SDT cannot add "as applicable" to a standard because this term will make the standard unenforceable. The SDT notes that Requirements R3.4 and R4.5.2 allow for identifying and evaluating only those Extreme Events that are expected to produce more severe System impacts. 35. Breaker internal fault is a term used in the existing TPL standard. The SDT has added clarifying footnote number 5 in Table 1 and footnote number 4 to Table 2. 36. The SDT has revised Tables 1 and 2 to replace the term "Firm Transfer" with "Firm Transmission Service". 37. The SDT has made this change. 38. The SDT corrected the note. 39. This is explained in Table 1 - Note 5. 40. 300 kV applies to the equipment being studied and as defined for transformers and generators in Table 1 – Note 3. 41. The tables have been re-formatted for clarity. The SDT considers the term Non-Bus-tie Breaker as common nomenclature and has provided a definition of Bus-tie Breaker for clarity. The SDT feels that this requirement must remain to cover those situations where ring busses are not employed. CFS is still being studied by the SDT and will be handled in future revisions. 42. The SDT has changed the heading. 43. The SDT has made this change. 44. The SDT has made this change. 45. The SDT expects that increased documentation will improve coordinated Planning Assessments among the Planning Coordinator and the Transmission Planners.			
Tenaska	☑		The proposed standard contains a number of areas that need further definition, more explanation, or more specificity. 1. For example, requirement R1 should be rewritten as follows to make it clear who has responsibility for each requirement AND sub-requirement as the standard as written could be read to imply that Transimssion Owners and Generation Owners have to supply a load forecast to the Planning Coordinator: R1. Each Resource Planner, Transmission Planner, Transmission Owner, Generator Owner, and Load-Serving Entity shall each provide, as specified below, its respective Planning Coordinator with the following modeling information required for System performance studies upon request (within 30 calendar days) : [Violation Risk Factor: TBD] [Time Horizon: TBD] R1.1. Each Load Serving Entity shall provide the Planning Coordinator load forecasts adhering, at a

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Commenter	**Yes**	**No**	**Comment**
			minimum, to the following criteria: R1.1.1. Use of expected Load mix based on the actual or expected aggregate mix of industrial, commercial, and residential Loads. R1.1.2. Based on normal weather patterns as agreed to by the Planning Coordinator(s) and the Transmission Planner(s) for the area(s) of their responsibility. R1.1.3. Identification of Demand Side Management (DSM) Load reductions consistent with operational requirements. R1.2. Each Load Serving Entity shall provide the Planning Coordinator load models with supporting rationale that include power factor data based on historical System performance, validated by measurement during stressed System conditions, or documented Transmission planning area requirements. R1.3. Each Load-Serving Entity shall provide the Planning Coordinator the Firm transfers/Interchange Schedules and resources required to supply Load for each Balancing Authority. R1.4. Each Transmission Owner and Generation Owner shall provide the Planning Coordinator with known planned outages and long-term outages for Transmission and Generation equipment including protective relays with consideration given to spare equipment strategy. R1.5. Each Transmission Owner, Generation Owner, Resource Planner, and Transmission Planner shall provide known planned Facilities defined in accordance with the documented criteria of the Planning Coordinator, including but not limited to: Transmission Lines, generators, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies. The above is an example and I apologize for the poor pagination. However, the drafting team should look at each requirement/sub-requirement and specify precisely to which entity the requirement/sub-requirement applies. Other comments/concerns/questions with the proposed standard: 2. Does requirement R2 mean that you could have two assessments: one performed by the Transmission Planner and one performed by the Planning Coordinator? This could result in two assessments of the same facilities which may or may not be desired. 3. In Requirement 2.5.1, what is meant by increasing generation? Is there a minimum amount of increased generation or is it any increase? 4. In Requirements 2.5.2, 2.6.1, 2.6.2, and 2.6.3, what is meant by "material"? This needs more

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Commenter	**Yes**	**No**	**Comment**
			definition wherever the word "material" is used throughout the standard. 5. In Requirements 2.6.1, 2.6.2, and 2.6.3, the word System and system are both used. Whose System or system needs to be defined. Does that include neighboring system(s)? 6. In Requirement 2.7.3, "committed" and "proposed" need to be defined. 7. In Requirement 2.7.5, what needs to happen as a result of such review? Is something supposed to happen in the Corrective Action Plans depending on the implementation status of identified System Facilities and Operating Procedures? 8. In R3, what is "normal" performance (n-0)? Should this be a defined term? 9. In R3.2.1 and 3.2.2, why are these issues covered in a TPL standard as it seems to be more applicable to the Facility Ratings standards or the MOD10, 11, 12, and 13 standards? The TPL standard should probably reference these other standards for issues associated with ratings. 10. In R3.3.2, the reference to "single contingency" should reference the category (P1, P@, P#, etc.) in Table 1. 11. In R3.3.2.2, the term "firm transfers" needs to be defined. 12. In R3.3.3 and R3.4, reference is made to "expected to produce more servere System impacts." How does somebody determine what Extreme Events that are "expected to produce more servere System impacts?"

Response: 1. The standard has been revised to identify specific entities responsible for providing the required information.
2. The SDT expects that the Transmission Planner is coordinating assessments with the Planning Coordinator
3. The term is 'increasing generation capability', e.g., if your generator is rated at 100 MW today and 110 MW tomorrow, the 10 MW differential is the increased generation capability. The minimum is defined in Requirement R5.6.
4. Requirements R2.5 and R2.6 have been modified to address this concern. The SDT expects that the Transmission Planner and Planning Coordinator would exercise good engineering judgement when determining the need to perform a new study.

R2.5. The ~~plant~~Generating Unit Stability analysis portion of the Planning Assessment shall be analyzed consistent with Requirement ~~R4.6~~ R5.6 with studies for the year when the following changes that could affect stability margins occur:
R2.5.1. New generator(s) are added or generation modifications are made such as ~~increasing~~changes in generation capability or replacing the exciter ~~or addition of a power System stabilizer~~.
R2.5.2. Material Transmission System changes ~~in the electrical vicinity of existing generation are made~~ are made at or near the point of Interconnection of existing Generation such as the ~~addition or~~ removal of a Transmission Line ~~at or near the point of Interconnection~~ or the

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Commenter	Yes	No	Comment

addition of a new substation in one of the Transmission Lines connected to the plant.

R2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:
R2.6.1. For steady state, short circuit, or System Stability analysis: ~~if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market structure changes~~ the study shall be five calendar years old or less.
R2.6.2. For steady state, short circuit ~~analysis~~, Generating Plant Stability, or System Stability analysis: ~~if the study is less than five years old and no material changes have occurred to the System in the intervening period.~~ the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area.
R2.6.3. ~~For plant and System Stability analysis: until material changes in the System make the study no longer valid. Material changes in the system include the addition of a Transmission Line or a generator.~~

5. R2.6.1, 2.6.2, 2.6.3 – Requirements R2.6.1, R2.6.2, and R2.6.3 have been revised to clarify intent.

R2.6.1. For steady state, short circuit, or System Stability analysis: ~~if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market structure changes~~ the study shall be five calendar years old or less.
R2.6.2. For steady state, short circuit ~~analysis~~, Generating Plant Stability, or System Stability analysis: ~~if the study is less than five years old and no material changes have occurred to the System in the intervening period.~~ the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area.
R2.6.3. ~~For plant and System Stability analysis: until material changes in the System make the study no longer valid. Material changes in the system include the addition of a Transmission Line or a generator.~~

6. Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted Requirements R2.7.2 through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions".

R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.

7. The intent is that a list of proposed upgrades be reviewed and modified on a periodic basis. The intent of making the information available is to notify parties that may be impacted by a particular project of a change in the implementation of the project.
8. Normal performance (n-0) describes the performance of the BES with no Contingencies. No other commenter expressed confusion. The

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Commenter	**Yes**	**No**	**Comment**
SDT does not believe a defined term is necessary. 9. Most commenters did not express concern regarding inclusion of these requirements in the proposed standard, so they were retained. The two requirements referenced relate to evaluation of Contingencies and are not addressed by the MOD or FAC standards. These requirements are intended to simulate the removal of Facilities that System protection is expected to disconnect for each Contingency without operator intervention in the steady state portion of the Planning Assessment. 10. R3.3.2.2 - Tables 1 and 2 have been modified to reflect your suggestion. 11. R3.3.2.2 – Requirement R3.3.2.2 has been revised and the term "firm transfers" has been deleted. **R3.3.2.2**. Following single Contingency events, ~~System adjustments other than shedding of firm Load or curtailment of firm transfers are permitted to meet performance requirements provided these adjustments can be accomplished within the time period allowed by the applicable time limited ratings.~~ Transmission configuration changes and redispatch of generation are allowed provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits**.** 12. R3.3.3 & R3.4 **-** The proposed standard allows the PC and TP to use engineering judgment and experience.			
TVA	☑		1. Requirement R1 does not belong in this standard. These requirements are covered by MOD standards. 2. Spare equipment strategy should be covered as a sensitivity study, but not included in the base case. 3. R2.1.1 should not be so prescriptive as to which years of 1-5 are studied. 4. The wording for R2.1.3 and R2.4.3 should be consistent. 5. Consideration should be given to the specific phases which are faulted in the simultaneous faults for P9 of the stability table. The results can be much different if the simultaneous faults occur on the same phase or different phases. 6. More guidance should be given for the term "Interruption of Firm Transfer Allowed" in Table 1. Firm transfer is not defined in the NERC glossary. The type of transmission service should be outlined here. 7. R2.7.1.1 - The project initiation date is not relevant in a reliability standard. 8. Extreme Event Descriptions 2. a. and b. should include mileage threshholds. 3. e. The term "large load" is vague and should be clarified. d. and f. are duplicates.

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Commenter	**Yes**	**No**	**Comment**
			c. and e. are duplicates. 9. Minimum generator voltage data required for R3.2.1 will be require extensive and costly generator testing and analysis to provide data necessary for transmission system studies. 10. R3.3.2.1 is an operational issue rather than a planning issue. 11. The addition of the "Corrective Action Plan" requires the TP to provide a significant amount of documentation for each deficiency identified by the studies. 12. Also, R3.2 requires that the studies simulate the protection scheme for all events. The current software tools cannot automate these studies for bus faults and breaker failure events, requiring each scenario to be studied manually. 13. The planning event designations are confusing because both the steady-state and stability tables have events P1-P9. A different designation should be used for one of the tables. 14. In R4.6 and other locations, the individual generator exemption of 20 MW should be increased to 75 MVA.

Response: 1. The SDT feels that some modeling requirements are not currently handled in the current MOD standards and has included them here until the MOD standards are revised.
2. The SDT assumed that all entities have a spare policy today. The studies are to be performed on that basis. Duration of Contingencies considered in the studies will be based on this policy as will be the applicable equipment ratings. If the entity feels that the policy may or can change, the entity may elect to add this change as a sensitivity study.
3. The SDT is providing guidance regarding the studies that could be incorporated in an assessment while not being totally prescriptive. The standard does not require that all 5 years be studied. The standard requires the assessment addresses the five year period. Section 2 provides guidance as to the minimum number of current studies required to produce a meaningful assessment without being totally prescriptive. It is the responsibility of the entity to determine if past studies, in conjunction current studies, sufficiently demonstrate that the performance requirements are met. If past studies in conjunction with the required current studies are not sufficient to demonstrate that the System can meet the performance needed, the entity will need to run additional current studies that demonstrate it can meet the requirements.
4. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. The wording in Requirement R2.1.3 describes sensitivities for the steady state horizon while Requirement R2.4.3 describes the sensitivities for dynamic analysis. The wording in these requirements is different but parrallel. To increase the consistency Requirement R2.4.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies.

R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected~~

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Commenter	**Yes**	**No**	**Comment**
~~sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: 5. The SDT agrees that the results can be different. However, the SDT feels that in most instances, the person performing the study will select a three phase fault which is the most severe case and easiest to simulate. 6. The SDT has revised Tables 1 and 2 to replace the term "Firm Transfer" with "Firm Transmission Service". 7. The SDT agrees that this information is not required to meet reliability standards. It was specifically added as an additional piece of information in the Planning Assessment to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. 8. The SDT believes that there should not be a threshold as you are trying to understand the robustness of the System. Large is left to the discretion and good professional judgment of the evaluator. Note 3 has been re-written for clarity and to delete duplications. 9. The requirement is intended to provide for the simulation of generator tripping in response to low system voltages that would cause auxiliary system motors to trip in the steady state portion of the Planning Assessment. 10. The requirement concerning Consequential Load is to address FERC Order 693, which directs that the ERO, among other things, to clarify footnote (b) in regard to Load loss following a single Contingency, specifying the amount and duration of Consequential Load Loss and System adjustments that are permitted after the first Contingency to return the System to a normal operating state. 11. The SDT does not percieve this as an onerous report requirement. The intent is that a list of proposed upgrades be reviewed and modified on a periodic basis. The intent of making the information available is to notify parties that may be impacted by a particular project of a change in the implementation of the project. 12. The SDT agrees that most automated Contingency analysis tools do not do this unless you actually modeled the bus in detail. However, we expect that "engineering judgment", based on intimate knowledge of the System, will be exercised by the planner to distinguish between what studies are important and those that aren't. The requirement is not intended to cover all possible scenarios. 13. The SDT discussed this suggestion and decided to retain the current designations. 14. This is consistent with FERC Order 693, the Large generator Interconnection procedures, and the registry criteria.			
TSGT	☑		1. R1 and R2 address some Load Forecast issues, but are not exhaustive specifications of what Load Forecast range to use in studies. There needs to be some mention of exceedance probability (ExPr) in Load Forecast criteria. For example, we use a forecast with a low ExPr in our studies because we are concerned that, if the system was planned for 50% ExPr (a lower forecast), actual deviation from that forecast might result in load at certain locations exceeding operating margins built into the interconnected transmission system designed to serve only the 50% ExPr forecast load. 2. Load Specifications in R2.4 are ambiguous for the reasons stated above. 3. Maximum study ages in R2.6.1 and R2.6.2 seem arbitrary. The time limit does not seem to add anything to the criteria if no material changes have occurred. If spot checks of the most critical areas indicated no criteria violations, there should be no reason to rerun studies. To correct this problem, we suggest using the term "assessment" rather than "study". For most people, "study" implies detailed modeling and simulation analyses summarized in a report, whereas "assessment" implies a

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Commenter	**Yes**	**No**	**Comment**
			reasonable, systematic evaluation of a system which does not necessarily include detailed analysis for the entire system.
Response: 1 & 2. Requirement R1 has been modified to make TPL-001-1 comport with existing modeling standards and to require documentation when modification of data provided in these standards is necessary for the planning studies addressed in TPL-001-1. Requirement R2.1.3.1 addresses your concern about Load forecast issues and allows for sensitivity studies of the variability of forecasts based on a number of factors. **R1**. ~~Each Resource Planner, Transmission Planner, Transmission Owner, Generator Owner, and Load-Serving Entity shall each provide its respective Planning Coordinator with the following modeling information required for System performance studies upon request (within 30 calendar days) :~~ Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources. 3. The SDT set the age limit on studies to 5 years based on the fact that relatively "small" changes can accumulate with time to the extent that study results might be affected. Requirement R2.6.2 sets reasonable criteria on what System changes might materially affect existing study results, and the SDT does not consider the criteria to be arbitrary. The term "study" was deemed more appropriate as used here than "assessment".			
AESO	☑		The Alberta Electric System Operator (AESO) supports the comments from WECC with the exception of Question #19 where the AESO agrees with the proposed requirement R2.7.4 by the SDT.
Response: The SDT has modified the standard to require only the Corrective Action Plan and indicates what is meant by the word plans. The SDT feels that the assessment and making it available to others will by its very nature provide all the information necessary to understand which plans changed and the basis for the new plans.			
WECC TEP	☑		1. R1.3 requires the provision of firm transfer/Interchange Schedules and resources required to supply load for each Balancing Authority. It may not be possible to have reasonably accurate information on firm transfers and Interchange Schedules for years into the future. Within WECC, we develop base cases that represent reasonably stressed conditions that model power flows stressing various paths. Therefore, within WECC, we design the system to operate at levels that can support all sorts of commerce, including the effects of loop flow, and firm and non-firm contracts, in addition to other possibilities. It would be difficult to develop information from this mixture that includes only firm transactions for such future base cases. In addition, WECC does not allow operations at levels not previously studied. Therefore, an exercise to determine firm transaction/schedules would produce information that will be of little value to support reliability in WECC. 2. R2.7.1.2 requires identification of system deficiencies and accociated corrective action for the Long Term Transmission Planning Horizon. This requirement needs to tie to the lead times to implement the corrective action(s). For example, if a 500 kV transmission line is needed to correct a deficiency that surfaces in the tenth year, then this requirement is reasonable. However, if the deficiency is on a low voltage system, that can be resolved with short lead-time projects (such as

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Commenter	**Yes**	**No**	**Comment**
			installing a small capacitor bank) then this requirement would seem to be too prescriptive. 3. R1.5 requires providing modeling information as part of R1 on a number of transmission planned facilities, including circuit breakers. Since circuit breakers are part of a transmission line, we are not sure how a circuit breaker would be modeled separately, as required. 4. R3.2.1 requires that "studies shall consider the minimum steady state voltage limitations of all generators". Since generators (as well as other facilities) have both high and low voltage limits, the standard should require consideration of both high and low voltage limits. 5. In R.3.2.2, please provide a reference for relay loadability. 6. R.3.3.2.1. requires that Consequential Load loss (expected maximum demand and expected duration) following a single contingency shall be identified in the Planning Assessment. We suggest deleting this requirement. By definition, consequential load loss following a contingency can not be avoided and should not be considered an impact on the operation of the BES. It should be part of local service reliability between an entity and its local regulatory agency or contractual relationship between individual parties and not in a NERC Standard governing the operation of a BES. 7. Proposed revision to R3.5 – "Manual and automatic generation runback and generator tripping are allowed as a response to single and multiple contingencies as long as Facility Ratings are not exceeded and the result of the generator action, such as loss of reactive resource, impact on reserves, and restart time of tripped unit(s), meets the performance requirements in the tables." Example for the need for flexibility in the selection of generation runback and/or tripping to meet the requirements of R3.5 – The time period for a particular Emergency Rating might require faster generation redispatch than a runback or set of runbacks are capable of providing. Therefore, it may be necessary to trip one 100 MW unit rather than runback several units for a total of 100 MW. Planning and Operations need flexibility to coordinate with the requirements of Engineering who established the Facility Ratings. No need for R3.6 with above revision to R3.5. 8. Performance standard "P5" (Q.21- 23) does not allow for the use of load shedding (safety nets) required by some utilities to protect against cascading outages if a transmission line is already out of service and a forced outage of another major element occurs. "System adjustments" might not be possible in a load pocket or local load-serving area to prevent "non-consequential load loss" after loss of a second transmission line to the load-serving area. The use of load shedding for such rare

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Commenter	**Yes**	**No**	**Comment**
			events is an established practice and least cost alternative that does not unreasonably compromise reliability of the WECC system. It is also an acceptable and necessary tradeoff from over burdening customers with additional expensive transmission lines and permitting risk in the West where remote generation resources have historically required power to be carried over long distances. The tradeoffs between economics (building hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation versus load shedding schemes) and the impact of these rare events should be under the purview of local and state jurisdictions, as long as impacts do not result in cascading events outside of the affected jurisdiction. As long as interconnected reliability or neighboring system operation is not negatively impacted, customer interruption size and frequency should be left to the Transmission Providers discretion and to the jurisdiction of state regulators. The amount of load to be shed and its frequency is primarily an issue for state jurisdiction because it is a matter of the cost/benefit associated with customer service regardless of the voltage level problem. In general, incidences of non-consequential loss of customer load events related to contingencies on the back-bone transmission system are rare when compared to other causes of customer outages. Assuming interruptions to customer service are significant, the state regulators and other related constituents will ultimately be responsible for approving any transmission line facilities or generation additions needed to assure reliability. Implementing an immediate change to this current established practice is not rational or technically feasible due to the long and arduous regulatory and permitting processes that are required to construct new transmission facilities or new load-side generation. Implementation of the standard as written would take many years. At a minimum, even if it is determined that Congress's intent was to create stricter standards, a phase-in period must be included to allow utilities time to obtain necessary permits, regulatory approval and cost recovery to meet the stricter standards.

Response: 1. The SDT understands your concern. The SDT only anticipates that known firm transfers and schedules be included in the base cases. Non-firm transfers may be included in the sensitivity studies as detailed in Requirement R2.1.3. Requirement R1.3 in the first draft of TPL-001-1 is now shown as Requirement R10 in the revised draft.

R10. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information.

2. Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted Requirements R2.7.2 through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions".

R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission~~

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Commenter	**Yes**	**No**	**Comment**
			~~and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. 3. The SDT agrees that circuit breakers are generally not modeled separately in planning simulations. However, the addition or removal of a circuit breaker could modify network topology as modeled for planning simulations, which this requirement attempts to capture. 4. Voltage limits are included in the tables to cover both high and low voltage limits. However, the minimum limits in Requirement R3.2.1 are, generally, the more critical concern for system performance scenarios and this requirement was included by team consensus. 5. NERC document "Relay Loadability Exceptions, Determination and Application of Practical Relaying Loadability Ratings ", is contained on this ftp site: ftp://ftp.nerc.com/pub/sys/all_updl/pc/spctf/ExceptionsV1.pdf. Other information may also be obtained from: http://www.nerc.com/~filez/spctf.html 6. R3.3.2.1 - The requirement concerning Consequential Load is to address FERC Order 693, which directs the ERO, among other things, to clarify footnote (b) in regard to Load loss following a single Contingency, specifying the amount and duration of Consequential Load Loss and System adjustments that are permitted after the first Contingency to return the System to a normal operating state. 7. The SDT has modified the requirements to allow for single and multiple Contingencies tripping (See Requirement R 3.5). **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met: 8. The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission Systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT believed the 300 kV and higher Systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many Systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. When EHV Systems are compromised, the large volumes of power served by them can place a severe amount of stress on parallel EHV or lower voltage paths. For example, if a large EHV transformer experiences a catastrophic failure not only are other System Facilities required to carry more Load but the System is also exposed to other N-1 conditions for long periods of time while awaiting a replacement or repair of the failed equipment. Large generation sources are typically connected at EHV levels and maintenance of the EHV Transmission lines within the vicinity of larges generation plants must often be coordinated during scheduled unit outages, resulting again in multiple Facility outages over extended periods of time. Therefore, it was the conclusion of the SDT in Draft 1 to propose greater reliability and operational flexibility through more stringent performance requirements when considering certain N-1 and N-1-1 Contingency events of EHV Systems. Throughout the industry substation arrangements at EHV levels reflect the importance of these Systems as the designs often consist of the more expensive ring-bus, breaker-and –a-half or double bus-double breaker protection schemes as opposed to the more simplistic and lesser cost single bus arrangements that are

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Commenter	**Yes**	**No**	**Comment**
commonly found on lower voltage Systems. The feedback received from industry was divided related to the SDT's emphasis placed on a higher expectation for the 300 kV and higher Systems. Some commenter's questioned the importance and the high costs that may be needed to mitigate existing System designs. Others agreed with the SDT's approach and indicated that the impact to their Systems would be minimal. Some commenter's even questioned why the more stringent approach was not applied to the entire 100kV and higher Systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission System. The SDT plans to draft an implementation plan. This implementation plan will address, among other issues, the other standards, which will need to be brought into alignment with this standard. The plan will be provided for the third posting of the standard.			
WPS	☑		Within R1.1.2, the Planning Coordinator and the Transmission Planner is required to define what constitutes "normal weather patterns" for the purpose of establishing load forecasts. However, the PC and/or TP are not the appropriate entities to establish "normal weather patterns"; the LSEs, who actually develop load forecasts and have the expertise, are the appropriate entities to establish normal weather patterns. Additionally, this requirement should consider requiring the 50/50 probability load forecast from the LSEs.
Response: This requirement has been eliminated in response to various industry comments.			
Duke Energy		☑	
Northwestern Energy		☑	
New York ISO		☑	
Response: Thank you.			

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Maureen E. Long
Standards Process Manager

October 8, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement: TPL-001 Web Ex and Conference Call and Correction to Comment Form

The Standards Committee (SC) announces the following:

WebEx and Conference Call to Provide Overview of First Draft of TPL-001-1 — Transmission System Planning Performance Requirements on Wednesday, October 10, 2007

The Assess Transmission Future Needs Standard Drafting Team (ATFN SDT) will hold a Web Ex and Conference Call on Wednesday, October 10th from 1 to 4 p.m. EDT to present and discuss the proposed requirements in TPL-001-1. The purpose of the proposed standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. The proposed standard consolidates, clarifies, and expands on the requirements that had been in TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0, and includes several new definitions.

The WebEx and conference call provides an overview of the proposed requirements to highlight the areas where the proposed requirements differ from the requirements in the existing TPL-001-0 through TPL-004-0 and to provide the opportunity to ask questions about the proposed requirements.

To join the WebEx, click on the following link **a few minutes before 1 p.m.** and select the meeting for the ATFN SDT:

https://nerc.webex.com/mw0304l/mywebex/default.do?siteurl=nerc
Password: standards

To join the conference call, dial the following number and, when prompted, provide the code:

Phone: 1-866-740-9357
Code: 1612521

Corrected Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

The comment form posted with the TPL-001-1 — Transmission System Planning Performance Requirements contained an error on question 29 and has been replaced.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List

116-390 Village Boulevard, Princeton, New Jersey 08540-5721
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NERC Roster

Comment Form for 2nd Draft of Standard TPL-001-1
Assess Transmission Future Needs (Project 2006-02)

Please **DO NOT** use this form to submit comments on the 2nd draft of the TPL-001-1 standard for Assess Transmission Future Needs (Project 2006-02). This comment form must be completed by **September 29, 2008.**

If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Background Information
TPL-001-1 Transmission System Planning Performance Requirements

Comments on the initial draft of the TPL-001-1 Transmission System Planning Performance Requirements standard were received from the industry through October 26, 2007. The Drafting Team sought and received feedback to 43 questions, and the team appreciates the tremendous industry participation that generated over 430 pages of comments, representing over 80 organizations. Below is a brief overview of the 2nd draft of the standard highlighting areas where the SDT made changes based on stakeholder feedback. The SDT is also presenting several new questions to seek the industry's position related to the changes made and to obtain clarifying data that will provide further direction for improvements. The team's objectives remain unchanged - to create a single Transmission planning standard 1) with clear, concise requirements set at an appropriate level to ensure reliability and 2) that fully addresses all issues raised by FERC Orders 693 and 890, and industry inputs, including the SAR scope document.

2nd Draft Overview:

1. At first glance the second draft of the standard seems to have several new requirements; however, this is in large part due to clarifying responsible entity assignments of the former Requirement R1 (Modeling Data) requirements. Also, based on industry feedback, we have moved many of the former R1 requirements to the end of the standard (new Requirements R9 through R14) to facilitate their removal as the SDT believes that they will ultimately reside in MOD standards. See question 4 below for more detail.
2. Aside from the modeling data changes, the flow and organization of the standard remains similar to the 1st draft. Two changes are noteworthy: Requirement R4 (short circuit) was formerly part of Requirement R2, and Requirement R6 is a new requirement related to proxies used by the Transmission Planner (TP) and Planning Coordinator (PC) to identify cascade conditions, voltage instability, or uncontrolled islanding. With the insertion of these items some re-numbering of requirements was required.
3. Several definitions were revised or deleted based on industry feedback. Of note are changes to the Consequential Load Loss, Non-Consequential Load Loss and Year One definitions. A new definition is provided for Bus-tie Breaker to help clarify its use in the Performance Tables. Also, Generating Unit Stability Study replaces the former Plant Stability Study terminology.
4. Performance Tables – The use of two tables (Steady-State and Stability) remains but they have been significantly modified for readability, clarity, and to improve consistency between them. The tables more closely resemble the format used in the existing TPL standards. Highlights of the changes made to the tables are:
    a. Several changes to performance table planning events, extreme events, notes, etc.

   b. Many responders questioned the need for higher performance expectations for facilities at or above 300 kV. The SDT has revised expectations for the N-1-1 (overlapping single Contingencies - Planning Event P6); however, the SDT continues to support a higher level of performance for the EHV System for common mode failures such as bus faults (P2.2), breaker faults (P2.3), stuck breaker (P4), and Protection System failures (P5).

   c. Protection System failure (P5) is a Planning Event added to the tables to provide greater distinction between a stuck breaker (P4) and a failure of a non-redundant Protection System component, such as a relay, CT, PT, or communication system.

5. Sensitivity Studies – There was confusion in the 1st draft related to how sensitivity studies are expected to impact Corrective Action Plans (CAP). This is now addressed in the 2nd draft and CAPs are not needed when a problem is due solely to a sensitivity review (see Requirement R2.7). Also, the unintentional exclusion of possible sensitivity studies beyond those listed in the standard has now been addressed. See Requirements R2.1.4 and R2.4.4.

6. Qualifications for "past" studies are better defined. See Requirement R2.6.

7. Corrective Action Plans (CAP)s:

   a. CAPs can now include use of SPS/RAS to respond to single or multiple Contingency events. (See Requirements R3.5 (steady-state) and R5.5.3 (Stability). The feedback from the industry was clear that an SPS/RAS should be permitted for generation runback or tripping in response to a single Contingency event.

   b. The SDT has removed the use of "committed" and "planned" in regards to CAPs.

   c. The SDT has removed the 1st draft Requirement R2.7.2 which required that CAPs be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The SDT has modified the definitions and requirements associated with System Stability and Generating Unit Stability (formerly Plant Stability) in response to industry comments. Do you concur with the modified definitions for stability and, if not, please state why and/or suggest specific changes.

   ☐ Yes
   ☐ No
   Comments:

2. Do you concur with the modified Requirements R2.4, R2.5, R5.4, and R5.5? If not, please state why and/or suggest specific changes.

   ☐ Yes
   ☐ No
   Comments:

3. The SDT has modified the definitions of Consequential and Non-Consequential Load Loss in response to industry comments. Do you concur with the modified definitions of Consequential and Non-Consequential Load Loss? If not, please state why and/or suggest specific changes.

   ☐ Yes
   ☐ No
   Comments:

4. The SDT has modified Requirement R3.5 and eliminated Requirement R3.6 from the first draft to clarify that manual and automatic generation run-back (redispatch) and tripping is allowed as a Corrective Action Plan as long as the conditions in Requirements R3.5.1, R3.5.2 and R3.5.3 are met. Do you agree that generation run-back and tripping (manual and automatic) should be limited by these conditions? If not, please explain why you disagree with the proposed requirements.

   ☐ Yes
   ☐ No
   Comments:

5. The SDT has modified the modeling requirements. Some commenters expressed concern that the modeling requirements contained in Requirement R1 of the first draft of TPL-001-1 were either duplicative of the requirements in the MOD standards, or to

the extent new modeling requirements were proposed, that the appropriate venue for such modeling requirements would be the MOD standards. The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has incorporated these additional requirements with the intent that they will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.

The SDT has also modified proposed modeling requirements contained in Requirement R1 of the first draft of TPL-001-1 based on industry comments and moved these requirements to Requirements R9 through R14 in the second draft for ease of removal later on. Furthermore, in response to industry comments, the SDT has separated the modeling requirements into individual requirements for each responsible entity. Do you concur with the modifications reflected in Requirements R9 – R14? If not, please state why and/or suggest specific changes.

☐ Yes

☐ No

Comments:

6. The SDT has modified the requirements relating to short circuit analysis Do you concur with the modifications reflected in Requirements R2.3 and R4. If not, please state why and/or suggest specific changes.

☐ Yes

☐ No

Comments:

7. The SDT has reformatted the Steady State and Stability Performance Tables. Do you concur with the modified format? If not, please state why and/or suggest specific changes.

☐ Yes

☐ No

Comments:

In questions 8 and 9, the SDT is soliciting the following feedback related to Bus-tie Breakers and non Bus-Tie Breakers (see Table 1, P2 and P4).

8. A new definition for "Bus-Tie Breaker" was added to clarify the type of substation design and breaker position that qualify as a Bus-tie Breaker. Do you agree with the proposed definition? If not, please explain.

☐ Yes

☐ No

Comments:

9. Some commenters questioned why a Bus-tie Breaker would have a different performance requirement than a non-Bus-tie Breaker, stating that all breakers have the same probability for failure. It may be true that generally the probability for failure

of any given breaker would not vary substantially among similar types of breakers, but the Bus-tie Breaker reduces exposure and consequences of bus faults. The different performance expectations in Tables 1 and 2 are based on promoting a higher level of reliability for the Transmission Systems operated above 300 kV.

It is recognized by the SDT that a straight bus design has some undesirable exposure to bus faults, but that Bus-tie Breakers can be utilized to improve reliability for bus faults and problems associated with exit breakers. As a result, the risk of an internal breaker fault was deemed to be significantly less than the benefit that is gained by reducing the exposure to a total bus failure. Therefore, provisions were built into the performance requirements that would not discourage their use.

Do you agree that non-Bus-tie Breakers rated above 300 kV should have more stringent performance requirements than Bus-tie Breakers? If not, please explain why and/or suggest specific changes.

☐ Yes

☐ No

Comments:

10. The SDT made modifications in this second draft to the requirements relating to sensitivity cases. Do you concur with the modifications reflected in Requirements R2.1.3 and 2.1.4? If not, please state why and/or suggest specific changes.

☐ Yes

☐ No

Comments:

11. In response to industry comments, the SDT modified Table 1 requirements for Planning Event P6. Planning Event P6 involves independent overlapping single contingencies (n-1-1) involving two Transmission Facilities excluding generators. This Planning Event generally correlates to P5 of the first draft and now includes shunt devices. The P6 event was also revised to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV.

Do you concur with the modifications? If not, please state why and/or suggest specific changes.

☐ Yes

☐ No

Comments:

Comments from some entities received from the posting of the 1st draft standard indicated that significant additional costs will be required to meet the proposed requirements and performance tables. Commenters also indicated that it would take several years to install the additional facilities needed to meet the change in requirements. The SDT has attempted to adjust and clarify the proposed requirements and performance in light of these initial comments; however, the SDT needs more specific information on these concerns so that it can put the proposed requirements in perspective and make more adjustments as appropriate. Questions 12, 13 & 14 address these concerns.

What do you estimate will be your additional approximate costs, if any, to support the proposed requirements and performance tables over and above what you are currently doing for the following:

12. Analysis:

    One time cost to supplement past study portfolio and analyze the supplemental studies (depending on the extent of supplemental work needed, this may be an accumulated cost over more than one year):

    Comments:

    How many years do you estimate that it will take to complete supplemental studies and associated analysis?

    Comments:

    On-going additional cost for expanded studies and analysis:

    Comments:

13. Documentation

    One time cost to prepare reporting documentation associated with studies needed to supplement past study portfolio (depending on the time required to complete the supplemental work, this may be an accumulated cost over more than one year):

    Comments:

    On-going additional cost for documentation of expanded studies and analysis:

    Comments:

14. System Reinforcement

    One time cost, capital investment, to expand your system reinforcement program (due to lead times associated with different types of facilities, this will probably be an accumulated cost over several years):

    Comments:

    How many years do you estimate that it will take to complete this initial expanded system reinforcement program:

    Comments:

15. (A) Do you generally support the revised standard? (B) Are you unsure whether you generally support the revised standard? or (C) Do you definitely not support the revised standard? Please check the appropriate box below. If your response is either (B) or (C), please explain your single biggest concern with the revised standard, including which specific requirement or set of requirements causes you the most concern and why.

    ☐ A – Generally support the revised standard

    ☐ B – Unsure about supporting the revised standard

    ☐ C – Definitely do not support the revised standard

    Comments:

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Version 1 of SAR posted for comment from April 2, 2002 through May 3, 2002.
2. Version 2 of SAR posted for comment from May 5, 2004 through June 5, 2004.
3. Version 3 of SAR posted on November 18, 2005.
4. SAR approved on April 30, 2006.
5. Version 1 of Supplemental SAR posted for comment from February 15, 2007 through March 16, 2007.
6. Version 2 of Supplemental SAR posted on April 9, 2007.
7. Version 1 of revised standard(s) posted for comment on September 17, 2007.

Proposed Action Plan and Description of Current Draft:

The SDT has established a schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 1Q10. The current draft is the second iteration of the revision of existing standards TPL-001 through TPL-006 and includes one revised standard, TPL-001-1, replacing TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. TPL-005 & -006 will be addressed later in the project. Violation Risk Factors, Time Horizons, Measures, Compliance and Implementation Plans will be included in subsequent postings.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Respond to comments from first posting of standard(s) and submit revision 1 of the standard(s).	2Q08
2. Respond to comments from second posting of standard(s) and submit revision 2 of the standard(s).	4Q08
3. Submit revision 3 of the standard(s) for balloting.	2Q09
4. Respond to comments from third posting and submit revision 3 of the standard.	3Q09
5. Submit standard(s) for recirculation balloting.	4Q09
6. Submit standard(s) to BOT.	1Q10
7. Submit to regulatory authorities for approval.	1Q10

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)

Consequential Load Loss: Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.

Extreme Events: Events which are more severe and have a lower probability of occurrence than Planning Events.

Generating Unit Stability Study: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Near-Term Transmission Planning Horizon: Transmission planning period that covers Years One through five.

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.

Planning Events: Events that require Transmission system performance requirements to be met.

Planning Coordinator: The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.

System Stability Study: Study that focuses on portions of the System, which may include many generating units, to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.

Year One: The first year that a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the completion of the previous annual Planning Assessment.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-1**

3. **Purpose:** Establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

   4.1.3. Resource Planner.

   4.1.4. Distribution Provider.

   4.1.5. Transmission Owner.

   4.1.6. Generator Owner.

5. **Effective Date:** As per Implementation Plan (to be supplied later).

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R1.1. The Planning Assessment shall include documentation of the technical rationale for modification of any data that was provided in Requirement R9 through R14, MOD-010, and MOD-012.

R2. Each Transmission Planner and Planning Coordinator shall conduct and document the results of its annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, and shall cover steady state analyses, short circuit analyses, and Stability analyses including both System and Generating Unit Stability. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported at a minimum by the following annual current studies, supplemented with qualified past studies as indicated in Requirement R2.6:

R2.1.1. System peak Load for either Year One or year two, and year five.

R2.1.2. System Off-Peak Load for one of the five years.

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall

be run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:

R.2.1.3.1. Higher or lower Load than forecasted with variability of Load/demand and Load power factors due to season, weather, or time of day.

R.2.1.3.2. Modification of expected transfers.

R.2.1.3.3. Unavailability of long lead time Facilities.

R.2.1.3.4. Variability and outages of reactive resources.

R.2.1.3.5. Generation additions, retirements, or other dispatch scenarios.

R.2.1.3.6. Decreased effectiveness of controllable Loads and Demand Side Management.

R.2.1.3.7. Modification of planned Transmission outages.

R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and the Planning Assessment shall include documentation of the technical rationale for why each was selected shall be supplied.

R2.2. For the Long-Term Transmission Planning Horizon portion of the steady state analysis, at a minimum, a current System peak Load study is required annually for one of the years in the assessment period to support the annual Planning Assessment.

R2.2.1. To accommodate any known longer lead time projects that may take longer than ten years to complete, the Planning Assessment shall be extended accordingly.

R2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually and supported by current or past studies.

R2.4. The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies. The following studies are required:

R2.4.1. System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads.

R2.4.2. System Off-Peak Load for one of the five years.

R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~s~~ensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:

R.2.4.3.1. Variations in Load model assumptions.

R.2.4.3.2. Modification of expected transfers.
R.2.4.3.3. Unavailability of long lead time Facilities.
R.2.4.3.4. Variability and outages of reactive resources.
R.2.4.3.5. Generation additions, retirements, or other dispatch scenarios.

R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and the Planning Assessment shall include documentation of the technical rationale for why each was selected shall be supplied.

R2.5. The Generating Unit Stability analysis portion of the Planning Assessment shall be analyzed consistent with Requirement R5.5 with studies for the year when the following changes that could affect stability margins occur:

R2.5.1. New generator(s) are added or generation modifications are made such as changes in generation capability or replacing the exciter.

R2.5.2. Material Transmission System changes are made at or near the point of Interconnection of existing Generation such as the removal of a Transmission Line or the addition of a new substation in one of the Transmission Lines connected to the plant.

R2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

R2.6.1. For steady state, short circuit, or System Stability analysis: the study shall be five calendar years old or less.

R2.6.2. For steady state, short circuit, Generating Plant Stability, or System Stability analysis: the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area.

R2.7. For Planning Events shown in Table 1 – Steady State Performance and Table 2 – Stability Performance, when the analysis indicates an inability of the System to meet the performance requirements in the tables, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed in subsequent assessments but the System shall continue to meet the performance requirements in the tables. Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities. The Corrective Action Plan shall:

R2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.

R.2.7.1.1. For the Near-Term Transmission Planning Horizon, include both a project initiation date as well as an in-service date.

R.2.7.1.2. For the Long-Term Transmission Planning Horizon, provide an in-service year.

R2.7.2. Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.

R2.7.3. Be reviewed in subsequent annual Planning Assessments as to implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to contingencies in Table 1 – Steady State Performance. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R3.1. Studies shall determine whether the BES meets the performance requirements in Table 1 – Steady State Performance.

R3.2. Contingency analyses shall simulate the removal of all elements including those that System protection is expected to disconnect for each Contingency without operator intervention.

R3.2.1. For all generators, studies shall consider the minimum steady state voltage limitations of all generators and identify how the generators are treated in the steady state simulation.

R3.2.2. For all Transmission lines, studies shall consider relay loadability and identify how loadability is treated in the steady state simulation.

R3.3. For Steady State studies:

R3.3.1. Performance criteria for System normal conditions and for Planning Events in Table 1 – Steady State Performance shall be met.

R3.3.2. Evaluations shall be performed for single Contingencies (identified in Table 1 – Steady State Performance).

R.3.3.2.1. Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment.

R.3.3.2.2. Following single Contingency events, Transmission configuration changes and redispatch of generation are allowed provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits.

R3.3.3. Those Planning Event Contingencies in Table 1 – Steady State Performance not covered in Requirement R3.3.2 that are expected to produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results.

R3.4. Those Extreme Events in Table 1 – Steady State Performance that are expected to produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. If the Extreme Events analysis concludes there are cascading outages caused by the occurrence of Extreme Events, an evaluation of implementing a change designed to reduce or mitigate the likelihood of such consequences shall be conducted.

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single or multiple Contingency if the following conditions are met:

R3.5.1. All Facilities shall be operating within their Facility Ratings.

R3.5.2. Such action would not violate safety, equipment, regulatory or statutory requirements.

R3.5.3. A sustainable, stable, operating condition is maintained.

R4. For the short circuit portion of the Planning Assessment, as described in Requirement R2.3, each Transmission Planner and Planning Coordinator shall assess the short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R5. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 and Requirement R2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 2 – Stability Performance. The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R5.1. Studies to meet the performance requirements in Table 2 – Stability Performance shall use computer Stability simulations that analyze the response of the BES.

R5.2. Contingency analyses shall simulate the removal of all elements including those that System protection and other automatic controls are expected to disconnect for each Contingency without operator intervention.

R5.3. Studies shall consider the voltage ride through capability of all generators and identify how the generators are treated in the simulation.

R5.4. For the System Stability study:

R5.4.1. At a minimum, those Planning Event Contingencies in Table 2 – Stability Performance that would produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information with an explanation of why the remaining Contingencies would produce less severe System results.

R5.4.2. Performance shall meet the requirements for Planning Events in Table 2 – Stability Performance.

R5.4.3. Automatic generation tripping is allowed to mitigate Stability violations if the following conditions are met:

R.5.4.3.1. All Facilities shall be operating within their Facility Ratings.

R.5.4.3.2. Such action would not violate safety, equipment, regulatory or statutory requirements.

R.5.4.3.3. A sustainable, stable, operating condition is maintained.

R5.4.4. At a minimum, those Extreme Events in Table 2 – Stability Performance that would produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. If the Extreme Events analysis concludes there are cascading outages, an evaluation of implementing a change designed to reduce or mitigate the likelihood of such consequences shall be conducted.

R5.5. For the Generating Unit Stability studies:

R5.5.1. Shall be performed for individual generating units 20 MW or greater directly connected through a step-up transformer to the BES and for generating units at the same location which total 75 MW or greater, directly connected through their step-up transformer(s) to the BES.

R5.5.2. Shall be performed for changes in the real power output of a generating unit by more than 10% of the existing capability or more than 20 MW whichever is greater.

R5.5.3. Shall be performed and evaluated for those Planning Events that would produce more severe System impacts and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results.

R5.5.4. Shall meet Performance requirements for Planning Events in Table 2 – Stability Performance.

R6. Each Transmission Planner and Planning Coordinator shall define and document the proxies used in simulation studies to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R7. Each Transmission Planner and Planning Coordinator shall determine and identify individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R8. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among neighboring systems, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890. *[Violation Risk Factor: TBD] [Time Horizon: TBD]* This distribution shall include:

R9. Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R10. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R11. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R12. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R13. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R14. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to Transmission Lines, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies, within ninety days of a request for such information. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

Table 1 – Steady State Performance

1. Facility Ratings shall not be exceeded. Planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings.
2. System steady state voltages and post-transient voltage deviations shall be within acceptable limits as established by the Planning Coordinator (or Transmission Planner if more restrictive).
3. Voltage instability, cascading outages, and uncontrolled islanding shall not occur.
4. Consequential Load and consequential generation loss is allowed for all events shown.
5. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each event.
6. Simulate Normal Clearing unless otherwise specified.

Planning Events						
Category	**Initial System Condition**	**Event[3]**	**BES Elements out of Service[2, 3]**		**Interruption of Firm Transmission Service Allowed**	**Non-Consequential Load Loss Allowed**
			(A) > 300 KV	**(B) <= 300 KV**		
P0 Normal System conditions	Normal System	None	X	X	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission circuit 3. Transformer 4. Shunt device 5. Single pole of a DC line	X	X	No Yes, if transfer is dependent on the outaged DC line.	No

P2 Single Contingency	Normal System	Loss of one of the following: 1. Breaker(s) opening without a Fault resulting in a single ended line	X	X	No	No
		2. Bus section	X		No	No
				X	Yes	Yes
		3. Internal Breaker Fault (non-bus-tie)	X		No	No
				X	Yes	Yes
		4. Internal Breaker Fault (bus tie)	X	X	Yes	Yes
P3 Multiple Contingency (Generator + 1)	Loss of a generator followed by System adjustments	Loss of one of the following: 1. Generator 2. Transmission circuit 3. Transformer 4. Shunt device 5. Single pole of a DC line	X	X	No Yes, if transfer is dependent on the outaged DC line.	No

P4 Multiple Contingency (Fault plus stuck breaker)[1]	Normal System	Stuck breaker (non-bus-tie) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission circuit 3. Transformer 4. Shunt device 5. Bus section	X		No	No
				X	Yes	Yes
		6. Stuck breaker (bus tie) attempting to clear a Fault on the associated bus	X	X	Yes	Yes
P5 Multiple Contingency (Fault plus Protection System failure)	Normal System	Loss of multiple elements due to a single component failure within a Protection System associated with clearing a Fault on one of the following: 1. Generator 2. Transmission circuit 3. Transformer 4. Shunt device 5. Bus section	X		No	No
				X	Yes	Yes

P6 Multiple Contingency (Two overlapping single Contingencies)	Loss of one of the following, followed by System adjustments: 1. Transmission circuit 2. Transformer 3. Single pole of a DC line 4. Shunt device	Loss of one of the following: 1. Transmission circuit 2. Transformer 3. Single pole of a DC line 4. Shunt device	X	X	Yes	Yes
P7 Multiple Contingency (Common Structure)	Normal System	1. Loss of any two Transmission circuits on a common structure. (Excludes circuits that share a common structure for 1 mile or less.) 2. Loss of a bipolar DC line	X	X	Yes	Yes
Extreme Events						
Evaluation Requirements						
For all Extreme Events evaluated: 1. See Requirement R3.4. 2. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency. 3. Simulate Normal Clearing unless otherwise specified.						
Extreme Event Descriptions						
1. Loss of a single generator, Transmission Circuit, DC Line, or transformer forced out of service followed by another single generator, Transmission Circuit,						

DC Line, or transformer forced out of service prior to System adjustments.

2. Local area events affecting the Transmission System such as:
    a. Loss of a tower line with three or more circuits.
    b. Loss of all Transmission lines on a common right-of-way.
    c. Loss of a switching station or substation (loss of one voltage level plus transformers).
    d. Loss of all generating units at a station.
    e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
    a. Loss of two generating plants resulting from conditions such as:
        i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
        ii. Loss of the use of a large body of water as the cooling source for generation.
        iii. Wildfires.
        iv. Severe weather, e.g., hurricanes, tornadoes, etc.
        v. A successful cyber attack.
        vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
    b. Loss of two Transmission lines in different rights-of-way prior to System adjustments for conditions such as:
        i. Wildfires.
        ii. Severe weather, e.g., hurricanes, tornadoes, etc.
    c. Other events based upon operating experience such as:
        i. Consideration of initiating events that experience suggests may result in wide area disturbances.

Notes

1. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) breaker, only one pole is assumed to remain closed. The stuck breaker event introduces a delayed clearing mode. Normal Clearing is when the Protection System operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Breaker fail relay operation is a predetermined time that occurs after the Protection System operates and the breaker has failed. Breaker fail relaying will also

isolate a predetermined portion of the electric system to isolate the failed breaker. Delayed clearing of a Fault is due to failure of any Protection System component that prevents the Protection System from operating normally.

2. If the event analyzed involves BES elements at multiple system voltage levels, the lowest system voltage level for stated performance criteria applies regarding allowances for interruptions of firm transmission service and Non-Consequential Load.
3. For transformer outage events, the reference voltage applies to the low-side winding (excluding tertiary windings) and excluding generator step-up transformers. For generator outage events, the reference voltage apply to the BES connected voltage (high-side of GSU transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
4. Requirements which are applicable to shunt devices also apply to FACTS devices.
5. An internal breaker Fault means a breaker failing internally, thus creating a System Fault which must be cleared by protection on both sides of the breaker.

Table 2 – Stability Performance

1. The System shall remain stable. [5]
2. Dynamic voltages shall be within acceptable limits established by the Planning Coordinator (or Transmission Planner if more restrictive).
3. Cascading outages and uncontrolled islanding shall not occur.
4. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each event.
5. Simulate Normal Clearing unless otherwise specified.

Planning Events						
Category	**Initial System Conditions**	**Event [3]**	**BES Elements out of Service [2, 3]**		**Interruption of Firm Transmission Service Allowed**	**Non-Consequential Load Loss Allowed**
			(A) > 300 KV	**(B) <= 300 KV**		
P1 Single Contingency	Normal System	SLG or 3-phase Fault on one of the following: 1. Generator 2. Transmission circuit 3. Transformer 4. Shunt device 5. Single pole of a DC line	X	X	No Yes, if transfer is dependent on the outaged DC line.	No

P2 Single Contingency	Normal System	1. Breaker(s) opening without a Fault resulting in a single ended line	X	X	No	No
		2. SLG Fault on bus section	X		No	No
				X	Yes	Yes
		3. SLG internal breaker Fault (non-bus-tie)	X		No	No
				X	Yes	Yes
		4. SLG internal breaker Fault (bus tie)	X	X	Yes	Yes
P3 Multiple Contingency (Generator + 1)	Loss of a generator followed by System adjustments	SLG or 3-phase Fault on one of the following: 1. Generator 2. Transmission circuit 3. Transformer 4. Shunt device 5. Single pole of a DC line	X	X	No Yes, if transfer is dependent on the outaged DC line.	No

P4 Multiple Contingency (Fault plus stuck breaker) [1]	Normal System	Stuck breaker (non-bus-tie) attempting to clear a SLG Fault on one of the following: 1. Generator 2. Transmission circuit 3. Transformer 4. Shunt device 5. Bus section	X		No	No
				X	Yes	Yes
		6. Stuck breaker (bus tie) attempting to clear an SLG Fault on the associated bus	X	X	Yes	Yes

P5 Multiple Contingency (Fault plus Protection System failure)	Normal System	Loss of multiple elements due to a single component failure within a Protection System associated with clearing an SLG Fault on one of the following: 1. Generator 2. Transmission circuit 3. Transformer 4. Shunt device 5. Bus section	X		No	No
				X	Yes	Yes
P6 Multiple Contingency (Two overlapping single Contingencies)	Loss of one of the following, followed by System adjustments: 1. Transmission circuit 2. Transformer 3. Single pole of a DC line 4. Shunt device	SLG or 3-phase Fault on one of the following: 1. Transmission circuit 2. Transformer 3. Shunt device 4. Loss of single pole of a DC line	X	X	Yes	Yes

P7 Multiple Contingency (Common structure)	Normal System	1. SLG Fault on each circuit of any two Transmission circuits on a common structure (Excludes circuits that share a common structure for one mile or less) 2. Loss of a bipolar DC line	X	X	Yes	Yes
Extreme Events						
Evaluation Requirements						
For all Extreme Events evaluated: 1. See Requirement R5.5.4. 2. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency. 3. Simulate Normal Clearing unless otherwise specified.						
Extreme Event Descriptions						
1. With an initial condition of a single generator, Transmission circuit, DC line, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, DC line, or transformer prior to System adjustments. 2. Local or wide area events affecting the Transmission System such as: a. 3Ø fault on generator with stuck breaker or a protection system failure due to a single component failure within the protection system. b. 3Ø fault on transmission circuit with stuck breaker or a protection system failure due to a single component failure within the protection system. c. 3Ø fault on transformer with stuck breaker or a protection system failure due to a single component failure within the protection system.						

d. 3Ø fault on bus section with stuck breaker or a protection system failure due to a single component failure within the protection system.

e. 3Ø internal breaker fault.

f. 3Ø fault on two or more circuits on a common structure.

g. SLG or 3Ø fault on all transmission lines on a common right-of-way.

h. 3Ø fault on switching station or substation (loss of one voltage level plus transformers)

i. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances.

Notes

1. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) breaker, only one pole is assumed to remain closed. The stuck breaker event introduces a delayed clearing mode. Normal Clearing is when the Protection System operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed Protection Systems and breakers. Breaker failure relay operation is a predetermined time that occurs after the Protection System operates and the breaker has failed. Breaker failure relaying will also isolate a predetermined portion of the electric System to isolate the failed breaker. Delayed clearing of a Fault is due to failure of any Protection System component or breaker that prevents the fault from clearing normally.
2. If the event analyzed involves BES elements at multiple system voltage levels, the lowest system voltage level for stated performance criteria applies regarding allowances for interruptions of firm transmission service and Non-Consequential Load.
3. For transformer outage events, the reference voltage applies to the low-side winding (excluding tertiary windings) and excluding generator step-up transformers. For generator outage events, the reference voltage apply to the BES connected voltage (high-side of GSU transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
4. An internal breaker fault means a breaker failing internally, thus creating a system fault which must be cleared by protection on both sides of the breaker.
5. System stable means:
   a. Angular Stability:
      i. For Planning Event P1: No generating unit or units shall be allowed to pull out of synchronism. A generator being disconnected from the System by Fault clearing action or by a Special Protection System is not considered pulling out of synchronism.
      ii. For all other Planning Events: No generating unit or units totaling more than the Contingency reserve of the Balancing Authority shall be allowed to pull out of synchronism. Generators that pull out of synchronism must have out-of-step protection or some other means to trip the generator for this condition and the resulting apparent impedance swings must not pass through relay characteristics that would result in the tripping of any Transmission System elements other than the generating unit and its direct connection Facilities.
   b. For all Planning Events evaluated: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator (or

Transmission Planner if more restrictive).

C. Measures

M1. To be supplied at a later date.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	TBD	Revision of TPL-001-0 as per Project 2006-02; includes merging requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-1	Not employed due to scope of revision

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Version 1 of SAR posted for comment from April 2, 2002 through May 3, 2002.
2. Version 2 of SAR posted for comment from May 5, 2004 through June 5, 2004.
3. Version 3 of SAR posted on November 18, 2005.
4. SAR approved on April 30, 2006.
5. Version 1 of Supplemental SAR posted for comment from February 15, 2007 through March 16, 2007.
6. Version 2 of Supplemental SAR posted on April 9, 2007.
7. Version 1 of revised standard(s) posted for comment on September 17, 2007.

Proposed Action Plan and Description of Current Draft:

The SDT has established a schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 1Q10. The current draft is the second iteration of the revision of existing standards TPL-001 through TPL-006 and includes one revised standard, TPL-001-1, replacing TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. TPL-005 & -006 will be addressed later in the project. Violation Risk Factors, Time Horizons, Measures, Compliance and Implementation Plans will be included in subsequent postings.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Respond to comments from first posting of standard(s) and submit revision 1 of the standard(s).	2Q08
2. Respond to comments from second posting of standard(s) and submit revision 2 of the standard(s).	4Q08
3. Submit revision 3 of the standard(s) for balloting.	2Q09
4. Respond to comments from third posting and submit revision 3 of the standard.	3Q09
5. Submit standard(s) for recirculation balloting.	4Q09
6. Submit standard(s) to BOT.	1Q10
7. Submit to regulatory authorities for approval.	1 Q10

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

~~**Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect Facility Ratings.~~

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)

Consequential Load Loss: Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.

Extreme Events: Events which are more severe and have a lower probability of occurrence than Planning Events ~~and have a low probability of occurrence~~.

Generating Unit Stability Study: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Near-Term Transmission Planning Horizon: Transmission planning period that covers Years One through five.

Non-Consequential Load Loss: ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-

voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~

Planning Events: Events ~~which~~ that require Transmission system performance requirements to be met.

Planning ~~Authority~~ Coordinator: The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.

~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~

System Stability Study: ~~Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.~~ Study that focuses on portions of the System, which may include many generating units, to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.

Year One: The first year that a Transmission Planner is responsible for ~~studying~~assessing. This is further defined as the planning window that begins ~~the next calendar year from the time the Transmission Planner submits their annual studies~~ 12-18 months from the completion of the previous annual Planning Assessment.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-1**

3. **Purpose:** Establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

   4.1.3. Resource Planner.

   4.1.4. ~~Load-Serving Entity~~ Distribution Provider.

   4.1.5. Transmission Owner.

   4.1.6. Generator Owner.

5. **Effective Date:** ~~TBD~~ As per Implementation Plan (to be supplied later).

B. Requirements

R1. ~~Each Resource Planner, Transmission Planner, Transmission Owner, Generator Owner, and Load-Serving Entity shall each provide its respective Planning Coordinator with the following modeling information required for System performance studies upon request (within 30 calendar days) :~~ Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R1.1. The Planning Assessment shall include documentation of the technical rationale for modification of any data that was provided in Requirement R9 through R14, MOD-010, and MOD-012.~~Load forecasts adhering, at a minimum, to the following criteria:~~

~~**R1.1.1.** Use of expected Load mix based on the actual or expected aggregate mix of industrial, commercial, and residential Loads.~~

~~**R1.1.2.** Based on normal weather patterns as agreed to by the Planning Coordinator(s) and the Transmission Planner(s) for the area(s) of their responsibility.~~

~~**R1.1.3.** Identification of Demand Side Management (DSM) Load reductions consistent with operational requirements.~~

~~**R1.2.** Load models with supporting rationale that include power factor data based on historical System performance, validated by measurement during stressed System conditions, or documented Transmission planning area requirements.~~

~~**R1.3.** Firm transfers/Interchange Schedules and resources required to supply Load for each Balancing Authority.~~

~~**R1.4.** Known planned outages and long-term outages for Transmission and generation equipment including protective relays with consideration given to spare equipment strategy.~~

R1.5. ~~Planned Facilities defined in accordance with the documented criteria of the Planning Coordinator, including but not limited to: Transmission Lines, generators, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies.~~

R2. Each Transmission Planner and Planning Coordinator shall conduct and document the results of its annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, and shall cover steady state analyses, short circuit analyses, and Stability analyses including both System and ~~plant~~ Generating Unit Stability. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R2.1. ~~The steady state portion of~~ ~~t~~The Near-Term Transmission Planning Horizon ~~Planning Assessment~~ portion of the steady state analysis shall ~~address all five years of the assessment period~~ be assessed annually and be supported at a minimum by the following annual current studies, supplemented with qualified past studies as ~~shown~~ indicated in Requirement R2.6:

R2.1.1. System peak Load for either Year One or year two, and year five.

R2.1.2. System Off-Peak Load for one of the five years.

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:

R.2.1.3.1. Higher or lower Load than forecast~~s~~ed ~~from the Base Case~~ with variability of Load/demand and Load power factors due to season, weather, or time of day.

R.2.1.3.2. Modification of expected transfers.

R.2.1.3.3. Unavailability of long lead time Facilities.

R.2.1.3.4. Variability and outages of reactive resources.

R.2.1.3.5. Generation additions, retirements, or other dispatch scenarios.

R.2.1.3.6. Decreased effectiveness of controllable Loads and Demand Side Management.

R.2.1.3.7. Modification of planned Transmission outages.

R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be

run and the Planning Assessment shall include documentation of the technical rationale for why each was selected shall be supplied.

R2.2. For the ~~steady state portion of the~~ Long-Term Transmission Planning Horizon portion of the steady state analysis, ~~Planning Assessment,~~ at a minimum, a current System peak Load study is required annually for one of the years in the assessment period to support the annual Planning Assessment.

R2.2.1. To accommodate any known longer lead time projects that may take longer than ten years to complete, the Planning Assessment shall be extended accordingly.

R2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually and supported by current or past studies.

~~**R2.3.1.** A current study shall be performed if changes in the BES result in increased fault currents such as resource additions and other Facility changes that result in reductions in impedance.~~

R2.4. The ~~System Stability portion of the~~ Near-Term Transmission Planning Horizon portion of the Stability analysis ~~Planning Assessment~~ shall be assessed annually ~~address all five years of the assessment period,~~ and be supported by current or past studies. The following studies are required ~~annually~~:

R2.4.1. System peak Load for one of the five years. For peak System Load levels, ~~the~~a Load model shall ~~include the dynamic effects~~ be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads.

R2.4.2. System Off-Peak Load for one of the five years.

R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:

R.2.4.3.1. Variations in Load model assumptions.

R.2.4.3.2. ~~Expected simultaneous transfers including non-firm~~ Modification of expected transfers.

R.2.4.3.3. Unavailability of long lead time Facilities.

R.2.4.3.4. ~~Reactive dispatch of generators and other reactive power devices~~ Variability and outages of reactive resources.

R.2.4.3.5. Generation additions, retirements, or other dispatch scenarios.

R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and the Planning Assessment shall include documentation of the technical rationale for why each was selected shall be supplied.

R2.5. The ~~plant~~Generating Unit Stability analysis portion of the Planning Assessment shall be analyzed consistent with Requirement ~~R4.6~~ R5.6 with studies for the year when the following changes that could affect stability margins occur:

R2.5.1. New generator(s) are added or generation modifications are made such as ~~increasing~~changes in generation capability or replacing the exciter ~~or addition of a power System stabilizer~~.

R2.5.2. Material Transmission System changes ~~in the electrical vicinity of existing generation are made~~ are made at or near the point of Interconnection of existing Generation such as the ~~addition or~~ removal of a Transmission Line ~~at or near the point of Interconnection~~ or the addition of a new substation in one of the Transmission Lines connected to the plant.

R2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

R2.6.1. For steady state, short circuit, or System Stability analysis: ~~if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market structure changes~~ the study shall be five calendar years old or less.

R2.6.2. For steady state, short circuit ~~analysis~~, Generating Plant Stability, or System Stability analysis: ~~if the study is less than five years old and no material changes have occurred to the System in the intervening period.~~ the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area.

~~**R2.6.3.** For plant and System Stability analysis: until material changes in the System make the study no longer valid. Material changes in the system include the addition of a Transmission Line or a generator.~~

R2.7. For Planning Events shown in Table 1 – Steady State Performance and Table 2 – Stability Performance, when the analysis indicates an inability of the System to meet the performance requirements in the tables, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed ~~over time~~ in subsequent assessments but the System shall continue to meet the performance requirements in the tables. ~~Such plans shall:~~ Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities. The Corrective Action Plan shall:

R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or

removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.

R.2.7.1.1. For the Near-Term Transmission Planning Horizon, include both a project initiation date as well as an in-service date.

R.2.7.1.2. For the Long-Term Transmission Planning Horizon, provide an in-service year.

R2.7.2. ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.

~~**R2.7.3.** Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~

~~**R2.7.4.** Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~

R2.7.5. Be reviewed in subsequent annual Planning Assessments as to implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to contingencies in Table 1 – Steady State Performance. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R3.1. Studies shall determine whether the BES meets the performance requirements in Table 1 – Steady State Performance.

R3.2. Contingency analyses shall simulate the removal of all elements including those that System protection is expected to disconnect for each Contingency without operator intervention.

R3.2.1. For all generators, studies shall consider the minimum steady state voltage limitations of all generators and identify how the generators are treated in the steady state simulation.

R3.2.2. For all Transmission lines, studies shall consider relay loadability and identify how loadability is treated in the steady state simulation.

R3.3. For Steady State studies:

R3.3.1. Performance criteria for System normal conditions and for Planning Events in Table 1 – Steady State Performance shall be met.

R3.3.2. Evaluations shall be performed for single Contingencies (identified in Table 1 – Steady State Performance).

R.3.3.2.1. Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment.

R.3.3.2.2. Following single Contingency events, ~~System adjustments other than shedding of firm Load or curtailment of firm transfers are permitted to meet performance requirements provided these adjustments can be accomplished within the time period allowed by the applicable time limited ratings.~~ Transmission configuration changes and redispatch of generation are allowed provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits.

R3.3.3. Those Planning Event Contingencies in Table 1 – Steady State Performance not covered in Requirement R3.3.2 that are expected to produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results.

R3.4. Those Extreme Events in Table 1 – Steady State Performance that are expected to produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. If the Extreme Events analysis concludes there are ~~C~~cascading ~~O~~outages caused by the occurrence of Extreme Events, an evaluation of implementing a change designed to reduce or mitigate the likelihood of such consequences shall be conducted.

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingencies~~y~~ ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:

R3.5.1. All Facilities shall be operating within their Facility Ratings.

R3.5.2. Such action would not violate safety, equipment, regulatory or statutory requirements.

R3.5.3. A sustainable, stable, operating condition is maintained.

~~**R3.6.** Manual and automatic generation tripping is allowed for multiple Contingencies and for single Contingencies only in situations that meet all of the following conditions:~~

~~**R3.6.1.** TBD~~

~~Note: WECC has informed the SDT that it will be submitting an Interconnection-wide regional variance to allow automatic generation tripping for single Contingencies. The regional variance will be justified based on physic differences in the western Interconnection. WECC is developing a white paper to support this position. The a regional variance will be included in the next posting of this standard.~~

R4.

R4. For the short circuit portion of the Planning Assessment, as described in Requirement R2.3, each Transmission Planner and Planning Coordinator shall assess the short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R5. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 and Requirement R2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 2 – Stability Performance. The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and ~~plant~~ Generating Unit Stability. The following requirements apply to both System Stability and ~~plant~~ Generating Unit Stability studies unless otherwise noted. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R5.1. Studies to meet the performance requirements in Table 2 – Stability Performance shall use computer Stability simulations that analyze the response of the BES.

R5.2. Contingency analyses shall simulate the removal of all elements including those that System protection and other automatic controls are ~~is~~ expected to disconnect for each Contingency without operator intervention.

R5.3. Studies shall consider the voltage ride through capability of all generators and identify how the generators are treated in the simulation.

~~**R5.4.** Studies shall identify any planned upgrades (including protection and control modifications) needed to meet the performance requirements of the Planning Events of Table 2 – Stability Performance and validate their effectiveness.~~

R5.5. For the System Stability study:

R5.5.1. At a minimum, those Planning Event Contingencies in Table 2 – Stability Performance that would produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information with an explanation of why the remaining Contingencies would produce less severe System results.

R5.5.2. Performance shall meet the requirements for Planning Events in Table 2 – Stability Performance.

R5.5.3. Automatic generation tripping is allowed to mitigate Stability violations if the following conditions are met:

R.5.5.3.1. All Facilities shall be operating within their Facility Ratings.

R.5.5.3.2. Such action would not violate safety, equipment, regulatory or statutory requirements.

R.5.5.3.3. A sustainable, stable, operating condition is maintained.

R5.5.4. At a minimum, those Extreme Events in Table 2 – Stability Performance that would produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. If the Extreme Events analysis concludes there are ~~C~~cascading ~~O~~outages, an evaluation of implementing a change designed to reduce or mitigate the likelihood of such consequences shall be conducted.

R5.6. For the ~~Plant~~ Generating Unit Stability studies:

R5.6.1. Shall be performed for individual generating units 20 MW or greater directly connected through a step-up transformer to the BES and for generating units at the same location which total 75 MW or greater, directly connected through their step-up transformer(s) to the BES.

R5.6.2. Shall be performed for changes in the real power output of a generating unit by more than 10% of the existing capability or more than 20 MW whichever is greater.

R5.6.3. Shall be performed and evaluated for those Planning Events that would produce more severe System impacts and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. ~~The identified Contingencies, at a minimum, shall be evaluated.~~

R5.6.4. Shall meet Performance requirements for Planning Events in Table 2 – Stability Performance.

R6. Each Transmission Planner and Planning Coordinator shall define and document the proxies used in simulation studies to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R7. Each Transmission Planner and Planning Coordinator shall determine and identify individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R8. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~affected entities~~ neighboring systems, coordinating analysis of these

results through an open and transparent peer review process such as described in FERC Order 890. *[Violation Risk Factor: TBD] [Time Horizon: TBD]* This distribution shall include:

~~**R8.1.** Transmission Planners within the Planning Coordinator's area~~

~~**R8.2.** Transmission Planners of neighboring impacted areas~~

R8.3. ~~Planning Coordinators of neighboring areas~~

R9. Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R10. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R11. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R12. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R13. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R14. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to Transmission Lines, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies, within ninety days of a request for such information. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

~~Table 1 – Steady State Performance~~

~~Performance Requirements~~

~~For all Planning Events:~~

- ~~Equipment Ratings shall not be exceeded.~~
- ~~System steady state voltages and post-transient voltage deviation shall be within acceptable limits established by the Planning Coordinator (or Transmission Planner if more restrictive.)~~
- ~~Voltage instability, cascading outages, and uncontrolled islanding shall not occur.~~
- ~~Consequential Load loss is allowed for all cases shown.~~
- ~~Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency.~~
- ~~Simulate Normal Clearing unless otherwise specified.~~

~~Planning Events~~			
#	**~~Event~~**	**~~Interruption of Firm Transfer Allowed (does not result in loss of Load)~~**	**~~Non-Consequential Load Loss Allowed~~**
~~P1~~ ~~(single Contingency)~~	~~Loss of:~~ ~~1. A generator~~ ~~2. A Transmission circuit~~ ~~3. A transformer~~ ~~4. A shunt device (including FACTS devices)~~	~~No~~	~~No~~
~~P2~~ ~~(single Contingency)~~	~~Loss of:~~ ~~1. Bus section above 300 kV~~ ~~2. Non-bus tie breaker (above 300 kV) due to internal fault~~ ~~3. Single pole of a DC line~~	~~Yes, if transfer is dependent on the outaged DC line~~ ~~No otherwise~~	~~No~~
~~P3~~ ~~(multiple Contingency)~~	~~Loss of either a generator, Transmission circuit, a transformer with low side voltage rating above 300 kV, or a bus and a stuck non-bus tie breaker (above 300 kV)~~	~~Yes, if transfer is dependent on the outaged DC line~~ ~~No otherwise~~	~~No~~
~~P4~~ ~~(multiple Contingency)~~	~~1. Loss of a generator followed by a System adjustment followed by the loss of a generator.~~ ~~2. Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line~~ ~~3. Loss of a generator followed by a System adjustment followed by the loss of a Transmission circuit~~ ~~4. Loss of a generator followed by a System adjustment followed by the~~	~~Yes, if transfer is dependent on the outaged DC line~~ ~~No otherwise~~	~~No~~

	~~loss of a transformer~~		
~~P5~~ ~~(multiple Contingency)~~	~~Above 300 kV, the loss of:~~ ~~1. A Transmission circuit followed by a System adjustment followed by the loss of another Transmission circuit~~ ~~2. A Transmission circuit followed by a System adjustment followed by the loss of a transformer with low side voltage rating above 300 kV~~ ~~3. A transformer with low side voltage rating above 300 kV followed by a System adjustment followed by the loss of another transformer~~	~~Yes~~	~~No~~
~~P6~~ ~~(single Contingency)~~	~~Loss of:~~ ~~1. A bus tie breaker due to internal fault~~ ~~2. A bipolar DC line or an asynchronous tie line~~ ~~3. A non-bus tie breaker (below 300 kV) due to internal fault~~ ~~4. A bus section below 300 kV~~	~~Yes~~	~~Yes~~
~~P7~~ ~~(multiple Contingency)~~	~~Loss of:~~ ~~1. A bus section above 300 kV and a stuck bus tie breaker~~ ~~2. Either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (below 300 kV)~~	~~Yes~~	~~Yes~~
~~P8~~ ~~(multiple Contingency)~~	~~Below 300 kV, the loss of:~~ ~~1. A Transmission circuit followed by a System adjustment followed by the loss of another Transmission circuit~~ ~~2. A Transmission circuit followed by a System adjustment followed by the loss of a transformer~~ ~~3. A transformer followed by a System adjustment followed by the loss of another transformer~~	~~Yes~~	~~Yes~~
~~P9~~ ~~(multiple Contingency)~~	~~1. Loss of any two circuits on a common structure (excluding where multiple circuits share a common structure for no more than one mile)~~ ~~2. Loss of a generator followed by a System adjustment followed by the loss of a monopolar or bipolar DC line, or an asynchronous tie line~~ ~~3. Loss of a DC line (monopolar or bipolar) or asynchronous tie followed by a System adjustment followed by the loss of a second DC line (monopolar or bipolar) or asynchronous tie~~ ~~4. Loss of a DC line (monopolar or bipolar) or asynchronous tie followed by a System adjustment followed by the loss of a Transmission circuit~~	~~Yes~~	~~Yes~~

	~~5. Loss of a transformer followed by a System adjustment followed by the loss of a DC line (monopolar or bipolar) or asynchronous tie line~~ ~~6. Loss of a transformer followed by a System adjustment with a spare transformer available followed by the loss of another transformer~~		

~~Extreme Events~~

~~Evaluation Requirements~~

~~For all Extreme Events:~~

1. ~~See Requirement R3.4~~
2. ~~Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency.~~
3. ~~Simulate Normal Clearing unless otherwise specified.~~

~~Extreme Event Descriptions~~

~~1.~~ ~~Loss of a single generator, Transmission circuit, DC line, or transformer forced out of service followed by another single generator, Transmission circuit, DC line, or transformer forced out of service prior to System adjustments.~~

~~2.~~ ~~Local area events affecting the Transmission System such as:~~

- ~~a. Loss of tower line with three or more circuits~~
- ~~b. Loss of all Transmission lines on a common right-of-way~~
- ~~c. Loss of switching station or substation (loss of one voltage level plus transformers)~~
- ~~d. Loss of all generating units at a station~~
- ~~e. Loss of a large Load or major Load center~~

~~3.~~ ~~Wide area events affecting the Transmission System such as:~~

- ~~a. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation~~
- ~~b. A successful cyber attack~~
- ~~c. Regulation that restricts or eliminates the use of a river or lake or other body of water as the cooling source for generation~~
- ~~d. Shutdown of a nuclear power plant(s) and other facilities a day or more prior to a hurricane, tornado or wildfire, or for other common causes~~
- ~~e. Regulation that restricts or eliminates the use of a river or lake or other body of water as the cooling source for generation~~
- ~~f. Shutdown of a nuclear power plant(s) and other facilities a day or more prior to a hurricane, tornado or wildfire, or for other common causes such as problems with similarly designed plants~~
- ~~g. The loss of older Transmission lines which may not be constructed to meet an entity's present radial ice or wind loading requirements, while the newer or stronger Transmission lines remain in service~~
- ~~h. Other events based upon operating experience~~

~~Table 2 – Stability Performance Table~~

~~Performance Requirements~~

~~For all Planning Events:~~

- ~~The System shall be stable[1]~~
- ~~Dynamic voltages shall be within acceptable limits established by the Planning Coordinator or Transmission Planner (if more restrictive)~~
- ~~Uncontrolled islanding and Cascading Outages shall not occur~~
- ~~Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency.~~
- ~~Simulate Normal Clearing unless otherwise specified.~~

~~Planning Events~~			
~~#~~	**~~Initial Condition~~**	**~~Event~~**	**~~Non-Consequential Load Loss Allowed~~**
~~P1~~ ~~(single Contingency)~~	~~System normal~~	~~Single Line Ground (SLG) fault on, a 3-Phase (3Ø) fault on, or an unexpected loss without a fault of (whichever is worst):~~ ~~1. A generator~~ ~~2. A Transmission circuit~~ ~~3. A transformer~~	~~No~~
~~P2~~ ~~(single Contingency)~~	~~System normal~~	~~1. SLG fault on bus section above 300 kV~~ ~~2. SLG internal fault in non-bus tie breaker (above 300 kV)~~ ~~3. A single pole block of a DC line~~	~~No~~
~~P3~~ ~~(multiple Contingency)~~	~~System normal~~	~~SLG fault on either a generator, Transmission circuit, a transformer, or a bus and a stuck[2] non-bus tie breaker (above 300 kV)~~	~~No~~
~~P4~~ ~~(multiple Contingency)~~	~~A single generator out of service followed by System adjustments~~	~~1. Apply a P1.1 Contingency.~~ ~~2. Apply a P2.3 Contingency.~~ ~~3. Apply a P1.2 Contingency.~~ ~~4. Apply a P1.3 Contingency.~~	~~No~~
~~P5~~ ~~(multiple Contingency)~~	~~A Transmission circuit above 300 kV out of service followed by System adjustments~~	~~1. Apply a P1.2 Contingency.~~ ~~2. Apply a P1.3 Contingency.~~	~~No~~

	~~A transformer with low side voltage rating above 300 kV out of service followed by System adjustments~~	~~3. Apply a P1.3 Contingency.~~	
~~P6~~ ~~(single Contingency)~~	~~System normal~~	~~1. SLG internal fault in bus tie breaker~~ ~~2. A bipolar block of a DC line~~ ~~3. SLG internal fault in non-bus tie breaker (below 300 kV)~~ ~~4. SLG fault on bus section (below 300 kV)~~	~~Yes~~
~~P7~~ ~~(multiple Contingency)~~	~~System normal~~	~~1. SLG fault on a bus section above 300 kV and a stuck bus tie breaker~~ ~~2. SLG fault on either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (below 300 kV)~~	~~Yes~~
~~P8~~ ~~(multiple Contingency)~~	~~A Transmission circuit below 300 kV out of service followed by System adjustments~~ ~~A transformer with low side voltage rating below 300 kV out of service followed by System adjustments~~	~~1. Apply a P1.2 Contingency.~~ ~~2. Apply a P1.3 Contingency.~~ ~~3. Apply a P1.3 Contingency.~~	~~Yes~~
~~P9~~ ~~(multiple Contingency)~~	~~System normal~~ ~~A single generator out of service followed by System adjustments~~ ~~A DC circuit out of service followed by~~	~~1. SLG fault on each circuit of any two circuits on a common structure (excluding events where multiple circuits share a common structure for no more than one mile).~~ ~~2. Apply a P6.2 Contingency.~~ ~~3. Apply a P2.3 Contingency.~~ ~~4. Apply a P1.2 Contingency.~~	~~Yes~~

	~~System adjustments~~ ~~A transformer out of service followed by System adjustments~~ ~~A spare transformer inserted to replace an outaged transformer followed by System adjustments~~	~~5. Apply a P2.3 Contingency.~~ ~~6. Apply a P1.3 Contingency.~~	
~~**Extreme Events**~~			
~~**Evaluation Requirements**~~ ~~For all Extreme Events:~~ ~~• See Requirement R4.5.2 in the text~~ ~~• Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency.~~ ~~• Simulate Normal Clearing unless otherwise specified.~~			
~~1. 3Ø fault on generator with stuck breaker~~ ~~2. 3Ø fault on Transmission circuit with stuck breaker~~ ~~3. 3Ø fault on transformer with stuck breaker~~ ~~4. 3Ø fault on bus section with stuck breaker~~ ~~5. 3Ø internal fault in breaker~~ ~~6. 3Ø fault on two or more circuits on a common structure~~ ~~7. SLG or 3Ø fault on all Transmission lines on a common right-of-way~~ ~~8. 3Ø fault on switching station or substation (loss of one voltage level plus transformers)~~ ~~9. 3Ø fault with loss of all generating units at a station~~			

~~Notes:~~

~~**1.** System stable means:~~

~~a. Angular stability:~~

~~i. For Planning Events P1 and P3.2: No generating unit or units shall be allowed to pull out of synchronism. A generator being disconnected from the system by fault clearing action or by a Special Protection Scheme is not considered pulling out of synchronism.~~

~~ii. For all other Planning Events: No generating unit or units totaling more than the contingency reserve (spinning reserve) of the Balancing Authority shall be allowed to pull out of synchronism. Generators that pull out of synchronism must have out-of-step protection and the resulting apparent impedance swings must not pass through relay characteristics that would result in the tripping of~~

~~any transmission system elements other than the generating unit and its direct connection facilities.~~

~~iii. For all Planning Events: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator or Transmission Planner (if more restrictive).~~

~~b. General: Unplanned islanding of portions of the system shall not occur for Planning Events.~~

~~**2.** A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) breaker, only one pole is assumed to remain closed.~~

Table 1 – Steady State Performance

1. Facility Ratings shall not be exceeded. Planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings.
2. System steady state voltages and post-transient voltage deviations shall be within acceptable limits as established by the Planning Coordinator (or Transmission Planner if more restrictive).
3. Voltage instability, cascading outages, and uncontrolled islanding shall not occur.
4. Consequential Load and consequential generation loss is allowed for all events shown.
5. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each event.
6. Simulate Normal Clearing unless otherwise specified.

Planning Events

Category	Initial System Condition	Event[3]	BES Elements out of Service[2,3]		Interruption of Firm Transmission Service Allowed	Non-Consequential Load Loss Allowed
			(A) > 300 KV	(B) <= 300 KV		
P0 Normal System conditions	Normal System	None	X	X	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission circuit 3. Transformer 4. Shunt device 5. Single pole of a DC line	X	X	No Yes, if transfer is dependent on the outaged DC line.	No

P2 Single Contingency	Normal System	Loss of one of the following:	X	X	No	No
		1. Breaker(s) opening without a Fault resulting in a single ended line				
		2. Bus section	X		No	No
				X	Yes	Yes
		3. Internal Breaker Fault (non-bus-tie)	X		No	No
				X	Yes	Yes
		4. Internal Breaker Fault (bus tie)	X	X	Yes	Yes
P3 Multiple Contingency (Generator + 1)	Loss of a generator followed by System adjustments	Loss of one of the following: 1. Generator 2. Transmission circuit 3. Transformer 4. Shunt device 5. Single pole of a DC line	X	X	No Yes, if transfer is dependent on the outaged DC line.	No

P4 Multiple Contingency (Fault plus stuck breaker)[1]	Normal System	Stuck breaker (non-bus-tie) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission circuit 3. Transformer 4. Shunt device 5. Bus section	X		No	No
				X	Yes	Yes
		6. Stuck breaker (bus tie) attempting to clear a Fault on the associated bus	X	X	Yes	Yes
P5 Multiple Contingency (Fault plus Protection System failure)	Normal System	Loss of multiple elements due to a single component failure within a Protection System associated with clearing a Fault on one of the following: 1. Generator 2. Transmission circuit 3. Transformer 4. Shunt device 5. Bus section	X		No	No
				X	Yes	Yes

P6 Multiple Contingency (Two overlapping single Contingencies)	Loss of one of the following, followed by System adjustments: 1. Transmission circuit 2. Transformer 3. Single pole of a DC line 4. Shunt device	Loss of one of the following: 1. Transmission circuit 2. Transformer 3. Single pole of a DC line 4. Shunt device	X	X	Yes	Yes
P7 Multiple Contingency (Common Structure)	Normal System	1. Loss of any two Transmission circuits on a common structure. (Excludes circuits that share a common structure for 1 mile or less.) 2. Loss of a bipolar DC line	X	X	Yes	Yes

Extreme Events

Evaluation Requirements

For all Extreme Events evaluated:

1. See Requirement R3.4.
2. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency.
3. Simulate Normal Clearing unless otherwise specified.

Extreme Event Descriptions

1. Loss of a single generator, Transmission Circuit, DC Line, or transformer forced out of service followed by another single generator, Transmission Circuit, DC Line, or transformer forced out of service prior to System adjustments.

2. Local area events affecting the Transmission System such as:
    a. Loss of a tower line with three or more circuits.
    b. Loss of all Transmission lines on a common right-of-way.
    c. Loss of a switching station or substation (loss of one voltage level plus transformers).
    d. Loss of all generating units at a station.
    e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
    a. Loss of two generating plants resulting from conditions such as:
        i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
        ii. Loss of the use of a large body of water as the cooling source for generation.
        iii. Wildfires.
        iv. Severe weather, e.g., hurricanes, tornadoes, etc.
        v. A successful cyber attack.
        vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
    b. Loss of two Transmission lines in different rights-of-way prior to System adjustments for conditions such as:
        i. Wildfires.
        ii. Severe weather, e.g., hurricanes, tornadoes, etc.
    c. Other events based upon operating experience such as:
        i. Consideration of initiating events that experience suggests may result in wide area disturbances.

Notes

1. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) breaker, only one pole is assumed to remain closed. The stuck breaker event introduces a delayed clearing mode. Normal Clearing is when the Protection System operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Breaker fail relay operation is a predetermined time that occurs after the Protection System operates and the breaker has failed. Breaker fail relaying will also isolate a predetermined portion of the electric system to isolate the failed breaker. Delayed clearing of a Fault is due to failure of any Protection System

component that prevents the Protection System from operating normally.

2. If the event analyzed involves BES elements at multiple system voltage levels, the lowest system voltage level for stated performance criteria applies regarding allowances for interruptions of firm ~~transfers~~ transmission service and Non-Consequential Load.
3. For transformer outage events, the reference voltage applies to the low-side winding (excluding tertiary windings) and excluding generator step-up transformers. For generator outage events, the reference voltage apply to the BES connected voltage (high-side of GSU transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
4. Requirements which are applicable to shunt devices also apply to FACTS devices.
5. An internal breaker Fault means a breaker failing internally, thus creating a System Fault which must be cleared by protection on both sides of the breaker.

Table 2 – Stability Performance

1. The System shall remain stable. [5]
2. Dynamic voltages shall be within acceptable limits established by the Planning Coordinator (or Transmission Planner if more restrictive).
3. Cascading outages and uncontrolled islanding shall not occur.
4. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each event.
5. Simulate Normal Clearing unless otherwise specified.

Planning Events

Category	Initial System Conditions	Event [3]	BES Elements out of Service [2,3]		Interruption of Firm Transmission Service Allowed	Non-Consequential Load Loss Allowed
			(A) > 300 KV	(B) <= 300 KV		
P1 Single Contingency	Normal System	SLG or 3-phase Fault on one of the following: 1. Generator 2. Transmission circuit 3. Transformer 4. Shunt device 5. Single pole of a DC line	X	X	No Yes, if transfer is dependent on the outaged DC line.	No

P2 Single Contingency	Normal System	1. Breaker(s) opening without a Fault resulting in a single ended line	X	X	No	No
		2. SLG Fault on bus section	X		No	No
				X	Yes	Yes
		3. SLG internal breaker Fault (non-bus-tie)	X		No	No
				X	Yes	Yes
		4. SLG internal breaker Fault (bus tie)	X	X	Yes	Yes
P3 Multiple Contingency (Generator + 1)	Loss of a generator followed by System adjustments	SLG or 3-phase Fault on one of the following: 1. Generator 2. Transmission circuit 3. Transformer 4. Shunt device 5. Single pole of a DC line	X	X	No Yes, if transfer is dependent on the outaged DC line.	No

P4 Multiple Contingency (Fault plus stuck breaker) [1]	Normal System	Stuck breaker (non-bus-tie) attempting to clear a SLG Fault on one of the following:	X		No	No
				X	Yes	Yes
		1. Generator				
		2. Transmission circuit				
		3. Transformer				
		4. Shunt device				
		5. Bus section				
		6. Stuck breaker (bus tie) attempting to clear an SLG Fault on the associated bus	X	X	Yes	Yes

P5 Multiple Contingency (Fault plus Protection System failure)	Normal System	Loss of multiple elements due to a single component failure within a Protection System associated with clearing an SLG Fault on one of the following: 1. Generator 2. Transmission circuit 3. Transformer 4. Shunt device 5. Bus section	X		No	No
				X	Yes	Yes
P6 Multiple Contingency (Two overlapping single Contingencies)	Loss of one of the following, followed by System adjustments: 1. Transmission circuit 2. Transformer 3. Single pole of a DC line 4. Shunt device	SLG or 3-phase Fault on one of the following: 1. Transmission circuit 2. Transformer 3. Shunt device 4. Loss of single pole of a DC line	X	X	Yes	Yes

P7 Multiple Contingency (Common structure)	Normal System	1. SLG Fault on each circuit of any two Transmission circuits on a common structure (Excludes circuits that share a common structure for one mile or less) 2. Loss of a bipolar DC line	X	X	Yes	Yes

Extreme Events

Evaluation Requirements

For all Extreme Events evaluated:

1. See Requirement R5.5.4.
2. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency.
3. Simulate Normal Clearing unless otherwise specified.

Extreme Event Descriptions

1. With an initial condition of a single generator, Transmission circuit, DC line, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, DC line, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
    a. 3Ø fault on generator with stuck breaker or a protection system failure due to a single component failure within the protection system.
    b. 3Ø fault on transmission circuit with stuck breaker or a protection system failure due to a single component failure within the protection system.
    c. 3Ø fault on transformer with stuck breaker or a protection system failure due to a single component failure within the protection system.

d. 3Ø fault on bus section with stuck breaker or a protection system failure due to a single component failure within the protection system.

e. 3Ø internal breaker fault.

f. 3Ø fault on two or more circuits on a common structure.

g. SLG or 3Ø fault on all transmission lines on a common right-of-way.

h. 3Ø fault on switching station or substation (loss of one voltage level plus transformers)

i. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances.

Notes

1. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) breaker, only one pole is assumed to remain closed. The stuck breaker event introduces a delayed clearing mode. Normal Clearing is when the Protection System operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed Protection Systems and breakers. Breaker failure relay operation is a predetermined time that occurs after the Protection System operates and the breaker has failed. Breaker failure relaying will also isolate a predetermined portion of the electric System to isolate the failed breaker. Delayed clearing of a Fault is due to failure of any Protection System component or breaker that prevents the fault from clearing normally.

2. If the event analyzed involves BES elements at multiple system voltage levels, the lowest system voltage level for stated performance criteria applies regarding allowances for interruptions of firm ~~transfers~~ transmission service and Non-Consequential Load.

3. For transformer outage events, the reference voltage applies to the low-side winding (excluding tertiary windings) and excluding generator step-up transformers. For generator outage events, the reference voltage apply to the BES connected voltage (high-side of GSU transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.

4. An internal breaker fault means a breaker failing internally, thus creating a system fault which must be cleared by protection on both sides of the breaker.

5. System stable means:

   a. Angular Stability:

      i. For Planning Event P1: No generating unit or units shall be allowed to pull out of synchronism. A generator being disconnected from the System by Fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

      ii. For all other Planning Events: No generating unit or units totaling more than the Contingency reserve of the Balancing Authority shall be allowed to pull out of synchronism. Generators that pull out of synchronism must have out-of-step protection or some other means to trip the generator for this condition and the resulting apparent impedance swings must not pass through relay characteristics that would result in the tripping of any Transmission System elements other than the generating unit and its direct connection Facilities.

   b. For all Planning Events evaluated: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator (or

Transmission Planner if more restrictive).

C. Measures

M1. To be supplied at a later date.

E. Regional Variances

~~1. WECC Interconnection-wide waiver is under development (see Requirement R3.6.2).~~

None.

Version History

Version	Date	Action	Change Tracking
1	TBD	Revision of TPL-001-0 as per Project 2006-02; includes merging requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-1	Not employed due to scope of revision

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Comment Period Opens
August 14–September 29, 2008

Now available at: http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

The second draft of TPL-001-1 — Transmission System Planning Performance Requirements (Project 2006-02) is posted for a 45-day comment period from August 14 through September 29, 2008.

The purpose of the proposed standard is to establish transmission system planning performance requirements within the planning horizon to develop a bulk electric system that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies.
The proposed standard consolidates, clarifies, and expands on the requirements that had been in TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0, and includes several new definitions. This effort is part of Project 2006-02 — Assess Transmission Future Needs and Develop Transmission Plans.

Note that the drafting team will hold a WebEx presentation and conference call on Tuesday, August 26, 2008 from 1330–1630 EDT to discuss the draft and to provide stakeholders with the opportunity to ask questions. An announcement containing further details about the call and links to the WebEx presentation will be sent separately.

Please use this electronic form to submit comments on the standard.

If you need an off-line, unofficial copy of the questions in the comment form, there is a copy of the comment form posted at the following site:

http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

Please use only the electronic form to submit comments by September 29, 2008. If you experience any difficulties in using the electronic form, please contact Barbara Bogenrief at 609-452-8060

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Shaun Streeter, Standards Program Administrator, at shaun.streeter@nerc.net or at 609.452.8060.

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Princeton, NJ 08540
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Individual or group. (80 Responses)
Name (59 Responses)
Organization (59 Responses)
Group Name (21 Responses)
Lead Contact (21 Responses)
Contact Organization (21 Responses)
Question 1 (72 Responses)
Question 1 Comments (80 Responses)
Question 2 (72 Responses)
Question 2 Comments (80 Responses)
Question 3 (72 Responses)
Question 3 Comments (80 Responses)
Question 4 (72 Responses)
Question 4 Comments (80 Responses)
Question 5 (73 Responses)
Question 5 Comments (80 Responses)
Question 6 (70 Responses)
Question 6 Comments (80 Responses)
Question 7 (74 Responses)
Question 7 Comments (80 Responses)
Question 8 (70 Responses)
Question 8 Comments (80 Responses)
Question 9 (68 Responses)
Question 9 Comments (80 Responses)
Question 10 (71 Responses)
Question 10 Comments (80 Responses)
Question 11 (73 Responses)
Question 11 Comments (80 Responses)
1 - Question 12 Comments (80 Responses)
2 - Question 12 Comments (80 Responses)
3 - Question 12 Comments (80 Responses)
1 - Question 13 Comments (80 Responses)
2 - Question 13 Comments (80 Responses)
1 - Question 14 Comments (80 Responses)
2 - Question 14 Comments (80 Responses)
Question 15 (73 Responses)
Question 15 Comments (80 Responses)

Individual
Dennis Malone
El Paso Electric Company

B â€" Unsure about supporting the revised standard

While this 2nd draft TPL standard has some positive changes, notably: The allowance to use RAS to trip generation for N-1 (see R3.5 Manual and automatic generation run-back/tripping is allowed as a response to a single or multiple Contingency ...) with some rather generic conditions. The allowance for Non-consequential Load Loss for loss of a transmission Facility, followed by system adjustment, followed by loss of a second transmission Facility (see P6 in draft performance Tables 1 and 2). This is the same as Category C3 in the existing TPL-003-0. On the down side, as proposed, Standard TPL-001-1: 1. Will not allow curtailment of firm transfer (or firm transmission service) after the first N-1, in preparation for the next N-1 regardless of transmission voltage level. This is a major issue. Curtailment of firm transfer after the first N-1 has always been a part of system adjustment in preparation for the next N-1 as stated in foot note b of the existing TPL-002-0: "b. Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers." Not allowing this could mean reduction of firm transfer capability pre-contingency unless new circuits are built. 2. The existing standard (http://www.nerc.com/files/TPL-003-0.pdf) does not distinguish between voltage classes, curtailment of firm transfer and, planned and controlled load shedding are allowed regardless of voltage class for Category C events. The proposed standard will not allow curtailment of firm transmission service, or planned and controlled load shedding for loss of Facilities with operating voltage above 300 kV involving the following in the proposed Performance Tables 1 and 2: P2-2: Bus Section fault (Category C1) P2-3: Breaker fault (Category C2) P4: SLG Fault + stuck breaker (Categories C6 - C9) P5: SLG Fault + protection system failure (Categories C6 - C9) The number of Facilities lost would depend on the bus configuration for above 300 kV. If you have a ring-bus, breaker and a half or double breaker double bus, you would lose at the most 2 Facilities. But if you have Main-Aux or single breaker double bus, you will lose all Facilities connecting to the faulted Facility.

Group

Dominion - Electric Transmission Planning

John Loftis

Dominion Virginia Power

Yes

No

Comments are subdivided according to different sections as listed below: R2.4.1: In principal, we agree that the dynamic behavior of loads, including consideration of the behavior of induction motor loads, should be represented. However, it is not easy to get the data on such loads. Most customers, including industrial ones, have no information/knowledge regarding their load characteristics. Also, the software tools currently in use do not accommodate the modeling of certain material effects (for example the load reduction due to thermal trips on large HVAC compressor motors). Additionally, if the entire case is populated with such detail dynamic load data, the case could not be solved. A lot of research would be required. A phase-in period of several years should be considered in order to accomplish the fundamental objective of dynamic load modeling. Please refer to Item 4 of Question 15 for further thoughts on modeling requirements. R2.4.3: It is acceptable to perform studies that include various sensitivity factors, but to document all rationals why they were chosen or not chosen for each study performed is burdensome. R2.5.1: Reduction in generation does not decrease stability margins. Therefore, the previous version's "increasing in generation" should be kept instead of changing it to "changes in generation." R5.4.3: This requirement allows automatic generation tripping to mitigate Stability violations (subject to meeting three listed conditions there in). Automatic generator trips should not be allowed for N-1 contingency studies (beginning with system normal and evaluating for the very first contingency) should the full output of the generating unit be classified as a capacity resource. Allowing a capacity resource generator to trip for N-1 contingency could result in reduced system reliability.

No

Non-Consequential Load Loss: In the example provided with the definition of Non-Consequential

Load Loss, it indicates that non-interruptible load loss that occurs through manual or automatic operations such as under voltage load shedding (UVLS), under-frequency load shedding (UFLS) or Special Protection Systems (SPS) would be considered Non-Consequential Load Loss. We recommend that the following statement be added to the standard in the definition -- "Interruptible loads such as the pump of a Pumped Storage Plant interrupted by an SPS should not be considered as a Non-Consequential load".

No

We generally agree with the modification, but feel that further clarification needs to be added as follows -- "Neither generation run-back (redispatch) nor tripping should be allowed to address deficiencies identified in single contingency (N-1) studies should the full output of the generation choose to be considered as a capacity resource". Should generation run-back be allowed, then a NERC Reliability Standard should be developed to require generator field testing to prove that generation run-back is a viable solution.

Yes and No

For requirements R9, R12, R13, the wording should be changed from ..."shall provide its respective Planning Coordinator with modeling information ..." to "shall provide its respective Planning Coordinator and Transmission Planner with modeling information ..."

Yes

Yes and No

(1) Dominion - Electric Transmission is okay with the format changes, but suggests that consideration be given to changing the category naming convention for Stability Performance Table 2 to S1, S2, etc. rather than P1, P2, etc. for clarity and to distinguish them from Steady State Performance Table 1. (2) The tables could be improved if the headings were put on each separate page.

Yes

Yes

No

We are of the opinion that the proof of a negative that is required for sensitivity cases (i.e. - that the sensitivity cases were more severe for those selected conditions vs. those not tested) is burdensome. The burden of proof lies on the transmission planner.

No

For Bulk Electric System (BES) Elements out of Service above 300 kV, interruption of Firm Transmission Service and Non-Consequential Load Loss should not be allowed. We favor the language proposed in the previous draft.

It is extremely difficult, if not impossible, to accurately determine the costs required to perform supplemental studies in order to become compliant with these proposed standards. It will take time to just become familiar with the proposed changes as well as developing the necessary documentation to show compliance. What is obvious is that increased staffing levels will be required to perform the assessments. Furthermore, it will take significant time to become fully compliant. Therefore, a grace period of 2 to 3 years should be granted in order to perform the required assessments and become compliant.

As stated above, this is difficult to predict but a grace period of 2 to 3 years should be considered.

At this point we are estimating at least 2 to 3 additional resources may be required to perform the additional studies on an ongoing basis. For Dominion, three (3) additional engineers to perform this analysis is approximately $500,000 per year (including benefits and overheads).

The initial process development and documentation will be the most difficult and time consuming portion. Dominion - Electric Transmission recommends a period of 3 to 5 years be given for this initial period of becoming compliant and preparing the documentation. As noted above, it is difficult to provide cost estimates, but we expect at least 2 to 3 additional resources will be required, at a minimum.

See response above.

Difficult to estimate the investment required, but it will be in the millions if not hundreds of millions of dollars.

Siting new transmission in Virginia can take a minimum of 5 to 7 years if new right-of-way acquisition is required. It is difficult to provide an estimate of time, but it will be quite extensive.

B â€" Unsure about supporting the revised standard

(1) Unsure about cost/effort necessary to meet requirements (2) Uncertain that compliance with the proposed requirements in this standard would significantly improve reliability (3) R2.6.2: The entire sentence is confusing as it is modified. The original sentence in the previous draft made more sense. Please check and correct accordingly. (4) R 5.3: This requirement considers voltage

ride-through capability of all generators. Nowhere in this TPL standard or in the MOD standards are Generator Owners specifically required to provide such data to Transmision Planners and Planning Coordinators. Stating the requirements for generator dynamics data and dynamic load characteristics in general terms, as listed below (from the MOD Standards), are vague. (a) shall provide appropriate equipment characteristics (b) shall provide dynamics system modeling and simulation data (c) Shall develop comprehensive dynamics data requirements .... to model and analyze the dynamic behavior.... (5) In Table-2 Stability Performance, several places refer to "SLG or 3-phase Faults" . Since it states "or", does this mean we can get by with studying only SLG faults? We do not think that is the intent of this phrase; thus, a clarification is warranted. (6) One of our comments on the previous draft was with respect to a second-zone fault clearing due to protection system failure for a fault beyond zone 1 coverage of primary relys. The SDT's response was (Specific 1): "The SDT agrees with your concern and is working on a solution for a future draft." The question is repeated below, as a pending "to do" item, using the revised 'Table-2 Stability Performance' as reference: Category 5 in 'Table-2 Stability Performance' refers to a protection system failure event. We interpret this as, among other things, having a fault beyond the first-zone coverage of the primary protection scheme with the carrier equipment failure (or the carrier cut-off switch left in "OFF" position by a technition - a human error) resulting in a second-zone trip of the faulted line. The second-zone trip time is generally in the range of 30-35 cycles. This may be critical from the stability aspect for the terminal end at a generating plant even though only one element will be lost. Also, the second-zone trips may need to be studied for transmission lines out of next terminal from the generator end if the next terminal is connected to the generator terminal via a short line. We think that an additional single contingency Category should be added to this Table to cover the "Event" of second-zone trip scenario.

Group

NPCC

Guy Zito

NPCC

No

There should be no difference beween System and Generating Unit Stability studies. Each require discretion regarding which events need to be tested. The consequences are potentially similar: either the instability of one or more generators. Extreme Events should be considered for any stability analysis, again, recognizing that discretion needs to be applied when selecting or dismissing particular contingencies. Therefore, the definition of Generating Unit Stability Study should be stricken from the standard.

No

a. A MOD standard should be developed to address the assembly of dynamic load models, rather than specifying modeling in paragraph 2.4.1 (dynamic behavior of loads). Paragraph 2.4.1 should instead read, "System Peak Load for one of the five years." b. In paragraph R.2.4.3.4, what does "variability" mean? c. Add a new requirement "R5.4.3.4 Automatic generator tripping shall not have an Adverse Reliability Impact on overall system reliability." d. Remove Heading R5.5 and make generator unit stability a section of overall stability requirements. e. Modify R5.5.1 to become R5.4.5, with the following, "Shall be performed for the addition of an individual generating unit or generating units at the same interconnection point of 20 MW or greater that are directly connected to the BES." There may be little difference between the stability performance of a single 20 MW unit and an aggregation of units totalling 20 MW at the same BES interconnection point f. Strike R5.5.3 and R5.5.4, as they become redundant to R5.4.1

No

In the Consequential Load Loss definition, the word 'source' needs to be defined or explained further since it is unclear.

No

We do not feel that R3.5.1, R3.5.2 and R3.5.3 are limiting enough. Add paragraph 3.5.4 "Manual and automatic generator tripping shall not have an Adverse Reliability Impact."

No

With respect to R9 "including the expected mix of industrial, commercial and residential loads", this provision may be inadequate to be practically useful. The potential issues include the variation in end-use load mix through the daily load cycle, seasonal load composition variations, and the ability to translate these end-uses into reasonable and useful steady-state and dynamic load models. It is important to understand how the information will be used and how much additional detail, such as distribution network detail, is also required. It is also important to note that some Canadian Provinces do not "classify" their load mix using "industrial, commercial and residential" designations but their load modeling is sufficient, accurate and granular enough to simulate system response. Add to the last sentence of R9 through R14 the following phrase, "within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator."

No

In R4, suggest striking, "that would result in greater circuit breaker interrupting dutiesâ€¦".

No

In both Table 1 and Table 2, the "Interruption of Firm Transmission Service Allowed" column. It is problematic to try to create an "exemption" based on type of facility such as HVDC. There are many other situations in which Firm Transmission Service has been provided, but may need to be curtailed partially or completely following an outage. It is recommended that a note be added stating that the only exception would be for curtailment of conditioned (or Conditional) Firm Transmission Service, recognizing that there may need to be some form of grandfathering in order to avoid having to rewrite transmission service agreements. In both Table 1 and Table 2, the "Extreme Event Descriptions" item 1 should add "or shunt device." In Table 1, the "Extreme Event Descriptions" item 3b should be deleted; it is redundant with Item 1. In Table 2, Note 5 includes significant clarifications and should not be buried in the bottom of the contingency table; Note 5 would be better placed in the definitions section. In Table 1 and Table 2, Contingency P5 requires a fault plus Protection System Failure, such as a battery system, which may remove ALL protection at some substations. This Contingency P5 requires all voltages and loadings to remain within criteria, and a stable system response; without interruption of firm transmission service and without Non-Consequential Load Loss, at voltages above 300 kV. Was this an intended outcome of this standard?

No

The definition provided is too limiting. It says that if you have two rings with a bus tie breaker in between, it is no longer a bus tie breaker. NPCC Participating Members Recommend, "A circuit breaker that is positioned to connect two individual station configurations." We do not agree that, "(Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)", as we have examples where stations of this nature are connected through a single "bus-tie breaker".

Yes

No

If a TP/PC conducts the studies specified in R2.1.1 and R2.1.2 with one or more of the sensitivities which stress the system in the normal course of study, are we to assume that fulfills the requirements of R2.1 completely, without additional studies of a less-stressed system?

Yes

NPCC Participating Members believe some additional cost for analysis and study may be required in order to meet the final requirements of the standard and the associated performance tables. However, the ability to accurately estimate the costs of these studies, how long the analysis may take and how much additional effort may need to be made to compile the documentation is not possible at this time. Many believe posing this question is premature and cannot be quantified at this time, and it may hold questionable value without a better understanding of the complete final requirements of the standard. Many believed that the sensitivity language, although currently being performed to some extent within NPCC, that now appears in the standard, could have a drastic effect on the extent to which this additional analysis is conducted and the associated costs.

See above

NPCC participating members have expressed compliance concerns that this standard, and in particular this question, imply NERC has the ability to "force" transmission reinforcements and construction. It should be emphasized and clarified that the standard should require transmission studies only, and per the Energy Policy Act, NERC does not have this authority as the ERO as granted by FERC in the US and NO authority allowing this in Canada. Also NPCC participating members expressed concern that a validly conducted assessment which shows that criteria are not met (in the 5 or 10 year horizon) could result in non-compliance with the Standard. If NERC believes that it can issue monetary penalties for 5 or 10 year assessments that show that performance criteria will not be met under future system conditions, there is a key question that requires explanation: What behavior is NERC attempting to incent through fining parties for conducting assessments which identify problems in a 5 to 10 year horizon? Also, NERC should further explain how it would view the relevance of a State or Provincial decision not to permit new facilities when issuing such a potential penalty such as preclusive siting issues with Generating Plants.

See above

C â€“ Definitely do not support the revised standard

This standard as drafted does not allow exceptions for small parts of the system as long as interconnected system reliability is maintained, which is allowed in the existing TPL standards in

footnotes b) and c) in Table 1. Unless such exceptions are allowed significant transfer restrictions or large reinforcements must be made. The applicable TPL footnotes are: Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers. Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (nonrecallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems. This comment form did not allow for the following items to be addressed: a. Definition of the Long-Term Planning Horizon. The planning horizon, for assessment purposes should be limited to 10 years. Such an assessment should be sufficient to identify requirements that may take an extended time to implement. b. Definition of Planning Coordinator is part of the NERC Functional Model, For consistency it should be removed from the Standard. c. Put headings on each section to identify requirements of section. Add headings to the tops of the subsequent pages in the performance tables. Headings only appear on the first page at the beginning of the Table. d. With respect to R2.2 - Delete "current" from the phrase"current System Peak Load study" and replace "study" with "assessment." e. Remove R2.2.1, the requirement to extend the assessment beyond 10 years. What does the length of the project have to do with the assessment? If it takes 15 years to build something, why does this require a review of year 15? What is the purpose of this assessment? f. R3.3.2 requires clarification - This standard needs to permit discretion regarding the single contingencies that need to be tested, similar to R 3.3.3 and R3.4. It is unnecessary to test all events. For example, contingencies may be limited to relevant disturbances that are contained within or directly impact the studied system. g. With respect to R3.2.1 - Clarify whether the intent of the standard is to address station service minimum voltage limitation, maximum leading VAR absorption capability or both at steady state. h. Remove R3.2.2 - Relay loadability is addressed in PRC-023 standard. i. With respect to R3.3.2.1 - Recommend the removal of the requirement to assess the expected duration of Consequential Load loss. It's not considered anywhere else in the standard. j. With respect to R3.3.3 - The paragraph refers to Table 1 Contingencies P3 through P7; this should be explicitly stated. Rationale for inclusion of testing should not be required; should only need to explain why certain Contingencies were not tested. This discretion should be applicable to all contingencies. k. With respect to section R5 - The concept of planned and long-term outages should apply to the general Planning Assessment, or not at all. It should not be specific to the Stability Assessment. l. The provisions of Section R.5.3 should have a corresponding MOD standard apply a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertant trip of the generator. Such a provision should include "other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation. m. Planned outages should be addressed in the operating horizion unless otherwise defined in the planning horizon.

Group

TVA System Planning

B. David Till

Tennessee Valley Authority

Yes

Yes

Yes

Yes

TVA agrees with the modified definitions. However, the definition for "Consequential Load Loss" can still be confusing. Suggest definition of "Load that is deenergized by relay action as a result of the the event being studied â€¦." Additional wording in "Consequential load loss" about transient conditions can be confusing as well - we suggest including this additional information later in the document. For Non-consequential load loss, suggest use of "Firm" instead of "Non - Interruptible" Load Loss.

Yes

Suggest applicable voltage limits must also be maintained during runback and tripping.

No

TVA provides the following comments: "Distribution Provider" in R9 should be replaced with "Load Serving Entity." Also in R9, is the expected mix of load to be presented individually or as a total of commerical, residential, and industrial loads? Would requiring this mix of load forecasts also result in a change to any MOD or FAC requirements dealing with load forecasts? "Transmission Planner" in R10 should be "Transmission Service Provider." Is this requirement also in MODs? In R11, R12, and R13 suggest adding "Transmission Planner" to "Planning Coordinator". In R13, Resource Planner may not have knowledge of Reactive Power devices and

new technologies.
Yes
Yes
TVA believes that the new table format does make the tables much easier to follow. However, the tables can be a little hard to follow for those categories that have both over and under 300-kV categories. Also having header pages at the top of each page of the tables would also help. Should P6 and P7 events be moved to Extreme Events since firm transmission and non-consequential load can be dropped for these events? Seems like these events are very similar to the Extreme Events.
Yes
TVA does appreciate this clarification, but suggests the following wording: "A circuit breaker that is positioned to connect two individual straight bus substation configurations that if faulted results in both bus sections being cleared."
No
Since an internal fault on any breaker is a low probability event, we believe that Non-consequential Load Loss should be allowed.
No
We recommend that sensitivity studies not be required for each of the near term years as required in R2.1.3 and R2.1.1. Sensitivities should only be required for only one year in the near term. These sensitivity study requirements are too prescriptive. Many examples of sensitivities are already inherent in the existing requirements. Sensitivity studies of load variation are inherent in the fact that several different study years and conditions are already being required. Outages of reactive sources and generation should already be included in studies of multiple contingencies. The process of planning new generation (system impact studies) will include studies of the future with and without the proposed new equipment. The TP and PC can better select the most appropriate sensitivities for their system.
Yes
One component of these costs is based on modification to the loadflow database. A massive effort would need to be undertaken to model bus sections and breaker codes in order to simulate the planning events needed to stay current with the proposed standards. Also, man-power to perform the extra analysis was considered. Additional man-power of 5 engineers (2 years) would be required at cost of $1,000,000
The majority of the time would be spent modifying the loadflow database so that the new planning event simulations could be analyzed. ï€ Time duration estimate of 2 years would be required.
Additional man-power of 4 engineers at costs of $400,000 per year would be required.
Additional man-power of 1 engineer (1 year) would be required at cost of $100,000
Additional man-power of 1 engineer at costs of $100,000 / year
Costs would include the implementation of redundant protection schemes for the P5 planning event (fault + failure of protection scheme), additional 500-kV facilities for P2.2 (single contingency - bus section outage) and P4 (fault + stuck breaker) events, and additional 161-kV facilities for the P3 (Generator +1) events. Estimated cost of $1 billion
Time duration of 10 years would be required
C â€‟ Definitely do not support the revised standard
TVA's main concern is that no technical justification for "raising the bar" on facilities above 300-kV has yet been demonstrated such as required on P2, P4, and P5 for 300 kV and above. TVA is very concerned that "raising the bar" would be a finacial burden on TVA's ratepayers. TVA would also like to provide the following additional comments to this second draft as follows: 1. In R2.4.1, load models that appropriately represent the dynamic behavior of motor loads are required. TVA believes that industry guidance is needed on how to properly model these loads. Does this requirement mandate the use of specific load models for each bus, or would an aggragete load model which represents the system as a whole be sufficient? It should be clearly stated whether the load model in R2.4.3.1 refers to system load or the dynamic load model at individual busses. 2. In R3.2.1 and R5.3, need industry guidance on how to actually determine the minimum steady state voltage limitations of generators. Is there a MOD or FAC requirement for generation owners to provide this information? 3. Which single contingency events should be included in calculations for Available Transfer Capacity? Should P2 events be included in addition to P1 events since P2 events are also defined as single contingency events in Tables? 4. Would like further clarification from the team on what does P5 exactly includes? For instance, does it include battery failures, CT failures, etc? 5. The existing TPL 002-0 allows for some local load to be dropped for a single contingency event as long as the Bulk system reliability was not impacted. However there is no such allowance any longer for losing such load for a single contingency in the proposed draft. It would be very expensive for TVA to fix all such events in

several remote areas that would have very little impact on the overall reliability of the TVA bulk system. TVA believes that the capital spent for these fixes could be used to better strengthen the overall bulk system in much better ways. 6. Suggest rewording R2.2.1 from "To accommodate any known longer lead time projects" to "To identify any potential longer lead time projects". 7. Can operational guides be used indefinitely in R2.7.1 or does the team propose a limit on how long operational guides can be used until a capital fix is implemented? 8. In R3.3.2.1, what is the purpose for needing the expected duration of consequential load loss? There is a concern that this requirement will be very burdensome to keep track of the quantity of consequential load loss as well as expected duration. Who is requesting this info? It appears that this may be a local regulatory issue, not a reliability issue. 9. Suggest changing definition of "Planning Events" in the Definitions to say "Events that have a higher probability of occurrence and require Transmission system performance requirements to be met." 10. Should the proposed standard mention that utilities should run contingencies outside their system that could impact their own internal system? TVA believes that additional documentation be included in the new standard to address this. 11. Functional entity in 4.1.4 should be "LSE" instead of "DP" 12. In the Definitions for "Year One", suggest replacing "previous" with "most recent" to help clarify when the planning window should begin. 13. Should "peak" in R2.1.1 be replaced with "On Peak" as shown in the NERC glossary of terms? Also the requirements in this requirement are too prescriptive - should allow some flexibility to allow the TP which years to study as long as a minimum number of cases are studied. 14. Suggest replacing "Plant" in R2.6.2 with "Unit" to match terms used in Definitions. 15. In R2.7.1.1, what is meant by "project initiation date"? Is it when engineering starts, construction starts, etc? 16. Suggest rewording requirements R3.3.3 and R3.4 to be more clear - such as breaking each of these into several sentences each. Existing wording is very confusing. 17. There is a concern with R5.6.1 with the requirement to perform simulation on 20 MW generators (to be consistent with the Registration Criteria). We recommend a 75 MW generator cutoff for required simulations. Also in R5.6.2, should last word in sentence be "greater" or "lesser"? 18. In the Tables under Extreme Events, is 3.b. (loss of two TLs on different ROWs actually already covered under 1 (loss of two elements prior to system adjustments)? Also in the Tables under Extreme Events, it may be difficult for a TP to know enough about nuclear plant design to perform studies mentioned under 3.a.vi. 19. In the notes under Extreme Events, we suggest that notes #2 and #3 be combined together since they are very similar in nature. 20. Should the P3 planning event descriptor (G+1) in the performance tables be (G+N-1) or (G-1, N-1)? The existing descriptor (G+1) tends to note that an element is being added to the system instead of being removed. 21. Should the new standard address specific voltage limit requirements that must be maintained during these planning events? Since different utilities have different voltage limits on their buses, should there be some consolidation to ensure the standard is applied equally at all utilities? 22. The note for Planning Event P1 states that â€œNo generating unit or units shall be allowed to pull out of synchronism. A generator being disconnected from the System by Fault clearing action or by a Special Protection System is not considered pulling out of synchronism.â€œ The standard does not allow consideration for small units with a Zone 2 fault. It is not practical to add pilot relaying on all lines from a plant with a small unit that would be stable for close-in three phase faults, and could be adequately protected when a Zone-2 fault would cause a small generator to trip off with out-of-step (OOS) protection. The table for P1 should allow small units (<75 MW) to trip using SPS or OOS protection.

Individual

Karl Kohlrus

City Water, Light & Power - Springfield, Illinois

Yes

No

Near term stability analysis should not need to be performed each year unless there is a significant change to the system or the previous stud(ies) showed marginal performance.

Yes

Yes and No

There should be a time limit for manual generation runback.

Yes

Yes and No

For R2.4 stability studies should not be required ammually but should only be required if there is a significant change to the system or system stability was marginal as shown in previous studies.

Yes and No

Place the titles on each page and put the borders back in.

Yes

Yes

Yes

Yes and No

Shunt devices should only need to be included in contingency analysis at the discretion of the TP or PC.

A â€" Generally support the revised standard

Individual

John P. Mayhan

Omaha Public Power District

No

The term "straight bus" is not an industry-standard term. Replace "straight bus" by "single-bus, single-breaker".

B â€" Unsure about supporting the revised standard

Event 1 of Category P2 in Tables 1 and 2 addresses events consisting of "Breaker(s) opening without a Fault resulting in a single ended line." Category P2 is labeled as a "single contingency" category, yet it seems like an event consisting of the opening of more than one breaker would actually be a multiple contingency. Please consider whether the "(s)" should be removed after the word "breaker" in the event description so that it addresses only a single breaker opening without a Fault. Table 1 does not address multiple contingencies consisting of loss of a transmission circuit, transformer, single pole of a DC line, or shunt device, followed by System adjustments, followed by the loss of a generator. It seems like Table 1 should be modified to address this type of multiple contingency. In the description of Event 1 of Category P2 in Table 1, remove the text "Loss of one of the following:". In the description of Event 2 of Category P2 in Table 1, replace "Bus section" by "Loss of a bus section". Assuming that this does not change the intent of the drafting team, in R3.3.2.2, R3.5.1, R5.4.3.1, change "shall be operating" to "are operating". In R3.3.2.2, consider removing the phrase "and within their thermal and voltage limits", because it seems like it may be redundant given the definition of the term "Facility Rating". In the event descriptions of Categories P1, P3, and P6 of Table 2, does the term "3-phase fault" apply to DC lines? If not, consider using a separate introductory phrase with the event descriptions of Categories P1, P3, and P6 of Table 2 that involve DC lines. Also consider removing the words "Loss of" in the description of Event 4 of Category P6 in Table 2. Since a definition was developed for "Bus-tie Breaker", capitalize the terms "bus-tie" and "bus tie" wherever they appear in the standard.

Individual
Mark Byrd
Progress Energy Carolinas
No
The System Stability Study definition could be improved by clarifying that it is a study that focuses on the impact of contingencies to the system itself and covers a larger geographical area than one Generating Plant. A specific proposal is as follows. â€œSystem Stability Study - Study that focuses on how contingencies impact a larger portion of the System than a Generating Unit Study. These studies would examine issues such as angular stability, inter-area power oscillations, and dynamic voltages.â€
No
R 2.4.1 Load models that appropriately represent the dynamic behavior of induction motors are currently under development and may not be available for sometime. We believe that modeling the dynamic effects of loads is becoming increasingly necessary to obtain meaningful results. Therefore, it is appropriate that the revised standards address this. However, the present state of the industry is such that effective implementation of this requirement, as currently written, cannot be realistically achieved in the near term. The software tools currently in use do not accommodate the modeling of certain material effects (for example the load reduction due to thermal trips on HVAC compressor motors). Additionally, detailed load information necessary to allow the models which are available to be populated with meaningful data is not typically available or readily obtainable. Without resolving these issues, load model data submitted via the MMWG process will not improve simulation accuracy and could actually reduce the accuracy of results. Therefore, we would recommend R 2.4.1 rewritten to either a) allow a multi-year, phased approach to incorporating dynamic load modeling in simulation dynamic databases or b) provide an effective date for this particular requirement well into the future. This will accomplish the fundamental objective in a more accurate and meaningful manner. At least 48 months should be allowed before this requirement becomes effective. ï€ R 2.4.3 The proposed sensitivities create significant amount of additional work for the sole purpose of demonstrating compliance to this standard without any demonstratable benefit towards improving system reliability. While sensitivities should be appropriately considered in studies, this standard should not be overly prescriptive with respect to specific sensitivities or study methodologies. We propose removing the enumerated list of sensitivities starting with R2.4.3.1 and rewording R2.4.3 as follows: ï€- R2.4.3 For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, sensitivity case(s) that stress the System to reflect one or more conditions such as variations in dynamic Load model assumptions, modification of expected transfers, unavailability of long lead time Facilities, variability and outages of reactive resources, generation additions, retirements, or other dispatch scenarios shall be performed. The rationale for the sensitivity (ies) selected shall be documented. ï€ R 2.4.3.1 As stated above, this sub-requirement should be removed. However, if it is to remain, it should be clearly stated whether the Load model refers to system load or the dynamic load model at individual busses.
Yes
The definition of Consequential load loss has been appropriately modified to include loss of Load as a result of the Load's response to the transient condition. This recognizes the fact that when subjected to fault voltages of sufficient depth and duration, the resulting Load dynamics will result is loss of Load. Therefore, in order to more accurately replicate real-world behavior through dynamic stability simuation analysis, the proper representation of expected real world loss of load is acceptable. It is also proper that the computation of expected consequential Load loss and duration is not required for stability analysis. Attempts at determining additional Load loss due to load dynamics would not result in any useful information contributing to increased reliability.
Yes
Furthermore, PEC believes that generation run-back and tripping should not be allowed as a CAP for N-1 events with the possible exception of small reductions of generation.
Yes
Yes
Yes
The readability of the tables could be improved if the headings were put on each separate page. Separating out the tables for steady state and stability greatly improves and clarifies the requirements of the standard. Additionally, we would prefer that dynamic planning events use labeling such as D1, D2, etc. instead of P1, P2, etc. to differentiate them from steady state events.
The use of the word â€œstraightâ€ in the definition raised questions. We recommend the word straight be removed or change the definition to the following. "Bus-tie Breaker: A circuit breaker

positioned to connect two individual buses with one or more other breaker positions on each bus. (Substation configurations such as a ring-bus, breaker-and-a-half, or double-breaker do not generally include bus-tie breakers.)"
Yes
No
These requirements are overly prescriptive. Many examples of sensitivities are already inherent in the existing requirements. Some sensitivity studies are in effect adding an additional level of contingency (N-2 or N-3). Sensitivity studies of load variation are already inherent in the fact that several different study years and conditions are already being required. Outages of reactive sources and generation should already be included in studies of multiple contingencies. The process of planning new generation (system impact studies) will include studies of the future with and without the proposed new equipment. Proper consideration and selection of the most appropriate sensitivities is within the engineering judgement of the Transmission Planner and Planning Coordinator. Singling out and creating sub-requirements for the sensitivities listed in the current TPL draft creates a special focus on these specific sensitivities that may not be warranted for a given system. This could easily lead to an over focus on these particular issues to the detriment of overall system reliability. There should be no enumerated list of required sensitivities. Engineering judgment needs to be permitted.
No
While we agree interruption of firm transmission service and non-consequential load loss should not be allowed to meet the planning requirements for the first system contingency (defined as initial system condition in the table), these system adjustments should be allowed to prepare for the second event so that the system will meet the requirements following the second event. We recommend that clarifying changes be made to ensure that this is clearly understood. One suggestion would be to include the following footnote to P6 in both the Steady State and Stability Tables. ï€ Foot note: Interruption of firm transmission service and/or non-consequential load loss is allowed after the first event as a System adjustment to prepare for and meet the requirements of the second event. See also our related response to question 15.
$150,000
3 Years
$50,000/year
$60,000
$20,000/year
$100,000,000
10 years
C â€" Definitely do not support the revised standard
While be believe that in many ways the proposed draft standard represents an improvement of the current standard, we have a number of significant concerns that preclude our endorsement for the proposed standard as currently drafted. These include those discussed in the comments to above questions and the below additional comments. 1) In both the Steady State and Stability Tables, Category P6 is the loss of a system element, following system adjustments, followed by the loss of another element. The table columns for this category say that interruption of firm transmission service is allowed. The table, however, is not clear whether the interruption of firm service is allowed as part of the system adjustment (between the outages) or whether it is only allowed after the second outage. It was stated in the NERC TPL SDT WebEx that the interruption is not allowed as part of the system adjustment. If this is the interpretation, this would be a dramatic change from the existing standard and would result in the unintended consequence of significantly reducing transfer capability of interfaces to a fraction of their currently reported capability. This would in effect be imposing an n-2 criteria for offering firm transmission service. This would not be an acceptable situation for the users, owners and operators of the bulk power system. 2) The proposed sensitivities create significant amount of additional work for the sole purpose of demonstrating compliance to this standard without any demonstratable benefit towards improving system reliability. While sensitivities should be appropriately considered in studies, this standard should not be overly prescriptive with respect to specific sensitivities or study methodologies.
Individual
John Collins
Platte River Power Authority
Yes and No
"Generator Unit Stability Study" assessments are applicable to FAC-001 and FAC-002. If specific requirements for a "Generator Unit Stability Study" are to be added to a standard, then those requirements belong in either a Revised FAC-001 or a Revised FAC-002 and not in a TPL standard. The "System Stability Study" assessments which are appropriate for TPL standards will capture both the performance of the system and the performance of specific generators at the

various demand and stressed sensitivity levels studied.

Yes and No

Yes

Yes

Yes

Yes and No

I like the emphasis on stability performance but I prefer one table combining steady-state and stability Categories since the Planning Events are common to both. Divide notes, Evaluation Requirements, and Extreme Events Descriptions into two sub-tables.

Yes and No

Delete the sentence in parentheses.

No

I think the performance for non-bus-tie breakers should be the same for all BES voltages for the same reason I agree with the performance of P2.4 Internal Breaker Fault (bus tie) and P4.6 Stuck Breaker where the Stuck Breaker could be a bus-tie or "sectionalizing" breaker.

Yes

Yes

A â€" Generally support the revised standard

In Tables 1 and 2, Categories P1 and P3, under the column heading "Interruption of Firm Transmission Service Allowed," change the note in the performance box to read "Yes, if transfer is dependent on the outaged Element." (Not just for a DC line Element.) This conditional statement applies to most Firm Point-To-Point Transmission Service (Firm PTP) applications where an outaged Element reduces the Transfer Capability of the PTP service if the Element cannot be restored to service after an allowable time frame (30 minutes or so) and the Transfer Capability is reduced to a Prior Outage System Conditions level. This "extended Contingency situation" could cause an interruption or curtailment to the firm service. The interruption and curtailment responses to a Contingency might be different between Firm PTP and Network Integration Transmission Service.

Individual

Phil Park

BCTC

No

BCTC agrees with many other commenters, ABB, Ameren, Central Maine Power, NPCC RCWS, FirstEnergy, WECC, HQTE, Tenaska, FPL, FRCC, National Grid, New England ISO, NU, NStar, United Illuminating, BPA, Progress-Carolinas, TEP, and Northwestern Energy that there is no significant distinction between generator and system stability. These entities have significant experience with stability studies. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without any explanation. We believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequate addressed by open access tariffs and FAC-001. This should not be duplicated in TPL.

No

BCTC's open access tariff requires generator owners to apply for interconnection studies and facility studies to interconnect to our system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. In fact, we may only be aware of the changes indentified in these requirements when generator owners make these applications. The generator owners are required to pay for these studies. Study requirements for generator interconnections are further defined by NERC Standards FAC-001 and FAC-002 (Coordination of Plans for New Facilities). By including these requirements in TPL, BCTC is concerned that generator owners may

think that they are no longer required to pay for the studies. Furthermore, the NERC standards would have redundant requirements. If SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Any studies resulting from new generators or increases in existing generator output should be charged to the owner.

No

Our understanding of these definitions and the performance requirements in Tables 1 and 2 is that they may eliminate the existing provision in Footnote (b) that allows loss of firm load for contingencies in local networks. Disconnection of loads on local networks in response to contingencies normally requires RAS/SPS, and the definition of NCLL states that this is NCLL. We are not clear whether our concern is with the definitions of CLL/NCLL, the Tables, or the definiton of BES. In the Consideration of Comments on First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is CLL, we do not see where FERC has ruled out the use of RAS/SPS for CLL - see BCTC comments on the First Draft at page 28 of the Consideration of Comments. BCTC concurs with SaskPower and Manitoba Hydro that that CLL needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. In addition, BCTC cannot meet the proposed P1 (A) > 300 kV Steady State Performance of no Non-Consequential Load Loss for part of our 500 kV system. One radial segment of the BCTC 500 kV transmission system, a single circuit 450 km 500 kV transmission system, serves load and interconnects generation. For outages of the 500 kV transmission line, a RAS is used to shed load to match the generation in this island. We have no plans for transmission reinforcements (280 miles of 500 kV transmission line) to remove this RAS. Therefore, we will require some further clarification of the proposed P1 (A) >300 kV requirement of no Non-Consequential Load Loss for this requirement to be suitable for all of our system.

Yes

We agree that runback/tripping should be permitted for all contingencies. However, we are concerned that listing runback/tripping as an acceptable alternative, at least as currently worded, may encourage use when system reinforcements should be built. BCTC would prefer TPL-001 to be silent on this issue and that R3.5 be deleted. The list of conditions is very generic and should apply to all of TPL-001. If R3.5 is retained, the list of conditions should also require that all generation reserves requirements are met.

Yes

We can live with the proposed Requirements, but expect some problems may arise with implementation. For example, to accurately model our system for stability studies, we require models of adjacent systems. It is not clear how we will coordinate this requirement within the WECC base case process.

Yes

R.3 and R4 are acceptable, although we note the R4 gets into details of how to do short circuit analysis which is unnecessary for this standard. In some cases it may be necessary to consider multiple contingencies. Should R2.6.2 say "the SYSTEM shall not include material changesâ€¦"?

No

The differences in the tables requiring two tables are not apparent. Furthermore, we have become familiar with working with the current Table 1. Changing to these new tables will result in transition costs. We see no problems with continuing to use the current Table 1 and would prefer to retain it.

No

Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. What would these breakers be called? We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.

Yes

BCTC agrees with different performance levels. However, we have a different rationale. Our reasoning is that a bus fault has a lower probability than a line fault. Bus tie breakers are called on to interrupt faults less often than line breakers. The failure probably may be the same but the frequency of failure is lower (because they are not called on to operate as often). The explanation given above by the SDT appears to be more related to a WECC issuee that bus breaker failure should be Category D.

Yes

Yes

We estimate an initial one time cost of up to $50,000 for BCTC planners to become familiar with the new format and requirements of the standards and make changes to their assessment

process. In addition, additional study costs for sensitivity studies (many stability studies) may cost an additional $50,000. Many segments of the BCTC system are stability limited and we have significant experience with the needs and timelines for doing stability studies. Stability studies identify the need for RAS for multiple contingencies, which is fairly short lead time. We are currently satisfied with the amount of stability studies we do for the near and long term planning horizons. We do not need to do sensitivity studies. We do not expect any significant additional costs for studying Extreme Events because most of the wide area events listed are not applicable to the BCTC system.

1 Year

The additional cost could be from $50,000 to $100,000 per year. We will incur additional study costs for sensitivity studies and expect additional planning administration costs for reconciling between reinforcements required to meet the CLL/NCLL definitions and P3 requirements vs. what we actually propose as doable projects.

Included in the above. We do not do analysis without documentation.

Included in the above. We do not do studies without documenting them

We do not believe that this cost is not relevant for determining the applicable standards and have not estimated it. The reinforcement costs are orders of magnitude greater that the costs of alternatives the changes in this standard propose to prohibit (e.g. use of RAS, curtailment in anticipation of the next contingency). We believe it is very unlikely that we would get approval for the projects that would be required to meet the proposed changes.

It is highly unlikely that we would be able to get funding approval for the system reinforcements required to meet the proposed changes in these standards.

C â€" Definitely do not support the revised standard

BCTC appreciates the efforts of the SDT to explore ways to improve our planning standards. We understand that some of the proposed enhancements may assist Transmission Planners with justifying the need for system reinforcements. Many areas of our system already meet the proposed improvements, for example, most (but not all) of our 500 kV system already meets the proposed standards for systems above 300 kV. We have planned our system without support from a standard. The proposed changes do not really help us in any way and have a number of undesirable consequences. Consequently, BCTC does not support a number of the proposed additions and is uncertain about supporting some of the other changes. Our concerns are summarized below under headings of System Issues and Study Issues. System Issues: 1. BCTC plans, manages and operates 18,000 km of transmission in British Columbia. This includes 5700 km of 500 kV transmission lines. For the BCTC system, the proposed definitions for Consequential Load Loss and Non-consequential Load Loss, specifically that load loss due to RAS/SPS is Non-Consequential Load Loss, will provide no reliability benefits for our 500 kV transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection relative to what we have today. No reinforcements of this 500 kV transmission will be required as a result of these more stringent definitions. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level, primarily in rural areas currently served by radial lines. The possible benefits would be small. There is a very low probability that we would get funding approval for these facilities. For most of our system including most of our backbone 500 kV and local networks in metropolitan and urban areas BCTC already meets the requirements for these definitions. As noted in our comments at item 3, a portion of the BCTC system above 300 kV cannot meet the proposed P1(A) > 300 kV. We require further clarification of these definitions such as allowing load shedding in local networks. Otherwise, we will not be planning a doable/plausible set of actions, but rather just generating a list of projects that will not be approved. Our resulting subsequent corrective plan will be to use load shedding RAS, which will conflict with the definitions. Order 693 does not require NERC to prohibit load shedding, only clarify the amount and duration of load shedding that is permitted (paragraphs 1795 and 1797). BCTC's concerns can be addressed by including the local network component of Footnote (b) - modify the definition of Consequential Load Loss to permit the use of RAS in local networks (including local networks interconnecting generation), by allowing Non-Consequential Load Loss for local networks in Tables 1 and 2, or by modifying the definition of BES to exempt local networks from the definition of BES. BCTC could also consider a limit on load shedding if the industry would develop one. BCTC raised these issues in our comments on the first draft. The SDT response (page 332) does not address our concerns. We also note FPL comment 7 (page 359) regarding removal of localized load reduction provided in Footnote (b). We do not believe that the SDT has addressed FPL's issue. Unless the local network component of Footnote (b) is included and we can get a clarification to address our concern with P1 (A), the proposed standard is not suitable for the BCTC system and we do not support the standard. 2. Contingency P1 needs to permit curtailment of firm service for flow through firm transmission service to prepare for the next contingency. If it does not, some flow through open access transmission customers may have less ATC available if RAS is not available to meet the new restrictions on the P6 contingency, while this ATC will be available for services sourcing or sinking within the transmission provider's system. P6 allows the use of RAS in response to the second contingency (Event). For firm service

originating or sinking in our system, we can use RAS and have many RAS systems already in place. However, for flow throughs it may not be possible to implement RAS or there may be a time delay until RAS can be installed. If RAS cannot be implemented, it would be preferrable to provide the firm service and curtail in preparation for the second contingency rather than deny the firm service (or require that the system be built for N-2 capability, which also may not be possible), which is what we will have to do to adhere to the new standard. The result is that flow through transactions will have to use non-firm service while non-flow-through may use exactly the same transmission for firm. Also keep in mind that while P4 and P5 are only those multiple contingencies initiated by a common mode failure, P6 is any two elements not necessarily common mode. Therefore, P6 can be more limiting than P4 or P5. For P4 and P5 contingencies the BCTC system has less dependence on RAS than does the second event of a P6. Consequently P6 will be more limiting on flow throughs than P4 and P5. Order 693 contains direction to NERC to address Footnote (b). Some commenters have taken issue with the SDT interpretation of Order 693 (e.g. FRCC item 2, page 365). Given the different interpretations and the potential for impacts on ATC, we suggest that the SDT review this issue with FERC and find out if what the SDT is proposing is what they really want. Without this change or clarification we do not support the standard. 3. Regarding Q30 in the Comments on First Draft, BCTC believes that DC and AC lines should have the same performance requirements with respect to interuption of firm transmission service. This relates to our concern above regarding flow through transactions. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable step to prepare for the next contingency of an AC line. We would ask that the SDT provide further explanation of its response that "many of the transfers over DC lines are automatically curtailed when the DC line is outaged" (page 220). We can do the same with AC lines for transfers sinking or sourcing within our system. Is the SDT assuming that RAS/SPS is used? We agree with the comments of FPL, FRCC, Southern Transmission and Manitoba Hydro (pages 219 and 221) and FPL (page 360, item 11). We disagree with the SDT decision to allow different performance for DC than AC lines. We do not support this element of this standard. 4. Contingency P3 should have the same performance requirement as P6. In two recent CPCN approvals for reinforcements of the BCTC backbone system, approval was granted based on generator contingencies being treated the same as transmission contingencies. We believe it highly unlikely that we would have received funding to approval to meet contingency P3. In our local service areas relying on generation for firm supply and for our bulk system, we consider dependable generator capacity on a case by case basis. We do not arbitrary assume a generator N-1 as a preexisting planning condition. We consider firm generator capability as a sensitivity case, not a planning criteria. We disagree with requiring a generator initial system condition having a more stringent performance requirement than other initial conditions. Without this change we do not support this standard. 5. BCTC is concerned that including the generator runback/tripping requirement in this standard will encourage more use of generator runback and tripping and will make it more difficult to get regulatory approval for transmission reinforcements. If retained, there needs to be a tie into reserves requirements. While we agree with permitting generator runback/tripping, at this time we are unsure about supporting this standard with this permissive requirement included. Study Issues: 6. R2.5 and R5.5 on Generating Unit Stability studies are adequately addressed by FAC-001 and 002. Triggering events such as increased output or new existers need to go through our generator interconnection process and be paid for by the customer. In fact, we would not be aware of any of these triggering events unless a request comes from a customer. Without clarification of which generator studies are addressed through FAC-001 first, we do not support this standard. 7. We request that the SDT provide an explanation of why it believes it is important to maintain a distinction between system and generating unit stability studies. 8. Table 1 Steady State Performance lists 6 items above the Planning Events title. Should these be listed below the Planning Events title?

Individual

Kris Manchur

Manitoba Hydro

No

Manitoba Hydro does not believe there is a need to distinquish between System Stablility Study and Generating Unit Stability Study. Both these studies as defined require that synchronous operation of generators is maintained (i.e. angular stability) and damping is acceptable (i.e. small signal stability). The stability assessment would cover the issues being requested in the Generating Unit stability Study. We suggest the defintion for System Stability Study - A study that determines whether angular stability is maintained, inter-area power oscillations are acceptably damped, and transient voltage swings remain within acceptable limits. Further, contrary to the SDT interpretation in the response to our first posting comments, Manitoba Hydro believes the Generating Unit Stability Study is a duplication of the what is required in FAC-002-0 as the FAC requirements mandate system performance required by the NERC Reliability Standards. Manitoba Hydro continues to believe this additional study is redundant. Should the SDT decide to retain the Generating Unit stability study, then Manitoba Hydro recommends that, consistent with the wording in other requirements of this assessment section, it would be more

appropriate to require that "Generating Unit Stability be assessed using current or qualifying past studies â€¦â€ This would allow use of current interconnection studies mandated by FAC-002-0 to be used to comply with the Generating Unit Study requirement. Currently, the wording in R2.5 requires that Generating unit stability be analyzed with studies for the conditions in R2.5.1 and/or R2.5.2.

Yes and No

R2.4: Agree with change except: R2.4.1.1: Needs to provide more detail on what is required to be compliant with respect to what is required to "appropriately represent the dynamic behaviour of Loads including consideration of the behavoiur of induction motor Loads". Is the appropriate modelling left to the judgement of the TP/PC, supported by peer review by adjacent planners? Should the TP be required to document why the dynamic modelling is appropriate. The requirement implies a requirement to consider detailed dynamic load modeling at every bus in the model as opposed in areas of high concentration of such load. - needs clarification. R2.4.3: Generally agree, except: R2.4.3.1:Can the SDT clarify if the Variations in load model refer to variations in dynamic load modelling? R2.4.3.4, what is meant by variability of reactive resources? R2.4.4:The use of the words â€œshall be runâ€ implies that additional scenario(s) are mandatory. Was this the intent of the SDT? R2.5: As stated in Q1 above,Manitoba Hydro continues to believe the Generating Unit Stability Analysis duplicates the FAC-002-0 requirements, creating potential for contradiction/non-compliance of both standards. The SDT should ensure there is no duplication of requirements of the FAC-002-0 standard. R2.5 should allow use of curent or qualifying past studies. R2.5.1: Is it the SDTs intent that the TP could rely on the Planning Assessment R2.5 and/or R5.6 to assess the impact of a generator addition or modification. This function should be the subject of an interconnection study conducted in accordance with the FERC tariff (LGIP) or other similar TP interconnection process. R2.5.2: The TP planning process for addition of facilities should be used to verify the impact of changes to the network, including changes near existing generators . A planning assessment is not the appropriate process. Other Comments related to R2: R2: There appears to be no requirement for an assessment of system stability in the long-term planning horizon. Was this the intent of the SDT? R2.1: States the â€œsteady state analysis shall be assessed annually and be supported at a minimum by the following annual current studies:â€ Does the term â€œannual current studiesâ€ preclude doing an assessment by using only qualified past studies? Please clarify! R2.1.1 & R2.1.2: NERC/ERAG will likely have to the models developed annually to ensure appropriate models are available. For example, in any given model series produced in past, there may not be a year five. Also, does System off-peak load refer to summer off peak? R2.1.3: WHiel Manitoba Hdro supports the need for scenario assessments, this significantly increase the workload for studies and documentation. The requirement to document why a scenario was not selected will present a problem, since without doing the study, the planner may not have a good justification. The long term objective to improve reliability could be met by requesting only different sensitivty per year, and dropping the need to justify why others were not done. R2.6: Manitoba Hydro suggests that this requirement be converted to a defintion of Past Studies. The definition should state that both R2.6.1 and 2.6.2 are necessary to qualify as a past study? R2.7:In the case were a CAP is required to meet the system performance requirements, will the assessment be deemed to be compliant on the assumption that the CAP will be put in place in a timely manner? R2.7.1.1: Can the SDT please clarify project initiation date? What is it? date permitting starts? Date construction starts? etc R5.4: System Stability The SDT should clarify if contingencies are to be applied to all elements in the case, or is it left to the judgement of the planner. Since there are numerous combinations of multiple contingencies, it is an impossible task to explain why the â€œremaining Contingencies" were not selected. If this is not the intent, can the SDT explain what is required? The requirement should simply allow the planner the discretion to use judgement to select these more severe Contingencies, and the elements they are applied to, with explanation as to why they are expected to be more severe. R5.4.1: Manitoba Hydro agrees that the rationale for Contingencies selected should be provided. However, it is an onerous task, and of little value to provide rationale for the contingencies not selected. R5.4.2: Manitoba Hydro's preference is that the performance requirements should be in the standard body. The approach in Table 2 is inconsistent. R5.4.2 refers to Table 2 for Planning Event performance requirements, however, for the Extreme Events, the Table 2 refers back to R5.4.4. R5.4.3: Manitoba Hydro agrees and commends the SDT for recognizing generator tripping as a viable option for meeting the performance requirements in certain systems. R5.4.3.2: Agree that regulatory and statutory requirements must be met; however, the references to safety violations and equipment requirements are very generic. It is difficult to imagine what type of safety violation may be caused by a generator trip considering this is a widely used practice in many regions. The SDT should also be more specific as to what is meant by "equipment requirements". The requirement to be within Facility (equipment) Ratings is already covered in R3.5.1. Manitoba Hydro recommends the reference to safety and equipment be removed. R5.4.3.3: can the SDT clarify how they want the planner to determine that "a sustainable operating condition is maintained". Demonstrating stability over a 20 second stability run may be sufficient, or is the SDT looking for longer time frame stability modeling. R5.4.4 The requirement to expain why extreme events were not chosen add extra documentation. The TP has to explain why certain events were chosen, consequently, events not chosen are judged to have less impact. What would the SDT

deem an adequate explanation? R5.5: Generating Unit Stability - As stated above, Manitoba Hydro does not agree that assessment of Generating Unit Stability iis necessary as it is covered by FAC-002-0. R5.5.1: This requirement implies the Generating Unit Study should consider every unit exceeding 20 MW. Consistent with R2.5, the SDT should clarify that only new generators need be studied. R5.5.3: Given the numerous possible contingencies that could be run if multiple contingencies are considered, it is impossible to explain why the remaining contingencies were not selected. Other Comments related to Requirement R5: R5: The sentence â€œThe studies shall be based on computer simulations using models using data provided in Requirements R9 to R14 â€¦â€ should apply to both steady state (R3) and stability portions, yet it is only included in R5. R5.1: Essentially repeats the requirement in the first sentence of R5 - suggest deleting. R5.2: Suggest deleting the words â€œincluding thoseâ€ R5.3: Manitoba Hydro suggests that frequency ride through be added in addition to voltage ride through. The language "how the generators are treated in the simulation" is not crisp. Is the SDT looking for information on how the voltage ride through and frequency ride through are modelled in the study?

No

The definition of Consequential Load Loss implies the load lost as a result of "response to the transient condition of the event" need not be load directly connected to the element impacted by the event, but load in the local area. This definition could result in an interpretation that would justify unlimited load loss resulting from say voltage depression in an area impacted by a transient system swing. This opens a loop hole for allowing load loss for many single contingencies as a result of a transient swing causing a voltage dip and motor contactor drop-out as an example. There is a fine line between providing adequate voltage support or operating guides to avoid such load loss. Should a maximum level of load loss be specified? Comments on Other Definitions: Extreme Events: The definition should clarify whether or not Transmission system performance requirements must be met. - Events should be changed to Event - same for Planning Events Planning Coordinator: The Planning Coordinator definition should be left to the functional model. Having the term defined here may cause future confusion. For example, the FMWG has discussed the possible elimination of the PC, based on the realization that it is the Transmission Planner who integrates resources into the transmission plans.

Yes

Manitoba Hydro commends the SDT for recognizing that generator run-back and tripping is a valid option in the transmission planner's tool box, not unlike more expensive devices such as FACTs devices. Can the SDT confirm that the conditons in R3.5.1, R3.5.2 and R3.5.3 apply to post generator tripping period. R3.5.2: The references to safety violations and equipment requirements are very generic. It is difficult to imagine what type of saftey violation may be casued by a generator trip considering this is a widely used practice in many regions. The SDT should also be more specific as to what is meant by "equipment requirements". The requirement to be within Facility (equipment) Ratings is already covered in R3.5.1. manitoba Hydro recommends the to "safety, equipment" be deleted from R3.5.2. Other Requirement R3 Comments: R3: In the first sentence, "perform analysisâ€ should be changed to "perform studiesâ€ and the word â€œstudiesâ€ after Horizon should be deleted. R3.2: Delete the words â€œincluding thoseâ€. R3.2.1: Can the SDT clarify what is required? Is the requirement to ensure the generator undervoltage ride through is not violated? If so, Manitoba Hydro recommends overvoltage ride-through (maximum voltage) should also be added. Also, is â€œFor all Generatorsâ€ and â€œof all generatorsâ€ both needed? R3.3.1: Appears to be a repeat of R3.1. R3.3.2: R3.3.1 requires performance criteria to be met for Planning Events, which includes both single and multiple contingency events. Doesnâ€™t R3.3.2 repeat R3.3.1? R3.3.2.1:The requirement to report duration of the Consequential Load Loss would be a wild guess as the duration will relate to the nature of the event, so Manitoba Hydro questions the value. For example, the the event is a simple lightning hit on a line, the restoration time is expected to be short, but if the cause of the line loss is a tornado that takes down structures, it could be days. Can the SDT clarify the requirement. R3.3.2.2: Are â€œTransmission reconfiguration changes and redispatch of generatorsâ€ only allowed for single contingencies? Is redispatch allowed if such redispatch results in curtailment of Firm Transmission Service? R3.3.2: It appears that R3.3.2 can be deleted, and its subrequirements placed under R3.3.3: The contingencies that â€œare expected to produce more severe System impactsâ€ are very likely multicple contingencies. Since there are numerous combinations of multiple contingencies, it is an impossible task to explain why the â€œremaining Contingencies were not selected. If this is not the intent, can the SDT explain what is required? The requirement should simply allow the planner the discretion to use judgement to select these more severe Contingencies, and the elements they are applied to, with explanation as to why they are expected to be more severe.

Yes and No

R1: Requirement R1 places the obligation for maintaining a model on the PC/TP. While the PC/TP can maintain data for its system(s), the models generally used for planning assessments are regional models developed and maintained by the Regions. Could the SDT explain its expectation of the scope and responsibilities of the model to be maintained? R9-R14: This TPL draft includes Requirements R9 to R14 that impose obligations on the PC/TP that differ from the way planning models are compiled in accordance with the existing MOD standards. Manitoba Hydro comments

on R9 to R14, as follows: R9: Agree. R10: The TSP is the Functional Model entity that should provide the Firm Transmission Service data and Interchange Schedules to the PC. R11: Agree R12: Agree R13: We disagree that the Resource planner is responsible for Reactive Power devices. Can the SDT explain what they consider should be included in new technologies? R14: While we agree that the TP can provide the PC data of planned facilties, isn't this data already required to be provided under the MOD standards?

No

R4: The wording for the assessment should be changed from "shall assess the short circuit ability of its equipment" to "shall assess whether bus short circuit levels are within the capability of its equipment". The short circuit assessment should only be required if changes to system topology or generation occur. While short circuit levels are critical for system equipment specifications, ten year planning horizon models are generally not adequate for this purpose as ultimate system fault levels are required. The SDT should clarify the modelling details required for the short circuit assessment and the deliverable of the short circuit assessment. The standard doesn't stipulate if an existing NERC model will need to be modified to include the sequence data and thus allow for three phase and SLG fault analysis or if the planner is to use our "in house" models and just report the results. Typically, short circuit models used for fault studies are not load or season specific, and the simulation is conducted using a flat-analysis (load ignored and voltage at 1.0 pu). Typically, all elements are in service to ensure maximum fault contribution. Can the SDT provide details on what cases have to be assessed â€" Year One, each of the first five year, etc. What is the generation dispatch that should be considered? For purposes of equipment rating, a dispatch considering all available generation may need to be considered. Manitoba Hydro requests the SDT to provide some specifics on the need for doing intact and n-1 fault analysis. We think the requirement to consider single contingency conditions is getting into the details of bus modeling to maximize the fault level. If so this seems to be getting into short circuit study methodolgy and is too prescriptive and unnecessary. To explain this comment, we include a summary of the process used at Manitoba Hydro as follows: Manitoba Hydro follows a two step procedure when studying breaker capability of our system: 1. Breaker Rating vs. Bus Fault - Breakers are required to accommodate the entire bus maximum symmetrical fault current at nominal bus voltage with no consideration given to what the circuit breaker may actually be required to interrupt due to its location in the ring. Stations with fault levels above 95% of rated breaker interrupting capability are flagged for further study. This type of analysis will accurately rule out a high percentage of breakers whose capability is adequate. If an appropriate model is available, this step could take up to three person-months for the Manitoba Hydro system. 2. Detailed Examination of Breaker Duty and Location - By considering faults on both the equipment and bus side of the breaker the exact fault current that the breaker must interrupt can be determined. In a ring bus arrangement the breaker in question is assumed the last breaker to clear the fault. In addition, factors such as X/R ratio & operating voltage are also taken into account. To provide a safety margin to account for modeling tolerances we recommend a circuit breaker for replacement when the fault value is greater then 95% of the breaker rating. Other companies may use different breaker replacement threshold levels. This detailed analysis could require up to one person-month, depending on the size of the station, for each detailed assessment. The standard should specify what is to be reported as a result of the short circuit study. Should the report include: â€¢ Documentation of the criteria used for the study â€¢ A listing of the SLG and three phase fault levels compared to the lowest breaker capability at a bus. â€¢ Documentation of more detailed analysis of for breakers wwhose capability is within threshold of the station fault level. â€¢ A listing of the breakers to be replaced. Alternatively, should the standard just require the planner have a separate report on the fault analysis that can be provided on request.

No

There appears to be little difference between Table I and II other than the performance requirements at the start of each table, which should be embedded within standard. Manitoba Hydro would prefer one table as we believe it serves to simplify the standard readibility. Additional Comments on Table 1: The Performance Requirements (Items 1 to 6) should have a heading "Evaluation Requirements". These evaluation requirements should be included in the standard body. Also they should be labeled A to F to avoid confusion with the Notes at the end of the Table. Item 6 is not applicable for steady state analysis. Suggest changing "Notes" to "Table I Notes" for improved readability if more than one table is retained. Planning Events: In cases where Non-consequential Load Loss is allowed, has the SDT discussed limiting the amount of load lost? Planning Events: For the multiple contingency events, in cases where Interruption of Firm Transmission Service or Non-Consequential Load Loss is allowed, the SDT should clarify that such loss is only allowed after the second event. P1: Similar to DC lines, interruption of Firm Transmission Service should be allowed for AC transmission lines, as in many cases, the firm transmission service is dependent on the outaged AC transmission line or transformer, that is, the contract path. P2-1: Suggest changing :single ended line: to "open ended line". P3: Similar to DC lines, interruption of Firm Transmission Service should be allowed if transfer is dependent on the outaged AC transmission line or transformer - the contract path. Planning Events >300 kV: Interruption of firm transfer should be allowed if AC contract path is lost due to an event. In

many cases the majority of the firm transfer is carried by the contract path ac line, not that unlike the case of the DC line. MH has sold Firm Transmisson Service, the delivery of which is dependent on the single circuit Wnnipeg-Twin Cities 500 kV line being in-service, This Firm Transmission Service is available in the order of 99.6% of the time. Assuming two 5 day planned maintenance outages per year the availability is 97.3% per year. MH's transmission customers did not want to pay some $800 million in capital costs for a second 500 kV line to increase the Firm Transmission Service availability by 2%, especially considering that Firm Transmission Service loss does not result in loss of load, but results in a call for redispatch (call for Operating Reserves being carried to cover for loss of the largest generator or largest loaded transmission line with associated fast generation runback (SPS)). The inability to interrupt Firm Transmission Service will drive expensive new line construction, or require withdrawal of 1500 MW of firm transmission service from the market. P4: Greater than 300 kV - Interruption of Firm Transmission Service should be allowed if transfer is dependent on the outaged AC transmission line or transformer.The low probability of P4 events does not warrant the cost of raising the reliability performance requirements. P5: Greater than 300 kV - Interruption of Firm Transmission Service should be allowed if transfer is dependent on the outaged AC transmission line or transformer. NERC defines a Protection System as "Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry. In many cases, the protective relays, associated communication circuits and DC control circuits consist of two separate or redundant systems, but the voltage and current devices and station battery may be common. Is the SDT considering a current sensing device, or the station battery, for example, to be a single point of failure? Table 1 Note 4: Imposes a requirement on FACTS devices, and therefore should be elevated to the Requirements in the standard body. Also FACTs devices can be put in a series connectionas well as shunt. Perhaps some additional clarification is required. Additional Comments on Table 2: Stability Performance Requirements: ï €The Performance Requirements (Items 1 to 5) should have a heading "Evaluation Requirements". These evaluation requirements should be included in the standard body. Also they should be labeled A to E to avoid confusion with the Notes at the end of the Table 2 - Item 4: should the simulation also include the efect of reclosing where applicable? Planning Events: Same as comments on Table 1 regarding treatment of Firm Transmission Service and Non-Consequential Load Loss for >300 kV P4: Greater than 300 kV - Interruption of Firm Transmission Service should be allowed if transfer is dependent on the outaged AC transmission line or transformer. P5: Greater than 300 kV - Interruption of Firm Transmission Service should be allowed if transfer is dependent on the outaged AC transmission line or transformer. Multiple Contingency events (P3, P6): Does the SDT envision these multiple events being simulated as a stability run for the second event using a base case with an adjusted system - considering the first event is typically P1 which has been previously run as a separate simulation, typically a P1 event? P5: see Table 1 comment re what is considered a single point of failure. Extreme Events: Evaluation Requirement 1 - R5.5.4 should be R5.4.4 Extreme Event Description 2H: A 3 phase bus fault on a switching station would not normally result in loss of a voltage level and transformers at a station. The event should just be loss of one voltage level plus transformers in a substation. Table 2 Notes: Suggest changing "Notes" to "Table 2 Notes" if more than one table is reatained. Note 5 a. Stipulates requirements for generating unit performance - should not be buried in the notes. Also, what is the SDT rationale for allowing units to pull out of synchronism for single contingency events like P2, or P5 - stuck breaker, or P7 - common tower, which is a normal clearing event. P1: Similar to DC lines, interruption of Firm Transmission Service should be allowed if transfer is dependent on the outaged AC transmission line or transformer. P3: Similar to DC lines, interruption of Firm Transmission Service should be allowed if transfer is dependent on the outaged AC transmission line or transformer. It is important for a probabilistic measure of likelihood to be considered in designing Table 1 and Table 2. The various categories of contingencies, P1 to P7, for example, should be ideally arranged in order of magnitude of likelihood, so that the acceptable consequences or the performance requirements may be in an increasing level of severity. However, there are events with intrinsically different probabilities currently classified within each of these contingency categories. For example, in P3 (following loss of a generator followed by system adjustments), another generator forced outage is more likely than a transformer forced outage. In P2 (single contingency), loss of a bus section is less likely than the P3 event of a double generator contingency. Therefore, these P categories, as currently defined, overlap one another in the scale of likelihood. As a result of it, Table 1 and Table 2 have allowed for certain rarer events (e.g., included in single-contingency P2 and double-contingency P3 categories) to incur some siginificant consequences with unspecified limits, e.g., interruption of firm transmission services or "non-consequential" load loss. It may be better to follow the NERC Reliability Concepts White Paper's approach of displaying these tables in categories of event likelihood, so that the acceptable consequences would be in an increasing level of severity. This approach would then be consistent with Probabilistic Risk Assessment, when the industry has collected enough transmission outage data to enable such a method be applied. Though the US power industry does not have transmission outage statistics collected and analyzed across the industry, Canadian utilities do have excellent data. It seems to be possible for the various contingency events in the current Tables 1 and 2 to be recategorized according to five or six groups of "order of magnitude of likelihood", e.g., M0, M1, M2, M3, M4 and M5. Each

order of magnitude of likelihood is ten times less likely than the preceding order. For example, the first order (M1) would be for outage probabilities greater than 1%. The second order (M2) would be for outage probabilities between 0.1% and 1%. The third order (M3) would be between 0.01% and 0.1%, etc. Multiple independent contingencies could be classified based on the product of their individual probabilities, e.g., a generator outage is of order M1, and a transmission circuit outage is of order M2. Therefore, a double contingency of a generator and a transmission circuit is of order M3, but a double generator contingency is of order M2. Having placed the initiating contingencies in these orders of likelihood, it is then feasible for the industry stakeholders to try to agree on the level of acceptable consequences for these magnitude orders of likelihood. In the current draft of this standard, there is no quantified variable degree of acceptable consequences, as envisioned in the NERC Reliability Concept White Paper. There is distinctly different treatment of whether the out-of-service element is below or above 300KV. There is difference in allowing or not allowing firm transaction interruption and/or non-consequential load loss, but neither of them has a specified limit on the MW amounts. With the current layout of Tables 1 and 2, it is not readily apparent that the proposed standard is consistent with a sound risk approach. Having a sound risk approach is very important because investment decisions will be made according to these new, proposed and still-deterministic standards. Planners may find out in their studies that the costs of meeting some unlikely contingencies requiring expensive transmission investments are very high and that these costs are not justifiable based on avoiding those rare consequences. On the other hand, because the amounts of acceptable firm transaction interruption and non-consequential load loss are not specified, the transmission system designed to that standard with unspecified limits may become vulnerable to cascading events that initiate in the transmission grid below 300 KV. Many entries in the Tables allow non-consequential load losses, but no limits are specified. It raises the question, "If any non-consequential load loss is acceptable, is there a need to study that contingency scenario?" Without a reasonable set of limits, the criteria may not be effective in assuring system reliability. NERC's event analysis group has been using five categories of consequences to classify recent blackouts or major disturbances. A condensed summary of this is as follows. Category 1. Abnormal frequencies > 5min; or inter-area oscillations Cateorgy 2. System separation with no loss of load or generation; or loss of generation (between 1,000 and 2,000 MW in the EI or WI and between 500 MW and 1,000 MW in ERCOT) Category 3. Loss of load (less than 1,000 MW); or loss of generation (> 2,000 MW in the EI or WI and > 500 MW in ERCOT); System separation or islanding with loss of load or generation (less than 1,000 MW). Category 4. System separation or islanding of more than 1,000 MW of load; or loss of load (1,000 to 9,999 MW). Category 5. Loss of load (10,000 MW or more) Lay persons as well as transmission planners can understand and appreciate these ways of defining consequences, e.g., category 5 events mean more than 10,000 MW of load or generation loss. A way to propose reasonable limits to the highly unlikely but potentially severe contingencies, e.g., M3, M4, and M5, would be to limit their designed consequences to Category 2, 3 or 4. A well designed transmission system should limit the consequences of potential cascading outages and their likelihood so that fewer major blackouts would occur, while balancing the cost of investment to the cost of outages to the customers. A number of utilities are already performing PRA studies for their transmission planning. The advantages of using PRA have been demonstrated in the nuclear power industry. It would be desirable to have a pathway for the power industry to transition from the still-deterministic planning criteria in TPL-001 to a probabilistic planning criteria, without having to wait for another major revision to the TPL standard. If the Tables 1 and 2 are arranged and presented consistently with the NERC Reliability Concepts White Paper, the approach will enable that transition to take place naturally. If the TPL-001 standards establish a PRA-compatible Table 1 and Table 2, with contingency categories sorted in order of magnitude of likelihood, and their acceptable consequences also arranged in order of consequences (such as the five categories), the reliability requirement is already seen in the PRA-compatible way of a constant Risk level, Risk = Likelihood x Consequence. When the industry has good data to quantify the probabilities of these various contingencies, the implication of this â€œalready-acceptedâ€ Risk Level would be clear and numerically expressable. What is useful at this time is for the industry to make a forward-looking estimate of what this Risk level would be like, and consider whether it is appropriate and consistent with sound economic and risk principles.

Yes

The Bus-tie Breaker definition provides the clarification Manitoba Hydro requested in our draft 1 comments. However, we suggest the wording in brackets should be deleted as it is possible to add bus-tie breakers to schemes like the breaker-and-a-third bus in large stations.

No

Based on inductry outage statistics, event P4, the non-bus tie breaker failure has a lower probability of occurrence than event P7, the common structure event. Consequently, Manitoba Hydro recommends that the performance requirenent for >300 kV should be the same as P7. Imposing a higher performance expectation on the >300 kV facilities will require significant bus reconfiguration costs to ensure compliance for existing stations. The additional cost can not be justified by the reliability gain given the low probability of the event.

Yes
Yes
Considering the very low probability of such an event (based on industry data), Manitoba Hydro agrees that Interruption of Firm Transmission Service and Non-consequential Load Loss is acceptable.
$500,000
2to 3 person years years
$300,000
$200,000
$100,000
An estimate of the cost to Manitoba Hydro is $1.0 Billion.
The licensing and construction of facilities to achieve compliance will require at least 10 years.
C â€" Definitely do not support the revised standard
Manitoba Hydro can not accept the standard due to the requirements imposed on Firm Transmission Service and on facilities >300 kV. The standard would have to allow Firm Transmission Service to be curtailed in situations where Non-consequential Load is not lost. The higher performance requirements for facilities >300 kV are tied to very low probability events, so the enhanced relaibility is not worth the cost. TPL-001-1 Other Comment Action Plan: Schedule of Anticipated Actions needs to be revised. - Action 3 shows rev 3 out for ballot in 2Q09. TPL-00101 Purpose:Is the purpose to â€œEstablish Transmission System planning performance requirementsâ€ or to â€œEstablish planned Transmission System performance requirementsâ €The term â€œprobable contingenciesâ€ is not defined or used in the standard â€" use of the term may cause confusion. R7: The TP and PC are required to determine the responsibilities for performing the assessment. Are the responsibilities to be documented as part of the assessment? R8: This requirement should avoid reference to a FERC order as the order does not apply to all entities. The requirement should just require the planner to demonstrate that the assessment was distributed to potentially impacted stakeholders. The last sentence is incomplete.
Individual
Tim Wu
Los Angeles Department of Water and Power
No
Changing the name does not change the fact that this is wrong. The stability criteria in the standards are all measured on the high-side, i.e., the system side. So when a stability simulation is performed, if there is any problems, whether it be loss of synchronism, out-of-step, damping, interarea oscilations, etc, they will all appear on the same run and there is no distinctions between system stability or unit stability. To separate the two mplies there is a difference and requires two different simulations is either confusing at best or imply ignorance of the physics. Maybe the drafting team is concerned with the proper modeling of the generator in a stability simulation. There may be practice to "lump" similar units in a plant as one "unit" or the dynamic characteristics of a unit were not explicitly or correctly modeled; in such instances, the behavior of individual unit cannot be observed. But if that is the case, the entire stability simulation is incorrect to begin with anyway, even on the system side. To properly deal with unit modeling, the standard should prohibit lumping of units and require all dynamic data (including governor controls, exciters, stablizers, etc.) are included in the simulation model.
No
R2.4.3 requires sensitivity on various operating scenarios. These are best required under TOP, not TPL. It is totally useless and a waste of time to look at operating scenarios under planning horizon by planners, whether it be short term or long term. Operating scenarios are absolutely necessary under operating horizons but they need not be repeated and required in TPL when TOP alread addressed these. R2.5 See my comment on question 1. This may be a suitable place to require proper modeling of the genrator units to replace the existing languages. R5.4 is fine. R5.5 See my comment on question 1. The language here actually infers the size of a unit that should be modeled individually and not be lumped. But it should be more precise to prohibit any lumping as well as the explicit modeling of all dynamic data of any generator unit meeting the size requirement.
No
In general, support the comment from WECC on this question, however, where there are different performance allowed solely based on an arbitrary voltage class separation, it is discriminatory and without any scientific or historical basis.
Yes and No
R3.5.1, 3.5.2, and 3.5.3 are redundant and already covered in other standards or safety codes such as FAC, TOP, OSHA, NRC, NESC, etc. If these kind of "reminder" is required here just to

make sure planners do not ignor all the relevent codes, then it could also be argued that an absence of such reminders in other section would mean that these codes do not need to be observed unless they are specifically called out. I think they should all be deleted to avoid such twisted argument but portential loopholes.

Yes

See the comment from WECC

No

Short circuit study is a static study, there is no dynamic involved. The main purpose of short circuit study, from a planning perspective, is to size the breakers to ensure the breakers can interrupt a fault in the system when called upon. R4 requries simulation inculding contingencies, for what purpose is not known. The language implies there are single contingencies that could result in higher duties. I disagree. The highest duty a circuit breaker will see is when the system is whole and with all generator units in service and the fault to be cleared is a bus fault. Any single contingency that involve losing a unit or any component in the systme will result in a weaker systme and less short circuit duties. This is elementary. I cannot envision of any single contingency that would put more units on line or switch in additional transmission facilities beyond a full system with all unit already in service. In R2.3, the requirement is to do the study on an annual basis "and" support of past studies. If the intent is to allow past studies to substitute for annual study, the word "and" should be changed to "or". If the intent is to mandate annual study, then the support of past studies is irrelevant since the annual study supercedes past ones. In addition, short circuit study does not need to be performed annually unless there is substantive addition to the system in the form of a generating unit or a major transmission facility. So it make sense to allow past studies in lieu of annual study if there is no substantive addition to the system.

No

The performance table allows different performance for same contingency at different voltage classes that is arbitrary separated. This is discriminatory and without any scientific or historical basis. There should be only one class for the whole transmission system. Transmission systme at below 300kV should not be granted preferential treatment. Mindful also that the initiating causes of last two major continental wide blackouts(one in WECC and the other in the Eastern Interconnections) both started in system at less than 300kV.

Yes

No

The arbitrary separation based on voltage class is discriminatory and without any scientific or historical basis. The probability of breaker failure do not increase with voltage class. In fact, breaker failures are seldom heard of at above the 300kV classes. Most breaker failures occur in lower voltage classes such as 230kv, 115kv, etc. where the short circuit current tends to be higher and thus stressing breaker contacts more severely giving rise to breaker failures. Delete any separation of voltage classess.

No

R2.1.3 and 2.1.4 deal with operating scenarios that need to be studied by operating engineers under TOP but is duplicative and serve no useful purpose when performed by planning engineers for the purpose of future expansions. Transmission planning is to ensure that future system is expanded to handle expected system growth. Mixing operating studies in the planning of future system shows a confused perspective on the different roles between operating studies and planning studies. A responsible utility must perform both types of studies but they should not be mixed together or be required under two different standards, the TOP and TPL. The consideration of load variations, different dispatching scenarios, planned or unplanned transmission outages, system expansion not coming in on schedule, etc., are operating issues that should be and must be addressed in operating studies, and the proper place is in TOP, not TPL.

Yes

yes, only because there is no discrimination among different and arbitrary voltage classes.

I do not object to added studies serving useful purposes; however, duplicative studies are a waste of resources. Mixing operating studies and requiring such studies in the planning of future system shows a confused perspective on the purpose of planning studies verses operating studies.

Please be more specific as to what additional studies are being referred here.

This assumes that past studies are inadequate and supplemental studies are needed. The standard does add a lot of duplicative and unnecessary operating scenarios that are already required under TOP and MOD; but they should be deleted because they serve no useful purpose under TPL, why even spend an extra penny if it is for naught.

If this question is referring to discriminatory treatment between different voltage classes that is

arbitrary; the effort should be directed to either treat all the voltage classes equally or do come up with a scientific or historical basis to support the requirement. This is an engineering standard, all the criteria should have some scientific/engineering rationale that can be supported either by physics or historical data.

C â€" Definitely do not support the revised standard

I do not support the standard as currently written. There are too many requirements that are discriminatory, duplicative, and arbitrary/punitive. The unintended consequence of this standard would be forcing companies and planners to plan the system to take advantage of some requirements that will result in a future system that is less robust (a single line serving multiple radial loads instead of network, for example) if not to entiely discourage any further expansion of the transmission system above 300kV (the discriminatory treatment of two classes without any rational justification).

Individual

Dave Larsen

Transmission Agency of Northern California

No

We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study â€œfocuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to â€œdevelop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingenciesâ€. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say â€œonly whenâ€ the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, â€œmaterial Transmission System changeâ€ and â€œat or near the point of Interconnectionâ€ to invoke a study.

Yes and No

- R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirements in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. - We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. - The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Ownerâ€™s open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Ownerâ€™s responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to

TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.

No

We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as â€œlocal Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systemsâ€ in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, â€œâ€¦load no longer being connected to a sourceâ€¦â€. As a result, service reliability to customer would be adversly impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (â€œAlthough Load which is lost as a result of the Loadâ€™s response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirementsâ€) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.

Yes

We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.

Yes

While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.

Yes and No

We agree with R2.3. However, R4 requires assessment of â€œShort-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting dutiesâ€. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute â€œnormalâ€ condition or â€œfollowing any single Contingency conditionâ€. Also, by specifying the normal and single contingency conditions, R4 is straying into â€œhowâ€ to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.

Yes and No

We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.

No

We do not disagree with the proposed definition change. However, we do not agree that â€œSubstation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.

Yes and No

We interpret â€œexit breakersâ€ to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes.

Yes and No

We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the â€œbase caseâ€ of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the â€œbase caseâ€ condition. R2.7 also states that â€œCorrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivitiesâ€. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the â€œbase caseâ€, will the judgment of the Transmission Planner be then questioned because theâ€œbase caseâ€ used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?

Yes

We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.

B â€" Unsure about supporting the revised standard

- We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before we can give a full approval of this Standard. - There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. - We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions. - We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with â€œraising the barâ€. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. - As mentioned in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms â€œinterruption of firm transmission serviceâ€, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what â€œFirm Transmission Serviceâ€ means. Two points, 1) the NERC definition states â€œhighest quality service offered to customers under a filed rate schedule that anticipates no planned interruption.â€ The Standard implies anticipation of â€œunplannedâ€ interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order 890, or firm transfers modeled for the conditions being studied? One way to interpret the intent is the firm transfers being modeled for the conditions in the powerflow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption of firm transmission service should also be allowed for P1 through P5 contingencies in the table. In addition, we believe that DC and AC lines should have the same performance requirements with respect to interuption of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines can automatically be curtailed when the line is outaged.

Individual

Carol Sedewitz

National Grid

No

There should be no difference beween System and Generating Unit Stability studies. Each require discretion regarding which events need to be tested. The consequences are potentially similar: either the instability of one of more generators. Extreme Events should be considered for any stability analysis, again, recognizing that discretion needs to be applied when selecting or dismissing particular contingencies. If no distinction is made between System and Generating Unit Stability studies is made, then the definition of Generating Unit Stability Study should be stricken from the standard.

No

a. A MOD standard should be developed to address the assembly of dynamic load models, rather than specifying modeling in paragraph 2.4.1 (dynamic behavior of loads, including consideration of the behavior of induction motor Loads). Paragraph 2.4.1 should instead read, "System Peak

Load for one of the five years." The remainder of the paragraph should be deleted. b. In paragraph R.2.4.3.4, what does "variability" mean? Is variablity more of a concern than an outage? Suggest changing paragraph R.2.4.3.4 to simple say "Outages of Reactive Resources" c. Add a new requirement, "R5.4.3.4 Automatic generator tripping shall not have an significant adverse impact on overall system reliability." d. Remove Heading R5.5 and make generator unit stability for a new facility a section of overall stability requirements. e. Modify R5.5.1 to become R5.4.5, with the following, "Shall be performed for the addition of an individual generating unit or generating units at the same interconnection point 20 MW or greater that are directly connected to the BES." There may be little difference between the stability performance of a single 20 MW unit and an aggregation of units totalling 20 MW at the same BES interconnection point. f. If planning assessment studies all generators or stations above 20 MW, as suggested by R5.5.1, then this provision is unnecessary and R5.5.2 should be deleted. g. If the output of a generatiing station does not change by more than 20MW, then no new study is required and, it should be acceptable to rely on past stability assessments. This is not clear in R5.5.1. h. With respect to section R5 - The concept of planned and long-term outages should be addressed uniformly for the general Planning Assessment. It should not be specific to the Stability Assessment. i. Planned and long-term outages are two fundamentally different concepts and should be treated separately. Planned and Long-Term outages should be defined. Define how planning events in Tables 1 and 2 are associated with each type of outage. Define length of a "Long Term" outage. Planned outages should be addressed in the operating horizion unless otherwise defined in the planning horizion. j. The provisions of Section R.5.3 should be included in a MOD standard and applied to a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertant trip of the generator. Such a provision should include " other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation. k. Strike R5.5.3 and R5.5.4, as they become redundant to R5.4.1

No

a. In the Consequential Load Loss definition, the word 'source' needs to be defined or explained further since it is unclear. b. Non-Consequential references non-interruptable load. Non-Interruptible load should be defined. Suggest: "Demand that the end-use customer has not made available to its Load-Serving Entity via contract or agreement for curtailment." c. The Consequential Load definition should specify "Interruptible and Non-Interruptible Load that is no longer connected to a sourceâ€¦" d. The inclusion of "or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes)" confuses the definition of Consequential Load Loss, because of the imbedded exception for steady state performance. It seems that the intent of this provision is to recognize that this type of load loss could occur for either transient or steady state conditions and that Planning Assessments should not be required to remedy this type of situation. However, this does seem to be at odds with the application and stated acceptability of Consequential Load Loss as noted in Table 1. Note: Table 2 has no reference to the treatment of Consequential Load Loss. It may be helpful to address the transient load loss situation in a separate definition. As proposed in the draft, Firm Transmission Service is treated equal to load. In New England and New York, we focus on stressing transfer limits across and within the systems. By so doing, we preserve the internal transfer capabilities by design rather than modeling specific contractual transfers, which may not stress the internal interfaces. The exception is for the inter-Area ties. For inter-Area ties, the import or export capability is comparable to a generating unit, which we believe is acceptable to interrupt. We therefore feel that it should be acceptable to interrupt Firm Transmission Service over inter-Area ties and that Firm Transmission Service shouldn't be treated equally with load. Suggested changes: Change "Consequential Load Loss" to "Consequential Interruption". Change the definition to "Load, Firm Demand, or Firm Transmission Service that is no longer connected ..." Change "Non-Consequential Load Loss" to "Non-Consequential Interruption". Change the definition to "Non-Interruptable Load, Firm Demand, or loss of Firm Transmission Service other than Consequential Interruption that occurs through manual (operator initiated), automatic operations (such as under-voltage load shedding, under-frequency load shedding, or Special Protection Systems), or uncontrolled loss of a local area which does not significantly impact the Bulk Electric System."

No

We do not feel that R3.5.1, R3.5.2 and R3.5.3 are limiting enough. We suggest adding a paragraph which which be numbered 3.5.4 and would read "Manual and automatic generator tripping shall not have a signifficant adverse impact on the system."

No

a. With respect to R9 "including the expected mix of industrial, commercial and residential loads", this provision may be inadequate to be practically useful. The potential issues include the variation in end-use load mix through the daily load cycle, seasonal load composition variations, and the ability to translate these end-uses into reasonable and useful steady-state and dynamic load models. It is important to understand how the information will be used and how much additional detail such as distribution network detail is also required. b. Add to the last sentence of R9 through R14 the following phrase, "within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator." c. Flexibility is

needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R10 to read as follows: R10. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator. d. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R11 to read as follows R11. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator. e. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R12 to read as follows: R12. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator. f. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R13 and R14 as follows: R13. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator.. [Violation Risk Factor: TBD] [Time Horizon: TBD] R14. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to Transmission Lines, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator. [Violation Risk Factor: TBD] [Time Horizon: TBD] g. Planned and long-term outages are two fundamentally different concepts and should be treated separately. Planned and Long-Term outages should be defined. Define how planning events in Tables 1 and 2 are associated with each type of outage (e.g. P4, P5, or P6). Should there be specific contingency descriptions associated with long-term outages? Define length of a "Long Term" outage. Planned outages should be addressed in the operating horizion unless otherwise defined in the planning horizion.

No

a. R2.3 should be changed to indicate the year(s) for short circuit analysis. b. In R4, suggest replacing, " and following any single Contingency condition that would result in greater circuit breaker interrupting duties" with , " giving due consideration to the potential sequence of equipment operation". c. It should be stated in the standard that assumptions should be based on procedures provided by each Transmission Planner and by the Planning Coordinator.

No

a. In the column "Interruption of Firm Transmission Service Allowed" in both Tables 1 and 2, it is problematic to try to create an "exemption" based on type of facility such as HVDC. There are many other situations in which Firm Transmission Service has been provided, but may need to be curtailed partially or completely following an outage. b. The term 'Firm' may have several different definitions. If 'Firm' Transmission Service or load may be interrupted for exceptional events, then it is conditional and 'Conditional Firm' should be defined. It is recommended that a note be added stating that "the only exception would be for curtailment of conditioned (or Conditional) Firm Transmission Service", recognizing that there may need to be some form of grandfathering in order to avoid having to rewrite transmission service agreements. c. In both Table 1 and Table 2, the "Extreme Event Descriptions" item 1 should add "or shunt device." d. In Table 1, the "Extreme Event Descriptions" items 3a and 3b should be deleted; they are redundant with Item 1. e. In Table 2, Note 5 includes significant clarifications and should not be buried in the bottom of the contingency table; Note 5 would be better placed in the definitions section. f. In Table 1 and Table 2, Contingency P5 requires a fault plus Protection System Failure. Assuming that the battery system is included in the Protection System, which it is in NPCC, then ALL protection at substations with single battery systems would be lost. This Contingency P5 requires a stable system response while all bus voltages and loadings to remain within criteria, without interruption of firm transmission service and without Non-Consequential Load Loss, at system voltages above 300 kV. Was this an intended outcome of this standard?

No

The definition provided is too limiting. It says that if you have a two rings with a bus tie breaker in between, it is no longer a bus tie breaker. We recommend modifying the definition to read, "A circuit breaker that is positioned to connect two individual station configurations. We do not agree that, "(Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)", as we have examples where stations of this nature are connected through a single "bus-tie breaker".

No
They should have the same performance requirements, however we understand that it is better to encourage bus-tie breakers in some applications than to hold them to the higher standard. Future station designs that need this differential treatment should be discouraged.
No
a. With respect to R2.1.3., delete "... that Stress the System with sensitivities ...". b. R2.1.3 should be revised to clarify that if a TP/PC conducts the studies specified in R2.1.1 and R2.1.2 with one or more of the sensitivities which stress the system in the normal course of study, then additional studies of a less-stressed system are not required. c. The intention of Paragraph R2.1.4 is unclear and appears to be unnecessary; therefore, it should be removed.
Yes
The comment period was not long enough to develop a thoughtfull response to the impact that the new standards might have. Therefore costs can be speculated to be incrementally hundreds of thousands per year.
The comment period was not long enough to develop a thoughtfull response to the impact that the new standards might have on the planning studies, but a very rough thought would be that any additional needs would be captured within the normal planning studies, which would likely occur within two study cycles of the effective date of the standard.
If the new requirements are included in the normal study cycle and the costs are the incremental costs required by additional study requirements, then the annual costs will be less than the first year costs, but we still will need additional staffing, which will cost hundreds of thousands per year. In addition to cost, there is a significant concern over whether or not the labor market can provide enough qualified staff to complete the required work.
See response to question 12.
See response to question 12.
The comment period was not long enough to develop a thoughtfull response to the impact that the new standards might have on the construction requirements. Therefore cost can not be reasonably speculated.
At least 5 beyond the study period. Lines requiring new Rights-of-Way may require 10.
B â€" Unsure about supporting the revised standard
Aside from the comments to the prior questions, there are several issues of concern that prevent us from supporting the present draft of the revised standard. We offer the following constructive comments in an effort to support the worthwhile effort that is being pursued so that we can reach a point of satisfaction that we could vote to support the revised standard. Our concerns are listed in a rough order of priority. a. This standard as drafted does not allow exceptions for small parts of the system as long as interconnected system reliability is maintained, which is allowed in the existing TPL standards in footnotes b) and c) in Table 1. Unless such exceptions are allowed significant transfer restrictions or large reinforcements must be made. The applicable TPL footnotes are: Existing TPL footnote b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers. Existing TPL footnote c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (nonrecallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems. b. This standard does not address base conditions. Without defining base conditions the initial status of generation dispatch and transfers across the system is ill defined. Therefore the contingency analysis doesn't have a predictable basis for a consistent and repeatable study. c. The reference to Special Protection Systems is completely permissive. Although there are good applications for Special Protection Systems, their use must be constrained to have a reliable system and to promote construction of needed infrastructure. d. This standard does not provide flexibility to shed load, which restricts the ability to control post contingency response for low impact events. This may result in advancing need for upgrades in response to low impact events. This is in conflict with FERC's directive to have the Trnamsission Provider waiting for market repsonse to transmission needs and having the Transmission Provider provide a role to back stop the market. e. Definition of the Long-Term Planning Horizion. The planning horizon, for assessment purposes should be limited to 10 years. Such an assessment should be sufficient to identify requirements that may take an extended time to implement. f. Definition of Planning Coordinator is part of the NERC Functional Model, Remove from Standard. g. Put headings on each section to identify requirements of section. h. With respect to R2.2 - Delete "current" from the phrase"current System Peak Load study" and replace "study" with "assessment." i. Remove R2.2.1, the requirement to extend the assessment beyond 10 years. What does the length of the project have to do with the

assessment? If it takes 15 years to build something, why does this require a review of year 15? What is the purpose of this assessment? j. R3.3.2 requires clarification - This standard needs to permit discretion regarding the single contingencies that need to be tested, similar to R 3.3.3 and R3.4. It is completely unnecessary to test all events. For example, contingencies may be limited to relevant disturbances that are contained within or directly impact the studied system. k. With respect to R3.2.1 - Clarify whether the intent of the standard is to address station service minimum voltage limitation, maximum leading VAR absorption capability or both at steady state. l. Remove R3.2.2 - Relay loadability is addressed in PRC-023 standard. m. With respect to R3.3.2.1 - Recommend the removal of the requirement to assess the expected duration of Consequential Load loss. It's not considered anywhere else in the standard. n. With respect to R3.3.3 - The paragraph refers to Table 1 Contingencies P3 through P7; this should be explicitly stated. Rationale for inclusion of testing should not be required; should only need to explain why certain Contingencies were not tested. This discretion should be applicable to all contingencies. o. With respect to section R5 - The concept of planned and long-term outages should apply to the general Planning Assessment, or not at all. It should not be specific to the Stability Assessment. p. The provisions of Section R.5.3 should have a corresponding MOD standard apply a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertant trip of the generator. Such a provision should include "other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation. q. Planned outages should be addressed in the operating horizion unless otherwise defined in the planning horizion. r. What is a "current" study?
Individual
Scott Helyer
Tenaska, Inc.
Yes
Yes
Yes
Yes
R.3.3.2.2 needs some re-wording to clarify that generator runback (re-dispatch) and tripping are allowed.
Yes
Yes
Yes and No
Should add a column to the tables indicated when automatic generation runback/tripping is allowed.
Yes
Yes and No
Voltage is a questionable criteria for determining whether a breaker's performance requirements should be different. May want to consider a lower voltage cutoff (below 100 or below 200) as lower performance MAY have less of an impact.
Yes
Yes
A â€" Generally support the revised standard
A few issues that may need some thought include: Are reactive power devices a responsibility of Resource Planners in R13? On the Extreme Events description for local area, what is a load center? Does the loss of a large body of water as a cooling source result in the immediate loss of generation such that it is a contingency which affects steady state, stability, or short circuit

studies?
Individual
Matthew J Muldoon
OPUC
Yes and No
We cannot evaluate the need to distinguish generating unit stability and system stability without greater explanation inclusive of examples. We also need clarification of the intended interactions of this proposed standard with of FAC-001 and 2 to avoid duplication of efforts. Finally, if FAC-001 will cover generating unit or interconnection stability R 2.5 should clearly address existing older generators.
Yes and No
The concept of Consequential Load Loss is generally acceptable. However, the presentation, notes and cross referencing need to be adjusted to avoid confusion.
Yes
Yes
R9 â€" 14 can be addressed in the MOD standards.
Yes and No
What constitutes a â€œnormal conditionâ€ still needs further clarity.
Yes and No
A better definition of Bus-Tie Breaker might be: â€œA circuit breaker that divides a bus section with multiple tap off points into two bus sections.â€
Yes
Individual
Chifong Thomas
Pacific Gas and Electric Co.
No
We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study â €œfocuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to â€œdevelop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingenciesâ€. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say â€œonly whenâ€ the changes in R2.5.1

and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, â€œmaterial Transmission System changeâ€ and â€œat or near the point of Interconnectionâ€ to invoke a study.

Yes and No

R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirement in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. ï€ We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. ï€ The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Ownerâ€™s open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Ownerâ€™s responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.

No

We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as â€œlocal Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systemsâ€ in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, â€œâ€¦load no longer being connected to a sourceâ€¦â€. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (â€œAlthough Load which is lost as a result of the Loadâ€™s response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission

planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirementsâ€) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.

Yes

We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.

Yes

While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.

Yes and No

We agree with R2.3. However, R4 requires assessment of â€œShort-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting dutiesâ€. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute â€œnormalâ€ condition or â€œfollowing any single Contingency conditionâ€. Also, by specifying the normal and single contingency conditions, R4 is straying into â€œhowâ€ to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.

Yes and No

We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.

No

We do not disagree with the proposed definition change. However, we do not agree that â€œSubstation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.

Yes and No

We interpret â€œexit breakersâ€ to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes

Yes and No

We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the â€œbase caseâ€ of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional

sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the â€œbase caseâ€ condition. R2.7 also states that â€œCorrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivitiesâ€. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the â€œbase caseâ€, will the judgment of the Transmission Planner be then questioned because theâ€œbase caseâ€ used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?

Yes

We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.

We expect supplemental studies to be needed for the entire 500 kV system and most of the 230 kV system. We estimate the one time cost for supllemental studies to be around $100,000.

Assuming that the supplemental studies would be added to the on-going work, we estimate the time to complete the supplemental studies to be about 2 to 3 years.

We estimate that the additional cost for the expanded studies and analysis would be about $50,000/year.

This cost would be included in the cost of performing the supplemental studies.

This cost would be included in the cost of preforming the expanded studies and analysis

The capital investments would be dependent on the system reinforcements needed due to the added requirements. For example, if after the first contingency, redispatch to curtail firm transfers is not allowed in anticipation of the next single contingency, the system reinforcements could easily include more 500 kV lines and related facilities. The costs of such reinforcements could be a few Billion dollars.

Any transmission facilities that would require a certification of public convenience and necessity could take more that five years for permitting, engineering and construction. Transmission Planning could take a few more years depending on the transmission reinforcements to be constructed.

B â€" Unsure about supporting the revised standard

We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. ï€ There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. ï€ We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions. ï€ We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with â€œraising the barâ€. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. ï€ As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the

interconnected system was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms â€œinterruption of firm transmission serviceâ€, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what â€œFirm Transmission Serviceâ€ means. Two points, 1) the NERC definition states â€œhighest quality service offered to customers under a filed rate schedule that anticipates no planned interruption.â€ The Standard implies anticipation of â€œunplannedâ€ interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order 890, or firm transfers modeled for the conditions being studied? One way to interpret the intent is the firm transfers being modeled for the conditions in the powerflow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption of firm transmission service should also be allowed for P1 through P5 contingencies in the table. In addition, we believe that DC and AC lines should have the same performance requirements with respect to interuption of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines can automatically be curtailed when the line is outaged.

Individual

Earl Fair

Gainesville Regional Utilities

No

Our small system does not have the present resources to deal with the large increase in stability type studies that this section seems to be requesting. Our system changes very little if at all from year to year. The ranking of the regional facilities where priority is given for stability study to the top 100 fault current buses shows that we do not have even a bus listed until position 611. We suggest that R2.4.1 should allow for only doing buses that have a ranking impact on the regional BES or no more that every 7 years for those systems without changes or are so small that their total separation or lost of their largest or almost total generation is not an issue for the RC. Stability should not have to be analyized annually for small, unchanging systems.

Yes and No

For smaller systems, please see Comment 1. As far as R.2.4.1, if the various loads are basic and not a large industrial type load (very large motors with across the line starting, electric arc furnances, etc.)then the dynamic behavior of the load should not require special consideration. Using proper power factors for the load should be enough for the transmission system evaluation. Under 2.4.3, as mentioned in Comment 1, evaluating the stressing of the smaller systems through a large amount of sensitivities does not add any reliability to the BES. It only adds much addition work to a limited resource entity. If the neighboring large systems agree that the smaller system can not impact them, this should support that the BES is not effected by any sensitivity that could exist on the smaller system. For R5.5, a threshold should be set to consider only the larger size units within the region. For a smaller system, the stability of a 50-100 MW unit probably would not perturb the interconnected regional BES's.

Yes

No

R3.5.3 is somewhat ambiguous. We need clarification as to whether the system needs to prepare for the next contingency (a secure state) or whether it needs to be maintained in a stable operating condition which is sustainable but not secure.

Yes and No

I agree with the approach you are taking concerning this modeling data. I understand that "long term outages" for transmission and generation elements refer to a time frame greater that one year. But I am unclear if the "known planned outage" refers to the same time frame or does it apply to a normal scheduled maintenance type outage of less that one year. Are these "shorter that one year" outages better handled by sensitivity studies since they are normally during an non-peak seasons of the year? Again, the smaller utilities should provide all the requested data to the RRO, but should only have to answer to issues involving their elements discovered at the RRO level.

Yes and No

With a small system like ours, I would like to see a provision where if you do not have any changes in our local portion of the BES, then the previous studies would support my assessment.

No

Some of the notes at the top of each table could be considered to apply to some of the events within the table that conflict in part with the standard and with what was stated in the nation wide phone conference. I would also like to see a note in the tables that reflect a technical rationale for the range of elements considered, since some may be impractical and of no technical value for contingencies involving certain facilities especially those on the smaller systems within the interconnected region.
Yes
Yes
Our control area operates at 138 kV. Does everyone think that holding the owners of above 300 kV operating voltage systems to a higher standard really increases the total BES reliability? Does giving the DC systems a pass on some of the requirements really make sense in the world of reliability?
No
If the RRO or the larger neighboring utilities agree, See Comment 1, it should be unnecessary for the smaller utility to performance any senstivities except for those agreed to and performed by the RRO level. If the smaller utility has any of their elements that create issues in these regionally conducted sensitivities, then they could be accoutable for providing potential remedies (most senstivities do not necessarily require a remedy or project, per say). The variety of sensitivities suggested to be performed for a smaller utility probably will not add any reliability to the regional BES while the effort will take up a very large amount of the smaller utilities' manpower resources.
Yes and No
I believe some clarification is needed to specify that you can or can not curtail firm transmission service prior to the next event, because as written it could lead to compliance audit issues. I don't believe the intend of order 693 was to cause a need for utilities to be exposed to large cost increases for their customers while very little to no improvement in reliability is provided as it deals with very low probability conditions which would yield no increase in transfer capability.
$50,000. I don't feel this is needed for smaller utilities.
3 years. Again, I don't feel this is needed for smaller utilities.
$60,000. Again, I don't feel this is needed for smaller utilities.
Probably would be covered in the previously provided annual cost. Again, I don't feel this is needed for smaller utilities.
Probably would be covered in the previously provided annual cost. Again, I don't feel this is needed for smaller utilities.
$50 Million. Again, I don't feel this is needed for smaller utilities.
7 years. Again, I don't feel this is needed for smaller utilities.
C â€" Definitely do not support the revised standard
First, a starting point for the study process (base case) needs to be better defined even if the intent was to allow the TP's & PC's to make the decision. The standard should describe the rules to properly conduct a base case study within each region. This should support any following analysis studies and their finding since you will be starting from the same set of system elements operating at a base condition. Secondly, this standard should focus on what is best for the customer considering 1) the probability of the contingency events, 2) the potential expense to the customer for practically NO improvement in BES reliability, and 3)the extraordinary added burden on the smaller utilities to run additional, no added value studies with documentation to meet an exhausted detailed audit with the potential for penalties probabaly not proportioned to the utilities revenue stream.
Individual
Karl Bryan
US Army Corsp of Engineers, Northwestern Division
Yes
Yes
Yes
Yes
Yes and No
R12 requires the GO to provide "modeling information" for planned outages and/or changes to the generator owner facilities to the Planning Coordinator for each year of the Transmission planning horizon. You need to be more specific with what type of "modeling information" you are

requesting from the GO. The GO may have the model parameters for their equipment but this doesn't mean that they have expertise necessary to model system responses or even run a model simulation. So if you are expecting the GO to perform model simulations for each year of the Transmission planning horizon the GO may not have the expertise necessary to comply. Recommend you clarify what you mean by "modeling information".

Individual

Tom Duane

Public Service Company of New Mexico

No

We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study â €œfocuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to â€œdevelop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingenciesâ€. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say â€œonly whenâ€ the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, â€œmaterial Transmission System changeâ€ and â€œat or near the point of Interconnectionâ€ to invoke a study.

Yes and No

R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirement in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. ï€ We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. ï€ The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC

standards would have redundant requirements. In addition, Transmission Ownerâ€™s open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Ownerâ€™s responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.

Yes and No

We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as â€œlocal Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systemsâ€ in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, â€œâ€¦load no longer being connected to a sourceâ€¦â€. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (â€œAlthough Load which is lost as a result of the Loadâ€™s response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirementsâ€) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.

Yes

We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.

Yes

While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.

Yes and No

We agree with R2.3. However, R4 requires assessment of â€œShort-circuit capability of its

equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting dutiesâ€. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute â€œnormalâ€ condition or â€œfollowing any single Contingency conditionâ€. Also, by specifying the normal and single contingency conditions, R4 is straying into â€œhowâ€ to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.

Yes and No

We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.

No

We do not disagree with the proposed definition change. However, we do not agree that â€œSubstation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.

Yes and No

We interpret â€œexit breakersâ€ to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes.

Yes and No

We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the â€œbase caseâ€ of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the â€œbase caseâ€ condition. R2.7 also states that â€œCorrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivitiesâ€. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the â€œbase caseâ€, will the judgment of the Transmission Planner be then questioned because theâ€œbase caseâ€ used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?

Yes

We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior

"planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
This ultimately depends on the degree to which the local area issues addressed by footnote b of Table 1 of the existing TPL are maintained. Without the local area concepts of the existing TPL, costs could run into the hundreds of millions of dollars.
This ultimately depends on the degree to which the local area issues addressed by footnote b of Table 1 of the existing TPL are maintained. Without the local area concepts of the existing TPL, permitting requirements would result in some projects exceeding 10-years.
C â€" Definitely do not support the revised standard
We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. ï€ There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. ï€ We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions. ï€ We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with â€œraising the barâ€. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. ï€ As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms â€œinterruption of firm transmission serviceâ€, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what â€œFirm Transmission Serviceâ€ means. Two points, 1) the NERC definition states â€œhighest quality service offered to customers under a filed rate schedule that anticipates no planned interruption.â€ The Standard implies anticipation of â€œunplannedâ€ interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order 890, or firm transfers modeled for the conditions being studied? One way to interpret the intent is the firm transfers being modeled for the conditions in the powerflow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption of firm transmission service should also be allowed for P1 through P5 contingencies in the table. In addition, we believe that DC and AC lines should have the same performance requirements with respect to interuption of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines can automatically be curtailed when the line is outaged.
Individual
Mace Hunter
Lakeland electric

Yes

Yes

Yes

Yes

Yes

Yes

Yes

Yes

Yes

B â€" Unsure about supporting the revised standard

Suggested changes listed below to more directly address what I think is the intent of the item: Planning Events: Events that require Transmission system performance requirements to be met. Comment: I think that this suggested revision better defines a Planning Event and how they may be used in a study or assessment. Revision to: Planning Events Planning Events: Simulated events that are modeled to test the Transmission systemâ€™s ability to meet performance requirements. R2.6.2. For steady state, short circuit, Generating Plant Stability, or System Stability analysis: the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Comment: the requirement as stated leaves one guessing about the usability of a study that may have included the changes that occurred in the intervening period. Changes that were studied but not implemented could also invalidate a study they were included in. Revision to R2.6.2 R2.6.2. For steady state, short circuit, Generating Plant Stability, or System Stability analysis: the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that were not included in the original study but have occurred in the intervening period and would impact the study area results.

Individual

Don Gilbert

JEA

Yes

Yes and No

R2.4.1 Do we mean "Appropriate" for overall regional system response/behaviour or for individual customer behaviour. JEA would agree to an "appropriate" overall regional system response/behaviour model with unique individual or sub-regional customer behaviour models if determined significant. R2.4.3.1 JEA would agree to a load characteristic sensitivity studies if conducted within the scope of a RRO study. Suggest modifying wording to "Variations in Regional Load model assumptions" R2.4.3.3 Not sure what we mean by Unavailability of long-lead time facilities. Need to add a definition. If the standard is suggesting to treat the unavailability of autotransformers like the unavailability of generators i.e. N-2 assessments with no firm consequential load shedding, then JEA does not agree that the failure rate of autotransformers is on the same level as generators and do not agree this requires a minimum performance standard to mainatain grid reliability. In addition, a utility is most likely to be successful in finding a reasonable useful spare autotranformer somewhere in the world to replace the failed

unit. R2.5 JEA agrees. R5.4.2 See comments for steady state requirements for Table 1 P5. R5.4.3 JEA does not understand what is meant by Stability violations. Do we mean to say "unstable system conditions"? R5.5 JEA agrees
Yes
Recommend changing "Non-Interruptible Load" to "non-Interruptible Load" (first occurence of use in the new definition.
Yes and No
R3.5.1 JEA does not understand what measure will be applied to determine that Facility Ratings were not violated during the generator run-back period. R3.5.2 JEA does not understand what measure will be applied to determine compliance that generator trips and runbacks will not violate safety, equipment, regulatory, or statutory requirements. R3.5.3 JEA does not understand what is meant by the word "Sustainable". Needs a practical definition.
Yes and No
R9. JEA does not agree that the Transmission Planners should have the responsibility to perform load development or sanity checks on the DP's forecasted real and reactive loads based upon superfluous information like the customer mix. Also, JEA recommends adding language that gives the Planning Coordinator the option to require the forecast by season. R10. JEA agrees R11. JEA recommends that R11 be split into two functional requirements: (A) the provision of known planned outage information, and (B) the provision of "potential long-term forced outages of transmission equipment where readily avaialble spares are not identified". JEA can support requirement (A), but believes that requirement (B) should be part of an operating horizon standard (TOP?) where the availability of spares and spare equipment strategies can be refined in a responsive manner as the opportunities evolve. JEA does not believe that the industry should overbuild its system for the possibility of a rare "low probility" equipment failure event will occur and no reasonable replacement alternative will exist in the world. R12. Need to define long-term outages R13. JEA agrees R14. JEA agrees
Yes and No
JEA can agree to this requirement; however, JEA would like to see it addressed in FAC-002 to maintain consistency with the FAC standard requirements.
Yes and No
JEA can live with them as is, but would also welcome enhancements. Will defer enhancements to others.
Yes
Yes
Yes and No
Will stress JEA resources to provide auditable evidence depending on the final measure applied.
Yes and No
JEA agrees with the changes on the surface, but still does not agree with the concept that it can not curtail Firm Transmission Service after the first N-1 event in preperation for the second N-1 event. JEA's existing Firm Transmission Servcie customers understand the need to maintain these existing transmission loading relief procedures in order to maintain security of the BES. The only JEA system element that causes this concern has a very high availability and would have a very costly infrastructure improvement to meet this requirement resulting in all of JEA's Firm Transmission Service Customers experiencing increased service cost or in the worst case having their service opportunities permenantly curtailed.
$80,000 per year.
3 years
$80,000 per year.
Included in Question 12 estimates.
Included in Question 12 estimates.
Could be up to $1 Billion and would depend on the physical ability to terminate at existing 500 kV substations and the ability to acquire 500 kV ROW outside of JEA's and Florida's jurisdiction.
Minimum of 7 years if DOE declares a Corridor of National Interest. Otherwise it could be longer and more costly.
C â€" Definitely do not support the revised standard
The inability to curtail Firm Transmission Service under P6 assessments in preperation for the next N-1 event. Also, under P1 and lower probability contingency events, JEA recommends a standard requirement that allows for the loss of Non-Consequential load during short term periods (suggest allowing up to 3 year minimum) where the system load growth has caused post-contingency remedial action plans to not be completely affective in bringing the Facility(ies) within normal operating limits. As a specific theoretical example, lets say a 10 year assessment

shows load growth causing this situation in year 5, but in year 7 generators are added to the area of concern and the issue is resolved, but in year 6, Non-consequential load is required to be shed, do we still need to propose a capital improvement project?

Group

PacifiCorp

Sandra Shaffer

PacifiCorp

Yes and No

We generally concur with the changes for the Requirements associated with the Generating Unit and System Stability, however, â€¢ Generating unit stability studies are typically performed at the time of interconnection. Even though stability studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of generating units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units. Will every TP have to benchmark their generating unit stability study for its entire fleet with the acceptance of this Standard? In other words, will every TP has to recreate documentation for all its older units? â€¢ We would appreciate that the SDT more clearly define the terms in R2.5.2, â€œmaterial Transmission System changeâ€ and â€œat or near the point of Interconnectionâ€ to invoke a study with examples.

Yes and No

av â€¢ We generally agree that utilities or large TPs and PCs need to perform and be held accountable for these Requirements; however, the SDT needs to define a organization size level, below which these requirements for the associated TP may be slightly relaxed. There are numerous TPs; (e.g., those associated with PUDs, Municipals or REA, etc.), for which performing these type of studies and assessments are onerous and do not yield reliability benefits for the network.

Yes and No

â€¢ We generally agree with the definition but have concerns about a potential unintended consequence. This definition will severely limit the loads that can be classified as â€œlocal Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systemsâ€ in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, â€œâ€¦load no longer being connected to a sourceâ€¦â€. At a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability.

Yes and No

â€¢ We generally agree, however, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest moving R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.

Yes

â€¢ We agree that the MOD Standards need modifications and additions to be used for Transmission Planning, â€¢ We also agree with the movement of the R1of the first draft to the R9 through R14 of this draft, â€¢ We also agree that when the MOD Standards are replaced, then remove these Requirements from the TPL Standard.

Yes and No

We agree with R2.3. However, R4 requires assessment of â€œShortcircuit capability of its equipment under normal condition and following any single Contingency condition that would result in greater circuit breaker interrupting dutiesâ€. Since short circuit studies are typically performed by applying a three phase fault on a Facility starting from a normal condition, please clarify whether the result would constitute â€œnormalâ€ condition or â€œfollowing any single Contingency conditionâ€.

Yes

We agree with the proposed format changes of the Tables.

Yes

We agree with the proposed format changes of the Tables.

No

We do not agree with the rationale for the requiring more stringent performance requirement levels for non-bus tie breakers above 300 kV. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes.
Yes and No
We generally agrees with the concept of the sensitivity analysis. However, clarifications of the following is needed: â€¢ For example, if a TP performs studies on the â€œbase caseâ€ of which the loads are 90/10, does this constitute a sensitivity analysis. If so, will the TP have to then perform additional less stringent studies at the 50/50 load level to demonstrate compliance? â€¢ R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the TP should not have to explain why they feel that this higher level (90/10) of load is the â€œbase caseâ€ condition. â€¢ R2.7 also states that â€œCorrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivitiesâ€. Consider a TP that has built transmission based on the 90/10 load assumed in the â€œbase caseâ€, will the judgment of the TP be then questioned because of itâ€™s sensitivity â€œbase caseâ€ and not a 50/50 base case?
Yes
We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV.
$500,000 (approx)
three years
$250,000
$250,000 over two years
$125,00
$100,000,000 + Will not be able to estimate the total cost until after the studies are complete.
10 years
A â€" Generally support the revised standard
We generally agree with the Standard as presented so far, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce.
Individual
Joe Seabrook
Puget Sound Energy, Inc.
No
We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study â €œfocuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to â€œdevelop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingenciesâ€. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say â€œonly whenâ€ the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, â€œmaterial Transmission System changeâ€ and â€œat or near the point of

Interconnectionâ€ to invoke a study.

Yes and No

R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirement in sub-requirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Ownerâ€™s open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Ownerâ€™s responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.

No

We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as â€œlocal Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systemsâ€ in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection used to improve service reliability just to fit in the Consequential Load Loss definition, â€œâ€¦load no longer being connected to a sourceâ€¦â€. As a result, service reliability to customer will be degraded without commensurate improvement in overall system reliability. In addition, existing design of many such local networks may use RAS/SPS to disconnect loads on local networks in response to low probability contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (â€œAlthough Load which is lost as a result of the Loadâ€™s response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirementsâ€) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.

Yes

We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.

Yes

While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.

Yes and No

We agree with R2.3. However, R4 requires assessment of â€œShort circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting dutiesâ€. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute â€œnormalâ€ condition or â€œfollowing any single Contingency conditionâ€. Also, by specifying the normal and single contingency conditions, R4 is straying into â€œhowâ€ to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.

Yes and No

We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for events could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.

No

We do not disagree with the proposed definition change. However, we do not agree that â€œSubstation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.

Yes

We agree that the failure of non-bus tie breakers above 300 kV to operate can have much higher consequence.

Yes and No

We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the â€œbase caseâ€ of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the â€œbase caseâ€ condition. R2.7 also states that â€œCorrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivitiesâ€. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the â€œbase caseâ€, will the judgment of the Transmission Planner be then questioned because the â€œbase caseâ€ used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?

Yes

We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300 kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission

facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
$1,000,000 for the STD in its current form. The recovery of firm transmission following N-1 will be the largest cost for PSE
10 years.
$300,000
$150,000 for the STD in its current form.
$50,000
$800,000,000 to recover Firm Transmission capacity with no adjustment following N-1.
15 years
C â€" Definitely do not support the revised standard
We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before PSE can give a full approval of this Standard. There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions. We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with â€œraising the barâ€. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms â€œinterruption of firm transmission serviceâ€, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what â€œFirm Transmission Serviceâ€ means. Two points, 1) the NERC definition states â€œhighest quality service offered to customers under a filed rate schedule that anticipates no planned interruption.â€ The Standard implies anticipation of â€œunplannedâ€ interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order 890, or firm transfers modeled for the conditions being studied? One way to interpret the intent is the firm transfers being modeled for the conditions in the power flow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption of firm transmission service should also be allowed for P1 through P5 contingencies in the table. In addition, we believe that DC and AC lines should have the same performance requirements with respect to interruption of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines can automatically be curtailed when the line is out of service.
Group
ITC Holdings: ITC, METC, ITC Midwest

Raymond Kershaw
ITC Holdings
Yes and No
Requirement R 5.4.4: Consider changing the last sentence to the following:â€œIf the Extreme Events analysis concludes there are widespread cascading outages, an evaluation of implementing a change designed to reduce or mitigate the likelihood of such consequences shall be conducted.â€
Yes and No
ï€ R 2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. ï€ R 2.4.2 System Off-Peak Load for one of the five years. ï€ Is there an inconsistency here in that the requirement for peak system load levels specifies details on what is needed for the load models, but the off-peak does not specify this? We donâ€™t believe this is the intent but it creates an appearance that the of the dynamic behavior of loads is not required for off-peak. ï€ Regarding R2.4 and R2.5 (& R5.4.1): It should be made clear that redoing studies is only necessary when it is not certain as to whether or not a system change will have a negative impact on system stability.An explanation should be sufficient if a study is unnecessary based on technical knowledge.. As to dynamic load models, we agree with a much longer implementation period than the rest of the standard. ï€ We have concerns that an auditor may not agree with our judgment as to what studies should be run or not run (R2.4, R2.5 and particularly in the case of R5.4.1). Additional guidelines, perhaps in the measurements section, would be appreciated. ï€
Yes
No
We do not believe that generation runback or tripping should be a CAP for a single contingency. This is particularly true if the generation scheme puts the system one contingency away from another potential condition requiring corrective action, such as load shedding. At a minimum R3.5.3 needs further definition as to what a â€œsustainable, stable, operating conditionsâ€ is. For example, creating another N-1 scenario is not a sustainable condition. Allowing for SPS is not raising the bar.
Yes and No
In general, we approve and concur with these requirements. The requirement R9 that the distribution providers submit the expected mix of residential, commercial, and industrial loads is necessary to model the dynamic behavior of loads as required in R 2.4.1. This requirement will better model the dynamic response of loads to voltage changes. In R10, the Transmission Planner provides OASIS type information. The TSP should provide this not the TP. R-13 â€" Reactive Power Devices and new technologies belongs under every entity, i.e., Distribution Planners should be included as a provider of reactive power devices as well as Resource Planner and Transmission Planner.
Yes
Yes and No
While we like the tables, we donâ€™t understand what â€œInterruption of Firm Transmission Service Allowedâ€ means in a stability study (as per table 2). How would you interpret that in real-time & study terms? Would you make the stability scenario a limit to selling transmission service? In table 2, should we interpret SLG or 3-phase Fault in P1 and P3 to mean that SLG is the criteria (minimum) but you can run and document the more severe 3 phase faults for compliance purposes? What is the minimum criteria?
Yes
Yes
No
While we appreciate that the addition of sensitivity studies is commendable and agree with 2.1.3 and 2.1.4 per se, the later clarification in R2.7 that â€œCorrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivitiesâ€ negates project justification (to many) based on sensitivity studies. Explaining as per R2.4.3 the reasons why you did or did not run a sensitivity study is less important, in many respects, than why you did or did not provide a Corrective Action Plan for performance failures observed in sensitivity studies. I.e., the study is the â€œcartâ€ and the CAP is the â€œhorseâ€. Hence, at a minimum some form of Corrective Action Plan should be required.
No
Allowing load loss for shutdown plus contingency might seriously jeopardize maintenance

outages when you actually encounter this situation in real-time. Itâ€™s easy to say these things in the â€œplanning horizonâ€ but it might be politically unacceptable for â€œreal-timeâ€. This is particularly true for higher voltage systems above 300kV. We understand that there could be â€œload-pocketâ€ situations at lower voltages where this might be allowed but EHV systems are back-bone systems. This would set a bad precedent if allowed.
While we recognize that the standards might require us to garner a little more manpower and will take a little more time, we believe that running these studies is important.
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Since we have been following the NERC Planning Standards, at this point we do not expect an additional one time system reinforcement cost.
Since we have been following the NERC Planning Standards, at this point we do not expect an additional time-frame for a system reinforcement program.
B â€" Unsure about supporting the revised standard
ITC and ITC Midwest biggest concerns are some missed opportunities to "raise the bar". We believe the draft standard is a significant improvement over existing standards which are largely fill-in-the-blank. However, we have some concerns regarding some of the language wherein CAPs are not required, even though a performance requirement has been violated. For example, providing for a bare minimum sensitivity study and not requiring a CAP based on a performance violation may increase operational awareness but does not â€˜raise the barâ€™ or improve transmission performance. Allowing for non-consequential load loss following a shutdown and contingency might be an acceptable real time operating procedure but is not a significant advancement on a transmission planning basis. Frequently, operating procedures like this should lead to a planning solution, particularly above 300kV
Individual
Milorad Papic
Idaho Power Company
No
We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study â€œfocuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to â€œdevelop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingenciesâ€. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequate addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say â€œonly whenâ€ the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, â€œmaterial Transmission System changeâ€ and â€œat or near the point of Interconnectionâ€ to invoke a study.
Yes and No
R2.4 is acceptable. Please consider deleting R5.4.3. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. ï€ We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators

need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. ï€ The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Ownerâ€™s open access tariff requires Generator Owner to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Ownerâ€™s responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.

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We generally agree, however, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.

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information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.

Yes and No

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Yes and No

We interpret â€œexit breakersâ€ to mean a breaker on an element that comes in from outside the substation. We agree with the rationale for the requiring more stringent performance requirement levels for non-bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes

Yes and No

We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the â€œbase caseâ€ of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the â€œbase caseâ€ condition. R2.7 also states that â€œCorrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivitiesâ€. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the â€œbase caseâ€, will the judgment of the Transmission Planner be then questioned because â€œbase caseâ€ used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?

Yes

We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not allowed as

part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.

Appx $50k

2 to 3 years

Appx $50k

Appx $50k

Appx $50k

Not sure

5 years

B â€" Unsure about supporting the revised standard

We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. âˆ’ There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. âˆ’ We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions. âˆ’ We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with â€œraising the barâ€. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. âˆ’ As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms â€œinterruption of firm transmission serviceâ€, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what â€œFirm Transmission Serviceâ€ means. Two points, 1) the NERC definition states â€œhighest quality service offered to customers under a filed rate schedule that anticipates no planned interruption.â€ The Standard implies anticipation of â€œunplannedâ€ interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order 890, or firm transfers modeled for the conditions being studied? One way Comment Form for 2nd Draft of Standard TPL-001-1 Assess Transmission Future Needs (Project 2006-02) Page 12 of 12 to interpret the intent is the firm transfers being modeled for the conditions in the powerflow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption of firm transmission service should also be allowed for P1 through P5 contingencies in the table. In addition, we believe that DC and AC lines should have the same performance requirements with respect to interuption of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC

lines can automatically be curtailed when the line is outaged.

Individual

Tacoma Power

Tacoma Power

Yes

Yes

Individual

Dilip Mahendra

SMUD

No

We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study â€œfocuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to â€œdevelop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingenciesâ€. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say â€œonly whenâ€ the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, â€œmaterial Transmission System changeâ€ and â€œat or near the point of Interconnectionâ€ to invoke a study.

Yes and No

R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirement in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is

acceptable. ï€ The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Ownerâ€™s open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Ownerâ€™s responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.

No

We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as â€œlocal Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systemsâ€ in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, â€œâ€¦load no longer being connected to a sourceâ€¦â€. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (â€œAlthough Load which is lost as a result of the Loadâ€™s response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirementsâ€) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.

Yes

We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables. Reference 3.5.1: In cases where an SPS is deployed to reduce thermal overloads such that flows are brought within established facility ratings, but, for a short duration (seconds) until it is fully executed, the facility flows exceed the established rating, is that considered a violation or an acceptable engineering judgment that facilities are judiciously being brought to operate within ratings? Or, should the facility owner ensure establishment of a documented rating even for the short duration of seconds?

Yes

Yes and No

We agree with R2.3. However, R4 requires assessment of â€œShort-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting dutiesâ€. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute â€œnormalâ€ condition or â€œfollowing any single Contingency conditionâ€. Also, by specifying the normal and single contingency conditions, R4 is straying into â€œhowâ€ to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.

Yes and No

We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.

No

We do not disagree with the proposed definition change. However, we do not agree that â€œSubstation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.

Yes and No

We interpret â€œexit breakersâ€ to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes

Yes and No

We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables. Added: Reference 3.5.1: In cases where an SPS is deployed to reduce thermal overloads such that flows are brought within established facility ratings, but, for a short duration (seconds) until it is fully executed, the facility flows exceed the established rating, is that considered a violation or an acceptable engineering judgment that facilities are judiciously being brought to operate within ratings? Or, should the facility owner ensure establishment of a documented rating even for the short duration of seconds? Q10: TSS response: We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the â€œbase caseâ€ of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the â€œbase caseâ€ condition. R2.7 also states that â€œCorrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivitiesâ€. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse

weather load assumed in the â€œbase caseâ€, will the judgment of the Transmission Planner be then questioned because the â€œbase caseâ€ used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case? Is some Non-Consequential Load Loss for an N-1 contingency on a sensitivity case using an extremely high load forecast acceptable as a Corrective Action Plan in the planning phase?

Yes

We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.

Three study cycles would be my guess. Related matters: Since the definition for â€œYear Oneâ€ allows for the start of each assessment to be up to 18 month from the â€˜completionâ€™ of the previous Planning Assessment, using the term â€˜annualâ€™, â€˜annuallyâ€™ in the definition and in various sections of the standard is confusing. An alternate word or dropping the words annual/annually would make more sense. What is considered as â€˜completionâ€™ of an assessment (in definition of Year One)?

A field test of the revised standard would be the appropriate way to arrive at the approximate costs to support the new/modified requirements.

A field test would be the time to get an educated estimate.

C â€“ Definitely do not support the revised standard

We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before giving a full approval of this Standard. ï€ There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. ï€ We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rata curtailments of firm transmission rights during forced and planned outage conditions. ï€ We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with â€œraising the barâ€. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. ï€ As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of trade offs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms â€œinterruption of firm transmission serviceâ€, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what â€œFirm

Transmission Serviceâ€ means. Two points, 1) the NERC definition states â€œhighest quality service offered to customers under a filed rate schedule that anticipates no planned interruption.â€ The Standard implies anticipation of â€œunplannedâ€ interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order 890, or firm transfers modeled for the conditions being studied? One way to interpret the intent is the firm transfers being modeled for the conditions in the powerflow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption of firm transmission service should also be allowed for P1 through P5 contingencies in the table. In addition, we believe that DC and AC lines should have the same performance requirements with respect to interuption of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines can automatically be curtailed when the line is outaged.

Individual

Roger Champagne

Hydro-Québec TransÉnergie (HQT)

No

There should be no difference beween System and Generating Unit Stability studies. Each require discretion regarding which events need to be tested. The consequences are potentially similar: either the instability of one of more generators. Extreme Events should be considered for any stability analysis, again, recognizing that discretion needs to be applied when selecting or dismissing particular contingencies. Therefore, the definition of Generating Unit Stability Study should be stricken from the standard.

No

a. A MOD standard should be developed to address the assembly of dynamic load models, rather than specifying modeling in paragraph 2.4.1 (dynamic behavior of loads). Paragraph 2.4.1 should instead read, "System Peak Load for one of the five years." b. In paragraph R.2.4.3.4, what does "variability" mean? c. Add a new requirement, "R5.4.3.4 Automatic generator tripping shall not have an significant adverse impact on overall system reliability." d. Remove Heading R5.5 and make generator unit stability a section of overall stability requirements. e. Modify R5.5.1 to become R5.4.5, with the following, "Shall be performed for the addition of an individual generating unit or generating units at the same interconnection point 20 MW or greater that are directly connected to the BES." There may be little difference between the stability performance of a single 20 MW unit and an aggregation of units totalling 20 MW at the same BES interconnection point f. Strike R5.5.3 and R5.5.4, as they become redundant to R5.4.1

Yes and No

In the Consequential Load Loss definition, the word 'source' needs to be defined or explained further since it is unclear. It should be indicated that this also applies to " stability performance requirements" (refer to the end of last sentence of the definition).

No

We do not feel that R3.5.1, R3.5.2 and R3.5.3 are limiting enough. Add paragraph 3.5.4 "Manual and automatic generator tripping shall not have an Adverse Reliability Impact."

No

With respect to R9 "including the expected mix of industrial, commercial and residential loads", this provision may be inadequate to be practically useful. The potential issues include the variation in end-use load mix through the daily load cycle, seasonal load composition variations, and the ability to translate these end-uses into reasonable and useful steady-state and dynamic load models. It is important to understand how the information will be used and how much additional detail such as distribution network detail is also required. It is also important to note that some Canadian Provinces do not "classify" their load mix using "industrial commercial and residential" designations but their load modeling is sufficient, accurate and granular enough to simulate system response. Add to the last sentence of R9 through R14 the following phrase, "within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator."

No

In R4, suggest striking, "that would result in greater circuit breaker interrupting dutiesâ€¦".

No

In both Table 1 and Table 2, the "Interruption of Firm Transmission Service Allowed", a definition should be provided to clarify that term. That term is more of a Market concept not used by all TOs and defined in their Transmission Tariff. Also, the standard might need to introduce a new term "Consequential Transmission Service Loss" as it does for the Load. Firm Transmission services are generally defined as a service of the same priority as the one for the native load. That does not mean it could not be interrupted. In both Table 1 and Table 2, the "Extreme Event

Descriptions" item 1 should add "or shunt device." In Table 1, the "Extreme Event Descriptions" item 3b should be deleted; it is redundant with Item 1. In Table 2, Note 5 includes significant clarifications and should not be buried in the bottom of the contingency table; Note 5 would be better placed in the definitions section. In Table 1 and Table 2, Contingency P5 requires a fault plus Protection System Failure. The "Protection System Failure" aspect of this contingency brings the necessity to define more clearly what is intended. The notion of needed redundancy or single elements of the protection system, be it physical or electric, has to be adressed to clearly understand the implication of that contingency. Until such clarification is included in this standard or in the future "Redundancy standard", this contingency should not be effective.

No

ï€ The definition provided is too limiting. It says that if you have a two rings with a bus tie breaker in between, it is no longer a bus tie breaker. HQT recommend, "A circuit breaker that is positioned to connect two individual station configurations. We do not agree that, "(Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)", as we have examples where stations of this nature are connected through a single "bus-tie breaker".

Yes

No

If a TP/PC conducts the studies specified in R2.1.1 and R2.1.2 with one or more of the sensitivities which stress the system in the normal course of study, are we to assume that fulfills the requirements of R2.1 completely, without additional studies of a less-stressed system?

Yes

HQT believe some additional cost for analysis and study may be required in order to meet the final requirements of the standard and the associated performance tables, however the ability to accurately estimate the costs of these studies, how long the analysis may take and how much additional effort may need to be made to compile the documentation is not possible at this time. Many believe posing this question is premature and cannot be quantified at this time and it may hold questionable value without a better understanding of the complete final requirements of the standard. Many believed that the sensitivity language, although currently being performed to some extent within NPCC, that now appears in the standard, could have a drastic affect on the extent to which this additional analysis is conducted and the associated costs

See Q12

HQT and NPCC participating members have expressed compliance concerns that this standard, and in particular this question, imply NERC has the ability to "force" transmission reinforcements and construction. It should be emphasized and clarified that the standard should require transmission studies only, and per the Energy Policy Act, NERC does not have this authority as the ERO as granted by FERC in the US and NO authority allowing this in Canada. Also HQT and NPCC participating members expressed concern that a validly-conducted assessment which shows that criteria are not met (in the 5 or 10 year horizon) could result in non-compliance with the Standard. If NERC believes that it can issue monetary penalties for 5 or 10 year assessments that show that performance criteria will not be met under future system conditions, there is a key question that requires explanation: What behavior is NERC attempting to incent through fining parties for conducting assessments which identify problems in a 5 to 10 year horizon? Also, NERC should further explain how it would view the relevance of a State or Provincial decision not to permit new facilities when issuing such a potential penalty such as preclusive siting issues with Generating Plants.

C â€" Definitely do not support the revised standard

This standard as drafted does not allow exceptions for small parts of the system as long as interconnected system reliability is maintained, which is allowed in the existing TPL standards in footnotes b) and c) in Table 1. Unless such exceptions are allowed significant transfer restrictions or large reinforcements must be made. The applicable TPL footnotes are: ï€ Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers. ï€ Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (nonrecallable reserved) electric power Transfers may be necessary to maintain the overall

reliability of the interconnected transmission systems. ï€ This comment form did not allow for the following items to be addressed: ï€ a. Definition of the Long-Term Planning Horizon. The planning horizon, for assessment purposes should be limited to 10 years. Such an assessment should be sufficient to identify requirements that may take an extended time to implement. ï€ b. Definition of Planning Coordinator is part of the NERC Functional Model, For consistency it should be removed from the Standard. ï€ c. We propose that the Standard be subdivided by subjects into 4 different Standards : ï€ TPL-001-1: Modeling and System Assessment (R1, R2, R9 to R14) ï€ TPL-002-1: Short circuit and Steady State Performance (R3, R4) ï€ TPL-003-1: Stability Performance (R5) ï€ TPL-004-1: Coordination (R6, R7, R8) ï€ If the previous proposition is not retained, at least the Standard Requirements should be organized by topics (Modeling, Assessment, Coordination, etc.) and headings put on each section to identify requirements of section. Add headings to the tops of the subsequent pages in the performance tables. Headings only appear on the first page at the beginning of the Table. ï€ d. With respect to R2.2 - Delete "current" from the phrase"current System Peak Load study" and replace "study" with "assessment." ï€ e. Remove R2.2.1, the requirement to extend the assessment beyond 10 years. What does the length of the project have to do with the assessment? If it takes 15 years to build something, why does this require a review of year 15? What is the purpose of this assessment? ï€ f. R3.3.2 requires clarification - This standard needs to permit discretion regarding the single contingencies that need to be tested, similar to R 3.3.3 and R3.4. It is unnecessary to test all events. For example, contingencies may be limited to relevant disturbances that are contained within or directly impact the studied system. ï€ g. With respect to R3.2.1 - Clarify whether the intent of the standard is to address station service minimum voltage limitation, maximum leading VAR absorption capability or both at steady state. ï€ h. Remove R3.2.2 - Relay loadability is addressed in PRC-023 standard. ï€ i. With respect to R3.3.2.1 - Recommend the removal of the requirement to assess the expected duration of Consequential Load loss. It's not considered anywhere else in the standard. ï€ j. With respect to R3.3.3 - The paragraph refers to Table 1 Contingencies P3 through P7; this should be explicitly stated. Rationale for inclusion of testing should not be required; should only need to explain why certain Contingencies were not tested. This discretion should be applicable to all contingencies. ï€ k. With respect to section R5 - The concept of planned and long-term outages should apply to the general Planning Assessment, or not at all. It should not be specific to the Stability Assessment. ï€ l. The provisions of Section R.5.3 should have a corresponding MOD standard apply a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertant trip of the generator. Such a provision should include "other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation. ï€ m. Planned outages should be addressed in the operating horizion unless otherwise defined in the planning horizion. ï€ n. In both Table 1 and Table 2, note 3, "variable frequency transformers" should be removed from the last sentence. A new sentence should be added for reference voltage as it applies to "variable frequency transformers" and "back-to-back" facilities.

Individual

Bart White

Progress Energy Florida, Inc.

No

Progress Energy Florida, Inc. (PEF) does not believe that Stability Analysis should be or can be successfully divided into the proposed two distinct concepts of System Stability and Generating Unit Stability. Most textbooks dealing with the matter of Stability Analysis divide the issue into two parts, steady state and transient, and then subdivide the transient part into power angle stability and voltage stability. PEF has been unable to find any engineering treatise that argues for dividing transient Stability Analysis into System Stability and Generating Unit Stability. NERC's present definition of Stability, "The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances", succinctly and correctly addresses the fact that stability issues regarding plants cannot be extricated from analysis of the rest of the system. PEF feels that this existing definition is accurate and not in need of clarification or improvement. To cite an example, if under the auspices of Generating Unit Stability, a transmission line trips, or if a load shedding scheme is activated, does the event then get defined as a System Stability event (or both)? It should be noted that the SDT attempted to both improve and clarify the definition of Stability in Note 5 of Table 2. The SDT's wording in Table 2 Note 5, while not containing any inappropriate or inaccurate information, has two fundamental flaws: a) it unnecessarily replaces the existing definition and b) it does not contain any language tying in the new definitions of System Stability and Generating Unit Stability. Furthermore, given that both of the new definitions are held to the exact same requirements, those found in Table 2, PEF can see no tangible benefit to two definitions, and therefore recommends removal of the new definitions of System Stability and Generating Unit Stability, and a return to the existing definition of Stability. Stability analyses that are taking place under the present definition and under the existing TPL Standards are more than adequate to demonstrate reliability of the BES, and PEF feels that the introduction of two new definitions would only serve to cause confusion and discussion regarding unmerited additional analyses.

No

R2.4.4 as worded does not make sense, and could potentially create illogical situations where the Transmission Planner or Planning Coordinator would "offer up" additional sensitivities specific to their systems, for which they might not presently be analyzing and immediately have to self-report non-compliance. As a substitute to the language in R2.4.4, PEF suggests either returning to the language in each existing Standard's R1.3.2, or adding an R2.4.3.6 that states "Other known critical system conditions specific to the system studied by the Transmission Planner or Planning Coordinator. Regarding R5.4 and R5.5, PEF disagrees to the extent that a differentiation has been made between System Stability and Generating Unit Stability (see Question 1 comments). Given that System Stability and Generating Unit Stability are held to precisely the same standards in Table 2, PEF feels that significant modification is required to R5.4 and R5.5, specifically that the two sections need to be consolidated into a single section. Given the complex nature of Stability Analysis, and the fact that Generators are inextricably intertwined with all other components of the BES, the distinction that the SDT is attempting to make with this issue makes no sense from a power systems engineering perspective.

No

The Definitions of â€œConsequential Load Lossâ€ and â€œNon-Consequential Load Lossâ€, bring to mind the following concerns: Both Definitions are confusing and unclear as to their intent and meaning, and as presently worded it is PEFâ€™s belief that these particular Definitions can be interpreted in ways not intended by the SDT. For example, the definition of Consequential Load Loss contains the phrase "Load that is no longer connected to a source"; presumably this means "Load that is no longer connected to any source", but is not stated as such. PEF would note, however, its disagreement with the definition even with the wording change, given how the definition would be applied. UVLS, UFLS and SPS schemes are excluded from Consequential Load Loss, and thus are not allowed as mitigations for several outage scenarios. The SDT is essentially discouraging Transmission Owners from constructing such schemes, which is counterproductive to reliability, and actually reduces reasonable options left for Transmission Owners to the point that possible outcomes might be a) radializing of systems or b) removing breakers in order to convert load previously deemed Non-Consequential Load into Consequential Load. PEF maintains that where particular outage scenarios dictate the need for UVLS, UFLS and SPS schemes, the right to implement them should be allowed regardless of the category of event, so long as implementation in lieu of a more expensive project will not compromise the reliability of the BES. Whether or not UVLS, UFLS and SPS schemes continue to be categorized as Non-Consequential Load Loss, however, PEF disagrees with the definition given how it would be applied.

No

PEF does not disagree with the conditions described in Requirements R3.5.1, R3.5.2 and R3.5.3 when taken in particular contexts. PEF, however, is compelled to check "no" for this question due to the fact that no specification has been made as to when such CAPs can be applied. PEF feels that the CAPs specified (as well as the curtailment of Firm Transactions and Non-Consequential Load) should be allowed following any N-1 event, and also as system adjustment actions in between the two events of a P6 event. Given that no such specification has been made here, PEF objects to the wording, and suggests that the language be modified to clarify that the application of these CAPs are allowable after N-1 events and in between the two events of Event P6.

No

PEF as a general rule believes that Requirements R9-14 can and should be addressed in a MOD Standard. Individual comments on particular ones that PEFs sees as problematic are as follows: R9: This requirement is problematic in its present wording. As worded it would appear to infringe upon the outlined process regarding provision of load forecast data as stipulated in PEF's Attachment K document, mandated to be included as an Attachment to our Tariff per FERC Order 890. In PEF's Attachment K, load forecast data, as submitted by all entities responsible for providing such data for PEF native load, must be submitted by January 1 of each year. Implementation of R9 would thus set in place two binding regulatory processes for a situation in which only one is needed. Furthermore, the requirement uses the term "transmission node", a term which is ambiguous and not easily applicable in the electric utility business. Terms such as "feeders", "substations" or "delivery points" might be more appropriate. R11: PEF appreciates the consideration given with the term "known planned outages", given that specific dates for planned outages in the long-term planning horizon are often difficult to know. This point concludes, however, with the addition of the phrase â€œwith consideration given to spare equipment strategyâ€, and PEF does not understand what is meant by this term nor why it is given special consideration in a discussion of planned outages. Spare equipment is just as crucial, if not more so, in the event of an unplanned outage. Furthermore, consideration of spare equipment strategy is already handled as part of PEF's planning processes and as part of the existing TPL Standards. PEF therefore requests that the phrase "with consideration given to spare equipment strategy" be removed from R11. R13: PEF is unsure as to the meaning of "for each year of the Planning horizon". PEF would point out that if from one planning cycle to the next, the modeling of a particular planned generator has not changed, the Resource Planners should not have to re-submit the same data over and over again on an annual basis. Additionally, PEF asserts that its Resource Planners are not involved in the development or implementation of Reactive Power devices or new technologies, and therefore requests that these specifications be removed.

No

PEF disagrees with, and recommends removal of both R2.3 and R4 on the following grounds: R2.3: Evidence that short circuit analysis has been performed is already mandated through Requirement R1.4 NERC Standard FAC-002-0. Inclusion of the mandate in the TPL Standard is redundant. R4: While the fundamental inadequacy of the short circuit issue is its inclusion in the TPL Standard to begin with (see R2.3 comments), PEF is perplexed at the proposed requirement to perform short circuit analysis for single contingencies. PEF cannot conceive of a scenario for which a single contingency scenario would result in increased fault duty. Such a mindset essentially considers short circuit analysis as equivalent to load flow analysis, which it clearly is not. Short circuit analysis is performed to adequately set relays, size equipment and prevent equipment damage, and as such is not appropriate for inclusion in a TPL Standard.

No

The Steady State and Stability Tables (Tables 1 and 2), are overly long, confusing, and contain circular references. PEF strongly advises returning to the content and format of Table 1 in the existing TPL Standards, or at the very least, consolidation of the Tables into a single Table. Furthermore, for certain events in Tables 1 and 2, the SDTâ€™s intent concerning the scope of the events and how the events would be simulated in Transmission Planning analyses is not clear. PEF furthermore does not agree with "Interruption of Firm Transmission Service Allowed" and "Non-Consequential Load Loss Allowed" as benchmarks for whether or not a particular BES is reliable (see additional comments in Question 15 on this issue). Tables 1 and 2 at present are 13 pages in total, whereas the existing Table 1, which PEF feels is comprehensive and not in need of revision, is merely 1.5 pages long. PEF understands that the reason behind the length and complexity of Tables 1 and 2 stems from a desire by some to contain all of the primary TPL compliance issues in a tabular format. The end result, however, is not effective and must be made more concise.

No

PEF understands the intent behind the wording of the definition, but neither agrees with the definition nor its use in various applications in the Standard. Bus tie breakers as defined in the draft Standard are limited to connecting two straight bus configurations. In reality, the term bus-tie breaker can be, and is used for other applications. PEF suggests that the SDT further research the use of this term in the industry. But more to the point, PEF does not see the need for a distinction between bus tie and non bus tie breakers and ultimately recommends that this be removed from the Standard.

No

PEF is opposed to distinction between non-Bus-tie breakers and Bus-tie breakers, and furthermore is opposed to the more stringent requirements for both in facilities above 300 kV. One primary reason has already been acknowledged by the SDT, that breakers have the same failure rate no matter the configuration in which they are placed. PEF can see two potential outcomes to the missteps being made regarding the breaker distinction: a) multiple redundancy of breakers for both Bus-tie and non-Bus-tie breaker schemes, which will require tearing down many Substations, acquiring additional property in many cases, and completely rebuilding the Substations to allow room for redundancy of breakers in series with one another; b) choosing to remove existing breakers for which a scenario of non-compliance is imminent, which could potentially pose a reliability risk to the system and possibly result in heightened risk for other Event categories.

No

PEF has significant concerns with each of the sub-Requirements listed in R2.1.3. Each is ambiguous, vague and open to variations in interpretation. It therefore makes no sense that "documentation of the technical rationale for why each of the conditions was or was not selected" is a requirement. Indeed, given that all of the sub-Requirements of R2.1.3 are vague, unspecific, unwieldy concepts, PEF is not sure how said documentation could be accomplished. Concerning R2.1.4, PEF has the same concerns that were expressed regarding the modified requirements mentioned in Question 2, and similarly here would suggest a substitute to the language in R2.1.4. Significant concerns with the previous sub-Requirements notwithstanding, PEF suggests either returning to the language in each existing Standard's R1.3.2, or adding an R2.1.3.8 that states "Other known critical system conditions specific to the system studied by the Transmission Planner or Planning Coordinator."

No

PEF is pleased that between the 1st and 2nd drafts, the "no" was changed to "yes" concerning allowance of curtailment of Firm Transmission Service or curtailment of Non-Consequential Load for Event P6. PEF has significant concerns, however, regarding the issue of "System Adjustments" associated with P6 and P6's direct association with P1, and thus must check "no" on this Question despite the improvements that have been made. A major misstep has been made with regard to development of P6. Every P1 event is by default the first half of a P6 event. Given that fact, PEF sees several concerns with this issue. First, for P1 events, neither curtailment of Firm Transmission Service nor curtailment of Non-Consequential Load are allowed, regardless of voltage. Both are allowed, however, for a P6 event. In order for the two events to

not contradict each other, the conclusion that must be reached is that curtailment of Firm Transmission Service and curtailment of Non-Consequential Load are not allowed as part of System Adjustments, i.e. they are not allowed in between the two steps of P6, only after the 2nd step of P6 (Note: this is not clear partly due to the fact that the term "System Adjustments" is not defined anywhere in the Standard, and PEF therefore requests that the SDT define the term, and that the term should include the allowance of curtailment of Firm Transmission Service and the loss of Non-Consequential Load). PEF has two very serious concerns with that conclusion: a) FERC in its Order 693 stated that the BES is not required to have to withstand another N-1 contingency. Specifically, in Paragraph 1788 of Order 693 FERC states that â€œUnder TPL-002-0 the system is not required to be able to withstand another N-1 contingency. That N-1 requirement is a Category C contingency which is addressed by TPL-003-0.â€ Thus FERC clearly made a distinction between N-1 events for which a 2nd N-1 event never happens and N-1-1 events. The SDT, however, has not written the draft TPL Standard in such a way that Transmission Owners can reasonably and fairly plan for the 2nd N-1 event as TPL-003-0 has done. b) PEF has several 1st N-1 events on their 500 kV system for which "System Adjustments" are necessarily going to have to include either the curtailment of Firm Transmission Service or the curtailment of Non-Consequential Load in order to prepare for the 2nd N-1 event. The draft TPL Standard, while far from definitive on this matter, appears to allow neither as part of System Adjustments. PEF will thus be forced to i) construct redundant 500 kV facilities, at a cost to our ratepayers that will doubtless run into the range of billions of dollars, or ii) significantly reduce the posted levels of ATC/TTC of the various transmission paths available. Option (ii) is not a better option than option (i), for two main reasons: reducing ATC/TTC essentially puts marketing entities out of business, and forces utilities to build more generation sites to compensate for the loss of energy brought in using the previously higher ATC values. Either option results in prohibitively high costs to be passed on to the ratepayers for no measurable increase in BES reliability. This discussion also brings up additional concerns that include the lack of consideration of State government jurisdiction, the lack of public involvement, and ultimately, the lack of sufficient reason to construct such redundancy. PEF has never had a 500 kV N-1-1 event on its system. For this draft Standard to require redundancy projects costing billions of dollars for events that to date have never occurred is preposterous (note: additional comments concerning public outreach, no State government involvement, etc., are contained in the response to Question 15).

Given that a) PEF has never performed analysis to the extent that the draft TPL Standard is requiring and b) the draft is going through an iterative process and is at present considered a "moving target", a reasonably accurate estimate, or even a wild guess, cannot be provided for this answer. Having said that, it can be reasonably said that any estimate that could safely claim a reasonable degree of accuracy would require analysis performed full-time by several individuals over a period of several months (or possibly a period greater than one year). Just the cost of the assessment analysis alone would present an O&M challenge to PEF's Transmission department.

PEF has assessed this question and determined that any period of time less than 10 years would be inadequate to assess the supplemental nature of the requirements of the draft TPL Standard, to say nothing of the time required to construct the required facilities.

PEF, again stating that this cannot be considered an accurate estimate for the reasons stated in 12a, would estimate the burdened labor cost to perform such supplemental analysis on an ongoing basis to be at least $1M annually.

Again, these costs cannot be reasonably estimated given the difficulties stated in the answer to Question 12a. It would reasonable to expect that the number of individuals in PEF's Transmission Planning group would have to dramatically increase, at least doubling in size or possibly significantly more than doubling.

Documentation cannot be separated from the actual analysis itself, and thus would be included as part of the $1M estimate stated in the answer to Question 12b above.

Again, due to the difficulties described in the answer to Question 12a, given that the amount of analysis cannot be reasonably estimated, neither can the one-time capital cost. PEF did state in the answer to Question 11 that the cost to our 500 kV system alone would easily run in to the range of costing billions of dollars. How many billions, we are not sure, but we have sufficient experience through presently planned 500 kV projects on our system to know that the cost for such expansion is in the range of billions of dollars. Given that PEF has not been able to comprehensively assess the costs to its 230 kV and 115 kV system, it is likely that the total cost of implementing the draft TPL Standard would be many, many billions of dollars. As stated earlier, this concern is reinforced in the answer to Question 15, but we are extremely concerned that our ratepayers will potentially be burdened with such exorbitant cost for so little benefit, and are certain that our PSC and our ratepayers will agree.

PEF does not believe the undertaking required in the present draft of the TPL Standard, questionably described here as an "initial" program, could reasonably be implemented in our lifetime. As stated in our answers to Questions 12 and 13, the planning time would run at least 10 years, or one complete long-term planning cycle. Implementation, particularly given the scope of 500 kV projects and challenges with operating the existing system while constructing such large projects, will take an additional 10 years. An estimate of 20 years, however, assumes

that the industry is in place to make such projects feasible continent-wide. Just a cursory assessment of the limited resources of the Transmission Construction industry, combined with the global demand for concrete and steel, leads us to conclude that implementation of the draft Standard's requirements is not feasible short of a World War II-scale re-tooling of our entire economy. Given the significant challenges the U.S. economy is already facing, the prudency of such a colossal undertaking with minimal benefit becomes even more questionable.

C â€" Definitely do not support the revised standard

PEF considers the draft TPL Standard in its present state to be infeasible, unnecessary, burdensome and inferior to the existing Standards. The basic approach to equate reliability of the BES to whether or not Firm Transmission Service and/or Non-Consequential Load Loss can be sustained is an erroneous approach, is not justifiable, infringes upon regulation already in place as part of dealings with the Florida Public Service Commission (PSC), and infringes upon requirements in the OATT. Given the numerous concerns PEF has with the revised draft Standard, expounding on those concerns requires extensive documentation. We therefore cannot reduce our concerns down to a single issue, nor can we single out a single requirement or set of requirements as the top concern, other than to say that the entire Standard development process either needs to be discontinued or the SDT should provide detail as to how much consideration would be given to transmission systems with historically excellent reliability via a variance process. The following is a list of PEFâ€™s primary concerns with the revised draft Standard and explanation as to why the Standard development process should be discontinued: 1. PEF has planned to, and demonstrated compliance with, the existing TPL Standards for several years now. PEF is intimately familiar with the existing Standards, and has done an excellent job in planning the PEF system, in conjunction with the other Transmission Owner members of FRCC, non-FRCC adjacent Transmission Owners, and all requestors of Transmission or Generator Interconnection Service using the existing TPL Standards. PEF thus believes that history has shown, particularly within the realm of PEFâ€™s Transmission Planning boundaries, that the existing four TPL Standards are not inadequate or inferior in any way. Statements in recent months alluding to the existing Standardsâ€™ inferiority, confusing language or language subject to opposing interpretations, do not hold up when applied to the PEF and FRCC systems. PEF thus does not believe the Standards require modification. 2. PEF, through its aforementioned participation with FRCC and through its interaction and compliance with regulation by the Florida PSC, has historically demonstrated excellent Transmission Reliability, and can provide documentation to that effect through FRCC and Florida PSC channels. PEF therefore again asserts that modification or increased stringency in the TPL Standards is not merited. 3. The development of TPL-001-1 stems from a fundamental misinterpretation of the intent of FERC Order 693. NERC for the most part, rather than â€œclarifyâ€ or â€œconsiderâ€ various matters raised by FERC, chose to accept all suggestions. Specifically, PEF notes the following misinterpretations regarding Order 693: a) In Paragraph 1692, the Commission agreed with one particular utilityâ€™s assertion that integrating the four existing TPL Standards into a single standard would be an improvement, and directed NERC to â€œconsiderâ€ this. NERC, rather than considering this, formed the SDT, which appears to have spent little considering the issue but rather have deemed it a foregone conclusion that the four existing TPL standards must be abolished and a new standard must be written. b) In Paragraphs 1694 and 1706, the Commission recognizes the significant differences in the various transmission systems, and the impossibility of developing a standardized list of â€œsensitivitiesâ€ of critical operating conditions that every Transmission Planner and Planning Coordinator must analyze, regardless of their applicability. The Commission therefore stated that it is reasonable for planning entities to have a means to identify an appropriate range of critical operating conditions, without having to anticipate â€œevery conceivable critical operating condition.â€ They furthermore state that their conclusion on the whole matter is that â€œonly those deemed to be significant need to be assessedâ€. PEF agrees, and thus is perplexed by the erroneous developments in Requirements R2.4, R2.5, R5.4, R5.5, R2.1.3 and R2.1.4. PEF has addressed the inadequacies of these Requirements in the answers to Questions 2 and 10. c) In Paragraph 1704, the Commission, amongst other statements, states that they â€œare not requiring the construction of additional facilitiesâ€. This general statement made by the Commission is demonstrated to be untrue upon examining the realities of the Standard development process. FERC, by directing NERC to consider various clarifications and/or improvements to the TPL Standards, has set in motion a process which will prohibit either Interruption of Firm Transmission Service or the loss of Non-Consequential Load for various outage scenarios, effectively necessitating the construction of redundant facilities. FERC's statement conflicts with the ongoing process in a major way, and PEF respectfully requests that the SDT confer with appropriate FERC personnel to get clarification on this matter. d) In Paragraph 1725, the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entityâ€™s spare equipment strategy. PEF does not disagree with the specifics of analyzing events with respect to spare equipment, except to the extent that the Commission appears to think that such analysis is not adequately covered in the existing TPL Standards. PEF believes that the existing TPL Standards adequately address this issue and all other issues pertaining to the planning of a transmission system. Furthermore, the process is to be followed â€œconsistent with the entityâ€™s spare equipment strategyâ€, thus deferring to the processes and judgment of the individual

Transmission Owners, which calls into question the need to include it in the draft Standard. For additional discussion on this issue, see the answer to Question 5 with regard to Requirement R11. e) In Paragraph 1782, PG&E points out the contradiction that FERC creates in Paragraph 1796 by directing NERC to remove the 2nd sentence of footnote (b). The contradiction also involves key statements made by the Commission in Paragraph 1788. For a more detailed explanation of this contradiction, see the answer to Question 11. f) Paragraph 1794 is part of the Commission Determination section. The Commission states its belief that no TPL Standard should allow an entity to plan for the loss of non-consequential load in the event of a single contingency. The Commission then directs NERC to â€œclarify the Reliability Standard.â€, and furthermore state that any Transmission Planners or Planning Coordinators seeking to plan for the loss of non-consequential load in the event of a single contingency can make their comments known through a) filing comments in the standards development process, or b) filing for a regional difference for case-specific circumstances. PEF points out that the Commission merely stated their belief and directed NERC to clarify the Standard. They did not order NERC to change the Standard to reflect its beliefs. NERC, while having the leeway to question FERCâ€™s approach in this Paragraph, did not question the approach, but rather deferred to the suggestion in Paragraph 1794 (as well as nearly every other suggestion or request for clarification) that FERC made. PEF is concerned that NERC and the SDT appear to be limiting the extent to which they question or make suggestions to FERC. PEF at present will take the approach of stating the prudency and need to plan for the curtailment of Firm Transmission Service and loss of non-consequential load in the event of a single contingency through the comments process. PEF, however, reserves the right to consider the variance approach or legal approaches, depending on further iterations in the development of the Standard. g) In Paragraph 1795, â€œThe Commissionâ€¦suggests that the ERO consider developing a ceiling on the amount and duration of consequential load loss that will be acceptable. If the ERO determines that such a ceiling is appropriate, it should be developed through the EROâ€™s Reliability Standards development process.â€ To this effect, the SDT drafted Requirement R.3.3.2.1, which at present states â€œConsequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment.â€ PEF asserts that this issue is under the jurisdiction of the State Public Service Commissions, who are already doing an excellent job in regulating Consequential Load Loss as part of SAIDI/CMI requirements. FERC and NERC are overstepping their bounds of jurisdiction by attempting to essentially â€œdouble-regulateâ€ an issue that is already adequately regulated via the States. PEF furthermore objects to Requirement R.3.3.2.1 on the grounds that duration of events cannot be estimated with any reasonable degree of accuracy. To handle the challenges of this issue by stating a long-duration worst-case scenario for each outage would be inaccurate, and would tend to foster needless scrutiny and concern on any and all outages associated with Consequential Load Loss. h) In Paragraph 1796, â€œThe Commissionâ€¦directs the ERO to modify the second sentence of footnote (b) to clarify that manual system adjustments other than shedding of firm load or curtailment of firm transfers are permitted to return the system to a normal operating state after the first contingency, provided these adjustment can be accomplished within the time period allowed by the short term or emergency ratings.â€ The Commission directed the ERO only to make modifications on the 2nd sentence of footnote (b). The SDT in the draft TPL Standard has eliminated footnote (b) altogether. PEF is surprised and disappointed at the response by FERC to PG&Eâ€™s very correct assertion that eliminating the allowance of shedding of firm load or curtailment of firm transfers from footnote (b) contradicts the allowance made in footnote (c) regarding C.3 events. FERCâ€™s only response was to state that â€œmanual adjustments referred to in both cases [i.e. Category B and Category C.3 events] apply after the first N-1 contingencyâ€. The fallacy of this statement is that shedding of firm load or curtailment of firm transfers is allowed by footnote (c) for C.3 events, and that every Category B event is by default the first part of a Category C.3 event. PEF asserts that FERC, and consequently the NERC SDT, has created a draft Standard that contradicts direction and suggestion in Order 693 regarding this issue. PEF furthermore asserts that curtailment of Firm Transmission Service or Non-Consequential Load are not valid benchmarks for assessing the reliability of the BES. For additional comments on this issue, see the answer to Question 11. i) Regarding Paragraph 1833, the paragraph in its entirety states: â€œMidAmerican states that it supports the proposal to modify TPL-004-0 to require identification of options for reducing the probability or impacts of extreme events that cause cascading. Accordingly, for the reasons cited in the NOPR, the Commission directs the ERO to modify the Reliability Standard to make this modification to the Reliability Standard.â€ PEF does not understand what FERC has directed on this matter. Furthermore, PEF does not understand the meaning or requirements behind the entire â€œExtreme Eventsâ€ section in the draft Standard, which appears to have resulted from the direction in this particular Paragraph. FERC wants NERC to modify the Standard to â€œrequire identification of options for reducing the probability or impacts of extreme events that cause cascading.â€ This statement is vague, confusing and does not appear to mandate anything. PEF therefore requests that language in TPL-001-1 to this effect be removed. Furthermore, in Paragraph 1834, the Commission, regarding its preference to expand TPL-004-0 to include analysis of more events such as hurricanes, ice storms, successful cyber attacks, etc., directs NERC to â€œexpand the list of events with examples of such events identified above.â€ This

request, similar to Paragraph 1833, does not appear to direct NERC to make specific directions in a Standard. If it was FERCâ€™s intent that TPL-004 or its successor be modified to include some or all of FERCâ€™s suggested events, and to expand the list further, PEF has many concerns concerning this. The direction in Paragraph 1834 has resulted in the aforementioned Extreme Events section, which contains a note 1 referring to Requirement R3.4. PEF has multiple questions and concerns with the language in this Requirement. The Requirement as worded appears to mandate that Transmission Planners and Planning Coordinators must find the most severe Extreme Event scenarios that can be conceived. Such wording would define any reasonable limit as to which Extreme Events are likely and worthy of analysis, and which are not. Furthermore, many of the events suggested by FERC, such as loss of a large gas pipeline, wildfires, hurricanes, tornadoes, cyber attacks, etc., cannot reasonably be studied. To make any assessment of these events that even approached a level of thoroughness is infeasible, and furthermore has no significant benefit. PEF requests that the SDT point out to FERC that these events cannot be studied, and therefore need to be excluded from any TPL Standard. 4. The main approach of the draft TPL Standard consists of whether to allow or disallow load loss for certain outage scenarios (the most problematic Event categories being P1, P2.2, P2.3, P3, P4, P5 and P6), an approach to which PEF is opposed, and furthermore believes that level of service to retail load is not an issue that NERC/FERC should be regulating. The local utility commissions (the Florida PSC, etc.) have already set in place processes for reviewing/approving the level of transmission built to support the level of service to load, and thus FERC and NERC inappropriately attempt to regulate an issue which the States already adequately regulate. PEF can, and has demonstrated in its internal planning assessments and in assessments performed with FRCC that load curtailment and/or Firm Transmission Service curtailment do not adversely impact the reliability of the BES. In fact, certain post-contingency scenarios can be shown to demonstrate that such curtailments actually promote reliability and a speedier, safer, more efficient recovery of the BES after an event. 5. Several Event categories as presently defined in the draft TPL Standard present outage scenarios on the PEF system for which implementation of redundant transmission facilities would be required, at an exorbitant cost to ratepayers. The redundancy requirements at PEFâ€™s 500 kV, 230 kV and 115 kV Substations are numerous, and have not yet been comprehensively quantified, although this analysis is underway. One scenario for which PEF is already certain that redundancy of the 500 kV system would be required is the apparent disallowance of curtailment of Firm Transmission Service or Non-Consequential Load as part of â€œSystem Adjustmentsâ€ in between the two events of P6. PEF again would point out that no definition of â€œSystem Adjustmentsâ€ exists at present, and the SDT therefore must define it if compliance is expected. Be that as it may, PEFâ€™s 500 kV redundancy projects would clearly cost many billions of dollars, with extremely little benefit. PEF would furthermore point out that this is but one example requiring unnecessary Transmission upgrades, and that further analysis will potentially reveal several more Event categories in Tables 1 and 2 for which additional cost-prohibitive and unneeded projects would be mandated. 6. PEF is surprised and disappointed that neither FERC nor NERC have accepted any responsibility to alert the public or the State and local governments to this process. The public have not been involved in the development of the draft standard, nor have they been informed that they would bear the financial impact of the increased stringency. In fact, The SDT on p. 369 of the 1st draft Comments Document has stated that â€œThis is a performance based reliability standard and does not and should not consider economics.â€ PEF considers this statement to be reckless and irresponsible, and does not accept FERCâ€™s and NERCâ€™s apparent position that they have no responsibility in this matter. The fact that the draft Standard and FERC Order 693 can be downloaded by anyone from FERCâ€™s and NERCâ€™s websites does not constitute a sufficient good-faith notice of this process to the public. PEF requests that FERC and NERC specifically address this issue by explaining their failure to involve and inform the public. Assigning this responsibility to each Transmission Planner and Planning Coordinator is not acceptable. FERC and NERC have set this process in motion, and as creators of the process owe an explanation to those who would â€œfoot the billâ€ for the process. 7. The low voltage threshold of jurisdiction of the draft Standard, previously defined in NERCâ€™s definition of the BES as 100 kV, is not specified in the draft Standard. This is a significant misstep by NERC in that a change to NERCâ€™s Glossary Definition of the BES, which would ostensibly be done outside the boundaries of this Standard, could profoundly change the requirement for complying with TPL-001-1 without changing a single word of the Standard. PEF is particularly concerned that this Standard must never have jurisdiction over local load-serving transmission systems, regardless of voltage. Any TPL Standard, existing or future, must focus on the reliability of the BES, i.e. the bulk grid, NOT the local load-serving portions of the transmission system. The draft Standard at present does not address this issue at all and leaves Transmission Planners and Planning Coordinators vulnerable to non-compliance with a mere change in the wording of a Definition outside of the Standard. 8. PEF strenuously objects to the allowance of interruption of Firm Transmission Service in Events P1 and P3 for DC lines, while disallowing the same for AC lines. PEF asserts that the determination should be â€œYesâ€ for both, and that disallowance for AC lines a) puts DC systems into an elite class of transmission for no explicable reason and b) encourages owners of AC Transmission Systems to replace them with DC, cost concerns notwithstanding. Furthermore, this differentiation fails to recognize or give consideration to the fact that AC

systems support Firm Transmission Service; some areas of the AC transmission system carry significant amounts of Firm Transmission Service, and thus a â€œNoâ€ determination for P1 and P3 essentially mandates either implementing redundancy for those parts of the AC system carrying significant amounts of Firm Transmission Service, or severely curtailing Firm Transmission Service on the existing AC systems.

Individual

Jessica Rice

Sierra Pacific Power Comapny / Nevada Power Company

No

We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study â €œfocuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to â€œdevelop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingenciesâ€. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequate addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say â€œonly whenâ€ the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, â€œmaterial Transmission System changeâ€ and â€œat or near the point of Interconnectionâ€ to invoke a study.

Yes and No

R2.4 is acceptable. Please consider deleting R5.4.3. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Ownerâ€™s open access tariff requires Generator Owner to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Ownerâ€™s responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.

No

We generally do not disagree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as â€œlocal Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systemsâ€ in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to

connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, â€œâ€¦load no longer being connected to a sourceâ€¦â€. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (â€œAlthough Load which is lost as a result of the Loadâ€™s response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirementsâ€) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.

Yes

We generally agree, however, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.

Yes

While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.

Yes and No

We agree with R2.3. However, R4 requires assessment of â€œShortcircuit capability of its equipment under normal condition and following any single Contingency condition that would result in greater circuit breaker interrupting dutiesâ€. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute â€œnormalâ€ condition or â€œfollowing any single Contingency conditionâ€. Also, by specifying the normal and single contingency conditions, R4 is straying into â€œhowâ€ to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.

Yes and No

We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some maybe some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SGT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believes there should be no distinction between the voltage classes and supports the use of load shed for all cases identified in P4

through P7.

No

We do not disagree with the proposed definition change. However, we do not agree that â€œSubstation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.

Yes

We interpret â€œexit breakersâ€ to mean a breaker on an element that comes in from outside the substation. We agree with the rationale for the requiring more stringent performance requirement levels for non-bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes

Yes and No

We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the â€œbase caseâ€ of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the â€œbase caseâ€ condition. R2.7 also states that â€œCorrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivitiesâ€. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the â€œbase caseâ€, will the judgment of the Transmission Planner be then questioned because â€œbase caseâ€ used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?

Yes

We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.

$400,000

2 Man Years

$250,000/year

$100,000

$50,000

$800 Million

10 years

B â€" Unsure about supporting the revised standard

We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system

adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions. We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with â€œraising the barâ€. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms â€œinterruption of firm transmission serviceâ€, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what â€œFirm Transmission Serviceâ€ means. Two points, 1) the NERC definition states â€œhighest quality service offered to customers under a filed rate schedule that anticipates no planned interruption.â€ The Standard implies anticipation of â€œunplannedâ€ interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order 890, or firm transfers modeled for the conditions being studied? One way to interpret the intent is the firm transfers being modeled for the conditions in the powerflow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption of firm transmission service should also be allowed for P1 through P5 contingencies in the table. In addition, we believe that DC and AC lines should have the same performance requirements with respect to interuption of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines can automatically be curtailed when the line is outaged.

Individual

Gary Newell (Thompson Coburn LLP -- Counsel to Lafayette Utilities System)

Lafayette Utilities System

No

Lafayette Utilities System (Lafayette) does not dispute the need for stability studies, especially in connection with significant system topology changes. We are concerned, however, by the possibility of inconsistencies between the results of interconnection studies conducted for new generating units pursuant to the Large Generator Interconnection Procedures prescribed by FERC and Generating Unit Stability Studies conducted as part of the TPL-001 planning assessment. For example, if a TPL-001 stability analysis indicates the need for more costly or extensive transmission upgrades that were indicated in an earlier LGIP interconnection study, the generation developer could be placed in an untenable situation: it would have proceeded with its project based on the assumption of responsibility for LGIP-indicated upgrades, but then could face demands for the funding of additional upgrades pursuant to the TPL-001 stability analysis. Improved integration between the two sets of stability studies appears warranted, in order to avoid placing generation developers in this position.

Yes and No

Requirement 2.4.1 directs the furnishing of information that would reveal the location of new large inductive loads. Large inductive loads typically are induction motors used in industrial applications. Therefore, a Distribution Provider's forecasts about the expected level of its inductive load could effectively reveal non-public information about the anticipated location of new industrial loads. If a Distribution Provider were required to disclose such information to its Transmission Planner, the confidentiality of information having considerable commercial and competitive significance could be compromised. This would be of particular concern if the Transmission Planner and the Distribution Provider also happen to be competitors for new retail loads.

No
Non-consequential load loss is described as including non-interruptible load lost that results from manual or automatic operations "such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems â€¦." It should be clarified that the quoted items are not intended to be exhaustive of the non-manual Load loss situations that would be considered the loss of Non-consequential Load. For instance, some types of industrial applications that are power-quality dependent may be expected to disconnect or shut down in the event of fluctuations in frequency, voltage or current. Foreseeable load interruptions of this nature should be treated as "Non-consequential Load loss" even if the mechanism by which the load disconnects is other than a UFLS, UVLS or SPS system operated by the Distribution Provider.
No
Requirement R.3.5 states that generation run-back is allowed as a response to single or multiple contingencies, as long as certain conditions are met. Lafayetteâ€™s concern is that the allowance for generation run-back is not limited to generation owned by the Transmission Planner or under the Transmission Plannerâ€™s direct operational control. For that reason, the language could be interpreted to permit reliance (for planning purposes) on redispatch of generation owned by third-party generation owners that is undertaken in compliance with Reliability Coordinator directives during a Transmission Loading Relief event. During the SDT conference call held on August 26, 2008, the SDT representative stated that the team did not intend that R.3.5 would permit a Transmission Planner to rely on third-party generation redispatch, and that the intent was only to permit reliance on run-back (redispatch) of generation owned by or under the direct control of the Transmission Planner. Lafayette believes the language of R.3.5 needs to be clarified to state in express terms the limitation intended by the SDT. Reliance on third-party redispatch should not be permitted unless a Transmission Planner has entered into a contractual arrangement with the generation owner authorizing such use.
No
In Draft 2 of TPL-001, the SDT has adopted â€œPlanning Coordinatorâ€ as a new defined term. That term is used frequently in the new draft Reliability Standard (including in Requirements R9 - R14 but also, most notably, in Section A.4.1.1). The SDT explained in its response to comments on Draft 1 that it had taken the definition of â€œPlanning Coordinatorâ€ from the NERC Functional Model. However, the term â€œPlanning Coordinatorâ€ is not used in the NERC Registry Criteria, nor does it appear in the NERC Glossary. Because the latter form the basis for allocating compliance responsibilities, the SDT should eliminate use of â€œPlanning Authorityâ€ and should adopt in its stead a term that is used in the Registry Criteria (such as â€œPlanning Authorityâ€). With respect to the incorporation of data provided under Reliability Standards MOD-010 and MOD-012 into the studies contemplated by the revised version of TPL-001 (see Requirements R1 and R5), Lafayette urges the SDT to clarify entitiesâ€™ obligations with respect to the provision and use of this data, particularly with respect to Planning Coordinators/Authorities. As presently drafted, MOD-010 and MOD-012 do not apply to Planning Coordinators or Planning Authorities, and these standards also do not provide for these entities to receive MOD-010 and MOD-012 data from the entities that are subject to these two Standards. Further, to the extent that Requirements R1 and R5 require Transmission Planners to use MOD-010 and MOD-012 data, is it contemplated that Transmission Planners will obtain this data from Resource Planners and Transmission/Generation Owners in their areas, or will Transmission Planners merely be obligated to incorporate the data that they themselves provide under MOD-010 and MOD-012 into their studies? Requirement R9 directs each Distribution Provider to furnish its â€œPlanning Coordinatorâ€ with modeling information that includes â€œreal and reactive load forecast data â€¦ at Transmission nodesâ€ and â€œthe expected mix of industrial, commercial, and residential Loads.â€ As discussed previously with respect to Requirement 2.4.1, Distribution Providers may consider the information required by R9 to be commercially sensitive such that its disclosure could have adverse competitive effects. The information specified in R9 therefore should be protected from disclosure unless the provider of the information authorizes its release or other appropriate protections are in place. Additionally, given that this requirement directs the provision of â€œload forecast data,â€ it seems more appropriate that the requirement apply to â€œLoad-Serving Entities,â€ â€œDistribution Providers that serve load,â€ or â€œDistribution Providers that are also Load-Serving Entities.â€ Requirement R10 assumes that the Transmission Planner has access at all times (and, therefore, is in a position to provide within 90 days of a request) to Firm Transmission Service Data, Interchange Schedules, and resources required to serve load for each of its Balancing Authorities for each year of the transmission planning horizon. The Transmission Planner, however, may only receive such information periodically (e.g., annually or semi-annually) from its Balancing Authorities for use in the planning process. It is more likely that, at any point during the year, the Transmission Owner, Transmission Operator, or Transmission Service Provider would have access to the specified information. Requirement R10 should be expanded to include these other entities, who probably will have access to the data throughout the planning cycle. Requirement R11 does not specify whether outage information provided by a Transmission Owner must be updated (e.g., if the outage schedule changes after being provided upon request by the Planning

Coordinator). The Transmission Ownerâ€™s obligations with respect to providing updated information should be clearly stated. Additionally, it is not clear what the SDT means by the phrase â€œgiving consideration to spare equipment strategy.â€ If the intent is that Transmission Owners shall factor into their outage decisions and timing the availability of spare equipment that might affect the need for or duration of an outage, that intent should be stated in clear terms.

No

Lafayette has identified two issues with respect to the Short Circuit Analysis required in TPL-001. First, Requirements R2.3 and R4 do not describe the required Short Circuit Analyses in sufficient detail to ensure that these studies are performed using topology assumptions that are consistent with the assumptions used in the Steady-State and Stability Studies. If inconsistent topology assumptions are used, the results of the analyses would not present a clear and consistent picture for planning purposes. Second, interconnection studies performed under the FERC LGIP procedures typically include considerable short-circuit analysis of the interconnecting transmission system. Entities required to perform an annual Planning Assessment should be permitted to use, for TPL-001 compliance purposes, any up-to-date short-circuit analyses that may have been conducted for an LGIP interconnection study. Forcing these entities to re-perform the analyses for TPL-001 compliance would impose unnecessary cost.

Yes

Yes

No

See paragraph (b) in response to Question 15.

No

As to the performance of sensitivity analyses under R2.1.3, Lafayette believes that insufficient detail is provided to define with clarity cases that involve â€œmodification of expected transfersâ€ (per R2.1.3.2). For example, it is unclear whether the phrase â€œmodification of expected transfersâ€ is intended to refer to a change in directional bias in the model, a reduction in flows due to variation between reservations and schedules, or something else. Additional definition should be provided to ensure that sensitivity cases performed pursuant to R2.1.3.2 are meaningful and useful.

No

Lafayette does not agree that the loss of Non-Consequential Load should be permitted as a corrective action. See also paragraph (b) in response to Question 15.

Lafayette has not analyzed in any detail the resource requirements addressed in this question. Based on available information, we estimate that supplementing existing studies would require at least 1 FTE familiar with stability analysis to be able to complete this portion of TPL. The new steady-state analysis will require the addition of 1 FTE to be able to complete the additional P5-P7 requirements. These will be ongoing expenses whether accomplished by hiring new staff or relying on external service providers.

See response to part 1 of Question 12.

See response to part 1 of Question 12.

See response to part 1 of Question 12.

See response to part 1 of Question 12.

See response to part 1 of Question 12.

See response to part 1 of Question 12.

C â€" Definitely do not support the revised standard

Lafayetteâ€™s single biggest concern is that the second draft version of TPL-001 imposes performance requirements that are less stringent than those imposed in the previous draft. As the SDT stated in its response to comments on Draft 1: â€œThe SDT modified the performance requirements relative to Non-Consequential Loss of Load and revised Tables 1 & 2 to add greater detail and provide for more situations where it is acceptable to lose Non-Consequential Load.â€ This â€œwatering downâ€ of the standard appears to result from complaints about the costs that certain commenting parties claimed would be necessary to achieve compliance with the performance requirements set forth in Draft 1. This is evident from the SDTâ€™s statement in the foreword to the comments form for Draft 2 that the SDT has â€œattempted to adjust and clarify the proposed requirements and performance in light of these initial comments,â€ and that the SDT needs additional information about cost and other compliance issues so that it can â€œmake more adjustments as appropriate.â€ Lafayette questions whether it is appropriate for the SDT to shape the performance standards to alleviate certain commentersâ€™ cost concerns. The SDT should be focused on developing performance requirements that are judged to be optimal from the standpoint of protecting reliability consistent with sound engineering and planning. Striking a balance between reliability and cost is a policy determination for which responsibility lies elsewhere than in the SDT. Claims that the standards would impose excessive

costs are more properly addressed to FERC when the revised TPL-001 is filed for approval because Congress assigned to FERC the responsibility to make judgments of this sort. The SDT should not be â€œadjustingâ€ (that is, watering down) the performance requirements in response to transmission owner arguments about the costs of compliance. The dilution of the performance requirements is manifest in a number of elements contained in the proposed draft, including (but not limited to) the following: a) Table 1 (Steady State Performance) would permit the interruption of Firm Transmission Service and the loss of Non-Consequential Load in three P1 (Single Contingency) scenarios involving AC lines. In Order 693 (at paragraph 1794), however, FERC emphasized that loss of Non-Consequential Load in single contingency situations is not permissible. b) Adopting less stringent performance requirements for loss of elements below 300kV may be discriminatory. Most wholesale customer loads are served from delivery facilities that operate at voltages lower than 300kV. The outage of facilities operating at less than 300kV therefore may encompass 100% of a wholesale customerâ€™s load, while it is likely to impact a much smaller portion of the total load served by the owner of the affected transmission facilities. Therefore, adopting less stringent performance requirements for facilities operating at less than 300kV would impose a disproportionate burden on affected wholesale customers, as compared to the transmission owner. c) In addition to its potentially discriminatory effect, the notion of imposing difference performance standards based on operating voltage would incent transmission owners to scrimp on needed improvements to lower voltage facilities. Presumably, the distinction originates from a belief that outages on 300kV and lower facilities will have less impact on the Bulk Electric System. As the August 2003 blackout demonstrated, however, disruptions on lower voltage circuits can cause real and reactive power flow fluctuations across, and eventual separation of, higher-voltage networks. d) Regarding the SDTâ€™s elimination of the requirement to re-test cases to ascertain the efficacy of additions included in a Corrective Action Plan (sub-requirement 2.7.2 in Draft 1), it is unclear why this requirement was deleted since very few commenters complained that it would be burdensome. It is hard to see how such a re-testing obligation would impose a significant burden, at least insofar as the steady state analysis is concerned. Eliminating the re-testing requirement seems likely to provide minimal savings, but could be important to verifying that appropriate Corrective Action Plan decisions are made.

Individual

Eric Egge

Black Hills Corporation

No

We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study â€œfocuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to â€œdevelop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingenciesâ€. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say â€œonly whenâ€ the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, â€œmaterial Transmission System changeâ€ and â€œat or near the point of Interconnectionâ€ to invoke a study.

Yes and No

R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirement in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the

Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Ownerâ€™s open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Ownerâ€™s responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.

No

We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as â€œlocal Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systemsâ€ in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, â€œâ€¦load no longer being connected to a sourceâ€¦â€. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (â€œAlthough Load which is lost as a result of the Loadâ€™s response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirementsâ€) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.

Yes

We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.

Yes

While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling

information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.

Yes and No

We agree with R2.3. However, R4 requires assessment of â€œShort-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting dutiesâ€. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute â€œnormalâ€ condition or â€œfollowing any single Contingency conditionâ€. Also, by specifying the normal and single contingency conditions, R4 is straying into â€œhowâ€ to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.

Yes and No

We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.

Yes

Yes and No

We interpret â€œexit breakersâ€ to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes

Yes and No

We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the â€œbase caseâ€ of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the â€œbase caseâ€ condition. R2.7 also states that â€œCorrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivitiesâ€. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the â€œbase caseâ€, will the judgment of the Transmission Planner be then questioned because theâ€œbase caseâ€ used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?

Yes

We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1

and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.

B â€" Unsure about supporting the revised standard

We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before a full approval of this Standard can be given. There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions. We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with â€œraising the barâ€. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms â€œinterruption of firm transmission serviceâ€, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what â€œFirm Transmission Serviceâ€ means. Two points, 1) the NERC definition states â€œhighest quality service offered to customers under a filed rate schedule that anticipates no planned interruption.â€ The Standard implies anticipation of â€œunplannedâ€ interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order 890, or firm transfers modeled for the conditions being studied? One way to interpret the intent is the firm transfers being modeled for the conditions in the powerflow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption of firm transmission service should also be allowed for P1 through P5 contingencies in the table. In addition, we believe that DC and AC lines should have the same performance requirements with respect to interuption of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines can automatically be curtailed when the line is outaged.

Individual

Baj Agrawaal

Arizona Public Service Co.

Yes and No

We generally concur with the changes for the Requirements associated with the Generating Unit and System Stability, however, â€¢ Generating unit stability studies are typically performed at

the time of interconnection. Even though stability studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of generating units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units. Will every TP have to benchmark their generating unit stability study for its entire fleet with the acceptance of this Standard? In other words, will every TP has to recreate documentation for all its older units? â€¢We would appreciate that the SDT more clearly define the terms in R2.5.2, â€œmaterial Transmission System changeâ€ and â€œat or near the point of Interconnectionâ€ to invoke a study with examples.

Yes and No

â€¢We generally agree that utilities or large TPs and PCs need to perform and be held accountable for these Requirements; however, the SDT needs to define a organization size level, below which these requirements for the associated TP may be slightly relaxed. There are numerous TPs; (e.g., those associated with PUDs, Municipals or REA, etc.), for which performing these type of studies and assessments are onerous and do not yield reliability benefits for the network.

Yes and No

We generally agree with the definition but have concerns about a potential unintended consequence. This definition will severely limit the loads that can be classified as â€œlocal Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systemsâ€ in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, â€œâ€¦load no longer being connected to a sourceâ€¦â€. At a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability.

Yes and No

We generally agree, however, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest moving R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.

Yes

â€¢We agree that the MOD Standards need modifications and additions to be used for Transmission Planning, â€¢We also agree with the movement of the R1of the first draft to the R9 through R14 of this draft, â€¢We also agree that when the MOD Standards are replaced, then remove these Requirements from the TPL Standard.

Yes and No

We agree with R2.3. However, R4 requires assessment of â€œShortcircuit capability of its equipment under normal condition and following any single Contingency condition that would result in greater circuit breaker interrupting dutiesâ€. Since short circuit studies are typically performed by applying a three phase fault on a Facility starting from a normal condition, please clarify whether the result would constitute â€œnormalâ€ condition or â€œfollowing any single Contingency conditionâ€.

Yes

We agrees with the proposed format changes of the Tables.

Yes

We agree with the proposed definition change.

No

We do not agree with the rationale for the requiring more stringent performance requirement levels for non-bus tie breakers above 300 kV. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes.

Yes and No

We generally agrees with the concept of the sensitivity analysis. However, clarifications of the following is needed: â€¢For example, if a TP performs studies on the â€œbase caseâ€ of which the loads are 90/10, does this constitute a sensitivity analysis. If so, will the TP have to then perform additional less stringent studies at the 50/50 load level to demonstrate compliance? â€¢R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the

above example, the TP should not have to explain why they feel that this higher level (90/10) of load is the â€œbase caseâ€ condition. â€¢R2.7 also states that â€œCorrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivitiesâ€. Consider a TP that has built transmission based on the 90/10 load assumed in the â€œbase caseâ€, will the judgment of the TP be then questioned because of itâ€™s sensitivity â€œbase caseâ€ and not a 50/50 base case?

Yes

We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV.

Two person-year.

2-years.

one person year.

$200,000.00

$100,000.

Hard to quantify without studying.

5 years

A â€" Generally support the revised standard

We generally agree with the Standard as presented so far, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard.

Individual

John E. Sullivan

Ameren

No

Agree with the revised definition of Generating Unit Stability Study. Propose new definition for System Stability Study, as follows - "Study that focuses on portions of the System, including the impact of contingencies on multiple generating units in an area. These studies would examine issues such as angular Stability, inter-area oscillation, and voltages during dynamic simulations."

Yes and No

In R2.4, it is suggested that the word "System" be re-inserted ahead of the word "Stability". It is believed that the sub-requirements of R2.4 are for System studies as opposed to Plant or Generator stability studies. In R2.4.1, agree that the system peak load should be studied for at least one of the five years in the near-term planning horizon. What is the meaning of the term "appropriate", and who decides what dynamic representation of load is "appropriate", and for what conditions? Guidelines for the development of load models used in powerflow and dynamic models to represent residential air conditioner induction motor load response including the effects of underground distribution cable and distribution capacitor banks are not available. Why can't the standard load representation be used to meet R2.4.1, and the more detailed load representation, including dynamic sytem induction motor load response, be used to meet R2.4.3? In R2.4.2, agree that off-peak load levels should be covered for one of the five years. In R2.4.3, there should not be a requirement to explain why sensitivites were not selected. Further, these items in R2.4.3.1-5 appear to be options and not sub-requirements, and therefore are too prescriptive and inappropriate for inclusion here. The proposed sensitivities appear to over-focus on the particular issues listed and may result in the detriment of overall system reliability. Engineering judgement should be used to develop the sensitivity scenarios, and it should be encouraged that the same scenarios should not be performed every year so that a portfolio of sensitivity scenarios would be developed over time. The standard should not include an enumerated list of required sensitivities. If two sensitivities are required to be performed each year, then the standard should state so, but we believe that more than one sensitivity scenario for each peak and off-peak case is burdensome. We are unsure if R2.4.4 is a requirement or an option. If R2.4.3 were not so prescriptive, the additional sensitivity could be covered under the engineering judgement comment provided above. The prescriptive listing of sensitivities under 2.4.3.1 through 2.4.3.5 should be eliminated. Proposed alternative wording for R2.4.3 which addresses above concerns is as follows: R2.4.3. "For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, sensitivity case(s) that stress the System to reflect one or more conditions such as variations in dynamic Load model assumptions, modification of expected transfers, variability and outages of reactive resources, generation additions, retirements, or other dispatch scenarios are integral to a thorough assessment of reliability. Document how and why appropriate sensitivities were selected." R2.5 should be reworded as follows. "The Generating Unit Stability portion of the Planning Assessment shall be assessed for the year and conditions when the following changes that could affect stability margins occur:" Agree with most of R5.5. In R5.5.4, a risk/benefit vs. cost analysis should be included in the evaluation of implementing a change to mitigate the likelihood of cascading outages for the extreme events. Agree with R5.6.

Yes and No

The revised definition of Consequential Load Loss needs to be simplified, as follows, "Consquential Load Loss: Load that is no longer served because it has been isolated from its network supply by a planned protection system operation to mitigate fault conditions." Additional clarifications as to when Consequential Load loss is allowed should not be included in the definition, but should instead be included in the Tables 1 and 2. Agree with the revised definition of Non-Consequential Load Loss.

Yes

R3.5.1 should be modified as "All Facilities shall be operating within their applicable Facility Ratings, including the use of short-time emergency ratings."

No

We consider the proposed requirements R9-R14 to be largely a duplication of the MOD standards and do not agree that they belong in the proposed TPL-001-1. We would propose that a reference to the MOD standards would be more appropriate so as not to create a double-jeopardy compliance situation. If it is determined that the requirements R9-R14 need to stay, the proposed standard needs to reflect the existing data flow processes and consider who builds the models, which is the Transmission Planner, and not the Planning Coordinator. According to the definition provided in this standard, the Planning Coordinator is "The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems." In our case, the Transmission Planner receives: a) load forecast (real and reactive) information from the Distribution Planner or Load Serving Entity, b) transmission ratings/impedance/topology(outage) information from the Transmission Owners, c) generation ratings/capabilities/outage information from the Generation Owners, and d) designated network resources (existing and future), as well as external obligations, from Resource Planners. The Transmission Planner develops powerflow and corresponding dynamic models from this information including load magnitude and distribution, generation dispatch, and net scheduled interchange, and provides the models or modeling components to the Reliabiity Coordinator and Planning Coordinator. Other organizations may have similar problems with data flow processes as specified in R9-R14. We view the R9 requirement of the proposed TPL-001-1 for the Distribution Provider to provide real and reactive load forecast data, including load mix information, to conflict with R1.4 of MOD-013-1 which has the RRO as setting the requirement for the dynamic load data. R10 needs to be modified to reflect the RTO activities related to the coordination and sale of Firm Transmission Service, which is not a Transmssion Planning activity. R11 needs to be modified to drop the "spare equipment strategy". This is not a modeling issue and should be covered in standard TOP-002-2 (see R1 and R6). R13 needs to be modified to drop the "Reactive Power devices and new technologies" because Resource Planners typically do not know about these devices. The Transmission Planner or Owner may be the more appropriate entity. We view R14 as an extension of Standards MOD-010-0, MOD-011-0, MOD-012-0, and MOD-013-0.

No

Requirement R4 should be modified to remove the Planning Coordinator such that the "Transmission Planner shall assess the short-circuit capability of its equipment considering maximum interrupting duty for normal or single element outage conditions".

Yes

The tables could be improved by including the column headings on each page. Separating the steady-state and stability performance requirements for each planning event helps to provide clarification.

No

To provide clarity, a revised definition is proposed. "A bus-tie breaker is a circuit breaker that connects two individual bus sections with one or more breaker positions on each bus; substation configurations such as ring-bus, breaker-and-a-half, or double bus-double-breaker do not have bus-tie circuit breakers."

Yes and No

Yes: The installation of bus-tie circuit breakers in a straight bus configuration would reduce exposure to a) bus faults or to b) line faults with breaker failure without adding much risk for internal fault in the bus-tie breaker. Those entities that employ a straight bus substation design with bus-tie breakers have recognized that failure of the bus-tie breaker, a very low probability event, would result in the loss of multiple transmission elements and perhaps firm load for a short time until the bus sections can be restored, but bus-tie breakers are an investment worth the risk. Therefore, it is generally agreed that the outage of non-bus-tie circuit breakers should have higher performance requirements than the outage of bus-tie circuit breakers. The SDT should be commended for this change since the previous draft version. No: However, it is not clear that adopting a higher standard of performance for planning events involving transmission facilities 345 kV and above will improve overall system reliability. Some areas of the continent already have n-2 planning criteria, yet these systems have still experienced significant outages including blackouts. It is suggested that a review of the Transmission Availability Data System (TADS) data, when available, should be conducted to help assess what system performance

requirements need to be strengthened before arbitrarily determining to "raise the bar" for certain voltage levels and system designs. The industry should not be forced to invest a great deal of capital to meet a new standard requirement when it would not have an immediate impact on system reliability. Some sort of cost/benefit analysis should be performed to justify any change from the present TPL-001 through 004 standard requirements. On the Ameren system, there is no indication that transmission system reliability has been degraded through the use of straight bus configurations. Also, further clarification is required to explain how to drop consequential load without cutting firm transmission service to those affected/outaged customers, and this needs to be added to the notes in Tables 1 and 2.

No

Similar to our comment above for R2.4.3, there should not be a requirement to explain why sensitivites were not selected. Also, it is not clear if R2.1.4 is a requirement or an option. While we agree that the system cannot be adequately planned based on a single snapshot of expected system conditions, these items in R2.1.3.1-7 are too prescriptive and are inappropriate for inclusion here. The sensitivities listed appear to be options and not sub-requirements, and may result in over-focusing on the particular issues listed to the detriment of overall system reliability. Some sensitivity studies are in effect adding an additional level of contingency to the analysis work (n-2 or n-3). Outages of reactive sources and generation should already be included in studies of multiple contingencies. The process of planning new generation (system impact studies) will include studies of the future system with and without the proposed new equipment. Engineering judgement should be used to develop the sensitivity scenarios, and it should be encouraged that the same scenarios should not be performed every year so that a portfolio of sensitivity scenarios would be developed over time. The standard should not include an enumerated list of required sensitivities. If two sensitivities are required to be performed each year, then the standard should state so, but we believe that more than one sensitivity scenario for each peak and off-peak case per year for asssessment is too burdensome to run complete contingency analyses. Proposed alternative wording for R2.1.3 which addresses above concerns is as follows: R2.1.3. "For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System to reflect one or more conditions such as variation in load assumptions, modification of expected transfers, variability and outages of reactive resources, generation additions, retirements, or other dispatch scenarios are integral to a thorough assessment of reliability. Document how and why appropriate sensitivities were selected."

No

Please clarify that the shunt devices to be considered for outage are those that are directly connected to the transmission system. For the P6 events involving a transmission facility and a shunt device, local voltage instability issues may result in dropping of load in the vicinity of the outaged facilities, but the concern should be that the load dropped is not wide-spread. The words "Voltage instability" should be removed from Header Note 3 of Table 1 so that it becomes "Cascading outages and uncontrolled islanding shall not occur."

One component of cost is to model in more detail all straight busses and bus-tie breakers at all transmission voltage levels. Contingency scenarios would also need to be developed and/or modified to correspond with the new powerflow models. The sensitivies presently specified will greatly increase the cost and time needed for updating all plant stability studies.

One-time costs to provide additional modeling detail and modify and test the revised contingency lists would be approximately 1 man-month or about $8000. Updating all plant stability studies would take approximately 5 man-years, at an estimated cost of approximately $500,000 (including benefits). Given existing regional requirements to complete the annual assessment by July 1 of the calendar year, additional staffing would likely be needed to complete this work, unless compliance were phased in over a number of years, similar to the MOD-024 and MOD-025 standards with respect to generator testing.

A review of the studies required for R2.1 indicates that at least 6 powerflow modeling scenarios would need to be completed to cover the base cases and sensitivities, which would be a 50% increase in the amount of work presently performed to meet the existing TPL-001 through 004 requirements for the near-term assessment. A review of the studies required for R2.4 indicates that at least 4 stability scenario models would need to be completed, which would be a 100% increase in the amount of work presently performed. Our present compliance performance and analyses activities take approximately 30 man-months to complete. We would expect the additional study analyses to add an additional 20 man-months of work and require 4-5 additional engineers at an annual cost of $400,000 to $500,000 (including benefits), given the regional requirement to complete the annual assessment by July 1.

Documentation preparation to include the short-circuit assessment, the amount of consequential load dropped for single contingencies, the expanded requirements of the Corrective Action Plan, and how the sensitivities affect the Corrective Action Plan would take a man-week or two at most (no significant cost increase or manpower increase).

Our present documentation activities to develop the assessment and the corrective action plan take approximately 2 man-months to complete. We would expect the documentation to cover

the additional study analyses to add an additional 2 man-months of work. The additional documentation for the Consequential Load Loss, short-circuit analysis, expanded requirements of the Corrective Action Plan, and documentation of how the sensitivities studied affect the corrective plan are estimated to double the existing reporting requirements, resulting in an increase of 3.5 man-months and require 2 additional engineers at an annual cost of $200,000 (including benefits), given the regional requirement to complete the assessment by July 1.
Our present interpretation is that the proposed revised standard would have a minimum impact on the reinforcement of the Ameren system. The modification to remove the requirement that bus-tie circuit breakers must have the same performance requirements as non-bus-tie breakers significantly reduces our issues of non-compliance, and particularly for circuit breakers 300 kV and above.
Our present interpretation is that the proposed revised standard would have a minimum impact on the reinforcement of the Ameren system.
C â€" Definitely do not support the revised standard
From an engineering perspective, the biggest concerns are the additional requirements, including prescribed sensitivity studies, associated with R2 for both steady-state and stability scenarios. We believe that we already cover the needs of our system with the existing NERC standards and Ameren Transmission Planning Criteria & Guidelines. The additional analyses proposed by the revised standard are not warrranted and any upgrades indentified by the additional analyses will not provide any significant increase in system reliability. For 2008 compliance, Ameren performed the following steady-state contingency analyses on each of four near-term models and one long-term model: 617 Category B single contingencies involving lines and transformers. 30 Category B single contingencies involving generators 50 MW and above. 1699 Category B single branch outages. 135 Category C-1 bus faults. 260 Category C-2 breaker failures. 112,575 Category C-3 double contingencies involving lines and transformers. 18,510 Category C3 contingencies involving 617 lines and transformers and 30 generating units. 73 Category C-5 double-circuit tower outages. For 2008 compliance, Ameren performed 496 stability scenarios of four near-term models and one long-term model: Assuming that we can acquire the qualified manpower, which is presently not available, we estimate that proposed new requirements will increase our compliance activity time by approximately 24 man-months or 2 man-years in a six-month window (January-June) to produce the same quality studies that we produce now. Consequently, we view these proposed additional study efforts as excessively burdensome. Further, we do not see how the additional study work and documentation required by the proposed standard will lead to any significant improvements in reliability. Additional comments: The question of expected Consequential Load Loss magnitude and duration, as specified in R3.3.2.1, is not germane to the reliability of the Bulk Electric System, and is a matter for Distribution Planners and local regulatory authority and is not needed in this reliability standard.
Individual
Gary S. Brinkworth, P.E.
City of Tallahassee, FL
Yes and No
while this was an improvement, the tables are still confusing and make determination of the compliance requirements difficult. Especially where there are multiple events within a single event category (like P3 or P6) there's confusion about what would be allowed between the two element outages.
we estimate a cost of $100,000 minimum since the City would likely have to outsource some of this analysis in addition to the work done by in-house system planning staff.
hard to give a good estimate since the full ramifications of the required studies is not clear in the current draft. I would estimate 2 years at least.
similar costs to what was estimated above for the supplemental study cost, since staffing level is such that much of this ongoing work will likely be outsourced.
documentation cost was included in the cost estimates for #12, since development of the documentation is part of the study work scope.

depending on the interpretation of the standard as currently drafted, this cost could be substantial (at least $20M) over a 5-year capital budget period (consistent with the City's current practice). It's doubtful this level of funding could be achieved/maintained given other financial pressures for local governments.

Unable to develop an answer to this question, since it depends on the ability to successfully site and permit generation and transmission facilities (which is becoming increasingly harder to complete), and the requirements of any successful siting effort may make the costs prohibitive (ie, underground transmission facilities and/or stringent controls on generating facilities).

C â€" Definitely do not support the revised standard

The requirement regarding non-interruption of firm transmission service in the steady state performance table for Category P1 events does not properly take into consideration the flexibility necessary for utilities with limited interconnections or interconnections with limited transfer capability. This flexibility, which currently exists in the TPL-001 standard (footnote b in the table), allows a utility to curtail firm transactions to prepare for the next contingency. As drafted, in the circumstance where the single element outage in Category P1 was a tie line, even if this line were critical to supporting the transaction (or were required to be in service by the terms of the power contract), interruption of firm service would be a violation of the proposed standard even though such interruption would be either required or appropriate to ensure the reliability of the bulk electric system. For utilities where tie line capacity is constrained or limited, this requirement for Category P1 will require substantial investment in duplicate facilities to ensure that firm transfers would not be interrupted, and the cost of that investment would likely not offer ratepayers a commensurate benefit (presuming such a duplicate facility could even be sited and permitted). For utilities with just a few large generating units (such as a small municipal utility), the requirements for Category P3 in Table 1 set a threshold for compliance that may not be achievable without substantial investment in additional/duplicate transmission facilities and possibly generating units. The concern relates to the restriction about limiting interruption of firm transmission service or non-consequential load following a G-1/N-1 event; the particular scenario is outlined in the bullets below: · Presume a utility with only two large units and some small gas turbines · Under P3, one of these large units is forced out of service · Reserves are called for and delivered along with replacement power using available import capability · Then presume that the N-1 outage in P3 is a major tie line that is critical to the support of the firm power imports · Under the proposed standard, the utility would be unable to curtail the firm purchase or shed any non-consequential load and remain compliant, even though there would be a significant generation/load imbalance & the appropriate response for the reliability of the grid in the region would be to interrupt the transaction and possibly shed load. The flexibility afforded in the existing TPL-001 standard would in fact allow the utility to respond to this event in a more appropriate way while avoiding a very expensive expansion/duplication of facilities (notwithstanding the considerable challenges that the utility would face for siting and permitting of the necessary facilities).

Group

Florida Power and Light

Hector J. Sanchez

Transmission Services and Planning

No

This draft did not modify the existing NERC definition of Stability. Footnote 5 of the Tables describes the expected acceptable performance of a System that is stable, but the terms â€œSystem Stabilityâ€ and â€œGenerating Unit Stabilityâ€ are not defined, except as studies. All stability studies must meet the Performance Requirements for Planning Events in Table 2 - Stability Performance. If there were different Performance Requirements then the distinction may be warranted. However system stability studies should be sufficient and not warrant additional work. R6 requires Transmission Planners to define proxies used to identify instability. Presumably the â€œproxiesâ€ would be used as a checklist for assessment of stability, however, not all stability limitations can be simplified as a proxy in the loadflow. Proxies should only be used as indicative of a potential stability issue, not "to identify System instabilityâ€¦", or replace stability studies, since a stability study to identify the issue was initially required to define the proxy. The requirement should be reworded to state "R6. If proxies are used in simulation studies to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding, then each Transmission Planner and Planning Coordinator shall define the proxies used in the simulation studies."

No

R2.4.4 is inappropriate for a compliance assessment. Essentially R2.4.4 requires the Transmission Planner or Planning Coordinator to deem appropriate and justify inclusion or exclusion of any sensitivity other than the required sensitivities listed in R2.4.3. The only way that a an entity could be found non-compliant is if the entity deems a sensitivity as appropriate, and then inexplicably did not perform the sensitivity, which makes no sense. The requirement seems to put a burden of justifying by "technical rationale" a sensitivity that is deemed appropriate already. R2.4.4 could be eliminated and its intent absorbed in R2.4.3 by changing its

wording slightly: "R2.4.3 For each of the studies in Requirement R2.4.1 and Requirement R2.4.2, sensitivity case(s) deemed appropriate by the Transmission Planner or Planning Coordinator that stress the System to reflect conditions including, but not limited to, one or more of the following conditions, shall be run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied."

Yes

None.

No

The sub-requirements of R3.5 are not clear as to whether the conditions apply to before or after generator run-back/tripping and mixes together N-1 and N-2 contingencies. In addition, the phrase "sustainable, stable, operating condition" in R3.5.3. is ambiguous as to whether it means the system is secure (prepared for the next contingency), or the system is maintained in a stable operating condition which is sustainable but not secure.

No

The requirement that â€œall projected firm transfers modeledâ€ (appropriate for the load level being studied) currently in the TPL Standards does not appear in the proposed standard. Does the SDT feel that Transmission Planners should have unlimited latitude in deciding which types of power transfers to assume in their reliability studies? R9. is not an appropriate requirement as the distribution provider will in many cases not know the exact mix of load types at each â€œtransmission nodeâ€ The meaning of â€œtransmission nodeâ€ is unclear, is this a substation? R11. is unclear as to what is meant by â€œconsideration given to spare equipment strategyâ€. What is the approriate consideration for compliance? What facilities are required to have a spare equipment strategy for compliance? Maintenance outages and times for all BES equipment are not likely to be scheduled or known throughout the entire planning horizon. Rather than specifying "for each year of the planning horizon" it should be limited to "if specifically known". The Resource Planners identified in R13. should know about future generation additions and retirements as well as expected range DSM capabilities but would not generally know about reactive power devices or new technologies. Reactive power devices or new technologies should be removed from R13.

No

R4. Why is short circuit analysis required for single contingencies? Removing equipment through contingency outages lowers available short circuit duty. Short circuit analysis is not a parallel version of load flow analysis. Evidence that short circuit studies have been performed is currently required in the existing FAC-002-0 Standard. Since the primary concern is the appropriate sizing of equipment and the prevention of equipment damage as opposed to overall grid reliability, we do not see the need for a set of requirements within the proposed TPL standard for short circuit studies.

No

The Table format is extremely confusing and too long. The allowed and disallowed actions as well as the applicable time frames for them is not clearly stated. The tables 1 &2 should be combined and condensed so that they can be read more easily. In their current format, these tables sprawl across 13 pages. The use of footnotes or expanded information in the Table headings is needed to understand the performance requirements.

No

Bus tie breakers are defined exclusively to straight bus configurations. They can be used for other breaker configurations. We do not see the need for a distinction between bus tie and non bus tie breakers.

No

These provisions made to not discourage the use of bus tie breakers will also not discourage the use of the single breaker/single bus substation arrangement which can have very severe consequence when used on critical BES substations. The TPL-001-1 draft also sets a threshold of higher performance to facilities above 300 kV than previously established in the existing standard. We do not agree that such a threshold is necessary or warranted. Requirements which are more stringent for these facilities may wrongly influence decisions on project alternatives in favor of facilities with less stringent requirements. Related to the more stringent requirements for facilities above 300 kV, FPL also disagrees with the performance requirements contemplated by the proposed draft standarad for DC lines. The SDT stated performance requirements for DC lines as currently drafted, is discriminatory as compared to AC line performance, and needs to be addressed. This could be viewed as an exemption for DC lines and violates FERC's comparability principle as it relates to reliability performance. The TPL-001-1 draft sets a lower performance requirement for the loss of a single pole of a DC line than in the existing standard by allowing interruption of firm transfer if the transfer is deemed to be dependent on the outaged line. Firm transfers are also dependent upon AC lines. The proposed standard does not distinguish between asynchronous DC ties and the more common parallel connected DC tie. With an asynchronous DC tie, the transfer is lost with the tie, which is anlogous to Consequential Load Loss which is already allowed. With a parallel DC tie, the transfer will be shifted to the parallel AC system and

should have the same performance requirements. We do not agree that such an exception for DC lines is necessary or warranted. The decision in selecting DC vs. AC in transmission lines has traditionally been based on the break-even cost and performance of the two alternatives. The lower performance requirement may wrongly influence decisions on project alternatives in favor of DC facilities because of the less stringent reliability performance requirements.

No

The words â€œdocumentation of the technical rationale for why each of the conditions was or was not selected shall be suppliedâ€ should be removed from R2.4.3. The sensitivity selection is necessarily subjective and judgmental. It is not clear what constitutes a valid rationale document. Compliance assessment of such a document would be subjective and is not needed.

No

The P6 Planning Event is not clearly defined. It appears that the Initial System Condition is the Planning Event of P1, with the â€œSystem Adjustmentsâ€ allowed under P1 to keep facilities within the applicable ratings. R3.5.3. requires that â€œa sustainable, stable, operating condition is maintained.â€ This does not state â€œprepared for the next contingencyâ€. Given FERCâ€™s interpretation of TPL-002-0 Category B (see paragraphs below for excerpts from Order 693) that the system is not required to be able to withstand another N-1 contingency, the proposed new standard appears to require that this state be â€œsustainedâ€ indefinetly after a P1 event, or until the P6 Event, which is loss of the second element, with no mention of the time duration between the initial system condition and the event. The performance criteria for a P1 event can be met as long as it does not contemplate another event that would change the event to a P6 event. However, a P6 event is a TPL-003-0 Category C event which must contemplate a second contingency after the first. The existing TPL standards accomplished this with footnote b) in the Tables for all of the TPL standards, allowing system adjustments including curtailment of contracted firm transfers to prepare for the next contingency. Since FERC clearly states that this is not a requirement under TPL-002-0, but that it is addressed in TPL-003-0, they directed the ERO to modify the footnote for TPL-002-0. In TPL-003-0 the Category C3 event refers to a "Category B contingency, manual system adjustments, followed by another Category B contingency", however since the footnote for Category B contained the "To prepare for the next contingencyâ€¦" language, and it is contained in the Table for TPL-003-0, that language must apply to the C3 event. Further, in Order 693, on TPL-003-0, FERC (1) did not direct the ERO to modify the same footnote which is contained in TPL-003-0, (2) recognizes that these are low probability events, and (3) stated that it "does not intend to recommend action on this issue [the appropriateness and value of including the ability of the system to withstand two simultaneous Category B contingencies for major load pockets] at this time and, instead, directs the ERO to consider the comments in possible future revisions to the Reliability Standard.â€ The SDT has inappropriately applied the direction of FERC on TPL-002-0 to the P6 event (which is similar to TPL-003-0 C3) without regard to its implications on the industry, the ratepayers, or even its own standards, as the impact of the team's interpretation would require changes in the methods of determining TTC's, ATC's, and SOL's. The additional costs (both monetary and intangible) incurred by ratepayers for no gain in the ability to transfer firm electric power, far outweigh any gain in reliability benefits for these low probability events. Just to provide one example to illustrate this point, if the SDT's current interpretation for a P6 event is not modified, FPL would have to spend in excess of $ 1 Billion dollars, in order to meet this performance criteria for 500 kV facilities, for an event with a probability of less than 0.07 per hundred mile-years (based on FPL's 500 kV facilities), which would be passed on to its ratepayers. There are many other examples on the FPL system, as well as other systems. This interpretation is fatally flawed and makes no sense from a reliability or cost perspective, not to mention the intangible impacts of siting, right-of-way acquisition, EMF, NIMBY, etc. Further, assuming the SDT interpretation, how could one justify the need before state commisions, and exercise eminent domain in the courts to take someone's land for right-of-way, a process that could take as long as 8-10 years, for minimal increase in reliability, and no increase in transfer capability. In order to assist the SDT, these paragraphs are included with references to FERC Order 693, to show that it has misinterpretedOrder 693. The following captions stated below should help clarify this point. Order 693 states: P.1788 â€œUnder TPL-002-0 the system is not required to be able to withstand another N-1 contingency. That N-1 requirement is a Category C contingency which is addressed by TPL-003-0.â€ Therefore, the end state of P1 is not a â€œsecureâ€ state, but a â€œnormal operating stateâ€, as stated in P. 1796 â€œThe Commission, therefore, directs the ERO to modify the second sentence of footnote (b) to clarify that manual system adjustments other than shedding of firm load or curtailment of firm transfers are permitted to return the system to a normal operating state after the first contingency, provided these adjustment can be accomplished within the time period allowed by the short term or emergency ratings.â€ These two determinations by FERC together show that their interpretation of normal operating state is not the secure, ready for the next contingency state, rather, it is the state in which the performance criteria have been met for that planning event. With regard to the FERC direction of Order 693 on TPL-003 and â€œthe appropriateness and value of including the ability of the system to withstand two simultaneous Category B contingencies for major load pocketsâ€, FERC states in P. 1824, â€œMany commenters indicated that this was a very low probability event and

the costs for addressing such an event would be significant. As a result, EEI states that a dialogue must first be initiated within the industry and with state public utility commissions to identify such load pockets, to target the required potentially significant transmission investments and to develop plans for allocating the costs of such investments. In light of these comments, the Commission does not intend to recommend action on this issue at this time and, instead, directs the ERO to consider the comments in possible future revisions to the Reliability Standard.â€ FPL agrees with the increased performance requirement for the P3 multiple contingency event that assumes the loss of a generator as the first contingency. Firm transfers should not depend upon specific generators being on line, however firm transfers must depend upon transmission lines being in-service.
These costs cannot be determined without having experience with the new standard and its analysis requirements. Analysis of existing studies will undoubtedly uncover substantial additional study that would need to be performed, but the costs of such analysis and studies could not be reasonably estimated beyond stating that the costs would be significant resulting from 1000's of man-hours spent on supplemental work that would only determine if we were in compliance, not including any work necessary to determine what would be necessary to bring deficiencies in to compliance.
It would not be unreasonable to find that it takes one full planning horizon (10 years) to complete supplemental studies and analysis for the draft standard, because it is so prescriptive. Requirements such as R2.2.1 that requires that the planning assessment be extended for longer lead time projects (such as the multiple new nuclear projects being considered across the U.S.) and R2.4.1 that specifies "...including the behavior of induction motor loads" will likely invalidate past studies that took considerable time to perform and would have to be reproduced with the newly required considerations. Requirements such as R2.6 (and subrequirenments) invalidate many existing studies, because of subjective terms such as "material changes" and "would impact the study area" without definitions of "material" or "impact". Re-analyzing all existing studies and re-writing the results and conclusions using the new terminology (P0, P1, P5 etc. instead of Category A, B or C2, C3, C5 etc.) used in the new performance tables will also add substanstially to the effort needed to insure compliance and make the information auditable.
$ 5 million dollars annually is perhaps very conservative.
These costs cannot be determined without having experience with the new standard and its documentation requirements. Analysis of existing studies will undoubtedly uncover substantial additional documentation that would need to be produced, but the costs of such document production could not be reasonably estimated beyond stating that the costs would be significant resulting from 1000's of man-hours spent on supplemental work that would only serve to meet audit requirements.
This would be included in the $5 million dollar estimate provided above.
These costs cannot be determined without having experience with the new standard and its performance requirements. The costs of such investment could be in the 10's of billions of dollars for FPL because of the increased level of performance contemplated by the draft standard.
If we knew what was needed today, it could conceivably take up to 10 years to complete, if the projects are all feasible. Without knowing what is necessary, a fair estimate would be 20 years. This does not take into consideration that the entire industry would be competing for the same limited resources of material and manpower to complete this reinforcement. Justification would be problematic and eminent domain may not be enforceable due to the remote low probability of an N-1-1 event, and lack of a true reliability need.
C â€" Definitely do not support the revised standard
The standard, as currently drafted, is unacceptable. Without the ability to curtail firm transfers to prepare for a next contingency, a â€œsuper-firmâ€ priority of transmission service is created for non-native load customers. This goes contrary to the intent of the Open Access Transmission Tariff (OATT) that curtailments be comparable and non-discriminatory. ï€ From the OATT: â €œCurtailment of Firm Transmission Service: In the event that a Curtailment on the Transmission Provider's Transmission System, or a portion thereof, is required to maintain reliable operation of such system, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the Transmission Provider will curtail service to Network Customers and Transmission Customers taking Firm Point-To-Point Transmission Service on a basis comparable to the curtailment of service to the Transmission Providerâ€™s Native Load Customers. All Curtailments will be made on a non-discriminatory basis, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. When the Transmission Provider determines that an electrical emergency exists on its Transmission System and implements emergency procedures to Curtail Firm Transmission Service, the Transmission Customer shall make the required reductions upon request of the Transmission Provider. However, the Transmission Provider reserves the right to Curtail, in whole or in part, any Firm Transmission Service provided under the Tariff when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Transmission System. The Transmission Provider will notify all

affected Transmission Customers in a timely manner of any scheduled Curtailments.â€ The SDT has drafted language contrary to FERC specific requirements on comparability. The FERC has consistently directed Transmission Providers to treat all firm transaction on a comparable basis, yet the SDT, in its latest draft is creating a "super-firm" category for only firm transmission service. By creating a higher priority ("super-firm", non-comparable service) for non-native load customers than for native load, native load customers bear a higher cost burden. This and the costs to the ratepayers for negligible increase in already high reliability due to the performance requirements of the standard makes this draft completely unacceptable for FPL to support. FPL will vote against acceptance of this draft standard unless significant changes are made to comport what FPL believes was the intent of FERC Order 693 with regard to the TPL standards.

Group

Exelon Transmission Planning

Eric Mortenson

Exelon - ComEd / PECO

Yes and No

The definitions of System Stability and Generating Unit Stability are clear. We agree that there is value in performing small signal analysis but we are concerned about the availability of software and exptertise required to execute the analysis. R5.3 is ambiguous, as it is not clear what the requirement to consider the voltage ride through capability of all generators entail. Ride through could involve the unit or station having the capability to ride through without tripping or the unit could trip but the system remain stable. General Observations R3.2.1 should be reworded so as not to be misinterpreted that GOs are prescribing their 'required' voltage levels. R2.6.2 should be Unit not Plant with regard to stability studies. R2.7.1 and elsewhere - The NERC Glossary specifies that SPSs are 'Special Protection Systems' (not 'schemes'). R5.2 Wording should be changed from '..disconnect for each contingency..' to '..isolate the disturbance..' R5.5.1 There are too many studies required. The 20 MW threshold for unit studies may be too low. There should be a mechanism to provide a proxy for smaller units on 138 or possible 230 kV systems that can't affect system stability rather than to automatically require a study every 5 years. R2.1 and 2.2 should have the words 'at a minimum' removed with regards to describing which studies are required annually. The requirement to supply a 'project initiation date' for near-term Corrective Action Plans should be removed. If it remains, it should be clarified (Project identification date, construction start date, PUC certification date, executive approval date, etc?)

No

R2.4 should be specific as to applicability to generator stability, system stability or both. R2.4.1 requires the use of load models for motors. Detailed load data may not be available and studies would therefore produce questionable results. It is our understanding that the industry has recognized the importance of using better load models and there are multiple ongoing initiatives to improve our ability to do this modeling but these initiatives are not complete. However, the industry's ability to provide accurate models is not sufficient to ensure compliance at this time. The sensitivities for near-term studies in R2.4.3 aren't clearly defined, especially R2.4.3.3, 'Unavailability of Long Lead Time Facilities'. Doesn't the study that determined the original need for these facilities document the consequence of unavailability? The peer review component of the Planning Assessment has CEII concerns, especially with regard to extreme contingencies and whether or not they involve cascading.

No

UVLS should be allowed for in the definition of non-consequential load shedding in certain lower probability contingencies above 300 kV. The complete disallowance seems to disincent their use, contrary to the NERC Blackout Recommendation 13c. There is a value in their use for certain voltage stability situations. There does not appear to be any limit (except no cascading) to the amount of acceptable load loss once non-consequential load loss is allowed.

Yes and No

We agree that manual and automatic generation run-back and tripping should be allowed in these situations. We do not agree with the portion of R3.5.2 that states that non-compliance would result if the action were to violate statutory or regulatory requirements. A local governmental body could impose a restriction that would then trigger NERC compliance issues without independent or sufficient review. Other regulatory entities have their own enforcement mechanisms. It should be clear that SPSs, by definition, are allowed for other purposes than generation runback or tripping (such as system reconfiguration with automated breaker operation).

Yes and No

R11 shouldn't include consideration of a spare equipment strategy. All known planned and long-term outages of transmission equipment should be included regardless of the spare equipment strategy.

No

R2.3 is not clear as to which years studies are required. Is the Planning Assessment time frames in R2 also applicable to R4? The phrase 'years one or two of the near-term planning horizon'

should be included.

No

Tables 1 and 2 should be changed such that the header should read 'BES Elements Overloaded' rather than 'BES Elements out of Service' regarding the voltage distinction. The header notes should either not be numbered or numbered with a different scheme to differentiate them from the numbered footnotes to avoid confusion. It is not obvious that all of the footnotes are used in the Tables. The headings should be repeated on each page. Could these tables be made smaller by eliminating some of the unused space such as the large boxes containing a single 'x'?

Yes

Yes

No

We support efforts to improve load and dynamic load modeling, however we have concerns in being able to do so in an accurate manner - See comments to question #2. The state of industry development is such that this is not ready for includion in a standard such as R2.4.1 and R2.4.3.1.

No

We do not agree that the requirement should be so much more severe for an internal breaker fault as opposed to two single line outages for elements over 300 kV.

Analysis has not been completed at this time to determine the extent of the additional burdeen, but significant expenditures, in terms of personnel, tools and transmission upgrades, are anticipated if this draft were implemented.

C â€" Definitely do not support the revised standard

We appreciate the effort involved in improving this planning standard, and believe in this goal. We are not yet able to support this revised at this time due to the concerns expressed above.

Group

CenterPoint Energy and CPS Energy

Paul Rocha

CenterPoint Energy

No

Most industry commenters from the previous draft advised against making a distinction between system and generating unit stability, which are not commonly accepted industry terms. We (CenterPoint Energy and CPS Energy) remain unconvinced that the distinction is needed. If most industry commenters concur after this second draft, we believe the SDT should listen.

No

We believe the requirements are overly broad and overly prescriptive. We further believe the extent of the "problem" these requirements would address does not justify such overly broad and overly prescriptive requirements. To clarify, we wholeheartedly agree that transmission planners should consider and selectively study potential stability concerns. However, we believe that transmission planners are already considering and selectively studying potential stability concerns. We are not aware of any signficant bulk electric reliability problem actually occurring in recent memory due to the failure of transmission planners to perform the assessments and studies this standard proposes to require. Some might argue that instability occurred in the northeast blackout, and we would agree. However, requiring transmission planners to perform all the assessments and all the studies proposed herein would not have prevented instability from occurring in that event. A targeted approach focusing on the specific vulnerabilities of that area of the network would be far more effective than the scattergun approach proposed here. Furthermore, even if all the stability analyses proposed in this standard were performed and audited, the studies likely would not have revealed the actual underlying reliability concern. In the end, the root cause of the failure was thermal overloading, not stability. Instability eventually occurred when the root cause (thermal overloading) led to a situation where circuits sequentially tripped over the course of an hour or so. Events that occur over the course of an hour are generally outside the scope of stability analyses, so these proposed requirements are off the mark for that event. We recommend deletion of R2.4.3, R2.4.4, R2.5, R5.2, R5.3, R5.4 (or 5.5), and R5.5 (or R5.6). Removing this excess baggage would allow transmission planners to use their judgment to selectively analyze stability concerns germane to their system. We realize such an

approach requires a recognition that transmission planners are already doing the appropriate analyses, and we encourage the SDT to be receptive to this premise. To further clarify this last point, some would argue that assuming entities are already doing the right thing belies the underlying premise behind enforceable reliability standards. We believe that acceptance of the need for enforceable reliability standards does not pre-suppose that some or all entities are always doing the wrong thing all the time in all aspects of their business. Nor does acceptance of mandatory reliability standards require acceptance that all aspects of the business are equally likely to produce reliability concerns. We believe most or all entities are already doing some things well such that, in some aspects of the business, there is no evidence that a "problem" actually exists. If the SDT accepts this premise, it would focus its attention on actual problem areas, not imaginary ones. We submit that performing appropriate stability studies is not a "problem" that requires an the overly prescriptive requirements proposed here. Rather than solving an actual problem, these requirements are more likely to detract resources from actual concerns by causing planning resources to be expended documenting and defending to auditors that imaginary concerns do not exist.

Yes

No

We believe the SDT should have reflected the views of most commenters in this revised draft. Requirements R9 through R14 are overly prescriptive and do not solve an actual problem. Furthermore, we are concerned about requirement "creep" where standards include new requirements appropriately addressed in other standards (in this case, the MOD standards) because a different SDT believes the approved standard is inadequate. To clarify our main premise that the excess, misplaced requirements do not solve an actual problem, we believe one would need an extensive imagination to conjure a scenario where insufficient modeling by transmission planners in the subject matter addressed by requirements R9 through R14 have contributed or are reasonably likely to contribute in any meaningful way to a significant reliability event. In summary, we concur with the majority of commenters from the previous draft that R9 through R14 should be deleted. We also believe R1.1 is hopelessly unrealistic. In fact, we are concerned it is counter-productive and more likely to degrade reliability than improve it. R1.1 discourages transmission planners from revising inaccurate, speculative, or outdated modeling data by imposing new documentation burdens and compliance liability. We recommend that R1.1 be deleted.

No

We believe R4 is unnecessary and, judging from industry comments to the previous draft, likely to cause confusion among auditors and planners alike. Furthermore, we believe R4 does not address an actual problem. We are not aware of situations where equipment has been under-rated from the standpoint of short circuit ratings. We recommend that R4 be deleted.

No

We originally believed that eliminating the old Category A, B, C, and D nomenclature would be beneficial. However, looking at the contingency types now being proposed, we are concerned that more confusion has been created. For example, matching applicable facility ratings to Category A, B, and C conditions is reasonably manageable. Matching applicable facility ratings to 7 contingency "buckets" is more confusing, less mangeable, and unnecessary. NYISO proposed the concept of analyzing credible multiple contingencies in the operating realm. Most industry opined that NYISO's proposal lacked merit for operating requirements, and we agreed. However, we believe the proposal may have merit for planning requirements. The concept of applying reasonable credibility criteria to multiple contingencies to be studied offers a way to limit multiple contingency analysis to credible scenarios. Less credible (or incredible) scenarios would then fall into the Extreme category. As proposed, the multiple (seven-fold) approach of categorizing contingencies, combined with various sensitivities or alternative scenarios, for multiple years, is unrealistic and unnecessary. We believe creating a separate table for stability performance might be beneficial, but we believe 7 buckets of contingencies is hopelessly unrealistic for stability analyses.

No

We believe R2.1.3 and R2.1.4 are overly prescriptive and should be deleted. It requires engineering judgement and experience to know whether a planning analysis is materially impacted by certain assumptions and, if so, which sensitivity analyses should be performed. Literally interpreted by an auditor, R2.1.3 would require at least one sensitivty analysis for each one of the contingencies shown in Tables 1 and 2 for each stuudy specified in R2.1.1 and R2.1.2 and documentation for each contingency of each study why each senstivity specified in R2.1.3 was or was not selected. The likely result is not value-added engineering analysis of actual reliability concerns. Instead, the likely outcome is unnecessary and burdensome additional

analysis and documentation that is impractical, creating confusion and uncertainty as to what the practical interpretation of impractical requirements might ultimately be.

No

We believe P6 should be deleted. As noted earlier, we believe credible multiple contingencies should be studied as planning events, with incredible multiple contingencies possibly considered as extreme events. If P6 is retained, we believe loss of shunt devices should not be studied and believes the ability to systematically study the contingency loss of every indiviudal switched shunt device is not supported by commercially available PTI software because up to this point it has not generally been recognized as a necessary or desirable analysis to perform. Also, if P6 is retained, we believe loss of Non-Consequential Load should be permitted at any voltage level for this type of extreme event.

We have no analysis to support an answer to this question, and we believe any such analysis would be speculative. We believe the reality of the situation is that the requirements are not practically achievable at any cost, so the ultimate cost would depend on practical interpretations of impractical requirements. Even if the cost could be reasonably estimated, we oppose detracting valuable expertise away from necessary, value-added analyses to unnecessary, over-reaching theoretical analyses and documentation for audit purposes.

3-4 years, assuming reasonably practical interpretation of the impractical requirements.

As with our response to question 12, we believe the answer depends upon the ultimate practical interpretation of the impractical requirements.

We believe the proposed requirements may not impose additional capital investment for system re-inforcements for our companies. We believe we are already achieving the reliability goals embodied in the proposed requirements but in a much more efficient and cost-effective way than the overly prescriptive approach proposed in these requirements.

C â€" Definitely do not support the revised standard

Without re-iterating previous comments, we will summarize that we find this proposed standard to be an overly prescriptive and unrealistic paper chase that does not add value to the planning process. We also are concerned that this standard demonstrates an unhealthy, one sided approach to planning that does not balance reliability goals against other public policy goals, such as cost and landowner impact.

Individual

Brian K. Keel

SRP

No

We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study â €œfocuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to â€œdevelop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingenciesâ€. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say â€œonly whenâ€ the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, â€œmaterial Transmission System changeâ€ and â€œat or near the point of Interconnectionâ€ to invoke a study.

Yes and No

R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirement in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. ï€ We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. ï€ The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Ownerâ€™s open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Ownerâ€™s responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.

No

We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as â€œlocal Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systemsâ€ in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, â€œâ€¦load no longer being connected to a sourceâ€¦â€. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (â€œAlthough Load which is lost as a result of the Loadâ€™s response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirementsâ€) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.

Yes

We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements

are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.

Yes

While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.

Yes and No

We agree with R2.3. However, R4 requires assessment of â€œShort-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting dutiesâ€. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute â€œnormalâ€ condition or â€œfollowing any single Contingency conditionâ€. Also, by specifying the normal and single contingency conditions, R4 is straying into â€œhowâ€ to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.

Yes and No

We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.

No

We do not disagree with the proposed definition change. However, we do not agree that â€œSubstation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.

Yes and No

We interpret â€œexit breakersâ€ to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes

Yes and No

We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the â€œbase caseâ€ of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the â€œbase caseâ€ condition. R2.7 also states that â€œCorrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivitiesâ€. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the â€œbase caseâ€, will the judgment of the Transmission Planner be then

questioned because theâ€œbase caseâ€ used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?

Yes

We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.

The additional study work associated with this Standard could cost up to SRP $100k.

1 to 2 years to complete these additional studies.

Estimate addition on-going costs of $50k.

Estimate $30k to prepare documentaion.

Estimate $15k each additional year documentation.

Unknown costs, there are numerous raise the bar Standards, hard to determine the additional cost to SRP until the complete studies are performed and evaluated.

Unknown unitl the reinforcements are determined.

B â€" Unsure about supporting the revised standard

SRP is concerned about what actions will be allowed to meet the higher performace requirements in the transition period and how long will these transition periods last for the different Requirements?

Individual

Tom Mielnik

MidAmerican Energy Company

Yes and No

MidAmerican Energy Company (MEC) believes the definitions are improved. However, MEC suggests that the SDT clarify what stability analyses are required such as angular and voltage stability for which time frames such as the transient and steady state time frames and for what planning horizons such as the Near-Term and Long-Term planning horizons.

No

a.MEC disagrees with the proposed R2.4.1 text. This inclusion of this requirement may be premature at this time for several reasons. There is presently no industry consensus on how the dynamic behavior of loads should be properly represented and analyzed. In addition, it would be a large and difficult effort to identify, collect, and maintain the pertinent information. It is presently difficult to obtain and maintain the percentage of residential, commercial, and industrial load at each transmission interconnection point, much less try to get the proper percentage of the various types of induction motor loads. If this requirement is retained then R2.4.1 should be modified to specify a minimum threshold size where dynamic induction motor load or dynamic load behavior becomes significant such as near mining areas. The SDT should consider a 25 MW size threshold for induction motors and a 100 MW size threshold for industrial complexes where the dynamic loads are inadequately represented by normal powerflow dynamic assumptions. b. R2.4 as stated refers to Near-Term Transmission Planning Horizon Stability analysis but there is no requirement in the standard refering to Long-Term Transmission Planning Horizon Stability analysis. The SDT should reword R2.4 so that it is clear that no Long-Term Stability analysis is required by stating that "Stability analysis for the Near-Term Transmission Planning Horizon shall be assessed annuallyâ€¦". ï€ In R2.4.4, we believe this requirement should not be added. Why was it included? It seems superfluous, because any entity can study other sensitivities if they want. Why should TP or PC have to study what the other entity wants to study? Who would be the judge in case of disagreement over the technical rationale? ï€ In R2.5.2, Why was the addition of a new substation included? We would not expect a new substation to negatively impact the system or generating unit stability. We note the R5.5 and R5.6 should really have been updated to refer to 5.4 and R5.5.

No

MEC notes that Non-Consequential Load Loss is defined by the SDT to include load dropped by Special Protection Systems while Consequential Load Loss does not exclude load dropped by Special Protection Systems. The SDT should resolve this contradiction between these two definitions by adding an appropriate reference to Special Protection Systems in the Consequential Load Loss.

Yes

No

MEC disagrees with the approach of temporary requirements because of the problems that arise due to conflicting or uncoordinated standards (e.g. conflicting requirements between FAC-010-1 and TPL-002-0). We suggest the the drafting team submitt SARs to make the desired changes in the appropriate MOD standards. However, if these requirements are retained than we suggest the following few changes to R9-R14: The R9 wording on providing "the expected mix of industrial, commercial, and residential loads" should be dropped as the representative mix is difficult to quantify and verify while the benefit to representing the mix is unproven versus normal regional dynamic load representation practices. Many regions already convert normal steady state powerflow loads to standard mixes of, constant MVA, constant currrent, and shunt admittances which accounts for dynamic behavior. If the SDT decides not to drop these words, the MRO recommends "the expected mix of industrial, commercial, and residential loads" be changed to "the forecasted mix of industrial, commercial, and residential loads". In R9 through R13 the reponsible entities should be giving their information to the Transmission Planner in addtion to the Planning Coordinator. In R10, revise the text to: "Each Transmission Service Provider shall provide â€¦" In R11, is the text referring to "known planned outages" and "known long term outages"? What is the distinction that is meant to be made between the two specified types of outages? In R12, revise the text to: "â€¦ modeling information for planned facilities changes, known planned outages â€¦". Also, is the text referring to "known planned outages" and "known long term outages"? What is the distinction that is meant to be made between the two specified types of outages? In R13, revise the text to: "â€¦ for planned facilities changes for each year of the Transmission planning horizon including but not limited to generators, and new technologies â€¦". This wording broadens the meaning from simply "new" facilities to also include any "changes" to existing facilities. In R14, revise the text to: "â€¦ for planned facilities changes for each year â€¦". This wording broadens the meaning from simply "new" facilities to also include any "changes" to existing facilities.

No

a. Since the TPL contingency requirements already require bus fault, stuck breaker, and breaker failure contingencies, MEC asks the SDT to clarify the purpose of the short circuit study requirements. The benefit to additional short-circuit studies is minimal since analyses already ensure that the system can withstand bus faults and breaker failures. b. The SDT should clarify what single contingencies are to be studied for short circuit studies in R2.4. Is it single contingency as defined in Table 1? Or is it a broader or narrower definition? MEC recommends that since this is a new requirement, that TPL-001-1 be limited to raise the bar only to involve the single contingencies identified in P1. Failure to do so will require a great deal of additional modeling work in short-circuit studies if single contingencies in P2 are to be included in these studies with minimal benefit.

No

MEC suggests that the Categories symbols in Table 1 and Table 2 be different to help distinguish between them (e.g. P1:S1, P2:S2, P3.2:S3.2, etc.) MEC suggests that the header text (i.e. Category, Initial System Condition, etc.) be repeated on every applicable page to be more reader-friendly. The superscripts do not refer clearly to the respective notes. (There are numbered notes in the beginning of the table, numbered items in the extreme events evaluation requirements section, numbered items in extreme event description section, and numbered notes at the end of the table). Perhaps the referenced notes should have unique numerology or format to make the superscript references clearer.

No

MEC suggests applying the proposed definition to a new term, "Straight Bus-Tie Breaker". The creation of a narrow, special application definition of "bus tie breaker" is generally confusing and misleading. The term "bus tie breakers" is widely used in the industry in the context of various bus configurations. In addition, this narrow definition may create confusion if other Standards refer to bus-tie breaker in a different context.

No

MEC recognizes that the addition of this requirement is an attempt to raise the bar above the existing standards. However, the more stringent non-bus-tie performance criteria should only be adopted if there is sufficient evidence to demonstrate the expected reliability risk (i.e. system impact x probability of occurance) is high enough to warrant the cost of the system modifications that would be needed to meet the criteria. System modifications that involve the installation of line and substation facilities >300 kV will likely take years and cost tens to hundreds of millions to build. There should be a reliability risk analysis that justifies the application of this performance criteria before it is adopted.

No

a. MEC is not sure why R2.4.3.1 for sensitivities for Stability studies is a less definitive definition for load model variations then the steady state studies in R2.1.3.1. MEC recommends that

R2.1.3.1 be changed to "Variations in Load model assumptions." b. MEC believes R2.1.4 and R2.4.4 should be deleted because its unnessesary to make a requirement of senitivities that an entity chooses to do above and beyond the requirements in R2.1.3 and R2.4.3. If the SDT chooses not to delete these requirements, then MEC believes that R2.1.4 should be a subrequirement of R2.1.3 and R2.4.4 should be made a subrequirement of R2.4.3. The responsible entity should be allowed to select the appropriate sensitivity that should be performed. This is especially necessary given the need to perform each of these sensitivity analyses for six situations each year: peak and off-peak for two short-term years and one long-term year. Even with the requirement for one senstivity for each case that amounts to six additional sets of analysis for steady-state and six for stability.

No

MEC suggests that there be more explanation of what system adjustments are permitted. There should be some specific limit like 100MW below which load loss is allowed. Otherwise, very high cost solutions will be required for very low probability events.

MEC estimates that the total cost for one-time software licenses would be about $100,000.

MEC estimates that the lead time to perform supplemental studies and analyses to meet the new requirements would be 2 years.

MEC estimates that the on-going additional cost of expanded studies and analyses to meet the new requirements would be about $150,000 to $200,000 for additional staff and continuing software fees.

Included in amounts for 12.

Included in amounts in 12.

The additional one-time costs of system reinforcements to meet the new requirements would depend on the results of the new studies and be hard to forecast. However, if they involved just a few 345 kV substation modifications and 345 kV line additions, then MEC estimates that it would cost in the range of hundreds of millions of dollars per responsible entity.

The lead time to build new system projects would depend on the results of new studies and be hard to forecast. However, if they involved a 345 kV substation modification or a 345 kV line addition, MEC estimates that it would take 5 to 7 years to complete the new projects.

C â€" Definitely do not support the revised standard

MEC commends the SDT for significantly improving the standard, MEC believes that the standard still must be improved significantly. Probably the most important improvement would be to completely reformat the standard to provide for more organization and clearer VSLs. MEC recognizes that this may result in some initial confusion during the standard writing process, but if such organization results in less confusion over the next decade of applying the standard, the reorganization is well worth it. If the SDT does nothing else, it should reorganize the standard. Here are some suggestions for improvement: a. R1.1 is not clear. What does this mean? Surely the SDT does not expect that any time the data is modified a rationale is required. Shouldn't this data be updated as necessary? Wouldn't a requirement for providing a rationale each time such changes are made potentially discourage improvements to the models? This requirement should be clarified and limited to a few specific cases that were there are real reliability concerns. b. R2.5.2 - the SDT should revise the material transmission system changes. Addition of a new substation in one of the transmission lines connected to the plant should be revised to specifically refer to a switching station or to a non-distribution substation. A substation directly serving load is not a good example of a material transmission system change in the context of Generation Unit Stability studies. c. R2.6.2 - The SDT should revise the material transmission system changes because as presently defined, studies will need to be conducted every year for every year in the assessment period. This is because apparently the SDT has defined any system change as a material change. Since it is rare for there to be a system that does not exhibit some system change from year to year, this will mean ten-year and more studies every year. MEC recommends that the SDT revise this requirement to make clear that only significant system changes are material changes. d. R2.7.1 - The SDT has written this requirement to include a requirement that the responsible entity must indicate how long Operating Procedures apply. This implies that Operating Procedures should be interim measures. MEC believes that reliability can be maintained with permanent Operating Procedures and recommends that the need to indicate "how long the Operating Procedures will be needed" be deleted from this requirement. e. R3.3.2.1 - The SDT should delete the need to provide the expected duration of the Consequential Load Loss in this requirement because this requirements a probabilistic calculation and probabilistic planning is not the state-of-the art of the industry. This is reflected in the standard which has been written to continue deterministic planning criteria. As a result, it is a contradiction to require this probabilistic quantity in the middle of this deterministic planning standard. f. R3.3.2.2 - clarify that the single contingency events are the events in the tab le. g. R3.4 and R5.4.4 - MEC urges that the SDT delete or revise the words "why the remaining Contingencies would produce less severe System results." Given the expansive nature of the Extreme events it is virtually impossible to comply with this requirement. It is more likely that the responsible entity could show that the more likely and more severe Extreme events were studied. It would be better yet if the SDT would merely require that the responsible entity

provide the rationale for the selection of Extreme Events that were studied. h. R5.5.1 provides an exclusion for changes in individual generating units that require study. Yet R2.6.2 has a broader defintion of when Generating Plant Stability is required. These definitions need to be consistent. The definition in R5.5.1 seems to narrow to be a good definition for "material changes." MEC believes that the R5.5.1 should be expanded. i. Year One definition - MEC suggests that the Standards Drafting Team's (SDT's) Year One definition unnecessarily constrains the time between the completion of assessments as compared to the study period to begin no more or no less than 12 to 18 months. There is no reliability benefits derived by constraining the period between the completion of an assessment and the study period for the next study period. In fact, this may encourage a Transmission Planner to unnecessarily delay "completing" a study just to ensure that the 12 to 18 month requirement is met. For example, lets assume that a Transmission Planner's 2008 Assessment is complete as of May 2008. By the definition of Year One, then the study period for the 2009 Assessment will need to begin from May 2009 through November 2009. This means that the 2009 Assessment must include the 2009-2010 Winter Peak and cannot start with the 2010 Calandar Year. Why??? If a Tranmission Planner wants to have a study period that begins with the calandar year, then the Transmission Planner would need to delay completing the study until July 2009. Why??? What is the reliability benefits for delay??? MidAmerican suggests that the definition of Year One be changed to allow the study period to begin no later than 24 months after the completion of the previous year's study. ï€- Accountability: We suggest that Transmission Service Provider be added because we also suggest that the Transmission Service Provider be responsible for R10. ï€ R2.1 - We suggest that this requirement involves too much study work and we ask that the SDT reduce the number of current studies needed for all subrequirements. ï€ R2.7.1 - We agree with the requirement, but suggest a slight text change replace "â€¦ or Special Protection Schemes,â€¦" with " . . . or Special Protection Systems, . . ." ï€ R2.7.1.1 - We disagree with the "include project initiation date" portion of this requirement. The initiation date is often uncertain and subject to change, which may add considerable work to investigate, monitor and update the date. In addition, we do not know why this information is required to assure BES reliability. ï€ R3.3.2.1 - We agree with the requirement, but suggest a slight text change of: ". . . shall be allowed in the Planning Assessment". ï€ R3.3.2.2 - We agree with the requirement, but suggest a slight text change of: ". . . within their Facility Ratings and within the time period allowed by the applicable time limited ratings.". ï€ R5.4.3.1 - We agree with the requirement, but suggest a slight text change of: ". . . within their Facility Ratings and within the time period allowed by the applicable time limited ratings.". ï€ Table 1 ï€ Planning Events ï€ Header: We suggest that the header be repeated on every applicable page to be more reader-friendly. ï€ Superscripts: The superscripts do not refer clearly to the respective notes (e.g. there are number notes in the beginning of the table, in the extreme events evaluation requirements section, in extreme event description section, and at the end of the table). Perhaps the notes at the end of the table should have unique numbering to make the superscript references clearer. ï€ Shunt device: To avoid the need for future interpretation or clarification, we suggest that the meaning of shunt device be explained or defined somewhere in the standard (e.g. cap bank, inductor bank, SVC, STATCOM, etc.). We need to find out how shunt device outages can (or could in the future) be automatically included in the ACCC routine. We interpret that if each stage of a capacitor bank has a circuit switcher, then the outage would be of the largest cap bank stage. ï€ Extreme Event Evaluation Requirements ï€ 3 Extreme Event Descriptions ï€ 2b & 3b - We agree with the descriptions, but suggest referring to the defined term: "Right-of-Way." ï€ Note 4 - We agree with the description, but the acronym FACTS should be explained in the standard or a definition be added for "FACTS". Table 2 Header: We suggest that the header be repeated on every applicable page to be more reader-friendly. Other numbering and format changes suggested for Table 1 should also be considered for Table 2.

Individual

Gary Trent

Tucson Electric Power Company

No

We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study â €œfocuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to â€œdevelop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingenciesâ€. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be

specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say â€œonly whenâ€ the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, â€œmaterial Transmission System changeâ€ and â€œat or near the point of Interconnectionâ€ to invoke a study.

Yes and No

In general, R2.4 is acceptable but some of the sub-requirements are to prescriptive. We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. Off-peak analysis (R2.4.2) in the Planning Horizon is of limited value for smaller entities. This analysis is best left to the Operating Horizon. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirement in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. ï€ The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Ownerâ€™s open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Ownerâ€™s responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.

No

We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as â€œlocal Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systemsâ€ in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, â€œâ€¦load no longer being connected to a sourceâ€¦â€. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected

system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (â€œAlthough Load which is lost as a result of the Loadâ€™s response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirementsâ€) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.

Yes

We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.

Yes

While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in addition to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.

Yes and No

We agree with R2.3. However, R4 requires assessment of â€œShort-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting dutiesâ€. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute â€œnormalâ€ condition or â€œfollowing any single Contingency conditionâ€. Also, by specifying the normal and single contingency conditions, R4 is straying into â€œhowâ€ to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.

Yes and No

We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7. The proposed format covers multiple pages. Add the header rows to each page for easier reading.

No

We do not disagree with the proposed definition change. However, we do not agree that â€œSubstation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.

Yes and No

We interpret â€œexit breakersâ€ to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes

Yes and No

We generally agree with the concept of the sensitivity analysis since this is standard practice in

understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the â€œbase caseâ€ of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the â€œbase caseâ€ condition. R2.7 also states that â€œCorrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivitiesâ€. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the â€œbase caseâ€, will the judgment of the Transmission Planner be then questioned because theâ€œbase caseâ€ used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?

Yes

We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.

$200,000

6 month study performed by consultant

1 man-year

included in previous question

included in previous question

unable to determine without actual studies

10+ years 5 year budget and 10 year plans have been approved. Proposed projects in the 5-10 year time frame would need revised and accelerated and new projects would be proposed following the completion of these proposed projects.

C â€" Definitely do not support the revised standard

The Standard as presented is clearer, but there are numerous issues that still need resolution. There should be no distinction in voltage classes for allowing or not allowing controlled load shed for applicable events. We support the use of load shed for events at voltages greater than 300 kV where load shed is allowed for the same type of event for voltages below 300 kV. We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. ï€ There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. ï€ We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions. ï€ We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with â€œraising the barâ€. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be

maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. ï€ As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms â€œinterruption of firm transmission serviceâ€, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what â€œFirm Transmission Serviceâ€ means. Two points, 1) the NERC definition states â€œhighest quality service offered to customers under a filed rate schedule that anticipates no planned interruption.â€ The Standard implies anticipation of â€œunplannedâ€ interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order 890, or firm transfers modeled for the conditions being studied? One way to interpret the intent is the firm transfers being modeled for the conditions in the powerflow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption of firm transmission service should also be allowed for P1 through P5 contingencies in the table. In addition, we believe that DC and AC lines should have the same performance requirements with respect to interuption of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines can automatically be curtailed when the line is outaged.

Group

SERC Dynamics Review Subcommittee

Herb Schrayshuen

SERC Reliability Corporation

No

An improvement for the System Stability Study definition is to clarify that it is a study that focuses on the impact to the system itself and covers an area larger than one Generating Plant, covering a large geographical area. See specific proposal below: â€œSystem Stability Study - Study that focuses on how contingencies impact a larger portion of the System than a Generating Unit Study. These studies would examine issues such as angular Stability, inter-area power oscillation, and dynamic voltages.â€

No

R 2.4.1 Load models that appropriately represent the dynamic behavior of induction motors are under development and may not be available for some time. The implementation plan should take this into account and allow at least 36 months for implementation; otherwise this requirement will not be achievable in the near term. R 2.4.3 One should only explain why sensitivity was performed. In general we believe that breaking these requirements into specific sub-requirements focusing on specific sensitivities is too prescriptive and inappropriate; it will lead to over-focus on these particular issues to the detriment of system reliability. There should be no enumerated list of required sensitivities. Engineering judgment needs to be permitted. R 2.4.3.1 It should be clearly stated whether the load model refers to system load or the dynamic load model at individual busses. We have a specific proposal for R2.4.3 which addresses the above concerns as follows: R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, sensitivity case(s) that stress the System to reflect one or more conditions such as variations in dynamic Load model assumptions, modification of expected transfers, unavailability of long lead time Facilities, variability and outages of reactive resources, generation additions, retirements, or other dispatch scenarios. Document why each sensitivity was selected.

Yes

The modified definitions of Consequential load loss has been appropriately modified to include loss of Load as a result of the Load's response to the transient condition. This recognizes the fact that when subjected to fault voltages of sufficient depth and duration, the resulting Load dynamics will result is loss of Load. Therefore, in order to more accurately replicate real-world behavior through dynamic stability simuation analysis, the proper representation of expected real world loss of load is acceptable. It is also proper that the computation of expected consequential Load loss and duration is not required for single contingency stability analysis. If there is a need, Load loss due to the resulting transmission system configuration would be captured by steady state analysis. Attempts at determining additional Load loss due to load dynamics would not

result in any useful information contributing to increased reliability.
Yes
Generation run-back and tripping should be allowed and the proposed sub-requirements are appropriate.
No
For R9 the LSE should provide the load forecast instead of the DP. For R9 - R14, It is not clear that the specification of data flow appropriate for both RTO and non-RTO situations because there are significant differences in the role of planning coordinator. For example: 1) Who builds and manages the base cases? Shouldnâ€™t the data be submitted to this entity? 2) According to the definition provided in this standard, the Planning Coordinator is â€œThe responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.â€ Additionally, we recommend the TPL SDT write a SAR to get the data related changes into the MOD standards or adding it the issues to be considered by the drafting team in the development plan under project number 2010-04 otherwise it will be difficult to remember to include these items in the revised MOD standards.
Yes
It is not clear in the standard what is meant by â€œsingle contingencyâ€? Is the concern in Requirement R4 limited to single contingencies that may result in a system state which results in a greater circuit breaker interrupting duty?
Yes
The tables could be improved if the headings were put on each separate page. Separating out the tables for steady state and stability improves and clarifies the requirements of the standard.
No
The use of the word â€œstraightâ€ in the definition raised questions. We recommend the word straight be removed or change the definition to the suggestion below: Suggestion: Bus-tie breakers are defined as a circuit breaker position that connects two individual buses with one or more breaker positions on each bus.
Yes
The logic and the proposal seem reasonable.
No
These requirements are very prescriptive. Many examples of sensitivities are already inherent in the existing requirements. Some sensitivity studies are in effect adding an additional level of contingency (N-2 or N-3). Sensitivity studies of load variation are already inherent in the fact that several different study years and conditions are already being required. Outages of reactive sources and generation should already be included in studies of multiple contingencies. The process of planning new generation (system impact studies) will include studies of the future with and without the proposed new equipment. The TP and PC can better select the most appropriate sensitivities for their system. In general we believe that breaking these requirements into specific sub requirements, focusing on specific sensitivities, is too prescriptive and inappropriate. It will lead to over focus on these particular issues to the detriment of system reliability. There should be no enumerated list of required sensitivities. Engineering judgment needs to be permitted.
Yes
The changes are more practical. If two or more 500kV lines are lost, it makes complete sense to allow loss of non-consequential load so long as cascading outages are not triggered. While we agree interruption of firm transmission service and non-consequential load loss should not be allowed to meet the planning requirements for the first system contingency (defined as initial system condition in the table), these system adjustments should be allowed to prepare for the second event so that the system will meet the requirements following the second event. We recommend that clarifying changes be made to incorporate this concept. We recommend that the statement above be included as modification or as a footnote for the P6 portion of the table as follows: Foot note: Interruption of firm transmission service and non-consequential load loss should be allowed after the first event as a system adjustment to prepare for the second event and meet the requirements following the second event. See our related response to question 15.
The sensitivities will greatly increase the cost and time need for planning because the work is directly proportional to the number of sensitivities.
The lead time for new line construction is at least 7 years.
B â€" Unsure about supporting the revised standard
SERC is in category B A â€" Generally support the revised standard â€" B â€" Unsure about supporting the revised standard â€" See three specific concerns below C â€" Definitely do not

support the revised standard â€" 1) Load Modeling is a significant open issue. The models for dynamic studies have yet to be developed and the data is not in hand. This is conflicting with implementation of the TPL standards because modeling details are a gating item to completing some system studies. 2) The proposed sensitivities create significant amount of additional work making the compliance aspect more burdensome and less clear. 3) Category P6 is the loss of a system element, following system adjustments, followed by the loss of another element. The table columns for this category say that interruption of firm transmission service is allowed. The table, however, is not clear whether the interruption of firm service is allowed as part of the system adjustment (between the outages) or whether it is only allowed after the second outage. It was stated in the NERC TPL SDT WebEx that the interruption is not allowed as part of the system adjustment. If this is the interpretation, this will cause many SERC members to not support the revised standard. This would be a dramatic change from the existing standard and would result in the unintended consequence of significantly reducing transfer capability of interfaces to a fraction of their currently reported capability. This would in effect be imposing an n-2 criteria for offering firm transmission service. This would not be an acceptable situation for the users, owners and operators of the bulk power system.

Group

MRO NERC Standards Review Subcommittee

Tom Mielnik

MEC

No

The MRO believes the definitions are improved. However, the MRO suggests that the SDT clarify what stability analysis are required such as angular and voltage stability for which time frames such as the transient and steady state time frames and for what planning horizons such as the Near-Term and Long-Term planning horizons. Generating Unit Stability Study definition - The MRO suggests deleting the text, "on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point.", because certain Generation Facility contingencies should be considered and key Transmission Facility contingencies can be more than one bus away from the interconnection point. System Stability Study definition - The MRO suggests this alternate wording: "Study that focuses on portions of the System, which may include many generating units with various Contingencies. This study is concerned with loss of synchronism, lack of damping of inter-area power oscillations, and voltages during the dynamic simulation." We suggest this wording because the definition of a study should not give the criteria, but rather the general elements of the study.

No

a. The MRO disagrees with the proposed R2.4.1 text. This inclusion of this requirement may be premature at this time for several reasons. There is presently no industry consensus on how the dynamic behavior of loads should be properly represented and analyzed. In addition, it would be a large and difficult effort to identify, collect, and maintain the pertinent information. It is presently difficult to obtain and maintain the percentage of residential, commercial, and industrial load at each transmission interconnection point, much less try to get the proper percentage of the various types of induction motor loads. If this requirement is retained then R2.4.1 should be modified to specify a minimum threshold size where dynamic induction motor load or dynamic load behavior becomes significant such as near mining areas. The SDT should consider a 25 MW size threshold for induction motors and a 100 MW size threshold for industrial complexes where the dynamic loads are inadequately represented by normal powerflow dynamic assumptions. b. R2.4 as stated refers to Near-Term Transmission Planning Horizon Stability analysis but there is no requirement in the standard refering to Long-Term Transmission Planning Horizon Stability analysis. The SDT should reword R2.4 so that it is clear that no Long-Term Stability analysis is required by stating that "Stability analysis for the Near-Term Transmission Planning Horizon shall be assessed annuallyâ€¦". ï€ The MRO does not accept the R2.4.3.1 text and want some explanation of the what, when, and how to provide the technical rationale for why each condition was or was not used. ï€ In R2.4.3.1, what is meant by â€œvariationsâ€ (e.g. how much variation is enough)? ï€ In R2.4.3.2, what is meant by â€œmodificationâ€ (e.g. how much modification is enough) and "expected transfers" (e.g. firm or non-firm transfers)? ï€ In R2.4.3.3, what is meant by â€œlong lead timeâ€ (e.g. 1 month, 1 season, 1 year, 2 years, etc.)? The MRO suggests that â€œlong lead timeâ€ be stated 18 months or more. ï€ In R2.4.4, we believe this requirement should not be added. Why was it included? It seems superfluous, because any entity can study other sensitivities if they want. Why should TP or PC have to study what the other entity wants to study? Who would be the judge in case of disagreement over the technical rationale? ï€ In R2.5.2, Why was the addition of a new substation included? We would not expect a new substation to negatively impact the system or generating unit stability. The MRO notes that R5.5 and R5.6 should really have been updated to refer to 5.4 and R5.5. In R5.4.3.1, we suggest that the time-limited aspect of Facility Ratings should be included in the Glossary Definition by adding the words "within the applicable time period of the rating" and then it would not need to be clarified in various locations (R3.3.2.2, R3.5.1, R5.4.3.1, Table 1-Note 1, & Table 2-Note 1) throughout the standard.

No

Non-Consequential Load Loss is defined by the SDT to include load dropped by Special Protection Systems while Consequential Load Loss does not exclude load dropped by Special Protection Systems. The SDT should resolve this contradiction between these two definitions by adding an appropriate reference to Special Protection Systems in the Consequential Load Loss. For Consequential Load Loss definition, The MRO suggests that the last sentence be deleted because it is application text, rather than definition text.

Yes

No

The MRO disagrees with the approach of temporary requirements because of the problems that arise due to conflicting or uncoordinated standards (e.g. conflicting requirements between FAC-010-1 and TPL-002-0). We suggest the drafting team submit SARs to make the desired changes in the appropriate MOD standards. However, if these requirements are retained than we suggest the following few changes to R9-R14: In R9, revise the text to: "â€¦ load forecast data for at least the coincident peak of each year â€¦" The R9 wording on providing "the expected mix of industrial, commercial, and residential loads" should be dropped as the representative mix is difficult to quantify and verify while the benefit to representing the mix is unproven versus normal regional dynamic load representation practices. Many regions already convert normal steady state powerflow loads to standard mixes of, constant MVA, constant current, and shunt admittances which accounts for dynamic behavior. If the SDT decides not to drop these words, the MRO recommends "the expected mix of industrial, commercial, and residential loads" be changed to "the forecasted mix of industrial, commercial, and residential loads". In R9 through R13 the responsible entities should be giving their information to the Transmission Planner in addition to the Planning Coordinator. In R9, revise the text to: "â€¦ load forecast data for at least the coincident peak of each year â€¦" In R10, revise the text to: "Each Transmission Service Provider shall provide â€¦" In R11, is the text referring to "known planned outages" and "known long term outages"? What is the distinction that is meant to be made between the two specified types of outages? In R12, revise the text to: "â€¦ modeling information for planned facilities changes, known planned outages â€¦". Also, is the text referring to "known planned outages" and "known long term outages"? What is the distinction that is meant to be made between the two specified types of outages? In R13, revise the text to: "â€¦ for planned facilities changes for each year of the Transmission planning horizon including but not limited to generators, and new technologies â€¦". This wording broadens the meaning from simply "new" facilities to also include any "changes" to existing facilities. We suggested removing the reference to Reactive Power Devices because these devices would not be owned by Resource Planners. In R14, revise the text to: "â€¦ for planned facilities changes for each year â€¦". This wording broadens the meaning from simply "new" facilities to also include any "changes" to existing facilities.

No

a. Since the TPL contingency requirements already require bus fault, stuck breaker, and breaker failure contingencies, the MRO asks the SDT to clarify the purpose of the short circuit study requirements. The benefit to additional short-circuit studies is minimal since analyses already ensure that the system can withstand bus faults and breaker failures. b. The SDT should clarify what single contingencies are to be studied for short circuit studies in R2.4. Is it single contingency as defined in Table 1? Or is it a broader or narrower definition? The MRO recommends that since this is a new requirement, that TPL-001-1 be limited to raise the bar only to involve the single contingencies identified in P1. Failure to do so will require a great deal of additional modeling work in short-circuit studies if single contingencies in P2 are to be included in these studies with minimal benefit. c. The MRO suggests added clarification of the following questions: 1. Should analysis be performed for the near-term and long-term planning horizon? 2. Should only the peak system condition be analyzed? 3. What does the analysis include (e.g. breaker overduty evaluation and protective relay coordination)? R4 - Clarify that the "short-circuit capability of its equipment under normal conditions" (P0) refers to interruptible rating for breakers only.

No

The MRO suggests that the Categories symbols in Table 1 and Table 2 be different to help distinguish between them (e.g. P1:S1, P2:S2, P3.2:S3.2, etc.) The MRO suggests that the header text (i.e. Category, Initial System Condition, etc.) be repeated on every applicable page to be more reader-friendly. The superscripts do not refer clearly to the respective notes. (There are numbered notes in the beginning of the table, numbered items in the extreme events evaluation requirements section, numbered items in extreme event description section, and numbered notes at the end of the table). Perhaps the referenced notes should have unique numerology or format to make the superscript references clearer.

No

The MRO suggests applying the proposed definition to a new term, "Straight Bus-Tie Breaker". The creation of a narrow, special application definition of "bus tie breaker" is generally confusing

and misleading. The term "bus tie breakers" is widely used in the industry in the context of various bus configurations. In addition, this narrow definition may create confusion if other Standards refer to bus-tie breaker in a different context.
No
The MRO recognizes that the addition of this requirement is an attempt top raise the bar above the existing standards. However, the more stringent non-bus-tie performance criteria should only be adopted if there is sufficient evidence to demonstrate the expected reliability risk (i.e. system impact x probability of occurrence) is high enough to warrant the cost of the system modifications that would be needed to meet the criteria. System modifications that involve the installation of line and substation facilities >300 kV will likely take years and cost tens to hundreds of millions to build. There should be a reliability risk analysis that justifies the application of this performance criteria before it is adopted.
No
a. The MRO is not sure why R2.4.3.1 for sensitivities for Stability studies is a less definitive definition for load model variations then the steady state studies in R2.1.3.1. The MRO recommends that R2.1.3.1 be changed to "Variations in Load model assumptions." b. The MRO believes R2.1.4 and R2.4.4 should be deleted because its unnecessary to make a requirement of senitivities that an entity chooses to do above and beyond the requirements in R2.1.3 and R2.4.3. If the SDT chooses not to delete these requirements, then MRO believes that R2.1.4 should be a subrequirement of R2.1.3 and R2.4.4 should be made a subrequirement of R2.4.3. The responsible entity should be allowed to select the appropriate sensitivity that should be performed. This is especially necessary given the need to perform each of these sensitivity analyses for six situations each year: peak and off-peak for two short-term years and one long-term year. Even with the requirement for one sensitivity for each case that amounts to six additional sets of analysis for steady-state and six for stability. c. For R2.1.4, we suspect that these analysis are similar to extreme event contingencies and do not have specific performance requirements. We would also like some explanation of what and how to provide the technical rationale for why each condition was or was not used.
No
The MRO suggests that there be more explanation of what system adjustments are permitted. There should be some specific limit like 100MW below which load loss is allowed. Otherwise, very high cost solutions will be required for very low probability events.
The MRO estimates that the additional one-time costs of supplemental studies and analysis to meet the new requirements might be spread over five years because some analysis only has to be updated every five years. The MRO estimates that the total cost over five years for additional staff, consulting services, or software fees would be about $200,000 to $300,000 per responsible entity.
The MRO estimates that the lead time to perform supplemental studies and analysis to meet the new requirements would be up to 5 years.
The MRO estimates that the on-going additional cost of expanded studies and analysis to meet the new requirements would be about $150,000 to $200,000 for additional staff and continuing software fees per responsible entity.
Included in amounts for 12.
Included in amounts for 12.
The additional one-time costs of system reinforcements to meet the new requirements would depend on the results of the new studies and be hard to forecast. However, if they involved just a few 345 kV substation modifications and 345 kV line additions, then we estimate that it would cost in the range of hundreds of millions of dollars per responsible entity.
The lead time to build new system projects would depend on the results of new studies and be hard to forecast. However, if they involved a 345 kV substation modification or a 345 kV line addition, we estimate that it would take 5 to 7 years to complete the substation project and 8 to 12 years (or more) to complete the new transmission line project.
C â€" Definitely do not support the revised standard
While the MRO commends the SDT for significantly improving the standard, the MRO believes that the standard still must be improved significantly. Here are some suggestions for improvement: a. R1.1 is not clear. What does this mean? Surely the SDT does not expect that any time the data is modified a rationale is required. Shouldn't this data be updated as necessary? Wouldn't a requirement for providing a rationale each time such changes are made potentially discourage improvements to the models? This requirement should be clarified and limited to a few specific cases that were there are real reliability concerns. b. R2.5.2 - the SDT should revise the material transmission system changes. Addition of a new substation in one of the transmission lines connected to the plant should be revised to specifically refer to a switching station or to a non-distribution substation. A substation directly serving load is not a good example of a material transmission system change in the context of Generation Unit Stability studies. c. R2.6.2 - The SDT should revise the material transmission system changes because as presently defined, studies will need to be conducted every year for every year in the assessment

period. This is because apparently the SDT has defined any system change as a material change. Since it is rare for there to be a system that does not exhibit some system change from year to year, this will mean ten-year and more studies every year. The MRO recommends that the SDT revise this requirement to make clear that only significant system changes are material changes. d. R2.7.1 - The SDT has written this requirement to include a requirement that the responsible entity must indicate how long Operating Procedures apply. This implies that Operating Procedures should be interim measures. The MRO believes that reliability can be maintained with permanent Operating Procedures and recommends that the need to indicate "how long the Operating Procedures will be needed" be deleted from this requirement. e. R3.3.2.1 - The SDT should delete the need to provide the expected duration of the Consequential Load Loss in this requirement because this requirements a probabilistic calculation and probabilistic planning is not the state-of-the art of the industry. This is reflected in the standard which has been written to continue deterministic planning criteria. As a result, it is a contradiction to require this probabilistic quantity in the middle of this deterministic planning standard. f. R3.3.2.2 - clarify that the single contingency events are the events in the table. g. R3.4 and R5.4.4 - the MRO urges that the SDT delete or revise the words "why the remaining Contingencies would produce less severe System results." Given the expansive nature of the Extreme events it is virtually impossible to comply with this requirement. It is more likely that the responsible entity could show that the more likely and more severe Extreme events were studied. It would be better yet if the SDT would merely require that the responsible entity provide the rationale for the selection of Extreme Events that were studied. h. R5.5.1 provides an exclusion for changes in individual generating units that require study. Yet R2.6.2 has a broader definition of when Generating Plant Stability is required. These definitions need to be consistent. The definition in R5.5.1 seems to narrow to be a good definition for "material changes." The MRO believes that the R5.5.1 should be expanded. i. Year One definition - The MRO suggests that the Standards Drafting Team's (SDT's) Year One definition unnecessarily constrains the time between the completion of assessments as compared to the study period to begin no more or no less than 12 to 18 months. There are no reliability benefits derived by constraining the period between the completion of an assessment and the study period for the next study period. In fact, this may encourage a Transmission Planner to unnecessarily delay "completing" a study just to ensure that the 12 to 18 month requirement is met. For example, letâ€™s assume that a Transmission Planner's 2008 Assessment is complete as of May 2008. By the definition of Year One, then the study period for the 2009 Assessment will need to begin from May 2009 through November 2009. This means that the 2009 Assessment must include the 2009-2010 Winter Peak and cannot start with the 2010 Calendar Year. Why? If a Transmission Planner wants to have a study period that begins with the calendar year, then the Transmission Planner would need to delay completing the study until July 2009. Why? What are the reliability benefits for delay? The MRO suggests that the definition of Year One be changed to allow the study period to begin no later than 24 months after the completion of the previous year's study. ï€ Definitions: The MRO agrees with the removal of the "Base Case" definition and the revisions to the other definitions, except as noted below or elsewhere. ï€ Long Term Planning Horizon definition: The MRO suggests a slight text change of: "Transmission planning period that covers years six through ten. Studies beyond ten years are required to accommodate . . .". ï€ Accountability: The MRO suggests that Transmission Service Provider be added because we also suggest that the Transmission Service Provider be responsible for R10. ï€ Requirements: The MRO agrees with the revisions to the Requirements, except as noted below or elsewhere. ï€ R1.1 - The MRO agrees with the requirement, but would like more description of what to provide in the technical rationale. ï€ R2.1 - The MRO suggests that this requirement involves too much study work and we ask that the SDT reduce the number of current studies needed for all subrequirements. ï€ R2.6.2 - The MRO agrees with the requirement, but suggest a slight text change of: " . . . short circuit, Generating Unit Stability or System Stability analysis . . .". ï€ R2.7 - The MRO agrees with the requirement, as long as it is really required by FERC Order 693 paragraph 1704. ï€ R2.7.1 - The MRO agrees with the requirement, but suggest a slight text change replace "â€¦ or Special Protection Schemes,â€¦" with " . . . or Special Protection Systems, . . ." ï€ R2.7.1.1 - The MRO disagrees with the "include project initiation date" portion of this requirement. The initiation date is often uncertain and subject to change, which may add considerable work to investigate, monitor and update the date. In addition, we do not know why this information is required to assure BES reliability. ï€- R2.7.2 - The MRO agrees with the requirement, as long as it is really required by FERC Order 693 paragraph 1704. ï€ R3.2.2 - The MRO agrees with the requirement, but suggest a slight text change of: "For all BES Transmission lines . . .". ï€ R3.3.2.1 - The MRO agrees with the requirement, but suggest a slight text change of: ". . . shall be allowed in the Planning Assessment". ï€ R3.3.2.2 - The MRO agrees with the requirement, but suggest a slight text change of: ". . . within their Facility Ratings and within the time period allowed by the applicable time limited ratings.". ï€ R5.1 - The MRO agrees with the requirement, but suggest a slight text change of: ". . . the response of the applicable portion of the BES". ï€ R5.2 - This clarifying requirement should also be included in the steady state and short circuit analysis sections. ï€- R5.3 - The MRO agrees with the requirement, but suggest a slight text change of: ". . . capability of all generators that may have a significant adverse effect on the BES." ï€ R5.4.3.1 - The MRO agrees with the requirement, but suggest a slight text change of: ". . . within their Facility

Ratings and within the time period allowed by the applicable time limited ratings.". ï€ R6 - The MRO agrees with the requirement, but suggest a slight text change of: ". . . shall provide the rationale for and document . . .". ï€ R8 - The MRO disagrees with the requirement, but suggest a text change of: "Each Planning Coordinator shall establish a list of neighboring system and coordinate the distribution of Planning Assessment results among affected entities the listed neighboring systems, coordinating analysis of these results through an open and transparent peer review process." ï€ Table 1 ï€ Planning Events ï€ Header: The MRO suggests that the header be repeated on every applicable page to be more reader-friendly. ï€ Superscripts: The superscripts do not refer clearly to the respective notes (e.g. there are number notes in the beginning of the table, in the extreme events evaluation requirements section, in extreme event description section, and at the end of the table). Perhaps the notes at the end of the table should have unique numbering to make the superscript references clearer. ï€ Shunt device: To avoid the need for future interpretation or clarification, we suggest that the meaning of shunt device be explained or defined somewhere in the standard (e.g. cap bank, inductor bank, SVC, STATCOM, etc.). We need to find out how shunt device outages can (or could in the future) be automatically included in the ACCC routine. We interpret that if each stage of a capacitor bank has a circuit switcher, then the outage would be of the largest cap bank stage. ï€ P2.2 (>300 kV), P2.3(>300 kV), P3 (>300 kV), P4 (>300 kV), P5 (>300 kV), P6 (>300 kV) - This requirement is raising the bar above the existing standards. In the existing standards, this is a Category C event in which load shedding was allowed. A higher criteria for >300 kV may not be appropriate at this time. The new requirement may require the installation of facilities that are costly and have a very long implementation timeframe. We should consider what the cost of this higher requirement might be for ATC and other utilities. If the new >300 kV requirement is not reduced, then we would want the implementation timeframe to be long enough to allow reasonable time to transition from a system built to the old requirement to a system built for the new requirement. The time needed for planning, design engineering, regulatory approvals, and construction of >300 kV facilities can be very long (e.g. up to 10 or more years). ï€ P6 - Why isnâ€™t the generator listed as a one of the possible subsequent element outages? ï€ P7 - The MRO disagrees with this requirement. Wisconsin statues require giving preference to using existing ROW for new transmission circuits, but this requirement discourages building multiple circuits on common ROW. Should there be an exclusion in this standard similar to the TLP-503-MRO-1 standard (e.g. could be slightly more than 1 mile due to review?. ï€ Extreme Event Evaluation Requirements ï€ 2 - The MRO agrees with the requirement, but perhaps a definition be added for "System Controls", since one exists for "System Protection". ï€ 3 - The MRO agrees with the requirement, but suggest a slight text change of: "Simulate Normal Clearing unless otherwise specified in the Extreme Event Descriptions." ï€ Extreme Event Descriptions ï€ 2a - The MRO agrees with the description, but suggest a slight text change of: "Loss of a structure or tower line with three or more circuits.." ï€ 2b & 3b - The MRO agrees with the descriptions, but suggest referring to the defined term: "Right-of-Way." ï€ 2e, 3.a.i, & 3.a.ii - The MRO agrees with the descriptions, but how large is "large" and how major is "major"? ï€ 3.a.v - What is meant by successful cyber attack? Is it a type of cyber attack that is documented to have been successful? ï€ 3c - The MRO agrees with the description, but suggest a slight text change of: "Other events based upon actual operating experience such as:" ï€ Note 4 - The MRO agrees with the description, but the acronym FACTS should be explained in the standard or a definition be added for "FACTS". ï€ Table 2 ï€ 1 - The MRO disagrees with this note. We suggest that it be expanded to include the applicable part as Table 1. "The System shall remain stable. In addition, Facility Equipment Ratings shall not be exceeded. Planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings." ï€ 3 - The MRO disagrees with this note. We suggest that it be expanded to include the applicable part as Table 1. "Dynamic voltage instability, Cascading outages, and uncontrolled islanding shall not occur." ï€ Between 3 & 4 - The MRO disagrees with omitting Note 4 of Table 1 from Table 2. We suggest including: "Consequential Load and consequential generation loss is allowed for all events shown." ï€ Planning Events ï€ Same comments on Header, Superscripts, and Shunt Device as in Table 1. ï€ Same comments about stricter requirements for P2.2 (>300 kV), P2.3(>300 kV), P3 (>300 kV), P4 (>300 kV), P5 (>300 kV), P6 (>300 kV) as in Table 1. ï€- Same comment about P7 as in Table 1. ï€ Extreme Event Evaluation Requirements ï€ Same comment about Requirement 2 and 3 as in Table 1. ï€ 3 - The MRO agrees with the requirement, but suggest a slight text change of: "Simulate Normal Clearing unless otherwise specified in the Extreme Event Descriptions." ï€ Notes 5 - The MRO disagrees with limiting this requirement to just Category P1 category. We suggest that the synchronism requirement be applied to more categories.

Individual

James C. Armke

Austin Energy

No

There is no need to separate system stability studies and generating unit stability studies. Requirement R5.4 should be written to include generating unit stability analysis.

No

The routine sensitivity cases requirement contained in R2.4.3 is overly burdensome and unnecessary and should be deleted. Sensitivity analysis should be limited to what may be deemed appropriate by the Transmission Planner or Planning Coordinator. Similarly, R2.5 and R5.5 requirements for Generating Unit Stability should be deleted. Removing these burdensom requirement will allow transmission planners and/or the Planning Coordinator (ISO)to determine the appropriate Generator Unit Stability analysis needed as part of R5.4 System Stability.

Yes

Yes

No

Requirements R9 through R14 should be deleted and re-introduced later as part of a change to MOD standards. R1.1 imposes burdensom documentation requirements which will likely become a disincentive for revising modeling data and should be deleted.

Yes and No

Transmission Planners should assess equipment short-circuit capability under normal conditions, but the need assess its capability following a contingency is so rare it should be left to the planner's selective analysis and not made a specific requirement in the standards.

No

Matching facility rating to seven contingency categories is confusing. Furthermore, these seven categoriesa combined with alternative scenarios and sensitivity studies for several years into the future is overly burdensom, unnecessary, and unrealistic.

Yes

Yes

No

Appropriate sensitivity analysis should be determined by the Transmission Planner and/or the Planning Coordinator (ISO or RTO) and not made a routine requirement. Therefore, R2.1.3 should be deleted.

No

It should be left to the Transmission Planner and/or Planning Coordinator (ISO or RTO) to select the credible multiple contingencies to be studied as planning evernts. Therefore P6 should be deleted.

C â€" Definitely do not support the revised standard

The proposed standard is overly burdensome and too perscriptive. It will only result in a marginal improvement in reliability and its primary effect will be to devolve into a paper-chase for auditors.

Individual

Spencer Tacke

Modesto Irrigation District

No

Comments: We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study â€œfocuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to â€œdevelop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingenciesâ€. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit

Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say â€œonly whenâ€ the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, â€œmaterial Transmission System changeâ€ and â€œat or near the point of Interconnectionâ€ to invoke a study.

Yes and No

Comments: R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirement in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. âˆ’ We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. âˆ’ The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Ownerâ€™s open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Ownerâ€™s responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.

Comments: We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as â€œlocal Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systemsâ€ in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, â€œâ€¦load no longer being connected to a sourceâ€¦â€. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non- Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL- 001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area.

An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (â€œAlthough Load which is lost as a result of the Loadâ€™s response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirementsâ€) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.

Yes

Comments: We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL- 001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.

Yes

Comments: While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.

Yes and No

Comments: We agree with R2.3. However, R4 requires assessment of â€œShort-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting dutiesâ€. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute â€œnormalâ€ condition or â€œfollowing any single Contingency conditionâ€. Also, by specifying the normal and single contingency conditions, R4 is straying into â€œhowâ€ to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.

Yes and No

Comments: We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.

No

We do not disagree with the proposed definition change. However, we do not agree that â€œSubstation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-ahalf and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.

Yes and No

Comments: We interpret â€œexit breakersâ€ to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non- Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes

Yes and No

We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous

from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the â€œbase caseâ€ of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the â€œbase caseâ€ condition. R2.7 also states that â€œCorrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivitiesâ€. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the â€œbase caseâ€, will the judgment of the Transmission Planner be then questioned because theâ€œbase caseâ€ used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?

Yes

We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1- 1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.

Unknown at this time.

B â€" Unsure about supporting the revised standard

Concerns about the following: attempt to introduce interconnection stability studies into TPL studies, and redefiniton of Consequential and Non-Consequential Load Loss.

Individual

Ronnie Frizzell

Arkansas Electric Coop. Corp.

Yes and No

There are situations where one bus away may not be far enough. While one bus may cover most situations the standard shouldn't limit the study to just one bus away. Suggested language change: Transmission Facilities connected to that generating unit(s) point(s) of inteconnection, one bus away from the electrically closely-coupled units.

Yes

No

These defintions are still confusing. I offer the following example to explain: If you have a networked transmission line serving several loads, a fault occurs on the line, and the load is dropped because of the line breakers at either end of the line operating. As a result the operator would normally sectionalize the line and isolate the faulted section. This results in the networked line now being two radials and the load is restored. From a planning standpoint the resulting steady state is the resulting two radials and there should not be any consequential load loss. From an operational standpoint steady state would have occurred at the time of the breakers opening and dropping the load. Operationally the load is consequential load loss. This being a planning standard the standard should require that all the load be served and the transmission line meet the (planning)steady state performance requirements. If the SDT agrees that the resulting radials should be capable of serving all the load and meet the planning steady state

performance requirements then I can agree with the definition. If not then I disagree. In the planning environment systems should be studied and assessed based on an switchable element to switchable element basis and not just breaker to breaker. Non-Consequential Load Loss - 1. Is it the intent of the SDT that Non-Consequential Load Loss be all firm load other than Consequential Load Loss? If not it should be. Is there a definition of "Non-Interruptible Load"? Didn't see it in the Glossary. 2. additional language should be added stating that the examples given are not inclusive. I have a problem with NERC providing examples in definitions because often the examples are interpreted as the definition itself when in reality their purpose is to clarify.

No

R9. I diagree with providing the mix of industrial, commercial and residential, especially within a 90 day period. It is difficult enough to be able to develop a forecast must less try to quesstimate the mix of the loads. R9 through R14 -- the timing requirement should be tied to the regions model development schedule and not 90 days. The 90 days is too restrictive and not practical however model data should be updated at least annually.

No

R2.3.1 should not be deleted. While system wide short circuit analysis should be done annually, there are situations where changes in the BES do impact the short circuit. If these changes result in new equipment needing to be ordered then this needs to be know as soon as possible in order to prevent exceeding equipment ratings or delays because of lead times on equipment.

No

I disagree with statement #4 for the reasons given in my comments on question 3. Also, if you are going to allow it then consequential generation loss needs to be defined. I also disagree with statement #5. This is a planning standard and as such systems should be planned for planning steady state. Statement #5 should only be allowed if the resulting operator actions are taken into account. A fault on a networked transmission line may open the breakers at each end. Statement #5 stops here when in reality operator actions would isolate the faulted sections and service restored with the transmission line now being operated as two radials. The resulting two radials are what need to meet the performance requirements. Events should be taken to their logical conclusions and the resulting system topology be what meets the performance requirements. The tables need some borders and section dividers. Headers should be on each page. No firm transmission or Non-Consequential Load Loss should be allowed for P2. I think the SDT has it backwards. Non-Consequential Load Loss should never occur and the tables should reflect what is allowed to happen with Consequential Load Loss for each event. Many of the scenarios reflect what should happen with Consequential Load Loss and not Non-Conseqeuntial Load Loss. For example: P2 Bus Section for less than 300 kV -- The load on that bus under this contingency would be Consequential NOT Non-Consequential. For the loss of that bus the load connected to that bus should be ALL the load that is lost, therefore no Non-Consequential Load Loss should occur.

Yes

Yes

No

Non-Consequential Load Loss should not be allowed. See comments to question 7.

B â€“ Unsure about supporting the revised standard

I have a growing concern that the NERC Reliability Standards are not going far enough to ensure adequate and reliabile service to customers and users of the BES. Each revision of the standards seem to be driven by the need to preserve the integrity of the grid and preventing cascading blackouts but stop short of ensuring that load continues to be served under contingency conditions and adequate grid capacity is available. For the customers and end users of the system if their load is allowed to be dropped or can not be served because of the lack of capacity then the BES is not reliable. The definitions of Consequential Load Loss and Non-Consequential Load Loss concern me the most. How these definitions are then applied in the tables is also a great concern. Hopefully my previous comments to the other questions in the comment form

provide explanation. Another concern I have is the fact that I tried to provide comments last fall to draft 1 of the standards and they were not allowed. After following the instructions provided I provided my comments before the deadline. I later discovered they were not posted. After repeated attempts asking NERC to determine why my comments were not received and posted and showing evidence that they had been provided by the deadline, the only response I received was pretty much "sorry Charlie". Mistakes happen. NERC should be big enough to admit when they make a mistake instead of just blowing them off. I have no way of knowing if or how many times this may have happened before. I am not trying to say that anything malicious was entended, however it does leaves me with concern that fair treatment is being given to all comments and cast a shadow over confidence in the standards approval process.

Individual

Marie Knox

Midwest ISO

Yes

No

The language in R2.4 retains the appropriate clarification that while annual assessments are required, these assessments do not necessarily have to be based upon annually performed simulations. This same distinction should be retained for steady-state assessments required under requirement R2.1, not withstanding the fact that steady-state simulations are easier to perform. The principle is the same for both. Requirement R2.4.1 is to open ended in specifying the years to be studied. Rather, it should parallel requirement R2.1.1 in requiring that at a minimum either year one or two should be evaluated, and additional years at the option of the responsible entity. If the system could go unstable in the next 1-2 years, it is important to know this. Regarding R2.4.3 & R2.4.4, the standards should not require analysis for which corrective action is optional regardless of the conclusion of the analysis. Requirement R2.7 establishes that corrective action to any sensistivities is optional. Therefore, the performance of sensitivities should be at the descretion of the applicable entity. If the SDT believes it is important to recommend that sensitivities be performed then those Requirements addressing sensitivities should state that the performance of the sensitivity is recommended but optional. If you keep sensistivities in the standard then the requirement in R2.4.4 to document why an entity performed sensitivities in addition to the Requirements should be dropped. As long as the entity selected a sensitivity and documented the results of the sensitivity there should be no reason to explain why he tested it. Requirement R2.5.2 is unclear with respect to when generator unit stability needs to be retested following modifications to the transmission system. Nearly all additions to the transmission system will tend to improve generator stability. We suggest this language be modified to say: "Material transmission system changes are made at or near the point of interconnection of existing generation that would tend to degrade stability margins of that generation, such as the removal of a transmission line, or associated with the addition of new generation, or other system changes as determined by the Planning Coordinator or Transmission Planner". R5.4.3.1 & R5.4.3.3 are redundant with the stated requirement to mitigate stability. Under the subrequirement of R5.4.3.2 it may not be possible for the PC/TP to determine whether the safety, equipment, regulatory or statuatory requirements are violated without collaboration with the Transmission Owner and/or the Generator Owner. Therefore, if this subrequirement is retained it should be ammended to include the following sentence: "Applicable Transmission Owners and/or Generator Owners shall collaborate with the PC/TP in determining whether such action would violate safety, equipment, regulatory or statuatory requirements". Subrequirements R5.4.3.X are superfluous; we suggest removing these subrequirements. However, if this requirement is retained it should be ammended to include the following sentence: "Automatic generation tripping is allowed to mitigate Stability violations if the performance criteria in Table 2 is met".

No

Under the definition of consequential load, it is not clear who the term "Transmission planning entities" is referring to. Perhaps it should say "entities to which the standard is applicable". The last sentence could be ammended to say: "Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transiet conditions of the event (other than through the action of UVLSâ€¦..

Yes and No

Under the subrequirement of R3.5.2 it may not be possible for the PC/TP to determine whether the safety, equipment, regulatory or statuatory requirements are violated without collaboration with the Transmission Owner and/or the Generator Owner. Therefore, if this subrequirement is retained it should be ammended to include the following sentence: "Applicable Transmission Owners and/or Generator Owners shall collaborate with the PC/TP in determining whether such action would violate safety, equipment, regulatory or statuatory requirements".

No

Since the Transmission Planner has the primary model building responsibility it makes sense to

have them aggregate model building information. Therefore, requirement R9 should have the Distribution Provider providing the Transmission Planner and Planning Coordinator with modeling information for real and reactive load forecastâ€¦etc. The data of R10 such as firm TS data may not be known by the Transmission Planner (ofter a TO in the RTOs). Also the langauge implies that there are more than one BA under a TP, also not a typical arrangement in an RTO/ISO. A hierarchical approach might be more appropriate such that the Distribution Provider, the Transmission Provider, and the Transmission Owner supply the data they control to the Tranmission Planner and the Planning AUthority so that those entities can build models they need to meet the study requirements of the standard.
No
The language throughout the standard is not precise as relates to "studies", "analysis", and "assessments". R2.3 appears to say that the actual simulations upon which the annual assessments are made need not be a current year study. If that is the intent the following wording would be more clear: "Short-circuit assessments shall be conducted annually and may be supported by current or past studies. R4 should be grouped with R2.4. In general the standard seems to meander and elements of the same types of studies are scattered, making it difficult to grasp the study requirements with clarity. Also the language of R4 is unclear as it describes short circuit studies in terms of contingencies. Better langauge would be "shall assess the short-circuit capability of its equipment under system intact topology and any single facility (or branch) out condition that is expected to result in greater â€¦".
No
Please add a General Requirements heading before items 1-6 (Steady State) and 1-5 (Stability) which appear to be applicable to all events for each table. The two columns under "BES elements out of Service" could be stricken for simplicity and clarity. If there is a voltage distinction needed, then add it next to the "Yes" or "No" under the "Interuption of Firm Service" or "Loss of Load" columns. Items P0 through P7 are identical in Table 1 - Steady State Performance and Table 2 Stability Performance. The only distinctions are the notes or whether it is an outaged event in Table 1 or a 3 phase/SLG fault in Table 2. Having two tables is redundant and unnecessary, and does not add clarity. It is also recommended that you combine the notes and extreme events from Table 1 - Steady State Performance and Table 2 - Stability Performance into one table. If both tables are to be retained then it is recommended that the SDT take into consideration the following suggestions. With the old Version 0 table, where there was not a separate stability table, it was understood that each of the event types needed to be assessed, but only those that the responsible entity knew were the more severe from a stability perspective needed to have stability analysis performed. By listing events such as single circuit faults (P1) under Table 2, this implies that all events should be simulated with dynamics, though requirement 5.4.1 states events "that would produce more severe System impacts shall be identified,...". The burden to explain why certain events were not selected can be construed now as having to run dynamics on all line faults, or explain why each line was not selected. Most lines embedded within the grid and not near generators or of particular significance to grid dynamic stability need not be studied. We do not believe that the SDT is requiring any additional burden of proof as to why every line in the system is not studied with dynamics, but the standard makes that question more murky than it was before. An overzealous compliance monitor could be confused by the new layout at great expense to the industry. If Table 2 remains, change Table 2 - Stability Performance to only those events that are important to Stability Analysis. For example the following faults to run would be: 1) Faults near large generators (generator buses, generator lines or transformers near generators) 2) Faults with delayed clearing near large generators 3) Faults on long or heavily loaded lines with large phase angle differences between terminals. A majority of faults on lines less than 200kV are rarely severe so it is recommeded to have the standards reflect this in Table 2 - Stability Performance.
Yes
This is a good definition.
Yes
No
This reminds us of Category D from original table--requiring us to study something but take no action. Sensitivities are not appropriate nor effective in a planning world in which you require an array of sensitivity studies but require no action will be taken. While running sensitivities enables us to better understand system limits, why have it as a requirement if there is no action plan obligation.
Yes
Some additional costs will be required to comply with all the requirements. This is difficult to quantify at this time.
This is difficult to quantify at this time, but any increased requirements should be clearly identified by the SDT and a transition period should be developed if the standards are intended

to be more restrictive.
There will be an increase in ongoing cost for expanded studies and analysis. A transition period for staffing and process development will be required.
We agree some additional costs will be incurred for expanded documentation.
ore requirements and more studies will increase documentation costs.
This is difficult to quantify at this time.
This is difficult to quantify at this time.
C â€" Definitely do not support the revised standard
We apprecaite the hard work of the SDT and understand the difficulty of this task. We applaud the efforts to imnprove the standard. However, in its present state, in general the revised standard fails in one if its primary stated goals: create a "clear and concise standard". While some of the ideas are an improvement, overall the standard is very meandering and it makes it difficult to figure out what the requirements are for a particular analysis type without flipping back and forth between the scaterred requirements. For example R2 addresses various aspects of both Near and long term studies, steady state, short circuit, stability, on peak, off peak and other topics. Then there are separate sections (R3, 4, 5) that speak to the various analysis types again. It probably makes sense to the SDT that has evolved with the drafts and discussions, but when you pick it up it is very confusing. One thing that would help greatly would be to label the major Requirements sections to convey the organization of the document. If the SDT made a topical outline of the standard by major Requirement this could help the team organize the standard better. Reulting topical headers may look something like the following for example, R1: Modeling R2: Study Types and Assessment Requirements R3: Steady State Analysis Methods R4: Short Circuit Analysis Methods? R5: Stability Analysis Methods Etc. If it has not been done (and it looks like it has not), the SDT should consider having the language reviewed by the NERC or other legal team. Langauge that seems clear to experienced engineers may not be precise as is critical for standards that carry monitary penalties. An independent review by a non-engineer lawyer would help greatly. Of course, the SDT would then have to undo some damage that would undoubteldy be done to context by the lawyers - but the pass through legal would be a good step. ï€ ï€ Other concerns: ï€ P5 requires testing for a single component failure within a Protection System. What is this referencing? How can a PC/TP be expected to be intricately aware of protection systems and effects of single component failures? Under 2.7.2, there is a generic requirement to expand a list of possible corrective actions under 2.7.1 for any sensitivies under R2.1.3, 2.1.4, 2.4.3 and 2.4.4. This is very open ended and subject to interpretation. How can an auditor review such requirements with consistency?
Individual
Mark Graham
Tri-State Generatino and Transmission Association, Inc.
No
Starting from this version, we think it would be clearer to not distinguish between generator and system stability studies, but rather list both as requirements for Stability Studies. Generating unit analyses would include tests of models such as generator exciters, and System Stability studies would model such things as bus faults.
Yes and No
R2.4.1 "System peak load" needs a definition. Forecast descriptions by the utility should describe probability levels and other specifics.
Yes
We agree with the definitions in concept - that Consequential Load Loss is load which would be unserved following a specific outage event, without any load shedding relay operations. However, there is some ambiguity in how things are defined for N-1-1 contingencies. For example, a firm contract or firm resource would not be automatically curtailed upon the first outage (N-1), but operators may need to curtail the contract or resource schedule to restore the system to acceptable operating limits, or arm relay schemes that would interrupt certain facilities for the second outage (N-1-1). It seems unreasonable that some such operator actions would not be allowed.
Yes
Agree with the described corrective actions, but wonder whether the sub-requirements R3.5.1 - R3.5.3 must be specifically listed.
Yes
We are pleased the SDT pulled out these Requirements. Does the SDT plan to leave them in the standard as notes until they can be incorporated into other standards where they belong? In R11, the term "long-term" is not clear.
Yes and No
R2.3 is acceptable as written. R4 is redundant and should be eliminated. Also, the contingency short circuit study requirement does not appear to meet the purpose described in this draft

standard (breaker duty monitoring). Three-phase short circuits on an intact system should cover the highest fault conditions, and thus the most critical breaker duty conditions.
Yes and No
It does not seem that there should be different performance limits for DC and AC lines. It is unclear why there is a separation of voltage classes. Perhaps it would be helpful for each TP to specify which voltage levels are considered Bulk on their particular system, then split studies according to that definition. We applaud the SDT's efforts to split contingencies into groups with more-or-less the same system impact. We encourage the SDT that it would be very beneficial to regroup them in order of probability of occurance, or even better, to group them by order-of-magnitude of occurance probability. The P categories as now defined seem to overlap in likelihood. For example, in P3 following loss of a generator followed by system adjustments, another generator forced outage is more likely than a transformer forced outage. Loss of a bus section (P2 single contingency) is less likely than the P3 event of a double generator contingency. There is more on the concept of grouping Performance Tables in order of event likelihood in the NERC White Paper, "Reliability Concepts". At the least, notes in the tables - regarding 1) system impact and 2) likelihood of events listed - would be most welcome.
Yes
No
Performance requirements should depend on the potential loss of load impact of a breaker failure, not the voltage level.
No
We appreciate the extra detail describing sensitivity cases, but do not think it is reasonable to require explanations of why each conditon suggested in R2.1.3.1-R2.1.3.7 was or was not studied. It should be sufficient that sensitivity studies are considered appropriate by the individual utility. R2.1.4 should be demoted to R2.1.3.8 (and the "shall include rationale" clause removed).
Yes
Scenario assessments will significantly increase workload. Development of dynamic load models is ongoing, and will need a much longer implementation period than the steady state portions of the standard. As much as $500,000 may be required to address all of R2.1.3 scenario requirements.
It would take as much as two years for the initial supplemental studies with existing staff.
Ongoing additional sensitivity and dynamic studies would cost approximately $300,000 per year.
An additional $100,000 would be required to document studies for compliance purposes.
Perhaps $50,000/year - half of the initial amount required.
We do not anticipate additional investment beyond currently planned facilities.
Transmission projects generally take between 3 and 6 years to complete.
A â€" Generally support the revised standard
We appreciate the efforts of the SDT, considering the difficulty of the task that was and is before them. Our biggest concern is potential confusion regarding sensitivity studies. Secondly, we absolutely must make the Performance Table completely clear and concise. Additional work now will pay big dividends later. Thirdly, there is some ambiguity of several terms used in the Standard that prevents exact interpretation of significant portions of the Standard. Here are a few additional comments we hope the SDT will find helpful: It may simplify considerations of assessments and modeling work to define â€œassessmentâ€ as including written documentation. Then the Standard would not need to separately include "and shall include written documentation" in the body of the standard titles. Also, the SDT should make it clear that "assessment" is what is required; that annual re-study analysis may not necessarily be required. Thanks to the SDT for keeping this feature. It will greatly simplify our work, and should speed the audit process as well. There seems to be some ambiguity between either 1) requiring specific years to be studied and 2) leaving timeframe selection to the TP. Assessment for year One or Two (R2.1.1) may be performed by either the TOP or the TP. Studies of year One or year Two are generally considered to be operating studies and should probably not be required in TPL-001-1. Also in R2.1.1, year Five is specified as a required study year. No matter what the requirement says, the TP will need to assess performance for critical timeframes. This would lead to additional study if year four were the critical year for example. And for sensitivity studies of delayed facilities (R2.1.3.3) additional study years might be required. Perhaps a reasonable compromise would be to require something in the 2 to 5-year timeframe, and something in the 6 to 10-year timeframe. For coordination with regional study groups in our area, one would logically choose year 5 and year 10, but the specific choice should be up to the TP (and PC if any). Sole-Customers on radial service who are responsible for facility upgrades should be allowed to elect a lower reliability than the rest of the system. It seems that operating scenarios required to be studied by TOP should not need study in the planning horizon by the TP, and

should be excluded from this standard. Specific comments concerning other sections of the draft standard: 1. In the definition of Generating Stability Study, we suggest "the lack of damping" be changed to "damping" 2. In R2.1 title, please move listed requirements in the second sentence to sub-requirements (they are already there). 3. In R2.1 title sentence, the term "annual current" presents two additional requirements. We suggest those words be deleted. 4. In R2.1, delete the end of the title sentence, ending the sentence with "the following studies" 5. In R2.1.3.2, the meaning of "transfer" is not clear. 6. In R2.1.3.4, the term "variability" is not clear. do you mean "Operating Capability"? 7. In R2.1, R2.2 and 2.4, the phrase "Near Term (or Long Term) Transmission Planning Horizon portion of the" could be omitted. "Near Term" and "Long Term" study horizons should just be specified as sub-requirements of Steady State, Stability, and Short Circuit 8. In R2.7.3, the term "identified System Facilities" is not clear. System Additions? 9. Heading R3.3 is not needed. Renumber section sub headings to 3.2.3, etc.

Individual

Andy Leoni

Tri-State G&T

No

We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study â€œfocuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to â€œdevelop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingenciesâ€. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say â€œonly whenâ€ the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, â€œmaterial Transmission System changeâ€ and â€œat or near the point of Interconnectionâ€ to invoke a study.

Yes and No

R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirement in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. ï€ We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. ï€ The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Ownerâ€™s open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Ownerâ€™s responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to

existing units with a change in dispatch.

No

We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as â€œlocal Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systemsâ€ in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, â€œâ€¦load no longer being connected to a sourceâ€¦â€. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (â€œAlthough Load which is lost as a result of the Loadâ€™s response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirementsâ€) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.

Yes

We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.

Yes

While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.

Yes and No

We agree with R2.3. However, R4 requires assessment of â€œShort-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting dutiesâ€. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute â€œnormalâ€ condition or â€œfollowing any single Contingency conditionâ€. Also, by specifying the normal and single contingency conditions, R4 is straying into â€œhowâ€ to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.

Yes and No

We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event

could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.

No

We do not disagree with the proposed definition change. However, we do not agree that â€œSubstation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.

Yes and No

We interpret â€œexit breakersâ€ to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes

Yes and No

e generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the â€œbase caseâ€ of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the â€œbase caseâ€ condition. R2.7 also states that â€œCorrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivitiesâ€. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the â€œbase caseâ€, will the judgment of the Transmission Planner be then questioned because theâ€œbase caseâ€ used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?

Yes

We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.

5

6-10

C â€" Definitely do not support the revised standard

We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. ï€ There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. ï€ We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions. ï€ We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with â€œraising the barâ€. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. ï€ As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms â€œinterruption of firm transmission serviceâ€, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what â€œFirm Transmission Serviceâ€ means. Two points, 1) the NERC definition states â€œhighest quality service offered to customers under a filed rate schedule that anticipates no planned interruption.â€ The Standard implies anticipation of â€œunplannedâ€ interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order 890, or firm transfers modeled for the conditions being studied? One way to interpret the intent is the firm transfers being modeled for the conditions in the powerflow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption of firm transmission service should also be allowed for P1 through P5 contingencies in the table. In addition, we believe that DC and AC lines should have the same performance requirements with respect to interuption of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines can automatically be curtailed when the line is outaged.

Individual

Thad Ness

AEP

Yes

No

We are concerned about unintended consequences with regard to System Stability studies, specifically, the possibility of generating unnecessary work. We would like the SDT to consider language changes that recognize the following realities. (1) While System Stability studies may be justified as a more detailed look at contingency scenarios whose observed severity in steady-state analysis suggests the need for more in-depth study, they cannot be expected to achieve the same breadth of scope as steady-state analyses. In decoupling System Stability studies from steady-state analysis, the draft standard may unnecessarily tend to force stability study scopes to approach those of steady-state analyses. (2) The characteristic limiting factors of systems are generally known (whether thermally limited, voltage drop limited, or transient or small-signal stability limited) and in many systems the limiting factors are thermal or steady-state voltage, but not stability. The draft standard may end up forcing System Stability studies to be done

solely for compliance. It is not that independent System Stability studies are never justified (they are, for example, where inter-area small-signal instability is a known factor), but in many systems, they are not necessary. We observe that as sub-requirements of R2 and R5, R2.5 and R5.5 are the responsibility of the Transmission Planner and Planning Coordinator. Is it the SDTâ€™s intention that these entities be responsible for conducting the Generating Unit Stability analysis, irrespective of the ownership of the generating units? Should the Generator Owner be responsible for conducting the Generating Unit Stability analysis?
No
Should clarify that itâ€™s load that is no longer connected since the transmission facilities to which it is connected have been outaged as expected by the normal relay response to the event being studied. In other words, the loss of load that is connected to facilities that have cascaded as a result of the event being studied is not consequential load loss (nor is it non-consequential load loss). See load loss definitions under Attachment D of PJM Manual 14B for additional wording suggestions.
No
Generator tripping should not be regarded the same as generator runback. With tripping, a resource is lost from the system and there is no assurance that it can be restored to service within a reasonable time. Runback allows the resource to stay connected and the original MW level is potentially restorable if the precipitating factors for runback can be resolved. The generator may be valuable for MVAR as well as MW. The existing TPL standards imply that generator tripping is not permissible in connection with Category B events in that Table 1 footnote b does not mention it, whereas it is mentioned in connection with Category C events in footnote c; we agree with this. Generation is a system resource and should be protected against the more common single contingency transmission events. We would like to see the present implied restriction on generator tripping following single contingencies to be maintained and clearly articulated in the new standard, with a provision for regional variance. In contrast to tripping, what the standard has now for manual or automatic runback in R3.5 is okay.
Yes
However, although the responsible entities listed for each individual requirement are correct from a functional model (compliance) perspective, in actual practice the data flow may not (and in many instances does not) follow the paths outlined in this draft. For example, the node loads, scheduled interchanges, generation models, facility additions, etc., are all provided to the Transmission Owner (TO), since itâ€™s the TO that typically builds the planning models for their transmission footprint and then provides those models to the Transmission Planner and Planning Coordinator. Therefore, the Transmission Owner should be added as a recipient of this type of data.
Yes
The formatting is okay. We would like to see the two tables merged. Except in the extreme disturbances sections, Table 1 and Table 2 are nearly identical (the only difference is that fault types are added to Table 2). The tables could easily be merged into one, including the extreme disturbances sections to some extent.
Yes
Yes
Yes
Yes
Table 1 does not specify a maximum amount of allowable non-consequential load loss for those categories (including P6) that have a "Yes" listed under the "Non-Consequential Load Loss Allowed" (last) column. See load loss definition under Attachment D of PJM Manual 14B for an example of a maximum amount specification.
Additional one-time cost of 33 man-months
2 years
Additional ongoing cost of 12 man-months
Additional one-time cost of 15 man-months
Additional ongoing cost of 7 man-months
Individual
Andrew Wilcox

NB Power Transmission

No

In the past, power systems within the NPCC Region have been designed to meet NPCC design criteria, which is basically that any design contingency does not cause instability of the NPCC defined bulk power system, and does not result in any emergency limit violations (thermal, voltage or stability), unless those violations are contained within a small local area of the system and can be mitigated. Design to NPCC criteria may include, and does include in many cases, interruption or curtailment of firm transmission service, underfrequency load shedding, undervoltage load shedding or SPS tripping of generation and/or load. The proposed table introduces new design criteria for which present power systems within NPCC are not presently designed to - being the restrictions on interruption of firm transmission service and consequential load for certain contingencies as outlined in the table, which up to this point was acceptable by NPCC design criteria, and the present NERC TPL Standard. The table should not impose new design criteria on the existing power system and should be relaxed such that present NPCC design criteria is acceptable into the future, as historically it has been proven to provide acceptable levels of reliability in the NPCC area. There would be enourmous impacts on existing transmission service agreements and compliance issues if the design criteria outlined in the table is imposed. Meeting the design criteria outline in the table would require building new transmission facilities with, in some cases, very little benefit to the loads in terms of reliability. For example, there is an area of the system consisting predominately load. This area is supplied by two 345 kV transmission lines and three 138 kV lines. Studies show that under certain low probability, but predictable, conditions that the loss of one of the 345 kV supplies will result in unacceptable low voltage or thermal limit violations on equipment within the area. Therefore, an SPS has been utilized which trips load within the area on the loss of the 345 kV line in order to prevent unacceptable low voltage or thermal limit violations under these low probability conditions. In this case these loads are considered non-consequential and tripping them for a loss of a 345 kV line is unacceptable as per P1 in the table. Now assume that this arrangement has been in service operationally for the past 10 years and has only operated twice resulting in a 2 hour outage to these loads each time. Now also assume that these same loads have been interrupted 15 times (for a total of 30 hours) in the past 10 years because outages of a radial line within the area that these loads connected to. In this case, the loads are considered consequential and these interruptions are acceptable. Compliance with the design criteria in the table in this case would require building additional transmission into this area to prevent the load loss by SPS on the loss of the 345 kV line. Assume the cost of this new transmission is 80 million dollars and its net benefit would be to prevent (historically) 2 interruptions out of 17 total interruptions to only the loads in question within the area. The design criteria in the table in this case do not provide adequate benefit for cost for these loads in this area. Adequate transmission planning must take into account engineering judgement concerning cost/benefit ratio to loads as well as type of loads served, expectations of loads in terms of interruptions and where money can be best spent to reduce interruptions to loads. The criteria outlined in the table does not achieve this in all cases. The table should not dictate what contingencies can result in consequential load loss or interruption of firm transmission service. These decisions should be left to local planning engineers who have in-depth knowledge of local tranmission issues (as well the interconnected power system)and reliabilitiy needs of loads involved. The table should only state that the listed contingencies will not result in system instability or violations of emergency thermal and voltage limits following all automatic actions. Table 1 in the existing version of the TPL Standards with its footnotes b) and C) presently allows for this and does not have criteria as stringent as the new table. The new table should not introduce new, more stringent design criteria.

Individual
Larry Watt
Lakeland Electric
Yes
No
Modeling the dynamic behavior of Loads is difficult at best and merits a discussion or white paper. Recommend requirement 2.4.1 specify the size of induction motor that should be considered and comment on modeling of small induction motor loads such as air conditioning.
No
Recommend: Consequential: Load that is no longer served because its electrical path to the BES is open as a direct result of system response to the event under study. Load lost due to event induced transients is Consequential load loss; however, the this load must be included in the model during steady-state analysis. Load lost due to UFLS, UVLS, Special Protection Schemes and operator actions are not considered Consequential. Non-Consequential: Load that is no longer served for any reason other than those identified in the definition on Consequential.
Yes
No
It is sufficienct to direct the TP or PC to obtain and include the appropriate data outlined in R9 through R14 in their respective model cases. The proposed addition of R9-R14 just adds more evidential paperwork requirements to the TP or PCs plate.
No
R2.3 or R4 should specify how many and / or how to choose which years of the planning horizon shall be studied. R4 should specify method of choosing which single contingencies to study as larger systems will require an inordinate amount of work to outage every element during each of the study years of the short circuit analysis.
No
Separating steady-state from dynamic (stability) in the tables makes sense. Several suggestions: On page 11 move the planning events note 1 below the Planning Events title or begin note 1 with "For planning events â€¦" to remove confusion between planning events and extreme event requirements. Include an analysis section in the steady-state and stability requirements sections of TPL-1 that explicitly lays out the performance requirements (including the notes) - this would make the performance requiements very clear on a line item basis and the tables would become a quick reference. Special attention should be given to defined period of time between multiple events and the actions available to the operator. In table 2 (page 17) note 3 should be changed to: "Uncontrolled cascading and islanding â€¦" in order to be consistant with R5.4.4. " . . . If the evaluation of implementing a change . . . shall be conducted."
Yes
Yes
No
R2.1.3.1 requires other than peak sensitivity studies while R2.1.2 requires Off peak studies. Recommend further defining of R2.1.2 to specific load level or points on forecast demand curves to eliminate any overlap between two requiements.
Yes
Unknown
Unknown
Unknown
Unknown
Unknown
Unknown
Unknown
B â€" Unsure about supporting the revised standard
Curtailing firm transmission should explicitly be a viable option when preparing for the next contingency if the previous contingency and a credible next contingency call for curtailing firm transactions for reliabilities sake. Not allowing for firm transmission curtailment in this case seems to be a market requirment driving a reliability requirement. Determining the duration of

consequential load loss (R3.3.2.1) is impractical as the root cause of the event vice the defined event type (e.g. - loss of line) determines the duration of the outage. A line can be outaged by a temperary lock out of protection device or 15 spans of a line might be destroyed by fire. The difference between the two make determination of duration impractical. System peak Load (R2.1.1) needs to specify if it is the specific year, season or historical peak demand. Forecasting methodologies affect the system peak load that is projected. Differences between a 50/50 and 80/20 case will result in different forecast peak data.
Group
Southern Company Transmission
Roman Carter
Southern Co. Transmission
No
We suggest the following for the System Stability Study definition: Study that focuses on large portions of the System (which may include many generating units) and how contingencies affect that larger area to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.
No
R 2.4 needs to have the word System inserted in front of the word Stability. R 2.4.3 One should only have to explain why a sensitivity was performed, not why it was not performed. In general we believe that breaking these requirements into specific sub requirements focusing on specific sensitivities is too prescriptive and inappropriate. It will lead to over focus on these particular issues to the detriment of system reliability. There should be no list of sensitivities enumerated as subrequirements. Engineering judgment needs to be permitted. R 2.4.3.1 It should be clearly stated whether the load model refers to system load or the dynamic load model at individual busses A specific proposal for R2.4.3 which addresses the above concerns is provided as follows: R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, sensitivity case(s) shall be run and documented that stress the System to reflect one or more conditions such as variations in dynamic Load model assumptions, modification of expected transfers, unavailability of long lead time facilities, variability and outages of reactive resources, generation additions, retirements, or other dispatch scenarios. Document why each sensitivity was selected.
Yes and No
Yes on the definition. The definition of Consequential Load Loss has been appropriately modified to include loss of load as a result of the load's response to the transient condition. This recognizes the fact that when subjected to fault voltages of sufficient depth and duration, the load undervoltage protection will result in loss of Load. Therefore, in order to more accurately replicate real-world behavior through dynamic stability simuation analysis, the proper representation of expected real world loss of load is acceptable. No on R3.3.2.1 dealing with Consequential Load. The computation of expected consequential load loss and duration does not result in any useful information contributing to increased reliability. Therefore, this requirement R3.3.2.1 should be dropped. If the computation is not deleted, at least the duration part of it should be dropped. In a Planning analysis, the duration is indeterminate.
No
Generation run-back and tripping should be allowed and most of the the proposed sub-requirements are appropriate. However, R3.5.2 is overly broad. We suggest that regulatory and statutory requirements should be deleted from R3.5.2.
No
R9 needs to be clarified that the forecast is based on expected mix of residential, commercial, and industrial loads, but that this mix does not have to be supplied.
Yes
Yes and No
We suggest that the word "requirements" be added to the title of the tables as in Steady State Performance Requirements. We also suggest for header note 2 of Table 2 that the words be changed from "Dynamic voltages shall" to "Voltages during dynamic simulation shall"
Yes
Yes
No
R 2.1.3 One should only have to explain why sensitivity was performed, not why it was not performed. In general we believe that breaking these requirements into specific sub requirements focusing on specific sensitivities is too prescriptive and inappropriate. It will lead to

over focus on these particular issues to the detriment of system reliability. There should be no list of sensitivities enumerated as subrequirements. Engineering judgment needs to be permitted. A specific proposal for R2.1.3 which addresses the above concerns is provided as follows: R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) shall be run and documented that stress the System to reflect one or more conditions such as higher or lower Load than forecasted with variability of Load/demand and Load power factors due to season, weather, or time of day; modification of expected transfers; unavailability of long lead time Facilities; variability and outages of reactive resources; generation additions, retirements, or other dispatch scenarios; decreased effectiveness of controllable Loads and Demand Side Management; modification of planned Transmission outages. Document why each sensitivity was selected.

Yes and No

The requirements are more practical now. If two or more 500kV lines are lost, it makes complete sense to allow loss of non-consequential load so long as cascading outages are not triggered. While we agree interruption of firm transmission service and non-consequential load loss should not be allowed to meet the planning requirements for the first system contingency (to get loadings back within normal ratings), these system adjustments should be allowed to prepare for the second event so that the system will meet the requirements following the second event. We recommend that clarifying changes be made to incorporate this concept. We recommend that the statement below be included as modification or as a footnote for the P6 portion of the table as follows: Interruption of firm transmission service and non-consequential load loss are allowed after the first event as a system adjustment to prepare for the second event in order to meet the requirements following the second event.

These costs cannot be determined without having experience with the new standard and its performance requirements.

C â€" Definitely do not support the revised standard

Category P6 is the loss of a system element, followed by system adjustments, followed by the loss of another element. The table columns for this category say that interruption of firm transmission service is allowed. The table, however, is not clear whether the interruption of firm service is allowed as part of the system adjustment (between the outages) or whether it is only allowed after the second outage. It was stated in the NERC TPL SDT WebEx (August 26, 2008) that the interruption is not allowed as part of the system adjustment. If this is the interpretation, this will cause Southern Company to not support the revised standard. This would be a dramatic change from the existing standard and would result in the unintended consequence of significantly reducing transmission system capability to accommodate firm transmission service including reduction of transfer capability of interfaces to a fraction of their currently reported capability. This would in effect be imposing an n-2 criteria for offering firm transmission service. This would not be an acceptable situation for the users, owners and operators of the bulk power system. In addition, the standard should clarify the accommodation of Conditional Firm Service as defined by FERC Order 890.

Individual

J. David Carpenter

Brazos Electric Power Cooperative, Inc.

No

We do not see the need to have 2 separate requirement sections nor definitions for both System and Generating stability studies. The section for stability studies should simply suggest when these studies should be performed, when new generation is added, conditions for that, etcâ€¦ Confusion continues to come from the ambiguous use of language such as 'Material Transmission System changes' or 'changes in generation capability'. Of note in 2.5.2, requiring stability studies for the addition of a new substation in a transmission line connected to a generator is completely unnecessary most of the time but the wording in 2.5 does not appear to allow flexibility. Discretion should be provided to the TP. A first course of action would be to bring the related stability criteria under one section. It seems like 5.6 can be combined under a requirements section for stability studies.

No

We do agree with the wording change in 2.4 which uses 'assessed annually'. 2.4.1 and 2.4.2 are ok. 2.4.3 is not agreeable, as it implies or could imply a number of studies are required. Stability studies are not required as often as steady state studies. A new in-line load serving substation can certainly impact the steady state results of an area but would not have the same impact

from a steady state perspective. In other words, we feel that running stability studies for a number of small variables does not provide any added benefit and thus stability studies should not be treated the same as steady state studies from a requirement standpoint. More emphasis should continue to be placed on the steady state analysis. 2.4.3 should be edited to say "Sensitivity cases as deemed appropriate by the TP or PC, that stress the System (or BES) may be run reflecting one or more of the following conditions. Other sensitivities not included below may also be run. Appropriate documention should be included describing the rationale for the selection of the cases and conditions" delete 2.4.4 as it is taken care of in 2.4.3 2.5 can be deleted as it adds nothing to the stability requirements 2.5.1 should be modified to be included under 2.4 as a required study with the caveats from 5.6 brought over defining parameters, or delete 2.5.1 altogether as 5.6 covers the addition of generation. 2.5.2 is still fairly ambiguous even with the changes and should be deleted. However if kept it should be modified to remove the last part of the sentence beginning with "or the addition of a new substationâ€¦". The addition of a simple in-line substation does not have a material impact on the stability of a near-by plant. 2.6.1 and 2.6.2 should be combined to remove the mention of generating plant stability. deleting 5.4 is ok Not sure of the need to add 5.5.2. Isn't that the intent of the whole Standard? 5.5.3 seems to be acceptable.
No
Non-consequential is fine. For 'Consequential Load Loss' the entire last part of the definition that begins with "Although Load which is lostâ€¦" can be deleted or at least deleted to the part that begins with "Transmission planning entities are not allowedâ€¦". We think the last part of the sentence is intuitive.
Yes
Yes
R9-R14 do not belong in this Standard. Adding requirements in the wrong location only adds to the confusion by forcing review of more Standards by other less relevant entities and causing additional burden by insuring the requirements match between Standards for the SDT. R1.1 should be deleted. Tracking all those changes (outages, etcâ€¦) is unreasonable and will essentially be unenforceable, for if the data is not tracked, how will anyone know it is not tracked?. Requiring large amounts of documention that provide no additional benefit or causes undo burden will result in fewer studies or effort placed into proper study.
No
2.3 is acceptable, the deletion was recommended in our previous comments. R4 should not be added to this Standard. It adds nothing to the document the way it is worded and is quite similar to 2.3.
No
Compared to the new table format, the old Categories were better. Perhaps if there is confusion with the old table or format, this should be cleaned up. We suggest the old tables remain, or combine some of the new sections to reduce the number of categories.
No
Part of the definition of a bus tie breaker as outlined in this Standard should be that it is the ONLY connection between 2 substation buses. Not sure why the word 'straight' is used in this definition. If a bus with a 90 degree turn is connected to another bus by a single tie breaker, does this not apply? Also, breaker and a half schemes do sometimes have a bus tie breaker in them although its probably not common. Including those specifics in not needed.
Yes
Yes but this seems to add another category of items to provide for in the assessment.
No
2.1.3 should have been left alone. We have a real problem with the addition of 'technical' and documenting why things were NOT selected. We would also like to see more leeway provided to the TP and PC by adding language similar to that mentioned above such as "as deemed necessary by the TP or PC". 2.1.4 should be incorporated into 2.1.3 in a similar fashion as our suggested changes for 2.4.3.
No
P6 should be incorporated back into P5. Up to this point, studying all shunt devices has not been considered to have a significant impact on the BES. In addition these are picked up when studying other contingencies. Certain type devices should be reviewed individually, FACTS devices, etcâ€¦ but this should be at the discretion of the TP or PC. Currently adding shunt devices as a category would reqiure modification to case data or software to be able to automatically run through them all and we are not convinced this is worth the effort.
We have no real way to estimate this or determine these costs.
Again, we have no real feel for making an estimate but it would be safe to say that the studies would take longer than the planning window. In other words, the results would not be completed before we would have to start them over again.

C â€" Definitely do not support the revised standard

Our biggest concern is the apparent lack of experience or understanding in the repercussions of including so many required studies and detailed documention. And to what end? The amount of data that would be required to be saved will be so voluminous no one could go through it all to make any meaningful determination in a timely fashion. It's one thing to study every possible combination of outage but you then have to do something with the results, not just record them somewhere because a standard requires it. On the other hand some progress is being made in removing some of the more ambiguous or useless items so we are getting there to some degree. Deleting 1.1.2, 1.1.3, 2.7.3, 2.7.4, and 5.4 are good starts. However it appears some things were added that are just confusing or are unnecessary. 5.5.2 seems to simply restate the obvious intent of the section, to meet the performance requirements so its not really needed. Phrases such as "document why categories were NOT selected" are intuitively obvious. Categories were not selected because, in the judgement of the TP or PC, they were not deemed useful to study so why document this each time. R6 is also a confusing addition to this Standard and we aren't sure what it's intended to require. Use of the word "proxies" is probably not the best substitute for what was intended. We suggest R6 be deleted as well.

Individual

Sergio Garza

LCRA TSC

Yes

Yes

Yes

Yes

No

R-11 states that "Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment." This is typically achieved through outage coordination between the individual Transmission Operators and the System Operator. More clarification may help by defining the difference between planned outages and long-term outages as they are used in R-11. This may be an Operations standard versus a Planning standard requirement.

Yes

Yes

Yes

Yes

Yes

Yes

A â€" Generally support the revised standard

LCRA had a comment on the first posting stating that the loss of any two Transmission circuits

on a common structure should be viewed as a single contingency as a single component failure (tower, shield wire, conductor, hardware) could in-fact lead to the loss of two circuits. In the second draft, this outage is still being viewed as a Multiple Contingency (P7). At the same time, the loss of a tower line with three or more circuits is being viewed as an Extreme Event, when the same single failure could lead to the loss of multiple circuits. So, even if a double circuit outage is viewed as a Multiple Contingency, shouldn't a multiple circuit outage be viewed the same. In the Definitions of Terms Used in Standard, Extreme Event is defined as Events which are more severe and have a lower probability of occurance than Planning Events. What is a "lower probability of occurance"? Is this to be determined by each TP or TO? How is this probability determined? Are we to assume from this definition that we can use probabilistic planning to determine which Events should be studies even at the N-1 level?

Group

PJM Interconnection LLC

Patrick Brown

NERC and Regional Coordination

No

In the definition of Consequential Load Loss - Revise Transmission Planning Entities to Transmission Planners; or otherwise clearly identifying the entiities that are meant to be addressed by the term "Transmission Planning Entities." Revise "which" to "that" as indicated by the text below that is in quotes and Upper Case: Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation connected to a source as a result of the event being studied or "THAT" is lost as a result of the loadâ€™s response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load "THAT" is lost as a result of the Loadâ€™s response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, [Transmission planning entities] TRANSMISSION PLANNERS are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements. Regarding the definition of Planning Event - The given words do not define the term. For example is an event meant to be an forced outage condition; or is meant to be any set of state conditions. If an event can be anything, then the term is not a definition. Planning Coordinator - Explicitly state that this defination will be deleted when the functional model defination for this entity is approved May consider deleting the term because it is not unique to this standard. The term is already defined in the Functional Model. R1.1 â€" Data changes are routine in such studies and need to better quantify when technical justification is required.

No

PJM concurs with the general direction; however the sensitivity analysis section as written requires explanation of why certain sensitivities were not selected. However the sensitivity requirement must be defined. Prove the rationing. R2.4 should state for stability we should use light load rather than system peak which is for steady state analysis. R2.4 should be modified as follows R2.4 should be modified as follows R2.4 The Near-Term Transmission Planning Horizon portion of the Stability analysis requires: Suggest making all sub requirements bullets under R2.4 The words in R2.4 seem to state that the "analysis must be assessed annually" which seems to leave open the option of assessing an old study, whereas R2.2. and R2.3 state a study is required each year, and a study is conducted each year. The words need R2 must be clearer and more consistent. System stability requirements seem to be poorly defined. It appears that there is going to be an expectation that inter-area oscillation and small signal analysis be performed frequently over a variety of conditions. I'm not sure how geared up industry is for this. R2.4.1 is too ambiguous. This subrequirement requires a model that "appropriately represents the dynamic behavior of loads". However, the requirement does not reference how that judgement is made nor who would make the judgement. The subbullets are vague and again provide no basis for performance or for arbitration. R2.4.4 should be deleted as it will deter TPs and PCs from conducting additional studies. R2.4.4.1-5; Should clearly define words like variation,modification, unavailabilty of long lead time facility,variability of reactive resources. R2.5 is ambiguous regarding the definition of "affects stability margins". What is the technical performance margin for "affect"? If not defined in the standard then who makes the decision? The TP? the auditor? NERC staff? Do you mean crtical clearing time and how much of change for example percentage or cycle.

Yes

No

Delete R3.5.2 as redundant. The limit data provided by the asset owners is expected to ensure that safty, equipment, regulatory and statutory requirements are met. For example to require the PC to ensure that equipement is not at risk would require the PC to make financial decisions that belong to the asset owner (e.g. the owner may be willing to exchange loss of equipment life for short term financial gains). R3.5.3 - the term sustainable, stable condition is not defined.

Futher the maintenance of such a state is beyond a PC's capability.

No

R9 - Reactive load forecasts are not generally provided by distribution provider to the Transmission Planner. R11 â€" The requirements for providing â€œlong term outagesâ€ to the Planning Coordinator is vague. What is a â€œlong term outageâ€ and do I need to plan for it? I think the right answer is only if it is expected to occur over the period that the TP establishes their critical system conditions. SDT should initiate the appropriate SAR prior to disbanding.

No

Attributes of the short circuit analysis needs to be better define. For example which studies need to be done, for what period and how often.

Yes

Yes

Yes

Comments: PJM supports the use of bus tie breakers.

No

The standard as worded: â€¢ Implies all tests are run for a given sensitivity o the standard should be revised to read applicable testing for the applicable sensitivity. â€¢ Requires proof of negative o Why a sensitivity was not selected â€¢ Requires that expansion plans identify the impact of sensitivity o Many sensitivities may have varying impacts on an expansion plan. Suggested changes: R2.1.3 - For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that reflect one or more of the following conditions shall be incorporated into the assessment. Documentation of the technical rationale for why each of the conditions was selected and the portion of the assessment that included each selected sensitivity shall be supplied. R2.1.4, R2.4.3, and R2.4.4 - need to be modified accordingly. Delete R2.1.4 as it is superfluous. If a PC runs a sensitivity study and includes that analysis in its Plan, then why would NERC mandate that the PC explain why the non-mandated sensitivity study was run. If a study is required then it should be mandated. If a study is not mandated then he PC should not be held accountable for explaining the un-mandated study. R2.4.3.1 â€" Variation in load model. Specific numbers should be included. R2.4.3.2 - Modification of expected transfers â€" Be more specific. Firm or non- firm transfer and amount of MW R2.4.3.3 - Unavailability of long lead time Facilities. How many years out we are looking at and for how long it must be out of service. R2.4.3.4 - Variability of Reactive Source â€" need to be more specific (give me MVARS). We already test this under FAC 010 for lost of shunt capacitor. R2.4.3.5 - This should already been taken into account when we do studies. So be more specific. R2.7.2 - Include a description of how results of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 impacted the list of actions developed in accordance with R2.7.1. R2.1 - Revise wording - The annual assessment of the of the NT Planning Horizon shall include: then go into the sub-bullets. The SDT must clarify exactly explicitly how many studies (in terms of numbers) must be done each planning horizon for short term and long term and how much sensitivity study for term.

Yes

Clarity about the exact number of supplemental studies required needs to be added to the standard before this question can bee addressed. The requirements contained within the standard are nebulous. The requirements need to clearly state the depth of the studies required for each time horizon.

Clarity about the required documentation and coordination needs to be added to the standard before this question can bee addressed. As written, our interpretation is the increase in documentation requirements is substantial.

Clarity needs to be added throughout the requirements. Our interpretation of the standards as written will not result in substantial capitol investment. These standards will not have a substantial impact on improved system reliability, however; the requirements do significantly increase the manpower investment in study documentation and efforts associated with reporting study results.

C â€" Definitely do not support the revised standard

Changes should be made to the sensitivity analysis. See question 10 above. R2.6 - The need to restudy previously studied years should be left to the transmission planner when in their judgment there is a material change. Based on the material change the TP should be responsible

for determining what aspects of the performance requirements need to be proven

Individual

Marv Landauer

ColumbiaGrid

Yes and No

We generally concur with the changes for the Requirements associated with the Generating Unit and System Stability, however, â€¢ Generating unit stability studies are typically performed at the time of interconnection. Even though stability studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of generating units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units. Will every TP have to benchmark their generating unit stability study for its entire fleet with the acceptance of this Standard? In other words, will every TP has to recreate documentation for all its older units? â€¢ We would appreciate that the SDT more clearly define the terms in R2.5.2, â€œmaterial Transmission System changeâ€ and â€œat or near the point of Interconnectionâ€ to invoke a study with examples.

Yes and No

R2.4 is acceptable. Please consider deleting R5.4.3. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Ownerâ€™s open access tariff requires Generator Owner to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Ownerâ€™s responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.

No

We generally do not disagree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as â€œlocal Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systemsâ€ in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, â€œâ€¦load no longer being connected to a sourceâ€¦â€. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of

providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (â€œAlthough Load which is lost as a result of the Loadâ€™s response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirementsâ€) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.

Yes

We generally agree, however, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.

Yes

While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.

Yes and No

We agree with R2.3. However, R4 requires assessment of â€œShortcircuit capability of its equipment under normal condition and following any single Contingency condition that would result in greater circuit breaker interrupting dutiesâ€. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute â€œnormalâ€ condition or â€œfollowing any single Contingency conditionâ€. Also, by specifying the normal and single contingency conditions, R4 is straying into â€œhowâ€ to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study. We suggest R4 be modified to read â€œShortcircuit capability of its equipment under plausible system configurations that would result in the greatest circuit breaker interrupting dutiesâ€.

Yes and No

We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some maybe some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SGT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Please explain/define the term "single ended line" used in Table 1, P2.1. We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.

No

We do not disagree with the proposed definition change. However, we do not agree that â€œSubstation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.

Yes

Please explain/define the term â€œexit breakersâ€. We agree with the rationale for the requiring more stringent performance requirement levels for non-bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes.

Yes

We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would

discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the â€œbase caseâ€ condition.

Yes

We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.

The new TPL Standard raises the bar of transmission system performance. This can be expected to require significant additional analysis, documentation and system reinforcements (or reduced firm transfers allowed on the system if system reinforcements are not made). We will defer to our members to provide quantification of those elements.

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A â€" Generally support the revised standard

We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution. There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions. We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with â€œraising the barâ€. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Interruption of firm transmission service does not mean that firm load is not served. If there is other generation in the system that could increase to meet the firm load requirements if the firm transfer being modeled is interrupted, then interruption of firm transmission service should be allowed for P1 through P5 contingencies in the table. In addition,

we believe that DC and AC lines should have the same performance requirements with respect to interruption of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines should be allowed to be curtailed when the line is outaged.

Individual

Dan Rochester

IESO

No

(i) Generating Unit Stability Study: We do not agree with the phrase ".. or one bus away from that point." This limits the scope of the testing to only the next bus. At times, contingencies that remove critical transmission facilities several buses away from a generating plant may affect generating unit stability performance. We suggest to reword this phrase to "..or in the nearby vicinty that can have an adverse reliability impact on the generating units' stability performance." (ii) Long-Term Transmission Planning Horizon: A nit-picking suggestion to change the first "longer" to "long". (iii) Planning Coordinator: We not not see the need to repeat a definition that is already proviced in the NERC Glossary of Terms and the Functional Model. There is a plan to implement a wholesale change from Planning Authority to Planning Coordinator. This is expected to occur in the first half of 2009. (iv) System Stability Study: Since voltage performance is included in this assessment, we suggest to add to the phrase "â€¦which may include many generating units AND GROUPS OF TRANSMISSION FACILITIES..". (v) Year One: The second part of the definition is confusing. By "12-18 months from the completion of the previous annual Planning Assessment." does it mean 12-18 months from the "complete date" of the previous assessment, or from the "end of the previous assessment period"? For example, a previous assessment was completed on April 30, 2008 that cover a 12 month period from May 1, 2008 to April 30, 2009. Does year one for the subsequent assessment start from May 1, 2009 or May 1, 2010? In view of the confusion, having only the first sentence would suffice. In fact, there is only one reference made in the requirement (R2.1.1). Qualifying "year one" can easily be made in that requirement without having to have a defined term. Adding defined terms without a good cause adds to the maintenance task for the glossary of terms. Further, it begs the question on why "year two" and "year five" referenced in that same requirement are not defined.

No

A. R2.4 (i) We suggest to remove words such as "consideration of" and "deemed appropriate" since these are not measurable and not enforceable. Further, we continue to disagree with mandating sensitivity testing with descriptive subrequirements. Sensitivity testing (ii) Specific to R2.4.3, we continue to express our disagreement to include sensitivity testing in the requirements. We are disappointed that despite disagreements by the majority of the commenters and their suggestions to leave sensitivity testing to the TP's and PC's discretion, the SDT continues to stipulate detailed requirements for sensitivity testing. The SDT in its summary response to comments indicates that these testing are intended as "â€¦providing some guidance on what could be included in the sensitivity studies without being too prescriptive." If these are indeed intended as guidance rather than enforceable requirements, then they should be provided in a technical document or a reference document that supports the standard, not in the standard itself. B. R2.5 (i) Similar to our comments unde Q1 (i), the requirements should not restrict to changes at or near the Interconnection point. Transmission changes several buses removed from the generator's Interconnection point may also affect the stability performance of the generators. Suggest to reword it to "â€¦ in the nearby vicinty that can have an adverse reliability impact on the generating units' stability performance". (ii) There seems to be a hole or incomplete scenario in R2.5.2 in the sentence: "removal of a Transmission Line or the addition of a new substation in one of the Transmission Lines connected to the plant." We agree that removal of a transmission line in the vicinity needs to be assessed; we also believe that addition of not just a substation but also any transmission facilities in the vicinity should be assessed. We therefore suggest to reword this to: "removal of a Transmission Line or the addition of new transmission facilities in the generating plant's nearby vicinty that can have an adverse reliability impact on the generating units' stability performance. C. R3.4 (i) We do not agree with the requirement that: "If the Extreme Events analysis concludes there are cascading outages, an evaluation of implementing a change designed to reduce or mitigate the likelihood of such consequences shall be conducted." Future transmission systems are planned and designed accordingly to Planning Events. It should not be a surprise that applying Extreme Events to the planned transmission system for which it is not designed to withstand such events would show instability and/or cascading outages. The follow on actions should be to evaluate possible acitions to contain and minimize the impact of cascading outages, rather than to come up with options or alternative designs to reduce or mitigate the likelihood of such occurrences (since doing so will imply that we design and plan for Extreme Events). We therefore suggest to reword it to: "If the Extreme Events analysis concludes there are cascading outages, an evaluation of possible acitions to contain and minimize the impacts of cascading outages.

Yes

Yes and No

We agree with the conditions stipulated in R3.5.2 and R3.5.3 but do not agree with R3.5.1. This is one of the performance objectives that the use of manual and/or automatic generation run-back/tripping is intended to achieve, and it is already stipulated in Table 1. Suggest to remove this condition.

Yes and No

A. R9: Agreed B. R10: Holding the TP to provide modeling information on Firm Transmission Service, (a TSP's role), Interchange Schedules (also a TSP's role), and resources required to supply Load for each of its Balancing Authorities (Resource Planner's role) may not be appropriate. In fact, the TP relies on others to provide this set of information for developing its own study model. We suggest to change the responsible entities to these specific entities; or if the TP is required to provide the PC with the model, then there should be requirements in other standards to obligte these other entities to provide the TP with the needed information. C. R11: The phrase "with consideration given to spare equipment strategy" is vague (not enforceable or measurable) and does not appear to add anything to the required product which should already have the spare strategy and capability taken into account when outage plans are developed. We suggest to remove this phrase. If this was retained, the follow on question is why R12 doesn't have a similar requirement (note that a generator outage may not be due to maintenance of the generator itself; it could be due to outages to step-up transformers, breakers or switches for which spares may be carried). D. R12: Agreed. E. R13: We are not sure what purpose to include "and new technologies" would serve if such technologies do not result in the provision of generators and/or reactive sources which are already covered. Further, this is vague to determine what consitutes "new technologies" and hence this is not enforceable or measurable. We suggest to remove this term. F. R14: Same comment as in R13 on "new technologies".

Yes

Yes and No

Condition (5) at the top of Table 1, and Condition (4) at the top of Table 2 are not required since they are already covered by R3.2 and R5.2, respectively. Further, Condition (6) in Table (1) and Condition (5) in Table 2 should be stipulated in R3 and R5 since these are not performance requirements, but rather the analysis (simulation) requirements.

Yes

No

We hold the view that all breakers can be exposed to the same types of event, i.e., they can have internal faults and can be "stuck" when attempting to open as instructed. As such, there should not be any difference in the expected system performance among them in response to system events, and regardless of the voltage levels. We suggest the SDT to revised Tables 1 and 2 such that their expected performance are identical.

No

As we commented on R2.4.3, we continue to express our disagreement to include sensitivity testing in R2.1.3 and R2.1.4. We are disappointed that despite disagreements by the majority of the commenters and their suggestions to leave sensitivity testing to the TP's and PC's discretion, the SDT continues to stipulate detailed requirements for sensitivity testing. The SDT in its summary response to comments indicates that these testing are intended as "â€¦providing some guidance on what could be included in the sensitivity studies without being too prescriptive." If these are indeed intended as guidance rather than enforceable requirements, then they should be provided in a technical document or a reference document that supports the standard, not in the standard itself.

Yes

We concur with the need to test N-1-1 contingencies involving transmission facilities allowing interruptions to firm transmission services and non-consequential load loss to meet performance requirements, for any voltage levels as long as adverse reliability impacts on the BES are exhibited.

Minimal, if any, since the IESO has been conducting and documenting planning studies that meet events and performance criteria that are very similar to those specified in the draft TPL-001 standard. However, this is speculative at this time since we are not sure what the eventual standard will be like. Another uncertain area is the extent to which additional studies are required if sensitivity testing is mandated. Please see our comments under Q2 and Q10 on sensitivity testing. If sentivity testing should become a requirement, then the scope is very wide and we are unable to have a good handle on the increamental time and cost to supplement past study portfolio.

Minimal, if any, for the reasons indicated above, other than for meeting the sensitivity testing

requirements (if mandated) which cannot be quantified.
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None expected at this time.
None expected at this time.
A â€" Generally support the revised standard
(i) We generally support the direction and principle of the revised standard. It is a step in the right direction to more clearly stipulate the types of events and expected performance requirements with inclusion of multiple element contingencies and multiple single contingencies, and allowance for interruptions to firm transmission services and non-consequential load loss. (ii) More details and refinements are expected to be provided that address the issue of sensitivity testing, reduce the number of layers in the subrequirements (to facilitate ease of developing Measures and Violation Severity Levels), more clearly specify the responsible entities, etc. We look forward to seeing these improvements in the next revision, along with the first draft of Violation Risk Factors, Time Horizons, Measures, Data Retention Periods, and Violation Risk Factors when the requirements approach their near final draft form. (iii) We suggest the SDT review the development plan with the Standard Process Manager, especially the timing for posting the standard for balloting, responding to comments and conducting recirculating ballot. the timing between the initial ballot and recirculating ballot is usually short, and the balloted standard is not supposed to change. The proposed development plan appears to allow a long lead time between the two ballots, and for making changes to the standard between them.
Group
Southern California Edison
Dana Cabbell
Transmission and Interconnection Planning
No
We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study â €œfocuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to â€œdevelop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingenciesâ€. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say â€œonly whenâ€ the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, â€œmaterial Transmission System changeâ€ and â€œat or near the point of Interconnectionâ€ to invoke a study.
Yes and No
R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirement in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. ï€ We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level

below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. ï€ The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Ownerâ€™s open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Ownerâ€™s responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.

No

We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as â€œlocal Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systemsâ€ in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, â€œâ€¦load no longer being connected to a sourceâ€¦â€. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (â€œAlthough Load which is lost as a result of the Loadâ€™s response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirementsâ€) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.

Yes

We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.

Yes

While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities

(LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.

Yes and No

We agree with R2.3. However, R4 requires assessment of â€œShort-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting dutiesâ€. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute â€œnormalâ€ condition or â€œfollowing any single Contingency conditionâ€. Also, by specifying the normal and single contingency conditions, R4 is straying into â€œhowâ€ to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.

Yes and No

We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.

No

We do not disagree with the proposed definition change. However, we do not agree that â€œSubstation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.

Yes and No

We interpret â€œexit breakersâ€ to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes

Yes and No

We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the â€œbase caseâ€ of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the â€œbase caseâ€ condition. R2.7 also states that â€œCorrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivitiesâ€. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the â€œbase caseâ€, will the judgment of the Transmission Planner be then questioned because theâ€œbase caseâ€ used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?

Yes

We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise,

the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.

B â€" Unsure about supporting the revised standard

Our Response is (B) and (C). We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. ï€ There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. ï€ We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions. ï€ We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with â€œraising the barâ€. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. ï€ As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms â€œinterruption of firm transmission serviceâ€, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what â€œFirm Transmission Serviceâ€ means. Two points, 1) the NERC definition states â€œhighest quality service offered to customers under a filed rate schedule that anticipates no planned interruption.â€ The Standard implies anticipation of â€œunplannedâ€ interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order 890, or firm transfers modeled for the conditions being studied? One way to interpret the intent is the firm transfers being modeled for the conditions in the powerflow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption of firm transmission service should also be allowed for P1 through P5 contingencies in the table. In addition, we believe that DC and AC lines should have the same performance requirements with respect to interuption of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines can automatically be curtailed when the line is outaged.

Individual

Rick White

Northeast Utilities
No
Northeast Utilties has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
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C â€" Definitely do not support the revised standard
Northeast Utilties has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
Group
North Carolina Electric Membership Corp
James Manning
North Carolina Electric Membership Corp
Yes and No
We think we understand the direction that the SDT is heading but needs to be clearer. Angular stability for a single unit is the focus of Generating Unit Stability where as System Stability involves multiple generating machines or plants, and may also encompass voltage stability of loads which should be addressed separately in our opinion since different tools are used for this assessment.

No

We assume that 2.4 is supposed to be for "System" Stability. Please confirm. R2.4.1 - Is this for On-Peak? Please confirm. Also the subrequirement that requires a model that "appropriately represents the dynamic behavior of loads" is too ambiguous. The requirement does not reference how that judgement is made nor who would makes the judgement. The subbullets are vague and provide no basis for performance. It should be clarified. How does the TP/PC model 3rd party loads from LSEs or DPs within its area that it interconnects? Is there an additional requirement to LSE/DPs needed in R9-R14 to collect such characteristics of load data? There is concern with load modeling requirements (use of word â€œappropriatelyâ€ in R2.4.1). Does this requirement mandate the use of specific load models for each bus, or would an aggregate load model which represents the system as a whole be sufficient? Does the use of the PSS/E CONL function satisfy the requirements for a load model? The subrequirements of R2.4.3 are much too vague and are subject to various interpretations. These should be more specific as to what should be assessed, e.g. 5% variation in load model. Why aren't the last 2 subrequirements already accounted for within the assessment? R2.5 is ambiguous. What is meant by "affects stability margins"? What is the technical performance margin for "affect"? As defined by whom? The TP/PC? the auditor? Is this a % change or what? R5.4 - OK R5.5 - We are OK with changes made, but we do share a concern with others that the requirement to perform simulations on 20 MW generators (to be consistent with the Registration Criteria) per R5.5.1 may be too much, and we recommend also a 75 MW generator cutoff for required simulations.

No

Although the modified definitions are an improvement over the previous version, addressing the following issues in the Consequential Load Loss definition will further improve clarity: 1) Redundancy: The second sentence in the definition says "Although Load which is lost as a result of the Load's response to the transient condtions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed,â€¦". It appears that "â€¦and is permitted when Consequential Load Loss is allowed,â€¦" is redundant and may be omitted/deleted -- isn't this *always* permitted for all events, except P0 (normal)? (See headnote 4 in Table 1 -- Steady State Performance). 2) Who are the "planning entities"? Suggest replacing with Functional Model terms Transmission Planner and Planning Coordinator. 3) Verbosity: It appears that the intent of the second sentence in the definition can be conveyed more concisely. Consider changing to "However, relying upon the expected Load loss during transient conditions of the event to meet steady state performance requirements is not allowed." 4) If the verbiage proposed above is found acceptable, we offer a follow-up suggestion. Because the second sentence in the definition essentially characterizes the exception to the allowed Consequential Load Loss during steady state performance evaluation, we suggest moving it out of the definition and appending it within headnote 4 in Table 1 -- Steady State Performance. 5) While the Consequential Load Loss definition employs the acronyms UFLS and UVLS, their expanded descriptions have been used in the Non-Consequential Load Loss definition. Suggest that these terms be used consistently in both definitions. Also, why is Special Protection Systems included as an example of what constitutes Non-Consequential Load Loss but is excluded from the list of exceptions to Consequential Load Loss (whereas UVLS and UFLS appear consistently in both)? Perhaps examples of each are needed: Consequential Load Loss examples might be a) tapped load from an outaged networked line from main station breaker to main station breaker of entire line, b) outaged T/T transformer serving radial load that that taps the networked transmission line, c) load served from a radial feeder from a single source. Non-consequential might include a) manual load dump or generator trip to mitigate cascading or uncontrolled load loss or an overload during adverse conditions, b) SPS addressing above, c) UFLS, d) UVLS.

Yes and No

The generation run-back/trip should not put any load or firm transfer at risk of also being harmed. Maybe this is implied within the conditions required.

Yes

We would like to add a couple of items for clarification. 1) Planning Coordinators and Transmission Planners should make it clear to LSEs, DPs and GOs as to what extent they model loads, reactive devices, and generators and not just rely on FAC-001, FAC-002 or the entities Facility Connection Requirements document to convey that information. 2) If requirements 9 through 14 are to be removed at a later date, then the SDT should be required to initiate the appropriate action or SAR before its disbanding to insure this happens.

Yes

Yes and No

We would like the headings to be repeated at the head of each page. Also, enumerate Stability Tables different from the Steady State to distinguish between them.

No

To provide clarity, a revised definition is proposed. A bus-tie breaker is a circuit breaker that connects two individual bus sections in a straight bus substation configuration. Substation

configurations such as ring-bus, breaker-and-a-half, or double bus-double-breaker do not have bus-tie circuit breakers.

Yes and No

The installation of bus-tie circuit breakers in a straight bus configuration would reduce exposure to a) bus faults or to b) line faults with breaker failure without adding much risk for internal fault in the bus-tie breaker. Those entities that employ a straight bus substation design with bus-tie breakers have recognized that failure of the bus-tie breaker, a very low probability event, would result in the loss of multiple transmission elements and perhaps firm load for a short time until the bus sections can be restored, but bus-tie breakers are an investment worth the risk. Therefore, it is generally agreed that the outage of non-bus-tie circuit breakers should have higher performance requirements than the outage of bus-tie circuit breakers. The SDT should be commended for this change since the previous draft version. However, it is not clear that adopting a higher standard of performance for planning events involving transmission facilities 345 kV and above will improve overall system reliability. Some areas of the continent already have n-2 planning criteria, yet these systems have still experienced significant outages including blackouts. It is suggested that a review of the Transmission Availability Data System (TADS) data, when available, should be conducted to help assess what system performance requirements need to be strengthened before arbitrarily determining to "raise the bar" for certain voltage levels and system designs. The industry should not be forced to invest a great deal of capital to meet a new standard requirement when it would not have an immediate impact on system reliability. Some sort of cost/benefit analysis should be performed to justify any change from the present TPL-001 through 004 standard requirements. Also, further clarification is required to explain how to drop consequential load without cutting firm transmission service to those affected/outaged customers, and this needs to be added to the notes in Tables 1 and 2.

Yes and No

Sensitivities to base assumptions for studies are always good utility practice. But we agree with others that these may be overly prescriptive in requiring each and every one. Allow the TP and PC to select the appropriate sensitivites for the annual assessments with input from customers and affected stakeholders. We are concerned that the requirement for every sensitivity each and every year would result in excessive burden to existing PCs and TPs doing this analysis with no resulting improvement to reliability.

Yes

N/A

N/A

N/A

N/A

N/A

N/A

N/A

B â€" Unsure about supporting the revised standard

While we are satified that the changes are moving in the right direction, we share concerns that are being expressed by other SERC TPs and PCs that the standard may be overly prescriptive in some areas such as the sensitivies being required.

Group

E.ON U.S. Transmission Planning

Keith Yocum - Manger, Transmission Strategy & Planning

E.ON U.S.

Yes

Yes and No

R2.4 â€œThe Near-Term Transmission Planning Horizon portionâ€ implies that there are other portions of the [System] Stability analysis. This needs to be reworded to make it clear that there are no other portions. Add the word â€œSystemâ€ to make it clear. R5 The data to be included in all models for the Planning Assessment is included in R1. The discussion here is redundant. This should be deleted. R5.4.3.1 Is this the intent? â€" Following Single Contingency events, Transmission configuration changes and redispatch of generation can be simulated to return the system to Normal Rating provided that all Facilities shall be operating within their Emergency Rating.

Yes

Yes and No

R3.5.1 Is this the intent? â€" Following Single Contingency events, Transmission configuration

changes and redispatch of generation can be simulated to return the system to Normal Rating provided that all Facilities shall be operating within their Emergency Rating.
Yes and No
R1 states â€œEach Transmission Planner and Planning Coordinator shall maintain System models â€¦ and R7 states â€œEach Transmission Planner and Planning Coordinator shall determine and identify individual and joint responsibilities â€¦ but R9-R14 requires that data flow through the Planning Coordinator. Requirements R9-R14 should allow the data to be provided to either, as appropriate for the situation. R9 â€œneighboring systemsâ€ should be replaced with more descriptive terms such as Planning Coordinators of â€¦ or Transmission Planners of â€¦ R10 The Transmission Planner is a user of this data, just like the Planning Coordinator, and is not the source of this data. The responsibility should be placed on the â€œsource providerâ€ like R9 and R11-R14. R11 The requirement should be limited to planned outages and existing outages that may be long-term due to the spare equipment strategy. The contingency analysis covers all other future outages. R12 The requirement should be limited to planned outages and existing outages that may be long-term due to the spare equipment strategy. The contingency analysis covers all other future outages.
Yes
Yes
Yes
Yes
Yes and No
2. R2.1.3.2 refers to modification of expected transfers as a sensitivity test. Does this include transfers across the system, such as a transfer from Cinergy to TVA?
Yes
C â€" Definitely do not support the revised standard
It is confusing that single Contingency and multiple Contingency are used throughout the document when the Categories in Tables 1 and 2 are Single Contingency and Multiple Contingency. Also System normal, normal conditions and Normal System are spread throughout the document. If they all mean the same, use the same wording. If not, explain the difference. R2.4.1. - Does this apply only to motors directly connected to the BES? Is there a size (hp/MW) limit? Who is responsible to provide this data to the Planning Coordinator? I would think it would both the Distribution Providers or the Generator Owners but R9 & R12 do not mention this. R2.4.1 refers to â€˜the dynamic behavior of Loadsâ€™ and induction motor loads. How would this model data be developed, and by who? R2.5.2. - Define â€œMaterialâ€. Is an addition of a load tap point material? R2.6.2. â€" Define â€œstudy areaâ€. Does a topology change over 300 miles away trigger a stability study for a generating plant? R2.7.1.1. â€" Define â€œproject initiation dateâ€. Would this include going to the PSC to get approval or just when construction begins? R3.2.1 states â€œâ€¦ and identify how the generators are treated in the steady state simulation.â€ What is meant by â€œtreatedâ€? I request the use of more descriptive wording. R3.2.2 states â€œâ€¦ and identify how loadability is treated in the steady state simulation.â€ What is meant by â€œtreatedâ€? I request the use of more descriptive wording. R3.3.1 â€œSystem normalâ€ is a Planning Event included in Table 1. R3.3.2 capitalize â€œSingleâ€ if you referring to P1 and P2 events. If not, this is confusing. R3.3.2.1 states â€œConsequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment.â€ Quantification of expected duration requires a probability analysis of load cycles, repair time, and potentially of other factors that will be difficult, if not impossible, to develop with any confidence. The Planning Assessment is based on a deterministic evaluation. Requiring the expected duration is inconsistent and useless. R3.3.2.2 Is this the intent? â€" Following Single Contingency events, Transmission configuration changes and redispatch of generation can be simulated to return the system to Normal Rating provided that all Facilities shall be operating within their Emergency Rating. R5.3 states â€œâ€¦ and identify how the generators are treated in the simulation.â€ What is meant by â€œtreatedâ€? I

request the use of more descriptive wording. R5.5.1 and R5.5.2 should be moved to 2.5. These requirements outline the generators and the sensitivities to be analyzed. R5 appears to focus on Tables 1 and 2. R5.5.2 states â€œShall be performed for changes in the real power outputâ€¦â€ What types of â€œchangesâ€, or â€œchangesâ€ due to what? Is intention of the requirement, that Generating Unit Stability be assessed at two levels of real power output that differ by more than 10% of the existing capability or more than 20 MW, whichever is greater? R6 states â€œâ €¦ and document the proxies used in the simulationâ€¦.â€ What is meant by â€œproxiesâ€? I request the use of more descriptive wording. R8 ends with â€œThis distribution shall include:â€ Include what? Table 1 There used to be limits on multiple circuit towers and common ROW greater than 1 mile. Is this left to the Transmission Planner and Planning Coordinator? Extreme Events â€" Item 3b is the same as Item 1, this should be removed. Table 2 Note 5.a.ii How can this be applied when the largest unit in the Balancing Authority Area is larger than the contingency reserve of the Balancing Authority. This requirement is excessive. At some level, subsequent trips of generators and/or lines should be allowed as long as Cascading does not occur.

Group

ERCOT System Planning

Jay Teixeira

ERCOT

No

Most industry commenters from the previous draft advised against making a distinction between system and generating unit stability, which are not commonly accepted industry terms. The only difference between the two seems to be location of contingencies tested. ERCOT suggests removing specific requirements for Generating Unit stability, as System Stability covers everything.

No

ERCOT believes R2.4.3, R2.4.4, R2.5, R5.2, and R5.3 should be deleted and R5.4 and R5.5 should be combined as follows: R2.4.3 should be deleted due to the unacceptable increase of stability runs required to meet the requirement. Considering sensitivities for outages of reactive resources and various dispatches and retirements for at least two different load levels is beyond the capability of most organizations, for both technical and manpower reasons. R2.4.4 is unbounded and not measurable, and should not be included as a requirement. R2.5 and all requirements for Generating Unit Stability analysis should be deleted since there is little or no difference between this and System Stability. R5.2 should be deleted because contingency definition standards should be defined in a modeling standard. R5.3 Voltage ride through capability should be included in the model provided by the generator and should not be necessary as a requirement in the TPL standard. R5.4 and R5.5 could be combined, as there is little or no difference between Generating Unit Stability analysis and System Stability analysis. In this case, R5.5.1 and R5.5.2 would be moved to R5.4 and R5.5.3 would be removed (repeats R.5.4.1). Also, it appears that R5.4.1 is in conflict with R5.4.2 because R5.4.1 says â€œidentified and evaluated for System Performanceâ€ but not have to meet requirements but R5.4.2 says â €œmeet requirements â€¦ Table 2â€. Also, R5.4.2 is repetitious with text of R5.

No

ERCOT feels the amount and duration of load loss should be considered in the definition.

No

The requirement is unclear whether runback is allowed if the conditions are met or if runback is allowed to meet the conditions. What is the need for generation run-back/tripping if all facilities are within their Facility Ratings? Many times the run-back/tripping of units, such as wind farms, is necessary to remove a post-contingency overload associated with these units. The protection scheme includes the run-back/tripping to allow these units to generate at higher levels pre-contingency.

No

ERCOT recommends that R1.1 be deleted. ERCOT shares the opinion of some that R1.1 is counter-productive and more likely to degrade reliability than improve it. R1.1 discourages transmission planners from revising inaccurate, speculative, or outdated modeling data by imposing new documentation burdens and compliance liability. Adding additional requirements to document changes to data required in requirements R9 through R14, MOD-010, and MOD-012 could induce an atmosphere of using inaccurate data to eliminate the need to document a needed change. Furthermore, it is believed that all modeling requirements should exist in a Modeling standard not a performance standard.

No

ERCOT believes R4 is unnecessary and does not address an actual problem; ERCOT recommends that R4 be deleted. ERCOT does not presently posess the capability or have access to the data needed to perform the calculations required by R4 as this requirement should apply to only the equipment owner (GO or TO).

No

The table is hard to read and follow since it spans multiple pages and the table headers are not repeated on each page. ERCOT believes that there are two many categories. For example, in Table 1 both Category P1 and Category P3 are not necessary. Since they require the same system performance and P3 is more severe than P1, it can be assumed that successful simulation of P3 would result in successful simulation of P1. Category P2-1 can not be simulated without modification to typical transmission models. Normal steady state power flow software typically has as a line either in or out of service, but not half in and half out. â€œBreaker Faultâ€ and â€œStuck Breakerâ€ definitions are included in the table notes, but would probably be better placed with the other defined terms. It is somewhat unclear as to why there are multiple names as the steady state system impact and requirements are the same. Also, the stability impacts would be more severe for a stuck breaker assuming delayed clearing. This would allow for removal of P2-3 and P2-4 in both Tables 1 & 2. It appears that P4 and P5 are duplicating efforts as well. It is not specified which entity is responsible to define and provide contingency definitions in industry standard software format such as those requiring knowledge of protection system failures and lines on the same structure for more than 1 mile. Only entities such as TOs and GOs have access to that knowledge.

Yes

Yes

The sensitivity cases suggested are unnecessary and unfeasible. For example, generation additions to cases that can already meet the load under contingency conditions do not create a reliability problem as the new generator can always be turned off. On the other extreme, sensitivity analysis of possible, unknown and uncontrollable generation retirements along with the Table 1 requirements of P3 (Generator + 1) contingency analysis presents an overwhelming study and documentation burden that will not add a corresponding benefit to the study and the results would be meaningless.

No

The former P5 of the first draft only required transmission circuits of 300 kV and above to be simulated out of service followed by loss of transmission circuit or transformer. P6 of the second draft requires all BES (100 kV and above) transmission circuits, transformers, dc lines, and shunt devices in combination of another BES circuit, transformer, dc line, and shunt device. The number of contingencies that have to be simulated increased dramatically to an impractical level and would require days of uninterrupted computer run time to complete. This, in combination with other contingencies and sensitivities required in this draft of the standard, is not feasible for large entities. ERCOT recommends that this planning event P6 retain the verbiage regarding transmission lines and transformer low side windings above 300kV.

At least 4 years. It will take as long as the largest entity in our system which has estimated about 4 years. We are totally dependent on them for all data needed for these studies.

he workload to support the existing TPL-001 to TPL-004 has already consumed two full-time senior positions. Add to that the new requirements for steady state studies necessary in this standard would take at least another full time position. The new stability study requirements and short circuit requirement added would double the number of people necessary for a total of approximately six full time positions with moderate to high experience levels. (Four incremental FTEs with estimated annual cost of $650,000). Purchasing additional licenses for study software is an additional expense.

C â€" Definitely do not support the revised standard

The NERC reliability standard requirements should represent the minimum studies necessary to achieve reliability given the broad range of entities of various sizes and capabilities. Instead, the standards seem to represent the gold standard of the kind of studies that could be accomplished (steady-state, short circuit, and stability) given infinite time and resources with the number and variety of contingencies and sensitivities necessary. This level of steady state and stability studies can only be undertaken by the larger entities with a deep and experienced engineering staff. Why are most of the requirements applicable to a Transmission Planner and Planning Coordinator? Unless they are the same entity, this is an unnecessary duplication of effort. If a Planning Coordinator has a number of Transmission Planners in its region, then these requirements have to be fulfilled by each Transmission Planner for its individual area and the Planning Coordinator for the region made up of the individual areas? What is the Planning Coordinator coordinating if it is duplicating the work of the Transmission Planner?

Individual

Jason Shaver

American Transmission Company

No

Generating Unit Stability Study definition - We suggest deleting the text, "on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point.", because certain Generation Facility contingencies should be considered and key Transmission Facility contingencies can be more than one bus away from the interconnection point. System Stability Study definition - We suggest this alternate wording: "Study that focuses on portions of the System, which may include many generating units with various Contingencies. This study is concerned with loss of synchronism, lack of damping of inter-area power oscillations, and voltages during the dynamic simulation." We suggest this wording because the definition of a study should not give the criteria, but rather the general elements of the study.

No

We disagree with the proposed R2.4.1 text. This inclusion of this requirement may be premature at this time for several reasons. There is presently no industry consensus on how the dynamic behavior of loads should be properly represented and analyzed. In addition, it would be a large and difficult effort to identify, collect, and maintain the pertinent information. It is presently difficult to obtain and maintain the percentage of residential, commercial, and industrial load at each transmission interconnection point, much less try to get the proper percentage of the various types of induction motor loads. We do not accept the R2.4.3.1 text and want some explanation of the what, when, and how to provide the technical rationale for why each condition was or was not used. In R2.4.3.1, what is meant by â€œvariationsâ€ (e.g. how much variation is enough)? In R2.4.3.2, what is meant by â€œmodificationâ€ (e.g. how much modification is enough) and "expected transfers" (e.g. firm or non-firm transfers)? In R2.4.3.3, what is meant by â€œlong lead timeâ€ (e.g. 1 month, 1 season, 1 year, 2 years, etc.)? In R2.4.4, we believe this requirement should not be added. Why was it included? It seems superfluous, because any entity can study other sensitivities if they want. Why should TP or PC have to study what the other entity wants to study? Who would be the judge in case of disagreement over the technical rationale? In R2.5.2, Why was the addition of a new substation included? We would not expect a new substation to negatively impact the system or generating unit stability. We note the R5.5 and R5.6 should really have been updated to refer to 5.4 and R5.5. In R5.4.3.1, we suggest that the time-limited aspect of Facility Ratings be included in the Glossary Definition and then it would not need to be clarified in various locations (R3.3.2.2, R3.5.1, R5.4.3.1, Table 1-Note 1, & Table 2-Note 1) throughout the standard.

No

For Consequential Load Loss definition, we suggest that the last sentence be deleted because it is application text, rather than definition text. We accept the Non-Consequential Load Loss definition as written.

No

We generally accept this text, but would like the Facility Rating reference to include the applicable time frame (see response to Question 2.)

No

We disagree with the approach of temporary requirements because of the problems that arise due to conflicting or uncoordinated standards (e.g. conflicting requirements between FAC-010-1 and TPL-002-0). We support the approach of developing appropriate MOD standards SARs to make the desired changes. However, if these requirements are retained than we suggest the following few changes to R9-R14. In R9, revise the text to: "â€¦ load forecast data for at least the coincident peak of each year â€¦" In R10, revise the text to: "Each Transmission Service Provider shall provide â€¦" In R11, is the text referring to "known planned outages" and "known long term outages"? What is the distinction that is meant to be made between the two specified types of outages? In R12, revise the text to: "â€¦ modeling information for planned facilities changes, known planned outages â€¦". Also, is the text referring to "known planned outages" and "known long term outages"? What is the distinction that is meant to be made between the two specified types of outages? In R13, revise the text to: "â€¦ for planned facilities changes for each year of the Transmission planning horizon including but not limited to generators, and new technologies â€¦". This wording broadens the meaning from simply "new" facilities to also include any "changes" to existing facilities. We suggested removing the reference to Reactive Power Devices because these devices would not be owned by Resource Planners. In R14, revise the text to: "â€¦ for planned facilities changes for each year â€¦". This wording broadens the meaning from simply "new" facilities to also include any "changes" to existing facilities.

No

We suggest added clarification of the following questions: 1. Should analysis be performed for the near-term and long-term planning horizon? 2. Should only the peak system condition be analyzed? 3. What does the analysis include (e.g. breaker overduty evaluation and protective relay coordination)? 4. Does the analysis of single contingency for greater duties refer to only the

P1 category or both the P1 and P2 categories? R4 - Does the equipment capability reference include the ground grid and bus structures?

No

We think that the tables are so similar that they should be recombined into one. This would require reasonable adaptation of the tables. If the tables are kept separate, then we suggest that the Categories symbols in Table 1 and Table 2 be different to help distinguish between them (e.g. P1:S1, P2:S2, P3.2:S3.2, etc. We suggest that the header text (i.e. Category, Initial System Condition, etc.) be repeated on every applicable page to be more reader-friendly. The superscripts do not refer clearly to the respective notes. (There are numbered notes in the beginning of the table, numbered items in the extreme events evaluation requirements section, numbered items in extreme event description section, and numbered notes at the end of the table). Perhaps the referenced notes should have unique numerology or format to make the superscript references clearer.

No

We suggest applying the proposed definition to a new term, "Straight Bus-Tie Breaker". The creation of a narrow, special application definition of "bus tie breaker" is generally confusing and misleading. The term "bus tie breakers" is widely used in the industry in the context of various bus configurations. In addition, this narrow definition may create confusion if other Standards refer to bus-tie breaker in a different context.

No

We recognize that the addition of this requirement is an attempt top raise the bar above the existing standards. However, the more stringent non-bus-tie performance criteria should only be adopted if there is sufficient evidence to demonstrate the expected reliability risk (i.e. system impact x probability of occurance) is high enough to warrant the cost of the system modifications that would be needed to meet the criteria. System modifications that involve the installation of line and substation facilities >300 kV will likely take years and cost tens to hundreds of millions to build. It would be helpful to have a reliability risk analysis that justifies the application of this performance criteria before it is adopted.

No

For R2.1.3, we would like further explanation of what technical rationale is expected and how it should be provided as to why each condition sensitivity was or was not used. In the subrequirements, we are unsure of what is exactly meant by "variability of load demand and load power factors", "modification of expected transfers", "long lead time Facitilites", and "modification of planned outages". For R2.1.4, it is unclear what specific performance requirements must be met for these other sensitivities. We would also like some explanation of what technical rationale is expected and how it should be provided as to why each condition sensitivity was or was not used.

Yes

We suggest that there be more explanation of what system adjustments are permitted. We understand that the revised P6 allows loss of Non-Consequential Load for Systems below 300 kV as well.

We estimate that the additional one-time costs of supplemental studies and analyses to meet the new requirements might be spread over five years because some analysis only has to be updated every five years. So, we estimate that the total cost over five years for additional staff or consulting services may about $200,000 to $300,000.

We estimate that the lead time to perform supplemental studies and analyses to meet the new requirements might be up to 5 years.

We estimate that the on-going additional cost of expanded studies and analyses to meet the new requirements might be about $150,000 to $200,000 for additional staff.

We estimate that the one time cost for expanded studies and analysis documentation to meet the new requirements might be about $20,000.

We estimate that the on-going cost for expanded studies and analysis documentation to meet the new requirements might be about $10,000.

The additional one-time costs of system reinforcements to meet the new requirements would depend on the results of the new studies and be hard to forecast. However, if they involved just a few 345 kV substation modifications and 345 kV line additions, then we would estimate that it costs may be in the range of hundreds of millions of dollars.

The lead time to build new system projects would depend on the results of new studies and be hard to forecast. However, if they involved a 345 kV substation modification or a 345 kV line addition, we estimate that it might take 5 to 7 years to complete the substation project and 8 to 12 years (or more) to complete the new transmission line project.

B â€" Unsure about supporting the revised standard

We agree with most of the requirements of revised standard. However, the following list of suggestions and comments are given for consideration. Definitions: We agree with the removal of the "Base Case" definition and the revisions to the other definitions, except as noted above or

below. Long Term Planning Horizon definition: We suggest a slight text change of: "Transmission planning period that covers years six through ten. Studies beyond ten years are required to accommodate . . .". Accountability: We suggest that Transmission Service Provider be added because we also suggest that the Transmission Service Provider be the responsible entity for R10. Requirements: We agree with the revisions to the Requirements, except as noted above or below. R1.1 - We agree with the requirement, but would like more description of what to provide in the technical rationale. R2.1 - We agree with the requirement, but suggest this text change, ". . . by the following annual studies . . .". R2.6.1 - We agree with the requirement, but suggest a slight text change of: " . . . short circuit, Generating Unit Stability or System Stability analysis . . .". R2.6.2 - We agree with the requirement, but suggest a slight text change of: " . . . short circuit, Generating Unit Stability or System Stability analysis . . .". R2.7 - We agree with the requirement, as long as it is really required by FERC Order 693 paragraph 1704. R2.7.1 - We agree with the requirement, but suggest a slight text change of: " . . . or Special Protection Systems, . . ." R2.7.1.1 - We disagree with the "include project initiation date" portion of this requirement. The initiation date is often uncertain and subject to change, which may add considerable work to investigate, monitor and update the date. In addition, we do not know why this information is required to assure BES reliability. R2.7.2 - We agree with the requirement, as long as it is really requried by FERC Order 693 paragraph 1704. R3.2.2 - We agree with the requirement, but suggest a slight text change of: "For all BES Transmission lines . . .". R3.3.2.1 - We agree with the requirement, but suggest a slight text change of: ". . . shall be allowed in the Planning Assessment". R3.3.2.2 - We agree with the requirement, but suggest a slight text change of: ". . . within their Facility Ratings and within the time period allowed by the applicable time limited ratings.". R5 - Is the text refering to "known planned outages" and "known long term outages"? What is the distinction that is meant to be made between the two specified types of outages? R5.1 - We agree with the requirement, but suggest a slight text change of: ". . . the response of the applicable portion of the BES". R5.2 - This clarifying requirement should also be included in the short circuit analysis section. R5.3 - We agree with the requirement, but suggest a slight text change of: ". . . capability of all generators that may have a significant adverse effect on the BES." R5.4.3.1 - We agree with the requirement, but suggest a slight text change of: ". . . within their Facility Ratings and within the time period allowed by the applicable time limited ratings.". R8 - We disagree with the requirement, but suggest a text change of: "Each Planning Coordinator shall establish a list of neighboring system and coordinate the distribution of Planning Assessment results among affected entities the listed neighboring systems, coordinating analysis of these results through an open and transparent peer review process." Table 1 Planning Events Header: We suggest that the header be repeated on every applicable page to be more reader-friendly. Superscripts: The superscripts do not refer clearly to the respective notes (e.g. there are number notes in the beginning of the table, in the extreme events evaluation requirements section, in extreme event description section, and at the end of the table). Perhaps the notes at the end of the table should have unique numbering to make the superscript references clearer. Shunt device: To avoid the need for future interpretation or clarification, we suggest that the meaning of shunt device be explained or defined somewhere in the standard (e.g. cap bank, inductor bank, SVC, STATCOM, etc.). We need to find out how shunt device outages can (or could in the future) be automatically included in the ACCC routine. We interpret that if each stage of a capacitor bank has a circuit switcher, then the outage would be of the largest cap bank stage. P2.2 (>300 kV), P2.3(>300 kV), P3 (>300 kV), P4 (>300 kV), P5 (>300 kV) - We recognize that the addition of this requirement is an attempt top raise the bar above the existing standards. However, the more stringent performance criteria should only be adopted if there is sufficient evidence to demonstrate the expected reliability risk (i.e. system impact x probability of occurance) is high enough to warrant the cost of the system modifications that would be needed to meet the criteria.. System modifications that involve the installation of line and substation facilities >300 kV will likely take years and cost tens to hundreds of millions to build. It would be helpful to have a reliability risk analysis that justifies the application of this performance criteria before it is adopted. If the proposed >300 kV performance requirement is retained, then we would want the implementation timeframe to be long enough to allow reasonable time to transition from a system built to the old requirement to a system built for the new requirement. The time needed for planning, design engineering, regulatory approvals, and construction of >300 kV facilities can be very long (e.g. up to 10 or more years). P7 - We disagree with this requirement. Wisconsin statues require giving preference to using existing ROW for new transmission circuits, but this requirement discourages building multiple circuits on common ROW. Should there be a waiver in this standard similar to the TLP-503-MRO-1 standard for lines slightly more than 1 mile based on a review? Extreme Event Evaluation Requirements 2 - We agree with the requirment, but perhaps a definition be added for "System Controls", since one exists for "System Protection". 3 - We agree with the requirement, but suggest a slight text change of: "Simulate Normal Clearing unless otherwise specified in the Extreme Event Descriptions." Extreme Event Descriptions 2a - We agree with the description, but suggest a slight text change of: "Loss of a structure or tower line with three or more circuits.." 2b & 3b - We agree with the descriptions, but suggest referring to the defined term: "Right-of-Way." 2e, 3.a.i, & 3.a.ii - We agree with the descriptiona, but how large is "large" and how major is "major"? 3.a.v - What is meant by successful cyber attack? Is it a type of cyber attack

that is documented to have been successful? 3c - We agree with the description, but suggest a slight text change of: "Other events based upon actual operating experience such as:" Note 4 - We agree with the description, but the acronym FACTS should be explained in the standard or a definition be added for "FACTS". Table 2 1 - We disagree with this note. We suggest that it be expanded to include the applicable part as Table 1. "The System shall remain stable. In addition, Facility Equipment Ratings shall not be exceeded. Planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings." 3 - We disagree with this note. We suggest that it be expanded to include the applicable part as Table 1. "Dynamic voltage instability, Cascading outages, and uncontrolled islanding shall not occur." Between 3 & 4 - We disagree with omitting Note 4 of Table 1 from Table 2. We suggest including: "Consequential Load and consequential generation loss is allowed for all events shown." Planning Events Same comments on Header, Superscripts, and Shunt Device as in Table 1. Same comments about stricter requirements for P2.2 (>300 kV), P2.3 (>300 kV), P3 (>300 kV), P4 (>300 kV), P5 (>300 kV) as in Table 1. Same comment about P7 as in Table 1. Extreme Event Evaluation Requirements Same comment about Requirement 2 and 3 as in Table 1. 3 - We agree with the requirement, but suggest a slight text change of: "Simulate Normal Clearing unless otherwise specified in the Extreme Event Descriptions." Notes 5 - We disagree with limiting this requirement to just Category P1 category. We suggest that the synchronism requirement be applied to more categories.

Individual

Greg Rowland

Duke Energy

Yes

No

R2.4.1 Load models that appropriately represent the dynamic behavior of induction motors are under development and may not be available for sometime. The implementation plan should take this into account and allow at least 36 months for implementation. This requirement is not immediately achievable. R2.4.3 - Although we agree with the perceived intent of R2.4.3, we believe the wording should be revised to make it very clear that it is not necessary to perform studies to substantiate your technical rationale for choosing not to perform any particular sensitivity study. Documented engineering judgment to support the decision not to perform the particular sensitivity studies should be sufficient. R2.4.3.1 should clearly state whether the load model refers to overall system load or parameters of the dynamic load model at individual busses. Recommend renumbering R2.4.4 to R2.4.3.6, and reword R2.4.3.6 as follows: Any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems. R2.4 should say "System Stability", not just "Stability".

Yes

Yes

Generation run-back and tripping should be allowed and the proposed sub-requirements are appropriate.

Yes

In order to ensure these requirements move to the MOD standards, the TPL SDT is encouraged to write a SAR to get the data related changes into the MOD standards or add it to the issues to be considered by the drafting team in the development plan under project number 2010-04.

No

It is not clear in R4 what is meant by â€œsingle contingencyâ€ and this situation is unlikely to increase fault current. The phrase â€œunder normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting dutiesâ€ should be deleted.

Yes

Separating the steady state and stability tables greatly improves and clarifies the requirements of the standard. The tables could be improved if the headings were put on each separate page. Placing headers in the requirements section of the standard would improve understanding of the flow of the document.

No

The use of the word â€œstraightâ€ in the definition raised questions and did not seem crucial to the definition. We recommend the word â€œstraightâ€ be removed from the definition.

No

In Table 1, Category P4, Events 1 through 5 addressing a stuck non-bus tie breaker >300kV should allow Interruption of Firm Transmission Service and Non-Consequential Load Loss, because P4 addresses a multiple contingency.

No

Although we agree with the perceived intent of R2.1.3, we believe the wording should be revised to make it very clear that it is not necessary to perform studies to substantiate your technical rationale for choosing not to perform any particular sensitivity study. Documented engineering judgment to support the decision not to perform the particular sensitivity studies should be sufficient. Recommend renumbering R2.1.4 to R2.1.3.8 and reword as follows: Any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems.

Yes

The changes are more practical. If two or more 500kV lines are lost, it makes complete sense to allow loss of non-consequential load so long as cascading outages are not triggered. ï€ While we agree interruption of firm transmission service and non-consequential load loss should not be allowed to meet the planning requirements for the first system contingency (defined as initial system condition in the table), these system adjustments should be allowed to prepare for the second event so that the system will meet the requirements following the second event. ï€ We recommend that clarifying changes be made to incorporate this concept. We recommend that the statement above be included as a modification or as a footnote for the P6 portion of the Steady State and Stability tables as follows: "For P6 multiple contingency events, Transmission configuration changes and redispatch of generation are allowed provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits. Permissible Transmission configuration changes include dropping of load and firm transfers needed to prepare for the second contingency. See our related response to question 15.

B â€" Unsure about supporting the revised standard

While we generally support the revised standard, we are unsure of the total cost impact, and whether the additional costs are justified by increased reliability. 1) Load Modeling is a significant open issue. The models for dynamic studies have yet to be developed and the data is not in hand. This standard should allow for the use of the best available information. 2) Category P6 is the loss of a system element, following system adjustments, followed by the loss of another element. The table columns for this category say that interruption of firm transmission service and non-consequential load loss is allowed. The table, however, is not clear whether the interruption of firm service and non-consequential load loss is allowed as part of the system adjustment (between the outages) or whether it is only allowed after the second outage. It was stated in the NERC TPL SDT WebEx that the interruption is not allowed as part of the system adjustment. This would be a dramatic change from the existing standard and would result in the unintended consequence of significantly reducing transfer capability of interfaces to a fraction of their currently reported capability. This would in effect be imposing an n-2 criteria for offering firm transmission service. Duke Energy does not believe this would be an acceptable situation for the users, owners and operators of the bulk power system. 3) The statement in R2.7 "Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities," implies that there are performance requirements for sensitivity studies. Recommend rewording to clarify that there are no performance requirements for sensitivity studies. 4) Recommend rewording R3.3.2.1 as follows: "The single highest consequential load loss and its expected duration following a single contingency shall be documented in the Planning Assessment." 5) In R5.3 the statement, â€œand identify how the generators are treated in the simulation,â€ should be deleted. The word "treated" is vague and typically specific equipment modeling is not identified in studies. The implementation schedule should also take into account the Standard to develop and provide this data is not approved. Since this data is not yet available, please revise the statement as follows: â€œStudies shall use the best available information to consider the voltage ride through capability of all generators." 6) In Table 1, Category P2 Event 1 needs to be revised to recognize the impact of this event on Bulk Electric System reliability for events on the system that are > 300 kV vs. events on the system that are <= 300 kV. P2.1 should not allow for interruption of firm transmission service or loss of non-consequential load for > 300kV; however, it should allow for interruption of firm transmission service or loss of non-consequential load for <= 300 kV. The requirement as currently written would require expenditures for the <= 300 KV system where such an event has minimal impact on Bulk Electric System reliability. In addition, the likelihood of events needs to be considered as requirements are developed. A review of Duke Energy Carolinas data shows that the likelihood of a P2.1 event on Dukeâ€™s 100 kV system is an order of magnitude less than for a P1 event on the same 100 kV system. This is another indicator that the requirement as written would result

in the need for expenditures that provide minimal value to enhancing the reliability of the Bulk Electric System.

Group

FRCC

Richard Becker

Florida Reliability Coordinating Council, inc

No

R2.4.4 and R2.4.3 as written can create issues during the compliance assessment. These requirements place the burden of justifying the inclusion / exclusion of the sensitivities on the TP or PC. Thus, only a sensitivity deem appropriate by the TP or PC and not performed can be found non-compliant. R2.4.4 can be eliminated by changing the wording in R2.4.3 to include sensitivitiesâ€™ deemed appropriate by the TP or PC as follows: â€œFor each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, sensitivity case(s) deemed appropriate by the Transmission Planner or Planning Coordinator that stress the System to reflect, but not limited to, one or more of the following conditions shall be run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied.â€

No

Propose changing the word â€œaâ€ to â€œanyâ€ in the definition of Consequential Load Loss. Consequential Load Loss: Load that is no longer connected to â€œANYâ€ source as a result â€¦ The second sentence in the definition could be interpreted to disallow voltage dependent load models to meet Steady State Performance requirements. Since many planning events result in steady state voltage significantly lower than nominal, system load would be reduced. This definition would be clarified by differentiating load that is lost (no longer connected to a source) and load that is reduced as a result of reduced system voltage. Although Load which is lost (no longer connected to a source) as a result of the Loadâ€™s response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load Loss to meet steady state performance requirements.

No

R3.5.1 â€“ This requirement should be clarified to state that all facilities shall operate within their Facility Ratings before, during and after system adjustments including generation adjustments. R3.5.2 â€“ How can an entity demonstrate that it is not violating this requirement.. The SDT should indicate the type of regulatory and/or statutory requirement that this requirement trying to address (i.e., FERC, EPA, etc.)?. Otherwise, the FRCC recommends removing R3.5.2. R3.5.3 â€“The SDT should clarify this requirement to define what is meant by sustainable and stable. Sustainable and stable may not necessarily be the same as being in a secure condition (ready for the next possible event).

No

R9 through R14 â€“R9 through R14 should not be addressed in this TPL Standard. Requirements R9 through R14 should be included in future revisions to the MOD standards. If R9 through R14 remain in the Standard, then the following comments are appropriate: R9 â€“ Recommend adding â€œand season (as defined by the Planning Coordinator)â€ after â€œâ€¦ load forecast data for each yearâ€. Recommend adding â€œ(as defined by the Planning Coordinator)â€ after â€œTransmission nodesâ€ to allow the Planning Coordinator to appropriately define the term Transmission node. Recommend deleting â€œincluding the expected mix of industrial, commercial, and residential Loads,â€ from the requirement since this information is not required by Transmission Planners or the Planning Coordinator. Many distribution providers will not know the mix of load type for a given Transmission node. R11 â€“Recommend the removal of â€œwith consideration given to spare equipment strategy,â€ from this requirement. We feel that the consideration of spare equipment strategy would be better suited in an operating horizon standard (TOPâ€™s) rather than in the TPL standard. The term â€œlong-term outageâ€ in this requirement is vague and the text â€œand long-term outagesâ€ should be eliminated. The FERC language in Order 693 P-1725 states â€œAccordingly, the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entityâ€™s spare equipment strategy.â€ There is no mention of â€œlong-term outagesâ€ in conjunction with spare equipment strategy. R12 â€“ Recommend rewording as follows: â€œEach Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned generator outages for each year of the Transmission planning horizon, within ninety days of a request for such information.â€ The language â€œlong-term outages for generation equipmentâ€ is vague and unclear as to what is a long-term outage and what specific type of generation equipment should be considered. R13 â€“ Propose adding â€œand any changes to existing plansâ€ after â€œnew planned facilitiesâ€ as shown below: â€œEach Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned Facilities and any changes to existing plans for each year of the Transmission

planning horizonâ€¦â€

No

Recommend for the removal of both R2.3 and R2.4. Short Circuit analysis should be addressed in FAC-002 by revising the standard to include additional detail within FAC-002. Another option would be to develop a new standard addressing short circuit studies and requirements.

No

The Steady State and Stability Performance Tables are very long (currently the these two table are 13 pages) and confusing. Please consider combining and condensing the two tables into one, and either add footnotes or expand the table headings to allow better understanding of the performance requirements.

No

R2.1.3 and R2.1.4 as written can create issues during the compliance assessment. These requirements place the burden of justifying the inclusion / exclusion of the sensitivities on the TP or PC. Thus, only a sensitivity deem appropriate by the TP or PC and not performed can be found non-compliant. R2.1.4 can be eliminated by modifying the wording in R2.1.3 as follows: â€œ For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, at least one sensitivity shall be performed that stress the system based on one or more of the following conditions, plus any additional conditions determined by the Transmission Planer and Planning Coordinator. The Planning Assessment will also include the technical rationale for why each of the conditions was or was not selected for study that year.â€

No

For P6 events (and all other events that allow system adjustments after the loss of a transmission device), this draft does not clearly define when the requirements in the columns marked as â€œInterruption of Firm Transmission Serviceâ€ or â€œNon-consequential Load Loss Allowedâ€ apply. The SDT should clearly state that the requirements in these columns are only applicable after the Event occurs from the Initial System Condition. In addition, the SDT should make it clear whether Interruption of Firm Transmission Service and Non-consequential Load Loss is allowed in preparation for the 2nd Event. On the NERC conference call for the 2nd draft, the SDT chair indicated that Interruption of Firm Transmission Service and Non-consequential Load Loss is not acceptable in preparation for the next event. In Order 693, Para. 1788 - Para. 1796, FERC distinguished between â€œpreparing for the next contingencyâ€ and returning to a system normal state. The SDT removed the allowance that was made in footnote c of TPL-003-0 to â€œTo prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.â€ (emphasis added) for Category C3 events (now P6 for facilities greater than 300kV). This change in the standard is not directed by the FERC Order 693 and is not a reliability improvement that is cost justified. Forced outage rates for equipment greater than 300kV is very low and the impact on markets is very large. Many utilities have granted long term transmission service to entities with the expectation that the service can be curtailed if required in preparation for the next event. If this is not allowed, entities within FRCC will have to greatly reduce the long term firm imports into FRCC or construct additional EHV transmission lines from a location well into Georgia down to a point in the southeastern portion of FRCC. While an in-depth cost has not been completed for a project of this size in many years, it is reasonable to expect that a cost in excess of $1.5 - $2.0 Billion. This investment will only slightly increase the amount of firm imports into FRCC (and replace the imports allowed before this change) for an event that may only occur only once every 20+ years. If this event happens, the Transmission Owners will re-dispatch their own generation to curtail their transactions in addition to curtailing the firm transmission service of others, per their OATT. The SDT should clearly state for these Planning Events, all system adjustments including Interruption of Firm Transmission Service and Non-consequential Load Loss is acceptable in preparation for the second Event where system adjustments are allowed between events.

C â€" Definitely do not support the revised standard

The SDT should consider and allow, for all planning events, , loss of Non-Consequential load as an interim measure for a period of up to 5 years in the situation where system load growth has caused post-contingency action plans to not effectively bring Facilities within normal operating limits due to unexpected or unforeseen regulatory requirements, equipment capability* and/or

the installation of large industrial/commercial customers. *Equipment Capability is added to address unforeseen industry changes in the methodology used to calculating the rating of equipment.

Individual

David M. Conroy

Central Maine Power Company

No

There should be no difference beween System and Generating Unit Stability studies. Each require discretion regarding which events need to be tested. The consequences are potentially similar: either the instability of one of more generators. Extreme Events should be considered for any stability analysis, again, recognizing that discretion needs to be applied when selecting or dismissing particular contingencies. Therefore, the definition of Generating Unit Stability Study should be stricken from the standard.

No

a. A MOD standard should be developed to address the assembly of dynamic load models, rather than specifying modeling in paragraph 2.4.1 (dynamic behavior of loads, including consideration of the behavior of induction motor Loads). Paragraph 2.4.1 should instead read, "System Peak Load for one of the five years." The remainder of the paragraph should be deleted. b. In paragraph R.2.4.3.4, what does "variability" mean? Is variablity more of a concern than an outage? Suggest changing paragraph R.2.4.3.4 to simple say "Outages of Reactive Resources" c. Add a new requirement, "R5.4.3.4 Automatic generator tripping shall not have an significant adverse impact on overall system reliability." d. Remove Heading R5.5 and make generator unit stability for a new facility a section of overall stability requirements. e. Modify R5.5.1 to become R5.4.5, with the following, "Shall be performed for the addition of an individual generating unit or generating units at the same interconnection point 20 MW or greater that are directly connected to the BES." There may be little difference between the stability performance of a single 20 MW unit and an aggregation of units totalling 20 MW at the same BES interconnection point. f. If planning assessment studies all generators or stations above 20 MW, as suggested by R5.5.1, then this provision is unnecessary and R5.5.2 should be deleted. g. If the output of a generatiing station does not change by more than 20MW, then no new study is required and, it should be acceptable to rely on past stability assessments. This is not clear in R5.5.1. h. With respect to section R5, the concept of planned and long-term outages should be addressed uniformly for the general Planning Assessment. It should not be specific to the Stability Assessment. i. Planned and long-term outages are two fundamentally different concepts and should be treated separately. Planned and Long-Term outages should be defined. Define how planning events in Tables 1 and 2 are associated with each type of outage. Define length of a "Long Term" outage. Planned outages should be addressed in the operating horizion unless otherwise defined in the planning horizion. j. The provisions of Section R.5.3 should be included in a MOD standard and applied to a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertant trip of the generator. Such a provision should include "other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation. k. Strike R5.5.3 and R5.5.4, as they become redundant to R5.4.1

No

There are a few significant concerns with these definitions: The definitions should be expanded to include interruption of Firm Transmission Service in a manner that is comparable to interruption of load; otherwise, Firm Transmission Service (FTS) is being treated in a manner that is superior to load. (The expansion of the defintions to include FTS would also address stated concerns associated with loss of radial or single facilities over which Firm Transmission arrangements have been made). There are perceived limitations to what constitutes Non-Consequential Load Loss. It must be clear that Non-Consequential load loss allows the cascading loss of a local area that does not adversely impact the BES. It would be impractical and unnecessary to anticipate that every such situation could be or needs to be managed by operator action or automatic control. Non-Interruptible load should be defined as, "Demand that the end-use customer has not made available to its Load-Serving Entity via contract or agreement for curtailment." The Consequential Load definition should specify "Interruptible and Non-Interruptible Load that is no longer connected to a sourceâ€¦" The inclusion of "or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes)" confuses the definition of Consequential Load Loss, because of the imbedded exception for steady state performance. It seems that the intent of this provision is to recognize that this type of load loss could occur for either transient or steady state conditions and that Planning Assessments should not be required to remedy this type of situation. However, this does seem to be at odds with the application and stated acceptability of Consequential Load Loss as noted in Table 1. Note: Table 2 has no reference to the treatment of Consequential Load Loss. It may be helpful to address the transient load loss situation in a separate defintion. Recommended Changes: Change "Consequential Load Loss" and definition to "Consequential Interruption - Load, Firm Demand, or Firm Transmission Service that is no longer connectedâ€¦" Change "Non-Consequential Load Loss" and definition to "Non-Consequential

Interruption - Non-Interruptible Load, Firm Demand, or Firm Transmission Service loss other than Consequential Interruption loss that occurs through manual (operator initiated), automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems, or uncontrolled loss of a local area which does not significantly impact the BES."
No
R3.5.1, R3.5.2 and R3.5.3 are not limiting enough. Add paragraph 3.5.4 "Automatic generator tripping shall not impose undue complexity and risk to the operation and relability of the system."
No
a. With respect to R9 "including the expected mix of industrial, commercial and residential loads", this provision may be inadequate to be practically useful. The potential issues include the variation in end-use load mix through the daily load cycle, seasonal load composition variations, and the ability to translate these end-uses into reasonable and useful steady-state and dynamic load models. It is important to understand how the information will be used and how much additional detail such as distribution network detail is also required. b. Add to the last sentence of R9 through R14 the following phrase, "within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator."
No
a. R2.3 should be changed to indicate the year(s) for short circuit analysis. b. In R4, suggest replacing, " and following any single Contingency condition that would result in greater circuit breaker interrupting duties" with, " giving due consideration to the potential sequence of equipment operation". c. It should be stated in the standard that assumptions should be based on procedures provided by each Transmission Planner and by the Planning Coordinator.
No
a. In both Table 1 and Table 2, the "Interruption of Firm Transmission Service Allowed" column. It is problematic to try to create an "exemption" based on type of facility such as HVDC. There are many other situations in which Firm Transmission Service has been provided, but may need to be curtailed partially or completely following an outage. b. The term 'Firm' may have several different definitions. If 'Firm' Transmission Service or load may be interrupted for exceptional events, then it is conditional and 'Conditional Firm' should be defined. It is recommended that a note be added stating that "the only exception would be for curtailment of conditioned (or Conditional) Firm Transmission Service", recognizing that there may need to be some form of grandfathering in order to avoid having to rewrite transmission service agreements. c. In both Table 1 and Table 2, the "Extreme Event Descriptions" item 1 should add "or shunt device." d. In Table 1, the "Extreme Event Descriptions" items 3a and 3b should be deleted; they are redundant with Item 1. e. In Table 2, Note 5 includes significant clarifications and should not be buried in the bottom of the contingency table; Note 5 would be better placed in the definitions section. f. In Table 1 and Table 2, Contingency P5 requires a fault plus Protection System Failure. Assuming that the battery system is included in the Protection System, which it is in NPCC, then ALL protection at substations with single battery systems would be lost. This Contingency P5 requires a stable system response while all bus voltages and loadings to remain within criteria, without interruption of firm transmission service and without Non-Consequential Load Loss, at system voltages above 300 kV. Was this an intended outcome of this standard?
No
The definition provided is too limiting. It indicates that if a substation has two rings with a bus tie breaker in between, that breaker is no longer a bus tie breaker. Recommend instead, "A circuit breaker that is positioned to connect two individual station configurations. The breakers in a bus scheme are not bus tie breakers but the breakers that tie bus schemes together are bus-tie breakers."
No
They should have the same performance requirements, however we understand that it is better to encourage bus-tie breakers in some applications than to hold them to the higher standard. Future station designs that need this differential treatment should be discouraged.
No
a. With respect to R2.1.3 delete "â€¦ that Stress the System with sensitivitiesâ€¦". b. R2.1.3 should be revised to clarify that if a TP/PC conducts the studies specified in R2.1.1 and R2.1.2 with one or more of the sensitivities which stress the system in the normal course of study, then additional studies of a less-stressed system are not required. c. The intention of Paragraph R2.1.4 is unclear and appears to be unnecessary; therefore, it should be removed.
Yes

B â€" Unsure about supporting the revised standard

Aside from the comments to the prior questions, there are several issues of concern that prevent us from supporting the present draft of the revised standard. We offer the following constructive comments in an effort to support the worthwhile effort that is being pursued so that we can reach a point of satisfaction that we could vote to support the revised standard. Our concerns are listed in a rough order of priority. a. This standard as drafted does not allow exceptions for small parts of the system as long as interconnected system reliability is maintained, which is allowed in the existing TPL standards in footnotes b) and c) in Table 1. Unless such exceptions are allowed significant transfer restrictions or large reinforcements must be made. The applicable TPL footnotes are: Existing TPL footnote b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers. Existing TPL footnote c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (nonrecallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems. b. This standard does no address base conditions. Without defining base conditions the initial status of genertaion dispatch and transers across the sysetm is ill defined. Therefore the contingency analysis doesn't have a predictable basis for a consistent and repeatable study. c. The reference to Special Protection Systems is completely permissive. Although there are good applications for Special Protection Systems, their use must be constrained to have a reliable system and to promote construction of needed infrastructure. d. This standard does not provide flexibility to shed load, which restricts the ability to control post contingency response for low impact events. This may result in advancing need for upgrades in response to low impact events. This may result in advancing need for upgrades in response to low impact events. This is in conflict with FERC's directive to have the Transmission Provider waiting for market response to transmission needs and having the Transmission Provider provide a role to back stop the market. e. Definition of the Long-Term Planning Horizion. The planning horizion, for assessment purposes should be limited to 10 years. Such an assessment should be sufficient to identify requirements that may take an extended time to implement. f. Definition of Planning Coordinator is part of the NERC Functional Model, Remove from the standard. g. Put headings on each section to identify the requirements of the section. h. With respect to R2.2 - Delete "current" from the phrase "current System Peak Load Study" and replace "study" with "assessment." i. Remove R2.2.1, the requirement to extend the assessment beyond 10 years. What does the length of the project have to do with the assessment? If it takes 15 years to build something, why does this require a review of year 15? What is the purpose of this assessment? j. R3.3.2 requires clarification - This standard needs to permit discretion regarding the single contingencies that need to be tested, similar to R3.3.3 and R3.4. It is completely unnecessary to test all events. For example, contingencies may be limited to relevant disturbances that are contained within or directly impact the studied system. k. With respect to R3.2.1 - Claraify whether the intent of the standard is to address station service minimum voltage limitation, maximum leading VAR absorption capability or both at steady state. l. Remove R3.2.2 - Relay loadibility is addressed in the PRC-023 Standard. m. With respect to R3.3.2.1 - Recommend the removal of the requirement to assess the expected duration of Consequential Load loss. It's not considered anywhere else in the standard. n. With respect to R3.3.3 - The paragraph refers to Table 1 Contingencies P3 through P7; this should be explicitly stated. Rationale for inclusion of testing should not be required; should only need to explain why certain Contingencies were not tested. This discretion should be applicable to all contingencies. o. With respect to section R5 - The concept of planned and long-term outages should apply to the general Planning Assessment, or not at all. It should not be specific to the Stability Assessment. p. The provisions of Section R5.3 should have a corresponding MOD standard apply a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertant trip of the generator. Such a provision should include "other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how those devices are treated in the simulation. q. Planned outages should be addressed in the operating horizion unless otherwise defined in the planning horizion. r. Recommend allowing the same non-consequential interuption for >300kV as for <300kV. Distinctions and acceptability should be based on consequence, not voltage class. s. What is a "current" study?

Individual

Steven Masse

NSTAR Electric

No

There should be no difference beween System and Generating Unit Stability studies. Each require discretion regarding which events need to be tested. The consequences are potentially similar: either the instability of one of more generators. Extreme Events should be considered for any stability analysis, again, recognizing that discretion needs to be applied when selecting or dismissing particular contingencies. If no distinction is made between System and Generating Unit Stability studies is made, then the definition of Generating Unit Stability Study should be stricken from the standard.

No

1. A MOD standard should be developed to address the assembly of dynamic load models, rather than specifying modeling in paragraph 2.4.1 (dynamic behavior of loads, including consideration of the behavior of induction motor Loads). Paragraph 2.4.1 should instead read, "System Peak Load for one of the five years." The remainder of the paragraph should be deleted. 2. Change paragraph R.2.4.3.4 to "Outages of Reactive Resources". It is not clear what "variability" means and why it would be more servere than outages. 3. Add a new requirement, "R5.4.3.4 Automatic generator tripping schemes shall not be overly complex or have an significant adverse impact on overall system reliability." 4. Requirements of R5.5 should be rolled into R5.4 and made applicable to all stability studies. 5. Modify R5.5.1 to the following "Shall be performed for an individual generating unit or generating units at the same interconnection point 20 MW or greater that are directly connected to the BES." There may be little difference between the stability performance of a single 20 MW unit and an aggregation of units totalling 20 MW at the same BES interconnection point. 6. Delete R5.5.2. If planning assessment studies all generators or stations above 20 MW, as suggested by R5.5.1, then this provision is unnecessary. If the system has not changed, it should be acceptable to rely on past stability assessments. 7. With respect to section R5, the concept of planned and long-term outages should be addressed uniformly for the general Planning Assessment. It should not be specific to the Stability Assessment. 8. Planned and long-term outages are two fundamentally different concepts and should be treated separately. Planned and Long-Term outages should be defined. Define how planning events in Tables 1 and 2 are associated with each type of outage. Define length of a "Long Term" outage. Planned outages should be addressed in the operating horizion unless otherwise defined in the planning horizion. 9. The provisions of Section R.5.3 should be included in an MOD standard and applied to a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertant trip of the generator. Such a provision should include " other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation.

No

There are a few significant concerns with these definitions: The definitions need to be expanded to include interruption of Firm Transmission Service in a manner that is comparable to interruption of load; otherwise, Firm Transmission Service (FTS) is being treated in a manner that is superior to load. The expansion of the defintions to include FTS would also address stated concerns associated with loss of radial or single facilities over which Firm Transmission arrangements have been made. There are perceived limitations to what constitutes Non-Consequential Load Loss. It must be clear that Non-Consequential load loss allows for the cascading loss of a local area that does not adversely impact the BES. It would be impractical and unnecessary to anticipate that every such situation could be or needs to be managed by operator action or automatic control. Non-Interruptible load needs to be defined as,"Demand that the end-use customer has not made available to its Load-Serving Entity via contract or agreement for curtailment." The Consequential Load definition should specify "Interruptible and Non-Interruptible Load that is no longer connected to a sourceâ€¦" The inclusion of "or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes)" confuses the definition of Consequential Load Loss, because of the imbedded exception for steady state performance. It seems that the intent of this provision is to recognize that this type of load loss could occur for either transient or steady state conditions and that Planning Assessments should not be required to remedy this type of situation. However, this does seem to be at odds with the application and stated acceptability of Consequential Load Loss as noted in Table 1. Note: Table 2 has no reference to the treatment of Consequential Load Loss. It may be helpful to address the transient load loss situation in a separate defintion. Recommended Changes: Change "Consequential Load Loss" and definition to "Consequential Interruption - Load, Firm Demand, or Firm Transmission Service that is no longer connectedâ€¦" Change "Non-Consequential Load Loss" and definition to "Non-Consequential Interruption - Non-Interruptible Load, Firm Demand, or Firm Transmission Service loss other than Consequential Interruption loss that occurs through manual (operator initiated), automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems, or uncontrolled loss of a local area which does not significantly impact the BES."

No

R3.5.1, R3.5.2 and R3.5.3 are not limiting enough. Add paragraph 3.5.4 "Automatic generator tripping schemes shall not be overly complex and risk to the operation and relability of the

system." Complex SPS's or multiple installations of SPS's can have an adverse impact on the ability to reliably operate the system, especially during maintenance outage conditions.
No
1. With respect to R9 "including the expected mix of industrial, commercial and residental loads", this provision may be inadequate to be practically useful. The potential issues include the variation in end-use load mix through the daily load cycle, seasonal load composition variations, and the ability to translate these end-uses into reasonable and useful steady-state and dynamic load models. It is important to understand how the information will be used and how much additional detail such as distribution network detail is also required. 2. Add to the last sentence of R9 as follows "within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator." 3. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R10 to read as follows: "R10. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator." 4. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R11 to read as follows: "R11. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator." 5. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R12 to read as follows: "R12. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator." 6. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R13 and R14 to read as follows: "R13. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator.. [Violation Risk Factor: TBD] [Time Horizon: TBD] R14. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to Transmission Lines, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator.. [Violation Risk Factor: TBD] [Time Horizon: TBD] " 7. Planned and long-term outages are two fundamentally different concepts and should be treated separately. Planned and Long-Term outages should be defined. Define how planning events in Tables 1 and 2 are associated with each type of outage (e.g. P4, P5, or P6). There should be specific contingency descriptions associated with long-term outages. Define length of a "Long Term" outage. Planned outages should be addressed in the operating horizion unless otherwise defined in the planning horizion.
No
1. R2.3 should be changed to indicate the year(s) for short circuit analysis. 2. In R4, suggest replacing, " and following any single Contingency condition that would result in greater circuit breaker interrupting duties" with , " giving due consideration to the potential sequence of equipment operation". 3. It should be stated in the standard that assumptions should be based on procedures provided by each Transmission Planner and by the Planning Coordinator.
No
1. Refering to both Table 1 and Table 2, the "Interruption of Firm Transmission Service Allowed" column, it is problematic to try to create an "exemption" based on the type of facility such as HVDC. There are situations in which Firm Transmission Service has been provided, but may need to be curtailed partially or completely following an outage. The term 'Firm' may have several different definitions. If 'Firm' Transmission Service or load may be interrupted for exceptional events, then it is conditional and 'Conditional Firm' should be defined. It is recommended that a note be added stating that "the only exception would be for curtailment of conditioned (or Conditional) Firm Transmission Service", recognizing that there may need to be some form of grandfathering in order to avoid having to rewrite transmission service agreements. 2. In both Table 1 and Table 2, the "Extreme Event Descriptions" item 1 should add "or shunt device." 3. In Table 1, the "Extreme Event Descriptions" items 3a and 3b should be deleted; they are redundant with Item 1. 4. Table 2, Note 5 includes significant clarifications which should not be buried in the back; they are better placed in the definitions section. 5. In Table 1 and Table 2, Contingency P5 requires a fault plus Protection System Failure. Protection System Failure should be defined and noted if the battery system is included.

No
The definition provided is too limiting and should be changed to "A circuit breaker that is positioned to connect two individual station configurations. The breakers in a bus scheme are not bus tie breakers but the breakers that tie bus schemes together are bus-tie breakers."
No
They should have the same performance requirements. The performance standards should not encourage differential treatment for the same equipment.
No
1. With respect to R2.1.3 delete "that Stress the System with sensitivities". 2. R2.1.3 should be revised to clarify that if a TP/PC conducts the studies specified in R2.1.1 and R2.1.2 with one or more of the sensitivities which stress the system in the normal course of study, then additional studies of a less-stressed system are not required. 3. The intention of Paragraph R2.1.4 is unclear and appears to be unnecessary; therefore, it should be removed.
Yes
B â€“ Unsure about supporting the revised standard
Aside from the comments to the prior questions, listed below are several others issues: 1. This standard does not address base conditions regarding generation dispatch and transers across the system. Initial condition guidelines would be very important to establishing consistent application of the performance standards. 2. This standard should allow exceptions for loss of small parts of the system as long as reliability is maintained on the interconnected BES. There is such an allowance in the existing TPL standards in Table 1, footnotes b) and c). 3. The reference to Special Protection Systems is too permissive. The use of Special Protection Systems and their inherent complexity should be restricted to ensure a reliable system and to promote construction of needed infrastructure. 4. The Long-Term Planning Horizion should be limited to 10 years, a sufficient timeframe to identify requirements that may take an extended time to implement. 5. Definition of Planning Coordinator is part of the NERC Functional Model. It should be removed from the TPL standard. 6. Put headings on each section to identify the requirements of the section. 7. With respect to R2.2, delete "current" from the phrase "current System Peak Load Study" and replace "Study" with "Assessment." 8. R3.3.2 should be changed to permit discretion regarding the single contingencies that need to be tested, similar to R3.3.3 and R3.4. It is unnecessary to test all possible events. 9. R3.2.1 should be clarified as to whether the intent of the standard is to address station service minimum voltage limitation, maximum leading VAR absorption capability or both. 10. Remove R3.2.2. Relay loadibility is addressed in the PRC-023 Standard. 11. In R3.3.2.1, remove the requirement to assess the expected duration of Consequential Load loss. This requirement is unnecessary and not considered anywhere else in the standard. 12. With respect to R3.3.3, the paragraph refers to Table 1 Contingencies P3 through P7; this should be explicitly stated. Also, the rationale for inclusion of testing should not be required. It only makes sense to explain why certain Contingencies were not tested. This discretion should be applicable to all contingencies in all sections of the standard.
Group
Compliance Elements Development Resource Pool (CEDRP)
John Blazekovich
Exelon Corporation

With regard to Violation Severity Levels for this standard, the CEDRP doesnâ€™t believe the version that has be posted for comment can be commented on from a VSL perspective for two reasons 1) it does not have any measures listed and 2) there are so many "sub-requirements" the VSLs would be quite unmanageable, unless each sub-requirement is of equal importance to fulfilling the objective of the standard. Because there are no measures we can't achieve any insight into importance. The SDT may want to consider trimming the standard down to its most basic elements and providing the details (sub-requirements) in a reference document.

Individual

Gregory Campoli

New York Independent System Operator

No

There should be no difference beween System and Generating Unit Stability studies. Each require discretion regarding which events need to be tested. The consequences are potentially similar: either the instability of one of more generators. Extreme Events should be considered for any stability analysis, again, recognizing that discretion needs to be applied when selecting or dismissing particular contingencies. Therefore, the definition of Generating Unit Stability Study should be stricken from the standard.

No

a. A MOD standard should be developed to address the assembly of dynamic load models, rather than specifying modeling in paragraph 2.4.1 (dynamic behavior of loads). Paragraph 2.4.1 should instead read, "System Peak Load for one of the five years." b. In paragraph R.2.4.3.4, what does "variability" mean? c. Add a new requirement, "R5.4.3.4 Automatic generator tripping shall not have an significant adverse impact on overall system reliability." d. Remove Heading R5.5 and make generator unit stability a section of overall stability requirements. e. Modify R5.5.1 to become R5.4.5, with the following, "Shall be performed for the addition of an individual generating unit or generating units at the same interconnection point 20 MW or greater that are directly connected to the BES." There may be little difference between the stability performance of a single 20 MW unit and an aggregation of units totalling 20 MW at the same BES interconnection point. f. ---- g. Strike R5.5.3 and R5.5.4, as they become redundant to R5.4.1

No

In the Consequential Load Loss definition, the word 'source' needs to be defined or explained further since it is unclear.

No

We do not feel that R3.5.1, R3.5.2 and R3.5.3 are limiting enough. Add paragraph 3.5.4 "Manual and automatic generator tripping shall not have an Adverse Reliability Impact."

No

With respect to R9 "including the expected mix of industrial, commercial and residential loads", this provision may be inadequate to be practically useful. The potential issues include the variation in end-use load mix through the daily load cycle, seasonal load composition variations, and the ability to translate these end-uses into reasonable and useful steady-state and dynamic load models. It is important to understand how the information will be used and how much additional detail such as distribution network detail is also required. Add to the last sentence of R9 through R14 the following phrase, "within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator."

No

In R4, suggest striking, "that would result in greater circuit breaker interrupting dutiesâ€¦".

No

In both Table 1 and Table 2, the "Interruption of Firm Transmission Service Allowed" column. It is problematic to try to create an "exemption" based on type of facility such as HVDC. There are many other situations in which Firm Transmission Service has been provided, but may need to be curtailed partially or completely following an outage. It is recommended that a note be added stating that the only exception would be for curtailment of conditioned (or Conditional) Firm Transmission Service, recognizing that there may need to be some form of grandfathering in order to avoid having to rewrite transmission service agreements. In both Table 1 and Table 2, the "Extreme Event Descriptions" item 1 should add "or shunt device." In Table 1, the "Extreme Event Descriptions" item 3b should be deleted; it is redundant with Item 1. In Table 2, Note 5 includes significant clarifications and should not be buried in the bottom of the contingency table;

Note 5 would be better placed in the definitions section. In Table 1 and Table 2, Contingency P5 requires a fault plus Protection System Failure, such as a battery system which may remove ALL protection at some substations. This Contingency P5 requires all voltages and loadings to remain within criteria, and a stable system response; without interruption of firm transmission service and without Non-Consequential Load Loss, at voltages above 300 kV. Was this an intended outcome of this standard?

No

The definition provided is too limiting. It says that if you have a two rings with a bus tie breaker in between, it is no longer a bus tie breaker. Recommend, "A circuit breaker that is positioned to connect two individual station configurations. We do not agree that, "(Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)", as we have examples where stations of this nature are connected through a single "bus-tie breaker".

No

If a TP/PC conducts the studies specified in R2.1.1 and R2.1.2 with one or more of the sensitivities which stress the system in the normal course of study, we assume that fulfills the requirements of R2.1 completely, without additional studies of a less-stressed system. Is that correct?

Yes

A very preliminary estimate would be potentially millions of dollars.

Again, a very preliminary estimate would be two years.

Preliminary estimate is on the order of hundreds of thousands of dollars In addition to cost, there is a significant concern over whether or not there will be enough staff to complete the required work.

included above

included above

Depending on facilities covered by the standard, it is estimated that the cost to bring facilities into compliance potentially could be on the order of billions of dollars.

A preliminary estimate is that it would take at least five but potentially up to ten years to bring facilities into compliance.

C â€" Definitely do not support the revised standard

This standard as drafted does not allow exceptions for small parts of the system as long as interconnected system reliability is maintained, which is allowed in the existing TPL standards in footnotes b) and c) in Table 1. Unless such exceptions are allowed significant transfer restrictions or large reinforcements must be made. The applicable TPL footnotes are: ï€ b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers. ï€ c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (nonrecallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems. This comment form did not allow for the following items to be addressed: a. Definition of the Long-Term Planning Horizion. The planning horizon, for assessment purposes should be limited to 10 years. Such an assessment should be sufficient to identify requirements that may take an extended time to implement. b. Definition of Planning Coordinator is part of the NERC Functional Model, Remove from Standard. c. Put headings on each section to identify requirements of section. d. With respect to R2.2 - Delete "current" from the phrase"current System Peak Load study" and replace "study" with "assessment." e. Remove R2.2.1, the requirement to extend the assessment beyond 10 years. What does the length of the project have to do with the assessment? If it takes 15 years to build something, why does this require a review of year 15? What is the purpose of this assessment? f. R3.3.2 requires clarification - This standard needs to permit discretion regarding the single contingencies that need to be tested, similar to R 3.3.3 and R3.4. It is completely unnecessary to test all events. For example, contingencies may be limited to relevant disturbances that are contained within or directly impact the studied system. g. With respect to R3.2.1 - Clarify whether the intent of the standard is to address station service minimum voltage limitation, maximum leading VAR absorption capability or both at steady state. h. Remove R3.2.2 - Relay loadability is addressed in PRC-023 standard. i. With respect to R3.3.2.1 - Recommend the removal of the requirement to assess the expected duration of Consequential Load loss. It's not considered anywhere else in the standard. j. With respect to R3.3.3 - The paragraph refers to Table 1 Contingencies P3 through P7; this should be explicitly stated. Rationale for inclusion of testing should not be required; should only need to explain why

certain Contingencies were not tested. This discretion should be applicable to all contingencies. k. With respect to section R5 - The concept of planned and long-term outages should apply to the general Planning Assessment, or not at all. It should not be specific to the Stability Assessment. l. The provisions of Section R.5.3 should have a corresponding MOD standard apply a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertant trip of the generator. Such a provision should include "other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation. m. Planned outages should be addressed in the operating horizion unless otherwise defined in the planning horizion.

Group

SERC Reliability Review Subcommittee and Planning Standards Subcommittee

Herbert Schrayshuen

SERC Reliability Corporation

No

There is an inconsistency between the defined terms â€œGenerating Unit Stability Studyâ€ and â€œSystem Stability Studyâ€ and the usage within the standard. The requirements refer to these terms by omitting the word â€œstudyâ€. An improvement for the System Stability Study definition is to clarify that it is a study that focuses on the impact to the system itself and covers an area larger than one Generating Plant, covering a large geographical area. See specific proposal below: â€œSystem Stability Study - Study that focuses on how contingencies impact a larger portion of the System than a Generating Unit Study. These studies would examine issues such as angular Stability, inter-area power oscillation, and dynamic voltages.â€

Yes and No

R2.4. No The word â€œSystemâ€ was deleted during the re-write and only â€œStabilityâ€ is used. However, the sub-sections appear to be more appropriate to a â€œSystem Stabilityâ€ assessment than for a â€œGenerating Unit Stabilityâ€ assessment. â€œGenerating Unit Stabilityâ€ assessments are the subject of Section R2.5 and â€œSystem Stabilityâ€ assessments appear to be the intent of Section R2.4. Why does Requirement 2.4. specify the near-term transmission planning horizon â€œportionâ€? We recommend removal of the words â€œportion of theâ€. R2.4.1. No Change â€œPeak System Loadâ€ to â€œSystem On-Peak Loadâ€. This is the term defined in the â€œNERC Glossaryâ€ and is consistent with the usage of â€œOff-Peak Loadâ€. This change would be required through out the TPL Standard as well as in other standards. There is concern with load modeling requirements (use of word â€œappropriatelyâ€ in R2.4.1). Does this requirement mandate the use of specific load models for each bus, or would an aggregate load model which represents the system as a whole be sufficient? Does the use of the PSS/E CONL function satisfy the requirements for a load model? R2.4.3 No In general we believe that breaking these requirements into specific sub-requirements, focusing on specific sensitivities, is too prescriptive and inappropriate. It will lead to over focus on these particular issues to the detriment of system reliability. The standard should not include an enumerated list of required sensitivities. Engineering judgment needs to be permitted. R2.5 Concur R5.4 Concur R5.5 No There is a concern with R5.5.1 with the requirement to perform simulations on 20 MW generators (to be consistent with the Registration Criteria). We recommend a 75 MW generator cutoff for required simulations.

No

Comments: Although the modified definitions are a good improvement over the previous version, addressing the following issues in the Consequential Load Loss definition will further improve clarity: 1) Redundancy: The second sentence in the definition says "Although Load which is lost as a result of the Load's response to the transient condtions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed,â€¦". It appears that "â€¦and is permitted when Consequential Load Loss is allowed,â€¦" is redundant and may be omitted/deleted -- isn't this *always* permitted for all events? (See headnote 4 in Table 1 -- Steady State Performance). 2) Who are the "planning entities"? Suggest replacing with Functional Model terms Transmission Planner and Planning Coordinator. 3) Verbosity: It appears that the intent of the second sentence in the definition can be conveyed more concisely. Consider changing to "However, relying upon the expected Load loss during transient conditions of the event to meet steady state performance requirements is not allowed." 4) If the verbiage proposed above is found acceptable, we offer a follow-up suggestion. Because the second sentence in the definition essentially characterizes the exception to the allowed Consequential Load Loss during steady state performance evaluation, we suggest moving it out of the definition and appending it within headnote 4 in Table 1 -- Steady State Performance. 5) While the Consequential Load Loss definition employs the acronyms UFLS and UVLS, their expanded descriptions have been used in the Non-Consequential Load Loss definition. Suggest that these terms be used consistently in both definitions. Also, why is Special Protection Systems included as an example of what constitutes Non-Consequential Load Loss but is excluded from the list of exceptions to Consequential Load Loss (whereas UVLS and UFLS appear consistently in both)?

Yes
Yes
Yes
We recommend that the headings be repeated at the head of each page.
No
To provide clarity, a revised definition is proposed. A bus-tie breaker is a circuit breaker that connects two individual bus sections in a straight bus substation configuration. Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double-breaker do not have bus-tie circuit breakers.
No
The installation of bus-tie circuit breakers in a straight bus configuration would reduce exposure to a) bus faults or to b) line faults with breaker failure without adding much risk for internal fault in the bus-tie breaker. Those entities that employ a straight bus substation design with bus-tie breakers have recognized that failure of the bus-tie breaker, a very low probability event, would result in the loss of multiple transmission elements and perhaps firm load for a short time until the bus sections can be restored, but bus-tie breakers are an investment worth the risk. Therefore, it is generally agreed that the outage of non-bus-tie circuit breakers should have higher performance requirements than the outage of bus-tie circuit breakers. The SDT should be commended for this change since the previous draft version. However, it is not clear that adopting a higher standard of performance for planning events involving transmission facilities 345 kV and above will improve overall system reliability. Some areas of the continent already have n-2 planning criteria, yet these systems have still experienced significant outages including blackouts. It is suggested that a review of the Transmission Availability Data System (TADS) data, when available, should be conducted to help assess what system performance requirements need to be strengthened before arbitrarily determining to "raise the bar" for certain voltage levels and system designs. The industry should not be forced to invest a great deal of capital to meet a new standard requirement when it would not have an immediate impact on system reliability. Some sort of cost/benefit analysis should be performed to justify any change from the present TPL-001 through 004 standard requirements. Also, further clarification is required to explain how to drop consequential load without cutting firm transmission service to those affected/outaged customers, and this needs to be added to the notes in Tables 1 and 2.
No
These requirements are very prescriptive. Many examples of sensitivities are already inherent in the existing requirements. Some sensitivity studies are in effect adding an additional level of contingency (N-2 or N-3). Sensitivity studies of load variation are already inherent in the fact that several different study years and conditions are already being required. Outages of reactive sources and generation should already be included in studies of multiple contingencies. The process of planning new generation (system impact studies) will include studies of the future with and without the proposed new equipment. The TP and PC can better select the most appropriate sensitivities for their system. In general we believe that breaking these requirements into specific sub requirements, focusing on specific sensitivities, is too prescriptive and inappropriate. It will lead to over focus on these particular issues to the detriment of system reliability. The standard should not include an enumerated list of required sensitivities Engineering judgment needs to be permitted.
Yes
Since Event P6 is essentially a sub-set of the existing Category C.3 Contingency events, we support these modifications which make the system performance requirements for P6 consistent with what exist today for Category C.3. While we agree interruption of firm transmission service and non-consequential load loss should not be allowed to meet the planning requirements for the first system contingency, these system adjustments should be allowed to prepare for the second event so that the system will meet the requirements following the second event. We recommend that clarifying changes be made to incorporate this concept. We recommend that the statement below be included as modification or as a footnote for the P6 portion of the table as follows: Interruption of firm transmission service and non-consequential load loss are allowed after the first event as a system adjustment to prepare for the second event in order to meet the requirements following the second event.
One component of these costs is based on modification to the loadflow database. A massive effort would need to be undertaken to model bus sections and breaker codes in order to simulate the planning events needed to stay current with the new standards. Also, man-power to perform the extra analysis was considered. Additional man-power: 5 engineers (2 years) Cost: $1,000,000
The majority of the time would be spent modifying the loadflow database so that the new planning event simulations could be analyzed. Time: 2 years
Additional man-power: 4 engineers Costs: $400,000 / year The following analysis was performed

by one large integrated utility in SERC. The results are not representative of all utilities in the SERC region, but would be multiplied many times over to fully represent the SERC region as a whole. A comprehensive study of the impact of these proposed and incomplete standards is not feasible until they are finalized. Regarding manpower, aside from the estimated costs there is the very real situation that the number of qualified engineers available in the industry is nowhere near what would be necessary to carry out the studies (including sensitivities) called for by the proposed standard. This reality needs to be taken into consideration by the Standards Drafting Team when it makes its implementation plan recommendations.

Additional man-power: 1 engineer (1 year) Costs: $100,000

Additional man-power: 1 engineer Costs: $100,000 / year The following analysis was performed by one large integrated utility in SERC. The results are not representative of all utilities in the SERC region, but would be multiplied many times over to fully represent the SERC region as a whole. A comprehensive study of the impact of these proposed and incomplete standards is not feasible until they are finalized. Regarding manpower, aside from the estimated costs there is the very real situation that the number of qualified engineers available in the industry is nowhere near what would be necessary to carry out the studies (including sensitivities) called for by the proposed standard. This reality needs to be taken into consideration by the Standards Drafting Team when it makes its implementation plan recommendations.

Typical costs for a large utility in SERC would include the implementation of redundant protection schemes for the P5 planning event (fault + failure of protection scheme), additional 500-kV facilities for P2.2 (single contingency - bus section outage) and P4 (fault + stuck breaker) events, and additional 161-kV facilities for the P3 (Generator +1) events. Cost: $1 billion

Time: 10 years The following analysis was performed by one large integrated utility in SERC. The results are not representative of all utilities in the SERC region, but would be multiplied many times over to fully represent the SERC region as a whole. A comprehensive study of the impact of these proposed and incomplete standards is not feasible until they are finalized. Regarding manpower, aside from the estimated costs there is the very real situation that the number of qualified engineers available in the industry is nowhere near what would be necessary to carry out the studies (including sensitivities) called for by the proposed standard. This reality needs to be taken into consideration by the Standards Drafting Team when it makes its implementation plan recommendations.

C. Definitely do not support the revised standard. A majority of SERC technical experts do not support the revised standard. The primary concern is that the need for additional requirements for planning 300kV systems and above has not been demonstrated. We do not believe that a sufficient case for â€œraising the barâ€ has been provided and that this requirement can have a huge impact on utilities and ratepayers. R2.1.3 and R2.4.3 requirements are very prescriptive. Many examples of sensitivities are already inherent in the existing requirements. Some sensitivity studies are in effect adding an additional level of contingency (N-2 or N-3). Sensitivity studies of load variation are already inherent in the fact that several different study years and conditions are already being required. Outages of reactive sources and generation should already be included in studies of multiple contingencies. The process of planning new generation (system impact studies) will include studies of the future with and without the proposed new equipment. The TP and PC can better select the most appropriate sensitivities for their system. We recommend that engineering judgment continue to be recognized as a vital component of planning. Category P6 is the loss of a system element, followed by system adjustments, followed by the loss of another element. The table columns for this category say that interruption of firm transmission service is allowed. The table, however, is not clear whether the interruption of firm service is allowed as part of the system adjustment (between the outages) or whether it is only allowed after the second outage. It was stated in the NERC TPL SDT WebEx (August 26, 2008) that the interruption is not allowed as part of the system adjustment. This would be a dramatic change from the existing standard and would result in the unintended consequence of significantly reducing transmission system capability to accommodate firm transmission service including reduction of transfer capability of interfaces to a fraction of their currently reported capability. This would in effect be imposing an n-2 criteria for offering firm transmission service. This would not be an acceptable situation for the users, owners and operators of the bulk power system. Additional Comments: There is concern with load modeling requirements (use of word â€œappropriatelyâ€ in R2.4.1). Does this requirement mandate the use of specific load models for each bus, or would an aggregate load model which represents the system as a whole be sufficient? Does the use of the PSS/E CONL function satisfy the requirements for a load model? There is a concern that R3.3.2.1 is burdensome regarding the need to keep track of the quantity of consequential load loss and expected duration. Who is collecting this information and why is it needed? It appears that this is a local regulatory issue, not a reliability issue. There is a concern with R5.6.1 with the requirement to perform simulations on 20 MW generators (to be consistent with the Registration Criteria). We recommend a 75 MW generator cutoff for required simulations.

Individual

Anita Lee

Alberta Electric System Operator

No

We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study â€œfocuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to â€œdevelop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingenciesâ€. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say â€œonly whenâ€ the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, â€œmaterial Transmission System changeâ€ and â€œat or near the point of Interconnectionâ€ to invoke a study.

No

R2.4 is acceptable. - Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirement in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. - The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Generator Owners are to apply for interconnection to the transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Ownerâ€™s responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. - Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.

No

We generally agree with the definitions by themselves but have concerns about regarding application, please refer to response in Q15. The last sentence in the Definition of Consequential Load Loss (â€œAlthough Load which is lost as a result of the Loadâ€™s response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirementsâ€) seems more appropriate to be requirements. Therefore, recommend moving this sentence to the Notes Section at the beginning of Table 1 as new Item 7.

Yes

We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest R3.5 and R3.4.3 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.

Yes

While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities

(LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.

No

We agree with R2.3. However, R4 requires assessment of â€œShort-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting dutiesâ€. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute â€œnormalâ€ condition or â€œfollowing any single Contingency conditionâ€. Also, by specifying the normal and single contingency conditions, R4 is straying into â€œhowâ€ to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.

No

We do not agree with the proposed format changes of the Tables, separating into two Tables is not necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.

No

We do not disagree with the proposed definition change. However, we do not agree that â€œSubstation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: "A circuit breaker thats only protective purpose is to isolate a segment of a bus."

No

We believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class.

No

We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the â€œbase caseâ€ of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the â€œbase caseâ€ condition. R2.7 also states that â€œCorrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivitiesâ€. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the â€œbase caseâ€, will the judgment of the Transmission Planner be then questioned because theâ€œbase caseâ€ used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?

Yes

We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1

and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
C â€" Definitely do not support the revised standard
We agree that the Standard as presented is clearer, but there are numerous identified issues that still need resolution, in addition to the Measures, VSLs, Implementation Plan, etc., before AESO could give a full approval of this Standard. - There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. - We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions. - We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with â€œraising the barâ€ for loss of Facilities with operating voltages 300 kV or higher (P2, P4, and P5 in the Performance Tables). We believe there should be no distinction between the voltage classes. - Regarding the terms â€œinterruption of firm transmission serviceâ€, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what â€œFirm Transmission Serviceâ€ means. Two points, 1) the NERC definition states â€œhighest quality service offered to customers under a filed rate schedule that anticipates no planned interruption.â€ The Standard implies anticipation of â€œunplannedâ€ interruption for certain contingencies. 2) Is this referring to a transmission product, or firm transfers modeled for the conditions being studied? One way to interpret the intent is the firm transfers being modeled for the conditions in the powerflow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption of firm transmission service should also be allowed for P1 through P5 contingencies in the table. - In addition, we believe that DC and AC lines should have the same performance requirements with respect to interuption of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines can automatically be curtailed when the line is outaged.
Individual
Greg Ward / Darryl Curtis
Oncor Electric Delivery
Yes
NA
No
For Requirement R2.4 would prefer to see more clarification on the System Off-Peak stability studies required and their purpose. Define/quantify type of stability issues to be addressed with this type of study. For sub requirement R2.4.3 the level of detail in the load modeling is very subjective and greatly impacts the analysis and results.
Yes
NA
Yes
NA
Yes
NA

Yes
NA
No
In Table 1-Steady State Performance several terms more relating to system stability performance appear such as post-transient voltage, voltage instability, fault plus stuck breaker, etc. These terms would appear to be most appropriate in only Table 2-Stability Performance, where this type of analysis is performed, e.g.- placing a fault at a location based on available short circuit MVA at that point in the transmission system and then analyzing the post transient voltage and generator response.
Yes
NA
Yes
NA
Yes
Generally agree with modifications although would again stress that detailed load modeling for stability analysis may be as revealing as some of the sensitity studies recommended in R2.1.3 if they were only run with steady state analysis.
Yes
NA
Cost to supplement past study portfolio would be between $250,000 to 750,000.
3 to 5 years with added resources (staff)
$500,000 annually
$250,000
$100,000
Unknown, dependent on results of analysis and solutions implemented
Unknown, dependent on results of analysis and solutions implemented
B â€" Unsure about supporting the revised standard
Initially performing outstanding tasks as well as annual maintenance of documentation and regular updates would require extreme significant resources both personel and financial. Transmission Planning to this level requires high level subject matter experts with both specific transmission system knowledge as well as overall industry experience. Considerable expense would also be required to train personel and track activities. The procurement documents necessary to interface with consultants in this area where "in house" expertise is not available would also be required. Time would also be spent on evaluating new software and analysis tools such as EPRI dynamic models. A phased in approach would be taken to complete the tasks while still perfoming essential Oncor and ERCOT related activities associated with System Planning.
Group
FirstEnergy
Sam Ciccone
FirstEnergy Corp.
Yes
No
R2.4.1 â€" This requirement should be separated into two requirements as it covers two distinct topics; a) peak load study for one of the near-term years and b) dynamic load modeling. The use of the words "appropriately represents" and "consideration" is too vague and not strong enough for requirement language. Also, the requirement needs to better describe what is needed related to the modeling of induction motor load. What % of the load needs to be represented as motor load for various load classes â€" commercial, industrial, residential? An industry white paper is needed to provide direction related to this undertaking. The SDT, when considering their Implementation Plan, will need to allow sufficient time to complete the dynamic load modeling which largely does not exist today. R2.4.3 â€" Typo, need to remove strikethrough text on the word sensitivity. R2.4.4 â€" Suggest making this a sub-requirement of R2.4.3 and only require documentation as to why each sensitivity case was selected. Documenting why something was not selected does not seem constructive and places an unneeded burden on documentation. It should be expected that over time, a range of sensitivities would be covered as a library of studies is built.
No
Regarding the definition of "Consequential Load Loss" we do not agree with the inclusion of Load which is lost as a result of the Loadâ€™s response to the transient conditions of the event and recommend that the team restrict the definition to account for only load which is directly served by the facilities which were de-energized as a result of the contingency event. To include this within in the definition seems counterproductive to the planning of the transmission system that

is required by this reliability standard. Comments on other definitions: 1) Planning Coordinator (PC) â€" The SDT included a new definition for PC for inclusion in the NERC Glossary of Terms. We agree that this addition better aligns the Glossary with the PC applicable entity which is prevalent in a variety of standards. However, we are curious why the SDT did not indicate a deletion of the Planning Authority (PA) definition and what steps, if any, are being made by NERC to align registry criteria which uses Planning Authority (PA) to the reliability standards use of the PC. 2) Year-One: The definition for Year-One is awkwardly written. We suggest that the definition be adjusted to read "The planning year that begins with the upcoming annual period under study". We believe the attempt to try and delineate between the near-term planning horizon and operational planning horizon is not needed within the TPL standard and that the near-term period should account for the upcoming annual study periods. If not revised, the need for two near-term studies on an annual basis is overly burdensome as many transmission planning organizations perform upcoming annual seasonal assessments for seasonal peak (summer/winter) periods. Requiring an additional two studies near-term does not provide significant benefit. Further reasoning for making the change is the allowance of operating procedures as part of Corrective Action plans. Operating procedures can easily be developed and implemented to mitigate projected performance violations prior to an upcoming seasonal period. 3) BES â€" The acronym BES is used throughout the standard but never defined. We suggest this could easily be done in the purpose statement by simply adding the text "(BES)" after the reference to Bulk Electric System.

Yes

No

FE does not support the modeling requirements within the TPL standard and suggest that the SDT remove these requirements. This standard should be viewed on a premise that a valid and appropriate system model exist so that the fundamental focus of the standard is as stated in its purpose statement "Establish Transmission System planning performance requirements... to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions." If the R9 through R14 requirements remain, we offer the following comments: R9 - In requirement R9, the DP is to provide nodal load projections and include the expected mix of industrial, commercial, and residential Loads. System planning software can not presently accommodate this level of detail along with other load codes/classifications that may already be in use; i.e. municipal load, rural electric cooperative load, etc. Is the intent to require this information in models built and maintained by industry, i.e. MMWG? R10 - The TP does not have access to Interchange Schedules and resources required to supply Load for each of its Balancing Authority. This information may need to be provided by the Resource Planner or some other appropriate entity.

No

We do not feel that it is necessary to annually update the short circuit analysis. We suggest the SDT consider increasing this timeframe. In addition, short circuit analysis should be reviewed in areas where transmission or generation changes are planned. Lastly, we feel it would be beneficial for the standard to provide examples of contingencies that could increase fault duties.

Yes

The overall table format is much improved over Draft 1 and it provides better alignment between the steady-state and stability tables. The SDT is encouraged to consider consolidation into one table based on the minimal differences within the two tables. FE offers the following additional comments related to the tables: TABLE 1, STEADY-STATE & TABLE 2, STABILITY: 1) Do the table notes at the top of the table only apply to the Planning Events? If so, it is suggested to move the row that says Planning Events to be positioned above the notes. 2) Top Table Notes, Item 2 - It is our opinion that it should be based on the TPs criteria. 3) Top Table Notes, Item 3 - These should read consistent on both tables. Also, is cascading well understood and how is it tested for? 4) The use of numeric notes at both the top and bottom of the table causes confusion related to the superscript number references on various terms within the table. The superscript items appear to be footnote references to the notes area at the bottom of the table. It is suggested that the items listed at the top of the table use alpha character references to demarcate each item. 5) Remove the footnote reference to note 3 on the Header titled "Event" (column 3). The reference in column 4 is better suited and covers the intent of the note. 6) For the P3 contingencies, it is unnecessary to individually analyze all BES generation units within a footprint along with an additional contingency. The planner allowed to use reasonable judgment and run only a subset of the larger units in this scenario. For example, there would be no need to contingencies against an outage of each unit at a multi-unit plant. Checking the contingencies against the outage of the largest unit at that plant would be sufficient. 7) A header row should be repeated on each page for improved readability. TABLE 1, STEADY-STATE: 1) Extreme event descriptions, item 2e â€" why is this needed? How would this occur? What would be evaluated, high voltage? Stability issues? Note that it wouldnâ€™t be stability concern - this is the steady state table. 2) Extreme event descriptions, item 3b - how is this condition any different than what is studied in extreme event item 1 (N-2, no adjustment)? We suggest that item 3b be

removed. 3) Extreme event descriptions, item 3c is too vague and it is suggested that it be removed. 4) Notes section (bottom of table), item 1 - Various topics are covered within this note - stuck breaker, breaker relay failure, normal clearing, delayed clearing - it should be broken up. Why include a discussion about delayed clearing in a steady-state table? 5) Notes section (bottom of table), item 4 â€" We interpret FACTS to mean Flexible AC Transmission Devices and this means different things to different companies. FACTS devices can be series devices and not necessarily shunts as referred to in the table. It is noted that there is not footnote reference pointing to item 4 within the table. TABLE 2, Stability: 1) Planning Event P1 - Indicates SLG or 3-PH, which one is needed? This should be clarified in the requirements that reference this table. The intent is likely that most planners would perform the less labor intensive 3-PH simulation and if criteria were met, then the conclusion would be that SLG is also met. However, as presently written, the "OR" could be manipulated to allow someone to meet criteria for SLG but not the 3-PH. The requirements should provide clear expectations in this regard. (Same comment applies to P3 and P6) 2) Planning Event P1.2 - At what position on the line is the fault to be tested? Either the table or requirements that reference this Planning Event should be clear in what is required. 3) Planning Event P1.3 â€" Is the fault to be placed on the high-side or low-side of the transformer? Either the table or requirements that reference this Planning Event should be clear. 4) Planning Events P1 and P2 - Is the intent that a TP would need to run all possible P1 and P2 events in dynamic stability simulations? If not, the requirements should be worded to allow the TP some flexibility in selecting the items having the most impact. To expect all of these events to be simulated within dynamics is unrealistic and unnecessary. 5) Planning Event P2.1 â€" While we agree this event is warranted in steady-state, we question the need to cover this item within stability. Wouldn't breaker action clearing a fault always produce a more severe system disturbance than an inadvertent breaker trip? 6) Extreme Events â€" The reference to R5.5.4 should be R5.4.4 7) Extreme Events - Items 2, a,b,c,d - should "protection system" be capitalized as the defined term in the NERC Glossary? 8) Extreme Events - Items 2f and 2gshould be removed. It is inconceivable that the simultaneous faults described could occur. 9) Notes section (bottom of table), item 1 - Does not read consistent with Note 1 from Table 1 Steady-State. As stated above, various topics are covered within this note - stuck breaker, breaker relay failure, normal clearing, delayed clearing - it should be broken up. 10) Note number 4 from Table 1 Steady-State (item on shunt/FACTS) is missing in Table 2. The first 5 notes from Table 1 should be reflected in Table 2 with the existing Table 2 note 5 being re-numbered to item 6. 11) Table 2 Note 5.a.ii. - We question whether the number of units totalling the Contingency reserve is a good criteria. Also, with regard to the phrase "the resulting apparent impedance swings must not pass through relay characteristics that would result in the tripping of any Transmission System elements", we suggest a change to "the resulting power swing shall not cause the system to separate or form electrical islands".

Yes

Yes and No

Fundamentally, from a purest perspective, we believe that all breakers should be treated as having the same probability of failure. However, we understand the SDT's intent and agree to the higher performance expectations for the above 300kV transmission system. We also agree that without the exception provided for bus-tie breakers, some entities may take the approach to simply operate their bus-tie breakers open in order to meet the performance requirements, which would be counterproductive to the improved reliability sought by the team. The alternative would be back to back bus-tie breaker installations which may not even be feasible due to space limitations. On a going forward basis, future station designs at this voltage level should avoid straight bus designs.

No

The requirements related to sensitivity cases as written in draft 2 are an improvement over draft 1 as they now allow flexibility in choosing sensitivities, compared to what use to be a fixed list of options. However, we do not agree with the need to document the technical rationale for why each listed condition was or was not selected. This seems to create a needless paper trail from an auditing viewpoint. If any documentation is needed, it should be limited to why the sensitivity was selected and it should not be required to indicate why others were not selected. Therefore, we suggest rewording 2.3.1 as follows: "For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation of the technical rationale for why each of the conditions was selected shall be supplied:" R2.1.4 - This is an optional requirement and should be worked into the list of options within 2.1.3. As a stand alone requirement, what type of measure or VSL would be applicable for this requirement? We suggest re-numbering this requirement as a new 2.1.3.8 and reword it as follows: "Any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems". R2.1.3.3 â€" This requirement indicates sensitivity is needed for "Unavailability of long lead time facilities." Why is this required in a near-term planning horizon? How long is long? Doesn't the N-1-1 (Planning Event P6) test already account for this related to the outage of existing equipment which may present long lead times? Same comments apply for

R2.4.3 and R2.4.4 in the stability study section.

Yes

We agree with the change that now permits the loss of Non-Consequential Load for N-1-1 to meet performance requirements regardless of the voltage level studied. It is well understood that following a single contingency (N-1) that no Non-Consequential Load loss or interruption of Firm Transmission service is permitted. The SDT needs to clarify for industry if interruption of Firm Transfers is permitted pre-contingency to prepare for the 2nd (over-lapping) contingency. This is presently permissible in the existing TPL standards as Table 1 footnote 'b' reads â€œâ€¦ To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.â€

A â€" Generally support the revised standard

1) For this standard, "Protection System" failure should be limited to only relay event failures. 2) R1 â€" As stated in our response to Question 5, FE does not support the modeling requirements within the TPL standard and suggest that the SDT remove these requirements. This standard should be viewed on a premise that a valid and appropriate system model exist so that the fundamental focus of the standard is as stated in its purpose statement "Establish Transmission System planning performance requirements... to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions." If R1 remains, the phrase "and other data sources" should be removed. 3) R1.1 â€" this requirement requires the documentation of ANY data modification. Do you really mean ANY? How much detail is needed in the documentation? Is a line by line comparison of all data values before/after needed or is a general overview discussion sufficient? For instance, FE replaces its system model as shown in the MMWG representation with a more detailed system representation model when performing planning studies. This can included many differences from the MMWG system equivalent. How much documentation is needed in this situation? 4) R2.6 â€" This is not a requirement and should be removed and shown as explanatory text (footnote). 5) R3 - Requirement R3.1 is redundant to statements in the text of R3 and R3.3 and R3.4. We suggest that R3.1 be removed. It is suggested that R3.4 be indented and become a R3.3 sub-requirement. R3.5 would be better placed ahead of R3.3 along with the existing R3.2.

Individual

Kathleen Goodman

ISO New England Inc.

No

There should be no difference beween System and Generating Unit Stability studies. Each require discretion regarding which events need to be tested. The consequences are potentially similar: either the instability of one of more generators. Extreme Events should be considered for any stability analysis, again, recognizing that discretion needs to be applied when selecting or dismissing particular contingencies. If no distinction is made between System and Generating Unit Stability studies is made, then the definition of Generating Unit Stability Study should be stricken from the standard.

No

a. A MOD standard should be developed to address the assembly of dynamic load models, rather than specifying modeling in paragraph 2.4.1 (dynamic behavior of loads, including consideration of the behavior of induction motor Loads). Paragraph 2.4.1 should instead read, "System Peak Load for one of the five years." The remainder of the paragraph should be deleted. b. In paragraph R.2.4.3.4, what does "variability" mean? Is variablity more of a concern than an outage? Suggest changing paragraph R.2.4.3.4 to simple say "Outages of Reactive Resources" c. Add a new requirement, "R5.4.3.4 Automatic generator tripping shall not have an significant adverse impact on overall system reliability." d. Remove Heading R5.5 and make generator unit stability for a new facility a section of overall stability requirements. e. Modify R5.5.1 to become R5.4.5, with the following, "Shall be performed for the addition of an individual generating unit or generating units at the same interconnection point 20 MW or greater that are directly connected to the BES." There may be little difference between the stability performance of a single 20 MW unit and an aggregation of units totalling 20 MW at the same BES interconnection point. f. If planning assessment studies all generators or stations above 20 MW, as suggested by R5.5.1, then this provision is unnecessary and R5.5.2 should be deleted. g. If the output of a generatiing station does not change by more than 20MW, then no new study is required and, it should be acceptable to rely on past stability assessments. This is not clear in R5.5.1. h. With respect to

section R5 - The concept of planned and long-term outages should be addressed uniformly for the general Planning Assessment. It should not be specific to the Stability Assessment. i. Planned and long-term outages are two fundamentally different concepts and should be treated separately. Planned and Long-Term outages should be defined. Define how planning events in Tables 1 and 2 are associated with each type of outage. Define length of a "Long Term" outage. Planned outages should be addressed in the operating horizion unless otherwise defined in the planning horizion. j. The provisions of Section R.5.3 should be included in a MOD standard and applied to a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertant trip of the generator. Such a provision should include " other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation. k. Strike R5.5.3 and R5.5.4, as they become redundant to R5.4.1

No

There are a few significant concerns with these definitions: The definitions need to be expanded to include interruption of Firm Transmission Service in a manner that is comparable to interruption of load; otherwise, Firm Transmission Service (FTS) is being treated in a manner that is superior to load. (The expansion of the defintions to include FTS would also address stated concerns associated with loss of radial or single facilities over which Firm Transmission arrangements have been made). There are perceived limitations to what constitutes Non-Consequential Load Loss. It must be clear that Non-Consequential load loss allows the cascading loss of a local area that does not adversely impact the BES. It would be impractical and unnecessary to anticipate that every such situation could be or needs to be managed by operator action or automatic control. Non-Interruptible load needs to be defined as,"Demand that the end-use customer has not made available to its Load-Serving Entity via contract or agreement for curtailment." The Consequential Load definition should specify "Interruptible and Non-Interruptible Load that is no longer connected to a sourceâ€¦" The inclusion of "or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes)" confuses the definition of Consequential Load Loss, because of the imbedded exception for steady state performance. It seems that the intent of this provision is to recognize that this type of load loss could occur for either transient or steady state conditions and that Planning Assessments should not be required to remedy this type of situation. However, this does seem to be at odds with the application and stated acceptability of Consequential Load Loss as noted in Table 1. Note: Table 2 has no reference to the treatment of Consequential Load Loss. It may be helpful to address the transient load loss situation in a separate defintion. Recommended Changes: Change "Consequential Load Loss" and definition to "Consequential Interruption - Load, Firm Demand, or Firm Transmission Service that is no longer connectedâ€¦" Change "Non-Consequential Load Loss" and definition- "Non-Consequential Interruption - Non-Interruptible Load, Firm Demand, or Firm Transmission Service loss other than Consequential Interruption loss that occurs through manual (operator initiated), automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems, or uncontrolled loss of a local area which does not significantly impact the BES."

No

We do not feel that R3.5.1, R3.5.2 and R3.5.3 are limiting enough. Add paragraph 3.5.4 "Manual and automatic generator tripping shall not have a signifficant adverse impact on the system."

No

a. With respect to R9 "including the expected mix of industrial, commercial and residential loads", this provision may be inadequate to be practically useful. The potential issues include the variation in end-use load mix through the daily load cycle, seasonal load composition variations, and the ability to translate these end-uses into reasonable and useful steady-state and dynamic load models. It is important to understand how the information will be used and how much additional detail such as distribution network detail is also required. b. Add to the last sentence of R9 through R14 the following phrase, "within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator." c. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R10 to read as follows: R10. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator. d. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R11 to read as follows R11. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator. e. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R12 to read as follows: R12. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for

generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator. f. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R13 and R14 as follows: R13. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator.. [Violation Risk Factor: TBD] [Time Horizon: TBD] R14. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to Transmission Lines, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator. [Violation Risk Factor: TBD] [Time Horizon: TBD] g. Planned and long-term outages are two fundamentally different concepts and should be treated separately. Planned and Long-Term outages should be defined. Define how planning events in Tables 1 and 2 are associated with each type of outage (e.g. P4, P5, or P6). Should there be specific contingency descriptions associated with long-term outages? Define length of a "Long Term" outage. Planned outages should be addressed in the operating horizion unless otherwise defined in the planning horizion.
No
a. R2.3 should be changed to indicate the year(s) for short circuit analysis. b. In R4, suggest replacing, " and following any single Contingency condition that would result in greater circuit breaker interrupting duties" with , " giving due consideration to the potential sequence of equipment operation". c. It should be stated in the standard that assumptions should be based on procedures provided by each Transmission Planner and by the Planning Coordinator.
No
a. In both Table 1 and Table 2, the "Interruption of Firm Transmission Service Allowed" column. It is problematic to try to create an "exemption" based on type of facility such as HVDC. There are many other situations in which Firm Transmission Service has been provided, but may need to be curtailed partially or completely following an outage. b. The term 'Firm' may have several different definitions. If 'Firm' Transmission Service or load may be interrupted for exceptional events, then it is conditional and 'Conditional Firm' should be defined. It is recommended that a note be added stating that "the only exception would be for curtailment of conditioned (or Conditional) Firm Transmission Service", recognizing that there may need to be some form of grandfathering in order to avoid having to rewrite transmission service agreements. c. In both Table 1 and Table 2, the "Extreme Event Descriptions" item 1 should add "or shunt device." d. In Table 1, the "Extreme Event Descriptions" items 3a and 3b should be deleted; they are redundant with Item 1. e. In Table 2, Note 5 includes significant clarifications and should not be buried in the bottom of the contingency table; Note 5 would be better placed in the definitions section. f. In Table 1 and Table 2, Contingency P5 requires a fault plus Protection System Failure. Assuming that the battery system is included in the Protection System, which it is in NPCC, then ALL protection at substations with single battery systems would be lost. This Contingency P5 requires a stable system response while all bus voltages and loadings to remain within criteria, without interruption of firm transmission service and without Non-Consequential Load Loss, at system voltages above 300 kV. Was this an intended outcome of this standard?
No
he definition provided is too limiting. It says that if you have two rings with a bus tie breaker in between, it is no longer a bus tie breaker. Recommend, "A circuit breaker that is positioned to connect two individual station configurations. The breakers in a bus scheme are not bus tie breakers but the breakers that tie bus schemes together are bus-tie breakers."
No
They should have the same performance requirements, however we understand that it is better to encourage bus-tie breakers in some applications than to hold them to the higher standard. Future station designs that need this differential treatment should be discouraged.
No
a. With respect to R2.1.3 delete "â€¦ that Stress the System with sensitivitiesâ€¦". b. R2.1.3 should be revised to clarify that if a TP/PC conducts the studies specified in R2.1.1 and R2.1.2 with one or more of the sensitivities which stress the system in the normal course of study, then additional studies of a less-stressed system are not required. c. The intention of Paragraph R2.1.4 is unclear and appears to be unnecessary; therefore, it should be removed.
Yes
The comment period was not long enough to develop a thoughtfull response to the impact that the new standards might have. Therefore cost can not be reasonably speculated.
The comment period was not long enough to develop a thoughtfull response to the impact that

the new standards might have on the planning studies, but a very rough thought would be that any additional needs would be captured within the normal planning studies, which would likely occur within two study cycles of the effective date of the standard.
The comment period was not long enough to develop a thoughtfull response to the impact that the new standards might have on study effort and the associated cost. In addition to cost, there is a significant concern over whether or not there will be enough staff to complete the required work.
See response to question 12.
See response to question 12.
See response to question 12.
See response to question 12.
B â€" Unsure about supporting the revised standard
side from the comments to the prior questions, there are several issues of concern that prevent us from supporting the present draft of the revised standard. We offer the following constructive comments in an effort to support the worthwhile effort that is being pursued so that we can reach a point of satisfaction that we could vote to support the revised standard. Our concerns are listed in a rough order of priority. a. This standard as drafted does not allow exceptions for small parts of the system as long as interconnected system reliability is maintained, which is allowed in the existing TPL standards in footnotes b) and c) in Table 1. Unless such exceptions are allowed significant transfer restrictions or large reinforcements must be made. The applicable TPL footnotes are: Existing TPL footnote b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers. Existing TPL footnote c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (nonrecallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems. b. This standard does no address base conditions. Without defining base conditions the initial status of genertaion dispatch and transers across the sysetm is ill defined. Therefore the contingency analysis doesn't have a predictable basis for a consistent and repeatable study. c. The reference to Special Protection Systems is completely permissive. Although there are good applications for Special Protection Systems, their use must be constrained to have a reliable system and to promote construction of needed infrastructure. d. This standard does not provide flexibility to shed load, which restricts the ability to control post contingency response for low impact events. This may result in advancing need for upgrades in response to low impact events. This may result in advancing need for upgrades in response to low impact events. This is in conflict with FERC's directive to have the Transmission Provider waiting for market response to transmission needs and having the Transmission Provider provide a role to back stop the market. e. Definition of the Long-Term Planning Horizion. The planning horizion, for assessment purposes should be limited to 10 years. Such an assessment should be sufficient to identify requirements that may take an extended time to implement. f. Definition of Planning Coordinator is part of the NERC Functional Model, Remove from the standard. g. Put headings on each section to identify the requirements of the section. h. With respect to R2.2 - Delete "current" from the phrase "current System Peak Load Study" and replace "study" with "assessment." i. Remove R2.2.1, the requirement to extend the assessment beyond 10 years. What does the length of the project have to do with the assessment? If it takes 15 years to build something, why does this require a review of year 15? What is the purpose of this assessment? j. R3.3.2 requires clarification - This standard needs to permit discretion regarding the single contingencies that need to be tested, similar to R3.3.3 and R3.4. It is completely unnecessary to test all events. For example, contingencies may be limited to relevant disturbances that are contained within or directly impact the studied system. k. With respect to R3.2.1 - Claraify whether the intent of the standard is to address station service minimum voltage limitation, maximum leading VAR absorption capability or both at steady state. l. Remove R3.2.2 - Relay loadibility is addressed in the PRC-023 Standard. m. With respect to R3.3.2.1 - Recommend the removal of the requirement to assess the expected duration of Consequential Load loss. It's not considered anywhere else in the standard. n. With respect to R3.3.3 - The paragraph refers to Table 1 Contingencies P3 through P7; this should be explicitly stated. Rationale for inclusion of testing should not be required; should only need to explain why certain Contingencies were not tested. This discretion should be applicable to all contingencies. o. With respect to section R5 - The concept of planned and long-term outages should apply to the general Planning Assessment, or not at all. It should not be specific to the Stability Assessment. p. The provisions of Section R5.3 should have a corresponding MOD standard apply a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertant trip of the generator. Such a provision should include "other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how those devices are treated in the simulation. q. Planned outages should be addressed in the operating horizion unless

otherwise defined in the planning horizion. r. Recommend allowing the same non-consequential interuption for >300kV as for <300kV. Distinctions and acceptability should be based on consequence, not voltage class. s. What is a "current" study?

Individual

Aaron Staley

Orlando Utiliites Commission

No

I support the comments from Florida Power & Light regarding System Stability vs Generating unit studies and proxies.

No

OUC supports the comments from FPL and Lakeland Electric on this issue.

No

The definition refers to "A source" which implies that an area served by several sources that loses access to one source could lose some load since it lost "a source" or "its source". This is a different meaning then the one expressed on the national conference call. As written this definition also implies that the triggering of a UVLS, UFLS or load shedding SPS is not acceptable under the conditions for which non-consequential load loss is not allowed. If the Drafting teamâ€™s intent is to forbid the use of these devices for certain levels of contingencies then it should be done directly in the standard not hidden in a definition. (While an SPS may or may not include load loss, UVLS and UFLS are effective because of the load loss.)

No

The requirement R3.5.1 is not clear. If the intent is that following a single or multiple contingency facilities are within their ratings before, during and after the generation adjustment it's should be specified that way. "All facilities shall operate within their facility ratings prior to, during, and after the generation adjustment". Also I am unclear on how I would prove that I am not violating and safety or statutory requirements, that seems to be attempting to prove a negative since it is not specific on which requirements. Maybe â€œNot violating any known safety and statutory requirementsâ€ if it is necessary to have this part. However since any real statutory and safety requirements have their own enforcement mechanism it is unnecessary to have the NERC auditor monitor these in addition to the existing monitors. I am not sure on the definition of sustainable? Is it a system that requires no further adjustment to be within itâ€™s long term ratings? Or is it a system that is prepared for the next event (Secure)?

No

If improvements are needed to the MOD standards then those should be addressed in the MOD standards. This is beyond the scope of the TPL standards. Creating requirements that are not within the scope of a particular standard invites compliances issues and also creates an environment where it may not be possible to comply with both standards. However if you are going to retain these please consider: R7: Revising to state "Each Transmission Planner and their associated Planning Coordinator" otherwise this could be interpreted that every TP & PC has to have an agreement with every other TP and PC in existence on their joint and individual responsibilities. R8: This seems to be redundant with the FERC order 890 requirements for an Attachment K process. That process already has an audit mechanism in FERC and a reporting mechanism in the form of the clients of that process. Having NERC auditors monitor this type of process seems a distraction from their purpose of enhancing system reliability.

Yes and No

OUC agrees with other commentors that if there is a need for monitoring this, it should perhaps be in a different standard.

Yes and No

I like the concept of the new performance tables however if they could be made shorter that would be handy. I have the following specific suggestions, although they may be moot if the table is redesigned. The way the notes at the top of table 1 and table 2 are written it appears that they apply to planning single, planning multiple and extreme event sub-tables. However this is in conflict with some parts of the standard itself and the teamâ€™s comments on the conference call. For example Requirement R3.3.2.2 applies facility ratings only to planning single contingencies only, so which is correct the requirement or the note that applies it to everything? I have several suggestions to fix this: 1. Move the "notes" to under the Planning Event sub table 2. Making 4 tables with the Extreme Events being a table 2 & 4 respectively 3. Indicating the notes as only applying to specific planning events. The discrepancy between requirement R3.3.2.2, the table note and comments on the conference call also needs to be corrected either by expanding the applicability of R3.3.2.2 to multiple contingencies or reducing the scope of the corresponding note. It should be clarified somewhere that the Transmission Planner and Planning Coordinator select the range of the system contingencies for N-1. Otherwise some may interpret this as only having to test contingencies on their own system (insufficient from a reliability perspective for many systems) while some auditors may interpret this as requiring every possible n-1 in the US and Canada as necessary. For example a requirement R3.2.3 could be added

stating "The planning assessment should include a technical rationale for the range of transmission lines, transformers and other equipment considered". This could also be handled as a note on the tables to the effect of "The study should include a technical rationale for the range of transmission line and generators considered."
Yes and No
I neither for or against breaking out these breakers as a seperate class. However a graphic or sketch of some example an easier concept to understand both in terms of what it is and why it is worthy of special attention.
Yes and No
If they are going to be two classes of equipment with an arbitrary cut off 300 kV is a good cutoff. However I would prefer to see the decision on what is "super BES" and regular "BES" less arbitrary and more reliablity driven, such as letting the regions define this cut off just as they define BES in a manner suitable to the design of their regional system.
Yes and No
I generally agree with the intent of requiring studies beyond just one load level and system condition; however I have some specific suggestions, questions and comments. R2.1.3: As worded I have several concerns: 1. This would make any study performed that did not include sensitivities useless for performing the assessment. I recommend identify sensitivities and studies separately, with sensitivities just being smaller versions of studies. (Our usual definition is that a study demonstrates specific solutions to problems identified, whereas a sensitivity merely comments on the presence or lack of problems and how they relate to what is seen in the more formal studies. Obviously a problem found in a sensitivity not seen in a regular study receives additional focus.) 2. This would force the study to look only at the sensitivities listed rather then allow one or more of the conditions, plus additional conditions all in one run. This would force an entity to run additional studies if they wished to exceed the requirements rather then a single study that meets and exceeds the requirements. I suggest the following wording instead to still require the sensitivities, but allow flexibility in how they are performed. "R 2.1.3: At least one sensitivity shall be performed that stress the system based on one or more of the following conditions, plus any additional conditions determined by the transmission planner and planning coordinator. The Planning Assessment will also include the technical rationale for why each of the conditions was or was not selected for study that year. R.2.1.3.1- Suggest adding system growth, for example "season, weather, unpredicted system growth, or time of day". As written it does not seem to allow a study based on the long range load growth prediction being off, but instead only on a change in season, weather or time of day. R2.1.4: What was intended by using the phrase "Documentation of the technical rationale" instead of simply saying "shall include technical rationale"? I suggest dropping the "documentation of the" as this could cause confusion on an audit as to what is the difference between the "technical rationale" and "documentation of the technical rationale" unless the drafting team plans to define what "documentation of technical rationale is" other then the rationale itself.
Yes and No
As written the standard does not seem to forbid the adjustment of firm transfers and non-consequential load in preparation for the second part of an N-1-1, however that conflicts with the teams statements on the recent national call. If the intent is to forbid the adjustment of firm transfers and non-consequential load in preparation for the second part of an n-1-1 that needs to be made explicitly clear in the standard. This is especially important since one of the current understandings of the standards relating to Transmission Planning and System Operating Limits clearly allow such adjustments, and to not make it clear is building a compliance trap for the unwary. While I do not support the creation of this n-1-1 threshold if it is going to be established it needs to be abundantly clear.
$75,000 to supplement past study portfolio. (We have a fairly small system, only 1400 MW)
Two years, one year to recruit additional planner, the second to perform the baseline studies. This assumes there are sufficent trained personnel in the industry and they can be recruited.
$75,000 each year.
$25,000
$25,000
$0.00 if system adjustment in preperation for the second part of N-1-1 can include firm transfer and non-consequential load adjustments when neccessary. $500 Million if n-1-1 conditions must be met without firm transfer and non-consequential load - adjustements before the second event, at 230 kV and above $1 Billion if n-1-1 conditions above are met on load serving systems below 230 kV.
10 Years to meet n-1-1 without curtialment/reduction prior to the second n-1. A significant portion of the work would be in either downtown, established residential or highly sensitive enviromental areas, all of which may require extensive legal proceedings to build the projects. There would also be a large amount of simultanenous work going on nationwide that would result in a shortage in construction & design personnel as well a scarcity in needed materials.
C â€" Definitely do not support the revised standard

This standard is a definite improvement over the current set of standards. The majority of my comments are on details rather then the overall concept. My single biggest concern is the handling of n-1-1. This represents a significant expense to transmission customers and serious restriction on making firm transmission available, but due to the low probability of these events it would represent little if any practical improvement in customer reliability or grid security.

Individual

Charles W. Long

Entergy Services, Inc.

Yes and No

Entergy agrees with the intent. However, there will be some confusion because the industry standard terms for stability are omitted. It should be clear that the System Stability Study is a wide area view/assessment of both angular and voltage stability. In contrast, the Generating Unit Stability Study is focused on a specific unit or plant and the immediate area. Typically, this study looks at angular stability. The confusion may be exacerbated by the exclusion of a definition for voltage (or load) stability in the notes on page 31. There is a discussion of angular stability, but voltage stability is conspicuously missing. An improvement for the System Stability Study definition is to clarify that it is a study that focuses on the impact to the system itself and covers an area larger than one Generating Plant, covering a large geographical area. See specific proposal below: â€œSystem Stability Study - Study that focuses on how contingencies impact a larger portion of the System than a Generating Unit Study. These studies would examine issues such as angular Stability, inter-area power oscillation, and dynamic voltages.â€

No

General Comments: The enhanced requirements in this standard will result in an exponential increase in the amount of studies required to become compliant. Some of the changes such as the list of specific sensitivity studies will make it difficult to audit. Standards need to be measurable. As currently written, these requirements are difficult to measure. Furthermore, as indicated in the later questions, there could be significant costs to comply with these revised requirements Specific Comments: In 2.4.1, it would be better to address the "consideration of the behavior of induction motor Loads" in the sensitivity studies bullet, 2.4.3.1.,if this bullet is to be included at all. Furthermore, induction motor modeling is primarily required in areas with high load concentration that could be subject to angular and voltage stability issues. Considerable effort is required to collect information on motors. Therefore, studies to evaluate induction motor effects should be included in the sensitivity analysis section. In 2.4.3, what was the rationale for including only a portion of the sub-bullets included in 2.1.3? Also, in 2.1.3.7, does "Modification of planned Transmission outages" imply changes in dates? It seems unlikely that the cancellation of an outage would have negative impacts. More clarification is needed on what "modification" means in this requirement. R 2.4.3 Each transmission provider has its own transmission planning needs and requirements. While it is true there are common elements and considerations that have to be incorporated in every transmission providerâ€™s planning process, it is difficult, if not impossible, to prescribe a list of sensitivities that is, or should be, applicable to everyone. Entergy has specific concerns regarding the following sensitivities. R.2.4.3.2 Modification of expected transfers: The use of "expected" transfer levels suggests that one can expect certain transfer patterns beyond what is modeled in base cases as firm. These sensitivities could result in an endless string of â€œwhat-ifâ€ scenarios where transmission users would attempt to influence these studies to advantage their respective market positions. Any system improvements based on such "expected" use of the system shall not result in discriminatory treatment of transmission users. R.2.4.3.5. Generation additions, retirements, or other dispatch scenarios. Generation additions are addressed by FERC-mandated study criteria. These requests are handled through the generation interconnection and system impact study processes. Generation retirements and other dispatch scenarios can have both positive and negative impacts on reliability. However, assumptions used to pick which resources are changed, and in what way, will likely be difficult to justify. R5.5 There is a concern with R5.5.1 with the requirement to perform simulations on 20 MW generators (to be consistent with the Registration Criteria). We recommend a 75 MW generator cutoff for required simulations.

No

To the extent stakeholders agree with the use of UVLS or other special protection systems to mitigate events and avoid costly infrastructure improvements, the load that is reduced due to the operation of these systems should be capable of being classified as consequential load. In some cases, these systems can enhance grid reliability by removing components that have no significant impact on the BES. The definition of Non-consequential Load Loss includes load dropped by UVLS, UFLS, as well as SPS. However, Consequential Load Loss does not name SPS load loss as an exception, while UVLS and UFLS are named specifically. Shouldn't load lost by SPS action also be included in this exception to reduce confusion? There also seems to be another category missing. Non-consequential load loss could also be a result of "regular" protection systems beyond those directly protecting the faulted equipment. The second part of the Consequential Load loss definition is confusing - "Although Load which is lost as a result of the Loadâ€™s response to the transient conditions of the event is considered Consequential Load

Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements." While it Is part of consequential load loss per the definition, planners are not allowed by the standard to plan for it. Therefore, this definition seems to make the Performance Tables incorrect. With this statement we seem to need another term like "Allowable Consequential Load loss."
Yes and No
The intent seems reasonable, but the wording needs work. There needs to be consistent verb usage. All 3 sub-bullets need to use "shall" instead of "would" and "is."
Yes
Yes
Yes and No
Given the type of information the SDT was trying to convey in the Tables, the format is fine. However, the enhanced standards create a conflict between the planning criteria used for evaluating transmission service (typically a standard N-1 thermal only analysis for ATC/AFC calculations) and the criteria for reliability as proposed by this standard. This disconnect will unfairly shift the cost of expanding the transmission system to the native load customers while wholesale and point-to-point transmission customers will reap the benefits of the additional capacity installed.
No
Change term from â€œBus-tie Breakerâ€ to â€œStraight Bus Substation Bus-tie Breakerâ€ with the following definition: A bus-tie breaker is a circuit breaker that connects two individual bus sections in a straight bus substation configuration. References to Bus-tie Breaker in the standard would also need to be changed accordingly.
No
The probability of an EHV breaker failure is extremely low. Statistically, the probability of an internal breaker failure on any given day in our system is approximately 1 failure every 10,000 days. The probability of a stuck EHV breaker in our system is approximately 1 failure every 21,000 days. While the impact of such events can be severe, the significant cost to remedy such low probability events seems unlikely to pass any reasonable cost/benefit analysis.
No
R2.1.3.2 - Modification of expected transfers: Modification of expected transfers infers that non-firm transmission use would be estimated based on historical data or perhaps an economic outlook. To plan the system for such non-firm use is an imprudent burden on rate payers. Economic tools are available to ascertain the benefits of system upgrades and prudently allocate the costs of such upgrades. Generation assets and the future plans of those assets is market sensitive information that could easily be extracted from such sensitivity analyses. Results of these sensitivity studies should be used to aid in reliably operating the system. They should not be a basis for constructing transmission facilities for reliability. These types of studies are aligned with the operating horizon. See also comments made above regarding 2.1.3.4 and 2.1.3.7. In general, we believe that breaking these requirements into specific sub requirements, focusing on specific sensitivities, is too prescriptive and inappropriate. It will lead to over focus on these particular issues to the detriment of system reliability. There should be no enumerated list of required sensitivities. Engineering judgment needs to be permitted. Many examples of sensitivities are already inherent in the existing requirements. Some sensitivity studies are in effect adding an additional level of contingency (N-2 or N-3). Sensitivity studies of load variation are already inherent in the fact that several different study years and conditions are already being required. Outages of reactive sources and generation should already be included in studies of multiple contingencies. The process of planning new generation (system impact studies) will include studies of the future with and without the proposed new equipment. The TP and PC can better select the most appropriate sensitivities for their system. We recommend that engineering judgment continue to be recognized as a vital component of planning.
Yes and No
Since Event P6 is essentially a sub-set of the existing Category C.3 Contingency events, we support these modifications which make the system performance requirements for P6 consistent with what exist today for Category C.3. While we agree interruption of firm transmission service and non-consequential load loss should not be allowed to meet the planning requirements for the first system contingency (to get loadings back within normal ratings), these system adjustments should be allowed to prepare for the second event so that the system will meet the requirements following the second event. We recommend that clarifying changes be made to incorporate this concept. We recommend that the statement below be included as modification or as a footnote for the P6 portion of the table as follows: Interruption of firm transmission service and non-consequential load loss are allowed after the first event as a system adjustment to prepare for the second event in order to meet the requirements following the second event. As the

requirement is now implemented in the table, transmission service would need to be made available only if they can be accommodated for N-2 events. This would place these services on equal footing from a reliability perspective but would virtually eliminate the firm transmission market.
Cost will be covered by the on-going study costs as indicated below.
18 to 24 months
$1,200,000 / year
$150,000
$100,000 / year
Without performing the requisite analyses, Entergy does not know definitively how much it will cost to comply with these revised standards. However, Entergy expects the cost could be up to $1 billion to become fully compliant.
15 - 20 years The time required for construction will be elongated due to the need for significant numbers of new construction projects. This will require that projects be queued by the TPs because of constraints in available materials, labor and other resources.
C â€" Definitely do not support the revised standard
No cost-benefit studies have been completed to justify the significant investment and no detailed analysis of the expected reliability impact has been conducted for the Eastern Interconnection. Some research suggests that infrastructure expansion will reduce the number of large BES events, but that each event would impact larger areas with longer restoration times. http://eceserv0.ece.wisc.edu/~dobson/PAPERS/complexsystemsresearch.html Additionally, there is a fatal disconnect between the enhanced reliability standard and the FERCâ€™s current standard for selling firm transmission service. A utility cannot be required to build to an N-1-1 standard to satisfy reliability requirements and also be required to sell additional firm transmission service using a lower N-1 reliability standard. Such a situation would create an untenable situation where reliability standards force construction that the utility is then required to make available for sale pursuant to the provisions of the OATT and, once sold in accordance with the OATT, results in the utility being out of compliance with the reliability requirement. Requirement P2.1 in the table will have direct impact on local load reliability but not grid reliability. For example, a long line in a radial configuration due to a single contingency would only impact the reliability in a local area. Any implementation plan should consider all aspects of obstacles that Transmission owners will encounter including, ROW and land acquisition delays, inflationary impact on raw materials and other resources, capital funding constraints and associated regulatory lag, etc. Category P6 prescribes what is effectively an n-2 criteria for offering firm transmission service by not allowing the curtailment of firm transmission service as a system adjustment. Many areas are limited in how much local generation is available for re-dispatch as a system adjustment and thus compliance would be realized only by costly transmission construction by TPs.
Individual
Jay Seitz
US Bureau of Reclamation
No
Comments: We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study â€œfocuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to â€œdevelop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingenciesâ€. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say â€œonly whenâ€ the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard

taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, â€œmaterial Transmission System changeâ€ and â€œat or near the point of Interconnectionâ€ to invoke a study.

No

Comments: R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirement in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. âˆ’ We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. âˆ’ The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Ownerâ€™s open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Ownerâ€™s responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.

No

We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as â€œlocal Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting Comment Form for 2nd Draft of Standard TPL-001-1 Assess Transmission Future Needs (Project 2006-02) Page 5 of 12 the overall reliability of the interconnected transmission systemsâ€ in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, â€œâ€¦load no longer being connected to a sourceâ€¦â€. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non- Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL- 001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non- Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (â€œAlthough Load which is lost as a result of the Loadâ€™s response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon

the expectation of such Load loss to meet steady state performance requirementsâ€) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.

Yes

We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL- 001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.

Yes

Comments: While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.

No

Comments: We agree with R2.3. However, R4 requires assessment of â€œShort-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting dutiesâ€. Comment Form for 2nd Draft of Standard TPL-001-1 Assess Transmission Future Needs (Project 2006-02) Page 7 of 12 Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute â€œnormalâ€ condition or â€œfollowing any single Contingency conditionâ€. Also, by specifying the normal and single contingency conditions, R4 is straying into â€œhowâ€ to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.

No

We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.

No

We do not disagree with the proposed definition change. However, we do not agree that â€œSubstation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-ahalf and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.

No

We interpret â€œexit breakersâ€ to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non- Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes

No

We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the â€œbase caseâ€ of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to

demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain Comment Form for 2nd Draft of Standard TPL-001-1 Assess Transmission Future Needs (Project 2006-02) Page 9 of 12 why they feel that this higher level (1 in 10 year adverse weather) of load is the â€œbase caseâ€ condition. R2.7 also states that â€œCorrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivitiesâ€. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the â€œbase caseâ€, will the judgment of the Transmission Planner be then questioned because theâ€œbase caseâ€ used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?

Yes

We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1- 1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.

C â€" Definitely do not support the revised standard

We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. âˆ’ There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. âˆ’ We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions. âˆ’ We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with â€œraising the barâ€. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. âˆ’ As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms â€œinterruption of firm transmission serviceâ€, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what â

€œFirm Transmission Serviceâ€ means. Two points, 1) the NERC definition states â€œhighest quality service offered to customers under a filed rate schedule that anticipates no planned interruption.â€ The Standard implies anticipation of â€œunplannedâ€ interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order 890, or firm transfers modeled for the conditions being studied? One way Comment Form for 2nd Draft of Standard TPL-001-1 Assess Transmission Future Needs (Project 2006-02) Page 12 of 12 to interpret the intent is the firm transfers being modeled for the conditions in the powerflow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption of firm transmission service should also be allowed for P1 through P5 contingencies in the table. In addition, we believe that DC and AC lines should have the same performance requirements with respect to interuption of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines can automatically be curtailed when the line is outaged.

Group

Bonneville Power Administration

Denise Koehn

Transmission Reliability Program

No

Generating Unit Stability is adequately addressed by the System Stability studies and does not need to be evaluated separately. Footnote 5.a.i in the notes following the Performance Requirements Tables, already specifies the requirements to meet. Therefore, we recommend removing the section on Generating Unit Stability Studies from standard TPL-001-1. The focus of this standard should be on "System Stability" which encompasses all generating units.

No

R2.4.1 references the use of a load model which appropriately represents the dynamic behavior of loads. However, such load models have not been developed yet. We recommend removing that requirement for load models until these models have been developed and approved. R2.5 and R5.5 refer to Generating Unit Stability studies. As stated above under Item 1, Generating Unit Stability is adequately addressed by the System Stability studies and does not need to be evaluated separately. Footnote 5.a.i in the notes following the Performance Requirements Tables, already specifies the requirements to meet. Therefore, we recommend removing the section on Generating Unit Stability Studies from standard TPL-001-1. The focus of this standard should be on "System Stability" which encompasses all generating units. Some of the requirements listed under R5.4 apply more generally than just within this section and are already covered elsewhere in the standards. R5.4.3.1 is already covered in Note 1 of Table 1. R5.4.3.2 is not relevant to Reliability Standards and would already be addressed by the the relevant regulations, so it does not belong in this Standard. R5.4.3.3 is already covered in Note 1 of Table 2. Because these requirements are already covered by other sections of the Standard, they can be removed from R5.4.

No

The definition of Consequential Load Loss needs to be modified to include all of the concepts that were contained in footnote b of the existing TPL standards.

No

R3.5 is not a requirement, but an allowed action in order to meet performance criteria. Therefore, the statement about generation run-back/tripping in R3.5 should be moved to become part of the notes in the Performance Tables and not part of the requirements text. The conditions described under R.3.5.1 through R.3.5.3 are covered elsewhere in the standards and should be removed from this section. Since R3.5 and R5.4 contain some similar wording, also see comments relating to R5.4 under Item 2, above.

No

Requirements for data gathering and load modeling belong in the MOD Standard and not in TPL-001-1. Requirements for dynamic load models should not be specified at this time, because the models have not been developed yet or approved by the RRO (also see comments regarding R2.4.1 under Item 2, above).

Yes and No

We agree with R2.3. However, we recommend removing the reference to single contingency conditions in R4, for the same reasons as described in the WECC comments. See below: "Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute â€œnormalâ€ condition or â€œfollowing any single Contingency conditionâ€. Also, by specifying the normal and single contingency conditions, R4 is straying into â€œhowâ€ to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.

No
We suggest that the tables for Steady State and Stability Performance could be combined into one table, for simplicity. Separate columns could be used for Steady State versus Stability performance criteria.
No
The term "Bus Tie" implies tying any two buses together. However, the intent of this standard is actually referring to connecting the main buses of two adjacent main and auxiliary configured substations together. Therefore, we recommend changing the term "Bus Tie Breaker" to "Bus Sectionalizing Breaker". We also recommend removing the parentheses portion of the Bus Tie Breaker definition. It does not provide clarification and may not apply to all utilities' systems.
Yes
In general, performance requirements should be more stringent for higher voltage systems. Therefore, we agree that non-bus-tie breakers above 300 kV should have more stringent requirements.
No
For those conditions that are "not" studied, it makes sense to explain why that particular condition was not selected. However, we do not agree with R2.1.3 that a rationale needs to be provided for why a particular sensitivity "is" selected for study. Running additional sensitivities provides a better understanding of system performance and doesn't need further justification. Requirement R2.1.4 is not needed and should be removed. It should be up to the Transmission Provider's discretion whether they run additional sensitivity studies beyond what the standard requires in R2.1.3, and it should not be necessary to justify why they chose to run them. What a sensitivity study consists of, needs further clarification. For example, if a system assessment is performed using a case with transmission paths stressed near their limits, is this considered the baseline or a sensitivity? If it is considered the baseline, would a sensitivity be required at reduced stress levels and what purpose would this serve when the original case produced the more severe system impacts? This needs further clarification.
Yes and No
We agree with the revision to permit the loss of Non-Consequential Load to meet performance requirements for Systems above 300 kV. However, a better definition is needed for "system adjustments". For example, are curtailments permitted as part of "system adjustments"? Within category P6, there needs to be a common reason for the overlapping outage to occur, such as lines on a common tower, and the appropriate reasons need to be clearly identified in the requirements. In general, we believe that performance category P6 should be part of the Operating Standards rather than the Planning Standards. For these types of events, it is the responsibility of Operations to determine the necessary system adjustments to prepare for the next contingency within the operating horizon prior to year one as defined in the Planning Standards. Therefore, the performance requirements for this category of contingencies, do not belong in the Planning Standards.
This information is not available.
This information is not available.
This information is not available.
This information is not available.
This information is not available.
This information is not available.
This information is not available.
B â€" Unsure about supporting the revised standard
We are unsure about supporting the revised standard. A couple of additional concerns are described below. The purpose of the Standard is not clearly defined. There should be more clarity given to what reliability means in the context of these standards (e.g. minimize load loss for more probable contingencies, etc.). Regarding the terms "interruption of firm transmission service", there needs to be clarification of what "Interruption" means. Does it include curtailment needed after a particular contingency and adjustments? There also needs to be clarification on what "Firm Transmission Service" means. Two points: 1) the NERC definition states "highest quality of service offered to customers under a filed rate schedule that anticipates no planned interruption." The Standard implies anticipation of "unplanned' interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order 890, or firm transfers modeled for the conditions being studied? One way to interpret the intent, is the firm transfers being modeled for the conditions in the powerflow, to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load, if the transfer being modeled is interrupted, then interruption of firm transmission service should be allowed for P1 through P5 contingencies in the table.
Individual
john cummings

ppl energy plus
Yes and No
R2.4.3 and 2.4.4 together with R2.7 are a very good effort to direct TSP's to not let scenarios drive their plans. Rather, the base case should drive the plan. If anything, the language in the standard could be strengthened.
Yes
The SDT conference call was helpful to my understanding of non-consequential. As I understand it, non-consequencial load loss allows transmission planners to drop load that chooses to be dropped under certain conditions. This is a useful tool as not all loads demand the same quality of service.
Yes and No
My concern is that some TSP's over-use RAS and at some point, system improvements must take place. The best approach is a collaborative effort of all stakeholders (esp operations folks) to prevent abusing RAS. Possibly R3.5 could tie to or be put under an Requirement that involves collaboration with stakeholders.
Yes
The new format is a nice improvement. On the SDT conference call, it was stated that table 1 and table 2 assume different starting points; if so, could this be spelled out in the standard? Also, consequential generatio nloss isn't defined.
Yes and No
All of the sensitivity requirements should be structured to keep sensitivities from forcing un-needed construction. R2.1.3 & 4 are a good step but the point about planning around the base case might be made even more forcefully.
Yes
A â€" Generally support the revised standard

Comments for 2nd Draft of Standard TPL-001-1 — Assess Transmission Future Needs (Project 2006-02)

The Assess Transmission Future Needs Standards Drafting Team thanks all commenters who submitted comments on the 2nd draft of reliability standard TPL-00101 — System Performance under Normal Conditions. The proposed standard was posted for a 45-day public comment period from August 14, 2008 through September 29, 2008. The stakeholders were asked to provide feedback on the proposed metrics through a special electronic Standard Comment Form. There were more than 80 sets of comments, including comments from more than 150 different people from more than 100 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

Due to the large number of comments received and the addition of VRF, Time Horizons, Measures, Data Retention requirements, and VSL, the SDT recommends an additional posting for this standard.

Due to industry comments, the following definitions have been changed: Bus-tie Breaker, Consequential Load Loss, Non-Consequential Load Loss, and Year One.

Due to industry comments, the following definitions have been deleted: Generating Unit Stability Study, Planning Coordinator, and System Stability Study.

Due to industry comments, the following definitions have been added: Load Reduction and Supplemental Load Loss.

Due to industry comments, the following requirements have been changed: R1, R1.1, R1.1.1, R1.1.2, R1.1.3, R1.1.4, R1.1.5, R1.1.6, R2, R2.1, R2.1.3, R2.1.3.4, R2.1.5, R2.2, R2.3, R2.4.1, R2.4.3, R2.6.1, R2.6.2, R2.6.2.1, R2.6.2, R2.7, R2.7.1, R2.7.1, R2.8, R2.8.1, R2.8.2, R2.9, R2.10, R3, R3.1, R3.2, R3.3, R3.3.1, R3.3.2, R3.3.3, R3.3.4, R3.5, R3.6, R5, R5.1, R5.2, R5.3, R5.3.2, R5.5, R5.6, R6, and R8.

Due to industry comments, the following requirements have been deleted: R2.1.4, R2.4.4, R2.5, R2.5.1, R2.5.2, R2.7.4, R3.4, R3.7, R4, R5.4, R5.5.1, R5.5.2, R5.5.3, R5.5.3.1, R5.5.3.2, R5.5.3.3, R5.7, R9, R10, R11, R12, R13, and R14.

Due to industry comments, the following table notes have been changed: Header note 'b', 'e', 'i', Footnotes 1.a.ii, 3, 5, 10 and 12.

The two table concept has been replaced by a single table with necessary corresponding changes to the notes and footnotes as appropriate. In addition, a typo in Extreme Event 2b was corrected due to an industry comment.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards,

Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses:

1. The SDT has modified the definitions and requirements associated with System Stability and Generating Unit Stability (formerly Plant Stability) in response to industry comments. Do you concur with the modified definitions for stability and, if not, please state why and/or suggest specific changes. 12

2. Do you concur with the modified Requirements R2.4, R2.5, R5.4, and R5.5? If not, please state why and/or suggest specific changes. 41

3. The SDT has modified the definitions of Consequential and Non-Consequential Load Loss in response to industry comments. Do you concur with the modified definitions of Consequential and Non-Consequential Load Loss? If not, please state why and/or suggest specific changes. 103

4. The SDT has modified Requirement R3.5 and eliminated Requirement R3.6 from the first draft to clarify that manual and automatic generation run-back (redispatch) and tripping is allowed as a Corrective Action Plan as long as the conditions in Requirements R3.5.1, R3.5.2 and R3.5.3 are met. Do you agree that generation run-back and tripping (manual and automatic) should be limited by these conditions? If not, please explain why you disagree with the proposed requirements. 144

5. The SDT has modified the modeling requirements. Some commenters expressed concern that the modeling requirements contained in Requirement R1 of the first draft of TPL-001-1 were either duplicative of the requirements in the MOD standards, or to the extent new modeling requirements were proposed, that the appropriate venue for such modeling requirements would be the MOD standards. The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has incorporated these additional requirements with the intent that they will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. The SDT has also modified proposed modeling requirements contained in Requirement R1 of the first draft of TPL-001-1 based on industry comments and moved these requirements to Requirements R9 through R14 in the second draft for ease of removal later on. Furthermore, in response to industry comments, the SDT has separated the modeling requirements into individual requirements for each responsible entity. Do you concur with the modifications reflected in Requirements R9 – R14? If not, please state why and/or suggest specific changes.. 160

6. The SDT has modified the requirements relating to short circuit analysis Do you concur with the modifications reflected in Requirements R2.3 and R4. If not, please state why and/or suggest specific changes. 189

7. The SDT has reformatted the Steady State and Stability Performance Tables. Do you concur with the modified format? If not, please state why and/or suggest specific changes. 206

8. A new definition for "Bus-Tie Breaker" was added to clarify the type of substation design and breaker position that qualify as a Bus-tie Breaker. Do you agree with the proposed definition? If not, please explain.....258

9. Some commenters questioned why a Bus-tie Breaker would have a different performance requirement than a non-Bus-tie Breaker, stating that all breakers have the same probability for failure. It may be true that generally the probability for failure of any given breaker would not vary substantially among similar types of breakers, but the Bus-tie Breaker reduces exposure and consequences of bus faults. The different performance expectations in Tables 1 and 2 are based on promoting a higher level of reliability for the Transmission Systems operated above 300 kV. It is recognized by

the SDT that a straight bus design has some undesirable exposure to bus faults, but that Bus-tie Breakers can be utilized to improve reliability for bus faults and problems associated with exit breakers. As a result, the risk of an internal breaker fault was deemed to be significantly less than the benefit that is gained by reducing the exposure to a total bus failure. Therefore, provisions were built into the performance requirements that would not discourage their use. Do you agree that non-Bus-tie Breakers rated above 300 kV should have more stringent performance requirements than Bus-tie Breakers? If not, please explain why and/or suggest specific changes. . 267

10. The SDT made modifications in this second draft to the requirements relating to sensitivity cases. Do you concur with the modifications reflected in Requirements R2.1.3 and 2.1.4? If not, please state why and/or suggest specific changes. 285

11. In response to industry comments, the SDT modified Table 1 requirements for Planning Event P6. Planning Event P6 involves independent overlapping single contingencies (n-1-1) involving two Transmission Facilities excluding generators. This Planning Event generally correlates to P5 of the first draft and now includes shunt devices. The P6 event was also revised to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300 kV. Do you concur with the modifications? If not, please state why and/or suggest specific changes. 320

12. Comments from some entities received from the posting of the 1st draft standard indicated that significant additional costs will be required to meet the proposed requirements and performance tables. Commenters also indicated that it would take several years to install the additional facilities needed to meet the change in requirements. The SDT has attempted to adjust and clarify the proposed requirements and performance in light of these initial comments; however, the SDT needs more specific information on these concerns so that it can put the proposed requirements in perspective and make more adjustments as appropriate. Questions 12, 13 & 14 address these concerns. 341

13. Documentation: 355

14. System Reinforcement: One time cost, capital investment, to expand your system reinforcement program (due to lead times associated with different types of facilities, this will probably be an accumulated cost over several years). How many years do you estimate that it will take to complete this initial expanded system reinforcement program: 361

15. (A) Do you generally support the revised standard? (B) Are you unsure whether you generally support the revised standard? or (C) Do you definitely not support the revised standard? Please check the appropriate box below. If your response is either (B) or (C), please explain your single biggest concern with the revised standard, including which specific requirement or set of requirements causes you the most concern and why. 370

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Thad Ness	AEP	x		x		x	x				
2.	Anita Lee	Alberta Electric System Operator		x								
3.	John E. Sullivan	Ameren	x		x		x	x				
4.	Jason Shaver	American Transmission Company	x									
5.	Baj Agrawaal	Arizona Public Service Co.	x									
6.	Ronnie Frizzell	Arkansas Electric Coop. Corp.				x						
7.	James C. Armke	Austin Energy	x				x					
8.	Phil Park	BCTC		x								
9.	Eric Egge	Black Hills Corporation	x									
10.	J. David Carpenter	Brazos Electric Power Cooperative, Inc.	x		x		x					
11.	Paul Rocha	CenterPoint Energy and CPS Energy	x									
Additional Member	Additional Organization	Region	Segment Selection									
1.	Glenn Pressler	City of San Antonio City Public Service (CPS Energy)	ERCOT	1								
12.	David M. Conroy	Central Maine Power Company	x									

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
13.	Gary S. Brinkworth, P.E.	City of Tallahassee, FL	x		x		x					
14.	Karl Kohlrus	City Water, Light & Power - Springfield, Illinois	x		x		x					
15.	Marv Landauer	ColumbiaGrid										
16.	John Blazekovich (Exelon Corporation)	Compliance Elements Development Resource Pool (CEDRP)										
17.	John Loftis (Dominion Virginia Power)	Dominion - Electric Transmission Planning	x									

Additional Member	Additional Organization	Region	Segment Selection
1.	John Loftis	SERC	1
2.	Ronnie Bailey	SERC	1
3.	Peter Nedwick	SERC	1
4.	William Bigdely	SERC	1
5.	Mark Gill	SERC	1
6.	Larry Carter	SERC	1
7.	Mehdi Shakibafar	SERC	1
8.	Kirit Doshi	SERC	1
9.	Craig Crider	SERC	1
10.	Solomon Yirga	SERC	1
11.	Matthew Gardner	SERC	1

18.	Greg Rowland	Duke Energy	x		x		x	x				
19.	Keith Yocum - Manger, Transmission Strategy & Planning	E.ON U.S. Transmission Planning	x									
20.	Dennis Malone	El Paso Electric Company	x		x		x					
21.	Charles W. Long	Entergy Services, Inc.	x									
22.	Jay Teixeira (ERCOT)	ERCOT System Planning		x								

Additional Member	Additional Organization	Region	Segment Selection
1.	John Schmall	ERCOT	ERCOT 2

23.	Eric Mortenson	Exelon Transmission Planning	x		x							
24.	Sam Ciccone	FirstEnergy Corp.	x		x	x	x	x				

Additional Member	Additional Organization	Region	Segment

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
			Selection									
1.	John Stephens	FE RFC	1									
2.	Doug Hohlbaugh	FE RFC	1, 3, 4, 5, 6									
3.	Don Morrison	FE RFC	1									
4.	Art Buanno	FE RFC	1									
25.	Hector J. Sanchez	Florida Power and Light	x		x		x					
	Additional Member	Additional Organization / Region	Segment Selection									
1.	Bob Schoneck	FRCC	1									
2.	Kiko Barredo	FRCC	1									
3.	John W. Shaffer	FRCC	1									
4.	Carlos Candelaria	FRCC	1									
26.	Richard Becker (FRCC)	Florida Reliability Coordinating Council, Inc										x
	Additional Member	Additional Organization / Region	Segment Selection									
1.	Ballard Keith Mutters	Orlando Utilities Commission / FRCC	3									
2.	Rodney Hawkins	Lee County Electric Cooperative / FRCC	1									
3.	Roger Allen Westphal	Gainesville Regional Utilities / FRCC	3									
4.	Luther E. Fair	Gainesville Regional Utilities / FRCC	1									
5.	Ted E. Hobson	JEA / FRCC	1									
6.	Garry Baker	JEA / FRCC	3									
7.	Donald Gilbert	JEA / FRCC	5									
8.	W. R. Schoneck	Florida Power & Light Co. / FRCC	3									
9.	Hector Sanchez	Florida Power & Light Co. / FRCC	1									
10.	John Shaffer	Florida Power & Light Co. / FRCC	5									
11.	Kiko Barredo	Florida Power & Light Co. / FRCC	1									
12.	Ronald L. Donahey	Tampa Electric Co. / FRCC	3									
13.	Gary S. Brinkworth	City of Tallahassee / FRCC	1									
14.	Larry E Watt	Lakeland Electric / FRCC	1									
15.	Bart B White	Florida Power Corporation / FRCC	1									
27.	Earl Fair	Gainesville Regional Utilities	x		x		x					
28.	Roger Champagne	Hydro-Québec TransÉnergie (HQT)	x									
29.	Milorad Papic	Idaho Power Company										
30.	Dan Rochester	IESO		x								

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
31.	Kathleen Goodman	ISO New England Inc.		x								
32.	Raymond Kershaw (ITC Holdings)	ITC Holdings: ITC, METC, ITC Midwest	x									
33.	Don Gilbert	JEA					x					
34.	Gary Newell (Thompson Coburn LLP -- Counsel to Lafayette Utilities System)	Lafayette Utilities System	x		x		x					
35.	Mace Hunter	Lakeland Electric	x		x		x					
36.	Larry Watt	Lakeland Electric	x									
37.	Sergio Garza	LCRA TSC	x									
38.	Tim Wu	Los Angeles Department of Water and Power	x		x		x					
39.	Kris Manchur	Manitoba Hydro	x		x		x	x				
40.	Tom Mielnik	MidAmerican Energy Company	x		x		x	x				
41.	Marie Knox	Midwest ISO										
42.	Spencer Tacke	Modesto Irrigation District	x		x		x	x				
43.	Tom Mielnik (MEC)	MRO NERC Standards Review Subcommittee	x		x		x	x				

Additional Member	Additional Organization	Region	Segment Selection
1.	Neal Balu	WPS	MRO	3, 4, 5, 6
2.	Terry Bilke	MISO	MRO	2
3.	Carol Gerou	MP	MRO	1, 3, 5, 6
4.	Jim Haigh	WAPA	MRO	1, 6
5.	Charles Lawrence	ATC	MRO	1
6.	Ken Goldsmith	ALTW	MRO	4
7.	Pam Sordet	XCEL	MRO	1, 3, 5, 6
8.	Dave Rudolph	BEPC	MRO	1, 3, 5, 6
9.	Eric Ruskamp	LES	MRO	1, 3, 5, 6
10.	Joseph Knight	GRE	MRO	1, 3, 5, 6
11.	Joe DePoorter	MGE	MRO	3, 4, 5, 6
12.	Larry Brusseau	MRO	MRO	10

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
13.	Michael Brytowski	MRO MRO 10										
44.	Carol Sedewitz	National Grid	x									
45.	Andrew Wilcox	NB Power Transmission	x			x						
46.	Patrick Brown (PJM Interconnection, L.L.C.	NERC and Regional Coordination		x								
47.	Gregory Campoli	New York Independent System Operator		x								
48.	James Manning	North Carolina Electric Membership Corp			x	x	x	x				

Additional Member	Additional Organization	Region	Segment Selection
1.	Bob Beadle	NCEMC SERC	3, 4, 5, 6

49.	Rick White	Northeast Utilities	x									
50.	Guy Zito (NPCC)	NPCC										x

Additional Member	Additional Organization	Region	Segment Selection
1.	David Kiguel	Hydro One Networks Inc.	NPCC 1
2.	Ralph Rufrano	New York Power Authority	NPCC 5
3.	Dan Rochester	Independent Electricity System Operator	NPCC 2
4.	Rick White	Northeast Utilities	NPCC 1
5.	Lee Pedowicz	NPCC	NPCC 10
6.	Gerry Dunbar	NPCC	10
7.	Brian Hogue	NPCC	10
8.	Alan Adamson	New York State Reliability Council	NPCC 10
9.	Donald E. Nelson	Massachusetts Dept. of Public Utilities	NPCC 9
10.	Kathleen Goodman	ISO - New England	NPCC 2
11.	Gregory Campoli	New York Independent System Operator	NPCC 2
12.	Chris De Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC 1
13.	Brian Gooder	Ontario Power Generation Incorporated	NPCC 5

51.	Steven Masse	NSTAR Electric	x		x							
52.	John P. Mayhan	Omaha Public Power District	x		x		x	x				
53.	Greg Ward / Darryl Curtis	Oncor Electric Delivery	x									
54.	Matthew J Muldoon	OPUC									x	
55.	Aaron Staley	Orlando Utilities Commission	x		x		x	x				

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
56.	Chifong Thomas	Pacific Gas and Electric Co.	x									
57.	Sandra Shaffer	PacifiCorp	x									
58.	John Collins	Platte River Power Authority	x		x			x				
59.	John Cummings	PPL EnergyPlus					x	x				
60.	Mark Byrd	Progress Energy Carolinas	x		x		x					
61.	Bart White	Progress Energy Florida, Inc.	x		x							
62.	Tom Duane	Public Service Company of New Mexico	x		x							
63.	Joe Seabrook	Puget Sound Energy, Inc.	x		x							
64.	Herb Schrayshuen (SERC Reliability Corporation)	SERC Dynamics Review Subcommittee										x
65.	Herbert Schrayshuen (SERC Reliability Corporation)	SERC Reliability Review Subcommittee and Planning Standards Subcommittee										x
66.	Jessica Rice	Sierra Pacific Power Company/Nevada Power Company	x									
67.	Dilip Mahendra	SMUD	x		x		x	x				
68.	Dana Cabbell	Southern California Edison	x	x								
69.	Roman Carter	Southern Company Transmission	x									

Additional Member	Additional Organization	Region	Segment Selection
1.	JT Wood	SOCO Transmission SERC	1
2.	Jim Busbin	SOCO Transmission SERC	1
3.	Shih-Min Hsu	SOCO Transmission SERC	1
4.	Rod Hardiman	SOCO Transmission SERC	1
5.	Randy Cobb	SOCO Transmission SERC	1
6.	Chase Battaglio	SOCO Transmission SERC	1
7.	Bill Botters	SOCO Transmission SERC	1
8.	Tom Sims	SOCO Transmission SERC	1
9.	Chuck Chakravarthi	SOCO Transmission SERC	1
10.	Gary Gorham	SOCO Transmission SERC	1
11.	Chris Wilson	SOCO Transmission SERC	1

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
12. Terry Coggins, SOCO Transmission, SERC, 1 13. Bob Jones, SOCO Transmission, SERC, 1 14. Raymond Vice, SOCO Transmission, SERC, 1												
70.	Brian K. Keel	SRP	x									
71.	Tacoma Power	Tacoma Power	x									
72.	Scott Helyer	Tenaska, Inc.	x									
73.	Dave Larsen	Transmission Agency of Northern California	x									
74.	Denise Koehn (BPA)	Transmission Reliability Program	x		x		x	x				
Additional Member, Additional Organization, Region, Segment Selection 1. Chuck Matthews, Transmission Planning, WECC, 1 2. Berhanu Tesema, Transmission Planning, WECC, 1 3. Kendall Rydell, Transmission Planning, WECC, 1												
75.	Andy Leoni	Tri-State G&T	x									
76.	Mark Graham	Tri-State Generation and Transmission Association, Inc.	x									
77.	Gary Trent	Tucson Electric Power Company	x		x		x					
78.	B. David Till (TVA)	TVA System Planning	x									
79.	Karl Bryan	US Army Corps of Engineers, Northwestern Division					x					
80.	Jay Seitz	US Bureau of Reclamation					x					

1. **The SDT has modified the definitions and requirements associated with System Stability and Generating Unit Stability (formerly Plant Stability) in response to industry comments. Do you concur with the modified definitions for stability and, if not, please state why and/or suggest specific changes.**

Summary Consideration:

By a significant majority (about 2/3), the industry did not agree with the two definitions as modified in the second draft. Most of those disagreeing still express a fundamental disagreement with the approach of separating plant Stability from System Stability. Essentially many argue that plant Stability is simply a subset of System Stability, and the standard requirements could be simplified by focusing on Stability performance in a generic way. In this way Stability performance could be viewed in the context of individual units (generating unit Stability) or groups of units (System Stability). Some of these same commenters also argue that generating unit Stability is already covered by FAC–001 and -002 and, therefore, should be dropped from the TPL-001-1 standard; otherwise double jeopardy could apply. Many of these same commenters also suggested that if separation of generating unit Stability is retained in the final draft, then certain refinements of the requirements language should be made.

Others who voted 'No', as well as some who generally support the language of the current draft, recommended a variety of changes to the definitions and requirements for further clarity.

Only some 20+ percent of the commenters supported the current draft Stability definitions without reservation.

The SDT agrees with the Industry's majority view that generating unit Stability and System Stability need not and should not be treated as distinct issues. Consequently, the two new Stability terms have been removed from the third draft, and this revised draft references the already approved term "Stability." Furthermore, as indicated by the SDT's response to commenters, the Stability related requirements have been modified to create a single generic set of requirements that no longer distinguishes between generating unit and System Stability.

In summary, due to these and other industry comments in response to this question, the SDT has changed the following definition and requirements:

Consequential Load Loss: ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions.

R2. Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses ~~including both System and Generating Unit Stability~~.

R2.1 The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported ~~at a minimum~~ by the following annual current studies, supplemented with qualified past studies as indicated in Requirement R2.6:

R2.2 For the Long-Term Transmission Planning Horizon portion of the steady state analysis, ~~at a minimum,~~ a current System peak Load study is required annually for one of the years in the assessment period to support the annual Planning Assessment.

R2.6.1 (now 2.5.1) For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less.

R2.6.2 (now 2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:

R3.3.1 (now 3.3.2) For all generators, studies shall consider the minimum steady state voltage limitations ~~of all generators~~ and identify how the generators are ~~treated~~ analyzed in the steady state simulation.

R5. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, ~~the~~any proxies used in ~~simulation studies~~ the analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.

The wording of sub-requirements R5.6.1 and R5.6.2 was modified and relocated to become bullets under Requirement R2.5.2.

- The addition/deletion/change of individual generating unit capability of 20 MW or greater.
- An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater.

The definitions of Generating Unit Stability Study and System Stability Study as well as the following sub-requirements were deleted: R2.5, R2.5.1, R2.5.2, and R5.5.

Organization	Question 1:	Question 1 Comments:
NPCC	No	There should be no difference between System and Generating Unit Stability studies. Each requires discretion regarding which events need to be tested. The consequences are potentially similar: either the instability of one or more generators. Extreme Events should be considered for any stability analysis, again, recognizing that discretion needs to be applied when selecting or dismissing particular contingencies. Therefore, the definition of Generating Unit Stability Study should be stricken from the standard.
Los Angeles	No	Changing the name does not change the fact that this is wrong. The stability criteria in the standards are all measured on

Organization	Question 1:	Question 1 Comments:
Department of Water and Power		the high-side, i.e., the system side. So when a stability simulation is performed, if there is any problems, whether it be loss of synchronism, out-of-step, damping, inter-area oscillations, etc, they will all appear on the same run and there is no distinctions between system stability or unit stability. To separate the two implies there is a difference and requires two different simulations is either confusing at best or imply ignorance of the physics. Maybe the drafting team is concerned with the proper modeling of the generator in a stability simulation. There may be practice to "lump" similar units in a plant as one "unit" or the dynamic characteristics of a unit were not explicitly or correctly modeled; in such instances, the behavior of individual unit cannot be observed. But if that is the case, the entire stability simulation is incorrect to begin with anyway, even on the system side. To properly deal with unit modeling, the standard should prohibit lumping of units and require all dynamic data (including governor controls, exciters, stabilizers, etc.) are included in the simulation model.
National Grid	No	There should be no difference between System and Generating Unit Stability studies. Each requires discretion regarding which events need to be tested. The consequences are potentially similar: either the instability of one of more generators. Extreme Events should be considered for any stability analysis, again, recognizing that discretion needs to be applied when selecting or dismissing particular contingencies. If no distinction is made between System and Generating Unit Stability studies is made, then the definition of Generating Unit Stability Study should be stricken from the standard.
PacifiCorp	Yes and No	We generally concur with the changes for the Requirements associated with the Generating Unit and System Stability, however, Generating unit stability studies are typically performed at the time of interconnection. Even though stability studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of generating units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units. Will every TP have to benchmark their generating unit stability study for its entire fleet with the acceptance of this Standard? In other words, will every TP has to recreate documentation for all its older units? We would appreciate that the SDT more clearly define the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study with examples.
Hydro-Québec TransEnergie (HQT)	No	There should be no difference between System and Generating Unit Stability studies. Each requires discretion regarding which events need to be tested. The consequences are potentially similar: either the instability of one of more generators. Extreme Events should be considered for any stability analysis, again, recognizing that discretion needs to be applied when selecting or dismissing particular contingencies. Therefore, the definition of Generating Unit Stability Study should be stricken from the standard.
CenterPoint Energy and CPS Energy	No	Most industry commenters from the previous draft advised against making a distinction between system and generating unit stability, which are not commonly accepted industry terms. We (CenterPoint Energy and CPS Energy) remain unconvinced that the distinction is needed. If most industry commenters concur after this second draft, we believe the

Organization	Question 1:	Question 1 Comments:
		SDT should listen.
Austin Energy	No	There is no need to separate system stability studies and generating unit stability studies. Requirement R5.4 should be written to include generating unit stability analysis.
Tri-State Generation and Transmission Association, Inc.	No	Starting from this version, we think it would be clearer to not distinguish between generator and system stability studies, but rather list both as requirements for Stability Studies. Generating unit analyses would include tests of models such as generator exciters, and System Stability studies would model such things as bus faults.
Brazos Electric Power Cooperative, Inc.	No	We do not see the need to have 2 separate requirement sections nor definitions for both System and Generating stability studies. The section for stability studies should simply suggest when these studies should be performed, when new generation is added, conditions for that, etc? Confusion continues to come from the ambiguous use of language such as 'Material Transmission System changes' or 'changes in generation capability'. Of note in 2.5.2, requiring stability studies for the addition of a new substation in a transmission line connected to a generator is completely unnecessary most of the time but the wording in 2.5 does not appear to allow flexibility. Discretion should be provided to the TP.A first course of action would be to bring the related stability criteria under one section. It seems like 5.6 can be combined under a requirements section for stability studies.
Northeast Utilities	No	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
North Carolina Electric Membership Corp	Yes and No	We think we understand the direction that the SDT is heading but needs to be clearer. Angular stability for a single unit is the focus of Generating Unit Stability where as System Stability involves multiple generating machines or plants, and may also encompass voltage stability of loads which should be addressed separately in our opinion since different tools are used for this assessment.
ERCOT System Planning	No	Most industry commenters from the previous draft advised against making a distinction between system and generating unit stability, which are not commonly accepted industry terms. The only difference between the two seems to be location of contingencies tested. ERCOT suggests removing specific requirements for Generating Unit stability, as System Stability covers everything.
Central Maine Power Company	No	There should be no difference between System and Generating Unit Stability studies. Each requires discretion regarding which events need to be tested. The consequences are potentially similar: either the instability of one of more generators. Extreme Events should be considered for any stability analysis, again, recognizing that discretion needs to be applied when selecting or dismissing particular contingencies. Therefore, the definition of Generating Unit Stability Study should

Organization	Question 1:	Question 1 Comments:
		be stricken from the standard.
NSTAR Electric	No	There should be no difference between System and Generating Unit Stability studies. Each requires discretion regarding which events need to be tested. The consequences are potentially similar: either the instability of one of more generators. Extreme Events should be considered for any stability analysis, again, recognizing that discretion needs to be applied when selecting or dismissing particular contingencies. If no distinction is made between System and Generating Unit Stability studies is made, then the definition of Generating Unit Stability Study should be stricken from the standard.
New York Independent System Operator	No	There should be no difference between System and Generating Unit Stability studies. Each requires discretion regarding which events need to be tested. The consequences are potentially similar: either the instability of one of more generators. Extreme Events should be considered for any stability analysis, again, recognizing that discretion needs to be applied when selecting or dismissing particular contingencies. Therefore, the definition of Generating Unit Stability Study should be stricken from the standard.
ISO New England Inc.	No	There should be no difference between System and Generating Unit Stability studies. Each requires discretion regarding which events need to be tested. The consequences are potentially similar: either the instability of one of more generators. Extreme Events should be considered for any stability analysis, again, recognizing that discretion needs to be applied when selecting or dismissing particular contingencies. If no distinction is made between System and Generating Unit Stability studies is made, then the definition of Generating Unit Stability Study should be stricken from the standard.
Entergy Services, Inc.	Yes and No	Entergy agrees with the intent. However, there will be some confusion because the industry standard terms for stability are omitted. It should be clear that the System Stability Study is a wide area view/assessment of both angular and voltage stability. In contrast, the Generating Unit Stability Study is focused on a specific unit or plant and the immediate area. Typically, this study looks at angular stability. The confusion may be exacerbated by the exclusion of a definition for voltage (or load) stability in the notes on page 31. There is a discussion of angular stability, but voltage stability is conspicuously missing. An improvement for the System Stability Study definition is to clarify that it is a study that focuses on the impact to the system itself and covers an area larger than one Generating Plant, covering a large geographical area. See specific proposal below: System Stability Study - Study that focuses on how contingencies impact a larger portion of the System than a Generating Unit Study. These studies would examine issues such as angular Stability, inter-area power oscillation, and dynamic voltages.
BPA Transmission	No	Generating Unit Stability is adequately addressed by the System Stability studies and does not need to be evaluated separately. Footnote 5.a.i in the notes following the Performance Requirements Tables, already specifies the

Organization	Question 1:	Question 1 Comments:
Reliability Program		requirements to meet. Therefore, we recommend removing the section on Generating Unit Stability Studies from standard TPL-001-1. The focus of this standard should be on "System Stability" which encompasses all generating units.

Response: The SDT agrees and has modified the definitions and Requirements accordingly.

R2. Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses ~~including both System and Generating Unit Stability~~.

R2.6.1 (now 2.5.1) For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less.

R2.6.2 (now 2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:

R5. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~

The wording of sub-requirements R5.6.1 and R5.6.2 was modified and relocated to become bullets under Requirement R2.5.2.

The addition/deletion/change of individual generating unit capability of 20 MW or greater.

An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater.

The definitions of Generating Unit Stability Study and System Stability Study as well as the following sub-requirements were deleted: R2.5, R2.5.1, R2.5.2, and R5.5

Progress Energy Carolinas	No	The System Stability Study definition could be improved by clarifying that it is a study that focuses on the impact of contingencies to the system itself and covers a larger geographical area than one Generating Plant. A specific proposal is as follows. System Stability Study - Study that focuses on how contingencies impact a larger portion of the System than a Generating Unit Study. These studies would examine issues such as angular stability, inter-area power oscillations, and dynamic voltages.

Organization	Question 1:	Question 1 Comments:
Ameren	No	Agree with the revised definition of Generating Unit Stability Study. Propose new definition for System Stability Study, as follows - "Study that focuses on portions of the System, including the impact of contingencies on multiple generating units in an area. These studies would examine issues such as angular Stability, inter-area oscillation, and voltages during dynamic simulations."
SERC Dynamics Review Subcommittee	No	An improvement for the System Stability Study definition is to clarify that it is a study that focuses on the impact to the system itself and covers an area larger than one Generating Plant, covering a large geographical area. See specific proposal below: System Stability Study - Study that focuses on how contingencies impact a larger portion of the System than a Generating Unit Study. These studies would examine issues such as angular Stability, inter-area power oscillation, and dynamic voltages.
Southern Company Transmission	No	We suggest the following for the System Stability Study definition: Study that focuses on large portions of the System (which may include many generating units) and how contingencies affect that larger area to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.
American Transmission Company	No	Generating Unit Stability Study definition - We suggest deleting the text, "on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point.", because certain Generation Facility contingencies should be considered and key Transmission Facility contingencies can be more than one bus away from the interconnection point. System Stability Study definition - We suggest this alternate wording: "Study that focuses on portions of the System, which may include many generating units with various Contingencies. This study is concerned with loss of synchronism, lack of damping of inter-area power oscillations, and voltages during the dynamic simulation." We suggest this wording because the definition of a study should not give the criteria, but rather the general elements of the study.
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	No	There is an inconsistency between the defined terms “Generating Unit Stability Study” and “System Stability Study” and the usage within the standard. The requirements refer to these terms by omitting the word “study” .An improvement for the System Stability Study definition is to clarify that it is a study that focuses on the impact to the system itself and covers an area larger than one Generating Plant, covering a large geographical area. See specific proposal below: System Stability Study - Study that focuses on how contingencies impact a larger portion of the System than a Generating Unit Study. These studies would examine issues such as angular Stability, inter-area power oscillation, and dynamic voltages.?

Organization	Question 1:	Question 1 Comments:
Response: The SDT appreciates your suggested improvements. However, a majority of the Industry believes that there should be no distinction between System Stability and Generating Unit Stability.		
Platte River Power Authority	Yes and No	"Generator Unit Stability Study" assessments are applicable to FAC-001 and FAC-002. If specific requirements for a "Generator Unit Stability Study" are to be added to a standard, then those requirements belong in either a Revised FAC-001 or a Revised FAC-002 and not in a TPL standard. The "System Stability Study" assessments which are appropriate for TPL standards will capture both the performance of the system and the performance of specific generators at the various demand and stressed sensitivity levels studied.
BCTC	No	BCTC agrees with many other commenters, ABB, Ameren, Central Maine Power, NPCC RCWS, FirstEnergy, WECC, HQTE, Tenaska, FPL, FRCC, National Grid, New England ISO, NU, NStar, United Illuminating, BPA, Progress-Carolinas, TEP, and Northwestern Energy that there is no significant distinction between generator and system stability. These entities have significant experience with stability studies. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without any explanation. We believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequate addressed by open access tariffs and FAC-001. This should not be duplicated in TPL.
Manitoba Hydro	No	Manitoba Hydro does not believe there is a need to distinguish between System Stability Study and Generating Unit Stability Study. Both these studies as defined require that synchronous operation of generators is maintained (i.e. angular stability) and damping is acceptable (i.e. small signal stability). The stability assessment would cover the issues being requested in the Generating Unit stability Study. We suggest the definition for System Stability Study - A study that determines whether angular stability is maintained, inter-area power oscillations are acceptably damped, and transient voltage swings remain within acceptable limits. Further, contrary to the SDT interpretation in the response to our first posting comments, Manitoba Hydro believes the Generating Unit Stability Study is a duplication of what is required in FAC-002-0 as the FAC requirements mandate system performance required by the NERC Reliability Standards. Manitoba Hydro continues to believe this additional study is redundant. Should the SDT decide to retain the Generating Unit stability study, then Manitoba Hydro recommends that, consistent with the wording in other requirements of this assessment section, it would be more appropriate to require that "Generating Unit Stability be assessed using current or qualifying past studies." This would allow use of current interconnection studies mandated by FAC-002-0 to be used to comply with the Generating Unit Study requirement. Currently, the wording in R2.5 requires that Generating unit stability be analyzed with studies for the conditions in R2.5.1 and/or R2.5.2.
Transmission Agency of	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is

Organization	Question 1:	Question 1 Comments:
Northern California		important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to “develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies”. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
OPUC	Yes and No	We cannot evaluate the need to distinguish generating unit stability and system stability without greater explanation inclusive of examples. We also need clarification of the intended interactions of this proposed standard with of FAC-001 and 2 to avoid duplication of efforts. Finally, if FAC-001 will cover generating unit or interconnection stability R 2.5 should clearly address existing older generators.
Pacific Gas and Electric Co.	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to "develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies". If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not

Organization	Question 1:	Question 1 Comments:
		need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
Public Service Company of New Mexico	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to "develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies". If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
Puget Sound Energy, Inc.	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit

Organization	Question 1:	Question 1 Comments:
		Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to "develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies". If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
Idaho Power Company	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to “develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies”. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequate addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to

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		say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
SMUD	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study focuses on an individual generating units or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to “develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies”. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
Sierra Pacific Power Company / Nevada Power Company	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study focuses on an individual generating units or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies? If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability.

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		Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequate addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
Black Hills Corporation	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to "develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies". If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
SRP	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the

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		objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study focuses on an individual generating units or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies?. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
Tucson Electric Power Company	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to ?develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies?. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability

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		problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
Modesto Irrigation District	No	Comments: We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study focuses on an individual generating units or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to “develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies”. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1.In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
Tri-State G&T	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to ?develop a Bulk Electric System that will

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		operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies?. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
Southern California Edison	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to ?develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies?. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection? to invoke a study.

Organization	Question 1:	Question 1 Comments:
Alberta Electric System Operator	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to ?develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies?. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
US Bureau of Reclamation	No	Comments: We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to ?develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies?. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1.In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units

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		at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say "only when" the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, "material Transmission System change" and "at or near the point of Interconnection" to invoke a study.

Response: The SDT disagrees with your view that generating unit Stability assessments should be covered in FAC-001 or FAC-002. The SDT recognizes that such studies are performed for new generator interconnection, following the requirements of the appropriate FAC Standards. However, the TPL-001-1 Standard is intended to ensure on-going assessments of generating unit Stability so as to capture any significant performance changes over the course of time. Nevertheless, the SDT has eliminated the distinction between generating unit Stability and System Stability by modifying the definitions and Requirements as shown.

R2. Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses ~~including both System and Generating Unit Stability~~.

R2.6.1 (now 2.5.1) For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less.

R2.6.2 (now 2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:

R5. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~

The wording of sub-requirements R5.6.1 and R5.6.2 was modified and relocated to become bullets under Requirement R2.5.2.

The addition/deletion/change of individual generating unit capability of 20 MW or greater.

An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater.

The definitions of Generating Unit Stability Study and System Stability Study as well as the following sub-requirements were deleted: R2.5, R2.5.1, R2.5.2, and

Organization	Question 1:	Question 1 Comments:
R5.5.		
Gainesville Regional Utilities	No	Our small system does not have the present resources to deal with the large increase in stability type studies that this section seems to be requesting. Our system changes very little if at all from year to year. The ranking of the regional facilities where priority is given for stability study to the top 100 fault current buses shows that we do not have even a bus listed until position 611. We suggest that R2.4.1 should allow for only doing buses that have a ranking impact on the regional BES or no more that every 7 years for those systems without changes or are so small that their total separation or lost of their largest or almost total generation is not an issue for the RC. Stability should not have to be analyzed annually for small, unchanging systems.
Response: Where material changes do not occur as you describe for your System, studies would not have to be run any more frequently than once every five years, as described in Requirement R2.6 (now R2.5).		
ITC Holdings: ITC, METC, ITC Midwest	Yes and No	Requirement R 5.4.4: Consider changing the last sentence to the following: “If the Extreme Events analysis concludes there are widespread cascading outages, an evaluation of implementing a change designed to reduce or mitigate the likelihood of such consequences shall be conducted.”
Response: The wording suggested is basically identical to what is already there. The SDT does not feel that this change provides any clarity or alters the context of the present text. Also, widespread is an ambiguous term and not measurable. No change made.		
Progress Energy Florida, Inc.	No	Progress Energy Florida, Inc. (PEF) does not believe that Stability Analysis should be or can be successfully divided into the proposed two distinct concepts of System Stability and Generating Unit Stability. Most textbooks dealing with the matter of Stability Analysis divide the issue into two parts, steady state and transient, and then subdivide the transient part into power angle stability and voltage stability. PEF has been unable to find any engineering treatise that argues for dividing transient Stability Analysis into System Stability and Generating Unit Stability. NERC's present definition of Stability, "The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances", succinctly and correctly addresses the fact that stability issues regarding plants cannot be extricated from analysis of the rest of the system. PEF feels that this existing definition is accurate and not in need of clarification or improvement. To cite an example, if under the auspices of Generating Unit Stability, a transmission line trips, or if a load shedding scheme is activated, does the event then get defined as a System Stability event (or both)? It should be noted that the SDT attempted to both improve and clarify the definition of Stability in Note 5 of Table 2. The SDT's wording in Table 2 Note 5, while not containing any inappropriate or inaccurate information, has two fundamental flaws: a) it unnecessarily replaces the existing definition and b) it does not contain any language tying in the new definitions of System Stability and Generating Unit Stability. Furthermore, given that both of the new definitions are held to the exact same requirements, those found in Table 2, PEF can see no tangible benefit to two definitions, and therefore recommends removal of the new definitions of System Stability and Generating Unit Stability, and a return to the existing

Organization	Question 1:	Question 1 Comments:
		definition of Stability. Stability analyses that are taking place under the present definition and under the existing TPL Standards are more than adequate to demonstrate reliability of the BES, and PEF feels that the introduction of two new definitions would only serve to cause confusion and discussion regarding unmerited additional analyses.

Response: The SDT agrees and has modified the definitions and Requirements accordingly. Furthermore, with these changes, the SDT believes that Note 5 of Table 2 has value to the Industry as a clarification of the existing Stability definition and should no longer be viewed as a replacement definition.

R2. Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses ~~including both System and Generating Unit Stability~~.

R2.6.1 (now 2.5.1) For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less.

R2.6.2 (now 2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:

R5. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~

The wording of sub-requirements R5.6.1 and R5.6.2 was modified and relocated to become bullets under Requirement R2.5.2.

The addition/deletion/change of individual generating unit capability of 20 MW or greater.

An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater.

The definitions of Generating Unit Stability Study and System Stability Study as well as the following sub-requirements were deleted: R2.5, R2.5.1, R2.5.2, and R5.5

Lafayette Utilities System	No	Lafayette Utilities System (Lafayette) does not dispute the need for stability studies, especially in connection with significant system topology changes. We are concerned, however, by the possibility of inconsistencies between the results of interconnection studies conducted for new generating units pursuant to the Large Generator Interconnection Procedures prescribed by FERC and Generating Unit Stability Studies conducted as part of the TPL-001 planning assessment. For example, if a TPL-001 stability analysis indicates the need for more costly or extensive transmission upgrades that were indicated in an earlier LGIP interconnection study, the generation developer could be placed in an

Organization	Question 1:	Question 1 Comments:
		untenable situation: it would have proceeded with its project based on the assumption of responsibility for LGIP-indicated upgrades, but then could face demands for the funding of additional upgrades pursuant to the TPL-001 stability analysis. Improved integration between the two sets of stability studies appears warranted, in order to avoid placing generation developers in this position.
Response: The SDT understands your concerns; however, we believe that TPL-001-1 will not create an untenable position for generation developers following the LGIP. Studies to interconnect the generator in accordance with the LGIP will identify those Facilities to be incorporated in the Interconnection Agreement. Future studies carried out in compliance with TPL-001-1 will ensure on-going System reliability, and any Facility upgrades required for that purpose will be the responsibility of the Transmission Owner, not the generation developer.		
Arizona Public Service Co.	Yes and No	We generally concur with the changes for the Requirements associated with the Generating Unit and System Stability, however, Generating unit stability studies are typically performed at the time of interconnection. Even though stability studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of generating units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units. Will every TP have to benchmark their generating unit stability study for its entire fleet with the acceptance of this Standard? In other words, will every TP has to recreate documentation for all its older units?? We would appreciate that the SDT more clearly define the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study with examples.
ColumbiaGrid	Yes and No	We generally concur with the changes for the Requirements associated with the Generating Unit and System Stability, however, Generating unit stability studies are typically performed at the time of interconnection. Even though stability studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of generating units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units. Will every TP have to benchmark their generating unit stability study for its entire fleet with the acceptance of this Standard? In other words, will every TP has to recreate documentation for all its older units?? We would appreciate that the SDT more clearly define the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study with examples.
Response: The SDT believes that the modified definitions and Requirements in the third draft address your concerns. **R2**. Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses ~~including both System and Generating Unit Stability~~		

Organization	Question 1:	Question 1 Comments:
R2.6.1 (now R2.5.1) For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less. **R2.6.2** (now R2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: **R5**. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~ The wording of sub-requirements R5.6.1 and R5.6.2 was modified and relocated to become bullets under Requirement R2.5.2. The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater. The definitions of Generating Unit Stability Study and System Stability Study as well as the following sub-requirements were deleted: R2.5, R2.5.1, R2.5.2, and R5.5 Specifically, as to your question regarding "benchmarking," the revised requirements would not necessitate studies of each individual generating unit or generating plant.		
Florida Power and Light	No	This draft did not modify the existing NERC definition of Stability. Footnote 5 of the Tables describes the expected acceptable performance of a System that is stable, but the terms "System Stability" and "Generating Unit Stability" are not defined, except as studies. All stability studies must meet the Performance Requirements for Planning Events in Table 2 - Stability Performance. If there were different Performance Requirements then the distinction may be warranted. However system stability studies should be sufficient and not warrant additional work. R6 requires Transmission Planners to define proxies used to identify instability. Presumably the "proxies" would be used as a checklist for assessment of stability; however, not all stability limitations can be simplified as a proxy in the load flow. Proxies should only be used as indicative of a potential stability issue, not "to identify System instability", or replace stability studies, since a stability study to identify the issue was initially required to define the proxy. The requirement should be reworded to state "R6. If proxies are used in simulation studies to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding, then each Transmission Planner and Planning Coordinator shall define the proxies used in the simulation studies."

Organization	Question 1:	Question 1 Comments:
Orlando Utilities Commission	No	I support the comments from Florida Power & Light regarding System Stability vs. Generating unit studies and proxies.

Response: The SDT agrees and has modified the definitions and Requirements accordingly. Furthermore, the SDT has also modified the wording of R6 to address your concern.

R2. Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses ~~including both System and Generating Unit Stability~~.

R2.6.1 (now R2.5.1) For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less.

R2.6.2 (now R2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:

R5. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~

The wording of sub-requirements R5.6.1 and R5.6.2 was modified and relocated to become bullets under Requirement R2.5.2.

The addition/deletion/change of individual generating unit capability of 20 MW or greater.

An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater.

The definitions of Generating Unit Stability Study and System Stability Study as well as the following sub-requirements were deleted: R2.5, R2.5.1, R2.5.2, and R5.5.

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, ~~the~~any proxies used in ~~simulation studies~~ the analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.

Exelon Transmission	Yes and No	The definitions of System Stability and Generating Unit Stability are clear. We agree that there is value in performing small signal analysis but we are concerned about the availability of software and expertise required to execute the

Organization	Question 1:	Question 1 Comments:
Planning		analysis.R5.3 is ambiguous, as it is not clear what the requirement to consider the voltage ride through capability of all generators entail. Ride through could involve the unit or station having the capability to ride through without tripping or the unit could trip but the system remain stable. General Observations R3.2.1 should be reworded so as not to be misinterpreted that GOs are prescribing their 'required' voltage levels. R2.6.2 should be Unit not Plant with regard to stability studies. R2.7.1 and elsewhere - The NERC Glossary specifies that SPSs are 'Special Protection Systems' (not 'schemes'). R5.2 Wording should be changed from '...disconnect for each contingency..' to '..isolate the disturbance... .' R5.5.1 There are too many studies required. The 20 MW threshold for unit studies may be too low. There should be a mechanism to provide a proxy for smaller units on 138 or possible 230 kV systems that can't affect system stability rather than to automatically require a study every 5 years. R2.1 and 2.2 should have the words 'at a minimum' removed with regards to describing which studies are required annually. The requirement to supply a 'project initiation date' for near-term Corrective Action Plans should be removed. If it remains, it should be clarified (Project identification date, construction start date, PUC certification date, executive approval date, etc?)

Response: The intent of Requirement R5.3 is to ensure that the generating unit models realistically replicate the behavior of the generator in response to a low voltage condition encountered during the simulation.

The requirement on voltage ride through has been changed to provide clarity (now R4.3.2).

R3.2.1 (now R3.3.2) For all generators, studies shall consider the minimum steady state voltage limitations ~~of all generators~~ and identify how the generators are ~~treated~~ analyzed in the steady state simulation.

The SDT has deleted the distinction between Unit/Plant and System Stability based on other comments.

The SDT agrees that SPS means “Special Protection Systems” and the third draft uses this terminology consistently.

The SDT disagrees with your suggested rewording of Requirement R5.2 because the concept that the requirement is addressing relates to the resultant topology of the system after the fault is cleared and not the removal of the disturbance.

In response to your comment on Requirement R5.5.1, the SDT believes that all of the studies needed to satisfy this requirement are essential to maintain reliability. The SDT has thoroughly debated the 20 MW generating unit threshold and continues to believe that this is the appropriate value.

In Requirements R2.1 and R2.2, the SDT has removed the words “at a minimum” as you have suggested.

Organization	Question 1:	Question 1 Comments:
R2.1 The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported ~~at a minimum~~ by the following annual current studies, supplemented with qualified past studies as indicated in Requirement R2.6: **R2.2** For the Long-Term Transmission Planning Horizon portion of the steady state analysis, ~~at a minimum,~~ a current System peak Load study is required annually for one of the years in the assessment period to support the annual Planning Assessment. In response to your comment on "project initiation date," the SDT considered your suggestion; however, the SDT believes that the current language is satisfactory, and few comments were received suggesting need for a modification.		
MidAmerican Energy Company	Yes and No	MidAmerican Energy Company (MEC) believes the definitions are improved. However, MEC suggests that the SDT clarify what stability analyses are required such as angular and voltage stability for which time frames such as the transient and steady state time frames and for what planning horizons such as the Near-Term and Long-Term planning horizons.
MRO NERC Standards Review Subcommittee	No	The MRO believes the definitions are improved. However, the MRO suggests that the SDT clarify what stability analysis are required such as angular and voltage stability for which time frames such as the transient and steady state time frames and for what planning horizons such as the Near-Term and Long-Term planning horizons. Generating Unit Stability Study definition - The MRO suggests deleting the text, "on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point.", because certain Generation Facility contingencies should be considered and key Transmission Facility contingencies can be more than one bus away from the interconnection point. System Stability Study definition - The MRO suggests this alternate wording: "Study that focuses on portions of the System, which may include many generating units with various Contingencies. This study is concerned with loss of synchronism, lack of damping of inter-area power oscillations, and voltages during the dynamic simulation." We suggest this wording because the definition of a study should not give the criteria, but rather the general elements of the study.
Response: The SDT believes that your comments requesting clarifications have been addressed through the changes made as shown. **R2**. Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses ~~including both System and Generating Unit Stability~~. **R2.6.1** (now R2.5.1) For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less. **R2.6.2** (now R2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: **R5**. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning		

Organization	Question 1:	Question 1 Comments:
Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~— Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~ The wording of sub-requirements R5.6.1 and R5.6.2 was modified and relocated to become bullets under Requirement R2.5.2. The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater. The definitions of Generating Unit Stability Study and System Stability Study as well as the following sub-requirements were deleted: R2.5, R2.5.1, R2.5.2, and R5.5		
Arkansas Electric Coop. Corp.	Yes and No	There are situations where one bus away may not be far enough. While one bus may cover most situations the standard shouldn't limit the study to just one bus away. Suggested language change: Transmission Facilities connected to that generating unit(s) point(s) of interconnection, one bus away from the electrically closely-coupled units.
Response: The definition for Generating Unit Stability Study has been deleted so the offending phrase is no longer in this standard.		
NERC and Regional Coordination (PJM)	No	In the definition of Consequential Load Loss - Revise Transmission Planning Entities to Transmission Planners; or otherwise clearly identifying the entities that are meant to be addressed by the term "Transmission Planning Entities. "Revise "which" to "that" as indicated by the text below that is in quotes and Upper Case: Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation connected to a source as a result of the event being studied or "THAT" is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load "THAT" is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, [Transmission planning entities] TRANSMISSION PLANNERS are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements. Regarding the definition of Planning Event -The given words do not define the term. For example is an event meant to be an forced outage condition; or is meant to be any set of state conditions. If an event can be anything, then the term is not a definition. Planning Coordinator -Explicitly state that this definition will be deleted when the functional model definition for this entity is approved May consider deleting the term because it is not unique to this standard. The term is already defined in the Functional Model.R1.1 ? Data changes are routine in such studies and need to better quantify when technical justification is required.

Organization	Question 1:	Question 1 Comments:
Response: The definition of Consequential Load Loss has been changed in an attempt to clear up issues such as you addressed. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions.		
IESO	No	(i) Generating Unit Stability Study: We do not agree with the phrase "…or one bus away from that point." This limits the scope of the testing to only the next bus. At times, contingencies that remove critical transmission facilities several buses away from a generating plant may affect generating unit stability performance. We suggest to reword this phrase to "..or in the nearby vicinity that can have an adverse reliability impact on the generating units' stability performance."(ii) Long-Term Transmission Planning Horizon: A nit-picking suggestion to change the first "longer" to "long".(iii) Planning Coordinator: We not see the need to repeat a definition that is already provided in the NERC Glossary of Terms and the Functional Model. There is a plan to implement a wholesale change from Planning Authority to Planning Coordinator. This is expected to occur in the first half of 2009.(iv) System Stability Study: Since voltage performance is included in this assessment, we suggest to add to the phrase "?which may include many generating units AND GROUPS OF TRANSMISSION FACILITIES..".(v) Year One: The second part of the definition is confusing. By "12-18 months from the completion of the previous annual Planning Assessment." does it mean 12-18 months from the "complete date" of the previous assessment, or from the "end of the previous assessment period"? For example, a previous assessment was completed on April 30, 2008 that covers a 12 month period from May 1, 2008 to April 30, 2009. Does year one for the subsequent assessment start from May 1, 2009 or May 1, 2010? In view of the confusion, having only the first sentence would suffice. In fact, there is only one reference made in the requirement (R2.1.1). Qualifying "year one" can easily be made in that requirement without having to have a defined term. Adding defined terms without a good cause adds to the maintenance task for the glossary of terms. Further, it begs the question on why "year two" and "year five" referenced in that same requirement are not defined.
Response: With regard to your comments (i) and (iv), the SDT agrees and has modified the definitions and Requirements accordingly. **R2**. Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses ~~including both System and Generating Unit Stability~~. **R2.6.1** (now R2.5.1) For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less.		

Organization	Question 1:	Question 1 Comments:
R2.6.2 (now R2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: **R5**. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~ The wording of sub-requirements R5.6.1 and R5.6.2 was modified and relocated to become bullets under Requirement R2.5.2. The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater. The definitions of Generating Unit Stability Study and System Stability Study as well as the following sub-requirements were deleted: R2.5, R2.5.1, R2.5.2, and R5.5. (ii) Thank you for your suggestion. The SDT sees no material difference in the suggested change and has decided to leave the definition unchanged. (iii) As you note, NERC is transitioning from the use of the term Planning Authority to the term Planning Coordinator. Since the new terminology has not been officially adopted yet in the Functional Model, it must be defined in this standard revision. (v) The definition is intended to be flexible to accommodate different practices and schedules. The key points are: 1) an assessment must be done each year and completed any time during the year, 2) the first year of the assessment period should be beyond the period examined to address operational planning issues, and 3) the time to complete the assessment could vary and take up to 18 months. In your example, if you have chosen Year One to be May 1, 2008 to April 30, 2009, then Year One for the subsequent assessment would begin May 1, 2009.		
Dominion - Electric Transmission Planning	Yes	
TVA System Planning	Yes	
City Water, Light & Power -	Yes	

Organization	Question 1:	Question 1 Comments:
Springfield, Illinois		
Tenaska, Inc.	Yes	
US Army Corps of Engineers, Northwestern Division	Yes	
JEA	Yes	
Midwest ISO	Yes	
AEP	Yes	
Lakeland Electric	Yes	
LCRA TSC	Yes	
E.ON U.S. Transmission Planning	Yes	
Duke Energy	Yes	
Oncor Electric Delivery	Yes	NA
FirstEnergy Corp.	Yes	
Response: Thank you for your response.		

2. Do you concur with the modified Requirements R2.4, R2.5, R5.4, and R5.5? If not, please state why and/or suggest specific changes.

Summary Consideration:

In response to industry comments, the SDT decided that generating unit Stability and System Stability need not and should not be treated as distinct issues. The Stability related requirements have been modified to create a single generic set of requirements that no longer distinguishes between generating unit and System Stability. This should address any potential conflict between this standard and the FAC standards.

Requirement R2.4.1 has been modified to clarify that a detailed dynamic Load model is not required at each bus. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Because of this clarification, the SDT believes that a 24 month implementation period for this requirement is sufficient.

Requirement R2.4.3 has been modified to remove the need for stating the technical rationale for why or why not a particular sensitivity was selected. Requirement R2.4.4 was deleted because it was essentially a voluntary requirement. The specific wording for each of the sensitivities to be considered has been changed and should be clearer as to what is needed. The TP is allowed to use its judgment as to how the variations of the sensitivity parameters should be made.

The requirement to include "known planned and long term outages of Transmission or generation equipment" has been removed from Requirement R5. This is covered in the revised Requirement R1.1.1.

Stability studies will continue to be required for smaller entities. Smaller entities have the option of not registering as a TP to avoid compliance concerns. Furthermore, it would be difficult to establish criteria for exempting “smaller entities.”

The definitions for Generating Unit Stability Study and System Stability Study have been deleted and the following requirements have been added or changed due to industry comments:

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R2.1.3 For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.1.4 When an entity’s spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

- ~~Variations in~~ Load model assumptions
- ~~Modification of e~~Expected transfers
- ~~Unavailability of long lead time Facilities~~ Timing of the installation of new or modified Facilities.
- ~~Variability and outages of r~~Reactive resource~~s~~ capability.

R2.6.2 (now R2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:

- The addition/deletion/change of individual generating unit capability of 20 MW or greater.
- An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater.

R3 For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. ~~The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to c~~Contingencies ~~in Table 1 – Steady State Performance.~~ The studies shall be based on computer simulations using models utilizing data provided in Requirement R1.

R3.4 (now R3.5) Those Extreme Events in Table 1 ~~– Steady State Performance~~ that are expected to produce more severe System impacts shall be identified~~,~~ and a list of those events to be evaluated for System performance in Requirement R3.2 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results. If the ~~Extreme Events~~ analysis concludes there are cascading outages caused by the occurrence of Extreme Events, an evaluation of ~~implementing a change~~ possible actions designed to reduce ~~or mitigate~~ the likelihood or mitigate ~~of such~~the consequences and adverse impacts of the event(s) shall be conducted.

R5. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted~~

R5.2 (now R4.3 and R4.3.1) Contingency analyses shall: ~~s~~Simulate the removal of all elements ~~including those~~ that the Protection System ~~protection~~ and other automatic controls are expected to disconnect for each Contingency without operator intervention.

R5.4.4 (now R4.5) ~~At a minimum, t~~Those Extreme Events in Table ~~2~~1 ~~– Stability Performance~~ that ~~would~~are expected to produce more severe System impacts shall be identified and a list of those events to be~~,~~ evaluated for System performance in Requirement R5.2 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results. If the ~~Extreme Events~~ analysis concludes there are cascading outages caused by the occurrence of Extreme Events, an evaluation of ~~implementing a change~~ possible actions designed to reduce ~~or mitigate~~ the likelihood or mitigate ~~of such~~the consequences of the event(s) shall be conducted.

The following requirements were deleted due to industry comment:

R2.4.4 ~~In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and the Planning Assessment shall include documentation of the technical rationale for why each was selected shall be supplied.~~

R2.5 ~~The Generating Unit Stability analysis portion of the Planning Assessment shall be analyzed consistent with Requirement R5.5 with studies for the year when the following changes that could affect stability margins occur:~~

R2.5.1 ~~New generator(s) are added or generation modifications are made such as changes in generation capability or replacing the exciter.~~

R2.5.2 ~~Material Transmission System changes are made at or near the point of Interconnection of existing Generation such as the removal of a Transmission Line or the addition of a new substation in one of the Transmission Lines connected to the plant.~~

R5.4.3 ~~Automatic generation tripping is allowed to mitigate Stability violations if the following conditions are met:~~

R5.4.3.1 ~~All Facilities shall be operating within their Facility Ratings~~

R5.4.3.2 ~~Such action would not violate safety, equipment, regulatory or statutory requirements~~

R5.4.3.3 ~~A sustainable, stable, operating condition is maintained~~

R5.5 ~~For the Generating Unit Stability studies:~~

R5.5.1 ~~Shall be performed for individual generating units 20 MW or greater directly connected through a step-up transformer to the BES and for generating units at the same location which total 75 MW or greater, directly connected through their step-up transformer(s) to the BES.~~

R5.5.2 ~~Shall be performed for changes in the real power output of a generating unit by more than 10% of the existing capability or more than 20 MW whichever is greater.~~

R5.5.3 ~~Shall be performed and evaluated for those Planning Events that would produce more severe System impacts and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results.~~

R5.5.4 ~~Shall meet Performance requirements for Planning Events in Table 2 – Stability Performance~~

Organization	Question 2:	Question 2 Comments:
Dominion - Electric Transmission Planning	No	Comments are subdivided according to different sections as listed below: R2.4.1: In principal, we agree that the dynamic behavior of loads, including consideration of the behavior of induction motor loads, should be represented. However, it is not easy to get the data on such loads. Most customers, including industrial ones, have no information/knowledge regarding their load characteristics. Also, the software tools currently in use do not accommodate the modeling of certain material effects (for example the load reduction due to thermal trips on large HVAC compressor motors). Additionally, if the entire case is populated with such detail dynamic load data, the case could not be solved. A lot of research would be required. A phase-in period of several years should be considered in order to accomplish the fundamental objective of dynamic load modeling. Please refer to Item 4 of Question 15 for further thoughts on modeling requirements. R2.4.3: It is acceptable to perform studies that include various sensitivity factors, but to document all rationales why they were chosen or not chosen for each study performed is burdensome. R2.5.1: Reduction in generation does not decrease stability margins. Therefore, the previous version's "increasing in generation" should be kept instead of changing it to "changes in generation." R5.4.3: This requirement allows automatic generation tripping to mitigate Stability violations (subject to meeting three listed conditions there in). Automatic generator trips should not be allowed for N-1 contingency studies (beginning with system normal and evaluating for the very first contingency) should the full output of the generating unit be classified as a capacity resource. Allowing a capacity resource generator to trip for N-1 contingency could result in reduced system reliability.

Response: Requirement R2.4.1 has been modified to clarify that a detailed dynamic Load model is not required at each bus. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Because of this clarification, the SDT believes that a 24 month implementation period for this requirement is sufficient. This will be covered in the Implementation Plan which will be posted along with the third draft of the standard.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.3: The SDT agrees and has modified the language of Requirement R2.4.3 to not require the rationale for why a sensitivity was chosen or not.

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

Organization	Question 2:	Question 2 Comments:
R2.5.1: The SDT has removed the distinction between System Stability and generating unit Stability. Requirement R2.5.1 has been deleted. R5.4.3: This requirement has been deleted.		
NPCC	No	a. A MOD standard should be developed to address the assembly of dynamic load models, rather than specifying modeling in paragraph 2.4.1 (dynamic behavior of loads). Paragraph 2.4.1 should instead read, "System Peak Load for one of the five years." b. In paragraph R.2.4.3.4, what does "variability" mean? c. Add a new requirement "R5.4.3.4 Automatic generator tripping shall not have an Adverse Reliability Impact on overall system reliability." d. Remove Heading R5.5 and make generator unit stability a section of overall stability requirements. e. Modify R5.5.1 to become R5.4.5, with the following, "Shall be performed for the addition of an individual generating unit or generating units at the same interconnection point of 20 MW or greater that are directly connected to the BES." There may be little difference between the stability performance of a single 20 MW unit and an aggregation of units totaling 20 MW at the same BES interconnection point f. Strike R5.5.3 and R5.5.4, as they become redundant to R5.4.1
Hydro-Québec TransEnergie (HQT)	No	a. A MOD standard should be developed to address the assembly of dynamic load models, rather than specifying modeling in paragraph 2.4.1 (dynamic behavior of loads). Paragraph 2.4.1 should instead read, "System Peak Load for one of the five years." b. In paragraph R.2.4.3.4, what does "variability" mean? c. Add a new requirement, "R5.4.3.4 Automatic generator tripping shall not have an significant adverse impact on overall system reliability." d. Remove Heading R5.5 and make generator unit stability a section of overall stability requirements. e. Modify R5.5.1 to become R5.4.5, with the following, "Shall be performed for the addition of an individual generating unit or generating units at the same interconnection point 20 MW or greater that are directly connected to the BES." There may be little difference between the stability performance of a single 20 MW unit and an aggregation of units totaling 20 MW at the same BES interconnection point f. Strike R5.5.3 and R5.5.4, as they become redundant to R5.4.1
New York	No	a. A MOD standard should be developed to address the assembly of dynamic load models, rather than specifying

Organization	Question 2:	Question 2 Comments:
Independent System Operator		modeling in paragraph 2.4.1 (dynamic behavior of loads). Paragraph 2.4.1 should instead read, "System Peak Load for one of the five years." b. In paragraph R.2.4.3.4, what does "variability" mean? c. Add a new requirement, "R5.4.3.4 Automatic generator tripping shall not have an significant adverse impact on overall system reliability." d. Remove Heading R5.5 and make generator unit stability a section of overall stability requirements. e. Modify R5.5.1 to become R5.4.5, with the following, "Shall be performed for the addition of an individual generating unit or generating units at the same interconnection point 20 MW or greater that are directly connected to the BES." There may be little difference between the stability performance of a single 20 MW unit and an aggregation of units totaling 20 MW at the same BES interconnection point. f. ---- g. Strike R5.5.3 and R5.5.4, as they become redundant to R5.4.1

Response: a: The SDT disagrees and believes it is appropriate to require this in the TPL standard. Requirement R2.4.1 has been modified to clarify that an aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. It is not necessary to have a dynamic Load model which is specific to each bus.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

b: The specific wording for Requirement R2.4.3.4 has been changed to variations in "reactive resource capability". The sub-requirement is now also part of a bulleted list. This could mean a degradation of the capability of a reactive resource. The TP is allowed to use its judgment as to how the variations of the sensitivity parameters should be made.

~~Variability and outages of r~~Reactive resource~~s~~ capability.

c: The SDT has decided to remove Requirement R5.4.3 because the sub-requirements are already implicitly covered by the standard. Your suggested sub-requirement is also already implicitly covered by the standard.

d: In response to industry comments, the SDT has removed the distinction in the standard between System Stability and generating unit Stability.

e: The SDT agrees that there is little distinction between a single unit of a specific MW and an aggregation of the same number of MW. The requirement for study has been changed to 20 MW for a single generator or for an aggregate of generators. This requirement is now located at Requirement R2.5.2.

Organization	Question 2:	Question 2 Comments:
R2.5.2 For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater. **f**: Generating unit Stability and System Stability have been combined.		
Northeast Utilities	No	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
ISO New England Inc.	No	a. A MOD standard should be developed to address the assembly of dynamic load models, rather than specifying modeling in paragraph 2.4.1 (dynamic behavior of loads, including consideration of the behavior of induction motor Loads). Paragraph 2.4.1 should instead read, "System Peak Load for one of the five years." The remainder of the paragraph should be deleted. b. In paragraph R.2.4.3.4, what does "variability" mean? Is variability more of a concern than an outage? Suggest changing paragraph R.2.4.3.4 to simple say "Outages of Reactive Resources" c. Add a new requirement, "R5.4.3.4 Automatic generator tripping shall not have an significant adverse impact on overall system reliability." d. Remove Heading R5.5 and make generator unit stability for a new facility a section of overall stability requirements. e. Modify R5.5.1 to become R5.4.5, with the following, "Shall be performed for the addition of an individual generating unit or generating units at the same interconnection point 20 MW or greater that are directly connected to the BES." There may be little difference between the stability performance of a single 20 MW unit and an aggregation of units totaling 20 MW at the same BES interconnection point. f. If planning assessment studies all generators or stations above 20 MW, as suggested by R5.5.1, then this provision is unnecessary and R5.5.2 should be deleted. g. If the output of a generating station does not change by more than 20MW, then no new study is required and, it should be acceptable to rely on past stability assessments. This is not clear in R5.5.1. h. With respect to section R5 - The concept of planned and long-term outages should be addressed uniformly for the general Planning Assessment. It should not be specific to the Stability Assessment. i. Planned and long-term outages are two fundamentally different concepts and should be treated separately.

Organization	Question 2:	Question 2 Comments:
		Planned and Long-Term outages should be defined. Define how planning events in Tables 1 and 2 are associated with each type of outage. Define length of a "Long Term" outage. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizon. j. The provisions of Section R.5.3 should be included in a MOD standard and applied to a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertent trip of the generator. Such a provision should include " other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation. k. Strike R5.5.3 and R5.5.4, as they become redundant to R5.4.1
National Grid	No	a. A MOD standard should be developed to address the assembly of dynamic load models, rather than specifying modeling in paragraph 2.4.1 (dynamic behavior of loads, including consideration of the behavior of induction motor Loads). Paragraph 2.4.1 should instead read, "System Peak Load for one of the five years." The remainder of the paragraph should be deleted. b. In paragraph R.2.4.3.4, what does "variability" mean? Is variability more of a concern than an outage? Suggest changing paragraph R.2.4.3.4 to simple say "Outages of Reactive Resources" c. Add a new requirement, "R5.4.3.4 Automatic generator tripping shall not have an significant adverse impact on overall system reliability." d. Remove Heading R5.5 and make generator unit stability for a new facility a section of overall stability requirements. e. Modify R5.5.1 to become R5.4.5, with the following, "Shall be performed for the addition of an individual generating unit or generating units at the same interconnection point 20 MW or greater that are directly connected to the BES." There may be little difference between the stability performance of a single 20 MW unit and an aggregation of units totaling 20 MW at the same BES interconnection point. f. If planning assessment studies all generators or stations above 20 MW, as suggested by R5.5.1, then this provision is unnecessary and R5.5.2 should be deleted. g. If the output of a generating station does not change by more than 20MW, then no new study is required and, it should be acceptable to rely on past stability assessments. This is not clear in R5.5.1. h. With respect to section R5 - The concept of planned and long-term outages should be addressed uniformly for the general Planning Assessment. It should not be specific to the Stability Assessment. i. Planned and long-term outages are two fundamentally different concepts and should be treated separately. Planned and Long-Term outages should be defined. Define how planning events in Tables 1 and 2 are associated with each type of outage. Define length of a "Long Term" outage. Planned outages should be addressed in the

Organization	Question 2:	Question 2 Comments:
		operating horizon unless otherwise defined in the planning horizon. j. The provisions of Section R.5.3 should be included in a MOD standard and applied to a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertent trip of the generator. Such a provision should include " other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation. k. Strike R5.5.3 and R5.5.4, as they become redundant to R5.4.1
Central Maine Power Company	No	a. A MOD standard should be developed to address the assembly of dynamic load models, rather than specifying modeling in paragraph 2.4.1 (dynamic behavior of loads, including consideration of the behavior of induction motor Loads). Paragraph 2.4.1 should instead read, "System Peak Load for one of the five years." The remainder of the paragraph should be deleted. b. In paragraph R.2.4.3.4, what does "variability" mean? Is variability more of a concern than an outage? Suggest changing paragraph R.2.4.3.4 to simple say "Outages of Reactive Resources" c. Add a new requirement, "R5.4.3.4 Automatic generator tripping shall not have an significant adverse impact on overall system reliability." d. Remove Heading R5.5 and make generator unit stability for a new facility a section of overall stability requirements. e. Modify R5.5.1 to become R5.4.5, with the following, "Shall be performed for the addition of an individual generating unit or generating units at the same interconnection point 20 MW or greater that are directly connected to the BES." There may be little difference between the stability performance of a single 20 MW unit and an aggregation of units totaling 20 MW at the same BES interconnection point. f. If planning assessment studies all generators or stations above 20 MW, as suggested by R5.5.1, then this provision is unnecessary and R5.5.2 should be deleted. g. If the output of a generating station does not change by more than 20MW, then no new study is required and, it should be acceptable to rely on past stability assessments. This is not clear in R5.5.1. h. With respect to section R5, the concept of planned and long-term outages should be addressed uniformly for the general Planning Assessment. It should not be specific to the Stability Assessment. i. Planned and long-term outages are two fundamentally different concepts and should be treated separately. Planned and Long-Term outages should be defined. Define how planning events in Tables 1 and 2 are associated with each type of outage. Define length of a "Long Term" outage. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizon.

Organization	Question 2:	Question 2 Comments:
		j. The provisions of Section R.5.3 should be included in a MOD standard and applied to a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertent trip of the generator. Such a provision should include "other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation. k. Strike R5.5.3 and R5.5.4, as they become redundant to R5.4.1

Response: a: The SDT disagrees and believes it is appropriate to require this in the TPL standard. Requirement R2.4.1 has been modified to clarify that an aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. It is not necessary to have a dynamic Load model which is specific to each bus.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

b: The specific wording for Requirement R2.4.3.4 has been changed to variations in "reactive resource capability". The sub-requirement has also been changed to become a part of a bulleted list. This could mean a degradation of the capability of a reactive resource. The TP is allowed to use its judgment as to how the variations of the sensitivity parameters should be made.

~~Variability and outages of r~~Reactive resource~~s~~ capability.

c: The SDT has decided to remove Requirement R5.4.3 because the sub-requirements are already implicitly covered by the standard. Your suggested sub-requirement is also already implicitly covered by the standard.

d: In response to industry comments, the SDT has removed the distinction in the standard between System Stability and generating unit Stability.

e: The SDT agrees that there is little distinction between a single unit of a specific MW and an aggregation of the same number of MW. The requirement for study has been changed to 20 MW for a single generator or for an aggregate of generators. This requirement is now located at Requirement R2.5.2.

R2.5.2 For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:

The addition/deletion/change of individual generating unit capability of 20 MW or greater.

An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater.

f: There are no longer two requirements covering this. The new generator size which requires a study and the change of generator size which requires a study have been combined into Requirement R2.6.2.

Organization	Question 2:	Question 2 Comments:
g: Requirement R5.5.1 has been deleted. h and i: The requirement to include "known planned and long term outages of Transmission or generation equipment" has been removed from Requirement R5. Planned outages are covered in Requirement R1.1.1 for both Stability and Steady State. Long term outages are covered in new Requirement R2.1.4. **R1.1.1** Planned outages of generation and Transmission Facilities, if specifically known. **R2.1.4** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment. j: This is the subject of PRC-024 currently under development. But the question of how you treated this in your planning studies belongs in TPL. **k**: Generating unit Stability and System Stability have been combined.		
NSTAR Electric	No	1. A MOD standard should be developed to address the assembly of dynamic load models, rather than specifying modeling in paragraph 2.4.1 (dynamic behavior of loads, including consideration of the behavior of induction motor Loads). Paragraph 2.4.1 should instead read, "System Peak Load for one of the five years." The remainder of the paragraph should be deleted. 2. Change paragraph R.2.4.3.4 to "Outages of Reactive Resources". It is not clear what "variability" means and why it would be more severe than outages. 3. Add a new requirement, "R5.4.3.4 Automatic generator tripping schemes shall not be overly complex or have an significant adverse impact on overall system reliability." 4. Requirements of R5.5 should be rolled into R5.4 and made applicable to all stability studies. 5. Modify R5.5.1 to the following "Shall be performed for an individual generating unit or generating units at the same interconnection point 20 MW or greater that are directly connected to the BES." There may be little difference between the stability performance of a single 20 MW unit and an aggregation of units totaling 20 MW at the same BES interconnection point. 6. Delete R5.5.2. If planning assessment studies all generators or stations above 20 MW, as suggested by R5.5.1, then this provision is unnecessary. If the system has not changed, it should be acceptable to rely on past stability assessments. 7. With respect to section R5, the concept of planned and long-term outages should be addressed uniformly for the general Planning Assessment. It should not be specific to the Stability Assessment.

Organization	Question 2:	Question 2 Comments:
		8. Planned and long-term outages are two fundamentally different concepts and should be treated separately. Planned and Long-Term outages should be defined. Define how planning events in Tables 1 and 2 are associated with each type of outage. Define length of a "Long Term" outage. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizion. 9. The provisions of Section R.5.3 should be included in an MOD standard and applied to a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertent trip of the generator. Such a provision should include "…other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation.

Response: 1: The SDT disagrees and believes it is appropriate to require this in the TPL standard. Requirement R2.4.1 has been modified to clarify that an aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. It is not necessary to have a dynamic Load model which is specific to each bus.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

2: The specific wording for old Requirement R2.4.3.4 has been changed to "reactive resource capability". This could mean a degradation of the capability of a reactive resource. The TP is allowed to use its judgment as to how the variations of the sensitivity parameters should be made.

~~Variability and outages of r~~Reactive resource~~s~~ capability.

3: The SDT has decided to remove Requirement R5.4.3 because the sub-requirements are already implicitly covered by the standard. Your suggested sub-requirement is also already implicitly covered by the standard.

4: In response to industry comments, the SDT has removed the distinction in the standard between System Stability and generating unit Stability.

5: The SDT agrees that there is little distinction between a single unit of a specific MW and an aggregation of the same number of MW. The requirement for study has been changed to 20 MW for a single generator or for an aggregate of generators. This requirement is now located at Requirement R2.5.2.

R2.5.2 For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:

The addition/deletion/change of individual generating unit capability of 20 MW or greater.

An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater.

Organization	Question 2:	Question 2 Comments:
6: There are no longer two requirements covering this. The new generator size which requires a study and the change of generator size which requires a study have been combined into Requirement R2.5.2. 7 and 8: The requirement to include "known planned and long term outages of Transmission or generation equipment" has been removed from R5. Planned outages are covered in Requirement R1.1.1 for both Stability and Steady State. Long term outages are covered in new Requirement R2.1.4. **R1.1.1** Planned outages of generation and Transmission Facilities, if specifically known. **R2.1.4** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment. 9: This is the subject of PRC-024 currently under development. But the question of how you treated this in your planning studies belongs in TPL.		
City Water, Light & Power - Springfield, Illinois	No	Near term stability analysis should not need to be performed each year unless there is a significant change to the system or the previous study(ies) showed marginal performance.
Response: The near term Stability analysis does NOT have to be performed every year as long as you have a qualified past study which covers it.		
Progress Energy Carolinas	No	R 2.4.1 Load models that appropriately represent the dynamic behavior of induction motors are currently under development and may not be available for sometime. We believe that modeling the dynamic effects of loads is becoming increasingly necessary to obtain meaningful results. Therefore, it is appropriate that the revised standards address this. However, the present state of the industry is such that effective implementation of this requirement, as currently written, cannot be realistically achieved in the near term. The software tools currently in use do not accommodate the modeling of certain material effects (for example the load reduction due to thermal trips on HVAC compressor motors). Additionally, detailed load information necessary to allow the models which are available to be populated with meaningful data is not typically available or readily obtainable. Without resolving these issues, load model data submitted via the MMWG process will not improve simulation accuracy and could actually reduce the accuracy of results. Therefore, we would recommend R 2.4.1 rewritten to either a) allow a multi-year, phased approach to incorporating dynamic load modeling in simulation dynamic databases or b) provide an effective date for this particular requirement well into the future. This will accomplish the fundamental objective in a more accurate and meaningful manner. At least 48 months should be allowed before this requirement becomes effective. R 2.4.3 The proposed sensitivities create significant amount of additional work for the sole purpose of demonstrating compliance to this standard without any demonstratable benefit towards improving system reliability. While sensitivities should be appropriately considered in studies, this standard should not be overly prescriptive with respect to specific sensitivities or study methodologies. We propose removing the enumerated list of sensitivities starting with

Organization	Question 2:	Question 2 Comments:
		R2.4.3.1 and rewording R2.4.3 as follows: R2.4.3 For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, sensitivity case(s) that stress the System to reflect one or more conditions such as variations in dynamic Load model assumptions, modification of expected transfers, unavailability of long lead time Facilities, variability and outages of reactive resources, generation additions, retirements, or other dispatch scenarios shall be performed. The rationale for the sensitivity(ies) selected shall be documented. R 2.4.3.1 As stated above, this sub-requirement should be removed. However, if it is to remain, it should be clearly stated whether the Load model refers to system load or the dynamic load model at individual busses.
Response: Requirement R2.4.1 has been modified to clarify that an aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. It is not necessary to have a dynamic Load model which is specific to each bus. Because of this clarification, the SDT believes that a 24 month implementation period for this requirement is sufficient. This will be covered in the Implementation Plan which will be posted along with the third draft of the standard. Requirement R2.4.3: The SDT believes that running sensitivity cases will give the TP a better understanding of its System and better understanding yields a more reliable System. The SDT believes an enumerated list is more appropriate than the list that you suggest and an enumerated list must have a sub-requirement format. The requirement for sensitivity studies is not overly prescriptive. There is much room for the engineering judgment of the TP. **R2.4.1** System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: R2.4.3.1: The variations in Load model assumptions are to be applied to the aggregate System Load model which represents the overall dynamic behavior of the Load		
BCTC	No	BCTC's open access tariff requires generator owners to apply for interconnection studies and facility studies to interconnect to our system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. In fact, we may only be aware of the changes indentified in these requirements when generator owners make these applications. The generator owners are required to pay for these studies. Study requirements for generator interconnections are further defined by NERC Standards FAC-001 and FAC-002 (Coordination of Plans for New Facilities). By including these requirements in TPL, BCTC is concerned that generator owners may think that they are no longer required to pay for the studies. Furthermore, the NERC standards would have redundant requirements. If SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Any

Organization	Question 2:	Question 2 Comments:
		studies resulting from new generators or increases in existing generator output should be charged to the owner.
Response: The SDT agrees with the Industry's majority view that generating unit Stability and System Stability need not and should not be treated as distinct issues. The Stability related requirements have been modified to create a single generic set of requirements that no longer distinguishes between generating unit and System Stability. This should address your concern with potential conflicts with the FAC standards.		
Manitoba Hydro	Yes and No	R2.4: Agree with change except:R2.4.1.1: Needs to provide more detail on what is required to be compliant with respect to what is required to "appropriately represent the dynamic behavior of Loads including consideration of the behavior of induction motor Loads". Is the appropriate modeling left to the judgment of the TP/PC, supported by peer review by adjacent planners? Should the TP be required to document why the dynamic modeling is appropriate. The requirement implies a requirement to consider detailed dynamic load modeling at every bus in the model as opposed in areas of high concentration of such load. - needs clarification. R2.4.3: Generally agree, except:R2.4.3.1:Can the SDT clarify if the Variations in load model refer to variations in dynamic load modeling" R2.4.3.4, what is meant by variability of reactive resources? R2.4.4: The use of the words "shall be run" implies that additional scenario(s) are mandatory. Was this the intent of the SDT? R2.5: As stated in Q1 above, Manitoba Hydro continues to believe the Generating Unit Stability Analysis duplicates the FAC-002-0 requirements, creating potential for contradiction/non-compliance of both standards. The SDT should ensure there is no duplication of requirements of the FAC-002-0 standard. R2.5 should allow use of current or qualifying past studies. R2.5.1: Is it the SDTs intent that the TP could rely on the Planning Assessment R2.5 and/or R5.6 to assess the impact of a generator addition or modification. This function should be the subject of an interconnection study conducted in accordance with the FERC tariff (LGIP) or other similar TP interconnection process. R2.5.2: The TP planning process for addition of facilities should be used to verify the impact of changes to the network, including changes near existing generators . A planning assessment is not the appropriate process. Other Comments related to R2:R2: There appears to be no requirement for an assessment of system stability in the long-term planning horizon. Was this the intent of the SDT? R2.1: States the "steady state analysis shall be assessed annually and be supported at a minimum by the following annual current studies: Does the term ?annual current studies? preclude doing an assessment by using only qualified past studies? Please clarify!

Organization	Question 2:	Question 2 Comments:
		R2.1.1 & R2.1.2: NERC/ERAG will likely have to the models developed annually to ensure appropriate models are available. For example, in any given model series produced in past, there may not be a year five. Also, does System off-peak load refer to summer off peak? R2.1.3: While Manitoba Hydro supports the need for scenario assessments, this significantly increase the workload for studies and documentation. The requirement to document why a scenario was not selected will present a problem, since without doing the study, the planner may not have a good justification. The long term objective to improve reliability could be met by requesting only different sensitivity per year, and dropping the need to justify why others were not done. R2.6: Manitoba Hydro suggests that this requirement be converted to a definition of Past Studies. The definition should state that both R2.6.1 and 2.6.2 are necessary to qualify as a past study? R2.7:In the case were a CAP is required to meet the system performance requirements, will the assessment be deemed to be compliant on the assumption that the CAP will be put in place in a timely manner? R2.7.1.1: Can the SDT please clarify project initiation date? What is it? date permitting starts? Date construction starts? Etc R5.4: System Stability. The SDT should clarify if contingencies are to be applied to all elements in the case, or is it left to the judgment of the planner. Since there are numerous combinations of multiple contingencies, it is an impossible task to explain why the ?remaining Contingencies" were not selected. If this is not the intent, can the SDT explain what is required? The requirement should simply allow the planner the discretion to use judgment to select these more severe Contingencies, and the elements they are applied to, with explanation as to why they are expected to be more severe. R5.4.1: Manitoba Hydro agrees that the rationale for Contingencies selected should be provided. However, it is an onerous task, and of little value to provide rationale for the contingencies not selected. R5.4.2: Manitoba Hydro's preference is that the performance requirements should be in the standard body. The approach in Table 2 is inconsistent. R5.4.2 refers to Table 2 for Planning Event performance requirements, however, for the Extreme Events, the Table 2 refers back to R5.4.4. R5.4.3: Manitoba Hydro agrees and commends the SDT for recognizing generator tripping as a viable option for meeting the performance requirements in certain systems. R5.4.3.2: Agree that regulatory and statutory requirements must be met; however, the references to safety violations and equipment requirements are very generic. It is difficult to imagine what type of safety violation may be caused by

Organization	Question 2:	Question 2 Comments:
		a generator trip considering this is a widely used practice in many regions. The SDT should also be more specific as to what is meant by "equipment requirements". The requirement to be within Facility (equipment) Ratings is already covered in R3.5.1. Manitoba Hydro recommends the reference to safety and equipment be removed. R5.4.3.3: can the SDT clarify how they want the planner to determine that "a sustainable operating condition is maintained". Demonstrating stability over a 20 second stability run may be sufficient, or is the SDT looking for longer time frame stability modeling. R5.4.4 The requirement to explain why extreme events were not chosen add extra documentation. The TP has to explain why certain events were chosen, consequently, events not chosen are judged to have less impact. What would the SDT deem an adequate explanation? R5.5: Generating Unit Stability - As stated above, Manitoba Hydro does not agree that assessment of Generating Unit Stability is necessary as it is covered by FAC-002-0. R5.5.1: This requirement implies the Generating Unit Study should consider every unit exceeding 20 MW. Consistent with R2.5, the SDT should clarify that only new generators need be studied. R5.5.3: Given the numerous possible contingencies that could be run if multiple contingencies are considered, it is impossible to explain why the remaining contingencies were not selected. Other Comments related to Requirement R5:R5: The sentence ?The studies shall be based on computer simulations using models using data provided in Requirements R9 to R14 ?..? should apply to both steady state (R3) and stability portions, yet it is only included in R5. R5.1: Essentially repeats the requirement in the first sentence of R5 - suggest deleting. R5.2: Suggest deleting the words ?including those? R5.3: Manitoba Hydro suggests that frequency ride through be added in addition to voltage ride through. The language "how the generators are treated in the simulation" is not crisp. Is the SDT looking for information on how the voltage ride through and frequency ride through are modeled in the study?
Response: R2.4.1 has been modified to clarify that an aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. It is not necessary to have a dynamic Load model which is specific to each bus. The determination of the aggregate Load model is left to the judgment of the TP/PC. **R2.4.1** System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.		

Organization	Question 2:	Question 2 Comments:

R2.4.3.1: The variations in load model assumptions are to be applied to the aggregate system Load model which represents the overall dynamic behavior of the Load.

R2.4.3.4: The specific wording for Requirement R2.4.3.4 has been changed to variations in "reactive resource capability". The sub-requirement has also been changed to become a part of a bulleted list. This could mean a degradation of the capability of a reactive resource. The TP is allowed to use his judgment as to how the variations of the sensitivity parameters should be made.

~~Variability and outages of r~~Reactive resource~~s~~ capability.

R2.4.4: Requirement R2.4.4 has been deleted.

R2.5: The SDT agrees with the Industry's majority view that generating unit Stability and System Stability need not and should not be treated as distinct issues. The Stability related requirements have been modified to create a single generic set of requirements that no longer distinguishes between generating unit and System Stability. This should address your concern with potential conflicts with the FAC standards.

Other Comments related to R2: Yes, no System Stability is required for the Long-term Planning Horizon.

R2.1: Yes, current studies are required for Requirement R2.1. The assessment for steady state cannot be based solely on past studies.

R2.1.1 & R2.1.2: Not necessarily. The intent was that off-peak refers to any Load level other than peak that the TP deems appropriate.

R2.1.3: R2.1.3 and R2.4.3 have been modified to remove the requirement for specifying the technical rationale for why or why not a particular sensitivity was selected.

R2.1.3 For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.6: A formal definition would apply to all NERC standards. The SDT believes this explanation of what qualifies as a past study should only apply to this standard.

R2.7: Not necessarily. While the SDT can't answer as to formal compliance, the intent was that If the corrective action will not be in place at the time it is needed, the PC/TP will not be in compliance unless it can find an acceptable way (perhaps an Operating Procedure) to meet the performance requirement.

R2.7.1.1: This requirement is now Requirement R2.6.2. It is left up to the individual entity to define and document what is meant by the project initiation date. This requirement was intended to represent the same thing as Requirement R2.1 in the existing TPL-002-0.

R5.4 and R5.4.1 (now R3.4): The SDT believes the existing wording does allow the planner the discretion to use judgment to select these more severe Contingencies, and the elements they are applied to, with explanation as to why they are expected to be more severe.

Organization	Question 2:	Question 2 Comments:
R5.4.2: The SDT agrees that this cross-referencing is inconsistent. The reference back to Requirement R5.4.4 has been removed from the Table. R5.4.3: Thank you for your comment. R5.4.3.2 and R5.4.3.3: The SDT agrees and has removed these requirements. R5.4.4: The SDT believes that Transmission Planners know their Systems well enough to select Contingencies for which they suspect cascading or severe problems will result. Since there are an infinite number of possible scenarios to study, judgment is a necessity to limit scope to a reasonable level. The judgment of the TP is assumed to be a sufficient explanation as to why certain Contingencies were chosen. R5.5: The distinction between Generating Unit Stability and System Stability has been removed from the standard. R5.5.3: The requirement has been deleted. R5: Requirement R3 has been modified to be consistent with Requirement R5. **R3** For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. ~~The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to c~~Contingencies in Table 1 – Steady State Performance. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. R5.1: There is a difference between the two. The first sentence of Requirement R5 says to run Contingencies. Requirement R5.1 says to meet performance requirements. R5.2: The SDT agrees and has removed those words from new Requirements R4.3 and 4.3.1: **R5.2 (new R4.3 and R4.3.1)** Contingency analyses shall: ~~s~~Simulate the removal of all elements ~~including those~~ that the Protection System ~~protection~~ and other automatic controls are expected to disconnect for each Contingency without operator intervention. R5.3: The SDT is looking for how generators were treated in the study when there were voltage excursions. Did you trip them or not? What criteria do you use to decide if they should be tripped?		
Los Angeles Department of Water and Power	No	R2.4.3 requires sensitivity on various operating scenarios. These are best required under TOP, not TPL. It is totally useless and a waste of time to look at operating scenarios under planning horizon by planners, whether it be short term or long term. Operating scenarios are absolutely necessary under operating horizons but they need not be repeated and required in TPL when TOP already addressed these. R2.5 See my comment on question 1. This may be a suitable place to require proper modeling of the generator units to replace the existing languages.

Organization	Question 2:	Question 2 Comments:
		R5.4 is fine. R5.5 See my comment on question 1. The language here actually infers the size of a unit that should be modeled individually and not be lumped. But it should be more precise to prohibit any lumping as well as the explicit modeling of all dynamic data of any generator unit meeting the size requirement.
Response: R2.4.3: The SDT does not view the required sensitivity studies as operating studies. These are planning studies intended to investigate conditions that are different from the base case to bracket the range of possible outcomes if conditions vary from expected. R2.5: The SDT agrees with the majority of the Industry, including your comments, that there is no significant distinction between generator and System Stability and has modified the third draft to remove that distinction. R5.4: Thanks for your comment. R5.5: This requirement has been deleted.		
Transmission Agency of Northern California	Yes and No	R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirements in sub requirements of R5.4.3. We believe these conditions should be met for a
Response: R2.4: thanks for your comment. The SDT agrees and has deleted Requirement R5.4.3.		
Pacific Gas and Electric Co.	Yes and No	R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirement in sub requirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable? We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT

Organization	Question 2:	Question 2 Comments:
		needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. ? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Public Service Company of New Mexico	Yes and No	R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirements in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable? We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. ? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or

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		modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Puget Sound Energy, Inc.	Yes and No	R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirements in sub-requirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Idaho Power Company	Yes and No	R2.4 is acceptable. Please consider deleting R5.4.3. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner

Organization	Question 2:	Question 2 Comments:
		may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. ? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariff requires Generator Owner to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
SMUD	Yes and No	R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirements in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable.? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. 'Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.

Organization	Question 2:	Question 2 Comments:
Sierra Pacific Power Company / Nevada Power Company	Yes and No	R2.4 is acceptable. Please consider deleting R5.4.3. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariff requires Generator Owner to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to 'cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Black Hills Corporation	Yes and No	R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirement in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or

Organization	Question 2:	Question 2 Comments:
		REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
SRP	Yes and No	R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirements in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable.? We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. ? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by

Organization	Question 2:	Question 2 Comments:
		the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Tucson Electric Power Company	Yes and No	In general, R2.4 is acceptable but some of the sub-requirements are to prescriptive. We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. Off-peak analysis (R2.4.2) in the Planning Horizon is of limited value for smaller entities. This analysis is best left to the Operating Horizon. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirements in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable.? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Modesto Irrigation District	Yes and No	Comments: R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to

Organization	Question 2:	Question 2 Comments:
		specifically call out these requirements in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable.? We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network.? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 andFAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yetR5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Tri-State G&T	Yes and No	R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirements in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable.? We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and

Organization	Question 2:	Question 2 Comments:
		assessments would be onerous and would not yield reliability benefits for the network. ? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
ColumbiaGrid	Yes and No	R2.4 is acceptable. Please consider deleting R5.4.3. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariff requires Generator Owner to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase

Organization	Question 2:	Question 2 Comments:
		in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Southern California Edison	Yes and No	R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirement in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable.? We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. ? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Alberta Electric System Operator	No	R2.4 is acceptable. - Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirement in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or

Organization	Question 2:	Question 2 Comments:
		are generic. Otherwise, R5.4 is acceptable.- The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Generator Owners are to apply for interconnection to the transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. – Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
US Bureau of Reclamation	No	Comments: R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirement in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable.? We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network.? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 andFAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yetR5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator.

Organization	Question 2:	Question 2 Comments:
		The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Response: R5.4.3: This requirement and its sub-requirements have been deleted. R2.4 and R5.4: Stability studies will continue to be required for smaller utilities. Small entities have the option of not registering as a TP to avoid compliance concerns. Furthermore, it would be difficult to establish criteria for exempting "smaller entities". R2.5 and R5.5: The SDT changed the language to reflect that updated Stability studies only need to be performed as specified in Requirements R2.5.2. The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater. R5.5.2 This has been clarified with the words "change of individual generating unit capability". This is now covered in Requirement R2.5.2		
Gainesville Regional Utilities	Yes and No	For smaller systems, please see Comment 1. As far as R.2.4.1, if the various loads are basic and not a large industrial type load (very large motors with across the line starting, electric arc furnaces, etc.) then the dynamic behavior of the load should not require special consideration. Using proper power factors for the load should be enough for the transmission system evaluation. Under 2.4.3, as mentioned in Comment 1, evaluating the stressing of the smaller systems through a large amount of sensitivities does not add any reliability to the BES. It only adds much addition work to a limited resource entity. If the neighboring large systems agree that the smaller system can not impact them, this should support that the BES is not affected by any sensitivity that could exist on the smaller system. For R5.5, a threshold should be set to consider only the larger size units within the region. For a smaller system, the stability of a 50-100 MW unit probably would not perturb the interconnected regional BES's.
Response: R2.4.1: Residential air conditioners and other small motors can have a significant impact on dynamic simulations of the System. Using proper power factors for the Load is definitely not enough for dynamic simulations of Systems with large amounts of residential air conditioning. R2.4.3: In Order 693, FERC directed NERC to modify the TPL standard to require that critical System conditions be determined by conducting sensitivity studies. The SDT believes this should apply to any entity regardless of size that is registered as a Transmission Planner.		

Organization	Question 2:	Question 2 Comments:
R5.5: The SDT believes the appropriate size to study is any generator of 20 MW or more.		
JEA	Yes and No	R2.4.1 Do we mean "Appropriate" for overall regional system response/behavior or for individual customer behavior. JEA would agree to an "appropriate" overall regional system response/behavior model with unique individual or sub-regional customer behavior models if determined significant. R2.4.3.1 JEA would agree to a load characteristic sensitivity studies if conducted within the scope of a RRO study. Suggest modifying wording to "Variations in Regional Load model assumptions" R2.4.3.3 Not sure what we mean by Unavailability of long-lead time facilities. Need to add a definition. If the standard is suggesting to treat the unavailability of autotransformers like the unavailability of generators i.e. N-2 assessments with no firm consequential load shedding, then JEA does not agree that the failure rate of autotransformers is on the same level as generators and do not agree this requires a minimum performance standard to maintain grid reliability. In addition, a utility is most likely to be successful in finding a reasonable useful spare autotransformer somewhere in the world to replace the failed unit. R2.5 JEA agrees. R5.4.2 See comments for steady state requirements for Table 1 P5.R5.4.3 JEA does not understand what is meant by Stability violations. Do we mean to say "unstable system conditions"? R5.5 JEA agrees

Response: R2.4.1: The intent is "appropriate for overall System behavior", but not just on a "Regional" basis. Requirement R2.4.1 has been modified to clarify that a detailed dynamic Load model is not required at each bus. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.3.1: The SDT believes that this requirement should apply to an individual TP, not on a Regional level.

R2.4.3.3: The requirement for unavailability of long lead time Facilities has been broken into two pieces for better clarity. Old Requirement R2.4.3.3 has been clarified with the words "Timing of the installation of new or modified Facilities". For example, this would include consideration of a new line not being in service by the scheduled date. Also a new requirement, Requirement R2.1.4 has been added to cover unavailability of major Transmission equipment. These modifications should help alleviate your concerns.

~~Unavailability of long lead time Facilities~~ Timing of the installation of new or modified Facilities.

R2.1.4 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more

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(such as a transformer), an analysis of the impact on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment. R2.5: Thank you for your comment. R5.4.2: "Stability violations" means that the System did not meet performance requirements for Stability studies. R5.5: Thank you for your comment.		
PacifiCorp	Yes and No	av? We generally agree that utilities or large TPs and PCs need to perform and be held accountable for these Requirements; however, the SDT needs to define a organization size level, below which these requirements for the associated TP may be slightly relaxed. There are numerous TPs; (e.g., those associated with PUDs, Municipals or REA, etc.), for which performing these type of studies and assessments are onerous and do not yield reliability benefits for the network.
Arizona Public Service Co.	Yes and No	We generally agree that utilities or large TPs and PCs need to perform and be held accountable for these Requirements; however, the SDT needs to define a organization size level, below which these requirements for the associated TP may be slightly relaxed. There are numerous TPs; (e.g., those associated with PUDs, Municipals or REA, etc.), for which performing these type of studies and assessments are onerous and do not yield reliability benefits for the network.
Response: Stability studies will continue to be required for smaller entities. Smaller entities have the option of not registering as a TP to avoid compliance concerns. Furthermore, it would be difficult to establish criteria for exempting "smaller entities.		
ITC Holdings: ITC, METC, ITC Midwest	Yes and No	? R 2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. R 2.4.2 System Off-Peak Load for one of the five years. Is there an inconsistency here in that the requirement for peak system load levels specifies details on what is needed for the load models, but the off-peak does not specify this? We don't believe this is the intent but it creates an appearance that the dynamic behavior of loads is not required for off-peak.? Regarding R2.4 and R2.5 (& R5.4.1): It should be made clear that redoing studies is only necessary when it is not certain as to whether or not a system change will have a negative impact on system stability. An explanation should be sufficient if a study is unnecessary based on technical knowledge.. As to dynamic load models, we agree with a much longer implementation period than the rest of the standard.

Organization	Question 2:	Question 2 Comments:
		We have concerns that an auditor may not agree with our judgment as to what studies should be run or not run (R2.4, R2.5 and particularly in the case of R5.4.1). Additional guidelines, perhaps in the measurements section, would be appreciated.?
Response: R2.4.1 and R2.4.2: The dynamic behavior of induction motor loads has caused problems (e.g., slow voltage recovery) at higher System Load levels. Thus the requirement in the TPL standard is to make sure you properly represent the behavior of induction motor Loads at high Load levels, i.e., peak. It is not as much of a problem at lower Load levels and therefore there is no requirement for off-peak Load levels. Of course, even at off-peak a proper representation of Loads is needed. But for lower system Load levels, standard models are usually sufficient. R2.4 and R2.5: For R2.4 (Stability Studies) current or qualified past studies must be used to show that the five year period has been assessed. This means the TP must be able to demonstrate with engineering judgment that past studies are still valid. Dynamic load models: R2.4.1 has been modified to clarify that a detailed dynamic Load model is not required at each bus. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Because of this clarification, the SDT believes that a 24 month implementation period for this requirement is sufficient. This will be covered in the Implementation Plan which will be posted along with the third draft of the standard. **R2.4.1** System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. R2.4 and R2.5: The SDT does not believe that additional guidelines are needed. The standard leaves room for appropriate engineering judgment by the TP.		
Progress Energy Florida, Inc.	No	R2.4.4 as worded does not make sense, and could potentially create illogical situations where the Transmission Planner or Planning Coordinator would "offer up" additional sensitivities specific to their systems, for which they might not presently be analyzing and immediately have to self-report non-compliance. As a substitute to the language in R2.4.4, PEF suggests either returning to the language in each existing Standard's R1.3.2, or adding an R2.4.3.6 that states "Other known critical system conditions specific to the system studied by the Transmission Planner or Planning Coordinator. Regarding R5.4 and R5.5, PEF disagrees to the extent that a differentiation has been made between System Stability and Generating Unit Stability (see Question 1 comments). Given that System Stability and Generating Unit Stability are held to precisely the same standards in Table 2, PEF feels that significant modification is required to R5.4 and R5.5, specifically that the two sections need to be consolidated into a single section. Given the complex nature of Stability Analysis, and the fact that Generators are inextricably intertwined with all other components of the BES, the distinction that the SDT is attempting to make with this issue makes no sense from a power systems engineering perspective.
Response: R2.4.4: The SDT agrees and has deleted this requirement.		

Organization	Question 2:	Question 2 Comments:
R5.4 and R5.5: In response to industry comments, the SDT decided that generating unit Stability and System Stability need not and should not be treated as distinct issues. The Stability related requirements have been modified to create a single generic set of requirements that no longer distinguishes between generating unit and System Stability.		
Lafayette Utilities System	Yes and No	Requirement 2.4.1 directs the furnishing of information that would reveal the location of new large inductive loads. Large inductive loads typically are induction motors used in industrial applications. Therefore, a Distribution Provider's forecasts about the expected level of its inductive load could effectively reveal non-public information about the anticipated location of new industrial loads. If a Distribution Provider were required to disclose such information to its Transmission Planner, the confidentiality of information having considerable commercial and competitive significance could be compromised. This would be of particular concern if the Transmission Planner and the Distribution Provider also happen to be competitors for new retail loads.
Lakeland Electric	No	Modeling the dynamic behavior of Loads is difficult at best and merits a discussion or white paper. Recommend requirement 2.4.1 specify the size of induction motor that should be considered and comment on modeling of small induction motor loads such as air conditioning.
Orlando Utilities Commission	No	OUC supports the comments from FPL and Lakeland Electric on this issue.
Response: Requirement R2.4.1 has been modified to clarify that a detailed dynamic load model is not required at each bus. An aggregate system load model which represents the overall dynamic behavior of the Load is acceptable. **R2.4.1** System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.		
Ameren	Yes and No	In R2.4, it is suggested that the word "System" be re-inserted ahead of the word "Stability". It is believed that the sub-requirements of R2.4 are for System studies as opposed to Plant or Generator stability studies. In R2.4.1, agree that the system peak load should be studied for at least one of the five years in the near-term planning horizon. What is the meaning of the term "appropriate", and who decides what dynamic representation of load is "appropriate", and for what conditions? Guidelines for the development of load models used in power flow and dynamic models to represent residential air conditioner induction motor load response including the effects of underground distribution cable and distribution capacitor banks are not available. Why can't the standard load representation be used to meet R2.4.1, and the more detailed load representation,

Organization	Question 2:	Question 2 Comments:
		including dynamic system induction motor load response, be used to meet R2.4.3? In R2.4.2, agree that off-peak load levels should be covered for one of the five years. In R2.4.3, there should not be a requirement to explain why sensitivities were not selected. Further, these items in R2.4.3.1-5 appear to be options and not sub-requirements, and therefore are too prescriptive and inappropriate for inclusion here. The proposed sensitivities appear to over-focus on the particular issues listed and may result in the detriment of overall system reliability. Engineering judgment should be used to develop the sensitivity scenarios, and it should be encouraged that the same scenarios should not be performed every year so that a portfolio of sensitivity scenarios would be developed over time. The standard should not include an enumerated list of required sensitivities. If two sensitivities are required to be performed each year, then the standard should state so, but we believe that more than one sensitivity scenario for each peak and off-peak case is burdensome. We are unsure if R2.4.4 is a requirement or an option. If R2.4.3 were not so prescriptive, the additional sensitivity could be covered under the engineering judgment comment provided above. The prescriptive listing of sensitivities under 2.4.3.1 through 2.4.3.5 should be eliminated. Proposed alternative wording for R2.4.3 which addresses above concerns is as follows:R2.4.3. "For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, sensitivity case(s) that stress the System to reflect one or more conditions such as variations in dynamic Load model assumptions, modification of expected transfers, variability and outages of reactive resources, generation additions, retirements, or other dispatch scenarios are integral to a thorough assessment of reliability. Document how and why appropriate sensitivities were selected." R2.5 should be reworded as follows. "The Generating Unit Stability portion of the Planning Assessment shall be assessed for the year and conditions when the following changes that could affect stability margins occur:" Agree with most of R5.5. In R5.5.4, a risk/benefit vs. cost analysis should be included in the evaluation of implementing a change to mitigate the likelihood of cascading outages for the extreme events. Agree with R5.6.
Response: R2.4: Adding the word "System" is no longer necessary because the SDT has eliminated the distinction between System Stability and Generating Unit Stability. R2.4.1: The TP and PC decide what is appropriate for their System. R2.4.1: The sensitivity of studying effects of induction motor Loads may not be chosen by the TP. The SDT thinks that studies incorporating the effects of induction motor Loads must be done for peak Load levels.		

Organization	Question 2:	Question 2 Comments:
R2.4.2: Thank you for your comment. R2.4.3: The requirement to explain why or why not sensitivities were selected has been deleted. The sub-requirements have been converted into bullet lists. R2.4.4: Requirement R2.4.4 has been deleted. R2.4.3: The SDT believes an enumerated list is more appropriate than the list that you suggest and as stated above, an enumerated list must have a sub-requirement format. The requirement for sensitivity studies is not overly prescriptive. There is much room for the engineering judgment of the TP. R2.5: In response to industry comments, Generating Unit Stability has been combined with System Stability. Requirement R2.5 on Generating Unit Stability has therefore been deleted. R5.5.4: This requirement has been deleted. R5.6: Thank you for your comment. The separate requirement for Generating Unit Stability Studies has been deleted.		
Florida Power and Light	No	R2.4.4 is inappropriate for a compliance assessment. Essentially R2.4.4 requires the Transmission Planner or Planning Coordinator to deem appropriate and justify inclusion or exclusion of any sensitivity other than the required sensitivities listed in R2.4.3. The only way that a an entity could be found non-compliant is if the entity deems a sensitivity as appropriate, and then inexplicably did not perform the sensitivity, which makes no sense. The requirement seems to put a burden of justifying by "technical rationale" a sensitivity that is deemed appropriate already. R2.4.4 could be eliminated and its intent absorbed in R2.4.3 by changing its wording slightly: "R2.4.3 For each of the studies in Requirement R2.4.1 and Requirement R2.4.2, sensitivity case(s) deemed appropriate by the Transmission Planner or Planning Coordinator that stress the System to reflect conditions including, but not limited to, one or more of the following conditions, shall be run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied."
Response: The SDT agrees and has deleted Requirement R2.4.4. Other sensitivities deemed appropriate by the TP or PC can always be run.		
Exelon Transmission Planning	No	R2.4 should be specific as to applicability to generator stability, system stability or both. R2.4.1 requires the use of load models for motors. Detailed load data may not be available and studies would therefore produce questionable results. It is our understanding that the industry has recognized the importance of using better load models and there are multiple ongoing initiatives to improve our ability to do this modeling but these initiatives are not complete. However, the industry's ability to provide accurate models is not sufficient to ensure compliance at this time. The sensitivities for near-term studies in R2.4.3 aren't clearly defined, especially R2.4.3.3, 'Unavailability of Long Lead Time Facilities'. Doesn't the study that determined the original need for these facilities document the consequence of

Organization	Question 2:	Question 2 Comments:
		unavailability? The peer review component of the Planning Assessment has CEII concerns, especially with regard to extreme contingencies and whether or not they involve cascading.

Response: R2.4: In response to industry comments, Generating Unit Stability has been combined with System Stability. Therefore, Requirement R2.4 applies to Stability analysis.

R2.4.1: The intent of R2.4.1 is to have dynamic Load models which are appropriate for overall system behavior, not necessarily on an individual substation basis. The SDT believes that type of model is available. Requirement R2.4.1 has been modified to clarify that a detailed dynamic Load model is not required at each bus. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.3 and R2.4.3.3: The sensitivities in Requirement R2.4.3 have been reworded for better clarity. Old Requirement R2.4.3.3 for unavailability of long lead time facilities has been broken into two pieces for better clarity. Old Requirement R2.4.3.3 has been clarified with the words "Timing of the installation of new or modified Facilities". For example, this would include consideration of a new line not being in service by the scheduled date and how you would plan to get around that problem. Also, a new Requirement R2.1.4 has been added to cover unavailability of major Transmission equipment.

~~Unavailability of long lead time Facilities~~ Timing of the installation of new or modified Facilities.

R2.1.4 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment.

Peer review comment: The SDT does not believe this to be an issue because the existing standards TPL-001 through TPL-004 already require in Requirement R1.3 a review of assessments by Regional Reliability Organizations.

CenterPoint Energy and CPS Energy	No	We believe the requirements are overly broad and overly prescriptive. We further believe the extent of the "problem" these requirements would address does not justify such overly broad and overly prescriptive requirements. To clarify, we wholeheartedly agree that transmission planners should consider and selectively study potential stability concerns. However, we believe that transmission planners are already considering and selectively studying potential stability concerns. We are not aware of any significant bulk electric reliability problem actually occurring in recent memory due to the failure of transmission planners to perform the assessments and studies this standard proposes to require. Some might argue that instability occurred in the northeast blackout, and we would agree. However, requiring transmission planners to perform all the assessments and all the studies proposed herein would not have prevented instability from occurring in that event. A targeted approach focusing on the specific vulnerabilities of that area of the

Organization	Question 2:	Question 2 Comments:
		network would be far more effective than the scattergun approach proposed here. Furthermore, even if all the stability analyses proposed in this standard were performed and audited, the studies likely would not have revealed the actual underlying reliability concern. In the end, the root cause of the failure was thermal overloading, not stability. Instability eventually occurred when the root cause (thermal overloading) led to a situation where circuits sequentially tripped over the course of an hour or so. Events that occur over the course of an hour are generally outside the scope of stability analyses, so these proposed requirements are off the mark for that event. We recommend deletion of R2.4.3, R2.4.4, R2.5, R5.2, R5.3, R5.4 (or 5.5), and R5.5 (or R5.6). Removing this excess baggage would allow transmission planners to use their judgment to selectively analyze stability concerns germane to their system. We realize such an approach requires a recognition that transmission planners are already doing the appropriate analyses, and we encourage the SDT to be receptive to this premise. To further clarify this last point, some would argue that assuming entities are already doing the right thing belies the underlying premise behind enforceable reliability standards. We believe that acceptance of the need for enforceable reliability standards does not pre-suppose that some or all entities are always doing the wrong thing all the time in all aspects of their business. Nor does acceptance of mandatory reliability standards require acceptance that all aspects of the business are equally likely to produce reliability concerns. We believe most or all entities are already doing some things well such that, in some aspects of the business, there is no evidence that a "problem" actually exists. If the SDT accepts this premise, it would focus its attention on actual problem areas, not imaginary ones. We submit that performing appropriate stability studies is not a "problem" that requires an the overly prescriptive requirements proposed here. Rather than solving an actual problem, these requirements are more likely to detract resources from actual concerns by causing planning resources to be expended documenting and defending to auditors that imaginary concerns do not exist.
Response: The SDT disagrees and believes the Stability requirements are necessary to ensure that appropriate studies are being made.		
MidAmerican Energy Company	No	a. MEC disagrees with the proposed R2.4.1 text. This inclusion of this requirement may be premature at this time for several reasons. There is presently no industry consensus on how the dynamic behavior of loads should be properly represented and analyzed. In addition, it would be a large and difficult effort to identify, collect, and maintain the pertinent information. It is presently difficult to obtain and maintain the percentage of residential, commercial, and industrial load at each transmission interconnection point, much less try to get the proper percentage of the various types of induction motor loads. If this requirement is retained then R2.4.1 should be modified to specify a minimum threshold size where dynamic induction motor load or dynamic load behavior becomes significant such as near mining areas. The SDT should consider a 25 MW size threshold for induction motors and a 100 MW size threshold for industrial complexes where the dynamic loads are inadequately represented by normal power flow dynamic assumptions. b. R2.4 as stated refers to Near-Term Transmission Planning Horizon Stability analysis but there is no requirement in the standard referring to Long-Term Transmission Planning Horizon Stability analysis. The SDT should reword R2.4 so that it is clear that no Long-Term Stability analysis is required by stating that "Stability analysis for the Near-Term

Organization	Question 2:	Question 2 Comments:
		Transmission Planning Horizon shall be assessed annually?.". ? In R2.4.4, we believe this requirement should not be added. Why was it included? It seems superfluous, because any entity can study other sensitivities if they want. Why should TP or PC have to study what the other entity wants to study? Who would be the judge in case of disagreement over the technical rationale?? In R2.5.2, Why was the addition of a new substation included? We would not expect a new substation to negatively impact the system or generating unit stability. We note the R5.5 and R5.6 should really have been updated to refer to 5.4 and R5.5.
Response: a: The intent of Requirement R2.4.1 is to have dynamic Load models which are appropriate for overall system behavior, not necessarily on an individual substation basis. The SDT believes that type of model is available. Requirement R2.4.1 has been modified to clarify that a detailed dynamic Load model is not required at each bus. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. **R2.4.1** System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. b: There is no requirement in the standard for Long-Term Transmission Planning Horizon Stability analysis. The only requirement is for Near-Term Transmission Planning Horizon Stability analysis. The SDT believes this is clear in the standard. R2.4.4: The SDT agrees and has deleted Requirement R2.4.4. R2.5.2: A new substation in a line could change the requirements for relaying on the new shorter line so that the generating unit remains stable. Zone 2 clearing from the generator end of the line may not be fast enough on a shorter line. Requirement R5 has been re-numbered due to deletions and the sub-requirement numbering is now correct.		
SERC Dynamics Review Subcommittee	No	R 2.4.1 Load models that appropriately represent the dynamic behavior of induction motors are under development and may not be available for some time. The implementation plan should take this into account and allow at least 36 months for implementation; otherwise this requirement will not be achievable in the near term. R 2.4.3 One should only explain why sensitivity was performed. In general we believe that breaking these requirements into specific sub-requirements focusing on specific sensitivities is too prescriptive and inappropriate; it will lead to over-focus on these particular issues to the detriment of system reliability. There should be no enumerated list of required sensitivities. Engineering judgment needs to be permitted. R 2.4.3.1 It should be clearly stated whether the load model refers to system load or the dynamic load model at individual busses. We have a specific proposal for R2.4.3 which addresses the above concerns as follows: R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, sensitivity case(s) that stress the

Organization	Question 2:	Question 2 Comments:
		System to reflect one or more conditions such as variations in dynamic Load model assumptions, modification of expected transfers, unavailability of long lead time Facilities, variability and outages of reactive resources, generation additions, retirements, or other dispatch scenarios. Document why each sensitivity was selected.
Response: R2.4.1: Requirement R2.4.1 has been modified to clarify that a detailed dynamic Load model is not required at each bus. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Because of this clarification, the SDT believes that a 24 month implementation period for this requirement is sufficient. This will be covered in the Implementation Plan which will be posted along with the third draft of the standard. **R2.4.1** System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. R2.4.3: The requirement to explain why or why not sensitivities were selected has been deleted. The sub-requirements are now part of a bullet list. For Requirement R2.4.3.1: The variations in Load model assumptions are to be applied to the aggregate System Load model which represents the overall dynamic behavior of the Load		
MRO NERC Standards Review Subcommittee	No	a. The MRO disagrees with the proposed R2.4.1 text. This inclusion of this requirement may be premature at this time for several reasons. There is presently no industry consensus on how the dynamic behavior of loads should be properly represented and analyzed. In addition, it would be a large and difficult effort to identify, collect, and maintain the pertinent information. It is presently difficult to obtain and maintain the percentage of residential, commercial, and industrial load at each transmission interconnection point, much less try to get the proper percentage of the various types of induction motor loads. If this requirement is retained then R2.4.1 should be modified to specify a minimum threshold size where dynamic induction motor load or dynamic load behavior becomes significant such as near mining areas. The SDT should consider a 25 MW size threshold for induction motors and a 100 MW size threshold for industrial complexes where the dynamic loads are inadequately represented by normal power flow dynamic assumptions. b. R2.4 as stated refers to Near-Term Transmission Planning Horizon Stability analysis but there is no requirement in the standard referring to Long-Term Transmission Planning Horizon Stability analysis. The SDT should reword R2.4 so that it is clear that no Long-Term Stability analysis is required by stating that "Stability analysis for the Near-Term Transmission Planning Horizon shall be assessed annually?.". ? The MRO does not accept the R2.4.3.1 text and want some explanation of the what, when, and how to provide the technical rationale for why each condition was or was not used. ? In R2.4.3.1, what is meant by “variations” (e.g. how much variation is enough)? ?

Organization	Question 2:	Question 2 Comments:
		In R2.4.3.2, what is meant by “modification” (e.g. how much modification is enough) and "expected transfers" (e.g. firm or non-firm transfers)? ? In R2.4.3.3, what is meant by “long lead time” (e.g. 1 month, 1 season, 1 year, 2 years, etc.)? The MRO suggests that “long lead time” be stated 18 months or more.? In R2.4.4, we believe this requirement should not be added. Why was it included? It seems superfluous, because any entity can study other sensitivities if they want. Why should TP or PC have to study what the other entity wants to study? Who would be the judge in case of disagreement over the technical rationale?? In R2.5.2, Why was the addition of a new substation included? We would not expect a new substation to negatively impact the system or generating unit stability. The MRO notes that R5.5 and R5.6 should really have been updated to refer to 5.4 and R5.5. In R5.4.3.1, we suggest that the time-limited aspect of Facility Ratings should be included in the Glossary Definition by adding the words "within the applicable time period of the rating" and then it would not need to be clarified in various locations (R3.3.2.2, R3.5.1, R5.4.3.1, Table 1-Note 1, & Table 2-Note 1) throughout the standard.

Response: a: The intent of Requirement R2.4.1 is to have dynamic Load models which are appropriate for overall System behavior, not necessarily on an individual substation basis. The SDT believes that type of model is available. Requirement R2.4.1 has been modified to clarify that a detailed dynamic Load model is not required at each bus. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

b: R2.4: There is no requirement in the standard for Long-Term Transmission Planning Horizon Stability analysis. The only requirement is for Near-Term Transmission Planning Horizon Stability analysis. The SDT believes this is clear in the standard.

R2.4.3: The requirement to explain why or why not sensitivities were selected has been deleted.

R2.4.3.1: The variations in load model assumptions are to be applied to the aggregate system Load model which represents the overall dynamic behavior of the Load. The amount of variation is left to the judgment of the TP and PC.

~~Variations in~~ Load model assumptions

R2.4.3.2: The wording has been changed to variations in expected transfers. The amount of variation is left to the judgment of the TP and PC.

~~Modification of e~~Expected transfers

R2.4.3.3: The requirement for unavailability of long lead time Facilities has been broken into two pieces for better clarity. Old Requirement R2.4.3.3 has been

Organization	Question 2:	Question 2 Comments:
clarified with the words "Timing of the installation of new or modified Facilities". For example, this would include consideration of a new line not being in service by the scheduled date. Also a new Requirement R2.1.5 has been added to cover unavailability of major Transmission equipment. These modifications should help alleviate your concerns. ~~Unavailability of long lead time Facilities~~ Timing of the installation of new or modified Facilities. **R2.1.4** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment. R2.4.4: The SDT agrees and has deleted Requirement R2.4.4. R2.5.2: This requirement has been deleted. Requirement R5 has been re-numbered due to deletions and the sub-requirement numbering is now correct. R5.4.3.1: The SDT believes the existing definitions of Facility Rating and Equipment Rating sufficiently cover the time limited aspect of the ratings.		
Austin Energy	No	The routine sensitivity cases requirement contained in R2.4.3 is overly burdensome and unnecessary and should be deleted. Sensitivity analysis should be limited to what may be deemed appropriate by the Transmission Planner or Planning Coordinator. Similarly, R2.5 and R5.5 requirements for Generating Unit Stability should be deleted. Removing these burdensome requirement will allow transmission planners and/or the Planning Coordinator (ISO) to determine the appropriate Generator Unit Stability analysis needed as part of R5.4 System Stability.
Response: R2.4.3: The SDT believes that running sensitivity cases will give the TP a better understanding of its System and better understanding yields a more reliable System. The requirement for sensitivity studies is not overly prescriptive. There is much room for the engineering judgment of the TP. The sub-requirements have been converted into a bullet list. R2.5 and R5.5: The separate System and Generator Unit Stability Requirements have been removed from the Standard and replaced with Requirement R2.4, which addresses all Stability studies. Appropriate levels of generation additions are listed as bullets under Requirement R2.5.2; The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater.		
Midwest ISO	No	The language in R2.4 retains the appropriate clarification that while annual assessments are required, these assessments do not necessarily have to be based upon annually performed simulations. This same distinction should be retained for steady-state assessments required under requirement R2.1, not withstanding the fact that steady-state simulations are easier to perform. The principle is the same for both. Requirement R2.4.1 is to open ended in

Organization	Question 2:	Question 2 Comments:
		specifying the years to be studied. Rather, it should parallel requirement R2.1.1 in requiring that at a minimum either year one or two should be evaluated, and additional years at the option of the responsible entity. If the system could go unstable in the next 1-2 years, it is important to know this. Regarding R2.4.3 & R2.4.4, the standards should not require analysis for which corrective action is optional regardless of the conclusion of the analysis. Requirement R2.7 establishes that corrective action to any sensitivities is optional. Therefore, the performance of sensitivities should be at the discretion of the applicable entity. If the SDT believes it is important to recommend that sensitivities be performed then those Requirements addressing sensitivities should state that the performance of the sensitivity is recommended but optional. If you keep sensitivities in the standard then the requirement in R2.4.4 to document why an entity performed sensitivities in addition to the Requirements should be dropped. As long as the entity selected a sensitivity and documented the results of the sensitivity there should be no reason to explain why he tested it. Requirement R2.5.2 is unclear with respect to when generator unit stability needs to be retested following modifications to the transmission system. Nearly all additions to the transmission system will tend to improve generator stability. We suggest this language be modified to say: "Material transmission system changes are made at or near the point of interconnection of existing generation that would tend to degrade stability margins of that generation, such as the removal of a transmission line, or associated with the addition of new generation, or other system changes as determined by the Planning Coordinator or Transmission Planner". R5.4.3.1 & R5.4.3.3 are redundant with the stated requirement to mitigate stability. Under the sub requirement of R5.4.3.2 it may not be possible for the PC/TP to determine whether the safety, equipment, regulatory or statutory requirements are violated without collaboration with the Transmission Owner and/or the Generator Owner. Therefore, if this sub requirement is retained it should be amended to include the following sentence: "Applicable Transmission Owners and/or Generator Owners shall collaborate with the PC/TP in determining whether such action would violate safety, equipment, regulatory or statutory requirements". Subrequirements R5.4.3.X are superfluous; we suggest removing these subrequirements. However, if this requirement is retained it should be amended to include the following sentence: "Automatic generation tripping is allowed to mitigate Stability violations if the performance criteria in Table 2 is met".

Response: R2.4 The Requirement is allowing the TP and PC the option to determine which time frame to study so as not to be as prescriptive as Requirement R 2.1.1.

R2.4.3 & R2.4.4: The language of Requirement R2.4.3 has been changed to clearly state the objective of sensitivity analyses and their applicability.

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

Organization	Question 2:	Question 2 Comments:
R2.5.2: This language has been removed from the Standard. R5.4.3.1 & R5.4.3.3: The specific sub-Requirements have been removed from the Standard; they are already implicitly covered in the Standard.		
Tri-State Generation and Transmission Association, Inc.	Yes and No	R2.4.1 "System peak load" needs a definition. Forecast descriptions by the utility should describe probability levels and other specifics.
Response: The SDT has changed this language in Requirement R2.4.3 by allowing the use of sensitivities already considered in the base case. **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
AEP	No	We are concerned about unintended consequences with regard to System Stability studies, specifically, the possibility of generating unnecessary work. We would like the SDT to consider language changes that recognize the following realities. (1) While System Stability studies may be justified as a more detailed look at contingency scenarios whose observed severity in steady-state analysis suggests the need for more in-depth study, they cannot be expected to achieve the same breadth of scope as steady-state analyses. In decoupling System Stability studies from steady-state analysis, the draft standard may unnecessarily tend to force stability study scopes to approach those of steady-state analyses. (2) The characteristic limiting factors of systems are generally known (whether thermally limited, voltage drop limited, or transient or small-signal stability limited) and in many systems the limiting factors are thermal or steady-state voltage, but not stability. The draft standard may end up forcing System Stability studies to be done solely for compliance. It is not that independent System Stability studies are never justified (they are, for example, where inter-area small-signal instability is a known factor), but in many systems, they are not necessary. We observe that as sub-requirements of R2 and R5, R2.5 and R5.5 are the responsibility of the Transmission Planner and Planning Coordinator. Is it the SDT's intention that these entities be responsible for conducting the Generating Unit Stability analysis, irrespective of the ownership of the generating units? Should the Generator Owner be responsible for conducting the Generating Unit Stability analysis?
Response: (1) The SDT agrees that Stability studies are more in-depth; the study requirements for Stability are less than that of Steady State. (2) Not in all areas, there are numerous Systems that are limited by Stability, not just thermal limits. R2 and R5, R2.5 and R5.5: The distinction between Generating Unit Stability and System Stability has been removed.		

Organization	Question 2:	Question 2 Comments:
Southern Company Transmission	No	R 2.4 needs to have the word System inserted in front of the word Stability. R 2.4.3 One should only have to explain why a sensitivity was performed, not why it was not performed. In general we believe that breaking these requirements into specific sub requirements focusing on specific sensitivities is too prescriptive and inappropriate. It will lead to over focus on these particular issues to the detriment of system reliability. There should be no list of sensitivities enumerated as subrequirements. Engineering judgment needs to be permitted. R 2.4.3.1 It should be clearly stated whether the load model refers to system load or the dynamic load model at individual busses A specific proposal for R2.4.3 which addresses the above concerns is provided as follows:R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, sensitivity case(s) shall be run and documented that stress the System to reflect one or more conditions such as variations in dynamic Load model assumptions, modification of expected transfers, unavailability of long lead time facilities, variability and outages of reactive resources, generation additions, retirements, or other dispatch scenarios. Document why each sensitivity was selected.
Response: R 2.4: The distinction between Unit and System Stability has been deleted. R 2.4.3 The SDT has changed the language of R2.4.3 to reflect this; to examine one or more sensitivities and the documentation of the technical rationale for why each of the sensitivities was not chosen has been removed. R 2.4.3.1: The language has been changed to allow the Transmission Planner to use their judgment in application of sensitivities. ~~Variations in~~ Load model assumptions R2.4.3 The SDT wanted to keep the sensitivities clear from the rest of the language for base case study requirements. The language of this section has been changed and the use of documentation has been removed. **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
Brazos Electric Power Cooperative, Inc.	No	We do agree with the wording change in 2.4 which uses 'assessed annually'. 2.4.1 and 2.4.2 are ok. 2.4.3 is not agreeable, as it implies or could imply a number of studies are required. Stability studies are not required as often as steady state studies. A new in-line load serving substation can certainly impact the steady state results of an area but would not have the same impact from a steady state perspective. In other words, we feel that running stability studies for a number of small variables does not provide any added benefit and thus stability studies should not be treated the same as steady state studies from a requirement standpoint. More emphasis should continue to be

Organization	Question 2:	Question 2 Comments:
		placed on the steady state analysis. 2.4.3 should be edited to say "Sensitivity cases as deemed appropriate by the TP or PC, that stress the System (or BES) may be run reflecting one or more of the following conditions. Other sensitivities not included below may also be run. Appropriate documentation should be included describing the rationale for the selection of the cases and conditions "delete 2.4.4 as it is taken care of in 2.4.3 2.5 can be deleted as it adds nothing to the stability requirements2.5.1 should be modified to be included under 2.4 as a required study with the caveats from 5.6 brought over defining parameters, or delete 2.5.1 altogether as 5.6 covers the addition of generation.2.5.2 is still fairly ambiguous even with the changes and should be deleted. However if kept it should be modified to remove the last part of the sentence beginning with "or the addition of a new substation?". The addition of a simple in-line substation does not have a material impact on the stability of a near-by plant.2.6.1 and 2.6.2 should be combined to remove the mention of generating plant stability. deleting 5.4 is ok Not sure of the need to add 5.5.2. Isn't that the intent of the whole Standard? 5.5.3 seems to be acceptable.
Response: R2.4: Thanks for your comment. R2.4.3: The SDT has changed this language to clarify the requirement; the use of documentation has been removed from the language. **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: R2.4.4: This part of the Standard language has been removed. R2.5: This part of the Standard language has been removed and bullets under (new) Requirements R2.5.2 have been added to the language to clarify this position. The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater. R5.5.2: This requirement was deleted.		
NERC and Regional	No	PJM concurs with the general direction; however the sensitivity analysis section as written requires explanation of why

Organization	Question 2:	Question 2 Comments:
Coordination		certain sensitivities were not selected. However the sensitivity requirement must be defined. Prove the rationing. R2.4 should state for stability we should use light load rather than system peak which is for steady state analysis. R2.4 should be modified as followsR2.4 should be modified as followsR2.4 The Near-Term Transmission Planning Horizon portion of the Stability analysis requires: Suggest making all sub requirements bullets under R2.4 The words in R2.4 seem to state that the "analysis must be assessed annually" which seems to leave open the option of assessing an old study, whereas R2.2. and R2.3 state a study is required each year, and a study is conducted each year. The words need R2 must be clearer and more consistent. System stability requirements seem to be poorly defined. It appears that there is going to be an expectation that inter-area oscillation and small signal analysis be performed frequently over a variety of conditions. I'm not sure how geared up industry is for this. R2.4.1 is too ambiguous. This sub requirement requires a model that "appropriately represents the dynamic behavior of loads". However, the requirement does not reference how that judgment is made nor who would make the judgment. The sub bullets are vague and again provide no basis for performance or for arbitration. R2.4.4 should be deleted as it will deter TPs and PCs from conducting additional studies. R2.4.4.1-5; Should clearly define words like variation, modification, unavailability of long lead time facility, variability of reactive resources. R2.5 is ambiguous regarding the definition of "affects stability margins". What is the technical performance margin for "affect"? If not defined in the standard then who makes the decision? The TP? the auditor? NERC staff? Do you mean critical clearing time and how much of change for example percentage or cycle.

Response: The SDT has changed this language to reflect that this is to examine one sensitivity or more and the documentation requirement has been removed.

R2.1.3 For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.4: The SDT has determined that both Peak and Off-Peak should be studied; another Load case can be evaluated as a sensitivity.

R2.4 does state that an assessment shall be performed each year and the applicability of past studies is listed in Requirement R2.6.

R2.2. and R2.3: The language clearly states that a study is required for one of the years in the assessment period.

The SDT believes that each TP and PC should have discretion to determine the appropriate Stability studies applicable to their System.

Organization	Question 2:	Question 2 Comments:
R2.4.1: The SDT has changed this language to clarify that aggregate Load can be used here as well. This Requirement is to make you properly represent the dynamic behavior of Loads at high System Load levels. **R2.4.1** System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. R2.4.4 The SDT has deleted this section. R2.4.4.1-4 (now R2.4.3): The SDT has changed the language in these sections and made them a bulleted list. ~~Variations in~~ Load model assumptions ~~Modification of e~~Expected transfers ~~Unavailability of long lead time Facilities~~ Timing of the installation of new or modified Facilities. ~~Variability and outages of r~~Reactive resource~~s~~ capability. R2.5 This section of the Standard language has been removed.		
IESO	No	A. R2.4(i) We suggest to remove words such as "consideration of" and "deemed appropriate" since these are not measurable and not enforceable. Further, we continue to disagree with mandating sensitivity testing with descriptive subrequirements. Sensitivity testing (ii) Specific to R2.4.3, we continue to express our disagreement to include sensitivity testing in the requirements. We are disappointed that despite disagreements by the majority of the commenters and their suggestions to leave sensitivity testing to the TPs and PCs discretion, the SDT continues to stipulate detailed requirements for sensitivity testing. The SDT in its summary response to comments indicates that these testing are intended as "?providing some guidance on what could be included in the sensitivity studies without being too prescriptive." If these are indeed intended as guidance rather than enforceable requirements, then they should be provided in a technical document or a reference document that supports the standard, not in the standard itself. B. R2.5 (i) Similar to our comments under Q1 (i), the requirements should not restrict to changes at or near the Interconnection point. Transmission changes several buses removed from the generator's Interconnection point may also affect the stability performance of the generators. Suggest to reword it to "? in the nearby vicinity that can have an adverse reliability impact on the generating units' stability performance".(ii) There seems to be a hole or incomplete scenario in R2.5.2 in the sentence: "removal of a Transmission Line or the addition of a new substation in one of the Transmission Lines connected to the plant." We agree that removal of a transmission line in the vicinity needs to be assessed; we also believe that addition of not just a substation but also any transmission facilities in the vicinity should be assessed. We therefore suggest to reword this to: "removal of a Transmission Line or the addition of new

Organization	Question 2:	Question 2 Comments:
		transmission facilities in the generating plant's nearby vicinity that can have an adverse reliability impact on the generating units' stability performance. C. R3.4 (i) We do not agree with the requirement that: "If the Extreme Events analysis concludes there are cascading outages, an evaluation of implementing a change designed to reduce or mitigate the likelihood of such consequences shall be conducted." Future transmission systems are planned and designed accordingly to Planning Events. It should not be a surprise that applying Extreme Events to the planned transmission system for which it is not designed to withstand such events would show instability and/or cascading outages. The follow on actions should be to evaluate possible actions to contain and minimize the impact of cascading outages, rather than to come up with options or alternative designs to reduce or mitigate the likelihood of such occurrences (since doing so will imply that we design and plan for Extreme Events). We therefore suggest to reword it to: "If the Extreme Events analysis concludes there are cascading outages, an evaluation of possible actions to contain and minimize the impacts of cascading outages.

Response: The SDT examined the use of these terms and still believes that these are the best terms to use here.

The SDT has changed the language of Requirement R2.4.3 to examine one or more sensitivities and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed.

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.5: This section of the Standard language has been removed.

R3.4: The SDT has modified this requirement (now Requirement R3.5 and also Requirement R5.5.4 – now Requirement R4.5) to include mitigating the "adverse impacts of the event(s)."

R3.5 Those Extreme Events in Table 1 ~~– Steady State Performance~~ that are expected to produce more severe System impacts shall be identified~~,~~ and a list of those events to be evaluated for System performance in Requirement R3.2 created~~,~~. ~~and~~ ~~t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results. If the ~~Extreme Events~~ analysis concludes there are cascading outages caused by the occurrence of Extreme Events, an evaluation of ~~implementing a change~~ possible actions designed to reduce ~~or mitigate~~ the likelihood or mitigate ~~of such~~the consequences and adverse impacts of the event(s) shall be conducted.

R4.5 ~~At a minimum, t~~Those Extreme Events in Table ~~2~~1 ~~– Stability Performance~~ that ~~would~~are expected to produce more severe System impacts shall be identified and a list of those events to be~~,~~ evaluated for System performance in Requirement R4.2 created~~,~~. ~~and~~ ~~t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results. If the ~~Extreme Events~~ analysis concludes there are cascading outages caused by the occurrence of Extreme Events, an evaluation of ~~implementing a change~~ possible actions designed to reduce ~~or mitigate~~ the likelihood or mitigate ~~of such~~the consequences of the event(s) shall be conducted

Organization	Question 2:	Question 2 Comments:
North Carolina Electric Membership Corp	No	We assume that 2.4 is supposed to be for "System" Stability. Please confirm.R2.4.1 - Is this for On-Peak? Please confirm. Also the subrequirement that requires a model that "appropriately represents the dynamic behavior of loads" is too ambiguous. The requirement does not reference how that judgment is made nor who would makes the judgment. The sub bullets are vague and provide no basis for performance. It should be clarified. How does the TP/PC model 3rd party loads from LSEs or DPs within its area that it interconnects? Is there an additional requirement to LSE/DPs needed in R9-R14 to collect such characteristics of load data? There is concern with load modeling requirements (use of word “appropriately” in R2.4.1). Does this requirement mandate the use of specific load models for each bus, or would an aggregate load model which represents the system as a whole be sufficient? Does the use of the PSS/E CONL function satisfy the requirements for a load model? The subrequirements of R2.4.3 are much too vague and are subject to various interpretations. These should be more specific as to what should be assessed, e.g. 5% variation in load model. Why aren't the last 2 subrequirements already accounted for within the assessment? R2.5 is ambiguous. What is meant by "affects stability margins"? What is the technical performance margin for "affect"? As defined by whom? The TP/PC? the auditor? Is this a % change or what? R5.4 – OK R5.5 - We are OK with changes made, but we do share a concern with others that the requirement to perform simulations on 20 MW generators (to be consistent with the Registration Criteria) per R5.5.1 may be too much, and we recommend also a 75 MW generator cutoff for required simulations.

Response: R2.4: The terms ‘unit’ and ‘System’ have been removed from the language and Stability has replaced them.

R2.4.1: Yes, this is for peak conditions. Requirement R2.4.2 is listed for Off-Peak Load.

R2.4.1: The SDT has changed this language to clarify that aggregate Load can be used here as well. This Requirement is to make you properly represent the dynamic behavior of Loads at high System Load levels.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.3: This list of sensitivities is not overly prescriptive and allows the use of engineering judgment of the Planner. Language has been changed to provide clarity.

Organization	Question 2:	Question 2 Comments:
		~~Variations in~~ Load model assumptions ~~Modification of e~~Expected transfers ~~Unavailability of long lead time Facilities~~ Timing of the installation of new or modified Facilities. ~~Variability and outages of r~~Reactive resource~~s~~ capability. The specific wording for Requirement R2.4.3.4 has been changed to "Reactive resource capability". This could mean a degradation of the capability of a reactive resource. This would not normally be covered in the assessment unless sensitivity studies require it. R.2.4.3.5. Generation additions, retirements, or other dispatch scenarios would not necessarily be studied in the assessment unless there were firm plans to change generation. The purpose of sensitivity studies is to answer "what if" questions which would not otherwise be covered in the assessment. R2.5: This language has been removed from the Standard. R5.5 The requirement for study has been changed to 25MW for a single generator or for an aggregate of generators. This language is now in Requirement R2.5.2. The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater.
E.ON U.S. Transmission Planning	Yes and No	R2.4 The Near-Term Transmission Planning Horizon portion? implies that there are other portions of the [System] Stability analysis. This needs to be reworded to make it clear that there are no other portions. Add the word "System" to make it clear. R5 The data to be included in all models for the Planning Assessment is included in R1. The discussion here is redundant. This should be deleted. R5.4.3.1 Is this the intent? ? Following Single Contingency events, Transmission configuration changes and redispatch of generation can be simulated to return the system to Normal Rating provided that all Facilities shall be operating within their Emergency Rating.
Response: R2.4: The wording used is appropriate; there are no Stability Requirements beyond Near-Term R5: That language has been removed and replaced by language in Requirement R1. **R5** (now R4.) For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in~~		

Organization	Question 2:	Question 2 Comments:
~~Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted~~ R5.4.3.1: This section of the language has been removed but these principles are applicable throughout the Standard.		
ERCOT System Planning	No	ERCOT believes R2.4.3, R2.4.4, R2.5, R5.2, and R5.3 should be deleted and R5.4 and R5.5 should be combined as follows: R2.4.3 should be deleted due to the unacceptable increase of stability runs required to meet the requirement. Considering sensitivities for outages of reactive resources and various dispatches and retirements for at least two different load levels is beyond the capability of most organizations, for both technical and manpower reasons. R2.4.4 is unbounded and not measurable, and should not be included as a requirement. R2.5 and all requirements for Generating Unit Stability analysis should be deleted since there is little or no difference between this and System Stability. R5.2 should be deleted because contingency definition standards should be defined in a modeling standard.R5.3 Voltage ride through capability should be included in the model provided by the generator and should not be necessary as a requirement in the TPL standard. R5.4 and R5.5 could be combined, as there is little or no difference between Generating Unit Stability analysis and System Stability analysis. In this case, R5.5.1 and R5.5.2 would be moved to R5.4 and R5.5.3 would be removed (repeats R.5.4.1).Also, it appears that R5.4.1 is in conflict with R5.4.2 because R5.4.1 says ?identified and evaluated for System Performance? but not have to meet requirements but R5.4.2 says ?meet requirements ? Table 2?. Also, R5.4.2 is repetitious with text of R5.
Response: The SDT has changed the language of R2.4.3 to examine one or more sensitivities and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed. **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: R2.4.4 and R2.5 were deleted from the language of this draft Standard. R5.2 and R5.3 The SDT did not agree to delete this language; language is needed to be in the Standard describing Contingencies and the use of low voltage ride through in studies. (Note that in the revised standard, Requirements R5.2 and R5.3 have become Requirements R4.3 through R4.3.2.) R5.4 & 5.5: The SDT has removed the distinction between System Stability and generator unit Stability.		

Organization	Question 2:	Question 2 Comments:
American Transmission Company	No	We disagree with the proposed R2.4.1 text. This inclusion of this requirement may be premature at this time for several reasons. There is presently no industry consensus on how the dynamic behavior of loads should be properly represented and analyzed. In addition, it would be a large and difficult effort to identify, collect, and maintain the pertinent information. It is presently difficult to obtain and maintain the percentage of residential, commercial, and industrial load at each transmission interconnection point, much less try to get the proper percentage of the various types of induction motor loads. We do not accept the R2.4.3.1 text and want some explanation of the what, when, and how to provide the technical rationale for why each condition was or was not used. In R2.4.3.1, what is meant by ?variations? (e.g. how much variation is enough)? In R2.4.3.2, what is meant by ?modification? (e.g. how much modification is enough) and "expected transfers" (e.g. firm or non-firm transfers)? In R2.4.3.3, what is meant by ?long lead time? (e.g. 1 month, 1 season, 1 year, 2 years, etc.)? In R2.4.4, we believe this requirement should not be added. Why was it included? It seems superfluous, because any entity can study other sensitivities if they want. Why should TP or PC have to study what the other entity wants to study? Who would be the judge in case of disagreement over the technical rationale? In R2.5.2, Why was the addition of a new substation included? We would not expect a new substation to negatively impact the system or generating unit stability. We note the R5.5 and R5.6 should really have been updated to refer to 5.4 and R5.5. In R5.4.3.1, we suggest that the time-limited aspect of Facility Ratings be included in the Glossary Definition and then it would not need to be clarified in various locations (R3.3.2.2, R3.5.1, R5.4.3.1, Table 1-Note 1, & Table 2-Note 1) throughout the standard.

Response: R2.4.1: The SDT has changed the language of Requirement R2.4.1. The SDT has changed this language to clarify that aggregate Load can be used here as well. This Requirement is to make you properly represent the dynamic behavior of Loads at high System Load levels.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.3.1 The SDT has changed the language of R2.4.3 to examine one or more sensitivities and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed.

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why~~

Organization	Question 2:	Question 2 Comments:
~~each of the conditions was or was not selected shall be supplied~~ included in the Assessment: R2.4.3.2, The SDT has changed the language of R2.4.3 to examine one or more sensitivities and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed. R2.4.4 has been removed from the language of this Standard draft. R2.5.2: This language has also been removed from this draft Standard. R5.5 and R5.6: This new version contains renumbering which should address your concerns. R5.4.3.1: This section of the language has been removed but these principles are applicable all throughout the Standard.		
Duke Energy	No	R2.4.1 Load models that appropriately represent the dynamic behavior of induction motors are under development and may not be available for sometime. The implementation plan should take this into account and allow at least 36 months for implementation. This requirement is not immediately achievable. R2.4.3 - Although we agree with the perceived intent of R2.4.3, we believe the wording should be revised to make it very clear that it is not necessary to perform studies to substantiate your technical rationale for choosing not to perform any particular sensitivity study. Documented engineering judgment to support the decision not to perform the particular sensitivity studies should be sufficient. R2.4.3.1 should clearly state whether the load model refers to overall system load or parameters of the dynamic load model at individual busses. Recommend renumbering R2.4.4 to R2.4.3.6, and reword R2.4.3.6 as follows: Any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems.R2.4 should say "System Stability", not just "Stability".
Response: R2.4.1 has been modified to clarify that a detailed dynamic Load model is not required at each bus. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Because of this clarification, the SDT believes that a 24 month implementation period for this requirement is sufficient. This will be covered in the Implementation Plan which will be posted along with the third draft of the standard. **R2.4.1** System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. R2.4.3 The SDT has changed the language of R2.4.3 to reflect this, to examine one or more sensitivity and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed. **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why~~		

Organization	Question 2:	Question 2 Comments:
~~each of the conditions was or was not selected shall be supplied~~ included in the Assessment: R2.4.3.1 The SDT has changed this language to clarify that aggregate load can be used here as well. This Requirement is to make you properly represent the dynamic behavior of loads at high system load levels. R2.4.4 to R2.4.3.6.The SDT has removed the distinction in the Standard between System Stability and generator unit Stability.		
Florida Reliability Coordinating Council, inc	No	R2.4.4 and R2.4.3 as written can create issues during the compliance assessment. These requirements place the burden of justifying the inclusion / exclusion of the sensitivities on the TP or PC. Thus, only a sensitivity deem appropriate by the TP or PC and not performed can be found non-compliant.R2.4.4 can be eliminated by changing the wording in R2.4.3 to include sensitivities? deemed appropriate by the TP or PC as follows:? For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, sensitivity case(s) deemed appropriate by the Transmission Planner or Planning Coordinator that stress the System to reflect, but not limited to, one or more of the following conditions shall be run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied.?
Response: The SDT has changed the language of Requirement R2.4.3 to examine one or more sensitivities and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed. **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	Yes and No	R2.4. No The word “System” was deleted during the re-write and only “Stability” is used. However, the sub-sections appear to be more appropriate to a “System Stability” assessment than for a “Generating Unit Stability” assessment. “Generating Unit Stability” assessments are the subject of Section R2.5 and “System Stability” assessments appear to be the intent of Section R2.4. Why does Requirement 2.4. specify the near-term transmission planning horizon “portion”? We recommend removal of the words “portion of the”. R2.4.1. No Change “Peak System Load” to “System On-Peak Load”. This is the term defined in the “NERC Glossary” and is consistent with the usage of “Off-Peak Load”. This change would be required through out the TPL Standard as well as in other standards. There is concern with load modeling requirements (use of word “appropriately” in R2.4.1). Does this requirement mandate the use of specific load models for each bus, or would an aggregate load model which represents the system as a whole be sufficient? Does the use of the PSS/E CONL function satisfy the requirements for a load model?

Organization	Question 2:	Question 2 Comments:
		R2.4.3 NoIn general we believe that breaking these requirements into specific sub-requirements, focusing on specific sensitivities, is too prescriptive and inappropriate. It will lead to over focus on these particular issues to the detriment of system reliability. The standard should not include an enumerated list of required sensitivities. Engineering judgment needs to be permitted. R2.5 Concur R5.4 Concur R5.5 No There is a concern with R5.5.1 with the requirement to perform simulations on 20 MW generators (to be consistent with the Registration Criteria). We recommend a 75 MW generator cutoff for required simulations.

Response: R2.4: The SDT has removed the distinction between System Stability and generator unit Stability.

R2.4.1 – The SDT does not believe there is any ambiguity in the term "peak System Load" and will continue to use that term.

R2.4.1 The SDT has changed this language to clarify that aggregate Load can be used here as well. This Requirement is to make you properly represent the dynamic behavior of Loads at high System Load levels.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.3 The SDT has changed the language of Requirement R2.4.3 to reflect examining one or more sensitivity and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed.

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R5.5: The SDT agrees that there is little distinction between a single unit of a specific MW and an aggregation of the same number of MW. The requirement for study has been changed to 20 MW for a single generator or for an aggregate of generators. This is now located at Requirement R2.5.2.

The addition/deletion/change of individual generating unit capability of 20 MW or greater.

An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater.

Oncor Electric Delivery	No	For Requirement R2.4 would prefer to see more clarification on the System Off-Peak stability studies required and their purpose. Define/quantify type of stability issues to be addressed with this type of study. For sub requirement R2.4.3 the level of detail in the load modeling is very subjective and greatly impacts the analysis

Organization	Question 2:	Question 2 Comments:
		and results.

Response: R2.4: Transient Stability is generally worse at lower System Load levels when base load units are still generating near maximum output. All of the Contingencies in the table are to be considered for Off-Peak Load levels

R2.4.3 The SDT has changed this language to clarify that aggregate Load can be used here as well. This Requirement is to make you properly represent the dynamic behavior of Loads at high System Load levels. The SDT has changed the language of Requirement R2.4.3 to examine one or more sensitivity and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed.

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment

FirstEnergy Corp.	No	R2.4.1 ? This requirement should be separated into two requirements as it covers two distinct topics; a) peak load study for one of the near-term years and b) dynamic load modeling. The use of the words "appropriately represents" and "consideration" is too vague and not strong enough for requirement language. Also, the requirement needs to better describe what is needed related to the modeling of induction motor load. What % of the load needs to be represented as motor load for various load classes ? commercial, industrial, residential? An industry white paper is needed to provide direction related to this undertaking. The SDT, when considering their Implementation Plan, will need to allow sufficient time to complete the dynamic load modeling which largely does not exist today. R2.4.3 ? Typo, need to remove strikethrough text on the word sensitivity. R2.4.4 ? Suggest making this a sub-requirement of R2.4.3 and only require documentation as to why each sensitivity case was selected. Documenting why something was not selected does not seem constructive and places an unneeded burden on documentation. It should be expected that over time, a range of sensitivities would be covered as a library of studies is built.

Response: R2.4.1: The SDT has changed this language to clarify that aggregate Load can be used here as well. This Requirement is to make you properly represent the dynamic behavior of Loads at high System Load levels.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable

R2.4.3 The SDT did not find the typo indicated.

R2.4.4 The language of R2.4.4 was deleted from the Standard language.

Organization	Question 2:	Question 2 Comments:
Entergy Services, Inc.	No	General Comments: The enhanced requirements in this standard will result in an exponential increase in the amount of studies required to become compliant. Some of the changes such as the list of specific sensitivity studies will make it difficult to audit. Standards need to be measurable. As currently written, these requirements are difficult to measure. Furthermore, as indicated in the later questions, there could be significant costs to comply with these revised requirements Specific Comments: In 2.4.1, it would be better to address the "consideration of the behavior of induction motor Loads" in the sensitivity studies bullet, 2.4.3.1.,if this bullet is to be included at all. Furthermore, induction motor modeling is primarily required in areas with high load concentration that could be subject to angular and voltage stability issues. Considerable effort is required to collect information on motors. Therefore, studies to evaluate induction motor effects should be included in the sensitivity analysis section. In 2.4.3, what was the rationale for including only a portion of the sub-bullets included in 2.1.3? Also, in 2.1.3.7, does "Modification of planned Transmission outages" imply changes in dates? It seems unlikely that the cancellation of an outage would have negative impacts. More clarification is needed on what "modification" means in this requirement. R 2.4.3Each transmission provider has its own transmission planning needs and requirements. While it is true there are common elements and considerations that have to be incorporated in every transmission provider's planning process, it is difficult, if not impossible, to prescribe a list of sensitivities that is, or should be, applicable to everyone. Entergy has specific concerns regarding the following sensitivities. R.2.4.3.2 Modification of expected transfers: The use of "expected" transfer levels suggests that one can expect certain transfer patterns beyond what is modeled in base cases as firm. These sensitivities could result in an endless string of "what-if" scenarios where transmission users would attempt to influence these studies to advantage their respective market positions. Any system improvements based on such "expected" use of the system shall not result in discriminatory treatment of transmission users. R.2.4.3.5. Generation additions, retirements, or other dispatch scenarios. Generation additions are addressed by FERC-mandated study criteria. These requests are handled through the generation interconnection and system impact study processes. Generation retirements and other dispatch scenarios can have both positive and negative impacts on reliability. However, assumptions used to pick which resources are changed, and in what way, will likely be difficult to justify. R5.5 There is a concern with R5.5.1 with the requirement to perform simulations on 20 MW generators (to be consistent with the Registration Criteria). We recommend a 75 MW generator cutoff for required simulations.
Response: R2.4.1 The SDT has changed this language to clarify that aggregate Load can be used here as well. This Requirement is to make you properly represent the dynamic behavior of Loads at high System Load levels. **R2.4.1** System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic		

Organization	Question 2:	Question 2 Comments:
behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable R2.4.3The SDT has changed the language of Requirement R2.4.3 to examine one or more sensitivity and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed. **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: ~~Variations in~~ Load model assumptions ~~Modification of e~~Expected transfers ~~Unavailability of long lead time Facilities~~ Timing of the installation of new or modified Facilities. ~~Variability and outages of r~~Reactive resource~~s~~ capability. R2.4.3.5: These are changes to consider as possible sensitivities to give the TP a better understanding of its System. There is no justification of your assumptions required by the Standard. R5.5 The requirement for study has been changed to 20 MW for a single generator or for an aggregate of generators. This is now located at Requirement R2.5.2. The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater		
BPA Transmission Reliability Program	No	R2.4.1 references the use of a load model which appropriately represents the dynamic behavior of loads. However, such load models have not been developed yet. We recommend removing that requirement for load models until these models have been developed and approved. R2.5 and R5.5 refer to Generating Unit Stability studies. As stated above under Item 1, Generating Unit Stability is adequately addressed by the System Stability studies and does not need to be evaluated separately. Footnote 5.a.i in the notes following the Performance Requirements Tables, already specifies the requirements to meet. Therefore, we recommend removing the section on Generating Unit Stability Studies from standard TPL-001-1. The focus of this standard should be on "System Stability" which encompasses all generating units .Some of the requirements listed under R5.4 apply more generally than just within this section and are already covered elsewhere in the standards. R5.4.3.1 is already covered in Note 1 of Table 1. R5.4.3.2 is not relevant to Reliability Standards and would already be addressed by the relevant regulations, so it does not belong in this Standard. R5.4.3.3 is already covered in Note 1 of

Organization	Question 2:	Question 2 Comments:
		Table 2. Because these requirements are already covered by other sections of the Standard, they can be removed from R5.4.

Response: R2.4.1 The SDT has changed this language to clarify that aggregate Load can be used here as well. This Requirement is to make you properly represent the dynamic behavior of Loads at high System Load levels.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable

R2.5 and R5.5: In response to industry comments, the SDT has to remove the distinction in the standard between System Stability and generating unit Stability.

R5.4.3.1: The SDT has decided to remove Requirement R5.4.3 because the sub-requirements are already implicitly covered by the standard. Your suggested sub-requirement is also already implicitly covered by the standard.

PPL EnergyPlus	Yes and No	R2.4.3 and 2.4.4 together with R2.7 are a very good effort to direct TSPs to not let scenarios drive their plans. Rather, the base case should drive the plan. If anything, the language in the standard could be strengthened.

Response: R2.4.4 has been removed from the language.

R2.4.3: The SDT has changed the language of Requirement R2.4.3 to one or more sensitivity and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed.

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

~~Variations in~~ Load model assumptions

~~Modification of e~~Expected transfers

~~Unavailability of long lead time Facilities~~ Timing of the installation of new or modified Facilities.

~~Variability and outages of r~~Reactive resource~~s~~ capability.

TVA System Planning	Yes	
Tenaska, Inc.	Yes	

Organization	Question 2:	Question 2 Comments:
US Army Corp of Engineers, Northwestern Division	Yes	
Arkansas Electric Coop. Corp.	Yes	
LCRA TSC	Yes	
Response: Thank you for your response.		

3. **The SDT has modified the definitions of Consequential and Non-Consequential Load Loss in response to industry comments. Do you concur with the modified definitions of Consequential and Non-Consequential Load Loss? If not, please state why and/or suggest specific changes.**

Summary Consideration:

In response to numerous concerns the following changes were made to the draft standard:

- The definitions of Consequential Load Loss and Non-Consequential Load Loss were modified to be more direct.
- New definitions were added for Load Reduction and Supplemental Load Loss to address issues that were previously included in the Consequential Load Loss definition.
- Changes were made in the notes for Table 1 (item b) to address application of the revised definitions.
- Note 'b' in Table 1 has been revised to associate comments on Load loss to Steady State rather than Stability.
- Footnotes 5 & 10 were added to the Table to differentiate between Firm Transfer Service and Load Loss.
- The SDT didn't feel non-interruptible Load needed to be defined because Interruptible Load is a defined term.
- The requirement (old Requirement R3.3.2.1 – new Requirement R2.9) to specify the amount and duration of Load that may be lost was clarified to be the maximum for any Contingency and the requirement for duration was eliminated.

There is lingering concern in the industry with the following issues:

- The inability to shed firm Load for a first Contingency event
  - The SDT considered this issue, but did not change the standard because it was specifically prohibited in FERC Order 693, Section 1773.
- The different treatment for Facilities greater than 300 kV versus Facilities less than 300 kV
  - The SDT considered this issue, but did not change its perspective since the last posting. The following is the response provided in response to the first posting and the SDT has not been convinced that it should change:

    "The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission Systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT believed the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated above 300 kV generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers where the energy is then delivered by other Transmission or sub-Transmission Systems to end-

use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability.

When EHV Systems are compromised, the large volumes of power they serve can place a severe amount of stress on parallel EHV or lower voltage paths. For example, if a large EHV transformer experiences a catastrophic failure, not only are other systems Facilities required to carry more Load but the System is also exposed to other N-1 conditions for long periods of time while awaiting a replacement or repair of the failed equipment. Large generation sources are typically connected at EHV levels and maintenance of the EHV Transmission lines within the vicinity of large generation plants must often be coordinated during scheduled unit outages, resulting again in multiple Facility outages over extended periods of time.

Therefore, it was the conclusion of the SDT in Draft 1 to propose greater reliability and operational flexibility through more stringent performance requirements when considering certain N-1 and N-1-1 Contingency events of EHV Systems. Throughout the industry, substation arrangements at EHV levels reflect the importance of these systems as the designs often consist of the more flexible and reliable ring-bus, breaker-and–a-half, or double bus-double breaker protection schemes as compared to the simpler, lower cost, single bus arrangements that are commonly found on lower voltage systems.

The feedback received from the industry was divided related to the SDT's emphasis placed on a higher expectation for the 300 kV and higher systems. Some commenters questioned the importance and the high costs that may be needed to mitigate existing system designs. Others agreed with the SDT's approach and indicated that the impact to their systems would be minimal. Some commenters even questioned why the more stringent approach was not applied to the entire 100 kV and higher systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission System."

There was no change with regards to the definition of Year One. The drafting team felt that if the studies referenced in the comments are duplicative, then the language in the Standard would allow them to use one study for both applications.

The definition for Planning Coordinator was deleted because the term has already been defined and added to the NERC Glossary by another SDT.

With regards to comments on the definitions creating a disincentive to build network Facilities, the Standards do not specify how an entity will comply.

The following changes have been made to the definitions due to industry comment:

Consequential Load Loss: ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions.

Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event.

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~.

Supplemental Load Loss: Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.

The following requirement was added due to industry comments:

R2.9 The Planning Assessment shall identify the maximum permissible Non-Consequential Load Loss (megawatt Demand) for those Planning Events where Non-Consequential Load Loss is allowed in Table 1.

The following notes in the Table have been changed due to industry comment: ‘b’, ‘e’, and ‘i’.

Organization	Question 3:	Question 3 Comments:
Dominion - Electric Transmission Planning	No	Non-Consequential Load Loss: In the example provided with the definition of Non-Consequential Load Loss, it indicates that non-interruptible load loss that occurs through manual or automatic operations such as under voltage load shedding (UVLS), under-frequency load shedding (UFLS) or Special Protection Systems (SPS) would be considered Non-Consequential Load Loss. We recommend that the following statement be added to the standard in the definition -- "Interruptible loads such as the pump of a Pumped Storage Plant interrupted by an SPS should not be considered as a Non-Consequential load".
Response: The definition of the Non-Consequential Load Loss is qualified as ‘Non-Interruptible Load”. In your example, the Pumped Hydro load is defined as ‘interruptible’. There is nothing in the standard that associates Interruptible Load with Non-Consequential Load and nothing that prohibits the interruption of Interruptible Load. However, the SDT did change the definition to provide additional clarity. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~.		
NPCC	No	In the Consequential Load Loss definition, the word 'source' needs to be defined or explained further since it is unclear.
Hydro-Québec TransEnergie (HQT)	Yes and No	In the Consequential Load Loss definition, the word 'source' needs to be defined or explained further since it is unclear. It should be indicated that this also applies to " stability performance requirements" (refer to the end of last sentence of the definition).

Organization	Question 3:	Question 3 Comments:
Ameren	Yes and No	The revised definition of Consequential Load Loss needs to be simplified, as follows, "Consequential Load Loss: Load that is no longer served because it has been isolated from its network supply by a planned protection system operation to mitigate fault conditions." Additional clarifications as to when Consequential Load loss is allowed should not be included in the definition, but should instead be included in the Tables 1 and 2.Agree with the revised definition of Non-Consequential Load Loss.
Midwest ISO	No	Under the definition of consequential load, it is not clear who the term "Transmission planning entities" is referring to. Perhaps it should say "entities to which the standard is applicable". The last sentence could be amended to say: "Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS?..
Brazos Electric Power Cooperative, Inc.	No	Non-consequential is fine. For 'Consequential Load Loss' the entire last part of the definition that begins with "Although Load which is lost?" can be deleted or at least deleted to the part that begins with "Transmission planning entities are not allowed?". We think the last part of the sentence is intuitive.
Northeast Utilities	No	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
American Transmission Company	No	For Consequential Load Loss definition, we suggest that the last sentence be deleted because it is application text, rather than definition text. We accept the Non-Consequential Load Loss definition as written.
Florida Reliability Coordinating Council, inc	No	Propose changing the word ?a? to ?any? in the definition of Consequential Load Loss. Consequential Load Loss: Load that is no longer connected to ?ANY? source as a result ? The second sentence in the definition could be interpreted to disallow voltage dependent load models to meet Steady State Performance requirements. Since many planning events result in steady state voltage significantly lower than nominal, system load would be reduced. This definition would be clarified by differentiating load that is lost (no longer connected to a source) and load that is reduced as a result of reduced system voltage. Although Load which is lost (no longer connected to a source) as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load Loss to meet steady state performance requirements.
New York Independent System Operator	No	In the Consequential Load Loss definition, the word 'source' needs to be defined or explained further since it is unclear.

Organization	Question 3:	Question 3 Comments:
Response: The definition of 'Consequential Load Loss' has been revised to make it more direct, which has resulted in the elimination of the reference. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions.		
TVA System Planning	Yes	TVA agrees with the modified definitions. However, the definition for "Consequential Load Loss" can still be confusing. Suggest definition of "Load that is deenergized by relay action as a result of the event being studied ?." Additional wording in "Consequential load loss" about transient conditions can be confusing as well - we suggest including this additional information later in the document. For Non-consequential load loss, suggest use of "Firm" instead of "Non - Interruptible" Load Loss.
Response: The definition of 'Consequential Load Loss' has been revised to make it more direct and has eliminated the reference to 'transient'. There are potential associations with the term 'Firm' that the SDT is trying to avoid in this definition and therefore has decided to stay with the reference to Non-interruptible. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions.		
Progress Energy Carolinas	Yes	The definition of Consequential load loss has been appropriately modified to include loss of Load as a result of the Load's response to the transient condition. This recognizes the fact that when subjected to fault voltages of sufficient depth and duration, the resulting Load dynamics will result is loss of Load. Therefore, in order to more accurately replicate real-world behavior through dynamic stability simulation analysis, the proper representation of expected real world loss of load is acceptable. It is also proper that the computation of expected consequential Load loss and duration is not required for stability analysis. Attempts at determining additional Load loss due to load dynamics would not result in any useful information contributing to increased reliability.
Response: New definitions have been created to recognize other forms of acceptable Load loss that might occur in response to an event. The calculation of the potential Load loss for anything other than Consequential Load Loss is not required and the analysis is not expected to include it (see new 'Supplemental Load Loss' definition). However, a calculation of the maximum expected contingent Consequential Load Loss is expected (see Requirement R2.9). Note 'b" in the table has been revised to associate requirements to serve Supplemental Load Loss in Steady State rather than Stability. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response~~		

Organization	Question 3:	Question 3 Comments:
~~to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions. **R2.9** The Planning Assessment shall identify the maximum permissible Non-Consequential Load Loss (megawatt Demand) for those Planning Events where Non-Consequential Load Loss is allowed in Table 1. **Note "b":** Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss ~~is allowed for all events shown.~~are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements.		
BCTC	No	Our understanding of these definitions and the performance requirements in Tables 1 and 2 is that they may eliminate the existing provision in Footnote (b) that allows loss of firm load for contingencies in local networks. Disconnection of loads on local networks in response to contingencies normally requires RAS/SPS, and the definition of NCLL states that this is NCLL. We are not clear whether our concern is with the definitions of CLL/NCLL, the Tables, or the definition of BES. In the Consideration of Comments on First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is CLL, we do not see where FERC has ruled out the use of RAS/SPS for CLL - see BCTC comments on the First Draft at page 28 of the Consideration of Comments. BCTC concurs with SaskPower and Manitoba Hydro that that CLL needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. In addition, BCTC cannot meet the proposed P1 (A) > 300 kV Steady State Performance of no Non-Consequential Load Loss for part of our 500 kV system. One radial segment of the BCTC 500 kV transmission system, a single circuit 450 km 500 kV transmission system, serves load and interconnects generation. For outages of the 500 kV transmission line, a RAS is used to shed load to match the generation in this island. We have no plans for transmission reinforcements (280 miles of 500 kV transmission line) to remove this RAS. Therefore, we will require some further clarification of the proposed P1 (A) >300 kV requirement of no Non-Consequential Load Loss for this requirement to be suitable for all of our system.
Response: FERC Order 693 Section 1773 does not permit loss of Non-Consequential Load (see reference). There is no provision in the FERC Order to allow		

Organization	Question 3:	Question 3 Comments:
loss of Load with the use of an RAS/SPS or to provide exceptions for local networks. The SDT's interpretation of the Order is that FERC is indicating that other alternatives must be pursued to eliminate this operating scheme. However, the SDT has provided an exception (Requirement R2.6.4) if a situation arises that is beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe. "1773. The Commission proposed in the NOPR to approve Reliability Standard TPL-002-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we proposed to direct NERC to submit a modification to TPL-002-0 that: (1) requires that critical system conditions be determined in the same manner as proposed for TPL-001-0; (2) requires the inclusion of the reliability impact of the entity's existing spare equipment strategy; (3) explicitly requires all generators to ride through the same set of Category B and C contingencies as required for wind generators in Order No. 661; (4) requires documentation of load models used in system studies and supporting rationale for their use; (5) clarifies the phrase "permit operating steps necessary to maintain system control" and (6) clarifies footnote (b) to Table 1 to allow no firm load or firm transactions to be interrupted except for consequential load loss."		
Manitoba Hydro	No	The definition of Consequential Load Loss implies the load lost as a result of "response to the transient condition of the event" need not be load directly connected to the element impacted by the event, but load in the local area. This definition could result in an interpretation that would justify unlimited load loss resulting from say voltage depression in an area impacted by a transient system swing. This opens a loop hole for allowing load loss for many single contingencies as a result of a transient swing causing a voltage dip and motor contactor drop-out as an example. There is a fine line between providing adequate voltage support or operating guides to avoid such load loss. Should a maximum level of load loss be specified? Comments on Other Definitions: Extreme Events: The definition should clarify whether or not Transmission system performance requirements must be met. – Events should be changed to Event - same for Planning Events Planning Coordinator: The Planning Coordinator definition should be left to the functional model. Having the term defined here may cause future confusion. For example, the FMWG has discussed the possible elimination of the PC, based on the realization that it is the Transmission Planner who integrates resources into the transmission plans.
Response: The standard is not designed to address regional performance standards, which should govern relative to acceptable voltage depressions or the magnitude of acceptable loss of Load during Planned Events or in response to Extreme Events. This is the responsibility of the Planning Coordinator and the Transmission Owner, which has been included as notes 'e' and 'i' in Table 1. **Header note 'e"** For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. **Header note 'i'**: ~~Dynamic voltages~~Transient voltage response shall be within acceptable limits established by the Planning Coordinator (or Transmission Planner if more restrictive).		

Organization	Question 3:	Question 3 Comments:
The reference has been reviewed and revised as appropriate. When the reference is to all events, such as in the title to Table 1, then 'Events' is correct. When the reference is to a single event, such as in the column header to Table 1, then 'Event' is correct. The definition for Planning Coordinator was deleted because the term has already been defined and added to the NERC Glossary by another SDT.		
Los Angeles Department of Water and Power	No	In general, support the comment from WECC on this question, however, where there are different performance allowed solely based on an arbitrary voltage class separation, it is discriminatory and without any scientific or historical basis.
Response: Many responders have asked the question why the distinction for bus sections above 300 kV. The SDT has prepared the following response. The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission Systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT believed the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated above 300 kV generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers where the energy is then delivered by other Transmission or sub-Transmission Systems to end-use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. When EHV Systems are compromised, the large volumes of power they serve can place a severe amount of stress on parallel EHV or lower voltage paths. For example, if a large EHV transformer experiences a catastrophic failure, not only are other systems Facilities required to carry more Load but the System is also exposed to other N-1 conditions for long periods of time while awaiting a replacement or repair of the failed equipment. Large generation sources are typically connected at EHV levels and maintenance of the EHV Transmission lines within the vicinity of large generation plants must often be coordinated during scheduled unit outages, resulting again in multiple Facility outages over extended periods of time. Therefore, it was the conclusion of the SDT in Draft 1 to propose greater reliability and operational flexibility through more stringent performance requirements when considering certain N-1 and N-1-1 Contingency events of EHV Systems. Throughout the industry, substation arrangements at EHV levels reflect the importance of these systems as the designs often consist of the more flexible and reliable ring-bus, breaker-and–a-half, or double bus-double breaker protection schemes as compared to the simpler, lower cost, single bus arrangements that are commonly found on lower voltage systems. The feedback received from the industry was divided related to the SDT's emphasis placed on a higher expectation for the 300 kV and higher systems. Some commenters questioned the importance and the high costs that may be needed to mitigate existing system designs. Others agreed with the SDT's approach and indicated that the impact to their systems would be minimal. Some commenters even questioned why the more stringent approach was not applied to the entire 100 kV and higher systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission System.		
Transmission Agency of Northern	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the

Organization	Question 3:	Question 3 Comments:
California		interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversely impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Pacific Gas and Electric Co.	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service

Organization	Question 3:	Question 3 Comments:
		reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Public Service Company of New Mexico	Yes and No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49,

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		response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Puget Sound Energy, Inc.	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection used to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer will be degraded without commensurate improvement in overall system reliability. In addition, existing design of many such local networks may use RAS/SPS to disconnect loads on local networks in response to low probability contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to

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		include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Idaho Power Company	No	We generally do not disagree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to

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		eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
SMUD	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable.

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Sierra Pacific Power Company / Nevada Power Company	No	We generally do not disagree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet

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		steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Black Hills Corporation	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Arizona Public	Yes and No	We generally agree with the definition but have concerns about a potential unintended consequence. This definition will

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Service Co.		severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. At a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability.
SRP	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load

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		Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Tucson Electric Power Company	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.

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Modesto Irrigation District		Comments: We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashioner avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require AS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6.While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote bof the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss disallowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Tri-State G&T	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for

Organization	Question 3:	Question 3 Comments:
		loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
ColumbiaGrid	No	We generally do not disagree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in

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		overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Southern California Edison	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the

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		faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
US Bureau of Reclamation	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting Comment Form for 2nd Draft of Standard TPL-001-1Assess Transmission Future Needs (Project 2006-02)Page 5 of 12the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without comments urate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6.While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential

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		Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote bof the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.

Response: With regards to the disincentives of the Consequential Load definition, the Standards do not specify how an entity will comply.

The SDT has made changes to the definitions and has clarified acceptable loss of Load situations. This includes moving the last sentence of the Consequential Load definition to the Table. However, FERC Order 693 Section 1773 does not permit loss of Non-Consequential Load (see reference). There is no provision in the FERC Order to allow loss of Load with the use of an RAS/SPS or to provide exceptions for local networks. Our interpretation of the Order is that FERC is indicating that other alternatives must be pursued to avoid loss of Non-Consequential Load. However, the SDT has provided an exception (Requirement R2.7.4) if a situation arises that is beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe.

Consequential Load Loss: ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions.

Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event.

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~.

Organization	Question 3:	Question 3 Comments:
Supplemental Load Loss: Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions. **Note 'b":** Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss ~~is allowed for all events shown.~~are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements. "1773. The Commission proposed in the NOPR to approve Reliability Standard TPL-002-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we proposed to direct NERC to submit a modification to TPL-002-0 that: (1) requires that critical system conditions be determined in the same manner as proposed for TPL-001-0; (2) requires the inclusion of the reliability impact of the entity's existing spare equipment strategy; (3) explicitly requires all generators to ride through the same set of Category B and C contingencies as required for wind generators in Order No. 661; (4) requires documentation of load models used in system studies and supporting rationale for their use; (5) clarifies the phrase "permit operating steps necessary to maintain system control" and (6) clarifies footnote (b) to Table 1 to allow no firm load or firm transactions to be interrupted except for consequential load loss."		
National Grid	No	a. In the Consequential Load Loss definition, the word 'source' needs to be defined or explained further since it is unclear. b. Non-Consequential references non-interruptible load. Non-Interruptible load should be defined. Suggest: "Demand that the end-use customer has not made available to its Load-Serving Entity via contract or agreement for curtailment." c. The Consequential Load definition should specify "Interruptible and Non-Interruptible Load that is no longer connected to a source?" d. The inclusion of "or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes)" confuses the definition of Consequential Load Loss, because of the imbedded exception for steady state performance. It seems that the intent of this provision is to recognize that this type of load loss could occur for either transient or steady state conditions and that Planning Assessments should not be required to remedy this type of situation. However, this does seem to be at odds with the application and stated acceptability of Consequential Load Loss as noted in Table 1. Note: Table 2 has no reference to the treatment of Consequential Load Loss. It may be helpful to address the transient load loss situation in a separate definition. As proposed in the draft, Firm Transmission Service is treated equal to load. In New England and New York, we focus on stressing transfer limits across and within the systems. By so doing, we preserve the internal transfer capabilities by design rather than modeling specific contractual transfers, which may not stress the internal interfaces. The exception is for the inter-Area ties. For inter-Area ties, the import or export capability is comparable to a generating unit, which we believe is acceptable to interrupt. We therefore feel that it should be acceptable to interrupt Firm Transmission Service over inter-Area ties and that Firm Transmission Service shouldn't be treated equally with load. Suggested changes: Change "Consequential Load Loss" to "Consequential Interruption". Change the definition to "Load, Firm Demand, or Firm Transmission Service that is no longer connected ..."Change "Non-Consequential Load Loss" to "Non-Consequential Interruption". Change the definition to "Non-Interruptible Load, Firm Demand, or loss of Firm Transmission Service other than Consequential Interruption that occurs

Organization	Question 3:	Question 3 Comments:
		through manual (operator initiated), automatic operations (such as under-voltage load shedding, under-frequency load shedding, or Special Protection Systems), or uncontrolled loss of a local area which does not significantly impact the Bulk Electric System."
Central Maine Power Company	No	There are a few significant concerns with these definitions: The definitions should be expanded to include interruption of Firm Transmission Service in a manner that is comparable to interruption of load; otherwise, Firm Transmission Service (FTS) is being treated in a manner that is superior to load. (The expansion of the definitions to include FTS would also address stated concerns associated with loss of radial or single facilities over which Firm Transmission arrangements have been made). There are perceived limitations to what constitutes Non-Consequential Load Loss. It must be clear that Non-Consequential load loss allows the cascading loss of a local area that does not adversely impact the BES. It would be impractical and unnecessary to anticipate that every such situation could be or needs to be managed by operator action or automatic control. Non-Interruptible load should be defined as, "Demand that the end-use customer has not made available to its Load-Serving Entity via contract or agreement for curtailment." The Consequential Load definition should specify "Interruptible and Non-Interruptible Load that is no longer connected to a source?" The inclusion of "or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes)" confuses the definition of Consequential Load Loss, because of the imbedded exception for steady state performance. It seems that the intent of this provision is to recognize that this type of load loss could occur for either transient or steady state conditions and that Planning Assessments should not be required to remedy this type of situation. However, this does seem to be at odds with the application and stated acceptability of Consequential Load Loss as noted in Table 1. Note: Table 2 has no reference to the treatment of Consequential Load Loss. It may be helpful to address the transient load loss situation in a separate definition. Recommended Changes: Change "Consequential Load Loss" and definition to "Consequential Interruption - Load, Firm Demand, or Firm Transmission Service that is no longer connected?" Change "Non-Consequential Load Loss" and definition to "Non-Consequential Interruption - Non-Interruptible Load, Firm Demand, or Firm Transmission Service loss other than Consequential Interruption loss that occurs through manual (operator initiated), automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems, or uncontrolled loss of a local area which does not significantly impact the BES."
NSTAR Electric	No	There are a few significant concerns with these definitions: The definitions need to be expanded to include interruption of Firm Transmission Service in a manner that is comparable to interruption of load; otherwise, Firm Transmission Service (FTS) is being treated in a manner that is superior to load. The expansion of the definitions to include FTS would also address stated concerns associated with loss of radial or single facilities over which Firm Transmission arrangements have been made. There are perceived limitations to what constitutes Non-Consequential Load Loss. It must be clear that Non-Consequential load loss allows for the cascading loss of a local area that does not adversely impact the BES. It would be impractical and unnecessary to anticipate that every such situation could be or needs to be managed by operator action or automatic control. Non-Interruptible load needs to be defined as," Demand that the end-use customer has not made available to its Load-Serving Entity via contract or agreement for curtailment." The Consequential Load definition should

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		specify "Interruptible and Non-Interruptible Load that is no longer connected to a source?" The inclusion of "or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes)" confuses the definition of Consequential Load Loss, because of the imbedded exception for steady state performance. It seems that the intent of this provision is to recognize that this type of load loss could occur for either transient or steady state conditions and that Planning Assessments should not be required to remedy this type of situation. However, this does seem to be at odds with the application and stated acceptability of Consequential Load Loss as noted in Table 1. Note: Table 2 has no reference to the treatment of Consequential Load Loss. It may be helpful to address the transient load loss situation in a separate definition. Recommended Changes: Change "Consequential Load Loss" and definition to "Consequential Interruption - Load, Firm Demand, or Firm Transmission Service that is no longer connected?" Change "Non-Consequential Load Loss" and definition to "Non-Consequential Interruption - Non-Interruptible Load, Firm Demand, or Firm Transmission Service loss other than Consequential Interruption loss that occurs through manual (operator initiated), automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems, or uncontrolled loss of a local area which does not significantly impact the BES."
ISO New England Inc.	No	There are a few significant concerns with these definitions: The definitions need to be expanded to include interruption of Firm Transmission Service in a manner that is comparable to interruption of load; otherwise, Firm Transmission Service (FTS) is being treated in a manner that is superior to load. (The expansion of the definitions to include FTS would also address stated concerns associated with loss of radial or single facilities over which Firm Transmission arrangements have been made). There are perceived limitations to what constitutes Non-Consequential Load Loss. It must be clear that Non-Consequential load loss allows the cascading loss of a local area that does not adversely impact the BES. It would be impractical and unnecessary to anticipate that every such situation could be or needs to be managed by operator action or automatic control. Non-Interruptible load needs to be defined as," Demand that the end-use customer has not made available to its Load-Serving Entity via contract or agreement for curtailment." The Consequential Load definition should specify "Interruptible and Non-Interruptible Load that is no longer connected to a source?" The inclusion of "or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes)" confuses the definition of Consequential Load Loss, because of the imbedded exception for steady state performance. It seems that the intent of this provision is to recognize that this type of load loss could occur for either transient or steady state conditions and that Planning Assessments should not be required to remedy this type of situation. However, this does seem to be at odds with the application and stated acceptability of Consequential Load Loss as noted in Table 1. Note: Table 2 has no reference to the treatment of Consequential Load Loss. It may be helpful to address the transient load loss situation in a separate definition. Recommended Changes: Change "Consequential Load Loss" and definition to "Consequential Interruption - Load, Firm Demand, or Firm Transmission Service that is no longer connected?" Change "Non-Consequential Load Loss" and definition- "Non-Consequential Interruption - Non-Interruptible Load, Firm Demand, or Firm Transmission Service loss other than Consequential Interruption loss that occurs through manual (operator initiated), automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems, or uncontrolled loss of a local area which does not significantly impact the BES."

Organization	Question 3:	Question 3 Comments:
Orlando Utilities Commission	No	The definition refers to "A source" which implies that an area served by several sources that loses access to one source could lose some load since it lost "a source" or "its source". This is a different meaning then the one expressed on the national conference call. As written this definition also implies that the triggering of a UVLS, UFLS or load shedding SPS is not acceptable under the conditions for which non-consequential load loss is not allowed. If the Drafting team's intent is to forbid the use of these devices for certain levels of contingencies then it should be done directly in the standard not hidden in a definition. (While an SPS may or may not include load loss, UVLS and UFLS are effective because of the load loss.)
Response: Definitions have been changed to clarify the definition of Consequential Load Loss. The reference to 'source' has been eliminated. The SDT does not believe that a definition for Non-Interruptible load is necessary because Interruptible Load is defined. Notes have been added to provide conditions and clarifications relative to the interruptions of Firm Transmission Service. The definition of Non-Consequential Load Loss has also been changed to remove the reference to UFLS and UVLS, which are systems used for operations and are not applicable to a planning standard. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions. **Note 'b":** Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss ~~is allowed for all events shown.~~are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements.		
OPUC	Yes and No	The concept of Consequential Load Loss is generally acceptable. However, the presentation, notes and cross referencing need to be adjusted to avoid confusion.
Response: The SDT has reviewed references for consistency as part of the changes made in response to the comments received in this posting.		
JEA	Yes	Recommend changing "Non-Interruptible Load" to "non-Interruptible Load" (first occurrence of use in the new definition.

Organization	Question 3:	Question 3 Comments:
Response: The first use is at the beginning of a sentence and the SDT feels that the term is correctly capitalized.		
PacifiCorp	Yes and No	? We generally agree with the definition but have concerns about a potential unintended consequence. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. At a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability.
Response: With regards to the disincentives of the Consequential Load definition, the Standards do not specify how an entity will comply. However, if Systems are upgraded such that Load is not interrupted for first Contingency events, then there will be improvements to the overall reliability of the System.		
Progress Energy Florida, Inc.	No	The Definitions of ?Consequential Load Loss? and ?Non-Consequential Load Loss?, bring to mind the following concerns: Both Definitions are confusing and unclear as to their intent and meaning, and as presently worded it is PEFs belief that these particular Definitions can be interpreted in ways not intended by the SDT. For example, the definition of Consequential Load Loss contains the phrase "Load that is no longer connected to a source"; presumably this means "Load that is no longer connected to any source", but is not stated as such. PEF would note, however, its disagreement with the definition even with the wording change, given how the definition would be applied. UVLS, UFLS and SPS schemes are excluded from Consequential Load Loss, and thus are not allowed as mitigations for several outage scenarios. The SDT is essentially discouraging Transmission Owners from constructing such schemes, which is counterproductive to reliability, and actually reduces reasonable options left for Transmission Owners to the point that possible outcomes might be a) radializing of systems or b) removing breakers in order to convert load previously deemed Non-Consequential Load into Consequential Load. PEF maintains that where particular outage scenarios dictate the need for UVLS, UFLS and SPS schemes, the right to implement them should be allowed regardless of the category of event, so long as implementation in lieu of a more expensive project will not compromise the reliability of the BES. Whether or not UVLS, UFLS and SPS schemes continue to be categorized as Non-Consequential Load Loss, however, PEF disagrees with the definition given how it would be applied.
Response: With regards to the disincentives of the Consequential Load definition, the Standards do not specify how an entity will comply. The SDT has made changes to the definitions and has clarified acceptable loss of Load situations. This includes moving the last sentence of the Consequential Load definition to the Table. However, FERC Order 693 Section 1773 does not permit loss of Non-Consequential Load (see reference). There is no provision in the FERC Order to allow loss of Load with the use of an RAS/SPS or to provide exceptions for local networks. Our interpretation of the Order is that FERC is indicating that other alternatives must be pursued to avoid loss of Non-Consequential Load. However, the SDT has provided an exception (Requirement R2.6.4) if		

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a situation arises that is beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe. "1773. The Commission proposed in the NOPR to approve Reliability Standard TPL-002-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we proposed to direct NERC to submit a modification to TPL-002-0 that: (1) requires that critical system conditions be determined in the same manner as proposed for TPL-001-0; (2) requires the inclusion of the reliability impact of the entity's existing spare equipment strategy; (3) explicitly requires all generators to ride through the same set of Category B and C contingencies as required for wind generators in Order No. 661; (4) requires documentation of load models used in system studies and supporting rationale for their use; (5) clarifies the phrase "permit operating steps necessary to maintain system control" and (6) clarifies footnote (b) to Table 1 to allow no firm load or firm transactions to be interrupted except for consequential load loss." The definition of Non-Consequential Load Loss has been changed to remove the reference to UFLS and UVLS, which are systems used for operations and are not applicable to a planning standard. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~		
Lafayette Utilities System	No	Non-consequential load loss is described as including non-interruptible load lost that results from manual or automatic operations "such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems ?." It should be clarified that the quoted items are not intended to be exhaustive of the non-manual Load loss situations that would be considered the loss of Non-consequential Load. For instance, some types of industrial applications that are power-quality dependent may be expected to disconnect or shut down in the event of fluctuations in frequency, voltage or current. Foreseeable load interruptions of this nature should be treated as "Non-consequential Load loss" even if the mechanism by which the load disconnects is other than a UFLS, UVLS or SPS system operated by the Distribution Provider.
Response: The definition of 'Consequential Load Loss' has been revised to make it more direct. New definitions have also been created to recognize other forms of acceptable Load loss that might occur in response to an event. The definition of Non-Consequential Load Loss has also been changed to remove the reference to UFLS and UVLS, which are systems used for operations and are not applicable to a planning standard. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event.		

Organization	Question 3:	Question 3 Comments:
Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.		
Exelon Transmission Planning	No	UVLS should be allowed for in the definition of non-consequential load shedding in certain lower probability contingencies above 300 kV. The complete disallowance seems to disincentive their use, contrary to the NERC Blackout Recommendation 13c. There is a value in their use for certain voltage stability situations. There does not appear to be any limit (except no cascading) to the amount of acceptable load loss once non-consequential load loss is allowed.
Response: Recommendation 13c appears to be focused on reviewing practices. It does not appear to make a recommendation relative to any of those practices. "Recommendation 13c: The Planning Committee, working in conjunction with the regional reliability councils, shall within two years reevaluate the criteria, methods, and practices used for system design, planning, and analysis; and shall report the results and recommendations to the NERC board. This review shall include an evaluation of transmission facility ratings methods and practices, and the sharing of consistent ratings information. Regional reliability councils may consider assembling a regional database that includes the ratings of all Bulk Electric System (100-kV and higher voltage) transmission lines, transformers, phase angle regulators, and phase shifters. This database should be shared with neighboring regions as needed for system planning and analysis. NERC and the regional reliability councils should review the scope, frequency, and coordination of interregional studies, to include the possible need for simultaneous transfer studies. Study criteria will be reviewed, particularly the maximum credible contingency criteria used for system analysis. Each control area will be required to identify, for both the planning and operating time horizons, the planned emergency import capabilities for each major load area." As a result, it is unclear whether the proposed Standard is actually contrary to the recommendation as you suggest. The definition of Non-Consequential Load Loss has also been changed to remove the reference to UFLS and UVLS, which are systems used for operations and are not applicable to a planning standard. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~.		
MidAmerican Energy Company	No	MEC notes that Non-Consequential Load Loss is defined by the SDT to include load dropped by Special Protection Systems while Consequential Load Loss does not exclude load dropped by Special Protection Systems. The SDT should resolve this contradiction between these two definitions by adding an appropriate reference to Special Protection Systems in the Consequential Load Loss.
MRO NERC Standards Review	No	Non-Consequential Load Loss is defined by the SDT to include load dropped by Special Protection Systems while Consequential Load Loss does not exclude load dropped by Special Protection Systems. The SDT should resolve this

Organization	Question 3:	Question 3 Comments:
Subcommittee		contradiction between these two definitions by adding an appropriate reference to Special Protection Systems in the Consequential Load Loss. For Consequential Load Loss definition, The MRO suggests that the last sentence be deleted because it is application text, rather than definition text.
Response: The definition of 'Consequential Load Loss' and 'Non-Consequential Load Loss' have been revised to make them more direct. New definitions have also been created to recognize other forms of acceptable Load loss that might occur in response to an event. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.		
SERC Dynamics Review Subcommittee	Yes	The modified definitions of Consequential load loss has been appropriately modified to include loss of Load as a result of the Load's response to the transient condition. This recognizes the fact that when subjected to fault voltages of sufficient depth and duration, the resulting Load dynamics will result is loss of Load. Therefore, in order to more accurately replicate real-world behavior through dynamic stability simulation analysis, the proper representation of expected real world loss of load is acceptable. It is also proper that the computation of expected consequential Load loss and duration is not required for single contingency stability analysis. If there is a need, Load loss due to the resulting transmission system configuration would be captured by steady state analysis. Attempts at determining additional Load loss due to load dynamics would not result in any useful information contributing to increased reliability.
Response: In response to other industry comments, the SDT has added a new definition which covers the loss of Load due to Load dynamics - Supplemental Load Loss. It is no longer included as part of Consequential Load Loss. In dynamic studies, Supplemental Load Loss is allowed for any planning or extreme event. The tabulation of Load lost due to a Contingency does not include Supplemental Load Loss.		
Arkansas Electric Coop. Corp.	No	These definitions are still confusing. I offer the following example to explain: If you have a networked transmission line serving several loads, a fault occurs on the line, and the load is dropped because of the line breakers at either end of the line operating. As a result the operator would normally sectionalize the line and isolate the faulted section. This results in the networked line now being two radials and the load is restored. From a planning standpoint the resulting steady state is

Organization	Question 3:	Question 3 Comments:
		the resulting two radials and there should not be any consequential load loss. From an operational standpoint steady state would have occurred at the time of the breakers opening and dropping the load. Operationally the load is consequential load loss. This being a planning standard the standard should require that all the load be served and the transmission line meet the (planning)steady state performance requirements. If the SDT agrees that the resulting radials should be capable of serving all the load and meet the planning steady state performance requirements then I can agree with the definition. If not then I disagree. In the planning environment systems should be studied and assessed based on an switchable element to switchable element basis and not just breaker to breaker. on-Consequential Load Loss - 1. Is it the intent of the SDT that Non-Consequential Load Loss be all firm load other than Consequential Load Loss? If not it should be. Is there a definition of "Non-Interruptible Load"? Didn't see it in the Glossary. 2. additional language should be added stating that the examples given are not inclusive. I have a problem with NERC providing examples in definitions because often the examples are interpreted as the definition itself when in reality their purpose is to clarify.

Response: In your example**,** Consequential Load Loss occurs with the initial event. The standard does not address the size of the Consequential Load or whether alternative sources are required to restore Consequential Load Loss.

Non-Consequential Load is intended to be Firm, which is evident by FERC Order 693 which states:

"1773. The Commission proposed in the NOPR to approve Reliability Standard TPL-002-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we proposed to direct NERC to submit a modification to TPL-002-0 that: (1) requires that critical system conditions be determined in the same manner as proposed for TPL-001-0; (2) requires the inclusion of the reliability impact of

the entity's existing spare equipment strategy; (3) explicitly requires all generators to ride through the same set of Category B and C contingencies as required for wind generators in Order No. 661; (4) requires documentation of load models used in system studies and supporting rationale for their use; (5) clarifies the phrase "permit operating steps necessary to maintain system control" and (6) clarifies footnote (b) to Table 1 to allow no firm load or firm transactions to be interrupted except for consequential load loss."

The definition of 'Consequential Load Loss' has been revised to make it more direct. New definitions have also been created to recognize other forms of acceptable Load loss that might occur in response to an event.

Consequential Load Loss: ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions.

Organization	Question 3:	Question 3 Comments:
Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions. The SDT didn't feel non-Interruptible Load needed to be defined because Interruptible Load is a defined term		
Tri-State Generation and Transmission Association, Inc.	Yes	We agree with the definitions in concept - that Consequential Load Loss is load which would be unserved following a specific outage event, without any load shedding relay operations. However, there is some ambiguity in how things are defined for N-1-1 contingencies. For example, a firm contract or firm resource would not be automatically curtailed upon the first outage (N-1), but operators may need to curtail the contract or resource schedule to restore the system to acceptable operating limits, or arm relay schemes that would interrupt certain facilities for the second outage (N-1-1). It seems unreasonable that some such operator actions would not be allowed.
Response: The SDT has revised the definitions and tables to provide greater clarification on what can be curtailed. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions. **Note 'b":** Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss ~~is allowed for all events shown.~~are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements.		
AEP	No	Should clarify that it's load that is no longer connected since the transmission facilities to which it is connected have been outaged as expected by the normal relay response to the event being studied. In other words, the loss of load that is connected to facilities that have cascaded as a result of the event being studied is not consequential load loss (nor is it non-

Organization	Question 3:	Question 3 Comments:
		consequential load loss). See load loss definitions under Attachment D of PJM Manual 14B for additional wording suggestions.
Response: The definition of 'Consequential Load Loss' has been revised to make it more direct, which clarifies that the causal event is a 'fault' that is cleared by 'planned protection system operation'. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions.		
Lakeland Electric	No	Recommend: Consequential: Load that is no longer served because its electrical path to the BES is open as a direct result of system response to the event under study. Load lost due to event induced transients is Consequential load loss; however, the this load must be included in the model during steady-state analysis. Load lost due to UFLS, UVLS, Special Protection Schemes and operator actions are not considered Consequential. Non-Consequential: Load that is no longer served for any reason other than those identified in the definition on Consequential.
Response: The SDT has made changes to the definitions which are conceptually consistent with your suggestion. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.		
Southern Company Transmission	Yes and No	Yes on the definition. The definition of Consequential Load Loss has been appropriately modified to include loss of load as a result of the load's response to the transient condition. This recognizes the fact that when subjected to fault voltages of sufficient depth and duration, the load undervoltage protection will result in loss of Load. Therefore, in order to more accurately replicate real-world behavior through dynamic stability simulation analysis, the proper representation of expected

Organization	Question 3:	Question 3 Comments:
		real world loss of load is acceptable. No on R3.3.2.1 dealing with Consequential Load. The computation of expected consequential load loss and duration does not result in any useful information contributing to increased reliability. Therefore, this requirement R3.3.2.1 should be dropped. If the computation is not deleted, at least the duration part of it should be dropped. In a Planning analysis, the duration is indeterminate.
Response: New definitions have been created to recognize other forms of acceptable Load loss that might occur in response to an event. The calculation of the potential Load loss for anything other than Consequential Load Loss is not required and the analysis is not expected to include it (see new 'Supplemental Load Loss' definition). However, a calculation of the maximum expected contingent Consequential Load Loss is expected (see Requirement R2.9). Requirement R3.3.2.1 has been rewritten as Requirement R2.9 to more specifically identify what is required and 'duration' has been dropped. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions. **R2.9** The Planning Assessment shall identify the maximum permissible Non-Consequential Load Loss (megawatt Demand) for those Planning Events where Non-Consequential Load Loss is allowed in Table 1.		
North Carolina Electric Membership Corp	No	Although the modified definitions are an improvement over the previous version, addressing the following issues in the Consequential Load Loss definition will further improve clarity:1) Redundancy: The second sentence in the definition says "Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed,?". It appears that "?and is permitted when Consequential Load Loss is allowed,?" is redundant and may be omitted/deleted -- isn't this *always* permitted for all events, except P0 (normal)? (See head note 4 in Table 1 -- Steady State Performance). 2) Who are the "planning entities"? Suggest replacing with Functional Model terms Transmission Planner and Planning Coordinator. 3) Verbosity: It appears that the intent of the second sentence in the definition can be conveyed more concisely. Consider

Organization	Question 3:	Question 3 Comments:
		changing to "However, relying upon the expected Load loss during transient conditions of the event to meet steady state performance requirements is not allowed." 4) If the verbiage proposed above is found acceptable, we offer a follow-up suggestion. Because the second sentence in the definition essentially characterizes the exception to the allowed Consequential Load Loss during steady state performance evaluation, we suggest moving it out of the definition and appending it within head note 4 in Table 1 -- Steady State Performance. 5) While the Consequential Load Loss definition employs the acronyms UFLS and UVLS, their expanded descriptions have been used in the Non-Consequential Load Loss definition. Suggest that these terms be used consistently in both definitions. Also, why is Special Protection Systems included as an example of what constitutes Non-Consequential Load Loss but is excluded from the list of exceptions to Consequential Load Loss (whereas UVLS and UFLS appear consistently in both)? Perhaps examples of each are needed: Consequential Load Loss examples might be a) tapped load from an outaged networked line from main station breaker to main station breaker of entire line, b) outaged T/T transformer serving radial load that that taps the networked transmission line, c) load served from a radial feeder from a single source. Non-consequential might include a) manual load dump or generator trip to mitigate cascading or uncontrolled load loss or an overload during adverse conditions, b) SPS addressing above, c) UFLS, d) UVLS.
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	No	Comments: Although the modified definitions are a good improvement over the previous version, addressing the following issues in the Consequential Load Loss definition will further improve clarity:1) Redundancy: The second sentence in the definition says "Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed,?". It appears that "?and is permitted when Consequential Load Loss is allowed,?" is redundant and may be omitted/deleted -- isn't this *always* permitted for all events? (See head note 4 in Table 1 -- Steady State Performance). 2) Who are the "planning entities"? Suggest replacing with Functional Model terms Transmission Planner and Planning Coordinator. 3) Verbosity: It appears that the intent of the second sentence in the definition can be conveyed more concisely. Consider changing to "However, relying upon the expected Load loss during transient conditions of the event to meet steady state performance requirements is not allowed." 4) If the verbiage proposed above is found acceptable, we offer a follow-up suggestion. Because the second sentence in the definition essentially characterizes the exception to the allowed Consequential Load Loss during steady state performance evaluation, we suggest moving it out of the definition and appending it within head note 4 in Table 1 -- Steady State Performance. 5) While the Consequential Load Loss definition employs the acronyms UFLS and UVLS, their expanded descriptions have been used in the Non-Consequential Load Loss definition. Suggest that these terms be used consistently in both

Organization	Question 3:	Question 3 Comments:
		definitions. Also, why is Special Protection Systems included as an example of what constitutes Non-Consequential Load Loss but is excluded from the list of exceptions to Consequential Load Loss (whereas UVLS and UFLS appear consistently in both)?
Response: The SDT has made changes to the definitions and text, which are conceptually consistent with your suggestions. The revised definitions are more direct and eliminate examples. The reference to Planning Entities has been deleted. The definition of Non-Consequential Load Loss has also been changed to remove the reference to UFLS and UVLS, which are systems used for operations and are not applicable to a planning standard. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.		
ERCOT System Planning	No	ERCOT feels the amount and duration of load loss should be considered in the definition.
Response: Requirement R3.3.2.1 has been rewritten as Requirement R2.9 to more specifically identify what is required. As part of that review, the consensus was that duration is too difficult to accurately prescribe and had no value in a Planning Standard and has been dropped. **R2.9** The Planning Assessment shall identify the maximum permissible Non-Consequential Load Loss (megawatt Demand) for those Planning Events where Non-Consequential Load Loss is allowed in Table 1.		
Alberta Electric System Operator	No	We generally agree with the definitions by themselves but have concerns about regarding application, please refer to response in Q15. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of

Organization	Question 3:	Question 3 Comments:
		such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, recommend moving this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Response: Definitions have been changed to clarify Consequential Load Loss and the last sentence in the definition has been moved to the tables. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Note 'b":** Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss ~~is allowed for all events shown.~~are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements.		
FirstEnergy Corp.	No	Regarding the definition of "Consequential Load Loss" we do not agree with the inclusion of Load which is lost as a result of the Load's response to the transient conditions of the event and recommend that the team restrict the definition to account for only load which is directly served by the facilities which were de-energized as a result of the contingency event. To include this within in the definition seems counterproductive to the planning of the transmission system that is required by this reliability standard. Comments on other definitions:1) Planning Coordinator (PC) ? The SDT included a new definition for PC for inclusion in the NERC Glossary of Terms. We agree that this addition better aligns the Glossary with the PC applicable entity which is prevalent in a variety of standards. However, we are curious why the SDT did not indicate a deletion of the Planning Authority (PA) definition and what steps, if any, are being made by NERC to align registry criteria which uses Planning Authority (PA) to the reliability standards use of the PC. 2) Year-One: The definition for Year-One is awkwardly written. We suggest that the definition be adjusted to read "The planning year that begins with the upcoming annual period under study". We believe the attempt to try and delineate between the near-term planning horizon and operational planning horizon is not needed within the TPL standard and that the near-term period should account for the upcoming annual study periods. If not revised, the need for two near-term studies on an annual basis is overly burdensome as many transmission planning organizations perform upcoming annual seasonal assessments for seasonal peak (summer/winter) periods. Requiring an additional two studies near-term does not provide significant benefit. Further reasoning for making the change is the allowance of operating procedures as part of Corrective Action plans. Operating procedures can easily be developed and implemented to mitigate projected performance violations prior to an upcoming seasonal period. 3) BES ? The acronym BES is used throughout the standard but never defined. We suggest this could easily be done in

Organization	Question 3:	Question 3 Comments:
		the purpose statement by simply adding the text "(BES)" after the reference to Bulk Electric System.
Response: Definitions have been changed to clarify Consequential Load Loss. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. The definition for Planning Coordinator was deleted because the term has already been defined and added to the NERC Glossary by another SDT. The standard does not require that studies are duplicated. If an operating study can be used to demonstrate an assessment for planning purposes, then the operating study would be sufficient. Bulk Electric System will be spelled out in the first reference.		
Entergy Services, Inc.	No	To the extent stakeholders agree with the use of UVLS or other special protection systems to mitigate events and avoid costly infrastructure improvements, the load that is reduced due to the operation of these systems should be capable of being classified as consequential load. In some cases, these systems can enhance grid reliability by removing components that have no significant impact on the BES. The definition of Non-consequential Load Loss includes load dropped by UVLS, UFLS, as well as SPS. However, Consequential Load Loss does not name SPS load loss as an exception, while UVLS and UFLS are named specifically. Shouldn't load lost by SPS action also be included in this exception to reduce confusion? There also seems to be another category missing. Non-consequential load loss could also be a result of "regular" protection systems beyond those directly protecting the faulted equipment. The second part of the Consequential Load loss definition is confusing - "Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements." While it Is part of consequential load loss per the definition, planners are not allowed by the standard to plan for it. Therefore, this definition seems to make the Performance Tables incorrect. With this statement we seem to need another term like "Allowable Consequential Load loss."
Response: The SDT has made changes to the definitions and text, which are conceptually consistent with your suggestion. The definition of Non-consequential Load Loss has also been changed to remove the reference to UFLS and UVLS, which are systems used for operations and are not applicable to a planning standard. Examples have been removed from definitions. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response~~		

Organization	Question 3:	Question 3 Comments:
~~to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.		
BPA Transmission Reliability Program	No	The definition of Consequential Load Loss needs to be modified to include all of the concepts that were contained in footnote b of the existing TPL standards.
Response: "All of the concepts that were contained" are subject to interpretation and there are different interpretations of what the concepts are. Therefore it is not clear what you would like to see. The SDT has continued to revise the definitions in response to the comments received subsequent to the second posting. Notes have been added to provide conditions and clarifications relative to the interruptions of Firm Transmission Service. Hopefully these changes will address your concerns. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions. **Note 'b":** Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss ~~is allowed for all events shown.~~are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements.		

Organization	Question 3:	Question 3 Comments:
PPL EnergyPlus	Yes	The SDT conference call was helpful to my understanding of non-consequential. As I understand it, non-consequential load loss allows transmission planners to drop load that chooses to be dropped under certain conditions. This is a useful tool as not all loads demand the same quality of service.
Response: Yes, interruption of Interruptible Load is acceptable.		
City Water, Light & Power - Springfield, Illinois	Yes	
Platte River Power Authority	Yes and No	
Tenaska, Inc.	Yes	
Gainesville Regional Utilities	Yes	
US Army Corp of Engineers, Northwestern Division	Yes	
ITC Holdings: ITC, METC, ITC Midwest	Yes	
Florida Power and Light	Yes	None.
Austin Energy	Yes	
LCRA TSC	Yes	

Organization	Question 3:	Question 3 Comments:
NERC and Regional Coordination	Yes	
IESO	Yes	
E.ON U.S. Transmission Planning	Yes	
Duke Energy	Yes	
Oncor Electric Delivery	Yes	NA
Response: Thank you for your response. However, the majority of commenters requested changes to the definitions which can be seen in the summary response above.		

4. **The SDT has modified Requirement R3.5 and eliminated Requirement R3.6 from the first draft to clarify that manual and automatic generation run-back (redispatch) and tripping is allowed as a Corrective Action Plan as long as the conditions in Requirements R3.5.1, R3.5.2 and R3.5.3 are met. Do you agree that generation run-back and tripping (manual and automatic) should be limited by these conditions? If not, please explain why you disagree with the proposed requirements.**

Summary Consideration:

By a nearly unanimous response the industry agrees with the modification to Requirement R3.5 in the latest draft that allows manual and automatic generation run-back and tripping as a response to a single or multiple Contingency. However, in response to the question, only a small percentage of the commenters supported the current modification including the conditions in Requirements R3.5.1, R3.5.2, and R3.5.3 without reservation. A wide variety of changes, additions and clarifications to these conditions were suggested.

The SDT agrees with the industry's majority view that the Sub-requirement conditions for manual and automatic generation run-back or tripping as a response to a single or multiple Contingency and the Sub-requirement conditions for automatic generation tripping as a response to mitigate Stability violations are applicable to all requirements of the TPL Standard and are already stated elsewhere in the Standard or should be eliminated because they are specified in other ways, including national codes such as OSHA and NESC. Consequently, these conditions, specified in Requirements R3.5.1, R3.5.2, and R3.5.3 have been removed from this third draft.

In summary, due to industry comments in response to this question, the SDT changed the following requirements and footnote:

R2.7.1. (now R2.6.1)– added bullet #3: Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.

R2.7.1. (now R2.6.1)– added bullet #4: Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations.

R2.9 The Planning Assessment shall identify the maximum permissible Non-Consequential Load Loss (megawatt Demand) for those Planning Events where Non-Consequential Load Loss is allowed in Table 1.

R3.2 (now R3.3 and R3.3.1) Contingency analyses shall simulate the removal of all elements ~~including those~~ that the Protection System ~~protection is~~ and other automatic controls are expected to disconnect for each contingency without operator intervention.

R3.2.1 (now R3.3.2) For all generators, studies shall consider the minimum steady state voltage limitations ~~of all generators~~ and identify how the generators are ~~treated~~ analyzed in the steady state simulation.

Footnote #10 – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load.

Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.

In addition, the following requirements have been deleted:

R3.5 ~~Manual and automatic generation run-back/tripping is allowed as a response to a single or multiple Contingency if the following conditions are met~~

R3.5.1 ~~All Facilities shall be operating within their Facility Ratings~~

R3.5.2 ~~Such action would not violate safety, equipment, regulatory or statutory requirements~~

R3.5.3 ~~A sustainable, stable, operating condition is maintained~~

R5.4.3 ~~Automatic generation tripping is allowed to mitigate Stability violations if the following conditions are met:~~

R5.4.3.1 ~~All Facilities shall be operating within their Facility Ratings~~

R5.4.3.2 ~~Such action would not violate safety, equipment, regulatory or statutory requirements~~

R5.4.3.3 ~~A sustainable, stable, operating condition is maintained~~

Organization	Question 4:	Question 4 Comments:
Dominion - Electric Transmission Planning	No	We generally agree with the modification, but feel that further clarification needs to be added as follows -- "Neither generation run-back (redispatch) nor tripping should be allowed to address deficiencies identified in single contingency (N-1) studies should the full output of the generation choose to be considered as a capacity resource". Should generation run-back be allowed, then a NERC Reliability Standard should be developed to require generator field testing to prove that generation run-back is a viable solution.
Duke Energy	Yes	Generation run-back and tripping should be allowed and the proposed sub-requirements are appropriate.
Progress Energy Carolinas	Yes	Furthermore, PEC believes that generation run-back and tripping should not be allowed as a CAP for N-1 events with the possible exception of small reductions of generation.

Organization	Question 4:	Question 4 Comments:
BCTC	Yes	We agree that runback/tripping should be permitted for all contingencies. However, we are concerned that listing runback/tripping as an acceptable alternative, at least as currently worded, may encourage use when system reinforcements should be built. BCTC would prefer TPL-001 to be silent on this issue and that R3.5 be deleted. The list of conditions is very generic and should apply to all of TPL-001. If R3.5 is retained, the list of conditions should also require that all generation reserves requirements are met.
ITC Holdings: ITC, METC, ITC Midwest	No	We do not believe that generation runback or tripping should be a CAP for a single contingency. This is particularly true if the generation scheme puts the system one contingency away from another potential condition requiring corrective action, such as load shedding. At a minimum R3.5.3 needs further definition as to what a ?sustainable, stable, operating conditions? is. For example, creating another N-1 scenario is not a sustainable condition. Allowing for SPS is not raising the bar.
AEP	No	Generator tripping should not be regarded the same as generator runback. With tripping, a resource is lost from the system and there is no assurance that it can be restored to service within a reasonable time. Runback allows the resource to stay connected and the original MW level is potentially restorable if the precipitating factors for runback can be resolved. The generator may be valuable for MVAR as well as MW. The existing TPL standards imply that generator tripping is not permissible in connection with Category B events in that Table 1 footnote b does not mention it, whereas it is mentioned in connection with Category C events in footnote c; we agree with this. Generation is a system resource and should be protected against the more common single contingency transmission events. We would like to see the present implied restriction on generator tripping following single contingencies to be maintained and clearly articulated in the new standard, with a provision for regional variance. In contrast to tripping, what the standard has now for manual or automatic runback in R3.5 is okay.
Response: By a nearly unanimous response the Industry favors manual and automatic generation run-back and tripping as a response to a single or multiple Contingency. Therefore, the SDT has modified Sub-requirement R3.5 for Contingency events and relocated it to become Sub-requirement R2.6.1- bullet #4. Likewise, the SDT has modified Sub-requirement R5.4.3 for Stability events and relocated it to become Sub-requirement R2.6.1- bullet #3. **R2.6.1. – bullet #3:** Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations. **R2.6.1. – bullet #4:** Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations.		
NPCC	No	We do not feel that R3.5.1, R3.5.2 and R3.5.3 are limiting enough. Add paragraph 3.5.4 "Manual and automatic generator tripping shall not have an Adverse Reliability Impact."
Northeast Utilities	No	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.

Organization	Question 4:	Question 4 Comments:
TVA System Planning	Yes	Suggest applicable voltage limits must also be maintained during runback and tripping.
National Grid	No	We do not feel that R3.5.1, R3.5.2 and R3.5.3 are limiting enough. We suggest adding a paragraph which be numbered 3.5.4 and would read "Manual and automatic generator tripping shall not have a significant adverse impact on the system."
Tenaska, Inc.	Yes	R.3.3.2.2 needs some re-wording to clarify that generator runback (re-dispatch) and tripping are allowed.
Gainesville Regional Utilities	No	R3.5.3 is somewhat ambiguous. We need clarification as to whether the system needs to prepare for the next contingency (a secure state) or whether it needs to be maintained in a stable operating condition which is sustainable but not secure.
Hydro-Québec TransEnergie (HQT)	No	We do not feel that R3.5.1, R3.5.2 and R3.5.3 are limiting enough. Add paragraph 3.5.4 "Manual and automatic generator tripping shall not have an Adverse Reliability Impact."
Central Maine Power Company	No	R3.5.1, R3.5.2 and R3.5.3 are not limiting enough. Add paragraph 3.5.4 "Automatic generator tripping shall not impose undue complexity and risk to the operation and reliability of the system."
NSTAR Electric	No	R3.5.1, R3.5.2 and R3.5.3 are not limiting enough. Add paragraph 3.5.4 "Automatic generator tripping schemes shall not be overly complex and risk to the operation and reliability of the system." Complex SPSs or multiple installations of SPSs can have an adverse impact on the ability to reliably operate the system, especially during maintenance outage conditions.
New York Independent System Operator	No	We do not feel that R3.5.1, R3.5.2 and R3.5.3 are limiting enough. Add paragraph 3.5.4 "Manual and automatic generator tripping shall not have an Adverse Reliability Impact."
ISO New England Inc.	No	We do not feel that R3.5.1, R3.5.2 and R3.5.3 are limiting enough. Add paragraph 3.5.4 "Manual and automatic generator tripping shall not have a significant adverse impact on the system."
Response: The SDT appreciates your suggested improvements. However, the SDT has eliminated these conditions in Sub-requirements R3.5.1, R3.5.2 and R3.5.3 for Contingency events as well as similar conditions in Sub-requirements R5.4.3.1, R5.4.3.2 and R5.4.3.3 for Stability events in the third draft. Accordingly, the SDT has modified Sub-requirement R3.5 for Contingency events and relocated it to become Sub-requirement R2.6.1- bullet #4. Likewise, the SDT has		

Organization	Question 4:	Question 4 Comments:
modified Sub-requirement R5.4.3 for Stability events and relocated it to become Sub-requirement R2.6.1 – bullet #3. **R2.6.1. – bullet# 3:** Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations. **R2.6.1. – bullet #4:** Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations.		
City Water, Light & Power - Springfield, Illinois	Yes and No	There should be a time limit for manual generation runback.
Response: As stated in Footnote 10 of Table 1, planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
Manitoba Hydro	Yes	Manitoba Hydro commends the SDT for recognizing that generator run-back and tripping is a valid option in the transmission planner's tool box, not unlike more expensive devices such as FACTs devices. Can the SDT confirm that the conditions in R3.5.1, R3.5.2 and R3.5.3 apply to post generator tripping period. R3.5.2: The references to safety violations and equipment requirements are very generic. It is difficult to imagine what type of safety violation may be caused by a generator trip considering this is a widely used practice in many regions. The SDT should also be more specific as to what is meant by "equipment requirements". The requirement to be within Facility (equipment) Ratings is already covered in R3.5.1. Manitoba Hydro recommends the to "safety, equipment" be deleted from R3.5.2. Other Requirement R3 Comments:R3: In the first sentence, "perform analysis? should be changed to "perform studies? and the word ?studies? after Horizon should be deleted. R3.2: Delete the words ?including those?. R3.2.1: Can the SDT clarify what is required? Is the requirement to ensure the generator undervoltage ride through is not violated? If so, Manitoba Hydro recommends overvoltage ride-through (maximum voltage) should also be added. Also, is ?For all Generators? and ?of all generators? both needed?

Organization	Question 4:	Question 4 Comments:
		R3.3.1: Appears to be a repeat of R3.1.R3.3.2: R3.3.1 requires performance criteria to be met for Planning Events, which includes both single and multiple contingency events. Doesn't R3.3.2 repeat R3.3.1? R3.3.2.1:The requirement to report duration of the Consequential Load Loss would be a wild guess as the duration will relate to the nature of the event, so Manitoba Hydro questions the value. For example, the event is a simple lightning hit on a line, the restoration time is expected to be short, but if the cause of the line loss is a tornado that takes down structures, it could be days. Can the SDT clarify the requirement. R3.3.2.2: Are ?Transmission reconfiguration changes and redispatch of generators? only allowed for single contingencies? Is redispatch allowed if such redispatch results in curtailment of Firm Transmission Service? R3.3.2: It appears that R3.3.2 can be deleted, and its subrequirements placed under R3.3.3: The contingencies that ?are expected to produce more severe System impacts? are very likely multiple contingencies. Since there are numerous combinations of multiple contingencies, it is an impossible task to explain why the ?remaining Contingencies were not selected. If this is not the intent, can the SDT explain what is required? The requirement should simply allow the planner the discretion to use judgment to select these more severe Contingencies, and the elements they are applied to, with explanation as to why they are expected to be more severe.

Response: The SDT has eliminated these conditions in Sub-Requirements R3.5.1, R3.5.2 and R3.5.3 for Contingency events as well as similar conditions in Sub-Requirements R5.4.3.1, R5.4.3.2 and R5.4.3.3 for Stability events in the third draft. Accordingly, the SDT has modified Sub-Requirement R3.5 for Contingency events and relocated to become Sub-Requirement R2.6.1. Likewise, the SDT has modified Sub-Requirement R5.4.3 for Stability events and relocated to become Sub-Requirement R2.6.1.

R3.5.2 – The SDT has modified Sub-requirement R3.5 for Contingency events and relocated it to become Sub-requirement R2.6.1 – bullet #4. Likewise, the SDT has modified Sub-requirement R5.4.3 for Stability events and relocated it to become Sub-requirement R2.6.1 – bullet #3.

R2.6.1. – bullet #3: Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.

R2.6.1. – bullet #4: Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations.

The SDT appreciates your suggested changes to Requirement R3 but after reviewing the suggestion has decided that the original wording is correct.

Your suggested change to Requirement R3.2 (now Requirement R3.3.1) has been adopted.

R3.3.1 Contingency analyses shall simulate the removal of all elements ~~including those~~ that the Protection System ~~protection is~~ and other automatic controls are expected to disconnect for each contingency without operator intervention.

Requirement R3.2.1 (now Requirement R3.3.2) is intended to require realistic representation in simulations of whether a generator will trip due to low voltage; it is not a requirement that the generator be able to ride through a low voltage condition. Your suggested deletion was accepted.

Organization	Question 4:	Question 4 Comments:
R3.3.2 For all generators, studies shall consider the minimum steady state voltage limitations ~~of all generators~~ and identify how the generators are ~~treated~~ analyzed in the steady state simulation. Regarding your comments on old Requirements R3.3.1 and R3.3.2, there is a subtle difference. Requirement R3.3.1 addresses performance criteria, while Requirement R3.3.2 deals with the Contingencies that need to be evaluated and to which the performance criteria should be applied. The requirement to report duration of Consequential Load Loss in R3.3.2.1 (now Requirement R2.9) has been removed from this draft. **R2.9** The Planning Assessment shall identify the maximum permissible Non-Consequential Load Loss (megawatt Demand) for those Planning Events where Non-Consequential Load Loss is allowed in Table 1. Curtailment of Firm Transmission Service is explained in the new footnote #10 in the Table. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. The SDT has considered your comments regarding the requirement to explain why less severe Contingencies were not selected; however, there were few other comments that raised this concern, and the SDT has retained the original language.		
Los Angeles Department of Water and Power	Yes and No	R3.5.1, 3.5.2, and 3.5.3 are redundant and already covered in other standards or safety codes such as FAC, TOP, OSHA, NRC, NESC, etc. If these kind of "reminder" is required here just to make sure planners do not ignore all the relevant codes, then it could also be argued that an absence of such reminders in other section would mean that these codes do not need to be observed unless they are specifically called out. I think they should all be deleted to avoid such twisted argument but potential loopholes.
Transmission Agency of Northern California	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Pacific Gas and Electric Co.	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability

Organization	Question 4:	Question 4 Comments:
		study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Public Service Company of New Mexico	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
JEA	Yes and No	R3.5.1 JEA does not understand what measure will be applied to determine that Facility Ratings were not violated during the generator run-back period.R3.5.2 JEA does not understand what measure will be applied to determine compliance that generator trips and runbacks will not violate safety, equipment, regulatory, or statutory requirements.R3.5.3 JEA does not understand what is meant by the word "Sustainable". Needs a practical definition.
PacifiCorp	Yes and No	? We generally agree, however, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest moving R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Puget Sound Energy, Inc.	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Idaho Power Company	Yes	We generally agree, however, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.

Organization	Question 4:	Question 4 Comments:
SMUD	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables. Reference 3.5.1: In cases where an SPS is deployed to reduce thermal overloads such that flows are brought within established facility ratings, but, for a short duration (seconds) until it is fully executed, the facility flows exceed the established rating, is that considered a violation or an acceptable engineering judgment that facilities are judiciously being brought to operate within ratings? Or, should the facility owner ensure establishment of a documented rating even for the short duration of seconds?
Progress Energy Florida, Inc.	No	PEF does not disagree with the conditions described in Requirements R3.5.1, R3.5.2 and R3.5.3 when taken in particular contexts. PEF, however, is compelled to check "no" for this question due to the fact that no specification has been made as to when such CAPs can be applied. PEF feels that the CAPs specified (as well as the curtailment of Firm Transactions and Non-Consequential Load) should be allowed following any N-1 event, and also as system adjustment actions in between the two events of a P6 event. Given that no such specification has been made here, PEF objects to the wording, and suggests that the language be modified to clarify that the application of these CAPs are allowable after N-1 events and in between the two events of Event P6.
Sierra Pacific Power Company / Nevada Power Company	Yes	We generally agree, however, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Black Hills Corporation	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Arizona Public Service Co.	Yes and No	We generally agree, however, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other

Organization	Question 4:	Question 4 Comments:
		Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest moving R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Florida Power and Light	No	The sub-requirements of R3.5 are not clear as to whether the conditions apply to before or after generator run-back/tripping and mixes together N-1 and N-2 contingencies. In addition, the phrase "sustainable, stable, operating condition" in R3.5.3. is ambiguous as to whether it means the system is secure (prepared for the next contingency), or the system is maintained in a stable operating condition which is sustainable but not secure.
Exelon Transmission Planning	Yes and No	We agree that manual and automatic generation run-back and tripping should be allowed in these situations. We do not agree with the portion of R3.5.2 that states that non-compliance would result if the action were to violate statutory or regulatory requirements. A local governmental body could impose a restriction that would then trigger NERC compliance issues without independent or sufficient review. Other regulatory entities have their own enforcement mechanisms. It should be clear that SPSs, by definition, are allowed for other purposes than generation runback or tripping (such as system reconfiguration with automated breaker operation).
SRP	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Tucson Electric Power Company	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
SERC Dynamics Review Subcommittee	Yes	Generation run-back and tripping should be allowed and the proposed sub-requirements are appropriate.

Organization	Question 4:	Question 4 Comments:
Modesto Irrigation District	Yes	Comments: We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Midwest ISO	Yes and No	Under the subrequirement of R3.5.2 it may not be possible for the PC/TP to determine whether the safety, equipment, regulatory or statutory requirements are violated without collaboration with the Transmission Owner and/or the Generator Owner. Therefore, if this subrequirement is retained it should be amended to include the following sentence: "Applicable Transmission Owners and/or Generator Owners shall collaborate with the PC/TP in determining whether such action would violate safety, equipment, regulatory or statutory requirements".
Tri-State Generation and Transmission Association, Inc.	Yes	Agree with the described corrective actions, but wonder whether the sub-requirements R3.5.1 - R3.5.3 must be specifically listed.
Tri-State G&T	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Southern Company Transmission	No	Generation run-back and tripping should be allowed and most of the proposed sub-requirements are appropriate. However, R3.5.2 is overly broad. We suggest that regulatory and statutory requirements should be deleted from R3.5.2.
NERC and Regional Coordination	No	Delete R3.5.2 as redundant. The limit data provided by the asset owners is expected to ensure that safety, equipment, regulatory and statutory requirements are met. For example to require the PC to ensure that equipment is not at risk would require the PC to make financial decisions that belong to the asset owner (e.g. the owner may be willing to exchange loss of equipment life for short term financial gains).R3.5.3 - the term sustainable, stable condition is not defined. Further the

Organization	Question 4:	Question 4 Comments:
		maintenance of such a state is beyond a PC's capability.
ColumbiaGrid	Yes	We generally agree, however, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
IESO	Yes and No	We agree with the conditions stipulated in R3.5.2 and R3.5.3 but do not agree with R3.5.1. This is one of the performance objectives that the use of manual and/or automatic generation run-back/tripping is intended to achieve, and it is already stipulated in Table 1. Suggest to remove this condition.
Southern California Edison	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
North Carolina Electric Membership Corp	Yes and No	The generation run-back/trip should not put any load or firm transfer at risk of also being harmed. Maybe this is implied within the conditions required.
ERCOT System Planning	No	The requirement is unclear whether runback is allowed if the conditions are met or if runback is allowed to meet the conditions. What is the need for generation run-back/tripping if all facilities are within their Facility Ratings? Many times the run-back/tripping of units, such as wind farms, is necessary to remove a post-contingency overload associated with these units. The protection scheme includes the run-back/tripping to allow these units to generate at higher levels pre-contingency.
Florida Reliability Coordinating Council, inc	No	R3.5.1 ? This requirement should be clarified to state that all facilities shall operate within their Facility Ratings before, during and after system adjustments including generation adjustments.R3.5.2 ? How can an entity demonstrate that it is not violating this requirement.. The SDT should indicate the type of regulatory and/or statutory requirement that this requirement trying to address (i.e., FERC, EPA, etc.)?. Otherwise, the FRCC recommends removing R3.5.2.R3.5.3 ?The SDT should clarify this requirement to define what is meant by sustainable and stable. Sustainable and stable may not necessarily be the same as

Organization	Question 4:	Question 4 Comments:
		being in a secure condition (ready for the next possible event).
Alberta Electric System Operator	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest R3.5 and R3.4.3 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Orlando Utilities Commission	No	The requirement R3.5.1 is not clear. If the intent is that following a single or multiple contingency facilities are within their ratings before, during and after the generation adjustment it's should be specified that way. "All facilities shall operate within their facility ratings prior to, during, and after the generation adjustment". Also I am unclear on how I would prove that I am not violating and safety or statutory requirements, that seems to be attempting to prove a negative since it is not specific on which requirements. Maybe ?Not violating any known safety and statutory requirements? if it is necessary to have this part. However since any real statutory and safety requirements have their own enforcement mechanism it is unnecessary to have the NERC auditor monitor these in addition to the existing monitors. I am not sure on the definition of sustainable? Is it a system that requires no further adjustment to be within it's long term ratings? Or is it a system that is prepared for the next event (Secure)?
Entergy Services, Inc.	Yes and No	The intent seems reasonable, but the wording needs work. There needs to be consistent verb usage. All 3 sub-bullets need to use "shall" instead of "would" and "is."
US Bureau of Reclamation	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
BPA Transmission Reliability Program	No	R3.5 is not a requirement, but an allowed action in order to meet performance criteria. Therefore, the statement about generation run-back/tripping in R3.5 should be moved to become part of the notes in the Performance Tables and not part of the requirements text. The conditions described under R.3.5.1 through R.3.5.3 are covered elsewhere in the standards and should be removed from this section. Since R3.5 and R5.4 contain some similar wording, also see comments relating to R5.4 under Item 2, above.
Response: The SDT agrees and has eliminated these conditions in Sub-requirements R3.5.1, R3.5.2 and R3.5.3 for Contingency events as well as similar conditions in Sub-requirements R5.4.3.1, R5.4.3.2 and R5.4.3.3 for Stability events in the third draft. Accordingly, the SDT has modified Sub-requirement R3.5 for		

Organization	Question 4:	Question 4 Comments:
Contingency events and relocated it to become Sub-requirement R2.6.1 – bullet #4. Likewise, the SDT has modified Sub-requirement R5.4.3 for Stability events and relocated it to become Sub-requirement R2.6.1 – bullet #3. **R2.6.1. – bullet #3:** Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations. **R2.6.1. – bullet #4:** Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations.		
Lafayette Utilities System	No	Requirement R.3.5 states that generation run-back is allowed as a response to single or multiple contingencies, as long as certain conditions are met. Lafayette's concern is that the allowance for generation run-back is not limited to generation owned by the Transmission Planner or under the Transmission Planner's direct operational control. For that reason, the language could be interpreted to permit reliance (for planning purposes) on redispatch of generation owned by third-party generation owners that is undertaken in compliance with Reliability Coordinator directives during a Transmission Loading Relief event. During the SDT conference call held on August 26, 2008, the SDT representative stated that the team did not intend that R.3.5 would permit a Transmission Planner to rely on third-party generation redispatch, and that the intent was only to permit reliance on run-back (redispatch) of generation owned by or under the direct control of the Transmission Planner. Lafayette believes the language of R.3.5 needs to be clarified to state in express terms the limitation intended by the SDT. Reliance on third-party redispatch should not be permitted unless a Transmission Planner has entered into a contractual arrangement with the generation owner authorizing such use.
Response: The SDT agrees that if a Transmission Planner does intend to rely upon third party generation as an option to meet this requirement then the Transmission Planner's contractual arrangements between that Generation Owner and the Transmission Operator must be in place. However, the SDT does not believe that this needs to be stated as a Requirement in this Standard.		
Ameren	Yes	R3.5.1 should be modified as "All Facilities shall be operating within their applicable Facility Ratings, including the use of short-time emergency ratings."
E.ON U.S. Transmission Planning	Yes and No	R3.5.1 Is this the intent? ? Following Single Contingency events, Transmission configuration changes and redispatch of generation can be simulated to return the system to Normal Rating provided that all Facilities shall be operating within their Emergency Rating.
Response: As stated in Footnote 10 of Table 1, planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within		

Organization	Question 4:	Question 4 Comments:
applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
American Transmission Company	No	We generally accept this text, but would like the Facility Rating reference to include the applicable time frame (see response to Question 2.)
Response: As stated in Footnote 1 of Table 1, planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings.		
PPL EnergyPlus	Yes and No	My concern is that some TSPs over-use RAS and at some point, system improvements must take place. The best approach is a collaborative effort of all stakeholders (esp. operations folks) to prevent abusing RAS. Possibly R3.5 could tie to or be put under an Requirement that involves collaboration with stakeholders.
Response: The SDT has modified Sub-requirement R3.5 for Contingency events and relocated it to become Sub-requirement R2.6.1 – bullet #4. Likewise, the SDT has modified Sub-requirement R5.4.3 for Stability events and relocated it to become Sub-requirement R2.6.1 – bullet #3. Collaboration between the Transmission Planner and the Planning Coordinator is referenced in Requirements R5, R6, and R7. **R2.6.1. – bullet #3:** Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations. **R2.6.1. – bullet #4:** Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations.		
OPUC	Yes	
US Army Corp of Engineers, Northwestern Division	Yes	
CenterPoint Energy and CPS Energy	Yes	

Organization	Question 4:	Question 4 Comments:
MidAmerican Energy Company	Yes	
MRO NERC Standards Review Subcommittee	Yes	
Austin Energy	Yes	
Lakeland Electric	Yes	
Brazos Electric Power Cooperative, Inc.	Yes	
LCRA TSC	Yes	
Oncor Electric Delivery	Yes	NA
FirstEnergy Corp.	Yes	
Platte River Power Authority	Yes	
Response: Thank you for your response.		

5. **The SDT has modified the modeling requirements. Some commenters expressed concern that the modeling requirements contained in Requirement R1 of the first draft of TPL-001-1 were either duplicative of the requirements in the MOD standards, or to the extent new modeling requirements were proposed, that the appropriate venue for such modeling requirements would be the MOD standards. The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has incorporated these additional requirements with the intent that they will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.**

   The SDT has also modified proposed modeling requirements contained in Requirement R1 of the first draft of TPL-001-1 based on industry comments and moved these requirements to Requirements R9 through R14 in the second draft for ease of removal later on. Furthermore, in response to industry comments, the SDT has separated the modeling requirements into individual requirements for each responsible entity. Do you concur with the modifications reflected in Requirements R9 – R14? If not, please state why and/or suggest specific changes..

Summary Consideration:

In response to industry comments, the SDT has removed requirements R9-R14 and enhanced requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments. Any comments received from the industry on MOD standards will be forwarded to NERC staff for inclusion in NERC Reliability Standards Development Projects 2010-04 Modeling Data and 2010-05 Demand Data.

The following requirements have been changed due to industry comments:

R1. Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R1.1 ~~The Planning Assessment shall include documentation of the technical rationale for modification of any data that was provided in Requirement R9 through R14, MOD-010, and MOD-012.~~Models for the Planning Assessment shall represent:

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R1.1.2 New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon, such as:

- Transmission Lines
- Generators
- Circuit breakers
- Reactive Power devices

- Protection System equipment
- Control devices
- New technologies

R1.1.3 Real and reactive Demand of Load

R1.1.4 Firm Transmission Service

R1.1.5 Interchange

R1.1.6 Network resources required to supply Load

R2.1.4 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment.

Organization	Question 5:	Question 5 Comments:
Dominion - Electric Transmission Planning	Yes and No	For requirements R9, R12, R13, the wording should be changed from ..."shall provide its respective Planning Coordinator with modeling information ..." to "shall provide its respective Planning Coordinator and Transmission Planner with modeling information ..."
NPCC	No	With respect to R9 "including the expected mix of industrial, commercial and residential loads", this provision may be inadequate to be practically useful. The potential issues include the variation in end-use load mix through the daily load cycle, seasonal load composition variations, and the ability to translate these end-uses into reasonable and useful steady-state and dynamic load models. It is important to understand how the information will be used and how much additional detail, such as distribution network detail, is also required. It is also important to note that some Canadian Provinces do not "classify" their load mix using "industrial, commercial and residential" designations but their load modeling is sufficient, accurate and granular enough to simulate system response. Add to the last sentence of R9 through R14 the following phrase, "within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator."
TVA System Planning	No	TVA provides the following comments: " Distribution Provider" in R9 should be replaced with "Load Serving Entity." Also in R9, is the expected mix of load to be presented individually or as a total of commercial, residential, and industrial loads? Would requiring this mix of load forecasts also result in a change to any MOD or FAC requirements dealing with

Organization	Question 5:	Question 5 Comments:
		load forecasts?” Transmission Planner" in R10 should be "Transmission Service Provider." Is this requirement also in MODs? In R11, R12, and R13 suggest adding "Transmission Planner" to "Planning Coordinator". In R13, Resource Planner may not have knowledge of Reactive Power devices and new technologies.
Manitoba Hydro	Yes and No	R1: Requirement R1 places the obligation for maintaining a model on the PC/TP. While the PC/TP can maintain data for its system(s), the models generally used for planning assessments are regional models developed and maintained by the Regions. Could the SDT explain its expectation of the scope and responsibilities of the model to be maintained? R9-R14: This TPL draft includes Requirements R9 to R14 that impose obligations on the PC/TP that differ from the way planning models are compiled in accordance with the existing MOD standards. Manitoba Hydro comments on R9 to R14, as follows: R9: Agree. R10: The TSP is the Functional Model entity that should provide the Firm Transmission Service data and Interchange Schedules to the PC. R11: Agree R12: Agree R13: We disagree that the Resource planner is responsible for Reactive Power devices. Can the SDT explain what they consider should be included in new technologies? R14: While we agree that the TP can provide the PC data of planned faculties, isn't this data already required to be provided under the MOD standards?
Transmission Agency of Northern California	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
OPUC	Yes	R9. — 14 can be addressed in the MOD standards.
Pacific Gas and Electric Co.	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective

Organization	Question 5:	Question 5 Comments:
		tariffs, and should not be included again in the proposed TPL-001-1 Standard.
US Army Corsp of Engineers, Northwestern Division	Yes and No	R12 requires the GO to provide "modeling information" for planned outages and/or changes to the generator owner facilities to the Planning Coordinator for each year of the Transmission planning horizon. You need to be more specific with what type of "modeling information" you are requesting from the GO. The GO may have the model parameters for their equipment but this doesn't mean that they have expertise necessary to model system responses or even run a model simulation. So if you are expecting the GO to perform model simulations for each year of the Transmission planning horizon the GO may not have the expertise necessary to comply. Recommend you clarify what you mean by "modeling information".
Public Service Company of New Mexico	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
Puget Sound Energy, Inc.	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
ITC Holdings: ITC, METC, ITC Midwest	Yes and No	In general, we approve and concur with these requirements. The requirement R9 that the distribution providers submit the expected mix of residential, commercial, and industrial loads is necessary to model the dynamic behavior of loads as required in R 2.4.1. This requirement will better model the dynamic response of loads to voltage changes. In R10, the Transmission Planner provides OASIS type information. The TSP should provide this not the TP. R-13 ? Reactive Power Devices and new technologies belongs under every entity, i.e., Distribution Planners should be included as a provider of reactive power devices as well as Resource Planner and Transmission Planner.
Idaho Power Company	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
Hydro-Québec TransEnergie (HQT)	No	With respect to R9 "including the expected mix of industrial, commercial and residential loads", this provision may be inadequate to be practically useful. The potential issues include the variation in end-use load mix through the daily load

Organization	Question 5:	Question 5 Comments:
		cycle, seasonal load composition variations, and the ability to translate these end-uses into reasonable and useful steady-state and dynamic load models. It is important to understand how the information will be used and how much additional detail such as distribution network detail is also required. It is also important to note that some Canadian Provinces do not "classify" their load mix using "industrial commercial and residential" designations but their load modeling is sufficient, accurate and granular enough to simulate system response. Add to the last sentence of R9 through R14 the following phrase, "within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator."
Sierra Pacific Power Company / Nevada Power Company	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
Black Hills Corporation	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
Florida Power and Light	No	The requirement that “all projected firm transfers modeled” (appropriate for the load level being studied) currently in the TPL Standards does not appear in the proposed standard. Does the SDT feel that Transmission Planners should have unlimited latitude in deciding which types of power transfers to assume in their reliability studies? R9. is not an appropriate requirement as the distribution provider will in many cases not know the exact mix of load types at each ?transmission node? The meaning of “transmission node” is unclear, is this substation? R11. is unclear as to what is meant by “consideration given to spare equipment strategy.” What is the appropriate consideration for compliance? What facilities are required to have a spare equipment strategy for compliance? Maintenance outages and times for all BES equipment are not likely to be scheduled or known throughout the entire planning horizon. Rather than specifying "for each year of the planning horizon" it should be limited to "if specifically known”. The Resource Planners identified in R13. should know about future generation additions and retirements as well as expected range DSM capabilities but would not generally know about reactive power devices or new technologies. Reactive power devices or new technologies should be removed from R13.
CenterPoint Energy	No	We believe the SDT should have reflected the views of most commenters in this revised draft. Requirements R9 through R14 are overly prescriptive and do not solve an actual problem. Furthermore, we are concerned about requirement

Organization	Question 5:	Question 5 Comments:
and CPS Energy		"creep" where standards include new requirements appropriately addressed in other standards (in this case, the MOD standards) because a different SDT believes the approved standard is inadequate. To clarify our main premise that the excess, misplaced requirements do not solve an actual problem, we believe one would need an extensive imagination to conjure a scenario where insufficient modeling by transmission planners in the subject matter addressed by requirements R9 through R14 have contributed or are reasonably likely to contribute in any meaningful way to a significant reliability event. In summary, we concur with the majority of commenters from the previous draft that R9 through R14 should be deleted. We also believe R1.1 is hopelessly unrealistic. In fact, we are concerned it is counter-productive and more likely to degrade reliability than improve it. R1.1 discourages transmission planners from revising inaccurate, speculative, or outdated modeling data by imposing new documentation burdens and compliance liability. We recommend that R1.1 be deleted.
SRP	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
Tucson Electric Power Company	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in addition to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
SERC Dynamics Review Subcommittee	No	For R9 the LSE should provide the load forecast instead of the DP. For R9 - R14, It is not clear that the specification of data flow appropriate for both RTO and non-RTO situations because there are significant differences in the role of planning coordinator. For example: 1) Who builds and manages the base cases? Shouldn't the data be submitted to this entity? 2) According to the definition provided in this standard, the Planning Coordinator is ?The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.? Additionally, we recommend the TPL SDT write a SAR to get the data related changes into the MOD standards or adding it the issues to be considered by the drafting team in the development plan under project number 2010-04 otherwise it will be difficult to remember to include these items in the revised MOD standards.
Modesto Irrigation District	Yes	Comments: While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the

Organization	Question 5:	Question 5 Comments:
		respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
Arkansas Electric Coop. Corp.	No	R9. I disagree with providing the mix of industrial, commercial and residential, especially within a 90 day period. It is difficult enough to be able to develop a forecast must less try to quesstimate the mix of the loads.R9 through R14 -- the timing requirement should be tied to the regions model development schedule and not 90 days. The 90 days is too restrictive and not practical however model data should be updated at least annually.
Midwest ISO	No	Since the Transmission Planner has the primary model building responsibility it makes sense to have them aggregate model building information. Therefore, requirement R9 should have the Distribution Provider providing the Transmission Planner and Planning Coordinator with modeling information for real and reactive load forecast? etc. The data of R10 such as firm TS data may not be known by the Transmission Planner (ofter a TO in the RTOs). Also the language implies that there are more than one BA under a TP, also not a typical arrangement in an RTO/ISO. A hierarchical approach might be more appropriate such that the Distribution Provider, the Transmission Provider, and the Transmission Owner supply the data they control to the Transmission Planner and the Planning Authority so that those entities can build models they need to meet the study requirements of the standard.
Tri-State Generation and Transmission Association, Inc.	Yes	We are pleased the SDT pulled out these Requirements. Does the SDT plan to leave them in the standard as notes until they can be incorporated into other standards where they belong? In R11, the term "long-term" is not clear.
Tri-State G&T	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
AEP	Yes	However, although the responsible entities listed for each individual requirement are correct from a functional model (compliance) perspective, in actual practice the data flow may not (and in many instances does not) follow the paths outlined in this draft. For example, the node loads, scheduled interchanges, generation models, facility additions, etc., are all provided to the Transmission Owner (TO), since it's the TO that typically builds the planning models for their transmission footprint and then provides those models to the Transmission Planner and Planning Coordinator. Therefore, the Transmission Owner should be added as a recipient of this type of data.
Austin Energy	No	Requirements R9 through R14 should be deleted and re-introduced later as part of a change to MOD standards. R1.1 imposes burdensome documentation requirements which will likely become a disincentive for revising modeling data and

Organization	Question 5:	Question 5 Comments:
		should be deleted.
Lakeland Electric	No	It is sufficient to direct the TP or PC to obtain and include the appropriate data outlined in R9 through R14 in their respective model cases. The proposed addition of R9-R14 just adds more evidential paperwork requirements to the TP or PCs plate.
Southern Company Transmission	No	R9 needs to be clarified that the forecast is based on expected mix of residential, commercial, and industrial loads, but that this mix does not have to be supplied.
Brazos Electric Power Cooperative, Inc.	Yes	R9-R14 do not belong in this Standard. Adding requirements in the wrong location only adds to the confusion by forcing review of more Standards by other less relevant entities and causing additional burden by insuring the requirements match between Standards for the SDT. R1.1 should be deleted. Tracking all those changes (outages, etc?) is unreasonable and will essentially be unenforceable, for if the data is not tracked, how will anyone know it is not tracked?. Requiring large amounts of documentation that provide no additional benefit or causes undo burden will result in fewer studies or effort placed into proper study.
ColumbiaGrid	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
Southern California Edison	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
Northeast Utilities	No	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
North Carolina Electric Membership Corp	Yes	We would like to add a couple of items for clarification. 1) Planning Coordinators and Transmission Planners should make it clear to LSEs, DPs and GOs as to what extent they model loads, reactive devices, and generators and not just rely on FAC-001, FAC-002 or the entities Facility Connection Requirements document to convey that information. 2) If requirements 9 through 14 are to be removed at a later date, then the SDT should be required to initiate the

Organization	Question 5:	Question 5 Comments:
		appropriate action or SAR before its disbanding to insure this happens.
ERCOT System Planning	No	ERCOT recommends that R1.1 be deleted. ERCOT shares the opinion of some that R1.1 is counter-productive and more likely to degrade reliability than improve it. R1.1 discourages transmission planners from revising inaccurate, speculative, or outdated modeling data by imposing new documentation burdens and compliance liability. Adding additional requirements to document changes to data required in requirements R9 through R14, MOD-010, and MOD-012 could induce an atmosphere of using inaccurate data to eliminate the need to document a needed change. Furthermore, it is believed that all modeling requirements should exist in a Modeling standard not a performance standard.
Duke Energy	Yes	In order to ensure these requirements move to the MOD standards, the TPL SDT is encouraged to write a SAR to get the data related changes into the MOD standards or add it to the issues to be considered by the drafting team in the development plan under project number 2010-04.
Central Maine Power Company	No	a. With respect to R9 "including the expected mix of industrial, commercial and residential loads", this provision may be inadequate to be practically useful. The potential issues include the variation in end-use load mix through the daily load cycle, seasonal load composition variations, and the ability to translate these end-uses into reasonable and useful steady-state and dynamic load models. It is important to understand how the information will be used and how much additional detail such as distribution network detail is also required. b. Add to the last sentence of R9 through R14 the following phrase, "within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator."
New York Independent System Operator	No	With respect to R9 "including the expected mix of industrial, commercial and residential loads", this provision may be inadequate to be practically useful. The potential issues include the variation in end-use load mix through the daily load cycle, seasonal load composition variations, and the ability to translate these end-uses into reasonable and useful steady-state and dynamic load models. It is important to understand how the information will be used and how much additional detail such as distribution network detail is also required. Add to the last sentence of R9 through R14 the following phrase, "within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator."
Alberta Electric System Operator	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.

Organization	Question 5:	Question 5 Comments:
FirstEnergy Corp.	No	FE does not support the modeling requirements within the TPL standard and suggest that the SDT remove these requirements. This standard should be viewed on a premise that a valid and appropriate system model exist so that the fundamental focus of the standard is as stated in its purpose statement "Establish Transmission System planning performance requirements... to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions." If the R9 through R14 requirements remain, we offer the following comments: R9 - In requirement R9, the DP is to provide nodal load projections and include the expected mix of industrial, commercial, and residential Loads. System planning software can not presently accommodate this level of detail along with other load codes/classifications that may already be in use; i.e. municipal load, rural electric cooperative load, etc. Is the intent to require this information in models built and maintained by industry, i.e. MMWG? R10 - The TP does not have access to Interchange Schedules and resources required to supply Load for each of its Balancing Authority. This information may need to be provided by the Resource Planner or some other appropriate entity.
US Bureau of Reclamation	Yes	Comments: While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
BPA Transmission Reliability Program	No	Requirements for data gathering and load modeling belong in the MOD Standard and not in TPL-001-1. Requirements for dynamic load models should not be specified at this time, because the models have not been developed yet or approved by the RRO (also see comments regarding R2.4.1 under Item 2, above).

Response: In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments.

R1. Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R1.1 ~~The Planning Assessment shall include documentation of the technical rationale for modification of any data that was provided in Requirement R9 through R14, MOD-010, and MOD-012.~~Models for the Planning Assessment shall represent:

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R1.1.2 New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon, such as Transmission Lines

Organization	Question 5:	Question 5 Comments:
Generators Circuit breakers Reactive Power devices Protection System equipment Control devices New technologies **R1.1.3** Real and reactive Demand of Load **R1.1.4** Firm Transmission Service **R1.1.5** Interchange **R1.1.6** Network resources required to supply Load		
Los Angeles Department of Water and Power	Yes	See the comment from WECC
Response: The SDT did not receive any specific comments from WECC.		
National Grid	No	a. With respect to R9 "including the expected mix of industrial, commercial and residential loads", this provision may be inadequate to be practically useful. The potential issues include the variation in end-use load mix through the daily load cycle, seasonal load composition variations, and the ability to translate these end-uses into reasonable and useful steady-state and dynamic load models. It is important to understand how the information will be used and how much additional detail such as distribution network detail is also required. b. Add to the last sentence of R9 through R14 the following phrase, "within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator." c. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R10 to read as follows: R10. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator.

Organization	Question 5:	Question 5 Comments:
		d. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R11 to read as follows R11. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator. e. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R12 to read as follows: R12. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator. f. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R13 and R14 as follows:R13. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator.. [Violation Risk Factor: TBD] [Time Horizon: TBD] R14. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to Transmission Lines, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator. [Violation Risk Factor: TBD] [Time Horizon: TBD] g. Planned and long-term outages are two fundamentally different concepts and should be treated separately. Planned and Long-Term outages should be defined. Define how planning events in Tables 1 and 2 are associated with each type of outage (e.g. P4, P5, or P6). Should there be specific contingency descriptions associated with long-term outages? Define length of a "Long Term" outage. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizon.
MidAmerican Energy Company	No	MEC disagrees with the approach of temporary requirements because of the problems that arise due to conflicting or uncoordinated standards (e.g. conflicting requirements between FAC-010-1 and TPL-002-0). We suggest the drafting team submit SARs to make the desired changes in the appropriate MOD standards. However, if these requirements are retained than we suggest the following few changes to R9-R14: The R9 wording on providing "the expected mix of industrial, commercial, and residential loads" should be dropped as the representative mix is difficult to quantify and verify while the benefit to representing the mix is unproven versus normal regional dynamic load representation practices. Many regions already convert normal steady state powerflow loads to standard mixes of, constant MVA, constant current, and shunt admittances which accounts for dynamic behavior. If the SDT decides not to drop these words, the MRO recommends "the expected mix of industrial, commercial, and residential loads" be changed to "the forecasted mix of industrial, commercial,

Organization	Question 5:	Question 5 Comments:
		and residential loads”. In R9 through R13 the responsible entities should be giving their information to the Transmission Planner in addition to the Planning Coordinator. In R10, revise the text to: "Each Transmission Service Provider shall provide ?" In R11, is the text referring to "known planned outages" and "known long term outages"? What is the distinction that is meant to be made between the two specified types of outages? In R12, revise the text to: "? modeling information for planned facilities changes, known planned outages ?". Also, is the text referring to "known planned outages" and "known long term outages"? What is the distinction that is meant to be made between the two specified types of outages? In R13, revise the text to: "? for planned facilities changes for each year of the Transmission planning horizon including but not limited to generators, and new technologies ?". This wording broadens the meaning from simply "new" facilities to also include any "changes" to existing facilities. In R14, revise the text to: "? for planned facilities changes for each year ?". This wording broadens the meaning from simply "new" facilities to also include any "changes" to existing facilities.
MRO NERC Standards Review Subcommittee	No	The MRO disagrees with the approach of temporary requirements because of the problems that arise due to conflicting or uncoordinated standards (e.g. conflicting requirements between FAC-010-1 and TPL-002-0). We suggest the drafting team submit SARs to make the desired changes in the appropriate MOD standards. However, if these requirements are retained than we suggest the following few changes to R9-R14: In R9, revise the text to: "? load forecast data for at least the coincident peak of each year ?" The R9 wording on providing "the expected mix of industrial, commercial, and residential loads" should be dropped as the representative mix is difficult to quantify and verify while the benefit to representing the mix is unproven versus normal regional dynamic load representation practices. Many regions already convert normal steady state powerflow loads to standard mixes of, constant MVA, constant current, and shunt admittances which accounts for dynamic behavior. If the SDT decides not to drop these words, the MRO recommends "the expected mix of industrial, commercial, and residential loads" be changed to "the forecasted mix of industrial, commercial, and residential loads”. In R9 through R13 the responsible entities should be giving their information to the Transmission Planner in addition to the Planning Coordinator. In R9, revise the text to: "? load forecast data for at least the coincident peak of each year ?"In R10, revise the text to: "Each Transmission Service Provider shall provide ?" In R11, is the text referring to "known planned outages" and "known long term outages"? What is the distinction that is

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		meant to be made between the two specified types of outages? In R12, revise the text to: "? modeling information for planned facilities changes, known planned outages ?". Also, is the text referring to "known planned outages" and "known long term outages"? What is the distinction that is meant to be made between the two specified types of outages? In R13, revise the text to: "? for planned facilities changes for each year of the Transmission planning horizon including but not limited to generators, and new technologies ?". This wording broadens the meaning from simply "new" facilities to also include any "changes" to existing facilities. We suggested removing the reference to Reactive Power Devices because these devices would not be owned by Resource Planners. In R14, revise the text to: "? for planned facilities changes for each year ?". This wording broadens the meaning from simply "new" facilities to also include any "changes" to existing facilities.
LCRA TSC	No	R-11 states that "Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment." This is typically achieved through outage coordination between the individual Transmission Operators and the System Operator. More clarification may help by defining the difference between planned outages and long-term outages as they are used in R-11. This may be an Operations standard versus a Planning standard requirement.
NERC and Regional Coordination	No	R9 - Reactive load forecasts are not generally provided by distribution provider to the Transmission Planner.R11 - The requirements for providing “long term outages” to the Planning Coordinator is vague. What is a “long term outage” and do I need to plan for it? I think the right answer is only if it is expected to occur over the period that the TP establishes their critical system conditions. SDT should initiate the appropriate SAR prior to disbanding.
American Transmission Company	No	We disagree with the approach of temporary requirements because of the problems that arise due to conflicting or uncoordinated standards (e.g. conflicting requirements between FAC-010-1 and TPL-002-0). We support the approach of developing appropriate MOD standards SARs to make the desired changes. However, if these requirements are retained than we suggest the following few changes to R9-R14.In R9, revise the text to: "? load forecast data for at least the coincident peak of each year In R10, revise the text to: "Each Transmission Service Provider shall provide "In R11, is the text referring to "known planned outages" and "known long term outages" What is the distinction that is meant to be made between the two specified types of outages In R12, revise the text to: "? modeling information for planned facilities changes, known planned outages ?". Also, is the text referring to "known planned outages" and "known long term outages"? What is the distinction that is meant to be made between the two specified types of outages

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		In R13, revise the text to: "? for planned facilities changes for each year of the Transmission planning horizon including but not limited to generators, and new technologies ?". This wording broadens the meaning from simply "new" facilities to also include any "changes" to existing facilities. We suggested removing the reference to Reactive Power Devices because these devices would not be owned by Resource Planners. In R14, revise the text to: "for planned facilities changes for each year ?". This wording broadens the meaning from simply "new" facilities to also include any "changes" to existing facilities.
Florida Reliability Coordinating Council, inc	No	R9 through R14 ?R9 through R14 should not be addressed in this TPL Standard. Requirements R9 through R14 should be included in future revisions to the MOD standards. If R9 through R14 remain in the Standard, then the following comments are appropriate: R9 ? Recommend adding ?and season (as defined by the Planning Coordinator)? after ?? load forecast data for each year? .Recommend adding ?(as defined by the Planning Coordinator)? after ?Transmission nodes? to allow the Planning Coordinator to appropriately define the term Transmission node. Recommend deleting ?including the expected mix of industrial, commercial, and residential Loads,? from the requirement since this information is not required by Transmission Planners or the Planning Coordinator. Many distribution providers will not know the mix of load type for a given Transmission node. R11 ?Recommend the removal of ?with consideration given to spare equipment strategy,? from this requirement. We feel that the consideration of spare equipment strategy would be better suited in an operating horizon standard (TOPs) rather than in the TPL standard. The term ?long-term outage? in this requirement is vague and the text ?and long-term outages? should be eliminated. The FERC language in Order 693 P-1725 states ?Accordingly, the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy.? There is no mention of ?long-term outages? in conjunction with spare equipment strategy. R12 ? Recommend rewording as follows: ?Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned generator outages for each year of the Transmission planning horizon, within ninety days of a request for such information." The language ?long-term outages for generation equipment? is vague and unclear as to what is a long-term outage and what specific type of generation equipment should be considered. R13 ? Propose adding ?and any changes to existing plans? after ?new planned facilities? as shown below: ?Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned Facilities and any changes to existing plans for each year of the Transmission planning horizon??
NSTAR Electric	No	1. With respect to R9 "including the expected mix of industrial, commercial and residential loads", this provision may be inadequate to be practically useful. The potential issues include the variation in end-use load mix through the daily load

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		cycle, seasonal load composition variations, and the ability to translate these end-uses into reasonable and useful steady-state and dynamic load models. It is important to understand how the information will be used and how much additional detail such as distribution network detail is also required. 2. Add to the last sentence of R9 as follows "within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator." 3. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R10 to read as follows: "R10. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator." 4. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R11 to read as follows:"R11. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator." 5. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R12 to read as follows:"R12. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator." 6. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R13 and R14 to read as follows:"R13. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator.. [Violation Risk Factor: TBD] [Time Horizon: TBD] R14. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to Transmission Lines, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator.. [Violation Risk Factor: TBD] [Time Horizon: TBD] " 7. Planned and long-term outages are two fundamentally different concepts and should be treated separately. Planned and Long-Term outages should be defined. Define how planning events in Tables 1 and 2 are associated with each type of outage (e.g. P4, P5, or P6). There should be specific contingency descriptions associated with long-term outages.

Organization	Question 5:	Question 5 Comments:
		Define length of a "Long Term" outage. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizon.
ISO New England Inc.	No	a. With respect to R9 "including the expected mix of industrial, commercial and residential loads", this provision may be inadequate to be practically useful. The potential issues include the variation in end-use load mix through the daily load cycle, seasonal load composition variations, and the ability to translate these end-uses into reasonable and useful steady-state and dynamic load models. It is important to understand how the information will be used and how much additional detail such as distribution network detail is also required. b. Add to the last sentence of R9 through R14 the following phrase, "within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator." c. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R10 to read as follows: R10. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator. d. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R11 to read as followsR11. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator. e. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R12 to read as follows: R12. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator. f. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R13 and R14 as follows:R13. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator.. [Violation Risk Factor: TBD] [Time Horizon: TBD] R14. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to Transmission Lines, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator.

Organization	Question 5:	Question 5 Comments:
		[Violation Risk Factor: TBD] [Time Horizon: TBD] g. Planned and long-term outages are two fundamentally different concepts and should be treated separately. Planned and Long-Term outages should be defined. Define how planning events in Tables 1 and 2 are associated with each type of outage (e.g. P4, P5, or P6). Should there be specific contingency descriptions associated with long-term outages? Define length of a "Long Term" outage. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizon.

Response: In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments.

The SDT agrees that the wording regarding modeling of outages is confusing. In response the SDT has eliminated Requirement R11 and included a new Requirement R1.1.1 to require modeling of planned outages of generation and Transmission Facilities when they are specifically known.

R1. Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources, ~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R1.1 ~~The Planning Assessment shall include documentation of the technical rationale for modification of any data that was provided in Requirement R9 through R14, MOD-010, and MOD-012.~~Models for the Planning Assessment shall represent:

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R1.1.2 New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon, such as

- Transmission Lines
- Generators
- Circuit breakers
- Reactive Power devices
- Protection System equipment
- Control devices
- New technologies

R1.1.3 Real and reactive Demand of Load

R1.1.4 Firm Transmission Service

Organization	Question 5:	Question 5 Comments:
R1.1.5 Interchange **R1.1.6** Network resources required to supply Load		
Gainesville Regional Utilities	Yes and No	I agree with the approach you are taking concerning this modeling data. I understand that "long term outages" for transmission and generation elements refer to a time frame greater that one year. But I am unclear if the "known planned outage" refers to the same time frame or does it apply to a normal scheduled maintenance type outage of less that one year. Are these "shorter that one year" outages better handled by sensitivity studies since they are normally during an non-peak seasons of the year? Again, the smaller utilities should provide all the requested data to the RRO, but should only have to answer to issues involving their elements discovered at the RRO level.
Response: The SDT agrees that the wording regarding modeling of outages is confusing. In response the SDT has eliminated Requirement R11 and included a new Requirement R1.1.1 to require modeling of planned outages of generation and Transmission Facilities when they are specifically known. **R1.1.1** Planned outages of generation and Transmission Facilities, if specifically known		
JEA	Yes and No	R9. JEA does not agree that the Transmission Planners should have the responsibility to perform load development or sanity checks on the DP's forecasted real and reactive loads based upon superfluous information like the customer mix. Also, JEA recommends adding language that gives the Planning Coordinator the option to require the forecast by season. R10. JEA agrees R11. JEA recommends that R11 be split into two functional requirements: (A) the provision of known planned outage information, and (B) the provision of "potential long-term forced outages of transmission equipment where readily available spares are not identified". JEA can support requirement (A), but believes that requirement (B) should be part of an operating horizon standard (TOP?) where the availability of spares and spare equipment strategies can be refined in a responsive manner as the opportunities evolve. JEA does not believe that the industry should overbuild its system for the possibility of a rare "low probability" equipment failure event will occur and no reasonable replacement alternative will exist in the world. R12. Need to define long-term outages R13. JEA agrees R14. JEA agrees
Ameren	No	We consider the proposed requirements R9-R14 to be largely a duplication of the MOD standards and do not agree that they belong in the proposed TPL-001-1. We would propose that a reference to the MOD standards would be more appropriate so as not to create a double-jeopardy compliance situation. If it is determined that the requirements R9-R14

Organization	Question 5:	Question 5 Comments:
		need to stay, the proposed standard needs to reflect the existing data flow processes and consider who builds the models, which is the Transmission Planner, and not the Planning Coordinator. According to the definition provided in this standard, the Planning Coordinator is "The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems." In our case, the Transmission Planner receives: a) load forecast (real and reactive) information from the Distribution Planner or Load Serving Entity, b) transmission ratings/impedance/topology(outage) information from the Transmission Owners, c) generation ratings/capabilities/outage information from the Generation Owners, and d) designated network resources (existing and future), as well as external obligations, from Resource Planners. The Transmission Planner develops powerflow and corresponding dynamic models from this information including load magnitude and distribution, generation dispatch, and net scheduled interchange, and provides the models or modeling components to the Reliability Coordinator and Planning Coordinator. Other organizations may have similar problems with data flow processes as specified in R9-R14.We view the R9 requirement of the proposed TPL-001-1 for the Distribution Provider to provide real and reactive load forecast data, including load mix information, to conflict with R1.4 of MOD-013-1 which has the RRO as setting the requirement for the dynamic load data. R10 needs to be modified to reflect the RTO activities related to the coordination and sale of Firm Transmission Service, which is not a Transmission Planning activity.R11 needs to be modified to drop the "spare equipment strategy". This is not a modeling issue and should be covered in standard TOP-002-2 (see R1 and R6).R13 needs to be modified to drop the "Reactive Power devices and new technologies" because Resource Planners typically do not know about these devices. The Transmission Planner or Owner may be the more appropriate entity. We view R14 as an extension of Standards MOD-010-0, MOD-011-0, MOD-012-0, and MOD-013-0.
Exelon Transmission Planning	Yes and No	R11 shouldn't include consideration of a spare equipment strategy. All known planned and long-term outages of transmission equipment should be included regardless of the spare equipment strategy.
IESO	Yes and No	A. R9: Agreed B. R10: Holding the TP to provide modeling information on Firm Transmission Service, (a TSP's role), Interchange Schedules (also a TSP's role), and resources required to supply Load for each of its Balancing Authorities (Resource Planner's role) may not be appropriate. In fact, the TP relies on others to provide this set of information for developing its own study model. We suggest to change the responsible entities to these specific entities; or if the TP is required to provide the PC with the model, then there should be requirements in other standards to obligate these other entities to provide the TP with the needed information. C. R11: The phrase "with consideration given to spare equipment strategy" is vague (not enforceable or measurable) and does not appear to add anything to the required product which should already have the spare strategy and capability taken into account when outage plans are developed. We suggest to remove this phrase. If this was retained, the follow on question is why R12 doesn't have a similar requirement (note that a generator outage may not be due to maintenance of the generator itself; it could be due to outages to step-up transformers, breakers or switches for which spares may be

Organization	Question 5:	Question 5 Comments:
		carried). D. R12: Agreed. E. R13: We are not sure what purpose to include "and new technologies" would serve if such technologies do not result in the provision of generators and/or reactive sources which are already covered. Further, this is vague to determine what constitutes "new technologies" and hence this is not enforceable or measurable. We suggest to remove this term. F. R14: Same comment as in R13 on "new technologies".

Response: In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments.

The standard's wording regarding "spare equipment strategy" has also been revised and removed from the modeling requirements. Requirement R2.1.5 now addresses how a Transmission Planner's "spare equipment strategy" should be considered in Transmission planning.

R1. Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R1.1 ~~The Planning Assessment shall include documentation of the technical rationale for modification of any data that was provided in Requirement R9 through R14, MOD-010, and MOD-012.~~Models for the Planning Assessment shall represent:

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R1.1.2 New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon, such as

- Transmission Lines
- Generators
- Circuit breakers
- Reactive Power devices
- Protection System equipment
- Control devices
- New technologies

R1.1.3 Real and reactive Demand of Load

Organization	Question 5:	Question 5 Comments:
R1.1.4 Firm Transmission Service **R1.1.5** Interchange **R1.1.6** Network resources required to supply Load **R2.1.4** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment.		
Progress Energy Florida, Inc.	No	PEF as a general rule believes that Requirements R9-14 can and should be addressed in a MOD Standard. Individual comments on particular ones that PEFs sees as problematic are as follows:R9: This requirement is problematic in its present wording. As worded it would appear to infringe upon the outlined process regarding provision of load forecast data as stipulated in PEFs Attachment K document, mandated to be included as an Attachment to our Tariff per FERC Order 890. In PEF's Attachment K, load forecast data, as submitted by all entities responsible for providing such data for PEF native load, must be submitted by January 1 of each year. Implementation of R9 would thus set in place two binding regulatory processes for a situation in which only one is needed. Furthermore, the requirement uses the term "transmission node", a term which is ambiguous and not easily applicable in the electric utility business. Terms such as "feeders", "substations" or "delivery points" might be more appropriate.R11: PEF appreciates the consideration given with the term "known planned outages", given that specific dates for planned outages in the long-term planning horizon are often difficult to know. This point concludes, however, with the addition of the phrase ?with consideration given to spare equipment strategy?, and PEF does not understand what is meant by this term nor why it is given special consideration in a discussion of planned outages. Spare equipment is just as crucial, if not more so, in the event of an unplanned outage. Furthermore, consideration of spare equipment strategy is already handled as part of PEF's planning processes and as part of the existing TPL Standards. PEF therefore requests that the phrase "with consideration given to spare equipment strategy" be removed from R11.R13: PEF is unsure as to the meaning of "for each year of the Planning horizon". PEF would point out that if from one planning cycle to the next, the modeling of a particular planned generator has not changed, the Resource Planners should not have to re-submit the same data over and over again on an annual basis. Additionally, PEF asserts that its Resource Planners are not involved in the development or implementation of Reactive Power devices or new technologies, and therefore requests that these specifications be removed.
Response: In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments. The standard's wording regarding "spare equipment strategy" has also been revised and removed from the modeling requirements. Requirement R2.1.4 now addresses how a Transmission Planner's "spare equipment strategy" should be considered in Transmission planning. The phrase "for each year of the Transmission Planning Horizon" was deleted in the associated requirements. Requirement R1.1.2 now addresses that the models		

Organization	Question 5:	Question 5 Comments:
shall represent each year of the Near-Term and Long Term Transmission Planning Horizon. The SDT agrees with your comment on the Resource Planner. The standard is no longer applicable to the Resource Planner and the requirement has been deleted. **R1.** Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations. **R1.1** ~~The Planning Assessment shall include documentation of the technical rationale for modification of any data that was provided in Requirement R9 through R14, MOD-010, and MOD-012.~~Models for the Planning Assessment shall represent: **R1.1.1** Planned outages of generation and Transmission Facilities, if specifically known. **R1.1.2** New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon, such as Transmission Lines Generators Circuit breakers Reactive Power devices Protection System equipment Control devices New technologies **R1.1.3** Real and reactive Demand of Load **R1.1.4** Firm Transmission Service **R1.1.5** Interchange **R1.1.6** Network resources required to supply Load **R2.1.4** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment.		
Lafayette Utilities	No	In Draft 2 of TPL-001, the SDT has adopted ?Planning Coordinator? as a new defined term. That term is used frequently in the new draft Reliability Standard (including in Requirements R9 - R14 but also, most notably, in Section A.4.1.1). The

Organization	Question 5:	Question 5 Comments:
System		SDT explained in its response to comments on Draft 1 that it had taken the definition of "Planning Coordinator" from the NERC Functional Model. However, the term "Planning Coordinator" is not used in the NERC Registry Criteria, nor does it appear in the NERC Glossary. Because the latter form the basis for allocating compliance responsibilities, the SDT should eliminate use of "Planning Authority" and should adopt in its stead a term that is used in the Registry Criteria (such as "Planning Authority"). With respect to the incorporation of data provided under Reliability Standards MOD-010 and MOD-012 into the studies contemplated by the revised version of TPL-001 (see Requirements R1 and R5), Lafayette urges the SDT to clarify entities? obligations with respect to the provision and use of this data, particularly with respect to Planning Coordinators/Authorities. As presently drafted, MOD-010 and MOD-012 do not apply to Planning Coordinators or Planning Authorities, and these standards also do not provide for these entities to receive MOD-010 and MOD-012 data from the entities that are subject to these two Standards. Further, to the extent that Requirements R1 and R5 require Transmission Planners to use MOD-010 and MOD-012 data, is it contemplated that Transmission Planners will obtain this data from Resource Planners and Transmission/Generation Owners in their areas, or will Transmission Planners merely be obligated to incorporate the data that they themselves provide under MOD-010 and MOD-012 into their studies? Requirement R9 directs each Distribution Provider to furnish its "Planning Coordinator" with modeling information that includes "real and reactive load forecast data" at Transmission nodes" and "the expected mix of industrial, commercial, and residential Loads." As discussed previously with respect to Requirement 2.4.1, Distribution Providers may consider the information required by R9 to be commercially sensitive such that its disclosure could have adverse competitive effects. The information specified in R9 therefore should be protected from disclosure unless the provider of the information authorizes its release or other appropriate protections are in place. Additionally, given that this requirement directs the provision of "load forecast data," it seems more appropriate that the requirement apply to "Load-Serving Entities," "Distribution Providers that serve load" or "Distribution Providers that are also Load-Serving Entities." Requirement R10 assumes that the Transmission Planner has access at all times (and, therefore, is in a position to provide within 90 days of a request) to Firm Transmission Service Data, Interchange Schedules, and resources required to serve load for each of its Balancing Authorities for each year of the transmission planning horizon. The Transmission Planner, however, may only receive such information periodically (e.g., annually or semi-annually) from its Balancing Authorities for use in the planning process. It is more likely that, at any point during the year, the Transmission Owner, Transmission Operator, or Transmission Service Provider would have access to the specified information. Requirement R10 should be expanded to include these other entities, which probably will have access to the data throughout the planning cycle. Requirement R11 does not specify whether outage information provided by a Transmission Owner must be updated (e.g., if the outage schedule changes after being provided upon request by the Planning Coordinator). The Transmission Owner's obligations with respect to providing updated information should be clearly stated. Additionally, it is not clear what the SDT means by the phrase "giving consideration to spare equipment strategy." If the intent is that Transmission Owners shall factor into their outage decisions and timing the availability of spare equipment that might affect the need for or duration of an outage, that intent should be stated in clear terms.
Response: v4 of the Functional Model which has been approved by the BOT includes the term 'Planning Coordinator'. The definition has been deleted from this		

Organization	Question 5:	Question 5 Comments:

posting as it has already been implemented in another project.

In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments.

The standard's wording regarding "spare equipment strategy" has also been revised and removed from the modeling requirements. Requirement R2.1.4 now addresses how a Transmission Planner's "spare equipment strategy" should be considered in Transmission planning.

R1. Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R1.1 ~~The Planning Assessment shall include documentation of the technical rationale for modification of any data that was provided in Requirement R9 through R14, MOD-010, and MOD-012.~~Models for the Planning Assessment shall represent:

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R1.1.2 New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon, such as

- Transmission Lines
- Generators
- Circuit breakers
- Reactive Power devices
- Protection System equipment
- Control devices
- New technologies

R1.1.3 Real and reactive Demand of Load

R1.1.4 Firm Transmission Service

R1.1.5 Interchange

R1.1.6 Network resources required to supply Load

R2.1.4 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment.

Organization	Question 5:	Question 5 Comments:
E.ON U.S. Transmission Planning	Yes and No	R1 states "Each Transmission Planner and Planning Coordinator shall maintain System models " and R7 states "Each Transmission Planner and Planning Coordinator shall determine and identify individual and joint responsibilities" but R9-R14 requires that data flow through the Planning Coordinator. Requirements R9-R14 should allow the data to be provided to either, as appropriate for the situation.R9 ?neighboring systems? should be replaced with more descriptive terms such as Planning Coordinators of ? or Transmission Planners of ? R10 The Transmission Planner is a user of this data, just like the Planning Coordinator, and is not the source of this data. The responsibility should be placed on the "source provider" like R9 and R11-R14. R11 The requirement should be limited to planned outages and existing outages that may be long-term due to the spare equipment strategy. The contingency analysis covers all other future outages. R12 The requirement should be limited to planned outages and existing outages that may be long-term due to the spare equipment strategy. The contingency analysis covers all other future outages.

Response: In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments.

The SDT agrees that the wording regarding modeling of outages is confusing. In response the SDT has eliminated Requirement R11 and included a new Requirement R1.1.1 to require modeling of planned outages of generation and Transmission Facilities when they are specifically known.

The standard's wording regarding "spare equipment strategy" has also been revised and removed from the modeling requirements. Requirement R2.1.4 now addresses how a Transmission Planner's "spare equipment strategy" should be considered in Transmission planning.

R1. Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R1.1 ~~The Planning Assessment shall include documentation of the technical rationale for modification of any data that was provided in Requirement R9 through R14, MOD-010, and MOD-012.~~Models for the Planning Assessment shall represent:

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R1.1.2 New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon, such as

- Transmission Lines
- Generators
- Circuit breakers
- Reactive Power devices

Organization	Question 5:	Question 5 Comments:
Protection System equipment Control devices New technologies **R1.1.3** Real and reactive Demand of Load **R1.1.4** Firm Transmission Service **R1.1.5** Interchange **R1.1.6** Network resources required to supply Load **R2.1.4** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment.		
Orlando Utiliites Commission	No	If improvements are needed to the MOD standards then those should be addressed in the MOD standards. This is beyond the scope of the TPL standards. Creating requirements that are not within the scope of a particular standard invites compliances issues and also creates an environment where it may not be possible to comply with both standards. However if you are going to retain these please consider: R7: Revising to state "Each Transmission Planner and their associated Planning Coordinator" otherwise this could be interpreted that every TP & PC has to have an agreement with every other TP and PC in existence on their joint and individual responsibilities. R8: This seems to be redundant with the FERC order 890 requirements for an Attachment K process. That process already has an audit mechanism in FERC and a reporting mechanism in the form of the clients of that process. Having NERC auditors monitor this type of process seems a distraction from their purpose of enhancing system reliability.
Response: In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments. **R1.** Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources, ~~-~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations. **R1.1** ~~The Planning Assessment shall include documentation of the technical rationale for modification of any data that was provided in Requirement R9 through R14, MOD-010, and MOD-012.~~Models for the Planning Assessment shall represent:		

Organization	Question 5:	Question 5 Comments:
R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known. **R1.1.2** New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon, such as Transmission Lines Generators Circuit breakers Reactive Power devices Protection System equipment Control devices New technologies **R1.1.3** Real and reactive Demand of Load **R1.1.4** Firm Transmission Service **R1.1.5** Interchange **R1.1.6** Network resources required to supply Load Regarding the comment pertaining to Requirement R7, the SDT believes there is an inherent association between the TP and its PC and it should not be interpreted that every TP needs an agreement with every other TP and PC. Regarding the comment pertaining to Requirement R8, the SDT believes the requirement captures the intent of FERC Order 890.		
BCTC	Yes	We can live with the proposed Requirements, but expect some problems may arise with implementation. For example, to accurately model our system for stability studies, we require models of adjacent systems. It is not clear how we will coordinate this requirement within the WECC base case process.
PacifiCorp	Yes	We agree that the MOD Standards need modifications and additions to be used for Transmission Planning, We also agree with the movement of the R1of the first draft to the R9 through R14 of this draft, We also agree that when the MOD Standards are replaced, then remove these Requirements from the TPL Standard.
Arizona Public Service Co.	Yes	We agree that the MOD Standards need modifications and additions to be used for Transmission Planning, We also agree with the movement of the R1of the first draft to the R9 through R14 of this draft, We also agree that when the MOD Standards are replaced, then remove these Requirements from the TPL Standard.

Organization	Question 5:	Question 5 Comments:
City Water, Light & Power - Springfield, Illinois	Yes	
Progress Energy Carolinas	Yes	
Platte River Power Authority	Yes	
Tenaska, Inc.	Yes	
SMUD	Yes	
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	Yes	
Oncor Electric Delivery	Yes	NA
Entergy Services, Inc.	Yes	
Response: Thank you for your response but the majority of the industry has responded negatively and the SDT has changed the requirements as shown in the summary response. .		

6. The SDT has modified the requirements relating to short circuit analysis Do you concur with the modifications reflected in Requirements R2.3 and R4. If not, please state why and/or suggest specific changes.

Summary Consideration:

The majority of commenters responded negatively. In general, commenters indicated a need for clarifying what specific short-circuit studies were required. While it's an annual requirement, what year or years should be studied? Is there both a short-term and long-term requirement or is it just short-term? In addition, the need for studies beyond those of a "normal system" was also questioned. To provide clarity on these issues, the SDT changed Requirements R2.3 and R2.6.2 and created a new Requirement, R2.7, to address the need for corrective actions specific to when fault interrupting duties are exceeded while also deleting Requirement R4 as those requirements are now included in Requirement R2.3. In addition, some entities suggested these requirements belong in a separate standard such as FAC-002 or a new standard. However, the SAR for this project specified that short-circuit requirements would be included in TPL-001; therefore, the suggestion to move these short-circuit study requirements to a separate standard cannot be implemented. Also, the need for, or applicability, of 'single Contingencies' in Requirement R4 was dropped when Requirement R4 was merged into Requirement R2.3.

In response to industry comments, Requirement R4 has been deleted and the following requirements have been changed:

R2.3 The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area.

R2.6.2 (now R2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:

- The addition/deletion/change of individual generating unit capability of 20 MW or greater.
- An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater.

R2.7 For short circuit analysis, if the short circuit current interruption duty on fault interrupting devices determined in Requirement R2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

R2.7.1 List System deficiencies and the associated actions needed to achieve required System performance.

R2.7.2 Be reviewed in subsequent annual Planning Assessments as to implementation status.

Organization	Question 6:	Question 6 Comments:
NPCC	No	In R4, suggest striking, "that would result in greater circuit breaker interrupting duties?".
Los Angeles Department of Water and Power	No	Short circuit study is a static study, there is no dynamic involved. The main purpose of short circuit study, from a planning perspective, is to size the breakers to ensure the breakers can interrupt a fault in the system when called upon. R4 requires simulation including contingencies, for what purpose is not known. The language implies there are single contingencies that could result in higher duties. I disagree. The highest duty a circuit breaker will see is when the system is whole and with all generator units in service and the fault to be cleared is a bus fault. Any single contingency that involve losing a unit or any component in the system will result in a weaker system and less short circuit duties. This is elementary. I cannot envision of any single contingency that would put more units on line or switch in additional transmission facilities beyond a full system with all unit already in service. In R2.3, the requirement is to do the study on an annual basis "and" support of past studies. If the intent is to allow past studies to substitute for annual study, the word "and" should be changed to "or". If the intent is to mandate annual study, then the support of past studies is irrelevant since the annual study supersedes past ones. In addition, short circuit study does not need to be performed annually unless there is substantive addition to the system in the form of a generating unit or a major transmission facility. So it make sense to allow past studies in lieu of annual study if there is no substantive addition to the system.
Transmission Agency of Northern California	Yes and No	We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute ?normal? condition or ?following any single Contingency condition?. Also, by specifying the normal and single contingency conditions, R4 is straying into ?how? to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
OPUC	Yes and No	What constitutes a ?normal condition? still needs further clarity.
Pacific Gas and Electric Co.	Yes and No	We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute “normal” condition or “following any single Contingency condition”. Also, by specifying the normal and single contingency conditions, R4 is straying into ?how? to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
Public Service Company of New Mexico	Yes and No	We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion

Organization	Question 6:	Question 6 Comments:
		whether the result would constitute ?normal? condition or ?following any single Contingency condition?. Also, by specifying the normal and single contingency conditions, R4 is straying into “how” to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
PacifiCorp	Yes and No	We agree with R2.3. However, R4 requires assessment of “Short circuit capability of its equipment under normal condition and following any single Contingency condition that would result in greater circuit breaker interrupting duties”. Since short circuit studies are typically performed by applying a three phase fault on a Facility starting from a normal condition, please clarify whether the result would constitute ?normal? condition or ?following any single Contingency condition?.
Puget Sound Energy, Inc.	Yes and No	We agree with R2.3. However, R4 requires assessment of “Short circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties”. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute “normal” condition or “following any single Contingency condition”. Also, by specifying the normal and single contingency conditions, R4 is straying into “how” to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
Idaho Power Company	Yes and No	We agree with R2.3. However, R4 requires assessment of “Short circuit capability of its equipment under normal condition and following any single Contingency condition that would result in greater circuit breaker interrupting duties”. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute “normal” condition or ?following any single Contingency condition”. Also, by specifying the normal and single contingency conditions, R4 is straying into “how” to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
SMUD	Yes and No	We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute ?normal? condition or ?following any single Contingency condition?. Also, by specifying the normal and single contingency conditions, R4 is straying into ?how? to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
Hydro-Quebec TransEnergie (HQT)	No	In R4, suggest striking, "that would result in greater circuit breaker interrupting duties?".
Sierra Pacific Power Comapny	Yes and No	We agree with R2.3. However, R4 requires assessment of “Short circuit capability of its equipment under normal condition and following any single Contingency condition that would result in greater circuit breaker interrupting duties”. Since short circuit

Organization	Question 6:	Question 6 Comments:
/ Nevada Power Company		studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute “normal” condition or “following any single Contingency condition”. Also, by specifying the normal and single contingency conditions, R4 is straying into “how” to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
Black Hills Corporation	Yes and No	We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute “normal” condition or “following any single Contingency condition”. Also, by specifying the normal and single contingency conditions, R4 is straying into “how” to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
Arizona Public Service Co.	Yes and No	We agree with R2.3. However, R4 requires assessment of “Short circuit capability of its equipment under normal condition and following any single Contingency condition that would result in greater circuit breaker interrupting duties”. Since short circuit studies are typically performed by applying a three phase fault on a Facility starting from a normal condition, please clarify whether the result would constitute “normal” condition or “following any single Contingency condition”.
Exelon Transmission Planning	No	R2.3 is not clear as to which year’s studies are required. Is the Planning Assessment time frames in R2 also applicable to R4? The phrase 'years one or two of the near-term planning horizon' should be included.
SRP	Yes and No	We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute ?normal? condition or ?following any single Contingency condition?. Also, by specifying the normal and single contingency conditions, R4 is straying into ?how? to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
Tucson Electric Power Company	Yes and No	We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute ?normal? condition or ?following any single Contingency condition?. Also, by specifying the normal and single contingency conditions, R4 is straying into ?how? to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.

Organization	Question 6:	Question 6 Comments:
SERC Dynamics Review Subcommittee	Yes	It is not clear in the standard what is meant by ?single contingency?? Is the concern in Requirement R4 limited to single contingencies that may result in a system state which results in a greater circuit breaker interrupting duty?
Austin Energy	Yes and No	Transmission Planners should assess equipment short-circuit capability under normal conditions, but the need assess its capability following a contingency is so rare it should be left to the planner's selective analysis and not made a specific requirement in the standards.
Modesto Irrigation District	Yes and No	Comments: We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute ?normal? condition or ?following any single Contingency condition?. Also, by specifying the normal and single contingency conditions, R4 is straying into “how” to perform a study, which is not necessary in a standard. We suggest deleting there reference to the contingencies to be used in the study.
Tri-State Generatino and Transmission Association, Inc.	Yes and No	R2.3 is acceptable as written. R4 is redundant and should be eliminated. Also, the contingency short circuit study requirement does not appear to meet the purpose described in this draft standard (breaker duty monitoring). Three-phase short circuits on an intact system should cover the highest fault conditions, and thus the most critical breaker duty conditions.
Tri-State G&T	Yes and No	We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute “normal” condition or “following any single Contingency condition.” Also, by specifying the normal and single contingency conditions, R4 is straying into “how” to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
Lakeland Electric	No	R2.3 or R4 should specify how many and / or how to choose which years of the planning horizon shall be studied. R4 should specify method of choosing which single contingencies to study as larger systems will require an inordinate amount of work to outage every element during each of the study years of the short circuit analysis.
Brazos Electric Power Cooperative, Inc.	No	2.3 is acceptable, the deletion was recommended in our previous comments.R4 should not be added to this Standard. It adds nothing to the document the way it is worded and is quite similar to 2.3.

Organization	Question 6:	Question 6 Comments:
NERC and Regional Coordination	No	Attributes of the short circuit analysis needs to be better define. For example which studies need to be done, for what period and how often.
ColumbiaGrid	Yes and No	We agree with R2.3. However, R4 requires assessment of “Short circuit capability of its equipment under normal condition and following any single Contingency condition that would result in greater circuit breaker interrupting duties”. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute “normal” condition or “following any single Contingency condition”. Also, by specifying the normal and single contingency conditions, R4 is straying into “how” to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study. We suggest R4 be modified to read “Short circuit capability of its equipment under plausible system configurations that would result in the greatest circuit breaker interrupting duties”.
Midwest ISO	No	The language throughout the standard is not precise as relates to "studies", "analysis", and "assessments". R2.3 appears to say that the actual simulations upon which the annual assessments are made need not be a current year study. If that is the intent the following wording would be more clear: "Short-circuit assessments shall be conducted annually and may be supported by current or past studies. R4 should be grouped with R2.4. In general the standard seems to meander and elements of the same types of studies are scattered, making it difficult to grasp the study requirements with clarity. Also the language of R4 is unclear as it describes short circuit studies in terms of contingencies. Better language would be "shall assess the short-circuit capability of its equipment under system intact topology and any single facility (or branch) out condition that is expected to result in greater ?".
Southern California Edison	Yes and No	We agree with R2.3. However, R4 requires assessment of “Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute “normal” condition or “following any single Contingency condition”. Also, by specifying the normal and single contingency conditions, R4 is straying into “how” to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
Northeast Utilities	No	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
Duke Energy	No	It is not clear in R4 what is meant by ?single contingency? and this situation is unlikely to increase fault current. The phrase ?under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting

Organization	Question 6:	Question 6 Comments:
		duties? should be deleted.
Central Maine Power Company	No	a. R2.3 should be changed to indicate the year(s) for short circuit analysis. b. In R4, suggest replacing, " and following any single Contingency condition that would result in greater circuit breaker interrupting duties" with, " giving due consideration to the potential sequence of equipment operation". c. It should be stated in the standard that assumptions should be based on procedures provided by each Transmission Planner and by the Planning Coordinator.
NSTAR Electric	No	1. R2.3 should be changed to indicate the year(s) for short circuit analysis. 2. In R4, suggest replacing, " and following any single Contingency condition that would result in greater circuit breaker interrupting duties" with , " giving due consideration to the potential sequence of equipment operation". 3. It should be stated in the standard that assumptions should be based on procedures provided by each Transmission Planner and by the Planning Coordinator.
New York Independent System Operator	No	In R4, suggest striking, "that would result in greater circuit breaker interrupting duties?".
Alberta Electric System Operator	No	We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute ?normal? condition or ?following any single Contingency condition?. Also, by specifying the normal and single contingency conditions, R4 is straying into ?how? to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
ISO New England Inc.	No	a. R2.3 should be changed to indicate the year(s) for short circuit analysis. b. In R4, suggest replacing, " and following any single Contingency condition that would result in greater circuit breaker interrupting duties" with , " giving due consideration to the potential sequence of equipment operation". c. It should be stated in the standard that assumptions should be based on procedures provided by each Transmission Planner and by the Planning Coordinator.
US Bureau of	No	Comments: We agree with R2.3. However, R4 requires assessment of “Short circuit capability of its equipment under normal

Organization	Question 6:	Question 6 Comments:
Reclamation		conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties". Comment Form for 2nd Draft of Standard TPL-001-1Assess Transmission Future Needs (Project 2006-02)Page 7 of 12Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute ?normal? condition or ?following any single Contingency condition?. Also, by specifying the normal and single contingency conditions, R4 is straying into ?how? to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
BPA Transmission Reliability Program	Yes and No	We agree with R2.3. However, we recommend removing the reference to single contingency conditions in R4, for the same reasons as described in the WECC comments. See below: "Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute "normal" condition or "following any single Contingency condition". Also, by specifying the normal and single contingency conditions, R4 is straying into "how" to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
Response: Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. Also, the need for, or applicability, of 'single Contingencies' in Requirement R4 was dropped when Requirement R4 was merged into Requirement R2.3. **R2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area.		
City Water, Light & Power - Springfield, Illinois	Yes and No	For R2.4 stability studies should not be required annually but should only be required if there is a significant change to the system or system stability was marginal as shown in previous studies.
Response: This question is related to short circuit, Requirement R2.3, not Requirement R2.4, Stability. However, if past studies are applicable, it is not necessary to rerun Stability studies more often than once every 5 years. Your examples are good examples of when a Stability study may need to be rerun more often than once every 5 years.		
BCTC	Yes	R.3 and R4 are acceptable, although we note the R4 gets into details of how to do short circuit analysis which is unnecessary for this standard. In some cases it may be necessary to consider multiple contingencies. Should R2.6.2 say "the SYSTEM shall not include material changes?"?
Response: Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. **R2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can		

Organization	Question 6:	Question 6 Comments:
be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area. The SDT has changed Requirement R2.6.2 (now R2.5.2) to provide clarification. **R2.5.2** For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:		
Manitoba Hydro	No	R4: The wording for the assessment should be changed from "shall assess the short circuit ability of its equipment" to "shall assess whether bus short circuit levels are within the capability of its equipment". The short circuit assessment should only be required if changes to system topology or generation occur. While short circuit levels are critical for system equipment specifications, ten year planning horizon models are generally not adequate for this purpose as ultimate system fault levels are required. The SDT should clarify the modelling details required for the short circuit assessment and the deliverable of the short circuit assessment. The standard doesn't stipulate if an existing NERC model will need to be modified to include the sequence data and thus allow for three phase and SLG fault analysis or if the planner is to use our "in house" models and just report the results. Typically, short circuit models used for fault studies are not load or season specific, and the simulation is conducted using a flat-analysis (load ignored and voltage at 1.0 pu). Typically, all elements are in service to ensure maximum fault contribution. Can the SDT provide details on what cases have to be assessed ? Year One, each of the first five year, etc. What is the generation dispatch that should be considered? For purposes of equipment rating, a dispatch considering all available generation may need to be considered. Manitoba Hydro requests the SDT to provide some specifics on the need for doing intact and n-1 fault analysis. We think the requirement to consider single contingency conditions is getting into the details of bus modeling to maximize the fault level. If so this seems to be getting into short circuit study methodology and is too prescriptive and unnecessary. To explain this comment, we include a summary of the process used at Manitoba Hydro as follows: Manitoba Hydro follows a two step procedure when studying breaker capability of our system:1. Breaker Rating vs. Bus Fault - Breakers are required to accommodate the entire bus maximum symmetrical fault current at nominal bus voltage with no consideration given to what the circuit breaker may actually be required to interrupt due to its location in the ring. Stations with fault levels above 95% of rated breaker interrupting capability are flagged for further study. This type of analysis will accurately rule out a high percentage of breakers whose capability is adequate. If an appropriate model is available, this step could take up to three person-months for the Manitoba Hydro system. 2. Detailed Examination of Breaker Duty and Location - By considering faults on both the equipment and bus side of the breaker the exact fault current that the breaker must interrupt can be determined. In a ring bus arrangement the breaker in question is assumed the last breaker to clear the fault. In addition, factors such as X/R ratio & operating voltage are also taken into account. To provide a safety margin to account for modeling tolerances we recommend a circuit breaker for replacement when the fault value is greater then 95% of the breaker rating. Other companies may use different breaker replacement threshold levels. This detailed analysis could require up to one person-month, depending on the size of the station, for each detailed assessment. The standard should specify what is to be reported as a result of the short circuit study. Should the report include:? Documentation of the criteria used for the study? A

Organization	Question 6:	Question 6 Comments:
		listing of the SLG and three phase fault levels compared to the lowest breaker capability at a bus. ? Documentation of more detailed analysis of for breakers whose capability is within threshold of the station fault level.? A listing of the breakers to be replaced. Alternatively, should the standard just require the planner have a separate report on the fault analysis that can be provided on request.
Response: Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. **R2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area. The SDT has chosen not to prescribe all conditions but expects that studies would assume all equipment in service, which could impact the study area, to calculate maximum potential fault currents.		
National Grid	No	a. R2.3 should be changed to indicate the year(s) for short circuit analysis. b. In R4, suggest replacing, " and following any single Contingency condition that would result in greater circuit breaker interrupting duties" with , " giving due consideration to the potential sequence of equipment operation". c. It should be stated in the standard that assumptions should be based on procedures provided by each Transmission Planner and by the Planning Coordinator.
Response: (a) & (b): Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. Also, the need for, or applicability, of 'single Contingencies' in Requirement R4 was dropped when Requirement R4 was merged into Requirement R2.3. **R2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area. (c) Procedures used to meet short-circuit requirements of Requirement R2.3 should be included in Requirement R2.7.1 mandated Corrective Action Plans.		
Gainesville Regional Utilities	Yes and No	With a small system like ours, I would like to see a provision where if you do not have any changes in our local portion of the BES, then the previous studies would support my assessment.
Response: This is addressed in the revised Requirement R2.6.2 (now R2.5.2). **R2.5.2** For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:		

Organization	Question 6:	Question 6 Comments:
The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater.		
JEA	Yes and No	JEA can agree to this requirement; however, JEA would like to see it addressed in FAC-002 to maintain consistency with the FAC standard requirements.
Response: FAC-002 references the TPL standards to ensure that a short-circuit study is run for new Facilities. The SDT believes that the consistency will continue to exist. The SAR for TPL-001-1 specified that short-circuit studies were to be included in the requirements.		
Progress Energy Florida, Inc.	No	PEF disagrees with, and recommends removal of both R2.3 and R4 on the following grounds:R2.3: Evidence that short circuit analysis has been performed is already mandated through Requirement R1.4 NERC Standard FAC-002-0. Inclusion of the mandate in the TPL Standard is redundant.R4: While the fundamental inadequacy of the short circuit issue is its inclusion in the TPL Standard to begin with (see R2.3 comments), PEF is perplexed at the proposed requirement to perform short circuit analysis for single contingencies. PEF cannot conceive of a scenario for which a single contingency scenario would result in increased fault duty. Such a mindset essentially considers short circuit analysis as equivalent to load flow analysis, which it clearly is not. Short circuit analysis is performed to adequately set relays, size equipment and prevent equipment damage, and as such is not appropriate for inclusion in a TPL Standard.
Florida Power and Light	No	R4. Why is short circuit analysis required for single contingencies? Removing equipment through contingency outages lowers available short circuit duty. Short circuit analysis is not a parallel version of load flow analysis. Evidence that short circuit studies have been performed is currently required in the existing FAC-002-0 Standard. Since the primary concern is the appropriate sizing of equipment and the prevention of equipment damage as opposed to overall grid reliability, we do not see the need for a set of requirements within the proposed TPL standard for short circuit studies.
Florida Reliability Coordinating Council, inc	No	Recommend for the removal of both R2.3 and R2.4. Short Circuit analysis should be addressed in FAC-002 by revising the standard to include additional detail within FAC-002. Another option would be to develop a new standard addressing short circuit studies and requirements.
Response: FAC-002 requires coordination for new Facilities but points back to the TPL standards for requirements that must be coordinated. The SDT believes short-circuit requirements belong in TPL-001-1 and the SAR for TPL-001-1 specified that short-circuit studies were to be included in requirements. Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. **R2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System		

Organization	Question 6:	Question 6 Comments:
short circuit model with any generation and Transmission Facilities in service which could impact the study area.		
Lafayette Utilities System	No	Lafayette has identified two issues with respect to the Short Circuit Analysis required in TPL-001. First, Requirements R2.3 and R4 do not describe the required Short Circuit Analyses in sufficient detail to ensure that these studies are performed using topology assumptions that are consistent with the assumptions used in the Steady-State and Stability Studies. If inconsistent topology assumptions are used, the results of the analyses would not present a clear and consistent picture for planning purposes. Second, interconnection studies performed under the FERC LGIP procedures typically include considerable short-circuit analysis of the interconnecting transmission system. Entities required to perform an annual Planning Assessment should be permitted to use, for TPL-001 compliance purposes, any up-to-date short-circuit analyses that may have been conducted for an LGIP interconnection study. Forcing these entities to re-perform the analyses for TPL-001 compliance would impose unnecessary cost.
Response: Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. **R2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area. Please note that this requirement allows for the utilization of past studies.		
Ameren	No	Requirement R4 should be modified to remove the Planning Coordinator such that the "Transmission Planner shall assess the short-circuit capability of its equipment considering maximum interrupting duty for normal or single element outage conditions".
Response: The Planning Coordinator is the appropriate entity in some areas. In those areas where this is not the case, the Planning Coordinator may defer to the Transmission Planner's studies. This is a joint responsibility between the Transmission Planner and Planning Coordinator.		
CenterPoint Energy and CPS Energy	No	We believe R4 is unnecessary and, judging from industry comments to the previous draft, likely to cause confusion among auditors and planners alike. Furthermore, we believe R4 does not address an actual problem. We are not aware of situations where equipment has been under-rated from the standpoint of short circuit ratings. We recommend that R4 be deleted.
Response: The SDT does not believe that the concepts of Requirement R4 should be eliminated as without them, there would be a requirement for short-circuit studies with no specific result expected. However, Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. **R2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System		

Organization	Question 6:	Question 6 Comments:
short circuit model with any generation and Transmission Facilities in service which could impact the study area.		
MidAmerican Energy Company	No	a. Since the TPL contingency requirements already require bus fault, stuck breaker, and breaker failure contingencies, MEC asks the SDT to clarify the purpose of the short circuit study requirements. The benefit to additional short-circuit studies is minimal since analyses already ensure that the system can withstand bus faults and breaker failures. b. The SDT should clarify what single contingencies are to be studied for short circuit studies in R2.4. Is it single contingency as defined in Table 1? Or is it a broader or narrower definition? MEC recommends that since this is a new requirement, that TPL-001-1 be limited to raise the bar only to involve the single contingencies identified in P1. Failure to do so will require a great deal of additional modeling work in short-circuit studies if single contingencies in P2 are to be included in these studies with minimal benefit.
Response: (a) These requirements apply to steady state (load flow) and Stability analysis but they do not specifically address short-circuit requirements. The performance requirements in Requirement R2.3 are specific to short-circuit studies. (b) Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. Also, the need for, or applicability, of 'single Contingencies' in Requirement R4 was dropped when Requirement R4 was merged into Requirement R2.3. **R2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area.		
MRO NERC Standards Review Subcommittee	No	a. Since the TPL contingency requirements already require bus fault, stuck breaker, and breaker failure contingencies, the MRO asks the SDT to clarify the purpose of the short circuit study requirements. The benefit to additional short-circuit studies is minimal since analyses already ensure that the system can withstand bus faults and breaker failures. b. The SDT should clarify what single contingencies are to be studied for short circuit studies in R2.4. Is it single contingency as defined in Table 1? Or is it a broader or narrower definition? The MRO recommends that since this is a new requirement, that TPL-001-1 be limited to raise the bar only to involve the single contingencies identified in P1. Failure to do so will require a great deal of additional modeling work in short-circuit studies if single contingencies in P2 are to be included in these studies with minimal benefit. c. The MRO suggests added clarification of the following questions: 1. Should analysis be performed for the near-term and long-term planning horizon? 2. Should only the peak system condition be analyzed? 3. What does the analysis include (e.g. breaker over duty evaluation and protective relay coordination)? R4 - Clarify that the "short-circuit capability of its equipment under normal conditions" (P0) refers to interruptible rating for breakers only.
Response: (a) These requirements apply to steady state (load flow) and Stability analysis but they do not specifically address short-circuit requirements. The		

Organization	Question 6:	Question 6 Comments:
performance requirements in Requirement R2.3 are specific to short-circuit studies. (b) Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. Also, the need for, or applicability, of 'single Contingencies' in Requirement R4 was dropped when Requirement R4 was merged into Requirement R2.3. **R2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area. (c) The SDT believes that the concerns raised here are covered in the revised requirement R2.3.		
Arkansas Electric Coop. Corp.	No	R2.3.1 should not be deleted. While system wide short circuit analysis should be done annually, there are situations where changes in the BES do impact the short circuit. If these changes result in new equipment needing to be ordered then this needs to be know as soon as possible in order to prevent exceeding equipment ratings or delays because of lead times on equipment.
Response: Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. **R2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area. The SDT has added Requirement R2.7 to provide a Corrective Action Plan. **R2.7** For short circuit analysis, if the short circuit current interruption duty on fault interrupting devices determined in Requirement R2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall: **R2.7.1** List System deficiencies and the associated actions needed to achieve required System performance. **R2.7.2** Be reviewed in subsequent annual Planning Assessments as to implementation status.		
ERCOT System Planning	No	ERCOT believes R4 is unnecessary and does not address an actual problem; ERCOT recommends that R4 be deleted. ERCOT does not presently possess the capability or have access to the data needed to perform the calculations required by R4 as this requirement should apply to only the equipment owner (GO or TO).
Response: The Planning Coordinator is the appropriate entity in some areas. In those areas where this is not the case, the Planning Coordinator may defer to the Transmission Planner's studies. This is a joint responsibility between the Transmission Planner and Planning Coordinator. Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. **R2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can		

Organization	Question 6:	Question 6 Comments:
be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area.		
American Transmission Company	No	We suggest added clarification of the following questions: 1. Should analysis be performed for the near-term and long-term planning horizon? 2. Should only the peak system condition be analyzed? 3. What does the analysis include (e.g. breaker over duty evaluation and protective relay coordination)? 4. Does the analysis of single contingency for greater duties refer to only the P1 category or both the P1 and P2 categories?R4 - Does the equipment capability reference include the ground grid and bus structures?
Response: The SDT did not add references to equipment beyond interrupting equipment. Circuit breaker or interrupting device ratings should already include support equipment. Lines are rated by the most limiting element and interrupting equipment ratings should also be rated by the most limiting equipment. Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. **R2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area.		
FirstEnergy Corp.	No	We do not feel that it is necessary to annually update the short circuit analysis. We suggest the SDT consider increasing this timeframe. In addition, short circuit analysis should be reviewed in areas where transmission or generation changes are planned. Lastly, we feel it would be beneficial for the standard to provide examples of contingencies that could increase fault duties.
Response: An annual "assessment" must be made, but this doesn't necessarily mean a new study unless topology changes accordingly. The SDT has revised Requirement R2.6.2 (now R2.5.2) which allows for the use of past studies. **R2.5.2** For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater. Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. **R2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System		

Organization	Question 6:	Question 6 Comments:
short circuit model with any generation and Transmission Facilities in service which could impact the study area.		
Orlando Utiliites Commission	Yes and No	OUC agrees with other commentors that if there is a need for monitoring this, it should perhaps be in a different standard.
Response: The SAR for TPL-001-1 specified that short-circuit studies were to be included in the requirements.		
Dominion - Electric Transmission Planning	Yes	
TVA System Planning	Yes	
Progress Energy Carolinas	Yes	
Platte River Power Authority	Yes	
Tenaska, Inc.	Yes	
ITC Holdings: ITC, METC, ITC Midwest	Yes	
Southern Company Transmission	Yes	
LCRA TSC	Yes	
IESO	Yes	

Organization	Question 6:	Question 6 Comments:
North Carolina Electric Membership Corp	Yes	
E.ON U.S. Transmission Planning	Yes	
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	Yes	
Oncor Electric Delivery	Yes	NA
Entergy Services, Inc.	Yes	
Response: Thank you for your response.		

7. **The SDT has reformatted the Steady State and Stability Performance Tables. Do you concur with the modified format? If not, please state why and/or suggest specific changes.**

Summary Consideration:

In responding to the reformatted performance tables, industry stakeholders had several comments related to the format changes and also took an opportunity to provide feedback on the table content as well. A summary of the more common industry responses is provided below along with the SDT's reply to each.

FORMAT COMMENTS:

1. The most common input received from industry related to the format of the tables was a desire for the SDT to consider a single table design covering both steady-state and stability. The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table design.

2. Many commenters felt the two table design was unduly long covering 13 pages compared to the two (2) pages used for the existing FERC approved TPL standards. Based on the redesigned single format table, the SDT has condensed the information to only 3 pages in the proposed Draft 3 version.

3. Another format change requested was to repeat the header row of column headings on each page. The SDT agrees and has made this change.

4. A few commenters correctly pointed out confusion between the introductory notes and the footnotes which both used numeric references. The SDT corrected this problem by using alpha character references for the introductory notes. The references within the table now clearly point to the footnotes and follow a more logical numerical order.

5. Several stakeholders suggested a Planning Event category naming convention for Planning Steady-State as (P1, P2, P3, …) and Stability as (S1, S2, S3, …) for the two table design. The SDT did not make this change based on a redesign to a single performance table. The team has retained the P1 through P7 references for Planning Events.

CONTENT COMMENTS:

1. The SDT agrees with a number of stakeholders that expressed an opinion on the need to allow for all types of conditional Firm Transmission Service Interruptions, not just those limited to HVDC. The SDT recognizes that the prior Draft 2 version unintentionally provided preferential treatment to HVDC. In the new performance Table 1, a new footnote has been added (see footnote 5) to the column title "Interruption of Firm Transmission Service Allowed" that corrects the problem identified.

2. Some commenters questioned the distinction in performance requirements for the above 300 kV systems. The SDT believes the Draft 2 changes are responsive to the prior industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission System. The team has now included a slightly modified version of stated performance requirements in Draft 3. The SDT has clarified that interruption of Firm Transmission Service is warranted for some Contingencies. The SDT has added footnotes 5 and 10 related to Firm Transmission Service. Footnote 5 indicates that interruption of conditional firm Transmission service is permitted for all Planning Events and footnote 10 indicates that interruption of Firm Transmission Service coupled with appropriate generation re-dispatch can be utilized for multiple Contingency events as a System adjustment, where indicated in Table 1 as being part of the Initial System Condition, and as a post-Contingency corrective action so long as no interruption of Non-Consequential Load occurs and all Facility Ratings are maintained.

3. A number of commenters expressed concern related to Planning Event P5 "Protection System Failure" and the need to evaluate a single component failure of a BES Protection System; particularly a failure of a station battery. The SDT has revised the P5 Planning Event description to remove the reference to "single component failure" and the event description was changed to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to normal fault clearing. A Protection System failure resulting in loss of the substation (one voltage level plus transformers) would not qualify as a P5 Planning Event since that event is considered an Extreme Event. A Standard Authorization Request (SAR) has been issued for industry comment (1/20/2009 through 2/18/2009) based on work completed by the System Protection and Controls Task Force (SPCTF). The proposed project will address the need for Protection System redundancy, based on an n-1 failure of individual components of the Protection System.

4. Some commenters were confused by Planning Event P2.1 and the SDT has added footnote 8 to better clarify the intent of the P2.1 Contingency review.

5. Many stakeholders correctly noted that Extreme Event item 1 excluded the reference to shunt device. This has been corrected and now includes shunt devices.

6. Some commenters questioned the order of the Planning Events and questioned if they were based on a high to low probability order. The SDT chose to order the table by three main areas: 1) no Contingency (P0), 2) single Contingency

(P1 and P2), and multiple Contingency (P3 through P7). While the SDT agrees there is some overlap in probability order, for example, between P2 and P3, the SDT has more importantly made the proper performance level requirements based on a reliability "risk" level where risk accounts for impact times (x) probability of occurrence.

7. Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these system designs are permissible under the presently approved TPL-002-0 standard. FERC, in Order 693, was clear in paragraph 1794 that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement. As an alternative, an entity could seek an entity variance for the situation described through their Regional Entity organization. In paragraph 1794, FERC clarified that "…an entity may seek a regional difference to the Reliability Standard from the ERO for case-specific circumstances". The process described by FERC as a regional difference is described in detail in the "NERC Standards Development Procedure" document under the subsection titled "Variances to NERC Reliability Standards".

The following changes have been made to the standard based on industry comments:

Requirements:

R2.8 The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1.

R2.9 The Planning Assessment shall identify the maximum permissible Non-Consequential Load Loss (megawatt Demand) for those Planning Events where Non-Consequential Load Loss is allowed in Table 1.

Table 1 Header Notes

e. For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

h. Planning Event P0 is applicable to steady state only.

Table 1 - Extreme Events – Steady State:

1. Loss of a single generator, Transmission Circuit, DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, DC Line, shunt device, or transformer forced out of service prior to System adjustments.

3b. ~~Loss of two Transmission lines in different rights-of-way prior to System adjustments for conditions such as:~~

Table 1 Footnotes:

2. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level for stated performance criteria applies regarding allowances for interruptions of Firm Transmission Service and loss of Non-Consequential Load.

3. Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø fault study indicating criteria are being met shall provide sufficient evidence that a SLG condition would also meet criteria.

5. When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed.

7. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.

8. Inadvertent tripping of breakers on one end of a normally networked Transmission circuit such that the line is now open at that end and possibly serving Load radial from a single source point.

10. Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.

11. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) breaker, only one pole is assumed to remain closed. ~~The~~A stuck breaker ~~event~~ introduces a delayed clearing mode. ~~Normal Clearing is when the Protection System operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Breaker fail relay operation is a predetermined time that occurs after the Protection System operates and the breaker has failed. Breaker fail relaying will also isolate a predetermined portion of the electric system to isolate the failed breaker. Delayed clearing of a Fault is due to failure of any Protection System component that prevents the Protection System from operating normally.~~

Organization	Question 7:	Question 7 Comments:
Dominion - Electric Transmission Planning	Yes and No	(1) Dominion - Electric Transmission is okay with the format changes, but suggests that consideration be given to changing the category naming convention for Stability Performance Table 2 to S1, S2, etc. rather than P1, P2, etc. for clarity and to distinguish them from Steady State Performance Table 1.(2) The tables could be improved if the headings were put on each separate page.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". This change has negated the need for the Planning		

Organization	Question 7:	Question 7 Comments:
Event category naming convention changes suggested by the commenter and the SDT retained the P1 through P7 references for Planning Events. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages.		
NPCC	No	In both Table 1 and Table 2, the "Interruption of Firm Transmission Service Allowed" column. It is problematic to try to create an "exemption" based on type of facility such as HVDC. There are many other situations in which Firm Transmission Service has been provided, but may need to be curtailed partially or completely following an outage. It is recommended that a note be added stating that the only exception would be for curtailment of conditioned (or Conditional) Firm Transmission Service, recognizing that there may need to be some form of grandfathering in order to avoid having to rewrite transmission service agreements. In both Table 1 and Table 2, the "Extreme Event Descriptions" item 1 should add "or shunt device." In Table 1, the "Extreme Event Descriptions" item 3b should be deleted; it is redundant with Item 1. In Table 2, Note 5 includes significant clarifications and should not be buried in the bottom of the contingency table; Note 5 would be better placed in the definitions section. In Table 1 and Table 2, Contingency P5 requires a fault plus Protection System Failure, such as a battery system, which may remove ALL protection at some substations. This Contingency P5 requires all voltages and loadings to remain within criteria, and a stable system response; without interruption of firm transmission service and without Non-Consequential Load Loss, at voltages above 300 kV. Was this an intended outcome of this standard?
Northeast Utilities	No	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
Response: The SDT team agrees with the commenter's opinion on the need to allow for all types of conditional Firm Transmission Service Interruptions and that the prior Draft 2 version unintentionally provided preferential treatment to HVDC. In the new performance Table 1, a new footnote has been added (see footnote 5) to the column title "Interruption of Firm Transmission Service Allowed" that corrects the problem identified by the commenter. **5**. When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed. The SDT agrees that shunt devices were excluded in Extreme Event item 1 of the Steady-State and Stability tables and the problem has been corrected. The SDT agrees with the commenter regarding the opinion that item 3B in the Extreme Event portion of the prior Daft 2 Table 1 Steady-State was redundant and the item has been removed and is no longer referenced in this draft. **Extreme Events - 3b**. ~~Loss of two Transmission lines in different rights-of-way prior to System adjustments for conditions such as:~~ The SDT appreciates the input related to the footnote on "System Stable" (new footnote 1). The SDT has chosen to leave the information within a footnote and		

Organization	Question 7:	Question 7 Comments:
did not include it as a new definition for the NERC Glossary of Terms as suggested by the commenter. Related to the P5 "Protection System Failure" Planning Event the SDT has not deviated from its stance of requiring more stringent performance requirements for the above 300 kV System. The SDT has revised the P5 Planning Event description to remove the reference to "single component failure" and the event description was changed to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to the normal fault clearing. A Protection System failure resulting in loss of the substation (one voltage level plus transformers) would not qualify as a P5 Planning Event since that event is considered an Extreme Event. A Standard Authorization Request (SAR) has been issued for industry comment (1/20/2009 through 2/18/2009) based on work completed by the System Protection and Controls Task Force (SPCTF). The proposed project will address the need for Protection System redundancy, based on an n-1 failure of individual components of the Protection System.		
TVA System Planning	Yes	TVA believes that the new table format does make the tables much easier to follow. However, the tables can be a little hard to follow for those categories that have both over and under 300-kV categories. Also having header pages at the top of each page of the tables would also help. Should P6 and P7 events be moved to Extreme Events since firm transmission and non-consequential load can be dropped for these events? Seems like these events are very similar to the Extreme Events.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages. The SDT has elected to retain both P6 (N-1-1) and P7 (Common Tower N-2) Planning Events in this third draft. There was no compelling industry opinion for the change and the events were considered by the SDT to be credible events and warrant the Planning Event level of scrutiny. There are more severe versions of these events contained with the Extreme Event area.		
City Water, Light & Power - Springfield, Illinois	Yes and No	Place the titles on each page and put the borders back in.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages. The SDT believes the new table will also address your concern regarding the borders. If not, please provide a more specific comment in your review of the Draft		

Organization	Question 7:	Question 7 Comments:
3 standard.		
Progress Energy Carolinas	Yes	The readability of the tables could be improved if the headings were put on each separate page. Separating out the tables for steady state and stability greatly improves and clarifies the requirements of the standard. Additionally, we would prefer that dynamic planning events use labeling such as D1, D2, etc. instead of P1, P2, etc. to differentiate them from steady state events.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table has negated the need for the Planning Event category naming convention changes suggested by the commenter and the team retained the P1 through P7 references for Planning Events. The move to a single table was based on a significant number of comments and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages.		
Platte River Power Authority	Yes and No	I like the emphasis on stability performance but I prefer one table combining steady-state and stability Categories since the Planning Events are common to both. Divide notes, Evaluation Requirements, and Extreme Events Descriptions into two sub-tables.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of commenters, like yourself, who felt a single table would suffice. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The SDT divided the top notes between those that are applicable to Steady-state, Stability or both as suggested by the commenter.		
BCTC	No	The differences in the tables requiring two tables are not apparent. Furthermore, we have become familiar with working with the current Table 1. Changing to these new tables will result in transition costs. We see no problems with continuing to use the current Table 1 and would prefer to retain it.
Response: While the new tables and naming conventions will require some effort for industry adaption, the SDT believes the tables provide greater clarity and drive the reliability improvements desired by FERC Order 693.		

Organization	Question 7:	Question 7 Comments:
Manitoba Hydro	No	There appears to be little difference between Table I and II other than the performance requirements at the start of each table, which should be embedded within standard. Manitoba Hydro would prefer one table as we believe it serves to simplify the standard readability. Additional Comments on Table 1:The Performance Requirements (Items 1 to 6) should have a heading "Evaluation Requirements". These evaluation requirements should be included in the standard body. Also they should be labeled A to F to avoid confusion with the Notes at the end of the Table. Item 6 is not applicable for steady state analysis. Suggest changing "Notes" to "Table I Notes" for improved readability if more than one table is retained. Planning Events: In cases where Non-consequential Load Loss is allowed, has the SDT discussed limiting the amount of load lost? Planning Events: For the multiple contingency events, in cases where Interruption of Firm Transmission Service or Non-Consequential Load Loss is allowed, the SDT should clarify that such loss is only allowed after the second event. P1: Similar to DC lines, interruption of Firm Transmission Service should be allowed for AC transmission lines, as in many cases, the firm transmission service is dependent on the outaged AC transmission line or transformer, that is, the contract path. P2-1: Suggest changing :single ended line: to "open ended line". P3: Similar to DC lines, interruption of Firm Transmission Service should be allowed if transfer is dependent on the outaged AC transmission line or transformer - the contract path. Planning Events >300 kV: Interruption of firm transfer should be allowed if AC contract path is lost due to an event. In many cases the majority of the firm transfer is carried by the contract path ac line, not that unlike the case of the DC line. MH has sold Firm Transmission Service, the delivery of which is dependent on the single circuit Winnipeg-Twin Cities 500 kV line being in-service, This Firm Transmission Service is available in the order of 99.6% of the time. Assuming two 5 day planned maintenance outages per year the availability is 97.3% per year. MH's transmission customers did not want to pay some $800 million in capital costs for a second 500 kV line to increase the Firm Transmission Service availability by 2%, especially considering that Firm Transmission Service loss does not result in loss of load, but results in a call for redispatch (call for Operating Reserves being carried to cover for loss of the largest generator or largest loaded transmission line with associated fast generation runback (SPS)). The inability to interrupt Firm Transmission Service will drive expensive new line construction, or require withdrawal of 1500 MW of firm transmission service from the market. P4: Greater than 300 kV - Interruption of Firm Transmission Service should be allowed if transfer is dependent on the outaged AC transmission line or transformer. The low probability of P4 events does not warrant the cost of raising the reliability performance requirements.

Organization	Question 7:	Question 7 Comments:
		P5: Greater than 300 kV - Interruption of Firm Transmission Service should be allowed if transfer is dependent on the outaged AC transmission line or transformer. NERC defines a Protection System as "Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry. In many cases, the protective relays, associated communication circuits and DC control circuits consist of two separate or redundant systems, but the voltage and current devices and station battery may be common. Is the SDT considering a current sensing device, or the station battery, for example, to be a single point of failure? Table 1 Note 4: Imposes a requirement on FACTS devices, and therefore should be elevated to the Requirements in the standard body. Also FACTs devices can be put in a series connection as well as shunt. Perhaps some additional clarification is required. Additional Comments on Table 2: Stability Performance Requirements: ?The Performance Requirements (Items 1 to 5) should have a heading "Evaluation Requirements". These evaluation requirements should be included in the standard body. Also they should be labeled A to E to avoid confusion with the Notes at the end of the Table 2 – Item 4: should the simulation also include the effect of reclosing where applicable? Planning Events: Same as comments on Table 1 regarding treatment of Firm Transmission Service and Non-Consequential Load Loss for >300 kV P4: Greater than 300 kV - Interruption of Firm Transmission Service should be allowed if transfer is dependent on the outaged AC transmission line or transformer. P5: Greater than 300 kV - Interruption of Firm Transmission Service should be allowed if transfer is dependent on the outaged AC transmission line or transformer. Multiple Contingency events (P3, P6): Does the SDT envision these multiple events being simulated as a stability run for the second event using a base case with an adjusted system - considering the first event is typically P1 which has been previously run as a separate simulation, typically a P1 event? P5: see Table 1 comment re what is considered a single point of failure. Extreme Events: Evaluation Requirement 1 - R5.5.4 should be R5.4.4 Extreme Event Description 2H: A 3 phase bus fault on a switching station would not normally result in loss of a voltage level and transformers at a station. The event should just be loss of one voltage level plus transformers in a substation. Table 2 Notes: Suggest changing "Notes" to "Table 2 Notes" if more than one table is retained. Note 5 a. Stipulates requirements for generating unit performance - should not be buried in the notes. Also, what is the SDT rationale for allowing units to pull out of synchronism for single contingency events like P2, or P5 - stuck breaker, or P7 - common tower, which is a normal clearing event.

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		P1: Similar to DC lines, interruption of Firm Transmission Service should be allowed if transfer is dependent on the outaged AC transmission line or transformer. P3: Similar to DC lines, interruption of Firm Transmission Service should be allowed if transfer is dependent on the outaged AC transmission line or transformer. It is important for a probabilistic measure of likelihood to be considered in designing Table 1 and Table 2. The various categories of contingencies, P1 to P7, for example, should be ideally arranged in order of magnitude of likelihood, so that the acceptable consequences or the performance requirements may be in an increasing level of severity. However, there are events with intrinsically different probabilities currently classified within each of these contingency categories. For example, in P3 (following loss of a generator followed by system adjustments), another generator forced outage is more likely than a transformer forced outage. In P2 (single contingency), loss of a bus section is less likely than the P3 event of a double generator contingency. Therefore, these P categories, as currently defined, overlap one another in the scale of likelihood. As a result of it, Table 1 and Table 2 have allowed for certain rarer events (e.g., included in single-contingency P2 and double-contingency P3 categories) to incur some significant consequences with unspecified limits, e.g., interruption of firm transmission services or "non-consequential" load loss. It may be better to follow the NERC Reliability Concepts White Paper's approach of displaying these tables in categories of event likelihood, so that the acceptable consequences would be in an increasing level of severity. This approach would then be consistent with Probabilistic Risk Assessment, when the industry has collected enough transmission outage data to enable such a method be applied. Though the US power industry does not have transmission outage statistics collected and analyzed across the industry, Canadian utilities do have excellent data. It seems to be possible for the various contingency events in the current Tables 1 and 2 to be recategorized according to five or six groups of "order of magnitude of likelihood", e.g., M0, M1, M2, M3, M4 and M5. Each order of magnitude of likelihood is ten times less likely than the preceding order. For example, the first order (M1) would be for outage probabilities greater than 1%. The second order (M2) would be for outage probabilities between 0.1% and 1%. The third order (M3) would be between 0.01% and 0.1%, etc. Multiple independent contingencies could be classified based on the product of their individual probabilities, e.g., a generator outage is of order M1, and a transmission circuit outage is of order M2. Therefore, a double contingency of a generator and a transmission circuit is of order M3, but a double generator contingency is of order M2. Having placed the initiating contingencies in these orders of likelihood, it is then feasible for the industry stakeholders to try to agree on the level of acceptable consequences for these magnitude orders of likelihood. In the current draft of this standard, there is no quantified variable degree of acceptable consequences, as envisioned in the NERC Reliability Concept White Paper.There is distinctly different treatment of whether the out-of-service element is below or above 300KV. There is difference in allowing or not allowing firm transaction interruption and/or non-consequential load loss, but neither of them has a specified limit on the MW amounts. With the current layout of Tables 1 and 2, it is not readily apparent that the proposed standard is consistent with a sound risk approach. Having a sound risk approach is very important because investment decisions will be made according to these new, proposed and still-deterministic standards. Planners may find out in their studies that the costs of meeting some unlikely contingencies requiring expensive transmission investments are very high and that these costs are not justifiable based on avoiding those rare consequences. On the other hand, because the amounts of acceptable firm transaction interruption and non-consequential load loss are not specified, the transmission system designed to that

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		standard with unspecified limits may become vulnerable to cascading events that initiate in the transmission grid below 300 KV. Many entries in the Tables allow non-consequential load losses, but no limits are specified. It raises the question, "If any non-consequential load loss is acceptable, is there a need to study that contingency scenario?" Without a reasonable set of limits, the criteria may not be effective in assuring system reliability. NERC's event analysis group has been using five categories of consequences to classify recent blackouts or major disturbances. A condensed summary of this is as follows. Category 1. Abnormal frequencies > 5min; or inter-area oscillations Cateorgy 2. System separation with no loss of load or generation; or loss of generation (between 1,000 and 2,000 MW in the EI or WI and between 500 MW and 1,000 MW in ERCOT) Category 3. Loss of load (less than 1,000 MW); or loss of generation (> 2,000 MW in the EI or WI and > 500 MW in ERCOT); System separation or islanding with loss of load or generation (less than 1,000 MW). Category 4. System separation or islanding of more than 1,000 MW of load; or loss of load (1,000 to 9,999 MW). Category 5. Loss of load (10,000 MW or more) Lay persons as well as transmission planners can understand and appreciate these ways of defining consequences, e.g., category 5 events mean more than 10,000 MW of load or generation loss. A way to propose reasonable limits to the highly unlikely but potentially severe contingencies, e.g., M3, M4, and M5, would be to limit their designed consequences to Category 2, 3 or 4. A well designed transmission system should limit the consequences of potential cascading outages and their likelihood so that fewer major blackouts would occur, while balancing the cost of investment to the cost of outages to the customers. A number of utilities are already performing PRA studies for their transmission planning. The advantages of using PRA have been demonstrated in the nuclear power industry. It would be desirable to have a pathway for the power industry to transition from the still-deterministic planning criteria in TPL-001 to a probabilistic planning criteria, without having to wait for another major revision to the TPL standard. If the Tables 1 and 2 are arranged and presented consistently with the NERC Reliability Concepts White Paper, the approach will enable that transition to take place naturally. If the TPL-001 standards establish a PRA-compatible Table 1 and Table 2, with contingency categories sorted in order of magnitude of likelihood, and their acceptable consequences also arranged in order of consequences (such as the five categories), the reliability requirement is already seen in the PRA-compatible way of a constant Risk level, Risk = Likelihood x Consequence. When the industry has good data to quantify the probabilities of these various contingencies, the implication of this ?already-accepted? Risk Level would be clear and numerically expressable. What is useful at this time is for the industry to make a forward-looking estimate of what this Risk level would be like, and consider whether it is appropriate and consistent with sound economic and risk principles.

Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled “Steady State and Stability Performance”. The move to a single table was based on a significant number of comments and based on the SDT’s view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages.

The top introductory notes have been retained and are now referred to alphabetically to avoid confusion with the referenced footer notes. The top notes also

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better clarify which are applicable to steady-state, stability or both.

The standard does not place a limit on the amount of Non-Consequential Load loss allowed. However, the maximum Consequential Load loss and its associated Contingency require documentation. See Requirements R2.9 and 2.10.

R2.8 The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1.

R2.9 The Planning Assessment shall identify the maximum permissible Non-Consequential Load Loss (megawatt Demand) for those Planning Events where Non-Consequential Load Loss is allowed in Table 1.

In regards to the Planning Event P3, the SDT team agrees with the commenter's opinion on the need to allow for all types of conditional Firm Transmission Service interruptions and that the prior Draft 2 version unintentionally provided preferential treatment to HVDC. In the new performance Table 1, a new footnote has been added (see footnote 5) to the column title "Interruption of Firm Transmission Service Allowed" that corrects the problem identified by the commenter. The SDT believes that interruption of Firm Transmission Service may be justified, so long no firm load loss occurs if the performance requirements do not permit the load shed. See new footnote 10 regarding the SDT stance on interruption of Firm Transmission Service and its use in multiple contingency Planning Events.

In regards to Planning Event P2.1, the reference to "single ended" has been removed and footnote 8 was added to further clarify the event required for study.

Based on feedback received the SDT was not compelled to alter its stance on the provision for Non-Consequential Load shed for a P4 and P5 event. However, the SDT has added footnotes 5 and 10 related to Firm Transmission Service. Footnote 5 indicates that interruption of conditional firm transfers is permitted for all Planning Events and footnote 10 indicates that interruption of Firm Transmission Service coupled with appropriate generation re-dispatch can be utilized for multiple Contingency events as a System adjustment, where indicated in Table 1 as being part of the Initial System Condition, and as a post-Contingency corrective action so long as no interruption of Non-Consequential Load occurs and all Facility Ratings are maintained.

The SDT has revised the P5 Planning Event description to remove the reference to "single component failure" and the event description was changed to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to the normal fault clearing. A Protection System failure resulting in loss of the substation (one voltage level plus transformers) would not qualify as a P5 Planning Event since that event is considered an Extreme Event. A Standard Authorization Request (SAR) has been issued for industry comment (1/20/2009 through 2/18/2009) based on work completed by the System Protection and Controls Task Force (SPCTF). The proposed project will address the need for Protection System redundancy, based on an n-1 failure of individual components of the Protection System.

The SDT agrees that FACTS can be series devices and the footnote reference has been modified to better clarify the intent is shunt devices, connected to ground. See footnote 7.

7. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.

The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of

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comments and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages. The requirements do not require study of reclosing actions. Only the initial Protection System responses must be simulated. P3 – see above response for Table 1. Based on feedback received the SDT was not compelled to alter its stance on the provision for Non-Consequential Load shed for a P4 and P5 event. However, the SDT has added footnotes 5 and 10 related to Firm Transmission Service. Footnote 5 indicates that interruption of conditional firm transfers is permitted for all Planning Events and footnote 10 indicates that interruption of Firm Transmission Service coupled with appropriate generation re-dispatch can be utilized for multiple Contingency events as a System adjustment, where indicated in Table 1 as being part of the Initial System Condition, and as a post-Contingency corrective action so long as no interruption of Non-Consequential Load occurs and all Facility Ratings are maintained. In the multiple Contingency P3 (Gen + 1) and P6 (N-1-1), within a stability study only the 2nd outage is required to be reviewed. The first Contingency is a precondition that needs to be modeled but not evaluated for its Stability response if the P3 or P6 condition is studied for Stability. The SDT has revised the P5 Planning Event description to remove the reference to "single component failure" and the event description was changed to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to the normal fault clearing. A Protection System failure resulting in loss of the substation (one voltage level plus transformers) would not qualify as a P5 Planning Event since that event is considered an Extreme Event. A Standard Authorization Request (SAR) has been issued for industry comment (1/20/2009 through 2/18/2009) based on work completed by the System Protection and Controls Task Force (SPCTF). The proposed project will address the need for Protection System redundancy, based on an n-1 failure of individual components of the Protection System. In the Extreme Events area of the Stability table the reference to Requirement R5.5.4 has been removed due to a circular reference between the requirements and the table. The Extreme Event item 2h is written consistent with the presently approved TPL D8 and D9 contingencies. The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages. The SDT team agrees with the commenter's opinion on the need to allow for all types of conditional Firm Transmission Service interruptions and that the prior Draft 2 version unintentionally provided preferential treatment to HVDC. In the new performance Table 1, a new footnote has been added (see footnote 5) to the		

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column title "Interruption of Firm Transmission Service Allowed" that corrects the problem identified by the commenter Regarding bottom note 5a, now shown as footnote 1, the SDT believes that no unit should be allowed to pull out of synchronism for more likely single Contingency events such as a three-phase fault on a line, transformer, or generator - a P1 event. The P2 events, even though classified as single Contingency events with normal clearing, are less likely to occur (bus faults, internal breaker faults, etc.). P5 and P7 are multiple Contingency events and are less likely to occur. The SDT believes it is appropriate to allow units to pull out of synchronism for less likely events as long as the other conditions of footnote 1 are maintained. The Planning Events, in general are ordered based on level of probability. However, the SDT chose to order the table by three main areas: 1) no Contingency (P0), 2) single Contingency (P1, P2) and 3) multiple Contingency (P3 through P7). While the SDT agrees with the commenter that there is some overlap in probability order, for example between P2 and P3, we believe the SDT has more importantly made the proper performance level requirements based on a reliability "risk" level where risk accounts for impact times (x) probability of occurrence. The commenter's proposed shift from deterministic planning to probabilistic planning is outside the scope of the SAR for this project. The SDT believes the commenters suggested focus on more detailed probabilistic analysis is better addressed after the industry obtains additional outage data and insight obtained through the TADS effort.		
Los Angeles Department of Water and Power	No	The performance table allows different performance for same contingency at different voltage classes that is arbitrary separated. This is discriminatory and without any scientific or historical basis. There should be only one class for the whole transmission system. Transmission system at below 300kV should not be granted preferential treatment. Mindful also that the initiating causes of last two major continental wide blackouts(one in WECC and the other in the Eastern Interconnections) both started in system at less than 300kV.
Response: The SDT believes it has provided sufficient reasoning why the above 300 kV System should be held to a higher standard. The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission Systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT believed the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated above 300 kV generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers where the energy is then delivered by other Transmission or sub-Transmission Systems to end-use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. Additionally, loss of the EHV system stresses the lower voltage parallel paths. EHV transformers can be exposed to long duration outages. Therefore, it was the conclusion of the SDT in Draft 1 to propose greater reliability and operational flexibility through more stringent performance requirements when considering certain N-1 and N-1-1 Contingency events of EHV Systems. Throughout the industry, substation arrangements at EHV levels reflect the importance of these Systems as the designs often consist of the more flexible and reliable ring-bus, breaker-and–a-half or double bus-double breaker protection schemes as compared to the simpler, lower cost single bus arrangements that are commonly found on lower voltage systems. The feedback received from the industry was divided related to the SDT's emphasis placed on a higher expectation for the 300 kV and higher systems. Some commenters questioned the importance and the high costs that may be needed to mitigate existing system designs. Others agreed with the SDT's approach and indicated that the impact to their systems would be minimal. Some commenters even questioned why the more stringent approach was not applied to the entire		

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100 kV and higher systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission System.		
Transmission Agency of Northern California	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.
Public Service Company of New Mexico	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.
Puget Sound Energy, Inc.	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for events could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not

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Black Hills Corporation	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.
Tucson Electric Power Company	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.The proposed format covers multiple pages. Add the header rows to each page for easier reading.

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Pacific Gas and Electric Co.	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.
Idaho Power Company	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some maybe some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SGT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believes there should be no distinction between the voltage classes and supports the use of load shed for all cases identified in P4 through P7.
SMUD	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state.

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Sierra Pacific Power Comapny / Nevada Power Company	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some maybe some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SGT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believes there should be no distinction between the voltage classes and supports the use of load shed for all cases identified in P4 through P7.
SRP	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.
Tucson Electric	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two

Organization	Question 7:	Question 7 Comments:
Power Company		Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.The proposed format covers multiple pages. Add the header rows to each page for easier reading.
Modesto Irrigation District	Yes and No	Comments: We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.
Tri-State G&T	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate

Organization	Question 7:	Question 7 Comments:
		interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.
ColumbiaGrid	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some maybe some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SGT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Please explain/define the term "single ended line" used in Table 1, P2.1. We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.
Alberta Electric System Operator	No	We do not agree with the proposed format changes of the Tables, separating into two Tables is not necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.
US Bureau of Reclamation	No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not

Organization	Question 7:	Question 7 Comments:
		modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.

Response: The SDT agrees with the commenter related to the prior two table format and based on feedback received from the Draft 2 standard the SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The SDT believes the commenter will find that the new format is greatly condensed and more user friendly from a readability view.

The commenter is correct that the use of the term "fault" in the P4 and P5 events is not needed from a steady-state view; however, the SDT felt the term is needed to accurately describe the event to be analyzed. From a steady-state perspective, only the resulting condition would be analyzed. Also, with the combined format the term is now better used as the Planning Events also describe the type of fault to be studied within a Stability study. Footnote 3 clarifies that the type of fault is referenced only for the Stability studies.

In regards to the P2.1 event, the intent is to capture a potential condition of serving Load that is tapped from a normally networked line from a single source location. If a line exists (breaker to breaker) that does not directly serve Load, the P2.1 condition would not apply and only the normal N-1 condition of the line would be studied. See the newly added footnote 8 that better describes the intent of the P2.1 Planning Event.

The SDT believes it provided sufficient justification in its Draft 1 response as to why a greater expectation is placed on the above 300 kV (EHV) system. The feedback received from the industry was divided related to the SDT's emphasis placed on a higher expectation for the 300 kV and higher systems. Some commenters questioned the importance and the high costs that may be needed to mitigate existing system designs. Others agreed with the SDT's approach and indicated that the impact to their systems would be minimal. Some commenters even questioned why the more stringent approach was not applied to the entire 100 kV and higher systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission System.

Based on feedback received the SDT was not compelled to alter its stance on the provision for non-consequential load shed. However, the SDT has added footnotes 5 and 10 related to Firm Transmission Service. Footnote 5 indicates that interruption of conditional firm transfers is permitted for all Planning Events and footnote 10 indicates that interruption of Firm Transmission Service coupled with appropriate generation re-dispatch can be utilized for multiple Contingency events as a System adjustment, where indicated in Table 1 as being part of the Initial System Condition, and as a post-Contingency corrective action so long as no interruption of Non-Consequential Load occurs and all Facility Ratings are maintained.

5. When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed.

Organization	Question 7:	Question 7 Comments:
National Grid	No	a. In the column "Interruption of Firm Transmission Service Allowed" in both Tables 1 and 2, it is problematic to try to create an "exemption" based on type of facility such as HVDC. There are many other situations in which Firm Transmission Service has been provided, but may need to be curtailed partially or completely following an outage. b. The term 'Firm' may have several different definitions. If 'Firm' Transmission Service or load may be interrupted for exceptional events, then it is conditional and 'Conditional Firm' should be defined. It is recommended that a note be added stating that "the only exception would be for curtailment of conditioned (or Conditional) Firm Transmission Service", recognizing that there may need to be some form of grandfathering in order to avoid having to rewrite transmission service agreements. c. In both Table 1 and Table 2, the "Extreme Event Descriptions" item 1 should add "or shunt device." d. In Table 1, the "Extreme Event Descriptions" items 3a and 3b should be deleted; they are redundant with Item 1. e. In Table 2, Note 5 includes significant clarifications and should not be buried in the bottom of the contingency table; Note 5 would be better placed in the definitions section. f. In Table 1 and Table 2, Contingency P5 requires a fault plus Protection System Failure. Assuming that the battery system is included in the Protection System, which it is in NPCC, then ALL protection at substations with single battery systems would be lost. This Contingency P5 requires a stable system response while all bus voltages and loadings to remain within criteria, without interruption of firm transmission service and without Non-Consequential Load Loss, at system voltages above 300 kV. Was this an intended outcome of this standard?
Central Maine Power Company	No	a. In both Table 1 and Table 2, the "Interruption of Firm Transmission Service Allowed" column. It is problematic to try to create an "exemption" based on type of facility such as HVDC. There are many other situations in which Firm Transmission Service has been provided, but may need to be curtailed partially or completely following an outage. b. The term 'Firm' may have several different definitions. If 'Firm' Transmission Service or load may be interrupted for exceptional events, then it is conditional and 'Conditional Firm' should be defined. It is recommended that a note be added stating that "the only exception would be for curtailment of conditioned (or Conditional) Firm Transmission Service", recognizing that there may need to be some form of grandfathering in order to avoid having to rewrite transmission service agreements. c. In both Table 1 and Table 2, the "Extreme Event Descriptions" item 1 should add "or shunt device." d. In Table 1, the "Extreme Event Descriptions" items 3a and 3b should be deleted; they are redundant with Item 1. e. In Table 2, Note 5 includes significant clarifications and should not be buried in the bottom of the contingency table; Note 5 would be better placed in the definitions section.

Organization	Question 7:	Question 7 Comments:
		f. In Table 1 and Table 2, Contingency P5 requires a fault plus Protection System Failure. Assuming that the battery system is included in the Protection System, which it is in NPCC, then ALL protection at substations with single battery systems would be lost. This Contingency P5 requires a stable system response while all bus voltages and loadings to remain within criteria, without interruption of firm transmission service and without Non-Consequential Load Loss, at system voltages above 300 kV. Was this an intended outcome of this standard?
NSTAR Electric	No	1. Referring to both Table 1 and Table 2, the "Interruption of Firm Transmission Service Allowed" column, it is problematic to try to create an "exemption" based on the type of facility such as HVDC. There are situations in which Firm Transmission Service has been provided, but may need to be curtailed partially or completely following an outage. The term 'Firm' may have several different definitions. If 'Firm' Transmission Service or load may be interrupted for exceptional events, then it is conditional and 'Conditional Firm' should be defined. It is recommended that a note be added stating that "the only exception would be for curtailment of conditioned (or Conditional) Firm Transmission Service", recognizing that there may need to be some form of grandfathering in order to avoid having to rewrite transmission service agreements. 2. In both Table 1 and Table 2, the "Extreme Event Descriptions" item 1 should add "or shunt device." 3. In Table 1, the "Extreme Event Descriptions" items 3a and 3b should be deleted; they are redundant with Item 1. 4. Table 2, Note 5 includes significant clarifications which should not be buried in the back; they are better placed in the definitions section. 5. In Table 1 and Table 2, Contingency P5 requires a fault plus Protection System Failure. Protection System Failure should be defined and noted if the battery system is included.
New York Independent System Operator	No	In both Table 1 and Table 2, the "Interruption of Firm Transmission Service Allowed" column. It is problematic to try to create an "exemption" based on type of facility such as HVDC. There are many other situations in which Firm Transmission Service has been provided, but may need to be curtailed partially or completely following an outage. It is recommended that a note be added stating that the only exception would be for curtailment of conditioned (or Conditional) Firm Transmission Service, recognizing that there may need to be some form of grandfathering in order to avoid having to rewrite transmission service agreements. In both Table 1 and Table 2, the "Extreme Event Descriptions" item 1 should add "or shunt device." In Table 1, the "Extreme Event Descriptions" item 3b should be deleted; it is redundant with Item 1. In Table 2, Note 5 includes significant clarifications and should not be buried in the bottom of the contingency table; Note

Organization	Question 7:	Question 7 Comments:
		5 would be better placed in the definitions section. In Table 1 and Table 2, Contingency P5 requires a fault plus Protection System Failure, such as a battery system which may remove ALL protection at some substations. This Contingency P5 requires all voltages and loadings to remain within criteria, and a stable system response; without interruption of firm transmission service and without Non-Consequential Load Loss, at voltages above 300 kV. Was this an intended outcome of this standard?
ISO New England Inc.	No	a. In both Table 1 and Table 2, the "Interruption of Firm Transmission Service Allowed" column. It is problematic to try to create an "exemption" based on type of facility such as HVDC. There are many other situations in which Firm Transmission Service has been provided, but may need to be curtailed partially or completely following an outage. b. The term 'Firm' may have several different definitions. If 'Firm' Transmission Service or load may be interrupted for exceptional events, then it is conditional and 'Conditional Firm' should be defined. It is recommended that a note be added stating that "the only exception would be for curtailment of conditioned (or Conditional) Firm Transmission Service", recognizing that there may need to be some form of grandfathering in order to avoid having to rewrite transmission service agreements. c. In both Table 1 and Table 2, the "Extreme Event Descriptions" item 1 should add "or shunt device." d. In Table 1, the "Extreme Event Descriptions" items 3a and 3b should be deleted; they are redundant with Item 1. e. In Table 2, Note 5 includes significant clarifications and should not be buried in the bottom of the contingency table; Note 5 would be better placed in the definitions section. f. In Table 1 and Table 2, Contingency P5 requires a fault plus Protection System Failure. Assuming that the battery system is included in the Protection System, which it is in NPCC, then ALL protection at substations with single battery systems would be lost. This Contingency P5 requires a stable system response while all bus voltages and loadings to remain within criteria, without interruption of firm transmission service and without Non-Consequential Load Loss, at system voltages above 300 kV. Was this an intended outcome of this standard?

Response:

The SDT agrees with the commenter's opinion on the need to allow for all types of conditional Firm Transmission Service interruptions and that the prior Draft 2 version unintentionally provided preferential treatment to HVDC. In the new performance Table 1, a new footnote has been added (see footnote 5) to the column title "Interruption of Firm Transmission Service Allowed" that corrects the problem identified by the commenter.

The SDT agrees with the commenter that interruption of Firm Transmission Service may be justified, so long as firm Non-Consequential Load is not interrupted if the performance requirements do not permit the Load shed. See new footnote 10 regarding the SDT stance on interruption of Firm Transmission Service and its use in multiple Contingency Planning Events.

Organization	Question 7:	Question 7 Comments:
The SDT agrees that shunt devices were excluded in Extreme Event item 1 of the Steady-State and Stability tables and the problem has been corrected. The SDT agrees with the commenter regarding the opinion that item 3B in the Extreme Event portion of the prior Daft 2 Table 1 Steady-State was redundant and the item has been removed and is no longer referenced in this draft. **Extreme Events - 3b**. ~~Loss of two Transmission lines in different rights-of-way prior to System adjustments for conditions such as:~~ The SDT appreciates the input related to the footnote on "System Stable" (new footnote 1) but the SDT chose to keep it as a footnote reference for convenience to the TPL standard and not include it as a new definition for the NERC Glossary of Terms as suggested by the commenter. Related to the P5 "Protection System Failure" Planning Event the SDT has not deviated from its stance of requiring more stringent performance requirements for the above 300 kV System. The SDT has revised the P5 Planning Event description to remove the reference to "single component failure" and the event description was changed to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to the normal fault clearing. A Protection System failure resulting in loss of the substation (one voltage level plus transformers) would not qualify as a P5 Planning Event since that event is considered an Extreme Event. A Standard Authorization Request (SAR) has been issued for industry comment (1/20/2009 through 2/18/2009) based on work completed by the System Protection and Controls Task Force (SPCTF). The proposed project will address the need for Protection System redundancy, based on an n-1 failure of individual components of the Protection System.		
Tenaska, Inc.	Yes and No	Should add a column to the tables indicated when automatic generation runback/tripping is allowed.
Response: Redispatch of generation is allowed for all Planning Events provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits. The requirement has been removed and replaced with Table 1 header note "e" since the text in the former requirement was explanatory of what was allowed and not requirement language. **Header note 'e'**: For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.		
Gainesville Regional Utilities	No	Some of the notes at the top of each table could be considered to apply to some of the events within the table that conflict in part with the standard and with what was stated in the nation wide phone conference. I would also like to see a note in the tables that reflect a technical rationale for the range of elements considered, since some may be impractical and of no technical value for contingencies involving certain facilities especially those on the smaller systems within the interconnected region.
Response: The SDT has adjusted the top notes and refer to them with alpha character references to avoid confusion with the table footnotes that are referenced within the table. The set of Contingencies considered are not greatly different than those in the currently approved TPL suite of standards. We have attempted to add simplicity as to those Contingencies that are deemed to be Planning Events, thus requiring corrective action plans, and the Extreme Events which do not require corrective action plans.		

Organization	Question 7:	Question 7 Comments:
ITC Holdings: ITC, METC, ITC Midwest	Yes and No	While we like the tables, we don't understand what ?Interruption of Firm Transmission Service Allowed? means in a stability study (as per table 2). How would you interpret that in real-time & study terms? Would you make the stability scenario a limit to selling transmission service? In table 2, should we interpret SLG or 3-phase Fault in P1 and P3 to mean that SLG is the criteria (minimum) but you can run and document the more severe 3 phase faults for compliance purposes? What is the minimum criteria?
Response: The SDT has added footnotes 5 and 10 related to Firm Transmission Service. Footnote 5 indicates that interruption of conditional firm transfers is permitted for all Planning Events and footnote 10 indicates that interruption of Firm Transmission Service coupled with appropriate generation re-dispatch can be utilized as a System adjustment, where indicated in Table 1 as being part of the Initial System Condition, and as a post-Contingency corrective action so long as no interruption of Non-Consequential Load occurs and all Facility Ratings are maintained. In some instances, it may be necessary to interrupt Firm Transmission Service in preparation for the studied condition. It could be that from a Stability point of view such action would be beneficial under some conditions. **Footnote 5.** When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. The SDT has corrected the confusion related to the "SLG or 3-phase" fault reference that the commenter describes in the P1 Planning Event. The table now says 3-phase. We added footnote #3 to clarify the fault types and what study results are sufficient for the case of an SLG fault condition. **3.** Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø fault study indicating criteria are being met shall provide sufficient evidence that a SLG condition would also meet criteria.		
Hydro-Quebec Transenergie (HQT)	No	In both Table 1 and Table 2, the "Interruption of Firm Transmission Service Allowed", a definition should be provided to clarify that term. That term is more of a Market concept not used by all TOs and defined in their Transmission Tariff. Also, the standard might need to introduce a new term "Consequential Transmission Service Loss" as it does for the Load. Firm Transmission services are generally defined as a service of the same priority as the one for the native load. That does not mean it could not be interrupted. In both Table 1 and Table 2, the "Extreme Event Descriptions" item 1 should add "or shunt device." In Table 1, the "Extreme Event Descriptions" item 3b should be deleted; it is redundant with Item 1.

Organization	Question 7:	Question 7 Comments:
		In Table 2, Note 5 includes significant clarifications and should not be buried in the bottom of the contingency table; Note 5 would be better placed in the definitions section. In Table 1 and Table 2, Contingency P5 requires a fault plus Protection System Failure. The "Protection System Failure" aspect of this contingency brings the necessity to define more clearly what is intended. The notion of needed redundancy or single elements of the protection system, be it physical or electric, has to be addressed to clearly understand the implication of that contingency. Until such clarification is included in this standard or in the future "Redundancy standard", this contingency should not be effective.

Response: The NERC Glossary of Terms presently defines Firm Transmission Service as "The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." FERC in Order 693 was clear that no planned interruption of Firm Transmission Service should be permitted for single Contingency conditions. We agree that there may be times when Firm Transmission Service should be permitted. The SDT has added footnotes 5 and 10 related to Firm Transmission Service. Footnote 5 indicates that interruption of conditional firm transfers is permitted for all Planning Events and footnote 10 indicates that interruption of Firm Transmission Service coupled with appropriate generation re-dispatch can be utilized for multiple Contingency events as a System adjustment, where indicated in Table 1 as being part of the Initial System Condition, and as a post-Contingency corrective action so long as no interruption of Non-Consequential Load occurs and all Facility Ratings are maintained.

5. When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed.

Footnote #10 – Curtailment of firm transmission service , when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.

The SDT agrees that shunt devices were excluded in Extreme Event item 1 of the Steady-State and Stability tables and the problem has been corrected.

Extreme Event Steady State #1

Loss of a single generator, Transmission Circuit, DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, DC Line, shunt device, or transformer forced out of service prior to System adjustments.

The SDT agrees with the commenter regarding the opinion that item 3B in the Extreme Event portion of the prior Daft 2 Table 1 Steady-State was redundant and the item has been removed and is no longer referenced in this draft.

Extreme Event – Steady State:

3b. ~~Loss of two Transmission lines in different rights-of-way prior to System adjustments for conditions such as:~~

The SDT appreciates the input related to the footnote on "System Stable" (new footnote 1) but the SDT chose to keep it as a footnote reference for convenience

Organization	Question 7:	Question 7 Comments:
to the TPL standard and not include it as definition for the NERC Glossary of Terms as suggested by the commenter. Related to the P5 "Protection System Failure" Planning Event the SDT has not deviated from its stance of requiring more stringent performance requirements for the above 300 kV System. The SDT has revised the P5 Planning Event description to remove the reference to "single component failure" and the event description was changed to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical facilities being removed when compared to the normal fault clearing. A Protection System failure resulting in loss of the substation (one voltage level plus transformers) would not qualify as a P5 Planning Event since that event is considered an Extreme Event. A Standard Authorization Request (SAR) has been issued for industry comment (1/20/2009 through 2/18/2009) based on work completed by the System Protection and Controls Task Force (SPCTF). The proposed project will address the need for Protection System redundancy, based on an n-1 failure of individual components of the Protection System.		
Progress Energy Florida, Inc.	No	The Steady State and Stability Tables (Tables 1 and 2), are overly long, confusing, and contain circular references. PEF strongly advises returning to the content and format of Table 1 in the existing TPL Standards, or at the very least, consolidation of the Tables into a single Table. Furthermore, for certain events in Tables 1 and 2, the SDT's intent concerning the scope of the events and how the events would be simulated in Transmission Planning analyses is not clear. PEF furthermore does not agree with "Interruption of Firm Transmission Service Allowed" and "Non-Consequential Load Loss Allowed" as benchmarks for whether or not a particular BES is reliable (see additional comments in Question 15 on this issue). Tables 1 and 2 at present are 13 pages in total, whereas the existing Table 1, which PEF feels is comprehensive and not in need of revision, is merely 1.5 pages long. PEF understands that the reason behind the length and complexity of Tables 1 and 2 stems from a desire by some to contain all of the primary TPL compliance issues in a tabular format. The end result, however, is not effective and must be made more concise.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. The new format more closely mimics the existing TPL table in its readability. The set of Contingencies considered are not greatly different than those in the currently approved TPL suite of standards. The SDT has attempted to add simplicity as to those Contingencies that are deemed to be Planning Events, thus requiring corrective action plans, and the Extreme Events which do not require corrective action plans. The change in performance expectations for the above 300 kV System are supported by many in the industry. Please see our response to Q15 for further information.		
Ameren	Yes	The tables could be improved by including the column headings on each page.

Organization	Question 7:	Question 7 Comments:
		Separating the steady-state and stability performance requirements for each planning event helps to provide clarification.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages.		
City of Tallahassee, FL	Yes and No	while this was an improvement, the tables are still confusing and make determination of the compliance requirements difficult. Especially where there are multiple events within a single event category (like P3 or P6) there's confusion about what would be allowed between the two element outages.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments to do so and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. The SDT believes the changes improve the readability of the tables. There are concerns expressed by numerous respondents that after the first single Contingency and System adjustment, curtailment of Firm Transmission Services (or firm transfers) and shedding of firm Load would not be allowed in preparation for the second Contingency. The SDT added Footnote # 10 to the end of Table 1 to reflect that Curtailment or Interruption of Firm Transmission Service in preparation for the next Contingency will be allowed as long as firm Load, not outaged by the initial event, continues to be served. **Footnote #10** – Curtailment of firm transmission service , when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
Florida Power and	No	The Table format is extremely confusing and too long.

Organization	Question 7:	Question 7 Comments:
Light		The allowed and disallowed actions as well as the applicable time frames for them is not clearly stated. The tables 1 &2 should be combined and condensed so that they can be read more easily. In their current format, these tables sprawl across 13 pages. The use of footnotes or expanded information in the Table headings is needed to understand the performance requirements.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments to do so and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. The SDT believes the changes improve the readability of the tables. The changes to the new table have removed the need for repeat headers. Regarding the commenter's statement "The allowed and disallowed actions as well as the applicable time frames for them is not clearly stated." It is assumed that this is in reference to the P6 N-1-1 Planning Event. There are concerns expressed by numerous respondents that after the first single Contingency and System adjustment, curtailment of Firm Transmission Services (or firm transfers) and shedding of firm Load would not be allowed in preparation for the second Contingency. The SDT added Footnote # 10 to the end of Table 1 to reflect that Curtailment or Interruption of Firm Transmission Service in preparation for the next Contingency will be allowed as long as firm Load, not outaged by the initial event, continues to be served. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
Exelon Transmission Planning	No	Tables 1 and 2 should be changed such that the header should read 'BES Elements Overloaded' rather than 'BES Elements out of Service' regarding the voltage distinction. The header notes should either not be numbered or numbered with a different scheme to differentiate them from the numbered footnotes to avoid confusion. It is not obvious that all of the footnotes are used in the Tables. The headings should be repeated on each page. Could these tables be made smaller by eliminating some of the unused space such as the large boxes containing a single

Organization	Question 7:	Question 7 Comments:
		'x'?
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments to do so and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. The SDT believes the changes improve the readability of the tables. The confusion with regards to the prior "BES Elements Overloaded" has been eliminated in the new table as the prior columns have been deleted. The commenters' suggestion to repeat table headings was a common response from industry, but is no longer a need based on the new table design. The SDT has now utilized alpha character references for the top notes of the table to avoid confusion with the footnotes which are referenced throughout the table. All footnotes are accounted for with the table and are now referenced sequentially for improved readability.		
CenterPoint Energy and CPS Energy	No	We originally believed that eliminating the old Category A, B, C, and D nomenclature would be beneficial. However, looking at the contingency types now being proposed, we are concerned that more confusion has been created. For example, matching applicable facility ratings to Category A, B, and C conditions is reasonably manageable. Matching applicable facility ratings to 7 contingency "buckets" is more confusing, less manageable, and unnecessary. NYISO proposed the concept of analyzing credible multiple contingencies in the operating realm. Most industry opined that NYISO's proposal lacked merit for operating requirements, and we agreed. However, we believe the proposal may have merit for planning requirements. The concept of applying reasonable credibility criteria to multiple contingencies to be studied offers a way to limit multiple contingency analysis to credible scenarios. Less credible (or incredible) scenarios would then fall into the Extreme category. As proposed, the multiple (seven-fold) approach of categorizing contingencies, combined with various sensitivities or alternative scenarios, for multiple years, is unrealistic and unnecessary. We believe creating a separate table for stability performance might be beneficial, but we believe 7 buckets of contingencies is hopelessly unrealistic for stability analyses.
Response: The set of Contingencies considered are not greatly different than those in the currently approved TPL suite of standards. The SDT tried to better clarify those Contingencies that are deemed to be Planning Events, thus requiring corrective action plans, and the Extreme Events which do not require corrective action plans. Most in industry are receptive to the new Contingency categorization so the TPL SDT has not altered its organization of the performance requirements. The SDT believes the Planning Events describe the credible Contingencies that warrant more rigorous study and the Extreme Events represent the less credible events that need to be reviewed on a more selective basis by the individual transmission planner. In regards to matching an applicable Facility Rating to the 7 Planning Event categories, the SDT believes the 7 categories do not add any additional level of		

Organization	Question 7:	Question 7 Comments:
complexity. The need to cover sensitivity analysis is based on a FERC directive from Order 693 and the SDT believes it is a reasonable request which will drive the industry to better understand their individual Transmission Systems. At this time all Planning Events are still within the scope of possible System conditions that could require a Stability review. The SDT believes the proposed TPL explicitly clarifies that only the "more severe" events require Stability analysis as stated in Requirement R4.4. At this time all Planning Events are still within the scope of possible system conditions that could require a Stability review. The SDT believes the proposed TPL explicitly clarifies that only the "more severe" events require Stability analysis which was implicitly understood within industry for the Version 0 standards as the commenter describes. Many of the conditions described by the commenter could be used as the basis for how a Transmission Planner would select the subset of Planning Events requiring a Stability review.		
MidAmerican Energy Company	No	MEC suggests that the Categories symbols in Table 1 and Table 2 be different to help distinguish between them (e.g. P1:S1, P2:S2, P3.2:S3.2, etc.) MEC suggests that the header text (i.e. Category, Initial System Condition, etc.) be repeated on every applicable page to be more reader-friendly. The superscripts do not refer clearly to the respective notes. (There are numbered notes in the beginning of the table, numbered items in the extreme events evaluation requirements section, numbered items in extreme event description section, and numbered notes at the end of the table). Perhaps the referenced notes should have unique numerology or format to make the superscript references clearer.
MRO NERC Standards Review Subcommittee	No	The MRO suggests that the Categories symbols in Table 1 and Table 2 be different to help distinguish between them (e.g. P1:S1, P2:S2, P3.2:S3.2, etc.) The MRO suggests that the header text (i.e. Category, Initial System Condition, etc.) be repeated on every applicable page to be more reader-friendly. The superscripts do not refer clearly to the respective notes. (There are numbered notes in the beginning of the table, numbered items in the extreme events evaluation requirements section, numbered items in extreme event description section, and numbered notes at the end of the table). Perhaps the referenced notes should have unique numerology or format to make the superscript references clearer.
American Transmission Company	No	We think that the tables are so similar that they should be recombined into one. This would require reasonable adaptation of the tables. If the tables are kept separate, then we suggest that the Categories symbols in Table 1 and Table 2 be different to help distinguish between them (e.g. P1:S1, P2:S2, P3.2:S3.2, etc. We suggest that the header text (i.e. Category, Initial System Condition, etc.) be repeated on every applicable page to be

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		more reader-friendly. The superscripts do not refer clearly to the respective notes. (There are numbered notes in the beginning of the table, numbered items in the extreme events evaluation requirements section, numbered items in extreme event description section, and numbered notes at the end of the table). Perhaps the referenced notes should have unique numerology or format to make the superscript references clearer.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". This changed has negated the need for the Planning Event category naming convention changes suggested by the commenter and the team retained the P1 through P7 references for Planning Events. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages. The SDT agrees with the commenter regarding the top notes within the table. We have changed the references to alpha characters to avoid confusion with the footnotes that are referenced with the tables using superscript characters.		
SERC Dynamics Review Subcommittee	Yes	The tables could be improved if the headings were put on each separate page. Separating out the tables for steady state and stability improves and clarifies the requirements of the standard.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". This changed has negated the need for the Planning Event category naming convention changes suggested by the commenter and the team retained the P1 through P7 references for Planning Events. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages. The move to a single table was based on a significant number of comments and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table.		
Austin Energy	No	Matching facility rating to seven contingency categories is confusing. Furthermore, these seven categories combined with alternative scenarios and sensitivity studies for several years into the future is overly burdensome, unnecessary, and unrealistic.
Response: In regards to matching an applicable Facility Rating to the 7 Planning Event categories, the SDT believes the 7 categories do not add any additional level of complexity. The set of Contingencies considered are not greatly different than those in the currently approved TPL suite of standards. The SDT tried to		

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better clarify those Contingencies that are deemed to be Planning Events, thus requiring corrective action plans, and the Extreme Events which do not require corrective action plans. Most in industry are receptive to the new Contingency categorization so the TPL SDT has altered its organization of the performance requirements. The need to cover sensitivity analysis is based on a FERC directive from Order 693 and the SDT believes it is a reasonable request which will drive the industry to better understand their individual transmission systems.		
Arkansas Electric Coop. Corp.	No	I disagree with statement #4 for the reasons given in my comments on question 3. Also, if you are going to allow it then consequential generation loss needs to be defined. I also disagree with statement #5. This is a planning standard and as such systems should be planned for planning steady state. Statement #5 should only be allowed if the resulting operator actions are taken into account. A fault on a networked transmission line may open the breakers at each end. Statement #5 stops here when in reality operator actions would isolate the faulted sections and service restored with the transmission line now being operated as two radials. The resulting two radials are what need to meet the performance requirements. Events should be taken to their logical conclusions and the resulting system topology be what meets the performance requirements. The tables need some borders and section dividers. Headers should be on each page. No firm transmission or Non-Consequential Load Loss should be allowed for P2. I think the SDT has it backwards. Non-Consequential Load Loss should never occur and the tables should reflect what is allowed to happen with Consequential Load Loss for each event. Many of the scenarios reflect what should happen with Consequential Load Loss and not Non-Conseqeuntial Load Loss. For example: P2 Bus Section for less than 300 kV -- The load on that bus under this contingency would be Consequential NOT Non-Consequential. For the loss of that bus the load connected to that bus should be ALL the load that is lost, therefore no Non-Consequential Load Loss should occur.
Response: Please see the SDT's response to your question 3 comment regarding your disagreement with statement #4. The SDT concluded from the overall industry comments that a definition for consequential generation loss was not needed and therefore was not added to the standard at this time. The commenter disagrees with statement #5 of the Draft 2 standard which states "Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each event." However, FERC Order 693 paragraph 1707 references that within the NOPR that preceded the Final Rule "…the Commission believes that the simulations used in planning assessments should faithfully duplicate what will happen in the actual power system and not a generic listing of outages" In paragraph 1716, the Final Rule further clarified that this is the intent of the Commission. Therefore, the wording in the proposed standard. The commenter's disagreement seems to be based on a feeling of needing to plan for no Load drop for single Contingency events; however, in paragraph 1773 it is clear the FERC does allow the loss of Consequential Load. Therefore, Consequential Load Loss that occurs with the initial event is permitted. Serving radial Load tapped from a networked line, from a "singled ended" view or from a single source end (one end of the line open) is covered by Planning Event P2.1 and new footnote 8 should help alleviate the commenter's concerns. Under P2.1 it should be expected that no Load loss would occur. **Footnote 8**: Inadvertent tripping of breakers on one end of a normally networked Transmission circuit such that the line is now open at that end and possibly		

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serving Load radial from a single source point. The need for headers on each page has been alleviated based on the SDT reformatting of the table to a single table format and greatly condensing the tabular information. The SDT disagrees with the commenter that the SDT "has it backwards" related to the references of Consequential Load Loss and Non-Consequential Load Loss for each event. The performance table accurately depicts when Non-Consequential Load Loss is permitted for various events. Consequential Load Loss is allowed for all events. The table does not try to categorize a type of Load (Consequential or Non-Consequential) that the event is causing to lose electrical service. The initial Protection System actions to the event always trip Consequential Load. The performance table merely clarifies if the Transmission Planner can drop any additional Firm Load (Non-Consequential Load Loss) to alleviate the event and meet performance requirements. In the P2.2 (bus section) event that the commenter references, the difference between the EHV and HV performance requirements is that the Transmission Planner is allowed to drop additional Non-Consequential Load for the HV event.		
Midwest ISO	No	Please add a General Requirements heading before items 1-6 (Steady State) and 1-5 (Stability) which appear to be applicable to all events for each table. The two columns under "BES elements out of Service" could be stricken for simplicity and clarity. If there is a voltage distinction needed, then add it next to the "Yes" or "No" under the "Interuption of Firm Service" or "Loss of Load" columns. Items P0 through P7 are identical in Table 1 - Steady State Performance and Table 2 Stability Performance. The only distinctions are the notes or whether it is an outaged event in Table 1 or a 3 phase/SLG fault in Table 2. Having two tables is redundant and unnecessary, and does not add clarity. It is also recommended that you combine the notes and extreme events from Table 1 - Steady State Performance and Table 2 - Stability Performance into one table. If both tables are to be retained then it is recommended that the SDT take into consideration the following suggestions. With the old Version 0 table, where there was not a separate stability table, it was understood that each of the event types needed to be assessed, but only those that the responsible entity knew were the more severe from a stability perspective needed to have stability analysis performed. By listing events such as single circuit faults (P1) under Table 2, this implies that all events should be simulated with dynamics, though requirement 5.4.1 states events "that would produce more severe System impacts shall be identified,...". The burden to explain why certain events were not selected can be construed now as having to run dynamics on all line faults, or explain why each line was not selected. Most lines embedded within the grid and not near generators or of particular significance to grid dynamic stability need not be studied. We do not believe that the SDT is requiring any additional burden of proof as to why every line in the system is not studied with dynamics, but the standard makes that question more murky than it was before. An overzealous compliance monitor could be confused by the new layout at great expense to the industry. If Table 2 remains, change

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		Table 2 - Stability Performance to only those events that are important to Stability Analysis. For example the following faults to run would be: 1) Faults near large generators (generator buses, generator lines or transformers near generators)2) Faults with delayed clearing near large generators3) Faults on long or heavily loaded lines with large phase angle differences between terminals. A majority of faults on lines less than 200kV are rarely severe so it is recommended to have the standards reflect this in Table 2 - Stability Performance.
Response: The SDT was persuaded by the commenter and other industry respondents that the two performance tables presented in Draft 2 were redundant in many areas. The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance" The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. At this time all Planning Events are still within the scope of possible system conditions that could require a Stability review. The SDT believes the proposed TPL explicitly clarifies that only the "more severe" events require Stability analysis which was implicitly understood within industry for the Version 0 standards as the commenter describes. Many of the conditions described by the commenter could be used as the basis for how a Transmission Planner would select the subset of Planning Events requiring a Stability review.		
Tri-State Generation and Transmission Association, Inc.	Yes and No	It does not seem that there should be different performance limits for DC and AC lines. It is unclear why there is a separation of voltage classes. Perhaps it would be helpful for each TP to specify which voltage levels are considered Bulk on their particular system, then split studies according to that definition. We applaud the SDT's efforts to split contingencies into groups with more-or-less the same system impact. We encourage the SDT that it would be very beneficial to regroup them in order of probability of occurrence, or even better, to group them by order-of-magnitude of occurrence probability. The P categories as now defined seem to overlap in likelihood. For example, in P3 following loss of a generator followed by system adjustments, another generator forced outage is more likely than a transformer forced outage. Loss of a bus section (P2 single contingency) is less likely than the P3 event of a double generator contingency. There is more on the concept of grouping Performance Tables in order of event likelihood in the NERC White Paper, "Reliability Concepts". At the least, notes in the tables - regarding 1) system impact and 2) likelihood of events listed - would be most welcome.
Response: The SDT agrees with the commenter's opinion on the need to allow for all types of conditional Firm Transmission Service interruptions and that the prior Draft 2 version unintentionally provided preferential treatment to HVDC. In the new performance Table 1, a new footnote has been added (see footnote 5) to the column title "Interruption of Firm Transmission Service Allowed" that corrects the problem identified by the commenter. **5**. When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed.		

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The SDT believes it provided sufficient justification in its Draft 1 response as to why a greater expectation is placed on the above 300 kV (EHV) System. The feedback received from the industry was divided related to the SDT's emphasis placed on a higher expectation for the 300 kV and higher Systems. Some commenters questioned the importance and the high costs that may be needed to mitigate existing System designs. Others agreed with the SDT's approach and indicated that the impact to their Systems would be minimal. Some commenters even questioned why the more stringent approach was not applied to the entire 100 kV and higher Systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission System. The performance requirements only apply to the Bulk Electric System and the split in voltage provides a subset of the BES. The Planning Events, in general, are ordered based on level of probability. However, the SDT chose to order the table by three main areas: 1) no Contingency (P0), 2) single Contingency (P1, P2) and 3) multiple Contingency (P3 through P7). While the SDT agrees with the commenter that there is some overlap in probability order, for example between P2 and P3, the SDT believes it has more importantly made the proper performance level requirements based on a reliability "risk" level where risk accounts for impact times (x) probability of occurrence.		
AEP	Yes	The formatting is okay. We would like to see the two tables merged. Except in the extreme disturbances sections, Table 1 and Table 2 are nearly identical (the only difference is that fault types are added to Table 2). The tables could easily be merged into one, including the extreme disturbances sections to some extent.
Response: The SDT was persuaded by the commenter and others industry respondents that the two performance tables presented in Draft 2 were redundant in many areas. The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance" The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed.		
NB Power Transmission	No	In the past, power systems within the NPCC Region have been designed to meet NPCC design criteria, which is basically that any design contingency does not cause instability of the NPCC defined bulk power system, and does not result in any emergency limit violations (thermal, voltage or stability), unless those violations are contained within a small local area of the system and can be mitigated. Design to NPCC criteria may include, and does include in many cases, interruption or curtailment of firm transmission service, underfrequency load shedding, undervoltage load shedding or SPS tripping of generation and/or load. The proposed table introduces new design criteria for which present power systems within NPCC are not presently designed to - being the restrictions on interruption of firm transmission service and consequential load for certain contingencies as outlined in the table, which up to this point was acceptable by NPCC design criteria, and the present NERC TPL Standard. The table should not impose new design criteria on the existing power system and should be relaxed such that present NPCC design criteria is acceptable into the future, as historically it has been proven to provide acceptable levels of reliability in the NPCC area. There would be enormous impacts on existing transmission service agreements and compliance issues if the design criteria outlined in the table is imposed. Meeting the design criteria outline in the table would require building new transmission facilities with, in some cases, very little benefit to the

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		loads in terms of reliability. For example, there is an area of the system consisting predominately load. This area is supplied by two 345 kV transmission lines and three 138 kV lines. Studies show that under certain low probability, but predictable, conditions that the loss of one of the 345 kV supplies will result in unacceptable low voltage or thermal limit violations on equipment within the area. Therefore, an SPS has been utilized which trips load within the area on the loss of the 345 kV line in order to prevent unacceptable low voltage or thermal limit violations under these low probability conditions. In this case these loads are considered non-consequential and tripping them for a loss of a 345 kV line is unacceptable as per P1 in the table. Now assume that this arrangement has been in service operationally for the past 10 years and has only operated twice resulting in a 2 hour outage to these loads each time. Now also assume that these same loads have been interrupted 15 times (for a total of 30 hours) in the past 10 years because outages of a radial line within the area that these loads connected to. In this case, the loads are considered consequential and these interruptions are acceptable. Compliance with the design criteria in the table in this case would require building additional transmission into this area to prevent the load loss by SPS on the loss of the 345 kV line. Assume the cost of this new transmission is 80 million dollars and its net benefit would be to prevent (historically) 2 interruptions out of 17 total interruptions to only the loads in question within the area. The design criteria in the table in this case do not provide adequate benefit for cost for these loads in this area. Adequate transmission planning must take into account engineering judgment concerning cost/benefit ratio to loads as well as type of loads served, expectations of loads in terms of interruptions and where money can be best spent to reduce interruptions to loads. The criteria outlined in the table does not achieve this in all cases. The table should not dictate what contingencies can result in consequential load loss or interruption of firm transmission service. These decisions should be left to local planning engineers who have in-depth knowledge of local transmission issues (as well the interconnected power system)and reliability needs of loads involved. The table should only state that the listed contingencies will not result in system instability or violations of emergency thermal and voltage limits following all automatic actions. Table 1 in the existing version of the TPL Standards with its footnotes b) and C) presently allows for this and does not have criteria as stringent as the new table. The new table should not introduce new, more stringent design criteria.

Response: The NB Power Transmission company has two primary concerns within their response: 1) an inability to interrupt Firm Transmission Service and 2) the inability to shed local Load for what they deem a low probability single Contingency event involving a 345 kV line.

Regarding the Firm Transmission Service concern, the SDT has added footnotes 5 and 10 that should help alleviate the NB Power Transmission company's concerns. Footnote 5 indicates that interruption of conditional firm transfers is permitted for all Planning Events and footnote 10 indicates that interruption of Firm Transmission Service coupled with appropriate generation re-dispatch can be utilized for multiple Contingency events as a System adjustment, where indicated in Table 1 as being part of the Initial System Condition, and as a post-Contingency corrective action so long as no interruption of Non-Consequential Load occurs and all Facility Ratings are maintained.

Footnote 5 – When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed.

Footnote 10 – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a

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System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. NB Power expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that they rely on an SPS to drop local area network Load in response to some single Contingency events and that these system designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of the TPL-001-1 and most stakeholders (and the SDT) aligned with FERC's position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement. As an alternative, an entity could seek an entity variance for the situation described. The process for obtaining an entity variance is described in detail in the "NERC Standards Development Procedure" document under the subsection titled "Variances to NERC Reliability Standards" The commenter seems to be confused by the term Consequential Load Loss based on the statement "…The proposed table introduces new design criteria for which present power systems within NPCC are not presently designed to - being the restrictions on interruption of firm transmission service and consequential load for certain contingencies as outlined in the table…" The proposed standard places no restrictions on Consequential Load Loss for any of the Planning Events or Extreme Events. The as designed Protection System actions to the event always trip Consequential Load. The performance table merely clarifies if the Transmission Planner can drop any additional Firm Load (Non-Consequential Load Loss) to alleviate the event and meet performance requirements.		
Lakeland Electric	No	Separating steady-state from dynamic (stability) in the tables makes sense. Several suggestions: On page 11 move the planning events note 1 below the Planning Events title or begin note 1 with "For planning events ?" to remove confusion between planning events and extreme event requirements. Include an analysis section in the steady-state and stability requirements sections of TPL-1 that explicitly lays out the performance requirements (including the notes) - this would make the performance requirements very clear on a line item basis and the tables would become a quick reference. Special attention should be given to defined period of time between multiple events and the actions available to the operator. In table 2 (page 17) note 3 should be changed to: "Uncontrolled cascading and islanding ?" in order to be consistent with R5.4.4. " . . . If the evaluation of implementing a change . . . shall be conducted."
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages		

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that the prior Table 1 and Table 2 encompassed. In the new table format, the top notes were placed under the heading of "Planning Events" as the commenter and other industry participants of suggested. It is not exactly clear what the commenter has in mind related to the "analysis section" described in the response. However, the SDT believes the new table format provides a better "at glance" view of what is needed. However, this does not negate the need to fully understand all requirements within the standard. The time period for allowable System adjustments made to avert performance requirement violations must be completed within the time duration rating and respect the ratings limit. The reference to Requirement R5.4.4 has been deleted.		
Southern Company Transmission	Yes and No	We suggest that the word "requirements" be added to the title of the tables as in Steady State Performance Requirements. We also suggest for header note 2 of Table 2 that the words be changed from "Dynamic voltages shall" to "Voltages during dynamic simulation shall"
Response: The SDT did not include the proposed use of "requirements" in the title of the performance table since they are not within the requirements section of the standard. The SDT agrees with the proposed change in note two of Table 2. The two tables have been consolidated into one table and the header note reference for this item is now note "h". **Header note 'h'**: Planning Event P0 is applicable to steady state only.		
Brazos Electric Power Cooperative, Inc.	No	Compared to the new table format, the old Categories were better. Perhaps if there is confusion with the old table or format, this should be cleaned up. We suggest the old tables remain, or combine some of the new sections to reduce the number of categories.
Response: The set of Contingencies considered are not greatly different than those in the currently approved TPL suite of standards. The SDT tried to better clarify those Contingencies that are deemed to be Planning Events, thus requiring corrective action plans, and the Extreme Events which do not require corrective action plans. Most in industry are receptive to the new Contingency.		
IESO	Yes and No	Condition (5) at the top of Table 1, and Condition (4) at the top of Table 2 are not required since they are already covered by R3.2 and R5.2, respectively. Further, Condition (6) in Table (1) and Condition (5) in Table 2 should be stipulated in R3 and R5 since these are not performance requirements, but rather the analysis (simulation) requirements.

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Response: The commenter is correct that Condition 5 of the Table 1 and condition 4 of Table 2 which state "Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each event" is also within the standard's requirement language. However, the SDT has retained this information within the new performance table as it is key information repeated for clarity and convenience. In regards to the comments on condition 6 and condition 5 which refer to "normal clearing", the SDT believes that Requirements R3 and R4 which refer to the need to meet performance requirements stated within Table 1 cover the concern raised. The table note that references "simulate Normal Clearing unless otherwise specified" is now introductory note "d".		
North Carolina Electric Membership Corp	Yes and No	We would like the headings to be repeated at the head of each page. Also, enumerate Stability Tables different from the Steady State to distinguish between them.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". This changed has negated the need for the Planning Event category naming convention changes suggested by the commenter and the team retained the P1 through P7 references for Planning Events. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Therefore, the need for repeating headers on subsequent pages has been eliminated as all Planning Events are presented on a single page.		
ERCOT System Planning	No	The table is hard to read and follow since it spans multiple pages and the table headers are not repeated on each page. ERCOT believes that there are two many categories. For example, in Table 1 both Category P1 and Category P3 are not necessary. Since they require the same system performance and P3 is more severe than P1, it can be assumed that successful simulation of P3 would result in successful simulation of P1. Category P2-1 can not be simulated without modification to typical transmission models. Normal steady state power flow software typically has as a line either in or out of service, but not half in and half out. "Breaker Fault" and "Stuck Breaker" definitions are included in the table notes, but would probably be better placed with the other defined terms. It is somewhat unclear as to why there are multiple names as the steady state system impact and requirements are the same. Also, the stability impacts would be more severe for a stuck breaker assuming delayed clearing. This would allow for removal of P2-3 and P2-4 in both Tables 1 & 2. It appears that P4 and P5 are duplicating efforts as well. It is not specified which entity is responsible to define and provide contingency definitions in industry standard software format such as those requiring knowledge of protection system failures and lines on the same structure for more than 1 mile. Only entities such as TOs and GOs have access to that knowledge.

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Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages.

The set of Contingencies considered are not greatly different than those in the currently approved TPL suite of standards. The SDT tried to better clarify those Contingencies that are deemed to be Planning Events, thus requiring corrective action plans, and the Extreme Events which do not require corrective action plans. Most in industry are receptive to the new Contingency categorization so the TPL SDT has not altered its organization of the performance requirements. The P3 and P1 Contingency events are unique and can provide differing results since they result in unique generation dispatch. The SDT believes it is import to study both conditions.

In regards to the P2.1 event, the intent is to capture a potential condition of serving Load that is tapped from a normally networked line from a single source location in the Contingency (single ended) condition. If a line exists (breaker to breaker) that does not directly serve Load, the P2.1 condition would not apply and only the normal N-1 condition of the line would be studied. See the newly added footnote 8 that better describes the intent of the P2.1 Planning Event. The SDT believe existing transmission models will not require adjustment for the P2.1 event, however, Contingency lists run against the model may require some adjustments.

8. Inadvertent tripping of breakers on one end of a normally networked Transmission circuit such that the line is now open at that end and possibly serving Load radial from a single source point.

The stuck breaker reference remains as a footnote to the table – see footnote #11.

11. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) breaker, only one pole is assumed to remain closed. ~~The~~A stuck breaker ~~event~~ introduces a delayed clearing mode. ~~Normal Clearing is when the Protection System operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Breaker fail relay operation is a predetermined time that occurs after the Protection System operates and the breaker has failed. Breaker fail relaying will also isolate a predetermined portion of the electric system to isolate the failed breaker. Delayed clearing of a Fault is due to failure of any Protection System component that prevents the Protection System from operating normally.~~

The commenter is correct that some conditions such as "stuck breaker" or "internal breaker fault" would yield similar outcomes from a steady-state perspective, however, when considered from a dynamic Stability analysis each could have unique outcomes. As the commenter notes a delayed clearing mode, such as the stuck breaker analysis, would be expected to be more severe from a Stability mode. The SDT has retained P2.3 and P2.4 as they are considered single Contingency events as compared to the multiple Contingency stuck breaker event.

The P4 and P5 are unique Planning Events. The P5 Protection System failure can produce various outcomes depending on the Protection System element which failed – relay, CT, PT, battery, etc. The SDT has revised the P5 event description to remove the reference to "single component failure" and has revised the P5 event description to retain what is stated in the currently approved TPL standards under Category C6 through C9 related to the study of Protection System failures. It is left to the judgment of the Transmission Planner and the Planning Coordinator to select the appropriate review and it is expected that a worst case scenario that is something less than loss of the substation, which is considered an Extreme Event, would be evaluated. Finally, as noted in Requirement R3.4,

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the Transmission Planner and Planning Coordinator is provided flexibility in selecting the more severe P5 events for study related to their system and it is not expected that every possible scenario for Protection System failure would be studied. It most cases it is unlikely that detailed system protection knowledge would be needed to develop the Contingency lists needed to perform Transmission planning studies. Ultimately it is the Transmission Planner and Planning Coordinator responsibility to ensure the simulated Contingencies accurately simulate the removal of all elements that the Protection Systems are expected to disconnect for a given event. If assistance is needed from asset owners then it is the Transmission Planner and/or Planning Coordinator's responsibility to coordinate such a review. The standard does not place requirements on the asset owners.		
Duke Energy	Yes	Separating the steady state and stability tables greatly improves and clarifies the requirements of the standard. The tables could be improved if the headings were put on each separate page. Placing headers in the requirements section of the standard would improve understanding of the flow of the document.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments to do so and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The SDT feels that with the consolidation of requirements that were made for the third posting that headings within the body of the requirements are not needed and NERC legal staff does not support the use of headings to subdivide requirements.		
Florida Reliability Coordinating Council, inc	No	The Steady State and Stability Performance Tables are very long (currently the these two table are 13 pages) and confusing. Please consider combining and condensing the two tables into one, and either add footnotes or expand the table headings to allow better understanding of the performance requirements.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Therefore, the need for repeating headers on subsequent pages has been eliminated as all Planning Events are presented on a single page.		

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The SDT believes the new table format improves the readability of the expected performance requirements.		
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	Yes	We recommend that the headings be repeated at the head of each page.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages.		
Oncor Electric Delivery	No	In Table 1-Steady State Performance several terms more relating to system stability performance appear such as post-transient voltage, voltage instability, fault plus stuck breaker, etc. These terms would appear to be most appropriate in only Table 2-Stability Performance, where this type of analysis is performed, e.g.- placing a fault at a location based on available short circuit MVA at that point in the transmission system and then analyzing the post transient voltage and generator response.
Response: The SDT agrees that the prior draft Table 1 included some terms that were more appropriate for stability analysis references. The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments to do so and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The SDT believes the new table format improves the readability of the expected performance requirements. Additionally, the SDT took great care to separate the introductory table notes for those items that apply to both steady-state and stability analysis as well as independently to one or the other.		
FirstEnergy Corp.	Yes	The overall table format is much improved over Draft 1 and it provides better alignment between the steady-state and stability tables. The SDT is encouraged to consider consolidation into one table based on the minimal differences within the two tables. FE offers the following additional comments related to the tables:TABLE 1, STEADY-STATE & TABLE 2, STABILITY: 1) Do the table notes at the top of the table only apply to the Planning Events? If so, it is suggested to move the row that says Planning Events to be positioned above the notes.

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		2) Top Table Notes, Item 2 - It is our opinion that it should be based on the TPs criteria. 3) Top Table Notes, Item 3 - These should read consistent on both tables. Also, is cascading well understood and how is it tested for? 4) The use of numeric notes at both the top and bottom of the table causes confusion related to the superscript number references on various terms within the table. The superscript items appear to be footnote references to the notes area at the bottom of the table. It is suggested that the items listed at the top of the table use alpha character references to demarcate each item. 5) Remove the footnote reference to note 3 on the Header titled "Event" (column 3). The reference in column 4 is better suited and covers the intent of the note. 6) For the P3 contingencies, it is unnecessary to individually analyze all BES generation units within a footprint along with an additional contingency. The planner allowed to use reasonable judgment and run only a subset of the larger units in this scenario. For example, there would be no need to contingencies against an outage of each unit at a multi-unit plant. Checking the contingencies against the outage of the largest unit at that plant would be sufficient. 7) A header row should be repeated on each page for improved readability. TABLE 1, STEADY-STATE: 1) Extreme event descriptions, item 2e ? why is this needed? How would this occur? What would be evaluated, high voltage? Stability issues? Note that it wouldn't be stability concern - this is the steady state table. 2) Extreme event descriptions, item 3b - how is this condition any different than what is studied in extreme event item 1 (N-2, no adjustment)? We suggest that item 3b be removed. 3) Extreme event descriptions, item 3c is too vague and it is suggested that it be removed. 4) Notes section (bottom of table), item 1 - Various topics are covered within this note - stuck breaker, breaker relay failure, normal clearing, delayed clearing - it should be broken up. Why include a discussion about delayed clearing in a steady-state table? 5) Notes section (bottom of table), item 4 ? We interpret FACTS to mean Flexible AC Transmission Devices and this means different things to different companies. FACTS devices can be series devices and not necessarily shunts as referred to in the table. It is noted that there is not footnote reference pointing to item 4 within the table. TABLE 2, Stability: 1) Planning Event P1 - Indicates SLG or 3-PH, which one is needed? This should be clarified in the requirements that reference this table. The intent is likely that most planners would perform the less labor intensive 3-PH simulation and if criteria were met, then the conclusion would be that SLG is also met. However, as presently written, the "OR" could be manipulated to allow someone to meet criteria for SLG but not the 3-PH. The requirements should provide clear

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		expectations in this regard. (Same comment applies to P3 and P6) 2) Planning Event P1.2 - At what position on the line is the fault to be tested? Either the table or requirements that reference this Planning Event should be clear in what is required. 3) Planning Event P1.3 ? Is the fault to be placed on the high-side or low-side of the transformer? Either the table or requirements that reference this Planning Event should be clear. 4) Planning Events P1 and P2 - Is the intent that a TP would need to run all possible P1 and P2 events in dynamic stability simulations? If not, the requirements should be worded to allow the TP some flexibility in selecting the items having the most impact. To expect all of these events to be simulated within dynamics is unrealistic and unnecessary. 5) Planning Event P2.1 ? While we agree this event is warranted in steady-state, we question the need to cover this item within stability. Wouldn't breaker action clearing a fault always produce a more severe system disturbance than an inadvertent breaker trip? 6) Extreme Events ? The reference to R5.5.4 should be R5.4.4 7) Extreme Events - Items 2, a,b,c,d - should "protection system" be capitalized as the defined term in the NERC Glossary? 8) Extreme Events - Items 2f and 2gshould be removed. It is inconceivable that the simultaneous faults described could occur. 9) Notes section (bottom of table), item 1 - Does not read consistent with Note 1 from Table 1 Steady-State. As stated above, various topics are covered within this note - stuck breaker, breaker relay failure, normal clearing, delayed clearing - it should be broken up. 10) Note number 4 from Table 1 Steady-State (item on shunt/FACTS) is missing in Table 2. The first 5 notes from Table 1 should be reflected in Table 2 with the existing Table 2 note 5 being re-numbered to item 6. 11) Table 2 Note 5.a.ii. - We question whether the number of units totaling the Contingency reserve is a good criteria. Also, with regard to the phrase "the resulting apparent impedance swings must not pass through relay characteristics that would result in the tripping of any Transmission System elements", we suggest a change to "the resulting power swing shall not cause the system to separate or form electrical islands".
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled “Steady State and Stability Performance”. The move to a single table was based on a significant number of comments to do so and based on the SDT’s view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table.		

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SDT RESPONSE TO THE COMMENTS MADE THAT ARE APPLICABLE TO BOTH TABLE 1 AND TABLE 2:

1) The notes at the top of the table are intended for the Planning Events. The SDT has taken the advance offered by FE and others within industry and moved the "Planning Events" title to be positioned above the introductory notes.

2) Regarding prior Top note 2, now note "g". The SDT did not make the change recommended and believes both the Transmission Planner and Planning Coordinator criteria need to be considered and the more restrictive criteria applied if warranted. Generally, the criteria used for applicable facilities would be known and agreed upon between the Transmission Planner and Planning Coordinator, for example within an RTO environment.

3) Top Table note item 3 is now referred to as note "a". The inconsistency described by the commenter is now corrected with the single table format. Cascading is a defined term in the NERC Glossary of Terms.

4) The SDT has adjusted the top notes and refer to them with alpha character references to avoid confusion with the table footnotes that are referenced within the table.

5) The footnote reference to note 3 on the Header titled "Event" (column 3) of the prior Table version has been removed. The footnote recommended by the commenter is now used and is referenced as footnote 2 in the new table.

2. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level for stated performance criteria applies regarding allowances for interruptions of Firm Transmission Service and loss of Non-Consequential Load.

6) Contingency P3 is considered a multiple Contingency event and as described in Requirement R3.4 the Transmission Planner is expected to cover those Contingencies "… that are expected to produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results." Therefore, the SDT agrees with the commenter that the Transmission Planner would not be required to run every generation outage in combination with an addition single Contingency.

7) The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages.

SDT RESPONSE TO THE COMMENTS MADE THAT ARE APPLICABLE ONLY TO TABLE 1:

1) The 2e Extreme Event came from the existing TPL standard, category D11 contingency. The SDT considers this to be more appropriate for steady state analysis than for Stability analysis and that the main intent is to guard against an extreme voltage rise.

2) The SDT agrees with FE related to Extreme Event item 3b and it has been removed in the new table.

3b. ~~Loss of two Transmission lines in different rights-of-way prior to System adjustments for conditions such as:~~

3) The SDT disagrees with the commenter that "Extreme event description item 3c is too vague and it is suggested that it be removed."

4) The SDT agrees that a variety of topics were covered in the prior footnote 1 of Table 1 and that a discussion on delayed clearing was not applicable to a steady-state table. We have revised this footnote which is now footnote 11 to focus on the stuck breaker topic. Many of the prior references in this note were

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NERC Glossary of Terms definitions and have been removed.

11. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) breaker, only one pole is assumed to remain closed. ~~The~~A stuck breaker ~~event~~ introduces a delayed clearing mode. ~~Normal Clearing is when the Protection System operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Breaker fail relay operation is a predetermined time that occurs after the Protection System operates and the breaker has failed. Breaker fail relaying will also isolate a predetermined portion of the electric system to isolate the failed breaker. Delayed clearing of a Fault is due to failure of any Protection System component that prevents the Protection System from operating normally.~~

5) The SDT has corrected the footnote reference to FACTS to better clarify that the SDT's intent of referring to only those FACTS devices which are shunt devices. The new footnote is footnote 7 and is now referenced within the Planning Event table information.

7. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.

SDT RESPONSE TO THE COMMENTS MADE THAT ARE APPLICABLE ONLY TO TABLE 2:

1) The confusion in Planning Event P1 – indicating a "SLG or 3-PH" has been resolved and now more clearly indicates that a 3-PH fault must be passed. The P3 and P6 Planning Events now indicate the intent is to pass a SLG event for these items. However, as stated in footnote 3, if a Stability study indicates that criteria is met for a 3-PH analysis, the results of that test are sufficient to meet the less stringent SLG criteria.

2) This is left to the judgment of the Transmission Planner and the Planning Coordinator. It is expected that you study the worst case fault location.

3) This is left to the judgment of the Transmission Planner and the Planning Coordinator. It is expected that you study the worst case fault location.

4) It is not expected that a Transmission Planner would analyze every Planning Event scenario for P1 and P2 within a Stability study. Requirement R4.5 provides the Transmission Planner the flexibility desired by FE in selecting the items having the most impact.

5) No. Sometimes opening a breaker produces a more severe dynamic voltage swing than clearing a fault at that location. A fault can stimulate machine exciters into a faster response. A slower response from exciters due to opening a breaker can result in larger dynamic voltage swings.

6) The reference to requirement R5.5.4 has been removed as some commenters felt this created a circular reference between the table and the requirement language.

7) The commenter is correct that the term "Protection System" as used in Extreme (Stability) Events items 2, a,b,c,d is a NERC defined term in the NERC Glossary of Terms and is now correctly capitalized within these Extreme Event descriptions

8) Extreme (Stability) Events items 2f and 2g have been retained by the SDT and these items are consistent with the current FERC approved TPL-004 category D6 and D7. Other commenters have not objected to these items.

9) The SDT agrees that a variety of topics were covered in the prior footnote 1 of Table 2 and that a discussion on delayed clearing was not applicable to a steady-state table. We have revised this footnote which is now footnote 11 to focus on the stuck breaker topic. Many of the prior references in this note were NERC Glossary of Terms definitions and have been removed. The prior footnote 1 inconsistencies indicated by the commenter have been resolved by moving to

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the single table format. 10) The SDT agrees that there were missing footnotes in Table 2 when compared to the prior Table 1 footnotes. This is no longer an issue in the single table format as only one set of footnotes is used. 11) The SDT believes that the Contingency reserve is the appropriate maximum amount of generation which should be allowed to be lost for Planning events P2-P7. Also, the SDT believes the appropriate performance requirement for Planning Events is for no additional lines to be allowed to trip due to apparent impedance swings.		
Orlando Utiliites Commission	Yes and No	I like the concept of the new performance tables however if they could be made shorter that would be handy. I have the following specific suggestions, although they may be moot if the table is redesigned. The way the notes at the top of table 1 and table 2 are written it appears that they apply to planning single, planning multiple and extreme event sub-tables. However this is in conflict with some parts of the standard itself and the team's comments on the conference call. For example Requirement R3.3.2.2 applies facility ratings only to planning single contingencies only, so which is correct the requirement or the note that applies it to everything? I have several suggestions to fix this: 1. Move the "notes" to under the Planning Event sub table 2. Making 4 tables with the Extreme Events being a table 2 & 4 respectively 3. Indicating the notes as only applying to specific planning events. The discrepancy between requirement R3.3.2.2, the table note and comments on the conference call also needs to be corrected either by expanding the applicability of R3.3.2.2 to multiple contingencies or reducing the scope of the corresponding note. It should be clarified somewhere that the Transmission Planner and Planning Coordinator select the range of the system contingencies for N-1. Otherwise some may interpret this as only having to test contingencies on their own system (insufficient from a reliability perspective for many systems) while some auditors may interpret this as requiring every possible n-1 in the US and Canada as necessary. For example a requirement R3.2.3 could be added stating "The planning assessment should include a technical rationale for the range of transmission lines, transformers and other equipment considered". This could also be handled as a note on the tables to the effect of "The study should include a technical rationale for the range of transmission line and generators considered."
Response: The introductory notes have been moved under the "Planning Event" portion of the performance table as suggested by the commenter. The notes apply to all Planning Events – system normal (n-0), single Contingency and multiple Contingency. The commenter raises a valid point of confusion related to allowable System adjustments as Requirement R3.3.2.2 seems to imply that the System adjustments may only be applicable for single Contingency. Redispatch of generation and other System adjustments are allowed for provided that all Facilities shall be operating within their Facility Ratings. The requirement has been removed and replaced with Table 1 header note "e" since the text in the former requirement was explanatory of what was allowed and not requirement language. **e.** For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such		

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adjustments are executable within the time duration applicable to the Facility Ratings. The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. The list of Contingencies is expected to cover the Transmission Planner or Planning Coordinator system for which they are responsible for, including any tie-lines to adjacent Transmission systems. The standard does not preclude the Transmission Planner or Planning Coordinator to expand the list of Contingencies to include some Contingencies of interest or known impact for the adjacent System(s). It is expected that through peer reviews, the Transmission Planner or Planning Coordinator may initially learn of any new event within an adjacent System that impacts their own System.		
Entergy Services, Inc.	Yes and No	Given the type of information the SDT was trying to convey in the Tables, the format is fine. However, the enhanced standards create a conflict between the planning criteria used for evaluating transmission service (typically a standard N-1 thermal only analysis for ATC/AFC calculations) and the criteria for reliability as proposed by this standard. This disconnect will unfairly shift the cost of expanding the transmission system to the native load customers while wholesale and point-to-point transmission customers will reap the benefits of the additional capacity installed.
Response: The SDT has added footnotes 5 and 10 related to Firm Transmission Service. Footnote 5 indicates that interruption of conditional firm transfers is permitted for all Planning Events and footnote 10 indicates that interruption of Firm Transmission Service coupled with appropriate generation re-dispatch can be utilized for multiple Contingency events as a System adjustment, where indicated in Table 1 as being part of the Initial System Condition, and as a post-Contingency corrective action so long as no interruption of Non-Consequential Load occurs and all Facility Ratings are maintained. **5**. When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
BPA Transmission Reliability Program	No	We suggest that the tables for Steady State and Stability Performance could be combined into one table, for simplicity. Separate columns could be used for Steady State versus Stability performance criteria.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments to do so and based on the SDT's view that the Planning Events were the same for		

Organization	Question 7:	Question 7 Comments:
both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages.		
PPL EnergyPlus	Yes	The new format is a nice improvement. On the SDT conference call, it was stated that table 1 and table 2 assume different starting points; if so, could this be spelled out in the standard? Also, consequential generation loss isn't defined.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages. The initial system conditions are described for each of the Planning Events and are the same for both steady-state and Stability. The SDT did not feel the need to define consequential generation loss for the standard.		
PacifiCorp	Yes	We agree with the proposed format changes of the Tables.
JEA	Yes and No	JEA can live with them as is, but would also welcome enhancements. Will defer enhancements to others.
Lafayette Utilities System	Yes	
Arizona Public Service Co.	Yes	We agrees with the proposed format changes of the Tables.
LCRA TSC	Yes	
NERC and Regional Coordination	Yes	

Organization	Question 7:	Question 7 Comments:
E.ON U.S. Transmission Planning	Yes	

Response: Thank you for your response. The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance".

The move to a single table was based on a significant number of comments and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table.

The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages.

8. **A new definition for "Bus-Tie Breaker" was added to clarify the type of substation design and breaker position that qualify as a Bus-tie Breaker. Do you agree with the proposed definition? If not, please explain.**

Summary Consideration:

Based on the comments received from the industry, the SDT has revised the definition of Bus-tie Breaker.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual ~~straight bus~~ substation bus configurations. ~~(Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)~~.

Organization	Question 8:	Question 8 Comments:
NPCC	No	The definition provided is too limiting. It says that if you have two rings with a bus tie breaker in between, it is no longer a bus tie breaker. NPCC Participating Members Recommend, "A circuit breaker that is positioned to connect two individual station configurations." We do not agree that, "(Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)", as we have examples where stations of this nature are connected through a single "bus-tie breaker".
TVA System Planning	Yes	TVA does appreciate this clarification, but suggests the following wording: "A circuit breaker that is positioned to connect two individual straight bus substation configurations that if faulted results in both bus sections being cleared."
Omaha Public Power District	No	The term "straight bus" is not an industry-standard term. Replace "straight bus" by "single-bus, single-breaker".
Progress Energy Carolinas		The use of the word "straight" in the definition raised questions. We recommend the word straight be removed or change the definition to the following. "Bus-tie Breaker: A circuit breaker positioned to connect two individual buses with one or more other breaker positions on each bus. (Substation configurations such as a ring-bus, breaker-and-a-half, or double-breaker do not generally include bus-tie breakers.)"
Platte River Power Authority	Yes and No	Delete the sentence in parentheses.
BCTC	No	Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. What would these breakers be called? We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.

Organization	Question 8:	Question 8 Comments:
Manitoba Hydro	Yes	The Bus-tie Breaker definition provides the clarification Manitoba Hydro requested in our draft 1 comments. However, we suggest the wording in brackets should be deleted as it is possible to add bus-tie breakers to schemes like the breaker-and-a-third bus in large stations.
Transmission Agency of Northern California	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
National Grid	No	The definition provided is too limiting. It says that if you have a two rings with a bus tie breaker in between, it is no longer a bus tie breaker. We recommend modifying the definition to read, "A circuit breaker that is positioned to connect two individual station configurations. We do not agree that, "(Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)", as we have examples where stations of this nature are connected through a single "bus-tie breaker".
OPUC	Yes and No	A better definition of Bus-Tie Breaker might be: “A circuit breaker that divides a bus section with multiple tap off points into two bus sections.”
Pacific Gas and Electric Co.	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
Public Service Company of New Mexico	No	We do not disagree with the proposed definition change. However, we do not agree that “Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
Puget Sound Energy, Inc.	No	We do not disagree with the proposed definition change. However, we do not agree that “Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two

Organization	Question 8:	Question 8 Comments:
		bus sections.
Idaho Power Company	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
SMUD	No	We do not disagree with the proposed definition change. However, we do not agree that “Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
Hydro-Qu?bec Trans?nergie (HQT)	No	? The definition provided is too limiting. It says that if you have a two rings with a bus tie breaker in between, it is no longer a bus tie breaker. HQT recommend, "A circuit breaker that is positioned to connect two individual station configurations. We do not agree that, "(Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)", as we have examples where stations of this nature are connected through a single "bus-tie breaker".
Sierra Pacific Power Comapny / Nevada Power Company	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
Ameren	No	To provide clarity, a revised definition is proposed. "A bus-tie breaker is a circuit breaker that connects two individual bus sections with one or more breaker positions on each bus; substation configurations such as ring-bus, breaker-and-a-half, or double bus-double-breaker do not have bus-tie circuit breakers."
SRP	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.

Organization	Question 8:	Question 8 Comments:
MidAmerican Energy Company	No	MEC suggests applying the proposed definition to a new term, "Straight Bus-Tie Breaker". The creation of a narrow, special application definition of "bus tie breaker" is generally confusing and misleading. The term "bus tie breakers" is widely used in the industry in the context of various bus configurations. In addition, this narrow definition may create confusion if other Standards refer to bus-tie breaker in a different context.
Tucson Electric Power Company	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
SERC Dynamics Review Subcommittee	No	The use of the word ?straight? in the definition raised questions. We recommend the word straight be removed or change the definition to the suggestion below: Suggestion: Bus-tie breakers are defined as a circuit breaker position that connects two individual buses with one or more breaker positions on each bus.
MRO NERC Standards Review Subcommittee	No	The MRO suggests applying the proposed definition to a new term, "Straight Bus-Tie Breaker". The creation of a narrow, special application definition of "bus tie breaker" is generally confusing and misleading. The term "bus tie breakers" is widely used in the industry in the context of various bus configurations. In addition, this narrow definition may create confusion if other Standards refer to bus-tie breaker in a different context.
Modesto Irrigation District	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
Tri-State G&T	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
Brazos Electric Power Cooperative,	No	Part of the definition of a bus tie breaker as outlined in this Standard should be that it is the ONLY connection between 2 substation buses. Not sure why the word 'straight' is used in this definition. If a bus with a 90 degree turn is connected to another bus by a single tie breaker, does this not apply? Also, breaker and a half schemes do

Organization	Question 8:	Question 8 Comments:
Inc.		sometimes have a bus tie breaker in them although its probably not common. Including those specifics in not needed.
ColumbiaGrid	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
Southern California Edison	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
Northeast Utilities	No	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
North Carolina Electric Membership Corp	No	To provide clarity, a revised definition is proposed. A bus-tie breaker is a circuit breaker that connects two individual bus sections in a straight bus substation configuration. Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double-breaker do not have bus-tie circuit breakers.
American Transmission Company	No	We suggest applying the proposed definition to a new term, "Straight Bus-Tie Breaker". The creation of a narrow, special application definition of "bus tie breaker" is generally confusing and misleading. The term "bus tie breakers" is widely used in the industry in the context of various bus configurations. In addition, this narrow definition may create confusion if other Standards refer to bus-tie breaker in a different context.
Duke Energy	No	The use of the word ?straight? in the definition raised questions and did not seem crucial to the definition. We recommend the word ?straight? be removed from the definition.
Central Maine Power Company	No	The definition provided is too limiting. It indicates that if a substation has two rings with a bus tie breaker in between, that breaker is no longer a bus tie breaker. Recommend instead, "A circuit breaker that is positioned to connect two individual station configurations. The breakers in a bus scheme are not bus tie breakers but the breakers that tie bus schemes together are bus-tie breakers."
NSTAR Electric	No	The definition provided is too limiting and should be changed to "A circuit breaker that is positioned to connect two individual station configurations. The breakers in a bus scheme are not bus tie breakers but the breakers that tie bus

Organization	Question 8:	Question 8 Comments:
		schemes together are bus-tie breakers."
New York Independent System Operator	No	The definition provided is too limiting. It says that if you have a two rings with a bus tie breaker in between, it is no longer a bus tie breaker. Recommend, "A circuit breaker that is positioned to connect two individual station configurations. We do not agree that, "(Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)", as we have examples where stations of this nature are connected through a single "bus-tie breaker".
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	No	To provide clarity, a revised definition is proposed. A bus-tie breaker is a circuit breaker that connects two individual bus sections in a straight bus substation configuration. Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double-breaker do not have bus-tie circuit breakers.
Alberta Electric System Operator	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: "A circuit breaker that's only protective purpose is to isolate a segment of a bus."
ISO New England Inc.	No	he definition provided is too limiting. It says that if you have two rings with a bus tie breaker in between, it is no longer a bus tie breaker. Recommend, "A circuit breaker that is positioned to connect two individual station configurations. The breakers in a bus scheme are not bus tie breakers but the breakers that tie bus schemes together are bus-tie breakers."
Orlando Utiliites Commission	Yes and No	I neither for or against breaking out these breakers as a separate class. However a graphic or sketch of some example an easier concept to understand both in terms of what it is and why it is worthy of special attention.
Entergy Services, Inc.	No	Change term from ?Bus-tie Breaker? to ?Straight Bus Substation Bus-tie Breaker? with the following definition: A bus-tie breaker is a circuit breaker that connects two individual bus sections in a straight bus substation configuration. References to Bus-tie Breaker in the standard would also need to be changed accordingly.
US Bureau of Reclamation	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two

Organization	Question 8:	Question 8 Comments:
		bus sections.
BPA Transmission Reliability Program	No	The term "Bus Tie" implies tying any two buses together. However, the intent of this standard is actually referring to connecting the main buses of two adjacent main and auxiliary configured substations together. Therefore, we recommend changing the term "Bus Tie Breaker" to "Bus Sectionalizing Breaker". We also recommend removing the parentheses portion of the Bus Tie Breaker definition. It does not provide clarification and may not apply to all utilities' systems.
Response: The SDT has revised the definition as follows: **Bus-tie Breaker**: A circuit breaker that is positioned to connect two individual ~~straight bus~~ substation bus configurations. ~~(Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)~~		
Progress Energy Florida, Inc.	No	PEF understands the intent behind the wording of the definition, but neither agrees with the definition nor its use in various applications in the Standard. Bus tie breakers as defined in the draft Standard are limited to connecting two straight bus configurations. In reality, the term bus-tie breaker can be, and is used for other applications. PEF suggests that the SDT further research the use of this term in the industry. But more to the point, PEF does not see the need for a distinction between bus tie and non bus tie breakers and ultimately recommends that this be removed from the Standard.
Florida Power and Light	No	Bus tie breakers are defined exclusively to straight bus configurations. They can be used for other breaker configurations. We do not see the need for a distinction between bus tie and non bus tie breakers.
Response: The SDT notes that a number of commenters disagreed with the definition. However, the number who indicate that the distinction should be eliminated is in the minority. Therefore, the SDT has retained the distinction while having made changes to provide a simpler and broader definition of bus-tie breaker.		
Dominion - Electric Transmission Planning	Yes	
City Water, Light & Power - Springfield, Illinois	Yes	

Organization	Question 8:	Question 8 Comments:
Los Angeles Department of Water and Power	Yes	
Tenaska, Inc.	Yes	
Gainesville Regional Utilities	Yes	
JEA	Yes	
PacifiCorp	Yes	We agree with the proposed format changes of the Tables.
ITC Holdings: ITC, METC, ITC Midwest	Yes	
Tacoma Power	Yes	
Lafayette Utilities System	Yes	
Black Hills Corporation	Yes	
Arizona Public Service Co.	Yes	We agree with the proposed definition change.
Exelon Transmission Planning	Yes	
Austin Energy	Yes	
Midwest ISO	Yes	This is a good definition.

Organization	Question 8:	Question 8 Comments:
Tri-State Generation and Transmission Association, Inc.	Yes	
AEP	Yes	
Lakeland Electric	Yes	
Southern Company Transmission	Yes	
LCRA TSC	Yes	
NERC and Regional Coordination	Yes	
IESO	Yes	
E.ON U.S. Transmission Planning	Yes	
ERCOT System Planning	Yes	
Oncor Electric Delivery	Yes	NA
FirstEnergy Corp.	Yes	
Response: The SDT thanks you for your response but the majority of commenters expressed a desire to change the definition.		

9. **Some commenters questioned why a Bus-tie Breaker would have a different performance requirement than a non-Bus-tie Breaker, stating that all breakers have the same probability for failure. It may be true that generally the probability for failure of any given breaker would not vary substantially among similar types of breakers, but the Bus-tie Breaker reduces exposure and consequences of bus faults. The different performance expectations in Tables 1 and 2 are based on promoting a higher level of reliability for the Transmission Systems operated above 300 kV.**

   It is recognized by the SDT that a straight bus design has some undesirable exposure to bus faults, but that Bus-tie Breakers can be utilized to improve reliability for bus faults and problems associated with exit breakers. As a result, the risk of an internal breaker fault was deemed to be significantly less than the benefit that is gained by reducing the exposure to a total bus failure. Therefore, provisions were built into the performance requirements that would not discourage their use.

   Do you agree that non-Bus-tie Breakers rated above 300 kV should have more stringent performance requirements than Bus-tie Breakers? If not, please explain why and/or suggest specific changes.

Summary Consideration:

While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV.

A number of commenters raised concerns with the less stringent requirement for DC systems. The SDT has removed the less stringent requirements for DC lines in the Table.

Due to industry comments, the SDT has changed/added the following:

Footnote 5 - When the conditions and/or event(s) being studied form the basis for conditional firm transmission service, curtailment of that conditional firm transmission service is allowed

Footnote #10 – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.

Consequential Load Loss: ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions.

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~

Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event.

Supplemental Load Loss: Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.

Organization	Question 9:	Question 9 Comments:
TVA System Planning	No	Since an internal fault on any breaker is a low probability event, we believe that Non-consequential Load Loss should be allowed.
Alberta Electric System Operator	No	We believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class.
Response: While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV.		
BCTC	Yes	BCTC agrees with different performance levels. However, we have a different rationale. Our reasoning is that a bus fault has a lower probability than a line fault. Bus tie breakers are called on to interrupt faults less often than line breakers. The failure probably may be the same but the frequency of failure is lower (because they are not called on to operate as often). The explanation given above by the SDT appears to be more related to a WECC issue that bus breaker failure should be Category D.
Response: Thank you for your support of the SDT's position.		
Platte River Power Authority	No	I think the performance for non-bus-tie breakers should be the same for all BES voltages for the same reason I agree with the performance of P2.4 Internal Breaker Fault (bus tie) and P4.6 Stuck Breaker where the Stuck Breaker could be a bus-tie or "sectionalizing" breaker.

Organization	Question 9:	Question 9 Comments:
Manitoba Hydro	No	Based on industry outage statistics, event P4, the non-bus tie breaker failure has a lower probability of occurrence than event P7, the common structure event. Consequently, Manitoba Hydro recommends that the performance requirement for >300 kV should be the same as P7. Imposing a higher performance expectation on the >300 kV facilities will require significant bus reconfiguration costs to ensure compliance for existing stations. The additional cost can not be justified by the reliability gain given the low probability of the event.
Transmission Agency of Northern California	Yes and No	We interpret ?exit breakers? to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes.
Pacific Gas and Electric Co.	Yes and No	We interpret “exit breakers” to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes
Public Service Company of New Mexico	Yes and No	We interpret “exit breakers” to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes.
PacifiCorp	No	We do not agree with the rationale for the requiring more stringent performance requirement levels for non-bus tie breakers above 300 kV. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes.
Idaho Power Company	Yes and No	We interpret ?exit breakers? to mean a breaker on an element that comes in from outside the substation. We agree with the rationale for the requiring more stringent performance requirement levels for non-bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes

Organization	Question 9:	Question 9 Comments:
SMUD	Yes and No	We interpret ?exit breakers? to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes
Sierra Pacific Power Company / Nevada Power Company	Yes	We interpret ?exit breakers? to mean a breaker on an element that comes in from outside the substation. We agree with the rationale for the requiring more stringent performance requirement levels for non-bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes
Black Hills Corporation	Yes and No	We interpret ?exit breakers? to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes
Arizona Public Service Co.	No	We do not agree with the rationale for the requiring more stringent performance requirement levels for non-bus tie breakers above 300 kV. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes.
SRP	Yes and No	We interpret ?exit breakers? to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes
MidAmerican Energy Company	No	MEC recognizes that the addition of this requirement is an attempt to raise the bar above the existing standards. However, the more stringent non-bus-tie performance criteria should only be adopted if there is sufficient evidence to demonstrate the expected reliability risk (i.e. system impact x probability of occurrence) is high enough to warrant the cost of the system modifications that would be needed to meet the criteria. System modifications that involve the installation of line and substation facilities >300 kV will likely take years and cost tens to hundreds of millions to build. There should be a reliability risk analysis that justifies the application of this performance criteria before it is adopted.

Organization	Question 9:	Question 9 Comments:
Tucson Electric Power Company	Yes and No	We interpret “exit breakers” to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes
MRO NERC Standards Review Subcommittee	No	The MRO recognizes that the addition of this requirement is an attempt top raise the bar above the existing standards. However, the more stringent non-bus-tie performance criteria should only be adopted if there is sufficient evidence to demonstrate the expected reliability risk (i.e. system impact x probability of occurrence) is high enough to warrant the cost of the system modifications that would be needed to meet the criteria. System modifications that involve the installation of line and substation facilities >300 kV will likely take years and cost tens to hundreds of millions to build. There should be a reliability risk analysis that justifies the application of this performance criteria before it is adopted.
Modesto Irrigation District	Yes and No	Comments: We interpret “exit breakers” to mean a breaker on an element that come in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes
Tri-State G&T	Yes and No	We interpret “exit breakers” to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes
ColumbiaGrid	Yes	Please explain/define the term “exit breakers”. We agree with the rationale for the requiring more stringent performance requirement levels for non-bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes.
Southern California Edison	Yes and No	We interpret “exit breakers” to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly

Organization	Question 9:	Question 9 Comments:
		different for different voltage classes
American Transmission Company	No	We recognize that the addition of this requirement is an attempt top raise the bar above the existing standards. However, the more stringent non-bus-tie performance criteria should only be adopted if there is sufficient evidence to demonstrate the expected reliability risk (i.e. system impact x probability of occurance) is high enough to warrant the cost of the system modifications that would be needed to meet the criteria. System modifications that involve the installation of line and substation facilities >300 kV will likely take years and cost tens to hundreds of millions to build. It would be helpful to have a reliability risk analysis that justifies the application of this performance criteria before it is adopted.
Entergy Services, Inc.	No	The probability of an EHV breaker failure is extremely low. Statistically, the probability of an internal breaker failure on any given day in our system is approximately 1 failure every 10,000 days. The probability of a stuck EHV breaker in our system is approximately 1 failure every 21,000 days. While the impact of such events can be severe, the significant cost to remedy such low probability events seems unlikely to pass any reasonable cost/benefit analysis.
US Bureau of Reclamation	No	We interpret “exit breakers” to mean a breaker on an element that come in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes
Response: The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV.		
Los Angeles Department of Water and Power	No	The arbitrary separation based on voltage class is discriminatory and without any scientific or historical basis. The probability of breaker failure do not increase with voltage class. In fact, breaker failures are seldom heard of at above the 300kV classes. Most breaker failures occur in lower voltage classes such as 230kv, 115kv, etc. where the short circuit current tends to be higher and thus stressing breaker contacts more severely giving rise to breaker failures. Delete any separation of voltage classes.
Response: The SDT believes that the separation for a more stringent requirement at above 300 kV is not “arbitrary”. The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems		

Organization	Question 9:	Question 9 Comments:
operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. The SDT believes that the separation above 300 kV is not “discriminatory” in that the standard is intended to be in place for all operators, owners, and users of the Transmission System. Finally, the SDT believes that there is scientific and historical basis in the sense that our representation of the differences between Systems above 300 kV as opposed to below 300 kV are a reasonable review of the uses of the NERC-wide Transmission System including scientific and historical considerations. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV.		
National Grid	No	They should have the same performance requirements, however we understand that it is better to encourage bus-tie breakers in some applications than to hold them to the higher standard. Future station designs that need this differential treatment should be discouraged.
Central Maine Power Company	No	They should have the same performance requirements, however we understand that it is better to encourage bus-tie breakers in some applications than to hold them to the higher standard. Future station designs that need this differential treatment should be discouraged.
NSTAR Electric	No	They should have the same performance requirements. The performance standards should not encourage differential treatment for the same equipment.
FirstEnergy Corp.	Yes and No	Fundamentally, from a purest perspective, we believe that all breakers should be treated as having the same probability of failure. However, we understand the SDT's intent and agree to the higher performance expectations for the above 300kV transmission system. We also agree that without the exception provided for bus-tie breakers, some entities may take the approach to simply operate their bus-tie breakers open in order to meet the performance requirements, which would be counterproductive to the improved reliability sought by the team. The alternative would be back to back bus-tie breaker installations which may not even be feasible due to space limitations. On a going forward basis, future station designs at this voltage level should avoid straight bus designs.
ISO New England Inc.	No	They should have the same performance requirements, however we understand that it is better to encourage bus-tie breakers in some applications than to hold them to the higher standard. Future station designs that need this differential treatment should be discouraged.

Organization	Question 9:	Question 9 Comments:
Northeast Utilities	Yes	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
Response: The SDT understands your comment as being supportive of the more stringent requirement for non-Bus-tie Breakers above 300 kV and of a more stringent requirement for Bus-tie Breakers above 300 kV in new substations. While there are a significant number of parties that commented negatively about the higher system performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the industry has indicated support for the higher performance requirement for non-Bus-tie Breakers above 300 kV and for a lower performance requirement for Bus-tie Breakers above 300 kV. Therefore, the SDT has not altered the higher system performance requirement for loss of non-Bus-tie Breakers above 300 kV and has not raised the system performance requirement for loss of Bus-tie Breakers above 300 kV for new substations.		
Tenaska, Inc.	Yes and No	Voltage is a questionable criteria for determining whether a breaker's performance requirements should be different. May want to consider a lower voltage cutoff (below 100 or below 200) as lower performance MAY have less of an impact.
Response: The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV and has not raised the system performance requirement for loss of breakers at lower voltages.		
Gainesville Regional Utilities	Yes	Our control area operates at 138 kV. Does everyone think that holding the owners of above 300 kV operating voltage systems to a higher standard really increases the total BES reliability? Does giving the DC systems a pass on some of the requirements really make sense in the world of reliability?
Response: The SDT believes that holding the owners of above 300 kV operating voltage systems to a higher standard increases the total BES reliability. The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV. A number of commenters raised concerns with the less stringent requirement for DC systems. The SDT has removed the less stringent requirements for DC lines.		

Organization	Question 9:	Question 9 Comments:
Progress Energy Florida, Inc.	No	PEF is opposed to distinction between non-Bus-tie breakers and Bus-tie breakers, and furthermore is opposed to the more stringent requirements for both in facilities above 300 kV. One primary reason has already been acknowledged by the SDT, that breakers have the same failure rate no matter the configuration in which they are placed. PEF can see two potential outcomes to the missteps being made regarding the breaker distinction: a) multiple redundancy of breakers for both Bus-tie and non-Bus-tie breaker schemes, which will require tearing down many Substations, acquiring additional property in many cases, and completely rebuilding the Substations to allow room for redundancy of breakers in series with one another; b) choosing to remove existing breakers for which a scenario of non-compliance is imminent, which could potentially pose a reliability risk to the system and possibly result in heightened risk for other Event categories.
Response: The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. Cost estimates were requested in other questions and were utilized by the SDT in determining a balance between such costs and reliability. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV. The SDT understands your argument about discouraging the use of breakers with a higher breaker failure performance requirement. However, the SDT notes that the Transmission Planner has always needed to plan for breaker failure since it is an event that does occur. Any reliability risk that is created by taking a breaker out of service to respond to this new higher performance requirement should be covered by the responsible entity by conducting system analysis using the new standard. If the reliability risk created by eliminating a breaker results in a failure to meet the performance requirements as outlined in the new standard, then the responsible entity will be required to develop Corrective Action Plans to mitigate the risk.		
Lafayette Utilities System	No	See paragraph (b) in response to Question 15.
Response: Lafayette Utilities System indicated in paragraph b in response to Question 15 that “Adopting less stringent performance requirements for loss of elements below 300 kV may be discriminatory.” Lafayette Utilities System further indicated that this may be because more wholesale customer Load may be served at these lower voltages than Transmission Owner Load. The SDT believes that the separation above 300 kV is not “discriminatory” in that the standard is intended to be in place for all operators, owners, and users of the Transmission System. Further, the SDT disagrees with the notion that it may be discriminatory in that more wholesale Load is served from under 300 kV than the Transmission Owner’s Load. As indicated in the SDT’s responses to the comments of others, the SDT believes that systems operating above 300 kV generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers.		

Organization	Question 9:	Question 9 Comments:
Ameren	Yes and No	Yes: The installation of bus-tie circuit breakers in a straight bus configuration would reduce exposure to a) bus faults or to b) line faults with breaker failure without adding much risk for internal fault in the bus-tie breaker. Those entities that employ a straight bus substation design with bus-tie breakers have recognized that failure of the bus-tie breaker, a very low probability event, would result in the loss of multiple transmission elements and perhaps firm load for a short time until the bus sections can be restored, but bus-tie breakers are an investment worth the risk. Therefore, it is generally agreed that the outage of non-bus-tie circuit breakers should have higher performance requirements than the outage of bus-tie circuit breakers. The SDT should be commended for this change since the previous draft version. No: However, it is not clear that adopting a higher standard of performance for planning events involving transmission facilities 345 kV and above will improve overall system reliability. Some areas of the continent already have n-2 planning criteria, yet these systems have still experienced significant outages including blackouts. It is suggested that a review of the Transmission Availability Data System (TADS) data, when available, should be conducted to help assess what system performance requirements need to be strengthened before arbitrarily determining to "raise the bar" for certain voltage levels and system designs. The industry should not be forced to invest a great deal of capital to meet a new standard requirement when it would not have an immediate impact on system reliability. Some sort of cost/benefit analysis should be performed to justify any change from the present TPL-001 through 004 standard requirements. On the Ameren system, there is no indication that transmission system reliability has been degraded through the use of straight bus configurations. Also, further clarification is required to explain how to drop consequential load without cutting firm transmission service to those affected/outaged customers, and this needs to be added to the notes in Tables 1 and 2.
North Carolina Electric Membership Corp	Yes and No	The installation of bus-tie circuit breakers in a straight bus configuration would reduce exposure to a) bus faults or to b) line faults with breaker failure without adding much risk for internal fault in the bus-tie breaker. Those entities that employ a straight bus substation design with bus-tie breakers have recognized that failure of the bus-tie breaker, a very low probability event, would result in the loss of multiple transmission elements and perhaps firm load for a short time until the bus sections can be restored, but bus-tie breakers are an investment worth the risk. Therefore, it is generally agreed that the outage of non-bus-tie circuit breakers should have higher performance requirements than the outage of bus-tie circuit breakers. The SDT should be commended for this change since the previous draft version. However, it is not clear that adopting a higher standard of performance for planning events involving transmission facilities 345 kV and above will improve overall system reliability. Some areas of the continent already have n-2 planning criteria, yet these systems have still experienced significant outages including blackouts. It is suggested that a review of the Transmission Availability Data System (TADS) data, when available, should be conducted to help assess what system performance requirements need to be strengthened before arbitrarily determining to "raise the bar" for certain voltage levels and system designs. The industry should not be forced to invest a great deal of capital to meet a new standard requirement when it would not have an immediate impact on system reliability. Some sort of cost/benefit analysis should be performed to

Organization	Question 9:	Question 9 Comments:
		justify any change from the present TPL-001 through 004 standard requirements. Also, further clarification is required to explain how to drop consequential load without cutting firm transmission service to those affected/outaged customers, and this needs to be added to the notes in Tables 1 and 2.
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	No	The installation of bus-tie circuit breakers in a straight bus configuration would reduce exposure to a) bus faults or to b) line faults with breaker failure without adding much risk for internal fault in the bus-tie breaker. Those entities that employ a straight bus substation design with bus-tie breakers have recognized that failure of the bus-tie breaker, a very low probability event, would result in the loss of multiple transmission elements and perhaps firm load for a short time until the bus sections can be restored, but bus-tie breakers are an investment worth the risk. Therefore, it is generally agreed that the outage of non-bus-tie circuit breakers should have higher performance requirements than the outage of bus-tie circuit breakers. The SDT should be commended for this change since the previous draft version. However, it is not clear that adopting a higher standard of performance for planning events involving transmission facilities 345 kV and above will improve overall system reliability. Some areas of the continent already have n-2 planning criteria, yet these systems have still experienced significant outages including blackouts. It is suggested that a review of the Transmission Availability Data System (TADS) data, when available, should be conducted to help assess what system performance requirements need to be strengthened before arbitrarily determining to "raise the bar" for certain voltage levels and system designs. The industry should not be forced to invest a great deal of capital to meet a new standard requirement when it would not have an immediate impact on system reliability. Some sort of cost/benefit analysis should be performed to justify any change from the present TPL-001 through 004 standard requirements. Also, further clarification is required to explain how to drop consequential load without cutting firm transmission service to those affected/outaged customers, and this needs to be added to the notes in Tables 1 and 2.

Response: The SDT thanks you for your support with regard to the reason for a less stringent requirement for Bus-tie breakers**.** The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. Cost estimates were requested in other questions and were utilized by the SDT in determining a balance between such costs and reliability. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV.

The SDT understands your issue with regard to explaining the dropping of consequential Load without cutting Firm Transmission Service to those affected/outaged customers. The SDT has made changes to footnotes 5 and 10 in the table and revised the definition of Consequential Load Loss and Non-Consequential Load Loss to clarify the issue.

Footnote 5 - When the conditions and/or event(s) being studied form the basis for conditional firm transmission service, curtailment of that conditional firm

Organization	Question 9:	Question 9 Comments:
transmission service is allowed. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~ **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.		
Florida Power and Light	No	These provisions made to not discourage the use of bus tie breakers will also not discourage the use of the single breaker/single bus substation arrangement which can have very severe consequence when used on critical BES substations. The TPL-001-1 draft also sets a threshold of higher performance to facilities above 300 kV than previously established in the existing standard. We do not agree that such a threshold is necessary or warranted. Requirements which are more stringent for these facilities may wrongly influence decisions on project alternatives in favor of facilities with less stringent requirements. Related to the more stringent requirements for facilities above 300 kV, FPL also disagrees with the performance requirements contemplated by the proposed draft standard for DC lines. The SDT stated performance requirements for DC lines as currently drafted, is discriminatory as compared to AC line performance, and needs to be addressed. This could be viewed as an exemption for DC lines and violates FERC's comparability principle as it relates to reliability performance. The TPL-001-1 draft sets a lower performance requirement for the loss of a single pole of a DC line than in the existing standard by allowing interruption of firm transfer if the transfer is deemed to be dependent on the outaged line. Firm transfers are also dependent upon AC lines. The proposed standard does not distinguish between asynchronous DC ties and the more common parallel connected DC tie. With an asynchronous DC tie, the transfer is lost with the tie, which is analogous to Consequential Load Loss which is already allowed. With a parallel DC

Organization	Question 9:	Question 9 Comments:
		tie, the transfer will be shifted to the parallel AC system and should have the same performance requirements. We do not agree that such an exception for DC lines is necessary or warranted. The decision in selecting DC vs. AC in transmission lines has traditionally been based on the break-even cost and performance of the two alternatives. The lower performance requirement may wrongly influence decisions on project alternatives in favor of DC facilities because of the less stringent reliability performance requirements.
Response: The SDT understands that the standard as drafted does not discourage the use of straight bus arrangements below 300 kV by allowing interruption of Firm Transmission Service and Non-Consequential Load Loss for all P4 events below 300 kV. The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV. A number of commenters raised concerns with the less stringent requirement for DC systems. The SDT has removed the less stringent requirements for DC lines.		
Tri-State Generatino and Transmission Association, Inc.	No	Performance requirements should depend on the potential loss of load impact of a breaker failure, not the voltage level.
Response: The SDT believes that while theoretically there would be potential merit in a loss of load impact approach to performance requirements for breaker failure; it would result in performance requirements that would be difficult to enforce. For example, such an approach would require completing estimates of the loss of Load for Contingencies for various conditions and then documenting it. The auditor would need to review these estimates as well as the documentation to become convinced that the correct performance requirement was used for each breaker. This review would need to be in addition to any other activity performed by the auditor to ensure compliance with the standard. The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV.		

Organization	Question 9:	Question 9 Comments:
Brazos Electric Power Cooperative, Inc.	Yes	Yes but this seems to add another category of items to provide for in the assessment.
Response: Thank you for your support.		
IESO	No	We hold the view that all breakers can be exposed to the same types of event, i.e., they can have internal faults and can be "stuck" when attempting to open as instructed. As such, there should not be any difference in the expected system performance among them in response to system events, and regardless of the voltage levels. We suggest the SDT to revised Tables 1 and 2 such that their expected performance are identical.
Response: The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV.		
Duke Energy	No	In Table 1, Category P4, Events 1 through 5 addressing a stuck non-bus tie breaker >300kV should allow Interruption of Firm Transmission Service and Non-Consequential Load Loss, because P4 addresses a multiple contingency.
Response: The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV. The SDT recognizes that Duke Energy has indirectly brought up the issue as to how the interruption of Firm Transmission Service relates to the dropping of Load in its comment. The SDT has made changes to footnotes 5 and 10 in the table and revised the definition of Consequential Load Loss and Non-Consequential Load Loss to clarify the issue. **Footnote 5** - When the conditions and/or event(s) being studied form the basis for conditional firm transmission service, curtailment of that conditional firm		

Organization	Question 9:	Question 9 Comments:
transmission service is allowed. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~ **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.		
Orlando Utilities Commission	Yes and No	If they are going to be two classes of equipment with an arbitrary cut off 300 kV is a good cutoff. However I would prefer to see the decision on what is "super BES" and regular "BES" less arbitrary and more reliability driven, such as letting the regions define this cut off just as they define BES in a manner suitable to the design of their regional system.
Response: The SDT believes that the separation for a more stringent requirement above 300 kV is not "arbitrary". The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. The SDT is preparing a NERC-wide standard for which a region can submit a regional difference that is justified based upon physical differences in that region and/or to result in a regional difference that is a higher performance requirement than the NERC-wide standard. Therefore, if a region has good cause for a different "cutoff", then the region can submit a regional difference through the NERC standards development process. This regional difference could even be submitted as part of this standards writing effort. However, it should be noted that once the regional difference is approved through the NERC standards development process, then it will be submitted to FERC and other regulatory authorities for approval. While there are a significant number of parties that commented negatively about the higher system performance requirement for non-Bus-tie Breakers above 300		

Organization	Question 9:	Question 9 Comments:
kV, higher performance requirements are encouraged by FERC Order No. 693 and the industry has indicated support for the higher performance requirement. Therefore, the SDT has not altered the higher system performance requirement for loss of non-Bus-tie Breakers above 300 kV.		
BPA Transmission Reliability Program	Yes	In general, performance requirements should be more stringent for higher voltage systems. Therefore, we agree that non-bus-tie breakers above 300 kV should have more stringent requirements.
Dominion - Electric Transmission Planning	Yes	
NPCC	Yes	
City Water, Light & Power - Springfield, Illinois	Yes	
Progress Energy Carolinas	Yes	
JEA	Yes	
Puget Sound Energy, Inc.	Yes	We agree that the failure of non-bus tie breakers above 300 kV to operate can have much higher consequence.
ITC Holdings: ITC, METC, ITC Midwest	Yes	
Tacoma Power	Yes	
Hydro-Quebec TransEnergie	Yes	

Organization	Question 9:	Question 9 Comments:
(HQT)		
Exelon Transmission Planning	Yes	
SERC Dynamics Review Subcommittee	Yes	The logic and the proposal seem reasonable.
Austin Energy	Yes	
Arkansas Electric Coop. Corp.	Yes	
Midwest ISO	Yes	
AEP	Yes	
Lakeland Electric	Yes	
Southern Company Transmission	Yes	
LCRA TSC	Yes	
NERC and Regional Coordination	Yes	Comments: PJM supports the use of bus tie breakers.
E.ON U.S. Transmission Planning	Yes	

Organization	Question 9:	Question 9 Comments:
ERCOT System Planning	Yes	
Oncor Electric Delivery	Yes	NA
Response: Thank you for your response.		

10. The SDT made modifications in this second draft to the requirements relating to sensitivity cases. Do you concur with the modifications reflected in Requirements R2.1.3 and 2.1.4? If not, please state why and/or suggest specific changes.

Summary Consideration:

A number of commenters agreed with the concept of the sensitivity analysis but were concerned that there is a conflict with sensitivities already included in base studies, sensitivity details, explaining why sensitivities were not run and how they affected Corrective Actions. The SDT has made the following changes:

1 – Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written, the standard is requiring at a minimum, one case run for each required year for steady state and Stability. The entity may run as many additional cases as it deems appropriate to understand how the System responds to the variances.

The revision also includes the removal of the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. Since these are sensitivities, any and all variances provide some level of information as to how the System responds to such variances.

2 – The sensitivities listed in Requirement R2.1.3 were revised for clarity; however, the SDT did not want to be more prescriptive because of the huge number of possible variances that can occur. It is up to the planning entity to determine which and how much of a variance is appropriate for its studies.

3 – Requirements R2.1.4 and R2.4.4 that require explanation of performing additional sensitivities that are not listed in Requirement R2.1.3 have been deleted.

4 – Requirement R2.6 has been revised for clarity. The entity can use any sensitivity studies it has performed in conjunction with the required current and past studies to develop its Corrective Action Plan.

The following requirements were changed due to industry comments:

R2.1.3 For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.7 (now R2.6) For Planning Events shown in Table 1 ~~– Steady State Performance and Table 2 – Stability Performance~~, when the analysis indicates an inability of the System to meet the performance requirements in the tables, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed in subsequent assessments but the System shall continue to meet the performance requirements in the tables. Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3 and R2.4.3. The Corrective Action Plan shall:

Organization	Question 10:	Question 10 Comments:
Dominion - Electric Transmission Planning	No	We are of the opinion that the proof of a negative that is required for sensitivity cases (i.e. - that the sensitivity cases were more severe for those selected conditions vs. those not tested) is burdensome. The burden of proof lies on the transmission planner.
NPCC	No	If a TP/PC conducts the studies specified in R2.1.1 and R2.1.2 with one or more of the sensitivities which stress the system in the normal course of study are we to assume that fulfills the requirements of R2.1 completely, without additional studies of a less-stressed system?
Hydro-Qu?bec Trans?nergie (HQT)	No	If a TP/PC conducts the studies specified in R2.1.1 and R2.1.2 with one or more of the sensitivities which stress the system in the normal course of study, are we to assume that fulfills the requirements of R2.1 completely, without additional studies of a less-stressed system?
Northeast Utilities	No	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.

Response: R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment".

R2.1.3 For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

Organization	Question 10:	Question 10 Comments:
TVA System Planning	No	We recommend that sensitivity studies not be required for each of the near term years as required in R2.1.3 and R2.1.1. Sensitivities should only be required for only one year in the near term. These sensitivity study requirements are too prescriptive. Many examples of sensitivities are already inherent in the existing requirements. Sensitivity studies of load variation are inherent in the fact that several different study years and conditions are already being required. Outages of reactive sources and generation should already be included in studies of multiple contingencies. The process of planning new generation (system impact studies) will include studies of the future with and without the proposed new equipment. The TP and PC can better select the most appropriate sensitivities for their system.
Response: The standard is requiring at a minimum one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the System responds to the variances. Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written, the standard is requiring at a minimum, one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the System responds to the variances. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
Progress Energy Carolinas	No	These requirements are overly prescriptive. Many examples of sensitivities are already inherent in the existing requirements. Some sensitivity studies are in effect adding an additional level of contingency (N-2 or N-3). Sensitivity studies of load variation are already inherent in the fact that several different study years and conditions are already being required. Outages of reactive sources and generation should already be included in studies of multiple contingencies. The process of planning new generation (system impact studies) will include studies of the future with and without the proposed new equipment. Proper consideration and selection of the most appropriate sensitivities is within the engineering judgment of the Transmission Planner and Planning Coordinator. Singling out and creating sub-requirements for the sensitivities listed in the current TPL draft creates a special focus on these specific sensitivities that may not be warranted for a given system. This could easily lead to an over focus on these particular issues to the detriment of overall system reliability. There should be no enumerated list of required sensitivities. Engineering judgment needs to be permitted.
Response: The SDT believes that sensitivities are necessary and consistent with the requirements of FERC Order 693. The draft standard includes the		

Organization	Question 10:	Question 10 Comments:
requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions", FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed. In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed System conditions. The SDT has included several parameters that can be varied to create the requisite sensitivity case(s). Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written, the standard is requiring at a minimum, one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the System responds to the variances. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
Los Angeles Department of Water and Power	No	R2.1.3 and 2.1.4 deal with operating scenarios that need to be studied by operating engineers under TOP but is duplicative and serve no useful purpose when performed by planning engineers for the purpose of future expansions. Transmission planning is to ensure that future system is expanded to handle expected system growth. Mixing operating studies in the planning of future system shows a confused perspective on the different roles between operating studies and planning studies. A responsible utility must perform both types of studies but they should not be mixed together or be required under two different standards, the TOP and TPL. The consideration of load variations, different dispatching scenarios, planned or unplanned transmission outages, system expansion not coming in on schedule, etc., are operating issues that should be and must be addressed in operating studies, and the proper place is in TOP, not TPL.
Response: The SDT believes that planners must consider these possible variances and reinforce the System so that when it comes to Real-time operation, the TOP will have a System sufficiently robust to operate around any of the conditions. Commenters generally agree that these are the responsibility of planning.		
Transmission Agency of Northern	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how

Organization	Question 10:	Question 10 Comments:
California		these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the “base case” condition. R2.7 also states that “Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities”. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the ?base case?, will the judgment of the Transmission Planner be then questioned because the “base case” used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Pacific Gas and Electric Co.	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the “base case” condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the ?base case?, will the judgment of the Transmission Planner be then questioned because the “base case” used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Public Service Company of New Mexico	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how

Organization	Question 10:	Question 10 Comments:
		these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the "base case" condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the "base case", will the judgment of the Transmission Planner be then questioned because the "base case" used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
PacifiCorp	Yes and No	We generally agree with the concept of the sensitivity analysis. However, clarifications of the following is needed: For example, if a TP performs studies on the "base case" of which the loads are 90/10, does this constitute a sensitivity analysis. If so, will the TP have to then perform additional less stringent studies at the 50/50 load level to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the TP should not have to explain why they feel that this higher level (90/10) of load is the "base case" condition.? R2.7 also states that Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a TP that has built transmission based on the 90/10 load assumed in the "base case", will the judgment of the TP be then questioned because of it's sensitivity "base case" and not a 50/50 base case?
Puget Sound Energy, Inc.	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the "base case" of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance?

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		R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the "base case" condition. R2.7 also states that "Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities". Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the "base case", will the judgment of the Transmission Planner be then questioned because the "base case" used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Idaho Power Company	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans.If a Transmission Planner performs studies on the "base case" of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the "base case" condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the ?base case?, will the judgment of the Transmission Planner be then questioned because ?base case? used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Sierra Pacific Power Company / Nevada Power Company	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage

Organization	Question 10:	Question 10 Comments:
		entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the ?base case? condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the ?base case?, will the judgment of the Transmission Planner be then questioned because ?base case? used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Black Hills Corporation	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the ?base case? condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the ?base case?, will the judgment of the Transmission Planner be then questioned because the “base case” used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Arizona Public Service Co.	Yes and No	We generally agrees with the concept of the sensitivity analysis. However, clarifications of the following is needed: For example, if a TP performs studies on the ?base case? of which the loads are 90/10, does this constitute a sensitivity analysis. If so, will the TP have to then perform additional less stringent studies at the 50/50 load level to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the TP should not have to explain why they feel that this higher level (90/10) of load is the “base case” condition. R2.7 also states that

Organization	Question 10:	Question 10 Comments:
		Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a TP that has built transmission based on the 90/10 load assumed in the ?base case?, will the judgment of the TP be then questioned because of it's sensitivity "base case" and not a 50/50 base case?
SRP	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the ?base case? condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the ?base case?, will the judgment of the Transmission Planner be then questioned because the "base case" used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Tucson Electric Power Company	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the ?base case? condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for

Organization	Question 10:	Question 10 Comments:
		sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the ?base case?, will the judgment of the Transmission Planner be then questioned because the “base case” used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Modesto Irrigation District	Yes and No	We generally agree with the concept of the sensitivity analysis since this is a standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the “base case” of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the “base case” condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the “base case”, will the judgment of the Transmission Planner be then questioned because the “base case” used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Tri-State G&T	Yes and No	e generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the “base case” condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for

Organization	Question 10:	Question 10 Comments:
		sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the “base case”, will the judgment of the Transmission Planner be then questioned because the “base case” used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Southern California Edison	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans .If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the “base case” condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the “base case”, will the judgment of the Transmission Planner be then questioned because the “base case” used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Alberta Electric System Operator	No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the ?base case? condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for

Organization	Question 10:	Question 10 Comments:
		sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the "base case", will the judgment of the Transmission Planner be then questioned because the "base case" used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
US Bureau of Reclamation	No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain Comment Form for 2nd Draft of Standard TPL-001-1Assess Transmission Future Needs (Project 2006-02) Page 9 of 12 why they feel that this higher level (1 in 10 year adverse weather) of load is the ?base case? condition. R2.7 also states that "Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities". Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the ?base case?, will the judgment of the Transmission Planner be then questioned because the ?base case? used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?

Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities".

R2.1.3 For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

The SDT agrees and has deleted Requirement R2.1.4.

Requirement R2.7 (now R2.6) has been revised for clarity. The entity can use any sensitivities studies it has performed in conjunction with the required current and

Organization	Question 10:	Question 10 Comments:
past studies to develop its Corrective Action Plan. **R2.6** For Planning Events shown in Table 1 ~~– Steady State Performance and Table 2 – Stability Performance~~, when the analysis indicates an inability of the System to meet the performance requirements in the tables, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed in subsequent assessments but the System shall continue to meet the performance requirements in the tables. Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3 and R2.4.3. The Corrective Action Plan shall:		
National Grid	No	a. With respect to R2.1.3., delete "... that Stress the System with sensitivities ...". b. R2.1.3 should be revised to clarify that if a TP/PC conducts the studies specified in R2.1.1 and R2.1.2 with one or more of the sensitivities which stress the system in the normal course of study, then additional studies of a less-stressed system are not required. c. The intention of Paragraph R2.1.4 is unclear and appears to be unnecessary; therefore, it should be removed.
Response: a. and b. Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: c. Requirement R2.1.4 has been deleted.		
Gainesville Regional Utilities	No	If the RRO or the larger neighboring utilities agree, See Comment 1, it should be unnecessary for the smaller utility to performance any sensitivities except for those agreed to and performed by the RRO level. If the smaller utility has any of their elements that create issues in these regionally conducted sensitivities, then they could be accountable for providing potential remedies (most sensitivities do not necessarily require a remedy or project, per say). The variety of sensitivities suggested to be performed for a smaller utility probably will not add any reliability to the regional BES while the effort will take up a very large amount of the smaller utilities' manpower resources.
Response: All planning entities need to follow the same set of requirements. Smaller entities may not have the resources to perform some studies but can depend on and point to studies run by larger surrounding entities to satisfy their planning requirements.		

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JEA	Yes and No	Will stress JEA resources to provide auditable evidence depending on the final measure applied.
Response: The SDT believes that sensitivities are necessary and consistent with the requirements in FERC Order 693. The draft standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed. The standard is requiring at a minimum one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the system responds to the variances.		
ITC Holdings: ITC, METC, ITC Midwest	No	While we appreciate that the addition of sensitivity studies is commendable and agree with 2.1.3 and 2.1.4 per se, the later clarification in R2.7 that "Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities" negates project justification (to many) based on sensitivity studies. Explaining as per R2.4.3 the reasons why you did or did not run a sensitivity study is less important, in many respects, than why you did or did not provide a Corrective Action Plan for performance failures observed in sensitivity studies. I.e., the study is the "cart" and the CAP is the "horse". Hence, at a minimum some form of Corrective Action Plan should be required.
PPL EnergyPlus	Yes and No	All of the sensitivity requirements should be structured to keep sensitivities from forcing un-needed construction. R2.1.3 & 4 are a good step but the point about planning around the base case might be made even more forcefully.
Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". Embedding the sensitivity in the "base case" will result in a CAP that addresses the particular "sensitivities". **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: In addition, Requirement R2.7 (now R2.6) has been revised for clarity. The entity can use any sensitivities studies it has performed in conjunction with the required current and past studies to develop its Corrective Action Plan. **R2.6** For Planning Events shown in Table 1 ~~– Steady State Performance and Table 2 – Stability Performance~~, when the analysis indicates an inability of the System to meet the performance requirements in the tables, the Planning Assessment shall include Corrective Action Plans addressing how the performance		

Organization	Question 10:	Question 10 Comments:
requirements will be met. Revisions to the Corrective Action Plans are allowed in subsequent assessments but the System shall continue to meet the performance requirements in the tables. Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3 and R2.4.3. The Corrective Action Plan shall:		
SMUD	Yes and No	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables .Added Reference 3.5.1: In cases where an SPS is deployed to reduce thermal overloads such that flows are brought within established facility ratings, but, for a short duration (seconds) until it is fully executed, the facility flows exceed the established rating, is that considered a violation or an acceptable engineering judgment that facilities are judiciously being brought to operate within ratings? Or, should the facility owner ensure establishment of a documented rating even for the short duration of seconds? Q10:TSS response: We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the “base case” condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the ?base case?, will the judgment of the Transmission Planner be then questioned because the “base case” used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case? Is some Non-Consequential Load Loss for an N-1 contingency on a sensitivity case using an extremely high load forecast acceptable as a Corrective Action Plan in the planning phase?
Response: The SDT agrees with your comment and has deleted Requirements R3.5.1, R3.5.2 and R3.5.3. Requirements R2.1.3 and R2.4.3 have been revised to make it clear that “sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the		

Organization	Question 10:	Question 10 Comments:
studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: The SDT agrees and has deleted Requirement R2.1.4. Requirement R2.7 (now R2.6) has been revised for clarity. The entity can use any sensitivities studies it has performed in conjunction with the required current and past studies to develop its Corrective Action Plan. **R2.6** For Planning Events shown in Table 1 ~~– Steady State Performance and Table 2 – Stability Performance~~, when the analysis indicates an inability of the System to meet the performance requirements in the tables, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed in subsequent assessments but the System shall continue to meet the performance requirements in the tables. Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3 and R2.4.3. The Corrective Action Plan shall:		
Progress Energy Florida, Inc.	No	PEF has significant concerns with each of the sub-Requirements listed in R2.1.3. Each is ambiguous, vague and open to variations in interpretation. It therefore makes no sense that "documentation of the technical rationale for why each of the conditions was or was not selected" is a requirement. Indeed, given that all of the sub-Requirements of R2.1.3 are vague, unspecific, unwieldy concepts, PEF is not sure how said documentation could be accomplished. Concerning R2.1.4, PEF has the same concerns that were expressed regarding the modified requirements mentioned in Question 2, and similarly here would suggest a substitute to the language in R2.1.4. Significant concerns with the previous sub-Requirements notwithstanding, PEF suggests either returning to the language in each existing Standard's R1.3.2, or adding an R2.1.3.8 that states "Other known critical system conditions specific to the system studied by the Transmission Planner or Planning Coordinator."
Response: The SDT did not want to be more prescriptive because of the huge number of possible variances that can occur. It is up to the planning entity to determine which and how much of a variance is appropriate for its studies. In addition, Requirements R2.1.3 and R2.4.3 have been revised to remove the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. Since these are sensitivities, any and all variances provide some level of information as to how the System responds to such variances. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical~~		

Organization	Question 10:	Question 10 Comments:
~~rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
Lafayette Utilities System	No	As to the performance of sensitivity analyses under R2.1.3, Lafayette believes that insufficient detail is provided to define with clarity cases that involve ?modification of expected transfers? (per R2.1.3.2). For example, it is unclear whether the phrase ?modification of expected transfers? is intended to refer to a change in directional bias in the model, a reduction in flows due to variation between reservations and schedules, or something else. Additional definition should be provided to ensure that sensitivity cases performed pursuant to R2.1.3.2 are meaningful and useful.
Response: The SDT did not want to be more prescriptive because of the huge number of possible variances that can occur. It is up to the planning entity to determine which and how much of a variance is appropriate for its studies		
Ameren	No	Similar to our comment above for R2.4.3, there should not be a requirement to explain why sensitivities were not selected. Also, it is not clear if R2.1.4 is a requirement or an option. While we agree that the system cannot be adequately planned based on a single snapshot of expected system conditions, these items in R2.1.3.1-7 are too prescriptive and are inappropriate for inclusion here. The sensitivities listed appear to be options and not sub-requirements, and may result in over-focusing on the particular issues listed to the detriment of overall system reliability. Some sensitivity studies are in effect adding an additional level of contingency to the analysis work (n-2 or n-3). Outages of reactive sources and generation should already be included in studies of multiple contingencies. The process of planning new generation (system impact studies) will include studies of the future system with and without the proposed new equipment. Engineering judgment should be used to develop the sensitivity scenarios, and it should be encouraged that the same scenarios should not be performed every year so that a portfolio of sensitivity scenarios would be developed over time. The standard should not include an enumerated list of required sensitivities. If two sensitivities are required to be performed each year, then the standard should state so, but we believe that more than one sensitivity scenario for each peak and off-peak case per year for assessment is too burdensome to run complete contingency analyses. Proposed alternative wording for R2.1.3 which addresses above concerns is as follows:R2.1.3. "For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System to reflect one or more conditions such as variation in load assumptions, modification of expected transfers, variability and outages of reactive resources, generation additions, retirements, or other dispatch scenarios are integral to a thorough assessment of reliability. Document how and why appropriate sensitivities were selected."
Response: Requirements R2.1.3 and R2.4.4 have been revised to remove the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run.		

Organization	Question 10:	Question 10 Comments:
Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written, the standard is requiring at a minimum, one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the System responds to the variances. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
Florida Power and Light	No	The words ?documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied? should be removed from R2.4.3. The sensitivity selection is necessarily subjective and judgmental. It is not clear what constitutes a valid rationale document. Compliance assessment of such a document would be subjective and is not needed.
Response: Requirements R2.1.3 and R2.4.3 have been revised to remove the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. The SDT believes that documentation of why a sensitivity was selected for study should be provided. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
Exelon Transmission Planning	No	We support efforts to improve load and dynamic load modeling, however we have concerns in being able to do so in an accurate manner - See comments to question #2. The state of industry development is such that this is not ready for inclusion in a standard such as R2.4.1 and R2.4.3.1.
Response: As with all planning models, assumptions must be made that the entity feels are representative of how the system will respond and perform. Models can only attempt to simulate the System based on expected conditions. The standard has been modified to explain that "an aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable".		

Organization	Question 10:	Question 10 Comments:
R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable		
CenterPoint Energy and CPS Energy	No	We believe R2.1.3 and R2.1.4 are overly prescriptive and should be deleted. It requires engineering judgment and experience to know whether a planning analysis is materially impacted by certain assumptions and, if so, which sensitivity analyses should be performed. Literally interpreted by an auditor, R2.1.3 would require at least one sensitivity analysis for each one of the contingencies shown in Tables 1 and 2 for each study specified in R2.1.1 and R2.1.2 and documentation for each contingency of each study why each sensitivity specified in R2.1.3 was or was not selected. The likely result is not value-added engineering analysis of actual reliability concerns. Instead, the likely outcome is unnecessary and burdensome additional analysis and documentation that is impractical, creating confusion and uncertainty as to what the practical interpretation of impractical requirements might ultimately be.
SERC Dynamics Review Subcommittee	No	These requirements are very prescriptive. Many examples of sensitivities are already inherent in the existing requirements. Some sensitivity studies are in effect adding an additional level of contingency (N-2 or N-3). Sensitivity studies of load variation are already inherent in the fact that several different study years and conditions are already being required. Outages of reactive sources and generation should already be included in studies of multiple contingencies. The process of planning new generation (system impact studies) will include studies of the future with and without the proposed new equipment. The TP and PC can better select the most appropriate sensitivities for their system. In general we believe that breaking these requirements into specific sub requirements, focusing on specific sensitivities, is too prescriptive and inappropriate. It will lead to over focus on these particular issues to the detriment of system reliability. There should be no enumerated list of required sensitivities. Engineering judgment needs to be permitted.
Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written the standard is requiring at a minimum one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the system responds to the variances. In addition, Requirements R2.1.4 and R2.4.4 have been deleted. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the~~		

Organization	Question 10:	Question 10 Comments:
~~conditions was or was not selected shall be supplied~~ included in the Assessment:		
MidAmerican Energy Company	No	a. MEC is not sure why R2.4.3.1 for sensitivities for Stability studies is a less definitive definition for load model variations then the steady state studies in R2.1.3.1. MEC recommends that R2.1.3.1 be changed to "Variations in Load model assumptions." b. MEC believes R2.1.4 and R2.4.4 should be deleted because its unnecessary to make a requirement of sensitivities that an entity chooses to do above and beyond the requirements in R2.1.3 and R2.4.3. If the SDT chooses not to delete these requirements, then MEC believes that R2.1.4 should be a subrequirement of R2.1.3 and R2.4.4 should be made a subrequirement of R2.4.3. The responsible entity should be allowed to select the appropriate sensitivity that should be performed. This is especially necessary given the need to perform each of these sensitivity analyses for six situations each year: peak and off-peak for two short-term years and one long-term year. Even with the requirement for one sensitivity for each case that amounts to six additional sets of analysis for steady-state and six for stability.
Response: a. As with all planning models, assumptions must be made that the entity feels are representative of how the System will respond and perform. Models can only attempt to simulate the System based on expected conditions. The standard has been modified to explain that "an aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable". **R2.4.1** System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable b. Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written, the standard is requiring at a minimum, one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the system responds to the variances. In addition, Requirements R2.1.4 and R2.4.4 have been deleted. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
MRO NERC	No	a. The MRO is not sure why R2.4.3.1 for sensitivities for Stability studies is a less definitive definition for load model

Organization	Question 10:	Question 10 Comments:
Standards Review Subcommittee		variations then the steady state studies in R2.1.3.1. The MRO recommends that R2.1.3.1 be changed to "Variations in Load model assumptions." b. The MRO believes R2.1.4 and R2.4.4 should be deleted because its unnecessary to make a requirement of sensitivities that an entity chooses to do above and beyond the requirements in R2.1.3 and R2.4.3. If the SDT chooses not to delete these requirements, then MRO believes that R2.1.4 should be a subrequirement of R2.1.3 and R2.4.4 should be made a subrequirement of R2.4.3. The responsible entity should be allowed to select the appropriate sensitivity that should be performed. This is especially necessary given the need to perform each of these sensitivity analyses for six situations each year: peak and off-peak for two short-term years and one long-term year. Even with the requirement for one sensitivity for each case that amounts to six additional sets of analysis for steady-state and six for stability. c. For R2.1.4, we suspect that these analysis are similar to extreme event contingencies and do not have specific performance requirements. We would also like some explanation of what and how to provide the technical rationale for why each condition was or was not used.

Response: As with all planning models, assumptions must be made that the entity feels are representative of how the System will respond and perform. Models can only attempt to simulate the System based on expected conditions. The standard has been modified to explain that "an aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable".

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

b. Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written, the standard is requiring at a minimum, one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the system responds to the variances. In addition, Requirements R2.1.4 and R2.4.4 have been deleted.

R2.1.3 For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

c. Requirement R2.1.4 has been deleted.

Organization	Question 10:	Question 10 Comments:
Austin Energy	No	Appropriate sensitivity analysis should be determined by the Transmission Planner and/or the Planning Coordinator (ISO or RTO) and not made a routine requirement. Therefore, R2.1.3 should be deleted.
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	No	These requirements are very prescriptive. Many examples of sensitivities are already inherent in the existing requirements. Some sensitivity studies are in effect adding an additional level of contingency (N-2 or N-3). Sensitivity studies of load variation are already inherent in the fact that several different study years and conditions are already being required. Outages of reactive sources and generation should already be included in studies of multiple contingencies. The process of planning new generation (system impact studies) will include studies of the future with and without the proposed new equipment. The TP and PC can better select the most appropriate sensitivities for their system. In general we believe that breaking these requirements into specific sub requirements, focusing on specific sensitivities, is too prescriptive and inappropriate. It will lead to over focus on these particular issues to the detriment of system reliability. The standard should not include an enumerated list of required sensitivities Engineering judgment needs to be permitted.

Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written the standard is requiring at a minimum one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the system responds to the variances.

R2.1.3 For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

Midwest ISO	No	This reminds us of Category D from original table--requiring us to study something but take no action. Sensitivities are not appropriate nor effective in a planning world in which you require an array of sensitivity studies but require no action will be taken. While running sensitivities enables us to better understand system limits, why have it as a requirement if there is no action plan obligation.

Response: The requirement was added to ensure that the entities do run certain variances that would stress the System. Requirement R2 requires that such studies are documented as part of the Planning Assessment. The entity is to determine the risk associated with not modifying the Corrective Action Plan to consider these studies. The documentation puts the entity on record as stating that the variance was considered but may or may not have been incorporated in the Plan makes the entity liable for its decision.

Organization	Question 10:	Question 10 Comments:
Tri-State Generation and Transmission Association, Inc.	No	We appreciate the extra detail describing sensitivity cases, but do not think it is reasonable to require explanations of why each condition suggested in R2.1.3.1-R2.1.3.7 was or was not studied. It should be sufficient that sensitivity studies are considered appropriate by the individual utility. R2.1.4 should be demoted to R2.1.3.8 (and the "shall include rationale" clause removed).
Response: Requirements R2.1.3 and R2.4.3 have been revised to remove the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. The SDT believes that documentation of why a sensitivity was selected for study should be provided. Requirements R2.1.4 and R2.4.4 have been deleted. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
Lakeland Electric	No	R2.1.3.1 requires other than peak sensitivity studies while R2.1.2 requires Off peak studies. Recommend further defining of R2.1.2 to specific load level or points on forecast demand curves to eliminate any overlap between two requirements.
Response: The SDT has used the defined term "Off-Peak" and believes that this is sufficient.		
Southern Company Transmission	No	R 2.1.3 One should only have to explain why sensitivity was performed, not why it was not performed. In general we believe that breaking these requirements into specific sub requirements focusing on specific sensitivities is too prescriptive and inappropriate. It will lead to over focus on these particular issues to the detriment of system reliability. There should be no list of sensitivities enumerated as subrequirements. Engineering judgment needs to be permitted. A specific proposal for R2.1.3 which addresses the above concerns is provided as follows:R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) shall be run and documented that stress the System to reflect one or more conditions such as higher or lower Load than forecasted with variability of Load/demand and Load power factors due to season, weather, or time of day; modification of expected transfers; unavailability of long lead time Facilities; variability and outages of reactive resources; generation additions, retirements, or other dispatch scenarios; decreased effectiveness of controllable Loads and Demand Side Management; modification of planned Transmission outages. Document why each sensitivity was selected.
Response: Requirements R2.1.3 and R2.4.4 have been revised to remove the requirement you reference. In addition, Requirements R2.1.3 and R2.4.3 have been		

Organization	Question 10:	Question 10 Comments:
revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
Brazos Electric Power Cooperative, Inc.	No	2.1.3 should have been left alone. We have a real problem with the addition of 'technical' and documenting why things were NOT selected. We would also like to see more leeway provided to the TP and PC by adding language similar to that mentioned above such as "as deemed necessary by the TP or PC".2.1.4 should be incorporated into 2.1.3 in a similar fashion as our suggested changes for 2.4.3.
Response: Requirements R2.1.3 and R2.4.4 have been revised to remove the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. In addition, Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, Requirements R2.1.4 and R2.4.4 have been deleted. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
NERC and Regional Coordination	No	The standard as worded:? Implies all tests are run for a given sensitivity the standard should be revised to read applicable testing for the applicable sensitivity.? Requires proof of negative o Why a sensitivity was not selected? Requires that expansion plans identify the impact of sensitivity o Many sensitivities may have varying impacts on an expansion plan. Suggested changes:R2.1.3 - For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that reflect one or more of the following conditions shall be incorporated into the assessment. Documentation of the

Organization	Question 10:	Question 10 Comments:
		technical rationale for why each of the conditions was selected and the portion of the assessment that included each selected sensitivity shall be supplied. R2.1.4, R2.4.3, and R2.4.4 - need to be modified accordingly. Delete R2.1.4 as it is superfluous. If a PC runs a sensitivity study and includes that analysis in its Plan, then why would NERC mandate that the PC explain why the non-mandated sensitivity study was run. If a study is required then it should be mandated. If a study is not mandated then he PC should not be held accountable for explaining the un-mandated study.R2.4.3.1 ? Variation in load model. Specific numbers should be included. R2.4.3.2 - Modification of expected transfers ? Be more specific. Firm or non-firm transfer and amount of MWR2.4.3.3 - Unavailability of long lead time Facilities. How many years out we are looking at and for how long it must be out of service.R2.4.3.4 - Variability of Reactive Source ? need to be more specific (give me MVARS). We already test this under FAC 010 for lost of shunt capacitor.R2.4.3.5 - This should already been taken into account when we do studies. So be more specific.R2.7.2 - Include a description of how results of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 impacted the list of actions developed in accordance with R2.7.1.R2.1 - Revise wording - The annual assessment of the of the NT Planning Horizon shall include: then go into the sub-bullets. The SDT must clarify exactly explicitly how many studies (in terms of numbers) must be done each planning horizon for short term and long term and how much sensitivity study for term.

Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities".

Also, Requirements R2.1.3 and R2.4.3 have been revised to remove the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run.

R2.1.3 For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

The SDT agrees with the commenter and has deleted Requirements R2.1.4 and R2.4.4.

The SDT did not want to be more prescriptive and provide specific details and number for variances that the entity may select because of the huge number of possible variances that can occur. It is up to the planning entity to determine which and how much of a variance is appropriate for its studies.

Requirement R2, along with its sub-requirements, requires the sensitivities run are to be documented. Requirement R2.6 requires that the Corrective Actions be listed. The entity can add the details and further explanation of how the sensitivities were incorporated into the Plans.

Organization	Question 10:	Question 10 Comments:
Since the basis of the standard is to allow the entity to support the Planning Assessment using current and past studies, the standard cannot dictate the specific number of studies to be made. The standard does specify the current cases that must be run in Requirements R2.1.1, R2.1.2, R2.2, R2.4.1 and R2.4.2.		
IESO	No	As we commented on R2.4.3, we continue to express our disagreement to include sensitivity testing in R2.1.3 and R2.1.4. We are disappointed that despite disagreements by the majority of the commenters and their suggestions to leave sensitivity testing to the TP's and PC's discretion, the SDT continues to stipulate detailed requirements for sensitivity testing. The SDT in its summary response to comments indicates that these testing are intended as "?providing some guidance on what could be included in the sensitivity studies without being too prescriptive." If these are indeed intended as guidance rather than enforceable requirements, then they should be provided in a technical document or a reference document that supports the standard, not in the standard itself.
Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written, the standard is requiring at a minimum, one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the System responds to the variances.		
North Carolina Electric Membership Corp	Yes and No	Sensitivities to base assumptions for studies are always good utility practice. But we agree with others that these may be overly prescriptive in requiring each and every one. Allow the TP and PC to select the appropriate sensitivities for the annual assessments with input from customers and affected stakeholders. We are concerned that the requirement for every sensitivity each and every year would result in excessive burden to existing PCs and TPs doing this analysis with no resulting improvement to reliability.
Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written the standard is requiring at a minimum one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the System responds to the variances.		
E.ON U.S. Transmission Planning	Yes and No	2. R2.1.3.2 refers to modification of expected transfers as a sensitivity test. Does this include transfers across the system, such as a transfer from Cinergy to TVA?
Response: The SDT did not want to be more prescriptive because of the huge number of possible variances that can occur. It is up to the planning entity to determine which and how much of a variance is appropriate for its studies		

Organization	Question 10:	Question 10 Comments:
ERCOT System Planning		The sensitivity cases suggested are unnecessary and unfeasible. For example, generation additions to cases that can already meet the load under contingency conditions do not create a reliability problem as the new generator can always be turned off. On the other extreme, sensitivity analysis of possible, unknown and uncontrollable generation retirements along with the Table 1 requirements of P3 (Generator + 1) contingency analysis presents an overwhelming study and documentation burden that will not add a corresponding benefit to the study and the results would be meaningless.
Response: The SDT believes that planners must consider these possible variances and reinforce the System so that when it comes to Real-time operation, the TOP will have a system sufficiently robust to operate around any of the conditions. Commenters generally agree that these are the responsibility of planning. Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
American Transmission Company	No	For R2.1.3, we would like further explanation of what technical rationale is expected and how it should be provided as to why each condition sensitivity was or was not used. In the subrequirements, we are unsure of what is exactly meant by "variability of load demand and load power factors", "modification of expected transfers", "long lead time Facilities", and "modification of planned outages". For R2.1.4, it is unclear what specific performance requirements must be met for these other sensitivities. We would also like some explanation of what technical rationale is expected and how it should be provided as to why each condition sensitivity was or was not used.
Response: Requirements R2.1.3 and R2.4.4 have been revised to remove the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. Since these are sensitivities, any and all variances provide some level of information as to how the system responds to such variances. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the~~		

Organization	Question 10:	Question 10 Comments:
~~conditions was or was not selected shall be supplied~~ included in the Assessment: The SDT did not want to be more prescriptive because of the huge number of possible variances that can occur. It is up to the planning entity to determine which and how much of a variance is appropriate for its studies. Also, Requirements R2.1.4 and R2.4.4 have been deleted.		
Duke Energy	No	Although we agree with the perceived intent of R2.1.3, we believe the wording should be revised to make it very clear that it is not necessary to perform studies to substantiate your technical rationale for choosing not to perform any particular sensitivity study. Documented engineering judgment to support the decision not to perform the particular sensitivity studies should be sufficient. Recommend renumbering R2.1.4 to R2.1.3.8 and reword as follows: Any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems.
Florida Reliability Coordinating Council, inc	No	R2.1.3 and R2.1.4 as written can create issues during the compliance assessment. These requirements place the burden of justifying the inclusion / exclusion of the sensitivities on the TP or PC. Thus, only a sensitivity deem appropriate by the TP or PC and not performed can be found non-compliant. R2.1.4 can be eliminated by modifying the wording in R2.1.3 as follows:? For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, at least one sensitivity shall be performed that stress the system based on one or more of the following conditions, plus any additional conditions determined by the Transmission Planer and Planning Coordinator. The Planning Assessment will also include the technical rationale for why each of the conditions was or was not selected for study that year.?
Response: Requirements R2.1.3 and R2.4.4 have been revised to remove the requirement to explain why sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. Since these are sensitivities, any and all variances provide some level of information as to how the system responds to such variances. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
Central Maine Power Company	No	a. With respect to R2.1.3 delete "that Stress the System with sensitivities". b. R2.1.3 should be revised to clarify that if a TP/PC conducts the studies specified in R2.1.1 and R2.1.2 with one or more of the sensitivities which stress the system in the normal course of study, then additional studies of a less-stressed system are not required.

Organization	Question 10:	Question 10 Comments:
		c. The intention of Paragraph R2.1.4 is unclear and appears to be unnecessary; therefore, it should be removed.
ISO New England Inc.	No	a. With respect to R2.1.3 delete " that Stress the System with sensitivities". b. R2.1.3 should be revised to clarify that if a TP/PC conducts the studies specified in R2.1.1 and R2.1.2 with one or more of the sensitivities which stress the system in the normal course of study, then additional studies of a less-stressed system are not required. c. The intention of Paragraph R2.1.4 is unclear and appears to be unnecessary; therefore, it should be removed.
ColumbiaGrid	Yes	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the ?base case? condition.
Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: The SDT agrees and has deleted R2.1.4.		
NSTAR Electric	No	1. With respect to R2.1.3 delete "that Stress the System with sensitivities".2. R2.1.3 should be revised to clarify that if a TP/PC conducts the studies specified in R2.1.1 and R2.1.2 with one or more of the sensitivities which stress the system in the normal course of study, then additional studies of a less-stressed system are not required.3. The intention of Paragraph R2.1.4 is unclear and appears to be unnecessary; therefore, it should be removed.
Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with		

Organization	Question 10:	Question 10 Comments:
~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: Requirements R2.1.4 and R2.4.4 have been deleted.		
New York Independent System Operator	No	If a TP/PC conducts the studies specified in R2.1.1 and R2.1.2 with one or more of the sensitivities which stress the system in the normal course of study, we assume that fulfills the requirements of R2.1 completely, without additional studies of a less-stressed system. Is that correct?
Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: The standard expects that at least one more of those variances listed in Requirement R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written the standard is requiring at a minimum one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the System responds to the variances.		
Oncor Electric Delivery	Yes	Generally agree with modifications although would again stress that detailed load modeling for stability analysis may be as revealing as some of the sensitivity studies recommended in R2.1.3 if they were only run with steady state analysis.
Response: As with all planning models, assumptions must be made that the entity feels are representative of how the System will respond and perform. Models can only attempt to simulate the System based on expected conditions. The standard has been modified to explain that "an aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable". **R2.4.1** System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic		

Organization	Question 10:	Question 10 Comments:
behavior of the Load is acceptable.		
FirstEnergy Corp.	No	The requirements related to sensitivity cases as written in draft 2 are an improvement over draft 1 as they now allow flexibility in choosing sensitivities, compared to what use to be a fixed list of options. However, we do not agree with the need to document the technical rationale for why each listed condition was or was not selected. This seems to create a needless paper trail from an auditing viewpoint. If any documentation is needed, it should be limited to why the sensitivity was selected and it should not be required to indicate why others were not selected. Therefore, we suggest rewording 2.3.1 as follows: "For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation of the technical rationale for why each of the conditions was selected shall be supplied:"R2.1.4 - This is an optional requirement and should be worked into the list of options within 2.1.3. As a stand alone requirement, what type of measure or VSL would be applicable for this requirement? We suggest re-numbering this requirement as a new 2.1.3.8 and reword it as follows: "Any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems".R2.1.3.3 ? This requirement indicates sensitivity is needed for "Unavailability of long lead time facilities." Why is this required in a near-term planning horizon? How long is long? Doesn't the N-1-1 (Planning Event P6) test already account for this related to the outage of existing equipment which may present long lead times? Same comments apply for R2.4.3 and R2.4.4 in the stability study section.
Response: Requirements R2.1.3 and R2.4.3 have been revised to remove the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: The STD agrees. Requirements R2.1.4 and R2.4.4 have been deleted. The near-term horizon extends from one to five years. Equipment scheduled for installation in five years requires ordering today. Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities".		
Orlando Utilities	Yes and No	I generally agree with the intent of requiring studies beyond just one load level and system condition; however I have some

Organization	Question 10:	Question 10 Comments:
Commission		specific suggestions, questions and comments. R2.1.3: As worded I have several concerns: 1. This would make any study performed that did not include sensitivities useless for performing the assessment. I recommend identify sensitivities and studies separately, with sensitivities just being smaller versions of studies. (Our usual definition is that a study demonstrates specific solutions to problems identified, whereas a sensitivity merely comments on the presence or lack of problems and how they relate to what is seen in the more formal studies. Obviously a problem found in a sensitivity not seen in a regular study receives additional focus.) 2. This would force the study to look only at the sensitivities listed rather then allow one or more of the conditions, plus additional conditions all in one run. This would force an entity to run additional studies if they wished to exceed the requirements rather then a single study that meets and exceeds the requirements. I suggest the following wording instead to still require the sensitivities, but allow flexibility in how they are performed. "R 2.1.3: At least one sensitivity shall be performed that stress the system based on one or more of the following conditions, plus any additional conditions determined by the transmission planner and planning coordinator. The Planning Assessment will also include the technical rationale for why each of the conditions was or was not selected for study that year. R.2.1.3.1- Suggest adding system growth, for example "season, weather, unpredicted system growth, or time of day". As written it does not seem to allow a study based on the long range load growth prediction being off, but instead only on a change in season, weather or time of day. R2.1.4: What was intended by using the phrase "Documentation of the technical rationale" instead of simply saying "shall include technical rationale"? I suggest dropping the "documentation of the" as this could cause confusion on an audit as to what is the difference between the "technical rationale" and "documentation of the technical rationale" unless the drafting team plans to define what "documentation of technical rationale is" other then the rationale itself.

Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written, the standard is requiring at a minimum, one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the system responds to the variances.

R2.1.3 For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

The SDT did not want to be more prescriptive because of the huge number of possible variances that can occur. It is up to the planning entity to determine which

Organization	Question 10:	Question 10 Comments:
and how much of a variance is appropriate for its studies. Requirements R2.1.3 and R2.4.4 have been revised to remove the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. Since these are sensitivities, any and all variances provide some level of information as to how the system responds to such variances. Requirements R2.1.4 and R2.4.4 have been deleted		
Entergy Services, Inc.	No	R2.1.3.2 - Modification of expected transfers: Modification of expected transfers infers that non-firm transmission use would be estimated based on historical data or perhaps an economic outlook. To plan the system for such non-firm use is an imprudent burden on rate payers. Economic tools are available to ascertain the benefits of system upgrades and prudently allocate the costs of such upgrades. Generation assets and the future plans of those assets is market sensitive information that could easily be extracted from such sensitivity analyses. Results of these sensitivity studies should be used to aid in reliably operating the system. They should not be a basis for constructing transmission facilities for reliability. These types of studies are aligned with the operating horizon. See also comments made above regarding 2.1.3.4 and 2.1.3.7.In general, we believe that breaking these requirements into specific sub requirements, focusing on specific sensitivities, is too prescriptive and inappropriate. It will lead to over focus on these particular issues to the detriment of system reliability. There should be no enumerated list of required sensitivities. Engineering judgment needs to be permitted. Many examples of sensitivities are already inherent in the existing requirements. Some sensitivity studies are in effect adding an additional level of contingency (N-2 or N-3). Sensitivity studies of load variation are already inherent in the fact that several different study years and conditions are already being required. Outages of reactive sources and generation should already be included in studies of multiple contingencies. The process of planning new generation (system impact studies) will include studies of the future with and without the proposed new equipment. The TP and PC can better select the most appropriate sensitivities for their system. We recommend that engineering judgment continue to be recognized as a vital component of planning.
Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written, the standard is requiring at a minimum, one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the system responds to the variances. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		

Organization	Question 10:	Question 10 Comments:
The SDT believes that planners must consider these possible variances and reinforce the System so that when it comes to Real-time operation, the TOP will have a System sufficiently robust to operate around any of the conditions. Commenters generally agree that these are the responsibility of planning. The SDT did not want to be more prescriptive because of the huge number of possible variances that can occur. It is up to the planning entity to determine which and how much of a variance is appropriate for its studies.		
BPA Transmission Reliability Program	No	For those conditions that are "not" studied, it makes sense to explain why that particular condition was not selected. However, we do not agree with R2.1.3 that a rationale needs to be provided for why a particular sensitivity "is" selected for study. Running additional sensitivities provides a better understanding of system performance and doesn't need further justification. Requirement R2.1.4 is not needed and should be removed. It should be up to the Transmission Provider's discretion whether they run additional sensitivity studies beyond what the standard requires in R2.1.3, and it should not be necessary to justify why they chose to run them. What a sensitivity study consists of, needs further clarification. For example, if a system assessment is performed using a case with transmission paths stressed near their limits, is this considered the baseline or a sensitivity? If it is considered the baseline, would a sensitivity be required at reduced stress levels and what purpose would this serve when the original case produced the more severe system impacts? This needs further clarification.
Response: Requirements R2.1.3 and R2.4.3 have been revised to remove the requirement to explain why sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: Requirements R2.1.4 and R2.4.4 have been deleted. Requirements R2.1.3 and R2.4.3 have been revised to make it clear that “sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment”. The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as “sensitivities”.		
City Water, Light & Power - Springfield, Illinois	Yes	

Organization	Question 10:	Question 10 Comments:
Platte River Power Authority	Yes	
BCTC	Yes	
Manitoba Hydro	Yes	
Tenaska, Inc.	Yes	
Arkansas Electric Coop. Corp.	Yes	
AEP	Yes	
LCRA TSC	Yes	
Response: Thank you for your response.		

11. **In response to industry comments, the SDT modified Table 1 requirements for Planning Event P6. Planning Event P6 involves independent overlapping single contingencies (n-1-1) involving two Transmission Facilities excluding generators. This Planning Event generally correlates to P5 of the first draft and now includes shunt devices. The P6 event was also revised to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300 kV.**

    Do you concur with the modifications? If not, please state why and/or suggest specific changes.

Summary Consideration:

A substantial majority of the industry respondents agree with the revision to permit loss of Non-Consequential Load to meet performance requirements for P6 Events involving systems above as well as below 300 kV, considering the low probability of such Events.

There are concerns that this change would make it difficult for scheduling maintenance outages because the existing TPL-003-0 allows shedding of Non-Consequential Load after the next outage . However, in the proposed standard, If a facility is scheduled out of service for maintenance, the next outage would be considered a single Contingency Event, and loss of Non-Consequential Load is not permitted.

There are concerns expressed by numerous respondents that after the first single Contingency and System adjustment, curtailment of Firm Transmission Services (or firm transfers) and shedding of firm Load would not be allowed in preparation for the second Contingency. The SDT added Footnote # 10 to the end of Table 1 to reflect that Curtailment or Interruption of Firm Transmission Service in preparation for the next Contingency will be allowed. However, until the next Contingency occurs, System performance will need to meet the requirements for a single Contingency Event. As such, the proposed standard will not allow loss of any firm Non-Consequential Load, except for contracted Interruptible Loads, in preparation for the next Contingency. Nonetheless, the SDT has provided an exception (Requirement R2.6.4) to address those situations, which may arise that are beyond the control of the Transmission Planner or Planning Coordinator, and, which can prevent the implementation of the relevant Corrective Action Plan in the required timeframe.

Some respondents requested that System adjustment be defined. The SDT believes that Header note ‘e’ and the new Footnote # 10 provides the description of the System adjustments allowed after a first Contingency Event.

There were also requests for clarification between a P1 Event, which occurred after another Facility has been out of service, for example, for scheduled maintenance, and a P6 Event, since the former will not allow loss of Non-Consequential Load, while the latter would allow it. The SDT believes that the difference between these two Events is whether the prior outage was planned (such as maintenance) or anticipated (such as extended outage). Therefore, if the Prior outage is planned or anticipated, then the next N-1 is a single Contingency Event, otherwise, it would be a P6 Event.

Concerns were also expressed that the TP and PC should have discretion on the Contingencies (for example, shunt devices) to study and analyze. One response suggests that the P6 Event to be studied should have a common reason to occur. The SDT modified Requirement R3.3 (now R3.4) to allow the PC and TP to determine the single and multiple Contingencies to be included in the planning analyses. This would give the TP and the PC the discretion to study the Contingency most suited to the area of study, and they can choose not to study loss of shunt devices, or those P6 Events that do not have a common reason to occur, if these are less severe than the Events studied.

Some responses suggest that there should be a specific limit to the amount of Load loss allowed. While the SDT does not disagree with having some specific limits below which Load loss would be allowed, arriving at such an amount may be too case-specific and too prescriptive for a Continent-wide Standard.

One response disagrees that the requirement should be so much more severe for an internal breaker fault as opposed to two single line outages for elements over 300 kV. The SDT believes that an internal breaker fault would remove from service all Facilities connecting to the faulted breaker simultaneously, which would likely be more severe than outage of two single lines.

As a result of industry comments, the following requirements were changed:

R3.3.3 (now R3.4) Those Planning Event Contingencies in Table 1 ~~– Steady State Performance~~ ~~not covered in Requirement R3.3.2~~ that are expected to produce more severe System impacts shall be identified~~,~~ and a list of those Contingencies to be evaluated for System performance in Requirement R3.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results.

Header note 'e' - For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Footnote #10 – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.

Organization	Question 11:	Question 11 Comments:
Dominion - Electric Transmission Planning	No	For Bulk Electric System (BES) Elements out of Service above 300 kV, interruption of Firm Transmission Service and Non-Consequential Load Loss should not be allowed. We favor the language proposed in the previous draft.
ITC Holdings: ITC, METC, ITC Midwest	No	Allowing load loss for shutdown plus contingency might seriously jeopardize maintenance outages when you actually encounter this situation in real-time. It's easy to say these things in the ?planning horizon? but it might be politically unacceptable for "real-time". This is particularly true for higher voltage systems above 300kV. We understand that there could be "load-pocket" situations at lower voltages where this might be allowed but EHV systems are back-bone systems. This would set a bad precedent if allowed.
Lafayette Utilities	No	Lafayette does not agree that the loss of Non-Consequential Load should be permitted as a corrective action. See also

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System		paragraph (b) in response to Question 15.
Arkansas Electric Coop. Corp.	No	Non-Consequential Load Loss should not be allowed. See comments to question 7.
Response: Thank you for your comments but the majority of the industry respondents agree with the revision to permit loss of Non-Consequential Load to meet performance requirements for P6 Events involving Systems above as well as below 300 kV considering the low probability of such Events.		
City Water, Light & Power - Springfield, Illinois	Yes and No	Shunt devices should only need to be included in contingency analysis at the discretion of the TP or PC.
CenterPoint Energy and CPS Energy	No	We believe P6 should be deleted. As noted earlier, we believe credible multiple contingencies should be studied as planning events, with incredible multiple contingencies possibly considered as extreme events. If P6 is retained, we believe loss of shunt devices should not be studied and believes the ability to systematically study the contingency loss of every individual switched shunt device is not supported by commercially available PTI software because up to this point it has not generally been recognized as a necessary or desirable analysis to perform. Also, if P6 is retained, we believe loss of Non-Consequential Load should be permitted at any voltage level for this type of extreme event.
Response: Requirement R3.3.3 (now Requirement R3.4) was modified to allow the PC and TP to determine the single and multiple Contingencies to be included in the planning analyses. This would give the TP and the PC the discretion to study the Contingencies most suited to the study area, including whether to include shunt devices in the analyses. **R3.4** Those Planning Event Contingencies in Table 1 ~~– Steady State Performance~~ ~~not covered in Requirement R3.3.2~~ that are expected to produce more severe System impacts shall be identified~~,~~ and a list of those Contingencies to be evaluated for System performance in Requirement R3.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results.		
Progress Energy Carolinas	No	While we agree interruption of firm transmission service and non-consequential load loss should not be allowed to meet the planning requirements for the first system contingency (defined as initial system condition in the table), these system adjustments should be allowed to prepare for the second event so that the system will meet the requirements following the second event. We recommend that clarifying changes be made to ensure that this is clearly understood. One suggestion would be to include the following footnote to P6 in both the Steady State and Stability Tables.? Foot note: Interruption of firm transmission service and/or non-consequential load loss is allowed after the first event as a System adjustment to prepare

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		for and meet the requirements of the second event. See also our related response to question 15.
Gainesville Regional Utilities	Yes and No	I believe some clarification is needed to specify that you can or can not curtail firm transmission service prior to the next event, because as written it could lead to compliance audit issues. I don't believe the intend of order 693 was to cause a need for utilities to be exposed to large cost increases for their customers while very little to no improvement in reliability is provided as it deals with very low probability conditions which would yield no increase in transfer capability.
JEA	Yes and No	JEA agrees with the changes on the surface, but still does not agree with the concept that it can not curtail Firm Transmission Service after the first N-1 event in preparation for the second N-1 event. JEA's existing Firm Transmission Service customers understand the need to maintain these existing transmission loading relief procedures in order to maintain security of the BES. The only JEA system element that causes this concern has a very high availability and would have a very costly infrastructure improvement to meet this requirement resulting in all of JEA's Firm Transmission Service Customers experiencing increased service cost or in the worst case having their service opportunities permanently curtailed.
Florida Power and Light	No	The P6 Planning Event is not clearly defined. It appears that the Initial System Condition is the Planning Event of P1, with the ?System Adjustments? allowed under P1 to keep facilities within the applicable ratings. R3.5.3. requires that a sustainable, stable, operating condition is maintained. This does not state prepared for the next contingency?. Given FERC's interpretation of TPL-002-0 Category B (see paragraphs below for excerpts from Order 693) that the system is not required to be able to withstand another N-1 contingency, the proposed new standard appears to require that this state be "sustained" indefinitely after a P1 event, or until the P6 Event, which is loss of the second element, with no mention of the time duration between the initial system condition and the event. The performance criteria for a P1 event can be met as long as it does not contemplate another event that would change the event to a P6 event. However, a P6 event is a TPL-003-0 Category C event which must contemplate a second contingency after the first. The existing TPL standards accomplished this with footnote b) in the Tables for all of the TPL standards, allowing system adjustments including curtailment of contracted firm transfers to prepare for the next contingency. Since FERC clearly states that this is not a requirement under TPL-002-0, but that it is addressed in TPL-003-0, they directed the ERO to modify the footnote for TPL-002-0. In TPL-003-0 the Category C3 event refers to a "Category B contingency, manual system adjustments, followed by another Category B contingency", however since the footnote for Category B contained the "To prepare for the next contingency?." language, and it is contained in the Table for TPL-003-0, that language must apply to the C3 event. Further, in Order 693, on TPL-003-0, FERC (1) did not direct the ERO to modify the same footnote which is contained in TPL-003-0, (2) recognizes that these are low probability events, and (3) stated that it "does not intend to recommend action on this issue [the appropriateness and value of including the ability of the system to withstand two simultaneous Category B contingencies for major load pockets] at

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		this time and, instead, directs the ERO to consider the comments in possible future revisions to the Reliability Standard.? The SDT has inappropriately applied the direction of FERC on TPL-002-0 to the P6 event (which is similar to TPL-003-0 C3) without regard to its implications on the industry, the ratepayers, or even its own standards, as the impact of the team's interpretation would require changes in the methods of determining TTC's, ATC's, and SOL's. The additional costs (both monetary and intangible) incurred by ratepayers for no gain in the ability to transfer firm electric power, far outweigh any gain in reliability benefits for these low probability events. Just to provide one example to illustrate this point, if the SDT's current interpretation for a P6 event is not modified, FPL would have to spend in excess of $ 1 Billion dollars, in order to meet this performance criteria for 500 kV facilities, for an event with a probability of less than 0.07 per hundred mile-years (based on FPL's 500 kV facilities), which would be passed on to its ratepayers. There are many other examples on the FPL system, as well as other systems. This interpretation is fatally flawed and makes no sense from a reliability or cost perspective, not to mention the intangible impacts of siting, right-of-way acquisition, EMF, NIMBY, etc. Further, assuming the SDT interpretation, how could one justify the need before state commissions, and exercise eminent domain in the courts to take someone's land for right-of-way, a process that could take as long as 8-10 years, for minimal increase in reliability, and no increase in transfer capability. In order to assist the SDT, these paragraphs are included with references to FERC Order 693, to show that it has misinterpreted Order 693. The following captions stated below should help clarify this point. Order 693 states: P.1788 ?Under TPL-002-0 the system is not required to be able to withstand another N-1 contingency. That N-1 requirement is a Category C contingency which is addressed by TPL-003-0.? Therefore, the end state of P1 is not a ?secure? state, but a ?normal operating state?, as stated in P. 1796 ?The Commission, therefore, directs the ERO to modify the second sentence of footnote (b) to clarify that manual system adjustments other than shedding of firm load or curtailment of firm transfers are permitted to return the system to a normal operating state after the first contingency, provided these adjustment can be accomplished within the time period allowed by the short term or emergency ratings.? These two determinations by FERC together show that their interpretation of normal operating state is not the secure, ready for the next contingency state, rather, it is the state in which the performance criteria have been met for that planning event. With regard to the FERC direction of Order 693 on TPL-003 and ?the appropriateness and value of including the ability of the system to withstand two simultaneous Category B contingencies for major load pockets?, FERC states in P. 1824, ?Many commenters indicated that this was a very low probability event and the costs for addressing such an event would be significant. As a result, EEI states that a dialogue must first be initiated within the industry and with state public utility commissions to identify such load pockets, to target the required potentially significant transmission investments and to develop plans for allocating the costs of such investments. In light of these comments, the Commission does not intend to recommend action on this issue at this time and, instead, directs the ERO to consider the comments in possible future revisions to the Reliability Standard.?FPL agrees with the increased performance requirement for the P3 multiple contingency event that assumes the loss of a generator as the first contingency. Firm transfers should not depend upon specific generators being on line, however firm transfers must depend upon transmission lines being in-service.
SERC Dynamics	Yes	The changes are more practical. If two or more 500kV lines are lost, it makes complete sense to allow loss of non-consequential load so long as cascading outages are not triggered. While we agree interruption of firm transmission service

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Review Subcommittee		and non-consequential load loss should not be allowed to meet the planning requirements for the first system contingency (defined as initial system condition in the table), these system adjustments should be allowed to prepare for the second event so that the system will meet the requirements following the second event. We recommend that clarifying changes be made to incorporate this concept. We recommend that the statement above be included as modification or as a footnote for the P6 portion of the table as follows:Foot note: Interruption of firm transmission service and non-consequential load loss should be allowed after the first event as a system adjustment to prepare for the second event and meet the requirements following the second event.See our related response to question 15.
Southern Company Transmission	Yes and No	The requirements are more practical now. If two or more 500kV lines are lost, it makes complete sense to allow loss of non-consequential load so long as cascading outages are not triggered. While we agree interruption of firm transmission service and non-consequential load loss should not be allowed to meet the planning requirements for the first system contingency (to get loadings back within normal ratings), these system adjustments should be allowed to prepare for the second event so that the system will meet the requirements following the second event. We recommend that clarifying changes be made to incorporate this concept. We recommend that the statement below be included as modification or as a footnote for the P6 portion of the table as follows: Interruption of firm transmission service and non-consequential load loss are allowed after the first event as a system adjustment to prepare for the second event in order to meet the requirements following the second event.
Duke Energy	Yes	The changes are more practical. If two or more 500kV lines are lost, it makes complete sense to allow loss of non-consequential load so long as cascading outages are not triggered.? While we agree interruption of firm transmission service and non-consequential load loss should not be allowed to meet the planning requirements for the first system contingency (defined as initial system condition in the table), these system adjustments should be allowed to prepare for the second event so that the system will meet the requirements following the second event.? We recommend that clarifying changes be made to incorporate this concept. We recommend that the statement above be included as a modification or as a footnote for the P6 portion of the Steady State and Stability tables as follows: "For P6 multiple contingency events, Transmission configuration changes and redispatch of generation are allowed provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits. Permissible Transmission configuration changes include dropping of load and firm transfers needed to prepare for the second contingency. See our related response to question 15.
SERC Reliability Review Subcommittee and Planning Standards	Yes	Since Event P6 is essentially a sub-set of the existing Category C.3 Contingency events, we support these modifications which make the system performance requirements for P6 consistent with what exist today for Category C.3. While we agree interruption of firm transmission service and non-consequential load loss should not be allowed to meet the planning requirements for the first system contingency, these system adjustments should be allowed to prepare for the second event so that the system will meet the requirements following the second event. We recommend that clarifying changes be made to incorporate this concept. We recommend that the statement below be included as modification or as a footnote for the P6 portion of the table as follows: Interruption of firm transmission service and non-consequential load loss are allowed after the

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Subcommittee		first event as a system adjustment to prepare for the second event in order to meet the requirements following the second event.
Orlando Utilities Commission	Yes and No	As written the standard does not seem to forbid the adjustment of firm transfers and non-consequential load in preparation for the second part of an N-1-1, however that conflicts with the teams statements on the recent national call. If the intent is to forbid the adjustment of firm transfers and non-consequential load in preparation for the second part of an n-1-1 that needs to be made explicitly clear in the standard. This is especially important since one of the current understandings of the standards relating to Transmission Planning and System Operating Limits clearly allow such adjustments, and to not make it clear is building a compliance trap for the unwary. While I do not support the creation of this n-1-1 threshold if it is going to be established it needs to be abundantly clear.
Entergy Services, Inc.	Yes and No	Since Event P6 is essentially a sub-set of the existing Category C.3 Contingency events, we support these modifications which make the system performance requirements for P6 consistent with what exist today for Category C.3.While we agree interruption of firm transmission service and non-consequential load loss should not be allowed to meet the planning requirements for the first system contingency (to get loadings back within normal ratings), these system adjustments should be allowed to prepare for the second event so that the system will meet the requirements following the second event. We recommend that clarifying changes be made to incorporate this concept. We recommend that the statement below be included as modification or as a footnote for the P6 portion of the table as follows: Interruption of firm transmission service and non-consequential load loss are allowed after the first event as a system adjustment to prepare for the second event in order to meet the requirements following the second event. As the requirement is now implemented in the table, transmission service would need to be made available only if they can be accommodated for N-2 events. This would place these services on equal footing from a reliability perspective but would virtually eliminate the firm transmission market.
Response: Footnote #10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency. However, until the next Contingency occurs, System performance will need to meet the requirements for Event P1. As such, the proposed standard will not allow loss of any Non-Consequential Load, except for contracted Interruptible Loads, in preparation for the next Contingency. Nonetheless, the SDT has provided an exception (R2.6.4) to address those situations, which may arise that are beyond the control of the Transmission Planner or Planning Coordinator, and, which can prevent the implementation of the relevant Corrective Action Plan in the required timeframe. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
Transmission	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above

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Agency of Northern California		300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
Pacific Gas and Electric Co.	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
Public Service Company of New Mexico	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
Puget Sound Energy, Inc.	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300 kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power

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		transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
Idaho Power Company	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
SMUD	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
Sierra Pacific Power Company / Nevada Power Company	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1

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		and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
Black Hills Corporation	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
SRP	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
Tucson Electric Power Company	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow

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		the Non-consequential Load Loss, while the latter would prohibit it.
Modesto Irrigation District	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the nextN-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
Tri-State G&T	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
ColumbiaGrid	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.

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Southern California Edison	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
Alberta Electric System Operator	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
US Bureau of Reclamation	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the nextN-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
BPA Transmission	Yes and No	We agree with the revision to permit the loss of Non-Consequential Load to meet performance requirements for Systems above 300 kV. However, a better definition is needed for "system adjustments". For example, are curtailments permitted as

Organization	Question 11:	Question 11 Comments:
Reliability Program		part of "system adjustments"? Within category P6, there needs to be a common reason for the overlapping outage to occur, such as lines on a common tower, and the appropriate reasons need to be clearly identified in the requirements. In general, we believe that performance category P6 should be part of the Operating Standards rather than the Planning Standards. For these types of events, it is the responsibility of Operations to determine the necessary system adjustments to prepare for the next contingency within the operating horizon prior to year one as defined in the Planning Standards. Therefore, the performance requirements for this category of contingencies, do not belong in the Planning Standards.
Response: Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. Regarding the difference between overlapping single Contingencies as denoted in Event P6 (N-1-1), and one where a single Contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (i.e., N-1), the difference would be whether the prior outage was planned (such as maintenance) or anticipated (such as extended outage). If the Prior outage is planned or anticipated, then the next N-1 is a P1 Event, otherwise, it is a P6 Event.		
Progress Energy Florida, Inc.	No	PEF is pleased that between the 1st and 2nd drafts, the "no" was changed to "yes" concerning allowance of curtailment of Firm Transmission Service or curtailment of Non-Consequential Load for Event P6. PEF has significant concerns, however, regarding the issue of "System Adjustments" associated with P6 and P6's direct association with P1, and thus must check "no" on this Question despite the improvements that have been made. A major misstep has been made with regard to development of P6. Every P1 event is by default the first half of a P6 event. Given that fact, PEF sees several concerns with this issue. First, for P1 events, neither curtailment of Firm Transmission Service nor curtailment of Non-Consequential Load are allowed, regardless of voltage. Both are allowed, however, for a P6 event. In order for the two events to not contradict each other, the conclusion that must be reached is that curtailment of Firm Transmission Service and curtailment of Non-Consequential Load are not allowed as part of System Adjustments, i.e. they are not allowed in between the two steps of P6, only after the 2nd step of P6 (Note: this is not clear partly due to the fact that the term "System Adjustments" is not defined anywhere in the Standard, and PEF therefore requests that the SDT define the term, and that the term should include the allowance of curtailment of Firm Transmission Service and the loss of Non-Consequential Load). PEF has two very serious concerns with that conclusion: a) FERC in its Order 693 stated that the BES is not required to have to withstand another N-1 contingency. Specifically, in Paragraph 1788 of Order 693 FERC states that ?Under TPL-002-0 the system is not required to be able to withstand another N-1 contingency. That N-1 requirement is a Category C contingency which is addressed by TPL-003-0.? Thus FERC clearly made a distinction between N-1 events for which a 2nd N-1 event never happens and N-1-1 events. The SDT, however, has

Organization	Question 11:	Question 11 Comments:
		not written the draft TPL Standard in such a way that Transmission Owners can reasonably and fairly plan for the 2nd N-1 event as TPL-003-0 has done. b) PEF has several 1st N-1 events on their 500 kV system for which "System Adjustments" are necessarily going to have to include either the curtailment of Firm Transmission Service or the curtailment of Non-Consequential Load in order to prepare for the 2nd N-1 event. The draft TPL Standard, while far from definitive on this matter, appears to allow neither as part of System Adjustments. PEF will thus be forced to i) construct redundant 500 kV facilities, at a cost to our ratepayers that will doubtless run into the range of billions of dollars, or ii) significantly reduce the posted levels of ATC/TTC of the various transmission paths available. Option (ii) is not a better option than option (i), for two main reasons: reducing ATC/TTC essentially puts marketing entities out of business, and forces utilities to build more generation sites to compensate for the loss of energy brought in using the previously higher ATC values. Either option results in prohibitively high costs to be passed on to the ratepayers for no measurable increase in BES reliability. This discussion also brings up additional concerns that include the lack of consideration of State government jurisdiction, the lack of public involvement, and ultimately, the lack of sufficient reason to construct such redundancy. PEF has never had a 500 kV N-1-1 event on its system. For this draft Standard to require redundancy projects costing billions of dollars for events that to date have never occurred is preposterous (note: additional comments concerning public outreach, no State government involvement, etc., are contained in the response to Question 15).
Response: Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency. However, until the next Contingency occurs, System performance will need to meet the requirements for a single Contingency Event. As such, the proposed standard will not allow loss of any Non-Consequential Load, except for contracted Interruptible Loads, in preparation for the next Contingency. Header note 'e' provides the System adjustments allowed after a first Contingency Event. **Header note 'e'** -- For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
Ameren	No	Please clarify that the shunt devices to be considered for outage are those that are directly connected to the transmission system. For the P6 events involving a transmission facility and a shunt device, local voltage instability issues may result in dropping of load in the vicinity of the outaged facilities, but the concern should be that the load dropped is not wide-spread. The words "Voltage instability" should be removed from Header Note 3 of Table 1 so that it becomes "Cascading outages and uncontrolled islanding shall not occur."

Organization	Question 11:	Question 11 Comments:
Response: Requirement R3.3.3 (now Requirement R3.4) was modified to allow the PC and TP to determine the single and multiple Contingencies to be included in the planning analyses. This would give the TP and the PC the discretion to study the Contingency most suited to the study area. **R3.4** Those Planning Event Contingencies in Table 1 ~~– Steady State Performance not covered in Requirement R3.3.2~~ that are expected to produce more severe System impacts shall be identified~~,~~ and a list of those Contingencies to be evaluated for System performance in Requirement R3.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results. However, "voltage instability" has not been removed from the Header Note 3 (now Note a) because voltage instability in a local area can spread to the rest of the System if not arrested in time, and a planning analysis is needed to ascertain if there is a voltage stability problem, and, if so, the corrective actions needed.		
Exelon Transmission Planning	No	We do not agree that the requirement should be so much more severe for an internal breaker fault as opposed to two single line outages for elements over 300 kV.
Response: An internal breaker fault is a single event covered in FERC Order 693. In addition, an internal breaker fault would remove from service all Facilities connecting to the faulted breaker simultaneously, which would likely be more severe than the outage of two single lines.		
MidAmerican Energy Company	No	MEC suggests that there be more explanation of what system adjustments are permitted. There should be some specific limit like 100MW below which load loss is allowed. Otherwise, very high cost solutions will be required for very low probability events.
MRO NERC Standards Review Subcommittee	No	The MRO suggests that there be more explanation of what system adjustments are permitted. There should be some specific limit like 100MW below which load loss is allowed. Otherwise, very high cost solutions will be required for very low probability events.
Response: Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency. While the SDT does not disagree with having some specific limits below which load loss would be allowed, arriving at such an amount may be too case-specific and too descriptive for a Continent-wide Standard. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		

Organization	Question 11:	Question 11 Comments:
Austin Energy	No	It should be left to the Transmission Planner and/or Planning Coordinator (ISO or RTO) to select the credible multiple contingencies to be studied as planning events. Therefore P6 should be deleted.
Brazos Electric Power Cooperative, Inc.	No	P6 should be incorporated back into P5. Up to this point, studying all shunt devices has not been considered to have a significant impact on the BES. In addition these are picked up when studying other contingencies. Certain type devices should be reviewed individually, FACTS devices, etc? but this should be at the discretion of the TP or PC. Currently adding shunt devices as a category would require modification to case data or software to be able to automatically run through them all and we are not convinced this is worth the effort.
Response: Requirement R3.3.3 (now Requirement R3.4) was modified to allow the PC and TP to determine the single and multiple Contingencies to be included in the planning analyses. This would give the TP and the PC the discretion to study the Contingency most suited to the study area, and can choose not to study P6 Events if they are less severe than the Events studied. Therefore, P6 is not deleted. **R3.4** Those Planning Event Contingencies in Table 1 ~~– Steady State Performance~~ ~~not covered in Requirement R3.3.2~~ that are expected to produce more severe System impacts shall be identified~~,~~ and a list of those Contingencies to be evaluated for System performance in Requirement R3.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results.		
AEP	Yes	Table 1 does not specify a maximum amount of allowable non-consequential load loss for those categories (including P6) that have a "Yes" listed under the "Non-Consequential Load Loss Allowed" (last) column. See load loss definition under Attachment D of PJM Manual 14B for an example of a maximum amount specification.
Response: While the SDT does not disagree with having some specific maximum amount of allowable Non-Consequential Load loss for these events, arriving at such an amount may be too case-specific and too descriptive for a Continent-wide Standard		
ERCOT System Planning	No	The former P5 of the first draft only required transmission circuits of 300 kV and above to be simulated out of service followed by loss of transmission circuit or transformer. P6 of the second draft requires all BES (100 kV and above) transmission circuits, transformers, dc lines, and shunt devices in combination of another BES circuit, transformer, dc line, and shunt device. The number of contingencies that have to be simulated increased dramatically to an impractical level and would require days of uninterrupted computer run time to complete. This, in combination with other contingencies and sensitivities required in this draft of the standard, is not feasible for large entities. ERCOT recommends that this planning event P6 retain the verbiage regarding transmission lines and transformer low side windings above 300kV.
Response: The previous draft P5 set requirements for N-1-1 300 kV and above; P8 sets requirements for N-1-1 below 300 kV. P6 in this draft combines both P5 and P8 from the previous draft. So, the work load for both drafts would be the same. In addition, Requirement R3.3.3 (now Requirement R3.4) was modified to allow the PC and TP to determine the single and multiple Contingencies to be included in the planning analyses. This would give the TP and the PC the discretion		

Organization	Question 11:	Question 11 Comments:
to study the Contingency most suited to the study area, and can choose not to study P6 Events if they are less severe than the events studied. **R3.4 T**hose Planning Event Contingencies in Table 1 ~~– Steady State Performance~~ ~~not covered in Requirement R3.3.2~~ that are expected to produce more severe System impacts shall be identified~~,~~ and a list of those Contingencies to be evaluated for System performance in Requirement R3.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results.		
American Transmission Company	Yes	We suggest that there be more explanation of what system adjustments are permitted. We understand that the revised P6 allows loss of Non-Consequential Load for Systems below 300 kV as well.
Response: Header note 'e' provides the System adjustments allowed after a first Contingency Event. In addition, Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of firm Transmission Service will be allowed in preparation for the next Contingency. **Header note 'e'** -- For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
Florida Reliability Coordinating Council, inc	No	For P6 events (and all other events that allow system adjustments after the loss of a transmission device), this draft does not clearly define when the requirements in the columns marked as ?Interruption of Firm Transmission Service? or ?Non-consequential Load Loss Allowed? apply. The SDT should clearly state that the requirements in these columns are only applicable after the Event occurs from the Initial System Condition. In addition, the SDT should make it clear whether Interruption of Firm Transmission Service and Non-consequential Load Loss is allowed in preparation for the 2nd Event. On the NERC conference call for the 2nd draft, the SDT chair indicated that Interruption of Firm Transmission Service and Non-consequential Load Loss is not acceptable in preparation for the next event. In Order 693, Para. 1788 - Para. 1796, FERC distinguished between ?preparing for the next contingency? and returning to a system normal state. The SDT removed the allowance that was made in footnote c of TPL-003-0 to ?To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.? (emphasis added) for Category C3 events (now P6 for facilities greater than 300kV). This change in the standard is not directed by the FERC Order 693 and is not a reliability improvement that is cost justified. Forced outage rates for equipment greater than 300kV is very low and the impact on markets is very large. Many utilities have granted long term transmission service to entities with the expectation that the service can be curtailed if required in preparation for the next event. If this is not allowed, entities

Organization	Question 11:	Question 11 Comments:
		within FRCC will have to greatly reduce the long term firm imports into FRCC or construct additional EHV transmission lines from a location well into Georgia down to a point in the southeastern portion of FRCC. While an in-depth cost has not been completed for a project of this size in many years, it is reasonable to expect that a cost in excess of $1.5 - $2.0 Billion. This investment will only slightly increase the amount of firm imports into FRCC (and replace the imports allowed before this change) for an event that may only occur only once every 20+ years. If this event happens, the Transmission Owners will re-dispatch their own generation to curtail their transactions in addition to curtailing the firm transmission service of others, per their OATT. The SDT should clearly state for these Planning Events, all system adjustments including Interruption of Firm Transmission Service and Non-consequential Load Loss is acceptable in preparation for the second Event where system adjustments are allowed between events.
Response: The SDT believes that Table 1 is clear that the events occur from P0 as the starting condition. Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency. However, until the next Contingency occurs, System performance will need to meet the requirements for event P1. As such, the proposed standard will not allow loss of any Non-Consequential Load, except for contracted Interruptible Loads, in preparation for the next Contingency. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
FirstEnergy Corp.	Yes	We agree with the change that now permits the loss of Non-Consequential Load for N-1-1 to meet performance requirements regardless of the voltage level studied. It is well understood that following a single contingency (N-1) that no Non-Consequential Load loss or interruption of Firm Transmission service is permitted. The SDT needs to clarify for industry if interruption of Firm Transfers is permitted pre-contingency to prepare for the 2nd (over-lapping) contingency. This is presently permissible in the existing TPL standards as Table 1 footnote 'b' reads ?? To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.?
Response: Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings		

Organization	Question 11:	Question 11 Comments:
in those regions must be considered.		
PPL EnergyPlus	Yes	
NPCC	Yes	
Northeast Utilities	Yes	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
TVA System Planning	Yes	
Platte River Power Authority	Yes	
BCTC	Yes	
National Grid	Yes	
Tenaska, Inc.	Yes	
OPUC	Yes	
PacifiCorp	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV.
Hydro-Quebec TransEnergie (HQT)	Yes	
Arizona Public Service Co.	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV.

Organization	Question 11:	Question 11 Comments:
Midwest ISO	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Lakeland Electric	Yes	
LCRA TSC	Yes	
NERC and Regional Coordination	Yes	
North Carolina Electric Membership Corp	Yes	
E.ON U.S. Transmission Planning	Yes	
Central Maine Power Company	Yes	
NSTAR Electric	Yes	

Organization	Question 11:	Question 11 Comments:
New York Independent System Operator	Yes	
Oncor Electric Delivery	Yes	NA
ISO New England Inc.	Yes	
Manitoba Hydro	Yes	Considering the very low probability of such an event (based on industry data), Manitoba Hydro agrees that Interruption of Firm Transmission Service and Non-consequential Load Loss is acceptable.
Los Angeles Department of Water and Power	Yes	yes, only because there is no discrimination among different and arbitrary voltage classes.
IESO	Yes	We concur with the need to test N-1-1 contingencies involving transmission facilities allowing interruptions to firm transmission services and non-consequential load loss to meet performance requirements, for any voltage levels as long as adverse reliability impacts on the BES are exhibited.
Response: Thank you for your response.		

12. **Comments from some entities received from the posting of the 1st draft standard indicated that significant additional costs will be required to meet the proposed requirements and performance tables. Commenters also indicated that it would take several years to install the additional facilities needed to meet the change in requirements. The SDT has attempted to adjust and clarify the proposed requirements and performance in light of these initial comments; however, the SDT needs more specific information on these concerns so that it can put the proposed requirements in perspective and make more adjustments as appropriate. Questions 12, 13 & 14 address these concerns.**

    What do you estimate will be your additional approximate costs, if any, to support the proposed requirements and performance tables over and above what you are currently doing for the following: Analysis:

    One time cost to supplement past study portfolio and analyze the supplemental studies (depending on the extent of supplemental work needed, this may be an accumulated cost over more than one year):

    How many years do you estimate that it will take to complete supplemental studies and associated analysis?

    On-going additional cost for expanded studies and analysis:

Summary Consideration:

The SDT has reviewed the responses and will use the data as background information in making any further decisions with regard to this standard. No direct changes were made to any of the requirements at this time based on this information.

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
Dominion - Electric Transmission Planning	It is extremely difficult, if not impossible, to accurately determine the costs required to perform supplemental studies in order to become compliant with these proposed standards. It will take time to just become familiar with the proposed changes as well as developing the necessary documentation to show compliance. What is obvious is that increased staffing levels will be required to perform the assessments. Furthermore, it will take significant time to become fully compliant. Therefore, a grace	As stated above, this is difficult to predict but a grace period of 2 to 3 years should be considered.	At this point we are estimating at least 2 to 3 additional resources may be required to perform the additional studies on an ongoing basis. For Dominion, three (3) additional engineers to perform this analysis is approximately $500,000 per year (including benefits and overheads).

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	period of 2 to 3 years should be granted in order to perform the required assessments and become compliant.		
NPCC	NPCC Participating Members believe some additional cost for analysis and study may be required in order to meet the final requirements of the standard and the associated performance tables. However, the ability to accurately estimate the costs of these studies, how long the analysis may take and how much additional effort may need to be made to compile the documentation is not possible at this time. Many believe posing this question is premature and cannot be quantified at this time, and it may hold questionable value without a better understanding of the complete final requirements of the standard. Many believed that the sensitivity language, although currently being performed to some extent within NPCC, that now appears in the standard, could have a drastic effect on the extent to which this additional analysis is conducted and the associated costs.		
TVA System Planning	One component of these costs is based on modification to the load flow database. A massive effort would need to be undertaken to model bus sections and breaker codes in order to simulate the planning events needed to stay current with the proposed standards. Also, man-power to perform the extra analysis was considered. Additional man-power of 5 engineers (2 years) would	The majority of the time would be spent modifying the load flow database so that the new planning event simulations could be analyzed. ? Time duration estimate of 2 years would be required.	Additional man-power of 4 engineers at costs of $400,000 per year would be required.

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	be required at cost of $1,000,000		
Progress Energy Carolinas	$150,000	3 Years	$50,000/year
BCTC	We estimate an initial one time cost of up to $50,000 for BCTC planners to become familiar with the new format and requirements of the standards and make changes to their assessment process. In addition, additional study costs for sensitivity studies (many stability studies) may cost an additional $50,000. Many segments of the BCTC system are stability limited and we have significant experience with the needs and timelines for doing stability studies. Stability studies identify the need for RAS for multiple contingencies, which is fairly short lead time. We are currently satisfied with the amount of stability studies we do for the near and long term planning horizons. We do not need to do sensitivity studies. We do not expect any significant additional costs for studying Extreme Events because most of the wide area events listed are not applicable to the BCTC system.	1 Year	The additional cost could be from $50,000 to $100,000 per year. We will incur additional study costs for sensitivity studies and expect additional planning administration costs for reconciling between reinforcements required to meet the CLL/NCLL definitions and P3 requirements vs. what we actually propose as doable projects.
Manitoba Hydro	$500,000	2 to 3 person years years	$300,000
Los Angeles Department of Water and Power	I do not object to added studies serving useful purposes; however, duplicative studies are a waste of resources. Mixing operating studies and requiring such studies in the planning of future system shows a confused perspective on the	Please be more specific as to what additional studies are being referred here.	

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	purpose of planning studies verses operating studies.		
National Grid	The comment period was not long enough to develop a thoughtful response to the impact that the new standards might have. Therefore costs can be speculated to be incrementally hundreds of thousands per year.	The comment period was not long enough to develop a thoughtful response to the impact that the new standards might have on the planning studies, but a very rough thought would be that any additional needs would be captured within the normal planning studies, which would likely occur within two study cycles of the effective date of the standard.	If the new requirements are included in the normal study cycle and the costs are the incremental costs required by additional study requirements, then the annual costs will be less than the first year costs, but we still will need additional staffing, which will cost hundreds of thousands per year. In addition to cost, there is a significant concern over whether or not the labor market can provide enough qualified staff to complete the required work.
Pacific Gas and Electric Co.	We expect supplemental studies to be needed for the entire 500 kV system and most of the 230 kV system. We estimate the one time cost for supplemental studies to be around $100,000.	Assuming that the supplemental studies would be added to the on-going work, we estimate the time to complete the supplemental studies to be about 2 to 3 years.	We estimate that the additional cost for the expanded studies and analysis would be about $50,000/year.
Gainesville Regional Utilities	$50,000. I don't feel this is needed for smaller utilities.	3 years. Again, I don't feel this is needed for smaller utilities.	$60,000. Again, I don't feel this is needed for smaller utilities.
JEA	$80,000 per year.	3 years	$80,000 per year.
PacifiCorp	$500,000 (approx)	three years	$250,000
Puget Sound Energy, Inc.	$1,000,000 for the STD in its current form. The recovery of firm transmission following N-1 will be the largest cost for PSE	10 years.	$300,000
ITC Holdings: ITC, METC, ITC Midwest	While we recognize that the standards might require us to garner a little more manpower and will take a little more time, we believe that running these studies is	While we recognize that the standards might require us to garner a little more manpower and will take a little more time, we believe that running these studies is	While we recognize that the standards might require us to garner a little more manpower and will take a little more time, we believe that running these studies is

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	important.	important.	important.
Idaho Power Company	Appx $50k	2 to 3 years	Appx $50k
SMUD		Three study cycles would be my guess. Related matters: Since the definition for “Year One” allows for the start of each assessment to be up to 18 month from the “completion” of the previous Planning Assessment, using the term ?annual?, “annually” in the definition and in various sections of the standard is confusing. An alternate word or dropping the words annual/annually would make more sense. What is considered as “completion” of an assessment (in definition of Year One)?	
Hydro-Québec TransÉnergie (HQT)	HQT believe some additional cost for analysis and study may be required in order to meet the final requirements of the standard and the associated performance tables, however the ability to accurately estimate the costs of these studies, how long the analysis may take and how much additional effort may need to be made to compile the documentation is not possible at this time. Many believe posing this question is premature and cannot be quantified at this time and it may hold questionable value without a better understanding of the complete final requirements of the standard. Many believed that the sensitivity language, although currently being performed to some extent within NPCC, that now appears in		

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	the standard, could have a drastic affect on the extent to which this additional analysis is conducted and the associated costs		
Progress Energy Florida, Inc.	Given that a) PEF has never performed analysis to the extent that the draft TPL Standard is requiring and b) the draft is going through an iterative process and is at present considered a "moving target", a reasonably accurate estimate, or even a wild guess, cannot be provided for this answer. Having said that, it can be reasonably said that any estimate that could safely claim a reasonable degree of accuracy would require analysis performed full-time by several individuals over a period of several months (or possibly a period greater than one year). Just the cost of the assessment analysis alone would present an O&M challenge to PEF's Transmission department.	PEF has assessed this question and determined that any period of time less than 10 years would be inadequate to assess the supplemental nature of the requirements of the draft TPL Standard, to say nothing of the time required to construct the required facilities.	PEF, again stating that this cannot be considered an accurate estimate for the reasons stated in 12a, would estimate the burdened labor cost to perform such supplemental analysis on an ongoing basis to be at least $1M annually.
Sierra Pacific Power Comapny / Nevada Power Company	$400,000	2 Man Years	$250,000/year
Lafayette Utilities System	Lafayette has not analyzed in any detail the resource requirements addressed in this question. Based on available information, we estimate that supplementing existing studies would require at least 1 FTE familiar with stability analysis to be able to complete this portion of TPL. The new steady-state analysis will require the addition of 1 FTE to be able to complete the additional P5-P7	See response to part 1 of Question 12.	See response to part 1 of Question 12.

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	requirements. These will be ongoing expenses whether accomplished by hiring new staff or relying on external service providers.		
Arizona Public Service Co.	Two person-year.	2-years.	one person year.
Ameren	One component of cost is to model in more detail all straight busses and bus-tie breakers at all transmission voltage levels. Contingency scenarios would also need to be developed and/or modified to correspond with the new powerflow models. The sensitivities presently specified will greatly increase the cost and time needed for updating all plant stability studies.	One-time costs to provide additional modeling detail and modify and test the revised contingency lists would be approximately 1 man-month or about $8000. Updating all plant stability studies would take approximately 5 man-years, at an estimated cost of approximately $500,000 (including benefits). Given existing regional requirements to complete the annual assessment by July 1 of the calendar year, additional staffing would likely be needed to complete this work, unless compliance were phased in over a number of years, similar to the MOD-024 and MOD-025 standards with respect to generator testing.	A review of the studies required for R2.1 indicates that at least 6 powerflow modeling scenarios would need to be completed to cover the base cases and sensitivities, which would be a 50% increase in the amount of work presently performed to meet the existing TPL-001 through 004 requirements for the near-term assessment. A review of the studies required for R2.4 indicates that at least 4 stability scenario models would need to be completed, which would be a 100% increase in the amount of work presently performed. Our present compliance performance and analyses activities take approximately 30 man-months to complete. We would expect the additional study analyses to add an additional 20 man-months of work and require 4-5 additional engineers at an annual cost of $400,000 to $500,000 (including benefits), given the regional requirement to complete the annual assessment by July 1.
City of Tallahassee, FL	we estimate a cost of $100,000 minimum since the City would likely have to outsource some of this analysis in addition to the work done by in-house system	hard to give a good estimate since the full ramifications of the required studies is not clear in the current draft. I would estimate 2 years at least.	similar costs to what was estimated above for the supplemental study cost, since staffing level is such that much of this ongoing work will likely be outsourced.

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	planning staff.		
Florida Power and Light	These costs cannot be determined without having experience with the new standard and its analysis requirements. Analysis of existing studies will undoubtedly uncover substantial additional study that would need to be performed, but the costs of such analysis and studies could not be reasonably estimated beyond stating that the costs would be significant resulting from 1000's of man-hours spent on supplemental work that would only determine if we were in compliance, not including any work necessary to determine what would be necessary to bring deficiencies in to compliance.	It would not be unreasonable to find that it takes one full planning horizon (10 years) to complete supplemental studies and analysis for the draft standard, because it is so prescriptive. Requirements such as R2.2.1 that requires that the planning assessment be extended for longer lead time projects (such as the multiple new nuclear projects being considered across the U.S.) and R2.4.1 that specifies "...including the behavior of induction motor loads" will likely invalidate past studies that took considerable time to perform and would have to be reproduced with the newly required considerations. Requirements such as R2.6 (and subrequirenments) invalidate many existing studies, because of subjective terms such as "material changes" and "would impact the study area" without definitions of "material" or "impact". Re-analyzing all existing studies and re-writing the results and conclusions using the new terminology (P0, P1, P5 etc. instead of Category A, B or C2, C3, C5 etc.) used in the new performance tables will also add substantially to the effort needed to insure compliance and make the information auditable.	$ 5 million dollars annually is perhaps very conservative.
CenterPoint Energy and CPS Energy	We have no analysis to support an answer to this question, and we believe any such analysis would be speculative. We believe the reality of the situation is that the requirements are not practically achievable	3-4 years, assuming reasonably practical interpretation of the impractical requirements.	

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	at any cost, so the ultimate cost would depend on practical interpretations of impractical requirements. Even if the cost could be reasonably estimated, we oppose detracting valuable expertise away from necessary, value-added analyses to unnecessary, over-reaching theoretical analyses and documentation for audit purposes.		
SRP	The additional study work associated with this Standard could cost up to SRP $100k.	1 to 2 years to complete these additional studies.	Estimate addition on-going costs of $50k.
MidAmerican Energy Company	MEC estimates that the total cost for one-time software licenses would be about $100,000.	MEC estimates that the lead time to perform supplemental studies and analyses to meet the new requirements would be 2 years.	MEC estimates that the on-going additional cost of expanded studies and analyses to meet the new requirements would be about $150,000 to $200,000 for additional staff and continuing software fees.
Tucson Electric Power Company	$200,000	6 month study performed by consultant	1 man-year
SERC Dynamics Review Subcommittee	The sensitivities will greatly increase the cost and time need for planning because the work is directly proportional to the number of sensitivities.		
MRO NERC Standards Review Subcommittee	The MRO estimates that the additional one-time costs of supplemental studies and analysis to meet the new requirements might be spread over five years because some analysis only has to be updated every five years. The MRO estimates that the total cost over five years for additional staff, consulting services, or software fees would be about $200,000 to $300,000 per	The MRO estimates that the lead time to perform supplemental studies and analysis to meet the new requirements would be up to 5 years.	The MRO estimates that the on-going additional cost of expanded studies and analysis to meet the new requirements would be about $150,000 to $200,000 for additional staff and continuing software fees per responsible entity.

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	responsible entity.		
Modesto Irrigation District	Unknown at this time.		
Midwest ISO	Some additional costs will be required to comply with all the requirements. This is difficult to quantify at this time.	This is difficult to quantify at this time, but any increased requirements should be clearly identified by the SDT and a transition period should be developed if the standards are intended to be more restrictive.	There will be an increase in ongoing cost for expanded studies and analysis. A transition period for staffing and process development will be required.
Tri-State Generation and Transmission Association, Inc.	Scenario assessments will significantly increase workload. Development of dynamic load models is ongoing, and will need a much longer implementation period than the steady state portions of the standard. As much as $500,000 may be required to address all of R2.1.3 scenario requirements.	It would take as much as two years for the initial supplemental studies with existing staff.	Ongoing additional sensitivity and dynamic studies would cost approximately $300,000 per year.
AEP	Additional one-time cost of 33 man-months	2 years	Additional ongoing cost of 12 man-months
Lakeland Electric	Unknown	Unknown	Unknown
Brazos Electric Power Cooperative, Inc.	We have no real way to estimate this or determine these costs.	Again, we have no real feel for making an estimate but it would be safe to say that the studies would take longer than the planning window. In other words, the results would not be completed before we would have to start them over again.	
NERC and Regional Coordination	Clarity about the exact number of supplemental studies required needs to be added to the standard before this question can bee addressed. The requirements		

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	contained within the standard are nebulous. The requirements need to clearly state the depth of the studies required for each time horizon.		
ColumbiaGrid	The new TPL Standard raises the bar of transmission system performance. This can be expected to require significant additional analysis, documentation and system reinforcements (or reduced firm transfers allowed on the system if system reinforcements are not made). We will defer to our members to provide quantification of those elements.		
IESO	Minimal, if any, since the IESO has been conducting and documenting planning studies that meet events and performance criteria that are very similar to those specified in the draft TPL-001 standard. However, this is speculative at this time since we are not sure what the eventual standard will be like. Another uncertain area is the extent to which additional studies are required if sensitivity testing is mandated. Please see our comments under Q2 and Q10 on sensitivity testing. If sensitivity testing should become a requirement, then the scope is very wide and we are unable to have a good handle on the incremental time and cost to supplement past study portfolio.	Minimal, if any, for the reasons indicated above, other than for meeting the sensitivity testing requirements (if mandated) which cannot be quantified.	Minimal, if any, for the reasons indicated above, other than for meeting the sensitivity testing requirements (if mandated) which cannot be quantified.
Northeast Utilities	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
North Carolina Electric Membership Corp	N/A	N/A	N/A
ERCOT System Planning		At least 4 years. It will take as long as the largest entity in our system which has estimated about 4 years. We are totally dependent on them for all data needed for these studies.	he workload to support the existing TPL-001 to TPL-004 has already consumed two full-time senior positions. Add to that the new requirements for steady state studies necessary in this standard would take at least another full time position. The new stability study requirements and short circuit requirement added would double the number of people necessary for a total of approximately six full time positions with moderate to high experience levels. (Four incremental FTEs with estimated annual cost of $650,000). Purchasing additional licenses for study software is an additional expense.
American Transmission Company	We estimate that the additional one-time costs of supplemental studies and analyses to meet the new requirements might be spread over five years because some analysis only has to be updated every five years. So, we estimate that the total cost over five years for additional staff or consulting services may about $200,000 to $300,000.	We estimate that the lead time to perform supplemental studies and analyses to meet the new requirements might be up to 5 years.	We estimate that the on-going additional cost of expanded studies and analyses to meet the new requirements might be about $150,000 to $200,000 for additional staff.
New York Independent System Operator	A very preliminary estimate would be potentially millions of dollars.	Again, a very preliminary estimate would be two years.	Preliminary estimate is on the order of hundreds of thousands of dollars In addition to cost, there is a significant concern over whether or not there will be

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
			enough staff to complete the required work.
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	One component of these costs is based on modification to the loadflow database. A massive effort would need to be undertaken to model bus sections and breaker codes in order to simulate the planning events needed to stay current with the new standards. Also, man-power to perform the extra analysis was considered. Additional man-power: 5 engineers (2 years) Cost: $1,000,000	The majority of the time would be spent modifying the loadflow database so that the new planning event simulations could be analyzed. Time: 2 years	Additional man-power: 4 engineers Costs: $400,000 / year The following analysis was performed by one large integrated utility in SERC. The results are not representative of all utilities in the SERC region, but would be multiplied many times over to fully represent the SERC region as a whole. A comprehensive study of the impact of these proposed and incomplete standards is not feasible until they are finalized. Regarding manpower, aside from the estimated costs there is the very real situation that the number of qualified engineers available in the industry is nowhere near what would be necessary to carry out the studies (including sensitivities) called for by the proposed standard. This reality needs to be taken into consideration by the Standards Drafting Team when it makes its implementation plan recommendations.
Oncor Electric Delivery	Cost to supplement past study portfolio would be between $250,000 to 750,000.	3 to 5 years with added resources (staff)	$500,000 annually
ISO New England Inc.	The comment period was not long enough to develop a thoughtful response to the impact that the new standards might have. Therefore cost can not be reasonably speculated.	The comment period was not long enough to develop a thoughtful response to the impact that the new standards might have on the planning studies, but a very rough thought would be that any additional needs would be captured within the normal planning studies, which would likely occur within two study cycles of the effective date of the standard.	The comment period was not long enough to develop a thoughtful response to the impact that the new standards might have on study effort and the associated cost. In addition to cost, there is a significant concern over whether or not there will be enough staff to complete the required work.

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
Orlando Utilities Commission	$75,000 to supplement past study portfolio. (We have a fairly small system, only 1400 MW)	Two years, one year to recruit additional planner, the second to perform the baseline studies. This assumes there are sufficient trained personnel in the industry and they can be recruited.	$75,000 each year.
Entergy Services, Inc.	Cost will be covered by the on-going study costs as indicated below.	18 to 24 months	$1,200,000 / year
BPA Transmission Reliability Program	This information is not available.	This information is not available.	This information is not available.
Response: The SDT thanks all who responded to this survey question.			

13. **Documentation: One time cost to prepare reporting documentation associated with studies needed to supplement past study portfolio (depending on the time required to complete the supplemental work, this may be an accumulated cost over more than one year) – and on-going additional cost for documentation of expanded studies and analysis:**

Summary Consideration:

The SDT has reviewed the responses and will use the data as background information in making any further decisions with regard to this standard. No direct changes were made to any of the requirements at this time based on this information.

Organization	1 - Question 13 Comments:	2 - Question 13 Comments:
Dominion - Electric Transmission Planning	The initial process development and documentation will be the most difficult and time consuming portion. Dominion - Electric Transmission recommends a period of 3 to 5 years be given for this initial period of becoming compliant and preparing the documentation. As noted above, it is difficult to provide cost estimates, but we expect at least 2 to 3 additional resources will be required, at a minimum.	See response above.
NPCC	See above	
TVA System Planning	Additional man-power of 1 engineer (1 year) would be required at cost of $100,000	Additional man-power of 1 engineer at costs of $100,000 / year
Progress Energy Carolinas	$60,000	$20,000/year
BCTC	Included in the above. We do not do analysis without documentation.	Included in the above. We do not do studies without documenting them
Manitoba Hydro	$200,000	$100,000
Los Angeles Department of Water and Power	This assumes that past studies are inadequate and supplemental studies are needed. The standard does add a lot of duplicative and unnecessary operating scenarios that are already required	

Organization	1 - Question 13 Comments:	2 - Question 13 Comments:
	under TOP and MOD; but they should be deleted because they serve no useful purpose under TPL, why even spend an extra penny if it is for naught.	
National Grid	See response to question 12.	See response to question 12.
Pacific Gas and Electric Co.	This cost would be included in the cost of performing the supplemental studies.	This cost would be included in the cost of performing the expanded studies and analysis
Gainesville Regional Utilities	Probably would be covered in the previously provided annual cost. Again, I don't feel this is needed for smaller utilities.	Probably would be covered in the previously provided annual cost. Again, I don't feel this is needed for smaller utilities.
JEA	Included in Question 12 estimates.	Included in Question 12 estimates.
PacifiCorp	$250,000 over two years	$125,00
Puget Sound Energy, Inc.	$150,000 for the STD in its current form.	$50,000
ITC Holdings: ITC, METC, ITC Midwest	While we recognize that the standards might require us to garner a little more manpower and will take a little more time, we believe that running these studies is important.	While we recognize that the standards might require us to garner a little more manpower and will take a little more time, we believe that running these studies is important.
Idaho Power Company	Appx $50k	Appx $50k
Hydro-Quebec TransEnergie (HQT)	See Q12	
Progress Energy Florida, Inc.	Again, these costs cannot be reasonably estimated given the difficulties stated in the answer to Question 12a. It would reasonable to expect that the number of individuals in PEF's Transmission Planning group would have to dramatically increase, at least doubling in size or possibly significantly more	Documentation cannot be separated from the actual analysis itself, and thus would be included as part of the $1M estimate stated in the answer to Question 12b above.

Organization	1 - Question 13 Comments:	2 - Question 13 Comments:
	than doubling.	
Sierra Pacific Power Comapny / Nevada Power Company	$100,000	$50,000
Lafayette Utilities System	See response to part 1 of Question 12.	See response to part 1 of Question 12.
Arizona Public Service Co.	$200,000.00	$100,000.00
Ameren	Documentation preparation to include the short-circuit assessment, the amount of consequential load dropped for single contingencies, the expanded requirements of the Corrective Action Plan, and how the sensitivities affect the Corrective Action Plan would take a man-week or two at most (no significant cost increase or manpower increase).	Our present documentation activities to develop the assessment and the corrective action plan take approximately 2 man-months to complete. We would expect the documentation to cover the additional study analyses to add an additional 2 man-months of work. The additional documentation for the Consequential Load Loss, short-circuit analysis, expanded requirements of the Corrective Action Plan, and documentation of how the sensitivities studied affect the corrective plan are estimated to double the existing reporting requirements, resulting in an increase of 3.5 man-months and require 2 additional engineers at an annual cost of $200,000 (including benefits), given the regional requirement to complete the assessment by July 1.
City of Tallahassee, FL	documentation cost was included in the cost estimates for #12, since development of the documentation is part of the study work scope.	
Florida Power and Light	These costs cannot be determined without having experience with the new standard and its documentation requirements. Analysis of existing studies will undoubtedly uncover substantial additional documentation that would need to be produced, but the costs of such document production could not be reasonably estimated beyond stating that the costs would be significant resulting from 1000's of man-hours spent on supplemental work	This would be included in the $5 million dollar estimate provided above.

Organization	1 - Question 13 Comments:	2 - Question 13 Comments:
	that would only serve to meet audit requirements.	
CenterPoint Energy and CPS Energy	As with our response to question 12, we believe the answer depends upon the ultimate practical interpretation of the impractical requirements.	
SRP	Estimate $30k to prepare documentation.	Estimate $15k each additional year documentation.
MidAmerican Energy Company	Included in amounts for 12.	Included in amounts in 12.
Tucson Electric Power Company	included in previous question	included in previous question
MRO NERC Standards Review Subcommittee	Included in amounts for 12.	Included in amounts for 12.
Midwest ISO	We agree some additional costs will be incurred for expanded documentation.	ore requirements and more studies will increase documentation costs.
Tri-State Generatino and Transmission Association, Inc.	An additional $100,000 would be required to document studies for compliance purposes.	Perhaps $50,000/year - half of the initial amount required.
AEP	Additional one-time cost of 15 man-months	Additional ongoing cost of 7 man-months
Lakeland Electric	Unknown	Unknown
NERC and Regional Coordination	Clarity about the required documentation and coordination needs to be added to the standard before this question can bee addressed. As written, our interpretation is the increase in documentation requirements is substantial.	

Organization	1 - Question 13 Comments:	2 - Question 13 Comments:
ColumbiaGrid	The new TPL Standard raises the bar of transmission system performance. This can be expected to require significant additional analysis, documentation and system reinforcements (or reduced firm transfers allowed on the system if system reinforcements are not made). We will defer to our members to provide quantification of those elements.	
IESO	Minimal, if any, for the reasons indicated above, other than for meeting the sensitivity testing requirements (if mandated) which cannot be quantified.	Minimal, if any, for the reasons indicated above, other than for meeting the sensitivity testing requirements (if mandated) which cannot be quantified.
Northeast Utilities	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
North Carolina Electric Membership Corp	N/A	N/A
American Transmission Company	We estimate that the one time cost for expanded studies and analysis documentation to meet the new requirements might be about $20,000.	We estimate that the on-going cost for expanded studies and analysis documentation to meet the new requirements might be about $10,000.
New York Independent System Operator	included above	included above
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	Additional man-power: 1 engineer (1 year)Costs: $100,000	Additional man-power: 1 engineer Costs: $100,000 / year. The following analysis was performed by one large integrated utility in SERC. The results are not representative of all utilities in the SERC region, but would be multiplied many times over to fully represent the SERC region as a whole. A comprehensive study of the impact of these proposed and incomplete standards is not feasible until they are finalized. Regarding manpower, aside from the estimated costs there is the very real situation that the number of qualified engineers available in the industry is nowhere

Organization	1 - Question 13 Comments:	2 - Question 13 Comments:
		near what would be necessary to carry out the studies (including sensitivities) called for by the proposed standard. This reality needs to be taken into consideration by the Standards Drafting Team when it makes its implementation plan recommendations.
Oncor Electric Delivery	$250,000	$100,000
ISO New England Inc.	See response to question 12.	See response to question 12.
Orlando Utilities Commission	$25,000	$25,000
Entergy Services, Inc.	$150,000	$100,000 / year
BPA Transmission Reliability Program	This information is not available.	This information is not available.
Response: The SDT thanks all who responded to this survey question.		

14. System Reinforcement: One time cost, capital investment, to expand your system reinforcement program (due to lead times associated with different types of facilities, this will probably be an accumulated cost over several years). How many years do you estimate that it will take to complete this initial expanded system reinforcement program:

Summary Consideration:

The SDT has reviewed the responses and will use the data as background information in making any further decisions with regard to this standard. No direct changes were made to any of the requirements at this time based on this information.

Organization	1 - Question 14 Comments:	2 - Question 14 Comments:
Dominion - Electric Transmission Planning	Difficult to estimate the investment required, but it will be in the millions if not hundreds of millions of dollars.	Siting new transmission in Virginia can take a minimum of 5 to 7 years if new right-of-way acquisition is required. It is difficult to provide an estimate of time, but it will be quite extensive.
NPCC	NPCC participating members have expressed compliance concerns that this standard, and in particular this question, imply NERC has the ability to "force" transmission reinforcements and construction. It should be emphasized and clarified that the standard should require transmission studies only, and per the Energy Policy Act, NERC does not have this authority as the ERO as granted by FERC in the US and NO authority allowing this in Canada. Also NPCC participating members expressed concern that a validly conducted assessment which shows that criteria are not met (in the 5 or 10 year horizon) could result in non-compliance with the Standard. If NERC believes that it can issue monetary penalties for 5 or 10 year assessments that show that performance criteria will not be met under future system conditions, there is a key question that requires explanation: What behavior is NERC attempting to incent through fining parties for conducting assessments which identify problems in a 5 to 10 year horizon? Also, NERC should further explain how it would view the relevance of a State or Provincial decision not to permit new facilities when issuing such a potential penalty such as preclusive siting issues with Generating Plants.	See above

Organization	1 - Question 14 Comments:	2 - Question 14 Comments:
TVA System Planning	Costs would include the implementation of redundant protection schemes for the P5 planning event (fault + failure of protection scheme), additional 500-kV facilities for P2.2 (single contingency - bus section outage) and P4 (fault + stuck breaker) events, and additional 161-kV facilities for the P3 (Generator +1) events. Estimated cost of $1 billion	Time duration of 10 years would be required
Progress Energy Carolinas	$100,000,000	10 years
BCTC	We do not believe that this cost is not relevant for determining the applicable standards and have not estimated it. The reinforcement costs are orders of magnitude greater that the costs of alternatives the changes in this standard propose to prohibit (e.g. use of RAS, curtailment in anticipation of the next contingency). We believe it is very unlikely that we would get approval for the projects that would be required to meet the proposed changes.	It is highly unlikely that we would be able to get funding approval for the system reinforcements required to meet the proposed changes in these standards.
Manitoba Hydro	An estimate of the cost to Manitoba Hydro is $1.0 Billion.	The licensing and construction of facilities to achieve compliance will require at least 10 years.
Los Angeles Department of Water and Power	If this question is referring to discriminatory treatment between different voltage classes that is arbitrary; the effort should be directed to either treat all the voltage classes equally or do come up with a scientific or historical basis to support the requirement. This is an engineering standard, all the criteria should have some scientific/engineering rationale that can be supported either by physics or historical data.	
National Grid	The comment period was not long enough to develop a thoughtful response to the impact that the new standards might have on the construction requirements. Therefore cost can not be reasonably speculated.	At least 5 beyond the study period. Lines requiring new Rights-of-Way may require 10.
Pacific Gas and	The capital investments would be dependent on the system	Any transmission facilities that would require a certification of

Organization	1 - Question 14 Comments:	2 - Question 14 Comments:
Electric Co.	reinforcements needed due to the added requirements. For example, if after the first contingency, redispatch to curtail firm transfers is not allowed in anticipation of the next single contingency, the system reinforcements could easily include more 500 kV lines and related facilities. The costs of such reinforcements could be a few Billion dollars.	public convenience and necessity could take more that five years for permitting, engineering and construction. Transmission Planning could take a few more years depending on the transmission reinforcements to be constructed.
Gainesville Regional Utilities	$50 Million. Again, I don't feel this is needed for smaller utilities.	7 years. Again, I don't feel this is needed for smaller utilities.
Public Service Company of New Mexico	This ultimately depends on the degree to which the local area issues addressed by footnote b of Table 1 of the existing TPL are maintained. Without the local area concepts of the existing TPL, costs could run into the hundreds of millions of dollars.	This ultimately depends on the degree to which the local area issues addressed by footnote b of Table 1 of the existing TPL are maintained. Without the local area concepts of the existing TPL, permitting requirements would result in some projects exceeding 10-years.
JEA	Could be up to $1 Billion and would depend on the physical ability to terminate at existing 500 kV substations and the ability to acquire 500 kV ROW outside of JEA's and Florida's jurisdiction.	Minimum of 7 years if DOE declares a Corridor of National Interest. Otherwise it could be longer and more costly.
PacifiCorp	$100,000,000 + Will not be able to estimate the total cost until after the studies are complete.	10 years
Puget Sound Energy, Inc.	$800,000,000 to recover Firm Transmission capacity with no adjustment following N-1.	15 years
ITC Holdings: ITC, METC, ITC Midwest	Since we have been following the NERC Planning Standards, at this point we do not expect an additional one time system reinforcement cost.	Since we have been following the NERC Planning Standards, at this point we do not expect an additional time-frame for a system reinforcement program.
Idaho Power Company	Not sure	5 years
SMUD	A field test of the revised standard would be the appropriate way to arrive at the approximate costs to support the new/modified	A field test would be the time to get an educated estimate.

Organization	1 - Question 14 Comments:	2 - Question 14 Comments:
	requirements.	
Hydro-Quebec Transenergie (HQT)	HQT and NPCC participating members have expressed compliance concerns that this standard, and in particular this question, imply NERC has the ability to "force" transmission reinforcements and construction. It should be emphasized and clarified that the standard should require transmission studies only, and per the Energy Policy Act, NERC does not have this authority as the ERO as granted by FERC in the US and NO authority allowing this in Canada. Also HQT and NPCC participating members expressed concern that a validly-conducted assessment which shows that criteria are not met (in the 5 or 10 year horizon) could result in non-compliance with the Standard. If NERC believes that it can issue monetary penalties for 5 or 10 year assessments that show that performance criteria will not be met under future system conditions, there is a key question that requires explanation: What behavior is NERC attempting to incent through fining parties for conducting assessments which identify problems in a 5 to 10 year horizon? Also, NERC should further explain how it would view the relevance of a State or Provincial decision not to permit new facilities when issuing such a potential penalty such as preclusive siting issues with Generating Plants.	
Progress Energy Florida, Inc.	Again, due to the difficulties described in the answer to Question 12a, given that the amount of analysis cannot be reasonably estimated, neither can the one-time capital cost. PEF did state in the answer to Question 11 that the cost to our 500 kV system alone would easily run in to the range of costing billions of dollars. How many billions, we are not sure, but we have sufficient experience through presently planned 500 kV projects on our system to know that the cost for such expansion is in the range of billions of dollars. Given that PEF has not been able to comprehensively assess the costs to its 230 kV and 115 kV system, it is likely that the total cost of implementing the draft TPL Standard would be many, many billions of dollars. As stated earlier, this concern is reinforced in the answer to Question 15, but	PEF does not believe the undertaking required in the present draft of the TPL Standard, questionably described here as an "initial" program, could reasonably be implemented in our lifetime. As stated in our answers to Questions 12 and 13, the planning time would run at least 10 years, or one complete long-term planning cycle. Implementation, particularly given the scope of 500 kV projects and challenges with operating the existing system while constructing such large projects, will take an additional 10 years. An estimate of 20 years, however, assumes that the industry is in place to make such projects feasible continent-wide. Just a cursory assessment of the limited resources of the Transmission Construction industry, combined with the global demand for concrete and steel, leads us to conclude that implementation of

Organization	1 - Question 14 Comments:	2 - Question 14 Comments:
	we are extremely concerned that our ratepayers will potentially be burdened with such exorbitant cost for so little benefit, and are certain that our PSC and our ratepayers will agree.	the draft Standard's requirements is not feasible short of a World War II-scale re-tooling of our entire economy. Given the significant challenges the U.S. economy is already facing, the prudency of such a colossal undertaking with minimal benefit becomes even more questionable.
Sierra Pacific Power Company / Nevada Power Company	$800 Million	10 years
Lafayette Utilities System	See response to part 1 of Question 12.	See response to part 1 of Question 12.
Arizona Public Service Co.	Hard to quantify without studying.	5 years
Ameren	Our present interpretation is that the proposed revised standard would have a minimum impact on the reinforcement of the Ameren system. The modification to remove the requirement that bus-tie circuit breakers must have the same performance requirements as non-bus-tie breakers significantly reduces our issues of non-compliance, and particularly for circuit breakers 300 kV and above.	Our present interpretation is that the proposed revised standard would have a minimum impact on the reinforcement of the Ameren system.
City of Tallahassee, FL	depending on the interpretation of the standard as currently drafted, this cost could be substantial (at least $20M) over a 5-year capital budget period (consistent with the City's current practice). It's doubtful this level of funding could be achieved/maintained given other financial pressures for local governments.	Unable to develop an answer to this question, since it depends on the ability to successfully site and permit generation and transmission facilities (which is becoming increasingly harder to complete), and the requirements of any successful siting effort may make the costs prohibitive (ie, underground transmission facilities and/or stringent controls on generating facilities).
Florida Power and Light	These costs cannot be determined without having experience with the new standard and its performance requirements. The costs of such investment could be in the 10's of billions of dollars for FPL because of the increased level of performance contemplated by the draft standard.	If we knew what was needed today, it could conceivably take up to 10 years to complete, if the projects are all feasible. Without knowing what is necessary, a fair estimate would be 20 years. This does not take into consideration that the entire industry would be competing for the same limited resources of material and manpower to complete this reinforcement. Justification would be

Organization	1 - Question 14 Comments:	2 - Question 14 Comments:
		problematic and eminent domain may not be enforceable due to the remote low probability of an N-1-1 event, and lack of a true reliability need.
Exelon Transmission Planning		Analysis has not been completed at this time to determine the extent of the additional burden, but significant expenditures, in terms of personnel, tools and transmission upgrades, are anticipated if this draft were implemented.
CenterPoint Energy and CPS Energy	We believe the proposed requirements may not impose additional capital investment for system re-enforcements for our companies. We believe we are already achieving the reliability goals embodied in the proposed requirements but in a much more efficient and cost-effective way than the overly prescriptive approach proposed in these requirements.	
SRP	Unknown costs, there are numerous raise the bar Standards, hard to determine the additional cost to SRP until the complete studies are performed and evaluated.	Unknown until the reinforcements are determined.
MidAmerican Energy Company	The additional one-time costs of system reinforcements to meet the new requirements would depend on the results of the new studies and be hard to forecast. However, if they involved just a few 345 kV substation modifications and 345 kV line additions, then MEC estimates that it would cost in the range of hundreds of millions of dollars per responsible entity.	The lead time to build new system projects would depend on the results of new studies and be hard to forecast. However, if they involved a 345 kV substation modification or a 345 kV line addition, MEC estimates that it would take 5 to 7 years to complete the new projects.
Tucson Electric Power Company	unable to determine without actual studies	10+ years5 year budget and 10 year plans have been approved. Proposed projects in the 5-10 year time frame would need revised and accelerated and new projects would be proposed following the completion of these proposed projects.
SERC Dynamics Review Subcommittee		The lead time for new line construction is at least 7 years.

Organization	1 - Question 14 Comments:	2 - Question 14 Comments:
MRO NERC Standards Review Subcommittee	The additional one-time costs of system reinforcements to meet the new requirements would depend on the results of the new studies and be hard to forecast. However, if they involved just a few 345 kV substation modifications and 345 kV line additions, then we estimate that it would cost in the range of hundreds of millions of dollars per responsible entity.	The lead time to build new system projects would depend on the results of new studies and be hard to forecast. However, if they involved a 345 kV substation modification or a 345 kV line addition, we estimate that it would take 5 to 7 years to complete the substation project and 8 to 12 years (or more) to complete the new transmission line project.
Midwest ISO	This is difficult to quantify at this time.	This is difficult to quantify at this time.
Tri-State Generatino and Transmission Association, Inc.	We do not anticipate additional investment beyond currently planned facilities.	Transmission projects generally take between 3 and 6 years to complete.
Tri-State G&T		10-Jun
Lakeland Electric	Unknown	Unknown
Southern Company Transmission	These costs cannot be determined without having experience with the new standard and its performance requirements.	
NERC and Regional Coordination	Clarity needs to be added throughout the requirements. Our interpretation of the standards as written will not result in substantial capitol investment. These standards will not have a substantial impact on improved system reliability, however; the requirements do significantly increase the manpower investment in study documentation and efforts associated with reporting study results.	
ColumbiaGrid	The new TPL Standard raises the bar of transmission system performance. This can be expected to require significant additional analysis, documentation and system reinforcements (or reduced firm transfers allowed on the system if system reinforcements are not made). We will defer to our members to provide quantification of those elements.	

Organization	1 - Question 14 Comments:	2 - Question 14 Comments:
IESO	None expected at this time.	None expected at this time.
Northeast Utilities	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
North Carolina Electric Membership Corp	N/A	N/A
American Transmission Company	The additional one-time costs of system reinforcements to meet the new requirements would depend on the results of the new studies and be hard to forecast. However, if they involved just a few 345 kV substation modifications and 345 kV line additions, then we would estimate that it costs may be in the range of hundreds of millions of dollars.	The lead time to build new system projects would depend on the results of new studies and be hard to forecast. However, if they involved a 345 kV substation modification or a 345 kV line addition, we estimate that it might take 5 to 7 years to complete the substation project and 8 to 12 years (or more) to complete the new transmission line project.
New York Independent System Operator	Depending on facilities covered by the standard, it is estimated that the cost to bring facilities into compliance potentially could be on the order of billions of dollars.	A preliminary estimate is that it would take at least five but potentially up to ten years to bring facilities into compliance.
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	Typical costs for a large utility in SERC would include the implementation of redundant protection schemes for the P5 planning event (fault + failure of protection scheme), additional 500-kV facilities for P2.2 (single contingency - bus section outage) and P4 (fault + stuck breaker) events, and additional 161-kV facilities for the P3 (Generator +1) events. Cost: $1 billion	Time: 10 years The following analysis was performed by one large integrated utility in SERC. The results are not representative of all utilities in the SERC region, but would be multiplied many times over to fully represent the SERC region as a whole. A comprehensive study of the impact of these proposed and incomplete standards is not feasible until they are finalized. Regarding manpower, aside from the estimated costs there is the very real situation that the number of qualified engineers available in the industry is nowhere near what would be necessary to carry out the studies (including sensitivities) called for by the proposed standard. This reality needs to be taken into consideration by the Standards Drafting Team when it makes its implementation plan recommendations.
Oncor Electric	Unknown, dependent on results of analysis and solutions	Unknown, dependent on results of analysis and solutions

Organization	1 - Question 14 Comments:	2 - Question 14 Comments:
Delivery	implemented	implemented
ISO New England Inc.	See response to question 12.	See response to question 12.
Orlando Utilities Commission	$0.00 if system adjustment in preparation for the second part of N-1-1 can include firm transfer and non-consequential load adjustments when necessary. $500 Million if n-1-1 conditions must be met without firm transfer and non-consequential load - adjustments before the second event, at 230 kV and above$1 Billion if n-1-1 conditions above are met on load serving systems below 230 kV.	10 Years to meet n-1-1 without curtailment/reduction prior to the second n-1. A significant portion of the work would be in either downtown, established residential or highly sensitive environmental areas, all of which may require extensive legal proceedings to build the projects. There would also be a large amount of simultaneous work going on nationwide that would result in a shortage in construction & design personnel as well a scarcity in needed materials.
Entergy Services, Inc.	Without performing the requisite analyses, Entergy does not know definitively how much it will cost to comply with these revised standards. However, Entergy expects the cost could be up to $1 billion to become fully compliant.	15 - 20 years The time required for construction will be elongated due to the need for significant numbers of new construction projects. This will require that projects be queued by the TPs because of constraints in available materials, labor and other resources.
BPA Transmission Reliability Program	This information is not available.	This information is not available.
Response: The SDT thanks all who responded to this survey question.		

15. (A) Do you generally support the revised standard? (B) Are you unsure whether you generally support the revised standard? or (C) Do you definitely not support the revised standard? Please check the appropriate box below. If your response is either (B) or (C), please explain your single biggest concern with the revised standard, including which specific requirement or set of requirements causes you the most concern and why.

A – Generally support the revised standard
B – Unsure about supporting the revised standard
C – Definitely do not support the revised standard

Summary Consideration: 50% of the commenters voted that they did NOT support the revised standard at this time. 35% are unsure. Some of the major issues that were raised by the industry for Question 15 include:

1. System Adjustment in event P6 - Many commenters believe that after the first N-1 in P6, curtailment of Firm Transmission Service or firm transfers should be allowed as part of System adjustment in preparation for the next N-1, citing that this is presently allowed in footnote b in existing Table 1. Otherwise, the Firm Transmission Service under normal System intact condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. Many believe this would in effect be imposing an N-2 criterion for offering Firm Transmission Service.

SDT response: The SDT agrees that clarification regarding treatment of Firm Transmission Service and Non-Consequential Load Loss during adjustment is necessary. Footnote 10 in Revision 3 of the Standard provides clarification.

2. Dropping local load - Many commenters opposed not being able to drop some local network Load for a single Contingency event as long as Bulk Electric System reliability was not impacted. This is presently allowed in footnote b of the existing TPL-002. However, there is no such allowance any longer for losing Non-Consequential Load for a single Contingency in the proposed draft. Many commenters suggested that orderly dropping of local network Load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. Some local network customer curtailments or local area Load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected System was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service.

SDT response: Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these System designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of the TPL-001-1

and most stakeholders and the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement. As an alternative, an entity could seek an Entity Variance for the situation described through their Regional Entity organization. In paragraph 1794 FERC clarified that "…an entity may seek a regional difference to the Reliability Standard from the ERO for case-specific circumstances". The process described by FERC as a regional difference is described in detail in the "NERC Standards Development Procedure" document under the subsection titled "Variances to NERC Reliability Standards".

3. Raising the bar for 300 kV and above - Many commenters believe that the SDT has not yet justified raising the bar on Facilities above 300 kV. Some pointed out that the higher performance requirements for Facilities >300 kV are tied to very low probability events, so the enhanced reliability is not worth the cost. Some also pointed out that disruptions on lower voltage circuits can cause real and reactive power flow fluctuations across, and eventual separation of, higher-voltage networks. Many believe that there should be no distinction in voltage classes for allowing or not allowing controlled Load shed for applicable events.

SDT response: The SAR for this standard recognized FERC orders which indicated a need to "raise the bar" for the industry. The SDT agrees and is attempting to do this in a reasonable fashion. There is significant flexibility in the Corrective Action Plans allowed for any additional performance requirements which must be met. Industry consensus, through approval of the SAR, is that revision of the existing TPL standards is appropriate.

4. Load modeling for dynamics - Many commenters believe that Load modeling is a significant open issue, such as the models for dynamic studies have yet to be developed and the data is not yet in hand. Many find this conflicting with implementation of the TPL standards due to modeling details being a gating item to completing some System studies.

SDT response: The SDT agrees and believes that industry guidance is needed to capture the appropriate dynamic behavior of Loads. In response to comments, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments. Any comments received from the industry on MOD standards will be forwarded to NERC for inclusion into NERC Reliability Standards Development Projects 2010-04 Modeling Data and 2010-05 Demand Data. Requirement R2.4.1 has been modified to include the following: "An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable."

5. Sensitivity analysis - Another concern of commenters is the prescriptive nature of sensitivity scenarios, listed within Requirement R2.1.3 for steady-state and Requirement R2.4.3 for Stability, and the volume of associated study work. Some commenters feel that the Transmission Planner and Planning Coordinator can better select the most appropriate sensitivities for their System. Commenters also feel that examples of sensitivities are already inherent in the existing requirements, such that some sensitivity studies are in effect adding an additional level of Contingency (N-2 or N-3). Many commenters feel that the additional analyses proposed by the revised standard are not warranted and are already covered adequately in the existing studies and TPL standards.

SDT response: The intent of the SDT in requiring performance of sensitivity studies is to identify critical System conditions and to expand the planners' portfolio of knowledge about vulnerabilities on their System. This is also an expectation from FERC Order 693 paragraphs 1704 - 1706.

As a result of industry comments, the following changes have been made to TPL-001-1:

Consequential Load Loss: ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions.

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~.~~ ~~For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~.

Year One: The first year that a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the ~~completion of the previous annual Planning Assessment~~ current calendar year.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R2 Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses ~~including both System and Generating Unit Stability~~.

R2.1.3 For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

- ~~Variability and outages of r~~Reactive resource~~s~~ capability

R2.1.4 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.6.1 (now R2.5.1) For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less.

R2.6.2 (now R2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:

R2.7 (now R2.6) For Planning Events shown in Table 1 ~~– Steady State Performance and Table 2 – Stability Performance~~, when the analysis indicates an inability of the System to meet the performance requirements in ~~the t~~Table~~s~~ 1, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed in subsequent assessments but the System shall continue to meet the performance requirements in the tables. Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3 and R2.4.3. The Corrective Action Plan shall:

Under Requirement R2.6.1:

- Installation or modification of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations.

R2.8 The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. ~~The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to c~~Contingencies in Table 1 ~~– Steady State Performance.~~ The studies shall be based on computer simulations using models utilizing data provided in Requirement R1.

R3.1 Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 ~~– Steady State Performance.~~ based on the lists created in Requirement R3.4.

R3.3.2 For all generators, studies shall consider the minimum steady state voltage limitations ~~of all generators~~ and identify how the generators are ~~treated~~ analyzed in the steady state simulation

R3.3.3 For all Transmission lines, studies shall consider relay loadability and identify how loadability is ~~treated~~ analyzed in the steady state simulation.

R3.4 Those Planning Event Contingencies in Table 1 ~~– Steady State Performance not covered in Requirement R3.3.2~~ that are expected to produce more severe System impacts shall be identified~~,~~ and a list of those Contingencies to be evaluated for System performance in Requirement R3.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results.

R4 For the Stability portion of the Planning Assessment, as described in Requirement R2.4~~ and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~

R4.3.2 ~~Studies shall consider~~ Simulate generator performance under anticipated conditions including how the voltage ride through capability ~~of all generators and identify how the generators are treated~~ is analyzed~~in the simulation~~.

R4.4 ~~At a minimum, t~~Those Planning Event Contingencies in Table ~~2~~1 – ~~Stability Performance~~ that ~~would~~are expected to produce more severe System impacts shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information with an explanation of why the remaining Contingencies would produce less severe System results.

R7. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among~~ neighboring systems~~ adjacent Planning Coordinators and any functional entity who has indicated a reliability need, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890.

Header note 'e' - For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Extreme Event 2b (steady state) - Loss of all Transmission lines on a common ~~r~~Right-of-~~w~~Way.

Footnote 1.a.ii - For all other Planning Events: No generating unit or units totaling more than the Contingency ~~r~~Reserve of the Balancing Authority (or Reserve Sharing Group if applicable) shall be allowed to pull out of synchronism. Generators that pull out of synchronism must have out-of-step protection or some other means to trip the generator for this condition and the resulting apparent impedance swings must not pass through relay characteristics that would result in the tripping of any Transmission System elements other than the generating unit and its direct connection Facilities.

Footnote 3 - Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø fault study indicating criteria are being met shall provide sufficient evidence that a SLG condition would also meet criteria.

Footnote 5 - When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed.

Footnote #10 – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.

Footnote #12 - Excludes circuits that share a common structure for 1 mile or less.

Organization	Question 15:	Question 15 Comments:
El Paso Electric Company	B — Unsure about supporting the revised standard	While this 2nd draft TPL standard has some positive changes, notably: The allowance to use RAS to trip generation for N-1 (see R3.5 Manual and automatic generation run-back/tripping is allowed as a response to a single or multiple Contingency ...) with some rather generic conditions. The allowance for Non-consequential Load Loss for loss of a transmission Facility, followed by system adjustment, followed by loss of a second transmission Facility (see P6 in draft performance Tables 1 and 2). This is the same as Category C3 in the existing TPL-003-0.On the down side, as proposed, Standard TPL-001-1:1. Will not allow curtailment of firm transfer (or firm transmission service) after the first N-1, in preparation for the next N-1 regardless of transmission voltage level. This is a major issue. Curtailment of firm transfer after the first N-1 has always been a part of system adjustment in preparation for the next N-1 as stated in foot note b of the existing TPL-002-0:"b. Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers." Not allowing this could mean reduction of firm transfer capability pre-contingency unless new circuits are built.2. The existing standard (http://www.nerc.com/files/TPL-003-0.pdf) does not distinguish between voltage classes, curtailment of firm transfer and, planned and controlled load shedding are allowed regardless of voltage class for Category C events. The proposed standard will not allow curtailment of firm transmission service, or planned and controlled load shedding for loss of Facilities with operating voltage above 300 kV involving the following in the proposed Performance Tables 1 and 2:P2-2: Bus Section fault (Category C1) P2-3: Breaker fault (Category C2) P4: SLG Fault + stuck breaker (Categories C6 - C9) P5: SLG Fault + protection system failure (Categories C6 - C9)The number of Facilities lost would depend on the bus configuration for above 300 kV. If you have a ring-bus, breaker and a half or double breaker double bus, you would lose at the most 2 Facilities. But if you have Main-Aux or single breaker double bus, you will lose all Facilities connecting to the faulted Facility.
Response: In response to your comment and those of others in the industry on allowing curtailment of Firm Transmission Service as System adjustment after		

Organization	Question 15:	Question 15 Comments:
an N-1 Contingency, the SDT has added footnotes 5 and 10 to Table 1 - Steady State & Stability Performance. **Footnote 5** - When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed. **Footnote 10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
Dominion - Electric Transmission Planning	B — Unsure about supporting the revised standard	(1) Unsure about cost/effort necessary to meet requirements (2) Uncertain that compliance with the proposed requirements in this standard would significantly improve reliability (3) R2.6.2: The entire sentence is confusing as it is modified. The original sentence in the previous draft made more sense. Please check and correct accordingly. (4) R 5.3: This requirement considers voltage ride-through capability of all generators. Nowhere in this TPL standard or in the MOD standards are Generator Owners specifically required to provide such data to Transmission Planners and Planning Coordinators. Stating the requirements for generator dynamics data and dynamic load characteristics in general terms, as listed below (from the MOD Standards), are vague. (a) shall provide appropriate equipment characteristics (b) shall provide dynamics system modeling and simulation data (c) Shall develop comprehensive dynamics data requirements .... to model and analyze the dynamic behavior... (5) In Table-2 Stability Performance, several places refer to "SLG or 3-phase Faults" . Since it states "or", does this mean we can get by with studying only SLG faults? We do not think that is the intent of this phrase; thus, a clarification is warranted. (6) One of our comments on the previous draft was with respect to a second-zone fault clearing due to protection system failure for a fault beyond zone 1 coverage of primary relies. The SDT's response was (Specific 1): "The SDT agrees with your concern and is working on a solution for a future draft." The question is repeated below, as a pending "to do" item, using the revised 'Table-2 Stability Performance' as reference: Category 5 in 'Table-2 Stability Performance' refers to a protection system failure event. We interpret this as, among other things, having a fault beyond the first-zone coverage of the primary protection scheme with the carrier equipment failure (or the carrier cut-off switch left in "OFF" position by a technician - a human error) resulting in a second-zone trip of the faulted line. The second-zone trip time is generally in the range of 30-35 cycles. This may be critical from the stability aspect for the terminal end at a generating plant even though only one element will be lost. Also, the second-zone trips may need to be studied for transmission lines out of next terminal from the generator end if the next terminal is connected to the generator terminal via a short line. We think that an

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		additional single contingency Category should be added to this Table to cover the "Event" of second-zone trip scenario.

Response: 1. The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus. The SDT is cognizant of the cost factors and additional efforts involved and has taken them into consideration in its deliberations in the development of this draft.

2. The SAR for this standard recognized FERC orders which indicated a need to "raise the bar" for the industry. The SDT agrees and is attempting to do this in a reasonable fashion. There is significant flexibility in the Corrective Action Plans allowed for any additional performance requirements which must be met. Industry consensus, through approval of the SAR, is that revision of the existing TPL standards is appropriate.

3. The SDT has revised the language of Requirement R2.6.2 (now R2.5.2).

R2.5.2 For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:

4. The SDT understands that the Transmission Planner and the Planning Coordinator need data from the Generator Owners. However, revising the MOD standards is beyond the scope of this standard revision. Further, we note that one of the requirements of FERC Order 890 for long-term Transmission planning involves formal data exchange between stakeholders and the Transmission Planner and the Planning Coordinator. It is our understanding that these data exchange processes have been successful in providing better planning information about stakeholders such as independent Generator Owners. Also, we note that there is an ongoing standards development project, Generation Verification Project 2007-2009. You may wish to submit your comment to that SDT about the need for the Generator Owner providing this information to the Transmission Planner and the Planning Coordinator.

5. The SDT has combined the tables into a single table and clarified the "SLG or 3 phase" designations. In addition, the SDT has added footnote 3 to provide clarity.

Footnote 3 - Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø fault study indicating criteria are being met shall provide sufficient evidence that a SLG condition would also meet criteria.

6. The SDT has revised the language in the P5 category to clearly identify the required performance for an event with a Protection System failure. The current draft requires the planner to recognize the equipment that will be removed from service and the timing (including delays with back-up Protection Systems if the primary is out of service) during their Stability studies. The scenario you described is therefore covered by P5. The SDT does not see a need to have a separate event for that scenario.

NPCC	C — Definitely do not support the revised standard	This standard as drafted does not allow exceptions for small parts of the system as long as interconnected system reliability is maintained, which is allowed in the existing TPL standards in footnotes b) and c) in Table 1. Unless such exceptions are allowed significant transfer restrictions or large reinforcements must be made. The applicable TPL footnotes are: Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall

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		reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers. Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (nonrecallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems. This comment form did not allow for the following items to be addressed: a. Definition of the Long-Term Planning Horizon. The planning horizon, for assessment purposes should be limited to 10 years. Such an assessment should be sufficient to identify requirements that may take an extended time to implement. b. Definition of Planning Coordinator is part of the NERC Functional Model, For consistency it should be removed from the Standard. c. Put headings on each section to identify requirements of section. Add headings to the tops of the subsequent pages in the performance tables. Headings only appear on the first page at the beginning of the Table. d. With respect to R2.2 - Delete "current" from the phrase "current System Peak Load study" and replace "study" with "assessment." e. Remove R2.2.1, the requirement to extend the assessment beyond 10 years. What does the length of the project have to do with the assessment? If it takes 15 years to build something, why does this require a review of year 15? What is the purpose of this assessment? f. R3.3.2 requires clarification - This standard needs to permit discretion regarding the single contingencies that need to be tested, similar to R 3.3.3 and R3.4. It is unnecessary to test all events. For example, contingencies may be limited to relevant disturbances that are contained within or directly impact the studied system. g. With respect to R3.2.1 - Clarify whether the intent of the standard is to address station service minimum voltage limitation, maximum leading VAR absorption capability or both at steady state. h. Remove R3.2.2 - Relay loadability is addressed in PRC-023 standard. i. With respect to R3.3.2.1 - Recommend the removal of the requirement to assess the expected duration of Consequential Load loss. It's not considered anywhere else in the standard. j. With respect to R3.3.3 - The paragraph refers to Table 1 Contingencies P3 through P7; this should be explicitly stated. Rationale for inclusion of testing should not be required; should only need to explain why certain Contingencies were not tested. This discretion should be applicable to all contingencies. k. With respect to section R5 - The concept of planned and long-term outages should apply to the general Planning Assessment, or not at all. It should not be specific to the Stability Assessment.

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		l. The provisions of Section R.5.3 should have a corresponding MOD standard apply a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertant trip of the generator. Such a provision should include "other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation. m. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizon.
New York Independent System Operator	C — Definitely do not support the revised standard	This standard as drafted does not allow exceptions for small parts of the system as long as interconnected system reliability is maintained, which is allowed in the existing TPL standards in footnotes b) and c) in Table 1. Unless such exceptions are allowed significant transfer restrictions or large reinforcements must be made. The applicable TPL footnotes are:? b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.? c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (nonrecallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems. This comment form did not allow for the following items to be addressed: a. Definition of the Long-Term Planning Horizion. The planning horizon, for assessment purposes should be limited to 10 years. Such an assessment should be sufficient to identify requirements that may take an extended time to implement. b. Definition of Planning Coordinator is part of the NERC Functional Model, Remove from Standard. c. Put headings on each section to identify requirements of section. d. With respect to R2.2 - Delete "current" from the phrase "current System Peak Load study" and replace "study" with "assessment." e. Remove R2.2.1, the requirement to extend the assessment beyond 10 years. What does the length of the project have to do with the assessment? If it takes 15 years to build something, why does this require a review of year 15? What is the purpose of this assessment? f. R3.3.2 requires clarification - This standard needs to permit discretion regarding the single contingencies that need to be tested, similar to R 3.3.3 and R3.4. It is completely unnecessary to test all events. For example, contingencies may be limited to relevant disturbances that are contained within or directly impact the studied system. g. With respect to R3.2.1 - Clarify whether the intent of the standard is to address station service minimum voltage limitation, maximum leading VAR absorption capability or both at steady state. h. Remove R3.2.2 - Relay loadability is addressed in PRC-023 standard. i. With respect to R3.3.2.1 - Recommend the removal of the requirement to assess the expected duration of

Organization	Question 15:	Question 15 Comments:
		Consequential Load loss. It's not considered anywhere else in the standard. j. With respect to R3.3.3 - The paragraph refers to Table 1 Contingencies P3 through P7; this should be explicitly stated. Rationale for inclusion of testing should not be required; should only need to explain why certain Contingencies were not tested. This discretion should be applicable to all contingencies. k. With respect to section R5 - The concept of planned and long-term outages should apply to the general Planning Assessment, or not at all. It should not be specific to the Stability Assessment. l. The provisions of Section R.5.3 should have a corresponding MOD standard apply a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertant trip of the generator. Such a provision should include "other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation. m. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizion.
Northeast Utilities	C — Definitely do not support the revised standard	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.

Response: Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these System designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of the TPL-001-1 and most stakeholders and the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement. As an alternative, an entity could seek an Entity Variance for the situation described through their Regional Entity organization. In paragraph 1794 FERC clarified that "…an entity may seek a regional difference to the Reliability Standard from the ERO for case-specific circumstances". The process described by FERC as a regional difference is described in detail in the "NERC Standards Development Procedure" document under the subsection titled "Variances to NERC Reliability Standards".

A. The SDT believes that a review of System conditions beyond the 10-year horizon is warranted. FERC Order 693 requires that the planning horizon take into account the lead times for siting and permitting of new long-distance Transmission lines and other long lead time solutions. The SDT has received industry comments regarding the need to exceed a 10-year horizon to account for longer lead time projects. Establishing planning horizons that are shorter than Transmission lead times may create gaps where the identification of a reliability need to which Transmission may be the best solution occurs too late to avert the identified reliability violation. Further, Operating Procedures or alternative short-term capital projects may be needed to limit the impact of the planning event until the planned Facilities can be completed. This information needs to be included in the Assessment.

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B. Planning Coordinator has been defined in another project and as such has been deleted here.

C. The SDT also feels that the Tables need to be as clear and concise as possible. To that end, this version combined Tables 1 and 2 into one table with a revised format. The Planning Events are shown on one page so repeating the headings will not be needed.

D. The SDT believes that the existing language is appropriate. No change made.

E The SDT believes that a review of System conditions beyond the 10-year horizon is warranted under some circumstances. For example, if it takes 15 years to build a Transmission line, then the need for that line would have to be determined 15 years ahead of the in-service date. Therefore, Requirement R2.2.1 requires you to perform an Assessment on year 15 if it takes you 15 years to build a line.

F. The SDT has removed Requirement R3.3.2 and replaced it with additional language in Requirement R3.1. The SDT agrees with your interpretation that it does not require evaluation of all single Contingencies. Rather, the SDT specifically states in Requirement R3.4 that those Contingencies that are expected to produce the more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe results.

R3.1 Studies shall be performed to determine whether the BES meets the performance requirements in Table 1~~ – Steady State Performance.~~ based on the lists created in Requirement R3.5.

G. The SDT has not limited the purpose of this requirement to either minimum acceptable station service voltages or maximum Mvar absorption. The SDT believes that the purpose of Requirement R3.2.1 (now R3.3.2) is to determine if generators will be able to operate or trip off following the Contingency.

H. The SDT believes that relay load limits or loadability needs to be considered in the Contingency analyses. The studies should determine if Transmission line loadings could reach the relay loadability level which may add to the existing Contingency and perhaps, result in an unbounded cascading event. No change made.

I. By definition, Consequential Load Loss is allowed. To meet industry concern as well as FERC Order 693, the SDT has added Requirement R2.~~-~~8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.8.

R2.8 The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1.

J. The SDT agrees that the rationale should be for all Planning Events but not for Extreme Events.

K. The SDT agrees and has moved this concept within Requirement R1 (see Requirement R1.1.1) so that it is applicable to all planning assessments. Further, both Requirements R3 and R5 (now R4) have been revised to make reference to Requirement R1.

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. ~~The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to c~~Contingencies in Table 1 ~~– Steady State Performance.~~ The studies shall be

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based on computer simulations using models utilizing data provided in Requirement R1. **R4** For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~ L. Requirement R5.3. has been modified (now R4.3.2) to address simulation of how generators perform under conditions being studied to address these concerns. "Other equipment" is addressed in Requirement R5.4. **R4.3.2** ~~Studies shall consider~~ Simulate generator performance under anticipated conditions including how the voltage ride through capability ~~of all generators and identify how the generators are treated~~ is analyzed~~in the simulation~~ M. While planned outages are addressed in the operating horizon, it is important that a Transmission Planner review the ability of its System to accommodate planned (maintenance) outages. Additionally, any specific known Facility outages need to be appropriately modeled for the planning horizon studied.		
TVA System Planning	C — Definitely do not support the revised standard	TVA's main concern is that no technical justification for "raising the bar" on facilities above 300-kV has yet been demonstrated such as required on P2, P4, and P5 for 300 kV and above. TVA is very concerned that "raising the bar" would be a financial burden on TVA's ratepayers. TVA would also like to provide the following additional comments to this second draft as follows: 1. In R2.4.1, load models that appropriately represent the dynamic behavior of motor loads are required. TVA believes that industry guidance is needed on how to properly model these loads. Does this requirement mandate the use of specific load models for each bus, or would an aggregate load model which represents the system as a whole be sufficient? It should be clearly stated whether the load model in R2.4.3.1 refers to system load or the dynamic load model at individual busses. 2. In R3.2.1 and R5.3, need industry guidance on how to actually determine the minimum steady state voltage limitations of generators. Is there a MOD or FAC requirement for generation owners to provide this information? 3. Which single contingency events should be included in calculations for Available Transfer Capacity? Should P2 events be included in addition to P1 events since P2 events are also defined as single contingency events in Tables? 4. Would like further clarification from the team on what does P5 exactly includes? For instance, does it include battery failures, CT failures, etc? 5. The existing TPL 002-0 allows for some local load to be dropped for a single contingency event as long as the Bulk system reliability was not impacted. However there is no such allowance any longer for losing such load for a single contingency in the proposed draft. It would be very expensive for TVA to fix all such events in several remote areas that

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		would have very little impact on the overall reliability of the TVA bulk system. TVA believes that the capital spent for these fixes could be used to better strengthen the overall bulk system in much better ways. 6. Suggest rewording R2.2.1 from "To accommodate any known longer lead time projects" to "To identify any potential longer lead time projects". 7. Can operational guides be used indefinitely in R2.7.1 or does the team propose a limit on how long operational guides can be used until a capital fix is implemented? 8. In R3.3.2.1, what is the purpose for needing the expected duration of consequential load loss? There is a concern that this requirement will be very burdensome to keep track of the quantity of consequential load loss as well as expected duration. Who is requesting this info? It appears that this may be a local regulatory issue, not a reliability issue. 9. Suggest changing definition of "Planning Events" in the Definitions to say "Events that have a higher probability of occurrence and require Transmission system performance requirements to be met." 10. Should the proposed standard mention that utilities should run contingencies outside their system that could impact their own internal system? TVA believes that additional documentation be included in the new standard to address this. 11. Functional entity in 4.1.4 should be "LSE" instead of "DP" 12. In the Definitions for "Year One", suggest replacing "previous" with "most recent" to help clarify when the planning window should begin. 13. Should "peak" in R2.1.1 be replaced with "On Peak" as shown in the NERC glossary of terms? Also the requirements in this requirement are too prescriptive - should allow some flexibility to allow the TP which years to study as long as a minimum number of cases are studied. 14. Suggest replacing "Plant" in R2.6.2 with "Unit" to match terms used in Definitions. 15. In R2.7.1.1, what is meant by "project initiation date"? Is it when engineering starts, construction starts, etc? 16. Suggest rewording requirements R3.3.3 and R3.4 to be more clear - such as breaking each of these into several sentences each. Existing wording is very confusing. 17. There is a concern with R5.6.1 with the requirement to perform simulation on 20 MW generators (to be consistent with the Registration Criteria). We recommend a 75 MW generator cutoff for required simulations. Also in R5.6.2, should last word in sentence be "greater" or "lesser"? 18. In the Tables under Extreme Events, is 3.b. (loss of two TLs on different ROWs actually already covered under 1 (loss of two elements prior to system adjustments)? Also in the Tables under Extreme Events, it may be difficult for a TP to know enough about nuclear plant design to perform studies mentioned under 3.a.vi.

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		19. In the notes under Extreme Events, we suggest that notes #2 and #3 be combined together since they are very similar in nature. 20. Should the P3 planning event descriptor (G+1) in the performance tables be (G+N-1) or (G-1, N-1)? The existing descriptor (G+1) tends to note that an element is being added to the system instead of being removed. 21. Should the new standard address specific voltage limit requirements that must be maintained during these planning events? Since different utilities have different voltage limits on their buses, should there be some consolidation to ensure the standard is applied equally at all utilities? 22. The note for Planning Event P1 states that “No generating unit or units shall be allowed to pull out of synchronism. A generator being disconnected from the System by Fault clearing action or by a Special Protection System is not considered pulling out of synchronism.” The standard does not allow consideration for small units with a Zone 2 fault. It is not practical to add pilot relaying on all lines from a plant with a small unit that would be stable for close-in three phase faults, and could be adequately protected when a Zone-2 fault would cause a small generator to trip off with out-of-step (OOS) protection. The table for P1 should allow small units (<75 MW) to trip using SPS or OOS protection.

Response: The SDT is attempting to raise the bar by developing a standard that appropriately supports BES reliability and has industry consensus. The majority of the SDT believes that 300 kV is an appropriate cutoff and that Transmission Systems above this level represent backbone Systems and are part of regional "grids". The SDT is cognizant of the cost factors involved here and is taking them into consideration in its deliberations and has provided for flexibility in Corrective Action Plans. FERC has noted in their orders that many of the concerns about raising the bar show more concern about economics than reliability (examples, Order 890, paragraph 423; Order 693, paragraph 1792, etc.).

1. The SDT agrees and believes that industry guidance is needed to capture the appropriate dynamic behavior of Loads. In response to comments, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments. Any comments received from the industry on MOD standards will be forwarded to NERC for inclusion into NERC Reliability Standards Development Projects 2010-04 Modeling Data and 2010-05 Demand Data. Requirement R2.4.1 has been modified to include the following: "An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable."

2. The SDT believes that FAC-009-1, Requirements R1 and R2 require that generators provide these low voltage limitations as part of their Facility Ratings. Also, PRC-024, which is under development, will attempt to require generators to meet voltage ride-through criteria.

FERC Order 693, paragraph 1773 regarding FERC Commission directed changes to TPL-002 states "...requires all generators to ride through the same set of Category B and C contingencies as required by wind generators in Order No. 661, or to simulate those generators that cannot ride through as tripping".

The current MOD standards that address steady-state and dynamic simulation data requirements do not explicitly require the Generator Operators to provide voltage ride-through capability. These standards are set to be addressed by Project 2010-04 within NERC's Standards Development Work Plan. Based on the proposed TPL requirement, Requirement R5.3 (now R4.3.2), it is expected that the Transmission Planner would contact Generator Operators applicable to their System to obtain such data. If the data is not provided, it would be expected that a Transmission Planner state its assumption on the Vmin used for a generator

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terminal voltage for assessing ride-through capability. It's likely such information could be obtained through generator manufacturers.

3. Questions related to ATC calculations are beyond the scope of this standard. Please see NERC Reliability Standard MOD 001-1, Requirement R7 & Measure M7 for additional information on ATC calculations.

4. The description of the P5 event has been clarified in this Revision of the Standard.

5. Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these System designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of the TPL-001-1 and most stakeholders and the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement.

6. The SDT believes that the existing language is appropriate. An assessment of year 15 would be needed to accommodate a Transmission line if it takes 15 years to build a line.

7. The SDT has not established a limit as to how long Operating Procedures may be used to meet System performance requirements and has left that decision for the Transmission Planner/Planning Coordinator.

8. By definition, Consequential Load Loss is allowed. To meet industry concern, as well as FERC Order 693, the SDT has added Requirement R2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.8.

R2.8 The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1.

9. The definition of Extreme Events already states that these events have a lower probability of occurrence than Planning Events. The SDT did not make the change suggested by the commenter as there was no industry consensus to alter the definition.

10. The list of Contingencies is expected to cover the Transmission Planner's or Planning Coordinator's System for which they are responsible, including any tie-lines to adjacent Transmission Systems. The standard does not preclude the Transmission Planner or Planning Coordinator to expand the list of Contingencies to include some Contingencies of interest or known impact for adjacent System(s). It is expected that through peer reviews, the Transmission Planner or Planning Coordinator may initially learn of any new event within an adjacent System that impacts their own System.

11. Applicability 4.1.4 has been deleted due to the deletion of Requirements R9 – 14.

12. The SDT believes that it is not necessary to replace "previous" with "most recent" since Planning Assessments are required on an annual basis.

13. The SDT believes that the term "System peak Load" is appropriate. The SDT does not believe that Requirement R2.1.1 is too prescriptive, but is the minimum needed to gauge the timing for System reinforcements in the near-term horizon.

14. This draft of standard has been revised to remove word "plant" from Requirement R2.6.2 (now R2.5.2). Requirement R2.5.2 from the last draft of the

Organization	Question 15:	Question 15 Comments:
standard has been deleted. **R2.5.2** For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: 15. The SDT has not defined a project initiation date and will leave that definition to be determined by the Transmission Planner and/or Planning Coordinator. 16. Most of the industry did not seem to find Requirements R3.3.3 and R3.4 unclear or confusing. Therefore, the SDT has decided to not undertake any rewording. Requirements R3.3.3 and R3.4 have been relabeled as Requirements R4.4 and R4.5 respectively. 17. The requirement for study has been changed to 20 MW for a single generator or for an aggregate of generators. This language is now in Requirement R2.5.2. Requirement R5.5.2 was deleted. 18. The SDT agrees and has removed the redundancy found with Extreme Event 3.b. Having multiple nuclear units out of service simultaneously is an Extreme Event, but it has occurred. The SDT recommends that the Transmission Planner consider sensitivities with different combinations of nuclear plants being out of service, including the possibility that they are all shut down simultaneously. To reinforce the more apparent combinations, the Transmission Planner may discuss the operational requirements and the equipment and design similarities of the nuclear plants with the appropriate Resource Planner or Generator Operator to determine credible scenarios which could commonly affect the nuclear plants. 19. The SDT discussed the combining of notes 2 & 3 but felt they wanted them separate for clarity. Note 2 is focusing on interruptions of Firm Transmission Service and Non-Consequential Load and Note 3 refers to transformer outage events. 20. The SDT has deleted the parenthetical to provide clarity. 21. The SDT has addressed this issue by the Header note 'b' for Steady State Only in Table 1 - Steady State & Stability Performance, where the Planning Coordinator sets the acceptable voltage deviations. The SDT believes that adjacent Planning Coordinators can adequately address this concern. 22. The SDT believes that any unit that is tripped by out of synchronism protection is actually in an "out of synchronism" condition and this should not occur for a P1 event regardless of generator size.		
City Water, Light & Power - Springfield, Illinois	A — Generally support the revised standard	
Response: Thank you for your response.		
Omaha Public	B — Unsure	Event 1 of Category P2 in Tables 1 and 2 addresses events consisting of "Breaker(s) opening without a Fault resulting in a

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Power District	about supporting the revised standard	single ended line." Category P2 is labeled as a "single contingency" category, yet it seems like an event consisting of the opening of more than one breaker would actually be a multiple contingency. Please consider whether the "(s)" should be removed after the word "breaker" in the event description so that it addresses only a single breaker opening without a Fault. Table 1 does not address multiple contingencies consisting of loss of a transmission circuit, transformer, single pole of a DC line, or shunt device, followed by System adjustments, followed by the loss of a generator. It seems like Table 1 should be modified to address this type of multiple contingency. In the description of Event 1 of Category P2 in Table 1, remove the text "Loss of one of the following:". In the description of Event 2 of Category P2 in Table 1, replace "Bus section" by "Loss of a bus section". Assuming that this does not change the intent of the drafting team, in R3.3.2.2, R3.5.1, R5.4.3.1, change "shall be operating" to "are operating". In R3.3.2.2, consider removing the phrase "and within their thermal and voltage limits", because it seems like it may be redundant given the definition of the term "Facility Rating". In the event descriptions of Categories P1, P3, and P6 of Table 2, does the term "3-phase fault" apply to DC lines? If not, consider using a separate introductory phrase with the event descriptions of Categories P1, P3, and P6 of Table 2 that involve DC lines. Also consider removing the words "Loss of" in the description of Event 4 of Category P6 in Table 2. Since a definition was developed for "Bus-tie Breaker", capitalize the terms "bus-tie" and "bus tie" wherever they appear in the standard.

Response: The SDT believes that events which can result in a single line or line section being fed radially from one end must be analyzed to ensure that Load served from the line can be reliably served from either end regardless of station configuration.

The SDT expanded the existing Table 1 description to include the requirement to study the loss of any generator followed by the loss of a transmission element. The SDT made this decision based on the fact that generator outages are more probable and in many cases have longer outage durations than transmission element outages. The SDT considered a requirement to study any outage of a transmission element followed by a generator outage but decided that this would be very burdensome for a lower probability event and therefore, decided not to add it in Table 1 of the draft standard.

P2 - The tables have been combined and the words "Loss of" have been removed.

The SDT agrees. Event 2 in P2 has been modified for clarity.

Requirement R3.3.2.2 has been deleted in favor of Header note ‘e’ in the Table. Please note that the two tables in the second draft have been reduced to one table in the third draft. Requirements R3.5.1 and R5.4.3.1 have been deleted from the Standard.

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The "3-phase faults" does not apply to DC lines. The SDT has revised the Table accordingly. P6 - The tables have been combined and the words "Loss of" have been removed. The final draft will have all defined terms capitalized.		
Progress Energy Carolinas	C — Definitely do not support the revised standard	While be believe that in many ways the proposed draft standard represents an improvement of the current standard, we have a number of significant concerns that preclude our endorsement for the proposed standard as currently drafted. These include those discussed in the comments to above questions and the below additional comments.1) In both the Steady State and Stability Tables, Category P6 is the loss of a system element, following system adjustments, followed by the loss of another element. The table columns for this category say that interruption of firm transmission service is allowed. The table, however, is not clear whether the interruption of firm service is allowed as part of the system adjustment (between the outages) or whether it is only allowed after the second outage. It was stated in the NERC TPL SDT WebEx that the interruption is not allowed as part of the system adjustment. If this is the interpretation, this would be a dramatic change from the existing standard and would result in the unintended consequence of significantly reducing transfer capability of interfaces to a fraction of their currently reported capability. This would in effect be imposing an n-2 criteria for offering firm transmission service. This would not be an acceptable situation for the users, owners and operators of the bulk power system. 2) The proposed sensitivities create significant amount of additional work for the sole purpose of demonstrating compliance to this standard without any demonstratable benefit towards improving system reliability. While sensitivities should be appropriately considered in studies, this standard should not be overly prescriptive with respect to specific sensitivities or study methodologies.
Response: 1. The SDT agrees that clarification regarding treatment of Firm Transmission Service and Non-Consequential Load Loss during adjustment is necessary. Footnote 10 in Draft 3 of the Standard provides this clarification. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. 2. The SDT agrees with the respondent that the sensitivities evaluated should be based on the individual situations and therefore, the SDT has not required specific sensitivities, but rather, required that at least one sensitivity should be evaluated for an Assessment to be complete.		
Platte River Power	A — Generally	In Tables 1 and 2, Categories P1 and P3, under the column heading "Interruption of Firm Transmission Service Allowed," change the note in the performance box to read "Yes, if transfer is dependent on the outaged Element." (Not just for a DC

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Authority	support the revised standard	line Element.) This conditional statement applies to most Firm Point-To-Point Transmission Service (Firm PTP) applications where an outaged Element reduces the Transfer Capability of the PTP service if the Element cannot be restored to service after an allowable time frame (30 minutes or so) and the Transfer Capability is reduced to a Prior Outage System Conditions level. This "extended Contingency situation" could cause an interruption or curtailment to the firm service. The interruption and curtailment responses to a Contingency might be different between Firm PTP and Network Integration Transmission Service.
Response: The SDT has removed the "Yes if transfer is dependent on the outaged DC line" comments from the Table to ensure that AC and DC lines are treated equally. The draft standard does not allow interruption of Firm Transmission Service as a System response to Event P1. However, the SDT added Footnotes # 5 and 10 to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service in preparation for the next Contingency will be allowed provided there is no shedding of firm Load. **Footnote 5** - When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
BCTC	C — Definitely do not support the revised standard	BCTC appreciates the efforts of the SDT to explore ways to improve our planning standards. We understand that some of the proposed enhancements may assist Transmission Planners with justifying the need for system reinforcements. Many areas of our system already meet the proposed improvements, for example, most (but not all) of our 500 kV system already meets the proposed standards for systems above 300 kV. We have planned our system without support from a standard. The proposed changes do not really help us in any way and have a number of undesirable consequences. Consequently, BCTC does not support a number of the proposed additions and is uncertain about supporting some of the other changes. Our concerns are summarized below under headings of System Issues and Study Issues. System Issues:1. BCTC plans, manages and operates 18,000 km of transmission in British Columbia. This includes 5700 km of 500 kV transmission lines. For the BCTC system, the proposed definitions for Consequential Load Loss and Non-consequential Load Loss, specifically that load loss due to RAS/SPS is Non-Consequential Load Loss, will provide no reliability benefits for our 500 kV transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection relative to what we have today. No reinforcements of this 500 kV transmission will be required as a result of these more stringent definitions. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level, primarily in rural areas currently served by radial lines. The possible benefits would be small. There is a very low probability that we would get funding approval for these facilities. For most of our system including most of our backbone 500 kV and local networks in

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		metropolitan and urban areas BCTC already meets the requirements for these definitions. As noted in our comments at item 3, a portion of the BCTC system above 300 kV cannot meet the proposed P1(A) > 300 kV. We require further clarification of these definitions such as allowing load shedding in local networks. Otherwise, we will not be planning a doable/plausible set of actions, but rather just generating a list of projects that will not be approved. Our resulting subsequent corrective plan will be to use load shedding RAS, which will conflict with the definitions. Order 693 does not require NERC to prohibit load shedding, only clarify the amount and duration of load shedding that is permitted (paragraphs 1795 and 1797). BCTC's concerns can be addressed by including the local network component of Footnote (b) - modify the definition of Consequential Load Loss to permit the use of RAS in local networks (including local networks interconnecting generation), by allowing Non-Consequential Load Loss for local networks in Tables 1 and 2, or by modifying the definition of BES to exempt local networks from the definition of BES. BCTC could also consider a limit on load shedding if the industry would develop one. BCTC raised these issues in our comments on the first draft. The SDT response (page 332) does not address our concerns. We also note FPL comment 7 (page 359) regarding removal of localized load reduction provided in Footnote (b). We do not believe that the SDT has addressed FPL's issue. Unless the local network component of Footnote (b) is included and we can get a clarification to address our concern with P1 (A), the proposed standard is not suitable for the BCTC system and we do not support the standard. 2. Contingency P1 needs to permit curtailment of firm service for flow through firm transmission service to prepare for the next contingency. If it does not, some flow through open access transmission customers may have less ATC available if RAS is not available to meet the new restrictions on the P6 contingency, while this ATC will be available for services sourcing or sinking within the transmission provider's system. P6 allows the use of RAS in response to the second contingency (Event). For firm service originating or sinking in our system, we can use RAS and have many RAS systems already in place. However, for flow throughs it may not be possible to implement RAS or there may be a time delay until RAS can be installed. If RAS cannot be implemented, it would be preferable to provide the firm service and curtail in preparation for the second contingency rather than deny the firm service (or require that the system be built for N-2 capability, which also may not be possible), which is what we will have to do to adhere to the new standard. The result is that flow through transactions will have to use non-firm service while non-flow-through may use exactly the same transmission for firm. Also keep in mind that while P4 and P5 are only those multiple contingencies initiated by a common mode failure, P6 is any two elements not necessarily common mode. Therefore, P6 can be more limiting than P4 or P5. For P4 and P5 contingencies the BCTC system has less dependence on RAS than does the second event of a P6. Consequently P6 will be more limiting on flow throughs than P4 and P5. Order 693 contains direction to NERC to address Footnote (b). Some commenters have taken issue with the SDT interpretation of Order 693 (e.g. FRCC item 2, page 365). Given the different interpretations and the potential for impacts on ATC, we suggest that the SDT review this issue with FERC and find out if what the SDT is proposing is what they really want. Without this change or clarification we do not support the standard. 3. Regarding Q30 in the Comments on First Draft, BCTC believes that DC and AC lines should have the same performance requirements with respect to interruption of firm transmission service. This relates to our concern above

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		regarding flow through transactions. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable step to prepare for the next contingency of an AC line. We would ask that the SDT provide further explanation of its response that "many of the transfers over DC lines are automatically curtailed when the DC line is outaged" (page 220). We can do the same with AC lines for transfers sinking or sourcing within our system. Is the SDT assuming that RAS/SPS is used? We agree with the comments of FPL, FRCC, Southern Transmission and Manitoba Hydro (pages 219 and 221) and FPL (page 360, item 11). We disagree with the SDT decision to allow different performance for DC than AC lines. We do not support this element of this standard. 4. Contingency P3 should have the same performance requirement as P6. In two recent CPCN approvals for reinforcements of the BCTC backbone system, approval was granted based on generator contingencies being treated the same as transmission contingencies. We believe it highly unlikely that we would have received funding to approval to meet contingency P3. In our local service areas relying on generation for firm supply and for our bulk system, we consider dependable generator capacity on a case by case basis. We do not arbitrary assume a generator N-1 as a preexisting planning condition. We consider firm generator capability as a sensitivity case, not a planning criteria. We disagree with requiring a generator initial system condition having a more stringent performance requirement than other initial conditions. Without this change we do not support this standard. 5. BCTC is concerned that including the generator runback/tripping requirement in this standard will encourage more use of generator runback and tripping and will make it more difficult to get regulatory approval for transmission reinforcements. If retained, there needs to be a tie into reserves requirements. While we agree with permitting generator runback/tripping, at this time we are unsure about supporting this standard with this permissive requirement included. Study Issues:6. R2.5 and R5.5 on Generating Unit Stability studies are adequately addressed by FAC-001 and 002. Triggering events such as increased output or new existers need to go through our generator interconnection process and be paid for by the customer. In fact, we would not be aware of any of these triggering events unless a request comes from a customer. Without clarification of which generator studies are addressed through FAC-001 first, we do not support this standard. 7. We request that the SDT provide an explanation of why it believes it is important to maintain a distinction between system and generating unit stability studies. 8. Table 1 Steady State Performance lists 6 items above the Planning Events title. Should these be listed below the Planning Events title?
Response: 1. The SDT has added footnote 10 and clarified that for a P1 event, Transmission service could be interrupted as long as all of the Non-Consequential Load continued to be served. This draft does not allow “local network” Load to be shed for a P1 event, however, the conditions that you describe could warrant a regional difference.		

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Footnote #10 – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. 2. Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency. However, until the next Contingency occurs, System performance will need to meet the requirements for Event P1. As such, the proposed standard will not allow loss of any Non-Consequential Load, except for contracted interruptible Loads, in preparation for the next Contingency. 3. The SDT has removed this differentiation in the Table such that AC and DC lines will be treated equally. See footnote #10. 4. The SDT believes that the loss of a generator unit is a much more likely to occur than the loss of other major BES elements and thus the P3 event warrants more stringent performance requirements than the P6 event. The performance requirements for P3 have been clarified by addition of footnote 10 in Revision 3 of the Standard. 5. By a nearly unanimous response the Industry favors manual and automatic generation run-back and tripping as a response to a single or multiple Contingency. The SDT has eliminated the conditions in Sub-requirements R3.5.1, R3.5.2, and R3.5.3 for Contingency events as well as similar conditions in Sub-requirements R5.4.3.1, R5.4.3.2, and R5.4.3.3 for Stability events in the third draft. Accordingly, the SDT has modified Sub-requirement R3.5 for Contingency events and relocated it under Requirement R2.6.1. Likewise, the SDT has modified Sub-requirement R5.4.3 for Stability events and relocated it to become a bullet under R2.6.1. The resource adequacy issues are not directly included in this standard. In addition, with the creation of P3, the SDT has addressed the issue of the reduction of generation resources by treating the loss of one generator unit, followed by System adjustment, as the initial condition for all other single Contingencies. Therefore, the SDT does not believe that generation tripping as a corrective action needs to be tied to resource adequacy issues. Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations. Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations 6. Both Requirement R2.5 and Requirement R5.5 have been deleted since, in response to industry comments, Generating Unit Stability is no longer separately addressed in the standard. 7. Based on comments from others, the SDT has removed the requirements for separate Generating Unit Stability analysis and System Stability analysis. 8. The SDT has reformatted and combined the two Tables into a single Table for this draft to address these types of problems.		
Manitoba Hydro	C — Definitely do	Manitoba Hydro can not accept the standard due to the requirements imposed on Firm Transmission Service and on facilities >300 kV. The standard would have to allow Firm Transmission Service to be curtailed in situations where Non-

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	not support the revised standard	consequential Load is not lost. The higher performance requirements for facilities >300 kV are tied to very low probability events, so the enhanced reliability is not worth the cost. TPL-001-1 Other Comment Action Plan: Schedule of Anticipated Actions needs to be revised. - Action 3 shows rev 3 out for ballot in 2Q09. TPL-00101 Purpose: Is the purpose to ?Establish Transmission System planning performance requirements? or to ?Establish planned Transmission System performance requirements? The term ?probable contingencies? is not defined or used in the standard ? use of the term may cause confusion. R7: The TP and PC are required to determine the responsibilities for performing the assessment. Are the responsibilities to be documented as part of the assessment? R8: This requirement should avoid reference to a FERC order as the order does not apply to all entities. The requirement should just require the planner to demonstrate that the assessment was distributed to potentially impacted stakeholders. The last sentence is incomplete.

Response: In response to your comment and those of others in the industry on allowing curtailment of Firm Transmission Service as a System adjustment after an N-1 Contingency, the SDT has added footnotes 5 and 10 to Table 1 - Steady State & Stability Performance.

Footnote 5 - When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed.

Footnote #10 – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.

The schedule has been updated.

The SDT believes the Purpose is accurate as written because it defines planning practices and conditions to be studied. As per A.3, the purpose of Standard TPL-001-1 is to "Establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies." In this definition, the word probable is left up to the Transmission Planner/Planning Coordinator to determine so that they can set System performance requirements locally based on experience.

R7 (now R6). There is no requirement to document the responsibilities as part of the Assessment but Measure M6 in the new draft clearly states that a document must be produced as evidence that Requirement R6 has been successfully completed. This could be a standalone document or part of the Assessment at the discretion of the responsible entity.

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R8 (now R7): The SDT believes the addition of the reference to the FERC Order 890 adds clarity to the expectations of the requirement without making the requirements of the Order applicable to all NERC entities. The incomplete sentence has been deleted.		
Los Angeles Department of Water and Power	C — Definitely do not support the revised standard	I do not support the standard as currently written. There are too many requirements that are discriminatory, duplicative, and arbitrary/punitive. The unintended consequence of this standard would be forcing companies and planners to plan the system to take advantage of some requirements that will result in a future system that is less robust (a single line serving multiple radial loads instead of network, for example) if not to entiely discourage any further expansion of the transmission system above 300kV (the discriminatory treatment of two classes without any rational justification).
Response: The SDT believes that the appropriate justifications have been made. The SDT changes made after the first draft were due to industry consensus. The SDT believes that these changes are justified by the various comments received from industry.		
Transmission Agency of Northern California	B — Unsure about supporting the revised standard	- We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before we can give a full approval of this Standard. - There is no mention in the purpose of the Sta
Response: Measures, VSL's and the Implementation Plan have been addressed in the third draft of the standard.		
National Grid	B — Unsure about supporting the revised standard	Aside from the comments to the prior questions, there are several issues of concern that prevent us from supporting the present draft of the revised standard. We offer the following constructive comments in an effort to support the worthwhile effort that is being pursued so that we can reach a point of satisfaction that we could vote to support the revised standard. Our concerns are listed in a rough order of priority. a. This standard as drafted does not allow exceptions for small parts of the system as long as interconnected system reliability is maintained, which is allowed in the existing TPL standards in footnotes b) and c) in Table 1. Unless such exceptions are allowed significant transfer restrictions or large reinforcements must be made. The applicable TPL footnotes are: Existing TPL footnote b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers. Existing TPL footnote c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (nonrecallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

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		b. This standard does not address base conditions. Without defining base conditions the initial status of generation dispatch and transfers across the system is ill defined. Therefore the contingency analysis doesn't have a predictable basis for a consistent and repeatable study. c. The reference to Special Protection Systems is completely permissive. Although there are good applications for Special Protection Systems, their use must be constrained to have a reliable system and to promote construction of needed infrastructure. d. This standard does not provide flexibility to shed load, which restricts the ability to control post contingency response for low impact events. This may result in advancing need for upgrades in response to low impact events. This is in conflict with FERC's directive to have the Transmission Provider waiting for market response to transmission needs and having the Transmission Provider provide a role to back stop the market. e. Definition of the Long-Term Planning Horizion. The planning horizon, for assessment purposes should be limited to 10 years. Such an assessment should be sufficient to identify requirements that may take an extended time to implement. f. Definition of Planning Coordinator is part of the NERC Functional Model, Remove from Standard. g. Put headings on each section to identify requirements of section. h. With respect to R2.2 - Delete "current" from the phrase"current System Peak Load study" and replace "study" with "assessment." i. Remove R2.2.1, the requirement to extend the assessment beyond 10 years. What does the length of the project have to do with the assessment? If it takes 15 years to build something, why does this require a review of year 15? What is the purpose of this assessment? j. R3.3.2 requires clarification - This standard needs to permit discretion regarding the single contingencies that need to be tested, similar to R 3.3.3 and R3.4. It is completely unnecessary to test all events. For example, contingencies may be limited to relevant disturbances that are contained within or directly impact the studied system. k. With respect to R3.2.1 - Clarify whether the intent of the standard is to address station service minimum voltage limitation, maximum leading VAR absorption capability or both at steady state. l. Remove R3.2.2 - Relay loadability is addressed in PRC-023 standard. m. With respect to R3.3.2.1 - Recommend the removal of the requirement to assess the expected duration of Consequential Load loss. It's not considered anywhere else in the standard. n. With respect to R3.3.3 - The paragraph refers to Table 1 Contingencies P3 through P7; this should be explicitly stated. Rationale for inclusion of testing should not be required; should only need to explain why certain Contingencies were not tested. This discretion should be applicable to all contingencies.

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		o. With respect to section R5 - The concept of planned and long-term outages should apply to the general Planning Assessment, or not at all. It should not be specific to the Stability Assessment. p. The provisions of Section R.5.3 should have a corresponding MOD standard apply a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertent trip of the generator. Such a provision should include "other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation. q. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizon. r. What is a "current" study?

Response: A. Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these System designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement. As an alternative, an entity could seek an Entity Variance for the situation described through their Regional Entity organization. In paragraph 1794, FERC clarified that "…an entity may seek a regional difference to the Reliability Standard from the ERO for case-specific circumstances". The process described by FERC as a regional difference is described in detail in the "NERC Standards Development Procedure" document under the subsection titled "Variances to NERC Reliability Standards".

B. The SDT has modified Requirement R1 to include additional details on what should be modeled in the cases. However, the SDT intentionally provides flexibility for the Transmission Planner/Planning Coordinator to decide which "base case" to use since initial conditions for a System will vary from region to region and will need to be established on a local level, not via a national standard. The required studies and sensitivity analysis ensures that sufficient study is performed to cover an appropriate range of System conditions.

C. The SDT does not believe that it would be appropriate to attempt to specify limitations to the use of Special Protection Systems in this standard. The proposed TPL-001-1 and existing standards provide adequate guidance to the industry on application of Special Protection Systems.

D. The SDT has made clarifications regarding Firm Transmission Service and Non-Consequential Load Loss. Footnote # 10 has been added to the end of Table 1. The standard does not preclude the possibility of obtaining contractually interruptible load. It is the general opinion of the SDT that dropping of Non-Consequential Load should not be allowed for the Planning Events involving only one element as described in Table 1 of the proposed Standard, and to meet the intent of FERC Order 693. Further, this Standard is proposed to "raise the bar" to improve System reliability, which would require responses (Corrective Action Plans) to address those so-called low-impact events that may have been overlooked or ignored with the existing Standard TPL-002-0.

Footnote #10 – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon,

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Facility Ratings in those regions must be considered.

E. The SDT believes that a review of System conditions beyond the 10-year horizon is warranted. FERC Order 693 requires that the planning horizon take into account the lead times for siting and permitting of new long-distance Transmission lines and other long lead time solutions. The SDT has received industry comments regarding the need to exceed a 10-year horizon to account for longer lead time projects. Establishing planning horizons that are shorter than Transmission lead times may create gaps where the identification of a reliability need to which Transmission may be the best solution occurs too late to avert the identified reliability violation. Further, Operating Procedures or alternative short-term capital projects may be needed to limit the impact of the Planning Event until the planned facilities can be completed. This information needs to be included in the Assessment.

F. The definition for Planning Coordinator was deleted because the term has already been defined and added to the NERC Glossary by another SDT.

G. The SDT also feels that the Tables need to be as clear and concise as possible. To that end, the next version will combine Tables 1 and 2 into one table with a revised format.

H. The SDT believes that the existing language is appropriate.

I. The SDT believes that a review of System conditions beyond the 10-year horizon is warranted under some circumstances. For example, if it takes 15 years to build a Transmission line, then the need for that line would have to be determined 15 years ahead of the in-service date. Therefore, Requirement R2.2.1 requires you to perform an Assessment on year 15 if it takes you 15 years to build a line.

J. The SDT has removed Requirement R3.3.2 and replaced it with additional language in Requirement R3.1. The SDT does agree with your interpretation that it does not require evaluation of all single Contingencies. The SDT specifically states in Requirement R3.4 that those Contingencies that are expected to produce the more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe results.

R3.1 Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 ~~– Steady State Performance.~~ based on the lists created in Requirement R3.4.

K. The SDT has not limited the purpose of this requirement to either minimum acceptable station service voltages or maximum Mvar absorption. The SDT believes that the purpose of Requirement R3.2.1 (now R3.3.2) is to determine if generators could continue to operate or if they would trip off following the Contingency.

L. The SDT believes that relay load limits or loadability need to be considered in the Contingency analyses. The studies should determine if Transmission line loadings could reach the relay loadability level, which may add to the existing Contingency and perhaps, result in an unbounded cascading event.

M. To meet industry concern as well as FERC Order 693, the SDT has added Requirement R 2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.8.

R2.8 The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1.

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N. The SDT has re-written Requirement R3.3 (now Requirement R3.4) to address your initial concern. Although the language and format of the proposed Standard have been revised from earlier versions, the SDT continues to believe that the Transmission Planners should evaluate the System performance for the events that are expected to produce the more severe System impacts, including both single and multi-Contingency events. The wording of new Requirement R3.4 (the old Requirement R3.3.3) now requires a listing of the Contingencies to be evaluated, the rationale for their selection and why the remaining Contingencies would be expected to produce less severe results. This will provide a complete evaluation of the potential Contingencies to be studied – those selected and those excluded.

R3.4 Those Planning Event Contingencies in Table 1 ~~– Steady State Performance not covered in Requirement R3.3.2~~ that are expected to produce more severe System impacts shall be identified~~,~~ and a list of those Contingencies to be evaluated for System performance in Requirement R3.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results.

O. The SDT agrees and has moved this concept within Requirement R1 (see Requirement R1.1.1) so that it is applicable to all planning Assessments. Further, both Requirement R3 and Requirement R5 (now R4) have been revised to make reference to Requirement R1.

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. ~~The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to c~~Contingencies ~~in Table 1 – Steady State Performance.~~ The studies shall be based on computer simulations using models utilizing data provided in Requirement R1.

R4 For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~

P. Requirement R5.3 (now R 4.3.2) has been modified to address simulation of how generators perform under conditions being studied. The current MOD standards that address steady-state and dynamic simulation data requirements do not explicitly require the Generator Operators to provide voltage ride-through capability. These standards are set to be addressed by Project 2010-04 within NERC's Standards Development Work Plan. It is expected that the Transmission Planner would contact Generator Operators applicable to their System to obtain such data. If the data is not provided, it would be expected that a Transmission Planner state its assumption on the Vmin used for a generator terminal voltage for assessing ride-through capability. It's likely such information could be obtained through generator manufacturers. The "Other equipment" is addressed in the revised Requirement R4.3.3.

Q. The SDT agrees and therefore has changed R1.1.1 to state "if specifically known."

R. The SDT believes that a current study is a study that has been completed for the latest Assessment, as opposed to a past study that may have been completed up to five years ago.

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Tenaska, Inc.	A — Generally support the revised standard	A few issues that may need some thought include: Are reactive power devices a responsibility of Resource Planners in R13? On the Extreme Events description for local area, what is a load center? Does the loss of a large body of water as a cooling source result in the immediate loss of generation such that it is a contingency which affects steady state, stability, or short circuit studies?
Response: In response to industry comments, the SDT has removed Requirements R9-R14 and thus eliminated the responsibility of a Resource Planner. The SDT believes that a Load center is a location where energy is delivered by Transmission or sub-Transmission Systems to end-use customers. The loss of a large body of water as a cooling source could cause an immediate loss of generation or could only cause some generation reduction. The Transmission Planner or Planning Coordinator would need to analyze their System in order to determine the proper simulation(s).		
Pacific Gas and Electric Co.	B — Unsure about supporting the revised standard	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. ? There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. ? We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions.? We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with “raising the bar”. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. As mention in comments to Q3 above, some local network customer

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Public Service Company of New Mexico	C — Definitely do not support the revised standard	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. ? There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. ? We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions.? We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with ?raising the bar?. Local Network load should be included in Consequential Load and the loss

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Puget Sound Energy, Inc.	C — Definitely do not support the revised standard	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before PSE can give a full approval of this Standard. There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting

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Idaho Power	B — Unsure	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures,

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Company	about supporting the revised standard	VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard.? There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability.? We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions.? We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with ?raising the bar?. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level.? As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms ?interruption of firm transmission service?, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what “Firm Transmission Service” means. Two points, 1) the NERC definition states ?highest quality service offered to customers under a filed rate schedule that anticipates no planned interruption.? The Standard implies anticipation of “unplanned” interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order 890, or firm transfers modeled for the conditions being studied? One way Comment Form for 2nd Draft of Standard TPL-001-1Assess Transmission Future Needs (Project 2006-02)Page 12 of 12to interpret the intent is the firm transfers being modeled for the conditions in the powerflow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption

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SMUD	C — Definitely do not support the revised standard	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before giving a full approval of this Standard. ? There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. ? We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rata curtailments of firm transmission rights during forced and planned outage conditions.? We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with ?raising the bar?. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. ? As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of trade offs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms ?interruption of firm transmission service?, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular

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Sierra Pacific Power Company / Nevada Power Company	B — Unsure about supporting the revised standard	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions. We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with ?raising the bar?. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these

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Black Hills Corporation	B — Unsure about supporting the revised standard	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before a full approval of this Standard can be given. There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions. We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load

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Tucson Electric Power Company	C — Definitely do not support the revised standard	The Standard as presented is clearer, but there are numerous issues that still need resolution. There should be no distinction in voltage classes for allowing or not allowing controlled load shed for applicable events. We support the use of load shed for events at voltages greater than 300 kV where load shed is allowed for the same type of event for voltages below 300 kV. We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. ?

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		There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. ? We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions.? We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with ?raising the bar?. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. ? As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms ?interruption of firm transmission service?, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what ?Firm Transmission Service? means. Two points, 1) the NERC definition states ?highest quality service offered to customers under a filed rate schedule that anticipates no planned interruption.? The Standard implies anticipation of ?unplanned? interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order 890, or firm transfers modeled for the conditions being studied? One way to interpret the intent is the firm transfers being modeled for the conditions in the powerflow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption of firm transmission service should also be allowed for P1 through P5 contingencies in the table. In addition, we believe that DC and AC lines should have the same performance requirements with respect to interruption

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		of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines can automatically be curtailed when the line is outaged.
Tri-State G&T	C — Definitely do not support the revised standard	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. ? There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. ? We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions.? We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with ?raising the bar?. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. ? As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms ?interruption of firm transmission service?, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what “Firm Transmission Service” means. Two points, 1) the NERC definition states ?highest quality service offered to customers under a filed rate schedule that

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		anticipates no planned interruption.? The Standard implies anticipation of "unplanned" interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order 890, or firm transfers modeled for the conditions being studied? One way to interpret the intent is the firm transfers being modeled for the conditions in the powerflow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption of firm transmission service should also be allowed for P1 through P5 contingencies in the table. In addition, we believe that DC and AC lines should have the same performance requirements with respect to interruption of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines can automatically be curtailed when the line is outaged.
ColumbiaGrid	A — Generally support the revised standard	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution. There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions. We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with "raising the bar". Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a

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		local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Interruption of firm transmission service does not mean that firm load is not served. If there is other generation in the system that could increase to meet the firm load requirements if the firm transfer being modeled is interrupted, then interruption of firm transmission service should be allowed for P1 through P5 contingencies in the table. In addition, we believe that DC and AC lines should have the same performance requirements with respect to interruption of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines should be allowed to be curtailed when the line is outaged.
Southern California Edison	B — Unsure about supporting the revised standard	Our Response is (B) and (C).We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions. We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with “raising the bar”. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a

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		result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms “interruption of firm transmission service”, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what “Firm Transmission Service” means. Two points, 1) the NERC definition states ?highest quality service offered to customers under a filed rate schedule that anticipates no planned interruption.? The Standard implies anticipation of “unplanned” interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order 890, or firm transfers modeled for the conditions being studied? One way to interpret the intent is the firm transfers being modeled for the conditions in the powerflow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption of firm transmission service should also be allowed for P1 through P5 contingencies in the table. In addition, we believe that DC and AC lines should have the same performance requirements with respect to interruption of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines can automatically be curtailed when the line is outaged.
Alberta Electric System Operator	C — Definitely do not support the revised standard	We agree that the Standard as presented is clearer, but there are numerous identified issues that still need resolution, in addition to the Measures, VSLs, Implementation Plan, etc., before AESO could give a full approval of this Standard. – There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. – We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions.- We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with ?raising the bar? for loss of Facilities with operating voltages 300 kV or higher (P2, P4, and P5 in the Performance Tables). We believe there should be no distinction between the voltage classes.-

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		Regarding the terms ?interruption of firm transmission service?, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what ?Firm Transmission Service? means. Two points, 1) the NERC definition states ?highest quality service offered to customers under a filed rate schedule that anticipates no planned interruption.? The Standard implies anticipation of ?unplanned? interruption for certain contingencies. 2) Is this referring to a transmission product, or firm transfers modeled for the conditions being studied? One way to interpret the intent is the firm transfers being modeled for the conditions in the powerflow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption of firm transmission service should also be allowed for P1 through P5 contingencies in the table.- In addition, we believe that DC and AC lines should have the same performance requirements with respect to interruption of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines can automatically be curtailed when the line is outaged.
US Bureau of Reclamation	C ? Definitely do not support the revised standard	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard.? There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability.? We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions.? We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with ?raising the bar?. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for

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		high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level.? As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms ?interruption of firm transmission service?, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what “Firm Transmission Service” means. Two points, 1) the NERC definition states ?highest quality service offered to customers under a filed rate schedule that anticipates no planned interruption.? The Standard implies anticipation of ?unplanned? interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order 890, or firm transfers modeled for the conditions being studied? One way Comment Form for 2nd Draft of Standard TPL-001-1Assess Transmission Future Needs (Project 2006-02) Page 12 of 12to interpret the intent is the firm transfers being modeled for the conditions in the powerflow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption of firm transmission service should also be allowed for P1 through P5 contingencies in the table. In addition, we believe that DC and AC lines should have the same performance requirements with respect to interruption of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines can automatically be curtailed when the line is outaged.

Response: Measures, VSL's, and the Implementation Plan will be addressed in the next draft of the standard.

The NERC standards are based on deterministic principles. Probability is considered in a high level perspective as a means of rationalizing the inclusion of various deterministic events; however it is difficult to discuss probability in this context without creating misunderstandings. The SDT recommends that you review the NERC definition of Adequate Level of Reliability (ALR), which is the reliability goal for all NERC standards. In response to your comment and those of others in the industry, the SDT has proposed differentiating between loss of firm Load and loss of Firm Transmission Service. This differentiation is provided in footnotes 5 and 10 to Table 1 - Steady State & Stability Performance. In the event that loss of Firm Transmission Service is inadequate, the SDT believes that there are alternatives to loss of Load or construction. For example, companies may contract with interruptible Load and shed customers voluntarily.

Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these System designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that that interruption of Non-Consequential Load is not

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permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement. Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency. However, until the next Contingency occurs, System performance will need to meet the requirements for Event P1. As such, the proposed standard will not allow loss of any Non-Consequential Load, except for contracted interruptible Loads, in preparation for the next Contingency. "Firm Transmission Service" is a NERC defined term and is also addressed by FERC in OATT. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. The SDT has removed this differentiation in the Table such that AC and DC lines will be treated equally.		
Gainesville Regional Utilities	C — Definitely do not support the revised standard	First, a starting point for the study process (base case) needs to be better defined even if the intent was to allow the TP's & PC's to make the decision. The standard should describe the rules to properly conduct a base case study within each region. This should support any following analysis studies and their finding since you will be starting from the same set of system elements operating at a base condition. Secondly, this standard should focus on what is best for the customer considering 1) the probability of the contingency events, 2) the potential expense to the customer for practically NO improvement in BES reliability, and 3)the extraordinary added burden on the smaller utilities to run additional, no added value studies with documentation to meet an exhausted detailed audit with the potential for penalties probably not proportioned to the utilities revenue stream.
Response: The SDT has modified Requirement R1 to include additional details on what should be modeled in the cases. However, the SDT intentionally provides flexibility for the Transmission Planner/Planning Coordinator to decide which "base case" to use since initial conditions for a system will vary from region to region and will need to be established on a local level, not via a national standard. The required studies and sensitivity analysis ensures that sufficient study is performed to cover an appropriate range of System conditions. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations. The SDT has retained the basis of the previous standard and raised the bar in some respects. While the performance requirements must be met, they do not necessarily mandate a solution. Considerable flexibility in Corrective Action Plans allows for economic considerations. The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus. The SDT is cognizant of the cost factors (including ROW) involved here and is		

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taking them into consideration in its deliberations.		
Lakeland electric	B — Unsure about supporting the revised standard	Suggested changes listed below to more directly address what I think is the intent of the item: Planning Events: Events that require Transmission system performance requirements to be met. Comment: I think that this suggested revision better defines a Planning Event and how they may be used in a study or assessment. Revision to: Planning Events Planning Events: Simulated events that are modeled to test the Transmission system's ability to meet performance requirements. R2.6.2. For steady state, short circuit, Generating Plant Stability, or System Stability analysis: the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Comment: the requirement as stated leaves one guessing about the usability of a study that may have included the changes that occurred in the intervening period. Changes that were studied but not implemented could also invalidate a study they were included in. Revision to R2.6.2R2.6.2. For steady state, short circuit, Generating Plant Stability, or System Stability analysis: the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that were not included in the original study but have occurred in the intervening period and would impact the study area results.
Response: The SDT did not incorporate the commenter's suggested change and the Planning Event definition remains the same as in Draft 2. The SDT believes the stated definition more correctly indicates the intent that for Planning Events the performance requirements must be met, not simply that simulations need to be completed to indicate if the performance requirements are met or not. The SDT does not agree with your comment and believes that the cancellation of a planned Facility that was included in prior models would be a material change to the network model and therefore would not allow the past study to support the Planning Assessment. The key phrase within the requirement is "the study", therefore, the intent is model simulation changes and not limited only to real physical System changes. Therefore, the SDT believes the instance raised by the commenter is adequately covered.		
JEA	C — Definitely do not support the revised standard	The inability to curtail Firm Transmission Service under P6 assessments in preparation for the next N-1 event. Also, under P1 and lower probability contingency events, JEA recommends a standard requirement that allows for the loss of Non-Consequential load during short term periods (suggest allowing up to 3 year minimum) where the system load growth has caused post-contingency remedial action plans to not be completely affective in bringing the Facility(ies) within normal operating limits. As a specific theoretical example, lets say a 10 year assessment shows load growth causing this situation in year 5, but in year 7 generators are added to the area of concern and the issue is resolved, but in year 6, Non-consequential load is required to be shed, do we still need to propose a capital improvement project?
Response: The SDT agrees that clarification regarding treatment of Firm Transmission Service and Non-Consequential Load Loss during adjustment is		

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necessary. Footnote 10 in the Revision 3 of the Standard provides clarification. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. The proposed standard does not require capital improvements, but it does require the performance metrics to be achieved. Certainly there will be circumstances where the addition of Transmission or generation facilities may be the only practical solution. For the specific example that you described, if there were no acceptable Operating Procedures to bridge the time period before the generator comes on line, entering into interruptible Load contracts would be another option. The standard does not preclude such actions.		
PacifiCorp	A — Generally support the revised standard	We generally agree with the Standard as presented so far, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce.
Response: Measures, VSL's, and the Implementation Plan will be addressed in the next draft of the standard. The SDT agrees that clarification regarding treatment of Firm Transmission Service and Non-Consequential Load Loss during adjustment is necessary. Footnote 10 in the Revision 3 of the Standard provides clarification. Requirement R3.3.2.2 has been deleted in favor of Header note 'e' in the Table. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
ITC Holdings: ITC, METC, ITC Midwest	B — Unsure about supporting the revised standard	ITC and ITC Midwest biggest concerns are some missed opportunities to "raise the bar". We believe the draft standard is a significant improvement over existing standards which are largely fill-in-the-blank. However, we have some concerns regarding some of the language wherein CAPs are not required, even though a performance requirement has been violated. For example, providing for a bare minimum sensitivity study and not requiring a CAP based on a performance violation may increase operational awareness but does not ?raise the bar? or improve transmission performance. Allowing for non-consequential load loss following a shutdown and contingency might be an acceptable real time operating

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		procedure but is not a significant advancement on a transmission planning basis. Frequently, operating procedures like this should lead to a planning solution, particularly above 300kV
Response: The SDT translated the existing TPL standards, added clarity, and "raised the bar" in areas where the SDT believes are merited. Even though the existing TPL standards do not address sensitivities, the SDT has added a requirement to complete at least one additional sensitivity. The SDT believes that it is important and valuable for the Transmission Planner and Planning Coordinator to run significant sensitivities and share the results with their neighbors. The SDT did not limit when Operating Procedures, other than Non-Consequential Load loss, could be utilized. The SDT believes that it is important for the Transmission Planner and Planning Coordinator to determine when an Operating Procedure can be utilized and when new Facilities need to be constructed. A Corrective Action Plan is required for all performance violations of all Planning Events in Table 1, except, as you have noted for sensitivity study performance violations. The SDT concurred with the FERC orders that sensitivity study results do not necessarily result in a Corrective Action Plan. From paragraph 1704 of Order 693: "The Commission notes that it is not the purpose of sensitivity studies to identify remedial actions, but, as stated in the NOPR, if different scenarios that lead to criteria violations are probable they require mitigation plans…… In any case, we are not requiring the construction of additional facilities." While the standard does not "require" a Corrective Action Plan, it does not preclude a Corrective Action Plan, particularly if it meets FERC requirements for a "mitigation" plan if the Planning Events are "probable". The majority of the SDT, based on industry comments, did not feel that Non-Consequential Load loss should be precluded from N-1-1 events. A Corrective Action Plan is not required if Non-Consequential Load loss is allowed under local criteria but the standard does not prevent local criteria from prohibiting Non-Consequential Load loss for N-1-1 events.		
Hydro-Quebec Transenergie (HQT)	C — Definitely do not support the revised standard	This standard as drafted does not allow exceptions for small parts of the system as long as interconnected system reliability is maintained, which is allowed in the existing TPL standards in footnotes b) and c) in Table 1. Unless such exceptions are allowed significant transfer restrictions or large reinforcements must be made. The applicable TPL footnotes are:? Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.? Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (nonrecallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.? This comment form did not allow for the following items to be addressed:? a. Definition of the Long-Term Planning Horizon. The planning horizon, for assessment purposes should be limited to 10 years. Such an assessment should be sufficient to identify requirements that may take an extended time to implement.? b. Definition of Planning Coordinator is part of the NERC Functional Model, For consistency it should be removed from the Standard.? c. We propose that the Standard be subdivided by subjects into 4 different Standards : ? TPL-001-1: Modeling and System Assessment (R1, R2, R9 to R14)? TPL-002-1: Short circuit and Steady State Performance (R3, R4)? TPL-003-1: Stability Performance (R5)? TPL-004-1: Coordination (R6, R7, R8)? If the previous proposition is not retained, at least the Standard

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		Requirements should be organized by topics (Modeling, Assessment, Coordination, etc.) and headings put on each section to identify requirements of section. Add headings to the tops of the subsequent pages in the performance tables. Headings only appear on the first page at the beginning of the Table.? d. With respect to R2.2 - Delete "current" from the phrase" current System Peak Load study" and replace "study" with "assessment."? e. Remove R2.2.1, the requirement to extend the assessment beyond 10 years. What does the length of the project have to do with the assessment? If it takes 15 years to build something, why does this require a review of year 15? What is the purpose of this assessment?? f. R3.3.2 requires clarification - This standard needs to permit discretion regarding the single contingencies that need to be tested, similar to R 3.3.3 and R3.4. It is unnecessary to test all events. For example, contingencies may be limited to relevant disturbances that are contained within or directly impact the studied system.? g. With respect to R3.2.1 - Clarify whether the intent of the standard is to address station service minimum voltage limitation, maximum leading VAR absorption capability or both at steady state.? h. Remove R3.2.2 - Relay loadability is addressed in PRC-023 standard.? i. With respect to R3.3.2.1 - Recommend the removal of the requirement to assess the expected duration of Consequential Load loss. It's not considered anywhere else in the standard.? j. With respect to R3.3.3 - The paragraph refers to Table 1 Contingencies P3 through P7; this should be explicitly stated. Rationale for inclusion of testing should not be required; should only need to explain why certain Contingencies were not tested. This discretion should be applicable to all contingencies.? k. With respect to section R5 - The concept of planned and long-term outages should apply to the general Planning Assessment, or not at all. It should not be specific to the Stability Assessment. ? l. The provisions of Section R.5.3 should have a corresponding MOD standard apply a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertent trip of the generator. Such a provision should include "other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation.? m. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizon. ? n. In both Table 1 and Table 2, note 3, "variable frequency transformers" should be removed from the last sentence. A new sentence should be added for reference voltage as it applies to "variable frequency transformers" and "back-to-back" facilities.

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Response: Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these System designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of the TPL-001-1 and most stakeholders and the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement.

A. The SDT believes that a review of System conditions beyond the 10-year horizon is warranted. FERC Order 693 requires that the planning horizon take into account the lead times for siting and permitting of new long-distance Transmission lines and other long lead time solutions. The SDT has received industry comments regarding the need to exceed a 10-year horizon to account for longer lead time projects. Establishing planning horizons that are shorter than Transmission lead times may create gaps where the identification of a reliability need to which Transmission may be the best solution occurs too late to avert the identified reliability violation. Further, Operating Procedures or alternative short-term capital projects may be needed to limit the impact of the planning event until the planned Facilities can be completed. This information needs to be included in the Assessment.

B. The definition for Planning Coordinator was deleted because the term has already been defined and added to the NERC Glossary by another SDT.

C. The SDT agrees with FERC Order 693 in aggregating all of the planning requirements into a single standard. The SDT also feels that the Tables need to be as clear and concise as possible. To that end, this version combined Tables 1 and 2 into one table with a revised format. The Planning Events are shown on one page so repeating the headings will not be needed.

D. The SDT believes that the existing language is appropriate. No change made.

E The SDT believes that a review of System conditions beyond the 10-year horizon is warranted under some circumstances. For example, if it takes 15 years to build a Transmission line, then the need for that line would have to be determined 15 years ahead of the in-service date. Therefore, Requirement R2.2.1 requires you to perform an Assessment on year 15 if it takes you 15 years to build a line.

F. The SDT has removed Requirement R3.3.2 and replaced it with additional language in Requirement R3.1. The SDT agrees with your interpretation that it does not require evaluation of all single Contingencies. Rather, the SDT specifically states in Requirement R3.4 that those Contingencies that are expected to produce the more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe results.

R3.1 Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 ~~– Steady State Performance.~~ based on the lists created in Requirement R3.5.

G. The SDT has not limited the purpose of this requirement to either minimum acceptable station service voltages or maximum Mvar absorption. The SDT believes that the purpose of Requirement R3.2.1 (now R3.3.2) is to determine if generators will be able to operate or trip off following the Contingency.

H. The SDT believes that relay load limits or loadability needs to be considered in the Contingency analyses. The studies should determine if Transmission line loadings could reach the relay loadability level which may add to the existing Contingency and perhaps, result in an unbounded cascading event. No change made.

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I. By definition, Consequential Load Loss is allowed. To meet industry concern as well as FERC Order 693, the SDT has added Requirement R2.~~-~~8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.8. **R2.8** The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1. J. The SDT agrees that the rationale should be for all Planning Events but not for Extreme Events. K. The SDT agrees and has moved this concept within Requirement R1 (see Requirement R1.1.1) so that it is applicable to all planning assessments. Further, both Requirements R3 and R5 (now R4) have been revised to make reference to Requirement R1. **R1.1.1** Planned outages of generation and Transmission Facilities, if specifically known. **R3**. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. ~~The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to c~~Contingencies in Table 1 ~~– Steady State Performance.~~ The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. **R4** For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~ L. Requirement R5.3 (now R4.3.2) has been modified to address simulation of how generators perform under conditions being studied. "Other equipment" is addressed in Requirement R5.4. **R4.3.2** ~~Studies shall consider~~ Simulate generator performance under anticipated conditions including how the voltage ride through capability ~~of all generators and identify how the generators are treated~~ is analyzed~~in the simulation~~ M. While planned outages are addressed in the operating horizon, it is important that a Transmission Planner review the ability of its System to accommodate planned (maintenance) outages. Additionally, any specific known Facility outages need to be appropriately modeled for the planning horizon studied. N. Tables 1 and 2 have been combined into one table for the next posting. The SDT believes that it has adequately addressed "variable frequency transformers" as well as "back-to-back" facilities by including it in the same note as other transformers (Note #3).		
Progress Energy Florida, Inc.	C — Definitely do not support the revised	PEF considers the draft TPL Standard in its present state to be infeasible, unnecessary, burdensome and inferior to the existing Standards. The basic approach to equate reliability of the BES to whether or not Firm Transmission Service and/or Non-Consequential Load Loss can be sustained is an erroneous approach, is not justifiable, infringes upon

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	standard	regulation already in place as part of dealings with the Florida Public Service Commission (PSC), and infringes upon requirements in the OATT. Given the numerous concerns PEF has with the revised draft Standard, expounding on those concerns requires extensive documentation. We therefore cannot reduce our concerns down to a single issue, nor can we single out a single requirement or set of requirements as the top concern, other than to say that the entire Standard development process either needs to be discontinued or the SDT should provide detail as to how much consideration would be given to transmission systems with historically excellent reliability via a variance process. The following is a list of PEF's primary concerns with the revised draft Standard and explanation as to why the Standard development process should be discontinued: 1. PEF has planned to, and demonstrated compliance with, the existing TPL Standards for several years now. PEF is intimately familiar with the existing Standards, and has done an excellent job in planning the PEF system, in conjunction with the other Transmission Owner members of FRCC, non-FRCC adjacent Transmission Owners, and all requestors of Transmission or Generator Interconnection Service using the existing TPL Standards. PEF thus believes that history has shown, particularly within the realm of PEF's Transmission Planning boundaries, that the existing four TPL Standards are not inadequate or inferior in any way. Statements in recent months alluding to the existing Standards? inferiority, confusing language or language subject to opposing interpretations, do not hold up when applied to the PEF and FRCC systems. PEF thus does not believe the Standards require modification. 2. PEF, through its aforementioned participation with FRCC and through its interaction and compliance with regulation by the Florida PSC, has historically demonstrated excellent Transmission Reliability, and can provide documentation to that effect through FRCC and Florida PSC channels. PEF therefore again asserts that modification or increased stringency in the TPL Standards is not merited. 3. The development of TPL-001-1 stems from a fundamental misinterpretation of the intent of FERC Order 693. NERC for the most part, rather than "clarify" or "consider" various matters raised by FERC, chose to accept all suggestions. Specifically, PEF notes the following misinterpretations regarding Order 693:a) In Paragraph 1692, the Commission agreed with one particular utility's assertion that integrating the four existing TPL Standards into a single standard would be an improvement, and directed NERC to "consider" this. NERC, rather than considering this, formed the SDT, which appears to have spent little considering the issue but rather have deemed it a foregone conclusion that the four existing TPL standards must be abolished and a new standard must be written. b) In Paragraphs 1694 and 1706, the Commission recognizes the significant differences in the various transmission systems, and the impossibility of developing a standardized list of "sensitivities" of critical operating conditions that every Transmission Planner and Planning Coordinator must analyze, regardless of their applicability. The Commission therefore stated that it is reasonable for planning entities to have a means to identify an appropriate range of critical operating conditions, without having to anticipate ?every conceivable critical operating condition.? They furthermore state that their conclusion on the whole matter is that ?only those deemed to be significant need to be assessed?. PEF agrees, and thus is perplexed by the erroneous developments in Requirements R2.4, R2.5, R5.4, R5.5, R2.1.3 and R2.1.4. PEF has

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		addressed the inadequacies of these Requirements in the answers to Questions 2 and 10. c) In Paragraph 1704, the Commission, amongst other statements, states that they ?are not requiring the construction of additional facilities?. This general statement made by the Commission is demonstrated to be untrue upon examining the realities of the Standard development process. FERC, by directing NERC to consider various clarifications and/or improvements to the TPL Standards, has set in motion a process which will prohibit either Interruption of Firm Transmission Service or the loss of Non-Consequential Load for various outage scenarios, effectively necessitating the construction of redundant facilities. FERC's statement conflicts with the ongoing process in a major way, and PEF respectfully requests that the SDT confer with appropriate FERC personnel to get clarification on this matter. d) In Paragraph 1725, the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy. PEF does not disagree with the specifics of analyzing events with respect to spare equipment, except to the extent that the Commission appears to think that such analysis is not adequately covered in the existing TPL Standards. PEF believes that the existing TPL Standards adequately address this issue and all other issues pertaining to the planning of a transmission system. Furthermore, the process is to be followed ?consistent with the entity's spare equipment strategy?, thus deferring to the processes and judgment of the individual Transmission Owners, which calls into question the need to include it in the draft Standard. For additional discussion on this issue, see the answer to Question 5 with regard to Requirement R11. e) In Paragraph 1782, PG&E points out the contradiction that FERC creates in Paragraph 1796 by directing NERC to remove the 2nd sentence of footnote (b). The contradiction also involves key statements made by the Commission in Paragraph 1788. For a more detailed explanation of this contradiction, see the answer to Question 11. f) Paragraph 1794 is part of the Commission Determination section. The Commission states its belief that no TPL Standard should allow an entity to plan for the loss of non-consequential load in the event of a single contingency. The Commission then directs NERC to "clarify the Reliability Standard.", and furthermore state that any Transmission Planners or Planning Coordinators seeking to plan for the loss of non-consequential load in the event of a single contingency can make their comments known through a) filing comments in the standards development process, or b) filing for a regional difference for case-specific circumstances. PEF points out that the Commission merely stated their belief and directed NERC to clarify the Standard. They did not order NERC to change the Standard to reflect its beliefs. NERC, while having the leeway to question FERC's approach in this Paragraph, did not question the approach, but rather deferred to the suggestion in Paragraph 1794 (as well as nearly every other suggestion or request for clarification) that FERC made. PEF is concerned that NERC and the SDT appear to be limiting the extent to which they question or make suggestions to FERC. PEF at present will take the approach of stating the prudency and need to plan for the curtailment of Firm Transmission Service and loss of non-consequential load in the event of a single contingency through the comments process. PEF, however, reserves the right to consider the variance approach or legal approaches, depending on further iterations in the development of the Standard. g) In Paragraph 1795, "The Commission" suggests that the ERO consider developing a ceiling on the amount and duration

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		of consequential load loss that will be acceptable. If the ERO determines that such a ceiling is appropriate, it should be developed through the ERO's Reliability Standards development process.? To this effect, the SDT drafted Requirement R.3.3.2.1, which at present states ?Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment.? PEF asserts that this issue is under the jurisdiction of the State Public Service Commissions, who are already doing an excellent job in regulating Consequential Load Loss as part of SAIDI/CMI requirements. FERC and NERC are overstepping their bounds of jurisdiction by attempting to essentially ?double-regulate? an issue that is already adequately regulated via the States. PEF furthermore objects to Requirement R.3.3.2.1 on the grounds that duration of events cannot be estimated with any reasonable degree of accuracy. To handle the challenges of this issue by stating a long-duration worst-case scenario for each outage would be inaccurate, and would tend to foster needless scrutiny and concern on any and all outages associated with Consequential Load Loss. h) In Paragraph 1796, "The Commission" directs the ERO to modify the second sentence of footnote (b) to clarify that manual system adjustments other than shedding of firm load or curtailment of firm transfers are permitted to return the system to a normal operating state after the first contingency, provided these adjustment can be accomplished within the time period allowed by the short term or emergency ratings.? The Commission directed the ERO only to make modifications on the 2nd sentence of footnote (b). The SDT in the draft TPL Standard has eliminated footnote (b) altogether. PEF is surprised and disappointed at the response by FERC to PG&E's very correct assertion that eliminating the allowance of shedding of firm load or curtailment of firm transfers from footnote (b) contradicts the allowance made in footnote (c) regarding C.3 events. FERC's only response was to state that ?manual adjustments referred to in both cases [i.e. Category B and Category C.3 events] apply after the first N-1 contingency?. The fallacy of this statement is that shedding of firm load or curtailment of firm transfers is allowed by footnote (c) for C.3 events, and that every Category B event is by default the first part of a Category C.3 event. PEF asserts that FERC, and consequently the NERC SDT, has created a draft Standard that contradicts direction and suggestion in Order 693 regarding this issue. PEF furthermore asserts that curtailment of Firm Transmission Service or Non-Consequential Load are not valid benchmarks for assessing the reliability of the BES. For additional comments on this issue, see the answer to Question 11. i) Regarding Paragraph 1833, the paragraph in its entirety states: ?MidAmerican states that it supports the proposal to modify TPL-004-0 to require identification of options for reducing the probability or impacts of extreme events that cause cascading. Accordingly, for the reasons cited in the NOPR, the Commission directs the ERO to modify the Reliability Standard to make this modification to the Reliability Standard.? PEF does not understand what FERC has directed on this matter. Furthermore, PEF does not understand the meaning or requirements behind the entire ?Extreme Events? section in the draft Standard, which appears to have resulted from the direction in this particular Paragraph. FERC wants NERC to modify the Standard to ?require identification of options for reducing the probability or impacts of extreme events that cause cascading.? This statement is vague, confusing and does not appear to mandate anything. PEF therefore requests that language in TPL-001-1 to this effect be removed. Furthermore, in Paragraph 1834, the Commission, regarding its preference to expand TPL-004-0 to include analysis of more events such as hurricanes, ice storms, successful cyber

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		attacks, etc., directs NERC to ?expand the list of events with examples of such events identified above.? This request, similar to Paragraph 1833, does not appear to direct NERC to make specific directions in a Standard. If it was FERC's intent that TPL-004 or its successor be modified to include some or all of FERC's suggested events, and to expand the list further, PEF has many concerns concerning this. The direction in Paragraph 1834 has resulted in the aforementioned Extreme Events section, which contains a note 1 referring to Requirement R3.4. PEF has multiple questions and concerns with the language in this Requirement. The Requirement as worded appears to mandate that Transmission Planners and Planning Coordinators must find the most severe Extreme Event scenarios that can be conceived. Such wording would define any reasonable limit as to which Extreme Events are likely and worthy of analysis, and which are not. Furthermore, many of the events suggested by FERC, such as loss of a large gas pipeline, wildfires, hurricanes, tornadoes, cyber attacks, etc., cannot reasonably be studied. To make any assessment of these events that even approached a level of thoroughness is infeasible, and furthermore has no significant benefit. PEF requests that the SDT point out to FERC that these events cannot be studied, and therefore need to be excluded from any TPL Standard. 4. The main approach of the draft TPL Standard consists of whether to allow or disallow load loss for certain outage scenarios (the most problematic Event categories being P1, P2.2, P2.3, P3, P4, P5 and P6), an approach to which PEF is opposed, and furthermore believes that level of service to retail load is not an issue that NERC/FERC should be regulating. The local utility commissions (the Florida PSC, etc.) have already set in place processes for reviewing/approving the level of transmission built to support the level of service to load, and thus FERC and NERC inappropriately attempt to regulate an issue which the States already adequately regulate. PEF can, and has demonstrated in its internal planning assessments and in assessments performed with FRCC that load curtailment and/or Firm Transmission Service curtailment do not adversely impact the reliability of the BES. In fact, certain post-contingency scenarios can be shown to demonstrate that such curtailments actually promote reliability and a speedier, safer, more efficient recovery of the BES after an event. 5. Several Event categories as presently defined in the draft TPL Standard present outage scenarios on the PEF system for which implementation of redundant transmission facilities would be required, at an exorbitant cost to ratepayers. The redundancy requirements at PEF's 500 kV, 230 kV and 115 kV Substations are numerous, and have not yet been comprehensively quantified, although this analysis is underway. One scenario for which PEF is already certain that redundancy of the 500 kV system would be required is the apparent disallowance of curtailment of Firm Transmission Service or Non-Consequential Load as part of ?System Adjustments? in between the two events of P6. PEF again would point out that no definition of ?System Adjustments? exists at present, and the SDT therefore must define it if compliance is expected. Be that as it may, PEF's 500 kV redundancy projects would clearly cost many billions of dollars, with extremely little benefit. PEF would furthermore point out that this is but one example requiring unnecessary Transmission upgrades, and that further analysis will potentially reveal several more Event categories in Tables 1 and 2 for which additional cost-prohibitive and unneeded projects would be mandated. 6. PEF is surprised and disappointed that neither FERC nor NERC have accepted any responsibility to alert the public or the State and local governments to this process. The public have not been involved in the development of the draft

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		standard, nor have they been informed that they would bear the financial impact of the increased stringency. In fact, The SDT on p. 369 of the 1st draft Comments Document has stated that ?This is a performance based reliability standard and does not and should not consider economics.? PEF considers this statement to be reckless and irresponsible, and does not accept FERC's and NERC's apparent position that they have no responsibility in this matter. The fact that the draft Standard and FERC Order 693 can be downloaded by anyone from FERC's and NERC's websites does not constitute a sufficient good-faith notice of this process to the public. PEF requests that FERC and NERC specifically address this issue by explaining their failure to involve and inform the public. Assigning this responsibility to each Transmission Planner and Planning Coordinator is not acceptable. FERC and NERC have set this process in motion, and as creators of the process owe an explanation to those who would "foot the bill" for the process. 7. The low voltage threshold of jurisdiction of the draft Standard, previously defined in NERC's definition of the BES as 100 kV, is not specified in the draft Standard. This is a significant misstep by NERC in that a change to NERC's Glossary Definition of the BES, which would ostensibly be done outside the boundaries of this Standard, could profoundly change the requirement for complying with TPL-001-1 without changing a single word of the Standard. PEF is particularly concerned that this Standard must never have jurisdiction over local load-serving transmission systems, regardless of voltage. Any TPL Standard, existing or future, must focus on the reliability of the BES, i.e. the bulk grid, NOT the local load-serving portions of the transmission system. The draft Standard at present does not address this issue at all and leaves Transmission Planners and Planning Coordinators vulnerable to non-compliance with a mere change in the wording of a Definition outside of the Standard. 8. PEF strenuously objects to the allowance of interruption of Firm Transmission Service in Events P1 and P3 for DC lines, while disallowing the same for AC lines. PEF asserts that the determination should be "Yes" for both, and that disallowance for AC lines a) puts DC systems into an elite class of transmission for no explicable reason and b) encourages owners of AC Transmission Systems to replace them with DC, cost concerns notwithstanding. Furthermore, this differentiation fails to recognize or give consideration to the fact that AC systems support Firm Transmission Service; some areas of the AC transmission system carry significant amounts of Firm Transmission Service, and thus a "No" determination for P1 and P3 essentially mandates either implementing redundancy for those parts of the AC system carrying significant amounts of Firm Transmission Service, or severely curtailing Firm Transmission Service on the existing AC systems.

Response: The SAR for this standard recognized FERC orders which indicated a need to "raise the bar" for the industry. The SDT is attempting to do this in a reasonable fashion. There is significant flexibility in the Corrective Action Plans allowed for any additional performance requirements which must be met. Industry consensus, through approval of the SAR, is that revision of the existing TPL standards is appropriate.

1 & 2. Industry consensus, through approval of the SAR, is that revision of the existing TPL standards is appropriate.

3A. The SDT and industry consensus, at this point in the development process, is that consolidation in a single standard is the best course of action. The SDT did not start out with a preconceived idea that there should only be one TPL standard. The SDT started the drafting process by reviewing all of the available

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documents. This included the existing TPL standards, the SAR, FERC Order 693, and other NERC documents. After reviewing this material, the SDT determined that the majority of the language in the individual standards was in all four of the standards. After much discussion, the SDT determined that the industry would be better served with a single standard instead of staying with four individual standards.

B. Please see the responses provided in questions 2 and 10.

C. The revised TPL-001-1 standard itself does not require construction of additional Facilities although that may be a consequence of application of the standard. Additional operating guides or changes in dispatch are other possible consequences. Footnotes 5 and 10 have been added that provide further clarification regarding interruption of Firm Transmission Service. FERC staff has been available to the SDT for consultation throughout the process.

Footnote 5 - When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed.

Footnote #10 – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.

D The SDT has removed Requirement R11 from the proposed standard and Requirement R2.1.4 has been included to help clarify the spare equipment strategy issue.

R2.1.4 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment.

E. Please see response to your comments on question 11.

F. FERC direction provided in Order 693, SDT expertise, and industry input are all being considered in development of the standard.

G. To meet industry concern as well as FERC Order 693, the SDT has added Requirement R 2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been removed from the draft.

R2.8 The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1.

H. The SDT is being responsive to FERC direction in paragraph 1796 and agrees that clarification regarding Non-Consequential Load Loss and Firm Transmission Service requirements is necessary. Table 1 specifies the specific events when Loss of Non-Consequential Load is allowed. Footnotes #5 & 10 have been added to the end of Table 1 to explain Firm Transmission Service requirements. Also, please see response to your comments on question 11.

I The SDT believes that the requirement to study Extreme Events in the existing TPL-004-0 must remain in this standard. The SDT has not expanded the number of Extreme Events that must be studied but rather gave examples of how the events may occur. The only significant change in the analysis of Extreme

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Events is the new requirement for the Transmission Planner or Planning Coordinator to evaluate whether there are cost effective ways to reduce the likelihood or the impact of a particular event and document those findings. The SDT believes that this is a very reasonable approach to ensuring that these major events, even with a small probability, are reviewed and prudent decisions are made. 4. The issues raised on NERC/FERC regulations are beyond the scope of the SDT. However, changes have been made to the 3rd draft of the standard to further clarify the SDT's position on curtailments and service to Loads. Also, Load curtailments are allowed if those customers have signed an Interruptible Load contract arrangement. **Footnote 5** - the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. 5. The SDT has made the following changes to address the concerns raised by you and others: 1) Added Header note 'e' to the table to show that System adjustments can be made following a single Contingency event, in preparation for the next event; 2) Added footnote 5 to address conditional firm issues, and 3) Added footnote 10 to address re-dispatching resources while continuing to serve firm Load. **Header note 'e' -** For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. **Footnote 5** - When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. 6. NERC is following the officially sanctioned standards development process with regard to this project just as it follows the process for all standards development work. This is an open, transparent process which has been approved by FERC. Any member of the public is free to participate and/or comment. State regulators are included in the process (Segment 9) and comments are welcome from them just as they are from any other segment of the public or industry. Comments are frequently received from state agencies during the lifetime of a project and two regulatory agencies did provide comments on the second posting. As for the comments on economics, it was not reckless but a statement of fact. However, costs are being considered as should be evident by the questions raised (Q12 thru Q14) in the second posting. The SDT is cognizant of the cost factors involved here and is taking them into consideration in its deliberations.		

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7. Revisions to definitions in the NERC Glossary of Terms must be approved in accordance with the standards process and issues with application to existing standards would be considered. In addition, each Regional Entity has the ability to establish its own unique definition of the BES. 8 The SDT has removed this differentiation in the Table such that AC and DC lines will be treated equally.		
Lafayette Utilities System	C — Definitely do not support the revised standard	Lafayette's single biggest concern is that the second draft version of TPL-001 imposes performance requirements that are less stringent than those imposed in the previous draft. As the SDT stated in its response to comments on Draft 1: ?The SDT modified the performance requirements relative to Non-Consequential Loss of Load and revised Tables 1 & 2 to add greater detail and provide for more situations where it is acceptable to lose Non-Consequential Load.? This ?watering down? of the standard appears to result from complaints about the costs that certain commenting parties claimed would be necessary to achieve compliance with the performance requirements set forth in Draft 1. This is evident from the SDT's statement in the foreword to the comments form for Draft 2 that the SDT has ?attempted to adjust and clarify the proposed requirements and performance in light of these initial comments,? and that the SDT needs additional information about cost and other compliance issues so that it can ?make more adjustments as appropriate.? Lafayette questions whether it is appropriate for the SDT to shape the performance standards to alleviate certain commenters? cost concerns. The SDT should be focused on developing performance requirements that are judged to be optimal from the standpoint of protecting reliability consistent with sound engineering and planning. Striking a balance between reliability and cost is a policy determination for which responsibility lies elsewhere than in the SDT. Claims that the standards would impose excessive costs are more properly addressed to FERC when the revised TPL-001 is filed for approval because Congress assigned to FERC the responsibility to make judgments of this sort. The SDT should not be ?adjusting? (that is, watering down) the performance requirements in response to transmission owner arguments about the costs of compliance. The dilution of the performance requirements is manifest in a number of elements contained in the proposed draft, including (but not limited to) the following: a) Table 1 (Steady State Performance) would permit the interruption of Firm Transmission Service and the loss of Non-Consequential Load in three P1 (Single Contingency) scenarios involving AC lines. In Order 693 (at paragraph 1794), however, FERC emphasized that loss of Non-Consequential Load in single contingency situations is not permissible. b) Adopting less stringent performance requirements for loss of elements below 300kV may be discriminatory. Most wholesale customer loads are served from delivery facilities that operate at voltages lower than 300kV. The outage of facilities operating at less than 300kV therefore may encompass 100% of a wholesale customer's load, while it is likely to impact a much smaller portion of the total load served by the owner of the affected transmission facilities. Therefore, adopting less stringent performance requirements for facilities operating at less than 300kV would impose a disproportionate burden on affected wholesale customers, as compared to the transmission owner. c) In addition to its potentially discriminatory effect, the notion of imposing difference performance standards based on operating voltage would incent transmission owners to scrimp on needed improvements to lower voltage facilities. Presumably, the distinction originates from a belief that outages on 300kV and lower facilities will have less impact on the

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		Bulk Electric System. As the August 2003 blackout demonstrated, however, disruptions on lower voltage circuits can cause real and reactive power flow fluctuations across, and eventual separation of, higher-voltage networks. d) Regarding the SDT's elimination of the requirement to re-test cases to ascertain the efficacy of additions included in a Corrective Action Plan (sub-requirement 2.7.2 in Draft 1), it is unclear why this requirement was deleted since very few commenters complained that it would be burdensome. It is hard to see how such a re-testing obligation would impose a significant burden, at least insofar as the steady state analysis is concerned. Eliminating the re-testing requirement seems likely to provide minimal savings, but could be important to verifying that appropriate Corrective Action Plan decisions are made.
Response: There are no intentions by the SDT to "water down" reliability. In fact the SDT has raised the bar in many places; e.g., above 300 kV requirements. Resources and expenditures versus adequate level of reliability are being given due consideration throughout the process and will ultimately be determined by the industry through the ballot process. a Table 1 does *not* permit the interruption of Firm Transmission Service or the loss of Non-Consequential Load in three P1 (Single Contingency) scenarios involving AC lines. b & c. The majority of the SDT believed the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated above 300 kV generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers where the energy is then delivered by other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. d. The retesting of the cases was deleted due to the SDT believing that this requirement was too burdensome; however, any utility may exceed the requirements listed and perform this retesting if they so desire.		
Arizona Public Service Co.	A —Generally support the revised standard	We generally agree with the Standard as presented so far, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard.
Compliance Elements Development Resource Pool (CEDRP)		With regard to Violation Severity Levels for this standard, the CEDRP doesn't believe the version that has be posted for comment can be commented on from a VSL perspective for two reasons 1) it does not have any measures listed and 2) there are so many "sub-requirements" the VSLs would be quite unmanageable, unless each sub-requirement is of equal importance to fulfilling the objective of the standard. Because there are no measures we can't achieve any insight into importance. The SDT may want to consider trimming the standard down to its most basic elements and providing the details (sub-requirements) in a reference document.

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Response: Measures, VSL's, and the Implementation plan will be addressed in the next draft of the standard.		
Ameren	C — Definitely do not support the revised standard	From an engineering perspective, the biggest concerns are the additional requirements, including prescribed sensitivity studies, associated with R2 for both steady-state and stability scenarios. We believe that we already cover the needs of our system with the existing NERC standards and Ameren Transmission Planning Criteria & Guidelines. The additional analyses proposed by the revised standard are not warranted and any upgrades indentified by the additional analyses will not provide any significant increase in system reliability. For 2008 compliance, Ameren performed the following steady-state contingency analyses on each of four near-term models and one long-term model:617 Category B single contingencies involving lines and transformers.30 Category B single contingencies involving generators 50 MW and above.1699 Category B single branch outages.135 Category C-1 bus faults. 260 Category C-2 breaker failures.112,575 Category C-3 double contingencies involving lines and transformers.18,510 Category C3 contingencies involving 617 lines and transformers and 30 generating units.73 Category C-5 double-circuit tower outages. For 2008 compliance, Ameren performed 496 stability scenarios of four near-term models and one long-term model: Assuming that we can acquire the qualified manpower, which is presently not available, we estimate that proposed new requirements will increase our compliance activity time by approximately 24 man-months or 2 man-years in a six-month window (January-June) to produce the same quality studies that we produce now. Consequently, we view these proposed additional study efforts as excessively burdensome. Further, we do not see how the additional study work and documentation required by the proposed standard will lead to any significant improvements in reliability. Additional comments: The question of expected Consequential Load Loss magnitude and duration, as specified in R3.3.2.1, is not germane to the reliability of the Bulk Electric System, and is a matter for Distribution Planners and local regulatory authority and is not needed in this reliability standard.
Response: The SDT has received many comments regarding the increased planning requirements to meet the proposed standard. The SDT has reviewed the study work required to comply with the proposed standard as compared to the existing TPL standards. The SDT believes that we have added some additional study work and asked a question about the additional man-hours required to complete any new analysis. However, after this review, the SDT still believes that the requirements for sensitivity studies must remain to document the selection of critical System conditions and study years used in assessing System conditions (see paragraph 1704 of Order 693) and that System conditions are as important as Contingencies in evaluating the performance of present and future Systems (paragraph 1705). The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus. The SDT is cognizant of the cost factors involved here and is taking them into consideration in its deliberations. To meet industry concern as well as FERC Order 693, the SDT has added Requirement R 2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.8. **R2.8** The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1.		

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City of Tallahassee, FL	C — Definitely do not support the revised standard	The requirement regarding non-interruption of firm transmission service in the steady state performance table for Category P1 events does not properly take into consideration the flexibility necessary for utilities with limited interconnections or interconnections with limited transfer capability. This flexibility, which currently exists in the TPL-001 standard (footnote b in the table), allows a utility to curtail firm transactions to prepare for the next contingency. As drafted, in the circumstance where the single element outage in Category P1 was a tie line, even if this line were critical to supporting the transaction (or were required to be in service by the terms of the power contract), interruption of firm service would be a violation of the proposed standard even though such interruption would be either required or appropriate to ensure the reliability of the bulk electric system. For utilities where tie line capacity is constrained or limited, this requirement for Category P1 will require substantial investment in duplicate facilities to ensure that firm transfers would not be interrupted, and the cost of that investment would likely not offer ratepayers a commensurate benefit (presuming such a duplicate facility could even be sited and permitted).For utilities with just a few large generating units (such as a small municipal utility), the requirements for Category P3 in Table 1 set a threshold for compliance that may not be achievable without substantial investment in additional/duplicate transmission facilities and possibly generating units. The concern relates to the restriction about limiting interruption of firm transmission service or non-consequential load following a G-1/N-1 event; the particular scenario is outlined in the bullets below:? Presume a utility with only two large units and some small gas turbines? Under P3, one of these large units is forced out of service? Reserves are called for and delivered along with replacement power using available import capability? Then presume that the N-1 outage in P3 is a major tie line that is critical to the support of the firm power imports? Under the proposed standard, the utility would be unable to curtail the firm purchase or shed any non-consequential load and remain compliant, even though there would be a significant generation/load imbalance & the appropriate response for the reliability of the grid in the region would be to interrupt the transaction and possibly shed load.The flexibility afforded in the existing TPL-001 standard would in fact allow the utility to respond to this event in a more appropriate way while avoiding a very expensive expansion/duplication of facilities (notwithstanding the considerable challenges that the utility would face for siting and permitting of the necessary facilities).
Response: The SDT has made clarifications regarding Firm Transmission Service and Non-Consequential Load Loss. Footnote # 10 has been added to the end of Table 1. The standard does not preclude the possibility of obtaining contractually interruptible load in lieu of system upgrades in the scenario described. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
Florida Power and Light	C — Definitely do not support the revised	The standard, as currently drafted, is unacceptable. Without the ability to curtail firm transfers to prepare for a next contingency, a "super-firm" priority of transmission service is created for non-native load customers. This goes contrary to the intent of the Open Access Transmission Tariff (OATT) that curtailments be comparable and non-discriminatory. – From

Organization	Question 15:	Question 15 Comments:
	standard	the OATT: – Curtailment of Firm Transmission Service: In the event that a Curtailment on the Transmission Provider's Transmission System, or a portion thereof, is required to maintain reliable operation of such system, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the Transmission Provider will curtail service to Network Customers and Transmission Customers taking Firm Point-To-Point Transmission Service on a basis comparable to the curtailment of service to the Transmission Provider's Native Load Customers. All Curtailments will be made on a non-discriminatory basis, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. When the Transmission Provider determines that an electrical emergency exists on its Transmission System and implements emergency procedures to Curtail Firm Transmission Service, the Transmission Customer shall make the required reductions upon request of the Transmission Provider. However, the Transmission Provider reserves the right to Curtail, in whole or in part, any Firm Transmission Service provided under the Tariff when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Transmission System. The Transmission Provider will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments. The SDT has drafted language contrary to FERC specific requirements on comparability. The FERC has consistently directed Transmission Providers to treat all firm transaction on a comparable basis, yet the SDT, in its latest draft is creating a "super-firm" category for only firm transmission service. By creating a higher priority ("super-firm", non-comparable service) for non-native load customers than for native load, native load customers bear a higher cost burden. This and the costs to the ratepayers for negligible increase in already high reliability due to the performance requirements of the standard makes this draft completely unacceptable for FPL to support. FPL will vote against acceptance of this draft standard unless significant changes are made to comport what FPL believes was the intent of FERC Order 693 with regard to the TPL standards.
Response: The SDT agrees that clarification regarding Firm Transmission Service and Non-Consequential Load Loss is necessary. Footnote # 10 has been added to the end of Table 1: **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
Exelon Transmission Planning	C — Definitely do not support the revised standard	We appreciate the effort involved in improving this planning standard, and believe in this goal. We are not yet able to support this revised at this time due to the concerns expressed above.

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Response: Thank you for your comments.		
CenterPoint Energy and CPS Energy	C — Definitely do not support the revised standard	Without re-iterating previous comments, we will summarize that we find this proposed standard to be an overly prescriptive and unrealistic paper chase that does not add value to the planning process. We also are concerned that this standard demonstrates an unhealthy, one sided approach to planning that does not balance reliability goals against other public policy goals, such as cost and landowner impact.
Austin Energy	C — Definitely do not support the revised standard	The proposed standard is overly burdensome and too prescriptive. It will only result in a marginal improvement in reliability and its primary effect will be to devolve into a paper-chase for auditors.
Response: The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus.		
SRP	B — Unsure about supporting the revised standard	SRP is concerned about what actions will be allowed to meet the higher performance requirements in the transition period and how long will these transition periods last for the different Requirements?
Response: The SDT has developed the Implementation Plan which is included in the 3rd draft of the standard.		
MidAmerican Energy Company	C — Definitely do not support the revised standard	MEC commends the SDT for significantly improving the standard, MEC believes that the standard still must be improved significantly. Probably the most important improvement would be to completely reformat the standard to provide for more organization and clearer VSLs. MEC recognizes that this may result in some initial confusion during the standard writing process, but if such organization results in less confusion over the next decade of applying the standard, the reorganization is well worth it. If the SDT does nothing else, it should reorganize the standard. Here are some suggestions for improvement: R1.1 is not clear. What does this mean? Surely the SDT does not expect that any time the data is modified a rationale is required. Shouldn't this data be updated as necessary? Wouldn't a requirement for providing a rationale each time such changes are made potentially discourage improvements to the models? This requirement should be clarified and limited to a few specific cases that were there are real reliability concerns R2.5.2 - the SDT should revise the material transmission system changes. Addition of a new substation in one of the transmission lines connected to the plant should be revised to specifically refer to a switching station or to a non-

Organization	Question 15:	Question 15 Comments:
		distribution substation. A substation directly serving load is not a good example of a material transmission system change in the context of Generation Unit Stability studies. R2.6.2 - The SDT should revise the material transmission system changes because as presently defined, studies will need to be conducted every year for every year in the assessment period. This is because apparently the SDT has defined any system change as a material change. Since it is rare for there to be a system that does not exhibit some system change from year to year, this will mean ten-year and more studies every year. MEC recommends that the SDT revise this requirement to make clear that only significant system changes are material changes. R2.7.1 - The SDT has written this requirement to include a requirement that the responsible entity must indicate how long Operating Procedures apply. This implies that Operating Procedures should be interim measures. MEC believes that reliability can be maintained with permanent Operating Procedures and recommends that the need to indicate "how long the Operating Procedures will be needed" be deleted from this requirement. R3.3.2.1 - The SDT should delete the need to provide the expected duration of the Consequential Load Loss in this requirement because this requirements a probabilistic calculation and probabilistic planning is not the state-of-the art of the industry. This is reflected in the standard which has been written to continue deterministic planning criteria. As a result, it is a contradiction to require this probabilistic quantity in the middle of this deterministic planning standard. R3.3.2.2 - clarify that the single contingency events are the events in the tab le. R3.4 and R5.4.4 - MEC urges that the SDT delete or revise the words "why the remaining Contingencies would produce less severe System results." Given the expansive nature of the Extreme events it is virtually impossible to comply with this requirement. It is more likely that the responsible entity could show that the more likely and more severe Extreme events were studied. It would be better yet if the SDT would merely require that the responsible entity provide the rationale for the selection of Extreme Events that were studied. R5.5.1 provides an exclusion for changes in individual generating units that require study. Yet R2.6.2 has a broader definition of when Generating Plant Stability is required. These definitions need to be consistent. The definition in R5.5.1 seems to narrow to be a good definition for "material changes." MEC believes that the R5.5.1 should be expanded. Year One definition - MEC suggests that the Standards Drafting Team's (SDT's) Year One definition unnecessarily constrains the time between the completion of assessments as compared to the study period to begin no more or no less than 12 to 18 months. There is no reliability benefits derived by constraining the period between the completion of an assessment and the study period for the next study period. In fact, this may encourage a Transmission Planner to unnecessarily delay "completing" a study just to ensure that the 12 to 18 month requirement is met. For example, lets assume that a Transmission Planner's 2008 Assessment is complete as of May 2008. By the definition of Year One, then the study period for the 2009 Assessment will need to begin from May 2009 through November 2009. This means that the 2009 Assessment must include the 2009-2010 Winter Peak and cannot start with the 2010 Calendar Year. Why??? If a Transmission Planner wants to have a study period that begins with the calendar year, then the Transmission Planner

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		would need to delay completing the study until July 2009. Why??? What is the reliability benefits for delay??? MidAmerican suggests that the definition of Year One be changed to allow the study period to begin no later than 24 months after the completion of the previous year's study.? Accountability: We suggest that Transmission Service Provider be added because we also suggest that the Transmission Service Provider be responsible for R10.? R2.1 - We suggest that this requirement involves too much study work and we ask that the SDT reduce the number of current studies needed for all subrequirements. ? R2.7.1 - We agree with the requirement, but suggest a slight text change replace "? or Special Protection Schemes,?" with " . . . or Special Protection Systems, . . ."? R2.7.1.1 - We disagree with the "include project initiation date" portion of this requirement. The initiation date is often uncertain and subject to change, which may add considerable work to investigate, monitor and update the date. In addition, we do not know why this information is required to assure BES reliability.? R3.3.2.1 - We agree with the requirement, but suggest a slight text change of: ". . . shall be allowed in the Planning Assessment".? R3.3.2.2 - We agree with the requirement, but suggest a slight text change of: ". . . within their Facility Ratings and within the time period allowed by the applicable time limited ratings.".? R5.4.3.1 - We agree with the requirement, but suggest a slight text change of: ". . . within their Facility Ratings and within the time period allowed by the applicable time limited ratings.".? Table 1? Planning Events ? Header: We suggest that the header be repeated on every applicable page to be more reader-friendly.? Superscripts: The superscripts do not refer clearly to the respective notes (e.g. there are number notes in the beginning of the table, in the extreme events evaluation requirements section, in extreme event description section, and at the end of the table). Perhaps the notes at the end of the table should have unique numbering to make the superscript references clearer.? Shunt device: To avoid the need for future interpretation or clarification, we suggest that the meaning of shunt device be explained or defined somewhere in the standard (e.g. cap bank, inductor bank, SVC, STATCOM, etc.). We need to find out how shunt device outages can (or could in the future) be automatically included in the ACCC routine. We interpret that if each stage of a capacitor bank has a circuit switcher, then the outage would be of the largest cap bank stage.? Extreme Event Evaluation Requirements? 3 Extreme Event Descriptions? 2b & 3b - We agree with the descriptions, but suggest referring to the defined term: "Right-of-Way."?

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		Note 4 - We agree with the description, but the acronym FACTS should be explained in the standard or a definition be added for "FACTS". Table 2 Header: We suggest that the header be repeated on every applicable page to be more reader-friendly. Other numbering and format changes suggested for Table 1 should also be considered for Table 2.

Response: A. The SDT agrees and has removed the need for documentation of the technical rationale for modification of any data.

B Requirement R2.5 and its sub-requirements have been removed from the proposed standard. Guidelines for the use of past studies to support the Planning Assessment have been added to what is now Requirement R2.5.2. The SDT did not want to be overly prescriptive when describing the type of changes that could be considered material and has left the text general. It is up to the Transmission Planner and Planning Coordinator to provide specificity as to what type of topology changes constitutes a change sufficient to warrant re-evaluation.

R2.5.2 For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:

C The SDT does not agree that studies are required for every year of the Assessment period. However, please note that Requirement R2.5 and its sub-requirements have been removed from the proposed standard. Guidelines for the use of past studies to support the Planning Assessment have been added to what is now Requirement R2.5.2. The SDT did not want to be overly prescriptive when describing the type of changes that could be considered material and has left the text general. It is up to the Transmission Planner and Planning Coordinator to provide specificity as to what type of topology changes constitutes a change sufficient to warrant re-evaluation.

D The SDT has retained this requirement and believes that this information should be included in the Planning Assessment.

E To meet industry concern as well as FERC Order 693, the SDT has added Requirement R 2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been removed from the draft.

R2.8 The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1.

F The SDT has deleted Requirement R3.3.2 and has replaced it with additional language in Requirement R3.1 which will hopefully clarify things.

R3.1 Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 ~~– Steady State Performance.~~ based on the lists created in Requirement R3.4.

G. The SDT disagrees with your comment. The SDT believes that this language is needed to ensure that the worst possible situation is studied based on engineering judgment and knowledge of the System.

H. To address industry comments such as yours, Generating Unit Stability is no longer explicitly addressed in the standard and the definitions of Consequential and Non-Consequential Load Loss have been modified.

Consequential Load Loss: ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's~~

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~~response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions.

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~.

I. The SDT has changed the definition for Year One to accommodate industry concerns.

Year One: The first year that a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the ~~completion of the previous annual Planning Assessment~~ current calendar year.

In response to industry comments, the SDT has removed Requirements R9-R14.

R2.1 – The SDT has received many comments regarding the increased planning requirements to meet the proposed standard. However, the SDT believes that the requirements for sensitivity studies must remain to satisfy FERC Order 693. FERC has stated that the sensitivity studies would be used to document the selection of critical System conditions and study years used in assessing System conditions (see paragraph 1704) and that System conditions are as important as Contingencies in evaluating the performance of present and future Systems (paragraph 1705).

R2.7.1 (now R2.6.1) – The SDT agrees and had replaced "schemes" with "systems".

Installation or modification of Protection Systems or Special Protection Systems

R2.7.1.1 (now R2.6.2) - The SDT believes that a project initiation date is an effective measure to track a functional entity's planning and engineering activities and its efforts to provide and maintain a reliable BES.

R3.3.2.1 - To meet industry concern as well as FERC Order 693, the SDT has added Requirement R 2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.8.

R3.3.2.2 - Based on your comment, the SDT has addressed the applicable time-limited rating in what was Header note 'a' for Steady State Only in Table 1 - Steady State & Stability Performance. Requirement R3.3.2.2 has been deleted in favor of Header note 'e' in the revised Table. Please note that the two tables in the second draft have been reduced to one table in the third draft.

Header note 'e' - For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

R5.4.3.1 - The SDT has deleted Requirement R5.4.3.1.

Headers - The SDT also feels that the Tables need to be as clear and concise as possible. To that end, Tables 1 and 2 have been combined into one table with

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a revised format. The Planning Events are shown on one page so repeating the headings will not be needed. Superscripts – As part of the change to a single table, the SDT has attempted to clean up various items such as superscripts. Shunt device - The SDT believes that shunt devices are commonly used in the electric utility industry and does not require any further explanation. The SDT recommends contacting the software manufacturer for additional information about the ACCC routine. The SDT believes that the cap bank outage would be based on what elements would need to trip in order to clear the simulated fault condition. Extreme Events - The SDT agrees with your comments and has made the change. The SDT has removed item 3.b. from Extreme Events since this was already covered in Extreme Event 1. **Extreme Event 2b -** Loss of all Transmission lines on a common ~~r~~Right-of-~~w~~Way. Note 4 - The SDT believes that "FACTS" is commonly used in the electric utility industry and does not require any further explanation.		
SERC Dynamics Review Subcommittee	B — Unsure about supporting the revised standard	SERC is in category BA ? Generally support the revised standard ? B ? Unsure about supporting the revised standard ? See three specific concerns below C ? Definitely do not support the revised standard ? 1) Load Modeling is a significant open issue. The models for dynamic studies have yet to be developed and the data is not in hand. This is conflicting with implementation of the TPL standards because modeling details are a gating item to completing some system studies. 2) The proposed sensitivities create significant amount of additional work making the compliance aspect more burdensome and less clear. 3) Category P6 is the loss of a system element, following system adjustments, followed by the loss of another element. The table columns for this category say that interruption of firm transmission service is allowed. The table, however, is not clear whether the interruption of firm service is allowed as part of the system adjustment (between the outages) or whether it is only allowed after the second outage. It was stated in the NERC TPL SDT WebEx that the interruption is not allowed as part of the system adjustment. If this is the interpretation, this will cause many SERC members to not support the revised standard. This would be a dramatic change from the existing standard and would result in the unintended consequence of significantly reducing transfer capability of interfaces to a fraction of their currently reported capability. This would in effect be imposing an n-2 criteria for offering firm transmission service. This would not be an acceptable situation for the users, owners and operators of the bulk power system.
Response: 1. The SDT agrees and believes that industry guidance is needed to capture the appropriate dynamic behavior of Loads. In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments. Any comments received from the industry on MOD standards will be forwarded to NERC for inclusion into NERC Reliability Standards Development Projects 2010-04, Modeling Data and 2010-05, Demand Data. Requirement R2.4.1 has been modified		

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to clarify expectations regarding load modeling for dynamics studies. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations. **R2.4.1** System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. 2. The intent of the SDT in requiring performance of sensitivity studies is to identify critical System conditions and to expand planners' portfolio of knowledge about vulnerabilities on their System. This is also an expectation from FERC Order 693 paragraphs 1704 - 1706. Requirement R2.1.3 has been reworded to account for sensitivity studies already performed by the planner. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: 3. The SDT agrees that clarification regarding treatment of Firm Transmission Service and Non-Consequential Load Loss during adjustment is necessary. Footnote 10 in the Revision 3 of the Standard provides clarification. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
MRO NERC Standards Review Subcommittee	C — Definitely do not support the revised standard	While the MRO commends the SDT for significantly improving the standard, the MRO believes that the standard still must be improved significantly. Here are some suggestions for improvement: a. R1.1 is not clear. What does this mean? Surely the SDT does not expect that any time the data is modified a rationale is required. Shouldn't this data be updated as necessary? Wouldn't a requirement for providing a rationale each time such changes are made potentially discourage improvements to the models? This requirement should be clarified and limited to a few specific cases that were there are real reliability concerns. b. R2.5.2 - the SDT should revise the material transmission system changes. Addition of a new substation in one of the transmission lines connected to the plant should be revised to specifically refer to a switching station or to a non-distribution substation. A substation directly serving load is not a good example of a material transmission system change in the context of Generation Unit Stability studies. c. R2.6.2 - The SDT should revise the material transmission system changes because as presently defined, studies will

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		need to be conducted every year for every year in the assessment period. This is because apparently the SDT has defined any system change as a material change. Since it is rare for there to be a system that does not exhibit some system change from year to year, this will mean ten-year and more studies every year. The MRO recommends that the SDT revise this requirement to make clear that only significant system changes are material changes. d. R2.7.1 - The SDT has written this requirement to include a requirement that the responsible entity must indicate how long Operating Procedures apply. This implies that Operating Procedures should be interim measures. The MRO believes that reliability can be maintained with permanent Operating Procedures and recommends that the need to indicate "how long the Operating Procedures will be needed" be deleted from this requirement. e. R3.3.2.1 - The SDT should delete the need to provide the expected duration of the Consequential Load Loss in this requirement because this requirements a probabilistic calculation and probabilistic planning is not the state-of-the art of the industry. This is reflected in the standard which has been written to continue deterministic planning criteria. As a result, it is a contradiction to require this probabilistic quantity in the middle of this deterministic planning standard. f. R3.3.2.2 - clarify that the single contingency events are the events in the table. g. R3.4 and R5.4.4 - the MRO urges that the SDT delete or revise the words "why the remaining Contingencies would produce less severe System results." Given the expansive nature of the Extreme events it is virtually impossible to comply with this requirement. It is more likely that the responsible entity could show that the more likely and more severe Extreme events were studied. It would be better yet if the SDT would merely require that the responsible entity provide the rationale for the selection of Extreme Events that were studied. h. R5.5.1 provides an exclusion for changes in individual generating units that require study. Yet R2.6.2 has a broader definition of when Generating Plant Stability is required. These definitions need to be consistent. The definition in R5.5.1 seems to narrow to be a good definition for "material changes." The MRO believes that the R5.5.1 should be expanded. i. Year One definition - The MRO suggests that the Standards Drafting Team's (SDT's) Year One definition unnecessarily constrains the time between the completion of assessments as compared to the study period to begin no more or no less than 12 to 18 months. There are no reliability benefits derived by constraining the period between the completion of an assessment and the study period for the next study period. In fact, this may encourage a Transmission Planner to unnecessarily delay "completing" a study just to ensure that the 12 to 18 month requirement is met. For example, let's assume that a Transmission Planner's 2008 Assessment is complete as of May 2008. By the definition of Year One, then the study period for the 2009 Assessment will need to begin from May 2009 through November 2009. This means that the 2009 Assessment must include the 2009-2010 Winter Peak and cannot start with the 2010 Calendar Year. Why? If a Transmission Planner wants to have a study period that begins with the calendar year, then the Transmission Planner would need to delay completing the study until July 2009. Why? What are the reliability benefits for delay? The MRO suggests that the definition of Year One be changed to allow the study period to begin no later than 24 months after the completion of the previous year's study.? Definitions: The MRO agrees with the removal of the "Base Case" definition and

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		the revisions to the other definitions, except as noted below or elsewhere.? Long Term Planning Horizon definition: The MRO suggests a slight text change of: "Transmission planning period that covers years six through ten. Studies beyond ten years are required to accommodate . . .".? Accountability: The MRO suggests that Transmission Service Provider be added because we also suggest that the Transmission Service Provider be responsible for R10.? Requirements: The MRO agrees with the revisions to the Requirements, except as noted below or elsewhere.? R1.1 - The MRO agrees with the requirement, but would like more description of what to provide in the technical rationale.? R2.1 - The MRO suggests that this requirement involves too much study work and we ask that the SDT reduce the number of current studies needed for all subrequirements. ? R2.6.2 - The MRO agrees with the requirement, but suggest a slight text change of: " . . . short circuit, Generating Unit Stability or System Stability analysis . . .".? R2.7 - The MRO agrees with the requirement, as long as it is really required by FERC Order 693 paragraph 1704.? R2.7.1 - The MRO agrees with the requirement, but suggest a slight text change replace "? or Special Protection Schemes,?" with " . . . or Special Protection Systems, . . ."? R2.7.1.1 - The MRO disagrees with the "include project initiation date" portion of this requirement. The initiation date is often uncertain and subject to change, which may add considerable work to investigate, monitor and update the date. In addition, we do not know why this information is required to assure BES reliability.? R2.7.2 - The MRO agrees with the requirement, as long as it is really required by FERC Order 693 paragraph 1704.? R3.2.2 - The MRO agrees with the requirement, but suggest a slight text change of: "For all BES Transmission lines . . .". ? R3.3.2.1 - The MRO agrees with the requirement, but suggest a slight text change of: ". . . shall be allowed in the Planning Assessment".? R3.3.2.2 - The MRO agrees with the requirement, but suggest a slight text change of: ". . . within their Facility Ratings and within the time period allowed by the applicable time limited ratings.".? R5.1 - The MRO agrees with the requirement, but suggest a slight text change of: ". . . the response of the applicable portion of the BES".? R5.2 - This clarifying requirement should also be included in the steady state and short circuit analysis sections.? R5.3 - The MRO agrees with the requirement, but suggest a slight text change of: ". . . capability of all generators that may have a significant adverse effect on the BES."?

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		R5.4.3.1 - The MRO agrees with the requirement, but suggest a slight text change of: ". . . within their Facility Ratings and within the time period allowed by the applicable time limited ratings.".? R6 - The MRO agrees with the requirement, but suggest a slight text change of: ". . . shall provide the rationale for and document . . .".? R8 - The MRO disagrees with the requirement, but suggest a text change of: "Each Planning Coordinator shall establish a list of neighboring system and coordinate the distribution of Planning Assessment results among affected entities the listed neighboring systems, coordinating analysis of these results through an open and transparent peer review process."? Table 1? Planning Events ? Header: The MRO suggests that the header be repeated on every applicable page to be more reader-friendly.? Superscripts: The superscripts do not refer clearly to the respective notes (e.g. there are number notes in the beginning of the table, in the extreme events evaluation requirements section, in extreme event description section, and at the end of the table). Perhaps the notes at the end of the table should have unique numbering to make the superscript references clearer.? Shunt device: To avoid the need for future interpretation or clarification, we suggest that the meaning of shunt device be explained or defined somewhere in the standard (e.g. cap bank, inductor bank, SVC, STATCOM, etc.). We need to find out how shunt device outages can (or could in the future) be automatically included in the ACCC routine. We interpret that if each stage of a capacitor bank has a circuit switcher, then the outage would be of the largest cap bank stage.? P2.2 (>300 kV), P2.3(>300 kV), P3 (>300 kV), P4 (>300 kV), P5 (>300 kV), P6 (>300 kV) - This requirement is raising the bar above the existing standards. In the existing standards, this is a Category C event in which load shedding was allowed. A higher criteria for >300 kV may not be appropriate at this time. The new requirement may require the installation of facilities that are costly and have a very long implementation timeframe. We should consider what the cost of this higher requirement might be for ATC and other utilities. If the new >300 kV requirement is not reduced, then we would want the implementation timeframe to be long enough to allow reasonable time to transition from a system built to the old requirement to a system built for the new requirement. The time needed for planning, design engineering, regulatory approvals, and construction of >300 kV facilities can be very long (e.g. up to 10 or more years).? P6 - Why isn't the generator listed as a one of the possible subsequent element outages?? P7 - The MRO disagrees with this requirement. Wisconsin statues require giving preference to using existing ROW for new transmission circuits, but this requirement discourages building multiple circuits on common ROW. Should there be an exclusion in this standard similar to the TLP-503-MRO-1 standard (e.g. could be slightly more than 1 mile due to review?.? Extreme Event Evaluation Requirements? 2 - The MRO agrees with the requirement, but perhaps a definition be added for "System Controls", since one exists for "System Protection".?

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		3 - The MRO agrees with the requirement, but suggest a slight text change of: "Simulate Normal Clearing unless otherwise specified in the Extreme Event Descriptions."? Extreme Event Descriptions? 2a - The MRO agrees with the description, but suggest a slight text change of: "Loss of a structure or tower line with three or more circuits.."? 2b & 3b - The MRO agrees with the descriptions, but suggest referring to the defined term: "Right-of-Way."? 2e, 3.a.i, & 3.a.ii - The MRO agrees with the descriptions, but how large is "large" and how major is "major"?? 3.a.v - What is meant by successful cyber attack? Is it a type of cyber attack that is documented to have been successful? ? 3c - The MRO agrees with the description, but suggest a slight text change of: "Other events based upon actual operating experience such as:" ? Note 4 - The MRO agrees with the description, but the acronym FACTS should be explained in the standard or a definition be added for "FACTS".? Table 2? 1 - The MRO disagrees with this note. We suggest that it be expanded to include the applicable part as Table 1. "The System shall remain stable. In addition, Facility Equipment Ratings shall not be exceeded. Planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings."? 3 - The MRO disagrees with this note. We suggest that it be expanded to include the applicable part as Table 1. "Dynamic voltage instability, Cascading outages, and uncontrolled islanding shall not occur."? Between 3 & 4 - The MRO disagrees with omitting Note 4 of Table 1 from Table 2. We suggest including: "Consequential Load and consequential generation loss is allowed for all events shown."? Planning Events? Same comments on Header, Superscripts, and Shunt Device as in Table 1.? Same comments about stricter requirements for P2.2 (>300 kV), P2.3(>300 kV), P3 (>300 kV), P4 (>300 kV), P5 (>300 kV), P6 (>300 kV) as in Table 1.? Same comment about P7 as in Table 1.? Extreme Event Evaluation Requirements? Same comment about Requirement 2 and 3 as in Table 1.? 3 - The MRO agrees with the requirement, but suggest a slight text change of: "Simulate Normal Clearing unless otherwise specified in the Extreme Event Descriptions."?

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		Notes5 - The MRO disagrees with limiting this requirement to just Category P1 category. We suggest that the synchronism requirement be applied to more categories.

Response: A. The SDT agrees and has removed the need for documentation of the technical rationale for modification of any data.

B Requirement R2.5 and its sub-requirements have been removed from the proposed standard. Guidelines for the use of past studies to support the Planning Assessment have been added to Requirement R2.6.2 (now R2.5.2). The SDT did not want to be overly prescriptive when describing the type of changes that could be considered material and has left the text general. It is up to the Transmission Planner and Planning Coordinator to provide specificity as to what type of topology changes constitutes a change sufficient to warrant re-evaluation.

R2.5.2 For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:

C The SDT does not agree that studies are required for every year of the Assessment period. However, please note that Requirement R2.5 and its sub-requirements have been removed from the proposed standard. Guidelines for the use of past studies to support the Planning Assessment have been added to what is now Requirement R2.5.2. The SDT did not want to be overly prescriptive when describing the type of changes that could be considered material and has left the text general. It is up to the Transmission Planner and Planning Coordinator to provide specificity as to what type of topology changes constitutes a change sufficient to warrant re-evaluation.

D The SDT has retained this requirement and believes that this information should be included in the Planning Assessment.

E To meet industry concern as well as FERC Order 693, the SDT has added Requirement R 2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been removed from the draft.

R2.8 The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1.

F The SDT has deleted Requirement R3.3.2 and has replaced it with additional language in Requirement R3.1 while adding Header note 'e' and deleting the reference to single Contingencies which will hopefully clarify things.

R3.1 Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 ~~– Steady State Performance.~~ based on the lists created in Requirement R3.4.

Header note 'e' - For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

G. The SDT disagrees with your comment. The SDT believes that this language is needed to ensure that the worst possible situation is studied based on engineering judgment and knowledge of the System.

H. To address industry comments such as yours, Generating Unit Stability is no longer explicitly addressed in the standard and the definitions of Consequential

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and Non-Consequential Load Loss have been modified.

Consequential Load Loss: ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions.

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~.

I. The SDT has changed the definition for Year One to accommodate industry concerns.

Year One: The first year that a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the ~~completion of the previous annual Planning Assessment~~ current calendar year.

Accountability - In response to industry comments, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R1.1 – The SDT agrees and has removed the need for documentation of the technical rationale for modification of any data.

R2.1 – The SDT has received many comments regarding the increased planning requirements to meet the proposed standard. However, the SDT believes that the requirements for sensitivity studies must remain to satisfy FERC Order 693. FERC has stated that the sensitivity studies would be used to document the selection of critical System conditions and study years used in assessing System conditions (see paragraph 1704) and that System conditions are as important as Contingencies in evaluating the performance of present and future Systems (paragraph 1705).

R2.6.2 – Based on comments from others, the SDT has removed the requirements for separate Generating Unit Stability analysis and System Stability analysis.

R2.7.1 (now R2.6.1) – The SDT agrees and had replaced "schemes" with "systems".

Installation or modification of Protection Systems or Special Protection Systems

R2.7.1.1 (now 2.6.2) - The SDT believes that a project initiation date is an effective measure to track a functional entities' planning and engineering activities and their efforts to provide and maintain a reliable BES.

R2.7.2 – The old Requirement R2.7.2 has been deleted.

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R3.2.2 – The Purpose section of the Standard states that this Standard is to develop requirements for the Bulk Electric System, BES.

R3.3.2.1 - To meet industry concern as well as FERC Order 693, the SDT has added Requirement R 2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.8.

R3.3.2.2 - Based on your comment, the SDT has addressed the applicable time-limited rating in what was Header note 'a' for Steady State Only in Table 1 - Steady State & Stability Performance. Requirement R3.3.2.2 has been deleted in favor of Header note 'e' in the revised Table. Please note that the two tables in the second draft have been reduced to one table in the third draft.

Header note 'e' - For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

R5.1 & R5.2 (now R4.1 and R4.2) – Most of the industry did not have difficulty understanding that the analysis is limited to the Transmission Planner's or Planning Coordinator's portion of the BES. Therefore, the SDT is not persuaded by your comment to add extra wording.

R5.3 (now R4.3) – The SDT disagrees with the suggested change due to the additional studies that would be required to determine which generators would have an adverse impact.

R5.4.3.1 - The SDT has deleted Requirement R5.4.3.1.

R6 – The SDT believes "define and document" as written are more appropriate than "rationale for and document". The SDT did not revise Requirement R6 (now R5) as proposed – but did make other modifications to this requirement based on other stakeholder comments..

R8 – The SDT has clarified this in a revised Requirement R7.

R7 Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~neighboring systems~~ adjacent Planning Coordinators and any functional entity who has indicated a reliability need, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890.

Headers - The SDT also feels that the Tables need to be as clear and concise as possible. To that end, Tables 1 and 2 have been combined into one table with a revised format. The headings are repeated on subsequent pages.

Superscripts – As part of the change to a single table, the SDT has attempted to clean up various items such as superscripts.

Shunt device - The SDT believes that shunt devices are commonly used in the electric utility industry and does not require any further explanation. The SDT recommends contacting the software manufacturer for additional information about the ACCC routine. The SDT believes that the cap bank outage would be based on what elements would need to trip in order to clear the simulated fault condition.

P2.2 – The majority of the SDT believed the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated above 300 kV generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers where the energy is then delivered by other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC

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and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. The Implementation Plan will address any need for transition and will be included in the next revision. P6 – This is already covered in P3. P7 – The SDT is cognizant of the concerns surrounding the construction of new Transmission lines, including the desire by many to fully utilize existing Right-of-Ways. In its consideration of Footnote 12 (exclusion for common structures less than 1 mile), the SDT considered the impact that this requirement could have on construction of new Facilities. However, after deliberations the SDT believes that the 1 mile exclusion should be maintained for the reliability of the BES and that individual exceptions can be addressed within the NERC process. Extreme Events 2 - The SDT agrees that "Protection System" is defined in the Glossary of Terms Used In Reliability Standards. However, the SDT believes that these "System Control" issues should be addressed by the NERC SPCTF drafting team. Extreme Events 3 – The SDT has already included "For all Extreme Events Evaluated" at the beginning of the Evaluation Requirements under Extreme Events. Extreme Events 2a – The SDT believes that the Extreme Events #2.a. is already sufficient. Extreme Events 2b & 3b - The SDT agrees with your comments and has made the change. The SDT has removed item 3.b. from Extreme Events since this was already covered in Extreme Event 1. **Extreme Event 2b -** Loss of all Transmission lines on a common ~~r~~Right-of-~~w~~Way. Extreme Event 2e – The SDT suggests that the terms "large", "major", and "successful" be defined between the TP and PC. Extreme Event 3a – A successful cyber attack would be any attack where an unauthorized person gained access to the systems described in the event. Extreme Event 3c – The SDT believes that the wording of 3b (was 3c) is already sufficient. Note 4 - The SDT believes that "FACTS" is commonly used in the electric utility industry and does not require any further explanation. Tables 2 – As part of the 3rd draft of the revised standard, the 2 tables have been merged into a single table and a general clean-up of the text has been made. Table 2, note 1 – The SDT has reviewed your comment and feels that your request to add "Facility Equipment Ratings shall not be exceeded. Planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings." apply to Stability is not appropriate. For the purposes of this standard, Facility Equipment ratings refer to steady state calculated values and planned System adjustments refer to the time frame associated with returning the thermal flow within the applicable steady state Facility Rating. Table 2, note 3 – The SDT agrees with your comment on making general note 3, located at the beginning of Table 1, "Voltage instability, cascading outages, and uncontrolled islanding shall not occur" applicable to both Steady State and Stability and has made that change in the next version. Note 4 – The SDT also agrees that the general note 4, at the beginning of Table 1, applicable to both Steady State and Stability and has made that change in the next version.		

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Note 3 – The SDT has already included "For all Extreme Events Evaluated" at the beginning of the Evaluation Requirements under Extreme Events. Note 5 – The SDT also feels that the synchronism requirement should apply to more than just the P1 Category but under certain conditions. As stated in Note 1.a.ii, for planning events other than P1, no generating unit or units totaling more than the Contingency reserve of the Balancing Authority shall be allowed to pull out of synchronism. If less than the Contingency reserve, then the resulting apparent impedance swings must not pass through relay characteristics that would result in the tripping of any Transmission System elements other than the generating unit and its direct connection Facilities		
Modesto Irrigation District	B — Unsure about supporting the revised standard	Concerns about the following: attempt to introduce interconnection stability studies into TPL studies, and redefinition of Consequential and Non-Consequential Load Loss.
Response: The SDT believes that there is no significant distinction between generator and System Stability and has modified the definitions and Requirements R2, R2.6.1 (now R2.5.1), R2.6.2 (now R2.5.2), R5 (now R4), and R5.5 (now R4.4) in the third draft. **R2** Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses ~~including both System and Generating Unit Stability~~. **R2.5.1** For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less. **R2.5.2** For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: **R4.** For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~ **R4.4** ~~At a minimum, t~~Those Planning Event Contingencies in Table ~~2~~1 – ~~Stability Performance~~ that ~~would~~are expected to produce more severe System impacts shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information with an explanation of why the remaining Contingencies would produce less severe System results. In response to numerous concerns, the following changes were made to the draft standard regarding Consequential and Non-Consequential Load Loss		

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definitions. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~.~~ ~~For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~.		
Arkansas Electric Coop. Corp.	B — Unsure about supporting the revised standard	I have a growing concern that the NERC Reliability Standards are not going far enough to ensure adequate and reliable service to customers and users of the BES. Each revision of the standards seem to be driven by the need to preserve the integrity of the grid and preventing cascading blackouts but stop short of ensuring that load continues to be served under contingency conditions and adequate grid capacity is available. For the customers and end users of the system if their load is allowed to be dropped or can not be served because of the lack of capacity then the BES is not reliable. The definitions of Consequential Load Loss and Non-Consequential Load Loss concern me the most. How these definitions are then applied in the tables is also a great concern. Hopefully my previous comments to the other questions in the comment form provide explanation. Another concern I have is the fact that I tried to provide comments last fall to draft 1 of the standards and they were not allowed. After following the instructions provided I provided my comments before the deadline. I later discovered they were not posted. After repeated attempts asking NERC to determine why my comments were not received and posted and showing evidence that they had been provided by the deadline, the only response I received was pretty much "sorry Charlie". Mistakes happen. NERC should be big enough to admit when they make a mistake instead of just blowing them off. I have no way of knowing if or how many times this may have happened before. I am not trying to say that anything malicious was intended, however it does leaves me with concern that fair treatment is being given to all comments and cast a shadow over confidence in the standards approval process.
Response: The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus. The SDT believes that your concerns are mostly addressed by the revised Table 1 - Steady State and Stability Performance, along with the revised definitions of Non-Consequential Load Loss and Consequential Load Loss in the updated draft of TPL-001 standard. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed,~~		

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~~Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. Comments from AECI were included in the responses to the comments from the first posting. Please go back and review the posted comment form.		
Midwest ISO	C — Definitely do not support the revised standard	We appreciate the hard work of the SDT and understand the difficulty of this task. We applaud the efforts to improve the standard. However, in its present state, in general the revised standard fails in one if its primary stated goals: create a "clear and concise standard". While some of the ideas are an improvement, overall the standard is very meandering and it makes it difficult to figure out what the requirements are for a particular analysis type without flipping back and forth between the scattered requirements. For example R2 addresses various aspects of both Near and long term studies, steady state, short circuit, stability, on peak, off peak and other topics. Then there are separate sections (R3, 4, 5) that speak to the various analysis types again. It probably makes sense to the SDT that has evolved with the drafts and discussions, but when you pick it up it is very confusing. One thing that would help greatly would be to label the major Requirements sections to convey the organization of the document. If the SDT made a topical outline of the standard by major Requirement this could help the team organize the standard better. Resulting topical headers may look something like the following for example, R1: ModelingR2: Study Types and Assessment RequirementsR3: Steady State Analysis MethodsR4: Short Circuit Analysis Methods?R5: Stability Analysis Methods Etc. If it has not been done (and it looks like it has not), the SDT should consider having the language reviewed by the NERC or other legal team. Language that seems clear to experienced engineers may not be precise as is critical for standards that carry monetary penalties. An independent review by a non-engineer lawyer would help greatly. Of course, the SDT would then have to undo some damage that would undoubtedly be done to context by the lawyers - but the pass through legal would be a good step.? ? Other concerns:? P5 requires testing for a single component failure within a Protection System. What is this referencing? How can a PC/TP be expected to be intricately aware of protection systems and effects of single component failures? Under 2.7.2, there is a generic requirement to expand a list of possible corrective actions under 2.7.1 for any sensitivities under R2.1.3, 2.1.4, 2.4.3 and 2.4.4. This is very open ended and subject to interpretation. How can an auditor review such requirements with consistency?
Response: The SDT has attempted to make the latest draft more clear and concise - such as condensing Table 1 and 2 into a single table. The SDT has considered having headers/labels in the document and these are strongly discouraged by NERC's legal staff. The overall format of the tables has been modified to make it more reader friendly. NERC is following the officially sanctioned standards development process with regard to this project just as it follows the process for all standards development		

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work. This is an open, transparent process which has been approved by FERC. Review and comment by any entity's legal staff is welcome, but not a required part of the process. The description of the P5 event has been clarified in draft 3 to address your concern. Requirement R2.7.2 has been removed. The SDT has modified Requirement R2.7 (now R2.6) to clarify that Correction Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3 and R2.4.3. **R2.6** For Planning Events shown in Table 1~~ – Steady State Performance and Table 2 – Stability Performance~~, when the analysis indicates an inability of the System to meet the performance requirements in ~~the t~~Table~~s~~ 1, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed in subsequent assessments but the System shall continue to meet the performance requirements in the tables. Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3 and R2.4.3. The Corrective Action Plan shall:		
Tri-State Generation and Transmission Association, Inc.	A — Generally support the revised standard	We appreciate the efforts of the SDT, considering the difficulty of the task that was and is before them. Our biggest concern is potential confusion regarding sensitivity studies. Secondly, we absolutely must make the Performance Table completely clear and concise. Additional work now will pay big dividends later. Thirdly, there is some ambiguity of several terms used in the Standard that prevents exact interpretation of significant portions of the Standard. Here are a few additional comments we hope the SDT will find helpful: It may simplify considerations of assessments and modeling work to define ?assessment? as including written documentation. Then the Standard would not need to separately include "and shall include written documentation" in the body of the standard titles. Also, the SDT should make it clear that "assessment" is what is required; that annual re-study analysis may not necessarily be required. Thanks to the SDT for keeping this feature. It will greatly simplify our work, and should speed the audit process as well. There seems to be some ambiguity between either 1) requiring specific years to be studied and 2) leaving timeframe selection to the TP. Assessment for year One or Two (R2.1.1) may be performed by either the TOP or the TP. Studies of year One or year Two are generally considered to be operating studies and should probably not be required in TPL-001-1. Also in R2.1.1, year Five is specified as a required study year. No matter what the requirement says, the TP will need to assess performance for critical timeframes. This would lead to additional study if year four were the critical year for example. And for sensitivity studies of delayed facilities (R2.1.3.3) additional study years might be required. Perhaps a reasonable compromise would be to require something in the 2 to 5-year timeframe, and something in the 6 to 10-year timeframe. For coordination with regional study groups in our area, one would logically choose year 5 and year 10, but the specific choice should be up to the TP (and PC if any). Sole-Customers on radial service who are responsible for facility upgrades should be allowed to elect a lower reliability

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		than the rest of the system. It seems that operating scenarios required to be studied by TOP should not need study in the planning horizon by the TP, and should be excluded from this standard. Specific comments concerning other sections of the draft standard: 1. In the definition of Generating Stability Study, we suggest "the lack of damping" be changed to "damping" 2. In R2.1 title, please move listed requirements in the second sentence to sub-requirements (they are already there). 3. In R2.1 title sentence, the term "annual current" presents two additional requirements. We suggest those words be deleted. 4. In R2.1, delete the end of the title sentence, ending the sentence with "the following studies" 5. In R2.1.3.2, the meaning of "transfer" is not clear. 6. In R2.1.3.4, the term "variability" is not clear. do you mean "Operating Capability"? 7. In R2.1, R2.2 and 2.4, the phrase "Near Term (or Long Term) Transmission Planning Horizon portion of the" could be omitted. "Near Term" and "Long Term" study horizons should just be specified as sub-requirements of Steady State, Stability, and Short Circuit 8. In R2.7.3, the term "identified System Facilities" is not clear. System Additions? 9. Heading R3.3 is not needed. Renumber section sub headings to 3.2.3, etc.

Response: In response to industry comments regarding sensitivity studies, the SDT has made changes to Requirements R2.1.3 and R2.4.3 and each of their sub-requirements to clarify expectations related to sensitivity studies.

R2.1.3 For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

The SDT also feels that the Tables need to be as clear and concise as possible. To that end, the next version will combine Tables 1 and 2 into one table with a revised format.

The SDT crafted the definition of Planning Assessment using the term "documented" instead of "written" such that an assessment can be either in written or

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electronic format. Requirement R2 states that the assessment is to be performed annually. The SDT chose the Year One definition such that this would be out of the operational planning horizon and into the planning horizon. The SDT chose the years to be studied such that both the Near-Term and Long-Term Planning Horizons would be adequately studied and has not seen a sufficient number of comments to warrant changing the requirements. . Sole-customers who are responsible for facility upgrades are allowed to elect lower reliability than the rest of the system if those customers have signed an Interruptible Load contract arrangement. The SDT believes that all significant probable Contingencies over a wide range of operating conditions should be studied. 1. The definitions for both Generating Unit Stability Study and System Stability Study have both been removed and these Stability areas have been combined into just one Stability area. 2, 3, and 4. The SDT disagrees with the proposed changes and believes that compliance with Requirement R2.1 can be shown through the use of both current and past studies. 5. The SDT believes that "transfers" is generally understood to mean electric power that is transferred or moved from one area to another, and as such, has not added a definition of transfers. 6. The SDT has revised the language to replace "variability" with reactive resources "capability". ~~Variability and outages of r~~Reactive resource~~s~~ capability. 7. The SDT believes that the format and the language of these requirements are appropriate and no additional changes are needed. 8.,The SDT received only a single comment regarding use of the terms "identified System Facilities" and therefore believes the proposed language is clear and appropriate. "Identified System Facilities" are those new or modified facilities which were identified in previous Corrective Action Plans. 9. Requirement R3.3 has been removed and replaced with additional language in Requirement R3.1. **R3.1** Studies shall be performed to determine whether the BES meets the performance requirements in Table 1~~ — Steady State Performance.~~ based on the lists created in Requirement R3.5.		
Lakeland Electric	B — Unsure about supporting the revised standard	Curtailing firm transmission should explicitly be a viable option when preparing for the next contingency if the previous contingency and a credible next contingency call for curtailing firm transactions for reliabilities sake. Not allowing for firm transmission curtailment in this case seems to be a market requirement driving a reliability requirement. Determining the duration of consequential load loss (R3.3.2.1) is impractical as the root cause of the event vice the defined event type (e.g. - loss of line) determines the duration of the outage. A line can be outaged by a temporary lock out of protection device or 15 spans of a line might be destroyed by fire. The difference between the two make determination of duration impractical.

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		System peak Load (R2.1.1) needs to specify if it is the specific year, season or historical peak demand. Forecasting methodologies affect the system peak load that is projected. Differences between a 50/50 and 80/20 case will result in different forecast peak data.
Response: Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency. However, until the next Contingency occurs, System performance will need to meet the requirements for Event P1. As such, the proposed standard will not allow loss of any Non-Consequential Load, except for contracted Interruptible Loads, in preparation for the next Contingency. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. To meet industry concern as well as FERC Order 693, the SDT has added Requirement R2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been removed from the draft. **R2.8** The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1. The SDT intentionally provides flexibility for the Transmission Planner/Planning Coordinator to decide which Load forecasting methodology to use. The required studies and sensitivity analysis ensures that sufficient study is performed to cover an appropriate range of System conditions.		
Southern Company Transmission	C — Definitely do not support the revised standard	Category P6 is the loss of a system element, followed by system adjustments, followed by the loss of another element. The table columns for this category say that interruption of firm transmission service is allowed. The table, however, is not clear whether the interruption of firm service is allowed as part of the system adjustment (between the outages) or whether it is only allowed after the second outage. It was stated in the NERC TPL SDT WebEx (August 26, 2008) that the interruption is not allowed as part of the system adjustment. If this is the interpretation, this will cause Southern Company to not support the revised standard. This would be a dramatic change from the existing standard and would result in the unintended consequence of significantly reducing transmission system capability to accommodate firm transmission service including reduction of transfer capability of interfaces to a fraction of their currently reported capability. This would in effect be imposing an n-2 criteria for offering firm transmission service. This would not be an acceptable situation for the users, owners and operators of the bulk power system. In addition, the standard should clarify the accommodation of Conditional Firm Service as defined by FERC Order 890.
Response: The SDT agrees that clarification regarding treatment of Firm Transmission Service and Non-Consequential Load Loss during adjustment is		

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necessary. Footnote 10 in draft 3 of the Standard provides clarification. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
Brazos Electric Power Cooperative, Inc.	C — Definitely do not support the revised standard	Our biggest concern is the apparent lack of experience or understanding in the repercussions of including so many required studies and detailed documentation. And to what end? The amount of data that would be required to be saved will be so voluminous no one could go through it all to make any meaningful determination in a timely fashion. It's one thing to study every possible combination of outage but you then have to do something with the results, not just record them somewhere because a standard requires it. On the other hand some progress is being made in removing some of the more ambiguous or useless items so we are getting there to some degree. Deleting 1.1.2, 1.1.3, 2.7.3, 2.7.4, and 5.4 are good starts. However it appears some things were added that are just confusing or are unnecessary. 5.5.2 seems to simply restate the obvious intent of the section, to meet the performance requirements so its not really needed. Phrases such as "document why categories were NOT selected" are intuitively obvious. Categories were not selected because, in the judgment of the TP or PC, they were not deemed useful to study so why document this each time. R6 is also a confusing addition to this Standard and we aren't sure what it's intended to require. Use of the word "proxies" is probably not the best substitute for what was intended. We suggest R6 be deleted as well.
Response: The SDT has received many comments regarding the increased planning requirements to meet the proposed standard. However, the SDT believes that the requirements for sensitivity studies must remain to satisfy FERC Order 693. FERC has stated that the sensitivity studies would be used to document the selection of critical System conditions and study years used in assessing System conditions (see paragraph 1704) and that System conditions are as important as Contingencies in evaluating the performance of present and future Systems (paragraph 1705). Neither FERC, nor the SDT, believes that every possible combination outage needs to be analyzed for every System condition, but FERC expects those that produce the most severe reliability impacts should be documented (paragraph 1706). In response to industry comments, Requirement R5.5 has been deleted since Generating Unit Stability is no longer explicitly addressed in the standard. The SDT agrees and has deleted the phrase from Requirements R2.1.3 and R2.4.3. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical~~		

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~~rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: The industry did not seem to find usage of "proxies" in Requirement R6 (now R5) unclear or confusing. Therefore, the SDT has determined that no change to Requirement R6 is needed with regard to the use of proxies.		
LCRA TSC	A — Generally support the revised standard	LCRA had a comment on the first posting stating that the loss of any two Transmission circuits on a common structure should be viewed as a single contingency as a single component failure (tower, shield wire, conductor, hardware) could in-fact lead to the loss of two circuits. In the second draft, this outage is still being viewed as a Multiple Contingency (P7). At the same time, the loss of a tower line with three or more circuits is being viewed as an Extreme Event, when the same single failure could lead to the loss of multiple circuits. So, even if a double circuit outage is viewed as a Multiple Contingency, shouldn't a multiple circuit outage be viewed the same. In the Definitions of Terms Used in Standard, Extreme Event is defined as Events which are more severe and have a lower probability of occurrence than Planning Events. What is a "lower probability of occurrence"? Is this to be determined by each TP or TO? How is this probability determined? Are we to assume from this definition that we can use probabilistic planning to determine which Events should be studies even at the N-1 level?
Response: The SDT does not believe that the loss of a tower line with three or more circuits is similar in probability to two circuits on a common structure. Therefore, it is appropriate to classify the events differently. The SDT views "lower probability of occurrence" events as those events that occur much less often than Planning Events. The SDT does not intend for this probability to be determined by each utility. The SDT desires that Extreme Events be studied - but do not necessarily have to have Corrective Action Plans.		
NERC and Regional Coordination	C — Definitely do not support the revised standard	Changes should be made to the sensitivity analysis. See question 10 above. R2.6 - The need to restudy previously studied years should be left to the transmission planner when in their judgment there is a material change. Based on the material change the TP should be responsible for determining what aspects of the performance requirements need to be proven
Response: Please see the response to question 10. The SDT believes that past studies must be five calendar years old or less to be relevant and the associated models should not have had material changes. Requirement R2.5 and its sub-requirements have been removed from the proposed standard. Guidelines for the use of past studies to support the Planning Assessment have been added to what is now Requirement R2.5.2. The SDT did not want to be overly prescriptive when describing the type of changes that could be considered material and has left the text general. It is up to the Transmission Planner and Planning Coordinator to provide specificity as to what type of		

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topology changes constitutes changes sufficient to warrant re-evaluation. **R2.5**2 For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:		
IESO	A — Generally support the revised standard	(i) We generally support the direction and principle of the revised standard. It is a step in the right direction to more clearly stipulate the types of events and expected performance requirements with inclusion of multiple element contingencies and multiple single contingencies, and allowance for interruptions to firm transmission services and non-consequential load loss. (ii) More details and refinements are expected to be provided that address the issue of sensitivity testing, reduce the number of layers in the subrequirements (to facilitate ease of developing Measures and Violation Severity Levels), more clearly specify the responsible entities, etc. We look forward to seeing these improvements in the next revision, along with the first draft of Violation Risk Factors, Time Horizons, Measures, Data Retention Periods, and Violation Risk Factors when the requirements approach their near final draft form. (iii) We suggest the SDT review the development plan with the Standard Process Manager, especially the timing for posting the standard for balloting, responding to comments and conducting recalculating ballot. The timing between the initial ballot and recirculation ballot is usually short, and the balloted standard is not supposed to change. The proposed development plan appears to allow a long lead time between the two ballots, and for making changes to the standard between them.
Response: i. Thank you for your comments. ii. The SDT has streamlined the document and the tables to add clarity and has added the elements that were missing from the previous drafts. VRF, tec., have been added to the 3rd draft. iii. All development plans are reviewed with the Process Manager prior to finalization as per established procedure.		
North Carolina Electric Membership Corp	B — Unsure about supporting the revised standard	While we are satisfied that the changes are moving in the right direction, we share concerns that are being expressed by other SERC TPs and PCs that the standard may be overly prescriptive in some areas such as the sensitivities being required.
Response: The SDT agrees and has clarified the language to allow the Transmission Planner and Planning Coordinator to choose the sensitivities (Requirements R2.1.3 & R2.4.3).		

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R2.1.3 For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
E.ON U.S. Transmission Planning	C — Definitely do not support the revised standard	It is confusing that single Contingency and multiple Contingency are used throughout the document when the Categories in Tables 1 and 2 are Single Contingency and Multiple Contingency. Also System normal, normal conditions and Normal System are spread throughout the document. If they all mean the same, use the same wording. If not, explain the difference. R2.4.1. - Does this apply only to motors directly connected to the BES? Is there a size (hp/MW) limit? Who is responsible to provide this data to the Planning Coordinator? I would think it would both the Distribution Providers or the Generator Owners but R9 & R12 do not mention this. R2.4.1 refers to ?the dynamic behavior of Loads? and induction motor loads. How would this model data be developed, and by who? R2.5.2. - Define “Material”. Is an addition of a load tap point material? R2.6.2. ? Define ?study area?. Does a topology change over 300 miles away trigger a stability study for a generating plant? R2.7.1.1. ? Define ?project initiation date?. Would this include going to the PSC to get approval or just when construction begins? R3.2.1 states ?? and identify how the generators are treated in the steady state simulation.? What is meant by ?treated?? I request the use of more descriptive wording. R3.2.2 states ?? and identify how loadability is treated in the steady state simulation.? What is meant by ?treated?? I request the use of more descriptive wording. R3.3.1 “System normal” is a Planning Event included in Table 1. R3.3.2 capitalize ?Single? if you referring to P1 and P2 events. If not, this is confusing. R3.3.2.1 states ?Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment.? Quantification of expected duration requires a probability analysis of load cycles, repair time, and potentially of other factors that will be difficult, if not impossible, to develop with any confidence. The Planning Assessment is based on a deterministic evaluation. Requiring the expected duration is

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		inconsistent and useless. R3.3.2.2 Is this the intent? ? Following Single Contingency events, Transmission configuration changes and redispatch of generation can be simulated to return the system to Normal Rating provided that all Facilities shall be operating within their Emergency Rating. R5.3 states ?? and identify how the generators are treated in the simulation.? What is meant by "treated"? I request the use of more descriptive wording. R5.5.1 and R5.5.2 should be moved to 2.5. These requirements outline the generators and the sensitivities to be analyzed. R5 appears to focus on Tables 1 and 2. R5.5.2 states ?Shall be performed for changes in the real power output?? What types of ?changes?, or ?changes? due to what? Is intention of the requirement, that Generating Unit Stability be assessed at two levels of real power output that differ by more than 10% of the existing capability or more than 20 MW, whichever is greater? R6 states ?? and document the proxies used in the simulation?.? What is meant by ?proxies?? I request the use of more descriptive wording. R8 ends with ?This distribution shall include:? Include what? Table 1 There used to be limits on multiple circuit towers and common ROW greater than 1 mile. Is this left to the Transmission Planner and Planning Coordinator ? Extreme Events ? Item 3b is the same as Item 1, this should be removed. Table 2 Note 5.a.ii How can this be applied when the largest unit in the Balancing Authority Area is larger than the contingency reserve of the Balancing Authority. This requirement is excessive. At some level, subsequent trips of generators and/or lines should be allowed as long as Cascading does not occur.

Response: The row headers are capitalized in the Table. Please note that the two Tables have been changed to just one Table in this draft.

R2.4.1 – The SDT does not believe the requirement applies only to motors directly connected to the BES, nor is there a specific hp/MW limit. In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R2.4.1 – Requirement R2.4.1 has been modified to clarify expectations regarding load modeling for dynamics studies.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic

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behavior of the Load is acceptable.

R2.5.2 – Requirement R2.5 and its sub-requirements have been removed from the proposed standard.

R2.6.2 (now R2.5.2) –The SDT believes that it is up to the Planning Coordinator and Transmission Planner to define the study area and to determine which System changes could impact the study area

R2.7.1.1 (now R2.6.2)– The SDT has not defined a project initiation date and will leave that definition to be determined by the Transmission Planner and Planning Coordinator.

R3.2.1 – "Identify how generators are treated" means that you identify at what voltage you would believe that the generator would trip. Any time you run a dynamic simulation or a steady state simulation and you don't trip the generator, you are implicitly assuming that it will ride through the voltage excursion obtained in the simulation. The requirement is to identify what you are assuming for voltage ride-through criteria for the generators you have modeled.

R3.2.2 – The SDT has changed 'treated' to analyzed'. .

R3.3.2 For all generators, studies shall consider the minimum steady state voltage limitations ~~of all generators~~ and identify how the generators are ~~treated~~ analyzed in the steady state simulation.

Requirement R3.3.1 has been removed and replaced with additional language in Requirement R3.1.

R3.1 Studies shall be performed to determine whether the BES meets the performance requirements in Table 1~~ – Steady State Performance.~~ based on the lists created in Requirement R3.5.

R3.3.2 – This requirement was deleted.

R3.3.2.1 **-** To meet industry concern as well as FERC Order 693, the SDT has added Requirement R2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.8.

R2.8 The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1.

R3.3.2.2 - Based on your comment, the SDT has addressed the applicable time-limited rating in what was Header note 'a' for Steady State Only in Table 1 - Steady State & Stability Performance. Requirement R3.3.2.2 has been deleted in favor of Header note 'e' in the revised Table. Please note that the two tables in the second draft have been reduced to one table in the third draft.

Header note 'e' - For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

R5.3 - The SDT agrees that the word "treated" is vague and has revised Requirement R5.3 (now Requirement R4.3.2) and Requirement R3.2.2 (now R3.3.3) to clarify the requirement.

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R3.3.3 For all Transmission lines, studies shall consider relay loadability and identify how loadability is ~~treated~~ analyzed in the steady state simulation. **R4.3.2** ~~Studies shall consider~~ Simulate generator performance under anticipated conditions including how the voltage ride through capability ~~of all generators and identify how the generators are treated~~ is analyzed~~in the simulation~~. R5.5.1 & R5.5.2 - In response to industry comments, both Requirement R2.5 and Requirement R5.5 have been deleted since Generating Unit Stability is no longer explicitly addressed in the standard. R6 (now R5) - Most of the industry did not find usage of "proxies" in Requirement R6 unclear or confusing. Therefore, the SDT has determined that no change to Requirement R6 is needed with regard to proxies. R8 - The incomplete sentence was a typo and has been deleted from Requirement R8. Footnote 12 has been added to Table 1 to address your comment on the exclusion criterion for multiple circuit towers. **Footnote 12** - Excludes circuits that share a common structure for 1 mile or less. The SDT agrees with removing the redundancy found with Extreme Event 3.b. Please see footnote 1.a.ii for clarification. **Footnote 1.a.ii -** For all other Planning Events: No generating unit or units totaling more than the Contingency ~~r~~Reserve of the Balancing Authority (or Reserve Sharing Group if applicable) shall be allowed to pull out of synchronism. Generators that pull out of synchronism must have out-of-step protection or some other means to trip the generator for this condition and the resulting apparent impedance swings must not pass through relay characteristics that would result in the tripping of any Transmission System elements other than the generating unit and its direct connection Facilities.		
ERCOT System Planning	C — Definitely do not support the revised standard	The NERC reliability standard requirements should represent the minimum studies necessary to achieve reliability given the broad range of entities of various sizes and capabilities. Instead, the standards seem to represent the gold standard of the kind of studies that could be accomplished (steady-state, short circuit, and stability) given infinite time and resources with the number and variety of contingencies and sensitivities necessary. This level of steady state and stability studies can only be undertaken by the larger entities with a deep and experienced engineering staff. Why are most of the requirements applicable to a Transmission Planner and Planning Coordinator? Unless they are the same entity, this is an unnecessary duplication of effort. If a Planning Coordinator has a number of Transmission Planners in its region, then these requirements have to be fulfilled by each Transmission Planner for its individual area and the Planning Coordinator for the region made up of the individual areas? What is the Planning Coordinator coordinating if it is duplicating the work of the Transmission Planner?
Response: The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus. The SDT is cognizant of the cost factors involved here and is taking them into consideration in its deliberations. This standard does not represent the gold standard, but rather the SDT is developing a standard based on consensus industry support.		

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The SDT recognizes that the Transmission Planner and Planning Coordinator must work closely together as defined in the NERC functional model. The Transmission Planner and Planning Coordinator should closely coordinate all work to avoid any unnecessary duplication. Requirement R6 has been included in the standard to ensure that Planning Assessments are complete and coordinated in situations where the Transmission Planner and Planning Coordinator are not the same entity.		
American Transmission Company	B — Unsure about supporting the revised standard	We agree with most of the requirements of revised standard. However, the following list of suggestions and comments are given for consideration. Definitions: We agree with the removal of the "Base Case" definition and the revisions to the other definitions, except as noted above or below. Long Term Planning Horizon definition: We suggest a slight text change of: "Transmission planning period that covers years six through ten. Studies beyond ten years are required to accommodate . . .". Accountability: We suggest that Transmission Service Provider be added because we also suggest that the Transmission Service Provider be the responsible entity for R10. Requirements: We agree with the revisions to the Requirements, except as noted above or below. R1.1 - We agree with the requirement, but would like more description of what to provide in the technical rationale. R2.1 - We agree with the requirement, but suggest this text change, ". . . by the following annual studies . . .". R2.6.1 - We agree with the requirement, but suggest a slight text change of: " . . . short circuit, Generating Unit Stability or System Stability analysis . . .". R2.6.2 - We agree with the requirement, but suggest a slight text change of: " . . . short circuit, Generating Unit Stability or System Stability analysis . . .". R2.7 - We agree with the requirement, as long as it is really required by FERC Order 693 paragraph 1704. R2.7.1 - We agree with the requirement, but suggest a slight text change of: " . . . or Special Protection Systems, . . ." R2.7.1.1 - We disagree with the "include project initiation date" portion of this requirement. The initiation date is often uncertain and subject to change, which may add considerable work to investigate, monitor and update the date. In addition, we do not know why this information is required to assure BES reliability. R2.7.2 - We agree with the requirement, as long as it is really required by FERC Order 693 paragraph 1704. R3.2.2 - We agree with the requirement, but suggest a slight text change of: "For all BES Transmission lines . . .". R3.3.2.1 - We agree with the requirement, but suggest a slight text change of: ". . . shall be allowed in the Planning

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		Assessment". R3.3.2.2 - We agree with the requirement, but suggest a slight text change of: ". . . within their Facility Ratings and within the time period allowed by the applicable time limited ratings.". R5 - Is the text referring to "known planned outages" and "known long term outages"? What is the distinction that is meant to be made between the two specified types of outages? R5.1 - We agree with the requirement, but suggest a slight text change of: ". . . the response of the applicable portion of the BES". R5.2 - This clarifying requirement should also be included in the short circuit analysis section. R5.3 - We agree with the requirement, but suggest a slight text change of: ". . . capability of all generators that may have a significant adverse effect on the BES." R5.4.3.1 - We agree with the requirement, but suggest a slight text change of: ". . . within their Facility Ratings and within the time period allowed by the applicable time limited ratings.". R8 - We disagree with the requirement, but suggest a text change of: "Each Planning Coordinator shall establish a list of neighboring system and coordinate the distribution of Planning Assessment results among affected entities the listed neighboring systems, coordinating analysis of these results through an open and transparent peer review process." Table 1Planning Events Header: We suggest that the header be repeated on every applicable page to be more reader-friendly. Superscripts: The superscripts do not refer clearly to the respective notes (e.g. there are number notes in the beginning of the table, in the extreme events evaluation requirements section, in extreme event description section, and at the end of the table). Perhaps the notes at the end of the table should have unique numbering to make the superscript references clearer. Shunt device: To avoid the need for future interpretation or clarification, we suggest that the meaning of shunt device be explained or defined somewhere in the standard (e.g. cap bank, inductor bank, SVC, STATCOM, etc.). We need to find out how shunt device outages can (or could in the future) be automatically included in the ACCC routine. We interpret that if each stage of a capacitor bank has a circuit switcher, then the outage would be of the largest cap bank stage. P2.2 (>300 kV), P2.3(>300 kV), P3 (>300 kV), P4 (>300 kV), P5 (>300 kV) - We recognize that the addition of this requirement is an attempt top raise the bar above the existing standards. However, the more stringent performance criteria should only be adopted if there is sufficient evidence to demonstrate the expected reliability risk (i.e. system impact x probability of occurrence) is high enough to warrant the cost of the system modifications that would be needed to meet the criteria. System modifications that involve the installation of line and substation facilities >300 kV will likely take years and cost tens to hundreds of millions to build. It would be helpful to have a reliability risk analysis that justifies the application of

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		this performance criteria before it is adopted. If the proposed >300 kV performance requirement is retained, then we would want the implementation timeframe to be long enough to allow reasonable time to transition from a system built to the old requirement to a system built for the new requirement. The time needed for planning, design engineering, regulatory approvals, and construction of >300 kV facilities can be very long (e.g. up to 10 or more years). P7 - We disagree with this requirement. Wisconsin statues require giving preference to using existing ROW for new transmission circuits, but this requirement discourages building multiple circuits on common ROW. Should there be a waiver in this standard similar to the TLP-503-MRO-1 standard for lines slightly more than 1 mile based on a review? Extreme Event Evaluation Requirements2 - We agree with the requirement, but perhaps a definition be added for "System Controls", since one exists for "System Protection". 3 - We agree with the requirement, but suggest a slight text change of: "Simulate Normal Clearing unless otherwise specified in the Extreme Event Descriptions." Extreme Event Descriptions2a - We agree with the description, but suggest a slight text change of: "Loss of a structure or tower line with three or more circuits.." 2b & 3b - We agree with the descriptions, but suggest referring to the defined term: "Right-of-Way." 2e, 3.a.i, & 3.a.ii - We agree with the description a, but how large is "large" and how major is "major"? 3.a.v - What is meant by successful cyber attack? Is it a type of cyber attack that is documented to have been successful? 3c - We agree with the description, but suggest a slight text change of: "Other events based upon actual operating experience such as:" Note 4 - We agree with the description, but the acronym FACTS should be explained in the standard or a definition be added for "FACTS". Table 21 - We disagree with this note. We suggest that it be expanded to include the applicable part as Table 1. "The System shall remain stable. In addition, Facility Equipment Ratings shall not be exceeded. Planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings." 3 - We disagree with this note. We suggest that it be expanded to include the applicable part as Table 1. "Dynamic voltage instability, Cascading outages, and uncontrolled islanding shall not occur." Between 3 & 4 - We disagree with omitting Note 4 of Table 1 from Table 2. We suggest including: "Consequential Load and consequential generation loss is allowed for all events shown." Planning Events Same comments on Header, Superscripts, and Shunt Device as in Table 1.Same comments about stricter requirements for P2.2 (>300 kV), P2.3 (>300 kV), P3 (>300 kV), P4 (>300 kV), P5 (>300 kV) as in Table 1.Same comment

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		about P7 as in Table 1.Extreme Event Evaluation Requirements Same comment about Requirement 2 and 3 as in Table 1. 3 - We agree with the requirement, but suggest a slight text change of: "Simulate Normal Clearing unless otherwise specified in the Extreme Event Descriptions." Notes5 - We disagree with limiting this requirement to just Category P1 category. We suggest that the synchronism requirement be applied to more categories.

Response: The SDT believes that a review of system conditions beyond the 10-year horizon is warranted. FERC Order 693 requires that the planning horizon take into account the lead times for siting and permitting of new long-distance Transmission lines and other long lead time solutions. The SDT has received industry comments regarding the need to exceed a 10-year horizon to account for longer lead time projects. Establishing planning horizons that are shorter than Transmission lead times may create gaps where the identification of a reliability need to which Transmission may be the best solution occurs too late to avert the identified reliability violation. Further, Operating Procedures or alternative short-term capital projects may be needed to limit the impact of the Planning Event until the planned Facilities can be completed. This information needs to be included in the Assessment.

In response to industry comments, the SDT has removed Requirements R9-R14 thus eliminating any need to add the Transmission Service Provider.

R1.1 - The SDT agrees and has removed the need for documentation of the technical rationale for modification of any data.

R2.1 - The SDT believes that the existing language is appropriate and there needs to be a distinction between current and past studies that would allow both to support compliance with the requirement.

R2.6.1 & R2.6.2 - Based on comments from others, the SDT has removed the requirements for separate Generating Unit Stability analysis and System Stability analysis.

R2.7 (now R2.6) – The SDT believes that it is.

R2.7.1 (now R2.6.1) - The SDT agrees with the proposed change.

Installation or modification of Protection Systems or Special Protection Systems.

R2.7.1.1 (now R2.6.2) - The SDT believes that a project initiation date is an effective measure to track a functional entity's planning and engineering activities and their efforts to provide and maintain a reliable BES.

R2.7.2 – Requirement R2.7.2 has been deleted.

R3.2.2 - The Purpose section of the Standard states that this Standard is to develop requirements for the Bulk Electric System, BES. No change required.

R3.3.2.1 – Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.8 which includes the term 'Planning Assessment'.

R2.8 The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1.

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R3.3.2.2 - Based on your comment, the SDT has addressed the applicable time-limited rating in what was Header note 'a' for Steady State Only in Table 1 - Steady State & Stability Performance. Requirement R3.3.2.2 has been deleted in favor of Header note 'e' in the revised Table. Please note that the two tables in the second draft have been reduced to one table in the third draft.

Header note 'e' - For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

R5 - The SDT agrees and has moved this concept within Requirement R1 (see Requirement R1.1.1) so that it is applicable to all Planning Assessments. Further, both Requirements R3 and R5 (now R4) have been revised to make reference to Requirement R1.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. ~~The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to c~~Contingencies ~~in Table 1 – Steady State Performance.~~ The studies shall be based on computer simulations using models utilizing data provided in Requirement R1.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~

R5.1 - Most of the industry did not have difficulty understanding that the analysis is limited to the Transmission Planner's or Planning Coordinator's portion of the BES. Therefore, the SDT is not persuaded by your comment to add extra wording.

R5.2 - The SDT has moved the short circuit analysis from Requirement R4 to Requirement R2.7 and R2 already references BES.

R5.3 - The SDT disagrees with the suggested change due to the additional studies that would be required to determine which generators would have an adverse impact.

The SDT has deleted R5.4.3.1.

The SDT has clarified this issue in Requirement R8 (now R7).

R7 Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~neighboring systems~~ adjacent Planning Coordinators and any functional entity who has indicated a reliability need, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890.

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Header - The SDT also feels that the Tables need to be as clear and concise as possible. To that end, the next version will combine Tables 1 and 2 into one table with a revised format. The Planning Events are shown on one page so repeating the headings will not be needed. Superscripts - All the notes from both tables have been combined and listed numerically. Shunt device - The SDT believes that shunt device is commonly used in the electric utility industry and does not require any further explanation. The SDT recommends contacting the software manufacturer for additional information about the ACCC routine. The SDT believes that the cap bank outage would be based on what elements would need to trip in order to clear the simulated fault condition. P2 - The SDT is attempting to raise the bar by developing a standard that appropriately supports BES reliability and has industry consensus. The majority of the SDT believes that 300 kV is an appropriate cutoff and that Transmission Systems above this level represent backbone Systems and are part of regional "grids". The SDT is cognizant of the cost factors involved here and is taking them into consideration in its deliberations and has provided for flexibility in Corrective Action Plans. The Implementation Plan will be addressed in the next posting of the standard. P7 - The SDT is cognizant of the concerns surrounding the construction of new Transmission lines, including the desire by many to fully utilize existing Right-of-Ways. In its consideration of Footnote 12 (exclusion for common structures less than 1 mile), the SDT considered the impact that this requirement could have on construction of new Facilities. However, after deliberations, the SDT believes that the 1 mile exclusion should be maintained for the reliability of the BES and that individual exceptions can be addressed within the NERC process. Extreme Events 2 - The SDT agrees that "Protection System" is defined in the Glossary of Terms Used In Reliability Standards. However, the SDT believes that this issue should be more properly addressed by the NERC SPCTF drafting team. 3 - The SDT has previously included "For all Extreme Events evaluated" at the beginning of the Evaluation Requirements for Extreme Events. No change required. 2a - The SDT believes that the Extreme Events #2.a. is already sufficient. 2b - The SDT will use the defined term of "Right-of-Way" as suggested (see 2b steady state and 2 g Stability). 2e et al - The SDT suggests that the terms "large", "major", and "successful" be defined between the Transmission Planner and Planning Coordinator. 3a - The SDT believes that the wording (was 3c) is already sufficient. No change required. Note 4 - The SDT believes that "FACTS" is commonly used in the electric utility industry and does not require any further explanation. Table 21 - The SDT has reviewed your comment and feels that your request to add "Facility Equipment Ratings shall not be exceeded. Planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings." apply to Stability is not appropriate. For the purposes of this standard, Facility Equipment Ratings refer to steady state calculated values and planned System adjustments refer to the time frame associated with returning the thermal flow within the applicable steady state Facility Rating. 3 - The SDT agrees with your comment and has made that change in Header note ‘a’ in the next version. Also, the next version will combine Tables 1 and 2			

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into one table with a revised format. 3 & 4 - The SDT has reformatted and combined the two Tables into a single Table for the next draft. 3 – The SDT has already included "For all Extreme Events Evaluated" at the beginning of the Evaluation Requirements for Extreme Events. 5 - The SDT also feels that the synchronism requirement should apply to more than just P1 Category but under certain conditions and has adjusted the notes accordingly. **Footnote 1.a.ii -** For all other Planning Events: No generating unit or units totaling more than the Contingency ~~r~~Reserve of the Balancing Authority (or Reserve Sharing Group if applicable) shall be allowed to pull out of synchronism. Generators that pull out of synchronism must have out-of-step protection or some other means to trip the generator for this condition and the resulting apparent impedance swings must not pass through relay characteristics that would result in the tripping of any Transmission System elements other than the generating unit and its direct connection Facilities.		
Duke Energy	B — Unsure about supporting the revised standard	While we generally support the revised standard, we are unsure of the total cost impact, and whether the additional costs are justified by increased reliability. 1) Load Modeling is a significant open issue. The models for dynamic studies have yet to be developed and the data is not in hand. This standard should allow for the use of the best available information. 2) Category P6 is the loss of a system element, following system adjustments, followed by the loss of another element. The table columns for this category say that interruption of firm transmission service and non-consequential load loss is allowed. The table, however, is not clear whether the interruption of firm service and non-consequential load loss is allowed as part of the system adjustment (between the outages) or whether it is only allowed after the second outage. It was stated in the NERC TPL SDT WebEx that the interruption is not allowed as part of the system adjustment. This would be a dramatic change from the existing standard and would result in the unintended consequence of significantly reducing transfer capability of interfaces to a fraction of their currently reported capability. This would in effect be imposing an n-2 criteria for offering firm transmission service. Duke Energy does not believe this would be an acceptable situation for the users, owners and operators of the bulk power system. 3) The statement in R2.7 "Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities," implies that there are performance requirements for sensitivity studies. Recommend rewording to clarify that there are no performance requirements for sensitivity studies. 4) Recommend rewording R3.3.2.1 as follows: "The single highest consequential load loss and its expected duration following a single contingency shall be documented in the Planning Assessment." 5) In R5.3 the statement, ?and identify how the generators are treated in the simulation,? should be deleted. The word "treated" is vague and typically specific equipment modeling is not identified in studies. The implementation schedule should also take into account the Standard to develop and provide this data is not approved. Since this data is not yet available, please revise the statement as follows: ?Studies shall use the best available information to consider the voltage

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		ride through capability of all generators." 6) In Table 1, Category P2 Event 1 needs to be revised to recognize the impact of this event on Bulk Electric System reliability for events on the system that are > 300 kV vs. events on the system that are <= 300 kV. P2.1 should not allow for interruption of firm transmission service or loss of non-consequential load for > 300kV; however, it should allow for interruption of firm transmission service or loss of non-consequential load for <= 300 kV. The requirement as currently written would require expenditures for the <= 300 KV system where such an event has minimal impact on Bulk Electric System reliability. In addition, the likelihood of events needs to be considered as requirements are developed. A review of Duke Energy Carolinas data shows that the likelihood of a P2.1 event on Duke's 100 kV system is an order of magnitude less than for a P1 event on the same 100 kV system. This is another indicator that the requirement as written would result in the need for expenditures that provide minimal value to enhancing the reliability of the Bulk Electric System.

Response: The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus. The SDT is cognizant of the cost factors involved here and has taken them into consideration in its deliberations in the development of this draft.

1. The SDT agrees and believes that industry guidance is needed to capture the appropriate dynamic behavior of loads. In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments. Requirement R2.4.1 has been modified to clarify expectations regarding Load modeling for dynamics studies.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources, ~~-~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R2.4.1 System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

2. The SDT agrees that clarification regarding treatment of Firm Transmission Service and Non-Consequential Load Loss during adjustment is necessary. Footnote 10 in the Revision 3 of the Standard provides clarification.

Footnote #10 – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.

3. The SDT has modified the language dealing with the sensitivities in Requirement R2.7 (now R2.6) and added the phrase "run in accordance with Requirements R2.1.3 and R2.4.3." However, the performance requirements for sensitivity studies are the same as the performance requirements for the base study. The difference is that a Corrective Action Plan is required when performance requirements are not met in the base study. A Corrective Action Plan is not

Organization	Question 15:	Question 15 Comments:
necessarily required when the performance requirements are not met for a sensitivity study. **R2.6** For Planning Events shown in Table 1~~— Steady State Performance and Table 2 – Stability Performance~~, when the analysis indicates an inability of the System to meet the performance requirements in ~~the t~~Table~~s~~ 1, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed in subsequent assessments but the System shall continue to meet the performance requirements in the tables. Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3 and R2.4.3. The Corrective Action Plan shall: 4. To meet industry concern as well as FERC Order 693, the SDT has added Requirement R2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been removed from the draft. **R2.8** The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1. 5. The SDT has revised Requirement R5.3 (now R4.3.2) to provide clarification in this area. **R4.3.2** ~~Studies shall consider~~ Simulate generator performance under anticipated conditions including how the voltage ride through capability ~~of all generators and identify how the generators are treated~~ is analyzed~~in the simulation~~ 6. The SDT feels that for this event (explained in detail in footnote 8 of draft 3 of this Standard) interruption of neither firm nor Non-Consequential Load should be allowed for any BES voltage level, i.e., above or below 300 kV. This is consistent with FERC Order 693 that does not allow dropping of Non-Consequential firm Load following any single Contingency.		
Florida Reliability Coordinating Council, inc	C — Definitely do not support the revised standard	The SDT should consider and allow, for all planning events, , loss of Non-Consequential load as an interim measure for a period of up to 5 years in the situation where system load growth has caused post-contingency action plans to not effectively bring Facilities within normal operating limits due to unexpected or unforeseen regulatory requirements, equipment capability* and/or the installation of large industrial/commercial customers. *Equipment Capability is added to address unforeseen industry changes in the methodology used to calculating the rating of equipment.
Response: Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these System designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an Interruptible Load contract arrangement.		
Central Maine Power	B —Unsure about supporting the	Aside from the comments to the prior questions, there are several issues of concern that prevent us from supporting the present draft of the revised standard. We offer the following constructive comments in an effort to support the worthwhile effort that is being pursued so that we can reach a point of satisfaction that we could vote to support the revised standard.

Organization	Question 15:	Question 15 Comments:
Company	revised standard	Our concerns are listed in a rough order of priority. a. This standard as drafted does not allow exceptions for small parts of the system as long as interconnected system reliability is maintained, which is allowed in the existing TPL standards in footnotes b) and c) in Table 1. Unless such exceptions are allowed significant transfer restrictions or large reinforcements must be made. The applicable TPL footnotes are: Existing TPL footnote b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers. Existing TPL footnote c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (nonrecallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems. b. This standard does no address base conditions. Without defining base conditions the initial status of generation dispatch and transfers across the system is ill defined. Therefore the contingency analysis doesn't have a predictable basis for a consistent and repeatable study. c. The reference to Special Protection Systems is completely permissive. Although there are good applications for Special Protection Systems, their use must be constrained to have a reliable system and to promote construction of needed infrastructure. d. This standard does not provide flexibility to shed load, which restricts the ability to control post contingency response for low impact events. This may result in advancing need for upgrades in response to low impact events. This may result in advancing need for upgrades in response to low impact events. This is in conflict with FERC's directive to have the Transmission Provider waiting for market response to transmission needs and having the Transmission Provider provide a role to back stop the market. e. Definition of the Long-Term Planning Horizion. The planning horizion, for assessment purposes should be limited to 10 years. Such an assessment should be sufficient to identify requirements that may take an extended time to implement. f. Definition of Planning Coordinator is part of the NERC Functional Model, Remove from the standard. g. Put headings on each section to identify the requirements of the section. h. With respect to R2.2 - Delete "current" from the phrase "current System Peak Load Study" and replace "study" with "assessment." i. Remove R2.2.1, the requirement to extend the assessment beyond 10 years. What does the length of the project have to do with the assessment? If it takes 15 years to build something, why does this require a review of year 15? What is the

Organization	Question 15:	Question 15 Comments:
		purpose of this assessment? j. R3.3.2 requires clarification - This standard needs to permit discretion regarding the single contingencies that need to be tested, similar to R3.3.3 and R3.4. It is completely unnecessary to test all events. For example, contingencies may be limited to relevant disturbances that are contained within or directly impact the studied system. k. With respect to R3.2.1 - Clarify whether the intent of the standard is to address station service minimum voltage limitation, maximum leading VAR absorption capability or both at steady state. l. Remove R3.2.2 - Relay loadibility is addressed in the PRC-023 Standard. m. With respect to R3.3.2.1 - Recommend the removal of the requirement to assess the expected duration of Consequential Load loss. It's not considered anywhere else in the standard. n. With respect to R3.3.3 - The paragraph refers to Table 1 Contingencies P3 through P7; this should be explicitly stated. Rationale for inclusion of testing should not be required; should only need to explain why certain Contingencies were not tested. This discretion should be applicable to all contingencies. o. With respect to section R5 - The concept of planned and long-term outages should apply to the general Planning Assessment, or not at all. It should not be specific to the Stability Assessment. p. The provisions of Section R5.3 should have a corresponding MOD standard apply a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertent trip of the generator. Such a provision should include "other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how those devices are treated in the simulation. q. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizon. r. Recommend allowing the same non-consequential interruption for >300kV as for <300kV. Distinctions and acceptability should be based on consequence, not voltage class. s. What is a "current" study?
ISO New England Inc.	B — Unsure about supporting the revised standard	Aside from the comments to the prior questions, there are several issues of concern that prevent us from supporting the present draft of the revised standard. We offer the following constructive comments in an effort to support the worthwhile effort that is being pursued so that we can reach a point of satisfaction that we could vote to support the revised standard. Our concerns are listed in a rough order of priority. a. This standard as drafted does not allow exceptions for small parts of the system as long as interconnected system reliability is maintained, which is allowed in the existing TPL standards in footnotes b) and c) in Table 1. Unless such exceptions are allowed significant transfer restrictions or large reinforcements must be made. The applicable TPL footnotes

Organization	Question 15:	Question 15 Comments:
		are: Existing TPL footnote b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers. Existing TPL footnote c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (nonrecallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems. b. This standard does no address base conditions. Without defining base conditions the initial status of generation dispatch and transfers across the system is ill defined. Therefore the contingency analysis doesn't have a predictable basis for a consistent and repeatable study. c. The reference to Special Protection Systems is completely permissive. Although there are good applications for Special Protection Systems, their use must be constrained to have a reliable system and to promote construction of needed infrastructure. d. This standard does not provide flexibility to shed load, which restricts the ability to control post contingency response for low impact events. This may result in advancing need for upgrades in response to low impact events. This may result in advancing need for upgrades in response to low impact events. This is in conflict with FERC's directive to have the Transmission Provider waiting for market response to transmission needs and having the Transmission Provider provide a role to back stop the market. e. Definition of the Long-Term Planning Horizion. The planning horizion, for assessment purposes should be limited to 10 years. Such an assessment should be sufficient to identify requirements that may take an extended time to implement. f. Definition of Planning Coordinator is part of the NERC Functional Model, Remove from the standard. g. Put headings on each section to identify the requirements of the section. h. With respect to R2.2 - Delete "current" from the phrase "current System Peak Load Study" and replace "study" with "assessment." i. Remove R2.2.1, the requirement to extend the assessment beyond 10 years. What does the length of the project have to do with the assessment? If it takes 15 years to build something, why does this require a review of year 15? What is the purpose of this assessment? j. R3.3.2 requires clarification - This standard needs to permit discretion regarding the single contingencies that need to be tested, similar to R3.3.3 and R3.4. It is completely unnecessary to test all events. For example, contingencies may be limited to relevant disturbances that are contained within or directly impact the studied system.

Organization	Question 15:	Question 15 Comments:
		k. With respect to R3.2.1 - Clarify whether the intent of the standard is to address station service minimum voltage limitation, maximum leading VAR absorption capability or both at steady state. l. Remove R3.2.2 - Relay loadibility is addressed in the PRC-023 Standard. m. With respect to R3.3.2.1 - Recommend the removal of the requirement to assess the expected duration of Consequential Load loss. It's not considered anywhere else in the standard. n. With respect to R3.3.3 - The paragraph refers to Table 1 Contingencies P3 through P7; this should be explicitly stated. Rationale for inclusion of testing should not be required; should only need to explain why certain Contingencies were not tested. This discretion should be applicable to all contingencies. o. With respect to section R5 - The concept of planned and long-term outages should apply to the general Planning Assessment, or not at all. It should not be specific to the Stability Assessment. p. The provisions of Section R5.3 should have a corresponding MOD standard apply a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertant trip of the generator. Such a provision should include "other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how those devices are treated in the simulation. q. Planned outages should be addressed in the operating horizion unless otherwise defined in the planning horizion. r. Recommend allowing the same non-consequential interruption for >300kV as for <300kV. Distinctions and acceptability should be based on consequence, not voltage class. s. What is a "current" study?
Response: A. Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these System designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement. B. The SDT has modified Requirement R1 to include additional details on what should be modeled in the cases. However, the SDT intentionally provides flexibility for the Transmission Planner/Planning Coordinator to decide which "base case" to use since initial conditions for a System will vary from region to region and will need to be established on a local level, not via a national standard. The required studies and sensitivity analysis ensures that sufficient study is performed to cover an appropriate range of System conditions. C. The SDT does not believe that it would be appropriate to attempt to specify limitations to the use of Special Protection Systems in this standard. The proposed TPL-001-1 and existing standards provide adequate guidance to the industry on application of Special Protection Systems.		

Organization	Question 15:	Question 15 Comments:
D. The SDT has made clarifications regarding Firm Transmission Service and Non-Consequential Load Loss. Footnote # 10 has been added to the end of Table 1. The standard does not preclude the possibility of obtaining contractually interruptible load. It is the general opinion of the SDT that dropping of Non-Consequential Load should not be allowed for the Planning Events involving only one element as described in Table 1 of the proposed Standard, and to meet the intent of FERC Order 693. Further, this Standard is proposed to "raise the bar" to improve System reliability, which would require responses (Corrective Action Plans) to address those so-called low-impact events that may have been overlooked or ignored with the existing Standard TPL-002-0. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. E. The SDT believes that a review of System conditions beyond the 10-year horizon is warranted. FERC Order 693 requires that the planning horizon take into account the lead times for siting and permitting of new long-distance Transmission lines and other long lead time solutions. The SDT has received industry comments regarding the need to exceed a 10-year horizon to account for longer lead time projects. Establishing planning horizons that are shorter than Transmission lead times may create gaps where the identification of a reliability need to which Transmission may be the best solution occurs too late to avert the identified reliability violation. Further, Operating Procedures or alternative short-term capital projects may be needed to limit the impact of the Planning Event until the planned facilities can be completed. This information needs to be included in the Assessment. F. The definition for Planning Coordinator was deleted because the term has already been defined and added to the NERC Glossary by another SDT. G. The SDT also feels that the Tables need to be as clear and concise as possible. To that end, the next version will combine Tables 1 and 2 into one table with a revised format. H. The SDT believes that the existing language is appropriate. I. The SDT believes that a review of System conditions beyond the 10-year horizon is warranted under some circumstances. For example, if it takes 15 years to build a Transmission line, then the need for that line would have to be determined 15 years ahead of the in-service date. Therefore, Requirement R2.2.1 requires you to perform an Assessment on year 15 if it takes you 15 years to build a line. J. The SDT has removed Requirement R3.3.2 and replaced it with additional language in Requirement R3.1. The SDT does agree with your interpretation that it does not require evaluation of all single Contingencies. The SDT specifically states in **R**equirement R3.4 that those Contingencies that are expected to produce the more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe results. **R3.1** Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 ~~– Steady State Performance.~~ based on the lists created in Requirement R3.5. K. The SDT has not limited the purpose of this requirement to either minimum acceptable station service voltages or maximum Mvar absorption. The SDT believes that the purpose of Requirement R3.2.1 is to determine if generators could continue to operate or if they would trip off following the Contingency.		

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L. The SDT believes that relay load limits or loadability need to be considered in the Contingency analyses. The studies should determine if Transmission line loadings could reach the relay loadability level, which may add to the existing Contingency and perhaps, result in an unbounded cascading event.

M. To meet industry concern as well as FERC Order 693, the SDT has added Requirement R 2.9 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.9.

R2.9 The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1.

N. The SDT has re-written Requirement R3.3 (now Requirement R3.5) to address your initial concern. Although the language and format of the proposed Standard have been revised from earlier versions, the SDT continues to believe that the Transmission Planners should evaluate the System performance for the events that are expected to produce the more severe System impacts, including both single and multi-Contingency events. The wording of new Requirement R3.5 (the old Requirement R3.3.3) now requires a listing of the Contingencies to be evaluated, the rationale for their selection and why the remaining Contingencies would be expected to produce less severe results. This will provide a complete evaluation of the potential Contingencies to be studied – those selected and those excluded.

R3.5 Those Planning Event Contingencies in Table 1 ~~– Steady State Performance not covered in Requirement R3.3.2~~ that are expected to produce more severe System impacts shall be identified~~,~~ and a list of those Contingencies to be evaluated for System performance in Requirement R3.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results.

O. The SDT agrees and has moved this concept within Requirement R1 (see Requirement R1.1.1) so that it is applicable to all planning Assessments. Further, both Requirement R3 and Requirement R5 have been revised to make reference to Requirement R1.

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. ~~The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to c~~Contingencies ~~in Table 1 – Steady State Performance.~~ The studies shall be based on computer simulations using models utilizing data provided in Requirement R1.

R5 For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~

P. Requirement R5.3 has been modified to address simulation of how generators perform under conditions being studied. The current MOD standards that address steady-state and dynamic simulation data requirements do not explicitly require the Generator Operators to provide voltage ride-through capability.

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These standards are set to be addressed by Project 2010-04 within NERC's Standards Development Work Plan. It is expected that the Transmission Planner would contact Generator Operators applicable to their System to obtain such data. If the data is not provided, it would be expected that a Transmission Planner state its assumption on the Vmin used for a generator terminal voltage for assessing ride-through capability. It's likely such information could be obtained through generator manufacturers. The "Other equipment" is addressed in the revised R5.4. Q. The SDT agrees and therefore has changed R1.1.1 to state "if specifically known." R. FERC order 693 (see paragraphs 342, 1792, 1794) suggests that Non-Consequential Load loss for single Contingencies is unacceptable. Note from paragraph 1792 of order 693: "We view these arguments as based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." The fact that the table allows Load loss for some "lower probability" N-1 events (some P2 events) for any Transmission voltage is recognition by the SDT that probability impacts both costs and practicality. S. The SDT believes that a current study is a study that has been completed for the latest Assessment, as opposed to a past study that may have been completed up to five years ago.		
NSTAR Electric	B — Unsure about supporting the revised standard	Aside from the comments to the prior questions, listed below are several others issues: 1. This standard does not address base conditions regarding generation dispatch and transfers across the system. Initial condition guidelines would be very important to establishing consistent application of the performance standards. 2. This standard should allow exceptions for loss of small parts of the system as long as reliability is maintained on the interconnected BES. There is such an allowance in the existing TPL standards in Table 1, footnotes b) and c). 3. The reference to Special Protection Systems is too permissive. The use of Special Protection Systems and their inherent complexity should be restricted to ensure a reliable system and to promote construction of needed infrastructure. 4. The Long-Term Planning Horizon should be limited to 10 years, a sufficient timeframe to identify requirements that may take an extended time to implement. 5. Definition of Planning Coordinator is part of the NERC Functional Model. It should be removed from the TPL standard. 6. Put headings on each section to identify the requirements of the section. 7. With respect to R2.2, delete "current" from the phrase "current System Peak Load Study" and replace "Study" with "Assessment." 8. R3.3.2 should be changed to permit discretion regarding the single contingencies that need to be tested, similar to R3.3.3 and R3.4. It is unnecessary to test all possible events. 9. R3.2.1 should be clarified as to whether the intent of the standard is to address station service minimum voltage

Organization	Question 15:	Question 15 Comments:
		limitation, maximum leading VAR absorption capability or both. 10. Remove R3.2.2. Relay loadibility is addressed in the PRC-023 Standard. 11. In R3.3.2.1, remove the requirement to assess the expected duration of Consequential Load loss. This requirement is unnecessary and not considered anywhere else in the standard. 12. With respect to R3.3.3, the paragraph refers to Table 1 Contingencies P3 through P7; this should be explicitly stated. Also, the rationale for inclusion of testing should not be required. It only makes sense to explain why certain Contingencies were not tested. This discretion should be applicable to all contingencies in all sections of the standard.

Response: 1. The SDT has modified Requirement R1 to include additional details on what should be modeled in the cases. However, the SDT intentionally provides flexibility for the Transmission Planner/Planning Coordinator to decide which "base case" to use since initial conditions for a System will vary from region to region and will need to be established on a local level, not via a national standard. The required studies and sensitivity analysis ensures that sufficient study is performed to cover an appropriate range of System conditions.

2. Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these System designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an Interruptible Load contract arrangement. As an alternative, an entity could seek an Entity Variance for the situation described through their Regional Entity organization. In paragraph 1794 FERC clarified that "…an entity may seek a regional difference to the Reliability Standard from the ERO for case-specific circumstances". The process described by FERC as a regional difference is described in detail in the "NERC Standards Development Procedure" document under the subsection titled "Variances to NERC Reliability Standards".

3. The SDT does not believe that it would be appropriate to attempt to specify limitations to the use of Special Protection Systems in this standard. The proposed TPL-001-1 and existing standards provide adequate guidance to the industry on application of Special Protection Systems.

4. The SDT believes that a review of System conditions beyond the 10-year horizon is warranted. FERC Order 693 requires that the planning horizon take into account the lead times for siting and permitting of new long-distance Transmission lines and other long lead time solutions. The SDT has received industry comments regarding the need to exceed a 10-year horizon to account for longer lead time projects. Establishing planning horizons that are shorter than Transmission lead times may create gaps where the identification of a reliability need to which Transmission may be the best solution occurs too late to avert the identified reliability violation. Further, Operating Procedures or alternative short-term capital projects may be needed to limit the impact of the Planning Event until the planned Facilities can be completed. This information needs to be included in the Assessment.

5. The definition for Planning Coordinator was deleted because the term has already been defined and added to the NERC Glossary by another SDT.

6. The SDT has considered this action but NERC's legal staff advised against using headings in the body of standards.

Organization	Question 15:	Question 15 Comments:
7. The SDT believes that the existing language is appropriate. 8. The SDT has removed the Requirement R3.3.2 and replaced it with additional language in Requirement R3.1. The SDT does agree with your interpretation that it does not require evaluation of all single Contingencies. The SDT specifically states in Requirement R3.4 that those Contingencies that are expected to produce the more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe results. **R3.1** Studies shall be performed to determine whether the BES meets the performance requirements in Table 1~~ – Steady State Performance.~~ based on the lists created in Requirement R3.4. 9. The SDT has not limited the purpose of this requirement to either minimum acceptable station service voltages or maximum Mvar absorption. The SDT believes that the purpose of Requirement R3.2.1 (now R3.3.2) is to determine if generators could continue to operate or if they would trip off following the contingency. 10. The SDT believes that relay load limits or loadability need to be considered in the Contingency analyses. The studies should determine if Transmission line loadings could reach the relay loadability limits, which may add to the existing Contingency and perhaps, result in an unbounded cascading event. 11. To meet industry concern as well as FERC Order 693, the SDT has added Requirement R2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been removed from the draft. **R2.8** The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1. 12. Although the implied assumption that the more severe impacts would be identified in the P3 through P7 Contingencies, there may be exceptions and the SDT does not believe it necessary to modify the language in this regard. The wording of new Requirement R3.~~5~~ 4 (the old Requirement R3.3.3) now requires a listing of the Contingencies to be evaluated, the rationale for their selection and why the remaining Contingencies would be expected to produce less severe results. This will provide a complete evaluation of the potential Contingencies to be studied – those selected and those excluded. **R3.4** Those Planning Event Contingencies in Table 1 ~~– Steady State Performance not covered in Requirement R3.3.2~~ that are expected to produce more severe System impacts shall be identified~~,~~ and a list of those Contingencies to be evaluated for System performance in Requirement R3.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results.		
SERC Reliability Review Subcommittee and Planning Standards Subcommittee		C. Definitely do not support the revised standard. A majority of SERC technical experts do not support the revised standard. The primary concern is that the need for additional requirements for planning 300kV systems and above has not been demonstrated. We do not believe that a sufficient case for ?raising the bar? has been provided and that this requirement can have a huge impact on utilities and ratepayers. R2.1.3 and R2.4.3 requirements are very prescriptive. Many examples of sensitivities are already inherent in the existing requirements. Some sensitivity studies are in effect adding an additional level of contingency (N-2 or N-3). Sensitivity studies of load variation are already inherent in the fact that several different study years and conditions are already being

Organization	Question 15:	Question 15 Comments:
		required. Outages of reactive sources and generation should already be included in studies of multiple contingencies. The process of planning new generation (system impact studies) will include studies of the future with and without the proposed new equipment. The TP and PC can better select the most appropriate sensitivities for their system. We recommend that engineering judgment continue to be recognized as a vital component of planning. Category P6 is the loss of a system element, followed by system adjustments, followed by the loss of another element. The table columns for this category say that interruption of firm transmission service is allowed. The table, however, is not clear whether the interruption of firm service is allowed as part of the system adjustment (between the outages) or whether it is only allowed after the second outage. It was stated in the NERC TPL SDT WebEx (August 26, 2008) that the interruption is not allowed as part of the system adjustment. This would be a dramatic change from the existing standard and would result in the unintended consequence of significantly reducing transmission system capability to accommodate firm transmission service including reduction of transfer capability of interfaces to a fraction of their currently reported capability. This would in effect be imposing an n-2 criteria for offering firm transmission service. This would not be an acceptable situation for the users, owners and operators of the bulk power system. Additional Comments: There is concern with load modeling requirements (use of word ?appropriately? in R2.4.1). Does this requirement mandate the use of specific load models for each bus, or would an aggregate load model which represents the system as a whole be sufficient? Does the use of the PSS/E CONL function satisfy the requirements for a load model? There is a concern that R3.3.2.1 is burdensome regarding the need to keep track of the quantity of consequential load loss and expected duration. Who is collecting this information and why is it needed? It appears that this is a local regulatory issue, not a reliability issue. There is a concern with R5.6.1 with the requirement to perform simulations on 20 MW generators (to be consistent with the Registration Criteria). We recommend a 75 MW generator cutoff for required simulations.

Response: The SDT is attempting to raise the bar by developing a standard that appropriately supports BES reliability and has industry consensus. The majority of the SDT believes that 300 kV is an appropriate cutoff and that Transmission Systems above this level represent backbone Systems and are part of regional "grids". The SDT is cognizant of the cost factors involved here and is taking them into consideration in its deliberations and has provided for flexibility in corrective action plans. FERC has noted in their orders that many of the concerns about raising the bar show more concern about economics than reliability (examples, Order 890, paragraph 423; Order 693, paragraph 1792, etc.).

The SDT agrees and have clarified the language to allow the Transmission Planner and Planning Coordinator to chose the sensitivities (Requirements R2.1.3 & R2.4.3)

R2.1.3 For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

Organization	Question 15:	Question 15 Comments:
		R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: The SDT agrees that clarification regarding treatment of Firm Transmission Service and Non-Consequential Load Loss during adjustment is necessary. Footnote 10 in the Revision 3 of the Standard provides clarification. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. The SDT does not believe that specific Load models for each bus are necessary. An aggregate Load model which represents the System behavior as a whole may be used. Requirement R2.4.1 has been revised. The SDT does not believe that the use of PSS/E Activity CONL by itself provides the appropriate representation for dynamic Loads. For example, the SDT believes that using PSS/E Activity CONL is not sufficiently robust to appropriately model summer peak Loads with high concentrations of induction motors during for low voltage/motor stall conditions. A dynamic Load model such as CLOD, in conjunction with Activity CONL to model the non-induction motor load would be required to more accurately assess the system for FIDVR - Fault Induced Delayed Voltage Recovery. **R2.4.1** System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. To meet industry concern as well as FERC Order 693, the SDT has deleted Requirement R3.3.2.1 and replaced it with Requirement R 2.8. The SDT believes that quantifying the single largest Consequential Load Loss and identifying the event causing it provides a useful metric for system performance and reliability. **R2.8** The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1. The requirement for study has been changed to 20 MW for a single generator or for an aggregate of generators. This language is now in Requirement R2.5.2. **R2.5.2** For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:
Oncor Electric Delivery	B — Unsure about supporting the revised	Initially performing outstanding tasks as well as annual maintenance of documentation and regular updates would require extreme significant resources both personal and financial. Transmission Planning to this level requires high level subject matter experts with both specific transmission system knowledge as well as overall industry experience. Considerable expense would also be required to train personal and track activities. The procurement documents necessary to interface

Organization	Question 15:	Question 15 Comments:
	standard	with consultants in this area where "in house" expertise is not available would also be required. Time would also be spent on evaluating new software and analysis tools such as EPRI dynamic models. A phased in approach would be taken to complete the tasks while still performing essential Oncor and ERCOT related activities associated with System Planning.
Response: The SDT has received many comments regarding the increased planning requirements to meet the proposed standard. However, the SDT believes that the requirements for sensitivity studies must remain to satisfy FERC Order 693. FERC has stated that the sensitivity studies would be used to document the selection of critical System conditions and study years used in assessing System conditions (see paragraph 1704) and that System conditions are as important as Contingencies in evaluating the performance of present and future Systems (paragraph 1705). The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus. The SDT is cognizant of the cost factors involved and has considered them in its deliberations. The SDT is developing the Implementation Plan and will include it in the next draft of the standard		
FirstEnergy Corp.	A — Generally support the revised standard	1) For this standard, "Protection System" failure should be limited to only relay event failures. 2) R1 ? As stated in our response to Question 5, FE does not support the modeling requirements within the TPL standard and suggest that the SDT remove these requirements. This standard should be viewed on a premise that a valid and appropriate system model exist so that the fundamental focus of the standard is as stated in its purpose statement "Establish Transmission System planning performance requirements... to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions." If R1 remains, the phrase "and other data sources" should be removed. 3) R1.1 ? this requirement requires the documentation of ANY data modification. Do you really mean ANY? How much detail is needed in the documentation? Is a line by line comparison of all data values before/after needed or is a general overview discussion sufficient? For instance, FE replaces its system model as shown in the MMWG representation with a more detailed system representation model when performing planning studies. This can included many differences from the MMWG system equivalent. How much documentation is needed in this situation? 4) R2.6 ? This is not a requirement and should be removed and shown as explanatory text (footnote). 5) R3 - Requirement R3.1 is redundant to statements in the text of R3 and R3.3 and R3.4. We suggest that R3.1 be removed. It is suggested that R3.4 be indented and become a R3.3 sub-requirement. R3.5 would be better placed ahead of R3.3 along with the existing R3.2.
Response: 1. The SDT believes that these protection issues will be further clarified by the NERC SPCTF drafting team. The spirit of the TPL standard will remain that Load loss must not be planned for any single failure. 2. The SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning		

Organization	Question 15:	Question 15 Comments:
Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations. 3. The SDT agrees and has removed the need for documentation of the technical rationale for modification of any data. 4. The SDT disagrees and believes that the format and language of Requirement R2.6 (now R2.5) and its new sub-requirements are appropriate. 5. The SDT has modified the language of Requirement R3.1 and deleted Requirement R3.3 to eliminate the redundancy. **R3.1** Studies shall be performed to determine whether the BES meets the performance requirements in Table 1~~ – Steady State Performance.~~ based on the lists created in Requirement R3.5.		
Orlando Utilities Commission	C — Definitely do not support the revised standard	This standard is a definite improvement over the current set of standards. The majority of my comments are on details rather then the overall concept. My single biggest concern is the handling of n-1-1. This represents a significant expense to transmission customers and serious restriction on making firm transmission available, but due to the low probability of these events it would represent little if any practical improvement in customer reliability or grid security.
Response: Please see footnote #10 with regard to N-1-1. The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus. The SDT is cognizant of the cost factors involved here and is taking them into consideration in its deliberations. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
Entergy Services, Inc.	C — Definitely do not support the revised standard	No cost-benefit studies have been completed to justify the significant investment and no detailed analysis of the expected reliability impact has been conducted for the Eastern Interconnection. Some research suggests that infrastructure expansion will reduce the number of large BES events, but that each event would impact larger areas with longer restoration times. http://eceserv0.ece.wisc.edu/~dobson/PAPERS/complexsystemsresearch.html Additionally, there is a fatal disconnect between the enhanced reliability standard and the FERC's current standard for selling firm transmission service. A utility cannot be required to build to an N-1-1 standard to satisfy reliability requirements and also be required to sell additional firm transmission service using a lower N-1 reliability standard. Such a situation would create an untenable situation where reliability standards force construction that the utility is then required to make available for sale pursuant to the provisions of the OATT and, once sold in accordance with the OATT, results in the utility being out of compliance with the reliability requirement. Requirement P2.1 in the table will have direct impact on local load reliability but not grid reliability. For example, a long line

Organization	Question 15:	Question 15 Comments:
		in a radial configuration due to a single contingency would only impact the reliability in a local area. Any implementation plan should consider all aspects of obstacles that Transmission owners will encounter including, ROW and land acquisition delays, inflationary impact on raw materials and other resources, capital funding constraints and associated regulatory lag, etc. Category P6 prescribes what is effectively an n-2 criteria for offering firm transmission service by not allowing the curtailment of firm transmission service as a system adjustment. Many areas are limited in how much local generation is available for re-dispatch as a system adjustment and thus compliance would be realized only by costly transmission construction by TPs.
Response: The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus. The SDT is cognizant of the cost factors involved here and is taking them into consideration in its deliberations. The SDT agrees that clarification regarding Firm Transmission Service and Non-Consequential Load Loss is necessary. Footnote # 10 has been added to the end of Table 1: **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered. The SDT agrees that the Implementation Plan should consider matters you have listed. Nevertheless, the SDT feels that for this event (explained in detail in the footnote 8 of draft 3 of this Standard) interruption of neither firm nor Non-Consequential Load should be allowed for any BES voltage level, i.e., above or below 300 kV. This is consistent with FERC Order 693 that does not allow dropping Non-Consequential firm Load following any single Contingency. The SDT agrees that clarification regarding treatment of Firm Transmission Service and Non-Consequential Load Loss during adjustment is necessary. Footnote 10 in draft 3 of the Standard provides clarification.		
BPA Transmission Reliability Program	B — Unsure about supporting the revised standard	We are unsure about supporting the revised standard. A couple of additional concerns are described below. The purpose of the Standard is not clearly defined. There should be more clarity given to what reliability means in the context of these standards (e.g. minimize load loss for more probable contingencies, etc.). Regarding the terms "interruption of firm transmission service", there needs to be clarification of what "Interruption" means. Does it include curtailment needed after a particular contingency and adjustments? There also needs to be clarification on what "Firm Transmission Service" means. Two points: 1) the NERC definition states "highest quality of service offered to customers under a filed rate schedule that anticipates no planned interruption." The Standard implies anticipation of "unplanned' interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order

Organization	Question 15:	Question 15 Comments:
		890, or firm transfers modeled for the conditions being studied? One way to interpret the intent, is the firm transfers being modeled for the conditions in the powerflow, to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load, if the transfer being modeled is interrupted, then interruption of firm transmission service should be allowed for P1 through P5 contingencies in the table.
Response: The SDT believes that the Purpose under A.3 adequately captures the main intent which is to develop a "Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies." Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency. However, until the next Contingency occurs, System performance will need to meet the requirements for Event P1. As such, the proposed standard will not allow loss of any Non-Consequential Load, except for contracted Interruptible Loads, in preparation for the next Contingency. "Firm Transmission Service" is a NERC defined term and is also addressed by FERC in OATT. **Footnote #10** – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.		
PPL EnergyPlus	A — Generally support the revised standard	
Response: Thank you for your support.		

Implementation Plan for TPL-001-1

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

TPL-001-1 – Transmission System Planning Performance Requirements

Revision to Sections of Approved Standards and Definitions

There are multiple new definitions in the proposed standard.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions.

Extreme Events: Events which are more severe and have a lower probability of occurrence than Planning Events.

Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Near-Term Transmission Planning Horizon: Transmission planning period that covers Years One through five.

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.

Planning Events: Events that require Transmission system performance requirements to be met.

Supplemental Load Loss: Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.

Year One: The first year that a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the current calendar year.

Compliance with Standards

Standard	Functions That Must Comply With the Associated Requirements	
TPL-001-1 – Transmission System Planning Performance Requirements	Transmission Planner	Planning Coordinator
	X	X

Effective Dates

The effective date is the date entities are expected to meet the performance identified in this standard.

Except as indicated below, all Requirements and associated sub-requirements shall become effective 24 months after the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect 24 months after Board of Trustees adoption.

TPL-001-0, TPL-002-0a, TPL-003-0a, and TPL-004-0 are being retired as they are replaced in their entirety by TPL-001-1. TPL-005-0 and TPL-006-0 are being retired because their requirements are adequately covered by the revised TPL-001-1 and NERC's Rules of Procedure, Section 800. However, during this 24-month period, all aspects of TPL-001-0 through TPL-006-0 shall remain in effect for compliance monitoring. This 24 month period is to allow entities to develop, perform and/or validate new and/or modified studies, methodologies, assessments, procedures, etc. necessary to implement and meet the TPL-001-1 requirements. The specified effective dates are expected to allow sufficient time for proper assessment of the available options necessary to create a viable Corrective Action Plan that is compliant with the new Standard.

R1. This Requirement is related to maintaining System models and the data needed to do so. This requirement shall become effective 12 months after the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes into effect 12 months after Board of Trustees adoption.

R7. This Requirement identifies an obligation to determine individual and joint responsibilities for performing studies needed to do the Planning Assessment. This requirement shall become effective 12 months after the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes into effect 12 months after Board of Trustees adoption.

TPL-001-1 'raises the bar' in several areas where performance requirements have been changed in the new Standard versus those in existing TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0 because loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain events, whereas the existing Standards were interpreted by many to allow such

actions. As shown in Table 1 of TPL-001-1, the performance requirements associated with the following events represent "raising the bar":

- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

This "raising the bar" is beyond the control of the Transmission Planner and Planning Coordinator and may have significant budget, siting, permitting, and construction impacts on many Transmission Owners. The SDT requested input from industry on the amount of time required to implement the Corrective Action Plans needed to address the 'raise the bar' issues. The SDT has studied the responses and determined that a timeframe coincident with the end of the Near-Term Transmission Planning Horizon would be the appropriate amount of time to implement the changes. Therefore, for 60 months after the first day of the first calendar quarter following applicable approval, Corrective Action Plans applying to performance elements P2-1, P2-2 (above 300 kV), P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 kV) are allowed to include tripping of Non-Consequential Load or curtailment of Firm Transmission Service (in accordance with Requirement R2.7.4) that would not otherwise be permitted by the requirements of TPL-001-1.

Any entity that cannot fully implement its Corrective Action Plan to eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for these performance elements by that date shall self report itself as being unable to meet the performance requirements of the Reliability Standard. The entity will submit a mitigation plan to its Regional Entity outlining the steps it will take to become compliant and the date it anticipates becoming compliant. The Regional Entity and NERC will review the mitigation plan and the Regional Entity/NERC will either approve it or remand it back for changes (this could include dates, steps, etc.). If the mitigation plan is approved by the Regional Entity and NERC and the entity completes the mitigation plan by the date contained within the mitigation plan, no penalties will be assessed. Those entities that do not meet the date outlined in the mitigation plan will begin settlement proceedings at that date.

NERC
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Please **DO NOT** use this form to submit comments. Please use the electronic form located at the site below to submit comments on the 3rd draft of the TPL-001-1 standard for Assess Transmission Future Needs (Project 2006-02). This comment form must be completed by **July 9, 2009.**

http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Background Information

TPL-001-1 Transmission System Planning Performance Requirements

Comments on the second draft of the TPL-001-1 Transmission System Planning Performance Requirements standard were received from the industry through September 29, 2008. The Drafting Team sought and received feedback to 15 questions, and the team appreciates the tremendous industry participation that generated over 500 pages of comments from over 100 organizations. Below is a brief overview of the 3rd draft of the standard highlighting areas where the SDT made changes based on stakeholder feedback from the second posting. The SDT is presenting several new questions to seek the industry's position related to the changes made and to obtain clarifying data that will provide further direction for improvements. The team's objectives remain unchanged - to create a single Transmission planning standard: 1) with clear, concise requirements set at an appropriate level to ensure reliability, and 2) that fully addresses all issues raised by FERC Orders 693 and 890, and industry inputs, including the SAR scope document.

3rd Draft Overview:

1. At first glance the third draft of the standard seems to have been substantially changed; however, this is not the case as the SDT has maintained its vision throughout the process and the changes shown are primarily clarifying in nature.
2. The flow and organization of the standard remain similar to the 2nd draft. However, some changes are noteworthy:
    a. Several definitions were revised or deleted based on industry feedback.
    b. Requirement R1 has been re-constituted to include all modeling/data issues needed for the assessment of Transmission System performance issues within this single Requirement. This change eliminates the need for Requirements R9 through R14.
    c. Assessment of spare equipment strategy has been clarified and merged into Requirement R2.
    d. The short circuit analysis has been moved back into Requirement R2.
    e. The use of an aggregate system Load model has been clarified in Requirement R2.4.1.
    f. How sensitivity studies fit into the overall assessment has been clarified in Requirement R2.4.3.
    g. The separate requirements for generating plant and System Stability have been consolidated into one Stability section.

   h. Qualifications for "past" studies have been further refined.
   i. Requirement R2.6.4 has been added to address situations beyond the control of the planner.
   j. Performance Tables – In response to industry comments, there is now one consolidated Table.

3. Violation Risk Factors (VRF) and Time Horizons were added to the requirements.
4. Measures have been added.
5. Data retention requirements have been added.
6. Violation Severity Levels (VSLs) have been added.
7. An Implementation Plan has been provided.

To facilitate the ability of industry respondents to comment in an orderly fashion and to ease the coordination burden on the SDT in responding to comments, the SDT is asking an all encompassing question for each requirement. This question solicits comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and the VSL associated with the requirement. Please note the numbering below refers to the clean copy of the third posting.

1. Requirement R1 — Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

   Comments:

2. Requirement R2 — Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

   Comments:

3. Requirement R3 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

   Comments:

4. Requirement R4 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

   Comments:

5. Requirement R5 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

   Comments:

6. Requirement R6 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

   Comments:

7. Requirement R7 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

   Comments:

The SDT is posing several other questions for industry consideration not related to the specific requirement questions above.

8. The SDT changed several definitions in response to industry comments to the second posting. Do you agree with these changes? If not, please clearly indicate which definition you disagree with and provide specific comments.

   ☐ Yes
   ☐ No

   Comments:

9. Do you agree with the changes in the performance elements and notes in Table 1? If not, please provide specific comments by note number, note alpha character, or performance category. Please note that footnotes 5 and 10 are handled separately in question 10.

   ☐ Yes
   ☐ No

   Comments:

10. The changes to the Table include the addition/revision of footnotes 5 and 10 that address curtailment of Firm Transmission Service and conditional Firm Transmission Service. Do you agree with the footnotes? If not, please provide specific comments.

    ☐ Yes
    ☐ No

    Comments:

11. The SDT has provided an Implementation Plan as part of this posting. The plan includes the retirement of TPL-005-0 and TPL-006-0. Do you agree with the elements of the Plan? If not, please provide specific comments.

    ☐ Yes
    ☐ No

    Comments:

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Version 1 of SAR posted for comment from April 2, 2002 through May 3, 2002.
2. Version 2 of SAR posted for comment from May 5, 2004 through June 5, 2004.
3. Version 3 of SAR posted on November 18, 2005.
4. SAR approved on April 30, 2006.
5. Version 1 of Supplemental SAR posted for comment from February 15, 2007 through March 16, 2007.
6. Version 2 of Supplemental SAR posted on April 9, 2007.
7. Version 1 of revised standard(s) posted for comment on September 17, 2007.
8. Version 2 of the revised standards posted for comment on August 15, 2008.

Proposed Action Plan and Description of Current Draft:

The SDT has established a schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 1Q10. The current draft is the second iteration of the revision of existing standards TPL-001 through TPL-006 and includes one revised standard, TPL-001-1, replacing TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. TPL-005 & -006 will be addressed later in the project.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Respond to comments from second posting of standard(s) and submit revision 3 of the standard(s).	4Q08
2. Respond to comments from third posting and submit revision 4 of the standard.	2Q09
3. Submit standard(s) for balloting.	3Q09
4. Submit standard(s) to BOT.	4Q09
5. Submit to regulatory authorities for approval.	1Q10

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions.

Extreme Events: Events which are more severe and have a lower probability of occurrence than Planning Events.

Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Near-Term Transmission Planning Horizon: Transmission planning period that covers Years One through five.

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction. .

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.

Planning Events: Events that require Transmission system performance requirements to be met.

Supplemental Load Loss: Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.

Year One: The first year that a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the current calendar year.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-1**

3. **Purpose:** Establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

   Except as indicated below, Requirements R2 through R6 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.

   - For 60 calendar months after the first day of the first calendar quarter following applicable regulatory approval, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-1, Table 1 are allowed to include tripping of Non-Consequential Load or curtailment of Firm Transmission Service (in accordance with Requirement R2.6.4) that would not otherwise be permitted by the requirements of TPL-001-1:

     - P2-1, P2-2 (above 300 kV)
     - P2-3 (above 300 kV)
     - P3-1 through P3-5
     - P4-1 through P4-5 (above 300 kV)
     - P5 (above 300 kV)

     Any entity that cannot fully implement its Corrective Action Plan to eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for the above listed performance elements within 60 calendar months of the compliance date for Requirements R2 through R4 shall self report itself as being unable to meet performance requirements of this Reliability Standard. Any such entity shall submit a mitigation plan to its Regional Entity outlining the steps it will take to become compliant and the date it anticipates becoming compliant. The Regional Entity and NERC shall review the mitigation plan and the Regional Entity/NERC will either approve it or remand it for changes (this could include dates, steps,

etc.). If the mitigation plan is approved by the Regional Entity and NERC and the entity completes the mitigation plan by the date contained within the mitigation plan, no penalties will be assessed. Those entities that do not meet the date outlined in an approved mitigation plan will begin settlement proceedings at that date.

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other data sources, and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R1.1. Models for the Planning Assessment shall represent:

R1.1.1. Planned outages of generation and Transmission Facilities, if specifically known.

R1.1.2. New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon, such as:

- Transmission Lines
- Generators
- Circuit breakers
- Reactive Power devices
- Protection System equipment
- Control devices
- New technologies.

R1.1.3. Real and reactive Demand of Load

R1.1.4. Firm Transmission Service

R1.1.5. Interchange

R1.1.6. Network resources required to supply Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies as indicated in Requirement R2.6:

R2.1.1. System peak Load for either Year One or year two, and for year five.

R2.1.2. System Off-Peak Load for one of the five years.

R2.1.3. For each of the studies described in Requirements R2.1.1 and R2.1.2, sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment:

- Forecasted Load and power factor.
- Expected transfers.
- Timing of the installation of new or modified Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Planned duration or timing of Transmission outages.

R2.1.4. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment.

R2.2. For the Long-Term Transmission Planning Horizon portion of the steady state analysis, a current System peak Load study is required annually for one of the years in the assessment period to support the annual Planning Assessment.

R2.2.1. To accommodate any known longer lead time projects that may take longer than ten years to complete, the Planning Assessment shall be extended accordingly.

R2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area.

R2.4. The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies. The following studies are required:

R2.4.1. System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.2. System Off-Peak Load for one of the five years.

R2.4.3. For each of the studies described in Requirements R2.4.1 and R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment:

- Load model assumptions.
- Expected transfers.
- Timing of the installation of new or modified Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

R2.5. Past studies may be used to support the Planning Assessment if they meet the following requirements:

R2.5.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less.

R2.5.2. For steady state, short circuit, or Stability analysis: the present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:

- The addition/deletion/change of individual generating unit capability of 20 MW or greater.
- An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater.

R2.6. For Planning Events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed in subsequent assessments but the System shall continue to meet the performance requirements in the tables. Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3 and R2.4.3. The Corrective Action Plan shall:

R2.6.1. List System deficiencies and the associated actions needed to achieve required System performance. Such actions may include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation or modification of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.

- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

R2.6.2. For the Near-Term Transmission Planning Horizon, include both a project initiation date as well as an in-service date.

R2.6.3. For the Long-Term Transmission Planning Horizon, provide an in-service year.

R2.6.4. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

R2.6.5. Be reviewed in subsequent annual Planning Assessments as to implementation status of identified System Facilities and Operating Procedures.

R2.7. For short circuit analysis, if the short circuit current interruption duty on fault interrupting devices determined in Requirement R2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

R2.7.1. List System deficiencies and the associated actions needed to achieve required System performance.

R2.7.2. Be reviewed in subsequent annual Planning Assessments as to implementation status.

R2.8. The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1.

R2.9. The Planning Assessment shall identify the maximum permissible Non-Consequential Load Loss (megawatt Demand) for those Planning Events where Non-Consequential Load Loss is allowed in Table 1.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. The studies shall be based on computer simulations using models utilizing data

provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R3.1. Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the lists created in Requirement R3.4.

R3.2. Studies shall be performed to assess the impact of the Extreme Events identified in Requirement R3.5.

R3.3. Contingency analyses shall:

R3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention.

R3.3.2. For all generators, studies shall consider the minimum steady state voltage limitations and identify how the generators are analyzed in the steady state simulation.

R3.3.3. For all Transmission lines, studies shall consider relay loadability and identify how loadability is analyzed in the steady state simulation.

R3.3.4. Simulate the expected operation of existing and planned devices designed to provide Steady State control of electrical system quantities. These devices include equipment such as phase-shifting transformers, load tap changing transformers, capacitors, and inductors.

R3.4. Those Planning Event Contingencies in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3.1 created. The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results.

R3.5. Those Extreme Events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3.2 created. The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. If the analysis concludes there are cascading outages caused by the occurrence of Extreme Events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2.4, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R4.1. Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the lists created in RequirementR4.4.

R4.2. Studies shall be performed to assess the impact of the Extreme Events identified in Requirement R4.5.

R4.3. Contingency analyses shall:

R4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention.

R4.3.2. Simulate generator performance under anticipated conditions including how the voltage ride through capability is analyzed.

R4.3.3. Simulate the expected operation of existing and planned devices designed to provide dynamic control of electrical system quantities. These devices include equipment such as generation exciter control and power system stabilizers, static VAR compensators, power flow controllers, and DC Transmission controllers.

R4.4. Those Planning Event Contingencies in Table 1 – that are expected to produce more severe System impacts shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4.1 created. The rationale for the Contingencies selected for evaluation shall be available as supporting information with an explanation of why the remaining Contingencies would produce less severe System results.

R4.5. Those Extreme Events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R4.2 created. The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. If the analysis concludes there are cascading outages caused by the occurrence of Extreme Events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, any proxies used in the analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall determine and identify individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among adjacent Planning Coordinators and any functional entity who has indicated a reliability need, coordinating analysis of these results through an open and

transparent peer review process such as described in FERC Order 890. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, such as the System model with the specified data in electronic or hard copy format, that it is maintaining System models, using data consistent with MOD-010 and MOD-012, simulating projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies, of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies, of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies, of the studies utilized in preparing the Planning Assessment in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide evidence, such as a dated document, that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies for the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient, date, and contents, or a demonstration of a public posting, that it has coordinated the distribution of Planning Assessment results among adjacent Planning Coordinators and any functional entity who has indicated a reliability need, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890 in accordance with Requirement R7.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity.

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current Planning Assessment and one previous Planning Assessment in accordance with Requirement R1.and Measure M1.
- All Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- All studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- All studies performed in support of its Planning Assessment since the last compliance audit in accordance with Requirement R4 and Measure M4.
- All studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The current, in force agreement on identified responsibilities, as well as all such agreements in force since the last compliance audit, in accordance with Requirement R6 and Measure M6.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R7 and Measure M7.

1.5 Additional Compliance Information

None.

2 Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Planner or Planning Coordinator's System model failed to represent one of the sub-requirements R1.1.1 through R1.1.6.	The Transmission Planner or Planning Coordinator's System model failed to represent two of the sub-requirements R1.1.1 through R1.1.6. OR The System model did not use data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other data sources.	The Transmission Planner or Planning Coordinator's System model failed to represent three of the sub-requirements R1.1.1 through R1.1.6.	The Transmission Planner or Planning Coordinator's System model failed to represent four or more of the sub-requirements R1.1.1 through R1.1.6. OR The System model did not simulate projected System conditions as described in Requirement R1.
R2	The Transmission Planner or Planning Coordinator failed to comply with one or both of the following sub-requirements: R2.8 or R2.9.	The Transmission Planner or Planning Coordinator failed to comply with one of the sub-requirements: R2.3 or R2.7.	The Transmission Planner or Planning Coordinator failed to comply with one of the sub-requirements: R2.1, R2.2, R2.4, or R2.6.	The Transmission Planner or Planning Coordinator failed to comply with two or more of the sub-requirements: R2.1, R2.2, R2.4, or R2.6.
R3	The Transmission Planner or Planning Coordinator did not identify Planning Events as described in Requirement R3.4 or Extreme Events as described in Requirement R3.5.	The Transmission Planner or Planning Coordinator did not perform studies as specified in Requirement R3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1. OR The Transmission Planner or Planning Coordinator did not perform studies as specified in Requirement R3.2 to assess the	The Transmission Planner or Planning Coordinator did not perform studies as specified in Requirement R3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in Table 1. OR The Transmission Planner or Planning Coordinator did not perform Contingency analysis as	The Transmission Planner or Planning Coordinator did not perform studies as specified in Requirement R3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1. OR The Transmission Planner or Planning Coordinator did not perform studies to determine that the BES meets the performance requirements for the P0 or

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		impact of Extreme Events. OR The Transmission Planner or Planning Coordinator did not base its studies on computer simulations using models utilizing data provided in Requirement R1.	described in Requirement R3.3.	P1 categories in Table 1.
R4	The Transmission Planner or Planning Coordinator did not identify Planning Events as described in Requirement R4.4 or Extreme Events as described in Requirement R4.5.	The Transmission Planner or Planning Coordinator did not perform studies as specified in Requirement R4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The Transmission Planner or Planning Coordinator did not perform studies as specified in Requirement R4.2 to assess the impact of Extreme Events. OR The Transmission Planner or Planning Coordinator did not base its studies on computer simulations using models utilizing data provided in Requirement R1.	The Transmission Planner or Planning Coordinator did not perform studies as specified in Requirement R4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The Transmission Planner or Planning Coordinator did not perform Contingency analysis as described in Requirement R4.3.	The Transmission Planner or Planning Coordinator did not perform studies as specified in Requirement R4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1.
R5	N/A	N/A	N/A	The Transmission Planner or Planning Coordinator failed to define and

	Lower VSL	Moderate VSL	High VSL	Severe VSL
				document the proxies for System instability used within their analysis as described in Requirement R5.
R6	N/A	N/A	N/A	The Transmission Planner or Planning Coordinator failed to determine and identify individual or joint responsibilities for performing required studies.
R7	N/A	N/A	The Planning Coordinator failed to coordinate the analysis of its Planning Assessment results through an open and transparent peer review process.	The Planning Coordinator failed to distribute the results of its Planning Assessment.

E. Regional Variances

None.

Table 1 – Steady State & Stability Performance
Planning Events

Steady State & Stability:

a. Voltage instability, cascading outages, and uncontrolled islanding shall not occur.

b. Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements.

c. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator (or Transmission Planner if more restrictive).

g. Planning Event P0 is applicable to steady state only.

Stability Only:

h. The System shall remain stable. [1]

i. Transient voltage response shall be within acceptable limits established by the Planning Coordinator (or Transmission Planner if more restrictive).

Category	Initial System Condition	Event [2]	Fault Type [3]	BES Level [4]	Interruption of Firm Transmission Service Allowed [5]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [6] 4. Shunt Device [7]	3Ø	EHV, HV	No	No
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of Breaker(s) w/o fault [8]	N/A	EHV, HV	No	No
		2. Bus Section Fault	SLG	EHV	No	No
				HV	Yes	Yes
		3. Internal Breaker Fault [9]	SLG	EHV	No	No

		(Non bus-tie)	SLG	HV	Yes	Yes
		4. Internal Breaker Fault (bus-tie) [9]	SLG	EHV, HV	Yes	Yes

Table 1 — Steady State & Stability Performance Planning Events						
Category	**Initial System Condition**	**Event [2]**	**Fault Type [3]**	**BES Level [4]**	**Interruption of Firm Transmission Service Allowed [5]**	**Non-Consequential Load Loss Allowed**
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[10]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [6] 4. Shunt Device [7]	3Ø	EHV, HV	No[10]	No
		5. Single pole of a DC line	SLG	EHV, HV	No[10]	No
P4 Multiple Contingency *(Fault plus stuck breaker [11])*	Normal System	Stuck breaker [11](non-bus-tie) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [6] 4. Shunt Device [7] 5. Bus Section	SLG	EHV	No[10]	No
			SLG	HV	Yes	Yes
		6. Stuck breaker (bus-tie) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus Protection System failure)*	Normal System	Loss of multiple elements caused by the failure of a single Protection System while clearing a fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [6] 4. Shunt Device [7] 5. Bus Section	SLG	EHV	No[10]	No
			SLG	HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping*	Loss of one of the following followed by System adj.[10]: 1. Transmission Circuit 2. Transformer [6]	Loss of one of the following: 1. Transmission Circuit 2. Transformer [6] 3. Shunt Device [7]	3Ø	EHV, HV	Yes	Yes

singles)	3. Shunt Device [7] 4. Single pole of a DC line	4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two circuits on common structure [12] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 — Steady State & Stability Performance
Extreme Events

Steady State & Stability

For all Extreme Events evaluated:

1. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency.
2. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
   a. Loss of a tower line with three or more circuits.[12]
   b. Loss of all Transmission lines on a common Right-of-Way.
   c. Loss of a switching station or substation (loss of one voltage level plus transformers).
   d. Loss of all generating units at a station.
   e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
   a. Loss of two generating plants resulting from conditions such as:
      i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
      ii. Loss of the use of a large body of water as the cooling source for generation.
      iii. Wildfires.
      iv. Severe weather, e.g., hurricanes, tornadoes, etc.
      v. A successful cyber attack.
      vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
   b. Other events based upon operating experience that may result in wide area disturbances.

Stability

1. With an initial condition of a single generator, Transmission circuit, DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
   a. 3Ø fault on generator with stuck breaker[11] or a Protection System failure resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[11] or a Protection System failure resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[11]or a Protection System failure resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[11] or a Protection System failure resulting in Delayed Fault Clearing.
   e. 3Ø internal breaker fault[11].
   f. 3Ø fault on two or more circuits on a common structure[12].
   g. SLG fault on all Transmission lines on a common Right-of-Way.
   h. 3Ø fault on switching station or substation (loss of one voltage level plus transformers)
   i. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 — Steady State & Stability Performance
Footnotes
(Planning Events and Extreme Events)

1. System stable means:
   a. Angular Stability:
      i. For Planning Event P1: No generating unit or units shall be allowed to pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.
      ii. For all other Planning Events: No generating unit or units totaling more than the Contingency Reserve of the Balancing Authority (or Reserve Sharing Group if applicable) shall be allowed to pull out of synchronism. Generators that pull out of synchronism must have out-of-step protection or some other means to trip the generator for this condition and the resulting apparent impedance swings must not pass through relay characteristics that would result in the tripping of any Transmission System elements other than the generating unit and its direct connection Facilities.
   b. For all Planning Events evaluated: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator (or Transmission Planner if more restrictive).
2. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level for stated performance criteria applies regarding allowances for interruptions of Firm Transmission Service and loss of Non-Consequential Load.
3. Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø fault study indicating criteria are being met shall provide sufficient evidence that a SLG condition would also meet criteria.
4. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruptions of Firm Transmission Service and Non-Consequential Load.
5. When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed.
6. For non-Generator Step Up transformer outage events, the reference voltage applies to the low-side winding (excluding tertiary windings). For generator and generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
7. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
8. Inadvertent tripping of breakers on one end of a normally networked Transmission circuit such that the line is now open at that end and possibly serving Load radial from a single source point.
9. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
10. Curtailment of firm transmission service , when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.
11. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) breaker,

Table 1 — Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
only one pole is assumed to remain closed. A stuck breaker introduces a delayed clearing mode.
12. Excludes circuits that share a common structure for 1 mile or less.

Version History

Version	Date	Action	Change Tracking
1	TBD	Revision of TPL-001-0 as per Project 2006-02; includes merging requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-1	Not employed due to scope of revision

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Version 1 of SAR posted for comment from April 2, 2002 through May 3, 2002.
2. Version 2 of SAR posted for comment from May 5, 2004 through June 5, 2004.
3. Version 3 of SAR posted on November 18, 2005.
4. SAR approved on April 30, 2006.
5. Version 1 of Supplemental SAR posted for comment from February 15, 2007 through March 16, 2007.
6. Version 2 of Supplemental SAR posted on April 9, 2007.
7. Version 1 of revised standard(s) posted for comment on September 17, 2007.
8. Version 2 of the revised standards posted for comment on August 15, 2008.

Proposed Action Plan and Description of Current Draft:

The SDT has established a schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 1Q10. The current draft is the second iteration of the revision of existing standards TPL-001 through TPL-006 and includes one revised standard, TPL-001-1, replacing TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. TPL-005 & -006 will be addressed later in the project.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Respond to comments from third posting and submit revision 4 of the standard.	2Q09
2. Submit standard(s) for balloting.	3Q09
3. Submit standard(s) to BOT.	4Q09
4. Submit to regulatory authorities for approval.	1Q10

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual ~~straight bus~~ substation bus configurations. ~~(Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)~~

Consequential Load Loss: ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions.

Extreme Events: Events which are more severe and have a lower probability of occurrence than Planning Events.

~~**Generating Unit Stability Study:** Study that focuses on an individual generating unit's or electrically-closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations.~~

Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Near-Term Transmission Planning Horizon: Transmission planning period that covers Years One through five.

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~.

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.

Planning Events: Events that require Transmission system performance requirements to be met.

~~**Planning Coordinator:** The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.~~

Supplemental Load Loss: Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.

~~**System Stability Study:** Study that focuses on portions of the System, which may include many generating units, to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.~~

Year One: The first year that a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the ~~completion of the previous annual Planning Assessment~~ current calendar year.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-1**

3. **Purpose:** Establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** ~~As per Implementation Plan (to be supplied later).~~ Requirements R1 and R7 shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

   Except as indicated below, Requirements R2 through R6 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.

   - For 60 calendar months after the first day of the first calendar quarter following applicable regulatory approval, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-1, Table 1 are allowed to include tripping of Non-Consequential Load or curtailment of Firm Transmission Service (in accordance with Requirement R2.6.4) that would not otherwise be permitted by the requirements of TPL-001-1:
     - P2-1, P2-2 (above 300 kV)
     - P2-3 (above 300 kV)
     - P3-1 through P3-5
     - P4-1 through P4-5 (above 300 kV)
     - P5 (above 300 kV)

     ~~5.~~Any entity that cannot fully implement its Corrective Action Plan to eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for the above listed performance elements within 60 calendar months of the compliance date for Requirements R2 through R4 shall self report itself as being unable to meet performance requirements of this Reliability Standard. Any such entity shall submit a mitigation plan to its Regional Entity outlining the steps it will take to become compliant and the date it anticipates becoming compliant. The Regional Entity and NERC shall review the mitigation plan and the Regional Entity/NERC will either approve it or remand it for changes (this could include dates, steps, etc.). If the mitigation plan is approved by the Regional Entity and

NERC and the entity completes the mitigation plan by the date contained within the mitigation plan, no penalties will be assessed. Those entities that do not meet the date outlined in an approved mitigation plan will begin settlement proceedings at that date.

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations. *[Violation Risk Factor: ~~TBD~~Medium] [Time Horizon: ~~TBD~~Long-term Planning]*

~~**R1.1.**~~

~~The Planning Assessment shall include documentation of the technical rationale for modification of any data that was provided in Requirement R9 through R14, MOD-010, and MOD-012~~.

R1.1. Models for the Planning Assessment shall represent:

R1.1.1. Planned outages of generation and Transmission Facilities, if specifically known.

R1.1.2. New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon, such as:

- -Transmission Lines
- -Generators
- -Circuit breakers
- -Reactive Power devices
- -Protection System equipment
- -Control devices
- -New technologies.

R1.1.3. Real and reactive Demand of Load

R1.1.4. Firm Transmission Service

R1.1.5. Interchange

R1.1.6. Network resources required to supply Load

R2. Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses ~~including both System and Generating Unit Stability~~. *[Violation Risk Factor: ~~TBD~~Medium] [Time Horizon: ~~TBD~~Long-term Planning]*

R2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported ~~at a minimum~~ by the following annual current studies, supplemented with qualified past studies as indicated in Requirement R2.6:

R2.1.1. System peak Load for either Year One or year two, and for year five.

R2.1.2. System Off-Peak Load for one of the five years.

R2.1.3. For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

- ~~P.2.1.3.1.~~ ~~Higher or lower Load than forecasted with variability of Load/demand and Load power factors due to season, weather, or time of day~~ Forecasted Load and power factor.
- ~~P.2.1.3.2.~~ ~~Modification of e~~Expected transfers.
- ~~P.2.1.3.3.~~ ~~Unavailability of long lead time Facilities~~ Timing of the installation of new or modified Facilities.
- ~~P.2.1.3.4.~~ ~~Variability and outages of r~~Reactive resource~~s~~ capability.
- ~~P.2.1.3.5.~~ Generation additions, retirements, or other dispatch scenarios.
- ~~P.2.1.3.6.~~ ~~Decreased effectiveness of c~~Controllable Loads and Demand Side Management.
- ~~P.2.1.3.7.~~ ~~Modification of p~~Planned duration or timing of Transmission outages.

R2.1.4. ~~In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and the Planning Assessment shall include documentation of the technical rationale for why each was selected shall be supplied.~~ When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment.

R2.2. For the Long-Term Transmission Planning Horizon portion of the steady state analysis, ~~at a minimum,~~ a current System peak Load study is required annually for one of the years in the assessment period to support the annual Planning Assessment.

R2.2.1. To accommodate any known longer lead time projects that may take longer than ten years to complete, the Planning Assessment shall be extended accordingly.

R2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area.

R2.4. The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies. The following studies are required:

R2.4.1. System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.2. System Off-Peak Load for one of the five years.

R2.4.3. For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

- ~~Variations in~~ Load model assumptions.
- ~~Modification of e~~Expected transfers.
- ~~Unavailability of long lead time Facilities~~ Timing of the installation of new or modified Facilities.
- ~~Variability and outages of r~~Reactive resource~~s~~ capability.
- Generation additions, retirements, or other dispatch scenarios.

~~**R2.4.4.** In addition to those sensitivities mentioned in Requirement 2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and the Planning Assessment shall include documentation of the technical rationale for why each was selected shall be supplied.~~

~~**R2.5.** The Generating Unit Stability analysis portion of the Planning Assessment shall be analyzed consistent with Requirement R5.5 with studies for the year when the following changes that could affect stability margins occur:~~

~~**R2.5.1.** New generator(s) are added or generation modifications are made such as changes in generation capability or replacing the exciter.~~

~~**R2.5.2.** Material Transmission System changes are made at or near the point of Interconnection of existing Generation such as the removal of a~~

~~Transmission Line or the addition of a new substation in one of the Transmission Lines connected to the plant.~~

~~R2.6.~~R2.5. Past studies may be used to support the Planning Assessment if they meet the following requirements:

~~R2.6.1.~~R2.5.1. For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less.

~~R2.6.2.~~R2.5.2. For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:

- ~~-~~The addition/deletion/change of individual generating unit capability of 20 MW or greater.
- ~~-~~An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater.

~~R2.7.~~R2.6. For Planning Events shown in Table 1~~— Steady State Performance and Table 2 – Stability Performance~~, when the analysis indicates an inability of the System to meet the performance requirements in ~~the t~~Table~~s~~ 1, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed in subsequent assessments but the System shall continue to meet the performance requirements in the tables. Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3 and R2.4.3. The Corrective Action Plan shall:

~~R2.7.1.~~R2.6.1. List System deficiencies and the associated actions needed to achieve required System performance. Such actions may include: ~~installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.~~

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation or modification of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.

- -Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations.
- -Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- -Use of rate applications, DSM, new technologies, or other initiatives.

~~R.2.7.1.1.~~R2.6.2. For the Near-Term Transmission Planning Horizon, include both a project initiation date as well as an in-service date.

~~R.2.7.1.2.~~R2.6.3. For the Long-Term Transmission Planning Horizon, provide an in-service year.

~~R2.7.4.~~~~Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.~~

R2.6.4. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

~~R2.7.3.~~R2.6.5. Be reviewed in subsequent annual Planning Assessments as to implementation status of identified System Facilities and Operating Procedures.

~~R2.8.1.~~R2.7. For short circuit analysis, if the short circuit current interruption duty on fault interrupting devices determined in Requirement R2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

R2.7.1. List System deficiencies and the associated actions needed to achieve required System performance.

R2.7.2. Be reviewed in subsequent annual Planning Assessments as to implementation status.

~~R2.7.~~R2.8. The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1.

R2.9. The Planning Assessment shall identify the maximum permissible Non-Consequential Load Loss (megawatt Demand) for those Planning Events where Non-Consequential Load Loss is allowed in Table 1.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. ~~The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to c~~Contingencies in Table 1 ~~– Steady State Performance.~~ The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. *[Violation Risk Factor: ~~TBD~~Medium]* *[Time Horizon: ~~TBD~~Long-term Planning]*

R3.1. Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 ~~– Steady State Performance.~~ based on the lists created in Requirement R3.4.

R3.2. Studies shall be performed to assess the impact of the Extreme Events identified in Requirement R3.5.

~~**R3.2.**~~**R3.3.** Contingency analyses shall: ~~simulate the removal of all elements including those that System protection is expected to disconnect for each Contingency without operator intervention.~~

R3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention.

~~**R3.2.1.**~~**R3.3.2.** For all generators, studies shall consider the minimum steady state voltage limitations ~~of all generators~~ and identify how the generators are ~~treated~~ analyzed in the steady state simulation.

~~**R3.2.2.**~~**R3.3.3.** For all Transmission lines, studies shall consider relay loadability and identify how loadability is ~~treated~~ analyzed in the steady state simulation.

R3.3.4. Simulate the expected operation of existing and planned devices designed to provide Steady State control of electrical system quantities. These devices include equipment such as phase-shifting transformers, load tap changing transformers, capacitors, and inductors.

~~**R3.2.**For Steady State studies:~~

~~**R3.2.1.**Performance criteria for System normal conditions and for Planning Events in Table 1 – Steady State Performance shall be met.~~

~~**R3.2.2.**Evaluations shall be performed for single Contingencies (identified in Table 1 – Steady State Performance).~~

~~**R.3.2.2.1.** Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment.~~

~~**R.3.2.2.2.** Following single Contingency events, Transmission configuration changes and redispatch of generation are allowed provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits.~~

~~**R3.3.3.**~~**R3.4.** Those Planning Event Contingencies in Table 1 ~~– Steady State Performance not covered in Requirement R3.3.2~~ that are expected to produce more severe System impacts shall be identified~~,~~ and a list of those Contingencies to be evaluated for System performance in Requirement R3.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results.

~~**R3.4.**~~**R3.5.** Those Extreme Events in Table 1 ~~– Steady State Performance~~ that are expected to produce more severe System impacts shall be identified~~,~~ and a list of those events to be evaluated for System performance in Requirement R3.2 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results. If the ~~Extreme Events~~ analysis concludes there are cascading outages caused by the occurrence of Extreme Events, an evaluation of ~~implementing a change~~ possible actions designed to reduce ~~or mitigate~~ the likelihood or mitigate ~~of such~~the consequences and adverse impacts of the event(s) shall be conducted.

~~R3.5.Manual and automatic generation run-back/tripping is allowed as a response to a single or multiple Contingency if the following conditions are met:~~

~~**R3.5.1.**All Facilities shall be operating within their Facility Ratings.~~

~~**R3.4.1.**Such action would not violate safety, equipment, regulatory or statutory requirements.~~

~~**R3.4.2.**A sustainable, stable, operating condition is maintained.~~

~~**R4.**For the short circuit portion of the Planning Assessment, as described in Requirement R2.3, each Transmission Planner and Planning Coordinator shall assess the short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*~~

~~**R5.**~~**R4.** For the Stability portion of the Planning Assessment, as described in Requirement R2.4~~ and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise~~

~~noted.~~ *[Violation Risk Factor: ~~TBD~~Medium] [Time Horizon: ~~TBD~~Long-term Planning]*

R4.1. Studies shall be performed to determine whether the BES meets the performance requirements in Table ~~2~~1 ~~– Stability Performance~~ based on the lists created in Requirement R4.4~~shall use computer Stability simulations that analyze the response of the BES~~.

R4.2. Studies shall be performed to assess the impact of the Extreme Events identified in Requirement R4.5.

R4.3. Contingency analyses shall:

R4.3.1. ~~s~~Simulate the removal of all elements ~~including those~~ that the Protection System ~~protection~~ and other automatic controls are expected to disconnect for each Contingency without operator intervention.

~~R5.3.~~R4.3.2. ~~Studies shall consider~~ Simulate generator performance under anticipated conditions including how the voltage ride through capability ~~of all generators and identify how the generators are treated~~ is analyzed ~~in the simulation~~.

R4.3.3. Simulate the expected operation of existing and planned devices designed to provide dynamic control of electrical system quantities. These devices include equipment such as generation exciter control and power system stabilizers, static VAR compensators, power flow controllers, and DC Transmission controllers.

~~**R5.2.**For the System Stability study:~~

~~R5.4.1.~~R4.4. ~~At a minimum, t~~Those Planning Event Contingencies in Table ~~2~~1 – ~~Stability Performance~~ that ~~would~~are expected to produce more severe System impacts shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information with an explanation of why the remaining Contingencies would produce less severe System results.

~~**R5.3.1.**Performance shall meet the requirements for Planning Events in Table 2 – Stability Performance.~~

~~**R5.3.2.**Automatic generation tripping is allowed to mitigate Stability violations if the following conditions are met:~~

~~**R.5.3.2.1.** All Facilities shall be operating within their Facility Ratings.~~

~~**R.5.3.2.2.**Such action would not violate safety, equipment, regulatory or statutory requirements.~~

~~R.5.4.3.3.A sustainable, stable, operating condition is maintained.~~

~~R5.4.4.~~R4.5. ~~At a minimum, t~~Those Extreme Events in Table ~~2~~1 ~~– Stability Performance~~ that ~~would~~are expected to produce more severe System impacts shall be identified and a list of those events to be~~,~~ evaluated for System performance in Requirement R4.2 created~~,~~. ~~and t~~The rationale for the

Contingencies selected for evaluation shall be available as supporting information and shall include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results. If the ~~Extreme Events~~ analysis concludes there are cascading outages caused by the occurrence of Extreme Events, an evaluation of ~~implementing a change~~ possible actions designed to reduce ~~or mitigate~~ the likelihood or mitigate ~~of such~~the consequences of the event(s) shall be conducted.

~~**R5.5.**For the Generating Unit Stability studies:~~

~~**R5.5.1.**Shall be performed for individual generating units 20 MW or greater directly connected through a step-up transformer to the BES and for generating units at the same location which total 75 MW or greater, directly connected through their step-up transformer(s) to the BES.~~

~~**R5.5.2.**Shall be performed for changes in the real power output of a generating unit by more than 10% of the existing capability or more than 20 MW whichever is greater.~~

~~**R5.5.3.**Shall be performed and evaluated for those Planning Events that would produce more severe System impacts and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results.~~

~~**R5.5.4.**Shall meet Performance requirements for Planning Events in Table 2 – Stability Performance.~~

~~**R6.**~~**R5.** Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, ~~the~~any proxies used in ~~simulation studies~~ the analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: ~~TBD~~Low] [Time Horizon: ~~TBD~~Long-term Planning]*

~~**R7.**~~**R6.** Each Transmission Planner and Planning Coordinator shall determine and identify individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: ~~TBD~~Low] [Time Horizon: ~~TBD~~Long-term Planning]*

~~**R8.**~~**R7.** Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~neighboring systems~~ adjacent Planning Coordinators and any functional entity who has indicated a reliability need, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890. *[Violation Risk Factor: ~~TBD~~Low] [Time Horizon: ~~TBD~~Long-term Planning]* ~~This distribution shall include:~~

~~**R9.**Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*~~

~~**R10.**Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*~~

~~**R11.**Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*~~

~~**R12.**Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*~~

~~**R13.**Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*~~

~~**R14.**Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to Transmission Lines, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies, within ninety days of a request for such information. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*~~

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, such as the System model with the specified data in electronic or hard copy format, that ~~they~~it ~~are~~is maintaining System models, using data consistent with MOD-010 and MOD-012, simulating projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies, of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

~~**M1.**Requirement R4 to be deleted.~~

~~**M5.**~~**M4.** Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies, of the studies utilized in preparing the Planning Assessment in accordance with Requirement R~~5~~4.

M5. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies, of the studies utilized in preparing the Planning Assessment in accordance with Requirement R~~6~~5.

~~**M7.**~~**M6.** Each Transmission Planner and Planning Coordinator shall provide evidence, such as a dated document, that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies for the Planning Assessment in accordance with Requirement R~~7~~6.

M7. Each Planning Coordinator shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient, date, and contents, or a demonstration of a public posting, that it has coordinated the distribution of Planning Assessment results among adjacent Planning Coordinators and any functional entity who has indicated a reliability need, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890 in accordance with Requirement R~~8~~7.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity.

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current Planning Assessment and one previous Planning Assessment in accordance with Requirement R1.and Measure M1.
- All Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- All studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.

- All studies performed in support of its Planning Assessment since the last compliance audit in accordance with Requirement R4 and Measure M4.
- All studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The current, in force agreement on identified responsibilities, as well as all such agreements in force since the last compliance audit, in accordance with Requirement R6 and Measure M6.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R7 and Measure M7.

1.5 Additional Compliance Information

None.

2 Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Planner or Planning Coordinator's System model failed to represent one of the sub-requirements R1.1.1 through R1.1.6.	The Transmission Planner or Planning Coordinator's System model failed to represent two of the sub-requirements R1.1.1 through R1.1.6. OR, The System model did not use data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other data sources.	The Transmission Planner or Planning Coordinator's System model failed to represent three of the sub-requirements R1.1.1 through R1.1.6.	The Transmission Planner or Planning Coordinator's System model failed to represent four or more of the sub-requirements R1.1.1 through R1.1.6. OR, The System model did not simulate projected System conditions as described in Requirement R1.
R2	The Transmission Planner or Planning Coordinator failed to comply with one or both of the following sub-requirements: R2.8 or R2.9.	The Transmission Planner or Planning Coordinator failed to comply with one of the sub-requirements: R2.3 or R2.7.	The Transmission Planner or Planning Coordinator failed to comply with one of the sub-requirements: R2.1, R2.2, R2.4, or R2.6.	The Transmission Planner or Planning Coordinator failed to comply with two or more of the sub-requirements: R2.1, R2.2, R2.4, or R2.6.
R3	The Transmission Planner or Planning Coordinator did not identify Planning Events as described in Requirement R3.4 or Extreme Events as described in Requirement R3.5.	The Transmission Planner or Planning Coordinator did not perform studies as specified in Requirement R3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1. OR, The Transmission Planner or Planning Coordinator did not perform studies as specified in	The Transmission Planner or Planning Coordinator did not perform studies as specified in Requirement R3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in Table 1. OR, The Transmission Planner or Planning Coordinator did not perform Contingency analysis as	The Transmission Planner or Planning Coordinator did not perform studies as specified in Requirement R3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1. OR, The Transmission Planner or Planning Coordinator did not perform studies to determine that

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Requirement R3.2 to assess the impact of Extreme Events. OR, The Transmission Planner or Planning Coordinator did not base its studies on computer simulations using models utilizing data provided in Requirement R1.	described in Requirement R3.3.	the BES meets the performance requirements for the P0 or P1 categories in Table 1.
R4	The Transmission Planner or Planning Coordinator did not identify Planning Events as described in Requirement R4.4 or Extreme Events as described in Requirement R4.5.	The Transmission Planner or Planning Coordinator did not perform studies as specified in Requirement R4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR, The Transmission Planner or Planning Coordinator did not perform studies as specified in Requirement R4.2 to assess the impact of Extreme Events. OR, The Transmission Planner or Planning Coordinator did not base its studies on computer simulations using models utilizing data provided in Requirement R1.	The Transmission Planner or Planning Coordinator did not perform studies as specified in Requirement R4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR, The Transmission Planner or Planning Coordinator did not perform Contingency analysis as described in Requirement R4.3.	The Transmission Planner or Planning Coordinator did not perform studies as specified in Requirement R4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	N/A	N/A	N/A	The Transmission Planner or Planning Coordinator failed to define and document the proxies for System instability used within their analysis as described in Requirement R5.
R6	N/A	N/A	N/A	The Transmission Planner or Planning Coordinator failed to determine and identify individual or joint responsibilities for performing required studies.
R7	N/A	N/A	The Planning Coordinator failed to coordinate the analysis of its Planning Assessment results through an open and transparent peer review process.	The Planning Coordinator failed to distribute the results of its Planning Assessment.

E. Regional Variances

None.

Table 1 – Steady State & Stability Performance
Planning Events

Steady State & Stability:

a. Voltage instability, cascading outages, and uncontrolled islanding shall not occur.

b. Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss ~~is allowed for all events shown.~~are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements.

c. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

~~b.~~f. ~~Facility Ratings shall not be exceeded. Unless precluded in the Requirements, planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings.~~System steady state voltages and post-~~transient~~ Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator (or Transmission Planner if more restrictive).

g. Planning Event P0 is applicable to steady state only.

Stability Only:

h. The System shall remain stable. [1]

~~f.Dynamic voltages~~Transient voltage response shall be within acceptable limits established by the Planning Coordinator (or Transmission Planner if more restrictive).

i. ~~Simulate Normal Clearing unless otherwise specified.~~

Category	Initial System Condition	Event [3]~~[2]~~	Fault Type [3]	BES Level [4]	Interruption of Firm Transmission Service Allowed [5]	Non-Consequential Load Loss Allowed
P0 No Contingency~~Normal System Conditions~~	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [6] 4. Shunt Device [7]	3Ø	EHV, HV	No	No
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	~~Loss of one of the following:~~ 1. Opening of Breaker(s) w/o fault [8]	N/A	EHV, HV	No	No
		2. Bus Section Fault	SLG	EHV	No	No
				HV	Yes	Yes
		3. Internal Breaker Fault [9]	SLG	EHV	No	No

		(Non bus-tie)	SLG	HV	Yes	Yes
		4. Internal Breaker Fault (bus-tie)[9]	SLG	EHV, HV	Yes	Yes
P3 Multiple Contingency ~~*(Generator + 1)*~~	Loss of generator unit followed by System adjustments[10]~~5~~	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[6] 4. Shunt Device[7] 5. ~~Single pole of a DC Line~~	~~SLG~~ 3Ø	EHV, HV	No[10]	No
		5. Single pole of a DC line	SLG	EHV, HV	No[10]	No
P4 Multiple Contingency *(Fault plus stuck breaker[11])*	Normal System	Stuck breaker[11] (non-bus-tie) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[6] 4. Shunt Device[7] 5. Bus Section	SLG	EHV	No[10]	No
			SLG	HV	Yes	Yes
		6. Stuck breaker (bus-tie) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance
Planning Events, Continued

Category	Initial System Condition	Event[2]	Fault Type[3]	BES Level[4]	Interruption of Firm Transmission Service Allowed[5]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus Protection System failure)*	Normal System	Loss of multiple elements ~~due to a single component~~caused by the failure ~~within~~ of a single Protection System ~~associated with~~ while clearing a ~~F~~fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[6] 4. Shunt Device[7] 5. Bus Section	SLG	EHV	No[10]	No
			SLG	HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adj.[10~~5~~]: 1. Transmission Circuit 2. Transformer[6] 3. Shunt Device[7] 4. Single pole of a DC line	Loss of one of the following ~~followed by System adjustments~~: 1. Transmission Circuit 2. Transformer[6] 3. Shunt Device[7] 4. ~~Single pole of a DC line~~	~~SLG~~ 3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two circuits on common structure[12] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance
Extreme Events

Steady State & Stability

For all Extreme Events evaluated:

1. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency.

~~2.~~Simulate Normal Clearing unless otherwise specified.

~~3.See Requirement R3.4~~

~~4.~~2. ~~See Requirement R5.5.4~~

Steady State

1. Loss of a single generator, Transmission Circuit, DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
   a. Loss of a tower line with three or more circuits.[12]
   b. Loss of all Transmission lines on a common ~~r~~Right-of-~~w~~Way.
   c. Loss of a switching station or substation (loss of one voltage level plus transformers).
   d. Loss of all generating units at a station.
   e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
   a. Loss of two generating plants resulting from conditions such as:
      i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
      ii. Loss of the use of a large body of water as the cooling source for generation.
      iii. Wildfires.
      iv. Severe weather, e.g., hurricanes, tornadoes, etc.
      v. A successful cyber attack.
      vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.

   ~~b.Loss of two Transmission lines in different rights-of-way prior to System adjustments for conditions such as:~~
      ~~i.Wildfires.~~
      ~~ii.Severe weather, e.g., hurricanes, tornadoes, etc.~~

   ~~c.~~b. Other events based upon operating experience that may result in wide area disturbances.

Stability

1. With an initial condition of a single generator, Transmission circuit, DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
   a. 3Ø fault on generator with stuck ~~breaker~~breaker[11] or a Protection System failure ~~due to a single component failure within the protection system~~resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck ~~breaker~~breaker[11] or a Protection System failure ~~due to a single component failure within the protection system~~resulting in Delayed Fault Clearing.
   ~~c. 3Ø fault on transformer with stuck breaker or a protection system failure due to a single component failure within the protection system.~~
   c. ~~3Ø fault on bus section with stuck breaker or a protection system failure due to a single component failure within the protection system.~~3Ø fault on transformer with stuck breaker[11]or a Protection System failure resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[11] or a Protection System failure resulting in Delayed Fault Clearing.
   e. 3Ø internal breaker fault[11].
   f. 3Ø fault on two or more circuits on a common structure[12].
   g. SLG ~~or 3Ø~~ fault on all Transmission lines on a common Right-of-Way~~right-of-way~~.
   h. 3Ø fault on switching station or substation (loss of one voltage level plus transformers)
   i. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances~~.~~

Table 1 – Steady State & Stability Performance
Footnotes
(Planning Events and Extreme Events)

1. System stable means:
   a. Angular Stability:
      i. For Planning Event P1: No generating unit or units shall be allowed to pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.
      ii. For all other Planning Events: No generating unit or units totaling more than the Contingency ~~r~~Reserve of the Balancing Authority (or Reserve Sharing Group if applicable) shall be allowed to pull out of synchronism. Generators that pull out of synchronism must have out-of-step protection or some other means to trip the generator for this condition and the resulting apparent impedance swings must not pass through relay characteristics that would result in the tripping of any Transmission System elements other than the generating unit and its direct connection Facilities.
   b. For all Planning Events evaluated: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator (or Transmission Planner if more restrictive).
2. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level for stated performance criteria applies regarding allowances for interruptions of Firm Transmission Service and loss of Non-Consequential Load.
3. Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø fault study indicating criteria are being met shall provide sufficient evidence that a SLG condition would also meet criteria.
4. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruptions of Firm Transmission Service and Non-Consequential Load.
5. When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed.
6. For non-Generator Step Up transformer outage events, the reference voltage applies to the low-side winding (excluding tertiary windings) ~~and excluding generator step-up transformers~~. For generator and generator Step Up transformer outage events, the reference voltage ~~apply~~applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
7. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
8. Inadvertent tripping of breakers on one end of a normally networked Transmission circuit such that the line is now open at that end and possibly serving Load radial from a single source point.
9. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
10. Curtailment of firm transmission service , when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.
11. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated

(IPO) breaker, only one pole is assumed to remain closed. ~~The~~A stuck breaker ~~event~~ introduces a delayed clearing mode. ~~Normal Clearing is when the Protection System operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Breaker fail relay operation is a predetermined time that occurs after the Protection System operates and the breaker has failed. Breaker fail relaying will also isolate a predetermined portion of the electric system to isolate the failed breaker. Delayed clearing of a Fault is due to failure of any Protection System component that prevents the Protection System from operating normally.~~

12. Excludes circuits that share a common structure for 1 mile or less.

~~Table 1 — Steady State Performance~~

~~h.Facility Ratings shall not be exceeded. Planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings.~~

~~i.System steady state voltages and post-transient voltage deviations shall be within acceptable limits as established by the Planning Coordinator (or Transmission Planner if more restrictive).~~

~~j.Voltage instability, cascading outages, and uncontrolled islanding shall not occur.~~

~~k.Consequential Load and consequential generation loss is allowed for all events shown.~~

~~l.Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each event.~~

~~m.Simulate Normal Clearing unless otherwise specified.~~

~~Planning Events~~						
~~Category~~	~~Initial System Condition~~	~~Event[3]~~	~~BES Elements out of Service[2, 3]~~		~~Interruption of Firm Transmission Service Allowed~~	~~Non-Consequential Load Loss Allowed~~
			~~(A) > 300 KV~~	~~(B) <= 300 KV~~		
~~P0~~ ~~Normal System conditions~~	~~Normal System~~	~~None~~	~~X~~	~~X~~	~~No~~	~~No~~
~~P1~~ ~~Single Contingency~~	~~Normal System~~	~~Loss of one of the following:~~ ~~1.Generator~~ ~~2.Transmission circuit~~ ~~3.Transformer~~ ~~4.Shunt device~~ ~~5.Single pole of a DC line~~	~~X~~	~~X~~	~~No~~ ~~Yes, if transfer is dependent on the outaged DC line.~~	~~No~~

Version History

Version	Date	Action	Change Tracking
1	TBD	Revision of TPL-001-0 as per Project 2006-02; includes merging requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-1	Not employed due to scope of revision

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Comment Period Open
May 26–July 9, 2009

Now available at: http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

Project Name:
2006-02 — Assess Transmission Future Needs

Due Date and Submittal Information:
The comment period is open **until 8 p.m. EDT on July 9, 2009**. Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at Lauren.Koller@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page: http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

Content for Comment Period:

- Draft three of TPL-001-1 — Transmission System Planning Performance Requirements
- A revised implementation plan

TPL-001-1 is designed to be a single, comprehensive, and coordinated standard that merges the requirements of four existing standards: TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The proposed standard includes several new definitions.

Other Materials Posted:

- The drafting team's consideration of industry comments received during the second comment period

Project Background:
The purpose of the proposed standard is to establish transmission system planning performance requirements within the planning horizon to develop a bulk electric system that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies. The project includes updating and consolidating the following standards:

- TPL-001-0 — System Performance under Normal Conditions
- TPL-002-0 — System Performance Following Loss of a Single BES Element
- TPL-003-0 — System Performance Following Loss of Two or More BES Elements
- TPL-004-0 — System Performance Following Extreme BES Events
- TPL-005-0 — Regional and Interregional Self-Assessment Reliability Reports

- TPL-006-0 — Data from the Regional Reliability Organization Needed to Assess Reliability

This part of the project addresses TPL-001-0 through TPL-004-0. TPL-005 and TPL-006 will be addressed later in the project.

Applicability of Standards in Project:

- Transmission Planner
- Planning Coordinator

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

Individual or group. (83 Responses)
Name (57 Responses)
Organization (57 Responses)
Group Name (26 Responses)
Question 1 (0 Responses)
Question 1 Comments (83 Responses)
Question 2 (0 Responses)
Question 2 Comments (83 Responses)
Question 3 (0 Responses)
Question 3 Comments (83 Responses)
Question 4 (0 Responses)
Question 4 Comments (83 Responses)
Question 5 (0 Responses)
Question 5 Comments (83 Responses)
Question 6 (0 Responses)
Question 6 Comments (83 Responses)
Question 7 (0 Responses)
Question 7 Comments (83 Responses)
Question 8 (67 Responses)
Question 8 Comments (83 Responses)
Question 9 (69 Responses)
Question 9 Comments (83 Responses)
Question 10 (51 Responses)
Question 10 Comments (83 Responses)
Question 11 (50 Responses)
Question 11 Comments (83 Responses)

Individual
John Allen
City Utilities of Springfield, MO
No
City Utilities of Springfield, Missouri does not agree with the restrictions placed on the Category P3 contingencies. Since this will simulate a multiple contingency similar to a Category P4, loss of firm transmission service and/or loss of non-consequential load should be allowed. We suggest that the drafting team expand the allowable mitigating measures for a Category P3 to be consistent with a Category P4, where loss of firm transmission service and/or loss of non-consequential load is allowed for HV levels.
Group
Dominion - Electric Transmission
R1 – Dominion questions the legal authority NERC has to include the recently inserted language "including requirements of regulatory authorities and other legal obligations." This language is

too broad and far exceeds the jurisdiction of NERC's mission. R1.1.5 - Dominion has seen base case models built by other transmission entities which do not include area interchanges for all areas and must be solved with area interchange "turned off". Would these base case models be in violation of R.1.1.5?

R2.1.3 - Dominion suggests that SDT needs to be more specific on which of the variations to include. Also for the last bullet, the SDT needs to clarify the duration or timing of planned transmission outages (in relation to Planning horizon). R2.4.1 - While we appreciate the intent of introducing induction motor modeling in simulations, this is a difficult proposal in actual practice. The question of how much of the load is comprised of induction motors and what is a reasonable/practical model has been around now for over twenty years yet is still not resolved satisfactorily. For example, we have heard several experts declare the CLOAD model is inadequate for study. NERC needs to take the lead in developing appropriate models for the widely used simulation software and a methodology for determining load composition prior to requiring induction Load modeling in dynamic simulation studies. Additionally, this requirement states that Aggregate System Load model is acceptable to represent the dynamic behavior of induction motor Loads. Our interpretation is that such aggregate models shall be inserted by the Planners at the time of study, over a specific study area as determined by TP, and these models are not to be represented in the interconnection-wide (i.e. ERAG/MMWG) dynamics base cases. If ERAG/MMWG dynamics base cases are populated with such aggregate load models, the dynamic simulation cases could become very difficult to solve, if not impossible. R2.8 - Dominion does not see any purpose in reporting largest consequential load loss. This is not easily calculated, and would vary from year by year, season by season. R2.9 - Dominion requests further clarification. Is the intent of this requirement to develop criteria for maximum allowable non-consequential load loss prior to requiring a corrective action plan or to just calculate such a load loss where it is permitted in Table 1?

No comments.

R4.4 - Dominion believes that creating a master list of all contingencies a planner must take is burdensome and provides no planning value. In addition the contingencies will vary based on the loading configuration and the specific study case. In general, we start out with the very worst contingencies. If these cause hard rotor swings, we know we will probably have to do most of the possible contingencies in the station until we get down to contingencies that do not swing the generator much. But if the swings are light, then that particular load/topology situation probably does not need in-depth exploration. Creating a master list could create unnecessary study. However, we do support a list of the extreme contingencies in R4.5.

R.5 - What is meant by proxies?

No comments.

No comments.

Yes

Yes

No

Table 1 – Interruption of Firm Transmission Service is not allowed for many of the events listed. Doesn't this imply that firm point-to-point service can't be interrupted even when the service is provided across points that are connected only by a radial facility? If so, does NERC have the authority to determine how transmission service providers calculate firm ATC? Dominion is also concerned that transmission service providers appear subject to 'double jeopardy' I.E, NERC fine for violations of applicable reliability standard and FERC sanctions if OATT is violated.

No

Dominion agrees with the retirement of TPL-005-0 and TPL-006-0. However, Dominion has some concern over the implementation period and believes that 60 months to implement corrective action plans may not be enough. This standard has more stringent requirements ("raising the bar") than the current TPL standards. Having to assess the system for these new standards as well as implementing corrective action plans within 60 months could be difficult to get approval to site and construct new transmission. Dominion suggests that an additional 12 to 24 months be given to allow time for the assessments to determine violations, solicit input from all stakeholders through RTO process (As required by FERC 890) to determine the most appropriate corrective action plans.

Group

Northeast Power Coordinating Council

R1--There needs to be some direction provided on the initial conditions used in the assessment. This guidance should include discussion as to whether or not representations of generator forced outages are to be represented in the base case or if they are addressed through the sensitivity testing (Could add R1.1.7 Reasonable representations of unplanned generator outages.) Additionally, the standard is also silent on the treatment of system transfers, both internal and

external, as to how they should be modeled in the base case. For some areas, their current practice is to include heavy system stresses in their base case, which leaves little for sensitivity testing. It is unclear if this practice works within the purview of this standard. Guidance is needed on how to treat base case generation dispatch and system transfers. The inclusion of "requirements of regulatory authorities and other legal obligations" is not understood. Even if some version of this language is kept in the final standard, it seems to belong in R2 rather than R1. "Simulate" should be changed to "incorporate". R1.1.1 Priority comment – Only known long-term outages of generation and transmission should be required to be modeled. R1.1.2 comment - Do we need to have the list of equipment to model? How are circuit breakers, and other equipment modeled? Also, what should be the level of detail and the form that Protection System Equipment and Control Devices be modeled? We recommend deleting the list. Make R1.1.2 simply read as follows: R1.1.2--Projected system configuration, taking into account new planned Facilities and changes to existing Facilities, for each year of the Near-Term and Long-Term Transmission Planning Horizon. R1.1.5 comment – What specifically needs to be modeled under Interchange? R1.1.6 comment – This needs further definition or it should be deleted. It is not clear what a "network resource required to supply load" is. Does this refer to Network Resource per FERC LGIP?

It is recommended to replace the phrase "prepare" with "conduct and document" in the first sentence. R2.1.1 Comment – The requirement to evaluate year one or year two should be removed. This is not consistent with the time horizon identified in R2. R2.1.3 Comment - The emphasis on sensitivity testing in the existing section appears misdirected and should be focused on reasonable risk. The assessment should have to include a discussion of reasonable risk. The sensitivity list can be used to select sensitivities to assess risk. Having a requirement to perform one sensitivity just to meet the requirement of the standard does not add value to the assessment. R2.1.4 – With respect to spare equipment strategy, this requirement imposes severe testing requirements upon the system. However, there is no discussion on the generation dispatch or system transfers that are to be used for this portion of the assessment. The expectations for changes in system stresses need to be clear as part of the standard. Additionally, this section does not contemplate changing the acceptability of load loss. After experiencing a major contingency such as this, some change in the acceptability of load loss should be expected. The standard should consider allowing Non-Consequential load loss for P1 & P2 events. The standard needs to allow Non-Consequential load loss for P3 & P4 events. Remove the wording "(such as a transformer)". What constitutes "spare equipment strategy"? Would a strategy that involves out-of-merit dispatch or operational restrictions be considered a valid "spare equipment strategy". If a transformer is lost, could a reconfiguration of the transmission system constitute a valid "spare equipment strategy"? R2.2 Comment – We suggest replacing the phrase "a current System peak Load study" with "a valid System peak Load study" in the first sentence. The word current is confusing as some read the word current to mean "today's" rather than "valid". R2.3 Comment – Please provide guidance as to what year should be represented when performing short circuit studies. R2.4.1 Comment – Change to read: "For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads or an aggregate System Load model which represents the overall dynamic behavior of the Load." R2.5.1 Comment – We suggest deleting this requirement, and incorporating it into R2.5.2. R2.5.2 Comment – To incorporate R.2.5.1 into R2.5.2; please modify the section as follows: For steady state, short circuit, or Stability analysis the study shall be less than five calendar years old or less: the latest Transmission Planning Horizon System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: • The addition/deletion/change of individual generating unit capability determined to be material by the Planning Coordinator or Transmission Planner. [A 20 MVA generator is fairly small in a 30,000 MW system and system concerns would already be addressed though the System Impact Study] • An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES determined to be material by the Planning Coordinator or Transmission Planner. R2.6 Priority Comment – As written, this section undermines the value of the sensitivity testing. This section should require a corrective action plan to fix problems determined in sensitivity analysis if there is a reasonable risk of occurrence. We suggest making the standard read "Provide documentation that explains the reasoning for the sensitivities considered and selected." R2.6 Comment – At the end of the second sentence, the phrase "in the tables" is used. We suggest using more definitive language such as "in Table 1". R2.6.2 Comment – The phrase "Project Initiation Date" needs to be defined. It is unclear if this is this the date of ground breaking, purchase orders being issued, solution study initiation, etc. Additionally, in the second sentence the phrase "as well as an in-service date" should be modified to read "as well as a target in-service date". R2.6.3 Comment – Plans can provide a target in-service year but not an actual in-service year. R2.6.4 Priority Comment – There should be a cutoff point when changes occur beyond a certain date. When that date occurs, further changes will be evaluated in the next year's assessment. Otherwise, if a state makes a decision not to site a project a few weeks prior to the end of the assessment period, there will not be sufficient time to incorporate this into that year's assessment and develop corrective actions.

R2.8 Comment –Largest consequential load loss is not factored into the Planning Assessment and should therefore be deleted. R2.9 Comment – This requirement is unclear. Is this requirement asking for each transmission planner to list their criteria for non-consequential load loss, or is it asking how much non-consequential load loss was being relied upon in the assessment? We recommend that the requirement be modified to require documentation of the maximum amount of non-consequential load loss that was relied upon during the assessment. It is strongly recommended that the standard should consider not allow non-consequential load loss to resolve any violation arising from the planning events in Table 1. Therefore, this requirement would then be deleted. The use of "System Off-Peak Load" is too general. Is the intention to have the system minimum load used here? Because of the seasonal differences in equipment ratings, seasonal peak and off peak (minimum) loads should be analyzed.
R3.3.2 – Traditionally transmission planners have used their judgment about the minimum steady state voltage limitations of generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R3.3.3 – PRC-023 requires relay loadability to be reflected in facility ratings. Therefore this additional requirement is unnecessary and should be deleted. R3.5 – We recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following: - Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events - It should be clear that an evaluation does not require solution development for all Extreme Events - Change "an evaluation of possible actions…" to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered." For Requirements R3.4 and R3.5, what defines "more severe System impacts"?
R4.3.2 - Traditionally transmission planners have assumed that generators would ride through low voltages associated with Planning Events which is generally adequate for non-wind generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R4.5 Priority Comment – We recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following: - Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events - It should be clear that an evaluation does not require solution development for all Extreme Events - Change "an evaluation of possible actions…" to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered." For Requirements R4.4 and R4.5, what defines "more severe System impacts"?
It is unclear as to what is meant by the term "proxy used in the analysis" used in this requirement. Does this mean Planning Coordinator established practices, thresholds or guidelines used to gauge when simulations suggest an event such as cascading outages occurs? If so the Requirement should be revised to read: R5. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, when established practices, thresholds or guidelines identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding. The VRF should be "Medium".
We do not feel that this requirement belongs in this standard and it should be deleted. The standard defines requirements for the assessment not who does what.
This standard should not be reiterating FERC Order 890. We do not feel that this requirement belongs in this standard and it should be deleted.
No
Revise the Load Reduction and Non-Consequential Load Loss definitions as follows. Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions resulting from following a Planning or Extreme Event. Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction. Intended post contingency loss of load (other than Interruptible Load, Supplemental Load or Load Reduction) caused by operator or SPS (RAS) action. (Priority Comment) For Drafting Team consideration: What types of non-interruptible load loss would be considered non-consequential load loss--manual load shedding for example? With this in mind, can the definition be simplified, maybe to read: Non-Consequential Load Loss: Operator action taken to deliberately remove load from service in response to adverse system conditions.
No
For Steady State & Stability: Steady State & Stability: a. Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur. b. Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance

requirements P5 Priority Comment – As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. P7 Priority Comment – Event 1 - This requirement requires the evaluation of the loss of two circuits on a multiple circuit tower. We recommend that this be modified so that only the loss of two adjacent (vertically or horizontally) circuits need be evaluated. We also recommend that the Planning Coordinator be allowed to evaluate and if appropriate exempt specific locations from this contingency based on acceptable risk. Comments on Extreme Events – Table 1- We recommend renumbering the Extreme Events table to be Table 2. Stability Condition 2 Note a - Priority Comment - As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary's Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. Stability Condition 2 Note h – Eliminate this requirement or change to loss of station following three-phase fault. This note is confusing. Without providing a better defined scenario, it is unclear as to what clearing times should be used in this simulation. Comments on Footnotes – Table 1- We recommend renumbering the Footnotes table to be Table 3. Footnote 1.a.i – Should clarify that this requirement refers to generator units that are connected to the BES system. Footnote 1.a.ii – Contingency Reserve is dependent on the generation on-line. We suggest changing the first sentence to say that you can't lose more than that permissible by the Planning Coordinator. Also change "pull out of synchronism" to "lose synchronism" in this sentence and in the second sentence. (Is "Lose synchronism" a more commonly used term?). Footnote 1.a.i, states "For Planning Event P1: No generating unit or units shall be allowed to pull out of synchronism." There is the potential for this requirement to be taken too far. Does this mean that someone's 4 kW generator at home needs to remain synchronized? Therefore, there needs to be some sort of qualifier on this requirement. Suggested wording: "For Planning Event P1: No generating unit or units greater than 20 MW and directly interconnected at 100 kV or above shall be allowed to lose synchronism. Note that synchronism applies to conventional synchronous generators and may not apply to other generation technology." Footnote 3 – We recommend revising the wording of the last sentence to "A three phase fault study indicating criteria are being met is sufficient evidence that a SLG condition would also meet criteria." Footnote 4 – We recommend that a lower bound be put on the HV electric systems (such as 100 kV), rather than just saying "and lower". As has been commented on in a previous draft, the Drafting Team should also consider not having a prescribed voltage definition of BES, be it called EHV or HV. Studies should determine what facilities should be part of the BES because of their impact on reliability. A proposal is to modify Footnote 4 to replace the phrase "…(EHV) Facilities defined as greater than 300 kV…" with "…(EHV) Facilities defined as having a significant impact on the reliability of the System, generally at voltages greater than 300 kV as determined by the Planning Coordinator…" In using such language, the more stringent requirements could apply to BES/EHV but not globally for Facilities operating at voltages greater than 300 kV. Using this methodology the extra investment required would go towards real improvement of the reliability of the System. EHV and HV should be added to the Definitions of Terms Used in Standard. Footnote 12 – We recommend adding an alternative modifier to the end of the sentence, "or for 5 towers or less." This is consistent with NPCC criteria.

No

Capitalize Firm Transmission Service in footnote 10 and instead of saying firm Load use Firm Demand to be consistent with the NERC Glossary.

No

Please clarify, since R2 through R6 should become effective before results could be distributed to adjacent Planning Coordinators and any functional entity. However, by the wording of the effective date of R1 and R7 it appears R7 becomes effective before R2 to R6. That is, 24 months are allowed by the standard to complete the planning assessments after regulatory approval. The results may not be ready for distribution by the planning coordinator after the first twelve months. The term "Planning Coordinator" is not defined in the NERC Glossary of Terms used in Reliability Standards and, therefore, this standard should indicate whether this term is the same as the "Planning Authority" defined in the glossary. Otherwise the definition of the Planning Coordinator should be included in the NERC Glossary of Terms used in Reliability Standards. With regard to the many changes/modifications from the previous draft and from the previous TPL standards being replaced by TPL-001-1, another posting of this Standard will be necessary to fully evaluate the impact (on reliability and also cost of implementation) of such changes. The decision to allow the use of all type of RAS or SPS (particularly generator tripping and run-back) as a common practice for single contingency does not "raise the bar" in the planning standard, and should be reviewed. How can higher system performance be required that involves substantial infrastructure investment to prevent events with a very low probability of occurrence, and allow use of a less reliable measure (SPS failure or misoperation having a higher probability of occurrence) to reduce the investment for more probable events?

Group

TVA System Planning

The phrase, "for each year of the Near-Term and Long-Term Transmission Planning Horizon", should be revised to remove "each year" because there may not be studies actually required in each year. The SDT stated during its June 30th Webinar that protection system equipment need not be explicitly represented in models, but had difficulty in determining adequate wording for the proposed sub-requirement. Because protection system action is described in R3.3.1, R3.3.4, R4.3.1, and R4.3.3 we suggest that protection system equipment be removed from the list in R1.1.2. If R1.1.2 is not removed, TVA is concerned about the level of resources that will be required to model these additional relay requirements in the one year allowed in the Implementation Plan. In bullet three of R1.1.2, are bus-tie circuit breakers to be represented in the models? Typically circuit breakers are included in the contingency definitions along with the protection system equipment used in the powerflow models. In bullet seven of Requirement R1.1.2, what "new technologies" are to be represented in the models?

Do not understand the rationale for being so prescriptive in requiring specific years to be studied in R2.1.1. Why not allow the TP and/or PC to decide on the three years to be studied in the Near Term? Since R2.3 short circuit analysis is a new "raising the bar" requirement, should the implementation plan for this be for 5 years like the other new "raising the bar" requirements? Further clarification is needed in R2.4.1 concerning load models that appropriately represent the dynamic behavior of loads. Is a NERC drafting team addressing these issues to determine an industry standard? If contingencies occur inside one utility that affect facilities in another utility, which utility is responsible for running these studies during the annual assessments? In R2.6.1, is there any limit to the time duration that a SPS and/or operating procedures can be used in the CAP? In Posting #2, undervoltage load shed, underfrequency load shed, and Special Protection Schemes were considered to be Non-Consequential Load Loss. In R2.6.1, installation or modification of Protection Systems or Special Protection Systems are now allowed as part of the Corrective Action Plan. Should undervoltage and underfrequency load shed also be allowed in the Corrective Action Plan? In R2.9, does the requirement require the maximum non-consequential load that can occur for contingencies in Table 1 or does it require just the maximum that a utility will allow on its system? Suggest clarifying "permissible" or perhaps using similar language as found in R2.8. Please explain the reason why Requirement R2.9 is needed in the Assessment. Reporting the largest Non-Consequential Load Loss doe not impact reliability. In R2.1, change the reference to requirement R2.6 (at the end of the last line) to R2.5. With the elimination of the distinction between system and generating plant stability studies, the blanket requirement in R2.5.1 that all stability analyses be five calendar years old or less, regardless of any material changes to the system, would cause needless work to be performed on those plants or areas of the system where no changes are occurring. Recommend add the following to the end of R2.5.1: "unless justification can be provided to demonstrate that the results of an older study are still valid." In Requirement R2.6.2, what constitutes a "project initiation date," and how will it be used? Please clarify. Please explain the reason why Requirement R2.8 is needed in the Assessment. Reporting the largest Consequential Load Loss does not impact reliability. R2.1 – What's the value in being able to use "qualified past studies" if you have to use "annual current studies"? Strike the words "supplemented with" and insert the word "or". R2.3 – Insert the phrase "one year of" after the word "addressing". In the subrequirements of 2.1.3 and 2.4.3, the use of the word "timing" is unclear. Consider using "in service date" or "schedule for". In R2.6, does the Corrective Action Plan need to show all possible alternatives to fix a problem that has been identified - or does only one solution need to be shown for a problem?

In R3.3.2, need guidance on how to consider minimum steady state voltage limitations. Is there a NERC team addressing this? It is not clear if it is referring to the ability of plants to meet their voltage schedule, or to their ability to stay connected during post contingencies. In R3, should the "and" in the first sentence actually be "or"? especially for same footprint? Perhaps the "and" should be replaced by "and/or". Can the PC satisfy this requirement by reviewing studies performed by differing TPs or is separate analysis really required especially when the TP and PC have the same footprint? In the VSL for R3, a severe VSL is listed as failing to meet performance requirement for P0 or P1. We do not understand why a severe VSL would be applied to an all ties closed event which should have little if any problems. We believe that this should be a lower or moderate VSL instead of severe. In R3.3.3 is the relay loadability required for all HV and EHV voltage levels? Previously NERC had required this for 230-kV and above only. This would be massive requirement for our TLs between 100 and 200-kV.

In R4, should the "and" in the first sentence actually be "or"? R4.3.2 requires that voltage ride through capability be analyzed. It is not clear what should be analyzed (e.g. auxiliary loads, generator protection, generator capability, etc.) This requirement needs more clarity. By in large, the industry does not have the input data or the methods to do this. It would seem necessary to have PRC-024 approved before this can be met.

In the VSL associated with R5, we believe that failure to define and document one of the proxies should be a moderate VSL, failure to define and document two proxies should me a high VSL, while failure to define and document three proxies should be a severe VSL. Otherwise failing to document only one proxy would result in a severe VSL. The word "proxies" in this context is confusing and subject to various interpretations. Recommend changing the word "proxies" to "criteria." There is no requirement that the Planning Coordinator (PC) must use the same proxies

as the Transmission Planner (TP). Since differences in proxy assumptions may lead to different study results, R5 should be revised to require the PC and TP to coordinate the use of proxies.

In the VSL associated with R6, we believe that failure to determine and identify one responsibility should be a moderate VSL, failure to determine and identify two responsibilities should me a high VSL, while failure to determine and identify three responsibilities should be a severe VSL. Otherwise failing to document only one responsibility would result in a severe VSL.

In the VSL associated with R7, we believe that the PC failing to coordinate analysis should be a moderate VSL, the PC failing to distribute should be a high VSL, and failing to do both of these tasks should be a severe VSL.

No

TVA suggests adding back the following to the Bus-tie breaker definition that was contained in Posting #2: "Substations configurations such as ring bus, breaker and a half, or double bus double breaker protection schemes do not use bus tie breakers". TVA believes that this additional wording helps explain this definition much more clearly. In Posting #2, undervoltage load shed, underfrequency load shed, and Special Protection Schemes were considered to be Non-Consequential Load Loss. Are these now no longer considered to be Non-Consequential Load Loss but instead now considered to be Load Reduction, Supplemental Load Loss, or something else? Should Supplemental Load Loss be further defined as load that is disconnected from the network by end-user equipment responding during duration of the fault as well as to post contingency system conditions? Also the definition of Supplemental Load Loss may benefit from some examples in the definition to further help clarify. Please clarify how Supplemental Load Loss would be included in the stability analysis. The second sentence in the Year One definition is rather confusing. We would suggest changing "calendar year" to "date". Otherwise it may be interpreted that Year One would begin 12 to 18 months from the end of the current calendar year. Suggest from "beginning". Load Reduction – Please clarify whether this includes both load response and operator initiated action, such as in changes to transformer LTC. Should definition also include that this load is continuing to be served? Consequential Load Loss must include load that is lost due to the inherent response of the particular type of load. Some motors, lighting and processes will naturally trip during an event, although not as a result of the protection system. It may have been the intent of the SDT to include this phenomenon in the Supplemental Load Loss defintion. However, this definition includes the phrase, "by end-user equipment", and that makes one think that there are devices at the end-user location that is removing this equipment (and conversely, load that is not disconneted "by" end-user equipment cannot be included). Also, the term "post-Contingency" can be confusing because in the case of faults, this phrase is not clear if it means conditions after the fault initiation itself or only after the clearing of the fault. Revise Supplemental Load Loss to read, "End-user Load that inherently disconnects from the System as a consequence of (or "in response") to the conditions created by the System event."

No

The existing TPL 002-0 allows for some local load to be dropped for a single contingency event as long as the Bulk system reliability was not impacted. However there is no such allowance any longer for losing such load for a single contingency in the proposed draft. It would be very expensive for TVA to fix all such events in several remote areas that would have very little impact on the overall reliability of the TVA bulk system. TVA believes that the capital spent for these fixes could be used to better strengthen the overall bulk system in much better ways. P5 should not be a planning event. PRC standards address protection system failures. The complexity associated with identifying and simulating such events is unknown and the defense of assumptions made and events simulated will lead to inconsistency in compliance and enforcement. Industry accepted proxies for such events could be developed that would allow for efficient identification of areas needing further study. Attempting to intermingle protection system operation with BES performance will be nearly impossible to implement given current technologies. Stability Extreme 2.g, and Steady State 2.b. both need a note like footnote number 12 that excludes short distances. Suggest footnote #12 be modified to include right-of-way in addition to structures.

Yes

No

TVA is concerned that the 5 year window for meeting the "raising the bar" requirements is still not adequate. For instance, it typically takes TVA 7 to 10 years to build a new 500-kV transmission line - including time required for such processes as federally mandated NEPA environmental reviews. Strongly suggest increasing this time window to 10 years. Also trying to construct enough facilities within the 5 year implementation period will result in multiple outages at same time - possibly affecting TVA's bulk reliability during this construction period. Also TVA is concerned that EHV equipment manufacturers will not be able to meet all the equipment orders that will be required to meet the "raising the bar" requirements. Thus TVA believes that these additional concerns strengthen the need to have a 10 year implementation period. Since breaker duty is a new "raising the bar" issue - should there also be a 5 year implementation plan for this as well? TVA is also concerned that the costs to meet the new requirements contained in this TPL

will amount to between $1 billion to $2 billion with very little impact overall on the reliability of the Bulk transmission system. TVA is also very concerned about the increase in rates that will be required to support these new facilities. When will the Implementation Plan be removed from the standard after it is officially approved? Will a revised TPL standard need to be prepared to omit this implementation language? If contingencies in one utility's system results in issues within another utility, who is responsible for studying the contingencies and who would be responsible for documenting the CAP? More time is needed for entities to determine the appropriate dynamic load model required by R2.4.1. We recommend at least 36 months before this requirement becomes effective.

Individual

Blake Williams

CPS Energy

As written, is it the intent of Requirement R2.1.4. to escalate the contingencies in Table 1 from "N-1" to "N-2" and "N-2" to N-3" for long lead-time replacement equipment, such as autotransformers and GSUs? If so, we feel that this requirement is overly burdensome that will result in unnecessary expense to the customers. In Requirement R2.4.1., what is the intent of the second sentence if an aggregate system load model is acceptable? We feel that the second sentence should be removed. In Requirement R2.6.2., we feel that statement of the project initiation date has no benefit and should be removed as a requirement. The required in-service date should be adequate. We do not believe that there is any benefit to reliability by documenting the Consequential and Non-Consequential Load Loss data required by Requirements R2.8. and R2.9.

Requirement R3.3.2. needs clarification.

Yes

Yes

Individual

Tom Mielnik

MidAmerican Energy Company

MidAmerican commends the SDT for all its hard work on this standard. MidAmerican offers the following comments on R2: • MidAmerican believes that the second sentence of R2.3 as written will result in unnecessary modeling for the required short circuit analysis. MidAmerican recommends that the sentence "The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area." MidAmerican recommends that R2.3 be changed by deleting the words "any" and "could" and replace with the words "materially". In this way, the sentence would read, "They analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with generation and Transmission Facilities in service which materially impact the study area." • Requirement 2.5 is too confining and is complicated and unnecessary. MidAmerican asks that the requirement be deleted in its entirety. Alternatively, if the SDT does not agree with deleting all of R2.5, then MidAmerican asks that the SDT consider deleting the R2.5.1. MidAmerican believes R2.4 will ensure that analysis is fresh by requiring a certain number of studies be conducted for certain years in the planning horizon. Why add the requirement for no older than 5 calander years? With the R2.4 and the material requirements in R2.5.2 shouldn't that be more than enough to ensure that the analysis is fresh enough to support the assessment? • If R2.5.2 is not deleted, the words "and interconnected to the Bulk Electric System" should be added behind 20 MW or greater. • Requirement 2.6.2 requires the "project initiation date". MidAmerican recommends that the SDT delete the requirement to provide this date as an initiation date is not related to system reliability. If the SDT believes it is critical to get this date, then the SDT should define it. Does it mean when engineering starts, when it is decided to proceed, or something else? • At a minimum, MidAmerican believes that the SDT should add the word "expected" behind largest to avoid unnecessary compliance issues for an unexpected event, and clarify that R2.8 and R2.9 are not required for sensitivity cases.

MidAmerican commends the SDT for it hard wok on this standard and specifically its R3.3.1

wording. MidAmerican has suggestions for the following parts of R3: • . • R3.3.2 – delete the words "For all generators" at the beginning. It is unnecessary in that later in the requirement it states specifically that the responsible entity is to "identify how the generators are analyzed in the steady state limitation". • R3.3.3 – use a similar construction to R3.3.2 but delete the words "For all transmission lines". In other words, replace "For all Transmission lines, studies shall consider relay loadability and identify how loadability is analyzed in the steady state limitations." With "Studies shall consider relay loadability and identify how loadability for transmission lines is analyzed in the steady state simulations." • R3.4 and R3.5 – change "remaining Contingencies" to "remaining unselected Contingencies".

MidAmerican commends the SDT for its hard work on this standard. MidAmerican suggests that R4.5 be revised by changing "remaining Contingencies" to "remaining unselected Contingencies."

MidAmerican commends the SDT for its hard work on this standard. MidAmerican recommends changing R7 by changing "FERC Order 890" to "FERC Order No. 890".

No

MidAmerican commends the SDT for its hard work on this standard. MidAmerican believes the SDT improved several of the definitions and believes additional changes are needed: • For the bus-tie definition, what does "individual substation bus configurations" mean? • The consequential load loss states that it is load that "removed from service by a planned Protection System operation to isolate fault conditions". This implies that a contingency that does not involve a fault could never have consequential load loss. MidAmerican suggests that the words "to isolate fault conditions" be replaced with "in response to a contingency event". Alternatively, consider using the words in R3.3.1 which defines the same information but without referring to fault conditions. • The definition of Long-Term Transmission Planning Horizon is confusing because it is not clear which term the words "when required to accommodate any known longer lead time projects that may take longer than ten years to complete" are meant to modify. MidAmerican believes the intent is that these words only apply to the years ten or beyond and not the entire period years six to ten and beyond. Therefore, we recommend that the words be changed by starting a new sentence in the definition and putting it in parentheses "(Years beyond ten years are required to accommodate any known longer lead time projects that may take longer than ten years to complete.) • MidAmerican commends the SDT for improving the Year One definition. MidAmerican still believes the Year One definition is too confining. It indicates that the first year is defined as the planning window that begins 12-18 months from the current calendar year. This means if the regional entity provides models during the current calendar year in April, the responsible entity cannot use those models in conducting planning until a year that begins in May of the next year. Why delay the start of Year One? What is gained by this delay? MidAmerican recommends that Year One NOT be a defined term. This definition clarifies a term that does NOT need to be clarified for any reason. MidAmerican believe this is a fix for a problem that does not exist. Does the SDT have evidence of lack of compliance in this regard? • Modify the Planning Assessment definition to more explicitly apply to the BES and the TPL-001 requirements. We suggest text of: "Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies in the BES from the steady state and stability performance requirements set forth in the TPL-001 standard." • Modify the Planning Events definition more explicitly apply to the TPL-001 requirements. We suggest text of: "Planning Events: Events that are identified in the steady state and stability performance requirements set forth in the TPL-001 standard."

No

MidAmerican commends the SDT for its hard work on this standard. MidAmerican commends the SDT for most of the changes to Table 1. MidAmerican does have a few comments: • MidAmerican suggests that Footnote 11 be added to the sixth item under P4. The note 11 clarifies the meaning of a stuck breaker yet this footnote isn't applied to item 6 under P4 which is a stuck-breaker item. • MidAmerican believes that it is confusing having a set of explanations for Extreme Events that are 1 through 3 under Steady State and 1 and 2 under Stability and yet have later footnotes listed that are 1 through 11. MidAmerican suggests that the items 1 through 3 under Steady State and 1 and 2 under Stability for Extreme Events be changed to some other designation such as bullets or letters so that it is easy to see that the numerical footnotes start after these explanations of the extreme events. • Further clarify the applicable shunt devices in Footnote 7 with the suggested text "7. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground, but not instrument voltage transformers or surge arrestors."

Yes

No

MidAmerican commends the SDT for its hard work on this standard. MidAmerican does not support the paragraph that states "Any entity that cannot fully implement its Corrective Action

Plan….shall self report itself…" MidAmerican believes that the Energy Policy Act of 2005 does not provide NERC or FERC the authority to require construction of facilities. Therefore, MidAmerican believes that this paragraph should be deleted in its entirety from the implementation plan as requiring responsibility to build facilities or else self report non-compliance. This is in direct contradiction to federal law.

Individual

James Tucker

Deseret Generation & Transmission

Comments: The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices where it is expected to impact the study outcome. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted. I disagree with the inclusion of the words "including requirements of regulatory authorities and other legal obligations" at the end of R1. Entities already are required to do this. It does not need to be included in the standard.

R2.5.2 For Past studies to be used in the Planning Assessment, the suggestion that the addition of a 20 MW generator would disqualify those past studies is way too restrictive. It should be left up to the Transmission Planner to evaluate the applicabililty of past studies and the two sub bullets should be removed and replace with a general statement about past studies should adequately represent the present system to be used in the Planning Assessment. Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the "largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event" if it is documented? R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.

As currently drafted, R3.3 is not a requirement. Without the statements in R3.3.1-R3.3.4, R3.3 is simply a phrase. Sub-Sub-Requirements R3.3.1 through R3.3.4 should be bullets under R3.3, with the language in R3.3 modified so that it becomes the requirement to conduct contingency analyses that address the four resulting bullets R3.3.2 is unclear as drafted. The minimum steady state voltage limitation for synchronous generators is not a very meaningful value. All generators with an automatic voltage regulator will maintain the set point voltage until the VAR capability of the generator is exceeded, and then the voltage will deteriorate. R3.5 – We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingencies than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.

As currently drafted, R4.3 is not a requirement. Without the statements in R4.3.1-R4.3.3, R4.3 is simply a phrase. Sub-Sub-Requirements R4.3.1 through R4.3.3 should be bullets under R4.3, with the language in R4.3 modified so that it becomes the requirement to conduct contingency analyses that address the three resulting bullets. R4.3.2 – it is not clear what is required to be modeled. Typically a generator may have 10 or more protective relays. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to do that for all generators in the system. R4.5 – We disagree with the requirement to explain why

remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingency than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.
The term proxy is unclear. Please provide an example or an explanation of proxy.
I believe that references to FERC Orders should not be included in requirements of standards. This comment also applies to M7.
No
Claification is needed on the use of UVLS. Is it acceptable or not. Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss Allowed column is No, is load disconnecetd from the system by UVLS a violation? What about Supplemental Load Loss or UFLS?
No
P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements. As such, this is a low probability condition and loss of Non-Consequential load should be allowed for EHV. We disagree with raising the bar for EHV for P4.
Yes
No
I agree that TPL-005 and TPL-006 appear to have been adequately covered in the draft TPL-001-1 as currently written. However, we will need to review this assessment after TPL-001-1 is finalized. In addition, there is no place to state our concerns for Section D. so we added it here. I question the "not applicable" entry under Section D 1.1.2. What does it mean when the reset period is not applicable? Does it mean there is no reset period, so all non-compliance in all prior years will be counted as prior violations when considering non-compliance in future years?
Individual
Michael R. Lombardi
Northeast Utilities
R1 Priority Comment- There needs to be some direction provided on the initial conditions used in the assessment. This guidance should include discussion as to whether or not representations of generator forced outages are to be represented in the base case or if they are addressed through the sensitivity testing (Could add R1.1.7 Reasonable representations of unplanned generator outages.) Additionally, the standard is also silent on the treatment of system transfers, both internal and external, as to how they should be modeled in the base case. For some areas, their current practice is to include heavy system stresses in their base case, which leaves little for sensitivity testing. It is unclear if this practice works within the purview of this standard. Guidance is needed on how to treat base case generation dispatch and system transfers. R1 Comment – We do not understand what it means to include "requirements of regulatory authorities and other legal obligations". Even if some version of this language is kept in the final standard, it seems to belong in R2 rather than R1. R1.1.1 Priority comment – R1.1.1 should be removed. It seems like there is an overlap between the requirements of this standard and Operational Planning studies with respect to known outages. Planned outages are addressed by our Operational Planning processes and Transmission Operating Procedures removing the need for this to be incorporated into Planning Assessments. In addition, outages are not generally known years in advance R1.1.2 comment - Do we need to have the list of equipment to model? How do we model circuit breakers, etc? Also, what should be the level of detail and the form that Protection System Equipment and Control Devices be modeled? We recommend deleting the list. Make R1.1.2 simply read as follows: R1.1.2 Projected system configuration, taking into account new planned Facilities and changes to existing Facilities, for each year of the Near-Term and Long-Term Transmission Planning Horizon. R1.1.5 comment – What specifically needs to be modeled under Interchange? R1.1.6 comment – This needs further definition or it should be deleted. It is not clear what a "network resource required to supply load" is. Does this refer to Network Resource per FERC LGIP?
R2 Comment – We recommend replacing the phrase "prepare" with "conduct and document" in the first sentence. R2.1.1 Comment – The requirement to evaluate year one or year two should be removed. This is not consistent with the time horizon identified in R2. R2.1.2 Comment – The requirement should be removed. With no description of the system stresses and generator outages to be applied when assessing the off-peak load, it is difficult to imagine any issues which

would arise which are not revealed in the peak load evaluation that could not be addressed through generation dispatch adjustments. R2.1.3 Comment - The emphasis on sensitivity testing in the existing section appears misdirected and should be focused on reasonable risk. The assessment should have to include a discussion of reasonable risk. The sensitivity list can be used to select sensitivities to assess risk. Having a requirement to perform one sensitivity study just to meet the requirement of the standard does not add value to the assessment. R2.1.3 Comment - What should be the time duration for the bullet that reads "Planned duration or timing of Transmission outages" R2.1.4 Priority Comment – With respect to spare equipment strategy, this requirement imposes severe testing requirements upon the system. However, there is no discussion on the generation dispatch or system transfers that are to be used for this portion of the assessment. The expectations for changes in system stresses need to be clear as part of the standard. Additionally, this section does not contemplate changing the acceptability of load loss. After experiencing a major contingency such as this, some change in the acceptability of load loss should be expected. The standard needs to allow Non-Consequential load loss for P3 & P6 events when spare equipment strategy is incorporated in the testing. An example of such an event, that non-consequential load loss should be acceptable, would be a long-term outage of one transformer at a station which would be modeled in the base, followed by event P6 testing on initial system condition of a transformer out of service then followed by a 2nd transformer outage. This would be three transformers out at the same station and this could approach Extreme Events Contingency. R2.2 Comment – We suggest replacing the phrase "a current System peak Load study" with "a valid System peak Load study" in the first sentence. The word current is confusing, as some read the word current to mean "today's" rather than "valid". R2.3 Comment – Please provide guidance as to what year should be represented when performing short circuit studies. R2.4.1 Comment – Change to read: "For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads or an aggregate System Load model which represents the overall dynamic behavior of the Load." R2.5.1 Comment– We suggest deleting this requirement, and incorporating it into R2.5.2. R2.5.2 Comment – To incorporate R.2.5.1 into R2.5.2; please modify the section as follows: For steady state, short circuit, or Stability analysis the study shall be less than five calendar years old or less: the present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: •The addition/deletion/change of individual generating unit capability determined to be material by the Planning Coordinator or Transmission Planner. [A 20 MW generator is fairly small in a 30,000 MW system and system concerns would already be addressed through the System Impact Study] •An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES determined to be material by the Planning Coordinator or Transmission Planner. R2.6 Priority Comment – As written, this section undermines the value of the sensitivity testing. This section should require a corrective action plan to fix problems determined in sensitivity analysis if there is a reasonable risk of occurrence. We suggest making the standard read "Provide documentation that explains the reasoning for the sensitivities considered and selected." R2.6 Comment – At the end of the second sentence, the phrase "in the tables" is used. We suggest using more definitive language such as "in Table 1". R2.6.2 Comment – The phrase "Project Initiation Date" needs to be defined. It is unclear if this is the date of ground breaking, purchase orders being issued, solution study initiation, etc. Additionally, in the second sentence the phrase "as well as an in-service date" should be modified to read "as well as a target in-service date". R2.6.3 Comment – Plans can provide a target in-service year but not an actual in-service year. R2.6.4 Priority Comment – There should be a cutoff point when changes occur beyond a certain date. When that date occurs, further changes will be evaluated in the next year's assessment. Otherwise, if a state makes a decision not to site a project a few weeks prior to the end of the assessment period, there will not be sufficient time to incorporate this into that year's assessment and develop corrective actions. R2.8 Comment –Largest consequential load loss is not factored into the Planning Assessment and should therefore be deleted. R2.9 Priority Comment – We highly recommend that the standard should not allow non-consequential load loss to resolve any violation arising from the planning events in Table 1. Therefore, this requirement should be deleted.

R3.3.2 Comment – Traditionally transmission planners have used their judgment about the minimum steady state voltage limitations of generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to inclusion of R3.3.2 as a requirement in this standard. R3.3.3 Comment – PRC-023 requires relay loadability to be reflected in facility ratings. Therefore this additional requirement is unnecessary and should be deleted. R3.5 Priority Comment – We recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following: -Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events -It should be clear that an evaluation does not require solution development for all Extreme Events -Change "an evaluation of possible actions…" to "where appropriate,

reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered."

R4.3.2 Priority Comment – Traditionally, transmission planners have assumed that generators would ride through low voltages associated with Planning Events, which is generally adequate for non-wind generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R4.5 Priority Comment – We recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following: -Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events -It should be clear that an evaluation does not require solution development for all Extreme Events -Change "an evaluation of possible actions…" to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered."

Comments: It is unclear as to what is meant by the term "proxy used in the analysis" as it is used in this requirement. Does this mean Planning Coordinator established practices, thresholds, or guidelines used to gauge when simulations suggest an event such as cascading outages occurs? If so the language should state: R5. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, when established practices, thresholds or guidelines identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.

We do not believe that this requirement belongs in this standard and it should be deleted. The standard defines requirements for the assessment not who does what.

This standard should not be reiterating FERC Order 890. We do not believe that this requirement belongs in this standard and it should be deleted.

No

Refine load loss definitions as follows. Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions resulting from a Planning or Extreme Event. Non-Consequential Load Loss: Intended post contingency loss of load (other than Interruptible Load, Supplemental Load or Load Reduction) caused by operator or SPS (RAS) action. (Priority Comment)

No

Steady State & Stability are as follows: Steady State & Stability: a. Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur. b. Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirements Non-Consequential Load Loss Allowed Comment (priority comment): We highly recommend that the standard as written should not allow non-consequential load loss to resolve any violation arising from the planning events in Table 1 (except when considering spare equipment strategy together with events P3 or P6). We believe that planning for reliable power should discourage load loss mitigation. Therefore, the column for the "Non-Consequential Load Loss Allowed" in Table 1 should all have entries of "No". P5 Priority Comment – As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary's Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. P7 Priority Comment – Event 1 - This requirement requires the evaluation of the loss of two circuits on a multiple circuit tower. We recommend that this be modified so that only the loss of two adjacent (vertically or horizontally) circuits need be evaluated. We also recommend that the Planning Coordinator be allowed to evaluate and, if appropriate, exempt specific locations from this contingency based on acceptable risk. Comments on Extreme Events – Table 1- We recommend renumbering the Extreme Events table to be Table 2. Stability Condition 2 Note a - Priority Comment - As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary's Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. Stability Condition 2 Note h – Eliminate this requirement or change to loss of station following three-phase fault. This note is confusing. Without providing a better defined scenario, it is unclear as to what clearing times should be used in this simulation. Comments on Footnotes – Table 1- We recommend renumbering the Footnotes table to be Table 3. Note 1.a.i – Should clarify that this requirement refers to generator units that are connected to the BES system. Note 1.a.ii – Contingency Reserve is dependent on the generation on-line. We suggest changing the first sentence to say that you can't lose more than that permissible by the Planning Coordinator. Also change "pull out of synchronism" to "lose synchronism" in this sentence and in the second sentence. (Is "Lose synchronism" a more commonly used term?). Note 3 – We recommend revising the wording of the last sentence to "A three-phase fault study indicating criteria are being met is sufficient

evidence that a SLG fault condition would also meet criteria." Note 4 – We recommend that a lower bound be put on the HV electric systems (such as 100 kV), rather than just saying "and lower".

Yes

Capitalize Firm Transmission Service in footnote 10 and instead of saying firm Load use Firm Demand to be consistent with the NERC Glossary.

Yes

Other Comments: Comment 1 – Please clarify, since R2 through R6 should become effective before results could be distributed to adjacent Planning Coordinators and any functional entity. However, by the wording of the effective date of R1 and R7 it appears R7 becomes effective before R2 to R6. That is, 24 months are allowed by the standard to complete the planning assessments after regulatory approval. The results may not be ready for distribution by the planning coordinator after the first twelve months. Comment 2 – The term "Planning Coordinator" is not defined in the NERC Glossary of Terms used in Reliability Standards and, therefore, this standard should indicate whether this term is the same as the "Planning Authority" defined in the glossary. Otherwise the definition of the Planning Coordinator should be included in the NERC Glossary of Terms used in Reliability Standards.

Individual

Brian Keel

SRP

The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices where it is expected to impact the study outcome. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted. We disagree with the inclusion of the words "including requirements of regulatory authorities and other legal obligations" at the end of R1. Entities already are required to do this. It does not need to be included in the standard.

Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement. The 20 MW threshold identified as "material change" for generation in R2.5 is too small. The limit should be raised or based on a percentage of the study area's installed generating capacity. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the "largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event" if it is documented? R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.

As currently drafted, R3.3 is not a requirement. Without the statements in R3.3.1-R3.3.4, R3.3 is simply a phrase. Sub-Sub-Requirements R3.3.1 through R3.3.4 should be bullets under R3.3, with the language in R3.3 modified so that it becomes the requirement to conduct contingency analyses that address the four resulting bullets R3.3.2 is unclear as drafted. The minimum steady state voltage limitation for synchronous generators is not a very meaningful value. All generators with an automatic voltage regulator will maintain the set point voltage until the VAR capability of the generator is exceeded, and then the voltage will deteriorate. R3.5 – We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingencies than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant

RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.
As currently drafted, R4.3 is not a requirement. Without the statements in R4.3.1-R4.3.3, R4.3 is simply a phrase. Sub-Sub-Requirements R4.3.1 through R4.3.3 should be bullets under R4.3, with the language in R4.3 modified so that it becomes the requirement to conduct contingency analyses that address the three resulting bullets. R4.3.2 – it is not clear what is required to be modeled. Typically a generator may have 10 or more protective relays. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to do that for all generators in the system. R4.5 – We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingency than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.
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We believe that references to FERC Orders should not be included in requirements of standards. This comment also applies to M7.
No
Claification is needed on the use of UVLS. Is it acceptable or not? Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss Allowed column is No, is load disconnecetd from the system by UVLS a violation? What about Supplemental Load Loss or UFLS?
No
P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements. As such, this is a low probability condition and loss of Non-Consequential load should be allowed for EHV. We disagree with raising the bar for EHV for P4.
We agree that TPL-005 and TPL-006 appear to have been adequately covered in the draft TPL-001-1 as currently written. However, we will need to review this assessment after TPL-001-1 is finalized. In addition, there is no place to state our concerns for Section D. so we added it here. We question the "not applicable" entry under Section D 1.1.2. What does it mean when the reset period is not applicable? Does it mean there is no reset period, so all non-compliance in all prior years will be counted as prior violations when considering non-compliance in future years?
Individual
L. Earl Fair
Gainesville Regional Utilities
Concerning the effective dates of R1 & R7, I suggest that you move them to be effective at the same time as R2 through R6 so you will not have to try to meet two standards during the same time period. Effective Date: Clarify how the effective date impacts which version of the standard (and it reference numbering) is to be used in an assessment just before (in cycle) a scheduled compliance audit. Suggest that the term "Corrective Action Plan" be retitled to "Improvement Action Plan" because the first implies that the situation is "wrong or incorrect" which may not be the case.
R2.1.1- References a "system peak Load" for each of the referenced years. Some utilities are summer peaking and some are winter peaking and others may have a history of having one or the other in any given year. So can you clarify which peak you are referring to or change to statement to perform studies involving both seasonal peaks? R.2.4.1- I suggest quantifying the reference to the behavior of induction motor loads to single motors greater than 1000 hp or multi motors at one bus totalling more that 2000 hp or so, since smaller induction motors probably will not have any significant impact of the BES. I feel this is best handled as a sensitivity issue determined by the PC who is familiar with this area. R2.5.1- If the system has not had any significant changes of the last ten years, then a study going back to that change should be acceptable for the assessment. R2.5.2- Should the "shall not include" really read as "shall include"? R2.6- The reference to "tables" in line 6 should be "table" since there is only a Table 1 in the standard. R2.6.1-R2.6.3- Question-- Why is the font size of the bullet text smaller that the other bullet segments?

Please provide a definition of "cascading outages" since the FERC and NERC removed their approval of the definition. Or use the definition of "cascading" found in the NERC Glossary of Terms. This term is also used in R3.5, R4.5, and Table 1.a. without any definition provided. NOTE: On December 27,2007, the Federal Energy Regulatory Commission remanded the definition of "Cascading Outage" to NERC. On February 12, 2008, the NERC Board of Trustees withdrew its November 1, 2006 approval of that definition, without prejudice to the ongoing work of the FAC standards drafting team and the revised standards that are developed through the standards development process. Therefore, the definition is no longer in effect. Please provide a definition of "voltage instability" since the NERC Glossary of Terms does not provide one. This term is also used in Table 1.a. without any definition provided. Please provide a definition of "uncontrolled islanding" since the NERC Glossary of Terms does not provide one. This term is also used in Table 1.a. without any definition provided.
Yes
But as referenced in question 5, I believe you need a good definition for the following terms; "cascading outages", "voltage instability", and "uncontrolled islanding".
Yes
Yes
Yes, Yes
Individual
Don Gilbert
JEA
Reword R1.1.2. New planned Facilities and changes to existing and old planned Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon where such Facilities affect the electric connectivity and topology of the system or affects the accurate simulation of system disturbance response where practical. [Delete bulleted list] Add R1.2. Where it is not practical to model all Facilities composing the electric system connectivity and topology, consideration of those Facilities and their affect on the model simulations shall be documented in detail in the annual Planning Assessment where appropriate. This addition may not be necessary with rewording of R3.
R2.1.4 It is not clear if this spare equipment strategy excludes Generator Owner's obligations for their generation plant equipment and only includes Transmission Owner's equipment. It is also not clear what Measurable document is required to back up a position of no vulnerabilities. I recommend that we limit the spare equipment strategy to TO equipment and not include GO equipment which excludes step-up transformers, turbines, generators, rotors, etc. Also, it does seem unreasonable to assess the long-term loss of a transformer to the "Extreme Events" of Table 1 or any other event other than the P3 events unless substituted in the assessment by a more extreme and probable event. An event from P3 alone should be sufficient to expose a weakness of a spare equipment strategy based on historical industry statistics for such likelihood. Propose changing "The analysis shall reflect the Contingencies identified in Table 1..." to "An analysis shall be performed that as a minimum assesses the impact of the long term outage of Transmission Owner equipment under either a P3 event that could occur in the absence of the subject equipment" or a more stressful event as deemed appropriate by the Functional Entity performing the assessment. R2.6.4 First of all, some level of expected Non-consequential load loss is always prudent to balance customer expectations on cost and reliability subject to Local and State Authority's guidance. Second, load development and gneration development are the major drivers for transmission development needs. Generation plans are more dependable and manageable as to timing and impact. Load development is not very dependable and manageable relative to transmission system improvement needs. It is not unusual for new load forecast to either expose a transmission weakness or on the other hand to eradicate a transmission weakness in the Near Term horizon. Without guidance, it could be assumed that affects from load forecast are beyond the control of the Transmission Planner and Transmission Coordinator. In addition, it is not unusual to have the load forecast lead the generation plan by a few years causing a need for Non-Consequential Load Loss until such time the additional generation is in-service providing generation balance to the load area and mitigating the transmission improvement needs. This occurs frequently as generation development lags load development in fast growing communities. Propose establishing a cap on Non-Consequential Load Loss for all Corrective Action Plans where the Table 1 events currently do not allow at all. An additional option for the SDT to consider could be to add an allowance of lag time (maybe 4-5 years) to cover the gap while the generation addition is being developed.

R3. Change wording from "The studies shall be based on computer simulations using models utilizing data provided in Requirement R1." to "The studies shall be based on computer simulations using models that are the best representation of the future planned system and its associated use as provided by Requirement R1. The studies shall detail the effects of all future equipment connectivity and topology arrangements and their associated Protection system responses to Contingency events regardless of model details." R3.3.2. I assume the concern here is on voltage ride through of generators and generator auxillary equipment. Propose changing language from "For all generators..." to "Include analysis of how generator and generator auxillary equipment over and under voltage protection and ride through capability were considered for the post-contingency steady state bus voltage levels." R3.3.3. I assume the concern here is ensuring consideration is given to how system protection relays could respond to post-contingency circuit emergency loadings. Protection systems that could limit the emergency ratings of transmission circuits should be considered in the Facitility Rating standard and therefore not necessary to include in the TPL standard. However, if requirement does remain in the TPL standard, propose changing language from: "For all transmission lines..." to "Include analysis of how implemented relay protection systems and their potential automatic response prior to timely corrective actions are considered for the post-contingency steady state circuit loadings".

Yes

No

Footnote 8 relative to P2.1 seems to imply that all of the single contingency assessments for circuits should include assessment of (1) both ends of the circuit disconnecting as in P1 and (2) either end of the circuit disconnceting as in P2. This results in 3 seperate single contingency assessments for the one circuit. I am not sure of the benefit other than trying to identify a high voltage situation or in the case of tap loads, a thermal loading issue. Recommend changing Footnote 8 to "For circuits with tapped load, a seperate analysis shall be performed for an outage of each end of the circuit where the load is tapped."

No

Footnote 10: First of all, the term firm Load is used instead of the term Non-Consequential load. Are these the same? If so, maybe we need to be consistent here. Assuming they are the same and in reference to previous comment on use of Non-Consequential load shedding: "Propose establishing a cap on Non-Consequential Load Loss for all Corrective Action Plans where the Table 1 events currently do not allow at all. The cap could also be accompanied by an allowance of lag time (maybe 4-5 years)." To be consistent, some level of Non-Consequential load shedding should be allowed where Generation redispatch falls short for a few years until new planned generation is added to the system.

Group

Transmission Planning

R1.1. COMMENT: Should read: “Models for performing the studies needed to complete the Planning Assessment shall represent:” instead of “Models for the Planning Assessment shall represent:” R1.1.1. COMMENT: Should the requirement specify which known outages should be modeled? For example, would it be considered incomplete and therefore a violation if a known generator maintenance outage with a one week duration is not included (not modeled off-line) in a case that represents a full summer season at peak conditions? Please provide guidelines as to what duration outages should be modeled in representative planning horizon cases. (i.e. one day, several days, one week, one month, in a case that represents a significantly longer time period.) R1.1.2. COMMENT: Should add Transformers to this list; COMMENT: What is meant by “represent” - Planning models do not typically include explicit Circuit breaker modeling. The planning models used for power flow, dynamics and short circuit analysis represent the power system with busses and branches. The effect of circuit breakers is taken into account as part of contingency modeling. Including circuit breakers as a sub-requirement is likely to result in transmission planners being required to demonstrate that circuit breakers are modeled. Explicit representation of circuit breakers with existing software would result in major convergence problems due to large number of low impedance branches. COMMENT: Should clarify "Protection System equipment" to apply only to system stability models. Does this mean all relays on the system must be included in the dynamics modeling? While a certain limited number of protective relays can be modeled with the software used for dynamics, it is not practical to model more than a very small percentage of the protection systems used in the BES. Including protective relays as a sub-requirement is likely to result in transmission planners being required to demonstrate that all protective relays are modeled which is an impossible task. The modeling of

protective relays should be caveated with “as deemed appropriate.” COMMENT: "Control devices" Should be specific. Is this for Phase Angle Regulators (PAR), Synchronous Condensers, Static Var Compensators (SVC), exciters, governors etc? Control devices should be specifically defined as the following: PAR, SVC, HVDC. COMMENT: "New technologies" seems too broad. Needs to be better defined. Planning models may not have the capability to adequately model “new technologies”. R1.1.4. Firm Transmission Service COMMENT: Should add “that is expected to be utilized in the study case scenario” because not all Firm Transmission Service can be included in every study case model. Some firm transmission reservations (Network Resources that could be Reserves)are used optionally depending upon the availability of other Network resources. The following apply to all VRF, Time Horizon, Measure, Data Retention, and VSL for all requirements in the standard. VRF: Agree. No comment. Time Horizon: COMMENT: Long-Term Planning – This is confusing. Is it only the newly defined Long-Term Transmission Planning Horizon? Shouldn’t it include the Near-Term Transmission Planning Horizon? Suggest “Long-Term and Near-Term Transmission Planning Horizon” as used in definitions. Measure: Agree. No comment. Data Retention: Agree. No comment. VSL: Are bullets in requirements all required? (i.e. If circuit breakers are not explicitly modeled, as the bullet list in R1.1.2 seems to indicate, is it a violation?) What is meant by “…did not simulate projected System conditions as described in R1. …” How are projected System conditions criteria described in R1?

R2.1.4. COMMENT: For the analysis to reflect the contingencies in Table 1 (P0 through P7 plus Extreme Events) is excessive. R2.5.2. COMMENT: The 20 MW change listed in bullet items are extremely small to larger transmission systems and by themselves would be unlikely to change BES response. As drafted, requirement 2.5 may be interpreted to preclude the use of any previous study in which the base case is not identical to the current planning case. It is recommended 2.5.2 be rewritten as follows; “For steady state, short circuit, or Stability analysis: the present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period that would impact the study area.” R2.6.2. COMMENT: What is considered a project initiation date … is it implying a construction start date, or the first time that it was identified as a mitigation plan? Additionally, R2.6.2 and R2.6.3 are not necessary because a Corrective Action Plan, by definition, includes an "associated timetable for implementation". Recommend deleting this requirement. R2.8. COMMENT: Why is this data collection a requirement? The effort required to determine this data is substantial and the value of this data is questionable. Recommend deleting this requirement. R2.9. COMMENT: Why is this data collection a requirement? The effort required to determine this data is substantial and the value of this data is questionable. Recommend deleting this requirement.

R3.3.1. COMMENT: This would make sense for 3-terminal lines which we are including in contingency files, but for normal 2-terminal lines, very unnecessary. Suggested language at the end would say “Simulation of individual element outages is allowed if it produces an effect more severe that the entire circuit outage”. This implies that by modeling individual branch outages would represent more severe conditions than entire circuit outages due to the fact that there would be consequential load loss. R3.4. COMMENT: Table 1 as drafted is very confusing and could be interpreted incorrectly. Recommend revising the header for “Table 1 – Steady State & Stability Performance Extreme Events” Should be changed to “Table 2 - Steady State & Stability Performance Extreme Events” because the expected performance requirements associated with Planning Events could be interpreted to be applicable to Extreme Events as well. Alternatively, the performance requirements at the top of Table 1 need to include a statement that they are applicable to Planning Events only.

R4.3.2. COMMENT: The inability to survive a given low voltage transient is often dependent on motor performance within the generating facility’s auxiliary load distribution system and is not a specific relay setting. Determination of specific generating plant low voltage ride through capability requires extensive modeling of the plant distribution system and is outside the scope of this standard.

Yes

No

COMMENT: P2-1. Opening of Breaker(s) w/o fault Event: Does the modeling of this event require that the line remains energized up to the breakers? This will require adding a bus at each end with a zero impedance branch connection to “open” representation of breakers. Explicit modeling of a circuit breaker opening would require a substantial modeling effort and would not produce results more adverse than any of the other P2 contingencies. Why is this necessary? Recommend deletion of this planning event. The threshold of higher performance for facilities above 300 kV may wrongly influence decisions on project alternatives in favor of facilities with less stringent requirements. We do not agree that such a threshold is necessary or warranted.

No

It appears that the reference callout to footnote 5 should be placed on every "No" in the "Interruption of Firm Transmission Service column instead of in the header, as was done with reference callouts to footnote 10. In footnote 5 "conditional" should be capitalized since it refers to a specific product defined under the OATT. Also, this only covers the specific condition form of the product, but does not address the specified number of hours form of the product. If the second form of the product is the basis for the service and the transaction is modeled in the case, and curtailment will mitigate an overload, it should also be allowed. Footnote 10 is too long and subjective. There is no purpose in adding the phrase "when coupled with the appropriate re-dispatch of resources obligated to re-dispatch" because if there is an obligation to re-dispatch, it is done, and if there is no obligation to do so, then curtailment is the only alternative – no coupling necessary, therefore, this phrase should be deleted. In addition, the last two sentences end in "must be considered". What is the appropriate amount of "consideration" and what defines whether the consideration is acceptable or not? The last sentence should be a stand alone performance requirement in the Steady State and Stability notes at the top of Table 1 (in the list a through e) and should end in "must be adhered to" instead of "must be considered". Suggested revision: 10. Curtailment of firm transmission service is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load.

Yes

Individual

Catherine Mathews

NorthWestern Corporation NorthWestern Energy (NWE) (NWMT)

The system models that are described in MOD-010 Requirement1, MOD-011 Requirement 1, MOD-012 Requirement 1, and MOD-013 Requirement 1 do not address all the bulleted items under R.1.2. Circuit breakers, protection system equipment and control devices are not modeled. Rather, the effect of these devices, such as circuit breaker misoperation, thermal overload, etc., on the transmission system are modeled. The wording of these bullets should be corrected to match what is actually modeled. Firm Transmission Service, listed in R.1.1.4, is not specifically addressed in MOD-010. Requirement 1 of MOD-010 states "existing and future Interchange Schedules" as data requirements for steady-state modeling and simulation. Models in the West do not model Firm Transmission Service as such. It is difficult to know what the Firm Transmission Service will be in the future. This is particularly true in regions where there is a predominance of merchant generation and proposals for the interconnection of new merchant generation. It is more reasonable to estimate the expected interchanges. The definition for Interchange – "Energy transfers that cross Balancing Authority boundaries" describes the modeling requirement better that the definition of Firm Transmission Service – "The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruptions". The wording "Expected Transfers" is used in R2.1.3 and R2.4.3. To maintain consistency, this term could be used in R.1.1.4 and could also be substituted in Table 1 for " Firm Transmission". From a Planning perspective, since Firm Transmission cannot be determined from a study model. R1.1.4 and R1.1.5 should be deleted and replaced with a requirement to model expected transfers on interconnections with neighboring Balancing Authorities. For study purposes R.1.1.6 is not needed either. In the models, the load represented is served by the generators modeled. Network Resources are more in tune with local area studies that ensure that the network load can be served by the network resources over available transmission. The words "including requirements of regulatory authorities and other legal obligations" at the end of R1. does not need to be in the standard.

Short circuit analysis is a local issue. The reliability of the BES does not depend on the regular assessment of short circuit duty. Therefore, we believe short circuit analysis should be deleted from R2. R2.1.4 needs more clarification as to what constitutes major Transmission equipment. This would require a separate analysis (study) for each transformer (or any long lead-time equipment) for which a spare is not available, which could result in numerous additional cases. Major Transmission equipment could be limited to voltage levels greater than 200 kV. An exception should be made for phase-shifting transformers. As the system changes, with new generation and transmission lines being added, these analyses could become outdated very quickly. If a transformer were to fail, the Planning Department would immediately study the current system with this transformer removed. As stated in R2.4.1, the requirement to include induction motor loads is too prescriptive. At this time, with all of the unknown or estimated variables in the system model, accuracy of the model would not be improved. If a highly industrialized section were to develop within the NWE footprint, induction motor load could be added to the system model. The 20 MW threshold identified as "material change" for generation in R2.5 is too small. A better number for material generation changes would be 100 MW or a limit based on a percentage of the study area's installed generating capacity. Also, an aggregate of 20 MW addition/deletion generation would depend on the location of the individual generators to determine whether the overall system would be affected or not. The statement at the end of

R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement. R2.8 should be deleted. It is not necessary for reliability. R2.9 should be deleted. It is not necessary for reliability.
R3.3 is unclear. Requirements R3.3.1 through R3.3.4 should be bullets under R3.3, with R3.3 modified so that it becomes the requirement to conduct contingency analyses that address the four resulting bullets R3.3.2 is unclear. The minimum steady state voltage limitation for synchronous generators is not a very meaningful value. All generators with an automatic voltage regulator will maintain the set point voltage until the VAR capability of the generator is exceeded, and then the voltage will deteriorate. In R3.3.3 the term "loadability" needs to be defined. R3.5 needs to be modified. It would be better to combine R3.2 with R3.5. The first part of the requirement requires identification of events that produce more severe System impacts. The presumed reason that the other contingencies were not selected is because they were deemed to be less severe or non-credible. In any case, theoretically, there can always be examples of more severe Extreme Contingencies than the one selected for study. This can be achieved by simply choosing events that are even less credible. For example, if the Extreme Contingency studied was a simultaneous loss of 3 transmission lines with the failure of a redundant RAS (SPS), then an event resulting in the simultaneous loss of 4 lines with the failure of 2 sets of redundant RASs would be even more severe. Listing all possible extreme events could result in a limitless list.
R4.3 is unclear. Requirements R4.3.1 through R4.3.3 should be bullets under R4.3, with R4.3 modified so that it becomes the requirement to conduct contingency analyses that address the three resulting bullets R4.3.2 is unclear. It appears to be a broken sentence. Typically a generator may have 10 or more protective relays. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to do that for all generators in the system. It is our understanding that the voltage ride through standard is not complete at this time. R4.5 needs to be modified. It would be better to combine R4.2 and R4.5. The first part of the requirement requires identification of events that produce more severe System impacts. The presumed reason that the other contingencies were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be examples of more severe Extreme Contingencies than the one selected for study. This can be achieved by simply choosing events that are even less credible. For example, if the Extreme Contingency studied was a simultaneous loss of 3 transmission lines with the failure of redundant RAS (SPS), then an event resulting in the simultaneous loss of 4 lines with the failure of 2 sets of redundant RASs would be even more severe. Listing all possible extreme events could result in a limitless list.
In R5 the term "proxy" needs to be defined. In addition, an example of a proxy should be given.
No comment.
In R7 the references to FERC Orders should not be included in requirements of standards. This comment also applies to M7.
No
In R7 the references to FERC Orders should not be included in requirements of standards. This comment also applies to M7
No
P6 on the table seems to be less severe than either P4 or P5, yet it allows loss of Firm Transmission Service and Non-consequential Load which are not allowed for EHV in P4 or P5. Interruption of Firm Transmission Service and Non-Consequential Load Loss should be allowed for P4, P5, and P6. Transmission lines should have the same requirements regardless of the voltage. Also, if not able to model Firm Transmission Service, how will one know if it is interrupted? The column labeled "Interruption of Firm Transmission Service Allowed" should be eliminated since it is not a clearly defined test of performance. It is not clear how to use the present definition of "Firm Transmission Service" for a planning horizon study. P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements. As such, this is a low probability condition and loss of Non-Consequential load should be allowed for EHV.
No
NWE has provided comments above concerning Firm Transmission Service and the foot notes should address the issues that we have raised above.
No Comment
Group
Exelon Transmission Planning
There are large amounts of resources required to perform the volume of studies required, including the dynamic and steady state sensitivities, extreme studies, and one-year lead time equipment spares. Many of these studies ultimately do not require additional consideration or reinforcement and have low threshold triggers, such as a 20 MW generation change. Performing

these studies will be very burdensome to many TPs and result in few, if any, reliability benefits. We believe that the TP should be given more flexibility to allocate planning resources to areas of maximum benefit. The Spare Strategy in R2.1.4 is still not well defined. What types of equipment are included? How would a one-year lead time element be determined for consideration in this requirement? In R2.4.1, we recommend changing 'appropriately represents' to 'a dynamic model appropriate for the type of stability study being performed' The TP should be allowed to perform only those specific stability studies needed and pertinent to its system. The same can be said about the dynamic load model. Differing interpretations are possible. We suggest changing the last sentence in R2.4.1 to – "….., a Load model shall be used which appropriately represents…..An aggregate System "Dynamic" Load model which represents the overall dynamic behavior of the Load is acceptable." In 2.1.3 and 2.4.3 strike 'Expected' from the phrase 'Expected transfers'. Expected transfers should already be in the base case. In R2.5.2, the determination of a 'Material change' is an engineering judgment issue and it should not be categorically defined here. There may be more significant material changes than a 20 MW increase in generation that would be better to study. In the phrase, "For steady state…such as generation or transmission additions/removals, or topology changes… and would impact the study area", it is suggested to change 'would' to 'could' and 'impact the study area' to 'significantly change the previous study results'. The term should not be 'Corrective Action Plan', which implies a violation of a requirement. Suggest changing this term to 'Future Reliability Plan'. What is the intended use for reporting the largest consequential and maximum non-consequential load loss amount and event? This would be a potential security concern if made public. There is a similar concern with the extreme event analysis. In 2.6.2 please define 'Initiation Date'. While we appreciate your previous consideration of this comment, it is still not clear what this means. Is this the date of mitigation identification, regulatory approval date, construction start date, equipment procurement date, etc? If this is a commonly understood term not requiring a formal definition, could you then please provide that definition in your response? If there is going to be a requirement to report on each contingency that results in non-consequential load loss it should be specified.

In R3.3.2 it should be clear that the TP / TO is not required to provide whatever voltage that the unit desires and that the intent of this requirement is to ensure that if a generator is going to trip due to low voltage that the simulation will include the generator tripping. 3.3.2 and 3.3.3. are somewhat redundant with 3.3.1 – suggest rewording 3.3.1 to say including transmission lines with respect to relay loadability and generators with respect to minimum operating voltage. If 3.3.3 is targeting the low voltage ride through capability of the wind generators it should be clear.

See comment in response to question 9 regarding the lack of definition related to the failure of a 'single Protection System'.

The determination of a failure to document a single proxy should not be categorized as 'severe'.

Yes

No

Table 1 comments in general: Even after modification from the previous version, it is still not clear if the 'BES Voltage Level' applies to the contingency element voltage level or to the monitored element voltage level. For example, If there is a 345 kV bus section fault that causes an overload on a 138 kV line, is non-consequential load loss allowed on the 138 kV system? There is a concern about the lack of definition related to the failure of a 'single Protection System' – this could be widely interpreted. Would over tripping for line faults fall into this definition?

Yes

Yes

Group

SERC Engineering Committee Planning Standards Subcommittee

R1.1.2: In bullet three of R1.1.2, are bus-tie circuit breakers to be represented in the models? Typically circuit breakers are included in the contingency definitions along with the protection system equipment used in the power flow models. The number of zero impedance branches which can presently be modeled using PSS/E software is limited to 4000. Also, the number of buses included in the power flow models would increase with additional breaker modeling. Protection System Equipment: The SDT stated during its June 30th Webinar that protection system equipment need not be explicitly represented in models, but had difficulty in determining adequate wording for the proposed sub-requirement. Because protection system action is described in R3.3.1, R3.3.4, R4.3.1, and R4.3.3 we suggest that protection system equipment be removed from the list in R1.1.2.

R2.1: In R2.1, change the reference to requirement R2.6 (at the end of the last line) to R2.5. R2.1.4: In Requirement R2.1.4, recommend that the requirement be revised as follows: "When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience the possible unavailability of the long lead time equipment." R2.4.1: In Requirement R2.4.1, it is suggested that it be reworded to the following: "System peak Load for one of the five years, including Load models which appropriately represents the dynamic behavior of Loads, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable." R2.5.1: With the elimination of the distinction between system and generating plant stability studies, the blanket requirement in R2.5.1 that all stability analyses be five calendar years old or less, regardless of any material changes to the system, would cause needless work to be performed on those plants or areas of the system where no changes are occurring. Recommend add the following to the end of R2.5.1: "unless justification can be provided to demonstrate that the results of an older study are still valid." R2.6.2: In Requirement R2.6.2, what constitutes a "project initiation date," and how will it be used? Please clarify. R2.8: Please explain the reason why Requirement R2.8 is needed in the Assessment. Reporting the largest Consequential Load Loss does not impact reliability. R2.9: Please explain the reason why Requirement R2.9 is needed in the Assessment. Reporting the largest Non-Consequential Load Loss does not impact reliability.
R3.1: In Requirement R3.1, it is suggested that the word "contingency" be added to describe the lists created in R3.4.: "Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists created in Requirement R3.4." R3.3.1: Recommend that it be clarified that simulation of the more conservative case of a single branch (bus-to-bus) outage is acceptable, as opposed to always simulating the full breaker-to-breaker outage. R3.3.2 The requirement needs to be clarified. It is not clear if it is referring to the ability of plants to meet their voltage schedule, or to their ability to stay connected during post contingencies. R3.3.4: In Requirement R3.3.4, it is suggested adding the words "and switched" to capacitors and reactors: "Simulate the expected operation of existing and planned devices designed to provide Steady State control of electrical system quantities. These devices include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors."
R4.1: In Requirement R4.1, it is suggested that the word "contingency" be added to describe the lists created in R4.4 "Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists created in Requirement R4.4." R4.4: Regarding Requirement R4.4, it is suggested that a rewording be considered such as described below: "For each category of the Planning Events in Table 1, those Planning Event Contingencies that are expected to produce more severe System impacts shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4.1 shall be created. The rationale for the Contingencies selected for evaluation shall be available as supporting information with an explanation of why the remaining Contingencies would produce less severe System results." R4.3.2: R4.3.2 requires that voltage ride through capability be analyzed. It is not clear what should be analyzed (e.g. auxiliary loads, generator protection, generator capability, etc.) This requirement needs more clarity. Footnote #3: Footnote #3 needs to be revised to include 2LG faults in addition to 3-Phase faults indicating that the SLG criteria is met.
Use of Proxies: There is no requirement that the Planning Coordinator (PC) must use the same proxies as the Transmission Planner (TP). Since differences in proxy assumptions may lead to different study results, R5 should be revised to require the PC and TP to coordinate the use of proxies.
no comments on this question
FERC Order 890: The reference to FERC Order 890 as it is currently written makes it seem like a suggestion to follow Order 890. If Order 890 explicitly describes this process then the sentence should read "as described in FERC Order 890." If not, this should not be mentioned at all.
No
Definitions: Revised Definitions are generally better than those from the previous version, but additional clarity could be provided. Load Reduction – Please clarify whether this includes both load response and operator initiated action, such as in changes to transformer LTC. Supplemental Load Loss - From a utility perspective, this would be considered as load response. Please clarify how Supplemental Load Loss would be included in the stability analysis. Bus tie breaker – A statement in the previous version which listed examples was removed from this version of the definition. The statement was helpful and should be re-inserted. The statement was: "Substation configurations such as ring bus, breaker and a half, or double-bus double-breaker do not use bus tie breakers."
No

Table 1 titles: The word "Requirements" needs to be added to the Table 1 titles in the existing tables. Table 1 – Steady State & Stability Performance Requirements Planning Events Table 1 — Steady State & Stability Performance Requirements Extreme Events Table 1 — Steady State & Stability Performance Requirements Footnotes (Planning Events and Extreme Events) Steady-state vs. stability analysis: We recommend that Table 1 be split back as was done in the previous draft to handle the 1) steady-state and 2) stability performance requirements. This is needed to provide clarity on which contingencies apply to steady-state and which apply to stability analysis. Table I, P7.1: It would not be likely to lose the two outside circuits on a vertically configured structure and not lose the middle circuit. Change the wording to: "Any two adjacent circuits on a common structure."

No

Footnote 5: Suggest rewording of footnote 5 to: Curtailment of conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the conditional Firm Transmission Service. Footnote 10: Footnote 10 is definitely an improvement from previous versions. It is suggested that the word "also" be added to the last line: "Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must also be considered."

No

Construction activities: 60 months effective date seems acceptable for planning activities, but may not adequate for all construction activities. Typical times to construct a transmission line in various areas of SERC can range between 7 to 10 years. Accordingly, we recommend the effective date for construction projects be changed to at least 84 months. Dynamic load models: More time is needed for entities to determine the appropriate dynamic load model required by R2.4.1. We recommend at least 36 months before this requirement becomes effective.

Individual

Dilip Mahendra

SMUD

R1: The requirement should end after the words "…shall simulate projected System conditions.". The following words should be deleted as it results in a clause that is overly broad and does not specify clear and concise reliability requirements: "…including requirements of regulatory authorities and other legal obligations".

R2.1.3 and R2.4.3 The sentence, "…sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment: …", should be modified by changing the second 'included' to 'considered'. R2.1.4 Since there is no NERC reliability standard requirement for a 'spare equipment strategy', what is the standing of a requirement that is based on having one? R2.5.2 There is no example given for 'Transmission additions/removals' ? Recommend that the wording of this requirement be made more discretionary with a requirement that the Transmission Planner include language explaining the reasons for using past studies.

R3.5 Listing all possible scenarios for studying extreme contingencies will result in a limitless list. Discretion should be given to the transmission planner on the selection of the contingencies without a requirement to list why other extreme contingencies have not been included. R3.3.2: When the word, 'consider' is used, it can be read as a guidance and not a requirement. The requirement is unclear.

R4.3: R4.3.2 – The requirement is unclear. If it is to cover modeling issues, then it should be under MOD series. If it is to cover voltage ride through performance, then performance metrics should be provided. R4.5 Listing all possible scenarios for studying extreme contingencies will result in a limitless list. Discretion should be given to the transmission planner on the selection of the contingencies without a requirement to list why other extreme contingencies have not been included.

R5: Guidelines for identifying proxies for unstable conditions would be helpful.

Requirement R7 should end after the words '....who has indicated a reliability need'. R7: The requirement should not invoke another document for compliance. The words, ", coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890', should be deleted. This comment also applies to M7.

No

The allowed corrective actions in Table 1 to meet performance standards do not explicitly state

how DSM solutions should be treated [there is a potential for 20% of national peak demand to be met by "demand response"] . If it is allowed to be used, and since this is a fairly significant amount, it would help if it is explicitly addressed in Table 1.

No

The allowed corrective actions in Table 1 to meet performance standards do not explicitly state how DSM solutions should be treated [there is a potential for 20% of national peak demand to be met by "demand response"] . If it is allowed to be used, and since this is a fairly significant amount, it would help if it is explicitly addressed in Table 1.

Group

Southern Company

The VSLs for Requirement R1 incorporates several sub-requirements but neglects one of the three components of the main requirement. Consider that R1 requires the TP and RC to (a) maintain System models, (b) use data consistent with certain MOD standards, and (c) simulate projected System conditions. Because the first component is not a part of the proposed VSL and the purpose of this standard mentions a "broad spectrum of System conditions," the recommendation is to add maintaining the system model into the VSLs for R1. R1.1.3 uses the terminology real and reactive "Demand" of Load. We suggest striking the word "Demand" because it refers only to real power. We recommend the the SDT limit R1 to load flow and stability models. Does R1 apply to short circuit models? If so does this imply that the short circuit model must be the same as the load flow model?

The Lower VSL describes a scenario where the TP or PC fails "one or both" of two particular sub-requirements. This language does not reconcile how failure of two sub-requirements is consistent with failure of only one of the same requirements. The recommendation is to restructure the VSL such that it is invoked when "either" sub-requirement is violated (not when both are violated). Generating unit stability has now been combined with system stability to be just one category - Stability. Previously, the shelf life of generating unit stability studies was indefinite -only needed to be restudied when system changes required it. Now the maximum shelf life of Stability studies is five years. Does this mean that generating unit stability studies must be repeated every five years whether system changes make it necessary or not? Requirement 2.3 stating that "the short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon." It is not clear if the intent of the requirement is to study every year within Year One and year five. A statement similar to R2.1.1 Year One or two and year five for steady state analysis would be helpful. Some clarification is needed for R2.3 on the term "Near-Term." Requirement 2.3 stating that "the analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area." What interrupting devices are included? Would the circuit breakers be enough? Moreover, the term "System short circuit model" is used for the first time (and the only time) here for the entire document. It is very common to use a different short circuit model for short circuit analysis while the steady state and stability analysis use different System models (power flow models). Some clarification is needed. R2.8 and R2.9 use the term megawatt "Demand". This is redundant. We suggest striking the word demand.

R3.3.3 applies to "all Transmission lines." To be consistent with the relay loadability standard, this should only apply to lines above 230 kV and lines between 100 kV and 230 kV identified as critical. R3.2 and R3.5 are both addressing the Extreme Events. However, R3.2 is referring to R3.5 while R3.5 is referring to R3.2. We suggest deleting the reference back to R3.2 which is in R3.5. A similar situation exists for R3.1 and R3.4. R3 seems to use the words studies and analyses interchangeably. Did the SDT intend for them to be the same? Using one term or the other would be better understood. There are two tables labeled table 1. It would be much clearer to mark them table 1 Planning Events and table 2 Extreme Events.

Generating unit stability should be separated from system stability like in previous drafts. R4.2 and R4.5 are both addressing the Extreme Events. However, R4.2 is referring to R4.5 while R4.5 is referring to R4.2. We suggest deleting the reference back to R4.2 which is in R4.5. A similar situation exists for R4.1 and R4.4.

We recommend using an alternate term for proxies such as criteria, guidelines, etc. to clarify what is meant.

We recommend the following wording for R7. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among adjacent Planning Coordinators and any functional entity who has indicated a reliability need. Each Planning Coordinator shall coordinate analysis of these results through an open and transparent peer review process such as described in FERC Order 890.

No

We disagree with deleting the definition of system stability and generating unit stability. The proposed definition for Year One reads as follows – Year One: The first year that a Transmission

Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the current year. Please clarify if this refers to the first "calendar" year when a Transmission Planner becomes responsible for assessments. If so, then add the word "Calendar" so that it reads "Year One: The first calendar year .....".

Yes

No

Footnote 10 should not be applied to P3. The curtailment of firm service should not be allowed for a unit out / line out contingency.

No

More time is needed for entities to determine the appropriate dynamic load model required by R2.4.1. We recommend at least 36 months before this requirement becomes effective. Other than that, the SDT has done a good job in allowing time for entities to get into compliance with the requirements where the bar has been raised.

Group

Modesto Irrigation District

Comment: Are all bullets under R1.1.2 required to be explicitly modeled or are the effect of the devices or the effect of the removal of the devices to be modeled? We don't explicitly model circuit breakers or explicitly model protection system equipment in the steady state model. R1.1.4 should refer to expected transfers to be consistent with the bullet under R2.1.3. Please explain the difference between R1.1.4 and R1.1.5

On pages 6 and 7 under sections R2.1.3 and R2.4.3, I think the magnitude of the "variations" in the conditions asked for in the sensitivity cases, should be defined and not left to the analyst to decide. On page 8 under Section R2.5.2, examples of "material changes" for generation are given, but no examples for transmission changes. Shouldn't we include examples of material transmission changes, too ? Comments: Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES R2.8 and R2.9 load loss comment. We don't agree with R2.8 & R2.9. What reliability purpose is served by these requirements?

On page 10 under Section R3.3.3, I believe more specifics on what is meant by "relay loadability" need to be given in regard to the requirement of "identify how loadability is analyzed in the steady state simulation". For example, does the analyst need to state that the maximum loading allowed on any system element is less than or equal to 150% of the element's maximum seasonal rating ? We believe that R3.3.1-R3.3.4 should be bullets under R3.3

Comments: We believe that R4.3.1-R4.3.3 should be bullets under R4.3

On page 13 under Section R5, can the term "proxies" be defined and clarified, and examples given, in this context ?

No

On page 2 under "Definitions of Terms Used in Standard", the red-lined out example used to clarify the definition of "Non-Consequential Load Loss" seems valuable to me, and I think they should not remove it but leave it in.

No

On page 20 under Table 1, why are "SLG" (i.e., single line to ground) type faults still specified when footnote 3 on page 24 indicates that analyzing three phase faults is sufficient ? On page 20 under Table 1 part f, changing "post transient" to "post Contingency" may be confusing to most analysts as post-transient is a well defined term that has been in use for many years, and is even referenced in Table W-1 of the WECC supplemental planning standard TPL - (001 thru 004) – WECC – 1 - CR. On page 20 under Table 1 part g, does that mean that for Planning Event P0 the analyst is not required to simulate a fault with normal clearing without a loss of any system element, in order to demonstrate system stability ? On page 24 under Footnote 1 a ii, I would like to suggest that we add the phrase "(unless the relays are equipped with blinders and timers)" right after the phrase "…must not pass through relay characteristics…". This is because the blinders (i.e., straight line characteristic of a distance relay) and timers can be used to prevent distance relays from tripping when power angle swings cause the apparent impedance the distance relays see to cross into the distance relay's zone of protection.

Individual

Bart White

Progress Energy Florida, Inc.

For R1.1.2, PEF has the following comments: T-T Transformers, as major components of the BES, should be on this list. PEF does not object to the inclusion of Circuit Breakers on this list,

provided that representation is not required in steady state load flow cases. Breaker failure scenarios can be extensively studied in the steady state and stability realms by removing from service the transmission facilities that such a breaker event would initiate. PEF assumes that the inclusion of Protection System Equipment applies only to Stability Analysis. As for breakers, relay failure scenarios can be extensively studied in the steady state realm by removing from service the transmission facilities that such a relay event would initiate. Additionally, PEF also assumes that a comprehensive modeling of all Protection System Equipment (e.g. Transformer Sudden Pressure Relays, Bus Diff Relays, etc.) in Stability Analysis is not required, since only a limited amount of relaying in dynamic modeling is needed to adequately model the system with respect to what transmission/generation components would trip for a given event. A lack of specificity on the term "Control devices" leaves it open to wide interpretation. The SDT should, in detail and/or with examples, state what is intended. The term "New technologies" is only acceptable for inclusion if provision is made for the fact that Planning analysis software often lags behind the design industry in getting new technologies modeled such that Planners can analyze them. For R1.1.4 on Firm Transmission Service: PEF assumes that the SDT understands that some firm transmission service is not always modeled in every case, depending upon the economics and availability of alternate resources.

Concerning R2.1.4, this sub-requirement is overly burdensome for two primary reasons: a) It amounts to a system-wide N-2 and N-3 analysis, which goes against FERC's policy of separation and distinction between types of events as stated in Paragraph 1788 of Order 693: "Under TPL-002-0 the system is not required to be able to withstand another N-1 contingency. That N-1 requirement is a Category C contingency which is addressed by TPL-003-0." b) The requirement to perform system-wide analysis for such a scenario is a significant workload issue, and will take time away from analysis of more probable events. Concerning the issue of material changes in past studies in sub-requirement R2.5.2, PEF objects to the specification of changes in units "of 20 MW or greater", due to the fact that a change (or even deletion) of a 20 MW unit in a case modeling a large BES does not truly constitute a material change. The SDT in its response to Question 15 in the comments for draft 2 stated that "The SDT did not want to be overly prescriptive when describing the type of changes that could be considered material and has left the text general." PEF suggests that the SDT take its own advice, making the language in R2.5.2 more general in nature and leaving such modeling details to the discretion of the Transmission Owner. In R2.6.2, PEF assumes that the term "project initiation date" is intended to mean the Construction Move-In date. If the term means the first date at which Planners had identified it as a mitigation, PEF would object to this as it would appear to preclude the right to develop superior mitigations, or to cancel a project if it can be demonstrated as no longer needed. Concerning R2.8 and R2.9, PEF strenuously objects to such requirements. These requirements have no bearing on demonstrating the reliability (or lack thereof) of the BES, and therefore should be removed from the Standard.

Concerning R3.3.1, PEF believes that, in virtually every conceivable scenario, contingency analyses show that analysis of individual elements will reveal overloading or undervoltages, whereas the same event modeled according to protection system design (i.e. simulating the event as the actual "breaker-to-breaker" operation would occur) may not. Analysis of individual elements is therefore a more conservative method for studying the BES. PEF is not opposed to analysis of entire circuit outages; PEF therefore suggests that in addition to the existing language of R3.3.1, an additional sentence be added as follows: "Simulation of the loss of individual elements is acceptable in lieu of simulating the loss of all elements in a protection zone if it produces greater overloads or lower voltages." This approach would allow for more efficient coordination with Transmission Operators as they schedule planned outages or make system adjustments in outage scenarios.

For R4.3.2, PEF assumes that the SDT understands that the extent of analyzing generation voltage ride-through capability does not extend to modeling of individual inductive loads on the Distribution side, as this does not fit the definition of the BES. Motor loads on the Distribution system do have an effect on generation voltage ride-through capability, however, and PEF therefore is perplexed as to what extent the SDT expects concerning analysis for this sub-requirement.

PEF does not presently have any concerns with R5.

PEF does not presently have any concerns with R6.

PEF does not presently have any concerns with R7.

No

PEF continues to disagree strenuously with differentiating between Consequential Load Loss and Non-Consequential Load Loss. PEF does not believe that load loss has anything whatsoever to do with demonstrating the robustness of the BES. The approach the SDT is taking with TPL-001-1 is essentially "Feeder Reliability", rather than BES Reliability. Should the SDT decide that they must continue with this approach, PEF will explore options for expressing concern about this at the FERC level. PEF is perplexed by the definition of Supplemental Load Loss. PEF, as a Transmission Owner, considers its "end-user" to be the Distribution System. PEF would therefore use this definition to design Distribution-side controlled load curtailment schemes that essentially qualify

as Consequential Load Loss. If this is not the intent of the SDT, PEF suggests that the SDT modify this definition to make its meaning clearer.
No
PEF has multiple concerns with Table 1, the most fundamental of these concerns being that the existing Table in the existing TPL Standards is far superior to the new table. PEF suspects that the large blackout/brownout events in the Northeast and West have been the primary impetus behind devising a new Standard that will allegedly improve BES reliability. PEF strongly feels that proper planning, operation and maintenance under existing NERC Standards could have prevented all of the aforementioned events, and thus a new TPL Standard and a new Table 1 is not necessary. PEF's specific concerns with Table 1 as it exists in this 3rd draft of TPL-001-1 are as follows: As a general concern, PEF, as has been stated already, does not believe that organizing a Reliability table according to whether or not loss of Firm Transmission Service or loss of Non-Consequential Load can occur is appropriate. The BES can be demonstrated to be robust and can even be continually improved under the existing TPL Standards. PEF fails to see how FERC's and NERC's desire to eliminate Footnote (b) as stated in the existing TPL Standards has anything to do with the desire to improve the reliability of the BES. Indeed, as TPL-001-1 exists at present, PEF suspects that many Transmission Owners will a) reduce posted ATC values to reduce risk of loss of Firm Transmission Service or b) remove breakers to convert Non-Consequential Load into Consequential Load. Both of these actions fly in the face of what FERC desires for the BES of the future. FERC certainly desires for power markets to open up further and thereby encourage lower energy prices, but at present TPL-001-1 and the accompanying Table 1 is in opposition to enhancing the power marketing industry. In addition, removing breakers is in opposition to reliability and customer service. An additional general concern involves the continued differentiation between HV and EHV. EHV by its very nature carries significantly larger amounts of power than HV, and therefore an EHV event inherently causes a greater disparity between Generation and Load than a HV event, making the loss of Firm Transmission Service or loss of Non-Consequential Load necessary for even a single contingency. Should all utilities be therefore required to make their EHV systems redundant? Such a suggestion is preposterous. Given this fact, and the fact that EHV events hardly ever occur (and, as outlined in the draft Table 1, have never occurred on PEF's system), PEF believes holding EHV to a higher standard is inappropriate, and will result in no more than a negligible reliability improvement at tremendous cost. Based on the above concerns, PEF believes for all event scenarios (P0 – P7), analysis according to whether or not loss of Firm Transmission Service or loss of Non-Consequential Load can occur is inappropriate and should be deleted from the Standard. Concerning event P2-1, PEF assumes that "opening of breaker w/o fault" means opening breakers from both sides of the circuit. PEF therefore does not understand the difference between event P2-1 and events P1-1 through P1-4, and therefore suggests deleting P2-1 and combining the remainder of P2 with P1. Given the concerns above, voicing additional concerns about the Footnotes, short of reinstating the existing Footnote (b), is irrelevant.
No
Again, given the fundamental concerns that PEF has stated in previous Questions, PEF sees voicing detailed concerns for these footnotes as irrelevant, short of suggesting the reinstatement of the existing Footnote (b).
No
While the Implementation Plan is extremely vague at present, making a specific enforcement date impossible to determine, PEF is concerned that the language at present will not allow enough time for Transmission Owners to prepare for the increased stringency.
Individual
Alice Murdock
Xcel Energy
R1 states that the models used in these studies shall be consistent with data provided through MOD-010 and MOD-012. The data submitted for these are updated on a schedule provided by the RRO and not necessarily reflective of any emerging changes that may have occurred between the MOD data collection cycle. The requirement should allow for exceptions to allow the most recent information to be included in the TPL studies.
R2.1.3 – is this indicating that only one of the variations need to be studied? ("…in one or more of the following conditions…"). Recommend having the planner work with the load to determine what sensitivity studies to perform. R2.1.4 – it is unclear as to what should be done with the analysis that incorporates the company's spare equipment strategy. Is this requirement inferring that a company's spare equipment strategy need to ensure that it can still operate to within the requirements for contingencies of Table 1 without the component? R2.2.1 – is the intent to have the study for the 10 year horizon or to include any project that is started within the next 10 years and thus the study must be extended to the forecasted completion of the project (conceivably as long as 20 years or more?) R2.6.4 – recommend clarifying how "situations beyond the control of the TP or PC" are determined. It is unclear if this is to imply that if something is outside of the control of the department who conducts the planning studies or if it is outside the control of the registered function's legal entity (i.e. corporation). R2.8 – appears to

be nonessential information for reliability; for what purpose does this requirement exist? R2.9 - appears to be nonessential information for reliability; for what purpose does this requirement exist?

R3.3.3: Relay loadability has no bearing beyond the near term horizon. Loadability is not determined several years out. R3.5 – does this imply that mitigation plans must be implemented? If not, then this is highly subjective and the last sentence of this requirement should be deleted.

R4.3 – requires very labor intensive and detailed studies to be conducted; there are concerns about being able to accomplish the required studies within the 24 month implementation period; additionally, while there may be some reliability benefit to requiring these studies, have the costs of this requirement been studied?; an alternative could be some sort of phased implementation (x% completed by 24months, etc.) R4.3.3 – to what degree is generator relaying factored into the model/study?

The term "proxies" is somewhat confusing; recommend the use of "assumptions" if that is an acceptable substitute.

Why is this needed if both entities must comply with the standard? At a minimum the requirement should include language to state that the one party must provide to the other with enough notice to comply with a required study if there is a shift or assignment of a responsibility.

Recommend deleting the portion of the requirement that states: "coordinating analysis of these results through an open and transparent review process such as described in FERC Order 890."

No

Clarification is needed on the use of UVLS. Is it acceptable or not. Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss Allowed column is No, is load disconnecetd from the system by UVLS a violation? What about Supplemental Load Loss or UFLS?

No

P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements.

Individual

Kathleen Goodman

ISO New England, Inc.

R1 Priority Comment- There needs to be some direction provided on the initial conditions used in the assessment. This guidance should include discussion as to whether or not representations of generator forced outages are to be represented in the base case or if they are addressed through the sensitivity testing (Could add R1.1.7 Reasonable representations of unplanned generator outages.) Additionally, the standard is also silent on the treatment of system transfers, both internal and external, as to how they should be modeled in the base case. For some areas, their current practice is to include heavy system stresses in their base case, which leaves little for sensitivity testing. It is unclear if this practice works within this standard. R1.1.1 Priority comment – R1.1.1 should be removed. It seems like there is an overlap between the requirements of this standard and Operational Planning studies with respect to known outages. Planned outages are addressed by our Operational Planning processes and Transmission Operating Procedures removing the need for this to be incorporated into Planning Assessments. In addition, outages are not generally known years in advance R1 Comment – We do not understand what it means to include "requirements of regulatory authorities and other legal obligations". Even if some version of this language is kept in the final standard, it seems to belong in R2 rather than R1. R1.1.2 comment - Do we need to have the list of equipment to model? How do we model circuit breakers, etc? We recommend deleting the list. Make R1.1.2 simply read: R1.1.2 New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon. R1.1.5 comment – What specifically needs to be modeled under Interchange? R1.1.6 comment – This needs further definition or it should be deleted. It is not clear what a "network resource required to supply load" is. Does this refer to Network Resource per FERC LGIP?

R2 Comment – We recommend replacing the phrase "prepare" with "conduct and document" in the first sentence. R2.1.1 Comment – The requirement to evaluate year one or year two should be removed. This is not consistent with the time horizon identified in R2. R2.1.2 Comment – The requirement should be removed. With no description of the system stresses and generator outages to be applied when assessing the off-peak load, it is difficult to imagine any issues which would arise which are not revealed in the peak load evaluation that could not be addressed through generation dispatch adjustments. R2.1.3 Comment - The emphasis on sensitivity testing in the existing section appears misdirected and should be focused on reasonable risk. The assessment should have to include a discussion of reasonable risk. The sensitivity list can be

used to select sensitivities to assess risk. Having a requirement to perform one sensitivity just to meet the requirement of the standard does not add value to the assessment. R2.1.4 Priority Comment – With respect to spare equipment strategy, this requirement imposes severe testing requirements upon the system. However, there is no discussion on the generation dispatch or system transfers that are to be used for this portion of the assessment. The expectations for changes in system stresses need to be clear as part of the standard. Additionally, this section does not contemplate changing the acceptability of load loss. After experiencing a major contingency such as this, some change in the acceptability of load loss should be expected. The standard should consider allowing Non-Consequential load loss for P1 & P2 events. The standard needs to allow Non-Consequential load loss for P3 & P4 events. Why doesn't the standard state "(such as a transformer, generator or power electronic device)" and not just "(such as a transformer)". R2.2 Comment – We suggest replacing the phrase "a current System peak Load study" with "a valid System peak Load study" in the first sentence. The word current is confusing as some read the word current to mean "today's" rather than "valid". R2.3 Comment – Please provide guidance as to what year should be represented when performing short circuit studies. R2.4.1 Comment – Change to read: "For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads or an aggregate System Load model which represents the overall dynamic behavior of the Load." R2.5.1 Comment– We suggest deleting this requirement, and incorporating it into R2.5.2. R2.5.2 Comment – To incorporate R.2.5.1 into R2.5.2; please modify the section as follows: For steady state, short circuit, or Stability analysis the study shall be less than five calendar years old or less: the present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: • The addition/deletion/change of individual generating unit capability determined to be material by the Planning Coordinator or Transmission Planner. [A 20 MVA generator is fairly small in a 30,000 MW system and system concerns would already be addressed though the System Impact Study] • An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES determined to be material by the Planning Coordinator or Transmission Planner. R2.6 Priority Comment – As written, this section undermines the value of the sensitivity testing. This section should require a corrective action plan to fix problems determined in sensitivity analysis if there is a reasonable risk of occurrence. We suggest making the standard read "Provide documentation that explains the reasoning for the sensitivities considered and selected." R2.6 Comment – At the end of the second sentence, the phrase "in the tables" is used. We suggest using more definitive language such as "in Table 1". R2.6.2 Comment – The phrase "Project Initiation Date" needs to be defined. It is unclear if this is this the date of ground breaking, purchase orders being issued, solution study initiation, etc. Additionally, in the second sentence the phrase "as well as an in-service date" should be modified to read "as well as a target in-service date". R2.6.3 Comment – Plans can provide a target in-service year but not an actual in-service year. R2.6.4 Priority Comment – There should be a cutoff point when changes occur beyond a certain date. When that date occurs, further changes will be evaluated in the next year's assessment. Otherwise, if a state makes a decision not to site a project a few weeks prior to the end of the assessment period, there will not be sufficient time to incorporate this into that year's assessment and develop corrective actions. R2.8 Comment –Largest consequential load loss is not factored into the Planning Assessment and should therefore be deleted. R2.9 Comment – This requirement is unclear. Is this requirement asking for each transmission planner to list their criteria for non-consequential load loss, or is it asking how much non-consequential load loss was being relied upon in the assessment? We recommend that the requirement be modified to require documentation of the maximum amount of non-consequential load loss that was relied upon during the assessment.

R3.3.2 Comment – Traditionally transmission planners have used their judgment about the minimum steady state voltage limitations of generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R3.3.3 Comment – PRC-023 requires relay loadability to be reflected in facility ratings. Therefore this additional requirement is unnecessary and should be deleted. R3.5 Priority Comment – We recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following: - Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events - It should be clear that an evaluation does not require solution development for all Extreme Events - Change "an evaluation of possible actions…" to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered."

R4.3.2 Priority Comment - Traditionally transmission planners have assumed that generators would ride through low voltages associated with Planning Events which is generally adequate for non-wind generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary

information prior to its inclusion as a requirement in this standard. R4.5 Priority Comment – We recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following: - Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events - It should be clear that an evaluation does not require solution development for all Extreme Events - Change "an evaluation of possible actions…" to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered."
It is unclear as to what is meant by the term "proxy used in the analysis" used in this requirement. Does this mean Planning Coordinator established practices, thresholds or guidelines used to gauge when simulations suggest an event such as cascading outages occurs? If so the language should state: R5. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, when established practices, thresholds or guidelines identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.
We do not feel that this requirement belongs in this standard and it should be deleted. The standard defines requirements for the assessment not who does what.
This standard should not be reiterating FERC Order 890. We do not feel that this requirement belongs in this standard and it should be deleted.
No
Refine load loss definitions as follows. Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions resulting from following a Planning or Extreme Event. Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction. Intended post contingency loss of load (other than Interruptible Load, Supplemental Load or Load Reduction) caused by operator or SPS (RAS) action. (Priority Comment)
No
Priority Comment – As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. Priority Comment – Event 1 - This requirement requires the evaluation of the loss of two circuits on a multiple circuit tower. We recommend that this be modified so that only the loss of two adjacent (vertically or horizontally) circuits need be evaluated. We also recommend that the Planning Coordinator be allowed to evaluate and if appropriate exempt specific locations from this contingency based on acceptable risk. Comments on Extreme Events – Table 1- We recommend renumbering the Extreme Events table to be Table 2. Stability Condition 2 Note h – Eliminate this requirement or change to loss of station following three phase fault. This note is confusing. Without providing a better defined scenario, it is unclear as to what clearing times should be used in this simulation. Note 1.a.ii – Contingency Reserve is dependent on the generation on-line. We suggest changing the first sentence to say that you can't lose more than that permissible by the Planning Coordinator. Also change "pull out of synchronism" to "lose synchronism" in this sentence and in the second sentence. (Is "Lose synchronism" a more commonly used term?). Note 3 – We recommend revising the wording of the last sentence to "A 3 phase fault study indicating criteria are being met is sufficient evidence that a SLG condition would also meet criteria." Note 4 – We recommend that a lower bound be put on the HV electric systems (such as 100 kV), rather than just saying "and lower".
Yes
Yes
Group
United Illuminating
R1 Priority Comment- There needs to be some direction provided on the initial conditions used in the assessment. This guidance should include discussion as to whether or not representations of generator forced outages are to be represented in the base case or if they are addressed through the sensitivity testing (Could add R1.1.7 Reasonable representations of unplanned generator outages.) Additionally, the standard is also silent on the treatment of system transfers, both internal and external, as to how they should be modeled in the base case. For some areas, their current practice is to include heavy system stresses in their base case, which leaves little for sensitivity testing. It is unclear if this practice works within this standard. R1.1.1 Priority comment – R1.1.1 should be removed. It seems like there is an overlap between the requirements of this standard and Operational Planning studies with respect to known outages. Planned outages are addressed by our Operational Planning processes and Transmission Operating Procedures removing the need for this to be incorporated into Planning Assessments. In addition, outages are not generally known years in advance R1 Comment – We do not

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We do not feel that this requirement belongs in this standard and it should be deleted. The standard defines requirements for the assessment not who does what.

This standard should not be reiterating FERC Order 890. We do not feel that this requirement belongs in this standard and it should be deleted.

No

Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions resulting from a Planning or Extreme Event. Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction. Intended post contingency loss of load (other than Interruptible Load, Supplemental Load or Load Reduction) caused by operator or SPS (RAS) action. (Priority Comment)

No

Steady State & Stability comments as follows: Steady State & Stability: a. Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur. b. Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirements P5 Priority Comment – As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. P7 Priority Comment – Event 1 - This requirement requires the evaluation of the loss of two circuits on a multiple circuit tower. We recommend that this be modified so that only the loss of two adjacent (vertically or horizontally) circuits need be evaluated. We also recommend that the Planning Coordinator be allowed to evaluate and if appropriate exempt specific locations from this contingency based on acceptable risk. Comments on Extreme Events – Table 1- We recommend renumbering the Extreme Events table to be Table 2. Stability Condition 2 Note a - Priority Comment - As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. Stability Condition 2 Note h – Eliminate this requirement or change to loss of station following three phase fault. This note is confusing. Without providing a better defined scenario, it is unclear as to what clearing times should be used in this simulation. Note 1.a.ii – Contingency Reserve is dependent on the generation on-line. We suggest changing the first sentence to say

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Yes

Yes

Individual

Baj Agrawal

Arizona Public Service Co

The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices only where it is expected to impact the study outcome. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted. We disagree with the inclusion of the words "including requirements of regulatory authorities and other legal obligations" at the end of R1. Entities already are required to do this. It does not need to be included in the standard. VSL: Under Severe VSL Column: The last sentence "The System model did not simulate projected System Conditions as described in Requirement R1" is vague and should be clarified. What is meant by "did not simulate." Is it referring to gross errors or something else? We recommend that Sever VSL be assigned only if the Transmission Planner failed to do the planning assessment. Hence it should not apply to R1 at all since R1 is only related to modeling accuracy.

Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement. The 20 MW threshold identified as "material change" for generation in R2.5 is too small. The limit should be raised or based on a percentage of the study area's installed generating capacity with a minimum of 100 MW change. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the "largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event" if it is documented? R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.

As currently drafted, R3.3 is not a requirement. Without the statements in R3.3.1-R3.3.4, R3.3 is simply a phrase. Sub-Sub-Requirements R3.3.1 through R3.3.4 should be bullets under R3.3, with the language in R3.3 modified so that it becomes the requirement to conduct contingency analyses that address the four resulting bullets R3.3.2 is unclear as drafted. The minimum steady state voltage limitation for synchronous generators is not a very meaningful value. All generators with an automotive voltage regulator will maintain the set point voltage until the VAR capability of the generator is exceeded, and then the voltage will deteriorate. R3.5 – We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingencies than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more

severe. Listing all possible extreme events could result in a limitless list.

As currently drafted, R4.3 is not a requirement. Without the statements in R4.3.1-R4.3.3, R4.3 is simply a phrase. Sub-Sub-Requirements R4.3.1 through R4.3.3 should be bullets under R4.3, with the language in R4.3 modified so that it becomes the requirement to conduct contingency analyses that address the three resulting bullets. R4.3.2 – it is not clear what is required to be modeled. Typically a generator may have 10 or more protective relays. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to do that for all generators in the system. R4.5 – We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingency than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.

The term proxy is unclear. Please provide an example or an explanation of proxy. If this is related to Note "i" in Table 1, it should be so stated. If it is related to assumptions or criteria, please state so.

We believe that references to FERC Orders should not be included in requirements of standards. This comment also applies to M7.

No

Claification is needed on the use of UVLS. Is it acceptable or not. Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss Allowed column has a No entry, is load disconnecetd from the system by UVLS a violation? What about Supplemental Load Loss or UFLS?

No

P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements. As such, this is a low probability condition and loss of Non-Consequential load should be allowed for EHV. We disagree with raising the bar for EHV for P4. We do not agree with Note "i" which requires establishing transient voltage response limits. There is no solid basis for such limits. In the past such limits were used as proxies for VAR margin and are not needed anymore. This will also result into non-uniform criteria throughout the interconnection. If such a limit were to be established, it should be based upon quantifiable reliably impact and should be supported by firm technical basis. Note 1b: Acceptable damping should not be defined by Planning coordinator and should be left to the Transmission Planner. Otherwise it would result into non-uniform criteria for the interconnections.

Group

Louisiana Energy and Power Authority

R2.5. This basic requirement intends, as we understand it, to require that earlier studies not be used for a current assessment if they are no longer accurate. But the phrasing is potentially confusing, and would be clearer if revised. Since the requirement deals with the use of past studies, we suggest that R2.5.2 be revised to state that "the study may be used only if there have been no material changes," so that R2.5 reads in full: "R2.5. Past studies may be used to support the Planning Assessment if they meet the following requirements: "R2.5.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less. "R2.5.2. For steady state, short circuit, or Stability analysis: the study may be used only if there have been no material changes, such as generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: "The addition/deletion/change of individual generating unit capability of 20 MW or greater. "An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater." With respect to footnote 10 to Table 1, we fear that the flexibility suggested by those provisions may be excessive for a planning standard. The ambiguity occasioned by stating emergency actions that can properly be taken in a planning standard can be utilized by those who plan the system in a manner which plans to drop non-consequential loads just as footnote b has been used in the past. If this is intended to "raise the bar" as stated these provisions do not belong in a planning standard, at least as now stated. It may be appropriate to remove the reference to footnote 10, at least in the Initial System Condition entry in P3, where it

suggests that it can be invoked after loss of a single generator, and we request the SDT to review that footnote to assure that it is appropriate in the other entries to which it is applied.

No

LEPA is in the area which is impacted by Entergy transmission planning. Entergy is one of the few NERC transmission owners which has for some years now relied upon its interpretation of "footnote b" in the previous TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0 as permitting planning for the loss of Non-Consequential Load or interruption of firm transfers as a way of planning and building less transmission than other utilities would have considered themselves obligated to build for reliability. That Entergy interpretation, and the consequent lower investment in transmission planning and construction, has been a matter of some concern among Entergy regulators at both State and Federal levels, as well as Entergy transmission customers, and has been rejected by the SPP, which has been given the authority to develop the base plan for transmission additions on the Entergy system. It was the Entergy rejection of that base plan that most recently led to a day long technical conference among regulators at the recent SEARUC conference in Charleston, SC. The proposed Implementation Plan for TPL-001-1 is drafted to make the new standard, which the proposed Implementation Plan describes as one that "raises the bar in several areas," effective only after the passage of 60 months from the first day of the first calendar quarter following applicable approval. That time for implementation is also embodied in A.5 of the proposed standard. This time lag is chosen, according to the proposed Implementation Plan, because of the "significant budget, siting, permitting, and construction impacts on many transmission owners." There are significant problems and costs for those whose electric service is dependent upon an inadequate transmission system, which would argue for a lesser period of time to reach compliance. This is especially true when the existing system is planned on an assumption as to the meaning of footnote b which assumption was clearly recognized as being controversial and a minority view. In recent years there have been repeated Entergy TLRs at quite high levels, which have repeatedly required emergency EEA-3s to keep firm load on line. And there has been an ongoing dispute between Entergy and the ICT as to footnote b and whether there should be limits on consequential load to be shed which has led the SPP (as the Entergy ICT) to have a complete base case for Entergy transmission construction already developed which is, by FERC direction, the basis for the Entergy construction plan. In its construction plan, however, Entergy dropped some 20 of the projects in the ICT base plan because of the Entergy view that it could go ahead and plan to drop non-consequential load as a means of remaining in compliance with Standards rather than building the transmission projects that would have been required in accordance with the ICT base plan. While not all of the proposed changes embodied in TPL-001-1 may have been incorporated in the SPP base plan development, certainly the footnote b issues were. The costs of the failure of reliability and congestion resulting from the Entergy failure have been quite high, for Entergy retail customers as well as for others, and will continue to be high so long as there is no obligation to comply. Firm transmission obligations are simply not met while there is no obligation to comply. While it is certainly true that transmission cannot be planned and constructed overnight, it is also true that those who relied upon the minority interpretation of footnote b have been on notice for years both that that interpretation was challenged, and also that it was a minority viewpoint, as NERC itself advised FERC in its response to the NOPR that preceded Order 693. In 2007 FERC directed that NERC clarify the intended meaning of footnote b in its Order 693, and pointed out at that time that the interpretation permitting loss of load was "based largely on the matter of economics, not reliability." Id., P 1792. At that time, only Entergy and NIPSCO would even admit to this less reliable interpretation of footnote b. NERC agreed that such an interpretation was incorrect in its filings leading up to Order 693. In its June 26, 2006 Comments of North American Electric Reliability Council and North American Electric Reliability Corporation on Staff Preliminary Assessment, at p. 57-58, NERC noted that load shedding in a single contingency event is not acceptable: "footnote b to TPL-002-0 is intended to provide a limited exception to the general rule for serving load from a radial transmission line and should only be applied in unique circumstances, as described above. NERC recognizes that looped configurations are key to the reliable operation of the interconnection, and to meet reasonable expectations for reliable service to loads. . . . NERC standards, including footnote b, are not intended to endorse or approve planning the interconnection using radial configurations as a preferred method for reliably serving load, nor do NERC standards consider load shedding acceptable for single contingency events." Hence, those recalcitrant transmission owners who intentionally failed to expend the money and effort that the responsible transmission owners did expend, have been rewarded at the expense

of those who rely on the transmission system to do its basic job. Order 693, P 1794, "strongly discourage[d] an approach that reflects the lowest common denominator." Many of those transmission owners and planners for whom this change constitutes "raising the bar" presumably had plenty of time to consider what their options would be if their interpretation was incorrect, and should be expected to have reserve plans on hand pretty close to being ready to go when the dispute was lost. In the Entergy case, the plan has been in its hands for some time, and it has chosen to reject the ICT plan based on its own minority interpretation of footnote b. LEPA asks that at least as to the changes tied to footnote b interpretation, and other excuses for dropping non-consequential load, the time for compliance be shortened to no more than two years following regulatory approval of the standard. R2.6 already provides for the development of a Corrective Action Plan, and it would not encourage reliability if five years were taken to develop a Corrective Action Plan, as opposed to complying with the standard. Second, LEPA suggests that, whether or not NERC chooses to stick with its 5-year time period to permit those entities which may have used a similar interpretation of footnote b, it not try to influence FERC and the courts as to legal questions that may develop during that period. We recognize that the changes made in what will be TPL-001-1 go well beyond the clarification of footnote b, so that for some changes there may be a reason for the 5 year phase in. But whether or not the 5 year phase in is going to be applicable to all of those changes, we suggest that it would be improper to mischaracterize what is being done in a way that appears to have been drafted to influence legal questions that may come up. Specifically, as currently drafted, the descriptive modifier "many" should not be used in describing the entities which had chosen to use the lower bar interpretation of footnote b. While we recognize that a number of commenters have looked to one interpretation or another of footnote b in a few extreme situations, a review of comments does not show other transmission owners who have relied on the extreme interpretation used by Entergy on a systematic basis, And we think it inappropriate for the description in the paragraph beginning at the bottom of p.1 of that draft Implementation Plan to focus on the footnote b issue, as it now does. We suggest a modification which makes the description accurate, and which avoids the kind of misinterpretation which led to the footnote b controversy in the first place. We suggest that that first part of that paragraph be revised to read as follows: "TPL-001-1 'raises the bar' in several areas where performance requirements have been changed in the new Standard versus those in existing TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0. Among other things, loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain events, whereas the existing Standards were interpreted by some to allow such actions. As shown in Table 1 of TPL-001-1, the performance requirements associated with the following events represent 'raising the bar'…"

Individual

Randy MacDonald

New Brunswick System Operator

It is not clear how TP and PC are to coordinate activities. If R6 provided direction on individual and joint responsibilities then R6 should be referred to in each of the requirements which require TP and PC coordination. The VSL and Measurement for requirement R1 appears focused the number of subrequirements represented in the model. Ideally the focus should be the impacts or error of the results if something is not properly represented. This shift in thinking will allow the planner to assess and focus on those subrequirements which are important to the study results. R1.1.1 Planned outage duration needs to be defined. For example, a planned outage for a year or more should be included in the Near term assessment.

R2.1.4 Major transmission element needs to be defined. For example, what about sync condenser, or generator step up transformer? R2.2 Clearity required. Example: What is meant by "current System peak load" It is not clear what supplemental load loss is. Would load tripped due to undervoltage or SPS as a result of a contingency be considered supplemental load? As a follow up what then is Non-consequential load (provide examples). How would this load be lost? The requirements appear the same regardless of the amount of Non-consequential load loss. Is there any consideration of applying thresholds both on suppmental and non-consequential load loss where these loads are defined as (or applied as) "…exceeding xxx amount of MW". Regarding Table 1 b, what does the following mean: "However, Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements." Please clearify the definition of Year One. This definition also does not include Planning coordinator. Was that intentional?

No comment

No comment

Please clearify "Proxies"

No comment

No comment

No comment

No comment

No comment

No comment

Individual

Dana Cabbell

Southern California Edison Company

The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices where it is expected to impact the study outcome. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted. We disagree with the inclusion of the words "including requirements of regulatory authorities and other legal obligations" at the end of R1. Entities already are required to do this. It does not need to be included in the standard.

Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement. The 20 MW threshold identified as "material change" for generation in R2.5 is too small. The limit should be raised or based on a percentage of the study area's installed generating capacity. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the "largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event" if it is documented? R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.

As currently drafted, R3.3 is not a requirement. Without the statements in R3.3.1-R3.3.4, R3.3 is simply a phrase. Sub-Sub-Requirements R3.3.1 through R3.3.4 should be bullets under R3.3, with the language in R3.3 modified so that it becomes the requirement to conduct contingency analyses that address the four resulting bullets R3.3.2 is unclear as drafted. The minimum steady state voltage limitation for synchronous generators is not a very meaningful value. All generators with an automatic voltage regulator will maintain the set point voltage until the VAR capability of the generator is exceeded, and then the voltage will deteriorate. R3.5 – We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingencies than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.

As currently drafted, R4.3 is not a requirement. Without the statements in R4.3.1-R4.3.3, R4.3 is simply a phrase. Sub-Sub-Requirements R4.3.1 through R4.3.3 should be bullets under R4.3, with the language in R4.3 modified so that it becomes the requirement to conduct contingency analyses that address the three resulting bullets. R4.3.2 – it is not clear what is required to be modeled. Typically a generator may have 10 or more protective relays. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to do that for all generators in the system. R4.5 – We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingency than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.

The term proxy is unclear. Please provide an example or an explanation of proxy.

We believe that references to FERC Orders should not be included in requirements of standards. This comment also applies to M7.

No

Claification is needed on the use of UVLS. Is it acceptable or not. Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss Allowed column is No, is load disconnecetd from the system by UVLS a violation? What about Supplemental Load Loss or UFLS?

No

P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements. As such, this is a low probability condition and loss of Non-Consequential load should be allowed for EHV. We disagree with raising the bar for EHV for P4.

Yes

We agree that TPL-005 and TPL-006 appear to have been adequately covered in the draft TPL-001-1 as currently written. However, we will need to review this assessment after TPL-001-1 is finalized. In addition, there is no place to state our concerns for Section D. so we added it here. We question the "not applicable" entry under Section D 1.1.2. What does it mean when the reset period is not applicable? Does it mean there is no reset period, so all non-compliance in all prior years will be counted as prior violations when considering non-compliance in future years?

Individual

Terry Huval

Lafayette Utilities System

R2.5. This basic requirement intends, as we understand it, to require that earlier studies not be used for a current assessment if they are no longer accurate. But the phrasing is potentially confusing, and would be clearer if revised. Since the requirement deals with the use of past studies, we suggest that R2.5.2 be revised to state that "the study may be used only if there have been no material changes," so that R2.5 reads in full: "R2.5. Past studies may be used to support the Planning Assessment if they meet the following requirements: "R2.5.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less. "R2.5.2. For steady state, short circuit, or Stability analysis: the study may be used only if there have been no material changes, such as generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: "The addition/deletion/change of individual generating unit capability of 20 MW or greater. "An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater." With respect to footnote 10 to Table 1, we fear that the flexibility suggested by those provisions may be excessive for a planning standard. The ambiguity occasioned by stating emergency actions that can properly be taken in a planning standard can be utilized by those who plan the system in a manner which plans to drop non-consequential loads just as footnote b has been used in the past. If this is intended to "raise the bar" as stated these provisions do not belong in a planning standard, at least as now stated. It may be appropriate to remove the reference to footnote 10, at least in the Initial System Condition entry in P3, where it suggests that it can be invoked after loss of a single generator, and we request the SDT to review that footnote to assure that it is appropriate in the other entries to which it is applied. In addition to the foregoing, we are concerned that the language of footnote 10 to Table 1 is unclear and subject to at least one interpretation that would seriously undermine reliability. Specifically, the first sentence of footnote 10 permits "[c]urtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch …." The reference to an "obligat[ion] to re-dispatch" is ambiguous at best and should be clarified. For example, footnote 10 should not be read as permitting Balancing Authority A to rely on curtailment of firm transmission service coupled with re-dispatch of generation by adjacent Balancing Authority B during a Level 5 TLR event, based on the theory that, if a Level 5 TLR is declared and the Reliability Coordinator assigns to Balancing Authority B an NNL reduction responsibility that compels it to reload its resources, Balancing Authority B is therefore "obligated to re-dispatch" within the meaning of footnote 10. We suspect the intent of the first sentence of footnote 10 was to recognize and give effect to arrangements in which (following the example) Balancing Authority A has made a prior contractual arrangement with Balancing Authority B (or another generation owner) to provide redispatch services when requested by Balancing Authority A. In that circumstance, Balancing Authority A would be allowed to couple the curtailment of firm transmission with redispatch provided by Balancing Authority B (or another generation owner)

pursuant to its contractual obligation. We suggest that this limitation be reflected by revising the first sentence of footnote 10 to read as follows: "Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources subject to a contractual obligation to provide re-dispatch service to the operator of the system for which the Transmission Planner is responsible, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load." Without the limitation reflected in the foregoing revision, an entity could interpret footnote 10 as allowing it to rely on the redispatch of generation by other systems that may be (in effect) mandated by a Reliability Coordinator during a Level 5 TLR event. That sort of "leaning" on adjacent systems should not be permitted as a System adjustment or corrective action under TPL-001, especially where it imposes uncompensated burdens and costs on the system(s) forced to redispatch under these circumstances.

No

Lafayette is in the area which is impacted by Entergy transmission planning. Entergy is one of the few NERC transmission owners which has for some years now relied upon its interpretation of "footnote b" in the previous TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0 as permitting planning for the loss of Non-Consequential Load or interruption of firm transfers as a way of planning and building less transmission than other utilities would have considered themselves obligated to build for reliability. That Entergy interpretation, and the consequent lower investment in transmission planning and construction, has been a matter of some concern among Entergy regulators at both State and Federal levels, as well as Entergy transmission customers, and has been rejected by the SPP, which has been given the authority to develop the base plan for transmission additions on the Entergy system. It was the Entergy rejection of that base plan that most recently led to a day long technical conference among regulators at the recent SEARUC conference in Charleston, SC. The proposed Implementation Plan for TPL-001-1 is drafted to make the new standard, which the proposed Implementation Plan describes as one that "raises the bar in several areas," effective only after the passage of 60 months from the first day of the first calendar quarter following applicable approval. That time for implementation is also embodied in A.5 of the proposed standard. This time lag is chosen, according to the proposed Implementation Plan, because of the "significant budget, siting, permitting, and construction impacts on many transmission owners." There are significant problems and costs for those whose electric service is dependent upon an inadequate transmission system, which would argue for a lesser period of time to reach compliance. This is especially true when the existing system is planned on an assumption as to the meaning of footnote b which assumption was clearly recognized as being controversial and a minority view. In recent years there have been repeated Entergy TLRs at quite high levels, which have repeatedly required emergency EEA-3s to keep firm load on line. And there has been an ongoing dispute between Entergy and the SPP as to footnote b and whether there should be limits on consequential load to be shed which has led the SPP (as the Entergy ICT) to have a complete base case for Entergy transmission construction already developed which is, by FERC direction, the basis for the Entergy construction plan. In its construction plan, however, Entergy dropped some 20 of the projects in the SPP base plan because of the Entergy view that it could go ahead and plan to drop non-consequential load as a means of remaining in compliance with Standards rather than building the transmission projects that would have been required in accordance with the SPP base plan. While not all of the proposed changes embodied in TPL-001-1 may have been incorporated in the SPP base plan development, certainly the footnote b issues were. The costs of the failure of reliability and congestion resulting from the Entergy failure have been quite high, for Entergy retail customers as well as for others, and will continue to be high so long as there is no obligation to comply. Firm transmission obligations are simply not met while there is no obligation to comply. While it is certainly true that transmission cannot be planned and constructed overnight, it is also true that those who relied upon the minority interpretation of footnote b have been on notice for years both that that interpretation was challenged, and also that it was a minority viewpoint, as NERC itself advised FERC in its response to the NOPR that preceded Order 693. In 2007 FERC directed that NERC clarify the intended meaning of footnote b in its Order 693, and pointed out at that time that the interpretation permitting loss of load was "based largely on the matter of economics, not reliability." Id., P 1792. At that time, only Entergy and NIPSCO (certainly not "many" Transmission Owners– a word that appears twice in the draft Implementation Plan) would even admit to their interpretation of footnote b to weaken the grid. NERC agreed that such

an interpretation was incorrect in its filings leading up to Order 693. In its June 26, 2006 Comments of North American Electric Reliability Council and North American Electric Reliability Corporation on Staff Preliminary Assessment, at p. 57-58, NERC noted that load shedding in a single contingency event is not acceptable: "footnote b to TPL-002-0 is intended to provide a limited exception to the general rule for serving load from a radial transmission line and should only be applied in unique circumstances, as described above. NERC recognizes that looped configurations are key to the reliable operation of the interconnection, and to meet reasonable expectations for reliable service to loads. . . . NERC standards, including footnote b, are not intended to endorse or approve planning the interconnection using radial configurations as a preferred method for reliably serving load, nor do NERC standards consider load shedding acceptable for single contingency events." It thus seems strange for NERC, an organization whose very existence was intended to assure the reliability of the grid, to reward those recalcitrant transmission owners who intentionally failed to expend the money and effort that the responsible transmission owners did expend, and at the expense of those who rely on the transmission system to do its basic job. Order 693, P 1794, "strongly discourage[d] an approach that reflects the lowest common denominator." Many of those transmission owners and planners for whom this change constitutes "raising the bar" presumably had plenty of time to consider what their options would be if their interpretation was incorrect, and should be expected to have reserve plans on hand pretty close to being ready to go when the dispute was lost. In the Entergy case, the plan has been in its hands for some time, and the fact that it has chosen to reject the SPP plan based on its own minority interpretation of footnote b is no one's fault but its own. And it certainly does not have to start from scratch to develop the plan; it consciously chose to reject the plan that the ICT developed for it. Lafayette asks that at least as to the changes tied to footnote b interpretation, and other excuses for dropping non-consequential load, the time for compliance be shortened to no more than two years following regulatory approval of the standard. R2.6 already provides for the development of a Corrective Action Plan, and it would not encourage reliability if five years were taken to develop a Corrective Action Plan, as opposed to complying with the standard. Second, Lafayette suggests that, whether or not NERC chooses to stick with its 5-year "lowering of the bar" to permit those entities which may have used a similar interpretation of footnote b to avoid building a sturdy grid, it not try to influence FERC and the courts as to legal questions that may develop during that period. We recognize that the changes made in what will be TPL-001-1 go well beyond the clarification of footnote b, so that for some changes there may be a reason for the 5 year phase in. But whether or not the 5 year phase in is going to be applicable to all of those changes, we suggest that it would be improper to mischaracterize what is being done in a way that appears to have been drafted to influence legal questions that may come up. Specifically, as currently drafted, the descriptive modifier "many" should not be used in describing the entities which had chosen to use the lower bar interpretation of footnote b. While we recognize that a number of commenters have looked to one interpretation or another of footnote b in a few extreme situations, a review of comments does not show other transmission owners who have relied on the extreme interpretation used by Entergy on a systematic basis, And we think it inappropriate for the description in the paragraph beginning at the bottom of p.1 of that draft Implementation Plan to focus on the footnote b issue, as it now does. We suggest a modification which makes the description accurate, and which avoids the kind of misinterpretation which led to the footnote b controversy in the first place. We suggest that that first part of that paragraph be revised to read as follows: "TPL-001-1 'raises the bar' in several areas where performance requirements have been changed in the new Standard versus those in existing TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0. Among other things, loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain events, whereas the existing Standards were interpreted by some to allow such actions. As shown in Table 1 of TPL-001-1, the performance requirements associated with the following events represent 'raising the bar'…"

Individual

Robert Easton

Western Area Power Administration

General, all-encompassing comment: The change in TPL Standards, while well intended, will be difficult to administer since it has taken a simple Performance Table and translated it into a legal-type document that is very complex to relate to the physical system for the planning and operations staff. The performance requirements must be related to the physical response characteristics of the interconnected system operation without depending on a legal advise for training my new transmission system planning staff. The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices where it is expected to impact the study outcome. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and

one should be deleted. I disagree with the inclusion of the words "including requirements of regulatory authorities and other legal obligations" at the end of R1. Entities already are required to do this. It does not need to be included in the standard.

Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). The last bullet under R2.1.3 - "Planned duration or timing of Transmission Outages." does not belong in a long-term planning standard. These-type of seasonal outages are studied and implemetation plans are derived as part of the TOP Standard requirements. In the WECC - this is also covered by the seasonal studies carried out by the Operating Transfer Capability Policy Committee (OTCPC) study groups. Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement - OR simply delete this spare equipment requirement. The 20 MW threshold identified as "material change" for generation in R2.5 is too small. The limit should be raised or based on a percentage of the study area's installed generating capacity. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the "largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event" if it is documented? R2.9 should be deleted. This requirement is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.

As currently drafted, R3.3 is not a requirement. Without the statements in R3.3.1-R3.3.4, R3.3 is simply a phrase. Sub-Sub-Requirements R3.3.1 through R3.3.4 should be bullets under R3.3, with the language in R3.3 modified so that it becomes the requirement to conduct contingency analyses that address the four resulting bullets. R3.3.2 is unclear as drafted. The minimum steady state voltage limitation for synchronous generators is not a very meaningful value. All generators with an automotive voltage regulator will maintain the set point voltage until the VAR capability of the generator is exceeded, and then the voltage will deteriorate. R3.5 – I disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingency than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.

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The term "proxy" is unclear. Please provide an example or an explanation of proxy.

None.

I believe that references to FERC Orders should not be included in requirements of standards. This comment also applies to M7.

No

Claification is needed on the use of UVLS. Is it acceptable or not? Typically UVLS relays are

modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss Allowed column is No, is load disconneced from the system by UVLS a violation? What about Supplemental Load Loss or UFLS?

No

P4: Under the event column, it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements. As such, this is a low probability condition and loss of Non-Consequential Load should be allowed for EHV. I disagree with raising the bar for EHV for P4.

Yes

I agree that TPL-005 and TPL-006 appear to have been adequately covered in the draft TPL-001-1 as currently written. However, we will need to review this assessment after TPL-001-1 is finalized. In addition, there is no place to state our concerns for Section D. so it is added here. I question the "not applicable" entry under Section D 1.1.2. What does it mean when the reset period is not applicable? Does it mean there is no reset period, so all non-compliance in all prior years will be counted as prior violations when considering non-compliance in future years?

Individual

Robert Priest

Mississippi Delta Energy Agency

R2.5. This basic requirement intends, as we understand it, to require that earlier studies not be used for a current assessment if they are no longer accurate. But the phrasing is potentially confusing, and would be clearer if revised. Since the requirement deals with the use of past studies, we suggest that R2.5.2 be revised to state that "the study may be used only if there have been no material changes," so that R2.5 reads in full: "R2.5. Past studies may be used to support the Planning Assessment if they meet the following requirements: "R2.5.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less. "R2.5.2. For steady state, short circuit, or Stability analysis: the study may be used only if there have been no material changes, such as generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: "The addition/deletion/change of individual generating unit capability of 20 MW or greater. "An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater." With respect to footnote 10 to Table 1, we fear that the flexibility suggested by those provisions may be excessive for a planning standard. The ambiguity occasioned by stating emergency actions that can properly be taken in a planning standard can be utilized by those who plan the system in a manner which plans to drop non-consequential loads just as footnote b has been used in the past. If this is intended to "raise the bar" as stated these provisions do not belong in a planning standard, at least as now stated. It may be appropriate to remove the reference to footnote 10, at least in the Initial System Condition entry in P3, where it suggests that it can be invoked after loss of a single generator, and we request the SDT to review that footnote to assure that it is appropriate in the other entries to which it is applied.

No

MDEA is in the area which is impacted by Entergy transmission planning. Entergy is one of the few NERC transmission owners which has for some years now relied upon its interpretation of "footnote b" in the previous TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0 as permitting planning for the loss of Non-Consequential Load or interruption of firm transfers as a way of planning and building less transmission than other utilities would have considered themselves obligated to build for reliability. That Entergy interpretation, and the consequent lower investment in transmission planning and construction, has been a matter of some concern among Entergy regulators at both State and Federal levels, as well as Entergy transmission customers, and has been rejected by the SPP, which has been given the authority to develop the base plan for transmission additions on the Entergy system. It was the Entergy rejection of that base plan that most recently led to a day long technical conference among regulators at the recent SEARUC conference in Charleston, SC. The proposed Implementation Plan for TPL-001-1 is

drafted to make the new standard, which the proposed Implementation Plan describes as one that "raises the bar in several areas," effective only after the passage of 60 months from the first day of the first calendar quarter following applicable approval. That time for implementation is also embodied in A.5 of the proposed standard. This time lag is chosen, according to the proposed Implementation Plan, because of the "significant budget, siting, permitting, and construction impacts on many transmission owners." There are significant problems and costs for those whose electric service is dependent upon an inadequate transmission system, which would argue for a lesser period of time to reach compliance. This is especially true when the existing system is planned on an assumption as to the meaning of footnote b which assumption was clearly recognized as being controversial and a minority view. In recent years there have been repeated Entergy TLRs at quite high levels, which have repeatedly required emergency EEA-3s to keep firm load on line. And there has been an ongoing dispute between Entergy and the SPP as to footnote b and whether there should be limits on consequential load to be shed which has led the SPP (as the Entergy ICT) to have a complete base case for Entergy transmission construction already developed which is, by FERC direction, the basis for the Entergy construction plan. In its construction plan, however, Entergy dropped some 20 of the projects in the SPP base plan because of the Entergy view that it could go ahead and plan to drop non-consequential load as a means of remaining in compliance with Standards rather than building the transmission projects that would have been required in accordance with the SPP base plan. While not all of the proposed changes embodied in TPL-001-1 may have been incorporated in the SPP base plan development, certainly the footnote b issues were. The costs of the failure of reliability and congestion resulting from the Entergy failure have been quite high, for Entergy retail customers as well as for others, and will continue to be high so long as there is no obligation to comply. Firm transmission obligations are simply not met while there is no obligation to comply. While it is certainly true that transmission cannot be planned and constructed overnight, it is also true that those who relied upon the minority interpretation of footnote b have been on notice for years both that that interpretation was challenged, and also that it was a minority viewpoint, as NERC itself advised FERC in its response to the NOPR that preceded Order 693. In 2007 FERC directed that NERC clarify the intended meaning of footnote b in its Order 693, and pointed out at that time that the interpretation permitting loss of load was "based largely on the matter of economics, not reliability." Id., P 1792. At that time, only Entergy and NIPSCO (certainly not "many" Transmission Owners– a word that appears twice in the draft Implementation Plan) would even admit to their interpretation of footnote b to weaken the grid. NERC agreed that such an interpretation was incorrect in its filings leading up to Order 693. In its June 26, 2006 Comments of North American Electric Reliability Council and North American Electric Reliability Corporation on Staff Preliminary Assessment, at p. 57-58, NERC noted that load shedding in a single contingency event is not acceptable: "footnote b to TPL-002-0 is intended to provide a limited exception to the general rule for serving load from a radial transmission line and should only be applied in unique circumstances, as described above. NERC recognizes that looped configurations are key to the reliable operation of the interconnection, and to meet reasonable expectations for reliable service to loads. . . . NERC standards, including footnote b, are not intended to endorse or approve planning the interconnection using radial configurations as a preferred method for reliably serving load, nor do NERC standards consider load shedding acceptable for single contingency events." It thus seems strange for NERC, an organization whose very existence was intended to assure the reliability of the grid, to reward those recalcitrant transmission owners who intentionally failed to expend the money and effort that the responsible transmission owners did expend, and at the expense of those who rely on the transmission system to do its basic job. Order 693, P 1794, "strongly discourage[d] an approach that reflects the lowest common denominator." Many of those transmission owners and planners for whom this change constitutes "raising the bar" presumably had plenty of time to consider what their options would be if their interpretation was incorrect, and should be expected to have reserve plans on hand pretty close to being ready to go when the dispute was lost. In the Entergy case, the plan has been in its hands for some time, and the fact that it has chosen to reject the SPP plan based on its own minority interpretation of footnote b is no one's fault but its own. And it certainly does not have to start from scratch to develop the plan; it consciously chose to reject the plan that the ICT developed for it. MDEA asks that at least as to the changes tied to footnote b interpretation, and other excuses for dropping non-consequential load, the time for compliance be shortened to no more than two years following regulatory approval of the standard. R2.6 already provides for the development of a Corrective Action Plan, and it would not encourage reliability if five years were taken to develop a Corrective Action Plan, as opposed to complying with the standard. Second, MDEA suggests that, whether or not NERC chooses to stick with its 5-year "lowering of the bar" to permit those entities which may have used a similar interpretation of footnote b to avoid building a sturdy grid, it not try to influence FERC and the courts as to legal questions that may develop during that period. We recognize that the changes made in what will be TPL-001-1 go well beyond the clarification of footnote b, so that for some changes there may be a reason for the 5 year phase in. But whether or not the 5 year phase in is going to be applicable to all of those changes, we suggest that it would be improper to mischaracterize what is being done in a way that appears to have been drafted to influence legal questions that may come up. Specifically, as currently drafted, the descriptive modifier "many"

should not be used in describing the entities which had chosen to use the lower bar interpretation of footnote b. While we recognize that a number of commenters have looked to one interpretation or another of footnote b in a few extreme situations, a review of comments does not show other transmission owners who have relied on the extreme interpretation used by Entergy on a systematic basis, And we think it inappropriate for the description in the paragraph beginning at the bottom of p.1 of that draft Implementation Plan to focus on the footnote b issue, as it now does. We suggest a modification which makes the description accurate, and which avoids the kind of misinterpretation which led to the footnote b controversy in the first place. We suggest that that first part of that paragraph be revised to read as follows: "TPL-001-1 'raises the bar' in several areas where performance requirements have been changed in the new Standard versus those in existing TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0. Among other things, loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain events, whereas the existing Standards were interpreted by some to allow such actions. As shown in Table 1 of TPL-001-1, the performance requirements associated with the following events represent 'raising the bar'…"

Individual

Roger Champagne

Hydro-Québec TransÉnergie (HQT)

No

Footnote 4 – We recommend that a lower bound be put on the HV electric systems (such as 100 kV), rather than just saying "and lower". As has been commented on in a previous draft, the Drafting Team should also consider not having a prescribed voltage definition of BES, be it called EHV or HV. Studies should determine what facilities should be part of the BES because of their impact on reliability. A proposal is to modify Footnote 4 to replace the phrase "…(EHV) Facilities defined as greater than 300 kV…" with "…(EHV) Facilities defined as having a significant impact on the reliability of the System, generally at voltages greater than 300 kV as determined by the Planning Coordinator…" In using such language, the more stringent requirements could apply to BES/EHV but not globally for Facilities operating at voltages greater than 300 kV. Using this methodology the extra investment required would go towards real improvement of the reliability of the System. EHV and HV should be added to the Definitions of Terms Used in Standard. Footnote 12 – We recommend adding an alternative modifier to the end of the sentence, "or for 5 towers or less." This is consistent with NPCC criteria.

No

With regard to the many changes/modifications from the previous draft and from the previous TPL standards being replaced by TPL-001-1, another posting of this Standard will be necessary to fully evaluate the impact (on reliability and also cost of implementation) of such changes. The decision to allow the use of all type of RAS or SPS (particularly generator tripping and run-back) as a common practice for single contingency does not "raise the bar" in the planning standard, and should be reviewed. How can higher system performance be required that involves substantial infrastructure investment to prevent events with a very low probability of occurrence, and allow use of a less reliable measure (SPS failure or misoperation having a higher probability of occurrence) to reduce the investment for more probable events?

Individual

Phil Sanchez

Western Area Power Administration

General Comment: The Change in TPL Standards, while well intended, will be difficult to administer since it has taken a simple Performance table and translated it into a legal-type document that is very complex to relate to the physical system for the planning and operations staff. The performance requirements must be related to the physical response characteristics of the interconnected system operation without depending on legal advice for training my new transmission system planning staff. The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices where it is expected to impact the study outcome. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service

is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted. I disagree with the inclusion of the words "including requirements of regulatory authorities and other legal obligations" at the end of R1. Entities already are required to do this. It does not need to be included in the standard.
Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement. The 20 MW threshold identified as "material change" for generation in R2.5 is too small. The limit should be raised or based on a percentage of the study area's installed generating capacity. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the "largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event" if it is documented? R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.
As currently drafted, R3.3 is not a requirement. Without the statements in R3.3.1-R3.3.4, R3.3 is simply a phrase. Sub-Sub-Requirements R3.3.1 through R3.3.4 should be bullets under R3.3, with the language in R3.3 modified so that it becomes the requirement to conduct contingency analyses that address the four resulting bullets R3.3.2 is unclear as drafted. The minimum steady state voltage limitation for synchronous generators is not a very meaningful value. All generators with an automotive voltage regulator will maintain the set point voltage until the VAR capability of the generator is exceeded, and then the voltage will deteriorate. R3.5 – We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingencies than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.
As currently drafted, R4.3 is not a requirement. Without the statements in R4.3.1-R4.3.3, R4.3 is simply a phrase. Sub-Sub-Requirements R4.3.1 through R4.3.3 should be bullets under R4.3, with the language in R4.3 modified so that it becomes the requirement to conduct contingency analyses that address the three resulting bullets. R4.3.2 – it is not clear what is required to be modeled. Typically a generator may have 10 or more protective relays. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to do that for all generators in the system. R4.5 – We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingency than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.
The term proxy is unclear. Please provide an example or an explanation of proxy.
no comment.
I believe that references to FERC Orders should not be included in requirements of standards. This comment also applies to M7.
No
Claification is needed on the use of UVLS. Is it acceptable or not. Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss

Allowed column is No, is load disconnecetd from the system by UVLS a violation? What about Supplemental Load Loss or UFLS?

No

P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements. As such, this is a low probability condition and loss of Non-Consequential load should be allowed for EHV. We disagree with raising the bar for EHV for P4.

I agree that TPL-005 and TPL-006 appear to have been adequately covered in the draft TPL-001-1 as currently written. However, I will need to review this assessment after TPL-001-1 is finalized. In addition, there is no place to state our concerns for Section D. so we added it here. I question the "not applicable" entry under Section D 1.1.2. What does it mean when the reset period is not applicable? Does it mean there is no reset period, so all non-compliance in all prior years will be counted as prior violations when considering non-compliance in future years?

Group

System Protection and Transmission Planning Department

R1 the requirement to maintain System models for performing the studies is redundant with MOD-010, and should be moved to MOD-010. The phrase that requires model data used in Studies used for Annual Assessments be consistent with data submitted under MOD-010 seems OK. R1.1.2, a sub-requirement of R1.1, states that models for Planning Assessments shall represent “new planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon”. Is this a requirement for maintaining a case representing every year of the near-term and long-term planning horizons (i.e. 10 cases)? We do not think that is what the SDT had in mind. If all that is required to remain cognizant of Facility In-Service dates so that topology is reliable, please so state. To make this read clearer, we suggest you take out the phrase “for each year”. Regarding bullet 5 of R1.1.2, does inclusion of Protection System equipment require modeling of all relays in dynamic studies? The NERC definition of Facility pertains to equipment energized at primary voltages, not Protective System equipment. We suggest the Protective Systems be eliminated from this list. To make this read clearer, we suggest you delete text and bullet items following “Transmission Planning Horizon”. Regarding R1.1.2 bullet items: The bullets list examples of Facilities. This list is not needed, since the term Facility is already defined in the NERC Glossary. If you do not remove all bullets, then we warn you that the bullet "New Technologies" can be interpreted to cover a broad range of topics by an auditor and is not clearly defined by NERC, so we cannot visualize measurable documentation.

R2 - The term "Stability Analysis" is used frequently in the standard, but is not clearly defined. Based on an IEEE paper ("Definition and Classification of Power System Stability," Kundar, et al) there are 5 different categories of stability analysis: 1)small signal angle stability; 2) transient angle stability; 3) frequency stability; 4) large disturbance voltage stability; and 5) small disturbance voltage stability. Does the writing committee intend to make the analysis of all these types of stability issues mandatory? I recommend inserting a new definition into the standard for stability as follows: "Stability Analysis - The study of the bulk electric power system's ability, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance.” There are 5 accepted categories of power system stability: 1) small signal angle stability; 2) transient angle stability; 3) frequency stability; 4) large disturbance voltage stability; and 5) small disturbance voltage stability. While there are situations that exist that require small signal angle and voltage stability analysis, only transient angle stability, frequency stability, and large disturbance voltage stability analysis are generally relevant to system planning performance assessments. R2.1.4 is a new requirement directing studies to consider impacts of spare equipment strategy. Does this require the TP to run scenario analysis without certain transformers? It is not clear what is required. How many spare transformers are required? What reliability level is acceptable? R2.1.4 The one year cut-off seems arbitrary. One MONTH may be unacceptably long in some cases. Instead of “one year or more”, we suggest the requirement state “an extended time period”. R2.2. The wording on this requirement is not clear. Is it trying to say that a long-term (5-10 year) peak loading study is required to be performed annually? R2.2: What is meant by the term “current System peak Load study “? A powerflow study performed under expected peak-load conditions? Or a forecast of peak loads? R2.3 A short circuit analysis requirement is now added to Planning Assessment requirements. Short circuit analysis appears to be in the standard to document adequate ratings for interrupting equipment. That would be the purpose of short circuit studies we perform. If there are other intended meanings, then additional detail is needed. R2.3 We do not agree that a short circuit analysis needs to be conducted annually. The requirement for a new short circuit duty study should be driven by changes in the system, as is done for powerflow study work. In short, until system changes are made, we would not anticipate higher fault duties, and there would be no reason to rerun studies. R2.4.1 requires dynamic load models. Development of dynamic load models is ongoing, and therefore will need a much longer implementation period

than the steady state portions of the standard. We are not sure two years will be enough. It depends partly on pending work that is not under our control. R1.1.2, R2.1.4, R2.5.2, R3.3.4, R4.3.3, R5 – When text of a Standard Requirement includes the phrase "such as" or "could include", then gives a list of possible choices, we take it to mean "just one of these items, or none of these, or something not listed here". In other words, "such as" lists are really non-required, non-interpretable, non-measurable options. They should not be included in requirements. Lists "such as" these belong in transmittal notes and associated SDT commentary, not in Compliance Standard Requirements. R2.5.2 Limits such as "addition/deletion/change to a group of generating units . . . which total 20 MW or greater." are not always appropriate. Appropriateness of Generation netting with load should depend on system size and engineering judgment, not artificial limits. The suggestion list following "generation changes could include:" should be eliminated. R2.6.2. "For the Near-Term Transmission Planning Horizon, include both a project initiation date as well as an in-service date" – The assessment report should not require a full project development – just a description of what is required to provide adequate service within specified operating criteria. The term "project initiation" is not clear. Requirement R2.6.2 should be eliminated. R2.8. "The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1. " is complicated, and may require new modeling software capability to comply. Software vendors would develop this capability. Why is this required? What is the expected benefit to system reliability?
R3 appears to require redundant studies by TP and PC. If the TP and PC participate in the same studies, would this meet the intent of this requirement? This would include studies that are RRO sponsored, or performed by sub-regional planning groups.
Comments under R1 apply here as well. The requirement to "utiliz[e] data provided in Requirement R1" is redundant with MOD-012, and should be moved to MOD-012. To conform with R1, we suggest a phrase be inserted that requires model data used in Stability Studies used for Annual Assessments be consistent with data submitted under MOD-012.
"Proxies" is not defined. We take "proxy" to mean a procedure used to model system response that is outside the capability of system modeling tools used in the analysis. For example, a powerflow model might not be able to model cascading events with built-in capabilities. As a proxy, the engineer would run follow-up studies that would mimic expected system response. Please define the term "proxy".
no comment
The phrase "coordinating analysis of these results" seems to indicate potential second-guessing by other entities. We suggest "coordinating REVIEW of these results" may be clearer. The term "such as described in FERC Order 890" allows non-jurisdictional utilities to establish an appropriate process. This is good. However, we still have the same misgivings about the term "such as" used here.
Yes
We appreciate the effort of the SDT to clarify "Consequential load loss", and think references to this term are clearer in this draft. "Proxies", used in R5, should be defined. See R5 comments for our suggestion.
No
The order of scenarios listed in the table should reflect the relative probability of events. Did the SDT intend to order listed contingencies by relative severity? Could it do so? Planning Events - SLG fault simulation should not be required. They should only be performed if more severe than 3-phase faults. A SLG fault with delayed breaker clearing could have more system impact than a 3-phase fault. The "Extreme Events" portion of the table is confusing – partly because the form differs from the Planning Event portion. The difference between contingencies in the Planning portion and the Extreme portion is not clear. Perhaps the Extreme Event portion could be a separate Table. Extreme Events / Stability section - Why specifically require "g. SLG fault on all Transmission lines on a common Right-of-Way."?
Yes
These concepts seem too important to relegate to footnotes. Could this discussion of how to handle Firm transactions and redispatch be moved to a more prominent place? Perhaps these concepts should be removed from this standard entirely. A more appropriate place for these concepts would be in ATC standards.
Yes
We concur with SDT intent to retire TPL-005 and TPL-006. As there is no comment form entry to accept comments on MEASURES, we add one note here, related to "such as" lists - as noted above for R1.1.2, R2.1.4, R2.5.2, R3.3.4, R4.3.3, and R5. As written now, all measures include "such as" lists. We strongly suggest you remove "such as electronic or hard copies" from all measure statements.
Group
PPL Energy Plus
PPL agrees with the requirement that regulatory and legal requirements need to be respected in

planning studies. Also, Requirement R1.1.6 appears to conflict with FERC Pro-forma OATT Section 30.4 in that Network Resource output should not be limited as this Requirement states.
The standard appropriately recognizes that the planning horizon must be as long as the longest lead-time system upgrade, typically 8+ years for a new line. However, while Requirement 2.2.1 states this, it could be more clearly stated. Requirement R2.5.2 should be clarified to point out if the TP has discretion or if the 20 MW is binding. Requirement R2.6.4 should require TP's and PC's to post on an OASIS to assure easy access by affected parties to information on what is "beyond the control" of these organizations. Please retain Requirements 2.8 and 2.9 as these are good measures of the quality of the plan produced by the planners.
It appears there is a 24 month grace period to allow modeling updates to meet R 3.3.1. This is a good idea since the powerflow computer models may not include the required data and will need to be updated.
It should be pointed out that Breaker Failure (i.e. fail to open) and Breaker Fault (internal fault in breaker) are two different events.
Please clarify how the term "Proxies" is used in this requirement.
Please continue to mention relevant FERC Orders (such as 890) in the standards since the FERC orders are the source of many of the planning standards. Planners need to acknowledge, respect, and design processes and systems around the FERC rulings.
No
The WECC suggests P4 penalizes EHV and if this is true, please re-write P4 to eliminate the penalty.
Group
OPUC
1. Requirement R1 — Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement. Comments: A: Language in R1.1.2 still needs further clarification. Base case models do not clarify modeling required for the effect or absence of circuit breakers, protection system equipment and control devices. B: Clarity would be increased were R1.1.4 to refer to expected transfers rather than Firm Transmission Service, permitting the elimination of then redundant R1.1.5 C: Removing "including requirements of regulatory authorities and other legal obligations" at the end of R1 would also eliminate redundant text.
2. Requirement R2 — Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement. Comments: A: Short circuit of over-stressed breakers is already addressed in Table 1. Ex1: P2-3,4 (Internal Breaker Fault), Ex2: P4 (Stuck Breaker while attempting to clear a fault). B: In R2.1.4 Table 1, it is unclear how transformer contingency analysis can be aggregated or batched. It is also still unclear whether corrective action plans are required solely to meet performance requirements for sensitivities.
3. Requirement R3 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement. Comments: A: R3.3 should be modified to become the requirement to conduct contingency analyses with R3.3.1 thru 4 presented as bullets there-under.
4. Requirement R4 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement. Comments: A: R4.3 should be modified to become the requirement to conduct contingency analyses with R4.3.1 thru 3 presented as bullets there-under. B: R4.3.2 should clarify whether all relay protection must be modeled
5. Requirement R5 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement. Comments: A: An example should be added for proxy use.

Individual
Chifong Thomas
Pacific Gas and Electric Co,
The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices where it is expected to impact the study outcome. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted. We disagree with the inclusion of the words "including requirements of regulatory authorities and other legal obligations" at the end of R1. Entities already are required to do this. It does not need to be included in the standard.
Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement. The 20 MW threshold identified as "material change" for generation in R2.5 is too small. The limit should be raised or based on a percentage of the study area's installed generating capacity. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the "largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event" if it is documented? R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.
As currently drafted, R3.3 is not a requirement. Without the statements in R3.3.1-R3.3.4, R3.3 is simply a phrase. Sub-Sub-Requirements R3.3.1 through R3.3.4 should be bullets under R3.3, with the language in R3.3 modified so that it becomes the requirement to conduct contingency analyses that address the four resulting bullets R3.3.2 is unclear as drafted. The minimum steady state voltage limitation for synchronous generators is not a very meaningful value. All generators with an automatic voltage regulator will maintain the set point voltage until the VAR capability of the generator is exceeded, and then the voltage will deteriorate. R3.5 – We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingency than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.
As currently drafted, R4.3 is not a requirement. Without the statements in R4.3.1-R4.3.3, R4.3 is simply a phrase. Sub-Sub-Requirements R4.3.1 through R4.3.3 should be bullets under R4.3, with the language in R4.3 modified so that it becomes the requirement to conduct contingency analyses that address the three resulting bullets. R4.3.2 – it is not clear what is required to be modeled. Typically a generator may have 10 or more protective relays. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to do that for all generators in the system. R4.5 – We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingency than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.
The term proxy is unclear. Please provide an example or an explanation of proxy. Perhaps a

different term, such as metric, may better describe this requirement to more people.

We believe that references to FERC Orders should not be included in requirements of standards. This comment also applies to M7.

No

Claification is needed on the use of UVLS. Is it acceptable or not? We understand from the discussion in the webinar that in the proposed TPL-001-1, Table 1, if there is a "no" in the column for allowable load loss, you are still allowed to have UVLS set up to drop the load, but cannot plan on meeting the standard with the load shedding. Therefore, if the Non-Consequential Load Loss Allowed column is No, is load disconnecetd from the system by UVLS a violation, given that you can lose the load but cannot plan on it? Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. What about the treatment of Supplemental Load Loss or UFLS?

No

P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements. As such, this is a low probability condition and loss of Non-Consequential load should be allowed for EHV. We disagree with raising the bar for EHV for P4.

Yes

We support the concept. However, we are unclear about the last sentence of Footnote 10, which reads "where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered." For resources from areas external to the Transmission Planner's planning regions, would identification of the need to, for example, increase System Operating Limits into the his/her Transmission Planning Area as part of the Corrective Action Plan be counted as having "considered" the "Facility Ratings in those impacted regions"? Otherwise, it may be difficult for the Transmission Planner to assess and identify all the Facility Ratings that may be impacted in a region external to his/her Transmission Planning Area.

Yes

We agree that TPL-005 and TPL-006 appear to have been adequately covered in the draft TPL-001-1 as currently written. However, we will need to review this assessment after TPL-001-1 is finalized. In addition, there is no place to state our concerns for Section D. so we added it here. We question the "not applicable" entry under Section D 1.1.2. What does it mean when the reset period is not applicable? Does it mean there is no reset period, so all non-compliance in all prior years will be counted as prior violations when considering non-compliance in future years?

Individual

Kirit Shah

Ameren

There may be a potential conflict between MOD-010 and MOD-012 and legal documents such as Interconnection Agreements e.g. IA may specify a capacity level that exceeds the reported test levels. In the case of such conflicts, it is not clear which one should rule. Suggest replacing 'circuit breakers' in R1.1.2 with 'terminal equipment' since circuit breakers are covered by Protection System Equipment. Consider adding a reference in R1 to NERC Reliability Assessment Guidebook version 1.2, pp 17-18 for use of a particular load forecast level for inclusion in the planning models. In R1.1.2, revise the language to show that we need to also represent the existing transmission system, and not just changes to the existing system. In R1.1.2, Clarification is needed for the phrase 'for each year' should signify only those years for which assessment work was performed, rather than each year of the Near-Term and Long-Term Transmission Planning Horizon. There typically is not a model built for each year of the Near-Term and Long-Term Transmission Planning Horizon. In bullet three of R1.1.2, it is not clear whether bus-tie circuit breakers to be represented in the models. Typically circuit breakers are included in the contingency definitions along with the protection system equipment used in the powerflow models. The number of zero impedance branches which can presently be modeled using PSS/E software is limited to 4000. Also, the number of buses included in the powerflow models would increase with additional breaker modeling. In bullet seven of Requirement R1.1.2, what "new technologies" are to be represented in the models? R1.1.4 Firm Transmission Service - a single source can have transmission service to multiple sinks, and can be associated with transmission service in excess of the capacity of the source. There is a lack of clarity regarding the means by which Firm Transmission Service, a marketing term, is to be included in planning models. For example, should the standard define how to model wind farms (100% - off-peak and 20% on-peak, based on firm capacity from the wind generators, or other dispatch levels)?

In R2, The phrase "document results" should be changed to "summarize results". While results will be documented, the Planning Assessment should just include a summary. In R2.1, the reference to requirement R2.6 (at the end of the last line) should be changed to R2.5. In R2.1.3, it is suggested that the studies be referred to as the "base studies" to avoid confusion with the

sensitivity studies. Also it is suggested that another phrase be added at the end for clarity. The entire R2.1.3 would then be as follows: For each of the base studies described in Requirements R2.1.1 and R2.1.2, sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment. Sensitivity studies would include changes to: In Requirement R2.1.4, it is suggested that language be added to reflect the possible unavailability of the equipment, such as: When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience the possible unavailability of the long lead time equipment. It is not clear how adequate lead times for equipment would be determined. In Requirements R2.3 and R2.4, consider adding a reference to Requirement R2.5 for the past studies. In Requirement R2.4.1, it is suggested that it be reworded to the following: System peak Load for one of the five years, including Load models which appropriately represents the dynamic behavior of Loads, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Load models referenced in R2.4.1 should be confined to the consideration of transient stability study work. With the elimination of the distinction between system and generating plant stability studies, the blanket requirement in R2.5.1 that all stability analyses be five calendar years old or less, regardless of any material changes to the system, would cause needless work to be performed on those plants or areas of the system where no changes are occurring. We suggest adding the following to the end of R2.5.1: "unless justification can be provided to demonstrate that the results of an older study are still valid." In Requirement R2.4.3, it is suggested that this sub-requirement be reworded to the following: For each of the base studies described in Requirements R2.4.1 and R2.4.2, sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the base studies shall be included in the Assessment. Sensitivity studies would include changes to: In bullet three of Requirement R2.6.1, would we allow automatic generation tripping for a single (P1) event if it is not consequential? It seems that tripping of generation should be restricted to P2 events 2 or 3 at a minimum. In bullet five of Requirement R2.6.1, is there a maximum duration that operating procedures can be used before a capital project must be included (or completed) in the Corrective Action Plan? In Requirement R2.6.2, it is not clear what constitutes a "project initiation date". Please clarify. Please explain the reason why Requirement R2.8 is needed in the Assessment. Reporting the largest Consequential Load Loss does not impact reliability. Please explain the reason why Requirement R2.9 is needed in the Assessment. Reporting the largest Non-Consequential Load Loss doe not impact reliability. The proposed standard not only raises the bar for system performance requirements, but also raises the bar for reporting and documentation. We need to employ almost as many librarians and technical writers as engineers to develop and keep track of the documentation. Engineers need to spend more time performing the studies and spend less time documenting studies keeping track of documentation for multiple years.

In Requirement R3.1, it is suggested that the word "contingency" be added to describe the lists created in R3.4. Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists created in Requirement R3.4. R3.3.2 "For all generators, studies shall consider the minimum steady state voltage limitations and identify how the generators are analyzed in the steady state simulation." The above wording needs to be changed, as the intent of this sentence is unclear. It is not clear whether Transmission Planners need to ensure that generating plants can meet their voltage schedule under Base Case (N-0) conditions, or whether this would be the same as the generator underexcited operation limit. R3.3.3 "For all Transmission lines, studies shall consider relay loadability and identify how loadability is analyzed in the steady state simulation." The above wording needs to be changed, as the intent of this sentence is unclear, whether the intent is that Transmission Planners ensure that relay loading limits are included in the facility ratings, or whether this reflect some rule of thumb, such as 130% of conductor rating. In Requirement R3.3.4, it is suggested adding the words "and switched" to capacitors and reactors: Simulate the expected operation of existing and planned devices designed to provide Steady State control of electrical system quantities. These devices include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

In Requirement R4.1, it is suggested that the word "contingency" be added to describe the lists created in R4.4 Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists created in Requirement R4.4. Regarding Requirement R4.4, it is suggested that a rewording be considered such as described below: For each category of the Planning Events in Table 1, those Planning Event Contingencies that are expected to produce more severe System impacts shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4.1 shall be created. The rationale for the Contingencies selected for evaluation shall be available as supporting information with an explanation of why the remaining Contingencies would produce less severe System results. R4.3.2 requires that voltage ride through capability be analyzed. It is not clear what should be analyzed. e.g. auxiliary loads, generator protection, generator capability, etc. We

would like to see more clarity on this requirement. It seems that the stuck breaker scenarios would always be more severe than the internal breaker failure scenario since they would be clearing in delayed clearing time and thus make P2.3 redundant. Are there is some question on whether P3 contingencies would be necessary for stability analysis. Revise wording in VSL from "categories" to "applicable categories". e.g. some entities may not have common tower facilities and thus there would be no P7 category contingencies to evaluate. Footnote #3 needs to be revised to include Double-Line-To-Ground faults in addition to Three-Phase faults indicating that the SLG criteria is met.
There is no requirement that the Planning Coordinator must use the same proxies as the Transmission Planner. Differences in proxy assumptions may lead to different study results. R5 needs to be modified to require coordination of proxies between Planning Coordinators and Transmission Planners.
In absence of these agreements, it is assumed that both Transmission Planners and Planning Coordinators would be responsible for performing the studies. It is not clear how the Corrective Action Plans get resolved between these entities if there is no agreement on the study results.
Requirement R7 describes that the Planning Coordinator is to share Planning Assessments with adjacent Planning Coordinators. It is not clear whether this needs to be expanded for the Transmission Planners to share their Planning Assessments with the Planning Coordinators. The reference to FERC Order 890 as it is currently written makes it seem like a suggestion to follow Order 890. If Order 890 explicitly describes this process then the sentence should read "as described in FERC Order 890." If not, maybe this should not be mentioned at all.
No
Extreme Events definition references severity and probability. These terms should be included in the definition of Planning Events. Add a definition of Planned and Proposed facilities. Planned facilities address the near term deficiencies and have been approved with a financial commitment while proposed facilities address long term deficiencies for which no commitment is required today since they may change based on future evaluation. Revised Definitions are generally better than those from the previous version, but additional clarity could be provided. Consequential Load Loss – Would an SPS to trip load qualify as a planned protection system? Load Reduction – Please clarify whether this includes both load response and operator initiated action, as in changes to transformer LTC. Supplemental Load Loss - From a utility perspective, this would be considered as load response. Please clarify how Supplemental Load Loss would be included in the stability analysis. Table 1 suggests that it cannot be included to meet steady-state performance. Suggest that the following be added to the definition: Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements.
No
The word "Requirements" needs to be added to the Table 1 titles in the existing tables. Table 1 – Steady State & Stability Performance Requirements Planning Events Table 1 — Steady State & Stability Performance Requirements Extreme Events Table 1 — Steady State & Stability Performance Requirements Footnotes (Planning Events and Extreme Events) Since it appears that the Table 1 cannot fit on a single page, it is suggested that multiple tables be developed to handle the 1) steady-state and 2) stability performance requirements. Footnotes may be included on a second page if needed. Comments were provided in early versions regarding the issues associated with raising the bar, and it was suggested that the marginal reliability benefits associated with these changes were not worth the marginal costs. We have not seen any significant changes from the earlier performance requirements. The question still remains, are we directing the resources where they need to be allocated to address and improve system reliability? So far the answer is believed to be "No".
No
Suggest rewording of footnote 5, though we do not use conditional firm service: Curtailment of conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the conditional Firm Transmission Service. Footnote 10 is definitely an improvement from previous versions. It is suggested that the word "also" be added to the last line: Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must also be considered.
No
At least 36 months would be needed for R1 compliance, should inclusion of explicit modeling of protection system equipment be required in dynamic model representations, and if all breakers would need to be explicitly modeled. More time is needed for entities to determine the appropriate dynamic load model required by R2.4.1. We recommend at least 36 months before this requirement becomes effective. 60 months effective date seems acceptable for planning

activities, but may not adequate for all construction activities. Typical times to construct a transmission line in various areas of SERC can range between 7 to 10 years. Accordingly, we recommend the effective date for construction projects be changed to at least 84 months. 12 months appears reasonable for R7.

Individual

Joe Seabrook

Puget Sound Energy, Inc.

The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices where it is expected to impact the study outcome. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted.

Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. The 20 MW threshold identified as "material change" for generation in R2.5 is too small. The limit should be raised or based on a percentage of the study area's installed generating capacity. R2.7 should be deleted, see comment on R2 above. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the "largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event" if it is documented? R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.

As currently drafted, R3.3 is not a requirement. Without the statements in R3.3.1-R3.3.4, R3.3 is simply a phrase. Sub-Sub-Requirements R3.3.1 through R3.3.4 should be bullets under R3.3, with the language in R3.3 modified so that it becomes the requirement to conduct contingency analyses that address the four resulting bullets R3.3.2 is unclear as drafted. The minimum steady state voltage limitation for synchronous generators is not a very meaningful value. All generators with an automatic voltage regulator will maintain the set point voltage until the VAR capability of the generator is exceeded, and then the voltage will deteriorate. R3.5 – We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingencies than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.

As currently drafted, R4.3 is not a requirement. Without the statements in R4.3.1-R4.3.3, R4.3 is simply a phrase. Sub-Sub-Requirements R4.3.1 through R4.3.3 should be bullets under R4.3, with the language in R4.3 modified so that it becomes the requirement to conduct contingency analyses that address the three resulting bullets. R4.3.2 – it is not clear what is required to be modeled. Typically a generator may have 10 or more protective relays. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to do that for all generators in the system. R4.5 – We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingency than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.

The term proxy is unclear. Please provide an example or an explanation of proxy.

We believe that references to FERC Orders should not be included in requirements of standards. This comment also applies to M7.

No

Claification is needed on the use of UVLS. Is it acceptable or not. Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss Allowed column is No, is load disconnecetd from the system by UVLS a violation? What about Supplemental Load Loss or UFLS? Provide clear explanations of the load definitions.

No

P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker).

We agree that TPL-005 and TPL-006 appear to have been adequately covered in the draft TPL-001-1 as currently written. However, we will need to review this assessment after TPL-001-1 is finalized. In addition, there is no place to state our concerns for Section D. so we added it here. We question the "not applicable" entry under Section D 1.1.2. What does it mean when the reset period is not applicable? Does it mean there is no reset period, so all non-compliance in all prior years will be counted as prior violations when considering non-compliance in future years?

Individual

Eric Bryant

Maine Public Advocate

No

P2, P3, P4, and P5 - The change allowing no load shedding or interruption of firm transmission service for the types of events and faults listed will lead to the construction and installation of more transmission plant. These expensive plant additions have not, however, been preceded or justified by any evidence that the reliability of the current system - using current planning standards which allow load shedding and interruption of firm transmission service - is lacking. The August 2003 blackout, to the extent utilities and other industry stakeholders have cited it for this purpose, was not caused by the lack of such planning standards; it was an event that should not have occured and would not have but for the utter failure of First Energy to pay attention to operations and vegetation management. The Joint US/Canada Report makes this clear. These proposed changes are not needed and will cause unreasonable increases in rates that are not justified by the putative increases in reliability. There is currently too much emphasis on reliability and not enough emphasis on costs. Utilities are spurred, of course, by the FERC's ROE incentive. NERC should not allow this incentive to influence the reasonalbeness of any of its standards, particularly this one which can only lead to unneeded redundancy in the high voltage transmission system and resulting higher costs.

Group

Pepco Holings, Inc. - Affiliates

Yes

Yes

PHI does not disagree with the performance elements, but suggests that the table would be improved if a leading sentence were added to the definition section at the beginning of the table.

Yes

Yes

Individual

Scott Helyer

Tenaska, Inc.

It is not clear that Requirement R1 requires ALL existing generators, substations, transmission line, transformers, etc. to be explicitly modeled for steady state and stability studies. In fact, Requirement 1.1.6 could be interpreted to exclude various generators from the models if they are not contracted to supply load. A suggestion is to re-word R1.1 to read as follows: R1.1 Models for the Planning Assessment shall represent all existing generators, substations (including specific busses within a substation), transmission lines, loads, capacitors, reactors, and other equipment connected to the transmission system and shall further represent the following: (continue with R1.1.1 through R1.1.6) A further refinement to R1.1.6 should also be considered as follows: R1.1.6 Committment and dispatch schedules of resources expected to serve Load for the specific model.

Individual

Kasia Mihalchuk

Manitoba Hydro

Requirement Text: R1: What is meant by "including requirements of regulatory authorities and other legal obligations"? This phase should be deleted. Can NERC make it an obligation in a standard to follow regulatory authority and other legal obligations? The planner has scope to determine the "projected system conditions", and if a local regulator mandated a requirement, the planner would be able to include it without this statement. R1.1.1: Only long duration known planned or scheduled outages that are expected to last over a system peak should be included in the scope of this standard. Known planned or scheduled maintenance outages should not be a part of the planning scope as they are short duration and are planned to be taken when system conditions allow. Suggest wording change to "Planned outages of generation and Transmission Facilities with an expected duration of 6 months or longer, if specifically known." R1.1.2: Suggest deleting new technologies as it is unknown as to what this is. If the SDT wants to make the list all inclusive, add words such as "shall include but not be limited to" in the requirement wording. Circuit breakers are not specifically represented in the planning models in order to keep the number of buses within the program capabilities. However, the effect of the circuit breaker configuration is normally considered in the creation of contingency files. Can the drafting team confirm that circuit breakers do not have to be specifically represented in the model? The same comment can be said about protection system equipment. Some generic zone 1 modeling may be included but in general the effect of protection equipment is included in contingency files. R1.1.4 & R1.1.5: Firm Transmission Service represents a contract that the planner is obligated to include. Based on the NERC definition, Interchange is defined as "Energy transfers that cross Balancing Authority boundaries". Including it as a requirement mandates system expansion for non-firm system usage. Interchange is already covered in the sensitivities (Expected Transfers) and should not be a specific sub requirement of R1.1.2. Perhaps simply documenting the value of the Interchange used in the Model is sufficient. This value may change in the sensitivity analysis conducted in R2.1.3 and the TP/PA will decide the level that they will plan on protecting. Measure: The measure requires the planner to provide evidence such as the System model. What further evidence is required to ensure the planner is using data consistent with the MOD standards, is simulating projected system conditions, and that the models represent the "required information in accordance with Requirement R1? It is suggested to remove "and shall simulate projected System conditions" from the main paragraph of R1 and reword R1.1 to "System models and contingency files for the Planning Assessment shall represent projected System Conditions including:" Requirement R1 is very vague, and the Measure refers back to R1. The MOD standards deal with the building of the model. Most planners provide data in accordance with the MOD standards for a regional model building process. These models form

the basis for the models the TPs and the PC use. The R1could be more specific by requiring the PC/TP to provide rationale for the projected system conditions used, which might include the generation schedule assumed, the transfer conditions, why peak or off-peak is important, etc.. VSLs: The requirement is very generic in nature and leans on the MOD requirements. Verification of compliance to this requirement will be problematic. What will be required to prove that the data "is consistent with the data provided in accordance with the MOD-010 and MOD-012 and other data sources"? What are these other data sources"? R1 only stipulates that the planner shall "simulate expected system conditions", so how does one decided that the "model did not simulate projected System Conditions as described in R1" (severe VSL)?

Requirement Text: R2.1: Reference of past studies should be to R2.5, not R2.6 (typo). R2.1.3: The sensitivity to "Planned duration or timing of Transmission Outages" should be modified to only include "Planned long duration Transmission outages that span multiple seasons, if known". Short duration planned maintenance outages should not be included in a planning assessment. R2.1.4 - The second sentence doesn't read right - the sentence should be changed to read: "The analysis shall reflect the Contingencies identified in Table 1 under the conditions that the System is expected to experience during the unavailability of the long lead time equipment." R2.2.1 - This sub-requirement should be deleted. Why do extra assessments beyond the 10 year period? Any items beyond 10 years will be covered when they fall into the 10 year period. For example, if we assess the 10 year horizon, then the project due to be complete in 12 years will be part of the assessment in 2 years when it is 10 years out. We will have to show every year how our system meets compliance regardless of this extra analysis, so what's the point. Every year we have to show how we comply in the short and long term so what difference does it make when each project is completed as long as we are in compliance or identify Corrective Action Plans (CAPs) along the way. R2.4.1: The statement "a Load model shall be used which appropriately represents the dynamic behavior of Loads" is not very crisp. What will "appropriate" be interpreted to mean by the NERC auditor? Does an MOD standard exist that covers gathering data and validating loads models? This should be a first step. The SDT should add a statement that the application of detailed induction motor modeling can be limited to areas where poor voltage recovery is expected due to a high concentration of such load. The requirement should be modified to require the PC/TP to provide a rationale for the load models used in its specific planning area. R2.5: A "Past Study" is a definition and should be moved to the definition section. The definition only identifies power changes as possible material changes, but should also include machine control (exciters/governors) changes. We suggest the bulleted list of "Material Generation changes" be expanded. R2.6.1: Can the SDT clarify how a rate application qualifies as a CAP action? R2.9 - The sentence should refer to "maximum Non-Consequential Load Loss" not "maximum permissible Non-Consequential Load Loss".

R3.1: The requirement text should be changed to read "studies shall be performed for Planning Events to determine whether the BES meets the performance requirements in Table 1 based on the contingency list of events created in Requirement R3.4.". R3.2: Requirement wording should be similar to R3.4 for consistency. R3.4 & R3.5: The selection of the contingency list is based on the knowledge of the PC/TP. How do you produce "an explanation of why the remaining Contingencies would produce less severe System results." without proving this with a study? If the explanation is "that based on engineering judgment, the remaining contingencies would produce less severe system results" then the explanation is implied and not necessary. VSLs: Under the moderate to severe VSL, the performance requirements currently refer to P2 through P7. We believe this is a typo and should be P1 through P7.

R4.1: The requirement text should be changed to read "studies shall be performed for Planning Events to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists of events created in Requirement R4.4.". R4.2: Requirement wording should be similar to R4.4 for consistency. R4.3: We agree that consideration of generator voltage ride through is important. However, we also suggest that frequency ride through capability be analyzed. R4.4 & R4.5: The selection of the contingency list is based on the knowledge of the PC/TP. How do you produce "an explanation of why the remaining Contingencies would produce less severe System results." without proving this with a study? If the explanation is "that based on engineering judgment, the remaining contingencies would produce less severe system results" then the explanation is implied and not necessary.

Data Retention: The 5th bullet should refer to "proxies" instead of "studies".

None

It is unclear as to what is meant by "coordinating analysis of these results"? Does this imply an obligation to conduct joint studies or just an obligation to distribute the assessment and respond to feedback? We suggest that the wording "such as described in FERC Order 890" be replaced with "such as may be required by a regulator in its PC/TP area". The SDT is posing several other questions for industry consideration not related to the specific requirement questions above.

No

Consequential Load Loss: the wording "by a planned Protection System operation to isolate fault conditions" is awkward wording. The wording should be changed to "by a Protection System operation designed to isolate fault conditions". Load Reduction: This definition is not needed and

load reduction is not prohibited in the standard. It will take some effort to even measure such a load reduction in simulation. Given that there are four load related definitions, the standard would be simplified by deleting this term. Any voltage dependent load will be reduced for a low voltage condition. In steady state (P0), load is normally modeled as constant MVA load so load is constant. In the steady state period after a contingency, transformer taps and voltage control devices will restore voltage, and consequently, any load modeled as voltage dependent will be restored to pre-contingency level. The term is not used anywhere in the requirements of the standard - it is only included in Table 1 Note b in the definition of Non-Consequential Load Loss. We do not think it is needed. Supplemental Load Loss: Why did the drafting team decide to include Supplemental load loss? In Table 1, it is stated under "note b" that Supplemental Load Loss cannot be used to meet steady state performance requirements. Does this imply that it is acceptable for "non-consequential" induction motor load to trip off as a result of undervoltage during the disturbance due to its protection setting? It is possible that this load loss during a stability simulation may avoid the need to add dynamic reactive support. Can the drafting team clarify the intent of the standard or delete Supplemental Load Loss. At minimum, the TP/PA should identify the minimum transient voltage that they are planning the system for. In that way, any load loss for unplanned events that cause lower transient voltages or load loss that occurs at a higher transient voltage wouldn't be a violation. Also, unless the end-user load is modeled in detail, or a proxy is used, the planner will not know if such load exists or would be lost in the simulation.

No

Note b should be reworded to "However, Supplemental Load Loss associated with a P2 through P5 event shall not be used to meet post-contingency steady-state performance requirements." Also we do not see a need for Load Reduction (see Q8 comment) Note b also implies that voltage dependent load is not permitted to be modeled for P0. This in turn means that the model must have all load represented as constant MVA. The load representation can change for categories P1 through P7. Is this the intent of the language? Note e: Are the planned System adjustments and redispatch allowed following all Planning Events if they result in curtailment of Firm Transmission Service? Should Note 10 also be referenced here? Footnote 7 applies to FACTS devices that are connected to ground. It is possible to have an ungrounded FACTS device (eg. Delta connected) or a series connected FACTS device (UPFC, SSSC, etc.). I would recommend deleting "that are connected to ground" so that the note is more general. Series connected FACTS will likely be separated via circuit breakers in a similar way as a transformer or phase shifter. Other series FACTS device, like a TCSC also typically self protect via a bypass breaker and should be considered as a separate element. Extreme Events: Steady State 1: Does the loss of a DC line refer to a bipole line? Steady State 2e: The loss of a large load could result from a Planning Event, perhaps even a P1 or P2 event - likely not an extreme event - compared to the loss of a major load center.

Yes

Note 10: The drafting team is to be congratulated for including the ability to curtail Firm Transmission Service as long as generation is available to redispatch to prevent firm load loss. Note 5: Firm transmission service can also be curtailed when the service is conditioned on the element is being available (note 5). It is recommended to add note 10 to contingencies P1 and P2. This would allow for curtailment of Firm Transmission Service via redispatch without dropping load when re-adjusting the system following these single contingency events, or automatically adjusting the system via an SPS action initiated by the P1 or P2 event, consistent with note b of the existing TPL standards. The consequence of not including Note 10 could mean extensive new transmission line construction without any increase in transfer capability. In Note 10, the SDT is assuming that the Firm transmission Service is Network Service to load. Does Note 10 also apply if the Firm Transmission Service is firm point-to-point service?

No

TPL-005-0 is a Regional and Interregional Self-Assessment Reliability Report. Such an assessment is beyond the capability of an individual PC or TP. While the new TPL-001-1 can and should include a requirement on the PC and TP to include in their assessments the interconnections with their adjacent systems, it does not make sense to mandate an individual TP or PC to conduct an interregional assessment. Consequently, TPL-005-0 should be retained and mandated on the regions via the NERC delegation agreements with the regions.

Group

PacifiCorp

The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices where it is expected to impact the study outcome. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5

would be redundant and one should be deleted. We disagree with the inclusion of the words "including requirements of regulatory authorities and other legal obligations" at the end of R1. Entities already are required to do this. It does not need to be included in the standard.
Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement. The 20 MW threshold identified as "material change" for generation in R2.5 is too small. The limit should be raised or based on a percentage of the study area's installed generating capacity. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the "largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event" if it is documented? R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.
As currently drafted, R3.3 is not a requirement. Without the statements in R3.3.1-R3.3.4, R3.3 is simply a phrase. Sub-Sub-Requirements R3.3.1 through R3.3.4 should be bullets under R3.3, with the language in R3.3 modified so that it becomes the requirement to conduct contingency analyses that address the four resulting bullets R3.3.2 is unclear as drafted. The minimum steady state voltage limitation for synchronous generators is not a very meaningful value. All generators with an automotive voltage regulator will maintain the set point voltage until the VAR capability of the generator is exceeded, and then the voltage will deteriorate. R3.5 – We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingencies than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.
As currently drafted, R4.3 is not a requirement. Without the statements in R4.3.1-R4.3.3, R4.3 is simply a phrase. Sub-Sub-Requirements R4.3.1 through R4.3.3 should be bullets under R4.3, with the language in R4.3 modified so that it becomes the requirement to conduct contingency analyses that address the three resulting bullets. R4.3.2 – it is not clear what is required to be modeled. Typically a generator may have 10 or more protective relays. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to do that for all generators in the system. R4.5 – We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingency than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.
The term proxy is unclear. Please provide an example or an explanation of proxy.
We believe that references to FERC Orders should not be included in requirements of standards. This comment also applies to M7.
No
: Claification is needed on the use of UVLS. Is it acceptable or not. Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss Allowed column is No, is load disconnecetd from the system by UVLS a violation? What about Supplemental Load Loss or UFLS?
No

P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements. As such, this is a low probability condition and loss of Non-Consequential load should be allowed for EHV. We disagree with raising the bar for EHV for P4.

: We agree that TPL-005 and TPL-006 appear to have been adequately covered in the draft TPL-001-1 as currently written. However, we will need to review this assessment after TPL-001-1 is finalized. In addition, there is no place to state our concerns for Section D. so we added it here. We question the "not applicable" entry under Section D 1.1.2. What does it mean when the reset period is not applicable? Does it mean there is no reset period, so all non-compliance in all prior years will be counted as prior violations when considering non-compliance in future years?

Individual

Brent Ingebrigtson

E.ON U.S.

R1. Delete “and other data sources”. Consistency with MOD-010 and MOD-012 standards is measurable and should suffice. Delete “including requirements of regulatory authorities and other legal obligations”. The term: “shall simulate projected System conditions” does not exclude the above. If there is some significance to this statement it should be an item in R1.1. R1.1.4. Firm Transmission Service is often sold for less than one year on an as available basis. Also, Firm Transmission Service may be sold on one system without a complete path. As stated, it appears necessary to include these examples in the Planning models. E.ON U.S. believes that there should be some limitations put on this requirement such as Long-Term Firm Transmission Service for a period of 5 or more years.

R2.1.3 Change “For each of the studies …” to “For at least one of the studies” R2.1.1 and R2.1.2 require that 3 studies be performed each year. As written, the requirement indicates that the transmission planner has to perform at least one sensitivity study for the 3 studies required by R2.1.1 and R2.1.2. This means that the transmission planner would also have to perform 3 or more sensitivity studies each year. One sensitivity study for one of the 3 studies required by R2.1.1 and R2.1.2 should suffice. R2.1.4. Delete “The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment.” This statement is redundant since R3 requires this analysis for all of R2.1. Including this statement in R2.1.4 and not in R2.1.1 and R2.1.2 makes it appear that this requirement has different performance requirements. R2.4.3 R2.4 does not require studies annually. However, if the transmission planner chooses to study a System Peak Load or a System Off-Peak Load condition R2.4.3 requires that the planner also study sensitivity to that same condition in the current year. E.ON U.S. believes it sufficient that the assessment include a sensitivity study for some System Peak Load and some System Off-Peak Load condition. R2.6 The third sentence should be modified to include R2.1.4., so that it reads “Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3, R2.1.4 and R2.4.3.” The annual studies performed for Category P6 alert the Transmission Planner to the risks of transformer failure. The Transmission Planner is required to design the system to limit those risks. If the delivery time for a piece of equipment is 11 months, then P6 allows Interruption of Firm Transmission Service and Non-Consequential Load Loss. If the delivery time for a piece of equipment is 12 months, then P1 requires that the system be designed for no Interruption of Firm Transmission Service and Non-Consequential Load Loss. This is a significant increase in performance requirements for an event that will most likely not extend beyond to a second System Peak Load period. If R2.1.4 is not included in the requirement the transmission planners would essentially be designing for an Extreme Event, i.e., events which are more severe and have a lower probability of occurrence than Planning Events. R2.6.1 Operating Procedures, by NERC definition, require significantly more detail than is appropriate for a Corrective Action Plan. It is not appropriate that Transmission Planners write Operating Procedures to be used by NERC Certified System Operators. E.ON U.S. suggests that “Operating Procedures” be changed to “mitigation plans”. R2.6.5 Planning Assessments and System Facilities are not NERC defined terms. Operating Procedures, by NERC definition, require significantly more detail than is appropriate for a Corrective Action Plan. It is not appropriate that Transmission Planners write Operating Procedures to be used by NERC Certified System Operators. E.ON U.S. suggests that “Operating Procedures” be changed to “mitigation plans”. R2.8 There are no requirements to limit Consequential Load Loss. Impacted customers are typically aware of the customary level of service and have chosen not to pay for extraordinary levels of service. E ON US questions the purpose and benefit of this requirement. While continuity of service to end use customers is an important measure of service reliability for which utilities answer to state authorities, BES reliability requires that the system remain balanced and that local failures not result in cascading BES events NERC standards should, pursuant to FPA Section 215, focus solely on BES reliability

No

Year One: The calendar year contains 12 months. As written, Year One could start as early as January 2010 (1/1/2009 plus 12 months) or as late as July 2011 (12/31/2009 plus 18 months). E.ON U.S. believes that the statement should be modified to: read " … that begins 12-18 months from the beginning of the current calendar year". This would limit the beginning of the current window to be January 2010 or July 2010.

Table 1 Extreme Events Comments Steady State 2.b Right-of-Way should include a reference to footnote 12. 2.d. Item 2.d. references loss of all generating units at a "station" but Item 3 references generating plants and nuclear power plants. It is unclear whether Item 2.d requires an outage of all generating units connected to a single transmission station (all voltages) or an outage of all generating units at a generating plant (although they may be connected to multiple transmission stations). 2.g Right-of-Way should include a reference to footnote 12. Footnotes 12 E ON U.S. suggests the definition be expanded to: Exclude circuits that share common structure for 1 mile or less and Transmission lines that share common Right-of-Way for 1 mile or less.

Individual

Sergio Garza

LCRA Transmission Services Corporation

In R2.6.2, it is stated that a project initiation date is required as well as an in-service date. What is considered the project initiation date, the point at which the project plan is approved or the time at which construction is to begin? If it is the time at which construction is to begin, then LCRA TSC believes this requirement does not belong in the TPL-001-1 standard as the construction timeframe for a project is developed by groups outside of Planning based on resources and outage availability.

In R3.3.4, what is meant by the term "electrical system quantities"? Quantities is typically an amount and its use here would indicate that a term such as parameters would be better suited.

In R4.3.3, what is meant by the term "electrical system quantities"? Quantities is typically an amount and its use here would indicate that a term such as parameters would be better suited.

In R5, what is meant by the term "any proxies"? Please clarify. This comment also pertains to this terms use in the VSL as well.

Individual

Carol Sedewitz

National Grid

Comments: R1: A. Priority Comment- There needs to be some direction provided on the initial conditions used in the assessment. This guidance should encourage the use of initial conditions that reasonably stress transfers across interfaces between companies, areas, regions, into load pockets, and out of constrained areas. The expectation that transfers are reasonably stressed for a variety of interface conditions will require the consideration of different generation dispatches, which goes beyond the single generator out of service requirement of the standard. If initial conditions consider reasonably stressed conditions, then sensitivity analysis is embedded in the process. If sensitivity is embedded in the process, it is unclear if additional sensitivity is still required by the standard. B. In the reference to regulatory authorities and other legal obligations it is suggested that the phrase be changed from "simulate projected System conditions including requirements of regulatory authorities and other legal obligations" to "include projected System conditions and requirements of regulatory authorities and other legal obligation." In common usage of terms, models are used to simulate system response, but models alone do not simulate the system. Violation Severity Levels: R1 – Suggest changing the phrase "simulate projected System conditions as described in Requirement R1" to "include projected System as described in Requirement R1," consistent with the recommended change to Requirement R1. Errata: Delete the period after "R1" in the first bullet in the Data Retention section. R1.1.1 Priority comment – R1.1.1 should be removed. - Planned outages are addressed by Operational Planning processes and Transmission Operating Procedures for up to two years ahead removing the need for this to be incorporated into Planning Assessments. - If outages are planned, but Operations can not

accommodate them in real time, then the outages are cancelled. - Outages are not generally known beyond one to two years in advance. R1.1.2 Comment - We recommend deleting the list of facilities: - Circuit breakers are not modeled as elements in a power flow nor are Control Devices and Protection Systems - The list of facilities is not consistent with the definition of 'Facilities' in the NERC Glossary R1.1.2 should simply read: R1.1.2 New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon. R1.1.3 Comment - The use of "real and reactive power" is prevalent within the industry, but R1.1.3 should be changed to "Active and reactive Demand of Load." When load is expressed as a complex quantity, active power is the real portion and reactive power is the imaginary portion. Thus for consistency, we should refer to active and reactive. R1.1.5 Comment – What specifically needs to be modeled under Interchange? R1.1.6 Comment – This needs further definition or it should be deleted. It is not clear what a "network resource required to supply load" is. Does this refer to Network Resource per FERC LGIP?

R2 Comment – In the first sentence, replace the phrase "prepare" with "conduct and document" and in the second sentence replace "This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses" with "The Planning Assessment shall review assumptions of current or past studies and assess the continuing validity of the steady state, short circuit, and stability results. The review of assumptions, supplemental analysis, and updated results shall be documented." R2.1 Comment – A. The terms assess and annual study are referenced in the same requirement. It is unclear what constitutes either. Is an annual study required for every area or is an annual assessment required for every area, which may include some supporting study to address changes to the conditions? B. Requirement R2.1 should refer to R2.5 rather than R2.6 R2.1.1 Comment – A. Year One and year two do not provide enough time to implement Corrective Action Plans and are better suited for Operations studies. The requirement to evaluate Year One or year two should be removed. B. Is a year 5 study required annually for every area of a system? R2.1.2 Comment – The requirement should be removed. With no description of the system stresses and generator outages to be applied when assessing the off-peak load, it is difficult to imagine any issues which would arise which are not revealed in the peak load evaluation that could not be addressed through generation dispatch adjustments. Need to define conditions for assessment. R2.1.3 Comment – A. The emphasis on sensitivity testing in the existing section appears misdirected and should be focused on the expected accuracy of the assumptions. The assessment should have to include a discussion of accuracy of the assumptions. Having a requirement to perform one more sensitivity not already included is vague and does not add value to the assessment or the standard. B. Planned Transmission Outages are not known in the Planning horizon. Also the release of the outage on any given day is controlled by operations based on the conditions. The conditions are not known for the Planning assessment. The last bullet referring to Planned Transmission Outages should be deleted. C. Delete the phrase "are intended to." It is difficult to measure intent and what is important is whether the system has been stressed, not whether the responsible entity intended to stress the system. D. What is expected from a sensitivity analysis? Is it to change the base case and see how the case responded, is it to create a new base case and rerun all of the events, or is it to change the base case and rerun a select number of events. It is anticipated that the answer will vary based on what is changed. R2.1.4 Priority Comment – With respect to spare equipment strategy, this requirement potentially imposes a requirement to plan for three events, which is overly severe. After experiencing a major contingency of a long lead time facility, there should be some change in the acceptability of risk. This change in risk could include an allowance for the loss of non-consequential load or some of the multiple events from Table 1 should be evaluated as Extreme Contingency events. R2.2 Comment – We suggest replacing the phrase "a current System peak Load study" with "a valid System peak Load study" in the first sentence. The word current is confusing as some read the word current to mean "today's" rather than "valid". R2.3 Comment – A. The requirement to "conduct annually" isn't consistent with "support". We suggest "Conducted annually" should be replaced with the phrase "assessed annually". B. "Interruption duty" should be changed to "interrupting duty." All terms in the IEEE dictionary related to breaker opening use the word "interrupting," while terms related to loss of supply to customers use the word "interruption." R2.4.1 Comment – A. The two sentences are describing an 'or' condition and they should be merged to read: "For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads or an aggregate System Load model which represents the overall dynamic behavior of the Load." R2.4.3 Comment - Delete the phrase "are intended to." It is difficult to measure intent and what is important is whether the system has been stressed, not whether the responsible entity intended to stress the system. R2.5 Comment – If past studies only support, then a new study is still required. We suggest changing "Past studies may be used to support the Planning Assessment if they meet the following requirements:" to "Past studies may be used to fulfill all or a portion of the Planning Assessment provided they meet the following requirements:" Violation Severity Levels: R2 - There is no VSL associated with R2.5. A VSL should be added, perhaps under Moderate, that "past studies were utilized to fulfill all or a portion of the requirement, but the studies did not meet the requirements in R2.5." R2.5.1 Comment– We suggest deleting this requirement, and

incorporating it into R2.5.2. R2.5.2 Comment – To incorporate R.2.5.1 into R2.5.2; please modify the section as follows: For steady state, short circuit, or stability analysis the study shall be less than five calendar years old from the date of completion. The present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. A material change does not require the whole study to be redone. It only requires that the affected portion of the study be reassessed. Material generation changes include: • The addition/deletion/change of individual generating unit capability determined to be material by the Planning Coordinator or Transmission Planner. • An aggregated addition/deletion/change to a group of generating units directly connected to the BES at one point of interconnection through one or more transformers and determined to be material by the Planning Coordinator or Transmission Planner. The reference to the step-up transformer may not capture a wind farm that could have transformers to step-up to a collection voltage and transformer that wouldn't be labeled a GSU to connect to the system. R2.6 Priority Comment – A. As written, this section undermines the value of the sensitivity testing. This section should require a corrective action plan to fix problems determined in sensitivity analysis if there is a reasonable risk of occurrence. We suggest making the standard read "Provide documentation that explains the reasoning for the sensitivities considered and selected." B. At the end of the second sentence, the phrase "in the tables" is used. We suggest using more definitive language such as "in Table 1". R2.6.1 Comment -In the last bullet, the reference to "rate application" is unclear. R2.6.2 Comment – The phrase "Project Initiation Date" needs to be defined. It is unclear if this is the date of ground breaking, purchase orders being issued, solution study initiation, etc. Additionally, in the second sentence the phrase "as well as an in-service date" should be modified to read "as well as a target in-service date". R2.6.3 Comment – Plans can provide a target in-service year, but not an actual in-service year. R2.6.4 Priority Comment – There should be a cutoff point when changes occur beyond a certain date. When that date occurs, further changes will be evaluated in the next year's assessment. Otherwise, if a state makes a decision not to site a project a few weeks prior to the end of the assessment period, there will not be sufficient time to incorporate this into that year's assessment and develop corrective actions. R2.7 Comment – A. "Interruption duty" should be changed to "interrupting duty." All terms in the IEEE dictionary related to breaker opening use the word "interrupting," while terms related to loss of supply to customers use the word "interruption." B. The requirement would be clearer if it we restructured as follows: "For short circuit analysis, if the short circuit interrupting duty determined in Requirement R2.3 exceeds the Equipment Rating of fault interrupting devices, the Planning Authority . . ." R2.8 Comment – A. Largest consequential load loss is not factored into the Planning Assessment and should therefore be deleted. B. If it is not deleted, do we have to prepare one number for P1 and a separate number for P2? The phrase "any P1 event and any P2 event in Table 1" could also be read as the worst loading for each event within P1 and P2, which could be hundreds of values depending on how many events are analyzed. We recommend that the requirement be modified to require documentation of the maximum amount of consequential load loss that was relied upon during the assessment of the P1 and P2 events. C. If it is not deleted, "shall provide" should be changed to "shall identify" for consistency with R2.9 R2.9 Comment – A. Largest consequential load loss is not factored into the Planning Assessment and should therefore be deleted. B. If it is not deleted, this requirement is unclear. Is this requirement asking for each transmission planner to list their criteria for non-consequential load loss, or is it asking how much non-consequential load loss was being relied upon in the assessment? Including the word "permissible" implies the responsible entity must decide how much Non-Consequential Load Loss is allowed. We recommend that the requirement be modified to require documentation of the maximum amount of non-consequential load loss that was relied upon during the assessment of the P1 and P2 events.

R3 Comment – "Planning Assessment" and "shall perform analysis" are contradictory. R3 and its sub-requirements then reference study requirements. If this is an assessment, then the standard shouldn't be requiring a study. R3.1 Comment – A. It is not clear what should be included in the list related to R3.4. Events P0 through P4 should include analysis of all BES facilities for which the Transmission Planner is responsible. Events P5 and higher should be limited to contingency events that are deemed the most significant by the Transmission Planner. B. R3.1 refers to 'lists'. Is R3.4 creating one list or multiple lists? Suggest changing 'lists' to 'list' R3.2 Comment - Since R3.4 and R3.5 both require the responsible entity to create a list, the words in R3.2 be should be revised to be more similar to the words in R3.1. Suggest changing "Studies shall be performed to assess the impact of the Extreme Events identified in Requirement R3.5. to "Studies shall be performed to assess the impact of the Extreme Events, which are identified by the list created in Requirement R3.5." R3.3.2 Comment – A. Traditionally transmission planners have used their judgment about the minimum steady state voltage limitations of generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. B. Voltage limitations are for both minimum and maximum. If this requirement is kept, then "minimum" should be deleted. C. Is this requirement really looking at "voltage limits" or generator "reactive capability"? R3.3.3 - This requirement should be deleted. Each reliability issue should be addressed in one standard and relay loadability is

addressed in PRC-023. If requirements of PRC-023 are met, the relay loadability does not constitute a limitation. If this requirement is intended to apply to modeling relay characteristics in stability simulations, which is not addressed by PRC-023, then the requirement should be more explicit. However, as written it appears that the intent was to be in-line with Blackout Recommendation 8a which relates to steady-state loadability, which is covered by PRC-023. R3.4 Comment - Table 1 includes both Steady State and Stability events. R3.4 needs to indicate that it only applies to the Steady State portion of the Table. R3.5 Priority Comment – It is recommended that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences and the requirements are too vague to have auditable value. If the requirement is not deleted, the following is recommended: - Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events. If not, it will be difficult to utilize the results to obtain projects approvals. - It should be clear that an evaluation does not require solution development for all Extreme Events - Change "an evaluation of possible actions…" to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered." - The statement "and shall include an explanation of why the remaining Contingencies would produce less severe System results" is too open and should be deleted. Violation Severity Levels: R3.4 Since this is a binary requirement, should this have a Severe VSL? R3.5 Since this is a binary requirement, should this have a Severe VSL?

R4 Comment – "Planning Assessment" and "shall perform analysis" are contradictory. R4 and its sub-requirements, then reference study requirements. If this is an assessment, then the standard shouldn't be requiring a study. R4.1 Comment – A. It is not clear what should be included in the list related to R4.4. Events P0 through P4 should include analysis of all facilities BES facilities for which the Transmission Planner is responsible. Events P5 and higher should be limited to contingency events that are deemed the most significant by the Transmission Planner. B. R4.1 refers to 'lists'. Is R4.4 creating one list or multiple lists? Suggest changing 'lists' to 'list' R4.2 Comment - Since R4.4 and R4.5 both require the responsible entity to create a list, the words in R4.2 be should be revised to be more similar to the words in R4.1. Suggest changing "Studies shall be performed to assess the impact of the Extreme Events identified in Requirement R4.5. " to "Studies shall be performed to assess the impact of the Extreme Events, which are identified by the list created in Requirement R4.5." R4.3.2 Priority Comment - Traditionally transmission planners have assumed that generators would ride through low voltages associated with Planning Events which is generally adequate for non-wind generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R4.5 Priority Comment – It is recommended that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. If the requirement is not deleted, the following is recommended: - Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events. If not, it will be difficult to utilize the results to obtain projects approvals. - It should be clear that an evaluation does not require solution development for all Extreme Events - Change "an evaluation of possible actions…" to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered." - The statement "and shall include an explanation of why the remaining Contingencies would produce less severe System results" is too open and should be deleted. Violation Severity Levels: R4.4 Since this is a binary requirement, should this have a Severe VSL? R4.5 Since this is a binary requirement, should this have a Severe VSL?

It is unclear as to what is meant by the term "proxy used in the analysis" used in this requirement. Is a 'proxy' a 'criteria'?

None

This standard should not be reiterating FERC Order 890. We do not feel that this requirement belongs in this standard and it should be deleted.

No

Comments: Can the definitions of the 'Planning Horizon' in the FAC, the 'Long-term Planning' Time Horizon (italicized and in parentheses next to the Violation Risk Factor), and the 'Near-Term' and 'Long-Term Transmission Planning' be included in the definitions section to avoid confusion? Refine load loss definitions as follows. Consequential Load Loss: All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. Comment – It is not clear if Consequential load includes load that is connected to transmission within an island. Suggest revising the definition to "..load no longer served by the Transmission System (or perhaps by the BES?) as a result of Transmission Facilities being removed…" Load Reduction: Quantity of Load that is reduced due to lower voltage conditions resulting from a Planning or Extreme Event. Comment – 'Load Reduction' as written is the load remaining after the reduction. This should be rewritten to indicate it is the change in load from the previous value to that still connected. Also, the defined term 'Load Reduction' is counter to what most engineers consider to

be a load reduction and as written it does not seem necessary to define this term. Most engineers associate Load Reduction as a manual or automatic action by a customer to reduce demand. As defined it appears that Load Reduction refers only to the voltage sensitivity of load which should be captured in the system model if it is necessary to model this effect. Therefore the reference should be changed from "Load Reduction" to "Voltage Sensitive Load Loss". Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction. Comment – The definition is indirect. Suggest to revise the definition to be direct by stating "Intended post contingency loss of load (other than Interruptible Load, Supplemental Load or Load Reduction) caused by operator or SPS (RAS) action." Planning Events: Events that require Transmission system performance requirements to be met. Comment - Suggest "Events for which Transmission system performance requirements shall be met". Supplemental Load Loss: Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions. Comment - Suggest rewording last phrase to "..responding to System Contingency conditions." - or perhaps just "..responding to System conditions." Year One: The first year that a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the current calendar year. Comment - Suggest rewording second sentence to "This is further defined as beginning 12-18 months from the current calendar year." - This avoids the awkwardness in present draft of seeming to define Year One as a planning window as well as a particular year.

No

Steady State & Stability comments are as follows: Steady State & Stability: a. Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur. How does this apply to Steady State testing? b. Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirements The second sentence re: Supplemental Load Loss implies need to test without end-user's actions and then assess whether action of separating end-user needs to be taken by Transmission system? B. Event P2-3 and P4 have the same impact; also events P2-4 and P4-6 have the same impact. Can these be consolidated? P5 Priority Comment – As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. P7 Priority Comment – Event 1 - This requirement requires the evaluation of the loss of two circuits on a multiple circuit tower. We recommend that this be modified so that only the loss of two adjacent (vertically or horizontally) circuits need be evaluated. Or allow the Planning Coordinator to evaluate and if appropriate exempt specific locations from this contingency based on acceptable risk. Comments on Extreme Events – Table 1- We recommend renumbering the Extreme Events table to be Table 2. Stability Condition 2 Note a - Priority Comment - As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. Stability Condition 2 Note h – Eliminate this requirement or change to loss of station following three phase fault. This note is confusing. Without providing a better defined scenario, it is unclear as to what clearing times should be used in this simulation. Note 1.a.i - For Planning Event P1: No generating unit or units shall be allowed to pull out of synchronism." There needs to be some sort of qualifier on this requirement. We suggest the following, "For Planning Event P1: No generating unit or units, directly interconnected at 100 kV or above, shall be allowed to lose synchronism." Note 1.a.ii – Contingency Reserve is dependent on the generation on-line. We suggest changing the first sentence to say that you can't lose more than that permissible by the Planning Coordinator. Also change "pull out of synchronism" to "lose synchronism" in this sentence and in the second sentence. (Is "Lose synchronism" a more commonly used term?). Note 3 – We recommend revising the wording of the last sentence to "A 3 phase fault study indicating criteria are being met is sufficient evidence that a SLG condition would also meet criteria." Note 11. Reference is made to Independent Pole Operation (IPO) – Can this be clarified by referencing it as IPO or Independent Pole Trip (IPT) as opposed to single-pole switching. Note 4 – We recommend that a lower bound be put on the HV electric systems (such as 100 kV), rather than just saying "and lower". Extreme Events: Steady State 3a - loss of two generating plants - This can be considered in two ways - one which results in loss of source (e.g. from fuel, cooling water, or nuke design shutdown) OR the second which could result in loss of stations including lines and breakers (e.g. from wildfires, weather, cyber attack, etc) - which is meant here? Both?

Yes

Capitalize "Firm Transmission Service" in footnote 10 and instead of saying firm Load use Firm Demand to be consistent with the NERC Glossary

Yes

Group

Bonneville Power Administration
The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices where it is expected to impact the study outcome. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted. We disagree with the inclusion of the words "including requirements of regulatory authorities and other legal obligations" at the end of R1. Entities already are required to do this. It does not need to be included in the standard.
Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). R2.1.1: Peak load modeled for the near term planning horizon may not be Year one or year two. Therefore, R2.1.1 should be revised to say "System peak load for one of the five years". Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement. The 20 MW threshold identified as "material change" for generation in R2.5 is too small. The limit should be raised or based on a percentage of the study area's installed generating capacity. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the "largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event" if it is documented? R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.
R3.1 should be clarified. Suggested clarification: R3.1 - "Studies shall be performed to determine whether the BES meets the performance requirements in Table 1. A reduced set of contingencies can be simulated based on a list created in requirement R3.4." As currently drafted, R3.3 is not a requirement. Without the statements in R3.3.1-R3.3.4, R3.3 is simply a phrase. Sub-Sub-Requirements R3.3.1 through R3.3.4 should be bullets under R3.3, with the language in R3.3 modified so that it becomes the requirement to conduct contingency analyses that address the four resulting bullets R3.3.2 is unclear as drafted. The minimum steady state voltage limitation for synchronous generators is not a very meaningful value. All generators with an automatic voltage regulator will maintain the set point voltage until the VAR capability of the generator is exceeded, and then the voltage will deteriorate. Requirement R3.4 also needs to be clarified as follows: R3.4 - "A reduced list of Contingencies can be developed for System Performance evaluation in Requirement R3.1 that includes those Planning Event Contingencies that are expected to produce more severe System impacts based on system performance as required in Table 1. " The Statement at the end of R3.4 and R4.4 says "rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would exhibit better system performance." The statement does not make sense and should be deleted since the contingencies selected are those to produce more sever system performance. R3.5 – We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingencies than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.
Requirement R4 should be consistent with R3. Suggested edit for R4. - "For the Stability portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term Transmission Planning Horizon studies in Requirement R2.4. The studies shall be based on computer simulations using models developed from the data provided in Requirement R1." R4.1 should be clarified consistent with comments to R3.1. Suggested

clarification for R4.1 - "Studies shall be performed to determine whether the BES meets the performance requirements in Table 1. A reduced set of contingencies can be simulated based on a list created in requirement R4.4." As currently drafted, R4.3 is not a requirement. Without the statements in R4.3.1-R4.3.3, R4.3 is simply a phrase. Sub-Sub-Requirements R4.3.1 through R4.3.3 should be bullets under R4.3, with the language in R4.3 modified so that it becomes the requirement to conduct contingency analyses that address the three resulting bullets. R4.3.2 – it is not clear what is required to be modeled. Typically a generator may have 10 or more protective relays. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to do that for all generators in the system. Requirement R4.4 also needs to be clarified as follows: R4.4 - "A reduced list of Contingencies can be developed for System Performance evaluation in Requirement R4.1 that includes those Planning Event Contingencies that are expected to produce more severe System impacts based on system performance as required in Table 1. R4.5 – We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingency than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.

The term proxy is unclear. Please provide an example or an explanation of proxy.

We believe that references to FERC Orders should not be included in requirements of standards. This comment also applies to M7.

No

Clarification is needed on the use of UVLS. Is it acceptable or not. Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss Allowed column is No, is load disconnecetd from the system by UVLS a violation? What about Supplemental Load Loss or UFLS?

No

P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements. As such, this is a low probability condition and loss of Non-Consequential load should be allowed for EHV. We disagree with raising the bar for EHV for P4.

We agree that TPL-005 and TPL-006 appear to have been adequately covered in the draft TPL-001-1 as currently written. However, we will need to review this assessment after TPL-001-1 is finalized. In addition, there is no place to state our concerns for Section D. so we've added it here. We question the "not applicable" entry under Section D 1.1.2. What does it mean when the reset period is not applicable? Does it mean there is no reset period, so all non-compliance in all prior years will be counted as prior violations when considering non-compliance in future years? OTHER COMMENTS: Would like to see TPL-001-1 more specifically address system performance required for radial load areas served by multiple transmission circuits (unequal capacity) from a single source substation. For example, a radial load served by a single circuit 115-kV line and a single circuit 230-kV line. For a single contingency loss of the 230-kV circuit, cannot serve peak load area demand. Is this situation meant to be covered by Category P1 in TPL-001-1? I don't see anything similar to TPL-002-0a, Category B, Note b under Loss of Demand.

Group

Western Area Power Administration

Since the modeling data used for the Planning Assessment is initially created and governed per Mod-10 & Mod-12 Standards, this requirement should be clarified to include “maintain revisions of the modeling data required to perform the Planning Assessment” and not just "maintain system models for performing the studies needed to complete their Planning Assessment”.

Short-circuit studies as related to maintaining adequate protection devices and systems are normally performed either by a specific System Protection Group/Department or System Maintenance Department and should not be in this requirement, but Post-Transient Analysis to mitigate voltage collapse scenarios should be included (includes R2.5.1 & R2.5.2). Also, System Protection including mitigation of short-circuit duty above installed facilities capabilities or for new planned facilities are already covered by the PRC Standards and need not be included and duplicated in the TPL Planning Standard such as in R2.3 & R2.7.

R3.3.3 should be covered in the PRC Standards. While R3.3 is labeled as “Contingency analysis”, R3.3.4 is related to Steady State control and therefore should not be within R3.3.

R4.3.3 need not include the operation of exciters and power system stabilizers as modeling of

these parts of a generation system is already covered in Mod-12 & Mod-13 Standards and therefore are inherent in the dynamic analysis conducted using a program such as the GE PSLF or PTI power system simulation programs.

Yes

Yes

There is information within the notes that is not required to correctly understand and apply the TPL Standard. Examples are: 1. Note 1.a.i – the 2nd sentence is not needed to say what is not an out-of-step occurrence. 2. Note 9 is not needed to clarify what "internal" means.

Yes

Yes

Individual

Edward J Davis

Entergy Services, Inc

• Planned facilities and planned changes to existing facilitiesshould be further defined to ensure facilities or changes that are unlikely to be constructed are not included in the models. See the proposed definition of "planned facilities" in the comments provided to question #8. Facilities included in the models should be only those projects that are committed to by the Transmission Owner or other users of the transmission grid. Consistent with the standard's requirement to include only "firm transmission service"(R1.1.4), uncommitted facilites should not be included because an oversubscription of the grid could occur. • R1.1: Please clarify what the SDT means by "models for the Planning Assessment shall present", expecially for facilities such as circuit breakers, protection system equipment, and new technologies. Models also need to represent existing facilities. • R1.1.2: The phrase, "for each year of the Near-Term and Long-Term Transmission Planning Horizon", should be revised to remove "each year" because there may not be studies in each year. • R1.1.4: Firm Transmission Service - a single source can have transmission service to multiple sinks, and can be associated with transmission service in excess of the capacity of the source. There is a lack of clarity regarding the means by which Firm Transmission Service, a marketing term, is to be included in planning models. Not sure if this is applicable to Requirement 1 or 2.

• The "study area" referred to in R2.3 should be defined. Does it mean external contingency events should be evaluated, or, the effects of internal contingency events on external parties. • It should be clarified that generating facilities are not included in R2.1.4. The strategy may include agreements to share spare equipment among facilities, generation owners, and transmission owners. • In R2.6.4 what is "prudent"? Who decides what is prudent? Recommend that the word be stricken. • R2.6.4 is in conflict with the Implementation Plan. The Implementation plan omits P1 as an event where the "bar has been raised" but R2.6.4 allows the use of non-consequential load and firm transmission service curtailment. Clearly, the bar has been raised for any event, including P1, which allowed the curtailment of non-consequential load or firm transmission service in the existing standard. • In R2.9 is the team requiring that a criteria be set by each Transmission Owner to set a maximum level of non-consequential load loss allowed by that Transmission Owner, or, that the amount of non-consequential load curtailment needed to meet the requirement be documented? • What is the rationale for being so prescriptive in requiring specific years to be studied in R2.1.1? Why not allow the TP and/or PC to decide on the three years to be studied in the Near Term? • In the subrequirements of R2.1.3 and R2.4.3, the use of the word "timing" is unclear. Consider using "in service date" or "schedule for". • R2.1.4: The spare equipment strategy is too severe. The requirement should take into consideration the probability of occurrence of the events. Losing a transformer followed by the loss of a generator and a second transmission element is very unlikely. Non-consequential load loss should be allowed for this type of analysis. • With the elimination of the distinction between system and generating plant stability studies, the blanket requirement in R2.5.1 that all stability analyses be five calendar years old or less, regardless of any material changes to the system, would cause needless work to be performed on those plants or areas of the system where no changes are occurring. Recommend adding the following to the end of R2.5.1: "unless justification can be provided to demonstrate that the results of an older study are still valid." • In R.2.4.1 it is mentioned that an aggregate System Load model that represents dynamic behavior of the load is acceptable. Does it mean that load at every bus in the study area has to be represented with an aggregate load model? This could be very cumbersome effort and we are not sure whether the software program can handle this magnitude of dynamic data. To help address this, revise "Load" to be "Load that could impact the study area is acceptable. • In Requirement R2.6.2, please clarify the definition of "project initiation date". • Please explain the reason why Requirement

R2.8 is needed in the Assessment and how does reporting the largest Consequential Load Loss impact reliability? • Please explain the reason why Requirement R2.9 is needed in the Assessment and how does reporting the largest Non-Consequential Load Loss impact reliability? • Please clarify the use of the word "permissible" in the phrase "maximum permissible Non Consequential Load Loss".
• In R3.5 what would constitute "an evaluation of possible actions designed to reduce…" R3 should be broken into two pieces where the near term portion could be a Medium VRF but the long term section should be a Low VRF. Violations occuring in the longer term horizon are subjective and assumptions concerning future plans too broad to justify a Medium VRF. • In Requirement R3.1, it is suggested that the word "contingency" be added to describe the lists created in R3.4.
• In R4.5 what would constitute "an evaluation of possible actions designed to reduce…" • R4.3.2 requires that voltage ride through capability be analyzed. It is not clear what should be analyzed (e.g. auxiliary loads, generator protection, generator capability, etc.) This requirement needs more clarity. • R4.3.2 – By in large, the industry does not have the input data or the methods to do this. It would seem necessary to have PRC-024 approved before this can be met.
• M5 doesn't make any sense. Need to revise this Measure so that it fits the Requirement R5. Also need to revise the Data Retention discussion in Section 1.4 to align with R5. • In the VSL associated with R5, we believe that failure to define and document the proxies should be a moderate VSL.
No comments.
• This requirement is addressed through FERC Order No. 890 (9 principles of transmission planning).
No
• Include a definition of "planned facilities": Facilities that address the near-term deficiencies and have been approved with a financial commitment. • In Posting #2, undervoltage load shed, underfrequency load shed, and Special Protection Schemes were considered to be Non-Consequential Load Loss. Are these now no longer considered to be Non-Consequential Load Loss but instead now considered to be Load Reduction, Supplemental Load Loss, or something else?
No
• P2.1 should allow the shedding of load along the line that would be served radially to mitigate overloads or undervoltages on the radial line. Doing so would clearly not result in degradations to the BES but only the local area served by the radial line. • P4.5 is an extremely unlikely occurrence and should be equivalent to P4.6. • P5 should not be a planning event. PRC standards address Protection systems. The complexity associated with identifying and simulating such events is unknown and the defense of assumptions made and events simulated will lead to inconsistency in compliance and enforcement. Industry accepted proxies for such events could be developed that would allow for efficient identification of areas needing further detailed study. Attempting to intermingle protection system operation with BES performance will be nearly impossible to implement given current technologies. • In general, the entire table should be reconciled, one way or another, with MOD standards governing ATC/AFC. If multiple contingencies, protection system failures, breaker failures, and other less likely events must be planned for, then ATC/AFC processes should be equally limited, at least for long term service. Any service granted on a simple N-1 basis should be Conditional Firm. Anything less than interconnection-wide application of more stringent AFC/ATC evaluation processes commensurate with the long term planning standards will result in the shifting of costs and risks from wholesale users to retail rate payers.
Yes
• Units obligated to re-dispatch must include all Network Resources
No
• P1 events needs to be correctly classified as "raising the bar": P1 events should be included in the bulleted list of areas where the "bar was raised". The paragraph beginning at the bottom of page 2 of the Implementation Plan clearly states that the bar was raised "because loss of Non-Consequential Load or interruption of firm transfers is no longer allowed". Since P1 events in the existing standard allow this, the revised P1 events should be categorized as a raising of the bar. • Effective date needs to be extended: Additionally, in the areas where the bar has been raised, the effective date needs to be extended to at least 7 years. Siting (environment assessment and permitting, right-of-way acquition, regulatory approvals) alone for many of the facilities likely needed can take 3 years or more in some areas. Likely delays due to litigation and affected stakeholder intervention must be considered. In addition, while the SDT has collected some cursory estimates of the costs which may be passed on to end-use customers, no discussion of the intended or expected increase in reliability has been published. Other considerations that will have an impact on the effective date are construction outages on the bulk transmission system and competition of resources (human and material). • Effect on reliability is not adequately quantified: Since one of the SDT's objectives is to ensure that "requirements set at an appropriate level to ensure reliability,"what reliability metrics are expected to be impacted? By

how much? What will the billions of dollars spent on transmission procure in terms of reliability to ratepayers? To what degree would the proposed standard decrease the probability of a blackout? If a blackout were to occur, would the proposed standard tend to decrease or increase the size and magnitude of the event? • More time is needed for entities to determine the appropriate dynamic load model required by R2.4.1. We recommend at least 36 months before this requirement becomes effective. • Since breaker duty is a new "raising the bar" issue - should there also be a 5 or more year implementation plan for this as well? • If a Transmission Planner has a Corrective Action Plan identified within the accepted time limitations but the facilities identified in the CAP cannot be implemented in time, would the TP be found non-compliant on the TPL-001-1? • If contingencies in one utility's system results in issues within another utility, who is responsible for studying the contingencies and who would be responsible for documenting the CAP?

Individual

Joe Knight

Great River Energy

R1.1 is just repeating what should already be in the MOD-010 and MOD-012 requirements. Why re-iterate this in the TPL standard? The planners are expecting that the model building process will already include these components listed in R1.1 otherwise there wouldn't be a functional model. R1.1.1 may be the only thing that needs to be identified in R1 as any known long-term outage or retirement of a facility may have happened after the model building process. If R1.1 is kept I would suggest removing "Models for" so that R1.1 reads "The Planning Assessment shall represent: R 1.1.1 says the assessment shall represent planned outages if specifically known. It does not however distinguish the length of the outage to be considered. Should a 1 week maintenance outage in Year five be included? Should a 2 year complete rebuild outage lasting through year two and three be included? It is GRE's opinion that the SDT needs to add a comment about the length of the planned outage and its relevance to the assessment. In the Violation Severity Levels, R1 seems to be weak since any solved model should meet this requirement. Again this would seem to be more related to the MOD010 and MOD012 process. R1 should focus on documenting changes that are being preformed against the data that was submitted in MOD-010 and MOD-012 process.

R 2.1, 2.3, and 2.4 need consistency. 2.1 says "The Near-Term Transmission Planning portion of the Steady State analysis..." 2.3 says "The short circuit portion of the Planning Assessment ... addressing the Near-Term Planning Horizon..." 2.4 says "The Near-Term Transmission Planning portion of the Stability analysis..." These three sentences confuse the order. As I understand the Planning Assessment has two parts, a Near-Term portion and a Long-Term portion. Each of those parts has three components, a Steady state component, a Short Circuit component, and a Stability component. I believe the standard's language should be structured as such. R2.1.3- The last bullet would seem to indicate that planners have the capability of predicting the future. The statement would seem to fit more in an operating standard. A suggested revision would be: Known long-term transmission outages with duration greater than one year R 2.1.4 addresses the spare equipment strategy. What is the scope of this sensitivity? Is the intent to do only a full steady state analysis with regard to long lead time spares? R2.6.2 would seem to be placing the planner again in the capability of predicting the future. Coming up with specific dates based on budgets, projected growth rates, potential permitting issues, and material delivery schedules would make it difficult to define an initiating date and an in-service date. An in-service season and year may be more applicable in a planning study for near-term projects. GRE is not sure why an initiating date is of relevance in an assessment.

R3.3.3 The relay loadability section needs better definition. Is this identifying that: if the relay load limit is the most Limiting Element of a transmission line how it would be handled if it is overloaded considering that there may be some margin before opening the line and/or if the line reaches a certain overload level based on a non-Relay Load Limit being the Most Limiting Element that the relay load limit should be analyzed to see if it will actually activate an opening of the transmission line or the planners need to review all of the relays associated with all transmission lines within the model and indicate if loadability is a concern for each contingency analyzed. There are a lot of lines, (probably the majority), that have not defined a relay capability within the rating fields of the model! This would seem to be a FAC-009 issue. As a discussion point on R3.3.3, it would seem that relay loadability should be addressed in FAC-009 and the Model Building process. Putting this burden in the planning assessment will be difficult to determine if the Most Limiting Element within the model is not a relay load limit as those parameters typically are not the Most Limiting Element. Every line in the model may need to be defined as to what its relay loadability is to meet this requirement. Our regional model build reports a Most Limiting Element, a short term emergency level, and a long-term emergency for the three ratings available within the model. It would seem that the long-term emergency field should be replaced with a Relay Load Limit value such that the R3.3.3 would not be as great of a burden on the planner.

No

Why is the P needed in defining the category? They all have a P. Top note f and i should reference the Planning criteria established by the Planning Coordinator (or the Transmission Owner if more restrictive). The Transmission Owner is typically the one that sets the limits on their facilities. The Planner just works for the Owner.

Individual

Pat Harrington

BC Hydro

Comments: Consider just referring to the MOD series of standards, not specific individual MOD standards because the numbering of the MOD standards could change and additional relevant MOD standards could be added. Consider rewording the second sentence to read, "The data and models shall meet all requirements of the MOD series of standards." The MOD standards should include the requirements of regulatory authorities and other legal obligations and need not be repeated in the TBL standard(s). R1.1.2: Consider changing to, "New planned Facilities and planned changes to existing…" and changing the fifth bullet to read, "Normal actions of Protection System equipment" R1.1.3: Consider changing to, "End-use customer loads and generators" [how small loads are aggregated should be covered in the MOD standards. A key point is that large industrial customers with significant generation that reduces their net peak demand should not be represented simply as a net load since that would not properly model the dynamic impacts of the load and generation components]. R1.1.4: Consider changing to, "Worst-case transfers on Firm Transmission Service Reservations". R1.1.5: Consider removing this requirement. It should be covered by R1.1.4 R1.1.6: Consider changing to, "Generating units" [the MOD standards should specify the details like how exciters, governors and associated control equipment must be modeled] Comment on M1: Consider changing to, "…using data consistent with the MOD series of standards, simulating …." Consider just referring to the entire series of a particular standard, not specific individual standards because the numbering of the standards being referenced could change and additional relevant individual standards could be added.

Comments: Consider changing the second sentence to read, "This Planning Assessment shall use current or past studies, document assumptions, document results and shall cover all analyses needed to clearly demonstrate that the proposed system expansion plan meets all planning criteria and standards." This standard should not limit the studies to only "steady state analyses, short circuit analyses and Stability analyses" none of which seem to be defined anywhere. In some cases it would be appropriate for planning studies to cover analyses of such phenomenon as electromagnetic transients, sub-synchronous resonance, ferroresonance and harmonics. The fact that "Stability" is capitalized suggests that it refers to the definition of "Stability" in the NERC glossary, but that definition reads just, "The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances", but stability analyses (often more properly termed "dynamic simulation studies") usually encompass more than simply electromechanical or voltage stability. Usually voltage and frequency excursions are also analyzed and perhaps temporary overcurrent also (eg, assessing temporary overvoltage levels across series capacitor banks).

R3.3.3: Consider changing it to read, "Demonstrate that, for all Transmission lines, relay loadability standards are met in accordance with the PRC series of standards"

Comments: Consider changing R4.3.2 to, "Confirm proper generator performance under anticipated conditions including low voltage ride-through capability" In R4.3.3, change "VAR" to "var". The IEC has adopted the name var, var (volt ampere reactive power), for the coherent SI unit volt ampere for reactive power. (see: http://www.iec.ch/zone/si/si_elecmag.htm#si_rpo). Is there an overlap between R4.3.3 and the MOD standards? If so, perhaps R4.3.3 should be deleted. If not, perhaps the MOD standard should be expanded to include this. Consider adding R4.3.4, "not simulate any operator intervention"

Comments: The meaning of the word "proxies" in this context seems uncommon making the requirement unclear. Perhaps "proxies" should be replaced with "criteria" or "criteria or proxies".

No

Comments: In almost all instances, the word "horizon" should be changed to "period" in both the definitions and throughout the standard. The word horizon refers to the end of the period; it literally means, "the limit of one's mental outlook" and the horizon is normally the furthest we can see. A long-term horizon-year study would be a study of conditions expected in the last year of the long-term planning period (often the 10th or 20th year). A long-term horizon-year study

would not be expected to refer to a series of studies of each year in the long-term planning period.

No

Comments: Note "d": The term "Normal Clearing" is not well defined. Consider adding a definition in this standard or changing the NERC Glossary definition of "Normal Clearing" to read, "A protection system operates as designed and the fault is cleared in the maximum time that a properly functioning protection system would be expected to take to clear the fault, considering tolerances in normal protection operating times and circuit breaker interrupting times" No generating unit or units totaling more than the Contingency Reserve of the Balancing Authority (or Reserve Sharing Group if applicable) shall be disconnected from the System by a Special Protection System Note "e": Consider changing to, "For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are automatic (ie, implemented by a NERC-certified Special Protection System, SPS) and executable within the time duration applicable to the Facility Ratings. For P1 and P2 events, (a) generation shedding shall be limited to the normal level of Contingency Reserve of the Balancing Authority (or Reserve Sharing Group if applicable) that would be carried in the control area under the system conditions being studied and (b) no manual operator actions should be necessary to ensure Facility Ratings are not exceeded. Note that, in the operating time frame, the operator would immediately take whatever actions and system adjustments are needed to prepare for the next set of possible contingencies". It should be recognized that this will result in a higher transmission planning standard than the previous wording and that should be seen as a desirable outcome of updating the NERC standards since transmission system reliability (or lack of it) is the impetus for the whole Mandatory Reliability Standards (MRS) process. It should also be emphasized that PLANNING standards are necessarily conservative, simple and easy to apply since in the planning time frame all possible circumstances that might be encountered in the operating timeframe cannot be assessed or nothing would ever get built. If operator action is permitted "if such adjustments are executable within the time duration applicable to the Facility Ratings", how will that be measured consistently to ensure the standard is met? One planner might count on five operators having nothing to distract them from adjusting the output levels of 10 plants to reduce the load on a line to below its 10-minute overload rating, whereas another might be more conservative and assume some of the operators may be busy with other things and be more conservative in estimating how much can be accomplished in 10 minutes. If no operator action is permitted, the standard is easily measured and a more secure system results, one of the main objectives of the MRS. The addition of the requirement that criteria are met without operator action is consistent with R3.3.1 that states "[Contingency analysis shall] simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention [emphasis added]". Performance Category P7: Consider changing the first event to, "All circuits on common structures" and consider changing the fault type to 3-phase. Extreme Events (Steady State): Consider changing item 1 to read, "With an initial condition of a single generator, Transmission Circuit, DC Line (one pole), shunt device or transformer forced out of service and prior to System adjustments, a second generator, Transmission Circuit, DC Line (one pole), shunt device or transformer is forced out of service." Extreme Events (Stability): Change item 1 to read, "With an initial condition of a single generator, Transmission Circuit, DC Line (one pole), shunt device or transformer forced out of service and prior to System adjustments, apply a 3Ø fault on a second generator, Transmission Circuit, DC Line (one pole), shunt device or transformer." Change item 2.g to read, "3Ø fault on all Transmission lines on a common Right-of-Way. Simultaneous 3Ø faults on all lines on a common right of way seems more likely (plane crash, avalanche, earth quake, wildfire) than simultaneous SLG faults. Footnote 1: Consider changing Item 1.a.I to read, "For Planning Events P1 and P2: No generating unit or units…." And consider adding the following sentence, "No generating unit or units totaling more than the Contingency Reserve of the Balancing Authority (or Reserve Sharing Group if applicable) shall be disconnected from the System by a Special Protection System". Footnote 8: Consider changing to, "Opening of Breaker(s) w/o fault in category P2 includes the situation in which one end of a normally networked Transmission circuit becomes open-ended, possibly resulting in voltage deviations outside acceptable limits especially at the open end of the line". Using the phrase "Opening of Breaker(s) w/o fault" that is used in the "event" column of category P2 will help people make the connection to the footnote.

No

Comments: Consider changing Footnote 10 to read, "Curtailment of firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled ["title" is a noun, not a verb and "titled" is an adjective meaning having a title, esp. of nobility] 'Initial System Conditions') and a corrective action provided both are accomplished automatically by a NERC-certified SPS, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings

in those regions must be considered.

Individual

Marie Knox

Midwest ISO

Generally the Midwest ISO agrees with FirstEnergy's comments regarding this requirement. However, if the SDT insists on keeping this requirement as is then we propose the following corrections specific to each requirement. Specific Comments for Requirement 1: A) Under R1 there is language that references "other data sources"; can the SDT please offer some clarification on what "other data sources" are to be? Could other data sources be Tariff requirements? B) Again under R1, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R1 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning". C) Under R1.1.1 it is required that models represent planned outages of generation and transmission facilities, if specifically known. This does not allow or require a Transmission Planner or Planning Coordinator to include outages due to maintenance and/or due to construction programs where certain facilities are out of service during various phases of construction, as part of the Assessment. For this reason, we believe the following language for R1.1.1 would improve this requirement: Planned outages of generation and Transmission Facilities if specifically scheduled or planned for. D) Under R1.1.1 we suggest adding sub-requirement R1.1.7 Generation dispatch patterns deemed appropriate by the Transmission Planner and Planning Coordinator. This clarifies that when building System models, generation dispatch is part of the model building process. E) Under R1.1.2 there is uncertainty around the language of "New planned Facilities". We offer the following definition for Planned Facilities to be added to the definition section of this standard and further added to the NERC Glossary of Terms: Planned Facilities – Generation and Transmission Facilities that are expected to be implemented with an in service date prior to the plan year being studied. F) Under R1.1.2 a bullet should be added for "Relay Loadability Limitations". The standard requirements for relay loadability are included in PRC-023-1.

Opening Remarks. Specific Comments for Requirement 2: A) Under R2, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R2 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning". B) Under R2.1 there is a reference to qualified past studies in R2.6. We believe that this reference should be pointing to R2.5 not R2.6. C) Under R2.1.3 there is ambiguity in the third bullet language "…new or modified Facilities…" and we believe that this language should mimic that of R1.1.2 in order to improve this requirement. The third bullet should read: Timing of the installation of new Planned Facilities or changes to existing Facilities. D) Under R2.1.3 there is ambiguity in the fourth bullet language "…capability…" and we believe that this language should read: Reactive resource capability (Generator, STATCOM, SVC, other…etc). We believe that this language addition improves this requirement. E) Under R2.1.3 there is ambiguity in the seventh bullet language "…Transmission outages…" and we believe that this language should read: Planned duration or timing of specifically scheduled or planned for Transmission outages. This language mimics similar language suggested above in R1.1.1 (letter C on page 3 of 9) F) When a spare equipment strategy does not cover the long lead time unavailability as stated in 2.1.4, will the system be treated as "normal system condition" and Table 1 requirements or as having a contingency from which system adjustments are to be made prior to subsequent events. We believe that this task will be burdensome for large entities such as RTOs and we are not clear on the benefit that this requirement brings. For example: If in an RTO system where a party has spare equipment, how can the RTO ensure that a spare part from one asset owner can be made available to other asset owners? G) Under R2.2 a System peak load study is required annually for one of the years in the assessment period. R2.2.1 requires the assessing entity to extend their planning assessment to accommodate any known longer lead time projects that may take longer than ten years to complete. It does not make sense to study the ten year horizon, find a problem in year ten which has a solution that required twelve years to build. For compliance with this standard, you would need to find another solution that can be built within ten years as opposed to the suggested language in R2.2.1 of extending the planning assessment beyond ten years to accommodate the solution that falls outside of the Long-Term Planning Horizon. No project solution greater than 10 years should be acceptable because it falls outside the Long-Term Transmission Planning Horizon. Suggestion to strike sub-requirement R2.2.1 from this standard. H) Under R2.3 the second sentence requires that "The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study year". We suggest changing the language to read: "The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with Planned Facilities in service which could impact the study year". The definition of Planned Facilities was suggested to be added in the comment above in R1.1.2

under letter (E). I) Under R2.4 the second sentence requires states "The following studies are required". We suggest changing the language to read: "The following current studies are required". We believe that this language addition improves this requirement. J) Under R2.4.1 the first sentence leaves to much ambiguity as to who determines whether severity of system peak or off peak as well as whether the system load levels appropriately represents the dynamic behavior of loads. If the monitoring agency wishes to make this determination than it should be explicitly written here in this requirement. If the assessing entity is to make this determination than we offer the following language suggestion that we feel will improve this requirement. "For one of the five years, the more severe System peak or off peak System load level, as judged by the assessing entity, shall be used which in the judgment of the assessing entity appropriately represents the dynamic behavior of Loads including consideration of the behavior of induction motors". K) For R2.4.2, we suggest striking this requirement altogether and add System Off-Peak to R2.4.1 above in R2.4.1 under letter (I). L) Under R2.4.3 there is ambiguity in the third bullet language "…new or modified Facilities…" and we believe that this language should mimic that of R1.1.2 in order to improve this requirement. The third bullet should read: Timing of the installation of new Planned Facilities or changes to existing Facilities. M) Under R2.4.3 there is ambiguity in the fourth bullet language "…capability…" and we believe that this language should read: Reactive resource capability (Generator, STATCOM, SVC, other…etc). We believe that this language addition improves this requirement. N) The sub requirement R2.5.2 states that for steady state, short circuit, or stability analysis; the "present System model" shall not include any material changes, such as…..etc. The present language in this section is vague and requires discretion on the part of both the Transmission Planner and the Planning Coordinator performing the assessment. For example, new transmission enhancements may have been added since the previous System model was developed. In general, such topology enhancements will only improve reliability and would not necessitate re-assessment with a newly updated System model. In addition, any significant generator additions would have been evaluated with a full separate generator interconnection study at which the full reliability of the System would have been taken into consideration. For this reason, we believe the following language for R2.5.2 would improve this requirement: For steady state, short circuit, or Stability analysis: the current System model of the assessed plan year shall not include any changes material to the assessment, as judged by the entity performing the assessment, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study year. Material generation changes could include: O) Under R2.6.1 the fifth bullet regarding the use of Operating Procedures needs to be made clearer. We believe that the following language will improve this requirement: Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan. Operating Procedures may not include Non-Consequential Load Loss when not permitted in Table 1. P) Under R2.6.1 the sixth bullet regarding the use of rate applications, DSM, new technologies or other initiatives can be improved with the following language additions: Use of rate applications, DSM, new technologies or other demand side initiatives can be improved with the following language additions. Q) Under R2.6.2 the language regarding project initiation date is vague. We suggest the following definition to be added to this standard and further added to the NERC Glossary of Terms: Project Initiation Date – A date in which Planned Facilities are expected to break ground. R) Under R2.8 please add a coma between the words event and caused. A PC/TP would study multiple P1 and P2 events involving consequential load loss not just the largest. Unless the SDT has a measure in mind for consequential load loss, this requirement should be removed. S) Under R2.9 please strike the word permissible and replace with necessary. It is not clear what the SDT is requesting with this requirement.

Opening Remarks. Specific Comments for Requirement 3: A) Under R3, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R3 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning". B) Under R3.1 the "Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the lists created in the Requirement 3.4". We believe that the following language will improve this requirement: Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the more severe contingency lists created in the Requirement 3.4. C) Under R3.3.2 the Midwest ISO generally agrees with FirstEnergy's comments on this. D) Under R3.3.3 the Midwest ISO feels that this sub-requirement is redundant with PRC-023-2 and therefore we feel that this sub-requirement needs to be removed and replaced with our suggested bullet language under R1.1.2 – Relay Loadability Limitation (see F on page 3 of 9 above) E) Under R3.4 to make this requirement clearer, please add the following language between the words "expected to" in the first sentence: …expected by the assessing entity to… We believe that this language addition improves the clarity of this requirement. The first sentence would then read: Those Planning Event Contingencies in Table 1 that are expected by the assessing entity to produce more severe System impacts shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3.1 created. F) Under R3.5 to make this requirement clearer, please add the following language between the words "expected to" in the first sentence: …expected by the assessing entity to… We believe that this

language addition improves the clarity of this requirement. The first sentence would then read: Those Extreme Events in Table 1 that are expected by the assessing entity to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3.2 created.
Opening Remarks. Specific Comments for Requirement 4: A) Under R4, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R4 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning".
Under R5, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R5 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning".
A) Under R6, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R6 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning".
A) Under R7, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R7 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning". B) The coordination of analysis of results through an open and transparent process is already a FERC requirement thus producing a double jeopardy for those entities that fall under the jurisdiction of FERC Order 890. We recommend striking the following language in the last sentence: ...coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890. C) Under R7 only the Planning Coordinator is required to coordinate the distribution of Planning Assessment results among adjacent PCs and any functional entity who has indicated a reliability need, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890. Should the TP be added to this requirement? We propose the suggested language change: Each Transmission Planner and Planning Coordinator shall coordinate the distribution of Planning Assessment results among adjacent Transmission Planners and Planning Coordinators, respectfully, and to any functional entity who has indicated a reliability need, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890. D) Based on the comments above in (B) and (C), our suggested requirement language is as follows: Each Transmission Planner and Planning Coordinator shall coordinate analysis in support of assessments in accordance with applicable regulatory requirements. Each Planning Coordinator shall distribute its completed planning assessment results among adjacent Planning Coordinators and any functional entity who indicated in writing a reliability related need.
No
Year One: At a minimum the SDT needs to address the applicability of this definition to include both the Transmission Planner and Planning Coordinator. The Year One definition needs additional clarification with the current calendar year. According to the definition, Year One can start any time between 12 and 18 months from a current calendar year. Suggested definition for Year One: The first year that each Transmission Planner and Planning Coordinator is responsible for conducting a Planning Assessment. This is further defined as the planning window that begins at least 12-18 months from the end of the current calendar year.
Yes
The stability studies require significantly more computer time and a more detailed model. The standard should allow the PC/TP to use judgment to manage size and complexity of the study.
Yes
Yes
The 3rd draft states that this will be addressed later in the project. Removal of these standards would not affect NERC and the RE's obligations to perform assessments. Will the PC/TP be obligated under NERC Rules of Procedure to provide Assessments to NERC and the Regions upon request?
Group
NERC Standards Review Subcommittee
N/A
MRO NSRS proposes the following comments for R2: Modify R2.6.2 to remove the obligation to include the project initiation date. The inclusion of this date would add unnecessary work that is not needed to assure adequate BES reliability In addition, it is not clear whether "initiation" refers to the commencement of engineering, design, construction, etc. Augment R2.6.5 to include annual verification of the continued validity of the Corrective Action Plan because the value of implementation status is dependent on the status of continued validity. MRO NSRS

suggests this text: "Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status . . ." Augment R2.7.2 to include annual verification of the continued validity of the Corrective Action Plan because the value of implementation status is dependent on the status of continued validity. MRO NSRS suggests this text that is similar to R2.6.5: "Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status." Remove R2.8., MRO NSRS does not know of any reason why the investigation and inclusion of the largest Consequential Load Loss caused by any P1 or any P2 events is needed to assure adequate BES reliability. In addition, all events involving Consequential Load Loss are studied, not just the largest load loss (see R3.3.1).

MRO NSRS proposes the following comments for R3. Revise the R3.3.2 text to clarify that subsequent analysis is performed on generators whose voltages are expected to fall below the minimum voltage limits. MRO NSRS suggests this text: "Consider the minimum steady state voltage limitations of all generators and identify how generators with bus voltages below its minimum voltage limits are analyzed in the subsequent steady state simulations." Revise the R3.3.3 text to more clearly relate to the specific requirements in PRC-023. MRO NSRS suggests this text: "Incorporate relay loadability per PRC-023 and identify how relay loadability is analyzed in the steady state simulation."

MRO NSRS proposes the following comments for R4: Add R4.3.3 text include relay loadability in the R4 (Stability) requirements to parallel R3.3.3 in the R3 (Steady State) requirement which would more clearly relate to the specific requirements in PRC-023. MRO NSRS suggests this text: "Incorporate relay loadability per PRC-023 and identify how relay loadability is analyzed in the dynamic simulation." In R4.3.4, MRO NSRS proposes limiting the scope to automatic devices and adding the notion of "including but not limited to". MRO NSRS suggests R4.3.4 text of: "Simulate the expected automatic operation of existing and planned control devices including but not limited to generation exciter control and power system stabilizers, static VAR compensators, power flow controllers, and DC Transmission controllers."

MRO NSRS proposes specifying that the proxy documentation be included in the Planning Assessment and add the rationale for the proxy. MRO NSRS suggests this text: "Each Transmission Planner and Planning Coordinator shall document within the Planning Assessment any proxies used in the analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding. The documentation will consist of the definition of each proxy used and the rationale for the proxies.

MRO NSRS is not clear if: 1) Each Transmission Planner is to meet all the requirements including doing all the studies and all Planning coordinators are to meet the requirements including doing all the studies. Or 2) If the Transmission Planner and Planning Coordinator are to work as a team to meet all the requirements including doing all the studies. Either one of them could do various parts of the required studies. For example, maybe the PC could do the stability part so all TP's would not necessarily have to buy that software if they did not need it for other planning purposes. In the first read of this standard, it appears that the intention was number 1, which sounds awfully duplicative. But then take a look at Requirement 6. R6. Each Transmission Planner and Planning Coordinator shall determine and identify individual and joint responsibilities for performing the required studies for the Planning Assessment. [Violation Risk Factor: Low] [Time Horizon: Long-term Planning] After reading R6, it appears that number 2 was intended. Perhaps R6 should be the very first requirement in the standard. The MRO NSRS requests that the NERC SDT clarify the responsibility of the requirements of this standard.

MRO NSRS proposes expanding the scope of entities to consider, limit it to those entities that indicate a reliability need for coordination, and eliminate the direct reference to Order 890. MRO NSRS suggests this text: "Each Planning Coordinator shall establish a list of adjacent Planning Coordinators and any functional entity who has indicated a reliability need, distribute its Planning Assessment results to the listed entities and consider comments on the assumptions and results through an open and transparent peer review process."

No

MRO NSRS suggests the following comments: Add a Consequential Generation Loss definition because both load and generation loss can be considered, but there is only Consequential Load Loss definition. MRO NSRS suggests text of: "Consequential Generation Loss: All Generation that is no longer delivered to any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions." Expand the Consequential Load Loss definition to include protection for abnormal operating conditions. MRO NSRS suggests text of: "Consequential Load Loss: All Load that is no longer served by any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions." Expand the Load Reduction definition to include consideration of TOP judgment and established protection schemes. MRO NSRS suggests text of: "Load Reduction: The reduction of Load that is still connected to the System, but in the judgment of the Transmission Operator or through the previous established Special Protection Systems, Under-Frequency Load Shedding programs, Over-Frequency Load Shedding program, should be reduced to overcome to lower voltage

conditions following a Planning or Extreme Event." Modify the Planning Assessment definition to more explicitly apply to the BES and the TPL-001 requirements. MRO NSRS suggests text of: "Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies in the BES from the steady state and stability performance requirements set forth in the TPL-001 standard." Modify the Planning Events definition more explicitly apply to the TPL-001 requirements. MRO NSRS suggests text of: "Planning Events: Events that are identified in the steady state and stability performance requirements set forth in the TPL-001 standard." Expand the Year One definition to include the PC, refer to the Planning Assessment, and refer to the current calendar year. MRO NSRS suggests text of: "Year One: The first year that each Transmission Planner and Planning Coordinator is responsible for conducting a Planning Assessment. This is further defined as the planning window that begins 12-18 months from the current calendar year." MRO NSRS would like to delete the definition of "Year One". This is already being done and adding a planning window opens entities to noncompliance for conditions i.e. Model building outside of entities control.

No

MRO NSRS suggests the following changes: MRO NSRS believes reference to the use of Load Reduction to meet steady state performance requirement was omitted in Planning Events, Steady State and Stability, Item b. MRO NSRS suggests modifying the last sentence in Item b: "However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirements." MRO NSRS proposes limiting the scope to automatic devices in Planning Events, Steady State and Stability, Item c. MRO NSRS suggests text of: "c. Simulate the removal of all elements that Protection Systems and other Controls are expected to disconnect automatically for each Contingency". Modify the P3 Category performance criteria to apply only to the loss of two generators because probability of the loss of two base load generators is an order of magnitude higher than the loss of a generator and any other transmission element. MRO NSRS suggests the listing of: the loss of transmission circuit, transformer, shunt device, and single pole of DC line be removed from the P3 Events column. The corresponding events be moved to the P6 Category by "1. Generator" to the listing in the Initial System Condition (Loss of . . .) column. Limit the scope of the simulations in Item 1 of the Extreme Events, Steady State and Stability section to automatic systems and controls. MRO NSRS suggests this text: "1. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect automatically for each Contingency." Clarify the meaning of the loss of multiple circuits in Item 2.a of the Extreme Events, Steady State section by using wording similar to P7. MRO NSRS suggests this text: "a. Loss of three or more circuits that share a common structure." Clarify the reference to actual, historical operating experience in Item 3.b of the Extreme Events, Steady State section. MRO NSRS suggests this text: "b. Other events based upon actual operating experience that may result in wide area disturbances." Clarify the reference to actual, historical operating experience in Item 2.i of the Extreme Events, Stability State section. MRO NSRS suggests this text that is similar to Steady State, Item 3.b: "i. Other events based upon actual operating experience that may result in wide area disturbances." Further clarify the applicable shunt devices in Footnote 7 with this suggested text: "7. Requirements which are applicable to shunt devices, also apply to FACTS devices that are connected to ground, but not instrument voltage transformers or surge arresters."

Yes

N/A

No

MRO NSRS offers the following comments. The last paragraph should be removed from the Effective Date section. This paragraph contains requirements and describes compliance procedures, rather than stating effective date details. If any requirements regarding Corrective Action Plans are included, then they should be placed in the R2 section. If descriptions of compliance procedures related to Corrective Action Plan implementation are deemed to be necessary, then they should be placed in NERC procedure documents. This standard should not contain any requirements regarding the implementation of Corrective Action Plans. The implementation of transmission system action plans depends on the actions (e.g. financing, regulatory approval, legal services, engineering, construction, commissioning) of many different entities, other than PCs or TPs. So, PCs and TPs should not be held responsible for the implementation of action plans since they have little or no control over the activities related to implementation. The standard could include requirements that obligate PCs and TPs to develop Corrective Action Plans that are executable (i.e. plans that are based on lead times that provide reasonable assurance that the planned facilities can be placed in service by the time that they are needed) or devise revised Corrective Action Plans when they learn that the actions plans are not expected to be implemented by the intended in-service date. The standard could also include requirements that obligate PCs and TPs to establish and apply project implementation lead time assumptions that are derived from historical experience and the implementation lead time projections from the applicable TOs, GOs, and DPs. Remove or modify the 60 month effective date statement because it's impractical and unreasonable. The effective date for performing analyses and developing subsequent Corrective Action Plans is 24 months. This leaves only 36

months to expect that the more stringent Corrective Action Plans would be implemented. It is improbable that all action plans related to BES facilities, especially above 300 kV could be implemented. Some EHV projects can take 5 to 10 years to implement depending on the size, complexity, and controversial nature of the project. MRO NSRS suggests that the effective date be stated in a more "implementation dependent" rather than a "fixed timeframe" manner. Consider wording such as "tripping of Non-Consequential Load or curtailment of Firm Transmission Service (in accordance with Requirement R2.6.4) is allowed until Corrective Action Plans based on TPL-001-1 analyses are implemented".

Individual

Jessica Rice

NV Energy

The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices where it is expected to impact the study outcome. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted. We disagree with the inclusion of the words "including requirements of regulatory authorities and other legal obligations" at the end of R1. Entities already are required to do this. It does not need to be included in the standard.

Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). R2.1.3 should be modified to remove the last bullet point. Transmission outages should be a part of operational study work not planning study work. Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement. The 20 MW threshold identified as "material change" for generation in R2.5 is too small. The limit should be based on a percentage of the study area's installed generating capacity. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the "largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event" if it is documented? R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.

As currently drafted, R3.3 is not a requirement. Without the statements in R3.3.1-R3.3.4, R3.3 is simply a phrase. Sub-Sub-Requirements R3.3.1 through R3.3.4 should be bullets under R3.3, with the language in R3.3 modified so that it becomes the requirement to conduct contingency analyses that address the four resulting bullets R3.3.2 is unclear as drafted. The minimum steady state voltage limitation for synchronous generators is not a very meaningful value. All generators with an automatic voltage regulator will maintain the set point voltage until the VAR capability of the generator is exceeded, and then the voltage will deteriorate. R3.5 – We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingencies than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.

As currently drafted, R4.3 is not a requirement. Without the statements in R4.3.1-R4.3.3, R4.3 is simply a phrase. Sub-Sub-Requirements R4.3.1 through R4.3.3 should be bullets under R4.3, with the language in R4.3 modified so that it becomes the requirement to conduct contingency analyses that address the three resulting bullets. R4.3.2 – it is not clear what is required to be modeled. Typically a generator may have 10 or more protective relays. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to

do that for all generators in the system. R4.5 – We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingency than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.
The term proxy is unclear. Please provide an example or an explanation of proxy.
No Comments
We believe that references to FERC Orders should not be included in requirements of standards. This comment also applies to M7.
No
Claification is needed on the use of UVLS. Is it acceptable or not. Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss Allowed column is No, is load disconnecetd from the system by UVLS a violation? What about Supplemental Load Loss or UFLS? We are also wondering how loads that have interruptible rates should be handled.
No
P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements. As such, this is a low probability condition and loss of Non-Consequential load should be allowed for EHV. We disagree with raising the bar for EHV for P4.
Yes
No
We agree that TPL-005 and TPL-006 appear to have been adequately covered in the draft TPL-001-1 as currently written. However, we will need to review this assessment after TPL-001-1 is finalized. In addition, there is no place to state our concerns for Section D. so we added it here. We question the "not applicable" entry under Section D 1.1.2. What does it mean when the reset period is not applicable? Does it mean there is no reset period, so all non-compliance in all prior years will be counted as prior violations when considering non-compliance in future years? Why is this changing from an annual reset period in the current standards?
Individual
Mark Kuras
PJM
In R1, why require a Planning Coordinator AND a Transmission Planner to maintain models for the same area? Concern with the words –- for each year—in R1.1.2. Does this mean that a case for each year, at least, will need to be produced? Will five, one for each season and a light load, each year need to be produced? R1.1.5 is not clear. Is the Interchange exclusive of Firm Transmission Service as mentioned in R1.1.4? Maybe –-non-firm transmission service-- is clearer.
In R2, why require a Planning Coordinator AND a Transmission Planner to perform this analysis? Isn't this a duplication of effort? In R2, I have always heard that dynamics studies are performed to determine Stability. In R2.1, need to update reference to R2.6 from R2.5. In 2.1.1 and R2.1.2, is this annual peak or seasonal peak? Summer peak for summer peaking entities and winter peak for winter peaking entities or both summer and winter peak for all entities. R2.1.1 year one or two studies should be only required as operating studies. By their nature, the upgrades or fixes that could be accomplished in this time frame are limited to short lead time fixes. These analyses are needed to determine how to accommodate construction schedule deviations and near term system issues that may cause issues. Traditional Planning studies will be of no benefit in this timeframe. Change the requirement to be a study for year 3,4 or 5 with updates for material changes that occur when a previous year study is still within this time frame. R2.1.2 and R2.1.1 should be combined and the TP should assess and justify its choice of the critical load scenarios to analyze. Concerned about the extent of variations required in R2.1.3. Like would I have to vary all proposed generator in-service dates? Just a couple? One? Requirements need to be clear or compliance will assume the largest scope possible. Also in R2.1.3, first bullet words should align with the words of R1.1.3. Also in R2.1.3, second bullet words should align with words of R1.1.4 and R1.1.5. Also in R2.1.3, third bullet, modified facilities are not installed, suggest changing –-installation— to –-availability--. Also in R2.1.3, fifth bullet, suggest moving –retirements-- up to third bullet and dropping -- Generation additions, retirements, or other…-- leaving just –dispatch scenarios— R2.1.4 should be deleted. There are no NERC requirements on spare equipment availability and this requirement seems like

a backhanded way to include such a requirement. R2.2.1 should be reworded because it now requires everyone to extend their studies. Suggest –If planned projects will take longer than ten years to complete, the Planning Assessment shall be extended accordingly- R2.4.1 – Not sure I understand. The second sentence and the third sentence seem to be in conflict R2.4.2. This requirement has lost significance with the deletion of unit stability. Off-Peak scenarios are critical for unit stability and analysis of pockets of known light load stability sensitivity. This requirement should not be worded to require a general system off-peak stability study since this will not provide useful information. The requirement should be reworded to clarify that the TP should identify its critical off-peak stability sensitivities and provide annual stability analyses that address the system's off peak stability issues. R.2.4.3 should only refer to R2.4.1 since R2.4.2 are sensitivities themselves. In R2.4.3, first bullet, how would load model assumptions be varied? Same comments on bullets here as R2.1.3 above. R2.5.2 is impossible to judge. Material changes needs to be defined. The word –could— in the sentence before the bullets makes them useless as a definition. By trying to define material changes the SDT has created a situation where, for large interconnection, it would be virtually impossible to use a past study. The addition of a 100 MW generator two states removed from the study area would not be considered material but by the guidelines in this requirement it can be interpreted as such. R2.5.2 Add that retools of past studies that address the local impacts of specific cumulative material changes that occur are sufficient to continue to support current planning assessment. R2.6 has a mixing sigular and plural tenses. What if only one problem is found and therefore only one Corrective Action Plan is needed. Or can one Plan cover all the problems found? Responses to R2.8 and R2.9 would be considered Critical Energy Infrastructure Information (CEII) and that should be noted so it can be protected. R2.8 and 2.9 change to read that the Planning Coordinator will provide its criteria for load loss that is adheared to for all events.

In R3, why require a Planning Coordinator AND a Transmission Planner to perform this analysis? Isn't this a duplication of effort? R3.4 should come before R3.1. You should never reference down in a standard. Please present the items in the order in which they should be performed/considered. R3.5 should come before R3.2. You should never reference down in a standard. Please present the items in the order in which they should be performed/considered. R3.3.2 should be broken into two requirements since two separate tasks need to be performed. R3.3.3 should be broken into two requirements since two separate tasks need to be performed. Also in R3.3.3, analysis of relay loadability will require the inclusion of all relay models 200 kV and above. This information is not presently gathered by the ERAG MMWG for the Eastern Interconnection. To help with compliance, questions R3.3.4 needs more specificity. Maybe define a minimum percentage of total possible contingencies as a bright line whether you have performed enough more severe contingencies. Would expect a number between 10 and 25 percent. R3.4 should be broken into two requirements since two separate tasks need to be performed. To help with compliance questions, R3.3.5 needs more specificity. Maybe define a minimum percentage of total possible contingencies as a bright line whether you have performed enough more severe extreme contingencies. Would expect a number between 10 and 25 percent. R3.5 should be broken into three requirements since three separate tasks need to be performed.

In R4, why require a Planning Coordinator AND a Transmission Planner to perform this analysis? Isn't this a duplication of effort? R4.4 should come before R4.1. You should never reference down in a standard. Please present the items in the order in which they should be performed/considered. Also in R4.1, a space is needed between –Requirement— and -R4.4-. R4.5 should come before R4.2. You should never reference down in a standard. Please present the items in the order in which they should be performed/considered. In R4.2.3, I question whether the existing dynamics models can evaluate voltage ride through. If you are just talking about modeling voltage protection of generators then maybe, but this protection information is presently not collected by the ERAG MMWG for the Eastern Interconnection. R4.4 should be broken into two requirements since two separate tasks need to be performed. R4.5 should be broken into three requirements since three separate tasks need to be performed.

R7 needs to be broken into two parts. First establish the list of entities that need to get the assessment results. Second would be to coordinate the results as mentioned. Are the results mentioned in R7 different from the Planning Assessment?

No

Planning Events and Extreme Events should refer to the lists in the tables since there is no other way to understand which contingency falls into what definition. The designation is deterministic and somewhat arbitrary but commonly accepted.

No

Table 1, Lead in Note I. The industry has not yet reached a consensus on appropriate Transient Voltage Limits. It's not clear that reliability will be enhanced by requiring each entity to establish a Transient Voltage Limit. Table 1 footnote 1 - System stable means: a. Angular Stability: i. For Planning Event P1: No generating unit or units shall be allowed to pull out of synchronism. A

generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism. This is not consistent with Loss of load whereby load can be lost due to a first contingency within contractual arrangements made with the load. This definition should be modified to read -A generator being disconnected from the System by fault clearing action or by a Special Protection System or prior arrangement…- as long as no other cascading outages occur. In Table 1, Extreme Events, Item 3a, i, ii, iii, iv and vi seem like events that would occur over long periods of time not in contingency simulation time frames. They seem more like sensitivities. Table 1 Delete P5 is the preferred option. If not deleted need to clarify that so that related or additional -faults in the vicinity of- are considered. As currently worded it can require all simultaneous N-2 combinations within some number of substation radius for which overtrips could occur. You would have to do all combinations since they are unpredictable. If the SDT means for the relay failure to be located at or very near to the initiating event, then perhaps the combinations are more manageable but still extremely burdensome.

Yes

No

Removal of these standards will not affect NERC and the Regional Entity's obligations to perform assessments. Will the PC/TP be obligated under NERC Rules of Procedure to provide Assessments to NERC and the Regions upon request?

Group

SERC Engineering Committee Dynamics Review Subcommittee (DRS)

There may be a potential conflict between MOD-010 and MOD-012 and legal documents such as Interconnection Agreements e.g. IA may specify a capacity level that exceeds the reported test levels. In the case of such conflicts, which one should rule? An order of precedence is needed as part of this requirement. Suggest adding terminal equipment to the list of planned facilities. The phrase, "for each year of the Near-Term and Long-Term Transmission Planning Horizon", should be revised to remove "each year" because there may not be studies in each year.

1. R2.1.4 –Loss of 2 transformers is itself a very severe contingency. However, when it is combined with R2.1.4 (spare equipment strategy) it can lead to a triple contingenecy which is unnecessarily severe and has an extremely low probability of occurrence. We recommend that the requirement be deleted from the standard. In the subrequirements of 2.1.3 and 2.4.3, the use of the word "timing" is unclear. Consider using "in service date" or "schedule for". With the elimination of the distinction between system and generating plant stability studies, the blanket requirement in R2.5.1 that all stability analyses be five calendar years old or less, regardless of any material changes to the system, would cause needless work to be performed on those plants or areas of the system where no changes are occurring. Recommend add the following to the end of R2.5.1: "unless justification can be provided to demonstrate that the results of an older study are still valid."

R3.3.3 applies to "all Transmission lines." Should this only apply to lines above 230 kV and lines identified as critical below 230 kV? At least this should be limited to BES lines. R3.3.4 says "Simulate the expected operation of existing and planned devices designed to provide Steady State control of electrical system quantities." This should say, "Simulate the expected operation of existing and planned BES devices designed to provide Steady State control of BES electrical system quantities."

None.

We recommend that the word "proxies" be changed to "criteria".

None.

None.

No

There is a need to add definitions to discriminate between planned and proposed projects. We propose the following definitions: Planned Facilities: Facilities that address the near-term deficiencies and have been approved with a financial commitment. Proposed Facilities: Facilities that address long-term deficiencies for which no commitment is required today since they may change based on future evaluation. We propose the following definitions for events: Planning Events: Events which are listed as Planning in Table 1 in Standard TPL-001-1. Extreme Events: Events which are listed as Extreme in Table 1 in Standard TPL-001-1. Bus-tie Breaker definition still seems somewhat generic and the use of 'configurations' causes uncertainty. We propose the following definition: Bus-tie Breaker: A circuit breaker whose intended purpose is to connect two individual substation buses. The definition of Supplemental Load Loss includes the phrase, "by end-user equipment", which could be understood to mean there are devices at the end-user location that remove this equipment (and conversely, load that is not disconnected "by" end-user equipment cannot be included). Also, the term "post-Contingency" can be confusing because in the case of faults, this phrase is not clear if it means conditions after the fault initiation itself or only after the clearing of the fault. We propose the following definition: Supplemental Load Loss: End-user Load that inherently disconnects from the System as a consequence of (or "in

response") to the conditions created by the System event. Load Reduction: A decrease in the amount of connected Load caused by lower voltage conditions following a Planning or Extreme Event.

No

P5 should not be a Planning Event. PRC Standards address protection system failures. The complexity associated with identifying and simulating such events is unknown and the defense of assumptions made and events simulated will lead to inconsistency in compliance and enforcement. Industry-accepted proxies for such events could be developed that would allow for efficient identification of areas needing further detailed study. Attempting to intermingle protection system operation with BES performance will be nearly impossible to implement given current technologies Stability Extreme 2g needs a note like number 12 that excludes short distances. Stability Extreme 2h: Is this meant to be an event initiated by a 3LG fault or is it a catastrophic event that leaves all the elements at a station with a 3LG fault. If it is the former, then 2h needs a note to limit this to locations where actual events could lead to the loss of the entire station. There is no need to study this if there are no protection system events that lead to loss of the whole station (there would be no scenario to model). If 2h is meant to represent some catastrophe that causes all the elements at the site to experience a fault, then some clarification is needed to get consistent studies. Possibly rewrite 2h as, "Assume all the buses at a single voltage level (one voltage level plus transformers) experience an event that results in a 3LG fault and disables local protection (fault must clear from remote stations or other side of transformer)."

Yes

None.

No

More time is needed for entities to determine the appropriate dynamic load model required by R2.4.1. We recommend at least 36 months before this requirement becomes effective. A 60 month effective date seems acceptable for planning activities, but may not adequate for all construction activities. Typical times to construct a transmission line in various areas of SERC can range between 7 to 10 years. Accordingly, we recommend the effective date for construction projects be changed to at least 84 months.

Individual

David Albers

Brazos Electric Cooperative

no comment

In R2.1, end of paragraph i believe you mean Requirement 2.5, not 2.6. In R2.6.2 we believe maintaining a 'project initiation date' serves no purpose and should be deleted. These dates are wildly variable given the nature of each project and the numerous issues that can affect these dates. 2.6.2 and 2.6.3 should be combined to simply require an in-service year/date and allow the owners to work as needed to meet these dates. We think R2.9 should be deleted as it is vague in nature, seems to serve no purpose and would be hard to verify the accuracy of the value in an audit. 2.8 is direct and can be easily detailed for an audit.

R3.4 and 3.5 give us a concern. Table 1 identifies a number of events that are to be assessed but requiring an explanation of why certain events would produce less severe results seems to be open ended thus making it hard to audit. If all the events in Table 1 are studied or have been studied in the past then what is one supposed to document? we understand this is to allow the planner a certain amount of flexibility in their analysis but it seems counter to the idea of requiring a review of all the events in Table 1. We don't have any suggested wording changes, just passing along a general idea.

Same general comment in 4.4 and 4.5 about the requirement to maintain documentation on why certain events would produce less severe results.

no comment

is there any other way to identify responsibilities between the parties than having an agreement? R6 seems to indicate an agreement of some sort must be in place. if that is the case then it could simply say an agreement must be in place.

no comment

Yes

No

For the most part Table 1 is acceptable but not entirely. The general 'feel' is that more studies are required. Requiring more studies is not going to provide additional reliability benefit but Brazos does not own many miles of transmission above 300 kV so the impact will be less for us than other larger TOs. We do not see the purpose of studying events where all forms of load loss is allowed. We understand upgrading the transmission system for these events is not required and is unneeded so why study certain events other than to insure that cascading outages don't occur? Without running a full set of studies it is a little hard to determine if Table 1 can be

readily assessed or the true value of the additional studies.
Yes
no comment
Yes
no comment at this time
Individual
James H. Sorrels, Jr.
American Electric Power
Under R1.1.2., Add "Transformers", otherwise, revise "Transmission Lines" to read "Transmission Facilities". Also under R1.1.2., add "Series Reactors and Capacitors" as a distinct category of facilities from "Reactive Power devices" that include shunt capacitors and reactors, and "Control devices" that include phase angle regulating and variable frequency transformers, FACTS devices, and other power electronics. These additions would further clarify the types of facilities that should be included, and these comments are made in full recognition that the introductory sentence to R1.1.2. contains the wording "such as".
AEP agrees with R2.3., but should note that the planning horizon short circuit models are not presently developed in any systematic fashion, since, unlike the development of steady-state (power flow) and stability models that are mandated under MOD-010 and MOD-012, respectively, there are no NERC Standards that mandate the development of short circuit models in a similar fashion. As to R2.4., requiring study of both peak and off-peak conditions in every stability assessment removes the possibility in this regard that stability study scopes may be defined most appropriately by engineering judgment. We believe system load level is often important, but not necessarily more important than any of the other sensitivity variables listed under R2.4.3. We suggest listing system load level along with these and removing R2.4.1. and R2.4.2. The text in R2.4.1., referring to dynamic load modeling, may still be retained somewhere, and since this falls in the category of modeling and data, we suggest including this under R1.1. With regard to R2.5., a 20 MW increase in generation may well be construed as a material generation change, but it is questionable whether a 20 MW decrease would be for transmission planning purposes. Also, the validity of many studies, particularly plant oriented stability studies, may well extend beyond five years if there have been no transmission modifications in the vicinity of the plant or to the plant itself. In these instances, it would seem counter-productive to disqualify a study after five years. The duration of the validity of certain types of past studies is better determined by the occurrence of significant transmission or generation changes. Please note, under R2.6.2., to define "project initiation date" [Changed sequence to keep in numerical order].
With regard to R3.3.3., please include transformers as relay loadability also applies to transformers.
The cross-referencing between R4.1 and R4.4, and between R4.2 and R4.5, seems to add unnecessary complexity and could be eliminated by merging each of these pairs of sub-requirements. Under the event column of Table 1 of the proposed TPL standard, considering entries P3 and P6, the option to apply either SLG or 3-phase fault types should be retained to be consistent with the existing TPL standards, which permit either SLG or 3-phase faults (see existing Table 1, Category B and Category C3). If the SDT decides not to make the requested change, then the SDT should give recognition to the unique characteristics of 765 kV lines where permanent 3-phase faults are virtually non-existent. AEP's 765 kV transmission facilities have been successfully planned and operated with only a SLG fault criterion. Therefore, Table 1 Planning Events P3 and P6 should permit application of SLG faults.
No comments.
No comments.
No comments.
No
"Load Reduction" does not need to be retained as a defined term; in fact it only appears once in the draft standard at the top of Table 1. In addition, it is well understood that load is sensitive to voltage, so it seems unnecessary to call attention to it. Furthermore, the "Supplemental Load Loss" definition should also be removed. These definitions are not generally relevant to planning studies. Neither steady-state nor stability planning studies should acknowledge or rely on "Supplemental Load Loss" because it is simply unpredictable without detailed load device protection data. In fact, properly set minimum voltage limits should ensure that no appreciable load is tripped by customer equipment response as long as that equipment meets generally accepted equipment and design standards. For the same reason, steady-state planning studies should not rely on "Load Reduction" because the planning function is supposed to ensure that a designated forecasted load can be served under credible contingencies. However, it is okay that stability studies acknowledge and rely on load voltage sensitivity ("Load Reduction"), and in fact this is required due to the nature of the analysis and cannot be otherwise. Therefore, there is no need to call attention to it. Given the above comments, the remaining two load loss definitions should be further clarified, though not changed substantively, to read as noted below.

Consequential Load Loss: All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. It excludes Load that is disconnected from the network by load internal protection or end-user equipment responding to post-Contingency System conditions. Also, it excludes Load that remains connected to the System, but that may be reduced due to lower voltage conditions as a consequence of a Planning or Extreme Event. Non-Consequential Load Loss: Any Load loss intentionally caused due to automatic system protective functions such as UVLS, special protection systems, or as the result of operating procedures. Finally, the lettered bullets at the top of Table 1 need to be modified as appropriate to reflect the above comments that load loss due to internal load protection or end-user equipment, what was called "Supplemental Load Loss", should NOT be permitted in complying with either steady-state or stability performance criteria. Load that remains connected to the System, but that may be reduced due to lower voltage, should NOT be permitted in complying with steady-state performance criteria, but should be allowed, by necessity, in complying with stability performance criteria.

No

Consider adding a Planning Event defined to address common mode outages of two generating units. The language could parallel that of P7, substituting "common system" for "common structure". In the present draft, Planning Events P4 and P5 address single faults that may result in multiple contingencies. Most of these events can be expected to involve either multiple transmission facilities or a mix of generating units and transmission facilities. P7 covers common mode (structure) outages of transmission lines. There are no common mode generator contingencies specified. Define the term "common Right-of-Way" and/or modify the term to "common or adjacent Right(s)-of-Way". In the absence of a definition, if two lines are built on opposite sides of some geographic boundary (such as a two-lane road) they may legally be completely separate, potentially with no overlap in the agreements between the Transmission Owner and landowners. However, from the standpoint of BES exposure to weather related outages, the lines clearly will simultaneously be exposed to similar conditions. Lines that follow geographically parallel routes for more than a minimum distance and are within some minimum separation should be considered to be on a common Right-of-Way. Suggestion for the minimum parallel distance would be 1 mile (based on footnote 12).

Yes

Yes

Group

Tampa Electric

R1 Ensure that statement reflects that TP and PC are only responsible for their planning area. R1.1.2 Add transformers to list and clarify modeling of circuit breakers and protection system equipment. Models should reflect the effect of this equipment, not the actual equipment. R1.1.4 Models should only reflect firm transmission service that is expected to be utilized in the study case. Consider changing effective dates of all requirements to be the same date so that you do not have to meet two standards during the same time period.

R2.1 should state R2.5 at the end of requirement instead of R2.6 R2.1.4 Consider revising to only include P0-P2 contingencies. R2.5.1 please clarify whether the 5 years is from the beginning of the assessment or end of the assessment. R2.6 Consider changing the terminology for "Corrective Action Plan" to "Transmission Plan" R2.8 Please clarify the reason for this requirement. This is not necessary for reliability and the effort to collect this information is substantial and does not benefit the BES. R2.9 Please clarify the reason for this requirement. This is not necessary for reliability and the effort to collect this information is substantial.

Consider revising standard for clarity. Subrequirements are not clear as written. Consider moving subrequirements R3.3.1 - R3.3.4 under other requirements for clarification. R3.5 Including an explanation of why remaining contingencies would produce less severe system results could be a limitless effort. Listing all "possible" extreme events seems unrealistic.

Clarification needed on modeling of protection system equipment.

Please define the term "proxies".

none

none

Yes

Yes

Yes

Yes

Consider having all requirements go into effect at the same time.

Individual

Michael Ayotte

ITC Holdings

Comments: We question the value of R1.1.1, which requires the inclusion of transmission or generator outages "if..known", in a planning standard. If an "outage" puts you in a compliance deficiency for the duration of any outage, would you be "fined" for such an instance? Category P6 contingencies should cover these outages and not require a separate requirement such as R1.1.1. This requirement could also make an entity subject to fines for long term outages needed to upgrade or replace equipment as part of a CAP for other category violations. If this requirement is kept, it should be restricted to very long term outages and exclude those outages needed to complete CAPs for other violations. R1.1.6 requires the use of "Network Resources" to supply load. For many planning studies, particularly beyond the five year window, the capacity additions needed to supply load are frequently unknown. Since there are no requirements or guidelines for assuming what and where these resources will be, "assumptions" will have to be made regarding the needed resources. Additionally, existing "network resources" could be retired or re-designated to serve other load. It is unclear as written exactly what would be a violation of this requirement if known network resources are not sufficient to serve projected load. Finally, with the advent of market power, would a dispatch utilizing this type of dispatch be considered a violation of this standard.

Comments: In R2.1, there is a reference to "R2. 6". Based on the posted red-line version, we believe this reference should be changed to "R2.5". Should this same reference be included in R2.4"? In R2.3, it is stated that the short circuit analysis should be supported by either current or past studies. Should a reference be added to R2.5? In R2.6 it is stated: "Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3 and R2.4.3. " While we recognize that this conforms to FERC orders, it would still seem that this statement might be interpreted to mean that CAPs intended to cover a number of sensitivities go beyond standards and be used by interveners to block such CAPs. A revision to the standard to the standard to encourage CAP when needed for numerous sensitivities might be appropriate. R 2.6.4, as written, is very subjective. While we understand the need for R2.6.4, who is the ultimate judge of what "situations" are "beyond the control" of the TP or PC responsible for the mitigation plan and if they "are taking prudent actions to resolve the situation"? As written, it is the auditor. This will be difficult to prove compliance and might provide significant discrepancies in compliance with standards.

Comments: If the SDT feels that a requirement such as R3.3.4 is necessary, it may also be necessary to identify further limitations on the use of the control devices referred to. For example, a manually controlled phase shifter would require a time period, or loading limits, to readjust flows to limit a post-contingency flow if not pre-set in the pre-contingency state. Similarly, a tap-changing transformer also requires an adjust period for voltage control. We suggest adding a statement to this requirement (or somewhere in performance requirements) that "all post-contingency flows/voltages must remain within the applicable facility ratings before, during, and after the use of such control devices."

Comments: In R2.5.1, a limitation is identified for stability studies that are used to support the annual assessment be less than five calendar years old. Should this reference be included in R4"?

None

Comments: Should this requirement state that "The Transmission Planner in conjunction with their Planning Coordinator shall determine and identify individual and joint responsibilities for performing the required studies for the Planning Assessment."

None

Yes

None

Yes

None

Yes

Comments: We concur that footnote 10 should not apply to P0, P1 or P2 events.

Yes

Comments: We generally concur. However, it would appear that there is no incentive to submit a mitigation plan for less than 60 months for the new requirements that raise the bar (those listed as bullet points). If "circumstances are within your control" to mitigate in less than 60 months, why not require it?

Group

SERC Engineering Committee Reliability Review Subcommittee (RRS)

•In bullet three of R1.1.2, are bus-tie circuit breakers to be represented in the models? Typically

circuit breakers are included in the contingency definitions along with the protection system equipment used in the powerflow models. The number of zero impedance branches which can presently be modeled using PSS/E software is limited to 4000. Also, the number of buses included in the powerflow models would increase with additional breaker modeling. •In R1.1.2, don't we need to also represent the existing transmission system, and not just changes to the existing system? •In R1.1.2, does the phrase 'for each year' signify each year for which assessment work was performed, or each year of the Near-Term and Long-Term Transmission Planning Horizon? The phrase, "for each year of the Near-Term and Long-Term Transmission Planning Horizon", should be revised to remove "each year" because there may not be studies in each year. •In bullet five of R1.1.2, what protection system equipment is to be included in the stability models? •In bullet seven of Requirement R1.1.2, what "new technologies" are to be represented in the models? •Concerned about only having one year to implement all new modeling requirements - especially the additional relay requirements noted in R1.1.2. •The SDT stated during its June 30th Webinar that protection system equipment need not be explicitly represented in models, but had difficulty in determining adequate wording for the proposed sub-requirement. Because protection system action is described in R3.3.1, R3.3.4, R4.3.1, and R4.3.3 we suggest that protection system equipment be removed from the list in R1.1.2. •There may be a potential conflict between MOD-010 and MOD-012 and legal documents such as Interconnection Agreements e.g. IA may specify a capacity level that exceeds the reported test levels. In the case of such conflicts, which one should rule? There may be a need to add definitions to discern the difference between planned and proposed projects. Suggest replacing 'circuit breakers' in R1.1.2 with 'terminal equipment' since circuit breakers are covered by Protection System Equipment. •Does there need to be a reference in R1 to NERC Reliability Assessment Guidebook version 1.2 on pp 17-18 for everyone to use a 50/50 load forecast for inclusion in the planning models? •R1.1.4 Firm Transmission Service - a single source can have transmission service to multiple sinks, and can be associated with transmission service in excess of the capacity of the source. There is a lack of clarity regarding the means by which Firm Transmission Service, a marketing term, is to be included in planning models. For example, should the standard define how to model wind farms (100% - off-peak and 20% on-peak, based on firm capacity from the wind generators, or other dispatch levels)? Not sure if this is applicable to Requirement 1 or 2.

•The proposed standard not only raises the bar for system performance requirements, but also raises the bar for reporting and documentation. We need to employ almost as many librarians and technical writers as engineers to develop and keep track of the documentation. Engineers need to spend more time performing the studies and spend less time documenting studies keeping track of documentation for multiple years. •R2 – Instead of "document results" the requirement should be to "summarize results". While results will be documented, the Planning Assessment should just include a summary. •R2.1 – What's the value in being able to use "qualified past studies" if you have to use "annual current studies"? Strike the words "supplemented with" and insert the word "or". •In R2.1, change the reference to requirement R2.6 (at the end of the last line) to R2.5. •Do not understand the rationale for being so prescriptive in requiring specific years to be studied in R2.1.1. Why not allow the TP and/or PC to decide on the three years to be studied in the Near Term? •In the subrequirements of R2.1.3 and R2.4.3, the use of the word "timing" is unclear. Consider using "in service date" or "schedule for". •In R2.1.3, it is suggested that the studies be referred to as the "base studies" to avoid confusion with the sensitivity studies. Also suggest that another phrase be added at the end for clarity. The entire R2.1.3 would then be as follows: For each of the base studies described in Requirements R2.1.1 and R2.1.2, sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment. Sensitivity studies would include changes to: oIn Requirement R2.1.4, it is suggested that language be added to reflect the possible unavailability of the equipment, such as: •When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience the possible unavailability of the long lead time equipment. •How would adequate lead times be determined? •In Requirement R2.1.4, recommend that the requirement be revised as follows: When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience the possible unavailability of the long lead time equipment. •Since R2.3 short circuit analysis is a new "raising the bar" requirement, should the implementation plan for this be for 5 years like the other new requirements? •R2.3 – Insert the phrase "one year of" after the word "addressing". •In Requirements R2.3 and R2.4, do we need a reference to Requirement R2.5 for the past studies? •Further clarification is needed in R2.4.1 concerning load models that appropriately represent the dynamic behavior of loads. •In Requirement R2.4.1, it is suggested that it be reworded to the following: System peak Load for one of the five years, including Load

models which appropriately represents the dynamic behavior of Loads, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. •R2.4.1: It is not clear how much Load must have a dynamic model. Likely, it must still be proven that the analysis software can accommodate every load in the model having a load model that includes induction motor models. To help address this, revise "Load" to be "Load that could impact the study area is acceptable. Is a NERC drafting team addressing these issues to determine an industry standard? •Load models referenced in R2.4.1 should be confined to the consideration of transient stability study work. •In Requirement R2.4.3, it is suggested that this sub-requirement be reworded to the following: For each of the base studies described in Requirements R2.4.1 and R2.4.2, sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the base studies shall be included in the Assessment. Sensitivity studies would include changes to: oRegarding Requirement R2.6, it is suggested that the word "modeled" be added as follows: For Planning Events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed in subsequent assessments but the System modeled shall continue to meet the performance requirements in the tables. Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3 and R2.4.3. The Corrective Action Plan shall: •In bullet three of Requirement R2.6.1, would we allow automatic generation tripping for a single (P1) event if it is not consequential? It seems that tripping of generation should be restricted to P2 events 2 or 3 at a minimum. •In bullet five of Requirement R2.6.1, is there a maximum duration that operating procedures can be used before a capital project must be included (or completed) in the Corrective Action Plan? •With the elimination of the distinction between system and generating plant stability studies, the blanket requirement in R2.5.1 that all stability analyses be five calendar years old or less, regardless of any material changes to the system, would cause needless work to be performed on those plants or areas of the system where no changes are occurring. Similar to the draft MOD-026-1 standard, this period should be 10 years. •With the elimination of the distinction between system and generating plant stability studies, the blanket requirement in R2.5.1 that all stability analyses be five calendar years old or less, regardless of any material changes to the system, would cause needless work to be performed on those plants or areas of the system where no changes are occurring. Recommend add the following to the end of R2.5.1: "unless justification can be provided to demonstrate that the results of an older study are still valid." •R2.5.2 – Suggest deleting the phrase "Material generation changes could include:" and the two accompanying bullets. A change of 20 MW on a large system may not always be material. •In Posting #2, undervoltage load shed, underfrequency load shed, and Special Protection Schemes were considered to be Non-Consequential Load Loss. In R2.6.1, installation or modification of Protection Systems or Special Protection Systems are now allowed as part of the Corrective Action Plan. Should undervoltage and underfrequency load shed also be allowed in the Corrective Action Plan? •In Requirement R2.6.2, what constitutes a "project initiation date," and how will it be used? Please clarify. •Please explain the reason why Requirement R2.8 is needed in the Assessment and how does reporting the largest Consequential Load Loss impact reliability? •Please explain the reason why Requirement R2.9 is needed in the Assessment and how does reporting the largest Non-Consequential Load Loss impact reliability? •If contingencies occur inside one utility that affect facilities in another utility, which utility is responsible for running these studies during the annual assessments? •R2.8 and R2.9 should be deleted. We don't see a reliability-related need for these requirements. •In R2.9, does the requirement require the maximum non-consequential load that can occur for contingencies in Table 1 or does it require just the maximum that a utility will allow on its system? Suggest clarifying "permissible" or perhaps using similar language as found in R2.8. •R2.9: One cannot determine the "maximum permissible Non-Consequential Load Loss" for every Planning Event. First of all, this should not be a requirement, as it is, for those events that do not even cause Non-Consequential Load Loss. Secondly, to obtain the "maximum permissible" value, one would have to stress the system in some way until one of the performance requirements are violated. That is an unreasonable stipulation and cumbersome to perform such an analysis.

•In R3, should the "and" in the first sentence actually be "or"? especially for same footprint? Perhaps the "and" should be replaced by "and/or". Can the PC satisfy this requirement by reviewing studies performed by differing TPs or is separate analysis really required especially when the TP and PC have the same footprint? •In Requirement R3.1, it is suggested that the word "contingency" be added to describe the lists created in R3.4. •R3.3.1. Recommend that it be clarified that simulation of the more conservative case of a single branch (bus-to-bus) outage is acceptable, as opposed to always simulating the full breaker-to-breaker outage. •R3.3.2 The requirement needs to be clarified. It is not clear if it is referring to the ability of plants to meet their voltage schedule, or to their ability to stay connected during post contingencies. •Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists created in Requirement R3.4. •R3.3.2 "For all generators, studies shall consider the minimum steady state voltage limitations and identify how the generators are analyzed in the steady state simulation." The above wording needs to be

changed, as the intent of this sentence is unclear. Is the intent that Transmission Planners need to ensure that generating plants can meet their voltage schedule under Base Case (N-0) conditions? Is this the same as the generator underexcited operation limit? •In R3.3.2, need guidance on how to consider minimum steady state voltage limitations. Is there a NERC team addressing this? •R3.3.3 "For all Transmission lines, studies shall consider relay loadability and identify how loadability is analyzed in the steady state simulation." The above wording needs to be changed, as the intent of this sentence is unclear. Is the intent that Transmission Planners need to ensure that relay loading limits are included in the facility ratings? Is this the 130% of conductor rating limit? •Revise M3 to include a reference to R6, since the allocation of responsibilities will directly affect the evidence which is to be provided. •In the VSL for R3, a severe VSL is listed as failing to meet performance requirement for P0 or P1. We do not understand why a severe VSL would be applied to an all ties closed event which should have little if any problems. We believe that this should be a lower or moderate VSL instead of severe. •In R3.3.3 is the relay loadability required for all HV and EHV voltage levels? Previously NERC had required this for 230-kV and above only. This would be massive requirement for our Transmission Lines between 100 and 200-kV. •Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists created in Requirement R3.4. •In Requirement R3.3.4, it is suggested adding the words "and switched" to capacitors and reactors: Simulate the expected operation of existing and planned devices designed to provide Steady State control of electrical system quantities. These devices include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

•In R4, should the "and" in the first sentence actually be "or"? •Footnote #3 needs to be revised to include 2LG faults in addition to 3Phase faults indicating that the SLG criteria is met. •In Requirement R4.1, it is suggested that the word "contingency" be added to describe the lists created in R4.4 •Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists created in Requirement R4.4. •Regarding Requirement R4.4, it is suggested that a rewording be considered such as the following: For each category of the Planning Events in Table 1, those Planning Event Contingencies that are expected to produce more severe System impacts shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4.1 shall be created. The rationale for the Contingencies selected for evaluation shall be available as supporting information with an explanation of why the remaining Contingencies would produce less severe System results. •R4.3.2 requires that voltage ride through capability be analyzed. It is not clear what should be analyzed (e.g. auxiliary loads, generator protection, generator capability, etc.) This requirement needs more clarity. •R4.3.2 – By in large, the industry does not have the input data or the methods to do this. It would seem necessary to have PRC-024 approved before this can be met. •In R4.3.2, need guidance on how to consider minimum steady state voltage limitations.

•There is no requirement that the Planning Coordinator (PC) must use the same proxies as the Transmission Planner (TP). Since differences in proxy assumptions may lead to different study results, R5 should be revised to require the PC and TP to coordinate the use of proxies. •M5 doesn't make any sense. Need to revise this Measure so that it fits the Requirement R5. Also need to revise the Data Retention discussion in Section 1.4 to align with R5. •In the VSL associated with R5, we believe that failure to define and document one of the proxies should be a moderate VSL, failure to define and document two proxies should me a high VSL, while failure to define and document three proxies should be a severe VSL. Otherwise failing to document only one proxy would result in a severe VSL.

•In absence of these agreements, it is assumed that both Transmission Planners and Planning Coordinators would be responsible for performing the studies. How do the Corrective Action Plans get resolved between these entities if there is no agreement on the study results? •Requirements R1, R2, R3, R4 and R5 should all be revised to include a reference to R6 regarding the determination of individual and joint responsibilities for performing the required studies. •In the VSL associated with R6, we believe that failure to determine and identify one responsibility should be a moderate VSL, failure to determine and identify two responsibilities should me a high VSL, while failure to determine and identify three responsibilities should be a severe VSL. Otherwise failing to document only one responsibility would result in a severe VSL.

•The reference to FERC Order 890 as it is currently written makes it seem like a suggestion to follow Order 890. If Order 890 explicitly describes this process then the sentence should read "as described in FERC Order 890." If not, this should not be mentioned at all. •Requirement R7 describes that the Planning Coordinator is to share Planning Assessments with adjacent Planning Coordinators. Does this need to be expanded for the Transmission Planners to share their Planning Assessments with the Planning Coordinators? •In the VSL associated with R7, we believe that the PC failing to coordinate analysis should be a moderate VSL, the PC failing to distribute should be a high VSL, and failing to do both of these tasks should be a severe VSL.

No

•Revised Definitions are generally better than those from the previous version, but additional clarity could be provided. •Load Reduction – Please clarify whether this includes both load

response and operator initiated action, such as in changes to transformer LTC. •Supplemental Load Loss - From a utility perspective, this would be considered as load response. Please clarify how Supplemental Load Loss would be included in the stability analysis. •Bus tie breaker – A statement in the previous version which listed examples was removed from this version of the definition. The statement was helpful and should be re-inserted. The statement was: "Substation configurations such as ring bus, breaker and a half, or double-bus double-breaker do not use bus tie breakers." •Extreme Events definition references severity and probability. These terms should be included in the definition of Planning Events. Add a definition of Planned and Proposed facilities. Planned facilities address the near term deficiencies and have been approved with a financial commitment while proposed facilities address long term deficiencies for which no commitment is required today since they may change based on future evaluation. •Revised Definitions are generally better than those from the previous version, but additional clarity could be provided. •Consequential Load Loss - Is an SPS to trip load qualify as a planned protection system? •Load Reduction - Is this automatic as in a load response or is it operator initiated as in changes to transformer LTC? •Supplemental Load Loss - From a utility perspective, this would be considered as load response. How would Supplemental Load Loss be included in the stability analysis? Table 1 suggests that it cannot be included to meet steady-state performance. Suggest that the following be added to the definition: Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements. •Where would interruptible load be included in these definitions? •Bus-tie Breaker definitions still seems somewhat generic and the use of 'configurations' causes uncertainty. Revise Bus-tie Breaker to read, "A circuit breaker whose intended purpose is to connect two individual substation buses." "Bus-tie" is not capitalized in the Table. •Consequential Load Loss must include load that is lost due to the inherent response of the particular type of load. Some motors, lighting and processes will naturally trip during an event, although not as a result of the protection system. It may have been the intent of the SDT to include this phenomenon in the Supplemental Load Loss defintion. However, this definition includes the phrase, "by end-user equipment", and that makes one think that there are devices at the end-user location that is removing this equipment (and conversely, load that is not disconneted "by" end-user equipment cannot be included). Also, the term "post-Contingency" can be confusing because in the case of faults, this phrase is not clear if it means conditions after the fault initiation itself or only after the clearing of the fault. Revise Supplemental Load Loss to read, "End-user Load that inherently disconnects from the System as a consequence of (or "in response") to the conditions created by the System event." •SERC RRS suggests adding back the following to the Bus-tie breaker definition that was contained in Posting #2: "Substations configurations such as ring bus, breaker and a half, or double bus double breaker protection schemes do not use bus tie breakers". SERC Members believe that this additional wording helps explain this definition much more clearly. •In Posting #2, undervoltage load shed, underfrequency load shed, and Special Protection Schemes were considered to be Non-Consequential Load Loss. Are these now no longer considered to be Non-Consequential Load Loss but instead now considered to be Load Reduction, Supplemental Load Loss, or something else? •Should Supplemental Load Loss be further defined as load that is disconnected from the network by end-user equipment responding during duration of the fault as well as to post contingency system conditions? Also the definition of Supplemental Load Loss may benefit from some examples in the definition to further help clarify. •The second sentence in the Year One definition is rather confusing. We would suggest changing "calendar year" to "date". Otherwise it may be interpreted that Year One would begin 12 to 18 months from the end of the current calendar year. Suggest from "beginning".

No

•The word "Requirements" needs to be added to the Table 1 titles in the existing tables. oTable 1 – Steady State & Stability Performance Requirements oPlanning Events Table 1 — Steady State & Stability Performance Requirements oExtreme Events Table 1 — Steady State & Stability Performance Requirements •Footnotes (Planning Events and Extreme Events) •We recommend that Table 1 be split back as was done in the previous draft to handle the 1) steady-state and 2) stability performance requirements. This is needed to provide clarity on which contingencies apply to steady-state and which apply to stability analysis. •Table I, P7.1: It would not be likely to lose the two outside circuits on a vertically configured structure and not lose the middle circuit. Change the wording to: "Any two adjacent circuits on a common structure." •The word "Requirements" needs to be added to the Table 1 titles in the existing tables. oTable 1 – Steady State & Stability Performance Requirements oPlanning Events Table 1 — Steady State & Stability Performance Requirements oExtreme Events Table 1 — Steady State & Stability Performance Requirements •Since it appears that the Table 1 cannot fit on a single page, it is suggested that multiple tables be developed to handle the 1) steady-state and 2) stability performance requirements. Footnotes may be included on a second page if needed. •Comments were provided in early versions regarding the issues associated with raising the bar, and it was suggested that the marginal reliability benefits associated with these changes were not worth the marginal costs. We have not seen any significant changes from the earlier performance requirements. The question still remains, are we directing the resources where they need to be allocated to address and improve system reliability? So far the answer is believed to be "No". •The existing TPL 002-0 allows for some local load to be dropped for a single contingency event

as long as the Bulk system reliability was not impacted. However there is no such allowance any longer for losing such load for a single contingency in the proposed draft. It would be very expensive for SERC Members to fix all such events in several remote areas that would have very little impact on the overall reliability of the SERC Members' bulk system. SERC Members believe that the capital spent for these fixes could be used to better strengthen the overall bulk system in much better ways. •P5 should not be a planning event. PRC standards address protection system failures. The complexity associated with identifying and simulating such events is unknown and the defense of assumptions made and events simulated will lead to inconsistency in compliance and enforcement. Industry accepted proxies for such events could be developed that would allow for efficient identification of areas needing further study. Attempting to intermingle protection system operation with BES performance will be nearly impossible to implement given current technologies.

No

•Suggest rewording of footnote 5 to: Curtailment of conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the conditional Firm Transmission Service. •Footnote 10 is definitely an improvement from previous versions. It is suggested that the word "also" be added to the last line: •Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must also be considered. •Stability Extreme 2g needs a note like number 12 that excludes short distances. •Stability Extreme 2h: Is this meant to be an event initiated by a 3LG fault or is it a catastrophic event that leaves all the elements at a station with a 3LG fault. If it is the former, then 2h needs a note to limit this to locations where actual events could lead to the loss of the entire station. There is no need to study this if there are no protection system events that lead to loss of the whole station (there would be no scenario to model). If 2h is meant to represent some catastrophe that causes all the elements at the site to experience a fault, then some clarification is needed to get consistent studies. Possibly rewrite 2h as, "Assume all the buses at a single voltage level (one voltage level plus transformers) experience an event that results in a 3LG fault and disables local protection (fault must clear from remote stations or other side of transformer)."

No

•60 months after effective date seems generally acceptable for planning activities, but may not adequate for all construction activities. Typical times to construct a transmission line in various areas of SERC can range between 7 to 10 years. Accordingly, we recommend the effective date for construction projects be changed to at least 84 months. •More time is needed for entities to determine the appropriate dynamic load model required by R2.4.1. We recommend at least 36 months before this requirement becomes effective. •Since breaker duty is a new "raising the bar" issue - should there also be a 5 or more year implementation plan for this as well? •Also trying to construct enough facilities within the 5 year implementation period will result in multiple outages at same time - possibly affecting SERC member's bulk reliability during this construction period. Also SERC members are concerned that EHV equipment manufacturers will not be able to meet all the equipment orders that will be required to meet the "raising the bar" requirements. •SERC members are also concerned that the costs to meet the new requirements contained in this TPL will amount to many billions of dollars with very little impact overall on the reliability of the Bulk transmission system. •When will the Implementation Plan be removed from the standard after it is officially approved? Will a revised TPL standard need to be prepared to omit this implementation language? •If contingencies in one utility's system results in issues within another utility, who is responsible for studying the contingencies and who would be responsible for documenting the CAP?

Individual

Mary Ann Groszek

Northern Indiana Public Service Company

Under R1.1, insert, "as applicable" after "represent". Since R1 covers steady state, short circuit and dynamic models, data requirements should be applicable to the specific model. Representation of circuits breakers, protection system equipment and control devices is not typical of steady state model inputs.

R2.3: Clarify the requirement. Does the short circuit study examine topology for a single year, the topology in years studied using the steady state models or each year of the near term planning horizon?

R3.3.3: Evaluation of loadability should be triggered only for those circuits with new protection settings issued since the last assessment; evaluation of circuits that have not been newly assigned or re-assign protection settings is a misuse of resources.

No

The definitions need clarification, especially if they will be extracted from the standard when approved and included in the NERC Glossary. The SDT should include a Technical Writer to clarify the proposed language.

No

In A5, text appearing under "Effective Date" is not clear regarding application of the phrase, "(above 300 kV)", for the first and fourth dot points.

Individual

Wang, Yu (David)

San Diego Gas and Electric Co

The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices where it is expected to impact the study outcome. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted. We disagree with the inclusion of the words "including requirements of regulatory authorities and other legal obligations" at the end of R1. Entities already are required to do this. It does not need to be included in the standard.

Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement. The 20 MW threshold identified as "material change" for generation in R2.5 is too small. The limit should be raised or based on a percentage of the study area's installed generating capacity. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the "largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event" if it is documented? R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.

As currently drafted, R3.3 is not a requirement. Without the statements in R3.3.1-R3.3.4, R3.3 is simply a phrase. Sub-Sub-Requirements R3.3.1 through R3.3.4 should be bullets under R3.3, with the language in R3.3 modified so that it becomes the requirement to conduct contingency analyses that address the four resulting bullets R3.3.2 is unclear as drafted. The minimum steady state voltage limitation for synchronous generators is not a very meaningful value. All generators with an automatic voltage regulator will maintain the set point voltage until the VAR capability of the generator is exceeded, and then the voltage will deteriorate. R3.5 – We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingencies than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.

As currently drafted, R4.3 is not a requirement. Without the statements in R4.3.1-R4.3.3, R4.3 is simply a phrase. Sub-Sub-Requirements R4.3.1 through R4.3.3 should be bullets under R4.3,

with the language in R4.3 modified so that it becomes the requirement to conduct contingency analyses that address the three resulting bullets. R4.3.2 – it is not clear what is required to be modeled. Typically a generator may have 10 or more protective relays. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to do that for all generators in the system. R4.5 – We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingency than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.

The term proxy is unclear. Please provide an example or an explanation of proxy.

We believe that references to FERC Orders should not be included in requirements of standards. This comment also applies to M7.

No

Claification is needed on the use of UVLS. Is it acceptable or not. Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss Allowed column is No, is load disconnecetd from the system by UVLS a violation? What about Supplemental Load Loss or UFLS?

No

P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements. As such, this is a low probability condition and loss of Non-Consequential load should be allowed for EHV. We disagree with raising the bar for EHV for P4.

We agree that TPL-005 and TPL-006 appear to have been adequately covered in the draft TPL-001-1 as currently written. However, we will need to review this assessment after TPL-001-1 is finalized. In addition, there is no place to state our concerns for Section D. so we added it here. We question the "not applicable" entry under Section D 1.1.2. What does it mean when the reset period is not applicable? Does it mean there is no reset period, so all non-compliance in all prior years will be counted as prior violations when considering non-compliance in future years?

Group

Florida Reliability Coordinating Council, Inc - Transmission Working Group

R1 and M1: Consider clarifying that it is not the TP or PC responsibility to independently verify the consistency of the System models for portions of the Bulk Electric System outside of the TP or PC planning area (related to not using data consistent with data submitted as part of MOD-010 and MOD-012, each TP and PC should not have to review the data submitted by those outside of its planning area, but only its own planning area). Please Clarify the phrase “Models shall use data consistent with ….MOD-010” – is the intent for the data to be “identical” to the data provided under MOD-10 and MOD-12, or “consistent” meaning that the data might be older or newer depending on when the assessment took place vs when the data was submitted. R1.1 Consider changing Assessment (which does not include models) or re-wording to “Models for performing the studies needed to complete the Planning Assessment shall represent:” R1.1.1 Brings clarity to the question regarding planned outages. R1.1.2: Consider adding “Transformers” to the list of facilities. R1.1.2, please clarify what the drafting team intentions are for Circuit Breakers. Planning models used for power flow, dynamics and short circuit do not include circuit breakers. Modeling circuit breakers would cause convergence problems in the models due to that large number of zero impedance line sections. We sugges eliminating circuit breaker from the bullet list. R1.1.2 “Protection System equipment” this should be clarified to only apply to system stability models. The modeling of protective relays should be caveated with “as deemed appropriate”. We suggest eliminating “Protection System equiptment” from the bullet list. R1.1.4 Consider adding “that is expected to be utilized in the study case scenario” not all Firm Transmission can be included in all studies and are only used upon the availability of other resources . Consider changing the effective dates of R1 and R7 to take effect at the same time as R2 through R6 so you do not have to meet two standards during the same time period. Otherwise, clarify how the effective date impacts which version of the standard is to be used in an assessment before a scheduled compliance audit.

Incorrect reference shown at the end of R2.1. The appropriate reference should be R2.5. The end of the first sentence of R2.3 should have a reference to R2.5. The end of the first sentence of R2.4 should have a reference to R2.5. R2.1.4 - Please consider revising this for the analysis to include only Contingencies P0-P2 in Table 1. Alternatively we suggest moving this requirement to

be under sections 2.1.3 and 2.4.3 and treated as a sensitivity. R2.5 – This requirement is very valuable in clarifying that past studies can be used and what criteria needs to be met for them to be used. However it is not clear if all new studies could be met using past studies (e.g. a small system with very few changes year to year) of if some sub-requirements require a new study every year, with past studies only used as supporting information. If the intent is that some sub-requirements can not be met with past studies, then consider making that clear through a foot note or a list under Section 2.5 listing which study requirements may depend only past studies that are still current. R2.5.1 – Please clarify if the 5 calendar years is from the date the assessment is "finished" or the date the study process for the assessment begins. R2.5.2 – the identified 20 MW threshold is extremely small and would be doubtful to change the response of the BES. This requirement could also be interpreted that a previous study where the base case is not identical to the current planning case could be used. Please consider the following proposed language: "For steady state, short circuit, or Stability analysis: the present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period that would impact the study area." (not show the list) R2.6 - Requiring sensitivities but not requiring that they meet specific performance requirements is a sound approach. R2.6 requires a corrective action plan when performance will not be met in the simulations. However, if an entity has already planned a needed facility and/or operation steps for a given conditions, the simulations will not show any deficiencies and therefore no corrective action plan is required. The term "Corrective Action Plan" implies that the situation is "wrong or incorrect", consider changing the approach to be to require an entity to have a "planning and Operations plan", "Improvement Action Plan", or simply a "Transmission Plan" that includes all facilities planned for the BES and descriptions of conditions where an operational process is being used. R2.6.1 – (Bullet 2) This requirement should also account for the removal of a Special Protection Systems: "Installation, modification or removal of Protection Systems or Special Protection Systems". R2.6.4 – This is an excellent addition R2.8 – Please explain the reason for this requirement. The effort required to collect this data is substantial and does not have any benefit to the BES. R2.9 – Please explain the reason for this requirement. It seems to cause Entities to develop performance criteria for themselves for Multiple and Extreme Contingencies that are not in Table 1. The effort required to collect this data to compare against any self-imposed criteria is substantial and does not have any benefit to the BES. The requirement will result in inconsistency across North America. There is also no discussion of what happens if a Multiple or Extreme contingency is shown to exceed the Entity's self-imposed criteria, is the Entity then non-compliant? If so, what if the Entity simply changes the self-imposed criteria? We suggest eliminating this requirement.

R3.3.1 & 3.3.4 – Consider adding language that the entity should not be held responsible for simulating "the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention" on neighboring systems, only on the entity's own system. Also, consider moving R3.3.1 and R3.3.4 under R3.1 as sub-requirements and require that the overall studies take into account the effect of protection systems and control devices in the performance of the BES and it's ability to meet the table 1 requirements. R3.3.1 – This seems unnecessary for normal 2-terminal lines, consider adding language to the effect of: "Simulation of individual element outages is allowed if it produces an effect more severe than the entire circuit outage". R3.4 – Consider changing the header for table 1 – "Steady State & Stability Performance Extreme Events" to Table 2 – "Steady State & Stability Performance Events". As is, it could be interpreted that the expected performance requirements associated with Planning Events apply to Extreme Events also.

R4.3.1 – Please clarify, is the intent of this requirement to have every relay modeled? We suggest clarifying that the intent is that Protection System Equipment would be incorporated into the contingency list, and that modeling the Protection System equipment settings and logic would only be done for Protection Systems that could significantly impact stability response (e.g., out-of-step relaying) as deemed appropriate through engineering judgment, and that the intent would be to do this only for the Region under study and not the entire Interconnection (e.g., studies in Florida should not need to include relays in Canada). R4.4 & R4.5 – Does the intent of allowing this "More severe events" to establish actual study parameter extend between the planned events and extreme events (e.g. if a range of extreme events establishes that planning events performance requirements are met, would a redundant analysis of the planning events still be required)

None - no concerns identified by the TWG

Please clarify that the phrase "individual and joint responsibilities" applies to entities (e.g., the TPs and PCs) and not specific individuals. R6 – Please clarify if this requirement is intended for cases where a TP is not a PC and therefore is working "under" a PC? Or if this is intended to apply across neighboring PC's?

The requirement as written requires that the results of the assessment are shared on a post assessment basis between entities in a manner similar to the Attachment K process. Please clarify whether: -Is this intended to be the end results? Or does this require the inviting of entities in at the very beginning and facilitating their participation throughout the process? -Is it intended that the process described in order 890 become essentially a NERC Standard that every

sentence must be met in the most literal of sense? Or is this referencing the order as a general guideline on what should be expected but not as a literal checkmark of the process? Consider adding a footnote or other clarifications that failure of others to participate in the process is not a non compliance by the entity inviting them to the process. Otherwise non-responsiveness of a neighboring PC who may not have reliability need to participate and whose participation is beyond the control of the PC that initiated the process could trigger non-compliance.

Yes

Excellent changes

The table is significantly improved from the prior versions and provides superior clarification over the existing standards. However, please explain why there is a performance difference between P2.3 (breaker failure), P4 (stuck breaker) and P7 (2 circuits on a common tower) for EHV. We recommend consistant critera between P2.3, P4 and P7 that allow curtailment of firm service and loss of non-consequential load.

Yes

Excellent addition Footnote 10 is long and subjective. There is no purpose in adding the phrase "when coupled with the appropriate re-dispatch of resources obligated to re-dispatch" because if there is an obligation to re-dispatch, it is done, and if there is no obligation to do so, then curtailment is the only alternative – no coupling necessary. Suggested revision: 10. Curtailment of firm transmission service is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and as a corrective action, providing those adjustments do not result in the shedding of any firm Load.

Overall the plan is an improvement! Allowing for a 60 month phase in of the more restrictive performance requirements is useful, however consider applying the 60 month phase in (or some timeframe) to P1 events for extenuating circumstances, e.g. unable to obtain ROW, etc. Having R1 and R7 going into effect first do raise the concern of what TPL standards are in effect during the time frame. The implementation should also be more specific on what "going into effect" means. Assessments are not a one day event but are a year long effort that culminates in a final "report" that is the assessment. Most NERC standards effect ongoing activities, and the day they go into effect the utilities functions are expected to be compliant. In this case that rationale would require that in the prior year two assessments where performed, one compliant with the current standard and one compliant with then new standard, however we don't believe that was the intent. Perhaps a statement below the paragraph regarding the 60 month implementation plan for Corrective Action Plans to the effect of: "Once effective all future assessments shall upon completion be compliant with this standard. Assessments completed prior to the effective date shall be based on the TPL standards in effect at the time. The standard is not intended to require a retroactively compliant assessment be in effect when the standard becomes active, but instead that the next assessment be compliant with the revised standard"

Individual

Peter S. Schommer

Minnesota Power

A) Under R1 there is language that references "other data sources"; can the SDT please offer some clarification on what "other data sources" are to be? Could other data sources be Tariff requirements? B) Again under R1, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R1 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning". C) Under R1.1.1 it is required that models represent planned outages of generation and transmission facilities, if specifically known. However, the requirement does not distinguish the length of the outage to be considered. Should a one week maintenance outage in Year Five be included? Should a two-year complete rebuild outage lasting through the entire years 2 and 3 be included? The SDT team needs to add a comment about the length of the planned outage and its relevance to the assessment. D) R1.1 is repeating what should already be in the MOD-010 and MOD-012 requirements. Is the inclusion of these elements in the TPL standard redundant? The planners expect the model building process will already included the components listed in R1.1, otherwise there would not be a functional model. If R1.1 is kept, we suggest removing the "Models for" so that R1.1 reads "The Planning Assessment shall represent:"

A) Under R2, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R2 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning". B) Under R2.1 there is a reference to qualified past studies in R2.6. We believe that this reference should be pointing to R2.5 not R2.6. C) R2.1.4 addresses the spare equipment strategy. What is the scope of this sensitivity? Is the intent only to do a steady state analysis on equipment with long lead time spares? D) Under R2.2 a System peak load study is required annually for one of the years in the assessment period. R2.2.1 requires the assessing entity to extend their planning assessment to accommodate any known longer lead time projects that may take longer than ten

years to complete. It does not make sense to study the ten year horizon, then find a problem in year ten which has a solution that requires twelve years to build. For compliance with this standard, you would need to find another solution that can be built within ten years as opposed to the suggested language in R2.2.1 of extending the planning assessment beyond ten years to accommodate the solution that falls outside of the Long-Term Planning Horizon. No project solution greater than 10 years should be acceptable because it falls outside the Long-Term Transmission Planning Horizon. Suggestion to strike sub-requirement R2.2.1 from this standard. E) Requirements R2.1, R2.3, and R2.4 are written inconsistently. 2.1 says "The Near-Term Transmission Planning portion of the Steady State analysis…" 2.3 says "The short circuit portion of the Planning Assessment … addressing the Near-Term Planning Horizon…" 2.4 says "The Near-Term Transmission Planning portion of the Stability Analysis…" These three sentences confuse the order. As we understand, the Planning assessment has two parts: a Near-Term portion and a Long-Term portion. Each of those parts has three components: a Steady State component, a Short Circuit component, and a Stability component. We suggest the language in the standard should be structured consistently and appropriately as such. F) Under R2.4.3 there is ambiguity in the third bullet language "…new or modified Facilities…" and we believe that this language should mimic that of R1.1.2 in order to improve this requirement. The third bullet should read: Timing of the installation of new Facilities or changes to existing Facilities. G) The sub requirement R2.5.2 states that for steady state, short circuit, or stability analysis; the "present System model" shall not include any material changes, such as…..etc. The present language in this section is vague and requires discretion on the part of both the Transmission Planner and the Planning Coordinator performing the assessment. For example, new transmission enhancements may have been added since the previous System model was developed. In general, such topology enhancements will only improve reliability and would not necessitate re-assessment with a newly updated System model. In addition, any significant generator additions would have been evaluated with a full separate generator interconnection study at which the full reliability of the System would have been taken into consideration. For this reason, we believe the following language for R2.5.2 would improve this requirement: "For steady state, short circuit, or Stability analysis: the current System model of the assessed plan year shall not include any changes material to the assessment, as judged by the entity performing the assessment, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study year. Material generation changes could include:" H) Modify R2.6.2 to remove the obligation to include the project initiation date. The inclusion of this date would add unnecessary work that is not needed to assure adequate BES reliability In addition, it is not clear whether "initiation" refers to the commencement of engineering, design, construction, etc.

A) Under R3, the Time Horizon of the TPL standards is intended for years one through 10; however, the Time Horizon shown in R3 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning". B) R3.3.3 Is this sub-requirement redundant with PRC-023-2? Is it covered in FAC-009? We believe the SDT should review these standards and if it is a redundant requirement, then this sub-requirement needs to be removed. C) Under R3.4 to make this requirement clearer, please add the following language between the words "expected to" in the first sentence: …expected by the assessing entity to…" We believe that this language addition improves the clarity of this requirement. The first sentence would then read: "Those Planning Event Contingencies in Table 1 that are expected by the assessing entity to produce more severe System impacts shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3.1 created." D) Under R3.5 to make this requirement clearer, please add the following language between the words "expected to" in the first sentence so that the phrase reads: "…expected by the assessing entity to…" We believe that this language addition improves the clarity of this requirement. The first sentence would then read: "Those Extreme Events in Table 1 that are expected by the assessing entity to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3.2 created."

Under R4, the Time Horizon of the TPL standards is intended for years one through 10; however, the Time Horizon shown in R4 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning".

Under R5, the Time Horizon of the TPL standards is intended for years one through 10; however, the Time Horizon shown in R5 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning".

Under R6, the Time Horizon of the TPL standards is intended for years one through 10; however, the Time Horizon shown in R6 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning".

Under R7, the Time Horizon of the TPL standards is intended for years one through 10; however,

the Time Horizon shown in R7 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning".

Yes

Yes

The stability studies require significantly more computer time and a more detailed model. The standard should allow the PC/TP to use judgment to manage size and complexity of the study.

Yes

Yes

Group

FMPA, and it's All-Requirements Project Participants, as follows: Lakeland Electric; Fort Pierce Utilities Authority; Keys Energy Services; City of Vero Beach; Beaches Energy Services; Kissimmee Utility Authority; and Lake Worth Utilities

R1, consider clarifying that it is not the TP or PC responsibility to independently verify the consistency of the System models for portions of the Bulk Electric System outside of the TP or PC planning area (related to not using data consistent with data submitted as part of MOD-010 and MOD-012, each TP and PC should not have to review the data submitted by those outside of its planning area, but only its own planning area). R1.1.2: Consider adding "Transformers" to the list of facilities. R1.1.2, please clarify what the SDTs intentions are for Circuit Breakers. Planning models used for power flow, dynamics and short circuit do not include circuit breakers. Modeling circuit breakers would cause convergence problems in the models due to that large number of zero impedance line sections. We suggest clarifying that the intent is to develop "planned" Facility Ratings in the models to reflect new Circuit Breakers, and to reflect the location and timing of circuit breakers in contingency lists, and not to model the actual circuit breakers. R1.1.2 "Protection System equipment" should be clarified to only apply to system stability models. The modeling of protective relays should be caveated with "as deemed appropriate". We suggest clarifying that the intent is, for power flow and short circuit studies, Protection System Equipment would be incorporated into Facility Ratings and the contingency list. And we suggest further clarifying that the intent is the same for Stability Studies, with the addition of modeling Protection System equipment that could significantly impact stability response (e.g., out-of-step relaying) as deemed appropriate through engineering judgment. R1.1.4 Consider adding "that is expected to be utilized in the study case scenario" not all Firm Transmission can be included in all studies and are only used upon the availability of other resources (for instance, if there are two firm point-to-point contracts in opposite directions across the same Interchange, both probably ought not to be modeled at the same time). Consider changing the effective dates of R1 and R7 to take effect at the same time as R2 through R6 so you do not have to meet two standards during the same time period. Otherwise, clarify how the effective date impacts which version of the standard is to be used in an assessment before a scheduled compliance audit.

Incorrect reference shown at the end of R2.1. The appropriate reference should be R2.5. The end of the first sentence of R2.3 should have a reference to R2.5. The end of the first sentence of R2.4 should have a reference to R2.5. R2.1.4, what does "(t)he analysis shall reflect the Contingencies identified in Table 1" mean? Is the intention similar to sensitivities, where there is no direct requirement to meet the performance standards of Table 1? If so, why not include loss of a long lead time Facility followed by other contingencies one of the Sensitivities and not have a separate sub-requirement for it? Or, is the intention that the TP and PC must meet the performance requirements of Table 1 considering the outage of a long lead time Facility? We hope that the intent is not to require Entities to be able to meet the performance requirements of Table 1 assuming a long lead time Facility out of service. If that is the intent, then we believe that only Contingencies P0- P2 in Table 1 ought to apply to Requirement R2.1.4. Otherwise, Requirement R2.1.4 would require building transmission to triple contingency (N-3) criteria. Contingency P3 requires building transmission to a single contingency plus a generator outage (a double contingency that has the same performance criteria requirements as single contingencies). Since generators are long term lead Facilities that no one that we know of carries spares for, R2.1.4 as written would mean that Contingency P3 becomes two generators out of service with system adjustments followed by another contingency (N-3). This would have the (possibly unintended) consequences of significantly reducing long-term firm ATC since utilities will likely use TRM to account for the potential for long-term outages. If meeting the criteria of Table 1 is the intent of the SDT, then a potential way to address this is to restate R2.1.4 to state that only P0 through P2 (zero and single contingency) apply to R2.1.4. If meeting the performance criteria of Table 1 is the intent of the SDT for R2.1.4, then we also believe that R2.1.4 should also only apply to the EHV and not the HV system. Yes, when a major piece of equipment such as a transformer fails, it could be out for a long period of time; however, a transformer failure is far less probable than an over-head transmission line failure (e.g., a

transformer failure is in the range of a once in 50 year event, whereas a transmission line fails probably once a year or once every other year, almost two orders of magnitude difference). A major 500 kV/230 kV autotransformer failure will have a far larger radius of impact than a 230 kV/138 kV autotransformer meant to serve the local area, giving additional support to purchasing a spare transformer for the 500/230 kV auto (EHV system). A small utility with only one or two 230 / 138 kV autos does not have sufficient justification to purchase a spare autotransformer due to the very low failure rate and the much more localized purpose of the transformer. If the intent of the SDT is to meet the performance requirements of Table 1 for R2.1.4, then the standard would essentially cause many small utilities who cannot justify spare autos to plan to serve only load and significantly reduce ATC in the planning horizon. Based on the lesser impact of HV connected autos as compared to EHV connected autos, and if the intent of the SDT is to meet the performance requirements of Table 1 for R2.1.4, then we would recommend that, for auto-transformers, R2.1.4 should only be applicable to EHV connected auto-transformers. R2.8 – Please explain the reason for this requirement. The effort required to collect this data is substantial and does not have any benefit to the BES. R2.9 – Please explain the reason for this requirement. It seems to cause Entities to develop performance criteria for themselves for Multiple and Extreme Contingencies that are not in Table 1. The effort required to collect this data to compare against any self-imposed criteria is substantial and does not have any benefit to the BES. The requirement will result in inconsistency across North America. There is also no discussion of what happens if a Multiple or Extreme contingency is shown to exceed the Entity's self-imposed criteria, is the Entity then non-compliant? If so, what if the Entity simply changes the self-imposed criteria?

R3.1, The criteria in Table 1 do not allow load shedding following a single contingency (e.g., the old footnote "b" was removed). While we agree this ought to be the case for the EHV system, we believe that there are cases where for the HV system, which often acts more like a distribution system, the costs to meet this standard would be prohibitive and unfair to the consumers served by those utilities. For instance, the Florida Keys served by the Florida Keys Electric Coop (FKEC) and Keys Energy Services (KEYS) is connected to the mainland by two 138 kV lines down to Tavernier Key (about 1/3rd the distance from the mainland to Key West). Currently, the system is planned and operated under single contingency to allow non consequential load shedding automatically via Under-Voltage Load Shedding, and to meet thermal limits by manual load shedding, all load shed is in the Florida Keys following the single contingency with no impact to the Bulk Electric System. The standard, as written, would force one of two things: 1) the construction of a third line in this environmentally pristine area at a very high cost that might increase rates to customers in the Florida Keys by 20% for a level of reliability that much of the Keys would not even experience since 2/3rds of the Keys is fed by a radial line with consequential load loss; or 2) separate the two lines such that both are operated radially with resultant consequential load loss, compliant with the standards, but actually causing consumers to have a lower level of reliability. We propose to reinstate footnote "b" for the HV system, allowing non-consequential load loss for lower voltage system that have little to no impact on the Bulk Electric System and limit the elimination of non-consequential load loss to be applicable to only the EHV. Alternatively, but less appealing and more of an administrative challenge would be to establish a Regional Entity administered process for application for exception to this criteria. FERC's Order 693 at paragraph 1794 states that: "(t)he Commission also clarifies that an entity may seek a regional difference to the Reliability Standard from the ERO for case-specific circumstances". We interpret this as meaning the Regional Entity can allow exceptions under certain criteria such as a significant increase in costs to consumers with little discernable benefit as is the case with the Florida Keys. For R3.2, we are at a loss of how a hurricane event can be modeled, and why such an evaluation is needed. Albeit, many contingencies can occur during a hurricane event, it is not likely that multiple contingencies will happen within the same < 1 minute window it takes to go from transient stability conditions to steady state conditions, and then it is unlikely that multiple significant contingency events will occur within the 30 minutes it takes operators to adjust the system to prepare for the next contingency. Therefore, we do not understand the significance of modeling a hurricane event. In addition, a hurricane can have an infinite number of different scenarios and time-lines of contingencies and picking one or two would be a meaningless exercise since an actual hurricane will be completely different than what is modeled. At least an earthquake has a fault line that makes it relatively easier to identify which facilities might be affected, but a hurricane has an infinite number of possibilities. We suggest eliminating hurricanes from extreme events and model potential results of a hurricane, such as loss of a ROW, loss of a substation or plant, and loss of a major load center. R3.3, the list ought to consider contingencies on neighboring systems that could impact the TP's / PC's system (this comment would not carry over to R4.3 since stability is more a protection system / clearing time issue). R3.3.1, the entity should not be held responsible for simulating "the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention" on neighboring systems, only on the Entity's own system. R3.4 and the first part of R3.5 ought to be combined, e.g., both require justification for why a limited set of worst case contingencies are studied for N-1, N-2 and extreme contingencies. The latter part of R3.5 concerning cascading outages for an extreme contingency should become the only requirement of R3.5 (there are currently two requirements

embedded within R3.5).

R4.2, see comment on R3.3 concerning how to model a hurricane event or other weather event. R4.3, contingency analysis ought to specifically exclude studying contingencies on neighboring systems since stability is more related to protection system and clearing times. R4.3.1, please clarify, is the intent of this requirement to have every distance relay in each Interconnect modeled? We suggest clarifying that the intent is that Protection System Equipment would be incorporated into Facility Ratings and the contingency list, and that modeling the Protection System equipment settings and logic would only be done for Protection Systems that could significantly impact stability response (e.g., out-of-step relaying) as deemed appropriate through engineering judgment, and that the intent would be to do this only for the Region under study and not the entire Interconnection (e.g., studies in Florida should not need to include relay models in Canada). R4.3.2, we assume that the intent of this requirement would be to help establish the magnitude and duration of acceptable post-transient voltage dips, presumable to meet the curve published in the PRC-023 standard under draft. Is this a correct assumption? We assume the drafting team does not expect models to be written for every generator to actually model potential loss of station service due to voltage dips and automatically model potential generator trips. R4.4 and R4.5, see comments on R3.4 and R3.5 about re-arranging these requirements.

No comments

Please clarify that the phrase “individual and joint responsibilities” applies to entities (e.g., the TPs and PCs) and not specific individuals.

No comments

Yes

No

Table 1 seems to have lost the requirement to be within Facility Ratings for single and double contingencies (e.g., the change in note “f” of Table 1). Are we missing something? If not, is this change intentional? Footnote 10 does not seem to adequately highlight that Facilities should be within applicable ratings for single and credible double contingencies. The table is significantly improved from the prior versions and provides superior clarification over the existing standards. However, please explain why there is a performance difference between P2.3 (breaker failure), P4 (stuck breaker) and P7 (2 circuits on a common tower) for EHV. Considering the frequency of these events in actual experience, it would seem that 2 circuits on a common tower should have a more restrictive or equal performance to a stuck breaker performance, yet the performance requirements are just the opposite. We recommend allowing curtailment of firm service and loss of non-consequential load for a stuck breaker or failed breaker.

Yes

We disagree with how the performance criteria is applied to different contingencies, but agree that firm transmission can be curtailed post-contingency as a system adjustment, and especially as preparation for the next contingency.

No

We suggest that the 60 month calendar apply to the HV system as well for all Categories. It is just as difficult, if not more difficult, to build a new 138 kV line in the Florida Keys as it is to build a 300+ kV line. The same time frame should apply to both. Also, as highlighted in the comments above to R2.1.4, P3 essentially causes utilities to build upgrades to N-3 planning criteria which may necessitate significant transmission upgrades if left unchanged. Hence, if left unchanged, P3 ought to have at least 5 years as well. The implementation plan ought to include an “out” for extenuating circumstances, e.g., unable to obtain ROW, etc. For instance, it is doubtful that another line in the Keys could ever get built without significant intervention and utilities that are unable to obtain ROW should not receive sanctions for something outside of their control. Consider changing the effective dates of R1 and R7 to take effect at the same time as R2 through R6 so you do not have to meet two standards during the same time period. Otherwise, clarify how the effective date impacts which version of the standard is to be used in an assessment before a scheduled compliance audit. The implementation should also be more specific on what “going into effect” means. Assessments are not a one day event but are a year long effort that culminates in a final “report” that is the assessment. Most NERC standards effect ongoing activities, and the day they go into effect the utilities functions are expected to be compliant. In this case that rationale would require that in the prior year two assessments were performed, one compliant with the current standard and one compliant with then new standard, however we don’t believe that was the intent. Perhaps a statement below the paragraph regarding the 60 month implementation plan for Corrective Action Plans to the effect of: “Once effective all future assessments shall upon completion be compliant with this standard. Assessments completed prior to the effective date shall be based on the TPL standards in effect at the time. The standard is not intended to require a retroactively compliant assessment be in effect when the standard becomes active, but instead that the next assessment be compliant with the revised standard”

Individual
Tim Wu
LADWP
For R1.1.4 the requirements should be based on "expected transfer" instead of "firm transmission service". When projecting into future, the term "firm transmission service" is meaningless because transmission service contracts can be changed overnight. Using "firm transmission service" as a base would also exclude any new contract that are not considered in the study. It is very short-sighted to plan new transmssion facilities only based on "firmed transmission services". R1.1.2 is very confusing. What is a new technology? Is it something we don't know? If we know what it is, is it still a new tchnology? If we don't know, how do we model it? Also, we do not model individual circuit breaker but the effect of the circuit breakers; same apply with control devices or protective system equipment. Need more clarity. In general, a laundry list of items to be represented is a bad idea because it gives the impression that anything not on the list does not need to be modeled.
R2.3 There is no value to conduct short circuit analysis on an annual basis. Short circuit contribution is location constrained. Maximum short circuit interrupting duty cannot be determined by any planning cases; so putting this requirement in TPL will cause only confusion and will creat misleading information. If there is a need to develop a standard on how to evaluate maximum short circuit interrupting duty, the more appropriate place would be FAC. R2.1.3 Controllable Loads and DWM: DSM should not be a stand alone item in planning studies because DSM already is imbedded in load forecasts. Not sure what controllable loads are. R2.1.4 Any requirment dealing with spare parts should be handled in TOP, not TPL. TOP is the forum to develop operating procedures,"work-arounds", and so on when the non-availability of spare forced a company to develop temporary mitigations and it would be a mistake to suggest that planners should be able to consider such temporary fixes as acceptable planning solutions. R 2.5.2 The 20 MW threshold, at best, is "noise" for us. We would not be concerned with generation chnages that is 10 times this threshold. What is the rationale for requiring a new study just because there is a change in generation capability? R2.8 and 2.9 What measurements would this required information be measured against? I can't find any and if there is no measurement, it really does not belong. R2.6.2 Project initiation date is hard to define. Is it the date the project is budgeted? or the date the management approved the budget and at what level? or is it the date when engineering design is initiated? For both short term and long term planning horizons, the project in service date should be sufficient. there are too many variables to define "project initiation date" not to mention there is no measurable to benchmark such a requirement.
R3.4 This requirement is very strange. If there is a known planning event that is more severe than those listed in Table 1, it should be so identified in Table 1. It is not fair to ask every planner to search for more severe contingencies without any specifics. R3.4 should be deleted. R3.5 This is similar to R3.4; this requires proving of null set. The only way this requirement can be met is to perform an exhaustive and unlimited list of extreme event, real or imaginery, before a rationale can be rendered. This requirement should be deleted with the exception of the last sentence regarding "cascading outages.
R4.5 See coments on R3.4 and 3.5
What is a proxy as related to transmission planning? The drafting team should not introduce "non-standard" terms in a Standard document.
R6: Does this requirement requires authors of the planning assessment report should be identified? If so, can we use plain English like "The authors of the Planning Assessment report shall be identified". If not, please explain what this requirement is all about.
FERC 890 stands on its own, why should a planning standard refers to a FERC Order? Does this imply that if a FERC Order is not referenced in the planning standard, we can ignor the order?
No
UVLS should be an allowed mitigation for multiple contingencies, P3 and above. UVLS is an effective measure against voltage collapse, a system condition that if not mitigated in a timely fashion could lead to cascading events. Saqme with UFLS.
No
Table 1 continues with discriminatory performance criteria required of 300kV and above facilities. This new "higher" criteria could lead to endless argument and litigations as to who did what to whom if implemented. Currently, all transmission facilities have same performance criteria; the impacts of each new facility are carefully evaluated and mitigations are included as part of the Plan of Service. This new, discriminatory requirement would force everyone with EHV facilities to re-do its palnning studies and mitigate the impacts. Unfortunately, the real world is quite messy. For example, Company A has put in a 500KV line twenty years ago and since then, Companies B, C, and D have put in several underlying 230 kV, 115 kV lines. Is company A on hook now to mitigate all the problems for lines that came in later? Or is it required to re-create the conditions 20 years ago and mitigate only what would have been required. This is a very simplistic example to illustrate potential disagreements that would arise by this discriminatory criteria. If there is

any engineering evidence to support this arbitrary requiremnts, it has yet to be presented. As I commented in the past, the last two major cyctme wide cascading event, both in WECC AND THE Eastern Interconnect, were both caused by 230kV systems.
No
The use of the term"Firm Transmission Service" is problematic at best. See my comments on R1. The proper term is "Expected Transfer Level"
No
Cannot agree to something when this is not final.
Individual
John Collins
Platte River Power Authority
R1.1.2. "....for each year of the Near-Term and Long-Term..." Models for each year of the 10 years in the planning horizons are not developed in our Region. Please clarify your intention. R1.1.2. 3rd bullet - "Circuit breakers (or the effects of)" R1.1.2. 4th bullet - "Protection System equipment (or the effects of)" R1.1.2. 5th bullet - "Control devices (or the effects of)" R1.1.2. 6th bullet - "New techonologies (or the effects of)" R1.1.4. "Firm Transmission Service (or expected transfers)
R2.6.2. Expand on the meaning of the "initiation date." R2.8. I don't understand the relevance of this requirement. May your intention be explained differently? R2.9. I don't understand the relevance of this requirement. May your intention be explained differently?
R3.3.3. Zone 3 type relay loadability studies (single and multiple contingency analyses) should be performed in the OPERATING HORIZON to provide results flagged for possible problems to the Relay Engineers who will evaluate a relay setting change on an Facility or a modification to a relay setting for a new Facility about to be put in-service. I do not see the value of Zone 3 relay loadability checks in the Planning Horizon.
R4.3.2. Delete this requirement as it is covered under MOD-013-1, R1.2 for RRO Dynamics Data requirements. When the generator is modeled accordingly the generator's performance will be simulated and analyzed in the stability studies. R4.3.3. Delete this requirement as it is covered under MOD-013-1, R1.2 and R1.3 for RRO Dynamics Data requirements. When the generator is modeled accordingly the generator's performance will be simulated and analyzed in the stability studies.
R5. For clarification, please list examples of "proxies" that might be used.
R7. Delete this requirement as it is the responsibility of the Transmission Provider under FERC Order 890.
No
Non-Consequential Loss of Load - It is not clear in all the Load Loss definitions where planned load shedding or "controlled interruption of electric supply" belong. However, the NERC Webinar on June 30 was very helpful, and I make the following comment in line with the answer I heard to my question. A "Yes" in the last column of Table 1 means that planned load shedding or "controlled interruption of electric supply" is allowed for that Category of Contingencies. (For a P2.2 Bus Section Fault, SLG, HV, "Yes", one could choose to implement a planned load shedding procedure or scheme to meet system performance requirements.) Planned load shedding may be manual load shedding or automatic actions such as direct load tripping or UVLS for example. Therefore, please add mention of the planned load shedding or the "controlled interruption of electric supply" and list specific examples in the definition for "Non-Consequential Loss of Load."
No
At the top of Table 1 Planning Events, under "Stability Only:" regarding Note "i": Suggest deleting everything from "established" on to the end. (WECC establishes acceptable limits for transient voltage response.)
Yes
Individual
Larry Brusseau
MAPPCOR
R1 - what it means to include “requirements of regulatory authorities and other legal obligations”. Even if some version of this language is kept in the final standard, it seems to belong in R2 rather than R1. R1.1.1 - should remove the word “specifically” since it means nothing. Only known long-term outages of generation and transmission should be required to be modeled. R1.1.2 in the first line should have the word “studied” to avoid confusion, to read “New planned Facilities and changes to existing Facilities for each year studied of the …” R1 states that the models used in these studies shall be consistent with data provided through MOD-010 and MOD-012. The data submitted for these are updated on a schedule provided by the RRO and not

necessarily reflective of any emerging changes that may have occurred between the MOD data collection cycle. The requirement should allow for exceptions to allow the most recent information to be included in the TPL studies.
R2.1.1 –Consider calling this "Near Term years" instead of specifically naming certain years. R2.1.3 – eliminate the last bullet. Planned duration or timing of Transmission outages is part of R1.1.1 which already specifies that models will include planned outages of generation and transmission facilities. R2.1.4 – the second line is unclear. There is a reference to "…lead time of one year or more…" Is the intent for that to mean "… outage duration of one year or more…"? If so, it should be written that way. Also, in the 3rd line, eliminate the words "… an analysis of…" (otherwise it would direct one to assess an analysis.) This in essence is an N-3 study. This risk that a TO or GO takes will show up in the operations of the BES. Also some states assess a penalty for equipment that is sitting idle that cost the taxpayers, so you could be penalize for not have spare equipment or if you do have it. R2.2.1 – does this mean, for example, that entities may be doing 12 year or 15 year assessments? It should be written to say what it means. R2.4.1 – Change to read: "For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads or an aggregate System Load model which represents the overall dynamic behavior of the Load." R2.5.1 – Suggest deleting this requirement, and incorporating it into R2.5.2. R2.5.2 – Incorporate R.2.5.1 into R2.5.2; please modify the section as follows: For steady state, short circuit, or Stability analysis the study shall be less than five calendar years old or less: the latest Transmission Planning Horizon System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: • The addition/deletion/change of individual generating unit capability determined to be material by the Planning Coordinator or Transmission Planner. • An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES determined to be material by the Planning Coordinator or Transmission Planner. R2.6 – The creation of hard and fast Corrective Action Plans for the LTRA is not a good use of resources. The reason for planning studies is to uncover possible weak spots in the system for some number of years into the future, and then pursue additional studies to examine the issues. Planning studies include many assumptions, and the issues may not even arise on the real system. If they do, there may be many possible remedies. Creating CAPs with milestones and other firm dates for potential problems uncovered in assessments of future years is simply not practical, and the PC (PA) may have little or no influence on what remedy is selected even if a problem appears to be real. R2.6.2 – The phrase "Project Initiation Date" needs to be defined. It is unclear if this is this the date of ground breaking, purchase orders being issued, solution study initiation, etc. Additionally, in the second sentence the phrase "as well as an in-service date" should be modified to read "as well as a target in-service date". R2.6.3 – Plans can provide a target in-service year but not an actual in-service year. R2.6.4 – recommend clarifying how "situations beyond the control of the TP or PC" are determined. It is unclear if this is to imply that if something is outside of the control of the department who conducts the planning studies or if it is outside the control of the registered function's legal entity (i.e. corporation). There should be a cutoff point when changes occur beyond a certain date. When that date occurs, further changes will be evaluated in the next year's assessment. Otherwise, if a state makes a decision not to site a project a few weeks prior to the end of the assessment period, there will not be sufficient time to incorporate this into that year's assessment and develop corrective actions. R2.8 – appears to be nonessential information for reliability; for what purpose does this requirement exist? R2.9 - appears to be nonessential information for reliability; for what purpose does this requirement exist?
R3.3.2 – Traditionally transmission planners have used their judgment about the minimum steady state voltage limitations of generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R3.3.3 – PRC-023 requires relay loadability to be reflected in facility ratings. Therefore this additional requirement is unnecessary and should be deleted. R3.4 – is there a measure for what is a "more severe system impact"? R3.5 – Recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following: -Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events -It should be clear that an evaluation does not require solution development for all Extreme Events -Change "an evaluation of possible actions…" to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered."
R4.3.2 - Traditionally transmission planners have assumed that generators would ride through low voltages associated with Planning Events which is generally adequate for non-wind generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R4.5 -Recommend that the

requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following: -Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events -It should be clear that an evaluation does not require solution development for all Extreme Events -Change "an evaluation of possible actions…" to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered."

an example of proxy may be helpful, not all entities use proxies.

Propose expanding the scope of entities to consider, limit it to those entities that indicate a reliability need for coordination, and eliminate the direct reference to Order 890. Suggest this text: "Each Planning Coordinator shall establish a list of adjacent Planning Coordinators and any functional entity who has indicated a reliability need, distribute its Planning Assessment results to the listed entities and consider comments on the assumptions and results through an open and transparent peer review process."

Individual

Aaron Staley

Orlando Utlities Commission

-This section is very clear. Section R1.1.1 brings clarity to the question regarding planned outages. -The phrase "Models shall use data consistent with ….MOD-010", is the intent for the data to be "identical" to the data provided under MOD-10 and -12, or just "consistent." For example does the data in the study have to be the same or can the studies be based on older or more up to date data depending on when the studies took place?

-I think R2.1 has a typo and should reference requirement R2.5, not R2.6. -R2 Does the phrase "System Peak Load" require true system peak be tested, or a peak condition. As an example, FRCC experience a two peak loads, a summer peak that occurs regularly on summer afternoons, and a slightly higher winter peak that occurs only every few years. While the load is lower, the summer condition is more critical since it is coincident with high ambient temperatures resulting in line and generator capabilities lower then those in the winter. -Overall I think Section R2.5 is very valuable in clarifying that past studies can be used and what criteria needs to be met for them to be used. However in reading through all the requirements I am unclear if all the studies could be met using past studies of if some require a new study every year. If the intent is that some sub requirements can not be met with a past study, that should be made clearer through a foot note or a list under Section 2.5 showing which study requirements may depend only on past studies that are still current. -R2.5.1: Is 5 calendar years from the date the assessment is "final" or the date the study process for the assessment begins? -R2.5.2: I believe this requirement is a sound approach to establishing the validity of past studies. From the structure it appears that the list of material changes is intended as an example not a prescribed list? -R2.6: This requirement as written is a sound approach to building a reliable system. -R2.6: Requires a corrective action plan when performance will not be met in simulations. Is this just plan that covers the gap between simulation performance and desired performance? To take this example further, in application it would seem a project need may be identified in the current set of studies and added to the corrective plan, but once that project was added to the simulation model (in subsequent years studies) then the project would not longer appear in the corrective plan. As a minor issue, if the actual intent is for this plan to cover all planned projects, not just the gap between current plan and current study, could the name be changed to something like "Transmission improvement and operational plan", the name "corrective action plan" always implies to me that you've actually violated something and are trying to correct it rather then the natural evolution of transmission plans. The section of this requirement addressing sensitivities and the corrective action plan is excellent. -R2.6.4: This is an excellent addition. There are certainly cases where a utility that is closely interconnected can be affected by a change of a neighbor's transmission plan. Requiring documentation of the steps being taken to resolve the issue is the appropriate requirement to place on utilities in that position. -R2.9: Is this the largest actual Non Consequential load loss that could occur for those events based on simulation (like R2.8), or is it an overall criteria that the utility sets and applies to itself during studies to determine when a Non Consequential load loss is large enough to require further action?

For Requirement 3.3.1 and 3.3.4 I suggest adding language similar to 3.3.2 and 3.3.3 establishing that "studies shall consider" rather then requiring every simulation precisely recreate this usually minor part of system performance. These devices generally do not respond except for a nearby event, and even then their response is rarely such that it would make the situation "worse". The effect of these devices must be considered, but mandating that every simulation

faithfully reproduce the response of every device is not only an efficient way to do this, it actually provides a counter incentive to going above and beyond the standard requirements. Any simulation used to meet this standard that failed to precisely reproduce the performance of this equipment would be a violation of this requirement (as currently written). As such there is no incentive for an entity to include anything but the absolute minimum number of simulations required to meet the standard, since each extra simulation represents an opportunity to miss this requirement. Good planning is based on running a broad range of events against a broad range of conditions and evaluating those responses against a set of performance criteria. This is encouraged by requiring that studies consider the response of equipment to these events rather then mandating their precise reproduction in simulation.

For Requirement 4.3.1 and 4.3.3 I suggest adding language similar to 3.3.2 and 3.3.3 establishing that "studies shall consider" rather then requiring every simulation precisely recreate this usually minor part of system performance. These devices generally do not respond except for a nearby event, and even then their response is rarely such that it would make the situation "worse". The effect of these devices must be considered, but mandating that every simulation faithfully reproduce the response of every device is not only an efficient way to do this, it actually provides a counter incentive to going above and beyond the standard requirements. Any simulation used to meet this standard that failed to precisely reproduce the performance of this equipment would be a violation of this requirement (as currently written). As such there is no incentive for an entity to include anything but the absolute minimum number of simulations required to meet the standard, since each extra simulation represents an opportunity to miss this requirement. Good planning is based on running a broad range of events against a broad range of conditions and evaluating those responses against a set of performance criteria. This is encouraged by requiring that studies consider the response of equipment to these events rather then mandating their precise reproduction in simulation. Requirement 4.4 and 4.5 establish that only those events that would cause the most severe system impacts should be studied. This is an excellent requirement since it focuses the large resource requirement in performing these studies on the events that will provide the best information. Does the intent of the "More severe events" to establish actual study parameter extend between the planned events (R4.4) and extreme events (R4.5)? Or phrased another way, if an entity selects a proper range of extreme events and establishes that planning event performance requirements are met, could that be used as evidence that R4.4 is met as well, or would R4.4 require the same conditions be reproduced in their less severe configuration.

R6: Is this requirement intended for cases where the TP is not also their PC, or is this between adjacent PC's?

The term "results of the assessment", is this is the final end result that is shared and analyzed? A requirement should not reference an order or another non NERC document. All the requirements and measures for performance should be covered in the standard or through reference to another NERC approved standard. The language used in other standards would be more appropriate and directly auditable. Require that the PC/TP to share assessment and support material with those requesting entities and respond to any of their specific comments. This will insure openness and transparency in a manner and can be directly audited.

Yes

Good Job.

Yes

Comments: The table is significantly improved from the prior versions and provides superior clarification over the existing standards. In areas where an entity is the TSP and the PC, it is obvious that the Firm Service provided by the TSP falls within the performance requirements of the standard regarding curtailment. However if the firm service is provided by another TSP (a different PC) and causes a problem, who is responsible for insuring it does not have to be curtailed. As an example if System A has a firm transmission service agreement that under contingency causes a problem on System C, is system C in violation if the service has to be cut to protect their system, or is System A that granted and is responsible for the service?

Yes

Overall the plan is excellent! Allowing for a 60 month phase in of the more restrictive performance requirements and an exception for those who need longer to meet them is an equitable and reliable practice. Having R1 and R7 go into effect first though raises the question of what TPL standard is in effect during that time frame? I recommend having the entire standard go into effect at the same time and avoid that issue. There is limited benefit to R1 and R7 going into effect early. The implementation should also be more specific on what "going into effect" means. Assessments are not a one day event but are a year long effort that culminates in a final "report" that is the assessment. Most NERC standards affect ongoing activities, and the day they go into effect the utilities functions are expected to be compliant, this is not however so clear when the "function" is the culmination of a year long effort. Perhaps a statement below the paragraph regarding the 60 month carve out to the effect of: "Once this standard becomes

effective all future assessments shall be compliant with this standard. Assessments completed prior to the effective date shall be judged by their compliance with TPL standards in effect at the time."

Group

Progress Energy Carolina (PEC)

PEC would like clarification on the following: "Models for the Planning Assessment shall represent: Circuit Breakers, Protection System Equipment, etc." The clarification should state that the models do not have to explicitly include these elements as long as their effect can be modeled.

PEC believes that "R2.1.1. System peak Load for either Year One or year two, and for year five" is unneccesarily prescriptive. PEC recommends eliminating the Year One or year two addition. PEC believes that R2.1.4. concerning an entity's spare equipment strategy is overly conservative. The standard should only require N-2 deep planning and not N-3. PEC believes that for R2.4.1 "a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads" should be clarified to include "as appropriate" clause. Induction motor load modeling should not be required for all dynamic studies. PEC believes that for R2.5.2. The language "For steady state, short circuit, or Stability analysis: the present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area" needs to be made more clear. The important point is that material changes must be modeled if they have occurred. Also the 20MW threshold is far too small to be material. PEC believes that R2.8. and P2.9 are unnecessary and should be removed.

No comments

No comment

No comment

No comment

No comment

No

In this definition: "Year One: The first year that a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the current calendar year" recommend that the '12-18 months' specification be removed. It is confusing.

PEC prefers having separate tables for steady-state and dynamic analyses. PEC believes the requirements were more clear in that format.

No

PEC believes that Footnote 10 should be clarified. The proposed wording "Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered" is unclear. It is not clear what "relied upon" means. Also, thermal overloads on neighboring systems are generally the neighboring system's responsibility to mitigate.

No

More time than 12 months is needed for modeling the complete effects of Relay Protection Systems and the effects of Relay Loadability. PEC suggests that this period of time be extended to 24 months or longer.

Individual

Jason Shaver

American Transmission Company

We propose the following comments for R2: In sections R2.1.3 and R2.4.3 please explain the reference to "expected transfers" and how that differs from R1.1.5 "interchange." If these are analogous, then change the references to "interchange." Modify R2.5.2 second bullet to clarify that this addresses "an aggregated addition/deletion/change to a group of generating units directly connected through a shared step-up transformer . . . ." Modify R2.6.2 to remove the obligation to include the project initiation date. The inclusion of this date would add unnecessary work that is not needed to assure adequate BES reliability. In addition, it is not clear whether "initiation" refers to the commencement of engineering, design, construction, etc. ATC agrees that the Transmission Planner should be responsible for a corrective action plan (R 2.6) and its associated sub-requirements, but we do not agree that the Planning Coordinator should also be listed. Unlike a Transmission Planner, a Planning Coordinator does not have the ability or responsibility to implement a corrective action plan. Requirement 2.6 and its associated sub-requirements should be limited to only the Transmission Planner. Remove the R2.8 requirement. The activity of identifying and including the largest Consequential Load Loss caused by any P1 or any P2 events in the Planning Assessment may not assure adequate BES reliability. A P1 or P2 event with the largest Consequential Load Loss could occur at a location on the system that is

strong enough to not result in any performance violation. The amount of Consequential Load Loss may not have a relevant correlation to system performance and reliability. Remove the R2.9 requirement. The activity of identifying and including the maximum permissible Non-Consequential Load Loss caused by selected Table 1 Planning Events may not assure adequate BES reliability. The maximum permissible Non-Consequential Load Loss could occur at a location on the system that is strong enough to not result in any performance violation. The maximum amount of Non-Consequential Load Loss may not have a relevant correlation to system performance and reliability. Add R2.10. The obligation to identify and observe applicable steady state voltage and post-Contingency voltage deviations should be a Requirement, rather than performance note "a" in the Planning Events, Steady State Only section of Table 1. And the obligation to identify and observe applicable transient voltage response limits should be a Requirement, rather than performance note "b" in the Planning Events, Stability Only section of Table 1. In addition, due to the system limit requirements of FAC-010 and FAC-014 the reference to the PC and TP is unnecessary. We suggest this text: "The Planning Assessment shall identify the applicable steady state voltage, post-Contingency voltage deviations, and transient voltage response limits."

We propose the following comments for R3. Revise the R3.3.2 text to clarify that subsequent analysis is performed on generators whose voltages are expected to fall below the minimum voltage limits. We suggest this text: "Consider the minimum steady state voltage limitations of all generators and identify how generators with bus voltages below its minimum voltage limits are analyzed in the subsequent steady state simulations." Revise the R3.3.3 text to more clearly relate to the specific requirements in PRC-023. We suggest this text: "Incorporate relay loadability per PRC-023 and identify how relay loadability is analyzed in the steady state simulation." Add R3.3.5. The obligation to consider only planned System adjustments that are executable should be a Requirement, rather than performance note "e" in the Planning Events, Steady State & Stability section of Table 1. We suggest this text: "Consider planned System adjustments, such as Transmission configuration changes and redispatch of generation, that are executable within the time duration of the applicable Facility Ratings."

We propose the following comments for R4: Add R4.3.3 text to include relay loadability in the R4 (Stability) requirements to parallel R3.3.3 in the R3 (Steady State) requirement which would more clearly relate to the specific requirements in PRC-023. We suggest this text: "Incorporate relay loadability per PRC-023 and identify how relay loadability is analyzed in the dynamic simulation." In R4.3.4, we propose limiting the scope to automatic devices and adding the notion of "including but not limited to". We suggest R4.3.4 text of: "Simulate the expected automatic operation of existing and planned control devices including but not limited to generation exciter control and power system stabilizers, static VAR compensators, power flow controllers, and DC Transmission controllers." Add R4.3.5. The obligation to consider only planned System adjustments that are executable should be a Requirement, rather than performance note "e" in the Planning Events, Steady State & Stability section of Table 1. We suggest this text that matches R3.3.5: "Consider planned System adjustments, such as Transmission configuration changes and redispatch of generation, that are executable within the time duration of the applicable Facility Ratings."

We propose specifying that the proxy documentation be included in the Planning Assessment and add the rationale for the proxy. We suggest this text: "Each Transmission Planner and Planning Coordinator shall document within the Planning Assessment any proxies used in the analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding. The documentation will consist of the definition of each proxy used and the rationale for the proxies.

We agree with the revisions to R6.

We propose expanding the scope of entities to consider, limit it to those entities that indicate a reliability need for coordination, and eliminate the direct reference to FERC Order 890 and peer review. We suggest this text: "Each Planning Coordinator shall establish a list of adjacent Planning Coordinators and any functional entity who has indicated a reliability need, and distribute its Planning Assessment results to the listed entities and consider comments on the assumptions and results."

No

We suggest the following comments: Add a Consequential Generation Loss definition because both load and generation loss can be considered, but there is only Consequential Load Loss definition. We suggest text of: "Consequential Generation Loss: All Generation that is no longer delivered to any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions." Expand the Consequential Load Loss definition to include protection for abnormal operating conditions. We suggest text of: "Consequential Load Loss: All Load that is no longer served by any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions." Expand the Load Reduction definition to include consideration of TOP judgment and established protection schemes. We

suggest text of: "Load Reduction: The reduction of Load that is still connected to the System, but in the judgment of the Transmission Operator or through the previous established Special Protection Systems, Under-frequency Load Shedding programs, Over-frequency Load Shedding program, should be reduced to overcome to lower voltage conditions following a Planning or Extreme Event." Modify the Planning Assessment definition to more explicitly apply to the BES and the TPL-001 requirements. We suggest text of: "Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies in the BES from the steady state and stability performance requirements set forth in the TPL-001 standard." Modify the Planning Events definition to more explicitly apply to the TPL-001 requirements. We suggest text of: "Planning Events: Events that are identified in the steady state and stability performance requirements set forth in the TPL-001 standard." Expand the Year One definition to include the PC, refer to the Planning Assessment, and refer to the current calendar year. We suggest text of: "Year One: The first year that each Transmission Planner and Planning Coordinator is responsible for conducting a Planning Assessment. This is further defined as the planning window that begins 12-18 months from the current calendar year."

No

We suggest the following changes: We believe reference to the use of Load Reduction to meet steady state performance requirement was omitted in Planning Events, Steady State and Stability, Item b. We suggest modifying the last sentence in Item b: "However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirements." We propose limiting the scope to automatic devices in Planning Events, Steady State and Stability, Item c. We suggest text of: "c. Simulate the removal of all elements that Protection Systems and other Controls are expected to disconnect automatically for each Contingency". Remove performance note "e" in the Planning Events, Steady State & Stability section and replace it with R3.3.5 and R4.3.5, as suggested in the comments for R3 and R4. The qualification of allowable planned System adjustments should be a Requirement, rather than a performance note. Remove performance note "a" in the Planning Events, Steady State Only section, and replace it with R2.10, as suggested in the comments for R2. The obligation to identify and observe applicable steady state voltage and post-Contingency voltage deviations should be a Requirement, rather than a performance note. Remove performance note "b" in the Planning Events, Stability Only section and replace it with R2.10, as suggested in the comment for R2. The obligation to identify and observe applicable transient voltage response limits should be a Requirement, rather a performance note. Modify the P3 Category performance criteria to apply only to the loss of two generators because the probability of the loss of two base load generators is an order of magnitude greater than the loss of a generator and any other transmission element. We suggest the listing of: the loss of transmission circuit, transformer, shunt device, and single pole of DC line be removed from the P3 Events column. The corresponding events be moved to the P6 Category by "1. Generator" to the listing in the Initial System Condition (Loss of . . .) column. Limit the scope of the simulations in Item 1 of the Extreme Events, Steady State and Stability section to automatic systems and controls. We suggest this text: "1. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect automatically for each Contingency." Clarify the meaning of the loss of multiple circuits in Item 2.a of the Extreme Events, Steady State section by using wording similar to P7. We suggest this text: "a. Loss of three or more circuits that share a common structure." Clarify the reference to actual, historical operating experience in Item 3.b of the Extreme Events, Steady State section. We suggest this text: "b. Other events based upon actual operating experience that may result in wide area disturbances." Clarify the reference to actual, historical operating experience in Item 2.i of the Extreme Events, Stability State section. We suggest this text that is similar to Steady State, Item 3.b: "i. Other events based upon actual operating experience that may result in wide area disturbances." Further clarify the applicable shunt devices in Footnote 7 with this suggested text: "7. Requirements which are applicable to shunt devices, also apply to FACTS devices that are connected to ground, but not instrument voltage transformers or surge arresters." ATC suggest that following change to Table 1, footnote 4. Existing language: "Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems." Suggested Modification: "Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 100kV through the 300kV Systems."

Yes

No

We offer the following comments. The proposed standard implies that the 24 and 60 month periods run in parallel rather than sequentially. As currently proposed, the effective date for performing analyses and developing subsequent Corrective Action Plans is 24 months. If the identification of new needs and action plans take 24 months, then only 36 months would be left to implement the new action plans. It may not be feasible to install some BES facilities, especially above 300 kV in less than 3 years. Some EHV projects can take 5 to 10 years to

implement depending on the size, complexity, and controversial nature of the project. We suggest that the effective date be stated in a more "implementation dependent" rather than a "fixed timeframe" manner. Consider wording such as "tripping of Non-Consequential Load or curtailment of Firm Transmission Service (in accordance with Requirement R2.6.4) is allowed until Corrective Action Plans that are based on TPL-001-1 analyses can be implemented".

Individual

John Mayhan

Omaha Public Power District

No

Header note 'f' under Planning Events: The redline version shows that the sentence "Facility Ratings shall not be exceeded" was removed from the beginning of header note 'f' (header note 'b' in the previous draft). This sentence needs to be reinserted at the beginning of header note 'f'. The requirement that Facility Ratings not be exceeded is a core principle of steady-state transmission-system assessment and needs to be explicitly stated somewhere in the standard. If this sentence is not reinserted, it could lead to a situation where different regions come up with different interpretations of the manner in which Facility Ratings need to be respected. Category P2: In the third column of the table, there is a dotted line that appears to be separating two parts of the description for event type P2.3. It appears that this dotted line should be removed. Category P3: In the fifth, sixth, and seventh columns of the table, there is one set of cells for event types P3.1 through P3.4 and another set of cells for event type P3.5. Since these two sets of cells are identical, they can be merged into one set that applies to event types P3.1 through P3.5. This would make the presentation of requirements for Category P3 consistent with that of Category P1. Category P7: Category P7 requires analyzing SLG faults on any two circuits on common structures. Add language to clarify whether SLG faults on both the same and different phases of the two circuits need to be considered or whether it is sufficient to assume that the SLG faults occur on the same phase of the two circuits.

Individual

David Angell

Idaho Power

The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices where it is expected to impact the study outcome. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted.

Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement. R2.5 "20 MW threshold is too small. The limit should be based on a percentage of the study area's installed generating capacity. R2.8 should be deleted. It is not necessary for reliability. What will be done with this

information on the "largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event" if it is documented? R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.
R3.3.2 is unclear as drafted. The minimum steady state voltage limitation for synchronous generators is not a very meaningful value. All generators with an automatic voltage regulator will maintain the set point voltage until the VAR capability of the generator is exceeded, and then the voltage will deteriorate. R3.5 – The requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study is overly burdensome. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. Listing all possible extreme events could result in a limitless list.
R4.3.2 – Generation protection system contain up to a dozen tripping functions functions. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to do that for all generators in the system. R4.5 – Again I disagree with this requirement. It is the same as R3.5 and overly burdensome.
No
Claification is needed on the use of UVLS. Is it acceptable or not. Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss Allowed column is No, is load disconnecetd from the system by UVLS a violation? What about Supplemental Load Loss or UFLS?
No
P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements. As such, this is a low probability condition and loss of Non-Consequential load should be allowed for EHV. We disagree with raising the bar for EHV for P4.
Yes
No
I would like to review this after completion of the standard.
Individual
Casey Hashimoto
Turlock Irrigation District
TPL 001-1 R1 could potentially result in a WECC auditor having to determine compliance with "requirements of regulatory authorities and other legal obligations," beyond the scope of its expertise. TID proposes that if that language is to be retained, it shall be assumed that the requirements of regulatory authorities and other legal obligations are being simulated unless those other entities have formally found the member to be in violation of their requirements or obligations.
TID expresses concern that the planning extension of R2.2.1 could lead to a scenario where a single member's long term project (beyond 10 years) could then require all neighboring members to extend their own planning horizons (similar to a "lowest common denominator" issue) and face unnecessary technical issues.
In light of the fact that FERC has determined not to apply the Order No. 890 transmission planning processes requirement to non-public utilities, TID expresses concern over the reference to Order No. 890 in R7. TID recommends that this reference be replaced with a more direct instruction that details what exactly is meant by the requirement of "an open and transparent peer review process." R7 makes reference to the peer review process laid out in FERC Order No. 890. This reference to Order No. 890 is duplicative and vague and must be clarified. The peer review process set forth in Attachment K of Order No. 890, lays out nine different principles (Coordination, Openness, Transparency, Information Exchange, Comparability, Dispute Resolution, Regional Participation, Economic Planning Studies, and Cost Allocation for New

Projects). Most of these principles are inapplicable when placed in the context of NERC Reliability Standards. Subjecting NERC members to all of these vague and broad principles without specific guidance as to their application would be a significant burden. TID proposes that the reference to Order No. 890 be removed from R7 and replaced with a provision that expressly details the principles of openness and transparency that are contemplated in R7. Such an express provision would bring clarity to the requirement so that entities subject to R7 would know exactly what they are expected to do to comply with the requirements of R7. As it is now written, the broad reference to Order No. 890 is vague and confusing. TID is also concerned with the fact that the Violation Severity Levels for R7 now appear to run from High to Severe, with the potential of significant penalties being assessed on noncompliant entities. The High and Severe Violation Severity Levels for TLP-001-1 R7 are inappropriate given the already vague and conflicting guidance of R7, especially as R7 merely duplicates the Order No. 890 requirements. Once the reference to Order No. 890 is replaced with a provision that expressly provides specific guidance as to what is meant by the "open and transparent peer review process," the appropriate Violation Severity Level for R7 would be Low to Moderate.

Individual

Gregory Campoli

New York Independent System Operator

R1.1.1 requires that models shall represent planned outages of generation and transmission facilities, if specifically known. The standard should be clarified to state whether it allows or requires a PC/TP to include as part of the Assessment outages due to maintenance and due to construction programs where certain facilities are out of service during phases of construction. Such maintenance and construction schedules are established but may not be finalized over the planning horizon. Further, the standard is not clear whether planned outages are to be treated as creating a "normal system condition" or as a contingency from which system adjustments are made prior to subsequent events? MOD 10 and 12 are based on requirements determined by the RRO in MOD 11 and 13 respectively. Is this appropriate? Further, the PC is not an applicable entity in MOD 10 and 12. Moreover, the standard should define "other data sources". R1.1.2. states that models for facilities such as circuit breakers and protection systems should be represented. Comment - The list of facilities should be deleted for the following reasons: - it is not needed; - the NYISO does not model circuit breakers, Control Devices, and Protection Systems; - it is not consistent with the definition of 'Facilities' in the NERC Glossary.

R2.1.2 - System off-peak is more likely a stability issue than a steady state issue. If system off-peak becomes a steady state issue, it can be mitigated through generation redispatch. Accordingly, it appears that this requirement is not necessary for steady state analysis.˜ R2.1.4 - With respect to spare equipment strategy, this requirement potentially imposes a requirement to plan for three events, which is overly severe. As previously stated in R1, the system model should be a model of the projected system, which would include a long term actual forced outage. If this requirement is not referring to actual outages, then it is suggesting an N-1-1-1 analysis, which is a requirement that would require significant additional work with little value added for reliability because such contingencies have a very low probability. Under R2.5 - "Past Studies may be used to support the Planning Assessment if they meet the following requirements" and the sub-requirement R2.5.2 states that for SS, SC, or stability analysis "the PRESENT (emphasis added) System model shall not include any material changes, such as, …." The NYISO interprets this language to mean that past studies may be used to support planning assessments as long as there are no material changes to the LATEST PLANNING HORIZON system model. The Standards Drafting Team should clarify whether this interpretation is correct. The standard should further state whether, if there was a material change such as a 20 MW generator, the past study may be used if the impact of this small change is assessed. Finally, the regional entity should have a process to determine whether changes are material that is similar to the NPCC's process for determining what level of annual transmission review should be conducted each year.

R3.5. - The Extreme Events testing in Table 1 should be removed from this standard since there is no requirement to develop a Corrective Action Plan to address unacceptable consequences and the requirements are very general or vague. At a minimum, testing should only be required for EHV facilities or facilities specified by the Regional Entity – for example, NPCC designates facilities that can have consequences outside an area as bulk power system facilities.

The Standards Drafting Team should clarify the standard as to whether the PC will be expected to distribute the TP Planning Assessments as part of its coordination requirement?

No

The Year One definition is confusing. According to the definition, "Year One" can start any time between 12 and 18 months from a current calendar year. Is that January 1 of the current calendar year? Further, when does year 2, year 3, etc… start? Is this definition only applicable to the TP?

The stability studies require significantly more computer time and a more detailed model. The standard should allow the PC/TP to use judgment to manage size and complexity of the study.

The 3rd draft states the Plan will be addressed later in the project. Removal of these standards would not affect NERC and the RE's obligations to perform assessments. The Standards Drafting Team should clarify whether the PC/TP will be obligated under NERC Rules of Procedure to provide Assessments to NERC and the Regions upon request.

Group

FirstEnergy Corp

As stated in prior comment periods, we hold the opinion that the TPL-001-1 standard should start from the premise that a valid system model exist based on MOD-010, MOD-012 and other FERC approved MOD standards that are not referenced by this TPL-001-1 standard. The inclusion of R1 introduces an overlap and potential for double jeopardy violations that need not occur. The TPL-001-1 standard should not delve into model building and keep to its core purpose of assessing future performance of the BES. Specific comments, Requirements of R1 A. R1.1.2: The last bullet "New Technologies" is too vague and should be struck from the requirement. B. R1.1.4: It is not well understood how "Firm Transmission Service" would be evaluated by a compliance auditor when reviewing a simulation model. The models contain agreed upon Interchange Transactions between BA areas, but no details are provided to reflect individual Firm Transmission Service arrangements. In reality only the net-Interchange values between BA areas are reflected in the simulation models. C. R1.1.6: FE believes this requirement would be more accurately assigned to the Resource Planner or Load Serving Entity and not the Transmission Planner. We agree with the stated Measures, VRF, Time-Horizon, Data Retention and VSL of requirement R1

The standard provides prescriptive language in requirement R2.4.1 regarding dynamic stability load models but is silent on steady-state load modeling. Most transmission planners use a conservative approach of simulating constant power loads in the steady-state environment, but other steady-state load modeling assumptions such as constant impedance load and constant current load can be utilized. At a minimum, the standard should require the transmission planner to document its load modeling assumptions for steady-state simulations. To this end, we suggest a new sub-requirement R2.1.1 be placed ahead of the existing R2.1.1 that parallels R2.4.1 and indicates the TP should document its load modeling assumptions for steady-state simulations. Specific comments, Requirements of R2 A. R2.1: The requirement incorrectly references R2.6 which should be a reference to R2.5. B. R2.1.1: We propose that the SDT adjust requirement R2.1.1 to annually require one current year Near-Term and one Long-Term study, with the Long-Term study required to alternate between year six and year ten every other assessment year. This would reduce the workload on the industry and cover the mid-point transition period between the Near-term and Long-Term horizons that the standard team believes needs some attention. We find the requirement to perform two Near-Term studies and one Long-Term study each year overly burdensome, in light of the increased workload caused by sensitivity analysis for each steady-state and stability review that is required. FE believes that one current year study within each time period should suffice in being able to interpolate and extrapolate results to cover the entire assessment range; especially when supplemented with qualified past study results. C. We offer the following comments related to requirement R2.4.1: 1. In the last round of comments we made the following comment "This requirement should be separated into two requirements as it covers two distinct topics; a) peak load study for one of the near-term years and b) dynamic load modeling." The SDT responded "...This Requirement is to make you properly represent the dynamic behavior of Loads at high System Load levels." Apparently, the SDT did not agree with our recommendation to split the requirement as no change was made in this regard. Therefore, as written the standard in R2.4.2 (stability study of the Off-Peak Load level) seems to imply that the appropriate modeling of dynamic behavior of loads, including consideration of induction motor loads, is NOT required for the Off-Peak Load stability study. Please clarify or confirm this view of R2.4.2. 2. R2.4.1: We are still of the opinion that the word "appropriately" is vague and only serves to add confusion within this requirement. It's recommended that "appropriately" be struck from the requirement. 3. R2.4.1: In Draft 3, the SDT added text to this requirement that states "An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable" to clarify that a detailed dynamic Load model is not required at each bus. We understand this to mean that the model is not expected to try and replicate the dynamic behavior of individual end-user Load characteristics and that general approximations for a customer class(es) (residential, commercial or industrial) simulated at a given load bus is acceptable. 4. Based on our comments C.1 through C.3 we propose the following requirement language: R2.4.1. System peak Load for one of the

five years. R2.4.2. System Off-Peak Load for on of the five years. R2.4.3. Load models used for stability analysis shall represent the dynamic behavior of Loads, including the behavior of induction motor Loads. The study shall document assumptions made for representing the dynamic behavior of Loads, based on the following load classes - residential, commercial and industrial. D. R2.5.2: For clarity and readability we propose to insert the word "that" between the words "and would" so the requirement reads "...intervening period and that would impact ...". E. R2.6.1: This requirement indicates that an entity's Corrective Action Plans list situations where Table 1 Performance Criteria are not met and the associated actions needed to achieve required System performance. What if the actions and plans associated with newly identified deficiencies (current year studies) are not yet fully known and require further analysis and a more detailed study of various options. Would it be acceptable for a TP to indicate that the planned solution is To Be Determined? This could be a likely scenario for a long-term planning horizon study which may identify a number of deficiencies which require more detailed analysis to determine the appropriate solution. F. R2.6.2: We believe this requirement is overly prescriptive in requiring a project initiate date. The standard should not question an entity's project management but stay focused on whether or not the Correct Action Plan was put in place in a timely fashion. We propose that the team strike from this requirement the reference to project initiation date and focus on whether or not Corrective Action Plans were completed in a timely manner to ensure Table 1 Performance Criteria is met. Additionally, project initiation date is pertinent to a operating procedure solution that is allowed by the standard. R2.6.4: We support requirement R2.6.4 but suggest the word "prudent" be struck from the text of the requirement as it can be subjective and open for debate. G. R2.7: This requirement introduces additional Corrective Action Plan requirements beyond what is stated in R2.6. FE proposes that the SDT restructure the two requirements into a single requirement (and sub-requirements) focused on Corrective Action Plans. H. R2.8: Does this requirement apply to sensitivity simulations? If so, it has limited applications to only those sensitivity analyses that consider variations in load such as a higher forecast (90/10), or increased reactive load (sensitivity to poor power-factor loads), etc. The SDT should consider clarifying the intent of the requirement if each current year study as well as their corresponding sensitivity simulation model(s) is intended to have this information documented within the assessment report. I. R2.9: We ask the SDT to confirm or correct our understanding that the requirement is asking about a TP's criteria for maximum allowable non-consequential load drop and NOT the maximum non-consequential load shed required to meet performance criteria for a particular contingency evaluation. We agree with the stated Measures, VRF, Time-Horizon, Data Retention and VSL of requirement R2

Specific comments, Requirements of R3: A. R3: For readability revise "computer simulations using models utilizing data" to "computer simulation models utilizing data" B. R3.3.2: The intent of this requirement is not clear. What is the voltage limitation sought? Vmin at the generator terminals, high-side of the GSU, low-side GSU, etc.? Also the requirement text "identify how the generators are analyzed in the steady state simulation" does not drive a particular reliability goal. If the objective is to require tripping of units during a contingency simulation that are identified to be below their stated Vmin then the requirement should clearly state that the unit should be tripped and solution resolved. C. R3.3.3: This requirement should be removed as it is redundant with facility rating requirements stated in PRC-023, FAC-008 and FAC-009. D. R3.3.4: For readability we suggest inserting the word "may" in between "devices include". We agree with the stated Measures, VRF, Time-Horizon, Data Retention and VSL of requirement R3

Specific comments, Requirements of R4: A. R4.1: A space is needed between the text "Requirement and R4.4" which are run together in the requirement. B. R4.3.3: For readability we suggest inserting the word "may" in between "devices include". We agree with the stated Measures, VRF, Time-Horizon, Data Retention and VSL of requirement R4

We agree with the stated Requirement, Measure, VRF, Time-Horizon, Data Retention and VSL of requirement R5.

We agree with the stated Requirement, Measure, VRF, Time-Horizon, Data Retention and VSL of requirement R6.

We agree with the stated Requirement, Measure, VRF, Time-Horizon, Data Retention and VSL of requirement R7.

No

A. Supplemental Load Loss: We disagree with newly proposed definition for "Supplemental Load Loss" which is introduced to address some stakeholders concerns related to a Load's response to transient conditions. Table 1 note "b" causes confusion indicating that Supplemental Load Loss is an acceptable consequence of a Planning Event or an Extreme Event but then goes on to say that Supplemental Load Loss can not be relied upon to meet steady state performance requirements. This seems to imply that it is permissible to use Supplemental Load Loss for stability analysis. It is not logical to allow its use in one time frame but not the other. The inclusion of the Supplemental Load Loss definition enters into a power quality issue at the end-user delivery point which is not the focus of the TPL-001-1 standard. FE suggests that this definition be removed. B. Load Reduction: The new proposed definition of "Load Reduction" while technically written correctly may not align with its common use throughout industry. Load Reduction is often thought of as an operator initiated response, rather than a natural system

response to a contingency event. If the definition remains, the SDT should consider striking the text "following a Planning or Extreme Event" so that the definition can more generally apply to other areas of the standards if needed. However, as stated in question 9, we believe Load Reduction was inadvertently omitted in note "b" of the Table 1. If so, we would have similar concerns with the occasional use of Load Reduction in that it would be allowed in stability and excluded in steady-state FE suggests that this definition be removed. The "Load Reduction" definitional term brings into question what is an acceptable steady-state load model within the TPL-001-1 standard. The standard provides some prescriptive language in requirement R2.4.1 regarding dynamic stability load models but is silent on steady-state load modeling. Most transmission planners use a conservative approach of simulating constant power loads in the steady-state environment and therefore the "Load Reduction" definition would not apply. However, if a constant impedance load model were used, Load Reduction would be reflected and less conservative outcomes would result. At a minimum, the standard should require the transmission planner to document its load modeling assumptions for steady-state simulations. [See above comment on Question 2 regarding a proposed new R2.1.1 requirement] C. Year One: We continue to oppose the Year One definition developed by the SDT. In our Draft 2 comments, FirstEnergy proposed a Year One definition of "The planning year that begins with the upcoming annual period under study". During the last comment period we indicated: "We believe the attempt to try and delineate between the near-term planning horizon and operational planning horizon is not needed within the TPL standard and that the near-term period should account for the upcoming annual study periods. If not revised, the need for two near-term studies on an annual basis is overly burdensome as many transmission planning organizations perform upcoming annual seasonal assessments for seasonal peak (summer/winter) periods. Requiring an additional two studies near-term does not provide significant benefit. Further reasoning for making the change is the allowance of operating procedures as part of Corrective Action plans. Operating procedures can easily be developed and implemented to mitigate projected performance violations prior to an upcoming seasonal period." The SDT's response from the Draft 2 comment period indicated "The standard does not require that studies are duplicated. If an operating study can be used to demonstrate an assessment for planning purposes, then the operating study would be sufficient." Since "Year One" is defined as "...a planning window that begins 12-18 months from the current calendar year" we would appreciate the SDT reconciling their Draft 2 response to the Year One definition and confirm whether or not it intends that a study of the next occurring seasonal peak period would suffice for meeting one of the current year Near-Term studies as required in requirement R2.1.1. A secondary concern with the Year One definition is its reference to the Transmission Planner with no mention of the Planning Coordinator. D. Planning Assessment: We suggest that the team consider an enhancement to the definition of "Planning Assessment". When read independently within the NERC Glossary of Terms a lay person should have a better understanding of the transmission Planning Assessment and it should set the foundational understanding that a Planning Assessment is not equivalent to a single study but rather a collection of studies. Additionally, the definition should more explicitly apply to the TPL-001-1 intended purpose. We propose a new definition based largely on the verbiage in requirement R2. "Planning Assessment: An annual documented evaluation of future Transmission System performance predicted over a minimum 10-year period, based on new or previously completed simulation studies and the Corrective Action Plans needed to satisfy steady-state, stability and short circuit performance requirements." E. Planning Event: We propose that the definition of "Planning Event" more explicitly apply to the TPL-001-1 standard and read as follows: "Planning Event: A contingency condition evaluated for its steady-state and stability impacts on the BES transmission System, requiring Corrective Action plans to remedy identified deficiencies" F. Consequential Load Loss: We suggest that the definition be revised to more closely align with the text stated in requirement R3.3.1. The proposed definition would read "Consequential Load Loss: All Load that is no longer served by any Transmission Facilities as a result of the removal of all elements that the Protection System and other automatic controls are expected to disconnect for a transmission System Contingency without operator intervention." If our proposed new definition is not acceptable, we suggest that the word "automatically" be added between "being removed" and replace "a planned" with "as designed".

No

A. Note b: Please see comments in our response to Question #8 related to note b and the Supplemental Load definition. B. Note b: We believe the SDT inadvertently allowed the used of Load Reduction to meet Steady State performance requirements. We suggest text of: "However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirements." C. Note b: If our assumption is correct on item B above, we fail to see the need to define two terms Load Reduction and Supplemental Load Loss which are not permitted within the Table 1 performance requirements for steady-state nor mentioned and used within the requirement language. It appears that the Load Reduction and Supplemental Load Loss are permissible within the stability timeframe. It is not understood why it would be valid to account for these in the stability timeframe but not steady-state. D. Note i: What if the TP or PC has no criteria for transient voltage response? The standard should have a requirement that ensures that such a criteria is documented by the entity if it is intended to be used within the TPL-001-1 standard. E. P2-3: It seems that footnote 10 should apply to the EHV

criteria stated in the column titled "Interruption of Firm Transmission Service Allowed" since it applies for the P5-1 through P5-5 EHV criterion. F. P5: We agree with the change made in Draft 3 to remove the reference to "single component" of the Protection System. Additionally, the SDT clarified its intended purpose of the P5 event as stated in the Draft 2, Q7 Summary Considerations: "A number of commenters expressed concern related to Planning Event P5 Protection System Failure and the need to evaluate a single component failure of a BES Protection System; particularly a failure of a station battery. The SDT has revised the P5 Planning Event description to remove the reference to single component failure and the event description was changed to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to normal fault clearing. A Protection System failure resulting in loss of the substation (one voltage level plus transformers) would not qualify as a P5 Planning Event since that event is considered an Extreme Event. A Standard Authorization Request (SAR) has been issued for industry comment (1/20/2009 through 2/18/2009) based on work completed by the System Protection and Controls Task Force (SPCTF). The proposed project will address the need for Protection System redundancy, based on an n-1 failure of individual components of the Protection System." It is suggested that a footnote be added the text Protection System as stated in the P5 Event Description. The footnote should read "Failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to normal fault clearing. This contingency is NOT based on failure of any particular single component of the Protection System design." This footnote will help clarify the intent without having to rely on the Comment record established during this standard development project. In the Extreme Event table we suggest event identifiers that are similar to those used in the Planning Events table. For Extreme Steady State we suggest ESS1, ESS2-1, ESS2-1... ESS2-5, ESS3-1 and ESS3-2. For the Extreme Stability we suggest ES1, ES2-1...ES2-9. This will provide a short-cut reference for industry when referring to a particular event.

Yes

We presently agree with the Footnote 5 and Footnote 10 text.

No

We disagree with the proposed Implementation Plan. The implementation period for the TPL-001-1 transmission planning standard should be limited to the time needed to transition to the new study requirements. The proposed 5-year implementation for the "raise the bar" aspects of this standard delves into project management and review of capital construction progress which should remain outside the scope of this standard. The standard should only consider if an entity has completed the required studies and has developed Corrective Action Plans to ensure performance criteria is being maintained. The last paragraph of the Implementation Plan is not appropriate for the Implementation Plan as it discusses compliance enforcement information. This paragraph should be srtuck.

Individual

Greg Rowland

Duke Energy

Revise R1.1.2 to include the phrase “to be studied” as follows: “New planned Facilities and changes to existing Facilities for each year to be studied of the Near-Term and Long-Term Transmission Planning Horizon, such as :”

R2 – Instead of “document results” the requirement should be to “summarize results”. While results will be documented, the Planning Assessment should just include a summary. R2.1 – What’s the value in being able to use “qualified past studies” if you have to use “annual current studies”? Strike the words “supplemented with” and insert the word “or”. R2.5.2 – Suggest deleting the phrase “Material generation changes could include:” and the two accompanying bullets. A change of 20 MW on a large system may not always be material. R2.8 and R2.9 should be deleted. We don’t see a reliability-related need for these requirements. In the sub-requirements of 2.1.3 and 2.4.3, the use of the word “timing” is unclear. Consider using “in service date” or “schedule for”. R2.4.1: It is not clear how much Load a dynamic model must have. Likely, it must still be proven that the analysis software can accommodate every load in the model having a load model that includes induction motor models. To help address this, revise “Load” to be “Load that could impact the study area is acceptable.”

Revise M3 to include a reference to R6, since the allocation of responsibilities will directly affect the evidence which is to be provided.

Revise M4 to include a reference to R6, since the allocation of responsibilities will directly affect the evidence which is to be provided.

M5 doesn’t make any sense. Need to revise this Measure so that it fits the Requirement R5. Also need to revise the Data Retention discussion in Section 1.4 to align with R5.

Requirements R1, R2, R3, R4 and R5 should all be revised to include a reference to R6 regarding the determination of individual and joint responsibilities for performing the required studies.

No

Bus-tie Breaker definitions still seems somewhat generic and the use of 'configurations' causes uncertainty. Revise Bus-tie Breaker to read, "A circuit breaker whose intended purpose is to connect two individual substation buses." "Bus-tie" is not capitalized in the Table. Consequential Load Loss must include load that is lost due to the inherent response of the particular type of load. Some motors, lighting and processes will naturally trip during an event, although not as a result of the protection system. It may have been the intent of the SDT to include this phenomenon in the Supplemental Load Loss definition. However, this definition includes the phrase, "by end-user equipment", and that makes one think that there are devices at the end-user location that are removing this equipment (and conversely, load that is not disconnected "by" end-user equipment cannot be included). Also, the term "post-Contingency" can be confusing because in the case of faults, this phrase is not clear if it means conditions after the fault initiation itself or only after the clearing of the fault. Revise Supplemental Load Loss to read, "End-user Load that, due to its characteristics, disconnects from the System in response to the conditions created by the System event."

Yes

No

Stability Extreme 2g needs a note like number 12 that excludes short distances. Stability Extreme 2h: Is this meant to be an event initiated by a 3LG fault or is it a catastrophic event that leaves all the elements at a station with a 3LG fault. If it is the former, then 2h needs a note to limit this to locations where actual events could lead to the loss of the entire station. There is no need to study this if there are no protection system events that lead to loss of the whole station (there would be no scenario to model). If 2h is meant to represent some catastrophe that causes all the elements at the site to experience a fault, then some clarification is needed to get consistent studies. Possibly rewrite 2h as, “Assume all the buses at a single voltage level (one voltage level plus transformers) experience an event that results in a 3LG fault and disables local protection (fault must clear from remote stations or other side of transformer).”

No

Requirements R2 through R6 are proposed to become effective the first day of the first calendar quarter 24 months after applicable regulatory approval, and we agree with that. However, the standard also provides that for 60 months following the first day of the first calendar quarter following applicable regulatory approval, Corrective Action Plans applying to performance elements P2-1, P2-2 (above 300 kV), P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 kV) are allowed to include tripping of Non-Consequential Load or curtailment of Firm Transmission Service (in accordance with Requirement R2.6.4) that would not otherwise be permitted by the requirements of TPL-001-1. Since the first 24 months following regulatory approval will be spent developing and validating new studies and methodologies needed to meet TPL-001-1, that would only leave 36 months to implement corrective actions. We propose that the 60 month clock start with the effective dates of Requirements R2 through R6, to allow sufficient time to implement corrective actions that are determined within the 24 month period, which could include system modifications that require long lead times. Also, the implementation plan contains the following wording regarding retirement of the existing TPL standards: “TPL-001-0, TPL-002-0a, TPL-003-0a, and TPL-004-0 are being retired as they are replaced in their entirety by TPL-001-1. TPL-005-0 and TPL-006-0 are being retired because their requirements are adequately covered by the revised TPL-001-1 and NERC’s Rules of Procedure, Section 800.” TPL-001-1 should not be used as a vehicle for fulfilling any of the TPL-005-0 and 006-0 requirements because of the difference in focus and entities involved. In reality, the new TPL-001-1 does not appear to have incorporated any of the requirements of TPL-005-0 and 006-0. TPL-001-1 appropriately focuses on how PC’s and TP’s should perform studies and document assessments of their transmission facilities’ impact on BES reliability. TPL-005-0 and 006-0 focus on assessments of regional and inter-regional BES reliability, including other non-transmission issues as well. The NERC Rules of Procedure and existing FERC Order 890 efforts appear to be sufficient to cover the requirements of TPL-005-0 and 006-0. Therefore, retirement of TPL-005-0 and 006-0 is still appropriate.

Individual

David M. Conroy

Central Maine Power Company

R1 Priority Comment- There needs to be some direction provided on the initial conditions used in the assessment. This guidance should include discussion as to whether or not representations of generator forced outages are to be represented in the base case or if they are addressed through the sensitivity testing (Could add R1.1.7 Reasonable representations of unplanned generator outages.) Additionally, the standard is also silent on the treatment of system transfers, both internal and external, as to how they should be modeled in the base case. For some areas, their

current practice is to include heavy system stresses in their base case, which leaves little for sensitivity testing. It is unclear if this practice works within this standard. R1.1.1 Priority comment – R1.1.1 should be removed. It seems like there is an overlap between the requirements of this standard and Operational Planning studies with respect to known outages. Planned outages are addressed by our Operational Planning processes and Transmission Operating Procedures removing the need for this to be incorporated into Planning Assessments. In addition, outages are not generally known years in advance R1 Comment – We do not understand what it means to include "requirements of regulatory authorities and other legal obligations". Even if some version of this language is kept in the final standard, it seems to belong in R2 rather than R1. R1.1.2 comment - Do we need to have the list of equipment to model? How do we model circuit breakers, etc? We recommend deleting the list. Make R1.1.2 simply read: R1.1.2 New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon. R1.1.5 comment – What specifically needs to be modeled under Interchange? R1.1.6 comment – This needs further definition or it should be deleted. It is not clear what a "network resource required to supply load" is. Does this refer to Network Resource per FERC LGIP?

R2 Comment – We recommend replacing the phrase "prepare" with "conduct and document" in the first sentence. R2.1.1 Comment – The requirement to evaluate year one or year two should be removed. This is not consistent with the time horizon identified in R2. R2.1.2 Comment – The requirement should be removed. With no description of the system stresses and generator outages to be applied when assessing the off-peak load, it is difficult to imagine any issues which would arise which are not revealed in the peak load evaluation that could not be addressed through generation dispatch adjustments. R2.1.3 Comment - The emphasis on sensitivity testing in the existing section appears misdirected and should be focused on reasonable risk. The assessment should have to include a discussion of reasonable risk. The sensitivity list can be used to select sensitivities to assess risk. Having a requirement to perform one sensitivity just to meet the requirement of the standard does not add value to the assessment. R2.1.4 Priority Comment – With respect to spare equipment strategy, this requirement imposes severe testing requirements upon the system. However, there is no discussion on the generation dispatch or system transfers that are to be used for this portion of the assessment. The expectations for changes in system stresses need to be clear as part of the standard. Additionally, this section does not contemplate changing the acceptability of load loss. After experiencing a major contingency such as this, some change in the acceptability of load loss should be expected. The standard should consider allowing Non-Consequential load loss for P1 & P2 events. The standard needs to allow Non-Consequential load loss for P3 & P4 events. Why doesn't the standard state "(such as a transformer, generator or power electronic device)" and not just "(such as a transformer)". What constitutes "spare equipment strategy"? Would a strategy that involves out-of-merit dispatch or operational restrictions be considered a valid "spare equipment strategy". If a transformer is lost, could a reconfiguration of transmission constitute a valid "spare equipment strategy"? R2.2 Comment – We suggest replacing the phrase "a current System peak Load study" with "a valid System peak Load study" in the first sentence. The word current is confusing as some read the word current to mean "today's" rather than "valid". R2.3 Comment – Please provide guidance as to what year should be represented when performing short circuit studies. R2.4.1 Comment – Change to read: "For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads or an aggregate System Load model which represents the overall dynamic behavior of the Load." R2.5.1 Comment– We suggest deleting this requirement, and incorporating it into R2.5.2. R2.5.2 Comment – To incorporate R.2.5.1 into R2.5.2; please modify the section as follows: For steady state, short circuit, or Stability analysis the study shall be less than five calendar years old or less: the present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: • The addition/deletion/change of individual generating unit capability determined to be material by the Planning Coordinator or Transmission Planner. [A 20 MVA generator is fairly small in a 30,000 MW system and system concerns would already be addressed though the System Impact Study] • An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES determined to be material by the Planning Coordinator or Transmission Planner. R2.6 Priority Comment – As written, this section undermines the value of the sensitivity testing. This section should require a corrective action plan to fix problems determined in sensitivity analysis if there is a reasonable risk of occurrence. We suggest making the standard read "Provide documentation that explains the reasoning for the sensitivities considered and selected." R2.6 Comment – At the end of the second sentence, the phrase "in the tables" is used. We suggest using more definitive language such as "in Table 1". R2.6.2 Comment – The phrase "Project Initiation Date" needs to be defined. It is unclear if this is this the date of ground breaking, purchase orders being issued, solution study initiation, etc. Additionally, in the second sentence the phrase "as well as an in-service date" should be modified to read "as well as a target in-service date". R2.6.3 Comment – Plans can provide a target in-service year but not an actual in-service year. R2.6.4 Priority Comment – There should be a cutoff point when changes occur beyond a certain date. When

that date occurs, further changes will be evaluated in the next year's assessment. Otherwise, if a state makes a decision not to site a project a few weeks prior to the end of the assessment period, there will not be sufficient time to incorporate this into that year's assessment and develop corrective actions. R2.8 Comment –Largest consequential load loss is not factored into the Planning Assessment and should therefore be deleted. R2.9 Comment – This requirement is unclear. Is this requirement asking for each transmission planner to list their criteria for non-consequential load loss, or is it asking how much non-consequential load loss was being relied upon in the assessment? We recommend that the requirement be modified to require documentation of the maximum amount of non-consequential load loss that was relied upon during the assessment.

R3.3.2 Comment – Traditionally transmission planners have used their judgment about the minimum steady state voltage limitations of generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R3.3.3 Comment – PRC-023 requires relay loadability to be reflected in facility ratings. Therefore this additional requirement is unnecessary and should be deleted. R3.5 Priority Comment – We recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following: - Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events - It should be clear that an evaluation does not require solution development for all Extreme Events Change "an evaluation of possible actions…" to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered."

R4.3.2 Priority Comment - Traditionally transmission planners have assumed that generators would ride through low voltages associated with Planning Events which is generally adequate for non-wind generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R4.5 Priority Comment – We recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following: - Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events - It should be clear that an evaluation does not require solution development for all Extreme Events Change "an evaluation of possible actions…" to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered."

Comments: It is unclear as to what is meant by the term "proxy used in the analysis" used in this requirement. Does this mean Planning Coordinator established practices, thresholds or guidelines used to gauge when simulations suggest an event such as cascading outages occurs? If so the language should state: R5. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, when established practices, thresholds or guidelines identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.

We do not feel that this requirement belongs in this standard and it should be deleted. The standard defines requirements for the assessment not who does what.

This standard should not be reiterating FERC Order 890. We do not feel that this requirement belongs in this standard and it should be deleted.

No

Refine load loss definitions as follows. Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions resulting from a Planning or Extreme Event. Non-Consequential Load Loss: Intended post contingency loss of load (other than Interruptible Load, Supplemental Load or Load Reduction) caused by operator or SPS (RAS) action. (Priority Comment)

No

Steady State & Stability comments as follows: Steady State & Stability: a. Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur. b. Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirements P5 Priority Comment – As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. P7 Priority Comment – Event 1 - This requirement requires the evaluation of the loss of two circuits on a multiple circuit tower. We recommend that this be modified so that only the loss of two adjacent (vertically or horizontally) circuits need be evaluated. We also recommend that the Planning Coordinator be

allowed to evaluate and if appropriate exempt specific locations from this contingency based on acceptable risk. Comments on Extreme Events – Table 1- We recommend renumbering the Extreme Events table to be Table 2. Extreme Event Stability Condition 2 Note a - Priority Comment - As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. Extreme Event Stability Condition 2 Note h – Eliminate this requirement or change to loss of station following three phase fault. This note is confusing. Without providing a better defined scenario, it is unclear as to what clearing times should be used in this simulation. Footnote 1.a.ii – Contingency Reserve is dependent on the generation on-line. We suggest changing the first sentence to say that you can't lose more than that permissible by the Planning Coordinator. Also change "pull out of synchronism" to "lose synchronism" in this sentence and in the second sentence. (Is "Lose synchronism" a more commonly used term?). Footnote 1.a.i, states "For Planning Event P1: No generating unit or units shall be allowed to pull out of synchronism." There is the potential for this requirement to be taken too far. Does this mean that someone's 4 kW generator at home needs to remain synchronized? Therefore, there needs to be some sort of qualifier on this requirement. Suggested wording: "For Planning Event P1: No generating unit or units greater than 20 MW and directly interconnected at 100 kV or above shall be allowed to lose synchronism. Note that synchronism applies to conventional synchronous generators and may not apply to other generation technology." Footnote 3 – We recommend revising the wording of the last sentence to "A three phase fault study indicating criteria are being met is sufficient evidence that a SLG condition would also meet criteria." Footnote 4 – We recommend that a lower bound be put on the HV electric systems (such as 100 kV), rather than just saying "and lower". Footnote 12 – We recommend adding an alternative modifier to the end of the sentence, "or for 5 towers or less." This is consistent with NPCC criteria.

Yes

Yes

Individual

Darcy O'Connell

California ISO

The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices where it is expected to impact the study outcome. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted. We disagree with the inclusion of the words "including requirements of regulatory authorities and other legal obligations" at the end of R1. Entities already are required to do this. It does not need to be included in the standard.

Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement. The 20 MW threshold identified as "material change" for generation in R2.5 is too small. The limit should be raised or based on a percentage of the study area's installed generating capacity. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the "largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event" if it is documented? R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.

As currently drafted, R3.3 is not a requirement. Without the statements in R3.3.1-R3.3.4, R3.3 is simply a phrase. Sub-Sub-Requirements R3.3.1 through R3.3.4 should be bullets under R3.3, with the language in R3.3 modified so that it becomes the requirement to conduct contingency analyses that address the four resulting bullets R3.3.2 is unclear as drafted. The minimum steady state voltage limitation for synchronous generators is not a very meaningful value. All generators with an automatic voltage regulator will maintain the set point voltage until the VAR capability of the generator is exceeded, and then the voltage will deteriorate. R3.5 – We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingencies than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.

As currently drafted, R4.3 is not a requirement. Without the statements in R4.3.1-R4.3.3, R4.3 is simply a phrase. Sub-Sub-Requirements R4.3.1 through R4.3.3 should be bullets under R4.3, with the language in R4.3 modified so that it becomes the requirement to conduct contingency analyses that address the three resulting bullets. R4.3.2 – it is not clear what is required to be modeled. Typically a generator may have 10 or more protective relays. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to do that for all generators in the system. R4.5 – We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingency than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.

The term proxy is unclear. Please provide an example or an explanation of proxy.

We believe that references to FERC Orders should not be included in requirements of standards. This comment also applies to M7.

No

Claification is needed on the use of UVLS. Is it acceptable or not. Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss Allowed column is No, is load disconnecetd from the system by UVLS a violation? What about Supplemental Load Loss or UFLS?

No

P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements. As such, this is a low probability condition and loss of Non-Consequential load should be allowed for EHV. We disagree with raising the bar for EHV for P4.

We agree that TPL-005 and TPL-006 appear to have been adequately covered in the draft TPL-001-1 as currently written. However, we will need to review this assessment after TPL-001-1 is finalized. In addition, there is no place to state our concerns for Section D. so we added it here. We question the "not applicable" entry under Section D 1.1.2. What does it mean when the reset period is not applicable? Does it mean there is no reset period, so all non-compliance in all prior years will be counted as prior violations when considering non-compliance in future years?

Individual

Gary Trent

Tucson Electric Power Company

The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices where it is expected to impact the study outcome. An alternative, instead of specifically listing elements, make a general statement that the models should include those elements required in MOD-010 through MOD-013. If an element is missing, double jeopardy could result due to a violation of the applicable MOD standard and this TPL standard. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4

should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted. We disagree with the inclusion of the words "including requirements of regulatory authorities and other legal obligations" at the end of R1. Entities already are required to do this. It does not need to be included in the standard.

Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). In R2.1, we believe the reference for past studies should be Requirement R2.5 not Requirement R2.6. Also, we suggest removing the phrase "supplemented with" and replacing it with the word "or". This phrase indicates that previous studies cannot be a primary source for the assessment, which contradicts section 2.5. Remove the phrase "not already included in the studies" in R2.1.3. With this phrase included, you cannot use a previous sensitivity study to support the current assessment and Requirement R2.5 allows the use of previous studies if the conditions are met. Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement. Remove the phrase "not already included in the studies" in R2.4.3. With this phrase included, you cannot use a previous sensitivity study to support the current assessment and Requirement R2.5 allows the use of previous studies if the conditions are met. The 20 MW threshold identified as "material change" for generation in R2.5 is too small. The limit should be raised or based on a percentage of the study area's installed generating capacity. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the "largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event" if it is documented? R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.

As currently drafted, R3.3 is not a requirement. Without the statements in R3.3.1-R3.3.4, R3.3 is simply a phrase. Sub-Sub-Requirements R3.3.1 through R3.3.4 should be bullets under R3.3, with the language in R3.3 modified so that it becomes the requirement to conduct contingency analyses that address the four resulting bullets R3.3.2 is unclear as drafted. The minimum steady state voltage limitation for synchronous generators is not a very meaningful value. All generators with an automatic voltage regulator will maintain the set point voltage until the VAR capability of the generator is exceeded, and then the voltage will deteriorate. R3.5 – We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingencies than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.

As currently drafted, R4.3 is not a requirement. Without the statements in R4.3.1-R4.3.3, R4.3 is simply a phrase. Sub-Sub-Requirements R4.3.1 through R4.3.3 should be bullets under R4.3, with the language in R4.3 modified so that it becomes the requirement to conduct contingency analyses that address the three resulting bullets. R4.3.2 – it is not clear what is required to be modeled. Typically a generator may have 10 or more protective relays. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to do that for all generators in the system. R4.5 – We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingency than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.

The term proxy is unclear. Please provide an example or an explanation of proxy.

We believe that references to FERC Orders should not be included in requirements of standards. This comment also applies to M7.

No

Claification is needed on the use of UVLS. Is it acceptable or not? Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss Allowed column is No, is load disconnecetd from the system by UVLS a violation? What about Supplemental Load Loss or UFLS? Year One – The use of calendar year is confusing. When does the 12-18 month window begin? We suggest "The year 18 months beyond the present month."

No

Clarify use of the term "single contingency" in P2 as P2-2 and P2-3 are labeled as single contingencies but multiple elements are effected. In the past loss of a branch or shunt element has been considered a single contingency but loss of a bus element could involve the loss of multiple branch or shunt elements. P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements. As such, this is a low probability condition and loss of Non-Consequential load should be allowed for EHV. We disagree with raising the bar for EHV for P4. We also disagree with raising the bar for P5. This is a multiple contingency condition and may result in loss of more than 2 elements. We strongly disagree with elimination of load shed (of non-consequential load) for loss of multiple branch or shunt elements >300 kV.

We agree that TPL-005 and TPL-006 appear to have been adequately covered in the draft TPL-001-1 as currently written. However, we will need to review this assessment after TPL-001-1 is finalized. In addition, there is no place to state our concerns for Section D. so we added it here. We question the "not applicable" entry under Section D 1.1.2. What does it mean when the reset period is not applicable? Does it mean there is no reset period, so all non-compliance in all prior years will be counted as prior violations when considering non-compliance in future years? We believe that 60 months is not sufficient to implement the Corrective Action Plan for the "raise the bar" requirements. Siting transmission lines can take longer than this window. We strongly recommend increasing the window to 120 months which is a more realistic estimate of the time required to bring an EHV transmission project from conception to construction.

Individual

Dan Rochester

Independent Electricity System Operator

1. R1: What modeling/simulation is envisaged by the phrase "requirements of regulatory authorities and other legal obligations"? Note that this condition is not included in the measure or the VSL, making its compliance (whatever it is) irrelevant. If it is indeed a needed condition, then it should be measured and included in the VSL language under the Severe condition. Further, we suggest replacing "simulate" with "incorporate" since R1 deals with building of the system model that will be used to perform simulations governed by Requirement R2. Moreover, we do not think this requirement (to simulate projected System conditions including requirements of regulatory authorities and other legal obligations) belongs to R1, which is a requirement to develop the system model. R2 is the requirement for conducting Planning Assessments which include simulation using the model. We suggest moving this requirement to R2 upon making appropriate changes, where necessary to address our comments on the wording. 2. We recommend introducing "applicable" before "regulatory authorities". 3. R1.1.2: suggest to add Transformers. 4. R1.1.5: suggest to change "Interchange" to "Interchange Schedules" or "Interchange Transactions". 5. We agree with the VRF, Time Horizon, Measures and VSLs, other than the "requirements of regulatory authorities and other legal obligations" noted above.

1. We think "conduct and document" is more appropriate than "prepare". Suggest to make this change. 2. We understand the reason for introducing the spare equipment strategy in R2.1.4 is to address comments raised on planned and long-term outages. However, this is not the only cause of unavailability of major Transmission equipment for more than 12 months. Construction or line upgrade program may also require certain transmission facilities be taken out of service for a protracted period. We suggest that R2.1.4 be revised to "……When an entity's spare equipment strategy or transmission project construction plan could result in the unavailability of….." 3. When would PCs and TPs be expected to perform the analysis referred to in R2.1.4 – in anticipation of the possibility of unavailability of major transmission equipment of after such unavailability has occurred or is planned? 4. R2.3: The first sentence is unclear and the wording "can be supported" is misleading. We suggest the first sentence be revised to: "The short circuit analysis portion of the Planning Assessment addressing the Near-Term Transmission Planning Horizon shall be conducted annually and be supported by current or past studies." Alternatively, language similar to R2.4 may be considered: "The Near-Term Transmission Planning Horizon portion of the short circuit analysis shall be assessed annually and be supported by current or

past studies." 5. R2.4 stipulates the details of the study for Near-Term Transmission Planning horizon for the stability analysis. Unlike its steady state analysis counterpart, there is no requirement stipulated for the Long-Term Transmission Planning horizon for the stability analysis. Is this intentional, or do the same conditions apply to the Long-Term stability analysis? 6. R2.6: Suggest to change "in the tables" to "Table 1" at the end of the second sentence. 7. We agree with the VRFs, Mitigation Horizons and Measures. We also agree with the VSLs except R2.5 is not included. However, If R2.5 is meant to be explanatory (to illustrate the conditions under which past studies may be used), then the conditions should be provided in those requirements (e.g. R2.3) that allow for the use of past studies. If, however, these conditions are meant to be requirements, then their VSLs should be developed.

1. In our opinion, R3 as drafted is rather convoluted as it attempts to cover several objectives. Firstly, we recommend replacing "utilizing data in Requirement R1" with "developed in accordance with Requirement R1" both in the requirement and the VSLs. Secondly, is the main objective of R3 to ensure studies are conducted based on computer simulation utilizing data provided in Requirement R1? Or is it to ensure that this is done, and that all the other objectives are also fulfilled, for example: assessment of system performance (R3.1 and R3.5), conducting the analysis as specified in R3.2 and R3.3, identification of critical Planning Event contingencies (R3.4), etc. If it is the former, then not conducting studies based on computer simulation utilizing data provided in Requirement R1 alone should have a VSL of Severe. If it is the latter, then the requirement should be either: (a) Revised to place all supporting conditions in the subrequirements. As an example, R3 could be revised as follows: R3. The steady state analyses of the Near-Term and Long-Term Planning Assessment as stipulated in R2.1 and R2.2 shall be performed as follows: R3.1. Studies are conducted based on computer simulation utilizing data provided in Requirement R1; R3.2. Studies shall be performed to determine…. (the rest of the existing R3.1) R3.2. The existing R3.3, and so on. This way, not conducting studies based on computer simulation utilizing data provided in Requirement R1 will be "rolled up" to the VSLs for the main requirement, as is currently stated in the VSL table. Or (b) Restructure, if there are multiple main objectives in R3, to clearly have the main objectives in the main requirement, or split it into more than one main requirement. 2. Based on the way R3 is written, we agree with the VRF, Time Horizon and Measure. However, we do have a difficulty with the VSL based on our comments above on the requirement, especially on the Moderate VSL for "The Transmission Planner or Planning Coordinator did not base its studies on computer simulations using models utilizing data provided in Requirement R1."

. Same comments as in R3, above, except our proposed wording on R4 will read: R4. The Stability analyses of the Near-Term Planning Assessment as stipulated in R2.4.2 shall be performed as follows:…. since there are no detailed requirements stipulated for Stability analysis portion for the Long-Term Planning Assessment. However, the main requirement contains a condition for performing the Contingency analyses listed in Table 1. First of all, there are no VSLs for failing to meet this condition. Secondly, this duplicates with some of the subrequirements, e.g. R4.4, R4.5. Suggest to remove this condition from the main requirement. If the main requirement is to be revised in a similar fashion as suggested for R3, then this will become a non-issue. 2. Similar to R3, we agree with the VRF, Time Horizon and Measure for R4. However, we do have the same difficulty with the VSL based on our comments on the convoluted nature of the requirement as indicated above, especially on the Moderate VSL for "The Transmission Planner or Planning Coordinator did not base its studies on computer simulations using models utilizing data provided in Requirement R1."

We agree with the requirement, the VRF, Time Horizon, Measure and VSLs.

We agree with the requirement, the VRF, Time Horizon, Measure and VSLs.

1. We question the need to mention FERC 890. If this meant to be an example for the US entities, we suggest this to be put into a footnote with indication that it is an example for the US entities only. 2. We agree with the requirement, the VRF, Time Horizon, Measure and VSLs.

No

Is Year One intended to coincide with a calendar year or can it start in any month of the year? We suggest the following change to the definition. Insert "calendar" before "first" and "within" before "12" and change "from" to "of". NERC should seek to reinstate a definition of "cascading outages" and create one for "uncontrolled islanding".

No

"Single-phase-to-ground" faults should replace all occurrences of "single-line-to-ground" faults. Events in P6 and P7 need more clarity for back to back installation where no DC line exists. In note footnote 11 we propose the following change. 11. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing. We do not agree with the removal of the provision to allow load rejection for 1 and 2 elements out of service under certain defined conditions as indicated in footnote "b" of Table I of the current TPL standards.

Yes

Group
IRC Standards Review Committee
(1) R1.1.1 requires that models shall represent planned outages of generation and transmission facilities, if specifically known. Does this allow or require a PC/TP to include outages due to maintenance and due to construction programs where certain facilities are out of service during phases of construction as part of the Assessment? Such maintenance and construction schedules are made but may not be finalized over the planning horizon. Further, are planned outages to be treated as creating a "normal system condition" or is the planned outage a contingency from which system adjustments are made prior to subsequent events? (2) MOD 10 and 12 are based on requirements determined by the RRO in MOD 11 and 13 respectively. Is this appropriate? Further, the PC is not an applicable entity in MOD 10 and 12. (3)What are "other data sources"?
(1) When a spare equipment strategy does not cover the long lead time unavailability as stated in 2.1.4, will the system be treated as "normal system condition" or as having a contingency from which system adjustments are to be made prior to subsequent events. (2) Under R2.5 "Past Studies may be used to support the Planning Assessment if they meet the following requirements" and the sub requirement R2.5.2 states that for SS, SC, or stability analysis; the PRESENT system model shall not include any material changes, such as …. Does this mean that past studies may be used to support planning assessments as long as there are no material changes to the present system model? If so, that would be an impossible scenario to recreate.
No comment.
No comment.
No comment
No comment.
Is the PC expected to distribute the TP Planning Assessments as part of its coordination requirement?
No
The Year One definition is confusing. According to the definition, Year One can start any time between 12 and 18 months from a current calendar year. Is that January 1 of the current calendar year? Further, when does year 2, year 3, etc… start? Is this definition only applicable to the TP?
Yes
The stability studies require significantly more computer time and a more detailed model. The standard should allow the PC/TP to use judgment to manage size and complexity of the study.
Yes
Yes
The 3rd draft states this will be addressed later in the project. Removal of these standards would not affect NERC and the RE's obligations to perform assessments. Will the PC/TP be obligated under NERC Rules of Procedure to provide Assessments to NERC and the Regions upon request?
Individual
Harold Wyble
Kansas City Power & Light
R1 states that the models used in these studies shall be consistent with data provided through MOD-010 and MOD-012. The data submitted for these are updated on a schedule provided by the RRO and not necessarily reflective of any emerging changes that may have occurred between the MOD data collection cycle. The requirement should allow for exceptions to allow the most recent information to be included in the TPL studies.
R2.1.3 – is this indicating that only one of the variations need to be studied? ("…in one or more of the following conditions…"). Recommend having the planner work with the load to determine what sensitivity studies to perform. R2.1.4 – it is unclear as to what should be done with the analysis that incorporates the company's spare equipment strategy. Is this requirement inferring that a company's spare equipment strategy need to ensure that it can still operate to within the requirements for contingencies of Table 1 without the component? R2.2.1 – is the intent to have the study for the 10 year horizon or to include any project that is started within the next 10 years and thus the study must be extended to the forecasted completion of the project (conceivably as long as 20 years or more?) R2.5.2 - Remove the word "intervening" and this requirement must be more specific about what this requirement is trying to communicate and acccomplish. R2.6.4 – recommend clarifying how "situations beyond the control of the TP or PC" are determined. It is unclear if this is to imply that if something is outside of the control of the department who conducts the planning studies or if it is outside the control of the registered function's legal entity (i.e. corporation). R2.8 – appears to be nonessential information for reliability; for what purpose does this requirement exist? R2.9 - appears to be nonessential information for reliability; for what purpose does this requirement exist?

R3.3.3: Relay loadability has no bearing beyond the near term horizon. Loadability is not determined several years out. R3.5 – does this imply that mitigation plans must be implemented? If not, then this is highly subjective and the last sentence of this requirement should be deleted.
R4.3 – requires very labor intensive and detailed studies to be conducted; there are concerns about being able to accomplish the required studies within the 24 month implementation period; additionally, while there may be some reliability benefit to requiring these studies have the costs of this reliability increase been studied?; an alternative could be some sort of phased implementation (x% completed by 24months, etc.) R4.3.3 – to what degree is generator relaying factored into the model/study?
The term "proxies" is somewhat confusing; recommend the use of "assumptions" if that is an acceptable substitute.
Why is this needed if both entities must comply with the standard? At a minimum the requirement should include language to state that the one party must provide to the other with enough notice to comply with a required study if there is a shift or assignment of a responsibility.
Recommend deleting the portion of the requirement that states: "coordinating analysis of these results through an open and transparent review process such as described in FERC Order 890."
Yes
Yes
Yes
No
Regional areas may be made up of multiple Planning Coordinators. It is important to maintain an assessment of an entire Regional Reliability Organizations area. TPL-005 and TPL-006 should not be replaced with this proposed TPL-001.

Consideration of Comments on Third Draft of Standard TPL-001-1 — Project 2006-02

The Assess Transmission Future Needs Standard Drafting Team thanks all commenters who submitted comments on the third draft of the TPL-001-1 standard. This standard was posted for a 45-day public comment period from May 26, 2009 through July 9, 2009. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 85 sets of comments, including comments from more than 170 different people from over 85 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

Due to industry comments and continuing review of Order 693 directives applicable to TPL, changes have been made to the following:

Definitions: Consequential Load Loss, Non-Consequential Load Loss, and Year One

Requirements: R1 and parts 1.1, 1.1.1, 1.1.2, 1.1.3, 1.1.4, 1.1.5, and 1.1.6; R2 and parts 2.1, 2.1.3, 2.1.4 (and bullets 1, 3, and 7), 2.1.5, 2.1.6, 2.2, 2.2.1, 2.3, 2.4, 2.4.1, 2.4.3 (and bullets 1 and 3), 2.5, 2.6.1, 2.6.2, 2.7, 2.7.1 bullet 2, 2.7.2, 2.7.5, 2.7.6, 2.8, 2.8.2, 2.9; R3 and parts 3.1, 3.2, 3.3, 3.3.2, 3.3.3, 3.3.4, 3.4, 3.4.1, 3.5, 3.6; R4 and parts 4.1, 4.1.1, 4.1.2, 4.1.3, 4.2, 4.3, 4.3.2, 4.3.3, 4.3.4, 4.4, 4.4.1, 4.5; R5, R6, R7; R8 and part 8.1.

Measures: M1, M5, M7, and M8.

VSLs: R1, R2, R3, R4, R5, R6, R7, and R8.

Table elements: Header notes 'a', 'c', 'f', and 'k'; P4, P7; extreme event 'a', steady state 1, Stability 1; footnotes: 2, 3, 4, 7, 9, 10, and 11

Implementation Plan

In addition, the SDT has reformatted the standard to meet the latest guidelines.

The SDT feels that the volume and scope of these changes warrants a fourth posting of this standard.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

1. Requirement R1 — Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement. 12

2. Requirement R2 — Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement. 59

3. Requirement R3 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement. 176

4. Requirement R4 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement. 211

5. Requirement R5 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement. 238

6. Requirement R6 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement. 245

7. Requirement R7 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement. 250

8. The SDT changed several definitions in response to industry comments to the second posting. Do you agree with these changes? If not, please clearly indicate which definition you disagree with and provide specific comments. 263

9. Do you agree with the changes in the performance elements and notes in Table 1? If not, please provide specific comments by note number, note alpha character, or performance category. Please note that footnotes 5 and 10 are handled separately in question 10. 289

10. The changes to the Table include the addition/revision of footnotes 5 and 10 that address curtailment of Firm Transmission Service and conditional Firm Transmission Service. Do you agree with the footnotes? If not, please provide specific comments.332

11. The SDT has provided an Implementation Plan as part of this posting. The plan includes the retirement of TPL-005-0 and TPL-006-0. Do you agree with the elements of the Plan? If not, please provide specific comments. 343

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	William Bigdely	Dominion - Electric Transmission	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	J. Ronnie Bailey	Dominion - Electric Transmission Planning	SERC	
2.	Kirit Doshi	Dominion - Electric Transmission Planning	SERC	
3.	Craig Crider	Dominion - Electric Transmission Planning	SERC	
4.	Mehdi Shakibafar	Dominion - Electric Transmission Planning	SERC	
5.	Dennis Kaminsky	Dominion - Electric Transmission Planning	SERC	
6.	Solomon Yirga	Dominion - Electric Transmission Planning	SERC	
7.	Michael Gildea	Dominion - Electric Market Policy	SERC	
8.	Louis Slade, Jr.	Dominion - Electric Market Policy	SERC	
9.	Jalal Babik	Dominion - Electric Market Policy	SERC	

2.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ralph Rufrano	New York Power Authority	NPCC	5
2.	Alan Adamson	New York State Reliability Council	NPCC	10
3.	Gregory Campoli	New York Independent System Operator	NPCC	2
4.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
5. Kurtis Chong	Independent Electricity System Operator	NPCC 2										
6. Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC 1										
7. Manuel Couto	National Grid	NPCC 1										
8. Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC 1										
9. Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC 3										
10. Mike Garton	Dominion Resources Services, Inc.	NPCC 5										
11. Brian L. Gooder	Ontario Power Generation Incorporated	NPCC 5										
12. Kathleen Goodman	ISO - New England	NPCC 2										
13. David Kiguel	Hydro One Networks Inc.	NPCC 1										
14. Michael R. Lombardi	Northeast Utilities	NPCC 1										
15. Michael Schiavone	National Grid	NPCC 1										
16. Bruce Metruck	New York Power Authority	NPCC 6										
17. Chris Orzel	FPL Energy/NextEra Energy	NPCC 5										
18. Robert Pellegrini	The United Illuminating Company	NPCC 1										
19. Gerry Dunbar	Northeast Power Coordinating Council	NPCC 10										
20. Lee Pedowicz	Northeast Power Coordinating Council	NPCC 10										
3. Group	W. R. Schoneck	Transmission Planning	X		X							

Additional Member	Additional Organization	Region	Segment Selection
1. John Shaffer	FPL	FRCC	
2. Pedro Modia	FPL	FRCC	
3. Carlos Candelaria	FPL	FRCC	
4. Kiko Barredo	FPL	FRCC	

4. Group	Phillip R. Kleckley	SERC Engineering Committee Planning Standards Subcommittee			X							

Additional Member	Additional Organization	Region	Segment Selection
1. John Sullivan	Ameren	SERC	1
2. Jim Kelley	PowerSouth Energy Coop	SERC	1
3. Pat Huntley	SERC Reliability Corp	SERC	10
4. Bob Jones	Southern Co. Services	SERC	1
5. David Marler	TVA	SERC	1

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
5.	Group	Steve Hill	Modesto Irrigation District	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Spencer Tacke	Modesto Irrigation	WECC	

6.	Group	Matt Muldoon	OPUC									X	

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jerry Murray	OPUC	WECC	9

7.	Group	Richard Kafka	Pepco Holdings, Inc. - Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Mitchell	Delmarva Power & Light	RFC	1
2.	John Radman	Potomac Electric Power Co.	RFC	1
3.	Jim Summers	Atlantic City Electric	RFC	1
4.	Brian Willis	Potomac Electric Power Co.	RFC	1
5.	Lisa Fairchild	Potomac Electric Power Co.	RFC	1

8.	Group	Denise Koehn	Bonneville Power Administration	X				X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Berhanu Tesema	Transmission Planning	WECC	1
2.	Chuck Matthews	Transmission Planning	WECC	1
3.	Kyle Kohne	Transmission Planning	WECC	1
4.	Melivin Rodrigues	Transmission Planning	WECC	1
5.	Kendall Rydell	Transmission Planning	WECC	1
6.	Larry Furumasu	Transmission Planning	WECC	1

9.	Group	Carol Gerou	MRO MRO NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Neal Balu	Wisconsin Public Service	MRO	3, 4, 5, 6
2.	Terry Bilke	Midwest ISO Inc.	MRO	2
3.	Ken Goldsmith	Alliant Energy	MRO	4

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
4. Jim Haigh	Western Area Power Administration	MRO	1, 6									
5. Joseph Knight	Great River Energy	MRO	1, 3, 5, 6									
6. Alice Murdock	Xcel Energy	MRO	1, 3, 5, 6									
7. Scott Nickels	Rochester Public Utilities	MRO	1, 3, 5, 6									
8. Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6									
9. Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6									
10. Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6									
10. Group	Rick Foster	SERC Engineering Committee Dynamics Review Subcommittee (DRS)	X									X

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren Services Company	SERC	1
2.	Anthony Williams	Duke Energy Carolinas	SERC	1
3.	Sujit Mandal	Entergy	SERC	1
4.	Venkat Kolluri	Entergy	SERC	1
5.	John O'Connor	Progress Energy Carolinas	SERC	1
6.	Bob Jones	Southern Company Services, Inc. - Trans	SERC	1
7.	Lee Taylor	Southern Company Services, Inc. - Trans	SERC	1
8.	Robbie Bottoms	Tennessee Valley Authority	SERC	1
9.	Tom Cain	Tennessee Valley Authority	SERC	1
10.	Herb Schrayshuen	SERC Reliability Corporation	SERC	10

11. Group	Ian Grant	SERC Engineering Committee Reliability Review Subcommittee (RRS)	X									X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Curtis Stepanek	Ameren Services Company	SERC	1
2.	Eugene Warnecke	Ameren Services Company	SERC	1
3.	Kevin Hopper	Associated Electric Cooperative, Inc.	SERC	1
4.	Karl Kohlrus	City of Springfield, IL - CWLP	SERC	1
5.	Brian D. Moss	Duke Energy Carolinas	SERC	1
6.	Julia Tucker	East Kentucky Power Cooperative	SERC	1
7.	Kham Vongkhamchanh	Entergy	SERC	1

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
8. Ken Wofford			Georgia Transmission Corporation SERC 1										
9. Mark Kuras			PJM Interconnection, LLC SERC 1										
10. Mark Byrd			Progress Energy Carolinas SERC 1										
11. Clay Young			South Carolina Electric & Gas Company SERC 1										
12. Rod Hardiman			Southern Company Services, Inc. - Trans SERC 1										
13. Timothy Smith			Tennessee Valley Authority SERC 1										
14. Herb Schrayshuen			SERC Reliability Corporation SERC 10										
12.	Group	Doug Hohlbaugh	FirstEnergy Corp	X		X	X	X	X				
Additional Member		**Additional Organization**	**Region** **Segment Selection**										
1. John Stephens		FE	RFC 1										
2. Jeff Mackauer		FE	RFC 1										
13.	Group	Ben Li	IRC Standards Review Committee		X								
Additional Member		**Additional Organization**	**Region** **Segment Selection**										
1. Matt Goldberg		ISO-NE	NPCC 2										
2. Bill Phillips		MISO	MRO 2										
3. Anita Lee		AESO	WECC 2										
4. James Castle		NYISO	NPCC 2										
5. Charles Yeung		SPP	SPP 2										
6. Steve Myers		ERCOT	ERCOT 2										
7. Lourdes Estrada-Salinero		CAISO	WECC 2										
8. Pat Brown		PJM	RFC 2										
14.	Individual	Tim Ponseti, VP	TVA System Planning	X									
15.	Individual	Eric Mortenson	Exelon Transmission Planning	X		X		X					
16.	Individual	Hugh Francis	Southern Company	X		X		X					
17.	Individual	David Bradt	United Illuminating	X									
18.	Individual	Cordell Grand	Louisiana Energy and Power Authority			X							

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
19.	Individual	Mark Graham	System Protection and Transmission Planning Department	X									
20.	Individual	John Cummings	PPL Energy Plus						X				
21.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
22.	Individual	Brandy A. Dunn	Western Area Power Administration	X									
23.	Individual	Min Tra	Tampa Electric	X				X					
24.	Individual	Richard Becker	Florida Reliability Coordinating Council, Inc - Transmission Working Group	X			X	X					X
25.	Group	Frank Gaffney, Regulatory Compliance Officer	FMPA, and it's All-Requirements Project Participants, as follows: Lakeland Electric; Fort Pierce Utilities Authority; Keys Energy Services; City of Vero Beach; Beaches Energy Services; Kissimmee Utility Authority; and Lake Worth Utilities	X		X			X				
26.	Individual	Mark Byrd	Progress Energy Carolina (PEC)	X									
27.	Individual	John Allen	City Utilities of Springfield, MO	X									
28.	Individual	Blake Williams	CPS Energy	X				X					
29.	Individual	Tom Mielnik	MidAmerican Energy Company	X		X		X	X				
30.	Individual	James Tucker	Deseret Generation & Transmission	X		X		X					
31.	Individual	Michael R. Lombardi	Northeast Utilities	X		X	X	X					
32.	Individual	Brian Keel	SRP	X									
33.	Individual	L. Earl Fair	Gainesville Regional Utilities	X									

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
34.	Individual	Don Gilbert	JEA	X		X		X					
35.	Individual	Catherine Mathews	NorthWestern Corporation NorthWestern Energy (NWE) (NWMT)	X		X		X					
36.	Individual	Dilip Mahendra	SMUD	X		X	X	X	X				
37.	Individual	Bart White	Progress Energy Florida, Inc.	X		X							
38.	Individual	Alice Murdock	Xcel Energy	X		X			X				
39.	Individual	Kathleen Goodman	ISO New England, Inc.		X								
40.	Individual	Baj Agrawal	Arizona Public Service Co	X		X							
41.	Individual	Randy MacDonald	New Brunswick System Operator		X								
42.	Individual	Dana Cabbell	Southern California Edison Company	X		X							
43.	Individual	Terry Huval	Lafayette Utilities System										
44.	Individual	Robert Easton	Western Area Power Administration	X								X	
45.	Individual	Robert Priest	Mississippi Delta Energy Agency										
46.	Individual	Roger Champagne	Hydro-Québec TransEnergie (HQT)	X									
47.	Individual	Phil Sanchez	Western Area Power Administration	X								X	
48.	Individual	Chifong Thomas	Pacific Gas and Electric Co,	X		X		X					
49.	Individual	Kirit Shah	Ameren	X		X		X	X				
50.	Individual	Joe Seabrook	Puget Sound Energy, Inc.	X									
51.	Individual	Eric Bryant	Maine Public Advocate								X	X	

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
52.	Individual	Scott Helyer	Tenaska, Inc.					X					
53.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
54.	Individual	Brent Ingebrigtson	E.ON U.S.	X		X		X	X				
55.	Individual	Sergio Garza	LCRA Transmission Services Corporation	X									
56.	Individual	Carol Sedewitz	National Grid	X									
57.	Individual	Edward J Davis	Entergy Services, Inc	X		X		X	X				
58.	Individual	Joe Knight	Great River Energy	X		X		X	X				
59.	Individual	Pat Harrington	BC Hydro			X		X	X				
60.	Individual	Marie Knox	Midwest ISO		X								
61.	Individual	Jessica Rice	NV Energy	X									
62.	Individual	Mark Kuras	PJM		X								
63.	Individual	David Albers	Brazos Electric Cooperative	X									
64.	Individual	James H. Sorrels, Jr.	American Electric Power	X		X		X	X				
65.	Individual	Michael Ayotte	ITC Holdings	X									
66.	Individual	Mary Ann Groszek	Northern Indiana Public Service Company	X									
67.	Individual	Wang, Yu (David)	San Diego Gas and Electric Co	X									
68.	Individual	Peter S. Schommer	Minnesota Power			X		X	X				
69.	Individual	Tim Wu	LADWP	X		X		X					

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
70.	Individual	John Collins	Platte River Power Authority	X									
71.	Individual	Larry Brusseau	MAPPCOR			X							
72.	Individual	Aaron Staley	Orlando Utilities Commission	X				X					
73.	Individual	Jason Shaver	American Transmission Company	X									
74.	Individual	John Mayhan	Omaha Public Power District	X		X		X	X				
75.	Individual	David Angell	Idaho Power	X									
76.	Individual	Casey Hashimoto	Turlock Irrigation District			X							
77.	Individual	Gregory Campoli	New York Independent System Operator		X								
78.	Individual	Greg Rowland	Duke Energy	X		X			X				
79.	Individual	David M. Conroy	Central Maine Power Company	X									
80.	Individual	Darcy O'Connell	California ISO		X								
81.	Individual	Gary Trent	Tucson Electric Power Company	X		X		X					
82.	Individual	Dan Rochester	Independent Electricity System Operator		X								
83.	Individual	Harold Wyble	Kansas City Power & Light	X		X		X	X				
84.	Individual	Rao Somayajula	ReliabilityFirst Corporation										
85.	Individual	Vivian Wang	British Columbia Transmission Corporation										

1. **Requirement R1 — Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.**

Summary Consideration: The SDT has made several clarifying changes to Requirement R1 and its various parts based on industry comments. The major changes made were to delete the phrase "including requirements of regulatory authorities and other legal obligations" from Requirement R1, the addition of "existing facilities' to the parts of Requirement R1, changing 'planned' outages to 'known' outages, combining the part calling for Firm Transmission Service and Interchange, and clarifying the final part as to the use of resources. Measure M1 was revised to provide greater clarity. The VSLs for Requirement R1 have been revised to match the new wording in the requirement.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.

1.1 System models shall represent:

1.1.1 Existing Facilities

1.1.2 Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3 New planned Facilities and changes to existing Facilities

1.1.4 Real and reactive Load forecasts

1.1.5 Known commitments for Firm Transmission Service and Interchange

1.1.6 Resources required to supply Load

M1 Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

R1 VSL	The responsible entity's System model failed to represent one of the Requirement R1, parts 1.1.1 through 1.1.6	The responsible entity's System model failed to represent two of the Requirement R1, parts 1.1.1 through 1.1.6. OR The System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and	The responsible entity's System model failed to represent three of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, parts 1.1.1 through 1.1.6. OR The System model did not represent projected System conditions as described in Requirement

		MOD-012 standards and other sources, including items represented in the Corrective Action Plan.		R1.

Organization	Question 1 Comment
Dominion - Electric Transmission	R1 - Dominion questions the legal authority NERC has to include the recently inserted language "including requirements of regulatory authorities and other legal obligations." This language is too broad and far exceeds the jurisdiction of NERC's mission. R1.1.5 - Dominion has seen base case models built by other transmission entities which do not include area interchanges for all areas and must be solved with area interchange "turned off". Would these base case models be in violation of R.1.1.5?
Response: The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The SDT believes that the base cases should include any area interchange that is planned between utilities. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange	
Northeast Power Coordinating Council	R1--There needs to be some direction provided on the initial conditions used in the assessment. This guidance should include discussion as to whether or not representations of generator forced outages are to be represented in the base case or if they are addressed through the sensitivity testing (Could add R1.1.7 Reasonable representations of unplanned generator outages.) Additionally, the standard is also silent on the treatment of system transfers, both internal and external, as to how they should be modeled in the base case. For some areas, their current practice is to include heavy system stresses in their base case, which leaves little for sensitivity testing. It is unclear if this practice works within the purview of this standard. Guidance is needed on how to treat base case generation dispatch and system transfers. The inclusion of "requirements of regulatory authorities and other legal obligations" is not understood. Even if some version of this language is kept in the final standard, it seems to belong in R2 rather than R1. "Simulate" should be changed to "incorporate". R1.1.1 Priority comment. Only known long-term outages of generation and transmission should be required to be modeled.

Organization	Question 1 Comment
	R1.1.2 comment - Do we need to have the list of equipment to model? How are circuit breakers, and other equipment modeled? Also, what should be the level of detail and the form that Protection System Equipment and Control Devices be modeled? We recommend deleting the list. Make R1.1.2 simply read as follows: R1.1.2--Projected system configuration, taking into account new planned Facilities and changes to existing Facilities, for each year of the Near-Term and Long-Term Transmission Planning Horizon. R1.1.5 comment What specifically needs to be modeled under Interchange "R1.1.6 comment " This needs further definition or it should be deleted. It is not clear what a network resource required to supply load is. Does this refer to Network Resource per FERC LGIP?

Response: The SDT believes that the outages should be modeled to insure the System reliability during the outage durations. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-Contingency. All performance criteria would then apply to that new base case. Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months.

1.1.2 Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange.

1.1.5 Known commitments for Firm Transmission Service and Interchange

The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models within their respective areas for performing the studies needed to complete their Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.

The SDT has changed the word "simulate" to "represent" in Requirement R1.

Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months.

The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices is typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list as they are already covered in the Corrective Action Plan under Requirement R2, part 2.7. Existing Facilities are now shown under Requirement R1, part 1.1.1.

1.1.1 Existing Facilities

Interchange is defined in the NERC glossary as "energy transfers that cross Balancing Authority boundaries" while Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.5 has been revised to include

Organization	Question 1 Comment
known commitments for Firm Transmission Service and Interchange. The intent of the SDT was that this includes network resource as per the FERC LGIP but that it is not limited to that. The SDT has clarified the wording for Requirement R1, part 1.1.6. **1.1.6** Resources required to supply Load	
Transmission Planning	R1.1. COMMENT: Should read: Models for performing the studies needed to complete the Planning Assessment shall represent: instead of Models for the Planning Assessment shall represent: R1.1.1. COMMENT: Should the requirement specify which known outages should be modeled? For example, would it be considered incomplete and therefore a violation if a known generator maintenance outage with a one week duration is not included (not modeled off-line) in a case that represents a full summer season at peak conditions? Please provide guidelines as to what duration outages should be modeled in representative planning horizon cases. (i.e. one day, several days, one week, one month, in a case that represents a significantly longer time period.) R1.1.2. COMMENT: Should add Transformers to this list; COMMENT: What is meant by “represent” - Planning models do not typically include explicit Circuit breaker modeling. The planning models used for power flow, dynamics and short circuit analysis represent the power system with busses and branches. The effect of circuit breakers is taken into account as part of contingency modeling. Including circuit breakers as a sub-requirement is likely to result in transmission planners being required to demonstrate that circuit breakers are modeled. Explicit representation of circuit breakers with existing software would result in major convergence problems due to large number of low impedance branches. COMMENT: Should clarify "Protection System equipment" to apply only to system stability models. Does this mean all relays on the system must be included in the dynamics modeling? While a certain limited number of protective relays can be modeled with the software used for dynamics, it is not practical to model more than a very small percentage of the protection systems used in the BES. Including protective relays as a sub-requirement is likely to result in transmission planners being required to demonstrate that all protective relays are modeled which is an impossible task. The modeling of protective relays should be caveated with as deemed appropriate. COMMENT: "Control devices" Should be specific. Is this for Phase Angle Regulators (PAR), Synchronous Condensers, Static Var Compensators (SVC), exciters, governors etc? Control devices should be specifically defined as the following: PAR, SVC, HVDC. COMMENT: "New technologies" seems too broad. Needs to be better defined. Planning models may not have the capability to adequately model new technologies. R1.1.4. Firm Transmission Service COMMENT: Should add that is expected to be utilized in the study case scenario because not all Firm Transmission Service can be included in every study case model. Some firm transmission reservations (Network Resources that could be Reserves) are used optionally depending upon the availability of other Network resources. The following apply to all VRF, Time Horizon, Measure, Data Retention, and VSL for all requirements in the standard.VRF: Agree. No comment.

Organization	Question 1 Comment
	Time Horizon: COMMENT: Long-Term Planning This is confusing. Is it only the newly defined Long-Term Transmission Planning Horizon? Shouldn't it include the Near-Term Transmission Planning Horizon Suggest Long-Term and Near-Term Transmission Planning Horizon as used in definitions. Measure: Agree. No comment. Data Retention: Agree. No comment. VSL: Are bullets in requirements all required? (I.e. If circuit breakers are not explicitly modeled, as the bullet list in R1.1.2 seems to indicate, is it a violation?) What is meant by did not simulate projected System conditions as described in R1. How are projected System conditions criteria described in R1?

Response: The SDT has reworded the requirement.

1.1 System models shall represent:

Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months.

1.1.2 Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list as they are already covered in the Corrective Action Plan under Requirement R2, part 2.7.

The SDT has revised Requirement R1, part 1.1.2 to provide clarity.

New technologies include any technology that is not currently in use on the electric power System that helps improve efficiency (i.e., energy storage/production technologies, low sag conductors, solid state interrupters, etc.). New technologies were removed from the equipment list under Requirement R1, part 1.1.2 since these are already covered in the Corrective Action Plan under Requirement R2, part 2.7

Models are only specific to the case study. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange.

1.1.5 Known commitments for Firm Transmission Service and Interchange

The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made.

Mitigation Time Horizon - The time horizons available for mitigating a violation to a requirement include the following::

- **Long-term Planning** — a planning horizon of one year or longer.

Organization	Question 1 Comment

- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

Thank you for your response on Measures and Data Retention.

The SDT has removed the equipment list. Transmission lines, generators, and reactive power devices were removed from the equipment list due to already being included in MOD standards. Circuit breakers, Protection System equipment, and control devices were removed from the equipment list since these items are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note c in Table 1. New technologies were removed from the list as they are already covered in the Corrective Action Plan under Requirement R2, part 2.7.

The SDT has deleted the equipment list.

The SDT has replaced "simulate" with "represent" under the Severe VSL category for R1.

R1 VSL	The responsible entity's System model failed to represent one of the Requirement R1, parts 1.1.1 through 1.1.6	The responsible entity's System model failed to represent two of the Requirement R1, parts 1.1.1 through 1.1.6. OR The System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.	The responsible entity's System model failed to represent three of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, parts 1.1.1 through 1.1.6. OR The System model did not represent projected System conditions as described in Requirement R1.

Requirement R1 contains the requirements needed for creating proper base cases.

SERC Engineering Committee Planning Standards	R1.1.2: In bullet three of R1.1.2, are bus-tie circuit breakers to be represented in the models? Typically circuit breakers are included in the contingency definitions along with the protection system equipment used in the power flow models. The number of zero impedance branches which can presently be modeled using PSS/E software is limited to 4000. Also, the number of buses

Organization	Question 1 Comment
Subcommittee	included in the power flow models would increase with additional breaker modeling. Protection System Equipment: The SDT stated during its June 30th Webinar that protection system equipment need not be explicitly represented in models, but had difficulty in determining adequate wording for the proposed sub-requirement. Because protection system action is described in R3.3.1, R3.3.4, R4.3.1, and R4.3.3 we suggest that protection system equipment be removed from the list in R1.1.2.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.	
Modesto Irrigation District	Comment: Are all bullets under R1.1.2 required to be explicitly modeled or are the effect of the devices or the effect of the removal of the devices to be modeled? We don't explicitly model circuit breakers or explicitly model protection system equipment in the steady state model. R1.1.4 should refer to expected transfers to be consistent with the bullet under R2.1.3. Please explain the difference between R1.1.4 and R1.1.5
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. Requirement R1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange Interchange is defined in the NERC glossary as "energy transfers that cross Balancing Authority boundaries" while Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption."	
OPUC	1. Requirement R1 Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.Comments: A: Language in R1.1.2 still needs further clarification. Base case models do not clarify modeling required for the effect or absence of circuit breakers, protection system equipment and control devices. B: Clarity would be increased were R1.1.4 to refer to expected transfers rather than Firm Transmission Service, permitting the elimination of then redundant R1.1.5 C: Removing "including requirements of regulatory authorities and other legal obligations" at the end of R1 would also eliminate redundant text.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices	

Organization	Question 1 Comment
are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. **1.1.3** New planned Facilities and changes to existing Facilities Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective areas for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.	
Bonneville Power Administration PacifiCorp Deseret Generation & Transmission SRP Southern California Edison Company Pacific Gas and Electric Co, NV Energy San Diego Gas and Electric Co California ISO	The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices where it is expected to impact the study outcome. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted. We disagree with the inclusion of the words including requirements of regulatory authorities and other legal obligations at the end of R1. Entities already are required to do this. It does not need to be included in the standard.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. Interchange is defined in the NERC glossary as "energy transfers that cross Balancing Authority boundaries" while Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.5 has been revised to include	

Organization	Question 1 Comment
known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.	
SERC Engineering Committee Dynamics Review Subcommittee (DRS)	There may be a potential conflict between MOD-010 and MOD-012 and legal documents such as Interconnection Agreements e.g. IA may specify a capacity level that exceeds the reported test levels. In the case of such conflicts, which one should rule? An order of precedence is needed as part of this requirement. Suggest adding terminal equipment to the list of planned facilities. The phrase, for each year of the Near-Term and Long-Term Transmission Planning Horizon, should be revised to remove each year because there may not be studies in each year.
Response: The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective areas for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The reference to "year" has been removed from Requirement R1, part 1.1.2 (now part 1.1.3). **1.1.3** New planned Facilities and changes to existing Facilities	
SERC Engineering Committee Reliability Review Subcommittee (RRS)	In bullet three of R1.1.2, are bus-tie circuit breakers to be represented in the models? Typically circuit breakers are included in the contingency definitions along with the protection system equipment used in the powerflow models. The number of zero impedance branches which can presently be modeled using PSS/E software is limited to 4000. Also, the number of buses included in the

Organization	Question 1 Comment
	powerflow models would increase with additional breaker modeling. In R1.1.2, don't we need to also represent the existing transmission system, and not just changes to the existing system In R1.1.2, does the phrase for each year signify each year for which assessment work was performed, or each year of the Near-Term and Long-Term Transmission Planning Horizon? The phrase, for each year of the Near-Term and Long-Term Transmission Planning Horizon, should be revised to remove each year because there may not be studies in each year. In bullet five of R1.1.2, what protection system equipment is to be included in the stability models In bullet seven of Requirement R1.1.2, what "new technologies" are to be represented in the models Concerned about only having one year to implement all new modeling requirements - especially the additional relay requirements noted in R1.1.2. The SDT stated during its June 30th Webinar that protection system equipment need not be explicitly represented in models, but had difficulty in determining adequate wording for the proposed sub-requirement. Because protection system action is described in R3.3.1, R3.3.4, R4.3.1, and R4.3.3 we suggest that protection system equipment be removed from the list in R1.1.2. There may be a potential conflict between MOD-010 and MOD-012 and legal documents such as Interconnection Agreements e.g. IA may specify a capacity level that exceeds the reported test levels. In the case of such conflicts, which one should rule? There may be a need to add definitions to discern the difference between planned and proposed projects. Suggest replacing circuit breakers in R1.1.2 with terminal equipment since circuit breakers are covered by Protection System Equipment. Does there need to be a reference in R1 to NERC Reliability Assessment Guidebook version 1.2 on pp 17-18 for everyone to use a 50/50 load forecast for inclusion in the planning models?? R1.1.4 Firm Transmission Service - a single source can have transmission service to multiple sinks, and can be associated with transmission service in excess of the capacity of the source. There is a lack of clarity regarding the means by which Firm Transmission Service, a marketing term, is to be included in planning models. For example, should the standard define how to model wind farms (100% - off-peak and 20% on-peak, based on firm capacity from the wind generators, or other dispatch levels)? Not sure if this is applicable to Requirement 1 or 2.

Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.

The SDT has revised Requirement R1, part 1.1.1 to include "existing system".

1.1.1 Existing Facilities

The reference to "year" has been removed from Requirement R1, part 1.1.2 (now part 1.1.3)

Organization	Question 1 Comment
	1.1.3 New planned Facilities and changes to existing Facilities Requirement R1, part 1.1.2 (now part1.1.3) has been revised as described above. New technologies include any technology that is not currently in use on the electric power System that helps improve efficiency (i.e., energy storage/production technologies, low sag conductors, solid state interrupters, etc.). New technologies were removed from the equipment list in Requirement R1, part 1.1.2 (now part 1.1.3) since these are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. In Draft 1, the SDT proposed using the terms "planned" and "committed" (similar to your proposal of proposed and planned) to distinguish the "firmness" of projects. Based on industry comments, the SDT eliminated the terms from Draft 2. No change made. Requirement R1, part 1.1.2 (now part1.1.3) has been revised as described above. The SDT does not believe that a reference is needed to the NERC Reliability Assessment Guidebook since most utilities are using at least a 50/50 Load forecast as a minimum. No change made. The SDT believes that all firm Transmission contracts should be modeled. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange
FirstEnergy Corp	As stated in prior comment periods, we hold the opinion that the TPL-001-1 standard should start from the premise that a valid system model exist based on MOD-010, MOD-012 and other FERC approved MOD standards that are not referenced by this TPL-001-1 standard. The inclusion of R1 introduces an overlap and potential for double jeopardy violations that need not occur. The TPL-001-1 standard should not delve into model building and keep to its core purpose of assessing future performance of the BES.Specific comments, Requirements of R1A. R1.1.2: The last bullet "New Technologies" is too vague and should be struck from the requirement. B. R1.1.4: It is not well understood how "Firm Transmission Service" would be evaluated by a compliance auditor when reviewing a simulation model. The models contain agreed upon Interchange Transactions between BA areas, but no details are provided to reflect individual Firm Transmission Service arrangements. In reality only the net-Interchange values between BA areas are reflected in the simulation models. C. R1.1.6: FE believes this requirement would be more accurately assigned to the Resource Planner or Load Serving Entity and not the Transmission Planner.

Organization	Question 1 Comment
	We agree with the stated Measures, VRF, Time-Horizon, Data Retention and VSL of requirement R1

Response: The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements.

> **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.

New technologies include any technology that is not currently in use on the electric power System that helps improve efficiency (i.e., energy storage/production technologies, low sag conductors, solid state interrupters, etc.). The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.

Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange.

> **1.1.5** Known commitments for Firm Transmission Service and Interchange

The SDT believes that the Transmission Planner/Planning Coordinator is responsible for incorporating this information into the System models. No change made.

Thank you for your response on Measures et al.

IRC Standards Review Committee	(1) R1.1.1 requires that models shall represent planned outages of generation and transmission facilities, if specifically known. Does this allow or require a PC/TP to include outages due to maintenance and due to construction programs where certain facilities are out of service during phases of construction as part of the Assessment? Such maintenance and construction schedules are made but may not be finalized over the planning horizon. Further, are planned outages to be treated as creating a "normal system condition" or is the planned outage a contingency from which system adjustments are made prior to subsequent events" (2) MOD 10 and 12 are based on requirements determined by the RRO in MOD 11 and 13 respectively. Is this appropriate? Further, the PC is not an applicable entity in MOD 10 and 12. (3)What are "other data sources"?

Response: The SDT believes that the outages (if known) should be modeled to insure the System reliability during the outage durations. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-contingency. All performance criteria would then apply to that new base case. Requirement R1, part 1.1.2 (now part 1.1.3) has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months.

Organization	Question 1 Comment
1.1.2 Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. The SDT understands that MOD-010 and -012 are impacted by MOD-011 and -013. The Planning Coordinator is not applicable - but has to utilize data provided by others such as in MOD-010 and -012.No change made. The SDT had removed the reference to "other data sources" under Requirement R1. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.	
TVA System Planning	The phrase, for each year of the Near-Term and Long-Term Transmission Planning Horizon, should be revised to remove each year because there may not be studies actually required in each year. The SDT stated during its June 30th Webinar that protection system equipment need not be explicitly represented in models, but had difficulty in determining adequate wording for the proposed sub-requirement. Because protection system action is described in R3.3.1, R3.3.4, R4.3.1, and R4.3.3 we suggest that protection system equipment be removed from the list in R1.1.2. If R1.1.2 is not removed, TVA is concerned about the level of resources that will be required to model these additional relay requirements in the one year allowed in the Implementation Plan. In bullet three of R1.1.2, are bus-tie circuit breakers to be represented in the models? Typically circuit breakers are included in the contingency definitions along with the protection system equipment used in the powerflow models. In bullet seven of Requirement R1.1.2, what "new technologies" are to be represented in the models?
Response: The reference to "year" has been removed from Requirement R1, part 1.1.2 (now part 1.1.3). **1.1.3** New planned Facilities and changes to existing Facilities The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. See Requirement R1, part 1.1.2 comment above New technologies include any technology that is not currently in use on the electric power System that helps improve efficiency (i.e., energy storage/production technologies, low sag conductors, solid state interrupters, etc.). New technologies were removed from the Requirement R1, part 1.1.2 list (now part 1.1.3) and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.	
Southern Company	The VSLs for Requirement R1 incorporates several sub-requirements but neglects one of the three components of the main requirement. Consider that R1 requires the TP and RC to (a) maintain System models, (b) use data consistent with certain MOD standards, and (c) simulate projected System conditions. Because the first component is not a part of the proposed VSL and the

Organization	Question 1 Comment
	purpose of this standard mentions a broad spectrum of System conditions, the recommendation is to add maintaining the system model into the VSLs for R1. R1.1.3 uses the terminology real and reactive Demand of Load. We suggest striking the word "Demand" because it refers only to real power. We recommend the the SDT limit R1 to load flow and stability models. Does R1 apply to short circuit models? If so does this imply that the short circuit model must be the same as the load flow model?
Response: The SDT revised the VSLs for Requirement R1 to align with the changes made to the requirement – note that the revised R1 does not use the word, "simulate." The SDT has modified Requirement R1, part 1.1.3 (now part 1.1.4). **1.1.4** Real and reactive Load forecasts The SDT believes that Requirement R1 also contains some requirements that are necessary for short circuit cases but R1 does not require the models to be the same, since different software applications may be used. No change made.	
United Illuminating Northeast Utilities ISO New England, Inc. Central Maine Power Company	R1 Priority Comment- There needs to be some direction provided on the initial conditions used in the assessment. This guidance should include discussion as to whether or not representations of generator forced outages are to be represented in the base case or if they are addressed through the sensitivity testing (Could add R1.1.7 Reasonable representations of unplanned generator outages.) Additionally, the standard is also silent on the treatment of system transfers, both internal and external, as to how they should be modeled in the base case. For some areas, their current practice is to include heavy system stresses in their base case, which leaves little for sensitivity testing. It is unclear if this practice works within this standard. R1.1.1 Priority comment R1.1.1 should be removed. It seems like there is an overlap between the requirements of this standard and Operational Planning studies with respect to known outages. Planned outages are addressed by our Operational Planning processes and Transmission Operating Procedures removing the need for this to be incorporated into Planning Assessments. In addition, outages are not generally known years in advance R1 Comment We do not understand what it means to include requirements of regulatory authorities and other legal obligations. Even if some version of this language is kept in the final standard, it seems to belong in R2 rather than R1. R1.1.2 comment - Do we need to have the list of equipment to model? How do we model circuit breakers, etc? We recommend deleting the list. Make R1.1.2 simply read: R1.1.2 New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon. R1.1.5 comment What specifically needs to be modeled under Interchange R1.1.6 comment This needs further definition or it should be deleted. It is not clear what a network resource required to supply load is. Does this refer to Network Resource per FERC LGIP?

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Response: The SDT believes that the outages should be modeled to insure the System reliability during the outage durations. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-contingency. All performance criteria would then apply to that new base case. Requirement R1, part 1.1.2 (now part 1.1.3) has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months. **1.1.3** New planned Facilities and changes to existing Facilities Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months. **1.1.2** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. Interchange is defined in the NERC glossary as "energy transfers that cross Balancing Authority boundaries" while Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.6 has been broadened while still incorporating Network Resources. **1.1.6** Resources required to supply Load	
System Protection and Transmission Planning Department	R1 the requirement to maintain System models for performing the studies is redundant with MOD-010, and should be moved to MOD-010. The phrase that requires model data used in Studies used for Annual Assessments be consistent with data submitted under MOD-010 seems OK. R1.1.2, a sub-requirement of R1.1, states that models for Planning Assessments shall represent "new planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon". Is this a requirement for maintaining a case representing every year of the near-term and long-term planning horizons (i.e. 10 cases)? We do not think that is what the SDT had in mind. If all that is required to remain cognizant of Facility In-Service dates so that topology is reliable, please so state. To make this read clearer, we suggest you take out the phrase for each year . Regarding bullet 5 of R1.1.2, does inclusion of Protection System equipment require modeling of all relays in dynamic studies? The NERC definition of Facility pertains to equipment energized at primary voltages, not Protective System equipment. We

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	suggest the Protective Systems be eliminated from this list. To make this read clearer, we suggest you delete text and bullet items following Transmission Planning Horizon. Regarding R1.1.2 bullet items: The bullets list examples of Facilities. This list is not needed, since the term Facility is already defined in the NERC Glossary. If you do not remove all bullets, then we warn you that the bullet "New Technologies" can be interpreted to cover a broad range of topics by an auditor and is not clearly defined by NERC, so we cannot visualize measurable documentation.
Response: The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. No change made. Thank you for your response. The reference to "year" has been removed from Requirement R1, part 1.1.2 (now part 1.1.3). **1.1.3** New planned Facilities and changes to existing Facilities The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The bulleted list has been deleted.	
PPL Energy Plus	PPL agrees with the requirement that regulatory and legal requirements need to be respected in planning studies. Also, Requirement R1.1.6 appears to conflict with FERC Pro-forma OATT Section 30.4 in that Network Resource output should not be limited as this Requirement states.
Response: The SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. Requirement R1, part 1.1.6 has been broadened while still incorporating Network Resources. **1.1.6** Resources required to supply Load	
Western Area Power Administration	Since the modeling data used for the Planning Assessment is initially created and governed per Mod-10 & Mod-12 Standards, this requirement should be clarified to include maintain revisions of the modeling data required to perform the Planning Assessment

Organization	Question 1 Comment
	and not just "maintain system models for performing the studies needed to complete their Planning Assessment?.
Orlando Utilities Commission	-This section is very clear. Section R1.1.1 brings clarity to the question regarding planned outages.-The phrase Models shall use data consistent with MOD-010?, is the intent for the data to be "identical" to the data provided under MOD-10 and -12, or
Kansas City Power & Light	R1 states that the models used in these studies shall be consistent with data provided through MOD-010 and MOD-012. The data submitted for these are updated on a schedule provided by the RRO and not necessarily reflective of any emerging changes that may have occurred between the MOD data collection cycle. The requirement should allow for exceptions to allow the most recent information to be included in the TPL studies.
Response: The SDT has modified Measure M1 to use the latest data available. **M1** Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.	
Tampa Electric	R1 Ensure that statement reflects that TP and PC are only responsible for their planning area. R1.1.2 Add transformers to list and clarify modeling of circuit breakers and protection system equipment. Models should reflect the effect of this equipment, not the actual equipment. R1.1.4 Models should only reflect firm transmission service that is expected to be utilized in the study case. Consider changing effective dates of all requirements to be the same date so that you do not have to meet two standards during the same time period.
Response: The SDT had modified Requirement R1 to state that the Transmission Planner/Planning Coordinator are each responsible for maintaining System models for its respective area. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement r4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT believes that all firm Transmission should be modeled. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange.	

Organization	Question 1 Comment
1.1.5 Known commitments for Firm Transmission Service and Interchange The SDT believes that certain steps need to be taken in succession to allow utilities to progress toward meeting the new requirements - while not placing an undue burden for utilities to meet all the new requirements at the same time. Also additional time is needed for many utilities to meet "raising the bar" requirements that may be required and which could take considerable lead time. No change made.	
Florida Reliability Coordinating Council, Inc - Transmission Working Group	R1 and M1: Consider clarifying that it is not the TP or PC responsibility to independently verify the consistency of the System models for portions of the Bulk Electric System outside of the TP or PC planning area (related to not using data consistent with data submitted as part of MOD-010 and MOD-012, each TP and PC should not have to review the data submitted by those outside of its planning area, but only its own planning area). Please Clarify the phrase Models shall use data consistent with .MOD-010 is the intent for the data to be identical to the data provided under MOD-10 and MOD-12, or consistent meaning that the data might be older or newer depending on when the assessment took place vs when the data was submitted. R1.1 Consider changing Assessment (which does not include models) or re-wording to Models for performing the studies needed to complete the Planning Assessment shall represent:?R1.1.1 Brings clarity to the question regarding planned outages. R1.1.2: Consider adding “Transformers” to the list of facilities. R1.1.2, please clarify what the drafting team intentions are for Circuit Breakers. Planning models used for power flow, dynamics and short circuit do not include circuit breakers. Modeling circuit breakers would cause convergence problems in the models due to that large number of zero impedance line sections. We sugges eliminating circuit breaker from the bullet list. R1.1.2 Protection System equipment this should be clarified to only apply to system stability models. The modeling of protective relays should be caveated with as deemed appropriate. We suggest eliminating Protection System equiptment from the bullet list. R1.1.4 Consider adding that is expected to be utilized in the study case scenario not all Firm Transmission can be included in all studies and are only used upon the availability of other resources . Consider changing the effective dates of R1 and R7 to take effect at the same time as R2 through R6 so you do not have to meet two standards during the same time period. Otherwise, clarify how the effective date impacts which version of the standard is to be used in an assessment before a scheduled compliance audit.
Response: The SDT has modified Requirement R1 to state that the Transmission Planner and Planning Coordinator are each responsible for maintaining System models for its respective area. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has incorporated these additional requirements with the intent that they will be removed from the TPL standard when they are incorporated into the MOD standards at a	

Organization	Question 1 Comment
later date. The SDT has modified Measure M1 to use the latest data available. **M1** Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1. The SDT agrees and has reworded Requirement R1, part 1.1. **1.1** System models shall represent: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange The SDT believes that certain steps need to be taken in succession to allow utilities to progress toward meeting the new requirements - while not placing an undue burden for utilities to meet all the new requirements at the same time. Also additional time is needed for many utilities to meet "raising the bar" requirements that may be required and which could take considerable lead time. No change made.	
FMPA	R1, consider clarifying that it is not the TP or PC responsibility to independently verify the consistency of the System models for portions of the Bulk Electric System outside of the TP or PC planning area (related to not using data consistent with data submitted as part of MOD-010 and MOD-012, each TP and PC should not have to review the data submitted by those outside of its planning area, but only its own planning area). R1.1.2: Consider adding Transformers to the list of facilities. R1.1.2, please clarify what the SDTs intentions are for Circuit Breakers. Planning models used for power flow, dynamics and short circuit do not include circuit breakers. Modeling circuit breakers would cause convergence problems in the models due to that large number of zero impedance line sections. We suggest clarifying that the intent is to develop planned Facility Ratings in the models to reflect new Circuit Breakers, and to reflect the location and timing of circuit breakers in contingency lists, and not to model the actual circuit breakers. R1.1.2 "Protection System equipment should be clarified to only apply to system stability models. The modeling of protective relays should be caveated with as deemed appropriate. We suggest clarifying that the intent is, for power flow and short circuit studies, Protection System Equipment would be incorporated into Facility Ratings and the contingency list. And we suggest further clarifying that the intent is the same for Stability Studies, with the addition of modeling Protection System equipment that could significantly impact stability response (e.g., out-of-step relaying) as deemed appropriate through engineering judgment. R1.1.4 Consider adding "that is expected to be utilized in the study case scenario" not all Firm Transmission can be included in all studies and are only used upon the availability of other resources (for instance, if there are two firm point-to-point contracts in opposite directions across the same Interchange, both probably ought not to be modeled at the same time). Consider changing the effective dates of R1 and R7 to take effect at the same time as R2 through R6 so you do not have to meet

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	two standards during the same time period. Otherwise, clarify how the effective date impacts which version of the standard is to be used in an assessment before a scheduled compliance audit.
Response: The SDT had modified Requirement R1 to state that the Transmission Planner/Planning Coordinator are each responsible for maintaining System models for its respective area. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement r4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT believes that all firm Transmission should be modeled. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange The SDT believes that certain steps need to be taken in succession to allow utilities to progress toward meeting the new requirements - while not placing an undue burden for utilities to meet all the new requirements at the same time. Also additional time is needed for many utilities to meet "raising the bar" requirements that may be required and which could take considerable lead time. No change made.	
Progress Energy Carolina (PEC)	PEC would like clarification on the following: "Models for the Planning Assessment shall represent: Circuit Breakers, Protection System Equipment, etc." The clarification should state that the models do not have to explicitly include these elements as long as their effect can be modeled.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.	
Gainesville Regional Utilities	Concerning the effective dates of R1 & R7, I suggest that you move them to be effective at the same time as R2 through R6 so you will not have to try to meet two standards during the same time period. Effective Date: Clarify how the effective date impacts which version of the standard (and it reference numbering) is to be used in an assessment just before (in cycle) a scheduled compliance audit. Suggest that the term "Corrective Action Plan" be retitled to "Improvement Action Plan" because the first implies that the situation is "wrong or incorrect" which may not be the case.

Organization	Question 1 Comment
Response: The SDT believes that certain steps need to be taken in succession to allow utilities to progress toward meeting the new requirements - while not placing an undue burden for utilities to meet all the new requirements at the same time. Also additional time is needed for many utilities to meet "raising the bar" requirements that may be required and which could take considerable lead time. No change made. The Effective Date of the requirements in force at the time the Planning Assessment is completed will dictate which requirements are the governing requirements. The SDT believes that the term "Corrective Action Plan" (a defined term) is sufficient due to lack of comments received from industry requesting this change. No change made.	
JEA	Reword R1.1.2. New planned Facilities and changes to existing and old planned Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon where such Facilities affect the electric connectivity and topology of the system or affects the accurate simulation of system disturbance response where practical. [Delete bulleted list]Add R1.2. Where it is not practical to model all Facilities composing the electric system connectivity and topology, consideration of those Facilities and their affect on the model simulations shall be documented in detail in the annual Planning Assessment where appropriate. This addition may not be necessary with rewording of R3.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.	
NorthWestern Corporation NorthWestern Energy (NWE) (NWMT)	The system models that are described in MOD-010 Requirement1, MOD-011 Requirement 1, MOD-012 Requirement 1, and MOD-013 Requirement 1 do not address all the bulleted items under R.1.2. Circuit breakers, protection system equipment and control devices are not modeled. Rather, the effect of these devices, such as circuit breaker misoperation, thermal overload, etc., on the transmission system are modeled. The wording of these bullets should be corrected to match what is actually modeled. Firm Transmission Service, listed in R.1.1.4, is not specifically addressed in MOD-010. Requirement 1 of MOD-010 states existing and future Interchange Schedules as data requirements for steady-state modeling and simulation. Models in the West do not model Firm Transmission Service as such. It is difficult to know what the Firm Transmission Service will be in the future. This is particularly true in regions where there is a predominance of merchant generation and proposals for the interconnection of new merchant generation. It is more reasonable to estimate the expected interchanges. The definition for Interchange Energy transfers that cross Balancing Authority boundaries describes the modeling requirement better that the definition of Firm Transmission Service The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruptions. The wording Expected Transfers" is used in R2.1.3 and R2.4.3. To maintain consistency, this term could be used in R.1.1.4 and could also be substituted in Table 1 for Firm Transmission. From a Planning perspective, since Firm Transmission cannot be determined from a study model. R1.1.4 and R1.1.5 should be deleted and replaced with a requirement to model expected transfers on interconnections with neighboring Balancing Authorities. For study purposes R.1.1.6 is not needed either. In the models, the load represented is served by the generators modeled. Network Resources are more in tune with local area studies that ensure that the network load can be served by the network

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	resources over available transmission. The words "including requirements of regulatory authorities and other legal obligations at the end of R1. does not need to be in the standard.
Response: The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. Interchange is defined in the NERC glossary as "energy transfers that cross Balancing Authority boundaries" while Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange The SDT believes that Requirement R1, part 1.1.6 is still required but it has been broadened. **1.1.6** Resources required to supply Load The SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions	
SMUD	R1: The requirement should end after the words "shall simulate projected System conditions.". The following words should be deleted as it results in a clause that is overly broad and does not specify clear and concise reliability requirements: "including requirements of regulatory authorities and other legal obligations".
Response: The SDT agrees and has changed Requirement R1 accordingly. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.	
Progress Energy Florida, Inc.	For R1.1.2, PEF has the following comments:T-T Transformers, as major components of the BES, should be on this list.PEF does not object to the inclusion of Circuit Breakers on this list, provided that representation is not required in steady state load flow

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	cases. Breaker failure scenarios can be extensively studied in the steady state and stability realms by removing from service the transmission facilities that such a breaker event would initiate.PEF assumes that the inclusion of Protection System Equipment applies only to Stability Analysis. As for breakers, relay failure scenarios can be extensively studied in the steady state realm by removing from service the transmission facilities that such a relay event would initiate. Additionally, PEF also assumes that a comprehensive modeling of all Protection System Equipment (e.g. Transformer Sudden Pressure Relays, Bus Diff Relays, etc.) in Stability Analysis is not required, since only a limited amount of relaying in dynamic modeling is needed to adequately model the system with respect to what transmission/generation components would trip for a given event.A lack of specificity on the term Control devices leaves it open to wide interpretation. The SDT should, in detail and/or with examples, state what is intended. The term New technologies is only acceptable for inclusion if provision is made for the fact that Planning analysis software often lags behind the design industry in getting new technologies modeled such that Planners can analyze them. For R1.1.4 on Firm Transmission Service: PEF assumes that the SDT understands that some firm transmission service is not always modeled in every case, depending upon the economics and availability of alternate resources.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. New technologies include any technology that is not currently in use on the electric power System that helps improve efficiency (i.e., energy storage/production technologies, low sag conductors, solid state interrupters, etc.). New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT believes that all firm Transmission should be modeled. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange	
Xcel Energy	R1 states that the models used in these studies shall be consistent with data provided through MOD-010 and MOD-012. The data submitted for these are updated on a schedule provided by the RRO and not necessarily reflective of any emerging changes that may have occurred between the MOD data collection cycle. The requirement should allow for exceptions to allow the most recent information to be included in the TPL studies.
Response: The SDT has modified Measure M1 to use the latest data available. **M1** Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.	
Arizona Public Service Co	The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of

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	the devices or the effect of the removal of the devices only where it is expected to impact the study outcome. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted. We disagree with the inclusion of the words including requirements of regulatory authorities and other legal obligations at the end of R1. Entities already are required to do this. It does not need to be included in the standard. VSL: Under Severe VSL Column: The last sentence The System model did not simulate projected System Conditions as described in Requirement R1 is vague and should be clarified. What is meant by did not simulate. Is it referring to gross errors or something else? We recommend that Sever VSL be assigned only if the Transmission Planner failed to do the planning assessment. Hence it should not apply to R1 at all since R1 is only related to modeling accuracy.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT believes that transfers and Firm Transmission Service can actually be two separate items since Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange The SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The SDT has replaced "simulate" with "represent" in the requirement, measure and under the Severe VSL category for Requirement R1. The SDT believes that the Severe level should be applied as noted in the VSL table since these cases are the basis for having an accurate planning assessment.	
New Brunswick System Operator	It is not clear how TP and PC are to coordinate activities. If R6 provided direction on individual and joint responsibilities then R6 should be referred to in each of the requirements which require TP and PC coordination. The VSL and Measurement for requirement R1 appears focused the number of subrequirements represented in the model. Ideally the focus should be the impacts or error of the results if something is not properly represented. This shift in thinking will allow the planner to assess and focus on those subrequirements which are important to the study results. R1.1.1 Planned outage duration needs to be defined. For example, a planned outage for a year or more should be included in the

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	Near term assessment.

Response: Requirement R7 (formerly Requirement R6) requires the Transmission Planner and Planning Coordinator to determine and identify joint responsibilities. The SDT believes that having this as a separate requirement is sufficient. No change made.

The SDT believes that the VSLs for Requirement R1 are already sufficient based on lack of industry comments. Note that the VSLs were modified to conform to the changes made to the requirement. Violation Risk Factors assess the impact to the BES of violating a requirement – not VSLs.

Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months.

1.1.2 Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

Western Area Power Administration	General, all-encompassing comment: The change in TPL Standards, while well intended, will be difficult to administer since it has taken a simple Performance Table and translated it into a legal-type document that is very complex to relate to the physical system for the planning and operations staff. The performance requirements must be related to the physical response characteristics of the interconnected system operation without depending on a legal advise for training my new transmission system planning staff. The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices where it is expected to impact the study outcome. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted. I disagree with the inclusion of the words including requirements of regulatory authorities and other legal obligations at the end of R1. Entities already are required to do this. It does not need to be included in the standard.

Response: The SDT believes that it is following the intent of FERC and NERC in creating a reliable Bulk Electric System by following the requirements in TPL 001-1.

The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.

The SDT believes that transfers and Firm Transmission Service are actually two separate items since Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange.

1.1.5 Known commitments for Firm Transmission Service and Interchange

The SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements.

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R1 Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.	
Ameren	There may be a potential conflict between MOD-010 and MOD-012 and legal documents such as Interconnection Agreements e.g. IA may specify a capacity level that exceeds the reported test levels. In the case of such conflicts, it is not clear which one should rule. Suggest replacing circuit breakers in R1.1.2 with terminal equipment since circuit breakers are covered by Protection System Equipment. Consider adding a reference in R1 to NERC Reliability Assessment Guidebook version 1.2, pp 17-18 for use of a particular load forecast level for inclusion in the planning models. I n R1.1.2, revise the language to show that we need to also represent the existing transmission system, and not just changes to the existing system. In R1.1.2, Clarification is needed for the phrase for each year should signify only those years for which assessment work was performed, rather than each year of the Near-Term and Long-Term Transmission Planning Horizon. There typically is not a model built for each year of the Near-Term and Long-Term Transmission Planning Horizon. In bullet three of R1.1.2, it is not clear whether bus-tie circuit breakers to be represented in the models. Typically circuit breakers are included in the contingency definitions along with the protection system equipment used in the powerflow models. The number of zero impedance branches which can presently be modeled using PSS/E software is limited to 4000. Also, the number of buses included in the powerflow models would increase with additional breaker modeling. In bullet seven of Requirement R1.1.2, what "new technologies" are to be represented in the models" R1.1.4 Firm Transmission Service - a single source can have transmission service to multiple sinks, and can be associated with transmission service in excess of the capacity of the source. There is a lack of clarity regarding the means by which Firm Transmission Service, a marketing term, is to be included in planning models. For example, should the standard define how to model wind farms (100% - off-peak and 20% on-peak, based on firm capacity from the wind generators, or other dispatch levels)?
Response: The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT does not believe that a reference is needed to the NERC Reliability Assessment Guidebook since most utilities are using at least a 50/50 Load forecast as a minimum. No change made.	

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The SDT has revised Requirement R1, part 1.1.1 to include "existing Facilities". **1.1.1** Existing Facilities The SDT has deleted the reference to year. **1.1.3** New planned Facilities and changes to existing Facilities See response to Requirement R1, part 1.1.2 above. . New technologies include any technology that is not currently in use on the electric power System that helps improve efficiency (i.e., energy storage/production technologies, low sag conductors, solid state interrupters, etc.). New technologies were removed from the list in Requirement R1, part 1.1.2 (now part 1.1.3) and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT believes that all firm Transmission contracts should be modeled. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange	
Puget Sound Energy, Inc.	The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices where it is expected to impact the study outcome. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT believes that transfers and Firm Transmission Service are actually two separate items since Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange	
Tenaska, Inc.	It is not clear that Requirement R1 requires ALL existing generators, substations, transmission line, transformers, etc. to be explicitly modeled for steady state and stability studies. In fact, Requirement 1.1.6 could be interpreted to exclude various generators from the models if they are not contracted to supply load. A suggestion is to re-word R1.1 to read as follows:R1.1 Models for the Planning Assessment shall represent all existing generators, substations (including specific busses within a substation), transmission lines, loads, capacitors, reactors, and other equipment connected to the transmission system and shall

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	further represent the following:(continue with R1.1.1 through R1.1.6) A further refinement to R1.1.6 should also be considered as follows:R1.1.6 Committment and dispatch schedules of resources expected to serve Load for the specific model.
Response: The intent of the SDT is to model all bulk electric Transmission Facilities depending on the model used - whether for load flow, Stability, or short circuit. The SDT has modified Requirement R1, part 1.1 to provide better clarity on these models. **1.1** System models shall represent: Requirement R1, part 1.1.6 has been broadened while still incorporating Network Resources. **1.1.6** Resources required to supply Load	
Manitoba Hydro	Requirement Text: R1: What is meant by including requirements of regulatory authorities and other legal obligations? This phase should be deleted. Can NERC make it an obligation in a standard to follow regulatory authority and other legal obligations? The planner has scope to determine the projected system conditions, and if a local regulator mandated a requirement, the planner would be able to include it without this statement. R1.1.1: Only long duration known planned or scheduled outages that are expected to last over a system peak should be included in the scope of this standard. Known planned or scheduled maintenance outages should not be a part of the planning scope as they are short duration and are planned to be taken when system conditions allow. Suggest wording change to Planned outages of generation and Transmission Facilities with an expected duration of 6 months or longer, if specifically known. R1.1.2: Suggest deleting new technologies as it is unknown as to what this is. If the SDT wants to make the list all inclusive, add words such as shall include but not be limited to in the requirement wording. Circuit breakers are not specifically represented in the planning models in order to keep the number of buses within the program capabilities. However, the effect of the circuit breaker configuration is normally considered in the creation of contingency files. Can the drafting team confirm that circuit breakers do not have to be specifically represented in the model? The same comment can be said about protection system equipment. Some generic zone 1 modeling may be included but in general the effect of protection equipment is included in contingency files. R1.1.4 & R1.1.5: Firm Transmission Service represents a contract that the planner is obligated to include. Based on the NERC definition, Interchange is defined as Energy transfers that cross Balancing Authority boundaries. Including it as a requirement mandates system expansion for non-firm system usage. Interchange is already covered in the sensitivities (Expected Transfers) and should not be a specific sub requirement of R1.1.2. Perhaps simply documenting the value of the Interchange used in the Model is sufficient. This value may change in the sensitivity analysis conducted in R2.1.3 and the TP/PA will decide the level that they will plan on protecting.Measure: The measure requires the planner to provide evidence such as the System model. What further evidence is required to ensure the planner is using data consistent with the MOD standards, is simulating projected system conditions, and that the models represent the required information in accordance with Requirement R1? It is suggested to remove and shall simulate projected System conditions from the main paragraph of R1 and reword R1.1 to System models and contingency files for the Planning Assessment shall represent projected System Conditions including:

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	Requirement R1 is very vague, and the Measure refers back to R1. The MOD standards deal with the building of the model. Most planners provide data in accordance with the MOD standards for a regional model building process. These models form the basis for the models the TPs and the PC use. The R1could be more specific by requiring the PC/TP to provide rationale for the projected system conditions used, which might include the generation schedule assumed, the transfer conditions, why peak or off-peak is important, etc.. VSLs: The requirement is very generic in nature and leans on the MOD requirements. Verification of compliance to this requirement will be problematic. What will be required to prove that the data "is consistent with the data provided in accordance with the MOD-010 and MOD-012 and other data sources"? What are these other data sources?? R1 only stipulates that the planner shall "simulate expected system conditions", so how does one decided that the "model did not simulate projected System Conditions as described in R1" (severe VSL)?

Response: The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements.

> **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.

Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months.

> **1.1.2** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months

New technologies include any technology that is not currently in use on the electric power System that helps improve efficiency (i.e., energy storage/production technologies, low sag conductors, solid state interrupters, etc.). New technologies were removed from the equipment list in Requirement R1.1.2 since these are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.

The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.

Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange.

> **1.1.5** Known commitments for Firm Transmission Service and Interchange

Requirement R1 has been revised to replace "simulate" with "represent".

> **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System

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conditions.

The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has incorporated these additional requirements with the intent that they will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.

The SDT has removed “and other date sources” from Requirement R1.

The SDT has replaced "simulate" with "represent" under the Severe VSL category for Requirement R1.

R1 VSL	The responsible entity’s System model failed to represent one of the Requirement R1, parts 1.1.1 through 1.1.6	The responsible entity’s System model failed to represent two of the Requirement R1, parts 1.1.1 through 1.1.6. OR The System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.	The responsible entity’s System model failed to represent three of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity’s System model failed to represent four or more of the Requirement R1, parts 1.1.1 through 1.1.6. OR The System model did not represent projected System conditions as described in Requirement R1.

E.ON U.S.	R1.Delete and other data sources. Consistency with MOD-010 and MOD-012 standards is measurable and should suffice. Delete including requirements of regulatory authorities and other legal obligations. The term: shall simulate projected System conditions does not exclude the above. If there is some significance to this statement it should be an item in R1.1. R1.1.4.Firm Transmission Service is often sold for less than one year on an as available basis. Also, Firm Transmission Service may be sold on one system without a complete path. As stated, it appears necessary to include these examples in the Planning models. E.ON U.S. believes that there should be some limitations put on this requirement such as Long-Term Firm Transmission Service for a period of 5 or more years.

Response: The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has removed “and other data sources”.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System

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	conditions. The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange
National Grid	Comments: R1: A. Priority Comment- There needs to be some direction provided on the initial conditions used in the assessment. This guidance should encourage the use of initial conditions that reasonably stress transfers across interfaces between companies, areas, regions, into load pockets, and out of constrained areas. The expectation that transfers are reasonably stressed for a variety of interface conditions will require the consideration of different generation dispatches, which goes beyond the single generator out of service requirement of the standard. If initial conditions consider reasonably stressed conditions, then sensitivity analysis is embedded in the process. If sensitivity is embedded in the process, it is unclear if additional sensitivity is still required by the standard. B. In the reference to regulatory authorities and other legal obligations it is suggested that the phrase be changed from "simulate projected System conditions including requirements of regulatory authorities and other legal obligations" to "include projected System conditions and requirements of regulatory authorities and other legal obligation." In common usage of terms, models are used to simulate system response, but models alone do not simulate the system. Violation Severity Levels:R1 Suggest changing the phrase "simulate projected System conditions as described in Requirement R1" to "include projected System as described in Requirement R1," consistent with the recommended change to Requirement R1. Errata:Delete the period after "R1" in the first bullet in the Data Retention section. R1.1.1 Priority comment ? R1.1.1 should be removed. - Planned outages are addressed by Operational Planning processes and Transmission Operating Procedures for up to two years ahead removing the need for this to be incorporated into Planning Assessments. - If outages are planned, but Operations can not accommodate them in real time, then the outages are cancelled. - Outages are not generally known beyond one to two years in advance. R1.1.2 Comment - We recommend deleting the list of facilities:- Circuit breakers are not modeled as elements in a power flow nor are Control Devices and Protection Systems - The list of facilities is not consistent with the definition of "Facilities" in the NERC GlossaryR1.1.2 should simply read:R1.1.2New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon. R1.1.3 Comment - The use of "real and reactive power" is prevalent within the industry, but R1.1.3 should be changed to "Active and reactive Demand of Load." When load is expressed as a complex quantity, active power is the real portion and reactive power is the imaginary portion. Thus for consistency, we should refer to active and reactive. R1.1.5 Comment What specifically needs to be modeled under Interchange" R1.1.6 Comment "This needs further definition or it should be deleted. It is not clear what a "network resource required to supply

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	load" is. Does this refer to Network Resource per FERC LGIP?

Response: Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. However the expected transfers under Requirement R2, part 2.1.3 are to further stress the system as a possible sensitivity analysis.

1.1.5 Known commitments for Firm Transmission Service and Interchange

The SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.

The SDT has replaced "simulate" with "represent" under the Severe VSL category for Requirement R1.

R1 VSL	The responsible entity's System model failed to represent one of the Requirement R1, parts 1.1.1 through 1.1.6	The responsible entity's System model failed to represent two of the Requirement R1, parts 1.1.1 through 1.1.6. OR The System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.	The responsible entity's System model failed to represent three of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, parts 1.1.1 through 1.1.6. OR The System model did not represent projected System conditions as described in Requirement R1.

The SDT agrees and had made this change under Data Retention.

Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months.

1.1.2 Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in

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MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT has modified Requirement R1, part 1.1.4 (former part 1.1.3). **1.1.4** Real and reactive Load forecasts Interchange is defined in the NERC glossary as "energy transfers that cross Balancing Authority boundaries" while Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." The intent is to include, but not be limited to these requirements. The SDT has revised Requirement R1, part 1.1.6. **1.1.6** Resources required to supply Load	
Entergy Services, Inc	Planned facilities and planned changes to existing facilities should be further defined to ensure facilities or changes that are unlikely to be constructed are not included in the models. See the proposed definition of planned facilities in the comments provided to question #8. Facilities included in the models should be only those projects that are committed to by the Transmission Owner or other users of the transmission grid. Consistent with the standards requirement to include only firm transmission service (R1.1.4), uncommitted facilites should not be included because an oversubscription of the grid could occur. R1.1: Please clarify what the SDT means by models for the Planning Assessment shall present, expecially for facilities such as circuit breakers, protection system equipment, and new technologies. Models also need to represent existing facilities R1.1.2: The phrase, for each year of the Near-Term and Long-Term Transmission Planning Horizon, should be revised to remove each year because there may not be studies in each year. R1.1.4: Firm Transmission Service - a single source can have transmission service to multiple sinks, and can be associated with transmission service in excess of the capacity of the source. There is a lack of clarity regarding the means by which Firm Transmission Service, a marketing term, is to be included in planning models. Not sure if this is applicable to Requirement 1 or 2.
Response: The projects that get included under the Corrective Action Plans are presumed to be the utility's best alternatives at that time in order to achieve compliance. The SDT understands that these alternatives may change over time - but these changes must be addressed under Requirement R2, part 2.7.6 in the revised standard. The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement r2, part 2.7.1 in the revised standard. The reference to year has been deleted. The SDT believes that all firm Transmission contracts should be modeled. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange.	

Organization	Question 1 Comment
1.1.5 Known commitments for Firm Transmission Service and Interchange	
Great River Energy	R1.1 is just repeating what should already be in the MOD-010 and MOD-012 requirements. Why re-iterate this in the TPL standard? The planners are expecting that the model building process will already include these components listed in R1.1 otherwise there wouldn't be a functional model. R1.1.1 may be the only thing that needs to be identified in R1 as any known long-term outage or retirement of a facility may have happened after the model building process. If R1.1 is kept I would suggest removing "Models for" so that R1.1 reads "The Planning Assessment shall represent: R 1.1.1 says the assessment shall represent planned outages if specifically known. It does not however distinguish the length of the outage to be considered. Should a 1 week maintenance outage in Year five be included? Should a 2 year complete rebuild outage lasting through year two and three be included? It is GRE's opinion that the SDT needs to add a comment about the length of the planned outage and its relevance to the assessment. In the Violation Severity Levels, R1 seems to be weak since any solved model should meet this requirement. Again this would seem to be more related to the MOD010 and MOD012 process. R1 should focus on documenting changes that are being preformed against the data that was submitted in MOD-010 and MOD-012 process.
Response: The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has incorporated these additional requirements with the intent that they will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT has revised the language in Requirement R1, part 1.1 (now part 1.1.2) based on industry comments. . **1.1.2** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. The SDT believes that the Severe level should be applied as noted in the VSL table since these cases are the basis for having an accurate Planning Assessment. No change made.	
BC Hydro	Comments: Consider just referring to the MOD series of standards, not specific individual MOD standards because the numbering of the MOD standards could change and additional relevant MOD standards could be added. Consider rewording the second sentence to read, The data and models shall meet all requirements of the MOD series of standards. The MOD standards should include the requirements of regulatory authorities and other legal obligations and need not be repeated in the TBL standard(s). R1.1.2: Consider changing to, New planned Facilities and planned changes to existing and changing the fifth bullet to read, Normal actions of Protection System equipment R1.1.3: Consider changing to, "End-use customer loads and generators [how small loads are aggregated should be covered in the MOD standards. A key point is that large industrial customers with significant generation that reduces their net peak demand should not be represented simply as a net load since that would not properly model the dynamic impacts of the load and

Organization	Question 1 Comment
	generation components]. R1.1.4: Consider changing to, Worst-case transfers on Firm Transmission Service Reservations. R1.1.5: Consider removing this requirement. It should be covered by R1.1.4 R1.1.6: Consider changing to, Generating units [the MOD standards should specify the details like how exciters, governors and associated control equipment must be modeled] Comment on M1: Consider changing to, using data consistent with the MOD series of standards, simulating. Consider just referring to the entire series of a particular standard, not specific individual standards because the numbering of the standards being referenced could change and additional relevant individual standards could be added.

Response: The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT referenced the specific MOD standards to ensure that the requirements were limited to those needed to complete the Planning Assessment. When the MOD standards are revised, this standard will be reviewed for conforming changes. The SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements.

> **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.

The SDT has reworded Requirement R1, part 1.1.1 to include existing Facilities.

> **1.1.1** Existing Facilities

The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement r4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.

The SDT has modified Requirement R1, part 1.1.4 (now part 1.1.5) to state "Real and reactive Load Forecasts. Note that the generator modeling is addressed in the MOD standards.

> **1.1.4** Real and reactive Load forecasts

The SDT believes that all contracted firm Transmission should be modeled. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange.

> **1.1.5** Known commitments for Firm Transmission Service and Interchange

See response for Requirement R1, part 1.1.2 above.

The SDT believes that the specific MOD standards should be addressed in this TPL 001-1 draft since they deal directly with the modeling requirements necessary for creating base cases. No change made.

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Midwest ISO	Generally the Midwest ISO agrees with FirstEnergy's comments regarding this requirement. However, if the SDT insists on keeping this requirement as is then we propose the following corrections specific to each requirement. Specific Comments for Requirement 1: A) Under R1 there is language that references "other data sources; can the SDT please offer some clarification on what "other data sources are to be Could other data sources be Tariff requirements" B) Again under R1, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R1 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: Near-Term and Long-Term Transmission Planning. C) Under R1.1.1 it is required that models represent planned outages of generation and transmission facilities, if specifically known. This does not allow or require a Transmission Planner or Planning Coordinator to include outages due to maintenance and/or due to construction programs where certain facilities are out of service during various phases of construction, as part of the Assessment. For this reason, we believe the following language for R1.1.1 would improve this requirement: Planned outages of generation and Transmission Facilities if specifically scheduled or planned for. D) Under R1.1.1 we suggest adding sub-requirement R1.1.7 Generation dispatch patterns deemed appropriate by the Transmission Planner and Planning Coordinator. This clarifies that when building System models, generation dispatch is part of the model building process. E) Under R1.1.2 there is uncertainty around the language of New planned Facilities. We offer the following definition for Planned Facilities to be added to the definition section of this standard and further added to the NERC Glossary of Terms: Planned Facilities Generation and Transmission Facilities that are expected to be implemented with an in service date prior to the plan year being studied. F) Under R1.1.2 a bullet should be added for Relay Loadability Limitations. The standard requirements for relay loadability are included in PRC-023-1.

Response: The SDT has removed the language "and other data sources".

> **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.

The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. No change made. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon.

Mitigation Time Horizon

The time horizons available for mitigating a violation to a requirement include the following:

- **Long-term Planning** — a planning horizon of one year or longer.

Organization	Question 1 Comment
	• **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal. • **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time. • **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system. • **Operations Assessment** — follow-up evaluations and reporting of real time operations. If a transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-contingency. Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months. **1.1.2** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. Requirement R1, part 1.1.6 now states Resources required to supply Load. **1.1.6** Resources required to supply Load Requirement R1, part 1.1.3 covers new planned Facilities and changes to existing Facilities. **1.1.3** New planned Facilities and changes to existing Facilities The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7. Relay loadability is covered under Requirement R3, part 3.3.3. No change made.
PJM	In R1, why require a Planning Coordinator AND a Transmission Planner to maintain models for the same area Concern with the words - for each yearin R1.1.2. Does this mean that a case for each year, at least, will need to be produced? Will five, one for each season and a light load, each year need to be produced R1.1.5 is not clear. Is the Interchange exclusive of Firm Transmission Service as mentioned in R1.1.4 Maybe -non-firm transmission service-- is clearer.
Response: Requirement R7 requires the Transmission Planner and Planning Coordinator to determine and identify joint responsibilities. The SDT has modified Requirement R1 to state that the Transmission Planner and Planning Coordinator are responsible for maintaining System models for their respective areas. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within their respective areas for performing the studies needed to complete their Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The SDT has revised Requirement R1, part 1.1.2 (now part 1.1.3) to delete the reference to "year".	

Organization	Question 1 Comment
1.1.3 New planned Facilities and changes to existing Facilities The SDT believes that transfers and Firm Transmission Service are actually two separate items since Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange	
American Electric Power	Under R1.1.2. Add Transformers, otherwise, revise Transmission Lines to read Transmission Facilities. Also under R1.1.2., add Series Reactors and Capacitors as a distinct category of facilities from Reactive Power devices that include shunt capacitors and reactors, and Control devices that include phase angle regulating and variable frequency transformers, FACTS devices, and other power electronics. These additions would further clarify the types of facilities that should be included, and these comments are made in full recognition that the introductory sentence to R1.1.2. contains the wording such as.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7. The SDT has also revised this requirement to remove 'such as'.	
ITC Holdings	Comments: We question the value of R1.1.1, which requires the inclusion of transmission or generator outages if..known, in a planning standard. If an outage puts you in a compliance deficiency for the duration of any outage, would you be fined for such an instance? Category P6 contingencies should cover these outages and not require a separate requirement such as R1.1.1. This requirement could also make an entity subject to fines for long term outages needed to upgrade or replace equipment as part of a CAP for other category violations. If this requirement is kept, it should be restricted to very long term outages and exclude those outages needed to complete CAPs for other violations. R1.1.6 requires the use of Network Resources to supply load. For many planning studies, particularly beyond the five year window, the capacity additions needed to supply load are frequently unknown. Since there are no requirements or guidelines for assuming what and where these resources will be, assumptions will have to be made regarding the needed resources. Additionally, existing network resources could be retired or re-designated to serve other load. It is unclear as written exactly what would be a violation of this requirement if known network resources are not sufficient to serve projected load. Finally, with the advent of market power, would a dispatch utilizing this type of dispatch be considered a violation of this standard.
Response: The SDT believes that the outages should be modeled to insure the system reliability during the outage durations. Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months. If a transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-contingency. All performance criteria would then apply to that new base case. **1.1.2** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.	

Organization	Question 1 Comment
The SDT has revised Requirement R1, part 1.1.6. to include Resources required to supply Load. **1.1.6** Resources required to supply Load	
Northern Indiana Public Service Company	Under R1.1, insert, "as applicable" after "represent". Since R1 covers steady state, short circuit and dynamic models, data requirements should be applicable to the specific model. Representation of circuits breakers, protection system equipment and control devices is not typical of steady state model inputs.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.	
Minnesota Power	A) Under R1 there is language that references other data sources; can the SDT please offer some clarification on what other data sources are to be? Could other data sources be Tariff requirements? B) Again under R1, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R1 only says Long-term Planning. By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: Near-Term and Long-Term Transmission Planning. C) Under R1.1.1 it is required that models represent planned outages of generation and transmission facilities, if specifically known. However, the requirement does not distinguish the length of the outage to be considered. Should a one week maintenance outage in Year Five be included? Should a two-year complete rebuild outage lasting through the entire years 2 and 3 be included? The SDT team needs to add a comment about the length of the planned outage and its relevance to the assessment. D) R1.1 is repeating what should already be in the MOD-010 and MOD-012 requirements. Is the inclusion of these elements in the TPL standard redundant? The planners expect the model building process will already included the components listed in R1.1, otherwise there would not be a functional model. If R1.1 is kept, we suggest removing the "Models for" so that R1.1 reads "The Planning Assessment shall represent:"
Response: The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. The SDT has deleted the language "and other data sources". **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within their respective areas for performing the studies needed to complete their Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made.	

Organization	Question 1 Comment
Mitigation Time Horizon The time horizons available for mitigating a violation to a requirement include the following: • **Long-term Planning** — a planning horizon of one year or longer. • **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal. • **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time. • **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system. • **Operations Assessment** — follow-up evaluations and reporting of real time operations. The SDT believes that the outages should be modeled to insure the system reliability during the outage durations. If a transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-contingency. All performance criteria would then apply to that new base case. Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months. **1.1.2** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has incorporated these additional requirements with the intent that they will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. The SDT has reworded Requirement R1, part 1.1. **1.1** System models shall represent:	
LADWP	For R1.1.4 the requirements should be based on "expected transfer" instead of "firm transmission service". When projecting into future, the term "firm transmission service" is meaningless because transmission service contracts can be changed overnight. Using "firm transmission service" as a base would also exclude any new contract that are not considered in the study. It is very short-sighted to plan new transmssion facilities only based on "firmed transmission services". R1.1.2 is very confusing. What is a new technology? Is it something we don't know? If we know what it is, is it still a new tchnology? If we don't know, how do we model it? Also, we do not model individual circuit breaker but the effect of the circuit breakers; same apply with control devices or protective system equipment. Need more clarity. In general, a laundry list of items to be represented is a bad idea because it gives the impression that anything not on the list does not need to be modeled.
Response: The SDT believes that transfers and Firm Transmission Service are actually two separate items since Firm Transmission Service is “the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.” Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange	

Organization	Question 1 Comment
New technologies include any technology that is not currently in use on the electric power System that helps improve efficiency (i.e., energy storage/production technologies, low sag conductors, solid state interrupters, etc.). New technologies were removed from the list in Requirement R1, part 1.1.2 and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.	
Platte River Power Authority	R1.1.2. "....for each year of the Near-Term and Long-Term..." Models for each year of the 10 years in the planning horizons are not developed in our Region. Please clarify your intention. R1.1.2. 3rd bullet - "Circuit breakers (or the effects of)" R1.1.2. 4th bullet - "Protection System equipment (or the effects of)" R1.1.2. 5th bullet - "Control devices (or the effects of)" R1.1.2. 6th bullet - "New techonologies (or the effects of)" R1.1.4. "Firm Transmission Service (or expected transfers)
Response: The SDT has deleted "year". **1.1.3** New planned Facilities and changes to existing Facilities The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT believes that transfers and Firm Transmission Service are actually two separate items since Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange	
MAPPCOR	R1 - what it means to include requirements of regulatory authorities and other legal obligations. Even if some version of this language is kept in the final standard, it seems to belong in R2 rather than R1. R1.1.1 - should remove the word specifically since it means nothing. Only known long-term outages of generation and transmission should be required to be modeled. R1.1.2 in the first line should have the word studied to avoid confusion, to read "New planned Facilities and changes to existing Facilities for each year studied of the "?

Organization	Question 1 Comment
	R1 states that the models used in these studies shall be consistent with data provided through MOD-010 and MOD-012. The data submitted for these are updated on a schedule provided by the RRO and not necessarily reflective of any emerging changes that may have occurred between the MOD data collection cycle. The requirement should allow for exceptions to allow the most recent information to be included in the TPL studies.

Response: : The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements.

> **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within their respective areas for performing the studies needed to complete their Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.

The SDT has deleted 'if specifically known'.

> **1.1.2** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

The SDT has deleted "year".

The SDT has modified Measure M1 to use the latest data available.

> **M1** Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

Idaho Power	The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices where it is expected to impact the study outcome. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted.

Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement r3, part 3.3, Requirement r4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.

The SDT believes that transfers and Firm Transmission Service are actually two separate items since Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange.

Organization	Question 1 Comment
1.1.5 Known commitments for Firm Transmission Service and Interchange	
Turlock Irrigation District	TPL 001-1 R1 could potentially result in a WECC auditor having to determine compliance with requirements of regulatory authorities and other legal obligations, beyond the scope of its expertise. TID proposes that if that language is to be retained, it shall be assumed that the requirements of regulatory authorities and other legal obligations are being simulated unless those other entities have formally found the member to be in violation of their requirements or obligations.
Response: The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.	
New York Independent System Operator	R1.1.1 requires that models shall represent planned outages of generation and transmission facilities, if specifically known. The standard should be clarified to state whether it allows or requires a PC/TP to include as part of the Assessment outages due to maintenance and due to construction programs where certain facilities are out of service during phases of construction. Such maintenance and construction schedules are established but may not be finalized over the planning horizon. Further, the standard is not clear whether planned outages are to be treated as creating a normal system condition or as a contingency from which system adjustments are made prior to subsequent eventsMOD 10 and 12 are based on requirements determined by the RRO in MOD 11 and 13 respectively. Is this appropriate? Further, the PC is not an applicable entity in MOD 10 and 12. Moreover, the standard should define other data sources. R1.1.2. states that models for facilities such as circuit breakers and protection systems should be represented. Comment - The list of facilities should be deleted for the following reasons:- it is not needed;- the NYISO does not model circuit breakers, Control Devices, and Protection Systems;- it is not consistent with the definition of Facilities in the NERC Glossary.
Response: The SDT believes that the outages should be modeled to insure the System reliability during the outage durations. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-contingency. Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months. **1.1.2** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. The Planning Coordinator is to still use the information provided under MOD-010 and -012. The SDT has removed "and other data sources". **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to	

Organization	Question 1 Comment
complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.	
Duke Energy	Revise R1.1.2 to include the phrase to be studied as follows: New planned Facilities and changes to existing Facilities for each year to be studied of the Near-Term and Long-Term Transmission Planning Horizon, such as :
Response: The SDT has deleted "year". **1.1.3** New planned Facilities and changes to existing Facilities Existing Facilities are now shown under Requirement R1, part 1.1.1. **1.1.1** Existing Facilities	
Tucson Electric Power Company	The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices where it is expected to impact the study outcome. An alternative, instead of specifically listing elements, make a general statement that the models should include those elements required in MOD-010 through MOD-013. If an element is missing, double jeopardy could result due to a violation of the applicable MOD standard and this TPL standard. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted. We disagree with the inclusion of the words including requirements of regulatory authorities and other legal obligations at the end of R1. Entities already are required to do this. It does not need to be included in the standard.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has incorporated these additional requirements with the intent that they will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.	

Organization	Question 1 Comment
The SDT believes that transfers and Firm Transmission Service are actually two separate items since Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.	
Independent Electricity System Operator	1. R1: What modeling/simulation is envisaged by the phrase requirements of regulatory authorities and other legal obligations? Note that this condition is not included in the measure or the VSL, making its compliance (whatever it is) irrelevant. If it is indeed a needed condition, then it should be measured and included in the VSL language under the Severe condition. Further, we suggest replacing simulate with incorporate since R1 deals with building of the system model that will be used to perform simulations governed by Requirement R2. Moreover, we do not think this requirement (to simulate projected System conditions including requirements of regulatory authorities and other legal obligations) belongs to R1, which is a requirement to develop the system model. R2 is the requirement for conducting Planning Assessments which include simulation using the model. We suggest moving this requirement to R2 upon making appropriate changes, where necessary to address our comments on the wording. 2. We recommend introducing applicable before regulatory authorities. 3. R1.1.2: suggest to add Transformers. 4. R1.1.5: suggest to change Interchange to Interchange Schedules or Interchange Transactions. 5. We agree with the VRF, Time Horizon, Measures and VSLs, other than the requirements of regulatory authorities and other legal obligations noted above.
Response: The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.	

Organization	Question 1 Comment
The SDT has changed the word "simulate" to "represent" in Requirement R1. The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange Thank you for your response on VRF et al.	
Kansas City Power & Light	R1 states that the models used in these studies shall be consistent with data provided through MOD-010 and MOD-012. The data submitted for these are updated on a schedule provided by the RRO and not necessarily reflective of any emerging changes that may have occurred between the MOD data collection cycle. The requirement should allow for exceptions to allow the most recent information to be included in the TPL studies.
Response: The SDT has modified Measure M1 to use the latest data available. **M1** Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.	
ReliabilityFirst Corporation	R1.1.1 requires to include Planned outages of generation and Transmission Facilities, "if specifically known" Should the generation be capitalized? Suggest changing it to "All planned Generation and Transmission facilities should be modeled. R1.1.2 Use of the word "such as" is not very clear and may not be enforceable. There are some size limitations in the study tools and it may not be possible to model all circuit breakers. Last three bullets are very hard to model and these are not consistent with MOD-010 and MOD-012. I am not sure what "New Technologies" mean. Does this require a model for each year? This contradicts the requirements in Sections R2.1-R2.1.1, R2.1.2 and R2.2. Suggest changing this to read "New planned Facilities and changes to existing Facilities for Near-Term and Long-Term Transmission Planning Horizon as described in Sections R2.1-R2.1.1, R2.1.2 and R2.2." Modeling of Protection Systems, Control Systems requires new data collection effort and falls under Section 1600 of NERC Rules of Procedure. The list does not include Transformers.Suggest removing Protection System equipment and Control devices from the list and adding another sub-section which states "Models should reflect the limitations imposed by Protective Devices and Control systems characteristics. Define "New Technologies"

Organization	Question 1 Comment
	R1.1.3 Here it is better to include the Type of Forecast (50/50 or 90/10). A reference NERC Reliability Assessment Guidebook can be included here.

Response: Generation is not a defined term itself in the NERC glossary - thus it does not need to be capitalized in Requirement R1.1.1. Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months.

1.1.2 Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

The SDT has revised R1.1.2 to remove "such as". The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.

New technologies include any technology that is not currently in use on the electric power System that helps improve efficiency (i.e., energy storage/production technologies, low sag conductors, solid state interrupters, etc.).

The SDT has deleted "year".

1.1.3 New planned Facilities and changes to existing Facilities

The SDT does not believe that a reference is needed to the NERC Reliability Assessment Guidebook since most utilities are using at least a 50/50 Load forecast as a minimum. No change made.

2. Requirement R2 — Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: The industry had many comments on Requirement R2 but for the most part, the questions were requesting clarification. The SDT has changed a number of the parts of this requirement with the major changes being: part 2.1.4 and part 2.4.3 on sensitivities, additional clarification on part 2.2 for the Long-Term Transmission Planning Horizon and the addition of a new part 2.7.2 on multiple sensitivity deficiencies. The full list of changes is:

Year One: The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.

2.1.4 (previously 2.1.3) For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of planned Transmission outages.

2.1.5 (previously 2.1.4) When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

2.2 The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, part 2.6:

2.2.1 A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3 The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4 The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part2.6. The following studies are required.

2.4.1 System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.3 For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Load level, Load forecast, or dynamic model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5 (new) The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported by current or past studies.

2.6.1 (previously 2.5.1) For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2 (previously 2.5.2) For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

2.7 (previously 2.6) For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7 (previously 2.6) bullet 2: Installation, modification, or removal of Protection Systems or Special Protection Systems

2.7.2 (new) Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.5 (previously 2.6.4) If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The

Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.6 (previously 2.6.5) Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8 (previously 2.7) For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.2 (previously 2.7.2) Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status.

2.9 (previously 2.8) The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.

R2 VSL	The responsible entity failed to comply with Requirement R2, part 2.9 or Requirement R2, part 2.6.	The responsible entity failed to comply withRequirement R2, part 2.3 or part 2.8.	The responsible entity failed to comply with one of the following parts of Requirement R2: part 2.1, part 2.2, part 2.4, part 2.5, or part 2.7	The responsible entity failed to comply with two or more of thefollowing parts of Requirement R2: part 2.1, part 2.2, part 2.4, or part 2.7.

Organization	Question 2 Comment
Dominion - Electric Transmission	R2.1.3 - Dominion suggests that SDT needs to be more specific on which of thevariations to include. Also for the last bullet, the SDT needs to clarify the duration ortiming of planned transmission outages (in relation to Planning horizon). R2.4.1 - While we appreciate the intent of introducing induction motor modeling in simulations, this is a difficult proposal in actual practice. The question of how much of the load is comprised of induction motors and what is a reasonable/practical model has been around now for over twenty years yet is still not resolved satisfactorily. For example, we have heard several experts declare the CLOAD model is inadequate for study. NERC needs to take the lead in developing appropriate models for the widely used simulation software and a methodology for determining load composition prior to requiring induction Load modeling in dynamic simulation studies. Additionally, this requirement states that Aggregate System Load model is acceptable to represent the dynamic behavior of induction motor Loads. Our interpretation is that such aggregate models shall be inserted by the Planners at the time of study, over a specific study area as determined by TP, and these models are not to be represented in the interconnection-wide (i.e. ERAG/MMWG) dynamics base cases. If ERAG/MMWG dynamics base cases are populated with such aggregate load models, the dynamic simulation cases could become very difficult to solve, if not impossible. R2.8 - Dominion does not see any purpose in reporting largest consequential load loss. This is not easily calculated, and

Organization	Question 2 Comment
	would vary from year by year, season by season. R2.9 - Dominion requests further clarification. Is the intent of this requirement to develop criteria for maximum allowable non-consequential load loss prior to requiring a corrective action plan or to just calculate such a load loss where it is permitted in Table 1?

Response: Part 2.1.3 (now Part 2.1.4) has been revised to provide greater clarification. It is intended that the Planning Coordinator or the Transmission Planner will select the variation to include in the sensitivity studies.

2.1.4 For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of planned Transmission outages.

The last bullet in Part R2.1.3 (now Part 2.1.4) is intended to cover planned outages of Facilities in sensitivity studies if such planned outages are known at the time the planning studies are performed, for example, nuclear power plant refueling, generating unit maintenance, etc.

Part 2.4.1 is intended to allow the Planning Coordinator and Transmission Planner the discretion in the use of aggregated System Load models in Stability Studies, if specific models are not available. However, it does not dictate the methodology or the process on how the studies are to be done.

Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only.

2.9 The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.

Northeast Power Coordinating Council	It is recommended to replace the phrase prepare with conduct and document in the first sentence.R2.1.1 Comment The requirement to evaluate year one or year two should be removed. This is not consistent with the time horizon

Organization	Question 2 Comment
	identified in R2. R2.1.3 Comment - The emphasis on sensitivity testing in the existing section appears misdirected and should be focused on reasonable risk. The assessment should have to include a discussion of reasonable risk. The sensitivity list can be used to select sensitivities to assess risk. Having a requirement to perform one sensitivity just to meet the requirement of the standard does not add value to the assessment. R2.1.4 With respect to spare equipment strategy; this requirement imposes severe testing requirements upon the system. However, there is no discussion on the generation dispatch or system transfers that are to be used for this portion of the assessment. The expectations for changes in system stresses need to be clear as part of the standard. Additionally, this section does not contemplate changing the acceptability of load loss. After experiencing a major contingency such as this, some change in the acceptability of load loss should be expected. The standard should consider allowing Non-Consequential load loss for P1 & P2 events. The standard needs to allow Non-Consequential load loss for P3 & P4 events. Remove the wording (such as a transformer). What constitutes "spare equipment strategy"? Would a strategy that involves out-of-merit dispatch or operational restrictions be considered a valid "spare equipment strategy". If a transformer is lost, could a reconfiguration of the transmission system constitute a valid "spare equipment strategy" R2.2 Comment We suggest replacing the phrase a current System peak Load study with a valid System peak Load study in the first sentence. The word current is confusing as some read the word current to mean today's rather than valid. R2.3 Comment Please provide guidance as to what year should be represented when performing short circuit studies. R2.4.1 Comment ? Change to read: "For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads or an aggregate System Load model which represents the overall dynamic behavior of the Load. R2.5.1 Comment We suggest deleting this requirement, and incorporating it into R2.5.2. R2.5.2 Comment To incorporate R.2.5.1 into R2.5.2; please modify the section as follows: For steady state, short circuit, or Stability analysis the study shall be less than five calendar years old or less: the latest Transmission Planning Horizon System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: The addition/deletion/change of individual generating unit capability determined to be material by the Planning Coordinator or Transmission Planner. [A 20 MVA generator is fairly small in a 30,000 MW system and system concerns would already be addressed though the System Impact Study]" An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES determined to be material by the Planning Coordinator or Transmission Planner. R2.6 Priority Comment As written, this section undermines the value of the sensitivity testing. This section should require a corrective action plan to fix problems determined in sensitivity analysis if there is a reasonable risk of occurrence. We suggest making the standard read Provide documentation that explains the reasoning for the sensitivities considered and selected. R2.6 Comment At the end of the second sentence, the phrase in the tables is used. We suggest using more definitive

Organization	Question 2 Comment
	language such as in Table 1. R2.6.2 Comment The phrase Project Initiation Date needs to be defined. It is unclear if this is this the date of ground breaking, purchase orders being issued, solution study initiation, etc. Additionally, in the second sentence the phrase as well as an in-service date should be modified to read as well as a target in-service date. R2.6.3 Comment Plans can provide a target in-service year but not an actual in-service year. R2.6.4 Priority Comment There should be a cutoff point when changes occur beyond a certain date. When that date occurs, further changes will be evaluated in the next year's assessment. Otherwise, if a state makes a decision not to site a project a few weeks prior to the end of the assessment period, there will not be sufficient time to incorporate this into that year's assessment and develop corrective actions. R2.8 Comment Largest consequential load loss is not factored into the Planning Assessment and should therefore be deleted. R2.9 Comment This requirement is unclear. Is this requirement asking for each transmission planner to list their criteria for non-consequential load loss, or is it asking how much non-consequential load loss was being relied upon in the assessment? We recommend that the requirement be modified to require documentation of the maximum amount of non-consequential load loss that was relied upon during the assessment. It is strongly recommended that the standard should consider not allow non-consequential load loss to resolve any violation arising from the planning events in Table 1. Therefore, this requirement would then be deleted. The use of System Off-Peak Load is too general. Is the intention to have the system minimum load used here? Because of the seasonal differences in equipment ratings, seasonal peak and off peak (minimum) loads should be analyzed.

Response: The SDT was not able to locate the word "prepare" in the first sentence of Part 2.1.1. However, Requirement R2 states, "Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses". The SDT assumes that the comment was meant for this sentence. The SDT does not think that replacing "prepare" with "conduct and document" would add clarity, since Requirement R2 includes the requirement to document assumptions and results. No change made.

The SDT disagrees that the requirement to evaluate Year One and year two is inconsistent with the Time Horizon in R2. The new definition defines Year One as the first year that the planner is responsible for assessing. No change made.

Part 2.1.3 (now Part 2.1.4) has been rewritten to clarify the intent of the requirement. The Planning Coordinator or Transmission Planner can include a discussion of risk in response to the new Part 2.7.2 on the actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary. No change made.

In Part 2.1.4 (now Part 2.1.5) when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. Part 2.1.4 is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Actions such as out of

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merit dispatch, operational restrictions, System reconfiguration can be part of a Corrective Action Plan if the System cannot meet performance requirements without the Facility in service. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.2 is intended to require a study performed in the current year, as opposed to studies performed in the past years. Part 2.2 has been revised to provide greater clarity. **2.2** The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: For Part 2.3 the decision on the year to be represented in the study is left to the discretion of the Planning Coordinator or Transmission Planner. Part 2.3 only requires it to be either a study that was performed during the current year or in the past. For example, this year is 2009 and a study performed in 2009 is a current study, the study can investigate the System in a future year, which is at the discretion of the Planning Coordinator or Transmission Planner performing the study. Part 2.3 has been revised to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. Part 2.4.1 was not changed as suggested because the intent of the last sentence is to allow the use of an aggregated System Load model as an appropriate Load representation. The suggested change could be read to mean that an aggregated System Load model would not appropriately represent the dynamic behavior of Loads. However, Part 2.4.1 has been revised to provide greater clarity. **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Parts 2.5 .1 and 2.5.2 (new Parts 2.6.1 and 2.6.2) were not combined. While the SDT appreciates the concern that a 20 MW generation addition can be small compared to a large System, a NERC standard needs to be clear as to the applicability. A requirement, which contains "determined to be material by the Planning Coordinator or Transmission Planner", is not clear. Therefore, changing from 20 MW to "material" will also have to require justification from the Planning Coordinator or Transmission Planner on what is "material". Material has been deleted from the requirement. Part 2.6.2 and 2.6.3 have been removed. Part 2.6 has been modified and included as new Part 2.7. The intent is to allow discretion for the Planning Coordinator or Transmission Planner to correct those deficiencies if they are prevalent (i.e., occur in more than one sensitivity). Although not required, the standard does not preclude the Planning Coordinator or Transmission Planner to develop Corrective Action Plans for high risk scenarios. However, if the scenario is high risk, then it should have been included in the base assumptions in the assessment and the Corrective Action Plan would have been required. The end of the second sentence has been changed to refer to

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Table 1 as suggested. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Part 2.6.4 (now 2.7.5) allows the Planning Coordinator or Transmission Planner to address situations that are beyond its control by utilizing Non-Consequential Load Loss and/or curtailment of Firm Transmission Service, which are normally not permitted. Depending on the urgency of the need, the Corrective Action Plan may be developed outside the normal Assessment cycle at the discretion of the Planning Coordinator or Transmission Planner involved. No change made. Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1. The recommendation that "the standard should consider not allow non-consequential load loss to resolve any violation arising from the planning events in Table 1" will include also the multiple Contingencies, for which loss of Non-Consequential Load is allowed in the existing TPL Standards. While the sentiment is laudable, it may not be practical. No change made. The use of System Off-Peak Load is intended to be general to allow the Planning Coordinator or the Transmission Planner to use their best judgment suited to the study area, since the System must be able to meet performance requirements over all demand levels. The Planning Coordinator or Transmission Planner is not precluded from investigating more System conditions than are required in this standard. No change made.	
Transmission Planning	R2.1.4. COMMENT: For the analysis to reflect the contingencies in Table 1 (P0 through P7 plus Extreme Events) is excessive. R2.5.2. COMMENT: The 20 MW change listed in bullet items are extremely small to larger transmission systems and by themselves would be unlikely to change BES response. As drafted, requirement 2.5 may be interpreted to preclude the use of any previous study in which the base case is not identical to the current planning case. It is recommended 2.5.2 be rewritten as follows; For steady state, short circuit, or Stability analysis: the present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period that would impact the study area. R2.6.2. COMMENT: What is considered a project initiation date is it implying a construction start date, or the first time that it was identified as a mitigation plan? Additionally, R2.6.2 and R2.6.3 are not necessary because a Corrective Action Plan, by definition, includes an "associated timetable for implementation". Recommend deleting this requirement. R2.8. COMMENT: Why is this data collection a requirement? The effort required to determine this data is substantial and the value of this data is questionable. Recommend deleting this requirement. R2.9. COMMENT: Why is this data collection a requirement? The effort required to determine this data is substantial and

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	the value of this data is questionable. Recommend deleting this requirement.

Response: Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

While the SDT appreciates the concern, the proposed revision could be interpreted as removing the threshold for minimum change in generation. Part 2.5.2 has been revised as Part 2.6.2 to include an alternative threshold to be based on the study area's installed generation capacity.

> **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required.

> **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only.

> **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.

SERC Engineering Committee Planning Standards Subcommittee	R2.1: In R2.1, change the reference to requirement R2.6 (at the end of the last line) to R2.5. R2.1.4: In Requirement R2.1.4, recommend that the requirement be revised as follows: "When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience the possible unavailability of the long lead time equipment. R2.4.1: In Requirement R2.4.1, it is suggested that it be reworded to the following: "System peak Load for one of the five years, including Load models which appropriately represents the dynamic behavior of Loads, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

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	R2.5.1:With the elimination of the distinction between system and generating plant stability studies, the blanket requirement in R2.5.1 that all stability analyses be five calendar years old or less, regardless of any material changes to the system, would cause needless work to be performed on those plants or areas of the system where no changes are occurring. Recommend add the following to the end of R2.5.1: unless justification can be provided to demonstrate that the results of an older study are still valid. R2.6.2: In Requirement R2.6.2, what constitutes a "project initiation date," and how will it be used? Please clarify. R2.8: Please explain the reason why Requirement R2.8 is needed in the Assessment. Reporting the largest Consequential Load Loss does not impact reliability. R2.9: Please explain the reason why Requirement R2.9 is needed in the Assessment. Reporting the largest Non-Consequential Load Loss does not impact reliability.

Response: In the new version, Part.2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made.

Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.4.1 has been revised to reflect your suggestion.

> **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

Part 2.5.1 has been revised and included as Part 2.6.1 to address your concerns.

> **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required.

> **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning

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Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Modesto Irrigation District	On pages 6 and 7 under sections R2.1.3 and R2.4.3, I think the magnitude of the variations in the conditions asked for in the sensitivity cases, should be defined and not left to the analyst to decide. On page 8 under Section R2.5.2, examples of material changes for generation are given, but no examples for transmission changes. Shouldn't we include examples of material transmission changes, too Comments: Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES R2.8 and R2.9 load loss comment. We don't agree with R2.8 & R2.9. What reliability purpose is served by these requirements?
Response: The items in Parts R2.1.3 (now Part 2.1.4) and 2.4.3 are intended for use as guides. NERC Standards must allow room for discretion of the Planning Coordinator and/or Transmission Planner who are closer to the issues in their respective areas. In Part 2.5.2 the SDT removed the examples related to the generation changes and therefore have not added examples of transmission changes. Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt and is not specifically related to new planned Facilities. Part 2.3 has been revised to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. Parts 2.8 and R2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
OPUC	2. Requirement R2 Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.Comments: A: Short circuit of over-stressed breakers is already addressed in Table 1.Ex1: P2-3,4 (Internal Breaker Fault),Ex2: P4 (Stuck Breaker while attempting to clear a fault). B: In R2.1.4 Table 1, it is unclear how transformer contingency analysis can be aggregated or batched. It is also still unclear

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	whether corrective action plans are required solely to meet performance requirements for sensitivities.

Response: Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt and is not specifically related to new planned Facilities. This is not the same as the examples cited. Part 2.3 has been revised to provide greater clarity.

> **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.6 has been revised and included as Part 2.7 to state that Corrective Action Plans do not need to be developed solely to meet the performance requirements for a single sensitivity run. Part 2.7.2 has also been added to require that the Corrective Action Plan include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary. The intent is to allow discretion for the Planning Coordinator or Transmission Planner to correct those deficiencies if they are prevalent (i.e., occur is more than one sensitivity).

> **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:
>
> **2.7.2** Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

Bonneville Power Administration	Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). R2.1.1: Peak load modeled for the near term planning horizon may not be Year one or year two. Therefore, R2.1.1 should be revised to say System peak load for one of the five years. Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer.

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	This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement. The 20 MW threshold identified as material change for generation in R2.5 is too small. The limit should be raised or based on a percentage of the study area's installed generating capacity. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event? if it is documented? R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.

Response: Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt and is not specifically related to new planned Facilities. Part 2.3 has been revised to provide greater clarity.

> **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

Part 2.1.1 is intended to require studies for System Peak Load Conditions for 2 of the years in the near-term planning horizon: 1) A Year five case to identify potential problem that can be addressed if the planned projects proceed as scheduled. 2) A Year one or Year two case to identify any potential problems unanticipated in the five-year case, which if not addressed, could impact operations as time progresses. Therefore, the SDT declines to make the change as suggested.

Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.5 has been revised and references to the 20 MW change have been deleted.

> **2.5** The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported by current or past studies.

Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees

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that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
MRO NERC Standards Review Subcommittee	MRO NSRS proposes the following comments for R2: Modify R2.6.2 to remove the obligation to include the project initiation date. The inclusion of this date would add unnecessary work that is not needed to assure adequate BES reliability In addition, it is not clear whether initiation refers to the commencement of engineering, design, construction, etc.Augment R2.6.5 to include annual verification of the continued validity of the Corrective Action Plan because the value of implementation status is dependent on the status of continued validity. MRO NSRS suggests this text: Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status . . . Augment R2.7.2 to include annual verification of the continued validity of the Corrective Action Plan because the value of implementation status is dependent on the status of continued validity. MRO NSRS suggests this text that is similar to R2.6.5: Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status. Remove R2.8. MRO NSRS does not know of any reason why the investigation and inclusion of the largest Consequential Load Loss caused by any P1 or any P2 events is needed to assure adequate BES reliability. In addition, all events involving Consequential Load Loss are studied, not just the largest load loss (see R3.3.1).
Response: In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Parts 2.6.5 and 2.7.2 have been revised and included as Parts 2.7.6 and 2.8.2 respectively to reflect your suggestion. **2.7.6** Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures. **2.8.2** Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status. Part 2.8 is intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed the requirement and agrees that as written, it was unclear. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	

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SERC Engineering Committee Dynamics Review Subcommittee (DRS)	1. R2.1.4 Loss of 2 transformers is itself a very severe contingency. However, when it is combined with R2.1.4 (spare equipment strategy) it can lead to a triple contingenecy which is unnecessarily severe and has an extremely low probability of occurrence. We recommend that the requirement be deleted from the standard. In the subrequirements of 2.1.3 and 2.4.3, the use of the word timing is unclear. Consider using in service date or schedule for. With the elimination of the distinction between system and generating plant stability studies, the blanket requirement in R2.5.1 that all stability analyses be five calendar years old or less, regardless of any material changes to the system, would cause needless work to be performed on those plants or areas of the system where no changes are occurring. Recommend add the following to the end of R2.5.1: unless justification can be provided to demonstrate that the results of an older study are still valid.

Response: Part 2.1.4 (now Part 2.1.5) is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

2.1.5 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Parts 2.1.3 (now Part 2.1.4) and 2.4.3 have been revised to reflect your suggestion.

2.1.4 For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of planned Transmission outages.

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	2.4.3 For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Load level, Load forecast, or dynamic model assumptions. • Expected transfers. • Expected in service dates of new or modified Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. Part 2.5.1 has been revised and included as Part 2.6.1 to address your concerns. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.
SERC Engineering Committee Reliability Review Subcommittee (RRS)	The proposed standard not only raises the bar for system performance requirements, but also raises the bar for reporting and documentation. We need to employ almost as many librarians and technical writers as engineers to develop and keep track of the documentation. Engineers need to spend more time performing the studies and spend less time documenting studies keeping track of documentation for multiple years. R2 Instead of document results the requirement should be to summarize results. While results will be documented, the Planning Assessment should just include a summary. R2.1 What's the value in being able to use qualified past studies if you have to use annual current studies? Strike the words supplemented with and insert the word or. In R2.1, change the reference to requirement R2.6 (at the end of the last line) to R2.5. Do not understand the rationale for being so prescriptive in requiring specific years to be studied in R2.1.1. Why not allow the TP and/or PC to decide on the three years to be studied in the Near Term? In the subrequirements of R2.1.3 and R2.4.3, the use of the word "timing" is unclear. Consider using in service date or schedule for. " In R2.1.3, it is suggested that the studies be referred to as the "base studies" to avoid confusion with the sensitivity studies. Also suggest that another phrase be added at the end for clarity. The entire R2.1.3 would then be as follows: For each of the base studies described in Requirements R2.1.1 and R2.1.2, sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment. Sensitivity studies would include changes to:oIn Requirement R2.1.4, it is suggested that language be added to reflect the possible unavailability of the equipment, such as: When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead

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	time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience the possible unavailability of the long lead time equipment. How would adequate lead times be determined" In Requirement R2.1.4, recommend that the requirement be revised as follows: When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience the possible unavailability of the long lead time equipment. Since R2.3 short circuit analysis is a new raising the bar requirement, should the implementation plan for this be for 5 years like the other new requirements? R2.3 Insert the phrase "one year of after the word addressing. In Requirements R2.3 and R2.4, do we need a reference to Requirement R2.5 for the past studies" Further clarification is needed in R2.4.1 concerning load models that appropriately represent the dynamic behavior of loads. In Requirement R2.4.1, it is suggested that it be reworded to the following: System peak Load for one of the five years, including Load models which appropriately represents the dynamic behavior of Loads, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. R2.4.1: It is not clear how much Load must have a dynamic model. Likely, it must still be proven that the analysis software can accommodate every load in the model having a load model that includes induction motor models. To help address this, revise Load to be Load that could impact the study area is acceptable. Is a NERC drafting team addressing these issues to determine an industry standard? Load models referenced in R2.4.1 should be confined to the consideration of transient stability study work. In Requirement R2.4.3, it is suggested that this sub-requirement be reworded to the following: For each of the base studies described in Requirements R2.4.1 and R2.4.2, sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the base studies shall be included in the Assessment. Sensitivity studies would include changes to: Regarding Requirement R2.6, it is suggested that the word "modeled" be added as follows: For Planning Events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed in subsequent assessments but the System modeled shall continue to meet the performance requirements in the tables. Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3 and R2.4.3. The Corrective Action Plan shall: In bullet three of Requirement R2.6.1, would we allow automatic generation tripping for a single (P1) event if it is not consequential? It seems that tripping of generation should be restricted to P2 events 2 or 3 at a minimum. In bullet five of Requirement R2.6.1, is there a maximum duration that operating procedures can be used before a capital

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	project must be included (or completed) in the Corrective Action Plan? With the elimination of the distinction between system and generating plant stability studies, the blanket requirement in R2.5.1 that all stability analyses be five calendar years old or less, regardless of any material changes to the system, would cause needless work to be performed on those plants or areas of the system where no changes are occurring. Similar to the draft MOD-026-1 standard, this period should be 10 years. With the elimination of the distinction between system and generating plant stability studies, the blanket requirement in R2.5.1 that all stability analyses be five calendar years old or less, regardless of any material changes to the system, would cause needless work to be performed on those plants or areas of the system where no changes are occurring. Recommend add the following to the end of R2.5.1: unless justification can be provided to demonstrate that the results of an older study are still valid. R2.5.2 Suggest deleting the phrase Material generation changes could include: and the two accompanying bullets. A change of 20 MW on a large system may not always be material. In Posting #2, undervoltage load shed, underfrequency load shed, and Special Protection Schemes were considered to be Non-Consequential Load Loss. In R2.6.1, installation or modification of Protection Systems or Special Protection Systems are now allowed as part of the Corrective Action Plan. Should undervoltage and underfrequency load shed also be allowed in the Corrective Action Plan? In Requirement R2.6.2, what constitutes a "project initiation date," and how will it be used? Please clarify. Please explain the reason why Requirement R2.8 is needed in the Assessment and how does reporting the largest Consequential Load Loss impact reliability? Please explain the reason why Requirement R2.9 is needed in the Assessment and how does reporting the largest Non-Consequential Load Loss impact reliability? If contingencies occur inside one utility that affect facilities in another utility, which utility is responsible for running these studies during the annual assessments?? R2.8 and R2.9 should be deleted. We don't see a reliability-related need for these requirements. In R2.9, does the requirement require the maximum non-consequential load that can occur for contingencies in Table 1 or does it require just the maximum that a utility will allow on its system? Suggest clarifying permissible or perhaps using similar language as found in R2.8. R2.9: One cannot determine the maximum permissible Non-Consequential Load Loss for every Planning Event. First of all, this should not be a requirement, as it is, for those events that do not even cause Non-Consequential Load Loss. Secondly, to obtain the maximum permissible value, one would have to stress the system in some way until one of the performance requirements are violated. That is an unreasonable stipulation and cumbersome to perform such an analysis.

Response: Requirement R2 has been revised to reflect your suggestion.

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning

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	Assessment shall use current or past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. In Part 2.1 it is envisioned that not all parts of the studies on which the Assessment is to be based can rely on past studies. For example, a study on year five performed during the past year may not be representative of year five in the current year. A past study can still be used if it can be demonstrated that the requirements for use of past studies are met. No change made. In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made. Part 2.1.1 is intended to require studies for System Peak Load Conditions for 2 of the years in the near-term planning horizon: 1) A Year five case to identify potential problem that can be addressed if the planned projects proceed as scheduled. 2) A Year one or Year two case to identify any potential problems unanticipated in the five-year case, which if not addressed, could impact operations as time progresses. Therefore, the SDT declines to make the change as suggested. Parts 2.1.3 (now Part 2.1.4) and R2.4.3 have been revised to clarify the word "timing". **2.1.4** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Real and reactive forecasted Load. • Expected transfers. • Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. • Controllable Loads and Demand Side Management. • Duration or timing of planned Transmission outages. **2.4.3** For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Load level, Load forecast, or dynamic model assumptions. • Expected transfers. • Expected in service dates of new or modified Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. The SDT reviewed Part 2.1.3 and declined to use the term "base study" because "base study" may have different meanings in different parts of the continent, and

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the term, "studies described in Parts 2.1.1 and R2.1.2" should be sufficient to avoid confusion. No change made. Part 2.1.4 (now Part 2.1.5) is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. The SDT does not feel that Part 2.3 raises the bar as entities should have been performing these studies all along. No change made. The SDT declines to revise Part 2.3 to include short circuit analysis for one of the years in the Near-Term Transmission Planning Horizon because Part 2.3 only requires that a Planning Assessment be performed. Past studies can be used to support the Planning Assessment. No change made. Parts 2.3 and 2.4 have been revised to include the reference to the requirements for use of past studies. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. **2.4** The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required: Part 2.4.1 has been revised to reflect your suggestion. In addition, Requirement R2.4 concerns only "The Near-Term Transmission Planning Horizon portion of the Stability analysis". Part 2.4.1 is a sub-part of Part 2.4, and so should also carry the same limitation. **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. The SDT reviewed Part 2.4.3 and declined to use the term "base study" because "base study" may have different meanings in different parts of the continent, and the term, "studies described in Parts 2.4.1 and R2.4.2" should be sufficient to avoid confusion. No change made. Part 2.6 has been revised and included as Part 2.7 to reflect your suggestion. The third bullet in Part 2.6.1 is intended to meet the requirements in Table 1. Generation tripping is allowed at the discretion of the Planning Coordinator or Transmission Planner for P1 Events as long as there is no loss of firm Non-Consequential Load. In addition, in the fifth bullet, the duration for use of an operating procedure is also at the discretion of the Planning Coordinator or Transmission Planner because it may not be feasible environmentally to implement Transmission reinforcements in some locations. Part 2.5.1 has been revised and included as Part 2.6.1 to address your concerns, but the SDT disagrees that the timeframe should be changed to 10 years. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided

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	to demonstrate that the results of an older study are still valid. Part 2.5 has been revised to reflect your suggestion. **2.5** The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported by current or past studies. Use of generation tripping not precluded within the Standard and the maximum duration for operating procedures in Corrective Action Plans is not addressed within the standard. UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1. If Contingencies occur inside one utility that affect facilities in another utility, the Planning Coordinator or Transmission Planner for the utility, whose system is impacted would be responsible for performing the annual Assessment for those contingencies known to cause the impact. A certain amount of coordination will need to occur between the utilities. The parties can then mutually agree upon a Corrective Action Plan.
FirstEnergy Corp	The standard provides prescriptive language in requirement R2.4.1 regarding dynamic stability load models but is silent on steady-state load modeling. Most transmission planners use a conservative approach of simulating constant power loads in the steady-state environment, but other steady-state load modeling assumptions such as constant impedance load and constant current load can be utilized. At a minimum, the standard should require the transmission planner to document its load modeling assumptions for steady-state simulations. To this end, we suggest a new sub-requirement R2.1.1 be placed ahead of the existing R2.1.1 that parallels R2.4.1 and indicates the TP should document its load modeling assumptions for steady-state simulations. Specific comments, Requirements of R2A. R2.1: The requirement incorrectly references R2.6 which should be a reference to R2.5. B. R2.1.1: We propose that the SDT adjust requirement R2.1.1 to annually require one current year Near-Term and one Long-Term study, with the Long-Term study required to alternate between year six and year ten every other assessment year. This would reduce the workload on the industry and cover the mid-point transition period between the Near-term and

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	Long-Term horizons that the standard team believes needs some attention. We find the requirement to perform two Near-Term studies and one Long-Term study each year overly burdensome, in light of the increased workload caused by sensitivity analysis for each steady-state and stability review that is required. FE believes that one current year study within each time period should suffice in being able to interpolate and extrapolate results to cover the entire assessment range; especially when supplemented with qualified past study results. C. We offer the following comments related to requirement R2.4.1: 1. In the last round of comments we made the following comment "This requirement should be separated into two requirements as it covers two distinct topics; a) peak load study for one of the near-term years and b) dynamic load modeling." The SDT responded "...This Requirement is to make you properly represent the dynamic behavior of Loads at high System Load levels." Apparently, the SDT did not agree with our recommendation to split the requirement as no change was made in this regard. Therefore, as written the standard in R2.4.2 (stability study of the Off-Peak Load level) seems to imply that the appropriate modeling of dynamic behavior of loads, including consideration of induction motor loads, is NOT required for the Off-Peak Load stability study. Please clarify or confirm this view of R2.4.2. 2. R2.4.1: We are still of the opinion that the word "appropriately" is vague and only serves to add confusion within this requirement. It's recommended that "appropriately" be struck from the requirement. 3. R2.4.1: In Draft 3, the SDT added text to this requirement that states "An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable" to clarify that a detailed dynamic Load model is not required at each bus. We understand this to mean that the model is not expected to try and replicate the dynamic behavior of individual end-user Load characteristics and that general approximations for a customer class(es) (residential, commercial or industrial) simulated at a given load bus is acceptable. 4. Based on our comments C.1 through C.3 we propose the following requirement language: R2.4.1. System peak Load for one of the five years.R2.4.2. System Off-Peak Load for on of the five years.R2.4.3. Load models used for stability analysis shall represent the dynamic behavior of Loads, including the behavior of induction motor Loads. The study shall document assumptions made for representing the dynamic behavior of Loads, based on the following load classes - residential, commercial and industrial. D. R2.5.2: For clarity and readability we propose to insert the word "that" between the words "and would" so the requirement reads "...intervening period and that would impact ...". E. R2.6.1: This requirement indicates that an entity's Corrective Action Plans list situations where Table 1 Performance Criteria are not met and the associated actions needed to achieve required System performance. What if the actions and plans associated with newly identified deficiencies (current year studies) are not yet fully known and require further analysis and a more detailed study of various options. Would it be acceptable for a TP to indicate that the planned solution is To Be Determined? This could be a likely scenario for a long-term planning horizon study which may identify a number of deficiencies which require more detailed analysis to determine the appropriate solution. F. R2.6.2: We believe this requirement is overly prescriptive in requiring a project initiate date. The standard should not question an entity's project management but stay focused on whether or not the Correct Action Plan was put in place in a timely fashion. We propose that the team strike from this requirement the reference to project initiation date and focus on

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	whether or not Corrective Action Plans were completed in a timely manner to ensure Table 1 Performance Criteria is met. Additionally, project initiation date is pertinent to a operating procedure solution that is allowed by the standard. R2.6.4: We support requirement R2.6.4 but suggest the word "prudent" be struck from the text of the requirement as it can be subjective and open for debate. G. R2.7: This requirement introduces additional Corrective Action Plan requirements beyond what is stated in R2.6. FE proposes that the SDT restructure the two requirements into a single requirement (and sub-requirements) focused on Corrective Action Plans. H. R2.8: Does this requirement apply to sensitivity simulations? If so, it has limited applications to only those sensitivity analyses that consider variations in load such as a higher forecast (90/10), or increased reactive load (sensitivity to poor power-factor loads), etc. The SDT should consider clarifying the intent of the requirement if each current year study as well as their corresponding sensitivity simulation model(s) is intended to have this information documented within the assessment report. I. R2.9: We ask the SDT to confirm or correct our understanding that the requirement is asking about a TPs criteria for maximum allowable non-consequential load drop and NOT the maximum non-consequential load shed required to meet performance criteria for a particular contingency evaluation. We agree with the stated Measures, VRF, Time-Horizon, Data Retention and VSL of requirement R2

Response: The language does not preclude the documentation of the steady state Load model used because steady state assumption of Load model is a degree of conservativeness. See header note b. No change made.

In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made.

As written, Requirements R2 and Part 2.1.1 provides flexibility for the Planning Coordinator or Transmission Planner to use past studies to support the current year assessment and to assess other years in addition to those identified in Part 2.1.1. So the suggestion to alternate between year six and year ten every other assessment is already allowed as written. No change made.

In Part 2.4.1 the SDT specifies the dynamic Load model representation for on peak because the System voltages are generally lower during on peak. The percentage of motor load, e.g., in air conditioners, could significantly increase reactive power requirements especially when they stall due to low System voltage and can therefore impact dynamic System performance on-peak. However, motor Load would likely not pose the same problem during off-peak as the System voltages are usually higher. So, in Part 2.4.2, it can be left to the discretion of the Planning Coordinator or Transmission Planner whether the dynamic motor Load would need to be represented per Part 2.4.1,

Part 2.5.2 has been modified and included as Part 2.6.2 and the “intervening period” language has been deleted.

2.6.2 For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required.

2.7 For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the

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	Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Part 2.6 has been modified and included as new Part 2.7. Part 2.6.1 requires a Corrective Action Plan be developed to enable the System performance requirements in Table 1 and Part 2.6 states that "revisions to the Corrective Action Plans are allowed in subsequent assessments but the System shall continue to meet the performance requirements in Table 1". This allows the Planning Coordinator or Transmission Planner to develop a Corrective Action Plan that can consist, for example, of a number of potential alternative solutions, and, the Corrective Action Plan can be revised as the study continues. 'Prudent' has been deleted in Part 2.6.4 (now Part 2.7.5). **2.7.5** If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service. Part 2.7: Short circuit duty Assessment has been revised for clarity and included as Part 2.8. **2.8** For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall: Parts 2.8 and R2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.
IRC Standards Review Committee	(1) When a spare equipment strategy does not cover the long lead time unavailability as stated in 2.1.4, will the system be treated as normal system condition or as having a contingency from which system adjustments are to be made prior to subsequent events. (2) Under R2.5 ?Past Studies may be used to support the Planning Assessment if they meet the following requirements and the sub requirement R2.5.2 states that for SS, SC, or stability analysis; the PRESENT system model shall not include any material changes, such as ".Does this mean that past studies may be used to support planning assessments as long as there are no material changes to the present system model" If so, that would be an impossible scenario to recreate.
Response: In Part 2.1.4 (now Part 2.1.5) when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1. Part 2.1.5 is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the	

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performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.5.2 is intended to allow the use of past study if the System that is being modeled for Assessment today has not materially changed from the one modeled in the past study for the study area. While changes are expected to occur between planning cycles, not all changes have significant impacts on System performance. For example, if the load growth in an area has not changed significantly, there is no change in the Transmission System and no addition of new generation, and then a case can be made that the past study can be used to support a new Assessment.	
TVA System Planning	Do not understand the rationale for being so prescriptive in requiring specific years to be studied in R2.1.1. Why not allow the TP and/or PC to decide on the three years to be studied in the Near Term? Since R2.3 short circuit analysis is a new raising the bar requirement, should the implementation plan for this be for 5 years like the other new raising the bar requirements? Further clarification is needed in R2.4.1 concerning load models that appropriately represent the dynamic behavior of loads. Is a NERC drafting team addressing these issues to determine an industry standard? If contingencies occur inside one utility that affect facilities in another utility, which utility is responsible for running these studies during the annual assessments? In R2.6.1, is there any limit to the time duration that a SPS and/or operating procedures can be used in the CAP? In Posting #2, undervoltage load shed, underfrequency load shed, and Special Protection Schemes were considered to be Non-Consequential Load Loss. In R2.6.1, installation or modification of Protection Systems or Special Protection Systems are now allowed as part of the Corrective Action Plan. Should undervoltage and underfrequency load shed also be allowed in the Corrective Action Plan? In R2.9, does the requirement require the maximum non-consequential load that can occur for contingencies in Table 1 or does it require just the maximum that a utility will allow on its system? Suggest clarifying permissible or perhaps using similar language as found in R2.8. Please explain the reason why Requirement R2.9 is needed in the Assessment. Reporting the largest Non-Consequential Load Loss doe not impact reliability. In R2.1, change the reference to requirement R2.6 (at the end of the last line) to R2.5. With the elimination of the distinction between system and generating plant stability studies, the blanket requirement in R2.5.1 that all stability analyses be five calendar years old or less, regardless of any material changes to the system, would

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	cause needless work to be performed on those plants or areas of the system where no changes are occurring. Recommend add the following to the end of R2.5.1: unless justification can be provided to demonstrate that the results of an older study are still valid. In Requirement R2.6.2, what constitutes a "project initiation date," and how will it be used? Please clarify. Please explain the reason why Requirement R2.8 is needed in the Assessment. Reporting the largest Consequential Load Loss does not impact reliability. R2.1 What's the value in being able to use qualified past studies if you have to use annual current studies Strike the words supplemented with and insert the word or R2.3 Insert the phrase one year of after the word addressing. In the subrequirements of 2.1.3 and 2.4.3, the use of the word timing is unclear. Consider using in service date or schedule for. In R2.6, does the Corrective Action Plan need to show all possible alternatives to fix a problem that has been identified - or does only one solution need to be shown for a problem?

Response: As written, Requirement R2 and Part 2.1.1 provides flexibility for the Planning Coordinator or Transmission Planner to use past studies to support the current year Planning Assessment, and to assess other years in addition to those identified in Part 2.1.1. So the suggestion is already allowed as written. No change made.

The SDT does not feel that Part 2.3 raises the bar as entities should have been performing these studies all along. No change made.

Part 2.4.1 requires only that the Load model appropriately represent the dynamic behavior of Loads. It is up to the Planning Coordinator and Transmission Planner, who are closer to the issues in the planning area to determine the application of the Load models. No change made.

If Contingencies occur inside one utility that affect Facilities in another utility, the Planning Coordinator or Transmission Planner for the utility whose System is impacted would be responsible for performing the annual Assessment for those Contingencies known to cause the impact. A certain amount of coordination will need to occur between the utilities. The parties can then mutually agree upon a Corrective Action Plan.

Part 2.6 has been revised and included as Part 2.7 in the new version. In the fifth bullet in Part 2.6.1, the duration for use of an operating procedure is at the discretion of the Planning Coordinator or Transmission Planner because it may not be feasible to implement Transmission reinforcements in some locations.

> **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled Load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. Part.2.6 does not specify how the Corrective Action Plan is written, it only requires that there is a plan to correct the potential problem identified in the Assessment. Therefore, it can be a number of alternatives or a single definitive alternative as long as the potential problem is addressed.

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Part 2.9 has been deleted. In the new version, Part.2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made. Part 2.5.1 has been revised and included as Part 2.6.1 to address your concerns. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required. The SDT believes that Requirement R2, part 2.8 (now part 2.9) supports the objective of ensuring BES reliability by ensuring that the largest expected amount of Consequential Load Loss is reported in an open, transparent process. Part 2.9 has been clarified. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1. In Part 2.1 it is envisioned that not all parts of the studies on which the Assessment is to be based can rely on past studies. For example, a study on year five performed during the past year may not be representative of year five in the current year. A past study can still be used if it can be demonstrated that the requirements for use of past studies are met. Parts 2.1.3 (now Part 2.1.4) and 2.4.3 have been revised to reflect your suggestion. **2.1.4** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Real and reactive forecasted Load. • Expected transfers. • Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. • Controllable Loads and Demand Side Management. • Duration or timing of planned Transmission outages. **2.4.3** For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

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	• Load level, Load forecast, or dynamic model assumptions. • Expected transfers. • Expected in service dates of new or modified Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. Part.2.6 does not specify how the Corrective Action Plan is written, it only requires that there is a plan to correct the potential problem identified in the Assessment. Therefore, it can be a number of alternatives or a single definitive alternative as long as the potential problem is addressed.
Exelon Transmission Planning	There are large amounts of resources required to perform the volume of studies required, including the dynamic and steady state sensitivities, extreme studies, and one-year lead time equipment spares. Many of these studies ultimately do not require additional consideration or reinforcement and have low threshold triggers, such as a 20 MW generation change. Performing these studies will be very burdensome to many TPs and result in few, if any, reliability benefits. We believe that the TP should be given more flexibility to allocate planning resources to areas of maximum benefit. The Spare Strategy in R2.1.4 is still not well defined. What types of equipment are included? How would a one-year lead time element be determined for consideration in this requirement? In R2.4.1, we recommend changing appropriately represents to a dynamic model appropriate for the type of stability study being performed? The TP should be allowed to perform only those specific stability studies needed and pertinent to its system. The same can be said about the dynamic load model. Differing interpretations are possible. We suggest changing the last sentence in R2.4.1 to .., a Load model shall be used which appropriately represents..An aggregate System Dynamic Load model which represents the overall dynamic behavior of the Load is acceptable. In 2.1.3 and 2.4.3 strike Expected from the phrase Expected transfers. Expected transfers should already be in the base case. In R2.5.2, the determination of a Material change is an engineering judgment issue and it should not be categorically defined here. There may be more significant material changes than a 20 MW increase in generation that would be better to study. In the phrase, For steady statesuch as generation or transmission additions/removals, or topology changes and would impact the study area, it is suggested to change would to could and impact the study area to significantly change the previous study results. The term should not be Corrective Action Plan, which implies a violation of a requirement. Suggest changing this term to Future Reliability Plan. What is the intended use for reporting the largest consequential and maximum non-consequential load loss amount and event? This would be a potential security concern if made public. There is a similar concern with the extreme event analysis. In 2.6.2 please define Initiation Date. While we appreciate your previous consideration of this comment, it is still not clear what this means. Is this the date of mitigation identification, regulatory approval date, construction start date, equipment procurement date, etc? If this is a commonly understood term not requiring a formal definition, could you then please

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	provide that definition in your response? If there is going to be a requirement to report on each contingency that results in non-consequential load loss it should be specified.

Response: If there are specific requirements in the standard that you feel would require the Transmission Planner to allocate their resources a certain way then you need to supply those specifics. As it stands, the SDT feels that the Transmission Planner can allocate resources any way they want. The standard does not dictate how they should meet requirements. No change made.

Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service such that the outage won't last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its system, or have an agreement with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.4.1 has been revised to address your concerns.

> **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

The SDT declines to strike "Expected Transfers" from Parts 2.1.3 (now Part 2.1.4) and 2.4.3. Parts 2.1.4 and 2.4.3 are sensitivity cases to be examined, which should cover conditions different from the base case. In any case, the Planning Coordinator or Transmission Planner are only required to examine one of the items from the list, and has the flexibility to choose other sensitivity cases if changes in expected transfer is not applicable.

Part 2.5.2 has been modified and included as Part 2.6.2. The SDT declines to change the term "Corrective Action Plan" to "Future Reliability Plan" because the Standard only requires the System performance to meet requirements. If a System meets requirements, then a Corrective Action Plan would not be necessary. An entity can still choose to install Transmission reinforcements for other reasons, but they would not be required by this Standard.

> **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. The SDT does not believe that this requirement represents a security concern as rewritten.

> **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2

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events in Table 1. In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: The comment – "If there is going to be a requirement to report on each contingency that results in non-consequential load loss it should be specified" does not reference any specific Requirement and therefore, the SDT can't respond. No change made.	
Southern Company	The Lower VSL describes a scenario where the TP or PC fails one or both of two particular sub-requirements. This language does not reconcile how failure of two sub-requirements is consistent with failure of only one of the same requirements. The recommendation is to restructure the VSL such that it is invoked when either sub-requirement is violated (not when both are violated). Generating unit stability has now been combined with system stability to be just one category - Stability. Previously, the shelf life of generating unit stability studies was indefinite -only needed to be restudied when system changes required it. Now the maximum shelf life of Stability studies is five years. Does this mean that generating unit stability studies must be repeated every five years whether system changes make it necessary or not? Requirement 2.3 stating that the short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon. It is not clear if the intent of the requirement is to study every year within Year One and year five. A statement similar to R2.1.1 Year One or two and year five for steady state analysis would be helpful. Some clarification is needed for R2.3 on the term Near-Term. Requirement 2.3 stating that "the analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area. What interrupting devices are included? Would the circuit breakers be enough? Moreover, the term System short circuit model is used for the first time (and the only time) here for the entire document. It is very common to use a different short circuit model for short circuit analysis while the steady state and stability analysis use different System models (power flow models). Some clarification is needed. R2.8 and R2.9 use the term megawatt "Demand". This is redundant. We suggest striking the word demand.

Response: The Lower VSL for Requirement R2 has been revised.

R2 VSL	The responsible entity failed to comply with Requirement R2, part 2.9	The responsible entity failed to comply withRequirement R2, part 2.3 or part 2.8.	The responsible entity failed to comply with one of the following parts of Requirement R2: part 2.1,	The responsible entity failed to comply with two or more of thefollowing parts of Requirement R2: part 2.1,

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			part 2.2, part 2.4, part 2.5, or part 2.7	part 2.2, part 2.4, or part 2.7.

Part 2.5.1 has been revised and included as Part 2.6.1 to address your concerns.

2.6.1 For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

The SDT declines to revise Part 2.3 to include short circuit analysis for one of the years in the Near-Term Transmission Planning Horizon because Part 2.3 only requires that a Planning Assessment be performed. Past studies can be used to support the Planning Assessment.

Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt and is not specifically related to new planned Facilities. Part 2.3 has been revised to provide greater clarity.

2.3 The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

The “megawatt” Is the qualifier for “Demand”. The SDT believe it is clear as written. No change made.

United Illuminating	R2 Comment We recommend replacing the phrase “prepare” with “conduct and document” in the first sentence. R2.1.1 Comment The requirement to evaluate year one or year two should be removed. This is not consistent with the time horizon identified in R2. R2.1.2 Comment The requirement should be removed. With no description of the system stresses and generator outages to be applied when assessing the off-peak load, it is difficult to imagine any issues which would arise which are not revealed in the peak load evaluation that could not be addressed through generation dispatch adjustments. R2.1.3 Comment - The emphasis on sensitivity testing in the existing section appears misdirected and should be focused on reasonable risk. The assessment should have to include a discussion of reasonable risk. The sensitivity list can be used to select sensitivities to assess risk. Having a requirement to perform one sensitivity just to meet the requirement of the standard does not add value to the assessment. R2.1.4 Priority Comment With respect to spare equipment strategy, this requirement imposes severe testing requirements upon the system. However, there is no discussion on the generation dispatch or system transfers that are to be used for this portion of the assessment. The expectations for changes in system stresses need to be clear as part of the standard. Additionally, this section does not contemplate changing the acceptability of load loss. After experiencing a major contingency such as this, some change in the acceptability of load loss should be expected. The standard should consider allowing Non-Consequential load loss for P1 & P2 events. The standard needs to allow Non-Consequential load loss for P3 & P4 events. Why doesn’t the standard state (such as a transformer, generator or power electronic device) and not just

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	(such as a transformer). R2.2 Comment We suggest replacing the phrase "a current System peak Load study" with a valid System peak Load study in the first sentence. The word current is confusing as some read the word current to mean today's rather than valid. R2.3 Comment Please provide guidance as to what year should be represented when performing short circuit studies. R2.4.1 Comment Change to read: "For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads or an aggregate System Load model which represents the overall dynamic behavior of the Load. R2.5.1 Comment? We suggest deleting this requirement, and incorporating it into R2.5.2. R2.5.2 Comment To incorporate R.2.5.1 into R2.5.2; please modify the section as follows: For steady state, short circuit, or Stability analysis the study shall be less than five calendar years old or less: the present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: The addition/deletion/change of individual generating unit capability determined to be material by the Planning Coordinator or Transmission Planner. [A 20 MVA generator is fairly small in a 30,000 MW system and system concerns would already be addressed though the System Impact Study]? An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES determined to be material by the Planning Coordinator or Transmission Planner. R2.6 Priority Comment As written, this section undermines the value of the sensitivity testing. This section should require a corrective action plan to fix problems determined in sensitivity analysis if there is a reasonable risk of occurrence. We suggest making the standard read Provide documentation that explains the reasoning for the sensitivities considered and selected. R2.6 Comment At the end of the second sentence, the phrase "in the tables" is used. We suggest using more definitive language such as in Table 1. R2.6.2 Comment The phrase Project Initiation Date needs to be defined. It is unclear if this is this the date of ground breaking, purchase orders being issued, solution study initiation, etc. Additionally, in the second sentence the phrase "as well as an in-service date" should be modified to read "as well as a target in-service date". R2.6.3 Comment Plans can provide a target in-service year but not an actual in-service year. R2.6.4 Priority Comment There should be a cutoff point when changes occur beyond a certain date. When that date occurs, further changes will be evaluated in the next year's assessment. Otherwise, if a state makes a decision not to site a project a few weeks prior to the end of the assessment period, there will not be sufficient time to incorporate this into that year's assessment and develop corrective actions. R2.8 Comment Largest consequential load loss is not factored into the Planning Assessment and should therefore be deleted. R2.9 Comment This requirement is unclear. Is this requirement asking for each transmission planner to list their criteria for

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	non-consequential load loss, or is it asking how much non-consequential load loss was being relied upon in the assessment? We recommend that the requirement be modified to require documentation of the maximum amount of non-consequential load loss that was relied upon during the assessment.

Response: The SDT does not think that replacing "prepare" with "conduct and document" would add clarity, since Requirement R2 includes a requirement to document assumptions and results. No change made.

The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. No change made. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon.

Mitigation Time Horizon

The time horizons available for mitigating a violation to a requirement include the following:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

Part 2.1.2 requires that the Planning Coordinator and/or Transmission Planner also consider off-peak conditions because the System must be able to meet performance requirements over all demand levels. System peak condition may not represent all stressed conditions. For example, during off-peak, the Load is low, and the generation would have to be turned off to achieve Load-resource balance. Turning down resources within a Load area could result in reliability problems. Lowering the Load in areas with many non-dispatchable resources could also pose potential problems. As the System incorporates more and more renewable resources, some of them are non-dispatchable; a standard must be forward looking so the Planning Coordinator and Transmission Planner can identify potential problems as part of the Assessment. No change made.

Part 2.1.3 (now Part 2.1.4) has been rewritten to clarify the intent of the requirement. The requirement does not preclude a discussion of risk.

> **2.1.4** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.
>
> - Real and reactive forecasted Load.
> - Expected transfers.
> - Expected in service dates of new or modified Transmission Facilities.

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	• Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. • Controllable Loads and Demand Side Management. • Duration or timing of planned Transmission outages. In Part 2.1.4 (now Part 2.1.5) when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. Part 2.1.5 is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the performance of their System. If a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Actions such as out of merit dispatch, operational restrictions, System reconfiguration can be part of a Corrective Action Plan if the System cannot meet performance requirements without the Facility in service. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.2 is intended to require a study performed in the current year, as opposed to studied performed in the past years. Part 2.2 has been revised to provide greater clarity. **2.2** The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: For Part 2.3 the decision on the year to be represented in the study is left to the discretion of the Planning Coordinator or Transmission Planner. Part 2.3 only requires it to be either a study that was performed during the current year or in the past. For example, this year is 2009 and a study performed in 2009 is a current study, the study can investigate the System in a future year, which is at the discretion of the Planning Coordinator or Transmission Planner performing the study. Requirement R2.3 has been revised to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. Part 2.4.1 was revised but not changed as proposed because the intent of the last sentence is to allow the use of an aggregated System Load model as an appropriate Load representation. The suggested change could be read to mean that an aggregated System Load model would not appropriately represent the dynamic behavior of Loads. Parts 2.5 .1 and 2.5.2 (new Parts 2.6.1 and 2.6.2) were not combined. While the SDT appreciates the concern that a 20 MW generation addition can be small compared to a large System, a NERC standard needs to be clear as to the applicability. A requirement which contains "determined to be material by the Planning Coordinator or Transmission Planner" is not clear. Therefore, changing from 20 MW to "material" will also have to require justification from the Planning

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Coordinator or Transmission Planner on what is "material". Material has been deleted. Part 2.6 has been modified and included as new Part 2.7. The intent is to allow discretion for the Planning Coordinator or Transmission Planner to correct those deficiencies if they are prevalent (i.e., occur is more than one sensitivity). Although not required, the standard does not preclude the Planning Coordinator or Transmission Planner to develop Corrective Action Plans for high risk scenarios. However, if the scenario is high risk, then it should have been included in the base assumptions in the assessment and the Corrective Action Plan would have been required. The end of the second sentence has been changed to refer to Table 1 as suggested. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required. Part 2.6.4 allows the Planning Coordinator or Transmission Planner to address situations that are beyond its control by utilizing Non-Consequential Load Loss and/or curtailment of Firm Transmission Service, which are normally not permitted. Depending on the urgency of the need, the Corrective Action Plan may be developed outside the normal Assessment cycle at the discretion of the Planning Coordinator or Transmission Planner involved. Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Louisiana Energy and Power Authority	R2.5. This basic requirement intends, as we understand it, to require that earlier studies not be used for a current assessment if they are no longer accurate. But the phrasing is potentially confusing, and would be clearer if revised. Since the requirement deals with the use of past studies, we suggest that R2.5.2 be revised to state that the study may be used only if there have been no material changes, so that R2.5 reads in full:R2.5. Past studies may be used to support the Planning Assessment if they meet the following requirements: R2.5.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less. R2.5.2. For steady state, short circuit, or Stability analysis: the study may be used only if there have been no material changes, such as generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater. With respect to footnote 10 to Table 1, we fear that the flexibility suggested by those provisions may be excessive for a planning standard. The ambiguity occasioned by stating emergency actions that can properly be taken in a planning standard can be utilized by those who plan the system in a manner which plans to drop non-consequential loads just as footnote b has been used in the past. If this is intended to raise the bar as stated these provisions do not belong in a

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	planning standard, at least as now stated. It may be appropriate to remove the reference to footnote 10, at least in the Initial System Condition entry in P3, where it suggests that it can be invoked after loss of a single generator, and we request the SDT to review that footnote to assure that it is appropriate in the other entries to which it is applied.
Response: Part 2.5 has been revised and included as Part 2.6 as shown. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Footnote 10 (now footnote 9) was added to address the disjoint between how some parties calculate ATC/AFC when assessing Long Term Firm Transmission Service and the currently proposed TPL-001-1 standard. TPL-001-1 requires Transmission Planners to plan their systems to meet multiple contingency events and some parties assess Long Term Firm Transmission Service on a first Contingency basis. Units obligated to re-dispatch, as contemplated in Footnote 9 are those units which are contractually bound to provide the service as well as those obligated to provide the service under Network Integrated Transmission Service, under FERC's pro forma OATT. Under the pro forma OATT, units designated as network resources receiving NITS are obligated to re-dispatch as requested by the Transmission Provider pursuant to Section 33.2 to maintain reliability. The footnote is worded such that curtailment/re-dispatch cannot result in the loss of firm Load preserves the guidance given by FERC in Order 693 that no single Contingency result in the loss of firm Load. No change made. The SDT has reviewed the application of footnote 10 (now footnote 9) and believes that it is correct. No change made.	
System Protection and Transmission Planning Department	R2 - The term "Stability Analysis" is used frequently in the standard, but is not clearly defined. Based on an IEEE paper ("Definition and Classification of Power System Stability," Kundar, et al) there are 5 different categories of stability analysis: 1)small signal angle stability; 2) transient angle stability; 3) frequency stability; 4) large disturbance voltage stability; and 5) small disturbance voltage stability. Does the writing committee intend to make the analysis of all these types of stability issues mandatory? I recommend inserting a new definition into the standard for stability as follows: "Stability Analysis - The study of the bulk electric power system's ability, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance. There are 5 accepted categories of power system stability: 1) small signal angle stability; 2) transient angle stability; 3) frequency stability; 4) large disturbance voltage stability; and 5) small disturbance voltage stability. While there are situations that exist that require small signal angle and voltage stability analysis, only transient angle stability, frequency stability, and large disturbance voltage stability analysis are generally relevant to system planning performance assessments. R2.1.4 is a new requirement directing studies to consider impacts of spare equipment strategy. Does this require the TP to run scenario analysis without certain transformers? It is not clear what is required. How many spare transformers are required? What reliability level is acceptable? R2.1.4 The one year cut-off seems arbitrary. One MONTH may be unacceptably long in some cases. Instead of one year or more, we suggest the requirement state an extended time period.

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	R2.2. The wording on this requirement is not clear. Is it trying to say that a long-term (5-10 year) peak loading study is required to be performed annually R2.2: What is meant by the term current System peak Load study A powerflow study performed under expected peak-load conditions? Or a forecast of peak loads? R2.3 A short circuit analysis requirement is now added to Planning Assessment requirements. Short circuit analysis appears to be in the standard to document adequate ratings for interrupting equipment. That would be the purpose of short circuit studies we perform. If there are other intended meanings, then additional detail is needed. R2.3 We do not agree that a short circuit analysis needs to be conducted annually. The requirement for a new short circuit duty study should be driven by changes in the system, as is done for powerflow study work. In short, until system changes are made, we would not anticipate higher fault duties, and there would be no reason to rerun studies. R2.4.1 requires dynamic load models. Development of dynamic load models is ongoing, and therefore will need a much longer implementation period than the steady state portions of the standard. We are not sure two years will be enough. It depends partly on pending work that is not under our control.R1.1.2, R2.1.4, R2.5.2, R3.3.4, R4.3.3, R5 When text of a Standard Requirement includes the phrase such as or could include, then gives a list of possible choices, we take it to mean "just one of these items, or none of these, or something not listed here". In other words, such as lists are really non-required, non-interpretable, non-measurable options. They should not be included in requirements. Lists such as these belong in transmittal notes and associated SDT commentary, not in Compliance Standard Requirements. R2.5.2 Limits such as "addition/deletion/change to a group of generating units . . . which total 20 MW or greater. are not always appropriate. Appropriateness of Generation netting with load should depend on system size and engineering judgment, not artificial limits. The suggestion list following generation changes could include: should be eliminated. R2.6.2. For the Near-Term Transmission Planning Horizon, include both a project initiation date as well as an in-service date? The assessment report should not require a full project development just a description of what is required to provide adequate service within specified operating criteria. The term project initiation is not clear. Requirement R2.6.2 should be eliminated. R2.8. The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1. is complicated, and may require new modeling software capability to comply. Software vendors would develop this capability. Why is this required? What is the expected benefit to system reliability?

Response: The SDT disagrees that the Standard should include a definition of Stability analysis because it is covered in Requirement R2. "Stability analysis" is not a defined NERC term and is not intended to be defined as in IEEE; however, it does not conflict with the IEEE definition. No change made.

Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service such that the outage won't last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, and may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its system, or have agreement with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than

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one year. The Planning Coordinator and/or Transmission Planner will need to decide which pieces of major Equipment in their respective Systems would be more vulnerable to long term outage. In Part 2.1.5 when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.2 has been revised to provide greater clarity. The standard will require that a study for one year within the Long-Term Transmission Planning Horizon be conducted. The Planning Assessment can be supplemented by past studies. **2.2** The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: Part 2.3 has been revised to provide greater clarity. In addition, Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt and is not specifically related to new planned Facilities. The Assessment is to be supported by a current or past study. Therefore, annual short circuit study is not required if no material change has occurred. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. Part 2.4.1 allows the use of an aggregate System Load model which represents the overall dynamic behavior of the Load that could impact the study area. Part 2.4.1 has been revised to provide greater clarity. In addition, the SDT was not able to locate the phrase "such as" in Requirement R2.4.1. There were two places in Requirement R2 that this phrase appears (Parts 2.1.4 and 2.5.2). In both instances, what follows were examples and not requirements. **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Part 2.5.2 has been revised and included as Part 2.6.2 to address your concerns. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with

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Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Part 2.8 is intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed the requirement and agrees that as written it was unclear. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
PPL Energy Plus	The standard appropriately recognizes that the planning horizon must be as long as the longest lead-time system upgrade, typically 8+ years for a new line. However, while Requirement 2.2.1 states this, it could be more clearly stated. Requirement R2.5.2 should be clarified to point out if the TP has discretion or if the 20 MW is binding. Requirement R2.6.4 should require TP's and PC's to post on an OASIS to assure easy access by affected parties to information on what is "beyond the control of these organizations. Please retain Requirements 2.8 and 2.9 as these are good measures of the quality of the plan produced by the planners.
Response: Part 2.2.1 has been revised because extending the Planning Horizon beyond 10 years for projects with lead time longer than 10 years is already covered in the definition of Long-Term Transmission Planning Horizon. **2.2.1** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected. Part 2.5.2 (now Part 2.6.2) has been revised to address your suggestion. Both bullets included references to 20 MW have been deleted from the revised standard. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. The SDT declines to require a specific venue for the Planning Coordinator and/or Transmission Planner to post the information regarding Part 2.6.4. The way information is shared should be left to the individual entities involved in accordance with Requirement R7, included in the new version as Requirement R8. Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and finds that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
PacifiCorp SRP Arizona Public Service Co	Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this

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Southern California Edison Company Pacific Gas and Electric Co, California ISO Idaho Power San Diego Gas and Electric Co	could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement. The 20 MW threshold identified as material change for generation in R2.5 is too small. The limit should be raised or based on a percentage of the study area's installed generating capacity. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event if it is documented? R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.
NV Energy	Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault).R2.1.3 should be modified to remove the last bullet point. Transmission outages should be a part of operational study work not planning study work. Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement. The 20 MW threshold identified as material change for generation in R2.5 is too small. The limit should be based on a percentage of the study area'sinstalled generating capacity. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event if it is documented R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent,

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	among other things, on the types of load being served. It very well may be a case by case situation.
Western Area Power Administration	Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault).The last bullet under R2.1.3 - "Planned duration or timing of Transmission Outages." does not belong in a long-term planning standard. These-type of seasonal outages are studied and implemetation plans are derived as part of the TOP Standard requirements. In the WECC - this is also covered by the seasonal studies carried out by the Operating Transfer Capability Policy Committee (OTCPC) study groups. Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement - OR simply delete this spare equipment requirement. The 20 MW threshold identified as material change for generation in R2.5 is too small. The limit should be raised or based on a percentage of the study area's installed generating capacity. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event if it is documented? R2.9 should be deleted. This requirement is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.

Response: Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt. Even though the effects of short circuit capability are localized and may be related to new planned Facilities, it is important to BES reliability. Part 2.3 has been revised to provide greater clarity.

> **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

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2.1.5 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.5 has been revised and included as Part 2.6 as shown. The references to a 20 MW threshold have been deleted from the revised standard. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Western Area Power Administration	Short-circuit studies as related to maintaining adequate protection devices and systems are normally performed either by a specific System Protection Group/Department or System Maintenance Department and should not be in this requirement, but Post-Transient Analysis to mitigate voltage collapse scenarios should be included (includes R2.5.1 & R2.5.2). Also, System Protection including mitigation of short-circuit duty above installed facilities capabilities or for new planned facilities are already covered by the PRC Standards and need not be included and duplicated in the TPL Planning Standard such as in R2.3 & R2.7.
Response: Parts 2.3 and 2.7 are intended for the Planning Coordinator and/or Transmission Planner to assess whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt, and develop Corrective Action Plan is needed. As such, they are not specifically related to new planned Facilities. Requirement for Post-transient voltage collapse is included in Table 1, Header note (a), which states "Voltage instability, cascading outages, and uncontrolled islanding shall not occur." No change made.	
Tampa Electric	R2.1 should state R2.5 at the end of requirement instead of R2.6 R2.1.4 Consider revising to only include P0-P2 contingencies. R2.5.1 please clarify whether the 5 years is from the beginning of the assessment or end of the assessment. R2.6 Consider changing the terminology for "Corrective Action Plan" to "Transmission Plan" R2.8 Please clarify the reason for this requirement. This is not necessary for reliability and the effort to collect this information is substantial and does not benefit the BES. R2.9 Please clarify the reason for this requirement. This is not necessary for reliability and the effort to collect this

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	information is substantial.

Response: In the new version, Part.2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference.

Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

For Part 2.5.1 the 5 years should be measured from the completion of the past study to be used to support the current Planning Assessment. However, Part 2.5.1 has been revised and included as Part 2.6.1, which will allow the use of studies older than 5 years if a technical rationale can be provided to demonstrate that the results of an older study are still valid.

> **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

In Part 2.6, the SDT declines to change the term "Corrective Action Plan" to "Transmission Plan" because the Standard only requires the System performance to meet requirements. If a System meets requirements, then a Corrective Action Plan would not be necessary. An entity can still choose to install Transmission reinforcements for other reasons, but they would not be required by this Standard.

Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Requirement R2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only.

> **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.

Florida Reliability Coordinating Council, Inc - Transmission Working Group	Incorrect reference shown at the end of R2.1. The appropriate reference should be R2.5. The end of the first sentence of R2.3 should have a reference to R2.5. The end of the first sentence of R2.4 should have a reference to R2.5. R2.1.4 - Please consider revising this for the analysis to include only Contingencies P0-P2 in Table 1. Alternatively we suggest moving this requirement to be under sections 2.1.3 and 2.4.3 and treated as a sensitivity. R2.5 ? This requirement is very valuable in clarifying that past studies can be used and what criteria needs to be met for them to be used. However it is not clear if all new studies could be met using past studies (e.g. a small system with very few changes year to year) of if some sub-requirements require a new study every year, with past studies only used as supporting information. If the intent is that some sub-requirements can not be met with past studies, then consider making that clear through a foot note or a list under Section 2.5 listing which study requirements may depend only past studies that are still current.

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	R2.5.1 Please clarify if the 5 calendar years is from the date the assessment is "finished" or the date the study process for the assessment begins. R2.5.2 the identified 20 MW threshold is extremely small and would be doubtful to change the response of the BES. This requirement could also be interpreted that a previous study where the base case is not identical to the current planning case could be used. Please consider the following proposed language: For steady state, short circuit, or Stability analysis: the present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period that would impact the study area. (not show the list) R2.6 - Requiring sensitivities but not requiring that they meet specific performance requirements is a sound approach.R2.6 requires a corrective action plan when performance will not be met in the simulations. However, if an entity has already planned a needed facility and/or operation steps for a given conditions, the simulations will not show any deficiencies and therefore no corrective action plan is required. The term Corrective Action Plan implies that the situation is wrong or incorrect, consider changing the approach to be to require an entity to have a planning and Operations plan, Improvement Action Plan?, or simply a Transmission Plan that includes all facilities planned for the BES and descriptions of conditions where an operational process is being used. R2.6.1 (Bullet 2) This requirement should also account for the removal of a Special Protection Systems: Installation, modification or removal of Protection Systems or Special Protection Systems?. R2.6.4 This is an excellent addition R2.8 Please explain the reason for this requirement. The effort required to collect this data is substantial and does not have any benefit to the BES. R2.9 Please explain the reason for this requirement. It seems to cause Entities to develop performance criteria for themselves for Multiple and Extreme Contingencies that are not in Table 1. The effort required to collect this data to compare against any self-imposed criteria is substantial and does not have any benefit to the BES. The requirement will result in inconsistency across North America. There is also no discussion of what happens if a Multiple or Extreme contingency is shown to exceed the Entity's self-imposed criteria, is the Entity then non-compliant? If so, what if the Entity simply changes the self-imposed criteria? We suggest eliminating this requirement.

Response: In the new version, Part.2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference.

Parts 2.3 & 2.4 have been revised to reflect your suggestion.

2.3 The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4 The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part2.6. The following studies are required.

Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the

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System is expected to experience due to the possible unavailability of the long lead time equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. For Part 2.5.1 the 5 years should be measured from the completion of the past study to be used to support the current Planning Assessment. However, Part 2.5.1 has been revised and included as Part 2.6.1, which will allow the use of studies older than 5 years if a technical rationale can be provided to demonstrate that the results of an older study are still valid. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. Part 2.5.2 has been revised and included as Part 2.6.2 to provide greater clarity. The references to a 20 MW threshold have been deleted from the revised standard. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. In Part 2.6 (now Part 2.7), the SDT declines to change the term "Corrective Action Plan" to "Transmission Plan" because the Standard only requires the System performance to meet requirements. If a System meets requirements, then a Corrective Action Plan would not be necessary. An entity can still choose to install Transmission reinforcements for other reasons, but they would not be required by this Standard. Although additions of Protection Systems and Special Projection Systems are usually associated with projects to enable the System to meet performance requirements, the second bullet in Part 2.7 has been modified to include removal of Protection Systems or Special Protection Systems to provide greater clarity. **2.7 bullet 2:** Installation, modification, or removal of Protection Systems or Special Protection Systems Parts 2.8 and R2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
FMPA	Incorrect reference shown at the end of R2.1. The appropriate reference should be R2.5. The end of the first sentence of R2.3 should have a reference to R2.5. The end of the first sentence of R2.4 should have a reference to R2.5. R2.1.4, what does (t)he analysis shall reflect the Contingencies identified in Table 1 mean? Is the intention similar to sensitivities, where there is no direct requirement to meet the performance standards of Table 1? If so, why not include loss of a long lead time Facility followed by other contingencies one of the Sensitivities and not have a separate sub-requirement for it? Or, is the intention that the TP and PC must meet the performance requirements of Table 1 considering the outage of a long lead time Facility? We hope that the intent is not to require Entities to be able to meet the performance requirements

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	of Table 1 assuming a long lead time Facility out of service. If that is the intent, then we believe that only Contingencies P0-P2 in Table 1 ought to apply to Requirement R2.1.4. Otherwise, Requirement R2.1.4 would require building transmission to triple contingency (N-3) criteria. Contingency P3 requires building transmission to a single contingency plus a generator outage (a double contingency that has the same performance criteria requirements as single contingencies). Since generators are long term lead Facilities that no one that we know of carries spares for, R2.1.4 as written would mean that Contingency P3 becomes two generators out of service with system adjustments followed by another contingency (N-3). This would have the (possibly unintended) consequences of significantly reducing long-term firm ATC since utilities will likely use TRM to account for the potential for long-term outages. If meeting the criteria of Table 1 is the intent of the SDT, then a potential way to address this is to restate R2.1.4 to state that only P0 through P2 (zero and single contingency) apply to R2.1.4.If meeting the performance criteria of Table 1 is the intent of the SDT for R2.1.4, then we also believe that R2.1.4 should also only apply to the EHV and not the HV system. Yes, when a major piece of equipment such as a transformer fails, it could be out for a long period of time; however, a transformer failure is far less probable than an over-head transmission line failure (e.g., a transformer failure is in the range of a once in 50 year event, whereas a transmission line fails probably once a year or once every other year, almost two orders of magnitude difference). A major 500 kV/230 kV autotransformer failure will have a far larger radius of impact than a 230 kV/138 kV autotransformer meant to serve the local area, giving additional support to purchasing a spare transformer for the 500/230 kV auto (EHV system). A small utility with only one or two 230 / 138 kV autos does not have sufficient justification to purchase a spare autotransformer due to the very low failure rate and the much more localized purpose of the transformer. If the intent of the SDT is to meet the performance requirements of Table 1 for R2.1.4, then the standard would essentially cause many small utilities who cannot justify spare autos to plan to serve only load and significantly reduce ATC in the planning horizon. Based on the lesser impact of HV connected autos as compared to EHV connected autos, and if the intent of the SDT is to meet the performance requirements of Table 1 for R2.1.4, then we would recommend that, for auto-transformers, R2.1.4 should only be applicable to EHV connected auto-transformers. R2.8 Please explain the reason for this requirement. The effort required to collect this data is substantial and does not have any benefit to the BES. R2.9 Please explain the reason for this requirement. It seems to cause Entities to develop performance criteria for themselves for Multiple and Extreme Contingencies that are not in Table 1. The effort required to collect this data to compare against any self-imposed criteria is substantial and does not have any benefit to the BES. The requirement will result in inconsistency across North America. There is also no discussion of what happens if a Multiple or Extreme contingency is shown to exceed the Entity's self-imposed criteria, is the Entity then non-compliant? If so, what if the Entity simply changes the self-imposed criteria?

Response: In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference.

Parts 2.3 and 2.4 have been revised to reflect your suggestion.

2.3 The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned

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	generation and Transmission Facilities in service which could impact the study area. **2.4** The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required. Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Transmission Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service such that the outage won't last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its System, or have agreement with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. The Planning Coordinator and/or Transmission Planner will need to decide which pieces of major Equipment in their respective systems would be more vulnerable to long term outage. In Part 2.1.5 when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.
Progress Energy Carolina (PEC)	PEC believes that "R2.1.1. System peak Load for either Year One or year two, and for year five" is unneccesarily prescriptive. PEC recommends eliminating the Year One or year two addition. PEC believes that R2.1.4. concerning an entity's spare equipment strategy is overly conservative. The standard should only require N-2 deep planning and not N-3. PEC believes that for R2.4.1 "a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads" should be clarified to include "as appropriate" clause. Induction motor load modeling should not be required for all dynamic studies. PEC believes that for R2.5.2. The language "For steady state, short circuit, or Stability analysis: the present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area" needs to be made more clear. The important point is that material changes must be modeled if they have occurred. Also the 20MW threshold is far too small to be material. PEC believes that R2.8. and P2.9 are unnecessary and should be removed.

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Response: Requirement R2, part 2.1.1 is intended to require studies for System Peak Load Conditions for 2 of the years in the Near-Term Transmission Planning Horizon: (1) A year five case to identify potential problem that can be addressed if the planned projects proceed as scheduled; (2) A Year One or year two case to identify any potential problems unanticipated in the five-year case, which if not addressed, could impact operations as time progresses. The standard provides flexibility for the Planning Coordinator or Transmission Planner to use past studies to support the current year assessment, and to assess other years in addition to those identified in Requirement R2, part 2.1.1. No change made. Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service such that the outage won't last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its System, or have agreement with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. In Part 2.1.5 when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.4.1 allows the use of an aggregate System Load model which represents the overall dynamic behavior of the Load that could impact the study area. Part 2.4.1 has been revised to provide greater clarity. **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Part 2.5.2 has been revised and included as Part 2.6.2 to address your concerns. The references to a 20 MW threshold have been deleted from the revised standard. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
CPS Energy	As written, is it the intent of Requirement R2.1.4. to escalate the contingencies in Table 1 from "N-1" to "N-2" and "N-2" to N-3" for long lead-time replacement equipment, such as autotransformers and GSUs? If so, we feel that this requirement is

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	overly burdensome that will result in unnecessary expense to the customers. In Requirement R2.4.1., what is the intent of the second sentence if an aggregate system load model is acceptable? We feel that the second sentence should be removed. In Requirement R2.6.2., we feel that statement of the project initiation date has no benefit and should be removed as a requirement. The required in-service date should be adequate. We do not believe that there is any benefit to reliability by documenting the Consequential and Non-Consequential Load Loss data required by Requirements R2.8. and R2.9.
Response: Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service such that the outage won't last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its System, or have agreement with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. In Part 2.4.1, the intent for the second sentence is that if more accurate Load Model is available it should be used. The standard should not inadvertently disallow improved Load modeling. In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
MidAmerican Energy Company	MidAmerican commends the SDT for all its hard work on this standard. MidAmerican offers the following comments on R2: MidAmerican believes that the second sentence of R2.3 as written will result in unnecessary modeling for the required short

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	circuit analysis. MidAmerican recommends that the sentence The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area. MidAmerican recommends that R2.3 be changed by deleting the words any and could and replace with the words materially. In this way, the sentence would read, They analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with generation and Transmission Facilities in service which materially impact the study area. Requirement 2.5 is too confining and is complicated and unnecessary. MidAmerican asks that the requirement be deleted in its entirety. Alternatively, if the SDT does not agree with deleting all of R2.5, then MidAmerican asks that the SDT consider deleting the R2.5.1. MidAmerican believes R2.4 will ensure that analysis is fresh by requiring a certain number of studies be conducted for certain years in the planning horizon. Why add the requirement for no older than 5 calander years? With the R2.4 and the material requirements in R2.5.2 shouldn't that be more than enough to ensure that the analysis is fresh enough to support the assessment?? If R2.5.2 is not deleted, the words and interconnected to the Bulk Electric System should be added behind 20 MW or greater. Requirement 2.6.2 requires the project initiation date. MidAmerican recommends that the SDT delete the requirement to provide this date as an initiation date is not related to system reliability. If the SDT believes it is critical to get this date, then the SDT should define it. Does it mean when engineering starts, when it is decided to proceed, or something else? At a minimum, MidAmerican believes that the SDT should add the word expected behind largest to avoid unnecessary compliance issues for an unexpected event, and clarify that R2.8 and R2.9 are not required for sensitivity cases.

Response: Part 2.3 has been revised to provide greater clarity. However, the SDT declines to make the changes suggested because Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt, and develop a Corrective Action Plan as needed. As such, they are not specifically related to individual new planned Facilities.

> **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

Deleting Part 2.5 would leave no guidance on when past studies can be used to support current Assessment. This can increase work load. Part 2.5 has been revised and included as Part 2.6 as shown.

> **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.
>
> **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required.

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2.7 For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Deseret Generation & Transmission	R2.5.2 For Past studies to be used in the Planning Assessment, the suggestion that the addition of a 20 MW generator would disqualify those past studies is way too restrictive. It should be left up to the Transmission Planner to evaluate the applicabililty of past studies and the two sub bullets should be removed and replace with a general statement about past studies should adequately represent the present system to be used in the Planning Assessment. Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the "largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event" if it is documented? R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.
Response: Part 2.5.2 has been revised and included as Part 2.6.2 to address your concerns. The references to a 20 MW threshold have been deleted from the revised standard. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to	

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	demonstrate that System changes do not impact the performance results in the study area. Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt and is not specifically related to new planned Facilities. Part 2.3 has been revised to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.6 has been modified and included as new Part 2.7. The intent is to allow discretion for the Planning Coordinator or Transmission Planner to correct those deficiencies if they are prevalent (i.e., occur is more than one sensitivity). Part 2.7.2 has also been added to require that the Corrective Action Plan include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary. The intent is to allow discretion for the Planning Coordinator or Transmission Planner to correct those deficiencies if they are prevalent (i.e., occur is more than one sensitivity). **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: **2.7.2** Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary. Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in he new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.
Northeast Utilities	R2 Comment We recommend replacing the phrase prepare with conduct and document in the first sentence. R2.1.1 Comment The requirement to evaluate year one or year two should be removed. This is not consistent with the time horizon identified in R2. R2.1.2 Comment The requirement should be removed. With no description of the system stresses and generator outages to be applied when assessing the off-peak load, it is difficult to imagine any issues which would arise which are not revealed in the peak load evaluation that could not be addressed through generation dispatch adjustments.

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	R2.1.3 Comment - The emphasis on sensitivity testing in the existing section appears misdirected and should be focused on reasonable risk. The assessment should have to include a discussion of reasonable risk. The sensitivity list can be used to select sensitivities to assess risk. Having a requirement to perform one sensitivity study just to meet the requirement of the standard does not add value to the assessment. R2.1.3 Comment - What should be the time duration for the bullet that reads Planned duration or timing of Transmission outages R2.1.4 Priority Comment With respect to spare equipment strategy, this requirement imposes severe testing requirements upon the system. However, there is no discussion on the generation dispatch or system transfers that are to be used for this portion of the assessment. The expectations for changes in system stresses need to be clear as part of the standard. Additionally, this section does not contemplate changing the acceptability of load loss. After experiencing a major contingency such as this, some change in the acceptability of load loss should be expected. The standard needs to allow Non-Consequential load loss for P3 & P6 events when spare equipment strategy is incorporated in the testing. An example of such an event, that non-consequential load loss should be acceptable, would be a long-term outage of one transformer at a station which would be modeled in the base, followed by event P6 testing on initial system condition of a transformer out of service then followed by a 2nd transformer outage. This would be three transformers out at the same station and this could approach Extreme Events Contingency. R2.2 Comment We suggest replacing the phrase a current System peak Load study with a valid System peak Load study in the first sentence. The word current is confusing, as some read the word current to mean today's rather than valid. R2.3 Comment Please provide guidance as to what year should be represented when performing short circuit studies. R2.4.1 Comment ? Change to read: "For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads or an aggregate System Load model which represents the overall dynamic behavior of the Load. R2.5.1 Comment" We suggest deleting this requirement, and incorporating it into R2.5.2. R2.5.2 Comment To incorporate R.2.5.1 into R2.5.2; please modify the section as follows: For steady state, short circuit, or Stability analysis the study shall be less than five calendar years old or less: the present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: The addition/deletion/change of individual generating unit capability determined to be material by the Planning Coordinator or Transmission Planner. [A 20 MW generator is fairly small in a 30,000 MW system and system concerns would already be addressed through the System Impact Study]?An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES determined to be material by the Planning Coordinator or Transmission Planner. R2.6 Priority Comment As written, this section undermines the value of the sensitivity testing. This section should require a corrective action plan to fix problems determined in sensitivity analysis if there is a reasonable risk of occurrence. We suggest making the standard read Provide documentation that explains the reasoning for the sensitivities considered and selected. R2.6 Comment At the end of the second sentence, the phrase in the tables is used. We suggest using more definitive language such as in Table 1.

Organization	Question 2 Comment
	R2.6.2 Comment The phrase Project Initiation Date needs to be defined. It is unclear if this is the date of ground breaking, purchase orders being issued, solution study initiation, etc. Additionally, in the second sentence the phrase as well as an in-service date should be modified to read as well as a target in-service date. R2.6.3 Comment Plans can provide a target in-service year but not an actual in-service year. R2.6.4 Priority Comment There should be a cutoff point when changes occur beyond a certain date. When that date occurs, further changes will be evaluated in the next year's assessment. Otherwise, if a state makes a decision not to site a project a few weeks prior to the end of the assessment period, there will not be sufficient time to incorporate this into that year's assessment and develop corrective actions. R2.8 Comment Largest consequential load loss is not factored into the Planning Assessment and should therefore be deleted. R2.9 Priority Comment We highly recommend that the standard should not allow non-consequential load loss to resolve any violation arising from the planning events in Table 1. Therefore, this requirement should be deleted.
ISO New England, Inc.	R2 Comment We recommend replacing the phrase prepare with conduct and document in the first sentence. R2.1.1 Comment The requirement to evaluate year one or year two should be removed. This is not consistent with the time horizon identified in R2. R2.1.2 Comment The requirement should be removed. With no description of the system stresses and generator outages to be applied when assessing the off-peak load, it is difficult to imagine any issues which would arise which are not revealed in the peak load evaluation that could not be addressed through generation dispatch adjustments. R2.1.3 Comment - The emphasis on sensitivity testing in the existing section appears misdirected and should be focused on reasonable risk. The assessment should have to include a discussion of reasonable risk. The sensitivity list can be used to select sensitivities to assess risk. Having a requirement to perform one sensitivity just to meet the requirement of the standard does not add value to the assessment. R2.1.4 Priority Comment With respect to spare equipment strategy, this requirement imposes severe testing requirements upon the system. However, there is no discussion on the generation dispatch or system transfers that are to be used for this portion of the assessment. The expectations for changes in system stresses need to be clear as part of the standard. Additionally, this section does not contemplate changing the acceptability of load loss. After experiencing a major contingency such as this, some change in the acceptability of load loss should be expected. The standard should consider allowing Non-Consequential load loss for P1 & P2 events. The standard needs to allow Non-Consequential load loss for P3 & P4 events. Why doesn't the standard state (such as a transformer, generator or power electronic device) and not just (such as a transformer). R2.2 Comment We suggest replacing the phrase a current System peak Load study with a valid System peak Load study in the first sentence. The word current is confusing as some read the word current to mean today's rather than valid. R2.3 Comment Please provide guidance as to what year should be represented when performing short circuit studies. R2.4.1 Comment Change to read: For peak System Load levels, a Load model shall be used which appropriately

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Central Maine Power Company	R2 Comment We recommend replacing the phrase prepare with conduct and document in the first sentence. R2.1.1 Comment The requirement to evaluate year one or year two should be removed. This is not consistent with the time horizon identified in R2.

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	R2.1.2 Comment The requirement should be removed. With no description of the system stresses and generator outages to be applied when assessing the off-peak load, it is difficult to imagine any issues which would arise which are not revealed in the peak load evaluation that could not be addressed through generation dispatch adjustments. R2.1.3 Comment - The emphasis on sensitivity testing in the existing section appears misdirected and should be focused on reasonable risk. The assessment should have to include a discussion of reasonable risk. The sensitivity list can be used to select sensitivities to assess risk. Having a requirement to perform one sensitivity just to meet the requirement of the standard does not add value to the assessment. R2.1.4 Priority Comment With respect to spare equipment strategy, this requirement imposes severe testing requirements upon the system. However, there is no discussion on the generation dispatch or system transfers that are to be used for this portion of the assessment. The expectations for changes in system stresses need to be clear as part of the standard. Additionally, this section does not contemplate changing the acceptability of load loss. After experiencing a major contingency such as this, some change in the acceptability of load loss should be expected. The standard should consider allowing Non-Consequential load loss for P1 & P2 events. The standard needs to allow Non-Consequential load loss for P3 & P4 events. Why doesn't the standard state "(such as a transformer, generator or power electronic device)" and not just "(such as a transformer)". What constitutes "spare equipment strategy" Would a strategy that involves out-of-merit dispatch or operational restrictions be considered a valid "spare equipment strategy". If a transformer is lost, could a reconfiguration of transmission constitute a valid "spare equipment strategy"? R2.2 Comment We suggest replacing the phrase a current System peak Load study with a valid System peak Load study in the first sentence. The word current is confusing as some read the word current to mean today's rather than valid. R2.3 Comment Please provide guidance as to what year should be represented when performing short circuit studies. R2.4.1 Comment Change to read: For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads or an aggregate System Load model which represents the overall dynamic behavior of the Load. R2.5.1 Comment We suggest deleting this requirement, and incorporating it into R2.5.2. R2.5.2 Comment To incorporate R.2.5.1 into R2.5.2; please modify the section as follows:For steady state, short circuit, or Stability analysis the study shall be less than five calendar years old or less: the present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: The addition/deletion/change of individual generating unit capability determined to be material by the Planning Coordinator or Transmission Planner. [A 20 MVA generator is fairly small in a 30,000 MW system and system concerns would already be addressed though the System Impact Study]? An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES determined to be material by the Planning Coordinator or Transmission Planner. R2.6 Priority Comment As written, this section undermines the value of the sensitivity testing. This section should require a corrective action plan to fix problems determined in sensitivity analysis if there is a reasonable risk of occurrence. We suggest making the standard read Provide documentation that explains the reasoning for the sensitivities considered and

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Response: The SDT does not think that in Requirement R2 replacing "prepare" with "conduct and document" would add clarity, since Requirement R2 includes requirement to document assumptions and results. No change made.

The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. No change made. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon.

Mitigation Time Horizon

The time horizons available for mitigating a violation to a requirement include the following:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

Part 2.1.2 requires that the Planning Coordinator and/or Transmission Planner also consider off-peak conditions because the System must be able to meet

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performance requirements over all demand levels. System peak condition may not represent all stressed conditions. For example, during off-peak, that Load is low, and the generation would have to be turned off to achieve Load-resource balance. Turning down resources within a Load area could result in reliability problems. Lowering the Load in areas with many non-dispatchable resources could also pose potential problems. As the System incorporates more and more renewable resources, some of them are non-dispatchable; a standard must be forward looking so the Planning Coordinator and Transmission Planner can identify potential problems as part of the Assessment. No change made.

Part 2.1.3 (now Part 2.1.4) has been rewritten to clarify the intent of the requirement. The requirement does not preclude a discussion of risk.

> **2.1.4** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.
>
> - Real and reactive forecasted Load.
> - Expected transfers.
> - Expected in service dates of new or modified Transmission Facilities.
> - Reactive resource capability.
> - Generation additions, retirements, or other dispatch scenarios.
> - Controllable Loads and Demand Side Management.
> - Duration or timing of planned Transmission outages.

Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service such that the outage won't last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its System, or have agreement with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. The Planning Coordinator and/or Transmission Planner will need to decide which pieces of major Equipment in their respective Systems would be more vulnerable to long term outage. In Part 2.1.5 when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.2 is intended to require a study performed in the current year, as opposed to studied performed in the past years. Part 2.2 has been revised to provide

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	greater clarity. **2.2** The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: For Part 2.3 the decision on the year to be represented in the study is left to the discretion of the Planning Coordinator or Transmission Planner. Part 2.3 only requires it to be either study that was performed during the current year or in the past. For example, this year is 2009 and a study performed in 2009 is a current study, the study can investigate the System in a future year, which is at the discretion of the Planning Coordinator or Transmission Planner performing the study. Part 2.3 has been revised to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. Part 2.4.1 was not changed as proposed because the intent of the last sentence is to allow the use of an aggregated System Load model as an appropriate Load representation. The suggested change could be read to mean that an aggregated System Load model would not appropriately represent the dynamic behavior of Loads. Note that changes were made to Part 2.4.1 based on other stakeholder comments. Parts 2.5 .1 and R2.5.2 (new Parts 2.6.1 and R2.6.2) were not combined. The references to the “20 MW” threshold have been deleted from the revised standard. Part 2.6 has been modified and included as new Part 2.7. The intent is to allow discretion for the Planning Coordinator or Transmission Planner to correct those deficiencies if they are prevalent (i.e., occur is more than one sensitivity). Although not required, the standard does not preclude the Planning Coordinator or Transmission Planner to develop Corrective Action Plans for high risk scenarios. However, if the scenario is high risk, then it should have been included in the base assumptions in the assessment and the Corrective Action Plan would have been required. The end of the second sentence has been changed to refer to Table 1 as suggested. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Requirement R2, part 2.6.3 has been deleted. Part 2.6.4 allows the Planning Coordinator or Transmission Planner to address situations that are beyond its control by utilizing Non-Consequential Load Loss and/or curtailment of Firm Transmission Service, which are normally not permitted. Depending on the urgency of the need, the Corrective Action Plan may be developed outside the normal Assessment cycle at the discretion of the Planning Coordinator or Transmission Planner involved. No change made. Parts 2.8 and R2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.

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Gainesville Regional Utilities	R2.1.1- References a "system peak Load" for each of the referenced years. Some utilities are summer peaking and some are winter peaking and others may have a history of having one or the other in any given year. So can you clarify which peak you are referring to or change to statement to perform studies involving both seasonal peaks? R.2.4.1- I suggest quantifying the reference to the behavior of induction motor loads to single motors greater than 1000 hp or multi motors at one bus totalling more that 2000 hp or so, since smaller induction motors probably will not have any significant impact of the BES. I feel this is best handled as a sensitivity issue determined by the PC who is familiar with this area. R2.5.1- If the system has not had any significant changes of the last ten years, then a study going back to that change should be acceptable for the assessment. R2.5.2- Should the "shall not include" really read as "shall include"? R2.6- The reference to "tables" in line 6 should be "table" since there is only a Table 1 in the standard. R2.6.1-R2.6.3- Question-- Why is the font size of the bullet text smaller that the other bullet segments?

Response: In Requirement R2, part 2.1.1, the selection of the system peak Load conditions is at the discretion of the Planning Coordinator or Transmission Planner. The standard allows for use of past studies to support a current Assessment. Therefore, for an area with both summer and winter peaks, the Planning Coordinator or Transmission Planner can choose to perform summer and winter peak cases on alternate years and the Assessment can rely on, e.g., a summer peak study performed in the current year and a winter peak study performed in the previous year, provided the requirement for use of past year studies is satisfied. No change made.

Part 2.4.1 allows for the use of an aggregate System Load model which represents the overall dynamic behavior of the Load that could impact the study area. So as written, the suggested representation is allowed. Note that changes were made to Part 2.4.1 based on other stakeholder comments.

Part 2.5.1 has been revised and included as Requirement R2, part 2.6.1 to address your concerns.

> **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

In Part 2.5.2 “shall not include” is correct because the intent is that for the past study to be applicable, the present System should not have changed materially compared to that represented in the past study. However, Requirement R2, part 2.5.2 has been revised and included as Requirement R2, part 2.6.2 in the new version to provide greater clarity.

> **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

Part 2.6 (now 2.7) was modified to use the phrase, “in Table 1” rather than “in the tables.”

Part 2.5.1 (now 2.6.1) has been revised as shown.

> **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

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2.6.2 For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. For Part 2.6.1 (now 2.7.1) the format has been corrected. Parts 2.6.2 and 2.6.3 were deleted from the revised standard.	
JEA	R2.1.4 It is not clear if this spare equipment strategy excludes Generator Owner's obligations for their generation plant equipment and only includes Transmission Owner's equipment. It is also not clear what Measurable document is required to back up a position of no vulnerabilities. I recommend that we limit the spare equipment strategy to TO equipment and not include GO equipment which excludes step-up transformers, turbines, generators, rotors, etc.Also, it does seem unreasonable to assess the long-term loss of a transformer to the "Extreme Events" of Table 1 or any other event other than the P3 events unless substituted in the assessment by a more extreme and probable event. An event from P3 alone should be sufficient to expose a weakness of a spare equipment strategy based on historical industry statistics for such likelihood. Propose changing "The analysis shall reflect the Contingencies identified in Table 1..." to "An analysis shall be performed that as a minimum assesses the impact of the long term outage of Transmission Owner equipment under either a P3 event that could occur in the absence of the subject equipment" or a more stressful event as deemed appropriate by the Functional Entity performing the assessment. R2.6.4 First of all, some level of expected Non-consequential load loss is always prudent to balance customer expectations on cost and reliability subject to Local and State Authority's guidance. Second, load development and gneration development are the major drivers for transmission development needs. Generation plans are more dependable and manageable as to timing and impact. Load development is not very dependable and manageable relative to transmission system improvement needs. It is not unusual for new load forecast to either expose a transmission weakness or on the other hand to eradicate a transmission weakness in the Near Term horizon. Without guidance, it could be assumed that affects from load forecast are beyond the control of the Transmission Planner and Transmission Coordinator. In addition, it is not unusual to have the load forecast lead the generation plan by a few years causing a need for Non-Consequential Load Loss until such time the additional generation is in-service providing generation balance to the load area and mitigating the transmission improvement needs. This occurs frequently as generation development lags load development in fast growing communities. Propose establishing a cap on Non-Consequential Load Loss for all Corrective Action Plans where the Table 1 events currently do not allow at all. An additional option for the SDT to consider could be to add an allowance of lag time (maybe 4-5 years) to cover the gap while the generation addition is being developed.
Response: Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Transmission Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service such that the outage won't last into the next planning cycle. However, the major Equipment is not limited to the major Equipment of the Transmission Owner; this standard covers major pieces of pieces of Transmission Equipment without regard to ownership. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its System, or have agreement with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. Requirement R2, part 2.1.5 has been revised to require that the analysis reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.	

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	2.1.5 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. For Part 2.6.4 (now 2.7.5), the SDT declines to set a cap on Non-Consequential Load Loss on situations that are outside the control of the Planning Coordinator or the Transmission Planner. The premise is that the Corrective Action Plan has already been developed, but was not able to be implemented in time. The situation can occur with both unexpected changes in generation, Load pattern or delay in permitting and construction of new Transmission Facilities. In addition, a cap on the allowable Non-Consequential Load Loss may be different for different areas and may not be practical in a Continent-wide standard. No change made.
NorthWestern Corporation NorthWestern Energy (NWE) (NWMT)	Short circuit analysis is a local issue. The reliability of the BES does not depend on the regular assessment of short circuit duty. Therefore, we believe short circuit analysis should be deleted from R2. R2.1.4 needs more clarification as to what constitutes major Transmission equipment. This would require a separate analysis (study) for each transformer (or any long lead-time equipment) for which a spare is not available, which could result in numerous additional cases. Major Transmission equipment could be limited to voltage levels greater than 200 kV. An exception should be made for phase-shifting transformers. As the system changes, with new generation and transmission lines being added, these analyses could become outdated very quickly. If a transformer were to fail, the Planning Department would immediately study the current system with this transformer removed. As stated in R2.4.1, the requirement to include induction motor loads is too prescriptive. At this time, with all of the unknown or estimated variables in the system model, accuracy of the model would not be improved. If a highly industrialized section were to develop within the NWE footprint, induction motor load could be added to the system model. The 20 MW threshold identified as "material change" for generation in R2.5 is too small. A better number for material generation changes would be 100 MW or a limit based on a percentage of the study area's installed generating capacity. Also, an aggregate of 20 MW addition/deletion generation would depend on the location of the individual generators to determine whether the overall system would be affected or not. The statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement. R2.8 should be deleted. It is not necessary for reliability. R2.9 should be deleted. It is not necessary for reliability.
Response: Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt and is not specifically related to new planned Facilities. Requirement R2, part 2.3 has been revised to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned	

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	generation and Transmission Facilities in service which could impact the study area. Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.4.1 is intended to allow the Planning Coordinator and Transmission Planner the discretion in the use of Aggregated System Load models in Stability Studies, if specific models are not available. However, it does not dictate the methodology or the process on how the studies are to be done. No change made. Part 2.5 has been revised and included as requirement R2, part 2.6 as shown. Note that the references to the "20 MW" threshold were deleted from the revised standard. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Parts 2.8 and R2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Requirement R2, part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.
SMUD	R2.1.3 and R2.4.3The sentence, "sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment: ", should be modified by changing the second 'included' to 'considered'. R2.1.4Since there is no NERC reliability standard requirement for a 'spare equipment strategy', what is the standing of a requirement that is based on having one R2.5.2There is no example given for 'Transmission additions/removals' Recommend that the wording of this requirement be made more discretionary with a requirement that the Transmission Planner include language explaining the reasons for using past studies.
Response: Parts 2.1.3 (now Part 2.1.4) and R2.4.3 have been revised. However, the SDT declines to change the work "included" to "considered" because the intent is that if the base case modeled already models the stressed condition, such as 1 in 10 adverse weather Load, even higher Load may not need to be included in the sensitivity study, **2.1.4** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of	

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	changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Real and reactive forecasted Load. • Expected transfers. • Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. • Controllable Loads and Demand Side Management. • Duration or timing of planned Transmission outages. **2.4.3** For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Load level, Load forecast, or dynamic model assumptions. • Expected transfers. • Expected in service dates of new or modified Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. The SDT has included the spare equipment strategy in Part 2.1.4 to ensure that the BES is designed so that it remains reliable even with long lead time Equipment unavailable, consistent with the directive from FERC Order 693. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. The SDT revised Part 2.5.2 (now Part 2.6.2) to remove the "Transmission additions/removals" and "generation changes" language.
Progress Energy Florida, Inc.	Concerning R2.1.4, this sub-requirement is overly burdensome for two primary reasons: a) It amounts to a system-wide N-2 and N-3 analysis, which goes against FERC's policy of separation and distinction between types of events as stated in Paragraph 1788 of Order 693: Under TPL-002-0 the system is not required to be able to withstand another N-1 contingency. That N-1 requirement is a Category C contingency which is addressed by TPL-003-0. b) The requirement to perform system-wide analysis for such a scenario is a significant workload issue, and will take time away from analysis of more probable events. Concerning the issue of material changes in past studies in sub-requirement

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	R2.5.2, PEF objects to the specification of changes in units of 20 MW or greater, due to the fact that a change (or even deletion) of a 20 MW unit in a case modeling a large BES does not truly constitute a material change. The SDT in its response to Question 15 in the comments for draft 2 stated that The SDT did not want to be overly prescriptive when describing the type of changes that could be considered material and has left the text general. PEF suggests that the SDT take its own advice, making the language in R2.5.2 more general in nature and leaving such modeling details to the discretion of the Transmission Owner. In R2.6.2, PEF assumes that the term "project initiation date" is intended to mean the Construction Move-In date. If the term means the first date at which Planners had identified it as a mitigation, PEF would object to this as it would appear to preclude the right to develop superior mitigations, or to cancel a project if it can be demonstrated as no longer needed. Concerning R2.8 and R2.9, PEF strenuously objects to such requirements. These requirements have no bearing on demonstrating the reliability (or lack thereof) of the BES, and therefore should be removed from the Standard.

Response: Part 2.1.4 (now Part 2.1.5) is based on FERC Order 693, Paragraphs 1724 – 1727. Part 2.1.5 is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Part 2.1.5 has been revised to require that the Planning Assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.5.2 has been revised and included as Requirement R2, part 2.6.2 to address your concerns. The revised standard does not include the reference to a "20 MW" threshold.

> **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

Part 2.6 has been revised and included as Requirement R2, part 2.7 in the new version.

> **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

Parts 2.8 and R2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Requirement R2, part 2.9 in he new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only.

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2.9 The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Xcel Energy	R2.1.3 is this indicating that only one of the variations need to be studied? ("in one or more of the following conditions"). Recommend having the planner work with the load to determine what sensitivity studies to perform. R2.1.4 it is unclear as to what should be done with the analysis that incorporates the company's spare equipment strategy. Is this requirement inferring that a company's spare equipment strategy need to ensure that it can still operate to within the requirements for contingencies of Table 1 without the component? R2.2.1 is the intent to have the study for the 10 year horizon or to include any project that is started within the next 10 years and thus the study must be extended to the forecasted completion of the project (conceivably as long as 20 years or more?) R2.6.4 recommend clarifying how situations beyond the control of the TP or PC are determined. It is unclear if this is to imply that if something is outside of the control of the department who conducts the planning studies or if it is outside the control of the registered function's legal entity (i.e. corporation). R2.8 appears to be nonessential information for reliability; for what purpose does this requirement exist? R2.9 - appears to be nonessential information for reliability; for what purpose does this requirement exist?

Response: Part 2.1.3 (now Part 2.1.4) does not preclude the Planning Coordinator or Transmission Planner working with other Functional Entities to develop strategies on performing sensitivity studies. Part 2.1.4 requires that the Planning Coordinator or Transmission Planner perform sensitivity studies for at least one of the variation not already covered in the studies described in Parts 2.1.1 and 2.1.2

Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service such that the outage won't last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its System, or have agreements with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.2.1 has been revised because extending the Planning Horizon beyond 10 years for projects with lead times longer than 10 years is already covered in the definition of Long-Term Transmission Planning Horizon. This allowance is needed to provide planning flexibility, and is at the discretion of the Planning Coordinator or Transmission Planner. For example, if the System is found not to meet performance standards in year 10, but the project to correct the loading cannot be placed in service for 12 years, then the Corrective Action Plan needs to identify the interim solutions before the project can be brought on line.

> **2.2.1** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the

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rationale for why that year was selected. Part 2.6.4 refers to the situations beyond the control of the Transmission Planner or Planning Coordinator as Functional Entities. Parts 2.8 and R2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as requirement R2, part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
New Brunswick System Operator	R2.1.4 Major transmission element needs to be defined. For example, what about sync condenser, or generator step up transformer R2.2 Clearity required. Example: What is meant by "current System peak load" It is not clear what supplemental load loss is. Would load tripped due to undervoltage or SPS as a result of a contingency be considered supplemental load? As a follow up what then is Non-consequential load (provide examples). How would this load be lost? The requirements appear the same regardless of the amount of Non-consequential load loss. Is there any consideration of applying thresholds both on suppmental and non-consequential load loss where these loads are defined as (or applied as) "exceeding xxx amount of MW". Regarding Table 1 b, what does the following mean: "However, Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements." Please clearify the definition of Year One. This definition also does not include Planning coordinator. Was that intentional?
Response: In Part 2.1.4 (now Part 2.1.5), major Transmission Equipment would be those pieces of Equipment, the loss of which can have significant impact on System performance. They are typically the ones listed in the Contingency Events in Table 1. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.2 refers to a "current System peak Load study". This would be a System peak Load study that is performed in the current year. In the Definition Section, Supplemental Load Loss is defined as Load that is disconnected from the network by end-user Equipment responding to post-Contingency System conditions. Because the disconnection is at the discretion of the Load customer, not the Planning Coordinator or Transmission Planner, they cannot be counted on to leave the System. Therefore, the Transmission System cannot be planned as if such Load would disconnect. Part 2.2 has been revised to provide greater clarity. **2.2** The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the	

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	following annual current study, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: A cap on the allowable Non-Consequential Load Loss may be different for different areas and may not be practical in a Continent-wide standard. No change made. See response for Part 2.2 above. The definition has been revised to include Planning Coordinator. **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.
Lafayette Utilities System	R2.5. This basic requirement intends, as we understand it, to require that earlier studies not be used for a current assessment if they are no longer accurate. But the phrasing is potentially confusing, and would be clearer if revised. Since the requirement deals with the use of past studies, we suggest that R2.5.2 be revised to state that the study may be used only if there have been no material changes, so that R2.5 reads in full: R2.5. Past studies may be used to support the Planning Assessment if they meet the following requirements: R2.5.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less. R2.5.2. For steady state, short circuit, or Stability analysis: the study may be used only if there have been no material changes, such as generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater. With respect to footnote 10 to Table 1, we fear that the flexibility suggested by those provisions may be excessive for a planning standard. The ambiguity occasioned by stating emergency actions that can properly be taken in a planning standard can be utilized by those who plan the system in a manner which plans to drop non-consequential loads just as footnote b has been used in the past. If this is intended to raise the bar as stated these provisions do not belong in a planning standard, at least as now stated. It may be appropriate to remove the reference to footnote 10, at least in the Initial System Condition entry in P3, where it suggests that it can be invoked after loss of a single generator, and we request the SDT to review that footnote to assure that it is appropriate in the other entries to which it is applied. In addition to the foregoing, we are concerned that the language of footnote 10 to Table 1 is unclear and subject to at least one interpretation that would seriously undermine reliability. Specifically, the first sentence of footnote 10 permits "[c]urtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch." The reference to an "obligat[ion] to re-dispatch" is ambiguous at best and should be clarified. For example, footnote 10 should not be read as permitting Balancing Authority A to rely on curtailment of firm transmission service coupled with re-dispatch of generation by adjacent Balancing Authority B during a Level 5 TLR event, based on the theory that, if a Level 5 TLR is declared and the Reliability Coordinator assigns to Balancing Authority B an NNL reduction responsibility that compels it to reload its resources, Balancing Authority B is therefore "obligated to re-dispatch" within the meaning of footnote 10. We suspect the intent of the first sentence of footnote 10 was to recognize and give effect to arrangements in which (following the example) Balancing Authority A has made a prior contractual arrangement with

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	Balancing Authority B (or another generation owner) to provide redispatch services when requested by Balancing Authority A. In that circumstance, Balancing Authority A would be allowed to couple the curtailment of firm transmission with redispatch provided by Balancing Authority B (or another generation owner) pursuant to its contractual obligation. We suggest that this limitation be reflected by revising the first sentence of footnote 10 to read as follows: Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources subject to a contractual obligation to provide re-dispatch service to the operator of the system for which the Transmission Planner is responsible, is allowed both as a System adjustment (as identified in the column titled "Initial System Conditions") and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Without the limitation reflected in the foregoing revision, an entity could interpret footnote 10 as allowing it to rely on the redispatch of generation by other systems that may be (in effect) mandated by a Reliability Coordinator during a Level 5 TLR event. That sort of "leaning" on adjacent systems should not be permitted as a System adjustment or corrective action under TPL-001, especially where it imposes uncompensated burdens and costs on the system(s) forced to redispatch under these circumstances.
Response: Part 2.5 has been revised and included as Requirement R2, part 2.6 as shown. Note that the revised standard does not include any reference to the "20 MW" threshold. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Footnote 10 (now footnote 9) was added to address the disjoint between how some parties calculate ATC/AFC when assessing Long Term Firm Transmission Service and the currently proposed TPL-001-1 standard. TPL-001-1 requires Transmission Planners to plan their systems to meet multiple contingency events and some parties assess Long Term Firm Transmission Service on a first Contingency basis. Units obligated to re-dispatch, as contemplated in Footnote 9 are those units which are contractually bound to provide the service as well as those obligated to provide the service under Network Integrated Transmission Service, under FERC's pro forma OATT. Under the pro forma OATT, units designated as network resources receiving NITS are obligated to re-dispatch as requested by the Transmission Provider pursuant to Section 33.2 to maintain reliability. The footnote is worded such that curtailment/re-dispatch cannot result in the loss of firm Load preserves the guidance given by FERC in Order 693 that no single Contingency result in the loss of firm Load. No change made. The SDT has reviewed the application of footnote 10 (now footnote 9) and believes that it is correct. No change made.	
Mississippi Delta Energy Agency	R2.5. This basic requirement intends, as we understand it, to require that earlier studies not be used for a current assessment if they are no longer accurate. But the phrasing is potentially confusing, and would be clearer if revised. Since the requirement deals with the use of past studies, we suggest that R2.5.2 be revised to state that the study may be used only if there have been no material changes, so that R2.5 reads in full:"R2.5. Past studies may be used to support the Planning Assessment if they meet the following requirements: R2.5.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less. R2.5.2. For steady state, short circuit, or Stability analysis: the study may be used only if there have been no material changes, such as generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated

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	addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater. With respect to footnote 10 to Table 1, we fear that the flexibility suggested by those provisions may be excessive for a planning standard. The ambiguity occasioned by stating emergency actions that can properly be taken in a planning standard can be utilized by those who plan the system in a manner which plans to drop non-consequential loads just as footnote b has been used in the past. If this is intended to raise the bar as stated these provisions do not belong in a planning standard, at least as now stated. It may be appropriate to remove the reference to footnote 10, at least in the Initial System Condition entry in P3, where it suggests that it can be invoked after loss of a single generator, and we request the SDT to review that footnote to assure that it is appropriate in the other entries to which it is applied.
Response: Part 2.5 has been revised and included as Requirement R2, part 2.6 as shown. Note that the revised standard does not include any reference to the "20 MW" threshold. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Footnote 10 (now footnote 9) was added to address the disjoint between how some parties calculate ATC/AFC when assessing Long Term Firm Transmission Service and the currently proposed TPL-001-1 standard. TPL-001-1 requires Transmission Planners to plan their systems to meet multiple contingency events and some parties assess Long Term Firm Transmission Service on a first Contingency basis.. Units obligated to re-dispatch, as contemplated in Footnote 9 are those units which are contractually bound to provide the service as well as those obligated to provide the service under Network Integrated Transmission Service, under FERC's pro forma OATT. Under the pro forma OATT, units designated as network resources receiving NITS are obligated to re-dispatch as requested by the Transmission Provider pursuant to Section 33.2 to maintain reliability. The footnote is worded such that curtailment/re-dispatch cannot result in the loss of firm Load preserves the guidance given by FERC in Order 693 that no single Contingency result in the loss of firm Load. No change made.	
Ameren	In R2, The phrase document results should be changed to summarize results. While results will be documented, the Planning Assessment should just include a summary. In R2.1, the reference to requirement R2.6 (at the end of the last line) should be changed to R2.5. In R2.1.3, it is suggested that the studies be referred to as the "base studies" to avoid confusion with the sensitivity studies. Also it is suggested that another phrase be added at the end for clarity. The entire R2.1.3 would then be as follows: For each of the base studies described in Requirements R2.1.1 and R2.1.2, sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment. Sensitivity studies would include changes to: In Requirement R2.1.4, it is suggested that language be added to reflect the possible unavailability of the equipment, such as: When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that

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	the System is expected to experience the possible unavailability of the long lead time equipment. It is not clear how adequate lead times for equipment would be determined. In Requirements R2.3 and R2.4, consider adding a reference to Requirement R2.5 for the past studies. In Requirement R2.4.1, it is suggested that it be reworded to the following: System peak Load for one of the five years, including Load models which appropriately represents the dynamic behavior of Loads, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Load models referenced in R2.4.1 should be confined to the consideration of transient stability study work. With the elimination of the distinction between system and generating plant stability studies, the blanket requirement in R2.5.1 that all stability analyses be five calendar years old or less, regardless of any material changes to the system, would cause needless work to be performed on those plants or areas of the system where no changes are occurring. We suggest adding the following to the end of R2.5.1: unless justification can be provided to demonstrate that the results of an older study are still valid. In Requirement R2.4.3, it is suggested that this sub-requirement be reworded to the following: For each of the base studies described in Requirements R2.4.1 and R2.4.2, sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the base studies shall be included in the Assessment. Sensitivity studies would include changes to: In bullet three of Requirement R2.6.1, would we allow automatic generation tripping for a single (P1) event if it is not consequential? It seems that tripping of generation should be restricted to P2 events 2 or 3 at a minimum. In bullet five of Requirement R2.6.1, is there a maximum duration that operating procedures can be used before a capital project must be included (or completed) in the Corrective Action Plan? In Requirement R2.6.2, it is not clear what constitutes a "project initiation date". Please clarify. Please explain the reason why Requirement R2.8 is needed in the Assessment. Reporting the largest Consequential Load Loss does not impact reliability. Please explain the reason why Requirement R2.9 is needed in the Assessment. Reporting the largest Non-Consequential Load Loss doe not impact reliability. The proposed standard not only raises the bar for system performance requirements, but also raises the bar for reporting and documentation. We need to employ almost as many librarians and technical writers as engineers to develop and keep track of the documentation. Engineers need to spend more time performing the studies and spend less time documenting studies keeping track of documentation for multiple years.

Response: Part 2 has been revised to reflect your suggestion.

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.

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In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made. The SDT reviewed Part 2.1.3 (now Part 2.1.4) and declined to use the term "base study" because "base study" may have different meanings in different parts of the continent, and the term, "studies described in Parts 2.1.1 and 2.1.2" should be sufficient to avoid confusion. No change made. Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Parts 2.3 and 2.4 have been revised to include the reference to the requirements for use of past studies. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. **2.4** The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part2.6. The following studies are required. Part 2.4.1 has been revised to reflect your suggestion. In addition, Part 2.4 concerns only "The Near-Term Transmission Planning Horizon portion of the Stability analysis". Part 2.4.1 carries the same limitation as Part 2.4. **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. The requirement has been revised as suggested. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. The SDT reviewed Part 2.4.3 and declined to use the term "base study" because "base study" may have different meanings in different parts of the continent, and the term, "studies described in Parts 2.4.1 and 2.4.2" should be sufficient to avoid confusion. No change made. Part 2.6 has been revised and included as Requirement, part 2.7 to reflect your suggestion. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: The third bullet in Part 2.6.1 (now 2.7.1) is intended to meet the requirements in Table 1. Generation tripping is allowed at the discretion of the Planning

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Coordinator or Transmission Planner for P1 Events as long as there is no loss of firm Non-Consequential Load. In addition, in the fifth bullet, the duration for use of an operating procedure is also at the discretion of the Planning Coordinator or Transmission Planner because it may not be feasible environmentally to implement Transmission reinforcements in some locations. Project initiation date has been deleted from the requirements. Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Requirement R2, part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Puget Sound Energy, Inc.	Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. The 20 MW threshold identified as material change for generation in R2.5 is too small. The limit should be raised or based on a percentage of the study area's installed generating capacity. R2.7 should be deleted, see comment on R2 above. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event? if it is documented? R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.
Response: Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt and is not specifically related to new planned Facilities. Part 2.3 has been revised to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.	

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Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. The language in Part 2.5.2 that referenced a 20 MW threshold was deleted from the revised standard. The SDT assumes that you meant the comment on short circuit analysis above. The SDT declines to delete the requirement as the SDT believes that it is a necessary part of an overall Planning Assessment. Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed the both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Requirement R2, part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Manitoba Hydro	Requirement Text: R2.1: Reference of past studies should be to R2.5, not R2.6 (typo). R2.1.3: The sensitivity to Planned duration or timing of Transmission Outages should be modified to only include Planned long duration Transmission outages that span multiple seasons, if known. Short duration planned maintenance outages should not be included in a planning assessment. R2.1.4 - The second sentence doesn't read right - the sentence should be changed to read: "The analysis shall reflect the Contingencies identified in Table 1 under the conditions that the System is expected to experience during the unavailability of the long lead time equipment. R2.2.1 - This sub-requirement should be deleted. Why do extra assessments beyond the 10 year period" Any items beyond 10 years will be covered when they fall into the 10 year period. For example, if we assess the 10 year horizon, then the project due to be complete in 12 years will be part of the assessment in 2 years when it is 10 years out. We will have to show every year how our system meets compliance regardless of this extra analysis, so what's the point. Every year we have to show how we comply in the short and long term so what difference does it make when each project is completed as long as we are in compliance or identify Corrective Action Plans (CAPs) along the way. R2.4.1: The statement "a Load model shall be used which appropriately represents the dynamic behavior of Loads is not very crisp. What will appropriate be interpreted to mean by the NERC auditor? Does an MOD standard exist that covers gathering data and validating loads models? This should be a first step. The SDT should add a statement that the application of detailed induction motor modeling can be limited to areas where poor voltage recovery is expected due to a high concentration of such load. The requirement should be modified to require the PC/TP to provide a rationale for the load models used in its specific planning area. R2.5: A Past Study is a definition and should be moved to the definition section. The definition only identifies power changes

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	as possible material changes, but should also include machine control (exciters/governors) changes. We suggest the bulleted list of Material Generation changes be expanded. R2.6.1: Can the SDT clarify how a rate application qualifies as a CAP action? R2.9 - The sentence should refer to maximum Non-Consequential Load Loss not maximum permissible Non-Consequential Load Loss.

Response: In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made.

In Part 2.1.3 (now Part 2.1.4), outages that span multiple seasons are included in the last bullet, "Planned duration or timing of Transmission outages". No change made.

Part 2.1.4 (now Part 2.1.5) has been revised to reflect your suggestion.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.2.1 has been revised because extending the Planning Horizon beyond 10 years for projects with lead times longer than 10 years is already covered in the definition of Long-Term Transmission Planning Horizon. This allowance is needed to provide planning flexibility, and is at the discretion of the Planning Coordinator or Transmission Planner. For example, if the System is found not to meet performance standards in year 10, but the project to correct the loading cannot be placed in service for 12 years, then the Corrective Action Plan needs to identify the interim solutions before the project can be brought on line.

> **2.2.1** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

Part 2.4.1 has been revised to provide greater clarity.

> **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

The SDT declines to move past study to the Definition Section because the Definition, once approved, will apply to all NERC Standards, however, past study is only used in this TPL Standard.

In Part 2.6.1, "rate application" refers to rate incentives to change behavior of end-use customers and can be part of the "actions to achieve required System performance". This is included to allow for non-traditional solutions to achieving required System performance.

Part 2.9 has been deleted.

E.ON U.S.	R2.1.3Change For each of the studies to For at least one of the studies R2.1.1 and R2.1.2 require that 3 studies be performed each year. As written, the requirement indicates that the transmission planner has to perform at least one sensitivity study for the 3 studies required by R2.1.1 and R2.1.2. This means that the transmission planner would also have to perform 3 or more sensitivity studies each year. One sensitivity study for one of the 3 studies required by R2.1.1 and

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	R2.1.2 should suffice. R2.1.4.Delete "The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment. This statement is redundant since R3 requires this analysis for all of R2.1. Including this statement in R2.1.4 and not in R2.1.1 and R2.1.2 makes it appear that this requirement has different performance requirements. R2.4.3R2.4 does not require studies annually. However, if the transmission planner chooses to study a System Peak Load or a System Off-Peak Load condition R2.4.3 requires that the planner also study sensitivity to that same condition in the current year. E.ON U.S. believes it sufficient that the assessment include a sensitivity study for some System Peak Load and some System Off-Peak Load condition.R2.6The third sentence should be modified to include R2.1.4., so that it reads "Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3, R2.1.4 and R2.4.3. The annual studies performed for Category P6 alert the Transmission Planner to the risks of transformer failure. The Transmission Planner is required to design the system to limit those risks. If the delivery time for a piece of equipment is 11 months, then P6 allows Interruption of Firm Transmission Service and Non-Consequential Load Loss. If the delivery time for a piece of equipment is 12 months, then P1 requires that the system be designed for no Interruption of Firm Transmission Service and Non-Consequential Load Loss. This is a significant increase in performance requirements for an event that will most likely not extend beyond to a second System Peak Load period. If R2.1.4 is not included in the requirement the transmission planners would essentially be designing for an Extreme Event, i.e., events which are more severe and have a lower probability of occurrence than Planning Events. R2.6.1Operating Procedures, by NERC definition, require significantly more detail than is appropriate for a Corrective Action Plan. It is not appropriate that Transmission Planners write Operating Procedures to be used by NERC Certified System Operators. E.ON U.S. suggests that Operating Procedures be changed to mitigation plans. R2.6.5 Planning Assessments and System Facilities are not NERC defined terms. Operating Procedures, by NERC definition, require significantly more detail than is appropriate for a Corrective Action Plan. It is not appropriate that Transmission Planners write Operating Procedures to be used by NERC Certified System Operators. E.ON U.S. suggests that Operating Procedures be changed to mitigation plans. R2.8There are no requirements to limit Consequential Load Loss. Impacted customers are typically aware of the customary level of service and have chosen not to pay for extraordinary levels of service. E ON US questions the purpose and benefit of this requirement. While continuity of service to end use customers is an important measure of service reliability for which utilities answer to state authorities, BES reliability requires that the system remain balanced and that local failures not result in cascading BES events NERC standards should, pursuant to FPA Section 215, focus solely on BES reliability

Response: Parts 2.1.3 (now Part 2.1.4) and 2.4.3: The SDT disagrees with changing Parts 2.1.4 and 2.4.3 to requiring sensitivity study for only one System condition because this change potentially could reduce the Assessment to be based on one sensitivity study on one System condition. Since the same sensitivity can have different impacts on System performance under different System conditions, and different System conditions may require different sensitivities to be investigated, such limitation may not be adequate to maintain reliability going forward. No change made.

Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Transmission Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service

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such that the outage won't last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its System, or have agreements with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.6 is not intended for the Planning Coordinator or Transmission Planner to write Operating Procedures, only to reflect the effects or results of the Operating Procedures in its Corrective Action Plan. Mitigation Plan carries a special meaning for Compliance and so may not be appropriate for use in this standard. No change made. The term, "Planning Assessment" is one of several terms proposed for addition to the NERC Glossary of Terms Used in Reliability Standards. "System" and "Facilities" are already approved terms. Part 2.8 is intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed the requirement and agrees that as written it was unclear. Part 2.8 has been revised and included as Requirement R2, part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
LCRA Transmission Services Corporation	In R2.6.2, it is stated that a project initiation date is required as well as an in-service date. What is considered the project initiation date, the point at which the project plan is approved or the time at which construction is to begin? If it is the time at which construction is to begin, then LCRA TSC believes this requirement does not belong in the TPL-001-1 standard as the construction timeframe for a project is developed by groups outside of Planning based on resources and outage availability.
Response: Project initiation date has been deleted from the requirements.	
National Grid	R2 Comment In the first sentence, replace the phrase prepare with conduct and document and in the second sentence replace "This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses" with "The Planning Assessment shall review assumptions of current or past studies and assess the continuing validity of the steady state, short circuit, and stability results. The review of assumptions, supplemental analysis, and updated results shall be documented. R2.1 Comment A. The terms assess and annual study are referenced in the same requirement. It is unclear what constitutes either. Is an annual study required for every area or is an annual assessment required for every area, which may include some supporting study to address changes to the conditions? B. Requirement R2.1 should refer to R2.5 rather than R2.6 R2.1.1 Comment A. Year One and year two do not provide enough time to implement Corrective Action Plans and are better

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	suited for Operations studies. The requirement to evaluate Year One or year two should be removed. B. Is a year 5 study required annually for every area of a system? R2.1.2 Comment ? The requirement should be removed. With no description of the system stresses and generator outages to be applied when assessing the off-peak load, it is difficult to imagine any issues which would arise which are not revealed in the peak load evaluation that could not be addressed through generation dispatch adjustments. Need to define conditions for assessment. R2.1.3 Comment A. The emphasis on sensitivity testing in the existing section appears misdirected and should be focused on the expected accuracy of the assumptions. The assessment should have to include a discussion of accuracy of the assumptions. Having a requirement to perform one more sensitivity not already included is vague and does not add value to the assessment or the standard. B. Planned Transmission Outages are not known in the Planning horizon. Also the release of the outage on any given day is controlled by operations based on the conditions. The conditions are not known for the Planning assessment. The last bullet referring to Planned Transmission Outages should be deleted. C. Delete the phrase "are intended to." It is difficult to measure intent and what is important is whether the system has been stressed, not whether the responsible entity intended to stress the system. D. What is expected from a sensitivity analysis? Is it to change the base case and see how the case responded, is it to create a new base case and rerun all of the events, or is it to change the base case and rerun a select number of events. It is anticipated that the answer will vary based on what is changed. R2.1.4 Priority Comment With respect to spare equipment strategy; this requirement potentially imposes a requirement to plan for three events, which is overly severe. After experiencing a major contingency of a long lead time facility, there should be some change in the acceptability of risk. This change in risk could include an allowance for the loss of non-consequential load or some of the multiple events from Table 1 should be evaluated as Extreme Contingency events. R2.2 Comment We suggest replacing the phrase a current System peak Load study? with a valid System peak Load study in the first sentence. The word current is confusing as some read the word current to mean today's rather than valid. R2.3 Comment A. The requirement to conduct annually isn't consistent with support. We suggest Conducted annually should be replaced with the phrase assessed annually?.B. "Interruption duty" should be changed to "interrupting duty." All terms in the IEEE dictionary related to breaker opening use the word "interrupting," while terms related to loss of supply to customers use the word "interruption." R2.4.1 Comment A. The two sentences are describing an or condition and they should be merged to read: For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads or an aggregate System Load model which represents the overall dynamic behavior of the Load. R2.4.3 Comment - Delete the phrase "are intended to." It is difficult to measure intent and what is important is whether the system has been stressed, not whether the responsible entity intended to stress the system.

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	R2.5 Comment If past studies only support, then a new study is still required. We suggest changing “Past studies may be used to support the Planning Assessment if they meet the following requirements:” to “Past studies may be used to fulfill all or a portion of the Planning Assessment provided they meet the following requirements:” Violation Severity Levels:R2 - There is no VSL associated with R2.5. A VSL should be added, perhaps under Moderate, that "past studies were utilized to fulfill all or a portion of the requirement, but the studies did not meet the requirements in R2.5." R2.5.1 Comment? We suggest deleting this requirement, and incorporating it into R2.5.2.R2.5.2 Comment To incorporate R.2.5.1 into R2.5.2; please modify the section as follows: For steady state, short circuit, or stability analysis the study shall be less than five calendar years old from the date of completion. The present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. A material change does not require the whole study to be redone. It only requires that the affected portion of the study be reassessed. Material generation changes include: The addition/deletion/change of individual generating unit capability determined to be material by the Planning Coordinator or Transmission Planner. “ An aggregated addition/deletion/change to a group of generating units directly connected to the BES at one point of interconnection through one or more transformers and determined to be material by the Planning Coordinator or Transmission Planner. The reference to the step-up transformer may not capture a wind farm that could have transformers to step-up to a collection voltage and transformer that wouldn’t be labeled a GSU to connect to the system. R2.6 Priority Comment A. As written, this section undermines the value of the sensitivity testing. This section should require a corrective action plan to fix problems determined in sensitivity analysis if there is a reasonable risk of occurrence. We suggest making the standard read Provide documentation that explains the reasoning for the sensitivities considered and selected. B. At the end of the second sentence, the phrase in the tables” is used. We suggest using more definitive language such as in Table 1. R2.6.1 Comment -In the last bullet, the reference to "rate application" is unclear. R2.6.2 Comment The phrase Project Initiation Date needs to be defined. It is unclear if this is the date of ground breaking, purchase orders being issued, solution study initiation, etc. Additionally, in the second sentence the phrase as well as an in-service date should be modified to read as well as a target in-service date. R2.6.3 Comment Plans can provide a target in-service year, but not an actual in-service year. R2.6.4 Priority Comment There should be a cutoff point when changes occur beyond a certain date. When that date occurs, further changes will be evaluated in the next year’s assessment. Otherwise, if a state makes a decision not to site a project a few weeks prior to the end of the assessment period, there will not be sufficient time to incorporate this into that year’s assessment and develop corrective actions. R2.7 Comment A. "Interruption duty" should be changed to "interrupting duty." All terms in the IEEE dictionary related to breaker opening use the word "interrupting," while terms related to loss of supply to customers use the word "interruption."B. The requirement would be clearer if it we restructured as follows: "For short circuit analysis, if the short circuit interrupting duty determined in Requirement R2.3 exceeds the Equipment Rating of fault interrupting devices, the Planning Authority . .

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	." R2.8 Comment A. Largest consequential load loss is not factored into the Planning Assessment and should therefore be deleted. B. If it is not deleted, do we have to prepare one number for P1 and a separate number for P2? The phrase any P1 event and any P2 event in Table 1 could also be read as the worst loading for each event within P1 and P2, which could be hundreds of values depending on how many events are analyzed. We recommend that the requirement be modified to require documentation of the maximum amount of consequential load loss that was relied upon during the assessment of the P1 and P2 events.C. If it is not deleted, "shall provide" should be changed to "shall identify" for consistency with R2.9 R2.9 Comment A. Largest consequential load loss is not factored into the Planning Assessment and should therefore be deleted. B. If it is not deleted, this requirement is unclear. Is this requirement asking for each transmission planner to list their criteria for non-consequential load loss, or is it asking how much non-consequential load loss was being relied upon in the assessment? Including the word "permissible" implies the responsible entity must decide how much Non-Consequential Load Loss is allowed. We recommend that the requirement be modified to require documentation of the maximum amount of non-consequential load loss that was relied upon during the assessment of the P1 and P2 events.

Response: The SDT does not think that in Requirement R2 replacing "prepare" with "conduct and document" would add clarity, since Requirement R2 includes requirement to document assumptions and results. No change made.

In the Definition Section, Planning Assessment is defined as "Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies". Therefore, in Part 2.1, an Assessment is an evaluation of System performance based on studies performed. While an Assessment is required annually, it can be based on past studies as long as the requirement for a valid past study is met. As such, all studies used to support the Assessment do not have to be preformed annually. No change made.

In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made.

For Part 2.1.1 Year One and year two are within the Planning Horizon. In the Definition Section, Year One is defined as "The first year that a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the current calendar year". Operating Studies are performed for system conditions within 12 months of the current calendar year. No change made.

Part 2.1.1 is intended to require studies for System Peak Load Conditions for 2 of the years in the Near-Term Transmission Planning Horizon: (1) A Year five case to identify potential problems that can be addressed if the planned projects proceed as scheduled; (2) A Year one or Year two case to identify any potential problems unanticipated in the five-year case, which if not addressed, could impact operations as time progresses. The standard provides flexibility for the Planning Coordinator or Transmission Planner to use past studies to support the current year assessment and to assess other years in addition to those identified in Part 2.1.1. No change made.

Part 2.1.2 requires that the Planning Coordinator and/or Transmission Planner also consider off-peak conditions because the System must be able to meet performance requirements over all demand levels. System peak condition may not represent all stressed conditions. For example, during off-peak, the Load is low and the generation would have to be turned off to achieve Load-resource balance. Turning off resources within a Load area could result in reliability problems. Lowering the Load in areas with many non-dispatchable resources could also pose potential problems. As the System incorporates more and more renewable resources, some of them are non-dispatchable; a standard must be forward looking so the Planning Coordinator and Transmission Planner can identify potential problems. If studies for one of the Load periods are not needed annually, the Planning Coordinator or Transmission Planner can rely on past studies for the

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Planning Assessment. No change made.

Part 2.1.3 (now Part 2.1.4) has been rewritten to clarify the intent of the requirement. The Planning Coordinator or Transmission Planner can include a discussion of accuracy of the assumptions in response to the new Part 2.7.2 on the actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.1.4 For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of planned Transmission outages.

2.7.2 Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

The last Bullet in Part 2.1.3 (now Part 2.1.4) is intended to cover planned outages of Facilities in sensitivity studies if such planned outages are known at the time the planning studies are performed, for example, planned outage of a major Transmission line during construction if the Corrective Action Plan calls for rebuilding of the line to a higher operating voltage. The sensitivity study can cover the "what if" situation where the project start can be delayed or the project may take longer to construct. No change made.

Part 2.1.3 - 'Are intended to' has been deleted.

The SDT declines to make the change as suggested. A Planning Assessment is not the same as a study. As stated in the Definition, a Planning Assessment is a "documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies". As such, a Planning Assessment is based on a number of studies from which to draw conclusions about System performance and to develop Corrective Action Plans where needed. The suggested change would necessarily imply that a study is the same as a Planning Assessment, which is not the intent of Part 2.3.

Part 2.1.4 (now Part 2.1.5) is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Part 2.1.5 has been revised to address some of your concerns. Part 2.1.4 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

2.1.5 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or

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	more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.2 is intended to require a study performed in the current year, as opposed to studies performed in the past years. Part 2.2 has been revised to provide greater clarity. **2.2** The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: Part 2.3 has been revised to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. Part 2.4.1 was not changed as suggested because the intent of the last sentence is to allow the use of an aggregated System Load model as an appropriate Load representation. The suggested change could be read to mean that an aggregated System Load model would not appropriately represent the dynamic behavior of loads. However, Part 2.4.1 has been revised to provide greater clarity. **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Part 2.4.3 has been revised to provide greater clarity, and the phrase, “are intended to” is no longer used. **2.4.3** For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Load level, Load forecast, or dynamic model assumptions. • Expected transfers. • Expected in service dates of new or modified Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. As revised Part 2.1.3 (now Part 2.1.4) requires the use of sensitivity studies to “demonstrate the impact of changes to the basic assumptions used in the model”. To this end the sensitivity studies need only to be able to demonstrate the impact of changes. Typically, a sensitivity study would be a subset of the study already performed. It usually involves comparing the base cases with and without the change under consideration, and rerunning a list of the worst Contingencies. However, each situation is different and the specifics are left to the Planning Coordinator or Transmission Planner who are more familiar with the situation(s) to be

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	investigated. Part 2.5 (now Part 2.6) was not changed because studies, including past studies, are used to support the annual Assessment, and are not used to support current studies. The VSL for Part 2.5 (now Part 2.6) was added as a Lower VSL. R2, Lower VSL: The responsible entity failed to comply with Requirement R2, part 2.9 or Requirement R2, part 2.6. Parts 2.5.1 and 2.5.2 (new Parts 2.6.1 and 2.6.2) were not combined; however, they have been revised to address your concerns. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Part 2.6 has been modified and included as new Part 2.7. The intent is to allow discretion for the Planning Coordinator or Transmission Planner to correct those deficiencies if they are prevalent (i.e., occur is more than one sensitivity). Although not required, the standard does not preclude the Planning Coordinator or Transmission Planner to develop Corrective Action Plans for high risk scenarios. However, if the scenario is high risk, then it should have been included in the base assumptions in the assessment and the Corrective Action Plan would have been required. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Part 2.6 has been modified and included as new Part 2.7 In Part 2.6.1, “rate application” refers to rate incentives to change behavior of end-use customers and can be part of the “actions to achieve required System performance”. This is included to allow for non-traditional solutions to achieving required System performance. Part 2.6.3 - Project initiation date and in service date are no longer used in the requirements. Part 2.6.4 allows the Planning Coordinator or Transmission Planner to utilize Non-Consequential Load Loss and/or curtailment of Firm Transmission Service, which are normally not permitted to address situations that are beyond its control. Depending on the urgency of the need, the Corrective Action Plan may be developed outside the normal Assessment cycle at the discretion of the Planning Coordinator or Transmission Planner involved. Part 2.7 has been revised and included as Requirement R2, part 2.8 to reflect your suggestion. **2.8** For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

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Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed the both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Requirement R2, part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Entergy Services, Inc	The "study area" referred to in R2.3 should be defined. Does it mean external contingency events should be evaluated, or, the effects of internal contingency events on external parties. It should be clarified that generating facilities are not included in R2.1.4. The strategy may include agreements to share spare equipment among facilities, generation owners, and transmission owners. In R2.6.4 what is "prudent"? Who decides what is prudent? Recommend that the word be stricken. R2.6.4 is in conflict with the Implementation Plan. The Implementation plan omits P1 as an event where the bar has been raised but R2.6.4 allows the use of non-consequential load and firm transmission service curtailment. Clearly, the bar has been raised for any event, including P1, which allowed the curtailment of non-consequential load or firm transmission service in the existing standard. In R2.9 is the team requiring that a criteria be set by each Transmission Owner to set a maximum level of non-consequential load loss allowed by that Transmission Owner, or, that the amount of non-consequential load curtailment needed to meet the requirement be documented? What is the rationale for being so prescriptive in requiring specific years to be studied in R2.1.1 Why not allow the TP and/or PC to decide on the three years to be studied in the Near Term?? In the subrequirements of R2.1.3 and R2.4.3, the use of the word timing is unclear. Consider using in service date or “schedule for”. R2.1.4: The spare equipment strategy is too severe. The requirement should take into consideration the probability of occurrence of the events. Losing a transformer followed by the loss of a generator and a second transmission element is very unlikely. Non-consequential load loss should be allowed for this type of analysis. With the elimination of the distinction between system and generating plant stability studies, the blanket requirement in R2.5.1 that all stability analyses be five calendar years old or less, regardless of any material changes to the system, would cause needless work to be performed on those plants or areas of the system where no changes are occurring. Recommend adding the following to the end of R2.5.1: unless justification can be provided to demonstrate that the results of an older study are still valid. In R.2.4.1 it is mentioned that an aggregate System Load model that represents dynamic behavior of the load is acceptable. Does it mean that load at every bus in the study area has to be represented with an aggregate load model? This could be very cumbersome effort and we are not sure whether the software program can handle this magnitude of dynamic data. To help address this, revise Load to be Load that could impact the study area is acceptable. In Requirement R2.6.2, please clarify the definition of "project initiation date". Please explain the reason why Requirement R2.8 is needed in the Assessment and how does reporting the largest

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	Consequential Load Loss impact reliability?? Please explain the reason why Requirement R2.9 is needed in the Assessment and how does reporting the largest Non-Consequential Load Loss impact reliability?? Please clarify the use of the word permissible in the phrase "maximum permissible Non Consequential Load Loss".

Response: In Part 2.3 because the area that can be impacted is not confined to Facilities ownership, the study area should therefore include all Facilities that can reasonably be impacted. Where the study area involves several owners, coordination is required. However, since short circuit analysis is usually a localized issue, the area impacted would not be extensive.

Part 2.1.4 (now Part 2.1.5) refers to "unavailability of major Transmission equipment" without regard to ownership. Also, Part 2.1.5 only requires a spare equipment strategy but does not dictate the details of that strategy. So sharing of spare equipment is allowed. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.6.4 has been revised to address your concerns and the word, "prudent" was removed.

The Implementation Plan has been revised to include certain P1 events where the bar is being raised.

Part 2.1.1 is intended to require studies for System Peak Load Conditions for 2 of the years in the near-term planning horizon: A Year five case to identify potential problem that can be addressed if the planned projects proceed as scheduled. A Year one or Year two case to identify any potential problems unanticipated in the five-year case, which if not addressed, could impact operations as time progresses. The standard provides flexibility for the Planning Coordinator or Transmission Planner to use past studies to support the current year assessment and to assess other years in addition to those identified in Part 2.1.1.

Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only.

> **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.

Part 2.1.3 (now Part 2.1.4) and R2.4.3 have been revised to reflect your suggestion.

> **2.1.4** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

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	• Real and reactive forecasted Load. • Expected transfers. • Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. • Controllable Loads and Demand Side Management. • Duration or timing of planned Transmission outages. **2.4.3** For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Load level, Load forecast, or dynamic model assumptions. • Expected transfers. • Expected in service dates of new or modified Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. Part 2.4.1 has been revised to address your concerns. **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Part 2.5 has been revised and included as Part 2.6. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Part 2.6.2 was removed.
Great River Energy	R 2.1, 2.3, and 2.4 need consistency. 2.1 says "The Near-Term Transmission Planning portion of the Steady State analysis..." 2.3 says "The short circuit portion of the Planning Assessment ... addressing the Near-Term Planning Horizon..." 2.4 says "The Near-Term Transmission Planning portion of the Stability analysis..." These three sentences confuse the order. As I understand the Planning Assessment has two parts, a Near-Term portion and a Long-Term portion. Each of those parts has three components, a Steady state component, a Short Circuit component, and a Stability component. I

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	believe the standard's language should be structured as such. R2.1.3- The last bullet would seem to indicate that planners have the capability of predicting the future. The statement would seem to fit more in an operating standard. A suggested revision would be: Known long-term transmission outages with duration greater than one year R 2.1.4 addresses the spare equipment strategy. What is the scope of this sensitivity? Is the intent to do only a full steady state analysis with regard to long lead time spares? R2.6.2 would seem to be placing the planner again in the capability of predicting the future. Coming up with specific dates based on budgets, projected growth rates, potential permitting issues, and material delivery schedules would make it difficult to define an initiating date and an in-service date. An in-service season and year may be more applicable in a planning study for near-term projects. GRE is not sure why an initiating date is of relevance in an assessment.

Response: In the third posting, the Standard, as proposed, requires steady state, Stability and short circuit analyses for the Near-Term Transmission Planning Horizon; steady state for the Long-Term Transmission Planning Horizon. In the fourth posting, the SDT proposes to add Stability analysis to the Long-Term Transmission Planning Horizon. So the requirements are not the same as you described. However, the Requirements have been revised to provide greater clarity.

> **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.
>
> **2.4** The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part2.6. The following studies are required.

The last Bullet in Part 2.1.3 (now Part 2.1.4) is intended to cover planned outages of Facilities in sensitivity studies if such planned outages are known at the time the planning studies are performed, for example, planned outage of a major Transmission line during construction if the Corrective Action Plan calls for rebuilding of the line to a higher operating voltage. The corresponding sensitivity could simulate unplanned delay starts or unplanned extension of construction period. No change made.

Part 2.1.4 (now Part 2.1.5) is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. As such the analysis is not limited to steady state studies. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Parts 2.6.2 and 2.6.3 have been removed since the definition of Corrective Action Plan already includes "timetable for implementation".

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BC Hydro	Comments: Consider changing the second sentence to read, This Planning Assessment shall use current or past studies, document assumptions, document results and shall cover all analyses needed to clearly demonstrate that the proposed system expansion plan meets all planning criteria and standards. This standard should not limit the studies to only steady state analyses, short circuit analyses and Stability analyses none of which seem to be defined anywhere. In some cases it would be appropriate for planning studies to cover analyses of such phenomenon as electromagnetic transients, sub-synchronous resonance, ferroresonance and harmonics. The fact that Stability is capitalized suggests that it refers to the definition of Stability in the NERC glossary, but that definition reads just, The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances?, but stability analyses (often more properly termed dynamic simulation studies) usually encompass more than simply electromechanical or voltage stability. Usually voltage and frequency excursions are also analyzed and perhaps temporary overcurrent also (eg, assessing temporary overvoltage levels across series capacitor banks).
Response: Even though the other types of studies as identified are important for specific cases, a NERC Standard needs to be applicable continent-wide. The modification could require the inclusion of studies such as EMTP, long-term stability, etc., in the annual Planning Assessment, which is not necessary in all cases. No change made.	
Midwest ISO	Opening Remarks. Specific Comments for Requirement 2:A) Under R2, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R2 only says Long-term Planning. By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: Near-Term and Long-Term Transmission Planning. B) Under R2.1 there is a reference to qualified past studies in R2.6. We believe that this reference should be pointing to R2.5 not R2.6. C) Under R2.1.3 there is ambiguity in the third bullet language new or modified Facilities and we believe that this language should mimic that of R1.1.2 in order to improve this requirement. The third bullet should read: Timing of the installation of new Planned Facilities or changes to existing Facilities. D) Under R2.1.3 there is ambiguity in the fourth bullet language capability and we believe that this language should read: Reactive resource capability (Generator, STATCOM, SVC, other?etc). We believe that this language addition improves this requirement. E) Under R2.1.3 there is ambiguity in the seventh bullet language Transmission outages and we believe that this language should read: Planned duration or timing of specifically scheduled or planned for Transmission outages. This language mimics similar language suggested above in R1.1.1 (letter C on page 3 of 9) F) When a spare equipment strategy does not cover the long lead time unavailability as stated in 2.1.4, will the system be treated as “normal system condition and Table 1 requirements or as having a contingency from which system adjustments are to be made prior to subsequent events. We believe that this task will be burdensome for large entities such as RTOs and we are not clear on the benefit that this requirement brings. For example: If in an RTO system where a party has spare equipment, how can the RTO ensure that a spare part from one asset owner can be made available to other asset owners”

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	G) Under R2.2 a System peak load study is required annually for one of the years in the assessment period. R2.2.1 requires the assessing entity to extend their planning assessment to accommodate any known longer lead time projects that may take longer than ten years to complete. It does not make sense to study the ten year horizon, find a problem in year ten which has a solution that required twelve years to build. For compliance with this standard, you would need to find another solution that can be built within ten years as opposed to the suggested language in R2.2.1 of extending the planning assessment beyond ten years to accommodate the solution that falls outside of the Long-Term Planning Horizon. No project solution greater than 10 years should be acceptable because it falls outside the Long-Term Transmission Planning Horizon. Suggestion to strike sub-requirement R2.2.1 from this standard. H) Under R2.3 the second sentence requires that "The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study year". We suggest changing the language to read: The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with Planned Facilities in service which could impact the study year". The definition of Planned Facilities was suggested to be added in the comment above in R1.1.2 under letter (E). I) Under R2.4 the second sentence requires states The following studies are required. We suggest changing the language to read: The following current studies are required. We believe that this language addition improves this requirement. J) Under R2.4.1 the first sentence leaves to much ambiguity as to who determines whether severity of system peak or off peak as well as whether the system load levels appropriately represents the dynamic behavior of loads. If the monitoring agency wishes to make this determination than it should be explicitly written here in this requirement. If the assessing entity is to make this determination than we offer the following language suggestion that we feel will improve this requirement. "For one of the five years, the more severe System peak or off peak System load level, as judged by the assessing entity, shall be used which in the judgment of the assessing entity appropriately represents the dynamic behavior of Loads including consideration of the behavior of induction motors". K) For R2.4.2, we suggest striking this requirement altogether and add System Off-Peak to R2.4.1 above in R2.4.1 under letter (I). L) Under R2.4.3 there is ambiguity in the third bullet language new or modified Facilities and we believe that this language should mimic that of R1.1.2 in order to improve this requirement. The third bullet should read: Timing of the installation of new Planned Facilities or changes to existing Facilities. M) Under R2.4.3 there is ambiguity in the fourth bullet language capability and we believe that this language should read: Reactive resource capability (Generator, STATCOM, SVC, other etc). We believe that this language addition improves this requirement. N) The sub requirement R2.5.2 states that for steady state, short circuit, or stability analysis; the present System model shall not include any material changes, such as..etc. The present language in this section is vague and requires discretion on the part of both the Transmission Planner and the Planning Coordinator performing the assessment. For example, new transmission enhancements may have been added since the previous System model was developed. In general, such topology enhancements will only improve reliability and would not necessitate re-assessment with a newly updated System

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	model. In addition, any significant generator additions would have been evaluated with a full separate generator interconnection study at which the full reliability of the System would have been taken into consideration. For this reason, we believe the following language for R2.5.2 would improve this requirement: For steady state, short circuit, or Stability analysis: the current System model of the assessed plan year shall not include any changes material to the assessment, as judged by the entity performing the assessment, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study year. Material generation changes could include: O) Under R2.6.1 the fifth bullet regarding the use of Operating Procedures needs to be made clearer. We believe that the following language will improve this requirement: Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan. Operating Procedures may not include Non-Consequential Load Loss when not permitted in Table 1. P) Under R2.6.1 the sixth bullet regarding the use of rate applications, DSM, new technologies or other initiatives can be improved with the following language additions: Use of rate applications, DSM, new technologies or other demand side initiatives can be improved with the following language additions. Q) Under R2.6.2 the language regarding project initiation date is vague. We suggest the following definition to be added to this standard and further added to the NERC Glossary of Terms: Project Initiation Date A date in which Planned Facilities are expected to break ground. R) Under R2.8 please add a coma between the words event and caused. A PC/TP would study multiple P1 and P2 events involving consequential load loss not just the largest. Unless the SDT has a measure in mind for consequential load loss, this requirement should be removed. S) Under R2.9 please strike the word permissible and replace with necessary. It is not clear what the SDT is requesting with this requirement.

Response: The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made.

Mitigation Time Horizon

The time horizons available for mitigating a violation to a requirement include the following:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.

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	• **Operations Assessment** — follow-up evaluations and reporting of real time operations In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made Part 2.1.3 (including the third and seventh bullets) (and now Part 2.1.4) has been revised to provide greater clarity. The SDT declines to change the fourth bullet because adding a partial list of devices that could provide reactive resources may not improve clarity beyond the present description. **2.1.4** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Real and reactive forecasted Load. • Expected transfers. • Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. • Controllable Loads and Demand Side Management. • Duration or timing of planned Transmission outages. Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service such that the outage won't last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its System, or have agreement with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. Perhaps it would help if sharing major Equipment can be part of an operating agreement within entities belonging to the RTO; however, that would be outside the scope of this Standard. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.2.1 has been revised because extending the Planning Horizon beyond 10 years for projects with lead time longer than 10 years is already covered in the definition of Long-Term Transmission Planning Horizon. This allowance is needed to provide planning flexibility, and is at the discretion of the Planning Coordinator or Transmission Planner. For example, if the System is found not to meet performance standard in year 10, but the project to correct the loading cannot be placed in service for 12 years, then the Corrective Action Plan needs to identify the interim solutions before the project can be brought on line. **2.2.1** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the

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	rationale for why that year was selected. Part 2.3 has been revised to reflect your suggestion. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. In Part 2.4.1, the SDT was not able to locate the reference to the comment on the "ambiguity as to who determines whether severity of system peak or off peak". No change made. Part 2.4.1 has been revised to provide greater clarity. However, the SDT declines to modify Part 2.4.1 to require study for "the more severe System peak or off peak System load level" for one of the five years in the Near-Term Transmission Planning Horizon because the System needs to meet performance requirements under all System conditions including peak and off-peak. In addition, the Planning Coordinator or Transmission Planner can rely on past studies as provided in Part 2.5 (Part 2.6 in the new version). For this reason Part 2.4.2 has been retained. **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Part 2.4.3 (including the third bullet) has been revised to provide greater clarity. The SDT declines to change the fourth bullet because adding a partial list of devices that could provide reactive resources may not improve clarity beyond the present description. **2.4.3** For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Load level, Load forecast, or dynamic model assumptions. • Expected transfers. • Expected in service dates of new or modified Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. Part 2.5 has been revised and included as Part 2.6. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Part 2.6.1 has been revised and included as Part 2.7.1 to provide greater clarity. However, the SDT declines to include "Operating Procedures may not include Non-Consequential Load Loss when not permitted in Table 1" because it is redundant. Part 2.6.1 (now Part 2.7.1) is a sub-part of Part 2.6 (now Part 2.7), which

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explicitly requires meeting the performance requirements in Table 1. Parts 2.6.2 and 2.6.3 have been removed since the definition of Corrective Action Plan already includes “timetable for implementation” so a new NERC definition is not required. Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
PJM	In R2, why require a Planning Coordinator AND a Transmission Planner to perform this analysis? Isn’t this a duplication of effort? In R2, I have always heard that dynamics studies are performed to determine Stability. In R2.1, need to update reference to R2.6 from R2.5. In 2.1.1 and R2.1.2, is this annual peak or seasonal peak? Summer peak for summer peaking entities and winter peak for winter peaking entities or both summer and winter peak for all entities. R2.1.1 year one or two studies should be only required as operating studies. By their nature, the upgrades or fixes that could be accomplished in this time frame are limited to short lead time fixes. These analyses are needed to determine how to accommodate construction schedule deviations and near term system issues that may cause issues. Traditional Planning studies will be of no benefit in this timeframe. Change the requirement to be a study for year 3,4 or 5 with updates for material changes that occur when a previous year study is still within this time frame.R2.1.2 and R2.1.1 should be combined and the TP should assess and justify its choice of the critical load scenarios to analyze. Concerned about the extent of variations required in R2.1.3. Like would I have to vary all proposed generator in-service dates? Just a couple? One? Requirements need to be clear or compliance will assume the largest scope possible. Also in R2.1.3, first bullet words should align with the words of R1.1.3. Also in R2.1.3, second bullet words should align with words of R1.1.4 and R1.1.5. Also in R2.1.3, third bullet, modified facilities are not installed, suggest changing -installation to -availability--. Also in R2.1.3, fifth bullet, suggest moving retirements-- up to third bullet and dropping -- Generation additions, retirements, or other-- leaving just dispatch scenarios R2.1.4 should be deleted. There are no NERC requirements on spare equipment availability and this requirement seems like a backhanded way to include such a requirement. R2.2.1 should be reworded because it now requires everyone to extend their studies. Suggest If planned projects will take longer than ten years to complete, the Planning Assessment shall be extended accordingly- R2.4.1 Not sure I understand. The second sentence and the third sentence seem to be in conflict

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	R2.4.2. This requirement has lost significance with the deletion of unit stability. Off-Peak scenarios are critical for unit stability and analysis of pockets of known light load stability sensitivity. This requirement should not be worded to require a general system off-peak stability study since this will not provide useful information. The requirement should be reworded to clarify that the TP should identify its critical off-peak stability sensitivities and provide annual stability analyses that address the system's off peak stability issues.R.2.4.3 should only refer to R2.4.1 since R2.4.2 are sensitivities themselves. In R2.4.3, first bullet, how would load model assumptions be varied? Same comments on bullets here as R2.1.3 above. R2.5.2 is impossible to judge. Material changes needs to be defined. The word could in the sentence before the bullets makes them useless as a definition. By trying to define material changes the SDT has created a situation where, for large interconnection, it would be virtually impossible to use a past study. The addition of a 100 MW generator two states removed from the study area would not be considered material but by the guidelines in this requirement it can be interpreted as such. R2.5.2 Add that retools of past studies that address the local impacts of specific cumulative material changes that occur are sufficient to continue to support current planning assessment. R2.6 has a mixing sigular and plural tenses. What if only one problem is found and therefore only one Corrective Action Plan is needed. Or can one Plan cover all the problems found? Responses to R2.8 and R2.9 would be considered Critical Energy Infrastructure Information (CEII) and that should be noted so it can be protected. R2.8 and 2.9 change to read that the Planning Coordinator will provide its criteria for load loss that is adheared to for all events.

Response: Requirement R2 applies to both the Planning Coordinator and Transmission Planner because the Planning Coordinator may have a larger area than the Transmission Planner. Functional Model Version 3 states that, "Like the Resource Planners and Transmission Planners at the 'local' level, the Planning Coordinator maintains system models and performs the necessary studies to evaluate whether the composite resource and transmission plans of its Resource Planners and Transmission Planners are in compliance with reliability standards". No change made.

Please suggest modifications to more accurately describe "stability" Analyses. No change made.

In the new version, Part.2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made.

For Part 2.1.1, Year One and year two are within the Planning Horizon. In the Definition Section, Year One is defined as "The first year that a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the current calendar year". Operating Studies are performed for system conditions within 12 months of the current calendar year. Part 2.1.1 is intended to require studies for System Peak Load Conditions for 2 of the years in the Near-Term Transmission Planning Horizon: (1) A Year five case to identify potential problem that can be addressed if the planned projects proceed as scheduled; (2) A Year one or year two case to identify any potential problems unanticipated in the five-year case, which if not addressed, could impact operations as time progresses. The standard provides flexibility for the Planning Coordinator or Transmission Planner to use past studies to support the current year assessment and to assess other years in addition to those identified in Part 2.1.1. Part 2.1.2 requires that the Planning Coordinator and/or Transmission Planner also consider off-peak conditions in addition to peak conditions because the System must be able to meet performance requirements over all demand levels. System peak condition may not represent all stressed conditions. For example, during off-peak, the Load is low, and the generation would have to be

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turned off to achieve Load-resource balance. Turning down resources within a Load area could result in reliability problems. Lowering the Load in areas with many non-dispatchable resources could also pose potential problems. As the System incorporates more and more renewable resources, some of them are non-dispatchable; a standard must be forward looking so the Planning Coordinator and Transmission Planner can identify potential problems. If studies for one of the Load periods are not needed annually, the Planning Coordinator or Transmission Planner can rely on past studies for the Planning Assessment.

The bullets under Requirement R1, Part 1.1.3 have been removed from the revised standard, so no effort was made to line up the bullets in Requirement R1, Part 1.1.3 with the first two bullets under Requirement R2, Part 2.1.3. Parts 2.1.3 (now Part 2.1.4) and 2.4.3 and associated bullet lists have been revised to provide greater clarity for the expected changes. "Installation" has been removed from the third bullet. The SDT believes it is appropriate to treat generation change and transmission changes separately and did not move retirements up to the third bullet. The extent of the variations for each item listed is left to the discretion of the Planning Coordinator or Transmission Planner who are more familiar with the system being studied. Load modeling assumptions can be varied by varying, for example, the percentage of motor Load or the customer mix. It is up to the Planning Coordinator or the Transmission Planner to decide how the assumptions would be varied.

2.1.4 For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of planned Transmission outages.

2.4.3 For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Load level, Load forecast, or dynamic model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

Part 2.1.4 (now Part 2.1.5) is based on FERC Order 693, Paragraphs 1724 – 1727. Part 2.1.4 requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or

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can be purchased and be placed in service such that the outage won't last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its System, or have agreement with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. The Planning Coordinator and/or Transmission Planner will need to decide which pieces of major Equipment in their respective systems would be more vulnerable to long term outage. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.2.1 has been revised to reflect your suggestion. **2.2.1** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected. Part 2.4.1 is intended to allow the use of aggregated system Load models if more accurate Load models are not available. Therefore, the second and third sentences are not in conflict. The SDT declines to include Part 2.4.2 in Part 2.4.3 because it is not intended to be a sensitivity study because the System needs to meet performance requirements under all System conditions including peak and off-peak. In addition, the Planning Coordinator or Transmission Planner can rely on past studies as provided in Part 2.5 (Part 2.6 in the new version). For this reason Part 2.4.2 has been retained. Part 2.5 has been revised and included as Part 2.6 as shown. The language referencing "material generation changes" has been removed from the revised standard. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Part 2.6 has been revised and included as Part 2.7 to address your concerns about mixing singular and plural possibilities. . **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Parts 2.8 and R2.9 were intended to contribute to open and transparent Transmission planning for peer review. The standard does not preclude protection of the Critical Energy Infrastructure Information (CEII). The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2

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events in Table 1.	
Brazos Electric Cooperative	In R2.1, end of paragraph i believe you mean Requirement 2.5, not 2.6. In R2.6.2 we believe maintaining a 'project initiation date' serves no purpose and should be deleted. These dates are wildly variable given the nature of each project and the numerous issues that can affect these dates. 2.6.2 and 2.6.3 should be combined to simply require an in-service year/date and allow the owners to work as needed to meet these dates. We think R2.9 should be deleted as it is vague in nature, seems to serve no purpose and would be hard to verify the accuracy of the value in an audit. 2.8 is direct and can be easily detailed for an audit.
Response: In the new version, Part.2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made. Project initiation date and in service date have been removed from the requirements. Parts 2.8 and R2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees with the majority of commenters that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
American Electric Power	AEP agrees with R2.3., but should note that the planning horizon short circuit models are not presently developed in any systematic fashion, since, unlike the development of steady-state (power flow) and stability models that are mandated under MOD-010 and MOD-012, respectively, there are no NERC Standards that mandate the development of short circuit models in a similar fashion. As to R2.4., requiring study of both peak and off-peak conditions in every stability assessment removes the possibility in this regard that stability study scopes may be defined most appropriately by engineering judgment. We believe system load level is often important, but not necessarily more important than any of the other sensitivity variables listed under R2.4.3. We suggest listing system load level along with these and removing R2.4.1. and R2.4.2. The text in R2.4.1., referring to dynamic load modeling, may still be retained somewhere, and since this falls in the category of modeling and data, we suggest including this under R1.1. With regard to R2.5., a 20 MW increase in generation may well be construed as a material generation change, but it is questionable whether a 20 MW decrease would be for transmission planning purposes. Also, the validity of many studies, particularly plant oriented stability studies, may well extend beyond five years if there have been no transmission modifications in the vicinity of the plant or to the plant itself. In these instances, it would seem counter-productive to disqualify a study after five years. The duration of the validity of certain types of past studies is better determined by the occurrence of significant transmission or generation changes. Please note, under R2.6.2., to define project initiation date [Changed sequence to keep in numerical order].

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Response: Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt and is not specifically related to new planned Facilities. However, a NERC-wide data base or models similar to MOD-010 or MOD-012 may be neither desirable nor necessary, since short circuit study concerns localized issues and can be contained within a study area. Part 2.3 has been revised to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. The SDT declines to include Load levels in sensitivity studies in Part 2.4.3 and remove Parts 2.4.1 and 2.4.2. Since Part 2.4.3 would only require studying one or more of the list of sensitivities, this change can result in no Stability study performed for either peak Load or off-peak Load condition in the Near-Term Transmission Planning Horizon. In addition, the standard does not require a new Stability study be performed annually; the Planning Coordinator or Transmission Planner can rely on past studies as provided in Part 2.5 (Part 2.6 in the new version). For this reason no change was made. Part 2.5 has been revised and included as Part 2.6 as shown. The reference to the "20 MW" threshold has been removed from the revised standard. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Project initiation date has been removed from the requirements.	
ITC Holdings	Comments: In R2.1, there is a reference to R2. 6. Based on the posted red-line version, we believe this reference should be changed to R2.5. Should this same reference be included in R2.4?? In R2.3, it is stated that the short circuit analysis should be supported by either current or past studies. Should a reference be added to R2.5? In R2.6 it is stated: Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3 and R2.4.3. While we recognize that this conforms to FERC orders, it would still seem that this statement might be interpreted to mean that CAPs intended to cover a number of sensitivities go beyond standards and be used by interveners to block such CAPs. A revision to the standard to the standard to encourage CAP when needed for numerous sensitivities might be appropriate. R 2.6.4, as written, is very subjective. While we understand the need for R2.6.4, who is the ultimate judge of what situations are beyond the control of the TP or PC responsible for the mitigation plan and if they "are taking prudent actions to resolve the situation" As written, it is the auditor. This will be difficult to prove compliance and might provide significant discrepancies in compliance with standards.

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Response: In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made.	
The reference has been added.	
2.4 The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required:	
Parts 2.3 and 2.4 have been revised to add reference to Part 2.5 (included in the new version as Part 2.6).	
2.3 The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.	
Part 2.6 has been revised and included as Part 2.7. A new Part 2.7.2 has been added to require that the Corrective Action Plan include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.	
2.7 For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:	
2.7.2 Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.	
Part 2.6.4 has been revised and included as Part 2.7.5 to address your concerns. The word "prudent" is no longer used.	
2.7.5 If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.	
Northern Indiana Public Service Company	R2.3: Clarify the requirement. Does the short circuit study examine topology for a single year, the topology in years studied using the steady state models or each year of the near term planning horizon?
Response: Part 2.3 requires that the Assessment of short circuit duty requirements are conducted annually addressing the Near-Term Transmission Planning Horizon. However, the specific methodology or assumptions to be used are left to the discretion of the Planning Coordinator or Transmission Planner.	
Minnesota Power	A) Under R2, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R2 only says Long-term Planning. By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: Near-Term and Long-Term Transmission

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	Plannin?. B) Under R2.1 there is a reference to qualified past studies in R2.6. We believe that this reference should be pointing to R2.5 not R2.6. C) R2.1.4 addresses the spare equipment strategy. What is the scope of this sensitivity? Is the intent only to do a steady state analysis on equipment with long lead time spares D) Under R2.2 a System peak load study is required annually for one of the years in the assessment period. R2.2.1 requires the assessing entity to extend their planning assessment to accommodate any known longer lead time projects that may take longer than ten years to complete. It does not make sense to study the ten year horizon, then find a problem in year ten which has a solution that requires twelve years to build. For compliance with this standard, you would need to find another solution that can be built within ten years as opposed to the suggested language in R2.2.1 of extending the planning assessment beyond ten years to accommodate the solution that falls outside of the Long-Term Planning Horizon. No project solution greater than 10 years should be acceptable because it falls outside the Long-Term Transmission Planning Horizon. Suggestion to strike sub-requirement R2.2.1 from this standard. E) Requirements R2.1, R2.3, and R2.4 are written inconsistently. 2.1 says The Near-Term Transmission Planning portion of the Steady State analysis 2.3 says The short circuit portion of the Planning Assessment addressing the Near-Term Planning Horizon 2.4 says The Near-Term Transmission Planning portion of the Stability Analysis These three sentences confuse the order. As we understand, the Planning assessment has two parts: a Near-Term portion and a Long-Term portion. Each of those parts has three components: a Steady State component, a Short Circuit component, and a Stability component. We suggest the language in the standard should be structured consistently and appropriately as such) Under R2.4.3 there is ambiguity in the third bullet language new or modified Facilities and we believe that this language should mimic that of R1.1.2 in order to improve this requirement. The third bullet should read: Timing of the installation of new Facilities or changes to existing Facilities. G) The sub requirement R2.5.2 states that for steady state, short circuit, or stability analysis; the present System model shall not include any material changes, such as..etc. The present language in this section is vague and requires discretion on the part of both the Transmission Planner and the Planning Coordinator performing the assessment. For example, new transmission enhancements may have been added since the previous System model was developed. In general, such topology enhancements will only improve reliability and would not necessitate re-assessment with a newly updated System model. In addition, any significant generator additions would have been evaluated with a full separate generator interconnection study at which the full reliability of the System would have been taken into consideration. For this reason, we believe the following language for R2.5.2 would improve this requirement: For steady state, short circuit, or Stability analysis: the current System model of the assessed plan year shall not include any changes material to the assessment, as judged by the entity performing the assessment, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study year. Material generation changes could include: H) Modify R2.6.2 to remove the obligation to include the project initiation date. The inclusion of this date would add unnecessary work that is not needed to assure adequate BES reliability In addition, it is not clear whether initiation refers to

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	the commencement of engineering, design, construction, etc.

Response: The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made.

Mitigation Time Horizon

The time horizons available for mitigating a violation to a requirement include the following:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations

In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made.

In Part 2.1.4 (now Part 2.1.5) when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1. Part 2.1.5 is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Transmission equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. It is not intended to limit to steady state analyses only. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.2.1 has been revised because extending the Planning Horizon beyond 10 years for projects with lead time longer than 10 years is already covered in the definition of Long-Term Transmission Planning Horizon. This allowance is needed to provide planning flexibility, and is at the discretion of the Planning Coordinator or Transmission Planner. For example, if the System is found not to meet performance standard in year 10, but the project to correct the loading cannot be placed in service for 12 years, then the Corrective Action Plan needs to identify the interim solutions before the project can be brought on line.

> **2.2.1** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

As written the Planning Assessment consists of 2 parts: Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon, Steady State and Stability Assessments are required for both near-term and long-Term, but short circuit assessment is required only for the near-term. Part 2.3 has been revised

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to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. The 3rd bullet of Part 2.4.3 has been revised. **2.4.3 bullet 3** Expected in service dates of new or modified Facilities Part 2.5.2 has been revised and included as Part 2.6.2 to provide greater clarity. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Project initiation date has been removed from the requirements.	
LADWP	R2.3 There is no value to conduct short circuit analysis on an annual basis. Short circuit contribution is location constrained. Maximum short circuit interrupting duty cannot be determined by any planning cases; so putting this requirement in TPL will cause only confusion and will creat misleading information. If there is a need to develop a standard on how to evaluate maximum short circuit interrupting duty, the more appropriate place would be FAC. R2.1.3 Controllable Loads and DWM: DSM should not be a stand alone item in planning studies because DSM already is imbedded in load forecasts. Not sure what controllable loads are. R2.1.4 Any requirment dealing with spare parts should be handled in TOP, not TPL. TOP is the forum to develop operating procedures,"work-arounds", and so on when the non-availability of spare forced a company to develop temporary mitigations and it would be a mistake to suggest that planners should be able to consider such temporary fixes as acceptable planning solutions.R 2.5.2 The 20 MW threshold, at best, is "noise" for us. We would not be concerned with generation chnages that is 10 times this threshold. What is the rationale for requiring a new study just because there is a change in generation capability? R2.8 and 2.9 What measurements would this required information be measured against? I can't find any and if there is no measurement, it really does not belong. R2.6.2 Project initiation date is hard to define. Is it the date the project is budgeted? or the date the management approved the budget and at what level? or is it the date when engineering design is initiated? For both short term and long term planning horizons, the project in service date should be sufficient. there are too many variables to define "project initiation date" not to mention there is no measurable to benchmark such a requirement.
Response: Parts 2.3 and 2.7 are intended for the Planning Coordinator and/or Transmission Planner to assess whether circuit breakers supporting the BES have the interrupting capability for Faults that they will be expected to interrupt. No change made. Part 2.1.3 (now Part 2.1.4) is intended to cover sensitivity studies, for example, if DSM is imbedded in the Load forecast, the sensitivity study can simulate	

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conditions where not all effects of DSM is realizable, and the Load may be higher than studied . Controllable Load can be part of the local rate incentive program, where the customer Load can be controlled by the Transmission Operator. The bullets are examples, so the Planning Coordinator or Transmission Planner can choose the sensitivity and does not have to study, for example, controllable Load, if the related Load-Serving Entity does not have such a program. Part 2.1.4 (now Part 2.1.5) is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Transmission Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Parts .2.8 and R2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1. Part 2.5.2 (now 2.6.2) has been revised for clarity and the 20 MW threshold has been removed. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Project initiation date has been removed from the requirements.	
Platte River Power Authority	R2.6.2. Expand on the meaning of the "initiation date." R2.8. I don't understand the relevance of this requirement. May your intention be explained differently? R2.9. I don't understand the relevance of this requirement. May your intention be explained differently?
Response: Project initiation date has been removed from the requirements. Parts 2.8 and R2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
MAPPCOR	R2.1.1 Consider calling this Near Term years instead of specifically naming certain years.

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	R2.1.3 eliminate the last bullet. Planned duration or timing of Transmission outages is part of R1.1.1 which already specifies that models will include planned outages of generation and transmission facilities. R2.1.4 the second line is unclear. There is a reference to lead time of one year or more Is the intent for that to mean outage duration of one year or more??? If so, it should be written that way. Also, in the 3rd line, eliminate the words an analysis of (otherwise it would direct one to assess an analysis.) This in essence is an N-3 study. This risk that a TO or GO takes will show up in the operations of the BES. Also some states assess a penalty for equipment that is sitting idle that cost the taxpayers, so you could be penalize for not have spare equipment or if you do have it. R2.2.1 does this mean, for example, that entities may be doing 12 year or 15 year assessments? It should be written to say what it means. R2.4.1 Change to read: For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads or an aggregate System Load model which represents the overall dynamic behavior of the Load. R2.5.1 Suggest deleting this requirement, and incorporating it into R2.5.2. R2.5.2 Incorporate R.2.5.1 into R2.5.2; please modify the section as follows:For steady state, short circuit, or Stability analysis the study shall be less than five calendar years old or less: the latest Transmission Planning Horizon System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include: The addition/deletion/change of individual generating unit capability determined to be material by the Planning Coordinator or Transmission Planner. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES determined to be material by the Planning Coordinator or Transmission Planner. R2.6 ? The creation of hard and fast Corrective Action Plans for the LTRA is not a good use of resources. The reason for planning studies is to uncover possible weak spots in the system for some number of years into the future, and then pursue additional studies to examine the issues. Planning studies include many assumptions, and the issues may not even arise on the real system. If they do, there may be many possible remedies. Creating CAPs with milestones and other firm dates for potential problems uncovered in assessments of future years is simply not practical, and the PC (PA) may have little or no influence on what remedy is selected even if a problem appears to be real. R2.6.2 The phrase Project Initiation Date needs to be defined. It is unclear if this is this the date of ground breaking, purchase orders being issued, solution study initiation, etc. Additionally, in the second sentence the phrase as well as an in-service date should be modified to read as well as a target in-service date. R2.6.3 Plans can provide a target in-service year but not an actual in-service year. R2.6.4 recommend clarifying how situations beyond the control of the TP or PC are determined. It is unclear if this is to imply that if something is outside of the control of the department who conducts the planning studies or if it is outside the control of the registered function's legal entity (i.e. corporation). There should be a cutoff point when changes occur beyond a certain date. When that date occurs, further changes will be evaluated in the next year's assessment. Otherwise, if a state makes a decision not to site a project a few weeks prior to the end of the assessment period, there will not be sufficient

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	time to incorporate this into that year's assessment and develop corrective actions. R2.8 appears to be nonessential information for reliability; for what purpose does this requirement exist? R2.9 - appears to be nonessential information for reliability; for what purpose does this requirement exist?

Response: Part 2.1.1 is intended to require studies for System Peak Load Conditions for 2 of the years in the Near-Term Transmission Planning Horizon: (1) A year five case to identify potential problem that can be addressed if the planned projects proceed as scheduled; (2) A Year One or year two case to identify any potential problems unanticipated in the five-year case, which if not addressed, could impact operations as time progresses. The standard provides flexibility for the Planning Coordinator or Transmission Planner to use past studies to support the current year assessment, and to assess other years in addition to those identified in R2.1.1.

The last Bullet in Part 2.1.3 is intended to cover planned outages of Facilities in sensitivity studies if such planned outages are known at the time the planning studies are performed, for example, a planned outage of a major Transmission line during construction if the Corrective Action Plan calls for rebuilding of the line to a higher operating voltage. The corresponding sensitivity could simulate unplanned delay starts or unplanned extension of construction period of the planned project. No change made.

Part 2.1.4 (now Part 2.1.5) is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Transmission equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.2.1 has been revised because extending the Planning Horizon beyond 10 years for projects with lead time longer than 10 years is already covered in the definition of Long-Term Transmission Planning Horizon. This allowance is needed to provide planning flexibility, and is at the discretion of the Planning Coordinator or Transmission Planner. For example, if the System is found not to meet performance standard in year 10, but the project to correct the loading cannot be placed in service for 12 years, then the Corrective Action Plan needs to identify the interim solutions before the project can be brought on line.

> **2.2.1** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

Part 2.4.1 has been modified.

> **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

Part 2.5.1 (now Part 2.6.1) is considered a separate requirement by the SDT and has not been deleted or merged. It has been revised for clarity.

> **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided

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to demonstrate that the results of an older study are still valid. Part 2.5.2 (now Part 2.6.2) has been revised for clarity. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Part 2.6 has been revised and included as Part 2.7 to address your concerns. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Project initiation date has been deleted from the requirements. The requirement for in service date has been deleted. Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees with the majority of the commenters that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in he new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Orlando Utilities Commission	-I think R2.1 has a typo and should reference requirement R2.5, not R2.6. – R2 Does the phrase “System Peak Load” require true system peak be tested, or a peak condition. As an example, FRCC experience a two peak loads, a summer peak that occurs regularl
Response: In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made. System peak Load means the highest Load within the time period that is being evaluated.	
American Transmission Company	We propose the following comments for R2:In sections R2.1.3 and R2.4.3 please explain the reference to expected transfers and how that differs from R1.1.5 interchange. If these are analogous, then change the references to interchange. Modify R2.5.2 second bullet to clarify that this addresses an aggregated addition/deletion/change to a group of generating units directly connected through a shared step-up transformer . . . . Modify R2.6.2 to remove the obligation to include the project initiation date. The inclusion of this date would add unnecessary work that is not needed to assure adequate BES reliability. In addition, it is not clear whether initiation refers to the commencement of engineering, design, construction, etc.ATC agrees that the Transmission Planner should be responsible for a corrective action plan (R 2.6) and its associated sub-requirements, but we do not agree that the Planning

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	Coordinator should also be listed. Unlike a Transmission Planner, a Planning Coordinator does not have the ability or responsibility to implement a corrective action plan. Requirement 2.6 and its associated sub-requirements should be limited to only the Transmission Planner. Remove the R2.8 requirement. The activity of identifying and including the largest Consequential Load Loss caused by any P1 or any P2 events in the Planning Assessment may not assure adequate BES reliability. A P1 or P2 event with the largest Consequential Load Loss could occur at a location on the system that is strong enough to not result in any performance violation. The amount of Consequential Load Loss may not have a relevant correlation to system performance and reliability. Remove the R2.9 requirement. The activity of identifying and including the maximum permissible Non-Consequential Load Loss caused by selected Table 1 Planning Events may not assure adequate BES reliability. The maximum permissible Non-Consequential Load Loss could occur at a location on the system that is strong enough to not result in any performance violation. The maximum amount of Non-Consequential Load Loss may not have a relevant correlation to system performance and reliability. Add R2.10. The obligation to identify and observe applicable steady state voltage and post-Contingency voltage deviations should be a Requirement, rather than performance note a in the Planning Events, Steady State Only section of Table 1. And the obligation to identify and observe applicable transient voltage response limits should be a Requirement, rather than performance note b in the Planning Events, Stability Only section of Table 1. In addition, due to the system limit requirements of FAC-010 and FAC-014 the reference to the PC and TP is unnecessary. We suggest this text: The Planning Assessment shall identify the applicable steady state voltage, post-Contingency voltage deviations, and transient voltage response limits.

Response: Part 1.1.5 has been revised to state "Known commitments for Firm Transmission Service and Interchange" The NERC Glossary of Terms defines Firm Transmission Service as "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption" and Interchange as "Energy transfers that cross Balancing Authority boundaries. "Transfer" can cover more than Firm Transmission Service or Interchange. Parts 2.1.3 and 2.4.3 would cover the sensitivity of changes in expected transfers regardless of the cause.

Part 2.5.2 – The examples in the bullets have been deleted.

Part 2.6.2 - Project initiation date has been deleted from the requirements.

Part 2.6 has been revised and included as Part 2.7 in the new version to address your concerns. The SDT declines to limit the application of Part 2.6 to the Transmission Planner because the Planning Coordinator would be responsible for coordination between Transmission Providers.

> **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees with the majority of the commenters that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new

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version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1. The obligation to identify potential steady state, transient, post-transient and post-Contingency problems is already included in Parts 2.1 through 2.4 and in Part 2.6 (Part 2.7 in the new version). Therefore adding a new Part 2.10 is not needed.	
Turlock Irrigation District	TID expresses concern that the planning extension of R2.2.1 could lead to a scenario where a single members long term project (beyond 10 years) could then require all neighboring members to extend their own planning horizons (similar to a lowest common denominator issue) and face unnecessary technical issues.
Response: Part 2.2.1 has been revised because extending the Planning Horizon beyond 10 years for projects with lead time longer than 10 years is already covered in the definition of Long-Term Transmission Planning Horizon. This allowance is needed to provide planning flexibility, and is at the discretion of the Planning Coordinator or Transmission Planner. For example, if the System is found not to meet performance standard in year 10, but the project to correct the loading cannot be placed in service for 12 years, then the Corrective Action Plan needs to identify the interim solutions before the project can be brought on line. If a neighboring Planning Coordinator or Transmission Planner extends their planning horizon beyond ten years, it may be prudent for the Planning Coordinator or Transmission Planner to similarly extend the associated planning horizon, but it is not necessary for compliance of this standard. Therefore, the Planning Coordinator or Transmission Planner can choose whether to extend the planning horizon beyond 10 years for its own planning area(s) for the purpose of compliance. **2.2.1** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.	
New York Independent System Operator	R2.1.2 - System off-peak is more likely a stability issue than a steady state issue. If system off-peak becomes a steady state issue, it can be mitigated through generation redispatch. Accordingly, it appears that this requirement is not necessary for steady state analysis R2.1.4 - With respect to spare equipment strategy, this requirement potentially imposes a requirement to plan for three events, which is overly severe. As previously stated in R1, the system model should be a model of the projected system, which would include a long term actual forced outage. If this requirement is not referring to actual outages, then it is suggesting an N-1-1-1 analysis, which is a requirement that would require significant additional work with little value added for reliability because such contingencies have a very low probability. Under R2.5 - Past Studies may be used to support the Planning Assessment if they meet the following requirements and the sub-requirement R2.5.2 states that for SS, SC, or stability analysis "the PRESENT (emphasis added) System model shall not include any material changes, such as, . The NYISO interprets this language to mean that past studies may be used to support planning assessments as long as there are no material changes to the LATEST PLANNING HORIZON system model. The Standards Drafting Team should clarify whether this interpretation is correct. The standard should further state whether, if there was a material change such as a 20 MW generator, the past study may be used if the impact of this small change is assessed. Finally, the regional entity should have a process to determine whether changes are material that is

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	similar to the NPCCs process for determining what level of annual transmission review should be conducted each year.

Response: Regarding comment on Part 2.1.2, NERC Standards require that Systems can operate reliably over all demand levels. If steady state problems under off-peak conditions needed to be corrected through re-dispatch and/or switching to reconfigure the System, then a Corrective Action Plan involving re-dispatch and switching will need to be developed to ensure that the plan can be implemented. Since a past study can be used to support a current Assessment in accordance with Part 2.5 (Part 2.6 in the new version), an off-peak study would not have to be performed every year.

In Part 2.1.4 (now Part 2.1.5) when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. Part 2.1.5 is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.5.2 (now 2.6.2) has been revised for clarity. The bullets under 2.5.2 have been removed from the revised standard.

> **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

Duke Energy	R2 Instead of document results the requirement should be to summarize results. While results will be documented, the Planning Assessment should just include a summary. R2.1 What's the value in being able to use qualified past studies if you have to use annual current studies? Strike the words supplemented with and insert the word or. R2.5.2 Suggest deleting the phrase Material generation changes could include: and the two accompanying bullets. A change of 20 MW on a large system may not always be material. R2.8 and R2.9 should be deleted. We don't see a reliability-related need for these requirements. In the sub-requirements of 2.1.3 and 2.4.3, the use of the word timing is unclear. Consider using in service date or schedule for. R2.4.1: It is not clear how much Load a dynamic model must have. Likely, it must still be proven that the analysis software can accommodate every load in the model having a load model that includes induction motor models. To help address this, revise Load to be Load that could impact the study area is acceptable.

Response: Requirement R2 has been revised to provide greater clarity and the word, "summarize" was added in support of your suggestion.

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	R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. In Part 2.1 it is envisioned that not all parts of the studies, on which the Assessment is to be based, can rely on past studies. For example, a study on year five performed during the past year may not be representative of year five in the current year. A past study can still be used if it can be demonstrated that the requirements for use of past studies are met. No change made. 2.5.2 – Both bullets under 2.5.2 have been deleted as suggested Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees with the majority of the commenters that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1. Parts 2.1.3 (now Part 2.1.4) and 2.4.3 have been revised. **2.1.4** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Real and reactive forecasted Load. • Expected transfers. • Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. • Controllable Loads and Demand Side Management. • Duration or timing of planned Transmission outages. **2.4.3** For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Load level, Load forecast, or dynamic model assumptions. • Expected transfers. • Expected in service dates of new or modified Facilities.

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	• Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. Part 2.4.1 has been revised to reflect your suggestion. **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.
Tucson Electric Power Company	Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). In R2.1, we believe the reference for past studies should be Requirement R2.5 not Requirement R2.6. Also, we suggest removing the phrase supplemented with and replacing it with the word or. This phrase indicates that previous studies cannot be a primary source for the assessment, which contradicts section 2.5.Remove the phrase not already included in the studies in R2.1.3. With this phrase included, you cannot use a previous sensitivity study to support the current assessment and Requirement R2.5 allows the use of previous studies if the conditions are met. Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement.Remove the phrase "not already included in the studies" in R2.4.3. With this phrase included, you cannot use a previous sensitivity study to support the current assessment and Requirement R2.5 allows the use of previous studies if the conditions are met. The 20 MW threshold identified as "material change" for generation in R2.5 is too small. The limit should be raised or based on a percentage of the study area'sinstalled generating capacity. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the "largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event" if it is documented? R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.
Response: Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt. Even though the effects of short circuit capability is localized and may be related to new	

Organization	Question 2 Comment
planned Facilities, it is important to BES reliability. Part 2.3 has been revised to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. Part 2.1 requires certain current studies be conducted each year for the Near-Term steady state assessment, which can be supplemented with past studies. The SDT disagrees that the statements are contradictory. No change made. Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.6 (now Part 2.7) has been revised for clarity. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: The material change wording has been deleted from the requirement. . Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Independent Electricity System Operator	1. We think "conduct and document" is more appropriate than "prepare". Suggest to make this change. 2. We understand the reason for introducing the spare equipment strategy in R2.1.4 is to address comments raised on planned and long-term outages. However, this is not the only cause of unavailability of major Transmission equipment for more than 12 months. Construction or line upgrade program may also require certain transmission facilities be taken out of service for a protracted period. We suggest that R2.1.4 be revised to "When an entity's spare equipment strategy or transmission project construction plan could result in the unavailability of".. 3. When would PCs and TPs be expected to perform the analysis referred to in R2.1.4 ? in anticipation of the possibility of unavailability of major transmission equipment of after such unavailability has occurred or is planned?

Organization	Question 2 Comment
	4. R2.3: The first sentence is unclear and the wording can be supported is misleading. We suggest the first sentence be revised to: The short circuit analysis portion of the Planning Assessment addressing the Near-Term Transmission Planning Horizon shall be conducted annually and be supported by current or past studies. Alternatively, language similar to R2.4 may be considered: "The Near-Term Transmission Planning Horizon portion of the short circuit analysis shall be assessed annually and be supported by current or past studies. 5. R2.4 stipulates the details of the study for Near-Term Transmission Planning horizon for the stability analysis. Unlike its steady state analysis counterpart, there is no requirement stipulated for the Long-Term Transmission Planning horizon for the stability analysis. Is this intentional, or do the same conditions apply to the Long-Term stability analysis" 6. R2.6: Suggest to change in the tables to Table 1 at the end of the second sentence. 7. We agree with the VRFs, Mitigation Horizons and Measures. We also agree with the VSLs except R2.5 is not included. However, If R2.5 is meant to be explanatory (to illustrate the conditions under which past studies may be used), then the conditions should be provided in those requirements (e.g. R2.3) that allow for the use of past studies. If, however, these conditions are meant to be requirements, then their VSLs should be developed.

Response: The SDT does not see the proposed language as an improvement. No change made.

In Part 2.1.4 (now Part 2.1.5) when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. Part 2.1.5 is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of equipment will be replaced. If not, its impact of unavailability would need to be assessed. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.3 has been revised to provide greater clarity.

> **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

The SDT added Part 2.5 to address your concern.

> **2.5** The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported by current or past studies.

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Part 2.6 (now Part 2.7) has been changed as suggested. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: The Lower VSL has been revised accordingly. R2, Lower VSL: The responsible entity failed to comply with Requirement R2, part 2.9 or Requirement R2, part 2.6.	
Kansas City Power & Light	R2.1.3 is this indicating that only one of the variations need to be studied? (in one or more of the following conditions). Recommend having the planner work with the load to determine what sensitivity studies to perform. R2.1.4 it is unclear as to what should be done with the analysis that incorporates the company's spare equipment strategy. Is this requirement inferring that a company's spare equipment strategy need to ensure that it can still operate to within the requirements for contingencies of Table 1 without the component? R2.2.1 ? is the intent to have the study for the 10 year horizon or to include any project that is started within the next 10 years and thus the study must be extended to the forecasted completion of the project (conceivably as long as 20 years or more?) R2.5.2 - Remove the word intervening and this requirement must be more specific about what this requirement is trying to communicate and acccomplish. R2.6.4 recommend clarifying how situations beyond the control of the TP or PC are determined. It is unclear if this is to imply that if something is outside of the control of the department who conducts the planning studies or if it is outside the control of the registered function's legal entity (i.e. corporation). R2.8 appears to be nonessential information for reliability; for what purpose does this requirement exist? R2.9 - appears to be nonessential information for reliability; for what purpose does this requirement exist?
Response: Part 2.1.3 (now Part 2.1.4) is intended for the Planning Coordinator or the Transmission Planner to investigate at least one of the conditions listed. Part 2.1.3 has been revised to provide greater clarity. It is expected that there will be coordination between the Planning Coordinator, the Transmission Planner and the other impacted Functional Entities. **2.1.4** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Real and reactive forecasted Load.	

Organization	Question 2 Comment
	• Expected transfers. • Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. • Controllable Loads and Demand Side Management. • Duration or timing of planned Transmission outages. In Part 2.1.4 (now Part 2.1.5) when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will apply. Part 2.1.5 is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of equipment will be replaced. If not, its impact of unavailability would need to be assessed. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.2.1 has been revised because extending the Planning Horizon beyond 10 years for projects with lead time longer than 10 years is already covered in the definition of Long-Term Transmission Planning Horizon. This allowance is needed to provide planning flexibility, and is at the discretion of the Planning Coordinator or Transmission Planner. For example, if the System is found not to meet performance standard in year 10, but the project to correct the loading cannot be placed in service for 12 years, then the Corrective Action Plan needs to identify the interim solutions before the project can be brought on line. **2.2.1** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected. Part 2.5.2 has been revised and included as Part 2.6.2 in the new version to provide greater clarity. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Part 2.6.4 (now 2.7.5) does not prejudge the acceptability of the situation outside the control of the Planning Coordinator or Transmission Planner, which has prevented the implementation of the Corrective Action Plan, provided that the Planning Coordinator or Transmission Planner documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service. Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning

Organization	Question 2 Comment
Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
ReliabilityFirst Corporation	R2- Suggest changing annual Planning Assessment to "annual Planning Assessment Report". Requires short circuit analysis, at present NERC wide common data base for conducting short circuit analysis, does not exist. Short circuit analysis is only performed when there are major system changes and their impact is local. R2.1.1 requires either Year One or year two, and year five. NERC members utilize Models developed by MMWG for the assessment study needs and they are usually lag by one year. R2.1.3 -Suggest changing last bullet to read "Transmission lines, Transformers, Generating unit and Reactive sources that are scheduled for extended outages during the study period should not be included in the Assessment Model." R2.4.1- The requirements in the two sentences seem to contradict each other. R2.4.2 – This does not mention modeling dynamic behavior of loads. R2.5.2 – "could include" is weak and may not be enforceable. Suggest removing all the text after the first paragraph. Does this require any additional studies to demonstrate that the changes do not impact previous conclusions? R2.7 – Short Circuit analysis should not be a part of Performance Requirements". These should be included in "PRC" Standards
Response: Requirement R2 has been revised. **R2.** Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. Part 2.1.1 is intended to require studies for System Peak Load Conditions for 2 of the years in the near-term planning horizon: (1) A year five case to identify potential problem that can be addressed if the planned projects proceed as scheduled; (2) A Year One or year two case to identify any potential problems unanticipated in the five-year case, which if not addressed, could impact operations as time progresses. The standard provides flexibility for the Planning Coordinator or Transmission Planner to use past studies to support the current year assessment, and to assess other years in addition to those identified in Part 2.1.1. Therefore, if the models developed by MMWG lag by one year, it can qualify as a valid past study. Planned outages of generation and Transmission Facilities are included in Part 1.1.1 (included as Part 1.1.2 in the new version). Transmission Facilities covers lines, reactive devices, and other substation equipment. Part 2.1.3 (now Part 2.1.4) is intended to cover sensitivity studies on "what if" scenarios. Part 2.1.4 has been revised to provide greater clarity. **2.1.4** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.	

Organization	Question 2 Comment
	• Real and reactive forecasted Load. • Expected transfers. • Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. • Controllable Loads and Demand Side Management. • Duration or timing of planned Transmission outages. Part 2.4.1 is intended to allow the use of aggregated system Load models if more accurate Load models are not available. Therefore, the second and third sentences are not in conflict. In Part 2.4.1 the SDT specifies the dynamic Load model representation for on peak because the System voltages are generally lower during on peak. The percentage of motor Load, e.g., in air conditioners, could significantly increase reactive power requirements especially when they stall due to low System voltage and can therefore impact dynamic System performance on-peak. However, motor Load would likely not pose the same problem during off-peak as the System voltages are usually higher. So, in Part 2.4.2, it can be left to the discretion of the Planning Coordinator or Transmission Planner whether the dynamic motor Load would need to be represented per the requirement in Part 2.4.1, Part 2.5.2 has been revised and included as Part 2.6.2 in the new version to provide greater clarity. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Part 2.7 is intent to require a Corrective Action Plan if the short circuit duty requirement exceeds the current interrupting duty of the circuit breaker. No change made.

3. Requirement R3 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: Minor wording changes were made to Requirement R3 to clarify that this requirement pertains to the requirements of the studies needed to support the Planning Assessment. Several industry commenters wanted confirmation that Requirement R3 applied to both the Planning Coordinator and the Transmission Planner feeling that the requirement could result in duplication of effort. The SDT directed the commenters to Requirement R6 (now Requirement R7), which provides a mechanism for determining individual and joint responsibilities for performing the required studies for the Planning Assessment. Several clarifying changes were made to the wording of the parts under Requirement R3 to address industry comments.

R3 For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1.

R3.1 Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4.

R3.2 Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, part 3.5.

R3.3 Contingency analyses shall be performed and:

R3.3.2 Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

R3.3.3 Ensure relay loadability limits are respected.

R3.3.4 Simulate the expected automatic operation of existing and planned devices designed to provide Steady State control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

R3.4 Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

R3.4.1 The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

R3.5 Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R3, moderate VSL: The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.

Organization	Question 3 Comment
Northeast Power Coordinating Council	R3.3.2 Traditionally transmission planners have used their judgment about the minimum steady state voltage limitations of generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R3.3.3 " PRC-023 requires relay loadability to be reflected in facility ratings. Therefore this additional requirement is unnecessary and should be deleted. R3.5 ? We recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following:- Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events- It should be clear that an evaluation does not require solution development for all Extreme Events- Change "an evaluation of possible actions" to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered. For Requirements R3.4 and R3.5, what defines "more severe System impacts"?
Response: R3.3.2: The SDT agrees that judgment is used today. There is a project (PRC-024) that will address this issue. The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure that they are being treated within the simulation as they will react in the real world. No change made for this comment. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections. **R3.3.3** Ensure relay loadability limits are respected. R3.5: The SDT disagrees that the standard should mandate corrective actions for extreme events due to the low probability of these events. However, the SDT believes that those extreme events that are expected to produce more serve System impacts should be analyzed to assess the extent of the impacts on the System to provide the Planning Coordinator/Transmission Planner with information to decide, where appropriate, if it is reasonable to provide some corrective actions to reduce the possibility or limit the consequences of an extreme event. The need to identify possible actions addresses an Order 693 directive. Your suggested wording would make identification of possible actions optional. No change made. R3.4 & R3.5: Requirement R3, parts 3.4 and 3.5 require the Planning Coordinator/Transmission Planner to prepare a list of planning event and extreme event Contingencies that, in the Planning Coordinator's and Transmission Planner's judgment, are expected to produce more severe System impacts, and to document the reasons for the Contingencies selected. The documented rationale provided by the Planning Coordinator/Transmission Planner will define what is considered to be the more severe System impacts.	
Transmission Planning	R3.3.1. COMMENT: This would make sense for 3-terminal lines which we are including in contingency files, but for normal 2-terminal lines, very unnecessary. Suggested language at the end would say "Simulation of individual element outages is allowed if it produces an effect more severe that the entire circuit outage". This implies that by modeling individual branch outages would represent more severe conditions than entire circuit outages due to the fact that there would be consequential load loss. R3.4. COMMENT: Table 1 as drafted is very confusing and could be interpreted incorrectly. Recommend revising the header for "Table 1 " Steady State & Stability Performance Extreme Events" Should be changed to "Table 2 - Steady State & Stability Performance Extreme Events" because the expected performance requirements associated with Planning Events could be

Organization	Question 3 Comment
	interpreted to be applicable to Extreme Events as well. Alternatively, the performance requirements at the top of Table 1 need to include a statement that they are applicable to Planning Events only.
Response: R3.3.1: The SDT disagrees with the comment as the intent of Requirement R3, part 3.3.1, consistent with FERC Order 693, is to perform the simulation to reflect how the Protection System will operate in the real System for each Contingency without operator intervention. The requirement does not preclude the Planning Coordinator/Transmission Planner from studying individual elements or other maintenance scenarios. Planning event P2-1 addresses an element outage configuration. Please also see footnote 8. No change made. R3.4: The SDT feels that the table headings are sufficiently clear as stated. No change made.	
SERC Engineering Committee Planning Standards Subcommittee	R3.1:In Requirement R3.1, it is suggested that the word "contingency" be added to describe the lists created in R3.4.: "Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists created in Requirement R3.4. R3.3.1: Recommend that it be clarified that simulation of the more conservative case of a single branch (bus-to-bus) outage is acceptable, as opposed to always simulating the full breaker-to-breaker outage. R3.3.2The requirement needs to be clarified. It is not clear if it is referring to the ability of plants to meet their voltage schedule, or to their ability to stay connected during post contingencies. R3.3.4:In Requirement R3.3.4, it is suggested adding the words "and switched" to capacitors and reactors:"Simulate the expected operation of existing and planned devices designed to provide Steady State control of electrical system quantities. These devices include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.
Response: R3.1: The SDT agrees and has modified Requirement R3, part 3.1 accordingly **R3.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4. R3.3.1: The SDT disagrees with the comment as the intent of Requirement R3, part 3.3.1, consistent with FERC Order 693, is to perform the simulation to reflect how the Protection System will operate in the real System for each Contingency without operator intervention. The requirement does not preclude the Planning Coordinator/Transmission Planner from studying individual elements or other maintenance scenarios. Planning event P2-1 addresses a branch outage configuration. Please also see footnote 8 (now footnote7). No change made. R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.4: The SDT agrees and has revised the wording. **R3.3.4** Simulate the expected automatic operation of existing and planned devices designed to provide Steady State control of electrical system quantities	

Organization	Question 3 Comment
when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.	
Modesto Irrigation District	On page 10 under Section R3.3.3, I believe more specifics on what is meant by "relay loadability" need to be given in regard to the requirement of "identify how loadability is analyzed in the steady state simulation". For example, does the analyst need to state that the maximum loading allowed on any system element is less than or equal to 150% of the element's maximum seasonal rating ? We believe that R3.3.1-R3.3.4 should be bullets under R3.3
Response: R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits, as defined in the relay loadability standard, are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected. R3.3.1-R3.3.4: The SDT disagrees as these are mandatory requirements of the Contingency analyses. Bullets are only used to identify the possible, but not all inclusive, elements of a menu. No change made.	
OPUC	3. Requirement R3 ? Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.Comments:A: R3.3 should be modified to become the requirement to conduct contingency analyses with R3.3.1 thru 4 presented as bullets there-under.
Response: R3.3.1-R3.3.4: The SDT disagrees as these are mandatory requirements of the Contingency analyses. Bullets are only used to identify the possible, but not all inclusive, elements of a menu. No change made.	
Bonneville Power Administration	R3.1 should be clarified. Suggested clarification: R3.1 - "Studies shall be performed to determine whether the BES meets the performance requirements in Table 1. A reduced set of contingencies can be simulated based on a list created in requirement R3.4." As currently drafted, R3.3 is not a requirement. Without the statements in R3.3.1-R3.3.4, R3.3 is simply a phrase. Sub-Sub-Requirements R3.3.1 through R3.3.4 should be bullets under R3.3, with the language in R3.3 modified so that it becomes the requirement to conduct contingency analyses that address the four resulting bullets R3.3.2 is unclear as drafted. The minimum steady state voltage limitation for synchronous generators is not a very meaningful value. All generators with an automatic voltage regulator will maintain the set point voltage until the VAR capability of the generator is exceeded, and then the voltage will deteriorate. Requirement R3.4 also needs to be clarified as follows: R3.4 - "A reduced list of Contingencies can be developed for System Performance evaluation in Requirement R3.1 that includes those Planning Event Contingencies that are expected to produce more severe System impacts based on system performance as required in Table 1. "The Statement at the end of R3.4 and R4.4 says "rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an

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	explanation of why the remaining Contingencies would exhibit better system performance." The statement does not make sense and should be deleted since the contingencies selected are those to produce more sever system performance. R3.5 ? We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingencies than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.

Response: R3.1: The SDT agrees and has modified the requirement.

> **R3.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4.

R3.3:The SDT has modified the wording to provide greater clarity. The SDT disagrees that Requirement R3 parts 3.3.1- 3.3.4 should be bullets as these are mandatory parts of the required contingency analyses. Bullets are only used to identify the possible but not all inclusive elements of a menu. No change made.

> **R3.3** Contingency analyses shall be performed and:

R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world.

> **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

R3.4: The SDT has made a revision to the posted wording of the requirement to add clarity and address your comment.

> **R3.4** Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

R3.4 & R4.4: Several industry commenters have indicated that an explanation of “why the remaining Contingencies would produce less severe System performance” should be deleted since the Contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an “explanation of why the remaining Contingencies would produce less severe System results”.

R3.5: Several industry commenters have indicated that an explanation of “why the remaining Contingencies would produce less severe System performance” should be deleted since the contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an “explanation of why the remaining Contingencies would produce less severe System results”.

> **R3.5** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible

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actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.	
MRO MRO NERC Standards Review Subcommittee	MRO NSRS proposes the following comments for R3.Revise the R3.3.2 text to clarify that subsequent analysis is performed on generators whose voltages are expected to fall below the minimum voltage limits. MRO NSRS suggests this text: "Consider the minimum steady state voltage limitations of all generators and identify how generators with bus voltages below its minimum voltage limits are analyzed in the subsequent steady state simulations. Revise the R3.3.3 text to more clearly relate to the specific requirements in PRC-023. MRO NSRS suggests this text: "Incorporate relay loadability per PRC-023 and identify how relay loadability is analyzed in the steady state simulation.
Response: R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement. **R3.3.3** Ensure relay loadability limits are respected.	
SERC Engineering Committee Dynamics Review Subcommittee (DRS)	R3.3.3 applies to "all Transmission lines. Should this only apply to lines above 230 kV and lines identified as critical below 230 kV" At least this should be limited to BES lines. R3.3.4 says "Simulate the expected operation of existing and planned devices designed to provide Steady State control of electrical system quantities. This should say, "Simulate the expected operation of existing and planned BES devices designed to provide Steady State control of BES electrical system quantities.
Response: R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits, as defined in the relay loadability standard, are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected. R3.3.4: The SDT disagrees as this standard only applies to the BES. No change made.	
SERC Engineering Committee Reliability Review Subcommittee (RRS)	In R3, should the "and" in the first sentence actually be "or"? especially for same footprint? Perhaps the "and" should be replaced by "and/or". Can the PC satisfy this requirement by reviewing studies performed by differing TPs or is separate analysis really required especially when the TP and PC have the same footprint"? In Requirement R3.1, it is suggested that the word "contingency" be added to describe the lists created in R3.4. R3.3.1. Recommend that it be clarified that simulation of the more conservative case of a single branch (bus-to-bus) outage is acceptable, as opposed to always simulating the full breaker-to-breaker outage. R3.3.2The requirement needs to be clarified. It is not clear if it is referring to the ability of plants to meet their voltage schedule, or

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	to their ability to stay connected during post contingencies. Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists created in Requirement R3.4. "R3.3.2"For all generators, studies shall consider the minimum steady state voltage limitations and identify how the generators are analyzed in the steady state simulation. The above wording needs to be changed, as the intent of this sentence is unclear. Is the intent that Transmission Planners need to ensure that generating plants can meet their voltage schedule under Base Case (N-0) conditions? Is this the same as the generator underexcited operation limit?? In R3.3.2, need guidance on how to consider minimum steady state voltage limitations. Is there a NERC team addressing this" R3.3.3"For all Transmission lines, studies shall consider relay loadability and identify how loadability is analyzed in the steady state simulation. The above wording needs to be changed, as the intent of this sentence is unclear. Is the intent that Transmission Planners need to ensure that relay loading limits are included in the facility ratings? Is this the 130% of conductor rating limit?? Revise M3 to include a reference to R6, since the allocation of responsibilities will directly affect the evidence which is to be provided. In the VSL for R3, a severe VSL is listed as failing to meet performance requirement for P0 or P1. We do not understand why a severe VSL would be applied to an all ties closed event which should have little if any problems. We believe that this should be a lower or moderate VSL instead of severe. In R3.3.3 is the relay loadability required for all HV and EHV voltage levels? Previously NERC had required this for 230-kV and above only. This would be massive requirement for our Transmission Lines between 100 and 200-kV. Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists created in Requirement R3.4. ? In Requirement R3.3.4, it is suggested adding the words "and switched" to capacitors and reactors: Simulate the expected operation of existing and planned devices designed to provide Steady State control of electrical system quantities. These devices include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

Response: R3: The SDT believes that the requirement belongs to both the Planning Coordinator and the Transmission Planner. Requirement R7 provides a mechanism for determining individual and joint responsibilities for performing the required studies for the Planning Assessment regardless of whether the Planning Coordinator and Transmission Planner footprints overlap or not. No change made.

R3.1. The SDT agrees and has modified the requirement.

> **R3.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4.

R3.3.1: The SDT disagrees with the comment as the intent of Requirement R3, part 3.3.1, consistent with FERC Order 693, is to perform the simulation to reflect how the Protection System will operate in the real System for each Contingency without operator intervention. The requirement does not preclude the Planning Coordinator/Transmission Planner from studying individual elements or other maintenance scenarios. Planning event P2-1 addresses a branch outage configuration. Please also see footnote 8 (now footnote 7). No change made.

R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage

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limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. There is a project (PRC-024) that will address this issue of minimum steady state voltage limitations. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits, as defined in the relay loadability standard, are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected. M3: The SDT disagrees. Requirement R6 (now Requirement R7) is an overarching requirement that applies to the entire set of analysis required to meet the requirements of the TPL standard and to the Corrective Action Plan developed as part of the assessment. The intent of this requirement is to clarify that TPL requirements can be met through joint or shared analysis. Coordinating and/or joint analysis does not alleviate the responsibility that all entities need to comply with the standard requirements. Therefore, the SDT sees no reason to link Requirement R3 directly to Requirement R6 (now Requirement R7) in the measure or anywhere else. The requirements stand by themselves and do not require such a linkage. No change made. VSL: The SDT disagrees with your assessment. The failure to perform studies to determine the BES meets performance requirement for the P0 and P1 categories is deemed to be severe as these categories represent steady state (no Contingency) and single Contingency (probable) operation and are significant elements of the overall requirement. No change made. R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits, as defined in the relay loadability standard, are respected in the analysis. R3.3.4: The SDT agrees and has revised the wording. **R3.3.4** Simulate the expected automatic operation of existing and planned devices designed to provide Steady State control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.	
FirstEnergy Corp	Specific comments, Requirements of R3:A. R3: For readability revise "computer simulations using models utilizing data" to "computer simulation models utilizing data" B. R3.3.2: The intent of this requirement is not clear. What is the voltage limitation sought? Vmin at the generator terminals, high-side of the GSU, low-side GSU, etc. Also the requirement text "identify how the generators are analyzed in the steady state simulation" does not drive a particular reliability goal. If the objective is to require tripping of units during a contingency simulation that are identified to be below their stated Vmin then the requirement should clearly state that the unit should be tripped and solution resolved. C. R3.3.3: This requirement should be removed as it is redundant with facility rating requirements stated in PRC-023, FAC-008 and FAC-009. D. R3.3.4: For readability we suggest inserting the word "may" in between "devices include".We agree with the stated Measures, VRF, Time-Horizon, Data Retention and VSL of requirement R3
Response: R3: The SDT has revised the wording accordingly.	

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	R3 For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections **R3.3.3** Ensure relay loadability limits are respected. R3.3.4: The STD has added the word "may" in between "devices include". **R3.3.4** Simulate the expected automatic operation of existing and planned devices designed to provide Steady State control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors. Measures, VRF, Time Horizon, Data Retention and VSLs: Thank you for your comment.
TVA System Planning	In R3.3.2, need guidance on how to consider minimum steady state voltage limitations. Is there a NERC team addressing this? It is not clear if it is referring to the ability of plants to meet their voltage schedule, or to their ability to stay connected during post contingencies. In R3, should the "and" in the first sentence actually be "or"? especially for same footprint? Perhaps the "and" should be replaced by "and/or". Can the PC satisfy this requirement by reviewing studies performed by differing TPs or is separate analysis really required especially when the TP and PC have the same footprint? In the VSL for R3, a severe VSL is listed as failing to meet performance requirement for P0 or P1. We do not understand why a severe VSL would be applied to an all ties closed event which should have little if any problems. We believe that this should be a lower or moderate VSL instead of severe. In R3.3.3 is the relay loadability required for all HV and EHV voltage levels? Previously NERC had required this for 230-kV and above only. This would be massive requirement for our TLs between 100 and 200-kV.
Response: R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. There is a project (PRC-024) that will address this issue. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through	

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voltage limitations. Include in the assessment any assumptions made. R3: The SDT believes that the requirement belongs to both the Planning Coordinator and the Transmission Planner regardless of whether the Planning Coordinator and Transmission Planner footprints overlap or not. No change made. VSL: The SDT disagrees with your assessment. The failure to perform studies to determine the BES meets performance requirement for the P0 and P1 categories is deemed to be severe as these categories represent steady state (no Contingency) and single Contingency (probable) operation and are significant elements of the overall requirement. No change made. R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits, as defined in the relay loadability standard, are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected.	
Exelon Transmission Planning	In R3.3.2 it should be clear that the TP / TO is not required to provide whatever voltage that the unit desires and that the intent of this requirement is to ensure that if a generator is going to trip due to low voltage that the simulation will include the generator tripping. 3.3.2 and 3.3.3. are somewhat redundant with 3.3.1 " suggest rewording 3.3.1 to say including transmission lines with respect to relay loadability and generators with respect to minimum operating voltage. If 3.3.3 is targeting the low voltage ride through capability of the wind generators it should be clear.
Response: R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and that they are being treated within the simulation as they will react in the real world (in your comment 3.3.3 referring to low voltage ride through, we assume in our response that you were referring to 3.3.2) **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.2 & R3.3.3: The SDT does not agree that Requirement R3 parts 3.3.1, 3.3.2 and 3.3.3 are somewhat redundant as they require distinctly different simulation actions. No change made. R3.3.3: This requirement is for all generators, not just wind. It is important for the planning models to accurately reflect how the System will actually perform.	
Southern Company	R3.3.3 applies to "all Transmission lines. To be consistent with the relay loadability standard, this should only apply to lines above 230 kV and lines between 100 kV and 230 kV identified as critical. R3.2 and R3.5 are both addressing the Extreme Events. However, R3.2 is referring to R3.5 while R3.5 is referring to R3.2. We suggest deleting the reference back to R3.2 which is in R3.5. A similar situation exists for R3.1 and R3.4. R3 seems to use the words studies and analyses interchangeably. Did the SDT intend for them to be the same? Using one term or the other would be better understood.

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	There are two tables labeled table 1. It would be much clearer to mark them table 1 Planning Events and table 2 Extreme Events.
Response: R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected. R3.1 & R3.4 and R3.2 & R3.5: The SDT has decided to retain the back references for clarity. No change made. R3: The SDT agrees that use of studies and analyses can be confusing. The wording in Requirement R3 has been revised to use studies. **R3** For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. Table 1: Based on Industry feedback, the SDT has decided to have one Table and believes that the headings are sufficiently clear to distinguish between planning and extreme events. No change made.	
United Illuminating	R3.3.2 Comment Traditionally transmission planners have used their judgment about the minimum steady state voltage limitations of generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R3.3.3 Comment ? PRC-023 requires relay loadability to be reflected in facility ratings. Therefore this additional requirement is unnecessary and should be deleted. R3.5 Priority Comment ?We recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following:- Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events- It should be clear that an evaluation does not require solution development for all Extreme Events- Change “an evaluation of possible actions”? to “where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered.
Response: R3.3.2: The SDT agrees that judgment is used today. There is a project (PRC-024) that will address this issue. The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections. **R3.3.3** Ensure relay loadability limits are respected. R3.5: The SDT disagrees that the standard should mandate corrective actions for extreme events due to the low probability of these events. However, SDT believes that those extreme events that are expected to produce more serve System impacts should be analyzed to assess the extent of the impacts on the System to provide the Planning Coordinator/Transmission Planner with information to decide, where appropriate, if it is reasonable to provide some corrective actions to reduce the	

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possibility or limit the consequences of an extreme event. The need to identify possible actions addresses an Order 693 directive. Your suggested wording would make identification of possible actions optional. No change made.	
System Protection and Transmission Planning Department	R3 appears to require redundant studies by TP and PC.If the TP and PC participate in the same studies, would this meet the intent of this requirement? This would include studies that are RRO sponsored, or performed by sub-regional planning groups.
Response: R3: The SDT believes that the requirement belongs to both the Planning Coordinator and the Transmission Planner. Requirement R7 (formerly Requirement R6) provides a mechanism for determining individual and joint responsibilities for performing the required studies for the Planning Assessment regardless of whether the PC and TP footprints overlap or not. No change made.	
PPL Energy Plus	It appears there is a 24 month grace period to allow modeling updates to meet R 3.3.1. This is a good idea since the powerflow computer models may not include the required data and will need to be updated.
Response: Thank you for your comment.	
PacifiCorp Deseret Generation & Transmission SRP Arizona Public Service Co Southern California Edison Company Western Area Power Administration Pacific Gas and Electric Co, Puget Sound Energy, Inc. NV Energy San Diego Gas and Electric Co California ISO Tucson Electric Power Company	As currently drafted, R3.3 is not a requirement. Without the statements in R3.3.1-R3.3.4, R3.3 is simply a phrase. Sub-Sub-Requirements R3.3.1 through R3.3.4 should be bullets under R3.3, with the language in R3.3 modified so that it becomes the requirement to conduct contingency analyses that address the four resulting bullets R3.3.2 is unclear as drafted. The minimum steady state voltage limitation for synchronous generators is not a very meaningful value. All generators with an automotive voltage regulator will maintain the set point voltage until the VAR capability of the generator is exceeded, and then the voltage will deteriorate. R3.5 ? We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingencies than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.
NorthWestern Corporation NorthWestern Energy (NWE)	R3.3 is unclear. Requirements R3.3.1 through R3.3.4 should be bullets under R3.3, with R3.3 modified so that it becomes the

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(NWMT)	requirement to conduct contingency analyses that address the four resulting bullets R3.3.2 is unclear. The minimum steady state voltage limitation for synchronous generators is not a very meaningful value. All generators with an automatic voltage regulator will maintain the set point voltage until the VAR capability of the generator is exceeded, and then the voltage will deteriorate. In R3.3.3 the term "loadability" needs to be defined. R3.5 needs to be modified. It would be better to combine R3.2 with R3.5. The first part of the requirement requires identification of events that produce more severe System impacts. The presumed reason that the other contingencies were not selected is because they were deemed to be less severe or non-credible. In any case, theoretically, there can always be examples of more severe Extreme Contingencies than the one selected for study. This can be achieved by simply choosing events that are even less credible. For example, if the Extreme Contingency studied was a simultaneous loss of 3 transmission lines with the failure of a redundant RAS (SPS), then an event resulting in the simultaneous loss of 4 lines with the failure of 2 sets of redundant RASs would be even more severe. Listing all possible extreme events could result in a limitless list.
Response: R3.3: The SDT has modified the wording to provide greater clarity. The SDT disagrees that Requirement R3, parts 3.3.1- 3.3.4 should be bullets as these are mandatory requirements of the contingency analyses. Bullets are only used to identify the possible but not all inclusive elements of a menu. **R3.3** Contingency analyses shall be performed and: R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.5: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the Contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining Contingencies would produce less severe System results". **R3.5** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.	
Western Area Power Administration	R3.3.3 should be covered in the PRC Standards. While R3.3 is labeled as "Contingency analysis", R3.3.4 is related to Steady State control and therefore should not be within R3.3.
Response: R3.3.3**:** The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections. **R3.3.3** Ensure relay loadability limits are respected. R3.3.4: The SDT disagrees with your comment. The simulation of the expected operation of devices such as phase-shifting transformers, load tap changing transformers, etc., impacts the post-Contingency performance of the System. No change made.	

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Tampa Electric	Consider revising standard for clarity. Subrequirements are not clear as written. Consider moving subrequirements R3.3.1 - R3.3.4 under other requirements for clarification. R3.5 Including an explanation of why remaining contingencies would produce less severe system results could be a limitless effort. Listing all "possible" extreme events seems unrealistic.
Response: The SDT requires more information in order to respond to your request to clarify the standard and sub-requirements. Numerous clarifications have been made to the fourth posting due to specific industry comments. R3.3.1-R3.3.4: The SDT disagrees as these are mandatory requirements of the Contingency analyses. No change made. R3.5: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining contingencies would produce less severe System results". **R3.5** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.	
Florida Reliability Coordinating Council, Inc - Transmission Working Group	R3.3.1 & 3.3.4 " Consider adding language that the entity should not be held responsible for simulating "the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention? on neighboring systems, only on the entity's own system. Also, consider moving R3.3.1 and R3.3.4 under R3.1 as sub-requirements and require that the overall studies take into account the effect of protection systems and control devices in the performance of the BES and it's ability to meet the table 1 requirements. R3.3.1 ? This seems unnecessary for normal 2-terminal lines, consider adding language to the effect of: "Simulation of individual element outages is allowed if it produces an effect more severe than the entire circuit outage". R3.4 - Consider changing the header for table 1 - "Steady State & Stability Performance Extreme Events" to Table 2 - "Steady State & Stability Performance Events". As is, it could be interpreted that the expected performance requirements associated with Planning Events apply to Extreme Events also.
Response: R3.3.1 & R3.3.4: The SDT has determined that it is necessary for the Planning Coordinator and Transmission Planner to coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list created in Requirement R3, part 3.4. Consequently, "the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention" will also apply for the Contingencies on adjacent Systems. The fourth draft of the standard will include this change by adding Requirement R3, part 3.4.1. **R3.4.1** The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.	

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The SDT believes that Requirement R3, parts 3.3.1 and 3.3.4 are separate mandatory requirements and disagrees that they should be moved under Requirement R3, part 3.1. No change made. R3.3.1: The SDT disagrees with the comment as the intent of Requirement R3, part 3.3.1, consistent with FERC Order 693, is to perform the simulation to reflect how the Protection System will operate in the real System for each Contingency without operator intervention. The requirement does not preclude the Planning Coordinator/Transmission Planner from studying individual elements or other maintenance scenarios. Planning event P2-1 addresses an individual outage configuration. Please also see footnote 8. No change made. R3.4 Table 1: Based on Industry feedback, the SDT has decided to have one Table and believes that headings are sufficiently clear. No change made.	
FMPA	R3.1, The criteria in Table 1 do not allow load shedding following a single contingency (e.g., the old footnote "b" was removed). While we agree this ought to be the case for the EHV system, we believe that there are cases where for the HV system, which often acts more like a distribution system, the costs to meet this standard would be prohibitive and unfair to the consumers served by those utilities. For instance, the Florida Keys served by the Florida Keys Electric Coop (FKEC) and Keys Energy Services (KEYS) is connected to the mainland by two 138 kV lines down to Tavernier Key (about 1/3rd the distance from the mainland to Key West). Currently, the system is planned and operated under single contingency to allow non consequential load shedding automatically via Under-Voltage Load Shedding, and to meet thermal limits by manual load shedding, all load shed is in the Florida Keys following the single contingency with no impact to the Bulk Electric System. The standard, as written, would force one of two things: 1) the construction of a third line in this environmentally pristine area at a very high cost that might increase rates to customers in the Florida Keys by 20% for a level of reliability that much of the Keys would not even experience since 2/3rds of the Keys is fed by a radial line with consequential load loss; or 2) separate the two lines such that both are operated radially with resultant consequential load loss, compliant with the standards, but actually causing consumers to have a lower level of reliability. We propose to reinstate footnote "b" for the HV system, allowing non-consequential load loss for lower voltage system that have little to no impact on the Bulk Electric System and limit the elimination of non-consequential load loss to be applicable to only the EHV. Alternatively, but less appealing and more of an administrative challenge would be to establish a Regional Entity administered process for application for exception to this criteria. FERC's Order 693 at paragraph 1794 states that: "(t)he Commission also clarifies that an entity may seek a regional difference to the Reliability Standard from the ERO for case-specific circumstances". We interpret this as meaning the Regional Entity can allow exceptions under certain criteria such as a significant increase in costs to consumers with little discernable benefit as is the case with the Florida Keys. For R3.2, we are at a loss of how a hurricane event can be modeled, and why such an evaluation is needed. Albeit, many contingencies can occur during a hurricane event, it is not likely that multiple contingencies will happen within the same < 1 minute window it takes to go from transient stability conditions to steady state conditions, and then it is unlikely that multiple significant contingency events will occur within the 30 minutes it takes operators to adjust the system to prepare for the next contingency. Therefore, we do not understand the significance of modeling a hurricane event. In addition, a hurricane can have an infinite number of different scenarios and time-lines of contingencies and picking one or two would be a meaningless exercise since an actual hurricane will be completely different than what is modeled. At least an earthquake has a fault line that makes it relatively easier to identify which facilities might be affected, but a hurricane has an infinite number of possibilities. We suggest eliminating hurricanes from extreme events and model potential results of a hurricane, such as loss of a ROW, loss of a substation or plant, and loss of a major load center. R3.3, the list ought to consider contingencies on neighboring systems that could impact the TP's / PC's system (this comment

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	would not carry over to R4.3 since stability is more a protection system / clearing time issue). R3.3.1, the entity should not be held responsible for simulating "the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention" on neighboring systems, only on the Entity's own system. R3.4 and the first part of R3.5 ought to be combined, e.g., both require justification for why a limited set of worst case contingencies are studied for N-1, N-2 and extreme contingencies. The latter part of R3.5 concerning cascading outages for an extreme contingency should become the only requirement of R3.5 (there are currently two requirements embedded within R3.5).
Response: R3.1: To comply with Order 693, the SDT have decided to raise the performance requirements such that Non-Consequential Load loss should not be allowed for P1 events of Table 1. No change made. R3.2: Table 1 extreme events: Requirement R3, part 3.5 requires the Planning Coordinator/Transmission Planner to identify and compile a list of the extreme events that are expected to produce more severe System impacts, along with a rationale for selection of those Contingencies. The wide area extreme events such as item 3.iv are provided as examples and not meant to be a mandatory list of events to be simulated. No change made. R3.3: The SDT assumes that the comment "R3.3, the list ought to consider contingencies on neighboring systems that could impact the TP's / PC's system" actually refers to Requirement R3, part 3.4 where the Contingency list is created. The SDT agrees with your comment and has determined that it is necessary for the Planning Coordinator and Transmission Planner to coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list created in Requirement R3, part 3.4. The fourth draft of the standard will include this change by adding Requirement R3, part 3.4.1. The need to include Contingencies on adjacent Systems will also apply to Stability. **R3.4.1** The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. R3.3.1: The SDT has determined that it is necessary for the Planning Coordinator and Transmission Planner to coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list created in Requirement R3, part 3.4. Consequently, "the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention" will also apply for the Contingencies on adjacent Systems. The fourth draft of the standard will include this change. R3.4 & R3.5: The SDT does not agree that these requirements should be combined. Requirement R3, part 3.4 requires the development of a Contingency list of planning events, and Requirement R3, part 3.5 requires a Contingency list of extreme events - two separate requirements. The SDT agrees that both require that a rationale be provided for stating why the events selected are expected to produce the more severe System impacts. No change made. R3.5: The SDT disagrees and sees no reason to split these out as they would still be essentially the same requirement. No change made.	
CPS Energy	Requirement R3.3.2. needs clarification.
Response: R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through	

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	voltage limitations. Include in the assessment any assumptions made.
MidAmerican Energy Company	MidAmerican commends the SDT for it hard wok on this standard and specifically its R3.3.1 wording. MidAmerican has suggestions for the following parts of R3:" . " R3.3.2 " delete the words "For all generators" at the beginning. It is unnecessary in that later in the requirement it states specifically that the responsible entity is to "identify how the generators are analyzed in the steady state limitation". R3.3.3 " use a similar construction to R3.3.2 but delete the words "For all transmission lines". In other words, replace "For all Transmission lines, studies shall consider relay loadability and identify how loadability is analyzed in the steady state limitations. With "Studies shall consider relay loadability and identify how loadability for transmission lines is analyzed in the steady state simulations. " R3.4 and R3.5 " change "remaining Contingencies" to "remaining unselected Contingencies".
Response: Thank you for your comments. R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits, as defined in the relay loadability standard, are respected in the analysis **R3.3.3** Ensure relay loadability limits are respected.. R3.4 & R3.5: The SDT has revised Requirement R3, parts 3.4 and 3.5 by eliminating the requirement to provide the rationale for the unselected Contingencies. **R3.4** Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. **R3.5** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.	
Northeast Utilities	R3.3.2 Comment - Traditionally transmission planners have used their judgment about the minimum steady state voltage limitations of generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to inclusion of R3.3.2 as a requirement in this standard. R3.3.3 Comment - PRC-023 requires relay loadability to be reflected in facility ratings. Therefore this additional requirement is

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	unnecessary and should be deleted. R3.5 Priority Comment - We recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following:-Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events-It should be clear that an evaluation does not require solution development for all Extreme Events-Change "an evaluation of possible actions"? to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered.
ISO New England, Inc. Central Maine Power Company	R3.3.2 Comment - Traditionally transmission planners have used their judgment about the minimum steady state voltage limitations of generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R3.3.3 Comment - PRC-023 requires relay loadability to be reflected in facility ratings. Therefore this additional requirement is unnecessary and should be deleted. R3.5 Priority Comment -We recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following:- Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events- It should be clear that an evaluation does not require solution development for all Extreme Events- Change "an evaluation of possible actions"? to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered.
Response: R3.3.2: The SDT agrees that judgment is used today. There is a project (PRC-024) that will address this issue. The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections. **R3.3.3** Ensure relay loadability limits are respected. R3.5: extreme events: The SDT disagrees that the standard should mandate corrective actions for extreme events due to the low probability of these events. However, the SDT believes that those extreme events that are expected to produce more serve System impacts should be analyzed to assess the extent of the impacts on the System to provide the Planning Coordinator/Transmission Planner with information to decide, where appropriate, if it is reasonable to provide some corrective actions to reduce the possibility or limit the consequences of an extreme event. No change made.	
JEA	R3. Change wording from "The studies shall be based on computer simulations using models utilizing data provided in Requirement R1." to "The studies shall be based on computer simulations using models that are the best representation of the future planned system and its associated use as provided by Requirement R1. The studies shall detail the effects of all future

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	equipment connectivity and topology arrangements and their associated Protection system responses to Contingency events regardless of model details." R3.3.2. I assume the concern here is on voltage ride through of generators and generator auxillary equipment. Propose changing language from "For all generators..." to"Include analysis of how generator and generator auxillary equipment over and under voltage protection and ride through capability were considered for the post-contingency steady state bus voltage levels." R3.3.3. I assume the concern here is ensuring consideration is given to how system protection relays could respond to post-contingency circuit emergency loadings. Protection systems that could limit the emergency ratings of transmission circuits should be considered in the Facitility Rating standard and therefore not necessary to include in the TPL standard. However, if requirement does remain in the TPL standard, propose changing language from:"For all transmission lines..." to"Include analysis of how implemented relay protection systems and their potential automatic response prior to timely corrective actions are considered for the post-contingency steady state circuit loadings".
Response: The SDT has revised Requirements R1 and R3 to provide greater clarity to the SDT's intent. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions **R3** For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections. **R3.3.3** Ensure relay loadability limits are respected.	
SMUD	R3.5Listing all possible scenarios for studying extreme contingencies will result in a limitless list. Discretion should be given to the transmission planner on the selection of the contingencies without a requirement to list why other extreme contingencies have not been included. R3.3.2:When the word, 'consider' is used, it can be read as a guidance and not a requirement. The requirement is unclear.
Response: R3.5: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the Contingencies selected are those to produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining Contingencies would produce less severe System results".	

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R3.5 Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted. R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.	
Progress Energy Florida, Inc.	Concerning R3.3.1, PEF believes that, in virtually every conceivable scenario, contingency analyses show that analysis of individual elements will reveal overloading or undervoltages, whereas the same event modeled according to protection system design (i.e. simulating the event as the actual "breaker-to-breaker" operation would occur) may not. Analysis of individual elements is therefore a more conservative method for studying the BES. PEF is not opposed to analysis of entire circuit outages; PEF therefore suggests that in addition to the existing language of R3.3.1, an additional sentence be added as follows: "Simulation of the loss of individual elements is acceptable in lieu of simulating the loss of all elements in a protection zone if it produces greater overloads or lower voltages. This approach would allow for more efficient coordination with Transmission Operators as they schedule planned outages or make system adjustments in outage scenarios.
Response: R3.3.1: The SDT disagrees with the comment as the intent of Requirement R3, part 3.3.1, consistent with FERC Order 693, is to perform the simulation to reflect how the Protection System will operate in the real System for each Contingency without operator intervention. The requirement does not preclude the Planning Coordinator/Transmission Planner from studying individual elements or other scenarios. Planning event P2-1 addresses an individual element outage configuration. Please also see footnote 8 (now footnote 7). No change made.	
Xcel Energy	R3.3.3: Relay loadability has no bearing beyond the near term horizon. Loadability is not determined several years out. R3.5 " does this imply that mitigation plans must be implemented" If not, then this is highly subjective and the last sentence of this requirement should be deleted.
Response: R3.3.3: The SDT does not agree with your comment**.** No change made. R3.5: The SDT disagrees that the standard should mandate corrective actions for extreme events due to the low probability of these events. However, the SDT believes that those extreme events that are expected to produce more serve System impacts should be analyzed to assess the extent of the impacts on the System to provide the Planning Coordinator/Transmission Planner with information to decide, where appropriate, if it is reasonable to provide some corrective actions to reduce the possibility or limit the consequences of an extreme event. The need to identify possible actions addresses an Order 693 directive. No change made.	
Ameren	In Requirement R3.1, it is suggested that the word "contingency" be added to describe the lists created in R3.4. Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists created

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	in Requirement R3.4. R3.3.2 -For all generators, studies shall consider the minimum steady state voltage limitations and identify how the generators are analyzed in the steady state simulation. The above wording needs to be changed, as the intent of this sentence is unclear. It is not clear whether Transmission Planners need to ensure that generating plants can meet their voltage schedule under Base Case (N-0) conditions, or whether this would be the same as the generator underexcited operation limit. R3.3.3?For all Transmission lines, studies shall consider relay loadability and identify how loadability is analyzed in the steady state simulation. The above wording needs to be changed, as the intent of this sentence is unclear, whether the intent is that Transmission Planners ensure that relay loading limits are included in the facility ratings, or whether this reflect some rule of thumb, such as 130% of conductor rating. In Requirement R3.3.4, it is suggested adding the words "and switched" to capacitors and reactors: Simulate the expected operation of existing and planned devices designed to provide Steady State control of electrical system quantities. These devices include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.
Response: R3.1: The SDT agrees and has modified the requirement. **R3.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4. R3.3.2: The SDT has changed the wording to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits, as defined in the relay loadability standard, are respected in the analysis **R3.3.3** Ensure relay loadability limits are respected. R3.3.4: The SDT agrees and has revised the wording to read “and switched capacitors and inductors”. **R3.3.4** Simulate the expected automatic operation of existing and planned devices designed to provide Steady State control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.	
Manitoba Hydro	R3.1: The requirement text should be changed to read “studies shall be performed for Planning Events to determine whether the BES meets the performance requirements in Table 1 based on the contingency list of events created in Requirement R3.4. . R3.2: Requirement wording should be similar to R3.4 for consistency. R3.4 & R3.5: The selection of the contingency list is based on the knowledge of the PC/TP. How do you produce “an explanation

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	of why the remaining Contingencies would produce less severe System results. without proving this with a study? If the explanation is "that based on engineering judgment, the remaining contingencies would produce less severe system results" then the explanation is implied and not necessary. VSLs: Under the moderate to severe VSL, the performance requirements currently refer to P2 through P7. We believe this is a typo and should be P1 through P7.
Response: R3.1: The SDT agrees and has modified the requirement. **R3.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4. R3.2: The SDT has revised the requirement. **R3.2** Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, part 3.5. R3.4 & R3.5: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining Contingencies would produce less severe System results". **R3.4** Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. **R3.5** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted. VSL: The VSL matrix is correct. No change made.	
LCRA Transmission Services Corporation	In R3.3.4, what is meant by the term "electrical system quantities"? Quantities is typically an amount and its use here would indicate that a term such as parameters would be better suited.
Response: R3.3.4 Checking a few dictionary definitions: parameter: "an expression, a constant or variable whose value determines the specific form of the expression; one of an independent variable in a set of parametric equations; whereas quantity is defined as: an exact or specified amount or measure; that property by virtue of which is measurable; extent; measure, size, any amount. It appears that "quantities" is the better choice. No change made.	
National Grid	R3 Comment "Planning Assessment" and "shall perform analysis" are contradictory. R3 and its sub-requirements then reference study requirements. If this is an assessment, then the standard shouldn't be requiring a study.R3.1 Comment ? A. It is not clear what should be included in the list related to R3.4. Events P0 through P4 should include analysis of all BES facilities for which the Transmission Planner is responsible. Events P5 and higher should be limited to contingency events

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	that are deemed the most significant by the Transmission Planner. B. R3.1 refers to “lists”. Is R3.4 creating one list or multiple lists” Suggest changing “lists” to “list” R3.2 Comment - Since R3.4 and R3.5 both require the responsible entity to create a list, the words in R3.2 be should be revised to be more similar to the words in R3.1. Suggest changing “Studies shall be performed to assess the impact of the Extreme Events identified in Requirement R3.5. to “Studies shall be performed to assess the impact of the Extreme Events, which are identified by the list created in Requirement R3.5. R3.3.2 Comment “ A. Traditionally transmission planners have used their judgment about the minimum steady state voltage limitations of generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. B. Voltage limitations are for both minimum and maximum. If this requirement is kept, then “minimum” should be deleted. C. Is this requirement really looking at “voltage limits” or generator “reactive capability”? R3.3.3 - This requirement should be deleted. Each reliability issue should be addressed in one standard and relay loadability is addressed in PRC-023. If requirements of PRC-023 are met, the relay loadability does not constitute a limitation. If this requirement is intended to apply to modeling relay characteristics in stability simulations, which is not addressed by PRC-023, then the requirement should be more explicit. However, as written it appears that the intent was to be in-line with Blackout Recommendation 8a which relates to steady-state loadability, which is covered by PRC-023. R3.4 Comment - Table 1 includes both Steady State and Stability events. R3.4 needs to indicate that it only applies to the Steady State portion of the Table. R3.5 Priority Comment ?It is recommended that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences and the requirements are too vague to have auditable value. If the requirement is not deleted, the following is recommended:- Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events. If not, it will be difficult to utilize the results to obtain projects approvals.- It should be clear that an evaluation does not require solution development for all Extreme Events- Change “an evaluation of possible actions”? to “where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered. – The statement “and shall include an explanation of why the remaining Contingencies would produce less severe System results” is too open and should be deleted. Violation Severity Levels:R3.4 Since this is a binary requirement, should this have a Severe VSL? R3.5 Since this is a binary requirement, should this have a Severe VSL?
Response: R3: The SDT agrees that use of studies and analyses can be confusing and has changed the wording to provide greater clarity. **R3** For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, parts 2.1, and 2.2. The studies shall be based on computer simulation models using	

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	data provided in Requirement R1. R3.4: Requirement R3, part 3.4 has been revised to indicate that the Planning Coordinator/Transmission Planner is to produce a Contingency list, of those planning events that are expected to produce more severe results on its portion of the BES. The Planning Coordinator/Transmission Planner is required to identify the Contingency list to be studied and provide the rationale as to why these Contingencies are expected to produce more severe results. There is no requirement to include all BES facilities for P0 to P4. No change made. R3.1: The SDT has changed "lists" to "list". **R3.1** Studies shall be performed for Planning Events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4. R3.2: The SDT has revised the wording of the requirement. **R3.2** Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, part 3.5. R3.3.2: The SDT agrees that judgment is used today. There is a project (PRC-024) that will address this issue. The SDT has changed the wording to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and that they are being treated within the simulation as they will react in the real world. The word minimum was retained as the intent is to address low voltage ride through. No change made. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections. R3.4: Although Table 1 includes both steady state and stability events, Requirement R3 is "for the steady state portion of the Planning Assessment.."; so there is no need for adding further clarification in Requirement R3, part 3.4. No change made. R3.5: The SDT disagrees that the standard should mandate corrective actions for extreme events due to the low probability of these events. However, SDT believes that those extreme events that are expected to produce more serve System impacts should be analyzed to assess the extent of the impacts on the System to provide the PC/TP with information to decide, where appropriate, if it is reasonable to provide some corrective actions to reduce the possibility or limit the consequences of an extreme event. The need to identify possible actions addresses an Order 693 directive. Your suggested wording would make identification of possible actions optional. No change made. Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the Contingencies selected are those to produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining contingencies would produce less severe System results". **R3.4** Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. **R3.5** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed

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to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted. VSLs: The VSLs for Requirement R3, parts 3.4 & 3.5 are required elements of the primary requirement. The VSLs categorize noncompliance with the requirement, "in total" – not with each of the individual parts of the requirement. No change made.	
Entergy Services, Inc	In R3.5 what would constitute "an evaluation of possible actions designed to reduce?" R3 should be broken into two pieces where the near term portion could be a Medium VRF but the long term section should be a Low VRF. Violations occuring in the longer term horizon are subjective and assumptions concerning future plans too broad to justify a Medium VRF. In Requirement R3.1, it is suggested that the word "contingency" be added to describe the lists created in R3.4.
Response: R3.5: In the event that an extreme event causes cascading outages, the "possible actions" would be the possible actions that would reduce the likelihood or mitigate the consequences and adverse impacts of the event". VRF: The SDT believes that all of the steady state responses are equally important. No change made. R3.1: The SDT agrees and has revised the wording. **R3.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4.	
Great River Energy	R3.3.3 The relay loadability section needs better definition. Is this identifying that: if the relay load limit is the most Limiting Element of a transmission line how it would be handled if it is overloaded considering that there may be some margin before opening the line and/orif the line reaches a certain overload level based on a non-Relay Load Limit being the Most Limiting Element that the relay load limit should be analyzed to see if it will actually activate an opening of the transmission line or the planners need to review all of the relays associated with all transmission lines within the model and indicate if loadability is a concern for each contingency analyzed. There are a lot of lines, (probably the majority), that have not defined a relay capability within the rating fields of the model! This would seem to be a FAC-009 issue. As a discussion point on R3.3.3, it would seem that relay loadability should be addressed in FAC-009 and the Model Building process. Putting this burden in the planning assessment will be difficult to determine if the Most Limiting Element within the model is not a relay load limit as those parameters typically are not the Most Limiting Element. Every line in the model may need to be defined as to what its relay loadability is to meet this requirement. Our regional model build reports a Most Limiting Element, a short term emergency level, and a long-term emergency for the three ratings available within the model. It would seem that the long-term emergency field should be replaced with a Relay Load Limit value such that the R3.3.3 would not be as great of a burden on the planner.
BC Hydro	R3.3.3: Consider changing it to read, "Demonstrate that, for all Transmission lines, relay loadability standards are met in accordance with the PRC series of standards"
Response: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections and to	

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ensure relay loadability limits, as defined in the relay loadability standard, are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected.	
Midwest ISO	Opening Remarks. Specific Comments for Requirement 3:A) Under R3, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R3 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning". B) Under R3.1 the "Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the lists created in the Requirement 3.4". We believe that the following language will improve this requirement: Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the more severe contingency lists created in the Requirement 3.4. C) Under R3.3.2 the Midwest ISO generally agrees with FirstEnergy's comments on this. D) Under R3.3.3 the Midwest ISO feels that this sub-requirement is redundant with PRC-023-2 and therefore we feel that this sub-requirement needs to be removed and replaced with our suggested bullet language under R1.1.2 ? Relay Loadability Limitation (see F on page 3 of 9 above) E) Under R3.4 to make this requirement clearer, please add the following language between the words "expected to" in the first sentence: "expected by the assessing entity to" We believe that this language addition improves the clarity of this requirement. The first sentence would then read: Those Planning Event Contingencies in Table 1 that are expected by the assessing entity to produce more severe System impacts shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3.1 created. F) Under R3.5 to make this requirement clearer, please add the following language between the words "expected to" in the first sentence: "expected by the assessing entity to" We believe that this language addition improves the clarity of this requirement. The first sentence would then read: Those Extreme Events in Table 1 that are expected by the assessing entity to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3.2 created.
Response: The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made. **Mitigation Time Horizon** The time horizons available for mitigating a violation to a requirement include the following: • **Long-term Planning** — a planning horizon of one year or longer. • **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.	

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	• **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time. • **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system. • **Operations Assessment** — follow-up evaluations and reporting of real time operations. R3.1: The SDT has modified the requirement. **R3.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4. R3.3.2 The SDT has changed the wording to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections. **R3.3.3** Ensure relay loadability limits are respected. R3.4 & R3.5: The Planning Coordinator/Transmission Planner are the applicable entities for this standard, so adding "by the assessing entity" is redundant. No change made.
PJM	In R3, why require a Planning Coordinator AND a Transmission Planner to perform this analysis? Isn't this a duplication of effort? R3.4 should come before R3.1. You should never reference down in a standard. Please present the items in the order in which they should be performed/considered. R3.5 should come before R3.2. You should never reference down in a standard. Please present the items in the order in which they should be performed/considered. R3.3.2 should be broken into two requirements since two separate tasks need to be performed. R3.3.3 should be broken into two requirements since two separate tasks need to be performed. Also in R3.3.3, analysis of relay loadability will require the inclusion of all relay models 200 kV and above. This information is not presently gathered by the ERAG MMWG for the Eastern Interconnection. To help with compliance, questions R3.3.4 needs more specificity. Maybe define a minimum percentage of total possible contingencies as a bright line whether you have performed enough more severe contingencies. Would expect a number between 10 and 25 percent. R3.4 should be broken into two requirements since two separate tasks need to be performed. To help with compliance questions, R3.3.5 needs more specificity. Maybe define a minimum percentage of total possible contingencies as a bright line whether you have performed enough more severe extreme contingencies. Would expect a number

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	between 10 and 25 percent. R3.5 should be broken into three requirements since three separate tasks need to be performed.
Response: R3: The SDT believes that the requirement belongs to both the Planning Coordinator and the Transmission Planner. No change made. R3.4 & R3.5: The SDT disagrees. No change made. R3.3.2: The SDT sees this as only one requirement to identify how the generators are analyzed. No change made. R3.3.3: The SDT sees this as only one requirement to identify how the relay loadability is analyzed. No change made. R3.3.3: The SDT has clarified the requirement to ensure all relay loadability limits are respected in the analysis. R3.3.4: The number of Contingencies is system specific and any percentage that the SDT would establish would be wrong for some entities. No change made. R3.4: The SDT disagrees as the tasks are related. No change made. R3.3.5: The number of Contingencies is system specific and any percentage that the SDT would establish would be wrong for some entities. No change made R3.5: The SDT disagrees as the tasks are related. No change made.	
Brazos Electric Cooperative	R3.4 and 3.5 give us a concern. Table 1 identifies a number of events that are to be assessed but requiring an explanation of why certain events would produce less severe results seems to be open ended thus making it hard to audit. If all the events in Table 1 are studied or have been studied in the past then what is one supposed to document? we understand this is to allow the planner a certain amount of flexibility in their analysis but it seems counter to the idea of requiring a review of all the events in Table 1. We don't have any suggested wording changes, just passing along a general idea.
Response: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the contingencies selected are those that produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining Contingencies would produce less severe System results".	
American Electric Power	With regard to R3.3.3., please include transformers as relay loadability also applies to transformers.
Response: The SDT has clarified the requirement to ensure relay loadability limits are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected.	
ITC Holdings	Comments: If the SDT feels that a requirement such as R3.3.4 is necessary, it may also be necessary to identify further limitations on the use of the control devices referred to. For example, a manually controlled phase shifter would require a time period, or loading limits, to readjust flows to limit a post-contingency flow if not pre-set in the pre-contingency state. Similarly, a tap-changing transformer also requires an adjust period for voltage control. We suggest adding a statement to this requirement (or somewhere in performance requirements) that "all post-contingency flows/voltages must remain within the applicable facility ratings before,

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	during, and after the use of such control devices.
Response: The SDT has revised the requirement wording to clarify that the intent is to simulate automatic operation of existing and planned devices. **R3.3.4** Simulate the expected automatic operation of existing and planned devices designed to provide Steady State control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.	
Northern Indiana Public Service Company	R3.3.3: Evaluation of loadability should be triggered only for those circuits with new protection settings issued since the last assessment; evaluation of circuits that have not been newly assigned or re-assign protection settings is a misuse of resources.
Response: The SDT has clarified the requirement to ensure all relay loadability limits are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected.	
Minnesota Power	A) Under R3, the Time Horizon of the TPL standards is intended for years one through 10; however, the Time Horizon shown in R3 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning". B) R3.3.3 Is this sub-requirement redundant with PRC-023-2? Is it covered in FAC-009? We believe the SDT should review these standards and if it is a redundant requirement, then this sub-requirement needs to be removed. C) Under R3.4 to make this requirement clearer, please add the following language between the words "expected to" in the first sentence: "expected by the assessing entity to"? We believe that this language addition improves the clarity of this requirement. The first sentence would then read: "Those Planning Event Contingencies in Table 1 that are expected by the assessing entity to produce more severe System impacts shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3.1 created. D) Under R3.5 to make this requirement clearer, please add the following language between the words "expected to" in the first sentence so that the phrase reads: "expected by the assessing entity to"? We believe that this language addition improves the clarity of this requirement. The first sentence would then read: "Those Extreme Events in Table 1 that are expected by the assessing entity to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3.2 created.
Response: The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made. **Mitigation Time Horizon** The time horizons available for mitigating a violation to a requirement include the following:	

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• **Long-term Planning** — a planning horizon of one year or longer. • **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal. • **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time. • **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system. • **Operations Assessment** — follow-up evaluations and reporting of real time operations. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections. **R3.3.3** Ensure relay loadability limits are respected. R3.4& R3.5: The Planning Coordinator/Transmission Planer are the applicable entities, so adding "by the assessing entity" is redundant. No change made.	
LADWP	R3.4 This requirement is very strange. If there is a known planning event that is more severe than those listed in Table 1, it should be so identified in Table 1. It is not fair to ask every planner to search for more severe contingencies without any specifics. R3.4 should be deleted. R3.5 This is similar to R3.4; this requires proving of null set. The only way this requirement can be met is to perform an exhaustive and unlimited list of extreme event, real or imaginery, before a rationale can be rendered. This requirement should be deleted with the exception of the last sentence regarding "cascading outages.
Response: R3.4: Requirement R3.4 has been revised. The intent is not to identify additional Contingencies in addition to the planning events in Table 1, but to identify those Table 1 planning events that are expected to be more severe for your portion of the BES. Based on industry comments, the SDT has deleted the requirement to provide an explanation of "why the remaining Contingencies would produce less severe System performance". **R3.4** Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. R3.4 & R3.5: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the Contingencies selected are those that produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining Contingencies would produce less severe System results". **R3.5** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.	
Platte River Power Authority	R3.3.3. Zone 3 type relay loadability studies (single and multiple contingency analyses) should be performed in the OPERATING HORIZON to provide results flagged for possible problems to the Relay Engineers who will evaluate a relay setting change on an Facility or a modification to a relay setting for a new Facility about to be put in-service. I do not see the value of Zone 3 relay

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	loadability checks in the Planning Horizon.
Response: The SDT does not agree that relay loadability should be limited to the Operating Horizon. The SDT has clarified the requirement to ensure relay loadability limits are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected.	
MAPPCOR	R3.3.2 - Traditionally transmission planners have used their judgment about the minimum steady state voltage limitations of generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R3.3.3 - PRC-023 requires relay loadability to be reflected in facility ratings. Therefore this additional requirement is unnecessary and should be deleted. R3.4 is there a measure for what is a "more severe system impact"? R3.5 Recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following:-Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events-It should be clear that an evaluation does not require solution development for all Extreme Events-Change "an evaluation of possible actions"? to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered.
Response: R3.3.2: The SDT agrees that judgment is used today. There is a project (PRC-024) that will address this issue. The SDT has changed the wording to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections **R3.3.3** Ensure relay loadability limits are respected. R3.4: Requirement R3, part 3.4 requires the Planning Coordinator/Transmission Planner to prepare a list of planning event Contingencies that, in the Planning Coordinator's and Transmission Planner's judgment, are expected to produce more severe System impacts, and to document the rationale for the Contingencies selected. The documented rationale provided by the Planning Coordinator/Transmission Planner will define what is considered to be the more severe System impacts relative to the Contingencies not selected because they are expected to be less severe. No change made. R3.5: The SDT disagrees that the standard should mandate corrective actions for extreme events due to the low probability of these events. However, the SDT believes that those extreme events that are expected to produce more serve System impacts should be analyzed to assess the extent of the impacts on the System to provide the Planning Coordinator/Transmission Planner with information to decide, where appropriate, if it is reasonable to provide some corrective actions to reduce the possibility or limit the consequences of an extreme event. The need to identify possible actions addresses an Order 693 directive. Your suggested wording would	

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make identification of possible actions optional. No change made.	
Orlando Utilities Commission	For Requirement 3.3.1 and 3.3.4 I suggest adding language similar to 3.3.2 and 3.3.3 establishing that "studies shall consider" rather then requiring every simulation precisely recreate this usually minor part of system performance. These devices generally do not respond except for a nearby event, and even then their response is rarely such that it would make the situation "worse". The effect of these devices must be considered, but mandating that every simulation faithfully reproduce the response of every device is not only an efficient way to do this, it actually provides a counter incentive to going above and beyond the standard requirements. Any simulation used to meet this standard that failed to precisely reproduce the performance of this equipment would be a violation of this requirement (as currently written). As such there is no incentive for an entity to include anything but the absolute minimum number of simulations required to meet the standard, since each extra simulation represents an opportunity to miss this requirement. Good planning is based on running a broad range of events against a broad range of conditions and evaluating those responses against a set of performance criteria. This is encouraged by requiring that studies consider the response of equipment to these events rather then mandating their precise reproduction in simulation.
Response: R3.3.1: The SDT disagrees with the comment as the intent of Requirement R3, part 3.3.1, consistent with Order 693, is to perform the simulation to reflect how the Protection System will operate in the real System for each Contingency without operator intervention. No change made. R3.3.4: The SDT disagrees with your comment. The simulation of the expected operation of devices such as phase-shifting transformers, load tap changing transformers ,etc. impacts post-Contingency the performance of the System. No change made.	
American Transmission Company	We propose the following comments for R3.Revise the R3.3.2 text to clarify that subsequent analysis is performed on generators whose voltages are expected to fall below the minimum voltage limits. We suggest this text: Consider the minimum steady state voltage limitations of all generators and identify how generators with bus voltages below its minimum voltage limits are analyzed in the subsequent steady state simulations. Revise the R3.3.3 text to more clearly relate to the specific requirements in PRC-023. We suggest this text: "Incorporate relay loadability per PRC-023 and identify how relay loadability is analyzed in the steady state simulation. Add R3.3.5. The obligation to consider only planned System adjustments that are executable should be a Requirement, rather than performance note "e" in the Planning Events, Steady State & Stability section of Table 1. We suggest this text: "Consider planned System adjustments, such as Transmission configuration changes and redispatch of generation, that are executable within the time duration of the applicable Facility Ratings.
Response: R3.3.2: The SDT has changed the wording to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected.	

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R3.3: The SDT disagrees as such planned System adjustments are considered to be operator corrective actions as opposed to automatic actions considered in Requirement R3, part 3.3. No change made.	
Idaho Power	R3.3.2 is unclear as drafted. The minimum steady state voltage limitation for synchronous generators is not a very meaningful value. All generators with an automatic voltage regulator will maintain the set point voltage until the VAR capability of the generator is exceeded, and then the voltage will deteriorate. R3.5 -The requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study is overly burdensome. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. Listing all possible extreme events could result in a limitless list.
Response: R3.3.2: The SDT has changed the wording to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.5: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the Contingencies selected are those to produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining contingencies would produce less severe System results". **R3.5** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.	
New York Independent System Operator	R3.5. - The Extreme Events testing in Table 1 should be removed from this standard since there is no requirement to develop a Corrective Action Plan to address unacceptable consequences and the requirements are very general or vague. At a minimum, testing should only be required for EHV facilities or facilities specified by the Regional Entity ? for example, NPCC designates facilities that can have consequences outside an area as bulk power system facilities.
Response: R3.5: extreme events: The SDT disagrees that the standard should mandate corrective actions for extreme events due to the low probability of these events. However, SDT believes that those extreme events that are expected to produce more serve System impacts should be analyzed to assess the extent of the impacts on the System to provide the Planning Coordinator/Transmission Planner with information to decide, where appropriate, if it is reasonable to provide some corrective actions to reduce the possibility or limit the consequences of an extreme event. No change made.	
Duke Energy	Revise M3 to include a reference to R6, since the allocation of responsibilities will directly affect the evidence which is to be provided.
Response: M3: The SDT disagrees. Requirement R6 (now Requirement R7) is an overarching requirement that applies to the entire set of analysis required to meet	

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the requirements of the TPL standard and to the Corrective Action Plan developed as part of the assessment. The intent of this requirement is to clarify that TPL requirements can be met through joint or shared analysis. Coordinating and/or joint analysis does not alleviate the responsibility that all entities need to comply with the standard requirements. Therefore, the SDT sees no reason to link Requirement R3 directly to Requirement R6 (now Requirement R7) in the measure or anywhere else. The requirements stand by themselves and do not require such a linkage. No change made	
Independent Electricity System Operator	1. In our opinion, R3 as drafted is rather convoluted as it attempts to cover several objectives. Firstly, we recommend replacing "utilizing data in Requirement R1" with "developed in accordance with Requirement R1" both in the requirement and the VSLs. Secondly, is the main objective of R3 to ensure studies are conducted based on computer simulation utilizing data provided in Requirement R1? Or is it to ensure that this is done, and that all the other objectives are also fulfilled, for example: assessment of system performance (R3.1 and R3.5), conducting the analysis as specified in R3.2 and R3.3, identification of critical Planning Event contingencies (R3.4), etc. If it is the former, then not conducting studies based on computer simulation utilizing data provided in Requirement R1 alone should have a VSL of Severe. If it is the latter, then the requirement should be either: (a) Revised to place all supporting conditions in the subrequirements. As an example, R3 could be revised as follows:R3. The steady state analyses of the Near-Term and Long-Term Planning Assessment as stipulated in R2.1 and R2.2 shall be performed as follows:R3.1. Studies are conducted based on computer simulation utilizing data provided in Requirement R1;R3.2. Studies shall be performed to determine?. (the rest of the existing R3.1) R3.2. The existing R3.3, and so on.This way, not conducting studies based on computer simulation utilizing data provided in Requirement R1 will be "rolled up" to the VSLs for the main requirement, as is currently stated in the VSL table.Or(b) Restructure, if there are multiple main objectives in R3, to clearly have the main objectives in the main requirement, or split it into more than one main requirement.2. Based on the way R3 is written, we agree with the VRF, Time Horizon and Measure. However, we do have a difficulty with the VSL based on our comments above on the requirement, especially on the Moderate VSL for "The Transmission Planner or Planning Coordinator did not base its studies on computer simulations using models utilizing data provided in Requirement R1.
Response: Requirement R3 has been modified. **R3** For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. R3 is a single requirement and the SDT disagrees with the concept of splitting this up into separate requirements. No change made. The moderate VSL has been modified to align with the changes made to the wording of the requirement. **R3, moderate VSL**: The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.	
Kansas City Power & Light	R3.3.3: Relay loadability has no bearing beyond the near term horizon. Loadability is not determined several years out. R3.5 " does this imply that mitigation plans must be implemented" If not, then this is highly subjective and the last sentence of this requirement should be deleted.

Organization	Question 3 Comment
Response: R3.3.3 The SDT does not agree that relay loadability should be limited to the near term horizon. The SDT has clarified the requirement to ensure relay loadability limits, as defined in the relay loadability standard, are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected. R3.5: extreme events: The SDT disagrees that the standard should mandate corrective actions for extreme events due to the low probability of these events. However, SDT believes that those extreme events that are expected to produce more serve System impacts should be analyzed to assess the extent of the impacts on the System to provide the Planning Coordinator/Transmission Planner with information to decide, where appropriate, if it is reasonable to provide some corrective actions to reduce the possibility or limit the consequences of an extreme event.	
ReliabilityFirst Corporation	R3- Throughout this requirement there is a mention of developing a contingency table. It will be nice that such a table is developed under MOD-010 and MOD-012 standard. ERAG can develop such a list as part of their base case development effort. R3.3.3- Suggest changing it to read “For all Transmission lines, studies shall consider relay loadability, if that is the limiting factor for line loading.” R3.3.4 The term “expected operation” is vague. Some of these devices have relays which cause them to automatically respond to system changes, others are controlled by an operator. In both cases, the devices are “expected” to be utilized. Given that operator controlled devices are less certain to be utilized, and may be delayed in being utilized. The expected operation needs to be studied differently for automated devices and those requiring operator interventions.
Response: R3: Requirements R3.4 & R3.5 place the responsibility of creating planning event and extreme event Contingency lists on the applicable entities, the Planning Coordinator and the Transmission Planner as owners, operators or users of the BES. The SDT believes that requirement to develop these Contingency lists of planning and extreme events expected to produce the most severe results, and the rationale for the selection of these events, is best left to the Planning Coordinator/Transmission Planner responsible for its portion of the BES. However, the SDT does not believe that the standard would preclude ERAG from playing a role in the development of these Contingency lists; however, the compliance responsibility will fall to the Planning Coordinator/Transmission Planner. R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected. R3.3.4: The SDT agrees and has added automatic to the requirement. **R3.3.4** Simulate the expected automatic operation of existing and planned devices designed to provide Steady State control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.	

4. Requirement R4 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: The SDT has made numerous clarifying changes to the requirements due to industry comments. In addition, Requirement R4, part 4.3.3 has been added.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1.

4.1 Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, part 4.4.

4.2 Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, part 4.5.

4.3 Contingency analyses shall be performed and:

4.3.2 Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.3 Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers.

4.3.4 Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4 Those planning events in Table 1that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4, part 4.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1 The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5 Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R4, part 4.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

Footnote 2 Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.

R4 VSL	The responsible entity did not identify planning events as described in Requirement R4, part 4.4 or extreme events as	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine that the BES meets the

	described in Requirement R4, part 4.5.	that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, part 4.2 to assess the impact of extreme events. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.	that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, part 4.3.	performance requirements for three or more of the categories (P1 through P7) in Table 1.

Organization	Question 4 Comment
Dominion - Electric Transmission	R4.4 - Dominion believes that creating a master list of all contingencies a planner must take is burdensome and provides no planning value. In addition the contingencies will vary based on the loading configuration and the specific study case. In general, we start out with the very worst contingencies. If these cause hard rotor swings, we know we will probably have to do most of the possible contingencies in the station until we get down to contingencies that do not swing the generator much. But if the swings are light, then that particular load/topology situation probably does not need in-depth exploration. Creating a master list could create unnecessary study. However, we do support a list of the extreme contingencies in R4.5.
Response: Requirement R4, part R4.4 does not require a master list of all possible contingencies. The requirement is to create a list of those Contingencies expected to produce more severe results. There is nothing that prevents you from modifying the list based on simulation results (e.g., hard rotor swings). No change made.	
Northeast Power Coordinating Council	R4.3.2 - Traditionally transmission planners have assumed that generators would ride through low voltages associated with Planning Events which is generally adequate for non-wind generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R4.5 Priority Comment ?We recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following:- Extreme Event performance should be a consideration when developing Corrective Action Plans to

Organization	Question 4 Comment
	address Planning Events- It should be clear that an evaluation does not require solution development for all Extreme Events- Change “an evaluation of possible actions”? to “where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered. For Requirements R4.4 and R4.5, what defines “more severe System impacts”?
Response: R4.3.2: There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should just document your assumptions regarding ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. R4.5: The SDT considers extreme event testing to be an important part of the assessment and therefore will not delete it. The expectation for extreme event testing is that for major problems you will evaluate actions to reduce likelihood or mitigate consequences. The SDT believes the original words express this concept better than your suggested words. No change made. R4.4 and R4.5: The definition of "more severe impacts" is left to the engineering judgment of the Transmission Planner and Planning Coordinator.	
Transmission Planning	R4.3.2. COMMENT: The inability to survive a given low voltage transient is often dependent on motor performance within the generating facility’s auxiliary load distribution system and is not a specific relay setting. Determination of specific generating plant low voltage ride through capability requires extensive modeling of the plant distribution system and is outside the scope of this standard.
Response: R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require extensive modeling of a generating plant's distribution system. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.	
SERC Engineering Committee Planning Standards Subcommittee	R4.1:In Requirement R4.1, it is suggested that the word "contingency" be added to describe the lists created in R4.4?Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists created in Requirement R4.4. R4.4:Regarding Requirement R4.4, it is suggested that a rewording be considered such as described below:? For each category of the Planning Events in Table 1, those Planning Event Contingencies that are expected to produce more severe System impacts shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4.1 shall be created. The rationale for the Contingencies selected for evaluation shall be available as supporting information

Organization	Question 4 Comment
	with an explanation of why the remaining Contingencies would produce less severe System results. R4.3.2:R4.3.2 requires that voltage ride through capability be analyzed. It is not clear what should be analyzed (e.g. auxiliary loads, generator protection, generator capability, etc.) This requirement needs more clarity. Footnote #3:Footnote #3 needs to be revised to include 2LG faults in addition to 3-Phase faults indicating that the SLG criteria is met.
Response: R4.1: The SDT agrees and has added the word "Contingency". **4.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, part 4.4. R4.4: The SDT agrees and has modified the wording similar to your suggested wording, however - due to other stakeholder comments, the phrase requiring an explanation was deleted from the revised standard. **4.4** Those planning events in Table 1that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4, part 4.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require extensive modeling of a generating plant's distribution system. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. Footnote #3 (now footnote #2): The SDT agrees and has modified the wording similar to your suggested wording. **Footnote 2** Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.	
Modesto Irrigation District	Comments: We believe that R4.3.1-R4.3.3 should be bullets under R4.3
Response: R4.3.1-R4.3.3: The SDT disagrees as these are mandatory elements of the Contingency analyses. Bullets are only used to identify the possible, but not all inclusive, elements of a menu. No change made.	
OPUC	4. Requirement R4 ? Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement. Comments: A: R4.3 should be modified to become the requirement to conduct contingency analyses with R4.3.1 thru 3

Organization	Question 4 Comment
	presented as bullets there-under. B: R4.3.2 should clarify whether all relay protection must be modeled
Response: R4.3: The SDT disagrees as these are mandatory requirements of the Contingency analyses. Bullets are only used to identify the possible, but not all inclusive, elements of a menu. However, R4.3 has been modified to read more like a requirement as shown below. **4.3** Contingency analyses shall be performed and: R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require extensive modeling of all relay protection. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.	
Bonneville Power Administration	Requirement R4 should be consistent with R3. Suggested edit for R4. - "For the Stability portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term Transmission Planning Horizon studies in Requirement R2.4. The studies shall be based on computer simulations using models developed from the data provided in Requirement R1." R4.1 should be clarified consistent with comments to R3.1. Suggested clarification for R4.1 - "Studies shall be performed to determine whether the BES meets the performance requirements in Table 1. A reduced set of contingencies can be simulated based on a list created in requirement R4.4." As currently drafted, R4.3 is not a requirement. Without the statements in R4.3.1-R4.3.3, R4.3 is simply a phrase. Sub-Sub-Requirements R4.3.1 through R4.3.3 should be bullets under R4.3, with the language in R4.3 modified so that it becomes the requirement to conduct contingency analyses that address the three resulting bullets. R4.3.2 ? it is not clear what is required to be modeled. Typically a generator may have 10 or more protective relays. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to do that for all generators in the system. Requirement R4.4 also needs to be clarified as follows: R4.4 - "A reduced list of Contingencies can be developed for System Performance evaluation in Requirement R4.1 that includes those Planning Event Contingencies that are expected to produce more severe System impacts based on system performance as required in Table 1. R4.5 ? We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingency than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then

Organization	Question 4 Comment
	simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.

Response: The wording in Requirement R4 has been made identical to that in Requirement R3.

> **R4.** For the Stability portion of the Planning Assessment, as described in Requirement R2, parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1.

R4.1: The intent is to run the contingencies developed in Requirement R4, part 4.4, not a reduced set of them. No change made.

R4.3: The SDT disagrees as these are mandatory elements of the Contingency analyses. Bullets are only used to identify the possible, but not all inclusive, elements of a menu. However, Requirement R4, part 4.3 has been modified to read more like a requirement as shown below.

> **4.3** Contingency analyses shall be performed and:

R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require modeling of all relay protection. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4.3.2 to clarify this.

> **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

R4.4: The intent of Requirement R4, part 4.4 is to identify and develop a list of Contingencies to be run. Your proposed wording does not capture that intent. No change made.

R4.5: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining Contingencies would produce less severe System results".

MRO MRO NERC Standards Review Subcommittee	MRO NSRS proposes the following comments for R4:Add R4.3.3 text include relay loadability in the R4 (Stability) requirements to parallel R3.3.3 in the R3 (Steady State) requirement which would more clearly relate to the specific requirements in PRC-023. MRO NSRS suggests this text: "Incorporate relay loadability per PRC-023 and identify how relay loadability is analyzed in the dynamic simulation. In R4.3.4, MRO NSRS proposes limiting the scope to automatic devices and adding the notion of "including but not limited to". MRO NSRS suggests R4.3.4 text of: "Simulate the expected automatic operation of existing and planned control devices including but not limited to generation exciter control and power system stabilizers, static VAR compensators, power flow controllers, and DC Transmission controllers.

Response: R4.3: The SDT agrees with the general idea and has added Requirement R4, part 4.3.3. However, Requirement R4, part 4.3.3 requires that you "Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers" rather than creating a stability requirement for relay loadability. This requirement is more applicable to stability studies than a relay loadability requirement would be. Relay loadability is more of a steady state

Organization	Question 4 Comment
issue than a dynamic issue. **4.3.3** Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers. R4.3.4: The SDT has added the word "automatic" into Requirement R4, part 4.3.4 such that it now reads as follows: **4.3.4** Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.	
SERC Engineering Committee Reliability Review Subcommittee (RRS)	In R4, should the “and” in the first sentence actually be “or”?” Footnote #3 needs to be revised to include 2LG faults in addition to 3Phase faults indicating that the SLG criteria is met. In Requirement R4.1, it is suggested that the word "contingency" be added to describe the lists created in R4.4”Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists created in Requirement R4.4. ? Regarding Requirement R4.4, it is suggested that a rewording be considered such as the following: For each category of the Planning Events in Table 1, those Planning Event Contingencies that are expected to produce more severe System impacts shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4.1 shall be created. The rationale for the Contingencies selected for evaluation shall be available as supporting information with an explanation of why the remaining Contingencies would produce less severe System results. ? R4.3.2 requires that voltage ride through capability be analyzed. It is not clear what should be analyzed (e.g. auxiliary loads, generator protection, generator capability, etc.) This requirement needs more clarity. ? R4.3.2 ? By in large, the industry does not have the input data or the methods to do this. It would seem necessary to have PRC-024 approved before this can be met. In R4.3.2, need guidance on how to consider minimum steady state voltage limitations.
Response: R4: Requiring the Planning Coordinator AND the Transmission Planner to perform analysis should not result in a duplication of effort. Requirement R6 (now Requirement R7) requires the two entities to agree on their individual and joint responsibilities. The SDT believes that ‘AND’ is the proper word rather than ‘OR’. Using ‘OR’ could be interpreted by one entity as not applying to them. No change made. Footnote #3 (now footnote #2): The SDT agrees and has made the suggested change. **Footnote 2** Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. R4.1: The SDT agrees and has made the suggested change. **4.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, part 4.4.	

Organization	Question 4 Comment
R4.4: The SDT agrees and has made the suggested change however - due to other stakeholder comments, the phrase requiring an explanation was deleted from the revised standard. **4.4** Those planning events in Table 1that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4, part 4.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require modeling of all relay protection. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.	
FirstEnergy Corp	Specific comments, Requirements of R4:A. R4.1: A space is needed between the text "Requirement and R4.4" which are run together in the requirement. B. R4.3.3: For readability we suggest inserting the word "may" in between "devices include". We agree with the stated Measures, VRF, Time-Horizon, Data Retention and VSL of requirement R4
Response: R4.1: The SDT has corrected this problem. **4.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, part 4.4. R4.3.3: The SDT agrees and has made the suggested change. **4.3.4** Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.	
TVA System Planning	In R4, should the “and” in the first sentence actually be “or”? R4.3.2 requires that voltage ride through capability be analyzed. It is not clear what should be analyzed (e.g. auxiliary loads, generator protection, generator capability, etc.) This requirement needs more clarity. By in large, the industry does not have the input data or the methods to do this. It would seem necessary to have PRC-024 approved before this can be met.
Response: R4: Requiring the Planning Coordinator AND the Transmission Planner to perform analysis should not result in a duplication of effort. Requirement R6 (now Requirement R7) requires the two entities to agree on their individual and joint responsibilities. The SDT believes that ‘AND’ is the proper word rather than ‘OR’. Using OR could be interpreted by one entity as not applying to them. No change made. R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require modeling of	

Organization	Question 4 Comment
all relay protection. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.	
Exelon Transmission Planning	See comment in response to question 9 regarding the lack of definition related to the failure of a "single Protection System".
Response: See response to question 9 comment.	
Southern Company	Generating unit stability should be separated from system stability like in previous drafts. R4.2 and R4.5 are both addressing the extreme events. However, R4.2 is referring to R4.5 while R4.5 is referring to R4.2. We suggest deleting the reference back to R4.2 which is in R4.5. A similar situation exists for R4.1 and R4.4.
Response: The majority of the industry believes that there should be no distinction between generating unit stability and System Stability. No change made. R4.2, R4.5, R4.1, R4.4: The SDT does not see any harm in having the cross referencing. No change made.	
United Illuminating Northeast Utilities ISO New England, Inc. Central Maine Power Company	R4.3.2 Priority Comment - Traditionally transmission planners have assumed that generators would ride through low voltages associated with Planning Events which is generally adequate for non-wind generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R4.5 Priority Comment ?We recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following:- Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events- It should be clear that an evaluation does not require solution development for all Extreme Events- Change "an evaluation of possible actions"? to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered.
Response: R4.3.2: There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. R4.5: The SDT considers extreme event testing to be an important part of the assessment and therefore will not delete it. The expectation for extreme event testing is that for major problems you will evaluate actions to reduce likelihood or mitigate consequences. The SDT believes the original words express this concept better	

Organization	Question 4 Comment
than your suggested words. No change made.	
System Protection and Transmission Planning Department	Comments under R1 apply here as well. The requirement to "utiliz[e] data provided in Requirement R1" is redundant with MOD-012, and should be moved to MOD-012. To conform with R1, we suggest a phrase be inserted that requires model data used in Stability Studies used for Annual Assessments be consistent with data submitted under MOD-012.
Response: R4: MOD-012 does not require the data to be used for an assessment of the Transmission System. Therefore, the requirement to utilize data provided under Requirement R1 is needed in this standard. No change made. R4: Because Requirement R1 references the data provided under MOD-012, there is no need for a reference to MOD-012 in Requirement R4. No change made.	
PPL Energy Plus	It should be pointed out that Breaker Failure (i.e. fail to open) and Breaker Fault (internal fault in breaker) are two different events.
Response: Breaker failure and breaker fault are two different events and that is reflected by having two different designations for these events in Table 1 (P2.3 and P4). No change made.	
PacifiCorp Deseret Generation & Transmission SRP Arizona Public Service Co Southern California Edison Company Western Area Power Administration Pacific Gas and Electric Co, Puget Sound Energy, Inc. NV Energy San Diego Gas and Electric Co Tucson Electric Power Company	As currently drafted, R4.3 is not a requirement. Without the statements in R4.3.1-R4.3.3, R4.3 is simply a phrase. Sub-Sub-Requirements R4.3.1 through R4.3.3 should be bullets under R4.3, with the language in R4.3 modified so that it becomes the requirement to conduct contingency analyses that address the three resulting bullets. R4.3.2 - it is not clear what is required to be modeled. Typically a generator may have 10 or more protective relays. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to do that for all generators in the system. R4.5 ? We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingency than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.
NorthWestern Corporation NorthWestern Energy (NWE)	R4.3 is unclear. Requirements R4.3.1 through R4.3.3 should be bullets under R4.3, with R4.3 modified so that it becomes the requirement to conduct contingency analyses that address the three resulting bullets

Organization	Question 4 Comment
(NWMT)	R4.3.2 is unclear. It appears to be a broken sentence. Typically a generator may have 10 or more protective relays. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to do that for all generators in the system. It is our understanding that the voltage ride through standard is not complete at this time. R4.5 needs to be modified. It would be better to combine R4.2 and R4.5. The first part of the requirement requires identification of events that produce more severe System impacts. The presumed reason that the other contingencies were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be examples of more severe Extreme Contingencies than the one selected for study. This can be achieved by simply choosing events that are even less credible. For example, if the Extreme Contingency studied was a simultaneous loss of 3 transmission lines with the failure of redundant RAS (SPS), then an event resulting in the simultaneous loss of 4 lines with the failure of 2 sets of redundant RASs would be even more severe. Listing all possible extreme events could result in a limitless list.
Response: R4.3: The SDT disagrees as these are mandatory elements of the Contingency analyses. Bullets are only used to identify the possible, but not all inclusive, elements of a menu. However, Requirement R4, part 4.3 has been modified to read more like a requirement as shown below. **4.3** Contingency analyses shall be performed and: R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require modeling of all relay protection. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. R4.5: Several industry commenters have indicated that an explanation of “why the remaining Contingencies would produce less severe System performance” should be deleted since the contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an “explanation of why the remaining Contingencies would produce less severe System results”.	
Western Area Power Administration	R4.3.3 need not include the operation of exciters and power system stabilizers as modeling of these parts of a generation system is already covered in Mod-12 & Mod-13 Standards and therefore are inherent in the dynamic analysis conducted using a program such as the GE PSLF or PTI power system simulation programs.
Response: R4.3.3: MOD-012 and MOD-013 do not require the data to be used for an assessment of the Transmission System. Therefore, the requirement to simulate the operation of exciters and stabilizers is needed in this standard. No change made.	
Tampa Electric	Clarification needed on modeling of protection system equipment.
Response: Requirement R4, parts 4.3.1 and 4.3.2 do not require modeling of Protection System equipment. It just requires you to have simulations which include the effect of Protection System equipment operation. You don't have to specifically model a relay to simulate the effect of clearing a fault at 3 cycles. No change made.	

Organization	Question 4 Comment
Florida Reliability Coordinating Council, Inc - Transmission Working Group	R4.3.1 - Please clarify, is the intent of this requirement to have every relay modeled? We suggest clarifying that the intent is that Protection System Equipment would be incorporated into the contingency list, and that modeling the Protection System equipment settings and logic would only be done for Protection Systems that could significantly impact stability response (e.g., out-of-step relaying) as deemed appropriate through engineering judgment, and that the intent would be to do this only for the Region under study and not the entire Interconnection (e.g., studies in Florida should not need to include relays in Canada). R4.4 & R4.5 - Does the intent of allowing this "More severe events" to establish actual study parameter extend between the planned events and extreme events (e.g. if a range of extreme events establishes that planning events performance requirements are met, would a redundant analysis of the planning events still be required)
Response: Requirement R4, part 4.3.1 does not require modeling of Protection System equipment. It just requires you to have simulations which include the effects of Protection System equipment operation. You don't have to specifically model a relay to simulate the effect of clearing a fault at 3 cycles. If you need to model a relay to capture its effect, then model that relay. And certainly engineering judgment should be used to determine which relay effects should be included in the simulations. No change made. R4.4 and R4.5: You can always demonstrate that performance requirements are met by meeting them for a more severe Contingency. It is possible that you could demonstrate that performance requirements are met for planning events by performing extreme events (e.g., using a three-phase fault with stuck breaker Contingency can demonstrate that performance requirements for a single phase fault plus stuck breaker contingency is met). No change made.	
FMPA	R4.2, see comment on R3.3 concerning how to model a hurricane event or other weather event. R4.3, contingency analysis ought to specifically exclude studying contingencies on neighboring systems since stability is more related to protection system and clearing times. R4.3.1, please clarify, is the intent of this requirement to have every distance relay in each Interconnect modeled? We suggest clarifying that the intent is that Protection System Equipment would be incorporated into Facility Ratings and the contingency list, and that modeling the Protection System equipment settings and logic would only be done for Protection Systems that could significantly impact stability response (e.g., out-of-step relaying) as deemed appropriate through engineering judgment, and that the intent would be to do this only for the Region under study and not the entire Interconnection (e.g., studies in Florida should not need to include relay models in Canada). R4.3.2, we assume that the intent of this requirement would be to help establish the magnitude and duration of acceptable post-transient voltage dips, presumable to meet the curve published in the PRC-023 standard under draft. Is this a correct assumption? We assume the drafting team does not expect models to be written for every generator to actually model potential loss of station service due to voltage dips and automatically model potential generator trips. R4.4 and R4.5, see comments on R3.4 and R3.5 about re-arranging these requirements.
Response: R4.2: There are no hurricane events or weather events in the extreme events for stability analysis. No change made. R4.3: The SDT disagrees. There may be some contingencies on external systems which can have a dynamic impact on the system under study. Part 4.4.1 has been added to Requirement R4 to address this possibility.	

Organization	Question 4 Comment
4.4.1 The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. R4.3.1: Requirement R4, part 4.3.1 does not require modeling of Protection System equipment. It just requires you to have simulations which include the effects of Protection System equipment operation. Certainly engineering judgment should be used to determine which relay effects should be included in the simulations. No change made. R4.3.2: The intent of this requirement is to include in the Planning Assessment how voltage ride-through capability is analyzed in your studies. It does not require extensive modeling of a generating plant's distribution system. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the Planning Assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. R4 and R5: The SDT does not agree that the requirements should be re-ordered. No change made.	
MidAmerican Energy Company	MidAmerican commends the SDT for its hard work on this standard. MidAmerican suggests that R4.5 be revised by changing "remaining Contingencies" to "remaining unselected Contingencies.
Response: R4.5: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining Contingencies would produce less severe System results". **4.5** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R4, part 4.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.	
SMUD	R4.3:R4.3.2 - The requirement is unclear. If it is to cover modeling issues, then it should be under MOD series. If it is to cover voltage ride through performance, then performance metrics should be provided. R4.5Listing all possible scenarios for studying extreme contingencies will result in a limitless list. Discretion should be given to the transmission planner on the selection of the contingencies without a requirement to list why other extreme contingencies have not been included.
Response: R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require extensive modeling of a generating plant's distribution system. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this.	

Organization	Question 4 Comment
4.3.2 Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. R4.5: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining Contingencies would produce less severe System results".	
Progress Energy Florida, Inc.	For R4.3.2, PEF assumes that the SDT understands that the extent of analyzing generation voltage ride-through capability does not extend to modeling of individual inductive loads on the Distribution side, as this does not fit the definition of the BES. Motor loads on the Distribution system do have an effect on generation voltage ride-through capability, however, and PEF therefore is perplexed as to what extent the SDT expects concerning analysis for this sub-requirement.
Response: R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require extensive modeling of a generating plant's distribution system. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.	
Xcel Energy	R4.3 - requires very labor intensive and detailed studies to be conducted; there are concerns about being able to accomplish the required studies within the 24 month implementation period; additionally, while there may be some reliability benefit to requiring these studies, have the costs of this requirement been studied?; an alternative could be some sort of phased implementation (x% completed by 24months, etc.) R4.3.3 - to what degree is generator relaying factored into the model/study?
Response: R4.3: The SDT believes that 24 months is sufficient to perform the additional studies. No change made. R4.3.3: Generator relaying is not a part of Requirement R4, part 4.3.3.	
Ameren	In Requirement R4.1, it is suggested that the word "contingency" be added to describe the lists created in R4.4Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists created in Requirement R4.4. Regarding Requirement R4.4, it is suggested that a rewording be considered such as described below:For each category of the Planning Events in Table 1, those Planning Event Contingencies that are expected to produce more severe System impacts shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4.1 shall be created. The rationale for the Contingencies selected for evaluation shall be available as supporting information with an explanation of why the remaining Contingencies would produce less severe System results.

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	R4.3.2 requires that voltage ride through capability be analyzed. It is not clear what should be analyzed. e.g. auxiliary loads, generator protection, generator capability, etc. We would like to see more clarity on this requirement. It seems that the stuck breaker scenarios would always be more severe than the internal breaker failure scenario since they would be clearing in delayed clearing time and thus make P2.3 redundant. Are there is some question on whether P3 contingencies would be necessary for stability analysis. Revise wording in VSL from “categories” to “applicable categories”. e.g. some entities may not have common tower facilities and thus there would be no P7 category contingencies to evaluate. Footnote #3 needs to be revised to include Double-Line-To-Ground faults in addition to Three-Phase faults indicating that the SLG criteria is met.

Response: R4.1: The SDT agrees and has added the word "Contingency".

> **4.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, part 4.4.

R4.4: The SDT agrees and has modified the wording similar to your suggested wording however - due to other stakeholder comments, the phrase requiring an explanation was deleted from the revised standard.

> **4.4** Those planning events in Table 1that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4, part 4.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require extensive modeling of a generating plant's distribution system. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this.

> **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

Stuck breaker comment: A stuck breaker scenario would not always be more severe than an internal breaker fault. Depending on the location of CTs and PTs, an internal fault could take longer to clear.

P3 comment: Fault induced delayed voltage recovery simulations could be more severe in a Load area when a generator is out of service. Therefore, P3 events are applicable to Stability analysis.

VSL: The SDT does not believe it is necessary to add the word "applicable" in front of "categories" in the VSL for Requirement R4. The requirement in Part 4.1 is to study the list (Part 4.4) of "Those planning event Contingencies in Table 1 that are expected to produce more severe System impacts". If you have no applicable events in one of the categories, then just state that in the Planning Assessment. This will not be considered as not performing a study for one of the categories.

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R4 VSL	The responsible entity did not identify planning events as described in Requirement R4, part 4.4 or extreme events as described in Requirement R4, part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, part 4.2 to assess the impact of extreme events. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1.
Footnote #3 (now footnote #2): The SDT agrees and has modified the wording similar to your suggested wording. **Footnote 2** Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.				
Manitoba Hydro	R4.1: The requirement text should be changed to read “studies shall be performed for Planning Events to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists of events created in Requirement R4.4. R4.2: Requirement wording should be similar to R4.4 for consistency. R4.3: We agree that consideration of generator voltage ride through is important. However, we also suggest that frequency ride through capability be analyzed. R4.4 & R4.5: The selection of the contingency list is based on the knowledge of the PC/TP. How do you produce “an explanation of why the remaining Contingencies would produce less severe System results. without proving this with a study” If the explanation is “that based on engineering judgment, the remaining contingencies would produce less severe system results” then the explanation is implied and not necessary.			

Organization	Question 4 Comment
Response: R4.1: The SDT agrees and has changed the wording similar to your suggestion. **4.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, part 4.4. R4.2: The SDT does not understand this comment. No change made. R4.3: Frequency ride-through for generators would only be needed for a limited number of simulations, and therefore the SDT does not see the need to make a general requirement for this. No change made. R4.4 and R4.5: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining Contingencies would produce less severe System results".	
LCRA Transmission Services Corporation	In R4.3.3, what is meant by the term "electrical system quantities"? Quantities is typically an amount and its use here would indicate that a term such as parameters would be better suited.
Response: "Electrical system quantities" are items such as voltage, current, power, etc. The SDT believes the use of this term is appropriate in Requirement R4, part 4.3.3 (now 4.3.4). No change made.	
National Grid	R4 Comment " "Planning Assessment" and "shall perform analysis" are contradictory. R4 and its sub-requirements, then reference study requirements. If this is an assessment, then the standard shouldn't be requiring a study. R4.1 Comment ? A. It is not clear what should be included in the list related to R4.4. Events P0 through P4 should include analysis of all facilities BES facilities for which the Transmission Planner is responsible. Events P5 and higher should be limited to contingency events that are deemed the most significant by the Transmission Planner. B. R4.1 refers to "lists". Is R4.4 creating one list or multiple lists? Suggest changing "lists" to "list" R4.2 Comment - Since R4.4 and R4.5 both require the responsible entity to create a list, the words in R4.2 be should be revised to be more similar to the words in R4.1. Suggest changing "Studies shall be performed to assess the impact of the Extreme Events identified in Requirement R4.5. " to "Studies shall be performed to assess the impact of the Extreme Events, which are identified by the list created in Requirement R4.5. R4.3.2 Priority Comment - Traditionally transmission planners have assumed that generators would ride through low voltages associated with Planning Events which is generally adequate for non-wind generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R4.5 Priority Comment ?It is recommended that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. If the requirement is not deleted, the following is recommended:- Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events. If not, it will be difficult to utilize the results to obtain projects approvals.- It should be clear that an evaluation does not require solution development for all Extreme Events- Change "an evaluation of possible

Organization	Question 4 Comment
	actions"? to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered. - The statement "and shall include an explanation of why the remaining Contingencies would produce less severe System results" is too open and should be deleted. Violation Severity Levels:R4.4 Since this is a binary requirement, should this have a Severe VS? R4.5 Since this is a binary requirement, should this have a Severe VSL?
Response: R4: The SDT does not see a contradiction. Requirement R4 is a study requirement. The assessment requirement for stability is Requirement R2, part 2.4 and requires the use of current or past studies. No change made. R4.1A: The SDT disagrees. P1 - P4 (P0 not applicable to Stability) should be run for those Contingencies expected to produce more severe results. It is not necessary to study faults on every line in the System. No change made. R4.1B: The SDT agrees and has changed "lists" to "list". **4.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, part 4.4. R4.2: The SDT agrees and has changed to your suggested wording. **4.2** Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, part 4.5. R4.3.2: There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. R4.5: The SDT considers extreme event testing to be an important part of the assessment and therefore will not delete it. The expectation for extreme event testing is that for major problems you will evaluate actions to reduce likelihood or mitigate consequences. The SDT believes the original words express this concept better than your suggested words. No change made. R4.4 and R4.5 VSLs: The VSLs are based on taking Requirement R4 as a whole with Requirement R4, parts 4.4 and 4.5 being portions of that whole. The SDT does not think that failing to create a list of Contingencies should be a severe violation. When taking Requirement R4 as a whole, failing to create the list was deemed to be lower violations. No change made.	
Entergy Services, Inc	In R4.5 what would constitute "an evaluation of possible actions designed to reduce?"? R4.3.2 requires that voltage ride through capability be analyzed. It is not clear what should be analyzed (e.g. auxiliary loads, generator protection, generator capability, etc.) This requirement needs more clarity. " R4.3.2 " By in large, the industry does not have the input data or the methods to do this. It would seem necessary to have PRC-024 approved before this can be met.

Organization	Question 4 Comment
Response: R4.5: "An evaluation of actions designed to reduce" means looking for ways to reduce the probability of the event occurring or reducing the magnitude of the consequences of that event. For example, if a three phase fault with a bus differential failing to operate results in the collapse of a large Load area, a possible action would be to add a redundant bus differential relay. This reduces the probability of the event occurring. Or if a three phase fault with a stuck breaker results in a large area of the system pulling out of synchronism, an SPS could be used to trip a generator and keep the rest of the system in synchronism. This would reduce the magnitude of the consequences of the event. The evaluation would be comparing potential solutions and their cost with the consequences of the event to determine the best course of action to take (if any). R4.3.2: There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.	
BC Hydro	Comments: Consider changing R4.3.2 to, “Confirm proper generator performance under anticipated conditions including low voltage ride-through capability” In R4.3.3, change “VAR” to “var”. The IEC has adopted the name var, var (volt ampere reactive power), for the coherent SI unit volt ampere for reactive power. (see: http://www.iec.ch/zone/si/si_elecmag.htm#si_rpo). Is there an overlap between R4.3.3 and the MOD standards? If so, perhaps R4.3.3 should be deleted. If not, perhaps the MOD standard should be expanded to include this. Consider adding R4.3.4, “not simulate any operator intervention”
Response: R4.3.2: The SDT has changed the wording of Requirement R4, part 4.3.2 for additional clarification. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. R4.3.3: The SDT agrees and has changed "VAR" to "var". **4.3.4** Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers. R4.3.3: MOD-012 and MOD-013 do not require the data to be used for an assessment of the Transmission System. Therefore, the requirement to simulate the operation of exciters and stabilizers is needed in this standard. No change made. R4.3.4: The SDT does not think it is necessary to add "not simulate any operator intervention". If operator intervention is appropriate in the time frame of the study, then simulate it. No change made.	
Midwest ISO	Opening Remarks. Specific Comments for Requirement 4:

Organization	Question 4 Comment
	A) Under R4, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R4 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning".
Minnesota Power	Under R4, the Time Horizon of the TPL standards is intended for years one through 10; however, the Time Horizon shown in R4 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning".

Response: The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made.

Mitigation Time Horizon

The time horizons available for mitigating a violation to a requirement include the following:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

PJM	In R4, why require a Planning Coordinator AND a Transmission Planner to perform this analysis? Isn't this a duplication of effort? R4.4 should come before R4.1. You should never reference down in a standard. Please present the items in the order in which they should be performed/considered. Also in R4.1, a space is needed between "Requirement" and -R4.4-. R4.5 should come before R4.2. You should never reference down in a standard. Please present the items in the order in which they should be performed/considered. In R4.2.3, I question whether the existing dynamics models can evaluate voltage ride through. If you are just talking about modeling voltage protection of generators then maybe, but this protection information is presently not collected by the ERAG MMWG for the Eastern Interconnection. R4.4 should be broken into two requirements since two separate tasks need to be performed. R4.5 should be broken into three requirements since three separate tasks need to be performed.

Organization	Question 4 Comment
Response: R4: Requiring the Planning Coordinator AND the Transmission Planner to perform analysis should not result in a duplication of effort. Requirement R6 (now Requirement R7) requires the two entities to agree on their individual and joint responsibilities. No change made. R4.4 & R4.5: The SDT does not believe that re-ordering the requirements serves any purpose. No change made. R4.1: The SDT has revised the requirement. **4.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, part 4.4. R4.2.3: The SDT assumes you meant Requirement R4.3.2: There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. R4.4: The SDT disagrees that this requirement should be broken into two requirements. There are not two independent tasks in the requirement. The tasks are inherently correlated and will be assessed as part of the primary Requirement R4. No change made. R4.5: The SDT disagrees that this requirement should be broken into three requirements. There are not three independent tasks in the requirement. The tasks are inherently correlated and will be assessed as part of the primary Requirement R4. No change made.	
Brazos Electric Cooperative	Same general comment in 4.4 and 4.5 about the requirement to maintain documentation on why certain events would produce less severe results.
Response: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining Contingencies would produce less severe System results".	
American Electric Power	The cross-referencing between R4.1 and R4.4, and between R4.2 and R4.5, seems to add unnecessary complexity and could be eliminated by merging each of these pairs of sub-requirements. Under the event column of Table 1 of the proposed TPL standard, considering entries P3 and P6, the option to apply either SLG or 3-phase fault types should be retained to be consistent with the existing TPL standards, which permit either SLG or 3-phase faults (see existing Table 1, Category B and Category C3). If the SDT decides not to make the requested change, then the SDT should give recognition to the unique characteristics of 765 kV lines where permanent 3-phase faults are virtually non-existent. AEP's 765 kV transmission facilities have been successfully planned and operated with only a SLG fault criterion. Therefore, Table 1 Planning Events P3 and P6 should permit application of SLG faults.
Response: The SDT does not see any harm in having the cross referencing. No change made.	

Organization	Question 4 Comment
Table 1: Requirement R1.3.1 in TPL-002-0a states that simulations should "Be performed and evaluated only for those Category B Contingencies that would produce the more severe System results or impacts." The SDT believes that the intent of the existing TPL standards is to simulate the worst case whether three phase or single-line-to-ground. The new standard is clarifying that three-phase is required for single Contingency events. No change made. Note that AEP may request an entity variance from this part of the standard.	
ITC Holdings	Comments: In R2.5.1, a limitation is identified for stability studies that are used to support the annual assessment be less than five calendar years old. Should this reference be included in R4??
Response: R4: Because the five year limitation is stated in Requirement R2, part 2.5.1, there is no need to repeat it in Requirement R4. No change made.	
LADWP	R4.5 See coments on R3.4 and 3.5
Response: See response to comments for Requirement R3, parts 3.4 and 3.5.	
Platte River Power Authority	R4.3.2. Delete this requirement as it is covered under MOD-013-1, R1.2 for RRO Dynamics Data requirements. When the generator is modeled accordingly the generator's performance will be simulated and analyzed in the stability studies. R4.3.3. Delete this requirement as it is covered under MOD-013-1, R1.2 and R1.3 for RRO Dynamics Data requirements. When the generator is modeled accordingly the generator's performance will be simulated and analyzed in the stability studies.
Response: R4.3.2: The SDT has changed the wording of Requirement R4, part 4.3.2 for additional clarification. This does not require the modeling of generator relays although that is one method that could be used to meet the requirement. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. R4.3.3: MOD-013 does not require the data to be used for an assessment of the Transmission System. Therefore, the requirement to simulate the operation of exciters and stabilizers is needed in this standard. No change made.	
MAPPCOR	R4.3.2 - Traditionally transmission planners have assumed that generators would ride through low voltages associated with Planning Events which is generally adequate for non-wind generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R4.5 -Recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following:-Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events-It should be clear that an evaluation does not require solution development for all Extreme Events-Change “an evaluation of possible actions”? to “where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered.

Organization	Question 4 Comment
Response: R4.3.2: There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. R4.5: The SDT considers extreme event testing to be an important part of the assessment and therefore will not delete it. The expectation for extreme event testing is that for major problems you will evaluate actions to reduce likelihood or mitigate consequences. The SDT believes the original words express this concept better than your suggested words. No change made.	
Orlando Utilities Commission	For Requirement 4.3.1 and 4.3.3 I suggest adding language similar to 3.3.2 and 3.3.3 establishing that "studies shall consider" rather then requiring every simulation precisely recreate this usually minor part of system performance. These devices generally do not respond except for a nearby event, and even then their response is rarely such that it would make the situation "worse". The effect of these devices must be considered, but mandating that every simulation faithfully reproduce the response of every device is not only an efficient way to do this, it actually provides a counter incentive to going above and beyond the standard requirements. Any simulation used to meet this standard that failed to precisely reproduce the performance of this equipment would be a violation of this requirement (as currently written). As such there is no incentive for an entity to include anything but the absolute minimum number of simulations required to meet the standard, since each extra simulation represents an opportunity to miss this requirement. Good planning is based on running a broad range of events against a broad range of conditions and evaluating those responses against a set of performance criteria. This is encouraged by requiring that studies consider the response of equipment to these events rather then mandating their precise reproduction in simulation. Requirement 4.4 and 4.5 establish that only those events that would cause the most severe system impacts should be studied. This is an excellent requirement since it focuses the large resource requirement in performing these studies on the events that will provide the best information. Does the intent of the "More severe events" to establish actual study parameter extend between the planned events (R4.4) and extreme events (R4.5)? Or phrased another way, if an entity selects a proper range of extreme events and establishes that planning event performance requirements are met, could that be used as evidence that R4.4 is met as well, or would R4.4 require the same conditions be reproduced in their less severe configuration.
Response: R4.3.1: The SDT believes you should simulate the removal of System elements that Protection System and other controls would remove, not just consider it. No change made. R4.3.3 (now Part 4.3.4): The SDT has clarified that the devices to be included in the study which provide dynamic control are those that impact the study area. R4.4 and R4.5: You can always demonstrate that performance requirements are met by meeting them for a more severe Contingency. It is possible that you could demonstrate that performance requirements are met for planning events by performing extreme events (e.g., using a three-phase fault with stuck breaker Contingency can demonstrate that performance requirements for a single phase fault plus stuck breaker Contingency is met).	
American Transmission	We propose the following comments for R4:Add R4.3.3 text to include relay loadability in the R4 (Stability) requirements to

Organization	Question 4 Comment
Company	parallel R3.3.3 in the R3 (Steady State) requirement which would more clearly relate to the specific requirements in PRC-023. We suggest this text: "Incorporate relay loadability per PRC-023 and identify how relay loadability is analyzed in the dynamic simulation. In R4.3.4, we propose limiting the scope to automatic devices and adding the notion of "including but not limited to". We suggest R4.3.4 text of: "Simulate the expected automatic operation of existing and planned control devices including but not limited to generation exciter control and power system stabilizers, static VAR compensators, power flow controllers, and DC Transmission controllers. Add R4.3.5. The obligation to consider only planned System adjustments that are executable should be a Requirement, rather than performance note "e" in the Planning Events, Steady State & Stability section of Table 1. We suggest this text that matches R3.3.5: "Consider planned System adjustments, such as Transmission configuration changes and redispatch of generation, that are executable within the time duration of the applicable Facility Ratings.
Response: R4.3.3: The SDT agrees with the general idea and has added Requirement R4, part 4.3.3. However, Requirement R4, part 4.3.3 requires that you "Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers" rather than creating a Stability requirement for relay loadability. This requirement is more applicable to Stability studies than a relay loadability requirement would be. Relay loadability is more of a steady state issue than a dynamic issue. **4.3.3** Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers. R4.3.4: The SDT has made the suggested changes. **4.3.4** Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers. R4.3.5: Header note 'e' gives permission to use System adjustments under certain conditions. This is not a requirement and doesn't need to be included in Requirement R4. No change made.	
Idaho Power	R4.3.2 Generation protection system contain up to a dozen tripping functions functions. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to do that for all generators in the system.R4.5 ? Again I disagree with this requirement. It is the same as R3.5 and overly burdensome.
Response: R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require extensive modeling of all relay protection. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.	

Organization	Question 4 Comment
Duke Energy	Revise M4 to include a reference to R6, since the allocation of responsibilities will directly affect the evidence which is to be provided.
Response: M4: The SDT disagrees. No change made.	
California ISO	As currently drafted, R4.3 is not a requirement. Without the statements in R4.3.1-R4.3.3, R4.3 is simply a phrase. Sub-Sub-Requirements R4.3.1 through R4.3.3 should be bullets under R4.3, with the language in R4.3 modified so that it becomes the requirement to conduct contingency analyses that address the three resulting bullets. R4.3.2 it is not clear what is required to be modeled. Typically a generator may have 10 or more protective relays. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to do that for all generators in the system. R4.5 We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingency than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.

Response: R4.3: The SDT disagrees as these are mandatory elements of the Contingency analyses. Bullets are only used to identify the possible, but not all inclusive, elements of a menu. However, Requirement R4, part 4.3 has been modified to read more like a requirement as shown below.

> **4.3** Contingency analyses shall be performed and:

R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require modeling of all relay protection. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this.

> **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

R4.5: Several industry commenters have indicated that an explanation of “why the remaining Contingencies would produce less severe System performance” should be deleted since the Contingencies selected are those that produce more severe System performance. The SDT agrees and has deleted the requirement for an “explanation of why the remaining Contingencies would produce less severe System results”.

> **4.5** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R4, part 4.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

Organization	Question 4 Comment
Independent Electricity System Operator	. Same comments as in R3, above, except our proposed wording on R4 will read:R4. The Stability analyses of the Near-Term Planning Assessment as stipulated in R2.4.2 shall be performed as follows:. since there are no detailed requirements stipulated for Stability analysis portion for the Long-Term Planning Assessment. However, the main requirement contains a condition for performing the Contingency analyses listed in Table 1. First of all, there are no VSLs for failing to meet this condition. Secondly, this duplicates with some of the subrequirements, e.g. R4.4, R4.5. Suggest to remove this condition from the main requirement. If the main requirement is to be revised in a similar fashion as suggested for R3, then this will become a non-issue. 2. Similar to R3, we agree with the VRF, Time Horizon and Measure for R4. However, we do have the same difficulty with the VSL based on our comments on the convoluted nature of the requirement as indicated above, especially on the Moderate VSL for The Transmission Planner or Planning Coordinator did not base its studies on computer simulations using models utilizing data provided in Requirement R1.
Response: R4: The SDT does not see any need for Requirement R4 to reference back to Requirement R2, part 2.4. No change made. R4 VSL: (1) The VSL for Requirement R4 does cover failing to perform the Contingency analysis in Table 1. Depending on how many Contingency categories are not addressed, the violation could be moderate, high, or severe. No change made. R4 VSL: (2) Requirement R4 provides the general requirement to perform the Contingency analysis in Table 1. The parts like Requirement R4, part 4.4 provide more details on what must be run. There is no duplication. No change made. R4.5: The SDT believes that Requirement R4, part 4.5 is a necessary part. No change made. R4 VSL: The SDT disagrees with this idea. No change made.	
Kansas City Power & Light	R4.3 requires very labor intensive and detailed studies to be conducted; there are concerns about being able to accomplish the required studies within the 24 month implementation period; additionally, while there may be some reliability benefit to requiring these studies have the costs of this reliability increase been studied?; an alternative could be some sort of phased implementation (x% completed by 24months, etc.) R4.3.3 to what degree is generator relaying factored into the model/study?
Response: R4.3: The SDT believes that 24 months is sufficient to perform the additional studies. No change made. R4.3.3: Generator relaying is not a part of Requirement R4, part 4.3.3.	
ReliabilityFirst Corporation	R4.3.2 – Requires simulating generator voltage ride through capability. This may require modeling generator protection schemes to existing Dynamic models. This falls under which again falls under Section 1600 of NERC Rules of Procedure.
Response: R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require modeling of generator protection schemes. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information	

Organization	Question 4 Comment
about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.	

5. Requirement R5 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: In response to industry comments, the SDT has deleted the word 'proxy' in favor of the terminology 'criteria or methodology' in Requirement R5 (now Requirement R6).

R6. Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, any criteria or methodology used in its analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.

Organization	Question 5 Comment
Dominion - Electric Transmission Tucson Electric Power Company	Use of Proxies: There is no requirement that the Planning Coordinator (PC) must use the same proxies as the Transmission Planner (TP). Since differences in proxy assumptions may lead to different study results, R5 should be revised to require the PC and TP to coordinate the use of proxies.
Hydro-Québec TransEnergie (HQT)	There is no requirement that the Planning Coordinator must use the same proxies as the Transmission Planner. Differences in proxy assumptions may lead to different study results. R5 needs to be modified to require coordination of proxies between Planning Coordinators and Transmission Planners.
Response: Criteria or methodologies will be fleshed out in peer review. No change made.	
OPUC	MRO NSRS proposes specifying that the proxy documentation be included in the Planning Assessment and add the rationale for the proxy. MRO NSRS suggests this text: "Each Transmission Planner and Planning Coordinator shall document within the Planning Assessment any proxies used in the analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding. The documentation will consist of the definition of each proxy used and the rationale for the proxies.
Response: The SDT has revised the requirement language to provide greater clarity as to the intent. **R6.** Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, any criteria or methodology used in its analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.	
Bonneville Power Administration	There is no requirement that the Planning Coordinator (PC) must use the same proxies as the Transmission Planner (TP). Since differences in proxy assumptions may lead to different study results, R5 should be revised to require the PC and TP to coordinate the use of proxies. M5 doesn't make any sense. Need to revise this Measure so that it fits the Requirement R5. Also need to revise the Data Retention discussion in Section 1.4 to align with R5. In the VSL associated with R5, we believe that failure to define and document one of the proxies should be a moderate VSL,

Organization	Question 5 Comment
	failure to define and document two proxies should me a high VSL, while failure to define and document three proxies should be a severe VSL. Otherwise failing to document only one proxy would result in a severe VSL.
Response: Criteria or methodologies will be fleshed out in peer review. The SDT has changed the language of Requirement R6 (formerly Requirement R5). **R6.** Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, any criteria or methodology used in its analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding. The SDT does not agree and believes that the Measure appropriately addresses Requirement R6 (formerly Requirement R5). No change made. The SDT does not agree and believes that the Data Retention for this Requirement is in line with accepted Guidelines. No change made. The SDT appreciates your comment on the level of severity for this Requirement but still believes this is the appropriate level to apply. No change made.	
MRO MRO NERC Standards Review Subcommittee	We agree with the stated Requirement, Measure, VRF, Time-Horizon, Data Retention and VSL of requirement R5.
PacifiCorp	None - no concerns identified by the TWG
JEA	PEF does not presently have any concerns with R5.
Central Maine Power Company	We agree with the requirement, the VRF, Time Horizon, Measure and VSLs.
Response: Thank you for your response. However, due to other responses, some changes have been made. Please see the summary response.	
SRP	In R5 the term “proxy” needs to be defined. In addition, an example of a proxy should be given.
Gainesville Regional Utilities	R5:Guidelines for identifying proxies for unstable conditions would be helpful.
Progress Energy Florida, Inc.	The term proxy is unclear. Please provide an example or an explanation of proxy. If this is related to Note “i” in Table 1, it should be so stated. If it is related to assumptions or criteria, please state so.
Xcel Energy	Please clearify "Proxies"
Mississippi Delta Energy Agency	The term proxy is unclear. Please provide an example or an explanation of proxy. Perhaps a different term, such as metric, may better describe this requirement to more people.
Tenaska, Inc.	In R5, what is meant by the term “any proxies”? Please clarify. This comment also pertains to this terms use in the VSL as well.

Organization	Question 5 Comment
Manitoba Hydro	It is unclear as to what is meant by the term “proxy used in the analysis” used in this requirement. Is a “proxy” a “criteria”?
National Grid	Comments: The meaning of the word “proxies” in this context seems uncommon making the requirement unclear. Perhaps “proxies” should be replaced with “criteria” or “criteria or proxies”.
Northern Indiana Public Service Company	What is a proxy as related to transmission planning? The drafting team should not introduce "non-standard" terms in a Standard document.
San Diego Gas and Electric Co	R5. For clarification, please list examples of "proxies" that might be used.
Minnesota Power	an example of proxy may be helpful, not all entities use proxies.
ISO New England, Inc. Western Area Power Administration American Electric Power Great River Energy New York Independent System Operator Modesto Irrigation District Louisiana Energy and Power Authority City Utilities of Springfield, MO Duke Energy New Brunswick System Operator MidAmerican Energy Company	The term proxy is unclear. Please provide an example or an explanation of proxy.
California ISO NorthWestern Corporation NorthWestern Energy (NWE) (NWMT)	The term “proxies” is somewhat confusing; recommend the use of “assumptions” if that is an acceptable substitute.
Independent Electricity System	On page 13 under Section R5, can the term “proxies” be defined and clarified, and examples given, in this context ?

Organization	Question 5 Comment
Operator Northeast Power Coordinating Council	
Kansas City Power & Light	5. Requirement R5 Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.Comments:A: An example should be added for proxy use.
IRC Standards Review Committee	We recommend using an alternate term for proxies such as criteria, guidelines, etc. to clarify what is meant.
Pepco Holdings, Inc. - Affiliates	We recommend that the word “proxies” be changed to “criteria”.
Transmission Planning	5. Requirement R5 Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.Comments:A: An example should be added for proxy use.
TVA System Planning	It is unclear as to what is meant by the term “proxy used in the analysis” used in this requirement. Does this mean Planning Coordinator established practices, thresholds or guidelines used to gauge when simulations suggest an event such as cascading outages occurs? If so the language should state: R5. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, when established practices, thresholds or guidelines identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.
United Illuminating	Please clarify how the term “Proxies” is used in this requirement.
PPL Energy Plus	Please define the term "proxies".
CPS Energy	Comments: It is unclear as to what is meant by the term “proxy used in the analysis” as it is used in this requirement. Does this mean Planning Coordinator established practices, thresholds, or guidelines used to gauge when simulations suggest an event such as cascading outages occurs? If so the language should state: R5. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, when established practices, thresholds or guidelines identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.
Response: The SDT agrees with this comment and has changed the Requirement language to provide clarity as to intent. **R6.** Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, any criteria or methodology used in its analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.	
SERC Engineering Committee	In the VSL associated with R5, we believe that failure to define and document one of the proxies should be a moderate VSL,

Organization	Question 5 Comment
Reliability Review Subcommittee (RRS)	failure to define and document two proxies should me a high VSL, while failure to define and document three proxies should be a severe VSL. Otherwise failing to document only one proxy would result in a severe VSL. The word "proxies" in this context is confusing and subject to various interpretations. Recommend changing the word "proxies" to "criteria. There is no requirement that the Planning Coordinator (PC) must use the same proxies as the Transmission Planner (TP). Since differences in proxy assumptions may lead to different study results, R5 should be revised to require the PC and TP to coordinate the use of proxies.
Response: The SDT appreciates your comment on the level of severity for this Requirement but still believes this is the appropriate level to apply. No change made. The SDT agrees with this comment and has changed the Requirement language to provide clarity as to intent. **R6.** Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, any criteria or methodology used in its analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding. The SDT does not see the need for a requirement to coordinate the use of proxies. No change made.	
FirstEnergy Corp	The determination of a failure to document a single proxy should not be categorized as "severe".
Response: The SDT appreciates your comment on the level of severity for this Requirement but still believes this is the appropriate level to apply. No change made.	
Southern Company	"Proxies" is not defined. We take "proxy" to mean a procedure used to model system response that is outside the capability of system modeling tools used in the analysis. For example, a powerflow model might not be able to model cascading events with built-in capabilities. As a proxy, the engineer would run follow-up studies that would mimic expected system response. Please define the term "proxy".
SMUD	It is unclear as to what is meant by the term "proxy used in the analysis" used in this requirement. Does this mean Planning Coordinator established practices, thresholds or guidelines used to gauge when simulations suggest an event such as cascading outages occurs? If so the language should state: R5. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, when established practices, thresholds or guidelines identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.
Platte River Power Authority	We propose specifying that the proxy documentation be included in the Planning Assessment and add the rationale for the proxy. We suggest this text: "Each Transmission Planner and Planning Coordinator shall document within the Planning Assessment any proxies used in the analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding. The documentation will consist of the definition of each proxy used and the rationale for the proxies.

Organization	Question 5 Comment
Turlock Irrigation District	Comments: It is unclear as to what is meant by the term "proxy used in the analysis" used in this requirement. Does this mean Planning Coordinator established practices, thresholds or guidelines used to gauge when simulations suggest an event such as cascading outages occurs? If so the language should state: R5. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, when established practices, thresholds or guidelines identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.
Response: The SDT agrees with this comment and has changed the Requirement language to provide clarity as to intent. **R6.** Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, any criteria or methodology used in its analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.	
Deseret Generation & Transmission	Please provide a definition of "cascading outages" since the FERC and NERC removed their approval of the definition. Or use the definition of "cascading" found in the NERC Glossary of Terms. This term is also used in R3.5, R4.5, and Table 1.a. without any definition provided. NOTE: On December 27,2007, the Federal Energy Regulatory Commission remanded the definition of" Cascading Outage" to NERC. On February 12, 2008, the NERC Board of Trustees withdrew its November 1, 2006 approval of that definition, without prejudice to the ongoing work of the FACstandards drafting team and the revised standards that are developed through the standardsdevelopment process. Therefore, the definition is no longer in effect. Please provide a definition of "voltage instability" since the NERC Glossary of Terms does not provide one. This term is also used in Table 1.a. without any definition provided. Please provide a definition of "uncontrolled islanding" since the NERC Glossary of Terms does not provide one. This term is also used in Table 1.a. without any definition provided.
Response: The SDT declines to provide definitions for the indicated terms.	
Puget Sound Energy, Inc.	Data Retention: The 5th bullet should refer to "proxies" instead of "studies".
Response: The SDT disagrees with your statement as the studies will reveal the Proxies (now criteria or methodology) used in the Planning Assessment. No change made.	
E.ON U.S.	M5 doesn't make any sense. Need to revise this Measure so that it fits the Requirement R5. Also need to revise the Data Retention discussion in Section 1.4 to align with R5. In the VSL associated with R5, we believe that failure to define and document the proxies should be a moderate VSL.
Response: The SDT does not agree and believes that the Measure appropriately addresses Requirement R6 (formerly Requirement R5). No change made. The SDT does not agree and believes that the Data Retention for this Requirement should be and is identical to the other Requirements. No change made. The SDT appreciates your comment on the level of severity for this Requirement but still believes this is the appropriate level to apply. No change made.	

Organization	Question 5 Comment
Entergy Services, Inc	Under R5, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R5 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning".
ITC Holdings	Under R5, the Time Horizon of the TPL standards is intended for years one through 10; however, the Time Horizon shown in R5 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning".

Response: The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made.

Mitigation Time Horizon

The time horizons available for mitigating a violation to a requirement include the following:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.

Operations Assessment — follow-up evaluations and reporting of real time operations.

Idaho Power	M5 doesn't make any sense. Need to revise this Measure so that it fits the Requirement R5. Also need to revise the Data Retention discussion in Section 1.4 to align with R5.

Response: The SDT does not agree and believes that the Measure appropriately addresses Requirement R6 (formerly Requirement R5). No change made.

6. Requirement R6 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: Requirement R6 (now Requirement R7) is an overarching requirement that applies to the entire set of analysis required to meet the requirements of the TPL standard and to the Corrective Action Plan developed as part of the Planning Assessment. The intent of this requirement is to clarify that while the responsibilities for the TPL requirements are for both the Transmission Planner and Planning Coordinator, the individual tasks may be met through joint or shared analysis. Industry feedback indicates that it is important to minimize duplicative studies to the greatest extent possible. Coordinating and/or joint analysis does not alleviate the responsibility that all entities need to comply with the standard requirements. The SDT has made changes for clarity.

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.

Organization	Question 6 Comment
Northeast Power Coordinating Council United Illuminating Northeast Utilities ISO New England, Inc. Central Maine Power Company	We do not feel that this requirement belongs in this standard and it should be deleted. The standard defines requirements for the assessment not who does what.
Response: The intent of this requirement is to clarify that TPL requirements can be meet through joint or shared analysis. Industry feedback indicates that it is important to minimize duplicative studies to the greatest extent possible. This requirement does not preclude any single entity from performing all the study work required to support an assessment. No change made.	
MRO NERC Standards Review Subcommittee	MRO NSRS is not clear if: 1) Each Transmission Planner is to meet all the requirements including doing all the studies and all Planning coordinators are to meet the requirements including doing all the studies.Or 2) If the Transmission Planner and Planning Coordinator are to work as a team to meet all the requirements including doing all the studies. Either one of them could do various parts of the required studies. For example, maybe the PC could do the stability part so all TP's would not necessarily have to buy that software if they did not need it for other planning purposes.In the first read of this standard, it appears that the intention was number 1, which sounds awfully duplicative. But then take a look at Requirement 6. R6. Each Transmission Planner and Planning Coordinator shall determine and identify individual and joint responsibilities for performing the required studies for the Planning Assessment. [Violation Risk Factor: Low] [Time Horizon: Long-term Planning]After reading R6, it appears that number 2 was intended. Perhaps R6 should be the very first requirement in the standard. The MRO NSRS requests that the NERC SDT clarify the responsibility of the requirements of this standard.

Organization	Question 6 Comment
Response: The requirement specifies that individual and joint responsibilities for performing the required studies be identified. Requirement R6 (now Requirement R7) is an overarching requirement that applies to the entire set of analysis required to meet all the requirements of the TPL. **R7**. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.	
SERC Engineering Committee Reliability Review Subcommittee (RRS)	In absence of these agreements, it is assumed that both Transmission Planners and Planning Coordinators would be responsible for performing the studies. How do the Corrective Action Plans get resolved between these entities if there is no agreement on the study results??Requirements R1, R2, R3, R4 and R5 should all be revised to include a reference to R6 regarding the determination of individual and joint responsibilities for performing the required studies. In the VSL associated with R6, we believe that failure to determine and identify one responsibility should be a moderate VSL, failure to determine and identify two responsibilities should me a high VSL, while failure to determine and identify three responsibilities should be a severe VSL. Otherwise failing to document only one responsibility would result in a severe VSL.
Response: Requirement R6 (now Requirement R7) is an overarching requirement that applies to the entire set of analysis required to meet all the requirements of the TPL and to the corrective action plan developed as part of the assessment. The proposed changes to the VSLs do not conform to Guideline 3 of the FERC VSL order. No change made to the VSL. **R7**. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.	
FirstEnergy Corp	We agree with the stated Requirement, Measure, VRF, Time-Horizon, Data Retention and VSL of requirement R6.
Progress Energy Florida, Inc.	PEF does not presently have any concerns with R6.
American Transmission Company	We agree with the revisions to R6.
Independent Electricity System Operator	We agree with the requirement, the VRF, Time Horizon, Measure and VSLs.
Response: Thank you for your response. However, please see changes indicated in the summary due to other industry comments.	
TVA System Planning	In the VSL associated with R6, we believe that failure to determine and identify one responsibility should be a moderate VSL, failure to determine and identify two responsibilities should me a high VSL, while failure to determine and identify three responsibilities should be a severe VSL. Otherwise failing to document only one responsibility would result in a severe VSL.
Response: The proposed changes to the VSL do not conform to Guideline 3 of the FERC VSL order. No change made	

Organization	Question 6 Comment
Florida Reliability Coordinating Council, Inc - Transmission Working Group	Please clarify that the phrase "individual and joint responsibilities" applies to entities (e.g., the TPs and PCs) and not specific individuals.R6 Please clarify if this requirement is intended for cases where a TP is not a PC and therefore is working "under" a PC? Or if this is intended to apply across neighboring PC's?
FMPA	Please clarify that the phrase "individual and joint responsibilities" applies to entities (e.g., the TPs and PCs) and not specific individuals.
Response: Thank you for pointing out a potential for misinterpretation of the intent of the requirement. The SDT has modified the language. **R7**. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.	
Xcel Energy	Why is this needed if both entities must comply with the standard?At a minimum the requirement should include language to state that the one party must provide to the other with enough notice to comply with a required study if there is a shift or assignment of a responsibility.
Ameren	In absence of these agreements, it is assumed that both Transmission Planners and Planning Coordinators would be responsible for performing the studies. It is not clear how the Corrective Action Plans get resolved between these entities if there is no agreement on the study results.
Duke Energy	Requirements R1, R2, R3, R4 and R5 should all be revised to include a reference to R6 regarding the determination of individual and joint responsibilities for performing the required studies.
Response: Requirement R6 (now Requirement R7) is an overarching requirement that applies to the entire set of analysis to meet all the requirements of the TPL. This includes the corrective action plan developed as part of the assessment. Coordinating and/or joint analysis does not alleviate the responsibility that all entities need to comply with the standard requirements. **R7**. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.	
Midwest ISO	A) Under R6, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R6 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning".
Minnesota Power	Under R6, the Time Horizon of the TPL standards is intended for years one through 10; however, the Time Horizon shown in R6 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning".
Response: The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time	

Organization	Question 6 Comment
frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made. **Mitigation Time Horizon** The time horizons available for mitigating a violation to a requirement include the following: • **Long-term Planning** — a planning horizon of one year or longer. • **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal. • **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time. • **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system. • **Operations Assessment** — follow-up evaluations and reporting of real time operations.	
Brazos Electric Cooperative	is there any other way to identify responsibilities between the parties than having an agreement? R6 seems to indicate an agreement of some sort must be in place. if that is the case then it could simply say an agreement must be in place.
Response: The requirement has been clarified in response to others' comments. The SDT did not want to imply that a separate agreement would be required for the purposes of the assessment. **R7**. Each Planning Coordinator, in conjunction with each of its Transmission Planners shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.	
ITC Holdings	Comments: Should this requirement state that ?The Transmission Planner in conjunction with their Planning Coordinator shall determine and identify individual and joint responsibilities for performing the required studies for the Planning Assessment.
Response: The SDT has modified the language. **R7**. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.	
LADWP	R6: Does this requirement requires authors of the planning assessment report should be identified? If so, can we use plain English like "The authors of the Planning Assessment report shall be identified". If not, please explain what this requirement is all about.
Kansas City Power & Light	Why is this needed if both entities must comply with the standard?At a minimum the requirement should include language to state that the one party must provide to the other with enough notice to comply with a required study if there is a shift or assignment of a responsibility.

Organization	Question 6 Comment
Response: Requirement R6 (now Requirement R7) is an overarching requirement that applies to the entire set of analysis required to meet all the requirements of the TPL and to the corrective action plan developed as part of the assessment. The intent of this requirement is to clarify TPL requirements can be met through joint or shared analysis. Industry feedback indicates that it is important to minimize duplicative studies to the greatest extent possible. Coordinating and/or joint analysis does not alleviate the responsibility that all entities need to comply with the standard requirements. **R7**. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.	
Orlando Utilities Commission	R6: Is this requirement intended for cases where the TP is not also their PC, or is this between adjacent PC's?
Response: The intent of this requirement is to clarify TPL requirements can be meet through joint or shared analysis. Industry feedback indicates that it is important to minimize duplicative studies to the greatest extent possible. The requirement has been clarified in response to others' comments. **R7**. Each Planning Coordinator, in conjunction with each of itsTransmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.	

7. Requirement R7 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: Many commenters feel that the reference to FERC Order 890 is inappropriate, but most do not argue against the importance of sharing Planning Assessment information. There was also concern about the meaning of the phrase "coordinating of analysis of these results", and what was specifically required. The SDT believes sharing of information, understanding the impact on/from neighboring areas, peer review/feedback, and wide area assessment are important to effective Transmission planning. As a result of the comments several revisions have been made to TPL-001-1.

Revisions to Requirement R3, part R3.4 and Requirement R4, part 4.4 will clarify the expectation that Transmission Planner's and Planning Coordinator's analyze Table 1 events outside their System for reliability impacts to understand neighboring System impacts. The revised TPL-001-1 Requirement R8 (formerly Requirement R7) will ensure appropriate information is exchanged between Transmission Planner's and Planning Coordinator's for sharing of information, review, and coordination of plans in conformance with Order 693, paragraph 1755 and 1756 expectations by requiring distribution of Planning Assessments to neighboring Transmission Planners and Planning Coordinators, as well as entities with a reliability-related need. The NERC Rules and Procedures and delegation agreements cover existing TPL-005-0 & TPL-006-0 assessment requirements for regional and inter-regional assessments allowing for retirement of these two standards. The aggregate effect of the above items will be an overlapping assessment of BES reliability from each Transmission Planner area up through each Interconnection.

R8 Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.

R8.1 If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M8 Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient, date, and contents, or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and any functional entity who has indicated a reliability need and has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

R8 VSL	The responsible entity failed to distribute the results of its Planning Assessment to any one of its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

Organization	Question 7 Comment
Northeast Power Coordinating Council United Illuminating Northeast Utilities ISO New England, Inc. National Grid Central Maine Power Company	This standard should not be reiterating FERC Order 890. We do not feel that this requirement belongs in this standard and it should be deleted.
SERC Engineering Committee Planning Standards Subcommittee	FERC Order 890:The reference to FERC Order 890 as it is currently written makes it seem like a suggestion to follow Order 890. If Order 890 explicitly describes this process then the sentence should read “as described in FERC Order 890. If not, this should not be mentioned at all.
Bonneville Power Administration PacifiCorp Deseret Generation & Transmission SRP Arizona Public Service Co Western Area Power Administration Pacific Gas and Electric Co, Puget Sound Energy, Inc. NV Energy Southern California Edison Company San Diego Gas and Electric Co California ISO Tucson Electric Power Company	We believe that references to FERC Orders should not be included in requirements of standards. This comment also applies to M7.

Organization	Question 7 Comment
NorthWestern Corporation NorthWestern Energy (NWE) (NWMT)	In R7 the references to FERC Orders should not be included in requirements of standards. This comment also applies to M7.
Response: The SDT agrees that the standard should not reference Order 890 and the reference has been deleted. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. **M8** Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient, date, and contents, or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and any functional entity who has indicated a reliability need and has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.	
MRO NERC Standards Review Subcommittee	MRO NSRS proposes expanding the scope of entities to consider, limit it to those entities that indicate a reliability need for coordination, and eliminate the direct reference to Order 890. MRO NSRS suggests this text: "Each Planning Coordinator shall establish a list of adjacent Planning Coordinators and any functional entity who has indicated a reliability need, distribute its Planning Assessment results to the listed entities and consider comments on the assumptions and results through an open and transparent peer review process.
Response: The scope of entities has been modified. Each Transmission Planner and Planning Coordinator shall distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. An additional sub-requirement has been added to require that if a recipient of the Planning Assessment results provides documented comments on the results, the respective Transmission Planner or Planning Coordinator shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. **R8.1** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	
SERC Engineering Committee Reliability Review Subcommittee (RRS)	The reference to FERC Order 890 as it is currently written makes it seem like a suggestion to follow Order 890. If Order 890 explicitly describes this process then the sentence should read "as described in FERC Order 890. If not, this should not be mentioned at all. " Requirement R7 describes that the Planning Coordinator is to share Planning Assessments with adjacent Planning Coordinators. Does this need to be expanded for the Transmission Planners to share their Planning Assessments with the Planning Coordinators?? In the VSL associated with R7, we believe that the PC failing to coordinate analysis should be a moderate VSL, the PC failing to distribute should be a high VSL, and failing to do both of these tasks should be a severe VSL.

Organization	Question 7 Comment

Response: The SDT agrees that the standard should not reference Order 890 and the reference has been deleted.

The scope of entities has been modified. Each Transmission Planner and Planning Coordinator shall distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment.

The VSL has been modified to reflect the changes to the requirement. The requirement no longer requires a coordinated analysis. The failure to distribute the results is a High VSL. Failure to respond to comments is a Severe VSL.

R8 Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.

R8 VSL	The Transmission Planner or Planning Coordinator failed to distribute the results of its Planning Assessment to any one of its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	N/A	The Transmission Planner or Planning Coordinator failed to distribute the results of its Planning Assessment to its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	The Transmission Planner or Planning Coordinator failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

FirstEnergy Corp	We agree with the stated Requirement, Measure, VRF, Time-Horizon, Data Retention and VSL of requirement R7.
Progress Energy Florida, Inc.	PEF does not presently have any concerns with R7.

Response: Thank you for your response. However, please note the changes made to Requirement R7, Measure R7, and the Requirement R7 VSL (now Requirement R8) due to a majority of industry commenters indicating that some changes were needed.

IRC Standards Review Committee	Is the PC expected to distribute the TP Planning Assessments as part of its coordination requirement?

Response: The term “coordinating analysis” has been deleted from the requirement and only distribution of assessments by the Transmission Planner and Planning Coordinator is required.

R8 Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.

Organization	Question 7 Comment			
TVA System Planning	In the VSL associated with R7, we believe that the PC failing to coordinate analysis should be a moderate VSL, the PC failing to distribute should be a high VSL, and failing to do both of these tasks should be a severe VSL.			
Response: The VSL has been modified to reflect the changes to the requirement. The requirement no longer requires a coordinated analysis. The failure to distribute the results is a High VSL. Failure to respond to comments is a Severe VSL. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.				
R8 VSL	The Transmission Planner or Planning Coordinator failed to distribute the results of its Planning Assessment to any one of its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	N/A	The Transmission Planner or Planning Coordinator failed to distribute the results of its Planning Assessment to its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	The Transmission Planner or Planning Coordinator failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.
Southern Company	We recommend the following wording for R7.Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among adjacent Planning Coordinators and any functional entity who has indicated a reliability need. Each Planning Coordinator shall coordinate analysis of these results through an open and transparent peer review process such as described in FERC Order 890.			
Response: The SDT agrees and, in addition, the scope of entities has been modified. Each Transmission Planner and Planning Coordinator shall distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. The VSL has been modified to reflect the changes to the requirement. The requirement no longer requires a coordinated analysis. The failure to distribute the results is a High VSL. Failure to respond to comments is a Severe VSL. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.				
R8 VSL	The responsible entity failed to distribute the results of its Planning Assessment to any one of	N/A	The responsible entity failed to distribute the results of its Planning Assessment to its adjacent Transmission	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment

Organization	Question 7 Comment			
	its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.		Planners and Planning Coordinators, respectively in accordance with Requirement R8.	results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.
System Protection and Transmission Planning Department	The phrase "coordinating analysis of these results" seems to indicate potential second-guessing by other entities. We suggest "coordinating REVIEW of these results" may be clearer. The term "such as described in FERC Order 890" allows non-jurisdictional utilities to establish an appropriate process. This is good. However, we still have the same misgivings about the term "such as" used here.			
Manitoba Hydro	It is unclear as to what is meant by “coordinating analysis of these results”? Does this imply an obligation to conduct joint studies or just an obligation to distribute the assessment and respond to feedback? We suggest that the wording “such as described in FERC Order 890” be replaced with “such as may be required by a regulator in its PC/TP area”. The SDT is posing several other questions for industry consideration not related to the specific requirement questions above.			
Response: The SDT agrees that the term “coordinating analysis” is unclear and has modified Requirement R7 (now Requirement R8) to only require distribution of planning assessments. The reference to Order 890 is no longer necessary. However, the SDT does believe it is appropriate to require a response if a recipient of the Planning Assessment results provides documented comments on the results. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.				
PPL Energy Plus	Please continue to mention relevant FERC Orders (such as 890) in the standards since the FERC orders are the source of many of the planning standards. Planners need to acknowledge, respect, and design processes and systems around the FERC rulings.			
MidAmerican Energy Company	MidAmerican commends the SDT for its hard work on this standard. MidAmerican recommends changing R7 by changing “FERC Order 890” to “FERC Order No. 890”.			
Response: The majority of commenters had an opposite opinion of referencing FERC Orders in NERC standards and the reference to Order 890 has been deleted.				
Florida Reliability Coordinating Council, Inc - Transmission Working Group	The requirement as written requires that the results of the assessment are shared on a post assessment basis between entities in a manner similar to the Attachment K process. Please clarify whether:-Is this intended to be the end results? Or does this require the inviting of entities in at the very beginning and facilitating their participation throughout the process? -Is it intended that the process described in order 890 become essentially a NERC Standard that every sentence must be met in the most literal of sense? Or is this referencing the order as a general guideline on what should be expected but not as a literal			

Organization	Question 7 Comment
	checkmark of the process? Consider adding a footnote or other clarifications that failure of others to participate in the process is not a non compliance by the entity inviting them to the process. Otherwise non-responsiveness of a neighboring PC who may not have reliability need to participate and whose participation is beyond the control of the PC that initiated the process could trigger non-compliance.
Entergy Services, Inc	This requirement is addressed through FERC Order No. 890 (9 principles of transmission planning).
Platte River Power Authority	R7. Delete this requirement as it is the responsibility of the Transmission Provider under FERC Order 890.
American Transmission Company	We propose expanding the scope of entities to consider, limit it to those entities that indicate a reliability need for coordination, and eliminate the direct reference to FERC Order 890 and peer review. We suggest this text: "Each Planning Coordinator shall establish a list of adjacent Planning Coordinators and any functional entity who has indicated a reliability need, and distribute its Planning Assessment results to the listed entities and consider comments on the assumptions and results.
Response: The reference to Order 890 created confusion regarding process requirements and the reference has been deleted. The standard now requires each Transmission Planner and Planning Coordinator to distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. In addition, if a recipient of the Planning Assessment results provides documented comments on the results, the respective Transmission Planner or Planning Coordinator shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. This simplifies the process while achieving appropriate involvement of affected entities. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. **R8.1** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	
SMUD	Requirement R7 should end after the words '....who has indicated a reliability need'. R7:The requirement should not invoke another document for compliance. The words, ", coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890', should be deleted. This comment also applies to M7.
Response: The reference to Order 890 created confusion regarding process requirements and the reference has been deleted. The standard now requires each Transmission Planner and Planning Coordinator to distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. In addition, if a recipient of the Planning Assessment results provides documented comments on the results, the respective Transmission Planner or Planning Coordinator shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. This simplifies the process while achieving appropriate involvement of affected entities. Conforming changes have been made to Measure M7 (now M8). **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and	

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Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. **R8.1** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. **M8** Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient, date, and contents, or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and any functional entity who has indicated a reliability need and has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.	
Xcel Energy	Recommend deleting the portion of the requirement that states: "coordinating analysis of these results through an open and transparent review process such as described in FERC Order 890.
LADWP	FERC 890 stands on its own, why should a planning standard refers to a FERC Order? Does this imply that if a FERC Order is not referenced in the planning standard, we can ignor the order?
Independent Electricity System Operator	1. We question the need to mention FERC 890. If this meant to be an example for the US entities, we suggest this to be put into a footnote with indication that it is an example for the US entities only.2. We agree with the requirement, the VRF, Time Horizon, Measure and VSLs.
Response: The reference to Order 890 created confusion regarding process requirements and the reference has been deleted. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.	
Ameren	Requirement R7 describes that the Planning Coordinator is to share Planning Assessments with adjacent Planning Coordinators. It is not clear whether this needs to be expanded for the Transmission Planners to share their Planning Assessments with the Planning Coordinators. The reference to FERC Order 890 as it is currently written makes it seem like a suggestion to follow Order 890. If Order 890 explicitly describes this process then the sentence should read "as described in FERC Order 890. If not, maybe this should not be mentioned at all.
Response: The scope of entities has been modified. Each Transmission Planner and Planning Coordinator shall distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. The reference to Order 890 created confusion regarding process requirements and the reference has been deleted. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.	
Midwest ISO	A) Under R7, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R7 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10

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	and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning". B) The coordination of analysis of results through an open and transparent process is already a FERC requirement thus producing a double jeopardy for those entities that fall under the jurisdiction of FERC Order 890. We recommend striking the following language in the last sentence: ...coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890. C) Under R7 only the Planning Coordinator is required to coordinate the distribution of Planning Assessment results among adjacent PCs and any functional entity who has indicated a reliability need, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890. Should the TP be added to this requirement? We propose the suggested language change: Each Transmission Planner and Planning Coordinator shall coordinate the distribution of Planning Assessment results among adjacent Transmission Planners and Planning Coordinators, respectfully, and to any functional entity who has indicated a reliability need, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890. D) Based on the comments above in (B) and (C), our suggested requirement language is as follows: Each Transmission Planner and Planning Coordinator shall coordinate analysis in support of assessments in accordance with applicable regulatory requirements. Each Planning Coordinator shall distribute its completed planning assessment results among adjacent Planning Coordinators and any functional entity who indicated in writing a reliability related need.

Response: The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. No change made.

Mitigation Time Horizon

The time horizons available for mitigating a violation to a requirement include the following:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

The reference to "coordinating analysis" and Order 890 created confusion regarding process requirements and the requirement has been modified. The standard now requires each Transmission Planner and Planning Coordinator to distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. In addition, if a recipient of the Planning Assessment results provides documented comments on the results, the respective Transmission Planner or Planning Coordinator shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. This simplifies the process while achieving appropriate involvement of affected entities.

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R8 Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. **R8.1** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	
PJM	R7 needs to be broken into two parts. First establish the list of entities that need to get the assessment results. Second would be to coordinate the results as mentioned. Are the results mentioned in R7 different from the Planning Assessment?
Response: The standard now requires each Transmission Planner and Planning Coordinator distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. In addition, if a recipient of the Planning Assessment results provides documented comments on the results, the respective Transmission Planner or Planning Coordinator shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. This simplifies the process while achieving appropriate involvement of affected entities. The reference to "results" in Requirement R7 (now Requirement R8) is to the Planning Assessment results. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. **R8.1** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	
Minnesota Power	Under R7, the Time Horizon of the TPL standards is intended for years one through 10; however, the Time Horizon shown in R7 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning".
Response: The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made. **Mitigation Time Horizon** The time horizons available for mitigating a violation to a requirement include the following: • **Long-term Planning** — a planning horizon of one year or longer. • **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal. • **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time. • **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.	

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• **Operations Assessment** — follow-up evaluations and reporting of real time operations.	
MAPPCOR	Propose expanding the scope of entities to consider, limit it to those entities that indicate a reliability need for coordination, and eliminate the direct reference to Order 890. Suggest this text: "Each Planning Coordinator shall establish a list of adjacent Planning Coordinators and any functional entity who has indicated a reliability need, distribute its Planning Assessment results to the listed entities and consider comments on the assumptions and results through an open and transparent peer review process.
Response: The standard now requires each Transmission Planner and Planning Coordinator distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. The reference to Order 890 created confusion regarding process requirements and the reference has been deleted. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.	
Orlando Utilities Commission	The term "results of the assessment", is this is the final end result that is shared and analyzed? A requirement should not reference an order or another non NERC document. All the requirements and measures for performance should be covered in the standard or through reference to another NERC approved standard. The language used in other standards would be more appropriate and directly auditable. Require that the PC/TP to share assessment and support material with those requesting entities and respond to any of their specific comments. This will insure openness and transparency in a manner and can be directly audited.
Response: The reference to "coordinating analysis" and Order 890 created confusion regarding process requirements and the reference has been deleted. The standard now requires each Transmission Planner and Planning Coordinator distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. In addition, if a recipient of the Planning Assessment results provides documented comments on the results, the respective Transmission Planner or Planning Coordinator shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. This simplifies the process while achieving appropriate involvement of affected entities. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. **R8.1** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	
Turlock Irrigation District	In light of the fact that FERC has determined not to apply the Order No. 890 transmission planning processes requirement to non-public utilities, TID expresses concern over the reference to Order No. 890 in R7. TID recommends that this reference be replaced with a more direct instruction that details what exactly is meant by the requirement of "an open and transparent peer review process. R7 makes reference to the peer review process laid out in FERC Order No. 890. This reference to Order No. 890 is duplicative and vague and must be clarified. The peer review process set forth in Attachment K of Order No. 890, lays out nine different principles (Coordination, Openness, Transparency, Information Exchange, Comparability, Dispute Resolution,

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	Regional Participation, Economic Planning Studies, and Cost Allocation for New Projects). Most of these principles are inapplicable when placed in the context of NERC Reliability Standards. Subjecting NERC members to all of these vague and broad principles without specific guidance as to their application would be a significant burden. TID proposes that the reference to Order No. 890 be removed from R7 and replaced with a provision that expressly details the principles of openness and transparency that are contemplated in R7. Such an express provision would bring clarity to the requirement so that entities subject to R7 would know exactly what they are expected to do to comply with the requirements of R7. As it is now written, the broad reference to Order No. 890 is vague and confusing.TID is also concerned with the fact that the Violation Severity Levels for R7 now appear to run from High to Severe, with the potential of significant penalties being assessed on noncompliant entities. The High and Severe Violation Severity Levels for TLP-001-1 R7 are inappropriate given the already vague and conflicting guidance of R7, especially as R7 merely duplicates the Order No. 890 requirements. Once the reference to Order No. 890 is replaced with a provision that expressly provides specific guidance as to what is meant by the "open and transparent peer review process," the appropriate Violation Severity Level for R7 would be Low to Moderate.

Response: The reference to "coordinating analysis" and Order 890 created confusion regarding process requirements and the reference has been deleted. The standard now requires each Transmission Planner and Planning Coordinator distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. In addition, if a recipient of the Planning Assessment results provides documented comments on the results, the respective Transmission Planner or Planning Coordinator shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. This simplifies the process while achieving appropriate involvement of affected entities.

The VSL's have been modified based on the clarified Requirement R7 (now Requirement R8) for distribution of Planning Assessments, the importance of sharing planning information and being responsive to neighboring entities reliability related concerns.

R8 Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.

R8.1 If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

R8 VSL	The responsible entity failed to distribute the results of its Planning Assessment to any one of its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

New York Independent System	The Standards Drafting Team should clarify the standard as to whether the PC will be expected to distribute the TP Planning

Organization	Question 7 Comment
Operator	Assessments as part of its coordination requirement?
Response: The language has been clarified as to the responsibility of each Transmission Planner and Planning Coordinator. The standard now requires each Transmission Planner and Planning Coordinator distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.	
Kansas City Power & Light	Recommend deleting the portion of the requirement that states: "coordinating analysis of these results through an open and transparent review process such as described in FERC Order 890.
Response: The reference to "coordinating analysis" and Order 890 created confusion regarding process requirements and the reference has been deleted. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.	

8. The SDT changed several definitions in response to industry comments to the second posting. Do you agree with these changes? If not, please clearly indicate which definition you disagree with and provide specific comments.

Summary Consideration: Many of the responders suggested that several of the definitions either be revised or deleted. As a result, the definitions for Supplemental Load Loss, Load Reduction, Planning Events and Extreme Events have been deleted and the definitions for Consequential Load Loss, Non-Consequential Load Loss and Year One have been revised.

In association with the changes in definitions, the SDT has also revised note 'b' and added note 'i' in the header to Table 1.

There were several requests to include comment on Under-frequency (UFLS) and Under-voltage load (UVLS) shedding. UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled Load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. As a result, no change was made.

There were some suggestions to include definitions and distinction between 'planned' and 'proposed'. The SDT tried to address the concepts of planned and proposed in a prior posting. The response from industry strongly discouraged the Standard from delving into the distinction. As a result, no change was made.

There were a couple of suggestions relative to adding back the examples of applications of Bus-tie Breakers or otherwise changing the definition. The SDT removed the statement on Bus-tie Breakers because comments were received to indicate that although the examples were true for most applications, it wasn't universal and examples were provided where Bus-tie Breakers were used between ring buses, etc. As a result, no change was made.

There was a suggestion to change the reference to 'Horizon'. "Horizon" is not something new and the SDT does not agree with changing it. As a result, no was change made.

There were a couple of requests to include new definitions for "cascading outages", "voltage instability", and "uncontrolled islanding". The SDT did not see a reason to define these terms in TPL-001-1. The requesters were invited to draft a SAR if they wanted to pursue having these terms defined. As a result, no change was made.

The following changes were made to definitions as a result of industry comments:

Consequential Load Loss: All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.

Year One: The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.

Header note 'b': Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme event excluding P0.

Header note 'i': The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Organization	Yes or No	Question 8 Comment
Northeast Power Coordinating Council	No	Revise the Load Reduction and Non-Consequential Load Loss definitions as follows.Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions resulting from following a Planning or Extreme Event. Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction. Intended post contingency loss of load (other than Interruptible Load, Supplemental Load or Load Reduction) caused by operator or SPS (RAS) action. (Priority Comment)For Drafting Team consideration: What types of non-interruptible load loss would be considered non-consequential load loss--manual load shedding for example? With this in mind, can the definition be simplified, maybe to read: Non-Consequential Load Loss: Operator action taken to deliberately remove load from service in response to adverse system conditions.
Response: The SDT has deleted the Load Reduction definition. The SDT has simplified the Non-Consequential Load Loss definition and has eliminated the references to Supplemental Load Loss and Load Reduction. The New definition is: **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.		
SERC Engineering Committee Planning Standards Subcommittee	No	Definitions: Revised Definitions are generally better than those from the previous version, but additional clarity could be provided. Load Reduction Please clarify whether this includes both load response and operator initiated action, such as in changes to transformer LTC. Supplemental Load Loss - From a utility perspective, this would be considered as load response. Please clarify how Supplemental Load Loss would be included in the stability analysis. Bus tie breaker A statement in the previous version which listed examples was removed from this version of the definition. The statement was helpful and should be re-inserted. The statement was: Substation configurations such as ring bus, breaker and a half, or double-bus double-breaker do not use bus tie breakers.
Response: The definitions for Load Reduction and Supplemental Load Loss have been deleted. The SDT has simplified the Non-Consequential Load Loss definition and has eliminated the references to Supplemental Load Loss and Load Reduction. The New definition is: **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment. In association with the changes in definitions, the SDT has revised note 'b' and added note 'i' in the header to Table 1.		

Organization	Yes or No	Question 8 Comment
Header note 'b': Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme event excluding P0. **Header note 'i':** The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements. The SDT removed the statement on Bus-tie Breakers because comments were received to indicate that although it was true for most applications, it wasn't universal and examples were provided where Bus-tie Breakers were used between ring buses, etc. No change made.		
Modesto Irrigation District	No	On page 2 under "Definitions of Terms Used in Standard", the red-lined out example used to clarify the definition of "Non-Consequential Load Loss" seems valuable to me, and I think they should not remove it but leave it in.
Response: The SDT has decided that it is inappropriate to include examples within a Standard's definition. The SDT is concerned that an example isn't all inclusive and it will create opportunities for loopholes. No change made.		
Bonneville Power Administration PacifiCorp Deseret Generation & Transmission SRP Xcel Energy Western Area Power Administration Southern California Edison Company San Diego Gas and Electric Co Idaho Power California ISO	No	Clarification is needed on the use of UVLS. Is it acceptable or not. Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss Allowed column is No, is load disconnecetd from the system by UVLS a violation? What about Supplemental Load Loss or UFLS?
Arizona Public Service Co	No	Claification is needed on the use of UVLS. Is it acceptable or not. Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss Allowed column has a No entry, is load disconnecetd from the system by UVLS a violation? What about Supplemental Load Loss or UFLS?

Organization	Yes or No	Question 8 Comment
Pacific Gas and Electric Co,	No	Claification is needed on the use of UVLS. Is it acceptable or not? We understand from the discussion in the webinar that in the proposed TPL-001-1, Table 1, if there is a "no" in the column for allowable load loss, you are still allowed to have UVLS set up to drop the load, but cannot plan on meeting the standard with the load shedding. Therefore, if the Non-Consequential Load Loss Allowed column is No, is load disconnecetd from the system by UVLS a violation, given that you can lose the load but cannot plan on it? Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. What about the treatment of Supplemental Load Loss or UFLS?
Puget Sound Energy, Inc.	No	Claification is needed on the use of UVLS. Is it acceptable or not. Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss Allowed column is No, is load disconnecetd from the system by UVLS a violation? What about Supplemental Load Loss or UFLS?Provide clear explanations of the load definitions.
NV Energy	No	Claification is needed on the use of UVLS. Is it acceptable or not. Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss Allowed column is No, is load disconnecetd from the system by UVLS a violation? What about Supplemental Load Loss or UFLS? We are also wondering how loads that have interruptible rates should be handled.
LADWP	No	UVLS should be an allowed mitigation for multiple contingencies, P3 and above. UVLS is an effective measure against voltage collapse, a system condition that if not mitigated in a timely fashion could lead to cascading events. Saqme with UFLS.
Response: UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. No change made.		
Tucson Electric Power Company	No	Claification is needed on the use of UVLS. Is it acceptable or not? Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss Allowed column is No, is load disconnecetd from the system by UVLS a violation? What about Supplemental Load Loss or UFLS? Year One The use of calendar year is confusing. When does the 12-18 month window begin? We suggest "The year 18 months beyond the present month.
Response: UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. No change made. The definition of Year One has been clarified. **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that		

Organization	Yes or No	Question 8 Comment
begins 12-18 months from the end of the current calendar year.		
MRO NERC Standards Review Subcommittee	No	MRO NSRS suggests the following comments: Add a Consequential Generation Loss definition because both load and generation loss can be considered, but there is only Consequential Load Loss definition. MRO NSRS suggests text of: Consequential Generation Loss: All Generation that is no longer delivered to any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions. Expand the Consequential Load Loss definition to include protection for abnormal operating conditions. MRO NSRS suggests text of: Consequential Load Loss: All Load that is no longer served by any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions. Expand the Load Reduction definition to include consideration of TOP judgment and established protection schemes. MRO NSRS suggests text of: Load Reduction: The reduction of Load that is still connected to the System, but in the judgment of the Transmission Operator or through the previous established Special Protection Systems, Under-Frequency Load Shedding programs, Over-Frequency Load Shedding program, should be reduced to overcome to lower voltage conditions following a Planning or Extreme Event. Modify the Planning Assessment definition to more explicitly apply to the BES and the TPL-001 requirements. MRO NSRS suggests text of: Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies in the BES from the steady state and stability performance requirements set forth in the TPL-001 standard. Modify the Planning Events definition more explicitly apply to the TPL-001 requirements. MRO NSRS suggests text of: Planning Events: Events that are identified in the steady state and stability performance requirements set forth in the TPL-001 standard. Expand the Year One definition to include the PC, refer to the Planning Assessment, and refer to the current calendar year. MRO NSRS suggests text of: Year One: The first year that each Transmission Planner and Planning Coordinator is responsible for conducting a Planning Assessment. This is further defined as the planning window that begins 12-18 months from the current calendar year. MRO NSRS would like to delete the definition of "Year One". This is already being done and adding a planning window opens entities to noncompliance for conditions i.e. Model building outside of entities control.
Response: Requirement R2, part 2.7.1 allows for generation tripping and run-back, so a definition for Consequential Generation Loss is not required. The proposed change to expand Protection System operation to include abnormal operating conditions is too vague and is too broad. In addition it would create an overlap with the definition of Non-Consequential Load because Protection Systems used to protect abnormal operating conditions would include Special Protection System which could be used to trip Non-Consequential Load. No change made. The SDT has deleted the Load Reduction definition. UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled load shedding is allowed. The Standard does not address the		

Organization	Yes or No	Question 8 Comment
acceptability of the tools to be used for any Corrective Action Plan. No change made. As stated in the "Purpose" the Standard establishes Transmission System planning performance for the BES. Repeating that within the Standard creates opportunities for confusion whenever it is not specifically noted. The SDT wants to minimize confusion by not repeating applicability throughout the document. Also the Planning Assessment involves more than remedying identified deficiencies. For example, it may also confirm that there are no deficiencies or it may evaluate the impacts of schedule changes in the Corrective Action Plans. No change made. The definition for Planning Events has been deleted. The SDT believes that a near term study requirement is a necessary part of the standard and that a definition for Year One is a necessary component to achieve that objective. The SDT has received several constructive comments on this and has made revisions to the definition. Although revisions fall short of your suggestion, the SDT hopes that additional clarity will help. The revised definition is: **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.		
SERC Engineering Committee Dynamics Review Subcommittee (DRS)	No	There is a need to add definitions to discriminate between planned and proposed projects. We propose the following definitions: Planned Facilities: Facilities that address the near-term deficiencies and have been approved with a financial commitment. Proposed Facilities: Facilities that address long-term deficiencies for which no commitment is required today since they may change based on future evaluation. We propose the following definitions for events: Planning Events: Events which are listed as Planning in Table 1 in Standard TPL-001-1. Extreme Events: Events which are listed as Extreme in Table 1 in Standard TPL-001-1. Bus-tie Breaker definition still seems somewhat generic and the use of 'configurations' causes uncertainty. We propose the following definition: Bus-tie Breaker: A circuit breaker whose intended purpose is to connect two individual substation buses. The definition of Supplemental Load Loss includes the phrase, "by end-user equipment", which could be understood to mean there are devices at the end-user location that remove this equipment (and conversely, load that is not disconnected "by" end-user equipment cannot be included). Also, the term "post-Contingency" can be confusing because in the case of faults, this phrase is not clear if it means conditions after the fault initiation itself or only after the clearing of the fault. We propose the following definition: Supplemental Load Loss: End-user Load that inherently disconnects from the System as a consequence of (or "in response") to the conditions created by the System event. Load Reduction: A decrease in the amount of connected Load caused by lower voltage conditions following a Planning or Extreme Event.
Response: The SDT tried to address the concepts of planned and proposed in a prior posting. The response from industry strongly discouraged the standard from delving into the distinction. No change made.		

Organization	Yes or No	Question 8 Comment
The definition for planning events has been deleted. The definition for extreme events has been deleted. The definition as proposed by SERC for a Bus-tie Breaker would apply to every breaker in any configuration. The definition in the Standard is trying to limit the application to a connection between configurations of buses, which could include flat buses, ring buses, breaker and a half, etc. The SDT is deliberately using the term configuration to avoid unintentionally excluding a particular configuration. No change made. The definition for Supplemental Load Loss has been deleted. The definition for Load Reduction has been deleted.		
SERC Engineering Committee Reliability Review Subcommittee (RRS)	No	Revised Definitions are generally better than those from the previous version, but additional clarity could be provided. Supplemental Load Loss - From a utility perspective, this would be considered as load response. Please clarify how Supplemental Load Loss would be included in the stability analysis. “Bus tie breaker “ A statement in the previous version which listed examples was removed from this version of the definition. The statement was helpful and should be re-inserted. The statement was: “Substation configurations such as ring bus, breaker and a half, or double-bus double-breaker do not use bus tie breakers. “Extreme Events definition references severity and probability. These terms should be included in the definition of Planning Events. Add a definition of Planned and Proposed facilities. Planned facilities address the near term deficiencies and have been approved with a financial commitment while proposed facilities address long term deficiencies for which no commitment is required today since they may change based on future evaluation. Consequential Load Loss - Is an SPS to trip load qualify as a planned protection system”? Load Reduction - Is this automatic as in a load response or is it operator initiated as in changes to transformer LTC? How would Supplemental Load Loss be included in the stability analysis? Table 1 suggests that it cannot be included to meet steady-state performance. Suggest that the following be added to the definition: Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements. “Where would interruptible load be included in these definitions” Bus-tie Breaker definitions still seems somewhat generic and the use of 'configurations' causes uncertainty. Revise Bus-tie Breaker to read, "A circuit breaker whose intended purpose is to connect two individual substation buses." "Bus-tie" is not capitalized in the Table. “Consequential Load Loss must include load that is lost due to the inherent response of the particular type of load. Some motors, lighting and processes will naturally trip during an event, although not as a result of the protection system. It may have been the intent of the SDT to include this phenomenon in the Supplemental Load Loss defintion. However, this definition includes the phrase, "by end-user equipment", and that makes one think that there are devices at the end-user location that is removing this equipment (and conversely, load that is not disconneted "by" end-user equipment cannot be

Organization	Yes or No	Question 8 Comment
		included). Also, the term "post-Contingency" can be confusing because in the case of faults, this phrase is not clear if it means conditions after the fault initiation itself or only after the clearing of the fault. Revise Supplemental Load Loss to read, "End-user Load that inherently disconnects from the System as a consequence of (or "in response") to the conditions created by the System event." SERC RRS suggests adding back the following to the Bus-tie breaker definition that was contained in Posting #2: ?Substations configurations such as ring bus, breaker and a half, or double bus double breaker protection schemes do not use bus tie breakers?. SERC Members believe that this additional wording helps explain this definition much more clearly. In Posting #2, undervoltage load shed, underfrequency load shed, and Special Protection Schemes were considered to be Non-Consequential Load Loss. Are these now no longer considered to be Non-Consequential Load Loss but instead now considered to be Load Reduction, Supplemental Load Loss, or something else? Should Supplemental Load Loss be further defined as load that is disconnected from the network by end-user equipment responding during duration of the fault as well as to post contingency system conditions? Also the definition of Supplemental Load Loss may benefit from some examples in the definition to further help clarify. The second sentence in the Year One definition is rather confusing. We would suggest changing “calendar year” to “date”. Otherwise it may be interpreted that Year One would begin 12 to 18 months from the end of the current calendar year. Suggest from “beginning”.

Response: The SDT has simplified the Non-Consequential Load Loss definition and has eliminated the references to Supplemental Load Loss and Load Reduction. The New definition is:

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.

In association with the changes in definitions, the SDT has revised note ‘b’ and added note ‘i’ in the header to Table 1.

Header note ‘b’: Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme event excluding P0.

Header note ‘i’: The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

The SDT removed the statement on Bus-tie Breakers because comments were received to indicate that although it was true for most applications, it wasn’t universal and examples were provided where bus tie breakers were used between ring buses, etc. No change made.

The SDT tried to address the concepts of planned and proposed in a prior posting. The response from industry strongly discouraged the standard from delving into the distinction. No change made.

An SPS does not qualify as a planned Protection System because it is not being used “to isolate the fault”, which is a condition of the statement. No change made.

The definition for Load Reduction has been deleted.

Interruptible load is either Consequential Load or Non-Consequential Load which is permitted to be lost for specific events and conditions defined in Table 1. No

Organization	Yes or No	Question 8 Comment
change made. The SDT removed the statement on Bus-tie Breakers because comments were received to indicate that although it was true for most applications, it wasn't universal and examples were provided where bus tie breakers were used between ring buses, etc. No change made. The definition for Supplemental Load Loss has been deleted. Bus-tie Breaker has been capitalized in the Table. The definition for Load Reduction has been deleted. The SDT removed the statement on Bus-tie Breakers because comments were received to indicate that although it was true for most applications, it wasn't universal and examples were provided where bus tie breakers were used between ring buses, etc. No change made. UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. No change made. The SDT has decided that it is inappropriate to include examples within a Standard's definition. The SDT is concerned that an example isn't all inclusive and it will create opportunities for loop holes. The definition for Year One has been revised to add clarity. The revised definition is: **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.		
FirstEnergy Corp	No	A. Supplemental Load Loss: We disagree with newly proposed definition for "Supplemental Load Loss" which is introduced to address some stakeholders concerns related to a Load's response to transient conditions. Table 1 note "b" causes confusion indicating that Supplemental Load Loss is an acceptable consequence of a Planning Event or an Extreme Event but then goes on to say that Supplemental Load Loss can not be relied upon to meet steady state performance requirements. This seems to imply that it is permissible to use Supplemental Load Loss for stability analysis. It is not logical to allow its use in one time frame but not the other. The inclusion of the Supplemental Load Loss definition enters into a power quality issue at the end-user delivery point which is not the focus of the TPL-001-1 standard. FE suggests that this definition be removed. B. Load Reduction: The new proposed definition of "Load Reduction" while technically written correctly may not align with its common use throughout industry. Load Reduction is often thought of as an operator initiated response, rather than a natural system response to a contingency event. If the definition remains, the SDT should consider striking the text "following a Planning or Extreme Event" so that the definition can more generally apply to other areas of the standards if needed. However, as stated in question 9, we believe Load Reduction was inadvertently omitted in note "b" of the Table 1. If so, we would have similar concerns with the occasional use of Load Reduction in that it would be allowed in stability and excluded in steady-state FE suggests that this definition be removed.The "Load Reduction" definitional term brings into question what is an acceptable steady-state load model within the TPL-001-1 standard. The standard provides some prescriptive language in requirement R2.4.1 regarding dynamic stability load models but is silent on steady-state load modeling. Most transmission planners use a conservative approach of simulating constant power loads in the steady-state environment and therefore the "Load Reduction" definition would not apply. However, if a constant impedance load

Organization	Yes or No	Question 8 Comment
		model were used, Load Reduction would be reflected and less conservative outcomes would result. At a minimum, the standard should require the transmission planner to document its load modeling assumptions for steady-state simulations. [See above comment on Question 2 regarding a proposed new R2.1.1 requirement] C. Year One: We continue to oppose the Year One definition developed by the SDT. In our Draft 2 comments, FirstEnergy proposed a Year One definition of "The planning year that begins with the upcoming annual period under study". During the last comment period we indicated:"We believe the attempt to try and delineate between the near-term planning horizon and operational planning horizon is not needed within the TPL standard and that the near-term period should account for the upcoming annual study periods. If not revised, the need for two near-term studies on an annual basis is overly burdensome as many transmission planning organizations perform upcoming annual seasonal assessments for seasonal peak (summer/winter) periods. Requiring an additional two studies near-term does not provide significant benefit. Further reasoning for making the change is the allowance of operating procedures as part of Corrective Action plans. Operating procedures can easily be developed and implemented to mitigate projected performance violations prior to an upcoming seasonal period." The SDT's response from the Draft 2 comment period indicated "The standard does not require that studies are duplicated. If an operating study can be used to demonstrate an assessment for planning purposes, then the operating study would be sufficient."Since "Year One" is defined as "...a planning window that begins 12-18 months from the current calendar year" we would appreciate the SDT reconciling their Draft 2 response to the Year One definition and confirm whether or not it intends that a study of the next occurring seasonal peak period would suffice for meeting one of the current year Near-Term studies as required in requirement R2.1.1.A secondary concern with the Year One definition is its reference to the Transmission Planner with no mention of the Planning Coordinator. D. Planning Assessment: We suggest that the team consider an enhancement to the definition of "Planning Assessment". When read independently within the NERC Glossary of Terms a lay person should have a better understanding of the transmission Planning Assessment and it should set the foundational understanding that a Planning Assessment is not equivalent to a single study but rather a collection of studies. Additionally, the definition should more explicitly apply to the TPL-001-1 intended purpose. We propose a new definition based largely on the verbiage in requirement R2. "Planning Assessment: An annual documented evaluation of future Transmission System performance predicted over a minimum 10-year period, based on new or previously completed simulation studies and the Corrective Action Plans needed to satisfy steady-state, stability and short circuit performance requirements." E. Planning Event: We propose that the definition of "Planning Event" more explicitly apply to the TPL-001-1 standard and read as follows: "Planning Event: A contingency condition evaluated for its steady-state and stability impacts on the BES transmission System, requiring Corrective Action plans to remedy identified deficiencies" F. Consequential Load Loss: We suggest that the definition be revised to more closely align with the text stated in requirement R3.3.1. The proposed definition would read "Consequential Load Loss: All Load that is no longer served by any Transmission Facilities as a result of the removal of all elements that the Protection System and other automatic controls are expected to disconnect for a transmission System Contingency without operator intervention." If our proposed new definition is not acceptable, we suggest that the word "automatically" be added between "being removed" and replace "a planned" with "as designed".

Organization	Yes or No	Question 8 Comment
Response: The definition of Supplemental Load Loss has been deleted from the revised standard. In association with the changes in definitions, the SDT has revised note 'b' and added note 'i' in the header to Table 1. **Header note 'b':** Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme event excluding P0. **Header note 'i':** The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements. The definition for Load Reduction has been deleted. The definition for Year One has been revised to reflect your comment. The revised definition is: **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year. The SDT does not agree with combining the types of studies in the definition of Planning Assessment. No change made. The definition for planning event has been deleted. The definition of Consequential Load Loss has been revised however the SDT did not believe that it was necessary to insert 'automatically' in the definition. The revised definition is: **Consequential Load Loss:** All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault .		
IRC Standards Review Committee New York Independent System Operator	No	The Year One definition is confusing. According to the definition, Year One can start any time between 12 and 18 months from a current calendar year. Is that January 1 of the current calendar year? Further, when does year 2, year 3, etc? start? Is this definition only applicable to the TP?
Progress Energy Carolina (PEC)	No	In this definition: "Year One: The first year that a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the current calendar year" recommend that the '12-18 months' specification be removed. It is confusing.
E.ON U.S.	No	Year One: The calendar year contains 12 months. As written, Year One could start as early as January 2010 (1/1/2009 plus 12 months) or as late as July 2011 (12/31/2009 plus 18 months). E.ON U.S. believes that the statement should be modified to: read " that begins 12-18 months from the beginning of the current calendar year". This would limit the beginning of the current window to be January 2010 or July 2010.
Midwest ISO	No	Year One: At a minimum the SDT needs to address the applicability of this definition to include both the Transmission

Organization	Yes or No	Question 8 Comment
		Planner and Planning Coordinator. The Year One definition needs additional clarification with the current calendar year. According to the definition, Year One can start any time between 12 and 18 months from a current calendar year. Suggested definition for Year One: The first year that each Transmission Planner and Planning Coordinator is responsible for conducting a Planning Assessment. This is further defined as the planning window that begins at least 12-18 months from the end of the current calendar year.
BPA		Definition of terms - Year one: The current draft defines "year one" as "the planning window that begins 12-18 months from the current calendar year". However it's not clear: 1. When this 12-18 months should start to be counted. Is it counted from Jaunuary 1 of this calendar year, or Dec. 31 of this calendar year, or somewhere in the middle of the year depending on the planning entity's choice. 2. Does this calendar year refer to the year when the annual assessment report is submitted, or the calendar year when the annual assessment is started? For example, we may start to work on an annual assessment report in late 2009 but finally complete it in early 2010. In this case which year should be the "current calendar year" for the report? Each year in July BCTC receives a new load forecast, which covers the next 10 years with year 1 starting on April 1 of the next calendar year. If we determine the TPL "year one" by counting 12-18 months from the beginning of this calendar year, we are oke to use this new load forecast. If we determine the TPL year one by counting 12-18 months from the end of this calendar year, the new load forecast for year 1 and year 10 are already out-of-date by the time we receive them. Clarify which year is the "current calendar year" and when is the start of the 12-18 months.
Response: Rather than removing the specification, the SDT has revised the definition to clarify the reference point. The revised definition is: **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.		
TVA System Planning	No	TVA suggests adding back the following to the Bus-tie breaker definition that was contained in Posting #2: Substations configurations such as ring bus, breaker and a half, or double bus double breaker protection schemes do not use bus tie breakers. TVA believes that this additional wording helps explain this definition much more clearly. In Posting #2, undervoltage load shed, underfrequency load shed, and Special Protection Schemes were considered to be Non-Consequential Load Loss. Are these now no longer considered to be Non-Consequential Load Loss but instead now

Organization	Yes or No	Question 8 Comment
		considered to be Load Reduction, Supplemental Load Loss, or something else? Should Supplemental Load Loss be further defined as load that is disconnected from the network by end-user equipment responding during duration of the fault as well as to post contingency system conditions? Also the definition of Supplemental Load Loss may benefit from some examples in the definition to further help clarify. Please clarify how Supplemental Load Loss would be included in the stability analysis. The second sentence in the Year One definition is rather confusing. We would suggest changing “calendar year” to “date”. Otherwise it may be interpreted that Year One would begin 12 to 18 months from the end of the current calendar year. Suggest from “beginning”. Load Reduction ? Please clarify whether this includes both load response and operator initiated action, such as in changes to transformer LTC. Should definition also include that this load is continuing to be served? Consequential Load Loss must include load that is lost due to the inherent response of the particular type of load. Some motors, lighting and processes will naturally trip during an event, although not as a result of the protection system. It may have been the intent of the SDT to include this phenomenon in the Supplemental Load Loss defintion. However, this definition includes the phrase, "by end-user equipment", and that makes one think that there are devices at the end-user location that is removing this equipment (and conversely, load that is not disconneted "by" end-user equipment cannot be included). Also, the term "post-Contingency" can be confusing because in the case of faults, this phrase is not clear if it means conditions after the fault initiation itself or only after the clearing of the fault. Revise Supplemental Load Loss to read, "End-user Load that inherently disconnects from the System as a consequence of (or "in response") to the conditions created by the System event."

Response: The SDT removed the statement on Bus-tie Breakers because comments were received to indicate that although it was true for most applications, it wasn’t universal and examples were provided where bus tie breakers were used between ring buses, etc. No change made.

The definition of Non-Consequential Load Loss has been revised to provide greater clarity.

> **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.

The definition for Supplemental Load Loss has been deleted.

The definition for Year One has been revised to reflect your comment. The revised definition is:

> **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.

The definition for Load Reduction has been deleted.

In association with the changes in definitions, the SDT has revised note ‘b’ and added note ‘h’ in the header to Table 1.

Organization	Yes or No	Question 8 Comment
Header note 'b': Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme event excluding P0. **Header note 'i':** The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements. The definition for Supplemental Load Loss has been deleted.		
Southern Company	No	We disagree with deleting the definition of system stability and generating unit stability. The proposed definition for Year One reads as follows Year One: The first year that a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the current year. Please clarify if this refers to the first "calendar" year when a Transmission Planner becomes responsible for assessments. If so, then add the word "Calendar" so that it reads "Year One: The first calendar year ..... .
Response: The SDT deleted the difference between generator unit Stability and System Stability due to a majority of comments received from industry in a previous posting. No change made. The definition for Year One has been revised to reflect your comment. The revised definition is: **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.		
United Illuminating	No	Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions resulting from a Planning or Extreme Event. Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction. Intended post contingency loss of load (other than Interruptible Load, Supplemental Load or Load Reduction) caused by operator or SPS (RAS) action. (Priority Comment)
Northeast Utilities Central Maine Power Company	No	Refine load loss definitions as follows.Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions resulting from a Planning or Extreme Event. Non-Consequential Load Loss: Intended post contingency loss of load (other than Interruptible Load, Supplemental Load or Load Reduction) caused by operator or SPS (RAS) action. (Priority Comment)
ISO New England, Inc.	No	Refine load loss definitions as follows.Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions resulting from following a Planning or Extreme Event. Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction. Intended post contingency loss of load (other than Interruptible Load, Supplemental Load or Load Reduction) caused by operator or SPS (RAS) action. (Priority Comment)

Organization	Yes or No	Question 8 Comment
Response: The definition for Load Reduction has been deleted. The SDT has simplified the Non-Consequential Load Loss definition and has eliminated the references to Supplemental Load Loss and Load Reduction. The New definition is: **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.		
System Protection and Transmission Planning Department	Yes	We appreciate the effort of the SDT to clarify "Consequential load loss", and think references to this term are clearer in this draft. Proxies?, used in R5, should be defined. See R5 comments for our suggestion.
Response: See response to question 5 comments. The term, "proxies" is not used in the revised standard.		
MidAmerican Energy Company	No	MidAmerican commends the SDT for its hard work on this standard. MidAmerican believes the SDT improved several of the definitions and believes additional changes are needed: For the bus-tie definition, what does "individual substation bus configurations" mean?? The consequential load loss states that it is load that "removed from service by a planned Protection System operation to isolate fault conditions". This implies that a contingency that does not involve a fault could never have consequential load loss. MidAmerican suggests that the words "to isolate fault conditions" be replaced with "in response to a contingency event". Alternatively, consider using the words in R3.3.1 which defines the same information but without referring to fault conditions. The definition of Long-Term Transmission Planning Horizon is confusing because it is not clear which term the words "when required to accommodate any known longer lead time projects that may take longer than ten years to complete" are meant to modify. MidAmerican believes the intent is that these words only apply to the years ten or beyond and not the entire period years six to ten and beyond. Therefore, we recommend that the words be changed by starting a new sentence in the definition and putting it in parentheses "(Years beyond ten years are required to accommodate any known longer lead time projects that may take longer than ten years to complete.) MidAmerican commends the SDT for improving the Year One definition. MidAmerican still believes the Year One definition is too confining. It indicates that the first year is defined as the planning window that begins 12-18 months from the current calendar year. This means if the regional entity provides models during the current calendar year in April, the responsible entity cannot use those models in conducting planning until a year that begins in May of the next year. Why delay the start of Year One? What is gained by this delay? MidAmerican recommends that Year One NOT be a defined term. This definition clarifies a term that does NOT need to be clarified for any reason. MidAmerican believe this is a fix for a problem that does not exist. Does the SDT have evidence of lack of compliance in this regard?? Modify the Planning Assessment definition to more explicitly apply to the BES and the TPL-001 requirements. We suggest text of: Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies in the BES from the steady state and stability performance requirements set forth in

Organization	Yes or No	Question 8 Comment
		the TPL-001 standard. Modify the Planning Events definition more explicitly apply to the TPL-001 requirements. We suggest text of: Planning Events: Events that are identified in the steady state and stability performance requirements set forth in the TPL-001 standard.
Response: Bus configurations could include flat buses, ring buses, breaker and a half, etc. The reference to fault conditions was intentionally used to exclude SPS action. A Contingency without a fault would be an inadvertent or mis-operation, which is not directly addressed by this standard. No change made. The SDT did not recognize a benefit to the proposed wording change for the definition of Long-Term Transmission Planning Horizon. No change made. The SDT believes that a near term study requirement is a necessary part of the standard and that a definition for Year One is a necessary component to achieve that objective. The SDT has received several constructive comments on this and has made revisions to the definition. Although revisions fall short of your suggestion, the SDT hopes that additional clarity will help. The revised definition is: **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year. As stated in the "Purpose" the Standard establishes Transmission System planning performance for the BES. Repeating that within the Standard creates opportunities for confusion whenever it is not specifically noted. The SDT wants to minimize confusion by not repeating applicability throughout the document. Also the Planning Assessment involves more than remedying identified deficiencies. For example, it may also confirm that there are no deficiencies or it may evaluate the impacts of schedule changes in the Corrective Action Plans. No change made. The definition for planning events has been deleted.		
Gainesville Regional Utilities	Yes	But as referenced in question 5, I believe you need a good definition for the following terms; "cascading outages", "voltage instability", and "uncontrolled islanding".
Response: The SDT sees no reason to define "cascading outages", "voltage instability", or "uncontrolled islanding" in TPL-001-1. If Gainsville wishes to pursue, please draft a SAR. No change made.		
Progress Energy Florida, Inc.	No	PEF continues to disagree strenuously with differentiating between Consequential Load Loss and Non-Consequential Load Loss. PEF does not believe that load loss has anything whatsoever to do with demonstrating the robustness of the BES. The approach the SDT is taking with TPL-001-1 is essentially "Feeder Reliability", rather than BES Reliability. Should the SDT decide that they must continue with this approach, PEF will explore options for expressing concern about this at the FERC level. PEF is perplexed by the definition of Supplemental Load Loss. PEF, as a Transmission Owner, considers its "end-user" to be the Distribution System. PEF would therefore use this definition to design Distribution-side controlled load curtailment schemes that essentially qualify as Consequential Load Loss. If this is not the intent of the SDT, PEF suggests that the

Organization	Yes or No	Question 8 Comment
		SDT modify this definition to make its meaning clearer.
Response: The SDT has revised the definitions and notes in the table, which should clarify the reference to the end-user. Pertinent revisions are: **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment. **Header note 'b':** Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme event excluding P0. **Header note 'i':** The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.		
Ameren	No	Extreme Events definition references severity and probability. These terms should be included in the definition of Planning Events. Add a definition of Planned and Proposed facilities. Planned facilities address the near term deficiencies and have been approved with a financial commitment while proposed facilities address long term deficiencies for which no commitment is required today since they may change based on future evaluation. Revised Definitions are generally better than those from the previous version, but additional clarity could be provided. Consequential Load Loss ? Would an SPS to trip load qualify as a planned protection system? Load Reduction ? Please clarify whether this includes both load response and operator initiated action, as in changes to transformer LTC. Supplemental Load Loss - From a utility perspective, this would be considered as load response. Please clarify how Supplemental Load Loss would be included in the stability analysis. Table 1 suggests that it cannot be included to meet steady-state performance. Suggest that the following be added to the definition: Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements.
Response: The definitions for both extreme events and planning events have been deleted. The SDT tried to address the concepts of planned and proposed in a prior posting. The response from industry strongly discouraged the standard from delving into the distinction. No change made. An SPS does not qualify as a planned Protection System because it is not being used "to isolate the fault", which is a condition of the statement. The definition for Load Reduction has been deleted. In association with the changes in definitions, the SDT has revised note 'b' and added note 'i' in the header to Table 1. **Header note 'b':** Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme event excluding P0. **Header note 'i':** The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an		

Organization	Yes or No	Question 8 Comment
event shall not be used to meet steady state performance requirements.		
Manitoba Hydro	No	Consequential Load Loss: the wording "by a planned Protection System operation to isolate fault conditions" is awkward wording. The wording should be changed to "by a Protection System operation designed to isolate fault conditions". Load Reduction: This definition is not needed and load reduction is not prohibited in the standard. It will take some effort to even measure such a load reduction in simulation. Given that there are four load related definitions, the standard would be simplified by deleting this term. Any voltage dependent load will be reduced for a low voltage condition. In steady state (P0), load is normally modeled as constant MVA load so load is constant. In the steady state period after a contingency, transformer taps and voltage control devices will restore voltage, and consequently, any load modeled as voltage dependent will be restored to pre-contingency level. The term is not used anywhere in the requirements of the standard - it is only included in Table 1 Note b in the definition of Non-Consequential Load Loss. We do not think it is needed. Supplemental Load Loss: Why did the drafting team decide to include Supplemental load loss? In Table 1, it is stated under "note b" that Supplemental Load Loss cannot be used to meet steady state performance requirements. Does this imply that it is acceptable for "non-consequential" induction motor load to trip off as a result of undervoltage during the disturbance due to its protection setting? It is possible that this load loss during a stability simulation may avoid the need to add dynamic reactive support. Can the drafting team clarify the intent of the standard or delete Supplemental Load Loss. At minimum, the TP/PA should identify the minimum transient voltage that they are planning the system for. In that way, any load loss for unplanned events that cause lower transient voltages or load loss that occurs at a higher transient voltage wouldn't be a violation. Also, unless the end-user load is modeled in detail, or a proxy is used, the planner will not know if such load exists or would be lost in the simulation.
Response: The definition for Consequential Load Loss has been revised to reflect your comment. The revised definition is: **Consequential Load Loss:** All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault . The definitions for Load Reduction and Supplemental Load Loss have been deleted. In association with the changes in definitions, the SDT has revised note 'b' and added note 'h' in the header to Table 1. **Header note 'b':** Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme event excluding P0. **Header note 'i':** The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.		
National Grid	No	Comments: Can the definitions of the "Planning Horizon" in the FAC, the "Long-term Planning" Time Horizon (italicized and in parentheses next to the Violation Risk Factor), and the "Near-Term" and "Long-Term Transmission Planning" be included in the definitions section to avoid confusion" Refine load loss definitions as follows. Consequential Load Loss: All Load that is no longer served by any Transmission

Organization	Yes or No	Question 8 Comment
		Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. Comment It is not clear if Consequential load includes load that is connected to transmission within an island. Suggest revising the definition to "..load no longer served by the Transmission System (or perhaps by the BES?) as a result of Transmission Facilities being removed?" Load Reduction: Quantity of Load that is reduced due to lower voltage conditions resulting from a Planning or Extreme Event. Comment "Load Reduction" as written is the load remaining after the reduction. This should be rewritten to indicate it is the change in load from the previous value to that still connected. Also, the defined term "Load Reduction" is counter to what most engineers consider to be a load reduction and as written it does not seem necessary to define this term. Most engineers associate Load Reduction as a manual or automatic action by a customer to reduce demand. As defined it appears that Load Reduction refers only to the voltage sensitivity of load which should be captured in the system model if it is necessary to model this effect. Therefore the reference should be changed from "Load Reduction" to "Voltage Sensitive Load Loss". Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction. Comment The definition is indirect. Suggest to revise the definition to be direct by stating "Intended post contingency loss of load (other than Interruptible Load, Supplemental Load or Load Reduction) caused by operator or SPS (RAS) action. Planning Events: Events that require Transmission system performance requirements to be met.Comment - Suggest "Events for which Transmission system performance requirements shall be met". Supplemental Load Loss: Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.Comment - Suggest rewording last phrase to "..responding to System Contingency conditions." - or perhaps just "..responding to System conditions." Year One: The first year that a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the current calendar year. Comment - Suggest rewording second sentence to "This is further defined as beginning 12-18 months from the current calendar year." - This avoids the awkwardness in present draft of seeming to define Year One as a planning window as well as a particular year.

Response: The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made.

Mitigation Time Horizon

The time horizons available for mitigating a violation to a requirement include the following:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.

Organization	Yes or No	Question 8 Comment
• **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system. • **Operations Assessment** — follow-up evaluations and reporting of real time operations. The definition for Consequential Load Loss has been revised to reflect your comment. **Consequential Load Loss:** All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault . The definitions for Load Reduction and Supplemental Load Loss have been deleted. The definition for Planning Event has been deleted. The definition for Year One has been revised to reflect your comment.. The revised definition is: **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.		
Entergy Services, Inc	No	Include a definition of "planned facilities": Facilities that address the near-term deficiencies and have been approved with a financial commitment. In Posting #2, undervoltage load shed, underfrequency load shed, and Special Protection Schemes were considered to be Non-Consequential Load Loss. Are these now no longer considered to be Non-Consequential Load Loss but instead now considered to be Load Reduction, Supplemental Load Loss, or something else?
Response: The SDT tried to address the concepts of planned and proposed in a prior posting. The response from industry strongly discouraged the standard from delving into the distinction. No change made. UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. No change made.		
BC Hydro	No	Comments: In almost all instances, the word "horizon" should be changed to "period" in both the definitions and throughout the standard. The word horizon refers to the end of the period; it literally means, "the limit of one's mental outlook" and the horizon is normally the furthest we can see. A long-term horizon-year study would be a study of conditions expected in the last year of the long-term planning period (often the 10th or 20th year). A long-term horizon-year study would not be expected to refer to a series of studies of each year in the long-term planning period.
Response: The reference to 'Horizon' is not something new and the SDT does not agree with changing it. No change made.		
PJM	No	Planning Events and Extreme Events should refer to the lists in the tables since there is no other way to understand which contingency falls into what definition. The designation is deterministic and somewhat arbitrary but commonly accepted.

Organization	Yes or No	Question 8 Comment
Response: The definitions for planning events and extreme events have been deleted.		
American Electric Power	No	"Load Reduction" does not need to be retained as a defined term; in fact it only appears once in the draft standard at the top of Table 1. In addition, it is well understood that load is sensitive to voltage, so it seems unnecessary to call attention to it. Furthermore, the "Supplemental Load Loss" definition should also be removed. These definitions are not generally relevant to planning studies. Neither steady-state nor stability planning studies should acknowledge or rely on "Supplemental Load Loss" because it is simply unpredictable without detailed load device protection data. In fact, properly set minimum voltage limits should ensure that no appreciable load is tripped by customer equipment response as long as that equipment meets generally accepted equipment and design standards. For the same reason, steady-state planning studies should not rely on "Load Reduction" because the planning function is supposed to ensure that a designated forecasted load can be served under credible contingencies. However, it is okay that stability studies acknowledge and rely on load voltage sensitivity ("Load Reduction"), and in fact this is required due to the nature of the analysis and cannot be otherwise. Therefore, there is no need to call attention to it.Given the above comments, the remaining two load loss definitions should be further clarified, though not changed substantively, to read as noted below. Consequential Load Loss: All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. It excludes Load that is disconnected from the network by load internal protection or end-user equipment responding to post-Contingency System conditions. Also, it excludes Load that remains connected to the System, but that may be reduced due to lower voltage conditions as a consequence of a Planning or Extreme Event.Non-Consequential Load Loss: Any Load loss intentionally caused due to automatic system protective functions such as UVLS, special protection systems, or as the result of operating procedures. Finally, the lettered bullets at the top of Table 1 need to be modified as appropriate to reflect the above comments that load loss due to internal load protection or end-user equipment, what was called "Supplemental Load Loss", should NOT be permitted in complying with either steady-state or stability performance criteria. Load that remains connected to the System, but that may be reduced due to lower voltage, should NOT be permitted in complying with steady-state performance criteria, but should be allowed, by necessity, in complying with stability performance criteria.
Response: The definitions for Load Reduction and Supplemental Load Loss have been deleted. The definitions for Consequential and Non-Consequential Load loss have been revised **Consequential Load Loss:** All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault . **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including		

Organization	Yes or No	Question 8 Comment
Load that is disconnected from the System by end-user equipment. In association with the changes in definitions, the SDT has revised note 'b' and added note 'i' in the header to Table 1. **Header note 'b':** Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme event excluding P0. **Header note 'i':** The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements. UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. No change made.		
Northern Indiana Public Service Company	No	The definitions need clarification, especially if they will be extracted from the standard when approved and included in the NERC Glossary. The SDT should include a Technical Writer to clarify the proposed language.
Response: Thank you for your response.		
Platte River Power Authority	No	Non-Consequential Loss of Load - It is not clear in all the Load Loss definitions where planned load shedding or "controlled interruption of electric supply" belong. However, the NERC Webinar on June 30 was very helpful, and I make the following comment in line with the answer I heard to my question. A "Yes" in the last column of Table 1 means that planned load shedding or "controlled interruption of electric supply" is allowed for that Category of Contingencies. (For a P2.2 Bus Section Fault, SLG, HV, "Yes", one could choose to implement a planned load shedding procedure or scheme to meet system performance requirements.) Planned load shedding may be manual load shedding or automatic actions such as direct load tripping or UVLS for example. Therefore, please add mention of the planned load shedding or the "controlled interruption of electric supply" and list specific examples in the definition for "Non-Consequential Loss of Load."
Response: The SDT has decided that it is inappropriate to include examples within a Standard's definition. The SDT is concerned that an example isn't all inclusive and it will create opportunities for loopholes. No change made. UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. No change made.		
American Transmission Company	No	We suggest the following comments: Add a Consequential Generation Loss definition because both load and generation loss can be considered, but there is only Consequential Load Loss definition. We suggest text of: "Consequential Generation Loss: All Generation that is no longer delivered to any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions.

Organization	Yes or No	Question 8 Comment
		Expand the Consequential Load Loss definition to include protection for abnormal operating conditions. We suggest text of: "Consequential Load Loss: All Load that is no longer served by any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions. Expand the Load Reduction definition to include consideration of TOP judgment and established protection schemes. We suggest text of: "Load Reduction: The reduction of Load that is still connected to the System, but in the judgment of the Transmission Operator or through the previous established Special Protection Systems, Under-frequency Load Shedding programs, Over-frequency Load Shedding program, should be reduced to overcome to lower voltage conditions following a Planning or Extreme Event. Modify the Planning Assessment definition to more explicitly apply to the BES and the TPL-001 requirements. We suggest text of: "Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies in the BES from the steady state and stability performance requirements set forth in the TPL-001 standard. Modify the Planning Events definition to more explicitly apply to the TPL-001 requirements. We suggest text of: "Planning Events: Events that are identified in the steady state and stability performance requirements set forth in the TPL-001 standard. Expand the Year One definition to include the PC, refer to the Planning Assessment, and refer to the current calendar year. We suggest text of: "Year One: The first year that each Transmission Planner and Planning Coordinator is responsible for conducting a Planning Assessment. This is further defined as the planning window that begins 12-18 months from the current calendar year.

Response: Requirement R2, part 2.7.1 allows for generation tripping and run-back, so a definition for Consequential Generation Loss is not required.

The definition for Consequential Load Loss has been revised to provide greater clarity.

> **Consequential Load Loss:** All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault .

The definition for Load Reduction has been deleted.

UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. No change made.

As stated in the "Purpose" the Standard establishes Transmission System planning performance for the BES. Repeating that within the Standard creates opportunities for confusion whenever it is not specifically noted. The SDT wants to minimize confusion by not repeating applicability throughout the document. Also the Planning Assessment involves more than remedying identified deficiencies. For example, it may also confirm that there are no deficiencies or it may evaluate the impacts of schedule changes in the Corrective Action Plans. No change made.

The definition of planning events has been deleted.

Organization	Yes or No	Question 8 Comment
The definition for Year One has been revised to reflect your comment. The revised definition is: **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.		
Duke Energy	No	Bus-tie Breaker definitions still seems somewhat generic and the use of 'configurations' causes uncertainty. Revise Bus-tie Breaker to read, "A circuit breaker whose intended purpose is to connect two individual substation buses." "Bus-tie" is not capitalized in the Table. Consequential Load Loss must include load that is lost due to the inherent response of the particular type of load. Some motors, lighting and processes will naturally trip during an event, although not as a result of the protection system. It may have been the intent of the SDT to include this phenomenon in the Supplemental Load Loss definition. However, this definition includes the phrase, "by end-user equipment", and that makes one think that there are devices at the end-user location that are removing this equipment (and conversely, load that is not disconnected "by" end-user equipment cannot be included). Also, the term "post-Contingency" can be confusing because in the case of faults, this phrase is not clear if it means conditions after the fault initiation itself or only after the clearing of the fault. Revise Supplemental Load Loss to read, "End-user Load that, due to its characteristics, disconnects from the System in response to the conditions created by the System event."
Response: The definition as proposed by Duke Energy for a Bus-tie Breaker would apply to every breaker in any configuration. The definition in the Standard is trying to limit the application to a connection between configurations of buses, which could include flat buses, ring buses, breaker and a half, etc. The SDT is deliberately using the term configuration to avoid unintentionally excluding a particular configuration. No change made. The table has been updated to capitalize the term, “Bus-tie Breaker” where used. The definition for Supplemental Load Loss has been deleted. The definition for Consequential Load Loss has been revised to reflect your comments. The revised definition is: **Consequential Load Loss:** All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault .		
Independent Electricity System Operator	No	Is Year One intended to coincide with a calendar year or can it start in any month of the year? We suggest the following change to the definition. Insert “calendar” before “first” and “within” before “12” and change “from” to “of”. NERC should seek to reinstate a definition of “cascading outages” and create one for “uncontrolled islanding”.
Response: The definition for Year One has been revised to reflect your comment. The revised definition is: **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.		

Organization	Yes or No	Question 8 Comment
The SDT sees no reason to define “cascading outages” or “uncontrolled islanding” in TPL-001-1. If IESO wishes to pursue, please draft a SAR. No change made.		
Kansas City Power & Light	Yes	
Dominion - Electric Transmission	Yes	
Transmission Planning	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
Exelon Transmission Planning	Yes	
Western Area Power Administration	Yes	
Tampa Electric	Yes	
Florida Reliability Coordinating Council, Inc - Transmission Working Group	Yes	Excellent changes
FMPA	Yes	
CPS Energy	Yes	
JEA	Yes	
Brazos Electric Cooperative	Yes	
ITC Holdings	Yes	None

Organization	Yes or No	Question 8 Comment
Minnesota Power	Yes	
Orlando Utilities Commission	Yes	Good Job.
ReliabilityFirst Corporation	Yes No	It would have been nice if a red lined list of these changes is attached to the standard.
Response: Thank you for your response. However, due to other comments, several definitions have been changed as shown above.		

9. Do you agree with the changes in the performance elements and notes in Table 1? If not, please provide specific comments by note number, note alpha character, or performance category. Please note that footnotes 5 and 10 are handled separately in question 10.

Summary Consideration: While many comments were received from industry for this question, the vast majority of them were of a clarifying nature. While there were still a few questions on raising the bar for 300 kV, the actual performance elements now seem to have been honed to a point that is acceptable. The following changes were made due to industry comments:

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.

R5 Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltages may remain outside that level.

Header note 'a': BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur.

Header note 'c': Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

Header note 'f': Facility Ratings shall not be exceeded.

Header note 'k': Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

P4: Loss of multiple elements caused by a stuck breaker [11](non-Bus-tie) attempting to clear a Fault on one of the following: & 6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie) attempting to clear a Fault on the associated bus

P7: Any two adjacent (vertically or horizontally) circuits on common structure

Extreme event 'a': Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency

Extreme event steady state 1: Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.

Extreme event Stability 1: With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.

Footnote 2: Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.

Footnote 3: Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems as defined by the Regional Entity. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruptions of Firm Transmission Service and Non-Consequential Load.

Footnote 7: Opening breaker(s) without a fault on one end of a normally networked Transmission circuit such that the line is now open at that end and possibly serving Load radial from a single source point.

Footnote 10: A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing .

Footnote 11: Excludes circuits that share a common structure or common Right-of-Way for 1 mile or less.

Organization	Yes or No	Question 9 Comment
Northeast Power Coordinating Council	No	For Steady State & Stability: Steady State & Stability: a. Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur. b. Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirementsP5 Priority Comment As written, this requirement is overly severe. This would require the simulation of a “dead” station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. P7 Priority Comment Event 1 - This requirement requires the evaluation of the loss of two circuits on a multiple circuit tower. We recommend that this be modified so that only the loss of two adjacent (vertically or horizontally) circuits need be evaluated. We also recommend that the Planning Coordinator be allowed to evaluate and if appropriate exempt specific locations from this contingency based on acceptable risk. Comments on Extreme Events Table 1- We recommend renumbering the Extreme Events table to be Table 2. Stability Condition 2 Note a - Priority Comment - As written, this requirement is overly severe. This would require the simulation of a “dead” station if only one battery is present (use of NERC Glossary’s Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. Stability Condition 2 Note h “ Eliminate this requirement or change to loss of station following three-phase fault. This note is confusing. Without providing a better defined scenario, it is unclear as to what clearing times should

Organization	Yes or No	Question 9 Comment
		be used in this simulation. Comments on Footnotes " Table 1- We recommend renumbering the Footnotes table to be Table 3. Footnote 1.a.i " Should clarify that this requirement refers to generator units that are connected to the BES system. Footnote 1.a.ii " Contingency Reserve is dependent on the generation on-line. We suggest changing the first sentence to say that you can't lose more than that permissible by the Planning Coordinator. Also change "pull out of synchronism" to "lose synchronism" in this sentence and in the second sentence. (Is "Lose synchronism" a more commonly used term?). Footnote 1.a.i, states "For Planning Event P1: No generating unit or units shall be allowed to pull out of synchronism." There is the potential for this requirement to be taken too far. Does this mean that someone's 4 kW generator at home needs to remain synchronized? Therefore, there needs to be some sort of qualifier on this requirement. Suggested wording: "For Planning Event P1: No generating unit or units greater than 20 MW and directly interconnected at 100 kV or above shall be allowed to lose synchronism. Note that synchronism applies to conventional synchronous generators and may not apply to other generation technology." Footnote 3 " We recommend revising the wording of the last sentence to "A three phase fault study indicating criteria are being met is sufficient evidence that a SLG condition would also meet criteria. Footnote 4 " We recommend that a lower bound be put on the HV electric systems (such as 100 kV), rather than just saying "and lower". As has been commented on in a previous draft, the Drafting Team should also consider not having a prescribed voltage definition of BES, be it called EHV or HV. Studies should determine what facilities should be part of the BES because of their impact on reliability. A proposal is to modify Footnote 4 to replace the phrase "?(EHV) Facilities defined as greater than 300 kV?? with "?(EHV) Facilities defined as having a significant impact on the reliability of the System, generally at voltages greater than 300 kV as determined by the Planning Coordinator?? In using such language, the more stringent requirements could apply to BES/EHV but not globally for Facilities operating at voltages greater than 300 kV. Using this methodology the extra investment required would go towards real improvement of the reliability of the System. EHV and HV should be added to the Definitions of Terms Used in Standard. Footnote 12 We recommend adding an alternative modifier to the end of the sentence, "or for 5 towers or less. This is consistent with NPCC criteria.

Response: NPCC suggested adding the word 'Transmission' to the beginning of header note 'a'. In TPL-001-1, draft 4, the SDT made a change to header note 'a' as suggested by the commenter but modified it to be 'BES Transmission'.

Header note 'a': BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur.

Additionally it is proposed to state in header note "b" that Load Reduction is not an acceptable means to meet steady state performance requirements. Regarding the

Organization	Yes or No	Question 9 Comment
suggested change to header note 'b', no change was made as the standard does not prescribe a particular Load model such as constant power, constant impedance, etc. Depending on the assumptions used by the Transmission Planner, a Load Reduction could occur in the steady state analysis. In response to industry comments on TPL-001-1, draft 2, the SDT clarified that the P5 event is not intended to include an evaluation of individual components of the Protection System. The intent of P5 is to evaluate the failure of a Protection System design, and it is not based on any particular component of that design. Also, please see the Summary Considerations for Question 7 from the second posting comments; specifically item 3 on page 207. The suggested wording change to include 'adjacent' for the P7 planning event is accepted by the SDT and reflected in TPL-001-1, draft 4. The SDT does not accept the proposed provision for the Planning Coordinator to exempt locations for study of the P7 event beyond what is already exempted per footnote 11. **P7:** Any two adjacent (vertically or horizontally) circuits on common structure The suggested change to reference the extreme events as Table 2 was not accepted by the SDT. The team feels sufficient clarity is provided by the division breaks within the table. The table is to be viewed holistically as a single table stating performance requirements and reference notes for the TPL-001-1 standard. Regarding extreme event Stability item 2a, the response to your P5 comment above applies. No changes were made in regard to extreme event 2a. Regarding extreme event Stability item 2h, items 2f through 2h are deleted as this was a mis-interpretation of the existing table and are not required in the Stability timeframe. The suggested change to reference the Footnotes area as Table 3 was not accepted by the SDT. The team feels sufficient clarity is provided by the division breaks within the table. The table is to be viewed holistically as a single table stating performance requirements and reference notes for the TPL-001-1 standard. Footnote 1 has been deleted and moved into Requirement R4, parts 4.1.1 – 4.1.3. The indicated change was not made by the SDT as it was felt that it added no additional clarity. Regarding footnote 1.a.ii the SDT did not accept the proposed wording changes related to loss of synchronism. The change proposed was not substantive and the wording presently used, "pulling out of synchronism", is sufficient. Footnote 1 has been deleted and moved into Requirement R4, parts 4.1.1 – 4.1.3. No change made. Regarding the suggestion for the Planning Coordinator to establish the maximum allowable amount, the SDT has set a maximum and believes that it is the appropriate value. An entity can always set more stringent criteria. No change made. The comment on footnote 1.a.i is redundant and already addressed above. Footnote 1 has been deleted and moved into Requirement R4, parts 4.1.1 – 4.1.3. The SDT accepts the NPCC proposed change for footnote 3 (now footnote 2). **Footnote 2:** Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. Regarding footnote 4 (now footnote 3), the SDT does not accept the proposed change to establish a lower bound on the HV electric System. The lower bound is based on the BES definition established by a Regional Entity organization. While this is generally understood to be 100kV, it may vary throughout the North American footprint. The SDT has however modified footnote 3 for clarity. **Footnote 3:** Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems as defined by the Regional Entity. The designation of EHV and HV is used to distinguish		

Organization	Yes or No	Question 9 Comment
between stated performance criteria allowances for interruptions of Firm Transmission Service and Non-Consequential Load. Regarding footnote 4 (now footnote 3), the commenter suggest that the standard should not prescribe a voltage definition of BES, be it called EHV or HV and that studies are needed to determine BES Facility definitions. The BES definition is defined by the Regional Entity organization and studies are not generally relied upon for BES determination. The additional changes suggested in revising footnote 3 to limit the EHV definition to only those Facilities deemed significant to reliability as determined by the Planning Coordinator was not accepted by the SDT. Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined. The EHV and HV definitions are not being added to the NERC Glossary of Terms based on their limited use within the TPL standard. Regarding footnote 12 (now footnote 11), the 1 mile exception is more precise as span lengths can vary greatly between towers. No change was made.		
Transmission Planning	No	COMMENT: P2-1. Opening of Breaker(s) w/o fault Event: Does the modeling of this event require that the line remains energized up to the breakers" This will require adding a bus at each end with a zero impedance branch connection to "open" representation of breakers. Explicit modeling of a circuit breaker opening would require a substantial modeling effort and would not produce results more adverse than any of the other P2 contingencies. Why is this necessary? Recommend deletion of this planning event. The threshold of higher performance for facilities above 300 kV may wrongly influence decisions on project alternatives in favor of facilities with less stringent requirements. We do not agree that such a threshold is necessary or warranted.
Response: In Draft 3, footnote 8 (now footnote 7) was added to further clarify the need for the P2-1. There is no need to show a line energized up to the breakers that opened. The intent is simply to look for low voltage or thermal problems while supplying Load from one end of a normally networked line. The SDT does not believe the proposed higher performance requirements for the EHV will cause a disincentive for the EHV infrastructure. Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined. No change made.		
SERC Engineering Committee Planning Standards Subcommittee	No	Table 1 titles: The word "Requirements" needs to be added to the Table 1 titles in the existing tables. Table 1 " Steady State & Stability Performance Requirements Planning Events Table 1 " Steady State & Stability Performance Requirements Extreme Events Table 1 " Steady State & Stability Performance Requirements Footnotes (Planning Events and Extreme Events)Steady-state vs. stability analysis: We recommend that Table 1 be split back as was done in the previous draft to handle the 1) steady-state and 2) stability performance requirements. This is needed to provide clarity on which contingencies apply to steady-state and which apply to stability analysis. Table I, P7.1: It would not be likely to lose the two outside circuits on a vertically configured structure and not lose the middle circuit. Change the wording to: "Any two adjacent circuits on a common structure.
Response: The Table 1 title does not include the word requirements since the table is referenced by the requirements of the standard. For example, see		

Organization	Yes or No	Question 9 Comment
Requirements R3, parts 3.1 and 3.4 which require the Transmission Planner to develop Contingency lists for study based on the table performance requirements. The tables were combined for convenience since each Contingency event was the same in each table and based on stakeholder input. The Fault Type column adequately describes what fault type is required for study in the dynamic Stability timeframe. No change made. The suggested wording change to include "adjacent" for the P7 planning event is accepted by the SDT and reflected in Draft 4. **P7:** Any two adjacent (vertically or horizontally) circuits on common structure		
Duke Energy	No	Stability Extreme 2g needs a note like number 12 that excludes short distances. Stability Extreme 2h: Is this meant to be an event initiated by a 3LG fault or is it a catastrophic event that leaves all the elements at a station with a 3LG fault. If it is the former, then 2h needs a note to limit this to locations where actual events could lead to the loss of the entire station. There is no need to study this if there are no protection system events that lead to loss of the whole station (there would be no scenario to model). If 2h is meant to represent some catastrophe that causes all the elements at the site to experience a fault, then some clarification is needed to get consistent studies. Possibly rewrite 2h as, ?Assume all the buses at a single voltage level (one voltage level plus transformers) experience an event that results in a 3LG fault and disables local protection (fault must clear from remote stations or other side of transformer).
Response: The SDT agrees with the proposed addition of a footnote to address a threshold distance for circuits considered for study in loss of common Right-of-Way. The team has set the threshold at 1 mile or more, consistent with footnote 11. Footnote 11 (formerly footnote 12) was revised to account for both the common tower and common Right-of-Way exemption. Footnote 11 has been added to the extreme event Stability 2f and steady-state 2b. **Footnote 11:** Excludes circuits that share a common structure or common Right-of-Way for 1 mile or less Regarding extreme event Stability item 2h, items 2f through 2h are deleted as this was a mis-interpretation of the existing table and are not required in the Stability timeframe.		
Modesto Irrigation District	No	On page 20 under Table 1, why are "SLG" (i.e., single line to ground) type faults still specified when footnote 3 on page 24 indicates that analyzing three phase faults is sufficient ? On page 20 under Table 1 part f, changing "post transient" to "post Contingency" may be confusing to most analysts as post-transient is a well defined term that has been in use for many years, and is even referenced in Table W-1 of the WECC supplemental planning standard TPL - (001 thru 004) " WECC " 1 - CR. On page 20 under Table 1 part g, does that mean that for Planning Event P0 the analyst is not required to simulate a fault with normal clearing without a loss of any system element, in order to demonstrate system stability " On page 24 under Footnote 1 a ii, I would like to suggest that we add the phrase "(unless the relays are equipped with blinders and timers)" right after the phrase "must not pass through relay characteristics". This is because the blinders (i.e., straight line characteristic of a distance relay) and timers can be used to prevent distance relays from tripping when power angle swings cause the apparent impedance the distance relays see to cross into the distance relay's zone of protection.

Organization	Yes or No	Question 9 Comment
Response: When a SLG fault type is specified in Table 1, it is the fault that must be satisfied to meet performance criteria for the referenced planning event. Since 3-phase faults are simpler to simulate, a planner may simulate the 3-phase fault and if performance criteria are met then no further work is needed since the 3-phase fault has a greater BES impact than an SLG fault. However, if the 3-phase screening does not meet performance criteria, then the planner must perform the more labor intensive SLG analysis to determine whether or not performance criteria are being met. Please see footnote 2. The change from post-transient to post-Contingency was made in the last draft since the note refers to a steady-state timeframe. No change made. No stability review for the P0 event is required. Footnote 1 has been deleted and moved to Requirement R4, parts 4.1.1 – 4.1.3 but the indicated change was not made as the SDT does not feel that it would add any clarity.		
Pepco Holdings, Inc. - Affiliates	Yes	PHI does not disagree with the performance elements, but suggests that the table would be improved if a leading sentence were added to the definition section at the beginning of the table.
Response: Without a specific recommendation, the SDT is unable to make a change.		
MRO NERC Standards Review Subcommittee	No	MRO NSRS suggests the following changes:MRO NSRS believes reference to the use of Load Reduction to meet steady state performance requirement was omitted in Planning Events, Steady State and Stability, Item b. MRO NSRS suggests modifying the last sentence in Item b: However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirements. MRO NSRS proposes limiting the scope to automatic devices in Planning Events, Steady State and Stability, Item c. MRO NSRS suggests text of: c. Simulate the removal of all elements that Protection Systems and other Controls are expected to disconnect automatically for each Contingency?. Modify the P3 Category performance criteria to apply only to the loss of two generators because probability of the loss of two base load generators is an order of magnitude higher than the loss of a generator and any other transmission element. MRO NSRS suggests the listing of: the loss of transmission circuit, transformer, shunt device, and single pole of DC line be removed from the P3 Events column. The corresponding events be moved to the P6 Category by “1. Generator” to the listing in the Initial System Condition (Loss of . . .) column. Limit the scope of the simulations in Item 1 of the Extreme Events, Steady State and Stability section to automatic systems and controls. MRO NSRS suggests this text: 1. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect automatically for each Contingency. Clarify the meaning of the loss of multiple circuits in Item 2.a of the Extreme Events, Steady State section by using wording similar to P7. MRO NSRS suggests this text: a. Loss of three or more circuits that share a common structure. Clarify the reference to actual, historical operating experience in Item 3.b of the Extreme Events, Steady State section. MRO NSRS suggests this text: b. Other events based upon actual operating experience that may result in wide area disturbances. Clarify the reference to actual, historical operating experience in Item 2.i of the Extreme Events, Stability State

Organization	Yes or No	Question 9 Comment
		section. MRO NSRS suggests this text that is similar to Steady State, Item 3.b: i. Other events based upon actual operating experience that may result in wide area disturbances. Further clarify the applicable shunt devices in Footnote 7 with this suggested text: 7. Requirements which are applicable to shunt devices, also apply to FACTS devices that are connected to ground, but not instrument voltage transformers or surge arresters.
Response: Regarding the suggested change to header note "b", no change was made as the standard does not prescribe a particular Load model such as constant power, constant impedance, etc. The SDT has added the suggested wording. **Header note 'c':** Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event. The SDT disagrees with the proposed change to the P3 event. The loss of a generator is highly probable and the SDT and other stakeholders support the P3 requirement to meet the P1 criteria for the loss of a generator unit plus the loss of any other P1 element, not just another generator. No change made. The SDT has added the suggested wording. **Extreme event 'a':** Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency The SDT disagrees that the proposed wording of extreme event 2a is needed since the proposed change is not substantive. The SDT disagrees that the proposed wording of extreme event 3b is needed since the proposed change is not substantive. Regarding the suggested change to footnote 7 (now footnote 6), the devices listed are not typically considered in a planning study. The SDT disagrees that the proposed change is needed for clarity. No change made.		
SERC Engineering Committee Dynamics Review Subcommittee (DRS)	No	P5 should not be a Planning Event. PRC Standards address protection system failures. The complexity associated with identifying and simulating such events is unknown and the defense of assumptions made and events simulated will lead to inconsistency in compliance and enforcement. Industry-accepted proxies for such events could be developed that would allow for efficient identification of areas needing further detailed study. Attempting to intermingle protection system operation with BES performance will be nearly impossible to implement given current technologies Stability Extreme 2g needs a note like number 12 that excludes short distances. Stability Extreme 2h: Is this meant to be an event initiated by a 3LG fault or is it a catastrophic event that leaves all the elements at a station with a 3LG fault. If it is the former, then 2h needs a note to limit this to locations where actual events could lead to the loss of the entire station. There is no need to study this if there are no protection system events that lead to loss of the whole station (there would be no scenario to model). If 2h is meant to represent some catastrophe that causes all the elements at the site to experience a fault, then some clarification is needed to get consistent studies. Possibly rewrite 2h as, "Assume all the buses at a single voltage level (one voltage level plus transformers) experience an event that results in a 3LG fault and disables local protection (fault must clear from remote stations or other side of transformer).

Organization	Yes or No	Question 9 Comment
Response: In P5 the event description was changed in Draft 3 to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to normal fault clearing. The SDT agrees with the proposed addition of a footnote to address a threshold distance for circuits considered for study in loss of common Right-of-Way. The team has set the threshold at 1 mile or more, consistent with footnote 12 (now footnote 11). Footnote 11 was revised to account for both the common tower and common Right-of-Way exemption. Footnote 11 has been added to the extreme event Stability 2f and steady-state 2b. **Footnote 11:** Excludes circuits that share a common structure or common Right-of-Way for 1 mile or less Regarding extreme event Stability item 2h, items 2f through 2h are deleted as this was a mis-interpretation of the existing table and are not required in the Stability timeframe.		
SERC Engineering Committee Reliability Review Subcommittee (RRS)	No	"The word "Requirements" needs to be added to the Table 1 titles in the existing tables.oTable 1 ? Steady State & Stability Performance Requirements Planning Events Table 1 ? Steady State & Stability Performance Requirements Extreme Events Table 1 Steady State & Stability Performance Requirements? Footnotes (Planning Events and Extreme Events)? We recommend that Table 1 be split back as was done in the previous draft to handle the 1) steady-state and 2) stability performance requirements. This is needed to provide clarity on which contingencies apply to steady-state and which apply to stability analysis. Table I, P7.1: It would not be likely to lose the two outside circuits on a vertically configured structure and not lose the middle circuit. Change the wording to: Any two adjacent circuits on a common structure. The word "Requirements" needs to be added to the Table 1 titles in the existing tables.oTable 1 Steady State & Stability Performance Requirements Planning Events Table 1 Steady State & Stability Performance Requirements Extreme Events Table 1 Steady State & Stability Performance Requirements? Since it appears that the Table 1 cannot fit on a single page, it is suggested that multiple tables be developed to handle the 1) steady-state and 2) stability performance requirements. Footnotes may be included on a second page if needed. Comments were provided in early versions regarding the issues associated with raising the bar, and it was suggested that the marginal reliability benefits associated with these changes were not worth the marginal costs. We have not seen any significant changes from the earlier performance requirements. The question still remains, are we directing the resources where they need to be allocated to address and improve system reliability? So far the answer is believed to be "No". The existing TPL 002-0 allows for some local load to be dropped for a single contingency event as long as the Bulk system reliability was not impacted. However there is no such allowance any longer for losing such load for a single contingency in the proposed draft. It would be very expensive for SERC Members to fix all such events in several remote areas that would have very little impact on the overall reliability of the SERC Members? bulk system. SERC Members believe that the capital spent for these fixes could be used to better strengthen the overall bulk system in much better ways.

Organization	Yes or No	Question 9 Comment
		P5 should not be a planning event. PRC standards address protection system failures. The complexity associated with identifying and simulating such events is unknown and the defense of assumptions made and events simulated will lead to inconsistency in compliance and enforcement. Industry accepted proxies for such events could be developed that would allow for efficient identification of areas needing further study. Attempting to intermingle protection system operation with BES performance will be nearly impossible to implement given current technologies.
Response: The Table 1 title does not include the word requirements since the table is referenced by the requirements of the standard. For example, see Requirement R3, parts 3.1 and 3.4 which require the Transmission Planner to develop Contingency lists for study based on the table performance requirements. The tables were combined for convenience since each Contingency event was the same in each table and based on stakeholder input. The Fault Type column adequately describes what fault type is required for study in the dynamic Stability timeframe. The suggested wording change to include "adjacent" for the P7 planning event is accepted by the SDT and reflected in Draft 4. **P7:** Any two adjacent (vertically or horizontally) circuits on common structure In regards to proposed change to prohibit Non-Consequential Load shed in response to a single Contingency event. FERC, in Order 693, was clear in paragraph 1794 that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the majority of the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement. The suggestion for multiple tables was not accepted by the SDT. The team feels sufficient clarity is provided by the division breaks within the table. The table is to be viewed holistically as a single table stating performance requirements and reference notes for the TPL-001-1 standard. In P5 the event description was changed in Draft 3 to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to normal fault clearing.		
FirstEnergy Corp	No	A. Note b: Please see comments in our response to Question #8 related to note b and the Supplemental Load definition. B. Note b: We believe the SDT inadvertently allowed the used of Load Reduction to meet Steady State performance requirements. We suggest text of: "However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirements." C. Note b: If our assumption is correct on item B above, we fail to see the need to define two terms Load Reduction and Supplemental Load Loss which are not permitted within the Table 1 performance requirements for steady-state nor mentioned and used within the requirement language. It appears that the Load Reduction and Supplemental Load Loss are permissible within the stability timeframe. It is not understood why it would be valid to account for these in the stability timeframe but not steady-state. D. Note i: What if the TP or PC has no criteria for transient voltage response? The standard should have a requirement that ensures that such a criteria is documented by the entity if it is intended to be used within the TPL-

Organization	Yes or No	Question 9 Comment
		001-1 standard. E. P2-3: It seems that footnote 10 should apply to the EHV criteria stated in the column titled "Interruption of Firm Transmission Service Allowed" since it applies for the P5-1 through P5-5 EHV criterion. F. P5: We agree with the change made in Draft 3 to remove the reference to "single component" of the Protection System. Additionally, the SDT clarified its intended purpose of the P5 event as stated in the Draft 2, Q7 Summary Considerations:"A number of commenters expressed concern related to Planning Event P5 Protection System Failure and the need to evaluate a single component failure of a BES Protection System; particularly a failure of a station battery. The SDT has revised the P5 Planning Event description to remove the reference to single component failure and the event description was changed to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to normal fault clearing. A Protection System failure resulting in loss of the substation (one voltage level plus transformers) would not qualify as a P5 Planning Event since that event is considered an Extreme Event. A Standard Authorization Request (SAR) has been issued for industry comment (1/20/2009 through 2/18/2009) based on work completed by the System Protection and Controls Task Force (SPCTF). The proposed project will address the need for Protection System redundancy, based on an n-1 failure of individual components of the Protection System."It is suggested that a footnote be added the text Protection System as stated in the P5 Event Description. The footnote should read "Failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to normal fault clearing. This contingency is NOT based on failure of any particular single component of the Protection System design." This footnote will help clarify the intent without having to rely on the Comment record established during this standard development project. G. In the Extreme Event table we suggest event identifiers that are similar to those used in the Planning Events table. For Extreme Steady State we suggest ESS1, ESS2-1, ESS2-1... ESS2-5, ESS3-1 and ESS3-2. For the Extreme Stability we suggest ES1, ES2-1...ES2-9. This will provide a short-cut reference for industry when referring to a particular event.

Response:

A) Please see our comments related to the Supplemental Load definition in question 8.

B) Regarding the suggested change to header note “b”, no change was made as the standard does not prescribe a particular Load model such as constant power, constant impedance, etc.

C) Voltage sensitive Load loss is permitted in the transient Stability timeframe as it is common in Stability simulation tools to assume a certain percentage of Load is removed based on motor stalling. To the extent a Transmission Planner accounts for this within their analysis, the standard does not prohibit its use in the Stability timeframe. However, for steady-state thermal and voltage criteria reviews the use of voltage sensitive Load loss is prohibited. The definition of Load reduction has been deleted and the concept has been incorporated in the definition of Non-Consequential Load Loss.

D) The standard drafting team has added new Requirement R5 to explicitly require criteria for transient voltage criteria.

Organization	Yes or No	Question 9 Comment
		R5 Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for their System. For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltages may remain outside that level. E) Footnote 10 (now footnote 9) does not apply since P2-3 is classified as a single Contingency. F) In regards to the P5 event, in response to industry comments on Draft 2, the SDT clarified that the P5 event is not intended to include an evaluation of individual components of the Protection System. The intent of P5 is to evaluate a failure of a Protection System design, and not based on any particular component of the design. Please see the Summary Considerations area of Question 7 from the Draft 2 comments; specifically item 3 on page 207. Since the P5 event description says loss of a single Protection System and not single Protection System device or component, the SDT believes sufficient clarity is inherent in the P5 event description. The proposed footnote was not accepted by the SDT. **G)** Regarding the proposed short-cut references to the extreme events, the SDT disagrees. No change made.
TVA System Planning	No	The existing TPL 002-0 allows for some local load to be dropped for a single contingency event as long as the Bulk system reliability was not impacted. However there is no such allowance any longer for losing such load for a single contingency in the proposed draft. It would be very expensive for TVA to fix all such events in several remote areas that would have very little impact on the overall reliability of the TVA bulk system. TVA believes that the capital spent for these fixes could be used to better strengthen the overall bulk system in much better ways. P5 should not be a planning event. PRC standards address protection system failures. The complexity associated with identifying and simulating such events is unknown and the defense of assumptions made and events simulated will lead to inconsistency in compliance and enforcement. Industry accepted proxies for such events could be developed that would allow for efficient identification of areas needing further study. Attempting to intermingle protection system operation with BES performance will be nearly impossible to implement given current technologies. Stability Extreme 2.g, and Steady State 2.b. both need a note like footnote number 12 that excludes short distances. Suggest footnote #12 be modified to include right-of-way in addition to structures.

Response: In regards to a proposed change to prohibit Non-Consequential Load shed in response to a single Contingency event, FERC, in Order 693, was clear in paragraph 1794 that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the majority of the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement.

In P5 the event description was changed in Draft 3 to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to normal fault clearing.

The SDT agrees with the proposed addition of a footnote to address a threshold distance for circuits considered for study in loss of common Right-of-Way. The SDT has set the threshold at 1 mile or more, consistent with footnote 12 (now footnote 11). Footnote 11 was revised to account for both the common tower and common ROW exemption. Footnote 11 has been added to the extreme event steady-state 2b.

Organization	Yes or No	Question 9 Comment
Footnote 11: Excludes circuits that share a common structure or common Right-of-Way for 1 mile or less		
Exelon Transmission Planning	No	Table 1 comments in general: Even after modification from the previous version, it is still not clear if the "BES Voltage Level" applies to the contingency element voltage leFRCCan overload on a 138 kV line, is non-consequential load loss allowed on the 138 kV system? There is a concern about the lack of definition related to the failure of a "single Protection System" this could be widely interpreted. Would over tripping for line faults fall into this definition?
Response: The BES Voltage Level column applies to the System voltage of the Facilities removed from service by the planning event studied. In the example provided by Exelon, Non-Consequential Load Loss would not be permitted since the outaged facility is at the EHV level. No, over tripping is mis-operation and that does not fall into this definition.		
United Illuminating	No	Steady State & Stability comments as follows: Steady State & Stability: a. Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur. b. Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirements P5 Priority Comment As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. P7 Priority Comment Event 1 - This requirement requires the evaluation of the loss of two circuits on a multiple circuit tower. We recommend that this be modified so that only the loss of two adjacent (vertically or horizontally) circuits need be evaluated. We also recommend that the Planning Coordinator be allowed to evaluate and if appropriate exempt specific locations from this contingency based on acceptable risk. Comments on Extreme Events Table 1- We recommend renumbering the Extreme Events table to be Table 2. Stability Condition 2 Note a - Priority Comment - As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. Stability Condition 2 Note h " Eliminate this requirement or change to loss of station following three phase fault. This note is confusing. Without providing a better defined scenario, it is unclear as to what clearing times should be used in this simulation. Note 1.a.ii " Contingency Reserve is dependent on the generation on-line. We suggest changing the first sentence to say that you can't lose more than that permissible by the Planning Coordinator. Also change "pull out of synchronism" to "lose synchronism" in this sentence and in the second sentence. (Is "Lose synchronism" a more

Organization	Yes or No	Question 9 Comment
		commonly used term?). Note 3 We recommend revising the wording of the last sentence to "A 3 phase fault study indicating criteria are being met is sufficient evidence that a SLG condition would also meet criteria. Note 4 " We recommend that a lower bound be put on the HV electric systems (such as 100 kV), rather than just saying "and lower".
Northeast Utilities	No	Steady State & Stability are as follows:Steady State & Stability: a. Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur. b. Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirements Non-Consequential Load Loss Allowed Comment (priority comment):We highly recommend that the standard as written should not allow non-consequential load loss to resolve any violation arising from the planning events in Table 1 (except when considering spare equipment strategy together with events P3 or P6). We believe that planning for reliable power should discourage load loss mitigation. Therefore, the column for the "Non-Consequential Load Loss Allowed" in Table 1 should all have entries of "No". P5 Priority Comment As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary's Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. P7 Priority Comment Event 1 - This requirement requires the evaluation of the loss of two circuits on a multiple circuit tower. We recommend that this be modified so that only the loss of two adjacent (vertically or horizontally) circuits need be evaluated. We also recommend that the Planning Coordinator be allowed to evaluate and, if appropriate, exempt specific locations from this contingency based on acceptable risk. Comments on Extreme Events Table 1- We recommend renumbering the Extreme Events table to be Table 2. Stability Condition 2 Note a - Priority Comment - As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary's Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. Stability Condition 2 Note h ? Eliminate this requirement or change to loss of station following three-phase fault. This note is confusing. Without providing a better defined scenario, it is unclear as to what clearing times should be used in this simulation. Comments on Footnotes Table 1- We recommend renumbering the Footnotes table to be Table 3. Note 1.a.i " Should clarify that this requirement refers to generator units that are connected to the BES system. Note 1.a.ii " Contingency Reserve is dependent on the generation on-line. We suggest changing the first sentence

Organization	Yes or No	Question 9 Comment
		to say that you can't lose more than that permissible by the Planning Coordinator. Also change "pull out of synchronism" to "lose synchronism" in this sentence and in the second sentence. (Is "Lose synchronism" a more commonly used term?). Note 3 We recommend revising the wording of the last sentence to "A three-phase fault study indicating criteria are being met is sufficient evidence that a SLG fault condition would also meet criteria. Note 4 " We recommend that a lower bound be put on the HV electric systems (such as 100 kV), rather than just saying "and lower".
Central Maine Power Company	No	Steady State & Stability comments as follows:Steady State & Stability: a. Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur. b. Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirements P5 Priority Comment As written, this requirement is overly severe. This would require the simulation of a ?dead? station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. P7 Priority Comment Event 1 - This requirement requires the evaluation of the loss of two circuits on a multiple circuit tower. We recommend that this be modified so that only the loss of two adjacent (vertically or horizontally) circuits need be evaluated. We also recommend that the Planning Coordinator be allowed to evaluate and if appropriate exempt specific locations from this contingency based on acceptable risk. Comments on Extreme Events Table 1- We recommend renumbering the Extreme Events table to be Table 2. Extreme Event Stability Condition 2 Note a - Priority Comment - As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. Extreme Event Stability Condition 2 Note h " Eliminate this requirement or change to loss of station following three phase fault. This note is confusing. Without providing a better defined scenario, it is unclear as to what clearing times should be used in this simulation. Footnote 1.a.ii " Contingency Reserve is dependent on the generation on-line. We suggest changing the first sentence to say that you can't lose more than that permissible by the Planning Coordinator. Also change "pull out of synchronism" to "lose synchronism" in this sentence and in the second sentence. (Is "Lose synchronism" a more commonly used term?). Footnote 1.a.i, states "For Planning Event P1: No generating unit or units shall be allowed to pull out of synchronism." There is the potential for this requirement to be taken too far. Does this mean that someone's 4 kW generator at home needs to remain synchronized" Therefore, there needs to be some sort of qualifier on this

Organization	Yes or No	Question 9 Comment
		requirement. Suggested wording: "For Planning Event P1: No generating unit or units greater than 20 MW and directly interconnected at 100 kV or above shall be allowed to lose synchronism. Note that synchronism applies to conventional synchronous generators and may not apply to other generation technology." Footnote 3 " We recommend revising the wording of the last sentence to "A three phase fault study indicating criteria are being met is sufficient evidence that a SLG condition would also meet criteria. Footnote 4 " We recommend that a lower bound be put on the HV electric systems (such as 100 kV), rather than just saying "and lower". Footnote 12 " We recommend adding an alternative modifier to the end of the sentence, "or for 5 towers or less. This is consistent with NPCC criteria.

Response: The stakeholders suggest adding the word "Transmission" to the beginning of header note "a". Additionally it is proposed to state in header note "b" that Load Reduction is not an acceptable means to meet steady state performance requirements. In Draft 4, the SDT made a change to header note "a" as suggested by the commenter but modified it to be "BES Transmission…". Regarding the suggested change to header note "b", no change was made as the standard does not prescribe a particular Load model such as constant power, constant impedance, etc. However, the load reduction definition has been deleted and incorporated in Non-Consequential Load.

Header note 'a': BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur.

The SDT agrees that Non-Consequential Load Loss should be discouraged, however, many of the events contained in Table 1 are very low probability events where intentionally dropping load to protect the integrity of the remainder of the BES may be an acceptable solution. Throughout the development process, the SDT has reviewed whether to allow Non-Consequential Load Loss for each event within Table 1 and has determined that "Yes" is the appropriate response where it is used within this column. No change made.

In regards to the P5 event, in response to industry comments on Draft 2, the SDT clarified that the P5 event is not intended to include an evaluation of individual components of the Protection System. The intent of P5 is to evaluate a failure of a Protection System design, and is not based on any particular component of the design. Please see the Summary Considerations area of Question 7 from the Draft 2 comments; specifically item 3 on page 207. Since the P5 event description says loss of a single Protection System and not single Protection System device or component, the SDT believes sufficient clarity is inherent in the P5 event description.

The suggested wording change to include "adjacent" for the P7 planning event is accepted by the SDT and reflected in Draft 4. The SDT does not accept the proposed provision for the Planning Coordinator to exempt locations for study of the P7 event beyond what is already exempted per footnote 12 (now footnote 11).

P7: Any two adjacent (vertically or horizontally) circuits on common structure

The suggested change to reference the extreme events as Table 2 was not accepted by the SDT. The team feels sufficient clarity is provided by the division breaks within the table. The table is to be viewed holistically as a single table stating performance requirements and reference notes for the TPL-001-1 standard.

Regarding extreme event Stability item 2a, our response to your P5 comment above applies. No changes were made in regard to the extreme event 2a.

Regarding extreme event Stability item 2h, items 2f through 2h are deleted as this was a mis-interpretation of the existing table and are not required in the Stability timeframe.

The suggested change to reference the Footnotes area as Table 3 was not accepted by the SDT. The team feels sufficient clarity is provided by the division breaks

Organization	Yes or No	Question 9 Comment
		within the table. The table is to be viewed holistically as a single table stating performance requirements and reference notes for the TPL-001-1 standard. Footnote 1 was deleted and moved to Requirement R4, parts 4.1.1 – 4.1.3 but the SDT did not make the suggested change as it felt that it didn't add any additional clarity. Regarding footnote 1.a.ii the SDT did not accept the proposed wording changes related to loss of synchronism. The change proposed was not substantive and the wording presently used, "pulling out of synchronism", is sufficient. No change made. Regarding the suggestion for the Planning Coordinator to establish the maximum allowable amount, the SDT has set a maximum and believes that it is the appropriate value. An entity can always set more stringent criteria. No change made. The comment on footnote 1.a.i is redundant and already addressed above. The SDT accepts the proposed change for footnote 3 (now footnote 2). **Footnote 2:** Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. Regarding footnote 4 (now footnote 3), the SDT does not accept the proposed change to establish a lower bound on the HV electric System. The lower bound is based on the BES definition established by a Regional Entity organization. While this is generally understood to be 100kV, it may vary throughout the North American footprint. The SDT has however modified footnote 3 for clarity. **Footnote 3:** Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems as defined by the Regional Entity. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruptions of Firm Transmission Service and Non-Consequential Load. Regarding footnote 4 (now footnote 3), the commenter suggest that the standard should not prescribe a voltage definition of BES, be it called EHV or HV and that studies are needed to determine BES Facility definitions. The BES definition is defined by the Regional Entity organization and studies are not generally relied upon for BES determination. The additional changes suggested in revising footnote 3 to limit the EHV definition to only those facilities deemed significant to reliability as determined by the Planning Coordinator was not accepted by the SDT. Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined. The EHV and HV definitions are not being added to the NERC Glossary of Terms based on their limited use within the TPL standard. Regarding footnote 12 (now footnote 11), the 1 mile exception is more precise as span lengths can vary greatly between towers. No change was made.
System Protection and Transmission Planning Department	No	The order of scenarios listed in the table should reflect the relative probability of events. Did the SDT intend to order listed contingencies by relative severity? Could it do so" Planning Events - SLG fault simulation should not be required. They should only be performed if more severe than 3-phase faults. A SLG fault with delayed breaker clearing could have more system impact than a 3-phase fault. The "Extreme Events" portion of the table is confusing " partly because the form differs from the Planning Event portion. The difference between contingencies in the Planning portion and the Extreme portion is not clear.

Organization	Yes or No	Question 9 Comment
		Perhaps the Extreme Event portion could be a separate Table. Extreme Events / Stability section - Why specifically require "g. SLG fault on all Transmission lines on a common Right-of-Way. "
Response: The order is not based on probability. When a SLG fault type is specified in Table 1, it is the fault that must be satisfied to meet performance criteria for the referenced planning event. Since 3-phase faults are simpler to simulate a planner may simulate the 3-phase and if performance criteria are met, then no further work is needed since the 3-phase fault has a greater BES impact than a SLG fault. However, if the 3-phase screening does not meet criteria, then the planner must perform the more labor intensive SLG analysis to determine whether or not performance criteria are being met. See footnote 2. The extreme events area of the table has not been reformatted. The SDT believes the table clearly delineates what is required in regards to studies required for stability and those required for steady-state. Regarding the extreme events Stability item "g" retains consistency with what is currently in the approved TPL-004-0 standard as a NERC category D7 event.		
PPL Energy Plus	No	The WECC suggests P4 penalizes EHV and if this is true, please re-write P4 to eliminate the penalty.
Response: In regards to the EHV performance criteria for the P4 event, the EHV performance expectations remain as stated in Draft 3. P4 events pose higher risk and impact to the BES since there is no time for System adjustments for potential multiple Facility outages that can result from a single fault. Since the EHV is considered the backbone of the BES carrying large amounts of power between generation and Load and typically not directly servicing end-user customers the higher performance expectations for the high impact P4 events is warranted.		
Bonneville Power Administration PacifiCorp Deseret Generation & Transmission SRP Southern California Edison Company Western Area Power Administration Pacific Gas and Electric Co, NV Energy San Diego Gas and Electric Co	No	P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements. As such, this is a low probability condition and loss of Non-Consequential load should be allowed for EHV. We disagree with raising the bar for EHV for P4.

Organization	Yes or No	Question 9 Comment
Idaho Power California ISO		
Xcel Energy	No	P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements.
Puget Sound Energy, Inc.	No	P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker).
Response: The SDT has added the introductory text proposed for the P4 "Event" column of the table to bring consistency with the P5 event. In regards to the EHV performance criteria for the P4 event, the EHV performance expectations remain as stated in Draft 3. P4 events pose higher risk and impact to the BES since there is no time for System adjustments for potential multiple Facility outages that can result from a single fault. Since the EHV is considered the backbone of the BES carrying large amounts of power between generation and Load and typically not directly servicing end-user customers the higher performance expectations for the high impact P4 events is warranted.		
Western Area Power Administration	Yes	There is information within the notes that is not required to correctly understand and apply the TPL Standard. Examples are: 1. Note 1.a.i " the 2nd sentence is not needed to say what is not an out-of-step occurrence. 2. Note 9 is not needed to clarify what "internal" means.
Response: The SDT believes the notes provided help clarify the performance criteria stated in Table 1. No changes were made in Draft 4.		
Florida Reliability Coordinating Council, Inc - Transmission Working Group		The table is significantly improved from the prior versions and provides superior clarification over the existing standards. However, please explain why there is a performance difference between P2.3 (breaker failure), P4 (stuck breaker) and P7 (2 circuits on a common tower) for EHV. We recommend consistant critera between P2.3, P4 and P7 that allow curtailment of firm service and loss of non-consequential load.
Response: The SDT appreciates your support in the overall table revisions. In the early stages of standard development, the SDT reviewed the various Contingency classifications for likelihood and impact. Single Contingency events were placed higher in the table than multiple Contingency events. The SDT determined that since the EHV System (300kV and above) was utilized to carry large amounts of power between generation and Load and typically not directly servicing end-user customers, higher performance expectations were appropriate for some higher impact events. The P2.3 (breaker failure) event poses a high risk and impact to the BES since it is a single Contingency event. The SDT raised the performance requirement on the P4 (stuck breaker) event for EHV to parallel that of the P2.3 event. The SDT considered that even though P4 is a multiple event, the design of the substation and Protection System can reduce the impact of events and the SDT believes that the standard should encourage designs that have a positive impact on the System's ability to serve Load. The SDT determined that the performance requirements for the P7 event for EHV should not be raised.		
FMPA	No	Table 1 seems to have lost the requirement to be within Facility Ratings for single and double contingencies (e.g., the change in note "f" of Table 1). Are we missing something? If not, is this change intentional?

Organization	Yes or No	Question 9 Comment
		Footnote 10 does not seem to adequately highlight that Facilities should be within applicable ratings for single and credible double contingencies. The table is significantly improved from the prior versions and provides superior clarification over the existing standards. However, please explain why there is a performance difference between P2.3 (breaker failure), P4 (stuck breaker) and P7 (2 circuits on a common tower) for EHV. Considering the frequency of these events in actual experience, it would seem that 2 circuits on a common tower should have a more restrictive or equal performance to a stuck breaker performance, yet the performance requirements are just the opposite. We recommend allowing curtailment of firm service and loss of non-consequential load for a stuck breaker or failed breaker.
Response: In Table 1, header note "f", the text "Facility Ratings shall not be exceeded" was inadvertently deleted in the Draft 3 standard and has been re-inserted in Draft 4. **Header note 'f':** Facility Ratings shall not be exceeded. Regarding footnote 10 (now footnote 9), the issue was addressed by adding Facility Ratings back in. The SDT appreciates your support in the overall table revisions. In the early stages of standard development, the SDT reviewed the various Contingency classifications for likelihood and impact. Single Contingency events were placed higher in the table than multiple Contingency events. The SDT determined that since the EHV System (300kV and above) was utilized to carry large amounts of power between generation and Load and typically not directly servicing end-user customers, higher performance expectations were appropriate for some higher impact events. The P2.3 (breaker failure) event poses a high risk and impact to the BES since it is a single Contingency event. The SDT raised the performance requirement on the P4 (stuck breaker) event for EHV to parallel that of the P2.3 event. The SDT considered that even though P4 is a multiple event, the design of the substation and Protection System can reduce the impact of events and the SDT believes that the standard should encourage designs that have a positive impact on the System's ability to serve Load. The SDT determined that the performance requirements for the P7 event for EHV should not be raised.		
Progress Energy Carolina (PEC)		PEC prefers having separate tables for steady-state and dynamic analyses. PEC believes the requirements were more clear in that format.
Response: The SDT consolidated the tables following several Draft 2 stakeholder comments to consolidate. The prior separate tables reflected the same planning events and the SDT agreed (although not unanimously) to consolidate for simplification. The column labeled "Fault Type" along with footnote 3 (now footnote 2) provides sufficient information regarding what is needed for the Stability analysis.		
City Utilities of Springfield, MO	No	City Utilities of Springfield, Missouri does not agree with the restrictions placed on the Category P3 contingencies. Since this will simulate a multiple contingency similar to a Category P4, loss of firm transmission service and/or loss of non-consequential load should be allowed. We suggest that the drafting team expand the allowable mitigating measures for a Category P3 to be consistent with a Category P4, where loss of firm transmission service and/or loss of non-consequential load is allowed for HV levels.
Response: The P3 Contingency (loss of a generator unit, followed by System adjustments follow by another N-1) was considered by the SDT as one of the more		

Organization	Yes or No	Question 9 Comment
likely planning events and therefore both the EHV and HV were kept to the more stringent planning performance criteria. No changes made for Draft 4.		
MidAmerican Energy Company	No	MidAmerican commends the SDT for its hard work on this standard. MidAmerican commends the SDT for most of the changes to Table 1. MidAmerican does have a few comments:? MidAmerican suggests that Footnote 11 be added to the sixth item under P4. The note 11 clarifies the meaning of a stuck breaker yet this footnote isn't applied to item 6 under P4 which is a stuck-breaker item. MidAmerican believes that it is confusing having a set of explanations for Extreme Events that are 1 through 3 under Steady State and 1 and 2 under Stability and yet have later footnotes listed that are 1 through 11. MidAmerican suggests that the items 1 through 3 under Steady State and 1 and 2 under Stability for Extreme Events be changed to some other designation such as bullets or letters so that it is easy to see that the numerical footnotes start after these explanations of the extreme events. ? Further clarify the applicable shunt devices in Footnote 7 with the suggested text 7. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground, but not instrument voltage transformers or surge arrestors.
Response: The SDT accepts the proposed change to add a reference to footnote 11 (now footnote 10) on planning event P4.6. The SDT believes that the formatting is correct and sufficiently clear. No change made. Regarding the suggested change to footnote 7 (now footnote 6), the devices listed are not BES Facilities typically considered in a planning study. The SDT disagrees that the proposed change is needed for clarity. No change made.		
JEA	No	Footnote 8 relative to P2.1 seems to imply that all of the single contingency assessments for circuits should include assessment of (1) both ends of the circuit disconnecting as in P1 and (2) either end of the circuit disconnceting as in P2. This results in 3 seperate single contingency assessments for the one circuit. I am not sure of the benefit other than trying to identify a high voltage situation or in the case of tap loads, a thermal loading issue. Recommend changing Footnote 8 to"For circuits with tapped load, a seperate analysis shall be performed for an outage of each end of the circuit where the load is tapped."
Response: The SDT did not change the footnote since there are other conditions that may need to be evaluated for an open ended line such as angular Stability and high voltage.		
NorthWestern Corporation NorthWestern Energy (NWE) (NWMT)	No	P6 on the table seems to be less severe than either P4 or P5, yet it allows loss of Firm Transmission Service and Non-consequential Load which are not allowed for EHV in P4 or P5. Interruption of Firm Transmission Service and Non-Consequential Load Loss should be allowed for P4, P5, and P6. Transmission lines should have the same requirements regardless of the voltage. Also, if not able to model Firm Transmission Service, how will one know if it is interrupted? The column labeled Interruption of Firm Transmission Service Allowed? should be eliminated since it is not a clearly defined test of

Organization	Yes or No	Question 9 Comment
		performance. It is not clear how to use the present definition of "Firm Transmission Service" for a planning horizon study. P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements. As such, this is a low probability condition and loss of Non-Consequential load should be allowed for EHV.
Response: The P6 event is considered a lower impact event since it requires two separate faults to occur. Therefore, interruption of Firm Transmission Service and Non-Consequential Load Loss following the second event is permitted. Conversely, the P4 and P5 events are based on a single fault and an abnormal clearing mode. These events pose higher risk and impact to the BES since there is no time for System adjustments for the multiple Contingency Facility outcomes resulting from a single fault. Therefore, the EHV is held to higher performance criteria. The SDT disagrees with the proposed change. The higher expectation placed on the EHV, and therefore differing requirements for portions of the Transmission System, is due to the EHV being the backbone of the BES carrying large amounts of power between generation and Load and typically not directly servicing end-user customers. The numerous Firm Transmission Service contracts occurring on a short-term basis within the operating horizon are not the focus in TPL-001-1. It is expected that any long-term Firm Transmission Service agreements required for consideration within a Transmission planning horizon will be limited and well known by the responsible entity. This has been further clarified in draft 4 per the revisions made to the Requirement R1 modeling requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The SDT has added the introductory text proposed for the P4 "Event" column of the table to bring consistency with the P5 event. In regards to the EHV performance criteria for the P4 event, the EHV performance expectations remain as stated in Draft 3. P4 events pose higher risk and impact to the BES since there is no time for System adjustments for potential multiple Facility outages that can result from a single fault. Since the EHV is considered the backbone of the BES carrying large amounts of power between generation and Load and typically not directly servicing end-user customers the higher performance expectations for the high impact P4 events is warranted. **P4:** Loss of multiple elements caused by a stuck breaker [11](non-Bus-tie) attempting to clear a Fault on one of the following: & 6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie) attempting to clear a Fault on the associated bus		
SMUD	No	The allowed corrective actions in Table 1 to meet performance standards do not explicitly state how DSM solutions should be treated [there is a potential for 20% of national peak demand to be met by "demand response"] . If it is allowed to be used, and since this is a fairly significant amount, it would help if it is explicitly addressed in Table 1.
Response: The standard does not place a ceiling on DSM that can be utilized. No changes made in Draft 4.		
Progress Energy Florida, Inc.	No	PEF has multiple concerns with Table 1, the most fundamental of these concerns being that the existing Table in the existing TPL Standards is far superior to the new table. PEF suspects that the large blackout/brownout events in the Northeast and West have been the primary impetus behind devising a new Standard that will allegedly

Organization	Yes or No	Question 9 Comment
		improve BES reliability. PEF strongly feels that proper planning, operation and maintenance under existing NERC Standards could have prevented all of the aforementioned events, and thus a new TPL Standard and a new Table 1 is not necessary. PEF's specific concerns with Table 1 as it exists in this 3rd draft of TPL-001-1 are as follows: As a general concern, PEF, as has been stated already, does not believe that organizing a Reliability table according to whether or not loss of Firm Transmission Service or loss of Non-Consequential Load can occur is appropriate. The BES can be demonstrated to be robust and can even be continually improved under the existing TPL Standards. PEF fails to see how FERC's and NERC's desire to eliminate Footnote (b) as stated in the existing TPL Standards has anything to do with the desire to improve the reliability of the BES. Indeed, as TPL-001-1 exists at present, PEF suspects that many Transmission Owners will a) reduce posted ATC values to reduce risk of loss of Firm Transmission Service or b) remove breakers to convert Non-Consequential Load into Consequential Load. Both of these actions fly in the face of what FERC desires for the BES of the future. FERC certainly desires for power markets to open up further and thereby encourage lower energy prices, but at present TPL-001-1 and the accompanying Table 1 is in opposition to enhancing the power marketing industry. In addition, removing breakers is in opposition to reliability and customer service. An additional general concern involves the continued differentiation between HV and EHV. EHV by its very nature carries significantly larger amounts of power than HV, and therefore an EHV event inherently causes a greater disparity between Generation and Load than a HV event, making the loss of Firm Transmission Service or loss of Non-Consequential Load necessary for even a single contingency. Should all utilities be therefore required to make their EHV systems redundant? Such a suggestion is preposterous. Given this fact, and the fact that EHV events hardly ever occur (and, as outlined in the draft Table 1, have never occurred on PEF's system), PEF believes holding EHV to a higher standard is inappropriate, and will result in no more than a negligible reliability improvement at tremendous cost.Based on the above concerns, PEF believes for all event scenarios (P0 P7), analysis according to whether or not loss of Firm Transmission Service or loss of Non-Consequential Load can occur is inappropriate and should be deleted from the Standard. Concerning event P2-1, PEF assumes that "opening of breaker w/o fault" means opening breakers from both sides of the circuit. PEF therefore does not understand the difference between event P2-1 and events P1-1 through P1-4, and therefore suggests deleting P2-1 and combining the remainder of P2 with P1. Given the concerns above, voicing additional concerns about the Footnotes, short of reinstating the existing Footnote (b), is irrelevant.

Response: In regards to proposed change to prohibit Non-Consequential Load shed in response to a single Contingency event, FERC, in Order 693, was clear in paragraph 1794 that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the majority of the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement.

In Draft 3, footnote 8 (now footnote 7) was added to further clarify the need for the P2-1 event. The intent is simply to look for low voltage or thermal problems while supplying Load from one end of a normally networked line. In planning event P1-2, the network line would be opened at both ends and any Load tapped to the

Organization	Yes or No	Question 9 Comment
network line would be dropped. For planning event P2-1 for the same line, the Load would be studied being served from either end of the line.		
ISO New England, Inc.	No	Priority Comment As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. Priority Comment Event 1 - This requirement requires the evaluation of the loss of two circuits on a multiple circuit tower. We recommend that this be modified so that only the loss of two adjacent (vertically or horizontally) circuits need be evaluated. We also recommend that the Planning Coordinator be allowed to evaluate and if appropriate exempt specific locations from this contingency based on acceptable risk. Comments on Extreme Events Table 1- We recommend renumbering the Extreme Events table to be Table 2. Stability Condition 2 Note h Eliminate this requirement or change to loss of station following three phase fault. This note is confusing. Without providing a better defined scenario, it is unclear as to what clearing times should be used in this simulation. Note 1.a.ii Contingency Reserve is dependent on the generation on-line. We suggest changing the first sentence to say that you can't lose more than that permissible by the Planning Coordinator. Also change "pull out of synchronism" to "lose synchronism" in this sentence and in the second sentence. (Is "Lose synchronism" a more commonly used term?). Note 3 We recommend revising the wording of the last sentence to ?A 3 phase fault study indicating criteria are being met is sufficient evidence that a SLG condition would also meet criteria. Note 4 We recommend that a lower bound be put on the HV electric systems (such as 100 kV), rather than just saying "and lower".
Response: In regards to the P5 event, in response to industry comments on Draft 2, the SDT clarified that the P5 event is not intended to include an evaluation of individual components of the Protection System. The intent of P5 is to evaluate a failure of a Protection System design, and not based on any particular component of the design. Please see the Summary Considerations area of Question 7 from the Draft 2 comments; specifically item 3 on page 207. Since the P5 event description says loss of a single Protection System and not single Protection System device or component, the SDT believes sufficient clarity is inherent in the P5 event description. The suggested wording change to include "adjacent" for the P7 planning event is accepted by the SDT and reflected in Draft 4. The SDT does not accept the proposed provision for the Planning Coordinator to exempt locations for study of the P7 event beyond what is already exempted per footnote 12 (now footnote 11).The suggested change to reference the extreme events as Table 2 was not accepted by the SDT. The team feels sufficient clarity is provided by the division breaks within the table. The table is to be viewed holistically as a single table stating performance requirements and reference notes for the TPL-001-1 standard. **P7:** Any two adjacent (vertically or horizontally) circuits on common structure The SDT believes that the table is formatted correctly and is sufficiently clear. No change made. Regarding extreme event Stability item 2h, items 2f through 2h are deleted as this was a mis-interpretation of the existing table and are not required in the Stability timeframe. Regarding footnote 1.a.ii the SDT did not accept the proposed wording changes related to loss of synchronism. The change proposed was not substantive		

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and the wording presently used, "pulling out of synchronism", is sufficient. Footnote 1 was deleted and moved to Requirement R4, parts 4.1.1 – 4.1.3. Regarding the suggestion for the Planning Coordinator to establish the maximum allowable amount, the SDT has set a maximum and believes that it is the appropriate value. An entity can always set more stringent criteria. No change made. The SDT accepts the proposed change for footnote 3 (now footnote 2). **Footnote 2:** Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. Regarding footnote 4 (now footnote 3), the SDT does not accept the proposed change to establish a lower bound on the HV electric System. The lower bound is based on the BES definition established by a Regional Entity organization. While this is generally understood to be 100kV, it may vary throughout the North American footprint. The SDT has however modified footnote 3 to include the text "defined by the applicable BES" to address the concern raised by the commenter. **Footnote 3:** Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems as defined by the Regional Entity. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruptions of Firm Transmission Service and Non-Consequential Load.		
Arizona Public Service Co	No	P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements. As such, this is a low probability condition and loss of Non-Consequential load should be allowed for EHV. We disagree with raising the bar for EHV for P4. We do not agree with Note "i" which requires establishing transient voltage response limits. There is no solid basis for such limits. In the past such limits were used as proxies for VAR margin and are not needed anymore. This will also result into non-uniform criteria throughout the interconnection. If such a limit were to be established, it should be based upon quantifiable reliably impact and should be supported by firm technical basis. Note 1b: Acceptable damping should not be defined by Planning coordinator and should be left to the Transmission Planner. Otherwise it would result into non-uniform criteria for the interconnections.
Response: The SDT has added the introductory text proposed for the P4 "Event" column of the table to bring consistency with the P5 event. In regards to the EHV performance criteria for the P4 event, the EHV performance expectations remain as stated in Draft 3. P4 events pose higher risk and impact to the BES since there is no time for System adjustments for potential multiple Facility outages that can result from a single fault. Since the EHV is considered the backbone of the BES carrying large amounts of power between generation and Load and typically not directly servicing end-user customers the higher performance expectations for the high impact P4 events is warranted. **P4:** Loss of multiple elements caused by a stuck breaker [11](non-Bus-tie) attempting to clear a Fault on one of the following: & 6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie) attempting to clear a Fault on the associated bus The SDT has added a Requirement R5 to explicitly require criteria for transient voltage criteria. **R5** Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for their System. For transient voltage response, the criteria shall at a minimum, specify a voltage level and a		

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		maximum length of time that transient voltages may remain outside that level. In regards to the comment on footnote 1b, as written it's based on the more restrictive criteria of the Planning Coordinator or the Transmission Planner. Since the Planning Coordinator has a wider area purview over the Transmission Planner, it is unclear why the commenter has a concern of Planning Coordinator criteria causing non-uniformity within the Interconnection. With fewer Planning Coordinators being involved there would be less disparity across an Interconnection if the Planning Coordinator's criteria were more restrictive than the Transmission Planner's criteria. No changes were made to this footnote in Draft 4.
Hydro-Québec TransEnergie (HQT)	No	Footnote 4 We recommend that a lower bound be put on the HV electric systems (such as 100 kV), rather than just saying "and lower". As has been commented on in a previous draft, the Drafting Team should also consider not having a prescribed voltage definition of BES, be it called EHV or HV. Studies should determine what facilities should be part of the BES because of their impact on reliability. A proposal is to modify Footnote 4 to replace the phrase "(EHV) Facilities defined as greater than 300 kV" with "(EHV) Facilities defined as having a significant impact on the reliability of the System, generally at voltages greater than 300 kV as determined by the Planning Coordinator"? In using such language, the more stringent requirements could apply to BES/EHV but not globally for Facilities operating at voltages greater than 300 kV. Using this methodology the extra investment required would go towards real improvement of the reliability of the System. EHV and HV should be added to the Definitions of Terms Used in Standard. Footnote 12 We recommend adding an alternative modifier to the end of the sentence, "or for 5 towers or less. This is consistent with NPCC criteria.
Response: Regarding footnote 4 (now footnote 3), the SDT does not accept the proposed change to establish a lower bound on the HV electric System. The lower bound is based on the BES definition established by a Regional Entity organization. While this is generally understood to be 100kV, it may vary throughout the North American footprint. The SDT has however modified footnote 3 to include the text "defined by the applicable BES" to address the concern raised by the commenter. **Footnote 3:** Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems as defined by the Regional Entity. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruptions of Firm Transmission Service and Non-Consequential Load. Regarding footnote 4 (now footnote 3), the commenter suggests that the standard should not prescribe a voltage definition of BES, be it called EHV or HV and that studies are needed to determine BES Facility definitions. The BES definition is defined by the Regional Entity organization and studies are not generally relied upon for BES determination. The additional changes suggested in revising footnote 3 to limit the EHV definition to only those Facilities deemed significant to reliability as determined by the Planning Coordinator was not accepted by the SDT. Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined. The EHV and HV definitions are not being added to the NERC Glossary of Terms based on their limited use within the TPL standard. Regarding footnote 12 (now footnote 11), the 1 mile exception is more precise as span lengths can vary greatly between towers. No change was made.		

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Ameren	No	The word "Requirements" needs to be added to the Table 1 titles in the existing tables.Table 1 Steady State & Stability Performance RequirementsPlanning Events Table 1 Steady State & Stability Performance RequirementsExtreme Events Table 1 Steady State & Stability Performance RequirementsFootnotes (Planning Events and Extreme Events) Since it appears that the Table 1 cannot fit on a single page, it is suggested that multiple tables be developed to handle the 1) steady-state and 2) stability performance requirements. Footnotes may be included on a second page if needed. Comments were provided in early versions regarding the issues associated with raising the bar, and it was suggested that the marginal reliability benefits associated with these changes were not worth the marginal costs. We have not seen any significant changes from the earlier performance requirements. The question still remains, are we directing the resources where they need to be allocated to address and improve system reliability? So far the answer is believed to be "No".
Response: The Table 1 title does not include the word requirements since the table is referenced by the requirements of the standard. For example, see Requirement R3, parts 3.1 and 3.4 which require the Transmission Planner to develop Contingency lists for study based on the table performance requirements. The suggestion for multiple tables was not accepted by the SDT. The team feels sufficient clarity is provided by the division breaks within the table. The table is to be viewed holistically as a single table stating performance requirements and reference notes for the TPL-001-1 standard. Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined.		
Maine Public Advocate	No	P2, P3, P4, and P5 - The change allowing no load shedding or interruption of firm transmission service for the types of events and faults listed will lead to the construction and installation of more transmission plant. These expensive plant additions have not, however, been preceded or justified by any evidence that the reliability of the current system - using current planning standards which allow load shedding and interruption of firm transmission service - is lacking. The August 2003 blackout, to the extent utilities and other industry stakeholders have cited it for this purpose, was not caused by the lack of such planning standards; it was an event that should not have occured and would not have but for the utter failure of First Energy to pay attention to operations and vegetation management. The Joint US/Canada Report makes this clear. These proposed changes are not needed and will cause unreasonable increases in rates that are not justified by the putative increases in reliability.There is currently too much emphasis on reliability and not enough emphasis on costs. Utilities are spurred, of course, by the FERC's ROE incentive. NERC should not allow this incentive to influence the reasonalbeness of any of its standards, particularly this one which can only lead to unneeded redundancy in the high voltage transmission system and resulting higher costs.
Response: FERC, in Order 693, was clear in paragraph 1794 that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the majority of the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement.		

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The P2 events are common failure, single Contingency events therefore the criteria is properly set. Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined.		
Manitoba Hydro	No	Note b should be reworded to ?However, Supplemental Load Loss associated with a P2 through P5 event shall not be used to meet post-contingency steady-state performance requirements. Also we do not see a need for Load Reduction (see Q8 comment) Note b also implies that voltage dependent load is not permitted to be modeled for P0. This in turn means that the model must have all load represented as constant MVA. The load representation can change for categories P1 through P7. Is this the intent of the language? Note e: Are the planned System adjustments and redispatch allowed following all Planning Events if they result in curtailment of Firm Transmission Service? Should Note 10 also be referenced here? Footnote 7 applies to FACTS devices that are connected to ground. It is possible to have an ungrounded FACTS device (eg. Delta connected) or a series connected FACTS device (UPFC, SSSC, etc.). I would recommend deleting "that are connected to ground" so that the note is more general. Series connected FACTS will likely be separated via circuit breakers in a similar way as a transformer or phase shifter. Other series FACTS device, like a TCSC also typically self protect via a bypass breaker and should be considered as a separate element. Extreme Events:Steady State 1: Does the loss of a DC line refer to a bipole line? Steady State 2e: The loss of a large load could result from a Planning Event, perhaps even a P1 or P2 event - likely not an extreme event - compared to the loss of a major load center.
Response: The commenter provides no reasoning for the proposed limitation. No changes made. See our response to your Q8 comment. The standard does not prescribe a particular Load model such as constant power, constant impedance, etc. Footnote 10 (now footnote 9) does not apply globally to the entire table so it should not be reflected on header note “e”. No change made. The phrase “connected to ground” is appropriate since the focus is on shunt devices. No changes made. Loss of a bipolar line is covered as a P7 planning event. The reference to DC Line for the extreme event in question is intended to be loss of two independent single pole DC lines without time for System adjustments between each outage. The SDT has revised the extreme event descriptions for item 1 of steady state and Stability for clarity. **Extreme event steady state 1:** Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments. **Extreme event Stability 1:** With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced		

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out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments. While it is true that large amounts of Load could result from single Contingency planning events, the focus with the extreme event Steady State 2e item is different and intended to cover the complete loss of a major population center or urban area.		
E.ON U.S.		Table 1 Extreme Events CommentsSteady State2.bRight-of-Way should include a reference to footnote 1 2.2.d.Item 2.d. references loss of all generating units at a "station" but Item 3 references generating plants and nuclear power plants. It is unclear whether Item 2.d requires an outage of all generating units connected to a single transmission station (all voltages) or an outage of all generating units at a generating plant (although they may be connected to multiple transmission stations). 2.gRight-of-Way should include a reference to footnote 12. Footnotes12E ON U.S. suggests the definition be expanded to: Exclude circuits that share common structure for 1 mile or less and Transmission lines that share common Right-of-Way for 1 mile or less.
Response: The SDT does not believe a reference to footnote 1 is needed as suggested by the commenter. If the intent was to say a reference to footnote 12 (now footnote 11) as raised by other stakeholders, the SDT agrees with the proposed addition of a footnote to address a threshold distance for circuits considered for study in loss of common Right-of-Way. The team has set the threshold at 1 mile or more, consistent with footnote 11. Footnote 11 was revised to account for both the common tower and common Right-of-Way exemption. Footnote 11 has been added to the extreme event steady-state 2b. **Footnote 11:** Excludes circuits that share a common structure or common Right-of-Way for 1 mile or less Extreme event 2d and 3a are similar in that each covers the loss of all generating units at a single plant location. However, in 3a, two plants are reviewed. In each case, all units are to be outaged regardless of the BES voltage level to which they connect.		
National Grid	No	Steady State & Stability comments are as follows:Steady State & Stability: a. Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur. How does this apply to Steady State testing?b. Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirementsThe second sentence re: Supplemental Load Loss implies need to test without end-user's actions and then assess whether action of separating end-user needs to be taken by Transmission system? B. Event P2-3 and P4 have the same impact; also events P2-4 and P4-6 have the same impact. Can these be consolidated? P5 Priority Comment ? As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. P7 Priority Comment Event 1 - This requirement requires the evaluation of the loss of two circuits on a multiple

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		circuit tower. We recommend that this be modified so that only the loss of two adjacent (vertically or horizontally) circuits need be evaluated. Or allow the Planning Coordinator to evaluate and if appropriate exempt specific locations from this contingency based on acceptable risk. Comments on Extreme Events Table 1- We recommend renumbering the Extreme Events table to be Table 2. Stability Condition 2 Note a - Priority Comment - As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. Stability Condition 2 Note h Eliminate this requirement or change to loss of station following three phase fault. This note is confusing. Without providing a better defined scenario, it is unclear as to what clearing times should be used in this simulation. Note 1.a.i - For Planning Event P1: No generating unit or units shall be allowed to pull out of synchronism." There needs to be some sort of qualifier on this requirement. We suggest the following, "For Planning Event P1: No generating unit or units, directly interconnected at 100 kV or above, shall be allowed to lose synchronism." Note 1.a.ii " Contingency Reserve is dependent on the generation on-line. We suggest changing the first sentence to say that you can't lose more than that permissible by the Planning Coordinator. Also change "pull out of synchronism" to "lose synchronism" in this sentence and in the second sentence. (Is "Lose synchronism" a more commonly used term?). Note 3 We recommend revising the wording of the last sentence to "A 3 phase fault study indicating criteria are being met is sufficient evidence that a SLG condition would also meet criteria. Note 11. Reference is made to Independent Pole Operation (IPO) " Can this be clarified by referencing it as IPO or Independent Pole Trip (IPT) as opposed to single-pole switching. Note 4 ? We recommend that a lower bound be put on the HV electric systems (such as 100 kV), rather than just saying "and lower". Extreme Events:Steady State 3a - loss of two generating plants - This can be considered in two ways - one which results in loss of source (e.g. from fuel, cooling water, or nuke design shutdown) OR the second which could result in loss of stations including lines and breakers (e.g. from wildfires, weather, cyber attack, etc) - which is meant here? Both?

Response: The identification of Transmission voltage instability, cascading outages, and uncontrolled islanding is an appropriate expectation for steady state analysis. Steady state power flow analysis such as P-V or Q-V is suitable for screening, final System reinforcement decisions or operating limits are generally confirmed by more accurate time domain (dynamic) simulation. The TPL-001-1 standard in Requirement R5 requires the Transmission Planner and Planning Coordinator to define and document any criteria used to identify System instability such as cascading events, voltage instability or uncontrolled islanding.

The commenter suggests adding the word "Transmission" to the beginning of header note "a". Additionally it is proposed to state in header note "b" that Load Reduction is not an acceptable means to meet steady state performance requirements. In Draft 4, the SDT made a change to header note "a" as suggested by the

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		commenter but modified it to be "BES Transmission…". Regarding the suggested change to header note "b", no change was made as the standard does not prescribe a particular Load model such as constant power, constant impedance, etc. However, the definition of Load reduction has been deleted as it is now contained within the definition of Non-Consequential Load Loss. The definition for Supplemental Load Loss was deleted and the definition of Non-Consequential Load Loss has been changed to reflect this. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment. The commenter proposes to consolidate planning events P2-3 & P4 as well as P2-4 & P4-6 indicating they will have the same result. Within the steady state timeframe, these events will result in common outcomes; however, considered with the transient Stability timeframe, different outcomes are expected due to the delayed clearing mode of the P4 events. No changes were made by the SDT in this regard. In regards to the P5 event, in response to industry comments on Draft 2, the SDT clarified that the P5 event is not intended to include an evaluation of individual components of the Protection System. The intent of P5 is to evaluate a failure of a Protection System design, and not based on any particular component of the design. Please see the Summary Considerations area of Question 7 from the Draft 2 comments; specifically item 3 on page 207. Since the P5 event description says loss of a single Protection System and not single Protection System device or component, the SDT believes sufficient clarity is inherent in the P5 event description. The suggested wording change to include "adjacent" for the P7 planning event is accepted by the SDT and reflected in Draft 4. The SDT does not accept the proposed provision for the Planning Coordinator to exempt locations for study of the P7 event beyond what is already exempted per footnote 12 (now footnote 11). **Footnote 11:** Excludes circuits that share a common structure or common Right-of-Way for 1 mile or less The suggested change to reference the extreme events as Table 2 was not accepted by the SDT. The team feels sufficient clarity is provided by the division breaks within the table. The table is to be viewed holistically as a single table stating performance requirements and reference notes for the TPL-001-1 standard. Regarding extreme event Stability item 2a, our response to your P5 comment above applies. No changes were made in regard to the extreme event 2a. Regarding extreme event Stability item 2h, items 2f through 2h are deleted as this was a mis-interpretation of the existing table and are not required in the Stability timeframe. The suggested change to reference the Footnotes area as Table 3 was not accepted by the SDT. The team feels sufficient clarity is provided by the division breaks within the table. The table is to be viewed holistically as a single table stating performance requirements and reference notes for the TPL-001-1 standard. Footnote 1 has been deleted and moved to Requirement R4, parts 4.1.1 – 4.1.3. No change was made to the requirement wording as this standard only applies to the BES. Regarding footnote 1.a.ii the SDT did not accept the proposed wording changes related to loss of synchronism. The change proposed was not substantive and that the wording presently used, "pulling out of synchronism", is sufficient. Regarding the suggestion for the Planning Coordinator to establish the maximum allowable amount, the SDT has set a maximum and believes that it is the appropriate value. An entity can always set more stringent criteria. No change made. The comment on footnote 1.a.i is redundant and already addressed above. The SDT accepts the proposed change for footnote 3 (now footnote 2). **Footnote 2:** Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient

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evidence that a SLG condition would also meet the criteria. Footnote 11 (now footnote 10) has been changed to address your concern. **Footnote 10:** A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing Regarding footnote 4 (now footnote 3), the SDT does not accept the proposed change to establish a lower bound on the HV electric System. The lower bound is based on the BES definition established by a Regional Entity organization. While this is generally understood to be 100kV, it may vary throughout the North American footprint. The SDT has however modified footnote 3 to include the text "defined by the applicable BES" to address the concern raised by the commenter. **Footnote 3:** Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems as defined by the Regional Entity. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruptions of Firm Transmission Service and Non-Consequential Load. Regarding footnote 12 (now footnote 11), the 1 mile exception is more precise as span lengths can vary greatly between towers. No change was made. For extreme event 3a, the minimum expectation is the loss of two entire generation plants due to some wide area event as described by the examples in roman numeral i through vi. The planner at its own discretion could simulate removal of Transmission lines, transformers, etc. for the initiating event scenario considered.		
Entergy Services, Inc	No	P2.1 should allow the shedding of load along the line that would be served radially to mitigate overloads or undervoltages on the radial line. Doing so would clearly not result in degradations to the BES but only the local area served by the radial line. P4.5 is an extremely unlikely occurrence and should be equivalent to P4.6. P5 should not be a planning event. PRC standards address Protection systems. The complexity associated with identifying and simulating such events is unknown and the defense of assumptions made and events simulated will lead to inconsistency in compliance and enforcement. Industry accepted proxies for such events could be developed that would allow for efficient identification of areas needing further detailed study. Attempting to intermingle protection system operation with BES performance will be nearly impossible to implement given current technologies. In general, the entire table should be reconciled, one way or another, with MOD standards governing ATC/AFC. If multiple contingencies, protection system failures, breaker failures, and other less likely events must be planned for, then ATC/AFC processes should be equally limited, at least for long term service. Any service granted on a simple N-1 basis should be Conditional Firm. Anything less than interconnection-wide application of more stringent AFC/ATC evaluation processes commensurate with the long term planning standards will result in the shifting of costs and risks from wholesale users to retail rate payers.
Response: FERC, in Order 693, was clear in paragraph 1794 that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the majority of the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement.		

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The likelihood of a bus fault is the same for each. However, the Bus-tie Breaker event (P4.6) has a lower risk simply because there are a limited set of Bus-tie Breakers compared to a entire population of BES breakers that could be in a stuck condition as in the P4.5 situation. No change was made in draft 4. The P5 the event description was changed in Draft 3 to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to normal fault clearing. The comments made on the needed for reconciling the ATC standards are beyond the scope of this project. However, it is expected that conforming changes in other standards that currently reference the existing TPL standards will need to occur.		
Great River Energy	No	Why is the P needed in defining the category? They all have a P. Top note f and i should reference the Planning criteria established by the Planning Coordinator (or the Transmission Owner if more restrictive).The Transmission Owner is typically the one that sets the limits on their facilities. The Planner just works for the Owner.
Response: P is used as shorthand for "planning" event contingency as opposed to an extreme event Contingency. The Transmission Owner would establish the Facility Ratings, however, the Planning Coordinator and Transmission Planner establish the System criteria that must be met. Header notes 'f' and 'l' refer to established System parameters or criteria for voltage. No changes made.		
BC Hydro	No	Comments: Note "d": The term "Normal Clearing" is not well defined. Consider adding a definition in this standard or changing the NERC Glossary definition of "Normal Clearing" to read, "A protection system operates as designed and the fault is cleared in the maximum time that a properly functioning protection system would be expected to take to clear the fault, considering tolerances in normal protection operating times and circuit breaker interrupting times"No generating unit or units totaling more than the Contingency Reserve of the Balancing Authority (or Reserve Sharing Group if applicable) shall be disconnected from the System by a Special Protection System Note "e": Consider changing to, "For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are automatic (ie, implemented by a NERC-certified Special Protection System, SPS) and executable within the time duration applicable to the Facility Ratings. For P1 and P2 events, (a) generation shedding shall be limited to the normal level of Contingency Reserve of the Balancing Authority (or Reserve Sharing Group if applicable) that would be carried in the control area under the system conditions being studied and (b) no manual operator actions should be necessary to ensure Facility Ratings are not exceeded. Note that, in the operating time frame, the operator would immediately take whatever actions and system adjustments are needed to prepare for the next set of possible contingencies". It should be recognized that this will result in a higher transmission planning standard than the previous wording and that should be seen as a desirable outcome of updating the NERC standards since transmission system reliability (or lack of it) is the impetus for the whole Mandatory Reliability Standards (MRS) process. It should also be emphasized that PLANNING standards are necessarily conservative, simple and easy to apply since in the planning time frame all possible circumstances that might be encountered in the operating timeframe cannot be

Organization	Yes or No	Question 9 Comment
		assessed or nothing would ever get built. If operator action is permitted "if such adjustments are executable within the time duration applicable to the Facility Ratings", how will that be measured consistently to ensure the standard is met? One planner might count on five operators having nothing to distract them from adjusting the output levels of 10 plants to reduce the load on a line to below its 10-minute overload rating, whereas another might be more conservative and assume some of the operators may be busy with other things and be more conservative in estimating how much can be accomplished in 10 minutes. If no operator action is permitted, the standard is easily measured and a more secure system results, one of the main objectives of the MRS. The addition of the requirement that criteria are met without operator action is consistent with R3.3.1 that states "[Contingency analysis shall] simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention [emphasis added]". Performance Category P7: Consider changing the first event to, "All circuits on common structures" and consider changing the fault type to 3-phase. Extreme Events (Steady State): Consider changing item 1 to read, "With an initial condition of a single generator, Transmission Circuit, DC Line (one pole), shunt device or transformer forced out of service and prior to System adjustments, a second generator, Transmission Circuit, DC Line (one pole), shunt device or transformer is forced out of service. Extreme Events (Stability): Change item 1 to read, "With an initial condition of a single generator, Transmission Circuit, DC Line (one pole), shunt device or transformer forced out of service and prior to System adjustments, apply a 3" fault on a second generator, Transmission Circuit, DC Line (one pole), shunt device or transformer. Change item 2.g to read, "3" fault on all Transmission lines on a common Right-of-Way. Simultaneous 3" faults on all lines on a common right of way seems more likely (plane crash, avalanche, earth quake, wildfire) than simultaneous SLG faults. Footnote 1: Consider changing Item 1.a.I to read, "For Planning Events P1 and P2: No generating unit or units". And consider adding the following sentence, "No generating unit or units totaling more than the Contingency Reserve of the Balancing Authority (or Reserve Sharing Group if applicable) shall be disconnected from the System by a Special Protection System?. Footnote 8: Consider changing to, "Opening of Breaker(s) w/o fault in category P2 includes the situation in which one end of a normally networked Transmission circuit becomes open-ended, possibly resulting in voltage deviations outside acceptable limits especially at the open end of the line". Using the phrase "Opening of Breaker(s) w/o fault" that is used in the "event" column of category P2 will help people make the connection to the footnote.

Response: The SDT reviewed the existing NERC Glossary of Terms definition for Normal Clearing and found it sufficient for use in the TPL-001-1 standard. No changes were made.

Header note 'e' is not limited to automatic System adjustments. Manual operator initiated System adjustments are permitted so long as the applicable time limited rating is maintained during the adjustment. The proposed change was not accepted by the SDT.

Organization	Yes or No	Question 9 Comment
a) The standard does not place a ceiling on consequential generation tripping. b) Manual operator actions are permitted for all Contingencies. The ratings must always be adhered to. If a Contingency were to cause current flows to exceed a 24-hour Facility Rating but a 4-hour rating was not, then either natural Load reduction or System adjustments must occur within the 4-hour period. The standard permits manual System adjustments. Requirement R3, part 3.3.1 only refers to the initial System reaction to the event that the simulation program must accurately represent. The proposed changes to P7 were not accepted by the SDT. The situation described is covered as an extreme event under Steady State item 2a. The proposed change of "DC Line (one pole)" over the existing text "DC Line" was accepted by the SDT with a slight modification to read single pole. Changes were made to items 1 for both extreme event Steady State and Stability. **Extreme event steady state 1:** Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments. **Extreme event Stability 1:** With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments. Regarding extreme event Stability item 2g, items 2f through 2h were deleted as this was a mis-interpretation of the existing table and are not required in the Stability timeframe. The change proposed is no longer required. The proposed change to footnote 1 was not accepted. Generation tripping by an SPS is permitted. Footnote 8 (now footnote 7) was changed for clarity. **Footnote 7:** Opening breaker(s) without a fault on one end of a normally networked Transmission circuit such that the line is now open at that end and possibly serving Load radial from a single source point.		
IRC Standards Review Committee Midwest ISO Minnesota Power New York Independent System Operator	Yes	The stability studies require significantly more computer time and a more detailed model. The standard should allow the PC/TP to use judgment to manage size and complexity of the study.
Response: The standard permits judgment on choosing those events that are "expected to produce more severe System impacts." See Requirement R3, part 3.4 and Requirement R4, part 4.4. Additionally, in this draft the SDT has removed extreme event Stability items 2f through 2h since this was a mis-interpretation of the existing table and are not required in the Stability timeframe.		
PJM	No	Table 1, Lead in Note I. The industry has not yet reached a consensus on appropriate Transient Voltage Limits.

Organization	Yes or No	Question 9 Comment
		It's not clear that reliability will be enhanced by requiring each entity to establish a Transient Voltage Limit. Table 1 footnote 1 - System stable means: a. Angular Stability:i. For Planning Event P1: No generating unit or units shall be allowed to pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.This is not consistent with Loss of load whereby load can be lost due to a first contingency within contractual arrangements made with the load. This definition should be modified to read -A generator being disconnected from the System by fault clearing action or by a Special Protection System or prior arrangement?- as long as no other cascading outages occur. In Table 1, Extreme Events, Item 3a, i, ii, iii, iv and vi seem like events that would occur over long periods of time not in contingency simulation time frames. They seem more like sensitivities. Table 1 Delete P5 is the preferred option. If not deleted need to clarify that so that related or additional -faults in the vicinity of- are considered. As currently worded it can require all simultaneous N-2 combinations within some number of substation radius for which overtrips could occur. You would have to do all combinations since they are unpredictable. If the SDT means for the relay failure to be located at or very near to the initiating event, then perhaps the combinations are more manageable but still extremely burdensome.
Response: The SDT has added new Requirement R5 to explicitly require criteria for transient voltage criteria. This new requirement allows for the responsible entity to determine the acceptable limit for its System. **R5** Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for their System. For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltages may remain outside that level. The proposed change for "or by prior agreement" was not accepted by the SDT since the addition of footnote 5 (now footnote 4) and the ability to shed Conditional Firm service should adequately cover the situation described. No change made. The intent of extreme event 3 'a' is simply to look at the loss of all units from two separate plants. Items i, ii, iii, iv and vi are merely explanatory to what could initiate this type of event. No change made. The P5 event description was changed in Draft 3 to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a Delayed Clearing mode that may also include additional electrical Facilities being removed when compared to normal fault clearing.		
Brazos Electric Cooperative	No	For the most part Table 1 is acceptable but not entirely. The general 'feel' is that more studies are required. Requiring more studies is not going to provide additional reliability benefit but Brazos does not own many miles of transmission above 300 kV so the impact will be less for us than other larger TOs. We do not see the purpose of studying events where all forms of load loss is allowed. We understand upgrading the transmission system for these events is not required and is unneeded so why study certain events other than to insure that cascading outages don't occur? Without running a full set of studies it is a little hard to determine if Table 1 can be readily assessed or the true value of the additional studies.

Organization	Yes or No	Question 9 Comment
Response: More studies are being required in the sense that sensitivity studies are now required. However, the number of scenarios covered in the planning events and extreme events is comparable to the existing Category A, B, C and D items in use today. For events that permit the loss of Non-Consequential Load, a Transmission Planner could elect to impose stricter criteria on itself than the minimum expectations of the standard. However, the SDT believes an appropriate criterion has been established. Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined. The sensitivity studies are intended to broaden the knowledge of the Transmission Planner. If several sensitivities show a susceptibility to a particular planning event, a Transmission Planner may elect to act and include in their Corrective Action Plans based on the risk and likelihood.		
American Electric Power	No	Consider adding a Planning Event defined to address common mode outages of two generating units. The language could parallel that of P7, substituting “common system” for “common structure”. In the present draft, Planning Events P4 and P5 address single faults that may result in multiple contingencies. Most of these events can be expected to involve either multiple transmission facilities or a mix of generating units and transmission facilities. P7 covers common mode (structure) outages of transmission lines. There are no common mode generator contingencies specified. Define the term “common Right-of-Way” and/or modify the term to “common or adjacent Right(s)-of-Way”. In the absence of a definition, if two lines are built on opposite sides of some geographic boundary (such as a two-lane road) they may legally be completely separate, potentially with no overlap in the agreements between the Transmission Owner and landowners. However, from the standpoint of BES exposure to weather related outages, the lines clearly will simultaneously be exposed to similar conditions. Lines that follow geographically parallel routes for more than a minimum distance and are within some minimum separation should be considered to be on a common Right-of-Way. Suggestion for the minimum parallel distance would be 1 mile (based on footnote 12).
Response: The common mode event described is classified as an extreme event, see item 1 in steady state and Stability. The Transmission Planner could elect to impose a higher criteria on itself and consider a variation of the P3.1 event that would not include a System adjustment between the loss of two units, but it is not required by the standard. No change made. The commenter accurately describes the potential outcome of the P4 and the P5 events. As described above, the Transmission Planner could elect to evaluate the simultaneous loss of two units, but it was not identified by data reviewed by the SDT as being a highly likely event and therefore not included as a planning event. The SDT has made clarifying changes to Footnote 12 (now footnote 11). Footnote 11 has been added to the extreme event steady-state 2b. Extreme event Stability 2f has been deleted. **Footnote 11:** Excludes circuits that share a common structure or common Right-of-Way for 1 mile or less		
LADWP	No	Table 1 continues with discriminatory performance criteria required of 300kV and above facilities. This new "higher" criteria could lead to endless argument and litigations as to who did what to whom if implemented. Currently, all transmission facilities have same performance criteria; the impacts of each new facility are carefully evaluated and mitigations are included as part of the Plan of Service. This new, discriminatory requirement would

Organization	Yes or No	Question 9 Comment
		force everyone with EHV facilities to re-do its palnning studies and mitigate the impacts. Unfortunately, the real world is quite messy. For example, Company A has put in a 500KV line twenty years ago and since then, Companies B, C, and D have put in several underlying 230 kV, 115 kV lines. Is company A on hook now to mitigate all the problems for lines that came in later? Or is it required to re-create the conditions 20 years ago and mitigate only what would have been required. This is a very simplistic example to illustrate potential disagreements that would arise by this discriminatory criteria. If there is any engineering evidence to support this arbitrary requiremnts, it has yet to be presented. As I commented in the past, the last two major cyctme wide cascading event, both in WECC AND THE Eastern Interconnect, were both caused by 230kV systems.
Response: Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined. In the example provided, each company A, B, C and D is responsible for ensuring that criteria is met for its own facilities.		
Platte River Power Authority	No	At the top of Table 1 Planning Events, under "Stability Only:" regarding Note "i": Suggest deleting everything from "established" on to the end. (WECC establishes acceptable limits for transient voltage response.)
Response: The SDT has revised the referenced header note, now header note “k” in draft 4. The note now says both the Transmission Planner’s and the Planning Coordinator’s criteria must be met. **Header note ‘k’:** Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.		
Orlando Utilities Commission	Yes	Comments: The table is significantly improved from the prior versions and provides superior clarification over the existing standards. In areas where an entity is the TSP and the PC, it is obvious that the Firm Service provided by the TSP falls within the performance requirements of the standard regarding curtailment. However if the firm service is provided by another TSP (a different PC) and causes a problem, who is responsible for insuring it does not have to be curtailed. As an example if System A has a firm transmission service agreement that under contingency causes a problem on System C, is system C in violation if the service has to be cut to protect their system, or is System A that granted and is responsible for the service?
Response: We appreciate your support of the TPL-001-1 standard and the revised Table 1. The Planning Coordinator or Transmission Planner is responsible for its portion of the BES and therefore is responsible for insuring there are no performance violations on its System. Further, the origin of the violation and the responsibility for curtailing service is not within the scope of the planning standards as it is an equity issue and not a reliability issue.		
American Transmission Company	No	We suggest the following changes:We believe reference to the use of Load Reduction to meet steady state performance requirement was omitted in Planning Events, Steady State and Stability, Item b. We suggest modifying the last sentence in Item b: However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirements. We propose limiting the scope to automatic devices in Planning Events, Steady State and Stability, Item c. We suggest text of: c. Simulate the removal of all elements that Protection Systems and other Controls are expected

Organization	Yes or No	Question 9 Comment
		to disconnect automatically for each Contingency?. Remove performance note ?e" in the Planning Events, Steady State & Stability section and replace it with R3.3.5 and R4.3.5, as suggested in the comments for R3 and R4. The qualification of allowable planned System adjustments should be a Requirement, rather than a performance note. Remove performance note "a" in the Planning Events, Steady State Only section, and replace it with R2.10, as suggested in the comments for R2. The obligation to identify and observe applicable steady state voltage and post-Contingency voltage deviations should be a Requirement, rather than a performance note. Remove performance note "b" in the Planning Events, Stability Only section and replace it with R2.10, as suggested in the comment for R2. The obligation to identify and observe applicable transient voltage response limits should be a Requirement, rather a performance note. Modify the P3 Category performance criteria to apply only to the loss of two generators because the probability of the loss of two base load generators is an order of magnitude greater than the loss of a generator and any other transmission element. We suggest the listing of: the loss of transmission circuit, transformer, shunt device, and single pole of DC line be removed from the P3 Events column. The corresponding events be moved to the P6 Category by "1. Generator" to the listing in the Initial System Condition (Loss of . . .) column.Limit the scope of the simulations in Item 1 of the Extreme Events, Steady State and Stability section to automatic systems and controls. We suggest this text: "1. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect automatically for each Contingency. Clarify the meaning of the loss of multiple circuits in Item 2.a of the Extreme Events, Steady State section by using wording similar to P7. We suggest this text: "a. Loss of three or more circuits that share a common structure. Clarify the reference to actual, historical operating experience in Item 3.b of the Extreme Events, Steady State section. We suggest this text: "b. Other events based upon actual operating experience that may result in wide area disturbances. Clarify the reference to actual, historical operating experience in Item 2.i of the Extreme Events, Stability State section. We suggest this text that is similar to Steady State, Item 3.b: "i. Other events based upon actual operating experience that may result in wide area disturbances. Further clarify the applicable shunt devices in Footnote 7 with this suggested text: "7. Requirements which are applicable to shunt devices, also apply to FACTS devices that are connected to ground, but not instrument voltage transformers or surge arresters. ATC suggest that following change to Table 1, footnote 4. Existing language:"Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems."Suggested Modification:"Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 100kV through the 300kV Systems."

Organization	Yes or No	Question 9 Comment
Response: Regarding the suggested change to header note "b", no change was made as the standard does not prescribe a particular Load model such as constant power, constant impedance, etc. The proposed change to header note "c" has been made. **Header note 'c':** Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event. The proposed deletion of header note "e" was not accepted. The note is explanatory describing something that is permitted rather than a requirement that shall be followed. The proposed change to move item header note 'e' to the requirements was not accepted. Additionally, under Requirement R3, part 3.1 and Requirement R4, part 4.1 the entire table is tied to a reliability requirement for both steady state and Stability. Regarding comments on header notes "a" and "b" - under Requirement R3, part 3.1 and Requirement R4, part 4.1 the entire table is tied to a reliability requirement for both steady state and Stability. The loss of a generator plus any other N-1 item was viewed as highly likely by the SDT. No change was made to the P3 and P6 events as proposed by the commenter. No change was made to the note as the SDT considered the present wording sufficient to describe the condition. No change was made to the note as the SDT considered the present wording sufficient to describe the condition. The proposed change to footnote 7 (now footnote 6) was not made as the SDT considers the present wording sufficient to describe the condition. The change to footnote 4 (now footnote 3) was not accepted although the SDT did make a clarifying change to the footnote. **Footnote 3:** Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems as defined by the Regional Entity. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruptions of Firm Transmission Service and Non-Consequential Load.		
Omaha Public Power District	No	Header note 'f' under Planning Events: The redline version shows that the sentence "Facility Ratings shall not be exceeded" was removed from the beginning of header note "f" (header note "b" in the previous draft). This sentence needs to be reinserted at the beginning of header note "f". The requirement that Facility Ratings not be exceeded is a core principle of steady-state transmission-system assessment and needs to be explicitly stated somewhere in the standard. If this sentence is not reinserted, it could lead to a situation where different regions come up with different interpretations of the manner in which Facility Ratings need to be respected. Category P2: In the third column of the table, there is a dotted line that appears to be separating two parts of the description for event type P2.3. It appears that this dotted line should be removed. Category P3: In the fifth, sixth, and seventh columns of the table, there is one set of cells for event types P3.1 through P3.4 and another set of cells for event type P3.5. Since these two sets of cells are identical, they can be merged into one set that applies to event types P3.1 through P3.5. This would make the presentation of requirements for Category P3 consistent with that of Category P1. Category P7: Category P7 requires analyzing SLG faults on any two circuits on common structures. Add language to clarify whether SLG faults on both the same and different phases of the two circuits need to be

Organization	Yes or No	Question 9 Comment
		considered or whether it is sufficient to assume that the SLG faults occur on the same phase of the two circuits.
Response: In header note "f", the text "Facility Ratings shall not be exceeded" was inadvertently deleted in the Draft 3 standard and has been re-inserted in Draft 4. The dotted line separator is appropriate and is used to distinguish between the EHV and HV performance criteria of the P2.3 event. The suggested table format change for the P3 event was accepted. The standard does not specify. It's at each Planning Coordinator's or Transmission Planner's discretion.		
Tucson Electric Power Company	No	Clarify use of the term "single contingency" in P2 as P2-2 and P2-3 are labeled as single contingencies but multiple elements are effected. In the past loss of a branch or shunt element has been considered a single contingency but loss of a bus element could involve the loss of multiple branch or shunt elements. P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements. As such, this is a low probability condition and loss of Non-Consequential load should be allowed for EHV. We disagree with raising the bar for EHV for P4.We also disagree with raising the bar for P5. This is a multiple contingency condition and may result in loss of more than 2 elements. We strongly disagree with elimination of load shed (of non-consequential load) for loss of multiple branch or shunt elements >300 kV.
Response: The P2-2 and P2-3 items are considered single Contingency since a single fault occurrence causes the event. While it is true that multiple elements are anticipated to trip, the event is still considered a single Contingency. TPL-001-1 differs from the existing standard in that it is clear that single branch outages that are not reflective of actual Protection Systems and controls design will not be acceptable. If a single fault can result in multiple elements being removed from service they must be simulated accordingly. The SDT has added the introductory text proposed for the P4 "Event" column of the table to bring consistency with the P5 event. In regards to the EHV performance criteria for the P4 event, the EHV performance expectations remain as stated in Draft 3. P4 events pose higher risk and impact to the BES since there is no time for System adjustments for potential multiple Facility outages that can result from a single fault. Since the EHV is considered the backbone of the BES carrying large amounts of power between generation and Load and typically not directly servicing end-user customers the higher performance expectations for the high impact P4 events is warranted. **P4:** Loss of multiple elements caused by a stuck breaker [11](non-Bus-tie) attempting to clear a Fault on one of the following: & 6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie) attempting to clear a Fault on the associated bus Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined. The Implementation Plan is intended to provide sufficient time to shift to the new expectations.		
Independent Electricity System Operator	No	"Single-phase-to-ground" faults should replace all occurrences of "single-line-to-ground" faults.

Organization	Yes or No	Question 9 Comment
		Events in P6 and P7 need more clarity for back to back installation where no DC line exists. In note footnote 11 we propose the following change. 11. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing. We do not agree with the removal of the provision to allow load rejection for 1 and 2 elements out of service under certain defined conditions as indicated in footnote "b" of Table I of the current TPL standards.
Response: The SLG fault description is a commonly understood term. No change was made. For back to back installations, each pole of the converter station would be treated the same as a DC line. No change made. The proposed change for footnote 11 (now footnote 10) was accepted. **Footnote 10:** A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing In regards to proposed change to prohibit Non-Consequential Load shed in response to a single Contingency event, FERC, in Order 693, was clear in paragraph 1794 that interruption of Non-Consequential Load are not permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the majority of the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement.		
ReliabilityFirst Corporation	Yes	The term "stuck breaker" has been mis-understood, and additional text is needed to make it clear. "A stuck breaker is defined as a breaker that failed to open due to a mechanical failure internal to the breaker which prevents it from opening or protection system failures that failed to send a trip signal.
Response: The SDT agrees in part with your response. We concur that a stuck breaker is based on a mechanical failure of a single breaker. However, a Protection System failure could result in different outcomes depending on the design implemented. The SDT has partitioned the prior C6 through C9 contingencies into the P4 and P5 planning events to bring greater focus on this distinction.		
Kansas City Power & Light	Yes	
ReliabilityFirst Corporation	Yes	
Dominion - Electric Transmission	Yes	
Duke Energy	Yes	
ITC Holdings	Yes	None

Organization	Yes or No	Question 9 Comment
New Brunswick System Operator		No comment
Gainesville Regional Utilities	Yes	
CPS Energy	Yes	
Southern Company	Yes	
Tampa Electric	Yes	
Response: Thank you for your response.		

10. The changes to the Table include the addition/revision of footnotes 5 and 10 that address curtailment of Firm Transmission Service and conditional Firm Transmission Service. Do you agree with the footnotes? If not, please provide specific comments.

Summary Consideration: The majority of respondents were positive with their comments on the addition of the two footnotes. A number of clarifying questions were asked and the SDT has attempted to quell those questions with clarifications made to the footnotes. Please note that footnote 5 is now footnote 4 and footnote 10 is now footnote 9.

Footnote 4: Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.

Footnote 9: Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.

Organization	Yes or No	Question 10 Comment
Dominion - Electric Transmission	No	Table 1 Interruption of Firm Transmission Service is not allowed for many of the events listed. Doesn't this imply that firm point-to-point service can't be interrupted even when the service is provided across points that are connected only by a radial facility? If so, does NERC have the authority to determine how transmission service providers calculate firm ATC? Dominion is also concerned that transmission service providers appear subject to "double jeopardy" I.E, NERC fine for violations of applicable reliability standard and FERC sanctions if OATT is violated.
Response: It is the SDT's opinion that the point-to-point service described is in essence; Conditional Firm Service based on the condition that the radial Facility is in service and could thus be interrupted under Footnote 5 (now footnote 4). No change made.		
Transmission Planning	No	It appears that the reference callout to footnote 5 should be placed on every "No" in the "Interruption of Firm Transmission Service column instead of in the header, as was done with reference callouts to footnote 10. In footnote 5 "conditional" should be capitalized since it refers to a specific product defined under the OATT. Also, this only covers the specific condition form of the product, but does not address the specified number of hours form of the product. If the second form of the product is the basis for the service and the transaction is modeled in the case, and curtailment will mitigate an overload, it should also be allowed. Footnote 10 is too long and subjective. There is no purpose in adding the phrase "when coupled with the appropriate re-dispatch of resources obligated to re-dispatch" because if there is an obligation to re-dispatch, it is done, and if there is no obligation to do so, then curtailment is the only alternative " no coupling necessary,

Organization	Yes or No	Question 10 Comment
		therefore, this phrase should be deleted. In addition, the last two sentences end in "must be considered". What is the appropriate amount of "consideration" and what defines whether the consideration is acceptable or not? The last sentence should be a stand alone performance requirement in the Steady State and Stability notes at the top of Table 1 (in the list a through e) and should end in "must be adhered to" instead of "must be considered".Suggested revision:10. Curtailment of firm transmission service is allowed both as a System adjustment (as identified in the column titled "Initial System Conditions") and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load.
Response: Footnote 5 (now footnote 4) is intended to apply to every row in the "Interruption of Firm Transmission Service Allowed" column while Footnote 10 (now footnote 9) does not. The placement of the footnotes is predicated on that premise. No change made. The SDT agrees with the capitalization of the word Conditional and has made the necessary corrections. **Footnote 4:** Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service. Footnote 5 (now footnote 4) states that "When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service…" The word "conditions" is intended to address the 'hours' form of Conditional Firm service in that the hours a service may not be available should be based on System conditions that exist for those hours. No change made. Footnote 10 (now footnote 9) was added to address the disjoint between how some parties calculate ATC/AFC when assessing Long Term Firm Transmission Service and the currently proposed TPL-001-1 standard. TPL-001-1 requires Transmission Planners to plan their systems to meet multiple contingency events and some parties assess Long Term Firm Transmission Service on a first Contingency basis. Units obligated to re-dispatch, as contemplated in Footnote 9 are those units which are contractually bound to provide the service as well as those obligated to provide the service under Network Integrated Transmission Service, under FERC's pro forma OATT. Under the pro forma OATT, units designated as network resources receiving NITS are obligated to re-dispatch as requested by the Transmission Provider pursuant to Section 33.2 to maintain reliability. The footnote is worded such that curtailment/re-dispatch cannot result in the loss of firm Load preserves the guidance given by FERC in Order 693 that no single Contingency result in the loss of firm Load. No change made. Where contractual agreements exist between entities allowing re-dispatch, and the curtailment of Firm Transmission Service associated with that re-dispatch is point-to-point, the point-to-point service curtailment would be allowed. In the case of units otherwise obligated, namely those resources with Network Integrated Transmission Service designated as network resources, curtailment of point-to-point service involving those resources would not be allowed. The SDT believes that applicable Facility Ratings noted throughout the standard cover all Facilities. No change made.		
SERC Engineering Committee Planning Standards Subcommittee	No	Footnote 5:Suggest rewording of footnote 5 to:Curtailment of conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the conditional Firm Transmission Service. Footnote 10: Footnote 10 is definitely an improvement from previous versions. It is suggested that the word "also" be added to the last line:Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of

Organization	Yes or No	Question 10 Comment
		resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled "Initial System Conditions") and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must also be considered.
Ameren	No	Suggest rewording of footnote 5, though we do not use conditional firm service:Curtailment of conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the conditional Firm Transmission Service. Footnote 10 is definitely an improvement from previous versions. It is suggested that the word "also" be added to the last line:Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled "Initial System Conditions") and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner'splanning region are relied upon, Facility Ratings in those regions must also be considered.
Response: The SDT agrees with proposed re-wording of Footnote 5 (now footnote 4) and the additional wording in Footnote 10 (now footnote 9). **Footnote 4:** Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.: **Footnote 9:** Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must should also be respected. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service. Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.		
SERC Engineering Committee Reliability Review Subcommittee	No	Suggest rewording of footnote 5 to: Curtailment of conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the conditional Firm Transmission Service.

Organization	Yes or No	Question 10 Comment
(RRS)		Footnote 10 is definitely an improvement from previous versions. It is suggested that the word "also" be added to the last line: Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled "Initial System Conditions") and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must also be considered.
Response: The SDT agrees with proposed re-wording of Footnote 5 (now footnote 4) and the additional wording in Footnote 10 (now footnote 9). **Footnote 4:** Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service. **Footnote 9:** Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must should also be respected. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service. Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.		
Southern Company	No	Footnote 10 should not be applied to P3. The curtailment of firm service should not be allowed for a unit out / line out contingency.
Response: Footnote 10 (now footnote 9) was added to address the disjoint between how some parties calculate ATC/AFC when assessing Long Term Firm Transmission Service and the currently proposed TPL-001-1 standard. TPL-001-1 requires Transmission Planners to plan their systems to meet multiple contingency events and some parties assess Long Term Firm Transmission Service on a first Contingency basis.. Units obligated to re-dispatch, as contemplated in Footnote 9 are those units which are contractually bound to provide the service as well as those obligated to provide the service under Network Integrated Transmission Service, under FERC's pro forma OATT. Under the pro forma OATT, units designated as network resources receiving NITS are obligated to re-dispatch as requested by the Transmission Provider pursuant to Section 33.2 to maintain reliability. The footnote is worded such that curtailment/re-dispatch cannot result in the loss of firm Load preserves the guidance given by FERC in Order 693 that no single Contingency result in the loss of firm Load. No change made.		
System Protection and Transmission Planning	Yes	These concepts seem too important to relegate to footnotes. Could this discussion of how to handle Firm transactions and redispatch be moved to a more prominent place? Perhaps these concepts should be removed

Organization	Yes or No	Question 10 Comment
Department		from this standard entirely. A more appropriate place for these concepts would be in ATC standards.
Response: While the SDT agrees that these are important concepts, given that the inclusion of all firm use of the BES, including the use created by Firm Transmission Service, is essential to meaningful Transmission Planning Assessments, The SDT therefore does not agree that the concepts can be removed entirely from the TPL standard. Ultimately Transmission planning engineers will be responsible for the study work done and the proposals to ensure each entity meets the requirements in the standard. The SDT believes that the tables will be the central point of reference and thus the most appropriate place for the provisions regarding how firm Transmission use can be handled. No change made.		
Florida Reliability Coordinating Council, Inc - Transmission Working Group	Yes	Excellent additionFootnote 10 is long and subjective. There is no purpose in adding the phrase "when coupled with the appropriate re-dispatch of resources obligated to re-dispatch" because if there is an obligation to re-dispatch, it is done, and if there is no obligation to do so, then curtailment is the only alternative " no coupling necessary. Suggested revision:10. Curtailment of firm transmission service is allowed both as a System adjustment (as identified in the column titled "Initial System Conditions") and as a corrective action, providing those adjustments do not result in the shedding of any firm Load.
Response: Footnote 10 (now footnote 9) was added to address the disjoint between how some parties calculate ATC/AFC when assessing Long Term Firm Transmission Service and the currently proposed TPL-001-1 standard. TPL-001-1 requires Transmission Planners to plan their systems to meet multiple contingency events and some parties assess Long Term Firm Transmission Service on a first Contingency basis.. Units obligated to re-dispatch, as contemplated in Footnote 9 are those units which are contractually bound to provide the service as well as those obligated to provide the service under Network Integrated Transmission Service, under FERC's pro forma OATT. Under the pro forma OATT, units designated as network resources receiving NITS are obligated to re-dispatch as requested by the Transmission Provider pursuant to Section 33.2 to maintain reliability. The footnote is worded such that curtailment/re-dispatch cannot result in the loss of firm Load preserves the guidance given by FERC in Order 693 that no single Contingency result in the loss of firm Load. No change made.		
FMPA	Yes	We disagree with how the performance criteria is applied to different contingencies, but agree that firm transmission can be curtailed post-contingency as a system adjustment, and especially as preparation for the next contingency.
NorthWestern Corporation NorthWestern Energy (NWE) (NWMT)	No	NWE has provided comments above concerning Firm Transmission Service and the foot notes should address the issues that we have raised above.
Progress Energy Florida, Inc.	No	Again, given the fundamental concerns that PEF has stated in previous Questions, PEF sees voicing detailed concerns for these footnotes as irrelevant, short of suggesting the reinstatement of the existing Footnote (b).
Response: The SDT thanks you for your comments.		
Progress Energy Carolina (PEC)	No	PEC believes that Footnote 10 should be clarified. The proposed wording "Where Facilities external to the Transmission Planner'splanning region are relied upon, Facility Ratings in those regions must be considered" is unclear. It is not clear what "relied upon" means. Also, thermal overloads on neighboring systems are generally

Organization	Yes or No	Question 10 Comment
		the neighboring system's responsibility to mitigate.
Response: The intent of Footnote 10 (now footnote 9) is to allow Transmission Planner's to use resources obligated to re-dispatch to meet reliability requirements. However, without due consideration to Facilities external to the Transmission Planner's study area, Facility Ratings could potentially be violated in those areas unbeknownst to the owners of those Facilities. Footnote 10 has been revised for clarity. **Footnote 9:** Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must should also be respected.		
JEA	No	Footnote 10: First of all, the term firm Load is used instead of the term Non-Consequential load. Are these the same? If so, maybe we need to be consistent here. Assuming they are the same and in reference to previous comment on use of Non-Consequential load shedding. :"Propose establishing a cap on Non-Consequential Load Loss for all Corrective Action Plans where the Table 1 events currently do not allow at all. The cap could also be accompanied by an allowance of lag time (maybe 4-5 years)."To be consistent, some level of Non-Consequential load shedding should be allowed where Generation redispatch falls short for a few years until new planned generation is added to the system.
Response: The SDT does not see where any additional clarity would be added by the suggested change. No change made. The SDT has considered establishing a cap on Consequential and Non-Consequential Load Loss. Currently the SDT has elected not to do so, but instead to add reporting requirements in Requirement R2, Part 2.9 for a possible cap in the future. Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must also be adhered to.		
SMUD	No	The allowed corrective actions in Table 1 to meet performance standards do not explicitly state how DSM solutions should be treated [there is a potential for 20% of national peak demand to be met by "demand response"] . If it is allowed to be used, and since this is a fairly significant amount, it would help if it is explicitly addressed in Table 1.
Response: The SDT agrees that DSM initiatives can impact TPL-001-1 assessments. It is the SDT's opinion that DSM initiatives would be reflected in the Load models. No change made.		
Pacific Gas and Electric Co,	Yes	We support the concept. However, we are unclear about the last sentence of Footnote 10, which reads "where

Organization	Yes or No	Question 10 Comment
		Facilities external to the Transmission Planner'splanning region are relied upon, Facility Ratings in those regions must be considered. For resources from areas external to the Transmission Planner'splanning regions, would identification of the need to, for example, increase System Operating Limits into the his/her Transmission Planning Area as part of the Corrective Action Plan be counted as having "considered" the "Facility Ratings in those impacted regions"? Otherwise, it may be difficult for the Transmission Planner to assess and identify all the Facility Ratings that may be impacted in a region external to his/her Transmission Planning Area.
Response: The SDT agrees and has strengthened the language in Footnote 10 (now footnote 9) **Footnote 9:** Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must should also be respected. Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must also be adhered to.		
Manitoba Hydro	Yes	Note 10: The drafting team is to be congratulated for including the ability to curtail Firm Transmission Service as long as generation is available to redispatch to prevent firm load loss. Note 5: Firm transmission service can also be curtailed when the service is conditioned on the element is being available (note 5). It is recommended to add note 10 to contingencies P1 and P2. This would allow for curtailment of Firm Transmission Service via redispatch without dropping load when re-adjusting the system following these single contingency events, or automatically adjusting the system via an SPS action initiated by the P1 or P2 event, consistent with note b of the existing TPL standards. The consequence of not including Note 10 could mean extensive new transmission line construction without any increase in transfer capability. In Note 10, the SDT is assuming that the Firm transmission Service is Network Service to load. Does Note 10 also apply if the Firm Transmission Service is firm point-to-point service?
Response: The SDT agrees that Footnote 10 (now footnote 9) all System adjustments. However, P1 and P2 do not include System Adjustments. While the SDT recognizes that firm service has been granted on radial Facilities it is the SDT's opinion that such service is, in essence, Conditional Firm Service based upon the condition that the radial Facility is in service. No change made. Footnote 10 (now footnote 9) was added to address the disjoint between how some parties calculate ATC/AFC when assessing Long Term Firm Transmission Service and the currently proposed TPL-001-1 standard. TPL-001-1 requires Transmission Planners to plan their systems to meet multiple contingency events and some parties assess Long Term Firm Transmission Service on a first Contingency basis. Units obligated to re-dispatch, as contemplated in Footnote 9 are those units which are contractually bound to provide the service as well as those obligated to provide the service under Network Integrated Transmission Service, under FERC's pro		

Organization	Yes or No	Question 10 Comment
forma OATT. Under the pro forma OATT, units designated as network resources receiving NITS are obligated to re-dispatch as requested by the Transmission Provider pursuant to Section 33.2 to maintain reliability. The footnote is worded such that curtailment/re-dispatch cannot result in the loss of firm Load preserves the guidance given by FERC in Order 693 that no single Contingency result in the loss of firm Load. No change made. Where contractual agreements exist between entities allowing re-dispatch, and the curtailment of Firm Transmission Service associated with that re-dispatch was point-to-point, the point-to-point service curtailment would be allowed. In the case of units otherwise obligated, namely those resources with Network Integrated Transmission Service designated as network resources, curtailment of point-to-point service involving those resources would not be allowed as there is no obligation to do so.		
National Grid Northeast Utilities	Yes	Capitalize "Firm Transmission Service" in footnote 10 and instead of saying firm Load use Firm Demand to be consistent with the NERC Glossary
Northeast Power Coordinating Council	No	Capitalize Firm Transmission Service in footnote 10 and instead of saying firm Load use Firm Demand to be consistent with the NERC Glossary.
Response: The SDT agrees with the proposed changes. **Footnote 9:** Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must should also be respected.: Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must also be adhered to.		
BC Hydro	No	Comments: Consider changing Footnote 10 to read, "Curtailment of firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled ["title" is a noun, not a verb and "titled" is an adjective meaning having a title, esp. of nobility] "Initial System Conditions") and a corrective action provided both are accomplished automatically by a NERC-certified SPS, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.
Response: The SDT agrees with the proposed use of "entitled". **Footnote 9:** Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed		

Organization	Yes or No	Question 10 Comment
		both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must should also be respected. Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must also be adhered to. The SDT respectfully disagree that inclusion of language limiting the use of Footnote 10 (now footnote 9) to only those applications where an SPS is involved would further complicate the application of the footnote and would unduly limit its application. No change made.
San Diego Gas and Electric Co		We agree that TPL-005 and TPL-006 appear to have been adequately covered in the draft TPL-001-1 as currently written. However, we will need to review this assessment after TPL-001-1 is finalized. In addition, there is no place to state our concerns for Section D. so we added it here. We question the "not applicable" entry under Section D 1.1.2. What does it mean when the reset period is not applicable? Does it mean there is no reset period, so all non-compliance in all prior years will be counted as prior violations when considering non-compliance in future years?
Response: The sanctions guidelines developed by the compliance program as part of the ERO start-up process eliminated the use of the concept of the "compliance reset period." The reason the heading "Compliance Monitoring and Reset Time" is still in the standards template is because some Standards Committee members felt that a change to the standard template couldn't be made without having the change go through full due process. Therefore, NERC staff agreed to always put, "Not applicable" under this heading until the next version of the manual is issued. This term will be eliminated in Version 8.		
LADWP	No	The use of the term"Firm Transmission Service" is problematic at best. See my comments on R1. The proper term is "Expected Transfer Level"
Response: Although Firm Transmission Service is a defined term in the NERC Glossary, it is recognized that some planning processes do not designate inter-area transfers as firm or non-firm. Re-dispatch of Designated Network Resources or resources contractually bound to participate in re-dispatch activities would in many cases result in changes in area interchange and thus would still be allowed in Footnote 10 (now footnote 9). Additionally, the proposed standard now requires sensitivities to be included in the Planning Assessment which may include expected transfers. No change made.		
Central Maine Power Company	Yes	
Independent Electricity System Operator	Yes	

Organization	Yes or No	Question 10 Comment
Kansas City Power & Light	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
MRO MRO NERC Standards Review Subcommittee	Yes	N/A
SERC Engineering Committee Dynamics Review Subcommittee (DRS)	Yes	None.
Platte River Power Authority	Yes	
American Transmission Company	Yes	
Idaho Power	Yes	
Minnesota Power	Yes	
Midwest ISO	Yes	
NV Energy	Yes	
PJM	Yes	
Brazos Electric Cooperative	Yes	no comment
American Electric Power	Yes	
ITC Holdings	Yes	Comments: We concur that footnote 10 should not apply to P0, P1 or P2 events.
Entergy Services, Inc	Yes	Units obligated to re-dispatch must include all Network Resources
ISO New England, Inc.	Yes	
New Brunswick System Operator		No comment

Organization	Yes or No	Question 10 Comment
Western Area Power Administration	Yes	
MidAmerican Energy Company	Yes	
Deseret Generation & Transmission	Yes	
Gainesville Regional Utilities	Yes	
Western Area Power Administration	Yes	
Tampa Electric	Yes	
IRC Standards Review Committee	Yes	
TVA System Planning	Yes	
Exelon Transmission Planning	Yes	
United Illuminating	Yes	
FirstEnergy Corp	Yes	We presently agree with the Footnote 5 and text.
Response: Thank you for your response.		

11. The SDT has provided an Implementation Plan as part of this posting. The plan includes the retirement of TPL-005-0 and TPL-006-0. Do you agree with the elements of the Plan? If not, please provide specific comments.

Summary Consideration: There were 3 main comments associated with this question.

Eleven commenters indicated that 60 months is not enough time to build major lines, especially if up to 24 months is needed to do the Planning Assessment and develop a Corrective Action Plan. The SDT considered this issue when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of the comments received from this posting. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. The third draft of TPL-001-1 does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply.

The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control.

Eight commenters indicated that more time is needed before dynamic Load modeling Requirement R2, part 2.4.1 becomes effective. However, Requirement R2, part 2.4.1 does not require a detailed dynamic Load model, only an aggregate System model. The SDT believes that such a model can be developed within the 24 month period before this requirement becomes effective.

Seven commenters raised concerns about the retirement of TPL-005-0 and TPL-006-0, regarding the requirements or lack thereof being placed on the Planning Coordinators and Transmission Planners to provide inputs to the Regional Entities so they can meet their obligations to NERC to prepare regional assessments. The SDT believes that the retirement of TPL-005-0 and TPL 006-0 have been adequately addressed by adding the Requirement R3, part 3.4.1, Requirement R4, part 4.4, and Requirement R8 with part 8.1 in the fourth draft of TPL-001-1 to ensure that Planning Coordinators and Transmission Planners will provide the necessary inputs to the Regions so that the Regions can fulfill their obligations to NERC in accordance with the NERC Rules of Procedure.

Changes were made to the following requirements due to industry comments:

3.4.1 The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.4.1 The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

R8 Each Planning Coordinator and Transmission Planner shall distribute its its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.

8.1 If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Organization	Yes or No	Question 11 Comment
Dominion - Electric Transmission	No	Dominion agrees with the retirement of TPL-005-0 and TPL-006-0. However, Dominion has some concern over the implementation period and believes that 60 months to implement corrective action plans may not be enough. This standard has more stringent requirements ("raising the bar") than the current TPL standards. Having to assess the system for these new standards as well as implementing corrective action plans within 60 months could be difficult to get approval to site and construct new transmission. Dominion suggests that an additional 12 to 24 months be given to allow time for the assessments to determine violations, solicit input from all stakeholders through RTO process (As required by FERC 890) to determine the most appropriate corrective action plans.
Response: The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. The third draft of TPL-001-1 does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control.		
Northeast Power Coordinating Council	No	Please clarify, since R2 through R6 should become effective before results could be distributed to adjacent Planning Coordinators and any functional entity. However, by the wording of the effective date of R1 and R7 it appears R7 becomes effective before R2 to R6. That is, 24 months are allowed by the standard to complete the planning assessments after regulatory approval. The results may not be ready for distribution by the planning coordinator after the first twelve months. As written, the Standard would become effective at different times in different jurisdictions. Requirement R7 requires coordination among adjacent Planning Coordinators and any Functional Entity that has indicated a reliability need. Such coordination cannot be granted until the Standard is effective for all involved jurisdictions. The term "Planning Coordinator" is not defined in the NERC Glossary of Terms used in Reliability Standards and, therefore, this standard should indicate whether this term is the same as the "Planning Authority" defined in the glossary. Otherwise the definition of the Planning Coordinator should be included in the NERC Glossary of Terms used in Reliability Standards. With regard to the many changes/modifications from the previous draft and from the previous TPL standards being replaced by TPL-001-1, another posting of this Standard will be necessary to fully evaluate the impact (on reliability and also cost of implementation) of such changes. The decision to allow the use of all type of RAS or SPS (particularly generator tripping and run-back) as a common practice for single contingency does not "raise the bar" in the planning standard, and should be reviewed. How can higher system performance be required that involves substantial infrastructure investment to prevent

Organization	Yes or No	Question 11 Comment
		events with a very low probability of occurrence, and allow use of a less reliable measure (SPS failure or misoperation having a higher probability of occurrence) to reduce the investment for more probable events?
Response: Distribution of Planning Assessments under Requirement R7 (now Requirement R8) is not limited to Planning Assessment results produced in conformance with the revised standard. Until such results are available, the SDT intended that Planning Assessments produced using the existing standards would be distributed. Planning Coordinator is listed as the new term for Planning Authority in the latest approved version of the Functional Model and is in the latest version of the NERC Glossary of Terms Used in Reliability Standards. No change made. The SDT agrees that another posting is required and has produced a fourth draft. The SDT's intent was to raise the bar where it was practical to do so and not lower the bar in any case. The allowance for the use of SPS and RAS in response to single Contingencies simply reflects the existing practice in many parts of North America. Where this has not been a common practice, individual Regional Entities, Planning Coordinators or Transmission Planners have the latitude to establish more stringent criteria.		
SERC Engineering Committee Planning Standards Subcommittee	No	Construction activities:60 months effective date seems acceptable for planning activities, but may not adequate for all construction activities. Typical times to construct a transmission line in various areas of SERC can range between 7 to 10 years. Accordingly, we recommend the effective date for construction projects be changed to at least 84 months.Dynamic load models:More time is needed for entities to determine the appropriate dynamic load model required by R2.4.1. We recommend at least 36 months before this requirement becomes effective.
Response: The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. The third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control. Requirement R2, part 2.4.1 does not require a detailed dynamic Load model, only an aggregate System model. The SDT believes that such a model can be developed within the 24 month period before this requirement becomes effective.		
Bonneville Power Administration		We agree that TPL-005 and TPL-006 appear to have been adequately covered in the draft TPL-001-1 as currently written. However, we will need to review this assessment after TPL-001-1 is finalized. In addition, there is no place to state our concerns for Section D. so we've added it here. We question the "not applicable" entry under Section D 1.1.2. What does it mean when the reset period is not applicable? Does it mean there is no reset period, so all non-compliance in all prior years will be counted as prior violations when considering non-compliance in future years? OTHER COMMENTS:Would like to see TPL-001-1 more specifically address system performance required for radial load areas served by multiple transmission circuits (unequal capacity) from a single source substation. For

Organization	Yes or No	Question 11 Comment
		example, a radial load served by a single circuit 115-kV line and a single circuit 230-kV line. For a single contingency loss of the 230-kV circuit, cannot serve peak load area demand. Is this situation meant to be covered by Category P1 in TPL-001-1? I don't see anything similar to TPL-002-0a, Category B, Note b under Loss of Demand.
Response: The sanctions guidelines developed by the compliance program as part of the ERO start-up process eliminated the use of the concept of the "compliance reset period." The reason the heading "Compliance Monitoring and Reset Time" is still in the standards template is because some Standards Committee members felt that a change to the standard template couldn't be made without having the change go through full due process. Therefore, NERC staff agreed to always put, "Not applicable" under this heading until the next version of the manual is issued. This term will be eliminated in Version 8. The loss of Load served by a single Transmission line would be considered Consequential Load Loss which is permitted by the TPL-001-1 standard. However, as in your example, if a Load is served by 2 Transmission lines and one of the lines is not sufficient to supply the Load for the loss of the other, then it would be considered Non-Consequential Load Loss which is not permitted.		
MRO MRO NERC Standards Review Subcommittee	No	MRO NSRS offers the following comments.The last paragraph should be removed from the Effective Date section. This paragraph contains requirements and describes compliance procedures, rather than stating effective date details. If any requirements regarding Corrective Action Plans are included, then they should be placed in the R2 section. If descriptions of compliance procedures related to Corrective Action Plan implementation are deemed to be necessary, then they should be placed in NERC procedure documents. This standard should not contain any requirements regarding the implementation of Corrective Action Plans. The implementation of transmission system action plans depends on the actions (e.g. financing, regulatory approval, legal services, engineering, construction, commissioning) of many different entities, other than PCs or TPs. So, PCs and TPs should not be held responsible for the implementation of action plans since they have little or no control over the activities related to implementation. The standard could include requirements that obligate PCs and TPs to develop Corrective Action Plans that are executable (i.e. plans that are based on lead times that provide reasonable assurance that the planned facilities can be placed in service by the time that they are needed) or devise revised Corrective Action Plans when they learn that the actions plans are not expected to be implemented by the intended in-service date. The standard could also include requirements that obligate PCs and TPs to establish and apply project implementation lead time assumptions that are derived from historical experience and the implementation lead time projections from the applicable TOs, GOs, and DPs. Remove or modify the 60 month effective date statement because it's impractical and unreasonable. The effective date for performing analyses and developing subsequent Corrective Action Plans is 24 months. This leaves only 36 months to expect that the more stringent Corrective Action Plans would be implemented. It is improbable that all action plans related to BES facilities, especially above 300 kV could be implemented. Some EHV projects can take 5 to 10 years to implement depending on the size, complexity, and controversial nature of the project. MRO NSRS suggests that the effective date be stated in a more "implementation dependent" rather than a "fixed timeframe" manner. Consider wording such as "tripping of Non-Consequential Load or curtailment of Firm Transmission Service (in accordance with Requirement R2.6.4) is allowed until Corrective Action Plans based on TPL-001-1 analyses are implemented".
Response: The SDT disagrees that the last paragraph of the Effective Date should be removed. No change made.		

Organization	Yes or No	Question 11 Comment
The SDT disagrees with your view that the Corrective Action Plans should not include implementation requirements. A plan has no value unless it is implemented. No change made. The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. The third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply. The SDT considered your suggestion to change the language of Requirement 2.7.5 to make it more "implementation dependent" rather than using a "fixed timeframe" but we do not believe such a change is appropriate because it would make auditing of this requirement difficult.		
SERC Engineering Committee Dynamics Review Subcommittee (DRS)	No	More time is needed for entities to determine the appropriate dynamic load model required by R2.4.1. We recommend at least 36 months before this requirement becomes effective. A 60 month effective date seems acceptable for planning activities, but may not adequate for all construction activities. Typical times to construct a transmission line in various areas of SERC can range between 7 to 10 years. Accordingly, we recommend the effective date for construction projects be changed to at least 84 months.
Response: The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. The third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control.		
SERC Engineering Committee Reliability Review Subcommittee (RRS)	No	60 months after effective date seems generally acceptable for planning activities, but may not adequate for all construction activities. Typical times to construct a transmission line in various areas of SERC can range between 7 to 10 years. Accordingly, we recommend the effective date for construction projects be changed to at least 84 months. More time is needed for entities to determine the appropriate dynamic load model required by R2.4.1. We recommend at least 36 months before this requirement becomes effective. Since breaker duty is a new "raising the bar" issue - should there also be a 5 or more year implementation plan for this as well? Also trying to construct enough facilities within the 5 year implementation period will result in multiple outages at same time - possibly affecting SERC member's bulk reliability during this construction period. Also SERC members are concerned that EHV equipment manufacturers will not be able to meet all the equipment orders that will be required to meet the "raising the bar" requirements. SERC members are also concerned that the costs to meet the new requirements contained in this TPL will amount to many billions of dollars with very little impact overall on the reliability of the Bulk transmission system. "When will the Implementation Plan be removed from the standard after it is officially approved" Will a revised

Organization	Yes or No	Question 11 Comment
		TPL standard need to be prepared to omit this implementation language?? If contingencies in one utility's system results in issues within another utility, who is responsible for studying the contingencies and who would be responsible for documenting the CAP?

Response: The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. This third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply.

The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control.

Requirement R2, part 2.4.1 does not require a detailed dynamic Load model, only an aggregate System model. The SDT believes that such a model can be developed within the 24 month period before this requirement becomes effective.

The SDT does not view the breaker duty requirements as a raising of the bar. While these may be new requirements in NERC Standards, the SDT believes that most entities already follow these practices because they are safety related.

If manufacturers or other service providers can not meet increased demands for equipment and services, that would be an event outside the control of the Planning Coordinator or Transmission Planner. With respect to any additional capital requirements driven by the new standard, the SDT can not speculate regarding the magnitude of such requirements. However, the SDT strongly believes that the revised standard is necessary to ensure an adequate level of reliability for North America's Bulk Electric Systems.

The Implementation Plan is not a part of the Standard per se but will be balloted.

The SDT has modified the language in Requirement R3, part 3.4.1 and Requirement R4, part 4.4.1 as well as Requirement R8 with part 8.1 to clarify the handling of "cross border" Contingencies and performance violations.

3.4.1 The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

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R8 Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.

8.1 If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

TVA System Planning	No	TVA is concerned that the 5 year window for meeting the "raising the bar" requirements is still not adequate. For instance, it typically takes TVA 7 to 10 years to build a new 500-kV transmission line - including time required for such processes as federally mandated NEPA environmental reviews. Strongly suggest increasing this time

Organization	Yes or No	Question 11 Comment
		window to 10 years.Also trying to construct enough facilities within the 5 year implementation period will result in multiple outages at same time - possibly affecting TVA's bulk reliability during this construction period. Also TVA is concerned that EHV equipment manufacturers will not be able to meet all the equipment orders that will be required to meet the "raising the bar" requirements. Thus TVA believes that these additional concerns strengthen the need to have a 10 year implementation period. Since breaker duty is a new "raising the bar" issue - should there also be a 5 year implementation plan for this as well? TVA is also concerned that the costs to meet the new requirements contained in this TPL will amount to between $1 billion to $2 billion with very little impact overall on the reliability of the Bulk transmission system. TVA is also very concerned about the increase in rates that will be required to support these new facilities. When will the Implementation Plan be removed from the standard after it is officially approved? Will a revised TPL standard need to be prepared to omit this implementation language? If contingencies in one utility's system results in issues within another utility, who is responsible for studying the contingencies and who would be responsible for documenting the CAP? More time is needed for entities to determine the appropriate dynamic load model required by R2.4.1. We recommend at least 36 months before this requirement becomes effective.

Response: The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. This third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply.

The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control.

If manufacturers or other service providers can not meet increased demands for equipment and services, that would be an event outside the control of the Planning Coordinator or Transmission Planner.

The SDT does not view the breaker duty requirements as a raising of the bar. While these may be new requirements in NERC Standards, the SDT believes that most entities already follow these practices because they are safety related.

With respect to any additional capital requirements driven by the new standard, the SDT can not speculate regarding the magnitude of such requirements. However, the SDT strongly believes that the revised standard is necessary to ensure an adequate level of reliability for North America's Bulk Electric Systems.

The Implementation Plan is not a part of the Standard per se but it will be balloted.

The SDT has modified the language in Requirement R3, part 3.4.1, Requirement R4, part 4.4.1, and Requirement R8 with part 8.1 to clarify the handling of "cross border" Contingencies and performance violations.

3.4.1 The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that

Organization	Yes or No	Question 11 Comment
Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. **4.4.1** The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. **8.1** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. Requirement R2, part 2.4.1 does not require a detailed dynamic Load model, only an aggregate System model. The SDT believes that such a model can be developed within the 24 month period before this requirement becomes effective.		
FirstEnergy Corp	No	We disagree with the proposed Implementation Plan. The implementation period for the TPL-001-1 transmission planning standard should be limited to the time needed to transition to the new study requirements. The proposed 5-year implementation for the "raise the bar" aspects of this standard delves into project management and review of capital construction progress which should remain outside the scope of this standard. The standard should only consider if an entity has completed the required studies and has developed Corrective Action Plans to ensure performance criteria is being maintained. The last paragraph of the Implementation Plan is not appropriate for the Implementation Plan as it discusses compliance enforcement information. This paragraph should be srtuck.
Response: The SDT disagrees with your view that the Corrective Action Plans should not include implementation requirements. A plan has no value unless it is implemented. No change made. The SDT disagrees that the last paragraph of the Effective Date should be removed. No change made.		
IRC Standards Review Committee	Yes	The 3rd draft states this will be addressed later in the project. Removal of these standards would not affect NERC and the RE's obligations to perform assessments. Will the PC/TP be obligated under NERC Rules of Procedure to provide Assessments to NERC and the Regions upon request?
Midwest ISO	Yes	The 3rd draft states that this will be addressed later in the project. Removal of these standards would not affect NERC and the RE's obligations to perform assessments. Will the PC/TP be obligated under NERC Rules of Procedure to provide Assessments to NERC and the Regions upon request?
New York Independent System Operator		The 3rd draft states the Plan will be addressed later in the project. Removal of these standards would not affect NERC and the RE's obligations to perform assessments. The Standards Drafting Team should clarify whether the PC/TP will be obligated under NERC Rules of Procedure to provide Assessments to NERC and the Regions upon request.
Response: Retirement of TPL-005-0 and TPL 006-0 have been addressed by adding the necessary requirements in the fourth draft of TPL-001-1 to ensure that Planning Coordinators and Transmission Planners will provide the necessary inputs to the Regions so that the Regions can fulfill their obligations to NERC in accordance with the NERC Rules of Procedure. **3.4.1** The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that		

Organization	Yes or No	Question 11 Comment
Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. **4.4.1** The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. **8.1** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.		
Southern Company	No	More time is needed for entities to determine the appropriate dynamic load model required by R2.4.1. We recommend at least 36 months before this requirement becomes effective.Other than that, the SDT has done a good job in allowing time for entities to get into compliance with the requirements where the bar has been raised.
Response: Requirement R2, part 2.4.1 does not require a detailed dynamic Load model, only an aggregate System model. The SDT believes that such a model can be developed within the 24 month period before this requirement becomes effective.		
Lafayette Utilities System	No	Lafayette is in the area which is impacted by Entergy transmission planning. Entergy is one of the few NERC transmission owners which has for some years now relied upon its interpretation of “footnote b” in the previous TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0 as permitting planning for the loss of Non-Consequential Load or interruption of firm transfers as a way of planning and building less transmission than other utilities would have considered themselves obligated to build for reliability. That Entergy interpretation, and the consequent lower investment in transmission planning and construction, has been a matter of some concern among Entergy regulators at both State and Federal levels, as well as Entergy transmission customers, and has been rejected by the SPP, which has been given the authority to develop the base plan for transmission additions on the Entergy system. It was the Entergy rejection of that base plan that most recently led to a day long technical conference among regulators at the recent SEARUC conference in Charleston, SC.The proposed Implementation Plan for TPL-001-1 is drafted to make the new standard, which the proposed Implementation Plan describes as one that “raises the bar in several areas,” effective only after the passage of 60 months from the first day of the first calendar quarter following applicable approval. That time for implementation is also embodied in A.5 of the proposed standard. This time lag is chosen, according to the proposed Implementation Plan, because of the “significant budget, siting, permitting, and construction impacts on many transmission owners. There are significant problems and costs for those whose electric service is dependent upon an inadequate transmission system, which would argue for a lesser period of time to reach compliance. This is especially true when the existing system is planned on an assumption as to the meaning of footnote b which assumption was clearly recognized as being controversial and a minority view. In recent years there have been repeated Entergy TLRs at quite high levels, which have repeatedly required emergency EEA-3s to keep firm load on line. And there has been an ongoing dispute between Entergy and the SPP as to footnote b and whether there should be limits on consequential load to be shed which has led the SPP (as the Entergy ICT) to have a complete base case for Entergy transmission construction already developed which is, by FERC direction, the basis for the Entergy construction plan. In its construction plan, however, Entergy dropped some 20 of the projects in the SPP base plan because of the Entergy view that it could go ahead and plan to drop non-consequential load as a means of remaining in compliance with Standards rather than building the transmission projects that would have been required in accordance with the

Organization	Yes or No	Question 11 Comment
		SPP base plan. While not all of the proposed changes embodied in TPL-001-1 may have been incorporated in the SPP base plan development, certainly the footnote b issues were. The costs of the failure of reliability and congestion resulting from the Entergy failure have been quite high, for Entergy retail customers as well as for others, and will continue to be high so long as there is no obligation to comply. Firm transmission obligations are simply not met while there is no obligation to comply. While it is certainly true that transmission cannot be planned and constructed overnight, it is also true that those who relied upon the minority interpretation of footnote b have been on notice for years both that that interpretation was challenged, and also that it was a minority viewpoint, as NERC itself advised FERC in its response to the NOPR that preceded Order 693.In 2007 FERC directed that NERC clarify the intended meaning of footnote b in its Order 693, and pointed out at that time that the interpretation permitting loss of load was "based largely on the matter of economics, not reliability. Id., P 1792. At that time, only Entergy and NIPSCO (certainly not "many" Transmission Owners" a word that appears twice in the draft Implementation Plan) would even admit to their interpretation of footnote b to weaken the grid. NERC agreed that such an interpretation was incorrect in its filings leading up to Order 693. In its June 26, 2006 Comments of North American Electric Reliability Council and North American Electric Reliability Corporation on Staff Preliminary Assessment, at p. 57-58, NERC noted that load shedding in a single contingency event is not acceptable: "footnote b to TPL-002-0 is intended to provide a limited exception to the general rule for serving load from a radial transmission line and should only be applied in unique circumstances, as described above. NERC recognizes that looped configurations are key to the reliable operation of the interconnection, and to meet reasonable expectations for reliable service to loads. . . . NERC standards, including footnote b, are not intended to endorse or approve planning the interconnection using radial configurations as a preferred method for reliably serving load, nor do NERC standards consider load shedding acceptable for single contingency events. It thus seems strange for NERC, an organization whose very existence was intended to assure the reliability of the grid, to reward those recalcitrant transmission owners who intentionally failed to expend the money and effort that the responsible transmission owners did expend, and at the expense of those who rely on the transmission system to do its basic job. Order 693, P 1794, "strongly discourage[d] an approach that reflects the lowest common denominator. Many of those transmission owners and planners for whom this change constitutes "raising the bar" presumably had plenty of time to consider what their options would be if their interpretation was incorrect, and should be expected to have reserve plans on hand pretty close to being ready to go when the dispute was lost. In the Entergy case, the plan has been in its hands for some time, and the fact that it has chosen to reject the SPP plan based on its own minority interpretation of footnote b is no one's fault but its own. And it certainly does not have to start from scratch to develop the plan; it consciously chose to reject the plan that the ICT developed for it.Lafayette asks that at least as to the changes tied to footnote b interpretation, and other excuses for dropping non-consequential load, the time for compliance be shortened to no more than two years following regulatory approval of the standard. R2.6 already provides for the development of a Corrective Action Plan, and it would not encourage reliability if five years were taken to develop a Corrective Action Plan, as opposed to complying with the standard. Second, Lafayette suggests that, whether or not NERC chooses to stick with its 5-year "lowering of the bar" to permit those entities which may have used a similar interpretation of footnote b to avoid building a sturdy grid, it not try to influence FERC and the courts as to legal questions that may develop during that period. We recognize that the changes made in what will be TPL-001-1 go well beyond the clarification of footnote b, so that for some changes there may be a reason for the 5 year phase in. But whether or not the 5 year phase in is going to be

Organization	Yes or No	Question 11 Comment
		applicable to all of those changes, we suggest that it would be improper to mischaracterize what is being done in a way that appears to have been drafted to influence legal questions that may come up.Specifically, as currently drafted, the descriptive modifier "many" should not be used in describing the entities which had chosen to use the lower bar interpretation of footnote b. While we recognize that a number of commenters have looked to one interpretation or another of footnote b in a few extreme situations, a review of comments does not show other transmission owners who have relied on the extreme interpretation used by Entergy on a systematic basis, And we think it inappropriate for the description in the paragraph beginning at the bottom of p.1 of that draft Implementation Plan to focus on the footnote b issue, as it now does. We suggest a modification which makes the description accurate, and which avoids the kind of misinterpretation which led to the footnote b controversy in the first place. We suggest that that first part of that paragraph be revised to read as follows:TPL-001-1 "raises the bar" in several areas where performance requirements have been changed in the new Standard versus those in existing TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0. Among other things, loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain events, whereas the existing Standards were interpreted by some to allow such actions. As shown in Table 1 of TPL-001-1, the performance requirements associated with the following events represent "raising the bar"??
Louisiana Energy and Power Authority	No	LEPA is in the area which is impacted by Entergy transmission planning. Entergy is one of the few NERC transmission owners which has for some years now relied upon its interpretation of "footnote b" in the previous TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0 as permitting planning for the loss of Non-Consequential Load or interruption of firm transfers as a way of planning and building less transmission than other utilities would have considered themselves obligated to build for reliability. That Entergy interpretation, and the consequent lower investment in transmission planning and construction, has been a matter of some concern among Entergy regulators at both State and Federal levels, as well as Entergy transmission customers, and has been rejected by the SPP, which has been given the authority to develop the base plan for transmission additions on the Entergy system. It was the Entergy rejection of that base plan that most recently led to a day long technical conference among regulators at the recent SEARUC conference in Charleston, SC.The proposed Implementation Plan for TPL-001-1 is drafted to make the new standard, which the proposed Implementation Plan describes as one that "raises the bar in several areas," effective only after the passage of 60 months from the first day of the first calendar quarter following applicable approval. That time for implementation is also embodied in A.5 of the proposed standard. This time lag is chosen, according to the proposed Implementation Plan, because of the "significant budget, siting, permitting, and construction impacts on many transmission owners. There are significant problems and costs for those whose electric service is dependent upon an inadequate transmission system, which would argue for a lesser period of time to reach compliance. This is especially true when the existing system is planned on an assumption as to the meaning of footnote b which assumption was clearly recognized as being controversial and a minority view. In recent years there have been repeated Entergy TLRs at quite high levels, which have repeatedly required emergency EEA-3s to keep firm load on line. And there has been an ongoing dispute between Entergy and the ICT as to footnote b and whether there should be limits on consequential load to be shed which has led the SPP (as the Entergy ICT) to have a complete base case for Entergy transmission construction already developed which is, by FERC direction, the basis for the Entergy construction plan. In its construction plan, however, Entergy dropped some 20 of the projects in the ICT base plan because of the Entergy view that it could go ahead and plan to drop non-consequential load as a means of remaining in compliance with

Organization	Yes or No	Question 11 Comment
		Standards rather than building the transmission projects that would have been required in accordance with the ICT base plan. While not all of the proposed changes embodied in TPL-001-1 may have been incorporated in the SPP base plan development, certainly the footnote b issues were. The costs of the failure of reliability and congestion resulting from the Entergy failure have been quite high, for Entergy retail customers as well as for others, and will continue to be high so long as there is no obligation to comply. Firm transmission obligations are simply not met while there is no obligation to comply. While it is certainly true that transmission cannot be planned and constructed overnight, it is also true that those who relied upon the minority interpretation of footnote b have been on notice for years both that that interpretation was challenged, and also that it was a minority viewpoint, as NERC itself advised FERC in its response to the NOPR that preceded Order 693.In 2007 FERC directed that NERC clarify the intended meaning of footnote b in its Order 693, and pointed out at that time that the interpretation permitting loss of load was "based largely on the matter of economics, not reliability. Id., P 1792. At that time, only Entergy and NIPSCO would even admit to this less reliable interpretation of footnote b. NERC agreed that such an interpretation was incorrect in its filings leading up to Order 693. In its June 26, 2006 Comments of North American Electric Reliability Council and North American Electric Reliability Corporation on Staff Preliminary Assessment, at p. 57-58, NERC noted that load shedding in a single contingency event is not acceptable: "footnote b to TPL-002-0 is intended to provide a limited exception to the general rule for serving load from a radial transmission line and should only be applied in unique circumstances, as described above. NERC recognizes that looped configurations are key to the reliable operation of the interconnection, and to meet reasonable expectations for reliable service to loads. . . . NERC standards, including footnote b, are not intended to endorse or approve planning the interconnection using radial configurations as a preferred method for reliably serving load, nor do NERC standards consider load shedding acceptable for single contingency events. Hence, those recalcitrant transmission owners who intentionally failed to expend the money and effort that the responsible transmission owners did expend, have been rewarded at the expense of those who rely on the transmission system to do its basic job. Order 693, P 1794, "strongly discourage[d] an approach that reflects the lowest common denominator. Many of those transmission owners and planners for whom this change constitutes "raising the bar" presumably had plenty of time to consider what their options would be if their interpretation was incorrect, and should be expected to have reserve plans on hand pretty close to being ready to go when the dispute was lost. In the Entergy case, the plan has been in its hands for some time, and it has chosen to reject the ICT plan based on its own minority interpretation of footnote b. LEPA asks that at least as to the changes tied to footnote b interpretation, and other excuses for dropping non-consequential load, the time for compliance be shortened to no more than two years following regulatory approval of the standard. R2.6 already provides for the development of a Corrective Action Plan, and it would not encourage reliability if five years were taken to develop a Corrective Action Plan, as opposed to complying with the standard. Second, LEPA suggests that, whether or not NERC chooses to stick with its 5-year time period to permit those entities which may have used a similar interpretation of footnote b, it not try to influence FERC and the courts as to legal questions that may develop during that period. We recognize that the changes made in what will be TPL-001-1 go well beyond the clarification of footnote b, so that for some changes there may be a reason for the 5 year phase in. But whether or not the 5 year phase in is going to be applicable to all of those changes, we suggest that it would be improper to mischaracterize what is being done in a way that appears to have been drafted to influence legal questions that may come up.Specifically, as currently drafted, the descriptive modifier "many" should not be

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		used in describing the entities which had chosen to use the lower bar interpretation of footnote b. While we recognize that a number of commenters have looked to one interpretation or another of footnote b in a few extreme situations, a review of comments does not show other transmission owners who have relied on the extreme interpretation used by Entergy on a systematic basis, And we think it inappropriate for the description in the paragraph beginning at the bottom of p.1 of that draft Implementation Plan to focus on the footnote b issue, as it now does. We suggest a modification which makes the description accurate, and which avoids the kind of misinterpretation which led to the footnote b controversy in the first place. We suggest that that first part of that paragraph be revised to read as follows:"TPL-001-1 "raises the bar" in several areas where performance requirements have been changed in the new Standard versus those in existing TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0. Among other things, loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain events, whereas the existing Standards were interpreted by some to allow such actions. As shown in Table 1 of TPL-001-1, the performance requirements associated with the following events represent "raising the bar""?
Mississippi Delta Energy Agency	No	MDEA is in the area which is impacted by Entergy transmission planning. Entergy is one of the few NERC transmission owners which has for some years now relied upon its interpretation of "footnote b" in the previous TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0 as permitting planning for the loss of Non-Consequential Load or interruption of firm transfers as a way of planning and building less transmission than other utilities would have considered themselves obligated to build for reliability. That Entergy interpretation, and the consequent lower investment in transmission planning and construction, has been a matter of some concern among Entergy regulators at both State and Federal levels, as well as Entergy transmission customers, and has been rejected by the SPP, which has been given the authority to develop the base plan for transmission additions on the Entergy system. It was the Entergy rejection of that base plan that most recently led to a day long technical conference among regulators at the recent SEARUC conference in Charleston, SC.The proposed Implementation Plan for TPL-001-1 is drafted to make the new standard, which the proposed Implementation Plan describes as one that "raises the bar in several areas," effective only after the passage of 60 months from the first day of the first calendar quarter following applicable approval. That time for implementation is also embodied in A.5 of the proposed standard. This time lag is chosen, according to the proposed Implementation Plan, because of the "significant budget, siting, permitting, and construction impacts on many transmission owners. There are significant problems and costs for those whose electric service is dependent upon an inadequate transmission system, which would argue for a lesser period of time to reach compliance. This is especially true when the existing system is planned on an assumption as to the meaning of footnote b which assumption was clearly recognized as being controversial and a minority view. In recent years there have been repeated Entergy TLRs at quite high levels, which have repeatedly required emergency EEA-3s to keep firm load on line. And there has been an ongoing dispute between Entergy and the SPP as to footnote b and whether there should be limits on consequential load to be shed which has led the SPP (as the Entergy ICT) to have a complete base case for Entergy transmission construction already developed which is, by FERC direction, the basis for the Entergy construction plan. In its construction plan, however, Entergy dropped some 20 of the projects in the SPP base plan because of the Entergy view that it could go ahead and plan to drop non-consequential load as a means of remaining in compliance with Standards rather than building the transmission projects that would have been required in accordance with the SPP base plan. While not all of the proposed changes embodied in TPL-001-1 may have been incorporated in the

Organization	Yes or No	Question 11 Comment
		SPP base plan development, certainly the footnote b issues were. The costs of the failure of reliability and congestion resulting from the Entergy failure have been quite high, for Entergy retail customers as well as for others, and will continue to be high so long as there is no obligation to comply. Firm transmission obligations are simply not met while there is no obligation to comply. While it is certainly true that transmission cannot be planned and constructed overnight, it is also true that those who relied upon the minority interpretation of footnote b have been on notice for years both that that interpretation was challenged, and also that it was a minority viewpoint, as NERC itself advised FERC in its response to the NOPR that preceded Order 693.In 2007 FERC directed that NERC clarify the intended meaning of footnote b in its Order 693, and pointed out at that time that the interpretation permitting loss of load was "based largely on the matter of economics, not reliability. Id., P 1792. At that time, only Entergy and NIPSCO (certainly not "many" Transmission Owners? a word that appears twice in the draft Implementation Plan) would even admit to their interpretation of footnote b to weaken the grid. NERC agreed that such an interpretation was incorrect in its filings leading up to Order 693. In its June 26, 2006 Comments of North American Electric Reliability Council and North American Electric Reliability Corporation on Staff Preliminary Assessment, at p. 57-58, NERC noted that load shedding in a single contingency event is not acceptable: "footnote b to TPL-002-0 is intended to provide a limited exception to the general rule for serving load from a radial transmission line and should only be applied in unique circumstances, as described above. NERC recognizes that looped configurations are key to the reliable operation of the interconnection, and to meet reasonable expectations for reliable service to loads. . . . NERC standards, including footnote b, are not intended to endorse or approve planning the interconnection using radial configurations as a preferred method for reliably serving load, nor do NERC standards consider load shedding acceptable for single contingency events. It thus seems strange for NERC, an organization whose very existence was intended to assure the reliability of the grid, to reward those recalcitrant transmission owners who intentionally failed to expend the money and effort that the responsible transmission owners did expend, and at the expense of those who rely on the transmission system to do its basic job. Order 693, P 1794, "strongly discourage[d] an approach that reflects the lowest common denominator. Many of those transmission owners and planners for whom this change constitutes "raising the bar" presumably had plenty of time to consider what their options would be if their interpretation was incorrect, and should be expected to have reserve plans on hand pretty close to being ready to go when the dispute was lost. In the Entergy case, the plan has been in its hands for some time, and the fact that it has chosen to reject the SPP plan based on its own minority interpretation of footnote b is no one's fault but its own. And it certainly does not have to start from scratch to develop the plan; it consciously chose to reject the plan that the ICT developed for it.MDEA asks that at least as to the changes tied to footnote b interpretation, and other excuses for dropping non-consequential load, the time for compliance be shortened to no more than two years following regulatory approval of the standard. R2.6 already provides for the development of a Corrective Action Plan, and it would not encourage reliability if five years were taken to develop a Corrective Action Plan, as opposed to complying with the standard. Second, MDEA suggests that, whether or not NERC chooses to stick with its 5-year "lowering of the bar" to permit those entities which may have used a similar interpretation of footnote b to avoid building a sturdy grid, it not try to influence FERC and the courts as to legal questions that may develop during that period. We recognize that the changes made in what will be TPL-001-1 go well beyond the clarification of footnote b, so that for some changes there may be a reason for the 5 year phase in. But whether or not the 5 year phase in is going to be applicable to all of those changes, we suggest that it would be improper to mischaracterize what is being done in a way that

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		appears to have been drafted to influence legal questions that may come up.Specifically, as currently drafted, the descriptive modifier "many" should not be used in describing the entities which had chosen to use the lower bar interpretation of footnote b. While we recognize that a number of commenters have looked to one interpretation or another of footnote b in a few extreme situations, a review of comments does not show other transmission owners who have relied on the extreme interpretation used by Entergy on a systematic basis, And we think it inappropriate for the description in the paragraph beginning at the bottom of p.1 of that draft Implementation Plan to focus on the footnote b issue, as it now does. We suggest a modification which makes the description accurate, and which avoids the kind of misinterpretation which led to the footnote b controversy in the first place. We suggest that that first part of that paragraph be revised to read as follows:TPL-001-1 "raises the bar" in several areas where performance requirements have been changed in the new Standard versus those in existing TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0. Among other things, loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain events, whereas the existing Standards were interpreted by some to allow such actions. As shown in Table 1 of TPL-001-1, the performance requirements associated with the following events represent "raising the bar"??
Response: Thank you for the background which helps the SDT understands your concerns. The SDT believes that this revised Standard has clarified the intent of the old footnote 'b' as well as other areas of the original standard that were open to interpretation. Standards must apply equally to all, so the SDT has chosen what it believes to be a reasonable implementation timeline that balances a wide variety of interests and circumstances. Finally, please note that the Implementation Plan document provided with this posting of the draft Standard is neither a part of the Standard or the Standard Roadmap but will be balloted. Therefore the SDT sees no need to modify the language.		
System Protection and Transmission Planning Department	Yes	We concur with SDT intent to retire TPL-005 and TPL-006. As there is no comment form entry to accept comments on MEASURES, we add one note here, related to "such as" lists - as noted above for R1.1.2, R2.1.4, R2.5.2, R3.3.4, R4.3.3, and R5. As written now, all measures include "such as" lists. We strongly suggest you remove "such as electronic or hard copies" from all measure statements.
Response: Thank you for your response. The SDT believes that examples of evidence "such as electronic or hard copies" help clarify the intent of the measure. Since no other responses requested removal of those words, the SDT will retain them.		
PacifiCorp Deseret Generation & Transmission SRP Southern California Edison Company Western Area Power Administration Pacific Gas and Electric Co, Puget Sound Energy, Inc.		We agree that TPL-005 and TPL-006 appear to have been adequately covered in the draft TPL-001-1 as currently written. However, we will need to review this assessment after TPL-001-1 is finalized. In addition, there is no place to state our concerns for Section D. so we added it here. We question the "not applicable" entry under Section D 1.1.2. What does it mean when the reset period is not applicable? Does it mean there is no reset period, so all non-compliance in all prior years will be counted as prior violations when considering non-compliance in future years?

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California ISO		
NV Energy	No	We agree that TPL-005 and TPL-006 appear to have been adequately covered in the draft TPL-001-1 as currently written. However, we will need to review this assessment after TPL-001-1 is finalized. In addition, there is no place to state our concerns for Section D. so we added it here. We question the "not applicable" entry under Section D 1.1.2. What does it mean when the reset period is not applicable? Does it mean there is no reset period, so all non-compliance in all prior years will be counted as prior violations when considering non-compliance in future years? Why is this changing from an annual reset period in the current standards?
Response: The sanctions guidelines developed by the compliance program as part of the ERO start-up process eliminated the use of the concept of the "compliance reset period." The reason the heading "Compliance Monitoring and Reset Time" is still in the standards template is because some Standards Committee members felt that a change to the standard template couldn't be made without having the change go through full due process. Therefore, NERC staff agreed to always put, "Not applicable" under this heading until the next version of the manual is issued. This term will be eliminated in Version 8.		
Tampa Electric	Yes	Consider having all requirements go into effect at the same time.
Response: The SDT chose a phased approach for establishing effective dates for individual requirements to reflect the broad range of implementation time frames associated with different requirements. Rather than use a least common denominator, which would have led to a new standard that would not be implemented for 60 months, those requirements that needed less time were assigned earlier effective dates. No change made.		
Florida Reliability Coordinating Council, Inc - Transmission Working Group		Overall the plan is an improvement! Allowing for a 60 month phase in of the more restrictive performance requirements is useful, however consider applying the 60 month phase in (or some timeframe) to P1 events for extenuating circumstances, e.g. unable to obtain ROW, etc. Having R1 and R7 going into effect first do raise the concern of what TPL standards are in effect during the time frame. The implementation should also be more specific on what "going into effect" means. Assessments are not a one day event but are a year long effort that culminates in a final "report" that is the assessment. Most NERC standards effect ongoing activities, and the day they go into effect the utilities functions are expected to be compliant. In this case that rationale would require that in the prior year two assessments where performed, one compliant with the current standard and one compliant with then new standard, however we don't believe that was the intent. Perhaps a statement below the paragraph regarding the 60 month implementation plan for Corrective Action Plans to the effect of:"Once effective all future assessments shall upon completion be compliant with this standard. Assessments completed prior to the effective date shall be based on the TPL standards in effect at the time. The standard is not intended to require a retroactively compliant assessment be in effect when the standard becomes active, but instead that the next assessment be compliant with the revised standard"
Response: The SDT believes that extenuating circumstances are covered in Requirement R2, part 2.7.5. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's		

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or Planning Coordinator's control. The SDT recognizes that assessments take a period of time to complete. The date on which the assessment was initiated would determine whether the current TPL standards or the revised TPL-001-1 would govern compliance requirements. No change made.		
FMPA	No	We suggest that the 60 month calendar apply to the HV system as well for all Categories. It is just as difficult, if not more difficult, to build a new 138 kV line in the Florida Keys as it is to build a 300+ kV line. The same time frame should apply to both. Also, as highlighted in the comments above to R2.1.4, P3 essentially causes utilities to build upgrades to N-3 planning criteria which may necessitate significant transmission upgrades if left unchanged. Hence, if left unchanged, P3 ought to have at least 5 years as well. The implementation plan ought to include an "out" for extenuating circumstances, e.g., unable to obtain ROW, etc. For instance, it is doubtful that another line in the Keys could ever get built without significant intervention and utilities that are unable to obtain ROW should not receive sanctions for something outside of their control. Consider changing the effective dates of R1 and R7 to take effect at the same time as R2 through R6 so you do not have to meet two standards during the same time period. Otherwise, clarify how the effective date impacts which version of the standard is to be used in an assessment before a scheduled compliance audit. The implementation should also be more specific on what "going into effect" means. Assessments are not a one day event but are a year long effort that culminates in a final "report" that is the assessment. Most NERC standards effect ongoing activities, and the day they go into effect the utilities functions are expected to be compliant. In this case that rationale would require that in the prior year two assessments were performed, one compliant with the current standard and one compliant with then new standard, however we don't believe that was the intent. Perhaps a statement below the paragraph regarding the 60 month implementation plan for Corrective Action Plans to the effect of:?Once effective all future assessments shall upon completion be compliant with this standard. Assessments completed prior to the effective date shall be based on the TPL standards in effect at the time. The standard is not intended to require a retroactively compliant assessment be in effect when the standard becomes active, but instead that the next assessment be compliant with the revised standard?
Response: The revised standard has raised the bar for certain planning events. In those cases, a 60 month effective date is permitted. The determination as to when the 60 month period applies is related to the Contingency and not the solution. Therefore, if a 138 kV line is proposed as a corrective action for one of the raising the bar events, 60 months would be provided to implement the construction of the 138 kV line. Regarding the impact of spare policies, the SDT does not agree with your premise that solutions to meet this requirement could take at least 5 years. Since the requirement addresses spare transmission equipment, and not generating equipment as your example suggests, one direct solution would be to purchase additional spare transmission equipment. In virtually all cases this could be accomplished in less than 5 years. The SDT believes that extenuating circumstances are covered in Requirement R2, part 2.7.5. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." The SDT chose a phased approach for establishing effective dates for individual requirements to reflect the broad range of implementation time frames associated with		

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different requirements. Rather than use a least common denominator, which would have led to a new standard that would not be implemented for 60 months, those requirements that needed less time were assigned earlier effective dates. No change made. The SDT recognizes that assessments take a period of time to complete. The date on which the assessment was initiated would determine whether the current TPL standards or the revised TPL-001-1 would govern compliance requirements. No change made		
Progress Energy Carolina (PEC)	No	More time than 12 months is needed for modeling the complete effects of Relay Protection Systems and the effects of Relay Loadability. PEC suggests that this period of time be extended to 24 months or longer.
Response: The standard does not require detailed modeling of Relay Protection Systems. It only requires that the impacts of those systems be reflected in the modeling of Contingencies and the evaluation of the resulting System performance. This is no different than the current standards.		
MidAmerican Energy Company	No	MidAmerican commends the SDT for its hard work on this standard. MidAmerican does not support the paragraph that states "Any entity that cannot fully implement its Corrective Action Plan".shall self report itself?? MidAmerican believes that the Energy Policy Act of 2005 does not provide NERC or FERC the authority to require construction of facilities. Therefore, MidAmerican believes that this paragraph should be deleted in its entirety from the implementation plan as requiring responsibility to build facilities or else self report non-compliance. This is in direct contradiction to federal law.
Response: The Corrective Action Plan requirements do not necessarily result in construction of new Facilities, although it is understood that in some cases the only practical solution to a performance violation will require new or upgraded Facilities. Therefore, the SDT does not believe that these requirements contradict federal law and disagrees with your recommendation that the paragraph you mentioned should be removed.		
Northeast Utilities	Yes	Other Comments:Comment 1 Please clarify, since R2 through R6 should become effective before results could be distributed to adjacent Planning Coordinators and any functional entity. However, by the wording of the effective date of R1 and R7 it appears R7 becomes effective before R2 to R6. That is, 24 months are allowed by the standard to complete the planning assessments after regulatory approval. The results may not be ready for distribution by the planning coordinator after the first twelve months. Comment 2 The term "Planning Coordinator" is not defined in the NERC Glossary of Terms used in Reliability Standards and, therefore, this standard should indicate whether this term is the same as the "Planning Authority" defined in the glossary. Otherwise the definition of the Planning Coordinator should be included in the NERC Glossary of Terms used in Reliability Standards.
Progress Energy Florida, Inc.	No	While the Implementation Plan is extremely vague at present, making a specific enforcement date impossible to determine, PEF is concerned that the language at present will not allow enough time for Transmission Owners to prepare for the increased stringency.
Response: The SDT chose a phased approach for establishing effective dates for individual requirements to reflect the broad range of implementation time frames associated with different requirements. Rather than use a least common denominator, which would have led to a new standard that would not be implemented for 60 months, those requirements that needed less time were assigned earlier effective dates. No change made. Planning Coordinator is defined in the latest approved version of the Glossary.		
Hydro-Québec TransEnergie (HQT)	No	With regard to the many changes/modifications from the previous draft and from the previous TPL standards being replaced by TPL-001-1, another posting of this Standard will be necessary to fully evaluate the impact (on

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		reliability and also cost of implementation) of such changes. The decision to allow the use of all type of RAS or SPS (particularly generator tripping and run-back) as a common practice for single contingency does not "raise the bar" in the planning standard, and should be reviewed. How can higher system performance be required that involves substantial infrastructure investment to prevent events with a very low probability of occurrence, and allow use of a less reliable measure (SPS failure or misoperation having a higher probability of occurrence) to reduce the investment for more probable events?
Response: The SDT agrees that another posting is required and has produced a fourth draft. The SDT's intent was to raise the bar where it was practical to do so and not lower the bar in any case. The allowance for the use of SPS and RAS in repose to single contingencies simply reflects the practice in many parts of North America. Where this has not been a common practice, individual Regional Entities, Planning Coordinators or Transmission Planners have the latitude to establish more stringent criteria.		
Ameren	No	At least 36 months would be needed for R1 compliance, should inclusion of explicit modeling of protection system equipment be required in dynamic model representations, and if all breakers would need to be explicitly modeled. More time is needed for entities to determine the appropriate dynamic load model required by R2.4.1. We recommend at least 36 months before this requirement becomes effective. 60 months effective date seems acceptable for planning activities, but may not adequate for all construction activities. Typical times to construct a transmission line in various areas of SERC can range between 7 to 10 years. Accordingly, we recommend the effective date for construction projects be changed to at least 84 months. 12 months appears reasonable for R7.
Response: The standard does not require detailed modeling of Relay Protection Systems or circuit breakers. It only requires that the impacts of those systems be reflected in the modeling of Contingencies and the evaluation of the resulting System performance. This is no different than the current standards. Requirement R2, part 2.4.1 does not require a detailed dynamic Load model, only an aggregate System model. The SDT believes that such a model can be developed within the 24 month period before this requirement becomes effective. The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. The third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control.		
Manitoba Hydro	No	TPL-005-0 is a Regional and Interregional Self-Assessment Reliability Report. Such an assessment is beyond the capability of an individual PC or TP. While the new TPL-001-1 can and should include a requirement on the PC and TP to include in their assessments the interconnections with their adjacent systems, it does not make sense to

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		mandate an individual TP or PC to conduct an interregional assessment. Consequently, TPL-005-0 should be retained and mandated on the regions via the NERC delegation agreements with the regions.
Response: The standard does not require an individual Planning Coordinator or Transmission Planner to conduct an interregional assessment. It would require Planning Coordinators to provide the necessary inputs and work with the Regional Entity to provide a regional assessment that would continue to satisfy NERC's needs. The filing of a Planning Assessment by the Regional Entity is no longer required by a standard because it is covered adequately in NERC's Rules of Procedure.		
Entergy Services, Inc	No	P1 events needs to be correctly classified as "raising the bar": P1 events should be included in the bulleted list of areas where the "bar was raised". The paragraph beginning at the bottom of page 2 of the Implementation Plan clearly states that the bar was raised "because loss of Non-Consequential Load or interruption of firm transfers is no longer allowed". Since P1 events in the existing standard allow this, the revised P1 events should be categorized as a raising of the bar. " Effective date needs to be extended: Additionally, in the areas where the bar has been raised, the effective date needs to be extended to at least 7 years. Siting (environment assessment and permitting, right-of-way acquition, regulatory approvals) alone for many of the facilities likely needed can take 3 years or more in some areas. Likely delays due to litigation and affected stakeholder intervention must be considered. In addition, while the SDT has collected some cursory estimates of the costs which may be passed on to end-use customers, no discussion of the intended or expected increase in reliability has been published. Other considerations that will have an impact on the effective date are construction outages on the bulk transmission system and competition of resources (human and material). " Effect on reliability is not adequately quantified: Since one of the SDTs objectives is to ensure that "requirements set at an appropriate level to ensure reliability,"what reliability metrics are expected to be impacted? By how much? What will the billions of dollars spent on transmission procure in terms of reliability to ratepayers? To what degree would the proposed standard decrease the probability of a blackout? If a blackout were to occur, would the proposed standard tend to decrease or increase the size and magnitude of the event?? More time is needed for entities to determine the appropriate dynamic load model required by R2.4.1. We recommend at least 36 months before this requirement becomes effective. Since breaker duty is a new "raising the bar" issue - should there also be a 5 or more year implementation plan for this as well? If a Transmission Planner has a Corrective Action Plan identified within the accepted time limitations but the facilities identified in the CAP cannot be implemented in time, would the TP be found non-compliant on the TPL-001-1?? If contingencies in one utility's system results in issues within another utility, who is responsible for studying the contingencies and who would be responsible for documenting the CAP?
Response: The SDT disagrees that P1 represents a raising of the bar. While the exiting standard was somewhat unclear about dropping firm Non-Consequential Load for P1 type events, there is little evidence to support that as a widespread practice. Therefore, the revised standard is simply a clarification of the intent of the earlier standards. The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the		

Organization	Yes or No	Question 11 Comment
standard by potentially delaying some corrective actions that could be implemented in 60 months or less. The third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control. With respect to any additional capital requirements driven by the new standard, the SDT can not speculate regarding the magnitude of such requirements. However, the SDT strongly believes that the revised standard is necessary to ensure an adequate level of reliability for North America's Bulk Electric Systems. Requirement R2.4.1 does not require a detailed dynamic Load model, only an aggregate System model. The SDT believes that such a model can be developed within the 24 month period before this requirement becomes effective. The SDT does not view the breaker duty requirements as a raising of the bar. While these may be new requirements in NERC Standards, the SDT believes that most entities already follow these practices because they are safety related. If a Transmission Planner has prepared an acceptable Corrective Action Plan within the required time limits, but the implementation of the plan cannot be completed in time for reasons that are beyond the control of the Transmission Planner, " then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." In such a case, it is the intent of the SDT that the Transmission Planner would be compliant. The SDT has modified the language in Requirement R3, part 3.4.1, Requirement R4, part 4.4.1, and Requirement R8 with part 8.1 to clarify the handling of "cross border" Contingencies and performance violations. **3.4.1** The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. **4.4.1** The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. **8.1** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.		
PJM	No	Removal of these standards will not affect NERC and the Regional Entity's obligations to perform assessments. Will the PC/TP be obligated under NERC Rules of Procedure to provide Assessments to NERC and the Regions upon request?
Response: The standard does not require an individual Planning Coordinator or Transmission Planner to conduct an interregional assessment. The filing of an		

Organization	Yes or No	Question 11 Comment
assessment by the Regional Entity is no longer required by a standard because it is covered adequately in NERC's Rules of Procedure.		
ITC Holdings	Yes	Comments: We generally concur. However, it would appear that there is no incentive to submit a mitigation plan for less than 60 months for the new requirements that raise the bar (those listed as bullet points). If "circumstances are within your control" to mitigate in less than 60 months, why not require it?
Response: While the SDT understands the basis for your suggestion, it would be cumbersome and possibly confusing to change the requirements to apply differently in different circumstances. The SDT believes that peer reviews of the Corrective Action Plan and compliance audits would incent completion of corrective actions as soon as practical. No change made.		
Northern Indiana Public Service Company	No	In A5, text appearing under "Effective Date" is not clear regarding application of the phrase, "(above 300 kV)", for the first and fourth dot points.
Response: For the first dot, the parenthetical "above 300 kV" applies only to P2-2 events. For the fourth dot, the parenthetical applies to all events P4-1 through P4-5		
LADWP	No	Cannot agree to something when this is not final.
Idaho Power	No	I would like to review this after completion of the standard.
Response: The SDT was simply asking whether you agree with the Implementation Plan as written.		
Orlando Utilities Commission	Yes	Overall the plan is excellent! Allowing for a 60 month phase in of the more restrictive performance requirements and an exception for those who need longer to meet them is an equitable and reliable practice. Having R1 and R7 go into effect first though raises the question of what TPL standard is in effect during that time frame? I recommend having the entire standard go into effect at the same time and avoid that issue. There is limited benefit to R1 and R7 going into effect early. The implementation should also be more specific on what "going into effect" means. Assessments are not a one day event but are a year long effort that culminates in a final "report" that is the assessment. Most NERC standards affect ongoing activities, and the day they go into effect the utilities functions are expected to be compliant, this is not however so clear when the "function" is the culmination of a year long effort. Perhaps a statement below the paragraph regarding the 60 month carve out to the effect of: Once this standard becomes effective all future assessments shall be compliant with this standard. Assessments completed prior to the effective date shall be judged by their compliance with TPL standards in effect at the time.
Response: The SDT chose a phased approach for establishing effective dates for individual requirements to reflect the broad range of implementation time frames associated with different requirements. Rather than use a least common denominator, which would have lead to a new standard that would not be implemented for 60 months, those requirements that needed less time were assigned earlier effective dates. The SDT recognizes that assessments take a period of time to complete. The date on which the assessment was initiated would determine whether the current TPL standards or the revised TPL-001-1 would govern compliance requirements.		
American Transmission Company	No	We offer the following comments.The proposed standard implies that the 24 and 60 month periods run in parallel rather than sequentially. As currently proposed, the effective date for performing analyses and developing subsequent Corrective Action Plans is 24 months. If the identification of new needs and action plans take 24 months, then only 36 months would be left to implement the new action plans. It may not be feasible to install some BES facilities, especially above 300 kV in less than 3 years. Some EHV projects can take 5 to 10 years to

Organization	Yes or No	Question 11 Comment
		implement depending on the size, complexity, and controversial nature of the project. We suggest that the effective date be stated in a more "implementation dependent" rather than a "fixed timeframe" manner. Consider wording such as "tripping of Non-Consequential Load or curtailment of Firm Transmission Service (in accordance with Requirement R2.6.4) is allowed until Corrective Action Plans that are based on TPL-001-1 analyses can be implemented".
Response: The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. This third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control. The SDT considered your suggestion to change the language of Requirement R2, part 2.7.5 to make it more "implementation dependent" rather than using a "fixed timeframe" but we do not believe such a change is appropriate because it would make auditing of this requirement difficult.		
Duke Energy	No	Requirements R2 through R6 are proposed to become effective the first day of the first calendar quarter 24 months after applicable regulatory approval, and we agree with that. However, the standard also provides that for 60 months following the first day of the first calendar quarter following applicable regulatory approval, Corrective Action Plans applying to performance elements P2-1, P2-2 (above 300 kV), P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 kV) are allowed to include tripping of Non-Consequential Load or curtailment of Firm Transmission Service (in accordance with Requirement R2.6.4) that would not otherwise be permitted by the requirements of TPL-001-1. Since the first 24 months following regulatory approval will be spent developing and validating new studies and methodologies needed to meet TPL-001-1, that would only leave 36 months to implement corrective actions. We propose that the 60 month clock start with the effective dates of Requirements R2 through R6, to allow sufficient time to implement corrective actions that are determined within the 24 month period, which could include system modifications that require long lead times. Also, the implementation plan contains the following wording regarding retirement of the existing TPL standards: TPL-001-0, TPL-002-0a, TPL-003-0a, and TPL-004-0 are being retired as they are replaced in their entirety by TPL-001-1. TPL-005-0 and TPL-006-0 are being retired because their requirements are adequately covered by the revised TPL-001-1 and NERC's Rules of Procedure, Section 800. TPL-001-1 should not be used as a vehicle for fulfilling any of the TPL-005-0 and 006-0 requirements because of the difference in focus and entities involved. In reality, the new TPL-001-1 does not appear to have incorporated any of the requirements of TPL-005-0 and 006-0. TPL-001-1 appropriately focuses on how PC's and TP's should perform studies and document assessments of their transmission facilities impact on BES reliability. TPL-005-0 and 006-0 focus on assessments of regional and inter-regional BES reliability, including other non-transmission issues as well. The NERC Rules of Procedure and existing FERC Order 890 efforts appear to be sufficient to cover the requirements of TPL-005-0 and 006-0.

Organization	Yes or No	Question 11 Comment
		Therefore, retirement of TPL-005-0 and 006-0 is still appropriate.
Response: The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. This third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control. The SDT believes that this revised standard together with NERC's Rules of Procedure will completely address the regional assessment requirements covered in the existing standards.		
Tucson Electric Power Company		We agree that TPL-005 and TPL-006 appear to have been adequately covered in the draft TPL-001-1 as currently written. However, we will need to review this assessment after TPL-001-1 is finalized. In addition, there is no place to state our concerns for Section D. so we added it here. We question the "not applicable" entry under Section D 1.1.2. What does it mean when the reset period is not applicable? Does it mean there is no reset period, so all non-compliance in all prior years will be counted as prior violations when considering non-compliance in future years? We believe that 60 months is not sufficient to implement the Corrective Action Plan for the "raise the bar" requirements. Siting transmission lines can take longer than this window. We strongly recommend increasing the window to 120 months which is a more realistic estimate of the time required to bring an EHV transmission project from conception to construction.
Response: The sanctions guidelines developed by the compliance program as part of the ERO start-up process eliminated the use of the concept of the "compliance reset period." The reason the heading "Compliance Monitoring and Reset Time" is still in the standards template is because some Standards Committee members felt that a change to the standard template couldn't be made without having the change go through full due process. Therefore, NERC staff agreed to always put, "Not applicable" under this heading until the next version of the manual is issued. This term will be eliminated in Version 8. The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT reconsidered its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. This third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control.		

Organization	Yes or No	Question 11 Comment
Kansas City Power & Light	No	Regional areas may be made up of multiple Planning Coordinators. It is important to maintain an assessment of an entire Regional Reliability Organizations area. TPL-005 and TPL-006 should not be replaced with this proposed TPL-001.
Response: The SDT recognizes that many of the Regional Entities have multiple Planning Coordinators within their boundaries. The filing of an assessment by the Regional Entity is no longer required by a standard because it is covered adequately in NERC's Rules of Procedure.		
ReliabilityFirst Corporation	Yes	
Transmission Planning	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
Exelon Transmission Planning	Yes	
United Illuminating	Yes	
Western Area Power Administration	Yes	
Gainesville Regional Utilities	Yes, Yes	,
ISO New England, Inc.	Yes	
National Grid	Yes	
Brazos Electric Cooperative	Yes	no comment at this time
American Electric Power	Yes	
Minnesota Power	Yes	
Central Maine Power Company	Yes	
Response: Thank you for your response.		

Implementation Plan for TPL-001-1

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

TPL-001-1 — Transmission System Planning Performance Requirements

In revising the TPL standards, the SDT is assuming that planners will receive valid data from the MOD standards link described in TPL-001-1, Requirement R1. Furthermore, there is a tacit assumption that future revisions of the MOD standards will include steps to validate MOD based data.

Revision to Sections of Approved Standards and Definitions

There are multiple new definitions in the proposed standard.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault .

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Near-Term Transmission Planning Horizon: Transmission planning period that covers Years One through five.

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.

Year One: The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.

Compliance with Standards

Standard	Functions That Must Comply With the Associated Requirements	
	Transmission Planner	Planning Coordinator
TPL-001-1 — Transmission System Planning Performance Requirements	X	X

Effective Dates

The effective date is the date entities are expected to meet the performance identified in this standard.

Except as indicated below, all Requirements and associated sub-requirements shall become effective 24 months after the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect 24 months after Board of Trustees adoption.

TPL-001-0, TPL-002-0a, TPL-003-0a, and TPL-004-0 are being retired as they are replaced in their entirety by TPL-001-1. TPL-005-0 and TPL-006-0 are being retired because their requirements are adequately covered by the revised TPL-001-1 and NERC's Rules of Procedure, Section 800. However, during this 24-month period, all aspects of TPL-001-0 through TPL-006-0 shall remain in effect for compliance monitoring. This 24 month period is to allow entities to develop, perform and/or validate new and/or modified studies, methodologies, assessments, procedures, etc. necessary to implement and meet the TPL-001-1 requirements. The specified effective dates are expected to allow sufficient time for proper assessment of the available options necessary to create a viable Corrective Action Plan that is compliant with the new Standard.

> R1. This Requirement is related to maintaining System models and the data needed to do so. This requirement shall become effective 12 months after the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes into effect 12 months after Board of Trustees adoption.
>
> R8. This Requirement identifies an obligation to determine individual and joint responsibilities for performing studies needed to do the Planning Assessment. This requirement shall become effective 12 months after the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes into effect 12 months after Board of Trustees adoption.

TPL-001-1 'raises the bar' in several areas where performance requirements have been changed in the new Standard versus those in existing TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0 because loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain events, whereas the existing Standards were interpreted by many to allow such actions. As shown in Table 1 of TPL-001-1, the performance requirements associated with the following events represent "raising the bar":

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

This "raising the bar" is beyond the control of the Transmission Planner and Planning Coordinator and may have significant budget, siting, permitting, and construction impacts on many Transmission Owners. In question 14 of the second posting of the revised standard, the SDT requested input from industry on the amount of time required to implement the Corrective Action Plans needed to address the 'raise the bar' issues. The SDT has studied the responses and determined that a timeframe coincident with the end of the Near-Term Transmission Planning Horizon would be the appropriate amount of time to implement the changes. Therefore, for 60 months after the first day of the first calendar quarter following applicable regulatory approval, Corrective Action Plans applying to performance elements P1-2 and P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element), P2-1, P2-2 (above 300 kV), P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 kV) are allowed to include tripping of Non-Consequential Load or curtailment of Firm Transmission Service (in accordance with Requirement R2.7.5) that would not otherwise be permitted by the requirements of TPL-001-1.

Any entity which cannot fully implement their Corrective Action Plan to eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for these performance elements by that date shall self report themselves as being unable to meet the performance requirements of the Reliability Standard. The entities will submit a mitigation plan to their Regional Entity outlining the steps they will take to become compliant and the date they anticipate becoming compliant. The Regional Entity and NERC will review the mitigation plan and the Regional Entity/NERC will either approve it or remand it back for changes (this could include dates, steps, etc.). If the mitigation plan is approved by the Regional Entity and NERC and the entity completes the mitigation plan by the date contained within the mitigation plan, it is the intent of the SDT that no penalties will be assessed. Those entities who do not meet the date outlined in the mitigation plan will begin settlement proceedings at that date.

Implementation Plan for TPL-001-1

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

TPL-001-1 – Transmission System Planning Performance Requirements

In revising the TPL standards, the SDT is assuming that planners will receive valid data from the MOD standards link described in TPL-001-1, Requirement R1. Furthermore, there is a tacit assumption that future revisions of the MOD standards will include steps to validate MOD based data.

Revision to Sections of Approved Standards and Definitions

There are multiple new definitions in the proposed standard.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: ~~All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions.~~ All Load that is no longer served by ~~any~~the Transmission ~~Facilities~~ System as a result of ~~the~~ Transmission Facilities being removed from service by a ~~planned~~ Protection System operation designed to isolate the fault ~~conditions~~.

~~**Extreme Events:** Events which are more severe and have a lower probability of occurrence than Planning Events.~~

~~**Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event.~~

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Near-Term Transmission Planning Horizon: Transmission planning period that covers Years One through five.

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss~~, Supplemental Load Loss, and Load Reduction~~ and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment..

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.

~~**Planning Events:** Events that require Transmission system performance requirements to be met.~~

~~**Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.~~

Year One: The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.

Compliance with Standards

Standard	Functions That Must Comply With the Associated Requirements	
	Transmission Planner	Planning Coordinator
TPL-001-1 – Transmission System Planning Performance Requirements	X	X

Effective Dates

The effective date is the date entities are expected to meet the performance identified in this standard.

Except as indicated below, all Requirements and associated sub-requirements shall become effective 24 months after the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect 24 months after Board of Trustees adoption.

TPL-001-0, TPL-002-0a, TPL-003-0a, and TPL-004-0 are being retired as they are replaced in their entirety by TPL-001-1. TPL-005-0 and TPL-006-0 are being retired because their requirements are adequately covered by the revised TPL-001-1 and NERC's Rules of Procedure, Section 800. However, during this 24-month period, all aspects of TPL-001-0 through TPL-006-0 shall remain in effect for compliance monitoring. This 24 month period is to allow entities to develop, perform and/or validate new and/or modified studies, methodologies, assessments, procedures, etc. necessary to implement and meet the TPL-001-1 requirements. The specified effective dates are expected to allow sufficient time for proper assessment of the available options necessary to create a viable Corrective Action Plan that is compliant with the new Standard.

R1. This Requirement is related to maintaining System models and the data needed to do so. This requirement shall become effective 12 months after the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes into effect 12 months after Board of Trustees adoption.

R~~7~~8. This Requirement identifies an obligation to determine individual and joint responsibilities for performing studies needed to do the Planning Assessment. This requirement shall become effective 12 months after the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory

approval is required, this requirement goes into effect 12 months after Board of Trustees adoption.

TPL-001-1 'raises the bar' in several areas where performance requirements have been changed in the new Standard versus those in existing TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0 because loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain events, whereas the existing Standards were interpreted by many to allow such actions. As shown in Table 1 of TPL-001-1, the performance requirements associated with the following events represent "raising the bar":

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

This "raising the bar" is beyond the control of the Transmission Planner and Planning Coordinator and may have significant budget, siting, permitting, and construction impacts on many Transmission Owners. In question 14 of the second posting of the revised standard, the SDT requested input from industry on the amount of time required to implement the Corrective Action Plans needed to address the 'raise the bar' issues. The SDT has studied the responses and determined that a timeframe coincident with the end of the Near-Term Transmission Planning Horizon would be the appropriate amount of time to implement the changes. Therefore, for 60 months after the first day of the first calendar quarter following applicable regulatory approval, Corrective Action Plans applying to performance elements P1-2 and P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element), P2-1, P2-2 (above 300 kV), P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 kV) are allowed to include tripping of Non-Consequential Load or curtailment of Firm Transmission Service (in accordance with Requirement R2.7.~~4~~5) that would not otherwise be permitted by the requirements of TPL-001-1.

Any entity which cannot fully implement their Corrective Action Plan to eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for these performance elements by that date shall self report themselves as being unable to meet the performance requirements of the Reliability Standard. The entities will submit a mitigation plan to their Regional Entity outlining the steps they will take to become compliant and the date they anticipate becoming compliant. The Regional Entity and NERC will review the mitigation plan and the Regional Entity/NERC will either approve it or remand it back for changes (this could include dates, steps, etc.). If the mitigation plan is approved by the Regional Entity and NERC and the entity completes the mitigation plan by the date contained within the mitigation plan, it is the intent of the SDT that no penalties will be assessed. Those entities who do not meet the date outlined in the mitigation plan will begin settlement proceedings at that date.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form for Fourth Draft of TPL-001-1 (Project 2006-02)

Please **DO NOT** use this form to submit comments. Please use the electronic form located at the link below to submit comments on the fourth draft of the TPL-001-1 standard for Assess Transmission Future Needs (Project 2006-02) by **October 16, 2009.**

If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

Background Information

TPL-001-1 Transmission System Planning Performance Requirements

Comments on the third draft of the TPL-001-1 Transmission System Planning Performance Requirements standard were received from the industry through July 9, 2009. The Drafting Team sought and received feedback to 11 questions, and the team appreciates the tremendous industry participation that generated over 400 pages of comments from over 85 organizations. Below is a brief overview of the 4th draft of the standard highlighting areas where the SDT made changes based on stakeholder feedback from the third posting. The team's objectives remain unchanged - to create a single Transmission planning standard: 1) with clear, concise requirements set at an appropriate level to ensure reliability, and 2) that fully addresses all issues raised by FERC Orders 693 and 890, and industry inputs, including the SAR scope document.

Fourth Draft Overview:

1. At first glance the fourth draft of the standard may appear to have been substantially changed; however, this is not the case as the SDT has maintained its vision throughout the process and the changes shown are primarily clarifying in nature.
2. The flow and organization of the standard remain similar to the 3rd draft. Requirement labeling has been modified in accordance with NERC's revised standards process to eliminate sub-requirements and re-label them as "parts."
3. However, some changes are noteworthy:
    a. Several definitions were revised or deleted based on industry feedback.
    b. Requirement R1 has been revised to clarify the SDT's intent with regard to modeling issues.
    c. Requirement R2, part 2.1.3 has been added to clarify that studies must be performed with known outages included in the base case.
    d. Requirement R2, part 2.1.5 has been revised to clarify the spare equipment strategy and limit the analysis to P0, P1 and P2 categories
    e. How sensitivity studies fit into the overall assessment has been clarified in Requirement R2, part 2.4.3.
    f. Requirement R2, part 2.5 has been added to require stability analysis for proposed generation additions or changes in the Long Term Transmission Planning Horizon.

g. Requirement R2, part 2.6.2 has been revised to decrease unnecessary documentation requirements and the examples of 'material generation changes' have been deleted.

h. Requirement R2, part 2.7.2 has been added to clarify necessary actions with regard to sensitivity studies.

i. Requirement R2, parts 2.7.3 and 2.7.4 have been deleted so inclusion of project initiation dates and in service dates are no longer required.

j. Requirement R2, part 2.10 has been deleted so the maximum permissible Non-Consequential Load Loss does not have to be reported.

k. Requirement R3, parts 3.3.2, 3.3.3 and 3.3.4 have been revised to clarify the requirements for contingency analysis.

l. Requirement R3, part 3.4.1 and Requirement R4, part 4.4.1 have been added to ensure that planners are coordinating with adjacent planners.

m. Requirement R3, part 3.6 has been added to require documentation of generation runback or tripping used to meet performance requirements.

n. Requirements R4, parts 4.1.1 through 4.1.3 have been added as requirements text to replace previous footnote 1 in Table 1.

o. Requirement R4, part 4.3.1 was revised to include the impacts of high speed reclosing.

p. Requirement R4, part 4.3.3 was added to ensure that the impacts of transient swings are simulated.

q. Requirement R5 was added so that appropriate criteria are set.

r. Requirement R8, part 8.1 was added to clarify actions for responding to comments on results of Planning Assessments.

s. All VSLs have been modified to match the new requirement language.

t. Miscellaneous clarifications to existing requirements and Table 1 footnote language.

4. The Implementation Plan has been revised to provide more time for entities to become compliant with P1-2 and P1-3 events with regard to local Load issues.

To facilitate the ability of industry respondents to comment in an orderly fashion and to ease the coordination burden on the SDT in responding to comments, the SDT is asking an all encompassing question for each requirement. This question solicits comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and the VSL associated with the requirement. Please note the numbering below refers to the clean copy of the fourth posting.

1. Requirement R1 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

   Comments:

2. Requirement R2 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

   Comments:

3. Requirement R3 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

   Comments:

4. Requirement R4 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

   Comments:

5. Requirement R5 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement. (Note – This is a new requirement.)

   Comments:

6. Requirement R6 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

   Comments:

7. Requirement R7 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Comments:

8. Requirement R8 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

   Comments:

The SDT is posing several other questions for industry consideration to supplement the specific requirement questions above.

9. The SDT has revised the definitions in response to industry comments to the third posting. Do you agree with these definition changes? If not, please clearly indicate which definition you disagree with and provide specific comments.

   ☐ Yes

   ☐ No

   Comments:

10. Do you agree with the changes in the performance elements and notes in Table 1? If not, please provide specific comments by note number, note alpha character, or performance category.

    ☐ Yes

    ☐ No

    Comments:

11. The SDT has provided a revised Implementation Plan as part of this posting. Do you agree with the revisions to the Plan? If not, please provide specific comments.

    ☐ Yes

    ☐ No

    Comments:

12. Do you believe that this standard is ready to go to ballot? (if 'No' is checked here, the SDT will consider that comments raised on the other questions drove that decision.)

    ☐ Yes

    ☐ No

    Comments:

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Version 1 of SAR posted for comment from April 2, 2002 through May 3, 2002.
2. Version 2 of SAR posted for comment from May 5, 2004 through June 5, 2004.
3. Version 3 of SAR posted on November 18, 2005.
4. SAR approved on April 30, 2006.
5. Version 1 of Supplemental SAR posted for comment from February 15, 2007 through March 16, 2007.
6. Version 2 of Supplemental SAR posted on April 9, 2007.
7. Version 1 of revised standard(s) posted for comment on September 17, 2007.
8. Version 2 of the revised standards posted for comment on August 15, 2008.
9. Version 3 of the revised standards posted for comment on May 26, 2009.

Proposed Action Plan and Description of Current Draft:

The SDT has established a schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 1Q10. The current draft is the second iteration of the revision of existing standards TPL-001 through TPL-006 and includes one revised standard, TPL-001-1, replacing TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. TPL-005 & -006 issues are addressed in this fourth draft.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Respond to comments from second posting of standard(s) and submit revision 4 of the standard(s).	4Q08
2. Respond to comments from third posting and submit revision 5 of the standard.	3Q09
3. Submit standard(s) for balloting.	4Q09
4. Submit standard(s) to BOT.	4Q09
5. Submit to regulatory authorities for approval.	1Q10

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault .

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Near-Term Transmission Planning Horizon: Transmission planning period that covers Years One through five.

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.

Year One: The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-1**

3. **Purpose:** Establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R8 shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 and R8 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

   Except as indicated below, Requirements R2 through R7 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.

   - For 60 calendar months after the first day of the first calendar quarter following applicable regulatory approval, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-1, Table 1 are allowed to include tripping of Non-Consequential Load or curtailment of Firm Transmission Service (in accordance with Requirement R2, part 2.7.5.) that would not otherwise be permitted by the requirements of TPL-001-1:
     - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
     - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
     - P2-1, P2-2 (above 300 kV)
     - P2-3 (above 300 kV)
     - P3-1 through P3-5
     - P4-1 through P4-5 (above 300 kV)
     - P5 (above 300 kV)

   Any entity that cannot fully implement its Corrective Action Plan to eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for the above listed performance elements within 60 calendar months of the compliance date for Requirements R2 through R4 shall self report itself as being unable to meet

performance requirements of this Reliability Standard. Any such entity shall submit a mitigation plan to its Regional Entity outlining the steps it will take to become compliant and the date it anticipates becoming compliant. The Regional Entity and NERC shall review the mitigation plan and the Regional Entity/NERC will either approve it or remand it for changes (this could include dates, steps, etc.). If the mitigation plan is approved by the Regional Entity and NERC and the entity completes the mitigation plan by the date contained within the mitigation plan, the intent of the SDT is that no penalties will be assessed. Those entities that do not meet the date outlined in an approved mitigation plan will begin settlement proceedings at that date.

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources required to supply Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies as indicated in Requirement R2, part 2.6:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1 for known outages, as modeled in Requirement R1, part 1.1.2 under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of

changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of planned Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

2.2. The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of

induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Load level, Load forecast, or dynamic model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported by current or past studies.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Such actions may include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.

- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status.

2.9. The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, parts 2.1, and 2.2. The studies

shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, part 3.5.

3.3. Contingency analyses shall be performed and:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention.

3.3.2. Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.3. Ensure relay loadability limits are respected.

3.3.4. Simulate the expected automatic operation of existing and planned devices designed to provide Steady State control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

3.6. When manual or automatic generation runback or tripping is used to meet steady state performance requirements for planning events P1 through P7 in Table 1, the amount of generation lost shall be documented in the Planning Assessment with a description of why the generation was runback or tripped for each event.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: A generator that pulls out of synchronism shall be tripped in the simulations and the resulting apparent impedance swings shall not result in the tripping of any Transmission System elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, part 4.5.

4.3. Contingency analyses shall be performed and:

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention while also considering the impact of successful or unsuccessful high speed reclosing.

4.3.2. Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.3. Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers.

4.3.4. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4, part 4.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R4, part 4.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltages may remain outside that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, any criteria or methodology used in the analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an

annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide evidence, such as a dated document, that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies for the Planning Assessment in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient, date, and contents, or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and any functional entity who has indicated a reliability need and has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity.

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- All Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- All studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- All studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- All documentation specifying the criteria since the last compliance audit in accordance with Requirement R5 and Measure M5.
- All studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force agreement on identified responsibilities, as well as all such agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

1.5 Additional Compliance Information

None.

2 Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, parts 1.1.1 through 1.1.6. OR The System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.	The responsible entity's System model failed to represent three of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, parts 1.1.1 through 1.1.6. OR The System model did not represent projected System conditions as described in Requirement R1.
R2	The responsible entity failed to comply with Requirement R2, part 2.9 or Requirement R2, part 2.6.	The responsible entity failed to comply with Requirement R2, part 2.3 or part 2.8.	The responsible entity failed to comply with one of the following parts of Requirement R2: part 2.1, part 2.2, part 2.4, part 2.5, or part 2.7.	The responsible entity failed to comply with two or more of the following parts of Requirement R2: part 2.1, part 2.2, part 2.4, or part 2.7.
R3	The responsible entity did not identify planning events as described in Requirement R3, part 3.4 or extreme events as described in Requirement R3, part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R3, part 3.2 to assess	The responsible entity did not perform studies as specified in Requirement R3, part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, part	The responsible entity did not perform studies as specified in Requirement R3, part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		the impact of extreme events. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.	3.3.	
R4	The responsible entity did not identify planning events as described in Requirement R4, part 4.4 or extreme events as described in Requirement R4, part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, part 4.2 to assess the impact of extreme events. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity failed to distribute the results of its Planning Assessment to any one of its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

E. Regional Variances

None.

Table 1 – Steady State & Stability Performance
Planning Events

Steady State & Stability:

a. BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur.

b. Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. For all planning events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Facility Ratings shall not be exceeded.

g. System steady state voltage limits and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. The System shall remain stable. [1]

k. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial System Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No	No
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of Breaker(s) w/o fault [7]	N/A	EHV, HV	No	No
		2. Bus Section Fault	SLG	EHV	No	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (Non Bus-tie)	SLG	EHV	No	No
			SLG	HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie) [8]	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Planning Events

Category	Initial System Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[19]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[19]	No
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker [101])*	Normal System	Loss of multiple elements caused by a stuck breaker [11](non-Bus-tie) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[10]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie) attempting to clear a Fault on the associated bus		EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus Protection System failure)*	Normal System	Loss of multiple elements caused by the failure of a single Protection System while clearing a fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[19]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adj.[9]: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events	
Steady State & Stability For all extreme events evaluated: a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency. b. Simulate Normal Clearing unless otherwise specified.	
Steady State 1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments. 2. Local area events affecting the Transmission System such as: a. Loss of a tower line with three or more circuits.[12] b. Loss of all Transmission lines on a common Right-of-Way[12]. c. Loss of a switching station or substation (loss of one voltage level plus transformers). d. Loss of all generating units at a station. e. Loss of a large Load or major Load center. 3. Wide area events affecting the Transmission System based on System topology such as: a. Loss of two generating plants resulting from conditions such as: i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation. ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants. b. Other events based upon operating experience that may result in wide area disturbances.	**Stability** 1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments. 2. Local or wide area events affecting the Transmission System such as: a. 3Ø fault on generator with stuck breaker[11] or a Protection System failure resulting in Delayed Fault Clearing. b. 3Ø fault on Transmission circuit with stuck breaker[11] or a Protection System failure resulting in Delayed Fault Clearing. c. 3Ø fault on transformer with stuck breaker[11]or a Protection System failure resulting in Delayed Fault Clearing. d. 3Ø fault on bus section with stuck breaker[11] or a Protection System failure resulting in Delayed Fault Clearing. e. 3Ø internal breaker fault[11]. f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level for stated performance criteria applies regarding allowances for interruptions of Firm Transmission Service and loss of Non-Consequential Load.
2. Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems as defined by the Regional Entity. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruptions of Firm Transmission Service and Non-Consequential Load.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-Generator Step Up transformer outage events, the reference voltage applies to the low-side winding (excluding tertiary windings). For generator and generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening breaker(s) without a fault on one end of a normally networked Transmission circuit such that the line is now open at that end and possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure or common Right-of-Way for 1 mile or less.

Version History

Version	Date	Action	Change Tracking
1	TBD	Revision of TPL-001-0 as per Project 2006-02; includes merging requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-1	Not employed due to scope of revision

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Version 1 of SAR posted for comment from April 2, 2002 through May 3, 2002.
2. Version 2 of SAR posted for comment from May 5, 2004 through June 5, 2004.
3. Version 3 of SAR posted on November 18, 2005.
4. SAR approved on April 30, 2006.
5. Version 1 of Supplemental SAR posted for comment from February 15, 2007 through March 16, 2007.
6. Version 2 of Supplemental SAR posted on April 9, 2007.
7. Version 1 of revised standard(s) posted for comment on September 17, 2007.
8. Version 2 of the revised standards posted for comment on August 15, 2008.
9. Version 3 of the revised standards posted for comment on May 26, 2009.

Proposed Action Plan and Description of Current Draft:

The SDT has established a schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 1Q10. The current draft is the second iteration of the revision of existing standards TPL-001 through TPL-006 and includes one revised standard, TPL-001-1, replacing TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. TPL-005 & -006 issues are addressed in this fourth draft.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Respond to comments from second posting of standard(s) and submit revision 4 of the standard(s).	4Q08
2. Respond to comments from third posting and submit revision 5 of the standard.	3Q09
3. Submit standard(s) for balloting.	4Q09
4. Submit standard(s) to BOT.	4Q09
5. Submit to regulatory authorities for approval.	1Q10

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Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Near-Term Transmission Planning Horizon: Transmission planning period that covers Years One through five.

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.

Year One: The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.

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Deleted: Extreme Events: Events which are more severe and have a lower probability of occurrence than Planning Events.

Deleted: Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event.

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Deleted: Planning Events: Events that require Transmission system performance requirements to be met.

Deleted: Supplemental Load Loss: Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.

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A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-1**

3. **Purpose:** Establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R8 shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 and R8 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

   Except as indicated below, Requirements R2 through R7 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.

   - For 60 calendar months after the first day of the first calendar quarter following applicable regulatory approval, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-1, Table 1 are allowed to include tripping of Non-Consequential Load or curtailment of Firm Transmission Service (in accordance with Requirement R2, part 2.7.5.) that would not otherwise be permitted by the requirements of TPL-001-1:
     - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
     - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
     - P2-1, P2-2 (above 300 kV)
     - P2-3 (above 300 kV)
     - P3-1 through P3-5
     - P4-1 through P4-5 (above 300 kV)
     - P5 (above 300 kV)

   Any entity that cannot fully implement its Corrective Action Plan to eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for the above listed performance elements within 60 calendar months of the compliance date for Requirements R2 through R4 shall self report itself as being unable to meet performance requirements of this Reliability Standard. Any such entity shall submit a mitigation plan to its Regional Entity outlining the steps it will take to become compliant and the date it anticipates becoming compliant. The Regional Entity and

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NERC shall review the mitigation plan and the Regional Entity/NERC will either approve it or remand it for changes (this could include dates, steps, etc.). If the mitigation plan is approved by the Regional Entity and NERC and the entity completes the mitigation plan by the date contained within the mitigation plan, the intent of the SDT is that no penalties will be assessed. Those entities that do not meet the date outlined in an approved mitigation plan will begin settlement proceedings at that date.

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months

1.1.3. New planned Facilities and changes to existing Facilities

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1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources required to supply Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies as indicated in Requirement R2, part2.6:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

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2.1.3. P1 events in Table 1 for known outages, as modeled in Requirement R1, part 1.1.2 under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of planned Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

2.2. The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

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2.4. The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Load level, Load forecast, or dynamic model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported by current or past studies.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

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2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the

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performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Such actions may include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3.

2.7.4.

2.7.5. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.6. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status.

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2.9. The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.

2.10.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, part 3.5.

3.3. Contingency analyses shall be performed and:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention.

3.3.2. Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.3. Ensure relay loadability limits are respected.

3.3.4. Simulate the expected automatic operation of existing and planned devices designed to provide Steady State control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

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3.6. When manual or automatic generation runback or tripping is used to meet steady state performance requirements for planning events P1 through P7 in Table 1, the amount of generation lost shall be documented in the Planning Assessment with a description of why the generation was runback or tripped for each event.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: A generator that pulls out of synchronism shall be tripped in the simulations and the resulting apparent impedance swings shall not result in the tripping of any Transmission System elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, part 4.5.

4.3. Contingency analyses shall be performed and:

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention while also considering the impact of successful or unsuccessful high speed reclosing.

4.3.2. Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.3. Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers.

4.3.4. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

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4.4. Those planning events in Table 1that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4, part 4.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

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4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R4, part 4.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

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R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltages may remain outside that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, any criteria or methodology used in the analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

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R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

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R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

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C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models, using the latest

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data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide evidence, such as a dated document, that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies for the Planning Assessment in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient, date, and contents, or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and any functional entity who has indicated a reliability need and has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

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D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity.

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

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Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- All Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- All studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- All studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- All documentation specifying the criteria since the last compliance audit in accordance with Requirement R5 and Measure M5.
- All studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force agreement on identified responsibilities, as well as all such agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

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1.5 Additional Compliance Information

None.

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2 Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, parts 1.1.1 through 1.1.6. OR The System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.	The responsible entity's System model failed to represent three of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, parts 1.1.1 through 1.1.6. OR The System model did not represent projected System conditions as described in Requirement R1.
R2	The responsible entity failed to comply with Requirement R2, part 2.9 or Requirement R2, part 2.6.	The responsible entity failed to comply withRequirement R2, part 2.3 or part 2.8.	The responsible entity failed to comply with one of the following parts of Requirement R2: part 2.1, part 2.2, part 2.4, part 2.5, or part 2.7.	The responsible entity failed to comply with two or more of thefollowing parts of Requirement R2: part 2.1, part 2.2, part 2.4, or part 2.7.
R3	The responsible entity did not identify planning events as described in Requirement R3, part 3.4 or extreme events as described in Requirement R3, part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R3, part 3.2 to assess	The responsible entity did not perform studies as specified in Requirement R3, part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, part	The responsible entity did not perform studies as specified in Requirement R3, part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1.

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	Lower VSL	Moderate VSL	High VSL	Severe VSL
		the impact of extreme events. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.	3.3.	
R4	The responsible entity did not identify planning events as described in Requirement R4, part 4.4 or extreme events as described in Requirement R4, part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, part 4.2 to assess the impact of extreme events. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.

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	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity failed to distribute the results of its Planning Assessment to any one of its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

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E. Regional Variances

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Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur.

b. Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. For all planning events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Facility Ratings shall not be exceeded.

g. System steady state voltage limits and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. The System shall remain stable. [1]

k. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial System Condition	Event[1]	Fault Type[2]	BES Level[3]	Interruption of Firm Transmission Service Allowed[4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No	No
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of Breaker(s) w/o fault[7]	N/A	EHV, HV	No	No
		2. Bus Section Fault	SLG	EHV	No	No
				HV	Yes	Yes
		3. Internal Breaker Fault[8] (Non Bus-tie)	SLG	EHV	No	No
			SLG	HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie)[8]	SLG	EHV, HV	Yes	Yes

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Table 1 – Steady State & Stability Performance Planning Events

Category	Initial System Condition	Event[1]	Fault Type[2]	BES Level[3]	Interruption of Firm Transmission Service Allowed[4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[19]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[19]	No
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker[11] (non-Bus-tie) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	EHV	No[10]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie) attempting to clear a Fault on the associated bus		EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus Protection System failure)*	Normal System	Loss of multiple elements caused by the failure of a single Protection System while clearing a fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	EHV	No[19]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adj[9]: 1. Transmission Circuit 2. Transformer[5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer[5] 3. Shunt Device[6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

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P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure[11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

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Table 1 – Steady State & Stability Performance
Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.
b. Simulate Normal Clearing unless otherwise specified.

Steady State	Stability
1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments. 2. Local area events affecting the Transmission System such as: a. Loss of a tower line with three or more circuits.[12] b. Loss of all Transmission lines on a common Right-of-Way[12]. c. Loss of a switching station or substation (loss of one voltage level plus transformers). d. Loss of all generating units at a station. e. Loss of a large Load or major Load center. 3. Wide area events affecting the Transmission System based on System topology such as: a. Loss of two generating plants resulting from conditions such as: i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation. ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants. b. Other events based upon operating experience that may result in wide area disturbances.	1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments. 2. Local or wide area events affecting the Transmission System such as: a. 3Ø fault on generator with stuck breaker[11] or a Protection System failure resulting in Delayed Fault Clearing. b. 3Ø fault on Transmission circuit with stuck breaker[11] or a Protection System failure resulting in Delayed Fault Clearing. c. 3Ø fault on transformer with stuck breaker[11]or a Protection System failure resulting in Delayed Fault Clearing. d. 3Ø fault on bus section with stuck breaker[11] or a Protection System failure resulting in Delayed Fault Clearing. e. 3Ø internal breaker fault[11]. f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

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Deleted: 3Ø fault on two or more circuits on a common structure[12]. ¶ <#>SLG fault on all Transmission lines on a common Right-of-Way. ¶ 3Ø fault on switching station or substation (loss of one voltage level plus transformers)

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Table 1 – Steady State & Stability Performance
Footnotes
(Planning Events and Extreme Events)

1.

a.

1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level for stated performance criteria applies regarding allowances for interruptions of Firm Transmission Service and loss of Non-Consequential Load.
2. Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems as defined by the Regional Entity. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruptions of Firm Transmission Service and Non-Consequential Load.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-Generator Step Up transformer outage events, the reference voltage applies to the low-side winding (excluding tertiary windings). For generator and generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening breaker(s) without a fault on one end of a normally networked Transmission circuit such that the line is now open at that end and possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure or common Right-of-Way for 1 mile or less.

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Version History

Version	Date	Action	Change Tracking
1	TBD	Revision of TPL-001-0 as per Project 2006-02; includes merging requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-1	Not employed due to scope of revision

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for all Transmission lines and identify how loadability is analyzed in the steady state simulation.

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and shall include an explanation of why the remaining Contingencies would produce less severe System results

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and shall include an explanation of why the remaining Contingencies would produce less severe System results

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one or both of the following sub-requirements: R2.8 or

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one of the sub-requirements

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Angular Stability:

For Planning Event P1: No generating unit or units shall be allowed to pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

For all other Planning Events: No generating unit or units totaling more than the Contingency Reserve of the Balancing Authority (or Reserve Sharing Group if applicable) shall be allowed to pull out of synchronism. Generators that pull out of synchronism must have out-of-step protection or some other means to trip the generator for this condition and the resulting apparent impedance swings must not pass through relay characteristics that would result in the tripping of any

Transmission System elements other than the generating unit and its direct connection Facilities.

For all Planning Events evaluated: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator (or Transmission Planner if more restrictive)

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When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Comment Period Open
September 16–October 16, 2009

Now available at: http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

Project 2006-02: Assess Transmission Future Needs

The Assess Transmission Future Needs Standard Drafting Team is seeking comments on the following documents **until 8 p.m. EDT on October 16, 2009**:

- Draft four of TPL-001-1 — Transmission System Planning Performance Requirements
- Revised implementation plan

TPL-001-1 is designed to be a single, comprehensive, and coordinated standard that merges the requirements of four existing standards: TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The proposed standard includes several new definitions.

This is the fourth comment period for the proposed standard and includes revisions based on industry comments. The team has posted its consideration of industry comments received during the previous comment period.

Instructions

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at Lauren.Koller@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page:
http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

Next Steps

The drafting team will draft and post responses to comments received during this period. The drafting team will also determine whether to post the standard for an additional comment period or seek approval from the Standards Committee to proceed to balloting.

Project Background

The purpose of the proposed standard is to establish transmission system planning performance requirements within the planning horizon to develop a bulk electric system that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies. The project includes updating and consolidating the following standards:

- TPL-001-0 — System Performance under Normal Conditions
- TPL-002-0 — System Performance Following Loss of a Single BES Element
- TPL-003-0 — System Performance Following Loss of Two or More BES Elements
- TPL-004-0 — System Performance Following Extreme BES Events
- TPL-005-0 — Regional and Interregional Self-Assessment Reliability Reports

- TPL-006-0 — Data from the Regional Reliability Organization Needed to Assess Reliability

This part of the project addresses TPL-001-0 through TPL-004-0. TPL-005 and TPL-006 will be addressed later in the project.

Applicability of Standards in Project:

Transmission Planner
Planning Coordinator

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

Individual or group. (66 Responses)
Name (48 Responses)
Organization (48 Responses)
Group Name (18 Responses)
Question 1 (0 Responses)
Question 1 Comments (66 Responses)
Question 2 (0 Responses)
Question 2 Comments (66 Responses)
Question 3 (0 Responses)
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Question 9 (61 Responses)
Question 9 Comments (66 Responses)
Question 10 (62 Responses)
Question 10 Comments (66 Responses)
Question 11 (55 Responses)
Question 11 Comments (66 Responses)
Question 12 (60 Responses)
Question 12 Comments (66 Responses)

Group
TIS
The six month limitation of requirement 1.1.2. "Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months." Is is applicable to near-term and long-term Planning studies, but makes the new TPL-001 standard non-extensible to the near-term operational planning studies (next month, next week, or next day). During near-term operational planning periods, it is essential to include the impacts of ALL known outages in the operational analysis. It should be made clear that the TPL-001 Standard is not applicable to the Operational Planning Horizon. This points out the need for a separate (but equal in scope) operational planning analysis standard. There appears to be a double-jeopardy issue related to relay loadability and protection system redundancy. Relay loadability is handled in greater detail (as it should be) under the proposed PRC-023 standard, so any reference here should only be a placeholder. Similarly, the issues of redundancy are being addressed in more detail in a new proposed standard on protection system reliability.
The reference in R2.1.3 to the outage schedules as listing in part R1.1.2 must be recognized as a limitation to the standard to the Planning Horizon. See the TIS comment tor R1. There is confusion in interpretation of the Table 1 — When the voltage class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied? For example if a SLG fault is on a 138-kV element or a 345/138-kV autotransformer, are you allowed to shed load to keep a345-kV element from overloading? Conversely, if the fault is on a 345-kV element, are you allowed to shed load to keep a 138-kV from overloading? It should be the voltage level of the overloaded element (not the outaged element) that determines whether or not non-consequential load shedding is allowed. The TIS believes that the requirement to report the largest single consequential load loss under Requirement 2.9 should not be included in the standard. If it remains, it must be made clear that it be applicable only to Year One, and there should be additional clarification that the requirement to report consequential load loss

(single number) is ONLY for the most severe contingencies studied for the P1 and P2 contingencies.

Nowhere in the stability requirements is it necessary for evaluating the loss of all generators in a station; it is included in the steady state requirements. The standard should require examination of all units in a generating station where single line-to-ground faults on generation station buses could cause the clearing of the entire station. Further, single phase faults with delayed clearing (or stuck breaker) are not included. Often, such exclusion of stability analysis for loss of all generators at a station – these are things that happen!

There appears to be a double-jeopardy issue related to voltage performance criteria related to the VAR Standards.

Term "document" in R8.1 – the term documented needs to be defined. TIS suggests using the term "written " i.e., "If a recipient of the Planning Assessment results provides documented written comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented written response to that recipient within 90 calendar days of receipt of those comments." The requirement to distribute reports to entities with "need" has very significant CEII implications. This should be tightened to a "bona fide reliability need" for the information, requiring CEII or confidential material handling procedures. Other general comments: 1. Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft.

Yes

Yes

Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft. There is confusion in interpretation of the Table 1 — When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied?. Please see additional comments provided for R2.

Yes

Yes

Individual

Tom Mielnik

MidAmerican Energy Company

MidAmerican recommends the words in all caps be added to M1 to indicate that each responsible entity must provide evidence that "it is maintaining System models WITHIN ITS RESPECTIVE AREA, using the latest…"

• MidAmerican commends the SDT for their hard work on this standard. MidAmerican does have comments about this requirement though. • MidAmerican recommends a minor editorial to 2.1.4. The subrequirement states that "To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies, by a sufficient amount to…" The subrequirement as written is not clear whether the condition to be varied is to be one not included in the base studies or a condition that is not varied as part of the sensitivity studies. MidAmerican recommends that this subrequirement be changed as follows: "To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions FOR WHICH VARIATION IS not already included in the studies, by a sufficient amount to…" The words in caps are words that MidAmerican suggests are added to this part of requirement 2. • MidAmerican recommends that the SDT clarify section 2.4.1 and when load models considering induction motors are required. The clarification should add limits or thresholds to provide load models based on areas that have stability limits or issues and to loads of substation size and having dynamic characteristic capable of significantly impacting system damping. Areas that don't have large motors or stability issues should not be required to add unnecessary load modeling. • MidAmerican recommends that the SDT modify 2.6.2 by changing "to demonstrate that System changes do no impact the performance results in the study area" to "to demonstrate that System changes do not SIGNIFICANTLY impact the performance results in the study area." The word that is in all caps is added. 2.6.2 as written results in an unrealistic requirement to review every impact minor or large and determine which meets this item and which do not. The recommended change solves this problem. • MidAmerican recommends the data retention for R2 and M2 be revised to change "All" to "The". The word "All" is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: "THE Planning Assessments performed since…." The word in all caps is a word suggested to be added.

• MidAmerican commends the SDT for their hard work on this standard. MidAmerican does have comments about this requirement though. • MidAmerican recommends the data retention for R3 and M3 be revised to change "All" to "The". The word "All" is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: "THE studies

performed in support….” The word in all caps is a word suggested to be added.
• MidAmerican commends the SDT for their hard work on this standard. MidAmerican does have comments about this requirement though. • MidAmerican urges that the SDT delete 4.1.1 which requires that no generating unit shall pull out of synchronism during a stability analysis. A generating unit pulling out of synchronism does not necessarily result in thermal, voltage, or stability violations and does not necessarily result in cascading, instability, or uncontrolled separation. The loss of synchronism and tripping of a generator is in effect no different than tripping due to mechanical issues such as tube leaks. Present electric grid design that allows tripping for out-of-synchronism is reliable and secure. Adding the requirement that no unit may pull out of synchronism goes well beyond current grid design practices. • MidAmerican believes that 4.1.2 and 4.3.3 as written would require responsible entities in the industry to add additional modeling of relaying in dynamic stability models of our system. MidAmerican suggests that 4.3.3 be limited to transient swings on facilities 345 kV and above so as to limit this part of requirement 4 to those situations that are most likely to result in cascading. If the SDT determines not to add such a limitation, MidAmerican asks that the implementation time for R4 to be increased. MidAmerican believes that many responsible entities would need 3 years to add these relaying models to system stability models so that the fourth year additional transmission planning analysis in this respect is conducted. MidAmerican urges that the SDT increase the implementation time for R4 from 2 years to 4 years. (MidAmerican also made this comment under Question 11.) • 4.3.1 indicates that for stability contingency analysis shall be performed to “Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention while also considering the impact of successful or unsuccessful high speed reclosing.” MidAmerican believes that it is over-kill to provide this as a general requirement as written. In such a case, such successful or unsuccessful high speed reclosing analysis conceivably would need to be performed for numerous unnecessary situations given the generally wide spread use of high speed reclosing on transmissions systems. MidAmerican urges the SDT to revise this requirement to only require the study of successful and unsuccessful high speed reclosing where high speed reclosing has been added to resolve a specific stability issue such as a breaker closing angle issue. • 4.5 MidAmerican believes that the extreme events that should be studied are the more credible ones. The credible events are those that the planner considers credible when considering both how severe the event is and how likely it is. For example, while a tornado might be the most severe event, its likelihood of hitting key facilities is low. It is more likely to have a severe thunderstorm that hits key facilities but causes less impact on the system. The planner should plan for the severe thunderstorm but perhaps should not plan for the tornado. MidAmerican recommends that 4.5 be revised to indicate that a list of those events that “produce more severe System impacts AND ARE MORE LIKELY” (the words in all caps are suggested words to be added) be studied as being more credible events. Then the purpose of the last sentence in 4.5 is clearer in that possible actions that reduce the likelihood or mitigate the consequences of the events shall be reviewed for those contingencies where likelihood in combination with consequences justify such evaluation. • MidAmerican recommends the data retention for R4 and M4 be revised to change “All” to “The”. The word “All” is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: “THE studies performed in support….” The word in all caps is a word suggested to be added.
• MidAmerican commends the SDT for their hard work on this standard. MidAmerican does have comments about this requirement though. • MidAmerican recommends the data retention for R5 and M5 be revised to change “All” to “The”. The word “All” is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: “THE documentation specifying the criteria since….” The word in all caps is a word suggested to be added.
• MidAmerican commends the SDT for their hard work on this standard. MidAmerican does have comments about this requirement though. • MidAmerican recommends the data retention for R6 and M6 be revised to change “All” to “The”. The word “All” is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: “THE studies performed in support….” The word in caps is a word suggested to be added.
• MidAmerican commends the SDT for their hard work on this standard. MidAmerican does have comments about this requirement though. • MidAmerican recommends the data retention for R7 and M7 be revised to delete “All”. The word “All” is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: “The current, in force agreement on identified responsibilities, as well as such agreements in force….”
• MidAmerican commends the SDT for their hard work on this standard. MidAmerican does have comments about this requirement though. • MidAmerican asks that the SDT revise R8 to limit the need to provide the Planning Assessment as follows “adjacent Planning Coordinators and ADJACENT Transmission Planners and to any REGISTERED functional entity…” The words in all caps are words that MidAmerican suggests are added to the requirement to clarify that the word adjacent also applies to Transmission Planners and to clarify that the functional entity must be registered in order for the requirement to provide the Planning Assessment to apply. • MidAmerican asks that the low VSL for R8 be revised to delete the word “any” from the requirement so that the requirement will read “The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners….”
No
The SDT is to be commended for working on the Year One definition, however, MidAmerican continues

to be concerned that if the standard is adopted with the Year One definition as written, it is incompatible with the eastern interconnection wide ERAG model process. The definition as currently provided in the draft standard states that Year One of analysis should begin 12-18 months from the end of the current calendar year. This contradicts the time frames that models are currently made available in the MRO as a result of the process for building models through the ERAG. For example, the models developed through the MRO and ERAG model building process in 2009 include cases for the years 2010, 2011, 2015, and 2020. According to the definition of Year One, the 2011 cases in the 2009 series models would be representative of Year One during the 2009 calendar year. However the ERAG models are not provided until late 2009, and some data sets may not be available until early 2010. With this Year One definition, there would be limited or no time where the ERAG model series would include cases representing Year One as defined in the draft standard. MidAmerican urges the SDT to delete the Year One definition altogether. Since the development of regional models are tied to ERAG models and since ERAG model timing is set at the interconnection-wide level, it is likely that nearly all Transmission Planners and Planning Coordinators are working with similar models that are available at similar times. It seems to MidAmerican that this detail on what Year One is can be easily controlled interconnection-wide through the ERAG and which models they provide when. However, if the SDT believes that the Year One definition is necessary, MidAmerican urges the SDT to revised the Year One definition from stating "12-18 months from the end of the current calendar year" to stating "0-18 months from the end of the current calendar year". This revised definition would be at least compatible with the current ERAG process.

No

• The SDT should be commended for the changes that were made to Table 1. However, MidAmerican does recommend a few editorial changes. On page 16 under the Steady State and Stability heading is item d. Simulate Normal Clearing unless otherwise specified. This is also listed as footnote 2 to the table. MidAmerican recommends that item d under the Steady State and Stability heading be deleted. • Why is there a footnote 1 indicator to note j. under Stability only? MidAmerican suggests that this footnote 1 indicator be deleted. • Item i. under Steady State only states that "the response of voltage sensitive Load that is disconnected form the System by end-user equipment" is not to be used to meet steady state requirements. However, the non-consequential load loss says yes meaning it is allowed for some events in the table and non-consequential load loss definition includes the "response of voltage sensitive Load that is disconnected from the System by end-user equipment." This seems to be a direct contradiction. MidAmerican suggest that Item i. under steady state only be deleted. • MidAmerican does not understand why there is a footnote 19 indicator for P3 and P5 – EHV in the table when no footnote 19 exists. Perhaps the SDT meant footnotes 1 and 9 but MidAmerican recommends that this be corrected. • MidAmerican does not understand why there is a footnote 12 indicator for Item 2 a and 2 b. on page 19. Perhaps the SDT meant footnotes 1 and 2 apply but MidAmerican recommends that this be corrected.

No

• MidAmerican commends the SDT for changes that improved the Implementation Plan, however, MidAmerican does have a comment about the plan. MidAmerican urges the SDT to modify the implementation plan where it is indicated that any "entity which cannot fully implement their Corrective Action Plan to eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for these performance elements by that date shall self report themselves as being unable to meet the performance requirements of the Reliability Standard." This is essentially requiring an entity to self report for failing to build facilities. The Energy Policy Act of 2005 did not give FERC and therefore, NERC, the authority to require construction of electric facilities. Therefore, this implementation plan is implying an authority that is not given to FERC or NERC. This provision of the implementation plan should be completely deleted from the standard, the provision to state that one is non-compliant for this should be deleted from the standard, or there should be a statement that such a requirement is subject to limitations of the Energy Policy Act of 2005. This is a deal-killer for MidAmerican with regard to voting on this standard. MidAmerican believes that 4.1.2 and 4.3.3 as written would require responsible entities in the industry to add additional modeling of relaying in dynamic stability models of our system. MidAmerican suggests that 4.3.3 be limited to transient swings on facilities 345 kV and above so as to limit this part of requirement 4 to those situations that are most likely to result in cascading. If the SDT determines not to add such a limitation, MidAmerican asks that the implementation time for R4 to be increased. MidAmerican believes that many responsible entities would need 3 years to add these relaying models to system stability models so that the fourth year additional transmission planning analysis in this respect is conducted. MidAmerican urges that the SDT increase the implementation time for R4 from 2 years to 4 years. (MidAmerican may this comment in response to Question 4 as well.)

No

• MidAmerican commends the SDT for their hard work on this standard. Although MidAmerican does not believe that the standard is ready to go to ballot unless all our comments to the other questions and those below are resolved. • MidAmerican urges the SDT to modify the effective date where it is indicated that any "entity that cannot fully implement its Corrective Action Plan to eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for the above listed performance elements within 60 calendar months of the compliance date for Requirements R2 through R4 shall self report itself as being unable to meet the performance requirements of this Reliability Standard." This is

essentially requiring an entity to self report for failing to build facilities. The Energy Policy Act of 2005 did not give FERC and therefore, NERC, the authority to require construction of electric facilities. Therefore, this implementation plan is implying an authority that is not given to FERC or NERC. This provision of the effective date should be completely deleted from the standard, the provision to state that one is non-compliant for this should be deleted from the standard, or there should be a statement that such a requirement is subject to limitations of the Energy Policy Act of 2005. • MidAmerican also recommends a minor editorial change to the "Effective Date" portion of the standard. In the bullets, one bullet indicates "P2-1, P2-2 (above 300 kV)". It is not clear that (above 300 KV) is meant to apply to both P2-1 and P2-2. MidAmerican recommends that this bullet be changed to state, "P2-1 and P2-2".

Individual

Pete Jones

Puget Sound Energy, Inc.

R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. For R1.1.5 we suggest changing the wording from "Known commitments for Firm Transmission Service and Interchange" to "Known commitments for Firm Transmission Service or Interchange". It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.

The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies…", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies…" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies…" The wording in R2.1.1 is unclear as to whether two studies are required or only one. Should it read "year one or year two or year 5" as opposed to "year 1 or year 2 and year 5?" The language in 2.3, indicating that short circuit analysis be studied as part a BES transmission planning assessment should not be required. The effects of the failure of over-stressed breakers are already included in the Events listed in Table 1. Examples would include P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). The addition of short circuit analysis study does not add any additional reliability information. It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. R2.9 should be deleted (or not required for local load loss). The SDT indicated in the response to 'Consideration of Comments on 3rd Draft of Standard TPL-001-1' that the requirement R2.9 is intended to "contribute to an open and transparent Transmission planning for peer review." And if the 'largest Consequential Load Loss' is a local (intra-network) event? Would the documentation of such an event contribute to reliability in any way?

R3.41 requires clarification. With respect to these "Contingencies on adjacent systems," the responsibility of listing and analyzing these events needs to be clarified. Should the event simulation be the responsibility of the 'neighboring' system (where the event would occur) or the adjacent system that may feel the impact of this event? Per the developed rationale from R3.4, the neighboring system may determine that a particular event is 'less severe' and hence not studied, even though this event may potentially impact a neighbor. Further, for these "Contingencies on adjacent systems" that result in system performance outside one's own operating limits, it is unclear who is responsible for mitigating these contingencies. It is potentially awkward in that one entity may be planning another entity's system improvements.

Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.41 requires clarification. With respect to these "Contingencies on adjacent systems," the responsibility of listing and analyzing these events needs to be clarified. Should the event simulation be the responsibility of the 'neighboring' system (where the event would occur) or the adjacent system that may feel the impact of this event? Per the developed rationale from R4.4, the neighboring system may determine that a particular event is 'less severe' and hence not studied, even though this event may potentially impact a neighbor. Further, for these "Contingencies on adjacent systems" that result in system performance outside one's own operating limits, it is unclear who is responsible for mitigating these contingencies. It is potentially awkward in that one entity may be planning another entity's system improvements.

As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."

Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?

No

The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language follows Non-Interruptible Load loss other than: • Consequential Load Loss • the response of voltage sensitive Load • Load that is disconnected from the System by end-user equipment. This version uses the same wording but clarifies that the term "other than" applies to all three things.

No

As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.

No

Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.

No

Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.

Individual

Baj Agrawal

Arizona Public Service Co.

R2.6.2: The wording "study shall not include" is confusing since it refers to the past studies.

It is not clear who this applies to. Is it both TP and PC individually, or one of the two, or both jointly?

No

The definition of Non-Consequential Load is confusing. It is not clear whether the response of voltage sensitive load and the load that is disconnected by the end user is included or not included. It is suggested that all items that are excluded be itemized and that there be no ambiguity.

No

Note a: It would be helpful if there was a clear understanding of what constitutes voltage instability for the purpose of this standard. Is TP expected to have its own criteria for voltage stability? Are the dynamic and angle stabilities intentionally excluded? P3 refers to foot note 19 but there is no foot note 19. P4 refers to foot note 11, but the foot note does not seem to be applicable. Foot notes in second to last column of the table are confusing.

Group

SRC of ISO/RTO

The PC may begin model building using provisions from tariff or agreements such as its Transmission Owners agreement. While the data may be consistent with that provided in MOD 10 and 12, there may not be a direct correllation. The following wording is suggested for R1. R1. Each Transmission Planner and Planner Coordinator shall maintain System Models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall reflect data consistent with that

provided in accordance with the MOD-010 and MOD-012 standards and/or data that is provided in accordance with tariff or transmission owner agreements. The models may be supplemented by other sources as needed including items represented in Corrective Action Plans, and shall represent projected System conditions. AESO does not comment on VSLs or VRFs.

Under 2.1.4- It should be made clear that the sensitivity findings do not obligate the PC or TP to establish Corrective Action Plans to address any needs identified in the sensitivity cases. Specifically, we do not believe the sentence "To accomplish this, the sensitivity analysis in the Planning Assesment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance." is measurable or necessary. The first part of 2.1.4 already stipulates sufficient details for the responsible entity to conduct sensitivity analysis including the parameters to be varied. Adding the "how-to-conduct" requirement is overly prescriptive and unnecessary, and the condition for "that demonstrate a measurable change in performance" is not measurable. It lacks a definitive target or direction for the responsible entity to determine (a) what conditions need to be attained to demonstrate a measurable change in performance, (b) what constitutes "measurable change in performance", and (c) what follow-up or corrective actions are needed to address the adverse performance as a result of stressing the system beyond the forecast conditions. Under 2.1.4 and 2.4.3 "sufficient" and "measurable" are too vague and hard to quantify. This may require an auditor's opinion. Suggest removing at least the word "sufficient" from the requirements. Under 2.3- Some PCs do not perform short circuit analysis. Is it the intent of the SDT to make the analysis standardized over a footprint? Alternatively, this could be a TP only responsibility. Further, Part 2.3 stipulates the short-circuit assessment requirements for the near-term horizon. Unlike its steady-state and stability counterparts, there are no requirements stipulated for short-circuit analysis for the long-term horizon. Is this intentional? If so, we are unable to identify the rationale for this decision. If not, we suggest revising Part 2.3 to: "The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the near-term and long-term Transmission Planning Horizons and can be supported by...". Under 2.7.2, it is not clear how an entity can provide rational for why actions are not necessary. If actions are not necessary, then no rationalizing is needed. Further, as stated above, corrective action plans should not be required for sensitivity studies. R2.7.2 should be struck. We propose to remove R2.9, since there is not a reliability need for this information and it is unnecessary. AESO does not comment on VSLs or VRFs.

R3 has become more of a "how to" requirement than a "what" requirement as illustrated below. (a) Part 3.3 is overly prescriptive. A requirement that says contingency analysis shall be performed which reflect proper operation of all Protection Systems and actions of all automatic devices would suffice. If necessary, some examples such as those listed in Part 3.3.4 may be added as illustration. (b) The parts that ask for creating a list of continencies and having rationale available as supporting information, in Part 3.4 for example, are overly prescriptive and unnecessary. These are documentation requirements, not reliability requirements. If one ask the question: Will reliability be adversely affected if the responsible entity failed to document the list and teh rationale for choosing the list? and the answer is no, then the requirement does not rise up to a reliability standard. To meet the intent of Part 3.4, a simple requirement that asks the responsible entity to demonstrate acceptable system performance for the applicable planning event in Table 1 would suffice. Table 1 already stipulates the event that must be considered in the analysis. We do not see the need to go into such details as "some events are expected to produce more severe impacts...", and the need to ask the planners to create a list of these more impactive contingencies for subsequent evaluation. Similar observation is made for Part 3.5 on the extreme event list and for Part 3.6 for the amount of generation loss, and the rationale. AESO does not comment on VSLs or VRFs>

1. Part 4.3: Similar comments as for Part 3.3 (i.e. overly prescriptive, etc...) provided under question 3 also apply here. 2. Parts 4.4 and 4.5: Similar comments on Part 3.4 and 3.5 provided under question 3 also apply here. AESO does not comment on VSLs or VRFs.

None

None

None

Under R8 it should be made clear that a TP should not be required to send their assessment to adjacent PCs and that PCs should not be required to send their assessments to TPs not in their footprint. Under R8.1: If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. This should not be required until the Assessment is final and could be an administrative intense task. The following wording is suggested for R8: R8. Each Planning Coordinator shall distribute its planning assessment results to adjacent Planning Coordinators and to any Planning Coordinator who indicates a reliability related need for the planning assessment results. Each Transmission Planner shall distribute its planning assessment results to adjacent Transmission Planners and to any other Transmission Planner who indicates they have a reliability need for the planning assessment results. R8.1 If a recipient of the Planning Assessment final results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments. AESO does not comment on VSLs or VRFs.

No

In note b of the steady state and stability section of Table 1, consequential generation loss is referenced; however, there is no definition of such. A definition of consequential generation loss that is defined similar to "consequential load loss" should be added. The definition for "Bus Tie Breaker" should be revised to clarify whether a breaker in a standard ring bus or breaker and one-half scheme should be considered a "bus tie breaker". "year one" definition changes have clarified what is intended. AESO does not comment on VSLs or VRFs.

No

Table 1 should appear right after the requirements and before the VSLs. AESO does not comment on VSLs or VRFs.

Yes

No

The proposed changes and comments need to be adequately addressed before any ballot.

Individual

Jay Teixeira

ERCOT ISO

* This requirement seems to be embedding information that should be contained in the MOD standards. Does this present double jeopardy? This requirement, measurement, and VSL are all about maintaining models – a MOD standard revision may need to be included or recommended to allow the focus of the TPL standard to be on transmission planning studies, not modeling. * Requirement 1.1.2 should read "all known outages of generation or transmission facilities with a duration of at least six months as appropriate for the timeframe represented by the particular model" * The moderate VSL category states "the System model did not use" – this is confusing as the model does not do anything. It should contain the latest data. We also want to ensure this is not implying that the studies must use the latest data – data changes continuously, and a study may never be complete if the data must be continuously updated. * Will any agreements made in R7 override the "each TP and PC" requirement? To clarify this, the requirement could be rephrased: "In accordance to the responsibilities assigned in R7, the responsible Transmission Planners and Planning Coordinators shall maintain System models for performing the studies needed to complete the required Planning Assessments. The models shall contain the latest data consistent with MOD-010 and MOD-012… "

* Requirement R2 (and throughout the standard) – What is meant by "its portion of the BES"? Will any agreements made in R7 override the "each TP and PC" requirement? To clarify this, the requirement could be rephrased: "In accordance to the responsibilities assigned in R7, the responsible Transmission Planners and Planning Coordinators shall prepare…" * Requirement 2.1.3: This is not needed if these outages are properly built into the model. * Requirement 2.1.4: This requirement applies to 2.1.1 and 2.1.2. Why does it omit 2.1.3? Should it be referring to 2.1.3 for P1 contingencies? * How will 2.1.4 be proven? What is the definition of "stress" in this context and what defines "sufficient" stress? What is "measureable change"? What is the expected response to the results of this analysis? For example, if the load forecast must double to "sufficiently" stress the system, is the expectation that facilities should be planned to respond to the stress? * Requirement 2.1.5: Including the spare equipment strategy will be difficult for a PC that doesn't own or manage the transmission equipment or the strategies. But if this inclusion is only done by a TP, the benefits of coordinating with other TPs may not be realized. * Requirement 2.2: If each entity is responsible to study the System peak Load of its area, but a PC is responsible for multiple TP systems, then what System Peak Load is the PC responsible to study – a model that includes the non-coincident peaks of all of the TP systems for which it is responsible or the coincident peak demand across the whole system for which the PC is responsible? * Requirements 2.4.1 and 2.4.2: These appear to have inconsistent references to defined terms. Should this be consistent? The NERC glossary states: "Off-Peak: Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand." "On-Peak: Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of higher electrical demand." "System: A combination of generation, transmission, and distribution components." * Requirement 2.6.2: Reads as if a change is being made to an existing study. It is confusing. Possibly restate: "2.6.2 For steady state, short circuit, or stability analysis: previous studies can be used only if a material change to the system has not occurred or if a change that did occur does not impact the study area." * Requirement 2.7: in each case throughout the standard, replace "planning events" with "planning events as defined in Table 1" and "extreme events" with "extreme events as defined in Table 1" * Requirement 2.7.2: It would be good to clearly state here or in 2.1.4 that results from stressing the system do not always need to be resolved.

* Will any agreements made in R7 override the "each TP and PC" requirement? To clarify this, the requirement could be rephrased: "In accordance to the responsibilities assigned in R7, the responsible Transmission Planners and Planning Coordinators shall perform…. " * Section 3.1 and 3.4 appear to be related. Confusing references can be eliminated by combining them and removing 3.4 as follows: "3.1. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES shall be identified and studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1. A list of those Contingencies and the

rationale for those Contingencies selected for evaluation shall be available as supporting information". * Similarly, Section 3.2 and 3.5 appear to be related. Confusing references can be eliminated by combining them and removing 3.5: "3.2. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and studies shall be performed to assess the impact of the extreme events. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted A list of the events and the rationale for those Contingencies selected for evaluation shall be available as supporting information."

* Will any agreements made in R7 override the "each TP and PC" requirement? To clarify this, the requirement could be rephrased: "In accordance to the responsibilities assigned in R7, the responsible Transmission Planners and Planning Coordinators shall perform…. " * Similar to comments provided in R3, Section 4.1 and 4.4 appear to be related. Confusing references can be eliminated by combining them and removing 4.4: "4.1. Those planning events in Table 1that are expected to produce more severe System impacts on its portion of the BES, shall be identified and studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1. A list of those Contingencies and the rationale for those Contingencies selected for evaluation shall be available as supporting information. " * Similarly, Section 4.2 and 4.5 appear to be related. Confusing references can be eliminated by combining them and removing 4.5: "4.2. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and studies shall be performed to assess the impact of the extreme events. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted. A list of those events and the rationale for those Contingencies selected for evaluation shall be available as supporting information. "

None.

None.

* Will any agreements made in R7 override the "each TP and PC" requirement? Would it be appropriate to say: " Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies and assessments. " * What kind of documentation will be acceptable to demonstrate "each entity's individual and joint responsibilities"?

* Will any agreements made in R7 override the "each TP and PC" requirement? To clarify this, the requirement could be rephrased: "In accordance to the responsibilities assigned in R7, the responsible Transmission Planners and Planning Coordinators shall distribute…. " * Include "within the interconnection" such as: "… distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners within the interconnection and to any functional entity that indicates a reliability related need for the Planning Assessment results" * Should "reliability related need" be defined? This appears in multiple standards.

No

* Planning horizon is not formally defined but used many times throughout the standards. If there is a need to define the Near- and Long-term Transmission Planning Horizons, then the transmission planning horizon itself also should be defined. Additional confusion on this issue is the use of Long-term Planning as a planning horizon of one year or longer, also not formally defined. We finally found this referenced in the NERC Drafting Team guideline, which is not an obvious place to look for a definition. * Year One is only used two times – once to define Near-term Transmission Planning Horizon and once in the TPL standard. If this is not used throughout the NERC standards, it should not be defined. As an alternative, the transmission planning horizon could be formally defined, with Near- and Long-term Transmission Planning Horizons defined as subsets of the main definition. This would eliminate the need for a formal definition of Year One. If Year One stays as a new definition, it seems to be too broad, potentially allowing for omission of a peak season in the study. For example, if Year One is the period 12 to 18 months from the end of 2009, then Year One is currently 2011. Why is the year 2010 not considered to be Year One. * Non-Consequential Load Loss is confusing – due to the base word "consequence". Consequential Load Loss is intended to be a load loss that is a result, or consequence, of the isolation. Non-Consequential Load Loss seems intended to imply it was not a consequence of the isolation. Although the standard attempts to define the term, this definition does not agree with the common English definition of the term. "Non-consequential" (or "Inconsequential") implies that the load loss is unimportant, minor or insignificant. This is the opposite intent of how this term is used in the standard, where it is used to mean the load that it is unacceptable to lose for a particular event. Alternatives could be "Direct Load loss" and "Indirect Load loss" to replace the two concepts that are included as Consequential and Non-Consequential respectively.

No

The references to the footnotes need commas – there are several references to footnote 19 and at least one to footnote 101.

No

* The implementation plan references revisions to the MOD standards. Should the team submit a SAR for the revision of the MOD standards to ensure TPL needs are considered? As stated in the comments for R1 – if the MOD standards are properly updated, there is no need to state MOD requirements in TPL-001. * Definition comments from Question 9 apply to implementation plan. * The Implementation

Plan references R1 and R8 to be effective within 12 months of regulatory approval. R8 per the implementation plan state that the responsibilities of the PC and TP will be defined. This appears to be R7 of Draft 4 and the requirement language does not align. Conversely, the Effective Date should be revised to ensure the references to the requirements align properly. As written it states the assessment should be available before the assessment is complete. * During the 24 month transition period, any entity that can prove compliance with the revised TPL-001 should not have to prove compliance to the old TPL-001 through TPL-004. * The SAR should state that TPL-005 and TPL-006 are to be retired. The only place this has been found is within the implementation plan. It is not an intuitive place to find this information.

No

ERCOT recognizes that much effort has been put into this standard. However, a lot of effort will be required to ensure documentation for the standard is sufficient, yet the benefit of the additional documentation effort required is marginal. For a standard like this, stating every possible issue and studying every possible scenario is not realistic and potentially will lead to complacency – very little planning outside the scope of this standard will be done regardless of the system needs.

Group

Northeast Power Coordinating Council--RSC

Requirement 1.1.1: Replace "Existing Facilities" with "Existing Facilities and Resources" so that it will be a lead in to the changes proposed for 1.1.6. Requirement 1.1.2 –Consideration of known outages should not be included in a planning assessment. Such outages are coordinated by operations and are only permitted if the system can be operated reliably, where assumptions may be different than those used in planning assessments. Including this as a requirement effectively means that the system must be designed to withstand three outages. In those cases where safety, or reliability, or both are a concern by long duration outages (e.g., more than one year), temporary Operating Protocols are implemented to mitigate their impact. During known outages for equipment upgrades or repairs there may be some increased exposure to load loss, which should be recognized as an acceptable exposure. If this requirement must be kept, the outages with duration in excess of a year should be considered, rather than those of six months. This type of event is sufficiently addressed within the existing testing requirements (P6) and therefore should be eliminated, beyond that such outages are reviewed and approved on an operational basis and should not be included in a planning standard. Known or "known planned" outages will not necessarily fall in the operations timeframe, and as such may not be subject to approval by operations departments. This is especially so given the fact that the earliest start date for Year One is 12 months beyond the current year. Requirement 1.1.5 – Interchange. Interchange usually refers to non-firm short-term economic transactions that often take place between Balancing Authorities to take advantage of their respective resources surplus (i.e. not needed for local reliability.) However, such transactions should not be modeled in the base case system representation, unless their neutrality to system reliability has been clearly demonstrated. For example, economic interchanges between New England and PJM through New York have an impact on the New York transmission system that may, at times, pose reliability constraints on the operation of the New York system. Requirement 1.1.6 – what are "resources required to supply load" – gens, HVDC, tie lines? Resources may not be exclusively sources supplying load. The focus should be on changes to resources. "Resources required to supply Load" should be replaced with New planned Resources and changes to existing Resources". NPCC suggests NERC develops a definition for "resource" or use the following definition found in NPCC Glossary of Terms, Document A-7: Resource — Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load. A Requirement 1.2 should be added to address the base assumptions for sensitivity and other issues' requirements. For Measure M1: Elaborate on "…hard copy format…". Does that entail maintaining a hard copy of the system model? It is impractical to retain system model information in a hard copy format. This provision should be dropped.

Requirement R2 (second line): " This Planning Assessment shall use current or past studies,…" should be replaced with "This Planning Assessment shall use current studies or qualified past studies as indicated in Requirement R2, part 2.6,…" Requirements 2.1, 2.2, 2.3, and 2.4--As written, are not clear. It is suggested to revise the language as follows: "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current studies or qualified past studies as indicated in Requirement R2, part 2.6. The following studies are required:" Requirement 2.1.2 – The use of the term "off peak" is a concern. The definition for this term is not provided, and can be read to say that it is any load level less than peak. This does not provide enough clarity to guide the required assessments. Requirement 2.1.3: It must be clarified that the reference to outages as listed in Requirement R1, part 1.1.2 must be limited to Planning Horizon. Refer to Requirement 1.1.2 in the response to Question 1. Requirement 2.1.4: Consistent with the suggestion made for Requirment 1.1.2 remove the last bulleted item in the list under Requirement 2.1.4 "Duration or timing of planned Transmission outages." The standard is referring to requirements for sensitivity without a reference to base cases. Refer to Comment on Proposal to add an item 1.2 Requirement 2.1.5: It needs to be clear that this is only an assessment, not a solution. Actions such as out of merit dispatch, operational restrictions, System reconfiguration can be part of a Corrective Action Plan if the System cannot meet performance requirements without the Facility in service. It can be reworded as –

"…an assessment of the impact of this possible unavailability on System performance shall be performed". Requirement 2.3: The requirement does not indicate a year to study. This should be modified to state that it is up to the Planner to determine the year of study within the Near Term Transmission Planning Horizon. Requirement 2.4.2: Same as 2.1.2 Requirement 2.4.3: Refer to the Comment for Question 1 to add a Requirement 1.2 Requirement 2.5: Revise language as follows: "…be supported by current studies or qualified past studies as indicated in Requirement R2, part 2.6." Requirement 2.7 – NPCC suggests changing the word "run" to "condition" so the wording will read "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity condition in accordance with Requirements R2, parts 2.1.4 and 2.4.3." Requirement 2.9 – It should not be necessary to identify the largest consequential load loss if the TPL standard does not limit the size of the consequential load loss. This requirement should be deleted. If it remains, it must be made clear that it be applicable only to Year One or Year Two.
Requirement 3.2: This requirement should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. Requirement 3.3.3: This requirement is already addressed in NERC Standard PRC-023 and reflected in the facility's rating and should be removed from TPL-001-1 since the standard already requires observance of facility ratings. Relay Loadability is handled in greater detail (as it should be) under the proposed PRC-023 standard, so no reference should be made in this standard, thereby introducing a double jeopardy issue. Requirement 3.4: It is strongly suggested that this requirement is made a sub-bullet of Requirement 3.1 to keep the related requirements together. Requirements 3.5--This requirement needs clarification as to what is specifically required for the "evaluation of possible actions." The list associated with Requirement 2. part 2.7.1 provides examples of possible actions, and leaving "evaluation" undefined offers the Planning Coordinator and Transmission Planner the leeway to use judgment in making their evaluations. Requirement 3.5 – NPCC strongly suggests making this a sub-bullet of Requirement 3.2 to keep the related requirements together. Provide clarification as to what is specifically required for the "evaluation of possible actions". Requirement 3.6 –Currently this requirement is not clear, and does not address any reliability issue. Clarification should be added that the "consequential generation" loss be excluded from the amount documented. Without the clarification, the Requirement should be deleted.
Requirement 4.1.1: This should be revised to only be applicable to generators interconnected to the BES. This may need an implementation period as not all existing units are interconnected in accordance with the standard as proposed. As written this applies to small generators and doesn't necessarily reflect reliability of the network. 20 MW is a recommended generator minimum size. Requirement 4.1.2: Simulating the tripping of a generator that pulls out of synchronism is presently not modeled and will require an implementation period. Requirement 4.2: This requirement should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. Requirement 4.4 – NPCC strongly suggests making this requirement a sub-bullet of Requirement 4.1 to keep the related requirements together. Requirement 4.5 – NPCC strongly suggests making this requirement a sub-bullet of Requirement 4.2 to keep the related requirements together. This requirement needs clarification as to what is specifically required for the "evaluation of possible actions." The list associated with Requirement 2. part 2.7.1 provides examples of possible actions, and leaving "evaluation" undefined offers the Planning Coordinator and Transmission Planner the leeway to use judgment in making their evaluations.
Voltage criteria are addressed by the VAR standards. Including a voltage requirement in the planning standards appears to be creating a double-jeopardy exposure. Also, implementing transient voltage criteria will require time. Replace "Each Transmission Planner and Planning Coordinator…" with "Each Transmission Planner OR Planning Coordinator…".
No comments.
No comments.
Requirements R8, 8.1, and Measure M8--There are a number of concerns with these requirements. There needs to be a specified time period upon which comments must be received. As written, there is no sunset on when comments may be made and therefore they must be responded to. Additionally, it is not clear if the 90-day response time may extend beyond the end of the year to maintain and maintain annual compliance. R8 also causes redundancy of distribution of assessments. There is no statute of limitation for comments. There is also potential conflict with the deadline for completing a study and when comments may be submitted (e.g. comments are received the day before the study is to be completed.) These issues must be addressed. This standard should not be used to remedy deficiencies in meeting the requirements of FERC Order 890. Therefore these should be deleted. If this requirement is retained the following revision to Requirement 8 is suggested: "Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to the functional entities that the Planning Coordinator and Transmission Planner recognize as having a reliability need for the Planning Assessment results." Compliance: 1.4 Data Retention: The Transmission Planner and the Planning

Coordinator may not be using the same software. If both are required to store the data, do they both have to have the software to use the data? Can this be changed to an 'or' such that one of them must retain the data and it can be up to them as to who it is? 1.4 – Data Retention, last bullet - this relates back to Requirements R8, 8.1, and Measure M8. "Three calendar years of the notifications" seems to be an unnecessary requirement, and should be deleted. As an alternative to deletion, the implementation of a rolling three calendar years of notifications could be considered.

No

Definitions – Year One – This still defines Year One as both a particular year AND a window. It cannot be both. Suggest rewording the second sentence to read: "This is further defined as beginning 12-18 months from the end of the current year." As currently defined Non-Consequential Load Loss could allow widespread or cascading motor stall. The language in the definition cannot be this generic. The text is broad enough that it could allow a voltage collapse. The definition is incompatible with Table 1a (BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur). The definition for the non-consequential load loss combined with Table 1 would prohibit any customer from tripping its own load for contingencies that indicate 'no' in the non-consequential load loss column. This is not practical and appears to be an unintended consequence of the change in definition. This requires a change in the definition or the table. It is suggested to redefine Non-Consequential Load Loss as "intended post contingency loss of load caused by operator or SPS (RAS) action."

No

There is confusion in interpretation of the Table 1 — When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading? Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft. Other footnotes appear to be mislabeled as well. If Extreme Events are not deleted from the standard, then a different number for the table for Extreme Events should be used. Extreme Events 2a – need to define towerline. Add language to replace towerline with structure. Table 1 Footnotes require a close editorial review. There are two number ones, and multiple items pointing to the wrong footnote or footnotes that don't exist (19, 101), etc. Several instances are discussed below but this is not an exhaustive list. Table 1 – Steady State & Stability Performance Planning Events - Note (a) – this note is placed under "Steady State & Stability" but issues of voltage instability, cascading outages, and uncontrolled islanding apply only to stability. NPCC suggests this note be relocated to "Stability Only." Table 1 – Steady State & Stability Performance Planning Events - Note (i) – this indicates that one cannot meet steady state requirements by depending on end-user owned equipment. Please clarify the purpose and performance requirement on this note with respect to end-user schemes and possible arrangements already in place to trip end-user equipment. Table 1, P4 – footnote reference in Category column needs to change from 101 to 10. Footnote reference in Event column lead-in description needs to change from 11 to 10. Table 1, P5 – As written, this requirement replicates a fault causing a loss of station anywhere that there is only one protection system. This is overly severe and would lead to the requirement for fully redundant protection systems at many stations. The use of the term "Protection System" in P5 is unacceptably inconsistent with the NERC definition of Protection System because it does not exclude the battery and its associated series elements. Battery systems should not be included. Table 1, P7 – for Event 1 (the loss of two adjacent circuits), this needs to specify if these are the same phase or different phases. Table 1 – Steady State & Stability Performance Extreme Events It appears that for Steady state, item 2, that item (a) is encompassed by (b). It if is not, what makes it different? Table 1, footnote #2 – typo – there is an erroneous comma in the phrase "are the fault types, that must be evaluated." Please remove said comma. Table 1, footnote #3, NPCC has asked NERC to put a lower bound on the HV but it seems that this remains unaddressed. More stringent performance requirements should be applied to Facilities that represent the backbone of the electric power grid and act as the medium for moving large amounts of power from production to various Load centers, rather than to those Facilities that directly serve end-use Load customers. However, as had been commented in preceding postings, the EHV breakpoint for these more stringent requirements, defined in note 3 of table 1 as "all Facilities greater than 300 kV", is not appropriately defined and should be reviewed. A uniform voltage-level threshold has not been shown to adequately cover all of the different power systems in North America, and significant additional costs will be incurred without proportional or measurable reliability benefits if this definition is not changed. The following is a proposed modification to the EHV definition "all Facilities greater than 300 kV…": "Facilities representing the backbone of the System, generally operating at voltages greater than 300 kV, as determined by the Planning Coordinator and approved by Regional Entity." In using such language, we believe that the extra investment required would go towards real improvement of the reliability of the Interconnected System.

Yes

No

There are still issues as indicated in the submitted comments that need to be addressed before this standard should go to ballot.

Individual

Milorad Papic

Idaho Power

R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. For R1.1.5 I suggest changing the wording from "Known commitments for Firm Transmission Service and Interchange" to "Known commitments for Firm Transmission Service or Interchange". It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.

The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies…", while R2.1 implies current studies must be used but can be supplemented by past studies. I suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies…" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies…" It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.

For clarity we suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits.

Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful and unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.

As worded R5 is unclear. I interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. I suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."

No

The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language follows Non-Interruptible Load loss other than: • Consequential Load Loss • the response of voltage sensitive Load • Load that is disconnected from the System by end-user equipment. This version uses the same wording but clarifies that the term "other than" applies to all three things.

No

As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. I believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.

No

Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.

No

Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, I believe modifications are necessary prior to

taking this standard to ballot.

Individual

James Tucker

Deseret Power

Comments: R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. For R1.1.5 we suggest changing the wording from "Known commitments for Firm Transmission Service and Interchange" to "Known commitments for Firm Transmission Service or Interchange". It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.

Comments: The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies…", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies…" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies…" It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.

Comments: For clarity we suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits.

Comments: Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.

Comments: As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."

Comments: Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?

No

Comments: The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language follows Non-Interruptible Load loss other than: • Consequential Load Loss • the response of voltage sensitive Load • Load that is disconnected from the System by end-user equipment. This version uses the same wording but clarifies that the term "other than" applies to all three things.

No

Comments: As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.

No

Comments: Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.

No

Comments: Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.

Individual

Adam Menendez

Portland General Electric Co.

PGE believes that the scope of the studies mandated by this requirement should be limited to elements energized at 200kV and above, elements included in generator interconnection, and elements included in interconnections with other utilities. PGE's 115kV system functions to provide "load service" rather than transmission and does not impact the grid in the same manner as the 230kV and 500kV elements that comprise PGE's transmission system. PGE further believes that the requirement to conduct off-peak studies should focus on the varied generation patterns and impact to recognized transmission paths (for WECC, those identified in the WECC Path Catalog) rather than including the full range of studies that are required for on-peak studies. PGE's transmission system is embedded within the larger regional transmission system of the Bonneville Power Administration, and studies of System Off-Peak Load will not reveal any meaningful data internal to PGE's system. Finally, PGE believes that the wording of R2.6.2 is so restrictive that the entire intent of the subrequirement would be negated. PGE believes that "material changes" is such a broad term that every past study would have to have such changes made to reflect the system as it currently exists. Therefore, a company seeking to use a past study to support its Planning Assessment would have to provide a "technical rationale" showing that the material changes do not impact performance results. An effort to demonstrate a technical rationale in a manner that would satisfy future auditors would in many cases be more burdensome than performing a new study.

No

PGE believes that this standard should not go to ballot without revisions to restrict the scope of the standard as outlined above.

Group

SERC Planning Standards Subcommittee

R1: MOD-010 and 012 are not directly applicability to the PC. References to other processes (e.g. tariff requirements or transmission owner agreements) that are utilized to provide this data may be desirable, but do not satisfy R1 as presently written. VSL: In the Moderate and Severe VSL, insert "responsible entity's" in front of the term "System model."

Part 2.1.4 and 2.4.3: delete the word "sufficient." We appreciate the deletion of the previous R2.9 on non-Consequential Load Loss from the previous draft of TPL-001-1. Part 2.9: Does this refer to customer loads only, or does it include pump-storage or compressed air generating plant pumping load.

It is not clear as to the expectations of standard drafting team for dynamic modeling of relays. Parts 4.1.2 and 4.3.3 imply that transmission relays may need to be explicitly modeled in the dynamic simulations. Is this the team's intent, please clarify? Part 4.3.1: add "when used as part of a protection system" to the end of the sentence. Part 4.3.3: add "when such devices affect the study area" to the end of the sentence.

The content in the severe VSL column should be split among the lower, moderate, and high categories, with failure to include one element as Moderate and two elements as High. It is stated that the Transmission Planner and Planning Coordinator shall have criteria specifying voltage limits, post-Contingency voltage deviations, and transient voltage response. How would an interaction with a third party system be handled? For example a contingency that occurs on a system that is within their voltage deviation criteria, but causes a voltage deviation violation on a neighboring system that has a more stringent criteria.

Comments: M6: The wording on this measure appears to have been copied from M3 or M4 but is not appropriate since R6 addresses criteria and methodology and not a study.

Comments: R8: It is not clear whether the assessment results must be distributed to all parties of interest, or if it would be sufficient to post the assessment at a central location, and distribute

information to access the information. Also, FERC Standards of Conduct issues would come into play in assuring that the information is available only to appropriate personnel. R8: It is not clear if the requirement to provide assessment results to adjacent PCs and TPs is required, or only upon a reliability related request. R8: The PC and TP responsibilities should be stated separately for clarity. Part 8.1: It is not clear what the form of the response to the comments should be – would an acknowledgement be sufficient, or would it be necessary to pursue a process of examining comments in detail and revising and reissuing the corresponding assessment? The requirement needs to be revised to make the above points clear.

No

With the simplified definition for Bus-tie Breaker, would a breaker in a standard ring bus or breaker-and-a-half scheme be considered a Bus-tie Breaker? Request the definition be revised to clarify this. Suggest revising the Non-Consequential Load Loss definition: Non-Interruptible Load loss other than (1) Consequential Load Loss and (2) the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.

No

Comments: Some of the footnote superscripts do not appear to have a corresponding reference in the footnotes, in the case of number 19 at several locations in the Firm Transmission Service column, and number 101 in the P4 cell in the Category column.

Yes

No

If the revisions recommended above are adopted, the standard would then be ready for ballot. We commend the drafting team for their efforts in preparing this draft standard for ballot.

Individual

Kasia Mihalchuk

Manitoba Hydro

Recommend removing "and shall represent projected System Conditions" from R1. This is already clearly contained in R1.1.1 through R1.1.6. If the drafting team knows of other projected system conditions then they should be listed in R1.1. "The System Model did not represent projected System Conditions as described in Requirement R1" should be removed from the severe VSL column. By failing to represent 4 or more of the requirements in 1.1.1 through 1.1.6, projected System Conditions are not represented.

R2.1.4.: The first sentence implies that all sensitivities should be studied. The second sentence refers to one or more. I suggest the following change to the first sentence: "....basic assumptions used in the model." (i.e. delete "for the list of items shown below." from the end of the first sentence.) R2.4.3: The exact same change as above in R2.1.4. R2.1.5: We assume the intent of the standard would be to perform an annual review of the inventory of spare equipment to determine if the spare strategy required updating. For example, if a transformer failed and the spare was moved into position, a new spare would be ordered to replace the failed one. During the period, when no spare was in place, additional assessments would be required to ensure meeting Table 1. Can the drafting team clarify? R2.5: The drafting team modified "material changes" to simply "changes" in R2.5. This does not add clarity. Given that R2.5 is related to Stability Analysis, perhaps "changes" could be modified to "changes that could impact stability or voltage". R2.6: Recommend changing "the study" to "the past study" and "an older study" to "an older past study" to ensure no confusion could result from past and current studies. Can the drafting team explain how a past study can have material changes in R2.6.2? Perhaps R2.6.2 could be deleted. VSL: We would recommend moving R2.8's VSL from Moderate to both High and Severe. R2.8 requires a corrective plan to be developed when the short circuit duty of a circuit breaker is known to be exceeded. This is safety issue and a reliability issue.

R3.2: Recommend changing "the list" to "the Contingency list" to add clarity and consistency.

R4.1.2: For P2 events, a generator that pulls out of synchronism must be tripped. Tripping of the generator could result in Interruption of Firm Transmission Service unless redispatch is allowed - Footnote 9 should be allowed. R4.1.3 states that "power oscillation shall exhibit acceptable damping as established by the PC and TP". There is no requirement for the PC or TP to develop criteria for acceptable damping. Requirement R5 or R6 should be expanded to require the PC and TP to establish criteria for acceptable power oscillation damping. R4.2: Recommend changing "the list" to "the Contingency list" to add clarity and consistency.

The R6 text does not match the Data Retention 6th bullet text "studies performed". The Retention 6th bullet text should be updated to reflect the R6 text "criteria or methodology used in the analysis to identify System instability". The R6 text does not match the M6 text. The M6 text should be revised as follows: replace "studies utilized in preparing the Planning Assessment" with "criteria and methodology to identify System instability used within its analysis".

Is there a need to retain comments and responses to comments for Requirement R8?

Yes

No

Table 1: 1. When two (or more) footnotes apply simultaneously they should be separated by commas; ot are these typos? 2. The P2 contingency "opening of a breaker without a fault" could be moved up to a P1 contingency. This is a higher probability event then a bus section fault. 3. P4, Event column: The 11 superscript, after the phrase "Loss of multiple elements....", should be a 10. In P3, should 19 be 9? 4. Footnote 9: The drafting team clearly permits generator redispatch coupled with curtailment of firm transmission service for multiple contingencies (P3-P5). We believe generator redispatch is appropriate for P1 and P2 as well. R2.7.1 lists several actions that are permitted to be used as corrective plans including Special Protection Systems, automatic generator tripping or manual generator runback to respond to both single and multiple contingencies. Any loss of generation will require redispatch to ensure emergency generation reserves are replenished and the system is ready for the next contingency. For contingency P1, loss of generator, load will not be lost because there are generation reserves, however redispatch will be required to restore these reserves. Footnote 9 should apply to P1 and P2 contingencies. 5. Footnote 11: This note is a reference for a common tower outage. I think the words "or common Right-of-Way" should be deleted from the sentence. It is obvious that circuits on a common tower must be on a common Right-of-Way. 6. Note b: Consequential generation loss could use a definition similar to consequential and non-consequential load loss to add clarity. The standard as written in R4.1.2 permits cascade tripping of generators due to pulling out of synchronism. Typically this has been defined as instability or cascade tripping and not permitted in the past. 7. Note i: note i implies that any voltage sensitive load or load dropped by end-user equipment shall not be used to meet steady-state performance requirements. However, given that this note is not included under the stability portion, does this mean that voltage sensitive load or load that is dropped by end-user equipment can be used to meet the TC and PC planning criteria established in R5? Induction motors could trip in the stability analysis if the transient voltage is low enough (non-consequential load loss). The R5 criteria will be met as long as the load is manually switched back in and the post-disturbance steady state loading is acceptable. Can the drafting team clarify the intent of Note i?

No

Requirement R8, as the standard is currently written, doesn't match the language on page 2 of the discussion provided by the drafting team (i.e. related to determining individual and joint assessments). The drafting team should flip Requirements R7 and R8 so that the implementation plan matches the intent or modify the implementation plan.

No

Individual

Tim Ponseti, VP

TVA System Planning

TVA agrees with the changes made in R1 - especially the minimum 6 month duration required for outages to be modeled. In R1.1.5, how should partial path transmission service be accounted for in the known commitments for firm transmission service and interchange? VSL: In the Moderate and Severe VSL, insert “responsible entity’s” in front of the term “System model” after the “or”.

In R2.1.4 and R2.4.3, TVA is concerned about the use of the words “sufficient” and “measurable” from a compliance standpoint. TVA believes that these words should be deleted or at least better defined to clarify the actual intent from the SDT on what is technically required for these sensitivity studies. TVA agrees with limiting R2.1.5 spare equipment strategy to just the P0, P1, and P2 single contingency categories. In R2.7.3, both Non-Consequential Load Loss and curtailment of Firm Transmission Service can be permitted if situations arise that are beyond the control of the TP or PC. However these actions are not useful for stability related issues. TVA suggests that for stability related issues, if situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the TP or PC is permitted to allow some generation to lose synchronism utilizing out of step relaying or other protection method to correct the situation that would normally not be permitted in Table 1. We appreciate the deletion of the previous requirement on non-Consequential Load Loss from the previous draft of TPL-001-1. R2.9: Recommend that this refers to customer loads only, and not to include utility loads such as pump-storage or compressed air generating plant pumping load.

In R3.3.3, TVA believes that relay loadability is already covered in PRC-023. TVA is concerned that including this requirement could result in possible double jeopardy if a utility was found non compliant with PRC-023. Is the SDT proposing that relay loadability be covered for all BES facilities or just those facilities identified in PRC-023?

For R4.1.2. Suggested change: For planning events P2 through P7: A generator that pulls out of synchronism shall be considered in the simulations and the resulting apparent impedance swings shall not result in the tripping of any Transmission System elements other than the generating unit and its directly connected Facilities. [Since often tripping a out of step generator reduces impedance swings, if the simulation shows acceptable impedance swings and voltage levels without tripping the generator, why would we be required to determine the tripping time and simulate tripping in each of the simulations that we have to run for these event categories? Without the suggested change involving the

word "considered", significant extra effort would be required to perform simulations for small generators with no added benefit in achieving the purpose of assuring that impedance swings from generators are not passing through lines on the Bulk Electric System for events P2-P7. 4.3.3. Suggested change: Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers when such devices impact the study area. Without this change, a significant amount of effort would be required (with no added benefit) to evaluate protection systems all over the grid that have little or no impact on the study area. R4.3.1: add "if reclosing is actually used as part of a protection system" to the end of the sentence.

In the VSL associated with R5, we believe that failure to define and document one of the criteria should be a moderate VSL, failure to define and document two criteria should me a high VSL, while failure to define and document three criteria should be a severe VSL. Otherwise failing to document only one criteria would result in a severe VSL.

M6: The wording on this measure appears to have been copied from M3 or M4 but is not appropriate since R6 addresses criteria and methodology and not a study.

In the VSL associated with R7, we believe that failure to determine and identify one responsibility should be a moderate VSL, failure to determine and identify two responsibilities should me a high VSL, while failure to determine and identify three responsibilities should be a severe VSL. Otherwise failing to document only one responsibility would result in a severe VSL.

TVA believes that the TP and PC are unnecessarily duplicating work as shown in R8 and in M8. TVA believes that just the PC should be responsible for this coordination. R8: It is not clear whether the assessment results must be distributed to all parties of interest, or if it would be sufficient to post the assessment at a central location, and distribute information necessary to access the results. Also, FERC Standards of Conduct issues would come into play in assuring that the information is available only to appropriate personnel. R8.1: It is not clear what the form of the response to the comments should be – would an acknowledgement be sufficient, or would it be necessary to pursue a process of examining comments in detail and revising and reissuing the corresponding assessment?

No

Is the 12-18 months referenced in the Year One definition actually from the start of the TA or the anticipated completion date of the same TA? Suggest revising the Non-Consequential Load Loss definition: Non-Interruptible Load loss other than (1) Consequential Load Loss, (2) the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment, and (3) utility loads such as pump storage loads, compressed air generating pumping loads, and scrubber loads, etc when such loads do not result in tripping of a generating unit.

No

In Header note j - the reference to footnote #1 should be removed. Are batteries included as part of Protection System for P5 events? P3 reference to footnote #19 under Initial System Condition and for Interruption of Firm Transmission Service Allowed should actually be footnote #9. P5 reference to footnote #19 for Interruption of Firm Transmission Service Allowed should actually be footnote #9. The reference to footnote #101 in the P4 category should actually be to #10. For Steady State notes under Extreme Events, events 2a and 2b should reference footnote #11 instead of #12. For Stability notes, event 2 should refer to footnote #10 instead of #11. In footnote #3, should there be an "or" before "as defined by the Regional Entity"?

No

TVA agrees with the inclusion of P1-2 and P1-3 in the 60 month implementation window. However TVA also strongly suggests that all Planning Events be included in the same implementation window where local load was allowed to be dropped in the past in footnotes b and c of the existing TPL standards. In the first bullet under Effective Date, both Non-Consequential Load Loss and curtailment of Firm Transmission Service can be permitted for certain events up to 60 months. However these actions are not useful for stability related issues. TVA suggests that out of step relaying or other protection method be allowed in for stability related issues when situations do arise that are beyond the control of the TP or PC. TVA is very concerned about the last paragraph in the Implementation Plan. TVA interprets this language to state that the entity is basically noncompliant if the mentioned Corrective Action Plans are not implemented within 60 calendar months. Due to the large amount of work that some utilities will have to meet these new requirements, TVA strongly suggests that the utilities be found compliant if the utilities are still putting a good faith effort forward in trying to meet the new standards, such as for constructing a long 500-kV transmission line that may take at least 10 years to construct TVA still believes that since breaker duty was not included in the previous TPL standards, this should also have a 60 month implementation window as well due to this now becoming a new TPL compliance issue. TVA noted this same comment in Posting #3; however, TVA requests that this be reconsidered due to being a new official TPL requirement like the other new requirements have with the 60 month implementation window. TVA is concerned that the 60 calendar month window for meeting the "raising the bar" requirements is still not adequate. For instance, it typically takes TVA 7 to 10 years to build a new 500-kV transmission line - including time required for such processes as federally mandated NEPA environmental reviews. Strongly suggest increasing this time window to 10 years.

No

TVA is very concerned about the tremendous amount of additional work that has been proposed for

both the steady state and for stability analysis. TVA believes that there will be very little payoff for these additional studies. TVA is concerned that the costs to meet the new requirements contained in this draft TPL will amount to between $1 billion to $2 billion with very little impact overall on the reliability of the Bulk transmission system. TVA is also very concerned about the increase in customer rates that will be required to support these new facilities.

Individual

Brian Keel

SRP

R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. For R1.1.5 we suggest changing the wording from "Known commitments for Firm Transmission Service and Interchange" to "Known commitments for Firm Transmission Service or Interchange". It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.

The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies…", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies…" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies…" It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.

For clarity we suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits.

Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.

As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."

Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?

No

The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language follows Non-Interruptible Load loss other than: • Consequential Load Loss • the response of voltage sensitive Load • Load that is disconnected from the System by end-user equipment. This version uses the same wording but clarifies that the term "other than" applies to all three things.

No

: As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.

No

Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.

No

: Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.

Individual

Vishal Patel

Southern California Edison (SCE)

R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. For R1.1.5 we suggest changing the wording from "Known commitments for Firm Transmission Service and Interchange" to "Known commitments for Firm Transmission Service or Interchange". It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.

The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies…", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies…" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies…" It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. Additionally, 2.4.2 is inconsistent with 2.4.1 with regards to language. It seems the intent of the Standards Drafting Team was to have the two consistent with each other. Specifically, the quote below, from section 2.4.1, is missing from section 2.4.2 (keeping in mind the word "peak" should be replaced with "Off-Peak". "System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable."

For clarity we suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits."

Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.

As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."

Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?

No

The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language follows Non-Interruptible Load loss other than: • Consequential Load Loss • the response of voltage sensitive Load • Load that is disconnected from the System by end-user equipment. This version uses the same wording but clarifies that the term "other than" applies to all three things.

No

As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.
No
Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
No
Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.
Individual
John Collins
Platte River Power Authority
Change R1.1.5 wording from "...Service and Interchange." to "...Service or Interchange."
No
1. Please make the definition for Non-Consequential Load Loss simple and straightforward. For example, Non-Consequential Load Loss: The planned shedding of firm load. (Note that phrases "firm load" and "firm load shedding" are used frequently in a dozen other standards.) 2. Move the remainder of the sentence about "the response of voltage sensitive Load including...by end-user equipment." from the Non-Consequential Load Loss definition to the Consequential Load Loss definition.
Yes
If clarity is given for the "Non-Consequential Load Loss Allowed" column of Yes/No that it refers to the planned shedding of firm load. (see my comment on Definition)
No
No, not until there is some form of common understanding, among the people reading this draft, of how to interpret from Table 1 (Planned and Extreme) all the contingency scenarios that will be required to demonstrate full compliance with the standard. It would be helpful if the Drafting Team spearheaded some workshops to walk us through how this might be done.
Individual
Gordon Rawlings
British Columbia Transmission Corp
none
none
none
none
none
none
none
None
Yes
No
1. Table 1 event indicates loss of one of the equipment. It appears to be silent on the event classification regarding multiple equipments within the same protection zone. Is this considered as a single contingency or multiple contingencies? Please clarify. 2. Table 1 P5 refers to the event on loss of multiple elements caused by the failure of a single protection system while clearing a fault on one contingency. For systems equipped with dual or redundant protections, is a protection failure still a valid concern? Shouldn't this contingency analysis be excluded from the requirement? Please clarify. 3. Table

1 Extreme Events under Stability section, there is a reference to protection failure during fault clearing. Again for systems equipped with dual or redundant protections the requirement should be reconsidered. Please confirm. 4. Table 1 Extreme Events under both Steady State and Stability sections, there is a reference to loss of transmission lines on a common right-of-way. Please consider adding a Footnote to define the common right-of-way using minimum length similar to the one used for circuits on common structure (Footnote 12). 5. Performance Table 1 Footnote Item 1 on definition of angular stability, it states "For Planning Event P1: No generating unit or units shall be allowed to pull out of synchronism." o The requirement of no unit pull out of sync is not clear. Does this apply to small generators connected to distribution or lower voltage class lines? Or this is only applicable to generators connected to BEC (i.e. 100kV and above) without intermediary transmission voltage line connections? 6. Table 1 Footnote Item 6 refers to the "reference voltage" for transformers. What is the purpose of a reference voltage? Is this used to determine a valid transformer contingency? If so, according to the present definition a 3 phase fault on the 138kV side of a 138/66kV transformer is not considered a valid contingency to be assessed. Is this the intent?

Yes

No

Group

NERC System Protection and Control Subcommittee (SPCS)

No

The Drafting Team should change the definition of Consequential Load Loss to clarify that load lost due to operation of remote backup protection is not Consequential Load Loss. Operation of remote backup protection is not Normal Clearing for a fault. Consequential Load Loss: All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by Normal Clearing initiated by the a Protection System operation designed to isolate the fault.

No

The Drafting Team should modify the P5 Category column in Table 1 to read "P5 Multiple Contingency (Fault plus Protection System failure to operate)." This addition will focus the P5 Category on the overall Protection System failure to operate. The Drafting Team should include requirements in P5 of Table 1 for simulating both single-phase and 3-phase fault types for Protection System failures to operate. P4 and P5 call for simulations with SLG faults. Prolonged clearing times that result from breaker failures or Protection System failures to operate increase the probability that the fault may evolve from single-phase to multi-phase, and that probability further increases in EHV substations due to the closer clearances of bus work and equipment. Whereas Breaker Failure times are more likely to be known and mitigated through Breaker Failure Protection Systems, the clearing times associated with Protection System failures to operate may be much longer, increasing the probability of evolving in to multi-phase faults. The phrase "or a protection system failure" should be removed from items 2a through 2e in the Extreme Event table following Table 1. If the initializing event is the SLG fault, its evolution to a multi-phase fault alone (due to a Protection System failure to operate) should not be considered an Extreme Event for stability analysis.

No

Inclusion of the changes proposed by the System Protection and Control Subcommittee (SPCS) drove the belief that the standard is not ready to go to ballot. Such changes would be substantial enough to invoke another round of comments by the Industry.

Group

Florida Power and Light

No entity that we know of provides specific reactive load forecasts. From the auditor's perspective, what is expected and acceptable for System models representing reactive load forecasts? Suggested change: "1.1.4 Real Load forecasts and future reactive Load assumptions" Not all system models can represent all "Known commitments for Firm Transmission Service and Interchange". The SDT needs to add "…that are expected to be utilized." to the requirement. 1.1.6 Recommend changing to "Resources expected to supply Load" The requirements seem to imply a difference in certainty between "known" and "planned". Known implies certainty, where planned implies less certainty, as in an assumption. Planned things can change but known things are much less subject to change. The drafting team should clarify the

distinction between the two terms or be more specific in the requirement as to what is expected rather than leaving it for interpretation as to meaning and intent.
The requirement clearly states that "For the steady state portion of the Planning Assessment …" it must perform simulations that show generator ride through voltage limitations under 3.3.2. However, ride through limitations are performed through stability simulations not steady state as required by R3. This is confusing as currently drafted, please provide clarity. Additionally, 3.2 requires studies to be performed to assess the impact of the extreme events. Yet, 3.3 requires analyses shall be performed but does not specify the events intended to study. Suggested language for 3.3 should say "Contingency analyses shall be performed to assess the impact of the extreme events and:" Under 3.3.1 it states that the Planner must simulate the removal of all elements that the Protection System would be expected to disconnect. Language should be included to allow the Planner to provide a rationale to assess more severe system conditions without needing to simulate the effects of Protection Systems. This would capture the intent of this requirement.
The requirement to distribute the Planning Assessment should not mandate distribution of a document but should be more flexible and allow for making the Planning Assessment available, such that those entities that need the information can have it readily available. R8 should be modified as follows: Each Planning Coordinator and Transmission Planner shall make available its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.
No
The definition of "Known Commitments" should explain how that would diferentiate between Planned Commitments Planning Assessment definition should be clarified as follows: Planning Assessment: Documented evaluation of (1) studies of future Transmission System performance and (2) Corrective Action Plans (included in studies) to remedy identified deficiencies. Non-Consequential Load Loss definition should be clarified as follows: Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, or (2) the response of voltage sensitive Load that is disconnected from the System by end-user equipment. The SDT should do a search through the document (and Table 1) on “cascading” and capitalize the “C” and delete “outages” where it appears after “Cascading”.
No
The P2-1 event needs to be clarified with its intent. In the SDT Consideration of Comments to the 3rd DRAFT posting, the response to Transmission Planning clarified that “There is no need to show a line energized up to the breakers that opened. The intent is simply to look for low voltage or thermal problems while supplying Load from one end of a normally networked line.” This could be accomplished by adding this to footnote 7 or re-naming the event “Opening of a Line Section w/o fault”.
No
Do not understand the parenthetical for P1-2 and P1-3. The language is confusing and needs to be clarified. Isn’t it referring to Consequential Load Loss that is allowed for P1 events?
No
Individual
James Starling
SCE&G
No Comments
Does R.2.9 refer to customer load only or does it include pumped storage facility pumping loads?
No Comments.
No Comments.
No Comments.
No Comments.
No Comments.
It is not clear if the requirement to provide assessment results to adjacent Planning Coordinators and Transmission Planners is always required or only upon a reliability related request.
Yes
Yes
Yes

No
As per our comments.
Individual
Catherine Mathews
NorthWestern Energy
As written R1.1.4, "Real and reactive Load forecasts", could mean that both Real and Reactive Load forecasts are required. Since most entities only forecast Real (MW) and apply a power factor for reactive (MVAR), wording could be changed to " forecasted demand and power factor" to clarify that forecasting reactive load is not required. In R1.1.5 Change "Firm Transmission Service and Interchange" to "Firm Transmission Service or Interchange". This way the requirement can be satisfied by either one or the other.
Short circuit analysis is a local issue. The reliability of the BES does not depend on the regular assessment of short circuit duty. Therefore, we believe short circuit analysis should be deleted from R2. The wording in R2.1 is unclear: Are new annual studies required each year or are qualified past studies acceptable if no changes have been made? R2 reads "This Planning Assessment shall use current or past studies…", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies…" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies…" Are the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3? Both are for Near-Term studies but for steady state and stability respectively. If they should align, the wording should be modified to be the same. As written R2.1.4, "Real and reactive Load forecasts", could mean that both Real and Reactive Load forecasts are required. Since most entities only forecast Real (MW) and apply a power factor for reactive (MVAR), wording could be changed to " forecasted demand and power factor" to clarify that forecasting reactive load is not required.
The wording in R3.3.3 should be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits. In R3.3.3 The term "loadability" needs to be defined. R3.5 needs to be modified. It would be better to combine R3.2 with R3.5. The first part of the requirement requires identification of events that produce more severe System impacts. The presumed reason that the other contingencies were not selected is because they were deemed to be less severe or non-credible. In any case, theoretically, there can always be examples of more severe Extreme Contingencies than the one selected for study. This can be achieved by simply choosing events that are even less credible. For example, if the Extreme Contingency studied was a simultaneous loss of 3 transmission lines with the failure of a redundant RAS (SPS), then an event resulting in the simultaneous loss of 4 lines with the failure of 2 sets of redundant RASs would be even more severe. Listing all possible extreme events could result in a limitless list.
R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. We suggest moving both R4.4 and R4.5 into R4.1 and R4.2, then R4.4 and R4.5 could be deleted. R4.3 is unclear whether the Contingency analyses need to be performed for all planning events or only the more severe events referenced in R4.1 and R4.2. R4.3 needs clarification. R4.3.1 requires considering the impact of both successful and unsuccessful high-speed reclosing. Since successful reclosing is a much less severe event, it seems unnecessary to assess both. If entities need to assess both, the assessment could be in the list of sensitivities. R4.5 needs to be modified. It would be better to combine R4.2 and R4.5. The first part of the requirement requires identification of events that produce more severe System impacts. The presumed reason that the other contingencies were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be examples of more severe Extreme Contingencies than the one selected for study. This can be achieved by simply choosing events that are even less credible. For example, if the Extreme Contingency studied was a simultaneous loss of 3 transmission lines with the failure of redundant RAS (SPS), then an event resulting in the simultaneous loss of 4 lines with the failure of 2 sets of redundant RASs would be even more severe. Listing all possible extreme events could result in a limitless list.
R5 could be interpreted to address both high voltage and low voltage criteria. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level." This way high voltage is definitely excluded.
None
None
The term "functional entity" needs to be defined.
No
The definition of Non-Consequential Load needs clarification. A possible revision is to list bulleted items in the definition: Non-Interruptible Load loss other than: • Consequential Load Loss • the response of voltage sensitive Load • Load that is disconnected from the System by end-user equipment. This way "other than" applies to all three bullets.

No

Several outages identified in Categories P2, P4, and P5 seem to result in the same elements being removed from service, even though the initiating event is different. Thus, the same scenario is evaluated more than once. Also, the footnote numbering is not correct. We would like the drafting team to conduct a workshop before this standard goes to ballot to educate the industry on what outages are required to be simulated for which Categories.

No

In the Effective Date section, 60 calendar months is allowed for Corrective Action Plans. When does the 60 month period start? From the day the problem is identified? From the modeled year? Or from the effective date of the standard?

No

Since the definition section needs to be changed, some wording in the requirements needs to be modified, and the footnote numbering in Table 1 need to be corrected, we believe another draft should be issued before taking this standard to ballot.

Individual

Dilip Mahendra

Sacramento Municipal Utility District

SMUD appreciates the diligence with which the SDT has responded to our earlier comments. SMUD offers the following comments on Draft #4 for the SDT's consideration: R2.1.4: To define a "sensitivity" case, the standard should first define a "base" case. If a sensitivity case is a more conservative scenario analysis than a base case, does an entity need to perform/document a Planning Assessment for both "base" and "sensitivity" or is a Planning Assessment that uses the "Sensitivity" case adequate? R2.1: The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies…", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies…" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies…". R2.1.4 and R2.4.3: The words, "by a sufficient amount" should be removed as it does not provide any more clarity. R2.1.5: The first part of the sentence calls for an analysis of the impact (of modeling the spare equipment strategy). The second part of the sentence that defines the applicable categories to study, starts with the words "The Planning Assessment…". Use of the defined words "Planning Assessment", broadens the study to both an impact assessment and providing details of a "Corrective Action Plan". The intent of the requirement should be made clear in the first sentence. R2.4.3: Suggest deleting the words "in the Planning Assessment". Since a corrective action is not required for all sensitivities (see R2.7), use of the defined term in this paragraph can be confusing. R2.6.1: SMUD agrees with allowing a study older than five years to be considered if a technical rationale can be provided. R2.9: The requirement to report the largest single consequential load loss should not be included in the standard. If it remains, it must be made clear that it be applicable only to Year One, and there should be additional clarification that the requirement to report consequential load loss (single number) is ONLY for the most severe contingencies studied for the P1 and P2 contingencies. Table 1 P1.3 and associated Note 5: Is the purpose of the 'reference voltage' to determine a valid transformer contingency (thereby, limiting the scope of R2.9)? R2.7 / Table 1, Notes e and i: Note (e) excludes references to load that is allowed to be dropped if it is NOT part of Non-Consequential Load Loss. This note should include such Load (if represented in the load forecast being studied as being part of the Demand Response) if it can be dropped within the time duration applicable to the Facility Ratings. Note (i): Since the definition of Non-CLL would allow interruptible load to be dropped, is note (i) stating that interruptible load cannot be dropped even if it meets the 'executable within the time duration' requirement?

R3.3.3: To implement this requirement, the standard appears to call for one more facility rating which is based on Relay Loadability. Is the intent to also model the protection system actions if this limit is violated? Should such a requirement be moved to the MOD or FAC standard with conformance subject to Note (f) of Table 1 (Facility ratings shall not be exceeded) and R3.3.1 (simulate the removal of all elements that the Protection System and other … are expected to disconnect…)?

R4.1.1: There appears to be a conflict between what is not allowed for a generator in R4.1.1 and what is allowed in Note (b) of Table 1 (…consequential generation loss – which is an undefined term – and hence can be interpreted as one sees fit). R4.3.3: It is unclear what is expected from this requirement. Are Protection personnel to take the results of the transient stability simulation and determine its impact on the Protection System? Or, is it that the Protection System should be properly modeled in stability simulations? If it is the latter, this requirement is already covered by R4.3.1 (simulate the removal of all elements …). R4.3.2: If done right, this requirement should be already complied with under R4.3.1. If it needs to be spelled out, a better place may be in the MOD Standards. R4.4 and R4.5: Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the

Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful and unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both, we suggest including the assessment in the list of sensitivities.
As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
No
Definition of Non-Consequential Load (Non-CLL): This definition excludes from the "Non-Consequential Load" only the "Interruptible" portion of Demand Response. The last SDT response to a comment on Draft #3 stated that there is no ceiling on the amount of DSM that can be utilitized (see Reference 1 below). Since Demand Response is more than just "Interruptible" demand, it is recommended that the exclusion in the definition for Non-CLL be broadened to include other relevant categories (see Reference 2 below) of Demand Response / DSM that is acceptable. Reference 1: pdf page 310, 337: SDT response related to DSM at http://www.nerc.com/docs/standards/sar/ATFNSDT_third_posting_comment_responses_2009Sept16.pdf Reference 2: http://www.nerc.com/docs/pc/drdtf/DADS_Phase_III_Final_090109.pdf, Figure 3 at pdf page 16, block under Capacity; and, associated definitions in Appendix III at pdf page 46 Use of the defined term "Planning Assessment" throughout the standard: Since the definition includes both performance evaluation (assessment) and corrective action to remedy identified deficiencies, its usage throughout the standard should be reviewed to ensure that it does not mandate corrective actions where the minimum requirement may be calling only for an assessment. The SDT should consider including a definition for "Spare Equipment Strategy". The SDT's comments on 'spare equipment strategy' (at pdf page 122 of Consideration of Comments on 3rd Draft) state that it is based on a directive from FERC Order 693. Directives that impact reliability should be translated in to a requirement in a Standard. Even the proposed scope of MOD-010-0 (reference http://www.nerc.com/files/2010-2012_RS-Development-Plan_Volume-I_II.pdf page 223) makes a reference to the strategy, but does not require it.
No
As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. Comments on notes have been provided with associated requirements.
No
Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
The SDT should develop a detailed sample assessment prior to balloting so that the SDT's hard work can be voted on by an informed ballot pool.
Group
Florida Municipal Power Agency, and its Member Cities, Lakeland Electric and Fort Pierce Utility Authority
The MOD standards for load forecasts (e.g., MOD-016 through 021) do not require submission of a reactive load forecast from the LSEs and RPs; therefore, why is it expected that the TPs and PCs use a reactive forecast that is not provided? From the auditor's perspective, what is expected and acceptable for System models representing reactive load forecasts? Suggested change: "1.1.4 Real Load forecasts and future reactive Load assumptions" Not all system models can represent all "Known commitments for Firm Transmission Service and Interchange". The SDT needs to add "…that are expected to be utilized." to the requirement.
As worded, 2.1 now seems to require power flow, short circuit and stability studies be done every year for the Near Term. Is this the intent of the SDT? There are smaller systems that do not require this (e.g., if a smaller system has nothing more change form year to year than a 1.5% load growth, and there is plenty of margin on various SOLs, why is another study needed?). FMPA suggests re-wording to: "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies or by qualified past studies as indicated in Requirement R2, part 2.6" Since 2.2 only has one sub-bullet, 2.2.1 ought to be collapsed into 2.2. We think it would read less confusing as well, see below for suggested phrasing: "The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by a current study of expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected,

supplemented with qualified past studies as indicated in Requirement R2, part 2.6." The short circuit studies of 2.3 should not only assess the fault current interrupting capability of breakers, but also circuit switchers and the momentary current carrying capability of other equipment, such as switches and substation bus. We recommend changing the phrase to: "The analysis shall be used to determine whether the fault current is within the momentary current carrying capabilities and/or fault current interrupting capabilities of (Elements or Facilities) using …. " Also, for the short circuit study of 2.3 (and 2.8), it is not necessary to study all of the contingencies, just P2. Taking other Facilities out in addition to the fault will only reduce fault current. Auditors may not be aware of that and maybe the standard could say that only P2 needs to be studied to reduce future confusion. In 2.6, "material change" is ambiguous, especially in regards to load growth. How much load growth is allowed before it is "material"? Is the intent of the SDT to have 2.7 apply to all previous bullets in R2? If so, then it could be made clearer by starting 2.7 with "For the analyses discussed in 2.1 through 2.5, and for the planning events shown in Table 1, when the analyses indicate …" 2.7 seems to have lost the reference to lead times for Corrective Action Plan(s) that were present in the existing TPL-001-0, TPL-002-0 and TPL-003-0 standards, is that the intent of the SDT? Since only two of the years in the near term need to be studied, and one of the year's in the long term study, there ought to be some method to determine when a Corrective Action Plan is needed, the lead time of that Corrective Action Plan, to give an indication of when activity needs to start to implement the Corrective Action Plan. The Planning Coordinator and Transmission Planner should not be responsible in 2.7 for any repercussion of an entity not implementing the Corrective Action Plan. Bullet 2.7 ought to be reworded to developing the Corrective Action Plan only and not implementation. For instance, 2.7.4 requires review of Corrective Action Plans. If a Corrective Action Plan calls for a major transmission addition, then that addition usually is in the domain of the Transmission Owner. If the Transmission Owner decides not to build the transmission upgrade for a variety of reasons (e.g., budgets, etc.), then the Planning Coordinator and Transmission Planner could end up being in violation of the standards through no fault of their own (e.g., even though curtailment of firm service would then be allowed in 2.7.3, if such curtailment would not solve the problem, e.g., if there is not enough pre-contingency re-dispatch available, then the Planning Coordinator would be in violation). Implementation of the Corrective Action Plan, however, is very important. FMPA suggests that another requirement be added to require Transmission Owners, Generation Owners, Transmission Operators, Generation Operators (latter two if there are operating schemes involved) within the planning area of the Planning Coordinators and Transmission Planners to implement the plan as determined by the Planning Coordinators and Transmission Planners, with another requirement requiring that the entities agree on the Corrective Action Plan. This would mean expanding the applicability of the standard. This new requirement ought to have a VRF of High because not implementing the Corrective Action Plan could have high risks. What is the reliability purpose of 2.9? Is it to identify the largest potential supply / demand mismatch? If so, the largest loss of source, usually about 1000 MW, will overwhelm this number. FMPA does not understand the reliability purpose of providing this number, especially since the power flow models already capture most of this information (e.g., amount of load connected to tap substations or radial feeds). This seems to be an administrative item with no reliability purpose, especially since it only applies to P1 (why does it apply to P1 – how can there be consequential load loss without a contingency, unless it's specific to 2.1.5?) and P2.
3.3.1, is the intent of the SDT that extreme events that may cause loading beyond relay trip settings (especially Zone 3) be simulated? There is no need for 3.3.3 since the Facility Ratings should already take this into account (FAC-008, R1.2.1 The scope of equipment addressed shall include, but not be limited to, … relay protective devices, …"). This adds unneeded burden to transmission planners in developing evidence for this that already exists elsewhere. In other words, by respecting Facility Ratings, we respect relay loadability.
4.1.1, suggest rewording "(a) generator being disconnected from the Bulk Electric System …", system as defined in the Glossary includes distribution, and we do not believe that is the intent of the SDT. 4.1.2, 4.3.1 and 4.3.3 essentially require modeling every Zone 3 (or higher, such as Zone 5) relay in each Interconnection (or at least in the Region under study and adjacent regions) because, in order to simulate the impact of a power swing on a distance relay, one would need to know the characteristics of the distance relay and how long the transient swing remains within that characteristic, which means modeling the relay. Is that the intent of the SDT? If so, FMPA suggests limiting these bullets to Facilities 230 kV and higher.
No comments
FMPA suggests adding the word "potential" into "… identify the potential for System instability …". The criteria and methodology may be used to determine if further analysis is warranted, e.g., if steady state voltages fall below 0.9 per unit, then do a voltage stability study, or something like that. Going below 0.9 does not mean voltage collapse, but, it may be an indicator to study it; hence, the word "potential".
The Measure and Data Retention for R7 is ambiguous. While the measure could be interpreted as not requiring a contract, the data retention uses the words "in force agreement" which implies a formal contract, where roles and responsibilities could very well be assigned in regional planning committee minutes and ensuing e-mail correspondence. Suggest changing the words to "Documentation of agreement on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence" in both locations.
No comment

Yes

No

Table 1, under Steady State & Stability, "a" states: "BES Transmission voltage instability, cascading outages and uncontrolled islanding shall not occur." There are small portions of the grid where there may be three long lines feeding a load, and if two of those two lines were lost (P6 for instance), the remaining line would go into voltage collapse losing a few hundred MWs of consequential load with no impact to the BES. FMPA suggests that the wording be appended by: "BES Transmission voltage instability, cascading outages and uncontrolled islanding shall not occur for P0 through P2. BES Transmission voltage instability, cascading outages and uncontrolled islanding causing a supply / demand mismatch of more than the largest single loss of source shall not occur." FMPA does not understand why a bus-tie breaker would be treated differently than another breaker. They both have the same chance of failure.

Yes

Group

Oklahoma Gas & Electric

R2.4.3 Not positive what this actually requires Transmission Planner to perform. Recommend compliance with requirement be the responsibility of the Transmission Coordinator. R2.9 OG&E has not provided this information in the past. Different sets of load flow models will result in different data results. Do not see any merit with providing information.

R 3.4, R3.5 There appear to be no standards of directions on identifying severe or extreme system impacts. OG&E does not like being held accountable to nebulas standards. Need more specific information.

R4 OG&E believes the Transmission Coordinator be held accountable for R4. The Transmission Coordinator should coordinate this type of study with the Transmission Planner for a regional look of the whole system. For example Southwest Power Pool should coordinate this type of study with the members of the Southwest Power Pool to better examine the entire region of the Southwest Power Pool. We do not see the need to duplicate the work. R4.4 & R4.5 There appear to be no standards of directions on identifying severe or extreme system impacts. OG&E does not like being held accountable to nebulas standards. Need more specific information.

R5 OG&E believes the Transmission Coordinator be held accountable for the transient voltage response portion of R5. The Transmission Coordinator should coordinate this type of voltage criteria with the Transmission Planner for a regional look of the whole system. For example Southwest Power Pool should coordinate this type of study with a stakeholder developed voltage criteria within the members of the Southwest Power Pool to better examine the entire region of the Southwest Power Pool. We do not see the need to duplicate the work.

R6 OG&E believes the Transmission Coordinator be held accountable for R6. The Transmission Coordinator should coordinate this type of study/documentation with the Transmission Planner for a regional look of the whole system. For example Southwest Power Pool should coordinate this type of study/documentation with the members of the Southwest Power Pool to better examine the entire region of the Southwest Power Pool. We do not see the need to duplicate the work.

We agree that it should be clearly stated who does what between the Transmission Planner and the Planning Coordinator. We feel like this will eliminate duplication of work and create a better overall regional examination of the electric grid.

R8 OG&E believes the Transmission Coordinator be held accountable for R8 and coordinate this type of data exchange to ensure a regional coordination effort is achieved.

No

R 3.4, R3.5, R4.4 & R4.5 There appear to be no standards of directions on identifying severe or extreme system impacts. This may need to be defined. Extreme events evaluated (last page of Table 1) – OG&E needs more specific information on what is defined to be an extreme event before offering support. It appears the number of possible combinations and permutations that could be run make any compressive study overwhelming to perform and would provide very limited benefits. This needs to be clarified.

No

Category P7 – OG&E supports as long as footnote 11 is included. Category P6 is an N-2 situation. OG&E does not support the wholesale study of every N-2 combination of contingencies even though one is allowed for the interruption of firm transmission service and non-consequential load loss. Establishing and maintaining operating guides associated with every N-2 set of contingencies is oppressive and would provide limited value. OG&E understands the need for targeted N-2 contingency studies; such as breaker failure. Category P5 – Need more specific description of "Protection System failure" before receiving OG&E's support. Category P4 – OG&E supports performing studies. OG&E also supports the differentiation between "DHV" and "HV". OG&E does not support developing operating guides for every

voltage or overload issue discovered. Category P3 – OG&E is concerned about the value of P3. Information about the expected value of performing studies for the category is needed before receiving OG&E support. Category P2 – OG&E supports even though there are a few minor issues. Category P1 – OG&E supports OG&E will need every bit of the 60 months time mentioned on page 3 under "Effective Date" to implement all indicated upgrades. There is benefit in hardening the OG&E electrical system for such protection system failures, such as P4 & P5, but it may not be cost effective. Comments – Stability Analysis Stability Analysis – Recommend Planning Coordinator will be responsible for running the stability analysis to assure NERC compliance. The Planning Coordinator and Transmission Planner should work together to prepare the data.

No

OG&E will need every bit of the 60 months time mentioned on page 3 under "Effective Date" to implement all indicated upgrades. There is benefit in hardening the OG&E electrical system for such protection system failures, such as P4 & P5, but it may not be cost effective.

No

This document needs to be cyrstal clear because of compliance requirements. It still needs some work to clarify some definitions and address duplication of work (between the Transmission Planner and Planning Coordinator).

Individual

Thad Ness

American Electric Power

Because the revised transmission planning standard now explicitly references short circuit analysis, we believe that there is a need for a parallel MOD standard to establish requirements for short circuit modeling and for a corresponding reference under R1, just as there are references made in R1 to MOD-010 (power flow models) and MOD-012 (stability models) . We recognize that such a MOD standard will not be addressed as part of this project, but we request that the SDT pass this comment on to NERC Staff.

R 2.6.2, as written, may lead to misinterpretation. Following are two alternative suggestions to remedy this issue for the SDT's consideration: 1) "For steady-state, short-circuit, or Stability analysis: the study shall be rendered obsolete by any material changes unless…" or 2) "For steady-state, short-circuit, or Stability analysis: the system shall not include any material changes unless…" While R3 (steady-state studies) covers 2.1 and 2.2 (steady-state assessments), and R4 (stability studies) covers 2.4 and 2.5 (stability assessments), there does not appear to be a corresponding requirement (short circuit studies) to cover 2.3 (short circuit assessments). We recommend that a new requirement be established and numbered to align between existing requirements R3 and R4.

No Comments.

We recommend inserting "unstable" in the requirement language as follows: "Simulate the impact of unstable transient swings on Protection System operation…" Our perception is that the wording of 4.3.3 is almost certain to require the representation of impedance relay characteristics on both ends of all lines in a study area in order to satisfy an audit, and would eventually require representation on both ends of all BES lines as all areas would be studied at some point. This sub-requirement would place a huge burden on transmission planning and protection engineering staff. Experience has shown that tripping of transmission lines or transformers on stable swings is extremely rare. The burden this sub-requirement would cause as presently worded is not commensurate with the expected benefit.

We believe that it is appropriate to eliminate the reference to transient voltage response as it is duplicative and unnecessary. System stability is already better addressed by other performance requirements defined in this standard.

M6 does not appear to align with the content of R6. M6 needs to be reworded to reference documentation of criteria or methodology rather than studies. Corresponding changes will also need to be made to the corresponding bullet under Data Retention.

No Comments.

No Comments.

Yes

Yes

In Table 1, footnotes 19 and 101 should probably read 9 and 10. Also, we suggest adding table borders in P4 to more clearly align the columns that correspond to Event 6 (similar use of table borders as was done in P2).

Yes

Yes

The SDT has done an exceptional job working through complex issues and varying perspectives to arrive at this solid draft. This version has significantly improved the standard and has raised the bar where appropriate to do so. With favorable consideration of comments from this round, the revised draft should be ready for ballot.

Individual
Bart White
Progress Energy Florida, Inc.
As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all appropriate parties to review PEF's previous comments to this effect.
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As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all appropriate parties to review PEF's previous comments to this effect.
No
As PEF is opposed to TPL-001-1 as a whole, we cannot comment on the details of the Implementation Plan, other than to say that given the fundamental inadequacies of TPL-001-1, PEF does not believe the Standard should be implemented at all. Given that the wording of Question 12 appears to imply that any general comments made in the Question 12 comments section would be unwelcome and disregarded, PEF would respectfully like to make the following comments regarding our overall position on TPL-001-1: PEF filed extensive comments for the 1st, 2nd and 3rd drafts of TPL-001-1 and voiced serious concerns about the consequences that Transmission Owners and ratepayers will undoubtedly face if TPL-001-1 were to be implemented. PEF respectfully asks the SDT to review PEF's previous comments, particularly from the perspective of the ratepayers. The average ratepayer in the U.S. is already experiencing high electricity bills based on fuel pass-through charges and electric utilities' needs to raise rates to successfully operate and maintain the system. Furthermore, the ratepayers have not been involved in this Standard drafting process, and indeed have not even been informed at even the most cursory level. PEF has pointed this out in previous comments, and the SDT's response has been inadequate. Given the erroneous approach of Table 1 in TPL-001-1 to gauge reliability based on whether or not firm transmission service or non-consequential load will be curtailed, implementation of the Standard will dramatically increase ratepayers' already-high rates with little or no appreciable reliability improvement. Additionally, Transmission Owners will be forced to reduce ATC in order to prevent compliance violations, thus shutting out Power Marketers and potentially resulting in construction of more new generation than is really needed. Another major conflict that TPL-001-1 will cause is a rift between the FERC/NERC regulatory environment and the various states' Public Service Commissions (PSC). The major transmission projects that TPL-001-1 will mandate (especially those mandated due to the overly burdensome and unnecessary > 300 kV section) will have to be approved for permitting and funding through Determination of Need hearings at the PSC. When questioned by the PSC on the need for such projects, Transmission Owners will be obligated to admit that the projects really aren't needed but for NERC's new TPL-001-1 Standard, which will undoubtedly result in the PSC's denial of approval. PEF also would like to note that the SDT still has not provided sufficient reason for the need to implement a new TPL Standard. PEF and its fellow members in FRCC have historically demonstrated excellent reliability while performing long-term Transmission Planning under the existing TPL Standards. There simply is no practical reason for improvement on the existing Standards. PEF is aware of the history of the drafting of a new TPL Standard, however, having reviewed FERC's direction to NERC in this matter. Regarding this, PEF feels that NERC should have pointed out the likely consequences to merely following FERC's directions in their entirety; instead, NERC formed a SDT which proceeded to draft a new TPL Standard that satisfied each and every direction FERC had given. This approach has resulted in a draft Standard that is much too stringent, not conducive to significant reliability improvement and prohibitively expensive to implement. In conclusion, PEF strenuously opposes TPL-001-1, and feels the implementation of TPL-001-1 is unfair, irresponsible and unnecessary. PEF furthermore feels that it has sufficiently proven this in previous comments, and will continue to seek additional avenues to ensure that said comments are given proper consideration. TPL-001-1 is thus not in a condition to go to ballot, and it would be highly inappropriate to send this Standard to ballot given the major concerns that PEF and numerous other utilities within NERC have

raised.

No

Individual

Terry Huval

Lafayette Utilities System

LUS is satisfied that the current version resolves the issues we raised as to R2.

The modified version resolves the confusion noted by several commenters in the earlier draft.

Yes

LUS generally supports the changes to the definitions and the changes to the rest of the standard. We appreciate the efforts of the SDT in responding to the many comments that were filed in response to version 3, and in crafting what appears to LUS to be a reasonable attempt to attain a consensus position, at least as we understand the result.

Yes

While LUS remains concerned as to the way in which what is now footnote 9 may be followed in operation in areas where there have been historic problems with the old "footnote b", we appreciate the clarifications that have been made, and recognize that this may be the best way to resolve an issue for the industry. Please note that there remains what appears to be a typographical error in Table 1, Category P3, under "Initial System Condition" in that the footnote reference is to footnote 19, which does not exist. The reference was to footnote 10 in v.3 and we assume that the correct reference here is to footnote 9, which used to be footnote 10.

LUS remains concerned as to the length of time permitted for implementation, and believes that it should be shorter, but would not oppose adoption of version 4, as it has now been clarified, if that is the only issue of concern. There may be ways, outside the standard development process, to limit the financial harms caused to others as a result of the failure to meet the clarified standard during the implementation period.

Yes

LUS believes that the current draft of the standard is a significant improvement on the previous draft, and that the standard is ready to go to ballot. While there are elements of the standard which we consider to be short of the ideal, we recognize that this has been a consensus-building process and that the version 4, as explained and clarified, is a compromise which may be the best attainable for the industry at the moment.

Individual

Jessica Rice

NV Energy

R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. For R1.1.5 we suggest changing the wording from "Known commitments for Firm Transmission Service and Interchange" to "Known commitments for Firm Transmission Service or Interchange". It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.

The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies…", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies…" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies…" It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.

For clarity we suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits.
Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
No Comments
No Comments
Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
No
The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language follows Non-Interruptible Load loss other than: • Consequential Load Loss • the response of voltage sensitive Load • Load that is disconnected from the System by end-user equipment. This version uses the same wording but clarifies that the term "other than" applies to all three things.
No
As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.
No
Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
No
Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.
Individual
L. Earl Fair
Gainesville Regional Utillities
I like the more simplified approach used in the requirement listing. As far as "using the latest data consistent with MOD-010 & MOD -012 data", I feel that unplanned or unknown system changes between the times when studies are actually ran for the long term planning process should not be an issue for any type of negative interpretation by a compliance auditor. I presently do not have a suggestion on how to guarantee such an understanding. Overall the revisions look good.
Combining 4 TPL standards into 1 standard makes for a situation that you will always be audited on all the covered functional areas instead of part of the functions in a given audit. Example, in 2009, TPL-004 was not part of the audit while the other 3 standards were part of the audit. Of course, you should always be current with all functional assessments. I use one assessment document to cover all the functional areas. I do like the added clarity on the time horizons for various studies. I find R2. part 2.1.5 to create a somewhat clearer focus on spare equipment strategy. But the created task could create a lot of work for a utility depending on its configuration and redundancy.
Even though I do assess my portion of the BES, I do so, not in an isolated, detached vacuum, but in light of its active connection to the rest of the FRCC Region and how, if at all possible, my small system could in any way be determined at the region level to have any impact in any of the functional areas of the entire region. So the requirements in this section are considered and assessed as "a part of the whole".
As generation and transmission elements are added to our small system, we evaluate the stability impact as part of its feasibility and impact studies. After installation and in each year of a critical conditions study at the regional level, our elements are considered in the regional priority listings to

determine if any stability issues need additional or continuous evaluation. Again, as a "part of the whole" our elements are considered and our assessment is based on these and other findings. Again, this revision seems to add clarity to this requirement and its parts. Good Job!
Voltage considerations can get lost in the various studies. This requirement brings focus to the voltage component which it rightly deserves.
I believe that this requirement is better defined and documented at the regional level with all involved parties contributing. If consensus is not achievable, then the exception utilities can create their own knowing that they need technically valid references to support their position.
Looks good.
The wording could be a little better to indicate that the PC and TP should always get each others planning assessments, but other entities need to indicate a reliability related need to get the same. I suggest making a second sentence and eliminating the word "and".
No
I still find the Non-Consequential Load Loss definition vague. But, I presently do not have anything better to offer and thus I can live with it.
Yes
Yes
Yes
Individual
Phuong Tran
Lakeland Electric
• Suggesting language "known planned" outages and in place of "known" outages • Suggesting language "real & reactive resources" in place of "Resources" • "within its respective area", how about ties?
Agree with the changes made to the spare equipment strategy requirement
No
Recommended the following changes to the HV definition: Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems, per the Regional Entity's BES criteria/definition. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems, per the Regional Entity's BES criteria/definition.
No
The effective section needs more clarification: The assessment and supporting studies in accordance with the new standard is not effective until two years after this new standard is approved, however, it is required (R8) that PCs and TPs distribute its planning Assessment and results to adjacent PCs and TPs one year after the standard is effective. Which standard does the SDT intend for the (the old TPL standards or the new TPL standard) PCs and TPs to use to assess their system during the first year after the standard is approved? R2 thru R7 (assessments and studies) becomes effective 2 yrs after regulatory approval. That means that utilities have three years left to build/upgrade the projects identified in the studies/assessment (which was not effective until the 2nd year). Three years might not be enough to build long EHV or HV lines to meet the standard requirement. What happens between year 5 and year 7? After year 5, utilities are not allowed to trip Non-Consequential Load or curtailment of Firm Transmission Service for those specific contingency listed. However, the utilities do not have to self report until year 7 ("60 months of the compliance date for R2 through R4")
Individual
Michael Ayotte
ITC Holdings
Comments: These requirements refer to new facilities which would include new generators. ITC requests clarification as to what constitutes a "new generator" that needs to be considered -- those in the queue, those with signed Interconnection Agreements, those under construction... What is the line of

demarcation between what is in and what is out? In addition to the above, ITC also requests clarification as to whether or not these requirements apply to new generators, who connect to the network as "Energy Only" resources and, are either, not required to construct facilities needed to meet reliability requirements or are allowed to operate as "Energy Only" until needed facilities are constructed. The CAP for these facilities is that they will be curtailed or other generation will be curtailed should "operating" violations occur. Under market mechanisms, these generators are allowed to operate if their energy prices are lower than other generators whose curtailment eliminates the violation, even though the curtailed generators have paid for the facilities needed to meet reliability requirements. As the standard is written, these requirements imply that all generators must be included in studies. Were we to do so, significant standards violations might result. Does the Transmission Owner have to study all violation scenarios or include all "Energy Only" generators in studies when the CAP is always the same: "Market redispatch". Please clarify study scenario requirements for "Energy Only" resources.

Comments: R2.1.1 – Are two distinct study years necessary if a transmission owner can demonstrate that loads within their footprint have minimal growth over the 5 year period, defined to be less than X% of growth? Since the standard requires a relatively large number of studies to meet performance requirements, an initial set of studies along with studies demonstrating that "CAPs work" seems sufficient during periods of load stagnation. R2.1.4, R2.4.3 & R2.7.1. These requirements refer to new facilities which would include new generators. ITC requests clarification as to what constitutes a "new generator" that needs to be considered -- those in the queue, those with signed Interconnection Agreements, those under construction... What is the line of demarcation between what is in and what is out? In addition to the above, ITC also requests clarification as to whether or not these requirements apply to new generators, who connect to the network as "Energy Only" resources and, are either, not required to construct facilities needed to meet reliability requirements or are allowed to operate as "Energy Only" until needed facilities are constructed. The CAP for these facilities is that they will be curtailed or other generation will be curtailed should "operating" violations occur. Under market mechanisms, these generators are allowed to operate if their energy prices are lower than other generators whose curtailment eliminates the violation, even though the curtailed generators have paid for the facilities needed to meet reliability requirements. As the standard is written, these requirements imply that all generators must be included in studies. Were we to do so, significant standards violations might result. Does the Transmission Owner have to study all violation scenarios or include all "Energy Only" generators in studies when the CAP is always the same: "Market redispatch". Please clarify study scenario requirements for "Energy Only" resources.

Comments: Assumptions regarding Low Voltage Ride Through (LVRT) capability are risky and not well understood. If the SDT feels this is a critical requirement that merits corrective action then we believe LVRT characteristics for various machine types should be developed through a NERC process. Without such "standards", it will be difficult to justify CAPs based on LVRT assumptions. For example, would the Transmission Owner (TO) or Generator Owner be responsible for the cost of VAR CAPs if an LVRT assumption were violated. Can a TO require an LSE to install automatic load shedding for an LVRT assumption when cascade or local load loss result from an LVRT assumption? In addition, as the SDT has already indicated, the industry is still in a learning curve regarding the dynamic behavior of certain loads. If LVRT capability is considered as a critical requirement, then what about High Voltage Ride Through (HVRT) capability? The violation of HVRT could also cause certain damages to the system. R3.4.1 – (contingency list coordination with neighbors) It's unclear as to the "measure" for this requirement. Do you give your neighbor a list of "contingencies" in your area. Should it include all categories (p1 thru p7 for example)? Does your neighbor have to study a cascade situation in his system caused by an outage in your system? Are joint studies merited? More importantly, if an outage in a neighboring system requires a CAP, who's responsible, particularly if the CAP involves the neighboring system. Does the neighbor have to have a CAP, according to this standard, if the violation is in your system, and the CAP is in his? Who pays? Are you putting a study burden on your neighbor when you do this? Do you include additional contingencies to ensure that you do not miss a contingency that might impact your neighbors system to avoid any potential compliance implication on you?

Comments: On R4.3.2: Assumptions regarding Low Voltage Ride Through (LVRT) capability are risky and not well understood. If the SDT feels this is a critical requirement that merits corrective action then we believe LVRT characteristics for various machine types should be developed through a NERC process. Without such "standards", it will be difficult to justify CAPs based on LVRT assumptions. For example, would the Transmission Owner (TO) or Generator Owner be responsible for the cost of VAR CAPs if an LVRT assumption were violated. Can a TO require an LSE to install automatic load shedding for an LVRT assumption when cascade or local load loss result from an LVRT assumption? In addition, as the SDT has already indicated, the industry is still in a learning curve regarding the dynamic behavior of certain loads. If LVRT capability is considered as a critical requirement, then what about High Voltage Ride Through (HVRT) capability? The violation of HVRT could also cause certain damages to the system. R4.4.1 - (contingency list coordination with neighbors) It's unclear as to the "measure" for this requirement. Do you give your neighbor a list of "contingencies" in your area. Should it include all categories (p1 thru p7 for example)? Does your neighbor have to study a cascade situation in his system caused by an outage in your system? Are joint studies merited? More importantly, if an outage in a neighboring system requires a CAP, who's responsible, particularly if the CAP involves the neighboring system. Does the neighbor have to have a CAP, according to this standard, if the violation is in your system, and the CAP is in his? Who pays? Are you putting a study burden on your neighbor

when you do this? Do you include additional contingencies to ensure that you do not miss a contingency that might impact your neighbors system to avoid any potential compliance implication on you?

none

none

none

none

Yes

none

Yes

none

Yes

none

No

Comments: In addition to our other comments, ITC offers the following feedback. The requirements are rather complex, yet the measures seem extremely simple. Have they been discussed in any detail and are they sufficiently described to insure and understanding of just what is expected (ie., Are the requirements sufficient as measures in and of themselves?) R2.1.5 for example discusses "spare equipment strategy for long-lead time facilities". If I have a 2p.u. xfmr, can I assume it spares all similar category transformers or would I have to study P0,P1 and P2 contingencies if it replaces a 3 p.u. xfmr. If I don't have a spare and can't meet P0,P1 or P2 contingencies without load shedding, do I need a CAP. See also our comments under R3.4.1. We haven't reviewed all requirements and all measures in this fashion but suggest the SDT do so.

Individual

John Pearson

ISO New England

R1.1.1 Make this read "Existing Facilities and Resources" so that it will be a lead in to the changes proposed for 1.1.6. R1.1.2 This type of event is sufficiently addressed within the existing testing requirements (P6) and therefore should be eliminated , beyond that such outages are reviewed and approved on an operational basis and should not be included in a planning standard. During known outages for equipment upgrades or repairs there may be some increased exposure to load loss, which should be recognized as an acceptable exposure. In the event that this requirement is maintained please change six months to one year. 1.1.6.. Resources may not be exclusively sources supplying load. Therefore the reference should not involve load. The focus should be on changes to resources and "resources required to supply load" should be replaced with "New planned Resources and changes to existing Resources" We suggest NERC develops a definition for "resource" or use the following definition found in NPCC Glossary of Terms, Document A-7: Resource — Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load. ADD 1.2 – The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions. The standard must describe base assumptions. M1 It is not practical to retain system model information in a hard copy form. This provision could be dropped. D.1.1.4 Data Retention: The Transmission Planner and the Planning Coordinator may not be using the same software. If both are required to store the data, do they both have to have the software to use the data? Can this be changed to an 'or' such that one of them must retain the data and it can be up to them as to who it is.

2.1.3: In the event that R1.1.2 is kept it must be clear that the reference to outage schedules as listed in part 1.1.2 must be limited to the Planning Horizon. Table 1 - There is confusion in interpretation of the table 1 — When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading? 2.1 – Language should be revised similar to R2.4 as follows: "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required:" 2.1.2 –Should be moved to the list of sensitivities currently in 2.1.4. (Off-peak needs to be more specifically defined). 2.1.4 Consistent with the suggestion made for section 1.1.2 please remove the last bulleted item in the list under section 2.1.4. "Duration or timing of planned Transmission outages." To define a sensitivity, NERC must define base assumptions. Refer to Comment on Proposal to add an item 1.2 2.2 – The language in 2.2 should be revised to be similar to 2.4 as follows: "The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required:" 2.3 This should be modified to state that it is up to the Planner to determine the year of study within the Near Term Transmission Planning Horizon. 2.4.2 This should be

deleted as it is covered under section 2.4.3. 2.4.3 To define a sensitivity, NERC must define base assumptions. Requirement 2.7 – We suggest changing the word "run" to "condition" such that it reads "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity condition in accordance with Requirements R2, parts 2.1.4 and 2.4.3." 2.9: The requirement to report the largest single consequential load loss under Requirement 2.9 should not be included in the standard. The TPL does not limit the size of the consequential load loss. If it remains, it must be made clear that it be applicable only to Year One or Year Two.
3.2 Item 3.2 should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. 3.3.2 This requirement is not practical unless a MOD is created so that known minimum generator steady state or ride through voltage limitations are used instead of assumed values. To create a MOD, collect the data, and incorporate the information into the studies will take time, which necessitates the need for an implementation period. Absent accepting this suggestion with respect to creating an MOD, please provide assumed minimum generator steady state or ride through voltage limitations as a standard reference for this analysis. 3.3.3 There appears to be a compliance double-jeopardy issue related to relay loadability. Relay loadability is handled in greater detail (as it should be) under the proposed PRC-023 standard, so any reference here should be deleted. 3.4 – It is suggested that this requirement is made a sub-bullet of Requirement 3.1 to keep the related requirements together. 3.5 and 4.5 – Both of these requirements need clarification as to what is specifically required for the "evaluation of possible actions." 3.5 – It is suggested that this be made a sub-bullet of Requirement 3.2 to keep the related requirements together. 3.6 Item 3.6 should be deleted since there is no limit defined in the standard.
4.1.1 This should be revised to only be applicable to generators interconnected to the BES. This may need an implementation period as not all existing units are interconnected in accordance with the standard as proposed. As written this applies to small generators and doesn't necessarily reflect reliability of the network. 20 MW is a recommended generator minimum size. 4.1.2 This will require implementation period. 4.2 Item 4.2 should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. 4.4 – It is suggested that this requirement is made a sub-bullet of Requirement 4.1 to keep the related requirements together. 4.5 – It is suggested that this requirement is made a sub-bullet of Requirement 4.2 to keep the related requirements together.
Voltage criteria is addressed by the VAR standards. Including a voltage requirement in the planning standards appears to be creating a double-jeopardy exposure. R5. Change to Read "Each Transmission Planner OR Planning Coordinator … Need time to implement transient voltage criteria.
R8, 8.1, and Measurement M8 – This standard should not be used to remedy deficiencies in meeting the coordination requirements of FERC Order 890. Therefore these should be deleted. If this requirement is retained the following is suggested: "Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to the functional entities that the Planning Coordinator and Transmission Planner recognizes as having a reliability need for the Planning Assessment results." Additionally, there is no statute of limitation for comments. There is also potential conflict with the deadline for completing a study and when comments may be submitted (e.g. comments are received the day before the study is to be completed.) These issues must be addressed. 1.4 – Data Retention: The last bullet is unnecessary and should be deleted from the standard.
No
As currently defined Non-Consequential Load Loss could allow widespread or cascading motor stall. The language in the definition cannot be this generic. The text is broad enough that it could allow a voltage collapse, the definition is incompatible with Table 1a (BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur). The definition for the non-consequential load loss combined with Table 1 would prohibit any customer from tripping its own load for contingencies that indicate 'no' in the non-consequential load loss column. This is not practical and appears to be unintended consequencetof the change in definition. This requires a change in the definition or the table. We suggest defining Non-Consequential Load Loss as "intended post contingency loss of load caused by operator or SPS (RAS) action."
No
We generally agree with the table however our issues are as follows: Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft. Other footnotes appear to be mislabeled as well. If Extreme Events are not deleted from the standard, then a different number for the table for Extreme Events should be used. There is confusion in interpretation of the Table 1 — When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-

consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading? P5 –The use of the term "Protection System" in P5 is unacceptably inconsistent with the NERC definition of Protection System because it does not exclude the battery and its associated series elements. Extreme Events 2a – need to define tower line. Add language to replace "tower line" with "structure". Table 1, footnote #3, change Regional Entity to Regional Reliability Organization.

Yes

No

It is closer, but there are still some unacceptable issues that need to be addressed. The single most important comment is to define the base assumptions for use in studies.

Individual

Darryl Curtis

Oncor Electric Delivery

The six month limitation of requirement 1.1.2. "Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months." is applicable to near-term and long-term Planning studies, but makes the new TPL-001 standard non-extendible to the near-term operational planning studies (next month, next week, or next day). During near-term operational planning periods, it is essential to include the impacts of ALL known outages in the operational analysis. It should be made clear that the TPL-001 Standard is not applicable to the Operational Planning Horizon. This non-applicability points out the need for a separate (but equal in scope) operational planning analysis standard. There appears to be a lack of clarity related to relay loadability and protection system redundancy. Relay loadability is handled in greater detail (as it should be) under the proposed PRC-023 standard, so any reference here should only be a placeholder. Similarly, the issues of redundancy are being addressed in more detail in a new proposed standard on protection system reliability. 1.1.2 – The requirement will result in the need to evaluate construction sequence in planning studies. 1.1.6 – What are "resources required to supply load" – gens, HVDC, tie lines? NPCC suggests NERC develops a definition for "resource" or use the following definition found in NPCC Glossary of Terms, Document A-7: Resource — Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load. 1.1.6 Resources are not serving load but are supporting network operations. ADD 1.1.7 – The standard is referring to requirements for sensitivity and other issues without a reference to base cases. It is recommended that each Region have a document that defines what constitutes "base case" conditions. M1 What does it mean to have a hardcopy of a system model? 1.4 Data Retention: The Transmission Planner and the Planning Coordinator may not be using the same software. If both are required to store the data, are they both required to have identical software to use the data? We recommend that the entities have an option to determine which of the two entities retains the information.

2.1.3: It must be clear that the reference to outage schedules listed in part 1.1.2 must be limited to the Planning Horizon. See the TIS comment tor R1. There is lack of clarity in the interpretation of certain rudiments of Table 1 — When the voltage class of the contingency element and the monitored element are different (one is HV and the other is EHV), which voltage class is the allowance for shedding of non-consequential load applied? For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are there allowances to shed load to keep the 345-kV from exceeding its load rating.? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, would there be allowances to shed load to keep the 138-kV from exceeding its load rating? 2.1 – Language should be revised similar to R2.4 as follows: "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required:" 2.1.2 – the term "off peak" is an issue. The definition just says less than peak. 2.1.4 Duration or timing of planned Transmission outages. In order to define a "sensitivity", NERC must define a base case. 2.1.5 There should be greater clarity to the fact that this is an assessment only, and not a solution. Actions such as "out of merit dispatch", "operational restrictions", "System reconfiguration" can be part of a Corrective Action Plan if the system cannot meet performance requirements without the facility in service. 2.2 – The language in 2.2 should be revised to be similar to 2.4 as follows: "The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required:" 2.3 The standard does not indicate a year to study. Is this the discretion of the Transmission Planner? [Review last comment/why doesn't this apply to stability?] 2.4.2 There should be greater clarity to the term "Off peak" Should the Transmission Planner have more discretion in selecting load level. Is there a need for this requirement? 2.4.3 To define a "sensitivity" a base case must be defined for comparison. Requirement 2.7 – suggest changing the term "run" to "condition" in "Corrective Action Plan(s) does not need to be developed solely to meet the performance requirements for a single sensitivity run(?) in accordance with Requirements R2, parts 2.1.4 and 2.4.3." 2.7.2 See previous comments on sensitivities. 2.9: The

requirement to report the largest single consequential load loss under Requirement 2.9 should not be included in the standard. If it remains, provide greater clarity that there is applicability only to Year One. Furthermore, additional clarification is needed to ensure that the requirement to report consequential load loss (single number) is ONLY for the most severe contingencies studied for the P1 and P2 contingencies. 2.9 – Why is it necessary to identify the largest consequential load loss if the TPL standard does not limit the size of the consequential load loss?

3.3.2 Do we want to be able to trip gen? 3.3.3 Relay loadability covered in PRC-023 3.6 Why is this information reported if there is no limit or reliability consequence. 3.3.3 – This requirement is already addressed in NERC Standard PRC-023 and reflected in the facility's rating and should be removed from TPL-001-1. 3.4 – It is strongly suggested that this requirement is made a sub-bullet of Requirement 3.1 to keep the related requirements together. 3.5 and 4.5 – Both of these requirements need clarification as to what is specifically required for the "evaluation of possible actions." 3.5 – It is strongly suggested that this be made a sub-bullet of Requirement 3.2 to keep the related requirements together. 3.6 – It is recommended that the "consequential generation" loss is excluded from the amount documented. [Why?]

Within "stability requirements" there is no requirement for evaluating the loss of all generators in a station; it is included in the steady state requirements. We recommend that the standard require examination of all units in a generating station where single line-to-ground faults on generation station buses could result in clearing of the entire station. Furthermore, single phase faults with delayed clearing (or stuck breaker) are not included. Often, such exclusion of stability analysis for loss of all generators at a station – these are things that happen! 4.1.1 This should be dropped. As written, this applies to small generators and doesn't necessarily reflect reliaiblity of the network. 4.1.2 This is not presently modeled and will require implementation period 4.2 Why do we need to do study extreme events? The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. 4.4 – It is strongly suggested that this requirement is made a sub-bullet of Requirement 4.1 to keep the related requirements together. 4.5 – It is strongly suggested that this requirement is made a sub-bullet of Requirement 4.2 to keep the related requirements together.

Voltage criteria is addressed within the VAR standards. This appears to be redundant.

8.1 This requirement should be removed because it appears redundant to FERC 890. (suggest having one statement or the other) However, if it isn't, then the Term "documented" in R8.1 – the term documented needs to be defined. Suggest adding the qualifier "written " i.e., "If a recipient of the Planning Assessment results provides 'documented written' comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a 'documented written' response to that recipient within 90 calendar days of receipt of those comments." The requirement to distribute reports to entities with "need" has very significant CEII implications. This should be tightened to a "bona fide reliability need" for the information, requiring CEII or confidential material handling procedures. R8, 8.1, and Measurement M8 – There is no statute of limitation for comments (Suggest clarifying what we mean here – assume we are note referring to the NERC Standards Commenting Process), nor is there a limit on the number of comments. There is also potential conflict with the deadline for completing a study and when comments may be submitted (e.g. comments are received the day before the study is to be completed. If this requirement is retained the following is suggested: "Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to functional entities that demonstrated a reliability need with concurrence from their planning coordinator for the Planning Assessment results." [I think there are issues still with this language. I think it needs to say "…and to the functional entities that the Planning Coordinator recognizes as having a reliability need for the Planning Assessment results."] Compliance 1.4 – Data Retention, last bullet - this relates back to Requirements R8, 8.1, and Measurement M8. This seems to be a nuisance requirement to get in trouble for. [Requirement is to keep 3 years of notifications related to R8 & 8.1.]

Yes

(Motor stall should not be included in this section) The language in the definition cannot be this generic. This becomes open to interpretation in Table 1. Localized load may not be an issue, but the text is broad enough that it could allow a voltage collapse.

Yes

Errata Changes - Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. Other Footnotes appear to be mislabeled as well. There is lack of clarity in the interpretation of Table 1 — When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from exceeding its load rating? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from exceeding its load rating? Table I, item "e" –It doesn't specify which units can be adjusted following the contingency. This seems to be similar to the fact that the standard doesn't address the base case.

Should the standard be clear that you can or cannot rely on generation redispatch? Should failure of a fast start generator to start up be included in the contingency, or is this another level of contingency? Table I, non-consequential load loss – under no circumstance is it acceptable to shed non-consequential load to address issues in a future looking system plan. Table 1 – Steady State & Stability Performance Planning Events - Note (i) – this indicates that one cannot meet steady state requirements by depending on end-user owned equipment. Please clarify the purpose and performance requirement on this note with respect to end-user UVLS scheme and possible contractual arrangement already in place to trip end-user equipment. Table 1, P7 – for the DCT, are these the same phase? Table 1 – Steady State & Stability Performance Extreme Events Steady state, item 2, isn't (a) covered by (b)? Table 1, footnote #3, NPCC has asked NERC to put a lower bound on the HV but it seems that this remains unaddressed. P5 – This test is overly severe since it could assume the total protection system failure and the system would have to rely on remote end clearing. Part of the problem seems to be that the battery is part of the protection system. The intent seems to have been to fail part of one system, not the battery. If the battery is to be excluded, then it should be clearly stated. Extreme Events 2a – The term "towerline" should be defined. We agree with the SDT that more stringent performance requirements be applied for the Facilities that do not directly serve end-use load but rather represent the backbone of the electric power grid and act as the medium for moving large amounts of power from production to various load centers. However, as HQT commented on previous draft, we strongly believe that the EHV breakpoint for these more stringent requirements, defined in note 3 of table 1 as "all Facilities greater than 300 kV" is not appropriately defined and should be reviewed. The SDT have not demonstrated that a uniform voltage-level threshold could adequately covers all different power system types in North America and we strongly believe that significant, additional costs will be incurred without proportional or measurable reliability benefits if this definition is not changed. We propose to modify EHV definition "all Facilities greater than 300 kV…" by the following " Facilities representing the backbone of the System, generally at voltage greater than 300 kV, as determined by the Planning Coordinator and approved by Regional Entity." In using such a language, we believe that the additional investment required would facilitate real improvement of the reliability of the interconnected System.

Yes

Yes

Individual

Scott Goodwin

Midwest ISO

Requirement R1: The Planning Coordinator may begin model building using provisions from tariff and/or other agreements such as its Transmission Owners agreement. While the data may be consistent with that provided in Mod 10 and 12, there may not be a direct correlation between the two sets of data. This could become burdensome for a Planning Coordinator to make that correlation between the two. Suggest the following wording for R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall reflect data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and/or data that is provided in accordance with tariff or transmission owner agreements. The models may be supplemented by other sources as needed including items represented in the Corrective Action Plan, and shall represent projected System conditions. Requirement R1.1.5: In the Moderate and Severe VSL, insert "responsible entity's" in front of the term "System Models" so it reads as such: "The responsible entity's System model did not…"

Requirement R2.1.4: It should be made clear that the sensitivity findings do not obligate the PC or TP to establish Corrective Action Plans to address any needs identified in the sensitivity cases. Also, the use of the following two words "sufficient" and "measurable" are too vague and hard to quantify. This may require an auditor's opinion. Suggest at least removing the word "sufficient" from the requirements. Requirement R2.1.5: This requirement states that we need to perform prior outage analysis for P0, P1 and P2 events for all long-lead time (>1year) components without spares. This seems redundant with P3 and P6 which will answer whether those events are an issue. Need to be clear that loss of load is or is not allowed for these events. P2 still allows for some loss of load. Bottom line is that P2.1.5 seems duplicative. What is intent of requirement? Rather say the P3 and P6 should note if long-lead time items are involved without spares. Also, the Planning Coordinator could have an administrative burden demonstrating compliance with a spare equipment strategy for its entire footprint. Requirement R2.4.3: the use of the following two words "sufficient" and "measurable" are too vague and hard to quantify. This may require an auditor's opinion. Suggest at least removing the word "sufficient" from the requirements. Requirement R2.7.2: As suggested in the comments above for R2.1.4, it should be clarified that corrective actions are not necessary for performance deficiencies identified by sensitivity studies. Request removing this requirement all together. If the SDT agrees to keep this requirement then we offer the following comments: It is not clear how an entity can provide rational for why actions were not necessary. Requirement R2.9: With regards to the largest consequential loss of loads for P1 and P2 events; if no action is required then why require the entities to provide this. Will it matter if 10MW or 100MW is tripped with the line? This is a system design issue which is not addressed by the standards, if this requirement is kept how is an entity expected to demonstrate compliance for this?

This requirement is an administrative burden and we propose to remove R2.9 all together considering that there is not a reliability-related need for this information and it is unnecessary.
Requirement R3.6: With regards to the Generation Runback MW reporting; if no action is required then why require the entities to provide this. Will it matter if 10MW or 100MW is part of the generation runback scheme tripped with the line? This is a system design issue which is not addressed by the standards, if this requirement is kept how is an entity expected to demonstrate compliance for this? This requirement is an administrative burden and we propose to remove R3.6 all together considering that there is not a reliability-related need for this information and it is unnecessary.
Requirement R4.3.1: Please consider adding the following language to the end of the sentence "when used as part of a protection system". Requirement R4.3.1: Please consider adding the following language to the end of the sentence "when such devices affect the study area".
Requirement R5: Not all Transmission Planners have delta voltage criteria which this requirement will now require them to have. Looks like this requirement is not a one shoe fits all requirement.
No comment!
No Comment!
Requirement R8- It should be made clear that a TP should not be required to send their assessment to adjacent PCs. Likewise the PCs should be required to send their assessment to TPs not in their footprint. Please consider the following language change for R8: Each Planning Coordinator shall distribute its planning assessment results to adjacent Planning Coordinators and to any other Planning Coordinators who indicate they have a reliability related need for the planning assessment results. Each Transmission Planner shall distribute its planning assessment results to adjacent Transmission Planner and to any other Transmission Planner who indicates they have a reliability related need for the planning assessment results. Requirement R8.1: This should be clarified such that this requirement is only required on Assessments that are completed and posted as final. If not, this could be an administratively burdensome task for an entity to have to respond to each and every comment and then document that they did respond within 90 days. Please consider the following language changes for R8.1 If a recipient of the Planning Assessment's final results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.
No
Definition Section: The definition for "Bus Tie Breaker" should be revised to clarify whether a breaker in a standard ring bus or breaker and one-half scheme should be considered a "bus tie breaker". Definition Section: We believe that the "Year One" definition changes have clarified what is intended. Definition Section: We suggest having the following definition of Consequential Generation Loss added to the definition section. Consequential Generation Loss - All generation that is no longer connected to the transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.
No
Table 1 – Steady State & Stability Performance Planning Events, Note "b": It states that consequential generation loss is acceptable; however, there is no definition of this in the definition section. We suggest having the following definition of Consequential Generation Loss added to the definition section. Table 1 – There appears to be a few typos on P3, P4 and P5 note references because there are no Note 19 nor Note 101. Please clarify this. Table 1 – Steady State & Stability Performance Planning Events: We believe that this table should appear right after the requirements but before the VSLs.
No Comment!
No
Only if the proposed changes and questions are adequately addressed.
Group
Southern Company
Part 4.3.1: add "when used on the system" to the end of the sentence. This is needed to clarify that you don't have to study high speed reclosing if you don't utilize it.
M6: The wording on this measure appears to have been copied from M3 or M4 but is not appropriate since R6 addresses criteria and methodology and not a study. Replace the word "studies" with "criteria or methodology".
For additional clarity in who should receive the assessment, we recommend replacing "indicates" with "has" and adding words to the end of the sentence so that it states the following: "and to any functional entity that has a reliability related need for the Planning Assessment results and provides a written request." For Part 8.1, we do not believe the intent is for casual emails to be documented and formally responded to. And we do not believe that anyone who happens to receive the assessment

should be able to comment. Therefore, we recommend the following wording: "If one of the above named entities provides formal written comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments." If these recommendations are accepted, then the wording of M8 would have to change accordingly.

Yes

Suggest revising the Non-Consequential Load Loss definition for additional clarity to the following: Non-Interruptible Load loss other than (1) Consequential Load Loss and (2) the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.

Yes

Some of the footnote superscripts do not appear to have a corresponding reference in the footnotes, in the case of number 19 at several locations in the Firm Transmission Service column (should be 9), and number 101 in the P4 cell in the Category column (should be 10). In header note j, the reference to footnote 1 should be removed. In steady state extreme events 2a and 2b, the reference to footnote 12 should be to footnote 11. In stability extreme events 2a through 2e, the reference to footnote 11 should be to footnote 10.

Yes

Yes

Individual

John Sullivan

Ameren

R1.1.2: Inclusion of outages of generation or transmission facilities with a duration of at least 6 months in the models is too restrictive. An outage duration of 1 month would be more appropriate for inclusion in the seasonal peak and off-peak models. R1.1.5: It is not clear from the wording how Firm Transmission Service and Interchange schedules should be considered, or whether the status quo is adequate. A given generating facility may have transmission service commitments which exceed the facility's generating capability. VSL: Given the annual cycle of collecting, revising and submitting system model data under MOD-010 and MOD-012, there could be a lag of several months between receipt of updated data prior to having this data included in the next round of system models. The TP/PC should not be penalized for this.

R2.1.3: The wording for this requirement needs clarification. It is suggested that the following language be submitted as a replacement: Known outages of generation or Transmission facilities should be included in the models representing those System peak or Off-peak conditions when outages are scheduled. R2.1.4 and R2.4.3: The phrase "by a sufficient amount" should be modified to "by an amount". Also, in R2.4.3, "dynamic model assumptions" should be changed to "dynamic load model assumptions." R2.6.2: Recognition should be made of the fact that cancellation of generation or transmission projects, which may have been included in a previous study, would decrease fault levels, and would reduce or eliminate the need for short circuit analysis. R2.8: Would the Planning Coordinator be required to review, replicate, or validate short circuit studies? We appreciate the deletion of R2.9 from the previous draft of TPL-001-1 and eliminated the reporting of Non-Consequential Load Loss for each of the planning events. In R2.9, it is recommended that the largest Consequential Load Loss not include items such as pumped storage load or other utility load.

The readability of R3.3 could be improved with the following wording changes: 3.3 Contingency analyses shall be performed: 3.3.1 To simulate the removal… 3.3.2 To simulate tripping generators where simulations show… 3.3.3 And results reviewed to ensure relay loadability limits… 3.3.4 To simulate the expected… Requirement R3.3.1 needs to include language regarding the automatic restoration of facilities. The following language is suggested: To simulate the removal of all elements that the Protection System is expected to disconnect and the restoration of all elements that the automatic controls are expected to restore for each Contingency without operator intervention. Requirement R3.6: What is the purpose of this Requirement? We do not see how the reporting of this information adds to system reliability, and believe that this is more of a market issue. For those systems that are planned based on a single contingency, it is believed that numerous generation facilities would be impacted by the N-2 planning events and particularly those involving transmission facilities in the vicinity of power plant switchyards. Documenting manual or automatic generation runback or tripping of generation for the proposed P1 and P2 events is not unreasonable, but it is expected that developing runback or tripping schemes for the proposed P3-P7 events and reporting those contingencies and the amount of generation curtailed on an annual basis is of little value. Further, what information is to be reported for the P6 events for R3.6? As P6 events allow system adjustment following the first contingency (P1 event) to prepare for the second contingency (P1 event), is the runback information to be reported the generation that is to be curtailed after the first event (which should already be reported for the P1 category), after the second event, or after both events? In real-time operations, security constrained economic redispatch continually adjusts generation to maintain transmission facility loadings within ratings anticipating the next single contingency event. Does the Standards Drafting Team intend for the industry to report the amount of curtailed generation in

anticipation of the next P1 event?

It is not clear as to the expectations of the standard drafting team for dynamic modeling of relays. Requirements 4.1.2 and 4.3.3 imply that transmission relays may need to be explicitly modeled in the dynamic simulations. Is this the team's intent? If so, has the team given consideration to the availability of relay models in the commonly used Power System simulation software programs, and considered the cost and effort required for such implementation versus the expected benefits? Is there any historical experience that would imply that such modeling is crucial to the reliability of the BES? It is suggested that generators that pull out of synchronism be given consideration for their effects on the system, without requiring simulation of generator tripping in R4.1.2. Requirement R4.3.1 needs to include some additional language regarding the automatic restoration of facilities and allowance of high-speed reclosing. The following language is suggested: Simulate the removal of all elements that the Protection System is expected to disconnect and the restoration of all elements that the automatic controls are expected to restore for each Contingency without operator intervention while also considering the impact of successful or unsuccessful high-speed reclosing, if high-speed reclosing is employed. R4.3.3: Suggested wording addition: "for those devices relevant to the study area." A space needs to be added between "Table 1" and "that" in Requirement 4.4.

With respect to specifying a voltage level and maximum duration for transient voltage response, does it make sense for each Transmission Planner to have their own criteria? Should we be meeting an industry standard such as the ITI (CBEMA) Curve published by the Technical Committee 3 (TC3) of the Information Technology Industry Council (ITI, formerly known as the Computer & Business Equipment manufacturer's Association) and available at www.itic.org? Meeting any of the criteria to be developed for Requirement R5 will depend on the load model assumptions used. It is stated that the Transmission Planner and Planning Coordinator shall have criteria specifying voltage limits, pos-Contingency voltage deviations, and transient voltage response. How would an interaction with a third party be handled, particularly if one entity has more stringent criteria? The content in the severe VSL column should be split among the lower, moderate, and high categories.

M6: The wording on this measure appears to have been copied from M3 or M4 but is not appropriate since R6 addresses criteria and methodology and not a study.

R8: It is not clear whether the assessment results must be distributed to all parties of interest, or if it would be sufficient to post the assessment at a central location, and distribute information to access the information. Also, FERC Standards of Conduct issues would come into play in assuring that the information is available only to appropriate personnel. R8.1: It is not clear what the form of the response to the comments should be – would an acknowledgement be sufficient, or would it be necessary to pursue a process of examining comments in detail and revising and reissuing the corresponding assessment? The audience of those able to provide comments to the assessments should be appropriately limited, and not open to anyone who wishes to comment.

No

The definition of Bus-tie Breaker is unclear. This definition needs to be made clearer to remove issues regarding P2 and P5 planning events. We suggest the following additional language: A breaker in a standard breaker-and-a-half or ring bus configuration is not a Bus-tie Breaker. Suggest rewording Non-Consequential Load Loss definition: Non-Interruptible Load loss other than Consequential Load Loss. Non-Consequential Load Loss does not include the response of voltage sensitive Load or Load that is disconnected from the System by end-user equipment.

No

Some of the footnote superscripts do not appear to have a corresponding reference in the footnotes, in the case of number 19 at several locations in the Firm Transmission Service column, which should be changed to number 9, and numbers 11 and 101 in the P4 cell in the Category column that should be changed to 10. Table 1 - Steady State and Stability Performance - Planning Events, note c., and Table 1 - Steady State & Stability Performance - Extreme Events, note a. will need to be revised to address the restoration of facilities as described above in comments to Questions 3 and 5. A header is needed on the third page of Table 1 Steady State & Stability Performance. Table 1 – Steady State and Stability Performance – Extreme Events - Steady State: Superscripts on items 2a and 2b should be 11 rather than 12. Similarly, for the Extreme Events - Stability items 2a through 2f, the superscript should be 10 rather than 11.

No

We appreciate that the Standards Drafting Team has proposed delayed effective dates to allow tripping of Non-Consequential Load or curtailment of Firm Transmission Service for a number of categories of contingency events to allow more time to become compliant. However, we do not look forward to having to self-report non-compliance because the industry and the government changed the planning rules in the middle of the game.

No

Certainly the proposed assessment and documentation requirements are more comprehensive and the performance standards are more rigorous than the existing TPL-001 through TPL-004 reliability standards. But, by performing the proposed additional required studies and documenting the results, how much additional reliability will be provided to the System? None, but we will be auditably

compliant. More planning engineers will need to be hired to perform the studies and develop the assessments, more librarians will need to be hired to keep track of all the paperwork and computer file storage, and more trees will be killed printing the paper to send to all those that need to review the documents and provide comments. Is this the most effective way to improve transmission system reliability from a planning perspective? What measurable benefits are to be accrued for providing an EHV system that would not result in the loss of non-consequential load for P2-2, P2-3, P4 1-5, and P5 1-5 planning events, all of which are rare and infrequent? What is the estimated cost for this incremental "improvement" to cover the System's short-comings? The EHV system is already the most reliable portion of the BES with an availability of approximately 99% and can withstand extreme events without widespread outages.

Individual

Saurabh Saksena

National Grid

Sub-Requirement 1.1.1: Replace "Existing Facilities" with "Existing Facilities and Resources" so that it will be a lead in to the changes proposed for 1.1.6. Sub-Requirement 1.1.2: This type of event is sufficiently addressed within the existing testing requirements (P6) and therefore should be eliminated, beyond that such outages are reviewed and approved on an operational basis and should not be included in a planning standard. During known outages for equipment upgrades or repairs there may be some increased exposure to load loss, which should be recognized as an acceptable exposure. In the event that this requirement is maintained please change six months to one year. Sub-Requirement 1.1.6: Resources may not be exclusively sources supplying load. Therefore the reference should involve load. The focus should be on changes to resources. "Resources required to supply Load" should be replaced with "New planned Resources and changes to existing Resources" It is suggested that NERC develop a definition for "resource" or use the following definition found in NPCC Glossary of Terms, Document A-7: Resource — Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load. ADD 1.2 – The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions. The standard must describe base assumptions. Measure M1: Elaborate on "…hard copy format…". Does that entail maintaining a hard copy of the system model? It is impractical to retain system model information in a hard copy format. This provision should be dropped.

Requirement R2 (second line): " This Planning Assessment shall use current or past studies,…" should be replaced with "This Planning Assessment shall use current studies or qualified past studies as indicated in Requirement R2, part 2.6,…" Sub-Requirements 2.1, 2,2, 2,3, and 2.4: Language to be revised to the following: "…be supported by current studies or qualified past studies as indicated in Requirement R2, part 2.6. The following studies are required." Sub-Requirement 2.1.2: Definition of "off-peak" not provided and can be read to say that it is any load level less than peak. This does not provide enough clarity to guide the required assessments. Sub-Requirement 2.1.3: It must be clarified that the reference to outages as listed in Requirement R1, part 1.1.2 must be limited to Planning Horizon. Refer to Sub-Requirement 1.1.2 in Question 1. Sub-Requirement 2.1.4: Consistent with the suggestion made for section 1.1.2 please remove the last bulleted item in the list under section 2.1.4. "Duration or timing of planned Transmission outages." The standard is referring to requirements for sensitivity without a reference to base cases. Refer to Comment on Proposal to add an item 1.2 Sub-Requirement 2.1.5: It needs to be clear that this is only an assessment, not a solution. Actions such as out of merit dispatch, operational restrictions, System reconfiguration can be part of a Corrective Action Plan if the System cannot meet performance requirements without the Facility in service. It can be reworded as – "…an assessment of the impact of this possible unavailability on System performance shall be performed" Sub-Requirement 2.3: The requirement does not indicate a year to study. This should be modified to state that it is up to the Planner to determine the year of study within the Near Term Transmission Planning Horizon. Sub-Requirement 2.4.2: Same as 2.1.2 Sub-Requirement 2.4.3: Refer to Comment on Proposal to add an item 1.2 Sub-Requirement 2.5: Revise language as follows: "…be supported by current studies or qualified past studies as indicated in Requirement R2, part 2.6. Sub-Requirement 2.7: It is suggested to change the word "run" to "condition" such that it reads "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity condition in accordance with Requirements R2, parts 2.1.4 and 2.4.3." Sub-Requirement 2.7.2: Refer to Comment on Proposal to add an item 1.2 Sub-Requirement 2.9: It should not be necessary to identify the largest consequential load loss if the TPL standard does not limit the size of the consequential load loss. This requirement should be deleted. If it remains, it must be made clear that it be applicable only to Year One or Year Two.

Sub-Requirement 3.2: This requirement should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. Sub-Requirement 3.3.3: Relay Loadability is handled in greater detail (as it should be) under the proposed PRC-023 standard, so no reference should be made in this standard. It indicates a double jeopardy. Sub-Requirement 3.4: It is strongly suggested that this requirement is made a sub-bullet of Requirement 3.1 to keep the related requirements together. Sub-

Requirement 3.5: It is strongly suggested that this requirement is made a sub-bullet of Requirement 3.2 to keep the related requirements together. Provide clarification as to what is specifically required for the "evaluation of possible actions." Sub-Requirement 3.6: This requirement does not address any reliability issue should be deleted. If it is to be kept, it is recommended that the "consequential generation" loss be excluded from the amount documented.
Sub-Requirement 4.1.1: This should be revised to only be applicable to generators interconnected to the BES. This may need an implementation period as not all existing units are interconnected in accordance with the standard as proposed. As written this applies to small generators and doesn't necessarily reflect reliability of the network. 20 MW is a recommended generator minimum size. Sub-Requirement 4.1.2: Simulating the tripping of a generator that pulls out of synchronism is presently not modeled and will require implementation period. Sub-Requirement 4.2: This requirement should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. Sub-Requirement 4.4: It is strongly suggested that this requirement is made a sub-bullet of Requirement 4.1 to keep the related requirements together. Sub-Requirement 4.5: It is strongly suggested that this requirement is made a sub-bullet of Requirement 4.2 to keep the related requirements together. Provide clarification as to what is specifically required for the "evaluation of possible actions."
Voltage criteria are addressed by the VAR standards. Including a voltage requirement in the planning standards appears to be creating a double-jeopardy exposure. Also, implementing transient voltage criteria will require time. Replace "Each Transmission Planner and Planning Coordinator…" with "Each Transmission Planner OR Planning Coordinator…".
No Comments.
No Comments.
This standard should not be used to remedy deficiencies in meeting the requirements of FERC Order 890. Therefore these should be deleted. If this requirement is retained the following is suggested: "Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to the functional entities that the Planning Coordinator and Transmission Planner recognizes as having a reliability need for the Planning Assessment results." Additionally, there is no statute of limitation for comments. There is also potential conflict with the deadline for completing a study and when comments may be submitted (e.g. comments are received the day before the study is to be completed.) These issues must be addressed. Compliance: 1.4 Data Retention: The Transmission Planner and the Planning Coordinator may not be using the same software. If both are required to store the data, do they both have to have the software to use the data? Can this be changed to an 'or' such that one of them must retain the data and it can be up to them as to who is it. 1.4 – Data Retention, last bullet - this relates back to Requirements R8, 8.1, and Measurement M8. "Three calendar years of notification" seems to be a nuisance requirement to get in trouble for. This is unnecessary and should be deleted.
No
As currently defined Non-Consequential Load Loss could allow widespread or cascading motor stall. The language in the definition cannot be this generic. The text is broad enough that it could allow a voltage collapse, the definition is incompatible with Table 1a (BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur). The definition for the non-consequential load loss combined with Table 1 would prohibit any customer from tripping its own load for contingencies that indicate 'no' in the non-consequential load loss column. This is not practical and appears to be unintended consequent of the change in definition. This requires a change in the definition or the table. It is suggested to redefine Non-Consequential Load Loss as "intended post contingency loss of load caused by operator or SPS (RAS) action."
No
There is confusion in interpretation of the Table 1 — When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading? Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft. Other footnotes appear to be mislabeled as well. If Extreme Events are not deleted from the standard, then a different number for the table for Extreme Events should be used. Table 1, P5: The use of the term "Protection System" in P5 is unacceptably inconsistent with the NERC definition of Protection System because it does not exclude the battery and its associated series elements. Extreme Events 2a – need to define towerline. Add language to replace towerline with structure. Table 1, footnote #3, change Regional Entity to Regional Reliability Organization.
Yes
None.
No

It is closer, but there are still some unacceptable issues that need to be addressed.

Individual

Robert H. Easton

Western Area Power Adm - RMR

R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. For R1.1.5, I suggest changing the wording from "Known commitments for Firm Transmission Service and Interchange" to "Known commitments for Firm Transmission Service or Interchange". It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.

The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies…", while R2.1 implies current studies must be used but can be supplemented by past studies. I suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies…" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies…" It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. In R2.1.5 – the opening statement "When an entity's 'spare equipment strategy'…" Does this imply an auditor would ask for this documentation as part of the review of this new TPL-001? Also – what other Standard requires the "spare equipment strategy"? I'm trying to determine what kind of documentation is required for this Requirement.

For clarity, I suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits."

Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2, respectively. I Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful and unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both.

As worded, R5 is unclear. I interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. I suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."

N/A

N/A

Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?

No

The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language follows: Non-Interruptible Load loss other than: • Consequential Load Loss • the response of voltage sensitive Load • Load that is disconnected from the System by end-user equipment. This version uses the same wording but clarifies that the term "other than" applies to all three things.

No

As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. I believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any footnote in the document, and some other footnotes seem to be misplaced. I encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.

No

Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for

Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the Effective Date of this standard.

No

Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, I believe modifications are necessary prior to taking this standard to ballot.

Group

Pepco Holdings, Inc. - Affiliates PHI

While the SDT has stated in the Description of Current Draft that the issues of TPL-005 and TPL-006 have been addressed. It is not clear to PHI Affiliates that this is true. It is not evident how wide area planning is performed. Requirement 2 states Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES.

Yes

No

Category P5 should be more appropriately titled DELAYED CLEARING OR Loss of multiple elements caused by the failure of a single Protection System while clearing a fault on one of the following.... A protection system failure does not necessarily lead to loss of multiple power system elements. Sometimes it may just be delayed clearing of the faulted element. The recommended change is based on the SDT's response to comments submitted to Draft #2 of the standard˜ -A number of commenters expressed concern related to Planning Event P5 “Protection System Failure” and the need to evaluate a single component failure of a BES Protection System; particularly a failure of a station battery. The SDT has revised the P5 Planning Event description to remove the reference to “single component failure” and the event description was changed to match what is stated in the currently approved TPL standards under Category C6 through C9. --The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to normal fault clearing.-- A Protection System failure resulting in loss of the substation (one voltage level plus transformers) would not qualify as a P5 Planning Event since that event is considered an Extreme Event. Also, the phrase "failure of a single Protection System" should be defined. Draft #1 language used the term -single component failure- of a protection system. Based on a number of comments that were received, that term was subsequently replaced with the term -failure of a single Protection System-. To avoid confusion, this term needs to be defined within this standard and / or examples provided. If not, there will be confusion on how to study this category of events. This issue has been raised by numerous commenters throughout the standard development process. That fact that it continues to be expressed through numerous drafts indicates a lack of clarity as to exactly what protection system failures are to be studied. For example - Assume there are two protection systems on a facility (Scheme A and Scheme B). Assume one publishes a clearing time for Scheme A, and a slower clearing time for Scheme B. The TPL standard, as written, could imply that for a P5 failure of a single Protection System (scheme A or B fails) you would study the event assuming the worst case clearing time (i.e., using the slower clearing time for Scheme B.) Is that what is intended? If so, it should be so stated. However, that interpretation assumes the failure of a single Protection System would not effect the operation of the second Protection System. In other words it would not address single component points of failure, which could disable both Scheme A and Scheme B. Suppose both schemes were fed from the same set of CT's, VT's, battery, etc. Since the phrase "single component failure of the protection system" was eliminated, does this mean failure of both schemes due to a single component failure is not required to be studied under the P5 category? The standard must be very clear as to what contingency (i.e., what kind of protection system failure) is to be studied. It should not be silent on this point, nor should it refer to another standard for guidance on what contingencies to study.

Yes

No

Group

FRCC Transmission Working Group

Several questions on the details: - R1 requires the maintenance of system models for the purpose of studies and establishes that these models should be updated with the latest data from various sources. Read in context this seems to require that a PA/TP has models, and they are updated either on some

sort of regular schedule, for example quarterly or before the start of a study, and use the latest information at the time they are updated. Is this a correct understanding of the requirement? - R1 states that the model should be "..supplemented by other sources as needed, including items represented in the corrective action plan…" Read in context with the overall requirement this allows for projects that are in the corrective action plan to be added to the model as needed, is this the correct understanding? -R1 requires the model to represent "projected system conditions" which include in the list below "Known Commitments for Firm Transmission Service" and "Load Forecast". This seems to require that your known firm transmission service commitments are matched to their corresponding customers load forecast and expected operation profile, relative to load level in the case. Or phrased another way, the model should represent the service and load as they would be expected to operate at the load level in the case. Is this a correct understanding? Comments: With regard to the Moderate Violation Severity Level, what if the entity does not have the "latest" data but the entity did include items in the corrective action plan? Should the "and" between MOD-010 and MOD-012 be an "OR" and have the "AND" be for the High VSL? Not all system models can represent all "Known commitments for Firm Transmission Service and Interchange". The SDT needs to add "…that are expected to be utilized." to the requirement. 1.1.6 Recommend changing to "Resources expected to supply Load"

Please further clarify the definition when past studies may be used. Requirement 2, bullets 2.1, 2.2 appear to say that current studies must be used, but that additional information can be provided if desired and it meets certain requirements. Sub-Requirements 2.3, 2.4 and 2.5 seem to allow use of past studies that meet the requirements of 2.6 in lieu of new work. If this is the correct understanding then I suggest the following: For 2.1 and 2.2 revise the statement to read "…and be supported by the following annual current studies. The analysis may also include other current and past studies in addition to the annual current studies listed below. R2Bullet 2.6 should also be revised to read "Past studies may be used in lieu of current studies for Bullets 2.3, 2.4, 2.6 if they meet the following requirements:" This will insure that it is very obvious the planner, when they may or may not use prior art in place of new work and it's specified in all places in the standard where this is referenced. For these supplemental or "above and beyond" studies, 2.6 should not be referenced. First of all it makes it confusing, since 2.6 is primarily concerned with prior art being used in lieu of new work. Also if the material is supplemental, then it's supplemental and setting requirements on it will only reduce the material provided not improve the reliability of the system. -2.6.2 Consider revising "the study shall not include any material changes" to "the system represented in the study shall not include any material changes". Stating that "the study shall not include material changes" implies changes to the study from the time it was performed to the time it was used, not changes in the underlying transmission system which is what I think you are really targeting. -2.1.4 and 2.4.3: The statement "sufficient amount to stress the system…credible conditions…demonstrate a measurable change" implies that a sensitivity must meet three general criteria: (I will be using load forecast as an easy example, but obviously there is a range of items that could be used) 1. That it is expected to increase stress, for example increasing the load forecast would general increase stress, where decreasing it would not. 2. That increases should be substantial, for example growing the load at 2x the expected rate vs 1.01x the expected rate. 3. That the change doesn't have to exceed the bounds of credibility. If a 2x or 3x increase doesn't result in a stack of new constraints, it does not mean the increase has to go to 10x the forecast just to show extensive effects. Is this a correct understanding? , realizing that I'm only referencing load growth for simplicity, it not being the only sensitivity? -2.1.4 and 2.4.3: The first sentence "impact of changes to the basic assumptions used in the model for the list of items below", please consider changing to just "impact of change to the basic assumptions used in the model". Including the "list of items below" implies that all items must be addressed, which seems to conflict with the second sentence which specifically allows one or more. -2.7: Is the "Corrective Action Plan" intended to document all of an entities planned future reliability related transmission projects and operational procedures? Or is it intended to address situations where simulation and the application of currently planned projects and procedures are insufficient to meet the performance requirements? -2.7: If a project is added one year to the "Corrective Action Plan" but then in the subsequent year has been added to the model, resulting in simulation showing no performance violations, should it be removed from the Corrective Action Plan? Or should it be referenced in the plan each year until it is either in service or demonstrated to no longer be required? Comments: With regard to the Lower VSL, is 2.6 considered to be met if only one of two sub-requirements (2.6.1 or 2.6.2) is met? With regard to the Moderate VSL, is 2.8 considered to be met if only one of two sub-requirements (2.8.1 or 2.8.2) is met? Also, since 2.3 depends on 2.6, what happens if an entity does not meet R2.6 because it did not meet one of the sub-requirements of 2.6? With regard to the High and Severe VSL, if any one of the sub-requirements of 2.1, 2.2, 2.4 or 2.7 is not met, is the entire sub-requirement considered not met? (This question is generic throughout all VSL) Also, for the short circuit study of 2.3 (and 2.8), it is not necessary to study all of the contingencies, just P2. Taking other Facilities out in addition to the fault will only reduce fault current. Auditors may not be aware of that and maybe the standard could say that only P2 needs to be studied to reduce future confusion. Is the intent of the SDT to have 2.7 apply to all previous bullets in R2? If so, then it could be made clearer by starting 2.7 with "For the analyses discussed in 2.1 through 2.5, and for the planning events shown in Table 1, when the analyses indicate …" 2.7 seems to have lost the reference to lead times for Corrective Action Plan(s) that were present in the existing TPL-001-0, TPL-002-0 and TPL-003-0 standards, is that the intent of the SDT? Since only two of the years in the near term need to be studied, and one of the year's in the long term study, there ought to be some method to determine when a Corrective Action Plan is needed, the lead time of that Corrective Action Plan, to

give an indication of when activity needs to start to implement the Corrective Action Plan. The requirement clearly states that "For the steady state portion of the Planning Assessment …" it must perform simulations that show generator ride through voltage limitations under 3.3.2. However, ride through limitations are performed through stability simulations not steady state as required by R3. Please provide clarity. Additionally, 3.2 requires studies to be performed to assess the impact of the extreme events. Yet, 3.3 requires analyses shall be performed but does not specify the events intended to study. Suggested language for 3.3 should say "Contingency analyses shall be performed to assess the impact of the extreme events and:" Under 3.3.1 it states that the Planner must simulate the removal of all elements that the Protection System would be expected to disconnect. Language should be included to allow the Planner to provide a rationale to assess more severe system conditions without needing to simulate the effects of Protection Systems. The references within the requirements are very confusing. 3.1 refers to a contingency list created in 3.4 which refers back to 3.1. Similarly 3.2 refers to a contingency list created in 3.5 which refers back to 3.2. These should be combined into one sub-requirement.

Comments: With regard to the Moderate VSL, consider deleting "utilizing data" in order to avoid penalizing twice for failing to meet R1. Please provide clarity to 3.3.2 which states that a Planning Assessment "it must perform simulation that show generator ride through voltage limitation". However, ride through is only performed through stability simulation. The references within the requirements are very confusing. 3.1 refers to a contingency list created in 3.4 which refers back to 3.1. Similarly 3.2 refers to a contingency list created in 3.5 which refers back to 3.2. These should be combined into one requirementbullet. Please provide clarity to 3.3.1. Is the intent of the drafting team that extreme events that may cause loading beyond relay trip settings (zone 3) be simulated?

With regard to the Moderate VSL, consider deleting "utilizing data" in order to avoid penalizing twice for failing to meet R1. 4.1.1, suggest rewording "(a) generator being disconnected from the Bulk Electric System …", system as defined in the Glossary includes distribution, and we do not believe that is the intent of the SDT. 4.1.2, 4.3.1 and 4.3.3 essentially requirerequires modeling every Zone 3 (or higher, such as Zone 5) relay in each Interconnection (or at least in the Region under study and adjacent regions) because, in order to simulate the impact of a power swing on a distance relay, one would need to know the characteristics of the distance relay and how long the transient swing remains within that characteristic, which means modeling the relay. Is that the intent of the SDT?

No Comment

For R6 please consider the following revision: "Each TP and PC shall define and document within their planning assessment any criteria or methodology used in their analysis to identify system instability /deleted/ for /deleted/ conditions such as cascading outages, voltage instability, or uncontrolled islanding." As written originally it could be taken to be the methods for determining if you have instability during a cascading outage, rather then the methods for determining if you are at risk for instability like a cascading outage. the word "potential" into "… identify the potential for System instability …". The criteria and methodology may be used to determine if further analysis is warranted, e.g., if steady state voltages fall below 0.9 per unit, then duedo a voltage stability study. Going below 0.9 does not mean voltage collapse, but, it may be an indicator to study it; hence, the word "potential".

No Comment

With regards to the High VSL, what about entities that indicate a reliability related need for the Planning Assessment? Should this be part of the High VSL? Consider changing the requirement to distribute the Planning Assessment to become more flexible and allow for making the Planning Assessment available to those entities that indicates a need. Consider revising as follows: Each Planning Coordinator and Transmission Planner shall make available its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. The definition of "Known Commitments" should explain how that would diferentiate between Planned Commitments

Consider the following definition for clarification: Planning Assessment: Documented evaluation of (1) studies of future Transmission System performance and (2) Corrective Action Plans (included in studies) to remedy identified deficiencies. Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, or (2) the response of voltage sensitive Load that is disconnected from the System by end-user equipment.

Please clearly indicate for P3 and P5 that note 1 and note 9 apply. Consider using a comma, not a note 19 that does not exist. The P2-1 event needs to be clarified with its intent. In the SDT Consideration of Comments to the 3rd DRAFT posting, the response to Transmission Planning clarified that "There is no need to show a line energized up to the breakers that opened. The intent is simply to look for low voltage or thermal problems while supplying Load from one end of a normally networked line." This could be accomplished by adding this to footnote 7 or re-naming the event "Opening of a Line Section w/o fault".

The implementation plan needs to be clarified that during the first year the existing TPL standards are still in effect. As written it appears that only R1 and R8 are in effect and the existing TPL standards are not. Assessments are a year long process and are based on a year or more worth of studies, the study work and assessment are not executed in a single day. R2 through R7 is unclear what "coming into effect means". Please consider adding the following paragraph: "Entities are not required to alter their annual schedule based on the R2-R7 requirements going into place or have duplicate efforts at

assessments in the year the old and new standard overlap. Therefore any assessment performed prior to R2-R7 going into effect shall meet R1, R8 and the prior TPL standards; an assessment under the revised standard is not required until the following annual cycle. An assessment performed after R2-R7 are in effect shall meet these new TPL Standard. The date the assessment is "performed" for the purposes of this phase in, shall be determined by the date the entity began formally sharing results with its neighbors under R8." Please clarify the parenthetical for P1-2 and P1-3. Is the intent of this parenthetical referring to Consequential Load Loss that is allowed for P1 events?

We the FRCC TWG feel that the standard is very close to ballot, but the drafting team still needs to address several issues raised in the comments before balloting.

Individual

Roger Champagne

Hydro-Québec TransÉnergie (HQT)

Requirement 1.1.2 –Consideration of known outages should not be included in a planning assessment. Such outages are coordinated by operations and are only permitted if the system can be operated reliably, where assumptions may be different than those used in planning assessments. Including this as a requirement effectively means that the system must be designed to withstand three outages. In those cases where safety, or reliability, or both are a concern by long duration outages (e.g., more than one year), temporary Operating Protocols are implemented to mitigate their impact. If this requirement must be kept, the outages with duration in excess of a year should be considered, rather than those of six months. Requirement 1.1.5 – Interchange. Interchange usually refers to non-firm short-term economic transactions that often take place between Balancing Authorities to take advantage of their respective resources surplus (i.e. not needed for local reliability.) However, such transactions should not be modeled in the base case system representation, unless their neutrality to system reliability has been clearly demonstrated. For example, economic interchanges between New England and PJM through New York have an impact on the New York transmission system that may, at times, pose reliability constraints on the operation of the New York system. Requirement 1.1.6 – what are "resources required to supply load" – gens, HVDC, tie lines? HQT, as does NPCC, suggests NERC develops a definition for "resource" or use the following definition found in NPCC Glossary of Terms, Document A-7: Resource — Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load.

Requirement 2.1 – As written, it is not clear. HQT, as does NPCC, suggests revising language as in 2.4 as follows: "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required:" Requirement 2.1.2 – The use of the term "off peak" is a concern. The definition for this term can be read to say that it is any load level less than peak. This does not provide enough clarity to guide the required assessments. Requirement 2.2 – As written, it is not clear. HQT, as does NPCC, suggests revising language in 2.2 as in 2.4 as follows: "The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required:" Requirement 2.7 – HQT,as does NPCC, suggests changing the word "run" to "condition" in "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3." Requirement 2.9 – It should not be necessary to identify the largest consequential load loss if the TPL standard does not limit the size of the consequential load loss. This requirement should be deleted.

Requirements 3.5 and 4.5 – Both of these requirements need clarification as to what is specifically required for the "evaluation of possible actions." Requirement 3.3.3 – This requirement is already addressed in NERC Standard PRC-023 and reflected in the facility's rating and should be removed from TPL-001-1 since the standard already requires observance of facility ratings. Requirement 3.4 – HQT, as does NPCC, strongly suggests making this requirement a sub-bullet of Requirement 3.1 to keep the related requirements together. Requirement 3.5 – HQT, as does NPCC, strongly suggests making this a sub-bullet of Requirement 3.2 to keep the related requirements together. Requirement 3.6 –Currently this requirement is not clear. HQT, as does NPCC, recommends clarification be added that the "consequential generation" loss is excluded from the amount documented.

Requirements 3.5 and 4.5 – Both of these requirements need clarification as to what is specifically required for the "evaluation of possible actions." Requirement 4.4 – HQT, as does NPCC, strongly suggests making this requirement a sub-bullet of Requirement 4.1 to keep the related requirements together. Requirement 4.5 – HQT, as does NPCC, strongly suggests making this requirement a sub-bullet of Requirement 4.2 to keep the related requirements together.

Requirements R8, 8.1, and Measurement M8 – There are a number of concerns with these requirements. There needs to be a specified time period upon which comments must be received. As written, there is no sunset on when comments may be made and therefore they must be responded to.

Additionally, it is not clear if the 90-day response time may extend beyond the end of the year to maintain and maintain annual compliance. R8 also causes redundancy of distribution of assessments. Suggested revised Requirement R8 to say:˜ "Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to functional entities that demonstrated a reliability need with concurrence from their planning coordinator for the Planning Assessment results."

No

Definitions – Year One – This still defines Year One as both a particular year AND a window. It cannot be both. Suggest rewording the second sentence to read:˜ "This is further defined as beginning 12-18 months from the end of the current year."

No

There is confusion in interpretation of the Table 1 — When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading? Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft. Other footnotes appear to be mislabeled as well. If Extreme Events are not deleted from the standard, then a different number for the table for Extreme Events should be used. Extreme Events 2a – need to define towerline. Add language to replace towerline with structure. Table 1 Footnotes require a close editorial review. There are two number ones, and multiple items pointing to the wrong footnote or footnotes that don't exist (19, 101), etc. Several instances are discussed below but this is not an exhaustive list. Table 1 – Steady State & Stability Performance Planning Events - Note (a) – this note is placed under "Steady State & Stability" but issues of voltage instability, cascading outages, and uncontrolled islanding apply only to stability. NPCC suggests this note be relocated to "Stability Only." Table 1 – Steady State & Stability Performance Planning Events - Note (i) – this indicates that one cannot meet steady state requirements by depending on end-user owned equipment. Please clarify the purpose and performance requirement on this note with respect to end-user schemes and possible arrangements already in place to trip end-user equipment. Table 1, P4 – footnote reference in Category column needs to change from 101 to 10. Footnote reference in Event column lead-in description needs to change from 11 to 10. Table 1, P5 – As written, this requirement replicates a fault causing a loss of station anywhere that there is only one protection system. This is overly severe and would lead to the requirement for fully redundant protection systems at many stations. The use of the term "Protection System" in P5 is unacceptably inconsistent with the NERC definition of Protection System because it does not exclude the battery and its associated series elements. Battery systems should not be included. Table 1, P7 – for Event 1 (the loss of two adjacent circuits), this needs to specify if these are the same phase or different phases. Table 1 – Steady State & Stability Performance Extreme Events It appears that for Steady state, item 2, that item (a) is encompassed by (b). It if is not, what makes it different? Table 1, footnote #2 – typo – there is an erroneous comma in the phrase "are the fault types, that must be evaluated." Please remove said comma. Table 1, footnote #3, HQT, as does NPCC, has asked NERC to put a lower bound on the HV but it seems that this remains unaddressed. More stringent performance requirements should be applied to Facilities that represent the backbone of the electric power grid and act as the medium for moving large amounts of power from production to various Load centers, rather than to those Facilities that directly serve end-use Load customers. However, as had been commented in preceding postings, the EHV breakpoint for these more stringent requirements, defined in note 3 of table 1 as "all Facilities greater than 300 kV", is not appropriately defined and should be reviewed. A uniform voltage-level threshold has not been shown to adequately cover all of the different power systems in North America, and significant additional costs will be incurred without proportional or measurable reliability benefits if this definition is not changed. The following is a proposed modification to the EHV definition "all Facilities greater than 300 kV…": "Facilities representing the backbone of the System, generally operating at voltages greater than 300 kV, as determined by the Planning Coordinator and approved by Regional Entity." In using such language, we believe that the extra investment required would go towards real improvement of the reliability of the Interconnected System. Furthermore, HQT believe that untill the BES/BPS definition debate is settled at NERC and FERC level, the proposed definition permits the use of the performance base methodology to determine the BPS element subjected to this standard. The way the standard is actually written, it can be interpreted as 300 kV and above, wheter it is part of BPS or not. HQT believe it is overly prescriptive and leaves no leeway.

Yes

No

There are still issues as indicated in the submitted comments that need to be addressed before this standard should go to ballot.

Group

E.ON U.S.

With respect to Category P6, a Multiple Contingency event (the overlapping occurrence of two or more single events) allows Non-Consequential Load Loss. The "System adjustments" do not list yet do not exclude Load Shedding. E.ON U.S believes that Load Shedding should be included as an option in similar manner to Curtailment of Firm Transmission Service. If the SDT disagrees with this recommendation, then E.ON U.S. suggests that the SDT clearly state the allowed use of Load Shedding. E.ON U.S. observes that in the case of Extreme Events the SDT provided the following response to a previous comment: Extreme event 2d and 3a are similar in that each covers the loss of all generating units at a single plant location. However, in 3a, two plants are reviewed. In each case, all units are to be outaged regardless of the BES voltage level to which they connect. E.ON U.S. recommends that the word "station" in event 2d to be changed "plant".

Group

SERC Dynamics Review Subcommittee (DRS)

R1: MOD-010 and 012 are not directly applicable to the PC. References to other processes (e.g. tariff requirements or transmission owner agreements) that are utilized to provide this data may be desirable, but do not satisfy R1 as presently written. VSL: In the Moderate and Severe VSL, insert “responsible entity’s” in front of the term “System model.”

Part 2.1.4 and 2.4.3: delete the word “sufficient.” We appreciate the deletion of the previous R2.9 on non-Consequential Load Loss from the previous draft of TPL-001-1. Bullet 1 of R.2.4.3: change “Dynamic Model” to “Dynamic Load Model”. Part 2.9: Does this refer to customer loads only, or does it include pump-storage or compressed air generating plant pumping load. We recommend that the expected largest consequential load be limited to customer load, not utility load, i.e., pump-storage.

R3.3.1: We propose to add “permanently” before “disconnect”.

It is not clear as to the expectations of standard drafting team for dynamic modeling of relays. Parts 4.1.2 and 4.3.3 imply that all transmission relays may need to be explicitly modeled in the dynamic simulations. Is this the team’s intent, please clarify? For R4.1.2. Suggested change: Replace word “tripped” with “considered”. Reasoning: Since often tripping an out-of-step generator reduces impedance swings, if the simulation shows acceptable impedance swings and voltage levels without tripping the generator, why would we be required to determine the tripping time and simulate tripping in each of the simulations that we have to run for these event categories? Without the suggested change involving the word “considered”, significant extra effort would be required to perform simulations for small generators with no added benefit in achieving the purpose of assuring that impedance swings from generators are not passing through lines on the Bulk Electric System for events P2-P7. Part 4.3.1: add “when used as part of a protection system” to the end of the sentence. Part 4.3.3: add “when such devices affect the study area” to the end of the sentence. Part 4.4: place a space between words “Table 1” and “that”.

The content in the severe VSL column should be split among the lower, moderate, and high categories, with failure to include one element as Moderate and two elements as High. It is stated that the Transmission Planner and Planning Coordinator shall have criteria specifying voltage limits, post-contingency voltage deviations, and transient voltage response. How would an nteraction with a third party system be handled? For example a contingency causes a voltage deviation on one system that is within thevoltage deviation criteria, but causes a voltage deviation violation on a neighboring system that has a more stringent criterion.

M6: The wording on this measure appears to have been copied from M3 or M4 but is not appropriate since R6 addresses criteria and methodology but not a study.

None.

R8: It is not clear whether the assessment results must be distributed to all parties of interest, or if it would be sufficient to post the assessment at a central location, and distribute information to access the information. Also, FERC Standards of Conduct issues would come into play in assuring that the information is available only to appropriate personnel. For additional clarity in who should receive the assessment, we recommend replacing "indicates" with "has" and adding words to the end of the sentence so that it states the following: "and to any functional entity that has a reliability related need for the Planning Assessment results and provides a written request." R8: The PC and TP responsibilities should be stated separately for clarity. Part 8.1: It is not clear what the form of the response to the comments should be. Would an acknowledgement be sufficient, or would it be necessary to pursue a process of examining comments in detail and revising and reissuing the corresponding assessment? The

requirement needs to be revised to make the above point clear.˜ For Part 8.1, we do not believe the intent is for casual emails to be documented and formally responded to. And we do not believe that anyone who happens to receive the assessment should be able to comment. Therefore, we recommend the following wording: "If one of the above named entities provides formal written comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments." If these recommendations are accepted, then the wording of M8 would have to change accordingly.

No

With the simplified definition for Bus-tie Breaker, would a breaker in a standard ring bus or breaker-and-a-half scheme be considered a Bus-tie Breaker? Request the definition be revised to clarify as follows: Add this sentence to the end of the definition: "A breaker in a standard breaker–and-a-half or ring bus configuration is not a Bus-tie Breaker". Suggest revising the Non-Consequential Load Loss definition to: Non-Interruptible Load loss other than (1) Consequential Load Loss and (2) the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.

No

Some of the footnote superscripts do not appear to have a corresponding reference in the footnotes, in the case of: Table 1 Planning Events P3 superscripts should be 9 and not 19. Table 1 P5 superscript 19 should also be 9. Table 1 Planning Events P4 superscript 101 should be 10, superscript 11 should also be 10. Table 1 Extreme Events steady state items 2A and 2B superscript should be 11, not 12. Table 1 Extreme Events stability items 2A-2F superscript should be 10, not 11. No header on third page of Table 1 Planning Events. Table 1, Planning Events, wherever it says "no" in the "interruptions of firm transmission service" column, generation tripping by fault clearing action should be allowed.

No

There is a concern about the last paragraph in the Implementation Plan. It is easy to interpret this language to state that the entity is noncompliant if the performance requirements are not completed within 5 years. The concern is that the 5 year window for meeting the "raising the bar" requirements is still not adequate. For instance, it typically takes 7 to 10 years to build a new 500-kV transmission line - including time required for such processes as federally mandated NEPA environmental reviews. We strongly suggest increasing this time window to 10 years.

No

If the revisions recommended above are adopted, the standard would then be ready for ballot. We commend the drafting team for their efforts in preparing this draft standard for ballot.

Individual

Greg Campoli

NYISO

R1 - The NYISO would like to align itself with the comments of the ISO/RTO Council stating that the PC may begin model building using provisions from tariff or agreements such as its Transmission Owners agreement. While the data may be consistent with that provided in Mod 10 and 12, there may not be a direct correlation. We, therefore, also suggest the following wording for R1. "Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall reflect data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and/or data that is provided in accordance with tariff or transmission owner agreements. The models may be supplemented by other sources as needed including items represented in the Corrective Action Plan, and shall represent projected System conditions." R1.1.2 - Outages of less than 12 months are generally coordinated by operations, not planning departments. In reference to system modeling, it doesn't make sense for outages of less than a year. We therefore recommend replacing "duration of at least six months" with duration of 12 months or more." R1.1.5 - Interchange should not be modeled in the base case system representation, unless their neutrality to system reliability has been clearly demonstrated. There are times that economic interchanges between New York and a neighbor may have an impact on one of the transmission systems that may, at times, pose reliability constraints on the operation of the New York system. R1.1.6 - Please define what is included in "resources required to supply load." It is unclear what is included or not included in this requirement. The NPCC definition of "resource" is inclusive.

R2. - The NYISO tariff establishes a biennial "Comprehensive System Planning Process," Compliance with an "Annual Planning Assessment" will therefore be a simple repetition of data reported in the prior year assessment. Please clarify that this is acceptable. We believe that the use of "past studies" provides for this. R2.1 - "Steady state" should be defined upfront with other definitions. In defining "steady state" is "thermal voltage" the primary metric being measured? R2.1.1 - Again want to confirm that due to the NYISO biennial planning cycle, that use of "past studies" will be acceptable. R2.1.2 - Please define what is intended by "off peak." Our reading is that it is ANY load level less than peak. Also, consistent with our comments on the prior draft, system off-peak is more likely a stability issue than a steady state issue. If system off-peak becomes a steady state issue, it can be mitigated through generation redispatch. Accordingly, it appears that this requirement is not necessary for steady state analysis. R2.1.4 - This is just too vague to be a useful requirement. The sentence " To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of

credible conditions that demonstrate a measurable change in performance." is too subjective to be enforceable. Either definitions of phrases like "sufficient amount" "credible conditions" and "measurable change" are included, or the requirement needs to be written more clearly to state what is actually being required without such high level of subjectivity. Further, we believe that this sentence may not be necessary at all, as the first sentence in 2.1.4 provides sufficient detail to conduct sensitivity analysis without being overly prescriptive. R2.4.3 As much of this language is a repeat of language in 2.1.4, above, our comments there also apply to this section. R2.6 - "Past Studies may be used to support the Planning Assessment if they meet the following requirements" and the sub-requirement R2.6.2 states that for SS, SC, or stability analysis the study shall not include any material changes, such unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. While this is better than the prior draft, the NYISO still would like more clarity on the definition of "material changes." Would the inclusion of a technical rationale satisfy ANY change, regardless of magnitude, in a past study. Or could we just invoke the usage of a statement such as "The NYISO feels this change does not constitute a "material change."" to be compliant with this requirement? We recommend that the regional entity should have a process to determine whether changes are material that is similar to the NPCC's process for determining what level of annual transmission review should be conducted each year. Finally, does this only relate to, or is limited to, the LATEST PLANNING HORIZON system model? R2.7 – Recommend that in the sentence "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity…" wording should be changed to "performance requirements for any single sensitivity…" R2.7.1 – Recommend changing phrase that leads into list to read "Such actions including, but not limited to:" R2.7.2 - Recommend consideration of striking this section. It is not clear how an entity can provide a rational for unnecessary actions. Further, if actions are not necessary, what limit would there be on a rational, so they would seemingly be useless? Finally, it is stated above, corrective action plans should not be required for sensitivity studies. R2.9 – There does not seem to relate to any reliability need the NYISO is aware of for this requirement to remain.

R3.3.3 – This requirement is already addressed in NERC Standard PRC-023 and reflected in the facility's rating and should be removed. R3.5. - The Extreme Events testing in Table 1 should be removed from this standard since there is no requirement to develop a Corrective Action Plan to address unacceptable consequences and the requirements are very general or vague. At a minimum, testing should only be required for EHV facilities or facilities specified by the Regional Entity – for example, NPCC designates facilities that can have consequences outside an area as bulk power system facilities. If this remains, the NYISO requests that the phrase "evaluation of possible actions" be greatly clarified. R3.6 – The NYISO seeks greater clarification of the phrase "consequential generation."

R7. - The NYISO requests clarification as to whether the PC will be expected to distribute the TP Planning Assessments as part of its coordination requirement?

R8- It should be made clear that a TP should not be required to send their assessment to adjacent PCs. Likewise the PCs should not be required to send their assessment to TPs not in their footprint. R8.1: This should not be required until the Assessment is complete and posted. Additionally, this could be an administratively intense task to respond to each and every comment and document that a response is made within 90 days. Is there any room for an extension to this requirement?

No

Question # 9 – The SDT has revised the definitions in response to industry comments to the third posting. Do you agree with these definition changes? If not, please clearly indicate which definition you disagree with and provide specific comments. No. Need to define "Steady State" and "Consequential Load" as well as other phrases included throughout the NYISO's response.

Yes

Question #10. – Do you agree with the changes in the performance elements and notes in Table 1? If not, please provide specific comments by note number, note alpha character, or performance category. Yes

Yes

Question #11 – The SDT has provided a revised Implementation Plan as part of this posting. Do you agree with the revisions to the Plan? If not, please provide specific comments. Yes

No

Question #12 – Do you believe that this standard is ready to go to ballot? (if 'No' is checked here, the SDT will consider that comments raised on the other questions drove that decision.) No. Too many significant questions and key definitions remain unanswered. Table 1 - General comment - Footnotes – needs significant clean-up Page 16 Note (a) – this note is placed under "Steady State & Stability" but issues of voltage instability, cascading outages, and uncontrolled islanding apply only to stability Note (f) – Does this refer to "Normal Ratings"? Please provide clarity. Note (g) – "System steady state" should be defined by applicable regional entity. Note (i) – indicates that one cannot meet steady state requirements by depending on end-user owned equipment. Please clarify the purpose and performance requirement on this note with respect to end-user schemes and possible arrangements already in place

to trip end-user equipment. Page 17 P5 – As written, this requirement replicates a fault causing a loss of station anywhere that there is only one protection system. This is overly severe and would lead to the requirement for fully redundant protection systems at many stations. Page 18 P7 – for Event 1 (the loss of two adjacent circuits), this needs to specify if these are the same phase or different phases Page 19 How could any system planner reasonably and accurately portray what contingencies might occur from any single or combination of extreme events listed? PAGE 20 Is the one mile exclusion in footnote 14 a contiguous mile, or a total of one mile for the entire length of the lines? (i.e. Are multiple instances of common towers or common rights of way exempt if each instance is less than a mile?) General Comment: The NYISO would like to align itself in supporting the following comment submitted by the NPCC: We agree with the SDT that more stringent performance requirements be applied for Facilities that do not directly serve end-use Load customers but rather represent the backbone of the electric power grid and act as the medium for moving large amounts of power from production to various Load centers. However, as HQT commented on previous draft, we strongly believe that the EHV breakpoint for these more stringent requirements, defined in note 3 of table 1 as "all Facilities greater than 300 kV" is not appropriately defined and should be reviewed. The SDT have not demonstrated that a uniform voltage-level threshold could adequately covers all different power system types in North America and we strongly believe that significant additional costs will be incurred without proportional or measurable reliability benefits if this definition is not changed. We propose to modify EHV definition "all Facilities greater than 300 kV…" by the following "Facilities representing the backbone of the System, generally at voltage greater than 300 kV, as determined by the Planning Coordinator and approved by Regional Entity." In using such a language, we believe that the extra investment required would go towards real improvement of the reliability of the interconnected System.

Individual

Chifong Thomas

Pacific Gas and Electric Co.

R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. For R1.1.5 we suggest changing the wording from "Known commitments for Firm Transmission Service and Interchange" to "Known commitments for Firm Transmission Service or Interchange". It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.

The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies…", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies…" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies…" It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.

Requirements R3.4 and R3.5 appear to be related to and set the limits for R3.1 and R3.2 respectively. Suggest moving both Requirements R3.4 and R3.5 into R3.1 and R3.2, allowing these sub-Requirements (R3.4 and 3.5) to be deleted. It is unclear from the wording in R3.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R3.1 and R3.2. Please clarify the wording of R3.3. For clarity we suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits.

Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.

As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."

Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?

No

The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language follows Non-Interruptible Load loss other than: • Consequential Load Loss • the response of voltage sensitive Load • Load that is disconnected from the System by end-user equipment. This version uses the same wording but clarifies that the term "other than" applies to all three things.

No

As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.

No

Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.

No

Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.

Group

Modesto Irrigation District Transmission Planning

R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. R1.1.5 we suggest changing the wording from "Known commitments for Firm Transmission Service and Interchange" to "Known commitments for Firm Transmission Service or Interchange". It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.

The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies…", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies…" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies…" It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. R2.1.4,R2.4.3 "... vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measureable change in performance." Please define measureable. An example would certainly help. This would be a good workshop item to show how to perform. R2.6.2 The previous version defined material change. This current version eliminated the definition of material change, but still indicates the study shall not include any material changes.... This is unclear; please clarify.

For clarity we suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits. Also please define relay loadability limit.

Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we

suggest including the assessment in the list of sensitivities.

R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."

Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?

No

The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language follows Non-Interruptible Load loss other than: • Consequential Load Loss • the response of voltage sensitive Load • Load that is disconnected from the System by end-user equipment. This version uses the same wording but clarifies that the term "other than" applies to all three things.

No

As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard. please define "post contingency" and "post transient" Why was the previous version footnote 1 defining "angular stability eliminated?

No

Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.

No

Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.

Individual

Greg Rowland

Duke Energy

No comments.

• Reword R2.1 as follows: "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be based on the following annual current studies, supplemented with qualified past studies that meet Requirement R2, part 2.6. The following studies are required:" • We believe that using a past study for the Long Term Assessment is adequate, as long as the past study meets R2.6. Reword R2.2 as follows: "The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be based on the following annual current study or qualified past study that meets Requirement R2, part 2.6. The following study is required:" • Reword R2.2.1 as follows: "System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected." • We believe that using past studies for the Near-Term Transmission Planning Horizon portion of the Stability analysis is adequate, as long as the past studies meet R2.6. Reword R2.4 as follows: "The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be based on the following annual current studies or qualified past studies that meet Requirement R2, part2.6. The following studies are required:" • R2.5 – Does the phrase "proposed generation additions or changes in that timeframe" refer only to generation changes, or does it also refer to transmission system changes?

R3.5 includes the phrase "cascading outages". We believe that the word "cascading" should be the capitalized NERC-defined term "Cascading".

• R4.3.3 must be clarified regarding what method is to be used for assessing the impact of transient swings on Protection System operation. For example, how is this to be included in models, is this referring to a post simulation evaluation comparing results to actual relay settings, etc? • R4.5 includes the phrase "cascading outages". We believe that the word "cascading" should be the capitalized NERC-defined term "Cascading".

No comments.

R6 includes the phrase "cascading outages". We believe that the word "cascading" should be the capitalized NERC-defined term "Cascading".

No comments.

No comments.

No

Reword the definition of Non-Consequential Load Loss as follows: Non-Interruptible Load loss other than Consequential Load Loss and other than the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.

No

• Reword Steady State Only: f. as follows: "Applicable Facility Ratings shall not be exceeded." • P3 Initial System Conditions footnote should be 9, not 19. Also, P4 footnote should not be 101. Please check all footnote references.

Yes

Yes, however we don't understand the meaning of this phrase which follows P1-2 and P1-3: "for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element".

Yes

Yes, assuming our comments are addressed effectively.

Group

FirstEnergy Corp

FirstEnergy believes the draft 4 version of requirement R1 is greatly improved over prior drafts. The team has correctly responded to industry stakeholders and arrived at an appropriate middle ground that should resolve most stakeholder concerns. The changes made in R1.1.2 stating modeling of known outages with a duration of 6-months or more helps clarify a requirement that was previous subjective and open for interpretation. The removal of the previously prescriptive "such as list" is also well received by FirstEnergy. Finally, the addition of the text "known commitments" in regards to Firm Transmission Service and Interchange resolves our prior concerns.

A. FirstEnergy disagrees with requirement R2 sub-part 2.1.1 requiring the annual completion of two near-term steady-state studies. We believe that on a yearly basis completion of one near-term study and one long-term study is sufficient to interpolate and extrapolate the results needed to cover the entire planning horizon. The team should keep in mind that the overall assessment will include qualified past studies to supplement the results for a more refined view of anticipated conditions. We request that the team revise the near-term annual study requirements to require completion of only one near-term steady-state study and allow the TP/PC flexibility in choosing the appropriate study year. B. In requirement 2.7.1 the team should consider collapsing the 3rd and 4th bullets into a more succinct single bullet that says "Installation or modification of automatic generation runback/tripping". The use of "manual" generation run-back should be accounted for in an Operating Procedure (5th bulleted item). The additional text on the existing 3rd and 4th bullets discussing "single or multiple contingency" is not needed as the text stated in the parent R2.7 text is sufficient. C. We concur with the team's removal of the overly prescriptive requirements to include "initiation dates" and "in-service dates" from the Corrective Action Plans. However, the team may want to ensure some aspect of timing is identified in the Corrective Action Plans. It is recommended that the team revise the text of sub-part 2.7.1 that precedes the bulleted list to read "List system deficiencies, associated actions needed to achieve required System performance and the timing of when the actions are needed"

A. The inclusion of sub-part 3.3.3 of Requirement R3 that reads "Ensure relay loadability limits are respected" is not needed as it is duplicative with standard PRC-023, and indirectly redundant with the facility rating standards FAC-008 and FAC-009. Additionally, the introductory notes of performance Table 1 item "f" is clear that Facility Ratings shall not be exceeded and PRC-023 makes it clear that relay loadability must be accounted for in Facility Ratings. In NERC's three-year assessment, Attachment 2 it clearly indicates that one goal of NERC's standards development work plan is " ...retiring redundant requirements ..." (Please reference page 4, the 6th bullet under plan objectives). To that end, we should not knowingly create redundant requirements that lead to double jeopardy issues for industry stakeholders. If a "belts and suspenders" is the goal here, it's suggested that a footnote be added to item "f" of the introductory notes that would clarify that PRC-023 must be adhered to with regard to Facility ratings. B. If the generator bus is modeled at the generator voltage, then this should be the reference voltage point. If the generator is modeled directly connected to the BES, then the transmission voltage should be the reference voltage. Either way, the reference point should be consistent. In addition, 3.3.2 requires the unit to be tripped. It should be noted that the minimum voltage point may be overly-conservative, since the minimum voltage that a unit can stay on line is MVA output dependent. For base load units, determining a generator minimum voltage should be relatively straightforward, however, peaking and regulating units, not so. Our experience has been that generating units at manned locations generally do not have undervoltage protection or alarms, so FE is not certain how this Requirement to trip those units matches the "real world". C. We suggest the team discontinue the use of "Coordinate with adjacent transmission planners" in regards to sub-part 3.4.1 related to the inclusion of contingencies from adjacent systems. The "coordination" type of requirements creates a need to develop compliance evidence such as e-mail correspondence, meeting minutes etc that serve no real reliability purpose. The requirement should simply be that the TP shall include adjacent System contingencies expected to produce the more severe System impacts on their

system. In fact, sub-part 3.4 already includes that language. We suggest the team append the sentence "The planning event contingencies shall include:" to the end of sub-part 3.4 followed by two bullets that indicate 1) events within the TP's system and 2) events on adjacent transmission Systems.
A. The SDT should bring consistency to the text used for sub-part 4.3.2 of R4 and sub-part 3.3.2 of R3. In R4 it indicates "generator bus voltages or high-side of GSU" as the reference voltage point whereas 3.3.2 only indicates "generator bus voltage" as the point of reference. If the generator bus is modeled at the generator voltage, then this should be the reference voltage point. If the generator is modeled directly connected to the BES (no transformer is explicitly modeled), then the transmission voltage should be the reference voltage. B. Requirement R4, sub-part 4.3.2 is well intentioned, but problematic for those performing dynamic simulations. Does a Guide or Practice exist to determine the dynamic undervoltage capability of a synchronous machine? Most excitation systems contain "field forcing" functions to maintain stability through fault conditions (1 second or so of capability), but FE is not aware of any published, readily available quantities or formulas that can be used to determine this highly time dependent function. Application of the steady state minimum voltage is grossly over-conservative. FE questions why low voltage limits should even be considered in dynamic simulations, since the primary concern for generating equipment during events of this nature and duration are metallurgical, not thermal (voltage). C. Requirement R3 sub-part 4.3.3 is troublesome since the modeling detail needed for Protection Systems within traditional stability programs is not available. It is expected that software adjustments will be needed from the software vendors before this requirement can be met. The implementation plan of 24 months may be insufficient in regards to 4.3.3. In draft 3 Progress Energy and Ameren in the Q11 comments indicated that more time is needed for Protection System modeling required by TPL-001-1. The SDT responded "The standard does not require detailed modeling of Relay Protection Systems. It only requires that the impacts of those systems be reflected in the modeling of Contingencies and the evaluation of the resulting System performance. This is no different than the current standards." The inclusion of sub-part 4.3.3 in Draft 4 does not appear to align with this response. Please clarify the intent of 4.3.3 and respond regarding FE's belief that more time is needed for software improvements. D. We suggest the team discontinue the use of "Coordinate with adjacent transmission planners" in regards to sub-part 4.4.1 related to the inclusion of contingencies from adjacent systems. The "coordination" type of requirements creates a need to develop compliance evidence such as e-mail correspondence, meeting minutes etc that serve no real reliability purpose. The requirement should simply be that the TP shall include adjacent contingencies expected to produce the more severe System impacts on their systems. In fact, sub-part 4.4 already includes that language. We suggest the team append the sentence "The planning event contingencies shall include:" to the end of sub-part 4.4 followed by two bullets that indicate 1) events within the TP's system and 2) events on adjacent transmission Systems.
We concur with the inclusion of R5 and the criteria needed for steady-state voltage limits, post-contingency deviations and the transient voltage response for its System. In regards to the transient voltage criteria, its our understanding that the this criteria is for planning purposes only and not intended for operation time horizon evaluations being performed by the TOP.
If an entity is required to adhere to its Facility Ratings, how is it feasible that a cascade violation would occur? FirstEnergy questions the need for this review based on Table 1 performance requirements and the need to adhere to Facility Ratings.
Yes
Yes
No
We disagree with the proposed Implementation Plan. The implementation period for the TPL-001-1 transmission planning standard should be limited to the time needed to transition to the new study requirements. The proposed 5-year implementation for the "raise the bar" aspects of this standard delves into project management and review of capital construction progress which should remain outside the scope of this standard. The standard should only consider if an entity has completed the required studies and has developed Corrective Action Plans to ensure performance criteria is being maintained. Implementation of transmission system action plans depends on the actions of many other functional entities, other than PCs or TPs. PC's and TP's should not be held responsible for the implementation of action plans since they have little or no control over the activities related to implementation. For example, an RTO/ISO may act as both the PC and the TP for its transmission owner or transmission operator membership, however, the RTO/ISO should not be subject to compliance sanctions for incomplete projects that it does not have direct responsibility. FirstEnergy suggests that a new TPL standard is required to successfully accomplish the vision and endpoint that this drafting team has in mind. It is our opinion that the TO, TOP, DP and GO are needed as applicable entities to bring to fruition the capital enforcement projects or operating procedures that are identified by the PC/TP. This TPL-001-1 standard should stop at the conclusion of studies, assessments and development of Corrective Action Plans and a new TPL standard should be developed to address implementation of Corrective Action Plans.

No

FirstEnergy does not believe the proposed TPL-001-1 standard is ready for ballot until our primary concern with the Implementation Plan as identified in our comment to Q11 is addressed. Additionally, our most pressing secondary concern is the modeling required for Protection Systems related to 4.3.3. Finally, we believe the standard is overly burdensome related to the annual near-term study requirements as stated in 2.1.1 as noted by our Q2 comments.

Individual

David M. Conroy

Central Maine Power Company

R1.1.1 Make this read "Existing Facilities and Resources" so that it will be a lead in to the changes proposed for 1.1.6. R1.1.2 This type of event is sufficiently addressed within the existing testing requirements (P6) and therefore should be eliminated , beyond that such outages are reviewed and approved on an operational basis and should not be included in a planning standard. During known outages for equipment upgrades or repairs there may be some increased exposure to load loss, which should be recognized as an acceptable exposure. In the event that this requirement is maintained please change six months to one year. 1.1.6 Resources may not be exclusively sources supplying load. Therefore the reference should not involve load. The focus should be on changes to resources and "resources required to supply load" should be replaced with "New planned Resources and changes to existing Resources" We suggest NERC develops a definition for "resource" or use the following definition found in NPCC Glossary of Terms, Document A-7: Resource — Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load. ADD 1.2 The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions. The standard must describe base assumptions. M1 It is not practical to retain system model information in a hard copy form. This provision should be dropped. D.1.1.4 Data Retention: The Transmission Planner and the Planning Coordinator may not be using the same software. If both are required to store the data, do they both have to have the software to use the data? Can this be changed to an 'or' such that one of them must retain the data and it can be up to them as to who is responsible for data retention.

2.1.3 In the event that R1.1.2 is kept it must be clear that the reference to outage schedules as listed in part 1.1.2 must be limited to the Planning Horizon. Table 1 There is confusion in interpretation of the table 1 — When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading? 2.1 Language should be revised similar to R2.4 as follows: "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required:" 2.1.2 Should be moved to the list of sensitivities currently in 2.1.4. (Off-peak needs to be more specifically defined). 2.1.4 Consistent with the suggestion made for section 1.1.2 please remove the last bulleted item in the list under section 2.1.4. "Duration or timing of planned Transmission outages." 2.2 The language in 2.2 should be revised to be similar to 2.4 as follows: "The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required:" 2.3 This should be modified to state that it is up to the Planner to determine the year of study within the Near Term Transmission Planning Horizon. 2.4.2 This should be deleted as it is covered under section 2.4.3. 2.4.3 To define a sensitivity, NERC must define base assumptions. 2.7 We suggest changing the word "run" to "condition" such that it reads "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity condition in accordance with Requirements R2, parts 2.1.4 and 2.4.3." 2.9 The requirement to report the largest single consequential load loss under Requirement 2.9 should not be included in the standard. The TPL does not limit the size of the consequential load loss. If it remains, it must be made clear that it be applicable only to Year One or Year Two.

3.2 Item 3.2 should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. 3.3.2 This requirement is not practical unless a MOD is created so that known minimum generator steady state or ride through voltage limitations are used instead of assumed values. To create a MOD, collect the data, and incorporate the information into the studies will take time, which necessitates the need for an implementation period. Absent accepting this suggestion with respect to creating an MOD, please provide assumed minimum generator steady state or ride through voltage limitations as a standard reference for this analysis. 3.3.3 There appears to be a compliance double-jeopardy issue related to relay loadability. Relay loadability is handled in greater detail (as it should be) under the proposed PRC-023 standard, so any reference here should be deleted. 3.4 It is suggested that this

requirement is made a sub-bullet of Requirement 3.1 to keep the related requirements together. 3.5 and 4.5 Both of these requirements need clarification as to what is specifically required for the "evaluation of possible actions." 3.5 It is suggested that this be made a sub-bullet of Requirement 3.2 to keep the related requirements together. 3.6 Item 3.6 should be deleted since there is no limit defined in the standard.

4.1.1 This should be revised to only be applicable to generators interconnected to the BES. This may need an implementation period as not all existing units are interconnected in accordance with the standard as proposed. As written this applies to small generators and doesn't necessarily reflect reliability of the network. 20 MW is a recommended generator minimum size. 4.1.2 This will require implementation period. 4.2 Item 4.2 should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. 4.4 It is suggested that this requirement is made a sub-bullet of Requirement 4.1 to keep the related requirements together. 4.5 It is suggested that this requirement is made a sub-bullet of Requirement 4.2 to keep the related requirements together.

Voltage criteria is addressed by the VAR standards. Including a voltage requirement in the planning standards appears to be creating a double-jeopardy exposure. R5. Change to Read "Each Transmission Planner OR Planning Coordinator … Need time to implement transient voltage criteria.

R8, 8.1, and Measurement M8 This standard should not be used to remedy deficiencies in meeting the coordination requirements of FERC Order 890. Therefore these should be deleted. If this requirement is retained the following is suggested: "Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to the functional entities that the Planning Coordinator and Transmission Planner recognizes as having a reliability need for the Planning Assessment results." Additionally, there is no deadline for comments. There is also potential conflict with the deadline for completing a study and when comments may be submitted (e.g. comments are received the day before the study is to be completed.) These issues must be addressed. 1.4 – Data Retention: The last bullet is unnecessary and should be deleted from the standard.

No

As currently defined Non-Consequential Load Loss could allow widespread or cascading motor stall. The language in the definition cannot be this generic. The text is broad enough that it could allow a voltage collapse; the definition is incompatible with Table 1a (BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur). The definition for the non-consequential load loss combined with Table 1 would prohibit any customer from tripping its own load for contingencies that indicate 'no' in the non-consequential load loss column. This is not practical and appears to be an unintended consequence of the change in definition. This requires a change in the definition or the table. We suggest defining Non-Consequential Load Loss as "intended post contingency loss of load caused by operator or SPS (RAS) action."

No

We generally agree with the table, however our issues are as follows: Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft. Other footnotes appear to be mislabeled as well. If Extreme Events are not deleted from the standard, then a different number for the table for Extreme Events should be used. There is confusion in interpretation of the Table 1 — When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading? P5 –The use of the term "Protection System" in P5 is unacceptably inconsistent with the NERC definition of Protection System because it does not exclude the battery and its associated series elements. Extreme Events 2a – need to define tower line. Add language to replace "tower line" with "structure". Table 1, footnote #3 – change Regional Entity to Regional Reliability Organization.

Yes

No

It is closer, but there are still some unacceptable issues that need to be addressed.

Group

Bonneville Power Administration

: R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. For R1.1.5 we suggest changing the wording from "Known

commitments for Firm Transmission Service and Interchange" to "Known commitments for Firm Transmission Service or Interchange". It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.
: The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies…", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies…" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies…" It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.
For clarity we suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits.
Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
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Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
No
The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language follows Non-Interruptible Load loss other than: • Consequential Load Loss • the response of voltage sensitive Load • Load that is disconnected from the System by end-user equipment. This version uses the same wording but clarifies that the term "other than" applies to all three things.
No
As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard. Table 1, the second to last column: Please clarify what is meant by "Interruption of Firm Transmission Service." Planning studies do not differentiate firm and non-firm transmission services. Planning studies model a load forecast, a generation dispatch, and the system topography. Interruption of firm transmission service is a commercial issue and is not related to assessing reliability of the system. If an assumed transfer is interrupted in a power flow case due to a contingency, and if no consequential load loss were allowed and all criteria were met, the system would still be exhibiting reliable performance. We believe interruption of firm transmission service should be allowed for all planning events P1 through P5 when assessing the reliability of the transmission system. At a minimum, footnote 9 in Table 1 should apply to all events in category's P1 through P5 that do not allow interruption of firm transmission service. The NERC definition of Firm Transmission Service states "highest quality of service offered to customers under a filed rate schedule that anticipates no planned interruption." Planning events required to be evaluated in Table 1 are unplanned interruptions by nature since they are studied to determine mitigation should they occur unexpectedly. This is inconsistent with the definition. Table 1, P1.4, P3.4, P4.4, P5.4, and P6.3: Shunt devices are not required to be in service at all times. It does not make sense to include it in the events column. How would you assess it while several of these devices are not

deployed because they are not needed for the conditions studied? Table 1, P1 & P2: What is the rational for having two categories for single contingency? Table 1, P2.1 (Opening of a breaker without a fault): Please clarify what constitutes opening a breaker without a fault mean? Planning for these events will be time consuming (modeling every breaker position open) and expensive to mitigate for events that occur solely due to human error and should be removed for the table. Table 1, P2.2, P2.3, and P2.4: These are not single contingency events and should be moved to P3.

No

Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.

No

Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.

Individual

Paul Rocha

CenterPoint Energy

CenterPoint Energy appreciates the SDT's efforts in revising R1 and generally agrees with the requirement except for verbiage and sub-requirements relating to modeling future transmission system projects, including projects identified in Corrective Action Plans. Specifically, CenterPoint Energy recommends that the SDT revise R1 by deleting the text "including items represented in the Corrective Action Plan" and delete part 1.1.3 in its entirety. Certainly, it is appropriate to model some limited subset of future projects, including projects included in Corrective Action Plans, which are reasonably "firm" or "committed". In previous drafts, the SDT tried to incorporate language to capture that concept but apparently abandoned the idea in response to industry comments. However, it remains true that many future "planned" projects, including projects in Corrective Action Plans, are tentative in nature and have a high degree of uncertainty due to uncertainty in forecasted system conditions. Because of this reality, and the fact that models are intended to be useful for identifying what future projects might be necessary, CenterPoint Energy believes many transmission planning organizations do not and should not model any and all new planned transmission facilities tentatively identified based upon studies and assessments of previous system models. Once the System model is updated with previously contemplated transmission projects, it is problematic to determine in future studies whether or not those projects are still needed, which is contrary to the intent of updating the model. If CenterPoint Energy's recommended changes are made, Transmission Planners and Planning Coordinators would not be precluded from incorporating future projects into their System models in accordance with their established practice but they would not be required to inappropriately model any and all previously contemplated projects.

Part 2.2: CenterPoint Energy recommends deleting part 2.2 since studies performed in the Long-Term Transmission Planning Horizon have dubious value for organizations whose longest lead time items take less than five years to construct. Even for organizations requiring longer than five years to build some projects, it should be noted that beyond the five year horizon, generation reserve margins have generally been exhausted, requiring speculation as to the location and size of future generating resources in developing system models. In recognition of this reality, the current set of TPL standards appropriately require that assessments be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may require longer lead time solutions. Part 2.5: Part 2.5 appears to have been added in response to one comment to the 3rd draft. In fact, the commenter did not recommend or propose the requirement found in 2.5, but only asked about the SDT's intent regarding this matter. CenterPoint Energy strongly disagrees that part 2.5 is necessary or advisable and recommends that it be deleted. We wholeheartedly agree that Transmission Planners should consider and selectively study potential stability concerns. However, we believe that Transmission Planners are already considering and selectively studying potential stability concerns, and deleting part 2.5 would not preclude the continuation of these practices. However, we oppose mandating stability analysis in the Long-Term Transmission Planning horizon of proposed generation additions or changes due to the uncertainty of where and how much generation will actually be constructed beyond the five year horizon, particularly since generation can be built much faster than five years and can easily invalidate any such assessment. Part 2.7: CenterPoint Energy recommends that part 2.7 be revised to add a reference to part 3.4 and part 4.4 as follows: "For planning events shown in Table 1, selected in accordance with parts 3.4 and 4.4, when the analysis…". This recommended change is to prevent possible ambiguity or conflicts between part 2.7 and parts 3.4 and 4.4. Part 2.9: – CenterPoint Energy agrees with multiple commenters to the 3rd draft that part 2.9 (previously 2.8) should be deleted. Part 2.9 is an unnecessary reporting requirement that has no actual bearing on reliability. By continuing to insist on R2.9, the SDT seems to have inappropriately ignored industry comments to the previous draft while ironically inserting R2.5 into this draft in response to only one industry comment (which did not actually advocate that R2.5 was necessary). CenterPoint Energy urges the SDT to reconsider its dismissal of industry concerns regarding R2.9.

CenterPoint Energy recommends references to "Long-Term Transmission Planning Horizon" be revised to contain comparable language as in the existing TPL standards that limit Long-Term studies to

marginal system conditions requiring longer lead times. See CenterPoint Energy's comments regarding part 2.2 for the rationale behind this recommendation. CenterPoint Energy also recommends deleting part 3.4.1 as being overly prescriptive and difficult to demonstrate in an audit.
CenterPoint Energy recommends deleting part 4.4.1 as being overly prescriptive and difficult to demonstrate in an audit.
CenterPoint Energy is not familiar with the phrase "post-Contingency voltage deviations" and recommends that this phrase be deleted. Alternatively, the text should be revised to read "steady state post-contingency voltage limits." Including both phrases is unnecessary and confusing.
CenterPoint Energy believes R7 relates to matters best addressed through registration, such as JROs or delegation agreements. If other commenters agree, CenterPoint Energy recommends that R7 be deleted.
CenterPoint Energy believes R8 is over-reaching and recommends deleting it. CenterPoint Energy is particularly concerned about requiring assessments to be distributed to "any functional entity that indicates a reliability related need". There is already a process in place for entities to request and receive the FERC Form 715 submittals of other entities. FERC's process appropriately recognizes and addresses CEII issues and imposes a requirement that the entity demonstrate need for the information and that the industry complies with certain security-related requirements. Beyond CEII matters, transmission planning information can have implications for market entities bidding on congestion rights in competitive energy markets. Therefore, the dissemination of transmission planning information may be governed by the regulatory authority having jurisdiction over the market functions, which is not necessarily FERC in all cases. In any case, given the availability of the FERC 715 process, there is no need for a somewhat duplicative requirement in this standard. Accordingly, CenterPoint Energy recommends that R8 be deleted in its entirety.
No
CenterPoint Energy is well aware of the diligence of the SDT in preparing this major consolidation and rewrite of the existing TPL standards. CenterPoint Energy believes this latest version is almost ready for ballot. CenterPoint Energy respectfully requests consideration by the SDT of the refinements to this latest draft proposed by CenterPoint Energy.
Individual
Mark Byrd
Progress Energy Carolinas
PEC believes that the language of R2.5 "proposed generation additions and changes" should be clarified as to whether transmission changes near generators are included or not. PEC believes that the requirement to report the largest single consequential load loss under Requirement 2.9 should not be included in the standard. If it remains, it must be made clear that it be applicable only to Year One, and there should be additional clarification that the requirement to report consequential load loss (single number) is ONLY for the most severe contingencies studied for the P1 and P2 contingencies.
PEC believes that R3.3.3 "Ensure relay loadability limits are respected" is unnecessary. The requirement to stay within Facility Limits is much more bounding. Several footnote references from Table 1 to the footnotes are incorrect.
There appears to be a double-jeopardy issue related to voltage performance criteria related to the VAR Standards. The voltage and var criteria will also be required in VAR-001 and 002.
Need to define "adjacent" Planning Coordinators. Does this mean a neighbor with at least one joint interconnection? The requirement to provide the Planning Assessment "to any functional entity that indicates a reliability related need" should be made subject to applicable confidentiality and CEII provisions.
Yes
Yes
Yes
Yes
Individual

Larry Brusseau
MAPP
It would be helpful to identify the relationship expected between the PC and the TP. It looks as if both PC and TP are expected to maintain the same models. We need to avoid duplicated effort. Does the standard really apply to "both", or could it be "either"? Is a Corrective Action Plan being used correctly throughout this standard? It seems like the specifics of a CAP aren't appropriate for future planning years. Planning studies are only estimates of expected system growth, and the apparent problem might turn out to be different, or not exist at all. Will compliance people start going "over the top" examining CAPs? The current practice of summarizing possible problems in future years and identifying possible solutions seems more appropriate than pinning entities down to Corrective Action Plans. Corrective Action Plans seem appropriate only for the Operating horizon. R1 – We interpret that "within their respective areas" refers the geographic footprint of the TP or PC transmission system. We propose clarifying that "within their respective area" does not require the inclusion of remote generation or load (metering) buses that are within the declared Balancing Authority area, but may be outside and separate from the TP or PC geographic footprint. M1 – We recommend the bolded words be added to M1 to indicate that each responsible entity must provide evidence that "it is maintaining System models within its respective area, using the latest…" What does it mean to have a hardcopy of a system model? R1.1.2 – We suggest that this requirement be removed because the "known outage(s)" are only to be included in the models when for P1 events are simulated, as specified in R2.1.3. We suggest that the intent can be more simply handled by stating in R2.1.3 that known outages be simulated along with P1 events for the System peak or Off-Peak conditions when the outages are scheduled to occur. R1.1.3 – Add the qualification of "for the years defined in R2". R1.1.6 – We interpret that "Resources required" allows the inclusion of fictional generators in the models when they are needed to make future normal system cases solve. If this is not the intended interpretation, then we suggest modifying the wording to make the desired interpretation more clear.
2.1.3: It must be clear that the reference to outage schedules as listing in part 1.1.2 must be limited to the Planning Horizon. There is confusion in interpretation of the Table 1 — When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading? R2.1.4/R2.4.3 – The terms 'credible' and 'measurable change' are ambiguous and not defined. Therefore, we suggest that these terms be defined or more clearly described to avoid the risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. R 2.1.5 - Spare equipment strategy. This appears to be more of a risk analysis than a simulation study requirement. If a simulation is required then it would appear that the PC/TP would need to rerun the entire system intact study with each "major transmission equipment "that is unavailable as a prior outage (i.e. for each generator, HVDC, SVC, XFMR) over the entire study parameters. How would this be evaluated? Is this not covered under P2 already? We also propose replacing the term 'major Transmission' with "BES" because BES is a well defined term while 'major Transmission' is not. R2.4.1 – We recommend that the SDT clarify section 2.4.1 and when load models considering induction motors are required. The clarification should add limits or thresholds to provide load models based on areas that have stability limits or issues and to loads of substation size and having dynamic characteristic capable of significantly impacting voltage stability. Areas that don't have large motors or stability issues should not be required to add unnecessary load modeling. R2.6.2 Change "to demonstrate that System changes do no impact the performance results in the study area" to "to demonstrate that System changes do not significantly impact the performance results in the study area." 2.6.2 As written results in an unrealistic requirement to review every impact minor or large and determine which meets this item and which do not. The recommended change solves this problem. R 2.7 – Corrective Action Plan: Is this not already apart of FERC Order 890? The PC may not be able to develop a CAP as they may not be the owners and would have no say about how a problem will be resolved. R 2.8.1 – Suggest using a word other than "deficiencies" as it is associated with non-compliance. R2.9 – We propose that this requirement be removed because annually stating the single, largest expected, Consequential Load Loss due to a P1 or P2 event in the TP or PC system is not needed to provide reliable BES performance or assure open and transparent Transmission planning peer review. In general, standards should not contain requirements that don't improve reliability.
R3.3.2 - We suggest that this requirement be removed because it is premature to require Transmission Planners to simulate under voltage tripping until the MOD standards require it. If the drafting team does not remove this requirement we propose revised wording to qualify which generating units to consider and which voltage limits to simulate, "Trip generating units that are connected to the BES when actual or assumed minimum generator steady state or ride through voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment". 3.3.3 – We suggest that R3.3.3 be removed and this System Protection simulation requirement should be included in R3.3.1, which is the requirement to properly simulate Protection System actions Add R3.3.5 – We suggest the addition of R3.3.5, "Applicable System Operating Limits for the planning horizon shall not be exceeded." because Note "a" and "b" under "Steady State Only" at the beginning of Table 1 are stated in the form of a Requirement (e.g. uses the

verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and hidden) in the performance notes of Table 1. [After R3.3.5 is added, Note "a" should be revised and refer to R3.3.5.] Add R3.3.6 – We suggest the addition of R3.3.6, "The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to steady state voltage requirements." because Note "d" under "Steady State Only" at the beginning of Table 1 is stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and hidden) in the performance notes of Table 1. [After R3.3.6 is added, Note "d" should be revised to refer to R3.3.6.] R3.4.1: Remove the Transmission Planner and change "coordinate" to "provide" information to adjacent PC. We are working on other standards to remove "coordinate" and we should avoid it here. Coordinate requires interaction between two entities (or more), so if one does not respond, the other could be found to be non-compliant for something they cannot control.

R4.1.1 & R4.1.2 - We propose that these sub-requirements be removed. The generating unit loss of synchronism does not necessary result in a thermal, voltage, or stability violations. R4.3.2 We suggest that this requirement be removed because it is premature to require Transmission Planners to simulate under voltage tripping until the MOD standards require it. If the drafting team does not remove this requirement we propose wording like, "Trip generating units that are connected to the BES when actual or assumed minimum generator transient voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment". The requirement should not apply to all relevant generating units until one of the MOD standards requires all Generator Owners to provide their minimum generating unit voltage limits to the TP and PC. If the wording of R4.3.2 must be different from its counterpart, R3.3.2, then please explain the reasons for any differences. Add R4.3.5 – We suggest the addition of R4.3.5, "Applicable System Operating Limits for the planning horizon shall not be exceeded." because Note "a" and "b" under "Stability Only" at the beginning of Table 1 are stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and hidden) in the performance notes of Table 1. [After R4.3.5 is added, Note "a" should revised and refer to R4.3.5.]

A voltage criterion is addressed by the VAR standards where they are applicable to TOs and TOPs. Including a voltage requirement in the planning standards appears to be creating a double-jeopardy exposure.

Suggest removing "Transmission Planner" since the PC performs the assessment.

Suggest moving this requirement to the head of the list. It's a basis for the rest of this standard.

R8: Remove Transmission Planners: Each PC shall distribute it Planning Assessment to adjacent PC and to any registered function entity that indicates a reliability need for the Planning Assessment results. R8.1 Remove Transmission Planners from subrequirement.

No

Add a Consequential Generation Loss definition, which would be a complement to the Consequential Load Loss definition. Both consequential load loss and consequential generation loss are referred to in note "b" of the Steady State & Stability section of Table 1, but only consequential load loss is defined. We suggest text of: "Consequential Generation Loss: All Generation that is no longer delivered to any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions." Add a Planning Horizon definition. This term is used in this proposed standard, in the FAC-010-2 standard, and possibly in other future standards, but it has not been defined yet.

No

The table needs to match the stated requirements in R3 & R4

No

The last part of the Effective Date section deals with the requirement to submit a Corrective Action Plan, and then to submit a mitigation plan to be approved by the Regional Entity and NERC. Failure do get those done would result in the initiation of "settlement proceedings." This means that entities may be found non-compliant for failure to build facilities. That seems to fly in the face of the EPAct of 2005.

No

MAPPCOR urges the SDT to modify the effective date where it is indicated that any "entity that cannot fully implement its Corrective Action Plan to eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for the above listed performance elements within 60 calendar months of the compliance date for Requirements R2 through R4 shall self report itself as being unable to meet the performance requirements of this Reliability Standard." This is essentially requiring an entity to self report for failing to build facilities. The Energy Policy Act of 2005 did not give FERC and therefore, NERC, the authority to require construction of electric facilities. Therefore, this implementation plan is implying an authority that is not given to FERC or NERC. This provision of the effective date should be completely deleted from the standard, the provision to state that one is non-compliant for this should be deleted from the standard, or there should be a statement that such a requirement is subject to limitations of the Energy Policy Act of 2005.

Individual

Aaron Staley
Orlando Utilities Commisssion
In general I support all the changes from the prior revision. I especially like the clarification that outages of 6 months or longer need attention in planning studies. Several questions on the details: R1 requires the maintenance of system models for the purpose of studies and establishes that these models should be updated with the latest data from various sources. Is this requiring that models should always be current, updated for the slightest change, even between studies? Or just that models are kept up to date in a more practical application such as monthly, quarterly or before their use in a study? R1 states that the model should be "..supplemented by other sources as needed, including items represented in the corrective action plan…" Read in context with the overall requirement this allows for projects that are in the corrective action plan to be added, but does not require that they are, is this the correct understanding? -R1 requires the model to represent Known Commitments for Firm Transmission Service, and also references load forecasts. The application of this requirement seems to be that the model should be based on the load forecast and include the appropriate known firm transmission service for the amount that would be used at that forecast level?
-I like the clarification of "summarize results" compared to the wording in the prior edition. -It is obvious an attempt has been made to further define when past studies may be used, but I think it is still a bit confusing. Requirement 2.1, 2.2 appear to be saying that current studies must be used, but that additional information can be provided if desired and it meets certain requirements. Sub-Requirements 2.3, 2.4 and 2.5 seem to allow use of past studies that meet the requirements of 2.6 in lieu of new work. If this is the correct understanding then I suggest the following: For 2.1 and 2.2 revise the statement to read "…and be supported by the following annual current studies. The analysis may also include other current and past studies in addition to the required annual current studies listed below. The reference to R2.6 is removed since including it invites confusion over when prior art can be used and if the material is solely supplemental, then there is no reliability advantage to limiting what can be incorporated a supplemental material. R2.6 should also be revised to read "Past studies may be used in lieu of current studies for R2.3, R2.4, R2.6 if they meet the following requirements:" This will insure that it is very obvious in both places when prior art may be used in lieu of new work. -R2.6.2 Consider revising "the study shall not include any material changes" to "the system represented in the study shall not include any material changes". Stating that "the study shall not include material changes" implies changes to the study from the time it was performed to the time it was used, like inserting or removing text, not changes in the underlying transmission system which is what I think you are really targeting. -R2.1.4 and 2.4.3: The statement "sufficient amount to stress the system…credible conditions…demonstrate a measurable change" implies that a sensitivity must meet three general criteria: (I will be using load forecast as an easy example, but obviously there is a range and combination of items that could be used) 1. That it is expected to increase stress, for example increasing the load forecast would general increase stress, where decreasing it would not. 2. That the increase should be substantial, for example growing the load at 2x the expected growth rate vs 1.01x the expected rate. 3. That the change doesn't have to exceed the bounds of credibility. If a 2x or 3x increase doesn't result in a stack of new constraints, it does not mean the sensitivity is inadmissible. Is this a correct understanding? -R2.7: Is the "Corrective Action Plan" intended to document all of an entities planned future reliability related transmission projects and operational procedures? Or is it intended to address situations where simulation and the application of currently planned projects and procedures are insufficient to meet the performance requirements? The next comment is very closely related to this one. -R2.7: If a project is added one year to the "Corrective Action Plan" but then in the subsequent year has been added to the model, resulting in simulation showing no performance violations, should it be removed from the Corrective Action Plan? Or should it be referenced in the plan each year until it is either in service or demonstrated to no longer be required?
No comments
No Comments
No Comments
For R6 please consider the following revision: "Each TP and PC shall define and document within their planning assessment any criteria or methodology used in <<their>> analysis to identify system instability //for// conditions such as cascading outages, voltage instability, or uncontrolled islanding." Adding the text in <<>> and deleting the text in ////. As written originally it could be taken to be the methods for determining if you have instability during a cascading outage, rather then the methods for determining if you are at risk for instability like a cascading outage.
The intent is much clearer, thank you for revising this.
Excellent requirement, thank you for revising this
Yes
I agree, but that is based on not having seen any proposed changes from others that might change my mind.
Yes
Note 2 regarding three phase faults being sufficient evidence for SLG faults is an excellent addition, thank you. For P3 and P5 it should be made clearer that note 1 AND note 9 apply, maybe by using a comma in-between, not a note 19 that I wasn't able to locate. For Note 9, reading the context it

applies only to P3, P5 and P6, but not to P1. To apply this to actual study methodology, in responding to a P1 event Note 9 can not be applied when returning the system to a continuous (sustainable) state. However after those adjustments are made if additional adjustments are needed to make the system "secure", that is prepared for the next event in the P3 or P6 contingency, then note 9 can be applied? Is this a correct understanding?

Yes

The phasing in of the higher performance criteria is a very reasonable approach. The implementation plan needs to be painfully clear that during the first year the existing TPL standards are still in effect, and that R1 and R8 are in effect in addition. Most NERC standards have one revision take effect on a specific date, make the old version out of date. In this case however if TPL 001 retires the prior standards, then only R1 and R8 would need to be performed in the first year, which I do not believe that is the intent. In addition to this, further clarification may be needed for the application of R2-R7, even if they were to come into effect the first year. Assessments are a year long process and published once a annually. As an example many entities "publish" or finish the Assessment in December, that being the culmination of months of work. If R2-R7 are effective on June 2011 then the intended application seems to be that the assessment in Dec 2011 should comply with the new standard. Is that the intent, or would there need to be a valid assessment based on the new standard available the day the standard is in effect? Maybe phrasing to this effect. "Entities are not required to alter there annual schedule based on the R2-R7 requirements going into place or have duplicate efforts at assessments in the annual period the old and new standard overlap. Any assessment completed (as determined by the date that the entity formally shared results under R8) after the effective date for R2-R7 shall comply with those requirements."

Yes

I have not seen all the comments of other entities, so there may be some comments that would require the standard be reposted. Assuming I have correctly read the standard, all of my comments would improve the communication of the existing intent, not alter the requirement.

Group

Exelon Transmission Planning

The feedback from Round 3 of comments is appreciated, but there is still a concern that the inclusion of known (or 'expected') transfers is to be studied as a sensitivity. We believe that the base case should already contain the most likely ('expected') transfer scenario and a sensitivity case would be studied with a less likely transfer scenario. As written it appears that the standard would require that the base case would contain no transfers or some transfer level other than what is 'expected'. It is suggested the term "Expected transfers" be changed to "Additional transfers beyond base case conditions". The use of this term will provide clarity between what is to be modeled in the basecase and what is to be studied as a sensitivity case. There are a number of overlapping requirements with this standard and other standards in various stages of development, such as voltage stability criteria, protection system redundancy, relay loadability, and protection system contingencies that could cause non-compliance with several standards for a single infraction. Suggest removing overlapping requirements be removed from R6, P5 from Table 1, R3.3.3 and R3.3.1, respectively.

We believe that the Table 1 performance criteria should be based on the voltage level of potentially overloaded elements and not based on the voltage level of the element(s) removed from service. If a 100 kV line were overloaded for a 500 kV contingency, it does not make sense to us to treat it differently than if the same overload occurred for a 100 kV contingency since the severity of the event is the same in both cases. The availability of load shedding to reduce overloads on EHV equipment and not for overloads on HV equipment makes sense since typically a greater amount of load would need to be shed to unload an EHV facility than an HV facility. We disagree with the requirement to report the largest amount of consequential load loss. If this information is not used to meet a requirement adding to reliability, it is creating undo burden. If the requirement is kept, it should be made clear as to which case or cases the requirement pertains. The Planning Assessment will contain extremely sensitive information. The threshold that it must be supplied to ANY functional entity is too low. There should be a CEII or other process to ensure that this information is adequately protected.

Yes

Yes

Yes

Yes

Concern is with the issues raised in Question 2. Performance requirements should be based on the voltage level of the overloaded element.
Individual
Martin Bauer
US Bureau of Reclamation
The requirement for the model is not clearly stated. Based on the requirement 2, the models must prove the Corrective Action Plan items developed in 2.7.1. The actions in 2.7.1 are developed by the Transmission Planner or Planning Authority ("List System deficiencies and associated actions needed to achieve required System performance"). Requirement 1 however requires that the model "shall represent projected System conditions". Is the intent of the modelling to demonstrate system performance based on changes proposed by the Tranmission Owners and Generator Owners. Or is it the intent to have the Transmission Planner and Planning Authority develop proposals through system studies that the Transmission Owners and Generator Owners must implement?
The conflict is created in Section 2.5 in that only proposed generation additions or changes are assessed in "Long-Term planning Horizon portion of the Stability analysis. This Section should also address proposed transmission facility additoins or changes. Section 2.7 indicates that the Planning Assessment shall include Corrective Action Plan(s) addressing how performance requirements will addressed. This implies that the Corrective Action plans are not proposed generation or transmission additions or changes. If Corrective Action Plan items are developed through Planning Assessments, they should be clarified as proposals for consideration by Generator Owners and Transmission owners in developed future system modifications or additions.
No comment
No comment
The requirement in Table 1 is for Planning Authority and Transmission Planner to establish accceptable voltage deviations and limits. The requirement only indicates the that each shall have a criteria. That does not imply an agreement on a single limit or deviation allowable under a System Steady State post-contingency condition.
No comment
No comment
Results of the Planning Assessments should be coordinated with all owner entities who all share in system reliability. Any owner that may choose to implement a Corrective ACtion Plan item should have access to the basis for the need.
No
The term "Conssequential Load Loss" and "Planning Assessment" contain the terms "Transmission System" and/or "Transmission Facilities". The terms "Transmission System and Transmission Facilities are not defined in the NERC Glossary of Terms. The terms should either be in lower case or a definition added. The Term "Non-Consequential Load Loss" refers to a "Non-Interruptible Load" loss which is other than Consequentail Load Loss. There is no mention in the Consequential Load Loss definition of the type of load (interrubtible or non-interrubptible). This adds confusion to what appears to be the distinction in the differences between the two, that one was the result of a fault and the other was the result of voltage.
No
Consequential Load Loss was defined, however, consequential generator loss was not. It may be easier to define "consequential loss" and let it apply to either.
Yes
No
The definitions require revisions. Additional work is required to clarify Corrective Action plan items, agreement on votlage limits and acceptable deviations, as well as coordination of Planning Assessment results with owner entities.
Individual
Michael R. Lombardi
Northeast Utilities
[R1.1.6] What is NERC's definition of "Resources required to supply load"? [Add R1.1.7] The standard is referring to requirements for sensitivity and other issues without a reference to base cases. There needs to be some direction provided on the initial conditions used in the assessment. This guidance should include a discussion as to whether or not generator forced outages are to be represented in the base cases. Additionally, the standard is also silent on the treatment of system transfers, both internal and external, as to how they should be modeled in the base cases. For some areas, their current practice is to include heavy system stresses in their base cases. It is unclear if this practice works within the purview of this standard. Therefore, it is recommended that each Region must have a document that defines what constitutes base case conditions.
[R2.1] The language of this requirement should be revised as follow: "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by

current or past studies as indicated in Requirement R2, part 2.6. The following studies are required:" [R2.1.2] Please clarify the load level to be used for "System Off-Peak Load". [R2.1.4] To include and define sensitivity cases and simulations in the standard NERC must also define base cases to be used in the assessments. Refer to comment suggesting the addition of Requirement R1.1.7. [R2.1.5] It is not clear whether a corrective action plan should be developed for this requirement and if we are to develop an action plan should it be temporary and cover only the time period that the major Transmission equipment was unavailable? [R2.2] The language of this requirement should be revised as follow: "The long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required:" [R2.3] Please provide guidance as to what year should be represented when performing short circuit studies or is it up to the Planner to select a year for the study? [R2.5] There is no guidance on the load level that should be used for the long-term stability study as is required by Requirement R2.2.1 for the Steady State assessment. [R2.9] Why the need to report the largest Consequential Load Loss since the TPL Standard does not limit the amount of Consequential Load that could be allowed? We recommend that this requirement should be deleted.

[R3.3.2] Traditionally, transmission planners have assumed that generators would ride through low voltages associated with Planning Events, which is generally adequate for non-wind generators. If this standard is going to require its incorporation into the assessments, there should be a MOD standard developed requiring the generator owners to provide the necessary information prior to its inclusion as a requirement in this standard. [R3.3.3] This requirement is already addressed in NERC Standard PRC-023 and reflected in facility ratings and therefore, should be removed from TPL-001-1. [R3.5] This requirement needs clarification as to what is specifically required for the "evaluation of possible actions". Otherwise the following is recommended: • It should be clear that an evaluation does not require solution development for all Extreme Events. • Change "an evaluation of possible actions…" to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered." [R3.6] Why the need to report the amount of "Consequential Generation Loss" since TPL-001-1 does not impose any limit or reliability consequence? We recommend that this requirement be deleted from the standard.

[R4.1.1] This requirement needs better clarification. Does it mean that a generator that trips on any other condition apart from tripping on out-of-synchronism is acceptable? Example if the generator is not able to ride through a low voltage condition created by a fault. We recommend that this requirement is dropped from TPL-001-1 standard. [R4.1.2] This approach will require a different modeling technique from current practice and will require an implementation period. [R4.3.2] Refer to comment for Requirement R3.3.2. [R4.5] This requirement needs clarification as to what is specifically required for the "evaluation of possible actions". Otherwise the following is recommended: • It should be clear that an evaluation does not require solution development for all Extreme Events • Change "an evaluation of possible actions…" to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered."

[R8.1] There is no statute of limitation for comments, nor is there a limit on the number of comments. There is also potential conflict with the deadline for completing a study and when comments may be submitted. If this requirement is retained the following is suggested: "Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to the functional entities that the Planning Coordinator recognizes as having a reliability need for the Planning Assessment results".

No

[Comment on Year One Definition] This still defines Year One as both a particular year AND a window. It cannot be both. We suggest rewording the second sentence to read: "This is further defined as the beginning 12-18 months from the end of the current year".

No

[Comment on Non-Consequential Load Allowed for certain Planning Events] We recommend that the standard as written should not allow non-consequential load loss to be used to resolve violations arising from the planning events in Table 1. We believe that planning for a reliable power system should discourage mitigation by load loss. Therefore, Non-Consequential Load Loss should not be allowed in a future looking system plan. [Comment on Table 1 Item e, under Steady State & Stability] Our understanding here is that we should be able to redispatch after the first contingency (using fast start generation) to secure the system in anticipation of a second contingency and not redispatch to fix first contingency violations. Is this interpretation correct? Further, this standard doesn't specify which units can be adjusted following the contingency. This seems to stress the fact that the standard needs to address the definition of what is a base case. Also, the standard should be clear on whether we can or cannot rely on generation redispatch after the first contingency, i.e., should the failure of a fast start generator to start up be included in the contingency, or is this another level of contingency? [Comments on Footnotes] Footnotes 1, 10, 11, 19 and 101 need to be fixed. They are either mislabeled or do not point to any item.

Yes

No
Individual
Alice Murdock
Xcel Energy
R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.
R2.1 The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies…", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies…" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies…" R2.1.5 Does "The Planning Assessment shall reflect" mean that the entity must meet the performance requirements for categories P0,P1,and P2 during the equipment unavailability? R2.9 As commented in the previous draft, we do not believe this requirement contributes anything to improving BES reliability. Therefore, we strongly recommend deleting this requirement.
R3.3.3 Xcel does not believe that relay loadability limits is a valid system planning performance criterion because we are unsure how transmission relay loadability settings developed in accordance with PRC-023 can be more limiting than the Facility Ratings. Note that the purpose of PRC-023 standard is "Protective relay settings shall not limit transmission loadability…" and it requires that the relay settings be higher than the "highest seasonal Facility Rating of a circuit". If relay settings limit the transmission loadability below its Facility Rating, then it is a violation of PRC-023. Requirements R3.4 and R3.5 appear to be related to and set the limits for R3.1 and R3.2 respectively. Suggest moving both Requirements R3.4 and R3.5 into R3.1 and R3.2, allowing these sub-Requirements (R3.4 and 3.5) to be deleted. R3.3 It is unclear from the wording in R3.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R3.1 and R3.2. Please clarify the wording of R3.3.
4.3 Does the requirement allow it to be optional as to whether an entity chooses to include generator exciter controls, PSS, etc.? To what degree must a device impact the study area, in order for it to be required to be included in the simulation? Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. R4.3 It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful and unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If it is the intent to require that entities assess both, we suggest including the assessment in the list of sensitivities.
R8 Xcel Energy appreciates the language stating 'reliability need' however it is unclear as to what constitutes this or who would make that determination. Please clarify so as to avoid future disputes on providing or obtaining the information.
No
The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language follows Non-Interruptible Load loss other than: • Consequential Load Loss • the response of voltage sensitive Load • Load that is disconnected from the System by end-user equipment. This version uses the same wording but clarifies that the term "other than" applies to all three things.
No
There are references to footnote 12 on page 19, and footnote 101 on page 17, yet no such footnotes exist on page 20. Some of the other footnotes seem to be misplaced. Please review and validate all footnote references.
No
Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem, or five years from the modeled year, or five years from the effective date of this standard.
No

As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different.
Individual
David Wang
San Diego Gas & Electric Co
R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. R1.1.5 "firm transmission service agreements" should be removed the from the requirement. Firm transmission service agreements, "known" or otherwise, have no effect on reliable operation of the grid; power will flow where it wants, not where, or how, the firm transmission service agreement may specify. From a reliability perspective this information is of no use.
The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies…", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies…" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies…" It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.
For clarity we suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits.
Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
No
The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language follows Non-Interruptible Load loss other than: • Consequential Load Loss • the response of voltage sensitive Load • Load that is disconnected from the System by end-user equipment.
No
As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different.
No
Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
No
Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.

Individual

Dan Rochester

Independent Electricity System Operator

Please explain what is envisaged by the phrase "and shall represent projected System conditions." that is not already covered by the list in Requirement R1, part 1.1. We suggest removing the phrase. We do not have any comments on the, measure, VRF and Time Horizon. Consistent with our comment above, we believe that the 2nd condition under the Severe VSL is (a) vague, and (b) already covered by parts 1.1.1 to 1.1.6. This second condition is not needed.

(1) Part 2.1.4: We do not believe the sentence: "To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance." is necessary or measurable. The first part of 2.1.4 already stipulates sufficient details for the responsible entity to conduct sensitivity analysis including the parameters to be varied. Adding the "how-to conduct" requirement is overly prescriptive and unnecessary, and the condition for "that demonstrate a measurable change in performance" is not measurable. It lacks a definitive target or direction for the responsible entity to determine (a) what conditions need to be attained to demonstrate a measurable change in performance, (b) what constitutes "measurable change in performance", and (c) what follow-up or corrective actions are needed to address the adverse performance as a result of stressing the system beyond the forecast conditions. In our comments on Draft 1, we disagreed with the requirement to conduct sensitivity testing. This is part of the analysis exercise that planners normally perform to help them identify critical parameters/conditions for consideration in planning assessments and in developing remedial plans. Having a reliability requirement to stipulate the details of sensitivity analysis is unnecessary but produces much increased work whose acts are difficult to measure and whose results are not taken any further to arrive at a useful outcome. Once again, we urge the SDT to consider dropping this requirement. (2) Part 2.3 stipulates the short-circuit assessment requirements for the near-term horizon. Unlike its steady-state and stability counterparts, there are no requirements stipulated for short-circuit analysis for the long-term horizon. Is this intentional? If so, we are unable to identify the rationale for this decision. If not, we suggest revising Part 2.3 to: "The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the near-term and long-term Transmission Planning Horizons and can be supported by…." (3) R2.4.1: We believe that "considering the behavior of induction motors" is not necessary since the wording "a Load model which represents the dynamic behavior" already covers this. (4) In part 2.5, we recommend inserting the text "and Transmission Facilities" after "generation" to be consistent with the wording of part 2.3 (5) As drafted, the VLSs do not address missing certain combinations of parts of Requirement R2. For example, the condition assigning a Low, Moderate or High VSL is the failure of one of the parts listed under these columns. There is no assignment for failing more than one of the listed parts. We propose adding a second condition under the High VSL as follows: "OR two or more of parts 2.3, 2.6, 2.8 and 2.9.". Also, part 2.5 is missing from the SEVERE VSL. We recommend including it. As written, it is possible to miss say parts 2.1 and 2.5 and still not be captured under the Severe VSL if that is the intent.

(1) R3 has become more of a "how to" requirement than a "what" requirement, as illustrated below. (a) Part 3.3 is overly prescriptive. A requirement that says contingency analysis shall be performed which reflect proper operation of all Protection Systems and actions of all automatic devices would suffice. If necessary, some examples such as those listed in Part 3.3.4 may be added as illustration. (b) The parts that ask for creating a list of contingencies and having rationale available as supporting information, in Part 3.4 for example, are overly prescriptive and unnecessary. These are documentation requirements, not reliability requirements. If one asked the question: will reliability be adversely affected if the responsible entity failed to document the list and the rationale for choosing this list? If the answer is no, then they don't rise up to a reliability standard. To meet the intent of Part 3.4, a simple requirement that asks the responsible entity to demonstrate acceptable system performance for the applicable planning events in Table 1 would suffice. Table 1 already stipulates the events that must be considered in the analysis. We do not see the need to go into such details as "some events are expected to produce more severe impacts…", and the need to ask the planners to create a list of these more impactive contingencies for subsequent evaluation. Similar observation is made for Part 3.5 on the extreme event list and for Part 3.6 for the amount of generation loss, and the rationale. (2) We have no comments on the measure, VRF and Time Horizon. However, there is no VSL for Part 3.6.

(1) Part 4.3: Similar comments on Part 3.3 provided under Q3 also apply here. (2) Parts 4.4 and 4.5: similar comments on Parts 3.4 and 3.5 provided under Q3 also apply here. (3) We do not have any comments on the measure, VRF, Time Horizon and VSLs.

(1) We do not have any concern with the requirement as written, but suggest the SDT consider adding "and associated reactive power requirements" after "acceptable System steady state voltage limits" to take care of the concern raised in the recently posted SAR for a new VAR standard. We do not think a new standard is required for stipulating reactive power requirements as they are best addressed in the planning assessment criteria and the SOL/IROL determination requirements. (2) We do not have any comments on the measure, VRF, Time Horizon and VSL.

We do not have any comments on the requirement, VRF, Time Horizon and the VSL. However, Measure M6 (which refers to "studies utilized in preparing the Planning Assessment") does not seem to be

relevant to Requirement R6, which deals with defining and documenting the criteria and methodology used in the analysis to identify System instability.

No comments on the requirement, measure, VRF, Time Horizon and VSLs.

(1) No comments on the requirement, measure, VRF and Time Horizon. (3) VSLs: (a) We do not agree with the Severe VSL condition. In our view, distributing planning assessment results is the intent of the requirement; it is more important to share results than to field questions from recipients of the results. Assigning a Severe VSL for failing Part 8.1 puts the driver at the wrong place. (b) The condition under Low and High seems to be the same. In the Low, failing to distribute the results to ANY ONE of the TPs and PCs means none, which is the same as the condition for High unless the condition under Low really means failing to distribute the results to ONE of the TPs and PCs whereas the High really means failing to distribute the results to two or more of the TPs and PCs. If this is the proper interpretation, then we'd suggest the VSLs be revised as follows: Low: failing to respond to comments within 90 days High: failing to distribute the results to one of the TPs and PCs Severe: failing to distribute the results to two or more of the TPs and PCs. Alternatively, a Moderate can be added to capture the condition for failing to distribute the results to two of the TPs and PCs, while the Severe can become failure to distribute the results to three of the TPs and PCs.

Yes

Yes

Yes

No

The standard has become overly prescriptive and unnecessary (see our comments under Q2, Q3 and Q4 on Part 2.1.4, Parts 3.3 to 3.6, Parts 4.3 to 4.5. Much work is needed to condense or remove these requirements.

Individual

Jason Shaver

American Transmission Company

We propose the following changes and questions: R1 – We interpret that "within their respective areas" refers the geographic footprint of the TP or PC transmission system. We propose clarifying that "within their respective area" does not require the inclusion of remote generation or load (metering) buses that are within the declared Balancing Authority area, but may be outside and separate from the TP or PC geographic footprint. R1.1.2 – We suggest that this requirement be removed because the "known outage(s)" are only to be included in the models when P1 events are simulated, as specified in R2.1.3. We suggest that the intent of this requirement can be more simply handled by stating in R2.1.3 that "known outages be simulated along with P1 events for the System peak or Off-Peak conditions when the outages are scheduled to occur". R1.1.3 – Add the qualification of "for the years defined in R2". R1.1.6 – We interpret that "Resources required" allows the inclusion of fictional generators in the models when they are needed to make future normal system cases solve. If this is not the intended interpretation, then we suggest modifying the wording to make the desired interpretation more clear. M1 – Revise M1 to indicate that each responsible entity must provide evidence with the added qualification, ". . . it is maintaining System models within its respective area, using the latest . . ."

We propose the following changes and following questions: New R2.1 – We suggest that R2.6 be relocated to the R2.1 position to allow the preferred style of backward references to text that occurs earlier in a document, rather than forward references to text that appears later in a document. R2.1.3 – As noted above, we suggest that R1.1.2 be removed and that R2.1.3 be revised to state that "Known outages of generation or Transmission Facilities with a duration of at least six months be simulated along with P1 events for the System peak or Off-Peak conditions when the outages are scheduled to occur." We interpret that simulation of known outages of at least six months should refer only to individual outages with duration of six months or more have to be simulated and not a set of sequential (back-to-back) outages where each individual outage is less than six months, but the composite duration of the set is more than six months. We also interpret that if two or more known outages with duration of at least six months are overlapping that the outage would be simulated as simultaneous for the System peak or Off-Peak conditions when the overlapping outages are scheduled to occur. R2.1.4 – The terms of 'credible' and 'measurable change" are ambiguous and not defined. Therefore, we suggest that these terms be defined or more clearly described to avoid the risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. R2.1.4 bullet items – We suggest that the number and description of the bullet items in R2.1.4 match the bullet points in R2.4.3. Otherwise, please explain the reasons for any differences between the bullet items in R2.1.4 and R2.4.3. R2.1.4 bullet #2 & # 5 – We suggest that the wording of bulletin #2 be changed to "Expected transfers and other generation dispatch scenarios". This modification would put the transfer and dispatch element, which are complementary, together in the same bullet item, rather than grouping the 'generation dispatch' (operating level) element together with the generation capacity elements in bullet item #5. R2.1.4 bullet #7 – We propose replacing the adjective "planned" with "known" for consistency with R2.1.3 and any other 'known' references in the standard. R2.1.5 – We propose replacing the term

	'major Transmission' with "BES" because BES is a well defined term, while 'major Transmission' is not. New R2.3.1 – We suggest the addition of new R2.3.1 to emulate the distinction between the requirement to perform a short circuit assessment and conduct required studies or analysis to support the assessment (e.g. R2.1/R2.1.1 and R2.2/R2.2.1). We propose wording such as, "Perform an analysis for at least one year in the Near Term Transmission Planning Horizon." This requirement would set an expectation that an analysis should be conducted to at least one or more years in the near-term planning horizon, rather than imply that an analysis of all five years in the near-term planning horizon must be conducted. R2.4.1 - The terms of 'study area' and 'represents' are ambiguous and not defined. Therefore, we suggest that these terms be more clearly described to avoid the risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. R2.4.3 – The terms of 'credible' and 'measurable change' are ambiguous and not defined. Therefore, we suggest that these terms be defined or more clearly described to avoid the risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. R2.4.3 bullet items – We suggest that the number and description of the bullet items in R2.1.4 match the bullet points in R2.1.4. Otherwise, please explain the reasons for any differences. R2.4.3 bullet #2 & # 5 – We suggest that the wording of bulletin #2 be changed to "Expected transfers and other generation dispatch scenarios". This would place these similar items in the same bullet item #2, rather than having the 'other generation dispatch' in bullet item #5. R2.4.3 bullet #3 – We suggest that the wording of "new or modified Transmission Facilities" to agree with the wording in bulletin #3 of R2.1.4. R2.6 – As noted earlier, we suggest that the numbering of this requirement be changing it to R2.1 to avoid the style of forward references. Add R2.7.1 Item #7 - We propose the addition of the following bullet item to R2.7.1 because any requirement in the head notes or foot motes of Table 1 should occur within the body of standard. Item #7 could read, "Planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration of the Facility Ratings." Note "e" in the Planning Events, Steady State & Stability section is stated in the form of a Requirement (e.g. use the verb "shall"), but all requirements should be included in the Requirements section and not introduced (and basically hidden) in the performance notes of Table 1. [After bullet item #7 is added, Note "e" under "Steady State & Stability section of Table 1 should refer to R2.7.1] R2.7.2 – We suggest using the term, "mitigation actions", to more clearly distinguish that this requirement is not asking for the development of "Corrective Action Plans", such as those that are needed for inability to meet base case performance requirements. R2.7.6 – We suggest that the wording of R2.7.6 be the same as R.2.8.2. Otherwise, we propose that R2.7.6 and R2.8.2 be revised with wording like, ". . . implementation status of identified Corrective Action Plans for System Facilities and Operating Procedures." to clarify that the identified system facilities and operating procedures refer only to those that were in the previous year's Corrective Action Plans. R2.9 – We still propose that this requirement be removed because annually stating the single, largest expected, Consequential Load Loss due to a P1 or P2 event in the TP or PC system is not needed to provide reliable BES performance or assure open and transparent Transmission planning peer review.
	We propose the following changes and questions: R3.3.1 – The term of 'controls' is ambiguous and not defined, unlike the term, 'Protection Systems', which is defined. Therefore, we suggest that this item be defined or more clearly described to avoid the risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. R3.3.1 – Add the wording, ". . . including the simulation of transmission circuit loadability protection." to this requirement, rather than have a separate R3.3.3 requirement for recognizing overload protection. Overload protection is simply one of the types of automatic Protection System that may remove one or more elements from service. R3.3.2 - We suggest qualifying which generating units to consider and which voltage limits to simulate with revised wording like, "Trip generating units that are connected to the BES when actual or assumed minimum generator steady state or ride through voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment". The requirement should not apply to all relevant generating units until one of the MOD standards requires all Generator Owners to provide their minimum generating unit voltage limits to the TP and PC. If the wording of R3.3.2 must be different from its counterpart, R4.3.2, then please explain the reasons for any differences. R3.3.3 – As noted above, we suggest that R3.3.3 be removed and that this System Protection loadability simulation requirement is included in R3.3.1 because overload protection is simply one type of automatic Protection System actions. Add R3.3.5 – We suggest the addition of R3.3.5 because any requirement in the head notes or foot notes of Table 1 should occur within the body of standard. The text of R3.3.5 should read, "Applicable System Operating Limits for the planning horizon shall not be exceeded." Presently, Note "a" and "b" under "Steady State Only" at the beginning of Table 1 are stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and basically hidden) in the performance notes of Table 1. [After R3.3.5 is added, Note "a" should be revised and refer to R3.3.5.] Add R3.3.6 – We suggest the addition of R3.3.6 because any requirement in the head notes or foot motes of Table 1 should occur within the body of standard. The text of R3.3.6 should read, "The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to steady state voltage requirements." because Note "d" under "Steady State Only" at the beginning of Table 1 is stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and basically hidden) in the performance notes of Table 1. [After R3.3.6 is added, Note "d" should be revised to refer to R3.3.6.] R3.5 - We interpret that R3.5 requires the TP and PC to conduct an

evaluation of possible actions to reduce the likelihood or impact of extreme events, which produce the more severe impacts, if cascading outages may occur. Does the drafting team intend for the TP and PC to fulfill this requirement for at least one event in each of the five categories (i.e. 3 steady state and 2 stability) or in each of the 21 categories/sub-categories (i.e. 14 steady state and 7 stability). Also, if the resulting cascading outages do not result in any overloads, under-voltages, voltage collapse, or loss of generator synchronization, then should the evaluation of possible actions to reduce likelihood or impact be required? R3.6 – We suggest the wording of this requirement be revised to, "Manual or automatic generation runback or tripping is permitted to meet steady state performance requirements for planning events P1 through P7 in Table 1." because Reliability Standard PRC-015-1 already includes requirements regarding the review and approval of Special Protection Systems. Therefore, the Planning Assessment does not need to duplicate description of the design and intent of the Special Protection System.

We propose the following changes and pose the following questions: R4.1.1 – We suggest that there should be some qualification of which generating units are referred to in this requirement. We propose that the requirement say, "No generating unit connected to the BES shall pull out of synchronism." For example, some utilities include smaller generation units that are connected at voltages below 100 kV and even down to distribution voltage in their base cases. R4.1.2 – We propose that the wording of this requirement be revised to reflect the same BES qualification of the generating unit that we noted in R4.1.1 above. 4.3.1 – This requirement refers to high speed reclosing and we presume that this is special high speed reclosing that is completed in several cycles, rather than the normal high speed reclosing that is completed in a number of seconds. We recommend that the term high speed reclosing be defined for this sub-requirement. R.4.3.2 – We suggest qualifying which generating units to consider and which voltage limits to simulate with revised wording like, "Trip generating units that are connected to the BES when actual or assumed minimum generator transient voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment". The requirement should not apply to all relevant generating units until one of the MOD standards requires all Generator Owners to provide their minimum generating unit voltage limits to the TP and PC. If the wording of R4.3.2 must be different from its counterpart, R3.3.2, then please explain the reasons for any differences. R4.3.3 – Every dynamic event simulation involves power system transient swings. What are the size and scope of the transient swings and what is the scope of the system to be examined, to which this requirement is referring? Please reword this requirement to give the industry a better understanding of what is intended. Add R4.3.5 – We suggest the addition of R4.3.5, "Applicable System Operating Limits for the planning horizon shall not be exceeded." Note "a" and "b" under "Stability Only" at the beginning of Table 1 are stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and basically hidden) in the performance notes of Table 1. [After R4.3.5 is added, Note "a" should be revised and refer to R4.3.5.] Add R4.3.5 – We suggest the addition of R4.3.5, "Applicable System Operating Limits for the planning horizon shall not be exceeded." because Note "a" and "b" under "Steady State Only" at the beginning of Table 1 is stated in the form of a Requirement (e.g. note usage of the verb, "shall") and all Requirements should be clearly included in the body of the standard and not be introduced (and basically hidden) in the performance notes of Table 1. [After R3.3.5 is added, Note "a" should allude to R3.3.5.]

R5 – This requirement should not include the criteria item, "post-Contingency voltage deviation", because this criteria is not used widely enough in the industry to be a well established criteria.

Revise part of the requirement text to read, ". . . identify each entity's individual and joint responsibilities . . ." to provide better clarity. Perhaps this requirement should be listed at the beginning of the Requirements section, instead being mentioned near the end of this section.

No

We suggest the following changes: Add a Consequential Generation Loss definition, which would be a complement to the Consequential Load Loss definition. Both consequential load loss and consequential generation loss are referred to in note "b" of the Steady State & Stability section of Table 1, but only consequential load loss is defined. We suggest text of: "Consequential Generation Loss: All Generation that is no longer delivered to any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions." Revise the Consequential Load Loss definition to include protection for abnormal operating conditions. We suggest text of: "Consequential Load Loss: All Load that is no longer served by any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions." Revise the Planning Assessment definition to more explicitly apply to the BES and the TPL-001 requirements. We suggest text of: "Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies in the BES from the steady state and stability performance requirements set forth in the TPL-001 standard." Add a Planning Horizon definition. This term is used in this proposed standard, in the FAC-010-2 standard, and possibly in other future standards, but it has not been defined yet.

No

We suggest the following changes: Note "e" in the Planning Events, Steady State & Stability section - After bulletin item #7 is added to R2.7.1 as proposed above, refer to this bulletin item with wording like, ". . . applicable to the Facility Ratings (as noted in R2.7.1).". Note "a" and Note "b" in the Planning Events, Steady State Only section – Both of these notes are stated in the form of a Requirement (e.g. use the verb "shall"), but all requirements should be included in the Requirements section and not introduced (hidden) in the performance notes of Table 1. After R3.3.5 is added as proposed above, replace Note "a" and "b" with wording from R3.3.5, "Applicable System Operating Limits for the planning horizon shall not be exceeded, as stated in R3.3.5.". Note "a" and "b" can be combined and replaced with a single Note because the observance of System Operating Limits related to steady state conditions covers both items. Note "d" in the Planning Events, Steady State Only section – This note is stated in the form of a Requirement (e.g. use the verb "shall"), but all requirements should be included in the Requirements section and not introduced in the performance notes of Table 1. After R3.3.6 is added as proposed above, replace Note "d" with wording from R3.3.6, "The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to steady state voltage requirements, as stated in R3.3.6." Note "a" and Note "b" in the Planning Events, Stability Only section – Both of these notes are stated in the form of a Requirement (e.g. use the verb "shall"), but all requirements should be included in the Requirements section and not introduced in the performance notes of Table 1. After R4.3.5 is added as proposed above, replace Note "a" and "b" with wording from R4.3.5, "Applicable System Operating Limits for the planning horizon shall not be exceeded, as stated in R4.3.5.". Note "a" and "b" can be combined and replaced with a single Note because the observance of System Operating Limits related to stability covers both items. P3 – Modify the P3 Category performance criteria to apply only to the loss of two generators because the probability of the loss of two base load generators is an order of magnitude greater than the loss of a generator and any other transmission element. We suggest the listing of: the loss of transmission circuit, transformer, shunt device, and single pole of DC line be removed from the P3 Events column. Move the "generator + another element" events to the P6 Category by adding "1. Generator" to the listing in the Initial System Condition (Loss of . . .) column. Item 2.a in the Extreme Events, Steady State section – Clarify the meaning of the loss of multiple circuits in Item 2.a by using wording similar to P7. We suggest this text: "a. Loss of three or more circuits that share a common tower." Item 3.b of the Extreme Events, Steady State section – Clarify the reference to actual, historical operating experience in Item 3.b. We suggest this text: "b. Other events based upon actual operating experience that may result in wide area disturbances." Item 2.i of the Extreme Events, Stability State section – Clarify the reference to actual, historical operating experience in Item 2.i. We suggest this text that is similar to Steady State, Item 3.b: "i. Other events based upon actual operating experience that may result in wide area disturbances." Extreme Event sections are not updated to reflect the new footnote numbering (for instance Item 2a and Item 2b of the Steady State column). Footnote 6 – Further clarify the applicable shunt devices in Footnote 6 with this suggested text: "6. Requirements which are applicable to shunt devices, also apply to FACTS devices that are connected to ground, but not instrument voltage transformers or surge arresters."

No

We offer the following comments. This standard does not contain any requirements regarding the implementation of the Corrective Action Plans. So, the wording in this section of "Any entity that cannot fully implement . . . ", should be replaced with wording like, "If the Corrective Action Plans to eliminate the need . . . can not be implemented within 60 calendar months . . . then the TP and PA should work with the applicable TO(s) and Re(s) to develop mitigation plans for revised Corrective Action Plans until the implementation issue is resolved". The proposed standard implies that the 24 month time period (for R2-R7) and 60 month time period (for specific allowances for selected event categories) run in parallel rather than sequentially. As currently proposed, the effective date for performing analyses and developing subsequent Corrective Action Plans is 24 months. If the identification of new needs and action plans take 24 months, then only 36 months would be left to implement the new corrective action plans. It may not be feasible to install some BES facilities, especially above 300 kV, in less than 3 years. Some EHV projects can take 5 to 10 years to implement depending on the size, complexity, and controversial nature of the project. We suggest that the effective date be stated in more "implementation dependent" terms for this 'one time' transient period, rather than specific and possibly inappropriate "fixed timeframe" terms. Consider wording such as "tripping of Non-Consequential Load or curtailment of Firm Transmission Service (in accordance with Requirement R2, part 2.7.5) is allowed until Corrective Action Plans that are based on TPL-001-1 analyses can be implemented". The 'implementation dependent' approach may allow the removal of all or part of the text on implementation exceptions and mitigation procedures that do not appear to be suitable in an Effective Date section.

Yes

Yes, if the proposed changes and questions are adequately addressed.

Individual

R. Peter Mackin

Utility System Efficiencies, Inc. (USE)

For R1.1.5 I suggest changing the wording from "Known commitments for Firm Transmission Service and Interchange" to "Known commitments for Firm Transmission Service or Interchange". It is difficult

to distinguish between the two in future cases where not all contractual arrangements are known.

The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies…", while R2.1 implies current studies must be used but can be supplemented by past studies. I suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies…" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies…" It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same.

For clarity I suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits.

It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.

Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?

No

The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language follows Non-Interruptible Load loss other than: • Consequential Load Loss • the response of voltage sensitive Load • Load that is disconnected from the System by end-user equipment. This version uses the same wording but clarifies that the term "other than" applies to all three things.

No

As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service. Simulations of these outages would then be the same, even though the initiating event is different. I believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any footnote in the document, and some other footnotes seem to be misplaced. I would encourage drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.

Yes

No

Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, I believe additional modifications are necessary prior to taking this standard to ballot.

Individual

Mark Graham, on behalf of the Power System Planning Department

Tri-State Generation and Transmission Association

R1 - The changes to R1 seem good.

•R2.2 What is an "annual current study"? Would this include previously performed studies that are still applicable? •R2.2. What is "qualified past studies"? We have no definitions for "qualifying" previous work. This might be remedied by inserting the term "qualified" in R2.6. •R2.1.4. Sensitivity cases could add much work to the existing process. However, the standard calls for "at least one" of the listed sensitivity studies to be performed. •R2.2.1. The requirement to perform a "current study" assessing expected System peak Load conditions, for one of the years in the Long-Term Transmission Planning Horizon, is extra work if a valid/qualified study is available. If the intention here is to have a valid study for at least one of the years 6 to 10, then perhaps some simple rewording will solve the problem. We ascribe to the concept of requiring annual assessments, but not necessarily requiring repeated analysis if system changes do not warrant restudy. •Hyphenate "in-service" •R2.6.1 Change "the study shall be five calendar years old or less" to: "the study is five calendar years old or less" •R2.6.2 change the phrase "shall not include any material changes" to "does not include any material changes •R2.6.2 it is not clear what is meant by "material changes" - different "Study conditions" or "changes that could cause different results for a particular study"?

•Thank you for removing the requirement to explain why "non-studied contingencies" would produce less severe results. •Don't say "R3, part 3.4". Instead, for much easier referencing of sections, just say

"R3.4". This applies throughout the entire Standard. •R3.5 In the phrase "extreme events in Table 1 that are expected to produce more severe System impacts", the term "extreme events" seems redundant with "more severe". If Extreme Events were capitalized, it would be apparent that the TP should choose more severe events typified by details listed in the Extreme Events section of Table 1.

•The standard needs to use the term "Dynamic Stability", not just "Stability", to differentiate between dynamic and voltage stability considerations. •R4.1 contains the phrase "based on the Contingency list created in Requirement R4.4". The contingency list is referred to in R4.4 (and R3.4), but is not created there. •In R4.3.1 the requirement for additional evaluation of "successful or unsuccessful high speed reclosing" is an additional performance requirement. Whether this refers to the possibility of reclosing mechanism failure, or the effectiveness of reclosing operations (there is some ambiguity here). •The reference to high speed reclosing in R4.3.1 is a good addition. For ease in auditing, it should be listed as a separate requirement (or sub-requirement).

R5 - no comment

R6 seems OK – but check M6. Should this refer to R2 and not R6?

•R7 - Duties of the Planning Coordinator are being created and changed as we go along, like changing rules of a flag football game as it is played. Is there any requirement that every TP have a PC? As far as we know, the PC was introduced as an additional authority level for regional or inter-utility study work. Previous R7 wording asked PCs and TPs to work together. The present wording implies that every TP must have a PC which is a separate entity, and that PC would dictate study responsibilities. The wording of R4.4.1 seems much better in this regard.

R8 - We find that web-site posting would be sufficient distribution if it were not for the need for auditability. Please consider a way to qualify web-posting as an acceptable distribution method.

No

•The SDT removed definitions of Extreme Events and Load Reduction. We still need to have some scale to differentiate N-1 from less likely but possibly higher impact events. However, we do understand that such a criteria will take some time to develop, and should perhaps be a separate subject addressed by a new SAR. •Year One has a flexible definition. It does not seem very intuitive. We can't say whether this is good or bad, although one entity's year one could overlap with another's year two.

No

•Extreme Events detailed at the end of Table 1 should be itemized in the same way as for so-called "Planning Events" at the beginning of Table 1. Steady State Extreme Event 1 would be EP1, Dynamic Stability Extreme Event 1 would be ED1, etc. Also, please use the term Dynamic Stability, not just Stability, as explained above. •It would be helpful if descriptions had unique identifiers, for example Dynamic Extreme Event 1 could be called N-1-1. •For Dynamic Extreme Event 1, the phrase "With an initial condition" conflicts with the phrase "prior to System adjustments" at the end of the sentence. The term "initial condition" suggests a maintenance outage, or at least an outage that has sustained long enough for the system to have responded/adjusted. Footnote text does not line-up with the body text in the Extreme Event Table. •It seems to us that a bus-tie breaker would have the same chance of failure as another breaker. Therefore differentiation is not needed in Table 1.

No

Yes and No. We see some potential problems. 12 months after BOT adoption, R1 – maintain system models - becomes effective. Why delay? Also 12 months after adoption, R8 – distribute planning assessment results - becomes effective. As an assessment cannot be distributed before it is completed, this must be coordinated with R2. 24 months after BOT adoption R2 – Annual Planning Assessment - timing must coordinate with R8 above.

No

•The SDT needs to look at the Measures section more closely. •Please consider: In what jurisdiction could it be developed, and would it be possible to develop estimates of costs to meet the new requirements contained in this draft TPL by Reliability Area, then have utilities examine whether there will be a corresponding increase in Bulk Transmission System reliability? •The primary directive of NERC Reliability Standards is to improve system reliability and thus minimize potential cascading of the Bulk Electric System. This developing TPL Standard will provide some needed clarification and perhaps better uniformity of Planning Study work. Any Standard that would move us toward the primary goal should be attended to meticulously. The SDT must endeavor to ensure this standard moves us in that direction and does not simply give us more structure. That said, please use this guiding test as we put final touches on this standard: Will each Requirement decrease the potential of cascading outages and increase service reliability?

Individual

David Bradt

United Illuminating

R1.1.1 Make this read "Existing Facilities and Resources" so that it will be a lead in to the changes proposed for 1.1.6. R1.1.2 This type of event is sufficiently addressed within the existing testing requirements (P6) and therefore should be eliminated , beyond that such outages are reviewed and approved on an operational basis and should not be included in a planning standard. During known outages for equipment upgrades or repairs there may be some increased exposure to load loss, which

should be recognized as an acceptable exposure. In the event that this requirement is maintained please change six months to one year. 1.1.6.. Resources may not be exclusively sources supplying load. Therefore the reference should not involve load. The focus should be on changes to resources and "resources required to supply load" should be replaced with "New planned Resources and changes to existing Resources" We suggest NERC develops a definition for "resource" or use the following definition found in NPCC Glossary of Terms, Document A-7: Resource — Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load. ADD 1.2 – The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions. The standard must describe base assumptions.
2.1.3: In the event that R1.1.2 is kept it must be clear that the reference to outage schedules as listed in part 1.1.2 must be limited to the Planning Horizon. Table 1 - There is confusion in interpretation of the table 1 — When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading? 2.1 – Language should be revised similar to R2.4 as follows: "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required:" 2.1.2 –Should be moved to the list of sensitivities currently in 2.1.4. (Off-peak needs to be more specifically defined). 2.1.4 Consistent with the suggestion made for section 1.1.2 please remove the last bulleted item in the list under section 2.1.4. "Duration or timing of planned Transmission outages." To define a sensitivity, NERC must define base assumptions. Refer to Comment on Proposal to add an item 1.2 2.2 – The language in 2.2 should be revised to be similar to 2.4 as follows: "The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required:" 2.3 This should be modified to state that it is up to the Planner to determine the year of study within the Near Term Transmission Planning Horizon. 2.4.2 This should be deleted as it is covered under section 2.4.3. 2.4.3 To define a sensitivity, NERC must define base assumptions. Requirement 2.7 – We suggest changing the word "run" to "condition" such that it reads "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity condition in accordance with Requirements R2, parts 2.1.4 and 2.4.3." 2.9: The requirement to report the largest single consequential load loss under Requirement 2.9 should not be included in the standard. The TPL does not limit the size of the consequential load loss. If it remains, it must be made clear that it be applicable only to Year One or Year Two.
3.2 Item 3.2 should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. 3.3.2 This requirement is not practical unless a MOD is created so that known minimum generator steady state or ride through voltage limitations are used instead of assumed values. To create a MOD, collect the data, and incorporate the information into the studies will take time, which necessitates the need for an implementation period. Absent accepting this suggestion with respect to creating an MOD, please provide assumed minimum generator steady state or ride through voltage limitations as a standard reference for this analysis. 3.3.3 There appears to be a compliance double-jeopardy issue related to relay loadability. Relay loadability is handled in greater detail (as it should be) under the proposed PRC-023 standard, so any reference here should be deleted. 3.4 – It is suggested that this requirement is made a sub-bullet of Requirement 3.1 to keep the related requirements together. 3.5 and 4.5 – Both of these requirements need clarification as to what is specifically required for the "evaluation of possible actions." 3.5 – It is suggested that this be made a sub-bullet of Requirement 3.2 to keep the related requirements together. 3.6 Item 3.6 should be deleted since there is no limit defined in the standard.
4.1.1 This should be revised to only be applicable to generators interconnected to the BES. This may need an implementation period as not all existing units are interconnected in accordance with the standard as proposed. As written this applies to small generators and doesn't necessarily reflect reliability of the network. 20 MW is a recommended generator minimum size. 4.1.2 This will require implementation period. 4.2 Item 4.2 should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. 4.4 – It is suggested that this requirement is made a sub-bullet of Requirement 4.1 to keep the related requirements together. 4.5 – It is suggested that this requirement is made a sub-bullet of Requirement 4.2 to keep the related requirements together.
Voltage criteria is addressed by the VAR standards. Including a voltage requirement in the planning standards appears to be creating a double-jeopardy exposure. R5. Change to Read "Each Transmission Planner OR Planning Coordinator … Need time to implement transient voltage criteria.

R8, 8.1, and Measurement M8 – This standard should not be used to remedy deficiencies in meeting the coordination requirements of FERC Order 890. Therefore these should be deleted. If this requirement is retained the following is suggested: "Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to the functional entities that the Planning Coordinator and Transmission Planner recognizes as having a reliability need for the Planning Assessment results." Additionally, there is no statute of limitation for comments. There is also potential conflict with the deadline for completing a study and when comments may be submitted (e.g. comments are received the day before the study is to be completed.) These issues must be addressed. Measures M1: It is not practical to retain system model information in a hard copy form. This provision could be dropped. Compliance: D 1.1.4 Data Retention: The Transmission Planner and the Planning Coordinator may not be using the same software. If both are required to store the data, do they both have to have the software to use the data? Can this be changed to an 'or' such that one of them must retain the data and it can be up to them as to who it is. Also, the last bullet is unnecessary and should be deleted from the standard.

No

As currently defined "Non-Consequential Load Loss" could allow widespread or cascading motor stall. The language in the definition cannot be this generic. The text is broad enough that it could allow a voltage collapse, the definition is incompatible with Table 1a (BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur). The definition for the non-consequential load loss combined with Table 1 would prohibit any customer from tripping its own load for contingencies that indicate 'no' in the non-consequential load loss column. This is not practical and appears to be an unintended consequence of the change in definition. This requires a change in the definition or the table. We suggest clearly defining exactly what Non-Consequential Load Loss is as "intended post contingency loss of load caused by operator or SPS (RAS) action."

No

We generally agree with the table however our issues are as follows: Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft. Other footnotes appear to be mislabeled as well. If Extreme Events are not deleted from the standard, then a different number for the table for Extreme Events should be used. There is confusion in interpretation of the Table 1 — When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading? P5 –The use of the term "Protection System" in P5 is unacceptably inconsistent with the NERC definition of Protection System because it does not exclude the battery and its associated series elements. Extreme Events 2a – need to define tower line. Add language to replace "tower line" with "structure". Table 1, footnote #3, change Regional Entity to Regional Reliability Organization.

Yes

No

Group

NERC Standards Review Subcommittee

R1 – The MRO NSRS interprets that "within their respective areas" refers to the geographic footprint of the TP or PC transmission system. The MRO NSRS proposes clarifying that "within their respective area" does not require the inclusion of remote generation or load (metering) buses that are within the declared Balancing Authority area, but may be outside and separate from the TP or PC geographic footprint. M1 – The MRO NSRS recommends that words be added to M1 to indicate that each responsible entity must provide evidence that "it is maintaining System models within its respective area, using the latest…"

Add R2.7.1 Item #7 – The MRO NSRS proposes the addition of the following bullet item to R2.7.1, "Planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration of the Facility Ratings." because this explains what is allowed to be considered for Corrective Action Plan developments. [After bullet item #7 is added, Note "e" under "Steady State & Stability section of Table 1 should refer to R2.7.1.] R2.9 – The MRO NSRS still proposes that this requirement be removed because annually stating the single, largest expected, Consequential Load Loss due to a P1 or P2 event in the TP or PC system is not needed to provide reliable BES performance or assure open and transparent Transmission planning peer review. In general, standards should not contain requirements that don't improve reliability. R2.4.1 – The MRO NSRS recommends that the SDT clarify section 2.4.1 and when load models considering induction motors are required. The clarification should add limits or thresholds to provide load models based on areas that have stability limits or issues and to loads of substation size and having dynamic

characteristic capable of significantly impacting voltage stability. Areas that don't have large motors or stability issues should not be required to add unnecessary load modeling.

R3.3.1 – Revise the wording to add, ". . . including the simulation of transmission circuit loadability protection." The Protection System actions should be included in this requirement regarding proper Protection System simulation, rather than as a separate requirement in R3.3.3. Otherwise there would be in double jeopardy of violating R3.3.1. and R3.3.3 when circuit loadability protection is not properly simulated. R3.3.2 – The MRO NSRS suggests that this requirement be removed because it is premature to requirement Transmission Planners to simulate under voltage tripping until the MOD standards require it. If the drafting team does not remove this requirement the MRO NSRS proposes revised wording to qualify which generating units to consider and which voltage limits to simulate, "Trip generating units that are connected to the BES when actual or assumed minimum generator steady state or ride through voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment". The requirement should not apply to all relevant generating units until one of the MOD standards requires all Generator Owners to provide their minimum generating unit voltage limits to the TP and PC. If the wording of R3.3.2 must be different from its counterpart, R4.3.2, then please explain the reasons for any differences. R3.3.3 – As noted above, The MRO NSRS suggests that R3.3.3 be removed and this System Protection simulation requirement should be included in R3.3.1, which is the requirement to properly simulate Protection System actions. Add R3.3.5 – The MRO NSRS suggests the addition of R3.3.5, "Applicable System Operating Limits for the planning horizon shall not be exceeded." because Note "a" and "b" under "Steady State Only" at the beginning of Table 1 are stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and hidden) in the performance notes of Table 1. [After R3.3.5 is added, Note "a" should be revised and refer to R3.3.5.] Add R3.3.6 – The MRO NSRS suggests the addition of R3.3.6, "The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to steady state voltage requirements." because Note "d" under "Steady State Only" at the beginning of Table 1 is stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and hidden) in the performance notes of Table 1. [After R3.3.6 is added, Note "d" should be revised to refer to R3.3.6.] R3.4.1 – The MRO NSRS suggests that the word "coordinate" and the reference to the Transmission Planner be removed and offer the following revised text, "the Planning Coordinator shall provide the list of contingencies that are simulated in the adjacent Planning Coordinator area to the respective Planning Coordinator for review and feedback.". Standard Drafting Teams are generally instructed not to use the word "coordinate". The MRO NSRS suggests that this requirement apply to the PC because the PC would share with any affected Transmission Planners. R3.6 – The MRO NSRS suggests the wording of this requirement be revised to, "Manual or automatic generation runback or tripping is permitted to meet steady state performance requirements for planning events P1 through P7 in Table 1." because Reliability Standard PRC-015-1 already includes requirements regarding the review and approval of Special Protection Systems. Therefore, the Planning Assessment does not need to duplicate description of the design and intent of the Special Protection System. M3 & R3 Data Retention - The MRO NSRS proposes that the wording in these elements be revised to change "All" to "The". The word "All" is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: "The studies performed in support…."

R4.1.1 & R4.1.2 – The MRO NSRS proposes that these sub-requirements be removed. The generating unit loss of synchronism does not necessary result in a thermal, voltage, or stability violations. R4.1.1 - Wording from R4.1.1 about no generating unit pulling out of synchronism should be deleted. The simple loss of synchronism of a unit or even multiple units does not necessarily result in thermal, voltage, or stability. All standards and requirements should demonstrate a reliability related basis. There is no direct reliability or security requirement that prevents a unit from loosing synchronism. The loss of a unit from synchronism is no different than the regular loss of the unit for mechanical reasons, therefore this requirement unnecessarily results in FERC directing utilities to build infrastructure beyond what is needed for system security. R4.1.3 – The MRO NSRS proposes that this sub-requirement be removed because there are no NERC power system damping standards. R.4.3.2 – The MRO NSRS suggests that this requirement be removed because it is premature to requirement Transmission Planners to simulate under voltage tripping until the MOD standards require it. If the drafting team does not remove this requirement the MRO NSRS proposes wording like, "Trip generating units that are connected to the BES when actual or assumed minimum generator transient voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment". The requirement should not apply to all relevant generating units until one of the MOD standards requires all Generator Owners to provide their minimum generating unit voltage limits to the Transmission Planner and Planning Coordinator. If the wording of R4.3.2 must be different from its counterpart, R3.3.2, then please explain the reasons for any differences. R4.3.3 – Every dynamic event simulation involves power system transient swings. What are the size and scope of the transient swings and what is the scope of the system to be examined, to which this requirement is referring? Please reword this requirement to give the industry a better understanding of what is intended. As written R4.3.3, it might be interpreted to require responsible entities to add the modeling of all relaying instead of just pertinent. Perhaps, R4.3.3 should be limited to transient swings on facilities 345 kV and above so as to limit this part of requirement 4 to those situations that are most

likely to result in cascading. If the SDT determines not to add such a limitation, the MRO NSRS proposes that the implementation time for R4 to be increased. The MRO NSRS believes that many responsible entities would need 3 years to add these relaying models to system stability models so that the fourth year additional transmission planning analysis in this respect is conducted. The MRO NSRS urges that the SDT increase the implementation time for R4 from 2 years to 4 years. When it may actually respond or triggered. R 4.3.1 – This requirement refers to high speed reclosing and the MRO NSRS presumes that this is special high speed reclosing that is completed in several cycles, rather than the normal high speed reclosing that is completed in a number of seconds. The MRO NSRS recommends that the term high speed reclosing be defined for this sub-requirement with an angular stability component. R4.5 - The MRO NSRS believes that the extreme events that should be studied are the more credible ones. The credible events are those that the planner considers credible when considering both how severe the event is and how likely it is. For example, while a tornado might be the most severe event, its likelihood of hitting key facilities is quite low. It is more likely to have a severe thunderstorm that hits key facilities but causes less impact on the system. The planner should plan for the severe thunderstorm but perhaps should not plan for the tornado. The MRO NSRS recommends that 4.5 be revised to indicate that a list of those events that "produce more severe System impacts and are more likely" (the bolded words are suggested words to be added) be studied as being more credible events. Then the purpose of the last sentence in 4.5 is clearer in that possible actions that reduce the likelihood or mitigate the consequences of the events shall be reviewed for those contingencies where likelihood in combination with consequences justify such evaluation.

A. The MRO NSRS recommends the data retention for R5 and M5 be revised to change "All" to "The". The word "All" is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: "The documentation specifying the criteria since…." B. This requirement should not include the criterion, "post-Contingency voltage deviation", because this criterion is not used widely enough in the industry to be a well established criterion.

The MRO NSRS recommends the data retention for R6 and M6 be revised to change "All" to "The". The word "All" is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: "The studies performed in support…."

The MRO NSRS recommends the data retention for R7 and M7 be revised to delete "All". The word "All" is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: "The current, in force agreement on identified responsibilities, as well as such agreements in force…."

The MRO NSRS asks that the SDT revise R8 to limit the need to provide the Planning Assessment as follows "adjacent Planning Coordinators and adjacent Transmission Planners and to any registered functional entity…" This MRO NSRS suggestion is added to the requirement to clarify that the word adjacent also applies to Transmission Planners and to clarify that the functional entity must be registered in order for the entity to be applicable to the requirement.

No

A. Add a Consequential Generation Loss definition, which would be a complement to the Consequential Load Loss definition. Both consequential load loss and consequential generation loss are referred to in note "b" of the Steady State & Stability section of Table 1, but only consequential load loss is defined. The MRO NSRS suggests text of: "Consequential Generation Loss: All Generation that is no longer delivered to any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions." B. The MRO NSRS offers the following comment to one of the proposed definitions of TPL-001. Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss that is the result of the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment. C. Add a Planning Horizon definition. This term is used in this proposed standard, in the FAC-010-2 standard, and possibly in other future standards, but it has not been defined yet. D. The SDT is to be commended for working on the Year one definition, however, concerns exist that if the standard is adopted as written, it is incompatible with the eastern interconnection wide ERAG model process. E. If the SDT intends to change the planning processes and model building processes throughout NERC in this regard, then the SDT should explain the benefits of changing this process and verify that it does not sabotage the normal model building and study process.

No

A. P3 – Modify the P3 Category performance criteria to apply only to the loss of two generators because the probability of the loss of two base load generators is an order of magnitude greater than the loss of a generator and any other transmission element. The MRO NSRS suggests the listing of: the loss of transmission circuit, transformer, shunt device, and single pole of DC line be removed from the P3 Events column. Move the "generator + another element" events to the P6 Category by adding "1. Generator" to the listing in the Initial System Condition (Loss of . . .) column. B. The SDT should be commended for the changes that were made to Table 1. However, the MRO NSRS does recommend a few editorial changes. On page 16 under the Steady State and Stability heading is item d. Simulate Normal Clearing unless otherwise specified. This is also listed as footnote 2 to the table. The MRO NSRS recommends that item d under the Steady State and Stability heading be deleted. C. Why is there a

footnote 1 indicator to note j. under Stability only? The MRO NSRS suggests that this footnote 1 indicator be deleted. D. Item i. under Steady State only states that "the response of voltage sensitive Load that is disconnected from the System by end-user equipment" is not to be used to meet steady state requirements. However, the non-consequential load loss says yes meaning it is allowed for some events in the table and non-consequential load loss definition includes the "response of voltage sensitive Load that is disconnected from the System by end-user equipment." This seems to be a direct contradiction. The MRO NSRS suggests that Item i. under steady state only be deleted. E. The MRO NSRS does not understand why there is a footnote 19 indicator for P3 and P5 – EHV in the table when no footnote 19 exists. Perhaps the SDT meant footnotes 1 and 9 but The MRO NSRS recommends that this be corrected. F. The MRO NSRS does not understand why there is a footnote 12 indicator for Item 2 a and 2 b. on page 19. Perhaps the SDT meant footnotes 1 and 2 apply but The MRO NSRS recommends that this be corrected.

No

A. In the implementation plan, the provision which indicates if an entity doesn't construct in time that entity has to report itself as noncompliant. This is a violation of the energy policy act. Since FERC can't force an entity to built, this provision should be deleted. B. This standard does not contain any requirements regarding the implementation of the Corrective Action Plans. So, the wording in this section of "Any entity that cannot fully implement . . . ", should be replaced with wording like, "If the Corrective Action Plans to eliminate the need . . . can not be implemented within 60 calendar months . . . then the Transmission Planner and Planning Authority should work with the applicable Transmission Owner (s) and Regional entity(s) to develop mitigation plans for revised Corrective Action Plans until the implementation issue is resolved". C. The proposed standard implies that the 24 month time period (for R2-R7) and 60 month time period (for specific allowances for selected event categories) run in parallel rather than sequentially. As currently proposed, the effective date for performing analyses and developing subsequent Corrective Action Plans is 24 months. If the identification of new needs and action plans take 24 months, then only 36 months would be left to implement the new corrective action plans. It may not be feasible to install some BES facilities, especially above 300 kV, in less than 3 years. Some EHV projects can take 5 to 10 years to implement depending on the size, complexity, and controversial nature of the project. D. The MRO NSRS suggests that the effective date be stated in more "implementation dependent" terms for this 'one time' transient period, rather than specific and possibly inappropriate "fixed timeframe" terms. Consider wording such as "tripping of Non-Consequential Load or curtailment of Firm Transmission Service (in accordance with Requirement R2, part 2.7.5) is allowed until Corrective Action Plans that are based on TPL-001-1 analyses can be implemented".

No

More discussion is needed pertaining to this standard.

Individual

John Mayhan

Omaha Public Power District

In the first sentence of the requirement text, change "voltage limits" to "voltage".

No

The definition of Non-Consequential Load Loss is not clear. It's not clear whether "the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment" is considered to be Non-Consequential Load Loss or not. Based on previous drafts, it appears that the SDT's intent is that "the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment" is considered to be a special type of Consequential Load Loss--a type that transmission-planning entities are not allowed to rely upon to meet steady-state performance requirements. Comments on this fourth draft from one commenter seemed to indicate that he was interpreting the definition of Non-Consequential Load Loss to mean that "the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment" is considered to be Non-Consequential Load Loss. Consider breaking the definition of Non-Consequential Load Loss into two or more sentences to prevent misinterpretation and confusion. Also consider including a reference to "the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment" in the definition of Consequential Load Loss if this type of load loss is considered to be a special type of Consequential Load Loss. If this type of load loss is considered to be a special type of Consequential Load Loss, add the following sentence to the end of Note "b" at the top of Table 1: 'However, see Note "i" for a restriction that applies to steady state performance.'

No

If "the response of voltage sensitive Load including Load that is disconnected from the System by end-

user equipment" is considered to be a special type of Consequential Load Loss, add the following sentence to the end of Note "b": 'However, see Note "i" for a restriction that applies to steady state performance.' In Note "g", change "voltage limits" to "voltages". In Note "j", it appears that the reference to Footnote 1 is not needed. For Category P3, should the reference to Footnote 19 in the second column be a reference to Footnote 9? For Categories P3, P4, and P5, in the column labeled "Interruption of Firm Transmission Service Allowed", are the references to Footnotes 19 and 10 needed? For Category P4, should the reference to Footnote 101 in the first column be a reference to Footnote 10? For Category P4, should the reference to Footnote 11 in the third column be a reference to Footnote 10? In Items 2a and 2b of the "Steady State" subsection of the "Extreme Events" section, should the references to Footnote 12 be references to Footnote 11? In Footnote 1, change "loss of Non-Consequential Load" to either "Non-Consequential loss of Load" or "Non-Consequential Load Loss". (The point here is that the adjective "Non-Consequential" applies to the word "loss" rather the word "Load".) In the first sentence of Footnote 2, change "Normal Clearing faults" to "Normal Clearing of faults". In the second sentence of Footnote 2, remove the comma following the word "types". In Footnote 3, change "Non-Consequential Load" to either "Non-Consequential loss of Load" or "Non-Consequential Load Loss". (The point here is that the adjective "Non-Consequential" applies to the word "loss" rather the word "Load".) In the second sentence of Footnote 5, change "generator Step Up" to "Generator Step Up" to be consistent with the rest of the footnote.

Consideration of Comments on Fourth Draft of Standard TPL-001-1 — Project 2006-02

The Assess Transmission Future Needs Standard Drafting Team thanks all commenters who submitted comments on the fourth draft of the TPL-001-1 standard. This standard was posted for a 30-day public comment period from September 16, 2009 through October 16, 2009. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 67 sets of comments, including comments from more than 180 different people from over 85 companies representing all of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

Due to industry comments, the SDT has made the following clarifying changes;

- Definition: Non-Consequential Load Loss
- Requirement R1, part 1.1.6
- Requirement R2, parts 2.1.3, 2.1.4, 2.1.5, 2.3, 2.4, 2.4.3 bullet #3, 2.5, 2.6.2, 2.7, 2.7.1 bullets #1 and #4, and 2.9
- Requirement R3, parts 3.3, 3.3.2, 3.3.3 and 3.6
- Requirement R4, parts 4.1.2, 4.3, and 4.5
- Requirement R5
- Requirement R6
- Requirement R8
- Measures M1, M6, M7, and M8
- Table 1, Header notes 'b', 'f', and 'g', footnotes 1, 2, 3, 5, and 7
- Data retention for Requirement R1, R3, R5, R6, and R8
- VSLs for Requirements R1 and R8

While the changes cited address the vast majority of comments received, the following minority viewpoints remain:

- Continued concern over the value of the "raising the bar" for EHV Facilities
- Continued concern with excessive study or documentation requirements
- Concerns that the Implementation Plan could be interpreted to require construction (contrary to the Energy Policy Act of 2005)

In addition, several commenters requested that workshops be conducted to explain the details of the new standard. To date, the SDT has conducted 3 webinars and presented the standard at 2 different NERC standards workshops. In addition, the NERC Planning Committee has had 2 presentations and several regional entities requested and received presentations from SDT members. If Regional Entities wish to conduct seminars on the standard, SDT members from that region could be made available as participants in the discussions.

The SDT does not feel that this standard requires field testing prior to ballot. The SDT has not made any substantive or contextual changes with this posting and has determined that this standard is ready to go to ballot.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

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The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Bob Cummings	TIS	X	X		X	X				X	X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Eric M. Mortenson (Chair)	Exelon Energy Delivery		
2.	Mark Byrd (Vice Chair)	Progress Energy Carolinas		
3.	Gary Brownfield	Ameren		
4.	Kenneth A. Donohoo	Oncor Electric Delivery		
5.	Patricia E. Metro	National Rural Electric Cooperative Association		
6.	I. Paul McCurley	National Rural Electric Cooperative Association		
7.	Scott M. Helyer	Tenaska, Inc.		
8.	Israel Melendez	Constellation Energy Commodities Group		
9.	Hari Singh	Siemens Power Technologies International		8
10.	John M. Simonelli	ISO New England, Inc.		2
11.	Digaunto Chatterjee	MISO		2
12.	Steve Corey	New York Independent System Operator		2
13.	Dana Walters	National Grid USA	NPCC	9
14.	Hai Quoc Le	Northeast Power Coordinating Council, Inc.	NPCC	9

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
15. Bill Harm	PJM	RFC	9										
16. Wenchun Zhu	American Transmission Company	MRO	9										
17. Salva R. Andiappan	Midwest Reliability Organization	MRO	9										
18. Hector Sanchez	Florida Power & Light Co.	FRCC	9										
19. Pedro Modia	Midwest Reliability Organization	FRCC	9										
20. W. Perry Stowe	Southern Company Transmission Company	SERC	9										
21. Jay Caspary	Southwest Power Pool	SPP	9										
22. Wesley Woitt	CenterPoint Energy	ERCOT	9										
23. David Franklin	Southern California Edison Company	WECC	9										
24. Branden Sudduth	Western Electricity Coordinating Council	WECC	9										
25. Other Observers and NERC Staff													
2.	Group	Ben Li	SRC of ISO/RTO (Comments submitted by Mark Westendorf of Midwest ISO on behalf of Ben Li)		X								
Additional Member	Additional Organization	Region	Segment Selection										
1. Ben Li	IESO	NPCC	2										
2. Bill Phillips	MISO	MRO	2										
3. Mark Thompson	AESO	WECC	2										
4. Charles Yeung	SPP	SPP	2										
5. Steve Myers	ERCOT	ERCOT	2										
6. Patrick Brown	PJM	RFC	2										
7. James Castle	NYISO	NPCC	2										
3.	Group	Guy Zito	Northeast Power Coordinating Council--RSC										X
Additional Member	Additional Organization	Region	Segment Selection										
1. Ralph Rufrano	New York Power Authority	NPCC	5										
2. Alan Adamson	New York State Reliability Council, LLC	NPCC	10										
3. Gregory Campoli	New York Independent System Operator	NPCC	2										
4. Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2										
5. Kurtis Chong	Independent Electricity System Operator	NPCC	2										

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
6. Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC 1										
7. Saurabh Saksena	National Grid	NPCC 1										
8. Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC 1										
9. Brian D. Evans-Mongeon	Utility Services	NPCC 8										
10. Mike Garton	Dominion Resources Services, Inc.	NPCC 5										
11. Brian L. Gooder	Ontario Power Generation Incorporated	NPCC 5										
12. Kathleen Goodman	ISO - New England	NPCC 2										
13. David Kiguel	Hydro One Networks Inc.	NPCC 1										
14. Michael R. Lombardi	Northeast Utilities	NPCC 1										
15. Randy MacDonald	New Brunswick System Operator	NPCC 2										
16. Greg Mason	Dynegy Generation	NPCC 5										
17. Bruce Metruck	New York Power Authority	NPCC 6										
18. Chris Orzel	FPL Energy/NextEra Energy	NPCC 5										
19. Robert Pellegrini	The United Illuminating Company	NPCC 1										
20. Michael Schiavone	National Grid	NPCC 1										
21. Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC 3										
22. Gerry Dunbar	Northeast Power Coordinating Council	NPCC 10										
23. Lee Pedowicz	Northeast Power Coordinating Council	NPCC 10										
4. Group	Philip R. Kleckley	SERC Planning Standards Subcommittee			X							

Additional Member	Additional Organization	Region	Segment Selection
1. John Sullivan	Ameren Services Co.	SERC	1
2. Charles Long	Entergy	SERC	1
3. Scott Goodwin	Midwest Independent Transmission System Operator	SERC	1
4. James Manning	North Carolina Electric Membership Corporation	SERC	3
5. Jim Kelley	PowerSouth Energy Cooperative	SERC	1
6. Pat Huntley	SERC Reliability Corporation	SERC	10
7. Bob Jones	Southern Company Services, Inc.-Trans	SERC	1
8. David Marler	Tenessee Valley Authority	SERC	1

5. Group	Bob Cummings (Coordinator)	NERC System Protection and Control Subcommittee (SPCS)	X	X		X	X				X	X

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	John L. Ciufo	Hydro One, Inc	NPCC	1
2.	Jonathan Sykes	PG&E	WECC	1
3.	Michael McDonald	Ameren Services Company	SERC	1
4.	William J. Miller	Exelon Corporation	RFC	1
5.	Josh Wooten	Tennessee Valley Authority	SERC	9
6.	Sungsoo Kim	Ontario Power Generation Inc	NPCC	5
7.	Joe T. Uchiyama	U.S. Bureau of Reclamation	WECC	5
8.	Charles W. Rogers	Consumers Energy	RFC	4
9.	Joseph M Burdis	PJM Interconnection, L.L.C.	RFC	2
10.	Jim Ingleson	New York Independent System Operator	NPCC	2
11.	Bryan J Gwyn	National Grid	NPCC	1, 10
12.	Henry G Miller	AEP Service Corp	RFC	1, 10
13.	Richard P. Quest	Xcel Energy	MRO	1, 10
14.	John Mulhausen	Florida Power & Light Co	FRCC	1, 10
15.	Philip Winston	Georgia Power Company	SERC	10, 1
16.	Dean Sikes	Cleco Power LLC	SPP	1, 10
17.	Samuel Francis	Oncor Electric Delivery	ERCOT	1, 10
18.	Baj Agrawal	Arizona Public Service Co	WECC	1, 10
19.	Thomas Wiedman	Wiedman Power System Consulting Ltd		NA
20.	Robert W. Cummings	NERC		NA
21.	Philip J Tatro	NERC		NA

6.	Group	W. R. Schoneck	Florida Power and Light	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Shaffer		FRCC	
2.	Pedro Modia		FRCC	
3.	Carlos Candelaria		FRCC	
4.	Kiko Barredo		FRCC	

7.	Group	Richard Kafka	Pepco Holdings, Inc. - Affiliates PHI	X		X		X	X				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
Additional Member	**Additional Organization**	**Region**	**Segment Selection**										
1. Bill Mitchell	Delmarva Power & Light Co.	RFC	1										
2. John Radman	Potomac Electric Power Co.	RFC	1										
3. Carl Kinsley	Atlantic City Electric	RFC	1										
8.	Group	Rick Foster	SERC Dynamics Review Subcommittee (DRS)	X								X	X
Additional Member	**Additional Organization**	**Region**	**Segment Selection**										
1. John Sullivan	Ameren Services Company	SERC	1										
2. Anthony Williams	Duke Energy Carolinas	SERC	1										
3. Sujit Mandal	Entergy	SERC	1										
4. Venkat Kolluri	Entergy	SERC	1										
5. John O'Connor	Progress Energy Carolinas	SERC	1										
6. Bob Jones	Southern Company Services, Inc. - Trans	SERC	1										
7. Jonathan Glidewell	Southern Company Services, Inc. - Trans	SERC	1										
8. Robbie Bottoms	Tennessee Valley Authority	SERC	1, 9										
9. Tom Cain	Tennessee Valley Authority	SERC	1, 9										
10. Herb Schrayshuen	SERC Reliability Corporation	SERC	10										
11. Carter Edge	SERC Reliability Corporation	SERC	10										
9.	Group	Steve Hill	Modesto Irrigation District Transmission Planning	X		X		X					
Additional Member	**Additional Organization**	**Region**	**Segment Selection**										
1. Spencer Tacke	MID	WECC	NA										
10.	Group	Doug Hohlbaugh	FirstEnergy Corp	X		X	X	X	X				
Additional Member	**Additional Organization**	**Region**	**Segment Selection**										
1. Ed Baznik	FE	RFC	1										
2. John Stephens	FE	RFC	1										
3. Jeff Mackauer	FE	RFC	1										
4. Carl Bridenbaugh	FE	RFC	1										
5. Sam Ciccone	FE		1, 3, 4, 6										

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
11.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Berhanu Tesema	BPA Transmission Planning	WECC	1
2.	Melvin Rodrigues	BPA Transmission Planning	WECC	1
3.	Chuck Matthews	BPA Transmission Planning	WECC	1
4.	Kyle Kohne	BPA Transmission Planning	WECC	1
5.	Larry Furumasu	BPA Transmission Planning	WECC	1

12.	Group	Carol Gerou	NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Neal Balu	WPS Corporation	MRO	3, 4, 5, 6
2.	Terry Bilke	Midwest ISO Inc.	MRO	2
3.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
4.	Ken Goldsmith	Alliant Energy	MRO	4
5.	Alice Murdock	Xcel Energy	MRO	1, 3, 5, 6
6.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
7.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
8.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
9.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
10.	Scott Nickels	Rochester Public Utilties Address	MRO	4
11.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6

13.	Individual	Frank Gaffney, Regulatory Compliance Officer	Florida Municipal Power Agency, and its Member Cities, Lakeland Electric and Fort Pierce Utility Authority	X		X	X	X	X	X			
14.	Individual	Travis Hyde	Oklahoma Gas & Electric	X									
15.	Individual	Hugh Francis	Southern Company	X		X		X					
16.	Individual	Richard	FRCC Transmission Working Group	X		X	X					X	X

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
17.	Individual	Brent Ingebrigtson	E.ON U.S.	X		X		X	X				
18.	Individual	Eric Mortenson	Exelon Transmission Planning	X		X							
19.	Individual	Tom Mielnik	MidAmerican Energy Company	X		X		X	X				
20.	Individual	Pete Jones	Puget Sound Energy, Inc.	X									
21.	Individual	Baj Agrawal	Arizona Public Service Co.	X		X		X					
22.	Individual	Jay Teixeira	ERCOT ISO		X								X
23.	Individual	Milorad Papic	Idaho Power	X									
24.	Individual	James Tucker	Deseret Power	X		X		X					
25.	Individual	Adam Menendez	Portland General Electric Co.	X		X		X	X				
26.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
27.	Individual	Tim Ponseti, VP	TVA System Planning	X									
28.	Individual	Brian Keel	SRP	X									
29.	Individual	Vishal Patel	Southern California Edison (SCE)	X		X		X					
30.	Individual	John Collins	Platte River Power Authority	X		X			X				
31.	Individual	Gordon Rawlings	British Columbia Transmission Corp	X	X								
32.	Individual	James Starling	SCE&G	X		X		X	X				
33.	Individual	Catherine Mathews	NorthWestern Energy	X		X		X					
34.	Individual	Dilip Mahendra	Sacramento Municipal Utility District	X		X	X	X					

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
35.	Individual	Thad Ness	American Electric Power	X		X		X	X				
36.	Individual	Bart White	Progress Energy Florida, Inc.	X		X							
37.	Individual	Terry Huval	Lafayette Utilities System										
38.	Individual	Jessica Rice	NV Energy	X									
39.	Individual	L. Earl Fair	Gainesville Regional Utilities	X		X		X					
40.	Individual	Phuong Tran	Lakeland Electric	X		X		X					
41.	Individual	Michael Ayotte	ITC Holdings	X									
42.	Individual	John Pearson	ISO New England		X								
43.	Individual	Darryl Curtis	Oncor Electric Delivery	X									
44.	Individual	Scott Goodwin	Midwest ISO		X								
45.	Individual	John Sullivan	Ameren	X		X		X	X				
46.	Individual	Saurabh Saksena	National Grid	X		X							
47.	Individual	Robert H. Easton	Western Area Power Adm - RMR	X								X	
48.	Individual	Roger Champagne	Hydro-Québec TransEnergie (HQT)	X									
49.	Individual	Greg Campoli	NYISO		X								
50.	Individual	Chifong Thomas	Pacific Gas and Electric Co.	X		X		X					
51.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
52.	Individual	David M. Conroy	Central Maine Power Company	X									

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
53.	Individual	Paul Rocha	CenterPoint Energy	X									
54.	Individual	Mark Byrd	Progress Energy Carolinas	X		X		X					
55.	Individual	Larry Brusseau	MAPP								X		
56.	Individual	Aaron Staley	Orlando Utilities Commission	X		X		X	X				
57.	Individual	Martin Bauer	US Bureau of Reclamation					X					
58.	Individual	Michael R. Lombardi	Northeast Utilities	X		X		X					
59.	Individual	Alice Murdock	Xcel Energy	X		X		X	X				
60.	Individual	David Wang	San Diego Gas & Electric Co	X									
61.	Individual	Dan Rochester	Independent Electricity System Operator		X								
62.	Individual	Jason Shaver	American Transmission Company	X									
63.	Individual	R. Peter Mackin	Utility System Efficiencies, Inc. (USE)										
64.	Individual	Mark Graham, on behalf of the Power System Planning Department	Tri-State Generation and Transmission Association	X		X		X	X				
65.	Individual	David Bradt	United Illuminating	X									
66.	Individual	John Mayhan	Omaha Public Power District	X		X		X	X				
67.	Individual	Mark Kuras	PJM										

1. **Requirement R1 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.**

Summary Consideration: The SDT has made several clarifying changes to Requirement R1, Measure M1, and to the VSLs for R1 based on industry comments.

Requirement R1, Part 1.1.6 has been clarified to reflect that this requirement may not be exclusively sources supplying load. As an example, Demand Side-Management (DSM) may be used.

The words "within its respective area" have been added after "that it is maintaining System models," to Measure M1 for additional clarification.

The words "responsible entity's" have been added after "OR The" under the Moderate and Severe VSLs for Requirement R1 for additional clarification as well.

R1, Part 1.1.6 - Resources (supply or demand side) required for Load

R3.3.3. Trip Transmission elements when relay loadability limits are exceeded

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, any criteria or methodology used in the analysis to identify System instability for conditions such as Cascading , voltage instability, or uncontrolled islanding.

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within its respective area, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

R1 VSL	The responsible entity's System model failed to represent one of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other	The responsible entity's System model failed to represent three of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1.

		sources, including items represented in the Corrective Action Plan.		

Organization	Comments for Question 1
ERCOT ISO	* This requirement seems to be embedding information that should be contained in the MOD standards. Does this present double jeopardy? This requirement, measurement, and VSL are all about maintaining models a MOD standard revision may need to be included or recommended to allow the focus of the TPL standard to be on transmission planning studies, not modeling. * Requirement 1.1.2 should read “all known outages of generation or transmission facilities with a duration of at least six months as appropriate for the timeframe represented by the particular model” * The moderate VSL category states “the System model did not use” this is confusing as the model does not do anything. It should contain the latest data. We also want to ensure this is not implying that the studies must use the latest data data changes continuously, and a study may never be complete if the data must be continuously updated. * Will any agreements made in R7 override the “each TP and PC” requirement? To clarify this, the requirement could be rephrased: "In accordance to the responsibilities assigned in R7, the responsible Transmission Planners and Planning Coordinators shall maintain System models for performing the studies needed to complete the required Planning Assessments. The models shall contain the latest data consistent with MOD-010 and MOD-012? "
Response: 1. The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has incorporated these additional requirements in the TPL standard with the intent that they will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. As for the double jeopardy comment - From the ERO Rules of Procedure, Appendix 4B- Sanction Guidelines, Section 3.10 Multiple Violations: “Strictly speaking, NERC or the regional entity can determine and levy a separate penalty or sanction, or direct remedial action, upon a violator for each individual violation. However, in instances of multiple violations related to a single act or common incidence of noncompliance, NERC or the regional entity will generally determine and issue a single aggregate penalty, sanction, or remedial action directive bearing reasonable relationship to the aggregate of the related violations. The penalty, sanction, or remedial action will not be that determined individually for the least serious of the violations; it will generally be at least as large or expansive as what would be called for individually for the most serious of the violations.” 2. The SDT does not believe that the proposed language adds any clarity. No change made. 3. The SDT does not believe that the proposed language adds any clarity. No change made. The system models should be updated per MOD-010 & MOD-012. 4. Requirement R7 identifies the individual and joint responsibilities for performing required studies only. The SDT believes that both the Transmission Planner and Planning Coordinator have this modeling responsibility. Therefore the SDT believes that the existing language is adequate and that no changes are required.	
Bonneville Power Administration	: R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change “real and reactive load forecast” to “forecasted demand and power factor” so it is clear that forecasting reactive load is not required.

Organization	Comments for Question 1
	For R1.1.5 we suggest changing the wording from "Known commitments for Firm Transmission Service and Interchange" to "Known commitments for Firm Transmission Service or Interchange". It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.
NorthWestern Energy	As written R1.1.4, "Real and reactive Load forecasts", could mean that both Real and Reactive Load forecasts are required. Since most entities only forecast Real (MW) and apply a power factor for reactive (MVAR), wording could be changed to " forecasted demand and power factor" to clarify that forecasting reactive load is not required. In R1.1.5 Change "Firm Transmission Service and Interchange" to "Firm Transmission Service or Interchange". This way the requirement can be satisfied by either one or the other.
Deseret Power	Comments: R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. For R1.1.5 we suggest changing the wording from "Known commitments for Firm Transmission Service and Interchange" to "Known commitments for Firm Transmission Service or Interchange". It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.
Idaho Power	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. For R1.1.5 I suggest changing the wording from "Known commitments for Firm Transmission Service and Interchange" to "Known commitments for Firm Transmission Service or Interchange". It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.
Modesto Irrigation District Transmission Planning	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. R1.1.5 we suggest changing the wording from "Known commitments for Firm Transmission Service and Interchange" to "Known commitments for Firm Transmission Service or Interchange". It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.
NV Energy	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. For R1.1.5 we suggest changing the wording from "Known commitments for Firm Transmission Service and Interchange" to "Known commitments for Firm Transmission Service or Interchange". It is difficult to distinguish between the two in future cases

Organization	Comments for Question 1
	where not all contractual arrangements are known.
Pacific Gas and Electric Co.	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change “real and reactive load forecast” to “forecasted demand and power factor” so it is clear that forecasting reactive load is not required. For R1.1.5 we suggest changing the wording from “Known commitments for Firm Transmission Service and Interchange” to “Known commitments for Firm Transmission Service or Interchange”. It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.
Puget Sound Energy, Inc.	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change “real and reactive load forecast” to “forecasted demand and power factor” so it is clear that forecasting reactive load is not required. For R1.1.5 we suggest changing the wording from “Known commitments for Firm Transmission Service and Interchange” to “Known commitments for Firm Transmission Service or Interchange”. It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.
San Diego Gas & Electric Co	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change “real and reactive load forecast” to “forecasted demand and power factor” so it is clear that forecasting reactive load is not required. R1.1.5 "firm transmission service agreements" should be removed the from the requirement. Firm transmission service agreements, "known" or otherwise, have no effect on reliable operation of the grid; power will flow where it wants, not where, or how, the firm transmission service agreement may specify. From a reliability perspective this information is of no use.
Southern California Edison (SCE)	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change “real and reactive load forecast” to “forecasted demand and power factor” so it is clear that forecasting reactive load is not required. For R1.1.5 we suggest changing the wording from “Known commitments for Firm Transmission Service and Interchange” to “Known commitments for Firm Transmission Service or Interchange”. It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.
SRP	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change “real and reactive load forecast” to “forecasted demand and power factor” so it is clear that forecasting reactive load is not required. For R1.1.5 we suggest changing the wording from “Known commitments for Firm Transmission Service and Interchange” to “Known commitments for Firm Transmission Service or Interchange”. It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.

Organization	Comments for Question 1
Western Area Power Adm - RMR	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. For R1.1.5, I suggest changing the wording from "Known commitments for Firm Transmission Service and Interchange" to "Known commitments for Firm Transmission Service or Interchange". It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.
Response: 1. Requirement R1, part 1.1.4 states that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast. No change made. 2. The SDT believes that the existing language is adequate and no further change is required. If you do not have any known Firm Transmission Service as an example, then this fact should just be documented.	
Northeast Utilities	[R1.1.6] What is NERC's definition of "Resources required to supply load"?[Add R1.1.7] The standard is referring to requirements for sensitivity and other issues without a reference to base cases. There needs to be some direction provided on the initial conditions used in the assessment. This guidance should include a discussion as to whether or not generator forced outages are to be represented in the base cases. Additionally, the standard is also silent on the treatment of system transfers, both internal and external, as to how they should be modeled in the base cases. For some areas, their current practice is to include heavy system stresses in their base cases. It is unclear if this practice works within the purview of this standard. Therefore, it is recommended that each Region must have a document that defines what constitutes base case conditions.
Response: 1. "Resources required to supply load" is not a NERC defined term. "Facility" is a defined term and does include generators. The SDT has made a clarifying change to Requirement R1, part 1.1.6. **R1, part 1.1.6** - Resources (supply or demand side) required for Load **2.** The SDT believes that "base case conditions" should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested. Please note that Requirement R1, part 1.1.2 includes only known outages of generation with duration of at least 6 months. Requirement R1, part 1.1.5 includes known commitments for Firm Transmission Service and Interchange - while the sensitivity analysis under Requirement R2, parts 2.1.4 and 2.4.3 can include varying expected transfers by a sufficient amount to stress the System. The Standard will leave it up to each Region to further define their own base case documentation if they desire to have such a document.	
Progress Energy Florida, Inc.	As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all appropriate parties to review PEF's previous comments to this effect.
Response: Throughout the drafting process, the SDT has carefully considered your comments as well comments from other industry members.	
American Electric Power	Because the revised transmission planning standard now explicitly references short circuit analysis, we believe that there is a

Organization	Comments for Question 1
	need for a parallel MOD standard to establish requirements for short circuit modeling and for a corresponding reference under R1, just as there are references made in R1 to MOD-010 (power flow models) and MOD-012 (stability models) . We recognize that such a MOD standard will not be addressed as part of this project, but we request that the SDT pass this comment on to NERC Staff.
Response: NERC has committed that it will update the appropriate MOD standards after the TPL revisions are finalized. A note has already been made in the official NERC issues database for a revision to the MOD standards based on the changes to TPL.	
CenterPoint Energy	CenterPoint Energy appreciates the SDT's efforts in revising R1 and generally agrees with the requirement except for verbiage and sub-requirements relating to modeling future transmission system projects, including projects identified in Corrective Action Plans. Specifically, CenterPoint Energy recommends that the SDT revise R1 by deleting the text "including items represented in the Corrective Action Plan" and delete part 1.1.3 in its entirety. Certainly, it is appropriate to model some limited subset of future projects, including projects included in Corrective Action Plans, which are reasonably "firm" or "committed". In previous drafts, the SDT tried to incorporate language to capture that concept but apparently abandoned the idea in response to industry comments. However, it remains true that many future "planned" projects, including projects in Corrective Action Plans, are tentative in nature and have a high degree of uncertainty due to uncertainty in forecasted system conditions. Because of this reality, and the fact that models are intended to be useful for identifying what future projects might be necessary, CenterPoint Energy believes many transmission planning organizations do not and should not model any and all new planned transmission facilities tentatively identified based upon studies and assessments of previous system models. Once the System model is updated with previously contemplated transmission projects, it is problematic to determine in future studies whether or not those projects are still needed, which is contrary to the intent of updating the model. If CenterPoint Energy's recommended changes are made, Transmission Planners and Planning Coordinators would not be precluded from incorporating future projects into their System models in accordance with their established practice but they would not be required to inappropriately model any and all previously contemplated projects.
Response: The SDT believes that the Corrective Action Plans and Requirement R1, part 1.1.3 are being correctly used in this planning standard. Please note that there are a variety of associated actions that can be used to achieve required System performance as noted in Requirement R2, part 2.7.1. The SDT agrees that systems can change over time which will result in some changes for the Corrective Action Plans. The SDT is not trying to "pin down" entities in regards to these plans but to ensure that entities are planning reliable Transmission Systems and have sufficient time to get needed plans in service to continue meeting the TPL 001-1 requirements. The SDT believes that these actions are needed in the planning horizons in order to have a reliable Bulk Electric System. No change made.	
Platte River Power Authority	Change R1.1.5 wording from "...Service and Interchange." to "...Service or Interchange."
Response: The SDT believes that the existing language is adequate and no further change is required. If you do not have any known Firm Transmission Service as an example, then this fact should just be documented.	
ITC Holdings	Comments: These requirements refer to new facilities which would include new generators. ITC requests clarification as to what constitutes a "new generator" that needs to be considered -- those in the queue, those with signed Interconnection Agreements, those under construction... What is the line of demarcation between what is in and what is out?

Organization	Comments for Question 1
	In addition to the above, ITC also requests clarification as to whether or not these requirements apply to new generators, who connect to the network as "Energy Only" resources and, are either, not required to construct facilities needed to meet reliability requirements or are allowed to operate as "Energy Only" until needed facilities are constructed. The CAP for these facilities is that they will be curtailed or other generation will be curtailed should "operating" violations occur. Under market mechanisms, these generators are allowed to operate if their energy prices are lower than other generators whose curtailment eliminates the violation, even though the curtailed generators have paid for the facilities needed to meet reliability requirements. As the standard is written, these requirements imply that all generators must be included in studies. Were we to do so, significant standards violations might result. Does the Transmission Owner have to study all violation scenarios or include all "Energy Only" generators in studies when the CAP is always the same: "Market redispatch". Please clarify study scenario requirements for "Energy Only" resources.
Response: 1. Requirement R1 is a modeling requirement which requires any expected operational Facilities to be modeled based on market and contractual obligations. 2. The SDT believes that the requirements under this standard do include "Energy Only" generators. Please note under Requirement R2, part 2.7.1 that manual and automatic generation runback/tripping is allowed as a response to single or multiple Contingencies to mitigate Steady State performance violations. Also automatic generation tripping is allowed for single and multiple Contingency events to mitigate Stability performance violations.	
FirstEnergy Corp	FirstEnergy believes the draft 4 version of requirement R1 is greatly improved over prior drafts. The team has correctly responded to industry stakeholders and arrived at an appropriate middle ground that should resolve most stakeholder concerns. The changes made in R1.1.2 stating modeling of known outages with a duration of 6-months or more helps clarify a requirement that was previous subjective and open for interpretation. The removal of the previously prescriptive "such as list" is also well received by FirstEnergy.Finally, the addition of the text "known commitments" in regards to Firm Transmission Service and Interchange resolves our prior concerns.
Gainesville Regional Utilities	I like the more simplified approach used in the requirement listing. As far as "using the latest data consistent with MOD-010 & MOD -012 data", I feel that unplanned or unknown system changes between the times when studies are actually ran for the long term planning process should not be an issue for any type of negative interpretation by a compliance auditor. I presently do not have a suggestion on how to guarantee such an understanding. Overall the revisions look good.
Tri-State Generation and Transmission Association	R1 - The changes to R1 seem good.
Response: Thank you for your comments.	
Utility System Efficiencies, Inc. (USE)	For R1.1.5 I suggest changing the wording from "Known commitments for Firm Transmission Service and Interchange" to "Known commitments for Firm Transmission Service or Interchange". It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.
Response: The SDT believes that the existing language is adequate and no further change is required. If you do not have any known Firm Transmission Service as	

Organization	Comments for Question 1
an example, then this fact should just be documented.	
Orlando Utilities Commission	In general I support all the changes from the prior revision. I especially like the clarification that outages of 6 months or longer need attention in planning studies. Several questions on the details: R1 requires the maintenance of system models for the purpose of studies and establishes that these models should be updated with the latest data from various sources. Is this requiring that models should always be current, updated for the slightest change, even between studies? Or just that models are kept up to date in a more practical application such as monthly, quarterly or before their use in a study?R1 states that the model should be "..supplemented by other sources as needed, including items represented in the corrective action plan"? Read in context with the overall requirement this allows for projects that are in the corrective action plan to be added, but does not require that they are, is this the correct understanding? -R1 requires the model to represent Known Commitments for Firm Transmission Service, and also references load forecasts. The application of this requirement seems to be that the model should be based on the load forecast and include the appropriate known firm transmission service for the amount that would be used at that forecast level?
Response: 1. Yes, your understanding is correct. Thank you for your comments. 2. The SDT agrees that the model should be based on the load forecast. The SDT believes that the appropriate known Firm Transmission Service should also be included. Please note that Requirement R1, part 1.1.6 has been clarified to state that supply or demand side can be used for supplying Load. **R1, part 1.1.6** - Resources (supply or demand side) required for Load	
MAPP	1. It would be helpful to identify the relationship expected between the PC and the TP. It looks as if both PC and TP are expected to maintain the same models. We need to avoid duplicated effort. Does the standard really apply to "both", or could it be "either"? 2. Is a Corrective Action Plan being used correctly throughout this standard? It seems like the specifics of a CAP aren't appropriate for future planning years. Planning studies are only estimates of expected system growth, and the apparent problem might turn out to be different, or not exist at all. Will compliance people start going "over the top" examining CAPs? The current practice of summarizing possible problems in future years and identifying possible solutions seems more appropriate than pinning entities down to Corrective Action Plans. Corrective Action Plans seem appropriate only for the Operating horizon.R1 We interpret that "within their respective areas" refers the geographic footprint of the TP or PC transmission system. 3. We propose clarifying that "within their respective area" does not require the inclusion of remote generation or load (metering) buses that are within the declared Balancing Authority area, but may be outside and separate from the TP or PC geographic footprint. 4. M1 We recommend the bolded words be added to M1 to indicate that each responsible entity must provide evidence that "it is maintaining System models within its respective area, using the latest"? What does it mean to have a hardcopy of a system model? 5. R1.1.2 We suggest that this requirement be removed because the "known outage(s)" are only to be included in the models

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	when for P1 events are simulated, as specified in R2.1.3. We suggest that the intent can be more simply handled by stating in R2.1.3 that known outages be simulated along with P1 events for the System peak or Off-Peak conditions when the outages are scheduled to occur. 6. R1.1.3 Add the qualification of "for the years defined in R2". 7. R1.1.6 We interpret that "Resources required" allows the inclusion of fictional generators in the models when they are needed to make future normal system cases solve. If this is not the intended interpretation, then we suggest modifying the wording to make the desired interpretation more clear.
Response: 1. The SDT believes that both the Transmission Planner and Planning Coordinator have this modeling responsibility. Therefore the SDT believes that the existing language is adequate and that no changes are required. 2. The SDT believes that the Corrective Action Plans are being correctly used in this planning standard and is appropriate for all planning years. Please note that there are a variety of associated actions that can be used to achieve required System performance as noted in Requirement R2, part 2.7.1. The SDT agrees that Systems can change over time which will result in some changes for the Corrective Action Plans. The SDT cannot speculate on auditor's actions. The SDT is not trying to "pin down" entities in regards to these plans but to ensure that entities are planning reliable Transmission Systems and have sufficient time to get needed plans in service to continue meeting the TPL-001-1 requirements. The SDT believes that these actions are needed in the planning horizons in order to have a reliable Bulk Electric System. The SDT believes that "within their respective area" does refer to the Transmission Planner's or Planning Coordinator's geographic footprint. 3. The SDT believes agrees that the "within their respective area" terminology excludes remote generation and Load buses since they are not within the Transmission Planner's or Planning Coordinator's geographic footprint. The SDT believes that the existing language is adequate and no further change is required. 4. The SDT agrees that adding "within its respective area" would help clarify this measure. The SDT has modified Measure M1 to include this new language. An example of a hard copy of a System model is having printouts of each individual bus showing Load, Transmission line, generator, capacitors, etc., connected to that bus with associated impedances, ratings, etc. **M1**. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within its respective area, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1 5. The SDT disagrees since multiple outages may be taken during the same time period under Requirement R1, part 1.1.2. The SDT believes that all outages should be modeled to insure the System reliability during the outage duration. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-Contingency. See Requirement R2, part 2.1.3 for additional details concerning studies required with known outages. No change made. 6. The SDT does not believe that the proposed language adds any clarity. No change made. 7. The SDT believes that this requirement includes any fictional generators that may be needed to match up generation and Load. The SDT has made clarifying change to Requirement R1, part 1.1.6. **R1, part 1.1.6** - Resources (supply or demand side) required for Load	
MidAmerican Energy Company	MidAmerican recommends the words in all caps be added to M1 to indicate that each responsible entity must provide evidence

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	that "it is maintaining System models WITHIN ITS RESPECTIVE AREA, using the latest"?
Response: The SDT agrees that adding "within its respective area" would help clarify this measure. The SDT has modified Measure M1 to include this new language. **M1**. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within its respective area, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.	
Florida Power and Light	No entity that we know of provides specific reactive load forecasts. From the auditor's perspective, what is expected and acceptable for System models representing reactive load forecasts? Suggested change: 1.1.4 Real Load forecasts and future reactive Load assumptions? Not all system models can represent all "Known commitments for Firm Transmission Service and Interchange". The SDT needs to add "that are expected to be utilized." to the requirement. 1.1.6 Recommend changing to "Resources expected to supply Load"The requirements seem to imply a difference in certainty between "known" and "planned". Known implies certainty, where planned implies less certainty, as in an assumption. Planned things can change but known things are much less subject to change. The drafting team should clarify the distinction between the two terms or be more specific in the requirement as to what is expected rather than leaving it for interpretation as to meaning and intent.
Response: 1. Requirement R1, part 1.1.4 states that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast. The SDT believes that the existing language is adequate. The SDT believes that all known commitments for Firm Transmission Service and Interchange should be modeled. The SDT does not believe that the proposed language adds any clarity. No change made. 2. The SDT has made clarifying change to Requirement R1, part 1.1.6 based on industry comments. Please note that the word "required" is used in Requirement R1, part 1.1.6. **R1, part 1.1.6** - Resources (supply or demand side) required for Load	
Independent Electricity System Operator	Please explain what is envisaged by the phrase "and shall represent projected System conditions." that is not already covered by the list in Requirement R1, part 1.1. We suggest removing the phrase. We do not have any comments on the, measure, VRF and Time Horizon. Consistent with our comment above, we believe that the 2nd condition under the Severe VSL is (a) vague, and (b) already covered by parts 1.1.1 to 1.1.6. This second condition is not needed.
Response: The goal is for the responsible entity to build a realistic simulation for the System models which may contain items not listed under Requirement R1, part 1.1. The SDT disagrees with the VSL comment and believes that the second condition under the Severe VSL covers additional items under Requirement R1 itself that are not covered under Requirement R1, parts 1.1.1 thru 1.1.6. No change made.	
NYISO	R1 - The NYISO would like to align itself with the comments of the ISO/RTO Council stating that the PC may begin model building using provisions from tariff or agreements such as its Transmission Owners agreement. While the data may be

Organization	Comments for Question 1
	consistent with that provided in Mod 10 and 12, there may not be a direct correlation. We, therefore, also suggest the following wording for R1."Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall reflect data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and/or data that is provided in accordance with tariff or transmission owner agreements. The models may be supplemented by other sources as needed including items represented in the Corrective Action Plan, and shall represent projected System conditions. "R1.1.2 - Outages of less than 12 months are generally coordinated by operations, not planning departments. In reference to system modeling, it doesn't make sense for outages of less than a year. We therefore recommend replacing "duration of at least six months" with duration of 12 months or more. R1.1.5 - Interchange should not be modeled in the base case system representation, unless their neutrality to system reliability has been clearly demonstrated. There are times that economic interchanges between New York and a neighbor may have an impact on one of the transmission systems that may, at times, pose reliability constraints on the operation of the New York system. R1.1.6 - Please define what is included in "resources required to supply load." It is unclear what is included or not included in this requirement. The NPCC definition of "resource" is inclusive.
Response: 1. The SDT believes the existing language is correct and that the suggested changes do not provide additional clarity. No change made. 2. The requirement does not refer to outages occurring within the next 6 months which the SDT agrees would be an operational issue and not a planning issue. The requirement is referring to outages in the planning horizon that have a duration of at least six months. The SDT believes that such outages should be incorporated into the Planning Assessment. No change made. 3. The SDT disagrees and believes that known firm transmission commitments and interchange should be modeled and can affect the transmission system reliability. No change made. 4. "Resources required to supply load" is not a NERC defined term. "Facility" is a defined term and does include generators. The SDT has made a clarifying change to Requirement R1, part 1.1.6. **R1, part 1.1.6** - Resources (supply or demand side) required for Load	
NERC Standards Review Subcommittee	R1 The MRO NSRS interprets that "within their respective areas" refers to the geographic footprint of the TP or PC transmission system. The MRO NSRS proposes clarifying that "within their respective area" does not require the inclusion of remote generation or load (metering) buses that are within the declared Balancing Authority area, but may be outside and separate from the TP or PC geographic footprint. M1 The MRO NSRS recommends that words be added to M1 to indicate that each responsible entity must provide evidence that "it is maintaining System models within its respective area, using the latest"?
Response: 1. The SDT believes agrees that the "within their respective area" terminology excludes remote generation and Load buses since they are not within the Transmission Planner's or Planning Coordinator's geographic footprint. The SDT believes that the existing language is adequate and no further change is required.	

Organization	Comments for Question 1
2. The SDT agrees that adding "within its respective area" would help clarify this measure. The SDT has modified M1 to include this new language. **M1**. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within its respective area, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1	
Central Maine Power Company	R1.1.1 Make this read "Existing Facilities and Resources" so that it will be a lead in to the changes proposed for 1.1.6. R1.1.2 This type of event is sufficiently addressed within the existing testing requirements (P6) and therefore should be eliminated , beyond that such outages are reviewed and approved on an operational basis and should not be included in a planning standard. During known outages for equipment upgrades or repairs there may be some increased exposure to load loss, which should be recognized as an acceptable exposure. In the event that this requirement is maintained please change six months to one year. 1.1.6 Resources may not be exclusively sources supplying load. Therefore the reference should not involve load. The focus should be on changes to resources and "resources required to supply load" should be replaced with "New planned Resources and changes to existing Resources"We suggest NERC develops a definition for "resource" or use the following definition found in NPCC Glossary of Terms, Document A-7: Resource - Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load. ADD 1.2 The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions. The standard must describe base assumptions. M1 It is not practical to retain system model information in a hard copy form. This provision should be dropped. D.1.1.4 Data Retention: The Transmission Planner and the Planning Coordinator may not be using the same software. If both are required to store the data, do they both have to have the software to use the data? Can this be changed to an "or" such that one of them must retain the data and it can be up to them as to who is responsible for data retention.
ISO New England	1. R1.1.1 Make this read "Existing Facilities and Resources" so that it will be a lead in to the changes proposed for 1.1.6. 2. R1.1.2 This type of event is sufficiently addressed within the existing testing requirements (P6) and therefore should be eliminated , beyond that such outages are reviewed and approved on an operational basis and should not be included in a planning standard. During known outages for equipment upgrades or repairs there may be some increased exposure to load loss, which should be recognized as an acceptable exposure. In the event that this requirement is maintained please change six months to one year. 3. 1.1.6.. Resources may not be exclusively sources supplying load. Therefore the reference should not involve load. The focus should be on changes to resources and "resources required to supply load" should be replaced with "New planned Resources and changes to existing Resources"We suggest NERC develops a definition for "resource" or use the following definition found in NPCC Glossary of Terms, Document A-7: Resource Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases

Organization	Comments for Question 1
	from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load. 4. ADD 1.2 The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions. The standard must describe base assumptions. 5. M1It is not practical to retain system model information in a hard copy form. This provision could be dropped. 6. D.1.1.4 Data Retention: The Transmission Planner and the Planning Coordinator may not be using the same software. If both are required to store the data, do they both have to have the software to use the data? Can this be changed to an "or" such that one of them must retain the data and it can be up to them as to who it is.
Response: 1. The SDT believes that the "and Resources" is not needed as a lead in to Requirement R1, part 1.1.6 since both Requirement R1, parts 1.1.1 and 1.1.6 are directly under Requirement R1, part 1.1. No change made. 2. The SDT disagrees since multiple outages may be taken during the same time period under Requirement R1, part 1.1.2, thus this situation may be worse than only having two Contingencies as noted in P6. The SDT believes that all outages should be modeled to ensure the System reliability during the outage duration. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-Contingency. See Requirement R2, part 2.1.3 for additional details concerning studies required with known outages. No change made. 3. The SDT agrees that this requirement may not be exclusively sources supplying Load. As an example, Demand Side-Management (DSM) may be used. The SDT has made clarifying change to Requirement R1, part 1.1.6 based on industry comments. **R1, part 1.1.6** - Resources (supply or demand side) required for Load 4. The SDT believes that the "base case conditions" should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested. 5. Since Measure M1 states that either electronic OR hard copy format is required, the SDT believes that no changes are required since either of the formats is acceptable. 6. The SDT believes that both the Transmission Planner and Planning Coordinator have this responsibility. Therefore the SDT believes that the existing language is adequate and that no changes are required.	
United Illuminating	R1.1.1 Make this read "Existing Facilities and Resources" so that it will be a lead in to the changes proposed for 1.1.6. R1.1.2 This type of event is sufficiently addressed within the existing testing requirements (P6) and therefore should be eliminated , beyond that such outages are reviewed and approved on an operational basis and should not be included in a planning standard. During known outages for equipment upgrades or repairs there may be some increased exposure to load loss, which should be recognized as an acceptable exposure. In the event that this requirement is maintained please change six months to one year. 1.1.6.. Resources may not be exclusively sources supplying load. Therefore the reference should not involve load. The focus should be on changes to resources and "resources required to supply load" should be replaced with "New planned Resources and changes to existing Resources"We suggest NERC develops a definition for "resource" or use the following definition found

Organization	Comments for Question 1
	in NPCC Glossary of Terms, Document A-7: Resource Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load. ADD 1.2 The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions. The standard must describe base assumptions.
Response: 1. The SDT believes that the "and Resources" is not needed as a lead in to Requirement R1, part 1.1.6 since both Requirement R1, parts 1.1.1 and 1.1.6 are directly under Requirement R1, part 1.1. No change made. 2. The SDT disagrees since multiple outages may be taken during the same time period under Requirement R1, part 1.1.2, thus this situation may be worse than only having two Contingencies as noted in P6. The SDT believes that all outages should be modeled to ensure the System reliability during the outage duration. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-Contingency. See Requirement R2, part 2.1.3 for additional details concerning studies required with known outages. No change made. 3. The SDT agrees that this requirement may not be exclusively sources supplying Load. As an example, Demand Side-Management (DSM) may be used. The SDT has made clarifying change to Requirement R1, part 1.1.6 based on industry comments. **R1, part 1.1.6** - Resources (supply or demand side) required for Load 4. The SDT believes that the "base case conditions" should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested.	
Ameren	R1.1.2: Inclusion of outages of generation or transmission facilities with a duration of at least 6 months in the models is too restrictive. An outage duration of 1 month would be more appropriate for inclusion in the seasonal peak and off-peak models. R1.1.5: It is not clear from the wording how Firm Transmission Service and Interchange schedules should be considered, or whether the status quo is adequate. A given generating facility may have transmission service commitments which exceed the facility's generating capability. VSL: Given the annual cycle of collecting, revising and submitting system model data under MOD-010 and MOD-012, there could be a lag of several months between receipt of updated data prior to having this data included in the next round of system models. The TP/PC should not be penalized for this.
Response: 1. The SDT believes that the 6 month outage duration required for modeling outages is sufficient. However a utility may exceed this requirement by having lower outage duration if they choose. The outages should be modeled in the appropriate cases whether the outages occur in the spring, summer, fall, winter, etc. 2. The Standard is requiring the modeling of known commitments for Firm Transmission Service and Interchange schedules as a means of stressing the transmission system pre-contingency. If a given generator is reserving transmission capability beyond the capability of the resources to deliver, then someone must have evaluated the system based on a set of assumptions that identified that the system is capable of delivering the service, which would be consistent with this requirement. 3 The System models should be updated in accordance with MOD-010 & MOD-012. No change made.	

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Xcel Energy	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.
Response: Requirement R1, part 1.1.4 states that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast.	
SERC Planning Standards Subcommittee	R1: MOD-010 and 012 are not directly applicability to the PC. References to other processes (e.g. tariff requirements or transmission owner agreements) that are utilized to provide this data may be desirable, but do not satisfy R1 as presently written.VSL: In the Moderate and Severe VSL, insert "responsible entity's" in front of the term "System model."
SERC Dynamics Review Subcommittee (DRS)	R1: MOD-010 and 012 are not directly applicable to the PC. References to other processes (e.g. tariff requirements or transmission owner agreements) that are utilized to provide this data may be desirable, but do not satisfy R1 as presently written.VSL: In the Moderate and Severe VSL, insert "responsible entity's" in front of the term "System model."

Response: The MOD-010 and MOD-012 standards are not directly applicable to the Planning Coordinator; however the Planning Coordinator has to utilize data provided by others such as that provided in accordance with MOD-010 and -012.

The SDT agrees and will insert this additional wording in the moderate and severe VSLs for Requirement R1.

R1 VSL	The responsible entity's System model failed to represent one of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.	The responsible entity's System model failed to represent three of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1.

Manitoba Hydro	Recommend removing "and shall represent projected System Conditions" from R1. This is already clearly contained in R1.1.1

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	through R1.1.6. If the drafting team knows of other projected system conditions then they should be listed in R1.1. "The System Model did not represent projected System Conditions as described in Requirement R1 should be removed from the severe VSL column. By failing to represent 4 or more of the requirements in 1.1.1 through 1.1.6, projected System Conditions are not represented.
Response: The SDT disagrees and believes that there may need to be additional information contained in the models that is not specifically noted under Requirement R1.1. The goal is for the responsible entity to build a realistic simulation for the System models. The SDT disagrees and believes that the second condition under the Severe VSL covers additional items under Requirement R1 itself that are not covered under Requirement parts 1.1.1 thru 1.1.6.	
Northeast Power Coordinating Council--RSC	1. Requirement 1.1.1: Replace "Existing Facilities" with "Existing Facilities and Resources" so that it will be a lead in to the changes proposed for 1.1.6. 2. Requirement 1.1.2 "Consideration of known outages should not be included in a planning assessment. Such outages are coordinated by operations and are only permitted if the system can be operated reliably, where assumptions may be different than those used in planning assessments. Including this as a requirement effectively means that the system must be designed to withstand three outages. In those cases where safety, or reliability, or both are a concern by long duration outages (e.g., more than one year), temporary Operating Protocols are implemented to mitigate their impact. During known outages for equipment upgrades or repairs there may be some increased exposure to load loss, which should be recognized as an acceptable exposure. If this requirement must be kept, the outages with duration in excess of a year should be considered, rather than those of six months. This type of event is sufficiently addressed within the existing testing requirements (P6) and therefore should be eliminated, beyond that such outages are reviewed and approved on an operational basis and should not be included in a planning standard. Known or "known planned" outages will not necessarily fall in the operations timeframe, and as such may not be subject to approval by operations departments. This is especially so given the fact that the earliest start date for Year One is 12 months beyond the current year. 3. Requirement 1.1.5 Interchange. Interchange usually refers to non-firm short-term economic transactions that often take place between Balancing Authorities to take advantage of their respective resources surplus (i.e. not needed for local reliability.) However, such transactions should not be modeled in the base case system representation, unless their neutrality to system reliability has been clearly demonstrated. For example, economic interchanges between New England and PJM through New York have an impact on the New York transmission system that may, at times, pose reliability constraints on the operation of the New York system. 4. Requirement 1.1.6 what are "resources required to supply load, gens, HVDC, tie lines? Resources may not be exclusively sources supplying load. The focus should be on changes to resources. "Resources required to supply Load" should be replaced with New planned Resources and changes to existing Resources. NPCC suggests NERC develops a definition for "resource" or use the following definition found in NPCC Glossary of Terms, Document A-7: Resource Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load.A

Organization	Comments for Question 1
	5. Requirement 1.2 should be added to address the base assumptions for sensitivity and other issues requirements. 6. For Measure M1: Elaborate on "hard copy format". Does that entail maintaining a hard copy of the system model? It is impractical to retain system model information in a hard copy format. This provision should be dropped.
Response: 1.The SDT believes that the "and Resources" is not needed as a lead in to Requirement R1, part 1.1.6 since both Requirement R1, parts 1.1.1 and 1.1.6 are directly under Requirement R1, part 1.1. 2. The SDT disagrees and believes that all outages should be modeled to ensure System reliability during the outage duration. Since multiple outages may be taken during the same time period under Requirement R1, part 1.1.2, this situation may be worse than only having two Contingencies as noted in P6. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-Contingency. See Requirement R2, part 2.1.3 for additional details concerning studies required with known outages. No change made. 3. The SDT disagrees and believes that known firm Transmission commitments and interchange should be modeled and can affect the Transmission System reliability. No change made. 4. The SDT agrees that this requirement may not be exclusively sources supplying Load. As an example, Demand Side-Management (DSM) may be used. The SDT has made a clarifying change to Requirement R1, part 1.1.6 based on industry comments. **R1, part 1.1.6** - Resources (supply or demand side) required for Load 5. The SDT believes that the "base case conditions" should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested. 6. Since Measure M1 states that either electronic OR hard copy format is required, the SDT believes that no changes are required since either of the formats is acceptable. An example of a hard copy of a System model is having printouts of each individual bus showing Load, Transmission line, generator, capacitors, etc., connected to that bus with associated impedances, ratings, etc.	
Hydro-Québec TransEnergie (HQT)	Requirement 1.1.2 Consideration of known outages should not be included in a planning assessment. Such outages are coordinated by operations and are only permitted if the system can be operated reliably, where assumptions may be different than those used in planning assessments. Including this as a requirement effectively means that the system must be designed to withstand three outages. In those cases where safety, or reliability, or both are a concern by long duration outages (e.g., more than one year), temporary Operating Protocols are implemented to mitigate their impact. If this requirement must be kept, the outages with duration in excess of a year should be considered, rather than those of six months. Requirement 1.1.5 Interchange. Interchange usually refers to non-firm short-term economic transactions that often take place between Balancing Authorities to take advantage of their respective resources surplus (i.e. not needed for local reliability.) However, such transactions should not be modeled in the base case system representation, unless their neutrality to system reliability has been clearly demonstrated. For example, economic interchanges between New England and PJM through New York have an impact on the New York transmission system that may, at times, pose reliability constraints on the operation of the New York system. Requirement 1.1.6 what are "resources required to supply load" " gens, HVDC, tie lines" HQT, as does NPCC, suggests NERC

Organization	Comments for Question 1
	develops a definition for "resource" or use the following definition found in NPCC Glossary of Terms, Document A-7: Resource - Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load.

Response: 1. The SDT disagrees and believes that all outages should be modeled to ensure System reliability during the outage duration. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-Contingency. See Requirement R2, part 2.1.3 for additional details concerning studies required with known outages.

The SDT believes that the 6 month duration is appropriate. No change made.

2. The SDT disagrees and believes that known firm Transmission commitments and interchange should be modeled and can affect the Transmission System reliability. No change made.

3. The SDT agrees that this requirement may not be exclusively sources supplying Load. As an example, Demand Side-Management (DSM) may be used. The SDT has made a clarifying change to Requirement R1, part 1.1.6 based on industry comments.

R1, part 1.1.6 - Resources (supply or demand side) required for Load

Organization	Comments for Question 1
Midwest ISO	Requirement R1: The Planning Coordinator may begin model building using provisions from tariff and/or other agreements such as its Transmission Owners agreement. While the data may be consistent with that provided in Mod 10 and 12, there may not be a direct correlation between the two sets of data. This could become burdensome for a Planning Coordinator to make that correlation between the two. Suggest the following wording for R1.Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall reflect data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and/or data that is provided in accordance with tariff or transmission owner agreements. The models may be supplemented by other sources as needed including items represented in the Corrective Action Plan, and shall represent projected System conditions Requirement R1.1.5: In the Moderate and Severe VSL, insert "responsible entity's" in front of the term "System Models" so it reads as such: "The responsible entity's System model did not"

Response: 1. The SDT does not believe that the proposed language adds any clarity. No change made.

The SDT agrees and will insert this additional wording in the moderate and severe VSLs for Requirement R1.

R1 VSL	The responsible entity's System model failed to represent one of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, parts 1.1.1 through 1.1.6. OR	The responsible entity's System model failed to represent three of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, parts 1.1.1 through 1.1.6. OR

Organization	Comments for Question 1
	The responsible entity's System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan. The responsible entity's System model did not represent projected System conditions as described in Requirement R1.
FRCC Transmission Working Group	Several questions on the details:- R1 requires the maintenance of system models for the purpose of studies and establishes that these models should be updated with the latest data from various sources. Read in context this seems to require that a PA/TP has models, and they are updated either on some sort of regular schedule, for example quarterly or before the start of a study, and use the latest information at the time they are updated. Is this a correct understanding of the requirement? - R1 states that the model should be "..supplemented by other sources as needed, including items represented in the corrective action plan"? Read in context with the overall requirement this allows for projects that are in the corrective action plan to be added to the model as needed, is this the correct understanding? -R1 requires the model to represent "projected system conditions" which include in the list below "Known Commitments for Firm Transmission Service" and "Load Forecast". This seems to require that your known firm transmission service commitments are matched to their corresponding customers load forecast and expected operation profile, relative to load level in the case. Or phrased another way, the model should represent the service and load as they would be expected to operate at the load level in the case. Is this a correct understanding? Comments: With regard to the Moderate Violation Severity Level, what if the entity does not have the "latest" data but the entity did include items in the corrective action plan? Should the "and" between MOD-010 and MOD-012 be an "OR" and have the "AND" be for the High VSL?Not all system models can represent all "Known commitments for Firm Transmission Service and Interchange". The SDT needs to add "that are expected to be utilized." to the requirement. 1.1.6 Recommend changing to "Resources expected to supply Load"

Response: 1. The SDT agrees with your understanding. The System models should be updated in accordance with MOD-010 & MOD-012.

2. Yes, this is the correct understanding. Items from the Corrective Action Plan should be included in the models as noted under Requirement R1.

3. The SDT agrees with your understanding.

4. If the entity does not have the latest data, but did include items in the Corrective Action Plan, then the SDT believes the entity would be in violation of a Moderate Severity level. The SDT believes that the existing language is correct. The SDT believes that all System models should represent all known commitments for Firm Transmission Service and Interchange. The SDT does not believe that the proposed language adds any clarity. No change made.

5 The SDT realizes that this requirement may not be exclusively sources supplying Load. As an example, Demand Side-Management (DSM) may be used. The SDT

Organization	Comments for Question 1
has made a clarifying change to Requirement R1, part 1.1.6 based on industry comments. **R1, part 1.1.6** - Resources (supply or demand side) required for Load	
National Grid	Sub-Requirement 1.1.1: Replace "Existing Facilities" with "Existing Facilities and Resources" so that it will be a lead in to the changes proposed for 1.1.6. Sub-Requirement 1.1.2: This type of event is sufficiently addressed within the existing testing requirements (P6) and therefore should be eliminated, beyond that such outages are reviewed and approved on an operational basis and should not be included in a planning standard. During known outages for equipment upgrades or repairs there may be some increased exposure to load loss, which should be recognized as an acceptable exposure. In the event that this requirement is maintained please change six months to one year. Sub-Requirement 1.1.6: Resources may not be exclusively sources supplying load. Therefore the reference should involve load. The focus should be on changes to resources. "Resources required to supply Load" should be replaced with "New planned Resources and changes to existing Resources"It is suggested that NERC develop a definition for "resource" or use the following definition found in NPCC Glossary of Terms, Document A-7: Resource - Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load. ADD 1.2 The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions. The standard must describe base assumptions. Measure M1: Elaborate on "hard copy format". Does that entail maintaining a hard copy of the system model? It is impractical to retain system model information in a hard copy format. This provision should be dropped.
Response: 1 The SDT believes that the "and Resources" is not needed as a lead in to Requirement R1, part 1.1.6 since both Requirement R1, parts 1.1.1 and 1.1.6 are directly under Requirement R1, part 1.1. 2. The SDT disagrees since multiple outages may be taken during the same time period under Requirement R1, part 1.1.2, thus this situation may be worse than only having two Contingencies as noted in P6. The SDT believes that all outages should be modeled to ensure the System reliability during the outage duration. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-Contingency. See Requirement R2, part 2.1.3 for additional details concerning studies required with known outages. 3. The SDT agrees that this requirement may not be exclusively sources supplying Load. As an example, Demand Side-Management (DSM) may be used. The SDT has made a clarifying change to Requirement R1, part 1.1.6 based on industry comments. **R1, part 1.1.6** - Resources (supply or demand side) required for Load 4 The SDT believes that the "base case conditions" should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested. 5. Since Measure M1 states that either electronic OR hard copy format is required, the SDT believes that no changes are required since either of the formats is acceptable. An example of a hard copy of a System model is having printouts of each individual bus showing Load, Transmission line, generator, capacitors, etc.,	

Organization	Comments for Question 1
connected to that bus with associated impedances, ratings, etc.	
Lakeland Electric	Suggesting language "known planned" outages and in place of "known" outages Suggesting language "real & reactive resources" in place of "Resources" "within its respective area", how about ties?
Response: The SDT does not believe that the proposed language adds any clarity. No change made. The SDT has made clarifying change to Requirement R1, part 1.1.6 based on industry comments since this requirement may not be exclusively sources supplying Load. **R1, part 1.1.6** - Resources (supply or demand side) required for Load Tie Lines should be modeled as required to achieve conformance with the MOD standards.	
Exelon Transmission Planning	The feedback from Round 3 of comments is appreciated, but there is still a concern that the inclusion of known (or "expected") transfers is to be studied as a sensitivity. We believe that the base case should already contain the most likely ("expected") transfer scenario and a sensitivity case would be studied with a less likely transfer scenario. As written it appears that the standard would require that the base case would contain no transfers or some transfer level other than what is "expected". It is suggested the term "Expected transfers" be changed to "Additional transfers beyond base case conditions". The use of this term will provide clarity between what is to be modeled in the basecase and what is to be studied as a sensitivity case. There are a number of overlapping requirements with this standard and other standards in various stages of development, such as voltage stability criteria, protection system redundancy, relay loadability, and protection system contingencies that could cause non-compliance with several standards for a single infraction. Suggest removing overlapping requirements be removed from R6, P5 from Table 1, R3.3.3 and R3.3.1, respectively.
Response: 1. Requirement R1, part 1.1.5 requires that known commitments for Firm Transmission Service and Interchange be modeled. However the sensitivity analysis under Requirement R2, parts 2.1.4 and 2.4.3 require that at least one condition not already in the studies be varied by a sufficient amount in order to stress the System by a measurable change in performance. The SDT does not believe that the proposed language adds any clarity. No change made 2. As for the double jeopardy comment - From the ERO Rules of Procedure, Appendix 4B- Sanction Guidelines, Section 3.10 Multiple Violations: "Strictly speaking, NERC or the regional entity can determine and levy a separate penalty or sanction, or direct remedial action, upon a violator for each individual violation. However, in instances of multiple violations related to a single act or common incidence of noncompliance, NERC or the regional entity will generally determine and issue a single aggregate penalty, sanction, or remedial action directive bearing reasonable relationship to the aggregate of the related violations. The penalty, sanction, or remedial action will not be that determined individually for the least serious of the violations; it will generally be at least as large or expansive as what would be called for individually for the most serious of the violations." 3. The SDT believes that some overlap is necessary but the SDT has tried to minimize this as much as possible. Requirement R6 deals with defining and documenting certain items such as Cascading, voltage instability, and uncontrolled islanding. Note that Requirement R6 has been clarified to remove "outages" from "Cascading outages". P5 is a multiple Contingency caused by loss of a single Protection System. R3.3.1 deals with the removal of elements that the Protection System and other	

Organization	Comments for Question 1
automatic controls are expected to disconnect. However the SDT has clarified the relay loadability issue in Requirement R3, part 3.3.3 by stating how these are handled in the simulations when these limits are exceeded. **R3.3.3**. Trip Transmission elements when relay loadability limits are exceeded **R6**. Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, any criteria or methodology used in the analysis to identify System instability for conditions such as Cascading , voltage instability, or uncontrolled islanding.	
Florida Municipal Power Agency, and its Member Cities	The MOD standards for load forecasts (e.g., MOD-016 through 021) do not require submission of a reactive load forecast from the LSEs and RPs; therefore, why is it expected that the TPs and PCs use a reactive forecast that is not provided? From the auditor's perspective, what is expected and acceptable for System models representing reactive load forecasts? Suggested change: 1.1.4 Real Load forecasts and future reactive Load assumptions? Not all system models can represent all "Known commitments for Firm Transmission Service and Interchange". The SDT needs to add "that are expected to be utilized." to the requirement.
Response: 1. Requirement R1, part 1.1.4 states that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast. The SDT cannot comment on what an auditor may find compliant or non-compliant. No change made. 2. The SDT believes that the existing language is adequate and no further change is required. If you do not have any known Firm Transmission Service as an example, then this fact should just be documented.	
SRC of ISO/RTO	The PC may begin model building using provisions from tariff or agreements such as its Transmission Owners agreement. While the data may be consistent with that provided in MOD 10 and 12, there may not be a direct correllation. The following wording is suggested for R1.R1. Each Transmission Planner and Planner Coordinator shall maintain System Models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall reflect data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and/or data that is provided in accordance with tariff or transmission owner agreements. The models may be supplemented by other sources as needed including items represented in Corrective Action Plans, and shall represent projected System conditions. AESO does not comment on VSLs or VRFs.
Response: 1. The SDT believes that this is adequate as long as the data remains consistent with that provided in MOD-010 and MOD-012.	
US Bureau of Reclamation	The requirement for the model is not clearly stated. Based on the requirement 2, the models must prove the Corrective Action Plan items developed in 2.7.1. The actions in 2.7.1 are developed by the Transmission Planner or Planning Authority ("List System deficiencies and associated actions needed to achieve required System performance"). Requirement 1 however requires that the model "shall represent projected System conditions". Is the intent of the modelling to demonstrate system performance based on changes proposed by the Tranmission Owners and Generator Owners. Or is it the intent to have the Transmission Planner and Planning Authority develop proposals through system studies that the Transmission Owners and Generator Owners must implement?

Organization	Comments for Question 1
Response: Requirement R1 requires that Corrective Action Plans be included in the models. Requirement R1 includes items represented in the Corrective Action Plans along with represented projected System conditions. The intent of the modeling is to ensure that entities are planning reliable Transmission Systems and have sufficient time to get needed plans in service to continue meeting the TPL-001-1 requirements. The SDT believes that these actions are needed in the planning horizons in order to have a reliable Bulk Electric System. No change made.	
Oncor Electric Delivery	The six month limitation of requirement 1.1.2. "Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months." is applicable to near-term and long-term Planning studies, but makes the new TPL-001 standard non-extendible to the near-term operational planning studies (next month, next week, or next day). During near-term operational planning periods, it is essential to include the impacts of ALL known outages in the operational analysis.It should be made clear that the TPL-001 Standard is not applicable to the Operational Planning Horizon. This non-applicability points out the need for a separate (but equal in scope) operational planning analysis standard.There appears to be a lack of clarity related to relay loadability and protection system redundancy. Relay loadability is handled in greater detail (as it should be) under the proposed PRC-023 standard, so any reference here should only be a placeholder. Similarly, the issues of redundancy are being addressed in more detail in a new proposed standard on protection system reliability. 1.1.2 ? The requirement will result in the need to evaluate construction sequence in planning studies. 1.1.6 ? What are "resources required to supply load gens, HVDC, tie lines" NPCC suggests NERC develops a definition for "resource" or use the following definition found in NPCC Glossary of Terms, Document A-7: Resource Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load.1.1.6 Resources are not serving load but are supporting network operations. ADD 1.1.7 The standard is referring to requirements for sensitivity and other issues without a reference to base cases. It is recommended that each Region have a document that defines what constitutes "base case" conditions. M1What does it mean to have a hardcopy of a system model? 1.4 Data Retention: The Transmission Planner and the Planning Coordinator may not be using the same software. If both are required to store the data, are they both required to have identical software to use the data? We recommend that the entities have an option to determine which of the two entities retains the information.
Response: 1. The SDT agrees that this standard does not apply to the operating planning horizon. Please see the NERC TOP standards, as an example, for additional information concerning operational planning. The SDT believes that relay redundancy is best handled in Project 2009-07: Reliability of Protection Systems. However, the SDT has clarified the relay loadability issue in Requirement R3, part 3.3.3 by stating how these are handled in the simulations when these limits are exceeded. **R3.3.3**. Trip Transmission elements when relay loadability limits are exceeded	

Organization	Comments for Question 1
2. The SDT agrees that evaluation of construction sequences would have to be performed in order to successfully model outages as required. 3. The SDT agrees that this requirement may not be exclusively sources supplying Load. As an example, Demand Side-Management (DSM) may be used. The SDT has made a clarifying change to Requirement R1, part 1.1.6 based on industry comments. **R1, part 1.1.6** - Resources (supply or demand side) required for Load 4. The SDT believes that the "base case conditions" should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested. 5. Since Measure M1 states that either electronic OR hard copy format is required, the SDT believes that no changes are required since either of the formats is acceptable. An example of a hard copy of a system model is having printouts of each individual bus showing Load, Transmission line, generator, capacitors, etc., connected to that bus with associated impedances, ratings, etc. 6. The SDT believes that both the Transmission Planner and Planning Coordinator have this responsibility. Therefore, the SDT believes that the existing language is adequate and that no changes are required.	
TIS	The six month limitation of requirement 1.1.2. "Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months." Is is applicable to near-term and long-term Planning studies, but makes the new TPL-001 standard non-extensible to the near-term operational planning studies (next month, next week, or next day). During near-term operational planning periods, it is essential to include the impacts of ALL known outages in the operational analysis.It should be made clear that the TPL-001 Standard is not applicable to the Operational Planning Horizon. This points out the need for a separate (but equal in scope) operational planning analysis standard. There appears to be a double-jeopardy issue related to relay loadability and protection system redundancy. Relay loadability is handled in greater detail (as it should be) under the proposed PRC-023 standard, so any reference here should only be a placeholder. Similarly, the issues of redundancy are being addressed in more detail in a new proposed standard on protection system reliability.
Response: 1. The SDT agrees that this standard does not apply to the operating planning horizon. See the NERC TOP standards, as an example, for additional information concerning operational planning. 2. As for the double jeopardy comment - From the ERO Rules of Procedure, Appendix 4B- Sanction Guidelines, Section 3.10 Multiple Violations: "Strictly speaking, NERC or the regional entity can determine and levy a separate penalty or sanction, or direct remedial action, upon a violator for each individual violation. However, in instances of multiple violations related to a single act or common incidence of noncompliance, NERC or the regional entity will generally determine and issue a single aggregate penalty, sanction, or remedial action directive bearing reasonable relationship to the aggregate of the related violations. The penalty, sanction, or remedial action will not be that determined individually for the least serious of the violations; it will generally be at least as large or expansive as what would be called for individually for the most serious of the violations." 3. The TPL draft is silent on the issue of redundancy. However the SDT has clarified the relay loadability issue in Requirement R3, part 3.3.3 by stating how these are handled in the simulations when these limits are exceeded. **R3.3.3**. Trip Transmission elements when relay loadability limits are exceeded	

Organization	Comments for Question 1
TVA System Planning	TVA agrees with the changes made in R1 - especially the minimum 6 month duration required for outages to be modeled.In R1.1.5, how should partial path transmission service be accounted for in the known commitments for firm transmission service and interchange? VSL: In the Moderate and Severe VSL, insert "responsible entity's" in front of the term "System model" after the "or".

Response: 1. The SDT believes that you should plan for known commitments. Therefore, the part of the partial path that is known should be modeled.

2. The SDT agrees and will insert this additional wording in the moderate and severe VSLs for R1.

R1 VSL	The responsible entity's System model failed to represent one of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.	The responsible entity's System model failed to represent three of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1.

American Transmission Company	We propose the following changes and questions: R1 We interpret that "within their respective areas" refers the geographic footprint of the TP or PC transmission system. We propose clarifying that "within their respective area" does not require the inclusion of remote generation or load (metering) buses that are within the declared Balancing Authority area, but may be outside and separate from the TP or PC geographic footprint. R1.1.2 We suggest that this requirement be removed because the "known outage(s)" are only to be included in the models when P1 events are simulated, as specified in R2.1.3. We suggest that the intent of this requirement can be more simply handled by stating in R2.1.3 that "known outages be simulated along with P1 events for the System peak or Off-Peak conditions when the outages are scheduled to occur". R1.1.3 Add the qualification of "for the years defined in R2". R1.1.6 We interpret that "Resources required" allows the inclusion of fictional generators in the models when they are needed to

Organization	Comments for Question 1
	make future normal system cases solve. If this is not the intended interpretation, then we suggest modifying the wording to make the desired interpretation more clear. M1 " Revise M1 to indicate that each responsible entity must provide evidence with the added qualification, ". . . it is maintaining System models within its respective area, using the latest . . ."
Response: 1. The SDT believes that the "within their respective area" does refer to the Transmission Planner's or Planning Coordinator's geographic footprint. The SDT does not believe that the proposed language adds any clarity. No change made. 2. The SDT disagrees since multiple outages may be taken during the same time period under Requirement R1, part 1.1.2. The SDT believes that all outages should be modeled to ensure the System reliability during the outage duration. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-Contingency. See Requirement R2, part 2.1.3 for additional details concerning studies required with known outages. 3. The requirements in TPL-001-1 are all inter-related so no change is required. 4. The SDT believes that this requirement includes any fictional generators that may be needed to match up generation and Load. The SDT has made a clarifying change to Requirement R1, part 1.1.6. **R1, part 1.1.6** - Resources (supply or demand side) required for Load 5. The SDT agrees that adding "within its respective area" would help clarify this measure. The SDT has modified Measure M1 to include this new language. **M1**. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within its respective area, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.	
PJM	Consider rewording R1.1 to, -Consistent with the desired year and season a system model shall represent-. This removes some ambiguity about what to include in each model. Possible confusion existed about the multitude of models and what needed to be in each of them. These words deal with each model separately.
Response: The SDT does not believe that the proposed language adds any clarity. No change made.	

2. Requirement R2 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: A number of Commenters requested clarification of on the use of past studies (Part 2.6) either as a supplement to or in place of the annual current year studies (in Parts 2.1 through 2.5). Many also requested that the requirements for Part 2.1 (Near-Term steady state studies) and Part 2.2 (Long-Term steady state studies) be changed from "annual current studies, supplemented by qualified past studies" to "annual current study or qualified past studies".

The SDT reviewed Requirement 2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the Near-Term and the Long-Term planning horizon, respectively. While the SDT envisions that the standard is flexible enough to allow the use of qualified past studies, the planning assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for the Near-Term Planning Horizon and one of the years in the Long-Term Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested.

A number of Commenters questioned the need for two distinct study years to support the planning assessment for the Near Term planning horizon, especially in areas with very low Load growth. They requested reducing the requirements for annual current studies to one study to support the Near-Term planning horizon.

The SDT reviewed the requirements and declines to change to one Near-Term study. Load growth may not be the only determination factor for System performance; other examples are addition or retirement of generation. The SDT therefore, believes that, as a minimum to support reliability, Transmission plans are needed for the time frame just after operation planning (Year One or year two), as well as the time frame at the end of the Near-Term (year five) to allow implementation of solutions, which may require longer lead time.

Many Commenters requested clarification of the Load level(s) to be used in an "off-peak" case. One Commenter explained that the NERC glossary defines Off-Peak as those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand and On-Peak as those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of higher electrical demand. Therefore, the Commenters pointed out that Off-peak can be ANY Load level less than peak, and, as such, can be confusing.

The SDT notes that the intent of Parts 2.1.2 and 2.4.2 is to assess those System conditions during periods with lower Load levels than peak when the System may show different potential problems than during periods with peak Load level. For example, during light Load conditions, there may be high voltage problems because of the charging in the lightly loaded lines. There could also be thermal overload problems for areas with more generation than Load. The System could have less damping and could result in potential Stability problems. For this reason, it would not be appropriate to eliminate the

requirement to investigate Off-Peak steady state conditions. At the same time, the standard should not be overly prescriptive; therefore, the exact System Off-Peak Load should be specified by the entity performing the study.

Commenters also questioned the need for Off-Peak studies because the System Off-Peak is more likely a Stability issue than a steady state issue, and if System Off-Peak becomes a steady state issue, it can be mitigated through generation re-dispatch. Three Commenters also suggest moving Part 2.1.2 to Part 2.1.4 and treating it as one of the sensitivity analyses.

Based on the need to assess System conditions during periods of lower Load, the SDT believes that it would not be appropriate to move the studies of Off-Peak Load conditions from Parts 2.1.2 or Part 2.4.2 to be included in the sensitivity studies required in Parts 2.1.4 or 2.4.3. Sensitivity studies only need to cover one of the six conditions included in the bullets, and this may not be the one selected by the entity, resulting in no study of Off-Peak conditions being performed.

Many Commenters suggested clarification that for Part 2.1.3 it must be clear that the reference to outage schedules as listed in Part 1.1.2 (which requires modeling of known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months) must be limited to the planning horizon.

Part 2.1.3 is a sub-part of Part 2.1 which is limited by the Near-Term Transmission Planning Horizon so no change is made.

One Commenter suggested that Part 2.1.3 is not needed if the outages in Part 1.1.2 are properly built into the model. Three Commenters suggested clarifying changes.

Part 2.1.3 codifies studies needed to support the Planning Assessment. The SDT intends for Part 2.1.3 to cover known long duration outages, for example, taking a 230 kV Transmission line out of service to rebuild it to operate at 500 kV. These cases are to simulate System conditions with the Facility in question out of service as Category P0 (or N-0). For the next outage, the System performance will need to meet requirements for Category P1. This is not the same as requirements for Category P6, which assumes that the outage for the first Facility would be of shorter duration than 6 months. To provide greater clarity, Part 2.1.3 has been revised.

Many Commenters expressed concerns that the use of the words and phrases, “credible”, “sufficient”, “stressed” conditions and “measurable change” may be too vague for compliance. Many Commenters also state that to include and define sensitivity cases and simulations in the standard, the base case assumptions to be used in the assessments must also be defined.

The SDT notes that it envisions that “credible”, “sufficient”, “stressed” conditions and “measurable change” are to be defined by the responsible Planning Coordinator or Transmission Planner because each System is different. Likewise, the SDT believes that the “base case conditions”, on which to base the sensitivity cases should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies.

Some Commenters suggested removing the last bulleted item in the list under Part 2.1.4. (Duration or timing of planned Transmission outages).

The SDT declines to remove the last bullet in Part 2.1.4, "Duration or timing of planned Transmission outages" as a potential sensitivity. The intent of this bullet item is to cover unexpected changes in plans, for example, a potential delay in returning a Transmission line back to service after a planned outage of 6 months or more for rebuilding to a higher capacity line. In this case, the System with the equipment in question out of service would be modeled as P0 (or N-0). For the next outage, the System performance will need to meet requirements for Category P1 and not P6.

Many Commenters also asked whether the (bulleted) list of potential sensitivities in Parts 2.1.4 and 2.4.3 should be the same. Many also expressed concern that Part 2.1.4 (as well as Part 1.1.4) seems to require forecasting reactive Load when most entities forecast demand (MW) and apply a power factor(s) to calculate reactive Load.

The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within Parts 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and Stability evaluations, respectively. Part 1.1.4 and Part 2.1.4 state that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast.

Two Commenters would like clarification that the sensitivity findings do not obligate the Planning Coordinator or Transmission Planner to establish Corrective Action Plans.

The SDT notes that Part 2.7 states, in part, that "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. In addition, Part 2.7.2 describes the requirement on Corrective Action Plans to "Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary".

Some Commenters suggested clarifying changes to the first sentence in Parts 2.1.4 and Part 2.4.3 from "impact of changes to the basic assumptions used in the model for the list of items below", to "impact of change to the basic assumptions used in the model". For Part 2.4.3, a number of Commenters also suggested a workshop to clarify some of the requirements.

The SDT modified Parts 2.1.4 and 2.4.3. The SDT agrees that a workshop is a good idea. However, because of differences in each Region/Interconnection, the SDT encourages the Regions to hold workshops on issues specific to the Regions utilizing SDT members as participants in the discussions.

Some Commenters expressed concerns that Part 2.1.5 may require entities to have a spare equipment strategy, about the amount of added work, and that it may be redundant with Categories P2, P3, or P6 in Table 1. One Commenter was concerned that this requirement may be difficult for entities such as the Planning Coordinator, who may not own or manage the Transmission equipment or the spare strategy.

The SDT notes that Part 2.1.5 only requires that the Planning Coordinator and the Transmission Planner plan for the potential unavailability of long lead time major Transmission equipment in accordance with its spare equipment strategy. For example, if an entity's spare equipment strategy is to have a spare transformer on site, then the unavailability of a similar transformer

(due to outages) would be limited to the time it would take to energize the spare transformer. Assuming that this time is no more than that required to return a similar outaged transformer back to service, Part 2.1.5 can be satisfied without performing additional planning studies. If on the other hand, the transformer would have to be purchased, then it would take more than a year to replace. In this case, for Part 2.1.5, P0 should be modeled with the transformer in question out of service. The performance requirements in Table 1 will apply for the next single Contingency. This is not the same as P2 or P6; both of which are events starting from System intact condition as P0. It is also not the same as P3, which covers loss of a generator as the first event, and Part 2.1.5 covers loss of a piece of major Transmission equipment for which there is no spare. In addition, the Planning Coordinator does not have to own or manage the Transmission equipment or the strategies, it only needs to know the strategy and take it into account in selecting the appropriate Contingencies to study and plans for the potential unavailability of long lead time major Transmission equipment. It also does not preclude a Transmission Planner from coordinating its spare equipment strategy with others.

Some Commenters state that the requirement is not clear as to whether a Corrective Action Plan is required for those pieces of long lead time equipment without spares. Others believe that the Corrective Action Plans should allow actions such as, "out of merit dispatch", "operational restrictions", and "System reconfiguration" if the System cannot meet performance requirements without the facility in service.The SDT notes that Part 2.1.5 is part of Requirement 2, for which a Corrective Action Plan would be required. As stated in Part 2.1.5, the corrective actions should, as a minimum, allow reliable operations for categories P0, P1, and P2 during the times when the equipment is expected to be unavailable. The SDT also believes that the concern of allowing actions such as, "out of merit dispatch", "operational restrictions", and "System reconfiguration" to be part of the Corrective Action Plan has already been addressed. These actions are allowed in Part 2.7.1 on Corrective Actions.

One commenter seeks clarification on the study requirements for Part 2.1.5 during the time period in which the spare was put in service and no spare would be in place.

The SDT notes that Part 2.1.5 does not address the specific requirements of an individual plan. Since a Planning Assessment is required annually, the analysis required under Part 2.1.5 is an annual requirement. The answer to the specific example would depend on a variety of factors, including the timing of the failure, the length of time that it would take to replace the spare, your Operation Planning time horizon and the specifics of your individual spare equipment strategy. In addition, to provide greater clarity, the SDT has revised the first sentence of Part 2.1.5.

A number of Commenters suggested that Part 2.3 be modified to state that it is up to the planner to determine the year of study within the Near-Term Transmission Planning Horizon.

The SDT notes that Part 2.3 is silent on the year of study within the Near-Term Transmission Planning Horizon. Therefore, it is up to the Transmission Planner or Planning Coordinator to select the study years most suited to the System in question. In addition, Part 2.3 only requires an annual Planning Assessment, which is to be supported by annual current or qualified past studies.

A number of Commenters asked why there is no requirement stipulating short-circuit analysis for the long-term horizon. Another Commenter asked why there is no requirement for short circuit studies similar to Requirement R3 for steady state studies or Requirement R4 for Stability studies.

The SDT notes that Part 2.3 is for short circuit assessment of the System in general and is more suited for the near-term planning horizon, when Transmission plans are more certain. Lead time to implement a corrective action if found necessary can reasonably be expected to be completed in the near-term time frame. Short circuit study for the longer term planning horizon should be studied on a case by case basis associated with specific project(s). In addition, the SDT does not believe a requirement to cover short circuit studies similar to Requirement R3 or Requirement R4 is required. The SDT's intent was that while the standard requires short circuit results to be included in the assessment, it does not need to address the technical requirements for completing the short circuit study as that may be entity specific.

Some Commenters questioned the need for short circuit studies to be required in this standard since Short circuit analysis is a local issue. The reliability of the BES does not depend on the regular assessment of short circuit duty. In addition, the effects of the failure of over-stressed breakers are already included in the events listed in Table 1: for example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault).

The SDT states that Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt. Even though the effects of short circuit capability are localized and may be related to new planned Facilities, it is important to BES reliability.

A number of Commenters requested that the SDT clarify Part 2.4.1 as to when "Load models considering induction motors" are required. They requested limits or thresholds to provide Load models based on areas that have Stability limits or issues and based on Loads capable of significantly impacting voltage Stability. This is so that areas that don't have large motors or Stability issues should not be required to add unnecessary Load modeling.

The SDT declines to add specifics on Load modeling requirements because such specificity needs to be determined by the entity performing the study. Part 2.4.1 allows the use of "an aggregate System Load model which represents the overall dynamic behavior of the Load". All areas including those that do not have large motors can use an appropriate aggregate System Load model.

One Commenter asked if Part 2.4.2 should include requirements for dynamic Load models, considering the behavior of induction motor Loads.

The SDT reviewed Parts 2.4.1 and 2.4.2. In Part 2.4.1 the SDT specifies the dynamic Load model representation for on peak because the System voltages are generally lower during on peak. The percentage of motor Load, e.g., in air conditioners, could significantly increase reactive power requirements especially when they stall due to low System voltage and can therefore impact dynamic System performance on-peak. However, motor Load would likely not pose the same problem during off-peak as the System voltages are usually higher. So, in Part 2.4.2, it can be left to the discretion of the Planning Coordinator or Transmission Planner whether the dynamic motor Load would need to be represented per the requirement in Part 2.4.1.

Some Commenters requested clarification as to whether the language in Part 2.5 "proposed generation additions and changes" should also include Transmission additions and changes.

The SDT intends for Part 2.5 to require investigation of Stability issues due to addition of generators, not system stability issues in general. The SDT does not believe that, in general, a Stability assessment is needed for the Long-Term Planning Horizon. The System model for that time frame is too uncertain for a meaningful assessment of the System's stability. However, for those situations where a specific generator is planned to be added in that time frame, the SDT believes that it will be appropriate to require that the generator's Stability impact be evaluated.

A number of Commenters request clarification on the phrase "material change", which could impact whether a past study can be used to support a current-year assessment.

The SDT notes that Part 2.6.2 also allows an entity to rely on a past study with a material change if "a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area". Therefore, it is up to the entities performing the study to provide the rationale based on changes, such as Load growth.

Some Commenters requested clarification of the intent of the Corrective Action Plan and whether projects added in the Corrective Action Plan should be modeled in subsequent years when assessing System performances.

The SDT believes that Part 2.7 requires a Corrective Action Plan to be developed "when the analysis indicates an inability of the System to meet the performance requirements in Table 1". Therefore, the intent is to address situations where simulation and the application of currently planned projects and procedures are insufficient to meet the performance requirements. If a project is added to the Corrective Action Plan, it should be included as part of the study assumptions based on the criteria Planning Coordinator's and Transmission Planner's use for inclusion of such planned projects, and clearly identified as an assumption for the annual assessment as required in Requirement R2 until it is in service or shown to be no longer needed. Two Commenters observed that Part 2.7 seems to have lost the reference to lead times for Corrective Action Plan(s) that were present in the existing TPL-001-0, TPL-002-0, and TPL-003-0 standards and requested to include in the standard some indication of when activity needs to start to implement the Corrective Action Plan. The SDT notes that the NERC Glossary of Terms defines Corrective Action Plan as "A list of actions and an associated timetable for implementation to remedy a specific problem. Also, Part 2.7.4 requires that the CAP be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures. By including the timing of needed action and requiring such reviews in subsequent assessments, any deficiencies, if not adequately addressed, will become violations. Therefore, the SDT believes that this concern has been addressed.

A majority of Commenters objected to the inclusion of Part 2.9 because it is not reliability related and does not address a performance oriented issue but is rather an information gathering exercise, and suggested that this requirement be deleted.

The SDT agrees with the Commenters as to the nature of the requirement. The SDT also reviewed FERC Order 693 and observed that it directs the ERO to consider including this effort in the standard development process. The SDT has tried through several postings but industry pushback is still significant that this doesn't belong in a standard. The SDT decided that

this effort should best be continued through a NERC data gathering request. The data gathered can then be used in a future revision of this standard.

The following changes were made to the standard requirements due to industry comments:

Requirement R2, part 2.1.3: P1 events in Table 1 with known outages modeled, as in Requirement R1, part 1.1.2 under those System peak or Off-Peak conditions when known outages are scheduled.

Requirement R2, part 2.1.4: For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

Requirement R2, part 2.1.5: When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Requirement R2, part 2.3: The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

Requirement R2, part 2.4: The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, part2.6. The following studies are required:

Requirement R2, part 2.4.3: For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

Requirement R2, part 2.4.3, bullet #1: Load level, Load forecast, or dynamic Load model assumptions

Requirement R2, part 2.4.3, **bullet #3**: Expected in service dates of new or modified Transmission Facilities

Requirement R2, part 2.5: The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, part 2.6.

Requirement R2, part 2.6.2: For steady state, short circuit, or Stability analysis: the System represented in the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

Requirement R2, part 2.7: For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

Requirement R2, part 2.7.1, bullet #4: Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.

Requirement R2, part 2.9:

Table 1, footnote 1: If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.

Requirement R2, data retention: The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.

Organization	Comments for Question 2
Independent Electricity System Operator	(1) Part 2.1.4: We do not believe the sentence: To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. is necessary or measurable. The first part of 2.1.4 already stipulates sufficient details for the responsible entity to conduct sensitivity analysis including the parameters to be varied. Adding the "how-to conduct" requirement is overly prescriptive and unnecessary, and the condition for "that demonstrate a measurable change in performance" is not measurable. It lacks a definitive target or direction for the responsible entity to determine (a) what conditions need to be attained to demonstrate a measurable change in performance, (b) what constitutes "measurable change in performance", and (c) what follow-up or corrective actions are needed to address the adverse performance as a result of stressing the system beyond the forecast conditions. In our comments on Draft 1, we disagreed with the requirement to conduct sensitivity testing. This is part of the analysis exercise that planners normally perform to help them identify critical parameters/conditions for consideration in planning assessments and in developing remedial plans. Having a reliability requirement to stipulate the details of sensitivity analysis is unnecessary but produces much increased work whose acts are difficult to measure and whose results are not taken any further to arrive at a useful outcome. Once again, we urge the SDT to consider dropping this requirement. (2) Part 2.3 stipulates the short-circuit assessment requirements for the near-term horizon. Unlike its steady-state and stability counterparts, there are no requirements stipulated for short-circuit analysis for the long-term horizon. Is this intentional? If so, we are unable to identify the rationale for this decision. If not, we suggest revising Part 2.3 to: The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the near-term and long-term Transmission Planning Horizons

Organization	Comments for Question 2
	and can be supported by. (3) R2.4.1: We believe that "considering the behavior of induction motors" is not necessary since the wording "a Load model which represents the dynamic behavior" already covers this. (4) In part 2.5, we recommend inserting the text "and Transmission Facilities" after "generation" to be consistent with the wording of part 2.3 (5) As drafted, the VLSs do not address missing certain combinations of parts of Requirement R2. For example, the condition assigning a Low, Moderate or High VSL is the failure of one of the parts listed under these columns. There is no assignment for failing more than one of the listed parts. We propose adding a second condition under the High VSL as follows: OR two or more of parts 2.3, 2.6, 2.8 and 2.9.. Also, part 2.5 is missing from the SEVERE VSL. We recommend including it. As written, it is possible to miss say parts 2.1 and 2.5 and still not be captured under the Severe VSL if that is the intent.
Response: For Part 2.1.4, The SDT envisions that stressed conditions and "measurable change" are to be defined by the responsible Planning Coordinator or Transmission Planner. Part 2.7 states, in part, that "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. In addition, Part 2.7.2 describes the requirement on corrective action plans to "Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary". No change made. Part 2.3 is for short circuit assessment of the System in general and is more suited for the near-term planning horizon, when Transmission plans are more certain. Lead time to implement corrective actions if found necessary can reasonably be expected to be completed in the near-term time frame. Short circuit studies for the longer term planning horizon should be studied on a case by case basis associated with specific project(s). Therefore the SDT declines to make the change as suggested. For Part 2.4.1, the clause "considering the behavior of induction motor Loads" is a clarification of the intent of this Requirement. Therefore, the SDT declines to make the change. Part 2.5 is intended for investigation of Stability issues due to addition of generators. The SDT does not believe that, in general, a Stability assessment is needed for the Long-Term Transmission Planning Horizon. The System model for that time frame is too uncertain for a meaningful assessment of the System's Stability. However, for those situations where a specific generator is planned to be added in that time frame, the SDT believes that it will be appropriate to require that the generator's Stability impact be evaluated. The SDT reviewed the VSL assignments and believes that as written they are as intended. In assigning the VSLs the SDT considers the potential lead time to implement the corrective action as well as the impact of non-compliance. Parts 2.1, 2.2, 2.4, and 2.7 cover the basics of planning activities and the lead time to implement the Corrective Action Plan can be longer than the near term planning horizon. As such, failure to comply with two of more of these parts can severely impact future System reliability. Part 2.5 covers long term Stability analysis, corrective actions would likely involve addition of dynamic voltage support, which can reasonably be expected to be implemented within the near term horizon.	
ERCOT ISO	* Requirement R2 (and throughout the standard) What is meant by "its portion of the BES"? Will any agreements made in R7 override the "each TP and PC" requirement? To clarify this, the requirement could be rephrased: "In accordance to the responsibilities assigned in R7, the responsible Transmission Planners and Planning Coordinators shall prepare?"* Requirement 2.1.3: This is not needed if these outages are properly built into the model.

Organization	Comments for Question 2
	* Requirement 2.1.4: This requirement applies to 2.1.1 and 2.1.2. Why does it omit 2.1.3? Should it be referring to 2.1.3 for P1 contingencies? * How will 2.1.4 be proven? What is the definition of “stress” in this context and what defines “sufficient” stress? What is “measureable change”? What is the expected response to the results of this analysis? For example, if the load forecast must double to “sufficiently” stress the system, is the expectation that facilities should be planned to respond to the stress? * Requirement 2.1.5: Including the spare equipment strategy will be difficult for a PC that doesn’t own or manage the transmission equipment or the strategies. But if this inclusion is only done by a TP, the benefits of coordinating with other TPs may not be realized. * Requirement 2.2: If each entity is responsible to study the System peak Load of its area, but a PC is responsible for multiple TP systems, then what System Peak Load is the PC responsible to study “ a model that includes the non-coincident peaks of all of the TP systems for which it is responsible or the coincident peak demand across the whole system for which the PC is responsible” * Requirements 2.4.1 and 2.4.2: These appear to have inconsistent references to defined terms. Should this be consistent? The NERC glossary states: "Off-Peak: Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand.""On-Peak: Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of higher electrical demand.""System: A combination of generation, transmission, and distribution components."* Requirement 2.6.2: Reads as if a change is being made to an existing study. It is confusing. Possibly restate: "2.6.2 For steady state, short circuit, or stability analysis: previous studies can be used only if a material change to the system has not occurred or if a change that did occur does not impact the study area." * Requirement 2.7: in each case throughout the standard, replace “planning events” with “planning events as defined in Table 1” and “extreme events” with “extreme events as defined in Table 1” * Requirement 2.7.2: It would be good to clearly state here or in 2.1.4 that results from stressing the system do not always need to be resolved.

Response: BES can cover the entire region or Interconnection. “Its portion of the BES” limits the accountability to only the portion for which the Planning Coordinator or Transmission Planner is responsible. Requirement R7 requires that the Planning Coordinator and Transmission Planner’s coordinate and delineate their individual responsibilities within their portions of BES if there are any overlaps. Therefore the SDT declines to make the change.

Part 2.1.3 codifies studies needed to support the Planning Assessment and as such must be retained.

Parts 2.1.1 and 2.1.2 are “normal” System conditions. Part 2.1.3 covers P1 Contingencies with known long duration outage of a Facility included as Category P0. Therefore, the standard does not require sensitivity studies on top of P1 outage events as specified in Part 2.1.3. However, the standard does not preclude applying Part 2.1.4 to Part 2.1.3.

For Part 2.1.4, The SDT envisions that stressed conditions and “measurable change” are to be defined by the responsible Planning Coordinator or Transmission Planner.

For Part 2.1.5, the Planning Coordinator does not have to own or manage the Transmission equipment or the strategies, it only needs to know the strategy and take it

Organization	Comments for Question 2
	into account in selecting the appropriate Contingencies to study. Part 2.1.5 does not require that each entity has a spare equipment strategy; only that it plans for the potential unavailability of long lead time major Transmission equipment. It also does not preclude a Transmission Planner from coordinating its spare equipment strategy with others. For Part 2.2, the intent of the System peak Load case is to model the System conditions at the time of Peak Demand of the System for which an entity is responsible. Therefore, this case should model the coincidental peak of the System. However, the standard does not preclude the Planning Coordinator from also studying System conditions at higher Load levels, such as the non-coincident peak. For Parts 2.4.1 and 2.4.2, the NERC Glossary defines "Peak Demand" as: "1. The highest hourly integrated Net Energy For Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year). 2. The highest instantaneous demand within the Balancing Authority Area." NERC also defines Load as, "An end-use device or customer that receives power from the electric system." The draft Standard uses "System peak Load" to refer to the System conditions when the Load level is at the Peak Demand of the System being studied; and "Off-Peak Load" to refer to those System conditions when the Load level is lower. For assessing System performance, reasonably adverse System conditions should be modeled. Part 2.6.2 is governed by Part 2.6, which states: "Past studies may be used to support the Planning Assessment if they meet the following requirements". Therefore the SDT believes that the proposed change does not add clarity and has already been covered. Furthermore, the proposed change would introduce confusion in Part 2.6.1, which is also governed by Part 2.6. Planning event appears once in Requirement R2: Part 2.7 begins with "For planning events shown in Table 1". The SDT cannot find "extreme events" in requirement R2. Therefore, the SDT was not clear on the issues being raised. Since the language used has the same intent as the proposed change, no change was made. Part 2.7 states, in part, that "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. In addition, Part 2.7.2 describes the requirement on Corrective Action Plans to "Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary". The SDT believes that this concern is covered in the existing draft.
Bonneville Power Administration	: The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies " It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most

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	entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.
Response: The SDT reviewed Requirement 2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the Near-Term and the Long-Term Transmission Planning Horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested. The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within Parts 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and stability evaluations, respectively. **Requirement R2, part 2.4.3**, **bullet #3**: Expected in service dates of new or modified Transmission Facilities Parts 1.1.4 and 2.1.4 state that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast	
Northeast Utilities	[R2.1] The language of this requirement should be revised as follow: The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required: [R2.1.2] Please clarify the load level to be used for "System Off-Peak Load". [R2.1.4] To include and define sensitivity cases and simulations in the standard NERC must also define base cases to be used in the assessments. Refer to comment suggesting the addition of Requirement R1.1.7. [R2.1.5] It is not clear whether a corrective action plan should be developed for this requirement and if we are to develop an action plan should it be temporary and cover only the time period that the major Transmission equipment was unavailable? [R2.2] The language of this requirement should be revised as follow: The long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required: [R2.3] Please provide guidance as to what year should be represented when performing short circuit studies or is it up to the Planner to select a year for the study? [R2.5] There is no guidance on the load level that should be used for the long-term stability study as is required by Requirement R2.2.1 for the Steady State assessment. [R2.9] Why the need to report the largest Consequential Load Loss since the TPL Standard does not limit the amount of Consequential Load that could be allowed? We recommend that this requirement should be deleted.

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Response: The SDT reviewed Requirement 2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the Near-Term and the Long-Term Transmission Planning Horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study will be performed. Therefore, the SDT declines to make the change as suggested. The intent of Part 2.1.2 is to assess those System conditions during periods with lower Load levels than peak when the System may show different potential problems than during periods with peak Load level. For example, during light Load conditions, there may be high voltage problems because of the charging in the lightly loaded lines. There could also be thermal overload problems for areas with more generation than Load. For this reason, it would not be appropriate to eliminate the requirement to investigate Off-Peak steady state or Stability conditions. At the same time, the standard is not intended to be prescriptive; therefore, the exact System Off-Peak Load can be specified by the entity performing the study. For Part 2.1.4, the SDT believes that the "base case conditions", on which to base the sensitivity cases should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested. The Corrective Action Plan is covered in Part 2.7 for planning events shown in Table 1 "when the analysis indicates an inability of the System to meet the performance requirements in Table 1". For Part 2.1.5, the corrective action should, as a minimum, allow reliable operations for categories P0, P1, and P2 during the times when the equipment is expected to be unavailable. For Part 2.2, while the SDT envisions that the standard is flexible enough to allow the use of qualified past studies; the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of basic planning process, the SDT believes that the steady state portion of the studies should be done annually covering one of the years in the Long-Term Transmission Planning Horizon. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire Long-Term Transmission Planning Horizon. Making the change as requested in Part 2.2 can result in no current-year study being performed for the Long-Term Transmission Planning Horizon. Therefore, the SDT declines to make the change as suggested. Part 2.3 is silent on the year of study within the Near-Term Transmission Planning Horizon. Therefore, it is up to the Transmission Planner or Planning Coordinator to select the study years most suited to the System in question. In addition, Part 2.3 only requires an annual Planning Assessment, which is to be supported by annual current or qualified past studies. For Part 2.5, the stressed conditions for Stability are often System specific. The intent is to allow the entity performing the Stability study, which is most knowledgeable about its System, to determine the System conditions, including Load levels, on which to perform the assessment. Part 2.9 has been deleted as suggested.	
Central Maine Power Company	2.1.3 In the event that R1.1.2 is kept it must be clear that the reference to outage schedules as listed in part 1.1.2 must be limited to the Planning Horizon. Table 1 There is confusion in interpretation of the table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to

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	shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading? 2.1 Language should be revised similar to R2.4 as follows: The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required: 2.1.2 Should be moved to the list of sensitivities currently in 2.1.4. (Off-peak needs to be more specifically defined). 2.1.4 Consistent with the suggestion made for section 1.1.2 please remove the last bulleted item in the list under section 2.1.4. Duration or timing of planned Transmission outages. 2.2 The language in 2.2 should be revised to be similar to 2.4 as follows: The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required: 2.3 This should be modified to state that it is up to the Planner to determine the year of study within the Near Term Transmission Planning Horizon. 2.4.2 This should be deleted as it is covered under section 2.4.3. 2.4.3 To define a sensitivity, NERC must define base assumptions. 2.7 We suggest changing the word “run” to “condition” such that it reads “Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity condition in accordance with Requirements R2, parts 2.1.4 and 2.4.3.” 2.9 The requirement to report the largest single consequential load loss under Requirement 2.9 should not be included in the standard. The TPL does not limit the size of the consequential load loss. If it remains, it must be made clear that it be applicable only to Year One or Year Two.
ISO New England	2.1.3: In the event that R1.1.2 is kept it must be clear that the reference to outage schedules as listed in part 1.1.2 must be limited to the Planning Horizon. Table 1 - There is confusion in interpretation of the table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading 2.1 Language should be revised similar to R2.4 as follows: “The Near-Term Transmission Planning Horizon portion of the steady stateanalysis shall be assessed annually and be supported by current or past studies as indicated inRequirement R2, part 2.6. The following studies are required:”2.1.2 Should be moved to the list of sensitivities currently in 2.1.4. (Off-peak needs to be

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	more specifically defined). 2.1.4 Consistent with the suggestion made for section 1.1.2 please remove the last bulleted item in the list under section 2.1.4. "Duration or timing of planned Transmission outages." To define a sensitivity, NERC must define base assumptions. Refer to Comment on Proposal to add an item 1.22.2 The language in 2.2 should be revised to be similar to 2.4 as follows: "The Long-Term Transmission Planning Horizon portion of the steady stateanalysis shall be assessed annually and be supported by current or past studies as indicated inRequirement R2, part 2.6. The following studies are required:"2.3 This should be modified to state that it is up to the Planner to determine the year of study within the Near Term Transmission Planning Horizon. 2.4.2 This should be deleted as it is covered under section 2.4.3. 2.4.3 To define a sensitivity, NERC must define base assumptions. Requirement 2.7 We suggest changing the word "run" to "condition" such that it reads "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity condition in accordance with Requirements R2, parts 2.1.4 and 2.4.3." 2.9: The requirement to report the largest single consequential load loss under Requirement 2.9 should not be included in the standard. The TPL does not limit the size of the consequential load loss. If it remains, it must be made clear that it be applicable only to Year One or Year Two.
United Illuminating	2.1.3: In the event that R1.1.2 is kept it must be clear that the reference to outage schedules as listed in part 1.1.2 must be limited to the Planning Horizon. Table 1 - There is confusion in interpretation of the table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading? 2.1 Language should be revised similar to R2.4 as follows: "The Near-Term Transmission Planning Horizon portion of the steady stateanalysis shall be assessed annually and be supported by current or past studies as indicated inRequirement R2, part 2.6. The following studies are required:"2.1.2 Should be moved to the list of sensitivities currently in 2.1.4. (Off-peak needs to be more specifically defined). 2.1.4 Consistent with the suggestion made for section 1.1.2 please remove the last bulleted item in the list under section 2.1.4. Duration or timing of planned Transmission outages. To define a sensitivity, NERC must define base assumptions. Refer to Comment on Proposal to add an item 1.22.2 The

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	language in 2.2 should be revised to be similar to 2.4 as follows: The Long-Term Transmission Planning Horizon portion of the steady stateanalysis shall be assessed annually and be supported by current or past studies as indicated inRequirement R2, part 2.6. The following studies are required: 2.3 This should be modified to state that it is up to the Planner to determine the year of study within the Near Term Transmission Planning Horizon. 2.4.2 This should be deleted as it is covered under section 2.4.3. 2.4.3 To define a sensitivity, NERC must define base assumptions. Requirement 2.7 We suggest changing the word "run" to "condition" such that it reads "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity condition in accordance with Requirements R2, parts 2.1.4 and 2.4.3." 2.9: The requirement to report the largest single consequential load loss under Requirement 2.9 should not be included in the standard. The TPL does not limit the size of the consequential load loss. If it remains, it must be made clear that it be applicable only to Year One or Year Two.

Response: Part 2.1.3 is a sub-part of Part 2.1 which is limited by the Near-Term Transmission Planning Horizon so no change is made.

The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT's intent.

> **Table 1, footnote 1**: If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.

While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because Near-Term steady state analysis as required in part 2.1 is part of the basic planning process, the SDT believes that the steady portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire Near-Term Transmission Planning Horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested.

The intent of Part 2.1.2 is to support the assessment of those System conditions during periods with lower Load levels than peak when the System may show different potential problems than during periods with peak Load level. For example, during light Load conditions, there may be high voltage problems because of the charging in the lightly loaded lines. There could also be thermal overload problems for areas with more generation than Load. The SDT therefore disagrees that studies of Off-Peak Load should be included in sensitivity studies. Sensitivity studies only need to cover one of the six conditions included in the bullets and may not be the one selected by the entity, resulting in no study of Off-Peak conditions being performed. The exact System Off-Peak Load should be specified by the entity performing the study.

The SDT declines to remove the last bullet in Part 2.1.4, "Duration or timing of planned Transmission outages" as a potential sensitivity. The intent is to cover unexpected changes in plans, for example, a potential delay in returning a Transmission line back to service after a planned outage of 6 months or more for rebuilding to

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	a higher capacity line. In this case, the System with the equipment in question out of service would be modeled as P0 (or N-0). For the next outage, the System performance will need to meet requirements for Category P1 and not P6. For Part 2.1.4, the SDT believes that the "base case conditions", on which to base the sensitivity cases, should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because Long-Term steady state analysis as required in part 2.2 is part of the basic planning process, the SDT believes that the steady state portion of the studies covering one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire Long-Term Transmission Planning Horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested. Part 2.3 is silent on the year of study within the Near-Term Transmission Planning Horizon. Therefore, it is up to the Transmission Planner or Planning Coordinator to select the study years most suited to the System in question. In addition, Part 2.3 only requires an annual Planning Assessment, which is to be supported by annual current or qualified past studies. . The SDT declines to delete part 2.4.2 as it does not believe that Part 2.4.3 covers System conditions at Off-Peak Load level(s) as envisioned. The Sensitivity study only needs to cover one of the six conditions included in the bullets and may not be the one selected by the entity, resulting in no study of Off-Peak conditions. As in Part 2.1.4, for Part 2.4.3, the SDT believes that the "base case conditions" on which to base the sensitivity cases, should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. Part 2.7 has been changed to address your concerns. **Requirement R2, part 2.7**: For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Part 2.9 has been deleted as suggested.
MAPP	2.1.3: It must be clear that the reference to outage schedules as listing in part 1.1.2 must be limited to the Planning Horizon. There is confusion in interpretation of the Table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading? R2.1.4/R2.4.3 The terms "credible" and "measurable change" are ambiguous and not defined. Therefore, we suggest that these terms be defined or more clearly described to avoid the risk of different and possibly contradictory interpretations by TPs, PCs, and auditors.

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	R 2.1.5 - Spare equipment strategy. This appears to be more of a risk analysis than a simulation study requirement. If a simulation is required then it would appear that the PC/TP would need to rerun the entire system intact study with each "major transmission equipment "that is unavailable as a prior outage (i.e. for each generator, HVDC, SVC, XFMR) over the entire study parameters. How would this be evaluated? Is this not covered under P2 already? We also propose replacing the term "major Transmission" with "BES" because BES is a well defined term while "major Transmission" is not. R2.4.1 We recommend that the SDT clarify section 2.4.1 and when load models considering induction motors are required. The clarification should add limits or thresholds to provide load models based on areas that have stability limits or issues and to loads of substation size and having dynamic characteristic capable of significantly impacting voltage stability. Areas that don't have large motors or stability issues should not be required to add unnecessary load modeling. R2.6.2 Change "to demonstrate that System changes do no impact the performance results in the study area" to "to demonstrate that System changes do not significantly impact the performance results in the study area." 2.6.2 As written results in an unrealistic requirement to review every impact minor or large and determine which meets this item and which do not. The recommended change solves this problem. R 2.7 Corrective Action Plan: Is this not already apart of FERC Order 890? The PC may not be able to develop a CAP as they may not be the owners and would have no say about how a problem will be resolved. R 2.8.1 Suggest using a word other than "deficiencies" as it is associated with non-compliance. R2.9 ? We propose that this requirement be removed because annually stating the single, largest expected, Consequential Load Loss due to a P1 or P2 event in the TP or PC system is not needed to provide reliable BES performance or assure open and transparent Transmission planning peer review. In general, standards should not contain requirements that don't improve reliability.

Response: Part 2.1.3 is a sub-part of Part 2.1 which is limited by the Near-Term Transmission Planning Horizon so no change is made.

The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT's intent and it now reads:

> **Table 1, footnote 1**: If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.

For Part 2.1.4, The SDT envisions that credible stressed conditions and "measurable change" are to be defined by the responsible Planning Coordinator or Transmission Planner.

Part 2.1.5 only requires that the Planning Coordinator or Transmission Planner plans for the potential unavailability of long lead time major Transmission equipment in accordance with its spare equipment strategy. For example, if an entity's spare equipment strategy is to have a spare transformer on site, then the unavailability of a

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similar transformer (due to outages) would be limited to the time it would take to energize the spare transformer. Assuming that this time is no more than that required to return a similar outaged transformer back to service, Part 2.1.5 can be satisfied without performing additional planning studies. If on the other hand, the transformer would have to be purchased, then it would take more than a year to replace. In this case, P0 should be modeled with the transformer in question out of service. This is not the same as P2. The SDT declines to replace the term "major Transmission equipment" with "BES equipment" because the intent is to investigate the unavailability of major pieces of equipment in the Transmission System. Transmission is defined in the NERC Glossary as, "An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems". For Part 2.4.1, the SDT declines to add specifics, which includes "limits or thresholds to provide Load models based on areas that have Stability limits or issues and to Loads of substation size and having dynamic characteristic capable of significantly impacting voltage Stability" because such specificity needs to be determined by the entity performing the study. Part 2.4.1 allows the use of "an aggregate System Load model which represents the overall dynamic behavior of the Load". All areas including those that do not have large motors can use an appropriate aggregate System Load model. The SDT declines to make the change suggested in Part 2.6.2 because it did not add more clarity than the existing language. In Part 2.7, the responsibility for developing CAPs lies with both the Planning Coordinator & Transmission Planner regardless of ownership. A FERC Order is not a NERC Standard, and not subject to the NERC audit and enforcement procedures. The SDT declines to change the word "deficiencies" in Part 2.8.1. The SDT believes it is the most appropriate word to capture the SDT intent. Part 2.9 has been deleted as suggested.	
Oncor Electric Delivery	2.1.3: It must be clear that the reference to outage schedules listed in part 1.1.2 must be limited to the Planning Horizon. See the TIS comment tor R1. There is lack of clarity in the interpretation of certain rudiments of Table 1 When the voltage class of the contingency element and the monitored element are different (one is HV and the other is EHV), which voltage class is the allowance for shedding of non-consequential load applied? For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are there allowances to shed load to keep the 345-kV from exceeding its load rating. Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, would there be allowances to shed load to keep the 138-kV from exceeding its load rating 2.1 Language should be revised similar to R2.4 as follows: "The Near-Term Transmission Planning Horizon portion of the steady stateanalysis shall be assessed annually and be supported by current or past studies as indicated inRequirement R2, part 2.6. The following studies are required: 2.1.2 the term "off peak" is an issue. The definition just says less than peak. 2.1.4 Duration or timing of planned Transmission outages. In order to define a "sensitivity", NERC must define a base case. 2.1.5 There should be greater clarity to the fact that this is an assessment only, and not a solution. Actions such as "out of merit dispatch", "operational restrictions", "System reconfiguration" can be part of a Corrective Action Plan if the system cannot meet

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	performance requirements without the facility in service. 2.2 The language in 2.2 should be revised to be similar to 2.4 as follows: The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as indicated inRequirement R2, part 2.6. The following studies are required:2.3 The standard does not indicate a year to study. Is this the discretion of the Transmission Planner? [Review last comment/why doesn't this apply to stability?] 2.4.2 There should be greater clarity to the term "Off peak" Should the Transmission Planner have more discretion in selecting load level. Is there a need for this requirement? 2.4.3 To define a "sensitivity" a base case must be defined for comparison. Requirement 2.7 suggest changing the term "run" to "condition" in "Corrective Action Plan(s) does not need to be developed solely to meet the performance requirements for a single sensitivity run(?) in accordance with Requirements R2, parts 2.1.4 and 2.4.3. 2.7.2 See previous comments on sensitivities. 2.9: The requirement to report the largest single consequential load loss under Requirement 2.9 should not be included in the standard. If it remains, provide greater clarity that there is applicability only to Year One. Furthermore, additional clarification is needed to ensure that the requirement to report consequential load loss (single number) is ONLY for the most severe contingencies studied for the P1 and P2 contingencies. 2.9 ? Why is it necessary to identify the largest consequential load loss if the TPL standard does not limit the size of the consequential load loss?

Response: Part 2.1.3 is a sub-part of Part 2.1 which is limited by the Near-Term Transmission Planning Horizon so no change is made.

The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT's intent and it now reads:

> **Table 1, footnote 1**: If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.

Part 2.1 covers near-term steady state studies and Part 2.4 covers near-term Stability studies. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire Near-Term Transmission Planning Horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested.

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	The intent of Part 2.1.2 is to assess those System conditions during periods with lower Load levels than peak when the System may show different potential problems than during periods with peak Load level. For example, during light Load conditions, there may be high voltage problems because of the charging in the lightly loaded lines. There could also be thermal overload problems for areas with more generation than Load. Since such conditions can be case specific, the standard should not be overly prescriptive; therefore, the exact System Off-Peak Load should be specified by the entity performing the study. The last bullet in Part 2.1.4, "Duration or timing of planned Transmission outages" is intended to cover unexpected changes in plans, for example, a potential delay in returning a Transmission line back to service after a planned outage of 6 months or more for rebuilding to a higher capacity line. The SDT believes that your concern on Part 2.1.5 has already been addressed. Part 2.7.1 Corrective Action can include, among other things: ○ Installation, modification, or removal of Protection Systems or Special Protection Systems ○ Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations. ○ Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations. ○ Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan. ○ Use of rate applications, DSM, new technologies, or other initiatives. For Part 2.2, while the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of basic planning process, the SDT believes that the long-term steady state portion of the studies in Part 2.2 should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire long-term planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested. Part 2.3 is silent on the year of study within the Near-Term Transmission Planning Horizon. Therefore, it is up to the Transmission Planner or Planning Coordinator to select the study years most suited to the System in question. In addition, Part 2.3 only requires an annual Planning Assessment, which is to be supported by annual current or qualified past studies. The NERC glossary states: "Off-Peak: Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand." The intent is to assess those System conditions during periods with lower Load levels than peak when the System may show different potential problems than during periods with peak Load levels. For example, during light Load conditions, there may be high voltage problems because of the charging in the lightly loaded lines. There could also be thermal overload problems for areas with more generation than Load. The exact System Off-Peak Load should be specified by the entity performing the study. For part 2.4.3, the SDT believes that the "base case conditions" should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies involving long-term forecasts. Part 2.7 has been changed to address your concerns. **Requirement R2, part 2.7**: For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: For Part 2.7.2, see the responses above to your other comments.

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Part 2.9 has been deleted as suggested.	
FirstEnergy Corp	A. FirstEnergy disagrees with requirement R2 sub-part 2.1.1 requiring the annual completion of two near-term steady-state studies. We believe that on a yearly basis completion of one near-term study and one long-term study is sufficient to interpolate and extrapolate the results needed to cover the entire planning horizon. The team should keep in mind that the overall assessment will include qualified past studies to supplement the results for a more refined view of anticipated conditions. We request that the team revise the near-term annual study requirements to require completion of only one near-term steady-state study and allow the TP/PC flexibility in choosing the appropriate study year. B. In requirement 2.7.1 the team should consider collapsing the 3rd and 4th bullets into a more succinct single bullet that says "Installation or modification of automatic generation runback/tripping". The use of "manual" generation run-back should be accounted for in an Operating Procedure (5th bulleted item). The additional text on the existing 3rd and 4th bullets discussing "single or multiple contingency" is not needed as the text stated in the parent R2.7 text is sufficient. C. We concur with the team's removal of the overly prescriptive requirements to include "initiation dates" and "in-service dates" from the Corrective Action Plans. However, the team may want to ensure some aspect of timing is identified in the Corrective Action Plans. It is recommended that the team revise the text of sub-part 2.7.1 that precedes the bulleted list to read "List system deficiencies, associated actions needed to achieve required System performance and the timing of when the actions are needed"
Response: For Part 2.1.1, the SDT declines to change to one near-term study because as a minimum to support reliability, Transmission plans are needed for the timeframe just after operation planning (Year One or year two), as well as the timeframe at the end of the near-term (year five) to allow implementation of solutions, which may require longer lead time. The SDT reviewed Requirement R2, part 2.7.1 and found that it is clear as written. The SDT therefore declines to make the change. For Requirement R2, part 2.7.1, the NERC Glossary of Terms defines Corrective Action Plan as "A list of actions and an associated timetable for implementation to remedy a specific problem. Therefore, the suggested change to include "timing" is not needed.	
NERC Standards Review Subcommittee	Add R2.7.1 Item #7 The MRO NSRS proposes the addition of the following bullet item to R2.7.1, "Planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration of the Facility Ratings." because this explains what is allowed to be considered for Corrective Action Plan developments. [After bullet item #7 is added, Note "e" under "Steady State & Stability section of Table 1 should refer to R2.7.1.] R2.9" The MRO NSRS still proposes that this requirement be removed because annually stating the single, largest expected, Consequential Load Loss due to a P1 or P2 event in the TP or PC system is not needed to provide reliable BES performance or assure open and transparent Transmission planning peer review. In general, standards should not contain requirements that don't improve reliability. R2.4.1 The MRO NSRS recommends that the SDT clarify section 2.4.1 and when load models considering induction motors are required. The clarification should add limits or thresholds to provide load models based on areas that have stability limits or issues and to loads of substation size and having dynamic characteristic capable of significantly impacting voltage stability.

Organization	Comments for Question 2
	Areas that don't have large motors or stability issues should not be required to add unnecessary load modeling.
Response: Planned system adjustments could include Operating Plans such as re-dispatch. Requirement R2, part 2.7.1 is a list of examples, so it could include more items than listed, including Note e in Table 1. The SDT declines to make the suggested change. Part 2.9 has been deleted as suggested. For Part 2.4.1, the SDT declines to add specifics, which includes "limits or thresholds to provide Load models based on areas that have Stability limits or issues and to Loads of substation size and having dynamic characteristic capable of significantly impacting voltage Stability" because such specificity needs to be determined by the entity performing the study. Part 2.4.1 allows the use of "an aggregate System Load model which represents the overall dynamic behavior of the Load". Areas that do not have large motors can use an appropriate aggregate System Load model.	
Lakeland Electric	Agree with the changes made to the spare equipment strategy requirement
Response: The SDT thanks you for your comments.	
Progress Energy Florida, Inc.	As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all appropriate parties to review PEF's previous comments to this effect.
Response: Throughout the drafting process, the SDT has carefully considered your comments as well as comments from other industry members.	
Florida Municipal Power Agency, and its Member Cities	As worded, 2.1 now seems to require power flow, short circuit and stability studies be done every year for the Near Term. Is this the intent of the SDT? There are smaller systems that do not require this (e.g., if a smaller system has nothing more change form year to year than a 1.5% load growth, and there is plenty of margin on various SOLs, why is another study needed?). FMPA suggests re-wording to: "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies or by qualified past studies as indicated in Requirement R2, part 2.6" Since 2.2 only has one sub-bullet, 2.2.1 ought to be collapsed into 2.2. We think it would read less confusing as well, see below for suggested phrasing: "The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by a current study of expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected, supplemented with qualified past studies as indicated in Requirement R2, part 2.6. The short circuit studies of 2.3 should not only assess the fault current interrupting capability of breakers, but also circuit switchers and the momentary current carrying capability of other equipment, such as switches and substation bus. We recommend changing the phrase to: "The analysis shall be used to determine whether the fault current is within the momentary current carrying capabilities and/or fault current interrupting capabilities of (Elements or Facilities) using ". Also, for the short circuit study of 2.3 (and 2.8), it is not necessary to study all of the contingencies, just P2. Taking other Facilities out in addition to the fault will only reduce fault current. Auditors may not be aware of that and maybe the standard

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	could say that only P2 needs to be studied to reduce future confusion. In 2.6, “material change” is ambiguous, especially in regards to load growth. How much load growth is allowed before it is “material”? Is the intent of the SDT to have 2.7 apply to all previous bullets in R2? If so, then it could be made clearer by starting 2.7 with “ For the analyses discussed in 2.1 through 2.5, and for the planning events shown in Table 1, when the analyses indicate “? 2.7 seems to have lost the reference to lead times for Corrective Action Plan(s) that were present in the existing TPL-001-0, TPL-002-0 and TPL-003-0 standards, is that the intent of the SDT? Since only two of the years in the near term need to be studied, and one of the year’s in the long term study, there ought to be some method to determine when a Corrective Action Plan is needed, the lead time of that Corrective Action Plan, to give an indication of when activity needs to start to implement the Corrective Action Plan. The Planning Coordinator and Transmission Planner should not be responsible in 2.7 for any repercussion of an entity not implementing the Corrective Action Plan. Bullet 2.7 ought to be reworded to developing the Corrective Action Plan only and not implementation. For instance, 2.7.4 requires review of Corrective Action Plans. If a Corrective Action Plan calls for a major transmission addition, then that addition usually is in the domain of the Transmission Owner. If the Transmission Owner decides not to build the transmission upgrade for a variety of reasons (e.g., budgets, etc.), then the Planning Coordinator and Transmission Planner could end up being in violation of the standards through no fault of their own (e.g., even though curtailment of firm service would then be allowed in 2.7.3, if such curtailment would not solve the problem, e.g., if there is not enough pre-contingency re-dispatch available, then the Planning Coordinator would be in violation).Implementation of the Corrective Action Plan, however, is very important. FMPA suggests that another requirement be added to require Transmission Owners, Generation Owners, Transmission Operators, Generation Operators (latter two if there are operating schemes involved) within the planning area of the Planning Coordinators and Transmission Planners to implement the plan as determined by the Planning Coordinators and Transmission Planners, with another requirement requiring that the entities agree on the Corrective Action Plan. This would mean expanding the applicability of the standard. This new requirement ought to have a VRF of High because not implementing the Corrective Action Plan could have high risks. What is the reliability purpose of 2.9? Is it to identify the largest potential supply / demand mismatch? If so, the largest loss of source, usually about 1000 MW, will overwhelm this number. FMPA does not understand the reliability purpose of providing this number, especially since the power flow models already capture most of this information (e.g., amount of load connected to tap substations or radial feeds). This seems to be an administrative item with no reliability purpose, especially since it only applies to P1 (why does it apply to P1 ? how can there be consequential load loss without a contingency, unless it’s specific to 2.1.5?) and P2.
Response: The SDT reviewed Requirement R2, parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require “annual current year study, supplemented by qualified past studies”. Parts 2.1 and 2.2 cover steady state studies in the Near-Term and the Long-Term planning horizons, respectively. Short circuit studies (Part 2.3), near-term Stability studies (Part 2.4) and long-term Stability studies (Part 2.5) allow the use of current or qualified past studies. Therefore, as drafted the standard only requires annual steady state studies. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for the Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon	

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	should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested. In addition, the two study years are intended to cover both the timeframe just after operation planning (Year One or year two), as well as the timeframe to allow implementation of solutions, which may require a longer lead time. Load growth may not be the only determination factor on System performance; other examples are addition or retirement of generation. The suggested change for Parts 2.2 and 2.2.1 does not provide additional clarity. The SDT declines to make the change. Part 2.3 was changed in the previous posting to include circuit breakers only due to a preponderance of industry comments in draft 3. The SDT declines to make the suggested change. The SDT believe this concern on Part 2.3 is covered. The Transmission Planner or Planning Coordinator can provide an explanation of why the Contingencies selected would produce the more severe conditions. Note that Part 2.3 requires an annual Planning Assessment only. Part 2.6.2 allows an entity to rely on a past study with a material change if "a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area". Therefore, it is up to the entities performing the study to provide the rationale based on changes, such as Load growth. The intent of Part 2.7 is to be applied to all "planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1". The SDT believes that the intent is clear. The SDT declines to make the suggested change. Part 2.7 requires that for all planning events in Table 1, the Planning Assessment includes a Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Also, Part 2.7.4 requires that the CAP be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures. For 2.7.1, the NERC Glossary of Terms defines Corrective Action Plan as "A list of actions and an associated timetable for implementation to remedy a specific problem. Therefore, your concerns have been addressed. The planners' responsibility is to always have a plan that meets the performance requirements during the planning horizon. If the original CAP can't be implemented, the planner must develop an alternate plan to meet the performance requirements. The definition of CAP includes a timing element as per the Glossary. For issues involving inability to implement a CAP, which is beyond the control of the Planning Coordinator or Transmission Planner, such as the example given, the Planning Coordinator or Transmission Planner can rely on Part 2.7.3 in addition to those actions already allowed tomeet performance requirements. Part 2.9 has been deleted to address your concerns.
Gainesville Regional Utilities	Combining 4 TPL standards into 1 standard makes for a situation that you will always be audited on all the covered functional areas instead of part of the functions in a given audit. Example, in 2009, TPL-004 was not part of the audit while the other 3 standards were part of the audit. Of course, you should always be current with all functional assessments. I use one assessment document to cover all the functional areas. I do like the added clarity on the time horizons for various studies. I find R2. part 2.1.5 to create a somewhat clearer focus on spare equipment strategy. But the created task could create a lot of

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	work for a utility depending on its configuration and redundancy.
Response: Combining TPL-001 through -006 into one standard was in response to comments from the industry and FERC Order 693. Part 2.1.5 only requires that the Planning Coordinator or Transmission Planner plans for the potential unavailability of long lead time major Transmission equipment in accordance with its spare equipment strategy. For example, if an entity's spare equipment strategy is to have a spare transformer on site, then the unavailability of a similar transformer (due to outages) would be limited to the time it would take to energize the spare transformer. Assuming that this time is no more than that required to return a similar outaged transformer back in service, Part 2.1.5 can be satisfied without performing additional planning studies. If on the other hand, the transformer would have to be purchased, then it would take more than a year to replace, and studies will likely needed to be done to plan for the potential unavailability.	
ITC Holdings	Comments: R2.1.1 Are two distinct study years necessary if a transmission owner can demonstrate that loads within their footprint have minimal growth over the 5 year period, defined to be less than X% of growth? Since the standard requires a relatively large number of studies to meet performance requirements, an initial set of studies along with studies demonstrating that "CAPs work" seems sufficient during periods of load stagnation. R2.1.4, R2.4.3 & R2.7.1. These requirements refer to new facilities which would include new generators. ITC requests clarification as to what constitutes a "new generator" that needs to be considered -- those in the queue, those with signed Interconnection Agreements, those under construction... What is the line of demarcation between what is in and what is out? In addition to the above, ITC also requests clarification as to whether or not these requirements apply to new generators, who connect to the network as "Energy Only" resources and, are either, not required to construct facilities needed to meet reliability requirements or are allowed to operate as "Energy Only" until needed facilities are constructed. The CAP for these facilities is that they will be curtailed or other generation will be curtailed should "operating" violations occur. Under market mechanisms, these generators are allowed to operate if their energy prices are lower than other generators whose curtailment eliminates the violation, even though the curtailed generators have paid for the facilities needed to meet reliability requirements. As the standard is written, these requirements imply that all generators must be included in studies. Were we to do so, significant standards violations might result. Does the Transmission Owner have to study all violation scenarios or include all "Energy Only" generators in studies when the CAP is always the same: "Market redispatch". Please clarify study scenario requirements for "Energy Only" resources.
Response: For Part 2.1.1, Load growth may not be the only determination factor on system performance; other examples are addition or retirement of generation. The two study years are intended to cover both the time frame just after operation planning (Year One or year two), as well as the time frame to allow implementation of solutions, which may require longer lead time. NERC Standards specify what the requirements are and not how to meet the requirements. The SDT therefore declines to specify how the studies are to be done. The intent of the standard is to allow the Planning Coordinator or the Transmission Planner performing the studies the discretion on the sensitivities (Parts 2.1.4 and 2.4.3) to investigate and the generators to be assumed in the Corrective Action Plan (Part 2.7.1). The SDT believes that the requirements under this draft do include "Energy Only" generators. Please note under Requirement R2, part 2.7.1 that manual and automatic generation runback/tripping is allowed as a response to single or multiple Contingencies to mitigate Steady State performance violations. Also automatic generation tripping is allowed for single and multiple Contingency events to mitigate Stability performance violations	

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Deseret Power	Comments: The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies" It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.
Response: The SDT reviewed Requirement R2, parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for the Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested. The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within Parts 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and Stability evaluations, respectively. **Requirement R2, part 2.4.3**, **bullet #3**: Expected in service dates of new or modified Transmission Facilities Part 1.1.4 and Part 2.1.4 state that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast	
SCE&G	Does R.2.9 refer to customer load only or does it include pumped storage facility pumping loads?
Response: Part 2.9 has been deleted based on industry input.	
Orlando Utilities Commission	I like the clarification of "summarize results" compared to the wording in the prior edition. -It is obvious an attempt has been made to further define when past studies may be used, but I think it is still a bit confusing. Requirement 2.1, 2.2 appear to be saying that current studies must be used, but that additional information can be provided if desired and it meets certain requirements. Sub-Requirements 2.3, 2.4 and 2.5 seem to allow use of past studies that meet the

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	requirements of 2.6 in lieu of new work. If this is the correct understanding then I suggest the following: For 2.1 and 2.2 revise the statement to read "…and be supported by the following annual current studies. The analysis may also include other current and past studies in addition to the required annual current studies listed below. The reference to R2.6 is removed since including it invites confusion over when prior art can be used and if the material is solely supplemental, then there is no reliability advantage to limiting what can be incorporated a supplemental material. R2.6 should also be revised to read "Past studies may be used in lieu of current studies for R2.3, R2.4, R2.6 if they meet the following requirements:" This will insure that it is very obvious in both places when prior art may be used in lieu of new work. -R2.6.2 Consider revising "the study shall not include any material changes" to "the system represented in the study shall not include any material changes". Stating that "the study shall not include material changes" implies changes to the study from the time it was performed to the time it was used, like inserting or removing text, not changes in the underlying transmission system which is what I think you are really targeting. -R2.1.4 and 2.4.3: The statement "sufficient amount to stress the system…credible conditions…demonstrate a measurable change" implies that a sensitivity must meet three general criteria: (I will be using load forecast as an easy example, but obviously there is a range and combination of items that could be used) 1. That it is expected to increase stress, for example increasing the load forecast would general increase stress, where decreasing it would not. 2. That the increase should be substantial, for example growing the load at 2x the expected growth rate vs 1.01x the expected rate. 3. That the change doesn't have to exceed the bounds of credibility. If a 2x or 3x increase doesn't result in a stack of new constraints, it does not mean the sensitivity is inadmissible. Is this a correct understanding? -R2.7: Is the "Corrective Action Plan" intended to document all of an entities planned future reliability related transmission projects and operational procedures? Or is it intended to address situations where simulation and the application of currently planned projects and procedures are insufficient to meet the performance requirements? The next comment is very closely related to this one. -R2.7: If a project is added one year to the "Corrective Action Plan" but then in the subsequent year has been added to the model, resulting in simulation showing no performance violations, should it be removed from the Corrective Action Plan? Or should it be referenced in the plan each year until it is either in service or demonstrated to no longer be required?

Response: The SDT reviewed Requirement R2, parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies should be done annually covering Year One or year two and year five for Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. The remaining requirements for Short circuit studies Part 2.3), near-term stability studies (Part 2.4) and long-term Stability studies (Part 2.5) can then be covered by current or past studies.

The SDT declines to change Part 2.6 to read "Past studies may be used in lieu of current studies for Requirement R2, parts 2.3, 2.4, and 2.6 if they meet the following requirements" because it does not add clarity.

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Part 2.6.2 has been revised to address your concerns. **Requirement R2, part 2.6.2**: For steady state, short circuit, or Stability analysis: the System represented in the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area For Parts 2.1.4 and 2.4.3, the example you gave is a valid example for addressing "the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance". Part 2.7 requires a Corrective Action Plan to be developed "when the analysis indicates an inability of the System to meet the performance requirements in Table 1". Therefore, the intent is to address situations where simulation and the application of currently planned projects and procedures are insufficient to meet the performance requirements. If a project is added to the Corrective Action Plan, it should be included as part of the study assumptions based on that the criteria Planning Coordinator and Transmission Planner use for inclusion of such planned projects, and clearly identified as an assumption for the annual Assessment as required in Requirement R2, until it is in service or shown to be no longer needed.	
TVA System Planning	In R2.1.4 and R2.4.3, TVA is concerned about the use of the words "sufficient" and "measurable" from a compliance standpoint. TVA believes that these words should be deleted or at least better defined to clarify the actual intent from the SDT on what is technically required for these sensitivity studies. TVA agrees with limiting R2.1.5 spare equipment strategy to just the P0, P1, and P2 single contingency categories. In R2.7.3, both Non-Consequential Load Loss and curtailment of Firm Transmission Service can be permitted if situations arise that are beyond the control of the TP or PC. However these actions are not useful for stability related issues. TVA suggests that for stability related issues, if situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the TP or PC is permitted to allow some generation to lose synchronism utilizing out of step relaying or other protection method to correct the situation that would normally not be permitted in Table 1. We appreciate the deletion of the previous requirement on non-Consequential Load Loss from the previous draft of TPL-001-1.R2.9: Recommend that this refers to customer loads only, and not to include utility loads such as pump-storage or compressed air generating plant pumping load.
Response: For Part 2.1.4, The SDT envisions that stressed conditions and "measurable change" are to be defined by the responsible Planning Coordinator or Transmission Planner. For Part 2.7.3, most of the situations that are beyond the control of the Transmission Planner or Planning Coordinator usually involve permitting or long lead time projects. If there is a Stability issue, there should be time to implement a CAP. No change made. Part 2.9 has been deleted in response to industry comments.	
Lafayette Utilities System	LUS is satisfied that the current version resolves the issues we raised as to R2.

Organization	Comments for Question 2
Response: The SDT thanks you for your comments.	
MidAmerican Energy Company	MidAmerican commends the SDT for their hard work on this standard. MidAmerican does have comments about this requirement though. MidAmerican recommends a minor editorial to 2.1.4. The subrequirement states that "To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies, by a sufficient amount to" The subrequirement as written is not clear whether the condition to be varied is to be one not included in the base studies or a condition that is not varied as part of the sensitivity studies. MidAmerican recommends that this subrequirement be changed as follows: "To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions FOR WHICH VARIATION IS not already included in the studies, by a sufficient amount to"? The words in caps are words that MidAmerican suggests are added to this part of requirement 2. MidAmerican recommends that the SDT clarify section 2.4.1 and when load models considering induction motors are required. The clarification should add limits or thresholds to provide load models based on areas that have stability limits or issues and to loads of substation size and having dynamic characteristic capable of significantly impacting system damping. Areas that don't have large motors or stability issues should not be required to add unnecessary load modeling. MidAmerican recommends that the SDT modify 2.6.2 by changing "to demonstrate that System changes do no impact the performance results in the study area" to "to demonstrate that System changes do not SIGNIFICANTLY impact the performance results in the study area." The word that is in all caps is added. 2.6.2 as written results in an unrealistic requirement to review every impact minor or large and determine which meets this item and which do not. The recommended change solves this problem. MidAmerican recommends the data retention for R2 and M2 be revised to change "All" to "The". The word "All" is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: "THE Planning Assessments performed since". The word in all caps is a word suggested to be added.
Response: The SDT declines to make the change because it does not add clarity to the requirement. For Part 2.4.1, the SDT declines to add specifics, which includes "limits or thresholds to provide load models based on areas that have stability limits or issues and to loads of substation size and having dynamic characteristic capable of significantly impacting voltage stability" because such specificity needs to be determined by the entity performing the study. Part 2.4.1 allows the use of "an aggregate System Load model which represents the overall dynamic behavior of the Load". Areas that do not have large motors can use an appropriate aggregate System Load model. The SDT declines to make the change suggested in Part 2.6.2 because it did not add more clarity than the existing language. The SDT has made the suggested change. **Requirement R2, data retention**: The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.	
British Columbia Transmission Corp	none

Organization	Comments for Question 2
Response: The SDT thanks you for your comments.	
SERC Dynamics Review Subcommittee (DRS)	Part 2.1.4 and 2.4.3: delete the word "sufficient." We appreciate the deletion of the previous R2.9 on non-Consequential Load Loss from the previous draft of TPL-001-1.Bullet 1 of R.2.4.3: change "Dynamic Model" to "Dynamic Load Model". Part 2.9: Does this refer to customer loads only, or does it include pump-storage or compressed air generating plant pumping load.We recommend that the expected largest consequential load be limited to customer load, not utility load, i.e., pump-storage.
Response: For Part 2.1.4, The SDT envisions that credible sufficient stressed conditions are to be defined by the responsible Planning Coordinator or Transmission Planner. Bullet 1 of Requirement R2, part 2.4.3: has been revised to address your concerns. **Requirement R2, part 2.4.3, bullet #1:** Load level, Load forecast, or dynamic Load model assumptions Part 2.9 has been deleted in response to industry comments.	
SERC Planning Standards Subcommittee	Part 2.1.4 and 2.4.3: delete the word "sufficient." We appreciate the deletion of the previous R2.9 on non-Consequential Load Loss from the previous draft of TPL-001-1. Part 2.9: Does this refer to customer loads only, or does it include pump-storage or compressed air generating plant pumping load.
Response: The word "sufficient" is needed in Part 2.1.4 and Part 2.4.3 to ensure that the variations made to the assumptions to investigate sensitivity are large enough to be meaningful so they can demonstrate the impacts of the changes. The SDT envisions that credible sufficient stressed conditions are to be defined by the responsible Planning Coordinator or Transmission Planner. As such, the SDT declines to revise Parts 2.1.4 and 2.4.3 as suggested. Part 2.9 has been deleted in response to industry comments.	
CenterPoint Energy	Part 2.2: CenterPoint Energy recommends deleting part 2.2 since studies performed in the Long-Term Transmission Planning Horizon have dubious value for organizations whose longest lead time items take less than five years to construct. Even for organizations requiring longer than five years to build some projects, it should be noted that beyond the five year horizon, generation reserve margins have generally been exhausted, requiring speculation as to the location and size of future generating resources in developing system models. In recognition of this reality, the current set of TPL standards appropriately require that assessments be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may require longer lead time solutions. Part 2.5: Part 2.5 appears to have been added in response to one comment to the 3rd draft. In fact, the commenter did not recommend or propose the requirement found in 2.5, but only asked about the SDT's intent regarding this matter. CenterPoint

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	Energy strongly disagrees that part 2.5 is necessary or advisable and recommends that it be deleted. We wholeheartedly agree that Transmission Planners should consider and selectively study potential stability concerns. However, we believe that Transmission Planners are already considering and selectively studying potential stability concerns, and deleting part 2.5 would not preclude the continuation of these practices. However, we oppose mandating stability analysis in the Long-Term Transmission Planning horizon of proposed generation additions or changes due to the uncertainty of where and how much generation will actually be constructed beyond the five year horizon, particularly since generation can be built much faster than five years and can easily invalidate any such assessment. Part 2.7: CenterPoint Energy recommends that part 2.7 be revised to add a reference to part 3.4 and part 4.4 as follows: For planning events shown in Table 1, selected in accordance with parts 3.4 and 4.4, when the analysis. This recommended change is to prevent possible ambiguity or conflicts between part 2.7 and parts 3.4 and 4.4. Part 2.9: CenterPoint Energy agrees with multiple commenters to the 3rd draft that part 2.9 (previously 2.8) should be deleted. Part 2.9 is an unnecessary reporting requirement that has no actual bearing on reliability. By continuing to insist on R2.9, the SDT seems to have inappropriately ignored industry comments to the previous draft while ironically inserting R2.5 into this draft in response to only one industry comment (which did not actually advocate that R2.5 was necessary). CenterPoint Energy urges the SDT to reconsider its dismissal of industry concerns regarding R2.9.
Response: For Part 2.2, the SDT believes there is value in taking a long range view in planning to assess the general trend. The effort can be useful even taking into consideration the uncertainty surrounding long-term planning studies. Since the Long-Term Transmission Planning Horizon is year 6 – year 10, the Planning Coordinator or Transmission Planner can for example, select year 6 or 7 in the Long-Term Transmission Planning Horizon and then use this study as the past study to supplement the near-term studies in the following year(s). For Part 2.5, The SDT believes it is important to evaluate Stability when the planners are evaluating new generation addition or changes which can be more than 5 years in the future, as required in NERC Standard FAC-001-0. Part 2.7 is the Corrective Action Plan resulting from the Planning Assessment. Part 3.4 covers the requirements for studies supporting the steady state portion of the assessment; and Part 4.4 covers the requirements for studies supporting the Stability portion. The SDT believes that Part 2.7 is clear as is and no change is needed. Part 2.9 has been deleted in response to industry comments.	
Progress Energy Carolinas	PEC believes that the language of R2.5 "proposed generation additions and changes" should be clarified as to whether transmission changes near generators are included or not. PEC believes that the requirement to report the largest single consequential load loss under Requirement 2.9 should not be included in the standard. If it remains, it must be made clear that it be applicable only to Year One, and there should be additional clarification that the requirement to report consequential load loss (single number) is ONLY for the most severe contingencies studied for the P1 and P2 contingencies.
Response: Part 2.5 is intended for investigation of Stability issues due to addition of generators. The SDT does not believe that, in general, a Stability assessment is needed for the Long-Term Transmission Planning Horizon. The System model for that timeframe is too uncertain for a meaningful assessment of the System's Stability. However, for those situations where a specific generator is planned to be added in that timeframe, the SDT believes that it will be appropriate to require that	

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the generator's Stability impact be evaluated. Part 2.9 has been deleted in response to industry comments.	
Portland General Electric Co.	PGE believes that the scope of the studies mandated by this requirement should be limited to elements energized at 200kV and above, elements included in generator interconnection, and elements included in interconnections with other utilities. PGE's 115kV system functions to provide "load service" rather than transmission and does not impact the grid in the same manner as the 230kV and 500kV elements that comprise PGE's transmission system. PGE further believes that the requirement to conduct off-peak studies should focus on the varied generation patterns and impact to recognized transmission paths (for WECC, those identified in the WECC Path Catalog) rather than including the full range of studies that are required for on-peak studies. PGE's transmission system is embedded within the larger regional transmission system of the Bonneville Power Administration, and studies of System Off-Peak Load will not reveal any meaningful data internal to PGE's system. Finally, PGE believes that the wording of R2.6.2 is so restrictive that the entire intent of the subrequirement would be negated. PGE believes that "material changes" is such a broad term that every past study would have to have such changes made to reflect the system as it currently exists. Therefore, a company seeking to use a past study to support its Planning Assessment would have to provide a "technical rationale" showing that the material changes do not impact performance results. An effort to demonstrate a technical rationale in a manner that would satisfy future auditors would in many cases be more burdensome than performing a new study.
Response: NERC Reliability Standards apply to BES elements as defined by each Regional Entity. No change made. The SDT believes that System Off-Peak Load studies are a valuable tool in proper planning. Therefore, your Planning Assessment needs to address the results for your System of an Off-Peak Load study regardless of whether you conduct the studies or you rely on studies done by others. No change made. The SDT does not agree that developing a 'technical rationale' is such an onerous task. One can utilize their professional judgment, point to past studies of similar conditions, etc. The key is to thoroughly explain your decisions. No change made.	
FRCC Transmission Working Group	Please further clarify the definition when past studies may be used. Requirement 2, bullets 2.1, 2.2 appear to say that current studies must be used, but that additional information can be provided if desired and it meets certain requirements. Sub-Requirements 2.3, 2.4 and 2.5 seem to allow use of past studies that meet the requirements of 2.6 in lieu of new work. If this is the correct understanding then I suggest the following:For 2.1 and 2.2 revise the statement to read "and be supported by the following annual current studies. The analysis may also include other current and past studies in addition to the annual current studies listed below. R2Bullet 2.6 should also be revised to read "Past studies may be used in lieu of current studies for Bullets 2.3, 2.4, 2.6 if they meet the following requirements: This will insure that it is very obvious the planner, when they may or may not use prior art in place of new work and it's specified in all places in the standard where this is referenced.For these supplemental or "above and beyond" studies, 2.6 should not be referenced. First of all it makes it confusing, since 2.6 is primarily concerned with prior art being used in lieu of new work. Also if the material is supplemental, then it's supplemental and setting requirements on it will

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	only reduce the material provided not improve the reliability of the system. -2.6.2 Consider revising "the study shall not include any material changes" to "the system represented in the study shall not include any material changes". Stating that "the study shall not include material changes" implies changes to the study from the time it was performed to the time it was used, not changes in the underlying transmission system which is what I think you are really targeting. -2.1.4 and 2.4.3: The statement "sufficient amount to stress the system"credible conditions"demonstrate a measurable change" implies that a sensitivity must meet three general criteria: (I will be using load forecast as an easy example, but obviously there is a range of items that could be used)1. That it is expected to increase stress, for example increasing the load forecast would general increase stress, where decreasing it would not.2. That increases should be substantial, for example growing the load at 2x the expected rate vs 1.01x the expected rate. 3. That the change doesn't have to exceed the bounds of credibility. If a 2x or 3x increase doesn't result in a stack of new constraints, it does not mean the increase has to go to 10x the forecast just to show extensive effects. Is this a correct understanding? , realizing that I'm only referencing load growth for simplicity, it not being the only sensitivity? -2.1.4 and 2.4.3: The first sentence "impact of changes to the basic assumptions used in the model for the list of items below", please consider changing to just "impact of change to the basic assumptions used in the model". Including the "list of items below" implies that all items must be addressed, which seems to conflict with the second sentence which specifically allows one or more. -2.7: Is the "Corrective Action Plan" intended to document all of an entities planned future reliability related transmission projects and operational procedures? Or is it intended to address situations where simulation and the application of currently planned projects and procedures are insufficient to meet the performance requirements? -2.7: If a project is added one year to the "Corrective Action Plan" but then in the subsequent year has been added to the model, resulting in simulation showing no performance violations, should it be removed from the Corrective Action Plan? Or should it be referenced in the plan each year until it is either in service or demonstrated to no longer be required? Comments: With regard to the Lower VSL, is 2.6 considered to be met if only one of two sub-requirements (2.6.1 or 2.6.2) is met? With regard to the Moderate VSL, is 2.8 considered to be met if only one of two sub-requirements (2.8.1 or 2.8.2) is met? Also, since 2.3 depends on 2.6, what happens if an entity does not meet R2.6 because it did not meet one of the sub-requirements of 2.6? With regard to the High and Severe VSL, if any one of the sub-requirements of 2.1, 2.2, 2.4 or 2.7 is not met, is the entire sub-requirement considered not met? (This question is generic throughout all VSL) Also, for the short circuit study of 2.3 (and 2.8), it is not necessary to study all of the contingencies, just P2. Taking other Facilities out in addition to the fault will only reduce fault current. Auditors may not be aware of that and maybe the standard could say that only P2 needs to be studied to reduce future confusion. Is the intent of the SDT to have 2.7 apply to all previous bullets in R2? If so, then it could be made clearer by starting 2.7 with

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	"For the analyses discussed in 2.1 through 2.5, and for the planning events shown in Table 1, when the analyses indicate " 2.7 seems to have lost the reference to lead times for Corrective Action Plan(s) that were present in the existing TPL-001-0, TPL-002-0 and TPL-003-0 standards, is that the intent of the SDT? Since only two of the years in the near term need to be studied, and one of the year's in the long term study, there ought to be some method to determine when a Corrective Action Plan is needed, the lead time of that Corrective Action Plan, to give an indication of when activity needs to start to implement the Corrective Action Plan. The requirement clearly states that "For the steady state portion of the Planning Assessment " it must perform simulations that show generator ride through voltage limitations under 3.3.2. However, ride through limitations are performed through stability simulations not steady state as required by R3. Please provide clarity. Additionally, 3.2 requires studies to be performed to assess the impact of the extreme events. Yet, 3.3 requires analyses shall be performed but does not specify the events intended to study. Suggested language for 3.3 should say "Contingency analyses shall be performed to assess the impact of the extreme events and:" Under 3.3.1 it states that the Planner must simulate the removal of all elements that the Protection System would be expected to disconnect. Language should be included to allow the Planner to provide a rationale to assess more severe system conditions without needing to simulate the effects of Protection Systems. The references within the requirements are very confusing. 3.1 refers to a contingency list created in 3.4 which refers back to 3.1. Similarly 3.2 refers to a contingency list created in 3.5 which refers back to 3.2. These should be combined into one sub-requirement.

Response: The SDT reviewed Requirement R2, parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon.

The SDT declines to make the suggested changes in Parts 2.1, 2.2, and 2.6 because they do not add clarity.

The SDT has revised Part 2.6.2 as suggested.

> **Requirement R2, part 2.6.2**: For steady state, short circuit, or Stability analysis: the System represented in the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

For Parts 2.1.4 and 2.4.3, the example you gave is a valid example for addressing "the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance".

Part 2.1.4 and 2.4.3 have been revised as suggested.

> **Requirement R2, part 2.1.4**: For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

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	Requirement R2, part 2.4.3: For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: Part 2.7 requires a Corrective Action Plan to be developed for "when the analysis indicates an inability of the System to meet the performance requirements in Table 1". Therefore, the intent is to address situations where simulation and the application of currently planned projects and procedures are insufficient to meet the performance requirements. If a project is added to the Corrective Action Plan, it should be included as part of the study assumptions (and clearly identified as such), based on the criteria that the Planning Coordinator and Transmission Planner use for inclusion of such planned projects, for the annual Assessment as required in requirement R2, until it is in service or shown to be no longer needed. For the VSL for Requirement 2, both Parts 2.6.1 and 2.6.2 as well as Parts 2.8.1 and 2.8.2 must be met for the requirements to be met. If an entity relied on a past study, which was not a qualified study in accordance with Part 2.6, then based on the standard, it would not meet the requirement in Part 2.3. The intent is that with regard to the High and Severe VSL, if any one of the sub-requirements of Parts 2.1, 2.2, 2.4, or 2.7 is not met, the entire sub-requirement will be considered not met. The SDT believes this concern on Part 2.3 is covered. The Transmission Planner or Planning Coordinator can provide an explanation for why the Contingencies selected would produce the more severe conditions. Part 2.3 requires annual Planning Assessment only. The intent of Part 2.7 is to be applied to all "planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1". Therefore, a reference to Parts 2.1 through 2.5 is not needed. For 2.7.1, NERC Glossary of Terms defines Corrective Action Plan as "A list of actions and an associated timetable for implementation to remedy a specific problem. Also, Part 2.7.4 requires that the CAP be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures. By including the timing of needed action and requiring such reviews in subsequent Assessments, any deficiencies, if not adequately addressed, will become violations. Therefore, the SDT believes that your concerns have been addressed. Part 3.3.2: Generator protections exist that can result in generator tripping for bus voltage below minimum generator steady state voltage limits. The SDT believes that the voltage ride through test is applicable in post-Contingency steady-state where the planner would know if post-Contingency bus voltage violates generator trip points. If a trip point is violated, Part 3.3.2 would require the planner to trip the generator in the post-Contingency case to assess if performance is met with the generator tripped. No change made. Part 3.2 & Part 3.3: The SDT revised the wording of Part 3.3 as shown below to make it clear that it applies to both planning and extreme events: **Requirement R3, part 3.3**: Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall: Part 3.3.1: The SDT disagrees with the comment as the intent of Requirement R3, part 3.3.1, consistent with Order 693, is to perform the simulation to reflect how the Protection System will operate in the real System for each Contingency without operator intervention. The requirement does not preclude the Planning Coordinator/Transmission Planner from studying more severe scenarios. No change made. Part 3.1/Part 3.4 & Part 3.2/Part 3.5: The SDT does not believe that combining the requirements would provide any significant advantage. No change made.

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American Electric Power	R 2.6.2, as written, may lead to misinterpretation. Following are two alternative suggestions to remedy this issue for the SDT's consideration: 1) "For steady-state, short-circuit, or Stability analysis: the study shall be rendered obsolete by any material changes unless?" or 2) "For steady-state, short-circuit, or Stability analysis: the system shall not include any material changes unless?" While R3 (steady-state studies) covers 2.1 and 2.2 (steady-state assessments), and R4 (stability studies) covers 2.4 and 2.5 (stability assessments), there does not appear to be a corresponding requirement (short circuit studies) to cover 2.3 (short circuit assessments). We recommend that a new requirement be established and numbered to align between existing requirements R3 and R4.
Response: Part 2.6.2 has been revised as suggested. **Requirement R2, part 2.6.2**: For steady state, short circuit, or Stability analysis: the System represented in the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. For Part 2.3, the SDT does not believe a requirement to cover short circuit studies similar to Requirement 3 or Requirement 4 is required. The SDT's intent is for the short circuit study results to be included in the assessment. It does not believe that the standard needs to address the technical requirements for completing the short circuit study as that may be entity specific. Therefore the SDT declines to make the change as suggested.	
NYISO	R2. - The NYISO tariff establishes a biennial "Comprehensive System Planning Process," Compliance with an "Annual Planning Assessment" will therefore be a simple repetition of data reported in the prior year assessment. Please clarify that this is acceptable. We believe that the use of "past studies" provides for this. R2.1 - "Steady state" should be defined upfront with other definitions. In defining "steady state" is "thermal voltage" the primary metric being measured? R2.1.1 - Again want to confirm that due to the NYISO biennial planning cycle, that use of "past studies" will be acceptable. R2.1.2 - Please define what is intended by "off peak." Our reading is that it is ANY load level less than peak. Also, consistent with our comments on the prior draft, system off-peak is more likely a stability issue than a steady state issue. If system off-peak becomes a steady state issue, it can be mitigated through generation redispatch. Accordingly, it appears that this requirement is not necessary for steady state analysis. R2.1.4 - This is just too vague to be a useful requirement. The sentence ? To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. is too subjective to be enforceable. Either definitions of phrases like "sufficient amount" "credible conditions" and "measurable change" are included, or the requirement needs to be written more clearly to state what is actually being required without such high level of subjectivity. Further, we believe that this sentence may not be necessary at all, as the first sentence in 2.1.4 provides sufficient detail to conduct sensitivity analysis without being overly prescriptive. R2.4.3 As much of this language is a repeat of language in 2.1.4, above, our comments there also apply to this section. R2.6 - "Past Studies may be used to support the Planning Assessment if they meet the following requirements" and the sub-

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	requirement R2.6.2 states that for SS, SC, or stability analysis the study shall not include any material changes, such unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. While this is better than the prior draft, the NYISO still would like more clarity on the definition of "material changes." Would the inclusion of a technical rationale satisfy ANY change, regardless of magnitude, in a past study. Or could we just invoke the usage of a statement such as "The NYISO feels this change does not constitute a "material change." to be compliant with this requirement? We recommend that the regional entity should have a process to determine whether changes are material that is similar to the NPCC's process for determining what level of annual transmission review should be conducted each year. Finally, does this only relate to, or is limited to, the LATEST PLANNING HORIZON system model R2.7 Recommend that in the sentence "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity" wording should be changed to "performance requirements for any single sensitivity" R2.7.1 Recommend changing phrase that leads into list to read "Such actions including, but not limited to:" R2.7.2 - Recommend consideration of striking this section. It is not clear how an entity can provide a rational for unnecessary actions. Further, if actions are not necessary, what limit would there be on a rational, so they would seemingly be useless? Finally, it is stated above, corrective action plans should not be required for sensitivity studies. R2.9 There does not seem to relate to any reliability need the NYISO is aware of for this requirement to remain.

Response: Regarding Requirement R2 and Part 2.1.1, the SDT believes that NYISO's current process is inconsistent with Parts 2.1 (covering near-term steady state studies) and 2.2 (covering long-term steady state studies) of the draft Standard. Both Parts 2.1 and 2.2 require an annual current year study. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for the Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon.

For part 2.1, the SDT does not believe a definition for steady state is needed as this is a well understood term. There is no 'primary' metric – see the Table 1 Header Notes for more details.

The intent of Part 2.1.2 is to assess those System conditions during periods with lower Load levels than peak when the System may show different potential problems than during periods with peak Load level. For example, during light Load conditions, there may be high voltage problems because of the charging in the lightly loaded lines. There could also be thermal overload problems for areas with more generation than Load. For this reason, it would be appropriate to investigate Off-Peak steady state conditions to ensure that System performance can meet requirements under all demand levels. At the same time, the standard should not be overly prescriptive; therefore, the exact System Off-Peak Load and System conditions should be specified by the entity performing the study.

For Parts 2.1.4 and 2.4.3, The SDT envisions that credible "sufficient" "stressed" conditions and "measurable change" are to be defined by the responsible Planning Coordinator or Transmission Planner because each System is different and the standard should not be overly prescriptive.

Part 2.6.2 allows an entity to rely on a past study with a material change if "a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area". The intent is to assess system performance based on the latest available information. Therefore, it is up to the entities performing the study to provide the rationale based on changes, such as Load growth, generation or Transmission additions or modifications.

Part 2.7 has been changed to address your concerns.

Requirement R2, part 2.7: For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements

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in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Part 2.7.1 is simply a list and an entity can always do more than what is required in the Standard. No change made. Part 2.7.2 provides for development of a Corrective Action Plan if a number of sensitivity studies result in the same potential problem. For example, if only one sensitivity study results in potential problems or if the probability of occurrences of the sensitivity scenarios is low, then this would be the rationale to state that a Corrective Action Plan would not be necessary. Part 2.9 has been deleted in response to industry comments.	
Xcel Energy	R2.1 The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies" R2.1.5 Does "The Planning Assessment shall reflect" mean that the entity must meet the performance requirements for categories P0,P1,and P2 during the equipment unavailability? R2.9 As commented in the previous draft, we do not believe this requirement contributes anything to improving BES reliability. Therefore, we strongly recommend deleting this requirement.
Response: The SDT reviewed Requirement R2, parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizon, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested. For 2.1.5, your interpretation is correct. Part 2.1.5 requires that the Planning Coordinator or Transmission Planner plans for the potential unavailability of long lead time major Transmission equipment in accordance with its spare equipment strategy. If the spare equipment strategy can result in unavailability of long lead time equipment, the study will need to also be modeled with the piece of equipment out of service as P0. Part 2.9 has been deleted as suggested.	
Ameren	R2.1.3: The wording for this requirement needs clarification. It is suggested that the following language be submitted as a replacement: Known outages of generation or Transmission facilities should be included in the models representing those

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	System peak or Off-peak conditions when outages are scheduled. R2.1.4 and R2.4.3: The phrase “by a sufficient amount” should be modified to “by an amount”. Also, in R2.4.3, “dynamic model assumptions” should be changed to “dynamic load model assumptions.” R2.6.2: Recognition should be made of the fact that cancellation of generation or transmission projects, which may have been included in a previous study, would decrease fault levels, and would reduce or eliminate the need for short circuit analysis. R2.8: Would the Planning Coordinator be required to review, replicate, or validate short circuit studies? We appreciate the deletion of R2.9 from the previous draft of TPL-001-1 and eliminated the reporting of Non-Consequential Load Loss for each of the planning events. In R2.9, it is recommended that the largest Consequential Load Loss not include items such as pumped storage load or other utility load.
Response: Part 2.1.3 covers known long duration outages, for example, taking a 230 kV Transmission line out of service to rebuild it to operate at 500 kV. These cases are to simulate System conditions with the Facility in question out of service as Category P0 (or N-0). For the next outage, the System performance will need to meet requirements for Category P1. For Parts 2.1.4 and 2.4.3, the SDT envisions that “credible”, “sufficient”, “stressed” conditions and “measurable change” are to be defined by the responsible Planning Coordinator or Transmission Planner because each System is different. Part 2.4.3 has been revised as suggested. **Requirement R2, part 2.4.3, bullet #1:** Load level, Load forecast, or dynamic Load model assumptions For Part 2.6.2, the SDT agrees with the expectation concerning short circuit studies. For Part 2.8, as in other parts of this draft standard, the Planning Coordinator is responsible for its portion of the BES. It may delegate the work by agreement, it is, however, still responsible. Part 2.9 has been deleted in response to industry comments.	
Manitoba Hydro	R2.1.4.: The first sentence implies that all sensitivities should be studied. The second sentence refers to one or more. I suggest the following change to the first sentence: "....basic assumptions used in the model." (i.e. delete "for the list of items shown below." from the end of the first sentence.) R2.4.3: The exact same change as above in R2.1.4. R2.1.5: We assume the intent of the standard would be to perform an annual review of the inventory of spare equipment to determine if the spare strategy required updating. For example, if a transformer failed and the spare was moved into position, a new spare would be ordered to replace the failed one. During the period, when no spare was in place, additional assessments would be required to ensure meeting Table 1. Can the drafting team clarify? R2.5: The drafting team modified “material changes” to simply “changes” in R2.5. This does not add clarity. Given that R2.5 is

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	related to Stability Analysis, perhaps "changes" could be modified to "changes that could impact stability or voltage". R2.6: Recommend changing "the study" to "the past study" and "an older study" to "an older past study" to ensure no confusion could result from past and current studies. Can the drafting team explain how a past study can have material changes in R2.6.2? Perhaps R2.6.2 could be deleted. VSL: We would recommend moving R2.8's VSL from Moderate to both High and Severe. R2.8 requires a corrective plan to be developed when the short circuit duty of a circuit breaker is known to be exceeded. This is safety issue and a reliability issue.

Response: In Parts 2.1.4 and 2.4.3, the first sentence has been revised as suggested.

> **Requirement R2, part 2.1.4**: For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:
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> **Requirement R2, part 2.4.3**: For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

Part 2.1.5 does not address the specific requirements of an individual plan. Since a Planning Assessment is required annually, the analysis required under Part 2.1.5 is an annual requirement. The answer to the specific example would depend on a variety of factors, including the timing of the failure, the length of time that it would take to replace the spare, your Operation Planning time horizon and the specifics of your individual spare equipment strategy. The language in Part 2.1.5 states "the impact of this possible unavailability on System performance shall be assessed", which must be completed annually as a part of your Planning Assessment. The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing (Year One) is defined as the planning window that begins 12-18 months from the end of the current calendar year. After the original spare is put to use, if a new spare can be made available before Year One in the next Planning Assessment, the time period during which no spare is available could then be covered in Operation Planning studies. Longer delivery times would impact the spare availability and an appropriate assessment would be expected in Year One by the Transmission Planner. In addition, to provide greater clarity, the SDT has revised the first sentence of Part 2.1.5 to read, "When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed.

> **Requirement R2, part 2.1.5**: When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.5, the SDT declines to make the change as suggested because the suggested change does not add clarity.

The SDT declines to make the change suggested in Part 2.6 because it did not add more clarity than the existing language.

The SDT has revised Part 2.6.2 to provide additional clarity.

> **Requirement R2, part 2.6.2**: For steady state, short circuit, or Stability analysis: the System represented in the study shall not include any material changes

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unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. While the SDT agrees that the short circuit analysis is important, Part 2.8 has been assigned a VSL based on its need to fulfill Requirement R2. Safety is covered in other venues.	
Tri-State Generation and Transmission Association	R2.2 What is an "annual current study"? Would this include previously performed studies that are still applicable?? R2.2. What is "qualified past studies"? We have no definitions for "qualifying" previous work. This might be remedied by inserting the term "qualified" in R2.6.? R2.1.4. Sensitivity cases could add much work to the existing process. However, the standard calls for "at least one" of the listed sensitivity studies to be performed. R2.2.1. The requirement to perform a "current study" assessing expected System peak Load conditions, for one of the years in the Long-Term Transmission Planning Horizon, is extra work if a valid/qualified study is available. If the intention here is to have a valid study for at least one of the years 6 to 10, then perhaps some simple rewording will solve the problem. We ascribe to the concept of requiring annual assessments, but not necessarily requiring repeated analysis if system changes do not warrant restudy. Hyphenate "in-service" R2.6.1 Change "the study shall be five calendar years old or less" to: "the study is five calendar years old or less" R2.6.2 change the phrase "shall not include any material changes" to "does not include any material changes" R2.6.2 it is not clear what is meant by "material changes" - different "Study conditions" or "changes that could cause different results for a particular study"?
Response: In Parts 2.2 & 2.2.1, an "annual current study" is one that must be done in the current assessment cycle. Previously performed studies can be used to supplement the current study, but not in place of it. Because steady state analysis is part of basic planning process, the SDT believes that the steady state portion of the studies covering one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire Long-Term Transmission Planning Horizon. In Part 2.2, the "qualified past studies" are as indicated in Requirement R2, part 2.6. The SDT believes that the existing language is clear and changes are not needed. Part 2.1.4 – There is no question here so the SDT is unable to provide a specific response. For Part 2.6.1, the SDT declines to make the changes as suggested because they do not provide more clarity than the existing language. The SDT has revised Part 2.6.2 to address your concerns. Part 2.6.2 also allows an entity to rely on a past study with a material change if "a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area". Therefore, it is up to the entities performing the study to provide the rationale based on changes, such as load growth. **Requirement R2, part 2.6.2**: For steady state, short circuit, or Stability analysis: the System represented in the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.	
Oklahoma Gas & Electric	R2.4.3 Not positive what this actually requires Transmission Planner to perform. Recommend compliance with requirement be

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	the responsibility of the Transmission Coordinator. R2.9 OG&E has not provided this information in the past. Different sets of load flow models will result in different data results. Do not see any merit with providing information.
Response: Part 2.4.3 is part of Requirement 2, which applies to both the Transmission Planner and the Planning Coordinator for their respective portion of the BES. So, both are responsible for meeting the requirements even though the actual work may be shared or delegated. Part 2.9 has been deleted in response to industry comments.	
Arizona Public Service Co.	R2.6.2: The wording "study shall not include" is confusing since it refers to the past studies.
Response: Part 2.6.2 has been to address your concerns. **Requirement R2, part 2.6.2**: For steady state, short circuit, or Stability analysis: the System represented in the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.	
Hydro-Québec TransEnergie (HQT)	Requirement 2.1 As written, it is not clear. HQT, as does NPCC, suggests revising language as in 2.4 as follows:"The Near-Term Transmission Planning Horizon portion of the steady state" analysis shall be assessed annually and be supported by current or past studies as indicated in? Requirement R2, part 2.6. The following studies are required: Requirement 2.1.2 The use of the term "off peak" is a concern. The definition for this term can be read to say that it is any load level less than peak. This does not provide enough clarity to guide the required assessments. Requirement 2.2 As written, it is not clear. HQT, as does NPCC, suggests revising language in 2.2 as in 2.4 as follows: The Long-Term Transmission Planning Horizon portion of the steady state" analysis shall be assessed annually and be supported by current or past studies as indicated in? Requirement R2, part 2.6. The following studies are required: Requirement 2.7 HQT,as does NPCC, suggests changing the word "run" to "condition" in "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3." Requirement 2.9 It should not be necessary to identify the largest consequential load loss if the TPL standard does not limit the size of the consequential load loss. This requirement should be deleted.
Response: The SDT reviewed Requirement R2, parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizon, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year	

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	study being performed. Therefore, the SDT declines to make the change as suggested. The intent of Part 2.1.2 is to assess those System conditions during periods with lower Load levels than peak when the System may show different potential problems than during periods with peak Load level. For example, during light Load conditions, there may be high voltage problems because of the charging in the lightly loaded lines. There could also be thermal overload problems for areas with more generation than Load. For this reason, it would not be appropriate to eliminate the requirement to investigate Off-Peak steady state or Stability conditions. At the same time, the standard should not be overly prescriptive; therefore, the exact System Off-Peak Load should be specified by the entity performing the study. Part 2.7 has been changed to address your concerns. **Requirement R2, part 2.7**: For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Part 2.9 has been deleted as suggested.
Northeast Power Coordinating Council--RSC	Requirement R2 (second line): "This Planning Assessment shall use current or past studies," should be replaced with "This Planning Assessment shall use current studies or qualified past studies as indicated in Requirement R2, part 2.6," Requirements 2.1, 2.2, 2.3, and 2.4--As written, are not clear. It is suggested to revise the language as follows: "The Near-Term Transmission Planning Horizon portion of the steady stateanalysis shall be assessed annually and be supported by current studies or qualified past studies as indicated in Requirement R2, part 2.6. The following studies are required:"Requirement 2.1.2 The use of the term "off peak" is a concern. The definition for this term is not provided, and can be read to say that it is any load level less than peak. This does not provide enough clarity to guide the required assessments. Requirement 2.1.3: It must be clarified that the reference to outages as listed in Requirement R1, part 1.1.2 must be limited to Planning Horizon. Refer to Requirement 1.1.2 in the response to Question 1. Requirement 2.1.4: Consistent with the suggestion made for Requirment 1.1.2 remove the last bulleted item in the list under Requirement 2.1.4 "Duration or timing of planned Transmission outages." The standard is referring to requirements for sensitivity without a reference to base cases. Refer to Comment on Proposal to add an item 1.2 Requirement 2.1.5: It needs to be clear that this is only an assessment, not a solution. Actions such as out of merit dispatch, operational restrictions, System reconfiguration can be part of a Corrective Action Plan if the System cannot meet performance requirements without the Facility in service. It can be reworded as "an assessment of the impact of this possible unavailability on System performance shall be performed". Requirement 2.3: The requirement does not indicate a year to study. This should be modified to state that it is up to the Planner to determine the year of study within the Near Term Transmission Planning Horizon.

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	Requirement 2.4.2: Same as 2.1.2 Requirement 2.4.3: Refer to the Comment for Question 1 to add a Requirement 1.2 Requirement 2.5: Revise language as follows: be supported by current studies or qualified past studies as indicated in Requirement R2, part 2.6. Requirement 2.7 NPCC suggests changing the word "run" to "condition" so the wording will read Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity condition in accordance with Requirements R2, parts 2.1.4 and 2.4.3. Requirement 2.9 It should not be necessary to identify the largest consequential load loss if the TPL standard does not limit the size of the consequential load loss. This requirement should be deleted. If it remains, it must be made clear that it be applicable only to Year One or Year Two.
National Grid	Requirement R2 (second line): This Planning Assessment shall use current or past studies, should be replaced with "This Planning Assessment shall use current studies or qualified past studies as indicated in Requirement R2, part 2.6," Sub-Requirements 2.1, 2,2, 2,3, and 2.4: Language to be revised to the following:"be supported by current studies or qualified past studies as indicated in Requirement R2, part 2.6. The following studies are required."Sub-Requirement 2.1.2: Definition of "off-peak" not provided and can be read to say that it is any load level less than peak. This does not provide enough clarity to guide the required assessments. Sub-Requirement 2.1.3: It must be clarified that the reference to outages as listed in Requirement R1, part 1.1.2 must be limited to Planning Horizon. Refer to Sub-Requirement 1.1.2 in Question 1.Sub-Requirement 2.1.4: Consistent with the suggestion made for section 1.1.2 please remove the last bulleted item in the list under section 2.1.4. "Duration or timing of planned Transmission outages." The standard is referring to requirements for sensitivity without a reference to base cases. Refer to Comment on Proposal to add an item 1.2 Sub-Requirement 2.1.5: It needs to be clear that this is only an assessment, not a solution. Actions such as out of merit dispatch, operational restrictions, System reconfiguration can be part of a Corrective Action Plan if the System cannot meet performance requirements without the Facility in service. It can be reworded as "an assessment of the impact of this possible unavailability on System performance shall be performed" Sub-Requirement 2.3: The requirement does not indicate a year to study. This should be modified to state that it is up to the Planner to determine the year of study within the Near Term Transmission Planning Horizon. Sub-Requirement 2.4.2: Same as 2.1.2Sub-Requirement 2.4.3: Refer to Comment on Proposal to add an item 1.2 Sub-Requirement 2.5: Revise language as follows:"be supported by current studies or qualified past studies as indicated in Requirement R2, part 2.6. Sub-Requirement 2.7: It is suggested to change the word "run" to "condition" such that it reads "Corrective Action Plan(s) do not

Organization	Comments for Question 2
	need to be developed solely to meet the performance requirements for a single sensitivity condition in accordance with Requirements R2, parts 2.1.4 and 2.4.3." Sub-Requirement 2.7.2: Refer to Comment on Proposal to add an item 1.2 Sub-Requirement 2.9: It should not be necessary to identify the largest consequential load loss if the TPL standard does not limit the size of the consequential load loss. This requirement should be deleted. If it remains, it must be made clear that it be applicable only to Year One or Year Two.

Response: The SDT reviewed Requirement R2, parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizon, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested.

The intent of Parts 2.1.2 and 2.4.2 is to support assessment of those System conditions during periods with lower Load levels than peak when the System may show different potential problems than during periods with peak Load level. For example, during light Load conditions, there may be high voltage problems because of the charging in the lightly loaded lines. There could also be thermal overload problems for areas with more generation than Load. The System could have less damping and could result in potential Stability problems. For this reason, it would not be appropriate to eliminate the requirement to investigate Off-Peak steady state or Stability conditions. At the same time, the standard should not be overly prescriptive; therefore, the exact System Off-Peak Load should be specified by the entity performing the study.

Part 2.1.2 – Off-Peak is a defined term in the NERC Glossary.

Part 2.1.3 is a sub-part of Part 2.1 which is limited by the Near-Term Transmission Planning Horizon so no change is made.

The SDT declines to remove the last bullet in Part 2.1.4, "Duration or timing of planned Transmission outages" as a potential sensitivity. The intent is to cover unexpected changes in plans, for example, a potential delay in returning a Transmission line back to service after a planned outage of 6 months or more for rebuilding to a higher capacity line. In this case, the System with the equipment in question out of service would be modeled as P0 (or N-0), the next outage would be, for example, P1 (N-1), and not covered in P6.

For Part 2.1.4, the SDT believes that the "base case conditions", on which to base the sensitivity cases, should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested.

The SDT believes that your concern on Part 2.1.5 has already been addressed. Part 2.7.1 - Corrective Action can include, among other things:

- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.

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	○ Use of rate applications, DSM, new technologies, or other initiatives. In addition, the first sentence of Part 2.1.5 has been revised. **Requirement R2, part 2.1.5**: When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. The SDT believes that this concern has been addressed. Part 2.3 is silent on the year of study within the Near-Term Transmission Planning Horizon. Therefore, it is up to the Transmission Planner or Planning Coordinator to select the study years most suited to the System in question. In addition, Part 2.3 only requires an annual Planning Assessment, which is to be supported by annual current or qualified past studies. For Part 2.4.3, the SDT believes that the "base case conditions", on which to base the sensitivity cases, should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested. The existing language in Part 2.5 already allows the assessment to be supported by current or past studies. Therefore, the suggested change is not needed. Part 2.7 has been changed to address your concerns. **Requirement R2, part 2.7**: For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: For response to comments on Part 2.7.2, please see previous response to proposal to add Part 1.2. Part 2.9 has been deleted due to industry comments.
Midwest ISO	Requirement R2.1.4: It should be made clear that the sensitivity findings do not obligate the PC or TP to establish Corrective Action Plans to address any needs identified in the sensitivity cases. Also, the use of the following two words "sufficient" and "measurable" are too vague and hard to quantify. This may require an auditor's opinion. Suggest at least removing the word "sufficient" from the requirements. Requirement R2.1.5: This requirement states that we need to perform prior outage analysis for P0, P1 and P2 events for all long-lead time (>1year) components without spares. This seems redundant with P3 and P6 which will answer whether those events are an issue. Need to be clear that loss of load is or is not allowed for these events. P2 still allows for some loss of load. Bottom line is that P2.1.5 seems duplicative. What is intent of requirement? Rather say the P3 and P6 should note if long-lead time items are involved without spares. Also, the Planning Coordinator could have an administrative burden demonstrating compliance with a spare equipment strategy for its entire footprint. Requirement R2.4.3: the use of the following two words "sufficient" and "measurable" are too vague and hard to quantify. This may require an auditor's opinion. Suggest at least removing the word "sufficient" from the requirements.

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	Requirement R2.7.2: As suggested in the comments above for R2.1.4, it should be clarified that corrective actions are not necessary for performance deficiencies identified by sensitivity studies. Request removing this requirement all together. If the SDT agrees to keep this requirement then we offer the following comments: It is not clear how an entity can provide rational for why actions were not necessary. Requirement R2.9: With regards to the largest consequential loss of loads for P1 and P2 events; if no action is required then why require the entities to provide this. Will it matter if 10MW or 100MW is tripped with the line? This is a system design issue which is not addressed by the standards, if this requirement is kept how is an entity expected to demonstrate compliance for this? This requirement is an administrative burden and we propose to remove R2.9 all together considering that there is not a reliability-related need for this information and it is unnecessary.
Response: The SDT believes that your concern on Part 2.1.4 is already covered in the existing draft. The existing Part 2.7 states, in part, that "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, parts 2.1.4 and 2.4.3. In addition, Part 2.7.2 describes the requirement on Corrective Action Plans to "Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary". For Parts 2.1.4 and 2.4.3, The SDT envisions that "credible", "sufficient", "stressed" conditions and "measurable change" are to be defined by the responsible Planning Coordinator or Transmission Planner because each System is different. Part 2.1.5 only requires that the Planning Coordinator or Transmission Planner plans for the potential unavailability of long lead time major Transmission equipment in accordance with its spare equipment strategy. For example, if an entity's spare equipment strategy is to have a spare transformer on site, then the unavailability of a similar transformer (due to outages) would be limited to the time it would take to energize the spare transformer. Assuming that this time is no more than that required to return a similar outaged transformer back in service, Part 2.1.5 can be satisfied without performing additional planning studies. If on the other hand, the transformer would have to be purchased, then it would take more than a year to replace. In this case, for Part 2.1.5, P0 should be modeled with the transformer in question out of service. The performance requirements in Table 1 will apply for the next single Contingency. This is not the same as P2 or P6; both of which are events starting from System intact condition as P0. It is also not the same as P3, which covers loss of a generator as the first event, and Part 2.1.5 covers loss of a piece of major Transmission equipment, for which there is no spare. The words "sufficient" and 'measurable' are needed in Part 2.4.3 to ensure that the variations made to the assumptions to investigate sensitivity are large enough to be meaningful so they can demonstrate the impacts of the changes. The SDT envisions that credible sufficient stressed conditions and measurable changes are to be defined by the responsible Planning Coordinator or Transmission Planner. As such, the SDT declines to revise Parts 2.1.4 and 2.4.3 as suggested. The SDT believes that your concern on Part 2.7 is covered in the existing draft. Part 2.7 states, in part, that "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. In addition, Part 2.7.2 provides for development of a Corrective Action Plan if a number of sensitivity studies result in the same potential problem. For example, if only one sensitivity study results in potential problems or if the probability of occurrences of the sensitivity scenarios is low, then this could be the rationale to state that corrective action plan would not be necessary. Part 2.9 has been deleted as suggested.	
Duke Energy	Reword R2.1 as follows: The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be based on the following annual current studies, supplemented with qualified past studies that meet Requirement R2, part 2.6.

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	The following studies are required: We believe that using a past study for the Long Term Assessment is adequate, as long as the past study meets R2.6. Reword R2.2 as follows: The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be based on the following annual current study or qualified past study that meets Requirement R2, part 2.6. The following study is required: Reword R2.2.1 as follows: System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected. We believe that using past studies for the Near-Term Transmission Planning Horizon portion of the Stability analysis is adequate, as long as the past studies meet R2.6. Reword R2.4 as follows: The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be based on the following annual current studies or qualified past studies that meet Requirement R2, part2.6. The following studies are required: R2.5 Does the phrase "proposed generation additions or changes in that timeframe" refer only to generation changes, or does it also refer to transmission system changes?
Response: The SDT declines to make the change to Part 2.1 as suggested because it does not add more clarity than the existing language. The SDT declines to make this change to Part 2.2 and Part 2.2.1. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire Long-Term Transmission Planning Horizon. Making the change as requested can result in no current-year study for the Long-Term Transmission Planning Horizon being performed. Therefore, the SDT declines to make the change as suggested. The SDT declines to make the change to Part 2.4 as suggested because it does not add more clarity than the existing language. Part 2.5 is intended for investigation of Stability issues due to addition of generators. The SDT does not believe that, in general, a Stability assessment is needed for the Long-Term Transmission Planning Horizon. The System model for that timeframe is too uncertain for a meaningful assessment of the System's Stability. However, for those situations where a specific generator is planned to be added in that timeframe, the SDT believes that it will be appropriate to require that the generator's Stability impact be evaluated.	
NorthWestern Energy	Short circuit analysis is a local issue. The reliability of the BES does not depend on the regular assessment of short circuit duty. Therefore, we believe short circuit analysis should be deleted from R2. The wording in R2.1 is unclear: Are new annual studies required each year or are qualified past studies acceptable if no changes have been made? R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies"

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	Are the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3? Both are for Near-Term studies but for steady state and stability respectively. If they should align, the wording should be modified to be the same. As written R2.1.4, "Real and reactive Load forecasts", could mean that both Real and Reactive Load forecasts are required. Since most entities only forecast Real (MW) and apply a power factor for reactive (MVAR), wording could be changed to " forecasted demand and power factor" to clarify that forecasting reactive load is not required.
Response: Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt. Even though the effects of short circuit capability are localized and may be related to new planned Facilities, it is important to BES reliability. Therefore, the SDT declines to delete the requirement for short circuit analysis from Requirement R2. The SDT reviewed Requirement 2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for the Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested. The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within Parts 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and stability evaluations, respectively. **Requirement R2, part 2.4.3**, **bullet #3**: Expected in service dates of new or modified Transmission Facilities Part 2.1.4 states that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast.	
Sacramento Municipal Utility District	SMUD appreciates the diligence with which the SDT has responded to our earlier comments. SMUD offers the following comments on Draft #4 for the SDT's consideration: R2.1.4: To define a "sensitivity" case, the standard should first define a "base" case. If a sensitivity case is a more conservative scenario analysis than a base case, does an entity need to perform/document a Planning Assessment for both "base" and "sensitivity" or is a Planning Assessment that uses the "Sensitivity" case adequate? R2.1: The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies". R2.1.4 and R2.4.3: The words, "by a sufficient amount" should be removed as it does not provide any more clarity.

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	R2.1.5: The first part of the sentence calls for an analysis of the impact (of modeling the spare equipment strategy). The second part of the sentence that defines the applicable categories to study, starts with the words "The Planning Assessment". Use of the defined words "Planning Assessment", broadens the study to both an impact assessment and providing details of a "Corrective Action Plan". The intent of the requirement should be made clear in the first sentence. R2.4.3: Suggest deleting the words "in the Planning Assessment". Since a corrective action is not required for all sensitivities (see R2.7), use of the defined term in this paragraph can be confusing. R2.6.1: SMUD agrees with allowing a study older than five years to be considered if a technical rationale can be provided. R2.9: The requirement to report the largest single consequential load loss should not be included in the standard. If it remains, it must be made clear that it be applicable only to Year One, and there should be additional clarification that the requirement to report consequential load loss (single number) is ONLY for the most severe contingencies studied for the P1 and P2 contingencies. Table 1 P1.3 and associated Note 5: Is the purpose of the "reference voltage" to determine a valid transformer contingency (thereby, limiting the scope of R2.9)? R2.7 / Table 1, Notes e and i: Note (e) excludes references to load that is allowed to be dropped if it is NOT part of Non-Consequential Load Loss. This note should include such Load (if represented in the load forecast being studied as being part of the Demand Response) if it can be dropped within the time duration applicable to the Facility Ratings. Note (i): Since the definition of Non-CLL would allow interruptible load to be dropped, is note (i) stating that interruptible load cannot be dropped even if it meets the "executable within the time duration' requirement"

Response: For Part 2.1.4, the SDT believes that the "base case conditions" on which to base the sensitivity cases should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. It is also up to the entity performing the study to determine the scenarios to be used for the Planning Assessment.

The SDT reviewed Requirement 2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested.

For Parts 2.1.4 and 2.4.3, The SDT envisions that "credible", "sufficient", "stressed" conditions and "measurable change" are to be defined by the responsible Planning Coordinator or Transmission Planner because each System is different.

Part 2.1.5 is part of Requirement R2, which requires that each Transmission Planner and Planning Coordinator prepare an annual Planning Assessment of its portion of the BES, therefore, the use of Planning Assessment in Part 2.1.5 has not broadened the requirement. The first sentence of Part 2.1.5 has been revised to provide more clarity.

Requirement R2, part 2.1.5: When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of

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one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. For Part 2.4.3, the SDT declines to delete "in the Planning Assessment" as suggested because Part 2.4.3 is part of Requirement R2, which covers the requirement of preparing an annual Planning Assessment. Part 2.9 has been deleted as suggested. Table 1, P1.3 and associated footnote 5: the term "reference voltage" is used in determining if a transformer is classified as EHV or HV for the BES. This classification then ties to footnote 1 in regards to provisions for the interruption of Firm Transmission Service and Non-Consequential Load Loss. For example, if a 345/138 kV transformer is outaged for the event studied the high-voltage (HV) allowances for interruption of Firm Transmission Service and loss of Non-Consequential Load would apply. The 138/66 kV transformer may not be classified as a BES Facility; your regional entity organization definition of the BES should be consulted for an official position. Note (e) in Table 1 refers to "planned System adjustments" and "Transmission configuration changes and re-dispatch of generation" are examples of "planned System adjustments". Table 1 note (i) is intended to clarify that even if it is known that an end-user who implements a more conservative practice than that of the Transmission Planner/Planning Coordinator regarding steady-state voltage criteria and chooses to interrupt its own Load, the end-use Load must still be represented in the steady-state timeframe. The Load tripping is permitted in a Stability review, however, it should be assumed that a customer will react quickly to restore its Load and therefore the standard requires the Load be represented in the steady-state timeframe. Only actions (manual or automatic) taken by the Transmission Planner/Planning Coordinator are permitted for consideration for a steady-state review.	
US Bureau of Reclamation	The conflict is created in Section 2.5 in that only proposed generation additions or changes are assessed in "Long-Term planning Horizon portion of the Stability analysis. This Section should also address proposed transmission facility additoins or changes. Section 2.7 indicates that the Planning Assessment shall include Corrective Action Plan(s) addressing how performance requirements will addressed. This implies that the Corrective Action plans are not proposed generation or transmission additions or changes. If Corrective Action Plan items are developed through Planning Assessments, they should be clarified as proposals for consideration by Generator Owners and Transmission owners in developed future system modifications or additions.
Response: Part 2.5 is intended for investigation of Stability issues due to addition of generators. The SDT does not believe that, in general, a Stability assessment is needed for the Long-Term Transmission Planning Horizon. The System model for that timeframe is too uncertain for a meaningful assessment of the System's Stability. However, for those situations where a specific generator is planned to be added in that timeframe, the SDT believes that it will be appropriate to require that the generator's Stability impact be evaluated. However, the standard does not preclude investigation of addition of other Facilities, such as Transmission Facilities. Part 2.7 does not imply that "the Corrective Action plans are not proposed generation or transmission additions or changes". Part 2.7.2 includes a list of actions that can be included as part of a Corrective Action Plan, which the Transmission Planner and Planning Coordinator are required to prepare.	
TIS	The reference in R2.1.3 to the outage schedules as listing in part R1.1.2 must be recognized as a limitation to the standard to the Planning Horizon. See the TIS comment tor R1.

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	There is confusion in interpretation of the Table 1 When the voltage class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied? For example if a SLG fault is on a 138-kV element or a 345/138-kV autotransformer, are you allowed to shed load to keep a345-kV element from overloading? Conversely, if the fault is on a 345-kV element, are you allowed to shed load to keep a 138-kV from overloading? It should be the voltage level of the overloaded element (not the outaged element) that determines whether or not non-consequential load shedding is allowed. The TIS believes that the requirement to report the largest single consequential load loss under Requirement 2.9 should not be included in the standard. If it remains, it must be made clear that it be applicable only to Year One, and there should be additional clarification that the requirement to report consequential load loss (single number) is ONLY for the most severe contingencies studied for the P1 and P2 contingencies.
Response: Part 2.1.3 is a sub-part of Part 2.1 which is limited by the Near-Term Transmission Planning Horizon so no change is made. The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT's intent and it now reads: **Table 1, footnote 1**: If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. Part 2.9 has been deleted as suggested.	
Idaho Power	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies"?, while R2.1 implies current studies must be used but can be supplemented by past studies. I suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies"? to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies"? It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.
Response: The SDT reviewed Requirement 2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be	

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Modesto Irrigation District Transmission Planning	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads “This Planning Assessment shall use current or past studies”, while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from “The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies” to “The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies” It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change “real and reactive load forecast” to “forecasted demand and power factor” so it is clear that forecasting reactive load is not required.R2.1.4, R2.4.3 "... vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measureable change in performance." Please define measureable. An example would certainly help. This would be a good workshop item to show how to perform. R2.6.2 The previous version defined material change. This current version eliminated the definition of material change, but still indicates the study shall not include any material changes.... This is unclear; please clarify.
Response: The SDT reviewed Requirement R2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require “annual current year study, supplemented by qualified past studies”. Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement	

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NV Energy	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies" It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.
Pacific Gas and Electric Co.	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies"? It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the

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San Diego Gas & Electric Co	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies"? It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.
SRP	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies" It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.
Response: The SDT reviewed Requirement R2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission	

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Puget Sound Energy, Inc.	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies" The wording in R2.1.1 is unclear as to whether two studies are required or only one. Should it read "year one or year two or year 5" as opposed to "year 1 or year 2 and year 5"? The language in 2.3, indicating that short circuit analysis be studied as part a BES transmission planning assessment should not be required. The effects of the failure of over-stressed breakers are already included in the Events listed in Table 1. Examples would include P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). The addition of short circuit analysis study does not add any additional reliability information. It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. R2.9 should be deleted (or not required for local load loss). The SDT indicated in the response to "Consideration of Comments on 3rd Draft of Standard TPL-001-1" that the requirement R2.9 is intended to "contribute to an open and transparent Transmission planning for peer review." And if the "largest Consequential Load Loss" is a local (intra-network) event? Would the documentation of such an event contribute to reliability in any way?
Response: The SDT reviewed Requirement R2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizon, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of	

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Southern California Edison (SCE)	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies"? It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. Additionally, 2.4.2 is inconsistent with 2.4.1 with regards to language. It seems the intent of the Standards Drafting Team was to have the two consistent with each other. Specifically, the quote below, from section 2.4.1, is missing from section 2.4.2 (keeping in mind the word "peak" should be replaced with "Off-Peak"."System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable."

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Response: The SDT reviewed Requirement R2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for the Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested. The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and stability evaluations, respectively. **Requirement R2, part 2.4.3**, **bullet #3**: Expected in service dates of new or modified Transmission Facilities Parts 1.1.4 and 2.1.4 state that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast. In Part 2.4.1, the SDT specifies the dynamic Load model representation for on peak because the System voltages are generally lower during on peak. The percentage of motor Load, e.g., in air conditioners, could significantly increase reactive power requirements especially when they stall due to low System voltage and can therefore impact dynamic System performance on-peak. However, motor Load would likely not pose the same problem during Off-peak as the System voltages are usually higher. So, in Part 2.4.2, it can be left to the discretion of the Planning Coordinator or Transmission Planner whether the dynamic motor Load would need to be represented per the requirement in Part 2.4.1.	
Utility System Efficiencies, Inc. (USE)	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. I suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies"? It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same.
Response: The SDT reviewed Requirement R2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for the Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested.	

Organization	Comments for Question 2
The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and stability evaluations, respectively. **Requirement R2, part 2.4.3**, **bullet #3**: Expected in service dates of new or modified Transmission Facilities	
Western Area Power Adm - RMR	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. I suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies"? It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. In R2.1.5 " the opening statement "When an entity's "spare equipment strategy" Does this imply an auditor would ask for this documentation as part of the review of this new TPL-001? Also " what other Standard requires the "spare equipment strategy"? I'm trying to determine what kind of documentation is required for this Requirement.
Response: The SDT reviewed Requirement R2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizon, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for the Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested. The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and stability evaluations, respectively. **Requirement R2, part 2.4.3**, **bullet #3**: Expected in service dates of new or modified Transmission Facilities Parts 1.1.4 and 2.1.4 state that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast. Part 2.1.5 does not require a spare equipment strategy. It only requires that the Planning Coordinator or Transmission Planner plans for the potential unavailability of long lead time major Transmission equipment in accordance with its spare equipment strategy. For example, if an entity's spare equipment strategy is to have a spare	

Organization	Comments for Question 2
transformer on site, then the unavailability of a similar transformer (due to outages) would be limited to the time it would take to energize the spare transformer. Assuming that this time is no more than that required to return a similar outaged transformer back in service, Part 2.1.5 can be satisfied without performing additional planning study. If on the other hand, the transformer would have to be purchased, then it would take more than a year to replace. In this case, P0 should also be modeled with the transformer in question out of service. The SDT cannot comment on what documentation an auditor would need to support an audit.	
SRC of ISO/RTO	Under 2.1.4- It should be made clear that the sensitivity findings do not obligate the PC or TP to establish Corrective Action Plans to address any needs identified in the sensitivity cases. Specifically, we do not believe the sentence "To accomplish this, the sensitivity analysis in the Planning Assesment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance." is measurable or necessary. The first part of 2.1.4 already stipulates sufficient details for the responsible entity to conduct sensitivity analysis including the parameters to be varied. Adding the "how-to-conduct" requirement is overly prescriptive and unnecessary, and the condition for "that demonstrate a measurable change in performance" is not measurable. It lacks a definitive target or direction for the responsible entity to determine (a) what conditions need to be attained to demonstrate a measurable change in performance, (b) what constitutes "measurable change in performance", and (c) what follow-up or corrective actions are needed to address the adverse performance as a result of stressing the system beyond the forecast conditions. Under 2.1.4 and 2.4.3 "sufficient" and "measurable" are too vague and hard to quantify. This may require an auditor's opinion. Suggest removing at least the word "sufficient" from the requirements. Under 2.3- Some PCs do not perform short circuit analysis. Is it the intent of the SDT to make the analysis standardized over a footprint? Alternatively, this could be a TP only responsibility. Further, Part 2.3 stipulates the short-circuit assessment requirements for the near-term horizon. Unlike its steady-state and stability counterparts, there are no requirements stipulated for short-circuit analysis for the long-term horizon. Is this intentional? If so, we are unable to identify the rationale for this decision. If not, we suggest revising Part 2.3 to: "The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the near-term and long-term Transmission Planning Horizons and can be supported by...". Under 2.7.2, it is not clear how an entity can provide rational for why actions are not necessary. If actions are not necessary, then no rationalizing is needed. Further, as stated above, corrective action plans should not be required for sensitivity studies. R2.7.2 should be struck. We propose to remove R2.9, since there is not a reliability need for this information and it is unnecessary. AESO does not comment on VSLs or VRFs.
Response: For Part 2.1.4, the requirement for Corrective Action Plans to address any needs identified in the sensitivity cases is included in Part 2.7. Part 2.7 states, in part, that “Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. In addition, Part 2.7.2 describes the requirement on Corrective Action Plans to “Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary”. For Parts 2.1.4 and 2.4.3, the SDT envisions that “credible”, “sufficient”, “stressed” conditions and “measurable change” are to be defined by the responsible Planning Coordinator or Transmission Planner because each System is different.	

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Part 2.3 is intended for the Planning Coordinator and Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt. The standard allows the Planning Coordinator and Transmission Planner to coordinate on who would perform short circuit studies. But each is still responsible for meeting the requirements. Part 2.3 is for short circuit assessment of the system in general and is more suited for the Near-Term Transmission Planning Horizon, when Transmission plans are more certain. Lead time to implement corrective action if found necessary can reasonably be expected to be completed in the near-term timeframe. Short circuit study for the longer term planning horizon should be studied on a case by case basis associated with specific project(s). The SDT disagrees that Part 2.7.2 should be struck. Part 2.7.2 provides for development of a Corrective Action Plan if a number of sensitivity studies result in the same potential problem. For example, if only one sensitivity study results in potential problems or if the probability of occurrences of the sensitivity scenarios is low, then this could be the rationale to state that corrective action plan would not be necessary. Part 2.9 has been deleted as suggested.	
Exelon Transmission Planning	We believe that the Table 1 performance criteria should be based on the voltage level of potentially overloaded elements and not based on the voltage level of the element(s) removed from service. If a 100 kV line were overloaded for a 500 kV contingency, it does not make sense to us to treat it differently than if the same overload occurred for a 100 kV contingency since the severity of the event is the same in both cases. The availability of load shedding to reduce overloads on EHV equipment and not for overloads on HV equipment makes sense since typically a greater amount of load would need to be shed to unload an EHV facility than an HV facility. We disagree with the requirement to report the largest amount of consequential load loss. If this information is not used to meet a requirement adding to reliability, it is creating undo burden. If the requirement is kept, it should be made clear as to which case or cases the requirement pertains. The Planning Assessment will contain extremely sensitive information. The threshold that it must be supplied to ANY functional entity is too low. There should be a CEII or other process to ensure that this information is adequately protected.
Response: The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined. Changes were made to footnote 1 to better clarify the SDT's intent and it now reads: **Table 1, footnote 1**: If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. Part 2.9 has been deleted based on industry responses.	
American Transmission Company	We propose the following changes and following questions:New R2.1 We suggest that R2.6 be relocated to the R2.1 position to allow the preferred style of backward references to text that occurs earlier in a document, rather than forward references to text that appears later in a document.

Organization	Comments for Question 2
	R2.1.3 As noted above, we suggest that R1.1.2 be removed and that R2.1.3 be revised to state that "Known outages of generation or Transmission Facilities with a duration of at least six months be simulated along with P1 events for the System peak or Off-Peak conditions when the outages are scheduled to occur." We interpret that simulation of known outages of at least six months should refer only to individual outages with duration of six months or more have to be simulated and not a set of sequential (back-to-back) outages where each individual outage is less than six months, but the composite duration of the set is more than six months. We also interpret that if two or more known outages with duration of at least six months are overlapping that the outage would be simulated as simultaneous for the System peak or Off-Peak conditions when the overlapping outages are scheduled to occur. R2.1.4 The terms of "credible" and "measurable change" are ambiguous and not defined. Therefore, we suggest that these terms be defined or more clearly described to avoid the risk of different and possibly contradictory interpretations by TPs, PCs, and auditors.R2.1.4 bullet items We suggest that the number and description of the bullet items in R2.1.4 match the bullet points in R2.4.3. Otherwise, please explain the reasons for any differences between the bullet items in R2.1.4 and R2.4.3. R2.1.4 bullet #2 & # 5 We suggest that the wording of bulletin #2 be changed to "Expected transfers and other generation dispatch scenarios". This modification would put the transfer and dispatch element, which are complementary, together in the same bullet item, rather than grouping the "generation dispatch" (operating level) element together with the generation capacity elements in bullet item #5. R2.1.4 bullet #7 We propose replacing the adjective "planned" with "known" for consistency with R2.1.3 and any other "known" references in the standard. R2.1.5 We propose replacing the term "major Transmission" with "BES" because BES is a well defined term, while "major Transmission" is not. New R2.3.1 We suggest the addition of new R2.3.1 to emulate the distinction between the requirement to perform a short circuit assessment and conduct required studies or analysis to support the assessment (e.g. R2.1/R2.1.1 and R2.2/R2.2.1). We propose wording such as, "Perform an analysis for at least one year in the Near Term Transmission Planning Horizon." This requirement would set an expectation that an analysis should be conducted to at least one or more years in the near-term planning horizon, rather than imply that an analysis of all five years in the near-term planning horizon must be conducted. R2.4.1 - The terms of "study area" and "represents" are ambiguous and not defined. Therefore, we suggest that these terms be more clearly described to avoid the risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. R2.4.3 The terms of "credible" and "measurable change" are ambiguous and not defined. Therefore, we suggest that these terms be defined or more clearly described to avoid the risk of different and possibly contradictory interpretations by TPs, PCs, and auditors.R2.4.3 bullet items We suggest that the number and description of the bullet items in R2.1.4 match the bullet points in R2.1.4. Otherwise, please explain the reasons for any differences. R2.4.3 bullet #2 & # 5 We suggest that the wording of bulletin #2 be changed to "Expected transfers and other generation dispatch scenarios". This would place these similar items in the same bullet item #2, rather than having the "other generation dispatch" in bullet item #5.

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	R2.4.3 bullet #3 We suggest that the wording of "new or modified Transmission Facilities" to agree with the wording in bulletin #3 of R2.1.4. R2.6 As noted earlier, we suggest that the numbering of this requirement be changing it to R2.1 to avoid the style of forward references. Add R2.7.1 Item #7 - We propose the addition of the following bullet item to R2.7.1 because any requirement in the head notes or foot motes of Table 1 should occur within the body of standard. Item #7 could read, "Planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration of the Facility Ratings." Note "e" in the Planning Events, Steady State & Stability section is stated in the form of a Requirement (e.g. use the verb "shall"), but all requirements should be included in the Requirements section and not introduced (and basically hidden) in the performance notes of Table 1. [After bullet item #7 is added, Note "e" under "Steady State & Stability section of Table 1 should refer to R2.7.1] R2.7.2 " We suggest using the term, "mitigation actions", to more clearly distinguish that this requirement is not asking for the development of "Corrective Action Plans", such as those that are needed for inability to meet base case performance requirements.R2.7.6 We suggest that the wording of R2.7.6 be the same as R.2.8.2. Otherwise, we propose that R2.7.6 and R2.8.2 be revised with wording like, ". . . implementation status of identified Corrective Action Plans for System Facilities and Operating Procedures." to clarify that the identified system facilities and operating procedures refer only to those that were in the previous year's Corrective Action Plans. R2.9 We still propose that this requirement be removed because annually stating the single, largest expected, Consequential Load Loss due to a P1 or P2 event in the TP or PC system is not needed to provide reliable BES performance or assure open and transparent Transmission planning peer review.

Response: The SDT reviewed the order of Parts 2.1 and 2.6 and declines to modify it as suggested because it does not add additional clarity.

Part 2.1.3 covers known long duration outages, for example, taking a 230 kV Transmission line out of service to rebuild it to operate at 500 kV. These cases are to simulate System conditions with the Facility in question out of service as Category P0 (or N-0). For the next outage, the System performance will need to meet requirements for Category P1. This is not the same as requirements for Category P6, which assumes that the outage for the first Facility would be of shorter duration than 6 months. Part 2.1.3 has been revised to read "P1 events in Table 1 with known outages modeled, as in Requirement R1, part 1.1.2 under those System peak or Off-Peak conditions when known outages are scheduled" to provide more clarity. The SDT agrees that if two or more known outages with duration of at least six months are overlapping that the outage should be simulated as simultaneous for the conditions when the overlapping outages are scheduled to occur. This is consistent with the requirement to simulate the System conditions as it is expected to operate.

For Parts 2.1.4 and 2.4.3, the SDT envisions that "credible", "sufficient", "stressed" conditions and "measurable change" are to be defined by the responsible Planning Coordinator or Transmission Planner because each System is different. The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within Parts 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and Stability evaluations, respectively.

Requirement R2, part 2.4.3, **bullet #3**: Expected in service dates of new or modified Transmission Facilities

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	The SDT declines to change the second and fifth bullets in Part 2.4.3 because the existing arrangement will keep the generator scenarios together. Expected transfers are not always associated with generation dispatch. In Part 2.1.4, bullet #7, the SDT declines to replace "planned" with "known" as suggested in "Duration or timing of planned Transmission outages". Part 2.1.4 covers sensitivity scenarios and reflects uncertainty in planning assumptions. The intent of this bullet is to cover unexpected changes in plans, for example, a potential delay in returning a Transmission line back to service after a planned outage of 6 months or more for rebuilding to a higher capacity line. If the outage is "known", then there would not be any need to perform this study as a sensitivity. In Part 2.1.5, the SDT declines to replace the term "major Transmission equipment" with "BES equipment" because the intent is to investigate the unavailability of major pieces of equipment in the Transmission System. Transmission is defined in the NERC Glossary as, "An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems". Part 2.3 is silent on the year of study within the Near-Term Transmission Planning Horizon. Therefore, it is up to the Transmission Planner or Planning Coordinator to select the study years most suited to the System in question. In addition, Part 2.3 only requires an annual Planning Assessment, which is to be supported by annual current or qualified past studies. As such, the SDT believes it is inappropriate to make the change as suggested Part 2.4.1: The SDT believes that the terms of "study area" and "represents" should be defined by the Planning Coordinator or Transmission Planner performing the study, and should be part of the coordination between the entities. For Parts 2.1.4 and 2.4.3, The SDT envisions that "credible", "sufficient", "stressed" conditions and "measurable change" are to be defined by the responsible Planning Coordinator or Transmission Planner because each System is different. The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within Parts 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and stability evaluations, respectively. **Requirement R2, part 2.4.3**, **bullet #3**: Expected in service dates of new or modified Transmission Facilities The SDT declines to change the second and fifth bullets in Part 2.4.3 because the existing arrangement will keep the generator scenarios together. Expected transfers are not always associated with generation dispatch. The SDT reviewed the order of Part 2.1 and Part 2.6 and declines to modify it as suggested because it does not add additional clarity. Note e in Table 1 is a condition for allowance of planned System adjustments, which could include Operating Plans such as re-dispatch. Part 2.7.1 is a list of examples, so it could include more items than listed, including Note e in Table 1. The SDT declines to make the suggested change. Part 2.7.2 provides for development of a Corrective Action Plan if a number of sensitivity studies result in the same potential problem. For example, if only one sensitivity study results in potential problems or if the probability of occurrences of the sensitivity scenarios is low, then this could be the rationale to state that corrective action plan would not be necessary. Part 2.9 has been deleted as suggested.
PJM	R2 should use the term –dynamics analysis- instead of –stability analysis-. A dynamics study is used to determine stability like a power flow study is used to determine overloads or voltage violations. In R2.1.1 is -System peak Load- seasonal peak load or the peaking season of that region? For example, if I'm a summer peaking

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	region, must I do a summer peak study and a winter peak study or just a summer peak study? In R2.1.3, change -for known outages, as modeled in- to –with known outages modeled, as required in-. R2.1.5 should be made clear that only one piece of equipment should be taken out at a time for each sensitivity. No matter what FERC says, this requirement should be deleted because this analysis serves no purpose. If a spare equipment strategy is required, please tell us so in a spare equipment standard, not hidden here in a performance standard. R2.4.3 – Please delete the words -for the list of items shown below- at the end of the first sentence. There is an implication in this sentence, as originally worded, that a sensitivity must be performed for the entire list of sensitivities instead of how it is explained in the second sentence. R2.6.2 – Please reword -the study shall not include any material changes- to –a study with material changes shall not be used- The old sentence sounded like you just exclude the material changes and you are good to go. R2.7.1 – Please change -List System deficiencies- to –List performance deficiencies-. R2.7.1 – 3rd Bullet – I would lump this under Special Protection Systems, also why is runback not allowed for dynamics problems, seems there are some restrictions buried here. R2.7.1 – 6th Bullet – What is a –rate application-? R2.7.2 – This is pushing us to plan the system for scenarios that may never happen. Pushing us to some higher level of reliability will cost significant money. Should the ratepayers be burdened with this excess? I say no, remove this requirement. R2.8.1 – Change -List System deficiencies- to –List short circuit deficiencies-.

Response: The SDT declines to replace "Stability analysis" with "dynamic analysis" because it does not add additional clarity.

The intent of Part 2.1.1 is to assess those System conditions under peak Load conditions when the System is reasonably stressed. It is envisioned that the Planning Coordinator or Transmission Planner will determine the System conditions for its planning studies.

Part 2.1.3 has been revised as suggested.

> **Requirement R2, part 2.1.3**: P1 events in Table 1 with known outages modeled, as in Requirement R1, part 1.1.2 under those System peak or Off-Peak conditions when known outages are scheduled.

Part 2.1.5 only requires that the Planning Coordinator or Transmission Planner plans for the potential unavailability of long lead time major Transmission equipment in accordance with its spare equipment strategy. For example, if an entity's spare equipment strategy is to have a spare transformer on site, then the unavailability of a similar transformer (due to outages) would be limited to the time it would take to energize the spare transformer. Assuming that this time is no more than that required to return a similar outaged transformer back in service, Part 2.1.5 can be satisfied without performing additional planning studies. If on the other hand, the transformer would have to be purchased, then it would take more than a year to replace. In this case, P0 should be modeled with the transformer in question out of service.

Part 2.4.3 has been revised as suggested.

> **Requirement R2, part 2.4.3**: For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of

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	the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: Part 2.6.2 has been revised as suggested. **Requirement R2, part 2.6.2**: For steady state, short circuit, or Stability analysis: the System represented in the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. The SDT declines to revise Part 2.7.1 as suggested because it does not add additional clarity. The SDT declines to combine the third bullet with Special Protection Schemes (SPS) because automatic generation tripping does not always have to be part of an SPS. In any case, this list contains examples only. It is envisioned that run-back would take a longer time period and would not fit in the transient Stability study period. Part 2.7.1, sixth bullet, "rate application" can be regulatory incentives, such as demand response, distributed generation, etc. Part 2.7.2 provides for development of a Corrective Action Plan if a number of sensitivity studies result in the same potential problem. For example, if only one sensitivity study results in potential problems or if the probability of occurrences of the sensitivity scenarios is low, then this could be the rationale to state that corrective action plan would not be necessary. In addition, Part 2.7.1 allows the use of lower cost alternatives, such as operating procedures, among other things to correct potential performance deficiencies identified. The SDT declines to revise Part 2.8.1 because the language as written is clear.

3. Requirement R3 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: The SDT has modified the wording of several parts of Requirement R3 to increase clarity as requested by many industry comments and shown below. Requirement R3, part 3.6 was deleted in response to industry comments as it is not a performance oriented requirement.

Requirement R3, part 3.3: Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

Requirement R3, part 3.3.2: Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

Requirement R3, part 3.3.3: Trip Transmission elements when relay loadability limits are exceeded.

Requirement R3, part 3.5: Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

Requirement R3, part 3.6:

Requirement R3, data retention: The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.

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Independent Electricity System Operator	(1) R3 has become more of a “how to” requirement than a “what” requirement, as illustrated below. (a) Part 3.3 is overly prescriptive. A requirement that says contingency analysis shall be performed which reflect proper operation of all Protection Systems and actions of all automatic devices would suffice. If necessary, some examples such as those listed in Part 3.3.4 may be added as illustration. (b) The parts that ask for creating a list of contingencies and having rationale available as supporting information, in Part 3.4 for example, are overly prescriptive and unnecessary. These are documentation requirements, not reliability requirements. If one asked the question: will reliability be adversely affected if the responsible entity failed to document the list and the rationale for choosing this list? If the answer is no, then they don’t rise up to a reliability standard. To meet the intent of Part 3.4, a simple requirement that asks the responsible entity to demonstrate acceptable system performance for the applicable planning events in Table 1 would suffice. Table 1 already stipulates the events that must be considered in the analysis. We do not see the need to go into such details as “some events are expected to produce more severe impacts”, and the need to ask the planners to

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	create a list of these more impactive contingencies for subsequent evaluation. Similar observation is made for Part 3.5 on the extreme event list and for Part 3.6 for the amount of generation loss, and the rationale. (2) We have no comments on the measure, VRF and Time Horizon. However, there is no VSL for Part 3.6.
Response: R3: The SDT disagrees with the comment. The parts of Requirement R3 specify the components required for a compliant study. No change made. Part 3.4 & Part 3.5: Require the planning entity to identify which Contingencies are chosen to be simulated in the study, and explain why these are chosen. The SDT assumes that the Planning Coordinator/Transmission Planner, applying experience of past studies and knowledge of its System, is in the best position to determine which Contingencies in Table 1 are most relevant, as it is impossible to study all Contingencies especially the multiple Contingency events. No change made. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES. VSL for Part 3.6: The SDT has deleted Part 3.6.	
ERCOT ISO	* Will any agreements made in R7 override the “each TP and PC” requirement? To clarify this, the requirement could be rephrased: "In accordance to the responsibilities assigned in R7, the responsible Transmission Planners and Planning Coordinators shall perform?. "* Section 3.1 and 3.4 appear to be related. Confusing references can be eliminated by combining them and removing 3.4 as follows: "3.1. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES shall be identified and studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1. A list of those Contingencies and the rationale for those Contingencies selected for evaluation shall be available as supporting information".* Similarly, Section 3.2 and 3.5 appear to be related. Confusing references can be eliminated by combining them and removing 3.5: "3.2. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and studies shall be performed to assess the impact of the extreme events. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted A list of the events and the rationale for those Contingencies selected for evaluation shall be available as supporting information."
Response: R7: The agreements required by Requirement R7 are intended to clarify the responsibilities among the Planning Coordinator and Transmission Planner. The SDT believes this is clear in the existing language. No change made. Parts 3.1 & 3.4: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Parts 3.2 & 3.5: The SDT does not believe that combining the requirements provides any significant advantage. No change made.	
Northeast Utilities	[R3.3.2] Traditionally, transmission planners have assumed that generators would ride through low voltages associated with Planning Events, which is generally adequate for non-wind generators. If this standard is going to require its incorporation into the assessments, there should be a MOD standard developed requiring the generator owners to provide the necessary

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	information prior to its inclusion as a requirement in this standard. [R3.3.3] This requirement is already addressed in NERC Standard PRC-023 and reflected in facility ratings and therefore, should be removed from TPL-001-1. [R3.5] This requirement needs clarification as to what is specifically required for the "evaluation of possible actions". Otherwise the following is recommended: It should be clear that an evaluation does not require solution development for all Extreme Events. Change "an evaluation of possible actions" to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered." [R3.6] Why the need to report the amount of "Consequential Generation Loss" since TPL-001-1 does not impose any limit or reliability consequence? We recommend that this requirement be deleted from the standard.
Response: Part 3.3.2: Where test data is not available, the SDT believes that most Transmission Planners/Planning Coordinators currently assume generators ride through low voltage based on extensive field experience. There is a project (Project 2007-09 — Generator Verification) that will provide the required generator data to validate the assumptions. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure that the simulation models the generator response as it will react in the real world. If voltage ride through limits would cause a generator to trip in the real world, the study must determine if the performance requirements are met for the initiating event and subsequent generator trip. No change made for this comment. Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.5: The requirement is to evaluate possible actions which, if implemented, could reduce the likelihood or mitigate the consequences of an extreme event. The SDT believes that what these "possible actions" are should be left to the judgment of the Planning Coordinator/Transmission Planner who has knowledge of their System. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.	
Central Maine Power Company	3.2 Item 3.2 should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. 3.3.2 This requirement is not practical unless a MOD is created so that known minimum generator steady state or ride through voltage limitations are used instead of assumed values. To create a MOD, collect the data, and incorporate the information into the studies will take time, which necessitates the need for an implementation period. Absent accepting this suggestion with respect to creating an MOD, please provide assumed minimum generator steady state or ride through voltage limitations as a standard reference for this analysis. 3.3.3 There appears to be a compliance double-jeopardy issue related to relay loadability. Relay loadability is handled in

Organization	Comments for Question 3
	greater detail (as it should be) under the proposed PRC-023 standard, so any reference here should be deleted. 3.4 It is suggested that this requirement is made a sub-bullet of Requirement 3.1 to keep the related requirements together. 3.5 and 4.5 Both of these requirements need clarification as to what is specifically required for the "evaluation of possible actions." 3.5 It is suggested that this be made a sub-bullet of Requirement 3.2 to keep the related requirements together. 3.6 Item 3.6 should be deleted since there is no limit defined in the standard.
ISO New England	3.2 Item 3.2 should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. 3.3.2 This requirement is not practical unless a MOD is created so that known minimum generator steady state or ride through voltage limitations are used instead of assumed values. To create a MOD, collect the data, and incorporate the information into the studies will take time, which necessitates the need for an implementation period. Absent accepting this suggestion with respect to creating an MOD, please provide assumed minimum generator steady state or ride through voltage limitations as a standard reference for this analysis. 3.3.3 There appears to be a compliance double-jeopardy issue related to relay loadability. Relay loadability is handled in greater detail (as it should be) under the proposed PRC-023 standard, so any reference here should be deleted. 3.4 It is suggested that this requirement is made a sub-bullet of Requirement 3.1 to keep the related requirements together. 3.5 and 4.5 Both of these requirements need clarification as to what is specifically required for the "evaluation of possible actions." 3.5 It is suggested that this be made a sub-bullet of Requirement 3.2 to keep the related requirements together. 3.6 Item 3.6 should be deleted since there is no limit defined in the standard.
United Illuminating	3.2 Item 3.2 should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. 3.3.2 This requirement is not practical unless a MOD is created so that known minimum generator steady state or ride through voltage limitations are used instead of assumed values. To create a MOD, collect the data, and incorporate the information into the studies will take time, which necessitates the need for an implementation period. Absent accepting this suggestion with respect to creating an MOD, please provide assumed minimum generator steady state or ride through voltage limitations as a standard reference for this analysis. 3.3.3 There appears to be a compliance double-jeopardy issue related to relay loadability. Relay loadability is handled in

Organization	Comments for Question 3
	greater detail (as it should be) under the proposed PRC-023 standard, so any reference here should be deleted. 3.4 It is suggested that this requirement is made a sub-bullet of Requirement 3.1 to keep the related requirements together. 3.5 and 4.5 Both of these requirements need clarification as to what is specifically required for the "evaluation of possible actions." 3.5 It is suggested that this be made a sub-bullet of Requirement 3.2 to keep the related requirements together. 3.6 Item 3.6 should be deleted since there is no limit defined in the standard.
Response: Part 3.2: The SDT disagrees and believes there is value in running extreme event analysis to test the robustness of the System. No change made. Part 3.3.2: Where test data is not available, the SDT believes that most Transmission Planners/Planning Coordinators currently assume generators ride through low voltage based on extensive field experience. There is a project (Project 2007-09 — Generator Verification) that will provide the required generator data to validate the assumptions. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure that the simulation models the generator response as it will react in the real world. If voltage ride through limits would cause a generator to trip in the real world, the study must determine if the performance requirements are met for the initiating event and subsequent generator trip. No change made. Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.4: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Parts 3.5 & 4.5 The requirement is to evaluate possible actions which, if implemented, could reduce the likelihood or mitigate the consequences of an extreme event. The SDT believes that what these "possible actions" are should be left to the judgment of the Planning Coordinator/Transmission Planner whose has knowledge of their System. Part 3.5: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.6: Part 3.6: The SDT has deleted part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.	
Florida Municipal Power Agency, and its Member Cities	3.3.1, is the intent of the SDT that extreme events that may cause loading beyond relay trip settings (especially Zone 3) be simulated? There is no need for 3.3.3 since the Facility Ratings should already take this into account (FAC-008, R1.2.1 The scope of equipment addressed shall include, but not be limited to, " relay protective devices, "). This adds unneeded burden to transmission planners in developing evidence for this that already exists elsewhere. In other words, by respecting Facility Ratings, we respect relay loadability.
Response: Part 3.3.1: The intent of the SDT is for the planner to simulate the Protection System operation so that all elements that the Protection System is designed to remove (breaker to breaker) are removed in the simulation for the list of Contingencies the planner has developed in Requirement R3, parts 3.4 (planning events)	

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and 3.5 (extreme events). Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded.	
Oncor Electric Delivery	3.3.2 Do we want to be able to trip gen? 3.3.3 Relay loadability covered in PRC-023 3.6 Why is this information reported if there is no limit or reliability consequence. 3.3.3 This requirement is already addressed in NERC Standard PRC-023 and reflected in the facility's rating and should be removed from TPL-001-1. 3.4 It is strongly suggested that this requirement is made a sub-bullet of Requirement 3.1 to keep the related requirements together. 3.5 and 4.5 Both of these requirements need clarification as to what is specifically required for the "evaluation of possible actions." 3.5 It is strongly suggested that this be made a sub-bullet of Requirement 3.2 to keep the related requirements together. 3.6 It is recommended that the "consequential generation" loss is excluded from the amount documented. [Why?]
Response: Part 3.3.2: In order to ensure performance requirements are met in cases where System conditions could cause a generator to trip, Requirement R3, part 3.3.2 requires that the entity trip a generator at locations where bus voltages in the simulation fall below known or assumed generator steady state or ride through voltage limits. No change made. Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded. Part 3.4: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Parts 3.5 & 4.5 The requirement is to evaluate possible actions which, if implemented, could reduce the likelihood or mitigate the consequences of an extreme event. The SDT believes that what these "possible actions" are should be left to the judgment of the Planning Coordinator/Transmission Planner who has knowledge of their System. Part 3.5: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.	

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FirstEnergy Corp	A. The inclusion of sub-part 3.3.3 of Requirement R3 that reads "Ensure relay loadability limits are respected" is not needed as it is duplicative with standard PRC-023, and indirectly redundant with the facility rating standards FAC-008 and FAC-009. Additionally, the introductory notes of performance Table 1 item "f" is clear that Facility Ratings shall not be exceeded and PRC-023 makes it clear that relay loadability must be accounted for in Facility Ratings. In NERC's three-year assessment, Attachment 2 it clearly indicates that one goal of NERC's standards development work plan is " ...retiring redundant requirements ..." (Please reference page 4, the 6th bullet under plan objectives). To that end, we should not knowingly create redundant requirements that lead to double jeopardy issues for industry stakeholders. If a "belts and suspenders" is the goal here, it's suggested that a footnote be added to item "f" of the introductory notes that would clarify that PRC-023 must be adhered to with regard to Facility ratings. B. If the generator bus is modeled at the generator voltage, then this should be the reference voltage point. If the generator is modeled directly connected to the BES, then the transmission voltage should be the reference voltage. Either way, the reference point should be consistent. In addition, 3.3.2 requires the unit to be tripped. It should be noted that the minimum voltage point may be overly-conservative, since the minimum voltage that a unit can stay on line is MVA output dependent. For base load units, determining a generator minimum voltage should be relatively straightforward, however, peaking and regulating units, not so. Our experience has been that generating units at manned locations generally do not have undervoltage protection or alarms, so FE is not certain how this Requirement to trip those units matches the "real world". C. We suggest the team discontinue the use of "Coordinate with adjacent transmission planners" in regards to sub-part 3.4.1 related to the inclusion of contingencies from adjacent systems. The "coordination" type of requirements creates a need to develop compliance evidence such as e-mail correspondence, meeting minutes etc that serve no real reliability purpose. The requirement should simply be that the TP shall include adjacent System contingencies expected to produce the more severe System impacts on their system. In fact, sub-part 3.4 already includes that language. We suggest the team append the sentence "The planning event contingencies shall include:" to the end of sub-part 3.4 followed by two bullets that indicate 1) events within the TP's system and 2) events on adjacent transmission Systems.
Response: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded. Part 3.3.2: Where test data is not available, the SDT believes that most Transmission Planners/Planning Coordinators currently assume generators ride through low voltage based on extensive field experience. There is a project (Project 2007-09 — Generator Verification) that will provide the required generator data to validate the assumptions. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure that the simulation models the generator response as it will react in the real world. If voltage ride through limits would cause a generator to trip in the real world, the study must determine if the performance requirements are met for the initiating event and subsequent generator trip. No change made. Part 3.4.1: SDT believes that it is necessary for the planner to coordinate with adjacent planners to identify contingencies in adjacent systems that could impact the planners system. No change made.	
Progress Energy Florida, Inc.	As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all

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	appropriate parties to review PEF's previous comments to this effect.
Response: Throughout the drafting process, the SDT has carefully considered your comments as well as comments from other industry members.	
CenterPoint Energy	CenterPoint Energy recommends references to "Long-Term Transmission Planning Horizon" be revised to contain comparable language as in the existing TPL standards that limit Long-Term studies to marginal system conditions requiring longer lead times. See CenterPoint Energy's comments regarding part 2.2 for the rationale behind this recommendation. CenterPoint Energy also recommends deleting part 3.4.1 as being overly prescriptive and difficult to demonstrate in an audit.
Response: Long-Term Transmission Planning Horizon: The SDT believes there is value in taking a long range view in planning to assess the general trend. Since the Long-Term planning horizon is year 6 – year 10, the Planning Coordinator or Transmission Planner can for example, select year 6 in the Long-Term Planning Horizon and then use this study as the past study to supplement the Near-Term year 5 study requirement the following year. No change made. Part 3.4.1: SDT believes that it is necessary for the planner to coordinate with adjacent planners to identify Contingencies in adjacent Systems that could impact the planners System. No change made.	
ITC Holdings	Comments: Assumptions regarding Low Voltage Ride Through (LVRT) capability are risky and not well understood. If the SDT feels this is a critical requirement that merits corrective action then we believe LVRT characteristics for various machine types should be developed through a NERC process. Without such "standards", it will be difficult to justify CAPs based on LVRT assumptions. For example, would the Transmission Owner (TO) or Generator Owner be responsible for the cost of VAR CAPs if an LVRT assumption were violated. Can a TO require an LSE to install automatic load shedding for an LVRT assumption when cascade or local load loss result from an LVRT assumption? In addition, as the SDT has already indicated, the industry is still in a learning curve regarding the dynamic behavior of certain loads. If LVRT capability is considered as a critical requirement, then what about High Voltage Ride Through (HVRT) capability? The violation of HVRT could also cause certain damages to the system. R3.4.1 (contingency list coordination with neighbors) It's unclear as to the "measure" for this requirement. Do you give your neighbor a list of "contingencies" in your area. Should it include all categories (p1 thru p7 for example)? Does your neighbor have to study a cascade situation in his system caused by an outage in your system? Are joint studies merited? More importantly, if an outage in a neighboring system requires a CAP, who's responsible, particularly if the CAP involves the neighboring system. Does the neighbor have to have a CAP, according to this standard, if the violation is in your system, and the CAP is in his? Who pays? Are you putting a study burden on your neighbor when you do this? Do you include additional contingencies to ensure that you do not miss a contingency that might impact your neighbors system to avoid any potential compliance implication on you?
Response: Part 3.3.2: Where test data is not available, the SDT believes that most Transmission Planners/Planning Coordinators currently assume generators ride through low voltage based on extensive field experience. There is a project (Project 2007-09 — Generator Verification) that will provide the required generator data to validate the assumptions. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure that the simulation models the generator response as it will react in the real world. If voltage ride through limits would cause a generator to trip in the real world, the study must determine	

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if the performance requirements are met for the initiating event and subsequent generator trip. No change made. If tripping of a generator results in performance which does not meet the requirements in Table 1, Requirement R2, part 2.6 requires the planner to develop a Corrective Action Plan. The allocation of costs to implement such a plan is beyond the scope of this standard. The SDT has decided not to include a requirement for high voltage ride through. Part 3.4.1: SDT believes that it is necessary for the planner to coordinate with adjacent planners to identify Contingencies in adjacent Systems that could impact the planners System. No change made. The SDT believes that the methodology for determining the appropriate Contingencies in the adjacent Systems is best left to the judgment of each planner. This could include Contingencies from all planning event categories (P1 to P7) if it is judged they could have an impact. Similarly, the neighboring System would select categories in adjacent Systems to study. The requirement does not mandate joint studies. If a performance deficiency is found in the planner's System due to a Contingency in an adjacent System, it is up to the planner in whose System the deficiency exists to develop the CAP. Cost allocation for the CAP is beyond the scope of this standard.	
FRCC Transmission Working Group	Comments: With regard to the Moderate VSL, consider deleting "utilizing data" in order to avoid penalizing twice for failing to meet R1. Please provide clarity to 3.3.2 which states that a Planning Assessment "it must perform simulation that show generator ride through voltage limitation". However, ride through is only performed through stability simulation.The references within the requirements are very confusing. 3.1 refers to a contingency list created in 3.4 which refers back to 3.1. Similarly 3.2 refers to a contingency list created in 3.5 which refers back to 3.2. These should be combined into one requirement bullet. Please provide clarity to 3.3.1. Is the intent of the drafting team that extreme events that may cause loading beyond relay trip settings (zone 3) be simulated?
Response: VSL: Requirement R1 requires you to maintain System models. Requirement R4 requires you to use that model data for your Stability studies. These are two different things requiring two VSLs. No change made. Part 3.3.2: Generators can trip when bus voltage drops below minimum generator steady state voltage limits. The SDT believes that the voltage ride through test is applicable in post-Contingency steady-state where the planner would know if post-contingency bus voltage violates generator trip points. If a trip point is violated, Requirement R3, part 3.3.2 would require the planner to remove the generator in the post-Contingency case to assess if performance is met with the generator removed. No change made. Parts 3.1 & 3.4; 3.2 & 3.5: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.3.1: The intent of the SDT is for the planner to simulate the Protection System operation so that all elements that the Protection System is designed to remove (breaker to breaker) are removed in the simulation for the list of Contingencies the planner has developed in Requirement R3, parts 3.4 (planning events) and 3.5 (extreme events). Requirement R3, Part 3.3 wording has been modified to add to clarify the intent. **Requirement R3, part 3.3**: Contingency analyses for Requirement R3, parts 3.1 & 3.2 shall:	
Gainesville Regional Utilities	Even though I do assess my portion of the BES, I do so, not in an isolated, detached vacuum, but in light of its active connection to the rest of the FRCC Region and how, if at all possible, my small system could in any way be determined at the region level

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	to have any impact in any of the functional areas of the entire region. So the requirements in this section are considered and assessed as "a part of the whole".
Response: As you have not referenced a specific section, the SDT can not provide a response.	
Utility System Efficiencies, Inc. (USE)	For clarity I suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits.
Bonneville Power Administration	For clarity we suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits.
Idaho Power	For clarity we suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits.
NV Energy	For clarity we suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits."
San Diego Gas & Electric Co	For clarity we suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits.
Southern California Edison (SCE)	For clarity we suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits."
SRP	For clarity we suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits."
Western Area Power Adm - RMR	For clarity, I suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits."
Deseret Power	Comments: For clarity we suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits.
Response: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded.	
TVA System Planning	In R3.3.3, TVA believes that relay loadability is already covered in PRC-023. TVA is concerned that including this requirement could result in possible double jeopardy if a utility was found non compliant with PRC-023. Is the SDT proposing that relay

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	loadability be covered for all BES facilities or just those facilities identified in PRC-023?
Response: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded. The SDT intent is that Requirement R3, part 3.3.3 applies to those BES elements where relay loadability limit is defined by PRC-023.	
Modesto Irrigation District Transmission Planning	For clarity we suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits. Also please define relay loadability limit.
Response: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded. R3.3.3: Relay loadability is defined in PRC-023-1.	
MidAmerican Energy Company	MidAmerican commends the SDT for their hard work on this standard. MidAmerican does have comments about this requirement though. MidAmerican recommends the data retention for R3 and M3 be revised to change "All" to "The". The word "All" is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: "THE studies performed in support". The word in all caps is a word suggested to be added.
Response: Data Retention: The SDT agrees with your suggestion. The wording in "data retention" for R3 has been changed. Measure M3 already use the word "the". **Requirement R3, data retention:** The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.	
Progress Energy Carolinas	PEC believes that R3.3.3 "Ensure relay loadability limits are respected" is unnecessary. The requirement to stay within Facility Limits is much more bounding. Several footnote references from Table 1 to the footnotes are incorrect.
Response: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Table1: The SDT has corrected the footnote references.	

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Oklahoma Gas & Electric	R 3.4, R3.5 There appear to be no standards of directions on identifying severe or extreme system impacts. OG&E does not like being held accountable to nebulas standards. Need more specific information.
Response: Parts 3.4 & 3.5: The SDT assumes that the Planning Coordinator/Transmission Planner applying experience of past studies and knowledge of its System is in the best position to determine which Contingencies in Table 1 are most relevant, as it is impossible to study all Contingencies especially the multiple Contingencies. No changes made.	
SRC of ISO/RTO	R3 has become more of a "how to" requirement than a "what" requirement as illustrated below. (a) Part 3.3 is overly prescriptive. A requirement that says contingency analysis shall be performed which reflect proper operation of all Protection Systems and actions of all automatic devices would suffice. If necessary, some examples such as those listed in Part 3.3.4 may be added as illustration. (b) The parts that ask for creating a list of contingencies and having rationale available as supporting information, in Part 3.4 for example, are overly prescriptive and unnecessary. These are documentation requirements, not reliability requirements. If one ask the question: Will reliability be adversely affected if the responsible entity failed to document the list and teh rationale for choosing the list? and the answer is no, then the requirement does not rise up to a reliability standard. To meet the intent of Part 3.4, a simple requirement that asks the responsible entity to demonstrate acceptable system performance for the applicable planning event in Table 1 would suffice. Table 1 already stipulates the event that must be considered in the analysis. We do not see the need to go into such details as "some events are expected to produce more severe impacts...", and the need to ask the planners to create a list of these more impactive contingencies for subsequent evaluation. Similar observation is made for Part 3.5 on the extreme event list and for Part 3.6 for the amount of generation loss, and the rationale. AESO does not comment on VSLs or VRFs>
Response: R3: The SDT disagrees with the comment. The parts of Requirement R3 specify the components required for a compliant study. No change made. Part 3.4 & Part 3.5: Require the planning entity to identify which contingencies are chosen to be simulated in the study, and explain why these are chosen. The SDT assumes that the Planning Coordinator/Transmission Planner, applying experience of past studies and knowledge of its System, is in the best position to determine which Contingencies in Table 1 are most relevant, as it is impossible to study all Contingencies especially the multiple Contingency events. No change made. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES. VSL: The SDT does not understand the reference to AESO.	
Manitoba Hydro	R3.2: Recommend changing “the list” to “the Contingency list” to add clarity and consistency.
Response: Part 3.2: SDT does not believe clarity is improved by adding the word "contingency" to the word "list". No change made.	

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MRO NERC Standards Review Subcommittee	R3.3.1 Revise the wording to add, ". . . including the simulation of transmission circuit loadability protection." The Protection System actions should be included in this requirement regarding proper Protection System simulation, rather than as a separate requirement in R3.3.3. Otherwise there would be in double jeopardy of violating R3.3.1. and R3.3.3 when circuit loadability protection is not properly simulated. R3.3.2 The MRO NSRS suggests that this requirement be removed because it is premature to requirement Transmission Planners to simulate under voltage tripping until the MOD standards require it. If the drafting team does not remove this requirement the MRO NSRS proposes revised wording to qualify which generating units to consider and which voltage limits to simulate, "Trip generating units that are connected to the BES when actual or assumed minimum generator steady state or ride through voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment". The requirement should not apply to all relevant generating units until one of the MOD standards requires all Generator Owners to provide their minimum generating unit voltage limits to the TP and PC. If the wording of R3.3.2 must be different from its counterpart, R4.3.2, then please explain the reasons for any differences. R3.3.3 As noted above, The MRO NSRS suggests that R3.3.3 be removed and this System Protection simulation requirement should be included in R3.3.1, which is the requirement to properly simulate Protection System actions. Add R3.3.5 The MRO NSRS suggests the addition of R3.3.5, "Applicable System Operating Limits for the planning horizon shall not be exceeded." because Note "a" and "b" under "Steady State Only" at the beginning of Table 1 are stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and hidden) in the performance notes of Table 1. [After R3.3.5 is added, Note "a" should be revised and refer to R3.3.5.] Add R3.3.6 The MRO NSRS suggests the addition of R3.3.6, "The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to steady state voltage requirements." because Note "d" under "Steady State Only" at the beginning of Table 1 is stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and hidden) in the performance notes of Table 1. [After R3.3.6 is added, Note "d" should be revised to refer to R3.3.6.] R3.4.1 The MRO NSRS suggests that the word "coordinate" and the reference to the Transmission Planner be removed and offer the following revised text, "the Planning Coordinator shall provide the list of contingencies that are simulated in the adjacent Planning Coordinator area to the respective Planning Coordinator for review and feedback.". Standard Drafting Teams are generally instructed not to use the word "coordinate". The MRO NSRS suggests that this requirement apply to the PC because the PC would share with any affected Transmission Planners. R3.6 The MRO NSRS suggests the wording of this requirement be revised to, "Manual or automatic generation runback or tripping is permitted to meet steady state performance requirements for planning events P1 through P7 in Table 1." because Reliability Standard PRC-015-1 already includes requirements regarding the review and approval of Special Protection Systems. Therefore, the Planning Assessment does not need to duplicate description of the design and intent of the Special Protection System. M3 & R3 Data Retention - The MRO NSRS proposes that the wording in these elements be revised to change "All" to "The". The word "All" is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data

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	retention would read as follows: "The studies performed in support".?
Response: Part 3.3.1: The intent of this requirement is to remove elements that the Protection System would remove to clear a fault (breaker-to-breaker). The Transmission circuit loadability protection could trip un-faulted lines due to the post fault System loadings. Adding the suggested wording "including the simulation of transmission circuit loadability protection." would change the intent of Requirement R3, part 3.1.1. No change made. Part 3.3.2: Where test data is not available, the SDT believes that most Transmission Planners/Planning Coordinators currently assume generators ride through low voltage based on extensive field experience. There is a project (Project 2007-09 — Generator Verification) that will provide the required generator data to validate the assumptions. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure that the simulation models the generator response as it will react in the real world. If voltage ride through limits would cause a generator to trip in the real world, the study must determine if the performance requirements are met for the initiating event and subsequent generator trip. No change made. The SDT added the phrase "or high side of the GSU voltages" to make Requirement R3, part 3.3.2 consistent with Requirement R4, part 4.3.2. Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.3.5 Proposed: The SDT believes that a new requirement is not needed. Requirement R3, part 3.1 states "Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1." Header notes are part of Table 1 and therefore included in Requirement R3. Part 3.3.6 Proposed: The SDT believes that a new requirement is not needed. Requirement R3, part 3.1 states "Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1.". Header notes are part of Table 1 and therefore included in Requirement R3. Part 3.4.1: The SDT believes that it is necessary for the planner to coordinate with adjacent planners to identify Contingencies in adjacent systems that could impact the planners System. Both the Transmission Planner and Planning Coordinator have this responsibility. No change made. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES. Data Retention: The SDT agrees with your suggestion. The wording in "data retention" for Requirement R3 has been changed. Measure M3 already uses the word "the". **Requirement R3, data retention:** The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.	
SERC Dynamics Review Subcommittee (DRS)	R3.3.1: We propose to add "permanently" before "disconnect".
Response: Part 3.3.1: The SDT believes that adding the word "permanently" has no significance for the steady state simulation of fault clearing. No change made.	
MAPP	R3.3.2 - We suggest that this requirement be removed because it is premature to require Transmission Planners to simulate under voltage tripping until the MOD standards require it. If the drafting team does not remove this requirement we propose revised wording to qualify which generating units to consider and which voltage limits to simulate, "Trip generating units that are

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	connected to the BES when actual or assumed minimum generator steady state or ride through voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment". 3.3.3 We suggest that R3.3.3 be removed and this System Protection simulation requirement should be included in R3.3.1, which is the requirement to properly simulate Protection System actions Add R3.3.5 We suggest the addition of R3.3.5, Applicable System Operating Limits for the planning horizon shall not be exceeded. because Note "a" and "b" under "Steady State Only" at the beginning of Table 1 are stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and hidden) in the performance notes of Table 1. [After R3.3.5 is added, Note "a" should be revised and refer to R3.3.5.] Add R3.3.6 We suggest the addition of R3.3.6, ?The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to steady state voltage requirements. because Note "d" under "Steady State Only" at the beginning of Table 1 is stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and hidden) in the performance notes of Table 1. [After R3.3.6 is added, Note "d" should be revised to refer to R3.3.6.] R3.4.1: Remove the Transmission Planner and change "coordinate" to "provide" information to adjacent PC. We are working on other standards to remove "coordinate" and we should avoid it here. Coordinate requires interaction between two entities (or more), so if one does not respond, the other could be found to be non-compliant for something they cannot control.

Response: Part 3.3.2: Where test data is not available, the SDT believes that most Transmission Planners/Planning Coordinators currently assume generators ride through low voltage based on extensive field experience. There is a project (Project 2007-09 — Generator Verification) that will provide the required generator data to validate the assumptions. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure that the simulation models the generator response as it will react in the real world. If voltage ride through limits would cause a generator to trip in the real world, the study must determine if the performance requirements are met for the initiating event and subsequent generator trip. No change made

Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded.

Requirement R3, part 3.3.3: Trip Transmission elements when relay loadability limits are exceeded

The intent of Requirement R3, part 3.3.1 is to remove elements that the Protection System would remove to clear a fault (breaker-to-breaker). The Transmission circuit loadability protection could trip unfaulted lines due to the post fault System loadings. Adding the suggested wording "including the simulation of transmission circuit loadability protection." would change the intent of Requirement R3, part 3.1.1. No change made.

Part 3.3.5 Proposed: The SDT believes that a new requirement is not needed. Requirement R3, part 3.1 states "Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1.". Header notes are part of Table 1 and therefore included in Requirement R3.

Part 3.3.6 Proposed: The SDT believes that a new requirement is not needed. Requirement R3, part 3.1 states "Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1.". Header notes are part of Table 1 and therefore included in Requirement R3.

Part 3.4.1: SDT believes that it is necessary for the planner to coordinate with adjacent planners to identify contingencies in adjacent systems that could impact the

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planners system. Both the Transmission Planner and Planning Coordinator have this responsibility. No change made.	
NYISO	R3.3.3 This requirement is already addressed in NERC Standard PRC-023 and reflected in the facility's rating and should be removed. R3.5. - The Extreme Events testing in Table 1 should be removed from this standard since there is no requirement to develop a Corrective Action Plan to address unacceptable consequences and the requirements are very general or vague. At a minimum, testing should only be required for EHV facilities or facilities specified by the Regional Entity for example, NPCC designates facilities that can have consequences outside an area as bulk power system facilities. If this remains, the NYISO requests that the phrase "evaluation of possible actions" be greatly clarified. R3.6 The NYISO seeks greater clarification of the phrase "consequential generation."
Response: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.5: The SDT believes, and the majority of the industry agrees as seen in the comments, that continuing to study these possible scenarios is a valuable planning exercise. The requirement is to evaluate possible actions which, if implemented, could reduce the likelihood or mitigate the consequences of an extreme event. No change made. Part 3.6: The term "consequential generation" is not used in Requirement R3, part 3.6. The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.	
Xcel Energy	R3.3.3 Xcel does not believe that relay loadability limits is a valid system planning performance criterion because we are unsure how transmission relay loadability settings developed in accordance with PRC-023 can be more limiting than the Facility Ratings. Note that the purpose of PRC-023 standard is "Protective relay settings shall not limit transmission loadability" and it requires that the relay settings be higher than the "highest seasonal Facility Rating of a circuit". If relay settings limit the transmission loadability below its Facility Rating, then it is a violation of PRC-023. Requirements R3.4 and R3.5 appear to be related to and set the limits for R3.1 and R3.2 respectively. Suggest moving both Requirements R3.4 and R3.5 into R3.1 and R3.2, allowing these sub-Requirements (R3.4 and 3.5) to be deleted. R3.3 It is unclear from the wording in R3.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R3.1 and R3.2. Please clarify the wording of R3.3.
Response: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded The SDT agrees that relay loadability limits would exceed Facility ratings except in cases where exceptions to the loadability standard exist.	

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Part 3.4: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.5: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.3: The SDT revised the wording of Part 3.3 as shown below to make it clear that it applies to both planning and extreme events: **Requirement R3, part 3.3**: Contingency analyses for Requirement R3, parts 3.1 & 3.2 shall:	
Sacramento Municipal Utility District	R3.3.3: To implement this requirement, the standard appears to call for one more facility rating which is based on Relay Loadability. Is the intent to also model the protection system actions if this limit is violated? Should such a requirement be moved to the MOD or FAC standard with conformance subject to Note (f) of Table 1 (Facility ratings shall not be exceeded) and R3.3.1 (simulate the removal of all elements that the Protection System and other " are expected to disconnect")?
Response: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.3.1: The intent of this requirement is to remove elements that the Protection System would remove to clear a fault (breaker-to-breaker). The Transmission circuit loadability protection could trip un-faulted lines due to the post fault System loadings. Adding the suggested wording "including the simulation of transmission circuit loadability protection." would change the intent of Requirement R3, part 3.1.1.	
Puget Sound Energy, Inc.	R3.41 requires clarification. With respect to these "Contingencies on adjacent systems," the responsibility of listing and analyzing these events needs to be clarified. Should the event simulation be the responsibility of the "neighboring" system (where the event would occur) or the adjacent system that may feel the impact of this event? Per the developed rationale from R3.4, the neighboring system may determine that a particular event is "less severe" and hence not studied, even though this event may potentially impact a neighbor. Further, for these "Contingencies on adjacent systems" that result in system performance outside one's own operating limits, it is unclear who is responsible for mitigating these contingencies. It is potentially awkward in that one entity may be planning another entity's system improvements.
Response: R3.4.1: The intent is for the Planning Coordinator/ Transmission Planner to include in their Contingency lists Contingencies from adjacent Systems which may impact their System, and to run these Contingencies. The Planning Coordinator/Transmission Planner is responsible for mitigation of performance deficiencies in their System caused by Contingencies on their list, including the Contingencies from adjacent Systems.	
Duke Energy	R3.5 includes the phrase "cascading outages". We believe that the word "cascading" should be the capitalized NERC-defined term "Cascading".
Response: R3.5: The SDT agrees. The phrase "cascading outages" has been changed to "Cascading" to align with the NERC Glossary of Terms. **Requirement R3, part 3.5**: Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be	

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available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.	
Northeast Power Coordinating Council--RSC	Requirement 3.2: This requirement should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. Requirement 3.3.3: This requirement is already addressed in NERC Standard PRC-023 and reflected in the facility's rating and should be removed from TPL-001-1 since the standard already requires observance of facility ratings. Relay Loadability is handled in greater detail (as it should be) under the proposed PRC-023 standard, so no reference should be made in this standard, thereby introducing a double jeopardy issue. Requirement 3.4: It is strongly suggested that this requirement is made a sub-bullet of Requirement 3.1 to keep the related requirements together. Requirements 3.5--This requirement needs clarification as to what is specifically required for the "evaluation of possible actions." The list associated with Requirement 2. part 2.7.1 provides examples of possible actions, and leaving "evaluation" undefined offers the Planning Coordinator and Transmission Planner the leeway to use judgment in making their evaluations. Requirement 3.5 NPCC strongly suggests making this a sub-bullet of Requirement 3.2 to keep the related requirements together.Provide clarification as to what is specifically required for the "evaluation of possible actions". Requirement 3.6 Currently this requirement is not clear, and does not address any reliability issue. Clarification should be added that the "consequential generation" loss be excluded from the amount documented. Without the clarification, the Requirement should be deleted.
Response: Part 3.2: The SDT disagrees and believes there is value in running extreme event analysis to test the robustness of the System. No change made. Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.4: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.5 The requirement is to evaluate possible actions which, if implemented, could reduce the likelihood or mitigate the consequences of an extreme event. The SDT believes that what these "possible actions" are should be left to the judgment of the Planning Coordinator/Transmission Planner who has knowledge of their System. Part 3.5: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.	
Midwest ISO	Requirement R3.6: With regards to the Generation Runback MW reporting; if no action is required then why require the entities

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	to provide this. Will it matter if 10MW or 100MW is part of the generation runback scheme tripped with the line? This is a system design issue which is not addressed by the standards, if this requirement is kept how is an entity expected to demonstrate compliance for this? This requirement is an administrative burden and we propose to remove R3.6 all together considering that there is not a reliability-related need for this information and it is unnecessary.
Response: Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.	
Hydro-Québec TransEnergie (HQT)	Requirements 3.5 and 4.5 Both of these requirements need clarification as to what is specifically required for the "evaluation of possible actions." Requirement 3.3.3 This requirement is already addressed in NERC Standard PRC-023 and reflected in the facility's rating and should be removed from TPL-001-1 since the standard already requires observance of facility ratings. Requirement 3.4 HQT, as does NPCC, strongly suggests making this requirement a sub-bullet of Requirement 3.1 to keep the related requirements together. Requirement 3.5 HQT, as does NPCC, strongly suggests making this a sub-bullet of Requirement 3.2 to keep the related requirements together. Requirement 3.6 ?Currently this requirement is not clear. HQT, as does NPCC, recommends clarification be added that the "consequential generation" loss is excluded from the amount documented.
Response: Part 3.5 The requirement is to evaluate possible actions which, if implemented, could reduce the likelihood or mitigate the consequences of an extreme event. The SDT believes that what these "possible actions" are should be left to the judgment of the Planning Coordinator/Transmission Planner whose has knowledge of their System. Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.4: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.5: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.	
Pacific Gas and Electric Co.	Requirements R3.4 and R3.5 appear to be related to and set the limits for R3.1 and R3.2 respectively. Suggest moving both Requirements R3.4 and R3.5 into R3.1 and R3.2, allowing these sub-Requirements (R3.4 and 3.5) to be deleted. It is unclear from the wording in R3.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R3.1 and R3.2. Please clarify the wording of R3.3.

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	For clarity we suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits.
Response: Part 3.4: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.5: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.3: The SDT revised the wording of Requirement R3, part 3.3 as shown below to make it clear that it applies to both planning and extreme events: **Requirement R3, part 3.3**: Contingency analyses for Requirement R3, parts 3.1 & 3.2 shall: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded	
National Grid	Sub-Requirement 3.2: This requirement should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. Sub-Requirement 3.3.3: Relay Loadability is handled in greater detail (as it should be) under the proposed PRC-023 standard, so no reference should be made in this standard. It indicates a double jeopardy. Sub-Requirement 3.4: It is strongly suggested that this requirement is made a sub-bullet of Requirement 3.1 to keep the related requirements together. Sub-Requirement 3.5: It is strongly suggested that this requirement is made a sub-bullet of Requirement 3.2 to keep the related requirements together. Provide clarification as to what is specifically required for the "evaluation of possible actions." Sub-Requirement 3.6: This requirement does not address any reliability issue should be deleted. If it is to be kept, it is recommended that the "consequential generation" loss be excluded from the amount documented.
Response: Part 3.2: The SDT disagrees and believes there is value in running extreme event analysis to test the robustness of the System. No change made. Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.4: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.5: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.5: The requirement is to evaluate possible actions which, if implemented, could reduce the likelihood or mitigate the consequences of an extreme event. The SDT believes that determining these "possible actions" should be left to the judgment of the Planning Coordinator/Transmission Planner who has knowledge of their	

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System. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.	
Tri-State Generation and Transmission Association	Thank you for removing the requirement to explain why "non-studied contingencies" would produce less severe results." Don't say "R3, part 3.4". Instead, for much easier referencing of sections, just say "R3.4". This applies throughout the entire Standard." R3.5 In the phrase "extreme events in Table 1 that are expected to produce more severe System impacts", the term "extreme events" seems redundant with "more severe". If Extreme Events were capitalized, it would be apparent that the TP should choose more severe events typified by details listed in the Extreme Events section of Table 1.
Response: R3, part 3.4: NERC has directed that the new terminology be adopted for all parts of a requirement. No changes made. R3.5: The SDT disagrees that the suggested changes add clarity. No change made. R3.5: The extreme events are listed in Table 1. Some of these events will have a greater impact than others on a given System. The SDT's expectation is that the planner knows his system and would use judgment to select the extreme events that would have a more severe impact on his System. No change made.	
Ameren	The readability of R3.3 could be improved with the following wording changes:3.3 Contingency analyses shall be performed: 3.3.1 To simulate the removal? 3.3.2 To simulate tripping generators where simulations show? 3.3.3 And results reviewed to ensure relay loadability limits? 3.3.4 To simulate the expected? Requirement R3.3.1 needs to include language regarding the automatic restoration of facilities. The following language is suggested: To simulate the removal of all elements that the Protection System is expected to disconnect and the restoration of all elements that the automatic controls are expected to restore for each Contingency without operator intervention. Requirement R3.6: What is the purpose of this Requirement? We do not see how the reporting of this information adds to system reliability, and believe that this is more of a market issue. For those systems that are planned based on a single contingency, it is believed that numerous generation facilities would be impacted by the N-2 planning events and particularly those involving transmission facilities in the vicinity of power plant switchyards. Documenting manual or automatic generation runback or tripping of generation for the proposed P1 and P2 events is not unreasonable, but it is expected that developing runback or tripping schemes for the proposed P3-P7 events and reporting those contingencies and the amount of generation curtailed on an annual basis is of little value. Further, what information is to be reported for the P6 events for R3.6? As P6 events allow system adjustment following the first contingency (P1 event) to prepare for the second contingency (P1 event), is the runback information to be reported the generation that is to be curtailed after the first event (which should already be reported for the P1 category), after the second

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	event, or after both events? In real-time operations, security constrained economic redispatch continually adjusts generation to maintain transmission facility loadings within ratings anticipating the next single contingency event. Does the Standards Drafting Team intend for the industry to report the amount of curtailed generation in anticipation of the next P1 event?
Response: Part 3.3: The SDT has not adopted your suggested wording, but has made wording revisions to improve clarity as follows: **Requirement R3, part 3.3**: Contingency analyses for Requirement R3, parts 3.1 & 3.2 shall: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded. Part 3.3.1: The reference to "other automatic controls" is intended to include other tripping means such as cross-tripping and not automatic restoration devices. No change made. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.	
Florida Power and Light	The requirement clearly states that "For the steady state portion of the Planning Assessment" it must perform simulations that show generator ride through voltage limitations under 3.3.2. However, ride through limitations are performed through stability simulations not steady state as required by R3. This is confusing as currently drafted, please provide clarity. Additionally, 3.2 requires studies to be performed to assess the impact of the extreme events. Yet, 3.3 requires analyses shall be performed but does not specify the events intended to study. Suggested language for 3.3 should say "Contingency analyses shall be performed to assess the impact of the extreme events and:" Under 3.3.1 it states that the Planner must simulate the removal of all elements that the Protection System would be expected to disconnect. Language should be included to allow the Planner to provide a rationale to assess more severe system conditions without needing to simulate the effects of Protection Systems. This would capture the intent of this requirement.
Response: Part 3.3.2: Generators can trip when bus voltage drops below minimum generator steady state voltage limits. The SDT believes that the voltage ride through test is applicable in post-contingency steady-state where the planner would know if post-Contingency bus voltage violates generator trip points. If a trip point is violated, Requirement R3, part 3.3.2 would require the planner to remove the generator in the post-Contingency case to assess if performance is met with the generator removed. No change made. Part 3.3: The SDT revised the wording of Requirement R3, part 3.3 as shown below to make it clear that it applies to both planning and extreme events: **Requirement R3, part 3.3**: Contingency analyses for Requirement R3, parts 3.1 & 3.2 shall: Part 3.3.1: Consistent with FERC Order 693, the intent of the SDT is for the planner to simulate the Protection System operation so that all elements that the Protection System is designed to remove (breaker to breaker) are removed in the simulation for the list of Contingencies the planner has developed in Requirement R3, parts 3.4 (planning events) and 3.5 (extreme events). The requirement does not preclude the Planning Coordinator/Transmission Planner from studying more severe scenarios. No change made.	

Organization	Comments for Question 3
NorthWestern Energy	The wording in R3.3.3 should be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits. In R3.3.3 The term "loadability" needs to be defined. R3.5 needs to be modified. It would be better to combine R3.2 with R3.5. The first part of the requirement requires identification of events that produce more severe System impacts. The presumed reason that the other contingencies were not selected is because they were deemed to be less severe or non-credible. In any case, theoretically, there can always be examples of more severe Extreme Contingencies than the one selected for study. This can be achieved by simply choosing events that are even less credible. For example, if the Extreme Contingency studied was a simultaneous loss of 3 transmission lines with the failure of a redundant RAS (SPS), then an event resulting in the simultaneous loss of 4 lines with the failure of 2 sets of redundant RASs would be even more severe. Listing all possible extreme events could result in a limitless list.
Response: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.3.3: Relay loadability is defined in NERC Standard PRC-023-1. R3.5: The SDT agrees that there could be an endless list of possible extreme events, The requirement has been written to allow the Planning Coordinator/Transmission Planner to use experience and the knowledge of their System to select relevant extreme events that have some reasonable probability of occurring. The SDT does not believe that combining Requirement R3, part 3.5 with Requirement R3, part 3.2 provides any significant advantage. No change made.	
American Transmission Company	We propose the following changes and questions: R3.3.1 The term of "controls" is ambiguous and not defined, unlike the term, "Protection Systems", which is defined. Therefore, we suggest that this item be defined or more clearly described to avoid the risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. R3.3.1 Add the wording, ". . . including the simulation of transmission circuit loadability protection." to this requirement, rather than have a separate R3.3.3 requirement for recognizing overload protection. Overload protection is simply one of the types of automatic Protection System that may remove one or more elements from service. R3.3.2 - We suggest qualifying which generating units to consider and which voltage limits to simulate with revised wording like, "Trip generating units that are connected to the BES when actual or assumed minimum generator steady state or ride through voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment". The requirement should not apply to all relevant generating units until one of the MOD standards requires all Generator Owners to provide their minimum generating unit voltage limits to the TP and PC. If the wording of R3.3.2 must be different from its counterpart, R4.3.2, then please explain the reasons for any differences. R3.3.3 As noted above, we suggest that R3.3.3 be removed and that this System Protection loadability simulation requirement is included in R3.3.1 because overload protection is simply one type of automatic Protection System actions.

Organization	Comments for Question 3
	Add R3.3.5 We suggest the addition of R3.3.5 because any requirement in the head notes or foot notes of Table 1 should occur within the body of standard. The text of R3.3.5 should read, "Applicable System Operating Limits for the planning horizon shall not be exceeded." Presently, Note "a" and "b" under "Steady State Only" at the beginning of Table 1 are stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and basically hidden) in the performance notes of Table 1. [After R3.3.5 is added, Note "a" should be revised and refer to R3.3.5.] Add R3.3.6 ? We suggest the addition of R3.3.6 because any requirement in the head notes or foot motes of Table 1 should occur within the body of standard. The text of R3.3.6 should read, "The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to steady state voltage requirements." because Note "d" under "Steady State Only" at the beginning of Table 1 is stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and basically hidden) in the performance notes of Table 1. [After R3.3.6 is added, Note "d" should be revised to refer to R3.3.6.] R3.5 - We interpret that R3.5 requires the TP and PC to conduct an evaluation of possible actions to reduce the likelihood or impact of extreme events, which produce the more severe impacts, if cascading outages may occur. Does the drafting team intend for the TP and PC to fulfill this requirement for at least one event in each of the five categories (i.e. 3 steady state and 2 stability) or in each of the 21 categories/sub-categories (i.e. 14 steady state and 7 stability). Also, if the resulting cascading outages do not result in any overloads, under-voltages, voltage collapse, or loss of generator synchronization, then should the evaluation of possible actions to reduce likelihood or impact be required? R3.6 We suggest the wording of this requirement be revised to, "Manual or automatic generation runback or tripping is permitted to meet steady state performance requirements for planning events P1 through P7 in Table 1." because Reliability Standard PRC-015-1 already includes requirements regarding the review and approval of Special Protection Systems. Therefore, the Planning Assessment does not need to duplicate description of the design and intent of the Special Protection System.

Response: Part 3.3.1: The SDT believes that the meaning of "controls" is clear in the context it is used - "Protection Systems and Other automatic controls" (such as a cross-trip scheme) that disconnect elements to clear a fault". No change made.

Part 3.3.1: The intent of this requirement is to remove elements that the Protection System would remove to clear a fault (breaker-to-breaker). The Transmission circuit loadability protection could trip un-faulted lines due to the post fault system loadings. Adding the suggested wording "including the simulation of transmission circuit loadability protection." would change the intent of Requirement R3, part 3.1.1. No change made.

Part 3.3.2: Where test data is not available, the SDT believes that most Transmission Planners/Planning Coordinators currently assume generators ride through low voltage based on extensive field experience. There is a project (Project 2007-09 — Generator Verification) that will provide the required generator data to validate the assumptions. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure that the simulation models the generator response as it will react in the real world. If voltage ride through limits would cause a generator to trip in the real world, the study must determine if the performance requirements are met for the initiating event and subsequent generator trip. No change made.

The phrase "or high side of the GSU voltages" was added to Requirement R3, part 3.3.2 to make the wording in Requirement R3, part 3.3.2 the same as in Requirement R4, part 4.3.2.

Requirement R3, part 3.3.2: Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed

Organization	Comments for Question 3
	minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. Combining Requirement R3, part 3.3.3 with Requirement R3, part 3.3.1 would change the intent of Requirement R3, part 3.3.1. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.3.5 Proposed: The SDT believes that a new requirement is not needed. Requirement R3, part 3.1 states "Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1.". Header notes are part of Table 1 and therefore included in Requirement R3. Part 3.3.6 Proposed: The SDT believes that a new requirement is not needed. Requirement R3, part 3.1 states "Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1." Header notes are part of Table 1 and therefore included in Requirement R3. Part 3.5: Requires the planning entity to identify which contingencies are chosen to be simulated in the study, and explain why these are chosen. The SDT assumes that the Planning Coordinator/Transmission Planner, applying experience of past studies and knowledge of its System, is in the best position to determine which Contingencies in Table 1 are most relevant, as it is impossible to study all Contingencies especially the multiple Contingency events. Requirement R3, part 3.5 requires "an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts" if cascading outages - the trigger for evaluation of possible mitigating actions is cascading outages, not "overloads, under-voltages, voltage collapse, or loss of generator synchronization". No change made. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES. The SDT notes that generator runback or tripping is not prohibited by the standard.
PJM	In R3.3.2, low voltage protection, like practically all generator protection, is not commonly collected, at least by MMWG, and will take a great deal of time and effort to gather. R3.3.3 – Relay loadability should not be evaluated in a performance standard. A separate line rating and protection setting evaluation can determine if relay loadability is exceeded. If kept, this protection information, is not commonly collected, at least by MMWG, and will take a great deal of time and effort to gather. R3.5 – Needs a 3.5.1 similar to 3.4.1. R3.6 needs some words about sending up a red flag is the generation tripped or runback is greater than the largest single contingency. Like –The Reliability Coordinator, Transmission Operator and Balancing Authority must be notified if the planned generation tripped or runback scheme is greater than the largest single contingency.-
Response: Part 3.3.2: Where test data is not available, the SDT believes that most Transmission Planners/Planning Coordinators currently assume generators ride through low voltage based on extensive field experience. There is a project (Project 2007-09 — Generator Verification) that will provide the required generator data to validate the assumptions. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure that the simulation models the generator response as it will react in the real world. If voltage ride through limits would cause a generator to trip in the real world, the study must determine if the performance requirements are met for the initiating event and subsequent generator trip. No change made. Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded.	

Organization	Comments for Question 3
	Requirement R3, part 3.3.3: Trip Transmission elements when relay loadability limits are exceeded Part 3.5.1 Proposed: The SDT has not included a requirement on the Planning Coordinator/ Transmission Planner to coordinate with adjacent Systems to identify extreme Contingencies in these adjacent Systems that would impact the Planning Coordinator/Transmission Planner's System. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.

4. Requirement R4 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: Many commenters expressed concerns that the new "relaying" requirements that were added to draft 4 would essentially require modeling every zone 3 relay in each Interconnection. The requirements do not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then one can either take action according to the generic model results or investigate the characteristics of the relays actually used on that branch.

In response to several commenters, Part 4.1.2 was modified to no longer require tripping of out-of-step generators in the simulations.

Clarifications to the requirements were made as follows:

Requirement R3, part 3.3.2 - Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

Requirement R4, part 4.1.2 - For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

Requirement R4, part 4.3 - Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

Requirement R4, part 4.5 - Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R4, part 4.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

Organization	Comments for Question 4
Independent Electricity System Operator	(1) Part 4.3: Similar comments on Part 3.3 provided under Q3 also apply here. (2) Parts 4.4 and 4.5: similar comments on Parts 3.4 and 3.5 provided under Q3 also apply here.(3) We do not have any comments on the measure, VRF, Time Horizon and VSLs.
SRC of ISO/RTO	1. Part 4.3: Similar comments as for Part 3.3 (i.e. overly prescriptive, etc...) provided under question 3 also apply here. 2. Parts 4.4 and 4.5: Similar comments on Part 3.4 and 3.5 provided under question 3 also apply here.

Organization	Comments for Question 4
	AESO does not comment on VSLs or VRFs.
Response: See response to your comments on Requirement R3, part 3.3. See response to your comments on Requirement R3, parts 3.4 and 3.5.	
ERCOT ISO	* Will any agreements made in R7 override the "each TP and PC" requirement? To clarify this, the requirement could be rephrased: "In accordance to the responsibilities assigned in R7, the responsible Transmission Planners and Planning Coordinators shall perform?. "* Similar to comments provided in R3, Section 4.1 and 4.4 appear to be related. Confusing references can be eliminated by combining them and removing 4.4: "4.1. Those planning events in Table 1that are expected to produce more severe System impacts on its portion of the BES, shall be identified and studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1. A list of those Contingencies and the rationale for those Contingencies selected for evaluation shall be available as supporting information. "* Similarly, Section 4.2 and 4.5 appear to be related. Confusing references can be eliminated by combining them and removing 4.5: "4.2. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and studies shall be performed to assess the impact of the extreme events. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted. A list of those events and the rationale for those Contingencies selected for evaluation shall be available as supporting information. "
Response: The agreements required by Requirement R7 are intended to clarify the responsibilities among the Planning Coordinator and Transmission Planners. The SDT believes this is clear in the existing language. Requirement R4, parts 4.1 & 4.4: The SDT does not believe that combining the requirements serves any purpose. No change made. Requirement R4, parts 4.2 & 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made.	
Northeast Utilities	[R4.1.1] This requirement needs better clarification. Does it mean that a generator that trips on any other condition apart from tripping on out-of-synchronism is acceptable? Example if the generator is not able to ride through a low voltage condition created by a fault. We recommend that this requirement is dropped from TPL-001-1 standard. [R4.1.2] This approach will require a different modeling technique from current practice and will require an implementation period. [R4.3.2] Refer to comment for Requirement R3.3.2. [R4.5] This requirement needs clarification as to what is specifically required for the "evaluation of possible actions". Otherwise the following is recommended:" It should be clear that an evaluation does not require solution development for all Extreme Events" Change "an evaluation of possible actions" to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered."

Organization	Comments for Question 4
Response: Part 4.1.1: The requirement will not be dropped. The requirement states that for event P1, no generating unit shall pull out of synchronism. If the event results in a unit tripping due to fault clearing action or due to an SPS action, this is acceptable. Low voltage ride-through is handled in a separate requirement (Requirement R4, part 4.3.2). Part 4.1.2: Tripping the generator is no longer required. The SDT has modified Requirement R4, part 4.1.2. **Requirement R4, part 4.1.2** - For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities. Part 4.3.2: See response to your comment on Requirement R3, part 3.3.2. Part 4.5: The requirement is to evaluate possible actions which could reduce the likelihood or mitigate the consequences of the event. The standard should not prescribe those actions. It is up to your judgment what those possible actions could be. No change made.	
Central Maine Power Company	4.1.1 This should be revised to only be applicable to generators interconnected to the BES. This may need an implementation period as not all existing units are interconnected in accordance with the standard as proposed. As written this applies to small generators and doesn't necessarily reflect reliability of the network. 20 MW is a recommended generator minimum size. 4.1.2 This will require implementation period. 4.2 Item 4.2 should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. 4.4 It is suggested that this requirement is made a sub-bullet of Requirement 4.1 to keep the related requirements together. 4.5 It is suggested that this requirement is made a sub-bullet of Requirement 4.2 to keep the related requirements together.
ISO New England	4.1.1 This should be revised to only be applicable to generators interconnected to the BES. This may need an implementation period as not all existing units are interconnected in accordance with the standard as proposed. As written this applies to small generators and doesn't necessarily reflect reliability of the network. 20 MW is a recommended generator minimum size. 4.1.2 This will require implementation period. 4.2 Item 4.2 should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. 4.4 It is suggested that this requirement is made a sub-bullet of Requirement 4.1 to keep the related requirements together. 4.5 It is suggested that this requirement is made a sub-bullet of Requirement 4.2 to keep the related requirements together.
United Illuminating	4.1.1 This should be revised to only be applicable to generators interconnected to the BES. This may need an implementation

Organization	Comments for Question 4
	period as not all existing units are interconnected in accordance with the standard as proposed. As written this applies to small generators and doesn't necessarily reflect reliability of the network. 20 MW is a recommended generator minimum size. 4.1.2 This will require implementation period. 4.2 Item 4.2 should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. 4.4 It is suggested that this requirement is made a sub-bullet of Requirement 4.1 to keep the related requirements together. 4.5 It is suggested that this requirement is made a sub-bullet of Requirement 4.2 to keep the related requirements together.
Response: Part 4.1.1: The standard applies only to the BES and therefore, without revision, does not place this requirement on generators not directly connected to the BES. The SDT believes that generators smaller than 20 MW also need to be stable for single Contingencies (P1). No change made. Part 4.1.2: Tripping the generator is no longer required. The SDT has modified Requirement R4, part 4.1.2. **Requirement R4, part 4.1.2** - For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities. Part 4.2: The SDT disagrees and believes there is value in running extreme event analysis. No change made. Part 4.4: The SDT does not believe that combining the requirements serves any purpose. No change made. Part 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made.	
Florida Municipal Power Agency, and its Member Cities	4.1.1, suggest rewording "(a) generator being disconnected from the Bulk Electric System ", system as defined in the Glossary includes distribution, and we do not believe that is the intent of the SDT. 4.1.2, 4.3.1 and 4.3.3 essentially require modeling every Zone 3 (or higher, such as Zone 5) relay in each Interconnection (or at least in the Region under study and adjacent regions) because, in order to simulate the impact of a power swing on a distance relay, one would need to know the characteristics of the distance relay and how long the transient swing remains within that characteristic, which means modeling the relay. Is that the intent of the SDT? If so, FMPA suggests limiting these bullets to Facilities 230 kV and higher.
Response: Part 4.1.1: The standard applies only to the BES and therefore, without revision, does not place this requirement on generators not directly connected to the BES. No change made. Parts 4.1.2, 4.3.1, & 4.3.3: This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. No change made.	

Organization	Comments for Question 4
Xcel Energy	4.3 Does the requirement allow it to be optional as to whether an entity chooses to include generator exciter controls, PSS, etc.? To what degree must a device impact the study area, in order for it to be required to be included in the simulation? Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. R4.3 It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful and unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If it is the intent to require that entities assess both, we suggest including the assessment in the list of sensitivities.
Response: Part 4.3: If generator exciter controls and PSS do not affect the study area, it is not necessary to model them. However, most Transmission Planners will have them in their simulations because these controls are already included in their model. It is up to your judgment as to what control devices have an impact on the study area. Parts 4.4 & 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made. Part 4.3: The Contingency analyses in Requirement R4, part 4.3 refer to the studies in Requirement R4, parts 4.1 and 4.2. However, for additional clarity, Requirement R4, part 4.3 has been modified. **Requirement R4, part 4.3** - Contingency analyses for Requirement R4, parts 4.1 and 4.2 shall : Part 4.3.1: The Standard requires you to study only the events which produce more severe System impacts. If two Systems are swinging apart, then successful high speed reclosing could show a more severe impact. However, if successful reclosing is not expected to produce a more severe impact, you are not required to study it. No change made.	
FirstEnergy Corp	A. The SDT should bring consistency to the text used for sub-part 4.3.2 of R4 and sub-part 3.3.2 of R3. In R4 it indicates "generator bus voltages or high-side of GSU" as the reference voltage point whereas 3.3.2 only indicates "generator bus voltage" as the point of reference. If the generator bus is modeled at the generator voltage, then this should be the reference voltage point. If the generator is modeled directly connected to the BES (no transformer is explicitly modeled), then the transmission voltage should be the reference voltage. B. Requirement R4, sub-part 4.3.2 is well intentioned, but problematic for those performing dynamic simulations. Does a Guide or Practice exist to determine the dynamic undervoltage capability of a synchronous machine? Most excitation systems contain "field forcing" functions to maintain stability through fault conditions (1 second or so of capability), but FE is not aware of any published, readily available quantities or formulas that can be used to determine this highly time dependent function. Application of the steady state minimum voltage is grossly over-conservative. FE questions why low voltage limits should even be considered in dynamic simulations, since the primary concern for generating equipment during events of this nature and duration are metallurgical, not thermal (voltage). C. Requirement R3 sub-part 4.3.3 is troublesome since the modeling detail needed for Protection Systems within traditional stability programs is not available. It is expected that software adjustments will be needed from the software vendors before this

Organization	Comments for Question 4
	requirement can be met. The implementation plan of 24 months may be insufficient in regards to 4.3.3. In draft 3 Progress Energy and Ameren in the Q11 comments indicated that more time is needed for Protection System modeling required by TPL-001-1. The SDT responded "The standard does not require detailed modeling of Relay Protection Systems. It only requires that the impacts of those systems be reflected in the modeling of Contingencies and the evaluation of the resulting System performance. This is no different than the current standards." The inclusion of sub-part 4.3.3 in Draft 4 does not appear to align with this response. Please clarify the intent of 4.3.3 and respond regarding FE's belief that more time is needed for software improvements. D. We suggest the team discontinue the use of "Coordinate with adjacent transmission planners" in regards to sub-part 4.4.1 related to the inclusion of contingencies from adjacent systems. The "coordination" type of requirements creates a need to develop compliance evidence such as e-mail correspondence, meeting minutes etc that serve no real reliability purpose. The requirement should simply be that the TP shall include adjacent contingencies expected to produce the more severe System impacts on their systems. In fact, sub-part 4.4 already includes that language. We suggest the team append the sentence "The planning event contingencies shall include:" to the end of sub-part 4.4 followed by two bullets that indicate 1) events within the TP's system and 2) events on adjacent transmission Systems.
Response: A. Part 4.3.2: To be consistent with Requirement R4, part 4.3.2., Requirement R3, part 3.3.2 has been modified to also allow the use of voltages on the high side of the GSU. The use of voltages on the high side of the GSU allows greater flexibility in applying voltage ride-through capability of generators - some of which are defined on the high side of the GSU. **Requirement R3, part 3.3.2** - Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. B. Part 4.3.2: The purpose of Requirement R4, part 4.3.2 is to take into account the low voltage ride-through capability of generators in the studies. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. No change made. C. Part 4.3.3: This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. Therefore, the SDT does not believe that more time is needed in the Implementation Plan. No change made. D. Part 4.4.1: The SDT strongly disagrees with your suggestion. It is much easier to coordinate with adjacent Transmission Planners for Stability simulations. A requirement to study Contingencies on adjacent Systems creates an enormous burden for Stability simulations which have to take into account substation configurations and relaying times. A much better method is to coordinate with neighbors as to which Contingencies on their System could impact your System and then study only those Contingencies on the neighbor's System. No change made.	
Gainesville Regional Utilities	As generation and transmission elements are added to our small system, we evaluate the stability impact as part of its feasibility and impact studies. After installation and in each year of a critical conditions study at the regional level, our elements are considered in the regional priority listings to determine if any stability issues need additional or continuous evaluation. Again, as a "part of the whole" our elements are considered and our assessment is based on these and other findings. Again, this revision

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	seems to add clarity to this requirement and its parts. Good Job!
Response: Thanks for your comment.	
Progress Energy Florida, Inc.	As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all appropriate parties to review PEF's previous comments to this effect.
Response: Throughout the drafting process, the SDT has carefully considered your comments as well as comments from other industry members.	
CenterPoint Energy	CenterPoint Energy recommends deleting part 4.4.1 as being overly prescriptive and difficult to demonstrate in an audit.
Response: Part 4.4.1: The SDT disagrees that this requirement is prescriptive and difficult to demonstrate compliance. There is a need to consider Contingencies on a neighbor's System which may impact your System. It is much easier to coordinate with adjacent Transmission Planners for Stability simulations than to study them all yourself. A requirement to study Contingencies on adjacent Systems creates an enormous burden for Stability simulations which have to take into account substation configurations and relaying times. A much better method is to coordinate with neighbors as to which Contingencies on their System could impact your System and then study only those Contingencies on the neighbor's System. For the audit you should show documentation where you asked and received these Contingencies from your neighbors. No change made.	
Deseret Power	Comments: Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
Response: Parts 4.4 & 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made. Part 4.3: The Contingency analyses in Requirement R4, part 4.3 refer to the studies in Requirement R4, parts 4.1 and 4.2. However, for additional clarity, Requirement R4, part 4.3 has been modified. **Requirement R4, part 4.3** - Contingency analyses for Requirement R4, parts 4.1 and 4.2 shall : Part 4.3.1: The Standard requires you to study only the events which produce more severe System impacts. If two Systems are swinging apart, then successful high speed reclosing could show a more severe impact. However, if successful reclosing is not expected to produce a more severe impact, you are not required to study it. No change made.	
ITC Holdings	Comments:On R4.3.2:Assumptions regarding Low Voltage Ride Through (LVRT) capability are risky and not well understood. If the SDT feels this is a critical requirement that merits corrective action then we believe LVRT characteristics for various machine types should be developed through a NERC process. Without such "standards", it will be difficult to justify CAPs based on LVRT

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	assumptions. For example, would the Transmission Owner (TO) or Generator Owner be responsible for the cost of VAR CAPs if an LVRT assumption were violated. Can a TO require an LSE to install automatic load shedding for an LVRT assumption when cascade or local load loss result from an LVRT assumption? In addition, as the SDT has already indicated, the industry is still in a learning curve regarding the dynamic behavior of certain loads. If LVRT capability is considered as a critical requirement, then what about High Voltage Ride Through (HVRT) capability? The violation of HVRT could also cause certain damages to the system. R4.4.1 - (contingency list coordination with neighbors) It's unclear as to the "measure" for this requirement. Do you give your neighbor a list of "contingencies" in your area. Should it include all categories (p1 thru p7 for example)? Does your neighbor have to study a cascade situation in his system caused by an outage in your system? Are joint studies merited? More importantly, if an outage in a neighboring system requires a CAP, who's responsible, particularly if the CAP involves the neighboring system. Does the neighbor have to have a CAP, according to this standard, if the violation is in your system, and the CAP is in his? Who pays? Are you putting a study burden on your neighbor when you do this? Do you include additional contingencies to ensure that you do not miss a contingency that might impact your neighbors system to avoid any potential compliance implication on you?
Response: Part 4.3.2: There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. And yes, you can make System improvements based on reasonable assumptions. The SDT does not believe that high voltage ride through of generators has been an issue in past events like low voltage ride through has been. Thus, there is no need to include it in the standard. Part 4.4.1: The intent of the requirement is to give your neighbor a list of Contingencies (P1-P7) for which you have observed an impact to the neighbor's System. Your neighbor will then study those Contingencies. Joint studies are not required. If a Contingency on a neighbor's System causes a problem on your System, you must find a solution and the reverse situation is the same.	
TVA System Planning	For R4.1.2. Suggested change: For planning events P2 through P7: A generator that pulls out of synchronism shall be considered in the simulations and the resulting apparent impedance swings shall not result in the tripping of any Transmission System elements other than the generating unit and its directly connected Facilities." [Since often tripping a out of step generator reduces impedance swings, if the simulation shows acceptable impedance swings and voltage levels without tripping the generator, why would we be required to determine the tripping time and simulate tripping in each of the simulations that we have to run for these event categories? Without the suggested change involving the word "considered", significant extra effort would be required to perform simulations for small generators with no added benefit in achieving the purpose of assuring that impedance swings from generators are not passing through lines on the Bulk Electric System for events P2-P7. 4.3.3. Suggested change: Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers when such devices impact the study area. Without this change, a significant amount of effort would be required (with no added benefit) to evaluate protection systems all over the grid that have little or no impact on the study area.

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	R4.3.1: add "if reclosing is actually used as part of a protection system" to the end of the sentence.
Response: Part 4.1.2: The SDT agrees with the concern and has modified Requirement R4, part 4.1.2. **Requirement R4, part 4.1.2** - For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities Part 4.3.3: This does not necessarily require modeling of specific relays all over the grid. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. Therefore, the SDT does not see a need to add words that specifically limit the simulation of these impacts to the study area. No change made. Part 4.3.1: The requirement is to consider the impact of high speed reclosing. This does not mean that you need to study high speed reclosing if you are not using it. No change made.	
SERC Dynamics Review Subcommittee (DRS)	It is not clear as to the expectations of standard drafting team for dynamic modeling of relays. Parts 4.1.2 and 4.3.3 imply that all transmission relays may need to be explicitly modeled in the dynamic simulations. Is this the team's intent, please clarify? For R4.1.2. Suggested change: Replace word "tripped" with "considered". Reasoning: Since often tripping an out-of-step generator reduces impedance swings, if the simulation shows acceptable impedance swings and voltage levels without tripping the generator, why would we be required to determine the tripping time and simulate tripping in each of the simulations that we have to run for these event categories? Without the suggested change involving the word "considered", significant extra effort would be required to perform simulations for small generators with no added benefit in achieving the purpose of assuring that impedance swings from generators are not passing through lines on the Bulk Electric System for events P2-P7. Part 4.3.1: add "when used as part of a protection system" to the end of the sentence. Part 4.3.3: add "when such devices affect the study area" to the end of the sentence. Part 4.4: place a space between words "Table 1" and "that".
Response: Parts 4.1.2 & 4.3.3: This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. Part 4.1.2: The SDT agrees with the concern and has modified Requirement R4, part 4.1.2. **Requirement R4, part 4.1.2** - For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities Part 4.3.1: The requirement is to consider the impact of high speed reclosing. This does not mean that you need to study high speed reclosing if you are not using it. No change made. Part 4.3.3: As stated above, a generic relay model can be used to meet this requirement. Therefore, the SDT does not see a need to add words that specifically limit the simulation of these impacts to the study area. No change made.	

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Part 4.4: The typo has been corrected.	
SERC Planning Standards Subcommittee	It is not clear as to the expectations of standard drafting team for dynamic modeling of relays. Parts 4.1.2 and 4.3.3 imply that transmission relays may need to be explicitly modeled in the dynamic simulations. Is this the team's intent, please clarify? Part 4.3.1: add "when used as part of a protection system" to the end of the sentence. Part 4.3.3: add "when such devices affect the study area" to the end of the sentence.
Response: Parts 4.1.2 & 4.3.3: This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. Part 4.3.1: The requirement is to consider the impact of high speed reclosing. This does not mean that you need to study high speed reclosing if you are not using it. No change made. Part 4.3.3: As stated above, a generic relay model can be used to meet this requirement. Therefore, the SDT does not see a need to add words that specifically limit the simulation of these impacts to the study area. No change made.	
Ameren	It is not clear as to the expectations of the standard drafting team for dynamic modeling of relays. Requirements 4.1.2 and 4.3.3 imply that transmission relays may need to be explicitly modeled in the dynamic simulations. Is this the team's intent? If so, has the team given consideration to the availability of relay models in the commonly used Power System simulation software programs, and considered the cost and effort required for such implementation versus the expected benefits? Is there any historical experience that would imply that such modeling is crucial to the reliability of the BES? It is suggested that generators that pull out of synchronism be given consideration for their effects on the system, without requiring simulation of generator tripping in R4.1.2. Requirement R4.3.1 needs to include some additional language regarding the automatic restoration of facilities and allowance of high-speed reclosing. The following language is suggested: Simulate the removal of all elements that the Protection System is expected to disconnect and the restoration of all elements that the automatic controls are expected to restore for each Contingency without operator intervention while also considering the impact of successful or unsuccessful high-speed reclosing, if high-speed reclosing is employed. R4.3.3: Suggested wording addition: "for those devices relevant to the study area." A space needs to be added between "Table 1" and "that" in Requirement 4.4.
Response: Parts 4.1.2 & 4.3.3: This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. Part 4.1.2: The SDT agrees with the concern and has modified 4.1.2.	

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Requirement R4, part 4.1.2 - For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities Part 4.3.1: The SDT does not see the need for the standard to specify other automatic controls. No change made. Part 4.3.3: As stated above, a generic relay model can be used to meet this requirement. Therefore, the SDT does not see a need to add words that specifically limit the simulation of these impacts to the study area. No change made. Part 4.4: The typo has been corrected.	
Utility System Efficiencies, Inc. (USE)	It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
Response: Part 4.3: The Contingency analyses in Requirement R4, part 4.3 refer to the studies in Requirement R4, parts 4.1 and 4.2. However, for additional clarity, Requirement R4, part 4.3 has been modified. **Requirement R4, part 4.3** - Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall : Part 4.3.1: The Standard requires you to study only the events which produce more severe System impacts. If two Systems are swinging apart, then successful high speed reclosing could show a more severe impact. However, if successful reclosing is not expected to produce a more severe impact, you are not required to study it.	
MidAmerican Energy Company	MidAmerican commends the SDT for their hard work on this standard. MidAmerican does have comments about this requirement though. MidAmerican urges that the SDT delete 4.1.1 which requires that no generating unit shall pull out of synchronism during a stability analysis. A generating unit pulling out of synchronism does not necessarily result in thermal, voltage, or stability violations and does not necessarily result in cascading, instability, or uncontrolled separation. The loss of synchronism and tripping of a generator is in effect no different than tripping due to mechanical issues such as tube leaks. Present electric grid design that allows tripping for out-of-synchronism is reliable and secure. Adding the requirement that no unit may pull out of synchronism goes well beyond current grid design practices. MidAmerican believes that 4.1.2 and 4.3.3 as written would require responsible entities in the industry to add additional modeling of relaying in dynamic stability models of our system. MidAmerican suggests that 4.3.3 be limited to transient swings on facilities 345 kV and above so as to limit this part of requirement 4 to those situations that are most likely to result in cascading. If the SDT determines not to add such a limitation, MidAmerican asks that the implementation time for R4 to be increased. MidAmerican believes that many responsible entities would need 3 years to add these relaying models to system stability models so that the fourth year additional transmission planning analysis in this respect is conducted. MidAmerican urges that the SDT increase the implementation time for R4 from 2 years to 4 years. (MidAmerican also made this comment under Question 11.)? 4.3.1 indicates that for stability contingency analysis shall be performed to “Simulate the removal of all elements that the

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	Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention while also considering the impact of successful or unsuccessful high speed reclosing." MidAmerican believes that it is over-kill to provide this as a general requirement as written. In such a case, such successful or unsuccessful high speed reclosing analysis conceivably would need to be performed for numerous unnecessary situations given the generally wide spread use of high speed reclosing on transmissions systems. MidAmerican urges the SDT to revise this requirement to only require the study of successful and unsuccessful high speed reclosing where high speed reclosing has been added to resolve a specific stability issue such as a breaker closing angle issue." 4.5 MidAmerican believes that the extreme events that should be studied are the more credible ones. The credible events are those that the planner considers credible when considering both how severe the event is and how likely it is. For example, while a tornado might be the most severe event, its likelihood of hitting key facilities is low. It is more likely to have a severe thunderstorm that hits key facilities but causes less impact on the system. The planner should plan for the severe thunderstorm but perhaps should not plan for the tornado. MidAmerican recommends that 4.5 be revised to indicate that a list of those events that "produce more severe System impacts AND ARE MORE LIKELY" (the words in all caps are suggested words to be added) be studied as being more credible events. Then the purpose of the last sentence in 4.5 is clearer in that possible actions that reduce the likelihood or mitigate the consequences of the events shall be reviewed for those contingencies where likelihood in combination with consequences justify such evaluation. MidAmerican recommends the data retention for R4 and M4 be revised to change "All" to "The". The word "All" is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: "THE studies performed in support". The word in all caps is a word suggested to be added.

Response: Part 4.1.1: The SDT disagrees. A unit's pulling out of synchronism for a normally cleared fault is an indication of a weak Transmission System or insufficient relaying. A corrective action should be developed. No change made.

Parts 4.1.2 & 4.3.3: This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line.

Part 4.3.3: As stated above, a generic relay model can be used to meet this requirement. Therefore, the SDT does not see a need to add words that specifically limit the simulation of these impacts to only high voltage lines. No change made.

Part 4.3.3: Because this requirement does not necessarily require modeling of specific relays (as described directly above), the SDT does not agree that a longer time is needed in the Implementation Plan. No change made.

Part 4.3.1: The SDT disagrees. The requirement is to consider the impact of high speed reclosing. This does not mean that you need to study high speed reclosing if you are not using it. If you are using it, then it should be covered in the studies. No change made.

Part 4.5: The extreme events for Stability analysis cover Contingencies like 3-phase fault with stuck breaker or a 3-phase fault after an element has gone out of service prior to System adjustments. These events are less likely to occur than the Planning Events. The SDT does not see any need to add the suggested qualifier "are more likely" because by definition none of the extreme events are more likely.

The SDT agrees and has made the suggested change.

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TIS	Nowhere in the stability requirements is it necessary for evaluating the loss of all generators in a station; it is included in the steady state requirements. The standard should require examination of all units in a generating station where single line-to-ground faults on generation station buses could cause the clearing of the entire station. Further, single phase faults with delayed clearing (or stuck breaker) are not included. Often, such exclusion of stability analysis for loss of all generators at a station these are things that happen!
Response: The SDT excluded loss of all units at a generating station as an extreme event for Stability. In general there are no Contingencies that could cause this to happen in a Stability time frame of interest. If there are faults or faults with breaker failure which could cause the loss of all generators at a plant, then that event is required to be studied under the other planning or extreme events. Single phase faults with stuck breaker are included in planning event P4.	
Southern Company	Part 4.3.1: add "when used on the system" to the end of the sentence. This is needed to clarify that you don't have to study high speed reclosing if you don't utilize it.
Response: Part 4.3.1: The requirement is to consider the impact of high speed reclosing. This does not mean that you need to study high speed reclosing if you are not using it. No change made.	
Oklahoma Gas & Electric	R4 OG&E believes the Transmission Coordinator be held accountable for R4. The Transmission Coordinator should coordinate this type of study with the Transmission Planner for a regional look of the whole system. For example Southwest Power Pool should coordinate this type of study with the members of the Southwest Power Pool to better examine the entire region of the Southwest Power Pool. We do not see the need to duplicate the work. R4.4 & R4.5 There appear to be no standards of directions on identifying severe or extreme system impacts. OG&E does not like being held accountable to nebulas standards. Need more specific information.
Response: R4: The SDT assumes you meant to say Planning Coordinator rather than Transmission Coordinator (which is not in the Functional Model). Requirement R7 requires the Planning Coordinator and Transmission Planner to work out who will be conducting what studies. Parts 4.4 & 4.5: Use your engineering judgment to determine which Contingencies could produce more severe results. For example, it could be argued that faults close in to generating plants would be more severe than faults two busses away from the plant.	
MAPP	R4.1.1 & R4.1.2 - We propose that these sub-requirements be removed. The generating unit loss of synchronism does not necessary result in a thermal, voltage, or stability violations. R4.3.2 We suggest that this requirement be removed because it is premature to require Transmission Planners to simulate under voltage tripping until the MOD standards require it. If the drafting team does not remove this requirement we propose wording like, "Trip generating units that are connected to the BES when actual or assumed minimum generator transient voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment". The requirement should not apply to all relevant generating units until one of the MOD standards

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	requires all Generator Owners to provide their minimum generating unit voltage limits to the TP and PC. If the wording of R4.3.2 must be different from its counterpart, R3.3.2, then please explain the reasons for any differences. Add R4.3.5 We suggest the addition of R4.3.5, "Applicable System Operating Limits for the planning horizon shall not be exceeded." because Note "a" and "b" under "Stability Only" at the beginning of Table 1 are stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and hidden) in the performance notes of Table 1. [After R4.3.5 is added, Note "a" should revised and refer to R4.3.5.]
Response: Parts 4.1.1 & 4.1.2: The SDT disagrees. A unit's pulling out of synchronism for a normally cleared fault is an indication of a weak Transmission System or insufficient relaying. A corrective action should be developed. The SDT sees no reason to delete Requirement R4, parts 4.1.1 and 4.1.2. Part 4.3.2: The purpose of Requirement R4, part 4.3.2 is to take into account the low voltage ride-through capability of generators in the studies. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. Your proposed wording is not significantly different from the existing wording. No change made. Part 4.3.2: To be consistent with Requirement R4, part 4.3.2, Requirement R3, part 3.3.2 has been modified to also allow the use of voltages on the high side of the GSU. The use of voltages on the high side of the GSU allows greater flexibility in applying voltage ride-through capability of generators - some of which are defined on the high side of the GSU. **Requirement R3, part 3.3.2** - Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. Part 4.3.5: The SDT does not see a need for making these header notes into requirements. These apply more directly as qualifiers for the results of the simulations and therefore, they fit better as header notes to the Table. No change made.	
NERC Standards Review Subcommittee	R4.1.1 & R4.1.2 The MRO NSRS proposes that these sub-requirements be removed. The generating unit loss of synchronism does not necessary result in a thermal, voltage, or stability violations.R4.1.1 - Wording from R4.1.1 about no generating unit pulling out of synchronism should be deleted. The simple loss of synchronism of a unit or even multiple units does not necessarily result in thermal, voltage, or stability. All standards and requirements should demonstrate a reliability related basis. There is no direct reliability or security requirement that prevents a unit from loosing synchronism. The loss of a unit from synchronism is no different than the regular loss of the unit for mechanical reasons, therefore this requirement unnecessarily results in FERC directing utilities to build infrastructure beyond what is needed for system security. R4.1.3 The MRO NSRS proposes that this sub-requirement be removed because there are no NERC power system damping standards. R.4.3.2 The MRO NSRS suggests that this requirement be removed because it is premature to requirement Transmission Planners to simulate under voltage tripping until the MOD standards require it. If the drafting team does not remove this requirement the MRO NSRS proposes wording like, "Trip generating units that are connected to the BES when actual or assumed minimum generator transient voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment". The requirement should not apply to all relevant

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	generating units until one of the MOD standards requires all Generator Owners to provide their minimum generating unit voltage limits to the Transmission Planner and Planning Coordinator. If the wording of R4.3.2 must be different from its counterpart, R3.3.2, then please explain the reasons for any differences. R4.3.3 Every dynamic event simulation involves power system transient swings. What are the size and scope of the transient swings and what is the scope of the system to be examined, to which this requirement is referring? Please reword this requirement to give the industry a better understanding of what is intended. As written R4.3.3, it might be interpreted to require responsible entities to add the modeling of all relaying instead of just pertinent. Perhaps, R4.3.3 should be limited to transient swings on facilities 345 kV and above so as to limit this part of requirement 4 to those situations that are most likely to result in cascading. If the SDT determines not to add such a limitation, the MRO NSRS proposes that the implementation time for R4 to be increased. The MRO NSRS believes that many responsible entities would need 3 years to add these relaying models to system stability models so that the fourth year additional transmission planning analysis in this respect is conducted. The MRO NSRS urges that the SDT increase the implementation time for R4 from 2 years to 4 years. When it may actually respond or triggered. R 4.3.1 This requirement refers to high speed reclosing and the MRO NSRS presumes that this is special high speed reclosing that is completed in several cycles, rather than the normal high speed reclosing that is completed in a number of seconds. The MRO NSRS recommends that the term high speed reclosing be defined for this sub-requirement with an angular stability component. R4.5 - The MRO NSRS believes that the extreme events that should be studied are the more credible ones. The credible events are those that the planner considers credible when considering both how severe the event is and how likely it is. For example, while a tornado might be the most severe event, its likelihood of hitting key facilities is quite low. It is more likely to have a severe thunderstorm that hits key facilities but causes less impact on the system. The planner should plan for the severe thunderstorm but perhaps should not plan for the tornado. The MRO NSRS recommends that 4.5 be revised to indicate that a list of those events that "produce more severe System impacts and are more likely" (the bolded words are suggested words to be added) be studied as being more credible events. Then the purpose of the last sentence in 4.5 is clearer in that possible actions that reduce the likelihood or mitigate the consequences of the events shall be reviewed for those contingencies where likelihood in combination with consequences justify such evaluation.
Response: Parts 4.1.1 & 4.1.2: The SDT disagrees. A unit's pulling out of synchronism for a normally cleared fault is an indication of a weak Transmission System or insufficient relaying. A corrective action should be developed. The SDT sees no reason to delete Requirement R4, parts 4.1.1 and 4.1.2. Part 4.1.3: Requirement R4, part 4.1.3 requires the Planning Coordinator and Transmission Planner to use their engineering judgment on what constitutes acceptable damping. The SDT did not think it appropriate to prescribe what acceptable damping is. Most Planning Coordinator's and Transmission Planner's should already have this kind of criteria for their systems. No change made. Part 4.3.2: The purpose of Requirement R4, part 4.3.2 is to take into account the low voltage ride-through capability of generators in the studies. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. Your proposed	

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wording is not significantly different from the existing wording. No change made. Part 4.3.2: To be consistent with Requirement R4, part 4.3.2., Requirement R3, art 3.3.2 has been modified to also allow the use of voltages on the high side of the GSU. The use of voltages on the high side of the GSU allows greater flexibility in applying voltage ride-through capability of generators - some of which are defined on the high side of the GSU. **Requirement R3, part 3.3.2** - Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. Part 4.3.3: This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. Therefore, the SDT does not believe this should be limited to only high voltage lines. Because this requirement does not necessarily require modeling of specific relays, the SDT also does not agree that a longer time is needed in the Implementation Plan. Part 4.3.1: The SDT believes that there is general understanding in the industry that reclosing that is accomplished in a number of seconds is not high speed reclosing. It is just known as reclosing. High speed reclosing would occur within a second after fault clearing. Part 4.5: The extreme events for Stability analysis cover Contingencies like 3-phase fault with stuck breaker or a 3-phase fault after an element has gone out of service prior to System adjustments. These events are less likely to occur than the planning events. The SDT does not see any need to add the suggested qualifier "are more likely" because by definition none of the extreme events are more likely.	
Sacramento Municipal Utility District	R4.1.1: There appears to be a conflict between what is not allowed for a generator in R4.1.1 and what is allowed in Note (b) of Table 1 (consequential generation loss " which is an undefined term " and hence can be interpreted as one sees fit). R4.3.3: It is unclear what is expected from this requirement. Are Protection personnel to take the results of the transient stability simulation and determine its impact on the Protection System? Or, is it that the Protection System should be properly modeled in stability simulations? If it is the latter, this requirement is already covered by R4.3.1 (simulate the removal of all elements). R4.3.2: If done right, this requirement should be already complied with under R4.3.1. If it needs to be spelled out, a better place may be in the MOD Standards. R4.4 and R4.5: Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3.R4.3.1 appears to require an assessment of both successful and unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both, we suggest including the assessment in the list of sensitivities.
Response: Part 4.1.1: The generation loss referred to in note b is the generation that is disconnected from the System by fault clearing action. This is completely different from a generator pulling out of synchronism. Part 4.3.3: The requirement is to take into account the impact of transient swings. This does not necessarily require modeling of specific relays. Some dynamic	

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simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. Part 4.3.2: Requirement R4, part 4.3.1 requires simulating the removal of elements which must be removed to clear the fault. Requirement R4, part 4.3.2 involves generator low voltage ride-through and tripping the generator when voltages are too low. These are two completely different things. Parts 4.4 & 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made. Part 4.3: The Contingency analyses in Requirement R4, part 4.3 refer to the studies in Requirement R4, parts 4.1 and 4.2. However, for additional clarity, Requirement R4, part 4.3 has been modified. **Requirement R4, part 4.3** - Contingency analyses for Requirement R4, parts 4.1 and 4.2 shall : Part 4.3.1: The Standard requires you to study only the events which produce more severe System impacts. If two Systems are swinging apart, then successful high speed reclosing could show a more severe impact. However, if successful reclosing is not expected to produce a more severe impact, you are not required to study it.	
Manitoba Hydro	R4.1.2: For P2 events, a generator that pulls out of synchronism must be tripped. Tripping of the generator could result in Interruption of Firm Transmission Service unless redispatch is allowed - Footnote 9 should be allowed. R4.1.3 states that “power oscillation shall exhibit acceptable damping as established by the PC and TP”. There is no requirement for the PC or TP to develop criteria for acceptable damping. Requirement R5 or R6 should be expanded to require the PC and TP to establish criteria for acceptable power oscillation damping. R4.2: Recommend changing “the list” to “the Contingency list” to add clarity and consistency.
Response: The SDT agrees and has changed Table 1 so that footnote 9 applies to planning event P2. Part 4.1.3: There doesn't have to be a specific requirement for the Planning Coordinator and Transmission Planner to establish damping criteria. Most should already have such a criteria. No change made. Part R4.2: The SDT does not see any value in adding the word "Contingency" to the word "list". No change made.	
Duke Energy	R4.3.3 must be clarified regarding what method is to be used for assessing the impact of transient swings on Protection System operation. For example, how is this to be included in models, is this referring to a post simulation evaluation comparing results to actual relay settings, etc?? R4.5 includes the phrase “cascading outages”. We believe that the word “cascading” should be the capitalized NERC-defined term “Cascading”.
Response: Part 4.3.3: The requirement is to take into account the impact of transient swings. This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. Part 4.5: The SDT has modified Requirement R4, part 4.5 to use the term "Cascading" rather than "cascading outages."	

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Requirement R4, part 4.5 - Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R4, part 4.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.	
NorthWestern Energy	R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. We suggest moving both R4.4 and R4.5 into R4.1 and R4.2, then R4.4 and R4.5 could be deleted. R4.3 is unclear whether the Contingency analyses need to be performed for all planning events or only the more severe events referenced in R4.1 and R4.2. R4.3 needs clarification. R4.3.1 requires considering the impact of both successful and unsuccessful high-speed reclosing. Since successful reclosing is a much less severe event, it seems unnecessary to assess both. If entities need to assess both, the assessment could be in the list of sensitivities. R4.5 needs to be modified. It would be better to combine R4.2 and R4.5. The first part of the requirement requires identification of events that produce more severe System impacts. The presumed reason that the other contingencies were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be examples of more severe Extreme Contingencies than the one selected for study. This can be achieved by simply choosing events that are even less credible. For example, if the Extreme Contingency studied was a simultaneous loss of 3 transmission lines with the failure of redundant RAS (SPS), then an event resulting in the simultaneous loss of 4 lines with the failure of 2 sets of redundant RASs would be even more severe. Listing all possible extreme events could result in a limitless list.
Response: Parts 4.4 & 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made. Part 4.3: The Contingency analyses in Requirement R4, part 4.3 refer to the studies in Requirement R4, parts 4.1 and 4.2. However, for additional clarity, Requirement R4, part 4.3 has been modified. **Requirement R4, part 4.3** - Contingency analyses for Requirement R4, parts 4.1 and 4.2 shall : Part 4.3.1: The Standard requires you to study only the events which produce more severe System impacts. If two Systems are swinging apart, then successful high speed reclosing could show a more severe impact. However, if successful reclosing is not expected to produce a more severe impact, you are not required to study it. Part 4.5: Requirement R4, Part 4.5 refers to the Contingency events listed in the extreme event Stability section of Table 1. Your example does not fall into the events listed. For this analysis you don't just keep adding more and more outaged elements. You only have to do the ones listed in the Table that would be expected to produce more severe results.	
Northeast Power Coordinating Council--RSC	Requirement 4.1.1: This should be revised to only be applicable to generators interconnected to the BES. This may need an implementation period as not all existing units are interconnected in accordance with the standard as proposed. As written this applies to small generators and doesn't necessarily reflect reliability of the network. 20 MW is a recommended generator minimum size. Requirement 4.1.2: Simulating the tripping of a generator that pulls out of synchronism is presently not modeled and will require

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	an implementation period. Requirement 4.2: This requirement should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. Requirement 4.4 NPCC strongly suggests making this requirement a sub-bullet of Requirement 4.1 to keep the related requirements together. Requirement 4.5 NPCC strongly suggests making this requirement a sub-bullet of Requirement 4.2 to keep the related requirements together. This requirement needs clarification as to what is specifically required for the "evaluation of possible actions." The list associated with Requirement 2. part 2.7.1 provides examples of possible actions, and leaving "evaluation" undefined offers the Planning Coordinator and Transmission Planner the leeway to use judgment in making their evaluations.
Response: Part 4.1.1: The standard applies only to the BES as defined by your Region.. No change made. Part 4.1.2: Tripping the generator is no longer required. The SDT has modified Requirement R4, part 4.1.2. **Requirement R4, part 4.1.2** - For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities. Part 4.2: The SDT disagrees and believes there is value in running extreme event analysis. No change made. Part 4.4: The SDT does not believe that combining the requirements serves any purpose. No change made. Part 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made. The requirement is to evaluate possible actions which could reduce the likelihood or mitigate the consequences of the event. The standard should not prescribe those actions. It is up to your judgment what those possible actions could be.	
Midwest ISO	Requirement R4.3.1: Please consider adding the following language to the end of the sentence "when used as part of a protection system". Requirement R4.3.1: Please consider adding the following language to the end of the sentence "when such devices affect the study area".
Response: Part 4.3.1: The requirement is to consider the impact of high speed reclosing. This does not mean that you need to study high speed reclosing if you are not using it. No change made. Part 4.3.1: High speed reclosing would be considered only for the line you are studying. Therefore, it always impacts the study area. No change made.	
Hydro-Québec TransEnergie	Requirements 3.5 and 4.5 Both of these requirements need clarification as to what is specifically required for the "evaluation of

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(HQT)	possible actions." Requirement 4.4 HQT, as does NPCC, strongly suggests making this requirement a sub-bullet of Requirement 4.1 to keep the related requirements together. Requirement 4.5 HQT, as does NPCC, strongly suggests making this requirement a sub-bullet of Requirement 4.2 to keep the related requirements together.
Response: Part 4.5: "An evaluation of actions designed to reduce" means looking for ways to reduce the probability of the event occurring or reducing the magnitude of the consequences of that event. For example, if a three phase fault with a bus differential failing to operate results in the collapse of a large Load area, a possible action would be to add a redundant bus differential relay. This reduces the probability of the event occurring. Or if a three phase fault with a stuck breaker results in a large area of the System pulling out of synchronism, an SPS could be used to trip a generator and keep the rest of the System in synchronism. This would reduce the magnitude of the consequences of the event. The evaluation would be comparing potential solutions and their cost with the consequences of the event to determine the best course of action to take (if any). Part 4.4: The SDT does not believe that combining the requirements serves any purpose. No change made. Part 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made.	
Bonneville Power Administration	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
Idaho Power	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful and unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
Modesto Irrigation District Transmission Planning	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more

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	severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
NV Energy	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
Pacific Gas and Electric Co.	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
Puget Sound Energy, Inc.	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.41 requires clarification. With respect to these “Contingencies on adjacent systems,” the responsibility of listing and analyzing these events needs to be clarified. Should the event simulation be the responsibility of the “neighboring” system (where the event would occur) or the adjacent system that may feel the impact of this event? Per the developed rationale from R4.4, the neighboring system may determine that a particular event is “less severe” and hence not studied, even though this event may potentially impact a neighbor. Further, for these “Contingencies on adjacent systems” that result in system performance outside one’s own operating limits, it is unclear who is responsible for mitigating these contingencies. It is potentially awkward in that one entity may be planning another entity’s system improvements.
San Diego Gas & Electric Co	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted.

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	It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
Southern California Edison (SCE)	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. t is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
SRP	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
Western Area Power Adm - RMR	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2, respectively. I Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful and unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both.

Response: Parts 4.4 & 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made.

Part 4.3: The Contingency analyses in Requirement R4, part 4.3 refer to the studies in Requirement R4, parts 4.1 and 4.2. However, for additional clarity, Requirement R4, part 4.3 has been modified.

Requirement R4, part 4.3 - Contingency analyses for Requirement R4, parts 4.1 and 4.2 shall :

Part 4.3.1: The Standard requires you to study only the events which produce more severe System impacts. If two Systems are swinging apart, then successful high

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speed reclosing could show a more severe impact. However, if successful reclosing is not expected to produce a more severe impact, you are not required to study it. No change made.	
National Grid	Sub-Requirement 4.1.1: This should be revised to only be applicable to generators interconnected to the BES. This may need an implementation period as not all existing units are interconnected in accordance with the standard as proposed. As written this applies to small generators and doesn't necessarily reflect reliability of the network. 20 MW is a recommended generator minimum size. Sub-Requirement 4.1.2: Simulating the tripping of a generator that pulls out of synchronism is presently not modeled and will require implementation period. Sub-Requirement 4.2: This requirement should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. Sub-Requirement 4.4: It is strongly suggested that this requirement is made a sub-bullet of Requirement 4.1 to keep the related requirements together. Sub-Requirement 4.5: It is strongly suggested that this requirement is made a sub-bullet of Requirement 4.2 to keep the related requirements together. Provide clarification as to what is specifically required for the "evaluation of possible actions."
Response: Part 4.1.1: The standard applies only to the BES as defined by your Region. No change made. Part 4.1.2: Tripping the generator is no longer required. The SDT has modified Requirement R4, part 4.1.2. **Requirement R4, part 4.1.2** - For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities. Part 4.2: The SDT disagrees and believes there is value in running extreme event analysis. No change made. Part 4.4: The SDT does not believe that combining the requirements serves any purpose. No change made. Part 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made. Part 4.5: "An evaluation of actions designed to reduce" means looking for ways to reduce the probability of the event occurring or reducing the magnitude of the consequences of that event. For example, if a three phase fault with a bus differential failing to operate results in the collapse of a large Load area, a possible action would be to add a redundant bus differential relay. This reduces the probability of the event occurring. Or if a three phase fault with a stuck breaker results in a large area of the system pulling out of synchronism, an SPS could be used to trip a generator and keep the rest of the system in synchronism. This would reduce the magnitude of the consequences of the event. The evaluation would be comparing potential solutions and their cost with the consequences of the event to determine the best course of action to take (if any).	
Tri-State Generation and	The standard needs to use the term "Dynamic Stability", not just "Stability", to differentiate between dynamic and voltage stability

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Transmission Association	considerations. R4.1 contains the phrase "based on the Contingency list created in Requirement R4.4". The contingency list is referred to in R4.4 (and R3.4), but is not created there. In R4.3.1 the requirement for additional evaluation of "successful or unsuccessful high speed reclosing" is an additional performance requirement. Whether this refers to the possibility of reclosing mechanism failure, or the effectiveness of reclosing operations (there is some ambiguity here). The reference to high speed reclosing in R4.3.1 is a good addition. For ease in auditing, it should be listed as a separate requirement (or sub-requirement).
Response: The SDT does not see any need to use that term as it does not provide any needed clarity. No change made. Parts 4.1 & 4.4: The Contingency list is created in Requirement R4, part 4.4. The SDT does not understand your comment. Part 4.3.1: The SDT does not see any value in making this a separate requirement. No change made.	
American Transmission Company	We propose the following changes and pose the following questions: R4.1.1 We suggest that there should be some qualification of which generating units are referred to in this requirement. We propose that the requirement say, "No generating unit connected to the BES shall pull out of synchronism." For example, some utilities include smaller generation units that are connected at voltages below 100 kV and even down to distribution voltage in their base cases. R4.1.2 We propose that the wording of this requirement be revised to reflect the same BES qualification of the generating unit that we noted in R4.1.1 above. 4.3.1 This requirement refers to high speed reclosing and we presume that this is special high speed reclosing that is completed in several cycles, rather than the normal high speed reclosing that is completed in a number of seconds. We recommend that the term high speed reclosing be defined for this sub-requirement.R. 4.3.2 We suggest qualifying which generating units to consider and which voltage limits to simulate with revised wording like, "Trip generating units that are connected to the BES when actual or assumed minimum generator transient voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment". The requirement should not apply to all relevant generating units until one of the MOD standards requires all Generator Owners to provide their minimum generating unit voltage limits to the TP and PC. If the wording of R4.3.2 must be different from its counterpart, R3.3.2, then please explain the reasons for any differences. R4.3.3 Every dynamic event simulation involves power system transient swings. What are the size and scope of the transient swings and what is the scope of the system to be examined, to which this requirement is referring? Please reword this requirement to give the industry a better understanding of what is intended. Add R4.3.5 We suggest the addition of R4.3.5, "Applicable System Operating Limits for the planning horizon shall not be exceeded." Note "a" and "b" under "Stability Only" at the beginning of Table 1 are stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and basically

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	hidden) in the performance notes of Table 1. [After R4.3.5 is added, Note "a" should be revised and refer to R4.3.5.] Add R4.3.5 We suggest the addition of R4.3.5, "Applicable System Operating Limits for the planning horizon shall not be exceeded." because Note "a" and "b" under "Steady State Only" at the beginning of Table 1 is stated in the form of a Requirement (e.g. note usage of the verb, "shall") and all Requirements should be clearly included in the body of the standard and not be introduced (and basically hidden) in the performance notes of Table 1. [After R3.3.5 is added, Note "a" should allude to R3.3.5.]
Response: Part 4.1.1: The standard applies only to the BES as defined by your Region. No change made. Part 4.1.2: The standard applies only to the BES as defined by your region. No change made. Part 4.3.1: The SDT believes that there is general understanding in the industry that reclosing that is accomplished in a number of seconds is not high speed reclosing. It is just known as reclosing. High speed reclosing would occur within a second after fault clearing. Part 4.3.2: The purpose of Requirement R4, part 4.3.2 is to take into account the low voltage ride-through capability of generators in the studies. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. Your proposed wording is not significantly different from the existing wording. No change made. Part 4.3.2: To be consistent with Requirement R4, part 4.3.2, Requirement R3, part 3.3.2 has been modified to also allow the use of voltages on the high side of the GSU. The use of voltages on the high side of the GSU allows greater flexibility in applying voltage ride-through capability of generators - some of which are defined on the high side of the GSU. **Requirement R3, part 3.3.2** - Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. Part 4.3.3: The requirement is to take into account the impact of transient swings. This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. Part 4.3.5: The SDT does not see a need for making these header notes into requirements. These apply more directly as qualifiers for the results of the simulations and therefore, they fit better as header notes to the Table.	
American Electric Power	We recommend inserting "unstable" in the requirement language as follows: "Simulate the impact of unstable transient swings on Protection System operation?" Our perception is that the wording of 4.3.3 is almost certain to require the representation of impedance relay characteristics on both ends of all lines in a study area in order to satisfy an audit, and would eventually require representation on both ends of all BES lines as all areas would be studied at some point. This sub-requirement would place a huge burden on transmission planning and protection engineering staff. Experience has shown that tripping of transmission lines or transformers on stable swings is extremely rare. The burden this sub-requirement would cause as presently worded is not commensurate with the expected benefit.
Response: Part 4.3.3: The requirement is to take into account the impact of transient swings. This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a	

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branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. The SDT does not agree to insert the word "unstable" before "transient swings" because some stable swings can get into relay characteristics.	
FRCC Transmission Working Group	With regard to the Moderate VSL, consider deleting “utilizing data” in order to avoid penalizing twice for failing to meet R1. 4.1.1, suggest rewording “(a) generator being disconnected from the Bulk Electric System “, system as defined in the Glossary includes distribution, and we do not believe that is the intent of the SDT. 4.1.2, 4.3.1 and 4.3.3 essentially requirerequires modeling every Zone 3 (or higher, such as Zone 5) relay in each Interconnection (or at least in the Region under study and adjacent regions) because, in order to simulate the impact of a power swing on a distance relay, one would need to know the characteristics of the distance relay and how long the transient swing remains within that characteristic, which means modeling the relay. Is that the intent of the SDT?
Response: Requirement R1 requires you to maintain System models. Requirement R4 requires you to use that model data for your Stability studies. These are two different things requiring two VSLs. No change made. Part 4.1.1: The standard applies only to the BES as defined by your Region. No change made. Parts 4.1.2, 4.3.1, & 4.3.3: This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line.	
E.ON U.S.	With respect to Category P6, a Multiple Contingency event (the overlapping occurrence of two or more single events) allows Non-Consequential Load Loss. The "System adjustments" do not list yet do not exclude Load Shedding. E.ON U.S believes that Load Shedding should be included as an option in similar manner to Curtailment of Firm Transmission Service. If the SDT disagrees with this recommendation, then E.ON U.S. suggests that the SDT clearly state the allowed use of Load Shedding. E.ON U.S. observes that in the case of Extreme Events the SDT provided the following response to a previous comment:Extreme event 2d and 3a are similar in that each covers the loss of all generating units at a single plant location. However, in 3a, two plants are reviewed. In each case, all units are to be outaged regardless of the BES voltage level to which they connect.E.ON U.S. recommends that the word "station" in event 2d to be changed "plant".
Response: In Event P6 the term System adjustments has a reference to footnote 9. This footnote clearly states that System adjustments do not include the shedding of firm Demand. The allowable loss of Non-Consequential Load for event P6 refers to after the second Contingency has occurred. The SDT agrees that there needs to be consistency and has changed the word "plants" to "stations" in extreme event 3a.	
Oncor Electric Delivery	Within “stability requirements” there is no requirement for evaluating the loss of all generators in a station; it is included in the steady state requirements. We recommend that the standard require examination of all units in a generating station where single line-to-ground faults on generation station buses could result in clearing of the entire station. Furthermore, single phase faults with delayed clearing (or stuck breaker) are not included. Often, such exclusion of stability

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	analysis for loss of all generators at a station these are things that happen! 4.1.1 This should be dropped. As written, this applies to small generators and doesn't necessarily reflect reliaiblity of the network. 4.1.2 This is not presently modeled and will require implementation period 4.2 Why do we need to do study extreme events? The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. 4.4 It is strongly suggested that this requirement is made a sub-bullet of Requirement 4.1 to keep the related requirements together. 4.5 It is strongly suggested that this requirement is made a sub-bullet of Requirement 4.2 to keep the related requirements together.
Response: The SDT excluded loss of all units at a generating station as an extreme event for Stability. In general there are no Contingencies that could cause this to happen in a Stability time frame of interest. If there are faults or faults with breaker failure which could cause the loss of all generators at a plant, then that event is required to be studied under the other planning or extreme Events. No change made. Single phase faults with stuck breaker are included in planning event P4. Part 4.1.1: The SDT believes that Part 4.1.1 is required for BES reliability. The standard applies only to the BES as defined by your Region. The SDT believes that all generators directly connected to the BES need to be stable for single Contingencies (P1). No change made. Part 4.1.2: Tripping the generator is no longer required. The SDT has modified Requirement R4, part 4.1.2. **Requirement R4, part 4.1.2** - For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities. Part 4.2: The SDT disagrees and believes there is value in running extreme event analysis. No change made. Part 4.4: The SDT does not believe that combining the requirements serves any purpose. No change made. Part 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made.	
PJM	in R4.1.2 – It should be made clear when the unit should be tripped. Timing is important in dynamics studies. Actual protection made need to be modeled to cover this item completely. In R4.3.3 - This protection information, is not commonly collected, at least by MMWG, and will take a great deal of time and effort to gather. R4.5 – Needs a 4.5.1 similar to 4.4.1.
Response: Part 4.1.2: Tripping the generator is no longer required. The SDT has modified Requirement R4, part 4.1.2. **Requirement R4, part 4.1.2** - For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent	

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	impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities Part 4.3.3: This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. The SDT believes the time allotted in the Implementation Plan is appropriate. Part 4.5: The SDT does not agree that a similar requirement is needed for extreme events. No change made.

5. Requirement R5 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement. (Note – This is a new requirement.)

Summary Consideration: Several commenters expressed concern with potential double jeopardy between this standard and the VAR standards. From the ERO Rules of Procedure, Appendix 4B- Sanction Guidelines, Section 3.10 Multiple Violations: "Strictly speaking, NERC or the regional entity can determine and levy a separate penalty or sanction, or direct remedial action, upon a violator for each individual violation. However, in instances of multiple violations related to a single act or common incidence of noncompliance, NERC or the regional entity will generally determine and issue a single aggregate penalty, sanction, or remedial action directive bearing reasonable relationship to the aggregate of the related violations. The penalty, sanction, or remedial action will not be that determined individually for the least serious of the violations; it will generally be at least as large or expansive as what would be called for individually for the most serious of the violations." The existing VAR standards (VAR-001-1a and VAR-002-1b) address the operational time horizon but do not address the planning horizon. NERC Standards Project 2008-1 is under development and the SAR addresses the planning horizon. As this project moves forward, the Standards Drafting Team for Project 2008-1 will more fully develop the requirements for reactive planning and will evaluate whether those requirements should reside in the TPL standard or the VAR standards.

Several commenters expressed concern that the requirement to develop a transient voltage response criterion was not limited to establishing a low voltage threshold. The SDT clarified that the minimum requirement for establishing a transient voltage response criterion was to establish a low voltage level and the maximum length of time that the transient voltages may remain below that level. To clarify the SDT's intent, the wording of R5 has been modified as follows:

R5. Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level.

Requirement R5 data retention: The documentation specifying the criteria since the last compliance audit in accordance with Requirement R5 and Measure M5.

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Independent Electricity System Operator	(1) We do not have any concern with the requirement as written, but suggest the SDT consider adding "and associated reactive power requirements" after "acceptable System steady state voltage limits" to take care of the concern raised in the recently posted SAR for a new VAR standard. We do not think a new standard is required for stipulating reactive power requirements as they are best addressed in the planning assessment criteria and the SOL/IROL determination requirements. (2) We do not have any comments on the measure, VRF, Time Horizon and VSL.
Response: 1) The SDT declines to add "and associated reactive power requirements". The Voltage and Reactive Planning and Control Project (2008-1) will more	

Organization	Comments for Question 5
fully develop the requirements for reactive planning and will evaluate whether those requirements should reside in the TPL standard or the VAR standards. 2) Thank you.	
MAPP	A voltage criterion is addressed by the VAR standards where they are applicable to TOs and TOPs. Including a voltage requirement in the planning standards appears to be creating a double-jeopardy exposure.
Response: As for the double jeopardy comment - From the ERO Rules of Procedure, Appendix 4B- Sanction Guidelines, Section 3.10 Multiple Violations: "Strictly speaking, NERC or the regional entity can determine and levy a separate penalty or sanction, or direct remedial action, upon a violator for each individual violation. However, in instances of multiple violations related to a single act or common incidence of noncompliance, NERC or the regional entity will generally determine and issue a single aggregate penalty, sanction, or remedial action directive bearing reasonable relationship to the aggregate of the related violations. The penalty, sanction, or remedial action will not be that determined individually for the least serious of the violations; it will generally be at least as large or expansive as what would be called for individually for the most serious of the violations." The existing VAR standards (VAR-001-1a and VAR-002-1b) address the operational time horizon but do not address the planning horizon. NERC Standards Project 2008-1 is under development and the SAR addresses the planning horizon. As this project moves forward, the Standards Drafting Team for Project 2008-1 will more fully develop the requirements for reactive planning and will evaluate whether those requirements should reside in the TPL standard or the VAR standards.	
NERC Standards Review Subcommittee	A. The MRO NSRS recommends the data retention for R5 and M5 be revised to change "All" to "The". The word "All" is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: "The documentation specifying the criteria since". B. This requirement should not include the criterion, "post-Contingency voltage deviation", because this criterion is not used widely enough in the industry to be a well established criterion.
Response: A. The SDT has modified the data retention for Requirement R5 to strike the word "All" and has replaced it with the word "The". **Requirement R5 data retention**: The documentation specifying the criteria since the last compliance audit in accordance with Requirement R5 and Measure M5. B. The SDT believes that the reference to 'post-Contingency voltage deviation' is widely used and is an acceptable reference in the standard. No change made.	
Progress Energy Florida, Inc.	As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all appropriate parties to review PEF's previous comments to this effect.
Response: Throughout the drafting process, the SDT has carefully considered your comments as well comments from other industry members.	
Idaho Power	As worded R5 is unclear. I interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. I suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."

Organization	Comments for Question 5
Bonneville Power Administration	As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
NV Energy	As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
Pacific Gas and Electric Co.	As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
Puget Sound Energy, Inc.	As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
Sacramento Municipal Utility District	As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
San Diego Gas & Electric Co	As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
Southern California Edison (SCE)	As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
SRP	As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum

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	length of time that transient voltage may remain below that level."
Western Area Power Adm - RMR	As worded, R5 is unclear. I interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. I suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
Response: The SDT clarified that the minimum for establishing a transient voltage response criterion was to establish a low voltage level and the maximum length of time that the transient voltages may remain below that level. **R5**. Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level.	
CenterPoint Energy	CenterPoint Energy is not familiar with the phrase "post-Contingency voltage deviations" and recommends that this phrase be deleted. Alternatively, the text should be revised to read "steady state post-contingency voltage limits." Including both phrases is unnecessary and confusing.
American Transmission Company	R5 This requirement should not include the criteria item, "post-Contingency voltage deviation", because this criteria is not used widely enough in the industry to be a well established criteria.
Response: The SDT believes that the term is widely used and believes that it is appropriate for inclusion in this standard. No change made.	
Deseret Power	Comments: As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
Response: The SDT clarified that the minimum for establishing a transient voltage response criterion was to establish a low voltage level and the maximum length of time that the transient voltages may remain below that level. **R5**. Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level.	
Omaha Public Power District	In the first sentence of the requirement text, change "voltage limits" to "voltage".
Response: The SDT believes that the use of "voltage limits" is correct. No change made.	

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TVA System Planning	In the VSL associated with R5, we believe that failure to define and document one of the criteria should be a moderate VSL, failure to define and document two criteria should me a high VSL, while failure to define and document three criteria should be a severe VSL. Otherwise failing to document only one criteria would result in a severe VSL.
Response: The SDT believes that establishing the criteria for acceptable voltage deviations should be a binary VSL. No change made.	
MidAmerican Energy Company	MidAmerican commends the SDT for their hard work on this standard. MidAmerican does have comments about this requirement though. MidAmerican recommends the data retention for R5 and M5 be revised to change "All" to "The". The word "All" is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: "THE documentation specifying the criteria since". The word in all caps is a word suggested to be added.
Response: The SDT has modified the data retention for R5 to strike the word "All" and has replaced it with the word "The". **Requirement R5 data retention**: The documentation specifying the criteria since the last compliance audit in accordance with Requirement R5 and Measure M5.	
NorthWestern Energy	R5 could be interpreted to address both high voltage and low voltage criteria. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level." This way high voltage is definitely excluded.
Modesto Irrigation District Transmission Planning	R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level.
Response: The SDT clarified that the minimum for establishing a transient voltage response criterion was to establish a low voltage level and the maximum length of time that the transient voltages may remain below that level. **R5**. Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level.	
Oklahoma Gas & Electric	R5 OG&E believes the Transmission Coordinator be held accountable for the transient voltage response portion of R5. The Transmission Coordinator should coordinate this type of voltage criteria with the Transmission Planner for a regional look of the whole system. For example Southwest Power Pool should coordinate this type of study with a stakeholder developed voltage criteria within the members of the Southwest Power Pool to better examine the entire region of the Southwest Power Pool. We do not see the need to duplicate the work.
Response: The SDT disagrees that only the transmission coordinator should be responsible for having a transient voltage response. Every planner, whether a	

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Transmission Planner or Planning Coordinator, needs to have a transient voltage response criterion to fully evaluate its portion of the BES.	
Midwest ISO	Requirement R5: Not all Transmission Planners have delta voltage criteria which this requirement will now require them to have. Looks like this requirement is not a one shoe fits all requirement.
Response: The SDT agrees that voltage criteria may not be a "one size fits all" criteria. This requirement requires each Transmission Planner and Planning Coordinator to have criteria for acceptable voltage limits.	
SERC Dynamics Review Subcommittee (DRS)	The content in the severe VSL column should be split among the lower, moderate, and high categories, with failure to include one element as Moderate and two elements as High. It is stated that the Transmission Planner and Planning Coordinator shall have criteria specifying voltage limits, post-contingency voltage deviations, and transient voltage response. How would an nteraction with a third party system be handled? For example a contingency causes a voltage deviation on one system that is within thevoltage deviation criteria, but causes a voltage deviation violation on a neighboring system that has a more stringent criterion.
SERC Planning Standards Subcommittee	The content in the severe VSL column should be split among the lower, moderate, and high categories, with failure to include one element as Moderate and two elements as High. It is stated that the Transmission Planner and Planning Coordinator shall have criteria specifying voltage limits, post-Contingency voltage deviations, and transient voltage response. How would an interaction with a third party system be handled? For example a contingency that occurs on a system that is within their voltage deviation criteria, but causes a voltage deviation violation on a neighboring system that has a more stringent criteria.
Response: The SDT believes that establishing the criteria for acceptable voltage deviations should be a binary VSL. No change made. This standard places the requirement for performance on each entity's portion of the BES (Requirement R2). In addition, Requirement R3, part 3.4.1 and Requirement R4, part 4.4.1 require the coordination of the Contingencies and Requirement R8 requires the distribution of the Planning Assessment. These requirements will ensure that third party impacts are identified.	
Lafayette Utilities System	The modified version resolves the confusion noted by several commenters in the earlier draft.
Response: Thank you.	
US Bureau of Reclamation	The requirement in Table 1 is for Planning Authority and Transmission Planner to establish accceptable voltage deviations and limits. The requirement only indicates the that each shall have a criteria. That does not imply an agreement on a single limit or deviation allowable under a System Steady State post-contingency condition.
Response: The SDT agrees with your statement.	
Progress Energy Carolinas	There appears to be a double-jeopardy issue related to voltage performance criteria related to the VAR Standards. The voltage and var criteria will also be required in VAR-001 and 002.

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TIS	There appears to be a double-jeopardy issue related to voltage performance criteria related to the VAR Standards.
National Grid	Voltage criteria are addressed by the VAR standards. Including a voltage requirement in the planning standards appears to be creating a double-jeopardy exposure. Also, implementing transient voltage criteria will require time.Replace "Each Transmission Planner and Planning Coordinator" with "Each Transmission Planner OR Planning Coordinator".
Northeast Power Coordinating Council--RSC	Voltage criteria are addressed by the VAR standards. Including a voltage requirement in the planning standards appears to be creating a double-jeopardy exposure. Also, implementing transient voltage criteria will require time.Replace "Each Transmission Planner and Planning Coordinator" with "Each Transmission Planner OR Planning Coordinator".
Response: As for the double jeopardy comment - From the ERO Rules of Procedure, Appendix 4B- Sanction Guidelines, Section 3.10 Multiple Violations: "Strictly speaking, NERC or the regional entity can determine and levy a separate penalty or sanction, or direct remedial action, upon a violator for each individual violation. However, in instances of multiple violations related to a single act or common incidence of noncompliance, NERC or the regional entity will generally determine and issue a single aggregate penalty, sanction, or remedial action directive bearing reasonable relationship to the aggregate of the related violations. The penalty, sanction, or remedial action will not be that determined individually for the least serious of the violations; it will generally be at least as large or expansive as what would be called for individually for the most serious of the violations." The existing VAR standards (VAR-001-1a and VAR-002-1b) address the operational time horizon but do not address the planning horizon. NERC Standards Project 2008-1 is under development and the SAR addresses the planning horizon. As this project moves forward, the Standards Drafting Team for Project 2008-1 will more fully develop the requirements for reactive planning and will evaluate whether those requirements should reside in the TPL standard or the VAR standards.	
Gainesville Regional Utilities	Voltage considerations can get lost in the various studies. This requirement brings focus to the voltage component which it rightly deserves.
Response: Thank you.	
Central Maine Power Company	Voltage criteria is addressed by the VAR standards. Including a voltage requirement in the planning standards appears to be creating a double-jeopardy exposure.R5. Change to Read "Each Transmission Planner OR Planning Coordinator " Need time to implement transient voltage criteria.
ISO New England	Voltage criteria is addressed by the VAR standards. Including a voltage requirement in the planning standards appears to be creating a double-jeopardy exposure.R5. Change to Read "Each Transmission Planner OR Planning Coordinator " Need time to implement transient voltage criteria.
United Illuminating	Voltage criteria is addressed by the VAR standards. Including a voltage requirement in the planning standards appears to be creating a double-jeopardy exposure.R5. Change to Read "Each Transmission Planner OR Planning Coordinator " Need time to implement transient voltage criteria.

Organization	Comments for Question 5
Response: As for the double jeopardy comment - From the ERO Rules of Procedure, Appendix 4B- Sanction Guidelines, Section 3.10 Multiple Violations: "Strictly speaking, NERC or the regional entity can determine and levy a separate penalty or sanction, or direct remedial action, upon a violator for each individual violation. However, in instances of multiple violations related to a single act or common incidence of noncompliance, NERC or the regional entity will generally determine and issue a single aggregate penalty, sanction, or remedial action directive bearing reasonable relationship to the aggregate of the related violations. The penalty, sanction, or remedial action will not be that determined individually for the least serious of the violations; it will generally be at least as large or expansive as what would be called for individually for the most serious of the violations." The existing VAR standards (VAR-001-1a and VAR-002-1b) address the operational time horizon but do not address the planning horizon. NERC Standards Project 2008-1 is under development and the SAR addresses the planning horizon. As this project moves forward, the Standards Drafting Team for Project 2008-1 will more fully develop the requirements for reactive planning and will evaluate whether those requirements should reside in the TPL standard or the VAR standards. The implementation Plan allows 24 months before Requirement R5 becomes effective.	
Oncor Electric Delivery	Voltage criteria is addressed within the VAR standards. This appears to be redundant.
Response: The existing VAR standards (VAR-001-1a and VAR-002-1b) address the operational time horizon but do not address the planning horizon. NERC Standards Project 2008-1 is under development and the SAR addresses the planning horizon. As this project moves forward, the Standards Drafting Team for Project 2008-1 will more fully develop the requirements for reactive planning and will evaluate whether those requirements should reside in the TPL standard or the VAR standards to ensure that it is not a redundant requirement.	
American Electric Power	We believe that it is appropriate to eliminate the reference to transient voltage response as it is duplicative and unnecessary. System stability is already better addressed by other performance requirements defined in this standard.
Response: The SDT believes that a criterion should be established for transient voltage response by each Transmission Planner and Planning Coordinator and that it is complementary to the other performance requirements in this standard, not duplicative.	
FirstEnergy Corp	We concur with the inclusion of R5 and the criteria needed for steady-state voltage limits, post-contingency deviations and the transient voltage response for its System. In regards to the transient voltage criteria, its our understanding that the this criteria is for planning purposes only and not intended for operation time horizon evaluations being performed by the TOP.
Response: The SDT agrees that the requirement for criteria for transient voltage responses is for planning studies and does not address operating studies since they are outside the scope of this standard.	
Ameren	With respect to specifying a voltage level and maximum duration for transient voltage response, does it make sense for each Transmission Planner to have their own criteria? Should we be meeting an industry standard such as the ITI (CBEMA) Curve published by the Technical Committee 3 (TC3) of the Information Technology Industry Council (ITI, formerly known as the Computer & Business Equipment manufacturer's Association) and available at www.itic.org? Meeting any of the criteria to be developed for Requirement R5 will depend on the load model assumptions used.It is stated that the Transmission Planner and Planning Coordinator shall have criteria specifying voltage limits, pos-Contingency voltage deviations, and transient voltage response. How would an interaction with a third party be handled, particularly if one entity has more stringent criteria?

Organization	Comments for Question 5
	The content in the severe VSL column should be split among the lower, moderate, and high categories.
Response: The SDT believes that each Transmission Planner and Planning Coordinator should have a criteria and has not placed bounds on how to establish the criteria. This standard places the requirement for performance on each entity's portion of the BES (Requirement R2). In addition, Requirement R3, part 3.4.1 and Requirement R4, part 4.4.1 require the coordination of the Contingencies and Requirement R8 requires the distribution of the Planning Assessment. These requirements will ensure that third party impacts are identified. The SDT believes that establishing the criteria for acceptable voltage deviations should be a binary VSL. No change made.	
PJM	Remove any mention of transient voltage response. Very few entities can perform this type of analysis.
Response: The SDT believes that a criterion should be established for transient voltage response by each Transmission Planner and Planning Coordinator and disagrees with the assertion that very few entities have the capability to complete this type of analysis. No change made.	

6. Requirement R6 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: The SDT has made clarifying changes based on industry comments as follows: **R6**. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, any criteria or methodology used in the analysis to identify System instability for conditions such as Cascading , voltage instability, or uncontrolled islanding**M6**. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of documentation specifying any criteria or methodology used in the analysis to identify System instability that was utilized in preparing the Planning Assessment in accordance with Requirement R6. **Requirement R6, data retention** - The documentation specifying any criteria or methodology utilized in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.

Organization	Comments for Question 6
Progress Energy Florida, Inc.	As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all appropriate parties to review PEF's previous comments to this effect.
Response: Throughout the drafting process, the SDT has carefully considered your comments as well as comments from other industry members.	
Florida Municipal Power Agency, and its Member Cities	FMPA suggests adding the word "potential" into " identify the potential for System instability". The criteria and methodology may be used to determine if further analysis is warranted, e.g., if steady state voltages fall below 0.9 per unit, then do a voltage stability study, or something like that. Going below 0.9 does not mean voltage collapse, but, it may be an indicator to study it; hence, the word "potential".
FRCC Transmission Working Group	For R6 please consider the following revision: "Each TP and PC shall define and document within their planning assessment any criteria or methodology used in their analysis to identify system instability /deleted/ for /deleted/ conditions such as cascading outages, voltage instability, or uncontrolled islanding." As written originally it could be taken to be the methods for determining if you have instability during a cascading outage, rather then the methods for determining if you are at risk for instability like a cascading outage. the word "potential" into "identify the potential for System instability ". The criteria and methodology may be used to determine if further analysis is warranted, e.g., if steady state voltages fall below 0.9 per unit, then duedo a voltage stability study. Going below 0.9 does not mean voltage collapse, but, it may be an indicator to study it; hence, the word "potential".
Response: The SDT disagrees with your suggestion of adding the term 'potential' in Requirement R6. The Standard does not preclude the application of criteria or methodology to determine potential instability. No change made.	
Orlando Utilities Commission	For R6 please consider the following revision: "Each TP and PC shall define and document within their planning assessment any criteria or methodology used in <<their>> analysis to identify system instability //for// conditions such as cascading outages, voltage instability, or uncontrolled islanding." Adding the text in <<>> and deleting the text in ////. As written originally it could

Organization	Comments for Question 6
	be taken to be the methods for determining if you have instability during a cascading outage, rather then the methods for determining if you are at risk for instability like a cascading outage.
Response: The SDT disagrees with your assessment that the language of "… criteria or methodology used in the analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding" is misleading. The System instability applies to the cascading outages, voltage instability, OR uncontrolled islanding, not just to cascading outages. No change made.	
Gainesville Regional Utilities	I believe that this requirement is better defined and documented at the regional level with all involved parties contributing. If consensus is not achievable, then the exception utilities can create their own knowing that they need technically valid references to support their position.
Response: The SDT disagrees as it is better to allow the individual a Transmission Planner or Planning Coordinator to determine this versus the region as the region could be quite varied. The Requirement does not preclude the region from doing as you suggest with coordination in the region. No change made.	
FirstEnergy Corp	If an entity is required to adhere to its Facility Ratings, how is it feasible that a cascade violation would occur? FirstEnergy questions the need for this review based on Table 1 performance requirements and the need to adhere to Facility Ratings.
Response: This may not be an issue in the application of this criteria or methodology for planning events P0 through P7, however, this needs to be available when evaluating System response when applying extreme events.	
Arizona Public Service Co.	It is not clear who this applies to. Is it both TP and PC individually, or one of the two, or both jointly?
Response: The requirement is for both.	
American Electric Power	M6 does not appear to align with the content of R6. M6 needs to be reworded to reference documentation of criteria or methodology rather than studies. Corresponding changes will also need to be made to the corresponding bullet under Data Retention.
Manitoba Hydro	The R6 text does not match the Data Retention 6th bullet text "studies performed". The Retention 6th bullet text should be updated to reflect the R6 text "criteria or methodology used in the analysis to identify System instability".The R6 text does not match the M6 text. The M6 text should be revised as follows: replace "studies utilized in preparing the Planning Assessment" with "criteria and methodology to identify System instability used within its analysis".
Response: The SDT agrees and has changed the language of Measure M6 and also the language for Data Retention. **M6**. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of documentation specifying any criteria or methodology used in the analysis to identify System instability that was utilized in preparing the Planning Assessment in accordance with Requirement R6. **Requirement R6, data retention** - The documentation specifying any criteria or methodology utilized in support of its Planning Assessments since the last	

Organization	Comments for Question 6
compliance audit in accordance with Requirement R6 and Measure M6.	
Ameren	M6: The wording on this measure appears to have been copied from M3 or M4 but is not appropriate since R6 addresses criteria and methodology and not a study.
SERC Dynamics Review Subcommittee (DRS)	M6: The wording on this measure appears to have been copied from M3 or M4 but is not appropriate since R6 addresses criteria and methodology but not a study.
Southern Company	M6: The wording on this measure appears to have been copied from M3 or M4 but is not appropriate since R6 addresses criteria and methodology and not a study. Replace the word "studies" with "criteria or methodology".
TVA System Planning	M6: The wording on this measure appears to have been copied from M3 or M4 but is not appropriate since R6 addresses criteria and methodology and not a study.
SERC Planning Standards Subcommittee	Comments: M6: The wording on this measure appears to have been copied from M3 or M4 but is not appropriate since R6 addresses criteria and methodology and not a study.
Response: The SDT agrees and has changed the language of Measure M6. **M6**. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of documentation specifying any criteria or methodology used in the analysis to identify System instability that was utilized in preparing the Planning Assessment in accordance with Requirement R6.	
MidAmerican Energy Company	MidAmerican commends the SDT for their hard work on this standard. MidAmerican does have comments about this requirement though. MidAmerican recommends the data retention for R6 and M6 be revised to change “All” to “The”. The word “All” is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: “THE studies performed in support”. The word in caps is a word suggested to be added.
NERC Standards Review Subcommittee	The MRO NSRS recommends the data retention for R6 and M6 be revised to change “All” to “The”. The word “All” is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: “The studies performed in support”.
Response: The SDT agrees with your suggestion of changing the “All” to “The” in the data retention section for Requirement R6 and Measure M6. **M6**. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of documentation specifying any criteria or methodology used in the analysis to identify System instability that was utilized in preparing the Planning Assessment in accordance with Requirement R6. **Requirement R6, data retention** - The documentation specifying any criteria or methodology utilized in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.	
Duke Energy	R6 includes the phrase “cascading outages”. We believe that the word “cascading” should be the capitalized NERC-defined

Organization	Comments for Question 6
	term "Cascading".
Response: The SDT agrees with your suggestion of changing "cascading" to Cascading". **R6**. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, any criteria or methodology used in the analysis to identify System instability for conditions such as Cascading , voltage instability, or uncontrolled islanding.	
Oklahoma Gas & Electric	R6 OG&E believes the Transmission Coordinator be held accountable for R6. The Transmission Coordinator should coordinate this type of study/documentation with the Transmission Planner for a regional look of the whole system. For example Southwest Power Pool should coordinate this type of study/documentation with the members of the Southwest Power Pool to better examine the entire region of the Southwest Power Pool. We do not see the need to duplicate the work.
Response: The SDT assumes that you mean Planning Coordinator. The requirement is for both entities.	
Tri-State Generation and Transmission Association	R6 seems OK but check M6. Should this refer to R2 and not R6?
Independent Electricity System Operator	We do not have any comments on the requirement, VRF, Time Horizon and the VSL. However, Measure M6 (which refers to "studies utilized in preparing the Planning Assessment") does not seem to be relevant to Requirement R6, which deals with defining and documenting the criteria and methodology used in the analysis to identify System instability.
Response: The SDT agrees and has changed the language of Measure M6. **M6**. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of documentation specifying any criteria or methodology used in the analysis to identify System instability that was utilized in preparing the Planning Assessment in accordance with Requirement R6.	
MAPP	Suggest removing "Transmission Planner" since the PC performs the assessment.
Response: The SDT disagrees with your comment as both entities should be documenting their criteria.	

7. Requirement R7 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: The SDT modified Measure M7 to clarify the supporting documentation used to establish the individual and joint responsibilities for performing the required studies. The SDT also clarified the data retention associated with Requirement R7. Measure M7 and the data retention associated with Requirement R7 now read:

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

Requirement R7 data retention: The current, in force documentation for the agreement(s) on roles and responsibilities, as well as all such documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

Organization	Comments for Question 7
ERCOT ISO	* Will any agreements made in R7 override the "each TP and PC" requirement? Would it be appropriate to say: "Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies and assessments."* What kind of documentation will be acceptable to demonstrate "each entity's individual and joint responsibilities"?
Response: The SDT sees no additional clarity being provided by your suggested wording. No change made. To address your concerns the SDT has changed Measure M7 to clarify the type of supporting documentation that could be used to establish individual and joint responsibilities for performing the required studies. **M7.** Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.	
American Transmission Company	Revise part of the requirement text to read, ". . . identify each entity's individual and joint responsibilities . . ." to provide better clarity. Perhaps this requirement should be listed at the beginning of the Requirements section, instead being mentioned near the end of this section.
Response: The SDT sees no additional clarity being provided by your suggested wording. No change made. The SDT discussed the change and based on industry input decided not to change the order of the requirements.	

Organization	Comments for Question 7
Progress Energy Florida, Inc.	As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all appropriate parties to review PEF's previous comments to this effect.
Response: Throughout the drafting process, the SDT has carefully considered your comments as well as comments from other industry members.	
CenterPoint Energy	CenterPoint Energy believes R7 relates to matters best addressed through registration, such as JROs or delegation agreements. If other commenters agree, CenterPoint Energy recommends that R7 be deleted.
Response: This requirement was inserted to address industry concern regarding the potential for duplication of work. No change made.	
TVA System Planning	In the VSL associated with R7, we believe that failure to determine and identify one responsibility should be a moderate VSL, failure to determine and identify two responsibilities should me a high VSL, while failure to determine and identify three responsibilities should be a severe VSL. Otherwise failing to document only one responsibility would result in a severe VSL.
Response: The SDT believes that procedurally, Requirement R7 is binary. No change made.	
MidAmerican Energy Company	MidAmerican commends the SDT for their hard work on this standard. MidAmerican does have comments about this requirement though. MidAmerican recommends the data retention for R7 and M7 be revised to delete "All". The word "All" is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: "The current, in force agreement on identified responsibilities, as well as such agreements in force".
NERC Standards Review Subcommittee	The MRO NSRS recommends the data retention for R7 and M7 be revised to delete "All". The word "All" is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: "The current, in force agreement on identified responsibilities, as well as such agreements in force".
Response: The SDT agrees that the proposed change to Measure M7 and the data retention removes the potential for an unintended interpretation. **M7.** Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7. **Requirement R7 data retention:** The current, in force documentation for the agreement(s) on roles and responsibilities, as well as all such documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.	
Tri-State Generation and Transmission Association	R7 - Duties of the Planning Coordinator are being created and changed as we go along, like changing rules of a flag football game as it is played. Is there any requirement that every TP have a PC? As far as we know, the PC was introduced as an additional authority level for regional or inter-utility study work. Previous R7 wording asked PCs and TPs to work together. The present wording implies that every TP must have a PC which is a separate entity, and that PC would dictate study responsibilities. The wording of R4.4.1 seems much better in this regard.

Organization	Comments for Question 7
Response: It does not create the requirement that each Transmission Planner report to a Planning Coordinator, that relationship is defined in the Functional Model This requirement specifies that, if there is a relationship between a Transmission Planner and Planning Coordinator there is no need for duplicate analysis if each entity agrees on the delegation of work. No change made.	
NYISO	R7. - The NYISO requests clarification as to whether the PC will be expected to distribute the TP Planning Assessments as part of its coordination requirement?
Response: This standard does not require the Planning Coordinator to distribute the individual Transmission Planner assessments.	
MAPP	Suggest moving this requirement to the head of the list. It's a basis for the rest of this standard.
Response: The SDT discussed the change and based on industry input decided not to change the order of the requirements.	
Orlando Utilities Commission	The intent is much clearer, thank you for revising this.
Oklahoma Gas & Electric	We agree that it should be clearly stated who does what between the Transmission Planner and the Planning Coordinator. We feel like this will eliminate duplication of work and create a better overall regional examination of the electric grid.
Gainesville Regional Utilities	Looks good.
Response: Thank you.	
Florida Municipal Power Agency, and its Member Cities	The Measure and Data Retention for R7 is ambiguous. While the measure could be interpreted as not requiring a contract, the data retention uses the words "in force agreement" which implies a formal contract, where roles and responsibilities could very well be assigned in regional planning committee minutes and ensuing e-mail correspondence. Suggest changing the words to "Documentation of agreement on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence" in both locations.
Response: The SDT agrees that the proposed changes to Measure M7 and the data retention remove the potential for an unintended interpretation. Measure M7 and the data retention associated with Requirement R7 now read: **M7.** Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7. **Requirement R7 data retention:** The current, in force documentation for the agreement(s) on roles and responsibilities, as well as all such documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.	

8. Requirement R8 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: The SDT believes revisions to Requirement R3, parts 3.4 and Requirement R4, part 4.4 will clarify the expectation that Transmission Planners and Planning Coordinators analyze Table 1 events outside their Systems for reliability impacts. The proposed, new Requirement R8 (old Requirement R7) requirement (below), will ensure appropriate information is exchanged between Transmission Planners and Planning Coordinators for sharing of information, review, and coordination of plans in conformance with Order 693 paragraph 1755 and 1756 expectations. The SDT believes the NERC Rules and Procedures and delegation agreements cover existing TPL-005 & -006 assessment requirements for regional and inter-regional assessments. The aggregate effect of the above items will be an overlapping assessment of BES reliability from each Transmission Planner area up through each Interconnection.

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information.

R8 data retention. Three calendar years of the notices and other documentation employed in accordance with Requirement R8 and Measure M8

R8 VSL	The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners or adjacent Planning Coordinators, and to one functional entity that has a reliability related need and has submitted a written request for the information, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to its adjacent Transmission Planners or adjacent Planning Coordinators, and to any functional entity that has a reliability related need and has submitted a written request for the information, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

Organization	Comments for Question 8
Independent Electricity System Operator	(1) No comments on the requirement, measure, VRF and Time Horizon. 3) VSLs:(a) We do not agree with the Severe VSL condition. In our view, distributing planning assessment results is the intent of the requirement; it is more important to share results than to field questions from recipients of the results. Assigning a Severe VSL for failing Part 8.1 puts the driver at the wrong place.(b) The condition under Low and High seems to be the same. In the Low, failing to distribute the results to ANY ONE of the TPs and PCs means none, which is the same as the condition for High unless the condition under Low really means failing to distribute the results to ONE of the TPs and PCs whereas the High really means failing to distribute the results to two or more of the TPs and PCs. If this is the proper interpretation, then we'd suggest the VSLs be revised as follows:Low: failing to respond to comments within 90 daysHigh: failing to distribute the results to one of the TPs and PCsSevere: failing to distribute the results to two or more of the TPs and PCs.Alternatively, a Moderate can be added to capture the condition for failing to distribute the results to two of the TPs and PCs, while the Severe can become failure to distribute the results to three of the TPs and PCs.

Response: The SDT disagrees because the requirement's focus is on coordination of planning. If questions/concerns are not responded to, coordination of planning is not being accomplished. The VSLs related to failing to distribute results are appropriate. However, the SDT agrees that the Lower VSL is unclear and will make a change to delete the word "any". In addition, the SDT has modified the Lower and High VSL wording to be clearer.

R8 VSL	The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners or adjacent Planning Coordinators, and to one functional entity that has a reliability related need and has submitted a written request for the information, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to its adjacent Transmission Planners or adjacent Planning Coordinators, and to any functional entity that has a reliability related need and has submitted a written request for the information, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

ERCOT ISO	* Will any agreements made in R7 override the "each TP and PC" requirement? To clarify this, the requirement could be rephrased: "In accordance to the responsibilities assigned in R7, the responsible Transmission Planners and Planning Coordinators shall distribute?. "* Include "within the interconnection" such as: "distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners within the interconnection and to any functional entity that indicates a reliability related need for the Planning Assessment results"* Should "reliability related need" be defined? This appears in multiple standards.

Response: No, the agreements made in Requirement R7 pertain to performance of the required studies and will not override the Planning Coordinator and Transmission Planner's responsibilities under Requirement R8 relating to distribution of Planning Assessments.

Organization	Comments for Question 8
The SDT does not believe the suggested language adds any clarity. No change made. A definition is not required. The present wording is in other approved standards and is sufficiently clear based on experience to date. No change made.	
Northeast Utilities	[R8.1] There is no statute of limitation for comments, nor is there a limit on the number of comments. There is also potential conflict with the deadline for completing a study and when comments may be submitted. If this requirement is retained the following is suggested: "Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to the functional entities that the Planning Coordinator recognizes as having a reliability need for the Planning Assessment results".
Response: The SDT disagrees that there should be a statute of limitation for asking questions related to coordination of planning and believes parties will act appropriately. The SDT disagrees that there should be a limit to the number of questions allowed related to coordination of planning and believes parties will act appropriately. The requirement is to distribute the results of the completed Planning Assessments associated with this standard therefore all related supporting studies are complete and there is no potential conflict. The word "indicates" has been changed to "has" to be clearer. This revised wording has the same meaning as the suggested wording and is sufficiently clear. Both the Transmission Planner and Planning Coordinator may be asked for their Planning Assessment by an entity with a reliability related need. Therefore the statement must apply to both the Transmission Planner and Planning Coordinator. **R8**. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information.	
Oncor Electric Delivery	8.1 This requirement should be removed because it appears redundant to FERC 890. (suggest having one statement or the other) However, if it isn't, then the Term "documented" in R8.1 the term documented needs to be defined. Suggest adding the qualifier "written " i.e., "If a recipient of the Planning Assessment results provides "documented written" comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a "documented written" response to that recipient within 90 calendar days of receipt of those comments. The requirement to distribute reports to entities with "need" has very significant CEII implications. This should be tightened to a "bona fide reliability need" for the information, requiring CEII or confidential material handling procedures. R8, 8.1, and Measurement M8 There is no statute of limitation for comments (Suggest clarifying what we mean here assume we are note referring to the NERC Standards Commenting Process), nor is there a limit on the number of comments. There is also potential conflict with the deadline for completing a study and when comments may be submitted (e.g. comments are received the day before the study is to be completed. If this requirement is retained the following is suggested: Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to functional entities that demonstrated a reliability need with concurrence from their planning coordinator for the Planning Assessment results. [I think there are issues still with this language. I think it needs to say "and to the functional entities that the Planning Coordinator recognizes as having a reliability need for the Planning Assessment results."]

Organization	Comments for Question 8
	Compliance 1.4 Data Retention, last bullet - this relates back to Requirements R8, 8.1, and Measurement M8. This seems to be a nuisance requirement to get in trouble for. [Requirement is to keep 3 years of notifications related to R8 & 8.1.]
Response: The SDT seeks to retire the existing TPL-005 & -006 while continuing to meet the purpose of their requirements. FERC Order 693 and 890 each provide expectations and direction to the ERO regarding enhancement of regional coordination and planning. The SDT believes the inclusion of Requirement R8 in the standard and performance of the regional assessments required under NERC delegation agreements will meet these objectives. The present wording is in other approved standards and is sufficiently clear based on experience to date. Bona fide does not add significant clarity. Control of CEII and control of competitive market information per Standards of Conduct are a fundamental expectation of all industry participants and is not required in the standard. The SDT disagrees that there should be a statute of limitation for asking questions related to coordination of planning and believes parties will act appropriately. The SDT also disagrees that there should be a limit to the number of questions allowed related to coordination of planning and believes parties will act appropriately. The requirement is to distribute the results of the completed Planning Assessments associated with this standard therefore all related supporting studies are complete and there is no potential conflict. The SDT agrees the wording is somewhat unclear and will clarify by adding "adjacent" before Transmission Planner. The word "indicates" has been changed to "has" to be clearer. This revised wording has the same meaning as the suggested wording and is sufficiently clear. **R8**. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information. The SDT believes that retaining the documentation for 3 years is consistent with other standards and appropriate for audit purposes. No change made.	
Progress Energy Florida, Inc.	As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all appropriate parties to review PEF's previous comments to this effect.
Response: Throughout the drafting process, the SDT has carefully considered your comments as well as comments from other industry members.	
CenterPoint Energy	CenterPoint Energy believes R8 is over-reaching and recommends deleting it. CenterPoint Energy is particularly concerned about requiring assessments to be distributed to "any functional entity that indicates a reliability related need". There is already a process in place for entities to request and receive the FERC Form 715 submittals of other entities. FERC's process appropriately recognizes and addresses CEII issues and imposes a requirement that the entity demonstrate need for the information and that the industry complies with certain security-related requirements. Beyond CEII matters, transmission planning information can have implications for market entities bidding on congestion rights in competitive energy markets. Therefore, the dissemination of transmission planning information may be governed by the regulatory authority having jurisdiction over the market functions, which is not necessarily FERC in all cases. In any case, given the availability of the FERC 715 process, there is no need for a somewhat duplicative requirement in this standard. Accordingly, CenterPoint Energy recommends that R8 be deleted in its entirety.
Response: Requirement R8 is necessary to ensure that appropriate coordination of planning occurs and supports regional assessments performed under NERC delegation agreements. Control of CEII is a fundamental expectation of all industry participants and the "reliability related need" restriction ensures only appropriate parties must be given	

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planning assessments. Control of competitive market information per Standards of Conduct is a fundamental expectation of all industry participants and the "reliability related need" restriction ensures only appropriate parties must be given planning assessments. The SDT seeks to retire the existing TPL-005 & -006 while continuing to meet the purpose of their requirements. FERC Orders 693 and 890 each provide expectations and direction to the ERO regarding enhancement of regional coordination and planning. The SDT believes the inclusion of Requirement R8 in the standard and performance of the regional assessments required under NERC delegation agreements will meet these objectives. FERC 715 is not adequate to achieve these objectives. No change made.	
Bonneville Power Administration	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
Modesto Irrigation District Transmission Planning	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
NV Energy	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
Pacific Gas and Electric Co.	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
Puget Sound Energy, Inc.	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
Sacramento Municipal Utility District	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
San Diego Gas & Electric Co	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
Southern California Edison (SCE)	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
SRP	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
Utility System Efficiencies, Inc. (USE)	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?

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Western Area Power Adm - RMR	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
Deseret Power	Comments: Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
Response: Yes - The NERC Reliability Functional Model defines the meaning of the term "functional entity".	
SERC Planning Standards Subcommittee	Comments: R8: It is not clear whether the assessment results must be distributed to all parties of interest, or if it would be sufficient to post the assessment at a central location, and distribute information to access the information. Also, FERC Standards of Conduct issues would come into play in assuring that the information is available only to appropriate personnel. R8: It is not clear if the requirement to provide assessment results to adjacent PCs and TPs is required, or only upon a reliability related request.R8: The PC and TP responsibilities should be stated separately for clarity. Part 8.1: It is not clear what the form of the response to the comments should be " would an acknowledgement be sufficient, or would it be necessary to pursue a process of examining comments in detail and revising and reissuing the corresponding assessment"The requirement needs to be revised to make the above points clear.
Response: The standard does not specify the mechanics of distribution of the information, only that it must occur. The method proposed would be acceptable as long as it met Measure M8 and Section 1.4 under compliance monitoring. Control of competitive market information per Standards of Conduct is a fundamental expectation of all industry participants and the "reliability related need" restriction ensures only appropriate parties must be given planning assessments. The SDT agrees and will clarify by adding "adjacent" before Transmission Planner and added wording requiring a written request. The word "indicates" has been changed to "has" to be clearer. **R8**. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information. The standard should not specify the means of providing and responding to comments, but ensures that appropriate communication is initiated. No change made.	
Orlando Utilities Commission	Excellent requirement, thank you for revising this
Response: Thank you.	
Southern Company	For additional clarity in who should receive the assessment, we recommend replacing "indicates" with "has" and adding words to the end of the sentence so that it states the following: "and to any functional entity that has a reliability related need for the Planning Assessment results and provides a written request." For Part 8.1, we do not believe the intent is for casual emails to be documented and formally responded to. And we do not believe that anyone who happens to receive the assessment should be able to comment. Therefore, we recommend the following wording: "If one of the above named entities provides formal written comments on the results, the respective Planning Coordinator or

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	Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments." If these recommendations are accepted, then the wording of M8 would have to change accordingly.
Response: The SDT agrees and will clarify by adding "adjacent" before Transmission Planner and added wording requiring a written request. **R8**. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information. The standard should not specify the means of providing and responding to comments, but ensures that appropriate communication is initiated. The SDT has altered the wording of Requirement R8 to provide clarity and to attempt to alleviate your concern.	
Manitoba Hydro	Is there a need to retain comments and responses to comments for Requirement R8?
Response: Yes, see Measure M8 and the following changes to 1.4 Data Retention. **R8 data retention**. Three calendar years of the notices and other documentation employed in accordance with Requirement R8 and Measure M8	
SCE&G	It is not clear if the requirement to provide assessment results to adjacent Planning Coordinators and Transmission Planners is always required or only upon a reliability related request.
Response: The SDT considers the distribution to Planning Coordinators and Transmission Planners as mandatory and has changed the wording of Requirement R8 to address the wording for other functional entities. **R8**. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information.	
MidAmerican Energy Company	MidAmerican commends the SDT for their hard work on this standard. MidAmerican does have comments about this requirement though. MidAmerican asks that the SDT revise R8 to limit the need to provide the Planning Assessment as follows “adjacent Planning Coordinators and ADJACENT Transmission Planners and to any REGISTERED functional entity”? The words in all caps are words that MidAmerican suggests are added to the requirement to clarify that the word adjacent also applies to Transmission Planners and to clarify that the functional entity must be registered in order for the requirement to provide the Planning Assessment to apply. MidAmerican asks that the low VSL for R8 be revised to delete the word “any” from the requirement so that the requirement will read “The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners”.
Response: The SDT agrees and will clarify by adding "adjacent" before Transmission Planner, but the SDT believes adding “registered” is unnecessary because it is understood that it relates to NERC Reliability Standards. **R8**. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information.	

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The SDT agrees and will make change to delete the word "any".

R8 VSL	The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners or adjacent Planning Coordinators, and to one functional entity that has a reliability related need and has submitted a written request for the information, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to its adjacent Transmission Planners or adjacent Planning Coordinators, and to any functional entity that has a reliability related need and has submitted a written request for the information, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

Progress Energy Carolinas	Need to define "adjacent" Planning Coordinators. Does this mean a neighbor with at least one joint interconnection? The requirement to provide the Planning Assessment "to any functional entity that indicates a reliability related need" should be made subject to applicable confidentiality and CEII provisions.

Response: The SDT believes "adjacent" is an understood term and would apply to any neighbor with a joint Interconnection. No change made.

Control of CEII is a fundamental expectation of all industry participants and the "reliability related need" restriction ensures only appropriate parties must be given planning assessments. No change made.

Tri-State Generation and Transmission Association	R8 - We find that web-site posting would be sufficient distribution if it were not for the need for auditability. Please consider a way to qualify web-posting as an acceptable distribution method.

Response: The standard does not specify the mechanics of distribution of the information, only that it must occur. The method proposed would be acceptable as long as it met Measure M8 and 1.4 under compliance monitoring. No change made.

NYISO	R8- It should be made clear that a TP should not be required to send their assessment to adjacent PCs. Likewise the PCs should not be required to send their assessment to TPs not in their footprint. R8.1: This should not be required until the Assessment is complete and posted. Additionally, this could be an administratively intense task to respond to each and every comment and document that a response is made within 90 days. Is there any room for an extension to this requirement?

Response: The SDT disagrees, the broader communication is necessary to achieve appropriate coordination. No change made.

The requirement is to distribute the results of completed Planning Assessments, then respond to comments. Therefore the assessment is posted and complete before

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comments can be received and responded to. The SDT recognizes this fact and believes 90 days should be sufficient to develop a response. No change made.	
Oklahoma Gas & Electric	R8 OG&E believes the Transmission Coordinator be held accountable for R8 and coordinate this type of data exchange to ensure a regional coordination effort is achieved.
Response: The SDT believes you were referring to Planning Coordinator in your comment. The SDT believes both the Transmission Planner and Planning Coordinator must distribute their assessments to meet the overall intent of Requirement R8 and achieve appropriate coordination. No change made.	
Xcel Energy	R8 Xcel Energy appreciates the language stating "reliability need" however it is unclear as to what constitutes this or who would make that determination. Please clarify so as to avoid future disputes on providing or obtaining the information.
Response: The present wording is in other approved standards and is sufficiently clear based on experience to date. No change made.	
Central Maine Power Company	R8, 8.1, and Measurement M8 This standard should not be used to remedy deficiencies in meeting the coordination requirements of FERC Order 890. Therefore these should be deleted. If this requirement is retained the following is suggested:"Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to the functional entities that the Planning Coordinator and Transmission Planner recognizes as having a reliability need for the Planning Assessment results." Additionally, there is no deadline for comments. There is also potential conflict with the deadline for completing a study and when comments may be submitted (e.g. comments are received the day before the study is to be completed.) These issues must be addressed. 1.4 Data Retention: The last bullet is unnecessary and should be deleted from the standard.
ISO New England	R8, 8.1, and Measurement M8 This standard should not be used to remedy deficiencies in meeting the coordination requirements of FERC Order 890. Therefore these should be deleted. If this requirement is retained the following is suggested: Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to the functional entities that the Planning Coordinator and Transmission Planner recognizes as having a reliability need for the Planning Assessment results. Additionally, there is no statute of limitation for comments. There is also potential conflict with the deadline for completing a study and when comments may be submitted (e.g. comments are received the day before the study is to be completed.) These issues must be addressed. 1.4 Data Retention: The last bullet is unnecessary and should be deleted from the standard.
Response: The SDT seeks to retire the existing TPL-005 & -006 while continuing to meet the purpose of their requirements. FERC Orders 693 and 890 each provide expectations and direction to the ERO regarding enhancement of regional coordination and planning. The SDT believes the inclusion of Requirement R8 in the standard	

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and performance of the regional assessments required under NERC delegation agreements will meet these objectives. No change made. This revised wording has the same meaning as the suggested wording and is sufficiently clear. The SDT disagrees that there should be a statute of limitation for asking questions related to coordination of planning and believes parties will act appropriately. The requirement is to distribute the results of the completed Planning Assessments associated with this standard therefore all related supporting studies are complete and there is no potential conflict. No change made. The SDT believes that data retention is a necessary function as outlined in the guidelines. No change made.	
United Illuminating	R8, 8.1, and Measurement M8 This standard should not be used to remedy deficiencies in meeting the coordination requirements of FERC Order 890. Therefore these should be deleted. If this requirement is retained the following is suggested:"Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to the functional entities that the Planning Coordinator and Transmission Planner recognizes as having a reliability need for the Planning Assessment results." Additionally, there is no statute of limitation for comments. There is also potential conflict with the deadline for completing a study and when comments may be submitted (e.g. comments are received the day before the study is to be completed.) These issues must be addressed. Measures M1:It is not practical to retain system model information in a hard copy form. This provision could be dropped. Compliance: D 1.1.4 Data Retention: The Transmission Planner and the Planning Coordinator may not be using the same software. If both are required to store the data, do they both have to have the software to use the data? Can this be changed to an "or" such that one of them must retain the data and it can be up to them as to who it is. Also, the last bullet is unnecessary and should be deleted from the standard.
Response: The SDT seeks to retire the existing TPL-005 & -006 while continuing to meet the purpose of their requirements. FERC Orders 693 and 890 each provide expectations and direction to the ERO regarding enhancement of regional coordination and planning. The SDT believes the inclusion of Requirement R8 in the standard and performance of the regional assessments required under NERC delegation agreements will meet these objectives. No change made. This revised wording has the same meaning as the suggested wording and is sufficiently clear. No change made. The SDT disagrees that there should be a statute of limitation for asking questions related to coordination of planning and believes parties will act appropriately. No change made. The requirement is to distribute the results of the completed Planning Assessments associated with this standard therefore all related supporting studies are complete and there is no potential conflict. Since Measure M1 states that either electronic OR hard copy format is required, the SDT believes that no changes are required since either of the formats is acceptable. An example of a hard copy of a system model is having printouts of each individual bus showing Load, Transmission line, generator, capacitors, etc., connected to that bus with associated impedances, ratings, etc. The SDT believes that both the Transmission Planner and Planning Coordinator have this responsibility for the data retention. Therefore the SDT believes that the	

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existing language is adequate and that no changes are required. The SDT believes that both should have the necessary software for using the data.	
Ameren	R8: It is not clear whether the assessment results must be distributed to all parties of interest, or if it would be sufficient to post the assessment at a central location, and distribute information to access the information. Also, FERC Standards of Conduct issues would come into play in assuring that the information is available only to appropriate personnel. R8.1: It is not clear what the form of the response to the comments should be " would an acknowledgement be sufficient, or would it be necessary to pursue a process of examining comments in detail and revising and reissuing the corresponding assessment" The audience of those able to provide comments to the assessments should be appropriately limited, and not open to anyone who wishes to comment.
Response: The standard does not specify the mechanics of distribution of the information, only that it must occur. The method proposed would be acceptable as long as it met Measure M8 and Section 1.4 under compliance monitoring. Control of competitive market information per Standards of Conduct is a fundamental expectation of all industry participants and the "reliability related need" restriction ensures only appropriate parties must be given planning assessments. The standard should not specify the means of providing and responding to comments, but ensures that appropriate communication is initiated. The SDT believes that the requirement limiting distribution to adjacent Planning Coordinator/Transmission Planner's and other functional entities with a reliability related need who request it appropriately limits those commenting. No change made.	
SERC Dynamics Review Subcommittee (DRS)	R8: It is not clear whether the assessment results must be distributed to all parties of interest, or if it would be sufficient to post the assessment at a central location, and distribute information to access the information. Also, FERC Standards of Conduct issues would come into play in assuring that the information is available only to appropriate personnel. For additional clarity in who should receive the assessment, we recommend replacing "indicates" with "has" and adding words to the end of the sentence so that it states the following: "and to any functional entity that has a reliability related need for the Planning Assessment results and provides a written request. "R8: The PC and TP responsibilities should be stated separately for clarity. Part 8.1: It is not clear what the form of the response to the comments should be. Would an acknowledgement be sufficient, or would it be necessary to pursue a process of examining comments in detail and revising and reissuing the corresponding assessment? The requirement needs to be revised to make the above point clear.? For Part 8.1, we do not believe the intent is for casual emails to be documented and formally responded to. And we do not believe that anyone who happens to receive the assessment should be able to comment. Therefore, we recommend the following wording: "If one of the above named entities provides formal written comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments." If these recommendations are accepted, then the wording of M8 would have to change accordingly.

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Response: The standard does not specify the mechanics of distribution of the information, only that it must occur. The method proposed would be acceptable as long as it met Measure M8 and Section 1.4 under compliance monitoring. Control of competitive market information per Standards of Conduct is a fundamental expectation of all industry participants and the "reliability related need" restriction ensures only appropriate parties must be given planning assessments. The word "indicates" has been changed to “has” to be clearer. The other revised wording has the same meaning as the suggested wording and is sufficiently clear. **R8**. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information. The standard should not specify the means of providing and responding to comments, but ensures that appropriate communication is initiated. The SDT believes that the requirement limiting distribution to adjacent Planning Coordinator/Transmission Planner's and other functional entities with a reliability related need who request it appropriately limits those commenting. The revised wording has the same meaning as the suggested wording which is sufficiently clear.	
MAPP	R8: Remove Transmission Planners: Each PC shall distribute it Planning Assessment to adjacent PC and to any registered function entity that indicates a reliability need for the Planning Assessment results. R8.1 Remove Transmission Planners from subrequirement.
Response: The SDT believes both the Transmission Planner and Planning Coordinator must distribute their assessments and respond to comments to meet the overall intent of Requirement R8 and achieve appropriate coordination. No change made.	
Midwest ISO	Requirement R8- It should be made clear that a TP should not be required to send their assessment to adjacent PCs. Likewise the PCs should be required to send their assessment to TPs not in their footprint. Please consider the following language change for R8:Each Planning Coordinator shall distribute its planning assessment results to adjacent Planning Coordinators and to any other Planning Coordinators who indicate they have a reliability related need for the planning assessment results. Each Transmission Planner shall distribute its planning assessment results to adjacent Transmission Planner and to any other Transmission Planner who indicates they have a reliability related need for the planning assessment results. Requirement R8.1: This should be clarified such that this requirement is only required on Assessments that are completed and posted as final. If not, this could be an administratively burdensome task for an entity to have to respond to each and every comment and then document that they did respond within 90 days. Please consider the following language changes for R8.1If a recipient of the Planning Assessment’s final results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.
Response: The SDT disagrees with the suggested limitations and believes both the Transmission Planner and Planning Coordinator must distribute their assessments to the applicable entities cited in the requirement to meet the overall intent of Requirement R8 and achieve appropriate coordination. No change made. The Requirement R8 requirement is to distribute Planning Assessment results associated with this standard. Therefore Requirement R8, part 8.1 only requires response to comments on the applicable assessment results. No change in wording is necessary.	

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Northeast Power Coordinating Council--RSC	Requirements R8, 8.1, and Measure M8--There are a number of concerns with these requirements. There needs to be a specified time period upon which comments must be received. As written, there is no sunset on when comments may be made and therefore they must be responded to. Additionally, it is not clear if the 90-day response time may extend beyond the end of the year to maintain and maintain annual compliance. R8 also causes redundancy of distribution of assessments. There is no statute of limitation for comments. There is also potential conflict with the deadline for completing a study and when comments may be submitted (e.g. comments are received the day before the study is to be completed.) These issues must be addressed. This standard should not be used to remedy deficiencies in meeting the requirements of FERC Order 890. Therefore these should be deleted. If this requirement is retained the following revision to Requirement 8 is suggested:"Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to the functional entities that the Planning Coordinator and Transmission Planner recognize as having a reliability need for the Planning Assessment results." Compliance: 1.4 Data Retention: The Transmission Planner and the Planning Coordinator may not be using the same software. If both are required to store the data, do they both have to have the software to use the data? Can this be changed to an "or" such that one of them must retain the data and it can be up to them as to who it is? 1.4 Data Retention, last bullet - this relates back to Requirements R8, 8.1, and Measure M8. "Three calendar years of the notifications" seems to be an unnecessary requirement, and should be deleted. As an alternative to deletion, the implementation of a rolling three calendar years of notifications could be considered.

Response: The SDT disagrees that there should be a statute of limitation for asking questions related to coordination of planning and believes parties will act appropriately. The SDT's intent is that compliance would be judged by whether the comment was responded to in the required 90 days.

The SDT disagrees, this communication is necessary to achieve appropriate coordination.

The SDT disagrees that there should be a statute of limitation for asking questions related to coordination of planning and believes parties will act appropriately. The requirement is to distribute the results of the completed Planning Assessments associated with this standard therefore all related supporting studies are complete and there is no potential conflict.

The SDT seeks to retire the existing TPL-005 & -006 while continuing to meet the purpose of their requirements. FERC Orders 693 and 890 each provide expectations and direction to the ERO regarding enhancement of regional coordination and planning. The SDT believes the inclusion of Requirement R8 in the standard and performance of the regional assessments required under NERC delegation agreements will meet these objectives. No change made.

The SDT agrees the wording could be clearer and will clarify by adding "adjacent" before Transmission Planner. The word "indicates" has been changed to "has" to be clearer. The other revised wording has the same meaning as the suggested wording.

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent

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Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information. The SDT believes that both the Transmission Planner and Planning Coordinator have the responsibility for data retention. Therefore, the SDT believes that the existing language is adequate and that no changes are required. The SDT believes that both should have the necessary software for using the data. The SDT believes that retaining the documentation for 3 years is consistent with other standards and appropriate for audit purposes.	
Hydro-Québec TransEnergie (HQT)	Requirements R8, 8.1, and Measurement M8 There are a number of concerns with these requirements. There needs to be a specified time period upon which comments must be received. As written, there is no sunset on when comments may be made and therefore they must be responded to. Additionally, it is not clear if the 90-day response time may extend beyond the end of the year to maintain and maintain annual compliance. R8 also causes redundancy of distribution of assessments.Suggested revised Requirement R8 to say: Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to functional entities that demonstrated a reliability need with concurrence from their planning coordinator for the Planning Assessment results.
Response: The SDT disagrees that there should be a statute of limitation for asking questions related to coordination of planning and believes parties will act appropriately. The SDT's intent is that compliance would be judged by whether the comment was responded to in the required 90 days. The SDT believes both the Transmission Planner and Planning Coordinator must distribute their assessments to meet the overall intent of Requirement R8 and achieve appropriate coordination. No change made.	
US Bureau of Reclamation	Results of the Planning Assessments should be coordinated with all owner entities who all share in system reliability. Any owner that may choose to implement a Corrective ACtion Plan item should have access to the basis for the need.
Response: The SDT agrees and believes Requirement R8 facilitate the necessary interaction between reliability related entities. No change made.	
TIS	Term “document” in R8.1 the term documented needs to be defined. TIS suggests using the term “written “ i.e., “If a recipient of the Planning Assessment results provides documented written comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented written response to that recipient within 90 calendar days of receipt of those comments. ”The requirement to distribute reports to entities with “need” has very significant CEII implications. This should be tightened to a “bona fide reliability need” for the information, requiring CEII or confidential material handling procedures. Other general comments:1. Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft.
Response: The present wording is in other approved standards and is sufficiently clear based on experience to date. Control of CEII is a fundamental expectation of all industry participants and the "reliability related need" restriction ensures only appropriate parties must be given	

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planning assessments. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the Summary Considerations for Question 10.	
NERC Standards Review Subcommittee	The MRO NSRS asks that the SDT revise R8 to limit the need to provide the Planning Assessment as follows "adjacent Planning Coordinators and adjacent Transmission Planners and to any registered functional entity"? This MRO NSRS suggestion is added to the requirement to clarify that the word adjacent also applies to Transmission Planners and to clarify that the functional entity must be registered in order for the entity to be applicable to the requirement.
Response: The SDT agrees and will clarify by adding "adjacent" before Transmission Planner, but the SDT believes adding "registered" is unnecessary because it is understood as it relates to NERC Reliability Standards. **R8**. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information.	
Florida Power and Light	The requirement to distribute the Planning Assessment should not mandate distribution of a document but should be more flexible and allow for making the Planning Assessment available, such that those entities that need the information can have it readily available. R8 should be modified as follows: Each Planning Coordinator and Transmission Planner shall make available its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.
Response: The SDT believes Requirement R8 must be a standards requirement and ensures communication of information necessary for regional assessments. No change made.	
NorthWestern Energy	The term "functional entity" needs to be defined.
Response: The NERC Reliability Functional Model defines the term "functional entity".	
Gainesville Regional Utilities	The wording could be a little better to indicate that the PC and TP should always get each others planning assessments, but other entities need to indicate a reliability related need to get the same. I suggest making a second sentence and eliminating the word "and".
Response: The SDT agrees that the wording could be a little better and will clarify by adding "adjacent" before Transmission Planner. **R8**. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information.	
National Grid	This standard should not be used to remedy deficiencies in meeting the requirements of FERC Order 890. Therefore these should be deleted.

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	If this requirement is retained the following is suggested: Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to the functional entities that the Planning Coordinator and Transmission Planner recognizes as having a reliability need for the Planning Assessment results. Additionally, there is no statute of limitation for comments. There is also potential conflict with the deadline for completing a study and when comments may be submitted (e.g. comments are received the day before the study is to be completed.) These issues must be addressed. Compliance: 1.4 Data Retention: The Transmission Planner and the Planning Coordinator may not be using the same software. If both are required to store the data, do they both have to have the software to use the data? Can this be changed to an "or" such that one of them must retain the data and it can be up to them as to who is it. 1.4 Data Retention, last bullet - this relates back to Requirements R8, 8.1, and Measurement M8. "Three calendar years of notification" seems to be a nuisance requirement to get in trouble for. This is unnecessary and should be deleted.
Response: The SDT seeks to retire the existing TPL-005 & -006 while continuing to meet the purpose of their requirements. FERC Orders 693 and 890 each provide expectations and direction to the ERO regarding enhancement of regional coordination and planning. The SDT believes the inclusion of Requirement R8 in the standard and performance of the regional assessments required under NERC delegation agreements will meet these objectives. No change made. The SDT agrees and will clarify by adding "adjacent" before Transmission Planner. The word "indicates" has been changed to "has" to be clearer. The other revised wording has the same meaning as the suggested wording which is sufficiently clear. **R8**. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information. The SDT disagrees that there should be a statute of limitation for asking questions related to coordination of planning and believes parties will act appropriately. No change made. The requirement is to distribute the results of the completed Planning Assessments associated with this standard therefore all related supporting studies are complete and there is no potential conflict. The SDT believes that both the Transmission Planner and Planning Coordinator have this responsibility for the data retention. Therefore the SDT believes that the existing language is adequate and that no changes are required. The SDT believes that both should have the necessary software for using the data. No change made. The SDT believes that retaining the documentation for 3 years is consistent with other standards and appropriate for audit purposes.	
TVA System Planning	TVA believes that the TP and PC are unnecessarily duplicating work as shown in R8 and in M8. TVA believes that just the PC should be responsible for this coordination. R8: It is not clear whether the assessment results must be distributed to all parties of interest, or if it would be sufficient to post the assessment at a central location, and distribute information necessary to access the results. Also, FERC Standards of Conduct issues would come into play in assuring that the information is available only to appropriate

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	personnel. R8.1: It is not clear what the form of the response to the comments should be " would an acknowledgement be sufficient, or would it be necessary to pursue a process of examining comments in detail and revising and reissuing the corresponding assessment"
Response: The SDT believes both the Transmission Planner and Planning Coordinator must distribute their assessments to meet the overall intent of Requirement R8 and achieve appropriate coordination. The standard does not specify the mechanics of distribution of the information, only that it must occur. The method proposed would be acceptable as long as it met Measure M8 and Section 1.4 under compliance monitoring. Control of competitive market information per Standards of Conduct is a fundamental expectation of all industry participants and the "reliability related need" restriction ensures only appropriate parties must be given planning assessments. The standard should not specify the means of providing and responding to comments, but ensures that appropriate communication is initiated. No change made.	
SRC of ISO/RTO	Under R8 it should be made clear that a TP should not be required to send their assessment to adjacent PCs and that PCs should not be required to send their assessments to TPs not in their footprint. Under R8.1: If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.This should not be required until the Assessment is final and could be an administrative intense task. The following wording is suggested for R8:R8. Each Planning Coordinator shall distribute its planning assessment results to adjacent Planning Coordinators and to any Planning Coordinator who indicates a reliability related need for the planning assessment results. Each Transmission Planner shall distribute its planning assessment results to adjacent Transmission Planners and to any other Transmission Planner who indicates they have a reliability need for the planning assessment results. R8.1 If a recipient of the Planning Assessment final results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments. AESO does not comment on VSLs or VRFs.
Response: The SDT believes both the Transmission Planner and Planning Coordinator must broadly distribute their assessments to meet the overall intent of Requirement R8 and achieve appropriate coordination. No change made. The requirement is to distribute the results of the completed Planning Assessments associated with this standard therefore all related supporting studies are complete and there is no potential conflict. The SDT recognizes this fact and believes 90 days should be sufficient to develop a response. The SDT disagrees with the suggested limitations and believes both the Transmission Planner and Planning Coordinator must distribute their assessments to the applicable entities cited in the requirement to meet the overall intent of Requirement R8 and achieve appropriate coordination. No change made.	
Pepco Holdings, Inc. - Affiliates	While the SDT has stated in the Description of Current Draft that the issues of TPL-005 and TPL-006 have been addressed. It is not clear to PHI Affiliates that this is true. It is not evident how wide area planning is performed. Requirement 2 states Each

Organization	Comments for Question 8
PHI	Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES.

Response: The SDT seeks to retire the existing TPL-005 & -006 while continuing to meet the purpose of their requirements. FERC Orders 693 and 890 each provide expectations and direction to the ERO regarding enhancement of regional coordination and planning. The SDT believes the inclusion of Requirement R8 in the standard and performance of regional assessments will meet these objectives.

FRCC Transmission Working Group	With regards to the High VSL, what about entities that indicate a reliability related need for the Planning Assessment? Should this be part of the High VSL? Consider changing the requirement to distribute the Planning Assessment to become more flexible and allow for making the Planning Assessment available to those entities that indicates a need. Consider revising as follows:Each Planning Coordinator and Transmission Planner shall make available its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. The definition of "Known Commitments" should explain how that would diferentiate between Planned Commitments

Response: The SDT agrees and will add those with a reliability related need to the Lower and High VSL.

R8 VSL	The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners or adjacent Planning Coordinators, and to one functional entity that has a reliability related need and has submitted a written request for the information, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to its adjacent Transmission Planners or adjacent Planning Coordinators, and to any functional entity that has a reliability related need and has submitted a written request for the information, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

The proposed revised wording is essentially the same as the current wording and does not provide any additional clarity. No change made.

The SDT believes that the existing language regarding known commitments is adequate and no further change is required.

9. The SDT has revised the definitions in response to industry comments to the third posting. Do you agree with these definition changes? If not, please clearly indicate which definition you disagree with and provide specific comments.

Summary Consideration: The SDT received several comments on definitions. The following summarizes the questions and response on the definitions. Planning Assessment: The SDT considered the comment, but feels that a Corrective Action Plan includes the 'do nothing' option, which would address the concern and decided not to change the definition.

Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition.

The SDT believes the exclusion of voltage sensitive load belongs in the Non-Consequential Load Loss definition because it is not Non-Consequential load.

Consequential Load Loss: Due to comments in prior postings, the SDT has elected to define Consequential Load specific to Load that is lost due to a fault. Non-Consequential Load has been defined to be all else, except as noted. That which has been noted is excluded from coverage by the standard. So it is not necessary to include the noted exclusions from the Non-Consequential Load Loss definition in the Consequential Load Loss definition.

Planning Horizon: The only location where planning horizon didn't specify Near-Term or Long-Term was in the 'Purpose'. The SDT didn't feel that this reference needed to be specific or was sufficient to warrant a definition. No changes have been made.

Year One: The SDT believes the definition will capture both a summer and winter peak and is necessary to provide a clear starting point for the planning horizon.

Year One is not considered to be the immediate year following the current year, as suggested by some, because if the study were completed at the end of the year, then there would be no time to implement a Corrective Action Plan. Also, that following year is in the Operational Planning time frame.

The SDT doesn't see a problem with entities having slightly different study periods. This situation exists under the current TPL Standards.

With regards to any possible inconsistencies within the practices of any entity, the SDT believes that the requirements as defined are required for a Planning Assessment. How these requirements are met is beyond the scope of this standard and should be discussed within the responsible entities.

Consequential Generation Loss: Generation run-back and tripping is acceptable. It is up to the Planning Coordinator and the Transmission Planner to determine how many units or cumulative MW may be interrupted due to either a consequential or non-consequential action. Therefore it isn't necessary for the SDT to define Consequential Generation Loss.

Note 'b' has been revised to clarify the issue. Consequential Load Loss as well as generation loss is acceptable as a consequence of any planning or extreme event excluding P0.

Bus-Tie Breaker: The SDT has elected to define a Bus-Tie Breaker. If the SDT were to also define what is not a Bus-Tie Breaker, then anything that was missed would not be defined. To be comprehensive, the SDT has to limit the definition to what a Bus-Tie Breaker is to avoid further complexity.

Steady State: 'Steady State' was changed to 'steady state', so no definition is required.

The following definition was changed for clarity due to industry comments:

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Note 'b': Consequential Load Loss as well as generation loss is acceptable as a consequence of any planning or extreme event excluding P0.

Organization	Yes or No	Comments for Question 9
FRCC Transmission Working Group		Consider the following definition for clarification: Planning Assessment: Documented evaluation of (1) studies of future Transmission System performance and (2) Corrective Action Plans (included in studies) to remedy identified deficiencies. Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, or (2) the response of voltage sensitive Load that is disconnected from the System by end-user equipment.
Response: Planning Assessment: The SDT considered the comment, but feels that a Corrective Action Plan includes the 'do nothing' option, which would address the concern and decided not to change the definition. Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
ERCOT ISO	No	* Planning horizon is not formally defined but used many times throughout the standards. If there is a need to define the Near- and Long-term Transmission Planning Horizons, then the transmission planning horizon itself also should be defined. Additional confusion on this issue is the use of Long-term Planning as a planning horizon of one year or longer, also not formally defined. We finally found this referenced in the NERC Drafting Team guideline, which is not an obvious place to look for a definition. * Year One is only used two times " once to define Near-term Transmission Planning Horizon and once in the TPL standard. If this is not used throughout the NERC standards, it should not be defined. As an alternative, the transmission planning horizon could be formally defined, with Near- and Long-term Transmission Planning Horizons defined as subsets of the main definition. This would eliminate the need for a formal definition of Year One. If Year One stays as a new definition, it seems to be too broad, potentially allowing for omission of a peak season in the study. For example, if Year One is the period 12 to 18 months from the end of 2009, then Year One is currently 2011. Why is the year 2010 not considered to be Year One.*

Organization	Yes or No	Comments for Question 9
		Non-Consequential Load Loss is confusing " due to the base word "consequence". Consequential Load Loss is intended to be a load loss that is a result, or consequence, of the isolation. Non-Consequential Load Loss seems intended to imply it was not a consequence of the isolation. Although the standard attempts to define the term, this definition does not agree with the common English definition of the term. "Non-consequential" (or "Inconsequential") implies that the load loss is unimportant, minor or insignificant. This is the opposite intent of how this term is used in the standard, where it is used to mean the load that it is unacceptable to lose for a particular event. Alternatives could be "Direct Load loss" and "Indirect Load loss" to replace the two concepts that are included as Consequential and Non-Consequential respectively.
Response: Planning Horizon: The only location where planning horizon didn't specify Near-Term or Long-Term was in the 'Purpose'. The SDT didn't feel that this reference needed to be specific or was sufficient to warrant a definition. No changes have been made. Year One: Year One is not considered to be the immediate year following the current year because if the study were completed at the end of the year, then there would be no time to implement a Corrective Action Plan. Also, that following year is in the Operational Planning time frame. No changes have been made. As you have indicated, the terms 'consequential' and 'non-sequential' can be interpreted consistent with the intent of the SDT. Further the use has been accepted by NERC and seems to have been accepted by the industry in the multiple postings to date. By changing 'Non-consequential' (or not-consequential) to 'inconsequential' you have changed the meaning. The SDT is content with the terms and has focused on the clarity of the definition, which also seems to be the focus of the comments from the industry. The SDT has decided to stay with the existing terms rather than changing them as this late date. No changes have been made.		
Northeast Utilities	No	[Comment on Year One Definition] This still defines Year One as both a particular year AND a window. It cannot be both. We suggest rewording the second sentence to read: "This is further defined as the beginning 12-18 months from the end of the current year".
Hydro-Québec TransEnergie (HQT)	No	Definitions " Year One " This still defines Year One as both a particular year AND a window. It cannot be both. Suggest rewording the second sentence to read: "This is further defined as beginning 12-18 months from the end of the current year."
Response: The SDT does not agree that there is an issue and has not changed the definition.		
Platte River Power Authority	No	1. Please make the definition for Non-Consequential Load Loss simple and straightforward. For example, Non-Consequential Load Loss: The planned shedding of firm load.(Note that phrases "firm load" and "firm load shedding" are used frequently in a dozen other standards.) 2. Move the remainder of the sentence about "the response of voltage sensitive Load including...by end-user equipment." from the Non-Consequential Load Loss definition to the Consequential Load Loss definition.
Response: Non-Consequential Load Loss; Due to comments received in earlier postings, the SDT believes that the definition can not be that simple. The SDT believes the exclusion of voltage sensitive load belongs in the Non-Consequential Load Loss definition because it is not Non-Consequential Load. Therefore, any reduction in load due to sensitivity to low voltage would not result in a compliance violation. No change made.		

Organization	Yes or No	Comments for Question 9
To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
NERC Standards Review Subcommittee	No	A. Add a Consequential Generation Loss definition, which would be a complement to the Consequential Load Loss definition. Both consequential load loss and consequential generation loss are referred to in note "b" of the Steady State & Stability section of Table 1, but only consequential load loss is defined. The MRO NSRS suggests text of: Consequential Generation Loss: All Generation that is no longer delivered to any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions. B. The MRO NSRS offers the following comment to one of the proposed definitions of TPL-001. Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss that is the result of the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment. C. Add a Planning Horizon definition. This term is used in this proposed standard, in the FAC-010-2 standard, and possibly in other future standards, but it has not been defined yet. D. The SDT is to be commended for working on the Year one definition, however, concerns exist that if the standard is adopted as written, it is incompatible with the eastern interconnection wide ERAG model process. E. If the SDT intends to change the planning processes and model building processes throughout NERC in this regard, then the SDT should explain the benefits of changing this process and verify that it does not sabotage the normal model building and study process.
Response: A. Generation run-back and tripping is acceptable. It is up to the Planning Coordinator and the Transmission Planner to determine how many units or cumulative MW may be interrupted due to either a consequential or non-consequential action. Therefore it isn't necessary for the SDT to define Consequential Generation Loss. Note 'b' has been revised to clarify the issue. **Note 'b':** Consequential Load Loss as well as generation loss is acceptable as a consequence of any planning or extreme event excluding P0. B. To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment C. The only location where planning horizon didn't specify Near-Term or Long-Term was in the 'Purpose'. The SDT didn't feel that this reference needed to be specific or was sufficient to warrant a definition. No changes have been made. D & E. With regards to any possible inconsistencies within the practices of any entity, the SDT believes that the requirements as defined are required for a Planning		

Organization	Yes or No	Comments for Question 9
Assessment. How these requirements are met is beyond the scope of this standard and should be discussed within the responsible entities.		
MAPP	No	Add a Consequential Generation Loss definition, which would be a complement to the Consequential Load Loss definition. Both consequential load loss and consequential generation loss are referred to in note "b" of the Steady State & Stability section of Table 1, but only consequential load loss is defined. We suggest text of: "Consequential Generation Loss: All Generation that is no longer delivered to any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions. Add a Planning Horizon definition. This term is used in this proposed standard, in the FAC-010-2 standard, and possibly in other future standards, but it has not been defined yet.
Response: Consequential Generation Loss: Generation run-back and tripping is acceptable. It is up to the Planning Coordinator and the Transmission Planner to determine how many units or cumulative MW may be interrupted due to either a consequential or non-consequential action. Therefore it isn't necessary for the SDT to define Consequential Generation Loss. Note 'b' has been revised to clarify the issue. **Note 'b':** Consequential Load Loss as well as generation loss is acceptable as a consequence of any planning or extreme event excluding P0. Planning Horizon: The only location where planning horizon didn't specify Near-Term or Long-Term was in the 'Purpose'. The SDT didn't feel that this reference needed to be specific or was sufficient to warrant a definition. No changes have been made.		
United Illuminating	No	As currently defined "Non-Consequential Load Loss" could allow widespread or cascading motor stall. The language in the definition cannot be this generic. The text is broad enough that it could allow a voltage collapse, the definition is incompatible with Table 1a (BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur). The definition for the non-consequential load loss combined with Table 1 would prohibit any customer from tripping its own load for contingencies that indicate 'no' in the non-consequential load loss column. This is not practical and appears to be an unintended consequence of the change in definition. This requires a change in the definition or the table.We suggest clearly defining exactly what Non-Consequential Load Loss is as "intended post-Contingency loss of load caused by operator or SPS (RAS) action."
Central Maine Power Company	No	As currently defined Non-Consequential Load Loss could allow widespread or cascading motor stall. The language in the definition cannot be this generic. The text is broad enough that it could allow a voltage collapse; the definition is incompatible with Table 1a (BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur). The definition for the non-consequential load loss combined with Table 1 would prohibit any customer from tripping its own load for contingencies that indicate 'no' in the non-consequential load loss column. This is not practical and appears to be an unintended consequence of the change in definition. This requires a change in the definition or the table.We suggest defining Non-

Organization	Yes or No	Comments for Question 9
		Consequential Load Loss as "intended post-Contingency loss of load caused by operator or SPS (RAS) action."
ISO New England	No	As currently defined Non-Consequential Load Loss could allow widespread or cascading motor stall. The language in the definition cannot be this generic. The text is broad enough that it could allow a voltage collapse, the definition is incompatible with Table 1a (BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur). The definition for the non-consequential load loss combined with Table 1 would prohibit any customer from tripping its own load for contingencies that indicate 'no' in the non-consequential load loss column. This is not practical and appears to be unintended consequencetof the change in definition. This requires a change in the definition or the table.We suggest defining Non-Consequential Load Loss as "intended post-Contingency loss of load caused by operator or SPS (RAS) action."
National Grid	No	As currently defined Non-Consequential Load Loss could allow widespread or cascading motor stall. The language in the definition cannot be this generic. The text is broad enough that it could allow a voltage collapse, the definition is incompatible with Table 1a (BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur). The definition for the non-consequential load loss combined with Table 1 would prohibit any customer from tripping its own load for contingencies that indicate 'no' in the non-consequential load loss column. This is not practical and appears to be unintended consequent of the change in definition. This requires a change in the definition or the table.It is suggested to redefine Non-Consequential Load Loss as "intended post-Contingency loss of load caused by operator or SPS (RAS) action."
Response: The SDT added Requirement R5 to require that every Transmission Planner and Planning Coordinator has a voltage criteria. The voltage criteria should prevent the exposure to widespread or cascading motor stall and should limit any potential misinterpretation that the Non-Consequential Load Loss would allow such events. Table 1a (BES Transmission voltage instability, Cascading, and uncontrolled islanding shall not occur) supports Requirement R5 and reinforces the point that the definition for Non-Consequential Load Loss should not be read so broadly as to allow for unacceptable events. The definition for the Non-Consequential Load Loss excludes end-user actions, which disconnect the Load from the system. So Table 1 does not apply to such Load. The proposed definition is too narrow and would only capture anticipated Load losses for predefined conditions. It would not capture unanticipated loss of Load, which still needs to be accounted for within the definition. To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment		
Progress Energy Florida, Inc.	No	As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all appropriate parties to review PEF's previous comments to this effect.
Response: Throughout the drafting process, the SDT has carefully considered your comments as well as comments from other industry members.		

Organization	Yes or No	Comments for Question 9
Deseret Power	No	Comments: The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language follows Non-Interruptible Load loss other than: "Consequential Load Loss" the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment. This version uses the same wording but clarifies that the term "other than" applies to all three things.
Response: Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
Sacramento Municipal Utility District	No	Definition of Non-Consequential Load (Non-CLL): This definition excludes from the "Non-Consequential Load" only the "Interruptible" portion of Demand Response. The last SDT response to a comment on Draft #3 stated that there is no ceiling on the amount of DSM that can be utilitized (see Reference 1 below). Since Demand Response is more than just "Interruptible" demand, it is recommended that the exclusion in the definition for Non-CLL be broadened to include other relevant categories (see Reference 2 below) of Demand Response / DSM that is acceptable. Reference 1: pdf page 310, 337: SDT response related to DSM at http://www.nerc.com/docs/standards/sar/ATFNSDT_third_posting_comment_responses_2009Sept16.pdf Reference 2: http://www.nerc.com/docs/pc/drdtf/DADS_Phase_III_Final_090109.pdf, Figure 3 at pdf page 16, block under Capacity; and, associated definitions in Appendix III at pdf page 46 Use of the defined term "Planning Assessment" throughout the standard: Since the definition includes both performance evaluation (assessment) and corrective action to remedy identified deficiencies, its usage throughout the standard should be reviewed to ensure that it does not mandate corrective actions where the minimum requirement may be calling only for an assessment. The SDT should consider including a definition for "Spare Equipment Strategy". The SDT's comments on "spare equipment strategy" (at pdf page 122 of Consideration of Comments on 3rd Draft) state that it is based on a directive from FERC Order 693. Directives that impact reliability should be translated in to a requirement in a Standard. Even the proposed scope of MOD-010-0 (reference http://www.nerc.com/files/2010-2012_RS-Development-Plan_Volume-I_II.pdf page 223) makes a reference to the strategy, but does not require it.
Response: DSM: The SDT believes that any Load that is interruptible should be so under an agreement or tariff provision, which excludes it from the constraints of the TPL standard. No changes have been made. Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment Planning Assessment: The SDT considered the comment, but feels that a Corrective Action Plan includes the 'do nothing' option, which would address the concern		

Organization	Yes or No	Comments for Question 9
and decided not to change the definition. Spare equipment strategy: The SDT believes that spare equipment strategy can be managed by individual Transmission Owners and that the term does not have to be defined in the Standard. The SDT further believes it has satisfied the intent of the directive of FERC Order 693 by including Requirement R2, part 2.1.5. No changes have been made.		
Midwest ISO	No	Definition Section: The definition for "Bus Tie Breaker" should be revised to clarify whether a breaker in a standard ring bus or breaker and one-half scheme should be considered a "bus tie breaker". Definition Section: We believe that the "Year One" definition changes have clarified what is intended. Definition Section: We suggest having the following definition of Consequential Generation Loss added to the definition section. Consequential Generation Loss - All generation that is no longer connected to the transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.
Response: Bus-Tie Breaker: The SDT has elected to define a Bus-Tie Breaker. If the SDT were to also define what is not a Bus-Tie Breaker, then anything that was missed would not be defined. To be comprehensive, the SDT has to limit the definition to what a Bus-Tie Breaker is to avoid further complexity. No changes have been made. Consequential Generation Loss: Generation run-back and tripping is acceptable. It is up to the Planning Coordinator and the Transmission Planner to determine how many units or cumulative MW may be interrupted due to either a consequential or non-consequential action. Therefore it isn't necessary for the SDT to define Consequential Generation Loss. Note 'b' has been revised to clarify the issue. Consequential Load Loss as well as generation loss is acceptable as a consequence of any planning or extreme event excluding P0. **Note 'b':** Consequential Load Loss as well as generation loss is acceptable as a consequence of any planning or extreme event excluding P0.		
Northeast Power Coordinating Council--RSC	No	Definitions " Year One " This still defines Year One as both a particular year AND a window. It cannot be both. Suggest rewording the second sentence to read: "This is further defined as beginning 12-18 months from the end of the current year." As currently defined Non-Consequential Load Loss could allow widespread or cascading motor stall. The language in the definition cannot be this generic. The text is broad enough that it could allow a voltage collapse. The definition is incompatible with Table 1a (BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur). The definition for the non-consequential load loss combined with Table 1 would prohibit any customer from tripping its own load for contingencies that indicate 'no' in the non-consequential load loss column. This is not practical and appears to be an unintended consequence of the change in definition. This requires a change in the definition or the table.It is suggested to redefine Non-Consequential Load Loss as "intended post-Contingency loss of load caused by operator or SPS (RAS) action."

Organization	Yes or No	Comments for Question 9
Response: Year One: The SDT does not agree that there is an issue and has not changed the definition. No change made. Non-Consequential Load Loss: The SDT added Requirement R5 to require that every Transmission Planner and Planning Coordinator has a voltage criteria. The voltage criteria should prevent the exposure to widespread or cascading motor stall and should limit any potential misinterpretation that the Non-Consequential Load Loss would allow such events. Table 1a (BES Transmission voltage instability, Cascading, and uncontrolled islanding shall not occur) supports Requirement R5 and reinforces the point that the definition for Non-Consequential Load Loss should not be read so broadly as to allow for unacceptable events. The definition for the Non-Consequential Load Loss excludes end-user actions, which disconnect the Load from the system. So Table 1 does not apply to such Load. The proposed definition is too narrow and would only capture anticipated Load losses for predefined conditions. It would not capture unanticipated loss of Load, which still needs to be accounted for within the definition. To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
Gainesville Regional Utilities	No	I still find the Non-Consequential Load Loss definition vague. But, I presently do not have anything better to offer and thus I can live with it.
Response: Thank you for your response.		
SRC of ISO/RTO	No	In note b of the steady state and stability section of Table 1, consequential generation loss is referenced; however, there is no definition of such. A definition of consequential generation loss that is defined similar to "consequential load loss" should be added. The definition for "Bus Tie Breaker" should be revised to clarify whether a breaker in a standard ring bus or breaker and one-half scheme should be considered a "bus tie breaker". "year one" definition changes have clarified what is intended. AESO does not comment on VSLs or VRFs.
Response: Consequential Generation Loss: Generation run-back and tripping is acceptable. It is up to the Planning Coordinator and the Transmission Planner to determine how many units or cumulative MW may be interrupted due to either a consequential or non-consequential action. Therefore it isn't necessary for the SDT to define Consequential Generation Loss. Note 'b' has been revised to clarify the issue. **Note 'b':** Consequential Load Loss as well as generation loss is acceptable as a consequence of any planning or extreme event excluding P0. Bus Tie Breaker: The SDT has elected to define a Bus Tie Breaker. If the SDT were to also define what is not a Bus Tie Breaker, then anything that was missed would not be defined. To be comprehensive the SDT has to limit the definition to what a Bus Tie Breaker is to avoid further complexity.		

Organization	Yes or No	Comments for Question 9
The SDT does not see the difference between what is in the draft and what is proposed and does not agree that there is an issue. No change has been made to the definition.		
TVA System Planning	No	Is the 12-18 months referenced in the Year One definition actually from the start of the TA or the anticipated completion date of the same TA? Suggest revising the Non-Consequential Load Loss definition: Non-Interruptible Load loss other than (1) Consequential Load Loss, (2) the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment, and (3) utility loads such as pump storage loads, compressed air generating pumping loads, and scrubber loads, etc when such loads do not result in tripping of a generating unit.
Response: Year One: Year One begins 12-18 months from the end of the calendar year. No change made. Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment. The SDT interpreted utility loads such as pump storage loads, compressed air generating pumping loads, and scrubber loads as interruptible loads, which don't need to be highlighted separately. As a result, no changes were made to include this list.		
NYISO	No	Question # 9 The SDT has revised the definitions in response to industry comments to the third posting. Do you agree with these definition changes? If not, please clearly indicate which definition you disagree with and provide specific comments. No. Need to define "Steady State" and "Consequential Load" as well as other phrases included throughout the NYISO's response.
Response: 'Steady State' was changed to 'steady state', so no definition is required. No change made. No instances of 'Consequential Load' were identified in the draft standard. All of the references were to 'Consequential Load Loss', which is defined. No change made.		
Oklahoma Gas & Electric	No	R 3.4, R3.5, R4.4 & R4.5 There appear to be no standards of directions on identifying severe or extreme system impacts. This may need to be defined. Extreme events evaluated (last page of Table 1) OG&E needs more specific information on what is defined to be an extreme event before offering support. It appears the number of possible combinations and permutations that could be run make any compressive study overwhelming to perform and would provide very limited benefits. This needs to be clarified.
Response: Extreme event: The SDT agrees that extreme event analysis could be overwhelming if all possible combinations and permutations were evaluated. However that is not the expectation. Requirement R3, part 3.5 of the standard requires only those extreme events "that are expected to produce more severe System Impacts". Therefore this is a judgment call with a corollary expectation that one can provide an explanation of the thoughts behind the judgment for selecting the events.		

Organization	Yes or No	Comments for Question 9
Duke Energy	No	Reword the definition of Non-Consequential Load Loss as follows: Non-Interruptible Load loss other than Consequential Load Loss and other than the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.
Response: Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
Florida Power and Light	No	The definition of "Known Commitments" should explain how that would differentiate between Planned Commitments Planning Assessment definition should be clarified as follows: Planning Assessment: Documented evaluation of (1) studies of future Transmission System performance and (2) Corrective Action Plans (included in studies) to remedy identified deficiencies. Non-Consequential Load Loss definition should be clarified as follows: Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, or (2) the response of voltage sensitive Load that is disconnected from the System by end-user equipment. The SDT should do a search through the document (and Table 1) on “cascading” and capitalize the “C” and delete “outages” where it appears after “Cascading”.
Response: Known Commitments: The SDT believes that the existing language is adequate and no further change is required. If you do not have any known Firm Transmission Service as an example, then this fact should just be documented. Planning Assessment: The SDT considered the comment, but feels that a Corrective Action Plan includes the ‘do nothing’ option, which would address the concern and decided not to change the definition. Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment. The SDT did change, “cascading outages” to “Cascading” throughout the standard as suggested.		
Ameren	No	The definition of Bus-tie Breaker is unclear. This definition needs to be made clearer to remove issues regarding P2 and P5 planning events. We suggest the following additional language: A breaker in a standard breaker-and-a-half or ring bus configuration is not a Bus-tie Breaker. Suggest rewording Non-Consequential Load Loss definition: Non-Interruptible Load loss other than Consequential Load Loss. Non-Consequential Load Loss does not include the response of voltage sensitive

Organization	Yes or No	Comments for Question 9
		Load or Load that is disconnected from the System by end-user equipment.
Response: Bus-Tie Breaker: The SDT has elected to define a Bus-Tie Breaker. If the SDT were to also define what is not a Bus-Tie Breaker, then anything that was missed would not be defined. To be comprehensive the SDT has to limit the definition to what a Bus-Tie Breaker is to avoid further complexity. Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
Arizona Public Service Co.	No	The definition of Non-Consequential Load is confusing. It is not clear whether the response of voltage sensitive load and the load that is disconnected by the end user is included or not included. It is suggested that all items that are excluded be itemized and that there be no ambiguity.
Response: Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
Bonneville Power Administration	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: " Consequential Load Loss " the response of voltage sensitive Load " Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term "other than" applies to all three things.
Idaho Power	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: " Consequential Load Loss " the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term "other than" applies to all three things.
Modesto Irrigation District Transmission Planning	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: " Consequential Load Loss " the response of voltage sensitive Load " Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term "other than" applies to all three things.
NV Energy	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: " Consequential Load Loss " the response of voltage sensitive Load ? Load that is disconnected from the System by end-user

Organization	Yes or No	Comments for Question 9
		equipment.This version uses the same wording but clarifies that the term “other than” applies to all three things.
Pacific Gas and Electric Co.	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: “ Consequential Load Loss “ the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term “other than” applies to all three things.
Puget Sound Energy, Inc.	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: “ Consequential Load Loss “ the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term “other than” applies to all three things.
San Diego Gas & Electric Co	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: “ Consequential Load Loss “ the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.
Southern California Edison (SCE)	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: “ Consequential Load Loss “ the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term “other than” applies to all three things.
SRP	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: “ Consequential Load Loss “ the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term “other than” applies to all three things.
Utility System Efficiencies, Inc. (USE)	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: “ Consequential Load Loss “ the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term “other than” applies to all three things.
Western Area Power Adm - RMR	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies.

Organization	Yes or No	Comments for Question 9
		Suggested revision to the language follows:Non-Interruptible Load loss other than: " Consequential Load Loss " the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term "other than" applies to all three things.
Xcel Energy	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: " Consequential Load Loss " the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term "other than" applies to all three things.
NorthWestern Energy	No	The definition of Non-Consequential Load needs clarification. A possible revision is to list bulleted items in the definition: Non-Interruptible Load loss other than: " Consequential Load Loss " the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.This way "other than" applies to all three bullets.
Response: Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
Omaha Public Power District	No	The definition of Non-Consequential Load Loss is not clear. It's not clear whether "the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment" is considered to be Non-Consequential Load Loss or not. Based on previous drafts, it appears that the SDT's intent is that "the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment" is considered to be a special type of Consequential Load Loss--a type that transmission-planning entities are not allowed to rely upon to meet steady-state performance requirements. Comments on this fourth draft from one commenter seemed to indicate that he was interpreting the definition of Non-Consequential Load Loss to mean that "the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment" is considered to be Non-Consequential Load Loss. Consider breaking the definition of Non-Consequential Load Loss into two or more sentences to prevent misinterpretation and confusion. Also consider including a reference to "the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment" in the definition of Consequential Load Loss if this type of load loss is considered to be a special type of Consequential Load Loss. If this type of load loss is considered to be a special type of Consequential Load Loss, add the following sentence to the end of Note "b" at the top of Table 1: However, see Note "i" for a restriction that applies to steady state performance.
Response: Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		

Organization	Yes or No	Comments for Question 9
The SDT believes the reference to exclude voltage sensitive load belongs in the Non-Consequential Load Loss definition because this is neither Consequential nor Non-Consequential. No change was made to Note 'b' or 'i' for this issue.		
NERC System Protection and Control Subcommittee (SPCS)	No	The Drafting Team should change the definition of Consequential Load Loss to clarify that load lost due to operation of remote backup protection is not Consequential Load Loss. Operation of remote backup protection is not Normal Clearing for a fault.Consequential Load Loss: All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by Normal Clearing initiated by the a Protection System operation designed to isolate the fault.
Response: Consequential Load Loss considering operation of remote backup protection: For the purpose of the Transmission Planning Standard the remote backup protection is still operating to isolate the fault and the SDT is interpreting the subsequent loss of Load to be Consequential Load Loss. No change was made.		
MidAmerican Energy Company	No	The SDT is to be commended for working on the Year One definition, however, MidAmerican continues to be concerned that if the standard is adopted with the Year One definition as written, it is incompatible with the eastern interconnection wide ERAG model process.The definition as currently provided in the draft standard states that Year One of analysis should begin 12-18 months from the end of the current calendar year. This contradicts the time frames that models are currently made available in the MRO as a result of the process for building models through the ERAG. For example, the models developed through the MRO and ERAG model building process in 2009 include cases for the years 2010, 2011, 2015, and 2020. According to the definition of Year One, the 2011 cases in the 2009 series models would be representative of Year One during the 2009 calendar year. However the ERAG models are not provided until late 2009, and some data sets may not be available until early 2010. With this Year One definition, there would be limited or no time where the ERAG model series would include cases representing Year One as defined in the draft standard. MidAmerican urges the SDT to delete the Year One definition altogether. Since the development of regional models are tied to ERAG models and since ERAG model timing is set at the interconnection-wide level, it is likely that nearly all Transmission Planners and Planning Coordinators are working with similar models that are available at similar times. It seems to MidAmerican that this detail on what Year One is can be easily controlled interconnection-wide through the ERAG and which models they provide when.However, if the SDT believes that the Year One definition is necessary, MidAmerican urges the SDT to revised the Year One definition from stating "12-18 months from the end of the current calendar year" to stating "0-18 months from the end of the current calendar year". This revised definition would be at least compatible with the current ERAG process.
Response: Year One: The SDT believes the definition will capture both a summer and winter peak and is necessary to provide a clear starting point for the planning horizon. With regards to any possible inconsistencies within the practices of any entity, the SDT believes that the requirements as defined are required for a Planning Assessment. How these requirements are met is beyond the scope of this standard and should be discussed within the responsible entities. No changes were made.		
Tri-State Generation and Transmission Association	No	The SDT removed definitions of Extreme Events and Load Reduction. We still need to have some scale to differentiate N-1 from less likely but possibly higher impact events. However, we do understand that such a

Organization	Yes or No	Comments for Question 9
		criteria will take some time to develop, and should perhaps be a separate subject addressed by a new SAR. Year One has a flexible definition. It does not seem very intuitive. We can't say whether this is good or bad, although one entity's year one could overlap with another's year two.
Response: The SDT doesn't see a problem with entities having slightly different study periods. This situation exists under the current TPL Standards.		
US Bureau of Reclamation	No	The term "Consequential Load Loss" and "Planning Assessment" contain the terms "Transmission System" and/or "Transmission Facilities". The terms "Transmission System and Transmission Facilities are not defined in the NERC Glossary of Terms. The terms should either be in lower case or a definition added. The Term "Non-Consequential Load Loss" refers to a "Non-Interruptible Load" loss which is other than Consequential Load Loss. There is no mention in the Consequential Load Loss definition of the type of load (interruptible or non-interruptible). This adds confusion to what appears to be the distinction in the differences between the two, that one was the result of a fault and the other was the result of voltage.
Response: Transmission system: The SDT was unable to find a reference to 'Transmission System'. The SDT believes the references to 'Transmission system' were used correctly and no change was made. Transmission Facility: 'Facility' is a defined term in the NERC Glossary. The SDT believes the references to 'Transmission Facilities' are used correctly and no change was made. Non- Interruptible Load: Consequential Load Loss can be either interruptible or Non-Interruptible, so the distinction is not required. Non-Consequential is not a concern if it is interrupting interruptible load, but is a concern if it is inappropriately interrupting Non-Interruptible load. So the definition for Non-Consequential Load Loss is specific to Non-Interruptible load. The SDT disagrees with your statement that the loss of Non-Consequential load is the result of voltage. Load Loss as a result of voltage sensitivity is excluded from Non-Consequential Load Loss by the definition. No changes have been made.		
American Transmission Company	No	We suggest the following changes: Add a Consequential Generation Loss definition, which would be a complement to the Consequential Load Loss definition. Both consequential load loss and consequential generation loss are referred to in note "b" of the Steady State & Stability section of Table 1, but only consequential load loss is defined. We suggest text of: "Consequential Generation Loss: All Generation that is no longer delivered to any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions. Revise the Consequential Load Loss definition to include protection for abnormal operating conditions. We suggest text of: "Consequential Load Loss: All Load that is no longer served by any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions."Revise the Planning Assessment definition to more explicitly apply to the BES and the TPL-001 requirements. We suggest text of: "Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies in the BES from the steady

Organization	Yes or No	Comments for Question 9
		state and stability performance requirements set forth in the TPL-001 standard." Add a Planning Horizon definition. This term is used in this proposed standard, in the FAC-010-2 standard, and possibly in other future standards, but it has not been defined yet.
Response: Consequential Generation Loss: Generation run-back and tripping is acceptable. It is up to the Planning Coordinator and the Transmission Planner to determine how many units or cumulative MW may be interrupted due to either a consequential or non-consequential action. Therefore it isn't necessary for the SDT to define Consequential Generation Loss. Note 'b' has been revised to clarify the issue. Consequential Load Loss as well as generation loss is acceptable as a consequence of any planning or extreme event excluding P0. **Note 'b':** Consequential Load Loss as well as generation loss is acceptable as a consequence of any planning or extreme event excluding P0. Consequential Load Loss: The SDT disagrees with your proposed revision to the definition for Consequential Load Loss because it would provide for the use of an SPS or RAS to trip Consequential Load for an undefined 'abnormal condition', which is not an acceptable definition. No change is made. Applicability to BES: It is stated in the Purpose that the Standard applies to the BES. Therefore, the SDT doesn't see the need to have to repeat that throughout the document. Therefore no change is made. Planning Horizon: The only location where planning horizon didn't specify Near-Term or Long-Term was in the 'Purpose'. The SDT didn't feel that this reference needed to be specific or was sufficient to warrant a definition. No changes have been made.		
SERC Dynamics Review Subcommittee (DRS)	No	With the simplified definition for Bus-tie Breaker, would a breaker in a standard ring bus or breaker-and-a-half scheme be considered a Bus-tie Breaker? Request the definition be revised to clarify as follows: Add this sentence to the end of the definition: "A breaker in a standard breaker"and-a-half or ring bus configuration is not a Bus-tie Breaker. Suggest revising the Non-Consequential Load Loss definition to: Non-Interruptible Load loss other than (1) Consequential Load Loss and (2) the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.
SERC Planning Standards Subcommittee	No	With the simplified definition for Bus-tie Breaker, would a breaker in a standard ring bus or breaker-and-a-half scheme be considered a Bus-tie Breaker? Request the definition be revised to clarify this. Suggest revising the Non-Consequential Load Loss definition: Non-Interruptible Load loss other than (1) Consequential Load Loss and (2) the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.
Response: Bus-Tie Breaker: A breaker in a ring bus or a breaker-and-a half scheme would not be considered Bus-tie breakers. The SDT has elected to define a Bus-Tie Breaker. If the SDT were to also define what is not a Bus-Tie Breaker, then anything that was missed would not be defined. To be comprehensive the SDT has to limit the definition to what a Bus-Tie Breaker is to avoid further complexity. Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss.		

Organization	Yes or No	Comments for Question 9
Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
American Electric Power	Yes	
British Columbia Transmission Corp	Yes	
Exelon Transmission Planning	Yes	
FirstEnergy Corp	Yes	
Florida Municipal Power Agency, and its Member Cities	Yes	
Independent Electricity System Operator	Yes	
Manitoba Hydro	Yes	
Pepco Holdings, Inc. - Affiliates PHI	Yes	
Progress Energy Carolinas	Yes	
SCE&G	Yes	
TIS	Yes	
Orlando Utilities Commission	Yes	I agree, but that is based on not having seen any proposed changes from others that might change my mind.
Lafayette Utilities System	Yes	LUS generally supports the changes to the definitions and the changes to the rest of the standard. We appreciate the efforts of the SDT in responding to the many comments that were filed in response to version 3, and in crafting what appears to LUS to be a reasonable attempt to attain a consensus position, at least as we understand the result.
ITC Holdings	Yes	None

Organization	Yes or No	Comments for Question 9
PJM	Yes	
Response: Thank you.		
Oncor Electric Delivery	Yes	(Motor stall should not be included in this section) The language in the definition cannot be this generic. This becomes open to interpretation in Table 1. Localized load may not be an issue, but the text is broad enough that it could allow a voltage collapse.
Response: Non-Consequential Load Loss: The SDT added Requirement R5 to require that every Transmission Planner and Planning Coordinator has a voltage criteria. The voltage criteria should prevent the exposure to widespread or cascading motor stall and should limit any potential misinterpretation that the Non-Consequential Load Loss would allow such events. Table 1a (BES Transmission voltage instability, Cascading, and uncontrolled islanding shall not occur) supports Requirement R5 and reinforces the point that the definition for Non-Consequential Load Loss should not be read so broadly as to allow for unacceptable events. The definition for the Non-Consequential Load Loss excludes end-user actions, which disconnect the Load from the system. So Table 1 does not apply to such Load. To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
Southern Company	Yes	Suggest revising the Non-Consequential Load Loss definition for additional clarity to the following: Non-Interruptible Load loss other than (1) Consequential Load Loss and (2) the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.
Response: Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		

10. Do you agree with the changes in the performance elements and notes in Table 1? If not, please provide specific comments by note number, note alpha character, or performance category.

Summary Consideration: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. Final edits failed to correctly show footnote renumbering needed for removal of the Draft 3 footnote 1 which was moved to Requirement R4. All references to the prior Draft 3 footnote 1 should have been removed in Draft 4 and the remaining footnote references as shown in Draft 3 should have been decremented by a value of one. In Draft 5, the SDT has corrected the footnote references and the changes made are summarized as follows:

Table Area Reference	Footnote Reference Errors in Draft 4	Comment
Header notes	Yes	For item "j" the footnote reference to footnote "1" is now removed.
Title Row, Planning Events	No	All footnote references were shown correctly in Draft 4. No changes required in Draft 5.
Planning Event P0	No	No footnote references are used in this row in Draft 4. No changes required in Draft 5.
Planning Event P1	No	All footnote references were shown correctly in Draft 4. No changes required in Draft 5.
Planning Event P2	No	All footnote references were shown correctly in Draft 4. No changes required in Draft 5.
Planning Event P3	Yes	Footnote references to "19" should have been "9".
Planning Event P4	Yes	In the column titled "Category" the footnote reference to "101" should have been "10". In the column titled "Interruption of Firm Transmission Service Allowed" the footnote reference to "10" should have been "9."
Planning Event P5	Yes	In the column titled "Interruption of Firm Transmission Service Allowed" the footnote reference to "19" should have been "9".
Planning Event P6	No	All footnote references were shown correctly in Draft 4. No changes required in Draft 5.
Planning Event P7	No	All footnote references were shown correctly in Draft 4. No changes required in Draft 5.
Extreme Events Steady-State 2a & 2b	Yes	Footnote references to "12" should have been "11".

Table Area Reference	Footnote Reference Errors in Draft 4	Comment
Extreme Events Stability 2a, 2b, 2c, 2d	Yes	Footnote references to "11" should have been "10".
Extreme Events Stability 2e	Yes	Footnote references to "11" should have been removed.

A number of commenters indicated that some planning events will result in the same elements being removed from service and sought clarification on whether or not each event required analysis. The SDT acknowledges that different initiating events may result in identical Facilities being removed by protection action. While there may be some overlap in the steady-state timeframe, care must be taken to ensure proper reviews are made in the Stability timeframe where warranted due to delayed clearing modes that may result from the initiating event. For example, a bus fault and a stuck breaker may each clear a bus; however, the stuck breaker will have different reaction times due to the delayed clearing mode and therefore may warrant a review in a Stability environment. The standard allows the Transmission Planner and Planning Coordinator flexibility in using engineering judgment for the Table 1 events it studies for both the steady-state and Stability environments. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission Planner/Planning Coordinator can justify that certain events are duplicative for a given timeframe then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System. Planning event P2-1 was renamed to "Opening of a line section w/o a fault" to better clarify the SDT's intended analysis. This was in response to some commenters who remained confused by the P2-1 event and felt a detailed breaker model may be necessary. The drafting team clarifies here that a detailed breaker model is not needed. Conforming changes were also made to footnote 7 to make clear the intent of this planning event.

The P5 Protection System Failure event description was changed in support of stakeholders who indicated that multiple element outages may not always result from a P5 event and that it may only result in Delayed Fault Clearing of the faulted Transmission element/Facility. The P5 event now states "Failure of a single Protection System that results in Delayed Fault Clearing on one of the following:"

Footnote 9 is now applied to all "No" items for the column "Interruption of Firm Transmission Service Allowed". Footnote 9 clarifies that Firm Transmission Service can be interrupted so long as appropriate re-dispatch of resources are available and obligated to re-dispatch without any firm Load loss and that Facility ratings are maintained.

Some commenters expressed confusion on whether or not an event is classified as an EHV or HV event. This is an important concept to understand as it directly relates to the stated Table 1 criteria for Interruption of Firm Transmission Service and Non-Consequential Load Loss. The event is classified as EHV or HV based on the lowest nominal system voltage level of all the Facilities removed by the event studied and regardless of the fault location. For example, a fault that removes a 345/138kV

transformer is classified as a high-voltage (HV) event and the HV criteria apply. Changes to footnotes 1 and 5 were made to aid understanding in this regard.

Note changes are as follows:

Header note 'f': Applicable Facility Ratings shall not be exceeded.

Header note 'g': System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

Footnote 1 - If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.

Footnote 2 - Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.

Footnote 3 - Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.

Footnote 5 - For non-Generator Step Up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.

Footnote 7 - Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.

In addition, the definition of Non-Consequential Load Loss was revised to provide greater clarity:

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Organization	Yes or No	Comments for Question 10
FRCC Transmission Working Group		Please clearly indicate for P3 and P5 that note 1 and note 9 apply. Consider using a comma, not a note 19 that does not exist. The P2-1 event needs to be clarified with its intent. In the SDT Consideration of Comments to the 3rd DRAFT posting, the response to Transmission Planning clarified that "There is no need to show a line energized up to the

Organization	Yes or No	Comments for Question 10
		breakers that opened. The intent is simply to look for low voltage or thermal problems while supplying Load from one end of a normally networked line." This could be accomplished by adding this to footnote 7 or re-naming the event "Opening of a Line Section w/o fault".
Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The SDT has accepted the commenter's suggestion to better clarify the P2-1 planning event. The Event description in Table 1 for the P2-1 planning event has been re-titled "Opening of a line section w/o a Fault[7]" and the corresponding footnote number 7 has been revised to read as follows: **Footnote 7** - Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.		
SRP	No	: As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.
Response: The SDT agrees that some planning events will result in the same elements being removed from service. However, the similarities may only be valid from a steady-state view point and care must be taken to review the events in the Stability timeframe due to delayed clearing modes that may result from the initiating event. For example, a bus fault and a stuck breaker may each clear a bus; however, the stuck breaker will have different reaction times due to the delayed clearing mode and therefore may warrant a review in a Stability environment. The standard allows the Transmission Planner and Planning Coordinator flexibility in using engineering judgment for the Table 1 events in which it studies for both the steady-state and Stability environments. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission Planner/Planning Coordinator can justify that certain events are duplicative for a given timeframe then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System. At this time the SDT does not plan to conduct a workshop as suggested by the commenter. If Regional Entities wish to conduct seminars on the standard, SDT members from that region could be made available as participants in the discussions. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.		
Northeast Utilities	No	[Comment on Non-Consequential Load Allowed for certain Planning Events] We recommend that the standard as written should not allow non-consequential load loss to be used to resolve violations arising from the planning events in Table 1. We believe that planning for a reliable power system should discourage mitigation by load loss. Therefore, Non-Consequential Load Loss should not be allowed in a future looking system plan.

Organization	Yes or No	Comments for Question 10
		[Comment on Table 1 Item e, under Steady State & Stability] Our understanding here is that we should be able to redispatch after the first contingency (using fast start generation) to secure the system in anticipation of a second contingency and not redispatch to fix first contingency violations. Is this interpretation correct?Further, this standard doesn't specify which units can be adjusted following the contingency. This seems to stress the fact that the standard needs to address the definition of what is a base case. Also, the standard should be clear on whether we can or cannot rely on generation redispatch after the first contingency, i.e., should the failure of a fast start generator to start up be included in the contingency, or is this another level of contingency? [Comments on Footnotes] Footnotes 1, 10, 11, 19 and 101 need to be fixed. They are either mislabeled or do not point to any item.
Response: The SDT disagrees with the commenter's view related to disallowing Non-Consequential Load Loss for any planning event. The SDT believes they have made the appropriate expectations in not permitting its use for some Contingency planning events involving EHV Facilities. A Transmission Planner/Planning Coordinator may implement a more conservative planning approach beyond what TPL-001-1 requires if they believe one is warranted. The standard in Requirement R2, sub-part 2.7.1 (Corrective Action Plans) indicates that generation curtailment, tripping and re-dispatch are permissible Corrective Action Plans for both single and multiple Contingency events. Therefore, the SDT does not agree with Northeast Utilities view in this regard. The standard does not include prescriptive expectations for a "base case" conditions and allows flexibility to the TP/PC in this regard. See requirement R1 for initial model (P0 starting conditions) requirements. Starting of a "fast-start" generation unit appears to be viewed in the context of a Corrective Action solution to a studied planning event. There may situations like this that lend themselves to sensitivity analysis as required by the TPL-001-1 standard. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.		
British Columbia Transmission Corp	No	1. Table 1 event indicates loss of one of the equipment. It appears to be silent on the event classification regarding multiple equipments within the same protection zone. Is this considered as a single contingency or multiple contingencies? Please clarify. 2. Table 1 P5 refers to the event on loss of multiple elements caused by the failure of a single protection system while clearing a fault on one contingency. For systems equipped with dual or redundant protections, is a protection failure still a valid concern? Shouldn't this contingency analysis be excluded from the requirement? Please clarify. 3. Table 1 Extreme Events under Stability section, there is a reference to protection failure during fault clearing. Again for systems equipped with dual or redundant protections the requirement should be reconsidered. Please confirm. 4. Table 1 Extreme Events under both Steady State and Stability sections, there is a reference to loss of transmission lines on a common right-of-way. Please consider adding a Footnote to define the common right-of-way using minimum length similar to the one used for circuits on common structure (Footnote 12).

Organization	Yes or No	Comments for Question 10
		5. Performance Table 1 Footnote Item 1 on definition of angular stability, it states "For Planning Event P1: No generating unit or units shall be allowed to pull out of synchronism." o The requirement of no unit pull out of sync is not clear. Does this apply to small generators connected to distribution or lower voltage class lines? Or this is only applicable to generators connected to BEC (i.e. 100kV and above) without intermediary transmission voltage line connections? 6. Table 1 Footnote Item 6 refers to the "reference voltage" for transformers. What is the purpose of a reference voltage? Is this used to determine a valid transformer contingency? If so, according to the present definition a 3 phase fault on the 138kV side of a 138/66kV transformer is not considered a valid contingency to be assessed. Is this the intent?
Response: 1. The P1 Event is a single Contingency condition. A P1 Event may or may not remove other BES Facilities with it depending on the Protection System design. For example, a fault on a Transmission line (single Contingency) may also remove a BES transformer if no high-side transformer protection device is installed. 2. A P5 Event with a redundant Protection System will be covered by the analogous single Contingency event from a steady-state view. However, even with redundant Protection System designs there may be a delayed clearing mode that may need to be considered with the Stability timeframe. The standard allows the Transmission Planner and Planning Coordinator flexibility in using engineering judgment for the Table 1 events in which it studies for both the steady-state and Stability environments. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission Planner/Planning Coordinator can justify that certain events are duplicative for a given timeframe then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System. 3. See response to item 2. 4. The commenter appears to have referenced a Draft 3 version of the standard. The change requested was included in Draft 4. Footnote 11 in draft 4 reads as follows: "Excludes circuits that share a common structure or common Right-of-Way for 1 mile or less". 5. The commenter appears to have referenced a Draft 3 version of the standard as the former Draft 3 footnote 1 was moved to Requirement R4, part 4.1.1 in draft 4. The applicability of the NERC Reliability Standards unless otherwise stated is the Bulk Electric System and Part 4.1.1 applies only to BES generating units. **6.** The commenter appears to have referenced a Draft 3 version of the standard and the question is related to footnote 5 of the Draft 4 standard. The term "reference voltage" is used in determining if a transformer is classified as EHV or HV for the BES. This classification then ties to footnote 1 in regards to provisions for the interruption of Firm Transmission Service and Non-Consequential Load Loss. For example, if a 345/138 kV TR is outaged for the Event studied, the high-voltage (HV) allowances for interruption of Firm Transmission Service and loss of Non-Consequential Load would apply. The 138/66 kV transformer may not be classified as a BES Facility, your Regional Entity definition of the BES should be consulted for an official position.		
NERC Standards Review Subcommittee	No	A. P3 Modify the P3 Category performance criteria to apply only to the loss of two generators because the probability of the loss of two base load generators is an order of magnitude greater than the loss of a generator and any other transmission element. The MRO NSRS suggests the listing of: the loss of transmission circuit, transformer, shunt device, and single pole of DC line be removed from the P3 Events column. Move the

Organization	Yes or No	Comments for Question 10
		"generator + another element" events to the P6 Category by adding "1. Generator" to the listing in the Initial System Condition (Loss of . . .) column. B. The SDT should be commended for the changes that were made to Table 1. However, the MRO NSRS does recommend a few editorial changes. On page 16 under the Steady State and Stability heading is item d. Simulate Normal Clearing unless otherwise specified. This is also listed as footnote 2 to the table. The MRO NSRS recommends that item d under the Steady State and Stability heading be deleted. C. Why is there a footnote 1 indicator to note j. under Stability only? The MRO NSRS suggests that this footnote 1 indicator be deleted. D. Item i. under Steady State only states that "the response of voltage sensitive Load that is disconnected from the System by end-user equipment" is not to be used to meet steady state requirements. However, the non-consequential load loss says yes meaning it is allowed for some events in the table and non-consequential load loss definition includes the "response of voltage sensitive Load that is disconnected from the System by end-user equipment." This seems to be a direct contradiction. The MRO NSRS suggests that Item i. under steady state only be deleted. E. The MRO NSRS does not understand why there is a footnote 19 indicator for P3 and P5 EHV in the table when no footnote 19 exists. Perhaps the SDT meant footnotes 1 and 9 but The MRO NSRS recommends that this be corrected.F. The MRO NSRS does not understand why there is a footnote 12 indicator for Item 2 a and 2 b. on page 19. Perhaps the SDT meant footnotes 1 and 2 apply but The MRO NSRS recommends that this be corrected.

Response:

A. The SDT disagrees with the proposed adjustment of moving select generator Contingency outages to new planning event designations. The Table 1 planning event order regarding outage probability is somewhat subjective and the SDT believes appropriate expectations were made for generation outages within the P3 event. No changes made.

B. The SDT appreciates the support for changes made. The SDT decided to keep both references to "simulate normal clearing unless otherwise specified". While redundant, we believe it is important information and should aid to ensure industry is aware of the intent.

C. The reference to footnote 1 in Table note "j" should have been deleted in Draft 4. The SDT has fixed a number of footnote reference errors in Draft 5.

D. The Draft 4 definition of Non-Consequential Load Loss confused some stakeholders in that some thought the voltage sensitive Load was "inclusive" to this type of Load. The definition was changed to better clarify the SDT's intent that customer sensitive Load and Load disconnected by the end-user is not included within the definition. With that change the perception of a conflict is now resolved.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

E. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.

Organization	Yes or No	Comments for Question 10
Bonneville Power Administration	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard. Table 1, the second to last column: Please clarify what is meant by "Interruption of Firm Transmission Service." Planning studies do not differentiate firm and non-firm transmission services. Planning studies model a load forecast, a generation dispatch, and the system topography. Interruption of firm transmission service is a commercial issue and is not related to assessing reliability of the system. If an assumed transfer is interrupted in a power flow case due to a contingency, and if no consequential load loss were allowed and all criteria were met, the system would still be exhibiting reliable performance. We believe interruption of firm transmission service should be allowed for all planning events P1 through P5 when assessing the reliability of the transmission system. At a minimum, footnote 9 in Table 1 should apply to all events in category's P1 through P5 that do not allow interruption of firm transmission service.The NERC definition of Firm Transmission Service states "highest quality of service offered to customers under a filed rate schedule that anticipates no planned interruption." Planning events required to be evaluated in Table 1 are unplanned interruptions by nature since they are studied to determine mitigation should they occur unexpectedly. This is inconsistent with the definition Table 1, P1.4, P3.4, P4.4, P5.4, and P6.3: Shunt devices are not required to be in service at all times. It does not make sense to include it in the events column. How would you assess it while several of these devices are not deployed because they are not needed for the conditions studied? Table 1, P1 & P2: What is the rational for having two categories for single contingency? Table 1, P2.1 (Opening of a breaker without a fault): Please clarify what constitutes opening a breaker without a fault mean? Planning for these events will be time consuming (modeling every breaker position open) and expensive to mitigate for events that occur solely due to human error and should be removed for the table. Table 1, P2.2, P2.3, and P2.4: These are not single contingency events and should be moved to P3.
Response: The SDT agrees that some planning events will result in the same elements being removed from service. However, the similarities may only be valid from a steady-state view point and care must be taken to review the events in the Stability timeframe due to delayed clearing modes that may result from the initiating event. For example, a bus fault and a stuck breaker may each clear a bus; however, the stuck breaker will have different reaction times due to the delayed clearing mode and therefore may warrant a review in a Stability environment. The standard allows the Transmission Planner and Planning Coordinator flexibility in using engineering judgment for the Table 1 events in which it studies for both the steady-state and Stability environments. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission		

Organization	Yes or No	Comments for Question 10
Planner/Planning Coordinator can justify that certain events are duplicative for a given timeframe then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System. At this time the SDT does not plan to conduct a workshop as suggested by the commenter. As an alternative, the SDT will ask WECC area SDT member(s) to discuss this matter via appropriate WECC technical committees utilizing SDT members as participants in the discussions. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The SDT agreed with the commenter regarding the Table 1 performance requirements related to the Interruption of Firm Transmission Service. The team has applied footnote 9 to all Events that indicated "No" in this column. The Firm Transmission Service within the context of a planning horizon are long-term service arrangements from one Balancing Authority area to another that should be reflected within the planning model and net-interchange. The standard allows engineering judgment and flexibility to exclude certain Contingencies that may not be pertinent for the conditions studied. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission Planner/Planning Coordinator can justify that certain events not pertinent for a given study then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System. The two Contingency categories are used to delineate between higher ranked P1 single Contingencies and the lower ranked, yet high impact P2 single Contingency events. In P2, the team chose to differentiate between the EHV and HV in regards to performance expectations whereas in P1 the performance requirements for both EHV and HV are the same. The SDT believes the P2.1 event is important for review and it remains in Draft 5. Inadvertent relay operation that trips a breaker(s) is the primary reason forced outage cause for a P2.1 event. The condition could also be a planned (maintenance) event. The P2.1 event has been renamed "opening of a line section w/o a fault" to better align with the team's intent. Additionally, footnote 7 was revised to better clarify the need to study the P2.1 event. Footnote 7 now reads: **Footnote 7** - Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point. The P2.2, P2.3, and P2.4 planning events are less likely yet higher impact single Contingency events. While its true that these events will likely result in multiple elements being disconnected from the System they are classified as single Contingency since they are a common mode event resulting from a single fault with normal Protection System clearing. As stated above, the SDT does not treat the P2 events in the same manner as P1 events and there are unique expectations in performance for P2 events that result in HV element outages versus solely EHV element outages.		
Idaho Power	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. I believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes

Organization	Yes or No	Comments for Question 10
		to ensure accuracy prior to balloting this standard.
Southern California Edison (SCE)	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.
Utility System Efficiencies, Inc. (USE)	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service. Simulations of these outages would then be the same, even though the initiating event is different. I believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any footnote in the document, and some other footnotes seem to be misplaced. I would encourage drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.
Western Area Power Adm - RMR	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. I believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any footnote in the document, and some other footnotes seem to be misplaced.I encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.
Response: The SDT agrees that some planning events will result in the same elements being removed from service. However, the similarities may only be valid from a steady-state view point and care must be taken to review the events in the Stability timeframe due to delayed clearing modes that may result from the initiating event. For example, a bus fault and a stuck breaker may each clear a bus; however, the stuck breaker will have different reaction times due to the delayed clearing mode and therefore may warrant a review in a Stability environment. The standard allows the Transmission Planner and Planning Coordinator flexibility in using engineering judgment for the Table 1 events in which it studies for both the steady-state and Stability environments. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission		

Organization	Yes or No	Comments for Question 10
Planner/Planning Coordinator can justify that certain events are duplicative for a given timeframe then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System. At this time the SDT does not plan to conduct a workshop as suggested by the commenter. As an alternative, the SDT will ask WECC area SDT member(s) to discuss this matter via appropriate WECC technical committees utilizing SDT members as participants in the discussions. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.		
Modesto Irrigation District Transmission Planning	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard. please define "post contingency" and "post transient" Why was the previous version footnote 1 defining "angular stability eliminated?
Response: The SDT agrees that some planning events will result in the same elements being removed from service. However, the similarities may only be valid from a steady-state view point and care must be taken to review the events in the Stability timeframe due to delayed clearing modes that may result from the initiating event. For example, a bus fault and a stuck breaker may each clear a bus; however, the stuck breaker will have different reaction times due to the delayed clearing mode and therefore may warrant a review in a Stability environment. The standard allows the Transmission Planner and Planning Coordinator flexibility in using engineering judgment for the Table 1 events in which it studies for both the steady-state and Stability environments. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission Planner/Planning Coordinator can justify that certain events are duplicative for a given timeframe then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System. At this time the SDT does not plan to conduct a workshop as suggested by the commenter. As an alternative, the SDT will ask WECC area SDT member(s) to discuss this matter via appropriate WECC technical committees utilizing SDT members as participants in the discussions. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The SDT did not receive a substantial appeal from industry to define the terms proposed by the commenter and these terms are widely used and accepted in the industry. The proposed definitions were not added in Draft 5. The prior footnote 1 regarding angular stability was moved into the requirements section of the standard under Requirement R4 per the request of various		

Organization	Yes or No	Comments for Question 10
stakeholders in prior drafts.		
NV Energy	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.
Pacific Gas and Electric Co.	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.
Puget Sound Energy, Inc.	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.
Deseret Power	No	Comments: As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document,

Organization	Yes or No	Comments for Question 10
		and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.
NorthWestern Energy	No	Several outages identified in Categories P2, P4, and P5 seem to result in the same elements being removed from service, even though the initiating event is different. Thus, the same scenario is evaluated more than once. Also, the footnote numbering is not correct. We would like the drafting team to conduct a workshop before this standard goes to ballot to educate the industry on what outages are required to be simulated for which Categories.
Response: The SDT agrees that some planning events will result in the same elements being removed from service. However, the similarities may only be valid from a steady-state view point and care must be taken to review the events in the Stability timeframe due to delayed clearing modes that may result from the initiating event. For example, a bus fault and a stuck breaker may each clear a bus; however, the stuck breaker will have different reaction times due to the delayed clearing mode and therefore may warrant a review in a Stability environment. The standard allows the Transmission Planner and Planning Coordinator flexibility in using engineering judgment for the Table 1 events in which it studies for both the steady-state and Stability environments. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission Planner/Planning Coordinator can justify that certain events are duplicative for a given timeframe then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System. At this time the SDT does not plan to conduct a workshop as suggested by the commenter. If Regional Entities wish to conduct seminars on the standard, SDT members from that region could be made available as participants in the discussions. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.		
Sacramento Municipal Utility District	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. Comments on notes have been provided with associated requirements.
San Diego Gas & Electric Co	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different.
Response: The SDT agrees that some planning events will result in the same elements being removed from service. However, the similarities may only be valid from a steady-state view point and care must be taken to review the events in the Stability timeframe due to delayed clearing modes that may result from the initiating event. For example, a bus fault and a stuck breaker may each clear a bus; however, the stuck breaker will have different reaction times due to the delayed clearing mode and therefore may warrant a review in a Stability environment. The standard allows the Transmission Planner and Planning Coordinator flexibility in using engineering judgment for the Table 1 events in which it studies for both the steady-state and Stability environments. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe		

Organization	Yes or No	Comments for Question 10
System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission Planner/Planning Coordinator can justify that certain events are duplicative for a given timeframe then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System.		
Progress Energy Florida, Inc.	No	As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all appropriate parties to review PEF's previous comments to this effect.
Response: Throughout the drafting process, the SDT has carefully considered your comments as well as comments from other industry members.		
Pepco Holdings, Inc. - Affiliates PHI	No	Category P5 should be more appropriately titled DELAYED CLEARING OR Loss of multiple elements caused by the failure of a single Protection System while clearing a fault on one of the following....A protection system failure does not necessarily lead to loss of multiple power system elements. Sometimes it may just be delayed clearing of the faulted element. The recommended change is based on the SDT's response to comments submitted to Draft #2 of the standard? -A number of commenters expressed concern related to Planning Event P5 "Protection System Failure" and the need to evaluate a single component failure of a BES Protection System; particularly a failure of a station battery. The SDT has revised the P5 Planning Event description to remove the reference to "single component failure" and the event description was changed to match what is stated in the currently approved TPL standards under Category C6 through C9. --The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to normal fault clearing.-- A Protection System failure resulting in loss of the substation (one voltage level plus transformers) would not qualify as a P5 Planning Event since that event is considered an Extreme Event. Also, the phrase "failure of a single Protection System" should be defined. Draft #1 language used the term -single component failure- of a protection system. Based on a number of comments that were received, that term was subsequently replaced with the term -failure of a single Protection System-. To avoid confusion, this term needs to be defined within this standard and / or examples provided. If not, there will be confusion on how to study this category of events. This issue has been raised by numerous commenters throughout the standard development process. That fact that it continues to be expressed through numerous drafts indicates a lack of clarity as to exactly what protection system failures are to be studied.For example - Assume there are two protection systems on a facility (Scheme A and Scheme B). Assume one publishes a clearing time for Scheme A, and a slower clearing time for Scheme B. The TPL standard, as written, could imply that for a P5 failure of a single Protection System (scheme A or B fails) you would study the event assuming the worst case clearing time (i.e., using the slower clearing time for Scheme B.) Is that what is intended? If so, it should be so stated. However, that interpretation assumes the failure of a single Protection System would not effect the operation of the second Protection System. In other words it would not address single component points of failure, which could disable both Scheme A and Scheme B. Suppose both schemes were fed from the same set of CT's, VT's, battery, etc. Since the phrase "single component failure of the protection system" was eliminated, does this mean failure of both schemes due to a single component failure is not required to be studied under the P5 category? The standard must be very clear as to what contingency (i.e., what kind of protection system failure) is

Organization	Yes or No	Comments for Question 10
		to be studied. It should not be silent on this point, nor should it refer to another standard for guidance on what contingencies to study.
Response: The SDT agrees with points raised by the commenter and has changed the event description of the P5 planning event to better clarify the intent of simulating this Contingency. The SDT did not agree with the proposal to add a definition for the phrase "failure of a single Protection System". The SDT believes the description modification in the Event column of Table 1 suffices in this regard. The P5 planning event remains unchanged in the study work intended by the SDT and the description modifications are aimed only at clarifying our intent. The SDT confirms that the intent of P5 is not to study the loss of both Scheme A and Scheme B for the example provided by the commenter and that the expectation would be the study of the slower clearing time scheme (Scheme B).		
Oklahoma Gas & Electric	No	Category P7 OG&E supports as long as footnote 11 is included. Category P6 is an N-2 situation. OG&E does not support the wholesale study of every N-2 combination of contingencies even though one is allowed for the interruption of firm transmission service and non-consequential load loss. Establishing and maintaining operating guides associated with every N-2 set of contingencies is oppressive and would provide limited value. OG&E understands the need for targeted N-2 contingency studies; such as breaker failure. Category P5 Need more specific description of "Protection System failure" before receiving OG&E's support. Category P4 OG&E supports performing studies. OG&E also supports the differentiation between "DHV" and "HV". OG&E does not support developing operating guides for every voltage or overload issue discovered. Category P3 OG&E is concerned about the value of P3. Information about the expected value of performing studies for the category is needed before receiving OG&E support. Category P2 OG&E supports even though there are a few minor issues. Category P1 OG&E supportsOG&E will need every bit of the 60 months time mentioned on page 3 under "Effective Date" to implement all indicated upgrades. There is benefit in hardening the OG&E electrical system for such protection system failures, such as P4 & P5, but it may not be cost effective. Comments Stability AnalysisStability Analysis Recommend Planning Coordinator will be responsible for running the stability analysis to assure NERC compliance. The Planning Coordinator and Transmission Planner should work together to prepare the data.
Response: In P7, footnote 11 remains, thanks for your support. In P6 not every possible combination would be expected to be studied, especially for a Transmission Planner/Planning Coordinator covering a very large geographic footprint. The standard allows engineering judgment and flexibility to exclude certain Contingencies that may not be pertinent for the conditions studied. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission Planner/Planning Coordinator can justify that certain events are not pertinent for a given study then at their discretion they may		

Organization	Yes or No	Comments for Question 10
elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System. Based on feedback from some commenters the SDT made changes to the P5 planning event description as shown in Table 1. The changes are not substantive, do not alter the team's prior intent and aimed at clarification only. Regarding the comments provided on P4. The SDT appreciates the commenter's support in regard to the bifurcated approach of performance expectations related to the BES. The SDT believes all performance deficiencies related to thermal ratings and voltage ratings require corrective actions and the standard provides the Transmission Planner/Planning Coordinator a wide range of alternatives, including but not limited to Operating Procedures. As stated above, the Contingencies studied are expected to be those that have the most severe impact on a particular Facility and not necessarily every possible scenario. The SDT's review of outage events associated with various System conditions revealed that the potential for a generating unit outage being coincident with a variety of other Contingency conditions requires close evaluation. Again, study of some your largest units in combination with other events may suffice to cover the "more severe" conditions for your System and flexibility is afforded to the Transmission Planner to ensure proper coverage without the needed to study each and every combination. We appreciate your support on planning event P1 & P2 expectations. Regarding the proposal for Stability to be covered by the Planning Coordinator. The standard in P7 requires the Transmission Planner and Planning Coordinator to determine and identify individual or joint responsibilities for performing required studies. The Transmission Planner may rely on work being preformed by its Planning Coordinator but each is responsible for showing auditable compliance for the TPL-001-1 study requirements including Stability.		
SERC Planning Standards Subcommittee	No	Comments: Some of the footnote superscripts do not appear to have a corresponding reference in the footnotes, in the case of number 19 at several locations in the Firm Transmission Service column, and number 101 in the P4 cell in the Category column.
Southern Company	Yes	Some of the footnote superscripts do not appear to have a corresponding reference in the footnotes, in the case of number 19 at several locations in the Firm Transmission Service column (should be 9), and number 101 in the P4 cell in the Category column (should be 10). In header note j, the reference to footnote 1 should be removed. In steady state extreme events 2a and 2b, the reference to footnote 12 should be to footnote 11. In stability extreme events 2a through 2e, the reference to footnote 11 should be to footnote 10.
Lafayette Utilities System	Yes	While LUS remains concerned as to the way in which what is now footnote 9 may be followed in operation in areas where there have been historic problems with the old "footnote b", we appreciate the clarifications that have been made, and recognize that this may be the best way to resolve an issue for the industry. Please note that there remains what appears to be a typographical error in Table 1, Category P3, under "Initial System Condition" in that the footnote reference is to footnote 19, which does not exist. The reference was to footnote 10 in v.3 and we assume that the correct reference here is to footnote 9, which used to be footnote 10.
Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT		

Organization	Yes or No	Comments for Question 10
has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.		
US Bureau of Reclamation	No	Consequential Load Loss was defined, however, consequential generator loss was not. It may be easier to define "consequential loss" and let it apply to either.
Response: The SDT does not believe a definition to differentiate between consequential or non-consequential generation loss is needed since generation tripping and re-dispatch is permitted as a corrective action for all planning events as stated in Requirement R2, part 2.7.1.		
Tri-State Generation and Transmission Association	No	Extreme Events detailed at the end of Table 1 should be itemized in the same way as for so-called "Planning Events" at the beginning of Table 1. Steady State Extreme Event 1 would be EP1, Dynamic Stability Extreme Event 1 would be ED1, etc. Also, please use the term Dynamic Stability, not just Stability, as explained above. It would be helpful if descriptions had unique identifiers, for example Dynamic Extreme Event 1 could be called N-1-1. For Dynamic Extreme Event 1, the phrase "With an initial condition" conflicts with the phrase "prior to System adjustments" at the end of the sentence. The term "initial condition" suggests a maintenance outage, or at least an outage that has sustained long enough for the system to have responded/adjusted. Footnote text does not line-up with the body text in the Extreme Event Table. It seems to us that a bus-tie breaker would have the same chance of failure as another breaker. Therefore differentiation is not needed in Table 1.
Response: The SDT recognizes a minority position to label the extreme events in a manner similar to the planning events for a short-hand notation. However, based on lack of a significant majority objection to the extreme event table layout the team determined no changes were needed in this regard. The SDT believes the references to Stability in the extreme events portion of the table are sufficient. No changes made. The SDT does not believe that a conflict exists for extreme event 1 in regards to "With an initial condition" and "prior to system adjustment". No changes made. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The SDT agrees that any breaker has an equal chance for failure due to a fault. However, when lumped together with all the BES line breakers and transformer breakers, the Bus-tie Breaker application is much less prevalent within the BES when considering all beaker fault possibilities. The SDT recognizes that Bus-tie Breaker applications are used to lessen the impact of a bus fault outage (P2.2). Therefore, in regards to meeting the single Contingency breaker fault condition, the SDT felt it was necessary to differentiate between performance expectations between bus-tie and non bus-tie breakers. See P2.3 and P2.4 planning events.		
Omaha Public Power District	No	If "the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment" is considered to be a special type of Consequential Load Loss, add the following sentence to the end

Organization	Yes or No	Comments for Question 10
		of Note "b": However, see Note "i" for a restriction that applies to steady state performance. In Note "g", change "voltage limits" to "voltages". In Note "j", it appears that the reference to Footnote 1 is not needed. For Category P3, should the reference to Footnote 19 in the second column be a reference to Footnote 9? For Categories P3, P4, and P5, in the column labeled "Interruption of Firm Transmission Service Allowed", are the references to Footnotes 19 and 10 needed? For Category P4, should the reference to Footnote 101 in the first column be a reference to Footnote 10? For Category P4, should the reference to Footnote 11 in the third column be a reference to Footnote 10? In Items 2a and 2b of the "Steady State" subsection of the "Extreme Events" section, should the references to Footnote 12 be references to Footnote 11? In Footnote 1, change "loss of Non-Consequential Load" to either "Non-Consequential loss of Load" or "Non-Consequential Load Loss". (The point here is that the adjective "Non-Consequential" applies to the word "loss" rather the word "Load".) In the first sentence of Footnote 2, change "Normal Clearing faults" to "Normal Clearing of faults". In the second sentence of Footnote 2, remove the comma following the word "types". In Footnote 3, change "Non-Consequential Load" to either "Non-Consequential loss of Load" or "Non-Consequential Load Loss". (The point here is that the adjective "Non-Consequential" applies to the word "loss" rather the word "Load".) In the second sentence of Footnote 5, change "generator Step Up" to "Generator Step Up" to be consistent with the rest of the footnote.

Response: Load removed by end-user action or voltage sensitive Load that trips while the Transmission Planner/Planning Coordinator transient voltage criteria is being met is NOT a special case on Consequential Load Loss. No changes made.

The SDT agrees with the proposed change to note "g" in Table 1.

> **Header note 'g'**: System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.

The SDT agrees with the proposed wording change to footnote 1. The SDT also made other changes to footnote 1 for clarity and it now reads:

> **Footnote 1 -** If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load

Organization	Yes or No	Comments for Question 10
Loss. The SDT agrees with the proposed wording change to footnote 2. **Footnote 2** - Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. The SDT agrees with the proposed wording change to footnote 3. The team also made other changes to footnote 3 for clarity and it now reads: **Footnote 3** - Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss. The SDT agrees with the proposed wording change to footnote 5. Footnote 5 now indicates: **Footnote 5** - For non-Generator Step Up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.		
TVA System Planning	No	In Header note j - the reference to footnote #1 should be removed. Are batteries included as part of Protection System for P5 events? P3 reference to footnote #19 under Initial System Condition and for Interruption of Firm Transmission Service Allowed should actually be footnote #9. P5 reference to footnote #19 for Interruption of Firm Transmission Service Allowed should actually be footnote #9. The reference to footnote #101 in the P4 category should actually be to #10. For Steady State notes under Extreme Events, events 2a and 2b should reference footnote #11 instead of #12. For Stability notes, event 2 should refer to footnote #10 instead of #11.In footnote #3, should there be an "or" before "as defined by the Regional Entity"?
Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The P5 event is not a review of individual Protection System components but rather evaluates the loss of a "single Protection System" scheme or design. It is acceptable to simulate that a local (at the same substation) alternate Protection System scheme is still operational when performing a P5 review. The SDT chose this language to align with the SAR titled: Reliability of Protection Systems (Project 2009-7). The SDT believes that the individual component level evaluation of Protection Systems and redundancy requirements should be covered under the PRC standards and has only addressed a single protection scheme failure in the Planning Assessment required for the TPL standard. A Protection System component failure (i.e., battery) that removes multiple Protection System schemes is beyond the P5		

Organization	Yes or No	Comments for Question 10
planning event. Based on feedback from some commenters, the SDT made changes to the P5 planning event description as shown in Table 1. The changes are not substantive, do not alter the team's prior intent, and are aimed at clarification only.		
Arizona Public Service Co.	No	Note a: It would be helpful if there was a clear understanding of what constitutes voltage instability for the purpose of this standard. Is TP expected to have its own criteria for voltage stability? Are the dynamic and angle stabilities intentionally excluded? P3 refers to foot note 19 but there is no foot note 19. P4 refers to foot note 11, but the foot note does not seem to be applicable. Foot notes in second to last column of the table are confusing.
Response: In Requirement R5 the Transmission Planner/Planning Coordinator is expected to have documented its criteria for transient voltage response. It is expected that this criteria would reflect what would be considered voltage instability. Related to the question on dynamic and angle stabilities, the standard provides a requirement for what is considered a stable System in Requirement R4, part 4.1. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.		
Lakeland Electric	No	Recommended the following changes to the HV definition:Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems, per the Regional Entity's BES criteria/definition. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems, per the Regional Entity's BES criteria/definition.
Response: The SDT has retained the same delineation of the Bulk Electric System (EHV and HV) in Draft 5. No changes made.		
Duke Energy	No	Reword Steady State Only: f. as follows: "Applicable Facility Ratings shall not be exceeded." P3 Initial System Conditions footnote should be 9, not 19. Also, P4 footnote should not be 101. Please check all footnote references.
Response: The SDT agrees with the proposed wording change to header note "f" and it now reads: **Header note 'f':** Applicable Facility Ratings shall not be exceeded. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.		

Organization	Yes or No	Comments for Question 10
Ameren	No	Some of the footnote superscripts do not appear to have a corresponding reference in the footnotes, in the case of number 19 at several locations in the Firm Transmission Service column, which should be changed to number 9, and numbers 11 and 101 in the P4 cell in the Category column that should be changed to 10. Table 1 - Steady State and Stability Performance - Planning Events, note c., and Table 1 - Steady State & Stability Performance - Extreme Events, note a. will need to be revised to address the restoration of facilities as described above in comments to Questions 3 and 5. A header is needed on the third page of Table 1 Steady State & Stability Performance. Table 1 Steady State and Stability Performance Extreme Events - Steady State: Superscripts on items 2a and 2b should be 11 rather than 12. Similarly, for the Extreme Events - Stability items 2a through 2f, the superscript should be 10 rather than 11.
Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. As stated in the SDT's response to comments made by Ameren in Question 3, in Requirement R3, part 3.3.1 the reference to "other automatic controls" is intended to include other tripping means such as cross-tripping and not automatic restoration devices. No change made. Ameren comments to Question 5 do not appear pertinent to "automatic restoration" of facilities. No change made. The SDT agrees that an appropriate page header is needed on for each page of the Table and has worked with NERC staff to correct this in Draft 5.		
SERC Dynamics Review Subcommittee (DRS)	No	Some of the footnote superscripts do not appear to have a corresponding reference in the footnotes, in the case of: Table 1 Planning Events P3 superscripts should be 9 and not 19. Table 1 P5 superscript 19 should also be 9. Table 1 Planning Events P4 superscript 101 should be 10, superscript 11 should also be 10. Table 1 Extreme Events steady state items 2A and 2B superscript should be 11, not 12. Table 1 Extreme Events stability items 2A-2F superscript should be 10, not 11. No header on third page of Table 1 Planning Events. Table 1, Planning Events, wherever it says "no" in the "interruptions of firm transmission service" column, generation tripping by fault clearing action should be allowed.
Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The SDT agrees that an appropriate page header is needed on for each page of the Table and has worked with NERC staff to correct this in Draft 5. The SDT agrees with the commenter regarding the suggestion to permit generation re-dispatch when a "No" is indicated in the Table 1 column titled "Interruption of		

Organization	Yes or No	Comments for Question 10
Firm Transmission Service Allowed" and footnote 9 is now reflected on each occurrence.		
SRC of ISO/RTO	No	Table 1 should appear right after the requirements and before the VSLs. AESO does not comment on VSLs or VRFs.
Response: The SDT agrees with the commenter's recommendation to move Table 1 within the standard so that it follows directly after the requirements. This change was made in Draft 5.		
ERCOT ISO	No	The references to the footnotes need commas there are several references to footnote 19 and at least one to footnote 101.
Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.		
MidAmerican Energy Company	No	The SDT should be commended for the changes that were made to Table 1. However, MidAmerican does recommend a few editorial changes. On page 16 under the Steady State and Stability heading is item d. Simulate Normal Clearing unless otherwise specified. This is also listed as footnote 2 to the table. MidAmerican recommends that item d under the Steady State and Stability heading be deleted. Why is there a footnote 1 indicator to note j. under Stability only? MidAmerican suggests that this footnote 1 indicator be deleted.? Item i. under Steady State only states that "the response of voltage sensitive Load that is disconnected form the System by end-user equipment" is not to be used to meet steady state requirements. However, the non-consequential load loss says yes meaning it is allowed for some events in the table and non-consequential load loss definition includes the "response of voltage sensitive Load that is disconnected from the System by end-user equipment." This seems to be a direct contradiction. MidAmerican suggest that Item i. under steady state only be deleted. MidAmerican does not understand why there is a footnote 19 indicator for P3 and P5 EHV in the table when no footnote 19 exists. Perhaps the SDT meant footnotes 1 and 9 but MidAmerican recommends that this be corrected. MidAmerican does not understand why there is a footnote 12 indicator for Item 2 a and 2 b. on page 19. Perhaps the SDT meant footnotes 1 and 2 apply but MidAmerican recommends that this be corrected.
Response: While the SDT agrees that the phrase appears twice, it does not create any confusion or unnecessary redundancy. Footnote 2 is just a more detailed explanation of what needs to be done in Stability studies. No change made. The footnote 1 indication has been deleted as suggested.		

Organization	Yes or No	Comments for Question 10
The definition of Non-Consequential Load Loss has been revised to provide greater clarity as to the SDT's intent. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.		
Xcel Energy	No	There are references to footnote 12 on page 19, and footnote 101 on page 17, yet no such footnotes exist on page 20. Some of the other footnotes seem to be misplaced. Please review and validate all footnote references.
Midwest ISO	No	Table 1 Steady State & Stability Performance Planning Events, Note "b": It states that consequential generation loss is acceptable; however, there is no definition of this in the definition section. We suggest having the following definition of Consequential Generation Loss added to the definition section. Table 1 There appears to be a few typos on P3, P4 and P5 note references because there are no Note 19 nor Note 101. Please clarify this. Table 1 Steady State & Stability Performance Planning Events: We believe that this table should appear right after the requirements but before the VSLs.
Response: It appears the commenter intended to suggest a definition for consequential generation loss but neglected to include its proposed definition. Regardless, the SDT considered the need for such a definition and concluded no definition was needed. No change made. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The SDT agrees with the commenter's recommendation to move Table 1 within the standard so that it follows directly after the requirements. This change was made in Draft 5.		
Florida Municipal Power Agency, and its Member Cities	No	Table 1, under Steady State & Stability, "a" states: "BES Transmission voltage instability, cascading outages and uncontrolled islanding shall not occur." There are small portions of the grid where there may be three long lines feeding a load, and if two of those two lines were lost (P6 for instance), the remaining line would go into voltage collapse losing a few hundred MWs of consequential load with no impact to the BES. FMPA suggests that the wording be appended by: "BES Transmission voltage instability, cascading outages and uncontrolled islanding shall not occur for P0 through P2. BES Transmission voltage instability, cascading outages and uncontrolled islanding causing a supply / demand mismatch of more than the largest single loss of source shall not occur." FMPA does not understand why a bus-tie breaker would be treated differently than another breaker. They both have the same chance of failure.
Response: The SDT considered the proposed change to note "a" but did not accept the proposed change. For the situation described, System adjustments are permitted between the outages of a P6 event to minimize the impact. Additionally, following the second outage the use of an SPS could be used to further minimize		

Organization	Yes or No	Comments for Question 10
the impact and avoid an unstable System condition. The team agrees that any breaker has an equal chance for failure due to a fault. However, when lumped together with all the BES line breakers and transformer breakers, the Bus-tie Breaker application is much less prevalent within the BES when considering all beaker fault possibilities. The SDT recognizes that Bus-tie Breaker applications are used to lessen the impact of a bus fault outage (P2.2). Therefore, in regards to meeting the single Contingency breaker fault condition the SDT felt it was necessary to differentiate between performance expectations between bus-tie and non bus-tie breakers. See P2.3 and P2.4 planning events.		
Manitoba Hydro	No	Table 1:1. When two (or more) footnotes apply simultaneously they should be separated by commas; ot are these typos? 2. The P2 contingency "opening of a breaker without a fault" could be moved up to a P1 contingency. This is a higher probability event then a bus section fault. 3. P4, Event column: The 11 superscript, after the phrase "Loss of multiple elements....", should be a 10. In P3, should 19 be 9? 4. Footnote 9: The drafting team clearly permits generator redispatch coupled with curtailment of firm transmission service for multiple contingencies (P3-P5). We believe generator redispatch is appropriate for P1 and P2 as well. R2.7.1 lists several actions that are permitted to be used as corrective plans including Special Protection Systems, automatic generator tripping or manual generator runback to respond to both single and multiple contingencies. Any loss of generation will require redispatch to ensure emergency generation reserves are replenished and the system is ready for the next contingency. For contingency P1, loss of generator, load will not be lost because there are generation reserves, however redispatch will be required to restore these reserves. Footnote 9 should apply to P1 and P2 contingencies. 5. Footnote 11: This note is a reference for a common tower outage. I think the words "or common Right-of-Way" should be deleted from the sentence. It is obvious that circuits on a common tower must be on a common Right-of-Way. 6. Note b: Consequential generation loss could use a definition similar to consequential and non-consequential load loss to add clarity. The standard as written in R4.1.2 permits cascade tripping of generators due to pulling out of synchronism. Typically this has been defined as instability or cascade tripping and not permitted in the past. 7. Note i: note i implies that any voltage sensitive load or load dropped by end-user equipment shall not be used to meet steady-state performance requirements. However, given that this note is not included under the stability portion, does this mean that voltage sensitive load or load that is dropped by end-user equipment can be used to meet the TC and PC planning criteria established in R5? Induction motors could trip in the stability analysis if the transient voltage is low enough (non-consequential load loss). The R5 criteria will be met as long as the load is manually switched back in and the post-disturbance steady state loading is acceptable. Can the drafting team

Organization	Yes or No	Comments for Question 10
		clarify the intent of Note i?

Response:

1. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.
2. The SDT did not accept the proposed change for the placement of the P2.1 planning event into the P1 group.
3. As noted above, errors in reference to various Table 1 footnotes are recognized by the SDT and have been corrected in Draft 5.
4. The SDT agreed with the commenter and footnote 9 was added to the P1 and P2 events in regard to the column titled "Interruption of Firm Transmission Service Allowed"
5. Common structure may be interpreted as common ROW but Common ROW does not necessarily equate to common structure. Since the wording is 'or', it covers both circumstances. No change made.
6. The SDT does not believe a definition to differentiate between consequential or non-consequential generation loss is needed since generation tripping and re-dispatch is permitted as a corrective action for all planning events as stated in Requirement R2, part 2.7.1.
7. Table 1, note "i" is intended to clarify that even if it is known that an end-user who implements a more conservative practice than that of the Transmission Planner/Planning Coordinator regarding steady-state voltage criteria and chooses to interrupt its own Load, the end-use Load must still be represented in the steady-state timeframe. The Load tripping is permitted in a Stability review, however, it should be assumed that a customer will react quickly to restore its Load and therefore the standard requires the Load be represented in the steady-state timeframe. Only actions (manual or automatic) taken by the Transmission Planner/Planning Coordinator are permitted for consideration for a steady-state review.

NERC System Protection and Control Subcommittee (SPCS)	No	The Drafting Team should modify the P5 Category column in Table 1 to read "P5 Multiple Contingency (Fault plus Protection System failure to operate). "This addition will focus the P5 Category on the overall Protection System failure to operate." The Drafting Team should include requirements in P5 of Table 1 for simulating both single-phase and 3-phase fault types for Protection System failures to operate.P4 and P5 call for simulations with SLG faults. Prolonged clearing times that result from breaker failures or Protection System failures to operate increase the probability that the fault may evolve from single-phase to multi-phase, and that probability further increases in EHV substations due to the closer clearances of bus work and equipment.Whereas Breaker Failure times are more likely to be known and mitigated through Breaker Failure Protection Systems, the clearing times associated with Protection System failures to operate may be much longer, increasing the probability of evolving in to multi-phase faults. The phrase "or a protection system failure" should be removed from items 2a through 2e in the Extreme Event table following Table 1.If the initializing event is the SLG fault, its evolution to a multi-phase fault alone (due to a Protection System failure to operate) should not be considered an Extreme Event for stability analysis.

Response: While the SDT did not accept the proposed P5 description change a change has been made for clarity. Based on feedback from some commenters the

Organization	Yes or No	Comments for Question 10
SDT made changes to the P5 planning event description as shown in Table 1. The changes are not substantive, do not alter the team's prior intent, and are aimed at clarification only. In regards to include both a SLG and 3-phase for the P5 planning event the SDT respectfully disagrees with the commenter. Based on the SDT's review of historical outage data the SDT believes that a SLG event evolving to a 3-phase item is less likely and that 3-phase fault with Protection System failure is appropriately treated with the standard as an extreme event under extreme event Stability item 2a through 2d. No change made.		
Florida Power and Light	No	The P2-1 event needs to be clarified with its intent. In the SDT Consideration of Comments to the 3rd DRAFT posting, the response to Transmission Planning clarified that "There is no need to show a line energized up to the breakers that opened. The intent is simply to look for low voltage or thermal problems while supplying Load from one end of a normally networked line." This could be accomplished by adding this to footnote 7 or re-naming the event "Opening of a Line Section w/o fault".
Response: The SDT agrees with comments in regard to the P2-1 planning event. A relay mis-operation that inadvertently trips a breaker is the primary reason forced outage cause for a P2.1 event. The condition could also be a planned (maintenance) event. P2.1 has been renamed "opening of a line section w/o a fault" to better align with the teams intent. Additionally, footnote 7 was revised to better clarify the need to study the P2.1 event. Footnote 7 now reads: **Footnote 7** - Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.		
MAPP	No	The table needs to match the stated requirements in R3 & R4
Response: The standard explicitly references Table 1 in both Requirements R3 and R4 regarding the need to address the planning events and extreme events from both a steady-state (Requirement R3) and stability (Requirement R4) timeframe. The standard is written in a manner where both the standard requirements and Table 1 work jointly together to describe study expectations. In short, Table 1 is part and parcel to the standard.		
Hydro-Québec TransEnergie (HQT)	No	There is confusion in interpretation of the Table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading? Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft. Other footnotes appear to be mislabeled as well. If Extreme Events are not deleted from the standard, then a different number for the table for Extreme Events should be used. Extreme Events 2a need to define towerline. Add language to replace towerline with structure. Table 1 Footnotes require a close editorial review. There are two number ones, and multiple items pointing to the

Organization	Yes or No	Comments for Question 10
		wrong footnote or footnotes that don't exist (19, 101), etc. Several instances are discussed below but this is not an exhaustive list. Table 1 Steady State & Stability Performance Planning Events - Note (a) this note is placed under "Steady State & Stability" but issues of voltage instability, cascading outages, and uncontrolled islanding apply only to stability. NPCC suggests this note be relocated to "Stability Only." Table 1 Steady State & Stability Performance Planning Events - Note (i) this indicates that one cannot meet steady state requirements by depending on end-user owned equipment. Please clarify the purpose and performance requirement on this note with respect to end-user schemes and possible arrangements already in place to trip end-user equipment. Table 1, P4 footnote reference in Category column needs to change from 101 to 10. Footnote reference in Event column lead-in description needs to change from 11 to 10. Table 1, P5 As written, this requirement replicates a fault causing a loss of station anywhere that there is only one protection system. This is overly severe and would lead to the requirement for fully redundant protection systems at many stations. The use of the term "Protection System" in P5 is unacceptably inconsistent with the NERC definition of Protection System because it does not exclude the battery and its associated series elements. Battery systems should not be included. Table 1, P7 for Event 1 (the loss of two adjacent circuits), this needs to specify if these are the same phase or different phases.Table 1 Steady State & Stability Performance Extreme Events It appears that for Steady state, item 2, that item (a) is encompassed by (b). It if is not, what makes it different? Table 1, footnote #2 typo there is an erroneous comma in the phrase "are the fault types, that must be evaluated." Please remove said comma. Table 1, footnote #3, HQT, as does NPCC, has asked NERC to put a lower bound on the HV but it seems that this remains unaddressed.More stringent performance requirements should be applied to Facilities that represent the backbone of the electric power grid and act as the medium for moving large amounts of power from production to various Load centers, rather than to those Facilities that directly serve end-use Load customers. However, as had been commented in preceding postings, the EHV breakpoint for these more stringent requirements, defined in note 3 of table 1 as "all Facilities greater than 300 kV", is not appropriately defined and should be reviewed. A uniform voltage-level threshold has not been shown to adequately cover all of the different power systems in North America, and significant additional costs will be incurred without proportional or measurable reliability benefits if this definition is not changed.The following is a proposed modification to the EHV definition "all Facilities greater than 300 kV" :"Facilities representing the backbone of the System, generally operating at voltages greater than 300 kV, as determined by the Planning Coordinator and approved by Regional Entity." In using such language, we believe that the extra investment required would go towards real improvement of the reliability of the Interconnected System. Furthermore, HQT believe that untill the BES/BPS definition debate is settled at NERC and FERC level, the proposed definition permits the use of the performance base methodology to determine the BPS element subjected to this standard. The way the standard is actually

Organization	Yes or No	Comments for Question 10
		written, it can be interpreted as 300 kV and above, wheter it is part of BPS or not. HQT believe it is overly prescriptive and leaves no leeway.

Response: The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV Facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT's intent and it now reads:

> **Footnote 1 -** If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.

Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.

The SDT has retained extreme events and believe it is important to review the extreme events for potential Cascading and if identified complete an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the extreme event(s). The SDT retained the same table reference area for extreme events.

The SDT believes that towerline is a commonly understood term and that the use of "structure" over "tower line" is not a substantive change. No change made in Draft 5 in this regard.

As noted above, errors in reference to Table 1 footnotes are recognized by the SDT and have been corrected in Draft 5.

The SDT disagrees with the commenter's view that Table 1 note "a" is not valid for the steady-state timeframe. The standard in Requirement R6 requires a Transmission Planner/Planning Coordinator to define and document, within their Planning Assessment, any criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. A steady-state review is not prohibited by the standard and may be included within the criteria used.

Table 1 note "i" is intended to clarify that even if it is known that an end-user who implements a more conservative practice than that of the Transmission Planner/Planning Coordinator regarding steady-state voltage criteria and chooses to interrupt its own Load, the end-use Load must still be represented in the steady-state timeframe. The Load tripping is permitted in a Stability review, however, it should be assumed that a customer will react quickly to restore its Load and therefore the standard requires the Load be represented in the steady-state timeframe. Only actions (manual or automatic) taken by the Transmission Planner/Planning Coordinator are permitted for consideration for a steady-state review.

As noted above, errors in reference to Table 1 footnotes are recognized by the SDT and have been corrected in Draft 5.

The P5 event is not a review of individual Protection System components but rather evaluates the loss of a "single Protection System" scheme or design. It is acceptable to simulate that a local (at the same substation) alternate Protection System scheme is still operational when performing a P5 review. The SDT chose this language to align with the SAR titled: Reliability of Protection Systems (Project 2009-7). The SDT believes that the individual component level evaluation of Protection Systems and redundancy requirements should be covered under the PRC standards and has only addressed a single protection scheme failure in the Planning Assessment required for the TPL standard. A Protection System component failure (i.e., battery) that removes multiple Protection System schemes is beyond the P5 planning event. Based on feedback from some commenters, the SDT made changes to the P5 planning event description as shown in Table 1. The P5 is now described as shown below. The changes are not substantive, do not alter the team's prior intent and aimed at clarification only.

Organization	Yes or No	Comments for Question 10
The standard does not specify common or different phase for the P7 planning event and is left to the engineering judgment of the Transmission Planner/Planning Coordinator. No change made. Extreme event 2a does not cover 2b when two or more tower lines are contained in the same Right-of-Way. Extreme event item "2a" is 3 or more circuits on the same tower line or structure. Extreme event item "2b" considers loss of multiple Transmission lines located on a different tower line but within the same the same Right-of-Way. The erroneous comma in footnote 2 has been removed as suggested by the commenter. The SDT has retained the same delineation of the Bulk Electric System (EHV and HV) in Draft 5. No changes made.		
National Grid	No	There is confusion in interpretation of the Table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading? Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft. Other footnotes appear to be mislabeled as well. If Extreme Events are not deleted from the standard, then a different number for the table for Extreme Events should be used. Table 1, P5: The use of the term "Protection System" in P5 is unacceptably inconsistent with the NERC definition of Protection System because it does not exclude the battery and its associated series elements. Extreme Events 2a need to define towerline. Add language to replace towerline with structure. Table 1, footnote #3, change Regional Entity to Regional Reliability Organization.
Response: The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV Facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT's intent and it now reads: **Footnote 1 -** If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The SDT has retained extreme events and believe it is important to review the extreme events for potential Cascading and if identified complete an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the extreme event(s). The SDT retained the same table		

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reference area for extreme events. The P5 event is not a review of individual Protection System components but rather evaluates the loss of a "single Protection System" scheme or design. It is acceptable to simulate that a local (at the same substation) alternate Protection System scheme is still operational when performing a P5 review. The SDT chose this language to align with the SAR titled: Reliability of Protection Systems (Project 2009-7). The SDT believes that the individual component level evaluation of Protection Systems and redundancy requirements should be covered under the PRC standards and has only addressed a single protection scheme failure in the Planning Assessment required for the TPL standard. A Protection System component failure (i.e., battery) that removes multiple Protection System schemes is beyond the P5 planning event Based on feedback from some commenters, the SDT made changes to the P5 planning event description as shown in Table 1. The changes are not substantive, do not alter the team's prior intent and aimed at clarification only. The SDT disagrees with the commenter that the P5 event is a misuse of the defined Protection System term. The SDT believes that tower line is a commonly understood term and that the use of "structure" over "tower line" is not a substantive change. No change made in Draft 5 in this regard. The SDT concluded that the use of Regional Entity is not necessary. Other changes have been made to footnote for clarity based on other comments. **Footnote 3** - Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.		
Northeast Power Coordinating Council--RSC	No	There is confusion in interpretation of the Table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading? Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft. Other footnotes appear to be mislabeled as well. If Extreme Events are not deleted from the standard, then a different number for the table for Extreme Events should be used. Extreme Events 2a need to define towerline. Add language to replace towerline with structure. Table 1 Footnotes require a close editorial review. There are two number ones, and multiple items pointing to the wrong footnote or footnotes that don't exist (19, 101), etc. Several instances are discussed below but this is not an exhaustive list. Table 1 Steady State & Stability Performance Planning Events - Note (a) this note is placed under "Steady State & Stability" but issues of voltage instability, cascading outages, and uncontrolled islanding apply only to stability. NPCC suggests this note be relocated to "Stability Only." Table 1 Steady State & Stability Performance Planning Events - Note (i) this indicates that one cannot meet steady state requirements by depending on end-user owned equipment. Please clarify the purpose and performance requirement on this note with respect to end-user schemes and possible arrangements already in

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		place to trip end-user equipment. Table 1, P4 footnote reference in Category column needs to change from 101 to 10. Footnote reference in Event column lead-in description needs to change from 11 to 10. Table 1, P5 As written, this requirement replicates a fault causing a loss of station anywhere that there is only one protection system. This is overly severe and would lead to the requirement for fully redundant protection systems at many stations. The use of the term "Protection System" in P5 is unacceptably inconsistent with the NERC definition of Protection System because it does not exclude the battery and its associated series elements. Battery systems should not be included. Table 1, P7 for Event 1 (the loss of two adjacent circuits), this needs to specify if these are the same phase or different phases. Table 1 Steady State & Stability Performance Extreme EventsIt appears that for Steady state, item 2, that item (a) is encompassed by (b). It if is not, what makes it different? Table 1, footnote #2 typo there is an erroneous comma in the phrase "are the fault types, that must be evaluated." Please remove said comma. Table 1, footnote #3, NPCC has asked NERC to put a lower bound on the HV but it seems that this remains unaddressed.More stringent performance requirements should be applied to Facilities that represent the backbone of the electric power grid and act as the medium for moving large amounts of power from production to various Load centers, rather than to those Facilities that directly serve end-use Load customers. However, as had been commented in preceding postings, the EHV breakpoint for these more stringent requirements, defined in note 3 of table 1 as "all Facilities greater than 300 kV", is not appropriately defined and should be reviewed. A uniform voltage-level threshold has not been shown to adequately cover all of the different power systems in North America, and significant additional costs will be incurred without proportional or measurable reliability benefits if this definition is not changed.The following is a proposed modification to the EHV definition "all Facilities greater than 300 kV"?: "Facilities representing the backbone of the System, generally operating at voltages greater than 300 kV, as determined by the Planning Coordinator and approved by Regional Entity." In using such language, we believe that the extra investment required would go towards real improvement of the reliability of the Interconnected System.

Response: The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV Facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT's intent and it now reads:

> **Footnote 1 -** If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.

Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected

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the footnote references and a detailed explanation of the changes required are summarized in the above Summary Considerations for Question 10. The SDT has retained extreme events and believe it is important to review the extreme events for potential Cascading and if identified complete an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the extreme event(s). The SDT retained the same table reference area for extreme events. The SDT believes that tower line is a commonly understood term and that the use of "structure" over "tower line" is not a substantive change. No change made. As noted above, errors in reference to Table 1 footnotes are recognized by the SDT and have been corrected in Draft 5. The SDT disagrees with the commenter's view that Table 1 note "a" is not valid for the steady-state timeframe. The standard in requirement R6 requires a Transmission Planner/Planning Coordinator to define and document, within their Planning Assessment, any criteria or methodology used in the analysis to identify System instability for conditions such as Cascading outages, voltage instability, or uncontrolled islanding. A steady-state review is not prohibited by the standard and may be included within the criteria used. Table 1 note "i" is intended to clarify that even if it is known that an end-user who implements a more conservative practice than that of the TP/PC regarding steady-state voltage criteria and chooses to interrupt its own Load, the end-use Load must still be represented in the steady-state timeframe. The Load tripping is permitted in a Stability review, however, it should be assumed that a customer will react quickly to restore its Load and therefore the standard requires the Load be represented in the steady-state timeframe. Only actions (manual or automatic) taken by the Transmission Planner/Planning Coordinator are permitted for consideration for a steady-state review. As noted above, errors in reference to Table 1 footnotes are recognized by the SDT and have been corrected in Draft 5. The P5 event is not a review of individual Protection System components but rather evaluates the loss of a "single Protection System" scheme or design. It is acceptable to simulate that a local (at the same substation) alternate Protection System scheme is still operational when performing a P5 review. The SDT chose this language to align with the SAR titled: Reliability of Protection Systems (Project 2009-7). The SDT believes that the individual component level evaluation of Protection Systems and redundancy requirements should be covered under the PRC standards and has only addressed a single protection scheme failure in the Planning Assessment required for the TPL standard. A Protection System component failure (i.e., battery) that removes multiple Protection System schemes is beyond the P5 planning event Based on feedback from some commenters, the SDT made changes to the P5 planning event description as shown in Table 1. The changes are not substantive, do not alter the team's prior intent and aimed at clarification only. The standard does not specify common or different phase for the P7 planning event and is left to the engineering judgment of the Transmission Planner/Planning Coordinator. No changes made. Extreme event 2a does not cover 2b when two or more tower lines are contained in the same Right-of-Way. Extreme event item "2a" is 3 or more circuits on the <u>same tower line or structure.</u> Extreme event item "2b" considers loss of multiple Transmission lines located on a different tower line but within the same the same Right-of-Way. The erroneous comma in footnote 2 has been removed as suggested by the commenter. The SDT has retained the same delineation of the Bulk Electric System (EHV and HV) in Draft 5. No change made.		
ISO New England	No	We generally agree with the table however our issues are as follows:Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft. Other footnotes appear to be mislabeled as well.

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United Illuminating	No	We generally agree with the table however our issues are as follows:Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft. Other footnotes appear to be mislabeled as well. If Extreme Events are not deleted from the standard, then a different number for the table for Extreme Events should be used. There is confusion in interpretation of the Table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading?P5 The use of the term "Protection System" in P5 is unacceptably inconsistent with the NERC definition of Protection System because it does not exclude the battery and its associated series elements. Extreme Events 2a need to define tower line. Add language to replace "tower line" with "structure". Table 1, footnote #3, change Regional Entity to Regional Reliability Organization.
Central Maine Power Company	No	We generally agree with the table, however our issues are as follows:Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft. Other footnotes appear to be mislabeled as well. If Extreme Events are not deleted from the standard, then a different number for the table for Extreme Events should be used. There is confusion in interpretation of the Table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV

Organization	Yes or No	Comments for Question 10
		autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading?P5 The use of the term "Protection System" in P5 is unacceptably inconsistent with the NERC definition of Protection System because it does not exclude the battery and its associated series elements. Extreme Events 2a need to define tower line. Add language to replace "tower line" with "structure". Table 1, footnote #3 change Regional Entity to Regional Reliability Organization.
Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The SDT has retained extreme events and believe it is important to review the extreme events for potential Cascading and if identified complete an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the extreme event(s). The SDT retained the same table reference area for extreme events The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV Facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT's intent and it now reads: **Footnote 1 -** If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. The SDT believes that tower line is a commonly understood term and that the use of "structure" over "tower line" is not a substantive change. No change made in Draft 5 in this regard. The SDT concluded that the use of Regional Entity in footnote 3 is not necessary. No change made to reflect the proposed Regional Reliability Organization as proposed by the commenter. **Footnote 3** - Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.		
American Transmission Company	No	We suggest the following changes:Note "e" in the Planning Events, Steady State & Stability section – After bulletin item #7 is added to R2.7.1 as proposed above, refer to this bulletin item with wording like, ". . . applicable to the Facility Ratings (as noted in R2.7.1).". Note "a" and Note "b" in the Planning Events, Steady State Only section Both of these notes are stated in the form of a Requirement (e.g. use the verb "shall"), but all requirements should be included in the Requirements section and not introduced (hidden) in the performance notes of Table 1. After R3.3.5 is added as proposed above, replace Note "a" and "b" with wording from R3.3.5, "Applicable System

Organization	Yes or No	Comments for Question 10
		Operating Limits for the planning horizon shall not be exceeded, as stated in R3.3.5.". Note "a" and "b" can be combined and replaced with a single Note because the observance of System Operating Limits related to steady state conditions covers both items. Note "d" in the Planning Events, Steady State Only section This note is stated in the form of a Requirement (e.g. use the verb "shall"), but all requirements should be included in the Requirements section and not introduced in the performance notes of Table 1. After R3.3.6 is added as proposed above, replace Note "d" with wording from R3.3.6, The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to steady state voltage requirements, as stated in R3.3.6. Note "a" and Note "b" in the Planning Events, Stability Only section Both of these notes are stated in the form of a Requirement (e.g. use the verb "shall"), but all requirements should be included in the Requirements section and not introduced in the performance notes of Table 1. After R4.3.5 is added as proposed above, replace Note "a" and "b" with wording from R4.3.5, "Applicable System Operating Limits for the planning horizon shall not be exceeded, as stated in R4.3.5.". Note "a" and "b" can be combined and replaced with a single Note because the observance of System Operating Limits related to stability covers both items P3 Modify the P3 Category performance criteria to apply only to the loss of two generators because the probability of the loss of two base load generators is an order of magnitude greater than the loss of a generator and any other transmission element. We suggest the listing of: the loss of transmission circuit, transformer, shunt device, and single pole of DC line be removed from the P3 Events column. Move the "generator + another element" events to the P6 Category by adding "1. Generator" to the listing in the Initial System Condition (Loss of . . .) column. Item 2.a in the Extreme Events, Steady State section Clarify the meaning of the loss of multiple circuits in Item 2.a by using wording similar to P7. We suggest this text: "a. Loss of three or more circuits that share a common tower." Item 3.b of the Extreme Events, Steady State section " Clarify the reference to actual, historical operating experience in Item 3.b. We suggest this text: "b. Other events based upon actual operating experience that may result in wide area disturbances." Item 2.i of the Extreme Events, Stability State section " Clarify the reference to actual, historical operating experience in Item 2.i. We suggest this text that is similar to Steady State, Item 3.b: "i. Other events based upon actual operating experience that may result in wide area disturbances." Extreme Event sections are not updated to reflect the new footnote numbering (for instance Item 2a and Item 2b of the Steady State column). Footnote 6 " Further clarify the applicable shunt devices in Footnote 6 with this suggested text: "6. Requirements

Organization	Yes or No	Comments for Question 10
		which are applicable to shunt devices, also apply to FACTS devices that are connected to ground, but not instrument voltage transformers or surge arresters."

Response: The SDT in ATC's Q2 comments declined to add the suggested 7th bullet to Requirement R2, part 2.7.1. The list in Requirement R2, part 2.7.1 provides examples of potential corrective actions and includes references to the use of generation tripping/runback when used to meet steady-state or Stability performance requirements. The note "e" in Table 1 is a condition for allowance of planned System adjustments, which could include Operating Plans such as re-dispatch and qualifies that the operating actions must be achievable with the timeframe of an applicable ratings. No change made.

The Table 1 performance requirements are tied to the standard through Requirements R3 and R4. For example in Requirement R3, part 3.1 the requirement indicates "Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1..". Header notes are part of Table 1 and therefore included in part 3.1 of requirement R3. No change made.

The proposed Requirement R3, part 3.3.5 was not adopted by the SDT. No change made.

Regarding note "d" comment - the Table 1 performance requirements are tied to the standard through Requirements R3 and R4.

The proposed Requirement R3, part 3.3.6 was not adopted by the SDT. No change made.

There are no notes "a" and "b" in the Stability only section. The correct reference is "j" and "k". The Table 1 performance requirements are tied to the standard through Requirements R3 and R4. No change made.

The SDT disagrees with the proposed adjustment of moving select generator Contingency outages to new planning event designations. The Table 1 planning event order is somewhat subjective and the SDT believes appropriate expectations were made for generation outages within the P3 event. No changes made.

Item 2.a in the Extreme Events, steady-state the language as shown in Draft 4 already indicates the text requested by the commenter. It's possible that an earlier draft of TPL-001-1 was referenced when making the comment. No change required.

Item 3b in the Extreme Events, steady-state the language as shown in Draft 4 already indicates the text requested by the commenter. It's possible that an earlier draft of TPL-001-1 was referenced when making the comment. No change required.

Item 2i in the Extreme Events, Stability language was revised to "2f" in Draft 4 and already indicates the text requested by the commenter. It's possible that an earlier draft of TPL-001-1 was referenced when making the comment. No change required.

Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.

Regarding footnote 6, the SDT believes the footnote is sufficient. Based on lack of support for the proposed change from other stakeholders the SDT determined no change was needed.

Oncor Electric Delivery	Yes	Errata Changes - Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. Other Footnotes appear to be mislabeled as well. There is lack of clarity in the interpretation of Table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from exceeding its load rating? Conversely, if

Organization	Yes or No	Comments for Question 10
		the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from exceeding its load rating? Table I, item "e" ?It doesn't specify which units can be adjusted following the contingency. This seems to be similar to the fact that the standard doesn't address the base case. Should the standard be clear that you can or cannot rely on generation redispatch? Should failure of a fast start generator to start up be included in the contingency, or is this another level of contingency? Table I, non-consequential load loss under no circumstance is it acceptable to shed non-consequential load to address issues in a future looking system plan. Table 1 Steady State & Stability Performance Planning Events - Note (i) this indicates that one cannot meet steady state requirements by depending on end-user owned equipment. Please clarify the purpose and performance requirement on this note with respect to end-user UVLS scheme and possible contractual arrangement already in place to trip end-user equipment. Table 1, P7 for the DCT, are these the same phase? Table 1 Steady State & Stability Performance Extreme EventsSteady state, item 2, isn't (a) covered by (b) Table 1, footnote #3, NPCC has asked NERC to put a lower bound on the HV but it seems that this remains unaddressed. P5 This test is overly severe since it could assume the total protection system failure and the system would have to rely on remote end clearing. Part of the problem seems to be that the battery is part of the protection system. The intent seems to have been to fail part of one system, not the battery. If the battery is to be excluded, then it should be clearly stated. Extreme Events 2a The term "towerline" should be defined. We agree with the SDT that more stringent performance requirements be applied for the Facilities that do not directly serve end-use load but rather represent the backbone of the electric power grid and act as the medium for moving large amounts of power from production to various load centers.However, as HQT commented on previous draft, we strongly believe that the EHV breakpoint for these more stringent requirements, defined in note 3 of table 1 as "all Facilities greater than 300 kV" is not appropriately defined and should be reviewed. The SDT have not demonstrated that a uniform voltage-level threshold could adequately covers all different power system types in North America and we strongly believe that significant, additional costs will be incurred without proportional or measurable reliability benefits if this definition is not changed.We propose to modify EHV definition "all Facilities greater than 300 kV" by the following " Facilities representing the backbone of the System, generally at voltage greater than 300 kV, as determined by the Planning Coordinator and approved by Regional Entity." In using such a language, we believe that the additional investment required would facilitate real improvement of the reliability of the interconnected System.
Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT		

Organization	Yes or No	Comments for Question 10
		has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV Facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT's intent and it now reads: **Footnote 1 -** If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. Regarding the note "e" reference to re-dispatch. The re-dispatch of any generation permissible for re-dispatch having impact on the Transmission Planner/Planning Coordinator area. The SDT believes that the standard is clear in Requirement R2, sub-part 2.7.1 (Corrective Action Plans) that generation curtailment, tripping and re-dispatch are permissible Corrective Action Plans for both single and multiple Contingency events. Starting of a "fast-start" generation unit appears to be viewed in the context of a corrective action solution to a studied planning event. There may situations like this that lend themselves to sensitivity analysis as required by the TPL-001-1 standard. The SDT respectfully disagrees with the commenter's view related to disallowing Non-Consequential Load Loss for any planning event. The SDT believes they have made the appropriate expectations in not permitting its use for some Contingency planning events involving EHV facilities. A Transmission Planner/Planning Coordinator may implement a more conservative planning approach beyond what TPL-001-1 requires if they believe one is warranted. Table 1 note "i" is intended to clarify that even if it is known that an end-user who implements a more conservative practice than that of the TP/PC regarding steady-state voltage criteria and chooses to interrupt its own Load, the end-use Load must still be represented in the steady-state timeframe. The Load tripping is permitted in a Stability review, however, it should be assumed that a customer will react quickly to restore its Load and therefore the standard requires the Load be represented in the steady-state timeframe. Only actions (manual or automatic) taken by the Transmission Planner/Planning Coordinator are permitted for consideration for a steady-state review. Interruptible Load agreements are permissible and the Load dropped through contractual arrangements with the end-user can be reflected in the steady-state analysis. The standard does not specify common or different phase for the P7 planning event and is left to the engineering judgment of the Transmission Planner/Planning Coordinator. No change made. Extreme event 2a does not cover 2b when two or more tower lines are contained in the same Right-of-Way. Extreme event item "2a" is 3 or more circuits on the <u>same tower line or structure.</u> Extreme event item "2b" considers loss of multiple Transmission lines located on a different tower line but within the same the same Right-of-Way. The SDT believes that tower line is a commonly understood term and that the use of "structure" over "tower line" is not a substantive change. No change made in Draft 5 in this regard. The SDT has retained the same delineation of the Bulk Electric System (EHV and HV) in Draft 5. No changes made.
TIS	Yes	Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft. There is confusion in interpretation of the Table 1 When the voltages class of the contingency element and the

Organization	Yes or No	Comments for Question 10
		monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied?. Please see additional comments provided for R2.
Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV Facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT's intent and it now reads: **Footnote 1 -** If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. See the SDT's response to your comments provided for Requirement R2.		
Platte River Power Authority	Yes	If clarity is given for the "Non-Consequential Load Loss Allowed" column of Yes/No that it refers to the planned shedding of firm load. (see my comment on Definition)
Response: See the SDT's response to your comment in Q9.		
American Electric Power	Yes	In Table 1, footnotes 19 and 101 should probably read 9 and 10. Also, we suggest adding table borders in P4 to more clearly align the columns that correspond to Event 6 (similar use of table borders as was done in P2).
Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The SDT has made changes to the table borders for the P4 planning event per your recommendation.		
Orlando Utilities Commission	Yes	Note 2 regarding three phase faults being sufficient evidence for SLG faults is an excellent addition, thank you. For P3 and P5 it should be made clearer that note 1 AND note 9 apply, maybe by using a comma in-between, not a note 19 that I wasn't able to locate. For Note 9, reading the context it applies only to P3, P5 and P6, but not to P1. To apply this to actual study methodology, in responding to a P1 event Note 9 can not be applied when returning the system to a continuous (sustainable) state. However after those adjustments are made if additional adjustments are needed to make the system "secure", that is prepared for the next event in the P3 or P6 contingency, then note 9 can be applied? Is

Organization	Yes or No	Comments for Question 10
		this a correct understanding?
Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. Footnote 9 is now applied to all "No" items for the column "Interruption of Firm Transmission Service Allowed". Footnote 9 clarifies that Firm Transmission Service can be interrupted so long as appropriate re-dispatch of resources are available and obligated to re-dispatch without any firm Load loss and that Facility ratings are maintained. Planning events P0, P1, and P2 now also include footnote 9 and is allowed both as a System adjustment to prepare for the next event and as a corrective action to the event studied. Please refer to the footnote for more details.		
NYISO	Yes	Question #10. Do you agree with the changes in the performance elements and notes in Table 1? If not, please provide specific comments by note number, note alpha character, or performance category. Yes
Exelon Transmission Planning	Yes	
FirstEnergy Corp	Yes	
Gainesville Regional Utilities	Yes	
Independent Electricity System Operator	Yes	
Progress Energy Carolinas	Yes	
SCE&G	Yes	
PJM	Yes	
ITC Holdings	Yes	none
Response: Thank you for your support of the SDT's work.		

11. The SDT has provided a revised Implementation Plan as part of this posting. Do you agree with the revisions to the Plan? If not, please provide specific comments.

Summary Consideration: There were 5 main comments associated with this question.

1. Thirteen commenters requested clarification to better define the 60 month effective date for certain "raising the bar" performance requirements. The SDT believes that the current language in Section A. 5 of the Standard, with a minor change that the SDT will incorporate in the next draft, is clear. That section, as modified, will state that the five year period starts "beginning on the first day of the first calendar quarter following applicable regulatory approval" of the revised standard.

2. Four commenters indicated that 60 months is not enough time to build major lines, especially if up to 24 months is needed to do the Planning Assessment and develop a Corrective Action Plan. The SDT considered this issue when TPL-001-1, draft 3 was prepared, and the SDT again discussed its position in light of the comments received from this posting. The SDT continues to believe that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. The current draft of TPL-001-1 does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.3 would apply.

3. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control.
   Four commenters believe that it is inappropriate or in violation of Energy Policy Act 2005 for the revised standard to require building new facilities and some also question the requirement to self-report inability to meet Corrective Action Plan requirements. The Corrective Action Plan, however, does not require construction of facilities per se and, therefore, the SDT does not believe that the language in the current draft violates the Energy Policy Act of 2005. Other choices available as part of the Corrective Action Plan besides constructing new facilities include use of interruptible Load contracts, implementation of Demand Side Management programs, and the addition of generation. The SDT understands that there may be certain circumstances where the only viable solution to a performance deficiency is to add a new Transmission Facility. This is no different than situations that Transmission Planners have faced under the current TPL standards as well as voluntary criteria that have existed for many years. The SDT also points out that should a Transmission Planner or Planning Coordinator find that they can not meet the performance requirements by the end of the 60 month transition period, they would need to submit a mitigation plan to their Regional Entity. As long as an acceptable mitigation plan is offered, the intent of the SDT is that the reporting entity will not be subject to penalties.

3. Four commenters pointed out a typographical error that reversed the numbering of Requirements R7 and R8 in the Implementation Plan. The implementation plan has been corrected to reflect the SDT's original intent that Requirements R1 and R7 (not Requirement R8) become effective 12 months after approval and Requirements R2 through R6 plus Requirement R8 (not Requirement R7), with the noted exceptions, become effective 24 months after approval.

4. Three commenters asked for clarification of the parenthetical language applicable to Events P1-2 and P1-3. The parenthetical phrase related to P1-2 and P1-3 is intended to limit the application of the 60 calendar month exception to those situations where footnote b of the existing standards was interpreted to mean that controlled interruption of electric supply to local network customers connected to or supplied by the faulted element is permitted. The SDT took this position in recognition of the fact that a significant number of entities interpret footnote 'b' in this manner and, therefore, the revised standard represents a "raising of the bar" for them.

Organization	Yes or No	Comments for Question 11
Lafayette Utilities System		LUS remains concerned as to the length of time permitted for implementation, and believes that it should be shorter, but would not oppose adoption of version 4, as it has now been clarified, if that is the only issue of concern. There may be ways, outside the standard development process, to limit the financial harms caused to others as a result of the failure to meet the clarified standard during the implementation period.
Response: Many industry entities have expressed concern that the stated implementation period may not be sufficient, particularly for major projects. The SDT believes it has struck the right balance between the differing views, and does not plan to shorten the time permitted for implementation as you have suggested.		
FRCC Transmission Working Group		The implementation plan needs to be clarified that during the first year the existing TPL standards are still in effect. As written it appears that only R1 and R8 are in effect and the existing TPL standards are not.Assessments are a year long process and are based on a year or more worth of studies, the study work and assessment are not executed in a single day. R2 through R7 is unclear what "coming into effect means". Please consider adding the following paragraph:"Entities are not required to alter their annual schedule based on the R2-R7 requirements going into place or have duplicate efforts at assessments in the year the old and new standard overlap. Therefore any assessment performed prior to R2-R7 going into effect shall meet R1, R8 and the prior TPL standards; an assessment under the revised standard is not required until the following annual cycle. An assessment performed after R2-R7 are in effect shall meet these new TPL Standard. The date the assessment is "performed" for the purposes of this phase in, shall be determined by the date the entity began formally sharing results with its neighbors under R8." Please clarify the parenthetical for P1-2 and P1-3. Is the intent of this parenthetical referring to Consequential Load Loss that is allowed for P1 events?
Response: The Implementation Plan has been corrected to reflect the SDT's original intent that Requirements R1 and R7 (not Requirement R8) become effective 12		

Organization	Yes or No	Comments for Question 11
months after approval and Requirements R2 through R6 plus Requirement R8 (not Requirement R7), with the noted exceptions, become effective 24 months after approval. The SDT does not believe that a clarification, as you suggested, is needed to cover the one-year period for months 13 through 24. The NERC standards process is clear that an existing standard that is being revised remains in force until the revised standard becomes effective. The SDT has reviewed your suggested addition to the paragraph that addresses the effective date for Requirements R2 through R6 plus Requirement R8. The SDT does not believe that your suggestion provides further clarification and the SDT has determined that no further change is warranted. The parenthetical phrase related to P1-2 and P1-3 is intended to limit the application of the 60 calendar month exception to those situations where footnote b of the existing standards was interpreted to mean that controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element is permitted. The SDT took this position in recognition of the fact that a significant number of entities interpret footnote b in this manner and, therefore, the revised standard represents a "raising of the bar" for them.		
ERCOT ISO	No	* The implementation plan references revisions to the MOD standards. Should the team submit a SAR for the revision of the MOD standards to ensure TPL needs are considered? As stated in the comments for R1 " if the MOD standards are properly updated, there is no need to state MOD requirements in TPL-001.* Definition comments from Question 9 apply to implementation plan.* The Implementation Plan references R1 and R8 to be effective within 12 months of regulatory approval. R8 per the implementation plan state that the responsibilities of the PC and TP will be defined. This appears to be R7 of Draft 4 and the requirement language does not align. Conversely, the Effective Date should be revised to ensure the references to the requirements align properly. As written it states the assessment should be available before the assessment is complete. * During the 24 month transition period, any entity that can prove compliance with the revised TPL-001 should not have to prove compliance to the old TPL-001 through TPL-004. * The SAR should state that TPL-005 and TPL-006 are to be retired. The only place this has been found is within the implementation plan. It is not an intuitive place to find this information.
Response: The SDT referenced revisions to the MOD standards to establish a record of the need to fill a gap in the overall coordination among the Reliability Standards. The SDT does not intend to submit a SAR; rather the expectation is that NERC will take the necessary action to follow through to address this need at the appropriate point in time. See the SDT's response to your definition comments in Question 9. The Implementation Plan has been corrected to reflect the SDT's original intent that Requirements R1 and R7 (not Requirement R8) become effective 12 months after approval and Requirements R2 through R6 plus Requirement R8 (not Requirement R7), with the noted exceptions, become effective 24 months after approval. The SDT disagrees with your comment regarding demonstration of compliance during the 24 month transition period. At any point in time, one and only one set of TPL related requirements will be in force. It is those requirements that the Planning Coordinator and Transmission Planner must comply with and not future requirements that have not yet become effective. The SDT assumes that in your last comment the reference to SAR should have been Standard (or more precisely "Standard Development Roadmap"). (A Supplemental SAR was posted for comment and added to this project that does address the possibility of retiring TPL-005 and TPL-006.) The SDT agrees with your		

Organization	Yes or No	Comments for Question 11
suggestion, and the Roadmap has been modified to state: "TPL-005 & -006 issues are addressed in the fourth draft and those standards will also be replaced by TPL-001-1. (See page 1, last sentence of section titled "Proposed Action Plan and Description of Current Draft:" In addition, the "Version History" has been updated to indicate that requirements from TPL-005-0 and TPL-006-0 have been incorporated into TPL-001-1.		
NERC Standards Review Subcommittee	No	A. In the implementation plan, the provision which indicates if an entity doesn't construct in time that entity has to report itself as noncompliant. This is a violation of the energy policy act. Since FERC can't force an entity to built, this provision should be deleted. B. This standard does not contain any requirements regarding the implementation of the Corrective Action Plans. So, the wording in this section of "Any entity that cannot fully implement . . . ", should be replaced with wording like, "If the Corrective Action Plans to eliminate the need . . . can not be implemented within 60 calendar months . . . then the Transmission Planner and Planning Authority should work with the applicable Transmission Owner (s) and Regional entity(s) to develop mitigation plans for revised Corrective Action Plans until the implementation issue is resolved". C. The proposed standard implies that the 24 month time period (for R2-R7) and 60 month time period (for specific allowances for selected event categories) run in parallel rather than sequentially. As currently proposed, the effective date for performing analyses and developing subsequent Corrective Action Plans is 24 months. If the identification of new needs and action plans take 24 months, then only 36 months would be left to implement the new corrective action plans. It may not be feasible to install some BES facilities, especially above 300 kV, in less than 3 years. Some EHV projects can take 5 to 10 years to implement depending on the size, complexity, and controversial nature of the project. D. The MRO NSRS suggests that the effective date be stated in more "implementation dependent" terms for this "one time" transient period, rather than specific and possibly inappropriate "fixed timeframe" terms. Consider wording such as "tripping of Non-Consequential Load or curtailment of Firm Transmission Service (in accordance with Requirement R2, part 2.7.5) is allowed until Corrective Action Plans that are based on TPL-001-1 analyses can be implemented".
Response: A. The SDT disagrees with your characterization of the Corrective Action Plan. The Corrective Action Plan does not require construction of facilities per se and, therefore, the SDT does not believe that the language in the current draft violates the Energy Policy Act of 2005. Other choices available as part of the Corrective Action Plan besides constructing new facilities include use of interruptible load contracts, implementation of Demand Side management programs, and the addition of generation. The SDT understands that there may be certain circumstances where the only viable solution to a performance deficiency is to add a new transmission facility. This is no different than situations that Transmission Planners have faced under the current TPL standards as well as voluntary criteria that have existed for many years. The SDT also points out that should a Transmission Planner or Planning Coordinator find that they can not meet the performance requirements by the end of the 60 month transition period, they would need to submit a mitigation plan to their Regional Entity. As long as an acceptable mitigation plan is offered, the intent of the SDT is that the reporting entity will not be considered non-compliant nor will penalties be imposed. The SDT has modified the Implementation Plan to clarify the wording. B. The SDT believes that the requirement language is clear that the Corrective Action Plan shall be implemented. In Requirement 2, part 2.7.5 reference is made to "implementation of a Corrective Action Plan," and in Requirement R2, part 2.7.6 there is a requirement to review "implementation status."		

Organization	Yes or No	Comments for Question 11
C. Your interpretation that the 24 month and 60 month time periods run in parallel is correct. The SDT understands that some large projects that are part of the Corrective Action Plan may take more than 60 months to complete. However, the SDT also believes that some time limit must be placed on the Corrective Action Plan and 60 months was chosen to strike a balance between those commenters who requested more time and those who would like to see corrective actions completed sooner. The SDT also provided a procedure for mitigation in those situations where 60 months was insufficient. It is the intent of the SDT that the development of an acceptable mitigation plan will avoid penalties. D. The SDT considered your suggested restatement of effective dates during the transition period. The SDT does not believe that such a change would materially improve the standard language. In fact, your specific example would be problematic because Requirement R2, part 2.7.5 applies universally not just to the transition period.		
Progress Energy Florida, Inc.	No	As PEF is opposed to TPL-001-1 as a whole, we cannot comment on the details of the Implementation Plan, other than to say that given the fundamental inadequacies of TPL-001-1, PEF does not believe the Standard should be implemented at all.Given that the wording of Question 12 appears to imply that any general comments made in the Question 12 comments section would be unwelcome and disregarded, PEF would respectfully like to make the following comments regarding our overall position on TPL-001-1:PEF filed extensive comments for the 1st, 2nd and 3rd drafts of TPL-001-1 and voiced serious concerns about the consequences that Transmission Owners and ratepayers will undoubtedly face if TPL-001-1 were to be implemented. PEF respectfully asks the SDT to review PEFs previous comments, particularly from the perspective of the ratepayers. The average ratepayer in the U.S. is already experiencing high electricity bills based on fuel pass-through charges and electric utilities? needs to raise rates to successfully operate and maintain the system. Furthermore, the ratepayers have not been involved in this Standard drafting process, and indeed have not even been informed at even the most cursory level. PEF has pointed this out in previous comments, and the SDTs response has been inadequate. Given the erroneous approach of Table 1 in TPL-001-1 to gauge reliability based on whether or not firm transmission service or non-consequential load will be curtailed, implementation of the Standard will dramatically increase ratepayers? already-high rates with little or no appreciable reliability improvement. Additionally, Transmission Owners will be forced to reduce ATC in order to prevent compliance violations, thus shutting out Power Marketers and potentially resulting in construction of more new generation than is really needed. Another major conflict that TPL-001-1 will cause is a rift between the FERC/NERC regulatory environment and the various states? Public Service Commissions (PSC). The major transmission projects that TPL-001-1 will mandate (especially those mandated due to the overly burdensome and unnecessary > 300 kV section) will have to be approved for permitting and funding through Determination of Need hearings at the PSC. When questioned by the PSC on the need for such projects, Transmission Owners will be obligated to admit that the projects really aren't needed but for NERC's new TPL-001-1 Standard, which will undoubtedly result in the PSCs denial of approval. PEF also would like to note that the SDT still has not provided sufficient reason for the need to implement a new TPL Standard. PEF and its fellow members in FRCC have historically demonstrated excellent reliability while performing long-term Transmission Planning under the existing TPL Standards. There simply is no practical reason for improvement on the existing Standards. PEF is aware of the history of the drafting of a new TPL

Organization	Yes or No	Comments for Question 11
		Standard, however, having reviewed FERCs direction to NERC in this matter. Regarding this, PEF feels that NERC should have pointed out the likely consequences to merely following FERCs directions in their entirety; instead, NERC formed a SDT which proceeded to draft a new TPL Standard that satisfied each and every direction FERC had given. This approach has resulted in a draft Standard that is much too stringent, not conducive to significant reliability improvement and prohibitively expensive to implement.In conclusion, PEF strenuously opposes TPL-001-1, and feels the implementation of TPL-001-1 is unfair, irresponsible and unnecessary. PEF furthermore feels that it has sufficiently proven this in previous comments, and will continue to seek additional avenues to ensure that said comments are given proper consideration. TPL-001-1 is thus not in a condition to go to ballot, and it would be highly inappropriate to send this Standard to ballot given the major concerns that PEF and numerous other utilities within NERC have raised.
Response: The wording in Question 12 has created confusion among many commenters and was not intended to imply that if you checked the YES box, the SDT would not consider your comments. The SDT is obligated to consider all comments, make changes in the drafts that the SDT, as representatives of the entire industry, believe need to be made and provide responses to all comments. The SDT has carefully considered the PEF comments throughout the drafting process and has made changes to the drafts based on your comments and those received from the other commenters. Throughout the process, the SDT has been attempting to iterate toward a standard that the industry, as a whole, can support. The SDT, FERC, and the majority of the industry (through their comments) support the need to improve the TPL standards.		
Florida Power and Light	No	Do not understand the parenthetical for P1-2 and P1-3. The language is confusing and needs to be clarified. Isn't it referring to Consequential Load Loss that is allowed for P1 events?
Response: The parenthetical phrase related to P1-2 and P1-3 is intended to limit the application of the 60 calendar month exception to those situations where footnote b of the existing standards was interpreted to mean that controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element is permitted. The SDT took this position in recognition of the fact that a significant number of entities interpret footnote b in this manner and, therefore, the revised standard represents a "raising of the bar" for them.		
MidAmerican Energy Company	No	MidAmerican commends the SDT for changes that improved the Implementation Plan, however, MidAmerican does have a comment about the plan. MidAmerican urges the SDT to modify the implementation plan where it is indicated that any "entity which cannot fully implement their Corrective Action Plan to eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for these performance elements by that date shall self report themselves as being unable to meet the performance requirements of the Reliability Standard." This is essentially requiring an entity to self report for failing to build facilities. The Energy Policy Act of 2005 did not give FERC and therefore, NERC, the authority to require construction of electric facilities. Therefore, this implementation plan is implying an authority that is not given to FERC or NERC. This provision of the implementation plan should be completely deleted from the standard, the provision to state that one is non-compliant for this should be deleted from the standard, or there should be a statement that such a requirement is subject to limitations of the Energy Policy Act of 2005. This is a deal-killer for MidAmerican with regard to voting on this standard. MidAmerican believes that 4.1.2 and 4.3.3 as written would require responsible entities in the industry to add

Organization	Yes or No	Comments for Question 11
		additional modeling of relaying in dynamic stability models of our system. MidAmerican suggests that 4.3.3 be limited to transient swings on facilities 345 kV and above so as to limit this part of requirement 4 to those situations that are most likely to result in cascading. If the SDT determines not to add such a limitation, MidAmerican asks that the implementation time for R4 to be increased. MidAmerican believes that many responsible entities would need 3 years to add these relaying models to system stability models so that the fourth year additional transmission planning analysis in this respect is conducted. MidAmerican urges that the SDT increase the implementation time for R4 from 2 years to 4 years. (MidAmerican may this comment in response to Question 4 as well.)
Response: The SDT disagrees with your characterization of the Corrective Action Plan. The Corrective Action Plan does not require construction of facilities per se and, therefore, the SDT does not believe that the language in the current draft violates the Energy Policy Act of 2005. Other choices available as part of the Corrective Action Plan besides constructing new facilities include use of interruptible load contracts, implementation of Demand Side management programs, and the addition of generation. The SDT understands that there may be certain circumstances where the only viable solution to a performance deficiency is to add a new transmission facility. This is no different than situations that Transmission Planners have faced under the current TPL standards as well as voluntary criteria that have existed for many years. The SDT also points out that should a Transmission Planner or Planning Coordinator find that they can not meet the performance requirements by the end of the 60 month transition period, they would need to submit a mitigation plan to their Regional Entity. As long as an acceptable mitigation plan is offered, the intent of the SDT is that the reporting entity will not be considered non-compliant nor will penalties be imposed. The SDT has modified the Implementation Plan to clarify the wording. Requirement R4, parts 4.1.2 and 4.3.3 do not necessarily require modeling of specific relays. Commercially available software includes a generic relay model which can easily be applied to every branch in the simulation. This generic relay includes assumed zone 1, 2, and 3 characteristics based on the branch impedance. If this model shows impedance swings in a branch element, then the Transmission Planner or Planning Coordinator can either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. The SDT agrees that studying the impact of swings should be limited to the study area. However, the SDT does not believe this should be limited to only high voltage lines. Because Requirement R4, part 4.3.3 does not necessarily require modeling of specific relays (as described directly above), the SDT does not agree that a longer time is needed in the Implementation Plan.		
Oklahoma Gas & Electric	No	OG&E will need every bit of the 60 months time mentioned on page 3 under “Effective Date” to implement all indicated upgrades. There is benefit in hardening the OG&E electrical system for such protection system failures, such as P4 & P5, but it may not be cost effective.
Response: Thank you for your comment.		
Manitoba Hydro	No	Requirement R8, as the standard is currently written, doesn't match the language on page 2 of the discussion provided by the drafting team (i.e. related to determining individual and joint assessments). The drafting team should flip Requirements R7 and R8 so that the implementation plan matches the intent or modify the implementation plan.
Response: The implementation plan has been corrected to reflect the SDT’s original intent that Requirements R1 and R7 (not Requirement R8) become effective 12 months after approval and Requirements R2 through R6 plus Requirement R8 (not Requirement R7), with the noted exceptions, become effective 24 months after approval.		

Organization	Yes or No	Comments for Question 11
Bonneville Power Administration	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
Idaho Power	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
Modesto Irrigation District Transmission Planning	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
NV Energy	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
Pacific Gas and Electric Co.	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
Puget Sound Energy, Inc.	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
Sacramento Municipal Utility District	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
San Diego Gas & Electric Co	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
Southern California Edison (SCE)	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
SRP	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five

Organization	Yes or No	Comments for Question 11
		years from the modeled year or five years from the effective date of this standard.
Western Area Power Adm - RMR	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the Effective Date of this standard.
Xcel Energy	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem, or five years from the modeled year, or five years from the effective date of this standard.
Deseret Power	No	Comments: Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
NorthWestern Energy	No	In the Effective Date section, 60 calendar months is allowed for Corrective Action Plans. When does the 60 month period start? From the day the problem is identified? From the modeled year? Or from the effective date of the standard?
Response: The SDT believes that the current language in Section A. 5 of the Standard, with a minor change that the SDT will incorporate in the next draft, is clear. That section, as modified, will state that the five year period begins "on the first day of the first calendar quarter following applicable regulatory approval" of the revised standard.		
MAPP	No	The last part of the Effective Date section deals with the requirement to submit a Corrective Action Plan, and then to submit a mitigation plan to be approved by the Regional Entity and NERC. Failure do get those done would result in the initiation of "settlement proceedings." This means that entities may be found non-compliant for failure to build facilities. That seems to fly in the face of the EPAct of 2005.
Response: The SDT disagrees with your characterization of the Corrective Action Plan. The Corrective Action Plan does not require construction of facilities per se and, therefore, the SDT does not believe that the language in the current draft violates the Energy Policy Act of 2005. Other choices available as part of the Corrective Action Plan besides constructing new facilities include use of interruptible load contracts, implementation of Demand Side management programs, and the addition of generation. The SDT understands that there may be certain circumstances where the only viable solution to a performance deficiency is to add a new transmission facility. This is no different than situations that Transmission Planners have faced under the current TPL standards as well as voluntary criteria that have existed for many years. The SDT also points out that should a Transmission Planner or Planning Coordinator find that they can not meet the performance requirements by the end of the 60 month transition period, they would need to submit a mitigation plan to their Regional Entity. As long as an acceptable mitigation plan is offered, the intent of the SDT is that the reporting entity will not be considered non-compliant nor will penalties be imposed.		
SERC Dynamics Review Subcommittee (DRS)	No	There is a concern about the last paragraph in the Implementation Plan. It is easy to interpret this language to state that the entity is noncompliant if the performance requirements are not completed within 5 years. The concern is that the 5 year window for meeting the "raising the bar" requirements is still not adequate. For

Organization	Yes or No	Comments for Question 11
		instance, it typically takes 7 to 10 years to build a new 500-kV transmission line - including time required for such processes as federally mandated NEPA environmental reviews. We strongly suggest increasing this time window to 10 years.
Response: The SDT understands that some large projects that are part of the Corrective Action Plan may take more than 60 months to complete. However, the SDT also believes that some time limit must be placed on the Corrective Action Plan and 60 months was chosen to strike a balance between those commenters who requested more time and those who would like to see corrective actions completed sooner. The SDT also provided a procedure for mitigation in those situations where 60 months was insufficient. It is the intent of the SDT that the development of an acceptable mitigation plan will avoid penalties.		
TVA System Planning	No	TVA agrees with the inclusion of P1-2 and P1-3 in the 60 month implementation window. However TVA also strongly suggests that all Planning Events be included in the same implementation window where local load was allowed to be dropped in the past in footnotes b and c of the existing TPL standards. In the first bullet under Effective Date, both Non-Consequential Load Loss and curtailment of Firm Transmission Service can be permitted for certain events up to 60 months. However these actions are not useful for stability related issues. TVA suggests that out of step relaying or other protection method be allowed in for stability related issues when situations do arise that are beyond the control of the TP or PC. TVA is very concerned about the last paragraph in the Implementation Plan. TVA interprets this language to state that the entity is basically noncompliant if the mentioned Corrective Action Plans are not implemented within 60 calendar months. Due to the large amount of work that some utilities will have to meet these new requirements, TVA strongly suggests that the utilities be found compliant if the utilities are still putting a good faith effort forward in trying to meet the new standards, such as for constructing a long 500-kV transmission line that may take at least 10 years to construct TVA still believes that since breaker duty was not included in the previous TPL standards, this should also have a 60 month implementation window as well due to this now becoming a new TPL compliance issue. TVA noted this same comment in Posting #3; however, TVA requests that this be reconsidered due to being a new official TPL requirement like the other new requirements have with the 60 month implementation window. TVA is concerned that the 60 calendar month window for meeting the “raising the bar” requirements is still not adequate. For instance, it typically takes TVA 7 to 10 years to build a new 500-kV transmission line - including time required for such processes as federally mandated NEPA environmental reviews. Strongly suggest increasing this time window to 10 years.
Response: The SDT believes that footnote ‘c’ conditions in the current TPL standards are adequately addressed in the revised standard. The SDT disagrees that Non-Consequential Load Loss is not useful for Stability related issues. The tripping of such Load as part of an SPS could be accomplished quickly enough to improve Stability margins. Furthermore, there is nothing in the revised standard that precludes the use of out of step relaying. The SDT believes that your interpretation of the last paragraph of the Implementation Plan is incorrect. Should a Transmission Planner or Planning Coordinator find that they can not meet the performance requirements by the end of the 60 month transition period, they would need to provide a mitigation plan to their Regional		

Organization	Yes or No	Comments for Question 11
Entity. Although the SDT agrees that the breaker duty requirement is new to this revision of the standard, the SDT does not believe that there is a need to allow a 60 month transition period for this requirement to become effective. Replacing over-dutied circuit breakers can often be accomplished within the 24 month period provided by the effective date of the requirement. In those cases where the replacement could take longer, there are other approaches available to mitigate the over-duty condition. The SDT understands that some large projects that are part of the Corrective Action Plan may take more than 60 months to complete. However, the SDT also believes that some time limit must be placed on the Corrective Action Plan and 60 months was chosen to strike a balance between those commenters who requested more time and those who would like to see corrective actions completed sooner.		
Ameren	No	We appreciate that the Standards Drafting Team has proposed delayed effective dates to allow tripping of Non-Consequential Load or curtailment of Firm Transmission Service for a number of categories of contingency events to allow more time to become compliant. However, we do not look forward to having to self-report non-compliance because the industry and the government changed the planning rules in the middle of the game.
Response: Please note that should a Transmission Planner or Planning Coordinator find that they can not meet the performance requirements by the end of the 60 month transition period, they would need to submit a mitigation plan to their Regional Entity. It is the intent of the SDT that the development of an acceptable mitigation plan will avoid penalties.		
FirstEnergy Corp	No	We disagree with the proposed Implementation Plan. The implementation period for the TPL-001-1 transmission planning standard should be limited to the time needed to transition to the new study requirements. The proposed 5-year implementation for the "raise the bar" aspects of this standard delves into project management and review of capital construction progress which should remain outside the scope of this standard. The standard should only consider if an entity has completed the required studies and has developed Corrective Action Plans to ensure performance criteria is being maintained.Implementation of transmission system action plans depends on the actions of many other functional entities, other than PCs or TPs. PCs and TPs should not be held responsible for the implementation of action plans since they have little or no control over the activities related to implementation. For example, an RTO/ISO may act as both the PC and the TP for its transmission owner or transmission operator membership, however, the RTO/ISO should not be subject to compliance sanctions for incomplete projects that it does not have direct responsibility.FirstEnergy suggests that a new TPL standard is required to successfully accomplish the vision and endpoint that this drafting team has in mind. It is our opinion that the TO, TOP, DP and GO are needed as applicable entities to bring to fruition the capital enforcement projects or operating procedures that are identified by the PC/TP. This TPL-001-1 standard should stop at the conclusion of studies, assessments and development of Corrective Action Plans and a new TPL standard should be developed to address implementation of Corrective Action Plans.
Response: The SDT has considered your position and still believes that the requirement to implement the Corrective Action Plan is appropriate. Furthermore, the SDT does not believe that the standard should apply to additional entities beyond the Transmission Planner and Planning Coordinator. In fact, doing so would tend to make implementation of the Corrective Action Plan more difficult by reducing clarity as to who is the responsible entity. Where the Transmission Planner or Planning Coordinator is an RTO, agreements between the RTO and its members, which typically include the entities you describe, require those members to implement plans		

Organization	Yes or No	Comments for Question 11
developed by the RTO. Where the Transmission Planner or Planning Coordinator is not an RTO, in most cases, they are a vertically integrated utility that includes all of the entities that you describe. In other cases, the Transmission Planner and Planning Coordinator can establish agreements with the entities for which they are providing those services to specify responsibilities for implementation of the Corrective Action Plan.		
American Transmission Company	No	We offer the following comments.This standard does not contain any requirements regarding the implementation of the Corrective Action Plans. So, the wording in this section of "Any entity that cannot fully implement . . . ", should be replaced with wording like, "If the Corrective Action Plans to eliminate the need . . . can not be implemented within 60 calendar months . . . then the TP and PA should work with the applicable TO(s) and Re(s) to develop mitigation plans for revised Corrective Action Plans until the implementation issue is resolved". The proposed standard implies that the 24 month time period (for R2-R7) and 60 month time period (for specific allowances for selected event categories) run in parallel rather than sequentially. As currently proposed, the effective date for performing analyses and developing subsequent Corrective Action Plans is 24 months. If the identification of new needs and action plans take 24 months, then only 36 months would be left to implement the new corrective action plans. It may not be feasible to install some BES facilities, especially above 300 kV, in less than 3 years. Some EHV projects can take 5 to 10 years to implement depending on the size, complexity, and controversial nature of the project. We suggest that the effective date be stated in more "implementation dependent" terms for this "one time" transient period, rather than specific and possibly inappropriate "fixed timeframe" terms. Consider wording such as "tripping of Non-Consequential Load or curtailment of Firm Transmission Service (in accordance with Requirement R2, part 2.7.5) is allowed until Corrective Action Plans that are based on TPL-001-1 analyses can be implemented".The "implementation dependent" approach may allow the removal of all or part of the text on implementation exceptions and mitigation procedures that do not appear to be suitable in an Effective Date section.
Response: The SDT believes that the requirement language is clear that the Corrective Action Plan shall be implemented. In Requirement 2, part 2.7.3 reference is made to "implementation of a Corrective Action Plan," and in Requirement R2, part 2.7.4 there is a requirement to review "implementation status." Your interpretation that the 24 month and 60 month time periods run in parallel is correct. The SDT understands that some large projects that are part of the Corrective Action Plan may take more than 60 months to complete. However, the SDT also believes that some time limit must be placed on the Corrective Action Plan and 60 months was chosen to strike a balance between those commenters who requested more time and those who would like to see corrective actions completed sooner. The SDT also provided a procedure to submit a mitigation plan to their Regional Entity where 60 months was insufficient. It is the intent of the SDT that the development of an acceptable mitigation plan will avoid penalties. The SDT has modified the Implementation Plan to clarify the wording. The SDT also considered your suggested restatement of effective dates during the transition period. The SDT does not believe that such a change would materially improve the standard language. In fact, your specific example would be problematic because Requirement R2, part 2.7.5 applies universally not just to the transition period.		
Tri-State Generation and Transmission Association	No	Yes and No. We see some potential problems.12 months after BOT adoption, R1 maintain system models - becomes effective. Why delay Also 12 months after adoption, R8 distribute planning assessment results - becomes effective. As an assessment cannot be distributed before it is completed, this must be coordinated with R2.24 months after BOT adoption R2 Annual Planning Assessment - timing must coordinate with R8 above.

Organization	Yes or No	Comments for Question 11
Response: The SDT attempted to strike a balance between those commenters who requested more time and those who would like to see some requirements become effective earlier. In the case of Requirement R1, the SDT saw little value in making this requirement effective before 12 months. Furthermore, doing so would break the standard effective dates into yet another time period possibly leading to confusion as to which portions of the revised and old standards are in effect. The implementation plan has been corrected to reflect the SDT's original intent that Requirements R1 and R7 (not Requirement R8) become effective 12 months after approval and Requirements R2 through R6 plus Requirements R8 (not Requirement R7), with the noted exceptions, become effective 24 months after approval.		
American Electric Power	Yes	
British Columbia Transmission Corp	Yes	
Central Maine Power Company	Yes	
Exelon Transmission Planning	Yes	
Florida Municipal Power Agency, and its Member Cities	Yes	
Gainesville Regional Utilities	Yes	
Hydro-Québec TransEnergie (HQT)	Yes	
Independent Electricity System Operator	Yes	
ISO New England	Yes	
Northeast Power Coordinating Council--RSC	Yes	
Northeast Utilities	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates PHI	Yes	

Organization	Yes or No	Comments for Question 11
Progress Energy Carolinas	Yes	
SCE&G	Yes	
SERC Planning Standards Subcommittee	Yes	
Southern Company	Yes	
SRC of ISO/RTO	Yes	
TIS	Yes	
United Illuminating	Yes	
US Bureau of Reclamation	Yes	
Utility System Efficiencies, Inc. (USE)	Yes	
ITC Holdings	Yes	none
National Grid	Yes	None.
NYISO	Yes	Question #11 The SDT has provided a revised Implementation Plan as part of this posting. Do you agree with the revisions to the Plan? If not, please provide specific comments. Yes
Response: Thank you for your input.		
Orlando Utilities Commission	Yes	The phasing in of the higher performance criteria is a very reasonable approach. The implementation plan needs to be painfully clear that during the first year the existing TPL standards are still in effect, and that R1 and R8 are in effect in addition. Most NERC standards have one revision take effect on a specific date, make the old version out of date. In this case however if TPL 001 retires the prior standards, then only R1 and R8 would need to be performed in the first year, which I do not believe that is the intent. In addition to this, further clarification may be needed for the application of R2-R7, even if they were to come into effect the first year. Assessments are a year long process and published once a annually. As an example many entities “publish” or finish the Assessment in December, that being the culmination of months of work. If R2-R7 are effective on June 2011 then the intended application seems to be that the assessment in Dec 2011 should comply with the new

Organization	Yes or No	Comments for Question 11
		standard. Is that the intent, or would there need to be a valid assessment based on the new standard available the day the standard is in effect? Maybe phrasing to this effect. "Entities are not required to alter there annual schedule based on the R2-R7 requirements going into place or have duplicate efforts at assessments in the annual period the old and new standard overlap. Any assessment completed (as determined by the date that the entity formally shared results under R8) after the effective date for R2-R7 shall comply with those requirements."
Response: First, it should be noted that the Implementation Plan has been corrected to reflect the SDT's original intent that Requirements R1 and R7 (not Requirement R8) become effective 12 months after approval and Requirements R2 through R6 plus Requirement R8 (not Requirement R7), with the noted exceptions, become effective 24 months after approval. The SDT does not believe that a clarification is needed to cover the one-year period for months 13 through 24 when Requirements R1 and R7 plus the existing standard will be in effect because Requirements R1 and R7 are new requirements that do not replace any requirements in the existing standards. The NERC standards process is clear that an existing standard that is being revised remains in force until replaced by revised standard requirements becomes effective. The SDT believes that sufficient flexibility was provided in the definition of Year One to permit Transmission Planners and Planning Coordinators to maintain their current assessment schedule if they desire. It is the SDT's expectation that any assessment initiated 24 months or more after the effective date of Requirements R2 through R6 plus Requirement R8 would adhere to the revised standard requirements.		
Duke Energy	Yes	Yes, however we don't understand the meaning of this phrase which follows P1-2 and P1-3: "for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element".
Response: The parenthetical phrase related to P1-2 and P1-3 is intended to limit the application of the 60 calendar month exception to those situations where footnote b of the existing standards was interpreted to mean that controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element is permitted. The SDT took this position in recognition of the fact that a significant number of entities interpret footnote b in this manner and, therefore, the revised standard represents a "raising of the bar" for them.		
PJM	No	The timeframe to gather additional protection and dynamic load modeling data is too short. Millions of pieces of new data will need to be collected and validated before valid models will be available. Extend the period to 24 months.
Response: The SDT does not intend that detailed protection and dynamic Load models will be required for all Transmission elements and Loads in the System models used for the assessments. In particular, Requirement R2, part 2.4.1 states that "An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable." Furthermore, there is no explicit requirement in Requirement R1 for representation of protection schemes. To the extent such detail is needed, it would apply to the Stability studies required as part of Requirement R4. Requirements R2 and R4 are already specified to be effective in 24 months following regulatory approval.		

12. Do you believe that this standard is ready to go to ballot? (if 'No' is checked here, the SDT will consider that comments raised on the other questions drove that decision.)

Summary Consideration: The initial response of the majority of the commenters was that this standard is not ready to go to ballot. The reasons for the negative responses included: 1) a desire to have a sample detailed Planning Assessment, 2) concern over the value of the "raising the bar" for EHV Facilities, 3) concern with excessive study or documentation requirements, 4) concern that the Implementation Plan could be interpreted to require construction (contrary to the Energy Policy Act of 2005), and 5) concern that some of the requirements are not clear and contain ambiguous language. The SDT learned that some commenters voted 'No' to ensure that their comments would be reviewed and considered by the SDT. Other commenters stated that this draft was ready to go to ballot and the remaining commenters stated that it was ready for ballot with favorable consideration of the comments provided.

The SDT has responded to all of these concerns in the responses to the comments. The majority of the issues raised about unclear and ambiguous language were clarified without material changes to the draft. The SDT evaluated the comments provided in response to this draft and has determined that the majority of the remaining 'No' votes are because the commenters disagree with the position(s) taken by the SDT and not because the standard is unclear or unenforceable. The issues that were raised about increased performance requirements, increased study requirements, and increased documentation have been vetted by the industry and the SDT through four posting periods over the last 3 years.

The SDT has posted this standard for four posting periods over the last 3 years. In the previous three postings, the SDT has developed more than 1300 pages of comments and responses. The form of the main requirements and sub-parts has changed in response to industry comment, but the substance of the main requirements and sub-parts has not changed substantially in the last two postings.

The SDT has not made any substantive or contextual changes with this posting and has determined that this standard is ready to go to ballot.

Organization	Yes or No	Comments for Question 12
Sacramento Municipal Utility District		The SDT should develop a detailed sample assessment prior to balloting so that the SDT's hard work can be voted on by an informed ballot pool.
Platte River Power Authority	No	No, not until there is some form of common understanding, among the people reading this draft, of how to interpret from Table 1 (Planned and Extreme) all the contingency scenarios that will be required to demonstrate full compliance with the standard. It would be helpful if the Drafting Team spearheaded some workshops to walk us through how this might be done.
Response: The SDT agrees that it is important to have an informed ballot pool; however, the SDT does not plan to develop a sample assessment prior to balloting. The SDT has taken several steps to inform the industry and will continue those outreach efforts.		

Organization	Yes or No	Comments for Question 12
FRCC Transmission Working Group		We the FRCC TWG feel that the standard is very close to ballot, but the drafting team still needs to address several issues raised in the comments before balloting.
CenterPoint Energy	No	CenterPoint Energy is well aware of the diligence of the SDT in preparing this major consolidation and rewrite of the existing TPL standards. CenterPoint Energy believes this latest version is almost ready for ballot. CenterPoint Energy respectfully requests consideration by the SDT of the refinements to this latest draft proposed by CenterPoint Energy.
FirstEnergy Corp	No	FirstEnergy does not believe the proposed TPL-001-1 standard is ready for ballot until our primary concern with the Implementation Plan as identified in our comment to Q11 is addressed. Additionally, our most pressing secondary concern is the modeling required for Protection Systems related to 4.3.3. Finally, we believe the standard is overly burdensome related to the annual near-term study requirements as stated in 2.1.1 as noted by our Q2 comments.
SERC Dynamics Review Subcommittee (DRS)	No	If the revisions recommended above are adopted, the standard would then be ready for ballot. We commend the drafting team for their efforts in preparing this draft standard for ballot.
SERC Planning Standards Subcommittee	No	If the revisions recommended above are adopted, the standard would then be ready for ballot. We commend the drafting team for their efforts in preparing this draft standard for ballot.
Midwest ISO	No	Only if the proposed changes and questions are adequately addressed.
NorthWestern Energy	No	Since the definition section needs to be changed, some wording in the requirements needs to be modified, and the footnote numbering in Table 1 need to be corrected, we believe another draft should be issued before taking this standard to ballot.
US Bureau of Reclamation	No	The definitions require revisions. Additional work is required to clarify Corrective Action plan items, agreement on votlage limits and acceptable deviations, as well as coordination of Planning Assessment results with owner entities.
SRC of ISO/RTO	No	The proposed changes and comments need to be adequately addressed before any ballot.
Independent Electricity System Operator	No	The standard has become overly prescriptive and unnecessary (see our comments under Q2, Q3 and Q4 on Part 2.1.4, Parts 3.3 to 3.6, Parts 4.3 to 4.5. Much work is needed to condense or remove these requirements.
Hydro-Québec TransEnergie (HQT)	No	There are still issues as indicated in the submitted comments that need to be addressed before this standard should go to ballot.
Northeast Power Coordinating	No	There are still issues as indicated in the submitted comments that need to be addressed before this standard

Organization	Yes or No	Comments for Question 12
Council--RSC		should go to ballot.
Orlando Utilities Commission	Yes	I have not seen all the comments of other entities, so there may be some comments that would require the standard be reposted. Assuming I have correctly read the standard, all of my comments would improve the communication of the existing intent, not alter the requirement.
American Electric Power	Yes	The SDT has done an exceptional job working through complex issues and varying perspectives to arrive at this solid draft. This version has significantly improved the standard and has raised the bar where appropriate to do so. With favorable consideration of comments from this round, the revised draft should be ready for ballot.
Duke Energy	Yes	Yes, assuming our comments are addressed effectively.
American Transmission Company	Yes	Yes, if the proposed changes and questions are adequately addressed.
Response: Please see the comment responses for each question to see how the SDT addressed the issues raised in your comments.		
Xcel Energy	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different.
Response: The SDT agrees that some planning events will result in the same elements being removed from service. However, the similarities may only be valid from a steady-state view point and care must be taken to review the events in the Stability timeframe due to delayed clearing modes that may result from the initiating event. For example, a bus fault and a stuck breaker may each clear a bus; however, the stuck breaker will have different reaction times due to the delayed clearing mode and therefore may warrant a review in a Stability environment. The standard allows the Transmission Planner and Planning Coordinator flexibility in using engineering judgment for the Table 1 events in which it studies for both the steady-state and Stability environments. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission Planner/Planning Coordinator can justify that certain events are duplicative for a given timeframe then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System.		
SCE&G	No	As per our comments.
British Columbia Transmission Corp	No	
Florida Power and Light	No	
Manitoba Hydro	No	

Organization	Yes or No	Comments for Question 12
Northeast Utilities	No	
Pepco Holdings, Inc. - Affiliates PHI	No	
Progress Energy Florida, Inc.	No	
United Illuminating	No	
PJM	No	
Bonneville Power Administration	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.
Idaho Power	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, I believe modifications are necessary prior to taking this standard to ballot.
Modesto Irrigation District Transmission Planning	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.
NV Energy	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.
Pacific Gas and Electric Co.	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.
Puget Sound Energy, Inc.	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.
San Diego Gas & Electric Co	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.

Organization	Yes or No	Comments for Question 12
Southern California Edison (SCE)	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.
Utility System Efficiencies, Inc. (USE)	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, I believe additional modifications are necessary prior to taking this standard to ballot.
Western Area Power Adm - RMR	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, I believe modifications are necessary prior to taking this standard to ballot.
Deseret Power	No	Comments: Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.
SRP	No	: Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.
Response: Please see the comment responses for each question to see how the SDT addressed the issues raised in your comments, including the clarifications that the SDT made concerning the Table 1 outages and footnotes.		
Ameren	No	Certainly the proposed assessment and documentation requirements are more comprehensive and the performance standards are more rigorous than the existing TPL-001 through TPL-004 reliability standards. But, by performing the proposed additional required studies and documenting the results, how much additional reliability will be provided to the System? None, but we will be auditably compliant. More planning engineers will need to be hired to perform the studies and develop the assessments, more librarians will need to be hired to keep track of all the paperwork and computer file storage, and more trees will be killed printing the paper to send to all those that need to review the documents and provide comments. Is this the most effective way to improve transmission system reliability from a planning perspective? What measurable benefits are to be accrued for providing an EHV system that would not result in the loss of non-consequential load for P2-2, P2-3, P4 1-5, and P5 1-5 planning events, all of which are rare and infrequent? What is the estimated cost for this incremental "improvement" to cover the System's short-comings? The EHV system is already the most reliable portion of the BES with an availability of approximately 99% and can withstand extreme events without widespread outages.
Response: The SDT believes that the added clarity of the proposed standard is very important to ensure that entities can clearly understand the requirements. Even though EHV outages are less frequent than outages of lower voltage Transmission Facilities, the SDT believes that there should not be Non-Consequential Load Loss		

Organization	Yes or No	Comments for Question 12
for the single Contingencies in P2 and for the failure of a circuit breaker or Protection Systems in the P4 and P5 events.		
ITC Holdings	No	Comments: In addition to our other comments, ITC offers the following feedback. The requirements are rather complex, yet the measures seem extremely simple. Have they been discussed in any detail and are they sufficiently described to insure and understanding of just what is expected (ie., Are the requirements sufficient as measures in and of themselves?) R2.1.5 for example discusses "spare equipment strategy for long-lead time facilities". If I have a 2p.u. xfmr, can I assume it spares all similar category transformers or would I have to study P0,P1 and P2 contingencies if it replaces a 3 p.u. xfmr. If I don't have a spare and can't meet P0,P1 or P2 contingencies without load shedding, do I need a CAP. See also our comments under R3.4.1. We haven't reviewed all requirements and all measures in this fashion but suggest the SDT do so.
Response: The SDT has reviewed the measures and believe that they are sufficient to measure compliance with the requirements. The issues raised about transformer assumptions are System specific and are, therefore, not addressed by the standard. If you do not have a spare for a piece of equipment with a long lead time and your System cannot meet the performance requirements without that piece of equipment, you must have a Corrective Action Plan to address that deficiency. Part 3.4.1: See response to Q3.		
ERCOT ISO	No	ERCOT recognizes that much effort has been put into this standard. However, a lot of effort will be required to ensure documentation for the standard is sufficient, yet the benefit of the additional documentation effort required is marginal. For a standard like this, stating every possible issue and studying every possible scenario is not realistic and potentially will lead to complacency very little planning outside the scope of this standard will be done regardless of the system needs.
Response: The SDT has attempted to clarify areas where the existing standard is ambiguous. In this effort to clarify, the SDT has introduced new areas where documentation is required; however, in most instances, this documentation was already implicitly required. The SDT believes that it has limited the documentation requirements to the minimum required to ensure thorough evaluation of BES reliability. While the SDT has expanded the scenario analysis required with additional study year requirements and sensitivity requirements, the SDT has not developed an exhaustive list of studies or analysis that the planner must conduct. The SDT believes that the requirements contained within the standard are the minimum requirements necessary to evaluate BES reliability, while continuing to give the planner latitude in the portfolio of studies that the planner will conduct.		
NERC System Protection and Control Subcommittee (SPCS)	No	Inclusion of the changes proposed by the System Protection and Control Subcommittee (SPCS) drove the belief that the standard is not ready to go to ballot. Such changes would be substantial enough to invoke another round of comments by the Industry.
Response: Please see the comment responses for each question to see how the SDT addressed the issues raised in your comments. The SDT has not made substantial changes based on the comments.		
Central Maine Power Company	No	It is closer, but there are still some unacceptable issues that need to be addressed.

Organization	Yes or No	Comments for Question 12
ISO New England	No	It is closer, but there are still some unacceptable issues that need to be addressed. The single most important comment is to define the base assumptions for use in studies.
National Grid	No	It is closer, but there are still some unacceptable issues that need to be addressed.
Response: The SDT has made changes based on the comments. Please see the individual comment responses to see how the SDT addressed the issues raised in your comments.		
MAPP	No	MAPPCOR urges the SDT to modify the effective date where it is indicated that any "entity that cannot fully implement its Corrective Action Plan to eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for the above listed performance elements within 60 calendar months of the compliance date for Requirements R2 through R4 shall self report itself as being unable to meet the performance requirements of this Reliability Standard." This is essentially requiring an entity to self report for failing to build facilities. The Energy Policy Act of 2005 did not give FERC and therefore, NERC, the authority to require construction of electric facilities. Therefore, this implementation plan is implying an authority that is not given to FERC or NERC. This provision of the effective date should be completely deleted from the standard, the provision to state that one is non-compliant for this should be deleted from the standard, or there should be a statement that such a requirement is subject to limitations of the Energy Policy Act of 2005.
Response: The SDT has modified the language in the Implementation Plan to address this concern. Additionally, the last paragraph of the effective date section of the standard was eliminated to address this concern.		
NERC Standards Review Subcommittee	No	More discussion is needed pertaining to this standard.
Response: The SDT believes with the clarifications made in Draft 5 that the standard is ready for ballot.		
Portland General Electric Co.	No	PGE believes that this standard should not go to ballot without revisions to restrict the scope of the standard as outlined above.
Response: The SDT has not restricted the standard to Facilities >200 kV, as proposed in your comment to Q2. The Facilities that make up the Bulk Electric System (BES) are defined by each Regional Entity and this standard must address all of the BES Facilities to ensure reliability of the BES.		
NYISO	No	Question #12 Do you believe that this standard is ready to go to ballot? (if "No" is checked here, the SDT will consider that comments raised on the other questions drove that decision.) No. Too many significant questions and key definitions remain unanswered.

Organization	Yes or No	Comments for Question 12
		Table 1 - General comment - Footnotes needs significant clean-up Page 16 Note (a) this note is placed under "Steady State & Stability" but issues of voltage instability, cascading outages, and uncontrolled islanding apply only to stability Note (f) Does this refer to "Normal Ratings"? Please provide clarity. Note (g) "System steady state" should be defined by applicable regional entity. Note (i) indicates that one cannot meet steady state requirements by depending on end-user owned equipment. Please clarify the purpose and performance requirement on this note with respect to end-user schemes and possible arrangements already in place to trip end-user equipment. Page 17 P5 As written, this requirement replicates a fault causing a loss of station anywhere that there is only one protection system. This is overly severe and would lead to the requirement for fully redundant protection systems at many stations. Page 18 P7 for Event 1 (the loss of two adjacent circuits), this needs to specify if these are the same phase or different phasesPage 19How could any system planner reasonably and accurately portray what contingencies might occur from any single or combination of extreme events listed? PAGE 20 Is the one mile exclusion in footnote 14 a contiguous mile, or a total of one mile for the entire length of the lines? (i.e. Are multiple instances of common towers or common rights of way exempt if each instance is less than a mile?)General Comment:The NYISO would like to align itself in supporting the following comment submitted by the NPCC: We agree with the SDT that more stringent performance requirements be applied for Facilities that do not directly serve end-use Load customers but rather represent the backbone of the electric power grid and act as the medium for moving large amounts of power from production to various Load centers.However, as HQT commented on previous draft, we strongly believe that the EHV breakpoint for these more stringent requirements, defined in note 3 of table 1 as "all Facilities greater than 300 kV" is not appropriately defined and should be reviewed. The SDT have not demonstrated that a uniform voltage-level threshold could adequately covers all different power system types in North America and we strongly believe that significant additional costs will be incurred without proportional or measurable reliability benefits if this definition is not changed.We propose to modify EHV definition "all Facilities greater than 300 kV" by the following "Facilities representing the backbone of the System, generally at voltage greater than 300 kV, as determined by the Planning Coordinator and approved by Regional Entity." In using such a language, we believe that the extra investment required would go towards real improvement of the reliability of the interconnected System.

Response: Footnote references were corrected.

The SDT does not agree that Header Note "a" should only apply in the Stability section, since these conditions should not be allowed to occur in any timeframe.

Header Note "f" is not limited to normal ratings. Facility Ratings are defined in the NERC Glossary as: The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility. Since these ratings are time

Organization	Yes or No	Comments for Question 12
dependent, a rating higher than a normal rating can be utilized, as long as Header Note "e" is maintained. Header Note "g" – The SDT believes that it is appropriate for each Transmission Planner and Planning Coordinator to define the acceptable Steady state voltages. Header Note "i" – The purpose of the restriction is to ensure that the planner develops the System so that all of the Load, including voltage sensitive Load, can be served after an event. The P5 event is a Category C event in the existing Table, and the SDT changed the requirement for >300 kV so that Non-Consequential Load Loss is not acceptable. For the P7 event, it is the responsibility of the planner to evaluate the loss of adjacent circuits as the planner believes is appropriate for their System. For footnote 14, the SDT intends to limit the exposure for multiple circuits to less than 1 mile total. It does not matter whether the exposure is contiguous or not. The SDT declines to add "generally" to the requirements that apply to Facilities operated at greater than 300 kV as that would make the requirements unmeasurable.		
Lakeland Electric	No	The effective section needs more clarification:The assessment and supporting studies in accordance with the new standard is not effective until two years after this new standard is approved, however, it is required (R8) that PCs and TPs distribute its planning Assessment and results to adjacent PCs and TPs one year after the standard is effective. Which standard does the SDT intend for the (the old TPL standards or the new TPL standard) PCs and TPs to use to assess their system during the first year after the standard is approved? R2 thru R7 (assessments and studies) becomes effective 2 yrs after regulatory approval. That means that utilities have three years left to build/upgrade the projects identified in the studies/assessment (which was not effective until the 2nd year). Three years might not be enough to build long EHV or HV lines to meet the standard requirement.What happens between year 5 and year 7? After year 5, utilities are not allowed to trip Non-Consequential Load or curtailment of Firm Transmission Service for those specific contingency listed. However, the utilities do not have to self report until year 7 ("60 months of the compliance date for R2 through R4")
Response: A number of commenters pointed out a typographical error that reversed the numbering of Requirements R7 and R8 in the Implementation Plan. The implementation plan has been corrected to reflect the SDT's original intent that Requirements R1 and R7 (not Requirement R8) become effective 12 months after approval and Requirements R2 through R6 plus Requirement R8 (not Requirement R7), with the noted exceptions, become effective 24 months after approval. Changes were made to the Standard and the Implementation Plan document. Consequently, the revised assessment requirements and Requirement R8 are all effective 24 months after applicable regulatory approval. During the one-year period after Requirements R1 and R7 become effective and before the remaining requirements become effective, Transmission Planners and Planning Coordinators should conduct their assessments based on the current requirements. The SDT considered the concerns of a number of commenters as to whether 60 months will be sufficient to complete major projects when TPL-001-1, draft 3 was prepared, and the SDT again discussed its position in light of the comments received from this posting. The SDT continues to believe that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. The current draft of TPL-001-1 does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.3 would apply. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the		

Organization	Yes or No	Comments for Question 12
Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. ….” This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner’s or Planning Coordinator’s control. All parts of the revised standard will be in effect 60 months after applicable regulatory approval, so there are no unique requirements that exist only between year 5 and year 7.		
Tri-State Generation and Transmission Association	No	The SDT needs to look at the Measures section more closely. Please consider: In what jurisdiction could it be developed, and would it be possible to develop estimates of costs to meet the new requirements contained in this draft TPL by Reliability Area, then have utilities examine whether there will be a corresponding increase in Bulk Transmission System reliability?The primary directive of NERC Reliability Standards is to improve system reliability and thus minimize potential cascading of the Bulk Electric System. This developing TPL Standard will provide some needed clarification and perhaps better uniformity of Planning Study work. Any Standard that would move us toward the primary goal should be attended to meticulously. The SDT must endeavor to ensure this standard moves us in that direction and does not simply give us more structure. That said, please use this guiding test as we put final touches on this standard: Will each Requirement decrease the potential of cascading outages and increase service reliability?
Response: Throughout the development process, the SDT has been cognizant of the changes in the requirements and their potential impact on BES reliability. The SDT believes that all of the requirements and their sub-parts contained in this standard address the NERC directive of ensuring Bulk Electric System reliability.		
Oklahoma Gas & Electric	No	This document needs to be cyrstal clear because of compliance requirements. It still needs some work to clarify some definitions and address duplication of work (between the Transmission Planner and Planning Coordinator).
Response: The SDT has worked diligently to make the requirements very clear and unambiguous. See responses to Q9 for changes made to the definitions in this draft. The SDT has written the standard such that each Transmission Planner and each Planning Coordinator is responsible for each requirement and its sub-parts.		
TVA System Planning	No	TVA is very concerned about the tremendous amount of additional work that has been proposed for both the steady state and for stability analysis. TVA believes that there will be very little payoff for these additional studies. TVA is concerned that the costs to meet the new requirements contained in this draft TPL will amount to between $1 billion to $2 billion with very little impact overall on the reliability of the Bulk transmission system. TVA is also very concerned about the increase in customer rates that will be required to support these new facilities.
Response: The SDT has made efforts to ensure that new study requirements in the proposed standard contribute to the completeness of Planning Assessments and remove the ambiguity in the existing standards. The SDT believes that the higher performance requirements are necessary to ensure a reliable BES.		
Gainesville Regional Utilities	Yes	
Oncor Electric Delivery	Yes	

Organization	Yes or No	Comments for Question 12
Progress Energy Carolinas	Yes	
Southern Company	Yes	
TIS	Yes	
Exelon Transmission Planning	Yes	Concern is with the issues raised in Question 2. Performance requirements should be based on the voltage level of the overloaded element.
Response: Please see the comment responses for Q2 to see how the SDT addressed the issues raised in your comments. The SDT disagrees that the voltage level of the overloaded element should be used to determine acceptable performance.		
Lafayette Utilities System	Yes	LUS believes that the current draft of the standard is a significant improvement on the previous draft, and that the standard is ready to go to ballot. While there are elements of the standard which we consider to be short of the ideal, we recognize that this has been a consensus-building process and that the version 4, as explained and clarified, is a compromise which may be the best attainable for the industry at the moment.
Response: Thank you for your comment.		

VRF and VSL Statement for Project 2006-02: Assess Transmission Future Needs

The proposed reliability standard includes Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") that are specific to individual Requirements. The ranges of penalties for violations of standards are based on the applicable VRFs and VSLs and will be administered based on the Sanctions Table and supporting penalty determination process described in FERC-approved NERC Sanction Guidelines, Appendix 4B in NERC's Rules of Procedure. The assignment of VRFs and VSLs included consideration of the NERC guidelines. Consistent with NERC's August 10, 2009 informational filing, assignments of VRFs and VSLs were made at the main requirement level of each standard.

VRF assignments were based on the criteria stated in the guidelines:

- High — A requirement that, if violated, could directly cause or contribute to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
- Medium — A requirement that, if violated, could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of a medium risk requirement is unlikely to lead to BES instability, separation, or cascading failures.
- Low — A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. A requirement that is administrative in nature.

Utilizing these criteria, the VRFs for TPL-001-1 were assigned as follows:

- Since this is a planning standard, dealing with items in the Long-term Planning Timing Horizon, no requirements were assigned a high VRF.
- A medium VRF was assigned to those requirements dealing with the Planning Assessment and its constituent parts. Therefore, a medium VRF was assigned to Requirements R1 through R5. .
- A lower VRF was assigned to Requirements R6, R7, and R8 which were seen as mainly administrative in nature.

VSLs have been assigned consistent with the established guidelines as can be seen in the following table.

TPL-001-1				
R#	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	This is a new requirement and is more stringent than previous performance.	The VSLs are clear and unambiguous and can only be interpreted one way. The VSLs cover all possible scenarios.	The VSLs do not add to the requirement and cover all elements of the requirement	The VSLs are based on a single violation and not cumulative violations.
R2.	This is a new requirement and is more stringent than previous performance.	The VSLs are clear and unambiguous and can only be interpreted one way. The VSLs cover all possible scenarios.	The VSLs do not add to the requirement and cover all elements of the requirement	The VSLs are based on a single violation and not cumulative violations.
R3.	This is a new requirement and is more stringent than previous performance.	The VSL is binary and the only possibility is Severe.	The VSLs do not add to the requirement and cover all elements of the requirement	The VSLs are based on a single violation and not cumulative violations.
R4.	This is a new requirement and is more stringent than previous performance.	The VSLs are clear and unambiguous and can only be interpreted one way. The VSLs cover all possible scenarios.	The VSLs do not add to the requirement and cover all elements of the requirement	The VSLs are based on a single violation and not cumulative violations.
R5.	This is a new requirement and is more stringent than previous performance.	The VSL is binary and the only possibility is Severe.	The VSLs do not add to the requirement and cover all elements of the requirement	The VSLs are based on a single violation and not cumulative violations.

TPL-001-1				
R#	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	This is a new requirement and is more stringent than previous performance.	The VSL is binary and the only possibility is Severe.	The VSLs do not add to the requirement and cover all elements of the requirement	The VSLs are based on a single violation and not cumulative violations.
R7.	This is a new requirement and is more stringent than previous performance.	The VSL is binary and the only possibility is Severe.	The VSLs do not add to the requirement and cover all elements of the requirement	The VSLs are based on a single violation and not cumulative violations.
R8.	This is a new requirement and is more stringent than previous performance.	The VSLs are clear and unambiguous and can only be interpreted one way. The VSLs cover all possible scenarios.	The VSLs do not add to the requirement and cover all elements of the requirement	The VSLs are based on a single violation and not cumulative violations.

Source	Standard No.	Project No	Language	Resolution
FERC Order 693	TPL Family	2006-02	1691 - Further, the proposed modifications are intended to ensure that the planning requirements are specific enough to promote rigor and consistency in assessments and provide clear and measurable rules for mandatory and enforceable Reliability Standards. The Commission therefore agrees with SDG&E's comments in this regard and on the need to balance "appropriateness" and "specificity."	TPL-001-1, Requirements R1-R8 & Table 1 - The standard strikes the desired balance between specific requirements (for example, Table 1 event descriptions and performance requirements) and appropriateness where the individual System concerns necessitates variations (for example, Requirement R2, part 2.4.3 addressing what sensitivities should be addressed) so that the standard ensures reliability is maintained
FERC Order 693	TPL Family	2006-02	1692 - Consider integrating TPL-001 through TPL-004 into one standard.	TPL-001-1 incorporates TPL-001-0 through TPL-004-
FERC Order 693	TPL Family	N/A	1693 -Submit an informational filing, in addition to regional criteria, all utility and RTO/ISO differences in transmission planning criteria that are more stringent than those specified by the TPL standards.	The data has been collected and distributed to the SDT and reviewed for consideration. Detailed discussions are contained in the SDT meeting minutes.
FERC Order 693	TPL Family	2006-02	1694, 1704, & 1706 - Consider the full range of variables when determining critical system conditions but only those deemed to be significant need to be assessed and documentation provided that explain the rationale for selection.	TPL-001-1, Requirement R3, part 3.4 & Requirement R4, part 4.4
FERC Order 693	TPL Family	2006-02	1716 - System performance should be assessed based on contingencies that mimic what happens in real-time.	TPL-001-1, Requirement R1
FERC Order 693	TPL Family	2006-02	1719 - Consider appropriate revisions to the reliability standards to deal with cyber security events.	Cyber security events have been added to the list of Extreme Events as #3a.v
FERC Order 693	TPL Family	N/A	Entities that have planned and designed their systems on the basis of a different approach to single contingencies should work with NERC in developing plans to transition to this new approach.	This is not an SDT issue. No action taken.
FERC Order 693 – TPL General Comments	TPL-001-0	2006-02	1693 - Submit an informational filing, in addition to regional criteria, all utility and RTO/ISO differences in transmission planning criteria that are more stringent than those specified by the TPL standards.	The data has been collected and distributed to the SDT and reviewed for consideration. Detailed discussions are contained in the SDT meeting minutes.
FERC Order 693	TPL-001-0	2006-02	1694, 1704, & 1706 - Determine critical system conditions and study years by conducting sensitivity analysis with due consideration of the factors outlined by the Commission.	TPL-001-1, Requirement R2, part 2.1.4
FERC Order 693 – TPL General Comments	TPL-001-0	2006-02	1694, 1704, & 1706 - Consider the full range of variables when determining critical system conditions but only those deemed to be significant need to be assessed and documentation provided that explain the rational for selection.	TPL-001-1, Requirement R3, part 3.4 & Requirement R4, part 4.4

Source	Standard No.	Project No	Language	Resolution
FERC Order 693 – TPL General Comments	TPL-001-0	2006-02	1716 - System performance should be assessed based on contingencies that mimic what happens in real-time.	TPL-001-1, Requirement R1
FERC Order 693 – TPL General Comments	TPL-001-0	2006-02	1719 - Consider appropriate revisions to the reliability standards to deal with cyber security events.	Cyber security events have been added to the list of Extreme Events as #3a.v
FERC Order 693	TPL-001-0	2006-02	1751 - Require a peer review of planning assessments with neighboring entities	TPL-001-1, Requirement R3, part 4.1, R4, part 4.2 and Requirement R8: R3 and R4 address the concern expressed about sharing and coordination of System Contingencies that may affect neighboring Systems. Order 693 uses the term 'neighboring' while the proposed Reliability Standard uses 'adjacent'. 'Adjacent' is actually a more encompassing term as it would pick up embedded cooperatives, municipals, etc., and thus is more stringent than the Order 693 terminology. Additionally, the term 'adjacent' clarifies the intent to cover Transmission Systems that interconnect to the entity System whereas neighbor is vague and could include Systems in the vicinity of an entity's System, but not directly connected.
			Continuation of 1751	Requirement R8 continues to address the appropriate sharing of information with neighboring Systems. Distribution is a better approach than just a peer review as an entity could always decline an offer to participate in a peer review even if they should have participated. The distribution approach means that they will receive the Planning Assessment regardless. R8 ensures that information is shared with those affected and input from those Systems is received, without dictating how the two-way sharing must take place, such as peer review. Due to the continuing cycle of Planning Assessments, comments from other entities at the end of a planning cycle will be utilized at the beginning of the next cycle as the planner moves forward in time. This approach tells entities what to do without stating how to do it but still makes certain that the goal is achieved. This is

Source	Standard No.	Project No	Language	Resolution
			Continuation of 1751	To cover those “neighboring” Systems that may not be adjacent, the standard requires the Transmission Planner and Planning Coordinator to distribute the Planning Assessment to additional “neighbors” who show a “reliability related need” who have requested information in writing and requires a documented response to their comments. This is an equally, effective manner to provide for the appropriate sharing of
FERC Order 693	TPL-001-0	2006-02	1759 - Modify requirement R1.3 to substitute the reference to regional reliability organization with regional entity.	References to RRO have been removed
FERC Order 693	TPL-001-0	2006-02	1786 - Require assessments of outages of critical long lead time equipment, consistent with an entity’s spare equipment strategy	TPL-001-1, Requirement R2, part 2.1.5
FERC Order 693	TPL-001-0	2006-02	1797 - Address concerns with footnote (a) of Table 1 with regard to applicability of emergency ratings and consistency of normal ratings and voltages with values obtained from other reliability standards and concerns raised by International Transmission with reg	TPL-001-1, Table 1, header note 'e'
FERC Order 693 – TPL General Comments	TPL-001-0	2006-02	Entities that have planned and designed their systems on the basis of a different approach to single contingencies should work with NERC in developing plans to transition to this new approach.	This is not an SDT issue. No action taken.
FERC Order 693 – TPL General Comments	TPL-001-0	2006-02	Consider integrating TPL-001 through TPL-004 into one standard.	TPL-001-1 incorporates TPL-001-0 through TPL-004-0
Fill in the Blank Team	TPL-001-0	2006-02	No action needed	No action taken.
Other	TPL-001-0	2006-02	Modify standard to conform to the latest version of NERC’s Reliability Standards Development Procedure, the NERC Standard Drafting Team Guidelines, and the ERO Rules of Procedure.	The SDT is working against the latest set of procedures
Phase III/IV Team	TPL-001-0	2006-02	Add a requirement to verify that there are sufficient reactive resources	TPL-001-1, Requirement R1, part 1.1.3
Phase III/IV Team	TPL-001-0	2006-02	Add a requirement to identify where UVLS should be installed	Not considered appropriate for TPL-001-1
Team Comments	TPL-001-0	2006-02	Provide clarity where the Planning Authority is mentioned	Planning Authority is now Planning Coordinator and clarity has been provided in each requirement as needed
Version 0 Team	TPL-001-0	2006-02	Need to address deliverability to load	TPL-001-1, Table 1, Footnote 10

Source	Standard No.	Project No	Language	Resolution
Version 0 Team	TPL-001-0	2006-02	Clarify use of applicable ratings in Table 1, note 'a'	TPL-001-1, Table 1, header note 'e'
Version 0 Team	TPL-001-0	2006-02	Clarify timing for submittal of corrective plan	TPL-001-1, Requirement R2, part 2.7
Version 0 Team	TPL-001-0	2006-02	Several semantic issues	The standard has been compeletly rewritten.
Version 0 Team	TPL-001-0	2006-02	Define critical system conditions	This terminology is no longer used.
Version 0 Team	TPL-001-0	2006-02	Having all projected firm transfers modeled may not be practical to achieve in a single shapshot of a powerflow model. The requirement should allow engineering judgment to determine the appropriate level of system utilization to assess reliability considering all projected firm uses.	TPL-001-1, Requirement R1
Version 0 Team	TPL-001-0	2006-02	Table 1, note 'b' – clarify when to curtail firm deliveries	TPL-001-1, Table 1, Interruption of Firm Transmission Service Allowed column added
Version 0 Team	TPL-001-0	2006-02	Table 1 – C.5 goes beyond double circuit outage criteria	TPL-001-1, Table 1, P7
Version 0 Team	TPL-001-0	2006-02	Does planned facilities include just those under construction?	This terminology has been cleared up in TPL-001-1, Requirement R1, part 1.1.2
Version 0 Team	TPL-001-0	2006-02	Table 1, items 6, 7, 8 & 9 need footnote stating that they do not apply to generator breaker failure	Table 1 has been rewritten
Version 0 Team	TPL-001-0	2006-02	Need to include multiple time frames	TPL-001-1, Requirement R2
Version 0 Team	TPL-001-0	2006-02	What is a major load center?	This terminology is no longer used.
VRFs Team	TPL-001-0	2006-02	R1 – time horizon should be long-term planning	All time horizons have been adjusted to Long-term Planning.
FERC Order 693	TPL-002-0	2006-02	1694, 1704, & 1706 - Determine critical system conditions in the same manner as proposed in TPL-001.	This terminology is no longer used.
FERC Order 693	TPL-002-0	2006-02	1773 - Footnote (b) should not allow for firm load shedding or curtailment of firm transfers as part of the system adjustments.	TPL-001-1, Table 1, P1 - associated footnote has been removed
FERC Order 693	TPL-002-0	2006-02	1773 - Clarify the phrase "permit operating steps necessary to maintain system control" in the footnote (a) and the use of emergency ratings.	TPL-001-1, Table 1, header note 'e'
FERC Order 693	TPL-002-0	2006-02	1773 - Clarifies footnote (b) in regard to load loss following a single contingency specifying the amount and duration of consequential load loss and system adjustments permitted after the first contingency to return the system to a normal operating state. NERC	TPL-001-1, Table 1, footnote 9.

Source	Standard No.	Project No	Language	Resolution
FERC Order 693	TPL-002-0	2006-02	1786 - Requires assessment of planned outages of long lead time critical equipment consistent with the entity's spare equipment strategy.	TPL-001-1, Requirement R2, part 2.1.5
FERC Order 693	TPL-002-0	2006-02	1787 - Requires all generators to ride through the same set of category B and C contingencies as required by wind generators in Order No. 661, or to simulate without this capability as tripping.	TPL-001-1, Requirement R3, part 3.3.2 & Requirement R4, part 4.3.2
FERC Order 693	TPL-002-0	2006-02	1788 - Consider NRC's comments regarding clarifying the N-1 state as being always applicable to the current conditions as part of the standards development process.	TPL-001-1, Table 1 & Requirement R1
FERC Order 693	TPL-002-0	2006-02	1789 - Document the load models used in system studies and the rationale for their use.	TPL-001-1, Requirement R1
FERC Order 693	TPL-002-0	2006-02	1794 - Standard should be clarified to not allow an entity to plan for the loss of non-consequential load in the event of a single contingency.	TPL-001-1, Table 1, P1
FERC Order 693	TPL-002-0	2006-02	1795 - Commission, therefore, suggests that the ERO consider developing a ceiling on the amount and duration of consequential load loss that will be acceptable. If the ERO determines that such a ceiling is appropriate, it should be developed through the ERO's Reliability Standards development process	and duration and if it "is appropriate" to develop the ceiling through the standards development process. Originally, the SDT debated the appropriateness and the need for a ceiling and after much debate determined that a single ceiling was not appropriate for the continent-wide standard. The SDT was divided on the reliability need for this item and vetting with industry was determined to be the best course of action. The directive was then further addressed in other stages of the project to determine if another equally effective method could be developed. The SDT added requirements covering the reporting of the magnitude and duration of Consequential Load Loss. In earlier postings, industry overwhelming protested the
			Continuation of 1795	duration than magnitude so the SDT attempted a compromise position. The duration element of the requirement was deleted and a revised requirement covering only magnitude was crafted and posted for comment. Again, the SDT was overwhelmed by industry comments pushing back about the inclusion of an administrative task without a reliability need in a Reliability Standard. At this point, the SDT discussed the matter at length and decided to delete the requirement in its entirety. The SDT addressed the directive to "consider developing a ceiling" as directed in Order 693 as evidenced in meeting notes and by its attempt to include the requirements for an equally effective method in the Reliability Standard. Therefore, the SDT
Fill in the Blank Team	TPL-002-0	2006-02	No action required	No action taken

Source	Standard No.	Project No	Language	Resolution
Phase III/IV Team	TPL-002-0	2006-02	Add a requirement to verify that there are sufficient reactive resources	TPL-001-1, Requirement R1, part 1.1.3
Phase III/IV Team	TPL-002-0	2006-02	Add a requirement to identify where UVLS should be installed	Not considered appropriate for TPL-001-1
Team Comments	TPL-002-0	2006-02	Provide clarity where the Planning Authority is mentioned	Planning Authority is now Planning Coordinator and clarity has been provided in each requirement
Version 0 Team	TPL-002-0	2006-02	Must study all contingencies and multiple demand levels & time frames	TPL-001-1, Requirement R3, part 3.4 &Requirement R4, part R4.4, & Requirement R2
Version 0 Team	TPL-002-0	2006-02	Define critical system conditions	This terminology is no longer used.
Version 0 Team	TPL-002-0	2006-02	Clarify timing for corrective plan	TPL-001-1, Requirement R2, part2.7
Version 0 Team	TPL-002-0	2006-02	Address deliverability of generation to load	TPL-001-1, Table 1, Footnote 9
Version 0 Team	TPL-002-0	2006-02	Don’t include generation runback or redispatch	Clarified usage in TPL-001-1, header note 'e & footnote 9
Version 0 Team	TPL-002-0	2006-02	Don’t include planning outage	Clarified in TPL-001-1, Requirement R1, part 1.1.1
Version 0 Team	TPL-002-0	2006-02	Single terminals are not included	Clarified in TPL-001-1, Table 1, P2.1 & footnote 8
Version 0 Team	TPL-002-0	2006-02	Clarify applicable ratings in Table 1, note ‘a’	TPL-001-1, Table 1, header note 'e'
VRFs Team	TPL-002-0	2006-02	Time horizon should be long-term planning and R2.2 – redundant with R1.3.8	All time horizons have been adjusted to Long-term Planning.
FERC Order 693	TPL-003-0	2006-02	1765 - Determine critical system conditions in the same manner as proposed in TPL-001.	TPL-001-1, Requirement R1 & Requirement R2, part 2.1.4
FERC Order 693	TPL-003-0	2006-02	1769 - Address LPPA’s concerns on changes to footnotes of Table 1 through the standard development process.	The Table & the footnotes have been completely rewritten.
FERC Order 693	TPL-003-0	2006-02	1788 - Address NRC concerns as described in TPL-002 through the standards development process.	TPL-001-1, Table 1 re-write
FERC Order 693	TPL-003-0	2006-02	1806 - Clarify the term “controlled load interruption”.	The terminology is no longer utilized.
FERC Order 693	TPL-003-0	2006-02	1820 - Applicable entities must define and document the proxies necessary to simulate cascading outages.	TPL-001-1, Requirement R6
FERC Order 693	TPL-003-0	2006-02	1821 - Tailor the purpose statement to reflect the specific goal of the standard.	The purpose statement of TPL-001-1 has been rewritten.
FERC Order 693	TPL-003-0	2006-02	1824 - Consider the comments on major load pockets as part of the standards development process.	In light of these comments, the Commission does not intend to recommend action on this issue at this time. - No action taken for this revision.

Source	Standard No.	Project No	Language	Resolution
Fill in the Blank Team	TPL-003-0	2006-02	No action required	No action taken
Phase III/IV Team	TPL-003-0	2006-02	Add a requirement to verify that there are sufficient reactive resources	TPL-001-1, Requirement R1, part 1.1.3
Phase III/IV Team	TPL-003-0	2006-02	Add a requirement to identify where UVLS should be installed	Not considered appropriate for TPL-001-1
Team Comments	TPL-003-0	2006-02	Provide clarity where the Planning Authority is mentioned	Planning Authority is now Planning Coordinator and clarity has been provided in each requirement
Version 0 Team	TPL-003-0	2006-02	Don't base penalties on low probability, low consequence events	VSLs have been added
Version 0 Team	TPL-003-0	2006-02	Use NERC Compliance Reporting Process	The Compliance section has been rewritten according to the latest rules
Version 0 Team	TPL-003-0	2006-02	Same as TPL-001 & 002	See TPL-001
Version 0 Team	TPL-003-0	2006-02	Clearly identify outages	TPL-001-1, Requirement R1, part 1.1.1, Requirement R3, part 3.4, & Requirement R4, part 4.4
Version 0 Team	TPL-003-0	2006-02	Development of mitigation plans requires subsequent studies, and may actually be done by a different entity than the entity performing the assessment (the TO instead of the RTO who may have done the assessment)	Assessments are performed by Transmission Planner or Planning Coordinator
VRFs Team	TPL-003-0	2006-02	R2.2 - lack of consistency with TPL-001 & TPL-007	All VRFs have been rewritten
VRFs Team	TPL-003-0	2006-02	R2.1.3 - lack of consistency with TPL-001 & TPL-006	TPL-006 will be retired
VRFs Team	TPL-003-0	2006-02	R2.1.2 - lack of consistency with TPL-001 & TPL-005	TPL-005 is being retired
VRFs Team	TPL-003-0	2006-02	R2.1.1 - lack of consistency with TPL-001 & TPL-004	TPL-004 has been merged into TPL-001-1
VRFs Team	TPL-003-0	2006-02	Time horizon should be long-term planning	All time horizons have been adjusted to Long-term Planning.
VRFs Team	TPL-003-0	2006-02	R2.1 - lack of consistency with TPL-001	TPL-003 has been merged into TPL-001-1
VRFs Team	TPL-003-0	2006-02	R2 – lack of consistency with TPL-001 & TPL-002	TPL-003 has been merged into TPL-001-1
FERC Order 693	TPL-004-0	2006-02	1765 - Determine critical system conditions in the same manner as proposed in TPL-001.	TPL-001-1, Requirement R2, part 2.1.4
FERC Order 693	TPL-004-0	2006-02	1835 - Tailor the purpose statement to reflect the specific goal of the standard.	The purpose statement of TPL-001-1 has been rewritten.
FERC Order 693	TPL-004-0	2006-02	1836 - Expand the list of category D events to include recent actual events.	The list of Extreme Events has been expanded to include wide-area events.
FERC Order 693	TPL-004-0	2006-02	1836 - Identify options for reducing the probability or impacts of extreme events that cause cascading.	TPL-001-1, Requirement R3, part 3.5 & Requirement R4, part 4.5
Fill in the Blank Team	TPL-004-0	2006-02	No action required	No action taken
Phase III/IV Team	TPL-004-0	2006-02	Add a requirement to verify that there are sufficient reactive resources	TPL-001-1, Requirement R1, part 1.1.3

Source	Standard No.	Project No	Language	Resolution
Phase III/IV Team	TPL-004-0	2006-02	Add a requirement to identify where UVLS should be installed	Not considered appropriate for TPL-001-1
Team Comments	TPL-004-0	2006-02	Provide clarity where the Planning Authority is mentioned	Planning Authority is now Planning Coordinator and clarity has been provided in each requirement
Version 0 Team	TPL-004-0	2006-02	Same as TPL-001	See TPL-001
Version 0 Team	TPL-004-0	2006-02	Perform analysis on credible contingency	Contingencies required to be analyzed are defined in Requirement R3, parts 3.1 & 3.4 as well as Requirement R4, parts 4.1 & 4.4
Version 0 Team	TPL-004-0	2006-02	R1.3.9 – remove from extreme events	Extreme events has been rewritten.
Version 0 Team	TPL-004-0	2006-02	TO should determine which events to study	TPL-001-1, Requirement R3, parts3.1 & 3.4 & Requirement R4, parts 4.1 & 4.4
FERC Order 693	TPL-005-0	2006-02	1841 - Encourages NERC to utilize input from the Commission's technical conferences on regional planning as directed in Order No. 890 to improve this standard.	TPL-001-1, Requirement R8
Fill in the Blank Team	TPL-005-0	2006-02	New SAR needed	Supplemental SAR was written before the current SDT began work in 2007
Version 0 Team	TPL-005-0	2006-02	Define fuel adequacy	Terminology no longer employed
Version 0 Team	TPL-005-0	2006-02	An RRO can't make a mandatory request for another RRO to perform a study	All references to RRO have been removed
Fill in the Blank Team	TPL-006-0	2006-02	No action required	No action taken

Implementation Plan for TPL-001-1

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

TPL-001-1 — Transmission System Planning Performance Requirements

In revising the TPL standards, the SDT is assuming that planners will receive valid data from the MOD standards link described in TPL-001-1, Requirement R1. Furthermore, there is a tacit assumption that future revisions of the MOD standards will include steps to validate MOD based data.

Revision to Sections of Approved Standards and Definitions

There are multiple new definitions in the proposed standard.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Near-Term Transmission Planning Horizon: Transmission planning period that covers Years One through five.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.

Year One: The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.

Compliance with Standards

Standard	Functions That Must Comply With the Associated Requirements	
TPL-001-1 — Transmission System Planning Performance Requirements	Transmission Planner	Planning Coordinator
	X	X

Effective Dates

The effective date is the date entities are expected to meet the performance identified in this standard.

Except as indicated below**,** all Requirements and associated parts shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.

TPL-001-0, TPL-002-0a, TPL-003-0a, and TPL-004-0 are being retired as they are replaced in their entirety by TPL-001-1. TPL-005-0 and TPL-006-0 are being retired because their requirements are adequately covered by the revised TPL-001-1 and NERC's Rules of Procedure, Section 800. However, during this 24-month period, all aspects of TPL-001-0 through TPL-006-0 shall remain in effect for compliance monitoring. This 24 month period is to allow entities to develop, perform and/or validate new and/or modified studies, methodologies, assessments, procedures, etc. necessary to implement and meet the TPL-001-1 requirements. The specified effective dates are expected to allow sufficient time for proper assessment of the available options necessary to create a viable Corrective Action Plan that is compliant with the new Standard.

> R1. This Requirement is related to maintaining System models and the data needed to do so. This requirement shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes into effect on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.
>
> R7. This Requirement identifies an obligation to determine individual and joint responsibilities for performing studies needed to do the Planning Assessment. This requirement shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes into effect on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

TPL-001-1 'raises the bar' in several areas where performance requirements have been changed in the new Standard versus those in existing TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0 because loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain events, whereas the existing Standards were interpreted by many to allow such actions. As shown in Table 1 of TPL-001-1, the performance requirements associated with the following events represent "raising the bar":

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

This "raising the bar" is beyond the control of the Transmission Planner and Planning Coordinator and may have significant budget, siting, permitting, and construction impacts on many Transmission Owners. To provide stakeholders with sufficient time to implement changes, a timeframe coincident with the end of the Near-Term Transmission Planning Horizon will be provided as follows:

- For 60 months after the first day of the first calendar quarter following applicable regulatory approval, Corrective Action Plans applying to performance elements P1-2 and P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element), P2-1, P2-2 (above 300 kV), P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 kV) are allowed to include tripping of Non-Consequential Load and curtailment of Firm Transmission Service (in accordance with Requirement R2.7.3) that would not otherwise be permitted by the requirements of TPL-001-1.

Any entity which cannot eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for these performance elements by that date shall submit a mitigation plan to its Regional Entity outlining the steps it will take to correct the problem . If the entities follow the established ERO procedure for mitigation, it is the intent of the SDT that no penalties will be assessed.

Implementation Plan for TPL-001-1

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

TPL-001-1 —~~–~~ Transmission System Planning Performance Requirements

In revising the TPL standards, the SDT is assuming that planners will receive valid data from the MOD standards link described in TPL-001-1, Requirement R1. Furthermore, there is a tacit assumption that future revisions of the MOD standards will include steps to validate MOD based data.

Revision to Sections of Approved Standards and Definitions

There are multiple new definitions in the proposed standard.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: ~~–~~All Load that is no longer served by the Transmission ~~S~~system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Near-Term Transmission Planning Horizon: Transmission planning period that covers Years One through five.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) ~~other than~~ Consequential Load Loss, (2) ~~and~~ the response of voltage sensitive Load, or (3) ~~including~~ Load that is disconnected from the System by end-user equipment.~~.~~

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.

Year One: The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.

Compliance with Standards

Standard	Functions That Must Comply With the Associated Requirements	
TPL-001-1 — Transmission System Planning Performance Requirements	Transmission Planner	Planning Coordinator
	X	X

Effective Dates

The effective date is the date entities are expected to meet the performance identified in this standard.

Except as indicated below, all Requirements and associated ~~sub-requirements~~parts shall become effective on the first day of the first calendar quarter, 24 months after ~~the first day of the first calendar quarter following~~ applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.

TPL-001-0, TPL-002-0a, TPL-003-0a, and TPL-004-0 are being retired as they are replaced in their entirety by TPL-001-1. TPL-005-0 and TPL-006-0 are being retired because their requirements are adequately covered by the revised TPL-001-1 and NERC's Rules of Procedure, Section 800. However, during this 24-month period, all aspects of TPL-001-0 through TPL-006-0 shall remain in effect for compliance monitoring. This 24 month period is to allow entities to develop, perform and/or validate new and/or modified studies, methodologies, assessments, procedures, etc. necessary to implement and meet the TPL-001-1 requirements. The specified effective dates are expected to allow sufficient time for proper assessment of the available options necessary to create a viable Corrective Action Plan that is compliant with the new Standard.

R1. This Requirement is related to maintaining System models and the data needed to do so. This requirement shall become effective on the first day of the first calendar quarter, 12 months after ~~the first day of the first calendar quarter following~~ applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes into effect on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

R7. This Requirement identifies an obligation to determine individual and joint responsibilities for performing studies needed to do the Planning Assessment. This requirement shall become effective on the first day of the first calendar quarter, 12 months after ~~the first day of the first calendar quarter following~~ applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes into effect on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

TPL-001-1 'raises the bar' in several areas where performance requirements have been changed in the new Standard versus those in existing TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0 because loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain events, whereas the existing Standards were interpreted by many to allow such actions. As shown in Table 1 of TPL-001-1, the performance requirements associated with the following events represent "raising the bar":

- P1-2 ~~-~~(for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

This "raising the bar" is beyond the control of the Transmission Planner and Planning Coordinator and may have significant budget, siting, permitting, and construction impacts on many Transmission Owners. ~~In question 14 of the second posting of the revised standard, the SDT requested input from industry on the amount of time required to implement the Corrective Action Plans needed to address the 'raise the bar' issues. The SDT has studied the responses and determined that~~ To provide stakeholders with sufficient time to implement changes, a timeframe coincident with the end of the Near-Term Transmission Planning Horizon ~~would be the appropriate~~will be provided as follows:~~ amount of time to implement the changes. Therefore,~~

- F~~f~~or 60 months after the first day of the first calendar quarter following applicable regulatory approval, Corrective Action Plans applying to performance elements P1-2 and P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element), P2-1, P2-2 (above 300 kV), P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 kV) are allowed to include tripping of Non-Consequential Load ~~or~~and curtailment of Firm Transmission Service (in accordance with Requirement R2.7.3) that would not otherwise be permitted by the requirements of TPL-001-1.

Any entity which cannot ~~fully implement their Corrective Action Plan to~~ eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for these performance elements by that date shall ~~self report themselves as being unable to meet the performance requirements of the Reliability Standard. The entities will~~ submit a mitigation plan to ~~their~~ its Regional Entity outlining the steps ~~they~~ it will take to correct the problem ~~to become compliant and the date they anticipate becoming compliant~~. ~~The Regional Entity and NERC will review the mitigation plan and the Regional Entity/NERC will either approve it or remand it back for changes (this could include dates, steps, etc.). If the mitigation plan is approved by the Regional Entity and NERC and the entity completes the mitigation plan by the date contained within the~~

~~mitigation plan,~~ If the entities follow the established ERO procedure for mitigation, it is the intent of the SDT that no penalties will be assessed. ~~Those entities who do not meet the date outlined in the mitigation plan will begin settlement proceedings at that date.~~

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Version 1 of SAR posted for comment from April 2, 2002 through May 3, 2002.
2. Version 2 of SAR posted for comment from May 5, 2004 through June 5, 2004.
3. Version 3 of SAR posted on November 18, 2005.
4. SAR approved on April 30, 2006.
5. Version 1 of Supplemental SAR posted for comment from February 15, 2007 through March 16, 2007.
6. Version 2 of Supplemental SAR posted on April 9, 2007.
7. Version 1 of revised standard(s) posted for comment on September 17, 2007.
8. Version 2 of the revised standards posted for comment on August 15, 2008.
9. Version 3 of the revised standards posted for comment on May 26, 2009.
10. Version 4 of the revised standards posted for comment on September 16, 2009.

Proposed Action Plan and Description of Current Draft:

The SDT has established a schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 1Q10. The current draft is the second iteration of the revision of existing standards TPL-001 through TPL-006 and includes one revised standard, TPL-001-1, replacing TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. TPL-005 & -006 issues are addressed in this fifth draft and those standards will also be replaced by TPL-001-1.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Submit standard(s) to BOT.	2Q10
2. Submit to regulatory authorities for approval.	3Q10

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Near-Term Transmission Planning Horizon: Transmission planning period that covers Years One through five.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies.

Year One: The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-1**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.

   - For 60 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-1, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-1:
     - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
     - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
     - P2-1, P2-2 (above 300 kV)
     - P2-3 (above 300 kV)
     - P3-1 through P3-5
     - P4-1 through P4-5 (above 300 kV)
     - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning

Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies as indicated in Requirement R2, part 2.6:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1 with known outages modeled, as in Requirement R1, part 1.1.2 under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

- Controllable Loads and Demand Side Management.
- Duration or timing of planned Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

2.2. The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.

- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, part 2.6.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: the System represented in the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Such actions may include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention.

3.3.2. Trip generators where simulations show generator bus voltages or high side of the Generation Step Up (GSU) transformer voltages are less than known or assumed minimum generator steady state or ride

through voltage limitations. Include in the assessment any assumptions made.

3.3.3. Trip Transmission elements when relay loadability limits are exceeded.

3.3.4. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, part 4.5.

4.3. Contingency analyses for Requirement R4, parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention while also considering the impact of successful or unsuccessful high speed reclosing.

4.3.2. Trip generators where simulations show generator bus voltages or high side of the GSU transformer voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.3. Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers.

4.3.4. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4, part 4.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R4, part 4.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, any criteria or methodology used in the analysis to identify System instability for conditions such as Cascading , voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance
Planning Events

Steady State & Stability:

a. BES Transmission voltage instability, Cascading, and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any planning or extreme event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. For all planning events, planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. The System shall remain stable.

k. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial System Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No[9]	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (Non Bus-tie)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial System Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus Protection System failure to operate)*	Normal System	Failure of a single Protection System that results in Delayed Fault Clearing on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adj.[9]: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance

Extreme Events	
Steady State & Stability For all extreme events evaluated: a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency. b. Simulate Normal Clearing unless otherwise specified.	
Steady State 1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments. 2. Local area events affecting the Transmission System such as: a. Loss of a tower line with three or more circuits.[11] b. Loss of all Transmission lines on a common Right-of-Way[11]. c. Loss of a switching station or substation (loss of one voltage level plus transformers). d. Loss of all generating units at a station. e. Loss of a large Load or major Load center. 3. Wide area events affecting the Transmission System based on System topology such as: a. Loss of two generating stations resulting from conditions such as: i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation. ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants. b. Other events based upon operating experience that may result in wide area disturbances.	**Stability** 1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments. 2. Local or wide area events affecting the Transmission System such as: a. 3Ø fault on generator with stuck breaker[10] or a Protection System failure resulting in Delayed Fault Clearing. b. 3Ø fault on Transmission circuit with stuck breaker[10] or a Protection System failure resulting in Delayed Fault Clearing. c. 3Ø fault on transformer with stuck breaker[10] or a Protection System failure resulting in Delayed Fault Clearing. d. 3Ø fault on bus section with stuck breaker[10] or a Protection System failure resulting in Delayed Fault Clearing. e. 3Ø internal breaker fault. f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-Generator Step Up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure or common Right-of-Way for 1 mile or less.

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within its respective area, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of documentation specifying any criteria or methodology used in the analysis to identify System instability that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and the Planning Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient, date, and contents, or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has indicated a reliability need and has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity.

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying any criteria or methodology utilized in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as all such documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.
- Three calendar years of the notices and other documentation employed in accordance with Requirement R8 and Measure M8.

1.5 Additional Compliance Information

None.

2 Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.	The responsible entity's System model failed to represent three of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1.
R2	The responsible entity failed to comply with Requirement R2, part 2.6.	The responsible entity failed to comply with Requirement R2, part 2.3 or part 2.8.	The responsible entity failed to comply with one of the following parts of Requirement R2: part 2.1, part 2.2, part 2.4, part 2.5, or part 2.7.	The responsible entity failed to comply with two or more of the following parts of Requirement R2: part 2.1, part 2.2, part 2.4, or part 2.7.
R3	The responsible entity did not identify planning events as described in Requirement R3, part 3.4 or extreme events as described in Requirement R3, part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R3, part 3.2 to assess	The responsible entity did not perform studies as specified in Requirement R3, part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, part	The responsible entity did not perform studies as specified in Requirement R3, part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		the impact of extreme events. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.	3.3.	or P1 categories in Table 1.
R4	The responsible entity did not identify planning events as described in Requirement R4, part 4.4 or extreme events as described in Requirement R4, part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, part 4.2 to assess the impact of extreme events. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1.
R5	N/A	N/A	N/A	The responsible entity failed to define and document its criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners or adjacent Planning Coordinators, and to one functional entity that has a reliability related need and has submitted a written request for the information, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to its adjacent Transmission Planners or adjacent Planning Coordinators, and to any functional entity that has a reliability related need and has submitted a written request for the information, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	TBD	Revision of TPL-001-0 as per Project 2006-02; includes merging requirements of TPL-001-0, TPL-002-0, TPL-003-0, TPL-004-0, TPL-005, and TPL-006-0 into one, single, comprehensive, coordinated standard: TPL-001-1	Not employed due to scope of revision

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Version 1 of SAR posted for comment from April 2, 2002 through May 3, 2002.
2. Version 2 of SAR posted for comment from May 5, 2004 through June 5, 2004.
3. Version 3 of SAR posted on November 18, 2005.
4. SAR approved on April 30, 2006.
5. Version 1 of Supplemental SAR posted for comment from February 15, 2007 through March 16, 2007.
6. Version 2 of Supplemental SAR posted on April 9, 2007.
7. Version 1 of revised standard(s) posted for comment on September 17, 2007.
8. Version 2 of the revised standards posted for comment on August 15, 2008.
9. Version 3 of the revised standards posted for comment on May 26, 2009.
10. Version 4 of the revised standards posted for comment on September 16, 2009.

Proposed Action Plan and Description of Current Draft:

The SDT has established a schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 1Q10. The current draft is the second iteration of the revision of existing standards TPL-001 through TPL-006 and includes one revised standard, TPL-001-1, replacing TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. TPL-005 & -006 issues are addressed in this fifth draft and those standards will also be replaced by TPL-001-1.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Submit standard(s) to BOT.	2Q10
2. Submit to regulatory authorities for approval.	3Q10

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission ~~S~~system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault~~-~~.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Near-Term Transmission Planning Horizon: Transmission planning period that covers Years One through five.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) ~~other than~~ Consequential Load Loss, (2) ~~and~~ the response of voltage sensitive Load, or (3) ~~including~~ Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission ~~S~~system performance and Corrective Action Plans to remedy identified deficiencies.

Year One: The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-1**

3. **Purpose:** Establish Transmission ~~S~~system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R~~8~~7 shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 and R~~8~~7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

   Except as indicated below, Requirements R2 through R~~7~~6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.

   - For 60 calendar months ~~after~~beginning the first day of the first calendar quarter following applicable regulatory approval, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-1, Table 1 are allowed to include ~~tripping of~~ Non-Consequential Load Loss ~~or~~and curtailment of Firm Transmission Service (in accordance with Requirement R2, part 2.7.~~5~~3.) that would not otherwise be permitted by the requirements of TPL-001-1:
     - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
     - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
     - P2-1, P2-2 (above 300 kV)
     - P2-3 (above 300 kV)
     - P3-1 through P3-5
     - P4-1 through P4-5 (above 300 kV)
     - P5 (above 300 kV)

   ~~Any entity that cannot fully implement its Corrective Action Plan to eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for the above listed performance elements within 60 calendar months of the compliance date for Requirements R2 through R4 shall self report itself as being unable to meet~~

~~performance requirements of this Reliability Standard. Any such entity shall submit a mitigation plan to its Regional Entity outlining the steps it will take to become compliant and the date it anticipates becoming compliant. The Regional Entity and NERC shall review the mitigation plan and the Regional Entity/NERC will either approve it or remand it for changes (this could include dates, steps, etc.). If the mitigation plan is approved by the Regional Entity and NERC and the entity completes the mitigation plan by the date contained within the mitigation plan, the intent of the SDT is that no penalties will be assessed. Those entities that do not meet the date outlined in an approved mitigation plan will begin settlement proceedings at that date.~~

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required ~~to supply~~for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies as indicated in Requirement R2, part 2.6:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1 ~~for~~with known outages modeled, as ~~modeled~~ in Requirement R1, part 1.1.2 under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of

changes to the basic assumptions used in the model~~ for the list of items shown below~~. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance~~.~~:

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of planned Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), ~~an analysis of~~ the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

2.2. The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as ~~indicated~~ qualified in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as ~~indicated~~qualified in Requirement R2, part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of

Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model~~ for the list of items shown below~~. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance~~.~~:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, part 2.6.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: the System represented in the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in ~~-~~Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity ~~run~~case analyzed in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Such actions may include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate ~~S~~steady ~~S~~state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

~~**2.8.2.**~~Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status.

~~**2.9.**~~**2.8.2.** ~~The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.~~

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, parts 2.1, and -2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, part 3.5.

3.3. Contingency analyses for Requirement R3, ~~p~~Parts 3.1 & 3.2 shall ~~be performed and~~:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention.

3.3.2. -Trip generators where simulations show generator bus voltages or high side of the Generation Step Up (GSU) transformer voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.3. ~~Ensure~~ Trip Transmission elements when relay loadability limits are ~~respected~~ exceeded.

3.3.4. Simulate the expected automatic operation of existing and planned devices designed to provide ~~S~~steady ~~S~~state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

~~**3.5.**~~Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there ~~are~~is ~~c~~Cascading ~~outages~~ caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

~~3.6.~~3.5. ~~When manual or automatic generation runback or tripping is used to meet steady state performance requirements for planning events P1 through P7 in Table 1, the amount of generation lost shall be documented in the Planning Assessment with a description of why the generation was runback or tripped for each event.~~

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. ~~—~~ *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When ~~A~~a generator ~~that~~ pulls out of synchronism ~~shall be tripped~~ in the simulations, ~~and~~ the resulting apparent impedance swings shall not result in the tripping of any Transmission ~~S~~system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, part 4.5.

4.3. Contingency analyses for Requirement R4, parts 4.1 and 4.2 shall ~~be performed and~~:

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention while also considering the impact of successful or unsuccessful high speed reclosing.

4.3.2. Trip generators where simulations show generator bus voltages or high side of the GSU transformer voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.3. Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers.

4.3.4. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power

system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4, part 4.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R4, part 4.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there ~~are~~is ~~c~~Cascading ~~outages~~ caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall ~~have~~define and document, within its Planning Assessment, criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain ~~outside~~below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within ~~their~~ its Planning Assessment, any criteria or methodology used in the analysis to identify System instability for conditions such as ~~c~~Cascading ~~outages~~, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, ~~and~~ adjacent Transmission Planners, and ~~to~~ any functional entity that ~~indicates~~ has a reliability related need ~~for the Planning Assessment results~~and submits a written request for the information. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. BES Transmission voltage instability, ~~c~~Cascading ~~outages~~, and uncontrolled islanding shall not occur.

b. Consequential Load Loss ~~and~~as well as ~~consequential~~ generation loss ~~are~~is acceptable as a consequence of any planning or extreme event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. For all planning events, planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages ~~limits~~ and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. The System shall remain stable.[4] ~~.~~

k. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial System Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No[9]	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of ~~Breaker(s)~~ a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (Non Bus-tie)	SLG ~~SLG~~	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial System Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[~~10~~9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[~~10~~9]	No
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[~~10~~10~~11~~10])*	Normal System	Loss of multiple elements caused by a stuck breaker [~~11~~10](non-Bus-tie) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[~~10~~9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus Protection System failure to operate)*	Normal System	~~Loss of multiple elements caused by the~~ ~~f~~Failure of a single Protection System that results in Delayed Fault ~~while~~ ~~c~~Clearing ~~a fault~~ on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[~~10~~9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adj.[9]: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events	
Steady State & Stability For all extreme events evaluated: a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency. b. Simulate Normal Clearing unless otherwise specified.	
Steady State 1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments. 2. Local area events affecting the Transmission ~~s~~System such as: a. Loss of a tower line with three or more circuits.[~~12~~11] b. Loss of all Transmission lines on a common Right-of-Way[~~12~~11]. c. Loss of a switching station or substation (loss of one voltage level plus transformers). d. Loss of all generating units at a station. e. Loss of a large Load or major Load center. 3. Wide area events affecting the Transmission ~~s~~System based on System topology such as: a. Loss of two generating ~~plants~~stations resulting from conditions such as: i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation. ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants. b. Other events based upon operating experience that may result in wide area disturbances.	**Stability** 1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments. 2. Local or wide area events affecting the Transmission ~~s~~System such as: a. 3Ø fault on generator with stuck breaker[~~11~~10] or a Protection System failure resulting in Delayed Fault Clearing. b. 3Ø fault on Transmission circuit with stuck breaker[~~11~~10] or a Protection System failure resulting in Delayed Fault Clearing. c. 3Ø fault on transformer with stuck breaker[~~11~~10] or a Protection System failure resulting in Delayed Fault Clearing. d. 3Ø fault on bus section with stuck breaker[~~11~~10] or a Protection System failure resulting in Delayed Fault Clearing. e. 3Ø internal breaker fault[~~11~~]. f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance
Footnotes
(Planning Events and Extreme Events)

1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event ~~for~~determines the stated performance criteria ~~applies~~ regarding allowances for interruptions of Firm Transmission Service and ~~loss of~~ Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three~~-~~-phase (3Ø) are the fault ~~types, that~~types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met ~~-~~is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems~~ as defined by the Regional Entity~~. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption~~s~~ of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-Generator Step Up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and ~~g~~Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening ~~breaker(s)~~ one end of a line section without a fault on ~~one end of~~ a normally networked Transmission circuit such that the line is ~~now open at that end and~~ possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure or common Right-of-Way for 1 mile or less.

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within its respective area, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of ~~the studies~~ documentation specifying any criteria or methodology used in the analysis to identify System instability that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide ~~evidence, such as a~~ dated documentation~~, that identifies that agreement~~ on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies ~~for~~and the Planning Assessments in accordance with Requirement R7.

~~**M8.**~~Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient, date, and contents, or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators, ~~and~~ adjacent Transmission Planners, and any functional entity ~~who~~ that has indicated a reliability need and has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

M8.

D. ~~D.~~ Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity.

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- ~~All~~The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- ~~All~~The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- ~~All~~The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- ~~All~~The documentation specifying the criteria since the last compliance audit in accordance with Requirement R5 and Measure M5.
- ~~All~~The ~~studies performed~~ documentation specifying any criteria or methodology utilized in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on ~~identified~~roles and responsibilities, as well as all such documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.
- ~~The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:~~

- Three calendar years of the ~~notifications~~ notices and other documentation employed in accordance with Requirement R8 and Measure M8.
-

1.5 Additional Compliance Information

None.

2 Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.	The responsible entity's System model failed to represent three of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1.
R2	The responsible entity failed to comply with ~~Requirement R2, part 2.9 or~~ Requirement R2, part 2.6.	The responsible entity failed to comply with Requirement R2, part 2.3 or part 2.8.	The responsible entity failed to comply with one of the following parts of Requirement R2: part 2.1, part 2.2, part 2.4, part 2.5, or part 2.7.	The responsible entity failed to comply with two or more of the following parts of Requirement R2: part 2.1, part 2.2, part 2.4, or part 2.7.
R3	The responsible entity did not identify planning events as described in Requirement R3, part 3.4 or extreme events as described in Requirement R3, part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R3, part 3.2 to assess	The responsible entity did not perform studies as specified in Requirement R3, part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, part	The responsible entity did not perform studies as specified in Requirement R3, part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		the impact of extreme events. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.	3.3.	or P1 categories in Table 1.
R4	The responsible entity did not identify planning events as described in Requirement R4, part 4.4 or extreme events as described in Requirement R4, part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, part 4.2 to assess the impact of extreme events. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1.
R5	N/A	N/A	N/A	The responsible entity ~~does not have~~ failed to define and document its criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity failed to distribute the results of its Planning Assessment to ~~any~~ one of its adjacent Transmission Planners ~~and~~or adjacent Planning Coordinators, and to one functional entity that has a reliability related need and has submitted a written request for the information, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to its adjacent Transmission Planners ~~and~~or adjacent Planning Coordinators, and to any functional entity that has a reliability related need and has submitted a written request for the information, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	TBD	Revision of TPL-001-0 as per Project 2006-02; includes merging requirements of TPL-001-0, TPL-002-0, TPL-003-0, TPL-004-0, TPL-005, and TPL-006-0 into one, single, comprehensive, coordinated standard: TPL-001-1	Not employed due to scope of revision

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Standards Announcement

Ballot Pool and Pre-ballot Window
January 20–February 19, 2010

Now available at: https://standards.nerc.net/BallotPool.aspx

Project 2006-02: Assess Transmission Future Needs

The proposed standard TPL-001-1 — Transmission System Planning Performance Requirements and its associated implementation plan are posted for a 30-day pre-ballot review. Registered Ballot Body members may join the ballot pool to be eligible to vote on these items **until 8 a.m. EST on February 19, 2010**.

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-2006-02_ATFNSDT_TPL_in@nerc.com

Next Steps

Voting will begin shortly after the pre-ballot review closes.

Project Background

The purpose of the proposed standard is to establish transmission system planning performance requirements within the planning horizon to develop a bulk electric system that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies. TPL-001-1 — Transmission System Planning Performance Requirements is an update and consolidation of the following standards:

- TPL-001-0 — System Performance under Normal Conditions
- TPL-002-0 — System Performance Following Loss of a Single BES Element
- TPL-003-0 — System Performance Following Loss of Two or More BES Elements
- TPL-004-0 — System Performance Following Extreme BES Events
- TPL-005-0 — Regional and Interregional Self-Assessment Reliability Reports
- TPL-006-0 — Data from the Regional Reliability Organization Needed to Assess Reliability

More information is available on the project page: http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

Applicability of Standards in Project

Planning Coordinator
Transmission Planner

Proposed Additions to Glossary of Terms

Bus-tie Breaker
Consequential Load Loss
Long-Term Transmission Planning Horizon
Near-Term Transmission Planning Horizon
Non-Consequential Load Loss
Planning Assessment
Year One

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

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Standards Announcement

Initial Ballot Window Open
February 19–March 1, 2010

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Project 2006-02: Assess Transmission Future Needs

An initial ballot window for proposed standard TPL-001-1 — Transmission System Planning Performance Requirements and its associated implementation plan is now open **until 8 p.m. EST on March 1, 2010**.

Instructions

Members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

Next Steps

Voting results will be posted and announced after the ballot window closes.

Project Background

The purpose of the proposed standard is to establish transmission system planning performance requirements within the planning horizon to develop a bulk electric system that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies. TPL-001-1 — Transmission System Planning Performance Requirements is an update and consolidation of the following standards:

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- TPL-005-0 — Regional and Interregional Self-Assessment Reliability Reports
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Year One

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For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

User Name
Password
Log in
Register

-Ballot Pools
-Current Ballots
-Ballot Results
-Registered Ballot Body
-Proxy Voters

Home Page

Ballot Results	
Ballot Name:	Project 2006-02 - Assess Transmission Future Needs - TPL-001-1_in
Ballot Period:	2/19/2010 - 3/1/2010
Ballot Type:	Initial
Total # Votes:	265
Total Ballot Pool:	290
Quorum:	**91.38 % The Quorum has been reached**
Weighted Segment Vote:	35.36 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	90	1	23	0.284	58	0.716	2	7
2 - Segment 2.	12	1	5	0.455	6	0.545	1	0
3 - Segment 3.	66	1	20	0.345	38	0.655	2	6
4 - Segment 4.	18	1	4	0.308	9	0.692	2	3
5 - Segment 5.	53	1	16	0.364	28	0.636	4	5
6 - Segment 6.	33	1	9	0.29	22	0.71	1	1
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	6	0.4	2	0.2	2	0.2	1	1
9 - Segment 9.	4	0.2	1	0.1	1	0.1	1	1
10 - Segment 10.	8	0.6	2	0.2	4	0.4	1	1
Totals	**290**	**7.2**	**82**	**2.546**	**168**	**4.654**	**15**	**25**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Affirmative	View
1	American Transmission Company, LLC	Jason Shaver	Negative	View
1	Arizona Public Service Co.	Robert D Smith	Negative	View
1	Associated Electric Cooperative, Inc.	John Bussman		
1	Austin Energy	James Armke	Negative	View
1	Avista Corp.	Scott Kinney	Affirmative	View

1	BC Transmission Corporation	Gordon Rawlings	Affirmative	
1	Beaches Energy Services	Joseph S. Stonecipher	Negative	View
1	Black Hills Corp	Eric Egge	Negative	View
1	Bonneville Power Administration	Donald S. Watkins	Negative	View
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Abstain	
1	CenterPoint Energy	Paul Rocha	Negative	View
1	Central Maine Power Company	Brian Conroy	Negative	View
1	City of Vero Beach	Randall McCamish	Negative	
1	City Utilities of Springfield, Missouri	Jeff Knottek	Negative	
1	Cleco Power LLC	Danny McDaniel	Negative	
1	Commonwealth Edison Co.	Daniel Brotzman	Negative	View
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	View
1	Dairyland Power Coop.	Robert W. Roddy	Negative	
1	Deseret Power	James Tucker	Negative	View
1	Dominion Virginia Power	William L. Thompson	Affirmative	View
1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	E.ON U.S. LLC	Larry Monday	Negative	
1	East Kentucky Power Coop.	George S. Carruba		
1	El Paso Electric Company	Dennis Malone	Affirmative	View
1	Empire District Electric Co.	Ralph Frederick Meyer	Negative	View
1	Entergy Corporation	George R. Bartlett	Affirmative	View
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Negative	View
1	Georgia Transmission Corporation	Harold Taylor, II	Negative	View
1	Great River Energy	Gordon Pietsch	Negative	View
1	Hydro One Networks, Inc.	Ajay Garg	Negative	View
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Negative	View
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	View
1	ITC Transmission	Elizabeth Howell	Negative	View
1	JEA	Ted E Hobson	Negative	
1	Kansas City Power & Light Co.	Michael Gammon		
1	Keys Energy Services	Stan T. Rzad	Negative	
1	Lakeland Electric	Larry E Watt	Negative	View
1	Lee County Electric Cooperative	John W Delucca	Negative	
1	Long Island Power Authority	Jonathan Appelbaum	Negative	
1	Los Angeles Department of Water & Power	Chuan-Hsier Wu		
1	Manitoba Hydro	Michelle Rheault	Affirmative	
1	MEAG Power	Danny Dees	Negative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	Minnesota Power, Inc.	Randi Woodward	Negative	View
1	National Grid	Saurabh Saksena	Affirmative	View
1	New York State Electric & Gas Corp.	Henry G. Masti	Negative	View
1	Northeast Utilities	David H. Boguslawski	Negative	View
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan	Negative	View
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Negative	View
1	Omaha Public Power District	Lorees Tadros	Negative	View
1	Oncor Electric Delivery	Michael T. Quinn	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Negative	View
1	Otter Tail Power Company	Lawrence R. Larson	Negative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Affirmative	View
1	PacifiCorp	Mark Sampson	Negative	View
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Negative	View
1	Potomac Electric Power Co.	Richard J. Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	View
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Puget Sound Energy, Inc.	Catherine Koch		
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Linda Brown	Affirmative	View
1	Santee Cooper	Terry L. Blackwell	Negative	View
1	SCE&G	Henry Delk, Jr.	Negative	View

1	Seattle City Light	Pawel Krupa		
1	Sierra Pacific Power Co.	Richard Salgo	Negative	View
1	South Texas Electric Cooperative	Richard McLeon	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	View
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Negative	View
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Tampa Electric Co.	Thomas J. Szelistowski	Abstain	
1	Tennessee Valley Authority	Larry Akens	Negative	View
1	Tri-State G & T Association Inc.	Keith V. Carman	Negative	View
1	Tucson Electric Power Co.	John Tolo	Negative	View
1	United Illuminating Co.	Robert Pellegrini	Negative	View
1	Westar Energy	Allen Klassen	Negative	
1	Western Area Power Administration	Brandy A Dunn	Negative	View
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	
2	Alberta Electric System Operator	Jason L. Murray	Affirmative	View
2	BC Transmission Corporation	Faramarz Amjadi	Affirmative	
2	California ISO	Timothy VanBlaricom	Affirmative	View
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Negative	
2	Florida Municipal Power Pool	Thomas E Washburn	Abstain	
2	Independent Electricity System Operator	Kim Warren	Affirmative	View
2	ISO New England, Inc.	Kathleen Goodman	Negative	View
2	Midwest ISO, Inc.	Jason L Marshall	Negative	View
2	New Brunswick System Operator	Alden Briggs	Negative	View
2	New York Independent System Operator	Gregory Campoli	Negative	View
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	View
2	Southwest Power Pool	Charles H Yeung	Negative	View
3	Alabama Power Company	Bobby Kerley	Affirmative	
3	American Electric Power	Raj Rana	Affirmative	View
3	Arizona Public Service Co.	Thomas R. Glock		
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	View
3	Black Hills Power	Andy Butcher		
3	Blue Ridge Power Agency	Duane S. Dahlquist	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	View
3	City of Bartow, Florida	Matt Culverhouse	Negative	
3	City of Clewiston	Lynne Mila	Negative	
3	City of Green Cove Springs	Gregg R Griffin	Negative	
3	Cleco Utility Group	Bryan Y Harper	Negative	
3	ComEd	Bruce Krawczyk	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	View
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Abstain	View
3	Dominion Resources, Inc.	Jalal (John) Babik	Affirmative	View
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	View
3	East Kentucky Power Coop.	Sally Witt	Abstain	
3	Entergy Services, Inc.	Matt Wolf	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power & Light Co.	W. R. Schoneck	Negative	View
3	Florida Power Corporation	Lee Schuster	Negative	View
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Negative	
3	Grays Harbor PUD	Wesley W Gray	Negative	
3	Great River Energy	Sam Kokkinen	Negative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Negative	View
3	JEA	Garry Baker	Negative	View
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory David Woessner	Negative	
3	Lakeland Electric	Mace Hunter	Negative	View
3	Lincoln Electric System	Bruce Merrill	Negative	View
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	View
3	Manitoba Hydro	Greg C Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View

3	Mississippi Power	Don Horsley	Affirmative	
3	New York Power Authority	Marilyn Brown	Negative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	View
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	Ocala Electric Utility	David T. Anderson	Negative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Negative	View
3	PacifiCorp	John Apperson	Negative	View
3	PECO Energy an Exelon Co.	Vincent J. Catania	Negative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Negative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange	Negative	View
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Negative	View
3	Seattle City Light	Dana Wheelock		
3	South Carolina Electric & Gas Co.	Hubert C. Young	Negative	View
3	Southern California Edison Co.	David Schiada		
3	Southern Indiana Gas and Electric Co.	Fred Frederick	Negative	View
3	Tampa Electric Co.	Ronald L Donahey	Negative	
3	Tri-State G & T Association Inc.	Janelle Marriott	Negative	View
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Negative	View
3	Xcel Energy, Inc.	Michael Ibold	Negative	View
4	Arkansas Electric Cooperative Corporation	Ricky Bittle	Affirmative	
4	City of Clewiston	Kevin McCarthy	Negative	
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Negative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Detroit Edison Company	Daniel Herring	Abstain	View
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas W. Richards	Negative	View
4	Georgia System Operations Corporation	Guy Andrews	Negative	
4	Integrys Energy Group, Inc.	Christopher Plante	Negative	View
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Negative	View
4	Northern California Power Agency	Fred E. Young		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	View
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	View
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li		
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko	Affirmative	View
5	Amerenue	Sam Dwyer	Negative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	View
5	City of Tallahassee	Alan Gale	Negative	
5	City Water, Light & Power of Springfield	Karl E. Kohlrus	Affirmative	
5	Cleco Power LLC	Grant Bryant	Negative	
5	Consolidated Edison Co. of New York	Edwin E Thompson		
5	Consumers Energy	James B Lewis	Affirmative	
5	Dairyland Power Coop.	Warren Schaefer	Negative	
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	View
5	Duke Energy	Robert Smith		
5	Dynegy	Greg Mason	Negative	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	View
5	Florida Municipal Power Agency	David Schumann	Negative	
5	Great River Energy	Cynthia E Sulzer	Negative	
5	Invenergy LLC	Alan Beckham	Abstain	
5	JEA	Donald Gilbert	Negative	View
5	Kansas City Power & Light Co.	Scott Heidtbrink	Negative	

5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	Thomas J Trickey	Negative	View
5	Lincoln Electric System	Dennis Florom	Negative	View
5	Louisville Gas and Electric Co.	Charlie Martin	Negative	View
5	Luminant Generation Company LLC	Mike Laney	Negative	View
5	Manitoba Hydro	Mark Aikens	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Abstain	
5	New York Power Authority	Gerald Mannarino	Negative	
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Negative	
5	Orlando Utilities Commission	Richard Kinas	Negative	View
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	View
5	PacifiCorp	Sandra L. Shaffer	Negative	View
5	Portland General Electric Co.	Gary L Tingley		
5	PPL Generation LLC	Mark A. Heimbach	Negative	View
5	Progress Energy Carolinas	Wayne Lewis	Negative	View
5	PSEG Power LLC	David Murray	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik		
5	RRI Energy	Thomas J. Bradish	Affirmative	View
5	Sacramento Municipal Utility District	Bethany Wright	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	South California Edison Company	Ahmad Sanati		
5	South Carolina Electric & Gas Co.	Richard Jones	Negative	View
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	Tennessee Valley Authority	George T. Ballew	Negative	View
5	Tri-State G & T Association Inc.	Barry Ingold	Negative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Negative	
5	Xcel Energy, Inc.	Liam Noailles	Negative	View
6	AEP Marketing	Edward P. Cox	Affirmative	View
6	Black Hills Corp	Tyson Taylor	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	View
6	Cleco Power LLC	Matthew D Cripps	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	View
6	Constellation Energy Commodities Group	Chris Lyons	Affirmative	
6	Dominion Resources, Inc.	Louis S Slade	Affirmative	View
6	Duke Energy Carolina	Walter Yeager	Negative	
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Negative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	View
6	Florida Power & Light Co.	Silvia P Mitchell	Negative	View
6	Great River Energy	Donna Stephenson	Negative	
6	Kansas City Power & Light Co.	Thomas Saitta	Negative	View
6	Lakeland Electric	Paul Shipps	Negative	View
6	Lincoln Electric System	Eric Ruskamp	Negative	View
6	Louisville Gas and Electric Co.	Daryn Barker	Negative	View
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	New York Power Authority	Thomas Papadopoulos	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	Omaha Public Power District	David Ried	Negative	
6	PacifiCorp	Gregory D Maxfield	Negative	View
6	Progress Energy	James Eckelkamp	Negative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	RRI Energy	Trent Carlson	Affirmative	
6	Santee Cooper	Suzanne Ritter	Negative	View
6	Seattle City Light	Dennis Sismaet	Abstain	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	South Carolina Electric & Gas Co.	Matt H Bullard	Negative	View
6	SunGard Data Systems	Christopher K Heisler	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	View
6	Xcel Energy, Inc.	David F. Lemmons	Negative	View
8		James A Maenner	Abstain	
8	Edward C Stein	Edward C Stein		

8	JDRJC Associates	Jim D. Cyrulewski	Negative	
8	Power Energy Group LLC	Peggy Abbadini	Affirmative	
8	Roger C Zaklukiewicz	Roger C Zaklukiewicz	Negative	View
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	Maine Public Utilities Commission	Jacob A McDermott	Abstain	
9	North Carolina Utilities Commission	Kimberly J. Jones	Negative	View
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Negative	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	Dan R. Schoenecker	Negative	View
10	New York State Reliability Council	Alan Adamson	Negative	View
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith	Negative	View
10	SERC Reliability Corporation	Carter B Edge		
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	

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Standards Announcement
Initial Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

Project 2006-02: Assess Transmission Future Needs
The initial ballot for proposed standard TPL-001-1 — Transmission System Planning Performance Requirements and its associated implementation plan ended on March 1, 2010.

Ballot Results
Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 91.38%
Approval: 35.36%

Since at least one negative ballot included a comment, these results are not final. A second (or recirculation) ballot must be conducted. Ballot criteria are listed at the end of the announcement.

Next Steps
As part of the recirculation ballot process, the drafting team must draft and post responses to voter comments. The drafting team will also determine whether or not to make revisions to the balloted item(s). Should the team decide to make revisions, the revised item(s) will return to the initial ballot phase.

Project Background
The purpose of the proposed standard is to establish transmission system planning performance requirements within the planning horizon to develop a bulk electric system that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies. TPL-001-1 — Transmission System Planning Performance Requirements is an update and consolidation of the following standards:

- TPL-001-0 — System Performance under Normal Conditions
- TPL-002-0 — System Performance Following Loss of a Single BES Element
- TPL-003-0 — System Performance Following Loss of Two or More BES Elements
- TPL-004-0 — System Performance Following Extreme BES Events
- TPL-005-0 — Regional and Interregional Self-Assessment Reliability Reports
- TPL-006-0 — Data from the Regional Reliability Organization Needed to Assess Reliability

More information is available on the project page: http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

Applicability of Standards in Project
Planning Coordinator
Transmission Planner

Proposed Additions to Glossary of Terms

Bus-tie Breaker
Consequential Load Loss
Long-Term Transmission Planning Horizon
Near-Term Transmission Planning Horizon
Non-Consequential Load Loss
Planning Assessment
Year One

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Ballot Criteria

Approval requires both a (1) quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention, and (2) A two-thirds majority of the weighted segment votes cast must be affirmative; the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and nonresponses. If there are no negative votes with reasons from the first ballot, the results of the first ballot shall stand. If, however, one or more members submit negative votes with reasons, a second ballot shall be conducted.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

Consideration of Comments on Initial Ballot — Assess Transmission Future Needs (Project 2006-02)

Summary Consideration: Due to industry comments, the SDT has made a number of changes to the standard as shown below. In making these changes, the SDT has attempted to be responsive to the information provided in the initial ballot comments while continuing to be responsive to the FERC Order 693 directives. Please note that footnote 12 on non-consequential load loss is currently being utilized as a placeholder. The resolution of this issue will be provided in Project 2010-11. When that resolution is reached, the content will be copied to TPL-001-2.

Year One: The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

Requirement R1 - Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes the normal system condition in Table 1.

Requirement R2 - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.

Requirement R2, part 2.1 - The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, part 2.6, as follows:

Requirement R2, part 2.1.4 - For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

Requirement R2, part 2.1.5 - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

Requirement R2, part 2.4.1 - System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

Requirement R2, part 2.4.3 - For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

Requirement R2, part 2.5 - The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, part2.6. The technical rationale for determining material changes shall be documented.

Requirement R3, part 3.3.1 - Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

- Tripping of generators where simulations show generator bus voltages or high side of the Generation Step Up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.
- Tripping of Transmission elements where relay loadability limits are exceeded.

Requirement R3, part 3.5 - Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

Requirement R4, part 4.3.1 - Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

- Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

Requirement R4, part 4.4 - Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

Requirement R4, part 4.5 - Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

Header note 'a': The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

Header note 'b': Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

Header note 'e': Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

P5. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following:

Extreme event 2d. Loss of all generating units at a generating station.

11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.

12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.

13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

M6. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of documentation specifying any criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity who has indicated a reliability need and that functional entity has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

R8 VSL	The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners, one adjacent Planning Coordinator, or to one functional entity that has a reliability related need and that has submitted a written request for the information, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to more than one of its adjacent Transmission Planners, adjacent Planning Coordinators, or functional entities that have a reliability related need and that have submitted a written request for the information, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herbert Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
Kent Kujala	Detroit Edison Company	3	Abstain	Document is overly complex.
Daniel Herring	Detroit Edison Company	4	Abstain	I don't believe this end product from the consolidation of the TPL standards into one standard turned out the way the industry was hoping it would. This standard is long, complex, and difficult to follow.
Response: The standard covers a number of complex issues and problems. The SDT has made every attempt to avoid unnecessary complexity. No change made.				
Paul Rocha	CenterPoint Energy	1	Negative	CenterPoint Energy believes the proposed standard has strayed far from its original intent as indicated in the 2002 Version 1 SAR and that this proposed standard is now overly prescriptive. CenterPoint Energy also will not support the proposed expansion of mandatory, auditable long term planning requirements beyond the requirements found in the existing TPL standards and the intent reflected in the 2002 version 1 SAR. This concern is exacerabated by the expansion of stability studies and corrective action plan requirements applied to the long term planning horizon.
Response: The SDT is providing clarity around all of the requirements consistent with the intent of the existing standards, the approved 2002 SAR, and the approved 2006 Supplemental SAR. No change made.				
Gregory L. Pieper	Xcel Energy	1	Negative	No comment.
Response: Without any specific comments to address, the SDT is unable to further address your concerns. No change made.				
Charles Locke	Kansas City Power & Light Co.	3	Negative	The standards are overly prescriptive and will increase industry costs substantially without materially improving customer service or reliability, and I believe they go significantly beyond the original standard. If the reason for a new standard is to clarify interpretation problems with Table I performance, that should be addressed without all the additional requirements that are added in the new standard.
Thomas Saitta	Kansas City Power & Light Co.	6	Negative	
Response: The SDT is providing clarity around all of the requirements consistent with the intent of the existing standards. The SDT has attempted to balance				

Voter	Entity	Segment	Vote	Comment
reliability versus cost based on responses to comments in previous postings. No change made.				
Saurabh Saksena	National Grid	1	Affirmative	1. An annual study shouldn't be required for all areas. A documented assessment based on past studies should be adequate for some areas. 2. Years 5 and 10 need to be defined. It appears that the difference between Year One and year 5 is only 3 years. 3. In Table 1, event P5 is not clear enough to communicate that it doesn't include the failure of a single element such as a battery, which is included in the NERC glossary definition for a Protection System. 4. Part 2.7.2 should include Runback or tripping of HVDC in the list of possible actions. 5. Parts 2.1.4 & 2.4.3 should be revised from ' ... the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies ....' to ' ... the sensitivity analysis in the Planning Assessment must vary one or more of the following original conditions in the studies ....'. This will provide a reference similar to a Base Case definition as a reference for the sensitivities and will eliminate the implication of infinitely adding one more sensitivity to the list of sensitivities. 6. The implementation window for part 2.4.1needs to be increased from 24 to 36 months.
Michael Schiavone	Niagara Mohawk (National Grid Company)	3	Affirmative	
Response: 1. The intent of the SDT wasn't that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and Part 2.1. **Requirement R2** - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. **Requirement R2, part 2.1.4 -** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: **Requirement R2, part 2.4.3 -** For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:				

Voter	Entity	Segment	Vote	Comment
2. The SDT believes that this concern is alleviated by the revised definition for Year One. **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013. Then Year 5 would be four years after Year One and Year 10 would be nine years after Year One. Using the example in the definition of Year One, Year 5 would be the 12 month period that includes the forecasted peak load period of either 2016 or 2017, respectively, and Year 10 would be 2021 or 2022, respectively. 3. The SDT has changed the text for the P5 event and added a footnote 13 as a result of your (and others') comments to address these concerns. **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following: **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94). 4. The SDT assumes that you meant Requirement R2, Part 2.7.1. As stated, the list is not all inconclusive but a list of possible actions. The SDT agrees that runback or tripping of HVDC would be allowable actions. No change made. 5. The SDT agrees that the current wording may be confusing and has made a change to promote clarity in this area. **Requirement R2** - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. **Requirement R2, part 2.1.4 -** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: **Requirement R2, part 2.4.3 -** For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: 6. The SDT has reviewed similar comments from earlier drafts and believes that the implementation timeframe for this item is appropriate. Without any further specific reasons, the SDT is unable to address your concerns. No change made.				

Voter	Entity	Segment	Vote	Comment
Linda Brown	San Diego Gas & Electric	1	Affirmative	1. The new standard is supposed to be a performance based standard, but goes beyond performance by suggesting solutions (2.7.1). 2. The new standard is an overly wordy and poorly organized version of the original four TPLs. In order to understand a requirement, the reader must jump to different sections in the document. 3. The new standard is poorly written making it confusing. For example, R2.1.1 says "System peak Load for either Year One or year two, and for year five". I think it means, "study the system as it may exists 5 years from now and as it may exist either one year from now, or two years from now." 4. Section R2.1.4 of the new standard requires Real and Reactive forecasted load. This makes no sense. To my knowledge, no one forecasts reactive load. They assume a power factor and using the real power load and the assumed power factor, they calculate the reactive load. 5. The load modeling requirement may take some time to achieve. 6. It asks for sensitivities that assume generation that may never be built. 7. The Corrective Action Plan doesn't define who gets the plan. It just says to make one. 8. The new standard makes requirements out of practices. For example, section 3.3.3 requires relay loading actions to be part of the analysis. Any competent transmission planning engineer does this.

Response: 1. The proposed standard clarifies allowable solutions but doesn't mandate any particular solution without deviating from performance-based requirements. No change made.

2. Without any specific comments to address, the SDT is unable to further address your concerns. No change made.

3. The SDT does not think the requirement is poorly worded nor are there other comments about this particular wording. Your assumption is correct but does not add any additional clarity. No change made.

4. Since the reactive Load is based on a forecast of the real Load, the SDT chose to characterize both real and reactive Loads as forecasts. No change made.

5. The SDT assumes that you are referring to the induction motor Load modeling required for Stability studies. The standard permits an aggregate model assumption that can be applied for a given system that is not substation specific. The SDT believes that 24 months is an adequate time period to accomplish this task. No change made.

6. The SDT has made a change to the requirements to promote clarity in this area. Generation is just one of the examples of what could be studied.

> **Requirement R2** - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.

Voter	Entity	Segment	Vote	Comment
Requirement R2, part 2.1.4 - For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: **Requirement R2, part 2.4.3 -** For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: 7. The Corrective Action Plan isn't delivered separately as it is part of the Planning Assessment. Requirement R8 specifies availability of Planning Assessments. No change made. 8. The SDT wrote the requirements for the proposed standard based on reliability-based needs for a continent-wide standard for transmission planning purposes and have been vetted through multiple industry comment periods. Requirements are often based on existing practices. No change made.				
Dana Cabbell	Southern California Edison Co.	1	Affirmative	1. We recommend moving the EHV and HV definition from the Performance Table footnote to "Definitions of Terms used in Standard" section. 2. While draft 5 of this proposed standard is a substantial improvement over the previous drafts and the existing TPL standards, there are still areas where additional clarity is needed. We believe that a workshop, after FERC approval of the standard, where issues can be discussed and clarified will go a long way towards smooth implementation of this proposed standard. Some of the areas that require additional clarification are: o Application of consequential and non-consequential load and the EHV and HV voltage levels o Discussion on what is needed to study the various Planning Events. One example is P5, which involves "failure of a single protection system." 3. We recommend the following slight modification to the specified subrequirements of R2 to include clarifying references to R3 and R4 as follows: o 2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: o 2.2. The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6:

Voter	Entity	Segment	Vote	Comment
				o 2.4. The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, part 2.6. The following studies are required in accordance with R4: o 2.5. The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported in accordance with R4 by current or past studies as qualified in Requirement R2, part 2.6
Response: 1. The EHV/HV differentiation is not meant to be a definition in that it only applies to this standard. No change made. 2. The SDT has held several webinars on this project and may well hold another before the project is complete. In addition, the SDT has performed numerous outreach activities to regional entities, sub-committees, etc., on the details of the standard. The project has been presented several times at the NERC Standards Workshops. Once the standard is approved by FERC, the SDT ceases to exist. Therefore, any activities subsequent to that approval would be under general NERC jurisdiction. The SDT suggests that you broach this idea with NERC staff. Also, the SDT has clarified P5 in this revision. 2.1 & 2.2 – The SDT feels that the linkage between requirements is properly cited in Requirement R3 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made. 2.4 – Part 2.4 is already part of Requirement R2 so no additional reference is required. No change made. 2.5 - The SDT feels that the linkage between requirements is properly cited in Requirement R4 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made.				
Thomas J. Bradish	RRI Energy	5	Affirmative	I support the WECC position paper on this subject. Namely: 1. While draft 5 of this proposed standard is a substantial improvement over the previous drafts and the existing TPL standards, there are still areas where additional clarity is needed. We believe that a workshop, after FERC approval of the standard, where issues can be discussed and clarified will go a long way towards smooth implementation of this proposed standard. Some of the areas that require additional clarification are: o Application of consequential and non-consequential load and the EHV and HV voltage levels o Discussion on what is needed to study the various Planning Events. One example is P5, which
Scott Kinney	Avista Corp.	1	Affirmative	
Dennis Malone	El Paso Electric Company	1	Affirmative	

Voter	Entity	Segment	Vote	Comment
Richard J. Padilla	Pacific Gas and Electric Company	5	Affirmative	involves "failure of a single protection system." 2. We recommend the following slight modification to the specified subrequirements of R2 to include clarifying references to R3 and R4 as follows: o 2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: o 2.2. The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: o 2.4. The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, part 2.6. The following studies are required in accordance with R4: o 2.5. The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported in accordance with R4 by current or past studies as qualified in Requirement R2, part 2.6
Response: 1. The SDT has held several webinars on this project and may well hold another before the project is complete. In addition, the SDT has performed numerous outreach activities to regional entities, sub-committees, etc., on the details of the standard. The project has been presented several times at the NERC Standards Workshops. Once the standard is approved by FERC, the SDT ceases to exist. Therefore, any activities subsequent to that approval would be under general NERC jurisdiction. The SDT suggests that you broach this idea with NERC staff. 2.1 & 2.2 – The SDT feels that the linkage between requirements is properly cited in Requirement R3 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made. 2.4 – Part 2.4 is already part of Requirement R2 so no additional reference is required. No change made. 2.5 - The SDT feels that the linkage between requirements is properly cited in Requirement R4 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made.				
Chifong L. Thomas	Pacific Gas and Electric Company	1	Affirmative	1. While draft 5 of this proposed standard is a substantial improvement over the previous drafts and the existing TPL standards, there are still areas where additional clarity is needed. We believe that a workshop, after FERC approval of the standard, where issues can be discussed and clarified will go a long way towards smooth implementation of this proposed standard.

Voter	Entity	Segment	Vote	Comment
				Some of the areas that require additional clarification are: o Application of consequential and non-consequential load and the EHV and HV voltage levels o Discussion on what is needed to study the various Planning Events. One example is P5, which involves "failure of a single protection system." 2. We recommend the following slight modification to the specified sub-requirements of R2 to inserting "in accordance with R3" or "in accordance with R4" to clarify references to R3 and R4, respectively, as follows: o 2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: o 2.2. The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: o 2.4. The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, part 2.6. The following studies are required in accordance with R4: o 2.5. The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported in accordance with R4 by current or past studies as qualified in Requirement R2, part 2.6 3. As proposed, Non-Consequential Load Loss is defined as "Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment". As voltage at the fault goes to zero, and voltages in the parts of the system near the fault become very low, some voltage sensitive Loads may be tripped, and, as a result may not "ride through" the fault. Would this types of Load loss be covered under item (2), "the response of voltage sensitive Load" during the transient dynamic study, as long as the TP and PC model these Loads as connected to the system in the post-contingency steady state power flow representation?
Response: 1. The SDT has held several webinars on this project and may well hold another before the project is complete. In addition, the SDT has performed numerous outreach activities to regional entities, sub-committees, etc., on the details of the standard. The project has been presented several times at the NERC Standards Workshops. Once the standard is approved by FERC, the SDT ceases to exist. Therefore, any activities subsequent to that approval would be under				

Voter	Entity	Segment	Vote	Comment
general NERC jurisdiction. The SDT suggests that you broach this idea with NERC staff. 2.1 & 2.2 – The SDT feels that the linkage between requirements is properly cited in Requirement R3 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made. 2.4 – Part 2.4 is already part of Requirement R2 so no additional reference is required. No change made. 2.5 - The SDT feels that the linkage between requirements is properly cited in Requirement R4 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made. Yes, your assumptions are correct.				
Timothy VanBlaricom	California ISO	2	Affirmative	2.1 The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, part 2.6: 2.2 The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, part 2.6:
Response: 2.1 & 2.2 – The SDT feels that the linkage between requirements is properly cited in Requirement R3 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made.				
Paul B. Johnson	American Electric Power	1	Affirmative	AEP appreciates the extensive efforts by the SDT to develop the version of this standard that is presently before the industry for ballot. The proposed version addresses much of the confusion that exists with the current standards that it will replace. The SDT should be commended for having gone to great lengths to explain the interpretation of this revised standard as part of its reply to industry comments. Adherence to this standard should result in a sufficiently reliable system by narrowing the broad interpretations that have been made of the requirements in the existing standards. AEP believes that the SDT has satisfied enough of FERC's concerns so that FERC will approve this standard if passed by the industry. Therefore, AEP supports approval of this standard. AEP would like to make a suggestion that any future revision of TPL-001-1 should place appropriate restrictions on the use of Special Protection Systems as a permanent solution in the Corrective Action Plan. While AEP recognizes that there are acceptable applications of SPS on a permanent basis, we are concerned that in highly interconnected portions of the grid the use of multiple SPS can cause complex interactions that would be difficult to predict and could lead to unintended consequences. AEP also recognizes that an SPS may be the only practical option on an interim basis.
Raj Rana	American Electric Power	3	Affirmative	
Brock Ondayko	AEP Service Corp.	5	Affirmative	
Edward P. Cox	AEP Marketing	6	Affirmative	

Voter	Entity	Segment	Vote	Comment
Response: Thank you for your response. The SDT will enter a comment in the official NERC issues database on your concern about permanent SPS solutions. That will assure that a future drafting team will address your concern.				
George R. Bartlett	Entergy Corporation	1	Affirmative	Entergy appreciates the work of the drafting team and recognizes the challenges associated with complexities of this effort. Entergy is voting "Affirmative" on the proposed standard but would appreciate the SDT consideration of the following comments in any further efforts to improve the standard: 1. The implementation plan is simply too aggressive. Locating and building transmission facilities continues to become more time consuming. Even lower voltage facilities can take 5 to 7 years to navigate through the various technical and regulatory challenges associated with building these facilities. Entergy would propose extending the implementation plan to 7 years for 230 kV and below, and 10 years for above 230 kV where transmission lines must be constructed. While the SDT has the intent that no penalties be imposed where facilities can not be constructed by the end of the implementation plan, we are concerned that ambiguity may exist may lead to issues should enforcement be left to interpret what is "beyond the control of the Transmission Planner or Planning Coordinator" in R2.7.3 2. 2. P5 in the new table is simply not defined to the extent that a consistent analysis method can be applied throughout the industry. While the process of identifying single points of failure will be time consuming and manpower intensive, it is feasible to complete. However, the consequences of those single points of failure can not be defined with consistency across the industry. Consequences of protection system failures are dependent on fault types, initial system conditions, and other factors which are not and can not be tracked in traditional planning tools. The ambiguities associated with P5 will almost certainly lead to additional standards needs and numerous requests for interpretation. Entergy would propose industry standardized proxies be allowed in lieu of detailed analysis of the interface between protection systems and the delivery aspects of the BES. Proxies could be developed to ensure the industry identifies and avoids events which have recently been associated with single points of failure in a protection system. 3. Entergy believes that more clarity is needed in R2.1.4 and R2.7 concerning sensitivity studies. The determination of when sensitivity study results should warrant mitigation should be left to the Transmission Planner and/or Planning Coordinator. The requirement to document the studies and their results will proved transparency and allow for transmission improvements through normal stakeholder and regulatory processes.

Voter	Entity	Segment	Vote	Comment
Response: 1. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility. 2. The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns. **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following: **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94). 3. The SDT did not receive any other comments in this regard and believes that the wording is clear. No change made.				
Robert Martinko	FirstEnergy Energy Delivery	1	Affirmative	FirstEnergy appreciates the dedication of the Assess Transmission and Future Needs Standards Drafting Team commends the group for their hard work to bring the proposed TPL-001-1 standard to industry for consideration. The TPL-001-1 standard provides greater compliance clarity than what presently exists in vague and open for interpretation TPL standards. The project appropriately consolidates six existing TPL standards into a single standard, while driving the industry to needed robust planning reviews. The team has carefully considered the industry feedback during the standards development and made many adjustments to better clarify the requirement language. The team is also commended for the improvements made to the Performance Table describing steady-state and stability performance expectations and creating the distinction between Planning Events and Extreme Events. FirstEnergy is voting to AFFIRM the standard and offers the following suggestions to the standards drafting team for areas of improvement and a more appropriate transition to the TPL-001-1 standard. 1) YearOne Definition: FirstEnergy requests that the team consider a change so that Year One is the planning window that begins 12-18 months from the "start" of the current calendar year, and not
Kevin Querry	FirstEnergy Solutions	3	Affirmative	
Douglas Hohlbaugh	Ohio Edison Company	4	Affirmative	
Kenneth Dresner	FirstEnergy Solutions	5	Affirmative	

Voter	Entity	Segment	Vote	Comment
Mark S Travaglianti	FirstEnergy Solutions	6	Affirmative	from the "end" of the calendar year. This change is needed so that minimal adjustments are needed to the ERAG MMWG model building process, which is the basis for planning models used by many within the Eastern Interconnection. The change would still meet the team's intent of requiring the industry to plan beyond current year load periods which are appropriately considered an operating timeframe in the context of TPL-001-1. If the team does not agree to this change for use in the TPL-001-1 standard, we ask the team to consider adding an Entity Variance that would permit the proposed change within the Eastern Interconnection. 2) Implementation Plan: The 60-month transition, as reflected in the team's Implementation Plan, may not be sufficient time for completion of new transmission facilities that may be needed as part of a Corrective Action Plan. The Implementation Plan calls for a 60-month period that is in parallel to the 24-month transition period for completing new model and study expectations per the TPL-001-1 standard. The proposed standard raises study expectations in a number of areas such as removing load shedding for n-1 conditions, more detailed load modeling regarding induction motor loads, developing and documenting transient voltage criterion, etc. FirstEnergy believes it is more appropriate for the 60-month transition for completed Corrective Action Plans to be sequential to the 24-month transitional items. It will take industry some time to transition to the new model and study expectations and industry should be allotted a full 60 months for the completion of major transmission infrastructure that may be included in Corrective Action Plans. 3) Two Near-Term Studies: FirstEnergy supports a need for "fresh" annual steady-state studies being completed for both the Near-Term and Long-Term planning horizons as reflected in requirement 2.1 which states "... be supported by the following annual current studies ...". However, we continue to stress that the need for two studies in the Near-Term horizon (requirement R2.1.1) creates unnecessary burden on industry resources, especially in light that sensitivity analyses are required for each study year. The focus should be that the Transmission Planner needs to cover the entire planning horizon through past and present (current annual) studies and allow the Transmission Planner more latitude to pick the current annual studies. A single present year study within the Near-term and Long-Term planning horizons, supplemented with past studies should be sufficient to effectively interpolate and extrapolate results to cover the entire planning horizon. To the extent a past study remains a qualified past study (as described in the standard in R2.6) we believe the transmission planner should still have discretion to continue to use those studies as their study time period moves forward.

Response: 1. Based on your comment and those of others, the SDT has revised the definition of Year One.

Year One: The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For

Voter	Entity	Segment	Vote	Comment
example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013. 2. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. 3. The intent of the SDT wasn't that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and part 2.1. **Requirement R2** - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. **Requirement R2, part 2.1 -** The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, part 2.6, as follows:				
William L. Thompson	Dominion Virginia Power	1	Affirmative	o Effective Date - For those raising the bar standards, corrective action plans must be implemented by 60 calendar months. We believe as we have commented previously that for new EHV facilities, this may be difficult to achieve. Our recommendation was to add an additional 24 months to that timeframe. However, they have added Requirement R2.7.3 which allows for situations out of our control to use non-consequential load loss to temporarily resolve violations until the corrective action plans are implemented. Although this does cover us as long as we have a legitimate reason, it does leave to the interpretation of the auditor that the reason is "valid". We therefore still believe more time should be allowed. o Requirement R3.3.2 - Dominion does not agree that the low voltage ride through is a steady-state issue as included in requirement R3.3.2. We foresee demonstrating compliance for this requirement as a difficult if not impossible task hence subjecting the industry to undue non-compliance risk. Furthermore, we believe that low voltage ride through is a dynamic modeling issue covered in requirement R4.3.2. o Assessment time and documentation - Although we do see the need and improvements in the standard, it is clear to Planning that more assessments and documentation will be the end result. It is difficult to determine how much time and resource requirements this will take until we begin implementing the standard. Planning does have a concern that additional resources will be required and have heard this from others in the industry.
Jalal (John) Babik	Dominion Resources, Inc.	3	Affirmative	
Mike Garton	Dominion Resources, Inc.	5	Affirmative	
Louis S Slade	Dominion Resources, Inc.	6	Affirmative	

Voter	Entity	Segment	Vote	Comment
Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility. The SDT voltage ride through is not confined to the dynamic period. There are protection requirements that could result in generator tripping and that must be considered in the steady-state analysis. The SDT has clarified the wording of the requirement. **Requirement R3, part 3.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: • Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. • Tripping of Transmission elements where relay loadability limits are exceeded. The SDT is sensitive to this issue and that is why there is a staggered Implementation Plan. The timeframes are designed to allow entities time to catch up to the new requirements and were derived from a specific question asked of the industry.				
Kim Warren	Independent Electricity System Operator	2	Affirmative	On page 3 of the Implementation Plan it is stated: "For 60 months after the first day of the first calendar quarter following applicable regulatory approval, Corrective Action Plans..." It is unclear how this should be interpreted in those jurisdictions where no regulatory approval is required. For consistency, we recommend the following wording: "For 60 months after the first day of the first calendar quarter following applicable regulatory approval, or, in those jurisdictions where no regulatory approval is required, 60 months after the first day of the first calendar quarter following Board of Trustees adoption, Corrective Action Plans..."
Response: As pointed out in the comment, the wording on page 3 of the Implementation Plan should agree with the wording on page 2. The SDT has made this change. However, due to other comments, the 60 month period has been changed to 84 months. For 84 months after the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required on the first day of the first calendar quarter, 84 months after Board of Trustees adoption, Corrective Action Plans applying to performance elements…				

Voter	Entity	Segment	Vote	Comment
Tom Bowe	PJM Interconnection, L.L.C.	2	Affirmative	PJM is supports the standard because it helps to remove the ambiguity in the existing TPL standards and it promotes actions that will result in an improvement in the reliability of the Bulk Electric System. PJM believes that the draft standard addresses the issues raised in the SAR and by FERC orders 672 and 693. The industry wide webinars conducted during the drafting process were particularly helpful in providing the industry with an additional vehicle to better understand the proposed modifications to the TPL standards and provided an additional avenue for industry feedback to the Standard Drafting Team. While supportive of the standard PJM believes additional clarifying language should be added to the following requirements: R 2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: R 2.1.1. System peak Load for either Year One or year two, and for year five. It should be made clear the intent of the requirement for a "Year One or year two" assessment is to "dovetail" with the operational horizon in order to assess the steady state impact of changes from the system as planned. As currently written, the intent and required depth of the additional "Year One or year two" study is ambiguous.
Response: Part 2.1 is already part of Requirement R2 so no additional reference is required. No change made. Based on your comment and those of others, the SDT has revised the definition of Year One. **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.				
Ronald D. Schellberg	Idaho Power Company	1	Affirmative	Recommend the following slight modification to the specified subrequirements of R2 to include clarifying references to R3 and R4 as follows: o 2.1. ...by the following annual current studies in accordance with R3, ... o 2.2. ...by the following annual current study in accordance with R3, ... o 2.4. ... The following studies are required in accordance with R4: o 2.5. ...and be supported in accordance with R4 by current or past studies ...

Voter	Entity	Segment	Vote	Comment
Response: 2.1 & 2.2 – The SDT feels that the linkage between requirements is properly cited in Requirement R3 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made. 2.4 – Part 2.4 is already part of Requirement R2 so no additional reference is required. No change made. 2.5 - The SDT feels that the linkage between requirements is properly cited in Requirement R4 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made.				
Jason L. Murray	Alberta Electric System Operator	2	Affirmative	While voting affirmative on this standard we agree with the following WECC comments: 1. While draft 5 of this proposed standard is a substantial improvement over the previous drafts and the existing TPL standards, there are still areas where additional clarity is needed. We believe that a workshop, after FERC approval of the standard, where issues can be discussed and clarified will go a long way towards smooth implementation of this proposed standard. Some of the areas that require additional clarification are: o Application of consequential and non-consequential load and the EHV and HV voltage levels o Discussion on what is needed to study the various Planning Events. One example is P5, which involves "failure of a single protection system." 2. We recommend the following slight modification to the specified subrequirements of R2 to include clarifying references to R3 and R4 as follows: o 2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: o 2.2. The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: o 2.4. The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, part 2.6. The following studies are required in accordance with R4: o 2.5. The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported in accordance with R4 by current or past studies as qualified in Requirement R2, part 2.6.

Voter	Entity	Segment	Vote	Comment
				The AESO would also like to add that due to provincial acts, regulations, policies and market structure in Alberta, the AESO and Alberta entities involved in the standards process will consider modifications to this standard when adopting it as an Alberta Reliability Standard. In particular we may need to consider rewording the requirements concerning the use of RAS as mitigation for single and multiple contingencies.
Response: 1. The SDT has held several webinars on this project and may well hold another before the project is complete. In addition, the SDT has performed numerous outreach activities to regional entities, sub-committees, etc., on the details of the standard. The project has been presented several times at the NERC Standards Workshops. Once the standard is approved by FERC, the SDT ceases to exist. Therefore, any activities subsequent to that approval would be under general NERC jurisdiction. The SDT suggests that you broach this idea with NERC staff. 2.1 & 2.2 – The SDT feels that the linkage between requirements is properly cited in Requirement R3 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made. 2.4 – Part 2.4 is already part of Requirement R2 so no additional reference is required. No change made. 2.5 - The SDT feels that the linkage between requirements is properly cited in Requirement R4 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made. Thank you for this information.				
Richard Jones	South Carolina Electric & Gas Co.	5	Negative	"SCE&G appreciates the efforts of the Standard Drafting Team and believes this version of the TPL standard has addressed most of the significant issues found in previous versions. However, SCE&G believes there are several significant issues that need modification or further explanation. 1. SCE&G agrees with other submitted comments that the requirement to complete new transmission construction to meet new performance requirements within 60 months is too short. SCE&G believes that 84 months is more reasonable. 2. SCE&G agrees with comments submitted by Duke Energy that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues, does not provide any real benefit to Bulk Electric System (BES) reliability, and may have unintended negative consequences on reliability and service quality. In many

Voter	Entity	Segment	Vote	Comment
Matt H Bullard	South Carolina Electric & Gas Co.	6	Negative	instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. The standard should continue to allow Transmission Planners to use discretion regarding loss of non-consequential load, such that Transmission Planners, customers, and local regulators jointly control the decision making when BES reliability is not an issue. 3. SCE&G believes there are still different interpretations of Consequential and Non-Consequential Load loss and how each should be applied or not applied. The Standard drafting team should provide several examples in its response to these comments showing how to apply and not apply Consequential and Non-Consequential Load Loss. Without clear examples, SCE&G believes many request for interpretation will be submitted to NERC by the industry."
Response: 1. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1, footnote b order. 2. The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others' concerns in this area. 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. 3. The SDT has clarified the issue of Non-Consequential Load Loss as shown above. Providing examples here of what is Non-Consequential Load Loss versus Consequential Load Loss would have no bearing. The words are what matter and the SDT feels that the clarification provided should alleviate your concern.				
Randi Woodward	Minnesota Power, Inc.	1	Negative	1. Requirement 2 - This requirement states that Stability analyses must be performed as part of the annual Planning Assessments. We would like to see the term "Stability analysis" more clearly defined as there are several different types of stability related analysis that can be performed for power systems including: transient stability, voltage stability and small signal stability. 2. Requirement 2.5 - This requirement states that "Stability analysis shall be assessed to address the impact of proposed generation additions or changes." We would like to see the term "proposed generation" more clearly defined. It is our opinion that only planned generation should be included in the Long-Term Transmission Planning Horizon assessment. In most generation queues there is a very large amount of proposed generation which would be impractical to study. These proposed generation additions are typically included in a System Impact Study which ultimately determines the transmission upgrades required for interconnection. 3. Requirement 2.1.5 - This requirement states that potential impact of the unavailability of major Transmission equipment be assessed annually for equipment (such as transformers) with long

Voter	Entity	Segment	Vote	Comment
				delivery lead times. We believe that it should be acceptable for a Transmission Owner to maintain a spare equipment plan that includes a reliability assessment. This plan would be reviewed and updated annually. We don't believe that a detailed assessment, as part of the Near-Term Transmission Planning Horizon assessment is warranted. 4. Requirement 4.1.2 - This requirement states that apparent impedance swings resulting from generator loss of synchronism shall not result in the tripping of any Transmission System elements. We believe that this requirement, as worded, precludes the use of transmission line out-of-step tripping relays to effectively island or isolate larger blocks of generation that have lost synchronism with the BES. 5. Requirement 4.3.3 - This requirement states that the assessments should simulate the impact of transient swings on Protection System operation. This would imply that detailed models of all transmission protection elements be included in the stability analysis. We believe that this is impractical due to the large number of relays that would need to be modeled. The standard should state that the use of a relay scanning model is an acceptable alternative to using detailed relay models. A scanning model typically monitors the apparent impedance for an established set of transmission lines and flags when the apparent impedances encroach on a classical 3-zone set of distance relay characteristics based on the monitored line impedance.

Response: 1. The SDT intended for the term Stability analysis to include system Stability and unit Stability analyses. These analyses could include all three aspects of Stability that you mentioned. It is left up to the judgment of the Planning Coordinator/Transmission Planner to decide which aspects of Stability may produce more severe results and therefore, must be analyzed. No change made.

2. Each Transmission Planner is governed by rules for when and how proposed generation units will be included in analyses. The current wording of the requirement is to allow for this degree of flexibility to remain part of the planning process. No change made.

3. The SDT has clarified the requirement based on your comments and those of others.

> **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

4. Requirement R4, part 4.1.2 – The SDT agrees that you can't use an out-of-step relay and that the situation you described is a system Stability issue and is considered an application for an SPS which is allowed by the standard. No change made.

5. The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern.

> **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect

Voter	Entity	Segment	Vote	Comment
for each Contingency without operator intervention. The analyses shall include the impact of subsequent: • Successful high speed reclosing and unsuccessful high speed reclosing into a Fault. • Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.				
Robert Pellegrini	United Illuminating Co.	1	Negative	1. Section 2 of the standard requires annual assessment of the system regardless of whether system conditions are essentially unchanged from year to year. This creates unnecessary study work and must be changed in order for UI to support the standard. 2. In Table 1 - Steady State & Stability Performance Planning Events, Category P5 wording for the EHV contingency continues to call for no loss of load in the event of the loss of a single protection system. This requirement as currently worded goes well beyond the intent of the Standard Committee as stated in response to comments as follows: "A Protection System component failure (i.e., battery) that removes multiple Protection System schemes is beyond the P5 planning event". It is UI's opinion that similar language excluding battery system failures should be incorporated into this requirement. 3. UI is concerned that the standard is completely silent regarding base case assumptions and stress levels (loads and interface transfers). The standard should provide some direction or statement of objective regarding base case development and sensitivity testing requirements. For example, the standard should include some statement(s) such as, "base cases(and/or) sensitivity testing must include consideration of reasonable unplanned and planned generation outages". On the other hand UI does not suggest trying to precisely describe the number of generators that should be assumed out of service in this national standard.
Response: 1. The intent of the SDT wasn't that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and part 2.1. **Requirement R2** - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. **Requirement R2, part 2.1 -** The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6, as follows:				

Voter	Entity	Segment	Vote	Comment
2. The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns. **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following: **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94). 3. The SDT is trying to provide guidance without being overly prescriptive. Projected System conditions as well as the types of sensitivities that need to be studied are described. No change made.				
Dan R. Schoenecker	Midwest Reliability Organization	10	Negative	1. Section 2.5 proposed generation is too broad and overly inclusive. It should be replaced with planned or committed. 2. We have a concern that the timeframe of 60-month (5 year) for implementing Corrective Action Plans (CAP), is insufficient. We believe that the implementation timeframe must be extended to seven (7) years. We are aware of Requirement 2.7.3, which covers situations that arise beyond the control of the Transmission Planner (TP) or Planning Coordinator (PC), but believes that the proposed language is ambiguous and maybe problematic for compliance. 3. We believe the spare equipment language doesn't belong in the standard. Whether a Transmission Owner has spare equipment is a risk for that Transmission Owner to evaluate and then take responsibility for the decision. For the Planning Coordinator, inclusion of the spare equipment language would mean that for each Transmission Owner's piece of equipment that cannot be replaced within one year 3 more base cases would need to be run for each season and load level, which may lead to an excessive amount of base case development with little resulting benefit to reliability.
Response: 1. Each Transmission Planner is governed by rules for when and how proposed generation units will be included in analyses. The current wording of the requirement is to allow for this degree of flexibility to remain part of the planning process. No change made. 2. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility. 3. The SDT has clarified the requirement based on your comments and those of others. **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a				

Voter	Entity	Segment	Vote	Comment
lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.				
Roger C Zaklukiewicz	Roger C Zaklukiewicz	8	Negative	1. There does not appear to be a resolution to the issue of BES definition 2. A concern that too many years are required to be studied annually. Are this many studies required especially if there are no substantial transmission infrastructure additions or modifications and virtually no generation resource additions or retirements. 3. At state siting hearings, the Standard has to address the appropriate use of 90/10 or 50/50 peak load forecasts, the requirement to maintain established intra- and inter-transfer limit levels under stressed conditions. Also, more specific requirements regarding appropriate generation dispatches for area studies and large area or regional load flow and voltage studies. 4. Re-think the need or justification for modeling loads dynamically. Simulations of actual system disturbances have represented past actual system responses with a high degree of accuracy.

Response: 1. The SDT does not believe that it needs to define BES. In their March 18th orders, FERC suggested a continent-wide definition of BES. No change made.

2. The intent of the SDT wasn't that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and part 2.1.

> **Requirement R2** - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.
>
> **Requirement R2, part 2.1 -** The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, part 2.6, as follows:

3. The SDT is trying to provide guidance without being overly prescriptive. Projected System conditions as well as the types of sensitivities that need to be studied are described. No change made.

4. Dynamic load modeling is important for correct dynamic simulations. Industry has acknowledged the need for accurate Load modeling and the SDT has codified this need in the proposed standard. No change made.

Voter	Entity	Segment	Vote	Comment
James Tucker	Deseret Power	1	Negative	1. While draft 5 of this proposed standard is a substantial improvement over the previous drafts and the existing TPL standards, there are still areas where additional clarity is needed. We believe that a workshop, after FERC approval of the standard, where issues can be discussed and clarified will go a long way towards smooth implementation of this proposed standard. Some of the areas that require additional clarification are: o Application of consequential and non-consequential load and the EHV and HV voltage levels o Discussion on what is needed to study the various Planning Events. One example is P5, which involves "failure of a single protection system." 2. We recommend the following slight modification to the specified subrequirements of R2 to include clarifying references to R3 and R4 as follows: o 2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: o 2.2. The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: o 2.4. The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, part 2.6. The following studies are required in accordance with R4: o 2.5. The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported in accordance with R4 by current or past studies as qualified in Requirement R2, part 2.6 3. Table 1-P5 Multiple Contingencies (Fault plus Protection System failure to operate) Normal System. There is a significant change in the system normal performance required for EHV systems from the current performance required in TPL-003 (Category C). This TPL-001-1 version does not allow any Non-Consequential load loss (table 1) or firm Demand (note 9) for EHV systems in the event of protection system failure and delayed clearing. This performance requirement would thus preclude use of existing protection systems that rely on remote clearing of interconnected EHV lines or stations if they provide local load service. As written the standard essentially now requires Category B performance rather than Category C performance for multiple contingencies. It is Deseret's opinion

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				that loss of Non-Consequential load or firm Demand should be allowed for the rare event involving multiple contingencies stated in P5 as long at the load or firm Demand loss is contained and controlled in the local load service area and the event does not impact other interconnected utilities or their loads. 4) Table 1 - Steady State & Stability Performance Planning Events Category P5 (Multiple Contingency (Fault plus Protection System failure to operate). Category P5 requires responsible entities to study the Event titled Failure of a single Protection System that results in Delayed Fault Clearing on one of the following: Generator, Transmission Circuit, Transformer, Shunt Device, or Bus Section. It appears that this requirement is an indication that multiple protection system failure is not allowed under the proposed TPL-001-1. This appears to be a requirement for redundant protection systems for all possible events on all voltage levels of the transmission system. It also appears that this requirement is attempting to define what comprises an adequate protection system. As the draft standard is presently written it appears that multiple protection system failures are not included in this part or any part of the draft TPL-001-1 standard. As written, it is Deseret's view that any multiple protection system failure would be categorized as an Extreme Event under the draft TPL-001-1 standard. Deseret contends that the many and varied issues associated with designing appropriate protection systems should be done in the context of the development of a protection system standard and not in the context of TPL-001-1. In fact, there is currently a proposed standard going through the NERC standards development process which goal is exactly that. If the standards drafting team intends to require responsible entities to have 100% redundant protection systems on all of its BES facilities, Deseret contends that this fact should be stated up front in the standard so that all interested parties may become aware of this requirement and provide informed comment. Deseret believes that it is appropriate to wait until the current protection system redundancy standard under development proceeds through the SAR process and approval system, given that this in an important generic issue that affects the entire industry. Notwithstanding the inappropriateness of raising the protection system issue in the context of a planning standard, Deseret believes that any planning requirement that includes the failure of a single protection system that results in delayed fault clearing must have a very clear definition of the terms "single protection system" and "delayed fault clearing" in or for entities to determine what compliance with the standard requires. The draft TPL-001-1 standard does not have clear definitions of these terms, leaving room for considerable latitude for interpretation by various responsible entities, auditors, and compliance enforcement authorities. Clear, specific, and technically defensible language is needed for these terms.
Response: 1. The SDT has held several webinars on this project and may well hold another before the project is complete. In addition, the SDT has performed numerous outreach activities to regional entities, sub-committees, etc., on the details of the standard. The project has been presented several times at the NERC Standards Workshops. Once the standard is approved by FERC, the SDT ceases to exist. Therefore, any activities subsequent to that approval would be under				

Voter	Entity	Segment	Vote	Comment
general NERC jurisdiction. The SDT suggests that you broach this idea with NERC staff. The SDT feels that the linkage between requirements is properly cited in Requirement R3 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made. Part 2.4 is already part of Requirement R2 so no additional reference is required. No change made. The SDT feels that the linkage between requirements is properly cited in Requirement R4 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made. The SDT agrees that the bar has been raised for the EHV system in that no planned Load shedding (Non-Consequential Load Loss) is permitted for the P5 condition beyond Protection System clearing that responds to the studied P5 event. All Load removed by the Protection System isolating the Fault is Consequential Load Loss for the event. The SAR for this standard recognized FERC orders which indicated a need to "raise the bar" for the industry. The SDT agrees with this premise and is attempting to do this in a reasonable fashion. No change made. The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns. **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following: **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).				
Bernard Pelletier	Hydro-Quebec TransEnergie	1	Negative	The reason for the No vote cast by HQT is that HQT still believe that the EHV and HV threshold defined as a fixed voltage (300 kV) on footnote 3 of Table 1 is too prescriptive, and unnecessary, for NPCC Members using a performance base methodology to determine elements of the BPS. HQT believes that if the 300 kV threshold was introduced as a necessity to reduce the BES portion of the system subject to the Standard in some region with a 100 kV bright line definition of BES so that entities in these regions do not incur prohibitive spending to respect this Standard, there should also be a way to accommodate NPCC Member's use of a performance methodology to determine on which elements to apply the Standards without having entities guessing the way Compliance will be implemented for this Standard in regard to specific voltage threshold. For HQT's system, EHV should correspond to 735 kV since more than half of our 315 kV substations directly supply load. The SDT gave this answer as the rational for choosing the 300 kV threshold when they replied to HQT concerns about the EHV voltage definition as 300 kV and over, in the first posting of the Standard : Â« Systems operated above 300 kV generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers where the energy is then delivered by other Transmission or sub-Transmission Systems to end use customers... Obviously the intent of the SDT when choosing a 300 kV threshold do not correspond to the reality of HQTs system characteristic. HQT agrees with the intent of the SDT to raise the bar in that important Standard but disagree with having to systematically apply the

Voter	Entity	Segment	Vote	Comment
				Standard to all 300 kV and above system. One way to clarify the Standard would be to mentioned in the footnote 3 that :`` In the region where there is a performance base methodology to determine BES element, these BES elements would be subject to the Standard; in other region, the 300 kV threshold would apply.
Response: This standard applies to the BES. If there are areas of your system that are not BES, then the standard doesn't apply to them. This would be true even if those elements are above 300 kV. No change made.				
Donald Gilbert	JEA	5	Negative	Although this proposed standard places additional burden of proof upon JEA's Transmission Planning process, JEA finds the overall direction of the standard requirements prudent. JEA appreciates the allowance of Non-Consequential Load Loss afforded in provision 2.7.3 where documented circumstances outside the control of the TP or PC suffice; however, JEA is concerned that there are some limited prudent cases where consumers, local jurisdictions, and state jurisdictions may find it prudent to plan on some Non-Consequential Load Loss in order to defer building transmission infrastructure (just for the purpose to serve speculative load growth) for the overall benefit of the consumer. Therefore, concerning the prohibition of Non-Consequential Load Loss, JEA proposes the addition to the standard that allows the use of Non-Consequential Load Loss for local area load for planning events where it is not presently allowed. In Â¶1794 of Order 693, FERC stated "Regarding the comments of Entergy and Northern Indiana that the Reliability Standard should allow entities to plan for the loss of firm service for a single contingency, the Commission finds that their comments may be considered through the Reliability Standards development process. However, we strongly discourage an approach that reflects the lowest common denominator." Clearly, FERC did not direct NERC to eliminate "all" use of Non-Consequential Load Loss for single contingencies, but rather stated that its use should be "considered through the Reliability Standards development process". Therefore, the SDT should define "local area" where load loss is allowed and either set limits on how much load can be lost or a reporting requirement to ensure transparency concerning this planning practice. I propose that the standard should define "local area" as the load that is located on a single loop between two BES sources and limit the Non-Consequential Load Loss to the amount of Consequential Load Loss that would occur if the networked loop of load serving stations were sectionalized such that the loop operated as two radial circuits. The Standard could further require the TP or PC to document the results of both simulations with and without the sectionalization of the loop comparing the levels of Non-Consequential Load Loss to the level of Consequential load loss." This approach would clearly not be "a least common denominator approach", but rather a practical manner to allow the balance between transmission expansion costs and the limited risk to the local load within an area.

Voter	Entity	Segment	Vote	Comment
Response: The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area. 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.				
Kirit S. Shah	Ameren Services	1	Negative	Ameren appreciates the diligence and dedication of the Standard Drafting Team and commends the group for their hard work to bring the proposed standard TPL-001-1 to this level. We have seen considerable improvements to the proposed standard from earlier versions and note the positive changes to many of the requirements. We also recognize that the overall language of the standard has improved to enhance its readability and the language and format of the Tables now provides a clear understanding of acceptable System performance for the various Planning Events. However, inasmuch as the proposed Standard has improved, we cannot support the approval of this document at this time. 1. We disagree with the proposed definition of Year One. We believe that Year One should be the planning window that begins 12-18 months from the start of the current calendar year, and not from the end of the calendar year. We believe that following this modification to the definition would require minimal adjustments to the ERAG MMWG model building process, which we all use as the basis for our planning models. Following the proposed definition would require additional models to be built by the MMWG or lead to holes in the model building effort for both the operating and planning horizons. 2. We do not believe that 60 months is a reasonable time period to build transmission facilities to meet the new performance requirements. Building a transmission line in Illinois is estimated to take 7 years (84 months) from the time the project is authorized. Though requirement R2.7.3 is included to address situations beyond the control of the Transmission Planner, it leaves to the interpretation of the auditor whether the appropriate actions are being taken to resolve the issue that would continue to allow dropping of Non-Consequential Load or curtailment of Firm Transmission Service. 3. We have concerns for including induction motor representations in the load models without any study or bench-marking activities to meet the requirements of R2.4.1. Although the proposed standard offers that an aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable (to relieve the burden of trying to develop specific induction motor load representation at each load bus), we believe that the modeled System response will be considerably different compared to the actual System response in some parts of the System which will open up the industry to additional scrutiny, such as the Compliance Inquiry (CIQ) and/or Compliance Violation Investigation (CVI). 4. We do not agree that low voltage ride-through is a steady-state issue as included in requirement

Voter	Entity	Segment	Vote	Comment
				R3.3.2. We believe that low voltage ride-through is a dynamic modeling issue as correctly included in requirement R4.3.2. 5. We have concerns that the dynamics models cannot support the additional data requirements to include actual impedance relay models for all transmission facilities to meet the requirements of R4.1.2 and R4.3.3. In an attempt to relieve our concerns, the SERC presenters indicated that generic PSS/E impedance relay models could be included in the dynamics models. However, we also have concerns for using generic PSS/E impedance relay models as the actual impedance relays may be set differently than the generic PSS/E relay models which will open up the industry to additional scrutiny, such as the Compliance Inquiry (CIQ) and/or Compliance Violation Investigation (CVI).

Response: 1. Based on your comment and those of others, the SDT has revised the definition of Year One.

> **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

2. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility.

3. The SDT assumes that you are referring to the induction motor Load modeling required for Stability studies. The standard permits an aggregate model assumption that can be applied for a given system that is not substation specific. The SDT believes that 24 months is an adequate time period to accomplish this task. Dynamic load modeling is important for correct dynamic simulations. Industry has acknowledged the need for accurate Load modeling and the SDT has codified this need in the proposed standard. No change made.

4. The SDT voltage ride through is not confined to the dynamic period. There are protection requirements that could result in generator tripping and that must be considered in the steady-state analysis. The SDT has clarified the wording of the requirement.

> **Requirement R3, part 3.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:
>
> - Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.
> - Tripping of Transmission elements where relay loadability limits are exceeded.

Voter	Entity	Segment	Vote	Comment
5. 4.3.3 - The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern. **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: • Successful high speed reclosing and unsuccessful high speed reclosing into a Fault. • Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.				
Robert D Smith	Arizona Public Service Co.	1	Negative	APS proposes that the standard allows the use of Non-Consequential Load Loss for local area load for P1 events. The current requirements may pose significant burden without appropriate benefits. As currently written APS does not believe that 60 months is a reasonable time period to build transmission facilities to meet the new performance requirements. Building a transmission line can often take more than 5 years to complete from the time the project is authorized. Though requirement R2.7.3 is included to address situations beyond the control of the Transmission Planner, it leaves to the interpretation of the audit whether the appropriate actions are being taken to resolve the issue. APS proposes that the requirement be changed to 84 months.
Response: The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area. 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility.				
John Tolo	Tucson Electric Power Co.	1	Negative	As currently written it is believed that 60 months is not a reasonable time period to build transmission facilities to meet the new performance requirements. Regional and local planning and review process, permitting, siting, legal challenges, routing, and system path rating process can often take more than 5 years to complete from the time the project is authorized. Category P2 requires responsible entities to study the opening of a line section without a fault. The

Voter	Entity	Segment	Vote	Comment
				standard as written states that the opening of this line section will not result in consequential load loss and no voltage or thermal violations will occur on the BES. This requirement should not be applicable to all HV facilities. From a reliability perspective, a more effective and efficient method would be a bifurcated functional requirement rather than a voltage requirement. This TPL-001-1 version does not allow any Non-Consequential load loss (table 1) or firm Demand (note 9) for EHV systems in the event of protection system failure and delayed clearing. This performance requirement would thus preclude use of existing protection systems that rely on remote clearing of interconnected EHV lines or stations if they provide local load service. Category P5 requires responsible entities to study the Event titled Failure of a single Protection System that results in Delayed Fault Clearing on one of the following: Generator, Transmission Circuit, Transformer, Shunt Device, or Bus Section. It appears that this requirement is an indication that multiple protection system failure is not allowed under the proposed TPL-001-1. This appears to be a requirement for redundant protection systems for all possible events on all voltage levels of the transmission system. It also appears that this requirement is attempting to define what comprises an adequate protection system. Many and varied issues associated with designing appropriate protection systems should be done in the context of the development of a protection system standard and not in the context of TPL-001-1. TPL-001-1 has added requirement 2.1.5 discussing spare equipment and lead times and inclusion in the "Planning Assessment". The standard in this section is not performance based requirement but an activity based requirement as currently stated under R2 2.1.5. The standard should be revised and 2.1.5 removed as it does not directly improve the systems performance requirements nor compliance stated in Table 1.

Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order.

The SDT believes that the addition of footnote 12 (when it is finalized) will address your concern.

The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area.

12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.

The SDT has clarified the requirement based on your comments and those of others.

Requirement R2, part 2.1.5 - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall

Voter	Entity	Segment	Vote	Comment
be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.				
Brandy A Dunn	Western Area Power Administration	1	Negative	As drafted the standard TPL-001-1 has added requirement 2.1.5 discussing spare equipment strategy and lead times and inclusion in the "Planning Assessment". The standard in this section is not a performance based requirement but an activity based requirement as currently stated under R2 2.1.5. We recommend that the standard be revised and 2.1.5 removed as it does not directly improve the systems performance requirements nor compliance stated in Table 1.
Joseph S. Stonecipher	Beaches Energy Services	1	Negative	We believe that requirement 2.1.5 on spare equipment strategy is discriminatory for smaller entities. For many smaller entities, having a spare transformer is not a practical solution and makes far less sense and has significantly more customer rate impacts than for a larger utility. Yes, it may be possible to arrange an agreement with a neighboring entity for use of their spare, but that assumes that the neighboring entity's transformer specifications are similar enough for use as a spare, which may not be the case. Order 693 states at Paragraph 1725: "... the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy". The standard oversteps this direction by not including a consideration of planned outages versus forced outages in requirement 2.1.5, in other words, if an entity has no plans for a long term outage of a transformer, it should be excluded from the assessment of 2.1.5. Such a condition would allow an entity to assess things like gas in oil analysis to predict when a long term outage might be planned, and the flexibility between start and end dates of that planned outage.
Bruce Merrill	Lincoln Electric System	3	Negative	Requirement 2.1.5 should only address known planned outages of major Transmission equipment that has a lead time of one year or more. As currently drafted requirement 2.1.5 does not specify whether it includes both forced outages and planned outages. Requirement 2.1.5 also does not specify that system adjustments are allowed since adjustments are not allowed in categories P0, P1, and P2. Without system adjustments the requirement 2.1.5 would always produce more severe System impacts than the categories P0, P1, and P2 in Table 1. Allowing System adjustments would make requirement 2.1.5 (P1) match category P6, yet requirement 2.1.5 (P2) would still result in more
Dennis Florom	Lincoln Electric System	5	Negative	

Voter	Entity	Segment	Vote	Comment
Eric Ruskamp	Lincoln Electric System	6	Negative	severe System impacts than currently contemplated in the TPL-001-1 Standard. It appears that requirement 2.1.5 would greatly increase the study work by requiring a new base case for each unique Transmission equipment and repeating the associated contingency analysis. Would Correction Action Plans be required for requirement 2.1.5, whereas, they do not need to be developed solely to meet the performance requirements for a single sensitivity?
Response: The SDT has clarified the requirement based on your comments and those of others. **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.				
Elizabeth Howell	ITC Transmission	1	Negative	As written, the balloted standard is a significant advancement over the past planning standards. It raises the bar for the EHV system (>300kV) and is a significant step forward toward the desired improvement in the North American electric grid. The detailed requirements along with the Table 1 performance expectations for Planning Events should result in Corrective Action Plans that improve the electric grid in measurable ways. The additional specifications to insure that load will not be lost, intentionally or otherwise, during relatively routine system outages reinforces the value of reliability standards. While ITC recognizes the significant improvement in the Planning Standard and applauds the Standard Drafting Team (SDT) for constructing this new document, we believe minor changes are still needed to provide clarity to the standard to avoid possible miss-interpretation of the intent of the SDT during compliance audits and the potential for unnecessary duplication of study effort in areas if differences between the studies conditions are relatively small. Minimally, ITC feels additional guidelines need to be supplied for some of the decisions left to engineering judgment, such as in R2.5 where it is clear as to the need for studies of "new" generation, no "minimum" size is indicated. Additional guidelines should be added to the standard and the Reliability Standard Audit Worksheet (RSAW) should be completed prior to balloting the standard. ITC is concerned about the mandatory need for the three distinct studies as required in R2.1 and R2.2 if the differences between the prevalent conditions are projected to be small. For example, if a systems load changes are insignificant between years 1 or 2 and year 5, and other conditions changes such as generation additions, power flow patterns and other are small for the system under study. The same issue may exist between year 5 and years 6 through 10 Under such conditions these studies may not be prudent and necessary to thoroughly evaluate the systems performance. ITC

Voter	Entity	Segment	Vote	Comment
				agrees with the SDT that the three studies make sense and are prudent when a system's conditions are changing. A review of how this section in the standard might be warranted. While a spare equipment strategy is a good idea, R2.1.5, the requirement should be clear to avoid compliance violations for the implications of a major piece of equipment failure with or without spare equipment. Until this is clearer for both Planners and auditors or an RSAW is available, there is a greater likelihood for compliance issues. ITC also has concerns regarding requirements R3.3.2 and R4.3.2 regarding Low Voltage Ride Through (LVRT). Both require tripping of generators when "voltages are less than known or assumed generator low voltage ride through capability". This means the planner either knows the limit or assumes one. For ITC, we only trip for "known" limits, such as those for wind generators. Our policy is to not "assume" LVRT. A concern is if a LVRT is not assumed for all plants will a transmission company be found not compliant. This should be made clearer either in the standard or in an RSAW. For these reasons, ITC is voting no at this time. ITC would like to see the SDT add clarity to the sections identified above or develop a Reliability Standard Audit Worksheet to accompany the standard being ballotted. Please feel free to contact us if you have questions regarding our comments.

Response: The SDT has clarified the requirement wording to address your concern.

> **Requirement R2, part 2.5 -** The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, part2.6. The technical rationale for determining material changes shall be documented.

The intent of the SDT wasn't that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and part 2.1.

> **Requirement R2** - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.

> **Requirement R2, part 2.1 -** The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, part 2.6, as follows:

The SDT has clarified the requirement based on your comments and those of others.

> **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible

Voter	Entity	Segment	Vote	Comment
unavailability of the long lead time equipment The SDT voltage ride through is not confined to the dynamic period. There are protection requirements that could result in generator tripping and that must be considered in the steady-state analysis. The SDT has clarified the wording of the requirement. **Requirement R3, part 3.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: • Tripping of generators where simulations show generator bus voltages or high side of the Generation Step Up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. • Tripping of Transmission elements where relay loadability limits are exceeded. The development of an RSAW is more properly the purview of the Compliance Dept. No change made.				
Jason Shaver	American Transmission Company, LLC	1	Negative	ATC believes that the Standard is moving in the right direction, but has identified the following concern which is preventing us from voting "affirmative". Our concern is that the timeframe of 60-month (5 year) for implementing Corrective Action Plans (CAP), is insufficient. We believe that the implementation timeframe must be extended to seven (7) years. ATC is aware of Requirement 2.7.3, which covers situations that arise beyond the control of the Transmission Planner (TP) or Planning Coordinator (PC), but believes that the proposed language is ambiguous. Clarity needed (R 2.7.3): 1) An auditor could identify many things that could reasonably be within the "control" of a TP or PC but are not covered by NERC standards or a TP / PC's process, procedures or criteria. This wide area of discretion leaves entities open to possible non-compliance violation based on an auditor's perception of what they believe should be in the TP / PC's control. 2) In addition, we believe that the concept of "control" must be limited to an entities compliance obligation as a Transmission Planner and/or Planning Coordinator. In other words entities must be allowed the ability identify situation which fall under its "control" as a Transmission Owner, Transmission Operator, Generator Owner or Generator Operator etc. but is beyond the responsibility of its Transmission Planner or Planning Coordinator functions. . Suggested footnote: A TP or PC is in compliance with this requirement if the situation being documented is not covered in its internal processes, procedures or criteria required for NERC/Regional compliance obligations assigned to the TP or PC functions. Transmission Planners and Planning Coordinators are responsible for the identification of a CAP but it is the Transmission Owner that is ultimately responsible for implementing the CAP.
Gregory J Le Grave	Wisconsin Public Service Corp.	3	Negative	

Voter	Entity	Segment	Vote	Comment
				Additional areas of concern: ATC requested that the SDT re-examine the following concerns which we have been previously identified: 1. R1.1.2 "known outages of at least six months in duration" - The present wording in inconsistent between R1.1.2 and R2.1.3. We suggest that this requirement be removed because the "known outage(s)" are only to be included in the models when P1 events are simulated, as specified in R2.1.3. We suggest that the intent of this requirement can be more simply handled by stating in R2.1.3 that "known outages be simulated along with P1 events for the System peak or Off-Peak conditions when the outages are scheduled to occur". 2. R2.1.4 & R2.4.3 "range of credible conditions that demonstrate a measurable change in performance" - We suggest that the terms "credible" and "measurable" be define or use words that more definitively describe the requirement. 3. Table 1 - Requirements are "buried" in the Performance Table, rather than being included in the Requirement Section - a. Add R2.7.5 - We believe that all requirements should appear in the Requirements section and not be "buried" in the performance tables. We propose the addition of the following bullet item to R2.7.5. It could read, "Planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration of the Facility Ratings." Note "e" in the Planning Events, Steady State & Stability section is stated in the form of a Requirement (e.g. use the verb "shall"), but all requirements should be included in the Requirements section and not introduced (and basically hidden) in the performance notes of Table 1. [After bullet item #7 is added, Note "e" under "Steady State & Stability section of Table 1 should refer to R2.7.5] b. Add R3.3.5 - We believe that all requirements should appear in the Requirements section and not be "buried" in the performance tables. We suggest the addition of R3.3.5. The text of R3.3.5 should read, "Applicable System Operating Limits for the planning horizon shall not be exceeded." Presently, Note "a" and "b" under "Steady State Only" at the beginning of Table 1 are stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and basically hidden) in the performance notes of Table 1. [After R3.3.5 is added, Note "a" should be revised and refer to R3.3.5.] c. Add R3.6 - We believe that all requirements should appear in the Requirements section and not be "buried" in the performance tables. We suggest the addition of R3.3.6. The text of R3.3.6 should read, "The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to steady state voltage requirements." because Note "d" under "Steady State Only" at the beginning of Table 1 is stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly

Voter	Entity	Segment	Vote	Comment
				stated under Requirements and not be introduced (and basically hidden) in the performance notes of Table 1. [After R3.3.6 is added, Note "d" should be revised to refer to R3.3.6.] 4. R2.7.2 - "include actions to resolve performance deficiencies identified in multiple sensitivity studies" - We do not think that mitigation plans should be required for deficiencies found in multiple sensitivity studies because the conditions in some sensitivity studies are more extreme and less likely than base case conditions. Some of the sensitivity study conditions are not credible or plausible enough to warrant the implementation of mitigation measures. What is the interpretation of multiple studies - more than one or a majority of the number that were studied? 5. R3.5 - We interpret that R3.5 requires the TP and PC to conduct an evaluation of possible actions to reduce the likelihood or impact of extreme events, which produce the more severe impacts, if cascading outages may occur. Does the drafting team intend for the TP and PC to fulfill this requirement for at least one event in each of the five categories (i.e. 3 steady state and 2 stability) or in each of the 21 categories/sub-categories (i.e. 14 steady state and 7 stability). Also, if the resulting cascading outages do not result in any overloads, under-voltages, voltage collapse, or loss of generator synchronization, then should the evaluation of possible actions to reduce likelihood or impact still be required?

Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility.

The SDT believes the existing wording is clear and that the suggested wording is equivalent without providing any additional clarity. No change made.

Requirement R2, part 2.1.4 is part of Requirement R2 which mandates that an entity must document all assumptions utilized in the Planning Assessment. No change made.

The suggested change would move header note 'e to new Requirement R2, part 2.7.5 on the premise that it is a buried requirement. The phrasing of header note 'e' does not indicate that it is a mandatory requirement. It is a statement of allowed actions consistent with other notes. No change made.

The SDT does not believe that the items mentioned are buried requirements; rather they are statements of system performance that are better placed in the performance table. Requirements R3 & R4 specifically refer to the table which makes the table part and parcel of the requirements. No change made.

The SDT believes that it is more effective to state this as a header note instead of repeating it multiple times throughout the table. It is not a buried requirement but a description of what is utilized in the simulation. No change made.

Voter	Entity	Segment	Vote	Comment
Requirement R2, part 2.7.2 already states that an entity must supply the rationale for when actions were not necessary so the SDT believes that your concerns have already been addressed. No change made. The requirement states that an entity must supply the rationale for those events selected so the SDT believes that your concern has already been addressed. It provides the necessary guidance while allowing needed flexibility and not being overly prescriptive. No change made.				
Larry E Watt	Lakeland Electric	1	Negative	Below are some proposed changes and requests for clarification concerning the new TPL-001-1 standard. R2.6.2 The phrase "material changes" is not explicitly defined, and it is unclear what changes constitute a "material" change. It is asked that more precise wording or a definition of the word "material change" be provided. R3.3.2 The words "...known or assumed minimum generator steady state or ride through voltage limitations..." could be (and were) read as a series, with "known", "assumed minimum generator steady state", and "ride through voltage limitations" interpreted as three items in the series. For clarity, it is suggested that the standard be rewritten as such: Trip generators where simulations show generator bus voltages or high side of the Generation Step Up (GSU) transformer voltages are less than the known or assumed minimum generator steady state, or the known or assumed ride through voltage limitations. Include in the assessment any assumptions made. Here, the comma separates the two items in the series, with the words "known" and "assumed" modifying each of the items. R4.3.2 Following the changes made to requirement 3.3.2, it is suggested that requirement 4.3.2 be changed to the following: Trip generators where simulations show generator bus voltages or high side of the Generation Step Up (GSU) transformer voltages are less than the known or assumed minimum generator low voltage ride through capability. Include in the assessment any assumptions made. R4.3.3 An issue has been raised as to whether the word "simulate" denotes the modeling of all relays that protect transmission lines and transformers within a power flow/transiant simulator. It is suggested that this word be changed to "assess," to clarify that this requirement does not compel the Planning Coordinator and Transmission Planner to conduct PSS/E simulations to study the above conditions. The revised requirement can read: Assess the impact of transient swings on Protection System operation for Transmission lines and transformers. R4.4.1 There are two concerns with this requirement. The first is that this requirement makes no provision for the adjacent Planning Coordinator (PC) and Transmission Planner (TP) with a System Contingency to notify the PC and TP of the impacted System. Instead, the responsibility falls on the

Voter	Entity	Segment	Vote	Comment
				PC and TP of the impacted System to confer with each of their adjacent PCs and TPs to verify if a contingency on an adjacent System impacts the formers System. Or, it can cause the PC and TP to perform exhaustive contingency analyses (P0-P7) on all adjacent systems to determine which contingency/contingencies can impact their system to include them in their Contingency list. The second is that the term "impact" is not defined. A concern is should a Contingency cause a line on an adjacent System to load from 99% to 101% of its SOL rating, does this 2% constitute an "impact"? Conversely, would a Contingency that causes a significant increase to an adjacent System's line of 5% or more, without violating that line's SOL rating, be considered as having "impacted" the adjacent System? The proposed change to this requirement is: Adjacent Planning Coordinators and adjacent Transmission Planners will coordinate the identification of those Contingencies within their Systems and determine which, if any, impact the adjacent System. Those identified Contingencies may then be added to the adjacent Planning Coordinators and Transmission Planners' Contingency List. With this change, PCs and TPs of both Systems are responsible for coordinating their efforts, and the definition of "impact" is left to the coordinating PCs and TPs to decide. R8 It is unclear whether the adjacent Planning Coordinators and adjacent Transmission Planners must submit a written request for the information, or if the written request applies only to the functional entity that has a reliability related need. If the adjacent Planning Coordinators and adjacent Transmission Planners do not need to submit a written request, should the Planning Assessment be sent to them automatically?

Response: Material change is system specific and difficult to define on a continent-wide basis and is left to engineering judgment with a documented technical rationale as stated in the requirement. No change made.

The SDT does not see any real difference in the suggested wording from what is already there. No change made.

The SDT does not see any real difference in the suggested wording from what is already there. No change made.

The SDT has clarified the requirement to address your concerns.

Requirement R4, part 4.3.1 - Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

- Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual

Voter	Entity	Segment	Vote	Comment
				relay models. Since the requirement is written for each Planning Coordinator and Transmission Planner, it covers the exchange of information on critical Contingencies and their impacts among all Planning Coordinators and Transmission Planners and thus distributes the responsibility and work load. No change made. The SDT does not see any real difference in the suggested wording from what is already there. No change made. The requirement clearly states that the entity must have a reliability-based need for the information so that unauthorized requests won't be made and the request for the information must be in writing. No change made.
Eric Egge	Black Hills Corp	1	Negative	BHC does not believe that 60 months is a reasonable time period to build transmission facilities to meet the new performance requirements. Building a transmission line varies significantly in regional and local planning and review process, permitting, siting, legal challenges, routing, and system path rating process can often take more than 5 years to complete from the time the project is authorized. Though requirement R2.7.3 is included to address situations beyond the control of the Transmission Planner, it leaves to the interpretation of the audit whether the appropriate actions are being taken to resolve the issue that would continue to allow dropping of Non-Consequential Load or curtailment of Firm Transmission Service. As drafted the standard TPL-001-1 has added requirement 2.1.5 discussing spare equipment and lead times and inclusion in the "Planning Assessment". The standard in this section is not performance based requirement but an activity based requirement as currently stated under R2 2.1.5. PacifiCorp recommends that the standard should be revised and 2.1.5 removed as it does not directly improve the systems performance requirements nor compliance stated in Table 1.
Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility. Requirement R2, part 2.7.3 requires an entity to document their actions. Therefore, it is up to the entity to ensure that the documentation sufficiently explains their position. No change made. The SDT has clarified the requirement based on your comments and those of others. **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall				

Voter	Entity	Segment	Vote	Comment
be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.				
Janelle Marriott	Tri-State G & T Association Inc.	3	Negative	Definitions section- Add a definition to this standard, which would revise the definition of "Stability" in the NERC glossary to read: "Stability: Unless qualified specifically as Voltage Stability, the term Stability shall mean the ability of system generators to maintain angular equilibrium, also known as Dynamic stability." Definitions section- The definition for Year One is vague. If the definition is intended to capture both a summer and winter season and is necessary to provide a clear starting point for the planning horizon, then this should be stated explicitly in the definition. We recommend inserting the phrase "12-month" before the phrase "planning window" R2.1 The word "current" can mean either "electrical current" - a physical measure of electron movement, or "at the present time" - most recent or up-to-date. If you must use the term "current" in R2.1, say "current annual studies" rather than "annual current studies". R2.1.4 Part 2.1.4 should be removed from the requirement. The benefits of requiring one or more of these is unclear. Which of the listed conditions does an entity choose? There are no criteria for selection of one of the listed sensitivity topics as most-significant to a particular system. It is not apparent how particular sensitivities would increase BES reliability. If this part is not deleted, we recommend removing the phrase "not already included in the studies". Also, this requirement must state how one could determine validity of chosen sensitivity conditions. R2.1.5 We suggest adding the word "individually" to the end of the first sentence of part R2.1.5: "impact of this possible unavailability on System performance shall be assessed individually." In R2.4.1, it is left to the utility what level of load modeling detail is used. This is good because it gives the utility flexibility to select and use appropriate models. However, is it not clear what behavior of induction motors is targeted here. We recommend deleting the phrase "considering the behavior of induction motor loads", or else please specify what behavior is of concern. Part 2.4.3 should be removed from the requirement. As commented in our response to part 2.1.4, the benefit of requiring one or more of these is unclear - which of the listed conditions does an entity choose? There are no criteria for selection of one of the listed sensitivity topics as most-significant to a particular system. It is not apparent how this would increase BES reliability. If this part is not deleted, we recommend removing the phrase "not already included in the studies". Also, this requirement must state how one could determine validity of chosen sensitivity conditions. R2.6.2 We suggest that 2.6.2 be modified to read: "the System represented in the study has not
Keith V. Carman	Tri-State G & T Association Inc.	1	Negative	

Voter	Entity	Segment	Vote	Comment
				materially changed, or a technical rationale can be given that the changes do not impact performance in the study area." If 2.1.4 and 2.4.3 are removed as we suggest, then this sentence in part 2.7 should be removed: "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirement R2, parts 2.1.4 and 2.4.3." In part 2.7.1, remove the second sentence and all bullets. These are not measurable performance criteria. R3.5 asks for evaluation of actions designed to reduce the likelihood of potential cascading caused by extreme events, but 1) does not require documentation of results, and 2) does not require that the evaluation show that proposed actions would affect or limit cascading. R4.1 Insert "compliance with" in R4.1 text, which will then read "based on the Contingency list created in compliance with Requirement R4, part 4.4." There is no list in part 4.4. Part 4.4 requires a list of more severe contingencies (Table 1 planning events) to be created. R4.1.2 is unrealistic. Utilities implement out-of-step tripping schemes to limit the extent of impacts of such events that cause out-of-step conditions. Some of these occurrences can be mitigated better by tripping transmission elements and not generation. The decision to trip either transmission or generation should not be predetermined in the standard. We recommend that part 4.1.2 be reworked. R4.1.3 Does this preclude the regional reliability organization from choosing to establish damping criteria at some time in the future? R4.3.1 It is unclear whether this refers to the possibility of reclosing system failure, or the impacts of reclosing into a still-faulted system. R4.3.2 This is an admirable goal, and we applaud the SDT's vision. However, modeling all Protection Systems may be beyond the capabilities of presently used dynamic modeling tools. The number of impedance and overcurrent relays that would need to be included for lines and transformers would likely overwhelm these programs. We are concerned that the programs in use may not have the capability to model important relay characteristics such as load encroachment or out-of-step operating characteristics. R4.3.4 The phrase "of electrical system quantities" is unclear and can be removed without changing the intent of the requirement. R6 Remove the "for conditions such as ..." list.

Voter	Entity	Segment	Vote	Comment
				Does Table 1, Category P5, require consideration of clearing from all remote terminals and evaluating those time delays assuming no tripping is available locally? Table 1 Extreme Events List- In the Stability section of the Table 1 Extreme Events List, use the term Dynamic Stability, not just Stability - or insert a revised Stability definition as noted above. M8, part 1.4 Simplify by changing "current, in force documentation" to "operative documentation". "Current" is redundant with "in force". Table 1 - Headnotes to Planning Events o Table 1, Headnote b - Delete "or extreme" since this headnote is for Planning Events. o Table 1, Headnote e - You may omit the phrase "For all planning events," since this headnote is for Planning Events. o Table 1, Headnote i - It is unclear what is meant by "end-user equipment associated with an event". o Table 1, Headnote h -We suggest this be moved to a footnote for P0: "Planning Event Category P0 is applicable to steady state only. No Dynamic Stability Analysis is required." o Headnote j - It is not clear why this falls under "Stability Only", and suggest that "dynamic stability" be included with headnote "a" Table 1 - Footnotes o Table 1, Footnote 2 - We suggest this footnote is not needed. R2.3 covers this sufficiently. o Table 1, new footnote- We suggest a footnote be added to the column labeled "Initial System Condition" indicating that "Normal System means all transmission elements are in service and all portions of the BES within the study area are performing within specified operating limits". Table 1 - Planning Events o Event P2 is categorized as 'Single Contingency'; however the listed events would typically result in the loss of more than one element. In other words, Category P2 contingencies are those in which a single system element is removed from service due to one of the listed initiating events. We are concerned because it appears that all events listed for the single-contingency Category P2 are not covered under other multiple-contingency Categories. For example, a faulted Bus Section. o Events P2 and P5 are described in terms of the elements initiating a fault, while the others are in terms of number of elements out-of-service due to a contingency. Event P4 is described in terms of

Voter	Entity	Segment	Vote	Comment
				both - the elements lost and the initiating fault. It would be helpful to have additional notes explaining the apparent inconsistent wording of Planning Events. o The distinction between 'Single Contingency' and 'Multiple Contingency' Category classifications for an event must be clear. Categories A through D have worked well for the industry to this point, and it would be helpful if the transitio

Response: The SDT feels that the current definition fits the intent of the standard. Modifying the definition could have unintended consequences on other standards. No change made.

Based on your comment and those of others, the SDT has revised the definition of Year One.

> **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

The SDT agrees and has made the change.

> **Requirement R2, part 2.1 -** The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, part 2.6, as follows:

The SDT has deleted the suggested phrase.

> **Requirement R2, part 2.1.4 -** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

The SDT has clarified the requirement based on your comments and those of others although the term 'individually' was not added as the SDT did not see that it added any clarity.

> **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment

The SDT has clarified the requirement.

> **Requirement R2, part 2.4.1** - System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the

Voter	Entity	Segment	Vote	Comment
				expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. The SDT has deleted the suggested phrase. **Requirement R2, part 2.4.3 -** For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: The SDT does not see that the suggested change adds clarity. No change made. Parts 2.1.4 or 2.4.3 were not removed so no change is needed here. The listed items are simply that – a list of actions that would be included. This is an allowable and encouraged format for Reliability Standards. No change made. Requirement R3, part 3.5 is part of Requirement R3 which links back to Requirement R2 where the documentation is required. No change made. The SDT believes that the present wording is correct. No change made. Requirement R4, part 4.1.2, deals with a single generator pulling out of synchronism. The situation you described is a system Stability issue and is considered an application for an SPS which is allowed by the standard. No change made. Nothing in this standard precludes a region from adopting an additional requirement in the future. No change made. The SDT modified the language of the requirement to address your concern. **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: • Successful high speed reclosing and unsuccessful high speed reclosing into a Fault. • Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models. The SDT believes that your comment is for requirement R4, part 4.3.3. The SDT has modified the wording of this requirement to address your concern. **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: • Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.

Voter	Entity	Segment	Vote	Comment
				• Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models. The SDT does not see any reason to delete the phrase as it is not causing any confusion. No change made. The SDT believes that the present wording is appropriate. No change made. You need to model the way that Protective System is expected to operate; if there is no local backup, then remote clearing will have to be simulated. No change made. All aspects of Stability are to be considered. No change made. The present language is common in many standards and the SDT sees no reason to change it here. There may be a difference between 'current' and 'in force' due to effective dates. No change made. The SDT has made a clarifying change to the note. **Header note 'b':** Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0. The SDT agrees and has modified the note accordingly. **e**. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. End-user equipment is that equipment owned and operated by an end-user over which an entity has no control. No change made. This is simply a matter of preference as the suggested change would not alter the meaning or intent. No change made. The SDT agrees and has deleted header note 'j'. Dynamic stability is covered in the requirements and no reference is needed in the header notes. This footnote is referring to Stability studies and not short circuit analysis. No change made. System normal, or P0, is the starting system condition for the projected study conditions per the model developed in accordance with Requirement R1. The SDT has adjusted Requirement R1 to provide this clarity. **Requirement R1 -** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes the normal system condition in Table 1. The category descriptions are meant to characterize the events. A single event may remove more than one element from service and that has been addressed in Header note 'c'. The SDT does not believe that there are inconsistencies within the table. The P2 category describes single events that may result in multiple

Voter	Entity	Segment	Vote	Comment
elements being removed from service. The P2 events differ from the multiple event categories which consider two or more sequential events. No change made. The SDT agrees that the structure of the descriptions are different because they are describing dissimilar types of events but the SDT does not feel that they are inconsistent or causing any confusion. No change made. The change was made since the table is now event based and because the four existing standards were consolidated into one standard. The industry has supported these changes. No change made.				
Fred Frederick	Southern Indiana Gas and Electric Co.	3	Negative	Definitions, Year One - Vectren disagrees with the proposed definition of Year One. Vectren believes that Year One should be the planning window that begins 12-18 months from the start of the current calendar year, and not from the end of the calendar year. Section 5 - Effective Date, the allowance of 60 calendar months for Corrective Action Plan implementation is too short. Recommend this be extended to 84 months to allow for proper planning, budgeting, right-of-way acquisition and construction. R2.4.1 - System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Vectren has concern with this requirement. The concern is that Vectren will be held to strict interpretation of this standard with regard to an actual event occurring that was not exactly reproduced by the Vectren model. R2.7.2 - The term "include actions to resolve performance deficiencies identified in multiple sensitivity studies" causes concern. Mitigation plans should not necessarily be required for deficiencies found in multiple sensitivity studies because the conditions in some sensitivity studies are typically extreme and less likely than base case conditions. Some of the sensitivity study conditions may not be credible or plausible enough to warrant the implementation of mitigation plans. Also, what is the interpretation of multiple studies? Is that more than one, a majority, 2/3 of the number that were studied, or some other number? R2.7.3 - The term “beyond the control of the Transmission Planner or Planning Coordinator” needs to be better defined. An auditor could interpret a situation to be within the “control” of a TP or PC but are not covered by NERC standards or a TP / PC’s process, procedures or criteria. This leaves entities open to possible non-compliance violations based on an auditor’s perception of what they believe should be in the TP / PC’s control. Also, Vectren is not in agreement that Non-Consequential Load Loss should not be allowed for any case. There may be cases, especially future year studies that indicate a need for building transmission infrastructure, to serve speculative load growth. In these cases the consumers, local

Voter	Entity	Segment	Vote	Comment
				jurisdictions, and state jurisdictions may find it a prudent plan to assume some Non-Consequential Load Loss in order to defer building transmission infrastructure. R3.3.3 - Trip Transmission elements when relay loadability limits are exceeded. Vectren has concerns that system models (or software applications) cannot support the requirements of R3.3.3. Another concern is that Vectren will be held to strict interpretation of this standard with regard to an actual event occurring that was not exactly reproduced by the Vectren model. R4.1.3 - For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner. Vectren has concerns with this requirement. What if the PC and the TP cannot reach an agreement in the definition of "acceptable damping"? R4.1.2 - When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities. Vectren has concerns that dynamics models (or software applications) cannot support the requirements of R4.1.2. Another concern is that Vectren will be held to strict interpretation of this standard with regard to an actual event occurring that was not exactly reproduced by the Vectren model. R4.3.3 - Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers. Vectren has concerns that dynamics models (or software applications) cannot support the requirements of R4.3.3. Another concern is that Vectren will be held to strict interpretation of this standard with regard to an actual event occurring that was not exactly reproduced by the Vectren model. Table 1 - Steady State & Stability Performance, Planning Events, k. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner. What if the PC and the TP cannot reach an agreement in the definition of "acceptable limits"? Table 1 - Steady State & Stability Performance, Extreme Events, V. A successful cyber attack. This requirement is too vague. It could be interpreted in any number of ways.

Response: Based on your comment and those of others, the SDT has revised the definition of Year One.

> **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen

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until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility. 2.4.1 – The SDT has added the word 'expected' to the text to alleviate your concern. Planning models are based on the best information available to the planners at the time of the study and it is well understood that they may not exactly represent actual conditions at any given time. The results of on-going benchmarking and model development activities can be incorporated when those activities yield more representative results. **Requirement R2, part 2.4.1** - System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Requirement R2, part 2.7.2 already states that an entity must supply the rationale for when actions were not necessary so the SDT believes that your concerns have already been addressed. No change made. If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility. No change made. The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area. 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. The expectation of this requirement is that relay tripping would be handled consistent with their PRC-023 expectations. Planning models are based on the best information available to the planners at the time of the study and it is well understood that they may not exactly represent actual conditions at any given time. No change made. Requirement R4, part 4.1.3 does not state that the criteria are set jointly. If such an item became an issue, the SDT believes that it is covered in Requirement R7. No change made. The SDT believes that the necessary tools are readily available. Planning models are based on the best information available to the planners at the time of the study and it is well understood that they may not exactly represent actual conditions at any given time. No change made. The table does not state that the limits are set jointly. If such an item became an issue, the SDT believes that it is covered in Requirement R7. No change made. The event is the loss of two generating stations. A successful cyber attack is simply an example of a cause of the event. No change made.				
Liam Noailles	Xcel Energy, Inc.	5	Negative	Xcel Energy appreciates the hard work of the Standard Drafting Team and commends the group for making substantial improvements in every successive draft of the TPL-001-1 standard to bring it to the proposed version for balloting. However, in as much as the proposed TPL-001-1 standard has

Voter	Entity	Segment	Vote	Comment
Michael Ibold	Xcel Energy, Inc.	3	Negative	improved, we cannot support its approval at this time for the following reasons: 1. Implementation Plan: Xcel Energy does not believe that 60 months is a reasonable time period to build transmission facilities to meet the new "raise-the bar" performance requirements. Building a transmission line in Xcel Energy's service area spanning eight-states (and two RTO's) varies significantly in regional and local planning and review process, regulatory approval process, permitting and routing process, legal challenges, etc. These processes can often take more than 5 years to complete from the time the project is conceived as a proposed solution. Though requirement R2.7.3 is included in the standard to address situations beyond the control of the Transmission Planner, we are concerned that it leaves to the interpretation and judgment of the auditor whether the Transmission Planner is taking appropriate actions to resolve the situation and consequently whether the interim solution of dropping Non-Consequential Load or curtailment of Firm Transmission Service is acceptable. Xcel Energy will be comfortable supporting the standard if the 60 months time-frame is increased to 84 months. 2. Intended Scope of Planning Event P5: Xcel Energy is unsure of what comprises the scope of "Failure of a single Protection System" - does it imply studying the failure to operate of the relay or communication channel utilized in the primary protection scheme for an equipment (e.g. transmission line), or does it also include studying the failure of other single Protection System components such as current/voltage transformer or station battery? Note that the former interpretation will result in delayed clearing of the faulted transmission element only, consistent with operation of the local backup protection (typically zone 2 operation of line distance relays). On the other hand, the failure of current/voltage transformer or station battery could compromise the operation of both primary and local backup protection schemes for the faulted equipment, thus requiring the remote backup protection to clear the fault, which results in longer-duration delayed clearing and the loss of more than one transmission element. In Table 1, characterizing P5 as a multiple contingency event (like P4 or P7) also contributes to the scope confusion. As discussed above, a primary protection relay failure will typically result in the loss of a single (faulted) element only, not the outage of multiple elements (that always occurs in P4 or P7 events). Then, should the P5 event be construed to study the failure of CT/PT and/or station battery which, as discussed above, will typically result in the loss of multiple elements? If yes, isn't the standard implicitly requiring redundant CTs/PTs or station batteries to enable meeting the EHV performance requirement? If no, shouldn't the P5 event description reflect the intended scope more clearly? This may presumably be achieved by modifying P5 to read "Failure of primary protective relay that results in Delayed Fault Clearing on one of the following:" 3. Steady-state Performance of Planning Event P5 versus P1: Assuming that the intent of the P5 event is to study the operation failure of primary protection scheme (failure of the relay or its communication channel), the delayed clearing time associated with local backup protection scheme is
David F. Lemmons	Xcel Energy, Inc.	6	Negative	

Voter	Entity	Segment	Vote	Comment
				only relevant to the stability performance. If the post-contingency outcome for P5 consists of the loss of the faulted transmission element only, can the post-contingency steady state system condition for event P5 be any different than for event P1? We contend that both events will result in the same post-contingency steady-state system condition since the only difference is the normal versus delayed clearing time. If so, should the steady-state performance requirements for event P5 be any different than for event P1? For steady-state analysis, the HV level performance requirements for P5 in Table 1 become contradictory to those for P1. This is another example of why the intended scope of P5 event needs to be specified more clearly. 4. Ambiguities and Inconsistencies: Xcel Energy is providing the following editorial comments for your consideration to improve the consistency and clarity of the standard. Several, but not all, of the ambiguities and/or inconsistencies are confusing enough to qualify as show-stoppers since they prevent the standard's intent and scope to come across clearly. 4.1 Table 1 - Headnotes to Planning Events o Headnote b - At a minimum, delete "or extreme" since it is out of place in this headnote. Consider truncating at "... generation loss is acceptable." since the headnote is by default applicable to all planning events, and P0 exclusion is implicit in the context. o Headnote e - Consider omitting the phrase "For all planning events," since the headnote is by default applicable to all planning events. o Headnote i - Consider re-wording to remove the unintended association of equipment with event being implied at "...by end-user equipment associated with an event...". Suggest deleting the redundant phrase "associated with an event" since the headnote is by default applicable to all planning events. Alternatively, modify to read as follows: "Load loss resulting from an event due to the response of voltage sensitive Load or due to Load that is disconnected from the System by end-user equipment shall not be used to meet steady state performance requirements." o Headnote h - Unlike other headnotes, this does not describe a system performance but offers a clarification on applicability. Therefore, like other clarifications/qualifications, it belongs in the footnotes - suggest changing it to footnote assigned to P0. o Headnote j - It is not clear why this falls under Stability Only, and it also lacks specificity in expected stability performance. Note that the generic 'stable' is an umbrella term that includes all types of system (in)stability including voltage (in)stability, frequency (in)stability and cascading facility outages, not simply angular (in)stability. Considering that headnote 'a' includes most varieties of system (in)stability, we suggest adding "angular instability" in headnote "a" and deleting this

Voter	Entity	Segment	Vote	Comment
				headnote. 4.2 Table 1 - Footnotes Footnote 2 - Suggest deletion of "Unless specified otherwise, simulate normal clearing of faults" since it is redundant with Headnote 'd' for Planning Events and Headnote 'b' for Extreme Events. Alternatively, delete both Headnotes and do not change Footnote 2. 4.3 Table 1 - Planning Events - Column 2 - Initial System Condition - Normal System What are the attributes of Normal System? Is this term intended to be synonymous with "system intact" or N-0 system topology? Is the event P0 intended to be identical to the existing Category A? The intent is not clear and needs to be explicitly stated. We suggest that the first occurrence of the term be modified as follows: "Normal System (all Facilities in service)" to explicitly convey the intent. Note that the qualifier in parenthesis is the verbiage for Category A used in the existing TPL standards. However, we also note that if P0 is intended to be synonymous with "system intact", then it does not appear that the base case system model built as per Requirement R1, part 1.1, will always be compatible with P0 - due to the known outages to be included in the model (part 1.1.2). Does the standard envisage P0 and "system intact" to connote "All Facilities in service minus the known outages"? If so, this must be clearly stated. .4 Table 1 - Planning Events - Column 1 - Category What is the significance of 'Single Contingency' or 'Multiple Contingency' qualifier for an event? Is it intended to characterize the number of elements outaged due to the initiating event, or is it intended to convey the number of equipment failures/faults comprising the initiating event? The NERC glossary definition of Contingency "The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element." does not help remove this ambiguity. Regardless of the chosen interpretation, inconsistency arises for the following events: Event P2 - Wouldn't initiating events P2-2, P2-3 and P2-4 typically result in the loss of more than one element? So qualifying P2 as single contingency appears to correspond with the equipment fault/failure description in the Event column but does not correspond to the total number of elements outaged due to the initiating event. Event P3 - Per the description in the Event column, the events P3-1 to P3-5 result in the loss of one element. So qualifying P3 as a multiple contingency appears to correspond with the total number of elements outaged, after including the (overlapping) prior outage. But the multiple contingency qualification is not consistent with the initiating event description in the Event column. Event P6 - Same comment as P3. Event P1 - Can the loss of only one element be presumed as an outcome of normal clearing of a fault, which appears to be the implicit initiating event here? How about the case of a normally cleared fault on a transformer-terminated line that is not breakered at the transformer end? Or the case of a normally cleared fault on a line-connected shunt reactor that is not breakered to the line? The resulting loss of two elements is not consistent

Voter	Entity	Segment	Vote	Comment
				with the event description. And by characterizing the event in terms of loss of one element, it is also inconsistent with headnote c that requires removal of all elements expected to automatically disconnect for each event. 4.5 Table 1 - Planning Events - Column 3 - Event Descriptions for events P1, P3, P6 and P7 are in terms of number of elements (one or multiple) outaged due to the contingency, whereas events P2 and P5 are described in terms of the initiating fault only. The exception is event P4 which is described in terms of both - the elements lost and the initiating fault. Is there a good reason why the event descriptions are not consistently worded? We note that the contingency descriptions in column 2 of the existing Table I are expressed in terms of "Initiating Event(s) and Contingency Element(s)." We think this issue is closely correlated to the previous comment on the apparent lack of consistency between the contingency terminology in column 1 and the event description in column 3.

Response: 1. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility.

2. The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns.

> **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following:
>
> **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

3. A P5 event is different and will not duplicate a P1 event for steady state if the entity does not have fully redundant Protection Systems. No change made.

The SDT agrees and has made a clarifying change.

> **Header note 'b':** Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

The SDT agrees and has modified the note accordingly.

> **Header note 'e'**. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

While technically correct, the suggested change does not create additional clarity and the existing wording doe not cause any confusion in the eyes of the SDT. No change made.

Voter	Entity	Segment	Vote	Comment
This is simply a matter of preference as the suggested change would not alter the meaning or intent. No change made. The SDT agrees and has deleted header note 'j'. This is simply a matter of preference. While somewhat duplicative, it may add clarity and hasn't seemed to cause any confusion. No change made. System normal is the starting system condition for the projected study conditions per the model developed in accordance with Requirement R1. The SDT has adjusted Requirement R1 to provide this clarity. **Requirement R1 -** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes the normal system condition in Table 1. The category descriptions are meant to characterize the events. A single event may remove more than one element from service and that has been addressed in Header note 'c'. The SDT does not believe that there are inconsistencies within the table. No change made. The SDT agrees that the structure of the descriptions are different because they are describing dissimilar types of events but the SDT does not feel that they are inconsistent or causing any confusion. No change made.				
Henry Ernst-Jr	Duke Energy Carolina	3	Negative	Duke appreciates the hard work that has been done by the Standard Drafting Team to get the standard to this point. Duke is supportive of the standard as it helps to remove some of the 'grey' in the existing TPL standards, as well as driving actions that will improve the reliability of the Bulk Electric System. However, Duke believes that two areas in the standard need to be improved in order for Duke to vote to approve the standard. 1. Duke does not believe that 60 months is a reasonable time period to build transmission facilities to meet the new performance requirements. In an email to the registered ballot body, Ameren stated " Building a transmission line in Illinois is estimated to take 7 years (84 months) from the time the project is authorized." Duke agrees with the point that Ameren is making that building of a new EHV transmission line can be a very lengthy process. Duke thinks that a more appropriate time frame would be 84 months. 2. Duke believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues, does not provide any real benefit to Bulk Electric System (BES) reliability, and may have unintended negative consequences on reliability. Often, corrective actions to mitigate these events are local in nature and only require minor additional loss of local load to avoid major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. The standard should continue to allow Transmission Planners to use

Voter	Entity	Segment	Vote	Comment
				discretion regarding loss of non-consequential load, such that Transmission Planners, customers, and local regulators jointly control the decision making when BES reliability is not an issue. The transparency requirements of the new standard facilitate this type of decision making. In addition, the prohibition on non-consequential load loss for these events creates an incentive for Transmission Planners to remove lines serving load from network (serve the loads radially) so that they are characterized as consequential load. The unintended consequence of the standard would be a reduction in reliability for service to local load.
Response: 1. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. 2. The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area. 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.				
Charles A. Freibert	Louisville Gas and Electric Co.	3	Negative	E.ON U.S. suggests that Extreme Event 2e be clarified by adding: if generating was added in front of station, "Loss of all generating units at a generating station." This would distinguish from a loss of all units at a transmission station. Also, it is consistent with 3a, "Loss of two generating stations ...". E.ON U.S. objects to the modification of P2-1 to only include "Opening of a line section w/o a fault". Footnote 7 indicates that this is to ensure that radial load that would have tripped with a fault can be served. This is a new criteria that opens a line without an actual fault and may result in converting some of these lines to radials to comply with this requirement which could decrease overall reliability.
Charlie Martin	Louisville Gas and Electric Co.	5	Negative	
Daryn Barker	Louisville Gas and Electric Co.	6	Negative	
Response: The SDT assumes that you meant 2d and of so, agrees and has made the change. **Extreme event 2d.** Loss of all generating units at a generating station. This is not a new criterion as this is exactly what was in TPL-002-0, Table 1, Category B "Loss of an Element without a Fault." No change made.				
Luther E. Fair	Gainesville Regional Utilities	1	Negative	Even though I am voting negative on this version of the standard, I want to acknowledge the considerable effort that the SDT has put into developing this change to the NERC Standard TPL-001, Transmission System Planning Performance Requirements. I do consider it, in most part, an improvement to the existing standard, but I feel it falls short by not providing more clarity and less ambiguity. As a very small utility that happens to have chosen a 138 kV loop to circle its city to serve

Voter	Entity	Segment	Vote	Comment
				its citizens, we feel unreasonably burdened at times to accomplish the documentation task at hand. I offer the following as a few examples of concern: GRU believes that requirement 2.1.5 on spare equipment strategy is discriminatory for smaller entities. For many smaller entities, having a spare transformer is not a practical solution and makes far less sense and has significantly more customer rate impacts than for a larger utility. Yes, it may be possible to arrange an agreement with a neighboring entity for use of their spare, but that assumes that the neighboring entity's transformer specifications are similar enough for use as a spare, which may not be the case. Order 693 states at Paragraph 1725: "... the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy". Next, Requirement 3.3.3 as written would require modeling of nearly every phase distance relay, especially when studying extreme events. The requirement ought to have the flexibility afforded in 3.3.2 where the planner can use a conservative assumption and screening methods (e.g., the proposed curves of PRC-024) for relay loadability (e.g., the requirements of PRC-023). Requirement 4.3.1 would also require modeling of nearly every phase distance relay in the Interconnection, again because it applies to extreme events and we will not know ahead of time where the power swings will traverse distance relay characteristics. I look forward to the next generation of this standard's development. L. Earl Fair

Response: The SDT has clarified the requirement based on your comments and those of others.

> **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment

The SDT agrees that a planner should be able to utilize conservative assumptions and screening methods and doesn't believe that there is anything in the requirement that precludes an entity from doing so. The SDT disagrees that the modeling of phase distance relays is required. No change made.

The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern.

> **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:
>
> - Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
> - Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

Voter	Entity	Segment	Vote	Comment
• Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.				
Daniel Brotzman	Commonwealth Edison Co.	1	Negative	Exelon is concerned with the use of the term 'Protection System' in Category P5 of the Table 1 performance criteria. 'Protection System' is a defined term in the NERC Glossary (Protection System - Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry). Thus, a potential interpretation of the standard as currently proposed would be that the loss of a station battery is to be included in analysis as a valid single contingency. We understand that the SDT response to previous comments on this issue indicates that the battery contingency was not intended to be part of the P5 contingencies. However, no changes or clarifications were subsequently made to the proposed Standard to clarify the requirements and exclude this interpretation. This leaves open the potential for multiple interpretations of the Standard and creates ambiguity for the functional entities that will have to implement the revised Standard. Additionally, Exelon is concerned that performance criteria in the draft Standard is based on the voltage level of the contingency element rather than the monitored element.
Response: The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns. **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following: **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94). The SDT placed greater emphasis on the facility being removed than the monitored remaining intact Facilities. The outage of an EHV Facility will typically be of greater concern for the potential of transferring power flow to lower voltage parallel paths than the reverse. No change made.				
Pat G. Harrington	BC Hydro and Power Authority	3	Negative	File: NERC_Std_TPL-001_Draft05_Ballot_Comments_BCH20100226.doc A. GENERAL COMMENTS The standard needs to better define the pre- and post-contingency generation dispatch conditions and stipulate that the worst-case combination of possible load levels and generation dispatch must be studied. For example, the portion of a transmission network connecting a "generation-rich" region (ie, a region with much more generating capacity than local load) to the rest of the BES, should be able to operate within normal voltage level limits without overloading any elements under normal system conditions (N-0). If there are intermittent resources like wind parks or run-of-the-river hydro plants that the system is not depending on to supply dependable generating capacity (or at least not to the full nameplate rating of those resources), generation shedding or run-back can be permitted for single-contingencies (N 1 situation). The amount of generation shedding should be limited to the difference between the aggregate maximum generating capacity of the region and the aggregate

Voter	Entity	Segment	Vote	Comment
				dependable generating capacity of the region and there should be further limits defined for generation shedding/run-back as described below. Add the following definitions: o 1. Consequential Generation Loss: All Generation that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault. o 2. Non-Consequential Generation Loss: Dependable Generating Capacity Loss that does not include: (1) Consequential Generation Loss, (2) Generation loss due to low voltage or (3) Generation loss due to protective relays of the generating unit or its step-up transformer. o 3. Dependable Generating Capacity: The level of generating capacity of a plant or unit that the system operator can count on to serve Non-Interruptible Load by virtue of the plant or unit's fuel supply being available to provide that level of generating capacity more than 97% of the time. "EHV" and "HV" need to be defined because they are not defined in the NERC Glossary (NERC Glossary (use "Edit, Find on this page..." and look for "Glossary": http://www.nerc.com/elibrary.php?doc_class=&doc_dept=&submit=Filter) B. SPECIFIC COMMENTS R2, 2.2.1: The system configuration of the last year of the planning period should be studied as well as at least one other year that is most-likely to fail to meet planning criteria with an explanation for why that year is considered the worst case. As it is written, it would be quite acceptable for the TP and/or TC to simply study the year immediately following a major system upgrade with the rationale being that it would likely be the least likely system condition to fail any reliability standards. As it is written, there is no requirement that the rationale provided be logical or reasonable. R2, 2.4: "Stability analysis" does not cover all of the dynamic criteria that need to be met. A more general term, like "Stability and dynamic simulation studies" should be used. "Stability" is defined by NERC as just, "The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances", but the assessments done in what people term "Stability" studies involve more than a check on the electromechanical stability (equilibrium) of the system. Voltage sags and swells, frequency deviations and short term overloading of equipment (eg, transient and dynamic current fluctuations through series capacitors that would provide an indication of the voltage stress across the capacitor dielectric) are usually included in "Stability" studies. R2, 2.4.1: "...for one of the five years" should be changed to "...for the most critical year of the 5 year Near-Term planning period". R2, 2.4.2: This requirement needs to be better defined. Is this requirement meant to demonstrate acceptable system performance during maintenance outages over the daily peak load periods of the off-peak season (ie, summertime for a winter-peaking region) or is this intended to address light-load

Voter	Entity	Segment	Vote	Comment
				issues like over-voltages and frequency deviations? R3, 3.2 The performance requirements for extreme events need to be defined in more detail. The criteria for acceptable system performance for extreme events seems to be only described vaguely in R3 item 3.5. R3, 3.5: Change "Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created" to, "Those extreme events in Table 1 that are expected to produce more severe System impacts most likely to cause Cascading,, equipment damage or pose a significant risk to public or worker safety [needs to be further defined] shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created" Also, simply providing "an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s)" is inadequate. One or more SPSs should be defined and studies should demonstrate that they prevent cascading outages and isolate, in a pre-planned controlled manner, the portion of the system experiencing the extreme event to minimize the extent of the disturbance. If necessary, an SPS should be provided that isolates the control area experiencing the extreme event from the rest of the interconnected system. R4, 4.1.1: Add (referring to the additional text suggested below for Note e of Table 1), "The amount of generating capacity disconnected or "run-back" by a Special Protection Scheme (SPS) shall be limited in accordance with Note e of Table 1". R4, 4.1.2: Add, "Studies shall be conducted to demonstrate that all circuit breakers that may be called upon to trip for an out-of-step condition (180 degrees across the open breaker) are properly rated for this duty considering the worst case voltage on any isolated transmission circuits due to trapped charge." R4, 4.1.3: Acceptable damping should be defined (eg, "studies must show that any oscillations are damped to less than 10% of their initial magnitude within 30 seconds") [or develop a different specific requirement that can be measured]. R4. 4.5" Change "Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R4, part 4.2 created" to, "Those extreme events in Table 1 that are expected to produce more severe System impacts most likely to cause Cascading, equipment damage or pose a significant risk to public or worker safety [needs to be further defined] shall be identified and a list of those events to be evaluated for System performance in Requirement R4, part 4.2 created".

Voter	Entity	Segment	Vote	Comment
				Also, simply providing "an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s)" is inadequate. One or more SPSs should be defined and studies should demonstrate that they prevent cascading outages and isolate, in a pre-planned controlled manner, the portion of the system experiencing the extreme event to minimize the extent of the disturbance. If necessary, an SPS should be provided that isolates the control area experiencing the extreme event. R5 & R6: Shouldn't the Load Serving Entities (LSEs) define system performance criteria instead of the Transmission Planner or the Planning Coordinator? The LSEs have an obligation to their customers and must demonstrate to their regulators that they are providing acceptable system performance and reliability of supply to their customers. The Transmission Planner and Planning Coordinator have less incentive to provide high levels of system performance. Due to regulatory difficulties in getting approvals for transmission system upgrades, there

Response: The standard requires a normal System model, P0, be developed that projects anticipated conditions for the period under study. Any additional stress of the System prior to loss of an element would be handled through sensitivity analysis as required in Requirement R2. In addition, the SDT explored the possibility of placing limits on the amount of generation runback and the industry clearly indicated in comments that they did not support such limits. No change made.

The EHV/HV differentiation is not meant to be a definition in that it only applies to this standard. No change made.

One can always study additional years if so desired. The SDT believes that "rationale" implies logic and reason. No change made.

The SDT intended for the term Stability analysis to include system Stability and unit Stability analyses. These analyses could include all aspects of Stability that you mentioned. It is left up to the judgment of the Planning Coordinator/Transmission Planner to decide which aspects of Stability may produce more severe results and therefore, must be analyzed. No change made.

The critical year can only be determined after reviewing the entire portfolio of current and past studies and is not a pre-determined condition. The SDT expectation is that an entity is building a portfolio over time that covers the entire planning horizon and thus determines any critical periods. No change made.

The requirement was intended to cover all conditions that could occur during Off-Peak periods. No change made.

Requirement R3, part 3.2 contains no performance obligations. It is simply a requirement to assess the impacts. No change made.

The SDT made a clarifying change to the requirement.

> **Requirement R3, part 3.5 -** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

Voter	Entity	Segment	Vote	Comment
Due to the complexity associated with extreme events, the SDT believes it is inappropriate to require any more than a list of possible actions. An SPS could be a solution but it is not the only one. No change made. The SDT explored the possibility of placing limits on the amount of generation runback and the industry clearly indicated in comments that they did not support such limits. No change made. This standard is not intended to address engineering specifications such as proposed here. No change made. There is no single definition; the SDT has left it up to each Planning Coordinator or Transmission Planner to define. No change made. The SDT has made a clarifying change to the requirement. **Requirement R4, part 4.5 -** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted. Due to the complexity associated with extreme events, the SDT believes it is inappropriate to require any more than a list of possible actions. An SPS could be a solution but it is not the only one. No change made. These are System requirements for the BES and properly belong to the Planning Coordinator and Transmission Planner. No change made.				
Paul Shipps	Lakeland Electric	6	Negative	Five years is not enough time in many circumstances to build significant new transmission lines.
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Negative	Our concern is that the timeframe of 60-month (5 year) for implementing Corrective Action Plans (CAP), is insufficient. We believe that the implementation timeframe must be extended to seven (7) years.
Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order.				

Voter	Entity	Segment	Vote	Comment
W. R. Schoneck	Florida Power & Light Co.	3	Negative	FPL Comments on TPL-001-1 Standard FPL believes the Standard requirements need to be clear and unambiguous. The SDT has addressed many of the gray areas of Draft four in their consideration of comments however these comments are not part of the Standard that is currently out for ballot. Incorporating these types of clarifing comments with the use of footnotes in the Standard to help clarify the intent would be a significant improvement for anyone interpreting the Standard including an auditor or investigator. The definition of Year One is an unnecessary departure from the planning practices used in most of the Eastern Interconnection. It is recommended the phrase end of the current calendar year be changed to the current calendar year. This change will allow PAs to begin their near term analysis with either next year or the year after as deemed appropriate. The performance requirements of Table 1 do not allow the loss of non-consequential load for single and multiple contingency events. The disallowance of load loss does not provide any real benefit to the reliability of the BES and is an unnecessary overreach into local quality of service issues that are best addressed by State, Provincial or Municipal authorities. There may be circumstances such as high local transmission costs or local opposition to transmission construction where prohibition of non-consequential load loss represents a poor cost/benefit or quality of life tradeoff. Providing a quantitative cap in non-consequential load loss such as 100 MW may be rationale compromise in the goal of limiting load loss for the more probable outage events. Our preference would be to retain the capability of limited non-consequential load loss. Absent this, the 60 calendar month phase in period described in the Introduction section is too short for transmission facilities rated above 300 kV. Approval and permitting of EHV transmission lines is extremely difficult and time consuming in most parts of the Eastern Interconnection. The phrase any material changes used in requirement R.2.6.2 will effectively cause all Planning Authorities to run all studies every year regardless of minor changes in the model. The overwhelming majority of PAs use a 10 year set of planning models developed annually by Regions or Subregions. These annual sets of planning models will always have some changes. The annual study requirement is especially problematic for Stability and Short circuit studies that require much more engineering time to complete and are mush less likely to have results impacted by minor model changes such as different load forecasts. Uncertainty with audit review of technical rationale documentation will serve to focus Transmission Planning engineering resources on short term compliance to an extent that is counter productive. Requirement 2.5 represents a significant expansion of Stability Studies into the Long Term horizon. In many cases the stability issue in long term scenarios will be with the response of new generating plants to fault scenarios such as a breaker failure event. The protection upgrades needed to mitigate performance issues are easily

Voter	Entity	Segment	Vote	Comment
				accomplished in the short term. The uncertainty of compliance judgement of rationale documentation will force a tremendous amount of unnecessary study work. It is recommend Requirement 2.5 be removed. We concur with the SDT's opinion expressed in the most recent consideration of comments that the individual component level evaluation of protection systems and redundancy requirements should be covered under the PRC standards and that the intent of the protection failure contingencies specified in Table 1 is to simulation the failure of a single protection scheme. The event description for the P5 contingency was revised in draft 5 but it continues to reflect a range of protection component failures that greatly exceed the intent of the SDT. The term Protection System is in direct conflict with the intent of the SDT, as it is defined in the Glossary to include components such as station batteries. The term Protection System should be replaced with Protection Scheme in Table 1. Requirement 4.3.1 can be interpreted to require dynamic simulation analysis of multiple fault event scenarios for transmission lines with high speed reclosing enabled. This additional analysis may be advisable for certain rare special situations but is unnecessary and burdensome as a general requirement for transmission planning contingency analysis. As such, requirement 4.3.1 will discourage application of high speed reclosing. This would be an unfortunate outcome given the benefits of high speed reclosing both for transmission reliability and customer power quality. It is recommended that 4.3.1 be reworded as follows; Simulate the operation of Protection Systems and other automatic controls as they would be expected for each contingency. The SDT has indicated in their responses to previous comments on requirement R4.3.3 that generic relay models could be used for screening purposes. While we agree with this as a practical method, the language of R4.3.3 could be interpreted to require explicit modeling of all protection and controls which is neither practicable nor an effective use of engineering resources. It is recommended that R4.3.3 be deleted.

Response: Based on your comment and those of others, the SDT has revised the definition of Year One.

> **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area.

> 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.

Material change is system specific and difficult to define on a continent-wide basis and is left to engineering judgment with a documented technical rationale as

Voter	Entity	Segment	Vote	Comment

stated in the requirement. No change made.

The SDT has clarified the requirement to address your concern.

> **Requirement R2, part 2.5 -** The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, part2.6. The technical rationale for determining material changes shall be documented.

The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns.

> **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following:
>
> **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern.

> **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:
>
> - Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
> - Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
> - Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.3 - The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern.

> **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:
>
> - Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
> - Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
> - Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

Voter	Entity	Segment	Vote	Comment
Thomas W. Richards	Fort Pierce Utilities Authority	4	Negative	FPUA believes that 5 years is not enough time in many circumstances to build significant new transmission lines. Seven years is a more appropriate lead time for the implementation plan / effective date. FPUA believes that requirement 2.1.5 on spare equipment strategy is discriminatory for smaller entities. For many smaller entities, having a spare transformer is not a practical solution and makes far less sense and has significantly more customer rate impacts than for a larger utility. Order 693 states at Paragraph 1725: "... the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy". The standard oversteps this direction by not including a consideration of planned outages versus forced outages in requirement 2.1.5, in other words, if an entity has no plans for a long term outage of a transformer, it should be excluded from the assessment of 2.1.5. Such a condition would allow an entity to assess things like gas in oil analysis to predict when a long term outage might be planned, and the flexibility between start and end dates of that planned outage. Requirement 3.3.3 as written would require modeling of nearly every phase distance relay, especially when studying extreme events. The requirement ought to have the flexibility afforded in 3.3.2 where the planner can use a conservative assumption (e.g., the proposed curves of PRC-024) for relay loadability (e.g., the requirements of PRC-023). Requirement 4.3.1 would also require modeling of nearly every phase distance relay in the Interconnection, again because it applies to extreme events and we will not know ahead of time where the power swings will traverse distance relay characteristics. FPUA agrees with Ameren's concerns about the ability of the programs to actually be able to model this requirement and FPUA fears that we are setting ourselves up for failure. We suppose that "generic" relays could be modeled to observe what distance relay characteristics are actually crossed by power swings and then, for that simulation, go back and individually model the actual relays for that specific simulation, but, that is a labor intensive process, not to mention the level of effort that would be required to maintain an interconnection wide database of relay settings. FPUA believes that the SDT ought to evaluate the perceived increase in accuracy that is intended with these requirements. It is FPUA's belief that the expected increase in accuracy is lost when considering other simulation inaccuracies that we really cannot improve (e.g., load modeling, load level modeled, dispatch modeled, etc., versus what would happen in an actual event) until much more work is done on improving our understanding of dynamic load behavior, benchmarking the model to actual system events, and possibly improvements on the ability to perform "real-time" stability analyses so that we have more practical operating experience to insert into our planning processes. Let's be practical in understanding the level of accuracy we can reasonably achieve in our simulations and model in accordance with that level of accuracy.

Voter	Entity	Segment	Vote	Comment
Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. The SDT has clarified the requirement based on your comments and those of others. **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment The SDT agrees that a planner should be able to utilize conservative assumptions and screening methods and doesn't believe that there is anything in the requirement that precludes an entity from doing so. No change made. The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern. **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: • Successful high speed reclosing and unsuccessful high speed reclosing into a Fault. • Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.				
Harold Taylor, II	Georgia Transmission Corporation	1	Negative	Georgia Transmission Corporation (GTC) supports the efforts of the study team and believes that their efforts to improve the Standard are moving in the right direction. However, we have identified the following concerns which prevent us from voting "affirmative". 1. GTC echoes ATC's concerns with the use of the word "control" in R2.7.3. (ref. ATC email; From: Shaver, Jason To: Gilbert, Don C. Manager, Electric System Planning ; bp-2006-02_ATFNSDT_TPL_in@nerc.com Sent: Wed Feb 24 09:43:11 2010 Subject: RE: Comments on TPL-001-1, Project 2006-02) An auditor could identify many things that may reasonably be within the "control" of a TP or PC, that are not covered by NERC standards or a TP / PC's process, procedures or criteria. This wide area of discretion leaves entities open to findings of possible non-compliance based solely on an auditor's perception of what he or she believes should be in the TP / PC's control. In addition, the concept of "control" must be limited to an entity's compliance obligation as a Transmission Planner and/or Planning Coordinator. In other words, an entity must be allowed the ability to identify situations which fall under its "control" as a Transmission Owner, Transmission Operator, Generator Owner or Generator Operator etc. but is beyond the responsibility of its

Voter	Entity	Segment	Vote	Comment
				Transmission Planner or Planning Coordinator functions. 2. R2.7.2 - "include actions to resolve performance deficiencies identified in multiple sensitivity studies" - Mitigation plans should not be required for deficiencies found in multiple sensitivity studies because the conditions in some sensitivity studies are more extreme and less likely than base case conditions. Some of the sensitivity study conditions are not credible or plausible enough to warrant the implementation of mitigation measures. It is not clear if the interpretation of multiple studies is more than one or a majority of the number that were studied. 3. Throughout the Standard there are circular references that make the interpretation confusing. We recommend that all references should refer back to previous sections and not to future sections, thereby avoiding circular references. 4. We disagree with the proposed definition of Year One. Year One should be the planning window that begins 12-18 months from the start of the calendar year, and not from the end of the calendar year. This would require minimal adjustments to the ERAG MMWG model building process. The proposed definition would force additional models to be built by the MMWG. 5. We agree with others that the timeframe of 60-month (5 year) for implementing Corrective Action Plans (CAP), is insufficient. We believe that the implementation timeframe must be extended to seven (7) years. GTC is aware of Requirement 2.7.3, which covers situations that arise beyond the control of the Transmission Planner (TP) or Planning Coordinator (PC), but believes that the proposed language is ambiguous. 6. We have concerns for including induction motor representations in the load models without any study or bench-marking activities to meet the requirements of R2.4.1. This information should be supplied by the LSE as part of the MOD standard. We understand that the proposed standard will accept an aggregate system load model which represents the overall dynamic behavior of the load to relieve the burden of trying to develop specific induction motor load representation at each load bus. However this modeled system response will be considerably different compared to the actual system response which will open up the industry to unwarranted scrutiny and possible compliance violation investigations. 7. We disagree with the inclusion of low voltage ride-through in requirement R3.3.2. Low voltage ride-through is a dynamic modeling issue as correctly included in requirement R4.3.2. 8. "EHV" and "HV" need to be defined in the NERC Glossary. 9. Requirement R2.4.2 needs to be better defined. It is not clear if this requirement is meant to demonstrate acceptable system performance during maintenance outages over the daily peak load

Voter	Entity	Segment	Vote	Comment
				periods of the off-peak season or intended to address light-load issues like over-voltages and frequency deviations. 10. A better definition for Consequential Load Loss is needed. The Non-Consequential Load Loss definition conflicts with the Consequential Load Loss definition. The Response of Voltage Sensitive Load exception under the Non-Consequential Load definition is a circular reference. It is not clear whether Voltage Sensitive Load is Consequential Load Loss or Non-Consequential Load Loss. 11. It is not clear if Consequential Load Loss is intended to be limited to: a) Load between two open (breaker/switches) protective devices and b) Protective devices (breakers/switches) for radial load. 12. Requirement R1.1.5 states that the system model shall represent "Known commitments for Firm Transmission Service and Interchange". GTC requests clarification of how to represent "Known commitments" whose collective magnitude can exceed the Load requirements.

Response: 1. If an entity can demonstrate that it has made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility.

2. Requirement R2, part 2.7.2 already states that an entity must supply the rationale for when actions were not necessary so the SDT believes that your concerns have already been addressed. No change made.

3. The SDT has made every attempt to make the standard as easy to follow as possible and believes that all references cited in the standard are correct. No change made.

4. Based on your comment and those of others, the SDT has revised the definition of Year One.

> **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

5. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility.

6. The SDT does not disagree that the Load Serving Entity may provide the initial information but someone needs to be responsible for adapting the model accordingly and that entity has to be the Transmission Planner or Planning Coordinator. No change made.

7. The SDT voltage ride through is not confined to the dynamic period. There are protection requirements that could result in generator tripping and that must be

Voter	Entity	Segment	Vote	Comment
considered in the steady-state analysis. The SDT has clarified the wording of the requirement. **Requirement R3, part 3.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: • Tripping of generators where simulations show generator bus voltages or high side of the Generation Step Up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. • Tripping of Transmission elements where relay loadability limits are exceeded. 8. The EHV/HV differentiation is not meant to be a definition in that it only applies to this standard. No change made. 9. The requirement was intended to cover all conditions that could occur during Off-Peak periods. No change made. 10. The definitions are not in conflict as the definition of Non-Consequential Load Loss specifically states that it doesn't include Consequential Load Loss. The response of Load to voltage is not classified as Consequential or Non-Consequential Load Loss. This standard articulates how voltage sensitive Load should be treated during different time periods of a simulation. No change made. 11. Both examples provided are Consequential Load Loss per the definition. 12. The SDT does not believe that a continent-wide standard should proscribe a single approach. Requirement R1 states that an entity must document its assumptions. No change made.				
Gordon Pietsch	Great River Energy	1	Negative	GRE recommends the following revision to the wording in subrequirement 2.5: "...the impact of proposed generation additions that have made a commitment to interconnect with the Bulk Electric System..." In addition, it appears that the drafting team has inadvertently included additional compliance requirements in the language of Table 1. The net result of this is that these requirements are effectively buried in the Table 1 language. GRE does not take exception to these additional requirements but believes that they should be included in the Requirements section of the Standard. Having the Table 1 language written as it is presents additional risks for non-compliance that would not otherwise be there if these requirements would be included in the Requirements section.
Response: The SDT has clarified this requirement based on industry comments. **Requirement R2, part 2.5 -** The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, part2.6. The technical rationale for determining material changes shall be documented.				

Voter	Entity	Segment	Vote	Comment
Without any specific comments to address, the SDT is unable to further address your concerns. No change made.				
Jacquie Smith	ReliabilityFirst Corporation	10	Negative	In R1.1.6 is OR the proper desciption of resources? Shouldn't this be AND? Resources are both supply AND demand side. Is R4.1.2 too stringent. At the least, shouldn't there be an exception for Special Protection Systems and Remedial Action Schemes to trip for apparent impedance swings? In 4.3.1 shouldn't the analysis be for both successful high speed reclosing and for unsuccessful high speed reclosing, (AND instead of OR) In Measure 8, the mixture of OR and AND is confusing. As presently written, as long as no entity makes a written request for the information they pass the test. Thus, as long as your neighbors do not complain about not receiving the information an entity is compliant. Better wording would be: The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners, or one of its adjacent Planning Coordinators, or to one functional entity ..... The responsible entity failed to distribute the results of its Planning Assessment to two or more of its adjacent Transmission Planners, adjacent Planning Coordinators, functional entity ..... Also, I think failure to distribute results is more severe than failing to respond to comments. Failing to give their neighbors an opportunity to comment is less severe than failing to acknowledge comments. I presume that the documented response to comments can be nothing more than "Thank you for your comments." All of the above are minor compared to this next problem. (I believe this needs to be addressed before we can vote yes.) The level of detail of Planning Assessment results is missing from the requirements. Is a message to your neighbors stating that you have performed a Planning Assessment and everything is OK, enough to meet the requirement, or does it need to be more detailed? The minimum contents of the Planning Assessment results shared with Transmission Planners, Planning Authorities, and other functional entities needs to be clearly stated. Also, the RRO is not a functional entity. As written, can this standard be used as justification for not sending detailed Reliability Assessment information to the ReliabilityFirst? Would requiring sharing with Stakeholders with a reliability need be better than limiting the required sharing to functional entities?
Response: The SDT believes that 'or' is appropriate. This allows for an entity to model supply or demand or both as appropriate. No change made. Requirement R4, part 4.1.2, deals with a single generator pulling out of synchronism. The situation you described is a system Stability issue and is considered an				

Voter	Entity	Segment	Vote	Comment

application for an SPS which is allowed by the standard. No change made.

The SDT has clarified the language of Requirement 4, part 4.3.1, bullet #1 to address your concerns and those of others.

Requirement R4, part 4.3.1 - Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

- Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

Measure M8 had a typo which has been corrected. The remainder of the comment seems to be directed to VSLs and the SDT reviewed the VSLs and has made a clarifying change.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity who has indicated a reliability need and that functional entity has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

R8 VSL	The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners, one adjacent Planning Coordinator, or to one functional entity that has a reliability related need and that has submitted a written request for the information, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to more than one of its adjacent Transmission Planners, adjacent Planning Coordinators, or functional entities that have a reliability related need and that have submitted a written request for the information, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

The definition of Planning Assessment details what must be exchanged. No change made.

Voter	Entity	Segment	Vote	Comment
Any functional entity such as a Regional Entity or Reliability Assurer would qualify which would allow RFC to get the information. No change made.				
Kathleen Goodman	ISO New England, Inc.	2	Negative	ISO New England is submitting a negative vote on the TPL-001 standard, because: 1. Section 2 of the standard requires annual assessment of the system regardless of whether system conditions are essentially unchanged from year to year. This creates unnecessary study work and must be changed in order for ISO NE to support the standard. 2. In Table 1 - Steady State & Stability Performance Planning Events, Category P5 wording for the EHV contingency continues to call for no loss of load in the event of the loss of a single protection system. This requirement as currently worded goes well beyond the intent of the Standard Committee as stated in response to comments as follows: "A Protection System component failure (i.e., battery) that removes multiple Protection System schemes is beyond the P5 planning event". It is ISO New England's opinion that similar language to the comment response should be incorporated into this requirement. 3. ISO New England has additional reservations about the standard that should be addressed in subsequent revisions however items 1 and 2 here must be addressed for ISO New England to support the standard.

Response: 1. The intent of the SDT wasn't that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and part 2.1.

> **Requirement R2** - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.
>
> **Requirement R2, part 2.1 -** The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, part 2.6, as follows:

2. The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns.

> **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following:
>
> **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

3. Without any specific comments to address, the SDT is unable to further address your concerns at this time. No change made.

Voter	Entity	Segment	Vote	Comment
Brian Conroy	Central Maine Power Company	1	Negative	Issues with TPL-001-1 draft 5 in ballot: R 1 & 2 - There is insufficient direction/specification regarding base case development and sensitivity testing. Only "known outage(s) of generation" is specified. R2.1.1 - Year One or year two are operating time frame studies. Year five, particularly with additional load from load growth, is appropriate for system planning. There should not be a requirement for any more than one short-term and one long-term steady-state assessment. 2.1.5 - The 'spare equipment strategy' requirement effectively amounts to a N-1-1 analysis, but without the system adjustment between contingencies. A N-1-1 analysis should be sufficient. R2 - An annual assessment of the system is required regardless of whether system conditions are essentially unchanged from year to year. Note that R2.6 is only for 'support' and are 'supplementation.' This creates unnecessary study work and must be changed in order for ISO NE to support the standard. R2.4.1 - The dynamic load model must consider the behavior of induction motor Loads in the stability assessment. The behavior of customers' induction motor loads is not known. Table 1, Category P5, EHV - loss of load in the event of a fault plus the loss of a protection system, should be allowed. This requirement as currently worded goes well beyond the intent of the Standard Committee as stated in response to comments as follows: "A Protection System component failure (i.e., battery) that removes multiple Protection System schemes is beyond the P5 planning event". The draft standard is too prescriptive in some areas and too open to various interpretations in others.

Response: System normal, or P0, is the starting system condition for the projected study conditions per the model developed in accordance with Requirement R1. Requirement R1 contains more than just 'known outages of generation' that need to be considered. The SDT has adjusted Requirement R1 to provide this clarity. The SDT believes that sufficient direction on sensitivities is in the requirement but the SDT has made a slight clarifying change to the requirement.

> **Requirement R1 -** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes the normal system condition in Table 1.

The SDT has changed the definition of Year One to more clearly show the SDT's intent. The SDT believes that two near-term studies are necessary in order to calibrate the planning assumptions against operations (Year One or year two) and to provide an additional data point for interpolation (Year One or year two and

Voter	Entity	Segment	Vote	Comment
year five). **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013. The SDT has clarified the requirement based on your comments and those of others. **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment An annual Planning Assessment is required but it can be supported by current or past studies. The SDT has clarified Requirement R2, part 2.1 accordingly. **Requirement R2, part 2.1 -** The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, part 2.6, as follows: The SDT has changed Requirement R2, part 2.1 as indicated above to address your concern. 2.4.1 The standard permits an aggregate model assumption that can be applied for a given system that is not substation specific. No change made. The SDT disagrees that Non-Consequential Load Loss should be allowed for EHV. The SDT feels that it was appropriate to raise the bar on situations that would impact the reliability and performance of the System and considered above 300 kV as the backbone of the System and thus needs to be extremely reliable and was an appropriate place for raising of the bar. The SDT has changed the text for the P5 event as a result of comments. **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following: **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).				

Voter	Entity	Segment	Vote	Comment
Lorees Tadros	Omaha Public Power District	1	Negative	It's unclear what the intent of the SDT was in Requirement R6, especially when R6 is considered in conjunction with Measurement M6. R6 includes the phrase "for conditions such as Cascading, voltage instability, or uncontrolled islanding", while M6 does not. R6 and M6 should use parallel language, similar to the way R5 and M5 use parallel language. Additionally, why is "System instability" mentioned in R6 for conditions such as Cascading, voltage instability, or uncontrolled islanding, when in Note "a" at the top of Table 1, the requirement that Cascading, voltage instability, and uncontrolled islanding not occur applies to both steady-state and stability analysis? In Note "f" at the top of Table 1, the word "applicable" was inserted in front of the term "Facility Ratings". The word "applicable" is unnecessary and should be struck. Inclusion of it could lead to certain Planning Coordinators and Transmission Planners interpreting it in ways that were never intended by the SDT. The word "applicable" should also be struck from Footnote 9 of Table 1. A reference to Footnote 9 was added to each occurrence of the word "No" in the second-to-last column of Table 1. This is confusing, because a "No" in this column means that interruption of firm transmission service is not allowed, while Footnote 9 says that curtailment of firm transmission service is allowed. This needs to be clarified.

Response: The SDT agrees and has revised the wording accordingly.

> **M6.** Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of documentation specifying any criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

Requirement R6 is documentation for criteria and methodology for risk exposure to those items. The SDT does not believe it is in conflict with header note 'a'. This is parallel to using thermal ratings to determine if lines become overloaded during the analysis. No change made.

The word 'applicable' is correct as ratings vary over time and the standard must accommodate this situation. No change made.

As a general rule, curtailment is not allowed. The footnote sets out exceptions to that as long as the conditions in the footnote are met. The SDT believes that this is the proper method to present the concept. No change made.

Voter	Entity	Segment	Vote	Comment
Garry Baker	JEA	3	Negative	JEA is concerned that there are some limited prudent cases where consumers, local jurisdictions, and state jurisdictions may find it prudent to plan on some Non-Consequential Load Loss in order to defer building transmission infrastructure for the overall benefit of the consumer. Therefore, JEA proposes the addition to the standard that allows the use of Non-Consequential Load Loss for local area planning.
Brad Chase	Orlando Utilities Commission	1	Negative	OUC appreciates that hard work of the STD and of the industry in reviewing and commenting on these standards. The STD has worked hard to try to address the concerns of the industry. OUC is voting against these standards. The proposed standard raise the bar in terms of study and performance requirements, an increase that will result in a non trivial increase in costs for utilities to meet the standards. The change in the standard did address some ambiguities in the old standard, but also introduced some new ones. Reviewing the new standard against the old OUC finds that our cost and that of our neighbors will increase to meet these standards. However OUC does not believe there will be a real increase in reliability on either the bulk system or at the individual user level due to these increased costs. In the current environment the direction from our customers is to keep rates as low as possible, and from our regulatory agency it is to have as little environmental impact as possible. The customers and regulatory agency do look at outages, but transmission is very rarely a contributor to those outages and funds expended can be better spent elsewhere, like on the distribution system or hurricane hardening, then on studying and constructing redundant transmission facilities that provide little to no increase in the end user's reliability. The standard also reduces the range of circumstances where non-consequential load loss is acceptable. OUC does not generally rely on consequential load loss for these circumstances, but this is a choice made based on feedback from our customers and local regulatory authorities. Consequential load loss, when confined to a limited area, is not a Bulk Electric System reliability issue. It is an issue best addressed locally where the cost in terms of capital facilities, condemnation, environmental impacts, probability of event and severity of event can be evaluated and a decision made that addresses these issues. A miniscule decrease in the risk of an outage would often be desirable to the community due to the subsequent rate increase and the impact of constructing power lines through their wetlands, scenic and urban areas. Since such an outage is not even noticeable at a regional scale, the choice should be left to those impacted, not mandated by NERC.
Richard Kinas	Orlando Utilities Commission	5	Negative	
Ballard Keith Mutters	Orlando Utilities Commission	3	Negative	
Kimberly J. Jones	North Carolina Utilities Commission	9	Negative	The NC Utilities Commission is concerned that the requirement prohibiting loss of non-consequential load for events in Table 1 of TPL-001-1 is an inappropriate overreach into service issues that are more appropriately addressed by state regulatory commissions. This requirement does not provide any benefit to reliability of the bulk electric system and could undermine state efforts to balance

Voter	Entity	Segment	Vote	Comment
				reliability issues with cost of service issues. Requiring remediation by a date certain could frustrate the coordinated siting of new lines with other planned infrastructure upgrades such as highways or bridges. The standard should continue to allow Transmission Planners to use discretion regarding loss of non-consequential load, understanding that state commissions are positioned to force electric utilities to address service quality issues on an expedited basis, should it be necessary and in the public interest.
Response: The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area. 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.				
Mike Laney	Luminant Generation Company LLC	5	Negative	Luminant supports the concept of a more robust transmission planning criteria as described in TPL-001-1, but has serious concerns about the timeline being proposed. The 60-month implementation timeframe associated with the elimination of non-consequential load loss does not have any mechanisms to respect the base level of construction activity already underway in the various NERC regions that may materially impact compliance with a 60-month timeline. In ERCOT, the Public Utility Commission of Texas (PUCT) has mandated the construction of over 4,400 circuit miles of transmission within the next five years to support over 18,000 MW of wind generation. The PUCT Competitive Renewable Energy Zones (CREZs) build out plan requires the ERCOT 345 kV transmission network to be expanded by ~51% (in terms of total circuit miles), necessitating complex coordination of transmission clearances for construction of new lines, making it difficult to economically operate in a secure manner. These new CREZ transmission facilities are scheduled for completion by 2014 (i.e., within the next 5 years). The concurrent implementation of TPL-001-01 will compete with the CREZ build-outs and other on-going transmission upgrades needed to support load growth in the ERCOT region, which has historically experienced higher load growth rates than other parts of the country. Given that these major activities (including CREZ) reflect the most aggressive transmission build out plan in the history of ERCOT and that the implementation of TPL-001-1 will only add to that, Luminant is concerned that adding the implementation of TPL-001-1 on top of these activities will not provide adequate clearance windows to economically or reliably implement this plan within the proposed 60-month implementation window. In light of these concerns, Luminant proposes a 120 month implementation timeline of TPL001-1 for the ERCOT region Additionally, Luminant would like to see safeguards added to TPL-001-1 that acknowledge that each NERC region must complete all of the identified transmission upgrades associated with implementation of TPL-001-1 before NERC regions are required to begin operating with this level of security constraints enforced. Given that it is not possible to operate a NERC region any more securely than it is planned to be operated, this type of safeguard may readily apparent, but explicitly

Voter	Entity	Segment	Vote	Comment
				stating it would still be helpful. With the modifications outlined above, Luminant could support TPL-001-1. Thanks for the opportunity to comment.
Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. The SDT has extended the implementation plan as described above and that Requirement R2, part 2.7.3 provides sufficient latitude for entities to accommodate your concern. No change made.				
Terry Harbour	MidAmerican Energy Co.	1	Negative	MidAmerican find P5 confusing. What analysis is required? Does P5 specify the analysis of individual components of a System Protection system, the entire protection system as a whole, or something else? Do the benefits justify the requirement?
Response: The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns. **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following: **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).				
John Canavan	NorthWestern Energy	1	Negative	NorthWestern Energy Rationale for our Vote NO: Below are NorthWestern's Comments on TPL-001-1 Draft 5: January 6, 2010: While this document has improved slightly with each successive draft, there are still several flaws that persist that NorthWestern finds to be unacceptable: 1. The definition of a Bus-tie Breaker is vague. As a practical matter any breaker could qualify. 2. The definition of Non-Consequential Load Loss doesn't fit its name. 3. The idea of a Planning Assessment (developed throughout the document) is loose enough that it seems always to be asking the Transmission Planner to "do another comprehensive study anyway just to be sure you won't get sanctioned". There were numerous discussions about this, but the Drafting team has not cleaned up the language on this. The original idea was that a TP whose comprehensive study was not rendered unusable by the developments of a single year could perform an Assessment, and reasonably re-use the results of that study for the following year. The language in R2.1 contains the language: "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following current studies, supplemented with qualified past studies as indicated in Requirement R2, part 2.6:" This language

Voter	Entity	Segment	Vote	Comment
				convinces any Transmission Planning person that an annual analytical study complete with power flow simulations is required. This requirement is onerous, since there is a significant waste of manpower and resources involved in conducting such a study when for most years a bi-annual study program would clearly be sufficient. NorthWestern considers that this one issue is worthy of a NO vote based on the excessive nature of the requirement. 4. The language in R2.3 requires a short circuit analysis to be conducted annually. As with our comment 3 above, we find this excessive. This level of vigilance is not commensurate with the potential threat of a situation where fault duty could exceed breaker interrupting capability. 5. The stricter requirements in the table for EHV lines certainly "raise the bar" for these facilities. They are also likely to reduce the enthusiasm for building such facilities. The outcome of this may be unintended consequences that are far more onerous to society that the amount of load loss that is avoided by the standard. It is not clear that this addition to the standard is well reasoned. 6. NorthWestern is concerned about the potential for uneven treatment by various auditors as they follow this standard. While there is some risk of this for any standard, we believe the language in this standard is still weak. 7. The 60 month time limit for implementing Corrective Action Plans may be quite unrealistic in the Montana transmission line environment. It really is not clear what is in the Transmission Planner's "control" in this arena. 8. The definition of "year one" is problematic. Presently the WECC does not produce base cases that are well suited to this choice. We would like to encourage the Drafting Team to work to "tighten up" the language in the standard. This particular standard is so important to the general reliability of the transmission system (BES) that it deserves an extra effort at clarity, conciseness, and thoughtful language to achieve truly beneficial practices in the design of the BES. We believe that a "NO" vote is our best recourse to promote this extra effort. We understand that this standard has been a "long time in the making". That is because it is truly a difficult drafting challenge, not because of a poor effort.
Response: 1. The definition has been iterated several times based on industry comments in the past and seems to have been accepted by the overwhelming majority of the industry to date. No change made. 2. The use of non-consequential is in line with the previously used term 'consequential' and doesn't imply that it isn't important. No change made. 3. The intent of the SDT wasn't that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and part 2.1.				

Voter	Entity	Segment	Vote	Comment
Requirement R2 - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. **Requirement R2, part 2.1 -** The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, part 2.6, as follows: 4. Past studies are allowed as long as they qualify as per Requirement R2, part 2.6 and that should alleviate your concern. No change made. 5. There are many other factors over and above this standard that will determine what entities build in the future. The SDT and many stakeholders believe that it is important to raise the bar for reliability. No change made. 6. The SDT has made every attempt to make this standard clear, unambiguous, and enforceable. Without any specific comments to address, the SDT is unable to further address your concerns. No change made. 7. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. 8. Based on your comment and those of others, the SDT has revised the definition of Year One. **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.				
David H. Boguslawski	Northeast Utilities	1	Negative	NU votes to oppose TPL-001-1 with the following comments: Northeast Utilities (NU) is very appreciative of the effort of the SDT in preparing TPL-001-1. NU believes that this effort has resulted in a new TPL standard that shows improvement over the existing TPL standards. However, there are still some important concerns that NU believes should be addressed prior to the adoption of TPL-001-1. Therefore, in its present state NU can not vote for the acceptance of the draft standard and votes to REJECT the proposed standard (TPL-001-1). NU would like the SDT to re-visit and address the concerns listed below: 1. The use of Non-Consequential Load Loss to mitigate violations arising from certain planning events: NU has objected to this requirement in comments submitted for previous drafts of TPL-001-1. NU believes that Non-Consequential Load Loss should not be considered for P1 to P7 events to achieve the level of reliability needed when planning the electric power system. The amount of load that could be shed is open ended in TPL-001-1 and this will lead to different interpretations which can be detrimental to the stakeholders. To put it simply the standard as currently drafted will lead to

Voter	Entity	Segment	Vote	Comment
				confusion as Transmission Owners, Regional Reliability Organizations, along with state and federal agencies will need to come to agreement on what the standard allows and what it doesn't. Ultimately, a standard that does not have clear measurable criteria will lead to difficulty in developing and obtaining approval for projects to achieve the required level of reliability. If the SDT and NERC believe that allowing the use of Non-Consequential Load Loss for multiple element contingencies (e.g., N-1-1 or P6 planning events) is necessary in achieving system reliability then NERC should specify that the amount should be minimal, such as less than 100 MW. 2. The use of past study reports to satisfy Requirement R2, parts R2.1 and R2.2: The language of Requirement R2, parts R2.1, R2.2 and R2.6 is confusing and will lead to different interpretations from different stakeholders. While Requirements R2.1 and R2.2 indicate that annual studies should be conducted and to be supplemented by past studies, Requirement R2.6 seems to suggest that past studies could be used instead. The SDT's response to NU's comment on this issue supports the assertion that annual studies should always be conducted even if there are no changes in the system conditions and past studies should be used for the years within the assessment period but not called out by the standard. If studies are conducted every year then why the need to use past studies. This creates unnecessary study work and should be changed. 3. Table 1 - Steady State & Stability Performance Planning Events, Category P5 Events: This requirement as currently worded goes well beyond the intent of the Standard Committee as stated in response to comments as follows: "A Protection System component failure (i.e., battery) that removes multiple Protection System schemes is beyond the P5 planning event". It is NU's opinion that similar language to the comment response should be incorporated into this requirement to avoid any confusion. 4. Base case initial conditions: NU believes that a great deal of confusion and uncertainty will be eliminated or reduced if the standard attempts to define the nature of initial base cases that should be used in planning studies. As it stands now this issue is left to interpretation, which can lead to confusion when determining appropriate planning projects to achieve a reliable power system. Depending upon the interpretation of the base case dispatches and the level of interface flows (level of stress) they may reveal reliability violations in the power system. Non-uniformity in developing base cases for an area or region may mask real reliability problems in the system. This is one of the primary weaknesses of the existing TPL standards. 5. Items 1, 2, 3 and 4 are Northeast Utilities primary concerns which should be addressed prior to NU accepting the standard. NU has additional reservations about the standard that should be addressed in subsequent revisions. 6. NU also supports the comments from other transmission owners that 60 months may not be

Voter	Entity	Segment	Vote	Comment
				sufficient to complete construction of transmission facilities.

Response: 1. The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others' concerns in this area.

12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.

2. The intent of the SDT wasn't that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and part 2.1.

Requirement R2 - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.

Requirement R2, part 2.1 - The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, part 2.6, as follows:

3. The SDT has changed the text for the P5 event as a result of your (and others') comments to address these concerns.

P5. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following:

13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

4. The SDT is trying to provide guidance without being overly prescriptive. Projected System conditions as well as the types of sensitivities that need to be studied are described. No change made.

5. Without any specific comments to address, the SDT is unable to further address your concerns. No change made.

6. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. ince problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order.

Henry G. Masti	New York State Electric & Gas Corp.	1	Negative	NYSEG supports the NYISO comments and also offer: The standard requires that dynamic load models be used that take into account induction motor effects. This information is generally not available and therefore it would be unworkable to develop an accurate model. The standard requires relays be modeled into the dynamic simulation. While standard mho, distance, or reactance distance relay model may exist, manufacturer-specific relay models often do not. Since this modeling is generally not available, it would be unworkable to develop an accurate dynamic model to test relay loadabilitiy.

Voter	Entity	Segment	Vote	Comment
Response: The standard permits an aggregate model assumption that can be applied for a given system that is not substation specific so this is not unworkable. No change made. The SDT has clarified Requirement R4, part 4.3.1, bullet #3 to address your concerns. **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: • Successful high speed reclosing and unsuccessful high speed reclosing into a Fault. • Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.				
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Negative	Oklahoma Gas & Electric (OG&E) Comments on Proposed NERC TPL-001-1 1.) OG&E feels that the effective dates of R1 and R7 shall become effective 18 months and not 12 months. Some entities budgeting cycles may not be based on 12 months and expenditures may be required by some to be compliant. 2.) OG&E feels that the effective dates of R2 through R6 shall become effective 30 months and not 24 months. This will allow entities adequate time to budget (personnel & tools), train, and perform the required studies. 3.) As others have mentioned, OG&E would like the 60 months extended to 84 months. 4.) Further examination should be conducted to evaluate the feasibility of performing the stability analysis every two years and not annually. 5.) OG&E has concerns for including induction motor representations in the load models without any study or bench-marking activities to meet the requirements of R2.4.1. 6.) The abbreviations of HV and EHV used in Table 1 shall be defined in the "Definitions of Terms Used in Standard" section. 7.) Although Table 1 has been improved, further work is needed to make Table 1 more intuitive. The notes at the beginning and ending of Table 1 seem awkward within the document.
Response: 1. The SDT believes that 12 months is sufficient. This isn't a completely new requirement – entities should be doing this work now for the existing TPL				

Voter	Entity	Segment	Vote	Comment
standards. No change made. 2. The SDT believes that 24 months is sufficient. This isn't a completely new requirement – entities should be doing this work now for the existing TPL standards. No change made. 3. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. 4. The requirement is for an annual assessment and past studies can be used if qualified as per Requirement R2, part 2.6. No change made. 5. The standard permits an aggregate model assumption that can be applied for a given system that is not substation specific. No change made. 6. The EHV/HV differentiation is not meant to be a definition in that it only applies to this standard. No change made. 7. Without any specific comments to address, the SDT is unable to further address your concerns. No change made.				
Mark Sampson	PacifiCorp	1	Negative	PacifiCorp appreciates the diligence and dedication of the Standard Drafting Team and commends the group for their hard work to bring the proposed standard TPL-001-1 to this level. PacifiCorp believes the overall language of the standard has improved to enhance its readability and the language and format of the Tables now provides some improvement in the understanding of acceptable System performance for the various Planning Events. However, inasmuch as the proposed Standard has improved, we cannot support the approval of this document at this time. The following comments and suggestions are provided in support of a no vote on the TPL-001-1 standard as currently proposed proposed. 1) As currently written our Company does not believe that 60 months is a reasonable time period to build transmission facilities to meet the new performance requirements. Building a transmission line in PacifiCorp's 6 state service areas varies significantly in regional and local planning and review process, permitting, siting, legal challenges, routing, and system path rating process can often take more than 5 years to complete from the time the project is authorized. Though requirement R2.7.3 is included to address situations beyond the control of the Transmission Planner, it leaves to the interpretation of the auditor whether the appropriate actions are being taken to resolve the issue that would continue to allow dropping of Non-Consequential Load or curtailment of Firm Transmission Service. Table 1 - Steady State & Stability Performance Planning Events Category P2 (Single Contingency). Category P2 requires responsible entities to study the opening of a line section without a fault. The standard as written states that the opening of this line section will not result in consequential load
John Apperson	PacifiCorp	3	Negative	
Sandra L. Shaffer	PacifiCorp	5	Negative	
Gregory D Maxfield	PacifiCorp	6	Negative	

Voter	Entity	Segment	Vote	Comment
				loss and no voltage or thermal violations will occur on the BES. . This requirement is applicable to EHV (above 300 kV) and HV (100-300 kV) facilities. PacifiCorp believes that this requirement should not be applicable to all HV facilities. From a reliability perspective, a more effective and efficient method would be a bifurcated functional requirement rather than a voltage requirement. In PacifiCorp's system, and in much of the Western Interconnection, a breaker that opens without a fault in the 115/138 kV system almost never has the potential to cause impacts beyond the local area. In most cases this extremely rare event (the unplanned opening of a breaker without a fault) cannot impact the EHV Bulk Electric System. As such, this requirement (P2-1) is not appropriate at the HV voltage levels. A more appropriate requirement for P2-1 would be to require this performance level only for the EHV portion of the BES and the HV facilities that perform a transmission service in addition to local load service. This should not be a requirement for HV facilities that only provide local load service. 2) Table 1-P5 Multiple Contingencies (Fault plus Protection System failure to operate) Normal System. There is a significant change in the system normal performance required for EHV systems from the current performance required in TPL-003 (Category C). This TPL-001-1 version does not allow any Non-Consequential load loss (table 1) or firm Demand (note 9) for EHV systems in the event of protection system failure and delayed clearing. This performance requirement would thus preclude use of existing protection systems that rely on remote clearing of interconnected EHV lines or stations if they provide local load service. As written the standard essentially now requires Category B performance rather than Category C performance for multiple contingencies. It is PacifiCorp's opinion that loss of Non-Consequential load or firm Demand should be allowed for the rare event involving multiple contingencies stated in P5 as long at the load or firm Demand loss is contained and controlled in the local load service area and the event does not impact other interconnected utilities or their loads. 3) Table 1 - Steady State & Stability Performance Planning Events Category P5 (Multiple Contingency (Fault plus Protection System failure to operate). Category P5 requires responsible entities to study the Event titled Failure of a single Protection System that results in Delayed Fault Clearing on one of the following: Generator, Transmission Circuit, Transformer, Shunt Device, or Bus Section. It appears that this requirement is an indication that multiple protection system failure is not allowed under the proposed TPL-001-1. This appears to be a requirement for redundant protection systems for all possible events on all voltage levels of the transmission system. It also appears that this requirement is attempting to define what comprises an adequate protection system. As the draft standard is presently written it appears that multiple protection system failures are not included in this part or any part of the draft TPL-001-1 standard. As written, it is PacifiCorp's view that any multiple protection system failure would be categorized as an Extreme Event under the draft TPL-001-1

Voter	Entity	Segment	Vote	Comment
				standard. PacifiCorp contends that the many and varied issues associated with designing appropriate protection systems should be done in the context of the development of a protection system standard and not in the context of TPL-001-1. In fact, there is currently a proposed standard going through the NERC standards development process which goal is exactly that. If the standards drafting team intends to require responsible entities to have 100% redundant protection systems on all of its BES facilities, PacifiCorp contends that this fact should be stated up front in the standard so that all interested parties may become aware of this requirement and provide informed comment. PacifiCorp believes that it is appropriate to wait until the current protection system redundancy standard under development proceeds through the SAR process and approval system, given that this in an important generic issue that affects the entire industry. Notwithstanding the inappropriateness of raising the protection system issue in the context of a planning standard, PacifiCorp believes that any planning requirement that includes the failure of a single protection system that results in delayed fault clearing must have a very clear definition of the terms "single protection system" and "delayed fault clearing" in or for entities to determine what compliance with the standard requires. The draft TPL-001-1 standard does not have clear definitions of these terms, leaving room for considerable latitude for interpretation by various responsible entities, auditors, and compliance enforcement authorities. Clear, specific, and technically defensible language is needed for these terms. 4) As drafted the standard TPL-001-1 has added requirement 2.1.5 discussing spare equipment and lead times and inclusion in the "Planning Assessment". The standard in this section is not performance based requirement but an activity based requirement as currently stated under R2 2.1.5. PacifiCorp recommends that the standard should be revised and 2.1.5 removed as it does not directly improve the systems performance requirements nor compliance stated in Table 1.

Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility.

The SDT believes that the addition of footnote 12 (when it is finalized) will address your concern.

The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area.

12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.

The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns.

Voter	Entity	Segment	Vote	Comment
P5. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following: **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94). The SDT has clarified the requirement based on your comments and those of others. **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment				
John C. Collins	Platte River Power Authority	1	Negative	Platte River appreciates the efforts and perseverance of the Drafting Team on this important standard. A "no" vote is cast because the following requirements are not clear and have RISKS for different interpretations that could result in non-compliance. (1) Table 1 Planning Events, column for Initial System Condition. Does "Loss of" refer to a planned outage or forced outage? (2) Table 1, Extreme Events, column for Stability. In Stability Event 1, what is the fault type for the first forced outage? (The second forced outage is specified as 3-phase.) (3) Contingency lists required for Planning Events in Table 1. The required scope of contingency analysis for each Category is not clear. P1. Create a list of Contingencies only for the more severe P1 type, or create lists for each of P1-1 through P1-5 types? P2. Create a list of Contingencies only for the more severe P2 type, or create lists for each of P2-1 through P2-4 types? P3. Create a list of Contingencies only for the more severe P3 type, or create lists for each of P3-1 through P3-5 types? P4. Create a list of Contingencies only for the more severe P4 type, or create lists for each of P4-1 through P4-6 types? P5. Create a list of Contingencies only for the more severe P5 type, or create lists for each of P5-1 through P5-5 types? P6. Create a list of Contingencies only for the more severe P6 type, or create lists for each of P6-1-1 through P6-4-4 types, 16 possible combinations? P7. Create a list of Contingencies only for the more severe P7 type, or create lists for each of P7-1 through P7-2 types? (4) Contingency lists required for Extreme Events in Table 1. The required scope of contingency analysis for each Steady State and Stability columns is not clear. Create a list of Contingencies only for the more severe type, or create lists for each of the "such as" types? (5) Table 1, compare footnotes 1, 3, and 5. Does a P4-3 or P5-3 contingency involving an EHV-HV transformer and causing deficiencies on the EHV allow Non-Consequential Load Loss to correct since

Voter	Entity	Segment	Vote	Comment
				the HV is the lowest voltage and override the "No" in the column for Non-Consequential Load Loss Allowed for EHV? (6) What is a "sufficient amount" and how much is a "measurable change" for sensitivity case stressing? See parts 2.1.4 and 2.4.3. (7) Are the actions associated with single vs. multiple sensitivity studies in part 2.7.2 Corrective Action Plans? (8) Are Long-term stability analyses required only if there are generation additions or changes in the long-term horizon? See part 2.5.
Response: 1. Planned outages of six months or more should be incorporated into the P0 condition as per the requirements. The events cited are forced outages. 2. It doesn't matter what type of Fault creates the first outage condition as it is the second outage that is studied. 3. The SDT believes that an entity only needs a list for those types of events that are more severe for your study area. 4. An entity doesn't need a list for each 'such as'. The rationale for those selected must be documented as stated in the requirements. 5. For an outage of an EHV/HV transformer, performance requirements specified as HV must be met. 6. Requirement R2, part 2.1.4 is part of Requirement R2 which mandates that an entity must document all assumptions utilized in the Planning Assessment. No change made. 7. Requirement R2, part 2.7.2 is for multiple sensitivities. Requirement R2, part 2.7 states that Corrective Action Plans are not required for single sensitivities. 8. Yes, it is required only if there are additions or changes in the long term.				
Christopher L de Graffenried	Consolidated Edison Co. of New York	1	Negative	Reword Table 1 Note (i) as follows: The response of voltage sensitive load that is disconnected from the system by end-user equipment associated with an event shall not be used to meet steady state performance requirements Reword Requirement R 1.1.5 as follows: Known commitments for Firm Transmission Service, and, additionally, other types of transactions provided they have been demonstrated to not violate existing reliability constraints
Nickesha P Carrol	Consolidated Edison Co. of New York	6	Negative	
Peter T Yost	Consolidated Edison Co. of New York	3	Negative	

Voter	Entity	Segment	Vote	Comment
Response: The header note is not just for disconnections by end-user equipment but would also cover the natural response of Load for voltage reduction. The suggested wording changes the intent of the SDT. No change made. The SDT believes that the defined term 'Interchange' covers other transfers as described in your comment. No change made.				
Henry Delk, Jr.	SCE&G	1	Negative	SCE&G appreciates the efforts of the Standard Drafting Team and believes this version of the TPL standard has addressed most of the significant issues found in previous versions. However, SCE&G believes there are several significant issues that need modification or further explanation. 1. SCE&G agrees with other submitted comments that the requirement to complete new transmission construction to meet new performance requirements within 60 months is too short. SCE&G believes that 84 months is more reasonable. 2. SCE&G agrees with comments submitted by Duke Energy that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues, does not provide any real benefit to Bulk Electric System (BES) reliability, and may have unintended negative consequences on reliability and service quality. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. The standard should continue to allow Transmission Planners to use discretion regarding loss of non-consequential load, such that Transmission Planners, customers, and local regulators jointly control the decision making when BES reliability is not an issue. 3. SCE&G believes there are still different interpretations of Consequential and Non-Consequential Load loss and how each should be applied or not applied. The Standard drafting team should provide several examples in its response to these comments showing how to apply and not apply Consequential and Non-Consequential Load Loss. Without clear examples, SCE&G believes many request for interpretation will be submitted to NERC by the industry.
Hubert C. Young	South Carolina Electric & Gas Co.	3	Negative	
Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area. 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. The SDT has clarified the issue of Non-Consequential Load Loss as shown above. Providing examples here of what is Non-Consequential Load Loss versus				

Voter	Entity	Segment	Vote	Comment
Consequential Load Loss would have no bearing on eventual compliance findings. The words are what matter and the SDT feels that the clarification provided should alleviate your concern.				
Charles H Yeung	Southwest Power Pool	2	Negative	SPP recommends the standards drafting team review the IRC SRC comments submitted in Oct 2009 and reassess those concerns.
Response: The SDT addressed the comments of the IRC SRC in its responses to the last posting which were captured in the Consideration of Comments report. Without any new specific comments to address, the SDT is unable to further address your concerns. No change made.				
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Negative	SWTC Comments: The SDT has done a lot of good work in developing the TPL 001 standard. However, I agree with the comments of others and suggest that another draft should be produced before the standard is sent to a ballot. SWTC forsees a problem with manpower and the cost of studies for small entities such as ourselves. This will be an extra burden and costs that will ultimately be borne by the consumer who is already not very happy lately. In part 2.7.1, remove the second sentence and all bullets. These are not measurable performance criteria. EHV" and "HV" need to be defined because they are not defined in the NERC Glossary. R4.3.2 This is an admirable goal, and we applaud the SDT's vision. However, modeling all Protection Systems may be beyond the capabilities of presently used dynamic modeling tools. The number of impedance and overcurrent relays that would need to be included for lines and transformers would likely overwhelm these programs. We are concerned that the programs in use may not have the capability to model important relay characteristics such as load encroachment or out-of-step operating characteristics. R5 & R6: Shouldn't the Load Serving Entities (LSEs) define system performance criteria instead of the Transmission Planner or the Planning Coordinator? The LSEs have an obligation to their customers and must demonstrate to their regulators that they are providing acceptable system performance and reliability of supply to their customers. The Transmission Planner and Planning Coordinator have less incentive to provide high levels of system performance. Due to regulatory difficulties in getting approvals for transmission system upgrades, there may be a tendency on the part of TPs and TCs to avoid proposing transmission upgrades, letting system performance degrade instead by abandoning traditional planning criteria and defining less stringent standards for themselves. R6 Remove the "for conditions such as ..." list.

Voter	Entity	Segment	Vote	Comment
Response: The SDT has clarified Requirement R2 and part 2.1 to make it clearer that qualified past studies can be utilized. **Requirement R2** - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. **Requirement R2, part 2.1 -** The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, part 2.6, as follows: The listed items are simply that – a list of actions that would be included. This is an allowable and encouraged format for Reliability Standards. No change made. The EHV/HV differentiation is not meant to be a definition in that it only applies to this standard. No change made. The SDT believes that your comment is for Requirement R4, part 4.3.3. The SDT has modified the wording of this requirement to address your concern. **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: • Successful high speed reclosing and unsuccessful high speed reclosing into a Fault. • Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models. These are System requirements for the BES and properly belong to the Planning Coordinator and Transmission Planner. No change made.				
Donald S. Watkins	Bonneville Power Administration	1	Negative	The Bonneville Power Administration (BPA) acknowledges and appreciates the hard work and diligence of the Standards Drafting team on such a large effort. BPA respectfully submits the following comments.

Voter	Entity	Segment	Vote	Comment
Rebecca Berdahl	Bonneville Power Administration	3	Negative	1. Requirement R1.1.2: BPA recommends that system models should only represent outages with a duration of one year or more. The planning horizon should not cover an outage less than one year because there is not adequate time for developing and implementing any necessary mitigation plan. Known outages with duration less than one year should be dealt with in the Operations horizon. In addition, the near term steady state studies represent year one or year two and year five as required by R2.1.1. Therefore it is not consistent with the rest of the standard to require modeling outages less than one year. 2. Requirement R3.5: BPA recommends removing the requirement to evaluate possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the extreme events. o This is more stringent than the existing requirement without providing any increased reliability benefit. The new standard already requires a significant increase of study cases and this additional requirement results in an undue study burden on utilities without adding any benefit. o In addition, Table 1, Extreme Events, should be reduced to a more prudent list of possible events to evaluate risks and consequences. It is obvious that several of the events, especially under item 3 (Wide Area Events), would cause cascading and it is not practical to evaluate possible mitigation plans for such extreme events. 3. Table 1: The category P2 Single Contingency should be removed. o Events P2.2, P2.3 and P2.4 should be moved to category P4 since these events are not single contingencies. P2 is a single contingency category, which by definition takes one system component out of service. Bus section faults and bus-tie breaker faults are multiple contingencies since they are events that take multiple system components out of service. o Event P2.1 "opening of a line section w/o a fault" should not be included in the planning standard. At a minimum Event P2.1 should be moved to Category P1 since it is a single contingency and it should allow Interruption of Firm Transmission Service and Non-Consequential Load Loss for the HV ((<300 kV) BES level. Many of the HV (115-kV) lines have taps that serve loads and are designed to remove all elements that the protection system and other automatic controls are expected to disconnect. This is consistent with Requirement 3.3.1 which states "Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention." Inadvertent opening of one end of an HV line section without a fault almost never has the potential to cause impacts beyond the local area, yet has a low probability of occurrence and would be very costly in some cases to mitigate. 4. Footnote 11: BPA recommends removing the reference to common Right-of-Way. This could be mis-interpreted that a common Right-of-Way longer than 1mile should be planned for under Category
Francis J. Halpin	Bonneville Power Administration	5	Negative	
Brenda S. Anderson	Bonneville Power Administration	6	Negative	

Voter	Entity	Segment	Vote	Comment
				P7. The NERC standards only include common Right-of-Way under extreme events and in this footnote. So, it would be consistent with the rest of the standard to remove this reference from the footnote and possibly make a specific reference in the Extreme Events category where it applies. 5. Requirement R2.4.1: BPA agrees with other commenter's concerns that requiring Load models that consider the behavior of induction motor Loads is premature without adequate development and benchmarking efforts. In addition, specific types of models and data required for analysis should not be mentioned here, but should be specified and submitted through the appropriate MOD Standard's. 6. Requirement R4.3.3: BPA agrees with other commenter's concerns regarding simulating the impact of transient swings on Protection System operation for Transmission lines and transformers. It would be an extremely burdensome task to model relay impedance characteristics for all elements with little or no benefit, and it is questionable whether the simulation programs would support this effort.

Response: 1. The time frame is for future outages in the planning horizon and last for at least six months. No change made.

2. The SDT disagrees as this is effectively the same requirement as presently stated in TPL-004. No change made.

The SDT does not agree that these conditions obviously will create Cascading. The SDT reminds the commenter that not all events must be studied. No change made.

3. The category descriptions are meant to characterize the events. A single event may remove more than one element from service and that has been addressed in Header note 'c'. The SDT does not believe that there are inconsistencies within the table. The P2 category describes single events that may result in multiple elements being removed from service. The P2 events differ from the multiple event categories which consider two or more sequential events. No change made.

4. The SDT has revised the footnote to provide additional clarity based on your comment.

> **11.** Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.

5. The standard permits an aggregate model assumption that can be applied for a given system that is not substation specific. No change made.

6. The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern.

> **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:
>
> - Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
> - Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
> - Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual

Voter	Entity	Segment	Vote	Comment
relay models.				
Ralph Frederick Meyer	Empire District Electric Co.	1	Negative	The Empire District Electric Company appreciates the dedication of the Standards Drafting Team Empire cannot support the approval of the proposed standard as written. Empire finds exception to the proposed standards in the following areas: 1) We disagree with the proposed requirement 2.1.5 on spare equipment strategy in that it is discriminatory for smaller entities like Empire. Having a spare transformer is not practical and makes far less sense for a smaller entity but yet has a significant rate impact to our customers. 2) We disagree with requirement 3.3.3 as written would require modeling of nearly every phase distance relay, especially when studying extreme events. The requirement deserves flexibility as allowed in requirement 3.3.2 3) We do not believe 60 months is a reasonable time period to build transmission facilities to meet the new performance requirements. Our suggestion to the drafting team would be some amount of time greater than 7 years (84 months).

Response: The SDT has clarified the requirement based on your comments and those of others.

> **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment

The SDT agrees that a planner should be able to utilize conservative assumptions and screening methods and doesn't believe that there is anything in the requirement that precludes an entity from doing so. No change made.

The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order.

Voter	Entity	Segment	Vote	Comment
Frank Gaffney	Florida Municipal Power Agency	4	Negative	The Florida Municipal Power Agency (FMPA) appreciates the hard work of the SDT, but, we believe there are significant issues that remain with the standard. FMPA believes that 5 years is not enough time to build significant new transmission lines and believes that 7 years is a more appropriate lead time. FMPA believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local quality of service issues and does not provide any real benefit to BES reliability. The standard ought to separate what an entity chooses to do for the benefit of its own customers and the impacts it may on the reliability of the BES. FMPA believes that an entity has the right to choose to utilize the existing footnote "b" in the version 0 standards if that choice does not detrimentally impact the ability to provide transmission service to others. FMPA believes that requirement 2.1.5 on spare equipment strategy is discriminatory to smaller entities. Also, Order 693 at Paragraph 1725 states: "... the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy". The standard oversteps this direction by not including a consideration of planned outages versus forced outages. Requirements 3.3.3 and 4.3.1 would require modeling of nearly every phase distance relay in the Interconnection. It is questionable whether we have the software tools to do so, and this would require a huge level of effort to maintain an interconnection wide database of relay settings for questionable benefit. FMPA believes that the SDT ought to evaluate the perceived increase in accuracy that is intended with these requirements. It is FMPA's belief that the expected increase in accuracy is lost when considering other simulation inaccuracies that we really cannot improve (e.g., load modeling) until much more work is done on improving our understanding of dynamic load behavior and benchmarking the model to actual system events.

Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order.

The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area.

12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.

The SDT has clarified the requirement based on your comments and those of others.

Requirement R2, part 2.1.5 - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a

Voter	Entity	Segment	Vote	Comment
lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment The SDT agrees that a planner should be able to utilize conservative assumptions and screening methods and doesn't believe that there is anything in the requirement that precludes an entity from doing so. No change made. The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern. **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: • Successful high speed reclosing and unsuccessful high speed reclosing into a Fault. • Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.				
Alden Briggs	New Brunswick System Operator	2	Negative	The NBSO applauds the efforts of the Drafting Team on this very important TPL standard. However, we feel that it is not quit ready for acceptance but with a few tweeks and some much needed clarity it would be. NBSO believes the BES versus BPS needs resolution as we much prefer standards that applicable to the bulk power system based on an impact assessment opposed to an arbitrary voltage level. The standard should be more flexible allowing for any trade off between temporarily shedding small amounts of load to recover from a single contingency where the alternative which may force significant transmission upgrades. The standard gives preference to a single line feeding a local area versus two lines, where the loss of one of two under high loading conditions should allow for portions of load to be shed to maintain voltage. The standard considers demand side management as an option but no allowance for instantaneous and temporary load loss that could be required before DSM could be activated. The standard should be clear that if in agreement with a distribution provider some portions of the distribution load (non-consequential load loss) may be shed for a single contingency for undervoltage and underfrequency conditions. The requirements for load models should be clarified so capture dynamic behaviour within reason.

Voter	Entity	Segment	Vote	Comment
				There should be a Q&A guide to allow for examples to clarify the requirements.
Response: The SDT does not believe that it needs to define BES. In its March 18th order, FERC suggested a continent-wide definition of the BES. No change made. The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area. **12.** Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. DSM is permitted because it is pre-arranged with the customer. For transmission systems, DSM is expected to be used in anticipation of the next transmission system Contingency, not in response to the transmission system Contingency. UVLS & UFLS are intended safety nets for operations and should not be relied upon in transmission planning. No change made. The standard permits an aggregate model assumption that can be applied for a given system that is not substation specific. Dynamic load modeling is important for correct dynamic simulations. Industry has acknowledged the need for accurate Load modeling and the SDT has codified this need in the proposed standard. No change made. While a Q&A providing examples may be helpful it would have no official bearing and such an effort is not in the project schedule.				
Gregory Campoli	New York Independent System Operator	2	Negative	The New York Independent System Operator (NYISO) believes this proposed standard is moving in the right direction with the right intentions, and while we truly appreciate the expertise and hard work that the standards drafting team (SDT) has consistently exhibited throughout this lengthy process, we have voted no on the adoption of this balloted version of the proposed NERC Standard TPL-001-1 for the following reasons: 1. The proposed Standard would significantly, and unnecessarily, shift responsibilities away from the Transmission Owner (TO). The proposal would require that for the Bulk Electric System (BES) throughout the New York Control Area (NYCA) the NYISO would annually evaluate: specified contingency events, all corrective action plans, and all spare equipment strategies. As we are not a BES facility owner, we believe that facility specific requirements should stay with facility owners. 2. The proposed Standard requires that Corrective Action Plans are included in each Planning Assessment and states "Such actions may include..." followed by a list of actions. Restricting allowable actions, and excluding runback/tripping of HVDC would have a direct impact on multiple existing facilities in New York and would adversely impact the reliability planning of the NYCA. 3. The proposed Standard would require the PC & TP to assess the impact and probability of the possible unavailability of any piece of equipment with a lead time of one year or more. Such an evaluation of spare equipment strategies would require significant additional resources and data, but

Voter	Entity	Segment	Vote	Comment
				provide no benefit to system reliability, as it is redundant to the existing N-1-1 contingency requirement (P6). 4. The proposed Standard would require an "annual" assessment of the system in order for it to be considered "current." The NYISO has a biennial reliability planning process and does not find it necessary to perform all studies annually in order to be current. We see no reliability benefit to requiring this to be done annually; in fact, dilution of planning efforts and resources is in itself a reliability risk. 5. The proposed Standard lacks a clear definition of the first year of the planning horizon. It is defined as the planning window that begins 12-18 months from the end of the current calendar year. If "Year One" is two calendar years out, what is year two? year five? This ambiguity poses an unacceptable risk to compliance. 6. For steady-state and stability analysis, the proposed Standard creates a limited list of required sensitivities, and may require sensitivities with no useful objective. The Standard should instead provide a list of suggested sensitivities to allow the planning entity to use its judgment to study sensitivities pertinent to its system. Furthermore, in the absence of a definition of base case conditions, it is difficult to determine, from a compliance standpoint, what is a "stressed" system. 7. The proposed Standard requires stability models to represent the dynamic behavior of loads, including the consideration of the behavior of induction motor loads. The NYISO, along with many other systems, has not determined a need to model dynamic loads, and therefore has not benchmarked any such models. The NYISO recommends that prior to this requirement being in place, a modeling standard should exist that is specific to dynamic loads.

Response: 1. Planning the system is the responsibility of the Planning Coordinator and Transmission Planner as per the Functional Model. The Planning Coordinator or Transmission Planner simply needs to account for those strategies and facility specific items that are passed to them by asset owners. No change made.

2. The list is not all inconclusive but a list of possible actions. The SDT agrees that runback or tripping of HVDC would be allowable actions. No change made.

3. The SDT has clarified the requirement based on your comments and those of others.

> **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment

4. The intent of the SDT wasn't that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words

Voter	Entity	Segment	Vote	Comment
may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and part 2.1. **Requirement R2** - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. **Requirement R2, part 2.1 -** The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, part 2.6, as follows: 5. Based on your comment and those of others, the SDT has revised the definition of Year One. **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013. 6. The SDT has made clarifying changes to Requirements R1 and R2, part 2.1.4 to address your concerns. **Requirement R1 -** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes the normal system condition in Table 1. **Requirement R2, part 2.1.4 -** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: 7. The standard permits an aggregate model assumption that can be applied for a given system that is not substation specific. Dynamic load modeling is important for correct dynamic simulations. Industry has acknowledged the need for accurate Load modeling and the SDT has codified this need in the proposed standard. No change made.				

Voter	Entity	Segment	Vote	Comment
Alan Adamson	New York State Reliability Council	10	Negative	The New York State Reliability Council (NYSRC) appreciates the hard work and time the drafting team has devoted during its preparation this standard. The present version represents a significant improvement over the present transmission planning TPL standards. However, the TPL-001-1 standard needs further improvement in several areas before the NYSRC can vote to approve the standard, as follows: 1. The standard requires annual assessment of the system regardless of whether system conditions are essentially unchanged from year to year. This may require unnecessary study work. 2. Testing requirements are rigidly defined in the standard, but specifically what is to be tested is loosely defined. 3. The standard requires analyses of a specific list of sensitivities. Instead, the standard should provide a list of suggested sensitivities and allow the planning entity to use its judgment to study those sensitivities that may be more pertinent to its system. 4. The standard requires stability models to represent the dynamic behavior of loads, considering the behavior of induction motor loads. New York has not modeled dynamic loads, and such modeling has never been benchmarked. For many years, simulations of actual system disturbances have been represented with excellent accuracy, without modeling loads dynamically. 5. The definition of BES (100kv bright line) is uncertain at this time. Therefore, until this definition and its application is resolved, it is not possible to know - without a clarifying provision in the standard - which portion of a system that presently has a performance based methodology, such as the New York State Power System, is subject to the TPL-001-1 standard.

Response: 1. The intent of the SDT wasn't that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and part 2.1.

> **Requirement R2** - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.
>
> **Requirement R2, part 2.1 -** The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, part 2.6, as follows:

2. What needs to be tested is the transmission system that is under the purview of the Planning Coordinator or Transmission Planner.

3. The SDT has made clarifying changes to Requirement R2, part 2.1.4 to address your concerns.

> **Requirement R2, part 2.1.4 -** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to

Voter	Entity	Segment	Vote	Comment
demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: 4. The SDT assumes that you are referring to the induction motor Load modeling required for Stability studies. The standard permits an aggregate model assumption that can be applied for a given system that is not substation specific. Dynamic load modeling is important for correct dynamic simulations. Industry has acknowledged the need for accurate Load modeling and the SDT has codified this need in the proposed standard. No change made. 5. The SDT does not believe that it needs to define BES. In its March 18th orders, FERC suggested a continent-wide definition of BES. No change made.				
James Armke	Austin Energy	1	Negative	The proposed TPL-001-1 Standard needs to be revised regarding the comments submitted by Ameren, Duke, and JEA.
Response: Please see responses to Ameren, Duke, and JEA.				
Silvia P Mitchell	Florida Power & Light Co.	6	Negative	The SDT has addressed many of the gray areas of Draft four in their consideration of comments however these comments are not part of the Standard that is currently out for ballot. Incorporating these type of clarifying comments in the Standard with the use of footnotes to clarify the intent would be a significant improvement for anyone interpreting the Standard including an auditor or investigator. The definition of Year One is an unnecessary departure from the planning practices used in most of the Eastern Interconnection. It is recommended the phrase end of the current calendar year be changed to the current calendar year. This change will allow PAs to begin their near term analysis with either next year or the year after as deemed appropriate. The performance requirements of Table 1 do not allow the loss of non-consequential load for single and multiple contingency events. The disallowance of load loss does not provide any real benefit to the reliability of the BES and is an unnecessary overreach into local quality of service issues that are best addressed by State, Provincial or Municipal authorities. There may be circumstances such as high local transmission costs or local opposition to transmission construction where prohibition of non-consequential load loss represents a poor cost/benefit or quality of life tradeoff. Providing a quantitative cap in non-consequential load loss such as 100 MW may be rationale compromise in the goal of limiting load loss for the more probable outage events. Our preference would be to retain the capability of limited non-consequential load loss. Absent this, the 60 calendar month phase in period described in the Introduction section is too short for transmission facilities rated above 300 kV. Approval and permitting of EHV transmission lines is

Voter	Entity	Segment	Vote	Comment
				extremely difficult and time consuming in most parts of the Eastern Interconnection. The phrase any material changes used in requirement R.2.6.2 will effectively cause all Planning Authorities to run all studies every year regardless of minor changes in the model. The overwhelming majority of PAs use a 10 year set of planning models developed annually by Regions or Subregions. These annual sets of planning models will always have some changes. The annual study requirement is especially problematic for Stability and Short circuit studies that require much more engineering time to complete and are much less likely to have results impacted by minor model changes such as different load forecasts. Uncertainty with audit review of technical rationale documentation will serve to focus Transmission Planning engineering resources on short term compliance to an extent that is counterproductive. Requirement 2.5 represents a significant expansion of Stability Studies into the Long Term horizon. In many cases the stability issue in long term scenarios will be with the response of new generating plants to fault scenarios such as a breaker failure event. The protection upgrades needed to mitigate performance issues are easily accomplished in the short term. The uncertainty of compliance judgment of rationale documentation will force a tremendous amount of unnecessary study work. It is recommend Requirement 2.5 be removed. We concur with the SDT's opinion expressed in the most recent consideration of comments that the individual component level evaluation of protection systems and redundancy requirements should be covered under the PRC standards and that the intent of the protection failure contingencies specified in Table 1 is to simulation the failure of a single protection scheme. The event description for the P5 contingency was revised in draft 5 but it continues to reflect a range of protection component failures that greatly exceed the intent of the SDT. The term Protection System is in direct conflict with the intent of the SDT, as it is defined in the Glossary to include components such as station batteries. The term Protection System should be replaced with Protection Scheme in Table 1. Requirement 4.3.1 can be interpreted to require dynamic simulation analysis of multiple fault event scenarios for transmission lines with high speed reclosing enabled. This additional analysis may be advisable for certain rare special situations but is unnecessary and burdensome as a general requirement for transmission planning contingency analysis. As such, requirement 4.3.1 will discourage application of high speed reclosing. This would be an unfortunate outcome given the benefits of high speed reclosing both for transmission reliability and customer power quality. It is recommended that 4.3.1 be reworded as follows; Simulate the operation of Protection Systems and other automatic controls as they would be expected for each contingency. The SDT has indicated in their responses to previous comments on requirement R4.3.3 that generic relay models could be used for screening purposes. While we agree with this as a practical method,

Voter	Entity	Segment	Vote	Comment
				the language of R4.3.3 could be interpreted to require explicit modeling of all protection and controls which is neither practicable nor an effective use of engineering resources. It is recommended that R4.3.3 be deleted.

Response: The SDT has made every attempt to fully clarify the intent of the requirements in response to official specific comments. Without specific references, the SDT is unable to act on your comment. No change made.

Based on your comment and those of others, the SDT has revised the definition of Year One.

> **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area.

> 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.

The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order.

Material change is system specific and difficult to define on a continent-wide basis and is left to engineering judgment with a documented technical rationale as stated in the requirement. No change made.

The SDT has clarified Requirement R2, part 2.5 to address your concerns.

> **Requirement R2, part 2.5 -** The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, part2.6. The technical rationale for determining material changes shall be documented.

The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns.

> **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following:
>
> **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern.

> **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

Voter	Entity	Segment	Vote	Comment
				• Successful high speed reclosing and unsuccessful high speed reclosing into a Fault. • Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models. 4.3.3 - The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern. **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: • Successful high speed reclosing and unsuccessful high speed reclosing into a Fault. • Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.
Christopher Plantev	Integrys Energy Group, Inc.	4	Negative	The Standard is moving in the right direction, but the following concern is preventing us from voting "affirmative". The timeframe of 60-months (5 year) for implementing Corrective Action Plans (CAP), is insufficient. We believe that the implementation timeframe must be extended to seven (7) years. Requirement 2.7.3, which covers situations that arise beyond the control of the Transmission Planner (TP) or Planning Coordinator (PC), but the proposed language is ambiguous. An auditor could identify many things that could reasonably be within the "control" of a TP or PC but are not covered by NERC standards or a TP / PC's process, procedures or criteria. This discretion leaves entities open to possible non-compliance violation based on an auditor's perception of what they believe should be in the TP / PC's control. In addition, the concept of "control" must be limited to an entities' compliance obligation as a Transmission Planner and/or Planning Coordinator. In other words entities must be allowed the ability identify situations which fall under its "control" as a Transmission Owner, Transmission Operator, Generator Owner or Generator Operator etc. but is beyond the responsibility of its Transmission Planner or Planning Coordinator functions.
Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can				

Voter	Entity	Segment	Vote	Comment
demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility. If an entity can demonstrate that it has made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility.				
Thomas J Trickey	Lakeland Electric	5	Negative	The timeframe of 60-month (5 year) for implementing Corrective Action Plans (CAP), is insufficient, recomend that the implementation timeframe be extended to seven (7) years.
Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order.				
Greg Lange	Public Utility District No. 2 of Grant County	3	Negative	There appears to be many questions about the correct planning long-term horizon. This alone is enough to vote no and ask the drafting team to reconsider that language and their thought process. Grant also has an issue with section 2.1.5. We are struggling with the phrase "major Transmission equipment" and the example of "a transformer". We think it is very important for equipment that is necessary for bulk transfers on the system or one that if lost would cause harm to a neighboring system to be considered in this planning standard. We don't believe a BPS standard should force prescriptive behavior onto an entity, for customer service issues. If the loss of a transformer only impacts local load, this standard should not contemplate or prescribe what the local entity should do. This leaves to much interpretation up to the auditor. The standard could easily become. "You must have spare transformers in inventory to pass compliance with this requirement". Grant is aware that this standard in version zero addressed customer load. Shame on us for not being more proactive and correcting that issue then. We have a new opportunity to correct it now and we would like to see it done. This and all standards should leave local customer service issues alone and concentrate on performance of the major transfers between generation and large load centers. This is not to say that our utilites will choose to leave load off for a year, just that the decision for how to solve this local problem should remain local.
Response: The SDT is unaware of many questions being raised on the long term horizon. Without specific comments, the SDT is unable to address your concern. No change made. The SDT has clarified the requirement based on your comments and those of others.				

Voter	Entity	Segment	Vote	Comment
Requirement R2, part 2.1.5 - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment FERC has been quite clear that this standard needs to address the issue of Non-Consequential Load Loss. The SDT has added footnote 12 to address your concerns. 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.				
Mace Hunter	Lakeland Electric	3	Negative	There are two requirements in this Standard that could be interpreted in many different ways and will greatly complicate dynamic simulation studies. 4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention while also considering the impact of successful or unsuccessful high speed reclosing. 4.3.3. Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers. Most problematic is 4.3.3 which can be interpreted as requiring discrete models of all relays protecting transmission lines and transformers. This is an impossible task. Developing explicit relay models for simulations of even a small subset of BES equipment would be an enormous engineering effort with little or no benefit. The SDT's response to this criticism is, "This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line." There are two problems with this response. First, if the SDT wishes to allow for the use of screening methods then this allowance needs to be part of the Standard language. The Standard development comments and responses have no standing once the Standard is approved by FERC as law. A narrow, strict interpretation of the Standard based on requirement language is to be expected from auditors and investigators. A second problem with the above SDT response is that applicability of generic models is subject to technical challenge. The generic model available within PSS/E sets up circular characteristics for each branch element that are fixed percentages of the branch impedance. These fixed, non adjustable percentages are 46% for zone A, 75% for zone B and 110% for zone C. These generic reaches are significantly smaller than loadability limits allowed under the PRC-023-1. The intent of Requirement 4.3.3 would be better served if reworded as follows; "R4.3.3 Consider the impact of dynamic swings on protection systems and model protection operation where appropriate" Requirement 4.3.1 can be

Voter	Entity	Segment	Vote	Comment
				interpreted to require dynamic simulation analysis of multiple fault event scenarios for transmission lines with high speed reclosing enabled. This additional analysis may be advisable for certain rare special situations but is unnecessary and burdensome as a general requirement for transmission planning contingency analysis. As such, requirement 4.3.1 will discourage application of high speed reclosing. This would be an unfortunate outcome given the benefits of high speed reclosing both for transmission reliability and customer power quality. It is recommended that 4.3.1 be reworded as follows; "4.3.1 Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each contingency."

Response: The SDT has modified the requirement to address your concern.

Requirement R4, part 4.3.1 - Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

- Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern.

Requirement R4, part 4.3.1 - Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

- Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

Voter	Entity	Segment	Vote	Comment
Larry Akens	Tennessee Valley Authority	1	Negative	TVA appreciates the work of the ATFN drafting team over the last several years in drafting this new standard. TVA does have concerns on several issues that need to be corrected as we move forward with this standard. Therefore TVA is voting "Negative" on this proposed standard due to the following issues: 1. TVA believes that the 5 year implementation plan allowed for "Raising the bar" facilities does not allow sufficient time for TVA to construct the required new facilities. TVA average time for constructing a new 500-kV line is approximately 7 to 10 years, given the lead time on ROW and following all NEPA requirements. If the 5 year implementation plan is not increased, TVA is also concerned about the extensive outages that must take in upgrading 500-kV facilities in order to meet the 5 year requirement. This would require multiple 500-kV outages in the same timeframe which could have a detrimental effect on the overall Bulk Electric System reliability during this construction phase. TVA does understand that the team has added language regarding the TP or PC inability to get the projects completed through no fault of its own; however, there is no guarantee that TVA will be found compliant if all the work cannot be accomplished in this time frame. 2. TVA believes that the footnotes b and c that allow for local load drop in the current TPL standards should still be allowed. TVA understands that this is addressed in FERC Order 693; however, the capital improvements to fix many of these issues will have no overall reliability gain for the Bulk Electric System. 3. TVA is concerned that no generating unit shall pull out of synchronism for Planning Event P1, while the standard does allow generator runback/tripping for the same event. TVA believes that this requirement is overly burdensome without providing any material improvement in system reliability. Additionally, R4.1.1 directly conflicts with Table 1, Note a (applicable to both Steady State & Stability) which states "Consequential Load as well as generation loss is acceptable as a consequence of any planning event ... excluding P0." TVA strongly suggests that this loss of synchronism be allowed for P1 or at least add the ability to trip these units for this P1 event by out of step relaying - since other means of tripping the units are allowed - such as thru the use of other actions including Special Protection Schemes as long as the instability does not spread beyond a local area. 4. TVA is concerned with the inclusion of battery failures being included in event P5. P5 states "Multiple Contingency Fault plus Protection System failure to operate". TVA understands that the drafting team believes that batteries are not intended to be included in this event; however, station batteries are presently included in the NERC Glossary definition of "Protection Systems." TVA believes that specific language excluding batteries is required for this P5 event in order to prevent future compliance issues regarding this.
George T. Ballew	Tennessee Valley Authority	5	Negative	
Marjorie S. Parsons	Tennessee Valley Authority	6	Negative	

Voter	Entity	Segment	Vote	Comment
Response: 1. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. 2. The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area. 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. 3. The SDT believes that if an entity has a known condition that identifies a generation unit(s) is prone to trip for a single Contingency event then the entity should proactively trip the unit(s) rather than relying on out-of-step protection to trip the unit. The SDT takes this position because of the concern of the possible detrimental effects of loss of synchronism on the overall reliability of the BES. No change made. 4. The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns. **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following: **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).				
Lee Schuster	Florida Power Corporation	3	Negative	We appreciate the challenging and time-consuming work that has been done by the Standard Drafting Team (SDT) to draft TPL-001-1 according to the specific requests made by FERC in Order 693. We are supportive of planning, constructing, operating and maintaining the most reliable Bulk Electric System (BES) that is reasonably feasible. We believe that collectively the industry has exhibited excellent BES reliability under existing NERC TPL Standards. For this reason and for others detailed below, we will vote "no" on the proposed standard. 1. We do not believe that 60 months is a reasonable time period to build transmission facilities to meet the new performance requirements. This is especially true of EHV projects. Ameren recently stated in an email to the RBB that "[b]uilding a transmission line in Illinois is estimated to take 7 years (84 months) from the time the project is authorized." In our own experience, we have been limited by permitting and local government processes to the extent that even 69 kV, 115 kV and 230 kV line projects are taking longer than 60 months. We therefore agree with Ameren's point that building of a new EHV transmission line can be a very lengthy process. We think that a more
Sam Waters	Progress Energy Carolinas	3	Negative	

Voter	Entity	Segment	Vote	Comment
Wayne Lewis	Progress Energy Carolinas	5	Negative	appropriate time frame would be 84 months, with provisions to limit or waive fines if a Transmission Owner can demonstrate that the implementation process was unavoidably impeded by permitting, environmental or governmental processes. 2. As has been stated in all four commenting periods by Progress as well as certain other registered entities, we believe that the requirement prohibiting loss of non-consequential load for events in Table 1 of TPL-001-1 is an inappropriate overreach by the standard into local load quality of service issues that are already adequately regulated by states' Public Service/Utility Commissions, and does not provide any benefit to BES reliability. The approach of prohibiting the shedding of even a single distribution feeder amounts to feeder reliability rather than BES reliability. This approach, if allowed to be in the Standard, may result in unintended negative results in BES reliability. We therefore appeal to the SDT to discuss this issue with NERC and FERC given the numerous utilities that share this concern. The standard should continue to allow Transmission Planners to use discretion regarding loss of non-consequential load. 3. Requirement R4.1.1 states in part that "for planning event P1: No generating unit shall pull out of synchronism." This requirement is overly burdensome without providing any material improvement in system reliability. Additionally, R4.1.1 directly conflicts with Table 1, Note (a) (applicable to both Steady State & Stability) which states "Consequential Load as well as generation loss is acceptable as a consequence of any planning event ... excluding P0." Clearly, the intent the TPL-001-1 standard is to maintain the integrity and reliability of the overall grid, not any particular element. In other words, throughout the standard it is acceptable to lose any generator, load, line or other element as long as more wide reaching consequences are precluded (i.e., cascading outages, non-consequential load loss, etc. is not allowed). As written, R4.1.1 would not allow the use of out of step protective relaying as a solution to trip an unstable generator for a P1 event. It does allow tripping of the same generator due to "fault clearing action" (such as for a fault on the generator terminals) or "by a Special Protection System". Therefore the loss of the generator itself must be acceptable. The notion that preventing loss of synchronism events is the only acceptable means of also precluding more widespread (and unacceptable) consequences resulting from the effect of stability swings is not valid. For some generating units (particularly small, remotely located units) these other unacceptable consequences may not even occur. Also, other means, such as out of step blocking of transmission lines applied in conjunction with out of step generator tripping, may be an effective solution. Any of these solutions is allowed for events P2 through P7 in requirement R4.1.2. We recommend that Requirement R4.1.1 be deleted and R.4.1.2 be revised to include events P1 through P7. Given the concerns raised above, we respectfully request that the SDT make the suggested improvements to TPL-001-1 and continue the process toward approval of the Standard.

Voter	Entity	Segment	Vote	Comment
Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area. 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. 3. The SDT believes that if an entity has a known condition that identifies a generation unit(s) is prone to trip for a single Contingency event then the entity should proactively trip the unit(s) rather than relying on out-of-step protection to trip the unit. The SDT takes this position because of the concern of the possible detrimental effects of loss of synchronism on the overall reliability of the BES. No change made.				
Jason L Marshall	Midwest ISO, Inc.	2	Negative	We are voting negative for several reasons. 1. We believe Requirement 2, Part 2.1.5 is an administrative requirement that is not consistent with the NERC BOT approved results/performance based standards effort. Furthermore, the additional reliability benefit is not clear to us. 2. We believe that Requirement 2, Part 2.3 should only be implemented when there is another requirement in the PRC standards for Transmission Owners and Generation Owners to supply the necessary protection information. 3. We believe that that Requirement 2, Part 2.4.1 needs to be further clarified that the dynamic behavior of load model is an estimate only based on engineering assumptions. As written now, it is not clear how much deviation is allowed from actual system operation. 4. We believe Requirement 4, Part 4.3.2 should not be implemented until there is a requirement for the Generator Owners/Operators to supply their generator low voltage ride through capability. 5. We believe Requirement 4, Part 4.3.3 should be further refined to clarify that the purpose is to screen zone 3 relay issues. As written now, it appears that zone 3 relays must be modeled in detail because it is not clear that the intent is to only screen potential problems. We are basing our comments on the drafting team's responses to previous comments that they view using generic zone 3 relay models in PSS/E is acceptable.
Response: 1. The SDT disagrees that this is an administrative requirement as it does not state that you must develop a strategy; it states that you must consider the strategy in your planning. Therefore, it has a direct bearing on the reliability of the BES. No change made. 2. This standard describes what must be done and not how to do it. The SDT expects that the information cited could be obtained through several different				

Voter	Entity	Segment	Vote	Comment
mechanisms such as delegation agreements or data requests. No change made. 3. The SDT has added the word 'expected' to the text to alleviate your concern. Planning models are based on the best information available to the planners at the time of the study and it is well understood that they may not exactly represent actual conditions at any given time. The results of on-going benchmarking and model development activities can be incorporated when those activities yield more representative results. **Requirement R2, part 2.4.1** - System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. 4. This standard describes what must be done and not how to do it. The SDT expects that the information cited could be obtained through several different mechanisms such as delegation agreements or data requests. No change made. 5. In the summary considerations in draft 4 of this project, the SDT indicated that generic relay models can be applied. If this model shows impedance swings in a branch element, then one can either take action according to the generic model results or investigate the characteristics of the relays actually used on that branch. In this draft, the SDT has clarified the requirement for the use of generic relay models. **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: • Successful high speed reclosing and unsuccessful high speed reclosing into a Fault. • Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.				
Brenda L Truhe	PPL Electric Utilities Corp.	1	Negative	We are voting 'no' on this ballot as this revision proposes to expand contingency requirements beyond traditional planning levels (example - stuck breaker AND protection failure).
Mark A. Heimbach	PPL Generation LLC	5	Negative	
Response: The SDT agrees that new expectations are contained within the requirements aimed at improving BES reliability. An implementation plan has been created to allow for the industry to comply with the new requirements.				
Terry L. Blackwell	Santee Cooper	1	Negative	We disagree with the proposed definition of Year One. We believe that Year One should be the planning window that begins 12-18 months from the start of the current calendar year, and not from

Voter	Entity	Segment	Vote	Comment
Zack Dusenbury	Santee Cooper	3	Negative	the end of the calendar year. We believe that following this modification to the definition would require minimal adjustments to the ERAG MMWG model building process, which we all use as the basis for our planning models. Following the proposed definition would require additional models to be built by the MMWG or lead to holes in the model building effort for both the operating and planning horizons. SCPSA does not believe that 60 months is a reasonable time period to build transmission facilities to meet the new performance requirements. In an email to the registered ballot body, Ameren stated " Building a transmission line in Illinois is estimated to take 7 years (84 months) from the time the project is authorized." SCPSA agrees with the point that Ameren is making that building of a new EHV transmission line can be a very lengthy process. SCPSA thinks that a more appropriate time frame would be 84 months. SCPSA believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues, does not provide any real benefit to Bulk Electric System (BES) reliability, and may have unintended negative consequences on reliability. Often, corrective actions to mitigate these events are local in nature and only require minor additional loss of local load to avoid major projects. The standard should continue to allow Transmission Planners to use discretion regarding loss of non-consequential load, such that Transmission Planners, customers, and local regulators jointly control the decision making when BES reliability is not an issue. The transparency requirements of the new standard facilitate this type of decision making. In addition, the prohibition on non-consequential load loss for these events creates an incentive for Transmission Planners to remove lines serving load from network (serve the loads radially) so that they are characterized as consequential load. The unintended consequence of the standard would be a reduction in reliability for service to local load.
Suzanne Ritter	Santee Cooper	6	Negative	

Response: Based on your comment and those of others, the SDT has revised the definition of Year One.

> **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order.

The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area.

Voter	Entity	Segment	Vote	Comment
12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.				
Thomas C. Mielnik	MidAmerican Energy Co.	3	Negative	We find P5, Multiple Contingency (Fault plus Protection System failure to operate) to be confusing. What analysis is required for this? Analysis of individual Protection System component failures or something else? Do the benefits justify this requirement?
Response: The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns. **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following: **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).				
Ajay Garg	Hydro One Networks, Inc.	1	Negative	We thank the Standard Drafting Team for their long and dedicated effort to develop this standard. At this time, Hydro One has decided to cast a negative vote with the following comments: 1. Note 3 in Table 1 refers to EHV Facilities (above 300 kV) and HV (300 kV and lower voltage systems) The standards uses this threshold to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss. We suggest the following be added to this note: "In the region(s) or area where there is a performance based methodology in place to determine Bulk Electric System (BES) elements (e.g. NPCC), only the BES portion of the system is subject to the Standard." 2. The Standard repeatedly uses the capitalized term "Firm Transmission Service (FTS)." The NERC Glossary of Terms defines FTS as "The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." We believe that the use of this term and that of "Transmission Service" in TPL-001-1 should be revised as they do not have the same meaning in all jurisdictions. A clarification within the standard will eliminate this confusion. 3. The Effective Date Section in the proposed standard gives a time of 60 months to implement certain Corrective Actions. We believe this Standard should not explicitly define timelines (5 years in this case) for transmission projects. Regulatory approvals for new or modified transmission systems may take a significant time in some jurisdictions. We suggest changing the wording to say that Transmission mitigation measures for the reliability of the Bulk Electric System must be implemented as soon as practical exercising due diligence. Progress of and/or delays associated with critical project(s) impacting BES reliability should be submitted to the respective regions and NERC. We recognize that Requirement 2.7.3 covers situations that arise beyond the control of the Transmission Planner (TP) or Planning Coordinator (PC), but we believe that the proposed 60 months timeline
Michael D. Penstone	Hydro One Networks, Inc.	3	Negative	

Voter	Entity	Segment	Vote	Comment
				should be removed.
Response: This standard applies to the BES. If there are areas of your system that are not BES, then the standard doesn't apply to them. This would be true even if those elements are above 300 kV. No change made. The SDT reviewed the use of Firm Transmission Service and believes that the term is used correctly in the standard. No change made. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility.				
Mark Ringhausen	Old Dominion Electric Coop.	4	Negative	While the SDT has made progress in their changes from the first draft, there are still some areas that need to be clarified. Others are proving more specific comments (PJM) so look for their comments and address.
Response: Please see response to PJM.				

Voter	Entity	Segment	Vote	Comment
Richard Salgo	Sierra Pacific Power Co.	1	Negative	While we greatly appreciate the work of the SDT, and feel that this Standard has achieved significant improvement, there are a number of issues precluding our approval as written: Spare Equipment: need a clarification on what the "assessment" of the impact of equipment availability entails. For instance, is the assessment a simple narrative of the necessary operational mitigation, engineering analysis of the impact, or on the other extreme, is it a full repeat of the NERC study work for all potential permutations of long lead-time equipment? We have difficulty accepting the language regarding the loss of non-consequential load. As written, this creates a disincentive for the implementation of incremental reliability improvements in the network; ie, creation of a parallel path that does not fully provide redundancy to load service would drive a violation of the requirement. Lastly, the treatment of firm transmission service from the standpoint that it cannot be curtailed under various contingencies is problematic. As written, it would appear that the single-contingency loss of a contract transmission path would require continuance of the firm transmission service via some alternate parallel path. Such methodology would require all such paths to have redundancy via parallel transmission or result in dramatic reductions in transfer ratings.

Response: The SDT has clarified the wording of the requirement and believes that this will address your concern.

> **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area.

> 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.

Footnote 9 states the conditions for when Firm Transmission Service may be curtailed. If what you are describing is actually Conditional Firm, then see footnote 4. No change made.

Unofficial Comment Form for Informal Comment Period on 5th Draft of Standard TPL-001-2 — Assess Transmission Future Needs (Project 2006-02)

Please **DO NOT** use this form. Please use the electronic form located at the link below to submit comments on the 5th draft of the TPL-001-2 standard for Assess Transmission Future Needs (Project 2006-02). The electronic comment form must be completed by **September 2, 2010. This is a 30-day informal comment period.** That means that for each question asked on this comment form:

- The drafting team will provide a summary response to indicate whether stakeholders who submitted comments support the modification made to the standard following the initial ballot.
- The drafting team will identify any additional modifications made to the standard based on stakeholder comments submitted in response to that question.
- The team will not provide a response to each individual comment submitted.

If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

Background Information
TPL-001-1 Transmission System Planning Performance Requirements
Comments on the initial ballot of the TPL-001-1 (now TPL-001-2) Transmission System Planning Performance Requirements standard were received from the industry through March 1, 2010. The Drafting Team received feedback on a number of issues, and the SDT appreciates the tremendous industry participation in the ballot process. Below is a brief overview of the 5th draft of the standard highlighting areas where the SDT made changes based on stakeholder feedback from the initial ballot. The team's objectives remain unchanged - to create a single Transmission planning standard: 1) with clear, concise requirements set at an appropriate level to ensure reliability, and 2) that fully addresses all issues raised by FERC Orders 693 and 890, and industry inputs, including the SAR scope document.

5th Draft Overview:

1. The Implementation Plan has been revised to provide more time for entities to become compliant.
2. The definition for Year One was changed and an example provided to clarify the intent of the SDT.
3. The following requirements were changed:
    a. R1 – To provide a reference for normal system conditions.
    b. R2 – To indicate that 'qualified' past studies can be utilized.
    c. R2, Part 2.1 – To indicate that 'qualified' past studies can be utilized.
    d. R2, Part 2.1.4 and Part 2.4.3 – To clarify the sensitivity analysis.
    e. R2, Part 2.1.5 – Semantic change for clarity.
    f. R2, Part 2.4.1 – Clarification of what is expected for dynamic load models.

   g. R2, Part 2.5 – Clarification of what is meant by 'material'.
   h. R3, Part 3.3.1 & R4, Part 4.3.1 – Semantic re-arrangement of conditions for clarity.
   i. R3, part 3.5, R4, part 4.4, & R4, part 4.5 – Semantic change for clarity.
4. Header note changes:
   a. Semantic change for clarity in 'a'.
   b. Deletion of redundant phrasing in 'e'.
   c. Move of 'j' to 'a'.
5. Performance table changes:
   a. Addition of footnote 12 reference in P1, P2-1, and P3.
   b. Description change in P5 and addition of footnote 13 for relay reference.
6. Extreme event – steady state 2d – Addition of 'generating' for clarity.
7. Footnote changes:
   a. #11 – Specific references supplied.
   b. #12 – Clarification of Non-Consequential Load Loss (pending resolution in Project 2010-11).
   c. #13 – Relay references supplied.
8. Measurement changes:
   a. M6 – Matching language to requirement.
   b. M8 – Semantic change for clarity.
9. R8 VSL – Semantic change for clarity and strict adherence to guidelines.

The SDT is interested in tracking comments to the changes made in response to the initial ballot comments and thus has asked only questions that refer solely and directly to those changes.

1. The SDT has revised the Implementation Plan based on industry comments to the initial ballot. Do you support this change? If you do not support this change, please specify why you disagree and include specific alternative language to resolve your concern.

   ☐ Yes

   ☐ No

   Comments:

2. The SDT has revised the definition of Year One based on industry comments to the initial ballot. Do you support this change? If you do not support this change, please specify why you disagree and include specific alternative language to resolve your concern.

   ☐ Yes

   ☐ No

   Comments:

3. The SDT has revised the Requirements language based on industry comments to the initial ballot. Do you support these changes? If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your concern.

   Requirement R1 – normal conditions:

   ☐ Yes

   ☐ No

   Comments:

   3.1 Requirement R2 and Part 2.1 – past studies:

   ☐ Yes

   ☐ No

   Comments:

   3.2 Requirement R2, Parts 2.1.4 & 2.4.3 – sensitivity analysis:

   ☐ Yes

   ☐ No

   Comments:

   3.3 Requirement R2, Part 2.4.1 – dynamic load models:

   ☐ Yes

   ☐ No

   Comments:

   3.4 Requirement R2, Part 2.5 – material clarification:

   ☐ Yes

☐ No

Comments:

4. The SDT has revised the header notes based on industry comments to the initial ballot. If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your concern.

   ☐ Yes

   ☐ No

   Comments:

5. The SDT has revised the performance table (including the list of extreme events and footnotes) based on industry comments to the initial ballot. If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your concern.

   ☐ Yes

   ☐ No

   Comments:

6. The SDT has revised the Measures based on industry comments to the initial ballot. If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your concern.

   ☐ Yes

   ☐ No

   Comments:

7. The SDT has revised the Requirement R8 VSL based on industry comments to the initial ballot. If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your concern.

   ☐ Yes

   ☐ No

   Comments:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan for TPL-001-1

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

TPL-001-1 — Transmission System Planning Performance Requirements

In revising the TPL standards, the SDT is assuming that planners will receive valid data from the MOD standards link described in TPL-001-1, Requirement R1. Furthermore, there is a tacit assumption that future revisions of the MOD standards will include steps to validate MOD based data.

Revision to Sections of Approved Standards and Definitions

There are multiple new definitions in the proposed standard.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Near-Term Transmission Planning Horizon: Transmission planning period that covers Years One through five.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.

Year One: The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

Compliance with Standards

Standard	Functions That Must Comply With the Associated Requirements	
TPL-001-1 — Transmission System Planning Performance Requirements	Transmission Planner	Planning Coordinator
	X	X

Effective Dates

The effective date is the date entities are expected to meet the performance identified in this standard.

Except as indicated below, all Requirements and associated parts shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.

TPL-001-0, TPL-002-0a, TPL-003-0a, and TPL-004-0 are being retired as they are replaced in their entirety by TPL-001-1. TPL-005-0 and TPL-006-0 are being retired because their requirements are adequately covered by the revised TPL-001-1 and NERC's Rules of Procedure, Section 800. However, during this 24-month period, all aspects of TPL-001-0 through TPL-006-0 shall remain in effect for compliance monitoring. This 24 month period is to allow entities to develop, perform and/or validate new and/or modified studies, methodologies, assessments, procedures, etc. necessary to implement and meet the TPL-001-1 requirements. The specified effective dates are expected to allow sufficient time for proper assessment of the available options necessary to create a viable Corrective Action Plan that is compliant with the new Standard.

> R1. This Requirement is related to maintaining System models and the data needed to do so. This requirement shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes into effect on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.
>
> R7. This Requirement identifies an obligation to determine individual and joint responsibilities for performing studies needed to do the Planning Assessment. This requirement shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes into effect on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

TPL-001-1 'raises the bar' in several areas where performance requirements have been changed in the new Standard versus those in existing TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0 because loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain events, whereas the existing Standards were interpreted by many to allow such actions. As shown in Table 1 of TPL-001-1, the performance requirements associated with the following events represent "raising the bar":

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

This "raising the bar" is beyond the control of the Transmission Planner and Planning Coordinator and may have significant budget, siting, permitting, and construction impacts on many Transmission Owners. To provide stakeholders with sufficient time to implement changes, a timeframe coincident with the end of the Near-Term Transmission Planning Horizon will be provided as follows:

- For 84 months after the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required on the first day of the first calendar quarter, 84 months after Board of Trustees adoption, Corrective Action Plans applying to performance elements P1-2 and P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element), P2-1, P2-2 (above 300 kV), P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 kV) are allowed to include tripping of Non-Consequential Load and curtailment of Firm Transmission Service (in accordance with Requirement R2.7.3) that would not otherwise be permitted by the requirements of TPL-001-1.

Any entity which cannot eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for these performance elements by that date shall submit a mitigation plan to its Regional Entity outlining the steps it will take to correct the problem. If the entities follow the established ERO procedure for mitigation, it is the intent of the SDT that no penalties will be assessed.

NERC
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Implementation Plan for TPL-001-1

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

TPL-001-1 — Transmission System Planning Performance Requirements

In revising the TPL standards, the SDT is assuming that planners will receive valid data from the MOD standards link described in TPL-001-1, Requirement R1. Furthermore, there is a tacit assumption that future revisions of the MOD standards will include steps to validate MOD based data.

Revision to Sections of Approved Standards and Definitions

There are multiple new definitions in the proposed standard.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Near-Term Transmission Planning Horizon: Transmission planning period that covers Years One through five.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.

Year One: The first ~~year~~twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. ~~This is further defined as the planning window that begins 12-18 months from the end of the current calendar year~~For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

Compliance with Standards

Standard	Functions That Must Comply With the Associated Requirements	
TPL-001-1 — Transmission System Planning Performance Requirements	Transmission Planner	Planning Coordinator
	X	X

Effective Dates

The effective date is the date entities are expected to meet the performance identified in this standard.

Except as indicated below**,** all Requirements and associated parts shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.

TPL-001-0, TPL-002-0a, TPL-003-0a, and TPL-004-0 are being retired as they are replaced in their entirety by TPL-001-1. TPL-005-0 and TPL-006-0 are being retired because their requirements are adequately covered by the revised TPL-001-1 and NERC's Rules of Procedure, Section 800. However, during this 24-month period, all aspects of TPL-001-0 through TPL-006-0 shall remain in effect for compliance monitoring. This 24 month period is to allow entities to develop, perform and/or validate new and/or modified studies, methodologies, assessments, procedures, etc. necessary to implement and meet the TPL-001-1 requirements. The specified effective dates are expected to allow sufficient time for proper assessment of the available options necessary to create a viable Corrective Action Plan that is compliant with the new Standard.

> R1. This Requirement is related to maintaining System models and the data needed to do so. This requirement shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes into effect on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.
>
> R7. This Requirement identifies an obligation to determine individual and joint responsibilities for performing studies needed to do the Planning Assessment. This requirement shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes into effect on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

TPL-001-1 'raises the bar' in several areas where performance requirements have been changed in the new Standard versus those in existing TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0 because loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain events, whereas the existing Standards were interpreted by many to allow such actions. As shown in Table 1 of TPL-001-1, the performance requirements associated with the following events represent "raising the bar":

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

This "raising the bar" is beyond the control of the Transmission Planner and Planning Coordinator and may have significant budget, siting, permitting, and construction impacts on many Transmission Owners. To provide stakeholders with sufficient time to implement changes, a timeframe coincident with the end of the Near-Term Transmission Planning Horizon will be provided as follows:

- For ~~60~~84 months after the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required on the first day of the first calendar quarter, 84 months after Board of Trustees adoption, Corrective Action Plans applying to performance elements P1-2 and P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element), P2-1, P2-2 (above 300 kV), P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 kV) are allowed to include tripping of Non-Consequential Load and curtailment of Firm Transmission Service (in accordance with Requirement R2.7.3) that would not otherwise be permitted by the requirements of TPL-001-1.

Any entity which cannot eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for these performance elements by that date shall submit a mitigation plan to its Regional Entity outlining the steps it will take to correct the problem~~-~~. If the entities follow the established ERO procedure for mitigation, it is the intent of the SDT that no penalties will be assessed.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Version 1 of SAR posted for comment from April 2, 2002 through May 3, 2002.
2. Version 2 of SAR posted for comment from May 5, 2004 through June 5, 2004.
3. Version 3 of SAR posted on November 18, 2005.
4. SAR approved on April 30, 2006.
5. Version 1 of Supplemental SAR posted for comment from February 15, 2007 through March 16, 2007.
6. Version 2 of Supplemental SAR posted on April 9, 2007.
7. Version 1 of revised standard(s) posted for comment on September 17, 2007.
8. Version 2 of the revised standards posted for comment on August 15, 2008.
9. Version 3 of the revised standards posted for comment on May 26, 2009.
10. Version 4 of the revised standards posted for comment on September 16, 2009.
11. Initial ballot completed on March 1, 2010.

Proposed Action Plan and Description of Current Draft:
The SDT has established a schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 1Q10. The current draft is the second iteration of the revision of existing standards TPL-001 through TPL-006 and includes one revised standard, TPL-001-1, replacing TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. TPL-005 & -006 issues are addressed in this fifth draft and those standards will also be replaced by TPL-001-2.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post fifth version of standard.	3Q10
2. Conduct ballot	TBD
3. Respond to comments and determine next step	TBD
4. Submit standard(s) to BOT.	2Q11
5. Submit to regulatory authorities for approval.	3Q11

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Near-Term Transmission Planning Horizon: Transmission planning period that covers Years One through five.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies.

Year One: The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-2**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.

   - For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-2, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-2:
     - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
     - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
     - P2-1, P2-2 (above 300 kV)
     - P2-3 (above 300 kV)
     - P3-1 through P3-5
     - P4-1 through P4-5 (above 300 kV)
     - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes the normal system condition in Table 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6, as follows:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of planned Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: the System represented in the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Such actions may include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

- Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.
- Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for

evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

- Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, any criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and that functional entity submits a written request for the information. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
d. Simulate Normal Clearing unless otherwise specified.
e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.
g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
h. Planning event P0 is applicable to steady state only.
i. The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial System Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No[9]	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8]	SLG	EHV	No[9]	No

		(Non Bus-tie)		HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie) [8]	SLG	EHV, HV	Yes	Yes
Category	**Initial System Condition**	**Event [1]**	**Fault Type [2]**	**BES Level [3]**	**Interruption of Firm Transmission Service Allowed [4]**	**Non-Consequential Load Loss Allowed**
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two*	Loss of one of the following followed by System adj.[9]: 1. Transmission Circuit	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes

overlapping singles)	2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line					
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events	
Steady State & Stability For all extreme events evaluated: a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency. b. Simulate Normal Clearing unless otherwise specified.	
Steady State 1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments. 2. Local area events affecting the Transmission System such as: a. Loss of a tower line with three or more circuits.[11] b. Loss of all Transmission lines on a common Right-of-Way[11]. c. Loss of a switching station or substation (loss of one voltage level plus transformers). d. Loss of all generating units at a generating station. e. Loss of a large Load or major Load center. 3. Wide area events affecting the Transmission System based on System topology such as: a. Loss of two generating stations resulting from conditions such as:	**Stability** 1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments. 2. Local or wide area events affecting the Transmission System such as: a. 3Ø fault on generator with stuck breaker[10] or a Protection System failure resulting in Delayed Fault Clearing. b. 3Ø fault on Transmission circuit with stuck breaker[10] or a Protection System failure resulting in Delayed Fault Clearing. c. 3Ø fault on transformer with stuck breaker[10] or a Protection System failure resulting in Delayed Fault Clearing. d. 3Ø fault on bus section with stuck breaker[10] or a Protection System failure resulting in Delayed Fault Clearing. e. 3Ø internal breaker fault.

i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation. ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants. b. Other events based upon operating experience that may result in wide area disturbances.	f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of documentation specifying any criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity who has indicated a reliability need and that functional entity has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying any criteria or methodology utilized in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as all such documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None.

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events. OR The responsible entity did not base its	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		studies on computer simulation models using data provided in Requirement R1.		
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its

	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners, one adjacent Planning Coordinator, or to one functional entity that has a reliability related need and that has submitted a written request for the information, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to more than one of its adjacent Transmission Planners, adjacent Planning Coordinators, or functional entities that have a reliability related need and that have submitted a written request for the information, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	TBD	Revision of TPL-001-0 as per Project 2006-02; includes merging requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-1	Not employed due to scope of revision

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Version 1 of SAR posted for comment from April 2, 2002 through May 3, 2002.
2. Version 2 of SAR posted for comment from May 5, 2004 through June 5, 2004.
3. Version 3 of SAR posted on November 18, 2005.
4. SAR approved on April 30, 2006.
5. Version 1 of Supplemental SAR posted for comment from February 15, 2007 through March 16, 2007.
6. Version 2 of Supplemental SAR posted on April 9, 2007.
7. Version 1 of revised standard(s) posted for comment on September 17, 2007.
8. Version 2 of the revised standards posted for comment on August 15, 2008.
9. Version 3 of the revised standards posted for comment on May 26, 2009.
10. Version 4 of the revised standards posted for comment on September 16, 2009.
11. Initial ballot completed on March 1, 2010.

Proposed Action Plan and Description of Current Draft:
The SDT has established a schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 1Q10. The current draft is the second iteration of the revision of existing standards TPL-001 through TPL-006 and includes one revised standard, TPL-001-1, replacing TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. TPL-005 & -006 issues are addressed in this fifth draft and those standards will also be replaced by TPL-001-2.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post fifth version of standard.	3Q10
2. Conduct ballot	TBD
3. Respond to comments and determine next step	TBD
4. Submit standard(s) to BOT.	2Q11
5. Submit to regulatory authorities for approval.	3Q11

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Near-Term Transmission Planning Horizon: Transmission planning period that covers Years One through five.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies.

Year One: The first ~~year~~twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. ~~This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.~~For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-~~1~~2**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.

   - For ~~60~~84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-~~1~~2, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, ~~part~~Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-~~1~~2:
     - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
     - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
     - P2-1, P2-2 (above 300 kV)
     - P2-3 (above 300 kV)
     - P3-1 through P3-5
     - P4-1 through P4-5 (above 300 kV)
     - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes the normal system condition in Table 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by ~~the following~~ current annual ~~current~~ studies~~, supplemented with~~ or qualified past studies as indicated in Requirement R2, ~~part~~ Part 2.6, as follows:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled~~,~~ as ~~-~~in Requirement R1, ~~part~~Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, ~~parts~~ Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions ~~not already included in the studies~~ by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of planned Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be ~~assessed~~studied. The ~~Planning Assessment~~ studies shall ~~reflect~~be performed for the P0, P1, and P2 categories identified in

Table 1 ~~during~~with the conditions that the System is expected to experience ~~due to~~during the possible unavailability of the long lead time equipment.

2.2. The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, ~~part~~Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, ~~part~~ Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, ~~part~~Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, ~~-~~considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, ~~part~~Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions ~~not already included in the studies~~ by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, ~~part~~Part2.6~~.~~ and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: the System represented in the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, ~~part~~Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Such actions may include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, ~~part~~Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, ~~part~~Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, ~~part~~Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, ~~part~~Part 3.5.

3.3. Contingency analyses for Requirement R3, ~~part~~Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

~~3.3.2.~~• Tripping of generators where simulations show generator bus voltages or high side of the ~~G~~generation ~~S~~step ~~U~~up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

~~3.3.3.~~• Tripping of Transmission elements ~~when~~where relay loadability limits are exceeded.

~~3.3.4.~~3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, ~~part~~Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated ~~for System performance~~ in Requirement R3, ~~part~~Part 3.2~~ created~~. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, ~~part~~Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, ~~part~~Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, ~~part~~Part 4.5.

4.3. Contingency analyses for Requirement R4, ~~part~~Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

- ~~while also considering the impact of s~~Successful high speed reclosing ~~or~~and unsuccessful high speed reclosing into a Fault.
- ~~4.3.2.~~ Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- ~~4.3.3.~~ ~~Simulate~~Tripping of Transmission lines and transformers ~~the impact of~~where transient swings ~~on~~ cause Protection System operation ~~for Transmission lines and transformers~~ based on generic or actual relay models.

~~4.3.4.~~4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers,

static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated ~~for System performance~~ in Requirement R4, ~~part~~Part 4.1~~ created~~. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated ~~for System performance~~ in Requirement R4, ~~part~~Part 4.2~~ created~~. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, any criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and ~~-~~any functional entity that has a reliability related need and that functional entity submits a written request for the information. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. ~~BES Transmission voltage instability,~~The System shall remain stable. Cascading~~,~~ and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any ~~planning or extreme~~ event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. ~~For all planning events, p~~Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

~~j.~~Stability Only:~~The System shall remain stable.~~

~~k.~~j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial System Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No[9]	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8]	SLG	EHV	No[9]	No

		(Non Bus-tie)		HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie) [8]	SLG	EHV, HV	Yes	Yes
Category	**Initial System Condition**	**Event [1]**	**Fault Type [2]**	**BES Level [3]**	**Interruption of Firm Transmission Service Allowed [4]**	**Non-Consequential Load Loss Allowed**
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus ~~Protection System~~ relay failure to operate)*	Normal System	~~Failure of a single Protection System that results in~~ Delayed Fault Clearing ~~on~~ due to the failure of a relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two*	Loss of one of the following followed by System adj.[9]: 1. Transmission Circuit	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes

overlapping singles)	2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line					
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events	
Steady State & Stability For all extreme events evaluated: a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency. b. Simulate Normal Clearing unless otherwise specified.	
Steady State 1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments. 2. Local area events affecting the Transmission System such as: a. Loss of a tower line with three or more circuits.[11] b. Loss of all Transmission lines on a common Right-of-Way[11]. c. Loss of a switching station or substation (loss of one voltage level plus transformers). d. Loss of all generating units at a generating station. e. Loss of a large Load or major Load center. 3. Wide area events affecting the Transmission System based on System topology such as: a. Loss of two generating stations resulting from conditions such as:	**Stability** 1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments. 2. Local or wide area events affecting the Transmission System such as: a. 3Ø fault on generator with stuck breaker[10] or a Protection System failure resulting in Delayed Fault Clearing. b. 3Ø fault on Transmission circuit with stuck breaker[10] or a Protection System failure resulting in Delayed Fault Clearing. c. 3Ø fault on transformer with stuck breaker[10] or a Protection System failure resulting in Delayed Fault Clearing. d. 3Ø fault on bus section with stuck breaker[10] or a Protection System failure resulting in Delayed Fault Clearing. e. 3Ø internal breaker fault.

i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation. ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants. b. Other events based upon operating experience that may result in wide area disturbances.	f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-~~G~~generator ~~S~~step ~~U~~up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening -one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.
~~12.~~13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of documentation specifying any criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient~~,~~ and date~~,~~; ~~and contents,~~ or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity who has indicated a reliability need and that functional entity has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying any criteria or methodology utilized in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as all such documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None.

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, ~~part~~Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, ~~part~~Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.	The responsible entity's System model failed to represent three of the Requirement R1, ~~part~~Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, ~~part~~Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1.
R2	The responsible entity failed to comply with Requirement R2, ~~part~~Part 2.6.	The responsible entity failed to comply with Requirement R2, ~~part~~Part 2.3 or ~~part~~Part 2.8.	The responsible entity failed to comply with one of the following ~~part~~Parts of Requirement R2: ~~part~~Part 2.1, ~~part~~Part 2.2, ~~part~~Part 2.4, ~~part~~Part 2.5, or ~~part~~Part 2.7.	The responsible entity failed to comply with two or more of the following ~~part~~Parts of Requirement R2: ~~part~~Part 2.1, ~~part~~Part 2.2, ~~part~~Part 2.4, or ~~part~~Part 2.7.
R3	The responsible entity did not identify planning events as described in Requirement R3, ~~part~~Part 3.4 or extreme events as described in Requirement R3, ~~part~~Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, ~~part~~Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R3, ~~part~~Part 3.2 to assess the impact of extreme events. OR The responsible entity did not base its	The responsible entity did not perform studies as specified in Requirement R3, ~~part~~Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, ~~part~~Part 3.3.	The responsible entity did not perform studies as specified in Requirement R3, ~~part~~Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		studies on computer simulation models using data provided in Requirement R1.		
R4	The responsible entity did not identify planning events as described in Requirement R4, ~~part~~Part 4.4 or extreme events as described in Requirement R4, ~~part~~Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, ~~part~~Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, ~~part~~Part 4.2 to assess the impact of extreme events. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.	The responsible entity did not perform studies as specified in Requirement R4, ~~part~~Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, ~~part~~Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, ~~part~~Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its

	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners, ~~or~~ one adjacent Planning Coordinator~~s~~, ~~and~~ or to one functional entity that has a reliability related need and that ~~functional entity~~ has submitted a written request for the information, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to more than one of its adjacent Transmission Planners, ~~or~~ adjacent Planning Coordinators, ~~and~~ or ~~to any~~ functional entit~~y~~ies that ~~has~~have a reliability related need and that ~~functional entity has~~have submitted a written request for the information, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	TBD	Revision of TPL-001-0 as per Project 2006-02; includes merging requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-1	Not employed due to scope of revision

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Informal Comment Period Open
August 3–September 2, 2010

Now available at: http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

Project 2006-02: Assess Transmission Future Needs

The Assess Transmission Future Needs Standard Drafting Team is seeking comments on the following documents **until 8 p.m. EDT on September 2, 2010**:

- Draft five of TPL-001-1 — Transmission System Planning Performance Requirements
- Revised implementation plan

TPL-001-1 is designed to be a single, comprehensive, and coordinated standard that merges the requirements of four existing standards: TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The proposed standard includes several new definitions.

This is the fifth comment period for the proposed standard and includes revisions based on industry comments submitted during the initial ballot for the standard and its implementation plan conducted from February 9–March 1, 2010. The team's response to initial ballot comments has been posted for stakeholder review on the drafting team web site.

Instructions

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Courtney.camburn@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page: http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html.

Next Steps

The drafting team will draft and post responses to comments received during this period. This is an informal comment period – for each question asked on the comment form, the drafting team will provide a summary response to indicate whether stakeholders support the proposed revision and to identify any additional changes made based on stakeholder comments. The team will not provide an individual response to each comment submitted. After reviewing the comments, the drafting team will determine whether to post the standard for an additional comment period or seek approval from the Standards Committee to proceed to balloting.

Project Background

The purpose of the proposed standard is to establish transmission system planning performance requirements within the planning horizon to develop a bulk electric system that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies. TPL-001-1 — Transmission System Planning Performance Requirements is an update and consolidation of the following standards:

- TPL-001-0 — System Performance under Normal Conditions
- TPL-002-0 — System Performance Following Loss of a Single BES Element
- TPL-003-0 — System Performance Following Loss of Two or More BES Elements
- TPL-004-0 — System Performance Following Extreme BES Events
- TPL-005-0 — Regional and Interregional Self-Assessment Reliability Reports
- TPL-006-0 — Data from the Regional Reliability Organization Needed to Assess Reliability

More information is available on the project page: http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

Applicability of Standards in Project

Planning Coordinator
Transmission Planner

Proposed Additions to Glossary of Terms

Bus-tie Breaker
Consequential Load Loss
Long-Term Transmission Planning Horizon
Near-Term Transmission Planning Horizon
Non-Consequential Load Loss
Planning Assessment
Year One

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Courtney Camburn at Courtney.camburn@nerc.net

Individual or group. (69 Responses)
Name (51 Responses)
Organization (51 Responses)
Group Name (18 Responses)
Lead Contact (18 Responses)
Question 1 (62 Responses)
Question 1 Comments (69 Responses)
Question 2 (63 Responses)
Question 2 Comments (69 Responses)
Question 3 (65 Responses)
Question 3 Comments (69 Responses)
Question 3.1 (64 Responses)
Question 3.1 Comments (69 Responses)
Question 3.2 (64 Responses)
Question 3.2 Comments (69 Responses)
Question 3.3 (65 Responses)
Question 3.3 Comments (69 Responses)
Question 3.4 (58 Responses)
Question 3.4 Comments (69 Responses)
Question 4 (64 Responses)
Question 4 Comments (69 Responses)
Question 5 (0 Responses)
Question 5 Comments (69 Responses)
Question 6 (51 Responses)
Question 6 Comments (69 Responses)
Question 7 (53 Responses)
Question 7 Comments (69 Responses)

-
Individual
Ray Mason
ReliabilityFirst
No
TPL-001-2 Draft 5 is much better than Draft 4. There is still one significant concern, that I do not believe the drafting team adequately addressed. It is unclear as to what “Planning Assessment results” and “results of its Planning Assessment” entail. The Draft 5 response that “Planning Assessment” is a defined term does not fully address this concern. “Planning Assessment results” or “results of its Planning Assessment” is not necessarily the same thing as “Planning Assessment”. As written, “Planning Assessment results” or “results of its Planning Assessment” could be anything from a single sentence, to a few brief high level paragraphs, to a detailed and technically complete Planning Assessment. The Standard needs to more clearly state what is required in the report to other entities. Based on the drafting team response in Draft 4, it seems that replacement of “Planning Assessment results” or “results of its

Planning Assessment" with the term "Planning Assessment" or "its Planning Assessment" would be appropriate. Violation Severity Levels: R8 The failure to provide documented responses to documented comments to "Planning Assessment results" is deemed to be a higher severity level than failing to distribute "results of its Planning Assessment". Failure to distribute denies functional entities an opportunity to comment, and could prevent coordinated planning, and thus should be deemed to be more severe than failing to provide documented responses to documented comments.
Individual
Greg Rowland
Duke Energy
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
We support the changes.
Yes
Yes
Individual
Catherine Mathews
NorthWestern Energy (NWMT)
Yes
Yes
Yes
Yes
Yes
Yes
Yes

Yes
Table 1, P5 currently requires the study of “[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed”. As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: “Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following”. In Table 1, P2 and P3, the last column “Non-Consequential Load Loss Allowed” where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote “b”. This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote “b” in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, “Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.”
No
Measure M6 is too vague. It is unclear how to identify the conditions of Cascading, voltage instability, or uncontrolled islanding. The Glossary of Terms defines Cascading as “The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.” Does the loss of system elements have to extend beyond the Control Area to be considered “Cascading”? Is there a Megawatt threshold that must be satisfied? Is there a time duration involved? Also, “cascading outages” needs to be defined. In addition, “voltage instability” and “uncontrolled islanding” should both be defined.
Yes
Individual
Phuong Tran
Lakeland Electric
Yes
Shouldn’t the “Implementation Plan for TPL-001-1” document be for TPL-001-2? Also, “TPL-001-1” is referenced throughout the document.
No
“the latest” is not needed from the second sentence of R1, since the sentence already ended with “..shall represent projected System conditions”. R1 Part 1.1.2 Suggest adding this clarification at the end “… six months during the period under study”. This language addition helps clarify the point that if an outage occurs during the summer and the entity’s system peak occurs in the winter, then the system peak Load study case (model) does not have to include this particular outage.
No
Please consider removing R.2.6.2
No

A “measureable change in performance” can be interpreted as not meeting one of the performance requirements as specified in Table 1 in order for the condition to be selected as a sensitivity. This will cause utilities to perform sensitivity analysis for all system conditions listed in R2.1.4 to determine which one fails to meet one of the performance requirements in Table 1, as one may not be able to tell performance impact until after the studies are performed. Suggested change: “…one of the following conditions by a sufficient amount…system conditions that may demonstrate a measurable change in system response.”
Yes
No
Please consider removing R2.6.2. The “any material change” language can cause utilities perform studies due to material changes outside of and remote to its system.
Yes
The performance requirements of Table 1 do not allow the loss of non-consequential load for single and multiple contingency events. The disallowance of load loss does not provide any real benefit to the reliability of the BES and is an unnecessary overreach into local quality of service issues that are best addressed by State, Provincial or Municipal authorities. There may be circumstances such as high local transmission costs or local opposition to transmission construction where prohibition of non-consequential load loss represents a poor cost/benefit or quality of life tradeoff. Having a provision at the regional level that a PA or TP can have a certain amount of non-consequential load loss designed or planned in to its system that would be reasonable if it is acceptable to the RE and does not have an adverse impact on the remaining BES. In lieu of such a RE provision, providing a quantitative cap in non-consequential load loss such as 100 MW may be rationale compromise in the goal of limiting load loss for the more probable outage events. Our preference would be to retain the capability of limited non-consequential load loss.It is our understanding that footnote 9 is under consideration as part of Project 2010-11 and should be noted as such for clarification.
No
please consider remove “the latest” from M1
No
The requirement to distribute the Planning Assessment should be more flexible and allow for making the Planning Assessment available, such that those entities that desire the information can have it readily available. R8 should be modified as follows: Each Planning Coordinator and Transmission Planner shall make available its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.
Individual
Tom Duane
PNM
Yes
We commend the SDT for its work to continue the improvement on the proposed TPL-001-1. We were not able to find a place to include comment on Requirement R4; therefore, we have included our comments here: Section R4.3.1, bullet point 3 requires the stability analyses to include the impact of subsequent “[t]ripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models”. As written, this bullet could be interpreted as requiring the inclusion of these relay models in stability data bases. We do not have generic or actual relay models in our dynamics data bases for tripping line faults on lines and transformers represented. We represent actual relay response and tripping times of relays, communications, and breakers to faults in tripping transmission lines and transformers. Requiring the inclusion of generic or actual relay models for all relays that can trip lines and transformers would add a large burden to the development and maintenance of accurate dynamics model files that would add little or no benefit. Please change this bullet to read: “Tripping of Transmission lines and transformers where transient swings cause Protection

System operation based on known Protection System response”.
Yes
Yes
Yes
Yes
Yes
Yes
Table 1, P5 currently requires the study of “[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed”. As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: “Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following”. In Table 1, P2 and P3, the last column “Non-Consequential Load Loss Allowed” where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote “b”. This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote “b” in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, “Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.” Timing of this project and project 2010-11 is critical. It would be very difficult to vote to approve the proposed TPL-001-2 prior to knowing the outcome of Project 2010-11 (footnote b issue).
Group
NERC Staff
Mallory Huggins
Yes
NERC staff supports the change to allow Corrective Action Plans to include tripping of Non-Consequential Load and curtailment of Firm Transmission Service for 7 years. This seems long, but staff understands the stakeholder concern that it could take that long to plan, site, and construct facilities required for compliance with the standard.
Yes
NERC staff supports the revisions to the definition of Year One. However, we believe an associated

change should be made where this term is used in part 2.1.1 of Requirement 2 which requires modeling of “System peak Load for either Year One or year two, and for year five.” It seems the new definition of Year One would negate the need to refer to year two. NERC staff recommends that part 2.1.1 be changed to “System peak Load for Year One and for year five.”
No
NERC staff suggests that the added sentence in R1 be deleted and “Normal System” in Table 1 be replaced with “No unplanned Element outages.” We have a problem with R1 establishing “normal system condition.” “Normal” is not defined, but the system condition that most people would define as “normal” is the System operating within its limits. There are no checks required on the projected system conditions to guarantee “operation within limits.” Staff realizes that if this were the case, the categories tested would all pass their respective tests. (In other words, the category tests may define operating limits that in turn define “normal” from a planning perspective.) Thus, the added sentence in R1 should be deleted. In Table 1, the use of the term “Normal System” in the column “Initial System Condition” really means “No unplanned Element outages.” All Elements that do not have a planned outage are assumed in-service (for transmission Elements) or available for dispatch (for generators). Contrast the term “Normal System” with categories P3 and P6, which have the loss of an Element (which is unplanned) followed by the loss of a second Element (also unplanned). “Normal System” should be replaced with “No unplanned Element outages.”
Yes
NERC staff supports the use of qualified past studies for the Near Term horizon.
Yes
NERC staff supports removing the phrase “not already included in the studies” from the parts 2.1.4 and 2.4.3 of Requirement R2. We believe that the requirement is more clear and less subject to interpretation without this phrase.
No
NERC staff understands why the SDT has inserted the word “expected” before “dynamic behavior of Loads,” but we have concerns with this addition. We understand that a PC or TP that models the best current industry understanding of load behavior should not need to worry about compliance if that model does not match actual load response for all possible system conditions. However, we are concerned that this change to part 2.4.1 of Requirement R2 may be too accommodating. If a PC or TP has unrealistic expectations about load behavior, would this permit the use of unrealistic models? While we have struggled to develop an alternative proposal, we hope that the SDT will identify a way to address this concern.
Yes
NERC staff supports inserting the word “material” in the reference to assessing the impact of proposed generation. We have some concern that this change leaves this part of the requirement open to interpretation, but we also understand the need to permit some degree of engineering judgment to be applied. It would not be appropriate to require that every potential generation addition be included in the assessment where some proposed additions may by inspection be deemed to be immaterial due to size and/or interconnection location.
Yes
NERC staff supports the changes to the header notes in Table 1.
NERC staff is concerned with P5 and footnote 9 and thus cannot support these changes in their entirety. First, a revision to the Draft 4 definition of P5 should be used in lieu of the current Draft 5 version: “Loss of multiple elements caused by the Fault clearing consistent with failure of a single Protection System while clearing a fault on one of the following: . . .” After reviewing the P5 contingency throughout various drafts of this standard, along with existing Table 1 for TPL-001 through TPL-004, NERC staff’s primary concern is that this most recent version is going in the wrong direction by becoming too limiting regarding which Protection System component failures are covered. Draft 5 is an improvement because it removes the reference to loss of multiple elements in Draft 4 (which defined P5 as “Loss of multiple elements caused by the failure of a single Protection System while clearing a fault on one of the following: . . .”). Draft 5 takes a step backward, however, by referring to Delayed Fault Clearing. The advantage of not referring to Delayed Fault Clearing is that for cases where redundant protection systems are provided,

the fault clearing may not be delayed even when a single Protection System failure occurs. Ideally, NERC staff believes that P5 should refer to “failure of any component of a Protection System,” but NERC staff recognizes that we cannot get there until the term Protection System is redefined and Project 2009-07—Reliability of Protection Systems is underway. Until that change is possible, NERC staff encourages the SDT to use the revised version of P5 proposed above. A second concern is with footnote 9, which is used numerous times in Table 1. System adjustments may be used in two different settings: the first is to address the aftermath of a particular Contingency; the second is to prepare for the next Contingency. Staff suggests that the current footnote 9 have this language added: “Post-Contingency Ccurtailment of Firm Transmission Service to address the simulated contingency, when coupled with ….” Footnote 9 is used in the column labeled “Interruption of Firm Transmission Service Allowed” whenever a “No” is provided. The footnote 9 in this column has to do with System adjustments that address the aftermath of the Contingency that is being simulated. Therefore, no footnote 9 appears appropriate for category P0 (No Contingency). The reference in footnote 9 to no load loss and staying within applicable Facility rating, including those on a neighboring system, is sufficient for addressing the aftermath of the Contingency being simulated. To address next Contingency, an additional footnote is needed in the “Initial System Condition” column for category P3 and category P6. The following is suggested: “System adjustments to prepare for the next Contingency must be completed within 30 minutes.” Footnote 9 is used in the column labeled “Initial System Condition” for category P3 and category P6, and these two categories define the loss of an Element “followed by System adjustments” and then followed by the loss of a second Element. It is unclear whether the intent in footnote 9 in these two cases is meant to address the same issue referenced above (i.e. the aftermath of the Contingency being simulated) or whether it is intended to address the next Contingency. Thus, both situations need to be addressed using the suggestions indicated above.
Yes
NERC staff supports the changes to the Measures.
Yes
NERC staff supports the changes to the VSL for Requirement R8.
Individual
Doug Hohlbaugh
FirstEnergy
Yes
We appreciate the effort of the standard drafting team and the changes reflected in the current draft of the TPL-001-1 standard. The changes are improvements that should move the standard towards greater industry consensus. The extended Implementation Plan aligns with suggestions in FE’s prior ballot comments. We support the Implementation Plan change made by the team.
Yes
The change in the Year One definition provides greater flexibility for the industry and also addresses a prior FE comment during the 1st ballot. We appreciate the team’s careful consideration of the industry feedback and support the change.
Yes
Yes
Yes
Yes
Yes
Yes

Table 1, P5 currently requires the study of “[d]elayed Fault Clearing due to the failure of a relay (footnote 13) protecting the Faulted element to operate as designed”. To the extent fully redundant relaying exists with no expected delay in Fault Clearing its understood that the P5 event would not be a concern for the redundant system design. The drafting team has taken appropriate steps within the TPL standard to focus on relaying failures to provide clarity in what is required for P5 planning event.
Yes
Yes
Individual
John Collins
Platte River Power Authority
Yes
We commend the SDT for its work to continue the improvement on the proposed TPL-001-1. We were not able to find a place to include comment on Requirement R4; therefore, we have included our comments here: Section R4.3.1, bullet point 3 requires the stability analyses to include the impact of subsequent “[t]ripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models”. As written, this bullet could be interpreted as requiring the inclusion of these relay models in stability data bases. We do not have generic or actual relay models in our dynamics data bases for tripping line faults on lines and transformers represented. We represent actual relay response and tripping times of relays, communications, and breakers to faults in tripping transmission lines and transformers. Requiring the inclusion of generic or actual relay models for all relays that can trip lines and transformers would add a large burden to the development and maintenance of accurate dynamics model files that would add little or no benefit. Please change this bullet to read: “Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on known Protection System response”.
Yes
Yes
No
I like that you have requirements for qualifying past studies, but Part 2.6.2 is confusing. Please change Part 2.6.2 to read something like: “For steady state, short circuit or Stability analysis: no material changes have occurred to the System represented in the study or, if material changes have occurred, a technical rationale can be provided to explain that the changes do not impact the performance results in the study area.”
Yes
Yes
For consistency, use the qualifier “expected” in the second sentence of Part 2.4.1 also, such that it reads “…represents the overall expected dynamic behavior…”
Yes
I like the flexibility you give the PC and TP to define what ‘material’ means in their ‘documentation to support the technical rationale for determining material changes.’ In Part 2.5 this rationale will decide whether or not any Long-Term Stability studies are required for the Planning Assessment. And in Part 2.6.2 this rationale will be a factor in qualifying a past study.
Yes
I like the flexibility you give the PC and TP in Requirements R3 and R4 to develop their rationale for the Contingencies they select for evaluation.
No. Table 1, P5 currently requires the study of “[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed”. As written, this requirement does not recognize

the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: “Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following”. In Table 1, P2 and P3, the last column “Non-Consequential Load Loss Allowed” where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote “b”. This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote “b” in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, “Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.” Timing of this project and project 2010-11 is critical. It would be very difficult to vote to approve the proposed TPL-001-2 prior to knowing the outcome of Project 2010-11 (footnote b issue). In Table 1 – Planning Events – Suggest changing the description for Events P2-3, P2-4, P4 and P4-6 to use the term ‘Bus-tie Breaker’ or ‘non-Bus-tie Breaker’ as applicable. In Table 1 – Extreme Events – Stability – Items 2a-2d, do you mean ‘Protection System failure’ here, or do you want to change to ‘relay failure’ to be consistent with changes in P5?
Yes
Yes
Group
SERC Planning Standards Subcommittee
Philip Kleckley
Yes
Yes
No
The definition does not adequately address normal (pre-contingency) operating procedures or system configurations. Language should be added to the requirement (perhaps as R1.1.7) to include normal operating procedures or system configurations in place prior to any contingency occurring.
Yes
Yes
Yes
Yes
Yes

Yes
Yes
Comments: We wish to make a comment on R4.3.1: it appears that this requires stability simulations of both successful and unsuccessful high-speed reclosing for all contingency simulations regardless of whether high-speed reclosing is used on the faulted line. We suggest the following wording be used to replace the first bullet: “Successful high-speed reclosing and unsuccessful high-speed reclosing onto a fault, where such reclosing is applied, and where such additional simulations are deemed appropriate by the PC or TP.” We wish to make a comment on the stability extreme event table: Changes were made in planning event P5 to narrow the focus to specific relay failures. The same changes are needed for stability extreme event 2a, 2b, 2c, and 2d.
Individual
Aaron Staley
Orlando Utilities Commission
Yes
Yes
Yes
No
Allowing the use of past studies in lieu of new studies for part or all of an assessment when the underlying system hasn't changed in a signficant change if very prudent. However the wording in 2.6.2 of "unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area" is of concern. By this wording is it intended that the planner must demonstrate that every material change has no impact? In essence doing more work to prove that a study isn't required then the study would take? Or that the planner must essentially have a technical rationale (overarching) for determining when a material change is "material enough" to impact system perofrmance?
No
What is meant by "measurable change in performance"? Is this a measure that the sensistivty should move the system from meeting the performance requirements to not meeting the performance requirements? Or just a measurable change in system response, IE the loading was 45% on this corridor but is now 76%.
Yes
No
I agree with what I think is the intent. The word "Material" is meant to allow for changes in model to occur that are "small" relative to the TP/PC. For example the 400 MW generator that might be built in 10 years by another utility over a hundred miles, several dozen buses and generators away to not force new study work. However as written in 2.5 it requires you to define what a material change is, and could be applied to mean every change must be identified and explained rather then an overarching rationale that would only have you looking for changes that meet the material criteria. But then in 2.6.2 the word material is used with no obligation to explain what material is, only to explain if a material change would not impact the results in a study area. I recommend leaving the term material, but setting a requirement, measure, or definition that requires the TP/PC to define what they consider material specific to their system and circumstance. Since this will by the hetreogenous nature of the grid be different for each it may not be reasonable to pre-define what is realibale. Just as was done with many items in the ATC (MOD) standards, require that it be documented and questions on that rationale be answered. If a specific level

of technical oversight is desired, consider requiring that description to be on file with the regional entity and approved by their planning committee. I think the team is heading in a good direction, it's just how the words will be applied that concern me. This may be a case where an Example or two would go a long way towards providing guidance to entities and auditors.
Yes
I am assuming you mean the header notes on the performance table
I generally agree with the direction the team has gone. Footnote 9 should also be highlighted as being part of the project 2010-11 discussion just as footnote 12 is.
Yes
No
R8 should require that the PC and TP make available it's planning assessment results when requested, rather then requring the preemptive transmittal. There is no reliablity purpose served by providing unsolicited information.
Individual
Kasia Mihalchuk
Manitoba Hydro
Yes
Yes
Yes
Yes
Yes
No
The last two sentences “System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.” belong in the MOD standards. They are not required in TPL-001-2.
No
Adding the word “material” does not clarify Part 2.5. The word “material” can be interpreted in many ways and is subjective. In order to have a consistent approach by all TPs, the drafting team should add a definition of the term “material”. One TP may consider a new 200 MW unit as not being material because there are several larger units in the TPs system.
Yes
In point g, violations are noted in terms of post-Contingency voltage deviations rather than post-Contingency voltage limits. This may lead to confusion, as some utilities evaluate performance based on a post-Contingency voltage deviation criterion while other utilities evaluate performance based on post-Contingency voltage limits. This same comment applies to Requirement R5. Suggested rewording for point g: System steady state voltages and post-Contingency voltages or voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner. Suggested rewording for the first sentence in Requirement R5: Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltages or voltage deviations, and the transient voltage response for its System. Note 12 states that an outstanding issue related to non-consequential load loss is being discussed. This will create a lot of uncertainty. Manitoba Hydro could not support this standard unless the resolution of Note B is known.

Yes
Yes
Individual
Randi Woodward
Minnesota Power
Yes
Yes
Yes
No
Requirement 2 - This requirement states that Stability analyses be performed as part of the annual Planning Assessments. Minnesota Power would like to see the term "Stability analysis" more clearly defined as there are several different types of stability related analysis that can be performed for power systems including: transient stability, voltage stability and small signal stability.
Yes
Yes
Yes
Yes
None.
Yes
Yes
Group
Northeast Power Coordinating Council
Guy Zito
No
Requirement R1 Part 1.1 and following states “System models shall represent:… 1.1.5. Known commitments for firm Transmission Service and Interchange. It was commented during a previous posting that 1.1.5 should be reworded to read: Known commitments for Firm Transmission Service, and, additionally, other types of transactions provided they have been demonstrated to not violate existing reliability constraints. The response was that “The SDT believes that the defined term ‘Interchange’ covers other transfers as described in your comment. No change made.” It is agreed that known Interchanges should be modeled. However, it is imperative that existing reliability constraints not be violated in the process. That is, Interchange relating to economic transactions should not drive planning studies. Reliability related investments should not be driven by congestion related to economic transactions incorporated into planning models. Following is a preferred/revised wording: • 1.1.5. Known commitments for firm Transmission Service and Interchange. Interchange is meant to refer to energy transactions other than firm Transmission Service. While rigorous planning studies have been conducted to permit the uninterrupted implementation of firm Transmission Service without jeopardizing the reliable operation of the Interconnected System, other types of energy transaction only take place whenever

system conditions permit them. They are usually of very short duration relative to planning assessment periods (usually spanning for a few hours to a few days) and deemed highly interruptible subject to reliability issues that may arise during operation of the system. In other words, the term Interchange refers to economic transactions that are permitted when the system is secure and there are reasonable reliability margins to effect dispatch changes to lower operating costs. As such, Interchange should not be reflected in system representation meant to assess system reliability in adherence to reliability criteria delineated in documents such as TPL-001.
No
The definition of Year One could be eliminated, and its wording used in place of Year One within the text of the requirement. The proposed definition has now added ambiguity with respect to “year two” and “year five” which are not defined. Year two could be deleted and R.2.1.1 modified as follows: System peak Load representing a point in time 12-24 months and another point in time 48-65 months into the future from the time the study is initiated. Define Year Five as the twelve month period 4 to 6 calendar years from the date of the Planning Assessment.
Yes
No
The revisions made to Requirement R2 Part 2.1 appear to resolve the concern that past studies could not be used to comply with the short-term steady state study requirements. This revision must be carried through to other sections (R2.2, 2.2.1). However, the language of Requirement R2 Part 2.2 still seems to suggest that current annual studies are always required for the long-term steady state assessment to be compliant. This may have been an oversight, for consistency Requirement R2 Part 2.2 should be modified to similarly read as Requirement R2, Part 2.1. Regarding R2.2, the language should be consistent with 2.1. For example, use "current or qualified past studies" instead of "the following annual current study". Revisions made to Requirement R2.1.5 have made it worse than was originally drafted. This would require the PC & TP to study (meaning performing a technical analysis) of the impact and probability of the possible unavailability of any piece of equipment with a lead time of one year or more. Such an evaluation of spare equipment strategies would require significant additional resources and data, but provide no benefit to system reliability, as it is redundant to the existing N-1-1 contingency requirement (P6). R2.7 requires that Corrective Action Plans are included in each Planning Assessment and states “Such actions may include…” followed by a list of actions. Restricting allowable actions, and excluding runback/tripping of HVDC would have a direct impact on multiple existing facilities in New York and would adversely impact the reliability planning of the NYCA. Runback/tripping of HVDC must be added to the list, and also suggest revising to “Such actions may include but not be limited to:”.
No
Part 2.1.4, requires an entity to vary one or more conditions to demonstrate a change in performance. If the cases were initially stressed, this may force an entity to simulate conditions with less severe stresses. At this point, there is limited to no value to this additional workload. Having a requirement to test at least one sensitivity as a blanket requirement may not be informative by itself and is more unclear since sensitivities are being required on an undefined base set of conditions. If an entity does a case with a stressed set of assumptions, is it necessary to do a non-stressed case? Additionally, our concern involves wording under 2.1.4 and 2.4.3 that sensitivities are required varying one or more conditions. Subsequently, in requirement 2.7.2 corrective action plans need to be developed to resolve performance deficiencies “only” if identified in multiple conditions or require a rationalization why no corrective action plan is necessary. Multiple conditions sensitivities under 2.1.4 and 2.4.3 are necessary to satisfy requirement 2.7.2. Requirement 2.7.2 adds ambiguity and should be removed. If not, a suggested revision to Requirement 2.7.2 as follows: 2.7.2. Corrective Action Plans are not required for performance deficiencies identified in a sensitivity analysis. In general, the scope of this requirement is too broad and non-specific, and only results in undue study burden. Is it necessary for sensitivity analysis to be included in requirements since in accordance with good engineering practices a conservative approach should be used in studies? The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions as commented in issue #3. The standard must describe base assumptions. To define a sensitivity condition, NERC must define base assumptions.

No
There is insufficient information and experience regarding dynamic load modeling. It may also be included as a “sensitivity” analysis in 3.2, rather than requiring and expecting accurate representation of a dynamic load model. If this requirement is kept, a modeling standard must be written that is specific to dynamic loads. Change belongs in a modeling standard, not in TPL-001.
Yes
No
Header note (i) in the first Table 1 (p. 10) could imply that voltage-varying load shall not be used to meet steady state performance requirements. Steady state load models in use include voltage-varying loads. The explicit representation of (voltage-dependent) load models is perfectly consistent with the requirements defined in R1 (which calls for a comprehensive representation of system components and their expected operating status in the planning assessment period) and the impetus to the creation of more specific load models in dynamic assessments found Requirement 2.4 of this draft of TPL-001-2. It is a known that depressed voltage conditions cause certain system elements to perform below their rated capacity. For example, capacitors provide less voltage support and voltage controlling transformers are impeded by their finite tap range to direct VAR flow into areas affected by low voltage conditions. Certain load types, on the other hand, provide a self-compensating relief to depressed voltage by naturally decreasing demand in a manner proportional to their characteristics, without operator intervention. Choosing to negate the voltage-dependence of one of these system elements (load, in our case) results in an inaccurate system representation that, in turn, may lead to erroneous assessments of the reliability state of the interconnected system and, potentially, to the implementation of unwarranted system upgrades. This note should be revised to only reference loads which are disconnected due to voltage.
To support the change to P5, other items need to also be modified. In Table 1 - Steady State & Stability Performance Extreme Events (p. 12), in the Stability Section, the language should be made similar to wording in P5. Protection System should be removed and replaced with the words “relay failure”. This change should be made for 2a through 2d: 2. Local or wide area events affecting the Transmission System such as: a. 3Ø fault on generator with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. b. 3Ø fault on Transmission circuit with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. c. 3Ø fault on transformer with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. d. 3Ø fault on bus section with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. Note 11 (p. 14) needs clarification as shown: Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for a total of 1 mile or less. There are two tables labeled “Table 1”. Suggest that the extreme events table be renamed “Table 2”.
Yes
No
Requirement 8 is an administrative burden to TPs and PCs that adds no value to Bulk Power System reliability. PCs should be including TPs, neighboring PCs and interested parties in its planning processes when developing the Planning Assessments. Therefore, the inclusion of a set of VSLs for Requirement 8 is unnecessary. Should the VSLs for Requirement 8 remain, Requirement 8.1 should be revised to reflect that comments only to the final Assessment (not drafts developed during a process) need a response as follows: If a recipient of the planning assessment final results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments. If Requirement 8 and 8.1 are retained, they should be revised to reflect that comments only to the final Assessment (not drafts developed during a process) need a response and there should be a limit on the comment period as follows: If a recipient of the planning assessment final results provides documented comments on the results within 90 days of receipt, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments. Other comments not addressed by this Comment Form as follows: Section 3.3 - The last sentence of 3.3.1 should be removed. This is addressed in PRC-023. Line ratings are addressed in PRC-023. PRC-

023 requires coordination with the Reliability Coordinator. Remove “Tripping of Transmission elements where relay loadability limits are exceeded.” Section 4.3 - High speed reclosing is not defined, and to help eliminate any confusion that it may introduce into the standard it will be worthwhile for the SDT to define this term. Several specific examples from previous comments on sensitivity analysis and guidance for base case assumptions: The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions. The standard must describe base assumptions. To define a sensitivity condition, NERC must define base assumptions. As for allowing con-consequential load loss for Categories P1 through P5, suggest approval at the Regional level, with a concept of allowing it in a “local area” that does not impact BPS reliability. All references to 300 kV in document should be replaced with EHV (for example in the Introduction, Section 5). The first phrase of Note 3 on p. 14 should be revised as follows: “Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as those representing the backbone of the System, generally at voltage greater than 300 kV, and high voltage (HV) Facilities defined as those not representing the backbone of the System, as determined by the Planning Coordinator and approved by Regional Entity.”

Individual

Martin Bauer

US Bureau of Reclamation

Yes

With exception of the definitions.

No

The language implies a requirement. The language "Year One must include the forecasted peak Load period for one of the following two calendar years" is a requirement and not a statement of clarification. If the definition is that “Year One” can also be the period used for forecast peak load, then it should be stated so. It is suggested that either the language in the definition is modified or the language is deleted from the definition and moved to the body of the standard.

Yes

No

The question is misleading in that R2 also include current studies. The overall structure of the standard could be greatly improved if the standard were segmented into Near Term and Long Term with sub segments for each specific type of analysis to be performed. Second, the standard does not use consistent terms. The Planning Assessment is to include Near Term and Long Term portions which must have steady state analysis, short circuit analysis, and stability analysis (ref. R2). Requirement R 2.1 introduces sensitivity analysis for the Near Term portion, and then refers to the Planning Analysis which is in reality both Near Term and Long Term portions. That implies that sensitivity analysis must be required for both? The standard repeats the requirement for annual stability studies in 2.4 which was already a requirement for Planning Assessments. The requirement 2.1.5 is one the most problematic requirements in this standard. This requirement implies that an entity must have spare equipment and a strategy to employ it. That is beyond the scope of the Energy Policy Act 2005. Spare equipment is not on-line and does not contribute to the reliability of the existing system. The Energy Policy Act of 2005 specifically prohibits the requirement to enhance or modify the system. The use, application, or requirement to have spare equipment violates that prohibition. This section should be removed. In addition, this requirement suffers from an ability to implement. In the first case, the requirement is invoked if the spare equipment strategy could result in unavailability of transmission equipment. How is that determined? There is no nexus to that determination. The unavailability may have already occurred once the transmission equipment has failed. The only way to avoid unavailability if the transmission equipment that fails has a hot stand-by with automatic fail-over. The presence or not of a suitable replacement will still result in unavailability by virtue of the failure o the first piece of transmission equipment. Next problem, who will second guess the owner of the replacement. Where is the requirement to make the replacement strategy available? The standard should focus on system

performance with existing equipment to meet current and future loads.
No
Sensitivity analysis is not included in R2. This gets back to the structure of the standard. There should a clear indication of the studies that are to be included in the Near-Term and Long-Term portions of the Planning Assessments.
No
Not included in R2. See response to Question 3.2
No
The term "material" is arbitrary. It is suggested that a specific value be used to trigger the assessment.
No
The language implies that the responsible entity may choose to not distribute it is feels the entity making the request does not have a "reliability related need". It is not clear why that distinction is being made?
Group
Exelon Transmission Planning
Eric Mortenson
Yes
Yes
Yes
Yes
Yes
No
There is not an industry consensus around best practices for modeling the dynamic behavior or characteristics of load. It is premature to make this a requirement in an enforceable standard which would be held to this degree of subjective auditing.
No
The term ‘material changes’ is subjective. It is very difficult to determine a base case to study combinations of generator additions on a changing transmission network in the 6 to 10 year time period to be used for dynamic simulations. Dynamic studies should be performed whenever new generator interconnections are proposed and it is at that time where meaningful calculations can be performed. The long term six to ten year out dynamic studies for groupings of potential units should be done at a high level, if at all.
Yes
Comments: The term ‘HV’ in the performance table should be defined as ‘Bulk Electric System elements up to 300 kV, not simply all elements ‘below 300 kV’. Footnote 12 should be clarified to specifically state the requirements before voting takes place. The performance criteria should be based on the voltage level of the element experiencing stress due to the contingency, not based on the voltage level of the outaged element. It does not seem to make sense that the loss of a 500 kV bus would not allow for any non-consequential load shedding unless the bus contained a 500 to 230 kV transformer, in which case additional load shedding would be allowed. If outages on a 230 kV system, such as bus fault with stuck breaker, were to cause overloads on a 500 kV network it is acceptable to shed load, but if the outages

were on the 500 kV system originally it would not be acceptable to shed additional load. It seems as if it should be the severity of the situation and the elements involved that would dictate allowable remedial actions and not the initial cause of the disturbance. If, for example, there was a 500 kV contingency outage that caused problems on the 230 kV system there would be a problem that may require load shedding on the 230 kV system. If there were a 230 kV contingency or series of contingencies that caused overloads on the 500 kV system, it would be more difficult to find enough lower voltage load to shed to bring the 500 kV system back to applicable ratings or conditions. The inability to shed non-consequential load could theoretically be resolved by hanging a small EHV / HV transformer on a particular bus, or by tapping a EHV line with an auto transformer.
Yes
Yes
Individual
Paul Rocha
CenterPoint Energy
No
The SDT did not incorporate CenterPoint Energy's previous comment regarding R1; therefore, CenterPoint Energy's concerns remain.
No
The SDT did not incorporate CenterPoint Energy's previous comments regarding R2; therefore, CenterPoint Energy's concerns remain.
No
The SDT did not incorporate CenterPoint Energy's previous comments regarding R2; therefore, CenterPoint Energy's concerns remain.
No
The SDT did not incorporate CenterPoint Energy's previous comments regarding R2; therefore, CenterPoint Energy's concerns remain.
No
The SDT did not incorporate CenterPoint Energy's previous comments regarding R2; therefore, CenterPoint Energy's concerns remain.
Yes
CenterPoint Energy appreciates the effort put forth by the SDT in revising the performance table. The current draft of P5 is preferable to previous versions.
Individual
Tim Ponseti, VP
TVA Transmission Planning & Compliance
Yes
TVA supports the change from five years to seven years for the implementation plan period.
Yes
TVA supports the change in the Year One definition - but would suggest that the word “started” should be changed to “completed” since a Planning Assessment may be started in one calendar year and finished in the next calendar year.
Yes

Yes
Yes
Yes
Yes
Yes
TVA is concerned about footnote 12 (known as footnote b in existing TPL standards). TVA believes that utilities should be given some freedom in dropping local load in response to N-1 events as long as overall BES reliability is not impacted. Otherwise significant capital improvements will be required that will have no overall reliability gain for the Bulk Electric System. TVA does agree with the revisions made specifically to the P5 event. TVA wishes to make a comment on the stability extreme event table: Changes were made in planning event P5 to narrow the focus to specific relay failures. The same changes are needed for stability extreme event 2a, 2b, 2c, and 2d.
Yes
Yes
Additional TVA comments: TVA wishes to make a comment on R4.3.1: it appears that this requires stability simulations of both successful and unsuccessful high-speed reclosing for all contingency simulations. Does high speed reclosing occur in less than 60 cycles or 60 seconds? If a utility does not have reclosing on a transmission line - then must the utility still perform stability studies assuming that there is reclosing? TVA suggests the following wording be used to replace the first bullet: “Successful high-speed reclosing and unsuccessful high-speed reclosing onto a fault, where such reclosing is applied, and where such additional simulations are deemed appropriate by the PC or TP.” In R4.1.1, TVA is concerned that no generating unit shall pull out of synchronism in a local area only (thus not impacting the overall reliability of the BES) for Planning Event P1, while the standard does allow generator runback/tripping for the same event. Thus the generating unit may be tripped by a special protection scheme - but may not be tripped by an out of step relay. TVA believes that out of step relaying should be allowed for this unit tripping as long as this does not affect the overall reliability of the BES.
Individual
Dan Rochester
Independent Electricity System Operator
Yes
We agree with this change. We further suggest that this change and the additional wording: “or in those jurisdictions where no regulatory approval is required on the first day of the first calendar quarter, 84 months after Board of Trustees adoption” be added to P. 3 of the standard that starts with “For 84 calendar months…” to be totally consistent.
Yes
Yes
Yes
Yes
Yes

Yes
We do not have a concern with this change but we don't think it is necessary. It is not a requirement, and appropriate wording in the Measures can take care of it.
Yes
Yes
Yes
Group
Southern Company
Andy Tillery
Yes
Yes
No
The definition does not adequately address normal (pre-contingency) operating procedures or system configurations. Language should be added to the requirement (perhaps as R1.1.7) to include normal operating procedures or system configurations in place prior to any contingency occurring.
Yes
Yes
Yes
Yes
Yes
NO We wish to make a comment on the stability extreme event table: Changes were made in planning event P5 to narrow the focus to specific relay failures. The same changes are needed for stability extreme event 2a, 2b, 2c, and 2d.
Yes
No
We wish to make a comment on R4.3.1: it appears that this requires stability simulations of both successful and unsuccessful high-speed reclosing for all contingency simulations regardless of whether high-speed reclosing is used on the faulted line. We suggest the following wording be used to replace the first bullet: "Successful high-speed reclosing and unsuccessful high-speed reclosing onto a fault, where such reclosing is applied, and where such additional simulations are deemed appropriate by the PC or TP." Also, we wish to make a comment on footnote #13 of Table 1. 13. Applies to any of the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, & 67), voltage (#27 & 59), directional (#32 & 67), and associated tripping (#86 & 94) relays.
Group
Hydro One Networks Inc.

David Kiguel
Yes
Yes
Yes
Yes
No
The scope of this requirement is too broad and non-specific and only results in undue study burden.
No
There is insufficient information and experience regarding dynamic load modeling. Hence, this should not be a requirement but a guide or an item to be considered to the extent possible. It may also be included as a “sensitivity” analysis in 3.2, rather than requiring and expecting accurate representation of dynamic load model.
Yes
Yes
No selection boxes in this question. Yes, we support.
Yes
Yes
Requirement 8 is an administrative burden and adds little or no value to the BPS reliability. Therefore, the inclusion of a set of VSLs for Requirement 8 is unnecessary.
Group
jWestern Electricity Coordinating Council
Steve Rueckert
Yes
We commend the SDT for its work to continue the improvement on the proposed TPL-001-1. We were not able to find a place to include comment on various requirements not identified in the questions below; therefore, we have included our comments here: Requirement and 2.6 and 2.6.1: A study that is five years old is very likely to be out of date. The entity's BES may have not changed much in five years but the entity cannot be certain whether or not their neighbor’s system may have changed. Changes outside the immediate entity's system can impact results of studies within their system. Suggest that two years is a maximum that past studies should be allowed. Requirement 3.4.1 and 4.4.1 require PCs and TPs to coordinate with adjacent PCs and TPs to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. Please clarify whether this means that a PC or TP must coordinate with others to identify contingencies on other Systems that the PC or TP must now include on their Contingency list to simulate and address any performance violations on their own System, or does it mean that the PC or TP must coordinate with others to identify contingencies on their System that the PC or TP must now include on their Contingency list to simulate and address any performance violations on other Systems. In either case, the standard does not seem to clearly state what must be done, or whose responsibility it is to mitigate, if a contingency in one System causes a performance violation in another System. Requirement R4.3.1, bullet point 3 requires the stability analyses to include the impact of subsequent “[t]ripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models”. As written, this bullet could be interpreted as requiring the inclusion of these relay models in stability data bases. We do not have generic or actual relay models in our dynamics data bases for tripping line faults on lines and

transformers represented. We represent actual relay response and tripping times of relays, communications, and breakers to faults in tripping transmission lines and transformers. Requiring the inclusion of generic or actual relay models for all relays that can trip lines and transformers would add a large burden to the development and maintenance of accurate dynamics model files that would add little or no benefit. Please change this bullet to read: “Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on known Protection System response”.
No
We recognize that the drafting team made changes to the definition of Year One based on industry comments. However, we believe that the revised language could allow for a situation where an entity could use its next season’s operating study as its Year One planning study. For example, if the entity does its study in the fall of 2011, the proposed definition would allow the entity to use its summer 2012 operating study as its Year One study. This is a very short period to address any issued identified. Suggest working into the requirement that Planning Studies must look out at least 12 months beyond when the study is performed. This would still allow for the provision in the current definition example (“if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013) because the entity would be able to use their 2013 Load period, but it would prevent the entity from using the 2012 Load period if they started the assessment late in 2011.
Yes
Yes
Yes
Yes
Yes

Table 1, P5 currently requires the study of “[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed”. As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: “Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following”. In Table 1, P2 and P3, the last column “Non-Consequential Load Loss Allowed” where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote “b”. This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote “b” in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, “Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.” Timing of this project and project 2010-11 is critical. It would be very difficult to vote to approve the proposed TPL-001-2 prior to knowing the outcome of Project 2010-11 (footnote b issue).
Individual
Dilip Mahendra
SMUD
R2.7.1, last bullet: Please provide specifics on the types of acceptable ‘Corrective Actions’ covered by ‘rate applications and DSM’ and the planning horizon for which they are considered acceptable. As an alternative, NERC should develop a process by which what is considered acceptable is published and continuously updated. (With due apologies for not raising this point earlier).
What is the significance of changing the wording for section R2.1.5 from ‘assessed’ to ‘studied’ and ‘Planning Assessments’ to ‘studies’?
For the Western Interconnection, the performance level for a Bus-tie breaker fault under TPL-001-2, Table 1, Item P2-4, Notes (a) and (f), requires no thermal overloads and no cascading. While, FAC-010-2.1, R1.2, R2.5-R2.6, as modified by E1.1, E1.1.7, E1.3, and E1.3.1 requires a different performance level of no cascading. Please explain why this regional variance is not included under TPL-001-2, Item E.
Group
Arizona Public Service Company
Jana Van Ness, Director Regulatory Compliance

Yes
We commend the SDT for its work to continue the improvement on the proposed TPL-001-1. We were not able to find a place to include comment on Requirement R4; therefore, we have included our comments here: Section R4.3.1, bullet point 3 requires the stability analyses to include the impact of subsequent “[t]ripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models”. As written, this bullet could be interpreted as requiring the inclusion of these relay models in stability data bases. We do not have generic or actual relay models in our dynamics data bases for tripping line faults on lines and transformers represented. We represent actual relay response and tripping times of relays, communications, and breakers to faults in tripping transmission lines and transformers. Requiring the inclusion of generic or actual relay models for all relays that can trip lines and transformers would add a large burden to the development and maintenance of accurate dynamics model files that would add little or no benefit. Please change this bullet to read: “Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on known Protection System response”.
Yes
Yes
Yes
Yes
Yes
Yes
Table 1, P5 currently requires the study of “[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed”. As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: “Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following”. In Table 1, P2 and P3, the last column “Non-Consequential Load Loss Allowed” where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote “b”. This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote “b” in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, “Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.” Timing of this project and project 2010-11 is critical. It would be very difficult to vote to approve the proposed TPL-001-2 prior to knowing the outcome of Project 2010-11 (footnote b issue).

Individual
RoLynda Shumpert
South Carolina and Gas
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
We wish to make a comment on the revisions to R4.3.1. We believe that the analysis of both successful and unsuccessful high speed reclosing for all cases is not justified and should be left to the discretion of the Transmission Planner.
Individual
Brian Keel
SRP
Yes
We commend the SDT for its work to continue the improvement on the proposed TPL-001-1. We were not able to find a place to include comment on Requirement R4; therefore, we have included our comments here: Section R4.3.1, bullet point 3 requires the stability analyses to include the impact of subsequent “[t]ripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models”. As written, this bullet could be interpreted as requiring the inclusion of these relay models in stability data bases. We do not have generic or actual relay models in our dynamics data bases for tripping line faults on lines and transformers represented. We represent actual relay response and tripping times of relays, communications, and breakers to faults in tripping transmission lines and transformers. Requiring the inclusion of generic or actual relay models for all relays that can trip lines and transformers would add a large burden to the development and maintenance of accurate dynamics model files that would add little or no benefit. Please change this bullet to read: “Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on known Protection System response”.
Yes
Yes

Yes
Yes
Yes
Yes
Yes
Table 1, P5 currently requires the study of “[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed”. As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: “Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following”. In Table 1, P2 and P3, the last column “Non-Consequential Load Loss Allowed” where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote “b”. This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote “b” in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, “Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.” Timing of this project and project 2010-11 is critical. It would be very difficult to vote to approve the proposed TPL-001-2 prior to knowing the outcome of Project 2010-11 (footnote b issue).
Individual
Darcy O'Connell
California ISO
Yes
Yes
Yes
Yes
No
Requirement 2.7.2 could be revised as follows: 2.7.2. Corrective Action Plans are not required for

performance deficiencies identified in a sensitivity analysis. If a Planning Coordinator includes Corrective Action Plans to resolve performance deficiencies identified in multiple sensitivity analysis, the Planning Coordinator shall provide documentation to support those Plans.
Yes
Yes
Yes
We support these changes, although we suggest that the proposed footnote 12 include an interim provision to default to the existing footnote “b” in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, “Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.”
Yes
No
Requirement 8 is an administrative burden to TPs and PCs that adds no value to reliability. PCs should be including TPs, neighboring PCs and interested parties in its planning processes when developing the Planning Assessments. Therefore, the inclusion of a set of VSLs for Requirement 8 is unnecessary. Should the SDT decide to leave the VSLs for Requirement 8, Requirement 8.1 should be revised to reflect that comments only to the final Assessment (not drafts developed during a process) need a response as follows: 8.1 If a recipient of the planning assessment final results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments. For a Planning Coordinator (PC) who distributes the Planning Assessment to many different entities (to adjacent PCs, TPs, and other functional entities), a concern regarding the Requirement R8 VSL is that it is overly restrictive to apply a violation for failing to distribute the results of its Planning Assessment to only one PC, TP, or functional entity (and to apply a High VSL for failing to distribute to more than one entity), particularly since an entity’s contact is subject to change over time, and since Measure M8 allows for publicly posting the results of its Planning Assessment to its website. Should the SDT decide to include the VSLs for Requirement 8, would recommend revising to use a percentage approach rather than applying a violation to a Planning Coordinator who fails to provide the results of its Planning Assessment to one PC, TP, or other functional entity (or applying a High VSL for failing to distribute to more than one entity.) Recommend applying a similar percentage approach to the VSLs drafted by NERC Staff for Project #2007-23 VSLs (e.g., for FAC-013-1) to be considered for the TPL-001-2 R8 VSLs. For example, • Lower VSL: The responsible entity failed to provide the Planning Assessment final results to 5% or less of the required entities. • Moderate VSL: The responsible entity failed to provide the Planning Assessment final results to more than 5% up to (and including) 10% of the required entities. • High VSL: The responsible entity failed to provide the Planning Assessment final results to more than 10% up to (and including) 15% of the required entities. • Severe VSL: The responsible entity failed to provide the Planning Assessment final results to more than 15% of the required entities OR [the existing language for the Severe VSL]. Explanation: The VSLs were modified for consistency with other standards and VSLs. Reference: Link to VSLs drafted by NERC Staff for Project #2007-23 VSLs (e.g., for FAC-013-1): http://www.nerc.com/docs/standards/sar/Staff_Proposed_VSLs_2010July27.pdf
Individual
Scott Inglebritson
Seattle City Light

Yes
No
The definition of Year One is now too flexible and does not meet the intent of the standard. For example, our system peak is generally in January of the year. If I perform TPL studies in November 2011, studying the peak in January 2012 is acceptable according to the new definition. This is only two months from the date of the study. The intent of the TPL standard should be that entities must study and plan for inadequacies found in the studies. A one- or two-month lead time is not adequate to address any problems identified. Year One should be the year containing the first peak 12 months or more from the current date. Otherwise, TPL studies become merely seasonal operational studies, not planning studies. Alternative Language: "For the Planning Assessment started in a given year, Year One should contain the first system peak that occurs twelve months or more after the date of the Planning Assessment."
Yes
Yes
Yes
Yes
Yes
Yes
Table 1, P5 does not recognize the existence of redundant (or backup) relays. These are an integral part of the protection system design and should be considered in analysis of SLG faults. The TPL standard should encourage redundant, fail-safe systems, not ignore them. In Table 1, P2 and P3, we have a concern about not allowing non-consequential load loss. Project 2010-11 is deciding on this issue, but is not completed (see footnote 12). Should the standard become effective before this project is completed, no non-consequential load loss would be allowed, requiring many transmission additions and reconfigurations. Please change the "NO" in the last column to "YES" until the completion of Project 2010-11.
Yes
Yes
Individual
Ean O'Neill
California Energy Commission
Yes
We commend the SDT for its work to continue the improvement on the proposed TPL-001-1. We were not able to find a place to include comment on Requirement R4; therefore, we have included our comments here: Section R4.3.1, bullet point 3 requires the stability analyses to include the impact of subsequent “[t]ripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models”. As written, this bullet could be interpreted as requiring the inclusion of these relay models in stability data bases. We do not have generic or actual relay models in our dynamics data bases for tripping line faults on lines and transformers represented. We represent actual relay response and tripping times of relays, communications, and breakers to faults in tripping transmission lines and transformers. Requiring the inclusion of generic or actual relay models for all relays that can trip lines and transformers would add a large burden to the development and

maintenance of accurate dynamics model files that would add little or no benefit. Please change this bullet to read: “Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on known Protection System response”.
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No. Table 1, P5 currently requires the study of “[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed”. As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: “Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following”. In Table 1, P2 and P3, the last column “Non-Consequential Load Loss Allowed” where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote “b”. This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote “b” in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, “Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.” Timing of this project and project 2010-11 is critical. It would be very difficult to vote to approve the proposed TPL-001-2 prior to knowing the outcome of Project 2010-11 (footnote b issue).
Individual
Kathleen Goodman
ISO New England Inc.
Yes
No
The definition of Year One could be deleted and used in place of Year One within the text of the

requirement. The proposed definition has now added ambiguity with respect to “year two” and “year five” which are not defined. Year two could be deleted and R.2.1.1 modified as follows: System peak Load representing a point in time 12-24 months and another point in time 48-65 months into the future from the time the study is initiated.
No
R1.1 Part 1.1.2. With respect to known outages, there needs to be greater flexibility in the standards (e.g. more tolerance to non-consequential load shedding or limitations to the contingencies that need to be considered (e.g. P0, P1, & P2)). Regional allowances for load shedding under this condition should be approved. Duration of known outages should be increased from six months to one year; R1.1 Part 1.1.6 Delete "required for Load". Resources may also be used for export to other areas, not just internal load.
No
We can agree with R2.1 however with respect to R2.2 Language should be consistent with 2.1 for example - use "current or qualified past studies" instead of "the following annual current study."
No
Part 2.1.4, requires an entity to vary one or more conditions to demonstrate a change in performance. If the cases were initially stressed, this may force an entity to simulate conditions with less severe stresses. At this point, there is limited to no value to this additional workload. Having a requirement to test at least one sensitivity as a blanket requirement may not be informative by itself and is more unclear since sensitivities are being required on an undefined base set of conditions. Additionally, our concern involves wording under 2.1.4 and 2.4.3 that sensitivities are required varying one or more conditions. Subsequently, in requirement 2.7.2 corrective action plans need to be developed to resolve performance deficiencies “only” if identified in multiple conditions or require a rationalization why no corrective action plan is necessary. Multiple conditions sensitivities under 2.1.4 and 2.4.3 are necessary to satisfy requirement 2.7.2. Requirement 2.7.2 adds ambiguity and should be removed. Requirement 2.7.2 should be revised as follows: 2.7.2. Corrective Action Plans are not required for performance deficiencies identified in a sensitivity analysis.
Yes
Yes
Yes
We are supportive of the change to P5. However, in making this modification, other items need to also be changed. In Table 1 – Stability, the language should be made similar to wording in P5. Protection System should be removed and replaced with the words “relay failure”. This change should be made for 2a through 2d: 2. Local or wide area events affecting the Transmission System such as: a. 3Ø fault on generator with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. b. 3Ø fault on Transmission circuit with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. c. 3Ø fault on transformer with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. d. 3Ø fault on bus section with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. We also believe that Note 11 needs clarifying wording as shown below: "Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for a total of 1 mile or less"
Yes
Yes
Requirement 8 and 8.1, should be revised to reflect that comments only to the final Assessment (not drafts developed during a process) need a response and there should be a limit on the comment period as follows: If a recipient of the planning assessment final results provides documented comments on the results within 90 days of receipt, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments. We have other comments not addressed by this Comment Form as follows - Sections 2.7, 3.3, 4.3 and

overall. R2.7 requires that Corrective Action Plans are included in each Planning Assessment and states “Such actions may include…” followed by a list of actions. Runback/tripping of HVDC should be added to the list. Section 3.3 - We feel that the last sentence of 3.3.1 should be removed. This is handled by PRC-023. Line ratings are addressed by PRC-023. PRC-023 requires coordination with the Reliability Coordinator. Remove “Tripping of Transmission elements where relay loadability limits are exceeded.” Section 4.3 - High speed reclosing needs to be defined.
Individual
Oscar Herrera
Los Angeles Department of Water and Power
Yes
We commend the SDT for its work to continue the improvement on the proposed TPL-001-1. We were not able to find a place to include comment on Requirement R4; therefore, we have included our comments here: Section R4.3.1, bullet point 3 requires the stability analyses to include the impact of subsequent “[t]ripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models”. As written, this bullet could be interpreted as requiring the inclusion of these relay models in stability data bases. We do not have generic or actual relay models in our dynamics data bases for tripping line faults on lines and transformers represented. We represent actual relay response and tripping times of relays, communications, and breakers to faults in tripping transmission lines and transformers. Requiring the inclusion of generic or actual relay models for all relays that can trip lines and transformers would add a large burden to the development and maintenance of accurate dynamics model files that would add little or no benefit. Please change this bullet to read: “Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on known Protection System response”.
Yes
Yes
Yes
Yes
Yes
Yes
No. Table 1, P5 currently requires the study of “[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed”. As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: “Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following”. In Table 1, P2 and P3, the last column “Non-Consequential Load Loss Allowed” where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote “b”. This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently

networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote “b” in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, “Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.” Timing of this project and project 2010-11 is critical. It would be very difficult to vote to approve the proposed TPL-001-2 prior to knowing the outcome of Project 2010-11 (footnote b issue).
Yes
Yes
Individual
Orlando A Ciniglio
Idaho Power Co
Yes
We were not able to find a place to include comment on Requirement R4; therefore, we have included our comments here: Section R4.3.1, bullet point 3 requires the stability analyses to include the impact of subsequent “[t]ripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models”. As written, this bullet could be interpreted as requiring the inclusion of these relay models in stability data bases. We do not have generic or actual relay models in our dynamics data bases for tripping line faults on lines and transformers represented. We represent actual relay response and tripping times of relays, communications, and breakers to faults in tripping transmission lines and transformers. Requiring the inclusion of generic or actual relay models for all relays that can trip lines and transformers would add a large burden to the development and maintenance of accurate dynamics model files that would add little or no benefit. Please change this bullet to read: “Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on known Protection System response”.
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Table 1, P5 currently requires the study of “[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed”. As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge redundant relays for primary protection: “Single failure of a protection relay13 protecting the Faulted element to operate as

designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following". In Table 1, P2 and P3, the last column "Non-Consequential Load Loss Allowed" where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote "b". This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote "b" in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, "Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers."
Yes
Yes
Individual
David Bradt
United Illuminating
Yes
No
Year One should be used within the text of the requirement. Do not have a definition for Year One.
No
For R1 Ambiguity regarding base case assumptions, in combination with lack of clarity and clear direction of purpose regarding the sensitivity analysis, undermines the objectives of the standard; R1.1 Part 1.1.2. With respect to known outages, there needs to be greater flexibility in the standards (e.g. more tolerance to non-consequential load shedding or limitations to the contingencies that need to be considered (e.g. P0, P1, & P2)). Regional allowances for load shedding under this condition should be approved. Duration of known outages should be increased from six months to one year; R1.1 Part 1.1.6 Delete "required for Load". Resources may also be used for export to other areas, not just internal load.
No
We can agree with R2.1 however with respect to R2.2 Language should be consistent with 2.1 for example - use "current or qualified past studies" instead of "the following annual current study".
No
If an entity does a stressed set of assumptions do they always need to do a non-stressed case?
Yes
Yes
Yes
In Table 1 – Stability, Make language similar to wording in P5. "Protection System" should be removed and replaced with the words "relay failure". This would avoid future interpretation issues about the intent of this requirement (as we understand it) to exclude more severe though less likely failures such as

battery systems. This change should be made for 2a through 2d on page 12). In Note 11 (page 14) ADD the wording shown in "quotes" below: Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for "a total of" 1 mile or less.
Yes
Yes
General Comment: We have other comments not addressed by this Comment Form as follows - Section 3.3, Section 4.3 and overall Section 3.3 - We feel that the last sentence of 3.3.1 should be removed. This is handled by PRC-023. Line ratings are addressed by PRC-023. PRC-023 requires coordination with the Reliability Coordinator. Remove “Tripping of Transmission elements where relay loadability limits are exceeded.” Section 4.3 - High speed reclosing is not defined. Overall – ISO New England and New England Transmission Owners have previously made comments which have not been addressed in the current version of the proposed standard. Support for the standard can at most be limited without addressing comments. We have previously commented on sensitivity analysis and guidance for base case assumptions. Also, extreme event analysis should not be mandated in this standard as no corrective action is required.
Group
Transmission Issues Subcommittee
Bob Cummings
No Comment
No Comment
Yes
No Comment
No comment
No
TIS believes that the term “expected” leaves the question as to “whose expectation.” It should be stated as to “expected…by the Transmission Planner.”
No comment
No
Delete the word “voltage” from the last header note J concerning Stability Only. All types of transient stability must be observed.
No comment
No comment
No comment
Group
SERC Dynamics Review Subcommittee
Robert Jones
Yes
“The comments expressed herein represent a consensus of the views of the above named members of the SERC Engineering Committee Dynamics Review Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.”
Yes
Yes
Yes

Yes
Yes
Yes
Yes
Yes. The SERC DRS supports the revisions.
Yes
Yes
We wish to make a comment on R4.3.1: it appears that this requires stability simulations of both successful and unsuccessful high-speed reclosing for all contingency simulations regardless of whether high-speed reclosing is used on the faulted line. We suggest the following wording be used to replace the first bullet: “Successful high-speed reclosing and unsuccessful high-speed reclosing onto a fault, where such reclosing is applied." We wish to make a comment on the stability extreme event table: Changes were made in planning event P5 to narrow the focus to specific relay failures. The same changes are needed for stability extreme event 2a, 2b, 2c, and 2d.
Individual
John Sullivan
Ameren
Yes
Yes
No
The definition does not adequately address normal (pre-contingency) operating procedures or system configurations. Language should be added to the requirement (perhaps as R1.1.7) to include normal operating procedures or system configurations in place prior to any contingency occurring.
Yes
Yes
No
Industry needs guidance regarding how to provide reasonable induction motor representation as opposed to generic models.
Yes
Yes
No
For measurements M3 and M4, there is some question as to what is to be provided as evidence of a study. Would the study results alone provide sufficient evidence, or does the entire powerflow, stability, or short circuit effort need to be documented in a formal study report? There are no measures for the creation and coordination of contingency lists that are to be developed in R3.4, R3.5, R4.4, and R4.5. Are these contingency lists required to be a documented part of the study?

No
The sharing issues of requirement R8 are still not clear, therefore the R8 VSL is not clear. It is not clear if the intent of the SDT is for the PC to share the assessments with PCs and TPs are to share the assessments with TPs, or whether the intent is for the TP to share its assessments with its PC. Will posting the assessment to a secure web-site meet the intent of the requirement? Although the comment form is not designed to allow for such, we need to comment on R4.3.1: As written, it appears that this requires stability simulations of both successful and unsuccessful high-speed reclosing for all contingency simulations, regardless of whether high-speed reclosing is actually implemented. A suggested wording change for the first bullet: “Successful high-speed reclosing and unsuccessful high-speed reclosing onto a fault, where such reclosing is applied, and where such additional simulations are deemed appropriate by the PC or TP.” Another comment needs to be made regarding the stability extreme event table: Changes were made in planning event P5 to concentrate on specific relay failures. The same changes need to be made for stability extreme events 2a, 2b, 2c, and 2d. The proposed standard will significantly increase the amount of work required to develop more detailed and complex system models, to perform and document the engineering studies to meet the performance requirements, and to develop the assessments necessary for compliance. All of these increased engineering activities are perceived to provide marginal benefit to the reliability of the bulk electric system, but will require significant increases in manpower across the industry. Further, the manpower is presently not available to develop these more detailed models and to perform these studies with any reasonable assuredness. It will be a continuing challenge to the industry to obtain and keep the engineering talent needed to perform these compliance activities for such marginal benefits.
Individual
Si Truc PHAN
Hydro-Quebec TransEnergie
Yes
Yes
Yes
No
Requirement R2 Part 2.2 should be modified to read as 2.1 (not impose current annual studies as the only requirement for assessment)
No
It is questionable that sensitivity analysis be included in Requirements since a conservative approach should already be used in studies, in accordance with good engineering practices.
No
There is insufficient data available to accurately model system wide motor loads.
Yes
Yes
In table 1 on page 12 (Stability section), Relay failure should replace Protection System
Yes
Yes
• All references to 300 kV in document should be replaced with EHV (In the introduction, section 5) • The first phrase of Note 3 on p 14 should be revised as follows: “Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as those representing the backbone of the System, generally at voltage greater than 300 kV, and high voltage (HV) Facilities defined as those not

representing the backbone of the System, as determined by the Planning Coordinator and approved by Regional Entity.”
Group
MRO's NERC Standards Review Subcommittee
Carol Gerou
Yes
Yes
Yes
We propose the following changes and questions: R1 – We offer the minor suggestion of replacing the wording of “maintain System models within their respective areas” with “maintain System models of elements that are interconnected to any portion of the BES that is owned or operated by the TP or PC”. This wording would avoid the ambiguity that can occur when a BA that is associated primarily with one TP declares ownership of a bus in another TP’s geographic area, but expects its primary TP to maintain the BA’s model data for the remote generation or load. R1.1.2 – We request the SDT opinion on how two individual outages should be modeled if they are both in excess of six months duration and they overlap by less than six months. Should the overlapping condition only be modeled if the condition is expected to last more than six months?
Yes
R2.1.3 – We offer the minor suggestion of revising R2.1.3 to state, “Known outages of generation or Transmission Facilities with a duration of at least six months be simulated along with P1 events for the System peak or Off-Peak conditions when the outages are scheduled to occur.” We interpret that the requirement should only call for the simulation of individual outages with duration of six months or more and not imply the simulation of sequential (back-to-back) outages where each individual outage is less than six months, but the composite duration of the back-to-back outages is more than six months. We also interpret that if two or more known outages with duration of at least six months are overlapping, then the overlapping outage condition would only be simulated for the conditions when the overlapping outages are scheduled to occur if the duration of the overlapping condition is at least six months. R2.1.5 – We offer a major suggestion regarding the phrase “could result in the unavailability of major transmission equipment” because this phrase is ambiguous and not defined. So, there is a significant risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. We proposed adding that the TP and PC “shall provide documentation to support the technical rationale for defining unavailability of major transmission equipment” similar to R2.5.
No
R2.1.4 & R2.4.3 – We offer a major suggestion regarding the terms of ‘credible’ and ‘measurable change” because these terms are ambiguous and not defined. So, there is a significant risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. We proposed adding that the TP and PC “shall provide documentation to support the technical rationale for determining the range of credible conditions and measurable change in performance” similar to R2.5. R2.1.4 & R2.4.3 bullet items – We offer the minor suggestion that the number and description of the bullet items in R2.1.4 match the bullet points in R2.4.3. Otherwise, please explain the reasons for any differences between the bullet items in R2.1.4 and R2.4.3. R2.1.4 bullet #2 & # 5 – We suggest that the wording in bullet #2 be changed to “Expected transfers and other generation dispatch scenarios”. This modification would put the transfer and dispatch element, which are complementary, together in the same bullet item, rather than grouping the ‘generation dispatch’ (operating level) element together with the generation capacity elements in bullet item #5. R2.1.4 bullet #7 – We offer the minor suggestion that the term “planned” be replaced with “known” to be consistent with R1.1.2 and R2.1.3. Besides the term “planned outage” has a specific meaning in the Reliability Standards that are specific to the Operating horizon. R2.7.2 – With regard to "include actions to resolve performance deficiencies identified in multiple sensitivity studies", we do not think that mitigation plans should be required for deficiencies found in multiple sensitivity studies because the conditions in some sensitivity studies are more extreme and less likely than base case conditions. It’s impractical to require corrective actions for longer term horizon sensitivities due to how fast the electric

grid changes. We believe sensitivity analyses are valuable to improving the development of mitigation plans to address base case performance limit concerns. Some of the sensitivity study conditions are not credible or plausible enough to warrant the implementation of mitigation measures. What is the interpretation of multiple sensitivity studies - more than one or a majority of the number that were studied?

Yes

Yes

Yes

We offer the major suggestion that Requirements not be created in the Performance Table and be absent from the Requirement section. Requirements should only be referred to in the Performance Table after they already exist in the Requirement section. a. Notes “f” and “g” under “Steady State Only” section in the Table 1 header create requirements (e.g. use the verb, “shall”) that do not appear in the Requirements section. We suggest adding R3.3.5, which could read, “Applicable System Operating Limits for the planning horizon shall not be exceeded.” [After R3.3.5 is added, Notes “f” and “g” should be revised and refer to R3.3.5.]. b. Note “i” under “Steady State Only” section in the Table 1 header creates a requirement (e.g. use the verb, “shall”) that does not appear in the Requirements section. We suggest adding R3.3.6, which could read, “The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state voltage requirements.” [After R3.3.6 is added, Note “d” should be revised to refer to R3.3.6. c. Note “j” under the “Stability Only” section in the Table 1 header creates a requirement (e.g. use the verb, “shall”) that does not appear in the Requirements section. We suggest adding R4.1.4, which could read, “Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner”. [After R4.1.4 is added, Note “j” should be revised to refer to R4.1.4.]

We offer the major suggestion that the P3 Category performance criteria be modified to apply only to the loss of two generators. The SDT properly recognizes that generator outages are significantly more probable than line or transformer outages and should be “higher” in the category list. However given the clearly higher probability of generator outages, the probability of the loss of two generators is clearly higher than the loss of a generator and line or the loss of a generator and transformer. Therefore, if the loss of two generators is in the P3 category, then the loss of a generator and line or transformer should be clearly “lower” in the category list. We suggest the listing of: the loss of a generator and some other element (e.g. transmission circuit, transformer, shunt device, and single pole of DC line) be moved to a lower event category, such as the P6 Category by adding “1. Generator” to the listing in the Initial System Condition (Loss of . . .) column. Item 2.a in the Extreme Events, Steady State section – Clarify the meaning of the loss of multiple circuits in Item 2.a by using wording similar to P7. We suggest this text: “a. Loss of three or more circuits that share a common structure.” Footnote 6 – Further clarify the applicable shunt devices in Footnote 6 with this suggested text: “6. Requirements which are applicable to shunt devices, also apply to FACTS devices that are connected to ground, but not instrument voltage transformers or surge arresters.”

Yes

Yes

Other Comments: 1. How are backup relays handled (TPL-002-0, R1.3.10 & TPL-001-2 R1 & P5)? What does FERC construe as normal system for a protection system. The TPL-001-2 R1 & P5, this standard doesn’t appear to address primary protection and how this handled. 2. Revise the Planning Assessment definition to more explicitly apply to the BES and the TPL-001 requirements. We suggest text of: “Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies in the BES from the steady state and stability performance requirements set forth in the TPL-001 standard.” 3. R2.1.5 – We propose replacing the term ‘major Transmission’ with “BES” because BES is a well defined term, while the term, ‘major Transmission‘, is not. 4. Add R2.3.1 – We suggest the addition of a R2.3.1 requirement to emulate the

distinction between the requirement to perform a short circuit assessment and conduct required studies or analysis to support the assessment (e.g. R2.1/R2.1.1 and R2.2/R2.2.1). We propose wording such as, “Perform an analysis for at least one year in the Near Term Transmission Planning Horizon.” This requirement would set an expectation that an analysis should be conducted to at least one or more years in the near-term planning horizon, rather than imply that an analysis of all five years in the near-term planning horizon must be conducted. 5. R2.7.4 – We suggest that the wording of R2.7.4 be the same as R.2.8.2. Otherwise, we propose that R2.7.4 and R2.8.2 be revised with wording like, “. . . implementation status of identified Corrective Action Plans for System Facilities and Operating Procedures.” to clarify that the identified system facilities and operating procedures refer only to those that were in the previous year’s Corrective Action Plans. 6. R3.3.1 – The term of ‘controls’ is ambiguous and not defined, unlike the term, ’Protection Systems’, which is defined. Therefore, we suggest that this item be defined or more clearly described to avoid the risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. 7. R3.3.1, bullet #1 - We suggest qualifying which generating units to consider and which voltage limits to simulate with revised wording like, “Trip generating units that are connected to the BES when actual or assumed minimum generator steady state or ride through voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment“. The requirement should not apply to all relevant generating units until one of the MOD standards requires all Generator Owners to provide their minimum generating unit voltage limits to the TP and PC. If the wording of R3.3.1 bullet #1 must be different from its counterpart, R4.3.1 bullet #2, then please explain the reasons for any differences. 8. R3.4.1 – Compliance with the requirement “to coordinate” is problematic and non-measureable We suggest replacing it with the requirement “to communicate”. 9. R3.5 - We interpret that R3.5 requires the TP and PC to conduct an evaluation of possible actions to reduce the likelihood or impact of extreme events, which produce the more severe impacts, if cascading outages may occur. Does the drafting team intend for the TP and PC to fulfill this requirement for at least one event in each of the five categories (i.e. 3 steady state and 2 stability) or in each of the 21 categories/sub-categories (i.e. 14 steady state and 7 stability). Also, if the resulting cascading outages do not result in any overloads, under-voltages, voltage collapse, or loss of generator synchronization, then should the evaluation of possible actions to reduce likelihood or impact be required? 10. R4.1.1 – We suggest that there should be some qualification of which generating units are referred to in this requirement. We propose that the requirement say, “No generating unit connected to the BES shall pull out of synchronism.” For example, some utilities include smaller generation units that are connected at voltages below 100 kV and even down to distribution voltage in their base cases. 11. R4.1.2 – We propose that the wording of this requirement be revised to reflect the same BES qualification of the generating unit that we noted in R4.1.1 above. 12. R4.3.1 – This requirement refers to high speed reclosing and we presume that this is special high speed reclosing that is completed in several cycles, rather than the normal high speed reclosing that is completed in a number of seconds. We recommend that the term high speed reclosing be more clearly defined for this sub-requirement. 13. R5 – This requirement should remove the criterion item, “post-Contingency voltage deviation”, because this criterion is not used widely enough in the industry to be well established criterion. 14. R8 – This requirement should be revised to limit the need to provide the Planning Assessment as follows “adjacent Planning Coordinators and adjacent Transmission Planners and to any registered functional entity…” This suggestion is added to the requirement to clarify that the word adjacent also applies to Transmission Planners and to clarify that the functional entity must be registered in order for the entity to be applicable to the requirement.
Individual
Sergio Garza
LCRA TSC
Yes
Yes
Yes

Yes
No
The first bullet item in Section 3.3.1 should be the same as the second bullet in Section 4.3.1. The wording is somewhat confusing in both. Also, the wording as proposed does not recognize that a high voltage limit could also be violated. Edits to the item as shown below are suggested. Tripping of generators where simulations show generation bus voltages or high side generation step up (GSU) voltages are outside known limits, or assumed to be outside generator steady state limits, or have reached the generator ride through voltage limit. Include in the assessment any assumptions made.
Yes
No
The third bullet of 4.3.1 requires the addition of relay models for stability studies. This type of analysis is performed today by scripting the tripping of multiple lines due to breaker failure events. The inclusion of relay models into the stability study will result in added complexity and an over reliance on relay models for system stability assessment. The stability assessment should assess stability resulting from the operation of relays as opposed to reliance on a relay model for proper system representations. Assurance of the proper operation of relays results from the analysis performed to set relays not from stability studies. From Section 4.3.1: “Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.” Section 4.5 requires that “The rationale for those Contingencies selected for evaluation shall be available as supporting information.” This will have to be developed. Requirement R5 requires the establishment of criteria for transient voltage response of the system. This seems unnecessary given the proposed changes to Table 1. The proposed changes to table 1 seem to make clear the type of system response that is allowable through its specification of what is allowable in terms of interruptions to Firm Transmission and Non-Consequential loads. R5 states: “Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level.”
An important footnote to Table 1 is omitted from this proposed revision. This omission prevents adequate evaluation of the footnote. Footnote 12 in Table 1 is no longer applied to P2.1, P2.2, P2.3, P4, and P5. The footnote states: “Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.” The footnote should be removed from the proposed revision until Project 2010-11 is concluded.
Individual
Saurabh Saksena
National Grid
Yes
No
Year One should be used within the text of the requirement. Do not have a definition for Year One. Year two could be deleted and R.2.1.1 modified as follows: For the Planning Assessment started in a given calendar year, the first year that is studied must include the forecasted peak Load period for one of the following two calendar years. An additional Near-term study must be performed that is four calendar years beyond the first year that is studied.
No
For R1: Ambiguity regarding base case assumptions, in combination with lack of clarity and clear

direction of purpose regarding the sensitivity analysis, undermines the objectives of the standard; R1.1 Part 1.1.2. With respect to known outages, there needs to be greater flexibility in the standards (e.g. more tolerance to non-consequential load shedding or limitations to the contingencies that need to be considered (e.g. P0, P1, & P2)). Regional allowances for load shedding under this condition should be approved. Duration of known outages should be increased from six months to one year; R1.1 Part 1.1.6 Delete "required for Load". Resources may also be used for export to other areas, not just internal load.
No
We can agree with R2.1 however with respect to R2.2 Language should be consistent with 2.1 for example - use "current or qualified past studies" instead of "the following annual current study".
No
If an entity does a stressed set of assumptions do they always need to do a non-stressed case?
Yes
Yes
Yes
In Table 1 – Stability, Make language similar to wording in P5. Protection System should be removed and replaced with the words relay failure. This change should be made for 2a through 2d: 2. Local or wide area events affecting the Transmission System such as: a. 3Ø fault on generator with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. b. 3Ø fault on Transmission circuit with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. c. 3Ø fault on transformer with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. d. 3Ø fault on bus section with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. In Note 11 change wording as shown below: Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for a total of 1 mile or less
Yes
Yes
Other Comments: Section 3.3 - We feel that the last sentence of 3.3.1 should be removed. This is handled by PRC-023. Line ratings are addressed by PRC-023. PRC-023 requires coordination with the Reliability Coordinator. Remove “Tripping of Transmission elements where relay loadability limits are exceeded.” Section 4.3 - High speed reclosing is not defined. We have previously commented on sensitivity analysis and guidance for base case assumptions. Also, extreme event analysis should not be mandated in this standard as no corrective action is required.
Individual
Charles Lawrence
American Transmission Company
Yes
Yes
No
We propose the following changes and questions: R1 – We offer the minor suggestion of replacing the wording of “maintain System models within their respective areas” with “maintain System models of elements that are interconnected to any portion of the BES that is owned or operated by the TP or PC”. This wording would avoid the ambiguity that can occur when a BA that is associated primarily with one TP declares ownership of a bus in another TP’s geographic area, but expects its primary TP to maintain the BA’s model data for the remote generation or load. R1.1.2 – We request a SDT opinion on how two individual outages should be modeled if they are both in excess of six months duration and they overlap by less than six months. Should the overlapping condition only be modeled if the condition is expected to

last more than six months?
No
R2.1.3 – We offer the minor suggestion of revising R2.1.3 to state, “Known outages of generation or Transmission Facilities with a duration of at least six months be simulated along with P1 events for the System peak or Off-Peak conditions when the outages are scheduled to occur.” We interpret that the requirement should only call for the simulation of individual outages with duration of six months or more and not imply the simulation of sequential (back-to-back) outages where each individual outage is less than six months, but the composite duration of the back-to-back outages is more than six months. We also interpret that if two or more known outages with duration of at least six months are overlapping, then the overlapping outage condition would only be simulated for the conditions when the overlapping outages are scheduled to occur if the duration of the overlapping condition is at least six months.
No
R2.1.4 & R2.4.3 – We offer a major suggestion regarding the terms of ‘credible’ and ‘measurable change” because these terms are ambiguous and not defined. So, there is a significant risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. We proposed adding that the TP and PC “shall provide documentation to support the technical rationale for determining the range of credible conditions and measurable change in performance” similar to R2.5. R2.1.4 & R2.4.3 bullet items – We offer the minor suggestion that the number and description of the bullet items in R2.1.4 match the bullet points in R2.4.3. Otherwise, please explain the reasons for any differences between the bullet items in R2.1.4 and R2.4.3. R2.1.4 bullet #7 – We offer the minor suggestion that the term “planned” be replaced with “known” to be consistent with R1.1.2 and R2.1.3. Besides the term “planned outage” has a specific meaning in the Reliability Standards that are specific to the Operating horizon. R2.7.2 – With regard to "include actions to resolve performance deficiencies identified in multiple sensitivity studies", we do not think that mitigation plans should be required for deficiencies found in multiple sensitivity studies because the conditions in sensitivity studies are more extreme and less likely than base case conditions. Some sensitivity study conditions are not credible or plausible enough to warrant the implementation of mitigation measures. What is the SDT interpretation of multiple studies - more than one or a majority of the sensitivities that were studied?
Yes
Yes
No
We offer the major suggestion that Requirements not be created in the Performance Table and be absent from the Requirement section. Requirements should only be referred to in the Performance Table after they already exist in the Requirement section. (a.) Notes “f” and “g” under “Steady State Only” section in the Table 1 header create requirements (e.g. use the verb, “shall”) that do not appear in the Requirements section. We suggest adding R3.3.5, which could read, “Applicable System Operating Limits for the planning horizon shall not be exceeded.” [After R3.3.5 is added, Note “a” should be revised and refer to R3.3.5.]. (b.) Note “i” under “Steady State Only” section in the Table 1 header creates a requirement (e.g. use the verb, “shall”) that does not appear in the Requirements section. We suggest adding R3.3.6, which could read, “The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to steady state voltage requirements.” [After R3.3.6 is added, Note “i” should be revised to refer to R3.3.6.]. (c.) Note “j” under the “Stability Only” section in the Table 1 header creates a requirement (e.g. use the verb, “shall”) that does not appear in the Requirements section. We suggest adding R4.1.4, which could read, “Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner”. [After R4.1.4 is added, Note “j” should be revised to refer to R4.1.4.]
We offer the major suggestion that the P3 Category performance criteria be modified to apply only to the loss of two generators. The SDT properly recognizes that generator outages are significantly more probable than line or transformer outages and should be “higher” in the category list. However given the clearly higher probability of generator outages, the probability of the loss of two generators is clearly

higher than the loss of a generator and line or the loss of a generator and transformer. Therefore, if the loss of two generators is in the P3 category, then the loss of a generator and line or transformer should be clearly “lower” in the category list. We suggest the listing of: the loss of a generator and some other element (e.g. transmission circuit, transformer, shunt device, and single pole of DC line) be moved to a lower event category, such as the P6 Category by adding “1. Generator” to the listing in the Initial System Condition (Loss of . . .) column. We offer the minor suggestion that Item 2.a in the Extreme Events, Steady State section – Clarify the meaning of the loss of multiple circuits in Item 2.a by using wording similar to P7. We suggest this text: “a. Loss of three or more circuits that share a common structure.” We offer the minor suggestion that Footnote 6 – Further clarify the applicable shunt devices in Footnote 6 with this suggested text: “6. Requirements which are applicable to shunt devices, also apply to FACTS devices that are connected to ground, but not instrument voltage transformers or surge arresters.” ATC has significant concerns with Q3.2 (R2.1.4 & R2.4.3), Q4 (Table requirements) and Q5 (P3 scope), as noted above. In addition, ATC offers the following suggestions to promote proper Reliability Standard quality and content. (1.) Revise the Planning Assessment definition to more explicitly apply to the BES and the TPL-001 requirements. We suggest text of: “Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies in the BES from the steady state and stability performance requirements set forth in the TPL-001 standard.” (2.) R2.1.5 – We propose replacing the term ‘major Transmission’ with “BES” because BES is a well defined term, while the term ‘major Transmission‘ is not. (3.) Add R2.3.1 – We suggest the addition of a R2.3.1 requirement to emulate the distinction between the requirement to perform a short circuit assessment and conduct required studies or analysis to support the assessment (e.g. R2.1/R2.1.1 and R2.2/R2.2.1). We propose wording such as, “Perform an analysis for at least one year in the Near Term Transmission Planning Horizon.” This requirement would set an expectation that an analysis should be conducted to at least one or more years in the near-term planning horizon, rather than imply that an analysis of all five years in the near-term planning horizon must be conducted. (4.) R2.7.4 – We suggest that the wording of R2.7.4 be the same as R.2.8.2. Otherwise, we propose that R2.7.4 and R2.8.2 be revised with wording like, “. . . implementation status of identified Corrective Action Plans for System Facilities and Operating Procedures.” to clarify that the identified system facilities and operating procedures refer only to those that were in the previous year’s Corrective Action Plans. (5.) R3.3.1 – The term of ‘controls’ is ambiguous and not defined, unlike the term, ’Protection Systems’, which is defined. Therefore, we suggest that this item be defined or more clearly described to avoid the risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. (6.) R3.3., bullet #1 - We suggest qualifying which generating units to consider and which voltage limits to simulate with revised wording like, “Trip generating units that are connected to the BES when actual or assumed minimum generator steady state or ride through voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment“. The requirement should not apply to all relevant generating units until one of the MOD standards requires all Generator Owners to provide their minimum generating unit voltage limits to the TP and PC. If the wording of R3.3.1, bullet #1 must be different from its counterpart, R4.3.1, then please explain the reasons for any differences. (7.) R3.4.1 – Compliance with the requirement “to coordinate” is problematic and non-measurable. We suggest replacing it with the requirement “to communicate”. (8.) R3.5 - We interpret that R3.5 requires the TP and PC to conduct an evaluation of possible actions to reduce the likelihood or impact of extreme events, which produce the more severe impacts, if cascading outages may occur. Does the drafting team intend for the TP and PC to fulfill this requirement for at least one event in each of the five categories (i.e. 3 steady state and 2 stability) or in each of the 21 categories/sub-categories (i.e. 14 steady state and 7 stability). Also, if the resulting cascading outages do not result in any overloads, under-voltages, voltage collapse, or loss of generator synchronization, then should the evaluation of possible actions to reduce likelihood or impact be required? (9.) R4.1.1 – We suggest that there should be some qualification of which generating units are referred to in this requirement. We propose that the requirement say, “No generating unit connected to the BES shall pull out of synchronism.” For example, some utilities include smaller generation units that are connected at voltages below 100 kV and even down to distribution voltage in their base cases. (10.) R4.1.2 – We propose that the wording of this requirement be revised to reflect the same BES qualification of the generating unit that we noted in R4.1.1 above. (11.) R4.3.1 – This requirement refers to high speed reclosing and we presume that this is special high speed reclosing that is completed in several cycles,

rather than the normal high speed reclosing that is completed in a number of seconds. We recommend that the term high speed reclosing be more clearly defined for this sub-requirement. (12.) R5 – We propose removing the criteria item, “post-Contingency voltage deviation”, because this criterion has not been developed and used widely enough in the industry to be introduced into the standards. (13.) R7 - Revise part of the requirement text to read, “. . . identify each entity’s individual and joint responsibilities . . .“ to provide better clarity. Perhaps this requirement should be listed at the beginning of the Requirements section, instead being mentioned near the end of this section. (14.) Change the forward referencing to backward referencing. We agree with R2.6, R3.1, R3.5, R4.1, and 4.2. However, we suggest that the requirements be ordered so that all of the references refer back to earlier text, rather later text to be consistent with the rest of this standard and other referencing in this standard (e.g. R2.1.3, R2.1.4, R2.4.3, R3, R3.3, R3.5, R4, R4.3, R4.4, R4.5), as well as other standards.
Yes
Yes
Individual
Thad Ness
American Electric Power (AEP)
Yes
Yes
Yes
Yes
R2, Part 2.1 – idicates that ‘qualified’ past studies can be utilized. This is an ambiguous term and we suggest the SDT consider the implications.
Yes
Yes
Yes
Yes
Yes
Yes
Individual
Bill Middaugh
Tri-State Generation & Transmission
Yes
No
Comments: The Year One definition is somewhat clearer now, but there is still some ambiguity. We recommend the removal of the term “Year One, year two, and year five” from R2.1.1. and deletion of the

Year One definition (definitions are not required for year two and year five, for instance). The Year One concept can be integrated into the definition of Near-Term Transmission Planning Horizon, which we suggest changing to “The period beginning with the first year following the operating horizon, as determined by the Transmission Planner or Planning Coordinator, through the fifth year.” Then, rather than say “Year One, year two, and year five”, we can use the phrase “at least one of the first two years of the Near-Term Transmission Planning Horizon, and the fifth year”. This will require corresponding changes in R2.1.1 and R2.1.2.
No
We suggest changing the added sentence to “This establishes the Category P0, No Contingency, Initial System Conditions in Table 1.”
No
2.1.5 – Change “shall be performed for” to “shall have been performed for.”
Yes
No
Rather than specifically call out induction motor loads, we recommend changing the second sentence to “Stability analysis shall include models that represent the expected dynamic behavior of system elements that could impact the study area.”
Yes
Yes
Table 1, P5 does not seem to account for redundant relays in the Protection System to mitigate potential relay failure. We recommend changing the “Event” to “Delayed Fault Clearing due to the failure of a relay to operate as designed, if that is the only relay protecting the Faulted element, for one of the following:” In Table 1, P2 and P3, the last column “Non-Consequential Load Loss Allowed” where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote “b”. This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote “b” in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, “Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.” Timing of this project and project 2010-11 is critical. It would be very difficult to vote to approve the proposed TPL-001-2 prior to knowing the outcome of Project 2010-11 (footnote b issue). Second, we are unclear why voltage relays are included in footnote 13 and think they can be removed. Third, in the Extreme Events – Stability section of Table 1, items 2a-2d “Protection System failure” should be changed to “relay failure” to be consistent with Table 1, Category P5.
Yes
Yes
None regarding R8. The following comments refer to parts of the proposed standard for which no questions are asked. R4, Part 4.1.2: The response to our previous comment indicated that our description was for a system Stability issue. R4 is addressing system Stability and we believe the

comment still applies and that it was not answered in the response. We have two issues with 4.1.2: Sometimes out-of-step (loss of generator synchronism) is better mitigated through islanding by tripping transmission rather than by tripping generators; the second point is that the ability of present modeling programs does not include the capability to model all types of impedance relays and their associated OOS blocking and tripping capabilities that are available. R4, Part 4.3.1: The third bullet implies that all impedance relays (and perhaps others) will need to be modeled in the stability databases. We question whether the existing simulation programs can accommodate this large magnitude of data inclusion and whether there is any benefit to BES reliability. Certainly using generic models rather than actual models would be of no benefit. We recommend changing the third bullet to “Evaluation of Protection System behavior when transient power swings are detected or predicted to have impedance characteristics that may approach relay operating characteristics.”
Individual
David Miller
Lakeland Electric
Yes
No
While the definition of Year One addresses the time span this year occupies, it does not address when that time span begins. The example which was added to the definition suggests that Year One begins twelve months from the start of the Planning Assessment, but it does not appear to be specifically stated. The following language is recommended: "The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing, beginning twelve months from the planned completion date of the Planning Assessment."
No
Consider removing “…the latest…” from R1 and changing R1.1.2 to state “…six months during the period of study.”
No
No, the phrase any material changes used in requirement R.2.6.2 will effectively cause all Planning Authorities to run all studies every year regardless of minor changes in the model. The overwhelming majority of PAs use a 10 year set of planning models developed annually by Regions or Subregions. These annual sets of planning models will always have some changes. The annual study requirement is especially problematic for Stability and Short circuit studies that require much more engineering time to complete and are much less likely to have results impacted by minor model changes such as different load forecasts. Uncertainty with audit review of technical rationale documentation will serve to focus Transmission Planning engineering resources on short term compliance to an extent that is counter productive. Please consider removing R.2.6.2
No
It is recommended that the phrase “…measureable change in performance…” be changed to “…measurable change in system response…” A change in performance is unclear, and could suggest that a sensitivity study is valid only if the System is stressed to the point that it no longer performs within the criteria established by Table 1. In addition, it is recommended that the following text appear after the last sentence of 2.4.3: “The condition or conditions to be varied shall be left to the discretion of the Transmission Planner or Planning Coordinator, provided they are selected from the list below.”
Yes
Yes
Yes
The performance requirements of Table 1 do not allow the loss of non-consequential load for single and multiple contingency events. The disallowance of load loss does not provide any real benefit to the

reliability of the BES and is an unnecessary overreach into local quality of service issues that are best addressed by State, Provincial or Municipal authorities. There may be circumstances such as high local transmission costs or local opposition to transmission construction where prohibition of non-consequential load loss represents a poor cost/benefit or quality of life tradeoff. Having a provision at the regional level that a PA or TP can have a certain amount of non-consequential load loss designed or planned in to its system that would be reasonable if it is acceptable to the RE and does not have an adverse impact on the remaining BES. In lieu of such a RE provision, providing a quantitative cap in non-consequential load loss such as 100 MW may be rationale compromise in the goal of limiting load loss for the more probable outage events. Our preference would be to retain the capability of limited non-consequential load loss. It is our understanding that footnote 9 is under consideration as part of Project 2010-11 and should be noted as such for clarification.
No
Consider removing “the latest” from M1.
No
The requirement to distribute the Planning Assessment should be more flexible and allow for making the Planning Assessment available, such that those entities that desire the information can have it readily available. R8 should be modified as follows: Each Planning Coordinator and Transmission Planner shall make available its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.
Group
E.ON U.S.
Brent.Ingebrigtson@eon-us.com
No
Comments: 2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected. E.ON U.S. believes the scope of the ‘current study’ should be defined. It is not clear whether the scope is the same as outlined in section 2.1.
No
In the statement: “the Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.” E.ON U.S. believes that the use of the pronoun “their” in the quoted section above is confusing. “Their” could be read as applying to the adjacent Planning Coordinators and not to the Planning Coordinator to whom the standard applies. E.ON U.S. recommends that the word “their” should be changed to “the Planning Coordinator’s and Transmission Planner’s” in order to make it clear.
E.ON U.S. believes that Table 1 should be formatted to avoid having the tables split by page breakers. In addition, tables spanning across multiple pages should have headers at the top of each page.
Individual
Steve Stafford
GTC
Yes

Yes
Yes
Yes
Yes
No
We have concerns for including induction motor representations in the load models without any study or bench-marking activities to meet the requirements of R2.4.1. This information should be supplied by the LSE as part of the MOD standard. We understand that the proposed standard will accept an aggregate system load model which represents the overall dynamic behavior of the load to relieve the burden of trying to develop specific induction motor load representation at each load bus. However this modeled system response will be considerably different compared to the actual system response which will open up the industry to unwarranted scrutiny and possible compliance violation investigations.
Yes
Yes
Yes
Yes
Individual
Chifong Thomas
Pacific Gas and Electric Company
Yes
We commend the SDT for its work to continue the improvement on the proposed TPL-001-1. We were not able to find a place to include comment on Requirement R3 or R4; therefore, we have included our comments here: Section R4.3.1, bullet point 3 requires the stability analyses to include the impact of subsequent “[t]ripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models”. As written, this bullet could be interpreted as requiring the inclusion of these relay models in stability data bases. We do not have generic or actual relay models in our dynamics data bases for tripping line faults on lines and transformers represented. We represent actual relay response and tripping times of relays, communications, and breakers to faults in tripping transmission lines and transformers. Requiring the inclusion of generic or actual relay models for all relays that can trip lines and transformers would add a large burden to the development and maintenance of accurate dynamics model files that would add little or no benefit. Please change this bullet to read: “Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on known Protection System response”. Section 3.4.1 and 4.4.1 require PCs and TPs to coordinate with adjacent PCs and TPs to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. Please clarify whether this means 1) that a PC or TP must coordinate with others to identify contingencies on other Systems that the PC or TP must now include on their Contingency list to simulate and address any performance violations on their own System, or 2) that the PC or TP must coordinate with others to identify contingencies on their System that this PC or TP must now include on their Contingency list to simulate and address any performance violations on the other Systems. In either case, the standard does not seem to clearly state what must be done, or whose responsibility it is to develop the corrective action plan, if a contingency in

one System causes a performance violation in another System.
We recognize that the drafting team made changes to the definition of Year One based on industry comments. However, we believe that the revised language could allow for a situation where an entity could use its next season's operating study as its Year One planning study. For example, if the entity does its study in the fall of 2011, the proposed definition would allow the entity to use its summer 2012 operating study as its Year One study. This is a very short period to address any issued identified. Suggest working into the requirement that Planning Studies must look out at least 12 months beyond when the study is performed. This would still allow for the provision in the current definition example ("if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013) because the entity would be able to use their 2013 Load period, but it would prevent the entity from using the 2012 Load period if they started the assessment late in 2011.
Yes
Yes
Yes
Yes
Yes
PG&E does not support the performance table, as currently revised. Table 1, P5 currently requires the study of "[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed". As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: "Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following". In Table 1, P2 and P3, the last column "Non-Consequential Load Loss Allowed" where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote "b". This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote "b" in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, "Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers." Timing of this project and project 2010-11 is critical. It would be very difficult to vote to approve the proposed TPL-001-2 prior to knowing the outcome of Project 2010-11 (footnote b issue).
Yes
Yes

Group
Florida Reliability Coordinating Council, Inc - Transmission Working Group
Richard BEcker
Yes
No
No, because it is worded to be dependent upon when an assessment is started rather than when the assessment is completed and valid. Assessments don't typically include a "start date". An assessment completed on a calendar date should include (be valid for) the forecasted peak load for a timeframe that begins no more than 24 months from the date that the assessment was completed.
No
No, Since "the latest" data may become available after the study is complete, a planner may not be able to ever complete a study. Please consider removing "the latest" from the second sentence.
No
No, Please consider removing R.2.6.2. The overwhelming majority of PAs use a 10 year set of planning models developed annually by Regions or Subregions. These annual sets of planning models will always have some changes. The annual study requirement is especially problematic for Stability and Short circuit studies that require much more engineering time to complete and are much less likely to have results impacted by minor model changes such as different load forecasts. Uncertainty with audit review of technical rationale documentation will serve to focus Transmission Planning engineering resources on short term compliance to an extent that is counter productive.
No
This change does not clarify the required sensitivity analysis. A measureable change in performance is unclear? Instead of a measurable change in performance, a measureable change in contingency response of the Bulk Electric System would be more appropriate. A change in performance implies not meeting one of the performance requirements as specified in Table 1.
Yes
No
This change does not clarify material. Material should be quantified somehow. We recommend changing the phrase "material generation additions or changes" to "generation in the vicinity with additions of changes larger than 200 MW".
Yes
We support the changes to the performance tables.
Footnote 12 performance requirements of Table 1 should allow the loss of non-consequential load for all contingency categories except for P0. The disallowance of load loss does not provide any real benefit to the reliability of the BES and is an unnecessary overreach into local quality of service issues that are best addressed by State, Provincial or Municipal authorities. There may be circumstances such as high local transmission costs or local opposition to transmission construction where prohibition of non-consequential load loss represents a poor cost/benefit or quality of life tradeoff. Having a provision at the regional level that a PA or TP can have a certain amount of non-consequential load loss designed or planned in to its system that would be reasonable if it is acceptable to the RE and does not have an adverse impact on the remaining BES. In lieu of such a RE provision, providing a quantitative cap in non-consequential load loss such as 100 MW may be rationale compromise in the goal of limiting load loss for the more probable outage events. Our preference would be to retain the capability of limited non-consequential load loss. Footnote 9 should also be under consideration as part of Project 2010-11 and should be noted as such for clarification.
No
It appears that there is a disagreement between R8 and M8, regarding public posting. We Agree with M8 posting option.
No

The requirement to distribute the Planning Assessment should be more flexible and allow for making the Planning Assessment available, such that those entities that desire the information can have it readily available. R8 should be modified to replace distribute with “make available:, so the new requirement would read as follows: Each Planning Coordinator and Transmission Planner shall make available its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.
Individual
Michael R. Lombardi
Northeast Utilities
Yes
No
NU does not support the revised definition of Year One as we believe it leads to confusion. Our suggestion is that Year One should be the Peak Load Year after the study is initiated. The subsequent years should be counted from Year One (e.g., a study that is started in year 2010 with peak load in 2011 will have Year One as 2011 and Year Two as 2012, etc.).
No
NU believes that the Normal System Conditions as stated in Requirement R1 should establish the base case conditions to be used for the assessment studies. More guidelines for developing base cases should be addressed in the requirements. What the statement in Requirement R1 lacks is the manner of creating generation dispatches and the level of interface flows (level of stress), which are central to any base case to be used to assess the reliability of the electric power network. Depending upon how the base case dispatches and the level of interface flows are created, a study may reveal reliability violations in the power system. This is a weakness of the existing TPL standards. NU, however, will support the idea of developing regional guidelines in regard to the nature of the base cases to be used for the NERC reliability studies. Comment on Requirement R1.1, Part 1.1.2: With respect to known outages NU requests that the six month duration listed by the requirement should be changed to one year duration. Requirement R1.1 Part 1.1.6: The phrase "required for Load" should be deleted as this confuses the issue [since resources may also be used for export to other areas and not just internal load].
No
The revisions made to Requirement R2 Part 2.1 appear to resolve the concern that past studies could not be used to comply with the short-term steady state study requirements. However, the language of Requirement R2 Part 2.2 still seems to suggest that current annual studies are always required for the long-term steady state assessment to be compliant. This may have been an oversight, for consistency Requirement R2 Part 2.2 should be modified to similarly read as Requirement R2, Part 2.1.
No
The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions as commented in Question #3. The standard must describe base assumptions. To define a sensitivity condition, NERC must define base assumptions.
Yes
Yes
Yes
Checked "No" NU agrees with the changes that have been made to the language of P5. However, for Table 1 (Steady State and Stability Performance Extreme Events) – Stability, the wording “Protection Systems failure” should be changed to “relay failure” similarly to the change in P5. This change should be made for items 2a through 2d.
Yes

Yes
No comments on Question 7. Other Comments: As detailed below, NU has other comments that are not addressed by this Comment Form as follows – Section 3.3, Section 4.3, Non-Consequential Load Loss as referenced in the events Table 1 and studies using extreme event contingencies. Section 3.3 – NU believes that the last sentence of Part 3.3.1 should be removed since this is handled by PRC-023. Line ratings are addressed by PRC-023 which requires coordination with the Reliability Coordinator. NU suggests the removal of the following sentence: "Tripping of Transmission elements where relay loadability limits are exceeded." Section 4.3 - High speed reclosing is not defined and to help eliminate any confusion that it may introduce into the standard it will be worthwhile for the SDT to define this term. Non-Consequential Load Loss – Depending upon the resolution of "Project 2010-11, TPL Table 1, Footnote b" NU may have additional comments regarding this issue. Studies Using Extreme Event Contingencies: The requirements for sensitivity analysis already address issues going beyond what is expected to meet the reliability requirements of the standard. Therefore, requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if a concern is identified.
Individual
Christopher L. de Graffenried
Consolidated Edison Co. of New York, Inc.
No
Requirement R1 Part 1.1 and following states "System models shall represent:… 1.1.5. Known commitments for firm Transmission Service and Interchange. It was commented during a previous posting that 1.1.5 should be reworded to read: Known commitments for Firm Transmission Service, and, additionally, other types of transactions provided they have been demonstrated to not violate existing reliability constraints. The response was that "The SDT believes that the defined term 'Interchange' covers other transfers as described in your comment. No change made." It is agreed that known Interchange should be modeled. However, it is imperative that existing reliability constraints not be violated in the process. That is, Interchange relating to economic transactions should not drive planning studies. Reliability-related investments should not be driven by congestion related to economic transactions incorporated into planning models. Con Edison's Preferred approach: • 1.1.5. Known commitments for firm Transmission Service and Interchange. Interchange is meant to refer to energy transactions other than firm Transmission Service. While rigorous planning studies have been conducted to permit the uninterrupted implementation of firm Transmission Service without jeopardizing the reliable operation of the Interconnected System, other types of energy transaction only take place whenever system conditions permit them. They are usually of very short duration relative to planning assessment periods (usually spanning for a few hours to a few days) and deemed highly interruptible subject to reliability issues that may arise during operation of the system. In other words, the term Interchange refers to economic transactions that are permitted when the system is secure and there are reasonable reliability margins to effect dispatch changes to lower operating costs. As such, Interchange should not be reflected in system representation meant to assess system reliability in adherence to reliability criteria delineated in documents such as TPL-001.
No
See NPCC comments
Yes
No
See NPCC comments
No
See NPCC comments
No
There is insufficient information and experience regarding dynamic load modeling. It may also be included as a "sensitivity" analysis in 3.2, rather than requiring and expecting accurate representation of a dynamic load model. If this requirement is kept, a modeling standard should be written that is specific

to dynamic loads. This change belongs in a modeling standard, not in TPL-001.
Yes
No
• Header note (i) in the first Table 1 (p. 10) The explicit representation of (voltage-dependent) load models is perfectly consistent with the requirements defined in R1 (which calls for a comprehensive representation of system components and their expected operating status in the planning assessment period) and the impetus to the creation of more specific load models in dynamic assessments found Requirement 2.4 of this draft of TPL-001-2. It is a known that depressed voltage conditions cause certain system elements to perform below their rated capacity. For example, capacitors provide less voltage support and voltage controlling transformers are impeded by their finite tap range to direct VAR flow into areas affected by low voltage conditions. Certain load types, on the other hand, provide a self-compensating relief to depressed voltage by naturally decreasing demand in a manner proportional to their characteristics, without operator intervention. Choosing to negate the voltage-dependence of one of these system elements (load, in this case) results in an inaccurate system representation that, in turn, may lead to erroneous assessments of the reliability state of the interconnected system and, potentially, to the implementation of unwarranted system upgrades.
See NPCC comments
Yes
No
See NPCC comments
Individual
Spencer Tacke
Modesto Irrigation District
Yes
We commend the SDT for its work to continue the improvement on the proposed TPL-001-1. We were not able to find a place to include comment on Requirement R4; therefore, we have included our comments here: Section R4.3.1, bullet point 3 requires the stability analyses to include the impact of subsequent “[t]ripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models”. As written, this bullet could be interpreted as requiring the inclusion of these relay models in stability data bases. We do not have generic or actual relay models in our dynamics data bases for tripping line faults on lines and transformers represented. We represent actual relay response and tripping times of relays, communications, and breakers to faults in tripping transmission lines and transformers. Requiring the inclusion of generic or actual relay models for all relays that can trip lines and transformers would add a large burden to the development and maintenance of accurate dynamics model files that would add little or no benefit. Please change this bullet to read: “Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on known Protection System response”.
No
The definition as it is in the current standards is fine. The new proposed definition is unclear.
Yes
Yes
No
This new requirement will expand the scope of the study work beyond a reasonable extent.
Yes

Yes
Table 1, P5 currently requires the study of “[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed”. As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: “Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following”. In Table 1, P2 and P3, the last column “Non-Consequential Load Loss Allowed” where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote “b”. This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote “b” in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, “Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.” Timing of this project and project 2010-11 is critical. It would be very difficult to vote to approve the proposed TPL-001-2 prior to knowing the outcome of Project 2010-11 (footnote b issue).
Group
Pepco Holings, Inc - Affiliates
Richard Kafka
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes

Yes
Individual
Alex Rost
NBSO
Yes
No
To avoid confusion, the formal definition for Year One should be eliminated and wording used to describe Year One be placed within the appropriate requirement. For example, R2.1.1 could be re-written to state: System peak Load representing a point in time 12-24 months and another point in time 48-65 months into the future from the time the study is initiated.
No
R1 should have some language to state that base case assumptions should be made such that they appropriately stress the system to be tested and are in accordance with good engineering practice.
No
NBSO agrees with the language for R2.1, but the language with R2.2 should be changed to be consistent with R2.1. NBSO disagrees with the revisions to R2.1.5. Requiring PAs to study instead of assess the possible unavailability of equipment with a lead time of a year or more will result in significant demand on resources with little impact on system reliability. NBSO also questions what additional value such studies will bring in addition to the N-1-1 requirements (P6).
No
Base case assumptions should be made such that they appropriately stress the system to be tested and are in accordance with good engineering practice. If the base cases are already stressed, the requirement to study sensitivity cases may result in the study of less severe conditions, and thus require additional time and resources while providing little additional value to the overall assessment.
No
By implication, the response of induction motor load would need to be considered when modeling the expected dynamic behaviour of loads that could impact the study area. NBSO suggests re-wording parts of R2.4.1 as follows: System peak load levels shall include a model which represents the expected dynamic behaviour of loads that could impact the study area. An aggregate system load model which represents the overall expected dynamic behaviour of load is acceptable.
Yes
Yes
For consistency, 'Protection System' should be replaced with 'relay' on Table 1 (p12) Stability Section, items 2a-2d.
Yes
Yes
NBSO suggests considering rewording the VSL so that they address the failure to distribute the final results of planning assessments.
Individual
Curtis A. Beveridge
Central Maine Power Company
Yes

No
The added clarification to the definition of Year One serves to remove most ambiguity with respect to Year One. However, the revision has added further ambiguity to the terms “year two” and “year five” which are not defined. For the Planning Assessment started in a given calendar year, the first year that is studied must include the forecasted peak Load period for one of the following two calendar years. An additional Near-term study must be performed that is four calendar years beyond the first year that is studied. We recommend defining Year Five as the twelve month period 4 to 6 calendar years from the date of the Planning Assessment. We further recommend revising R2.1.1 as follows: “System peak Load for Year One and for Year Five.” Alternatively, the definition of Year One could be eliminated and described within the text of the requirements.
No
For R1 Ambiguity regarding base case assumptions, in combination with lack of clarity and clear direction of purpose regarding the sensitivity analysis, undermines the objectives of the standard; R1.1 Part 1.1.2. With respect to known outages, there needs to be greater flexibility in the standards (e.g. more tolerance to non-consequential load shedding or limitations to the contingencies that need to be considered (e.g. P0, P1, & P2)). Regional allowances for load shedding under this condition should be approved. Duration of known outages should be increased from six months to one year; R1.1 Part 1.1.6 Delete "required for Load". Resources may also be used for export to other areas, not just internal load.
No
We completely agree with the revision to R2.1, but this revision must be carried through to other sections (R2.2, 2.2.1) and R2.2 language should be consistent with 2.1 for example - use "current or qualified past studies" instead of "the following annual current study". Revisions made to Requirement R2.1.5 have made it worse than as originally drafted. This would require the PC & TP to study, or in other words perform technical analysis of, the impact and probability of the possible unavailability of any piece of equipment with a lead time of one year or more. Such an evaluation of spare equipment strategies would require significant additional resources and data, but provide no benefit to system reliability, as it is redundant to the existing N-1-1 contingency requirement (P6).
No
These sensitivities need to be considered if not already included in the base case assumptions.
No
We have not determined a need to model dynamic loads, and therefore have not benchmarked any such models. We recommend that prior to this requirement being in place, a modeling standard should exist that is specific to dynamic loads.
Yes
No
Header note (i) in the first Table 1 could imply that voltage-varying load shall not be used to meet steady state performance requirements. NYISO steady state load models include voltage-varying loads. This note should be revised to only reference loads which are disconnected due to voltage.
In Table 1 – Stability, Make language similar to wording in P5. Protection System should be removed and replaced with the words relay failure. This change should be made for 2a through 2d: 2. Local or wide area events affecting the Transmission System such as: a. 3Ø fault on generator with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. b. 3Ø fault on Transmission circuit with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. c. 3Ø fault on transformer with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. d. 3Ø fault on bus section with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. In Note 11 change wording as shown below to include the words “a total of”: Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for a total of 1 mile or less
Yes
No

Requirement 8 is an administrative burden to TPs and PCs that adds no value to reliability. PCs should be including TPs, neighboring PCs and interested parties in its planning processes when developing the Planning Assessments. Therefore, the inclusion of a set of VSLs for Requirement 8 is unnecessary. Furthermore, the requirement lacks a specified time frame to receive comments, thereby implying that TPs and PCs would be required to reply to comments forever following the finalization of a Planning Assessment. The NYISO proposes a limit of six months. Should the SDT decide to leave the VSLs for Requirement 8, Requirement 8.1 should be revised to reflect that comments only to the final Assessment (not drafts developed during a process) need a response as follows: If a recipient of the planning assessment final results provides documented comments on the results within 180 calendar days of the issuance of those final results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments. We also have other comments not addressed by this Comment Form as follows – Section 2.7, Section 3.3, Section 4.3, and overall: Section 2.7 requires that Corrective Action Plans are included in each Planning Assessment and states “Such actions may include…” followed by a list of actions. Restricting allowable actions, and excluding runback/tripping of HVDC would have a direct impact on multiple existing facilities in New York and would adversely impact the reliability planning of the NYCA. Runback/tripping of HVDC must be added to the list. Section 3.3 - We feel that the last sentence of 3.3.1 should be removed. This is handled by PRC-023. Line ratings are addressed by PRC-023. PRC-023 requires coordination with the Reliability Coordinator. Remove “Tripping of Transmission elements where relay loadability limits are exceeded.” Section 4.3 - High speed reclosing is not defined. Overall – We have previously made comments which have not been addressed in the current version of the proposed standard. Support for the standard can at most be limited without addressing comments. We have previously commented on sensitivity analysis and guidance for base case assumptions. Also, extreme event analysis should not be mandated in this standard as no corrective action is required. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required, and there is no requirement for corrective action if anything is identified. The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions. The standard must describe base assumptions. To define a sensitivity condition, NERC must define base assumptions.

Group

Western Area Power Administration

Brandy A. Dunn

Yes

The whole bullet point section in the Effective Date section referring to Corrective Action Plans could be deleted and instead captured by Requirement R2.7.3. A seven year grace period is probably not favorable to FERC, and a better solution could be developed to meet industry needs. In R2.7.3, a possible example of "beyond the control of the Transmission Planner" could be that the physics of a significant percentage of induction motors in low inertia air-conditioning loads would tend to pull out for certain N-1 events. This may in significant part occur because such motors may have nearly no dynamic stability margin to withstand such N-1 events as close-in 3-phase faults with normal clearing during peak load conditions. So until the Transmission Planner has been able to institute changes in the industry to address the basic physics of such loads, this Requirement 2.7.3 would permit the use of such "Non-Consequential" Load Loss and curtailment of Firm Transmission Service. In this example, it may take longer than a seven year time period to fix the problem. On the other hand, some examples of Non-Consequential Load Loss could perhaps be mitigated in a shorter timeframe. Provided that an entity has a good technical justification and defined margin for “Non-Consequential” Load Loss or curtailment of Firm Transfers, then it may be acceptable. Requirement R2.7.3 seems to move in this direction. Section R4.3.1, bullet point 3 requires the stability analyses to include the impact of subsequent “[t]ripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models”. As written, this bullet could be interpreted as requiring the inclusion of these relay models in stability data bases. We do not have generic or actual relay models in our dynamics data bases for tripping line faults on lines and transformers represented. We represent actual relay response and tripping times of relays, communications, and breakers to faults in tripping

transmission lines and transformers. Requiring the inclusion of generic or actual relay models for all relays that can trip lines and transformers would add a large burden to the development and maintenance of accurate dynamics model files that would add little or no benefit. Please change this bullet to read: “Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on known Protection System response”.

Yes

Yes, this clarification helps. The drafting team could also define “year five”.

No

It’s difficult to tell whether Requirement R1 is intended to require only one base case or whether it was intended to require creation of separate models for each possible N-0 condition (“normal system condition”) under a variety of stressing scenarios. The inserted language does not seem to provide additional clarity. Suggested language may be ”This establishes the initial 'Normal System' condition corresponding to category P0 in Table 1.” Also, in Requirement R1.1.5, how are the Firm Transmission Service commitments supposed to be modeled in Power Flow Cases? Are they just to be modeled as loads, generation, and control area interchanges? Suppose a POR or POD is not at a generator or load bus. What selection of generation and load would represent the projected system conditions for this Firm Transmission Service commitment?

No

R 2.1.5: The issue in this Requirement is studied in the Operations next-day; next-week; next-month studies required under the TOP Standards; and are also covered by processes such as the Operational Transfer Capability Policy Committee (OTCPC) seasonal study process within the WECC. It would be quite onerous to run a complete power flow simulation on separate base cases for each transformer (or other equipment with long lead time) initially out of service. The revision in language from “Planning Assessment” to “studies” does not clarify that a power flow simulation is not necessarily required for each situation. A valid assessment could include other methods such as using sound technical reasoning to relate the initial out-of-service condition to a condition that has already been studied. This condition may have taken place in previous operational studies. The language in the standard could be improved to make this clarification – perhaps reference R2.6. Additionally, this Requirement still needs further clarification. Currently the scope of equipment applicable to the requirement could be misinterpreted as larger than that contemplated by FERC. The standard as written seems to say that the responsible entity needs to study the spare equipment strategy for all "major transmission equipment" with long lead times. In the directive to include this requirement, FERC used the term "critical facilities". In the NOPR to Order No. 693 they stated, "Critical facilities are those facilities that impact IROLs and deliverability of generation to firm load" (P1081). In Order No. 693 FERC also said, "if an entity’s spare equipment strategy for the permanent loss of a transformer is to use a 'hot spare' or to relocate a transformer from another location in a timely manner, the outage of the transformer need not be assessed under peak system conditions" (P1725). Finally, the drafting team could clarify if this requirement applies to radial branches (such as generator step-ups or step-down to load). Such branches may be construed as “critical facilities” but the impediment to deliverability of generation to firm load is consequential to the initial outage.

Yes

In Requirement 2.1.4, "Sensitivity Analysis”. How much change does it take in any of the modeling assumptions (load, generation, voltage support, topology, etc.) to significantly stress the system within a range of credible condition? As this Requirement relates to R2.7, Would it be necessary to have Corrective Action Plan(s) if needed to meet all the Sensitivity Cases? How many Sensitivities before must have Corrective Action Plan? Also – why is it essential to use the qualifier “annual” for “current studies” in Part 2.1? Can a study be considered current if it is conducted less frequently than once per year? Note that Parts 2.3, 2.4 and 2.5 do not use the “annual” qualifier, nor does Requirement R2. Recommend deleting this apparently non-essential qualifier in both R2.1 and R2.2. We are unable to appreciate why the wording in Part 2.3 is not consistent with that in Part 2.1, 2.2, 2.4 or 2.5. Note that the semantics of the wording “… (steady state / stability) analysis shall be assessed annually…” can be interpreted to be much different than the semantics of the Part 2.3 wording “The short circuit analysis…. shall be conducted annually …”. The former requires the analysis to be *assessed* annually but 2.3 requires the analysis to be *conducted* annually without explicitly requiring it be assessed –- is the usage

of “conducted” instead of ‘assessed” consistent with the intent? In Part 2.6.2, the intent is awkwardly conveyed within the phrase “…the System represented in the study shall not include any material changes unless…”. In the context of a *past* study, how can the System represented possibly include any material changes (that would have presumably occurred after the study)? Suggest modifying Part 2.6.2 to read “For steady state, short circuit or Stability analysis: no material changes have occurred in the System represented in the study or, if material changes have occurred, a technical rationale shall be provided to explain why they do not significantly impact the study results.”

Yes

Yes

The drafting team could provide guidance on what is "material". In Part 2.5, should “annually” be inserted after “shall be assessed” to make it consistent with Parts 2.1, 2.2, 2.3 and 2.4? If the omission is intentional in 2.5, please explain why.

Yes

Following is a suggested re-ordering of header notes to replace of the three categories concept – same information: a. Applicable Facility Ratings shall not be exceeded. The System shall remain stable. Cascading and uncontrolled islanding shall not occur. b. Planning event P0 is applicable to steady state only. c. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event except P0. d. The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment as a consequence of any event shall not be used to meet steady state performance requirements. e. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits established by the Planning Coordinator and Transmission Planner. f. Transient voltage response shall be within acceptable limits as established by the Planning Coordinator and Transmission Planner. g. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. h. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event. Simulate Normal Clearing unless otherwise specified.

In footnotes 9 and 12, two critical issues are being addressed in large part via these "clarifying" footnotes. These are curtailment of "Firm Transmission Service" (which seems primarily to be a contract/scheduling issue) and the loss of "Non-Consequential Load." Perhaps these issues should receive more attention in the actual requirements. In P5 the term “Protection System” was removed and replaced with “relay”. How are protection system elements other than relays accounted for? In studying a multiple contingency event with a communication system or control circuitry failure would it be necessary demonstrate P1 performance levels? These details could become critical as industry deals with issues such as FERC’s interpretation of TPL-002-0 Requirement R1.3.10 (RM10-6-000). In Table 1 – Extreme Events – Stability – Items 2a-2d, change “Protection System failure” to “relay failure” to be consistent with changes in P5. Table 1, P5 currently requires the study of “[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed”. As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: “Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following”. Footnote 13 – Delete “voltage (#27, #59)” since the under/over voltage relays are not called upon to provide the primary protection for fault clearing on Transmission elements. Suggest modifying Event P4 description to be more consistent with Event P5 description by including Delayed Fault Clearing in the description in lieu of “Loss of multiple elements”. Suggested Event P4 description is: “Delayed Fault Clearing caused by a stuck non Bus-tie Breaker attempting to clear a fault on one of the following:” In Table 1, P2 and P3, the last column “Non-Consequential Load Loss Allowed” where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed

in the existing TPL-002-0, footnote “b”. This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote “b” in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, “Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.” Timing of this project and project 2010-11 is critical. It would be very difficult to vote to approve the proposed TPL-001-2 prior to knowing the outcome of Project 2010-11 (footnote b issue).
Yes
Yes
Individual
Darryl Curtis
Oncor Electric Delivery
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Group
IRC Standards Review Committee
Ben Li
Yes
Yes

Yes
Yes
No
The primary concern involves wording under 2.1.4 and 2.4.3 that sensitivities are required by varying one or more conditions. Subsequently, in requirement 2.7.2 corrective action plans need to be developed to resolve performance deficiencies “only” if identified in multiple conditions or require a rationalization why no corrective action plan is necessary. Multiple conditions sensitivities under 2.1.4 and 2.4.3 are necessary to satisfy requirement 2.7.2. Requirement 2.7.2 adds ambiguity and should be removed. Alternatively, Requirement 2.7.2 could be revised as follows: 2.7.2. Corrective Action Plans are not required for performance deficiencies identified in a sensitivity analysis. If a Planning Coordinator includes Corrective Action Plans to resolve performance deficiencies identified in multiple sensitivity analysis, the Planning Coordinator shall provide documentation to support those Plans.
Yes
Yes
However, the requirement infers that a subjective judgment from a compliance auditor will be required.
Yes
Yes
No
(AESO is not a party to the following comments since its VSLs are set by the Alberta regulatory authority.) Requirement 8 is an administrative burden to TPs and PCs that adds no value to reliability. PCs should be including TPs, neighboring PCs and interested parties in its planning processes when developing the Planning Assessments. Therefore, the inclusion of a set of VSLs for Requirement 8 is unnecessary. Should the SDT decide to leave the VSLs for Requirement 8, Requirement 8.1 should be revised to reflect that comments only to the final Assessment (not drafts developed during a process) need a response as follows: 8.1 If a recipient of the planning assessment final results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments. For a Planning Coordinator (PC) who distributes the Planning Assessment to many different entities (to adjacent PCs, TPs, and other functional entities), a concern regarding the Requirement R8 VSL is that it is overly restrictive to apply a violation for failing to distribute the results of its Planning Assessment to only one PC, TP, or functional entity (and to apply a High VSL for failing to distribute to more than one entity), particularly since an entity’s contact is subject to change over time, and since Measure M8 allows for publicly posting the results of its Planning Assessment to its website. Should the SDT decide to include the VSLs for Requirement 8, we would recommend revising to use a percentage approach rather than applying a violation to a Planning Coordinator who fails to provide the results of its Planning Assessment to one PC, TP, or other functional entity (or applying a High VSL for failing to distribute to more than one entity.) Recommend applying a similar percentage approach to the VSLs drafted by NERC Staff for Project #2007-23 VSLs (e.g., for FAC-013-1) to be considered for the TPL-001-2 R8 VSLs. For example, • Lower VSL: The responsible entity failed to provide the Planning Assessment final results to 5% or less of the required entities. • Moderate VSL: The responsible entity failed to provide the Planning Assessment final results to more than 5% up to (and including) 10% of the required entities. • High VSL: The responsible entity failed to provide the Planning Assessment final results to more than 10% up to (and including) 15% of the required entities. • Severe VSL: The responsible entity failed to provide the Planning Assessment final results to more than 15% of the required entities OR [the existing language for the Severe VSL]. Explanation: The VSLs were modified for consistency with other standards and VSLs. Reference: Link to VSLs drafted by NERC Staff for

Project #2007-23 VSLs (e.g., for FAC-013-1): http://www.nerc.com/docs/standards/sar/Staff_Proposed_VSLs_2010July27.pdf
Individual
Jeffrey McKinney
New York State Electric & Gas Corp
Yes
No
The added clarification to the definition of Year One serves to remove most ambiguity with respect to Year One. However, the revision has added further ambiguity to the terms “year two” and “year five” which are not defined. For the Planning Assessment started in a given calendar year, the first year that is studied must include the forecasted peak Load period for one of the following two calendar years. An additional Near-term study must be performed that is four calendar years beyond the first year that is studied. We recommend defining Year Five as the twelve month period 4 to 6 calendar years from the date of the Planning Assessment. We further recommend revising R2.1.1 as follows: “System peak Load for Year One and for Year Five.” Alternatively, the definition of Year One could be eliminated and described within the text of the requirements.
No
For R1 Ambiguity regarding base case assumptions, in combination with lack of clarity and clear direction of purpose regarding the sensitivity analysis, undermines the objectives of the standard; R1.1 Part 1.1.2. With respect to known outages, there needs to be greater flexibility in the standards (e.g. more tolerance to non-consequential load shedding or limitations to the contingencies that need to be considered (e.g. P0, P1, & P2)). Regional allowances for load shedding under this condition should be approved. Duration of known outages should be increased from six months to one year; R1.1 Part 1.1.6 Delete "required for Load". Resources may also be used for export to other areas, not just internal load.
No
We completely agree with the revision to R2.1, but this revision must be carried through to other sections (R2.2, 2.2.1) and R2.2 language should be consistent with 2.1 for example - use "current or qualified past studies" instead of "the following annual current study". Revisions made to Requirement R2.1.5 have made it worse than as originally drafted. This would require the PC & TP to study, or in other words perform technical analysis of, the impact and probability of the possible unavailability of any piece of equipment with a lead time of one year or more. Such an evaluation of spare equipment strategies would require significant additional resources and data, but provide no benefit to system reliability, as it is redundant to the existing N-1-1 contingency requirement (P6).
No
These sensitivities need to be considered if not already included in the base case assumptions.
No
We have not determined a need to model dynamic loads, and therefore have not benchmarked any such models. We recommend that prior to this requirement being in place, a modeling standard should exist that is specific to dynamic loads.
Yes
No
Header note (i) in the first Table 1 could imply that voltage-varying load shall not be used to meet steady state performance requirements. NYISO steady state load models include voltage-varying loads. This note should be revised to only reference loads which are disconnected due to voltage.
In Table 1 – Stability, Make language similar to wording in P5. Protection System should be removed and replaced with the words relay failure. This change should be made for 2a through 2d: 2. Local or wide area events affecting the Transmission System such as: a. 3Ø fault on generator with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. b. 3Ø fault on Transmission circuit with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. c. 3Ø fault on transformer with stuck

breaker10 or a relay failure resulting in Delayed Fault Clearing. d. 3Ø fault on bus section with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. In Note 11 change wording as shown below to include the words “a total of”: Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for a total of 1 mile or less
Yes
No
Requirement 8 is an administrative burden to TPs and PCs that adds no value to reliability. PCs should be including TPs, neighboring PCs and interested parties in its planning processes when developing the Planning Assessments. Therefore, the inclusion of a set of VSLs for Requirement 8 is unnecessary. Furthermore, the requirement lacks a specified time frame to receive comments, thereby implying that TPs and PCs would be required to reply to comments forever following the finalization of a Planning Assessment. The NYISO proposes a limit of six months. Should the SDT decide to leave the VSLs for Requirement 8, Requirement 8.1 should be revised to reflect that comments only to the final Assessment (not drafts developed during a process) need a response as follows: If a recipient of the planning assessment final results provides documented comments on the results within 180 calendar days of the issuance of those final results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments. We also have other comments not addressed by this Comment Form as follows – Section 2.7, Section 3.3, Section 4.3, and overall: Section 2.7 requires that Corrective Action Plans are included in each Planning Assessment and states “Such actions may include…” followed by a list of actions. Restricting allowable actions, and excluding runback/tripping of HVDC would have a direct impact on multiple existing facilities in New York and would adversely impact the reliability planning of the NYCA. Runback/tripping of HVDC must be added to the list. Section 3.3 - We feel that the last sentence of 3.3.1 should be removed. This is handled by PRC-023. Line ratings are addressed by PRC-023. PRC-023 requires coordination with the Reliability Coordinator. Remove “Tripping of Transmission elements where relay loadability limits are exceeded.” Section 4.3 - High speed reclosing is not defined. Overall – We have previously made comments which have not been addressed in the current version of the proposed standard. Support for the standard can at most be limited without addressing comments. We have previously commented on sensitivity analysis and guidance for base case assumptions. Also, extreme event analysis should not be mandated in this standard as no corrective action is required. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required, and there is no requirement for corrective action if anything is identified. The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions. The standard must describe base assumptions. To define a sensitivity condition, NERC must define base assumptions.
Individual
Bart White
Progress Energy
Yes
Yes
Yes
No
While PE does not disagree with the basic premise of 2.1, PE disagrees with the language to the extent that 2.1 is qualified by language in 2.6 and 2.6.2. The issue of managing modeling of case data is already adequately handled in MOD Standards. Furthermore, PE does not feel that the term “material” can be defined with any mutually agreed-upon boundaries, and could be construed to require any and all

Transmission Planners and/or Planning Authorities to make multiple revisions of base cases each year. PE therefore appeals to the SDT to remove the language referring to R2 Part 2.6.2 and furthermore appeals for the deletion of R2.6.2. Furthermore, PE appeals to the SDT to modify R2.6.1 to say “For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate the validity of the results of any studies older than five years or any studies using cases containing major modeling differences from other submitted studies.”
No
PE does not have concerns in general with either 2.1.4 or 2.4.3. PE does, however, disagree with the wording at the end of the main paragraph of 2.4.3. Whether or not analysis qualifies as sensitivity analysis should not be predicated upon the end results; rather, it should be based upon major case modeling differences. PE therefore recommends that the phrase “…that demonstrate a measurable change in performance” be removed so that the last sentence in the main paragraph read “…by a sufficient amount to stress the System within a range of credible conditions.”
Yes
No
PE agrees in general with the changes made to R2.5. PE disagrees, however, with the language stipulating that current and past studies be qualified by the language in R2.6 Part 2.6.2 (see notes for Question 3.1 regarding recommending changes with regard to R2.6.2).
Yes
PE assumes the term “header notes” is referring to the “Planning Performance Events” at the top of Table 1. If this is the case, PE has no concerns with the present language.
PE remains concerned with the present draft of TPL-001-2 regarding the presence or absence of footnotes in particular events. PE believes that, for all events in Table 1 except P0, any “No” designation in the “Non-Consequential Load Loss allowed” column should have Footnote 12 appended to it. Several events do append footnote 12 to a “No” answer, but several do not. PE does not see why certain events should be denied the use of Footnote 12 as long as Footnote 12 is worded in a manner such that the BES will not be adversely affected. PE has additional concerns regarding two Footnotes. Footnote 9 contains language regarding firm transmission service that is very similar to language presently under review in NERC Project 2010-11. PE feels that Footnote 9 should have had a statement at the end similar to that of Footnote 12, such as “Note: Firm Transmission Service is being decided in Project 2010-11. When that project is finalized, the resolution will be copied into Footnote 9.” Without such a statement, PE cannot understand why the Firm Transmission language in footnote (b) under Project 2010-11 is being reviewed, while it is apparently no longer being reviewed in Project 2006-02. Footnote 12 contains the following language as a place holder: “Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.” PE has filed substantial comments on the footnote (b) issue in previous drafts, pointing out that disallowance of curtailment of non-consequential load is a local load issue and not a BES concern. PE therefore cannot make any positive determination as to whether the draft Standard, TPL-001-2, and its associated Table 1, will be a viable Standard until the language in Footnote 12 is resolved via Project 2010-11. Given the potential for unresolved and confusing issues regarding the parallel development of Project 2006-02 and 2010-11, PE encourages NERC to resolve all issues within Project 2010-11 before taking the draft Standard TPL-001-2 to ballot in Project 2006-02.
Yes
Yes
Group
Bonneville Power Administration
Denise Koehn
Yes

Yes
No
Please clarify R1.1.2 to state “Known outage(s) of generation or Transmission Facility(ies) during the Planning Horizon with a duration of of at least six months.”
Yes
Yes
Yes
Yes
It should be noted that if there is more generation proposed in an area than there load and export capability, all proposed material generation additions would not be represented. Determining what future generation additions to include in the Long-Term Transmission Planning Horizon may be based on a non-technical rationale rather than a technical rationale.
Yes
Table 1, P5 currently requires the study of “[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed”. As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: “Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following”. In Table 1, P2 and P3, the last column “Non-Consequential Load Loss Allowed” where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore the proposed footnote 12 should include a provision to default to the existing footnote “b” in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, “Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.”
Individual
L Zotter, M Morais, J Billo, J Conto, S Jue, JC Culberson, J Teixeira, G Gnanam, S Myers
ERCOT ISO
Yes
Yes
Yes
No
Previous Comment unaddressed: Requirement 2.1.5: Including the spare equipment strategy will be difficult for a PC that doesn’t own or manage the transmission equipment or the strategies. This

requirement should only be applicable to TP. Furthermore, R7 should be deleted and the responsibilities of each entity should be explicitly stated within the specific requirements.
No
The stress test requirements should be deleted. The purpose of this proposed Standard is to establish planning performance standards that support reliable operation. This is achieved by imposing performance requirements relative to specific conditions and contingencies. Compliance with the performance metrics within these boundaries is presumably indicative of a reliable system. It is unclear what value is added by stress testing the system in accordance with undefined, vague parameters, as required by Requirements 2.1.4 and 2.4.3. The criteria in the relevant requirements that govern the stress testing are defined by the following ambiguous phrase: 1) “by a sufficient amount”; 2) “range of credible conditions”; and 3) “measurable change of performance”. Application of these criteria introduces uncertainty for both the regulated community and the relevant compliance enforcement authorities, which, in turn, creates audit risks for regulated entities. Furthermore, there is no reliability value because the stress test requirements do not establish objective criteria and do not prescribe any actions based on the stress test results. Reliability Standards should set specific obligations that are readily discernible and achievable on a consistent basis. The existing Standard does this by setting specific performance obligations relative to specific conditions and contingencies. Conversely, the stress test requirements introduce ambiguity and uncertainty with no reliability benefit; the only apparent effect is unnecessary audit liability risk for regulated entities. Accordingly, ERCOT believes that these requirements should be deleted.
No
ERCOT ISO suggests adding “best available” as a descriptor to load models. Distribution Providers (DPs)/Load Serving Entities (LSEs) are the appropriate NERC functional entities to provide dynamic load data. Accordingly, Planning Coordinators (PCs) and Transmission Planners (TPs) must rely on those entities for that data. Despite reliance on DPs/LSEs for this data, the Standard proposes to impose an obligation on PCs and TPs to include a load model representative of “expected” dynamic behavior. Simply put, PCs and TPs do not have this information and should not be subject to compliance liability risk for an issue that is beyond their control. This change will still accomplish the goal of reflecting dynamic data in the relevant models, while mitigating PC/TP compliance risk by basing their compliance on information that is within their control – i.e. the “best available” information. Based on this change, the language should read - “System peak Load levels shall include best available Load models which represent the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads”. This language is also a more accurate reflection of the Consideration of Comments by the Standard Drafting Team after the March 2010 comment period. To address this issue in the most appropriate manner, the Standard should be revised to establish an appropriate process for collection, reporting and use of dynamic data based on assigning obligations to the appropriate functional entities. In essence, DPs/LSEs should be required to collect the data and report it to TPs. Because TP models are the basis for PC models, the dynamic data will be included in PC models as part of the process. However, DPs and TPs should still only be required to use the “best available” data. Continued use of this language will mitigate the liability risk associated with a requirement related to data that is within the control of a third party. Even under a construct where DPs/LSEs are required to collect and report dynamic data, there is no guarantee they will do so and PCs/TPs should not be held accountable in those circumstances. Accordingly, PC/TP compliance risk will be mitigated by use of a “best available” standard.
Yes
Yes
Yes
Yes
ADDITIONAL COMMENTS: Short circuit analysis (R2.3 and R2.8) should only be applicable to TPs.

Fault duty issues are typically local in nature and it would be an overlap for PCs to perform this same analysis done by the local Transmission Planner. Furthermore, R7 should be deleted and the responsibilities of each entity should be explicitly stated within the specific requirements. Previous Comment Unaddressed : Requirement 2.6.2: Reads as if a change is being made to an existing study. It is confusing. Possibly restate: "2.6.2 For steady state, short circuit, or stability analysis: previous studies can be used only if a material change to the system has not occurred or if a change that did occur does not impact the study area." R4.1.2 – Planning Coordinators do not perform protection coordination nor do they have access to the relay settings information required to do this analysis. This requirement should apply to Transmission Planners only because they perform system protection. The substantive scope of the standard is relative to Long-Term Transmission Planning Horizon and Near-Term Transmission Planning Horizon. The Purpose section is described in terms of the “planning horizon” generally. It may be worthwhile aligning the two to mitigate the potential for any confusion. ERCOT proposes the following revisions to the Purpose section: 3.Purpose: Establish Transmission system planning performance requirements within the relevant planning horizon (i.e. Long-Term or Near-Term) to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. In addition, the “Time Horizon” for the Standard is “Long-Term Planning”. Obviously, this necessarily encompasses both Long-Term and Near-Term Transmission Planning Horizons. However, the scope of the Long-Term Planning time horizon is not readily apparent. ERCOT recommends appropriate revisions that clearly define the applicable time horizons.

Individual

Gary Trent

Tucson Electric Power Company

Yes

We commend the SDT for its work to continue the improvement on the proposed TPL-001-1. We have included additional comments here since we were not able to find a place to include comments on the following: Requirement R4; Requirement, Parts 2.1.5, 2.3, and 2.8; Requirement 3, Part 3.3.2; and Requirement 4, Parts 4.3.1and Part 4.3.2 Requirement 2, Part 2.1.5: The spare equipment strategy does not improve reliability performance. If an outage of a long lead time piece of equipment occurs, the system should still be able to operate in a reliable manner that meets the performance measures of Categories P3 and P6. If an entity cannot meet its performance requirements under this standard, a capital project is indicated. Spare equipment being available would not mitigate this need it only increases expenses until the item is needed. Requirement 2, Parts 2.3 and 2.8: Short circuit fault duty is a localized phenomena that is mainly impacted by the addition of new generation or transmission facilities. Due to proprietary concerns of generation and transmission interconnection requests, short circuit studies are performed in forums outside the annual Planning Assessment. Normally, these studies will be conducted before the projects can be included in regional base cases. As such, short circuit analysis should not be included in this Standard since it would provided limited benefit. Requirement 3, Part 3.3.2 and Requirement 4, Part 4.3.2 Steady state response of dynamic control devices should also be included in the Part 3.3.2. and the list of possible devices included should be removed from Part 3.3.2 and 4.3.2. Section R4.3.1, bullet point 3 requires the stability analyses to include the impact of subsequent “[t]ripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models”. As written, this bullet could be interpreted as requiring the inclusion of these relay models in stability data bases. We do not have generic or actual relay models in our dynamics data bases for tripping line faults on lines and transformers represented. We represent actual relay response and tripping times of relays, communications, and breakers to faults in tripping transmission lines and transformers. Requiring the inclusion of generic or actual relay models for all relays that can trip lines and transformers would add a large burden to the development and maintenance of accurate dynamics model files that would add little or no benefit. Please change this bullet to read: “Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on known Protection System response”.

No

A seasonal reference should be included in the example. Alternative language beginning with the second sentence: For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak load period for the forecasted peak load season that is between 12 and 24 months into

the future from the current season. For example, if a Planning Assessment was started in 2011 prior to the forecasted peak season, then Year One must include the forecasted peak load for 2012. If the Planning Assessment was started in 2011 during or after the forecasted peak season, then Year One must include the forecasted peak load for 2013.
No
Proposed changes 1.1.1 Existing Facilities that will not be changed before the study year 1.1.3 New planned Facilities and planned changes to existing facilities
Yes
No
TEP agrees with removing the phrase "not already included in the studies." However, TEP does not understand the purpose of sensitivity studies. TEP is concerned that imposing additional sensitivity studies could lead to requirements that exceed the proposed standards. TEP recommends removing sesnitivity analysis from the standard.
Yes
No
If a material change (generator addition/retirement, new generator models based on unit testing, or transmission line or non-distribution transformer addition) is not planned for the longer-term planning horizon, do the longer-term stability studies need to be performed? TEP's agreement/disagreement with Part 2.4.1 is dependent on the response to this question. If the answer is the studies do not need to be performed, then TEP supports these changes.
Yes
Table 1, P5 currently requires the study of “[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed”. As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: “Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following”. In Table 1, P2 and P3, the last column “Non-Consequential Load Loss Allowed” where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote “b”. This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote “b” in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, “Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.” Timing of this project and project 2010-11 is critical. It would be very difficult to vote to approve the proposed TPL-001-2 prior to knowing the outcome of Project 2010-11 (footnote b issue). Non-Consequential Load Loss and curtailment of Firm Transmission Service should be allowed for loss of EHV BES elements for Category P4 and P5 events.
Yes

Yes
Individual
Gregory Campoli
New York Independent System Operator
Yes
No
The added clarification to the definition of Year One serves to remove most ambiguity with respect to Year One. However, the revision has added further ambiguity to the terms “year two” and “year five” which are not defined. NYISO recommends defining Year Five as the twelve month period 4 to 6 calendar years from the date of the Planning Assessment. NYISO further recommends revising R2.1.1 as follows: “System peak Load for Year One and for Year Five.” Alternatively, the definition of Year One could be eliminated and described within the text of the requirements.
Yes
No
NYISO completely agrees with the revision to R2.1, but this revision must be carried through to other sections (R2.2, 2.2.1). Revisions made to Requirement R2.1.5 have made it worse than as originally drafted. This would require the PC & TP to study, or in other words perform technical analysis of, the impact and probability of the possible unavailability of any piece of equipment with a lead time of one year or more. Such an evaluation of spare equipment strategies would require significant additional resources and data, but provide no benefit to system reliability, as it is redundant to the existing N-1-1 contingency requirement (P6). R2.7 requires that Corrective Action Plans are included in each Planning Assessment and states “Such actions may include…” followed by a list of actions. Restricting allowable actions, and excluding runback/tripping of HVDC would have a direct impact on multiple existing facilities in New York and would adversely impact the reliability planning of the NYCA. Runback/tripping of HVDC must be added to the list.
No
Our concern involves wording under 2.1.4 and 2.4.3 that sensitivities are required varying one or more conditions. Subsequently, in requirement 2.7.2 corrective action plans need to be developed to resolve performance deficiencies “only” if identified in multiple conditions or require a rationalization why no corrective action plan is necessary. Multiple conditions sensitivities under 2.1.4 and 2.4.3 are necessary to satisfy requirement 2.7.2. Requirement 2.7.2 adds ambiguity and should be removed. Requirement 2.7.2 should be revised as follows: 2.7.2. Corrective Action Plans are not required for performance deficiencies identified in a sensitivity analysis.
No
The NYISO, along with many other systems, has not determined a need to model dynamic loads, and therefore has not benchmarked any such models. The NYISO recommends that prior to this requirement being in place, a modeling standard should exist that is specific to dynamic loads.
Yes
No
Header note (i) in the first Table 1 could imply that voltage-varying load shall not be used to meet steady state performance requirements. NYISO steady state load models include voltage-varying loads. This note should be revised to only reference loads which are disconnected due to voltage.
There are two tables labeled “Table 1”. The extreme events table should be renamed “Table 2”.
Yes

No
Requirement 8 is an administrative burden to TPs and PCs that adds no value to reliability. PCs should be including TPs, neighboring PCs and interested parties in its planning processes when developing the Planning Assessments. Therefore, the inclusion of a set of VSLs for Requirement 8 is unnecessary. Furthermore, the requirement lacks a specified time frame to receive comments, thereby implying that TPs and PCs would be required to reply to comments forever following the finalization of a Planning Assessment. The NYISO proposes a limit of six months. Should the SDT decide to leave the VSLs for Requirement 8, Requirement 8.1 should be revised to reflect that comments only to the final Assessment (not drafts developed during a process) need a response as follows: If a recipient of the planning assessment final results provides documented comments on the results within 180 calendar days of the issuance of those final results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments.
Group
PacifiCorp
Sandra Shaffer
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Under Category P2 (Single Contingency) and Normal System Conditions, the performance table indicates that, for both HV and EHV, interruption of firm transmission service and non-consequential load loss are not allowed following the opening of a line section without a fault. This section of the performance table should distinguish between EHV and HV – performance requirements following the opening of a line section without a fault should be the same as those for a bus section fault. As with the bus section fault, interruption of firm transmission service and non-consequential load loss should be allowed for HV.
Yes
No
The language for Requirement R8 is ambiguous with regard to which adjacent entities must request in writing the results of the Planning Assessment. The language should be clarified to read: “Upon request made in writing, each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any other functional entity that has a reliability related need.” The Requirement R8 VSL language should also be revised accordingly.
Individual
Claudiu Cadar
GDS Associates, Inc.

No
We disagree with the Implementation Plan and we suggest changes as follows: - The title should read “Implementation Plan for TPL-001-2” - With regards to the Prerequisite Approvals, NERC project #2010-11 still in progress (Table 1, Footnote ‘b’) must be implemented before this current TPL-001-2 standard gets implemented. However, while the 2010-11 NERC project does not define any of the new terms such as consequential / non-consequential load, the footnote ‘b’ cannot be just copied into the new standard (see TPL-001-2 standard Table 1, note 12). Note ‘b’ may further change to reflect the verbiage in the TPL-001-2 standard. - Not sure what is the intent of the last paragraph. While the proposed changes to Table 1, footnote ‘b’ are quite precise, are we still open a door to those entities that will continue to trip Non-Consequential Load and curtail Firm Transmission Service? If no penalties for such practices while the proposed standard allows a sufficient time frame to correct any deficiencies, then what is the point to all the effort behind the development of a new TPL standard?
No
The definition it seem both incomplete and exhaustive: - If taken out of the planning assessment context, the definition is missing the matter that is supposed to identify. We suggest changing the first sentence such as “The first twelve month period to which the functional entity is responsible for the assessment of Transmission System Planning performance.” - While it will be a burdensome task to define each year that follows Year One, the definition of Year One may include a sentence that define the rule for the following years such as “All of the twelve months period following Year One shall commence immediately after the end of the preceding twelve months period.” - The definition should not include examples.
No
The Time Horizon should be for both Near-Term and Long-Term Planning.
Yes
No
The requirements are extremely burdensome. We recommend changing the last sentence of 2.1.4 requirement by removing “by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:” because there are instances where listed conditions may not result in measurable changes in performance (Ex. An increase in load in a well built system may not cause any measurable changes in performance because there is sufficient transmission capacity to serve the load).
No
We disagree with the content of this requirement based on several facts: - We believe that the dynamic behavior of the load cannot be accurately estimated beyond current time. We are concern about the effort required to ascertain the dynamic response of the load - The requirement references “Loads that could impact the study area” without specifying how an entity will identify these loads. Perhaps the standard should provide guidelines to determine which loads would impact the study area.
No
We are not sure what will be included in these “material generation additions or changes”. Perhaps the standard should provide guidelines to determine what are these material changes or additions?
Yes
Individual
Terry Harbour
MidAmerican Energy
Yes
Yes

No
There are concerns over the FERC outstanding March order on TPL and how FERC interprets “normal” or base case conditions and “assuming” an entities primary protection system is out of service and must rely on its backup protection system to operate. This concept combined with the new tables cannot be perpetuated.
Yes
Yes
R2.1.4 bullet #7 – Replace the adjective “planned” with “known” for consistency with R1.1.2 and R2.1.3. R2.3 Replace “conducted” with “assess” for consistency with R1.1.2 and R2.1.3. R2.4 Replace “current or past studies as qualified” with “current or qualified past studies as indicated” for consistency with R2
No
MidAmerican questions if the widespread use of composite load models really provides significant benefits to additional dynamic analyses over generic load conversion assumptions which have been historically used. The use of composite load models may result in more precise individual load models, but no more accurate dynamic simulations. This poorly worded requirement should be deleted in its entirety as providing additional burden without any additional reliability benefits. If the composite load model requirement must be kept, it should be modified to include the following bolded text: “…System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads, but without requiring a detailed load survey be conducted…”
Yes
No
The reference to BES should be placed back into Note a in the header above table 1.
Voting "no" - Footnote 6 – Further clarify the applicable shunt devices in Footnote 6 with this suggested text: 6. Requirements which are applicable to shunt devices, also apply to FACTS devices that are connected to ground, but not instrument voltage transformers or surge arresters
No
Revise measures to be consistent with requirements. 1. R6 Delete “any”. The use of the word any in standards should not be allowed. 2. Revise the Planning Assessment definition to more explicitly apply to the BES and the TPL-001 requirements. We suggest text of: “Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies in the BES from the steady state and stability performance requirements set forth in the TPL-001 standard.” 3. R2.1.5 – We propose replacing the term ‘major Transmission’ with “BES” because BES is a well defined term, while the term, ‘major Transmission‘, is not. 4. Add R2.3.1 – We suggest the addition of a R2.3.1 requirement to emulate the distinction between the requirement to perform a short circuit assessment and conduct required studies or analysis to support the assessment (e.g. R2.1/R2.1.1 and R2.2/R2.2.1). We propose wording such as, “Perform an analysis for at least one year in the Near Term Transmission Planning Horizon.” This requirement would set an expectation that an analysis should be conducted to at least one or more years in the near-term planning horizon, rather than imply that an analysis of all five years in the near-term planning horizon must be conducted. 5. R2.7.2 – Delete 2.7.2. With regard to "include actions to resolve performance deficiencies identified in multiple sensitivity studies", mitigation plans should not be required for deficiencies found in multiple sensitivity studies because the conditions in some sensitivity studies are more extreme and less likely than base case conditions. Some of the sensitivity study conditions are not credible. 6. R2.7.4 – We suggest that the wording of R2.7.4 be the same as R.2.8.2. 7. R3.5 - We interpret that R3.5 requires the TP and PC to conduct an evaluation of possible actions to reduce the likelihood or impact of extreme events, which produce the more severe impacts, if cascading outages may occur. Does the drafting team intend for the TP and PC to fulfill this requirement for at least one event in each of the five categories (i.e. 3 steady state and 2 stability) or in each of the 21 categories/sub-categories (i.e. 14 steady state and 7 stability).

Also, if the resulting cascading outages do not result in any overloads, under-voltages, voltage collapse, or loss of generator synchronization, then should the evaluation of possible actions to reduce likelihood or impact be required? 8. R4.1.1 – We suggest that there should be some qualification of which generating units are referred to in this requirement. We propose that the requirement say, “No generating unit with a Point of Interconnection connected to the BES shall pull out of synchronism.” For example, some utilities include smaller generation units that are connected at voltages below 100 kV and even down to distribution voltage in their base cases. 9. R4.1.2 – We propose that the wording of this requirement be revised to reflect the same BES qualification of the generating unit that we noted in R4.1.1 above. 10. R4.3.1 – This requirement refers to high speed reclosing and we presume that this is special high speed reclosing that is completed in several cycles, rather than the normal high speed reclosing that is completed in a number of seconds. We recommend that the term high speed reclosing be more clearly defined for this sub-requirement. 11. R.4.3.2 – We suggest qualifying which generating units to consider and which voltage limits to simulate with revised wording like, “Trip generating units that are connected to the BES when actual or assumed minimum generator transient voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment“. The requirement should not apply to all relevant generating units until one of the MOD standards requires all Generator Owners to provide their minimum generating unit voltage limits to the TP and PC. If the wording of R4.3.2 must be different from its counterpart, R3.3.2, then please explain the reasons for any differences. 12. R5 – This requirement should allow the applicable entity (such as the TOP / TO) to define a “Post-Contingency Voltage Deviation” as this criteria is not used widely enough in the industry to be a well established criteria. 13. Revise R8 to limit the need to provide the Planning Assessment as follows “adjacent Planning Coordinators and adjacent Transmission Planners and to any registered functional entity…” 14. Data Retention for R3, R5, R6, & R7 - The MRO NSRS proposes that the wording in these elements be revised to change “All” to “The”. The word “All” is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: “The studies performed in support….”
Yes
Individual
Catherine Koch
Puget Sound Energy
Yes
We commend the SDT for its work to continue the improvement on the proposed TPL-001-1. We were not able to find a place to include comment on Requirement R4; therefore, we have included our comments here: Section R4.3.1, bullet point 3 requires the stability analyses to include the impact of subsequent “[t]ripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models”. As written, this bullet could be interpreted as requiring the inclusion of these relay models in stability data bases. We do not have generic or actual relay models in our dynamics data bases for tripping line faults on lines and transformers represented. We represent actual relay response and tripping times of relays, communications, and breakers to faults in tripping transmission lines and transformers. Requiring the inclusion of generic or actual relay models for all relays that can trip lines and transformers would add a large burden to the development and maintenance of accurate dynamics model files that would add little or no benefit. Please change this bullet to read: “Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on known Protection System response”.
Yes
Yes
Yes
Yes

Yes

Yes

Table 1, P5 currently requires the study of “[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed”. As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: “Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following”. In Table 1, P2 and P3, the last column “Non-Consequential Load Loss Allowed” where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote “b”. This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote “b” in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, “Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.” Timing of this project and project 2010-11 is critical. It would be very difficult to vote to approve the proposed TPL-001-2 prior to knowing the outcome of Project 2010-11 (footnote b issue).

Individual

Joe Tarantino

Sacramento Municipal Utility District

Yes

We commend the SDT for its work to continue the improvement on the proposed TPL-001-1. We were not able to find a place to include comment on Requirement R4; therefore, we have included our comments here: Section R4.3.1, bullet point 3 requires the stability analyses to include the impact of subsequent “[t]ripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models”. As written, this bullet could be interpreted as requiring the inclusion of these relay models in stability data bases. We do not have generic or actual relay models in our dynamics data bases for tripping line faults on lines and transformers represented. We represent actual relay response and tripping times of relays, communications, and breakers to faults in tripping transmission lines and transformers. Requiring the inclusion of generic or actual relay models for all relays that can trip lines and transformers would add a large burden to the development and maintenance of accurate dynamics model files that would add little or no benefit. Please change this bullet to read: “Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on known Protection System response”.

Yes

Yes
Yes
Yes
Yes
Yes
Yes
Table 1, P5 currently requires the study of “[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed”. As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: “Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following”. In Table 1, P2 and P3, the last column “Non-Consequential Load Loss Allowed” where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote “b”. This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote “b” in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, “Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.” Timing of this project and project 2010-11 is critical. It would be very difficult to vote to approve the proposed TPL-001-2 prior to knowing the outcome of Project 2010-11 (footnote b issue).
Individual
Patrick Farrell
Southern California Edison Company
Yes
Yes
Yes
Yes

Yes
Yes
Yes
Yes
SCE supports the revised performance table.
Yes
Yes
Individual
John Mayhan
Omaha Public Power District
Why is Footnote 12 used for some occurrences of the word "No" in the last column of Table 1 but not other occurrences of the word "No"?

CHECKBOX

Informal Comments on Assess Transmission Future Needs – Project 2006-02.

The TPL-001-2 standard for Assess Transmission Future Needs (Project 2006-02) Drafting Team thanks all commenters who submitted comments on the fifth draft overview. These standards were posted for a 30-day public comment period from August 3, 2010 through September 2, 2010. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 7 sets of comments, including comments from 77 different people from approximately 69 companies representing 6 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

The SDT has completed the review of the informal comments from industry for Project 2006-02: Assess Transmission Future Needs. Each and every comment was reviewed and considered by the SDT regardless of whether there is a formal written response shown. The majority of the cases where the SDT did not make a change or provide a written response was because the SDT had already responded to the issue or the SDT did not believe that the proposed revision added clarity or otherwise improved the quality of the proposed standard.

The SDT made a number of changes due to the comments received from industry and drafting team discussions arising from those comments as highlighted below:

- Year One definition – deleted 'must'
- Conforming changes to the language in the Effective Date – made language consistent with the Implementation Plan
- Requirement R1 and M1 – changed, ". . . the latest data consistent with . . ." to "data consistent with. . . " and established P0 as normal System condition in Table 1
- Requirement R2, part 2.1.4 – replaced 'performance' with 'System response' and changed last bullet from ". . . planned Transmission outages" to ". . . known Transmission outages"
- Requirement R2, part 2.6.2 – require documentation explaining material changes
- Requirement R2, part 2.7.1 – made it clear that statement is not all inclusive
- Requirement R2, part 2.8.2 – made language consistent with Requirement R2, part 2.7.4
- Requirement R4, part 4.3.1, bullet #1 – added qualifier for high speed reclosing
- Requirement R6 and M6 and data retention for R6 – changed 'any' to 'the'
- Table 1, header note 'i' – deleted 'including Load'
- Table 1, P0 – delete superscript in column 6
- Table 1, P2 – added 'Breaker' to description
- Table 1, P4 – added 'Breaker' to description
- Table 1, P5: added 'non-redundant'
- Table 1, extreme events – Stability: made language consistent with Table 1, P5
- Measure M8 – spelled out the functional entity involved
- Data retention for Requirement R7 – deleted 'all such'
- Changed, "Initial System Conditions" to "Initial Conditions" in column heading of Table 1 and Table 1 Note 9
- Deleted section, "Compliance Monitoring and Reset Timeframe as this is no longer included in the standard template.

The SDT believes that with these changes, the industry concerns have been addressed except for Footnote 12 (content of existing footnote b). Until the issues with footnote 'b' in Project 2010-11: TPL Table 1 are resolved, the SDT will not request the Standards Committee to move the project to the ballot phase. This could mean that Project 2006-02 may sit in limbo for several months pending the outcome of the Project 2010-11 deliberations. So that industry can see what has transpired with regard to their comments on Project 2006-02, the SDT is requesting that the consideration of comments document, along with the redlined version of TPL-001-2 corresponding to those comment responses be posted immediately. In this way, the industry can see what the SDT has decided in response to comments while the content of the comments is still fresh in the minds of the commenters. The SDT encourages anyone reading the posted documents to reach out to members of the SDT for informal discussions of posted documents.

Once Project 2010-11 is resolved, the wording for footnote 'b' will be essentially copied to TPL-001-2. The SDT realizes that this cannot be a simple cut and paste due to format differences between the old standard and the revised TPL-001-2 and will take appropriate actions to make things fit correctly. Once this has been accomplished, the SDT expects to ask the Standards Committee to move Project 2006-02 to the ballot stage.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

1. The SDT has revised the Implementation Plan based on industry comments to the initial ballot. Do you support this change? If you do not support this change, please specify why you disagree and include specific alternative language to resolve your concern. 10

2. The SDT has revised the definition of Year One based on industry comments to the initial ballot. Do you support this change? If you do not support this change, please specify why you disagree and include specific alternative language to resolve your concern. 20

3. The SDT has revised the Requirements language based on industry comments to the initial ballot. Do you support these changes? If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your cncern. 28

3.1 Requirement R2 and Part 2.1 – past studies 36

3.2 Requirement R2, Parts 2.1.4 & 2.4.3 – sensitivity analysis: 47

3.3 Requirement R2, Part 2.4.1 – dynamic load models: 57

3.4 Requirement R2, Part 2.5 – material clarification: 64

4. The SDT has revised the header notes based on industry comments to the initial ballot. If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your concern. 70

5. The SDT has revised the performance table (including the list of extreme events and footnotes) based on industry comments to the initial ballot. If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your concern. 78

6. The SDT has revised the Measures based on industry comments to the initial ballot. If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your concern. 95

7. The SDT has revised the Requirement R8 VSL based on industry comments to the initial ballot. If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your concern. 102

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Mallory Huggins	NERC Staff										
2.	Group	Philip Kleckley	SERC Planning Standards Subcommittee	X		X		X					
3.	Group	Guy Zito	Northeast Power Coordinating Council										X
4.	Group	David Kiguel	Hydro One Networks Inc.	X		X							
5.	Group	Bob Cummings	Transmission Issues Subcommittee										
6.	Group	Robert Jones	SERC Dynamics Review Subcommittee	X									X
7.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee										X
8.	Group	Richard Kafka	Pepco Holdings, Inc - Affiliates	X		X		X	X				
9.	Group	Ben Li	IRC Standards Review Committee		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
10.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				
11.	Individual	Eric Mortenson	Exelon Transmission Planning	X									
12.	Individual	Andy Tillery	Southern Company	X		X							
13.	Individual	Steve Rueckert	Western Electricity Coordinating Council										X
14.	Individual	Jana Van Ness, Director Regulatory Compliance	Arizona Public Service Company	X		X		X					
15.	Individual	Brent.Ingebrigtson@eon-us.com	E.ON U.S.	X		X		X	X				
16.	Individual	Richard Becker	Florida Reliability Coordinating Council, Inc - Transmission Working Group	X	X	X	X						X
17.	Individual	Brandy A. Dunn	Western Area Power Administration	X					X				
18.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
19.	Individual	Ray Mason	ReliabilityFirst										X
20.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
21.	Individual	Catherine Mathews	NorthWestern Energy (NWMT)	X									
22.	Individual	Phuong Tran	Lakeland Electric	X		X		X					
23.	Individual	Tom Duane	PNM	X		X							

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
24.	Individual	Doug Hohlbaugh	FirstEnergy	X		X	X	X	X				
25.	Individual	John Collins	Platte River Power Authority	X		X			X				
26.	Individual	Aaron Staley	Orlando Utilities Commission	X									
27.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
28.	Individual	Randi Woodward	Minnesota Power	X									
29.	Individual	Martin Bauer	US Bureau of Reclamation					X					
30.	Individual	Paul Rocha	CenterPoint Energy	X									
31.	Individual	Tim Ponseti, VP	TVA Transmission Planning & Compliance									X	
32.	Individual	Dan Rochester	Independent Electricity System Operator		X								
33.	Individual	Dilip Mahendra	SMUD	X		X	X	X					
34.	Individual	RoLynda Shumpert	South Carolina and Gas	X		X		X	X				
35.	Individual	Brian Keel	SRP	X									
36.	Individual	Darcy O'Connell	California ISO		X								
37.	Individual	Scott Inglebritson	Seattle City Light	X		X	X	X		X			
38.	Individual	Ean O'Neill	California Energy Commission									X	
39.	Individual	Kathleen Goodman	ISO New England Inc.		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
40.	Individual	Oscar Herrera	Los Angeles Department of Water and Power	X		X		X	X				
41.	Individual	Orlando A Ciniglio	Idaho Power Co	X		X							
42.	Individual	David Bradt	United Illuminating	X		X							
43.	Individual	John Sullivan	Ameren	X		X		X	X				
44.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
45.	Individual	Sergio Garza	LCRA TSC	X									
46.	Individual	Saurabh Saksena	National Grid	X		X							
47.	Individual	Charles Lawrence	American Transmission Company	X									
48.	Individual	Thad Ness	American Electric Power (AEP)	X		X		X	X				
49.	Individual	Bill Middaugh	Tri-State Generation & Transmission	X									
50.	Individual	David Miller	Lakeland Electric	X		X		X					
51.	Individual	Steve Stafford	GTC	X									
52.	Individual	Chifong Thomas	Pacific Gas and Electric Company	X		X		X					
53.	Individual	Michael R. Lombardi	Northeast Utilities	X		X		X					
54.	Individual	Christopher L. de	Consolidated Edison Co. of New York, Inc.	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
		Graffenried											
55.	Individual	Spencer Tacke	Modesto Irrigation District			X	X						
56.	Individual	Alex Rost	NBSO		X								
57.	Individual	Curtis A. Beveridge	Central Maine Power Company	X									
58.	Individual	Darryl Curtis	Oncor Electric Delivery	X									
59.	Individual	Jeffrey McKinney	New York State Electric & Gas Corp	X									
60.	Individual	Bart White	Progress Energy	X		X		X	X				
61.	Group	L Zotter, M Morais, J Billo, J Conto, S Jue, JC Culberson, J Teixeira, G Gnanam, S Myers	ERCOT ISO		X								
62.	Individual	Gary Trent	Tucson Electric Power Company	X		X		X					
63.	Individual	Gregory Campoli	New York Independent System Operator		X								
64.	Individual	Claudiu Cadar	GDS Associates, Inc.	X									
65.	Individual	Terry Harbour	MidAmerican Energy	X									
66.	Individual	Catherine Koch	Puget Sound Energy	X									
67.	Individual	Joe Tarantino	Sacramento Municipal Utility District	X		X	X	X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
68.	Individual	Patrick Farrell	Southern California Edison Company	X		X		X	X				
69.	Individual	John Mayhan	Omaha Public Power District	X		X		X	X				
70.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X				

1. **The SDT has revised the Implementation Plan based on industry comments to the initial ballot. Do you support this change? If you do not support this change, please specify why you disagree and include specific alternative language to resolve your concern.**

Summary Consideration:

The majority of respondents agree with the changes to the Implementation Plan and no further changes to the Implementation Plan are deemed necessary.

The SDT fully realizes that Project 2010-11 (Table 1 - footnote "b") must reach resolution prior to finalizing TPL-001-2 and stated the same in the information attached with the fifth posting of Project 2006-02.

The SDT reviewed the comment on consistency of language in the Implementation Plan and the Roadmap and agrees with the comment. The paragraph under Effective Date in the standard has been changed accordingly.

> For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required on the first day of the first calendar quarter 84 months after Board of Trustees adoption, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-2, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-2:

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered the comments. In many of the cases relating to the comments, the SDT has already responded to similar comments and those responses are quoted here for convenience:

1.1.5 – "The SDT believes that the base cases should include any area interchange that is planned between utilities." In addition, non-firm transactions are not required to be modeled.

2.1.5 – "When a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. This requirement is intended for the Planning Coordinator and/or Transmission Planner to take into account its spare equipment strategy for long lead time Equipment when assessing the performance of its System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Actions such as out of merit dispatch, operational restrictions, System reconfiguration can be part of a Corrective Action Plan if the System cannot meet performance requirements without the Facility in service."

2.3/2.8 – "is intended for the Planning Coordinator and/or Transmission Planner to assess whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt. Even though the effects of short circuit capability are localized and may be related to new planned Facilities, it is important to BES reliability."

3.4.1/4.4.1 – "The SDT has determined that it is necessary for the Planning Coordinator and Transmission Planner to coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list created." In addition, the SDT wants to make it clear that an entity is responsible for corrective actions on its own System.

4.3.1 – "does not require modeling of Protection System equipment. It just requires you to have simulations which include the effects of Protection System equipment operation. You don't have to specifically model a relay to simulate the effect of clearing a fault at 3 cycles. If you need to model a relay to capture its effect, then model that relay. And certainly engineering judgment should be used to determine which relay effects should be included in the simulations."

References to TPL-001-1 are a typo and will be cleaned up. The correct reference, as pointed out, is TPL-001-2.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council Consolidated Edison Co. of New York, Inc	No	Requirement R1 Part 1.1 and following states "System models shall represent:... 1.1.5. Known commitments for firm Transmission Service and Interchange. It was commented during a previous posting that 1.1.5 should be reworded to read: Known commitments for Firm Transmission Service, and, additionally, other types of transactions provided they have been demonstrated to not violate existing reliability constraints. The response was that "The SDT believes that the defined term 'Interchange' covers other transfers as described in your comment. No change made."It is agreed that known Interchanges should be modeled. However, it is imperative that existing reliability constraints not be violated in the process. That is, Interchange relating to economic transactions should not drive planning studies. Reliability related investments should not be driven by congestion related to economic transactions incorporated into planning models. Following is a preferred/revised wording: o 1.1.5. Known commitments for firm Transmission Service and Interchange. Interchange is meant to refer to energy transactions other than firm Transmission Service. While rigorous planning studies have been conducted to permit the uninterrupted implementation of firm Transmission Service without jeopardizing the reliable operation of the Interconnected System, other types of energy transaction only take place whenever system conditions permit them. They are usually of very short duration relative to planning assessment periods (usually spanning for a few hours to a few days) and deemed highly interruptible subject to reliability issues that may arise during operation of the system. In other words, the term Interchange refers to economic transactions that are permitted when the system is secure and there are reasonable reliability margins to effect dispatch changes to lower operating costs. As such, Interchange should not be reflected in system representation meant to assess system reliability in adherence to reliability criteria delineated in documents such as TPL-001.

Organization	Yes or No	Question 1 Comment
GDS Associates, Inc.	No	We disagree with the Implementation Plan and we suggest changes as follows:- The title should read "Implementation Plan for TPL-001-2"- With regards to the Prerequisite Approvals, NERC project #2010-11 still in progress (Table 1, Footnote 'b') must be implemented before this current TPL-001-2 standard gets implemented. However, while the 2010-11 NERC project does not define any of the new terms such as consequential / non-consequential load, the footnote 'b' cannot be just copied into the new standard (see TPL-001-2 standard Table 1, note 12). Note 'b' may further change to reflect the verbiage in the TPL-001-2 standard.- Not sure what is the intent of the last paragraph. While the proposed changes to Table 1, footnote 'b' are quite precise, are we still open a door to those entities that will continue to trip Non-Consequential Load and curtail Firm Transmission Service? If no penalties for such practices while the proposed standard allows a sufficient time frame to correct any deficiencies, then what is the point to all the effort behind the development of a new TPL standard?
SMUD		R2.7.1, last bullet: Please provide specifics on the types of acceptable 'Corrective Actions' covered by 'rate applications and DSM' and the planning horizon for which they are considered acceptable. As an alternative, NERC should develop a process by which what is considered acceptable is published and continuously updated. (With due apologies for not raising this point earlier).
Western Electricity Coordinating Council	Yes	We commend the SDT for its work to continue the improvement on the proposed TPL-001-1. We were not able to find a place to include comment on various requirements not identified in the questions below; therefore, we have included our comments here: Requirement and 2.6 and 2.6.1: A study that is five years old is very likely to be out of date. The entity's BES may have not changed much in five years but the entity cannot be certain whether or not their neighbor's system may have changed. Changes outside the immediate entity's system can impact results of studies within their system. Suggest that two years is a maximum that past studies should be allowed. Requirement 3.4.1 and 4.4.1 require PCs and TPs to coordinate with adjacent PCs and TPs to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. Please clarify whether this means that a PC or TP must coordinate with others to identify contingencies on other Systems that the PC or TP must now include on their Contingency list to simulate and address any performance violations on their own System, or does it mean that the PC or TP must coordinate with others to identify contingencies on their System that the PC or TP must now include on their Contingency list to simulate and address any performance violations on other Systems. In either case, the standard does not seem to clearly state what must be done, or whose responsibility it is to mitigate, if a contingency in one System causes a performance violation in another System. Requirement R4.3.1, bullet point 3 requires the stability analyses to include the impact of subsequent "[t]ripping

Organization	Yes or No	Question 1 Comment
		of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models". As written, this bullet could be interpreted as requiring the inclusion of these relay models in stability data bases. We do not have generic or actual relay models in our dynamics data bases for tripping line faults on lines and transformers represented. We represent actual relay response and tripping times of relays, communications, and breakers to faults in tripping transmission lines and transformers. Requiring the inclusion of generic or actual relay models for all relays that can trip lines and transformers would add a large burden to the development and maintenance of accurate dynamics model files that would add little or no benefit. Please change this bullet to read: "Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on known Protection System response".
Tucson Electric Power Company	Yes	We commend the SDT for its work to continue the improvement on the proposed TPL-001-1. We have included additional comments here since we were not able to find a place to include comments on the following: Requirement R4; Requirement, Parts 2.1.5, 2.3, and 2.8; Requirement 3, Part 3.3.2; and Requirement 4, Parts 4.3.1and Part 4.3.2 Requirement 2, Part 2.1.5:The spare equipment strategy does not improve reliability performance. If an outage of a long lead time piece of equipment occurs, the system should still be able to operate in a reliable manner that meets the performance measures of Categories P3 and P6. If an entity cannot meet its performance requirements under this standard, a capital project is indicated. Spare equipment being available would not mitigate this need it only increases expenses until the item is needed. Requirement 2, Parts 2.3 and 2.8:Short circuit fault duty is a localized phenomena that is mainly impacted by the addition of new generation or transmission facilities. Due to proprietary concerns of generation and transmission interconnection requests, short circuit studies are performed in forums outside the annual Planning Assessment. Normally, these studies will be conducted before the projects can be included in regional base cases. As such, short circuit analysis should not be included in this Standard since it would provided limited benefit. Requirement 3, Part 3.3.2 and Requirement 4, Part 4.3.2Steady state response of dynamic control devices should also be included in the Part 3.3.2. and the list of possible devices included should be removed from Part 3.3.2 and 4.3.2. Section R4.3.1, bullet point 3 requires the stability analyses to include the impact of subsequent "[t]ripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models". As written, this bullet could be interpreted as requiring the inclusion of these relay models in stability data bases. We do not have generic or actual relay models in our dynamics data bases for tripping line faults on lines and transformers represented. We represent actual relay response and tripping times of relays, communications, and breakers to faults in tripping transmission lines and transformers. Requiring

Organization	Yes or No	Question 1 Comment
		the inclusion of generic or actual relay models for all relays that can trip lines and transformers would add a large burden to the development and maintenance of accurate dynamics model files that would add little or no benefit. Please change this bullet to read: “Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on known Protection System response”.
Western Area Power Administration	Yes	The whole bullet point section in the Effective Date section referring to Corrective Action Plans could be deleted and instead captured by Requirement R2.7.3. A seven year grace period is probably not favorable to FERC, and a better solution could be developed to meet industry needs. In R2.7.3, a possible example of "beyond the control of the Transmission Planner" could be that the physics of a significant percentage of induction motors in low inertia air-conditioning loads would tend to pull out for certain N-1 events. This may in significant part occur because such motors may have nearly no dynamic stability margin to withstand such N-1 events as close-in 3-phase faults with normal clearing during peak load conditions. So until the Transmission Planner has been able to institute changes in the industry to address the basic physics of such loads, this Requirement 2.7.3 would permit the use of such "Non-Consequential" Load Loss and curtailment of Firm Transmission Service. In this example, it may take longer than a seven year time period to fix the problem. On the other hand, some examples of Non-Consequential Load Loss could perhaps be mitigated in a shorter timeframe. Provided that an entity has a good technical justification and defined margin for “Non-Consequential” Load Loss or curtailment of Firm Transfers, then it may be acceptable. Requirement R2.7.3 seems to move in this direction. Section R4.3.1, bullet point 3 requires the stability analyses to include the impact of subsequent “[t]ripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models”. As written, this bullet could be interpreted as requiring the inclusion of these relay models in stability data bases. We do not have generic or actual relay models in our dynamics data bases for tripping line faults on lines and transformers represented. We represent actual relay response and tripping times of relays, communications, and breakers to faults in tripping transmission lines and transformers. Requiring the inclusion of generic or actual relay models for all relays that can trip lines and transformers would add a large burden to the development and maintenance of accurate dynamics model files that would add little or no benefit. Please change this bullet to read: “Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on known Protection System response”.
NERC staff	Yes	NERC staff supports the change to allow Corrective Action Plans to include tripping of Non-Consequential Load and curtailment of Firm Transmission Service for 7 years. This seems long, but staff understands the stakeholder concern that it could take that long to plan, site, and construct facilities required for compliance with the standard.
SERC Dynamics Review	Yes	“The comments expressed herein represent a consensus of the views of the above named members of the SERC Engineering Committee Dynamics Review Subcommittee only and should not be construed as the

Organization	Yes or No	Question 1 Comment
Subcommittee		position of SERC Reliability Corporation, its board or its officers."
Lakeland Electric	Yes	Shouldn't the "Implementation Plan for TPL-001-1" document be for TPL-001-2? Also, "TPL-001-1" is referenced throughout the document.
FirstEnergy	Yes	We appreciate the effort of the standard drafting team and the changes reflected in the current draft of the TPL-001-1 standard. The changes are improvements that should move the standard towards greater industry consensus. The extended Implementation Plan aligns with suggestions in FE's prior ballot comments. We support the Implementation Plan change made by the team.
US Bureau of Reclamation	Yes	With exception of the definitions.
TVA Transmission Planning & Compliance	Yes	TVA supports the change from five years to seven years for the implementation plan period.
Independent Electricity System Operator	Yes	We agree with this change. We further suggest that this change and the additional wording: "or in those jurisdictions where no regulatory approval is required on the first day of the first calendar quarter, 84 months after Board of Trustees adoption" be added to P. 3 of the standard that starts with "For 84 calendar months..." to be totally consistent.
Pacific Gas and Electric Company	Yes	We commend the SDT for its work to continue the improvement on the proposed TPL-001-1. We were not able to find a place to include comment on Requirement R3 or R4; therefore, we have included our comments here: Section R4.3.1, bullet point 3 requires the stability analyses to include the impact of subsequent "[t]ripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models". As written, this bullet could be interpreted as requiring the inclusion of these relay models in stability data bases. We do not have generic or actual relay models in our dynamics data bases for tripping line faults on lines and transformers represented. We represent actual relay response and tripping times of relays, communications, and breakers to faults in tripping transmission lines and transformers. Requiring the inclusion of generic or actual relay models for all relays that can trip lines and transformers would add a large burden to the development and maintenance of accurate dynamics model files that would add little or no benefit. Please change this bullet to read: "Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on known Protection System response". Section 3.4.1 and 4.4.1 require PCs and TPs to coordinate with adjacent PCs and TPs to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. Please clarify whether this means 1) that a PC or TP must coordinate with others to identify contingencies on other

Organization	Yes or No	Question 1 Comment
		Systems that the PC or TP must now include on their Contingency list to simulate and address any performance violations on their own System, or 2) that the PC or TP must coordinate with others to identify contingencies on their System that this PC or TP must now include on their Contingency list to simulate and address any performance violations on the other Systems. In either case, the standard does not seem to clearly state what must be done, or whose responsibility it is to develop the corrective action plan, if a contingency in one System causes a performance violation in another System.
Puget Sound Energy Sacramento Municipal Utility District Modesto Irrigation District Los Angeles Department of Water and Power Idaho Power Co California Energy Commission SRP Platte River Power Authority PNM Arizona Public Service Company	Yes	We commend the SDT for its work to continue the improvement on the proposed TPL-001-1. We were not able to find a place to include comment on Requirement R4; therefore, we have included our comments here: Section R4.3.1, bullet point 3 requires the stability analyses to include the impact of subsequent "[t]ripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models". As written, this bullet could be interpreted as requiring the inclusion of these relay models in stability data bases. We do not have generic or actual relay models in our dynamics data bases for tripping line faults on lines and transformers represented. We represent actual relay response and tripping times of relays, communications, and breakers to faults in tripping transmission lines and transformers. Requiring the inclusion of generic or actual relay models for all relays that can trip lines and transformers would add a large burden to the development and maintenance of accurate dynamics model files that would add little or no benefit. Please change this bullet to read: "Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on known Protection System response".
SERC Planning Standards Subcommittee	Yes	
Hydro One Networks Inc.	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
Pepco Holings, Inc - Affiliates	Yes	
IRC Standards Review	Yes	

Organization	Yes or No	Question 1 Comment
Committee		
Bonneville Power Administration	Yes	
Exelon Transmission Planning	Yes	
Southern Company	Yes	
Florida Reliability Coordinating Council, Inc - Transmission Working Group	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
NorthWestern Energy (NWMT)	Yes	
Orlando Utilities Commission	Yes	
Manitoba Hydro	Yes	
Minnesota Power	Yes	
South Carolina and Gas	Yes	
California ISO	Yes	
Seattle City Light	Yes	
ISO New England Inc.	Yes	
United Illuminating	Yes	

Organization	Yes or No	Question 1 Comment
Ameren	Yes	
Xcel Energy	Yes	
Hydro-Quebec TransEnergie	Yes	
National Grid	Yes	
American Transmission Company	Yes	
American Electric Power (AEP)	Yes	
Tri-State Generation & Transmission	Yes	
Lakeland Electric	Yes	
GTC	Yes	
Northeast Utilities	Yes	
NBSO	Yes	
Central Maine Power Company	Yes	
Oncor Electric Delivery	Yes	
New York State Electric & Gas Corp	Yes	
Progress Energy	Yes	
ERCOT ISO	Yes	

Organization	Yes or No	Question 1 Comment
New York Independent System Operator	Yes	
MidAmerican Energy	Yes	
Southern California Edison Company	Yes	

2. The SDT has revised the definition of Year One based on industry comments to the initial ballot. Do you support this change? If you do not support this change, please specify why you disagree and include specific alternative language to resolve your concern.

Summary Consideration:

The majority of respondents agree with the changes to the Year One definition but there was one change made due to industry comments for consistency of terminology.

> **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One ~~must~~ includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One ~~must~~ includes the forecasted peak Load period for either 2012 or 2013.

The SDT acknowledges the concerns expressed by a minority of commenters on ambiguity of wording, embedding the definition in the requirements, and use of operating horizon studies. However, the SDT believes that the definition has been vetted through numerous industry comment periods and that it now represents a reasonable definition for a continent-wide standard while still providing a level of flexibility for the planner.

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered the comments.

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	No	The definition of Year One could be eliminated, and its wording used in place of Year One within the text of the requirement. The proposed definition has now added ambiguity with respect to “year two” and “year five” which are not defined. Year two could be deleted and R.2.1.1 modified as follows: System peak Load representing a point in time 12-24 months and another point in time 48-65 months into the future from the time the study is initiated. Define Year Five as the twelve month period 4 to 6 calendar years from the date of the Planning Assessment.
ISO New England Inc.	No	The definition of Year One could be deleted and used in place of Year One within the text of the requirement. The proposed definition has now added ambiguity with respect to “year two” and “year five” which are not defined. Year two could be deleted and R.2.1.1 modified as follows: System peak Load representing a point in time 12-24 months and another point in time 48-65 months into the future from the time the study is initiated.

Organization	Yes or No	Question 2 Comment
Western Electricity Coordinating Council	No	We recognize that the drafting team made changes to the definition of Year One based on industry comments. However, we believe that the revised language could allow for a situation where an entity could use its next season's operating study as its Year One planning study. For example, if the entity does its study in the fall of 2011, the proposed definition would allow the entity to use its summer 2012 operating study as its Year One study. This is a very short period to address any issued identified. Suggest working into the requirement that Planning Studies must look out at least 12 months beyond when the study is performed. This would still allow for the provision in the current definition example ("if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013) because the entity would be able to use their 2013 Load period, but it would prevent the entity from using the 2012 Load period if they started the assessment late in 2011.
E.ON U.S.	No	Comments: 2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected. E.ON U.S. believes the scope of the 'current study' should be defined. It is not clear whether the scope is the same as outlined in section 2.1.
Florida Reliability Coordinating Council, Inc - Transmission Working Group	No	No, because it is worded to be dependent upon when an assessment is started rather than when the assessment is completed and valid. Assessments don't typically include a "start date". An assessment completed on a calendar date should include (be valid for) the forecasted peak load for a timeframe that begins no more than 24 months from the date that the assessment was completed.
Lakeland Electric	No	"the latest" is not needed from the second sentence of R1, since the sentence already ended with "..shall represent projected System conditions". R1 Part 1.1.2 Suggest adding this clarification at the end "... six months during the period under study". This language addition helps clarify the point that if an outage occurs during the summer and the entity's system peak occurs in the winter, then the system peak Load study case (model) does not have to include this particular outage.
Seattle City Light	No	The definition of Year One is now too flexible and does not meet the intent of the standard. For example, our system peak is generally in January of the year. If I perform TPL studies in November 2011, studying the peak in January 2012 is acceptable according to the new definition. This is only two months from the date of the study. The intent of the TPL standard should be that entities must study and plan for inadequacies found in the studies. A one- or two-month lead time is not adequate to address any problems identified. Year One should be the year containing the first peak 12 months or more from the current date. Otherwise, TPL studies become merely seasonal operational studies, not planning studies. Alternative Language: "For the Planning Assessment started in a given year, Year One should contain the first system peak that occurs twelve months or more after the date

Organization	Yes or No	Question 2 Comment
		of the Planning Assessment."
US Bureau of Reclamation	No	The language implies a requirement. The language "Year One must include the forecasted peak Load period for one of the following two calendar years" is a requirement and not a statement of clarification. If the definition is that "Year One" can also be the period used for forecast peak load, then it should be stated so. It is suggested that either the language in the definition is modified or the language is deleted from the definition and moved to the body of the standard.
United Illuminating	No	Year One should be used within the text of the requirement. Do not have a definition for Year One.
National Grid	No	Year One should be used within the text of the requirement. Do not have a definition for Year One. Year two could be deleted and R.2.1.1 modified as follows: For the Planning Assessment started in a given calendar year, the first year that is studied must include the forecasted peak Load period for one of the following two calendar years. An additional Near-term study must be performed that is four calendar years beyond the first year that is studied.
Tri-State Generation & Transmission	No	Comments: The Year One definition is somewhat clearer now, but there is still some ambiguity. We recommend the removal of the term "Year One, year two, and year five" from R2.1.1. and deletion of the Year One definition (definitions are not required for year two and year five, for instance). The Year One concept can be integrated into the definition of Near-Term Transmission Planning Horizon, which we suggest changing to "The period beginning with the first year following the operating horizon, as determined by the Transmission Planner or Planning Coordinator, through the fifth year." Then, rather than say "Year One, year two, and year five", we can use the phrase "at least one of the first two years of the Near-Term Transmission Planning Horizon, and the fifth year".This will require corresponding changes in R2.1.1 and R2.1.2.
Lakeland Electric	No	While the definition of Year One addresses the time span this year occupies, it does not address when that time span begins. The example which was added to the definition suggests that Year One begins twelve months from the start of the Planning Assessment, but it does not appear to be specifically stated. The following language is recommended: "The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing, beginning twelve months from the planned completion date of the Planning Assessment."
Northeast Utilities Consolidated Edison Co. of New York, Inc.	No	NU does not support the revised definition of Year One as we believe it leads to confusion. Our suggestion is that Year One should be the Peak Load Year after the study is initiated. The subsequent years should be counted from Year One (e.g., a study that is started in year 2010 with peak load in 2011 will have Year One as

Organization	Yes or No	Question 2 Comment
		2011 and Year Two as 2012, etc.).
Modesto Irrigation District	No	The definition as it is in the current standards is fine. The new proposed definition is unclear.
NBSO	No	To avoid confusion, the formal definition for Year One should be eliminated and wording used to describe Year One be placed within the appropriate requirement. For example, R2.1.1 could be re-written to state: System peak Load representing a point in time 12-24 months and another point in time 48-65 months into the future from the time the study is initiated.
Central Maine Power Company New York State Electric & Gas Corp New York Independent System Operator	No	The added clarification to the definition of Year One serves to remove most ambiguity with respect to Year One. However, the revision has added further ambiguity to the terms “year two” and “year five” which are not defined. For the Planning Assessment started in a given calendar year, the first year that is studied must include the forecasted peak Load period for one of the following two calendar years. An additional Near-term study must be performed that is four calendar years beyond the first year that is studied. We recommend defining Year Five as the twelve month period 4 to 6 calendar years from the date of the Planning Assessment. We further recommend revising R2.1.1 as follows: “System peak Load for Year One and for Year Five.”Alternatively, the definition of Year One could be eliminated and described within the text of the requirements.
Tucson Electric Power Company	No	A seasonal reference should be included in the example. Alternative language beginning with the second sentence: For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak load period for the forecasted peak load season that is between 12 and 24 months into the future from the current season. For example, if a Planning Assessment was started in 2011 prior to the forecasted peak season, then Year One must include the forecasted peak load for 2012. If the Planning Assessment was started in 2011 during or after the forecasted peak season, then Year One must include the forecasted peak load for 2013.
GDS Associates, Inc.	No	The definition it seem both incomplete and exhaustive:- If taken out of the planning assessment context, the definition is missing the matter that is supposed to identify. We suggest changing the first sentence such as “The first twelve month period to which the functional entity is responsible for the assessment of Transmission System Planning performance.”- While it will be a burdensome task to define each year that follows Year One, the definition of Year One may include a sentence that define the rule for the following years such as “All of the twelve months period following Year One shall commence immediately after the end of the preceding twelve months period.”- The definition should not include examples.
Pacific Gas and Electric Company		We recognize that the drafting team made changes to the definition of Year One based on industry comments. However, we believe that the revised language could allow for a situation where an entity could use its next season’s operating study as its Year One planning study. For example, if the entity does its study in the fall of

Organization	Yes or No	Question 2 Comment
		2011, the proposed definition would allow the entity to use its summer 2012 operating study as its Year One study. This is a very short period to address any issued identified. Suggest working into the requirement that Planning Studies must look out at least 12 months beyond when the study is performed. This would still allow for the provision in the current definition example ("if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013) because the entity would be able to use their 2013 Load period, but it would prevent the entity from using the 2012 Load period if they started the assessment late in 2011.
NERC staff	Yes	NERC staff supports the revisions to the definition of Year One. However, we believe an associated change should be made where this term is used in part 2.1.1 of Requirement 2 which requires modeling of "System peak Load for either Year One or year two, and for year five." It seems the new definition of Year One would negate the need to refer to year two. NERC staff recommends that part 2.1.1 be changed to "System peak Load for Year One and for year five."
Western Area Power Administration	Yes	Yes, this clarification helps. The drafting team could also define "year five".
FirstEnergy	Yes	The change in the Year One definition provides greater flexibility for the industry and also addresses a prior FE comment during the 1st ballot. We appreciate the team's careful consideration of the industry feedback and support the change.
TVA Transmission Planning & Compliance	Yes	TVA supports the change in the Year One definition - but would suggest that the word "started" should be changed to "completed" since a Planning Assessment may be started in one calendar year and finished in the next calendar year.
SERC Planning Standards Subcommittee	Yes	
Hydro One Networks Inc.	Yes	
SERC Dynamics Review Subcommittee	Yes	
MRO's NERC Standards Review Subcommittee	Yes	

Organization	Yes or No	Question 2 Comment
Pepco Holings, Inc - Affiliates	Yes	
IRC Standards Review Committee	Yes	
Bonneville Power Administration	Yes	
Exelon Transmission Planning	Yes	
Southern Company	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
NorthWestern Energy (NWMT)	Yes	
PNM	Yes	
Platte River Power Authority	Yes	
Orlando Utilities Commission	Yes	
Manitoba Hydro	Yes	
Minnesota Power	Yes	
Independent Electricity System Operator	Yes	
South Carolina and Gas	Yes	

Organization	Yes or No	Question 2 Comment
SRP	Yes	
California ISO	Yes	
California Energy Commission	Yes	
Los Angeles Department of Water and Power	Yes	
Idaho Power Co	Yes	
Ameren	Yes	
Hydro-Quebec TransEnergie	Yes	
LCRA TSC	Yes	
American Transmission Company	Yes	
American Electric Power (AEP)	Yes	
GTC	Yes	
Oncor Electric Delivery	Yes	
Progress Energy	Yes	
ERCOT ISO	Yes	
MidAmerican Energy	Yes	
Puget Sound Energy	Yes	

Organization	Yes or No	Question 2 Comment
Sacramento Municipal Utility District	Yes	
Xcel Energy	Yes	
Southern California Edison Company	Yes	

3.

The SDT has revised the Requirements language based on industry comments to the initial ballot. Do you support these changes? If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your concern.

Summary Consideration:

Due to various industry comments, the SDT made the following clarifying change to Requirement R1:

> **R1**. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use ~~the latest~~ data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes P0 as the normal ~~s~~System condition in Table 1.

The SDT believes that 6 months is the correct number in Requirement R1, Part 1.1.2 because the planner is evaluating longer term periods, and shorter duration outages, which have scheduling flexibility, are addressed by Operations Planning. Outages six months or longer will typically be over the study periods (peak and Off-Peak) addressed in Requirement R2, Part 2.1.3.

Requirement R1, Part 1.1.6 – An issue was raised that resources could be used for export to other areas. The SDT did not make a change to the requirement since exports to other areas are covered in Requirement R1, Part 1.1.5.

The majority of respondents agree with the posted changes to these requirements and no other changes have been made based on stakeholder comments.

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered the comments.

Organization	Yes or No	Question 3 Comment
NERC staff	No	NERC staff suggests that the added sentence in R1 be deleted and “Normal System” in Table 1 be replaced with “No unplanned Element outages.” We have a problem with R1 establishing “normal system condition.” “Normal” is not defined, but the system condition that most people would define as “normal” is the System operating within its limits. There are no checks required on the projected system conditions to guarantee “operation within limits.” Staff realizes that if this were the case, the categories tested would all pass their respective tests. (In other words, the category tests may define operating limits that in turn define “normal” from a planning perspective.) Thus, the added sentence in R1 should be deleted. In Table 1, the use of the term “Normal System” in the column “Initial System Condition” really means “No unplanned Element outages.” All Elements that do not have a planned outage are assumed in-service (for transmission Elements) or available for dispatch (for generators).

Organization	Yes or No	Question 3 Comment
		Contrast the term "Normal System" with categories P3 and P6, which have the loss of an Element (which is unplanned) followed by the loss of a second Element (also unplanned). "Normal System" should be replaced with "No unplanned Element outages."
SERC Planning Standards Subcommittee Southern Company Ameren	No	The definition does not adequately address normal (pre-contingency) operating procedures or system configurations. Language should be added to the requirement (perhaps as R1.1.7) to include normal operating procedures or system configurations in place prior to any contingency occurring.
Bonneville Power Administration	No	Please clarify R1.1.2 to state "Known outage(s) of generation or Transmission Facility(ies) during the Planning Horizon with a duration of of at least six months."
E.ON U.S.	No	In the statement: "the Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list."E.ON U.S. believes that the use of the pronoun "their" in the quoted section above is confusing. "Their" could be read as applying to the adjacent Planning Coordinators and not to the Planning Coordinator to whom the standard applies. E.ON U.S. recommends that the word "their" should be changed to "the Planning Coordinator's and Transmission Planner's" in order to make it clear.
Florida Reliability Coordinating Council, Inc - Transmission Working Group	No	No, Since "the latest" data may become available after the study is complete, a planner may not be able to ever complete a study. Please consider removing "the latest" from the second sentence.
Western Area Power Administration	No	It's difficult to tell whether Requirement R1 is intended to require only one base case or whether it was intended to require creation of separate models for each possible N-0 condition ("normal system condition") under a variety of stressing scenarios. The inserted language does not seem to provide additional clarity. Suggested language may be "This establishes the initial 'Normal System' condition corresponding to category P0 in Table 1." Also, in Requirement R1.1.5, how are the Firm Transmission Service commitments supposed to be modeled in Power Flow Cases? Are they just to be modeled as loads, generation, and control area interchanges? Suppose a POR or POD is not at a generator or load bus. What selection of generation and load would represent the projected system conditions for this Firm Transmission Service commitment?
CenterPoint Energy	No	The SDT did not incorporate CenterPoint Energy's previous comment regarding R1; therefore, CenterPoint Energy's concerns remain.

Organization	Yes or No	Question 3 Comment
United Illuminating National Grid Central Maine Power Company New York State Electric & Gas Corp	No	For R1 Ambiguity regarding base case assumptions, in combination with lack of clarity and clear direction of purpose regarding the sensitivity analysis, undermines the objectives of the standard; R1.1 Part 1.1.2. With respect to known outages, there needs to be greater flexibility in the standards (e.g. more tolerance to non-consequential load shedding or limitations to the contingencies that need to be considered (e.g. P0, P1, & P2)). Regional allowances for load shedding under this condition should be approved. Duration of known outages should be increased from six months to one year; R1.1 Part 1.1.6 Delete "required for Load". Resources may also be used for export to other areas, not just internal load.
ISO New England Inc.	No	R1.1 Part 1.1.2. With respect to known outages, there needs to be greater flexibility in the standards (e.g. more tolerance to non-consequential load shedding or limitations to the contingencies that need to be considered (e.g. P0, P1, & P2)). Regional allowances for load shedding under this condition should be approved. Duration of known outages should be increased from six months to one year; R1.1 Part 1.1.6 Delete "required for Load". Resources may also be used for export to other areas, not just internal load.
American Transmission Company	No	We propose the following changes and questions: R1 - We offer the minor suggestion of replacing the wording of “maintain System models within their respective areas” with “maintain System models of elements that are interconnected to any portion of the BES that is owned or operated by the TP or PC”. This wording would avoid the ambiguity that can occur when a BA that is associated primarily with one TP declares ownership of a bus in another TP’s geographic area, but expects its primary TP to maintain the BA’s model data for the remote generation or load. R1.1.2 - We request a SDT opinion on how two individual outages should be modeled if they are both in excess of six months duration and they overlap by less than six months. Should the overlapping condition only be modeled if the condition is expected to last more than six months?
Tri-State Generation & Transmission	No	We suggest changing the added sentence to “This establishes the Category P0, No Contingency, Initial System Conditions in Table 1.”
Lakeland Electric	No	Consider removing “...the latest...” from R1 and changing R1.1.2 to state “...six months during the period of

Organization	Yes or No	Question 3 Comment
		study."
Northeast Utilities	No	NU believes that the Normal System Conditions as stated in Requirement R1 should establish the base case conditions to be used for the assessment studies. More guidelines for developing base cases should be addressed in the requirements. What the statement in Requirement R1 lacks is the manner of creating generation dispatches and the level of interface flows (level of stress), which are central to any base case to be used to assess the reliability of the electric power network. Depending upon how the base case dispatches and the level of interface flows are created, a study may reveal reliability violations in the power system. This is a weakness of the existing TPL standards. NU, however, will support the idea of developing regional guidelines in regard to the nature of the base cases to be used for the NERC reliability studies. Comment on Requirement R1.1, Part 1.1.2: With respect to known outages NU requests that the six month duration listed by the requirement should be changed to one year duration. Requirement R1.1 Part 1.1.6: The phrase "required for Load" should be deleted as this confuses the issue [since resources may also be used for export to other areas and not just internal load].
NBSO	No	R1 should have some language to state that base case assumptions should be made such that they appropriately stress the system to be tested and are in accordance with good engineering practice.
Tucson Electric Power Company	No	Proposed changes1.1.1 Existing Facilities that will not be changed before the study year 1.1.3 New planned Facilities and planned changes to existing facilities
GDS Associates, Inc.	No	The Time Horizon should be for both Near-Term and Long-Term Planning.
MidAmerican Energy	No	There are concerns over the FERC outstanding March order on TPL and how FERC interprets "normal" or base case conditions and "assuming" an entities primary protection system is out of service and must rely on its backup protection system to operate. This concept combined with the new tables cannot be perpetuated.
Xcel Energy	No	Although we support the change conceptually, we believe the sentence added in R1 needs more specificity to ensure a better correlation to the relevant portions of Table 1. Please make it clear that the system model created as per R1 corresponds to Category P0 by explicitly referring to it. Suggested language is: 'This establishes the "Normal System" initial condition corresponding to category P0 in Table 1.' Further, consider omitting the word "System" in Table 1 Column 2 heading by calling it "Initial Condition" – the redundancy produced by its usage in both heading and entry does not appear to provide any

Organization	Yes or No	Question 3 Comment
		value. Alternative suggested language is: 'This establishes the "Normal" initial system condition corresponding to category P0 in Table 1." This alternative approach envisages changing the Column 2 entries to "Normal" since the word "System" is now retained in the heading.
MRO's NERC Standards Review Subcommittee	Yes	We propose the following changes and questions:R1 - We offer the minor suggestion of replacing the wording of "maintain System models within their respective areas" with "maintain System models of elements that are interconnected to any portion of the BES that is owned or operated by the TP or PC". This wording would avoid the ambiguity that can occur when a BA that is associated primarily with one TP declares ownership of a bus in another TP's geographic area, but expects its primary TP to maintain the BA's model data for the remote generation or load. R1.1.2 - We request the SDT opinion on how two individual outages should be modeled if they are both in excess of six months duration and they overlap by less than six months. Should the overlapping condition only be modeled if the condition is expected to last more than six months?
Northeast Power Coordinating Council	Yes	
Hydro One Networks Inc.	Yes	
Transmission Issues Subcommittee	Yes	
SERC Dynamics Review Subcommittee	Yes	
Pepco Holings, Inc - Affiliates	Yes	
IRC Standards Review Committee	Yes	
Exelon Transmission Planning	Yes	

Organization	Yes or No	Question 3 Comment
Western Electricity Coordinating Council	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
NorthWestern Energy (NWMT)	Yes	
PNM	Yes	
FirstEnergy	Yes	
Platte River Power Authority	Yes	
Orlando Utilities Commission	Yes	
Manitoba Hydro	Yes	
Minnesota Power	Yes	
US Bureau of Reclamation	Yes	
TVA Transmission Planning & Compliance	Yes	
Independent Electricity System Operator	Yes	
South Carolina and Gas	Yes	
SRP	Yes	

Organization	Yes or No	Question 3 Comment
California ISO	Yes	
Seattle City Light	Yes	
California Energy Commission	Yes	
Los Angeles Department of Water and Power	Yes	
Idaho Power Co	Yes	
Hydro-Quebec TransEnergie	Yes	
LCRA TSC	Yes	
American Electric Power (AEP)	Yes	
GTC	Yes	
Pacific Gas and Electric Company	Yes	
Consolidated Edison Co. of New York, Inc.	Yes	
Modesto Irrigation District	Yes	
Oncor Electric Delivery	Yes	
Progress Energy	Yes	
ERCOT ISO	Yes	
New York Independent System	Yes	

Organization	Yes or No	Question 3 Comment
Operator		
Puget Sound Energy	Yes	
Sacramento Municipal Utility District	Yes	
Southern California Edison Company	Yes	

3.1 Requirement R2 and Part 2.1 – past studies

Summary Consideration:

The majority of respondents agree with the changes to these requirements and only the changes to these requirements noted below have been made.

The SDT believes that the supposed inconsistencies mentioned in the language are not inconsistencies at all but necessary qualifiers. No change made.

Based on comments received, the SDT has modified Requirement R2, part 2.6.2 as follows to provide additional clarity:

> **2.6.2** For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. ~~shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.~~ Documentation to support the technical rationale for determining material changes shall be included.

The following change was made to clarify that the list following the statement is not all inclusive:

> **2.7.1** List System deficiencies and the associated actions needed to achieve required System performance. Examples of ~~S~~such actions ~~may~~ include:

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered them. In some of the cases relating to the above comments, the SDT has already responded to similar comments and those responses are quoted here for convenience:

2.1.5 – "When a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. This requirement is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Actions such as out of merit dispatch, operational restrictions, System reconfiguration can be part of a Corrective Action Plan if the System cannot meet performance requirements without the Facility in service."

Organization	Yes or No	Question 4 Comment
Northeast Power Coordinating Council Consolidated Edison Co. of New York, Inc.	No	The revisions made to Requirement R2 Part 2.1 appear to resolve the concern that past studies could not be used to comply with the short-term steady state study requirements. This revision must be carried through to other sections (R2.2, 2.2.1). However, the language of Requirement R2 Part 2.2 still seems to suggest that current annual studies are always required for the long-term steady state assessment to be compliant. This may have been an oversight, for consistency Requirement R2 Part 2.2 should be modified to similarly read as Requirement R2, Part 2.1. Regarding R2.2, the language should be consistent with 2.1. For example, use "current or qualified past studies" instead of "the following annual current study". Revisions made to Requirement R2.1.5 have made it worse than was originally drafted. This would require the PC & TP to study (meaning performing a technical analysis) of the impact and probability of the possible unavailability of any piece of equipment with a lead time of one year or more. Such an evaluation of spare equipment strategies would require significant additional resources and data, but provide no benefit to system reliability, as it is redundant to the existing N-1-1 contingency requirement (P6). R2.7 requires that Corrective Action Plans are included in each Planning Assessment and states “Such actions may include...” followed by a list of actions. Restricting allowable actions, and excluding runback/tripping of HVDC would have a direct impact on multiple existing facilities in New York and would adversely impact the reliability planning of the NYCA. Runback/tripping of HVDC must be added to the list, and also suggest revising to “Such actions may include but not be limited to:”.
Florida Reliability Coordinating Council, Inc - Transmission Working Group	No	No, Please consider removing R.2.6.2. The overwhelming majority of PAs use a 10 year set of planning models developed annually by Regions or Subregions. These annual sets of planning models will always have some changes. The annual study requirement is especially problematic for Stability and Short circuit studies that require much more engineering time to complete and are much less likely to have results impacted by minor model changes such as different load forecasts. Uncertainty with audit review of technical rationale documentation will serve to focus Transmission Planning engineering resources on short term compliance to an extent that is counter productive.
Western Area Power Administration	No	R 2.1.5: The issue in this Requirement is studied in the Operations next-day; next-week; next-month studies required under the TOP Standards; and are also covered by processes such as the Operational Transfer Capability Policy Committee (OTCPC) seasonal study process within the WECC. It would be quite onerous to run a complete power flow simulation on separate base cases for each transformer (or other equipment with long lead time) initially out of service. The revision in language from “Planning Assessment” to “studies” does not clarify that a power flow simulation is not necessarily required for each situation. A valid assessment could include other methods such as using sound technical reasoning to relate the initial out-of-service

Organization	Yes or No	Question 4 Comment
		condition to a condition that has already been studied. This condition may have taken place in previous operational studies. The language in the standard could be improved to make this clarification - perhaps reference R2.6. Additionally, this Requirement still needs further clarification. Currently the scope of equipment applicable to the requirement could be misinterpreted as larger than that contemplated by FERC. The standard as written seems to say that the responsible entity needs to study the spare equipment strategy for all "major transmission equipment" with long lead times. In the directive to include this requirement, FERC used the term "critical facilities". In the NOPR to Order No. 693 they stated, "Critical facilities are those facilities that impact IROLs and deliverability of generation to firm load" (P1081). In Order No. 693 FERC also said, "if an entity's spare equipment strategy for the permanent loss of a transformer is to use a 'hot spare' or to relocate a transformer from another location in a timely manner, the outage of the transformer need not be assessed under peak system conditions" (P1725).Finally, the drafting team could clarify if this requirement applies to radial branches (such as generator step-ups or step-down to load). Such branches may be construed as "critical facilities" but the impediment to deliverability of generation to firm load is consequential to the initial outage.
Lakeland Electric	No	Please consider removing R.2.6.2
Platte River Power Authority	No	I like that you have requirements for qualifying past studies, but Part 2.6.2 is confusing. Please change Part 2.6.2 to read something like: "For steady state, short circuit or Stability analysis: no material changes have occurred to the System represented in the study or, if material changes have occurred, a technical rationale can be provided to explain that the changes do not impact the performance results in the study area."
Orlando Utilities Commission	No	Allowing the use of past studies in lieu of new studies for part or all of an assessment when the underlying system hasn't changed in a signficant change if very prudent. However the wording in 2.6.2 of "unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area" is of concern. By this wording is it intended that the planner must demonstrate that every material change has no impact? In essence doing more work to prove that a study isn't required then the study would take? Or that the planner must essentially have a technical rationale (overarching) for determining when a material change is "material enough" to impact system perofrmance?
Minnesota Power	No	Requirement 2 - This requirement states that Stability analyses be performed as part of the annual Planning Assessments. Minnesota Power would like to see the term "Stability analysis" more clearly defined as there are several different types of stability related analysis that can be performed for power systems including: transient stability, voltage stability and small signal stability.
US Bureau of Reclamation	No	The question is misleading in that R2 also include current studies. The overall structure of the standard

Organization	Yes or No	Question 4 Comment
		could be greatly improved if the standard were segmented into Near Term and Long Term with sub segments for each specific type of analysis to be performed. Second, the standard does not use consistent terms. The Planning Assessment is to include Near Term and Long Term portions which must have steady state analysis, short circuit analysis, and stability analysis (ref. R2). Requirement R 2.1 introduces sensitivity analysis for the Near Term portion, and then refers to the Planning Analysis which is in reality both Near Term and Long Term portions. That implies that sensitivity analysis must be required for both? The standard repeats the requirement for annual stability studies in 2.4 which was already a requirement for Planning Assessments. The requirement 2.1.5 is one the most problematic requirements in this standard. This requirement implies that an entity must have spare equipment and a strategy to employ it. That is beyond the scope of the Energy Policy Act 2005. Spare equipment is not on-line and does not contribute to the reliability of the existing system. The Energy Policy Act of 2005 specifically prohibits the requirement to enhance or modify the system. The use, application, or requirement to have spare equipment violates that prohibition. This section should be removed. In addition, this requirement suffers from an ability to implement. In the first case, the requirement is invoked if the spare equipment strategy could result in unavailability of transmission equipment. How is that determined? There is no nexus to that determination. The unavailability may have already occurred once the transmission equipment has failed. The only way to avoid unavailability if the transmission equipment that fails has a hot stand-by with automatic fail-over. The presence or not of a suitable replacement will still result in unavailability by virtue of the failure o the first piece of transmission equipment. Next problem, who will second guess the owner of the replacement. Where is the requirement to make the replacement strategy available? The standard should focus on system performance with existing equipment to meet current and future loads.
CenterPoint Energy	No	The SDT did not incorporate CenterPoint Energy's previous comments regarding R2; therefore, CenterPoint Energy's concerns remain.
ISO New England Inc. United Illuminating National Grid	No	We can agree with R2.1 however with respect to R2.2 Language should be consistent with 2.1 for example - use "current or qualified past studies" instead of "the following annual current study."
Northeast Utilities	No	The revisions made to Requirement R2 Part 2.1 appear to resolve the concern that past studies could not be used to comply with the short-term steady state study requirements. However, the language of Requirement R2 Part 2.2 still seems to suggest that current annual studies are always required for the long-term steady state assessment to be compliant. This may have been an oversight, for consistency Requirement R2 Part

Organization	Yes or No	Question 4 Comment
		2.2 should be modified to similarly read as Requirement R2, Part 2.1.
Hydro-Quebec TransEnergie	No	Requirement R2 Part 2.2 should be modified to read as 2.1 (not impose current annual studies as the only requirement for assessment)
American Transmission Company	No	R2.1.3 - We offer the minor suggestion of revising R2.1.3 to state, "Known outages of generation or Transmission Facilities with a duration of at least six months be simulated along with P1 events for the System peak or Off-Peak conditions when the outages are scheduled to occur." We interpret that the requirement should only call for the simulation of individual outages with duration of six months or more and not imply the simulation of sequential (back-to-back) outages where each individual outage is less than six months, but the composite duration of the back-to-back outages is more than six months. We also interpret that if two or more known outages with duration of at least six months are overlapping, then the overlapping outage condition would only be simulated for the conditions when the overlapping outages are scheduled to occur if the duration of the overlapping condition is at least six months.
Tri-State Generation & Transmission	No	2.1.5 - Change "shall be performed for" to "shall have been performed for."
Lakeland Electric	No	No, the phrase any material changes used in requirement R.2.6.2 will effectively cause all Planning Authorities to run all studies every year regardless of minor changes in the model. The overwhelming majority of PAs use a 10 year set of planning models developed annually by Regions or Subregions. These annual sets of planning models will always have some changes. The annual study requirement is especially problematic for Stability and Short circuit studies that require much more engineering time to complete and are much less likely to have results impacted by minor model changes such as different load forecasts. Uncertainty with audit review of technical rationale documentation will serve to focus Transmission Planning engineering resources on short term compliance to an extent that is counter productive. Please consider removing R.2.6.2
NBSO	No	NBSO agrees with the language for R2.1, but the language with R2.2 should be changed to be consistent with R2.1. NBSO disagrees with the revisions to R2.1.5. Requiring PAs to study instead of assess the possible unavailability of equipment with a lead time of a year or more will result in significant demand on resources with little impact on system reliability. NBSO also questions what additional value such studies will bring in addition to the N-1-1 requirements (P6).

Organization	Yes or No	Question 4 Comment
Central Maine Power Company New York State Electric & Gas Corp	No	We completely agree with the revision to R2.1, but this revision must be carried through to other sections (R2.2, 2.2.1) and R2.2 language should be consistent with 2.1 for example - use "current or qualified past studies" instead of "the following annual current study". Revisions made to Requirement R2.1.5 have made it worse than as originally drafted. This would require the PC & TP to study, or in other words perform technical analysis of, the impact and probability of the possible unavailability of any piece of equipment with a lead time of one year or more. Such an evaluation of spare equipment strategies would require significant additional resources and data, but provide no benefit to system reliability, as it is redundant to the existing N-1-1 contingency requirement (P6).
Progress Energy	No	While PE does not disagree with the basic premise of 2.1, PE disagrees with the language to the extent that 2.1 is qualified by language in 2.6 and 2.6.2. The issue of managing modeling of case data is already adequately handled in MOD Standards. Furthermore, PE does not feel that the term “material” can be defined with any mutually agreed-upon boundaries, and could be construed to require any and all Transmission Planners and/or Planning Authorities to make multiple revisions of base cases each year. PE therefore appeals to the SDT to remove the language referring to R2 Part 2.6.2 and furthermore appeals for the deletion of R2.6.2. Furthermore, PE appeals to the SDT to modify R2.6.1 to say “For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate the validity of the results of any studies older than five years or any studies using cases containing major modeling differences from other submitted studies.”
ERCOT ISO	No	Previous Comment unaddressed: Requirement 2.1.5: Including the spare equipment strategy will be difficult for a PC that doesn’t own or manage the transmission equipment or the strategies. This requirement should only be applicable to TP. Furthermore, R7 should be deleted and the responsibilities of each entity should be explicitly stated within the specific requirements.
New York Independent System Operator	No	NYISO completely agrees with the revision to R2.1, but this revision must be carried through to other sections (R2.2, 2.2.1). Revisions made to Requirement R2.1.5 have made it worse than as originally drafted. This would require the PC & TP to study, or in other words perform technical analysis of, the impact and probability of the possible unavailability of any piece of equipment with a lead time of one year or more. Such an evaluation of spare equipment strategies would require significant additional resources and data, but provide no benefit to system reliability, as it is redundant to the existing N-1-1 contingency requirement (P6).

Organization	Yes or No	Question 4 Comment
		R2.7 requires that Corrective Action Plans are included in each Planning Assessment and states "Such actions may include..." followed by a list of actions. Restricting allowable actions, and excluding runback/tripping of HVDC would have a direct impact on multiple existing facilities in New York and would adversely impact the reliability planning of the NYCA. Runback/tripping of HVDC must be added to the list.
Xcel Energy	No	Specifically, the phrase "as follows" at the end of Part 2.1 does not appear to be an appropriate lead-in for the sub-parts under 2.1. Please consider re-wording Part 2.1 consistent with Part 2.4 to use the lead-in "The following studies are required:" Why is it essential to use the qualifier "annual" for "current studies" in Part 2.1? Can a study be considered current if it is conducted less frequently than once every year? Note that Parts 2.3, 2.4 and 2.5 do not use the "annual" qualifier, nor does Requirement R2. Recommend deleting this apparently non-essential qualifier in both 2.1 and 2.2 to improve consistency. In Part 2.5, should "annually" be inserted after "shall be assessed" to make it consistent with Parts 2.1, 2.2, 2.3 and 2.4? If the omission is intentional in 2.5, please explain why. To improve semantics and consistency, please modify 2.2.1 as follows to make it consistent with 2.1.1 and 2.4.1 "System peak Load for one of the years in the…" We are unable to appreciate why the wording in Part 2.3 is not consistent with that in Part 2.1, 2.2, 2.4 or 2.5. Note that the semantics of the wording "… (steady state / stability) analysis shall be assessed annually…" can be interpreted to be much different than the semantics of the Part 2.3 wording "The short circuit analysis…. shall be conducted annually …". The former requires the analysis to be *assessed* annually but 2.3 requires the analysis to be *conducted* annually without explicitly requiring it be assessed –- is the usage of "conducted" instead of 'assessed" consistent with the intent? It is unclear why the stipulation to use "current or qualified past studies" needs to be repeated in each of the Parts 2.1, 2.2, 2.3, 2.4 and 2.5 when it is already specified in Requirement R2 at the highest hierarchy level. Suggest eliminating redundant usage by deleting from the parts under R2. In Part 2.6.2, the intent is awkwardly conveyed within the phrase "…the System represented in the study shall not include any material changes unless…". In the context of a *past* study, how can the System represented possibly include any material changes (that would have presumably occurred after the study)? Suggest modifying Part 2.6.2 to read "For steady state, short circuit or Stability analysis: no material changes have occurred in the System represented in the study or, if material changes have occurred, a technical rationale shall be provided to explain why they do not significantly impact the study results." In Parts 2.6.1 and 2.6.2, the lead-in phrase "For steady state, short circuit or Stability analysis:" does not appear to be essential. Even in the absence of this phrase, wouldn't these two attributes of a qualified past study apply (by default) to all types of analysis? Suggest deleting this seemingly redundant phrase in both 2.6.1 and 2.6.2.

Organization	Yes or No	Question 4 Comment
		Perhaps this comment is more persuasive when considered together with the next comment. Recommend moving Part 2.6 to the first part under R2 (Part 2.1) because it defines the qualified past studies which are applicable to all types of analysis (steady state, stability and short circuit) that are detailed in the subsequent parts.
MRO's NERC Standards Review Subcommittee	Yes	R2.1.3 - We offer the minor suggestion of revising R2.1.3 to state, "Known outages of generation or Transmission Facilities with a duration of at least six months be simulated along with P1 events for the System peak or Off-Peak conditions when the outages are scheduled to occur." We interpret that the requirement should only call for the simulation of individual outages with duration of six months or more and not imply the simulation of sequential (back-to-back) outages where each individual outage is less than six months, but the composite duration of the back-to-back outages is more than six months. We also interpret that if two or more known outages with duration of at least six months are overlapping, then the overlapping outage condition would only be simulated for the conditions when the overlapping outages are scheduled to occur if the duration of the overlapping condition is at least six months. R2.1.5 - We offer a major suggestion regarding the phrase "could result in the unavailability of major transmission equipment" because this phrase is ambiguous and not defined. So, there is a significant risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. We proposed adding that the TP and PC "shall provide documentation to support the technical rationale for defining unavailability of major transmission equipment" similar to R2.5.
NERC staff	Yes	NERC staff supports the use of qualified past studies for the Near Term horizon.
American Electric Power (AEP)	Yes	R2, Part 2.1 - idicates that 'qualified' past studies can be utilized. This is an ambiguous term and we suggest the SDT consider the implications.
SERC Planning Standards Subcommittee	Yes	
Hydro One Networks Inc.	Yes	
SERC Dynamics Review Subcommittee	Yes	
Pepco Holings, Inc - Affiliates	Yes	

Organization	Yes or No	Question 4 Comment
IRC Standards Review Committee	Yes	
Bonneville Power Administration	Yes	
Exelon Transmission Planning	Yes	
Southern Company	Yes	
Western Electricity Coordinating Council	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
NorthWestern Energy (NWMT)	Yes	
PNM	Yes	
FirstEnergy	Yes	
Manitoba Hydro	Yes	
TVA Transmission Planning & Compliance	Yes	
Independent Electricity System Operator	Yes	
South Carolina and Gas	Yes	

Organization	Yes or No	Question 4 Comment
SRP	Yes	
California ISO	Yes	
Seattle City Light	Yes	
California Energy Commission	Yes	
Los Angeles Department of Water and Power	Yes	
Idaho Power Co	Yes	
Ameren	Yes	
LCRA TSC	Yes	
GTC	Yes	
Pacific Gas and Electric Company	Yes	
Modesto Irrigation District	Yes	
Oncor Electric Delivery	Yes	
Tucson Electric Power Company	Yes	
GDS Associates, Inc.	Yes	
MidAmerican Energy	Yes	
Puget Sound Energy	Yes	

Organization	Yes or No	Question 4 Comment
Sacramento Municipal Utility District	Yes	
Southern California Edison Company	Yes	

3.2 Requirement R2, Parts 2.1.4 & 2.4.3 – sensitivity analysis:

Summary Consideration:

The SDT intent is that multiple condition sensitivities will be assessed since you are required to run the cases for peak and Off-peak conditions, multiple years, etc. If the problem exists in two or more of these cases, it would be an indication of 'multiple' problems. No change made.

The SDT understands that running sensitivities may require additional work for some entities. The sensitivities studied should be used to compare system response to different conditions to provide a broader perspective for the planner and the SDT believes that this is important enough to justify the additional work.

The SDT has made a clarifying change to the words in Requirement R2, part 2.1.4 based on comments received:

> **2.1.4** For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response~~performance~~:

The SDT has made the language in Requirement R2, part 2.7, bullet 7 consistent with the other parts of the standard as follows:

- List System deficiencies and the associated actions needed to achieve required System performance. Examples of ~~S~~such actions ~~may~~ include:

The majority of respondents agree with the changes to these requirements and only the changes to the requirements noted above have been made in response to stakeholder comments.

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered the comments.

Organization	Yes or No	Question 5 Comment
Northeast Power Coordinating Council Consolidated Edison Co. of New York, Inc.	No	Part 2.1.4, requires an entity to vary one or more conditions to demonstrate a change in performance. If the cases were initially stressed, this may force an entity to simulate conditions with less severe stresses. At this point, there is limited to no value to this additional workload. Having a requirement to test at least one sensitivity as a blanket requirement may not be informative by itself and is more unclear since sensitivities are being required on an undefined base set of conditions. If an entity does a case with a stressed set of assumptions, is it

Organization	Yes or No	Question 5 Comment
		necessary to do a non-stressed case? Additionally, our concern involves wording under 2.1.4 and 2.4.3 that sensitivities are required varying one or more conditions. Subsequently, in requirement 2.7.2 corrective action plans need to be developed to resolve performance deficiencies "only" if identified in multiple conditions or require a rationalization why no corrective action plan is necessary. Multiple conditions sensitivities under 2.1.4 and 2.4.3 are necessary to satisfy requirement 2.7.2. Requirement 2.7.2 adds ambiguity and should be removed. If not, a suggested revision to Requirement 2.7.2 as follows:2.7.2. Corrective Action Plans are not required for performance deficiencies identified in a sensitivity analysis. In general, the scope of this requirement is too broad and non-specific, and only results in undue study burden. Is it necessary for sensitivity analysis to be included in requirements since in accordance with good engineering practices a conservative approach should be used in studies? The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions as commented in issue #3. The standard must describe base assumptions. To define a sensitivity condition, NERC must define base assumptions.
Hydro One Networks Inc.	No	The scope of this requirement is too broad and non-specific and only results in undue study burden.
MRO's NERC Standards Review Subcommittee	No	R2.1.4 & R2.4.3 - We offer a major suggestion regarding the terms of 'credible' and 'measurable change" because these terms are ambiguous and not defined. So, there is a significant risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. We proposed adding that the TP and PC "shall provide documentation to support the technical rationale for determining the range of credible conditions and measurable change in performance" similar to R2.5. R2.1.4 & R2.4.3 bullet items - We offer the minor suggestion that the number and description of the bullet items in R2.1.4 match the bullet points in R2.4.3. Otherwise, please explain the reasons for any differences between the bullet items in R2.1.4 and R2.4.3. R2.1.4 bullet #2 & # 5 - We suggest that the wording in bullet #2 be changed to "Expected transfers and other generation dispatch scenarios". This modification would put the transfer and dispatch element, which are complementary, together in the same bullet item, rather than grouping the 'generation dispatch' (operating level) element together with the generation capacity elements in bullet item #5. R2.1.4 bullet #7 - We offer the minor suggestion that the term "planned" be replaced with "known" to be consistent with R1.1.2 and R2.1.3. Besides the term "planned outage" has a specific meaning in the Reliability Standards that are specific to the Operating horizon. R2.7.2 - With regard to "include actions to resolve performance deficiencies identified in multiple sensitivity

Organization	Yes or No	Question 5 Comment
		studies", we do not think that mitigation plans should be required for deficiencies found in multiple sensitivity studies because the conditions in some sensitivity studies are more extreme and less likely than base case conditions. It's impractical to require corrective actions for longer term horizon sensitivities due to how fast the electric grid changes. We believe sensitivity analyses are valuable to improving the development of mitigation plans to address base case performance limit concerns. Some of the sensitivity study conditions are not credible or plausible enough to warrant the implementation of mitigation measures. What is the interpretation of multiple sensitivity studies - more than one or a majority of the number that were studied?
IRC Standards Review Committee	No	The primary concern involves wording under 2.1.4 and 2.4.3 that sensitivities are required by varying one or more conditions. Subsequently, in requirement 2.7.2 corrective action plans need to be developed to resolve performance deficiencies "only" if identified in multiple conditions or require a rationalization why no corrective action plan is necessary. Multiple conditions sensitivities under 2.1.4 and 2.4.3 are necessary to satisfy requirement 2.7.2. Requirement 2.7.2 adds ambiguity and should be removed. Alternatively, Requirement 2.7.2 could be revised as follows:2.7.2. Corrective Action Plans are not required for performance deficiencies identified in a sensitivity analysis. If a Planning Coordinator includes Corrective Action Plans to resolve performance deficiencies identified in multiple sensitivity analysis, the Planning Coordinator shall provide documentation to support those Plans.
Florida Reliability Coordinating Council, Inc - Transmission Working Group	No	This change does not clarify the required sensitivity analysis. A measureable change in performance is unclear? Instead of a measurable change in performance, a measureable change in contingency response of the Bulk Electric System would be more appropriate. A change in performance implies not meeting one of the performance requirements as specified in Table 1.
Lakeland Electric	No	A "measureable change in performance" can be interpreted as not meeting one of the performance requirements as specified in Table 1 in order for the condition to be selected as a sensitivity. This will cause utilities to perform sensitivity analysis for all system conditions listed in R2.1.4 to determine which one fails to meet one of the performance requirements in Table 1, as one may not be able to tell performance impact until after the studies are performed. Suggested change: "...one of the following conditions by a sufficient amount...system conditions that may demonstrate a measurable change in system response."
Orlando Utilities Commission	No	What is meant by "measurable change in performance"? Is this a measure that the sensistivty should move the system from meeting the performance requirements to not meeting the performance requirements? Or just a measurable change in system response, IE the loading was 45% on this corridor but is now 76%.
US Bureau of Reclamation	No	Sensitivity analysis is not included in R2. This gets back to the structure of the standard. There should a clear indication of the studies that are to be included in the Near-Term and Long-Term portions of the Planning

Organization	Yes or No	Question 5 Comment
		Assessments.
CenterPoint Energy	No	The SDT did not incorporate CenterPoint Energy's previous comments regarding R2; therefore, CenterPoint Energy's concerns remain.
California ISO	No	Requirement 2.7.2 could be revised as follows:2.7.2. Corrective Action Plans are not required for performance deficiencies identified in a sensitivity analysis. If a Planning Coordinator includes Corrective Action Plans to resolve performance deficiencies identified in multiple sensitivity analysis, the Planning Coordinator shall provide documentation to support those Plans.
ISO New England Inc.	No	Part 2.1.4, requires an entity to vary one or more conditions to demonstrate a change in performance. If the cases were initially stressed, this may force an entity to simulate conditions with less severe stresses. At this point, there is limited to no value to this additional workload. Having a requirement to test at least one sensitivity as a blanket requirement may not be informative by itself and is more unclear since sensitivities are being required on an undefined base set of conditions Additionally, our concern involves wording under 2.1.4 and 2.4.3 that sensitivities are required varying one or more conditions. Subsequently, in requirement 2.7.2 corrective action plans need to be developed to resolve performance deficiencies "only" if identified in multiple conditions or require a rationalization why no corrective action plan is necessary. Multiple conditions sensitivities under 2.1.4 and 2.4.3 are necessary to satisfy requirement 2.7.2. Requirement 2.7.2 adds ambiguity and should be removed. Requirement 2.7.2 should be revised as follows:2.7.2. Corrective Action Plans are not required for performance deficiencies identified in a sensitivity analysis.
United Illuminating National Grid	No	If an entity does a stressed set of assumptions do they always need to do a non-stressed case?
Hydro-Quebec TransEnergie	No	It is questionable that sensitivity analysis be included in Requirements since a conservative approach should already be used in studies, in accordance with good engineering practices.
American Transmission Company	No	R2.1.4 & R2.4.3 - We offer a major suggestion regarding the terms of 'credible' and 'measurable change" because these terms are ambiguous and not defined. So, there is a significant risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. We proposed adding that the TP and PC "shall provide documentation to support the technical rationale for determining the range of credible conditions and measurable change in performance" similar to R2.5. R2.1.4 & R2.4.3 bullet items - We offer the minor suggestion that the number and description of the bullet items in R2.1.4 match the bullet points in R2.4.3. Otherwise, please explain the reasons for any differences between

Organization	Yes or No	Question 5 Comment
		the bullet items in R2.1.4 and R2.4.3. R2.1.4 bullet #7 - We offer the minor suggestion that the term “planned” be replaced with “known” to be consistent with R1.1.2 and R2.1.3. Besides the term “planned outage” has a specific meaning in the Reliability Standards that are specific to the Operating horizon. R2.7.2 - With regard to "include actions to resolve performance deficiencies identified in multiple sensitivity studies", we do not think that mitigation plans should be required for deficiencies found in multiple sensitivity studies because the conditions in sensitivity studies are more extreme and less likely than base case conditions. Some sensitivity study conditions are not credible or plausible enough to warrant the implementation of mitigation measures. What is the SDT interpretation of multiple studies - more than one or a majority of the sensitivities that were studied?
Lakeland Electric	No	It is recommended that the phrase “...measureable change in performance...” be changed to “...measurable change in system response...” A change in performance is unclear, and could suggest that a sensitivity study is valid only if the System is stressed to the point that it no longer performs within the criteria established by Table 1. In addition, it is recommended that the following text appear after the last sentence of 2.4.3: “The condition or conditions to be varied shall be left to the discretion of the Transmission Planner or Planning Coordinator, provided they are selected from the list below.”
Northeast Utilities	No	The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions as commented in Question #3. The standard must describe base assumptions. To define a sensitivity condition, NERC must define base assumptions.
Modesto Irrigation District	No	This new requirement will expand the scope of the study work beyond a reasonable extent.
NBSO	No	Base case assumptions should be made such that they appropriately stress the system to be tested and are in accordance with good engineering practice. If the base cases are already stressed, the requirement to study sensitivity cases may result in the study of less severe conditions, and thus require additional time and resources while providing little additional value to the overall assessment.
Central Maine Power Company New York State Electric & Gas	No	These sensitivities need to be considered if not already included in the base case assumptions.

Organization	Yes or No	Question 5 Comment
Corp		
Progress Energy	No	PE does not have concerns in general with either 2.1.4 or 2.4.3. PE does, however, disagree with the wording at the end of the main paragraph of 2.4.3. Whether or not analysis qualifies as sensitivity analysis should not be predicated upon the end results; rather, it should be based upon major case modeling differences. PE therefore recommends that the phrase "...that demonstrate a measurable change in performance" be removed so that the last sentence in the main paragraph read "...by a sufficient amount to stress the System within a range of credible conditions."
ERCOT ISO	No	The stress test requirements should be deleted. The purpose of this proposed Standard is to establish planning performance standards that support reliable operation. This is achieved by imposing performance requirements relative to specific conditions and contingencies. Compliance with the performance metrics within these boundaries is presumably indicative of a reliable system. It is unclear what value is added by stress testing the system in accordance with undefined, vague parameters, as required by Requirements 2.1.4 and 2.4.3. The criteria in the relevant requirements that govern the stress testing are defined by the following ambiguous phrase: 1) "by a sufficient amount"; 2) "range of credible conditions"; and 3) "measurable change of performance". Application of these criteria introduces uncertainty for both the regulated community and the relevant compliance enforcement authorities, which, in turn, creates audit risks for regulated entities. Furthermore, there is no reliability value because the stress test requirements do not establish objective criteria and do not prescribe any actions based on the stress test results. Reliability Standards should set specific obligations that are readily discernible and achievable on a consistent basis. The existing Standard does this by setting specific performance obligations relative to specific conditions and contingencies. Conversely, the stress test requirements introduce ambiguity and uncertainty with no reliability benefit; the only apparent effect is unnecessary audit liability risk for regulated entities. Accordingly, ERCOT believes that these requirements should be deleted.
Tucson Electric Power Company	No	TEP agrees with removing the phrase "not already included in the studies." However, TEP does not understand the purpose of sensitivity studies. TEP is concerned that imposing additional sensitivity studies could lead to requirements that exceed the proposed standards. TEP recommends removing sesnitivity analysis from the standard.
New York Independent System Operator	No	Our concern involves wording under 2.1.4 and 2.4.3 that sensitivities are required varying one or more conditions. Subsequently, in requirement 2.7.2 corrective action plans need to be developed to resolve performance deficiencies "only" if identified in multiple conditions or require a rationalization why no corrective action plan is necessary. Multiple conditions sensitivities under 2.1.4 and 2.4.3 are necessary to satisfy requirement 2.7.2.

Organization	Yes or No	Question 5 Comment
		Requirement 2.7.2 adds ambiguity and should be removed. Requirement 2.7.2 should be revised as follows:2.7.2. Corrective Action Plans are not required for performance deficiencies identified in a sensitivity analysis.
GDS Associates, Inc.	No	The requirements are extremely burdensome. We recommend changing the last sentence of 2.1.4 requirement by removing "by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:" because there are instances where listed conditions may not result in measurable changes in performance (Ex. An increase in load in a well built system may not cause any measurable changes in performance because there is sufficient transmission capacity to serve the load).
SMUD		What is the significance of changing the wording for section R2.1.5 from 'assessed' to 'studied' and 'Planning Assessments' to 'studies'?
Western Area Power Administration	Yes	In Requirement 2.1.4, "Sensitivity Analysis". How much change does it take in any of the modeling assumptions (load, generation, voltage support, topology, etc.) to significantly stress the system within a range of credible condition? As this Requirement relates to R2.7, Would it be necessary to have Corrective Action Plan(s) if needed to meet all the Sensitivity Cases? How many Sensitivities before must have Corrective Action Plan? Also - why is it essential to use the qualifier "annual" for "current studies" in Part 2.1? Can a study be considered current if it is conducted less frequently than once per year? Note that Parts 2.3, 2.4 and 2.5 do not use the "annual" qualifier, nor does Requirement R2. Recommend deleting this apparently non-essential qualifier in both R2.1 and R2.2. We are unable to appreciate why the wording in Part 2.3 is not consistent with that in Part 2.1, 2.2, 2.4 or 2.5. Note that the semantics of the wording "... (steady state / stability) analysis shall be assessed annually..." can be interpreted to be much different than the semantics of the Part 2.3 wording "The short circuit analysis.... shall be conducted annually ...". The former requires the analysis to be *assessed* annually but 2.3 requires the analysis to be *conducted* annually without explicitly requiring it be assessed -- is the usage of "conducted" instead of 'assessed" consistent with the intent? In Part 2.6.2, the intent is awkwardly conveyed within the phrase "...the System represented in the study shall not include any material changes unless...". In the context of a *past* study, how can the System represented possibly include any material changes (that would have presumably occurred after the study)? Suggest modifying Part 2.6.2 to read "For steady state, short circuit or Stability analysis: no material changes have occurred in the System represented in the study or, if material changes have occurred, a technical rationale shall be provided to explain why they do not significantly impact the study results."

Organization	Yes or No	Question 5 Comment
NERC staff	Yes	NERC staff supports removing the phrase “not already included in the studies” from the parts 2.1.4 and 2.4.3 of Requirement R2. We believe that the requirement is more clear and less subject to interpretation without this phrase.
MidAmerican Energy	Yes	R2.1.4 bullet #7 - Replace the adjective “planned” with “known” for consistency with R1.1.2 and R2.1.3.R2.3 Replace “conducted” with “assess” for consistency with R1.1.2 and R2.1.3.R2.4 Replace “current or past studies as qualified” with “current or qualified past studies as indicated” for consistency with R2
SERC Planning Standards Subcommittee	Yes	
SERC Dynamics Review Subcommittee	Yes	
Pepco Holings, Inc - Affiliates	Yes	
Bonneville Power Administration	Yes	
Exelon Transmission Planning	Yes	
Southern Company	Yes	
Western Electricity Coordinating Council	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
NorthWestern Energy (NWMT)	Yes	
PNM	Yes	

Organization	Yes or No	Question 5 Comment
FirstEnergy	Yes	
Platte River Power Authority	Yes	
Manitoba Hydro	Yes	
Minnesota Power	Yes	
TVA Transmission Planning & Compliance	Yes	
Independent Electricity System Operator	Yes	
South Carolina and Gas	Yes	
SRP	Yes	
Seattle City Light	Yes	
California Energy Commission	Yes	
Los Angeles Department of Water and Power	Yes	
Idaho Power Co	Yes	
Ameren	Yes	
LCRA TSC	Yes	
American Electric Power (AEP)	Yes	
Tri-State Generation &	Yes	

Organization	Yes or No	Question 5 Comment
Transmission		
GTC	Yes	
Pacific Gas and Electric Company	Yes	
Oncor Electric Delivery	Yes	
Puget Sound Energy	Yes	
Sacramento Municipal Utility District	Yes	
Xcel Energy	Yes	
Southern California Edison Company	Yes	

3.3 Requirement R2, Part 2.4.1 – dynamic load models:

Summary Consideration:

The majority of respondents agree with the changes to these requirements and no changes to these requirements have been made in response to stakeholder comments.

The SDT does not intend that detailed dynamic Load models will be required for Loads in the System models used for the assessments. In particular, Requirement R2, part 2.4.1 states that an aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

The SDT has placed this requirement in TPL standards because it is not presently covered in MOD standards.

Organization	Yes or No	Question 6 Comment
NERC staff	No	NERC staff understands why the SDT has inserted the word “expected” before “dynamic behavior of Loads,” but we have concerns with this addition. We understand that a PC or TP that models the best current industry understanding of load behavior should not need to worry about compliance if that model does not match actual load response for all possible system conditions. However, we are concerned that this change to part 2.4.1 of Requirement R2 may be too accommodating. If a PC or TP has unrealistic expectations about load behavior, would this permit the use of unrealistic models? While we have struggled to develop an alternative proposal, we hope that the SDT will identify a way to address this concern.
Northeast Power Coordinating Council	No	There is insufficient information and experience regarding dynamic load modeling. It may also be included as a “sensitivity” analysis in 3.2, rather than requiring and expecting accurate representation of a dynamic load model. If this requirement is kept, a modeling standard must be written that is specific to dynamic loads. Change belongs in a modeling standard, not in TPL-001.
Hydro One Networks Inc.	No	There is insufficient information and experience regarding dynamic load modeling. Hence, this should not be a requirement but a guide or an item to be considered to the extent possible. It may also be included as a “sensitivity” analysis in 3.2, rather than requiring and expecting accurate representation of dynamic load model.
Transmission Issues Subcommittee	No	TIS believes that the term “expected” leaves the question as to “whose expectation.” It should be stated as to “expected...by the Transmission Planner.”

Organization	Yes or No	Question 6 Comment
Exelon Transmission Planning	No	There is not an industry consensus around best practices for modeling the dynamic behavior or characteristics of load. It is premature to make this a requirement in an enforceable standard which would be held to this degree of subjective auditing.
Manitoba Hydro	No	The last two sentences "System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable." belong in the MOD standards. They are not required in TPL-001-2.
US Bureau of Reclamation	No	Not included in R2. See response to Question 3.2
CenterPoint Energy	No	The SDT did not incorporate CenterPoint Energy's previous comments regarding R2; therefore, CenterPoint Energy's concerns remain.
Ameren	No	Industry needs guidance regarding how to provide reasonable induction motor representation as opposed to generic models.
Hydro-Quebec TransEnergie	No	There is insufficient data available to accurately model system wide motor loads.
LCRA TSC	No	The first bullet item in Section 3.3.1 should be the same as the second bullet in Section 4.3.1. The wording is somewhat confusing in both. Also, the wording as proposed does not recognize that a high voltage limit could also be violated. Edits to the item as shown below are suggested. Tripping of generators where simulations show generation bus voltages or high side generation step up (GSU) voltages are outside known limits, or assumed to be outside generator steady state limits, or have reached the generator ride through voltage limit. Include in the assessment any assumptions made.
Tri-State Generation & Transmission	No	Rather than specifically call out induction motor loads, we recommend changing the second sentence to "Stability analysis shall include models that represent the expected dynamic behavior of system elements that could impact the study area."
GTC	No	We have concerns for including induction motor representations in the load models without any study or bench-marking activities to meet the requirements of R2.4.1. This information should be supplied by the LSE as part of the MOD standard. We understand that the proposed standard will accept an aggregate system load model which represents the overall dynamic behavior of the load to relieve the burden of trying to develop specific induction motor load representation at each load bus. However this modeled system response will be considerably different compared to the actual system response which will open up the

Organization	Yes or No	Question 6 Comment
		industry to unwarranted scrutiny and possible compliance violation investigations.
Consolidated Edison Co. of New York, Inc.	No	There is insufficient information and experience regarding dynamic load modeling. It may also be included as a "sensitivity" analysis in 3.2, rather than requiring and expecting accurate representation of a dynamic load model. If this requirement is kept, a modeling standard should be written that is specific to dynamic loads. This change belongs in a modeling standard, not in TPL-001.
NBSO	No	By implication, the response of induction motor load would need to be considered when modeling the expected dynamic behaviour of loads that could impact the study area. NBSO suggests re-wording parts of R2.4.1 as follows: System peak load levels shall include a model which represents the expected dynamic behaviour of loads that could impact the study area. An aggregate system load model which represents the overall expected dynamic behaviour of load is acceptable.
Central Maine Power Company New York State Electric & Gas New York Independent System Operator	No	We have not determined a need to model dynamic loads, and therefore have not benchmarked any such models. We recommend that prior to this requirement being in place, a modeling standard should exist that is specific to dynamic loads.
ERCOT ISO	No	ERCOT ISO suggests adding "best available" as a descriptor to load models. Distribution Providers (DPs)/Load Serving Entities (LSEs) are the appropriate NERC functional entities to provide dynamic load data. Accordingly, Planning Coordinators (PCs) and Transmission Planners (TPs) must rely on those entities for that data. Despite reliance on DPs/LSEs for this data, the Standard proposes to impose an obligation on PCs and TPs to include a load model representative of "expected" dynamic behavior. Simply put, PCs and TPs do not have this information and should not be subject to compliance liability risk for an issue that is beyond their control. This change will still accomplish the goal of reflecting dynamic data in the relevant models, while mitigating PC/TP compliance risk by basing their compliance on information that is within their control - i.e. the "best available" information. Based on this change, the language should read - "System peak Load levels shall include best available Load models which represent the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads". This language is also a more accurate reflection of the Consideration of Comments by the Standard Drafting Team after the March 2010 comment period.To address this issue in the most appropriate manner, the Standard should be revised to establish an appropriate process for collection, reporting and use of dynamic data based on assigning obligations to the appropriate functional entities. In essence, DPs/LSEs should be required to collect the data and report it to TPs. Because TP models are the basis for PC models, the dynamic data will be included in PC models as part of the process. However, DPs and TPs should still only be required to use the "best available" data. Continued use of this language will mitigate the liability risk associated with a

Organization	Yes or No	Question 6 Comment
		requirement related to data that is within the control of a third party. Even under a construct where DPs/LSEs are required to collect and report dynamic data, there is no guarantee they will do so and PCs/TPs should not be held accountable in those circumstances. Accordingly, PC/TP compliance risk will be mitigated by use of a "best available" standard.
GDS Associates, Inc.	No	We disagree with the content of this requirement based on several facts:- We believe that the dynamic behavior of the load cannot be accurately estimated beyond current time. We are concern about the effort required to ascertain the dynamic response of the load- The requirement references "Loads that could impact the study area" without specifying how an entity will identify these loads. Perhaps the standard should provide guidelines to determine which loads would impact the study area.
MidAmerican Energy	No	MidAmerican questions if the widespread use of composite load models really provides significant benefits to additional dynamic analyses over generic load conversion assumptions which have been historically used. The use of composite load models may result in more precise individual load models, but no more accurate dynamic simulations. This poorly worded requirement should be deleted in its entirety as providing additional burden without any additional reliability benefits. If the composite load model requirement must be kept, it should be modified to include the following bolded text:"...System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads, but without requiring a detailed load survey be conducted..."
Platte River Power Authority	Yes	For consistency, use the qualifier "expected" in the second sentence of Part 2.4.1 also, such that it reads "...represents the overall expected dynamic behavior..."
Xcel Energy	Yes	For consistency, use the qualifier "expected" in the second sentence of Part 2.4.1 also, such that it reads "…represents the overall *expected* dynamic behavior…"
SERC Planning Standards Subcommittee	Yes	
SERC Dynamics Review Subcommittee	Yes	
MRO's NERC Standards Review Subcommittee	Yes	

Organization	Yes or No	Question 6 Comment
Pepco Holings, Inc - Affiliates	Yes	
IRC Standards Review Committee	Yes	
Bonneville Power Administration	Yes	
Southern Company	Yes	
Western Electricity Coordinating Council	Yes	
Arizona Public Service Company	Yes	
Florida Reliability Coordinating Council, Inc - Transmission Working Group	Yes	
Western Area Power Administration	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
NorthWestern Energy (NWMT)	Yes	
Lakeland Electric	Yes	
PNM	Yes	
FirstEnergy	Yes	
Orlando Utilities Commission	Yes	

Organization	Yes or No	Question 6 Comment
Minnesota Power	Yes	
TVA Transmission Planning & Compliance	Yes	
Independent Electricity System Operator	Yes	
South Carolina and Gas	Yes	
SRP	Yes	
California ISO	Yes	
Seattle City Light	Yes	
California Energy Commission	Yes	
ISO New England Inc.	Yes	
Los Angeles Department of Water and Power	Yes	
Idaho Power Co	Yes	
United Illuminating	Yes	
National Grid	Yes	
American Transmission Company	Yes	
American Electric Power (AEP)	Yes	

Organization	Yes or No	Question 6 Comment
Lakeland Electric	Yes	
Pacific Gas and Electric Company	Yes	
Northeast Utilities	Yes	
Modesto Irrigation District	Yes	
Oncor Electric Delivery	Yes	
Progress Energy	Yes	
Tucson Electric Power Company	Yes	
Puget Sound Energy	Yes	
Sacramento Municipal Utility District	Yes	
Southern California Edison Company	Yes	

3.4 Requirement R2, Part 2.5 – material clarification:

Summary Consideration:

The majority of respondents agree with the changes to these requirements and no changes to these requirements have been made based on stakeholder comments.

The SDT discussed defining 'material change' but did not believe that such a definition was appropriate in a continent-wide standard. With the wide variety in sizes and types of systems, the number of parameters that need to be considered, etc., there are too many variables involved. With the inclusion of Requirement R8 and the sharing of information, there is an opportunity for open discussion on such matters.

The SDT notes that Part 2.6.2 allows an entity to rely on a past study with a material change if "a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area". Therefore, it is up to the entities performing the study to provide the rationale based on changes, such as Load growth.

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered the comments.

Organization	Yes or No	Question 7 Comment
Exelon Transmission Planning	No	The term 'material changes' is subjective. It is very difficult to determine a base case to study combinations of generator additions on a changing transmission network in the 6 to 10 year time period to be used for dynamic simulations. Dynamic studies should be performed whenever new generator interconnections are proposed and it is at that time where meaningful calculations can be performed. The long term six to ten year out dynamic studies for groupings of potential units should be done at a high level, if at all.
Florida Reliability Coordinating Council, Inc - Transmission Working Group	No	This change does not clarify material. Material should be quantified somehow. We recommend changing the phrase "material generation additions or changes" to "generation in the vicinity with additions of changes larger than 200 MW".
Lakeland Electric	No	Please consider removing R2.6.2. The "any material change" language can cause utilities perform studies due to material changes outside of and remote to its system.

Organization	Yes or No	Question 7 Comment
Orlando Utilities Commission	No	I agree with what I think is the intent. The word "Material" is meant to allow for changes in model to occur that are "small" relative to the TP/PC. For example the 400 MW generator that might be built in 10 years by another utility over a hundred miles, several dozen buses and generators away to not force new study work. However as written in 2.5 it requires you to define what a material change is, and could be applied to mean every change must be identified and explained rather then an overarching rationale that would only have you looking for changes that meet the material criteria. But then in 2.6.2 the word material is used with no obligation to explain what material is, only to explain if a material change would not impact the results in a study area. I recommend leaving the term material, but setting a requirement, measure, or definition that requires the TP/PC to define what they consider material specific to their system and circumstance. Since this will by the hetreogenous nature of the grid be different for each it may not be reasonable to pre-define what is reliable. Just as was done with many items in the ATC (MOD) standards, require that it be documented and questions on that rationale be answered. If a specific level of technical oversight is desired, consider requiring that description to be on file with the regional entity and approved by their planning committee. I think the team is heading in a good direction, it's just how the words will be applied that concern me. This may be a case where an Example or two would go a long way towards providing guidance to entities and auditors.
Manitoba Hydro	No	Adding the word “material” does not clarify Part 2.5. The word “material” can be interpreted in many ways and is subjective. In order to have a consistent approach by all TPs, the drafting team should add a definition of the term “material”. One TP may consider a new 200 MW unit as not being material because there are several larger units in the TPs system.
US Bureau of Reclamation	No	The term "material" is arbitrary. It is suggested that a specific value be used to trigger the assessment.
CenterPoint Energy	No	The SDT did not incorporate CenterPoint Energy's previous comments regarding R2; therefore, CenterPoint Energy's concerns remain.
Progress Energy	No	PE agrees in general with the changes made to R2.5. PE disagrees, however, with the language stipulating that current and past studies be qualified by the language in R2.6 Part 2.6.2 (see notes for Question 3.1 regarding recommending changes with regard to R2.6.2).
Tucson Electric Power Company	No	If a material change (generator addition/retirement, new generator models based on unit testing, or transmission line or non-distribution transformer addition) is not planned for the longer-term planning horizon, do the longer-term stability studies need to be performed? TEP's agreement/disagreement with Part 2.4.1 is

Organization	Yes or No	Question 7 Comment
		dependent on the response to this question. If the answer is the studies do not need to be performed, then TEP supports these changes.
GDS Associates, Inc.	No	We are not sure what will be included in these "material generation additions or changes". Perhaps the standard should provide guidelines to determine what are these material changes or additions?
Xcel Energy	No	It appears that the requirement appended at the end of Part 2.5 "…and shall include documentation to support the technical rationale for determining material changes." is duplicative of Part 2.6.2. Please address this apparent redundancy.
NERC staff	Yes	NERC staff supports inserting the word "material" in the reference to assessing the impact of proposed generation. We have some concern that this change leaves this part of the requirement open to interpretation, but we also understand the need to permit some degree of engineering judgment to be applied. It would not be appropriate to require that every potential generation addition be included in the assessment where some proposed additions may by inspection be deemed to be immaterial due to size and/or interconnection location.
IRC Standards Review Committee	Yes	However, the requirement infers that a subjective judgment from a compliance auditor will be required.
Bonneville Power Administration	Yes	It should be noted that if there is more generation proposed in an area than there load and export capability, all proposed material generation additions would not be represented. Determining what future generation additions to include in the Long-Term Transmission Planning Horizon may be based on a non-technical rationale rather than a technical rationale.
Western Area Power Administration	Yes	The drafting team could provide guidance on what is "material". In Part 2.5, should "annually" be inserted after "shall be assessed" to make it consistent with Parts 2.1, 2.2, 2.3 and 2.4? If the omission is intentional in 2.5, please explain why.
Platte River Power Authority	Yes	I like the flexibility you give the PC and TP to define what 'material' means in their 'documentation to support the technical rationale for determining material changes.' In Part 2.5 this rationale will decide whether or not any Long-Term Stability studies are required for the Planning Assessment. And in Part 2.6.2 this rationale will be a factor in qualifying a past study.
Independent Electricity System	Yes	We do not have a concern with this change but we don't think it is necessary. It is not a requirement, and

Organization	Yes or No	Question 7 Comment
Operator		appropriate wording in the Measures can take care of it.
SERC Planning Standards Subcommittee	Yes	
Northeast Power Coordinating Council	Yes	
Hydro One Networks Inc.	Yes	
SERC Dynamics Review Subcommittee	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
Pepco Holings, Inc - Affiliates	Yes	
Southern Company	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
NorthWestern Energy (NWMT)	Yes	
FirstEnergy	Yes	
Minnesota Power	Yes	
TVA Transmission Planning & Compliance	Yes	
South Carolina and Gas	Yes	

Organization	Yes or No	Question 7 Comment
SRP	Yes	
California ISO	Yes	
Seattle City Light	Yes	
California Energy Commission	Yes	
ISO New England Inc.	Yes	
Los Angeles Department of Water and Power	Yes	
Idaho Power Co	Yes	
United Illuminating	Yes	
Ameren	Yes	
Hydro-Quebec TransEnergie	Yes	
LCRA TSC	Yes	
National Grid	Yes	
American Transmission Company	Yes	
American Electric Power (AEP)	Yes	
Tri-State Generation & Transmission	Yes	
Lakeland Electric	Yes	

Organization	Yes or No	Question 7 Comment
GTC	Yes	
Northeast Utilities	Yes	
Consolidated Edison Co. of New York, Inc.	Yes	
NBSO	Yes	
Central Maine Power Company	Yes	
Oncor Electric Delivery	Yes	
New York State Electric & Gas Corp	Yes	
ERCOT ISO	Yes	
New York Independent System Operator	Yes	
MidAmerican Energy	Yes	
Sacramento Municipal Utility District	Yes	
Southern California Edison Company	Yes	

4. The SDT has revised the header notes based on industry comments to the initial ballot. If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your concern.

Summary Consideration:

The SDT clarified the language of header note 'i' as a result of comments received as follows:

i. The response of voltage sensitive Load ~~including Load~~ that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

The majority of respondents agree with the changes to the header notes and no other changes to the header notes have been made based on stakeholder comments.

Requirements cannot be 'hidden' in the Table because the Table is specifically cited in the requirements text and is thus part of the requirements.

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered the comments.

Organization	Yes or No	Question 8 Comment
Northeast Power Coordinating Council	No	Header note (i) in the first Table 1 (p. 10) could imply that voltage-varying load shall not be used to meet steady state performance requirements. Steady state load models in use include voltage-varying loads. The explicit representation of (voltage-dependent) load models is perfectly consistent with the requirements defined in R1 (which calls for a comprehensive representation of system components and their expected operating status in the planning assessment period) and the impetus to the creation of more specific load models in dynamic assessments found Requirement 2.4 of this draft of TPL-001-2. It is a known that depressed voltage conditions cause certain system elements to perform below their rated capacity. For example, capacitors provide less voltage support and voltage controlling transformers are impeded by their finite tap range to direct VAR flow into areas affected by low voltage conditions. Certain load types, on the other hand, provide a self-compensating relief to depressed voltage by naturally decreasing demand in a manner proportional to their characteristics, without operator intervention. Choosing to negate the voltage-dependence of one of these system elements (load, in our case) results in an inaccurate system representation that, in turn, may lead to erroneous assessments of the reliability state of the interconnected system and, potentially, to the implementation of unwarranted system upgrades. This note should be revised

Organization	Yes or No	Question 8 Comment
		to only reference loads which are disconnected due to voltage.
Transmission Issues Subcommittee	No	Delete the word "voltage" from the last header note J concerning Stability Only. All types of transient stability must be observed.
LCRA TSC	No	The third bullet of 4.3.1 requires the addition of relay models for stability studies. This type of analysis is performed today by scripting the tripping of multiple lines due to breaker failure events. The inclusion of relay models into the stability study will result in added complexity and an over reliance on relay models for system stability assessment. The stability assessment should assess stability resulting from the operation of relays as opposed to reliance on a relay model for proper system representations. Assurance of the proper operation of relays results from the analysis performed to set relays not from stability studies. From Section 4.3.1:"Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models." Section 4.5 requires that "The rationale for those Contingencies selected for evaluation shall be available as supporting information." This will have to be developed. Requirement R5 requires the establishment of criteria for transient voltage response of the system. This seems unnecessary given the proposed changes to Table 1. The proposed changes to table 1 seem to make clear the type of system response that is allowable through its specification of what is allowable in terms of interruptions to Firm Transmission and Non-Consequential loads. R5 states: "Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level."
Consolidated Edison Co. of New York, Inc.	No	o Header note (i) in the first Table 1 (p. 10) The explicit representation of (voltage-dependent) load models is perfectly consistent with the requirements defined in R1 (which calls for a comprehensive representation of system components and their expected operating status in the planning assessment period) and the impetus to the creation of more specific load models in dynamic assessments found Requirement 2.4 of this draft of TPL-001-2. It is a known that depressed voltage conditions cause certain system elements to perform below their rated capacity. For example, capacitors provide less voltage support and voltage controlling transformers are impeded by their finite tap range to direct VAR flow into areas affected by low voltage conditions. Certain load types, on the other hand, provide a self-compensating relief to depressed voltage by naturally decreasing demand in a manner proportional to their characteristics, without operator intervention. Choosing to negate the voltage-dependence of one of these system elements (load, in this case) results in an inaccurate system representation that, in turn, may lead to erroneous assessments of the reliability state of the interconnected

Organization	Yes or No	Question 8 Comment
		system and, potentially, to the implementation of unwarranted system upgrades.
Central Maine Power Company New York State Electric & Gas Corp New York Independent System Operator	No	Header note (i) in the first Table 1 could imply that voltage-varying load shall not be used to meet steady state performance requirements. NYISO steady state load models include voltage-varying loads. This note should be revised to only reference loads which are disconnected due to voltage.
MidAmerican Energy	No	The reference to BES should be placed back into Note a in the header above table 1.
Xcel Energy	No	Although we support the revised header notes, we believe that the following additional changes are needed to enhance clarity and improve consistency: We are unable to see the compelling need and/or the value of separating the header notes in three categories. Since the applicability of each header to either one or both steady-state and stability performance is obvious from its respective verbiage, we suggest eliminating the categorization. This will also allow the header notes to be reordered/regrouped as per related functionality, thus improving the Table 1 readability. Following is a suggested re-ordering of header notes: a. Applicable Facility Ratings shall not be exceeded. The System shall remain stable. Cascading and uncontrolled islanding shall not occur. b. Planning event P0 is applicable to steady state only. c. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event except P0. d. The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment as a consequence of any event shall not be used to meet steady state performance requirements. e. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits established by the Planning Coordinator and Transmission Planner. f. Transient voltage response shall be within acceptable limits as established by the Planning Coordinator and Transmission Planner. g. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. h. Simulate the removal of all elements that Protection Systems and other controls are expected

Organization	Yes or No	Question 8 Comment
		to automatically disconnect for each event. Simulate Normal Clearing unless otherwise specified.
MRO's NERC Standards Review Subcommittee American Transmission Company	Yes	We offer the major suggestion that Requirements not be created in the Performance Table and be absent from the Requirement section. Requirements should only be referred to in the Performance Table after they already exist in the Requirement section. a. Notes “f” and “g” under “Steady State Only” section in the Table 1 header create requirements (e.g. use the verb, “shall”) that do not appear in the Requirements section. We suggest adding R3.3.5, which could read, “Applicable System Operating Limits for the planning horizon shall not be exceeded.” [After R3.3.5 is added, Notes “f” and “g” should be revised and refer to R3.3.5.]. b. Note “i” under “Steady State Only” section in the Table 1 header creates a requirement (e.g. use the verb, “shall”) that does not appear in the Requirements section. We suggest adding R3.3.6, which could read, “The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state voltage requirements.” [After R3.3.6 is added, Note “d” should be revised to refer to R3.3.6. c. Note “j” under the “Stability Only” section in the Table 1 header creates a requirement (e.g. use the verb, “shall”) that does not appear in the Requirements section. We suggest adding R4.1.4, which could read, “Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner”. [After R4.1.4 is added, Note “j” should be revised to refer to R4.1.4.]
Western Area Power Administration	Yes	Following is a suggested re-ordering of header notes to replace of the three categories concept - same information: a. Applicable Facility Ratings shall not be exceeded. The System shall remain stable. Cascading and uncontrolled islanding shall not occur. b. Planning event P0 is applicable to steady state only. c. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event except P0. d. The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment as a consequence of any event shall not be used to meet steady state performance requirements. e. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits established by the Planning Coordinator and Transmission Planner. f. Transient voltage response shall be within acceptable limits as established by the Planning Coordinator and Transmission Planner. g. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. h. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event. Simulate Normal Clearing unless otherwise specified.
NERC staff	Yes	NERC staff supports the changes to the header notes in Table 1.

Organization	Yes or No	Question 8 Comment
Florida Reliability Coordinating Council, Inc - Transmission Working Group	Yes	We support the changes to the performance tables.
Platte River Power Authority	Yes	I like the flexibility you give the PC and TP in Requirements R3 and R4 to develop their rationale for the Contingencies they select for evaluation.
Orlando Utilities Commission	Yes	I am assuming you mean the header notes on the performance table
Progress Energy	Yes	PE assumes the term “header notes” is referring to the “Planning Performance Events” at the top of Table 1. If this is the case, PE has no concerns with the present language.
SERC Planning Standards Subcommittee	Yes	
Hydro One Networks Inc.	Yes	
SERC Dynamics Review Subcommittee	Yes	
Pepco Holings, Inc - Affiliates	Yes	
IRC Standards Review Committee	Yes	
Bonneville Power Administration	Yes	
Exelon Transmission Planning	Yes	
Southern Company	Yes	
Western Electricity Coordinating Council	Yes	

Organization	Yes or No	Question 8 Comment
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
NorthWestern Energy (NWMT)	Yes	
Lakeland Electric	Yes	
PNM	Yes	
FirstEnergy	Yes	
Manitoba Hydro	Yes	
Minnesota Power	Yes	
CenterPoint Energy	Yes	
TVA Transmission Planning & Compliance	Yes	
Independent Electricity System Operator	Yes	
South Carolina and Gas	Yes	
SRP	Yes	
California ISO	Yes	
Seattle City Light	Yes	

Organization	Yes or No	Question 8 Comment
California Energy Commission	Yes	
ISO New England Inc.	Yes	
Los Angeles Department of Water and Power	Yes	
Idaho Power Co	Yes	
United Illuminating	Yes	
Ameren	Yes	
Hydro-Quebec TransEnergie	Yes	
National Grid	Yes	
American Electric Power (AEP)	Yes	
Tri-State Generation & Transmission	Yes	
Lakeland Electric	Yes	
GTC	Yes	
Pacific Gas and Electric Company	Yes	
Northeast Utilities	Yes	
Modesto Irrigation District	Yes	
NBSO	Yes	

Organization	Yes or No	Question 8 Comment
Oncor Electric Delivery	Yes	
ERCOT ISO	Yes	
Tucson Electric Power Company	Yes	
GDS Associates, Inc.	Yes	
Puget Sound Energy	Yes	
Sacramento Municipal Utility District	Yes	
Southern California Edison Company	Yes	

5.

The SDT has revised the performance table (including the list of extreme events and footnotes) based on industry comments to the initial ballot. If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your concern.

Summary Consideration:

The SDT has made the following clarifying changes to address concerns raised in the comments:

- P0 – delete superscript 9 in column 6: No[9]
- P5 event description: Delayed Fault -Clearing —due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following:
- Extreme events language for Stability events has been made consistent with P5.
- Added 'Breaker' to the Bus-tie and non-Bus-tie phrases in P2 and P4

No other changes were made to the Performance Table based on stakeholder comments.

The SDT fully realizes that Project 2010-11 must reach resolution prior to finalizing TPL-001-2 and stated same in the information attached with the fifth posting of Project 2006-02.

The SDT has made the language in Requirement R2, part 2.8.2 consistent with that in Requirement R2, part 2.7.4:

> **2.8.2** Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered the comments.

Organization	Yes or No	Question 9 Comment
NERC staff		NERC staff is concerned with P5 and footnote 9 and thus cannot support these changes in their entirety. First, a revision to the Draft 4 definition of P5 should be used in lieu of the current Draft 5 version: "Loss of multiple elements caused by the Fault clearing consistent with failure of a single Protection System while clearing a fault on one of the following: . . ."After reviewing the P5 contingency throughout various drafts of this standard, along with existing Table 1 for TPL-001 through TPL-004, NERC staff's primary concern is that this most recent version is going in the wrong direction by becoming too limiting regarding which Protection System component failures are covered. Draft 5 is an improvement because it removes the reference to loss of

Organization	Yes or No	Question 9 Comment
		multiple elements in Draft 4 (which defined P5 as "Loss of multiple elements caused by the failure of a single Protection System while clearing a fault on one of the following: . . ."). Draft 5 takes a step backward, however, by referring to Delayed Fault Clearing. The advantage of not referring to Delayed Fault Clearing is that for cases where redundant protection systems are provided, the fault clearing may not be delayed even when a single Protection System failure occurs. Ideally, NERC staff believes that P5 should refer to "failure of any component of a Protection System," but NERC staff recognizes that we cannot get there until the term Protection System is redefined and Project 2009-07-Reliability of Protection Systems is underway. Until that change is possible, NERC staff encourages the SDT to use the revised version of P5 proposed above. A second concern is with footnote 9, which is used numerous times in Table 1. System adjustments may be used in two different settings: the first is to address the aftermath of a particular Contingency; the second is to prepare for the next Contingency.Staff suggests that the current footnote 9 have this language added: "Post-Contingency Ccurtailment of Firm Transmission Service to address the simulated contingency, when coupled with ...." Footnote 9 is used in the column labeled "Interruption of Firm Transmission Service Allowed" whenever a "No" is provided. The footnote 9 in this column has to do with System adjustments that address the aftermath of the Contingency that is being simulated. Therefore, no footnote 9 appears appropriate for category P0 (No Contingency). The reference in footnote 9 to no load loss and staying within applicable Facility rating, including those on a neighboring system, is sufficient for addressing the aftermath of the Contingency being simulated. To address next Contingency, an additional footnote is needed in the "Initial System Condition" column for category P3 and category P6. The following is suggested: "System adjustments to prepare for the next Contingency must be completed within 30 minutes." Footnote 9 is used in the column labeled "Initial System Condition" for category P3 and category P6, and these two categories define the loss of an Element "followed by System adjustments" and then followed by the loss of a second Element. It is unclear whether the intent in footnote 9 in these two cases is meant to address the same issue referenced above (i.e. the aftermath of the Contingency being simulated) or whether it is intended to address the next Contingency. Thus, both situations need to be addressed using the suggestions indicated above.
Northeast Power Coordinating Council Consolidated Edison Co. of New York, Inc.		To support the change to P5, other items need to also be modified. In Table 1 - Steady State & Stability Performance Extreme Events (p. 12), in the Stability Section, the language should be made similar to wording in P5. Protection System should be removed and replaced with the words "relay failure". This change should be made for 2a through 2d:2. Local or wide area events affecting the Transmission System such as: a. 3Ã˜ fault on generator with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. b. 3Ã˜ fault on Transmission circuit with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. c. 3Ã˜ fault on transformer with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. d. 3Ã˜ fault on bus section with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing.

Organization	Yes or No	Question 9 Comment
		Note 11 (p. 14) needs clarification as shown: Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for a total of 1 mile or less. There are two tables labeled “Table 1”. Suggest that the extreme events table be renamed “Table 2”.
MRO's NERC Standards Review Subcommittee		We offer the major suggestion that the P3 Category performance criteria be modified to apply only to the loss of two generators. The SDT properly recognizes that generator outages are significantly more probable than line or transformer outages and should be “higher” in the category list. However given the clearly higher probability of generator outages, the probability of the loss of two generators is clearly higher than the loss of a generator and line or the loss of a generator and transformer. Therefore, if the loss of two generators is in the P3 category, then the loss of a generator and line or transformer should be clearly “lower” in the category list. We suggest the listing of: the loss of a generator and some other element (e.g. transmission circuit, transformer, shunt device, and single pole of DC line) be moved to a lower event category, such as the P6 Category by adding “1. Generator” to the listing in the Initial System Condition (Loss of . . .) column. Item 2.a in the Extreme Events, Steady State section - Clarify the meaning of the loss of multiple circuits in Item 2.a by using wording similar to P7. We suggest this text: “a. Loss of three or more circuits that share a common structure.” Footnote 6 - Further clarify the applicable shunt devices in Footnote 6 with this suggested text: “6. Requirements which are applicable to shunt devices, also apply to FACTS devices that are connected to ground, but not instrument voltage transformers or surge arresters.”
Bonneville Power Administration		Table 1, P5 currently requires the study of “[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed”. As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: “Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following”. In Table 1, P2 and P3, the last column “Non-Consequential Load Loss Allowed” where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore the proposed footnote 12 should include a provision to default to the existing footnote “b” in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, “Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial

Organization	Yes or No	Question 9 Comment
		customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers."
Exelon Transmission Planning		Comments: The term 'HV' in the performance table should be defined as 'Bulk Electric System elements up to 300 kV, not simply all elements 'below 300 kV'. Footnote 12 should be clarified to specifically state the requirements before voting takes place. The performance criteria should be based on the voltage level of the element experiencing stress due to the contingency, not based on the voltage level of the outaged element. It does not seem to make sense that the loss of a 500 kV bus would not allow for any non-consequential load shedding unless the bus contained a 500 to 230 kV transformer, in which case additional load shedding would be allowed. If outages on a 230 kV system, such as bus fault with stuck breaker, were to cause overloads on a 500 kV network it is acceptable to shed load, but if the outages were on the 500 kV system originally it would not be acceptable to shed additional load. It seems as if it should be the severity of the situation and the elements involved that would dictate allowable remedial actions and not the initial cause of the disturbance. If, for example, there was a 500 kV contingency outage that caused problems on the 230 kV system there would be a problem that may require load shedding on the 230 kV system. If there were a 230 kV contingency or series of contingencies that caused overloads on the 500 kV system, it would be more difficult to find enough lower voltage load to shed to bring the 500 kV system back to applicable ratings or conditions. The inability to shed non-consequential load could theoretically be resolved by hanging a small EHV / HV transformer on a particular bus, or by tapping a EHV line with an auto transformer.
Southern Company		NO. We wish to make a comment on the stability extreme event table: Changes were made in planning event P5 to narrow the focus to specific relay failures. The same changes are needed for stability extreme event 2a, 2b, 2c, and 2d.
Western Electricity Coordinating Council Arizona Public Service Company PNM SRP California Energy Commission Los Angeles Department of		Table 1, P5 currently requires the study of "[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed". As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: "Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following". In Table 1, P2 and P3, the last column "Non-Consequential Load Loss Allowed" where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential

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Water and Power Pacific Gas and Electric Company Modesto Irrigation District Puget Sound Energy Sacramento Municipal Utility District		Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote "b". This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote "b" in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, "Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers." Timing of this project and project 2010-11 is critical. It would be very difficult to vote to approve the proposed TPL-001-2 prior to knowing the outcome of Project 2010-11 (footnote b issue).
E.ON U.S.		E.ON U.S. believes that Table 1 should be formatted to avoid having the tables split by page breakers. In addition, tables spanning across multiple pages should have headers at the top of each page.
Florida Reliability Coordinating Council, Inc - Transmission Working Group		Footnote 12 performance requirements of Table 1 should allow the loss of non-consequential load for all contingency categories except for P0. The disallowance of load loss does not provide any real benefit to the reliability of the BES and is an unnecessary overreach into local quality of service issues that are best addressed by State, Provincial or Municipal authorities. There may be circumstances such as high local transmission costs or local opposition to transmission construction where prohibition of non-consequential load loss represents a poor cost/benefit or quality of life tradeoff. Having a provision at the regional level that a PA or TP can have a certain amount of non-consequential load loss designed or planned in to its system that would be reasonable if it is acceptable to the RE and does not have an adverse impact on the remaining BES. In lieu of such a RE provision, providing a quantitative cap in non-consequential load loss such as 100 MW may be rationale compromise in the goal of limiting load loss for the more probable outage events. Our preference would be to retain the capability of limited non-consequential load loss. Footnote 9 should also be under consideration as part of Project 2010-11 and should be noted as such for clarification.
Western Area Power Administration		In footnotes 9 and 12, two critical issues are being addressed in large part via these "clarifying" footnotes. These are curtailment of "Firm Transmission Service" (which seems primarily to be a contract/scheduling issue) and the loss of "Non-Consequential Load." Perhaps these issues should receive more attention in the

Organization	Yes or No	Question 9 Comment
		actual requirements. In P5 the term “Protection System” was removed and replaced with “relay”. How are protection system elements other than relays accounted for? In studying a multiple contingency event with a communication system or control circuitry failure would it be necessary demonstrate P1 performance levels? These details could become critical as industry deals with issues such as FERC’s interpretation of TPL-002-0 Requirement R1.3.10 (RM10-6-000). In Table 1 - Extreme Events - Stability - Items 2a-2d, change “Protection System failure” to “relay failure” to be consistent with changes in P5. Table 1, P5 currently requires the study of “[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed”. As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: “Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following”. Footnote 13 - Delete “voltage (#27, #59)” since the under/over voltage relays are not called upon to provide the primary protection for fault clearing on Transmission elements. Suggest modifying Event P4 description to be more consistent with Event P5 description by including Delayed Fault Clearing in the description in lieu of “Loss of multiple elements”. Suggested Event P4 description is: “Delayed Fault Clearing caused by a stuck non Bus-tie Breaker attempting to clear a fault on one of the following:” In Table 1, P2 and P3, the last column “Non-Consequential Load Loss Allowed” where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote “b”. This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote “b” in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, “Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the

Organization	Yes or No	Question 9 Comment
		affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers." Timing of this project and project 2010-11 is critical. It would be very difficult to vote to approve the proposed TPL-001-2 prior to knowing the outcome of Project 2010-11 (footnote b issue).
PacifiCorp		Under Category P2 (Single Contingency) and Normal System Conditions, the performance table indicates that, for both HV and EHV, interruption of firm transmission service and non-consequential load loss are not allowed following the opening of a line section without a fault. This section of the performance table should distinguish between EHV and HV - performance requirements following the opening of a line section without a fault should be the same as those for a bus section fault. As with the bus section fault, interruption of firm transmission service and non-consequential load loss should be allowed for HV.
NorthWestern Energy (NWMT) Idaho Power Co		Table 1, P5 currently requires the study of "[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed". As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: "Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following". In Table 1, P2 and P3, the last column "Non-Consequential Load Loss Allowed" where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote "b". This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote "b" in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, "Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers."

Organization	Yes or No	Question 9 Comment
Lakeland Electric		The performance requirements of Table 1 do not allow the loss of non-consequential load for single and multiple contingency events. The disallowance of load loss does not provide any real benefit to the reliability of the BES and is an unnecessary overreach into local quality of service issues that are best addressed by State, Provincial or Municipal authorities. There may be circumstances such as high local transmission costs or local opposition to transmission construction where prohibition of non-consequential load loss represents a poor cost/benefit or quality of life tradeoff. Having a provision at the regional level that a PA or TP can have a certain amount of non-consequential load loss designed or planned in to its system that would be reasonable if it is acceptable to the RE and does not have an adverse impact on the remaining BES. In lieu of such a RE provision, providing a quantitative cap in non-consequential load loss such as 100 MW may be rationale compromise in the goal of limiting load loss for the more probable outage events. Our preference would be to retain the capability of limited non-consequential load loss. It is our understanding that footnote 9 is under consideration as part of Project 2010-11 and should be noted as such for clarification.
FirstEnergy		Table 1, P5 currently requires the study of "[d]elayed Fault Clearing due to the failure of a relay (footnote 13) protecting the Faulted element to operate as designed". To the extent fully redundant relaying exists with no expected delay in Fault Clearing its understood that the P5 event would not be a concern for the redundant system design. The drafting team has taken appropriate steps within the TPL standard to focus on relaying failures to provide clarity in what is required for P5 planning event.
Platte River Power Authority		No. Table 1, P5 currently requires the study of "[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed". As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: "Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following". In Table 1, P2 and P3, the last column "Non-Consequential Load Loss Allowed" where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote "b". This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote "b" in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, "Note:

Organization	Yes or No	Question 9 Comment
		Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers." Timing of this project and project 2010-11 is critical. It would be very difficult to vote to approve the proposed TPL-001-2 prior to knowing the outcome of Project 2010-11 (footnote b issue). In Table 1 - Planning Events - Suggest changing the description for Events P2-3, P2-4, P4 and P4-6 to use the term 'Bus-tie Breaker' or 'non-Bus-tie Breaker' as applicable. In Table 1 - Extreme Events - Stability - Items 2a-2d, do you mean 'Protection System failure' here, or do you want to change to 'relay failure' to be consistent with changes in P5?
Orlando Utilities Commission		I generally agree with the direction the team has gone. Footnote 9 should also be highlighted as being part of the project 2010-11 discussion just as footnote 12 is.
Manitoba Hydro		In point g, violations are noted in terms of post-Contingency voltage deviations rather than post-Contingency voltage limits. This may lead to confusion, as some utilities evaluate performance based on a post-Contingency voltage deviation criterion while other utilities evaluate performance based on post-Contingency voltage limits. This same comment applies to Requirement R5.Suggested rewording for point g:System steady state voltages and post-Contingency voltages or voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner. Suggested rewording for the first sentence in Requirement R5:Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltages or voltage deviations, and the transient voltage response for its System. Note 12 states that an outstanding issue related to non-consequential load loss is being discussed. This will create a lot of uncertainty. Manitoba Hydro could not support this standard unless the resolution of Note B is known.
CenterPoint Energy		CenterPoint Energy appreciates the effort put forth by the SDT in revising the performance table. The current draft of P5 is preferable to previous versions.
TVA Transmission Planning & Compliance		TVA is concerned about footnote 12 (known as footnote b in existing TPL standards). TVA believes that utilities should be given some freedom in dropping local load in response to N-1 events as long as overall

Organization	Yes or No	Question 9 Comment
		BES reliability is not impacted. Otherwise significant capital improvements will be required that will have no overall reliability gain for the Bulk Electric System. TVA does agree with the revisions made specifically to the P5 event. TVA wishes to make a comment on the stability extreme event table: Changes were made in planning event P5 to narrow the focus to specific relay failures. The same changes are needed for stability extreme event 2a, 2b, 2c, and 2d.
SMUD		For the Western Interconnection, the performance level for a Bus-tie breaker fault under TPL-001-2, Table 1, Item P2-4, Notes (a) and (f), requires no thermal overloads and no cascading. While, FAC-010-2.1, R1.2, R2.5-R2.6, as modified by E1.1, E1.1.7, E1.3, and E1.3.1 requires a different performance level of no cascading. Please explain why this regional variance is not included under TPL-001-2, Item E.
California ISO		We support these changes, although we suggest that the proposed footnote 12 include an interim provision to default to the existing footnote “b” in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, “Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.”
Seattle City Light		Table 1, P5 does not recognize the existence of redundant (or backup) relays. These are an integral part of the protection system design and should be considered in analysis of SLG faults. The TPL standard should encourage redundant, fail-safe systems, not ignore them. In Table 1, P2 and P3, we have a concern about not allowing non-consequential load loss. Project 2010-11 is deciding on this issue, but is not completed (see footnote 12). Should the standard become effective before this project is completed, no non-consequential load loss would be allowed, requiring many transmission additions and reconfigurations. Please change the "NO" in the last column to "YES" until the completion of Project 2010-11.
ISO New England Inc.		We are supportive of the change to P5. However, in making this modification, other items need to also be changed. In Table 1 - Stability, the language should be made similar to wording in P5. Protection System should be removed and replaced with the words “relay failure”. This change should be made for 2a through 2d:2. Local or wide area events affecting the Transmission System such as: a. 3Ã˜ fault on generator with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. b. 3Ã˜ fault on Transmission circuit with

Organization	Yes or No	Question 9 Comment
		stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. c. 3Ã˜ fault on transformer with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. d. 3Ã˜ fault on bus section with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. We also believe that Note 11 needs clarifying wording as shown below:"Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for a total of 1 mile or less"
United Illuminating National Grid Central Maine Power Company New York State Electric & Gas Corp		In Table 1 - Stability, Make language similar to wording in P5. "Protection System" should be removed and replaced with the words "relay failure". This would avoid future interpretation issues about the intent of this requirement (as we understand it) to exclude more severe though less likely failures such as battery systems. This change should be made for 2a through 2d on page 12).In Note 11 (page 14) ADD the wording shown in "quotes" below: Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for "a total of" 1 mile or less.
Hydro-Quebec TransEnergie		In table 1 on page 12 (Stability section), Relay failure should replace Protection System
LCRA TSC		An important footnote to Table 1 is omitted from this proposed revision. This omission prevents adequate evaluation of the footnote. Footnote 12 in Table 1 is no longer applied to P2.1, P2.2, P2.3, P4, and P5. The footnote states: “Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.” The footnote should be removed from the proposed revision until Project 2010-11 is concluded.
American Transmission Company		We offer the major suggestion that the P3 Category performance criteria be modified to apply only to the loss of two generators. The SDT properly recognizes that generator outages are significantly more probable than line or transformer outages and should be “higher” in the category list. However given the clearly higher probability of generator outages, the probability of the loss of two generators is clearly higher than the loss of a generator and line or the loss of a generator and transformer. Therefore, if the loss of two generators is in the P3 category, then the loss of a generator and line or transformer should be clearly “lower” in the category list. We suggest the listing of: the loss of a generator and some other element (e.g. transmission circuit, transformer, shunt device, and single pole of DC line) be moved to a lower event category, such as the P6 Category by adding “1. Generator” to the listing in the Initial System Condition (Loss of . . .) column. We offer the minor suggestion that Item 2.a in the Extreme Events, Steady State section - Clarify the meaning of the loss of multiple circuits in Item 2.a by using wording similar to P7. We suggest this text: “a. Loss of three or more circuits that share a common structure.”

Organization	Yes or No	Question 9 Comment
		We offer the minor suggestion that Footnote 6 - Further clarify the applicable shunt devices in Footnote 6 with this suggested text: "6. Requirements which are applicable to shunt devices, also apply to FACTS devices that are connected to ground, but not instrument voltage transformers or surge arresters." ATC has significant concerns with Q3.2 (R2.1.4 & R2.4.3), Q4 (Table requirements) and Q5 (P3 scope), as noted above. In addition, ATC offers the following suggestions to promote proper Reliability Standard quality and content. (1.) Revise the Planning Assessment definition to more explicitly apply to the BES and the TPL-001 requirements. We suggest text of: "Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies in the BES from the steady state and stability performance requirements set forth in the TPL-001 standard." 2.) R2.1.5 - We propose replacing the term 'major Transmission' with "BES" because BES is a well defined term, while the term 'major Transmission' is not. (3.) Add R2.3.1 - We suggest the addition of a R2.3.1 requirement to emulate the distinction between the requirement to perform a short circuit assessment and conduct required studies or analysis to support the assessment (e.g. R2.1/R2.1.1 and R2.2/R2.2.1). We propose wording such as, "Perform an analysis for at least one year in the Near Term Transmission Planning Horizon." This requirement would set an expectation that an analysis should be conducted to at least one or more years in the near-term planning horizon, rather than imply that an analysis of all five years in the near-term planning horizon must be conducted. 4.) R2.7.4 - We suggest that the wording of R2.7.4 be the same as R.2.8.2. Otherwise, we propose that R2.7.4 and R2.8.2 be revised with wording like, ". . . implementation status of identified Corrective Action Plans for System Facilities and Operating Procedures." to clarify that the identified system facilities and operating procedures refer only to those that were in the previous year's Corrective Action Plans. (5.) R3.3.1 - The term of 'controls' is ambiguous and not defined, unlike the term, 'Protection Systems', which is defined. Therefore, we suggest that this item be defined or more clearly described to avoid the risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. (6.) R3.3., bullet #1 - We suggest qualifying which generating units to consider and which voltage limits to simulate with revised wording like, "Trip generating units that are connected to the BES when actual or assumed minimum generator steady state or ride through voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment". The requirement should not apply to all relevant generating units until one of the MOD standards requires all Generator Owners to provide their minimum generating unit voltage limits to the TP and PC. If the wording of R3.3.1, bullet #1 must be different from its counterpart, R4.3.1, then please explain the reasons for any differences.

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		(7.) R3.4.1 - Compliance with the requirement "to coordinate" is problematic and non-measurable. We suggest replacing it with the requirement "to communicate". 8.) R3.5 - We interpret that R3.5 requires the TP and PC to conduct an evaluation of possible actions to reduce the likelihood or impact of extreme events, which produce the more severe impacts, if cascading outages may occur. Does the drafting team intend for the TP and PC to fulfill this requirement for at least one event in each of the five categories (i.e. 3 steady state and 2 stability) or in each of the 21 categories/sub-categories (i.e. 14 steady state and 7 stability). Also, if the resulting cascading outages do not result in any overloads, under-voltages, voltage collapse, or loss of generator synchronization, then should the evaluation of possible actions to reduce likelihood or impact be required? (9.) R4.1.1 - We suggest that there should be some qualification of which generating units are referred to in this requirement. We propose that the requirement say, "No generating unit connected to the BES shall pull out of synchronism." For example, some utilities include smaller generation units that are connected at voltages below 100 kV and even down to distribution voltage in their base cases. (10.) R4.1.2 - We propose that the wording of this requirement be revised to reflect the same BES qualification of the generating unit that we noted in R4.1.1 above. (11.) R4.3.1 - This requirement refers to high speed reclosing and we presume that this is special high speed reclosing that is completed in several cycles, rather than the normal high speed reclosing that is completed in a number of seconds. We recommend that the term high speed reclosing be more clearly defined for this sub-requirement. (12.) R5 - We propose removing the criteria item, "post-Contingency voltage deviation", because this criterion has not been developed and used widely enough in the industry to be introduced into the standards. (13.) R7 - Revise part of the requirement text to read, ". . . identify each entity's individual and joint responsibilities . . ." to provide better clarity. Perhaps this requirement should be listed at the beginning of the Requirements section, instead being mentioned near the end of this section. (14.) Change the forward referencing to backward referencing. We agree with R2.6, R3.1, R3.5, R4.1, and 4.2. However, we suggest that the requirements be ordered so that all of the references refer back to earlier text, rather later text to be consistent with the rest of this standard and other referencing in this standard (e.g. R2.1.3, R2.1.4, R2.4.3, R3, R3.3, R3.5, R4, R4.3, R4.4, R4.5), as well as other standards.
Tri-State Generation & Transmission		Table 1, P5 does not seem to account for redundant relays in the Protection System to mitigate potential relay failure. We recommend changing the "Event" to "Delayed Fault Clearing due to the failure of a relay to operate as designed, if that is the only relay protecting the Faulted element, for one of the following:" In Table 1, P2 and P3, the last column "Non-Consequential Load Loss Allowed" where the requirement

Organization	Yes or No	Question 9 Comment
		"No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote "b". This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote "b" in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, "Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers." Timing of this project and project 2010-11 is critical. It would be very difficult to vote to approve the proposed TPL-001-2 prior to knowing the outcome of Project 2010-11 (footnote b issue). Second, we are unclear why voltage relays are included in footnote 13 and think they can be removed. Third, in the Extreme Events - Stability section of Table 1, items 2a-2d "Protection System failure" should be changed to "relay failure" to be consistent with Table 1, Category P5.
Lakeland Electric		The performance requirements of Table 1 do not allow the loss of non-consequential load for single and multiple contingency events. The disallowance of load loss does not provide any real benefit to the reliability of the BES and is an unnecessary overreach into local quality of service issues that are best addressed by State, Provincial or Municipal authorities. There may be circumstances such as high local transmission costs or local opposition to transmission construction where prohibition of non-consequential load loss represents a poor cost/benefit or quality of life tradeoff. Having a provision at the regional level that a PA or TP can have a certain amount of non-consequential load loss designed or planned in to its system that would be reasonable if it is acceptable to the RE and does not have an adverse impact on the remaining BES. In lieu of such a RE provision, providing a quantitative cap in non-consequential load loss such as 100 MW may be rationale compromise in the goal of limiting load loss for the more probable outage events. Our preference would be to retain the capability of limited non-consequential load loss.It is our understanding that footnote 9 is under consideration as part of Project 2010-11 and should be noted as such for clarification.
NBSO		For consistency, 'Protection System' should be replaced with 'relay' on Table 1 (p12) Stability Section, items

Organization	Yes or No	Question 9 Comment
		2a-2d.
Progress Energy		PE remains concerned with the present draft of TPL-001-2 regarding the presence or absence of footnotes in particular events. PE believes that, for all events in Table 1 except P0, any "No" designation in the "Non-Consequential Load Loss allowed" column should have Footnote 12 appended to it. Several events do append footnote 12 to a "No" answer, but several do not. PE does not see why certain events should be denied the use of Footnote 12 as long as Footnote 12 is worded in a manner such that the BES will not be adversely affected.PE has additional concerns regarding two Footnotes. Footnote 9 contains language regarding firm transmission service that is very similar to language presently under review in NERC Project 2010-11. PE feels that Footnote 9 should have had a statement at the end similar to that of Footnote 12, such as "Note: Firm Transmission Service is being decided in Project 2010-11. When that project is finalized, the resolution will be copied into Footnote 9." Without such a statement, PE cannot understand why the Firm Transmission language in footnote (b) under Project 2010-11 is being reviewed, while it is apparently no longer being reviewed in Project 2006-02.Footnote 12 contains the following language as a place holder: "Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here." PE has filed substantial comments on the footnote (b) issue in previous drafts, pointing out that disallowance of curtailment of non-consequential load is a local load issue and not a BES concern. PE therefore cannot make any positive determination as to whether the draft Standard, TPL-001-2, and its associated Table 1, will be a viable Standard until the language in Footnote 12 is resolved via Project 2010-11. Given the potential for unresolved and confusing issues regarding the parallel development of Project 2006-02 and 2010-11, PE encourages NERC to resolve all issues within Project 2010-11 before taking the draft Standard TPL-001-2 to ballot in Project 2006-02.
Tucson Electric Power Company		Table 1, P5 currently requires the study of "[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed". As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: "Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following". In Table 1, P2 and P3, the last column "Non-Consequential Load Loss Allowed" where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote "b". This will require immediate redesigns to meet this

Organization	Yes or No	Question 9 Comment
		particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote "b" in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, "Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers." Timing of this project and project 2010-11 is critical. It would be very difficult to vote to approve the proposed TPL-001-2 prior to knowing the outcome of Project 2010-11 (footnote b issue).Non-Consequential Load Loss and curtailment of Firm Transmission Service should be allowed for loss of EHV BES elements for Category P4 and P5 events.
New York Independent System Operator		There are two tables labeled "Table 1". The extreme events table should be renamed "Table 2".
MidAmerican Energy		Voting "no" - Footnote 6 - Further clarify the applicable shunt devices in Footnote 6 with this suggested text: 6. Requirements which are applicable to shunt devices, also apply to FACTS devices that are connected to ground, but not instrument voltage transformers or surge arresters
Southern California Edison Company		SCE supports the revised performance table.
Omaha Public Power District		Why is Footnote 12 used for some occurrences of the word "No" in the last column of Table 1 but not other occurrences of the word "No"?
Hydro One Networks Inc.		No selection boxes in this question. Yes, we support.
SERC Dynamics Review Subcommittee		Yes. The SERC DRS supports the revisions.
Duke Energy		We support the changes.

Organization	Yes or No	Question 9 Comment
South Carolina and Gas		Yes
Xcel Energy		The defined term "Bus-tie Breaker" is not used per se anywhere in the Requirements or in Table 1. Suggest changing the description for Events P2-3, P2-4, P4 and P4-6 to use the term Bus-tie Breaker or non-Bus-tie Breaker, as applicable. Existing P5 event description needs improvement since the phrase "…failure of relay protecting the Faulted element to operate as designed…" reads awkwardly and also includes some superfluous verbiage that can be omitted. For example, isn't "protecting the faulted element" the basic function of every protective relay? Also, isn't "(failure) to operate as designed" inherent in the definition of Delayed Fault Clearing? Suggested P5 event description is: "Delayed Fault Clearing due to the operation failure of a primary protection relay[13] when attempting to clear a fault on one of the following:" Footnote 13 – Delete "voltage (#27, #59)" since the under/over voltage relays are not called upon to provide the primary protection for fault clearing on Transmission elements. In Table 1 – Extreme Events – Stability – Items 2a-2d, change "Protection System failure" to "relay failure" to be consistent with changes in P5. Suggest modifying Event P4 description to be more consistent with Event P5 description by including Delayed Fault Clearing in the description in lieu of "Loss of multiple elements". Suggested Event P4 description is: "Delayed Fault Clearing caused by a stuck non Bus-tie Breaker attempting to clear a fault on one of the following:"

6. The SDT has revised the Measures based on industry comments to the initial ballot. If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your concern.

Summary Consideration:

The SDT has made the following changes due to industry comments:

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using ~~the latest~~ data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, ~~any~~ the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity who has indicated a reliability need and that the ~~functional entity~~ Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

Data retention for R7 - The current, in force documentation for the agreement(s) on roles and responsibilities, as well as ~~all such~~ documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

Conforming changes were made to M6 and the data retention for R6/M6. Conforming changes were made to R1 to eliminate the phrase, "the latest." The majority of respondents agree with the changes to the Measures and no other changes to the Measures have been made based on stakeholder comments.

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered the comments.

Organization	Yes or No	Question 10 Comment

Organization	Yes or No	Question 10 Comment
Florida Reliability Coordinating Council, Inc - Transmission Working Group	No	It appears that there is a disagreement between R8 and M8, regarding public posting. We Agree with M8 posting option.
NorthWestern Energy (NWMT)	No	Measure M6 is too vague. It is unclear how to identify the conditions of Cascading, voltage instability, or uncontrolled islanding. The Glossary of Terms defines Cascading as "The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies." Does the loss of system elements have to extend beyond the Control Area to be considered "Cascading"? Is there a Megawatt threshold that must be satisfied? Is there a time duration involved? Also, "cascading outages" needs to be defined. In addition, "voltage instability" and "uncontrolled islanding" should both be defined.
Lakeland Electric	No	please consider remove "the latest" from M1
Ameren	No	For measurements M3 and M4, there is some question as to what is to be provided as evidence of a study. Would the study results alone provide sufficient evidence, or does the entire powerflow, stability, or short circuit effort need to be documented in a formal study report? There are no measures for the creation and coordination of contingency lists that are to be developed in R3.4, R3.5, R4.4, and R4.5. Are these contingency lists required to be a documented part of the study?
MidAmerican Energy	No	Revise measures to be consistent with requirements. 1. R6 Delete "any". The use of the word any in standards should not be allowed. 2. Revise the Planning Assessment definition to more explicitly apply to the BES and the TPL-001 requirements. We suggest text of: "Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies in the BES from the steady state and stability performance requirements set forth in the TPL-001 standard." 3. R2.1.5 - We propose replacing the term 'major Transmission' with "BES" because BES is a well defined term, while the term, 'major Transmission', is not. 4. Add R2.3.1 - We suggest the addition of a R2.3.1 requirement to emulate the distinction between the requirement to perform a short circuit assessment and conduct required studies or analysis to support the assessment (e.g. R2.1/R2.1.1 and R2.2/R2.2.1). We propose wording such as, "Perform an analysis for at least one year in the Near Term Transmission Planning Horizon." This requirement would set an expectation

Organization	Yes or No	Question 10 Comment
		that an analysis should be conducted to at least one or more years in the near-term planning horizon, rather than imply that an analysis of all five years in the near-term planning horizon must be conducted. 5. R2.7.2 - Delete 2.7.2. With regard to "include actions to resolve performance deficiencies identified in multiple sensitivity studies", mitigation plans should not be required for deficiencies found in multiple sensitivity studies because the conditions in some sensitivity studies are more extreme and less likely than base case conditions. Some of the sensitivity study conditions are not credible. 6. R2.7.4 - We suggest that the wording of R2.7.4 be the same as R.2.8.2. 7. R3.5 - We interpret that R3.5 requires the TP and PC to conduct an evaluation of possible actions to reduce the likelihood or impact of extreme events, which produce the more severe impacts, if cascading outages may occur. Does the drafting team intend for the TP and PC to fulfill this requirement for at least one event in each of the five categories (i.e. 3 steady state and 2 stability) or in each of the 21 categories/sub-categories (i.e. 14 steady state and 7 stability). Also, if the resulting cascading outages do not result in any overloads, under-voltages, voltage collapse, or loss of generator synchronization, then should the evaluation of possible actions to reduce likelihood or impact be required? 8. R4.1.1 - We suggest that there should be some qualification of which generating units are referred to in this requirement. We propose that the requirement say, “No generating unit with a Point of Interconnection connected to the BES shall pull out of synchronism.” For example, some utilities include smaller generation units that are connected at voltages below 100 kV and even down to distribution voltage in their base cases. 9. R4.1.2 - We propose that the wording of this requirement be revised to reflect the same BES qualification of the generating unit that we noted in R4.1.1 above. 10. R4.3.1 - This requirement refers to high speed reclosing and we presume that this is special high speed reclosing that is completed in several cycles, rather than the normal high speed reclosing that is completed in a number of seconds. We recommend that the term high speed reclosing be more clearly defined for this sub-requirement. 11. R.4.3.2 - We suggest qualifying which generating units to consider and which voltage limits to simulate with revised wording like, “Trip generating units that are connected to the BES when actual or assumed minimum generator transient voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment”. The requirement should not apply to all relevant generating units until one of the MOD standards requires all Generator Owners to provide their minimum generating unit voltage limits to the TP and PC. If the wording of R4.3.2 must be different from its counterpart, R3.3.2, then please explain the reasons for any differences. 12. R5 - This requirement should allow the applicable entity (such as the TOP / TO) to define a “Post-Contingency Voltage Deviation” as this criteria is not used widely enough in the industry to be a well

Organization	Yes or No	Question 10 Comment
		established criteria. 13. Revise R8 to limit the need to provide the Planning Assessment as follows “adjacent Planning Coordinators and adjacent Transmission Planners and to any registered functional entity...” 14. Data Retention for R3, R5, R6, & R7 - The MRO NSRS proposes that the wording in these elements be revised to change “All” to “The”. The word “All” is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: “The studies performed in support....”
NERC staff	Yes	NERC staff supports the changes to the Measures.
SERC Planning Standards Subcommittee	Yes	
Northeast Power Coordinating Council	Yes	
Hydro One Networks Inc.	Yes	
SERC Dynamics Review Subcommittee	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
Pepco Holings, Inc - Affiliates	Yes	
IRC Standards Review Committee	Yes	
Exelon Transmission Planning	Yes	
Southern Company	Yes	
Western Area Power	Yes	

Organization	Yes or No	Question 10 Comment
Administration		
PacifiCorp	Yes	
Duke Energy	Yes	
FirstEnergy	Yes	
Platte River Power Authority	Yes	
Orlando Utilities Commission	Yes	
Manitoba Hydro	Yes	
Minnesota Power	Yes	
TVA Transmission Planning & Compliance	Yes	
Independent Electricity System Operator	Yes	
South Carolina and Gas	Yes	
California ISO	Yes	
Seattle City Light	Yes	
ISO New England Inc.	Yes	
Los Angeles Department of Water and Power	Yes	
Idaho Power Co	Yes	

Organization	Yes or No	Question 10 Comment
United Illuminating	Yes	
Hydro-Quebec TransEnergie	Yes	
National Grid	Yes	
American Transmission Company	Yes	
American Electric Power (AEP)	Yes	
Tri-State Generation & Transmission	Yes	
GTC	Yes	
Pacific Gas and Electric Company	Yes	
Northeast Utilities	Yes	
Consolidated Edison Co. of New York, Inc.	Yes	
NBSO	Yes	
Central Maine Power Company	Yes	
Oncor Electric Delivery	Yes	
New York State Electric & Gas Corp	Yes	
Progress Energy	Yes	

Organization	Yes or No	Question 10 Comment
ERCOT ISO	Yes	
Tucson Electric Power Company	Yes	
New York Independent System Operator	Yes	
Xcel Energy	Yes	
Southern California Edison Company	Yes	

7. The SDT has revised the Requirement R8 VSL based on industry comments to the initial ballot. If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your concern.

Summary Consideration:

The SDT made the following clarification due to industry comments:

> **4.3.1, bullet #1**: Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

The VSL was not changed as the majority response was that the industry is in general agreement with the VSL.

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered the comments.

Organization	Yes or No	Question 11 Comment
Northeast Power Coordinating Council Consolidated Edison Co. of New York, Inc.	No	Requirement 8 is an administrative burden to TPs and PCs that adds no value to Bulk Power System reliability. PCs should be including TPs, neighboring PCs and interested parties in its planning processes when developing the Planning Assessments. Therefore, the inclusion of a set of VSLs for Requirement 8 is unnecessary. Should the VSLs for Requirement 8 remain, Requirement 8.1 should be revised to reflect that comments only to the final Assessment (not drafts developed during a process) need a response as follows:If a recipient of the planning assessment final results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments.If Requirement 8 and 8.1 are retained, they should be revised to reflect that comments only to the final Assessment (not drafts developed during a process) need a response and there should be a limit on the comment period as follows:If a recipient of the planning assessment final results provides documented comments on the results within 90 days of receipt, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments. Other comments not addressed by this Comment Form as follows: Section 3.3 - The last sentence of 3.3.1 should be removed. This is addressed in PRC-023. Line ratings are addressed in PRC-023. PRC-023 requires coordination with the Reliability Coordinator. Remove “Tripping of Transmission elements where relay loadability limits are exceeded.” Section 4.3 - High speed reclosing is not defined, and to help eliminate any confusion that it may introduce

Organization	Yes or No	Question 11 Comment
		into the standard it will be worthwhile for the SDT to define this term. Several specific examples from previous comments on sensitivity analysis and guidance for base case assumptions: The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions. The standard must describe base assumptions. To define a sensitivity condition, NERC must define base assumptions. As for allowing con-consequential load loss for Categories P1 through P5, suggest approval at the Regional level, with a concept of allowing it in a "local area" that does not impact BPS reliability. All references to 300 kV in document should be replaced with EHV (for example in the Introduction, Section 5).The first phrase of Note 3 on p. 14 should be revised as follows: "Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as those representing the backbone of the System, generally at voltage greater than 300 kV, and high voltage (HV) Facilities defined as those not representing the backbone of the System, as determined by the Planning Coordinator and approved by Regional Entity."
IRC Standards Review Committee	No	(AESO is not a party to the following comments since its VSLs are set by the Alberta regulatory authority.)Requirement 8 is an administrative burden to TPs and PCs that adds no value to reliability. PCs should be including TPs, neighboring PCs and interested parties in its planning processes when developing the Planning Assessments. Therefore, the inclusion of a set of VSLs for Requirement 8 is unnecessary.Should the SDT decide to leave the VSLs for Requirement 8, Requirement 8.1 should be revised to reflect that comments only to the final Assessment (not drafts developed during a process) need a response as follows: 8.1 If a recipient of the planning assessment final results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments.For a Planning Coordinator (PC) who distributes the Planning Assessment to many different entities (to adjacent PCs, TPs, and other functional entities), a concern regarding the Requirement R8 VSL is that it is overly restrictive to apply a violation for failing to distribute the results of its Planning Assessment to only one PC, TP, or functional entity (and to apply a High VSL for failing to distribute to more than one entity), particularly since an entity's contact is subject to change over time, and since Measure M8 allows for publicly posting the results of its Planning Assessment to its website. Should the SDT decide to include the VSLs for Requirement 8, we would recommend revising to use a percentage approach rather than applying a violation to a Planning

Organization	Yes or No	Question 11 Comment
		Coordinator who fails to provide the results of its Planning Assessment to one PC, TP, or other functional entity (or applying a High VSL for failing to distribute to more than one entity.) Recommend applying a similar percentage approach to the VSLs drafted by NERC Staff for Project #2007-23 VSLs (e.g., for FAC-013-1) to be considered for the TPL-001-2 R8 VSLs. For example, o Lower VSL: The responsible entity failed to provide the Planning Assessment final results to 5% or less of the required entities. o Moderate VSL: The responsible entity failed to provide the Planning Assessment final results to more than 5% up to (and including) 10% of the required entities. o High VSL: The responsible entity failed to provide the Planning Assessment final results to more than 10% up to (and including) 15% of the required entities. o Severe VSL: The responsible entity failed to provide the Planning Assessment final results to more than 15% of the required entities OR [the existing language for the Severe VSL].Explanation: The VSLs were modified for consistency with other standards and VSLs.Reference: Link to VSLs drafted by NERC Staff for Project #2007-23 VSLs (e.g., for FAC-013-1):http://www.nerc.com/docs/standards/sar/Staff_Proposed_VSLs_2010July27.pdf
Southern Company	No	We wish to make a comment on R4.3.1: it appears that this requires stability simulations of both successful and unsuccessful high-speed reclosing for all contingency simulations regardless of whether high-speed reclosing is used on the faulted line. We suggest the following wording be used to replace the first bullet: "Successful high-speed reclosing and unsuccessful high-speed reclosing onto a fault, where such reclosing is applied, and where such additional simulations are deemed appropriate by the PC or TP." Also, we wish to make a comment on footnote #13 of Table 1. 13. Applies to any of the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, & 67), voltage (#27 & 59), directional (#32 & 67), and associated tripping (#86 & 94) relays.
Florida Reliability Coordinating Council, Inc - Transmission Working Group	No	The requirement to distribute the Planning Assessment should be more flexible and allow for making the Planning Assessment available, such that those entities that desire the information can have it readily available. R8 should be modified to replace distribute with "make available:, so the new requirement would read as follows: Each Planning Coordinator and Transmission Planner shall make available its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.
PacifiCorp	No	The language for Requirement R8 is ambiguous with regard to which adjacent entities must request in writing the results of the Planning Assessment. The language should be clarified to read: "Upon request made in

Organization	Yes or No	Question 11 Comment
		writing, each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any other functional entity that has a reliability related need." The Requirement R8 VSL language should also be revised accordingly.
ReliabilityFirst	No	TPL-001-2 Draft 5 is much better than Draft 4.There is still one significant concern, that I do not believe the drafting team adequately addressed. It is unclear as to what "Planning Assessment results" and "results of its Planning Assessment" entail. The Draft 5 response that "Planning Assessment" is a defined term does not fully address this concern. "Planning Assessment results" or "results of its Planning Assessment" is not necessarily the same thing as "Planning Assessment". As written, "Planning Assessment results" or "results of its Planning Assessment" could be anything from a single sentence, to a few brief high level paragraphs, to a detailed and technically complete Planning Assessment. The Standard needs to more clearly state what is required in the report to other entities. Based on the drafting team response in Draft 4, it seems that replacement of "Planning Assessment results" or "results of its Planning Assessment" with the term "Planning Assessment" or "its Planning Assessment" would be appropriate. Violation Severity Levels: R8The failure to provide documented responses to documented comments to "Planning Assessment results" is deemed to be a higher severity level than failing to distribute "results of its Planning Assessment". Failure to distribute denies functional entities an opportunity to comment, and could prevent coordinated planning, and thus should be deemed to be more severe than failing to provide documented responses to documented comments.
Lakeland Electric	No	The requirement to distribute the Planning Assessment should be more flexible and allow for making the Planning Assessment available, such that those entities that desire the information can have it readily available. R8 should be modified as follows: Each Planning Coordinator and Transmission Planner shall make available its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.
Orlando Utilities Commission	No	R8 should require that the PC and TP make available it's planning assessment results when requested, rather then requring the preemptive transmittal. There is no reliablity purpose served by providing unsolicited information.
US Bureau of Reclamation	No	The language implies that the responsible entity may choose to not distribute it is feels the entity making the request does not have a "reliability related need". It is not clear why that distinction is being made?
California ISO	No	Requirement 8 is an administrative burden to TPs and PCs that adds no value to reliability. PCs should be including TPs, neighboring PCs and interested parties in its planning processes when developing the

Organization	Yes or No	Question 11 Comment
		Planning Assessments. Therefore, the inclusion of a set of VSLs for Requirement 8 is unnecessary.Should the SDT decide to leave the VSLs for Requirement 8, Requirement 8.1 should be revised to reflect that comments only to the final Assessment (not drafts developed during a process) need a response as follows: 8.1 If a recipient of the planning assessment final results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments.For a Planning Coordinator (PC) who distributes the Planning Assessment to many different entities (to adjacent PCs, TPs, and other functional entities), a concern regarding the Requirement R8 VSL is that it is overly restrictive to apply a violation for failing to distribute the results of its Planning Assessment to only one PC, TP, or functional entity (and to apply a High VSL for failing to distribute to more than one entity), particularly since an entity's contact is subject to change over time, and since Measure M8 allows for publicly posting the results of its Planning Assessment to its website.Should the SDT decide to include the VSLs for Requirement 8, would recommend revising to use a percentage approach rather than applying a violation to a Planning Coordinator who fails to provide the results of its Planning Assessment to one PC, TP, or other functional entity (or applying a High VSL for failing to distribute to more than one entity.) Recommend applying a similar percentage approach to the VSLs drafted by NERC Staff for Project #2007-23 VSLs (e.g., for FAC-013-1) to be considered for the TPL-001-2 R8 VSLs. For example, o Lower VSL: The responsible entity failed to provide the Planning Assessment final results to 5% or less of the required entities. o Moderate VSL: The responsible entity failed to provide the Planning Assessment final results to more than 5% up to (and including) 10% of the required entities. o High VSL: The responsible entity failed to provide the Planning Assessment final results to more than 10% up to (and including) 15% of the required entities. o Severe VSL: The responsible entity failed to provide the Planning Assessment final results to more than 15% of the required entities OR [the existing language for the Severe VSL].Explanation: The VSLs were modified for consistency with other standards and VSLs.Reference: Link to VSLs drafted by NERC Staff for Project #2007-23 VSLs (e.g., for FAC-013-1):http://www.nerc.com/docs/standards/sar/Staff_Proposed_VSLs_2010July27.pdf
Ameren	No	The sharing issues of requirement R8 are still not clear, therefore the R8 VSL is not clear. It is not clear if the intent of the SDT is for the PC to share the assessments with PCs and TPs are to share the assessments with TPs, or whether the intent is for the TP to share its assessments with its PC. Will posting the assessment to a secure web-site meet the intent of the requirement? Although the comment form is not designed to allow for such, we need to comment on R4.3.1: As written, it appears that this requires stability simulations of both successful and unsuccessful high-speed reclosing for all contingency simulations, regardless of whether high-speed reclosing is actually implemented. A suggested wording change for the first bullet: "Successful high-speed reclosing and unsuccessful high-speed reclosing onto a fault, where such reclosing is applied, and where such additional simulations are deemed appropriate by the PC or TP."

Organization	Yes or No	Question 11 Comment
		Another comment needs to be made regarding the stability extreme event table: Changes were made in planning event P5 to concentrate on specific relay failures. The same changes need to be made for stability extreme events 2a, 2b, 2c, and 2d.The proposed standard will significantly increase the amount of work required to develop more detailed and complex system models, to perform and document the engineering studies to meet the performance requirements, and to develop the assessments necessary for compliance. All of these increased engineering activities are perceived to provide marginal benefit to the reliability of the bulk electric system, but will require significant increases in manpower across the industry. Further, the manpower is presently not available to develop these more detailed models and to perform these studies with any reasonable assuredness. It will be a continuing challenge to the industry to obtain and keep the engineering talent needed to perform these compliance activities for such marginal benefits.
Central Maine Power Company New York State Electric & Gas Corp	No	Requirement 8 is an administrative burden to TPs and PCs that adds no value to reliability. PCs should be including TPs, neighboring PCs and interested parties in its planning processes when developing the Planning Assessments. Therefore, the inclusion of a set of VSLs for Requirement 8 is unnecessary.Furthermore, the requirement lacks a specified time frame to receive comments, thereby implying that TPs and PCs would be required to reply to comments forever following the finalization of a Planning Assessment. The NYISO proposes a limit of six months.Should the SDT decide to leave the VSLs for Requirement 8, Requirement 8.1 should be revised to reflect that comments only to the final Assessment (not drafts developed during a process) need a response as follows:If a recipient of the planning assessment final results provides documented comments on the results within 180 calendar days of the issuance of those final results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments. We also have other comments not addressed by this Comment Form as follows - Section 2.7, Section 3.3, Section 4.3, and overall:Section 2.7 requires that Corrective Action Plans are included in each Planning Assessment and states “Such actions may include...” followed by a list of actions. Restricting allowable actions, and excluding runback/tripping of HVDC would have a direct impact on multiple existing facilities in New York and would adversely impact the reliability planning of the NYCA. Runback/tripping of HVDC must be added to the list. Section 3.3 - We feel that the last sentence of 3.3.1 should be removed. This is handled by PRC-023. Line ratings are addressed by PRC-023. PRC-023 requires coordination with the Reliability Coordinator. Remove “Tripping of Transmission elements where relay loadability limits are exceeded.” Section 4.3 - High speed reclosing is not defined.Overall - We have previously made comments which have not been addressed in the current version of the proposed standard. Support for the standard can at most be limited without addressing comments.

Organization	Yes or No	Question 11 Comment
		We have previously commented on sensitivity analysis and guidance for base case assumptions. Also, extreme event analysis should not be mandated in this standard as no corrective action is required. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required, and there is no requirement for corrective action if anything is identified. The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions. The standard must describe base assumptions. To define a sensitivity condition, NERC must define base assumptions.
New York Independent System Operator	No	Requirement 8 is an administrative burden to TPs and PCs that adds no value to reliability. PCs should be including TPs, neighboring PCs and interested parties in its planning processes when developing the Planning Assessments. Therefore, the inclusion of a set of VSLs for Requirement 8 is unnecessary.Furthermore, the requirement lacks a specified time frame to receive comments, thereby implying that TPs and PCs would be required to reply to comments forever following the finalization of a Planning Assessment. The NYISO proposes a limit of six months.Should the SDT decide to leave the VSLs for Requirement 8, Requirement 8.1 should be revised to reflect that comments only to the final Assessment (not drafts developed during a process) need a response as follows:If a recipient of the planning assessment final results provides documented comments on the results within 180 calendar days of the issuance of those final results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments.
NERC staff	Yes	NERC staff supports the changes to the VSL for Requirement R8.
SERC Planning Standards Subcommittee	Yes	Comments: We wish to make a comment on R4.3.1: it appears that this requires stability simulations of both successful and unsuccessful high-speed reclosing for all contingency simulations regardless of whether high-speed reclosing is used on the faulted line. We suggest the following wording be used to replace the first bullet: “Successful high-speed reclosing and unsuccessful high-speed reclosing onto a fault, where such reclosing is applied, and where such additional simulations are deemed appropriate by the PC or TP.” We wish to make a comment on the stability extreme event table: Changes were made in planning event P5 to narrow the focus to specific relay failures. The same changes are needed for stability extreme event 2a, 2b, 2c, and 2d.
Hydro One Networks Inc.	Yes	Requirement 8 is an administrative burden and adds little or no value to the BPS reliability. Therefore, the inclusion of a set of VSLs for Requirement 8 is unnecessary.
SERC Dynamics Review	Yes	We wish to make a comment on R4.3.1: it appears that this requires stability simulations of both successful

Organization	Yes or No	Question 11 Comment
Subcommittee		and unsuccessful high-speed reclosing for all contingency simulations regardless of whether high-speed reclosing is used on the faulted line. We suggest the following wording be used to replace the first bullet: "Successful high-speed reclosing and unsuccessful high-speed reclosing onto a fault, where such reclosing is applied."We wish to make a comment on the stability extreme event table: Changes were made in planning event P5 to narrow the focus to specific relay failures. The same changes are needed for stability extreme event 2a, 2b, 2c, and 2d.
MRO's NERC Standards Review Subcommittee	Yes	Other Comments:1. How are backup relays handled (TPL-002-0, R1.3.10 & TPL-001-2 R1 & P5)? What does FERC construe as normal system for a protection system. The TPL-001-2 R1 & P5, this standard doesn't appear to address primary protection and how this handled. 2. Revise the Planning Assessment definition to more explicitly apply to the BES and the TPL-001 requirements. We suggest text of: "Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies in the BES from the steady state and stability performance requirements set forth in the TPL-001 standard." 3. R2.1.5 - We propose replacing the term 'major Transmission' with "BES" because BES is a well defined term, while the term, 'major Transmission', is not. 4. Add R2.3.1 - We suggest the addition of a R2.3.1 requirement to emulate the distinction between the requirement to perform a short circuit assessment and conduct required studies or analysis to support the assessment (e.g. R2.1/R2.1.1 and R2.2/R2.2.1). We propose wording such as, "Perform an analysis for at least one year in the Near Term Transmission Planning Horizon." This requirement would set an expectation that an analysis should be conducted to at least one or more years in the near-term planning horizon, rather than imply that an analysis of all five years in the near-term planning horizon must be conducted. 5. R2.7.4 - We suggest that the wording of R2.7.4 be the same as R.2.8.2. Otherwise, we propose that R2.7.4 and R2.8.2 be revised with wording like, ". . . implementation status of identified Corrective Action Plans for System Facilities and Operating Procedures." to clarify that the identified system facilities and operating procedures refer only to those that were in the previous year's Corrective Action Plans. 6. R3.3.1 - The term of 'controls' is ambiguous and not defined, unlike the term, 'Protection Systems', which is defined. Therefore, we suggest that this item be defined or more clearly described to avoid the risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. 7. R3.3.1, bullet #1 - We suggest qualifying which generating units to consider and which voltage limits to simulate with revised wording like, "Trip generating units that are connected to the BES when actual or assumed minimum generator steady state or ride through voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment". The requirement should not apply to all relevant generating units until one of the MOD

Organization	Yes or No	Question 11 Comment
		standards requires all Generator Owners to provide their minimum generating unit voltage limits to the TP and PC. If the wording of R3.3.1 bullet #1 must be different from its counterpart, R4.3.1 bullet #2, then please explain the reasons for any differences. 8. R3.4.1 - Compliance with the requirement "to coordinate" is problematic and non-measureable We suggest replacing it with the requirement "to communicate". 9. R3.5 - We interpret that R3.5 requires the TP and PC to conduct an evaluation of possible actions to reduce the likelihood or impact of extreme events, which produce the more severe impacts, if cascading outages may occur. Does the drafting team intend for the TP and PC to fulfill this requirement for at least one event in each of the five categories (i.e. 3 steady state and 2 stability) or in each of the 21 categories/sub-categories (i.e. 14 steady state and 7 stability). Also, if the resulting cascading outages do not result in any overloads, under-voltages, voltage collapse, or loss of generator synchronization, then should the evaluation of possible actions to reduce likelihood or impact be required? 10. R4.1.1 - We suggest that there should be some qualification of which generating units are referred to in this requirement. We propose that the requirement say, "No generating unit connected to the BES shall pull out of synchronism." For example, some utilities include smaller generation units that are connected at voltages below 100 kV and even down to distribution voltage in their base cases. 11. R4.1.2 - We propose that the wording of this requirement be revised to reflect the same BES qualification of the generating unit that we noted in R4.1.1 above. 12. R4.3.1 - This requirement refers to high speed reclosing and we presume that this is special high speed reclosing that is completed in several cycles, rather than the normal high speed reclosing that is completed in a number of seconds. We recommend that the term high speed reclosing be more clearly defined for this sub-requirement. 13. R5 - This requirement should remove the criterion item, "post-Contingency voltage deviation", because this criterion is not used widely enough in the industry to be well established criterion. 14. R8 - This requirement should be revised to limit the need to provide the Planning Assessment as follows "adjacent Planning Coordinators and adjacent Transmission Planners and to any registered functional entity..." This suggestion is added to the requirement to clarify that the word adjacent also applies to Transmission Planners and to clarify that the functional entity must be registered in order for the entity to be applicable to the requirement.
TVA Transmission Planning & Compliance	Yes	Additional TVA comments:TVA wishes to make a comment on R4.3.1: it appears that this requires stability simulations of both successful and unsuccessful high-speed reclosing for all contingency simulations. Does high speed reclosing occur in less than 60 cycles or 60 seconds? If a utility does not have reclosing on a

Organization	Yes or No	Question 11 Comment
		transmission line - then must the utility still perform stability studies assuming that there is reclosing? TVA suggests the following wording be used to replace the first bullet: "Successful high-speed reclosing and unsuccessful high-speed reclosing onto a fault, where such reclosing is applied, and where such additional simulations are deemed appropriate by the PC or TP." In R4.1.1, TVA is concerned that no generating unit shall pull out of synchronism in a local area only (thus not impacting the overall reliability of the BES) for Planning Event P1, while the standard does allow generator runback/tripping for the same event. Thus the generating unit may be tripped by a special protection scheme - but may not be tripped by an out of step relay. TVA believes that out of step relaying should be allowed for this unit tripping as long as this does not affect the overall reliability of the BES.
South Carolina and Gas	Yes	We wish to make a comment on the revisions to R4.3.1. We believe that the analysis of both successful and unsuccessful high speed reclosing for all cases is not justified and should be left to the discretion of the Transmission Planner.
ISO New England Inc.	Yes	Requirement 8 and 8.1, should be revised to reflect that comments only to the final Assessment (not drafts developed during a process) need a response and there should be a limit on the comment period as follows:If a recipient of the planning assessment final results provides documented comments on the results within 90 days of receipt, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments. We have other comments not addressed by this Comment Form as follows - Sections 2.7, 3.3, 4.3 and overall. R2.7 requires that Corrective Action Plans are included in each Planning Assessment and states "Such actions may include..." followed by a list of actions. Runback/tripping of HVDC should be added to the list. Section 3.3 - We feel that the last sentence of 3.3.1 should be removed. This is handled by PRC-023. Line ratings are addressed by PRC-023. PRC-023 requires coordination with the Reliability Coordinator. Remove "Tripping of Transmission elements where relay loadability limits are exceeded." Section 4.3 - High speed reclosing needs to be defined.
Hydro-Quebec TransEnergie	Yes	o All references to 300 kV in document should be replaced with EHV (In the introduction, section 5) o The first phrase of Note 3 on p 14 should be revised as follows: "Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as those representing the backbone of the System, generally at voltage greater than 300 kV, and high voltage (HV) Facilities defined as those not representing the backbone of the System, as determined by the Planning Coordinator and approved by Regional Entity."

Organization	Yes or No	Question 11 Comment
National Grid	Yes	Other Comments:Section 3.3 - We feel that the last sentence of 3.3.1 should be removed. This is handled by PRC-023. Line ratings are addressed by PRC-023. PRC-023 requires coordination with the Reliability Coordinator. Remove "Tripping of Transmission elements where relay loadability limits are exceeded." Section 4.3 - High speed reclosing is not defined. We have previously commented on sensitivity analysis and guidance for base case assumptions. Also, extreme event analysis should not be mandated in this standard as no corrective action is required.
Tri-State Generation & Transmission	Yes	None regarding R8. The following comments refer to parts of the proposed standard for which no questions are asked.R4, Part 4.1.2: The response to our previous comment indicated that our description was for a system Stability issue. R4 is addressing system Stability and we believe the comment still applies and that it was not answered in the response. We have two issues with 4.1.2: Sometimes out-of-step (loss of generator synchronism) is better mitigated through islanding by tripping transmission rather than by tripping generators; the second point is that the ability of present modeling programs does not include the capability to model all types of impedance relays and their associated OOS blocking and tripping capabilities that are available. R4, Part 4.3.1: The third bullet implies that all impedance relays (and perhaps others) will need to be modeled in the stability databases. We question whether the existing simulation programs can accommodate this large magnitude of data inclusion and whether there is any benefit to BES reliability. Certainly using generic models rather than actual models would be of no benefit. We recommend changing the third bullet to "Evaluation of Protection System behavior when transient power swings are detected or predicted to have impedance characteristics that may approach relay operating characteristics."
Northeast Utilities	Yes	No comments on Question 7.Other Comments: As detailed below, NU has other comments that are not addressed by this Comment Form as follows - Section 3.3, Section 4.3, Non-Consequential Load Loss as referenced in the events Table 1 and studies using extreme event contingencies. Section 3.3 - NU believes that the last sentence of Part 3.3.1 should be removed since this is handled by PRC-023. Line ratings are addressed by PRC-023 which requires coordination with the Reliability Coordinator. NU suggests the removal of the following sentence: "Tripping of Transmission elements where relay loadability limits are exceeded." Section 4.3 - High speed reclosing is not defined and to help eliminate any confusion that it may introduce into the standard it will be worthwhile for the SDT to define this term. Non-Consequential Load Loss - Depending upon the resolution of "Project 2010-11, TPL Table 1, Footnote b" NU may have additional comments regarding this issue. Studies Using Extreme Event Contingencies: The requirements for sensitivity analysis already address issues

Organization	Yes or No	Question 11 Comment
		going beyond what is expected to meet the reliability requirements of the standard. Therefore, requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if a concern is identified.
NBSO	Yes	NBSO suggests considering rewording the VSL so that they address the failure to distribute the final results of planning assessments.
ERCOT ISO	Yes	ADDITIONAL COMMENTS: Short circuit analysis (R2.3 and R2.8) should only be applicable to TPs. Fault duty issues are typically local in nature and it would be an overlap for PCs to perform this same analysis done by the local Transmission Planner. Furthermore, R7 should be deleted and the responsibilities of each entity should be explicitly stated within the specific requirements. Previous Comment Unaddressed : Requirement 2.6.2: Reads as if a change is being made to an existing study. It is confusing. Possibly restate: "2.6.2 For steady state, short circuit, or stability analysis: previous studies can be used only if a material change to the system has not occurred or if a change that did occur does not impact the study area." R4.1.2 - Planning Coordinators do not perform protection coordination nor do they have access to the relay settings information required to do this analysis. This requirement should apply to Transmission Planners only because they perform system protection.The substantive scope of the standard is relative to Long-Term Transmission Planning Horizon and Near-Term Transmission Planning Horizon. The Purpose section is described in terms of the “planning horizon” generally. It may be worthwhile aligning the two to mitigate the potential for any confusion. ERCOT proposes the following revisions to the Purpose section: 3.Purpose: Establish Transmission system planning performance requirements within the relevant planning horizon (i.e. Long-Term or Near-Term) to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies .In addition, the “Time Horizon” for the Standard is “Long-Term Planning”. Obviously, this necessarily encompasses both Long-Term and Near-Term Transmission Planning Horizons. However, the scope of the Long-Term Planning time horizon is not readily apparent. ERCOT recommends appropriate revisions that clearly define the applicable time horizons.
MidAmerican Energy	Yes	

Organization	Yes or No	Question 11 Comment
Southern California Edison Company	Yes	
Pepco Holings, Inc - Affiliates	Yes	
Exelon Transmission Planning	Yes	
Western Area Power Administration	Yes	
Duke Energy	Yes	
NorthWestern Energy (NWMT)	Yes	
FirstEnergy	Yes	
Platte River Power Authority	Yes	
Manitoba Hydro	Yes	
Minnesota Power	Yes	
Independent Electricity System Operator	Yes	
Seattle City Light	Yes	
Los Angeles Department of Water and Power	Yes	
Idaho Power Co	Yes	
American Transmission Company	Yes	

Organization	Yes or No	Question 11 Comment
American Electric Power (AEP)	Yes	
GTC	Yes	
Oncor Electric Delivery	Yes	
Progress Energy	Yes	
Xcel Energy	Yes	
Tucson Electric Power Company	Yes	

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Version 1 of SAR posted for comment from April 2, 2002 through May 3, 2002.
2. Version 2 of SAR posted for comment from May 5, 2004 through June 5, 2004.
3. Version 3 of SAR posted on November 18, 2005.
4. SAR approved on April 30, 2006.
5. Version 1 of Supplemental SAR posted for comment from February 15, 2007 through March 16, 2007.
6. Version 2 of Supplemental SAR posted on April 9, 2007.
7. Version 1 of revised standard(s) posted for comment on September 17, 2007.
8. Version 2 of the revised standards posted for comment on August 15, 2008.
9. Version 3 of the revised standards posted for comment on May 26, 2009.
10. Version 4 of the revised standards posted for comment on September 16, 2009.
11. Initial ballot completed on March 1, 2010.
12. Version 5 of the revised standard posted for comment on August 3, 2010.

Proposed Action Plan and Description of Current Draft:
The SDT has established a schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 1Q10. The current draft is the second iteration of the revision of existing standards TPL-001 through TPL-006 and includes one revised standard, TPL-001-1, replacing TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. TPL-005 & -006 issues are addressed in this fifth draft and those standards will also be replaced by TPL-001-2.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Conduct ballot	TBD
2. Submit standard(s) to BOT.	2Q11
3. Submit to regulatory authorities for approval.	3Q11

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Near-Term Transmission Planning Horizon: Transmission planning period that covers Years One through five.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies.

Year One: The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One includes the forecasted peak Load period for either 2012 or 2013.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-2**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required on the first day of the first calendar quarter 84 months after Board of Trustees adoption, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-2, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-2:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1, P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes P0 as the normal System condition in Table 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6, as follows:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Include documentation to support the technical rationale for determining material changes.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the

Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

- Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.
- Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes

there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

- Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and that functional entity submits a written request for the information. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
d. Simulate Normal Clearing unless otherwise specified.
e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.
g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
h. Planning event P0 is applicable to steady state only.
i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8]	SLG	EHV	No[9]	No

		(non-Bus-tie Breaker)		HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	EHV, HV	Yes	Yes
Category	**Initial Condition**	**Event [1]**	**Fault Type [2]**	**BES Level [3]**	**Interruption of Firm Transmission Service Allowed [4]**	**Non-Consequential Load Loss Allowed**
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes

P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adj.[9]: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
   a. Loss of a tower line with three or more circuits.[11]
   b. Loss of all Transmission lines on a common Right-of-Way[11].
   c. Loss of a switching station or substation (loss of one voltage level plus transformers).
   d. Loss of all generating units at a generating station.
   e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
   a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.

a. Loss of two generating stations resulting from conditions such as: i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation. ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants. b. Other events based upon operating experience that may result in wide area disturbances.	e. 3Ø internal breaker fault. f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity who has indicated a reliability need and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.4 Additional Compliance Information

None.

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events. OR The responsible entity did not base its	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		studies on computer simulation models using data provided in Requirement R1.		
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its

	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners, one adjacent Planning Coordinator, or to one functional entity that has a reliability related need and that has submitted a written request for the information, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to more than one of its adjacent Transmission Planners, adjacent Planning Coordinators, or functional entities that have a reliability related need and that have submitted a written request for the information, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	TBD	Revision of TPL-001-0 as per Project 2006-02; includes merging requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-1	Not employed due to scope of revision

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Version 1 of SAR posted for comment from April 2, 2002 through May 3, 2002.
2. Version 2 of SAR posted for comment from May 5, 2004 through June 5, 2004.
3. Version 3 of SAR posted on November 18, 2005.
4. SAR approved on April 30, 2006.
5. Version 1 of Supplemental SAR posted for comment from February 15, 2007 through March 16, 2007.
6. Version 2 of Supplemental SAR posted on April 9, 2007.
7. Version 1 of revised standard(s) posted for comment on September 17, 2007.
8. Version 2 of the revised standards posted for comment on August 15, 2008.
9. Version 3 of the revised standards posted for comment on May 26, 2009.
10. Version 4 of the revised standards posted for comment on September 16, 2009.
11. Initial ballot completed on March 1, 2010.
~~11.~~12. Version 5 of the revised standard posted for comment on August 3, 2010.

Proposed Action Plan and Description of Current Draft:
The SDT has established a schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 1Q10. The current draft is the second iteration of the revision of existing standards TPL-001 through TPL-006 and includes one revised standard, TPL-001-1, replacing TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. TPL-005 & -006 issues are addressed in this fifth draft and those standards will also be replaced by TPL-001-2.

Future Development Plan:

Anticipated Actions	Anticipated Date
~~Post fifth version of standard.~~	~~3Q10~~
1. Conduct ballot	TBD
~~Respond to comments and determine next step~~	~~TBD~~
2. Submit standard(s) to BOT.	2Q11
3. Submit to regulatory authorities for approval.	3Q11

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Near-Term Transmission Planning Horizon: Transmission planning period that covers Years One through five.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies.

Year One: The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One ~~must~~ includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One ~~must~~ includes the forecasted peak Load period for either 2012 or 2013.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-2**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required on the first day of the first calendar quarter 84 months after Board of Trustees adoption, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-2, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-2:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1, P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use ~~the latest~~ data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes P0 as the normal ~~s~~System condition in Table 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual -studies or qualified past studies as indicated in Requirement R2, Part 2.6, as follows:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response ~~performance~~:

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of ~~planned~~ known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. ~~shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.~~ Include documentation to support the technical rationale for determining material changes.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of ~~S~~such actions ~~may~~ include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

- Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.
- Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in

Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

- Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those

Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, ~~any~~ the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and that functional entity submits a written request for the information. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load ~~including Load~~ that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial ~~System~~ Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No[9]	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8]	SLG	EHV	No[9]	No

		(~~N~~non-Bus-tie Breaker)		HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	EHV, HV	Yes	Yes
Category	**Initial ~~System~~ Condition**	**Event [1]**	**Fault Type [2]**	**BES Level [3]**	**Interruption of Firm Transmission Service Allowed [4]**	**Non-Consequential Load Loss Allowed**
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes

P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adj.[9]: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
   a. Loss of a tower line with three or more circuits.[11]
   b. Loss of all Transmission lines on a common Right-of-Way[11].
   c. Loss of a switching station or substation (loss of one voltage level plus transformers).
   d. Loss of all generating units at a generating station.
   e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
   a. 3Ø fault on generator with stuck breaker[10] or a ~~Protection System~~ relay failure[13] resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] or a ~~Protection System~~ relay failure[13] resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] or a ~~Protection System~~ relay failure[13] resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] or a ~~Protection~~

a. Loss of two generating stations resulting from conditions such as: i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation. ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants. b. Other events based upon operating experience that may result in wide area disturbances.	~~System~~ relay failure[13] resulting in Delayed Fault Clearing. e. 3Ø internal breaker fault. f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial ~~System~~ Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using ~~the latest~~ data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of documentation specifying ~~any~~the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity who has indicated a reliability need and that the ~~functional entity~~ Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

~~1.2 Compliance Monitoring Period and Reset Timeframe~~

~~Not applicable.~~

~~1.3~~1.2 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

~~1.4~~1.3 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying ~~any~~the criteria or methodology utilized in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as ~~all such~~ documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

~~1.5~~1.4 Additional Compliance Information

None.

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events. OR The responsible entity did not base its	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		studies on computer simulation models using data provided in Requirement R1.		
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its

	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners, one adjacent Planning Coordinator, or to one functional entity that has a reliability related need and that has submitted a written request for the information, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to more than one of its adjacent Transmission Planners, adjacent Planning Coordinators, or functional entities that have a reliability related need and that have submitted a written request for the information, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	TBD	Revision of TPL-001-0 as per Project 2006-02; includes merging requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-1	Not employed due to scope of revision

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Response to Comments Posted

Available at: http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

Project 2006-02 - Assess Transmission Future Needs and Develop Transmission Plans

The standard drafting team working on Project 2006-02 (ATFN SDT) has posted its response to comments to Draft 5 of TPL-001-2 and a preliminary, informational draft of Draft 6 of TPL-001-2. Formal comments will be solicited at a later time.
TPL-001-1 is designed to be a single, comprehensive, and coordinated standard that merges the requirements of four existing standards: TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The proposed standard includes several new definitions.

The standard drafting team working on Project 2006-02 (AFTN SDT) solicited comments from industry on the fifth posting of the revised TPL-001-2 through an informal comment period that ended on September 2, 2010. That posting represented the changes made to the revised standard based on industry comments received on the initial ballot of TPL-001-2 with one exception – inclusion of a final solution for Project 2010-11 TPL Table 1 (footnote 'b'). The revisions to Table 1 footnote 'b' are being addressed under Project 2010-11, and that project is still in progress. The objective of the AFTN SDT is to adapt the technical tenets of the final solution for footnote 'b' for inclusion in TPL-001-2.

Project 2006-02 can't move forward until Project 2010-11 is complete however the ATFN SDT believes that there is benefit to posting the other changes made in response to industry comments as quickly as possible. Therefore, the AFTN SDT has posted its consideration of comments report showing the comments received in response to the fifth posting of the standard and the proposed revisions to TPL-001-2 associated with those comments. Posting now will allow interested stakeholders to observe the progress being made in achieving consensus on the standard.

Project Background

The purpose of the proposed standard is to establish transmission system planning performance requirements within the planning horizon to develop a bulk electric system that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies. TPL-001-1 — Transmission System Planning Performance Requirements is an update and consolidation of the following standards:

- TPL-001-0 — System Performance under Normal Conditions
- TPL-002-0 — System Performance Following Loss of a Single BES Element
- TPL-003-0 — System Performance Following Loss of Two or More BES Elements
- TPL-004-0 — System Performance Following Extreme BES Events

- TPL-005-0 — Regional and Interregional Self-Assessment Reliability Reports
- TPL-006-0 — Data from the Regional Reliability Organization Needed to Assess Reliability

More information is available on the project page: http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

Applicability of Standards in Project
Planning Coordinator
Transmission Planner

Proposed Additions to Glossary of Terms
Bus-tie Breaker
Consequential Load Loss
Long-Term Transmission Planning Horizon
Near-Term Transmission Planning Horizon
Non-Consequential Load Loss
Planning Assessment
Year One

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

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A. Introduction

1. **Title:** **Data From the Regional Reliability Organization Needed to Assess Reliability**

2. **Number:** TPL-006-0.1

3. **Purpose:** To ensure that each Regional Reliability Organization complies with planning criteria, for assessing the overall reliability (Adequacy and Security) of the interconnected Bulk Electric Systems, both existing and as planned.

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization shall provide, as requested (seasonally, annually, or as otherwise specified) by NERC, system data, including past, existing, and future facility and Bulk Electric System data, reports, and system performance information, necessary to assess reliability and compliance with the NERC Reliability Standards and the respective Regional planning criteria.

The facility and Bulk Electric System data, reports, and system performance information shall include, but not be limited to, one or more of the following types of information as outlined below:

R1.1. Electric Demand and Net Energy for Load (actual and projected demands and Net Energy for Load, forecast methodologies, forecast assumptions and uncertainties, and treatment of Demand-Side Management.)

R1.2. Resource Adequacy and supporting information (Regional assessment reports, existing and planned resource data, resource availability and characteristics, and fuel types and requirements.)

R1.3. Demand-Side resources and their characteristics (program ratings, effects on annual system loads and load shapes, contractual arrangements, and program durations.)

R1.4. Supply-side resources and their characteristics (existing and planned generator units, Ratings, performance characteristics, fuel types and availability, and real and reactive capabilities.)

R1.5. Transmission system and supporting information (thermal, voltage, and Stability Limits, contingency analyses, system restoration, system modeling and data requirements, and protection systems.)

R1.6. System operations and supporting information (extreme weather impacts, Interchange Transactions, and Congestion impacts on the reliability of the interconnected Bulk Electric Systems.)

R1.7. Environmental and regulatory issues and impacts (air and water quality issues, and impacts of existing, new, and proposed regulations and legislation.)

Measures

M1. The Regional Reliability Organization shall provide evidence to its Compliance Monitor that it provided Regional system data, reports, and system performance information per Reliability Standard TPL-006-0_R1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Requested Regional system data, reports, or system performance information were incomplete.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Requested Regional system data, reports, or system performance information were not provided.

D. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0.1	April 15, 2009	Corrected formatting for M1.	Errata

A. Introduction

1. **Title:** **Regional and Interregional Self-Assessment Reliability Reports**
2. **Number:** TPL-005-0
3. **Purpose:** To ensure that each Regional Reliability Organization complies with planning criteria, for assessing the overall reliability (Adequacy and Security) of the interconnected Bulk Electric Systems, both existing and as planned.
4. **Applicability:**

   4.1. Regional Reliability Organization
5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization shall annually conduct reliability assessments of its respective existing and planned Regional Bulk Electric System (generation and transmission facilities) for:

R1.1. Current year:

R1.1.1. Winter.

R1.1.2. Summer.

R1.1.3. Other system conditions as deemed appropriate by the Regional Reliability Organization.

R1.2. Near-term planning horizons (years one through five). Detailed assessments shall be conducted.

R1.3. Longer-term planning horizons (years six through ten). Assessment shall focus on the analysis of trends in resources and transmission Adequacy, other industry trends and developments, and reliability concerns.

R1.4. Inter-Regional reliability assessments to demonstrate that the performance of these systems is in compliance with NERC Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0, TPL-004-0 and respective Regional transmission and generation criteria. These assessments shall also identify key reliability issues and the risks and uncertainties affecting Adequacy and Security.

R2. The Regional Reliability Organization shall provide its Regional and Inter-Regional seasonal, near-term, and longer-term reliability assessments to NERC on an annual basis.

R3. The Regional Reliability Organization shall perform special reliability assessments as requested by NERC or the NERC Board of Trustees under their specific directions and criteria. Such assessments may include, but are not limited to:

R3.1. Security assessments.

R3.2. Operational assessments.

R3.3. Evaluations of emergency response preparedness.

R3.4. Adequacy of fuel supply and hydro conditions.

R3.5. Reliability impacts of new or proposed environmental rules and regulations.

R3.6. Reliability impacts of new or proposed legislation that affects, has affected, or has the potential to affect the Adequacy of the interconnected Bulk Electric Systems in North America.

C. Measures

M1. The Regional Reliability Organization shall provide evidence to its Compliance Monitor that annual Regional and Inter-Regional assessments of reliability for seasonal, near-term, and longer-term planning horizons, and special assessments, were developed and provided as requested by other Regional Reliability Organizations or NERC.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Regional, Inter-Regional, and/or special reliability assessments were provided as requested, but were incomplete.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Regional, Inter-Regional, and/or special reliability assessments were not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. Title: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. Number: TPL-004-1

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-1_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-1_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	Approved by the Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009.	Revised (Project 2010-11)

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

A. Introduction

1. Title: **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. Number: TPL-003-1a

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-1_R1 and TPL-003-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
1a	Approved by the Board of Trustees February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised (Project 2010-11)

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

A. Introduction

1. Title: **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. Number: TPL-002-1b

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-1_R1 and TPL-002-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition
1b	Approved by the Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)." 2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)." 3. "Include the effects of existing and planned protection systems, including any backup or redundant systems." *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

A. Introduction

1. Title: System Performance Under Normal (No Contingency) Conditions (Category A)

2. Number: TPL-001-1

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-1_R1 and TPL-001-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility
Compliance Monitor: Regional Reliability Organization.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame
Annually

1.3. Data Retention
None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Comment Form for 6th Draft of Standard TPL-001-1
Assess Transmission Future Needs (Project 2006-02)

Please **DO NOT** use this form to submit comments on the 6th draft of the TPL-001-2 standard for Assess Transmission Future Needs (Project 2006-02). This comment form must be completed by **May 31, 2011.**

If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Background Information
TPL-001-1 Transmission System Planning Performance Requirements

Comments on the 5th draft of the TPL-001-2 Transmission System Planning Performance Requirements standard were received from the industry through September 2, 2010. The Drafting Team received feedback on a number of issues, and the SDT appreciates the tremendous industry participation in the process. Below is a brief overview of the 6th draft of the standard highlighting areas where the SDT made changes based on stakeholder feedback as well as the Standards Quality Review Team. The team's objectives remain unchanged - to create a single Transmission planning standard: 1) with clear, concise requirements set at an appropriate level to ensure reliability, and 2) that fully addresses all issues raised by FERC Orders 693 and 890, and industry inputs, including the SAR scope document.

6th Draft Overview:

The following changes were made due to industry comments:

1. The definitions of Near-Term Transmission Planning Horizon and Year One have been deleted as the same definition has already been filed by another project.
2. The following requirements were changed:
    a. Several grammatical changes for clarity.
    b. R1 – Establish P0 as the normal system condition.
    c. R2 – The VRF has been changed to High to reflect the importance of the Planning Assessment and to meet the latest guidelines.
    d. R2, part 2.1.4 – Change from 'performance' to 'System response'. .
    e. R2, part 2.1.4, bullet #7 –Change 'planned' to 'known'.
    f. R2, part 2.6.2 – Added documentation of technical rationale.
    g. R2, part 2.8 2– Added '…of identified System Facilities and Operating Procedures'.
    h. R4, part 4.3.1 – Provided timing criteria and added that it is only applicable when high speed reclosing is utilized.
    i. R8 – Changed VRF from Low to Medium to meet latest guidelines.
3. Header note changes:
    a. Deleted 'including Load' as a redundant phrase.
4. Performance table changes:
    a. Changed Column 2 heading to 'Initial Condition'.

   b. Deleted superscript for footnote 9 in P0, column 6
   c. Added 'Breaker' to P2 Event column, parts 3 & 4 and P4 Event for clarity.
   d. Added 'non-redundant' to P5 Event for clarity.
   e. Spelled out 'adjustments' to P6 Initial Condition for clarity.
5. Extreme event – Stability 2 – Changed Protection System' to 'relay' for clarity and added footnote 13 reference.
6. Footnote changes:
   a. #9 – Added resolutions from footnote 'b' clarification (Project 2010-11).
   b. #12 – Added resolutions from footnote 'b' clarification (Project 2010-11).
7. Measurement changes:
   a. Updated to reflect changes in requirements.
8. Data Retention – grammatical changes for clarity.

The following changes were made due to the Quality Review:

1. Added 'Category' to Requirement R1 for clarity.
2. Made grammatical changes to requirement R2 for clarity.
3. Added 'For the Planning Assessment' and made grammatical changes to Requirement R2 for clarity.
4. Added 'For the Planning Assessment' to Requirement R2, parts 2.2, 2.4, and 2.5 for clarity.
5. Added timing elements to Requirement R8 and adjusted Measure M8 and the VSL accordingly.
6. Added 'dated' to Measures M2, M3, M4, M5, and M6 to conform to the latest guidelines.
7. Added 'in-force' to Data retention for Requirement R1 and Measure M1 to conform to the latest guidelines.
8. Moved one item from Moderate to Severe in the VSL for Requirements R1, R2, and R4 to conform to the latest guidelines.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The SDT has made revisions to the requirements language of TPL-001-2 based on industry comments and the Quality Review. Do you agree with these changes? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments with clear indications as to which requirement you are commenting on.

   Yes:

   No:

   Comments:

2. The SDT has made revisions to the VRF and VSL of TPL-001-2 which will be part of a non-binding poll with this posting based on industry comments and the Quality Review. Do you agree with these changes? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   Yes:

   No:

   Comments:

3. If you have any other comments on this Standard that you have not already provided in response to the prior questions, please provide them here.

   Comments:

Implementation Plan for TPL-001-2

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

TPL-001-2 — Transmission System Planning Performance Requirements

In revising the TPL standards, the SDT is assuming that planners will receive valid data from the MOD standards link described in TPL-001-2, Requirement R1. Furthermore, there is a tacit assumption that future revisions of the MOD standards will include steps to validate MOD based data.

Revision to Sections of Approved Standards and Definitions

There are multiple new definitions in the proposed standard.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.

Compliance with Standards

Standard	Functions That Must Comply With the Associated Requirements	
	Transmission Planner	Planning Coordinator
TPL-001-2 — Transmission System Planning Performance Requirements	X	X

Effective Dates

The effective date is the date entities are expected to meet the performance identified in this standard.

Except as indicated below, all Requirements and associated parts shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where

no regulatory approval is required, all requirements go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.

TPL-001-0, TPL-002-0a, TPL-003-0a, and TPL-004-0 are being retired as they are replaced in their entirety by TPL-001-2. TPL-005-0 and TPL-006-0 are being retired because their requirements are adequately covered by the revised TPL-001-2 and NERC's Rules of Procedure, Section 800. However, during this 24-month period, all aspects of TPL-001-0 through TPL-006-0 shall remain in effect for compliance monitoring. This 24 month period is to allow entities to develop, perform and/or validate new and/or modified studies, methodologies, assessments, procedures, etc. necessary to implement and meet the TPL-001-2 requirements. The specified effective dates are expected to allow sufficient time for proper assessment of the available options necessary to create a viable Corrective Action Plan that is compliant with the new Standard.

> R1. This Requirement is related to maintaining System models and the data needed to do so. This requirement shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes into effect on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.
>
> R7. This Requirement identifies an obligation to determine individual and joint responsibilities for performing studies needed to do the Planning Assessment. This requirement shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes into effect on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

TPL-001-2 'raises the bar' in several areas where performance requirements have been changed in the new Standard versus those in existing TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0 because loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain events, whereas the existing Standards were interpreted by many to allow such actions. As shown in Table 1 of TPL-001-2, the performance requirements associated with the following events represent "raising the bar":

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

This "raising the bar" is beyond the control of the Transmission Planner and Planning Coordinator and may have significant budget, siting, permitting, and construction impacts on many Transmission Owners. To provide stakeholders with sufficient time to implement changes, a timeframe coincident with the end of the Near-Term Transmission Planning Horizon will be provided as follows:

- For 84 months after the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required on the first day of the first calendar quarter, 84 months after Board of Trustees adoption, Corrective Action Plans

applying to performance elements P1-2 and P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element), P2-1, P2-2 (above 300 kV), P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 kV) are allowed to include tripping of Non-Consequential Load and curtailment of Firm Transmission Service (in accordance with Requirement R2.7.3) that would not otherwise be permitted by the requirements of TPL-001-2.

Any entity which cannot eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for these performance elements by that date shall submit a mitigation plan to its Regional Entity outlining the steps it will take to correct the problem. If the entities follow the established ERO procedure for mitigation, it is the intent of the SDT that no penalties will be assessed.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Version 1 of SAR posted for comment from April 2, 2002 through May 3, 2002.
2. Version 2 of SAR posted for comment from May 5, 2004 through June 5, 2004.
3. Version 3 of SAR posted on November 18, 2005.
4. SAR approved on April 30, 2006.
5. Version 1 of Supplemental SAR posted for comment from February 15, 2007 through March 16, 2007.
6. Version 2 of Supplemental SAR posted on April 9, 2007.
7. Version 1 of revised standard(s) posted for comment on September 17, 2007.
8. Version 2 of the revised standards posted for comment on August 15, 2008.
9. Version 3 of the revised standards posted for comment on May 26, 2009.
10. Version 4 of the revised standards posted for comment on September 16, 2009.
11. Initial ballot completed on March 1, 2010.
12. Version 5 of the revised standard posted for comment on August 3, 2010.
13. Version 6 of the revised standard posted for information on October 19, 2010.

Proposed Action Plan and Description of Current Draft:
The SDT has established a schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 1Q11. The current draft is the sixth iteration of the revision of existing standards TPL-001 through TPL-006 and includes one revised standard, TPL-001-2, replacing TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. TPL-005 & -006 issues are addressed in this sixth draft and those standards will also be replaced by TPL-001-2.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Conduct ballot	1Q11
2. Submit standard(s) to BOT.	2Q11
3. Submit to regulatory authorities for approval.	3Q11

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-2**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required on the first day of the first calendar quarter 84 months after Board of Trustees adoption, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-2, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-2:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1, P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies (as indicated in Requirement R2, Part 2.6). Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is

expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

- Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.
- Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that

Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

- Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment

such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
d. Simulate Normal Clearing unless otherwise specified.
e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.
g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
h. Planning event P0 is applicable to steady state only.
i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8]	SLG	EHV	No[9]	No

		(non-Bus-tie Breaker)		HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	EHV, HV	Yes	Yes
Category	**Initial Condition**	**Event [1]**	**Fault Type [2]**	**BES Level [3]**	**Interruption of Firm Transmission Service Allowed [4]**	**Non-Consequential Load Loss Allowed**
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes

P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
   a. Loss of a tower line with three or more circuits.[11]
   b. Loss of all Transmission lines on a common Right-of-Way[11].
   c. Loss of a switching station or substation (loss of one voltage level plus transformers).
   d. Loss of all generating units at a generating station.
   e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
   a. Loss of two generating stations resulting from conditions such as:
      i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
      ii. Loss of the use of a large body of water as the cooling source for generation.
      iii. Wildfires.
      iv. Severe weather, e.g., hurricanes, tornadoes, etc.
      v. A successful cyber attack.
      vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
   b. Other events based upon operating experience that may result in wide area disturbances.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
   a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   e. 3Ø internal breaker fault.
   f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to address BES performance requirements. When Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss is documented, including alternatives evaluated; and where the utilization of Non-Consequential Load Loss is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None.

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR, The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the

	Lower VSL	Moderate VSL	High VSL	Severe VSL
	R3, Part 3.5.	categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	(P2 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient

	Lower VSL	Moderate VSL	High VSL	Severe VSL
				voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR The responsible entity did not distribute its Planning Assessment to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	TBD	Revision of TPL-001-0 as per Project 2006-02; includes merging requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2	Not employed due to scope of revision

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Version 1 of SAR posted for comment from April 2, 2002 through May 3, 2002.
2. Version 2 of SAR posted for comment from May 5, 2004 through June 5, 2004.
3. Version 3 of SAR posted on November 18, 2005.
4. SAR approved on April 30, 2006.
5. Version 1 of Supplemental SAR posted for comment from February 15, 2007 through March 16, 2007.
6. Version 2 of Supplemental SAR posted on April 9, 2007.
7. Version 1 of revised standard(s) posted for comment on September 17, 2007.
8. Version 2 of the revised standards posted for comment on August 15, 2008.
9. Version 3 of the revised standards posted for comment on May 26, 2009.
10. Version 4 of the revised standards posted for comment on September 16, 2009.
11. Initial ballot completed on March 1, 2010.
12. Version 5 of the revised standard posted for comment on August 3, 2010.
13. Version 6 of the revised standard posted for information on October 19, 2010.

Proposed Action Plan and Description of Current Draft:
The SDT has established a schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in ~~1Q10~~1Q11. The current draft is the ~~second~~sixth iteration of the revision of existing standards TPL-001 through TPL-006 and includes one revised standard, TPL-001-~~1~~2, replacing TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. TPL-005 & -006 issues are addressed in this ~~fifth~~sixth draft and those standards will also be replaced by TPL-001-2.

Future Development Plan:

Anticipated Actions	Anticipated Date
~~1. Post fifth version of standard.~~	~~3Q10~~
~~2.~~1. Conduct ballot	~~TBD~~1Q11
~~3. Respond to comments and determine next step~~	~~TBD~~
~~4.~~2. Submit standard(s) to BOT.	2Q11
~~5.~~3. Submit to regulatory authorities for approval.	3Q11

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

~~**Near-Term Transmission Planning Horizon:** Transmission planning period that covers Years One through five.~~

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies.

~~**Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.~~

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-2**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required on the first day of the first calendar quarter 84 months after Board of Trustees adoption, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-2, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-2:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1, P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use ~~the latest~~ data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, ~~summarize documented~~and document summarized results~~, and cover~~ of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: ~~Medium~~High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies (as indicated in Requirement R2, Part 2.6~~, as follows~~). Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in ~~performance~~System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of ~~planned~~known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is

expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study~~ shall not include any material changes unless a~~. Documentation to support the technical rationale ~~can be provided to demonstrate that System~~for determining material changes ~~do not impact the performance results in the study area.~~shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions ~~may~~ include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

- Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.
- Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that

Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

- Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment

such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, ~~any~~the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators~~,~~ and adjacent Transmission Planners~~, and~~ within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and ~~that functional entity~~ submits a written request for the information~~.~~ within 30 days of such a request. *[Violation Risk Factor: ~~Low~~Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load ~~including Load~~ that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial ~~System~~ Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	~~No~~ [9]No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8]	SLG	EHV	No[9]	No

		(non-Bus-tie Breaker)		HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	EHV, HV	Yes	Yes
Category	**Initial ~~System~~ Condition**	**Event [1]**	**Fault Type [2]**	**BES Level [3]**	**Interruption of Firm Transmission Service Allowed [4]**	**Non-Consequential Load Loss Allowed**
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes

P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System ~~adj~~adjustments.[9]~~:~~ 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
   a. Loss of a tower line with three or more circuits.[11]
   b. Loss of all Transmission lines on a common Right-of-Way[11].
   c. Loss of a switching station or substation (loss of one voltage level plus transformers).
   d. Loss of all generating units at a generating station.
   e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
   a. Loss of two generating stations resulting from conditions such as:
      i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
      ii. Loss of the use of a large body of water as the cooling source for generation.
      iii. Wildfires.
      iv. Severe weather, e.g., hurricanes, tornadoes, etc.
      v. A successful cyber attack.
      vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
   b. Other events based upon operating experience that may result in wide area disturbances.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
   a. 3Ø fault on generator with stuck breaker[10] or a ~~Protection System failure~~relay failure[13] resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] or a ~~Protection System failure~~relay failure[13] resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] or a ~~Protection System failure~~relay failure[13] resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] or a ~~Protection System failure~~relay failure[13] resulting in Delayed Fault Clearing.
   e. 3Ø internal breaker fault.
   f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes
(Planning Events and Extreme Events)

1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service ~~, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch,~~ is allowed both as a System adjustment (as identified in the column entitled 'Initial ~~System Conditions'~~Condition') and a corrective action~~,~~ when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and ~~those adjustments do~~the re-dispatch does not result in ~~the shedding of~~ any ~~firm Demand~~Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. ~~Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.~~
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.

~~12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.~~

12. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to address BES performance requirements. When Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss is documented, including alternatives evaluated; and where the utilization of Non-Consequential Load Loss is subject to review in

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
an open and transparent stakeholder process that includes addressing stakeholder comments.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using ~~the latest~~ data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying ~~any~~the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators~~,~~ and adjacent Transmission Planners~~, and~~ within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that ~~functional entity~~the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying ~~any~~the criteria or methodology utilized in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as ~~all such~~ documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None.

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6. ~~OR~~ ~~The responsible entity's System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.~~	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR, The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the

	Lower VSL	Moderate VSL	High VSL	Severe VSL
	R3, Part 3.5.	categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events. ~~OR~~ ~~The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.~~	(P2 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events. ~~OR~~ ~~The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.~~	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity ~~failed to distribute the results of~~distributed its Planning Assessment to ~~one of its~~ adjacent Planning Coordinators and adjacent Transmission Planners~~, one adjacent Planning Coordinator,~~ but it was more than 90 days but less than or ~~to one~~ equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment to functional ~~entity that has~~entities having a reliability related need ~~and that has submitted a written~~ who requested the Planning Assessment in writing	~~N/A~~ The responsible entity distributed its Planning Assessment to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity ~~failed to distribute the results of~~distributed its Planning Assessment to ~~more than one of its adjacent Transmission Planners,~~ adjacent Planning Coordinators~~,~~ and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment to functional entities ~~that have~~having a reliability related need ~~and that have submitted a written~~ who requested the Planning	The responsible entity ~~failed~~ distributed its Planning Assessment to ~~provide a documented response~~adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment to ~~a recipient of~~adjacent Planning Coordinators and adjacent Transmission Planners. OR

	Lower VSL	Moderate VSL	High VSL	Severe VSL
	but it was more than 30 days but less than or equal to 40 days following the request ~~for the information, respectively in accordance with Requirement R8~~.		Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request ~~for the information, respectively in accordance with Requirement R8~~.	The responsible entity distributed its Planning Assessment to functional entities having a reliability related need who requested the Planning Assessment ~~results who provided documented comments on~~in writing but it was more than 60 days following the ~~results within 90 calendar days of receipt of those comments in accordance with Requirement R8~~request. OR The responsible entity did not distribute its Planning Assessment to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	TBD	Revision of TPL-001-0 as per Project 2006-02; includes merging requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-~~1~~2	Not employed due to scope of revision

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Version 1 of SAR posted for comment from April 2, 2002 through May 3, 2002.
2. Version 2 of SAR posted for comment from May 5, 2004 through June 5, 2004.
3. Version 3 of SAR posted on November 18, 2005.
4. SAR approved on April 30, 2006.
5. Version 1 of Supplemental SAR posted for comment from February 15, 2007 through March 16, 2007.
6. Version 2 of Supplemental SAR posted on April 9, 2007.
7. Version 1 of revised standard(s) posted for comment on September 17, 2007.
8. Version 2 of the revised standards posted for comment on August 15, 2008.
9. Version 3 of the revised standards posted for comment on May 26, 2009.
10. Version 4 of the revised standards posted for comment on September 16, 2009.
11. Initial ballot completed on March 1, 2010.
12. Version 5 of the revised standard posted for comment on August 3, 2010.
13. Version 6 of the revised standard posted for information on October 19, 2010.

Proposed Action Plan and Description of Current Draft:
The SDT has established a schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 1Q1~~0~~1. The current draft is the ~~second~~sixth iteration of the revision of existing standards TPL-001 through TPL-006 and includes one revised standard, TPL-001-~~1~~2, replacing TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. TPL-005 & -006 issues are addressed in this ~~f~~s~~i~~~~f~~xth draft and those standards will also be replaced by TPL-001-~~1.~~ 2.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Conduct ballot	1Q11
~~1.~~2. Submit standard(s) to BOT.	2Q1~~0~~1
~~2.~~3. Submit to regulatory authorities for approval.	3Q1~~0~~1

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

~~**Near-Term Transmission Planning Horizon:** Transmission planning period that covers Years One through five.~~

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies.

~~**Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.~~

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-~~1~~2**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.

   For ~~60~~84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required on the first day of the first calendar quarter 84 months after Board of Trustees adoption, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-~~1~~2, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-~~1~~2:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1, P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use ~~the latest~~ data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.

This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies~~,~~ (as indicated in Requirement R2, Part 2.6), document assumptions, ~~summarize documented~~and document summarized results~~, and cover~~ of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: ~~Medium~~High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by ~~the following annual~~ current annual studies~~, supplemented with~~ or qualified past studies (as indicated in Requirement R2, Part 2.6). Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled~~,~~ as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions ~~not already included in the studies~~ by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in ~~performance~~System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of ~~planned~~known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be ~~assessed~~studied. The ~~Planning Assessment~~studies shall ~~reflect~~be performed for the P0, P1, and P2 categories identified in Table 1 ~~during~~with the conditions that the System is expected to experience ~~due to~~during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions ~~not already included in the studies~~ by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past

studies as qualified in Requirement R2, ~~part 2.6.~~Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study~~ shall not include any material changes unless a~~ . Documentation to support the technical rationale ~~can be provided to demonstrate that System~~for determining material changes ~~do not impact the performance results in the study area.~~shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions ~~may~~ include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would

normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

- ~~Trip~~Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) ~~transformer~~ voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.
- ~~Trip~~Tripping of Transmission elements whe~~n~~re relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated ~~for System performance~~ in Requirement R3, Part 3.2 ~~created~~. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention ~~while also considering~~. The analyses shall include the impact of ~~successful or unsuccessful high speed reclosing.~~subsequent:

- ~~Trip~~Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

- Tripping of generators where simulations show generator bus voltages or high side of the GSU ~~transformer~~ voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- ~~Simulate the impact~~Tripping of Transmission lines and transformers where transient swings ~~on~~cause Protection System operation ~~for Transmission lines and transformers~~based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated ~~for System performance~~ in Requirement R4, Part 4.1 ~~created~~. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated ~~for System performance~~ in Requirement R4, Part 4.2 ~~created~~. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall ~~define and document, within its Planning Assessment,~~have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within ~~its~~their Planning Assessment, ~~any~~the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators~~,~~ and adjacent Transmission Planners~~, and~~ within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a

reliability related need and submits a written request for the information~~.~~ within 30 days of such a request. *[Violation Risk Factor: ~~Low~~Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. ~~BES Transmission voltage instability,~~The System shall remain stable. Cascading~~,~~ and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any ~~planning or extreme~~ event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. ~~For all planning events,~~ Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive ~~Load including~~ Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

~~j. The System shall remain stable.~~

~~k.~~j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial ~~System~~ Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	~~No~~[9]No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	~~No~~No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	~~No~~No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8]	SLG	EHV	No[9]	No

		(non-Bus-tie Breaker)		HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	EHV, HV	Yes	Yes
Category	**Initial ~~System~~ Condition**	**Event [1]**	**Fault Type [2]**	**BES Level [3]**	**Interruption of Firm Transmission Service Allowed [4]**	**Non-Consequential Load Loss Allowed**
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus ~~Protection System~~relay failure to operate)*	Normal System	~~Failure of a single Protection System that results in~~ Delayed Fault Clearing ~~on~~due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes

P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System ~~adj~~adjustments.[9]~~:~~ 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
   a. Loss of a tower line with three or more circuits.[11]
   b. Loss of all Transmission lines on a common Right-of-Way[11].
   c. Loss of a switching station or substation (loss of one voltage level plus transformers).
   d. Loss of all generating units at a generating station.
   e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
   a. Loss of two generating stations resulting from conditions such as:
      i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
      ii. Loss of the use of a large body of water as the cooling source for generation.
      iii. Wildfires.
      iv. Severe weather, e.g., hurricanes, tornadoes, etc.
      v. A successful cyber attack.
      vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
   b. Other events based upon operating experience that may result in wide area disturbances.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
   a. 3Ø fault on generator with stuck breaker[10] or a ~~Protection System failure~~relay failure[13] resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] or a ~~Protection System failure~~relay failure[13] resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] or a ~~Protection System failure~~relay failure[13] resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] or a ~~Protection System failure~~relay failure[13] resulting in Delayed Fault Clearing.
   e. 3Ø internal breaker fault.
   f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service ~~, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch,~~ is allowed both as a System adjustment (as identified in the column entitled 'Initial ~~System Conditions'~~Condition') and a corrective action~~,~~ when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and ~~those adjustments do~~the re-dispatch does not result in ~~the shedding of~~ any ~~firm Demand~~Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. ~~Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.~~
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to address BES performance requirements. When Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss is documented, including alternatives evaluated; and where the utilization of Non-Consequential Load Loss is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
~~11.~~13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within ~~its~~their respective area, using ~~the latest~~ data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying ~~any~~the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and ~~the Planning~~ Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient~~, date,~~ and ~~contents,~~date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators~~,~~ and adjacent Transmission Planners~~, and~~ within 90 days of having completed its Planning Assessment, and to any functional entity ~~that~~who has indicated a reliability need ~~and~~within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. ~~1.~~ Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity~~.~~

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying ~~any~~the criteria or methodology utilized in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as ~~all such~~ documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the ~~notices and other documentation~~notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None.

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6. ~~OR~~ ~~The responsible entity's System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.~~	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR, The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the

	Lower VSL	Moderate VSL	High VSL	Severe VSL
	R3, Part 3.5.	categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events. ~~OR~~ ~~The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.~~	(P2 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events. ~~OR~~ ~~The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.~~	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	N/A	N/A	N/A	The responsible entity ~~failed to define and document its~~does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity ~~failed to distribute the results of~~distributed its Planning Assessment to ~~one of its adjacent Transmission Planners or~~ adjacent Planning Coordinators~~,~~ and ~~to one~~ adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment to functional ~~entity that has~~entities having a	~~N/A~~ The responsible entity distributed its Planning Assessment to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to	The responsible entity ~~failed to distribute the results of~~distributed its Planning Assessment to ~~its adjacent Transmission Planners or~~ adjacent Planning Coordinators~~,~~ and ~~to any~~ adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment to functional ~~entity that has~~entities having a	The responsible entity ~~failed~~ distributed its Planning Assessment to ~~provide a documented response~~adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment to ~~a recipient of~~adjacent Planning Coordinators and adjacent

	Lower VSL	Moderate VSL	High VSL	Severe VSL
	reliability related need ~~and has submitted a written~~ who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request ~~for the information, respectively in accordance with Requirement R8~~.	50 days following the request.	reliability related need ~~and has submitted a written~~ who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request ~~for the information, respectively in accordance with Requirement R8~~.	Transmission Planners. OR The responsible entity distributed its Planning Assessment to functional entities having a reliability related need who requested the Planning Assessment ~~results who provided documented comments on~~in writing but it was more than 60 days following the ~~results within 90 calendar days of receipt of those comments in accordance with Requirement R8~~request. OR The responsible entity did not distribute its Planning Assessment to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. ~~E.~~ Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	TBD	Revision of TPL-001-0 as per Project 2006-02; includes merging requirements of TPL-001-0, TPL-002-0, TPL-003-0, ~~TPL-004-0, TPL-005,~~ and TPL-~~006~~004-0 into one, single, comprehensive, coordinated standard: TPL-001-~~1~~2	Not employed due to scope of revision

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2006-02 Assess Transmission Future Needs
Ballot Pool Window Open: April 18 – May 18, 2011
Successive Formal Comment Period Open: April 18 – May 31, 2011

Now available at: http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

The standard drafting team working on Project 2006-02 (ATFN SDT) is seeking comments on revisions to TPL-001-2 after submitting Draft 6 of the standard and supporting documents for quality review, and now that TPL Table 1 footnote 'b' changes have been approved by the ballot pool and filed with FERC. Clean and redline versions of the standard showing revisions since the last posting, along with the associated implementation plan, are posted on the project page. No redline of the implementation plan has been posted since only formatting changes have been made since the last posting.

Ballot Pool Open through 8 a.m. on May 18, 2011

A new ballot pool is being formed for the balloting of revisions to TPL-001-2. The Standards Committee has authorized posting the standard and implementation plan for a formal comment period with a successive ballot and concurrent non-binding poll conducted during the last 10 days of that comment period. The Standards Committee also authorized forming a new ballot pool because the last ballot of this project was conducted more than a year ago.

The ballot pool will be open through 8 a.m. on May 18, 2011, and the ballot window will be from 8 a.m. Eastern on May 18 through 8 p.m. Eastern on May 31, 2011.

Instructions for Joining the New Ballot Pool for Project 2006-02

Registered Ballot Body members may join the ballot pool to be eligible to vote in the upcoming ballot at the following page: https://standards.nerc.net/BallotPool.aspx

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-2006-02_TPL_sb_in@nerc.com

Members who join the ballot pool to vote on the standard will automatically be entered in a separate pool to participate in the non-binding poll of the associated violation risk factor (VRF) and violation severity levels (VSLs).

Instructions for Commenting

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page: http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

Next Steps

A successive ballot of draft 7 of TPL-001-2, and a concurrent non-binding poll of the associated VRFs and VSLs, will begin on May 18, 2011 and end at 8 p.m. Eastern on Tuesday, May 31, 2011.

Background

TPL-001-1 is designed to be a single, comprehensive, and coordinated standard that merges the requirements of four existing standards: TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The proposed standard includes several new definitions. The purpose of the proposed standard is to establish transmission system planning performance requirements within the planning horizon to develop a bulk electric system that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies.

The AFTN SDT solicited comments from the industry on the fifth posting of the revised TPL-001-2 through an informal comment period that ended on September 2, 2010. The team revised the standard in response to comments received, and posted Draft 6 for information, while awaiting the outcome of Project 2010-11 TPL Table 1 (footnote 'b'). The revisions to Table 1 footnote 'b' have been approved by the NERC Board of Trustees and filed with FERC. The AFTN SDT adopted the technical tenets of the final solution for footnote 'b' for inclusion in TPL-001-2.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Revised Standards Announcement

Project 2006-02 Assess Transmission and Future Needs
Successive Ballot and Non-Binding Poll Now Open
May 18 – 31, 2011

Now available at: https://standards.nerc.net/CurrentBallots.aspx

A successive ballot for the proposed standard, TPL-001-2 — Transmission System Planning Performance Requirements, and a concurrent, non-binding poll of the revised VRFs and VSLs are being conducted through **8:00 pm Eastern on Tuesday, May 31, 2011**.

Since the last time this standard was balloted was prior to the approval of footnote 'b', a redline showing all changes made to the standard since the last balloted version of the standard has been added to the project page: http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

Instructions

Members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx.

Special Instructions for Submitting Comments With a Ballot or Non-Binding Poll

Comments submitted with ballots are extremely valuable to help the drafting team revise its work. In an effort to reduce the burden on stakeholders providing comments, the drafting team requests that all comments (both those submitted with a ballot and those submitted by stakeholders not balloting) be submitted through the electronic comment form. Note that question 2 asks specifically about revisions the team has made to the VRFs and VSLs, and members of the ballot pool who wish to enter comments to support their opinion in the non-binding poll may provide them in response to question 2.

This approach will ensure that stakeholders only provide a single set of comments, but have an opportunity to notify the drafting team if they have provided comments. During the successive ballot window, members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx. When submitting a ballot with comments, simply record a "Comments submitted" in the comments field of the ballot to indicate that comments were submitted.

Documents for this project, including an off-line unofficial copy of the questions listed in the comment forms are posted at the following site: http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

Next Steps

The drafting team will consider all comments received during the formal comment period, ballot, and non-binding poll, and will determine whether to make additional changes to the standard and its implementation plan

Background

TPL-001-2 is designed to be a single, comprehensive, and coordinated standard that merges the requirements of four existing standards: TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The proposed standard includes several new definitions. The purpose of the proposed standard is to establish transmission system planning performance requirements within the planning horizon to develop a bulk electric system that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies.

The AFTN SDT solicited comments from the industry on the fifth posting of the revised TPL-001-2 through an informal comment period that ended on September 2, 2010. The team revised the standard in response to comments received, and posted Draft 6 for information, while awaiting the outcome of Project 2010-11 TPL Table 1 (footnote 'b'). The revisions to Table 1 footnote 'b' have been approved by the NERC Board of Trustees and filed with FERC. The AFTN SDT adopted the technical tenets of the final solution for footnote 'b' for inclusion in TPL-001-2.

Additional information about this project is available on the project page at:
http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Individual or group. (44 Responses)
Name (30 Responses)
Organization (30 Responses)
Group Name (14 Responses)
Question 1 (43 Responses)
Question 1 Comments (44 Responses)
Question 2 (36 Responses)
Question 2 Comments (44 Responses)
Question 3 (0 Responses)
Question 3 Comments (44 Responses)

Group
SERC Planning Standards Subcommittee
Yes
Yes
R1 does not seem to address issues where data errors have been introduced into the latest model data. Also, R1 and its VSL may be interpreted to exclude the use of past studies. The Implementation Plan should include a five-year delay in the effective date for short circuit studies (R2 parts 2.3 and 2.8) since these studies are not required in the current version 0 standards. The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Group
Progress Energy
First, Progress Energy ("PE") notes that many changes to the Requirements language have been appropriate or have improved upon the language of the previous drafts, and PE commends the SDT in this. PE does have concerns, however, with the language in R8 and its corresponding Measure M8, and therefore must select 'no' for Q1 and provide comments. PE disagrees with the language of R8 primarily to the extent that the use of the verb "distribute" with respect to communicating Planning Assessments leads the reader to M8, which lacks language that would provide for the optimal correlation with R8. Regarding the M8 language, PE feels that the term "demonstration of a public posting" is a valid action in demonstrating compliance with R8 and thus should be more clearly described as one of several acceptable methods of distributing Planning Assessments. In addition, given the appropriate concern that NERC and FERC have recently raised regarding Cyber threats and the need for additional Cyber Security measures, PE feels that the public posting language should contain a qualification regarding the security of CEII information. PE thus recommends that an appropriate phrase to use would be "demonstration of a secure public posting", thereby making clear that a public posting would not be a website accessible to just anyone due to CEII concerns.
Yes
Group
Northeast Power Coordinating Council
No
The wording of Part 1.1.2, "known outages...with a duration of at least 6 months" should be revised to "…at least 1 year". Also for consideration is that "known outages...with a duration of at least 6 months" are dealt with in operational studies rather than planning studies. Any adverse impacts that these outages might have are mitigated by operational decisions rather than planning decisions within a 6 month horizon. Moving this requirement out of the TPL Standard to an operational standard should be considered. Make the wording consistent between 2.1 and 2.2 as it relates to qualified past studies. Specifically: Parts 2.1.2, 2.1.4, 2.1.5 The language of requirements 2.1.4 and 2.4.3 allowing the performance of one or more sensitivities appears to be inconsistent with language in 2.7.2. 2.7.2

requires multiple sensitivities to determine if actions to resolve performance deficiencies are necessary. Will varying only one measurable quantity several times in multiple simulations satisfy multiple sensitivity studies or just one sensitivity study? The numbers and types of required sensitivity studies is unclear, and subject to interpretation by PCs and TPs. The current wording in Part 2.1.5, "spare strategy", appears to be open-ended regarding the number of permutations to be analyzed. It should be restricted to assessing only one piece of equipment being unavailable or outaged at a time. 2.1.5 should be consistent with R2 and 2.1 regarding the use of the terms assessment and studies. As with the preceding comment regarding Part 1.1.2, moving this requirement out of the TPL Standard and to an operational standard should be considered. It is unclear if the last sentence of R2.1.5 allows for the curtailment of firm transmission service before the application of category P0, P1 and P2 events. This last sentence states: "…with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment." The wording in Part 2.2 "be supported by the following annual current study, supplemented with qualified past studies" should be replaced with the similar statement in Part 2.1: "be supported by current annual studies or qualified past studies". Part 2.7.1 lists potential system actions to address System deficiencies. It is suggested that this list be moved to a guideline or white paper. The wording in Part 8.1 needs to be amended to restrict comments to the most recent assessment only. Contingencies on back to back HVDC installations are not mentioned in the standard. The treatment of combined cycle facilities (all units in outage?) needs to be clarified, as well as Footnote 7 of Table 1 requiring clarification. In Table 1, Event 1 of Category P2 and related Footnote 7 are not clear because of the use of the word "possibly". If the intension is to simulate the line end opening condition of tapped lines, this should be clearly stated in the table (without reference to "Opening of a line section" and use of different language in the footnote). From Table 1b: "Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0." Firm Transmission Services Loss is also acceptable and should be added (particularly in P1 loss of a single pole of a DC line for which the transfer is reduced accordingly to the remaining pole capability).

Individual

John Bussman

Associated Electric Cooperative Inc

No

R2.4.1: The SDT has put a stronger emphasis on dynamic load behavior in stability studies (FIDVR, induction motor loads, etc) to be included in the peak models. The standard does indicate that "An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable." We feel that this should be clarified to ensure that the current modeling processes address what NERC desires with this requirement. At a minimum, we recommend that a grace period be implemented to account for any regional modeling practices which need time to implement dynamic load behavior per the draft standard. R2.5: It is our understanding that the Long-Term Transmission Planning Horizon does not require the sensitivity analysis which is required in R2.4 for the Near-Term Transmission Planning Horizon for the stability portion of the studies. R2.7: It is our understanding that Corrective Action Plan(s) do not need to be developed for performance violations observed in the sensitivity analysis (steady state and stability) unless the violation is observed in several sensitivities as it is indicated in R2.7.2: "Include actions to resolve performance deficiencies indentified in multiple sensitivity studies or provide rationale for why actions were not necessary". We feel that this needs to be further clarified. R3.3.1: This requirement indicates that steady state analysis should include the effect of ride-through voltage limitations of generating units. We are having difficulty seeing how this is a steady-state issue. Generally one would expect a generator to experience ride-through voltage issues during faults. Per Table 1, P1.1 already require generator outages be taken – wouldn't that cover this issue? We feel that this needs to be further clarified. R3.4.1: This requirement states that "Transmission Planners shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list". We feel that the coordination requirement should be removed from the standard as this will result in a massive increase in workload/time required to perform the TPL studies. AECI has several ties to adjacent Transmission Planners and Planning Coordinators – it will be a very time intensive task to coordinate with all of these parties. If the standard wants to ensure that the Contingencies overlap – we can agree to that, however we feel

that the SDT needs to give some firm clarity on how far to go with it (how many buses away, only include ties, etc?). R4.1.2: We would like clarification on what is mean by "apparent impedance swings". R4.3.1: Is the intent of the SDT to require that generic or actual relay models be added to the stability models? We feel that this needs to be further clarified. R8: This requirement states that the Planning Assessments shall be distributed within 90 days of their completion to adjacent Planning Coordinators, Transmission Planners, and functional entities that have a reliability need (3rd Interconnection Customers?). We do not agree with the mandatory requirement of distributing the results of our TPL studies: We consider this information to be CEII We can agree to distribute the results upon request, but do not agree with the 30 day timeframe as more time will be needed to sign applicable Non-Disclosure Agreements, etc.
Individual
Thad Ness
American Electric Power
Yes
Yes
Individual
Greg Rowland
Duke Energy
Yes
Yes
Group
SPP Reliability Standards Development Team
Yes
Yes
A5 It would seem that 84 months wouldn't be universally attainable due to different system configurations, terrain, geography, and permitting issues that are required to complete a corrective action plan. In 2.4.1 we would like to see better clarity on what an Aggregate system load model is and how granular it should be. If the answer is a very detailed representation of the load system then it may take a longer time to implement. In section 2.7 we would to see clarification on the sensitivity analysis. Is this in reference to seasonal models and differences in fuel availability? We need more detail on how this is to be done so that it won't be left up to interpretation. We would like for clarification of the planning assessment and who is performing which tasks. We would also like to utilize a regional assessment due to limited resources. Under which criteria should the assessment fall under the regional entity or the individual companies? In section 3.4.1 this type of coordination could be difficult due to other adjacent entities on different schedules and some possibly couldn't have the amount of detail to incorporate into another's processes. We know this is generally covered in coordination of real time operations and wonder if it is appropriate to require this type of coordination in the long term process. Is there already an operational standard that covers this? Would it be better to address this in the operational standards? PC's between regions are already coordinating for long term studies. Should this standard fall more on the back of the PC's rather than the TP Can we get a bright line definition of what apparent impedance swings means? R4.3.1 will the detailed amount of data then be incorporated back into the NERC modeling processes and create a more detailed model with better accuracy? R8 We do not agree that we should provide the assessment to every adjacent

PC and TP. We do agree however that if requested by these entities we would provide the assessment. We don't mind sharing information with requestors but would like a longer duration than 30 days due to the fact that we would like to know what type of "reliability need" any entity would have considering that some of the information could be considered CEII. Non disclosure agreements may be needed in order to provide this information.
Individual
Bernie Pasternack
Transmission Strategies, LLC
Yes
Yes
The SDT, Observers, and the Industry as a whole have put a tremendous amount of thought and work into the development of this latest draft. While nobody should claim that this latest version is perfect, it is far clearer, more in tune with current industry needs, and much improved compared to the existing approved Standards that it will replace.
Group
Arizona Public Service Company
Yes
No
With regards to R2, it appears that the VRF has changed from Medium to High without any justification; and with the time horizon of long term planning, AZPS believes there is no justification for changing it from Medium to High.
AZPS would like to reiterate its "Affirmative" voting recommendation with regard to the proposed revisions to the Standard. AZPS erroneously entered a "Negative" Standard vote for one of its voting segments.
Individual
Joe O'Brien
NIPSCO
Yes
Yes
1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. This is a little confusing to me. Does this mean the outage must last at least six months? Or does this mean at least model outages that last six months or more. If it is the latter then, I'm not sure that is stringent enough. There may be known critical outages occurring over peak that do not last 6 months. If non-consequential load loss is not allowed for loss of one element, then what about the next contingency? Couldn't that result in having to interrupt Firm service? Is that okay as a corrective action plan in the outage coordination horizon? Does this apply to both near-term and long-term planning? If so, we probably need to model additional unplanned potential outages on top of n-1 conditions. Lastly. in section 2.1.4 should there be a category for high/low wind conditions?
Individual
Scott Bos
Muscatine Power and Water
Yes
No
MP&W would like to recommend that the VRF for Requirement 8 remain "Low", rather than "Medium." It is our belief that there is not a significant risk to the reliability of the BES if an annual Planning Assessment is not distributed to another entities or a documented response to Planning Assessment

comments is not provided within 90 days of a request. This is more administrative in nature. The findings in an assessment report are not urgent, but address system needs that will emerge over years in the future. Additionally, entities with a reliability-related need for Planning Assessment information generally have the ability to perform their own independent planning assessment of adjacent systems or other areas of interest.
MP&W recommends that the term "System" be replaced with "BES" in various places throughout the standard when the reference should not be to the collective generation, transmission, and distribution systems. This is the current definition of the NERC Glossary term "System". The locations where "System" can be found in the Standard are: R2.1.4, R2.1.5, R2.4.3, R2.6.2, R2.7, R2.7.1, R2.7.4, R2.8.1, R2.8.2, R3.5, R4.5, R5, and R6.
Individual
Sunitha Kothapalli
Puget Sound Energy, Inc.
Yes
We Appreciate SDTs efforts in bringing clarity to the TPL standards.
Yes
Group
Bonneville Power Administration
Yes
1. If current study is performed to assess the system, there is no need to supplement with past studies. • Suggested language for R2.2:- For the planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed and be supported by the following annual current study or qualified past studies as indicated in Requirement R2, Part 2.6 2. Load models should be consistent across the region • Suggested language for R2.4.1:- System peak load for one of the five years. System peak load levels shall include a the latest load model developed by the regional planning coordinator which represents the expected dynamic behavior of loads that could impact the study area, considering the behavior of induction motor loads. 3. R2.5 is redundant and should be deleted. It is already included in R1.1.3 and R2.6.2. 4. R3.5: This standard requires mitigating the consequences of extreme events. Requiring potentially very costly mitigation actions for very low probability event is unnecessary burden to utilities. • Suggested language for R3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. Evaluation of the risk, consequences and adverse impacts of the event(s) shall be conducted.
No
The VRF for R2 was changed from Medium to High without any explanation. Since the time horizon for R2 is Long Term Planning, BPA believes that the VRF should be Medium, as are the VRFs for the other requirements related to conducting the assessments, rather than High.
Group
Tri-State Generation & Transmission
Yes
No
Many of the sub-requirements of R2 do not warrant high risk VRFs, yet violation of any R2 sub-requirement would result in a "High Risk Factor" violation assessment. We believe that having so many sub-requirements can result in inaccurate overall severity classification. For example, skipping one study defined in R2.1.2 (Planning Assessments) for a particular time frame or load level would probably not result in a direct actual degradation in system performance, but would still result in a High Violation Risk Factor.
Change R1.1 to "System models used for Steady State and Stability Analysis shall represent:" Much

of what is in R1.1 is unnecessary for Short Circuit studies. In contrast, there are items not mentioned in R1.1 that are necessary for short circuit studies. R2.1.4 requires sensitivity analysis to study "a range of credible conditions that demonstrate a measurable change". How will the required actions in R2.1.4 be documented or measured, and what is accomplished by performing sensitivity analysis in the context of a system performance assessment? In R2.3, change the first sentence to read "The short circuit analysis portion of the Planning Assessment shall be conducted annually, using one of the cases described in 2.1.1, addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6." There appears to be no reason to perform short circuit studies for all three Near-Term Transmission Planning Horizon cases. R2.4.3 requires sensitivity analysis to study "a range of credible conditions that demonstrate a measurable change". How will the required actions in R2.4.3 be documented or measured, and what is accomplished by performing sensitivity analysis in the context of a system performance assessment? R2.7.1 remove the last bullet. We believe these programs are already factored into the load forecast, as they are associated with resource scheduling and planning load serving, and not transmission planning. In particular, DSM measures would fall under R2.4.1, and the term "new technologies, or other initiatives" The language of Requirement 3 unnecessarily repeats the language of R1 and R2. As now written, R3 states "For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1." R3 We recommend that the introductory language in Requirement R3 be changed to read "The studies in Requirement R2, Parts 2.1, and 2.2 shall be performed using models as defined in Requirement R1 in accordance with the following criteria." We believe that Requirements 3.1 and 3.4 should be combined into R3.1, eliminating R3.4. It is redundant to have Requirement 3.1 say "perform R3.4". We recommend that R3.4 be deleted and that R3.1 be replaced with: R3.1 Planning event studies shall be performed in accordance with "Table 1 – Steady State & Stability Performance Planning Events;" and shall be based on a supportable Contingency list. Comment: The content of 3.4.1 was intentionally omitted as it is redundant with R7. Also, the language "…more severe System impacts…" was intentionally omitted as it could be subject to a wide range of interpretations. Similarly, we recommend that R3.5 be deleted and that R3.2 be replaced with: R3.2 Extreme event studies shall be performed in accordance with "Table 1 – Steady State & Stability Extreme Events;" and shall be based on a supportable Contingency list. We recommend the following new requirement be inserted after the revised R3.2 language: Should the extreme event studies identify potential Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted. Comment: As before, the language "…more severe System impacts…" was intentionally omitted as it could be subject to a wide range of interpretations. We recommend removing the second bullet of R3.3.1, "Tripping of Transmission elements where relay loadability limits are exceeded" for the following reasons: 1. There is currently no tool to model relay loadability characteristics in Steady State analysis. 2. Requirement R3.3.1 would require inclusion of relay models in modeling data that are not currently provided. MOD-012 does not require impedance or overcurrent relay models to be submitted. 3. In Requirement 3.3.1, the second bullet, it is impossible to model complete and accurate relay loadability using present-day steady state simulation tools. At best an individual point could be chosen to model relays based on a selected power factor. We recommend changing the opening text of Requirement R.3.3.2 to say "Simulate the expected automatic or manual operation…" Subrequirement R4.1.2 represents a tremendous increase in dynamic modeling complexity. Modeling relay action during apparent impedance swings would require inclusion of impedance relay models in modeling data that are not required to be submitted in MOD-012. If such modeling is necessary, then the corresponding data requirements need to be addressed in MOD standards. We believe that Requirements 4.1 and 4.4 should be combined into R4.1 as shown below and R4.4 should be deleted. It is redundant to have Requirement 4.1 say "perform R4.4." We recommend R4.1 language be revised to read as follows: R4.1 Planning event studies shall be performed in accordance with "Table 1 – Steady State & Stability Performance Planning Events;" and shall be based on a supportable Contingency list. Comment: The content of 4.4.1 should be omitted as it is redundant with R7. Also, the language "…more severe System impacts…" should be omitted as it could be subject to a wide range of interpretations. Similarly, R4.5 should be deleted and R4.2 should be replaced with: R4.2 Extreme event studies shall be performed in accordance with "Table 1 – Steady State & Stability Extreme Events;" and shall be based on a supportable Contingency list. We recommend the following new requirement be inserted after the revised R4.2: Should the extreme

event studies identify potential Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the even(s) shall be conducted. Comment: As before, the language "…more severe System impacts…" was intentionally omitted as it could be subject to a wide range of interpretations. Clarify the first bullet in Requirement R4, part 4.3.1 by changing it to "High-speed (less than 1 second) reclosing, where the fault has cleared, and high-speed reclosing into the permanent fault , but in each case only if high-speed reclosing is utilized". In Requirement R4, part 4.3.1, third bullet, it is impossible to model complete and accurate relay loadability using present-day steady state simulation tools. Existing applications do have impedance relay models, but these models do not model many relay capabilities– for example, non-circular protection regions and load-encroachment. We recommend removing this bullet. The comment statement we made above referring to R4.1.2 also applies to R4.3.1. MOD-012 does not require reclosing relay model data to be submitted. If such modeling is necessary, then the corresponding data requirements need to be addressed in MOD standards. Furthermore, there is not a standard built-in reclosing relay model in current stability simulation tools. Comments regarding Table 1- We assume the headnote i. to Table 1 - "The response of voltage sensitive Load…" - means that studies must not rely on end-user load tripping to meet the performance requirements defined in TPL-001-2 but that it should be modeled (when known) so that its occurrence would be evident. We don't see the need to apply Footnote 12 to only certain contingency categories or certain events in categories. Recommend putting the footnote in the column header just as with Footnotes 1, 2, 3, and 4. Recommend changing "utilized" in Measurement M3 to "performed." Recommend changing "utilized" in Measurement M4 to "performed." Modify Measurement M7 to "Each Planning Coordinator shall provide dated documentation on roles and responsibilities of its Transmission Planners, such as…" The deleted phrase, "in conjunction with each of its Transmission Planners," appears to be unnecessary.
Individual
Anthony Jablonski
ReliabilityFirst
Yes
1. In requirement 4.3, the high speed recloser time of 1 second is too restrictive. We suggest that the time be expanded to 2 seconds to capture all reclosing operations that might impact stability studies. We interpret the use of bullet points in Requirement 4.3.1 to mean that any one of the statements can be included in the analyses. In this requirement, the use of bullet points should be removed and replaced with language that requires all of the statements to be included in the analyses. We strongly believe that the language needs amended in requirement 4.3.1, such that, we will reconsider our voting position. 2. In Table 1 labeled Steady State and Stability Performance Extreme Events we contend that the change to "relay failure" is unnecessarily limiting. The previous use of Protection system was satisfactory. Protection System is a defined term and encompasses many components that may fail and not just the relay. 3. In table 1 Steady State & Stability Performance Planning Events under P5 "non-redundant" needs to be better defined. We suggest saying in a footnote that two devices do not need to be identical in order to be redundant. Redundant relays or relay schemes need to have the same performance level to be considered redundant but do not need to be identical equipment.
No
ReliabilityFirst generally agrees with the Violation Risk Factors (VRFs) but disagrees with the Violation Severity Levels (VSLs) for the following reasons: 1. VSL for R1 a. Under the last "Severe" VSL, the word "latest" should be removed to be consistent with the language in Requirement 1. This is a violation of the FERC Guideline 3: "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement" 2. VSLs for R2 a. To be consistent with the language in Requirement 2, suggest modifying the last "Severe" VSL to state "The responsible entity failed to prepare an annual Planning Assessment of its portion of the BES" 3. VSLs for R3 a. Under the last VSL under the "High" category, the word "perform" should be replaced with "simulate" to be consistent with the requirement. (e.g. "The responsible entity did not simulate Contingency analysis as described in Requirement R3, Part 3.3.") 4. VSL's for R4 a. Under the last VSL under the "High" category, the word "perform" should be replaced with "simulate" to be consistent with the requirement (e.g. "The responsible entity did not simulate Contingency analysis as described in Requirement R4, Part 4.3."). 5. VSLs for R6 a. To be consistent with the language in Requirement 6, suggest modifying the "Severe" VSL to state "The responsible entity failed to define and document, within their Planning

Assessment, the criteria or methodology used in the analysis to identify System instability for conditions, as described in Requirement R6." 6. VSLs for R7 a. Suggest adding the following language to the end of the "Severe" VSL; "for the Planning Assessment", to be consistent with the requirement. 7. VSL for R8 a. Under all four categories of VSLs, any reference to "Planning Assessment" should be changed to "Planning Assessment results" to be consistent with the language in Requirement 8 (or more appropriately, the term "results" should be removed from Requirement 8). This is a violation of the FERC Guideline 3: "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement" b. Under the "Lower" VSL, it is unclear why there is a 30 day timeframe for the first VSL, while the "Moderate", and "High" VSLs have a 10 day timeframe. Based on FERC recommendations, suggest making the timeframe for all four VSL s, 10 day increments. c. VSLs need to be developed to deal with a violation of Part 8.1 (i.e. the PC or TP failed to provide a documented response to that recipient within 90 calendar days of receipt of those comments)
1. Requirement 8 and 8.1 uses the language of "Planning Assessment results". This language is not defined in the section of the standard that defines the terms of use. For consistency "Planning Assessment results" should be replaced with "Planning Assessment". 2. Requirement 2.1.5 has statements that are ambiguous. What is considered major transmission equipment? What is an entity's "spare equipment strategy"? The requirement is not clear as to how many power flow models are required (one per piece of "major transmission equipment" without a spare, or one model with every piece of "major transmission equipment" without a spare being out of service)? As written, if an entity has no "spare equipment strategy" they could be exempt from this requirement. 3. We interpret the use of bullet points in Requirement 3.3.1 to mean that either one of the statements can be chosen. This requirement should be written where all the bulleted statements are included in the analyses.
Group
MRO's NERC Standards Review Forum
Yes
No
The NSRF recommends that the VRF for Requirement 8 remain "Low", rather than be changed to "Medium". We do not believe that there is significant risk to the reliability of the BES if an annual Planning Assessment is not distributed to another entities or a documented response to Planning Assessment comments is not provided within 90 days of a request. The findings in an assessment report are not urgent, but address system needs that will emerge over years in the future. In addition, entities with a reliability related need for Planning Assessment information generally have the means to make their own independent planning assessment of adjacent systems or other areas of interest.
The NSRF recommends that the term, "System" be replaced with "BES" in various places throughout the standard when the reference should not be to the collective generation, transmission, and distribution systems, which is the definition of the NERC Glossary term, "System". These locations are: R2.1.4, R2.1.5, R2.4.3, R2.6.2, R2.7, R2.7.1, R2.7.4, R2.8.1, R2.8.2, R3.5, R4.5, R5, and R6
Individual
Michael Moltane
ITC
Yes
No
ITC recommends revising R8 VSLs as follows: Lower VSL The responsible entity distributed its Planning Assessment to known adjacent Planning Coordinators and known adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request. Moderate VSLs The responsible entity distributed its Planning Assessment more than 30days but less than 60 days after subsequent requests by adjacent Planning Coordinators or adjacent Transmission Planners who were not sent copies upon completion of the Planning Assessment. OR, The responsible entity distributed its

Planning Assessment to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request High VSLs - eliminate this section. i.e., no high VSLs only lower,moderate and severe Severe VSLs The responsible entity distributed its Planning Assessment to functional entities having a reliability related need, adjacent Transmission Planners and adjacent Planning coordinators who requested the Planning Assessment in writing but it was more than 60 days following the request.
ITC COMMENTS on TPL-001 vote ITC will reluctantly vote to approve the draft standard. While we have concerns, we are voting to approve this standard because we believe the positive elements outweigh the portions of the draft standard that we object to. It is important that the improved requirements that effectively "raise the bar" over the existing standard should become effective sooner rather than later. A negative vote, which might cause a further delay in implementation of the standard, would be the least desirable outcome. However, we still believe that the VSL that would find that an entity had committed a "severe" violation for failure to distribute its planning assessment to an adjacent Transmission Planner or Planning Coordinator has the potential to overly punish a simple error in oversight. We would agree that willfully withholding an assessment from a neighbor or a valid requestor justifies a severe violation but an administrative or clerical oversight does not. For example, it might escape our attention that an entity, particularly a smaller one, registers as a TP or TP. As far as we know, there is no requirement that a registrant, or even one who de-registers, must notify an "adjacent" TP or PC of their change in status. As written, the standard requires you be found in "severe" violation, even if that new entity fails to notify you of their change in status. You would still be in severe violation even if they later ask for your planning assessment. Even if the standard passes, we request that this VSL be fixed to make the distinction between an administrative error and willful neglect. Our response to question 2 offers a suggested method to do this.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Yes
Yes
R1 does not seem to address errors in data that have been introduced in the latest model data. In addition, R1 and its VSL may be interpreted to exclude the use of past studies. The Implementation Plan should include a five year delay in the effective date for short circuit studies for parts 2.3 and 2.8 of R2 because these studies are not required in the current Version 0 standards.
Individual
Joe Petaski
Manitoba Hydro
No
-R2.1.4 and R2.4.3: 'Expected transfers' should be replaced with 'Firm Transmission Service and Interchange' to correlate to R1 (R1.1.5 states 'Known commitments for Firm Transmission Service and Interchange' must be represented in system models). -R2.1.4 and R2.4.3: 'Generation additions, retirements, or other dispatch scenarios' should be deleted since generator connections are required to be studied as specified in FAC-002. -R2.1.5: The Standard Drafting Team needs to clarify R2.1.5 for a scenario where a spare transformer is available but is used to replace a failed transformer say one month before the expected system peak. If this scenario occurs, does the Transmission Planner need to study the impact of the unavailability of a transformer to cover the situation that could occur if a second transformer failure occurs before the expected system peak? -R2.4 and R2.5: 'current or past studies' should be replaced with 'current annual studies or qualified past studies' to be consistent with R2.1. -R2.5: The wording allows the PC/TP to determine what is 'material'. This could lead to large differences in generator additions or changes that would be included. The Standard Drafting Team should consider registration criteria to set size limits for this sensitivity. -R2.7.3: What is the required timeframe? How long will Non-Consequential Load Loss or curtailment of Firm Transmission Service be allowed with this exception? -R3.3.1 Second bullet: If relay loadability limits are exceeded, the protection would be in violation of PRC-023. This standard should assume this situation would not

occur. -R3.5 and R4.5: What is the point of identifying mitigating measures for extreme events when there is no Requirement to implement such measures? -R4: The first sentence in R4 requires one to perform the Contingencies in Table 1. This sentence should read 'For the Stability portion of the Planning Assessment, as described in Requirement R2, -Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform Contingency analyses based on the list of Table 1 Contingencies defined in Requirement R4, Part 1'. -R4.1.2: A generator should not be allowed to pull out of synchronism for P2.1. -R4.1.3: The Planning Coordinator and Transmission Planner should have to document the damping criteria used to access 'acceptable damping'. -R8: Why 30 days for 'any functional entity that has a reliability related need and submits a written request'? The timeframe should be 90 days as it is for 'adjacent Planning Coordinators and adjacent Transmission Planners'. -Table 1-Steady State and Stability Performance Planning Events, Category P5, now includes "non-redundant" relay in the Event column. What is meant by non-redundant relay? The term "non-redundant" is not a defined term. -Regarding Note 12- An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to address BES performance requirements. When Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss is documented, including alternatives evaluated; and where the utilization of Non-Consequential Load Loss is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. -Non-Consequential Load Loss is only allowed in very unlikely scenarios as a last resort that would cause local load issues. When used as intended by the drafting team (ie. as a last resort) Non-Consequential Load Loss would have no negative effect on the network since it would only be used to improve network conditions like low voltage or line overloads. Should NERC be worried about documenting this use of Non-Consequential Load Loss? NERC should focus on network issues, not local load issues. -NERC should remove the last part of Note 12: "and where the utilization of Non-Consequential Load Loss is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments." It is inappropriate for NERC to mandate an open stakeholder process and Manitoba Hydro cannot support this mandate. In addition, it is unclear how NERC can mandate an open stakeholder process and who that might include. FERC has defined such a process in Order 890. Is that what is envisioned?
No
-The language "latest data" is used in the Severe VSL for R1, however "latest" was removed from R1 and M1. "Latest" should also be removed from the Severe VSL for consistency. -What is the rationale for changing the preparation of the Planning Assessment (R2) VRF to High from Medium? The R2 VRF should remain at Medium. The R2 Time Horizon is Long-term Planning, an entity can rely on qualified past studies to complete the Planning Assessment and the actual performance of studies (R3 and R4) have Medium VRFs. -Please explain the phrase 'completed annual Planning Assessment' used in the Severe VSL for R2. What is the reason for the change in VSL for having a 'completed annual Planning Assessment'? -Can the drafting team please explain why defining the criteria for steady-state voltage limits etc. in R5 has a VRF of medium? Criteria development is administrative, therefore the VRF for R5 should be Low. Setting the VRF for R5 to Low would be consistent with the Low VRF for R6 that relates to defining the criteria for cascading. -Requirement 8 is an administrative burden that adds little to improve reliability. The revisions made to the VRF and VSL for Requirement 8 further exacerbate this administrative burden. One could conclude from observation of the VSLs and VRFs, that Requirement 8 was the most important requirement of TPL-001-2. The drafting team should simplify the VSLs and revert R8 back to a low VRF. Where are the timeframes used in the VSLs for Requirement 8 coming from? Requirement R8 does not specify these timeframes.
-Why was the Near Team Transmission Planning Horizon definition moved to the Glossary prior to TPL-001-2 approval? -The definition of Non-Consequential Load Loss should not contain '(2) the response of voltage sensitive Load' because voltage sensitive load is not load that is lost (it is load that is still served). -M8: Why 30 days for 'any functional entity who has indicated a reliability need'? The timeframe should be 90 days as it is for adjacent Planning Coordinators and adjacent Transmission Planners.
Group
Hydro One Networks Inc.
No
Other than a few changes related to Footnotes 9 and 12 of Table 1 and VSLs, the other changes in the

April 15, 2011, draft are minor. The concerns of the industry on several important issues have not been sufficiently addressed in this draft (see our response to Question 3).
A. Regarding Requirement 1.1.2, assessment of "known outages... with a duration of at least 6 months", are dealt with in the operational studies rather than planning studies. In addition, any adverse impact that these outages might have, are mitigated by operational decisions rather than "planning" decisions within a 6-month horizon. It is suggested to move this requirement out of TPL standards and instead include it a relevant operational standards. B. The statement in R 2.1.4, "must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response", leaves room for very different interpretations by PCs and TPs as to the number and type of required sensitivity studies. Are all interpretations, based on the engineering judgment of the PC and TP, acceptable? C. The language of R 2.1.4 and 2.4.3 allowing to perform one or more sensitivities appears to be inconsistent with the language in R 2.7.2 which requires multiple sensitivities to determine if actions to resolve performance deficiencies are necessary. Will varying only one measurable quantity several times in multiple simulations constitute multiple sensitivity studies or one sensitivity study? D. The language of Requirement 2.1.5, "spare strategy", appears to be open-ended regarding the number of permutations to be analyzed. It is suggested to move this requirement out of TPL standard and instead have this issue dealt with in the operational standards. E. In R 2.2, the statement "be supported by the following annual current study, supplemented with qualified past studies" should be replaced with a similar statement in R 2.1 which says: "be supported by current annual studies or qualified past studies". F. In R 4.1.1, "For planning event P1: No generating unit shall pull out of synchronism" is too restrictive. In many cases a P1 event may result in instability of a small nearby generator without a significant impact on the reliability of BES. The same requirement states that "A generator being disconnected from the System … by a Special Protection System is not considered pulling out of synchronism". If rejection of ANY generator by SPS is acceptable, why should instability of a small generator, resulting in its disconnection by its protection without a severe impact on the system, be unacceptable in all circumstances? If this requirement is unchanged, it dictates the addition of an SPS (Generation Rejection) for any unit that might go unstable without any benefit for the reliability of the BES. G. In Table 1, Event 1 of Category P2 and related Footnote 7 (simulation of LEO condition) are not clear (concern with the use of the word "possibly"). If the intension is to simulate LEO condition of tapped lines, this should be clearly stated in the table (without reference to "Opening of a line section" and use of different language in the footnote).
Individual
Tony Eddleman
Nebraska Public Power District
No
The existing TPL-001 through TPL-004 Standards and Requirements are clear and concise. The new merged TPL-001-1 Standard and Requirements is no longer clear and concise. Further, the modification made to allow an SPS to trip a remote generator for an N-1 (TPL-002) type of event is a degradation of system reliability. Transmission system facilities should be added to maintain stability for a new generator interconnection for any N-1 Category B event. An SPS should not be relied upon for a Category B event, an SPS should only be allowed for Category C & D (TPL-003 & TPL-004) type events.
No
No comments.
N/A
Individual
Robert Casey
Georgia Transmission Corporation
Yes
Yes

All of our prior issues have been addressed.
Group
BC Hydro
Yes
BC Hydro agrees with merging the standards together into one and we feel the new version brings further clarity to the annual planning assessment. BC Hydro would vote Affirmative for bringing clarity, however we do not believe the rewording in Footnote 9 is clear which is why we are voting Negative. Footnote B, as approved by the NERC Board of Trustees on February 17, 2011 was reworded as Foot Note 9 in the proposed TPL 001-2 draft 7 amendment. This rewording still does not clearly define what impact the proposed revision would have on the curtailment of firm transfers in the regional entities.
Individual
Jonathan Appelbaum
United Illuminating
No
a. 2.6.2 - What was the intent of this change? The old language seemed to work. The language should not be changed from the previous version. b. For 2.8.2 - Was the phrase changed to reflect modifications of facilities? If so the requirement should be modified to read "Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures with respect to modifications of facilities. Otherwise the requirement is unclear. c. For Section R8.1 - the proposed requirement conflicts with a long standing stakeholder process in our area which posts study results and allows comment within a defined period before studies are finalized. If this section is to be retained then it should be modified to only allow comments on Transmission studies less than one-year old. Requirement 8 and 8.1, should be revised to include a limit on the comment period as follows: If a recipient of the planning assessment final results provides documented comments on the results within 90 days of receipt, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments. d. With respect to Table 1 – We suggest adding an event 6 to P1 to address the contingent loss of back to back HVDC Facilities. If not added to P1 then this event needs to be added somewhere in the standard. e. We don't agree with footnote 7 specifying that only one end of the line should be open for this condition. If the SDT is to keep this concept make P2 event 1 simply say "Opening one end of a line section w/o a fault" and delete the footnote. The existing footnote is unclear due to the use of language such as "possibly".
Yes
Individual
Andrew Z.Pusztai
American Transmission Company, LLC
Yes
No
ATC recommends that the VRF for Requirement 8 remain "Low", rather than be changed to "Medium". ATC does not believe that there is significant risk to the reliability of the BES if an annual Planning Assessment is not distributed to another entities or a documented response to Planning Assessment comments is not provided within 90 days of a request. The findings in an assessment report are not urgent, but address system needs that will emerge over years in the future. In addition, entities with a reliability related need for Planning Assessment information generally have the means to make their own independent planning assessment of adjacent systems or other areas of interest.
Individual

Michael Jones
National Grid
No
R2.8.2 We recommend this requirement be clarified with the following modification: The Corrective Action Plan shall: 2.8.1. List System deficiencies and the associated actions needed to achieve required System performance. 2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of planned modifications to System Facilities and Operating Procedures.
No
R 2.0 We recommend that the VRF for this Planning Requirement remain at “Medium”. The risks associated with Planning Requirements have a longer time horizon for corrective action than, for example, those risks associated with much shorter Operational time frames.
R 1.1.2 We recommend the known facility outage duration be defined as facility outage durations lasting at least twelve months. R 1.1. (page 4) System models shall represent: 1.1.1. Existing Facilities 1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six twelve months. 1.1.3 …… R 2.1.4 We recommend that this requirement be eliminated. We do not see the value of this additional analysis when the number, type and severity of the sensitivity tests are not well defined. These tests are then used to define Corrective Action Plans in cases only where multiple tests show performance deficiencies. R 2.1.5 Spare equipment strategies are typically designed to prevent long outages (possibility a year or more) of equipment with very long lead times. Any such strategy “could” result in these long outages depending upon the number of failures that may be postulated. This requirement is misleading and we thus recommend it be eliminated. R 2.2 We recommend the language for R 2.2 should be consistent with 2.1 for example - use "current or qualified past studies" instead of "the following annual current study." R 2.6.2 We recommend that the wording of this requirement remain unchanged. R 2.7.1 This portion of the requirement provides a list of “acceptable” Corrective Action Plans. It provides equal weight to infrastructure reinforcements and Special Protection Systems as means to mitigate violations resulting form single or multiple contingencies at both the EHV and HV levels. National Grid’s position is that a national standard should not endorse the use of Special Protection Systems as corrective actions to mitigate single contingency violations. Local Northeast Planning Criteria indicates that special protection systems (SPS) shall be used judiciously and may be used to provide protection for infrequent contingencies, or for temporary conditions that may exist such as project delays, unusual combinations of system demand and equipment outages or availability, or specific equipment maintenance outages. A SPS may also be applied to preserve system integrity in the event of severe facility outages and extreme contingencies. The decision to employ a SPS shall take into account the complexity of the scheme and the consequences of correct or incorrect operation as well as its benefits. We are further of the opinion that specific methods of correcting system performance deficiencies should not be specified in a National Standard. We thus recommend that the Corrective Action List be eliminated from this requirement as illustrated below. 2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. R 2.7.2 We feel that this requirement and requirement R 2.1.4 adds ambiguity to the process as we have indicated above. We thus recommend that this requirement be eliminated. R 3.3.1 We feel that the last sentence of 3.3.1 should be removed. This is handled by PRC-023. Line ratings are addressed by PRC-023. PRC-023 requires coordination with the Reliability Coordinator. Remove “Tripping of Transmission elements where relay loadability limits are exceeded” Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall: 3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: • Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R 3.4.1 We would recommend the following addition as a clarification to the required information exchange: 3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. 3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their respective Systems are

included in the Contingency list. R 8.1 National Grid's concern regarding this requirement stems from the apparent open ended time frame afforded report recipients in their review of the Planning Assessment. This has the potential to stall the review process. National Grid thus recommends that any recipient of the Planning Assessments be given a specific time period for their response as indicated in R 8.1 below. R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, and adjacent Transmission Planners, within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. [Violation Risk Factor: LowMedium] [Time Horizon: Long-term Planning] 8.1. The recipient of the Planning Assessment results shall provides documented final comments on the results within 90 calendar days of receipt of the Planning Assessment. The respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. Table 1 Steady State & Stability Performance Planning Events (Page10). The event description for Category P2 Event 1. along with the accompanying footnote 7 (Page 14) creates some confusion for multi-terminal lines. We recommend that Footnote 7 be eliminated and the event description be changed as follows: Category Initial Conditions Event P2 Normal System 1. Opening of a single load interrupting device at one terminal of a line without a fault. Table 1 (Planning Events and Extreme Events) Footnote 12 (Page 14). We are concerned that additional stakeholder process indicated in Footnote 12 has the potential to stall the Planning Assessment review process. We recommend that reference to this new process be eliminated from the Footnote. Our additional, concerns with Footnote 12 are addressed in comments originally provided by ISO-NE. We agree with their following comments : The following language for Footnote 12 is proposed: "Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems." If Footnote 12 in Table 1 must be retained, the following language is proposed: "An objective of the planning process shall be to minimize the likelihood and magnitude of interruption of Demand, (excluding Interruptible Demand or Demand-Side Management), following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: a. Interruptible Demand or Demand-Side Management b. Circumstances where the uses of Demand interruption not directly interrupted by the contingency are documented c. Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than Interruptible Demand or Demand Side Management)"

Individual

Tim E. Ponseti, VP

TVA TP&C

Yes

Yes

TVA - has following comments: TVA is concerned about footnote 12 (known as footnote b in existing TPL standards). TVA believes that utilities should be given some freedom in dropping local load in response to N-1 events as long as overall BES reliability is not impacted. Otherwise significant capital improvements will be required that will have no overall reliability gain for the Bulk Electric System. In R4.1.1, TVA is concerned that no generating unit (including distributed generation) shall pull out of synchronism in a local area only (thus not impacting the overall reliability of the BES) for Planning Event P1, while the standard does allow generator runback/tripping for the same event. Thus the generating unit may be tripped by a special protection scheme - but may not be tripped by an out of step relay. TVA believes that out of step relaying should be allowed for this unit tripping as long as this does not affect the overall reliability of the BES. Table 1 contains both planning events and extreme events. Suggest labeling the planning events as Table 1 and the extreme events as Table 2 to help reduce confusion. VSL for R1 does not seem to address issues where data errors have been

introduced into the latest model data. Also, R1 and its VSL may be interpreted to exclude the use of past models. The Implementation Plan should include a five-year delay in the effective date for short circuit studies (R2 parts 2.3 and 2.8) since these studies are a new TPL requirement and are not required in the current version 0 standards.
Group
Entergy Services
Yes
Yes
Footnote 12 to Table 1 concerning non-consequential load loss should be clarified. The existing language will result in difficulties in proving compliance. Suggested language would be: "Planned or controlled interruption of Demand supplied by Transmission Facilities made temporarily radial as a result of a P1 or P2 event and where the location of the planned loss of Demand is limited to those Transmission Facilities made radial.
Individual
Michael Falvo
Independent Electricity System Operator
No
IESO is generally supportive of the draft of TPL-001-2 as evidenced by our previous AFFIRMATIVE vote during the last ballot. Further, IESO also supported the revisions to Footnote 'b' to Table 1 of the TPL standards under Project 2010-11. That revision was balloted and approved by the ballot pool in February 2011 and filed with FERC for approval in March 2011. The revised footnote has been incorporated into the current draft of TPL-001-2 as Footnotes 9 and 12 but the Commission, by letter to NERC dated May 17, 2011, has requested NERC to provide supplemental information before the revised Footnote 'b' could be approved. In light of FERC's request and the uncertainty regarding the final provisions of these footnotes, coupled with the ongoing work on Project 2010-17 for the revision of the BES definition and development of an Exception Process and the impact that may have, we respectfully suggest that the drafting team delay further work on TPL-001-2 pending FERC's ruling on NERC's petition seeking approval of the transmission planning standards that contain the revised Footnote 'b' to Table 1.
No
See our response to Q1.
See our response to Q1.
Individual
Alex Rost
NBSO
No
Items that, if not addressed, will likely cause a negative vote from NBSO: R2.2 differs from R2.1, R2.3, R2.4 and R2.5 since R2.2 does not state that the annual assessment of the Long-Term Transmission Planning Horizon portion of the steady state analysis can be supported by qualified past studies. Likely this omission is an oversight, but unresolved it can cause significant burden with little gain in reliability. Individual items that, if not addressed, may not cause NBSO to vote Negative, but in combination may result in a negative vote: The language of requirements R2.1.4 and R2.4.3 allowing the performance of one or more sensitivities appears to be inconsistent with language in R2.7.2 that requires multiple sensitivities to determine if actions to resolve performance deficiencies are necessary. R7 (and M7) seem to indicate that the PC is ultimately responsible for determining the individual and joint responsibilities for performing the required planning assessment studies, with the expectation to consult and come to agreement with its corresponding TPs, but this interpretation is not clear. The correct interpretation of this requirement is important for resolving situations where a PC and TP do not agree on the assignment of responsibilities. Suggested wording: "Each PC shall work in conjunction with each of its TPs to determine and identify…" The language in R8 is unclear. One point of confusion relates to which entity is responsible for sending their Planning assessments to other entities. For example, who does a PC distribute their planning assessments to?: -Adjacent PC?

(Seems to be clearly addressed) -TPs within its PC footprint? (Not clearly covered by the language in R8) -TPs adjacent to its PC footprint (Not clear if this is the responsibility of the PC, TP or both) In addition, the language in R8.1 appears to offer unlimited opportunity to request response to comments on any past assessment, long after their release. Providing limits in the langue of R8.1 is recommended in order to avoid unnecessary burden on PCs and TPs for little gain in reliability or constructive stakeholder involvement.

Items that, if not addressed, will likely cause a negative vote from NBSO: NBSO believes that R1.1.2 is more appropriately addressed in the operational timeframe. Perhaps more appropriate alternatives could include: -only considering planned outages with durations of one year or more (in-line with typical planning timeframes), or -requiring that facilities with planned outages lasting over the complete duration of time period being studied be modeled out of service. R2.1.5 may significantly increase the demands of the planning assessments with little gain in reliability. Depending on interpretation, R2.1.5 could exponentially increase the work load of the annual planning assessment. NBSO interprets the intent of R2.1.5 to require that entities have, review and evaluate their spare equipment strategies. Perhaps the assessment of a spare equipment strategy would be more appropriately addressed in a separate standard. Further, categories P0, P1 and P2 do not reference footnote 9 in the Initial Condition column. NBSO is unclear if the last sentence of R2.1.5 allows for the curtailment of firm transmission service under the N-1 conditions before the application of category P0, P1 and P2 events. This last sentence states: "…with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment." Table 1, note b should be modified to allow for the loss of Firm Transmission Service. This addresses cases where Firm Transmission Service is lost in direct consequence to the event (e.g. loss of one DC pole, an interface comprised of a single line, a bus fault that clears multiple lines in an interface, etc...) Individual items that, if not addressed, may not cause NBSO to vote Negative, but in combination may result in a negative vote: The definitions of "near-term transmission planning horizon" and "year one" have been removed from the standard, yet they are still used in draft 7. Further, the definition of these terms is being filed as part of another project. NBSO is concerned with endorsing a standard based on terms whose definitions may change independently of this project. For R7, NBSO is concerned that one entity may be found noncompliant should another entity fail to meet their agreed upon responsibilities. For example, a PC may be relying on the results from a TP's studies to complete its own planning assessment, but the TP did not meet their responsibilities. In this case, the PC should not be found non-compliant for an incomplete planning assessment due to the failure of the TP to meet their responsibilities. Contingencies on back to back HVDC facilities are not addressed in the standard.

Group

Western Area Power Administration

No

We concur that the standard is an improvement over previous drafts, but we vote "No" to the existing draft and request additional clarifications and/or modified language for a re-circulated vote prior to adoption. The following are areas where we suggest improvement or have questions: Please further define Consequential and/or Non-Consequential Load Loss: Does the Consequential Load Loss definition include underfrequency or undervoltage load shedding installed to protect transmission system reliability? Does the Consequential Load Loss definition include load tripped by a Special Protection System (SPS) or a Remedial Action Scheme (RAS)? Either how underfrequency and undervoltage load shedding or how load shedding by a RAS relates to Consequential Load Loss should be clear in the Consequential and/or Non-Consequential Load Loss definition of the approved version of this NERC standard. Why is Near-Term Tranmission Planning Horizon deleted from the definitions of Terms Used in this Standard, yet it is used throughout the standard? This definition should remain. R1.1.5: How are "known commitments for Firm Transmission Service" to be modeled and tracked in power flow cases? Is it acceptable for Transmission Planners to simply assume what the ultimate sources and ultimate sinks are for each firm transmission service commitment or are Transmission Planners to know exactly which ultimate sources and ultimate sinks are associated with each commitment and to track each one accordingly in each power flow case? Assuming the intent here is reliability based and not marketing based, is the application of Firm Transmission intended to apply to reliability designated 'paths'? Most all Firm Transmission service contracts have caveats for unplanned interruption and such agreements should qualify as "re-dispatch" per Footnote 9? R2.1.5: If a group

of utilities were to develop and manage among themselves a coordinated spare equipment program, such that the risk to any one of its participating entities of experiencing a significant unavailability for any major Transmission equipment that has a lead time of one year or more is deemed not significant, then would those utilities still have to do the studies required by R2.1.5 to evaluate the system impact of extended outages of such equipment? Scenario for Clarification: Short of spare equipment for items with a greater than 1 yr lead time, assessment studies are required to include sensitivities and operating plans for sustained loss of these equipment items, as a prior outage. For example, if an EHV facility is lost for more than 1 yr, and firm transmission interruption is not allowed, it appears the only compliant alternative (to a redundant facility) is a redispatch plan that is well documented and accepted by all stakeholders, per Footnote 9. R2.3: Is only the 5-year Near-Term Transmission Planning Horizon case required for the annual short-circuit analysis? R2.4.1: How is the dynamic modeling of induction motor Loads to be developed by the Transmission Planners? Is it acceptable for Transmission Planners to assume the same induction motor modeling as has generally been assumed and applied by most Transmission Planners throughout the Western Interconnection or will the induction motor modeling have to be based upon the type and amount of actual induction motors installed in the system? R2.5: Does NERC have a particular technical rationale about what determines "proposed material generation additions or changes?" R2.6.2: Does NERC have a particular technical rationale about what determines "material changes?" R2.7.3: Please define "beyond the control" under Definition of Terms Used in Standard. This is an important concept. Without NERC definition, this term is highly debatable and should be eliminated. Scenario for Clarification: If the stakeholder rate payers do not approve expenditures for facility improvements required to eliminate non-consequential load loss, is this beyond the control of the Transmission Planner? Rate payers should be able make the ultimate free market choice determination of risk versus cost associated with their reliability. Otherwise market interests (particularly generation) disproportionately pressure excessive reliability based improvements that must be borne by all rate payers. R3.3.1: Please define "relay loadability limit" under Definitions of Terms Used in Standard. This is an extremely important concept. This term has been used quite commonly for decades and is now used in this latest proposed standard. Without NERC definition, this term is highly debatable and should be eliminated. Scenario for Clarification: If PRC-023 is met whereby all "relay loadability limits" are set at least 150% of the highest thermal limiter (0.85 voltage and 30 lagging powerfactor) this sensitivity would justifiably not be needed so long as verification is shown that no element overloaded greater than 150%. R3.1 and R3.4: The interrelation between these two paragraphs needs additional clarification. R3.1 calls for verification via studies that the BES meets Table 1 performance criteria based on the contingency list resulting from R3.4. However, R3.4 states that the contingency list used to meet R3.1 only need include "Those planning events in Table 1, that are expected to produce more severe System impacts on.....the BES" and the associated "rationale" for those chosen contingencies. Is NERC suggesting that the studies do not need to include all contingencies based on Table 1, so long as ample "rationale" is provided? However, the Transmission Planner must provide studies to determine if every contingency of Table 1 meets performance requirements. How are the "more severe" contingencies determined if the Table 1 contingencies are not evaluated comprehensively? It seems R3.4 could be eliminated and the contingencies be based simply on Table 1. Please define "more severe", relative to less severe under Definitions of Terms Used in Standard, in an effort to help evaluate the suitability of a particular contingency for inclusion on this list. Looking at context, it appears that the purpose of this statement is to ensure that the worst contingencies are studied. Is the intent here simply to allow a given contingency to cover for a less severe or similar contingency and avoid duplicate simulations? R3.4.1 and R4.4.1 Please include and define a reasonable number of contingent buses into adjacent systems that should be considered. No more than 2 are recommended for the standard. R3.5 and R4.5: How many of the "events in Table 1 that are expected to produce more severe system impacts" should the required evaluation identify and evaluate? To what extent should the evaluation focus on the "other" Extreme Events described under items 3.b and 2.f in Table 1, particularly if existing disturbance reports in the Western (or Eastern) Interconnection have recorded and evaluated the occurrence of particular events that have already created cascading? Because the requirement seems to involve a check for Cascading, perhaps some clarity could be provided with respect to the NERC definition of "Cascading." In particular, in the Cascading definition, how widespread is "widespread;" is the phrase "electric service interruption" only about the loss of firm load or could it also be only about the loss of firm generation or only about the loss of firm transmission service or is it about some combination of loss of firm load, loss of firm generation, and loss of firm transmission service; how large an area is meant by the expression "spreading beyond an

area predetermined by studies" when the simulations that analyze the initiating Extreme Event will model the entire Western (or Eastern) Interconnection? So how does the study determine that the sequentially spreading service interruption has spread beyond the entire Western (or Eastern) Interconnection that is modeled in the simulation? Or is the term "area" meant to describe only that part of the Western (or Eastern) Interconnection that the Transmission Planner has evaluated for system impacts while ignoring impacts to the rest of the Interconnection? Table 1 – Planning Events, Steady State Only Note i: "The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event" seems to be included as items 2) and 3) under the Non-Consequential Load Loss definition. So, it seems acceptable to use this form of load loss to meet the stability performance requirements. However, the "Steady State Only" note i in Table 1 specifically does not allow its use to meet steady state performance requirements. Therefore, the "Steady State Only" note i in Table 1 should clarify why it seems acceptable to use it to meet stability performance requirements but not to meet steady state performance requirements. Table 1 – Planning Events, Category P2: Category P2 seems to include an unrelated mix of planning events ranging from a seemingly benign event (i.e., opening of a line section without a fault) to what would seem to be much more severe events (i.e., bus section fault or internal breaker fault). A clarification of why these planning events were lumped into the same Category P2 would be helpful to the Transmission Planner. Also, does the language in footnote 7 (i.e., "opening one end of a line section without a fault on a normally networked Transmission circuit …") mean that P2-1 ("opening of a line section without a fault") should be modeled as an open-ended line section? Table 1 – Planning Events, P2-2 (EHV) and P2-3 (EHV): For each of these planning events, its corresponding "Non-Consequential Load Loss Allowed" column should include a footnote 12 with each of the "No" boxes, similar to that allowed under the seemingly much less severe event P2-1 ("opening of a line section without a fault"). Otherwise, please explain why the seemingly much less severe P2 event (P2-1) has a footnote 12 exception for Non-Consequential Load Loss Allowed but the two seemingly more severe P2 events (P2-2 and P2-3) do not. Table 1 – Planning Events, P4-1 through P4-5 (EHV): For the stuck breaker planning events of P4-1 through P4-5 on the EHV system, their corresponding "Non-Consequential Load Loss Allowed" column should include a footnote 12 with their "No" box, similar to that allowed under the seemingly much less severe N 1 planning events (P1-1 through P1-5). Otherwise, please explain why the seemingly much less severe N 1 events (P1-1 through P1-5) have a footnote 12 exception for Non-Consequential Load Loss Allowed but the seemingly much more severe stuck breaker events (P4-1 through P4-5) do not. Table 1 – Planning Events, P5-1 through P5-5 (EHV): For the relay failure planning events of P5-1 through P5-5 on the EHV system, their corresponding "Non-Consequential Load Loss Allowed" column should include a footnote 12 with their "No" box, similar to that allowed under the seemingly much less severe N 1 events (P1-1 through P1-5). Otherwise, please explain why the seemingly much less severe N 1 events (P1-1 through P1-5) have a footnote 12 exception for Non-Consequential Load Loss Allowed but the seemingly much more severe relay failure events (P5-1 through P5-5) do not.

Individual

Alice Ireland

Xcel Energy

Yes

Effective Date: The effective date section seems to imply that Non-Consequential Load Loss will not be permitted after the 84 month implementation period. We do not believe that was the drafting team's intent and request that it be modified. Footnote # 12 in Table 1, in particular, seems to support our assumption that the team did not intend to disallow it. For reference, the footnote states: "12. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to address BES performance requirements. When Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss is documented, including alternatives evaluated; and where the utilization of Non-Consequential Load

Loss is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments." However, if it was the drafting team's intent to not allow Non-consequential Load Loss after the 84 month implementation period, we disagree and ask the team to reconsider. Particularly for rural areas, in some cases, this will be the only action possible. R2.1.4: a) We would like to see clarification on the term "sensitivity analysis". Is this in reference to seasonal models and differences in fuel availability? We would like more detail on how this is to be done so that it won't be left up to interpretation. b) We would like the drafting team to consider stratification of the tasks needed to perform a Planning Assessment. In our opinion, having both the TP and PC do exactly the same study produces tremendous and unnecessary duplication. Without stratification, the TPL-001 standard will continue to perpetuate the same paradigm used in the existing TPL-001 through TPL-004 standards. The NERC Functional Model makes a clear distinction between PC and TP functions/responsibilities. It is not clear why that distinction is not leveraged in the new TPL-001 standard. This will be particularly troublesome in areas where an ISO or RTO is the Planning Coordinator. In order for the RTO/ISO, as the PC, to be able to do their Planning Assessment, the Transmission Planners would have to provide a lot of detailed input data. So, in effect, both the PC and TP would be performing their assessment from the same data. It would make more sense if the RTO (as the PC) performed the required studies on the 500-345 kV network and the TP performed the required studies on everything below 230 KV. We also recommend the allowance for utilization of a regional assessment, instead of performing your own, due to individual entity resource constraints. R2.4.1: We would like to see better clarity on what an Aggregate system load model is and how granular it should be. If the intent is for the model to contain a very detailed representation of the load system, then it may take a longer time to implement. R3.4.1: a) This type of coordination could be difficult due to other adjacent entities on different schedules and some may not have the amount of detail to incorporate into another's processes. We know this is generally covered in coordination of real time operations and wonder if it is appropriate to require this type of coordination in the long term process. Is there already an operational standard that covers this? Would it be better to address this in the operational standards? We would like the roles of the coordinators vs. the planners to be clarified in order to ensure that no work is being duplicated. b) PC's between regions, such as RTOs, are already coordinating for long term studies. In these cases, we feel the PC should alone be responsible for the requirements, rather than also the TPs. c) Can we get a clear definition of what apparent impedance swings means? We interpret it as rotor angle stability. R4.3.1: We would like to see that the detailed data is incorporated back into the NERC modeling processes and create a more detailed model with better accuracy. R8: We do not agree with the requirement to provide the assessment to every adjacent PC and TP because we fail to see the reliability benefit in doing so. However, we do agree that the PC and TP should be required to provide the assessment to any of these entities, if requested. Additionally, for entities that make such requests, we would like to have 90 days instead of 30 to respond. In many cases a non-disclosure agreement will have to be executed due to CEII classification of some information, and this can take several months.

Individual

Christine Hasha

Electric Reliability Council of Texas, Inc.

No

ERCOT ISO believes that the revisions do not go far enough in addressing previously submitted comments. As written this standard would require restructuring of the functions in the ERCOT Region because several requirements are being assigned to the PC that are currently performed only by the TPs. It would not provide any reliability benefits to have the ERCOT PC assume these functions. Specifically, the following requirements should be modified: R2.1.5 should be clarified to be applicable to TPs only since the ERCOT PC does not have the information necessary to perform this analysis; R2.3 and R2.8 should be clarified to be applicable to TPs only since the ERCOT PC does not perform this analysis (it is performed by the TPs in ERCOT); R4.1.2 should be clarified to only apply to TPs because the ERCOT PC does not have the modeling information necessary to perform this analysis. Additionally, R2.1.4 and R2.4.3 should be removed because the requirements are subjective and there are no actions prescribed to be taken based on the sensitivity results. The Load model requirement should be removed from R2.4.1 because this would be better addressed in a MOD standard. Alternatively, R2.4.1 should be rewritten as "System peak Load for one of the five years with expected dynamic load models." A concurrent requirement should be incorporated to mandate DSPs and TPs to supply dynamic load model data to the PC to perform the required studies.

No
ERCOT ISO believes that the VRF for R8 should be "low". The distribution of the Planning Assessment is administrative in nature, the failure to distribute the Planning Assessment does not necessarily equate to not communicating the content of the assessment, and the consequence of not distributing the Planning Assessment does not immediately impact the reliability of the BES; thus it does not warrant a 'Medium' risk factor.
Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.
No
Requirement R1.1.5: Delete "and Interchange." The inclusion of other than Firm transactions (e.g. economic transactions in Interchange) in a base power flow case utilized for planning/designing the interconnected system blurs the boundary between reliability issues and purely economic issues. Reliability issues are issues that a Transmission Owner (TO) must address for the purpose of meeting its load demand, and are defined by the application of well established reliability standards and criteria that are based on the electrical characteristics of the interconnected system, but without economic considerations. Instead, economic transactions are types of transactions that a TO may enter into once its load obligations are met, and are evaluated based on economic parameters that are markedly different from the aforementioned reliability criteria (e.g. congestion costs). Modeling all types of transactions in a power flow case without distinction detracts from the accuracy and validity of either assessment (reliability and economic).
Individual
Kathleen Goodman
ISO New England Inc.
No
a. 2.6.2 - What was the intent of this change? The old language seemed to work. The language should not be changed from the previous version. b. For 2.8.2 - Was the phrase changed to reflect modifications of facilities? If so the requirement should be modified to read "Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures with respect to modifications of facilities. Otherwise the requirement is unclear. c. For Section R8.1 - the proposed requirement conflicts with a long standing stakeholder process in our area which posts study results and allows comment within a defined period before studies are finalized. If this section is to be retained then it should be modified to only allow comments on Transmission studies less than one-year old. Requirement 8 and 8.1, should be revised to include a limit on the comment period as follows: If a recipient of the planning assessment final results provides documented comments on the results within 90 days of receipt, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments. d. With respect to Table 1 – We suggest adding an event 6 to P1 to address the contingent loss of back to back HVDC Facilities. If not added to P1 then this event needs to be added somewhere in the standard. e. We don't agree with footnote 7 specifying that only one end of the line should be open for this condition. If the SDT is to keep this concept make P2 event 1 simply say "Opening one end of a line section w/o a fault" and delete the footnote. The existing footnote is unclear due to the use of language such as "possibly".
Yes
We feel previous comments have largely been ignored by the Standards Drafting Team leading to a lack of support for the standard. Overall the standard should be more precise in its language. The following comments are provided for serious consideration with respect to revisions: Comments: From Section A.3 – the introduction please strike the word "probable" as shown below Purpose: Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies This is deterministic contingency testing and this

word introduces probability into the standard where it does not belong. For R1.1 Part 1.1.2. With respect to known outages, there needs to be greater flexibility in the standards (e.g. more tolerance to non-consequential load shedding or limitations to the contingencies that need to be considered (e.g. P0, P1, & P2)). Regional allowances for load shedding under this condition should be acceptable. Duration of known outages should be increased from six months to one year. For R1.1 Part 1.1.6 Delete "required for Load". Resources may also be used for export to other areas, not just internal load. REMOVE INTERCHANGE from 1.1.5 - Definition of Interchange – The inclusion of Interchange requires designing for non-Firm service. In the NERC Glossary of Terms Used the term Interchange is defined as "Energy transfers that cross Balancing Authority boundaries." It is meant to refer to energy transaction other than firm Transmission Service. While rigorous planning studies have been conducted to permit the uninterrupted implementation of firm Transmission Service without jeopardizing the reliable operation of the Interconnected System, other types of energy transaction only take place whenever system conditions permit them. They are usually of very short duration relative to planning assessment periods (usually spanning for a few hours to a few days) and are deemed highly interruptible and subject to reliability issues that may arise during operation of the system. In other words, the term Interchange refers to economic transactions that are permitted when the system is secure and there are reasonable reliability margins to effect dispatch changes to lower operating costs. As such, Interchange should not be reflected in system representation meant to assess system reliability under TPL-001. Part 2.1.4, requires an entity to vary one or more conditions to demonstrate a change in performance. If the cases were initially stressed, this may force an entity to simulate conditions with less severe stresses. At this point, there is limited or no value to this additional workload. Having a requirement to test at least one sensitivity as a blanket requirement may not be informative by itself and is more unclear since sensitivities are being required on an undefined base set of conditions. Additionally, our concern involves wording under 2.1.4 and 2.4.3 that sensitivities are required varying one or more conditions. Subsequently, in requirement 2.7.2 corrective action plans need to be developed to resolve performance deficiencies "only" if identified in multiple conditions or require a rationalization why no corrective action plan is necessary. Multiple condition sensitivities under 2.1.4 and 2.4.3 are necessary to satisfy requirement 2.7.2. Requirement 2.7.2 adds ambiguity and should be removed or revised as follows: 2.7.2. Corrective Action Plans are not required for performance deficiencies identified in a sensitivity analysis. We agree with R2.1 however with respect to R2.2 Language should be consistent with 2.1 for example - use "current or qualified past studies" instead of "the following annual current study." For 2.7.1 – We don't believe this list provides value nor should it be included in the standard. Section 3.3 - We feel that the last sentence of 3.3.1 should be removed. This is handled by PRC-023. Line ratings are addressed by PRC-023. PRC-023 requires coordination with the Reliability Coordinator. Remove "Tripping of Transmission elements where relay loadability limits are exceeded." In Table 1 - The fault descriptions must be clear. They must use "3-phase", "single-phase-to ground", or "2-phases-to ground" in the descriptions of a fault rather than SLG (a line is not a phase in electrical terms--single line to ground is not precise enough). In Table 1 - Where two elements are affected by a fault it must be clear whether the requirement is for a single-phase-to ground fault, or a 2-phase-to ground fault. They are different faults that will have different dynamic responses. For Table 1– add a footnote for the term generator to address the treatment of Combined Cycle Generators – "In addition to evaluating the loss of a single generator, the loss of all interrelated generators shall also be considered as a single contingency." Operating experience has shown that trips of the entire CC facility often occur even on facilities that claim the combined cycle generators are independent. Where a category involves an initial condition representing the loss of a facility followed by an event represeting the loss of a facility such as P3, the standard must be clear as to the amount of time assumed between faults. An assumption may be 30 minutes, but the standard must not leave this unsaid. This clarity must be provided in the Table 1 Notes. In addition, the standard must be clear on the allowable re-adjustments between contingencies such as P3, or better, must be clearly limit the permissible re-adjustments. For example, it is not realistic to assume an unlimited amount of re-dispatch between faults—e.g. the allowable re-adjustment should be limited to actions that can be effectively implemented in less than 30 minutes, such as a, b, c, d, ..., and the amount of generation re-dispatch must not exceed the amount of future planned contingency reserve, or similar language. This clarity must be derivable from the Table 1 Notes.

Individual
Claudiu Cadar

GDS Associates, Inc.
No
1. Footnote a. Footnote should state “Draft 7” instead 2. Requirement R1 a. Time Horizon should include both Near-term and Long-term Planning 3. Requirement R2 a. Time Horizon should include both Near-term and Long-term Planning b. Requirement R2, Part 2.1 • The inclusion of the words "For the Planning Assessment" it seem unnecessary as long as main requirement R2 is only about the Planning Assessment and nothing else. • The term “Qualifying studies” from the last sentence is referring to the qualified past studies, or the annual studies, or both actually? Suggesting adjusting the verbiage so it would not create confusion. • Subpart 2.1.4 - Requirement R2, Part 2.1.1 and Part 2.1.2 are referring to system conditions, not studies. The second sentence may be subject of non-objective interpretations and may generate burdensome and unrealistic amount of work. The requirement should state instead "For each of the system conditions described in Requirement R2, Part 2.1.1 and Part 2.1.2, the studies shall include sensitivity cases utilized to demonstrate whether there is any significant impact due to changes on the basic assumptions used in the model. The analysis, by case, may contemplate varying one or more of the following conditions:” • Subpart 2.1.5 - We suggest adjusting the time threshold of potential equipment unavailability in order to be consistent with the time frame for the "known Transmission outages". c. Requirement R2, Part 2.2 • The inclusion of the words "For the Planning Assessment" it seem unnecessary as long as main requirement R2 is only about the Planning Assessment and nothing else. • While the Near-Term portion of the Planning Assessment details the premises of the study, the Long-Term is lacking in such thing. d. Requirement R2, Part 2.3 • Although both the steady-state and transient stability studies are required for the Near-Term and Long-Term, the short-circuit study is required only for the Near-Term. This is big disconnect, because there can be stability analyses conducted without a short-circuit assessment. • Breakers should be checked for their breaking capability, as well as to withstand the fault. All other disconnecting equipment, as well as current transformers in particular shall be also verified for their withstand capabilities. The current statement should be replaced with "The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term and Long-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to assess performances of transmission elements affected by a potential increase of short-circuit contributions to fault” e. Requirement R2, Part 2.4 • The inclusion of the words "For the Planning Assessment" it seem unnecessary as long as main requirement R2 is only about the Planning Assessment and nothing else. • Similar with 2.1, the last sentence should read "The studies should include the following conditions:" • Subpart 2.4.1 - We believe that the dynamic behavior of the load cannot be accurately estimated beyond current time. We are concerned about the effort required to ascertain the dynamic response of the load. As for the “Loads that could impact the study area” the standard doesn't include any directions in how an entity will identify these loads. Perhaps the standard should provide guidelines to determine which loads would impact the study area. • Subpart 2.4.3 - See comments from Subpart 2.1.4 f. Requirement R2, Part 2.5 • The inclusion of the words "For the Planning Assessment" it seem unnecessary as long as main requirement R2 is only about the Planning Assessment and nothing else. g. Requirement R2, Part 2.6 • Subpart 2.6.2 - We agree with the suggested changes as responding to previous comments h. Requirement R2, Part 2.7 • Subpart 2.7.1 - We disagree with the implemented changes. The standard should not include examples. If needed, a white paper can accompany the standard. We suggest adjusting the last sentence to read “Such actions may include, but are not limited to, the following:” i. Requirement R2, Part 2.8 • This should apply to all disconnecting equipment and CT in particular with respect not only to their interrupting duty, but to their withstand capabilities also. See comment on Part 2.3. 4. Table 1 a. Footnote 9 • With respect to the Curtailment of Firm Transmission Service we suggest SDT to revise the language in order to be consistent with the Implementation Plan. 5. Measure M1 a. This measure it is hard to read. For simplicity, we suggest adjusting this measure to read "Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, and the models reflect the System conditions in accordance with Requirement R1." 6. Measure M7 a. The measure encompasses the particular scenario where the parties involved have reached an agreement for performing the required studies. In order to cover situations where the parties have not reach an agreement, the measure should read "Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies all individual and joint responsibilities for

performing the required studies and Assessments in accordance with Requirement R7." 7. Compliance a. Data retention • The 5th bullet should read "The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5." • The 6th bullet should read "The documentation specifying the criteria or methodology used to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding since the last compliance audit in accordance with Requirement R6 and Measure M6." • The 7th bullet should be reworded in accordance with suggested changes at M7.
Yes
Agree in general.
N/A
Individual
David Thorne
Pepco Holdings Inc
Yes
Pepco Holdings Inc supports the proposed revisions.
Yes
Individual
Michael Lombardi
Northeast Utilities
No
Definition of Terms Used in the Standard The definitions of “Near-Term Transmission Planning Horizon” and “Year One” have been deleted from the standard, yet they are still used in draft 7. NU is concerned about voting in favor of this standard with these terms being defined by another project without a full discussion of the impact to this proposed standard. NU suggests repeating the definitions in this proposed standard. Requirement R1 NU believes that the Normal System Conditions as stated in Requirement R1 should establish the base case conditions to be used for the assessment studies. However, a more detailed guideline for developing base cases should be addressed by the requirements. By just modifying the language of requirement R1 to indicate that “P0” constitutes the initial system conditions does not address this concern in Draft #7. A more detailed guideline for base case development is needed. Requirement R8 The wording in requirement R8 needs to be amended to restrict comments to the most recent assessment only, for a limited period (say 3 months) after its release. The current wording appears to offer unlimited opportunity to comment on past assessments, long after their release. Footnote 7 It appears there is a discrepancy between Footnote 7 and Event P2-1. Footnote 7 could be eliminated by rewording Event P2-1 as follows: “Opening one end of a line section w/o a fault”. Footnote 12 NU did not agree with the clarification of Table 1 Footnote B of TPL-002 and did not vote for its approval. Therefore, NU does not agree with the same clarification being applied here for Non-Consequential Load Loss. For reference, below is NU’s comment on TPL-002 Table 1, Footnote B: “The revised language of Footnote b suggests that non-consequential demand interruption (load that is not directly served by the elements removed from service as a result of the contingency) could be used to mitigate reliability concerns arising from NERC Category B contingency events (i.e., single element contingencies). This language seems to encourage operational workarounds and adds burdens for operators of the system. NU believes this is not consistent with planning a highly reliable bulk electric system and thus does not support this weaker language”. General comment NU believes that a standard should contain statements and requirements that are direct and measurable. TPL-001-2 should not be an exception to this rule. Therefore, statements like “An objective” which appears in Footnotes 9 and 12 shall not be used.
Yes
The following previous comments that were filed by NU were not addressed by the SDT in the current draft. For NU to support the standard these comments should be addressed or reasons should be provided why they have not been addressed. Repeated below are NU’s comments that were filed for

the previous draft. Requirement R1, Part 1.1.2 NU requests that the six month duration stated by Requirement R1, Part 1.1.2 should be modified to one year duration to eliminate outages that occur within the "operational planning timeframe". Requirement R1, Part 1.1.6 The phrase "required for Load" should be deleted as this confuses the issue. Requirement R2, Part 2.2 The language of Requirement R2 Part 2.2 seems to suggest that current annual studies are always required for the long-term steady state assessment. This may have been an oversight, for consistency Requirement R2 Part 2.2 should be modified to similarly read as Requirement R2, Part 2.1. Requirement R2, Parts 2.1.4 & 2.4.3 1) The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions. The standard must describe base assumptions. To define a sensitivity condition, NERC must define base assumptions. 2) Requirement R2, Part 2.1.4 and Part 2.4.3 should clarify what is meant by multiple sensitivity studies and one sensitivity study. Will varying only one measurable quantity several times in multiple simulations constitute multiple sensitivity studies or one sensitivity study? Requirement R3, Part 3.3.1 NU feels that the last sentence of Requirement R3, Part 3.3.1 should be removed since this is handled by PRC-023. Line ratings are addressed by PRC-023 which requires coordination with the Reliability Coordinator. NU suggests the removal of the following sentence: "Tripping of Transmission elements where relay loadability limits are exceeded."

Individual

Marie Knox

MISO

Yes

No

Regarding Requirement 8, we do not believe that there is significant risk to the reliability of the BES if an annual Planning Assessment is not distributed to another entity or if a documented response to Planning Assessment comments is not provided within 90 days of a request. Requirement 8 is an administrative requirement that adds little to improve reliability. We recommend that the VRF for Requirement 8 remain "Low", rather than be changed to "Medium".

Overall, we remain concerned that the revisions to the TPL standard are not on balance an improvement to the original. The document is not well organized topically, making it more difficult to navigate and understand. If the primary improvements sought in requirements for reliability planning were to increase system performance levels (no loss of firm demand) for certain multiple contingency events, and to ensure more stressed system sensitivities are analyzed, this can be accomplished in a much simpler revision. We do not believe that this standard as written improves the clarity of what is required, and therefore provides an opportunity for greater disputes between compliance monitors and applicable entities, and this is not a positive outcome. We also believe that the standard is too prescriptive as to what critical system conditions must be modeled, as these conditions vary considerably from system to system and within large systems. Table 1-Steady State and Stability Performance Planning Events, Category P5, now includes "non-redundant" relay in the Event column. What is meant by non-redundant relay? It is unclear if the SDT's intent is to provide distinction between a back-up relay and a redundant relay. We recommend that the SDT provide a definition for the term "non-redundant".

Group

Imperial Irrigation District

Yes

Yes

Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In our view, board of directors/Public Utility should have the determination what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote. 1. R2 (2.5): The value of assessing system stability for years 6-10 is questionable. Stability studies should be conducted for new generation interconnections or for planned major transmission system improvements that have regional impact. 2. R8 requirement to distribute all Planning Assessment results to adjacent PCs and TPs are excessive and

cumbersome. Regarding R8, IID suggest the following languages: Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners in accordance with the overseeing Reliability Coordinator requirements. Any functional entity that has a reliability related need and submits a written request for the Planning Assessment results, the Transmission Planner and Planning Coordinator shall provide the latest Planning Assessment results within 30 days of such request.
Individual
Gregory Campoli
New York Independent System Operator
No
If the following recommended revisions are made to the requirements listed, subject to other unforeseen material changes, NYISO would no longer oppose the approval of this standard. Requirement R2.1.5 The current requirement language can be interpreted to require evaluation of the simultaneous unavailability of multiple long-lead-time components. Also, as a transformer outage is already evaluated as part of category P6 in Table 1, additional studies should not be required, however spare equipment strategies could be ASSESSED in the context of the Planning Assessment. NYISO thus recommends this requirement be revised as follows: R 2.1.5 When an entity's spare equipment strategy could result in the unavailability of a major Transmission component that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed with due regard to categories P0, P1, and P2 identified in Table 1. Requirement R2.2 The language in this requirement is materially inconsistent with R2.1, unnecessarily requiring a current study. NYISO requests that R2.2 and the sub-requirement be revised as follows: 2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies shall include: 2.2.1. Expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected. Requirement R8.1 There is an apparent open ended time frame afforded report recipients in their review of any Planning Assessment. This requirement should apply to only the most recent Planning Assessment. NYISO thus recommends the following language: 8.1. If a recipient of the most recent Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.
No
Requirement 8 is an administrative burden that adds no value to reliability. Comments have been provided on several past drafts highlighting this effect. The revisions made to the VRF and VSL for Requirement 8 further exacerbate this burden. One could conclude from observation of the VSLs and VRFs, that Requirement 8 was the most important requirement of TPL-001-1. Many Planning Coordinators and Transmission Planners have stakeholder processes that govern participation and notification. Further, FERC Order 890 requires stakeholder participation and transparent processes.
Requirement R2.4.1 The NYISO, along with many other systems, has not determined a need to model dynamic loads, and therefore has not benchmarked any such models. The NYISO recommends that prior to the implementation of this requirement a modeling standard should exist that is specific to dynamic loads, including as assessment for the need for dynamic load models.
Group
Tri-State Generation and Transmission Assn., Inc.
Yes
In general, revisions are editorial and seem to have improved the overall document.
No
Many of the sub-requirements of R2 do not warrant high risk VRFs, yet violation of any R2 sub-requirement would result in a "High Risk Factor" violation assessment. We believe that having so many sub-requirements can result in inaccurate overall severity classification. For example, skipping one study defined in R2.1.2 (Planning Assessments) for a particular time frame or load level would probably not result in a direct actual degradation in system performance, but would still result in a High Violation Risk Factor.

R1.1 to "System models used for Steady State and Stability Analysis shall represent:" Much of what is in R1.1 is unnecessary for Short Circuit studies. In contrast, there are items not mentioned in R1.1 that are necessary for short circuit studies. R2.1.4 requires sensitivity analysis to study "a range of credible conditions that demonstrate a measurable change". How will the required actions in R2.1.4 be documented or measured, and what is accomplished by performing sensitivity analysis in the context of a system performance assessment? In R2.3, change the first sentence to read "The short circuit analysis portion of the Planning Assessment shall be conducted annually, using one of the cases described in 2.1.1, addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6." There appears to be no reason to perform short circuit studies for all three Near-Term Transmission Planning Horizon cases. R2.4.3 requires sensitivity analysis to study "a range of credible conditions that demonstrate a measurable change". How will the required actions in R2.4.3 be documented or measured, and what is accomplished by performing sensitivity analysis in the context of a system performance assessment? R2.7.1 remove the last bullet. We believe these programs are already factored into the load forecast, as they are associated with resource scheduling and planning load serving, and not transmission planning. In particular, DSM measures would fall under R2.4.1, and the term "new technologies, or other initiatives" The language of Requirement 3 unnecessarily repeats the language of R1 and R2. As now written, R3 states "For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1." R3 We recommend that the introductory language in Requirement R3 be changed to read "The studies in Requirement R2, Parts 2.1, and 2.2 shall be performed using models as defined in Requirement R1 in accordance with the following criteria." We believe that Requirements 3.1 and 3.4 should be combined into R3.1, eliminating R3.4. It is redundant to have Requirement 3.1 say "perform R3.4". We recommend that R3.4 be deleted and that R3.1 be replaced with: R3.1 Planning event studies shall be performed in accordance with "Table 1 – Steady State & Stability Performance Planning Events;" and shall be based on a supportable Contingency list. Comment: The content of 3.4.1 was intentionally omitted as it is redundant with R7. Also, the language "…more severe System impacts…" was intentionally omitted as it could be subject to a wide range of interpretations. Similarly, we recommend that R3.5 be deleted and that R3.2 be replaced with: R3.2 Extreme event studies shall be performed in accordance with "Table 1 – Steady State & Stability Extreme Events;" and shall be based on a supportable Contingency list. We recommend the following new requirement be inserted after the revised R3.2 language: Should the extreme event studies identify potential Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted. Comment: As before, the language "…more severe System impacts…" was intentionally omitted as it could be subject to a wide range of interpretations. We recommend removing the second bullet of R3.3.1, "Tripping of Transmission elements where relay loadability limits are exceeded" for the following reasons: 1. There is currently no tool to model relay loadability characteristics in Steady State analysis. 2. Requirement R3.3.1 would require inclusion of relay models in modeling data that are not currently provided. MOD-012 does not require impedance or overcurrent relay models to be submitted. 3. In Requirement 3.3.1, the second bullet, it is impossible to model complete and accurate relay loadability using present-day steady state simulation tools. At best an individual point could be chosen to model relays based on a selected power factor. We recommend changing the opening text of Requirement R.3.3.2 to say "Simulate the expected automatic or manual operation…" Subrequirement R4.1.2 represents a tremendous increase in dynamic modeling complexity. Modeling relay action during apparent impedance swings would require inclusion of impedance relay models in modeling data that are not required to be submitted in MOD-012. If such modeling is necessary, then the corresponding data requirements need to be addressed in MOD standards. We believe that Requirements 4.1 and 4.4 should be combined into R4.1 as shown below and R4.4 should be deleted. It is redundant to have Requirement 4.1 say "perform R4.4." We recommend R4.1 language be revised to read as follows: R4.1 Planning event studies shall be performed in accordance with "Table 1 – Steady State & Stability Performance Planning Events;" and shall be based on a supportable Contingency list. Comment: The content of 4.4.1 should be omitted as it is redundant with R7. Also, the language "…more severe System impacts…" should be omitted as it could be subject to a wide range of interpretations. Similarly, R4.5 should be deleted and R4.2 should be replaced with: R4.2 Extreme event studies shall be performed in accordance with "Table 1 – Steady State & Stability Extreme Events;" and shall be based on a supportable Contingency list. We

recommend the following new requirement be inserted after the revised R4.2: Should the extreme event studies identify potential Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the even(s) shall be conducted. Comment: As before, the language "…more severe System impacts…" was intentionally omitted as it could be subject to a wide range of interpretations. Clarify the first bullet in Requirement R4, part 4.3.1 by changing it to "High-speed (less than 1 second) reclosing, where the fault has cleared, and high-speed reclosing into the permanent fault , but in each case only if high-speed reclosing is utilized". In Requirement R4, part 4.3.1, third bullet, it is impossible to model complete and accurate relay loadability using present-day steady state simulation tools. Existing applications do have impedance relay models, but these models do not model many relay capabilities– for example, non-circular protection regions and load-encroachment. We recommend removing this bullet. The comment statement we made above referring to R4.1.2 also applies to R4.3.1. MOD-012 does not require reclosing relay model data to be submitted. If such modeling is necessary, then the corresponding data requirements need to be addressed in MOD standards. Furthermore, there is not a standard built-in reclosing relay model in current stability simulation tools. Comments regarding Table 1- We assume the headnote i. to Table 1 - "The response of voltage sensitive Load…" - means that studies must not rely on end-user load tripping to meet the performance requirements defined in TPL-001-2 but that it should be modeled (when known) so that its occurrence would be evident. We don't see the need to apply Footnote 12 to only certain contingency categories or certain events in categories. Recommend putting the footnote in the column header just as with Footnotes 1, 2, 3, and 4. Recommend changing "utilized" in Measurement M3 to "performed." Recommend changing "utilized" in Measurement M4 to "performed." Modify Measurement M7 to "Each Planning Coordinator shall provide dated documentation on roles and responsibilities of its Transmission Planners, such as…" The deleted phrase, "in conjunction with each of its Transmission Planners," appears to be unnecessary.

Individual

Kirit Shah

Ameren

No

There were a number of comments made on the previous draft of TPL-001-2 for which there were few, if any, changes made to the latest draft of the standard. Specifically: Requirement R1 does not address normal (pre-contingency) operating procedures or system configurations. Language should be added to the requirement (possibly as an additional Requirement R1.1.7) to include normal operating procedures or system configurations in place prior to any contingency occurring. Requirement R2.4.1, which addresses dynamic load modeling, has been a cause for concern because of the lack of guidance regarding reasonable induction motor representation as opposed to generic load models. While it is recognized that the effort to simulate the effects of induction motor loads is important, it is premature to include such modeling as part of the requirements for this standard. In addition, it appears that only the peak load model in R2.4.1 is required to represent expected dynamic behavior of Load. Such load models, if adopted should represent dynamic behavior of the load for all dynamic studies.

No

The VRF for Requirement R8 should remain Low. There is no significant risk to the reliability of the BES if a Planning Assessment is not distributed to another entity, or if a documented response is not provided within 90 days of a request. The assignment of some VRFs are inconsistent with the importance of the requirements. R2 requires the development of an assessment and it is determined to have a high VRF. However, R3 and R4 require that studies be performed and these studies are determined to have a medium VRF. Performing the studies is essential to developing an assessment and more important to maintaining reliability. If the VRFs for R3 and R4 are correct, then the VRF for R2 should be no higher than medium. The VRF for R5 to develop a steady-state voltage criteria is determined to be medium. However, the VRF for R6 to develop instability criteria is determined to be low. If the VRF for R6 is correct, then the VRF for R5 should also be low.

With respect to Requirement R8, will posting the assessment to a secure web site meet the intent of the requirement? What are the Planning Assessment results identified in R8, and how are they different from the Planning Assessment? It appears that the language for R8 is inconsistent with the VSL for R8. The revised language for the VSL for R8 has removed the word "results". For

Measurements M3 and M4, there is still some question as to what is to be provided as sufficient evidence of a study. It is not clear whether the study results would be sufficient, or whether the entire powerflow, stability, or short circuit effort needs to be documented in a formal study report. For example, it is not clear whether contingency lists used in performing the study work would need to be retained as part of the documentation. The items listed as 4.1.1 through 4.1.3 are not requirements but are performance criteria and should be included in the Table 1 only, consistent with the other performance criteria. Overall, we believe that this standard does not improve the clarity of what is required, and would give additional occasions for disputes between compliance monitors and various registered entities. The standard as written is too prescriptive with regard to critical system conditions which are to be modeled. Such conditions would vary considerably for different systems across the continent.
Individual
Darryl Curtis
Oncor Electric Delivery Company LLC
Yes
Yes

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Ballot Results	
Non-Binding Poll Name:	Project 2006-02 ATFN non-binding April 2011
Poll Period:	5/18/2011 - 5/31/2011
Total # Opinions:	210
Total Ballot Pool:	333
Summary Results:	86.79% of those who registered to participate provided an opinion; 71.9% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Kirit S. Shah	Abstain	
1	American Electric Power	Paul B. Johnson	Affirmative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Robert D Smith	Negative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	View
1	Austin Energy	James Armke	Abstain	
1	Avista Corp.	Scott Kinney	Abstain	
1	Balancing Authority of Northern California NCR11118	Kevin Smith	Negative	View
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S. Stonecipher	Negative	View
1	Black Hills Corp	Eric Egge	Negative	View
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy Houston Electric	Dale G Bodden	Negative	
1	Central Maine Power Company	Kevin L Howes	Negative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma	Chang G Choi	Affirmative	

	Power			
1	City of Vero Beach	Randall McCamish	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	View
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker	Negative	View
1	Dominion Virginia Power	Michael S Crowley		
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph Frederick Meyer		
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Abstain	
1	GDS Associates, Inc.	Claudiu Cadar	Abstain	View
1	Georgia Transmission Corporation	Harold Taylor, II		
1	Grand River Dam Authority	James M Stafford		
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Negative	View
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Ronald D. Schellberg	Negative	View

1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	View
1	Kansas City Power & Light Co.	Michael Gammon		
1	Keys Energy Services	Stan T. Rzad	Affirmative	View
1	Lake Worth Utilities	Walt Gill	Affirmative	
1	Lakeland Electric	Larry E Watt	Negative	
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam		
1	Lone Star Transmission, LLC	Julius Horvath	Affirmative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	Ly M Le		
1	Lower Colorado River Authority	Martyn Turner		
1	Manitoba Hydro	Joe D Petaski	Negative	View
1	MEAG Power	Danny Dees	Affirmative	
1	Mid-Continent Area Power Pool	Larry E. Brusseau	Abstain	
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	Minnkota Power Coop. Inc.	Richard Burt	Affirmative	View
1	National Grid	Saurabh Saksena		
1	Nevada Power Co.	James McMorran	Affirmative	
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Negative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Utilities	David H. Boguslawski	Abstain	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	

1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Douglas G Peterchuck	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	PacifiCorp	Colt Norrish		
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Negative	View
1	Portland General Electric Co.	Frank F. Afranji	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	View
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Abstain	View
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Abstain	

1	South Texas Electric Cooperative	Richard McLeon	Negative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Robert A Schaffeld		
1	Southern Illinois Power Coop.	William G. Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young	Affirmative	
1	Tennessee Valley Authority	Larry Akens	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	View
1	Tucson Electric Power Co.	John Tolo	Negative	View
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Negative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	Alberta Electric System Operator	Mark B Thompson	Abstain	View
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Richard K Vine	Negative	View
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Negative	View
2	Independent Electricity System Operator	Kim Warren	Negative	View
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	

2	Southwest Power Pool	Charles H Yeung	Abstain	
3	Ameren Services	Mark Peters		
3	APS	Steven Norris	Negative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Robert Lafferty	Abstain	
3	Bandera Electric Cooperative	Brian D Bartos	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	View
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	View
3	City of Redding	Bill Hughes	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Lisa Cleary	Affirmative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy	David A. Lapinski	Negative	View
3	Cowlitz County PUD	Russell A Noble	Abstain	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F Gildea	Abstain	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	East Kentucky Power Coop.	Sally Witt	Affirmative	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	
3	Florida Power and Light / NextEra Energy	Chantel Haswell	Abstain	

3	Florida Power Corporation	Lee Schuster	Affirmative	View
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Systems Operations Corporation	William N Phinney	Abstain	
3	Great River Energy	Sam Kokkinen	Negative	
3	Hydro One Networks, Inc.	David L Kiguel	Negative	View
3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory David Woessner	Negative	
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Lincoln Electric System	Bruce Merrill	Negative	View
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	View
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	John Apperson	Abstain	

3	Platte River Power Authority	Terry L Baker	Negative	View
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	View
3	Salt River Project	John T. Underhill		
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	View
3	Xcel Energy, Inc.	Michael Ibold		
4	American Municipal Power	Kevin Koloini	Negative	View
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	Central Lincoln PUD	Shamus J Gamache		
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Abstain	
4	Cowlitz County PUD	Rick Syring	Abstain	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	View

4	Fort Pierce Utilities Authority	Thomas W. Richards	Abstain	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	LaGen	Richard Comeaux	Abstain	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	View
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko	Affirmative	View
5	Amerenue	Sam Dwyer		
5	Arizona Public Service Co.	Edward Cambridge	Negative	
5	Avista Corp.	Edward F. Groce	Abstain	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	View

5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	View
5	City of Redding	Paul A Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Abstain	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Consumers Energy	James B Lewis	Negative	View
5	Cowlitz County PUD	Bob Essex	Abstain	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton		
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	View
5	Great River Energy	Preston L Walsh	Negative	
5	I do not represent an Entity	Bruce Paggeot	Abstain	
5	Indeck Energy Services, Inc.	Rex A Roehl	Negative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	Jim M Howard	Abstain	

5	Lincoln Electric System	Dennis Florom	Negative	View
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Negative	
5	Manitoba Hydro	S N Fernando	Negative	View
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	View
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	William O Thompson	Affirmative	
5	Occidental Chemical	Michelle DAntuono	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard Kinas		
5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Sandra L. Shaffer	Abstain	
5	Platte River Power Authority	Pete Ungerman	Negative	View
5	Portland General Electric Co.	Gary L Tingley		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	View
5	Proven Compliance Solutions	Mitchell E Needham		
5	PSEG Fossil LLC	Mikhail Falkovich	Abstain	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik		
5	Sacramento Municipal Utility District	Bethany Hunter	Negative	View
5	Salt River Project	Glen Reeves	Affirmative	

5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Barry Ingold	Negative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.		
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Abstain	
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Affirmative	View
6	Arizona Public Service Co.	Justin Thompson	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	View
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Abstain	
6	Constellation Energy Commodities Group	Brenda Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	

6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	View
6	Florida Municipal Power Pool	Thomas E Washburn	Negative	View
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Abstain	
6	Lincoln Electric System	Eric Ruskamp	Negative	View
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Scott L Smith	Abstain	
6	Platte River Power Authority	Carol Ballantine	Negative	View
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon	Affirmative	View
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	View
6	Sacramento Municipal Utility District	Claire Warshaw	Negative	View
6	Salt River Project	Steven J Hulet	Abstain	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seattle City Light	Dennis Sismaet	Abstain	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	

6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Xcel Energy, Inc.	David F. Lemmons		
8		James A Maenner	Abstain	
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein	Affirmative	
8	INTELLIBIND	Kevin Conway	Abstain	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Transmission Strategies, LLC	Bernie M Pasternack	Affirmative	View
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell		
10	Midwest Reliability Organization	James D Burley	Abstain	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	View
10	SERC Reliability Corporation	Carter B. Edge	Abstain	
10	Southwest Power Pool Regional Entity	Stacy Dochoda	Affirmative	View

10	Texas Reliability Entity	Larry D. Grimm	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	View

Ballot Results

Ballot Name:	Project 2006-02 Assess Transmission Future Needs April 2011_in
Ballot Period:	5/18/2011 - 5/31/2011
Ballot Type:	Initial
Total # Votes:	325
Total Ballot Pool:	353
Quorum:	**92.07 % The Quorum has been reached**
Weighted Segment Vote:	73.99 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	103	1	66	0.759	21	0.241	7	9
2 - Segment 2.	11	1	3	0.273	8	0.727	0	0
3 - Segment 3.	73	1	52	0.8	13	0.2	5	3
4 - Segment 4.	27	1	13	0.813	3	0.188	6	5
5 - Segment 5.	72	1	44	0.746	15	0.254	6	7
6 - Segment 6.	46	1	30	0.732	11	0.268	3	2
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.4	4	0.4	0	0	3	1
9 - Segment 9.	4	0.4	4	0.4	0	0	0	0
10 - Segment 10.	9	0.8	7	0.7	1	0.1	0	1
Totals	**353**	**7.6**	**223**	**5.623**	**72**	**1.978**	**30**	**28**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit S. Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Affirmative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	View
1	Arizona Public Service Co.	Robert D Smith	Affirmative	View
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	View
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott Kinney	Affirmative	
1	Balancing Authority of Northern California NCR11118	Kevin Smith	Affirmative	

1	BC Hydro and Power Authority	Patricia Robertson	Negative	View
1	Beaches Energy Services	Joseph S. Stonecipher	Negative	View
1	Black Hills Corp	Eric Egge	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	View
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy Houston Electric	Dale G Bodden	Negative	
1	Central Maine Power Company	Kevin L Howes	Negative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Vero Beach	Randall McCamish	Affirmative	View
1	Clark Public Utilities	Jack Stamper	Affirmative	View
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	View
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph Frederick Meyer		
1	Entergy Services, Inc.	Edward J Davis	Affirmative	View
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	View
1	GDS Associates, Inc.	Claudiu Cadar	Negative	View
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	View
1	Grand River Dam Authority	James M Stafford		
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Negative	View
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Negative	View
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	View
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	View
1	Kansas City Power & Light Co.	Michael Gammon		
1	Keys Energy Services	Stan T. Rzad	Affirmative	View
1	Lake Worth Utilities	Walt Gill	Affirmative	
1	Lakeland Electric	Larry E Watt	Negative	View
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Lone Star Transmission, LLC	Julius Horvath	Affirmative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	Ly M Le	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	View
1	Manitoba Hydro	Joe D Petaski	Negative	View
1	MEAG Power	Danny Dees	Affirmative	
1	Mid-Continent Area Power Pool	Larry E. Brusseau	Abstain	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	View
1	Minnkota Power Coop. Inc.	Richard Burt	Affirmative	
1	National Grid	Saurabh Saksena	Affirmative	View
1	Nevada Power Co.	James McMorran		
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Negative	View
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Utilities	David H. Boguslawski	Negative	View
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Douglas G Peterchuck	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	PacifiCorp	Colt Norrish		
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Negative	View

1	Portland General Electric Co.	Frank F. Afranji	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	View
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Chelan County	Chad Bowman	Affirmative	View
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Negative	View
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	View
1	San Diego Gas & Electric	Will Speer	Abstain	View
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	View
1	South Texas Electric Cooperative	Richard McLeon	Negative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Robert A Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William G. Hutchison	Abstain	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young	Affirmative	
1	Tennessee Valley Authority	Larry Akens	Negative	View
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	View
1	Tucson Electric Power Co.	John Tolo	Negative	View
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Abstain	
1	Western Area Power Administration	Brandy A Dunn	Negative	View
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	View
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	View
2	California ISO	Richard K Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Negative	View
2	Independent Electricity System Operator	Kim Warren	Negative	View
2	ISO New England, Inc.	Kathleen Goodman	Negative	View
2	Midwest ISO, Inc.	Marie Knox	Negative	View
2	New Brunswick System Operator	Alden Briggs	Negative	View
2	New York Independent System Operator	Gregory Campoli	Negative	View
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung	Negative	
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters		
3	APS	Steven Norris	Affirmative	View
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Robert Lafferty	Affirmative	
3	Bandera Electric Cooperative	Brian D Bartos	Negative	
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	View
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	View
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	View
3	City of Redding	Bill Hughes	Affirmative	
3	Clatskanie People's Utility District	Brian Fawcett	Abstain	
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Lisa Cleary	Affirmative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	View
3	Consumers Energy	David A. Lapinski	Negative	View
3	Cowlitz County PUD	Russell A Noble	Abstain	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	East Kentucky Power Coop.	Sally Witt	Affirmative	
3	Entergy	Joel T Plessinger	Affirmative	

3	FirstEnergy Solutions	Kevin Querry	Affirmative	
3	Florida Power and Light / NextEra Energy	Chantel Haswell	Abstain	
3	Florida Power Corporation	Lee Schuster	Affirmative	View
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia Systems Operations Corporation	William N Phinney	Abstain	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Negative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David L Kiguel	Negative	View
3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	View
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory David Woessner	Negative	
3	Lakeland Electric	Mace Hunter	Abstain	
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	View
3	Mississippi Power	Don Horsley	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	View
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	View
3	PacifiCorp	John Apperson	Affirmative	
3	Platte River Power Authority	Terry L Baker	Negative	View
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	View
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey	Affirmative	
3	Tennessee Valley Authority	Ian S Grant	Negative	View
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	View
3	Xcel Energy, Inc.	Michael Ibold		
4	American Municipal Power	Kevin Koloini	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	Central Lincoln PUD	Shamus J Gamache		
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	View
4	Consumers Energy	David Frank Ronk	Negative	View
4	Cowlitz County PUD	Rick Syring	Abstain	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	View
4	Fort Pierce Utilities Authority	Thomas W. Richards	Affirmative	View
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	LaGen	Richard Comeaux	Abstain	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Affirmative	View
4	Modesto Irrigation District	Spencer Tacke	Negative	View

4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Affirmative	View
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko	Affirmative	View
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge	Negative	View
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Negative	View
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	View
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	View
5	City of Redding	Paul A Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	View
5	Consumers Energy	James B Lewis	Negative	View
5	Cowlitz County PUD	Bob Essex	Abstain	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton		
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	View
5	Great River Energy	Preston L Walsh	Negative	
5	I do not represent an Entity	Bruce Paggeot	Abstain	
5	Indeck Energy Services, Inc.	Rex A Roehl	Abstain	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	Jim M Howard	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Affirmative	View
5	Luminant Generation Company LLC	Mike Laney	Negative	View
5	Manitoba Hydro	S N Fernando	Negative	View
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	View
5	Muscatine Power & Water	Mike Avesing	Affirmative	View
5	Nebraska Public Power District	Don Schmit	Negative	View
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	William O Thompson	Affirmative	
5	Occidental Chemical	Michelle DAntuono	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard Kinas	Affirmative	
5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Pete Ungerman	Negative	View
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	View
5	Proven Compliance Solutions	Mitchell E Needham		
5	PSEG Fossil LLC	Mikhail Falkovich	Affirmative	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	

5	Reedy Creek Energy Services	Bernie Budnik		
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	View
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	Tennessee Valley Authority	David Thompson	Negative	View
5	Tri-State G & T Association, Inc.	Barry Ingold	Negative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.		
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Abstain	
5	Xcel Energy, Inc.	Liam Noailles	Negative	View
6	AEP Marketing	Edward P. Cox	Affirmative	View
6	Arizona Public Service Co.	Justin Thompson	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	View
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	View
6	Constellation Energy Commodities Group	Brenda Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	View
6	Eugene Water & Electric Board	Daniel Mark Bedbury		
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	View
6	Florida Municipal Power Pool	Thomas E Washburn	Negative	View
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones	Negative	View
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	View
6	Omaha Public Power District	David Ried	Affirmative	
6	Orlando Utilities Commission	Claston Augustus Sunanon	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Negative	View
6	Powerex Corp.	Daniel W. O'Hearn	Negative	View
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon	Affirmative	View
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	View
6	Sacramento Municipal Utility District	Claire Warshaw	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	View
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	View
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Negative	View
6	Xcel Energy, Inc.	David F. Lemmons	Negative	View
8		James A Maenner	Abstain	View
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein	Affirmative	

8	INTELLIBIND	Kevin Conway	Abstain	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Transmission Strategies, LLC	Bernie M Pasternack	Affirmative	View
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell		
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Negative	View
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	View
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	View
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Southwest Power Pool Regional Entity	Stacy Dochoda	Affirmative	
10	Texas Reliability Entity	Larry D. Grimm	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	View

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2006-02 Assess Transmission Future Needs Successive Ballot and Non-binding Poll Results

Now available at: https://standards.nerc.net/Ballots.aspx

A successive ballot on revisions to TPL-001-2 Transmission System Planning Performance Requirements, and a concurrent non-binding poll of associated VRFs and VSLs, concluded on May 31, 2011. The standard was approved by the ballot pool with an approval rating of 73.99% and a quorum of 92.07%.

Ballot Results for Revisions to TPL-001-2

Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:
Quorum: 92.07 %
Approval: 73.99 %

Non-binding Poll Results for Associated VRF and VSLs

Of those who registered to participate, 86.79% provided an opinion; 71.9% of those who provided an opinion indicated support for the VRFs and VSLs that were proposed.

Next Steps

The drafting team will consider all comments received during the formal comment period, ballot, and non-binding poll, and will determine whether to make additional changes to the standard and its implementation plan and associated VRFs and VSLs. If the team makes substantive changes to address issues raised in comments, an additional 30-day formal comment period will be conducted with a successive ballot during the last ten days of the comment period. If the team makes only minor clarifying changes to address issues identified in comments, a recirculation ballot may be conducted.

Background:

TPL-001-2 is designed to be a single, comprehensive, and coordinated standard that merges the requirements of four existing standards: TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The proposed standard includes several new definitions. The purpose of the proposed standard is to establish transmission system planning performance requirements within the planning horizon to develop a bulk electric system that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies.

The AFTN SDT solicited comments from the industry on the fifth posting of the revised TPL-001-2 through an informal comment period that ended on September 2, 2010. The team revised the standard in response to comments received, and posted Draft 6 for information, while awaiting the outcome of Project 2010-11 TPL Table 1 (footnote 'b'). The revisions to Table 1 footnote 'b' have been approved by the NERC Board of Trustees and filed with FERC. The AFTN SDT adopted the technical tenets of the final solution for footnote 'b' for inclusion in TPL-001-2.
Additional information about this project is available on the project page at:

http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Assess Transmission Future Needs and Develop Transmission Plans — Project 2006-02

The Assess Transmission Future Needs and Develop Transmission Plans Drafting Team thanks all commenters who submitted comments on the 6th draft of the TPL-001-2 standard for Assess Transmission Future Needs (Project 2006-02). These standards and associated documents were posted for a 45-day public comment period from April 18, 2011 through May 31, 2011. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 43 sets of comments, including comments from approximately 78 different people and approximately 69 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

No changes were made to the text of any Requirement. The SDT made several changes in response to comments submitted during the formal comment period and successive ballot that ended May 31, 2011.

- The 5th and 6th bullets of the Data Retention section to make the language in the data retention statements consistent with the language in the requirements.
- The third part of the Severe VSL for Requirement R1 to make the language consistent with the requirement.
- The VSL for Requirement R8 to make the language consistent with the language in the requirement.
- The Effective Date section of the Implementation Plan to make the language consistent with the language in the Effective Date section in the proposed TPL-001-2.
- The bullets in Requirement R3, Part 3.3.1 were replaced with numbers because the bullets were inconsistent with NERC's protocol on the use of bullets in Requirements.
- The bullets in Requirement R4, Part 4.3.1 were replaced with numbers because the bullets were inconsistent with NERC's protocol on the use of bullets in Requirements.

The SDT is requesting that this project be moved to the recirculation ballot stage.

All comments submitted may be reviewed in their original format on the standard's project page:

http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

1. The SDT has made revisions to the requirements language of TPL-001-2 based on industry comments and the Quality Review. Do you agree with these changes? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments with clear indications as to which requirement you are commenting on. …..... 10
2. The SDT has made revisions to the VRF and VSL of TPL-001-2 which will be part of a non-binding poll with this posting based on industry comments and the Quality Review. Do you agree with these changes? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. …..... 39
3. If you have any other comments on this Standard that you have not already provided in response to the prior questions, please provide them here. …..... 54

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Charles W. Long	SERC Planning Standards Subcommittee	X									X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Pat Huntley	SERC Reliability Corporation	SERC	10
2.	Bob Jones	Southern Company Services	SERC	1
3.	Darrin Church	Tennessee Valley Authority	SERC	1
4.	Phil Kleckley	South Carolina Electric & Gas Co.	SERC	1
5.	John Sullivan	Ameren Services Co.	SERC	1
6.	Charles Long	Entergy Services, Inc.	SERC	1

2.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1

Group/Individual		Commenter	Organization		Registered Ballot Body Segment									
					1	2	3	4	5	6	7	8	9	10
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1										
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10										
7.	Brian Evans-Mongeon	Utility Services	NPCC	8										
8.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5										
9.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5										
10.	Kathleen Goodman	ISO - New England	NPCC	2										
11.	Chantel Haswell	FPL Group, Inc.	NPCC	5										
12.	David Kiguel	Hydro One Networks Inc.	NPCC	1										
13.	Michael R. Lombardi	Northeast Utilities	NPCC	1										
14.	Randy MacDonald	Nerw Brunswick Power Transmission	NPCC	1										
15.	Bruce Metruck	New York Power Authority	NPCC	6										
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10										
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1										
18.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1										
19.	Saurabh Saksena	National Grid	NPCC	1										
20.	Michael Schiavone	National Grid	NPCC	1										
21.	Wayne Sipperly	New York Power Authority	NPCC	5										
22.	Donald Weaver	New Brunswick System Operator	NPCC	1										
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1										
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3										
3.	Group	Jonathan Hayes	SPP Reliability Standards Development Team		X	X	X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charles Yeung	SPP	SPP	2
2.	John Allen	City Utilities of Springfield	SPP	1, 4
3.	John Fulton	Xcel Energy	SPP	1, 3, 5
4.	Mark Hamilton	Oklahoma Gas & Electric	SPP	1, 3, 5
5.	Michelle Corley	CLECO	SPP	1, 3, 5

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10
6. Nathan McNeil	Midwest Energy	SPP 1, 3										
7. Tony Gott	Associated Electric Coop, Inc	SERC 1, 3, 5										
8. Matt Bordelon	CLECO	SPP 1, 3, 5										
9. Valerie Pinamonti	American Electric Power	SPP 1, 3, 5										
4. Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				
Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1. Berhanu Tesema	BPA, Transmission Planning	WECC	1									
2. Chuck Matthews	BPA, Transmission Planning	WECC	1									
3. Kyle Kohne	BPA, Transmission Planning	WECC	1									
4. Patrick Rochelle	BPA, Transmission Planning	WECC	1									
5. Kendall Rydell	BPA, Transmission Planning	WECC	1									
5. Group	Carol Gerou	MRO's NERC Standards Review Forum										X
Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1. Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6									
2. Chuck Lawrence	American Transmission Company	MRO	1									
3. Tom Webb	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6									
4. Jodi Jenson	Western Area Power Administration	MRO	1, 6									
5. Ken Goldsmith	Alliant Energy	MRO	4									
6. Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6									
7. Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6									
8. Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6									
9. Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6									
10. Scott Nickels	Rochester Public Utilties	MRO	4									
11. Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6									
12. Marie Knox	Midwest ISO Inc.	MRO	2									
13. Lee Kittelson	Otter Tail Power Company	MRO										
14. Scott Bos	Muscatine Power & Water	MRO										

Group/Individual		Commenter	Organization		Registered Ballot Body Segment									
					1	2	3	4	5	6	7	8	9	10
15.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5										
16.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6										
17.	Richard Burt	Minnkota Power Cooperative, Inc.	MRO	1, 3, 5, 6										
6.	Group	Patricia Robertson	BC Hydro		X									
	Additional Member	Additional Organization	Region	Segment Selection										
1.	Venkataramakrishnan Vinnakota	BC Hydro	WECC	2										
2.	Pat Harrington	BC Hydro	WECC	3										
3.	Clement Ma	BC Hydro	WECC	5										
4.	Daniel O'Hearn	BC Hydro	WECC	6										
7.	Group	Ed Davis	Entergy Services		X		X		X	X				
	Additional Member	Additional Organization	Region	Segment Selection										
1.	Stan Jaskot	Entergy Services	SERC	5										
2.	Terry Benoit	Entergy Services	SERC	6										
3.	Joel Plessinger	Entergy Services	SERC	3										
4.	Ed Davis	Entergy Services	SERC	1										
8.	Group	Brandy A. Dunn	Western Area Power Administration		X					X				
	Additional Member	Additional Organization	Region	Segment Selection										
1.	Pete Kinney	Western Area Power Administration	MRO	6										
9.	Group	Sammy Alcaraz	Imperial Irrigation District		X		X	X		X				
	Additional Member	Additional Organization	Region	Segment Selection										
1.	David Barajas		WECC											
2.	Marcela Caballero		WECC											
3.	Tino Zaragoza		WECC	1										
4.	Jesus Alcaraz		WECC	3										
5.	Diana Torres		WECC	4										

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
6. Cathy Bretz			WECC 6										
10.	Group	Bill Middaugh	Tri-State Generation and Transmission Assn., Inc.	X		X		X					
Additional Member		**Additional Organization**	**Region**	**Segment Selection**									
1. Mark Graham		Tri-State G&T	WECC	1									
2. Chris Pink		Tri-State G&T	WECC	1									
11.	Individual	David Kiguel	Hydro One Networks Inc.	X		X							
12.	Individual	Jim Eckelkamp	Progress Energy	X		X		X	X				
13.	Individual	Janet Smith	Arizona Public Service Company	X		X		X	X				
14.	Individual	John Bussman	Associated Electric Cooperative Inc	X		X		X	X				
15.	Individual	Thad Ness	American Electric Power	X		X		X	X				
16.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
17.	Individual	Bernie Pasternack	Transmission Strategies, LLC								X		
18.	Individual	Joe O'Brien	NIPSCO	X		X		X	X				
19.	Individual	Scott Bos	Muscatine Power and Water	X		X		X	X				
20.	Individual	Sunitha Kothapalli	Puget Sound Energy, Inc.	X		X		X					
21.	Individual	Anthony Jablonski	ReliabilityFirst										X

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
22.	Individual	Michael Moltane	ITC	X									
23.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
24.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
25.	Individual	Tony Eddleman	Nebraska Public Power District	X		X		X					
26.	Individual	Robert Casey	Georgia Transmission Corporation	X									
27.	Individual	Jonathan Appelbaum	United Illuminating	X									
28.	Individual	Andrew Z.Pusztai	American Transmission Company, LLC	X									
29.	Individual	Michael Jones	National Grid	X		X							
30.	Individual	Tim E. Ponseti, VP	TVA TP&C	X									
31.	Individual	Michael Falvo	Independent Electricity System Operator		X								
32.	Individual	Alex Rost	NBSO		X								
33.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
34.	Individual	Christine Hasha	Electric Reliability Council of Texas, Inc.		X								
35.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
36.	Individual	Kathleen Goodman	ISO New England Inc.		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
37.	Individual	Claudiu Cadar	GDS Associates, Inc.	X									
38.	Individual	David Thorne	Pepco Holdings Inc	X		X							
39.	Individual	Michael Lombardi	Northeast Utilities	X		X		X					
40.	Individual	Marie Knox	MISO		X								
41.	Individual	Gregory Campoli	New York Independent System Operator		X								
42.	Individual	Kirit Shah	Ameren	X		X		X	X				
43.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X									

1. **The SDT has made revisions to the requirements language of TPL-001-2 based on industry comments and the Quality Review. Do you agree with these changes? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments with clear indications as to which requirement you are commenting on.**

Summary Consideration: Several commenters stated that Requirement R1, Part 1.1.5 should not include interchange because interchange introduces economic considerations into a Reliability Standard. The SDT explained that the requirement is to include known commitments for interchange and therefore the requirement is not for economic purposes, but rather planning to meet obligations.

A number of commenters stated that they believed that there was an inconsistency between Requirement R2, Parts 2.1 and 2.2, since qualified studies were not allowed for the Long-Term Transmission Planning Horizon case. The SDT believes that the requirement to conduct the annual study on one of the study years in the Long-Term Transmission Planning Horizon ensures that the planner conducts a new study annually to evaluate the System improvement needs in the Long-Term Transmission Planning Horizon, even if they utilize qualified past studies for the Near-Term Transmission Planning Horizon cases.

Several commenters stated that they believed that Requirement R2, Part 2.1.5 was ambiguous since it was not clear that the planner did not have to include multiple outages of long lead time components simultaneously. The SDT explained that Requirement R2, Part 2.1.5 does not require simultaneous outages of multiple long lead time components.

Some commenters expressed concerns with Requirement R2, Part 2.4.1 since they were concerned with the ability for planners to adequately model the dynamic behavior of Load. The SDT explained that since it is important to correctly model the characteristics of the Load, it believes that the requirement to represent the dynamic behavior of the Load is needed to ensure BES reliability.

A number of commenters expressed concern that Requirement R7 was administrative and was not required. The SDT explained that it believes that the requirement is necessary to ensure that there are no gaps created between the Transmission Planners and the Planning Coordinators when they determine their individual responsibilities.

Several commenters stated that they had concerns with Requirement R8. These concerns are that the requirements create excessive work and should include time limits on requesting the Planning Assessment, are ambiguous, and should include the ability to post the Planning Assessment. The SDT explained that the requirements are only to distribute the Planning Assessment, which should not require a large amount of work, and the requirements are clear that the planners must distribute to adjacent Transmission Planners and Planning Coordinators and others with a reliability need. The SDT further explained that posting the Planning Assessment could meet the requirement to distribute.

Several commenters stated that they believed that Table 1, P2-1 was inconsistent with Footnote 7. The SDT explained that Footnote 7 was included to clarify that "Opening a line section without a fault" could include, but does not always, creating a radial line section with Load and that the planner must evaluate this situation as a part of P2-1.

A number of commenters expressed concern that Footnote 12 was not appropriate or that this standard should be delayed until FERC approved TPL-002-1 Footnote 'b'. The SDT explained that Footnote 12 was consistent with language in the recent NERC Board of Trustees approved TPL-002-1 Footnote 'b" and that this standard should not be delayed until FERC rules on the other standard.

No changes were made to requirements due to industry comments to question 1. However changes were made to the wording of the Implementation Plan to make it consistent with the language in the Effective Date section of the standard. Also, the language in the data retention section was changed for bullets five and six to make it consistent with the language in the requirements – no changes were made to the timeframe for data retention.

DR, 5th bullet: The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.

DR, 6th bullet: The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.

Organization	Yes / No	Question 1 Comment
Lower Colorado River Authority	Ballot Comment	1. R2 (2.5): The requirement for stability assessment in years 6-10 should be limited for new generation interconnections or for planned major transmission system improvements that have regional impact. The standard should clarify the 'material changes' that would necessitate stability planning assessments and documentation. 2. R8 requirement to distribute all Planning Assessment results to adjacent PCs and TPs are excessive and cumbersome. Regarding R8, LCRA TSC suggests the following language: Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners in accordance with the overseeing Reliability Coordinator requirements. Any functional entity that has a reliability related need and submits a written request for the Planning Assessment results, the Transmission Planner and Planning Coordinator shall provide the latest Planning Assessment results within 30 days of such request.

Organization	Yes / No	Question 1 Comment
Response: For Requirement R2, Part 2.5, the SDT believes it is important to evaluate Stability when the planners are evaluating new generation additions or changes which can be more than 5 years in the future, as required in NERC Standard FAC-001-0. The SDT discussed defining 'material change' but did not believe that such a definition was appropriate in a continent-wide standard. With the wide variety in sizes and types of systems, the number of parameters that need to be considered, etc., there are too many variables involved. No change made. For Requirement R8, the SDT disagrees that the requirement is excessive and cumbersome and did not make the suggested change. In addition, the proposed language would place requirements on the Reliability Coordinators, who are not included in the Applicability for this standard, and they should not be involved in determining the extent of the distribution of the Planning Assessments.		
Florida Municipal Power Agency	Ballot Comment	FMPA has minor comments to help improve the clarity of the standard. R7 is not needed and administrative in nature. Instead is should say that an entity can use as evidence another entity's study, but not in the requirement and rather in the measures. R8 is ambiguous, does the requirement require submitting the Planning Assessment only after receiving a written request, or automatic distribution to neighboring PCs and TPs without a written request, and to others with a reliability related need following a written request? Table 1, under first heading of "Steady State and Stability", bullet c should be removed since it is duplicative of the standard, and not entirely consistent with the standard (e.g., open to interpretation whereas the standard better clarifies how to study protection system operation)
Response: Requirement R7 ensures that there are no gaps between Transmission Planners or the Planning Coordinators that may cause reliability concerns. No change made. Requirement R8 requires the automatic distribution to neighboring Planning Coordinators and Transmission Planners without a written request and to others with a reliability related need following a written request. The SDT believes this is an important considerations and not ambiguous. No change made. Table 1, bullet c under first heading, is not in conflict with the requirements. The SDT decided to include additional details in Table 1 so that it would have the basic information necessary for the planner to develop the simulations for their studies without always referring back to the requirements language. No change made.		
Madison Gas and Electric Co.	Ballot Comment	Please revise the words "System" to "system" or preface with BES System. NERC defines System to include distribution components. Plus this Standard is only applicable to PCs and TPs.

Organization	Yes / No	Question 1 Comment
MidAmerican Energy Co.	Ballot Comment	Resolve the conflict between R2 and other requirements in the TPL standards by replacing the term, "System" with "BES" in various places throughout the standard when the reference should not be to the collective generation, transmission, and distribution systems, which is the definition of the NERC Glossary term, "System". These locations are: R2.1.4, R2.1.5, R2.4.3, R2.6.2, R2.7, R2.7.1, R2.7.4, R2.8.1, R2.8.2, R3.5, R4.5, R5, and R6.
Response: Even though the capitalized term "System" includes distribution components, the SDT believes that its usage within this standard is correct because the Reliability Standards apply only to the BES. Therefore, adding additional qualifiers is not needed. No change made.		
City of Austin dba Austin Energy Lower Colorado River Authority	Ballot Comment	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In our view, a Registered Entity's Board of Directors, local public utility commission, and/or its customers should determine what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote. Regarding R2 (2.5): The value of annually assessing system stability for years 6-10 is questionable. The requirement for stability assessment in years 6-10 should be limited to new generation interconnections or planned major transmission system improvements with regional impact. The standard should clarify the 'material changes' that would necessitate stability planning assessments and documentation. Regarding the R8 requirement to distribute all Planning Assessment results to adjacent Planning Coordinators and Transmission Planners is excessive and cumbersome. Regarding R8, we suggest the following language: Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners in accordance with the requirements of the applicable Reliability Coordinator. Any Registered Entity with a reliability-related need may submit a written request for the Planning Assessment results and the Transmission Planner or Planning Coordinator shall provide the latest Planning Assessment results within 30 days of such request.
Response: The SDT incorporated the language in Footnote 12 that was approved in Project 2010-11 TPL Table 1 Footnote B. For Requirement R2, Part 2.5, the SDT believes it is important to evaluate Stability when the planners are evaluating new generation additions or changes which can be more than 5 years in the future, as required in NERC Standard FAC-001-0. The SDT discussed defining 'material change' but did not believe that such a definition was appropriate in a continent-wide standard. With the wide variety in sizes and types of systems, the number of parameters that need to be considered, etc., there are too many variables involved. No change made.		

Organization	Yes / No	Question 1 Comment
For Requirement R8, the SDT disagrees that the requirement is excessive and cumbersome and did not make the suggested change. In addition, the proposed language would place requirements on the Reliability Coordinators, who are not included in the Applicability for this standard, and they should not be involved in determining the extent of the distribution of the Planning Assessments.		
City of Green Cove Springs City of Vero Beach Fort Pierce Utilities Authority Keys Energy Services	Ballot Comment	R7is not needed and administrative in nature. Instead is should say that an entity can use as evidence another entity's study, but not in the requirement and rather in the measures. R8 is ambiguous, does the requirement require submitting the Planning Assessment only after receiving a written request, or automatic distribution to neighboring PCs and TPs without a written request, and to others with a reliability related need following a written request? Table 1, under first heading of "Steady State and Stability", bullet c should be removed since it is duplicative of the standard, and not entirely consistent with the standard (e.g., open to interpretation whereas the standard better clarifies how to study protection system operation)
Response: Requirement R7 ensures that there are no gaps between Transmission Planners or the Planning Coordinators that may cause reliability concerns. No change made. Requirement R8 requires the automatic distribution to neighboring Planning Coordinators and Transmission Planners without a written request and to others with a reliability related need following a written request. The SDT believes this is an important considerations and not ambiguous. No change made.		
Alberta Electric System Operator	Ballot Comment	With respect to R2, Part 2.7.1 which lists system deficiencies and the associated actions needed to achieve System performance, the 3rd and 4th bullet identify the following actions as being acceptable. :Installation or modification of automatic generation tripping as a response to a single or multiple contingency to mitigate Stability performance violations. :Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations. The current Alberta transmission policy does not allow for the tripping or runback of generation for a single contingency; however for multiple contingencies it is acceptable. The AESO will bring TPL-001-2, with any modifications, through the standard development consultation process in Alberta and ultimately to the Alberta Utilities Commission for approval.
Response: The list in Requirement R2, Part 2.7.1 are examples of actions that are acceptable under the NERC Reliability Standard, however, certain actions may not be acceptable under state, provincial, or other regulatory policies or requirements and are not intended to supersede other regulations or policies.		

Organization	Yes / No	Question 1 Comment
ReliabilityFirst	Yes	1. In requirement 4.3, the high speed recloser time of 1 second is too restrictive. We suggest that the time be expanded to 2 seconds to capture all reclosing operations that might impact stability studies.We interpret the use of bullet points in Requirement 4.3.1 to mean that any one of the statements can be included in the analyses. In this requirement, the use of bullet points should be removed and replaced with language that requires all of the statements to be included in the analyses. We strongly believe that the language needs amended in requirement 4.3.1, such that, we will reconsider our voting position. 2. In Table 1 labeled Steady State and Stability Performance Extreme Events we contend that the change to "relay failure" is unnecessarily limiting. The previous use of Protection system was satisfactory. Protection System is a defined term and encompasses many components that may fail and not just the relay. 3. In table 1 Steady State & Stability Performance Planning Events under P5 "non-redundant" needs to be better defined. We suggest saying in a footnote that two devices do not need to be identical in order to be redundant. Redundant relays or relay schemes need to have the same performance level to be considered redundant but do not need to be identical equipment.
Response: The SDT believes that high speed reclosing is less than one second and has not received other comments that the time should be extended. The SDT believes that the language is clear that any of the three items shall be included in the analyses, if applicable. No change made. Table 1, Extreme Events, Stability Item 2 – The SDT made the language consistent with the language in the Planning Events to ensure that the planner was evaluating Stability based on performance of the System after the failure of a relay to operate and the planner should not address the many component failures that could create different failure modes. No change made. The SDT believes that non-redundant is understood by the industry. No change made.		
Bonneville Power Administration	Yes	1. If current study is performed to assess the system, there is no need to supplement with past studies. o Suggested language for R2.2:- For the planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed and be supported by the following annual current study or qualified past studies as indicated in Requirement R2, Part 2.6 2. Load models should be consistent across the region o Suggested language for R2.4.1:- System peak load for one of the five years. System peak load levels shall include a the latest load model developed by the regional planning coordinator which represents the expected dynamic behavior of loads that could impact the study area, considering the behavior of induction motor loads. 3. R2.5 is redundant and should be deleted. It is already included in R1.1.3 and R2.6.2.4. R3.5: This

Organization	Yes / No	Question 1 Comment
		standard requires mitigating the consequences of extreme events. Requiring potentially very costly mitigation actions for very low probability event is unnecessary burden to utilities. o Suggested language for R3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. Evaluation of the risk, consequences and adverse impacts of the event(s) shall be conducted.
Response: For Requirement R2, Part 2 - If the planner chooses to annually complete current studies to assess the system, the planner is not required to use past studies, but rather is allowed to use information from past studies in lieu of completing additional current studies. No change made. For Requirement R2, Part 2.4.1 – Not all Transmission Planners and Planning Coordinators are under a regional Planning Coordinator. However, for areas with a regional Planning Coordinator, that regional Planning Coordinator may have a requirement for all Transmission Planners and Planning Coordinators in its area utilize the regional Load model. No change made. Requirement R2, Part 2.5 is not redundant since the referenced requirements do not require the planner to assess the impact in the Long-Term Transmission Planning Horizon. The requirement is that the planners assess the impact of proposed material changes and have corrective action plans to resolve concerns from those proposed changes. The planner is not required to implement the corrective action plans unless the proposed material changes occur and the issues remain unresolved. No change made. Requirement R3, Part 3.5 – The SDT does not believe that the suggested language adds clarity and is also concerned that evaluation of possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event are not required by the proposed language. No change made.		
Ameren Services	Ballot Comment	(1) Requirement R2.4.1, which addresses dynamic load modeling, has been a cause for concern because of the lack of guidance regarding reasonable induction motor representation as opposed to generic load models. While it is recognized that the effort to simulate the effects of induction motor loads is important, it is premature to include such modeling as part of the requirements for this standard. (2) For Measurements M3 and M4, there is still some question as to what is to be provided as sufficient evidence of a study. It is not clear whether the study results would be sufficient, or whether the entire powerflow, stability, or short circuit effort needs to be documented in a formal study report. For example, it is not clear whether contingency lists used in performing the study work would need to be retained as part of the documentation. (3) The standard as written is too prescriptive with regard to critical system conditions which are to be modeled. Such conditions would vary considerably for different systems across the continent. (4) Overall,

Organization	Yes / No	Question 1 Comment
		we believe that this standard does not improve the clarity of what is required, and would give additional occasions for disputes between compliance monitors and various registered entities.
Response: For Requirement R2, Part 2.4.1, the SDT believes that there are models available that account for the dynamic nature of the Load. No change made. For Measurements M3 and M4, the planner is required to retain evidence that they completed the tasks required in each sub-part of Requirements R3 & R4. These sub-parts require evidence including steady state power flow, Stability and short circuit. Further, the Contingency lists are specifically required in Requirement R3, Parts 3.4 & 3.5 and Requirement R4, Parts 4.4 & 4.5. No change made. The SDT disagrees that the standard is too restrictive about the system conditions to be evaluated. The SDT believes that this standard is a significant improvement and adds needed clarity to the existing TPL standards. No change made.		
New York State Reliability Council	Ballot Comment	1. In R1.1.5, known commitments for Firm Transmission Service, plus other Interchange that does not violate reliability constraints - it is imperative to model other Interchange after accounting for all existing and planned Firm Transmission Service to ensure that reliability-based transactions are not confused with economic interchange. 2. In R2.2.5, the current requirement language can be interpreted to require evaluation of the simultaneous unavailability of multiple long-lead-time components. Also, as a transformer outage is already evaluated as part of category P6 in Table 1, additional studies should not be required; however, spare equipment strategies could be assessed in the context of the planning assessment. 3. In R2.2, the language in this requirement is materially inconsistent with R2.1, unnecessarily requiring a current study.
Response: The SDT selected known commitments for Firm Transmission Service and Interchange to separate the planning requirements of commitments from the economic transactions. No change made. In Requirement R2, Part 2.1.5, the requirement is for the planner to make an assessment of the loss of long lead time (>1 year) equipment, unless the entity's spare equipment strategy can mitigate the issue in less than one year. Therefore, in those instances, the system will be evaluated against the system with the component out of service (multiple Contingencies). While P6 will simulate the same set of outages, the requirements of P1 and P2 are different than P6. Therefore, the planner needs to make an assessment of their system under the more stringent performance requirements. No change made. Requirement R2, Part 2.1 and 2.2 – The SDT left the requirement to conduct the annual study on one of the study years in the Long-Term Planning Horizon to ensure that the planner would conduct a new study annually to evaluate the System improvement needs in the Long-Term Planning Horizon. No change made.		

Organization	Yes / No	Question 1 Comment
Tennessee Valley Authority	Ballot Comment	1. TVA is concerned about the additional studies, modeling, and projects that must be performed to meet this proposed standard. TVA believes that this amount of work will have little overall improvement on the reliability of the BES. 2. TVA believes that the 7 year implementation plan allowed for "Raising the bar" facilities does not allow sufficient time for TVA to construct the required new facilities. TVA average time for constructing a new 500-kV line can be up to 10 years, given the lead time on ROW and following all NEPA requirements. TVA does understand that the team has language (R2.7.3) regarding the TP or PC inability to get the projects completed through no fault of its own; however, there is no safeguard that the entity will be found non-compliant if all the work cannot be accomplished in this time frame. 3. TVA believes that the footnotes b and c that allow for local load drop in the current TPL standards should still be allowed. TVA understands that this is addressed in FERC Order 693; however, the capital improvements to fix many of these issues will have little overall reliability gain for the Bulk Electric System. TVA believes that this is a local load reliability issue and not a BES concern. 4. TVA is concerned that no generating unit shall pull out of synchronism for Planning Event P1, while the standard does allow generator runback/tripping for the same event. TVA believes that this requirement is overly burdensome without providing any material improvement in system reliability. Does distributed generation have to meet the same requirements for not pulling out of synchronism as a large nuclear unit? 5. The Implementation Plan should include a five-year delay in the effective date for short circuit studies (R2 parts 2.3 and 2.8) since these studies are a new TPL requirement and are not required in the current version 0 standards.
Response: 1) The SDT appreciates the concern about additional work compared to the reliability benefits. The SDT believes that the changes within the proposed standard represent the appropriate work to ensure BES reliability. No change made. 2) The SDT believes that the Implementation Plan gives entities the necessary time to develop and implement Corrective Action Plans. No change made. 3) The SDT incorporated the language in Footnote 12 that was approved in Project 2010-11 TPL Table 1 Footnote B. No change made. 4) The SDT does not believe that any generator should pull out of synchronism for a single Contingency. No change made. 5) While short circuit study requirements may be new in the realm of mandatory enforceable standards, the SDT does not believe that they present a significant "raising of the bar" for industry. The SDT believes that prudent short circuit practices are effectively in place today to ensure safe operation of the equipment.		

Organization	Yes / No	Question 1 Comment
Therefore, no extension in the Implementation Plan was made in regard to short circuit studies.		
Florida Municipal Power Pool	Ballot Comment	A. Spare Equipment, R2.1.5 - The requirement reaches beyond the FERC directive. The directive was: "Accordingly, the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy." So, the directive is only to address planned outage, not unplanned outages. Also note that the applicability to GSUs is ambiguous. "Transmission" is defined as: "An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems." Is the "point of supply" the generator terminal, or the GSU high side terminal? B. Table 1, under first heading of "Steady State Only", bullet i is open to interpretation. Many utilities use steady state P-V analyses to study voltage stability and design UVLS systems in apart around those steady state analyses. Would this bullet essentially eliminate P-V and Q-V studies and the related use of UVLS? C. R7 is not needed and administrative in nature. Instead is should say that an entity can use as evidence another entity's study, but not in the requirement and rather in the measures. D. R8 is ambiguous, does the requirement require submitting the Planning Assessment only after receiving a written request, or automatic distribution to neighboring PCs and TPs without a written request, and to others with a reliability related need following a written request? E. Table 1, under first heading of "Steady State and Stability", bullet c should be removed since it is duplicative of the standard, and not entirely consistent with the standard (e.g., open to interpretation whereas the standard better clarifies how to study protection system operation)
Response: The SDT respectfully disagrees that the Commission directive regarding a spare equipment strategy is limited to planned outages. In Order 693, Par 1725, the Commission states in its discussion "Thus, if an entity's spare equipment strategy for the permanent loss of a transformer is to use a "hot spare" or to relocate a transformer from another location in a timely manner, the outage of the transformer need not be assessed under peak system conditions." The SDT believes FERC clearly intended the spare equipment strategy to cover a catastrophic loss of such long lead-time equipment. Further, the SDT believes it has appropriately limited this review to a small subset of the overall Planning Events – P0, P1, and P2 and for a loss that would be sustained for a year or longer. No change made. Table 1, Steady State and Stability, Item I does not restrict the use of UVLS since it only addresses equipment disconnected by end-user equipment. No change made.		

Organization	Yes / No	Question 1 Comment
Requirement R7 ensures that there are no gaps between Transmission Planners or the Planning Coordinators that may cause reliability concerns. No change made. Requirement R8 requires the automatic distribution to neighboring Planning Coordinators and Transmission Planners without a written request and to others with a reliability related need following a written request. The SDT believes this is an important consideration and not ambiguous. No change made. Table 1, Bullet c under first heading, is not in conflict with the requirements. The SDT decided to include additional details in Table 1 so that it would have the basic information necessary for the planner to develop their simulations for their studies without always referring back to the requirements language. No change made.		
Modesto Irrigation District	Ballot Comment	Both Sections 2.1.4 (seven sensitivities) and 2.4.3 (five sensitivities) require sensitivity studies to be run for all planning events and for all years specified , which increases the number of required studies beyond a reasonable and manageable limit. Also, both Section 2.1.4 and 2.4.3 specify that running studies over "...a range of credible conditions that demonstrate a measurable change in System response (performance)." must be completed, yet using "credible conditions" and also "demonstrating a measurable change in System response (performance)", may be mutually exclusive. "Measurable change in System response (performance)" is open to a broad interpretation, which increases the risk that the auditor may very likely interpret it differently than the utility system planner. The definition of the extreme events that have to be analyzed has been made nebulous, where in the existing standards they are quite specific. Requirement 2.1.5 requires the modeling of the loss of any system element that does not have a back-up or spare available sooner than 1 year, as part of the system normal state. It is not clear why using 1 year of loss of use for a system element is being used as the triggering point requiring further system enhancements. Thank you.
Response: Requirement R2, Part 2.1.4 and Part 2.4.3 do not require an unreasonable amount of sensitivities, since they both state the planner must "vary one or more of the following conditions". No change made. Requirement R2, Parts 2.1.4 and Part 2.4.3 allow the planner to use engineering judgment to determine the sensitivities to be completed. No change made. Requirement R2, Part 2.1.5 uses one year as a typical definition of a long lead time for equipment, so that the planner will assess their system performance without that equipment over peak periods. No change made.		

Organization	Yes / No	Question 1 Comment
Hydro One Networks, Inc.	Ballot Comment	Hydro One Networks is casting a negative vote. Other than a few changes related to Footnotes 9 and 12 of Table 1 and VSLs, the other changes in the proposed draft are minor. The concerns of the industry on several important issues have not been sufficiently addressed in this draft. For detailed comments please refer to our submission through the on-line comment form.
Response: The SDT posted a redline draft against the last posted draft and also posted a redline draft against the previous ballot draft. The SDT addressed important issues that were raised during the first ballot. Please see specific responses to your comments where they were submitted.		
Luminant Energy	Ballot Comment	Our most significant concerns are related to the following: (1) The requirements for Sensitivity Analysis are not stringent enough. (2)Studies should include variations in the duration and timing of transmission outages. "Anticipated" outages should be included in the studies and not just "known" transmission outages. It is our experience that only including "known" outages drastically under represents the actual number of transmission outages. (3) Major equipment outages lasting three or more months, as a result of Spare equipment strategies should be included in studies. The time limit of one year as specified in the Standard is too lax. Specific suggested language: 1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months or any known outage(s) of generation or Transmission Facility(ies) that will extend into the high stress period of the BES. 2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies (as indicated in Requirement R2, Part 2.6, as follows). Qualifying studies shall include the following conditions: Add language between 2.1.3 and 2.1.4 to account for generation limitations due to Ancillary Services. Suggested wording: All planning studies must recognize and make provision for secure delivery of each of the Ancillary Services (eg Operating Reserve). In no case shall these studies double count capacity as being available for congestion management and Ancillary Services unless processes are in place to allow for location specific deployment of these Ancillary Service reserves for congestion management purposes.

Organization	Yes / No	Question 1 Comment
		2.1.4 (bullet 7) Duration and timing of anticipated Transmission outages such as required maintenance activities. 2.1.4 (bullet 8 added) Reasonable variations of anticipated generator availability after accounting for equivalent forced outage rate. 2.1.5 If an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that would cause an outage of three months or more, (such as a transformer) the impact of this outage on System performance shall be studied. 2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: â€¢ Load level, Load forecast, or dynamic Load model assumptions. â€¢ Expected transfers. â€¢ Expected in service dates of new or modified Transmission Facilities. â€¢ Reactive resource capability. â€¢ Generation additions, retirements, or other dispatch scenarios. â€¢ Duration or timing of anticipated Transmission outages such as required maintenance activities. â€¢ Reasonable variations of anticipated generator availability after accounting for equivalent forced outage rate. 2.4.4. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled. 2.4.5 If an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that would cause an outage of three months or more, (such as a transformer) the impact of this outage on System performance shall be studied.
Response: 1) The sensitivities addressed in Requirement R2, Parts 2.1.4 and Part 2.4.3 allow the planner to use engineering judgment to determine the sensitivities to be completed. Since sensitivities are included to ensure that the planner evaluates alternative conditions, it is necessary to allow flexibility to evaluate different types of changes that could occur. No change made. 2) Reliability Standards are the minimum requirements and if conditions warrant, entities may add additional outages to be evaluated in their planning studies.		

Organization	Yes / No	Question 1 Comment
No change made. 3) Requirement R2, Part 2.1.5 uses one year as a typical definition of a long lead time for equipment, so that the planner will assess their system performance without that equipment over peak periods. No change made. For Requirement R2, Part 2.1, the SDT did not add language between Parts 2.1.3 and 2.1.4 to account for generation limitations due to Ancillary Services. The proposed addition assumes a particular market structure and that market structure is not uniform across North America. The "projected System conditions" in Requirement R1 would be violated if an entity double counted its Ancillary Services. No change made. Requirement R2, Part 2.1.4, bullet 7 & 8 are examples of sensitivities and the examples provided would address those contemplated by the SDT. No change made. Requirement R2, Part 2.1.5 uses one year as a typical definition of a long lead time for equipment, so that the planner will assess their system performance without that equipment over peak periods. No change made. Requirement R2, Part 2.4.3 – Since the five conditions for sensitivities have been vetted through six postings, the SDT did not add the two proposed conditions. No change made. Requirement R2, proposed 2.4.4 – Since the known outages are already included in the cases, as required by Requirement R.1, Part 1.1.2, there is not a need to require specific studies that include them – No change made. Requirement R2, proposed Part 2.4.5 – The proposed requirement is already contained in Requirement 2, Part 2.1.5 and does not need to be duplicated here. The SDT has used the typical one year time period to define long lead time for equipment and believes that three months is too short a time period for this requirement. No change made.		
MidAmerican Energy Co.	Ballot Comment	Regarding Requirement 8, there is not a significant risk to the reliability of the BES if an annual Planning Assessment is not distributed to another entity or if a documented response to Planning Assessment comments is not provided within 90 days of a request. Requirement 8 is an administrative requirement that adds little to improve reliability. We recommend that the VRF for Requirement 8 remain "Low", rather than be changed to "Medium".
Response: The SDT believes that sharing the Planning Assessments with adjacent Transmission Planners and Planning Coordinators is an important component of the planning process. The SDT did not change the VRF. The previous change reflects the latest guidelines on the topic.		

Organization	Yes / No	Question 1 Comment
Consolidated Edison Co. of New York	Ballot Comment	Requirement R1.1.5: Delete "and Interchange." The inclusion of other than Firm transactions (e.g. economic transactions in Interchange) in a base power flow case utilized for planning/designing the interconnected system blurs the boundary between reliability issues and purely economic issues. Reliability issues are issues that a Transmission Owner (TO) must address for the purpose of meeting its load demand, and are defined by the application of well established reliability standards and criteria that are based on the electrical characteristics of the interconnected system, but without economic considerations. Instead, economic transactions are types of transactions that a TO may enter into once its load obligations are met, and are evaluated based on economic parameters that are markedly different from the aforementioned reliability criteria (e.g. congestion costs). Modeling all types of transactions in a power flow case without distinction detracts from the accuracy and validity of either assessment (reliability and economic).
Response: Requirement R1, Part 1.5 does not require Interchange for economic purposes. The requirement is to represent "Known commitments". No change made.		
Platte River Power Authority	Ballot Comment	Stability requirements R4.1.2, along with the second and third bullets of R4.3.1, could be misunderstood to require the development of comprehensive relaying models for all Facilities represented in the stability model. These requirements should be made clear that Stability studies are to simulate the effects of relaying (tripping certain Facilities) and not require relaying models to trigger and cause the effects.
Response: The SDT language in Requirement R4, Part 4.3.1 states "The analyses shall include the impact of subsequent" and does not require comprehensive relaying models. However, it does require that the planner take into account the effects of System Protection on System performance. No change made.		
GDS Associates, Inc.	No	1. Footnotea. Footnote should state "Draft 7" instead 2. Requirement R1a. Time Horizon should include both Near-term and Long-term Planning3. Requirement R2a. Time Horizon should include both Near-term and Long-term Planningb. Requirement R2, Part 2.1 o The inclusion of the words "For the Planning Assessment" it seem unnecessary as long as main requirement R2 is only about the Planning Assessment and nothing else. o The term "Qualifying studies" from the last sentence is referring to the qualified past studies, or the annual studies, or both actually? Suggesting adjusting the verbiage so it would not create confusion. o Subpart 2.1.4- Requirement R2, Part 2.1.1 and Part 2.1.2 are referring to system conditions, not studies. The second sentence may be subject of non-objective interpretations and may generate burdensome and

Organization	Yes / No	Question 1 Comment
		unrealistic amount of work. The requirement should state instead "For each of the system conditions described in Requirement R2, Part 2.1.1 and Part 2.1.2, the studies shall include sensitivity cases utilized to demonstrate whether there is any significant impact due to changes on the basic assumptions used in the model. The analysis, by case, may contemplate varying one or more of the following conditions:" o Subpart 2.1.5- We suggest adjusting the time threshold of potential equipment unavailability in order to be consistent with the time frame for the "known Transmission outages". c. Requirement R2, Part 2.2 o The inclusion of the words "For the Planning Assessment" it seem unnecessary as long as main requirement R2 is only about the Planning Assessment and nothing else. o While the Near-Term portion of the Planning Assessment details the premises of the study, the Long-Term is lacking in such thing. d. Requirement R2, Part 2.3 o Although both the steady-state and transient stability studies are required for the Near-Term and Long-Term, the short-circuit study is required only for the Near-Term. This is big disconnect, because there can be stability analyses conducted without a short-circuit assessment. o Breakers should be checked for their breaking capability, as well as to withstand the fault. All other disconnecting equipment, as well as current transformers in particular shall be also verified for their withstand capabilities. The current statement should be replaced with "The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term and Long-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to assess performances of transmission elements affected by a potential increase of short-circuit contributions to fault" e. Requirement R2, Part 2.4 o The inclusion of the words "For the Planning Assessment" it seem unnecessary as long as main requirement R2 is only about the Planning Assessment and nothing else. o Similar with 2.1, the last sentence should read "The studies should include the following conditions:" o Subpart 2.4.1- We believe that the dynamic behavior of the load cannot be accurately estimated beyond current time. We are concerned about the effort required to ascertain the dynamic response of the load. As for the "Loads that could impact the study area" the standard doesn't include any directions in how an entity will identify these loads. Perhaps the standard should provide guidelines to determine which loads would impact the study area. o Subpart 2.4.3- See comments from Subpart 2.1.4f.

Organization	Yes / No	Question 1 Comment
		Requirement R2, Part 2.5 o The inclusion of the words "For the Planning Assessment" it seem unnecessary as long as main requirement R2 is only about the Planning Assessment and nothing else. g. Requirement R2, Part 2.6 o Subpart 2.6.2- We agree with the suggested changes as responding to previous commentsh. Requirement R2, Part 2.7 o Subpart 2.7.1- We disagree with the implemented changes. The standard should not include examples. If needed, a white paper can accompany the standard. We suggest adjusting the last sentence to read “Such actions may include, but are not limited to, the following:” i. Requirement R2, Part 2.8 o This should apply to all disconnecting equipment and CT in particular with respect not only to their interrupting duty, but to their withstand capabilities also. See comment on Part 2.3.4. Table 1a. Footnote 9 o With respect to the Curtailment of Firm Transmission Service we suggest SDT to revise the language in order to be consistent with the Implementation Plan. 5. Measure M1a. This measure it is hard to read. For simplicity, we suggest adjusting this measure to read "Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, and the models reflect the System conditions in accordance with Requirement R1." 6. Measure M7a. The measure encompasses the particular scenario where the parties involved have reached an agreement for performing the required studies. In order to cover situations where the parties have not reach an agreement, the measure should read "Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies all individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7." 7. Compliancea. Data retention o The 5th bullet should read "The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5." o The 6th bullet should read "The documentation specifying the criteria or methodology used to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding since the last compliance audit in accordance with Requirement R6 and Measure M6." o The 7th bullet should be reworded in accordance with suggested changes at M7.

Organization	Yes / No	Question 1 Comment
Response: 1. This is the sixth time that this standard has been posted for comments. The reference to a seventh posting on the web site is because the standard was posted once for informational purposes. No change made. 2. Requirement R1. Per the standards process, the Time Horizon for this standard is Long-term Planning; which includes both the Short-Term and Long-Term Planning Horizon. No change made. 3. Requirement R2, Part 2.1 – "For the Planning Assessment" were added in a previous draft for clarity – No change made. Requirement R2, Part 2.1 – "Qualifying Studies" could be either or both – No change made. Requirement R2, Part 2.1.4 – The requirement is for the planner to have a completed study for each of the conditions in Parts 2.1.1 & 2.1.2. The requirement to complete sensitivity studies has been included to ensure that the planner tests their system by stressing the system beyond what is within their base cases. Since the System conditions vary across North America, the relevant sensitivities are best determined by the planner. The proposed language does not convey the same intent. No change made. Requirement R2, Part 2.1.5 – The SDT determined that the impact of "known outages …" does not directly coorelate to the entity's spare equipment strategy. No change made. c. Requirement R2, Part 2.2 – "For the Planning Assessment" were added in a previous draft for clarity – No change made. Requirement R2, Part 2.2 - The SDT limited the requirements in the Long-Term to allow the planner more latitude in that time frame, while ensuring that the planner conducted a Long-Term assessment of their portion of the BES. No change made. d. Requirement R2, Part 2.3 - A planner may choose to complete a short circuit study in conjunction with its Long-Term Steady Steady State and Stability studies, but the SDT does not believe that the planner should be required to complete a short circuit study in the Long-Term Transmission Planning Horizon. No change made. The SDT agrees that any system element must be able to withstand the stresses that they may be subjected to, however, the standard must ensure BES reliability. Therefore, the SDT limited the requirement to the breakers since they protect other system elements from the fault. No change made. e. Requirement R2, Part 2.4 – "For the Planning Assessment" were added in a previous draft for clarity . The SDT does not believe that replacing the last sentence as proposed adds any additional clarity. No change made. Requirement R2, Part 2.4.1 – The SDT believes that the planner must consider the dynamic behavior of its System Load and develop a representative model, however, the SDT should not dictate "how" the Load should be modeled. Those specific details must be included in the model by the individual planner. No change made. Requirement R2, Part 2.4.3 - The requirement is for the planner to have a completed study for each of the conditions in Parts 2.4.1 & 2.4.2. The requirement to		

Organization	Yes / No	Question 1 Comment
complete sensitivity studies has been included to ensure that the planner tests their system by stressing the system beyond what is within their base cases. Since the System conditions vary across North America, the relevant sensitivities are best determined by the planner. The proposed language does not convey the same intent. No change made. Requirement R2, Part 2.5 – "For the Planning Assessment" were added in a previous draft for clarity – No change made. Requirement R2, Part 2.7.1 – The SDT has included limited examples where we believe that additional clarity is needed. Since the list is clearly marked as "examples", the SDT believes the phrase "but not limited to", is not required. No change made. Requirement R2, Part 2.8 - The SDT agrees that any system element must be able to withstand the stresses that they may be subjected to, however, the standard must ensure BES reliability. Therefore, the SDT limited the requirement to the breakers since they protect other system elements from the fault. No change made. The Implementation Plan has been revised as suggested although the SDT wishes to point out that no dates have been changed. Measure M1 – While the suggested langauage is shorter it does not contain all of the terminology of the matching requirement and thus violates a basic guideline for measures. No change made. 6. Measure 7 – The suggested langauge doesn't change the assumed scenario cited and provides no additional clarity. No change made. 7. Data retention, 5th bullet – The SDT agrees that for consistency the suggested terms should be added so that this bullet matches up with the language of the requirement. DR, 5th bullet: The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5. Data retention, 6th bullet - The SDT agrees that for consistency the suggested terms should be added so that this bullet matches up with the language of the requirement. DR, 6th bullet: The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6. Data retention, 7th bullet – The SDT declined to make the suggested changes to Requirement R7 so no change is necessary for Measure M7.		
United Illuminating ISO New England Inc	No	a. 2.6.2 - What was the intent of this change? The old language seemed to work. The language should not be changed from the previous version. b. For 2.8.2 - Was the phrase changed to reflect modifications of facilities? If so the requirement should be

Organization	Yes / No	Question 1 Comment
		modified to read "Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures with respect to modifications of facilities. Otherwise the requirement is unclear. c. For Section R8.1 - the proposed requirement conflicts with a long standing stakeholder process in our area which posts study results and allows comment within a defined period before studies are finalized. If this section is to be retained then it should be modified to only allow comments on Transmission studies less than one-year old. Requirement 8 and 8.1, should be revised to include a limit on the comment period as follows: If a recipient of the planning assessment final results provides documented comments on the results within 90 days of receipt, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments. d. With respect to Table 1 - We suggest adding an event 6 to P1 to address the contingent loss of back to back HVDC Facilities. If not added to P1 then this event needs to be added somewhere in the standard. e. We don't agree with footnote 7 specifying that only one end of the line should be open for this condition. If the SDT is to keep this concept make P2 event 1 simply say "Opening one end of a line section w/o a fault" and delete the footnote. The existing footnote is unclear due to the use of language such as "possibly".

Response: a. Requirement R2, Part 2.6.2 was revised in response to comments that a "qualified" study may have material changes remote from the area of study and the previous version would not have allowed the use of that study. No change made.

b. Requirement R2, Part 2.8.2 – The added phrase – "of identified System Facilities and Operating Procedures" was added to ensure that it was clear what "implementation status" was referencing. No change made.

c. Requirement R8, Part 8.1 - The SDT does not believe that the requirement conflicts with other stakeholder processes and does not believe that a time limit is required. Beyond responding to the comment, other actions by the planner are at the discretion of the planner. No change made.

d. Table 1, P1 back to back DC - The contingent loss of back to back HVDC facilities is included as a transformer. Footnote 5 states, in part, that "Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. Therefore, the SDT has not explicitly included back-to-back HVDC as a separate Contingency. No change made.

e. Table 1, footnote 7 – The SDT added the footnote to further explain its intent for P2-1 and to ensure that the planner assess the voltage of a load bus that was on a radial line. The word "possibly" was used since having load on a radial is not always the outcome of opening one end of a line section. No change made.

Organization	Yes / No	Question 1 Comment
Northeast Utilities	No	Definition of Terms Used in the StandardThe definitions of "Near-Term Transmission Planning Horizon" and "Year One" have been deleted from the standard, yet they are still used in draft 7. NU is concerned about voting in favor of this standard with these terms being defined by another project without a full discussion of the impact to this proposed standard. NU suggests repeating the definitions in this proposed standard. Requirement R1NU believes that the Normal System Conditions as stated in Requirement R1 should establish the base case conditions to be used for the assessment studies. However, a more detailed guideline for developing base cases should be addressed by the requirements. By just modifying the language of requirement R1 to indicate that "P0" constitutes the initial system conditions does not address this concern in Draft #7. A more detailed guideline for base case development is needed. Requirement R8The wording in requirement R8 needs to be amended to restrict comments to the most recent assessment only, for a limited period (say 3 months) after its release. The current wording appears to offer unlimited opportunity to comment on past assessments, long after their release. Footnote 7It appears there is a discrepancy between Footnote 7 and Event P2-1. Footnote 7 could be eliminated by rewording Event P2-1 as follows: "Opening one end of a line section w/o a fault". Footnote 12NU did not agree with the clarification of Table 1 Footnote B of TPL-002 and did not vote for its approval. Therefore, NU does not agree with the same clarification being applied here for Non-Consequential Load Loss. For reference, below is NU's comment on TPL-002 Table 1, Footnote B:"The revised language of Footnote b suggests that non-consequential demand interruption (load that is not directly served by the elements removed from service as a result of the contingency) could be used to mitigate reliability concerns arising from NERC Category B contingency events (i.e., single element contingencies). This language seems to encourage operational workarounds and adds burdens for operators of the system. NU believes this is not consistent with planning a highly reliable bulk electric system and thus does not support this weaker language". General commentNU believes that a standard should contain statements and requirements that are direct and measurable. TPL-001-2 should not be an exception to this rule. Therefore, statements like "An objective" which appears in Footnotes 9 and 12 shall not be used.
Response: Definitions of Near-Term Transmission Planning Horizon and Year One are now approved NERC Glossary Terms and are no longer needed in this proposed standard. The definitions have been vetted through this process through the 1st six postings of this standard and were approved by the Commission in		

Organization	Yes / No	Question 1 Comment
FAC-013. With the wide variety of system conditions and market structures across North America, the SDT chose not to establish a single set of conditions for a base case. Each planner shall establish their base case that meets their needs and their other regulatory requirements. No change made. Requirement R8, Part 8.1 - The SDT does not believe that a time limit for commenting on a Planning Assessment is required. Beyond responding to the comment, other actions by the planner are at the discretion of the planner. No change made. Table 1, P2-1 – The SDT does not agree that there is a discrepancy between the Contingency and Footnote 7. Footnote 7 was utilized to clarify a specific condition that would need to be evaluated as a part of P2-1. No change made. Footnotes 12 and 9 were translated from the BOT approved language from TPL-002-1, Footnote 'b'.		
Electric Reliability Council of Texas, Inc.	No	ERCOT ISO believes that the revisions do not go far enough in addressing previously submitted comments. As written this standard would require restructuring of the functions in the ERCOT Region because several requirements are being assigned to the PC that are currently performed only by the TPs. It would not provide any reliability benefits to have the ERCOT PC assume these functions. Specifically, the following requirements should be modified: R2.1.5 should be clarified to be applicable to TPs only since the ERCOT PC does not have the information necessary to perform this analysis; R2.3 and R2.8 should be clarified to be applicable to TPs only since the ERCOT PC does not perform this analysis (it is performed by the TPs in ERCOT); R4.1.2 should be clarified to only apply to TPs because the ERCOT PC does not have the modeling information necessary to perform this analysis. Additionally, R2.1.4 and R2.4.3 should be removed because the requirements are subjective and there are no actions prescribed to be taken based on the sensitivity results. The Load model requirement should be removed from R2.4.1 because this would be better addressed in a MOD standard. Alternatively, R2.4.1 should be rewritten as "System peak Load for one of the five years with expected dynamic load models." A concurrent requirement should be incorporated to mandate DSPs and TPs to supply dynamic load model data to the PC to perform the required studies.
Response: Requirement R2, Part 2.1.5 requires that studies be completed based on an entity's spare equipment strategy. The ERCOT Planning Coordinator could utilize Requirement R7 to document the individual and joint responsibilities for these studies and document the outcome of these studies. No change made.		

Organization	Yes / No	Question 1 Comment
Requirement R2, Parts 2.3 and 2.8 – The ERCOT Planning Coordinator could utilize Requirement R7 to document the individual and joint responsibilities for these studies and document the outcome of these studies. No change made. Requirement R4, Part 4.1.2 requires the Transmission Planner and Planning Coordinator to accurately represent the behavior of the system if a generator pulls out of synchronism. Therefore, this information is needed by each Transmission Planner and Planning Coordinator to ensure that the appropriate system response is modeled. No change made. Requirement R2, Parts 2.1.4 and R2.4.3 require the completion of sensitivity studies and allows the planner the discretion on which variables to vary. In addition, Requirement R2, Part 2.7 requires Corrective Action Plans to address issues that are present in multiple sensitivities. The MOD standards only require data to be submitted, and this requirement allows the variation of the forecasted load as one of the possible sensitivities. No change made. Requirement R2, Part 2.4.1 – The SDT believes that the drafted language more clearly explains the requirement than the proposed language. This requirement is for the planner to utilize models that reflect the dynamic nature of the load with an expectation that the planner will obtain the required information in Requirement R1 to determine how it is modeled. No change made.		
Independent Electricity System Operator	No	IESO is generally supportive of the draft of TPL-001-2 as evidenced by our previous AFFIRMATIVE vote during the last ballot. Further, IESO also supported the revisions to Footnote 'b' to Table 1 of the TPL standards under Project 2010-11. That revision was balloted and approved by the ballot pool in February 2011 and filed with FERC for approval in March 2011. The revised footnote has been incorporated into the current draft of TPL-001-2 as Footnotes 9 and 12 but the Commission, by letter to NERC dated May 17, 2011, has requested NERC to provide supplemental information before the revised Footnote 'b' could be approved. In light of FERC's request and the uncertainty regarding the final provisions of these footnotes, coupled with the ongoing work on Project 2010-17 for the revision of the BES definition and development of an Exception Process and the impact that may have, we respectfully suggest that the drafting team delay further work on TPL-001-2 pending FERC's ruling on NERC's petition seeking approval of the transmission planning standards that contain the revised Footnote 'b' to Table 1.
Response: The SDT believes that it is important to continue with the approval of this standard. If FERC directs changes based on TPL-002-1, Footnote 'b', they will be addressed with this project.		
New York Independent System Operator	No	If the following recommended revisions are made to the requirements listed, subject to other unforeseen material changes, NYISO would no longer oppose the approval of this standard. Requirement R2.1.5 The current requirement language can be interpreted to require evaluation of the simultaneous unavailability of multiple long-lead-time components. Also, as a transformer outage is already

Organization	Yes / No	Question 1 Comment
		evaluated as part of category P6 in Table 1, additional studies should not be required, however spare equipment strategies could be ASSESSED in the context of the Planning Assessment. NYISO thus recommends this requirement be revised as follows: R 2.1.5 When an entity's spare equipment strategy could result in the unavailability of a major Transmission component that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed with due regard to categories P0, P1, and P2 identified in Table 1. Requirement R2.2The language in this requirement is materially inconsistent with R2.1, unnecessarily requiring a current study. NYISO requests that R2.2 and the sub-requirement be revised as follows:2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies shall include: 2.2.1. Expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected. Requirement R8.1There is an apparent open ended time frame afforded report recipients in their review of any Planning Assessment. This requirement should apply to only the most recent Planning Assessment. NYISO thus recommends the following language: 8.1. If a recipient of the most recent Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.
Response: Requirement R2, Part 2.1.5 is not the same as P6 – Table 1, however, the analysis for P6 could be utilized, if the results show there will not be load loss. Except for the outages being evaluated under P0, P1, and P2 for individual components out of service without a long term spare, the requirement does not require the evaluation of the simultaneous loss of multiple long lead time components. The SDT believes that the language "with due regard to" is not as clear as the proposed language. No change made. Requirement R2, Part 2.1 and 2.2 – The SDT left the requirement to conduct the annual study on one of the study years in the Long-Term Planning Horizon to ensure that the planner would conduct a new study annually to evaluate the System improvement needs in the Long-Term Planning Horizon. No change made. Requirement R8, Part 8.1 - The SDT does not believe that a time limit for commenting on a Planning Assessment is required. Beyond responding to the comment, other actions by the planner are at the discretion of the planner. No change made.		
NBSO	No	Items that, if not addressed, will likely cause a negative vote from NBSO:R2.2 differs from R2.1, R2.3, R2.4 and R2.5 since R2.2 does not state that the annual assessment of the Long-Term Transmission Planning

Organization	Yes / No	Question 1 Comment
		Horizon portion of the steady state analysis can be supported by qualified past studies. Likely this omission is an oversight, but unresolved it can cause significant burden with little gain in reliability. Individual items that, if not addressed, may not cause NBSO to vote Negative, but in combination may result in a negative vote:The language of requirements R2.1.4 and R2.4.3 allowing the performance of one or more sensitivities appears to be inconsistent with language in R2.7.2 that requires multiple sensitivities to determine if actions to resolve performance deficiencies are necessary. R7 (and M7) seem to indicate that the PC is ultimately responsible for determining the individual and joint responsibilities for performing the required planning assessment studies, with the expectation to consult and come to agreement with its corresponding TPs, but this interpretation is not clear. The correct interpretation of this requirement is important for resolving situations where a PC and TP do not agree on the assignment of responsibilities. Suggested wording: "Each PC shall work in conjunction with each of its TPs to determine and identify..." The language in R8 is unclear. One point of confusion relates to which entity is responsible for sending their Planning assessments to other entities. For example, who does a PC distribute their planning assessments to?:-Adjacent PC? (Seems to be clearly addressed)-TPs within its PC footprint? (Not clearly covered by the language in R8)-TPs adjacent to its PC footprint (Not clear if this is the responsibility of the PC, TP or both)In addition, the language in R8.1 appears to offer unlimited opportunity to request response to comments on any past assessment, long after their release. Providing limits in the langue of R8.1 is recommended in order to avoid unnecessary burden on PCs and TPs for little gain in reliability or constructive stakeholder involvement.
Response: Requirement R2, Part 2.1 and 2.2 – The SDT left the requirement to conduct the annual study on one of the study years in the Long-Term Planning Horizon to ensure that the planner would conduct a new study annually to evaluate the System improvement needs in the Long-Term Planning Horizon. No change made. Requirement R2, Parts 2.1.4 and 2.4.3 are not inconsistent with Requirement R2, Part 2.7.2. With the various requirements, the planners are required to conduct multiple sensitivities. Therefore, Requirement R2, Part 2.7.2 could be used when the results of these multiple sensitivities identify common concerns. No change made. Requirement R7 – The SDT believes that the current language addresses the various arrangements that could exist between the Planning Coordinator and Transmission Planner, better than the proposed language. If agreement is not reached, both the Planning Coordinator and the Transmission Planner would be required individually to perform all of the required studies. No change made.		

Organization	Yes / No	Question 1 Comment
Requirement R8 – Each planner is required to distribute its Planning Assessment to all adjacent planners (Transmission Planners and Planning Coordinators). Requirement R8, Part 8.1 - The SDT does not believe that a time limit for commenting on a Planning Assessment is required. Beyond responding to the comment, other actions by the planner are at the discretion of the planner. No change made.		
Hydro One Networks Inc.	No	Other than a few changes related to Footnotes 9 and 12 of Table 1 and VSLs, the other changes in the April 15, 2011, draft are minor. The concerns of the industry on several important issues have not been sufficiently addressed in this draft (see our response to Question 3).
Response: Please see the response to Question 3.		
Manitoba Hydro	No	-R2.1.4 and R2.4.3: 'Expected transfers' should be replaced with 'Firm Transmission Service and Interchange' to correlate to R1 (R1.1.5 states 'Known commitments for Firm Transmission Service and Interchange' must be represented in system mode
Response: Requirement R2, Parts 2.1.4 and R2, Part 2.4.3 use the more inclusive term - Expected transfers – for sensitivities. The SDT does not want to unnecessarily restrict the transfers that could be evaluated as a part of a sensitivity study. No change made.		
Associated Electric Cooperative Inc	No	R2.4.1:The SDT has put a stronger emphasis on dynamic load behavior in stability studies (FIDVR, induction motor loads, etc) to be included in the peak models. The standard does indicate that "An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable." We feel that this should be clarified to ensure that the current modeling processes address what NERC desires with this requirement. At a minimum, we recommend that a grace period be implemented to account for any regional modeling practices which need time to implement dynamic load behavior per the draft standard. R2.5:It is our understanding that the Long-Term Transmission Planning Horizon does not require the sensitivity analysis which is required in R2.4 for the Near-Term Transmission Planning Horizon for the stability portion of the studies. R2.7:It is our understanding that Corrective Action Plan(s) do not need to be developed for performance violations observed in the sensitivity analysis (steady state and stability) unless the violation is observed in several sensitivities as it is indicated in R2.7.2: "Include actions to resolve performance deficiencies indentified in multiple sensitivity studies or provide rationale for why actions were not necessary". We feel

Organization	Yes / No	Question 1 Comment
		that this needs to be further clarified. R3.3.1:This requirement indicates that steady state analysis should include the effect of ride-through voltage limitations of generating units. We are having difficulty seeing how this is a steady-state issue. Generally one would expect a generator to experience ride-through voltage issues during faults. Per Table 1, P1.1 already require generator outages be taken - wouldn't that cover this issue? We feel that this needs to be further clarified. R3.4.1:This requirement states that "Transmission Planners shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list". We feel that the coordination requirement should be removed from the standard as this will result in a massive increase in workload/time required to perform the TPL studies. AECI has several ties to adjacent Transmission Planners and Planning Coordinators - it will be a very time intensive task to coordinate with all of these parties. If the standard wants to ensure that the Contingencies overlap - we can agree to that, however we feel that the SDT needs to give some firm clarity on how far to go with it (how many buses away, only include ties, etc?). R4.1.2:We would like clarification on what is mean by "apparent impedance swings". R4.3.1:Is the intent of the SDT to require that generic or actual relay models be added to the stability models? We feel that this needs to be further clarified. R8:This requirement states that the Planning Assessments shall be distributed within 90 days of their completion to adjacent Planning Coordinators, Transmission Planners, and functional entities that have a reliability need (3rd Interconnection Customers?). We do not agree with the mandatory requirement of distributing the results of our TPL studies: We consider this information to be CEII We can agree to distribute the results upon request, but do not agree with the 30 day timeframe as more time will be needed to sign applicable Non-Disclosure Agreements, etc.
Response: Requirement R2, Part 2.4.1 – The SDT has allowed flexibility for the planner to determine how to meet this requirement. The implementation plan has allowed at least 24 months for coordination and development of modeling practices. No change made. Requirement R2, Part 2.5 – Sensitivities are not required for years in the Long-Term Transmission Planning Horizon. Requirement R2, Part 2.7 – Your understanding of the need for Corrective Action Plans to address deficiencies identified by sensitivity studies is correct. The SDT believes that the proposed language is clear. No change made.		

Organization	Yes / No	Question 1 Comment
Requirement R3, Part 3.3.1 – Within the steady state analysis, the planner is required to represent the actual state of each generator based on the system response to a contingency and this includes voltage ride-through for generators. Table 1, P1-1 does not address this issue, since it is only a single generator outage and the requirements of Requirement R3, Part 3.3.1 could be a generator out of service (because it doesn't ride-through) as a result of a more severe contingency. No change made. Requirement R3, Part 3.4.1 – The SDT added the requirement to coordinate Contingency lists to ensure that these lists do not omit Contingencies on adjacent systems that may cause performance concerns. The SDT believes that most planners are already considering outages on the fringes of their neighbors system to ensure that they meet the performance requirements. The SDT does not agree that this will be a massive increase in workload for planners. No change made. Requirement R4, Part 4.1.2 – The "apparent impedance swing" is the trajectory of changes in the apparent impedance seen by a distance relay for various system and fault conditions. In the case contemplated in Requirement R4, Part 4.1.2, it is the trajectory seen by the distance relay for the initial fault and the subsequent generator(s) pulling out of synchronism. If that trajectory were to come within the tripping characteristic of the relay for a sufficient length of time, the relay would cause its associated line to trip. No change made. Requirement R4, Part 4.3.1, bullet 3 – The planner may reflect the effects of either generic or actual relay models. No change made. Requirement R8 – The SDT believes that 30 days should be adequate time to get the necessary agreements in place to make the Planning Assessment available. No change made.		
National Grid	No	R2.8.2We recommend this requirement be clarified with the following modification: The Corrective Action Plan shall:2.8.1. List System deficiencies and the associated actions needed to achieve required System performance. 2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of planned modifications to System Facilities and Operating Procedures.
Response: The proposed change of "identified" to "planned modifications to" does not change the proposed requirement or add clarity. No change made.		
Consolidated Edison Co. of NY, Inc.	No	Requirement R1.1.5: Delete "and Interchange." The inclusion of other than Firm transactions (e.g. economic transactions in Interchange) in a base power flow case utilized for planning/designing the interconnected system blurs the boundary between reliability issues and purely economic issues. Reliability issues are issues that a Transmission Owner (TO) must address for the purpose of meeting its load demand, and are defined by the application of well established reliability standards and criteria that are based on the electrical characteristics of the interconnected system, but without economic considerations. Instead, economic transactions are types of transactions that a TO may enter into once its load obligations are met, and are evaluated based on economic parameters that are markedly different from the aforementioned reliability criteria (e.g. congestion costs). Modeling all types of transactions in a power flow

Organization	Yes / No	Question 1 Comment
		case without distinction detracts from the accuracy and validity of either assessment (reliability and economic).
Response: Requirement R1, Part 1.5 does not require Interchange for economic purposes. The requirement is to represent "Known commitments". No change made.		
Nebraska Public Power District	No	The existing TPL-001 through TPL-004 Standards and Requirements are clear and concise. The new merged TPL-001-1 Standard and Requirements is no longer clear and concise. Further, the modification made to allow an SPS to trip a remote generator for an N-1 (TPL-002) type of event is a degradation of system reliability. Transmission system facilities should be added to maintain stability for a new generator interconnection for any N-1 Category B event. An SPS should not be relied upon for a Category B event, an SPS should only be allowed for Category C & D (TPL-003 & TPL-004) type events.
Response: The SDT believes that there is much less ambiguity in the proposed standard than the existing standards. There is no restriction in the existing TPL-002-1 on a planner's ability to utilize an SPS to trip a remote generator for a Category B event and the SDT did not change this. No change made.		
Northeast Power Coordinating Council	No	The wording of Part 1.1.2, "known outages...with a duration of at least 6 months" should be revised to "...at least 1 year". Also for consideration is that "known outages...with a duration of at least 6 months" are dealt with in operational studies rather than planning studies. Any adverse impacts that these outages might have are mitigated by operational decisions rather than planning decisions within a 6 month horizon. Moving this requirement out of the TPL Standard to an operational standard should be considered. Make the wording consistent between 2.1 and 2.2 as it relates to qualified past studies. Specifically:Parts 2.1.2, 2.1.4, 2.1.5The language of requirements 2.1.4 and 2.4.3 allowing the performance of one or moresensitivities appears to be inconsistent with language in 2.7.2. 2.7.2 requires multiplesensitivities to determine if actions to resolve performance deficiencies are necessary.Will varying only one measurable quantity several times in multiple simulationssatisfy multiple sensitivity studies or just one sensitivity study? The numbers and types of required sensitivity studies is unclear, and subject to interpretation by PCs and TPs. The current wording in Part 2.1.5, "spare strategy", appears to be open-ended regarding the number of

Organization	Yes / No	Question 1 Comment
		permutations to be analyzed. It should be restricted to assessing only one piece of equipment being unavailable or outaged at a time. 2.1.5 should be consistent with R2 and 2.1 regarding the use of the terms assessment and studies. As with the preceding comment regarding Part 1.1.2, moving this requirement out of the TPL Standard and to an operational standard should be considered.It is unclear if the last sentence of R2.1.5 allows for the curtailment of firm transmission service before the application of category P0, P1 and P2 events. This last sentence states:"...with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment." The wording in Part 2.2 "be supported by the following annual current study, supplemented with qualified past studies" should be replaced with the similar statement in Part 2.1: "be supported by current annual studies or qualified past studies". Part 2.7.1 lists potential system actions to address System deficiencies. It is suggested that this list be moved to a guideline or white paper. The wording in Part 8.1 needs to be amended to restrict comments to the most recent assessment only. Contingencies on back to back HVDC installations are not mentioned in the standard. The treatment of combined cycle facilities (all units in outage?) needs to be clarified, as well as Footnote 7 of Table 1 requiring clarification. In Table 1, Event 1 of Category P2 and related Footnote 7 are not clear because of the use of the word "possibly". If the intension is to simulate the line end opening condition of tapped lines, this should be clearly stated in the table (without reference to "Opening of a line section" and use of different language in the footnote). From Table 1b: "Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0." Firm Transmission Services Loss is also acceptable and should be added (particularly in P1 loss of a single pole of a DC line for which the transfer is reduced accordingly to the remaining pole capability).
Response: Requirement R1, Part 1.1.2 does not address the outages in the operational time frame. However, if a planner knows that a System component is going to be out of service for more than 6 months, the planner must model the component outage in the appropriate models and evaluate the System to ensure that the System meets the performance requirements of the standard. No change made. Requirement R2, Part 2.1 and 2.2 – The SDT left the requirement to conduct the annual study on one of the study years in the Long-Term Planning Horizon to		

Organization	Yes / No	Question 1 Comment
ensure that the planner would conduct a new study annually to evaluate the System improvement needs in the Long-Term Planning Horizon. No change made. Requirement R2, Part 2.1.4 and 2.4.3 each require two studies on sensitivity cases, but more studies can be performed by the planner. Requirement R2, Part 2.7.2 states that Corrective Action Plans are required (or rationale for why they are not needed) are required if performance deficiency exists in multiple sensitivity studies, not just one study. No change made. Requirement R2, Part 2.1.5 requires the study of each major Transmission equipment outage, consistent with spare equipment strategy, for System normal and P1 and P2 Contingencies. It does not require the study of P1 and P2 Contingencies with more than one major Transmission equipment, except for other equipment that are modeled out as "Known outages" consistent with Requirement R1, Part 1.1.2. No change made. Requirement R2, Part 2.1.5 is a planning requirement to ensure that an entity's spare equipment strategy is considered during the development of the Planning Assessment. The curtailment of Firm Transmission Service (FTS) for the situation outlined would be considered curtailing FTS for Normal System conditions and is not allowed. No change made. Requirement R2, Part 2.1 and 2.2 – The SDT left the requirement to conduct the annual study on one of the study years in the Long-Term Planning Horizon to ensure that the planner would conduct a new study annually to evaluate the System improvement needs in the Long-Term Planning Horizon. No change made. Requirement R2, Part 2.7.1 – The list represents examples, but not an exhaustive list of actions that could make up a Corrective Action Plan. No change made. Requirement R8, Part 8.1 - The SDT does not believe that a time limit for commenting on a Planning Assessment is required. Beyond responding to the comment, other actions by the planner are at the discretion of the planner. No change made. Table 1, P1 {back to back DC - The contingent loss of back to back HVDC facilities is included as a transformer. Footnote 5 states, in part, that "Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. Therefore, the SDT has not explicitly included back-to-back HVDC as a separate Contingency. No change made. Combined cycle generation outages are expected to be modeled in the manner that they would be tripped, per Requirement R3, Part 3.3.1 and Requirement R4, Part 4.3.1. Therefore, if the outage of one generator causes more generation to be lost (via the Protection System or other automatic controls are expected to disconnect), then, the entire amount of generation lost must be modeled for that specific contingency. No change made. Table 1, footnote 7 – The SDT added the footnote to further explain its intent for P2-1 and to ensure that the planner assess the voltage of a load bus that was on a radial line. The word "possibly" was used since having load on a radial is not always the outcome of opening one end of a line section. No change made. Table 1, Top note 1b – The SDT disagrees that Firm Transmission Service (FTS) may be interrupted for all events. The events where the interruption of FTS is not permitted are shown with a "No" in the column titled "Interruption of Firm Transmission Service Allowed", however, footnote 9 clarifies that interruption of Firm Transmission Service can be used as both a corrective action and system adjustment as permitted within Table 1. For the specific issue raised, loss of a single pole of a DC line, to the extent the availability of the DC pole is a condition of the transfer being viable, footnote 4 may also address the commenter's		

Organization	Yes / No	Question 1 Comment
concern. No change made.		
Ameren	No	There were a number of comments made on the previous draft of TPL-001-2 for which there were few, if any, changes made to the latest draft of the standard. Specifically:Requirement R1 does not address normal (pre-contingency) operating procedures or system configurations. Language should be added to the requirement (possibly as an additional Requirement R1.1.7) to include normal operating procedures or system configurations in place prior to any contingency occurring. Requirement R2.4.1, which addresses dynamic load modeling, has been a cause for concern because of the lack of guidance regarding reasonable induction motor representation as opposed to generic load models. While it is recognized that the effort to simulate the effects of induction motor loads is important, it is premature to include such modeling as part of the requirements for this standard. In addition, it appears that only the peak load model in R2.4.1 is required to represent expected dynamic behavior of Load. Such load models, if adopted should represent dynamic behavior of the load for all dynamic studies.
Response: The SDT posted a redline draft against the last posted draft and also posted a redline draft against the previous ballot draft. The SDT addressed many important issues that were raised during the first ballot. The SDT did not include all of the different procedures that are permitted. Normal operation procedures or system configuration may be utilized as long as they are consistent with the way the System would be operated and not inconsistent with the requirements within the standard. Requirement 2, Part 2.4.1 – One focus of dynamic Load model requirement in Part 2.4.1 is "considering the behavior of induction motor Load". The areas of concern for induction motor Load are the Peak Load periods since Fault Induced Delayed Voltage Recovery (FIDVR) is primarily a concern at high Load levels with a high penetration of induction motor Loads. The SDT has spelled out this requirement in the Peak Load studies but did not include the explicit requirement, with focus on induction motor Load, for the other Load periods. Even though the standard doesn't have the explicit requirement for other Load levels, Requirement R1 includes the statement "shall represent projected System conditions", so the planner cannot ignore the dynamic behavior of the Load for those other Load periods. No change made.		
Western Area Power Administration	No	We concur that the standard is an improvement over previous drafts, but we vote "No" to the existing draft and request additional clarifications and/or modified language for a re-circulated vote prior to adoption. The following are areas where we suggest improvement or have questions:Please further define Consequential and/or Non-Consequential Load Loss: Does the Consequential Load Loss definition include underfrequency or undervoltage load shedding installed to protect transmission system reliability? Does the Consequential Load Loss definition include load tripped by a Special Protection System (SPS) or a

Organization	Yes / No	Question 1 Comment
		Remedial Action Scheme (RAS)? Either how underfrequency and undervoltage load shedding or how load shedding by a RAS relates to Consequential Load Loss should be clear in the Consequential and/or Non-Consequential Load Loss definition of the approved version of this NERC standard. Why is Near-Term Tranmission Planning Horizon deleted from the definitions of Terms Used in this Standard, yet it is used throughout the standard? This definition should remain. R1.1.5: How are "known commitments for Firm Transmission Service" to be modeled and tracked in power flow cases? Is it acceptable for Transmission Planners to simply assume what the ultimate sources and ultimate sinks are for each firm transmission service commitment or are Transmission Planners to know exactly which ultimate sources and ultimate sinks are associated with each commitment and to track each one accordingly in each power flow case?Assuming the intent here is reliability based and not marketing based, is the application of Firm Transmission intended to apply to reliability designated 'paths'? Most all Firm Transmission service contracts have caveats for unplanned interruption and such agreements should qualify as "re-dispatch" per Footnote 9? R2.1.5: If a group of utilities were to develop and manage among themselves a coordinated spare equipment program, such that the risk to any one of its participating entities of experiencing a significant unavailability for any major Transmission equipment that has a lead time of one year or more is deemed not significant, then would those utilities still have to do the studies required by R2.1.5 to evaluate the system impact of extended outages of such equipment?Scenario for Clarification: Short of spare equipment for items with a greater than 1 yr lead time, assessment studies are required to include sensitivities and operating plans for sustained loss of these equipment items, as a prior outage. For example, if an EHV facility is lost for more than 1 yr, and firm transmission interruption is not allowed, it appears the only compliant alternative (to a redundant facility) is a redispatch plan that is well documented and accepted by all stakeholders, per Footnote 9. R2.3: Is only the 5-year Near-Term Transmission Planning Horizon case required for the annual short-circuit analysis? R2.4.1: How is the dynamic modeling of induction motor Loads to be developed by the Transmission Planners? Is it acceptable for Transmission Planners to assume the same induction motor modeling as has generally been assumed and applied by most Transmission Planners throughout the Western Interconnection or will the induction motor modeling have to be based upon the type and amount of actual

Organization	Yes / No	Question 1 Comment
		induction motors installed in the system? R2.5: Does NERC have a particular technical rationale about what determines “proposed material generation additions or changes?” R2.6.2: Does NERC have a particular technical rationale about what determines “material changes?” R2.7.3: Please define “beyond the control” under Definition of Terms Used in Standard. This is an important concept. Without NERC definition, this term is highly debatable and should be eliminated. Scenario for Clarification: If the stakeholder rate payers do not approve expenditures for facility improvements required to eliminate non-consequential load loss, is this beyond the control of the Transmission Planner? Rate payers should be able make the ultimate free market choice determination of risk versus cost associated with their reliability. Otherwise market interests (particularly generation) disproportionately pressure excessive reliability based improvements that must be borne by all rate payers. R3.3.1: Please define “relay loadability limit” under Definitions of Terms Used in Standard. This is an extremely important concept. This term has been used quite commonly for decades and is now used in this latest proposed standard. Without NERC definition, this term is highly debatable and should be eliminated. Scenario for Clarification: If PRC-023 is met whereby all “relay loadability limits” are set at least 150% of the highest thermal limiter (0.85 voltage and 30 lagging powerfactor) this sensitivity would justifiably not be needed so long as verification is shown that no element overloaded greater than 150%. R3.1 and R3.4: The interrelation between these two paragraphs needs additional clarification. R3.1 calls for verification via studies that the BES meets Table 1 performance criteria based on the contingency list resulting from R3.4. However, R3.4 states that the contingency list used to meet R3.1 only need include “Those planning events in Table 1, that are expected to produce more severe System impacts on.....the BES” and the associated “rationale” for those chosen contingencies. Is NERC suggesting that the studies do not need to include all contingencies based on Table 1, so long as ample “rationale” is provided? However, the Transmission Planner must provide studies to determine if every contingency of Table 1 meets performance requirements. How are the “more severe” contingencies determined if the Table 1 contingencies are not evaluated comprehensively? It seems R3.4 could be eliminated and the contingencies be based simply on Table 1. Please define “more severe”, relative to less severe under Definitions of Terms Used in Standard, in an effort to help evaluate the suitability of a particular contingency for inclusion on this list. Looking at context, it appears that the purpose of this statement is to ensure that the worst contingencies are studied. Is the intent here simply to allow a given contingency to cover for a less severe or similar contingency and avoid duplicate simulations?

Organization	Yes / No	Question 1 Comment
		R3.4.1 and R4.4.1 Please include and define a reasonable number of contingent buses into adjacent systems that should be considered. No more than 2 are recommended for the standard. R3.5 and R4.5: How many of the "events in Table 1 that are expected to produce more severe system impacts" should the required evaluation identify and evaluate? To what extent should the evaluation focus on the "other" Extreme Events described under items 3.b and 2.f in Table 1, particularly if existing disturbance reports in the Western (or Eastern) Interconnection have recorded and evaluated the occurrence of particular events that have already created cascading? Because the requirement seems to involve a check for Cascading, perhaps some clarity could be provided with respect to the NERC definition of "Cascading." In particular, in the Cascading definition, how widespread is "widespread;" is the phrase "electric service interruption" only about the loss of firm load or could it also be only about the loss of firm generation or only about the loss of firm transmission service or is it about some combination of loss of firm load, loss of firm generation, and loss of firm transmission service; how large an area is meant by the expression "spreading beyond an area predetermined by studies" when the simulations that analyze the initiating Extreme Event will model the entire Western (or Eastern) Interconnection? So how does the study determine that the sequentially spreading service interruption has spread beyond the entire Western (or Eastern) Interconnection that is modeled in the simulation? Or is the term "area" meant to describe only that part of the Western (or Eastern) Interconnection that the Transmission Planner has evaluated for system impacts while ignoring impacts to the rest of the Interconnection? Table 1 - Planning Events, Steady State Only Note i: "The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event" seems to be included as items 2) and 3) under the Non-Consequential Load Loss definition. So, it seems acceptable to use this form of load loss to meet the stability performance requirements. However, the "Steady State Only" note i in Table 1 specifically does not allow its use to meet steady state performance requirements. Therefore, the "Steady State Only" note i in Table 1 should clarify why it seems acceptable to use it to meet stability performance requirements but not to meet steady state performance requirements. Table 1 - Planning Events, Category P2: Category P2 seems to include an unrelated mix of planning events ranging from a seemingly benign event (i.e., opening of a line section without a fault) to what would seem to be much more severe events (i.e., bus section fault or internal breaker fault). A clarification of why these planning events were lumped into the same Category P2 would be helpful to the Transmission Planner. Also, does the language in footnote 7 (i.e., "opening one end of a line section without a fault on a normally networked Transmission circuit ...") mean that P2-1 ("opening of a line section without a fault") should be

Organization	Yes / No	Question 1 Comment
		modeled as an open-ended line section? Table 1 - Planning Events, P2-2 (EHV) and P2-3 (EHV): For each of these planning events, its corresponding "Non-Consequential Load Loss Allowed" column should include a footnote 12 with each of the "No" boxes, similar to that allowed under the seemingly much less severe event P2-1 ("opening of a line section without a fault"). Otherwise, please explain why the seemingly much less severe P2 event (P2-1) has a footnote 12 exception for Non-Consequential Load Loss Allowed but the two seemingly more severe P2 events (P2-2 and P2-3) do not. Table 1 - Planning Events, P4-1 through P4-5 (EHV): For the stuck breaker planning events of P4-1 through P4-5 on the EHV system, their corresponding "Non-Consequential Load Loss Allowed" column should include a footnote 12 with their "No" box, similar to that allowed under the seemingly much less severe N 1 planning events (P1-1 through P1-5). Otherwise, please explain why the seemingly much less severe N 1 events (P1-1 through P1-5) have a footnote 12 exception for Non-Consequential Load Loss Allowed but the seemingly much more severe stuck breaker events (P4-1 through P4-5) do not. Table 1 - Planning Events, P5-1 through P5-5 (EHV): For the relay failure planning events of P5-1 through P5-5 on the EHV system, their corresponding "Non-Consequential Load Loss Allowed" column should include a footnote 12 with their "No" box, similar to that allowed under the seemingly much less severe N 1 events (P1-1 through P1-5). Otherwise, please explain why the seemingly much less severe N 1 events (P1-1 through P1-5) have a footnote 12 exception for Non-Consequential Load Loss Allowed but the seemingly much more severe relay failure events (P5-1 through P5-5) do not.

Response: The definition of Consequential Load Loss does not include underfrequency or undervoltage load shedding, since this Load is not interrupted by the "Protection System operation designed to isolate the fault". No change made.

The definition of Consequential Load Loss does not include Load tripped by a Special Protection System (SPS) or a Remedial Action Scheme (RAS), since this Load is not interrupted by the "Protection System operation designed to isolate the fault". No change made.

The definition of Near-Term Transmission Planning Horizon is now an approved NERC Glossary Term. No change made.

Requirement R1, Part 1.1.5 (Known commitments for Firm Transmission Service and Interchange) is required to ensure that planners consider those transactions that have been committed to and meet the system performance requirements. "How" the planners account for these commitments should be developed by the planner in accordance to all of the regulatory and market rules that apply to them. No change made.

Requirement R2, Part 2.1.5 does not require a planner to study the unavailability of major long lead time equipment if the entity's spare equipment strategy could

Organization	Yes / No	Question 1 Comment
not result in the unavailability of that equipment for one year or more. No change made. Requirement R2, Part 2.3 requires the short circuit analysis only for the years of the Near-Term Transmission Planning Horizon. No change made. RequirementR2, Part 2.4.1 – The SDT believes that the planner must consider the dynamic behavior of its System load and develop a representative model, however, the SDT should not dictate "how" the load should be modeled. No change made. Requirement R2, Part 2.5 does not specify "how" an entity determines that "proposed material generation additions or changes" have occurred. It is up to each entity to develop its technical rationale for its determination. No change made. Requirement R2, Part 2.6.2 does not specify "how" an entity determines that "material changes" have occurred. It is up to each entity to develop its technical rationale for its determination. No change made. Requirement R2, Part 2.7.3 has been included to account that certain Corrective Action Plans may not be able to be implemented due to circumstances that the planner cannot control. The SDT expects that these situations will be limited and that the impact to BES will be limited to interrupting Non-Consequential Load if the Contingency were to occur. Due to the wide variety of circumstances across North America, the SDT did not believe that it was appropriate to articulate the acceptable set of conditions. No change made. Requirement R3, Part 3.3.1 utilizes the term "relay loadability limits" as it is utilized in the PRC standard. No change made. Requirement R3, Parts 3.1 and 3.4 together require the planner to create a list of the "more severe" Contingencies, along with the rationale for "why" those Contingencies were selected, that will be simulated to ensure that the System meets the performance requirements. This language was included to be consistent with the existing TPL standards that do not require the planner to run simulations of all possible Contingencies. No change made. Requirements R3, Part 3.4.1 and Requirement R4 Part 4.4.1 do not include "how" to define the Contingencies in adjacent systems that should be included since it will be variable based on the conditions of the System. It is the responsibility of the planners to coordinate the list of Contingencies to ensure BES reliability. No change made. Requirement R3, Part 3.5 and Requirement R4 Part 4.5 require the planner to identify the "events in Table 1 that are expected to produce more severe system impacts". The number of "events" that should be included in the list are a "how" that the planner must determine. No change made. Table 1, Extreme Events Steady State 3b and Stability 2f are included to ensure that the planner considers "operating experience" when determining the extent of Contingency analysis to conduct for the entity's Extreme Event simulations. The term "widespread" categorizes those events that are more far-reaching than the Local Area events identified in Extreme Events Steady State 2 a-e. No change made. Table 1, Top note 'i' Steady State Only does not apply to Stability studies. Therefore, voltage sensitive Load disconnected by end-user equipment may be used during Stability simulations. The planner should not depend on this voltage sensitive Load being disconnected to meet the performance requirements (steady state after the system transient reaction ends) but this Load should be disconnected from the System for the Stability simulations to accurately represent how the		

Organization	Yes / No	Question 1 Comment
System will respond. No change made. Table 1, P2 contains single Contingency events that have the same performance requirements. No change made. Table 1, P2-1 covers the opening of line section without a fault and Footnote 7 clarifies that the line section may be energized from one end and still serving Load. The expectation is that both situations are evaluated when appropriate. No change made. Table 1 P2-2 (EHV) and P2-3 (EHV) do not allow the exception allowed by Footnote 12. The SDT believes that the EHV system should be planned to handle these single Contingencies without Non-Consequential Load Loss. No change made. Table 1, P4-1 through P4-5 (EHV) does not allow the exception allowed by Footnote 12. The SDT believes that the EHV system should be planned to handle these Contingencies without Non-Consequential Load Loss. No change made. Table 1, P5-1 through P5-5 (EHV) does not allow the exception allowed by Footnote 12. The SDT believes that the EHV system should be planned to handle these Contingencies without Non-Consequential Load Loss. No change made.		
Progress Energy		First, Progress Energy ("PE") notes that many changes to the Requirements language have been appropriate or have improved upon the language of the previous drafts, and PE commends the SDT in this. PE does have concerns, however, with the language in R8 and its corresponding Measure M8, and therefore must select 'no' for Q1 and provide comments. PE disagrees with the language of R8 primarily to the extent that the use of the verb “distribute” with respect to communicating Planning Assessments leads the reader to M8, which lacks language that would provide for the optimal correlation with R8. Regarding the M8 language, PE feels that the term “demonstration of a public posting” is a valid action in demonstrating compliance with R8 and thus should be more clearly described as one of several acceptable methods of distributing Planning Assessments. In addition, given the appropriate concern that NERC and FERC have recently raised regarding Cyber threats and the need for additional Cyber Security measures, PE feels that the public posting language should contain a qualification regarding the security of CEII information. PE thus recommends that an appropriate phrase to use would be “demonstration of a secure public posting”, thereby making clear that a public posting would not be a website accessible to just anyone due to CEII concerns.
Response: Requirement R8 - The SDT agrees that posting is an acceptable method of distributing but the intent of the standard requirement is to ensure that affected parties obtain the Planning Assessment. Measure M8 clarifies that posting is acceptable but not the only way to meet the requirement. While the SDT recognizes that certain planning information is covered by CEII requirements, the responsibility to protect that information already resides with the entity and is therefore not needed within this standard. No change made.		

Organization	Yes / No	Question 1 Comment
SERC Planning Standards Subcommittee	Yes	
SPP Reliability Standards Development Team	Yes	
MRO's NERC Standards Review Forum	Yes	
BC Hydro	Yes	
Entergy Services	Yes	
Imperial Irrigation District	Yes	
Arizona Public Service Company	Yes	
American Electric Power	Yes	
Duke Energy	Yes	
Transmission Strategies, LLC	Yes	
NIPSCO	Yes	
Muscatine Power and Water	Yes	
ITC	Yes	
Tri-State Generation and Transmission Assn., Inc.	Yes	In general, revisions are editorial and seem to have improved the overall document.

Organization	Yes / No	Question 1 Comment
Pepco Holdings Inc	Yes	Pepco Holdings Inc supports the proposed revisions.
Puget Sound Energy, Inc.	Yes	We Appreciate SDTs efforts in bringing clarity to the TPL standards.
South Carolina Electric and Gas	Yes	
Georgia Transmission Corporation	Yes	
American Transmission Company, LLC	Yes	
TVA TP&C	Yes	
Xcel Energy	Yes	
MISO	Yes	
Consumers Energy	Ballot Comment	We agree with the comments of MISO.
Oncor Electric Delivery Company LLC	Yes	
Response: Thank you for your support.		

2. **The SDT has made revisions to the VRF and VSL of TPL-001-2 which will be part of a non-binding poll with this posting based on industry comments and the Quality Review. Do you agree with these changes? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: Comments received were predominantly about individual assessments of whether a VRF or VSL had been assigned correctly and some pointed out what they thought were incorrect interpretations of established guidelines by the SDT. The SDT followed guidelines established by FERC and NERC in these areas and therefore no changes were made in this regard.

In two particular instances, inconsistencies between wording in the requirement and VSL were pointed out and the SDT made the following changes due to those comments:

R1. VSL – Severe (third part): The responsible entity's System model did not use ~~the latest~~ data consistent with ~~the data~~that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.

R8 VSL	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners.

	it was more than 30 days but less than or equal to 40 days following the request	it was more than 40 days but less than or equal to 50 days following the request.	it was more than 50 days but less than or equal to 60 days following the request.	OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

Organization	Yes / No	Question 2 Comment
Consolidated Edison Co. of New York	Ballot Comment	Requirement R1.1.5: Delete “and Interchange.” The inclusion of other than Firm transactions (e.g. economic transactions in Interchange) in a base power flow case utilized for planning/designing the interconnected system blurs the boundary between reliability issues and purely economic issues. Reliability issues are issues that a Transmission Owner (TO) must address for the purpose of meeting its load demand, and are defined by the application of well established reliability standards and criteria that are based on the electrical characteristics of the interconnected system, but without economic considerations. Instead, economic transactions are types of transactions that a TO may enter into once its load obligations are met, and are

Organization	Yes / No	Question 2 Comment
		evaluated based on economic parameters that are markedly different from the aforementioned reliability criteria (e.g. congestion costs). Modeling all types of transactions in a power flow case without distinction detracts from the accuracy and validity of either assessment (reliability and economic).
Response: The SDT selected Known commitments for Firm Transmission Service and Interchange to separate the planning requirements of commitments from the economic transactions. No change made.		
San Diego Gas & Electric	Ballot Comment	The clarity of this standard is getting worse. Our earlier comments did not seem impacting. At this point, we believe the existing TPL-001-0.1, TPL-002-0a, TPL-003-0a and TPL-004-0 provide much better clarify for us to comply with the TPL standards.
Response: The SDT believes that there is much less ambiguity in the proposed standard than the existing standards, based on feedback from previous postings. . No change made.		
Alberta Electric System Operator	Ballot Comment	The AESO casts an abstain vote as the VSLs and VRFs in Alberta are established by provincial authorities.
Response: Thank you for your response.		
Western Electricity Coordinating Council	Ballot Comment	I'm not certain that I agree with changing the VRF for R2 from Medium to High. I understand that it is accordance with the VRF guidelines, but I guess I disagree with the guidelines. I don't believe that any requirement with a planning time frame, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.
Response: The SDT is required to follow the VRF guidelines established by FERC, which apply to both operations and planning on equal footing. No change made.		
Florida Municipal Power Agency	Ballot Comment	FMPA has minor comments to help improve the clarity of the standard. R7 is not needed and administrative in nature. Instead is should say that an entity can use as evidence another entity's study, but not in the requirement and rather in the measures.

Organization	Yes / No	Question 2 Comment
		R8 is ambiguous, does the requirement require submitting the Planning Assessment only after receiving a written request, or automatic distribution to neighboring PCs and TPs without a written request, and to others with a reliability related need following a written request? Table 1, under first heading of "Steady State and Stability", bullet c should be removed since it is duplicative of the standard, and not entirely consistent with the standard (e.g., open to interpretation whereas the standard better clarifies how to study protection system operation)
Keys Energy Services City of Green Cove Springs	Ballot Comment	R7 is not needed and administrative in nature. Instead is should say that an entity can use as evidence another entity's study, but not in the requirement and rather in the measures. R8 is ambiguous, does the requirement require submitting the Planning Assessment only after receiving a written request, or automatic distribution to neighboring PCs and TPs without a written request, and to others with a reliability related need following a written request? Table 1, under first heading of "Steady State and Stability", bullet c should be removed since it is duplicative of the standard, and not entirely consistent with the standard (e.g., open to interpretation whereas the standard better clarifies how to study protection system operation)
Response: Requirement R7 ensures that there are no gaps between Transmission Planners or the Planning Coordinators that may cause reliability concerns. No change made. Requirement R8 requires the automatic distribution to neighboring Planning Coordinators and Transmission Planners without a written request and to others with a reliability related need following a written request. The SDT believes this is an important consideration and not ambiguous. No change made. Table 1, Bullet c under first heading, is not in conflict with the requirements. The SDT decided to include additional details in Table 1 so that it would have the basic information necessary for the planner to develop their simulations for their studies without always referring back to the requirements language. No change made.		
City of Austin dba Austin Energy	Ballot Comment	Previous TPL Standard balloting included the FERC Order that clarified footnote "b" regarding the planned or controlled interruption of electric supply for an N-1 event. In our view, a Registered Entity's Board of Directors, local public utility commission or customers should determine the acceptable level of service and the associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote. Additionally, with respect to R2 (2.5), the value of annually assessing system stability for years 6-10 is

Organization	Yes / No	Question 2 Comment
		questionable. The requirement for stability assessment in years 6-10 should be limited to new generation interconnections or planned major transmission system improvements with regional impact. The standard should clarify the "material changes" that would necessitate stability planning assessments and documentation. Finally, The R8 requirement to distribute all Planning Assessment results to adjacent Planning Coordinators and Transmission Planners is excessive and cumbersome. Regarding R8, we suggest the following language: "Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners in accordance with the requirements of the applicable Reliability Coordinator. Any Registered Entity with a reliability-related need may submit a written request for the Planning Assessment results and the Transmission Planner or Planning Coordinator shall provide the latest Planning Assessment results within 30 days of such request."
Response: Footnotes 12 and 9 were translated from the BOT approved language from TPL-002-1, Footnote 'b'. No change made. For Requirement R2, Part 2.5, the SDT believes it is important to evaluate Stability when the planners are evaluating new generation additions or changes which can be more than 5 years in the future, as required in NERC Standard FAC-001-0. The SDT discussed defining 'material change' but did not believe that such a definition was appropriate in a continent-wide standard. With the wide variety in sizes and types of systems, the number of parameters that need to be considered, etc., there are too many variables involved. No change made. For Requirement R8, the SDT disagrees that the requirement is excessive and cumbersome and did not make the suggested change. In addition, the proposed language would place requirements on the Reliability Coordinators, who are not included in the Applicability for this standard, and they should not be involved in determining the extent of the distribution of the Planning Assessments.		
Southwest Power Pool Regional Entity	Ballot Comment	I'm voting affirmative, but I'd prefer to avoid having VSLs where the only choice is Severe. I'd like to see either some gradation or we should use a different term to clarify that the requirement is either met or not (binary) instead of Severe VSL.
Response: The SDT is required to follow the guidelines established by NERC and FERC. No change made. No change made.		
Arizona Public Service Co.	Ballot Comment	While AZPS generally supports this standard, AZPS cannot support the violation severity levels that are proposed in the recirculation ballot. AZPS believes the time frames set forth in the proposed security levels are unreasonably short (10 days) and should be extended to 30 days between each elevation in severity level. For these reasons, AZPS has changed its vote to "negative."

Organization	Yes / No	Question 2 Comment
Response: The SDT has followed the accepted guidelines for timeframes in the proposed VSLs. The SDT is required to follow the guidelines established by NERC and FERC. . No change made.		
Balancing Authority of Northern California NCR11118	Ballot Comment	SMUD believes believes that the VRF should be Medium, as are the VRFs for the other requirements related to conducting the assessments, rather than High.
Response: The SDT is required to follow the VRF guidelines established by FERC,.. No change made.		
Black Hills Corp	Ballot Comment	Black Hills is voting against the proposed VRF/VSL's based on the fact that the VRF for R2 was changed from Medium to High without any explanation.
Deseret Power	Ballot Comment	R2 was moved from medium to high without reason. Since it is long term it should remain medium.
California ISO	Ballot Comment	The VRF for Requirement R2 was changed from Medium to High without explanation. The other VRF's for assessment requirements continue to have a Medium VRF designation, and for consistency it would be appropriate for Requirement R2 to continue to have a Medium VRF designation.
Bonneville Power Administration	No	The VRF for R2 was changed from Medium to High without any explanation. Since the time horizon for R2 is Long Term Planning, BPA believes that the VRF should be Medium, as are the VRFs for the other requirements related to conducting the assessments, rather than High.
Arizona Public Service Company	No	With regards to R2, it appears that the VRF has changed from Medium to High without any justification; and with the time horizon of long term planning, AZPS believes there is no justification for changing it from Medium to High.
Idaho Power Company	Ballot Comment	The VRF for R2 was changed from Medium to High without any explanation. The time horizon for R2 is Long Term Planning and the Idaho Power believes that the VRF should be Medium, as are the VRFs for the other requirements related to conducting the assessments, rather than High.
Tucson Electric Power Co.	Ballot	This recommendation is based on the fact that the VRF for R2 was changed from Medium to High without any

Organization	Yes / No	Question 2 Comment
	Comment	explanation. The time horizon for R2 is Long Term Planning and it is believed that the VRF should be Medium, as are the VRFs for the other requirements related to conducting the assessments, rather than High.
Response: In the comment form for this posting, the SDT did address this issue as shown below: R2 – The VRF has been changed to High to reflect the importance of the Planning Assessment and to meet the latest guidelines. No change made.		
MidAmerican Energy Co.	Ballot Comment	Regarding Requirement 8, we do not believe that there is significant risk to the reliability of the BES if an annual Planning Assessment is not distributed to another entity or if a documented response to Planning Assessment comments is not provided within 90 days of a request. Requirement 8 is an administrative requirement that adds little to improve reliability. We recommend that the VRF for Requirement 8 remain "Low", rather than be changed to "Medium".
Response: In assigning the VRF for Requirement R8, the SDT is required to follow the guidelines established by NERC and FERC. No change made.		
Independent Electricity System Operator	Ballot Comment	IESO is generally supportive of the draft of TPL-001-2 as evidenced by our previous AFFIRMATIVE vote during the last ballot. Further, IESO also supported the revisions to Footnote 'b' to Table 1 of the TPL standards under Project 2010-11. That revision was balloted and approved by the ballot pool in February 2011 and filed with FERC for approval in March 2011. The revised footnote has been incorporated into the current draft of TPL-001-2 as Footnotes 9 and 12 but the Commission, by letter to NERC dated May 17, 2011, has requested NERC to provide supplemental information before the revised Footnote 'b' could be approved. In light of FERC's request and the uncertainty regarding the final provisions of these footnotes, coupled with the ongoing work on Project 2010-17 for the revision of the BES definition and development of an Exception Process and the impact that may have, we respectfully suggest that the drafting team delay further work on TPL-001-2 pending FERC's ruling on NERC's petition seeking approval of the transmission planning standards that contain the revised Footnote 'b' to Table 1.
Response: The SDT believes that it is important to continue with the approval of this standard. If FERC directs changes based on TPL-002-1, Footnote 'b', they will be addressed with this project.		
Hydro One Networks, Inc.	Ballot	Hydro One Networks is casting a negative vote. Other than a few changes related to Footnotes 9 and 12 of Table 1 and VSLs, the other changes in the proposed draft are minor. The concerns of the industry on several

Organization	Yes / No	Question 2 Comment
	Comment	important issues have not been sufficiently addressed in this draft. For detailed comments please refer to our submission through the on-line comment form.
Response: Please see responses to on-line comments.		
Platte River Power Authority	Ballot Comment	VRF for R2 should be changed back to Medium. VRF for R8 should be changed back to Low.
Response: The SDT is required to follow the VRF guidelines established by NERC and FERC. . No change made.		
American Municipal Power	Ballot Comment	The VSLs appear to have a very low threshold for a SEVERE violation of the individual standard requirements for a planning standard. Please consider the impact of having arbitrarily low thresholds for SEVERE violations. The way the VSLs are set now, an honest interpretation or a small administrative mistake could result in a very high dollar penalty and would be construed as having a high correlation with causing a cascading outage by the media. I think we all just want the appropriate fines or sanctions for a violation and to have minimal fines or sanctions for accidental interpretations or menial paperwork based violations. Please consider another metric or raising the current thresholds.
Response: The SDT is required to follow the VSL guidelines established by NERC and FERC, which apply to both operations and planning on equal footing. No change made.VSL		
Florida Municipal Power Pool	Ballot Comment	A. Spare Equipment, R2.1.5 - The requirement reaches beyond the FERC directive. The directive was: "Accordingly, the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy." So, the directive is only to address planned outage, not unplanned outages. Also note that the applicability to GSUs is ambiguous. "Transmission" is defined as: "An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems." Is the "point of supply" the generator terminal, or the GSU high side terminal? B. Table 1, under first heading of "Steady State Only", bullet i is open to interpretation. Many utilities use steady state P-V analyses to study voltage stability and design UVLS systems in apart around those steady

Organization	Yes / No	Question 2 Comment
		state analyses. Would this bullet essentially eliminate P-V and Q-V studies and the related use of UVLS? C. R7 is not needed and administrative in nature. Instead is should say that an entity can use as evidence another entity's study, but not in the requirement and rather in the measures. D. R8 is ambiguous, does the requirement require submitting the Planning Assessment only after receiving a written request, or automatic distribution to neighboring PCs and TPs without a written request, and to others with a reliability related need following a written request? E. Table 1, under first heading of "Steady State and Stability", bullet c should be removed since it is duplicative of the standard, and not entirely consistent with the standard (e.g., open to interpretation whereas the standard better clarifies how to study protection system operation)
Response: Requirement R2, Part 2.1.5 ensures BES reliability by requiring the planner to assess the system for long lead time items based on the entities' spare equipment strategy. The footnotes in Table 1 clearly define the way transformers are evaluated. No change made. Table 1, Steady State and Stability, Item I does not restrict the use of UVLS since it only addresses equipment disconnected by end-user equipment. No change made. Requirement R7 ensures that there are no gaps between Transmission Planners or the Planning Coordinators that may cause reliability concerns. No change made. Requirement R8 requires the automatic distribution to neighboring Planning Coordinators and Transmission Planners without a written request and to others with a reliability related need following a written request. The SDT believes this is an important consideration and not ambiguous. No change made. Table 1, Bullet c under first heading, is not in conflict with the requirements. The SDT decided to include additional details in Table 1 so that it would have the basic information necessary for the planner to develop their simulations for their studies without always referring back to the requirements language. No change made.		
MRO's NERC Standards Review Forum	No	The NSRF recommends that the VRF for Requirement 8 remain "Low", rather than be changed to "Medium". We do not believe that there is significant risk to the reliability of the BES if an annual Planning Assessment is not distributed to another entities or a documented response to Planning Assessment comments is not provided within 90 days of a request. The findings in an assessment report are not urgent, but address system needs that will emerge over years in the future. In addition, entities with a reliability related need for Planning Assessment information generally have the means to make their own independent planning assessment of adjacent systems or other areas of interest.

Organization	Yes / No	Question 2 Comment
Minnkota Power Coop. Inc.	Ballot Comment	MPC echoes the comments of the MRO NSRS/F
Lincoln Electric System	Ballot Comment	Refer to comments submitted by the MRO NERC Standards Review Subcommittee.
Response: The SDT is required to follow the guidelines established by NERC and FERC.. No change made.		
Tri-State Generation and Transmission Assn., Inc.	No	Many of the sub-requirements of R2 do not warrant high risk VRFs, yet violation of any R2 sub-requirement would result in a "High Risk Factor" violation assessment. We believe that having so many sub-requirements can result in inaccurate overall severity classification. For example, skipping one study defined in R2.1.2 (Planning Assessments) for a particular time frame or load level would probably not result in a direct actual degradation in system performance, but would still result in a High Violation Risk Factor.
Response: The SDT is required to follow the VRF guidelines established by NERC and FERC, which apply to both operations and planning on equal footing.. No change made.		
Muscatine Power and Water	No	MP&W would like to recommend that the VRF for Requirement 8 remain "Low", rather than "Medium." It is our belief that there is not a significant risk to the reliability of the BES if an annual Planning Assessment is not distributed to another entities or a documented response to Planning Assessment comments is not provided within 90 days of a request. This is more administrative in nature. The findings in an assessment report are not urgent, but address system needs that will emerge over years in the future. Additionally, entities with a reliability-related need for Planning Assessment information generally have the ability to perform their own independent planning assessment of adjacent systems or other areas of interest.
American Transmission Company, LLC	No	ATC recommends that the VRF for Requirement 8 remain "Low", rather than be changed to "Medium". ATC does not believe that there is significant risk to the reliability of the BES if an annual Planning Assessment is not distributed to another entities or a documented response to Planning Assessment comments is not provided within 90 days of a request. The findings in an assessment report are not urgent, but address system needs that will emerge over years in the future. In addition, entities with a reliability related need for Planning Assessment information generally have the means to make their own independent planning assessment of adjacent systems or other areas of interest.

Organization	Yes / No	Question 2 Comment
Electric Reliability Council of Texas, Inc.	No	ERCOT ISO believes that the VRF for R8 should be "low". The distribution of the Planning Assessment is administrative in nature, the failure to distribute the Planning Assessment does not necessarily equate to not communicating the content of the assessment, and the consequence of not distributing the Planning Assessment does not immediately impact the reliability of the BES; thus it does not warrant a 'Medium' risk factor.
Response: The SDT is required to follow the VRF guidelines established by NERC and FERC. No change made.		
ReliabilityFirst	No	ReliabilityFirst generally agrees with the Violation Risk Factors (VRFs) but disagrees with the Violation Severity Levels (VSLs) for the following reasons:1. VSL for R1a. Under the last "Severe" VSL, the word "latest" should be removed to be consistent with the language in Requirement 1. This is a violation of the FERC Guideline 3: "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement"2. VSLs for R2a. To be consistent with the language in Requirement 2, suggest modifying the last "Severe" VSL to state "The responsible entity failed to prepare an annual Planning Assessment of its portion of the BES" 3. VSLs for R3a. Under the last VSL under the "High" category, the word "perform" should be replaced with "simulate" to be consistent with the requirement. (e.g. "The responsible entity did not simulate Contingency analysis as described in Requirement R3, Part 3.3.") 4. VSL's for R4a. Under the last VSL under the "High" category, the word "perform" should be replaced with "simulate" to be consistent with the requirement (e.g. "The responsible entity did not simulate Contingency analysis as described in Requirement R4, Part 4.3."). 5. VSLs for R6a. To be consistent with the language in Requirement 6, suggest modifying the "Severe" VSL to state "The responsible entity failed to define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions, as described in Requirement R6." 6. VSLs for R7a. Suggest adding the following language to the end of the "Severe" VSL; "for the Planning Assessment", to be consistent with the requirement. 7. VSL for R8a. Under all four categories of VSLs, any reference to "Planning Assessment" should be changed to "Planning Assessment results" to be consistent with the language in Requirement 8 (or more appropriately, the term "results" should be removed from Requirement 8). This is a violation of the FERC

Organization	Yes / No	Question 2 Comment
		Guideline 3: "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement" b. Under the "Lower" VSL, it is unclear why there is a 30 day timeframe for the first VSL, while the "Moderate", and "High" VSLs have a 10 day timeframe. Based on FERC recommendations, suggest making the timeframe for all four VSL s, 10 day increments. c. VSLs need to be developed to deal with a violation of Part 8.1 (i.e. the PC or TP failed to provide a documented response to that recipient within 90 calendar days of receipt of those comments)

Response: 1. The SDT has corrected the language used as shown:

R1. VSL – Severe (third part): The responsible entity's System model did not use ~~the latest~~ data consistent with ~~the data~~that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.

2. The SDT believes that the wording shown must be taken in context and thus is clear. No change made.

3. & 4. The SDT believes the word 'perform' is consistent with the language used in the requirement. No change made.

5. The SDT sees the suggested change as unecessary and not providing any additional clarity as it is clear that the analysis is part of the Planning Assessment. No change made.

6. The entire standard is about the Planning Assessment and the SDT believes that this is clear in the language used. No change made.

7. The SDT has made the suggested change as shown below:

R8 VSL	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR,	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR,	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR,	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR

Organization	Yes / No	Question 2 Comment			
		The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

7b. The 30 days shown is according to the established guidelines as are the 10 day increments that follow. The SDT is required to follow the guidelines established by NERC and FERC. No change made.e.

7c. VSLs have been developed with regard to Requirement R8, part 8.1 and were shown in the posted version. No change made.

Organization	Yes / No	Question 2 Comment
ITC	No	ITC recommends revising R8 VSLs as follows:Lower VSLThe responsible entity distributed its Planning Assessment to known adjacent Planning Coordinators and known adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request. Moderate VSLsThe responsible entity distributed its Planning Assessment more than 30days but less than 60 days after subsequent requests by adjacent Planning Coordinators or adjacent Transmission Planners who were not sent copies upon completion of the Planning Assessment. OR, The responsible entity distributed its Planning Assessment to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request High VSLs - eliminate this section. i.e., no high VSLs only lower,moderate and severe Severe VSLsThe responsible entity distributed its Planning Assessment to functional entities having a reliability related need, adjacent Transmission Planners and adjacent Planning coordinators who requested the Planning Assessment in writing but it was more than 60 days following the request.
Response: 1. The suggested wording change is not consistent with the language used in the Requirement. Furthermore, the SDT does not believe that the word 'known' is necessary in this regard. No change made. 2. The suggested wording is not consistent with the language used in the requirement. Furthermore, the increment suggested would violate established guidelines. The SDT is required to follow the VSL guidelines established by FERC. No change made. 3. When dealing with incremental times in VSLs, the established guidelines indicate that all 4 types of VSL should be utilized. No change made. 4. The SDT believes the suggested change makes the VSL less clear. No change made.		
Manitoba Hydro	No	-The language "latest data" is used in the Severe VSL for R1, however "latest" was removed from R1 and M1. "Latest" should also be removed from the Severe VSL for consistency.-What is the rationale for changing the preparation of the Planning
Response: The SDT has corrected the language used as shown: **R1. VSL – Severe** (third part): The responsible entity's System model did not use ~~the latest~~ data consistent with ~~the data~~that provided in accordance with the		

Organization	Yes / No	Question 2 Comment
MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.		
National Grid	No	R 2.0 We recommend that the VRF for this Planning Requirement remain at "Medium". The risks associated with Planning Requirements have a longer time horizon for corrective action than, for example, those risks associated with much shorter Operational time frames.
Response: The SDT is required to follow the VRF guidelines established by NERC and FERC. No change made.		
Independent Electricity System Operator	No	See our response to Q1.
Response: See response to Q1.		
Consumers Energy	Ballot Comment	We agree with comments submitted by MISO
MISO	No	Regarding Requirement 8, we do not believe that there is significant risk to the reliability of the BES if an annual Planning Assessment is not distributed to another entity or if a documented response to Planning Assessment comments is not provided within 90 days of a request. Requirement 8 is an administrative requirement that adds little to improve reliability. We recommend that the VRF for Requirement 8 remain "Low", rather than be changed to "Medium".
Response: The SDT is required to follow the VRF guidelines established by NERC and FERC. No change made.		
New York Independent System Operator	No	Requirement 8 is an administrative burden that adds no value to reliability. Comments have been provided on several past drafts highlighting this effect. The revisions made to the VRF and VSL for Requirement 8 further exacerbate this burden. One could conclude from observation of the VSLs and VRFs, that Requirement 8 was the most important requirement of TPL-001-1.Many Planning Coordinators and Transmission Planners have stakeholder processes that govern participation and notification. Further, FERC Order 890 requires stakeholder participation and transparent processes.
Response: The SDT is required to follow the VRF guidelines established by NERC and FERC.. No change made.		

Organization	Yes / No	Question 2 Comment
Ameren	No	The VRF for Requirement R8 should remain Low. There is no significant risk to the reliability of the BES if a Planning Assessment is not distributed to another entity, or if a documented response is not provided within 90 days of a request. The assignment of some VRFs are inconsistent with the importance of the requirements. R2 requires the development of an assessment and it is determined to have a high VRF. However, R3 and R4 require that studies be performed and these studies are determined to have a medium VRF. Performing the studies is essential to developing an assessment and more important to maintaining reliability. If the VRFs for R3 and R4 are correct, then the VRF for R2 should be no higher than medium. The VRF for R5 to develop a steady-state voltage criteria is determined to be medium. However, the VRF for R6 to develop instability criteria is determined to be low. If the VRF for R6 is correct, then the VRF for R5 should also be low.
Response: The SDT is required to follow the VRF guidelines established by NERC and FERC. No change made. The SDT agrees that studies are essential to the Planning Assessment but believes that the Planning Assessments are more than just the studies. For example, under the correct set of circumstances, an entity can use past studies in their Planning Assessment. Therefore, the SDT believes that the VRFs assigned are correct and in adherence with established guidelines. No change made. The SDT believes that having the criteria (Requirement R5) is more important for the reliability of the BES than documenting the methodology (Requirement R6). No change made.		
SERC Planning Standards Subcommittee	Yes	
SPP Reliability Standards Development Team	Yes	
Entergy Services	Yes	
Imperial Irrigation District	Yes	
Progress Energy	Yes	

Organization	Yes / No	Question 2 Comment
American Electric Power	Yes	
Duke Energy	Yes	
Transmission Strategies, LLC	Yes	
NIPSCO	Yes	
Puget Sound Energy, Inc.	Yes	
South Carolina Electric and Gas	Yes	
Georgia Transmission Corporation	Yes	
United Illuminating	Yes	
TVA TP&C	Yes	
ISO New England Inc.	Yes	
GDS Associates, Inc.	Yes	Agree in general.
Pepco Holdings Inc	Yes	
Northeast Utilities	Yes	
Oncor Electric Delivery Company LLC	Yes	
Response: Thank you for your support.		

3. **If you have any other comments on this Standard that you have not already provided in response to the prior questions, please provide them here.**

Summary Consideration: Several commenters stated that the SDT failed to address significant concerns and that only minor changes were made from the prior draft. The SDT believes that some stakeholders based their review on a red-line document of the TPL standard which only describes changes made following the Quality Review (QR) team review of the standard; shown as a red-line document http://www.nerc.com/docs/standards/sar/tpl-001-2_redline_to_last_posted_110415.pdf. A complete and thorough red-line of all changes made from the prior 3/01/10 ballot period to the version posted on the most recent ballot (concluded on 5/31/11) was posted and communicated after the start of the last comment period. A number of changes were made in response to industry feedback prior to the latest ballot. Those changes can be viewed at: http://www.nerc.com/docs/standards/sar/TPL-001-2_Redline_to_last_balloted.pdf.

A number of commenters indicated they cast a negative vote and recommended the SDT delay further work on TPL-001-2 pending FERC's ruling on the revised Footnote 'b' to Table 1 found in the existing TPL standards. The SDT believes concerns in process efficiency related to this project and FERC's on-going review of the revised footnote 'b' should not be the sole reason for a negative vote on the new proposed TPL standard and that an entity's vote should be based on the technical merits of the standard. The SDT has taken care to ensure footnotes 9 and 12 in combination are written consistently with footnote 'b'. The SDT encourages that any negative ballot based solely on FERC's pending ruling on footnote "b" be revisited.

Some commenters stated they find the new standard to be poorly organized and too prescriptively written and that the existing standards are preferred over the proposed TPL-001-2. The SDT and others in industry, as evidenced by the 74% ballot approval, hold a different opinion in regard to the standard. The SDT believes the comments of one stakeholder well articulate its view of the standard: "The SDT, Observers, and the Industry as a whole have put a tremendous amount of thought and work into the development of this latest draft. While nobody should claim that this latest version is perfect, it is far clearer, more in tune with current industry needs, and much improved compared to the existing approved Standards that it will replace." The SDT believes many important improvements in transmission planning are driven by the proposed TPL-001-2 that will further improve reliability of the Bulk Electric System.

A few commenters questioned the term "non-redundant relay" as used in planning event P5 and asked the SDT to clarify a distinction between a "back-up relay" and a "redundant relay" and proposed the SDT provide a definition for the term "non-redundant". The SDT clarifies that redundant means 'duplicate capability resulting in the same outcome.' A redundant relay is not the same as back-up relaying capability which may result in more Facilities being removed for failure of the primary/redundant relay to operate as designed. The SDT believes this concept is widely understood by most in industry and does not see the need for a NERC Glossary Definition.

Several commenters noted that the standard makes use of new capitalized "defined" terms, yet the definitions proposed in previous drafts were removed from the most recent draft of TPL-001-2. The SDT clarified that two previously proposed

definitions that were part of this project were moved to another standard development project – Project 2010-10, titled "FAC Order 729". The two definitions, "Near-Term Transmission Planning Horizon" and "Year One" were approved by the NERC Board of Trustees on January 24, 2011.

Some commenters indicated that the standard' Implementation Plan should be extended to permit a full 5-years implementation of any Corrective Action Plans required due to short circuit studies. The commenters indicate that these studies are not presently covered by a NERC Reliability Standard and they see this as a significant "raising of the bar" as characterized by other new requirements. The SDT clarified that while a short circuit study requirement is new to mandatory enforceable standards, the SDT does not believe the short circuit study requirements present a significant "raising of the bar" for industry and that good utility short circuit practices are already in place to ensure safe operation of equipment. No extension in the Implementation Plan was made in regard to short circuit studies.

Several commenters stated an opinion that Requirement R1, Part 1.1.2 indicating the models maintained by the Transmission Planners should reflect "known outages … with a duration of at least 6 months", are more appropriately dealt with in the operational studies rather than planning studies and that the item should be removed from the standard. The SDT disagrees with the view that outages of 6 months or more should only be reviewed in the operations timeframe. Such an outage could be for an upcoming construction project requiring certain Facilities to be removed from service for long durations of time one or more years in the future and those situations should be evaluated with sufficient lead time to determine any vulnerabilities and development of sufficient Corrective Action Plans as required. The SDT retained the requirement in the standard.

A number of commenters stated that they believed that there was an inconsistency between Requirement R2, Parts 2.1 and 2.2, since qualified past studies were not allowed for the Long-Term Transmission Planning Horizon case. The SDT clarifies that the requirement to conduct a current annual study for one of the study years in the Long-Term Transmission Planning Horizon is intentional to drive earlier identification of potential Transmission performance limitations and earlier development of Corrective Action Plans (CAP). The study results can be used as qualified past studies as they advance to later years, including moving to the Near-Term Transmission Planning Horizon.

Several commenters stated that they believed that Requirement R2, Part 2.1.5 was ambiguous since it was not clear that the planner did not have to include multiple outages of long lead time components simultaneously. The SDT explained that Requirement R2, Part 2.1.5 does not require simultaneous outages of multiple long lead time components.

Some commenters expressed concerns with Requirement R2, Part 2.4.1 since they were concerned with the ability of planners to adequately model the dynamic behavior of Load. The SDT explained that the "aggregate" dynamic Load model may include high-level assumptions on Load profiles for industrial, commercial, and residential Loads that are applied generically across the planning area study based on the planner's engineering judgment and system knowledge. The model is not required to be "bus" specific.

The SDT appreciates the concern raised by multiple commenters in regard to the inclusion of the 2nd bulleted item of Requirement R3, Part 3.3.1 that states the steady-state Contingency analysis should include subsequent "Tripping of

Transmission elements where relay loadability limits are exceeded". The commenters believe this concern is addressed by PRC-023 and should be removed from the standard. The SDT believes the item is warranted and that TPL studies may earlier identify and flag relay setting concerns based on required Long-Term Transmission Planning Horizon studies. Within the TPL standard, such a concern would have a Corrective Action Plan that would address the issue which would also meet the expectations of PRC-023. The SDT sees this as a defense in depth approach.

A number of commenters expressed concern that Requirement R7 was administrative and was not required. The SDT explained that it believes that the requirement is necessary to ensure that there are no gaps created between the Transmission Planners and the Planning Coordinators when they determine their individual responsibilities.

Several commenters stated that they had concerns with Requirement R8. These concerns are that the requirements create excessive work and should include time limits on requesting the Planning Assessment, are ambiguous, and should include the ability to post the Planning Assessment. The SDT explained that the requirements are only to distribute the Planning Assessment, which should not require a large amount of work, and the requirements are clear that the planners must distribute to adjacent Transmission Planners and Planning Coordinators and others with a reliability need. The SDT further explained that posting the Planning Assessment could meet the requirement to distribute.

Several commenters stated that they believed that Table 1, P2-1 was inconsistent with Footnote 7. The SDT explained that Footnote 7 was included to clarify that "Opening a line section without a fault" could include, but does not always, creating a radial line section with Load and that the planner must evaluate this situation as a part of P2-1.

No requirements were changed as a result of comments received. However, two bulleted items were marked as bullets incorrectly and that formatting has been corrected.

3.1.1 Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2 Tripping of Transmission elements where relay loadability limits are exceeded.

4.3.1.1 Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2 Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3 Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

Organization	Yes/ No	Question 3 Comment
James A. Maenner	Ballot Comment	The medium VRF for R8 should remain at low. Not sharing planning assessments with other entities within 90 days doesn't create a serious or imminent threat to the BES.
Response: The change to a Medium VRF resulted from the Quality Review (QR) conducted by the independent QR team prior to the last ballot. This requirement is seen as more than simply an administrative response to a request but rather a proactive step required of the applicable planner to share results of its system assessment which may include and reflect potential system impacts to neighboring systems. The SDT is required to follow the VRF guidelines established by NERC and FERC. No change made.		
San Diego Gas & Electric	Ballot Comment	Clarity of this standard is getting worse. Our earlier comments did not seem impacting. At this point, we believe the existing TPL-001-0.1, TPL-002-0a, TPL-003-0a and TPL-004-0 provide much better clarify for us to comply with the TPL standards.
Response: The SDT respectfully disagrees with your view. According to results of the last ballot, 74% of the ballot poolsupport the proposed standard. The SDT believes the standard clarifies a number of expectations and that appropriate changes have been made to further improve the future planning and review of the Bulk Electric System's ability to reliably serve users of the system. No change made.		
Western Electricity Coordinating Council	Ballot Comment	It is unknown at this time what the outcome of the FERC request for additional infomation related to footnote B will be, but if if results in changes to the language of footnote B, that may change our support for this standard.
Salt River Project	Ballot Comment	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In SRP's view, a Registered Entity's Board of Directors, state Utilities Commission, and/or its customers should determine what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining Affirmative vote.
Public Utility District No. 1 of Chelan County	Ballot Comment	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In our view, board of directors/Public Utility should have the determination what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote.
Snohomish County PUD No. 1	Ballot	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or

Organization	Yes/ No	Question 3 Comment
	Comment	controlled interruption of electric supply for an N-1 situation. In our view, a Registered Entity's Board of Directors, Utility Commission, and/or its customers should determine what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote.
Public Utility District No. 1 of Chelan County	Ballot Comment	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In our view, board of directors/Public Utility should have the determination what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote.
Clark Public Utilities	Ballot Comment	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In our view, the utility's elected board of commissioners should have the determination what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote.
Response: The SDT has taken care to ensure consistency in footnote 12 (and footnote 9) with the prior footnote 'b' revision supported by industry, approved by the NERC Board of Trustees and submitted for regulatory approval. No change made.		
Imperial Irrigation District		Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In our view, board of directors/Public Utility should have the determination what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote. 1. R2 (2.5): The value of assessing system stability for years 6-10 is questionable. Stability studies should be conducted for new generation interconnections or for planned major transmission system improvements that have regional impact. 2. R8 requirement to distribute all Planning Assessment results to adjacent PCs and TPs are excessive and cumbersome. Regarding R8, IID suggest the following languages:Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners in accordance with the overseeing Reliability Coordinator requirements. Any functional entity that has a reliability related need and submits a written request for the Planning Assessment results, the Transmission Planner and Planning Coordinator shall provide the latest Planning Assessment

Organization	Yes/ No	Question 3 Comment
		results within 30 days of such request.
Response: The SDT has taken care to ensure consistency in footnote 12 (and footnote 9) with the prior footnote 'b' revision supported by industry, approved by the NERC Board of Trustees and submitted for regulatory approval. No change made. Regarding Requirement R2, Part 2.5, the SDT believes the requirement as written meets your perspective. For the long-term period, the stability assessment is only required to address "… the impact of proposed material generation additions or changes in that timeframe …". No change made. Regarding Requirement R8, the SDT disagrees that the requirements for distributing assessment results should be based on requirements of the Reliability Coordinator. The Reliability Coordinator is primarily focused on real-time issues/concerns not planning horizon timeframes. The SDT does not see this requirement as overly burdensome as the results could be emailed to multiple entities in a single notification. Additionally, we do not see Requirement R8 as excessive as we believe it is important to communicate assessment results with others in industry whose systems for which they are responsible for may be impacted by the host analysis being communicated. No changes made.		
Gainesville Regional Utilities	Ballot Comment	I do have one point of concern for your consideration; This standard does raise the bar in some areas, most notably for an entity the size of GVL it applies performance requirements for long lead equipment emergency replacement. For example if we don't have the ability to replace a transformer at Parker within a few months of failure, then we would have to demonstrate that we can meet many (but not all) of the same performance criteria without the transformer that we can with the transformer.
Response: The commenter is referring to expectations stated in Requirement R2, Part 2.1.5 related to a spare equipment strategy regarding the potential unavailability of long lead time equipment that could be out of service for a year or more in the absence of a spare replacement. The SDT believes it has appropriately limited the analysis to address Planning Events P0, P1, and P2 as stated in Table 1. No change made.		
Beaches Energy Services	Ballot Comment	My biggest concern is the spare transformer issue. Beaches Energy Services is fine because our Transmission Planner (FMPA) actually run the assessments proposed in the new standard and we have excess transformer capacity; but, I'm concerned for other small entities. Essentially, the requirement will likely be interpreted as requiring us to meet the loss of a Bulk Electric System transformer, plus another contingency (two contingencies) to the same performance criteria as a single contingency, if we don't have a spare. This seems discriminatory to small entities.
Response: The commenter is referring to expectations stated in Requirement R2, Part 2.1.5 related to a spare equipment strategy regarding the potential unavailability of long lead time equipment that could be out of service for a year or more in the absence of a spare replacement. The SDT believes it has appropriately limited the analysis to address Planning Events P0, P1, and P2 as stated in Table 1. Any organization – large or small - meeting functional entity		

Organization	Yes/ No	Question 3 Comment
registration obligations has the potential to impact the Bulk Electric System and their assessments must include appropriate spare equipment strategies. No change made.		
Hydro One Networks, Inc.	Ballot Comment	Hydro One Networks is casting a negative vote. Other than a few changes related to Footnotes 9 and 12 of Table 1 and VSLs, the other changes in the proposed draft are minor. The concerns of the industry on several important issues have not been sufficiently addressed in this draft. For detailed comments please refer to our submission through the on-line comment form.
Response: The SDT believes the commenter's response is based on their review of red-line document of the TPL standard which only describe changes made following the Quality Review (QR) team review of the standard which was conducted prior to the last ballot. That red-line was shown as http://www.nerc.com/docs/standards/sar/tpl-001-2_redline_to_last_posted_110415.pdf. A complete and thorough red-line of the TPL standard showing all changes made from the prior 3/01/10 ballot period to the version posted on the most recent ballot (concluded on 5/31/11) was posted during the last comment/ballot period. A number of changes were made in response to industry feedback prior to the last ballot. Those changes can be viewed at: http://www.nerc.com/docs/standards/sar/TPL-001-2_Redline_to_last_balloted.pdf. The SDT's response to input provided by the on-line comment form is addressed in responses to Q1 and Q2 above. No change made.		
Hydro-Quebec TransEnergie	Ballot Comment	These are the two major concerns : * In Table 1 footnote 3 : Again, the definition of EHV facilities shoud be changed to something like : Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as those representing the backbone of the System, generally at voltage greater than 300 kV, and high voltage (HV) Facilities defined as those not representing the backbone of the System, as determined by the Planning Coordinator and approved by Regional Entity. * In Table 1 b : "Consequential Load Loss as well as generation loss is acceptable as a a consequence of any event excluding P0". We should also add Firm Transmission Services Loss is also acceptable (particularly in P1 Loss of a single pole of a DC line for which the transfer is reduced accordingly to the remaining pole capability). "
Response: In regard to Table 1 footnote 3, the SDT respectfully disagrees and believes the footnote is clear in regards to what subset of Bulk Electric System Facilities are classified as EHV and that the remaining fall to HV Facilities. Anything not deemed Bulk Electric System by a Regional Entity is outside of the scope of footnote 3 and the footnote clarifies that Table 1 sometimes has unique performance requirements depending on the event studied. The SDT believes the categorization is correct. No change made. The SDT disagrees that Firm Transmission Service (FTS) may be interrupted for all events. The events where the interruption of FTS is not permitted are shown with a "No" in the column titled "Interruption of Firm Transmission Service Allowed", however, footnote 9 clarifies that interruption of Firm Transmission Service		

Organization	Yes/ No	Question 3 Comment
can be used as both a corrective action and system adjustment as permitted within Table 1. For the specific issue raised, loss of a single pole of a DC line, to the extent the availability of the DC pole is a condition of the transfer being viable, footnote 4 may also address the commenter's concern. No change made.		
Independent Electricity System Operator	Ballot Comment	IESO is generally supportive of the draft of TPL-001-2 as evidenced by our previous AFFIRMATIVE vote during the last ballot. Further, IESO also supported the revisions to Footnote 'b' to Table 1 of the TPL standards under Project 2010-11. That revision was balloted and approved by the ballot pool in February 2011 and filed with FERC for approval in March 2011. The revised footnote has been incorporated into the current draft of TPL-001-2 as Footnotes 9 and 12 but the Commission, by letter to NERC dated May 17, 2011, has requested NERC to provide supplemental information before the revised Footnote 'b' could be approved. In light of FERC's request and the uncertainty regarding the final provisions of these footnotes, coupled with the ongoing work on Project 2010-17 for the revision of the BES definition and development of an Exception Process and the impact that may have, we respectfully suggest that the drafting team delay further work on TPL-001-2 pending FERC's ruling on NERC's petition seeking approval of the transmission planning standards that contain the revised Footnote 'b' to Table 1.
Response: The SDT believes IESO's concerns in process efficiency related to this project and FERC's on-going review of the prior submittal of a revised footnote 'b' should not be the sole reason for a negative vote on the new proposed TPL standard and that IESO's vote should be based on the technical merits of the standard. The SDT encourages IESO to revisit its negative ballot position during the recirculation ballot. As stated in the comment provided, IESO finds footnotes 9 and 12 to be written consistently with footnote 'b' and if IESO supported footnote 'b', the SDT encourages continued support of the issue in the new proposed TPL-001-2 and doing so shows support of the standard on its technical merits. No change made.		
Lakeland Electric	Ballot Comment	LAK appreciates the hard work of the Standard Drafting team and applauds the significant improvement of clarity of the draft standard. FMPA believes we are almost there, but, there are a number of issues left to resolve. Issues that Cause FMPA to Recommend a Negative Vote A. Spare Equipment, R2.1.5 - The requirement reaches beyond the FERC directive. The directive was: "Accordingly, the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy." So, the directive is only to address planned outage, not unplanned outages. Also note that the applicability to GSUs is ambiguous. "Transmission" is defined as: "An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems." Is the "point of supply" the generator terminal, or the GSU high side terminal?

Organization	Yes/ No	Question 3 Comment
		B. Table 1, under first heading of "Steady State Only", bullet i is open to interpretation. Many utilities use steady state P-V analyses to study voltage stability and design UVLS systems in apart around those steady state analyses. Would this bullet essentially eliminate P-V and Q-V studies and the related use of UVLS?
Response: The SDT respectfully disagrees that the Commission directive regarding a spare equipment strategy is limited to planned outages. In Order 693, Par 1725, the Commission states in its discussion "Thus, if an entity's spare equipment strategy for the permanent loss of a transformer is to use a "hot spare" or to relocate a transformer from another location in a timely manner, the outage of the transformer need not be assessed under peak system conditions." The SDT believes FERC clearly intended the spare equipment strategy to cover a catastrophic loss of such long lead-time equipment. Further, the SDT believes it has appropriately limited this review to a small subset of the overall Planning Events – P0, P1, and P2 and for a loss that would be sustained for a year or longer. No change made. The SDT refers the commenter to footnote 5 in regards to the applicability of GSU transformers. The "point of supply" is irrelevant in regards to planning a Transmission system for potential generation loss. The applicable generation is any unit deemed to be BES generation supply by the applicable regional entity. No change made. The SDT points out that Table 1 header note "i" applies to steady-state only and is intended to prevent any reduction in non-consequential Load due to what the planner believes to be sensitive Load loss that may drop out as voltage declines. It is the understanding of the SDT that most utilities only reflect or account for such reduction in Load in the transient timeframe and that planning decisions based on steady-state analysis would appropriately account for serving the non-consequential Load unless subject to interruption per that studied planning event. The bullet does not eliminate P-V or Q-V studies nor does it prohibit use of UVLS as a mitigating action where non-consequential load interruption is permitted. No change made.		
New Brunswick Power Transmission Corporation	Ballot Comment	Foot Note 12: Rather than requiring planning entities to have a open and transparent planning stakeholder process, which could require significant costs and administration, the foot note should focus on ensuring that affected loads/entities are aware of the possible risks of load loss and alternatives and provide for affected stakeholder feedback
Response: The SDT believes the open and transparent stakeholder process described by footnote 12 provides an efficient platform for which the affected end-users and other registered entities would be made aware of instances where non-consequential Load loss is being considered as a Corrective Action Plan and provides the best opportunity for feedback. The process envisioned is already in place in various areas across the various Interconnections in which the NERC Reliability Standards are enforceable. No change made.		
Powerex Corp.	Ballot Comment	Powerex has submitted a negative ballot for Draft #6 of Standard TPL-001 because Powerex has concerns regarding Footnotes 9 and 4 that need to be addressed. Details of our concerns are summarized below.

Organization	Yes/ No	Question 3 Comment
		Background: The work that transmission planners do to ensure Firm Transmission Service is tremendously important for the reliability of the Bulk Electric System and forms a key part of the foundation upon which system operators and energy market participants interact. As a Purchasing-Selling Entity, Powerex is primarily concerned about Footnote 9 that conditions when interruption of Firm Transmission Service may allowed. We believe that the goals of maintaining system reliability and enhancing market participation will both be best served if the conditions for interrupting Firm Transmission Service become clear and unambiguous in the TPL-001-2 Standard. In our experience, Transmission Providers have different interpretations of the TPL-001 Performance Table and because of latitude previously granted by Footnote B have different perspectives of when Interuptions of Firm Transfers is acceptable. Below we describe the two interpretations using the language of the proposed TPL-001 standard. Interpretation #1: Following loss of the most critical transmission element under stressed conditions, the transmission provider plans to supply the forecast peak loads and Firm Transmission Service indefinitely. o Typically this is achieved by assuming that the System Operators would, within a few minutes of the P1 Single Contingency, curtail all non-firm transmission service and then arm Special Protection Schemes that could result in Interruption of Firm Transmission Service or Non-Consequential Load Loss in the event of a P6 Multiple contingency. Interpretation #2: Following loss of the most critical transmission element under stressed conditions, the transmission provider plans to supply the forecast peak loads indefinitely but may curtail all Firm Transmission Service within 20 minutes if required. o Typically this occurs on systems where there are no Special Protection Schemes to address P6 Multiple contingencies, consequently, the transmission planners assume that curtailment of all non-firm AND as much Firm Transmission Service as required will occur within ~20 minutes of the P1 Single Contingency because the Operators must prepare their transmission system to withstand the next worst contingency. Currently, Purchasing-Selling Entities must plan for situations where they could see their Firm Transmission Service on certain paths curtailed within 20 minutes of a P1 contingency. The less stringent interpretation of the TPL-001 Performance Table that allowed a P1 contingency to change into a P6 contingency within the same operating hour, has resulted in situations where the Firm Transmission Service for inter-regional transfers face significantly greater risks of interruption than the Firm Transmission Service provided to local Load Serving Entities. Powerex recommends that the Standards Drafting Team revise TPL-001 such that all Transmission Planners will know that they should plan for Firm Transmission Service to be sustained indefinitely following P1 contingencies. Specific Comments on TPL-001-2: Footnote 9: Deviation from the Approved Footnote B Powerex believes that the Footnote B, as approved by the NERC Board of Trustees on February 17, 2011, is more stringent than the previous Footnote B and will have the effect of ensuring that Firm Transmission Service can be sustained indefinitely following P1 contingencies. The key difference of the proposed Footnote 9 is that it adds

Organization	Yes/ No	Question 3 Comment
		the phrase "as a System adjustment" to the approved version of Footnote B. We believe this addition would cause the practice of curtailing Firm Transmission Service within 20 minutes of P1 contingencies to continue. Consequently, we recommend that the proposed Footnote 9 maintain the approved wording as follows: Footnote 9: An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed (deletion)[as] a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch.... For consistency, Table 1 should also be modified to remove the Footnote 9 reference from the Initial Condition Column for the P3-Multiple Contingency and P6 Multiple Contingency Categories. Footnote 9: Clarity on what is meant by "Resources obligated to re-dispatch" It is unclear to many parties what is meant by an obligation to re-dispatch. Some interpret this as a right to direct the Source to curtail energy scheduled on Firm Transmission Service. Our belief is that "an obligation to re-dispatch" should correspond to a formal agreement with a Generation Owner, located on the load side of a transmission constraint, to resupply the load that had been receiving energy from a remote source before the Firm Transmission Service was curtailed. Consequently, we recommend that Footnote 9 be revised as follows: Footnote 9: ..... a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch [to ensure uninterrupted energy supply to the Load-Serving Entity(ies)], where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss.... Footnote 4: Conditional Firm Transmission Service Footnote 4: "Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service." In a sense, offering conditional firm transmission service is analogous to selling land in a known flood plane - this can be a perfectly acceptable option provided all parties involved in current and future transactions can quantify the risks and manage them appropriately. There needs to be coordination between the planners, operators and marketers to ensure that the conditions that could lead to curtailment of Conditional Firm Transmission Service are understood and the associated risks properly managed. We are concerned that in the absence of coordination, specifically additional requirements included in the BAL and INT standards, energy that is scheduled on conditional firm could actually be marketed as firm and as a result the counterparties to some transactions may not be aware of the curtailment risks they could face.
Response: Footnote 9 - The SDT believes that footnote 9 appropriately allows interruption of Firm Transmission Service as both a corrective action to the initial event studied and as a permissible intermediate "system adjustment" when evaluating a multiple Contingency event such as P3 or P6. The key is that there must		

Organization	Yes/ No	Question 3 Comment
be no loss of Load and the planner must be able to show that the curtailment is supported by a valid re-dispatch of generation that would be "obligated to re-dispatch." Therefore, the planner cannot simply re-dispatch units outside the area of control for the transmission system for which it is reviewing – the re-dispatch must be valid and realistic. The commenter indicates an opinion that footnote 9 introduces a difference from the revised footnote 'b' because footnote 9 is applied to multiple Contingency planning events P3 and P6 as an intermediate step – system adjustment. However, the SDT believes that footnote 'b' is consistent as it does not explicitly distinguish between the two – corrective action or system adjustment following the single Contingency event that may precede a multiple Contingency event. No change made. Footnote 4 – The SDT agrees with the commenter that the specifics of Conditional Firm Transmission service including the potential/rights for curtailments need to be well understood by all parties involved but the SDT has not identified any BES reliability gaps. No change made.		
Tucson Electric Power Co.	Ballot Comment	The definition for Near Term Planning Horizon was deleted, but the formal term is used in other sections such as R2.2.1. There should be a linkage to MOD standard (e.g. 028, 029 & 030) definitions such as 13 months, etc.
Response: Two previously proposed definitions that were part of this project were moved to another standard development project – Project 2010-10 titled "FAC Order 729". The two definitions, "Near-term Transmission Planning Horizon" and "Year One" were approved by the Board of Trustees on January 24, 2011.		
Western Area Power Administration	Ballot Comment	Standard is improved over previous drafts, but would like to see further changes. Please see suggestions and comments provided on the Official Comment Form.
Response: Please see the SDT's response to your suggestions in Question 1.		
SERC Planning Standards Subcommittee		R1 does not seem to address issues where data errors have been introduced into the latest model data. Also, R1 and its VSL may be interpreted to exclude the use of past studies. The Implementation Plan should include a five-year delay in the effective date for short circuit studies (R2 parts 2.3 and 2.8) since these studies are not required in the current version 0 standards. The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Response: Requirement R1 of the new TPL standard requires the Transmission Planner and Planning Coordinator to maintain System models within its		

Organization	Yes/ No	Question 3 Comment
respective area of responsibility. The requirement indicates that information received via MOD-010 and MOD-012 shall be "supplemented by other sources as needed" and to the extent errors and omissions were either discovered by, or brought to the attention of, the Transmission Planner or Planning Coordinator Requirement R1 establishes an expectation that these "other sources" would be utilized to accurately "represent the project System conditions" being studied. No change made. Requirement R1 is applicable to models used for both current and past studies. No change made. Implementation Plan, Short Circuit Studies – While short circuit study requirements may be new in the realm of mandatory enforceable standards, the SDT does not believe that they present a significant "raising of the bar" for industry. The SDT believes that prudent short circuit practices are effectively in place today to ensure safe operation of the equipment. Therefore, no extension in the Implementation Plan was made in regard to short circuit studies.		
SPP Reliability Standards Development Team		A5 It would seem that 84 months wouldn't be universally attainable due to different system configurations, terrain, geography, and permitting issues that are required to complete a corrective action plan. In 2.4.1 we would like to see better clarity on what an Aggregate system load model is and how granular it should be. If the answer is a very detailed representation of the load system then it may take a longer time to implement. In section 2.7 we would to see clarification on the sensitivity analysis. Is this in reference to seasonal models and differences in fuel availability? We need more detail on how this is to be done so that it won't be left up to interpretation. We would like for clarification of the planning assessment and who is performing which tasks. We would also like to utilize a regional assessment due to limited resources. Under which criteria should the assessment fall under the regional entity or the individual companies? In section 3.4.1 this type of coordination could be difficult due to other adjacent entities on different schedules and some possibly couldn't have the amount of detail to incorporate into another's processes. We know this is generally covered in coordination of real time operations and wonder if it is appropriate to require this type of coordination in the long term process. Is there already an operational standard that covers this? Would it be better to address this in the operational standards? PC's between regions are already coordinating for long term studies. Should this standard fall more on the back of the PC's rather than the TP Can we get a bright line definition of what apparent impedance swings means? R4.3.1 will the detailed amount of data then be incorporated back into the NERC modeling processes and create a more detailed model with better accuracy?

Organization	Yes/ No	Question 3 Comment
		R8 We do not agree that we should provide the assessment to every adjacent PC and TP. We do agree however that if requested by these entities we would provide the assessment. We don't mind sharing information with requestors but would like a longer duration than 30 days due to the fact that we would like to know what type of "reliability need" any entity would have considering that some of the information could be considered CEII. Non disclosure agreements may be needed in order to provide this information.

Response: Effective Date (A5) – The SDT believes the 7 year (84 month) transition to areas where the standard significantly raises planning expectations over the existing standard is more than sufficient for the vast majority of the continent and for most Corrective Action Plans. To the extent additional time is required an entity would need to submit a timely mitigation plan with its Regional Entity organization. No change made.

The "aggregate" dynamic Load model may include high-level assumptions on Load profiles for industrial, commercial, and residential Loads that are applied generically across the planning area study based on the planner's engineering judgment and system knowledge. The model is not required to be "bus" specific. No change made.

In Requirement R2, Part 2.7, it is stated that a Corrective Action Plan is not required solely for a "single sensitivity study". The standard envisions a portfolio of sensitivity analyses being established for a planning area and the standard does not require Corrective Action Plans for single sensitivity results that may have placed the system in a greater stressed analysis (i.e., heavy system transfers) for its initial (P0) sensitivity model over other models that did not identify performance criteria violations for the same Contingency event studied. No change made.

If a Regional Entity acts as your "Planning Coordinator" then tasks between the Planning Coordinator and Transmission Planner are to be defined as part of Requirement R7. The standard does not prohibit the use of valid studies performed by 3rd parties for a given planning area. No change made.

In regards to Requirement R3, Part 3.4.1, the SDT envisions that knowledge of the applicable Contingencies on neighboring systems would develop over time and be discovered with the results being distributed in Requirement R8. The SDT believes that this is an important improvement to the planning timeframe analysis and that system information learned in the operations environment should most certainly be considered to the extent it improves the robustness of the Planning Assessment. No change made.

Both the registered Transmission Planner and Planning Coordinator have functional entity responsibility for Transmission system planning as defined by NERC's Functional Model. The SDT believes the new TPL-001-2 is appropriately aimed at both throughout the standard. Additionally, Requirement R7 should address the commenter's concern and if greater responsibility can be agreed upon for the Planning Coordinator for a particular area of the continent the standard would not prohibit such a determination. No change made.

The "apparent impedance swing" is the trajectory of changes in the apparent impedance seen by a distance relay for various system and fault conditions. In the case contemplated in Requirement R4, Part 4.1.2, it is the trajectory seen by the distance relay for the initial fault and the subsequent generator(s) pulling out of synchronism. If that trajectory were to come within the tripping characteristic of the relay for a sufficient length of time, the relay would cause its associated line

Organization	Yes/ No	Question 3 Comment
to trip. No change made. This standard does not address the studies performed by NERC or its model building practices. The SDT and (based on the recent ballot approval of 74%) the majority of industry support Requirement R8 – no change made.		
MRO's NERC Standards Review Forum		The NSRF recommends that the term, "System" be replaced with "BES" in various places throughout the standard when the reference should not be to the collective generation, transmission, and distribution systems, which is the definition of the NERC Glossary term, "System". These locations are: R2.1.4, R2.1.5, R2.4.3, R2.6.2, R2.7, R2.7.1, R2.7.4, R2.8.1, R2.8.2, R3.5, R4.5, R5, and R6
Muscatine Power and Water		MP&W recommends that the term "System" be replaced with "BES" in various places throughout the standard when the reference should not be to the collective generation, transmission, and distribution systems. This is the current definition of the NERC Glossary term "System". The locations where "System" can be found in the Standard are: R2.1.4, R2.1.5, R2.4.3, R2.6.2, R2.7, R2.7.1, R2.7.4, R2.8.1, R2.8.2, R3.5, R4.5, R5, and R6.
Response: Even though the capitalized term "System" includes distribution components, the SDT believes that its usage within this standard is correct because the Reliability Standards apply only to the BES. Therefore, adding additional qualifiers is not needed. No change made.		
BC Hydro		BC Hydro agrees with merging the standards together into one and we feel the new version brings further clarity to the annual planning assessment. BC Hydro would vote Affirmative for bringing clarity, however we do not believe the rewording in Footnote 9 is clear which is why we are voting Negative. Footnote B, as approved by the NERC Board of Trustees on February 17, 2011 was reworded as Foot Note 9 in the proposed TPL 001-2 draft 7 amendment. This rewording still does not clearly define what impact the proposed revision would have on the curtailment of firm transfers in the regional entities.
Response: The equivalent of the revised footnote 'b' as approved by the NERC Board of Trustees on February 17, 2011 is addressed by the combination of two footnotes – footnote 9 and footnote 12 – in the new proposed TPL-001-2 standard. The SDT believes that footnote 9 appropriately allows interruption of Firm Transmission Service as both a corrective action to the initial event studied and as a permissible intermediate "system adjustment" when evaluating a multiple Contingency event such as P3 or P6. The reliance on the interruption of Firm Transmission Service in the Planning Horizon is limited in two ways. First, there must be no planned use of firm Load shedding and second, the planner must be able to demonstrate that the curtailment is supported by a valid re-dispatch of generation that would be "obligated to re-dispatch." Therefore, the planner cannot simply re-dispatch units outside the area of control for the transmission system for which it is reviewing – the re-dispatch must be valid and realistic. No change made.		

Organization	Yes/ No	Question 3 Comment
Entergy Services		Footnote 12 to Table 1 concerning non-consequential load loss should be clarified. The existing language will result in difficulties in proving compliance. Suggested language would be:"Planned or controlled interruption of Demand supplied by Transmission Facilities made temporarily radial as a result of a P1 or P2 event and where the location of the planned loss of Demand is limited to those Transmission Facilities made radial.
Response: The SDT in a separate standards development project - Project 2010-11 TPL Table 1 Order – attempted the radial concept described by the commenter in its revision of footnote 'b' as used in the existing set of TPL standards. The proposed "radial" footnote 'b' was presented for industry ballot from 05/17/10 through 05/27/10 and failed at 63.8%. Following an industry technical conference, the SDT continued to work on footnote 'b' and a revised version was approved by the NERC Board of Trustees on February 17, 2011. The combination of footnotes 9 and 12 consistently apply the industry approved revised footnote 'b' in the new standard. No change made.		
Tri-State Generation and Transmission Assn., Inc.		R1.1 to "System models used for Steady State and Stability Analysis shall represent:" Much of what is in R1.1 is unnecessary for Short Circuit studies. In contrast, there are items not mentioned in R1.1 that are necessary for short circuit studies. R2.1.4 requires sensitivity analysis to study "a range of credible conditions that demonstrate a measurable change". How will the required actions in R2.1.4 be documented or measured, and what is accomplished by performing sensitivity analysis in the context of a system performance assessment? In R2.3, change the first sentence to read "The short circuit analysis portion of the Planning Assessment shall be conducted annually, using one of the cases described in 2.1.1, addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6." There appears to be no reason to perform short circuit studies for all three Near-Term Transmission Planning Horizon cases. R2.4.3 requires sensitivity analysis to study "a range of credible conditions that demonstrate a measurable change". How will the required actions in R2.4.3 be documented or measured, and what is accomplished by performing sensitivity analysis in the context of a system performance assessment? R2.7.1 remove the last bullet. We believe these programs are already factored into the load forecast, as they are associated with resource scheduling and planning load serving, and not transmission planning. In particular, DSM measures would fall under R2.4.1, and the term "new technologies, or other initiatives" The language of Requirement 3 unnecessarily repeats the language of R1 and R2. As now written, R3 states "For the steady state portion of the Planning Assessment, each Transmission Planner and Planning

Organization	Yes/ No	Question 3 Comment
		Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1." R3 We recommend that the introductory language in Requirement R3 be changed to read "The studies in Requirement R2, Parts 2.1, and 2.2 shall be performed using models as defined in Requirement R1 in accordance with the following criteria." We believe that Requirements 3.1 and 3.4 should be combined into R3.1, eliminating R3.4. It is redundant to have Requirement 3.1 say "perform R3.4". We recommend that R3.4 be deleted and that R3.1 be replaced with:R3.1 Planning event studies shall be performed in accordance with "Table 1 - Steady State & Stability Performance Planning Events;" and shall be based on a supportable Contingency list. Comment: The content of 3.4.1 was intentionally omitted as it is redundant with R7. Also, the language "...more severe System impacts..." was intentionally omitted as it could be subject to a wide range of interpretations.Similarly, we recommend that R3.5 be deleted and that R3.2 be replaced with:R3.2 Extreme event studies shall be performed in accordance with "Table 1 - Steady State & Stability Extreme Events;" and shall be based on a supportable Contingency list. We recommend the following new requirement be inserted after the revised R3.2 language:Should the extreme event studies identify potential Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted. Comment: As before, the language "...more severe System impacts..." was intentionally omitted as it could be subject to a wide range of interpretations. We recommend removing the second bullet of R3.3.1, "Tripping of Transmission elements where relay loadability limits are exceeded" for the following reasons:1. There is currently no tool to model relay loadability characteristics in Steady State analysis. 2. Requirement R3.3.1 would require inclusion of relay models in modeling data that are not currently provided. MOD-012 does not require impedance or overcurrent relay models to be submitted.3. In Requirement 3.3.1, the second bullet, it is impossible to model complete and accurate relay loadability using present-day steady state simulation tools. At best an individual point could be chosen to model relays based on a selected power factor. We recommend changing the opening text of Requirement R.3.3.2 to say "Simulate the expected automatic or manual operation..." Subrequirement R4.1.2 represents a tremendous increase in dynamic modeling complexity. Modeling relay

Organization	Yes/ No	Question 3 Comment
		action during apparent impedance swings would require inclusion of impedance relay models in modeling data that are not required to be submitted in MOD-012. If such modeling is necessary, then the corresponding data requirements need to be addressed in MOD standards. We believe that Requirements 4.1 and 4.4 should be combined into R4.1 as shown below and R4.4 should be deleted. It is redundant to have Requirement 4.1 say "perform R4.4." We recommend R4.1 language be revised to read as follows:R4.1 Planning event studies shall be performed in accordance with "Table 1 - Steady State & Stability Performance Planning Events;" and shall be based on a supportable Contingency list.Comment: The content of 4.4.1 should be omitted as it is redundant with R7. Also, the language "...more severe System impacts..." should be omitted as it could be subject to a wide range of interpretations. Similarly, R4.5 should be deleted and R4.2 should be replaced with:R4.2 Extreme event studies shall be performed in accordance with "Table 1 - Steady State & Stability Extreme Events;" and shall be based on a supportable Contingency list. We recommend the following new requirement be inserted after the revised R4.2:Should the extreme event studies identify potential Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the even(s) shall be conducted. Comment: As before, the language "...more severe System impacts..." was intentionally omitted as it could be subject to a wide range of interpretations. Clarify the first bullet in Requirement R4, part 4.3.1 by changing it to "High-speed (less than 1 second) reclosing, where the fault has cleared, and high-speed reclosing into the permanent fault , but in each case only if high-speed reclosing is utilized". In Requirement R4, part 4.3.1, third bullet, it is impossible to model complete and accurate relay loadability using present-day steady state simulation tools. Existing applications do have impedance relay models, but these models do not model many relay capabilities- for example, non-circular protection regions and load-encroachment. We recommend removing this bullet. The comment statement we made above referring to R4.1.2 also applies to R4.3.1. MOD-012 does not require reclosing relay model data to be submitted. If such modeling is necessary, then the corresponding data requirements need to be addressed in MOD standards. Furthermore, there is not a standard built-in reclosing relay model in current stability simulation tools. Comments regarding Table 1-We assume the headnote i. to Table 1 - "The response of voltage sensitive Load..." - means that studies must not rely on end-user load tripping to meet the performance requirements defined in TPL-001-2 but that it should be modeled (when known) so that its occurrence would be evident.

Organization	Yes/ No	Question 3 Comment
		We don't see the need to apply Footnote 12 to only certain contingency categories or certain events in categories. Recommend putting the footnote in the column header just as with Footnotes 1, 2, 3, and 4.Recommend changing "utilized" in Measurement M3 to "performed."Recommend changing "utilized" in Measurement M4 to "performed."Modify Measurement M7 to "Each Planning Coordinator shall provide dated documentation on roles and responsibilities of its Transmission Planners, such as..." The deleted phrase, "in conjunction with each of its Transmission Planners," appears to be unnecessary.

Response: Requirement R1, Part 1.1 – The SDT believes that the planners must have the general information in Requirement R1, Part 1.1 in order to conduct the necessary studies for steady state, stability, and short circuit. The requirement states that the planner shall maintain System models, not to have a single model that covers all three categories. The SDT believes that the planner will need the items in Requirement R1, Part 1.1 to develop the smaller set of items that are necessary for their short circuit models. No change made.

Requirement R2, Part 2.1.4 – This item requires the planner to show evidence of one or more sensitivity studies which show appreciable change from the prior projected (P0) system condition (pre-sensitivity adjustment). Measurable changes for the revised P0 system condition could be evidenced by line or transformer flows, voltages, a change in dispatch, load increase, etc., assuming the change places additional stress on a portion of the system being reviewed for the sensitivity studied. The sensitivity analysis is important for the applicable entity to better understand their system's vulnerability to alternate "base (P0)" conditions. The intent is to develop a portfolio of potential credible conditions so that the planner better understands potential vulnerabilities. In the Corrective Action Plans (CAP) area of the standard, Requirement R2, Part 2.7, a CAP may be required if a Planning Event shows performance criteria concerns for one or more sensitivity scenarios. No change made.

Requirement R2, Part 2.3 – The standard states that the planner shall maintain System models, not to have a single model that covers all three categories - for steady state, stability, and short circuit. It is common within many organizations that separate models are maintained for short circuit analysis since they require breaker configuration details not contained within steady-state load flows. Additionally, short circuit models may not have end-use Load represented but rather emphasis is on system topology, impedance, generation dispatch, fault location etc. No change made.

Requirement R2, Part 2.4.3 – same response as Requirement R2, Part 2.1.4 above.

Requirement R2, Part 2.7.1 – The SDT disagrees that the last bulleted item which includes use of a rate application or DSM program would be inclusive to the forecasted Load within the model studied. No change made.

Requirement R3 – The SDT clarifies that Requirement R2 refers to an "annual assessment" which collectively includes current or past studies, Corrective Action Plans, etc. required for steady-state, stability, and short circuit analysis. Requirement R3 deals with a portion of the overall assessment and is focused on the

Organization	Yes/ No	Question 3 Comment
steady-state "study" requirements for the Near-Term and Long-Term Transmission Planning Horizons. No change made. Requirement R3, Part 3.1 – The SDT did not receive any significant industry objection to having Parts 3.1 and 3.4 separated. The proposed change is based on a formatting and style preference and does not address a reliability gap in the standard. No change made. Requirement R3, Part 3.2 – The SDT did not receive any significant industry objection to having Parts 3.2 and 3.5 separated. The proposed change is based on a formatting and style preference and does not address a reliability gap in the standard. No change made. Requirement R3, Part 3.4.1 and Requirement R7 are uniquely different and not redundant as suggested by the commenter. No change made. Requirement R3, Part 3.5 (proposed new 3.2 by commenter) – The commenter finds the term "more severe System impacts" too open to interpretation and suggests a focus on Cascading conditions. The SDT believes the requirement is clear as written and that the statement "more severe System impacts" is used to describe the latitude in engineering judgment afforded to the planner in developing its extreme Contingency list. Action is only required on the subset of items that show the potential for Cascading. No change made. Requirement R3, Part 3.3.1, bullet 2 – this does not require an "automatic" modeling feature but rather it could be further subsequent manual analysis performed as needed for a given Planning Event. For example, if a line flow shows >150% loading the planner may need to trip the circuit to see if a stable condition results and what performance criteria issues may be present. To the extent this could be automated through programming the planner may do so at their discretion. No change made. For similar reasons stated in the response to Requirement R3, Part 3.5, the SDT does not find the phrase "more severe System impacts" as vague and open to interpretation. No change made. Requirement R3, Part 3.3.1 - The SDT language does not require comprehensive relaying models. No change made. Requirement R3, Part 3.3.2 - The SDT does not believe the proposed wording changes provide any clarity and finds the item clear as stated. No change made. Requirement R4, Part 4.1.2 – The "apparent impedance swing" is the trajectory of changes in the apparent impedance seen by a distance relay for various system and Fault conditions. In the case contemplated in Requirement R4, Part 4.1.2, it is the trajectory seen by the distance relay for the initial Fault and the subsequent generator(s) pulling out of synchronism. If that trajectory were to come within the tripping characteristic of the relay for a sufficient length of time, the relay would cause its associated line to trip. With that explanation, the SDT does not believe the modeling requirements are overly complex or difficult to achieve. No change		

Organization	Yes/ No	Question 3 Comment
made. Requirement R4, Parts 4.1 and 4.4 - The SDT did not receive any significant industry objection to having Parts 4.1 and 4.4 separated. The proposed change is based on a formatting and style preference and does not address a reliability gap in the standard. No change made. Requirement R4, Part 4.5 - the SDT does not believe the proposed wording changes are warranted and finds the item clear as stated. No change made. Requirement R4, Part 4.3.1, first bullet – the SDT does not believe the proposed wording changes are warranted and finds the item clear as stated. No change made. Requirement R4, Part 4.3.1, third bullet – The SDT language in Requirement R4, Part 4.3.1 states "The analyses shall include the impact of subsequent" and does not require comprehensive relaying models. However, it does require that the planner take into account the effects of System Protection on System performance. No change made. Table 1 header note "i" – The SDT notes that this item only applies to steady-state load flow analysis and no assumed shedding of non-consequential sensitive Load is permitted for the steady-state analysis unless it is to be intentionally dropped as part of a Corrective Action Plan where warranted. No change made.		
Hydro One Networks Inc.		A. Regarding Requirement 1.1.2, assessment of "known outages... with a duration of at least 6 months", are dealt with in the operational studies rather than planning studies. In addition, any adverse impact that these outages might have, are mitigated by operational decisions rather than "planning" decisions within a 6-month horizon. It is suggested to move this requirement out of TPL standards and instead include it a relevant operational standards. B. The statement in R 2.1.4, "must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response", leaves room for very different interpretations by PCs and TPs as to the number and type of required sensitivity studies. Are all interpretations, based on the engineering judgment of the PC and TP, acceptable? C. The language of R 2.1.4 and 2.4.3 allowing to perform one or more sensitivities appears to be inconsistent with the language in R 2.7.2 which requires multiple sensitivities to determine if actions to resolve performance deficiencies are necessary. Will varying only one measurable quantity several times in multiple simulations constitute multiple sensitivity studies or one sensitivity study?

Organization	Yes/ No	Question 3 Comment
		D. The language of Requirement 2.1.5, "spare strategy", appears to be open-ended regarding the number of permutations to be analyzed. It is suggested to move this requirement out of TPL standard and instead have this issue dealt with in the operational standards. E. In R 2.2, the statement "be supported by the following annual current study, supplemented with qualified past studies" should be replaced with a similar statement in R 2.1 which says: "be supported by current annual studies or qualified past studies". F. In R 4.1.1, "For planning event P1: No generating unit shall pull out of synchronism" is too restrictive. In many cases a P1 event may result in instability of a small nearby generator without a significant impact on the reliability of BES. The same requirement states that "A generator being disconnected from the System ... by a Special Protection System is not considered pulling out of synchronism". If rejection of ANY generator by SPS is acceptable, why should instability of a small generator, resulting in its disconnection by its protection without a severe impact on the system, be unacceptable in all circumstances? If this requirement is unchanged, it dictates the addition of an SPS (Generation Rejection) for any unit that might go unstable without any benefit for the reliability of the BES. G. In Table 1, Event 1 of Category P2 and related Footnote 7 (simulation of LEO condition) are not clear (concern with the use of the word "possibly"). If the intension is to simulate LEO condition of tapped lines, this should be clearly stated in the table (without reference to "Opening of a line section" and use of different language in the footnote).

Response: A: The SDT disagrees with the view that outages of 6-months or more should only be reviewed in the operations timeframe. Such an outage could be for an upcoming construction project requiring certain facilities to be removed from service for long durations of time and those situations should be evaluated with sufficient lead time to determine any vulnerabilities and development of sufficient Corrective Action Plans as required. No change made.

B. The standard does not mandate the number of sensitivity analyses performed nor the number of adjustments made and engineering judgment of the Transmission Planner and Planning Coordinator is acceptable. No change made.

C. Requirement R2, Parts 2.1.4 and 2.4.3 are not inconsistent with Requirement R2, Part 2.7.2. With the various requirements, the planners are required to conduct multiple sensitivities. Therefore, Requirement R2, Part 2.7.2 could be used when the results of these multiple sensitivities identify common concerns. The situation described ~~would~~ could be considered multiple sensitivity studies, if the multiple simulations represent more than one of the studies in Requirement R2, Part 2.1.1 and 2.1.2 or Requirement R2, Part 2.4.1 and 2.4.2. No change made.

D. The spare equipment strategy is an important planning aspect to better assist operations. The SDT disagrees that the number of permutations is open-ended. The evaluation is simply a new P0 condition starting with a long lead-time (one year or more) facility removed from service followed by an analysis

Organization	Yes/ No	Question 3 Comment
covering the P0, P1 and P2 studies. No change made. E. The requirement for an annual current steady-state study in the Long-term Transmission Planning Horizon is intentional to drive earlier identification of potential transmission performance limitations and earlier development of Corrective Action Plans. The study results can be used as qualified studies as they advance to later years, including moving to the Near-Term Transmission Planning Horizon. No change made. F. The SDT respectfully disagrees with the commenter. For a P1 single Contingency event, the SDT believes, and a majority of industry stakeholders find it reasonable, that no Bulk Electric System (BES) generation unit be pulled out of synchronism due to the P1 event studied. If the "small" nearby unit is served below threshold kV and MW size limitations set by your Regional Entity to qualify as a BES unit, the unit would not be within scope of the standard. No change made. G. Table 1, footnote 7 – The SDT added the footnote to further explain its intent for P2-1 and to ensure that the planner assess the voltage of a load bus that was on a radial line. The word "possibly" was used since having load on a radial is not always the outcome of opening one end of a line section. No change made.		
Arizona Public Service Company		AZPS would like to reiterate its "Affirmative" voting recommendation with regard to the proposed revisions to the Standard. AZPS erroneously entered a "Negative" Standard vote for one of its voting segments.
Transmission Strategies, LLC		The SDT, Observers, and the Industry as a whole have put a tremendous amount of thought and work into the development of this latest draft. While nobody should claim that this latest version is perfect, it is far clearer, more in tune with current industry needs, and much improved compared to the existing approved Standards that it will replace.
Response: Thank you for your support.		
NIPSCO		1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. This is a little confusing to me. Does this mean the outage must last at least six months?Or does this mean at least model outages that last six months or more. If it is the latter then, I'm not sure that is stringent enough.There may be known critical outages occurring over peak that do not last 6 months. If non-consequential load loss is not allowed for loss of one element, then what about the next contingency? Couldn't that result in having to interrupt Firm service? Is that okay as a corrective action plan in the outage coordination horizon?Does this apply to both near-term and long-term planning? If so, we probably need to model additional unplanned potential outages on top of n-1 conditions.

Organization	Yes/ No	Question 3 Comment
		Lastly. in section 2.1.4 should there be a category for high/low wind conditions?
Response: Requirement R1, Part 1.1.2 is related to known existing conditions or known future conditions of facilities being removed from service; i.e., a construction project that requires an existing facility to be de-energized for a period of 6-months or more. This requirement should not be confused with hypothetical situations that could result in an extended loss of a facility. Those situations are the intended purpose of a sound spare equipment strategy. The standard only requires analysis of known or planned outages of 6-months or greater to be included within a P0 system condition. The planner could review shorter duration planned outages as part of its sensitivity analysis portfolio. No change made. The SDT does not believe there is a need to account for a high/low wind condition situation. The intended purpose of this suggested condition within the sensitivity portfolio is not clear. No change made.		
ReliabilityFirst		1. Requirement 8 and 8.1 uses the language of "Planning Assessment results". This language is not defined in the section of the standard that defines the terms of use. For consistency "Planning Assessment results" should be replaced with "Planning Assessment". 2. Requirement 2.1.5 has statements that are ambiguous. What is considered major transmission equipment? What is an entity's "spare equipment strategy"? The requirement is not clear as to how many power flow models are required (one per piece of "major transmission equipment" without a spare, or one model with every piece of "major transmission equipment" without a spare being out of service)? As written, if an entity has no "spare equipment strategy" they could be exempt from this requirement. 3. We interpret the use of bullet points in Requirement 3.3.1 to mean that either one of the statements can be chosen. This requirement should be written where all the bulleted statements are included in the analyses.
Response: 1. The SDT sees no reliability reason or clarity for the change suggested. No change made. 2. Requirement R2, Part 2.1.5 is intended to analyze the removal of a single piece of long lead time equipment (one year or more) to the extent there is no existing spare equipment strategy to provide a means of returning to service (in a less than one year) a comparable replacement. If this condition exists, then the facility (single element) in question must be removed in the model to establish a new P0 system condition and studies must then be run for P0, P1, and P2 for the new system scenario. The spare equipment strategy must be reviewed for the entity's system exposure to catastrophic failures resulting in the long lead-time facility outages, however, only one facility must be removed at a time if the condition exists for multiple facilities. A Transmission Planner may have no spare equipment strategy if they are able to demonstrate they are not responsible for any facilities which they believe could place them in a "long lead-time" scenario. No change made.		

Organization	Yes/ No	Question 3 Comment
3. The bulleted items of Requirement R3, Part 3.3.1 were meant to be inclusive. This means that the use of bullets here was incorrect and the items should be numbered elements. This same change was made to Requirement R4, Part 4.3.1. **3.3.1.1** Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. **3.3.1.2** Tripping of Transmission elements where relay loadability limits are exceeded. **4.3.1.1** Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized. **4.3.1.2** Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. **4.3.1.3** Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.		
ITC		ITC COMMENTS on TPL-001 voteITC will reluctantly vote to approve the draft standard. While we have concerns, we are voting to approve this standard because we believe the positive elements outweigh the portions of the draft standard that we object to. It is important that the improved requirements that effectively "raise the bar" over the existing standard should become effective sooner rather than later. A negative vote, which might cause a further delay in implementation of the standard, would be the least desirable outcome. However, we still believe that the VSL that would find that an entity had committed a "severe" violation for failure to distribute its planning assessment to an adjacent Transmission Planner or Planning Coordinator has the potential to overly punish a simple error in oversight. We would agree that willfully withholding an assessment from a neighbor or a valid requestor justifies a severe violation but an administrative or clerical oversight does not. For example, it might escape our attention that an entity, particularly a smaller one, registers as a TP or TP. As far as we know, there is no requirement that a registrant, or even one who de-registers, must notify an "adjacent" TP or PC of their change in status. As written, the standard requires you be found in "severe" violation, even if that new entity fails to notify you of their change in status. You would still be in severe violation even if they later ask for your planning assessment. Even if the standard passes, we request that this VSL be fixed to make the distinction between an administrative error and willful neglect. Our response to question 2 offers a suggested method to do this.
Response: Requirement R8 is an important aspect of the new TPL-001-2 standard to communicate results with neighboring systems and those demonstrating a reliability need. The SDT notes that the VSL Guidelines require a Severe VSL for each and every requirement but encourages graded (multiple level) VSLs where		

Organization	Yes/ No	Question 3 Comment
possible. In regard to Requirement R8, the SDT has established four VSLs. It is noted that an entity can be up to 120 days (~ 4 months) late in its delivery of the information and remain in the Lower VSL category before being exposed to the Severe VSL category. The 10 day increment in the other VSL categories, above the 120 day Lower VSL, conforms to NERC's VSL Guidelines. See the response to your suggested VSL changes in Question 2, however, it is noted that no changes were made to the Requirement R8 VSLs. No change made.		
South Carolina Electric and Gas		R1 does not seem to address errors in data that have been introduced in the latest model data. In addition, R1 and its VSL may be interpreted to exclude the use of past studies. The Implementation Plan should include a five year delay in the effective date for short circuit studies for parts 2.3 and 2.8 of R2 because these studies are not required in the current Version 0 standards.
Response: Requirement R1 of the new TPL-001-2 standard requires the Transmission Planner and Planning Coordinator to maintain System models within its respective area of responsibility. The requirement indicates that information received via MOD-010 and MOD-012 shall be "supplemented by other sources as needed" and to the extent errors and omissions were to be discovered by, or brought to the attention of, the Transmission Planner or Planning Coordinator Requirement R1 establishes an expectation that these "other sources" would be utilized to accurately "represent the project System conditions" being studied. No change made. Requirement R1 is applicable to models used for both current and past studies. No change made. Implementation Plan, Short Circuit Studies – While short circuit study requirements may be new in the realm of mandatory enforceable standards, the SDT does not believe that they present a significant "raising of the bar" for industry. The SDT believes that prudent short circuit practices are effectively in place today to ensure safe operation of the equipment. Therefore, no extension in the Implementation Plan was made in regard to short circuit studies.		
Manitoba Hydro		-Why was the Near Team Transmission Planning Horizon definition moved to the Glossary prior to TPL-001-2 approval?- The definition of Non-Consequential Load Loss should not contain '(2) the response of voltage sensitive Load' because voltage sensitive
Response: Two previously proposed definitions that were part of this project were moved to another standard development project – Project 2010-10 titled "FAC Order 729". The two definitions, "Near-term Transmission Planning Horizon" and "Year One" were approved by the Board of Trustees on January 24, 2011. The statement related to the "Non-Consequential Load Loss" definition is incomplete. No change made.		

Organization	Yes/ No	Question 3 Comment
National Grid		R 1.1.2 We recommend the known facility outage duration be defined as facility outage durations lasting at least twelve months. R 1.1. (page 4) System models shall represent: 1.1.1. Existing Facilities 1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six twelve months. 1.1.3 ..... R 2.1.4 We recommend that this requirement be eliminated. We do not see the value of this additional analysis when the number, type and severity of the sensitivity tests are not well defined. These tests are then used to define Corrective Action Plans in cases only where multiple tests show performance deficiencies. R 2.1.5 Spare equipment strategies are typically designed to prevent long outages (possibility a year or more) of equipment with very long lead times. Any such strategy “could” result in these long outages depending upon the number of failures that may be postulated.This requirement is misleading and we thus recommend it be eliminated. R 2.2 We recommend the language for R 2.2 should be consistent with 2.1 for example - use "current or qualified past studies" instead of "the following annual current study." R 2.6.2 We recommend that the wording of this requirement remain unchanged. R 2.7.1 This portion of the requirement provides a list of “acceptable” Corrective Action Plans. It provides equal weight to infrastructure reinforcements and Special Protection Systems as means to mitigate violations resulting form single or multiple contingencies at both the EHV and HV levels.National Grid’s position is that a national standard should not endorse the use of Special Protection Systems as corrective actions to mitigate single contingency violations.Local Northeast Planning Criteria indicates that special protection systems (SPS) shall be used judiciously and may be used to provide protection for infrequent contingencies, or for temporary conditions that may exist such as project delays, unusual combinations of system demand and equipment outages or availability, or specific equipment maintenance outages. A SPS may also be applied to preserve system integrity in the event of severe facility outages and extreme contingencies. The decision to employ a SPS shall take into account the complexity of the scheme and the consequences of correct or incorrect operation as well as its benefits. We are further of the opinion that specific methods of correcting system performance deficiencies should not be specified in a National Standard. We thus recommend that the Corrective Action List be eliminated from this requirement as illustrated below. 2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. R 2.7.2 We feel that this requirement and requirement R 2.1.4 adds ambiguity to the process as we have

Organization	Yes/ No	Question 3 Comment
		indicated above. We thus recommend that this requirement be eliminated. R 3.3.1 We feel that the last sentence of 3.3.1 should be removed. This is handled by PRC-023. Line ratings are addressed by PRC-023. PRC-023 requires coordination with the Reliability Coordinator. Remove "Tripping of Transmission elements where relay loadability limits are exceeded" Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall: 3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: o Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R 3.4.1 We would recommend the following addition as a clarification to the required information exchange: 3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. 3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their respective Systems are included in the Contingency list. R 8.1 National Grid's concern regarding this requirement stems from the apparent open ended time frame afforded report recipients in their review of the Planning Assessment. This has the potential to stall the review process. National Grid thus recommends that any recipient of the Planning Assessments be given a specific time period for their response as indicated in R 8.1 below. R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, and adjacent Transmission Planners, within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of sucha request. [Violation Risk Factor: LowMedium] [Time Horizon: Long-term Planning] 8.1. The recipient of the Planning Assessment results shall provides documented final comments on the results within 90 calendar days of receipt of the Planning Assessment. The respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. Table 1 Steady State & Stability Performance Planning Events (Page10). The event description for

Organization	Yes/ No	Question 3 Comment
		Category P2 Event 1. along with the accompanying footnote 7 (Page 14) creates some confusion for multi-terminal lines. We recommend that Footnote 7 be eliminated and the event description be changed as follows: Category Initial Conditions Event P2 Normal System 1. Opening of a single load interrupting device at one terminal of a line without a fault. Table 1 (Planning Events and Extreme Events) Footnote 12 (Page 14).We are concerned that additional stakeholder process indicated in Footnote 12 has the potential to stall the Planning Assessment review process. We recommend that reference to this new process be eliminated from the Footnote.Our additional, concerns with Footnote 12 are addressed in comments originally provided by ISO-NE. We agree with their following comments : The following language for Footnote 12 is proposed:"Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems."If Footnote 12 in Table 1 must be retained, the following language is proposed: "An objective of the planning process shall be to minimize the likelihood and magnitude of interruption of Demand, (excluding Interruptible Demand or Demand-Side Management), following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: a. Interruptible Demand or Demand-Side Managementb. Circumstances where the uses of Demand interruption not directly interrupted by the contingency are documentedc. Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than Interruptible Demand or Demand Side Management)"
Response: Requirement R1, Part 1.1.2 – The SDT and a majority of industry stakeholder support the 6-month period stated in the requirement. No change made. Requirement R1, Part 1.1 – Same comment as above. No change made. Requirement R2, Part 2.1.4 – Requirement R2, Parts 2.1.4 and 2.4.3 are not inconsistent with Requirement R2, Part 2.7.2. With the various requirements, the planners are required to conduct multiple sensitivities. Therefore, Requirement R2, Part 2.7.2 could be used when the results of these multiple sensitivities identify common concerns. No change made. Requirement R2, Part 2.1.5 is intended to analyze the removal of a single piece of long lead time equipment (one year or more) to the extent there is no existing		

Organization	Yes/ No	Question 3 Comment
		spare equipment strategy to provide a means of returning to service (in less than one year) a comparable replacement. If this condition exists, then the facility (single element) in question must be removed in the model to establish a new P0 system condition and studies must then be run for P0, P1, and P2 for the new system scenario. The spare equipment strategy must be reviewed for the entity's system exposure to catastrophic failures resulting in the long lead-time facility outages, however, only one facility must be removed at a time if the condition exists for multiple facilities. A Transmission Planner may have no spare equipment strategy if they are able to demonstrate they are not responsible for any facilities which they believe could place them in a "long lead-time" scenario. No change made. Requirement R2, Part 2.2 - The requirement for an annual current steady-state study in the Long-Term Transmission Planning Horizon is intentional to drive earlier identification of potential Transmission performance limitations and earlier development of Corrective Action Plans. The study results can be used as qualified studies as they advance to later years, including moving to the Near-Term Transmission Planning Horizon. No change made. Requirement R2, Part 2.6 – The changes made to this requirement in the last draft were essentially style changes and the most substantive change is the introduction of documentation required to support the technical rationale for determining whether or not material changes have occurred. This was a recommendation made by the Quality Review process and agreed to by the SDT. No change made. Requirement R2, R2.7.1 – The SDT respectfully disagrees that actions that could be part of a Corrective Action Plan (CAP) should be eliminated. In regard to the concern of allowing SPS within the CAP, this view is not shared across the continent-wide footprint and National Grid and its Regional Entity always have the ability to go above and beyond the requirements of a NERC standard if they believe such action is warranted. No change made. Requirement R2, Part 2.7.2 - Requirement R2, Parts 2.1.4 and 2.4.3 are not inconsistent with Requirement R2, Part 2.7.2. With the various requirements, the planners are required to conduct multiple sensitivities. Therefore, Requirement R2, Part 2.7.2 could be used when the results of these multiple sensitivities identify common concerns. No change made. Requirement R3, Part 3.3.1 – The SDT appreciates the concern raised; however, it believes the subsequent tripping of "Transmission elements where relay loadability limits are exceeded" is warranted. The TPL studies may earlier identify and flag relay setting concerns based on required Long-Term Transmission Planning Horizon studies. Within the TPL standard, such a concern would have a Corrective Action Plan that would address the issue which would also meet the expectations of PRC-023. The SDT sees this as a defense in depth approach. No change made. Requirement R3, Part 3.4.1 – The additional information suggested was not implemented as it did not add to reliability or clarify the issue beyond the present wording. No change made. Requirement R8, Part 8.1 – The SDT does not see a reliability related need for the suggestion and believes a response regarding a Planning Assessment is warranted no matter when raised by the reviewing party. No change made.

Organization	Yes/ No	Question 3 Comment
Table 1, footnote 7 – The SDT added the footnote to further explain its intent for P2-1 and to ensure that the planner assess the voltage of a load bus that was on a radial line. The word "possibly" was used since having load on a radial is not always the outcome of opening one end of a line section. No change made. Table 1, Footnote 12 – The SDT believes the stakeholder process provides a level of transparency needed when an entity intends to utilize provisions offered by footnote 12 (and footnote 9). No change made.		
TVA TP&C		TVA - has following comments:TVA is concerned about footnote 12 (known as footnote b in existing TPL standards). TVA believes that utilities should be given some freedom in dropping local load in response to N-1 events as long as overall BES reliability is not impacted. Otherwise significant capital improvements will be required that will have no overall reliability gain for the Bulk Electric System. In R4.1.1, TVA is concerned that no generating unit (including distributed generation) shall pull out of synchronism in a local area only (thus not impacting the overall reliability of the BES) for Planning Event P1, while the standard does allow generator runback/tripping for the same event. Thus the generating unit may be tripped by a special protection scheme - but may not be tripped by an out of step relay. TVA believes that out of step relaying should be allowed for this unit tripping as long as this does not affect the overall reliability of the BES. Table 1 contains both planning events and extreme events. Suggest labeling the planning events as Table 1 and the extreme events as Table 2 to help reduce confusion. VSL for R1 does not seem to address issues where data errors have been introduced into the latest model data. Also, R1 and its VSL may be interpreted to exclude the use of past models. The Implementation Plan should include a five-year delay in the effective date for short circuit studies (R2 parts 2.3 and 2.8) since these studies are a new TPL requirement and are not required in the current version 0 standards.
Response: The SDT has taken care to ensure consistency in footnote 12 (and footnote 9) with the prior footnote 'b' revision supported by industry, approved by the NERC Board of Trustees, and submitted for regulatory approval. No change made. Requirement R4, Part 4.1.1 - The SDT respectfully disagrees with the commenter. For a P1 single Contingency event, the SDT believes, and a majority of industry stakeholders find it reasonable, that no Bulk Electric System (BES) generation unit be pulled out of synchronism due to the P1 event studied. If the "small" nearby unit is served below threshold kV and MW size limitations set by the Regional Entity to qualify as a BES unit, the unit would not be within scope of the standard. No change made.		

Organization	Yes/ No	Question 3 Comment
Desire for Two Tables – This has been vetted within industry in prior comment/ballot periods. The majority of stakeholders support the current format. No change made. Requirement R1 VSL – The requirement indicates that supplied data may have to be supplemented as appropriate. The SDT believes that this covers correcting any data errors. The SDT sees no reason why the current language invalidates the use of past models as long as they meet the requirements. No change made. While short circuit study requirements may be new in the realm of mandatory enforceable standards, the SDT does not believe that they present a significant "raising of the bar" for industry. The SDT believes that prudent short circuit practices are effectively in place today to ensure safe operation of the equipment. Therefore, no extension in the Implementation Plan was made in regard to short circuit studies.		
Independent Electricity System Operator		See our response to Q1.
Response: See response to Q1.		
NBSO		Items that, if not addressed, will likely cause a negative vote from NBSO: NBSO believes that R1.1.2 is more appropriately addressed in the operational timeframe. Perhaps more appropriate alternatives could include:-only considering planned outages with durations of one year or more (in-line with typical planning timeframes), or -requiring that facilities with planned outages lasting over the complete duration of time period being studied be modeled out of service. R2.1.5 may significantly increase the demands of the planning assessments with little gain in reliability. Depending on interpretation, R2.1.5 could exponentially increase the work load of the annual planning assessment. NBSO interprets the intent of R2.1.5 to require that entities have, review and evaluate their spare equipment strategies. Perhaps the assessment of a spare equipment strategy would be more appropriately addressed in a separate standard. Further, categories P0, P1 and P2 do not reference footnote 9 in the Initial Condition column. NBSO is unclear if the last sentence of R2.1.5 allows for the curtailment of firm transmission service under the N-1 conditions before the application of category P0, P1 and P2 events. This last sentence states:"...with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment." Table 1, note b should be modified to allow for the loss of Firm Transmission Service. This addresses cases where Firm Transmission Service is lost in direct consequence to the event (e.g. loss of one DC pole, an

Organization	Yes/ No	Question 3 Comment
		interface comprised of a single line, a bus fault that clears multiple lines in an interface, etc...) Individual items that, if not addressed, may not cause NBSO to vote Negative, but in combination may result in a negative vote:The definitions of “near-term transmission planning horizon” and “year one” have been removed from the standard, yet they are still used in draft 7. Further, the definition of these terms is being filed as part of another project. NBSO is concerned with endorsing a standard based on terms whose definitions may change independently of this project. For R7, NBSO is concerned that one entity may be found noncompliant should another entity fail to meet their agreed upon responsibilities. For example, a PC may be relying on the results from a TP’s studies to complete its own planning assessment, but the TP did not meet their responsibilities. In this case, the PC should not be found non-compliant for an incomplete planning assessment due to the failure of the TP to meet their responsibilities.Contingencies on back to back HVDC facilities are not addressed in the standard.

Response: Requirement R1, Part 1.1.2 - The SDT disagrees with the view that outages of 6 months or more should only be reviewed in the operations timeframe. Such an outage could be for an upcoming construction project requiring certain facilities to be removed from service for long durations of time and those situations should be evaluated with sufficient lead time to determine any vulnerabilities and development of sufficient Corrective Action Plans as required. No change made.

Requirement R2, Part 2.1.5 is intended to analyze the removal of a single piece of long lead time equipment (one year or more) to the extent there is no existing spare equipment strategy to provide a means of returning to service (in a less than one year) a comparable replacement. If this condition exists, then the facility (single element) in question must be removed in the model to establish a new P0 system condition and studies must then be run for P0, P1, and P2 for the new system scenario. The spare equipment strategy must be reviewed for the entity’s system exposure to catastrophic failures resulting in the long lead-time facility outages, however, only one facility must be removed at a time if the condition exists for multiple facilities. A Transmission Planner may have no spare equipment strategy if they are able to demonstrate they are not responsible for any facilities which they believe could place them in a “long lead-time” scenario. No change made.

Requirement R2, Part 2.1.5 & Footnote 9 – Footnote 9 is not applicable to the Initial Condition (Pre-contingency) of P0, P1, and P2 even with a long lead-time device out of service. No change made.

Table 1, footnote ‘b’ - The SDT believes the concern should be addressed by footnote 4, Conditional Firm Transmission Service. No change made.

Removal of Definitions - Two previously proposed definitions that were part of this project were moved to another standard development project – Project 2010-10 titled “FAC Order 729”. The two definitions, “Near-Term Transmission Planning Horizon” and “Year One” were approved by the Board of Trustees on January 24, 2011.

Requirement R7 – The SDT disagrees, having documented clear lines of responsibility should protect against the concern raised. No change made.

Organization	Yes/ No	Question 3 Comment
Back to Back HVDC – The contingent loss of back to back HVDC facilities is included as a transformer. Footnote 5 states, in part, that "Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. Therefore, the SDT has not explicitly included back-to-back HVDC as a separate Contingency. No change made.		
Xcel Energy		Effective Date: The effective date section seems to imply that Non-Consequential Load Loss will not be permitted after the 84 month implementation period. We do not believe that was the drafting team's intent and request that it be modified. Footnote # 12 in Table 1, in particular, seems to support our assumption that the team did not intend to disallow it. For reference, the footnote states:"12. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to address BES performance requirements. When Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss is documented, including alternatives evaluated; and where the utilization of Non-Consequential Load Loss is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments." However, if it was the drafting team's intent to not allow Non-consequential Load Loss after the 84 month implementation period, we disagree and ask the team to reconsider. Particularly for rural areas, in some cases, this will be the only action possible. R2.1.4: a) We would like to see clarification on the term "sensitivity analysis". Is this in reference to seasonal models and differences in fuel availability? We would like more detail on how this is to be done so that it won't be left up to interpretation. b) We would like the drafting team to consider stratification of the tasks needed to perform a Planning Assessment. In our opinion, having both the TP and PC do exactly the same study produces tremendous and unnecessary duplication. Without stratification, the TPL-001 standard will continue to perpetuate the same paradigm used in the existing TPL-001 through TPL-004 standards. The NERC Functional Model makes a clear distinction between PC and TP functions/responsibilities. It is not clear why that distinction is not leveraged in the new TPL-001 standard. This will be particularly troublesome in areas where an ISO or RTO is the Planning Coordinator. In order for the RTO/ISO, as the PC, to be able to do their Planning Assessment, the Transmission Planners would have to provide a lot of detailed input data. So, in effect, both the PC and TP would be performing their assessment from the same data. It would make more sense if the RTO (as the PC) performed the required studies on the 500-345 kV network and the TP performed the required studies on everything below 230 KV.

Organization	Yes/ No	Question 3 Comment
		We also recommend the allowance for utilization of a regional assessment, instead of performing your own, due to individual entity resource constraints. R2.4.1: We would like to see better clarity on what an Aggregate system load model is and how granular it should be. If the intent is for the model to contain a very detailed representation of the load system, then it may take a longer time to implement. R3.4.1: a) This type of coordination could be difficult due to other adjacent entities on different schedules and some may not have the amount of detail to incorporate into another's processes. We know this is generally covered in coordination of real time operations and wonder if it is appropriate to require this type of coordination in the long term process. Is there already an operational standard that covers this? Would it be better to address this in the operational standards? We would like the roles of the coordinators vs. the planners to be clarified in order to ensure that no work is being duplicated. b) PC's between regions, such as RTOs, are already coordinating for long term studies. In these cases, we feel the PC should alone be responsible for the requirements, rather than also the TPs. c) Can we get a clear definition of what apparent impedance swings means? We interpret it as rotor angle stability. R4.3.1: We would like to see that the detailed data is incorporated back into the NERC modeling processes and create a more detailed model with better accuracy. R8: We do not agree with the requirement to provide the assessment to every adjacent PC and TP because we fail to see the reliability benefit in doing so. However, we do agree that the PC and TP should be required to provide the assessment to any of these entities, if requested. Additionally, for entities that make such requests, we would like to have 90 days instead of 30 to respond. In many cases a non-disclosure agreement will have to be executed due to CEII classification of some information, and this can take several months.
Response: Effective Date - The SDT believes the Effective Date section is sufficiently clear. The use of Non-Consequential Load Loss while discouraged by the standard is permitted when justified and presented in a transparent manner to other stakeholders (footnote 12). No change made. Sensitivity Analysis – This analysis should be viewed as a modified study of the Peak or off-peak studies required in Requirement R2, Parts 2.1.1 and 2.1.2. The SDT believes the examples provided in the bulleted list of Requirement R2, Part 2.1.4 are sufficiently clear as examples of what could be modified to create the sensitivity model. No change made.		

Organization	Yes/ No	Question 3 Comment
Delineation of tasks between Transmission Planner and Planning Coordinator – The issue raised is addressed by Requirement R7. No change made. Regional Assessments – The standard does not prohibit the use of valid studies performed by 3rd parties for use in the assessment results. No change made. Requirement R2, Part 2.4.1 - The "aggregate" dynamic Load model may include high-level assumptions on Load profiles for industrial, commercial, and residential Loads that are applied generically across the planning area study based on the planner's engineering judgment and system knowledge. The model is not required to be "bus" specific. No change made. Requirement R3, Part 3.4.1 - The SDT envisions that knowledge of the applicable Contingencies on neighboring systems would develop over time and be discovered with the results being distributed in Requirement R8. The SDT believes that this is an important improvement to the planning timeframe analysis and that system information learned in the operations environment should most certainly be considered to the extent it improves the robustness of the planning assessment. No change made. Planning Coordinator responsibility – NERC's Functional Model clearly places Transmission planning responsibility both on the Transmission Planner and Planning Coordinator. Requirement R7 should help alleviate any overlap concerns in responsibility. No change made. Apparent Impedance Swings - The "apparent impedance swing" is the trajectory of changes in the apparent impedance seen by a distance relay for various system and Fault conditions. In the case contemplated in Requirement R4, Part 4.1.2, it is the trajectory seen by the distance relay for the initial Fault and the subsequent generator(s) pulling out of synchronism. If that trajectory were to come within the tripping characteristic of the relay for a sufficient length of time, the relay would cause its associated line to trip. No change made. NERC Modeling Process – The standard does not govern NERC actions as they are not a registered entity. To the extent NERC pulls information from a model building process such as MMWG (ERAG) then the models used by NERC will likely contain the information desired. No change made. Requirement R8 – The SDT and a majority of industry support Requirement R8. No change made.		
ISO New England Inc.		We feel previous comments have largely been ignored by the Standards Drafting Team leading to a lack of support for the standard. Overall the standard should be more precise in its language. The following comments are provided for serious consideration with respect to revisions:Comments: From Section A.3 - the introduction please strike the word "probable" as shown below Purpose: Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies This is deterministic contingency testing and this word introduces probability into the standard where it does not belong. For R1.1 Part 1.1.2. With respect to known outages, there needs to be greater flexibility in the standards (e.g. more tolerance to non-consequential load shedding or limitations to the contingencies that need to be

Organization	Yes/ No	Question 3 Comment
		considered (e.g. P0, P1, & P2)). Regional allowances for load shedding under this condition should be acceptable. Duration of known outages should be increased from six months to one year. For R1.1 Part 1.1.6 Delete "required for Load". Resources may also be used for export to other areas, not just internal load. REMOVE INTERCHANGE from 1.1.5 - Definition of Interchange - The inclusion of Interchange requires designing for non-Firm service.In the NERC Glossary of Terms Used the term Interchange is defined as "Energy transfers that cross Balancing Authority boundaries." It is meant to refer to energy transaction other than firm Transmission Service. While rigorous planning studies have been conducted to permit the uninterrupted implementation of firm Transmission Service without jeopardizing the reliable operation of the Interconnected System, other types of energy transaction only take place whenever system conditions permit them. They are usually of very short duration relative to planning assessment periods (usually spanning for a few hours to a few days) and are deemed highly interruptible and subject to reliability issues that may arise during operation of the system. In other words, the term Interchange refers to economic transactions that are permitted when the system is secure and there are reasonable reliability margins to effect dispatch changes to lower operating costs. As such, Interchange should not be reflected in system representation meant to assess system reliability under TPL-001. Part 2.1.4, requires an entity to vary one or more conditions to demonstrate a change in performance. If the cases were initially stressed, this may force an entity to simulate conditions with less severe stresses. At this point, there is limited or no value to this additional workload. Having a requirement to test at least one sensitivity as a blanket requirement may not be informative by itself and is more unclear since sensitivities are being required on an undefined base set of conditions. Additionally, our concern involves wording under 2.1.4 and 2.4.3 that sensitivities are required varying one or more conditions. Subsequently, in requirement 2.7.2 corrective action plans need to be developed to resolve performance deficiencies "only" if identified in multiple conditions or require a rationalization why no corrective action plan is necessary. Multiple condition sensitivities under 2.1.4 and 2.4.3 are necessary to satisfy requirement 2.7.2. Requirement 2.7.2 adds ambiguity and should be removed or revised as follows: 2.7.2. Corrective Action Plans are not required for performance deficiencies identified in a sensitivity analysis. We agree with R2.1 however with respect to R2.2 Language should be consistent with 2.1 for example - use "current or qualified past studies" instead of "the following annual current study." For 2.7.1 - We don't believe this list provides value nor should it be included in the standard. Section 3.3 - We feel that the last sentence of 3.3.1 should be removed. This is handled by PRC-023. Line

Organization	Yes/ No	Question 3 Comment
		ratings are addressed by PRC-023. PRC-023 requires coordination with the Reliability Coordinator. Remove "Tripping of Transmission elements where relay loadability limits are exceeded." In Table 1 - The fault descriptions must be clear. They must use "3-phase", "single-phase-to ground", or "2-phases-to ground" in the descriptions of a fault rather than SLG (a line is not a phase in electrical terms--single line to ground is not precise enough). In Table 1 - Where two elements are affected by a fault it must be clear whether the requirement is for a single-phase-to ground fault, or a 2-phase-to ground fault. They are different faults that will have different dynamic responses. For Table 1- add a footnote for the term generator to address the treatment of Combined Cycle Generators - "In addition to evaluating the loss of a single generator, the loss of all interrelated generators shall also be considered as a single contingency." Operating experience has shown that trips of the entire CC facility often occur even on facilities that claim the combined cycle generators are independent. Where a category involves an initial condition representing the loss of a facility followed by an event represeting the loss of a facility such as P3, the standard must be clear as to the amount of time assumed between faults. An assumption may be 30 minutes, but the standard must not leave this unsaid. This clarity must be provided in the Table 1 Notes.In addition, the standard must be clear on the allowable re-adjustments between contingencies such as P3, or better, must be clearly limit the permissible re-adjustments. For example, it is not realistic to assume an unlimited amount of re-dispatch between faults-e.g. the allowable re-adjustment should be limited to actions that can be effectively implemented in less than 30 minutes, such as a, b, c, d, ..., and the amount of generation re-dispatch must not exceed the amount of future planned contingency reserve, or similar language. This clarity must be derivable from the Table 1 Notes.
Response: A.3 Purpose Statement – While admittedly "probable" is somewhat in the eye of the beholder the intent is that Bulk Electric System (BES) should operate reliably for the more "probable" or "credible" Contingencies, i.e., Planning Events (Table 1), and that the BES reliability performance expectation is lower for the less "probable" extreme events. The SDT does not see this statement as defining the standard as probabilistic Contingency planning and agrees that the standard is deterministic planning. No change made. Requirement R2, Part 1.1.2 – The SDT disagrees that the duration of known outages should be increased from 6 months to one year. The intent is to ensure review of an upcoming construction project requiring certain facilities to be removed from service for long durations of time and those situations should be evaluated with sufficient lead time to determine any vulnerabilities and development of sufficient Corrective Action Plans (CAP) as required. The SDT believes it is		

Organization	Yes/ No	Question 3 Comment
appropriate to study all planning events for the projected system and not limit it to just P0, P1. or P2. Load shedding could be part of a "temporary" CAP when justified by the use of footnote 12. No change made. Requirement R1, Part 1.1.6 - The SDT does not believe the phrase "required for Load" is confusing. Without the statement, in theory, one could have a model with lots of supply resources but none which are dispatched to serve the Load. The term Load does not depict whether it is located internal or external to the Transmission system footprint. No change made. Requirement R1, Part 1.1.5 – Both firm and non-firm transfers of power should be modeled to the extent they are "known commitments" in the Planning Horizon. The short duration transactions described would likely not be known and therefore should not be included in a planning model. No change made. Requirement R2, Part 2.1.4 – the commenter has missed the key phrase "… by a sufficient amount to stress the System …". So, by definition of the requirement the sensitivity analysis is not intended to lower the overall stress of the system being analyzed. Additionally, Requirement R2, Parts 2.1.4 and 2.4.3 are not inconsistent with Requirement R2, Part 2.7.2. With the various requirements, the planners are required to conduct multiple sensitivities. Therefore, Requirement R2, Part 2.7.2 could be used when the results of these multiple sensitivities identify common concerns. No change made. Requirement R2, Part 2.2 - The requirement for an annual current steady-state study in the Long-Term Transmission Planning Horizon is intentional to drive earlier identification of potential transmission performance limitations and earlier development of Corrective Action Plans (CAPs). The study results can be used as qualified studies as they advance to later years, including moving to the Near-Term Transmission Planning Horizon. No change made. Requirement R2, R2.7.1 – The SDT respectfully disagrees that example actions that could be part of a Corrective Action Plan (CAP) should be eliminated. If an entity takes issue with the use of one of the stated items as part of a CAP, they are always free to go above and beyond the requirements of a NERC standard if they believe such action is warranted. No change made. Requirement R3, Part 3.3.1 – The SDT appreciates the concern raised; however, it believes the subsequent tripping of "Transmission elements where relay loadability limits are exceeded" is warranted. The TPL studies may earlier identify and flag relay setting concerns based on required Long-Term Transmission Planning Horizon studies. Within the TPL standard, such a concern would have a CAP that would address the issue which would also meet the expectations of PRC-023. The SDT sees this as a defense in depth approach. No change made. Fault Types – Only single line to ground (SLG) and three-phase (3PH) fault types are covered by the standard. See Table 1, footnote 2 for further information on fault types and standard expectations. No change made. Combined Cycle Plants – If the planner believes it is appropriate to model the tripping of the combined cycle generation as a set then they should do so. Recall, in planning assessments, you are analyzing Contingency events based on electrical Faults and the SDT reminds the commenter that adherence to introductory Table 1 note "c" is required. Additionally, to the extent the combined cycle units deliver their power via a common GSU transformer the loss of the GSU should also address the concern. No change made. System Adjustments – The timing between events which are not common mode events (P3, P6) is not defined by the standard. Engineering judgment should		

Organization	Yes/ No	Question 3 Comment
prevail and if the planner believes a susceptibility to an N-2 event of quick duration places their system at risk then the use of automatic controls should be considered. The only qualifier on System adjustments is that Facility Ratings must be adhered to during the adjustment. So, if you are adhering to a 30-minute Emergency Rating, but are exceeding a 24-hour Emergency Rating then the adjustment must be completed within the time limitation of the rating. No change made.		
Northeast Utilities		The following previous comments that were filed by NU were not addressed by the SDT in the current draft. For NU to support the standard these comments should be addressed or reasons should be provided why they have not been addressed. Repeated below are NU's comments that were filed for the previous draft. Requirement R1, Part 1.1.2 NU requests that the six month duration stated by Requirement R1, Part 1.1.2 should be modified to one year duration to eliminate outages that occur within the "operational planning timeframe". Requirement R1, Part 1.1.6The phrase "required for Load" should be deleted as this confuses the issue.Requirement R2, Part 2.2The language of Requirement R2 Part 2.2 seems to suggest that current annual studies are always required for the long-term steady state assessment. This may have been an oversight, for consistency Requirement R2 Part 2.2 should be modified to similarly read as Requirement R2, Part 2.1. Requirement R2, Parts 2.1.4 & 2.4.31) The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions. The standard must describe base assumptions. To define a sensitivity condition, NERC must define base assumptions. 2) Requirement R2, Part 2.1.4 and Part 2.4.3 should clarify what is meant by multiple sensitivity studies and one sensitivity study. Will varying only one measurable quantity several times in multiple simulations constitute multiple sensitivity studies or one sensitivity study? Requirement R3, Part 3.3.1NU feels that the last sentence of Requirement R3, Part 3.3.1 should be removed since this is handled by PRC-023. Line ratings are addressed by PRC-023 which requires coordination with the Reliability Coordinator. NU suggests the removal of the following sentence: "Tripping of Transmission elements where relay loadability limits are exceeded."
Response: Requirement R1, Part 1.1.2 - The SDT disagrees with the view that outages of 6 months or more should only be reviewed in the operations timeframe. Such an outage could be for an upcoming construction project requiring certain Facilities to be removed from service for a long durations of time and those situations should be evaluated with sufficient lead time to determine any vulnerabilities and development of sufficient Corrective Action Plans as required. The		

Organization	Yes/ No	Question 3 Comment
review of known and planned construction items should not be delayed until the operations timeframe. No change made. Requirement R1, Part 1.1.6 - The SDT does not believe the phrase "required for Load" is confusing. Without the statement, in theory, one could have a model with lots of supply resources but none which are dispatched to serve the load. No change made. Requirement R2, Part 2.2 - The requirement for an annual current steady-state study in the Long-term Transmission Planning Horizon is intentional to drive earlier identification of potential Transmission performance limitations and earlier development of Corrective Action Plans (CAP). The study results can be used as qualified studies as they advance to later years, including moving to the Near-Term Transmission Planning Horizon. No change made. Requirement R2, Parts 2.1.4 & 2.4.3 – The "base case" assumption is described in Requirement R1 by the fact that the P0 model "shall represent the projected System conditions" for the study period. That essentially establishes the "base case" condition. The sensitivity analysis in Requirement R2, Part 2.1.4 is intended to address some potential "what if" conditions that the planner should consider as an alternate base P0 condition. The SDT believes Requirement R2, Part 2.1.4 provides sufficient detail and clarity of the intended purpose of a sensitivity study and defers to engineering judgment in how the alternate base (sensitivity) model is established. Varying one variable multiple times would cover multiple sensitivities. For example, one may vary the Load modeled. If the base condition is a 50/50 forecast model, one sensitivity may be an 80/20 forecast, while yet another is a 90/10 forecast model. No change made. Requirement R3, Part 3.3.1 – The SDT appreciates the concern raised; however, it believes the subsequent tripping of "Transmission elements where relay loadability limits are exceeded" is warranted. The TPL studies may earlier identify and flag relay setting concerns based on required Long-Term Transmission Planning Horizon studies. Within the TPL standard, such a concern would have a CAP that would address the issue which would also meet the expectations of PRC-023. The SDT sees this as a defense in depth approach. No change made.		
MISO		Overall, we remain concerned that the revisions to the TPL standard are not on balance an improvement to the original. The document is not well organized topically, making it more difficult to navigate and understand. If the primary improvements sought in requirements for reliability planning were to increase system performance levels (no loss of firm demand) for certain multiple contingency events, and to ensure more stressed system sensitivities are analyzed, this can be accomplished in a much simpler revision. We do not believe that this standard as written improves the clarity of what is required, and therefore provides an opportunity for greater disputes between compliance monitors and applicable entities, and this is not a positive outcome. We also believe that the standard is too prescriptive as to what critical system conditions must be modeled, as these conditions vary considerably from system to system and within large systems. Table 1-Steady State and Stability Performance Planning Events, Category P5, now includes "non-redundant" relay in the Event column. What is meant by non-redundant relay? It is unclear if the SDT's intent is to provide distinction between a back-up relay and a redundant relay. We recommend that the SDT provide a definition for the term "non-redundant".

Organization	Yes/ No	Question 3 Comment
Consumers Energy	Ballot Comment	We agree with comments submitted by MISO
Response: The SDT and others in industry hold a different opinion in regards to the standard. The SDT refers you to the comments provided by Transmission Strategies, LLC which well articulates what it believe is the opinion of many in industry evidenced by the 74% approval during the last ballot. Transmission Strategies, LLC states "The SDT, Observers, and the Industry as a whole have put a tremendous amount of thought and work into the development of this latest draft. While nobody should claim that this latest version is perfect, it is far clearer, more in tune with current industry needs, and much improved compared to the existing approved Standards that it will replace". No change made. Redundant Relay – Redundant means duplicate capability resulting in the same outcome. The redundant relay is not the same as a back-up relaying capability which may result in more Facilities being removed for failure of the primary/redundant relay to operate as designed. The SDT believes this concept is widely understood by most in industry and does not see the need for a NERC Glossary Definition. No change made.		
New York Independent System Operator		Requirement R2.4.1The NYISO, along with many other systems, has not determined a need to model dynamic loads, and therefore has not benchmarked any such models. The NYISO recommends that prior to the implementation of this requirement a modeling standard should exist that is specific to dynamic loads, including as assessment for the need for dynamic load models.
Response: Requirement 2, Part 2.4.1 – One focus of the dynamic Load model requirement in Requirement R2, Part 2.4.1 is "considering the behavior of induction motor load". The areas of concern for induction motor load are the Peak load periods since Fault Induced Delayed Voltage Recovery (FIDVR) is primarily a concern at a high load levels with a high penetration of induction motor loads. The SDT has spelled out this requirement in the Peak Load studies but did not include the explicit requirement, with focus on induction motor load, for the other load periods. Even though the standard doesn't have the explicit requirement for other load levels, Requirement R1 includes the statement "shall represent projected System conditions", so the planner cannot ignore the dynamic behavior of the load for those other load periods. No change made.		
Ameren		With respect to Requirement R8, will posting the assessment to a secure web site meet the intent of the requirement? What are the Planning Assessment results identified in R8, and how are they different from the Planning Assessment? It appears that the language for R8 is inconsistent with the VSL for R8. The revised language for the VSL for R8 has removed the word "results". For Measurements M3 and M4, there is still some question as to what is to be provided as sufficient evidence of a study. It is not clear whether the study results would be sufficient, or whether the entire powerflow,

Organization	Yes/ No	Question 3 Comment
		stability, or short circuit effort needs to be documented in a formal study report. For example, it is not clear whether contingency lists used in performing the study work would need to be retained as part of the documentation. The items listed as 4.1.1 through 4.1.3 are not requirements but are performance criteria and should be included in the Table 1 only, consistent with the other performance criteria. Overall, we believe that this standard does not improve the clarity of what is required, and would give additional occasions for disputes between compliance monitors and various registered entities. The standard as written is too prescriptive with regard to critical system conditions which are to be modeled. Such conditions would vary considerably for different systems across the continent.
Response: Requirement R8 – Posting results to a secure website with adequate communication that the results are available for review would suffice for Requirement R8. The "Planning Assessment" and "Planning Assessment results" are one and the same. No change made. Measures M3 and M4 – The evidence could be a combination of summary documented results, the power flow case itself, the Contingency lists, output files showing evidence of the Contingency analysis being performed, etc. No change made. The SDT believes the items in Requirement R4, Parts 4.1.1 through 4.1.3 are properly located. The standard is the sum of the parts – requirements and the Table and the location of the highlighted items is not critical to the desired outcome. No change made. Clarity of the standard - The SDT and others in industry hold a different opinion in regard to the standard. The SDT refers you to the comments provided by Transmission Strategies, LLC which well articulates what it believes is the opinion of many in industry evidenced by the 74% approval during the last ballot. Transmission Strategies, LLC states "The SDT, Observers, and the Industry as a whole have put a tremendous amount of thought and work into the development of this latest draft. While nobody should claim that this latest version is perfect, it is far clearer, more in tune with current industry needs, and much improved compared to the existing approved Standards that it will replace". No change made.		

A. Introduction

1. **Title:** **Data From the Regional Reliability Organization Needed to Assess Reliability**

2. **Number:** TPL-006-0.1

3. **Purpose:** To ensure that each Regional Reliability Organization complies with planning criteria, for assessing the overall reliability (Adequacy and Security) of the interconnected Bulk Electric Systems, both existing and as planned.

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization shall provide, as requested (seasonally, annually, or as otherwise specified) by NERC, system data, including past, existing, and future facility and Bulk Electric System data, reports, and system performance information, necessary to assess reliability and compliance with the NERC Reliability Standards and the respective Regional planning criteria.

The facility and Bulk Electric System data, reports, and system performance information shall include, but not be limited to, one or more of the following types of information as outlined below:

R1.1. Electric Demand and Net Energy for Load (actual and projected demands and Net Energy for Load, forecast methodologies, forecast assumptions and uncertainties, and treatment of Demand-Side Management.)

R1.2. Resource Adequacy and supporting information (Regional assessment reports, existing and planned resource data, resource availability and characteristics, and fuel types and requirements.)

R1.3. Demand-Side resources and their characteristics (program ratings, effects on annual system loads and load shapes, contractual arrangements, and program durations.)

R1.4. Supply-side resources and their characteristics (existing and planned generator units, Ratings, performance characteristics, fuel types and availability, and real and reactive capabilities.)

R1.5. Transmission system and supporting information (thermal, voltage, and Stability Limits, contingency analyses, system restoration, system modeling and data requirements, and protection systems.)

R1.6. System operations and supporting information (extreme weather impacts, Interchange Transactions, and Congestion impacts on the reliability of the interconnected Bulk Electric Systems.)

R1.7. Environmental and regulatory issues and impacts (air and water quality issues, and impacts of existing, new, and proposed regulations and legislation.)

Measures

M1. The Regional Reliability Organization shall provide evidence to its Compliance Monitor that it provided Regional system data, reports, and system performance information per Reliability Standard TPL-006-0_R1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Requested Regional system data, reports, or system performance information were incomplete.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Requested Regional system data, reports, or system performance information were not provided.

D. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0.1	April 15, 2009	Corrected formatting for M1.	Errata

A. Introduction

1. **Title:** **Regional and Interregional Self-Assessment Reliability Reports**
2. **Number:** TPL-005-0
3. **Purpose:** To ensure that each Regional Reliability Organization complies with planning criteria, for assessing the overall reliability (Adequacy and Security) of the interconnected Bulk Electric Systems, both existing and as planned.
4. **Applicability:**

   4.1. Regional Reliability Organization
5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization shall annually conduct reliability assessments of its respective existing and planned Regional Bulk Electric System (generation and transmission facilities) for:

R1.1. Current year:

R1.1.1. Winter.

R1.1.2. Summer.

R1.1.3. Other system conditions as deemed appropriate by the Regional Reliability Organization.

R1.2. Near-term planning horizons (years one through five). Detailed assessments shall be conducted.

R1.3. Longer-term planning horizons (years six through ten). Assessment shall focus on the analysis of trends in resources and transmission Adequacy, other industry trends and developments, and reliability concerns.

R1.4. Inter-Regional reliability assessments to demonstrate that the performance of these systems is in compliance with NERC Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0, TPL-004-0 and respective Regional transmission and generation criteria. These assessments shall also identify key reliability issues and the risks and uncertainties affecting Adequacy and Security.

R2. The Regional Reliability Organization shall provide its Regional and Inter-Regional seasonal, near-term, and longer-term reliability assessments to NERC on an annual basis.

R3. The Regional Reliability Organization shall perform special reliability assessments as requested by NERC or the NERC Board of Trustees under their specific directions and criteria. Such assessments may include, but are not limited to:

R3.1. Security assessments.

R3.2. Operational assessments.

R3.3. Evaluations of emergency response preparedness.

R3.4. Adequacy of fuel supply and hydro conditions.

R3.5. Reliability impacts of new or proposed environmental rules and regulations.

R3.6. Reliability impacts of new or proposed legislation that affects, has affected, or has the potential to affect the Adequacy of the interconnected Bulk Electric Systems in North America.

C. Measures

M1. The Regional Reliability Organization shall provide evidence to its Compliance Monitor that annual Regional and Inter-Regional assessments of reliability for seasonal, near-term, and longer-term planning horizons, and special assessments, were developed and provided as requested by other Regional Reliability Organizations or NERC.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Regional, Inter-Regional, and/or special reliability assessments were provided as requested, but were incomplete.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Regional, Inter-Regional, and/or special reliability assessments were not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. Title: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. Number: TPL-004-1

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-1_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-1_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	Approved by the Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009.	Revised (Project 2010-11)

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

A. Introduction

1. Title: **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. Number: TPL-003-1a

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-1_R1 and TPL-003-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
1a	Approved by the Board of Trustees February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised (Project 2010-11)

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

A. Introduction

1. Title: **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. Number: TPL-002-1b

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-1_R1 and TPL-002-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition
1b	Approved by the Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)." 2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)." 3. "Include the effects of existing and planned protection systems, including any backup or redundant systems." *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

A. Introduction

1. Title: System Performance Under Normal (No Contingency) Conditions (Category A)

2. Number: TPL-001-1

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-1_R1 and TPL-001-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility
Compliance Monitor: Regional Reliability Organization.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame
Annually

1.3. Data Retention
None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

VRFs and VSLs for TPL-001-2 – Transmission System Planning Performance Requirements					
R#	VRF	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Medium	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	High	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR, The responsible entity does not have a completed annual Planning Assessment.
R3	Medium	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the

VRFs and VSLs for TPL-001-2 – Transmission System Planning Performance Requirements					
R#	VRF	Lower VSL	Moderate VSL	High VSL	Severe VSL
		described in Requirement R3, Part 3.5.	performance requirements for one of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	performance requirements for two of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	performance requirements for three or more of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	Medium	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	Medium	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage

VRFs and VSLs for TPL-001-2 – Transmission System Planning Performance Requirements					
R#	VRF	Lower VSL	Moderate VSL	High VSL	Severe VSL
					deviations, or the transient voltage response for its System.
R6	Low	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.
R7	Low	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	Medium	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed

VRFs and VSLs for TPL-001-2 – Transmission System Planning Performance Requirements					
R#	VRF	Lower VSL	Moderate VSL	High VSL	Severe VSL
					its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

Project 2006-02 Assess Transmission and Future Needs

New Definitions for Approval:

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies.

Implementation Plan for TPL-001-2

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

TPL-001-2 — Transmission System Planning Performance Requirements

In revising the TPL standards, the SDT is assuming that planners will receive valid data from the MOD standards link described in TPL-001-2, Requirement R1. Furthermore, there is a tacit assumption that future revisions of the MOD standards will include steps to validate MOD based data.

Revision to Sections of Approved Standards and Definitions

There are multiple new definitions in the proposed standard.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.

Compliance with Standards

Standard	Functions That Must Comply With the Associated Requirements	
TPL-001-2 — Transmission System Planning Performance Requirements	Transmission Planner	Planning Coordinator
	X	X

Effective Dates

The effective date is the date entities are expected to meet the performance identified in this standard.

Note – The changes shown below were done solely to make the effective date language used in the Implementation Plan consistent with that shown in the proposed standard effective date section. No changes were made to the content or context of the dates, durations, or requirements.

Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.

For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required on the first day of the first calendar quarter 84 months after Board of Trustees adoption, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-2, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-2:

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1 are being retired at midnight the day before TPL-001-2 becomes effective as they are replaced in their entirety by TPL-001-2. TPL-005-0 and TPL-006-0.1 are being retired at midnight the day before TPL-001-2 becomes effective because their requirements are adequately covered by the revised TPL-001-2 and NERC's Rules of Procedure, Section 800. However, during this 24-month period, all aspects of the latest enforceable versions of TPL-001 through TPL-006 shall remain in effect for compliance monitoring. This 24 month period is to allow entities to develop, perform and/or validate new and/or modified studies, methodologies, assessments, procedures, etc. necessary to implement and meet the TPL-001-2 requirements. The specified effective dates are expected to allow sufficient time for proper assessment of the available options necessary to create a viable Corrective Action Plan that is compliant with the new Standard.

R1. This Requirement is related to maintaining System models and the data needed to do so. This requirement shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes into effect on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

R7. This Requirement identifies an obligation to determine individual and joint responsibilities for performing studies needed to do the Planning Assessment. This requirement shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes into effect on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

TPL-001-2 'raises the bar' in several areas where performance requirements have been changed in the new Standard versus those in existing TPL-001-1, TPL-002-1b, TPL-003-1a and TPL-004-1 because loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain events, whereas the existing Standards were interpreted by many to allow such actions. As shown in Table 1 of TPL-001-2, the performance requirements associated with the following events represent "raising the bar":

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

This "raising the bar" is beyond the control of the Transmission Planner and Planning Coordinator and may have significant budget, siting, permitting, and construction impacts on many Transmission Owners. To provide stakeholders with sufficient time to implement changes, a timeframe coincident with the end of the Near-Term Transmission Planning Horizon has been provided

Any entity which cannot eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for these performance elements by that date shall submit a mitigation plan to its Regional Entity outlining the steps it will take to correct the problem. If the entities follow the established ERO procedure for mitigation, it is the intent of the SDT that no penalties will be assessed.

Implementation Plan for TPL-001-2

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

TPL-001-2 — Transmission System Planning Performance Requirements

In revising the TPL standards, the SDT is assuming that planners will receive valid data from the MOD standards link described in TPL-001-2, Requirement R1. Furthermore, there is a tacit assumption that future revisions of the MOD standards will include steps to validate MOD based data.

Revision to Sections of Approved Standards and Definitions

There are multiple new definitions in the proposed standard.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.

Compliance with Standards

Standard	Functions That Must Comply With the Associated Requirements	
	Transmission Planner	Planning Coordinator
TPL-001-2 — Transmission System Planning Performance Requirements	X	X

Effective Dates

The effective date is the date entities are expected to meet the performance identified in this standard.

Note – The changes shown below were done solely to make the effective date language used in the Implementation Plan consistent with that shown in the proposed standard effective date section. No changes were made to the content or context of the dates, durations, or requirements.

~~Except as indicated below, all Requirements and associated parts shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.~~
Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter~~,~~ 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.

For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required on the first day of the first calendar quarter 84 months after Board of Trustees adoption, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-2, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-2:

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

TPL-001-~~0~~1, TPL-002-~~0a~~1b, TPL-003-~~0a~~1a, and TPL-004-~~0~~ 1 are being retired at midnight the day before TPL-001-2 becomes effective as they are replaced in their entirety by TPL-001-2. TPL-005-0 and TPL-006-0.1 are being retired at midnight the day before TPL-001-2 becomes effective because their requirements are adequately covered by the revised TPL-001-2 and NERC's Rules of Procedure, Section 800. However, during this 24-month period, all aspects of the latest enforceable versions TPL-001-~~0~~ through TPL-006-~~0~~ shall remain in effect for compliance monitoring. This 24 month period is to allow entities to develop, perform and/or validate new and/or modified studies, methodologies, assessments, procedures, etc. necessary to implement and meet the TPL-001-2 requirements. The specified effective dates are expected to allow sufficient time for proper assessment of the available options necessary to create a viable Corrective Action Plan that is compliant with the new Standard.

R1. This Requirement is related to maintaining System models and the data needed to do so. This requirement shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required,

this requirement goes into effect on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

R7. This Requirement identifies an obligation to determine individual and joint responsibilities for performing studies needed to do the Planning Assessment. This requirement shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes into effect on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

TPL-001-2 'raises the bar' in several areas where performance requirements have been changed in the new Standard versus those in existing TPL-001-~~0~~1, TPL-002-~~0a~~1b, TPL-003-~~0~~1a and TPL-004-~~0~~1 because loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain events, whereas the existing Standards were interpreted by many to allow such actions. As shown in Table 1 of TPL-001-2, the performance requirements associated with the following events represent "raising the bar":

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

This "raising the bar" is beyond the control of the Transmission Planner and Planning Coordinator and may have significant budget, siting, permitting, and construction impacts on many Transmission Owners. To provide stakeholders with sufficient time to implement changes, a timeframe coincident with the end of the Near-Term Transmission Planning Horizon ~~will be~~has been provided ~~as follows:~~

- ~~For 84 months after the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required on the first day of the first calendar quarter, 84 months after Board of Trustees adoption, Corrective Action Plans applying to performance elements P1-2 and P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element), P2-1, P2-2 (above 300 kV), P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 kV) are allowed to include tripping of Non-Consequential Load and curtailment of Firm Transmission Service (in accordance with Requirement R2.7.3) that would not otherwise be permitted by the requirements of TPL-001-2.~~

Any entity which cannot eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for these performance elements by that date shall submit a mitigation plan to its Regional Entity outlining the steps it will take to correct the problem. If the entities follow the established ERO procedure for mitigation, it is the intent of the SDT that no penalties will be assessed.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Version 1 of SAR posted for comment from April 2, 2002 through May 3, 2002.
2. Version 2 of SAR posted for comment from May 5, 2004 through June 5, 2004.
3. Version 3 of SAR posted on November 18, 2005.
4. SAR approved on April 30, 2006.
5. Version 1 of Supplemental SAR posted for comment from February 15, 2007 through March 16, 2007.
6. Version 2 of Supplemental SAR posted on April 9, 2007.
7. Version 1 of revised standard(s) posted for comment on September 17, 2007.
8. Version 2 of the revised standards posted for comment on August 15, 2008.
9. Version 3 of the revised standards posted for comment on May 26, 2009.
10. Version 4 of the revised standards posted for comment on September 16, 2009.
11. Initial ballot completed on March 1, 2010.
12. Version 5 of the revised standard posted for comment on August 3, 2010.
13. Version 6 of the revised standard posted for information on October 19, 2010.
14. Version 7 posted for a parallel comment and initial ballot ending May 31, 2011.

Proposed Action Plan and Description of Current Draft:
The current draft is the eighth iteration of the revision of existing standards TPL-001 through TPL-006 and includes one revised standard, TPL-001-2, replacing TPL-001, TPL-002, TPL-003 and TPL-004. TPL-005 & -006 issues are addressed in this sixth draft and those standards will also be replaced by TPL-001-2.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Conduct recirculation ballot	3Q11
2. Submit standard(s) to BOT.	3Q11
3. Submit to regulatory authorities for approval.	3Q11

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-2**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required on the first day of the first calendar quarter 84 months after Board of Trustees adoption, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-2, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-2:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1
   - P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes

Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1,

and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that

Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when

such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
d. Simulate Normal Clearing unless otherwise specified.
e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.
g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
h. Planning event P0 is applicable to steady state only.
i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
   a. Loss of a tower line with three or more circuits.[11]
   b. Loss of all Transmission lines on a common Right-of-Way[11].
   c. Loss of a switching station or substation (loss of one voltage level plus transformers).
   d. Loss of all generating units at a generating station.
   e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
   a. Loss of two generating stations resulting from conditions such as:
      i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
      ii. Loss of the use of a large body of water as the cooling source for generation.
      iii. Wildfires.
      iv. Severe weather, e.g., hurricanes, tornadoes, etc.
      v. A successful cyber attack.
      vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
   b. Other events based upon operating experience that may result in wide area disturbances.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
   a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   e. 3Ø internal breaker fault.
   f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to address BES performance requirements. When Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss is documented, including alternatives evaluated; and where the utilization of Non-Consequential Load Loss is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	03/17/2001	Revision of TPL-001-0 to modify only Table 1 footnote b. Approved by Board of Trustees	Project 2006-02 – revision to address FERC directive
2	To be Determined	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Version 1 of SAR posted for comment from April 2, 2002 through May 3, 2002.
2. Version 2 of SAR posted for comment from May 5, 2004 through June 5, 2004.
3. Version 3 of SAR posted on November 18, 2005.
4. SAR approved on April 30, 2006.
5. Version 1 of Supplemental SAR posted for comment from February 15, 2007 through March 16, 2007.
6. Version 2 of Supplemental SAR posted on April 9, 2007.
7. Version 1 of revised standard(s) posted for comment on September 17, 2007.
8. Version 2 of the revised standards posted for comment on August 15, 2008.
9. Version 3 of the revised standards posted for comment on May 26, 2009.
10. Version 4 of the revised standards posted for comment on September 16, 2009.
11. Initial ballot completed on March 1, 2010.
12. Version 5 of the revised standard posted for comment on August 3, 2010.
13. Version 6 of the revised standard posted for information on October 19, 2010.
14. Version 7 posted for a parallel comment and initial ballot ending May 31, 2011.

Proposed Action Plan and Description of Current Draft:
The current draft is the eighth iteration of the revision of existing standards TPL-001 through TPL-006 and includes one revised standard, TPL-001-2, replacing TPL-001, TPL-002, TPL-003 and TPL-004. TPL-005 & -006 issues are addressed in this sixth draft and those standards will also be replaced by TPL-001-2.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Conduct recirculation ballot	3Q11
2. Submit standard(s) to BOT.	3Q11
3. Submit to regulatory authorities for approval.	3Q11

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-2**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required on the first day of the first calendar quarter 84 months after Board of Trustees adoption, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-2, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-2:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1
   - ~~,~~P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes

Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies ~~(~~as indicated in Requirement R2, Part 2.6~~)~~.. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1,

and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that

Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when

such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
d. Simulate Normal Clearing unless otherwise specified.
e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.
g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
h. Planning event P0 is applicable to steady state only.
i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
   a. Loss of a tower line with three or more circuits.[11]
   b. Loss of all Transmission lines on a common Right-of-Way[11].
   c. Loss of a switching station or substation (loss of one voltage level plus transformers).
   d. Loss of all generating units at a generating station.
   e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
   a. Loss of two generating stations resulting from conditions such as:
      i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
      ii. Loss of the use of a large body of water as the cooling source for generation.
      iii. Wildfires.
      iv. Severe weather, e.g., hurricanes, tornadoes, etc.
      v. A successful cyber attack.
      vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
   b. Other events based upon operating experience that may result in wide area disturbances.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
   a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   e. 3Ø internal breaker fault.
   f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to address BES performance requirements. When Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss is documented, including alternatives evaluated; and where the utilization of Non-Consequential Load Loss is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None.

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use ~~the latest~~ data consistent with ~~the data~~that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR~~,~~ The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		(P2 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	through P7) in Table 1. OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in

	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Requirement R6.
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	03/17/2001	Revision of TPL-001-0 to modify only Table 1 footnote b. Approved by Board of Trustees	Project 2006-02 – revision to address FERC directive
~~1~~2	~~TBD~~To be Determined	Revision of TPL-001-~~0 as per Project 2006-02~~1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	~~Not employed due to scope of~~Project 2006-02 – complete revision

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2006-02 Assess Transmission and Future Needs Recirculation Ballot Now Open July 13-July 22, 2011

Now available at: https://standards.nerc.net/CurrentBallots.aspx

A recirculation ballot for the proposed standard, TPL-001-2 — Transmission System Planning Performance Requirements is being conducted through **8:00 pm Eastern on Friday, July 22, 2011**.

The drafting team has made a number of non-substantive changes to address comments from the parallel comment period and successive ballot that concluded on May 31, 2011. No changes were made to the text of any Requirements; however, the team made the following minor modifications to the standard:

- Changed bullets under Requirements R3 and R4 to numbers
- Added more words to the evidence retention for Requirements R5 and R6 to align more closely with the language in the associated requirement
- Rearranged the wording of the third Severe VSL for R1 for clarity
- Added the word, "results" to all VSLs for Requirement R8 for closer alignment with the language in the associated requirement

The team also made the following minor modifications to the Implementation Plan:

- Rearranged content but did not change proposed phasing of requirements
- Added more specificity to the language identifying when the already approved standards will be retired. (Midnight the day before TPL-001-2 becomes effective)
- Corrected some typographical errors.

Documents for this project, including clean and redline versions of TPL-001-2 and the implementation plan are posted at the following site: http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html. Note that because TPL-001-2 incorporates requirements from several standards, it is not practical to produce a redline showing changes to the last approved version. The last approved versions of each of the following standards have been posted for reference: TPL-001-1; TPL-002-1b; TPL-003-1a; TPL-004-1; TPL-005-0; and TPL-006-0.1.

Instructions

In the recirculation ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their prior votes. A ballot pool member who failed to cast a ballot during the last ballot window may cast a ballot in the recirculation ballot window. If a ballot pool member does not

participate in the recirculation ballot, that member's last vote cast in the successive ballot that ended on May 31, 2011 will be carried over.

Members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx.

Next Steps

Voting results will be posted and announced after the ballot window closes. If the standard is approved by a two-thirds majority, it will be submitted for adoption by the NERC Board of Trustees prior to filing with regulatory authorities for approval.

Background

TPL-001-2 is designed to be a single, comprehensive, and coordinated standard that merges the requirements of four existing standards: TPL-001-1; TPL-002-1b; TPL-003-1a; TPL-004-1 and also results in the retirement of TPL-005 and TPL-006. The proposed standard includes several new definitions. The purpose of the proposed standard is to establish transmission system planning performance requirements within the planning horizon to develop a bulk electric system that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies.

Additional information about this project is available on the project page at http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Consideration of Comments on Initial Ballot — Assess Transmission Future Needs and Develop Transmission Plans (Project 2006-02)
Date of Initial Ballot: July 13 – July 22, 2011

Summary Consideration:

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Voter	Entity	Segment	Vote	Comment
Brock Ondayko	AEP Service Corp.	5	Affirmative	Comments submitted via electronic form by Thad Ness on behalf of American Electric Power.
Mark B Thompson	Alberta Electric System Operator	2	Affirmative	With respect to R2, Part 2.7.1 which lists system deficiencies and the associated actions needed to achieve System performance, the 3rd and 4th bullet identify the following actions as being acceptable. :Installation or modification of automatic generation tripping as a response to a single or multiple contingency to mitigate Stability performance violations. :Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations. The current Alberta transmission policy does not allow for the tripping or runback of generation for a single contingency; however for multiple contingencies it is acceptable. The AESO will bring TPL-001-2, with any modifications, through the standard development consultation process in Alberta and ultimately to the Alberta Utilities Commission for approval.
Kirit Shah	Ameren Services	1	Negative	(1) Requirement R2.4.1, which addresses dynamic load modeling, has been a cause for concern because of the lack of guidance regarding reasonable induction motor representation as opposed to generic load models. While it is recognized that the effort to simulate the effects of induction motor loads is important, it is premature to include such modeling as part of the requirements for this standard. (2) For Measurements M3 and M4, there is still some question as to what is to be provided as sufficient evidence of a study. It is not clear whether the study results would be sufficient, or whether the entire powerflow, stability, or short circuit effort needs to be documented in a formal study report. For example, it is not clear whether contingency lists used in performing the study work would need to be

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
				retained as part of the documentation. (3) The standard as written is too prescriptive with regard to critical system conditions which are to be modeled. Such conditions would vary considerably for different systems across the continent. (4) Overall, we believe that this standard does not improve the clarity of what is required, and would give additional occasions for disputes between compliance monitors and various registered entities.
Paul B. Johnson	American Electric Power	1	Affirmative	Comments submitted by Thad Ness on behalf of American Electric Power
Steven Norris	APS	3	Affirmative	Comments submitted.
Robert Smith	Arizona Public Service Co.	1	Affirmative	Comments submitted.
Edward Cambridge	Arizona Public Service Co.	5	Negative	While AZPS generally supports this standard, AZPS cannot support the violation severity levels that are proposed in the recirculation ballot. AZPS believes the time frames set forth in the proposed security levels are unreasonably short (10 days) and should be extended to 30 days between each elevation in severity level. For these reasons, AZPS has changed its vote to "negative."
John Bussman	Associated Electric Cooperative, Inc.	1	Negative	see comments
Kevin Smith	Balancing Authority of Northern California NCR11118	1	Affirmative	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', that addressed planned or controlled interruption of electric supply for N-1 conditions. Registered Entity's Board of Directors, state Utilities Commission, and/or its customers should determine what level of service is acceptable with the associated cost. This point is captured in footnote #12 of Table 1 in the TPL Standard and is necessary for maintaining SMUD's Affirmative vote.
Venkataramakrishnan Vinnakota	BC Hydro	2	Negative	Comments submitted.
Patricia Robertson	BC Hydro and Power Authority	1	Negative	Comments submitted
Pat G. Harrington	BC Hydro and Power	3	Negative	Comments Submitted

Voter	Entity	Segment	Vote	Comment
	Authority			
Clement Ma	BC Hydro and Power Authority	5	Negative	Comments submitted.
Donald S. Watkins	Bonneville Power Administration	1	Affirmative	comments submitted
Rebecca Berdahl	Bonneville Power Administration	3	Affirmative	BPA comments submitted separately.
Francis J. Halpin	Bonneville Power Administration	5	Affirmative	Comments have been submitted separately.
Brenda S. Anderson	Bonneville Power Administration	6	Affirmative	Comments have been submitted.
Jeanie Doty	City of Austin dba Austin Energy	5	Affirmative	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In our view, a Registered Entity's Board of Directors, local public utility commission, and/or its customers should determine what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote. Regarding R2 (2.5): The value of annually assessing system stability for years 6-10 is questionable. The requirement for stability assessment in years 6-10 should be limited to new generation interconnections or planned major transmission system improvements with regional impact. The standard should clarify the 'material changes' that would necessitate stability planning assessments and documentation. Regarding the R8 requirement to distribute all Planning Assessment results to adjacent Planning Coordinators and Transmission Planners is excessive and cumbersome. Regarding R8, we suggest the following language: Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners in accordance with the requirements of the applicable Reliability Coordinator. Any Registered Entity with a reliability-related need may submit a written request for the Planning Assessment results and the

Voter	Entity	Segment	Vote	Comment
				Transmission Planner or Planning Coordinator shall provide the latest Planning Assessment results within 30 days of such request.
Gregg R Griffin	City of Green Cove Springs	3	Affirmative	R7 is not needed and administrative in nature. Instead is should say that an entity can use as evidence another entity's study, but not in the requirement and rather in the measures. R8 is ambiguous, does the requirement require submitting the Planning Assessment only after receiving a written request, or automatic distribution to neighboring PCs and TPs without a written request, and to others with a reliability related need following a written request? Table 1, under first heading of "Steady State and Stability", bullet c should be removed since it is duplicative of the standard, and not entirely consistent with the standard (e.g., open to interpretation whereas the standard better clarifies how to study protection system operation)
Bill Hughes	City of Redding	3	Affirmative	Registered Entity's Board of Directors, state Utilities Commission, and/or its customers should determine what level of service is acceptable and with what associated cost. We believe that this is a local load reliability issue and not a BES concern. This view is captured as footnote #12 that allows loss on Non-Consequential load loss under certain circumstances and is essential in maintaining an affirmative vote.
Nicholas Zettel	City of Redding	4	Affirmative	Registered Entity's Board of Directors, state Utilities Commission, and/or its customers should determine what level of service is acceptable and with what associated cost. We believe that this is a local load reliability issue and not a BES concern. This view is captured as footnote #12 that allows loss on Non-Consequential load loss under certain circumstances and is essential in maintaining an affirmative vote.
Paul Cummings	City of Redding	5	Affirmative	Registered Entity's Board of Directors, state Utilities Commission, and/or its customers should determine what level of service is acceptable and with what associated cost. We believe that this is a local load reliability issue and not a BES concern. This view is captured as footnote #12 that allows loss on Non-Consequential load loss under certain circumstances and is essential in maintaining an affirmative vote.
Marvin Briggs	City of Redding	6	Affirmative	Registered Entity's Board of Directors, state Utilities Commission, and/or its customers should determine what level of service is acceptable and with what associated cost. We believe that this is a local load reliability issue and not a BES concern. This view is captured as footnote #12 that allows loss on Non-Consequential load loss under certain circumstances and is essential in maintaining an affirmative vote.

Voter	Entity	Segment	Vote	Comment
Randall McCamish	City of Vero Beach	1	Affirmative	R7 is not needed and administrative in nature. Instead is should say that an entity can use as evidence another entity's study, but not in the requirement and rather in the measures. R8 is ambiguous, does the requirement require submitting the Planning Assessment only after receiving a written request, or automatic distribution to neighboring PCs and TPs without a written request, and to others with a reliability related need following a written request? Table 1, under first heading of "Steady State and Stability", bullet c should be removed since it is duplicative of the standard, and not entirely consistent with the standard (e.g., open to interpretation whereas the standard better clarifies how to study protection system operation).
Jack Stamper	Clark Public Utilities	1	Affirmative	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In our view, the utility's elected board of commissioners should have the determination what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote.
Peter T Yost	Consolidated Edison Co. of New York	3	Negative	Requirement R1.1.5: Delete "and Interchange." The inclusion of other than Firm transactions (e.g. economic transactions in Interchange) in a base power flow case utilized for planning/designing the interconnected system blurs the boundary between reliability issues and purely economic issues. Reliability issues are issues that a Transmission Owner (TO) must address for the purpose of meeting its load demand, and are defined by the application of well established reliability standards and criteria that are based on the electrical characteristics of the interconnected system, but without economic considerations. Instead, economic transactions are types of transactions that a TO may enter into once its load obligations are met, and are evaluated based on economic parameters that are markedly different from the aforementioned reliability criteria (e.g. congestion costs). Modeling all types of transactions in a power flow case without distinction detracts from the accuracy and validity of either assessment (reliability and economic).
Wilket (Jack) Ng	Consolidated Edison Co. of New York	5	Negative	Requirement R1.1.5: Delete "and Interchange." The inclusion of other than Firm transactions (e.g. economic transactions in Interchange) in a base power flow case utilized for planning/designing the interconnected system blurs the boundary between reliability issues and purely economic issues. Reliability issues are issues that a Transmission Owner (TO) must address for the purpose of meeting its load demand, and are defined by the

Voter	Entity	Segment	Vote	Comment
				application of well established reliability standards and criteria that are based on the electrical characteristics of the interconnected system, but without economic considerations. Instead, economic transactions are types of transactions that a TO may enter into once its load obligations are met, and are evaluated based on economic parameters that are markedly different from the aforementioned reliability criteria (e.g. congestion costs). Modeling all types of transactions in a power flow case without distinction detracts from the accuracy and validity of either assessment (reliability and economic).
Nickesha P Carrol	Consolidated Edison Co. of New York	6	Negative	Requirement R1.1.5: Delete "and Interchange." The inclusion of other than Firm transactions (e.g. economic transactions in Interchange) in a base power flow case utilized for planning/designing the interconnected system blurs the boundary between reliability issues and purely economic issues. Reliability issues are issues that a Transmission Owner (TO) must address for the purpose of meeting its load demand, and are defined by the application of well established reliability standards and criteria that are based on the electrical characteristics of the interconnected system, but without economic considerations. Instead, economic transactions are types of transactions that a TO may enter into once its load obligations are met, and are evaluated based on economic parameters that are markedly different from the aforementioned reliability criteria (e.g. congestion costs). Modeling all types of transactions in a power flow case without distinction detracts from the accuracy and validity of either assessment (reliability and economic).
David A. Lapinski	Consumers Energy	3	Negative	We agree with the comments of MISO.
David Frank Ronk	Consumers Energy	4	Negative	We agree with comments submitted by MISO
James B Lewis	Consumers Energy	5	Negative	We endorse the comments of MISO.
Sally Witt	East Kentucky Power Coop.	3	Negative	(1) While the Planning Coordinator and Transmission Planner should share the results of their respective Planning Assessments with entities that have a reliability related need, Requirement R8 doesn't have a significant impact on reliability. The Violation Risk Factor should be changed to Lower. (2) Footnote 3, which applies to BES Level in Table 1, draws in non-BES facilities. It states that HV is defined as 300 kV and lower voltage systems, which includes all voltages below the traditional 100-kV cutoff for the BES.

Voter	Entity	Segment	Vote	Comment
				(3) Requirement R1 could be modified unintentionally and fundamentally change the requirement because R1 references MOD-010 and MOD-012 without a version number. Thus, all future updates to these standards directly modify TPL-001-2 Requirement R1 whether it was intended or not.
Stephen Ricker	East Kentucky Power Coop.	5	Negative	Comments on Project 2006-02 Assess Transmission Future Needs and Develop Transmission Plans Recirculation Ballot (1) While the Planning Coordinator and Transmission Planner should share the results of their respective Planning Assessments with entities that have a reliability related need, Requirement R8 doesn't have a significant impact on reliability. The Violation Risk Factor should be changed to Lower. (2) Footnote 3, which applies to BES Level in Table 1, draws in non-BES facilities. It states that HV is defined as 300 kV and lower voltage systems, which includes all voltages below the traditional 100-kV cutoff for the BES. (3) Requirement R1 could be modified unintentionally and fundamentally change the requirement because R1 references MOD-010 and MOD-012 without a version number. Thus, all future updates to these standards directly modify TPL-001-2 Requirement R1 whether it was intended or not.
Charles B Manning	Electric Reliability Council of Texas, Inc.	2	Negative	ERCOT's comments have been submitted via the online form.
Edward J Davis	Entergy Services, Inc.	1	Affirmative	Commens Submitted
Terri F Benoit	Entergy Services, Inc.	6	Affirmative	'Commits Submitted".
Lee Schuster	Florida Power Corporation	3	Affirmative	Comments Submitted
Luther E. Fair	Gainesville Regional Utilities	1	Affirmative	I do have one point of concern for your consideration; This standard does raise the bar in some areas, most notably for an entity the size of GVL it applies performance requirements for long lead equipment emergency replacement. For example if we don't have the ability to replace a transformer at Parker within a few months of failure, then we would have to demonstrate that we can meet many (but not all) of the same performance criteria without the transformer that we can with the transformer.

Voter	Entity	Segment	Vote	Comment
Harold Taylor	Georgia Transmission Corporation	1	Affirmative	All of our concerns have been addressed. Regards, Robert Casey Georgia Transmission Corporation
Ajay Garg	Hydro One Networks, Inc.	1	Negative	Hydro One Networks is casting a negative vote. Other than a few changes related to Footnotes 9 and 12 of Table 1 and VSLs, the other changes in the proposed draft are minor. The concerns of the industry on several important issues have not been sufficiently addressed in this draft. For detailed comments please refer to our submission through the on-line comment form.
David Kiguel	Hydro One Networks, Inc.	3	Negative	Hydro One Networks is casting a negative vote. Other than a few changes related to Footnotes 9 and 12 of Table 1 and VSLs, the other changes in the proposed draft are minor. The concerns of the industry on several important issues have not been sufficiently addressed in this draft. For detailed comments please refer to our submission through the on-line comment form.
Bernard Pelletier	Hydro-Quebec TransEnergie	1	Negative	These are the two major concerns : * In Table 1 footnote 3 : Again, the definition of EHV facilities shoud be changed to something like : Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as those representing the backbone of the System, generally at voltage greater than 300 kV, and high voltage (HV) Facilities defined as those not representing the backbone of the System, as determined by the Planning Coordinator and approved by Regional Entity. * In Table 1 b : "Consequential Load Loss as well as generation loss is acceptable as a a consequence of any event excluding P0". We should also add Firm Transmission Services Loss is also acceptable (particularly in P1 Loss of a single pole of a DC line for which the transfer is reduced accordingly to the remaining pole capability). "
Tino Zaragoza	Imperial Irrigation District	1	Affirmative	Comments provided
Jesus S. Alcaraz	Imperial Irrigation District	3	Affirmative	IID submits a Affirmative vote with comments.
Kim Warren	Independent Electricity System Operator	2	Affirmative	We thank the drafting team for considering the concerns and suggestions submitted with our previous ballot. We reiterate our view that we have no issues with the standard per se and we agree that the current draft is a significant improvement over the currently approved TPL-001 through TPL-004 standards. We recognize that it is necessary to move forward with this

Voter	Entity	Segment	Vote	Comment
				important work. The uncertainties created as a result of the evolving BES definition and BES Exception Process, as well as regulatory review of the TPL-001-1 Footnote 'b' revision still persist and will not go away for some time to come. These are significant parallel developments that will define applicability of the TPL standard (and all NERC standards) and establish performance requirements. We do however believe that this lingering uncertainty is insufficient grounds for us to vote against a standard we otherwise fully support.
Michael Moltane	International Transmission Company Holdings Corp	1	Affirmative	Comments submitted.
Kathleen Goodman	ISO New England, Inc.	2	Negative	Please see the comments submitted along with this ballot.
Larry E Watt	Lakeland Electric	1	Negative	LAK appreciates the hard work of the Standard Drafting team and applauds the significant improvement of clarity of the draft standard. FMPA believes we are almost there, but, there are a number of issues left to resolve. Issues that Cause FMPA to Recommend a Negative Vote A. Spare Equipment, R2.1.5 - The requirement reaches beyond the FERC directive. The directive was: "Accordingly, the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy." So, the directive is only to address planned outage, not unplanned outages. Also note that the applicability to GSUs is ambiguous. "Transmission" is defined as: "An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems." Is the "point of supply" the generator terminal, or the GSU high side terminal? B. Table 1, under first heading of "Steady State Only", bullet i is open to interpretation. Many utilities use steady state P-V analyses to study voltage stability and design UVLS systems in apart around those steady state analyses. Would this bullet essentially eliminate P-V and Q-V studies and the related use of UVLS?
Martyn Turner	Lower Colorado River Authority	1	Affirmative	1. R2 (2.5): The requirement for stability assessment in years 6-10 should be limited for new generation interconnections or for planned major transmission system improvements that have regional impact. The standard should clarify the 'material changes' that would necessitate stability planning assessments and documentation. 2. R8 requirement to

Voter	Entity	Segment	Vote	Comment
				distribute all Planning Assessment results to adjacent PCs and TPs are excessive and cumbersome. Regarding R8, LCRA TSC suggests the following language: Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners in accordance with the overseeing Reliability Coordinator requirements. Any functional entity that has a reliability related need and submits a written request for the Planning Assessment results, the Transmission Planner and Planning Coordinator shall provide the latest Planning Assessment results within 30 days of such request.
Tom Foreman	Lower Colorado River Authority	5	Affirmative	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In our view, board of directors/Public Utility should have the determination what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote. 1. R2 (2.5): The value of assessing system stability for years 6-10 is questionable. Stability studies should be conducted for new generation interconnections or for planned major transmission system improvements that have regional impact. 2. R8 requirement to distribute all Planning Assessment results to adjacent PCs and TPs are excessive and cumbersome. Regarding R8, LCRA suggests the following language: Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners in accordance with the overseeing Reliability Coordinator requirements. Any functional entity that has a reliability related need and submits a written request for the Planning Assessment results, the Transmission Planner and Planning Coordinator shall provide the latest Planning Assessment results within 30 days of such request.
Brad Jones	Luminant Energy	6	Negative	Our most significant concerns are related to the following: (1) The requirements for Sensitivity Analysis are not stringent enough. (2)Studies should include variations in the duration and timing of transmission outages. "Anticipated" outages should be included in the studies and not just "known" transmission outages. It is our experience that only including "known" outages drastically under represents the actual number of transmission outages. (3) Major equipment outages lasting three or more months, as a result of Spare equipment strategies should be included in studies. The time limit of one year as specified in the Standard is too lax. Specific suggested language: 1.1.2. Known outage(s) of generation or

Voter	Entity	Segment	Vote	Comment
				Transmission Facility(ies) with a duration of at least six months or any known outage(s) of generation or Transmission Facility(ies) that will extend into the high stress period of the BES. 2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies (as indicated in Requirement R2, Part 2.6, as follows). Qualifying studies shall include the following conditions: Add language between 2.1.3 and 2.1.4 to account for generation limitations due to Ancillary Services. Suggested wording: All planning studies must recognize and make provision for secure delivery of each of the Ancillary Services (eg Operating Reserve). In no case shall these studies double count capacity as being available for congestion management and Ancillary Services unless processes are in place to allow for location specific deployment of these Ancillary Service reserves for congestion management purposes. 2.1.4 (bullet 7) Duration and timing of anticipated Transmission outages such as required maintenance activities. 2.1.4 (bullet 8 added) Reasonable variations of anticipated generator availability after accounting for equivalent forced outage rate. 2.1.5 If an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that would cause an outage of three months or more, (such as a transformer) the impact of this outage on System performance shall be studied. 2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: o Load level, Load forecast, or dynamic Load model assumptions. o Expected transfers. o Expected in service dates of new or modified Transmission Facilities. o Reactive resource capability. o Generation additions, retirements, or other dispatch scenarios. o Duration or timing of anticipated Transmission outages such as required maintenance activities. o Reasonable variations of anticipated generator availability after accounting for equivalent forced outage rate. 2.4.4. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled. 2.4.5 If an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that would cause an outage of three months or more, (such as

Voter	Entity	Segment	Vote	Comment
				a transformer) the impact of this outage on System performance shall be studied.
Joe D Petaski	Manitoba Hydro	1	Negative	Please see Manitoba Hydro's comments submitted in the formal commenting period.
Greg C. Parent	Manitoba Hydro	3	Negative	Please see Manitoba Hydro's comments submitted in the formal commenting period.
S N Fernando	Manitoba Hydro	5	Negative	Please see Manitoba Hydro's comments submitted in the formal commenting period.
Daniel Prowse	Manitoba Hydro	6	Negative	Please see Manitoba Hydro's comments submitted in the formal commenting period.
Terry Harbour	MidAmerican Energy Co.	1	Affirmative	Resolve the conflict between R2 and other requirements in the TPL standards by replacing the term, "System" with "BES" in various places throughout the standard when the reference should not be to the collective generation, transmission, and distribution systems, which is the definition of the NERC Glossary term, "System". These locations are: R2.1.4, R2.1.5, R2.4.3, R2.6.2, R2.7, R2.7.1, R2.7.4, R2.8.1, R2.8.2, R3.5, R4.5, R5, and R6
Thomas C. Mielnik	MidAmerican Energy Co.	3	Affirmative	Resolve the conflict between R2 and other requirements in the TPL standards by replacing the term, "System" with "BES" in various places throughout the standard when the reference should not be to the collective generation, transmission, and distribution systems, which is the definition of the NERC Glossary term, "System". These locations are: R2.1.4, R2.1.5, R2.4.3, R2.6.2, R2.7, R2.7.1, R2.7.4, R2.8.1, R2.8.2, R3.5, R4.5, R5, and R6.
Marie Knox	Midwest ISO, Inc.	2	Negative	Comments. Regarding Requirement 8, we still do not believe that there is significant risk to the reliability of the BES if an annual Planning Assessment is not distributed to another entity or if a documented response to Planning Assessment comments is not provided within 90 days of a request. Requirement 8 is an administrative requirement that adds little to improve reliability. We recommend that the VRF for Requirement 8 remain "Low", rather than be changed to "Medium". We also believe that the standard is too prescriptive as to what critical system conditions must be modeled, as these conditions vary considerably from system to system and within large systems. Table 1-Steady State and Stability Performance Planning Events, Category P5, includes "non-redundant" relay in the Event column. It is unclear if the SDT's intent is to provide distinction between a

Voter	Entity	Segment	Vote	Comment
				back-up relay and a redundant relay. We still believe that a definition for the term "non-redundant" should be provided along with the standard.
Richard Burt	Minnkota Power Coop. Inc.	1	Negative	In general, MPC feels that this standard has some organizational issues and is unclear in many areas. General comments include the following: 1. Use of the word "stability" should be qualified as "dynamic stability" or "transient stability" to avoid confusion with small signal stability or voltage stability. 2. The term "Planning Events" should be relabeled. It's not descriptive enough. Somehow it should be identifiable as being "more likely to occur than Extreme Events." 3. There are numerous forward and backward references between the different requirements, e.g. between R4.1 and R4.4. I see no reason why these isolated sections can't be put under the same requirement. For instance, move the text of R4.4 to R4.1, and move the text of R4.5 to R4.2. 4. There are numerous references to "more severe System impacts" e.g. R3.4. This is vague unless there is some sort of definition included to quantify severity of impacts. The following comments correlate to specific requirements in the new TPL standard. R2.1.5 Need a definition of "major Transmission equipment." It is too open-ended otherwise. R2.7 What is meant by "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with ... 2.1.4 and 2.4.3"? Does it mean that if we can only find one condition that's problematic, we don't need a CAP? R2.7.2 What is meant by "multiple sensitivity studies"? R2.7.3 There should be further explanation of things that qualify as being "beyond the control of the Transmission Planner"? R4.1.2 Need more clarity on "its directly connected Facilities". R5 It's not clear what's meant by "post-Contingency voltage deviations". Why wouldn't they just be voltage limits instead of voltage deviations? Table 1 The notes at the beginning of Table 1 should be labeled as performance requirements or something similar, for convenient reference in discussion and reports. Perhaps they should be in a separate list rather than part of Table 1 itself. The Extreme Events list should be in a separate Table, not part of Table 1. In Table 1 footnote 13, it may be better to describe the protective system functions, such as "protective relays, associated communications, and auxiliary tripping outputs" instead of listing relay types.
Spencer Tacke	Modesto Irrigation District	4	Negative	Both Sections 2.1.4 (seven sensitivities) and 2.4.3 (five sensitivities) require sensitivity studies to be run for all planning events and for all years specified , which increases the number of required studies beyond a reasonable and manageable limit. Also, both Section 2.1.4 and 2.4.3

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				specify that running studies over "...a range of credible conditions that demonstrate a measurable change in System response (performance)." must be completed, yet using "credible conditions" and also "demonstrating a measurable change in System response (performance)", may be mutually exclusive. "Measurable change in System response (performance)" is open to a broad interpretation, which increases the risk that the auditor may very likely interpret it differently than the utility system planner. The definition of the extreme events that have to be analyzed has been made nebulous, where in the existing standards they are quite specific. Requirement 2.1.5 requires the modeling of the loss of any system element that does not have a back-up or spare available sooner than 1 year, as part of the system normal state. It is not clear why using 1 year of loss of use for a system element is being used as the triggering point requiring further system enhancements. Thank you.
Mike Avesing	Muscatine Power & Water	5	Affirmative	no comments
Saurabh Saksena	National Grid	1	Affirmative	Comments submitted.
Tony Eddleman	Nebraska Public Power District	3	Negative	Comments submitted through electronic comment form.
Don Schmit	Nebraska Public Power District	5	Negative	Comments have been submitted by NPPD.
Randy MacDonald	New Brunswick Power Transmission Corporation	1	Negative	Foot Note 12: Rather than requiring planning entities to have a open and transparent planning stakeholder process, which could require significant costs and administration, the foot note should focus on ensuring that affected loads/entities are aware of the possible risks of load loss and alternatives and provide for affected stakeholder feedback
Alden Briggs	New Brunswick System Operator	2	Negative	See NBSO submitted comments
Gregory Campoli	New York Independent System Operator	2	Negative	Comments were provided

Voter	Entity	Segment	Vote	Comment
Alan Adamson	New York State Reliability Council	10	Negative	1. In R1.1.5, known commitments for Firm Transmission Service, plus other Interchange that does not violate reliability constraints - it is imperative to model other Interchange after accounting for all existing and planned Firm Transmission Service to ensure that reliability-based transactions are not confused with economic interchange. 2. In R2.2.5, the current requirement language can be interpreted to require evaluation of the simultaneous unavailability of multiple long-lead-time components. Also, as a transformer outage is already evaluated as part of category P6 in Table 1, additional studies should not be required; however, spare equipment strategies could be assessed in the context of the planning assessment. 3. In R2.2, the language in this requirement is materially inconsistent with R2.1, unnecessarily requiring a current study.
Guy V. Zito	Northeast Power Coordinating Council, Inc.	10	Affirmative	NPCC will be submitting a list of comments.
David Boguslawski	Northeast Utilities	1	Negative	Footnote 7 It appears there is a discrepancy between Footnote 7 and Event P2-1. Footnote 7 could be eliminated by rewording Event P2-1 as follows: "Opening one end of a line section w/o a fault". Footnote 12 NU continues to disagree with the language for Footnote 12 (formerly Footnote b) - Specifically NU believes that the revised language of Footnote 12 suggests that non-consequential demand interruption (load that is not directly served by the elements removed from service as a result of the contingency) could be used to mitigate reliability concerns arising from NERC Category B contingency events (i.e., single element contingencies). This language seems to encourage operational workarounds and adds burdens for operators of the system. NU believes this is not consistent with planning a highly reliable bulk electric system and thus does not support this weaker language". Requirement R1, Part 1.1.6 The phrase "required for Load" should be deleted as this confuses the issue. Requirement R2, Part 2.2 The language of Requirement R2 Part 2.2 seems to suggest that current annual studies are always required for the long-term steady state assessment. This may have been an oversight, for consistency Requirement R2 Part 2.2 should be modified to similarly read as Requirement R2, Part 2.1. Requirement R3, Part 3.3.1 NU feels that the last sentence of Requirement R3, Part 3.3.1 should be removed since this is handled by PRC-023. Line ratings are addressed by PRC-023 which requires coordination with the Reliability Coordinator. NU suggests the removal of the following sentence: "Tripping of Transmission elements

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				where relay loadability limits are exceeded." General comment NU believes that a standard should contain statements and requirements that are direct and measurable. TPL-001-2 should not be an exception to this rule. Therefore, statements like "An objective" which appears in Footnotes 9 and 12 shall not be used.
Joseph O'Brien	Northern Indiana Public Service Co.	6	Affirmative	see comment form
John H Hagen	Pacific Gas and Electric Company	3	Affirmative	prior comments have been addressed
John C. Collins	Platte River Power Authority	1	Negative	Stability requirements R4.1.2, along with the second and third bullets of R4.3.1, could be misunderstood to require the development of comprehensive relaying models for all Facilities represented in the stability model. These requirements should be made clear that Stability studies are to simulate the effects of relaying (tripping certain Facilities) and not require relaying models to trigger and cause the effects.
Terry L Baker	Platte River Power Authority	3	Negative	Stability requirements R4.1.2, along with the second and third bullets of R4.3.1, could be misunderstood to require the development of comprehensive relaying models for all Facilities represented in the stability model. These requirements should be made clear that Stability studies are to simulate the effects of relaying (tripping certain Facilities) and not require relaying models to trigger and cause the effects.
Pete Ungerman	Platte River Power Authority	5	Negative	Stability requirements R4.1.2, along with the second and third bullets of R4.3.1, could be misunderstood to require the development of comprehensive relaying models for all Facilities represented in the stability model. These requirements should be made clear that Stability studies are to simulate the effects of relaying (tripping certain Facilities) and not require relaying models to trigger and cause the effects.
Daniel W. O'Hearn	Powerex Corp.	6	Negative	Powerex has submitted a negative ballot for Draft #6 of Standard TPL-001 because Powerex has concerns regarding Footnotes 9 and 4 that need to be addressed. Details of our concerns are summarized below. Background: The work that transmission planners do to ensure Firm Transmission Service is tremendously important for the reliability of the Bulk Electric System and forms a key part of the foundation upon which system operators and energy market participants interact. As a Purchasing-Selling Entity, Powerex is primarily concerned about Footnote 9 that conditions when interruption of Firm Transmission Service may allowed. We believe

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				that the goals of maintaining system reliability and enhancing market participation will both be best served if the conditions for interrupting Firm Transmission Service become clear and unambiguous in the TPL-001-2 Standard. In our experience, Transmission Providers have different interpretations of the TPL-001 Performance Table and because of latitude previously granted by Footnote B have different perspectives of when Interuptions of Firm Transfers is acceptable. Below we describe the two interpretations using the language of the proposed TPL-001 standard. Interpretation #1: Following loss of the most critical transmission element under stressed conditions, the transmission provider plans to supply the forecast peak loads and Firm Transmission Service indefinitely. o Typically this is achieved by assuming that the System Operators would, within a few minutes of the P1 Single Contingency, curtail all non-firm transmission service and then arm Special Protection Schemes that could result in Interruption of Firm Transmission Service or Non-Consequential Load Loss in the event of a P6 Multiple contingency. Interpretation #2: Following loss of the most critical transmission element under stressed conditions, the transmission provider plans to supply the forecast peak loads indefinitely but may curtail all Firm Transmission Service within 20 minutes if required. o Typically this occurs on systems where there are no Special Protection Schemes to address P6 Multiple contingencies, consequently, the transmission planners assume that curtailment of all non-firm AND as much Firm Transmission Service as required will occur within ~20 minutes of the P1 Single Contingency because the Operators must prepare their transmission system to withstand the next worst contingency. Currently, Purchasing-Selling Entities must plan for situations where they could see their Firm Transmission Service on certain paths curtailed within 20 minutes of a P1 contingency. The less stringent interpretation of the TPL-001 Performance Table that allowed a P1 contingency to change into a P6 contingency within the same operating hour, has resulted in situations where the Firm Transmission Service for inter-regional transfers face significantly greater risks of interruption than the Firm Transmission Service provided to local Load Serving Entities. Powerex recommends that the Standards Drafting Team revise TPL-001 such that all Transmission Planners will know that they should plan for Firm Transmission Service to be sustained indefinitely following P1 contingencies. Specific Comments on TPL-001-2: Footnote 9: Deviation from the Approved Footnote B Powerex believes that the Footnote B, as approved by the NERC Board of Trustees on February 17, 2011, is more stringent than the previous Footnote B and

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				will have the effect of ensuring that Firm Transmission Service can be sustained indefinitely following P1 contingencies. The key difference of the proposed Footnote 9 is that it adds the phrase "as a System adjustment" to the approved version of Footnote B. We believe this addition would cause the practice of curtailing Firm Transmission Service within 20 minutes of P1 contingencies to continue. Consequently, we recommend that the proposed Footnote 9 maintain the approved wording as follows: Footnote 9: An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed (deletion)[as] a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch.... For consistency, Table 1 should also be modified to remove the Footnote 9 reference from the Initial Condition Column for the P3-Multiple Contingency and P6 Multiple Contingency Categories. Footnote 9: Clarity on what is meant by "Resources obligated to re-dispatch" It is unclear to many parties what is meant by an obligation to re-dispatch. Some interpret this as a right to direct the Source to curtail energy scheduled on Firm Transmission Service. Our belief is that "an obligation to re-dispatch" should correspond to a formal agreement with a Generation Owner, located on the load side of a transmission constraint, to resupply the load that had been receiving energy from a remote source before the Firm Transmission Service was curtailed. Consequently, we recommend that Footnote 9 be revised as follows: Footnote 9: ..... a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch [to ensure uninterrupted energy supply to the Load-Serving Entity(ies)], where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss.... Footnote 4: Conditional Firm Transmission Service Footnote 4: "Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service." In a sense, offering conditional firm transmission service is analogous to selling land in a known flood plane - this can be a perfectly acceptable option provided all parties involved in current and future transactions can quantify the risks and manage them appropriately. There needs to be coordination between the planners, operators and marketers to ensure that the conditions that could lead to curtailment of Conditional Firm Transmission Service are understood and the associated

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				risks properly managed. We are concerned that in the absence of coordination, specifically additional requirements included in the BAL and INT standards, energy that is scheduled on conditional firm could actually be marketed as firm and as a result the counterparties to some transactions may not be aware of the curtailment risks they could face.
John T Sturgeon	Progress Energy	6	Affirmative	"Comments Submitted"
Sammy Roberts	Progress Energy Carolinas	1	Affirmative	Comments submitted.
Sam Waters	Progress Energy Carolinas	3	Affirmative	Comments submitted
Wayne Lewis	Progress Energy Carolinas	5	Affirmative	Comments Submitted
Peter Dolan	PSEG Energy Resources & Trade LLC	6	Affirmative	no comments
Chad Bowman	Public Utility District No. 1 of Chelan County	1	Affirmative	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In our view, board of directors/Public Utility should have the determination what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote.
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Affirmative	"Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In our view, a Registered Entity's Board of Directors, Utility Commission, and/or its customers should determine what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote."
Anthony E Jablonski	ReliabilityFirst Corporation	10	Affirmative	Comments submitted
Tim Kelley	Sacramento Municipal Utility District	1	Affirmative	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', that addressed planned or controlled interruption of electric supply for N-1 conditions. Registered Entity's Board of Directors, state

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				Utilities Commission, and/or its customers should determine what level of service is acceptable with the associated cost. This point is captured in footnote #12 of Table 1 in the TPL Standard and is necessary for maintaining SMUD's Affirmative vote.
James Leigh-Kendall	Sacramento Municipal Utility District	3	Affirmative	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', that addressed planned or controlled interruption of electric supply for N-1 conditions. Registered Entity's Board of Directors, state Utilities Commission, and/or its customers should determine what level of service is acceptable with the associated cost. This point is captured in footnote #12 of Table 1 in the TPL Standard and is necessary for maintaining SMUD's Affirmative vote.
Mike Ramirez	Sacramento Municipal Utility District	4	Affirmative	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', that addressed planned or controlled interruption of electric supply for N-1 conditions. Registered Entity's Board of Directors, state Utilities Commission, and/or its customers should determine what level of service is acceptable with the associated cost. This point is captured in footnote #12 of Table 1 in the TPL Standard and is necessary for maintaining SMUD's Affirmative vote.
Bethany Hunter	Sacramento Municipal Utility District	5	Affirmative	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', that addressed planned or controlled interruption of electric supply for N-1 conditions. Registered Entity's Board of Directors, state Utilities Commission, and/or its customers should determine what level of service is acceptable with the associated cost. This point is captured in footnote #12 of Table 1 in the TPL Standard and is necessary for maintaining SMUD's Affirmative vote.
Claire Warshaw	Sacramento Municipal Utility District	6	Affirmative	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', that addressed planned or controlled interruption of electric supply for N-1 conditions. Registered Entity's Board of Directors, state Utilities Commission, and/or its customers should determine what level of service is acceptable with the associated cost. This point is captured in footnote #12 of Table 1 in the TPL Standard and is necessary for maintaining SMUD's Affirmative vote.
Robert Kondziolka	Salt River Project	1	Affirmative	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In SRP's view, a Registered Entity's Board of Directors, state Utilities Commission, and/or its customers should determine what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining Affirmative vote.

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John T. Underhill	Salt River Project	3	Affirmative	"Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In SRP's view, a Registered Entity's Board of Directors, state Utilities Commission, and/or its customers should determine what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining our Affirmative vote."
Steven J Hulet	Salt River Project	6	Affirmative	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In SRP's view, a Registered Entity's Board of Directors, state Utilities Commission, and/or its customers should determine what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining our Affirmative vote.
Will Speer	San Diego Gas & Electric	1	Abstain	Clarity of this standard is getting worse. Our earlier comments did not seem impacting. At this point, we believe the existing TPL-001-0.1, TPL-002-0a, TPL-003-0a and TPL-004-0 provide much better clarify for us to comply with the TPL standards.
Rich Salgo	Sierra Pacific Power Co.	1	Affirmative	No additional comments submitted.
Sam Nietfeld	Snohomish County PUD No. 1	5	Affirmative	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In our view, a Registered Entity's Board of Directors, Utility Commission, and/or its customers should determine what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote.
James Jones	Southwest Transmission Cooperative, Inc.	1	Negative	Requirement R1 puts registered entities at compliance risk for failure of a Regional Entity to take action and presents a conflict of interest for the Regional Entity. TPL-001-2 references MOD-010 and MOD-012 in Requirement R1. MOD-010 and MOD-012 require applicable registered entities to supply steady-state and dynamics data, respectively, per the Regional Reliability Organizations (RRO) procedures. MOD-011 and MOD-013 specify the RROs to establish procedures but are "fill-in-the-blank" standards that were not approved by the Commission. Thus, they are not enforceable. Since RROs were the predecessors to the Regional Entities (RE), it is commonly understood the standards that apply to the RRO would now apply to the RE. In summary, the TP and PC/PA are dependent on the

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				RE to have the procedures but there are not penalties for the RE if it does not have them. Since the RE would be enforcing the penalty, it could directly contribute to a penalty that is used to offset its compliance budget. While the Planning Coordinator and Transmission Planner should share the results of its Planning Assessment with entities that have a reliability related need, Requirement R8 is purely administrative, does not have any direct impact on reliability, and, therefore, should be removed. At the very least, the VRF should be changed to Lower. This standard is full of double jeopardy issues. Based on the definition of Planning Assessment, Requirement R2 appears to be intended to document Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon studies and the evaluation and meaning of those study results. R3 and R4 require the TP and PC to conduct the steady-state and dynamic planning studies. Given the document/evidence centric ERO enforcement process, Requirement R3 and R4 have implicit obligations to document the study results. Otherwise, how do you prove you complied with R3 and R4? Thus, failure to have a planning assessment documenting your results will result in a simultaneous violation of R2, R3 and R4. In fact, both R3 and R4 even require studies to be completed according to Parts 2.1 and 2.2 for R3 and Parts 2.4 and 2.5 for R4. This further contributes to double jeopardy potential and blurs the line between assessment and study. Footnote 3 which applies to BES Level in Table 1 draws in non-BES facilities. It states that HV is defined as 300 kV and lower voltage systems which includes all voltages below the traditional 100-kV cutoff for the BES. TPL-001-2 Requirement R1 could be modified unintentionally and fundamentally change the requirement because R1 references MOD-010 and MOD-012 without a version number. Thus, all future updates to these standards directly modifies TPL-001-2 Requirement R1 whether it was intended or not. Generally, it is bad form to reference another standard for these reasons.
Larry Akens	Tennessee Valley Authority	1	Negative	1. TVA is concerned about the additional studies, modeling, and projects that must be performed to meet this proposed standard. TVA believes that this amount of work will have little overall improvement on the reliability of the BES. 2. TVA believes that the 7 year implementation plan allowed for "Raising the bar" facilities does not allow sufficient time for TVA to construct the required new facilities. TVA average time for constructing a new 500-kV line can be up to 10 years, given the lead time on ROW and following all NEPA requirements. TVA does understand that the team has language (R2.7.3) regarding the TP or PC inability to get the projects

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				completed through no fault of its own; however, there is no safeguard that the entity will be found non-compliant if all the work cannot be accomplished in this time frame. 3. TVA believes that the footnotes b and c that allow for local load drop in the current TPL standards should still be allowed. TVA understands that this is addressed in FERC Order 693; however, the capital improvements to fix many of these issues will have little overall reliability gain for the Bulk Electric System. TVA believes that this is a local load reliability issue and not a BES concern. 4. TVA is concerned that no generating unit shall pull out of synchronism for Planning Event P1, while the standard does allow generator runback/tripping for the same event. TVA believes that this requirement is overly burdensome without providing any material improvement in system reliability. Does distributed generation have to meet the same requirements for not pulling out of synchronism as a large nuclear unit? 5. The Implementation Plan should include a five-year delay in the effective date for short circuit studies (R2 parts 2.3 and 2.8) since these studies are a new TPL requirement and are not required in the current version 0 standards.
Ian S Grant	Tennessee Valley Authority	3	Negative	TVA appreciates the work of the ATFN drafting team over the last several years in drafting this new standard. TVA does have concerns on several issues we believe should be corrected as we move forward with this standard. Therefore TVA is voting "Negative" on this proposed standard due to the following issues: 1. TVA is concerned about the additional studies, modeling, and projects that must be performed to meet this proposed standard. TVA believes that this amount of work will have little overall improvement on the reliability of the BES. 2. TVA believes that the 7 year implementation plan allowed for "Raising the bar" facilities does not allow sufficient time for TVA to construct the required new facilities. TVA average time for constructing a new 500-kV line can be up to 10 years, given the lead time on ROW and following all NEPA requirements. TVA does understand that the team has language (R2.7.3) regarding the TP or PC inability to get the projects completed through no fault of its own; however, there is no safeguard that the entity will be found non-compliant if all the work cannot be accomplished in this time frame. 3. TVA believes that the footnotes b and c that allow for local load drop in the current TPL standards should still be allowed. TVA understands that this is addressed in FERC Order 693; however, the capital improvements to fix many of these issues will have little overall reliability gain for the Bulk Electric System. TVA believes that this is a local load reliability issue and not a BES concern.

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				4. TVA is concerned that no generating unit shall pull out of synchronism for Planning Event P1, while the standard does allow generator runback/tripping for the same event. TVA believes that this requirement is overly burdensome without providing any material improvement in system reliability. Does distributed generation have to meet the same requirements for not pulling out of synchronism as a large nuclear unit? 5. The Implementation Plan should include a five-year delay in the effective date for short circuit studies (R2 parts 2.3 and 2.8) since these studies are a new TPL requirement and are not required in the current version 0 standards.
David Thompson	Tennessee Valley Authority	5	Negative	TVA appreciates the work of the ATFN drafting team over the last several years in drafting this new standard. TVA does have concerns on several issues we believe should be corrected as we move forward with this standard. Therefore TVA is voting "Negative" on this proposed standard due to the following issues: 1. TVA is concerned about the additional studies, modeling, and projects that must be performed to meet this proposed standard. TVA believes that this amount of work will have little overall improvement on the reliability of the BES. 2. TVA believes that the 7 year implementation plan allowed for "Raising the bar" facilities does not allow sufficient time for TVA to construct the required new facilities. TVA average time for constructing a new 500-kV line can be up to 10 years, given the lead time on ROW and following all NEPA requirements. TVA does understand that the team has language (R2.7.3) regarding the TP or PC inability to get the projects completed through no fault of its own; however, there is no safeguard that the entity will be found non-compliant if all the work cannot be accomplished in this time frame. 3. TVA believes that the footnotes b and c that allow for local load drop in the current TPL standards should still be allowed. TVA understands that this is addressed in FERC Order 693; however, the capital improvements to fix many of these issues will have little overall reliability gain for the Bulk Electric System. TVA believes that this is a local load reliability issue and not a BES concern. 4. TVA is concerned that no generating unit shall pull out of synchronism for Planning Event P1, while the standard does allow generator runback/tripping for the same event. TVA believes that this requirement is overly burdensome without providing any material improvement in system reliability. Does distributed generation have to meet the same requirements for not pulling out of synchronism as a large nuclear unit? 5. The Implementation Plan should include a five-year delay in the effective date for short circuit studies (R2 parts 2.3 and 2.8) since these studies are a

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				new TPL requirement and are not required in the current version 0 standards.
Marjorie S. Parsons	Tennessee Valley Authority	6	Negative	TVA appreciates the work of the ATFN drafting team over the last several years in drafting this new standard. TVA does have concerns on several issues we believe should be corrected as we move forward with this standard. Therefore TVA is voting "Negative" on this proposed standard due to the following issues: 1. TVA is concerned about the additional studies, modeling, and projects that must be performed to meet this proposed standard. TVA believes that this amount of work will have little overall improvement on the reliability of the BES. 2. TVA believes that the 7 year implementation plan allowed for "Raising the bar" facilities does not allow sufficient time for TVA to construct the required new facilities. TVA average time for constructing a new 500-kV line can be up to 10 years, given the lead time on ROW and following all NEPA requirements. TVA does understand that the team has language (R2.7.3) regarding the TP or PC inability to get the projects completed through no fault of its own; however, there is no safeguard that the entity will be found non-compliant if all the work cannot be accomplished in this time frame. 3. TVA believes that the footnotes b and c that allow for local load drop in the current TPL standards should still be allowed. TVA understands that this is addressed in FERC Order 693; however, the capital improvements to fix many of these issues will have little overall reliability gain for the Bulk Electric System. TVA believes that this is a local load reliability issue and not a BES concern. 4. TVA is concerned that no generating unit shall pull out of synchronism for Planning Event P1, while the standard does allow generator runback/tripping for the same event. TVA believes that this requirement is overly burdensome without providing any material improvement in system reliability. Does distributed generation have to meet the same requirements for not pulling out of synchronism as a large nuclear unit? 5. The Implementation Plan should include a five-year delay in the effective date for short circuit studies (R2 parts 2.3 and 2.8) since these studies are a new TPL requirement and are not required in the current version 0 standards.
Bernie M Pasternack	Transmission Strategies, LLC	8	Affirmative	Comments submitted
Tracy Sliman	Tri-State G & T Association,	1	Negative	Comments submitted

Voter	Entity	Segment	Vote	Comment
	Inc.			
Janelle Marriott	Tri-State G & T Association, Inc.	3	Negative	Comments submitted formally on Comment Form
John Tolo	Tucson Electric Power Co.	1	Negative	The definition for Near Term Planning Horizon was deleted, but the formal term is used in other sections such as R2.2.1. There should be a linkage to MOD standard (e.g. 028, 029 & 030) definitions such as 13 months, etc.
Brandy A Dunn	Western Area Power Administration	1	Negative	Standard is improved over previous drafts, but would like to see further changes. Please see suggestions and comments provided on the previously submitted Official Comment Form.
Peter H Kinney	Western Area Power Administration - UGP Marketing	6	Negative	See comments from WAPA made on official comment form.
Steven L. Rueckert	Western Electricity Coordinating Council	10	Affirmative	It is unknown at this time what the outcome of the FERC request for additional infomation related to footnote B will be, but if if results in changes to the language of footnote B, that may change our support for this standard.
Liam Noailles	Xcel Energy, Inc.	5	Negative	Xcel Energy's concerns are detailed in the formal comment submission
David F. Lemmons	Xcel Energy, Inc.	6	Negative	Xcel Energy's concerns are detailed in the formal comment submission.
Roger C Zaklukiewicz		8	Negative	Footnote #7: There appears to be a discrepency between Footnote 7 and Event P2-1; therefore, I recommend the elimination of Footnote 7. Footnote #12: I interpret Footnote 12 to suggest that non-consequential demand interruption could be used to mitigate reliability concerns arising from a NERC Category B contingency event (a single element contingency). The approval of such a reliability policy is inconsistent with a inter- or intra-regional or Area transmission plan than ensure the development of a reliable transmission grid. Such wording is unacceptable as it will lead to large scale inter-regional blackouts, similar to experienced in August, 2003. R1- Part 1.1.6: Delete the words "required for load". R2-Part 2.2: Clarify whether the current annual studies must always be performed as part of the long-term steady-state transmission assessment studies. The wording conveys such a requirement; however, it is not clear whether such studies

Voter	Entity	Segment	Vote	Comment
				are in fact required. Such a requirement would not always be necessary and an unwise use of valuable planning resources. R3-Part 3.3.1: Remove the last sentence since it is already addressed by PRC-023; therefore, it is not required in this document.

Ballot Results

Ballot Name:	Project 2006-02 Assess Transmission Future Needs April 2011_rc
Ballot Period:	7/13/2011 - 7/22/2011
Ballot Type:	recirculation
Total # Votes:	333
Total Ballot Pool:	353
Quorum:	**94.33 % The Quorum has been reached**
Weighted Segment Vote:	75.37 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	103	1	65	0.747	22	0.253	8	8
2 - Segment 2.	11	1	4	0.364	7	0.636	0	0
3 - Segment 3.	73	1	53	0.791	14	0.209	4	2
4 - Segment 4.	27	1	16	0.889	2	0.111	6	3
5 - Segment 5.	72	1	47	0.783	13	0.217	7	5
6 - Segment 6.	46	1	33	0.805	8	0.195	3	2
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.5	3	0.3	2	0.2	3	0
9 - Segment 9.	4	0.4	4	0.4	0	0	0	0
10 - Segment 10.	9	0.9	8	0.8	1	0.1	0	0
Totals	**353**	**7.8**	**233**	**5.879**	**69**	**1.921**	**31**	**20**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Affirmative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	View
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	View
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California NCR11118	Kevin Smith	Affirmative	View

1	BC Hydro and Power Authority	Patricia Robertson	Negative	View
1	Beaches Energy Services	Joseph S Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	View
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy Houston Electric	Dale Bodden	Negative	
1	Central Maine Power Company	Kevin L Howes	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Vero Beach	Randall McCamish	Affirmative	View
1	Clark Public Utilities	Jack Stamper	Affirmative	View
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph F Meyer		
1	Entergy Services, Inc.	Edward J Davis	Affirmative	View
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Michael Anderson	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	View
1	GDS Associates, Inc.	Claudiu Cadar	Abstain	
1	Georgia Transmission Corporation	Harold Taylor	Affirmative	View
1	Grand River Dam Authority	James M Stafford		
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Negative	View
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Negative	View
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	View
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	View
1	Kansas City Power & Light Co.	Michael Gammon		
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lake Worth Utilities	Walt J Gill	Affirmative	
1	Lakeland Electric	Larry E Watt	Negative	View
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Lone Star Transmission, LLC	Julius Horvath	Affirmative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	Ly M Le	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	View
1	Manitoba Hydro	Joe D Petaski	Negative	View
1	MEAG Power	Danny Dees	Affirmative	
1	Mid-Continent Area Power Pool	Larry E. Brusseau	Abstain	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	View
1	Minnkota Power Coop. Inc.	Richard Burt	Negative	View
1	National Grid	Saurabh Saksena	Affirmative	View
1	Nevada Power Co.	James McMorran		
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Negative	View
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Utilities	David Boguslawski	Negative	View
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	PacifiCorp	Colt Norrish		
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Negative	View

1	Portland General Electric Co.	Frank F Afranji	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	View
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Chelan County	Chad Bowman	Affirmative	View
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	View
1	Salt River Project	Robert Kondziolka	Affirmative	View
1	San Diego Gas & Electric	Will Speer	Abstain	View
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	View
1	South Texas Electric Cooperative	Richard McLeon	Negative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Robert Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Abstain	
1	Southwest Transmission Cooperative, Inc.	James Jones	Negative	View
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young	Affirmative	
1	Tennessee Valley Authority	Larry Akens	Negative	View
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	View
1	Tucson Electric Power Co.	John Tolo	Negative	View
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Abstain	
1	Western Area Power Administration	Brandy A Dunn	Negative	View
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	View
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	View
2	California ISO	Richard K Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Charles B Manning	Negative	View
2	Independent Electricity System Operator	Kim Warren	Affirmative	View
2	ISO New England, Inc.	Kathleen Goodman	Negative	View
2	Midwest ISO, Inc.	Marie Knox	Negative	View
2	New Brunswick System Operator	Alden Briggs	Negative	View
2	New York Independent System Operator	Gregory Campoli	Negative	View
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles Yeung	Negative	
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters		
3	APS	Steven Norris	Affirmative	View
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Robert Lafferty	Affirmative	
3	Bandera Electric Cooperative	Brian D Bartos	Negative	
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	View
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	View
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	View
3	City of Redding	Bill Hughes	Affirmative	View
3	Clatskanie People's Utility District	Brian Fawcett	Abstain	
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Lisa Cleary	Affirmative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	View
3	Consumers Energy	David A. Lapinski	Negative	View
3	Cowlitz County PUD	Russell A Noble	Abstain	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	East Kentucky Power Coop.	Sally Witt	Negative	View
3	Entergy	Joel T Plessinger	Affirmative	

3	FirstEnergy Solutions	Kevin Querry	Affirmative	
3	Florida Power and Light / NextEra Energy	Chantel Haswell	Abstain	
3	Florida Power Corporation	Lee Schuster	Affirmative	View
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia Systems Operations Corporation	William N Phinney	Abstain	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Negative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Negative	View
3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	View
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	View
3	Mississippi Power	Don Horsley	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	View
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	View
3	PacifiCorp	John Apperson	Affirmative	
3	Platte River Power Authority	Terry L Baker	Negative	View
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	View
3	Salt River Project	John T. Underhill	Affirmative	View
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey	Affirmative	
3	Tennessee Valley Authority	Ian S Grant	Negative	View
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	View
3	Xcel Energy, Inc.	Michael Ibold	Negative	
4	American Municipal Power	Kevin Koloini	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	Central Lincoln PUD	Shamus J Gamache		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	View
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Negative	View
4	Cowlitz County PUD	Rick Syring	Abstain	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas Richards	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	LaGen	Richard Comeaux	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Negative	View

4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Affirmative	View
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	View
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko	Affirmative	View
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge	Negative	View
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Negative	View
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	View
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	View
5	City of Redding	Paul Cummings	Affirmative	View
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	View
5	Consumers Energy	James B Lewis	Negative	View
5	Cowlitz County PUD	Bob Essex	Abstain	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker	Negative	View
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Negative	
5	I do not represent an Entity	Bruce Paggeot	Abstain	
5	Indeck Energy Services, Inc.	Rex A Roehl	Abstain	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Affirmative	View
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	Manitoba Hydro	S N Fernando	Negative	View
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	View
5	Nebraska Public Power District	Don Schmit	Negative	View
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	William O Thompson	Affirmative	
5	Occidental Chemical	Michelle R DAntuono	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard Kinas	Affirmative	
5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Pete Ungerman	Negative	View
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	View
5	Proven Compliance Solutions	Mitchell E Needham		
5	PSEG Fossil LLC	Mikhail Falkovich	Affirmative	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	

5	Reedy Creek Energy Services	Bernie Budnik	Abstain	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	View
5	Salt River Project	Glen Reeves	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	View
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M Helyer	Affirmative	
5	Tennessee Valley Authority	David Thompson	Negative	View
5	Tri-State G & T Association, Inc.	Barry Ingold	Negative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Abstain	
5	Xcel Energy, Inc.	Liam Noailles	Negative	View
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Arizona Public Service Co.	Justin Thompson	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	View
6	City of Redding	Marvin Briggs	Affirmative	View
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	View
6	Constellation Energy Commodities Group	Brenda Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	View
6	Eugene Water & Electric Board	Daniel Mark Bedbury		
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones	Negative	View
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	View
6	Omaha Public Power District	David Ried	Affirmative	
6	Orlando Utilities Commission	Claston Augustus Sunanon	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Powerex Corp.	Daniel W. O'Hearn	Negative	View
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon	Affirmative	View
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	View
6	Sacramento Municipal Utility District	Claire Warshaw	Affirmative	View
6	Salt River Project	Steven J Hulet	Affirmative	View
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	View
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Negative	View
6	Xcel Energy, Inc.	David F. Lemmons	Negative	View
8		James A Maenner	Abstain	
8		Roger C Zaklukiewicz	Negative	View
8		Edward C Stein	Affirmative	

8	INTELLIBIND	Kevin Conway	Abstain	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Transmission Strategies, LLC	Bernie M Pasternack	Affirmative	View
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Negative	View
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	View
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	View
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Southwest Power Pool Regional Entity	Stacy Dochoda	Affirmative	
10	Texas Reliability Entity, Inc.	Larry D Grimm	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	View

Legal and Privacy : 609.452.8060 voice : 609.452.9550 fax : 116-390 Village Boulevard : Princeton, NJ 08540-5721
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Account Log-In/Register

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A New Jersey Nonprofit Corporation

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2006-02 Assess Transmission and Future Needs Recirculation Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

Ballot Results for Revisions to TPL-001-2

A recirculation ballot on revisions to TPL-001-2 — Transmission System Planning Performance Requirements concluded on Friday, July 22, 2011. The revised standard, TPL-001-2, was approved by the associated ballot pool.

Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 94.33%
Approval: 75.37%

Next Steps

TPL-001-2 will be presented to the NERC Board of Trustees for adoption and filed with regulatory authorities.

Background

TPL-001-2 is designed to be a single, comprehensive, and coordinated standard that merges the requirements of four existing standards: TPL-001-1; TPL-002-1b; TPL-003-1a; TPL-004-1 and also results in the retirement of TPL-005 and TPL-006. The proposed standard includes several new definitions. The purpose of the proposed standard is to establish transmission system planning performance requirements within the planning horizon to develop a bulk electric system that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies.

Additional information about this project is available on the project page at http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Exhibit G

Standard Drafting Team Roster and Biographical Information

Drafting Team Roster
Project 2006-02 Assess Transmission and Future Needs

Name and Title	Company and Address	Contact Info	Bio
John Odom, Chair Vice President of Planning and Operations	Florida Reliability Coordinating Council, Inc. 1408 N. Westshore Blvd., Suite 1002 Tampa, FL 33607-4512	(813)207-7985 jodom@frcc.com	John Odom is Vice President of Planning and Operations at the Florida Reliability Coordinating Council (FRCC). John joined FRCC in May 2005 after 26 years at Progress Energy Corporation (PEF). He is responsible for oversight of all Member Services Activities, including the FRCC standing committees, FRCC Reliability Coordinator, and Planning Authority function. Additionally, he oversees the Regional Entity functions of reliability assessment, situational awareness, training, certification of system operators, and event analysis. From 2001 – 2007, John was the FRCC Representative on the NERC Reliability Assessment Subcommittee (RAS). John is currently the chair of the Assess Future Transmission Needs Standards Drafting Team (AFTNSDT), which is re-writing the existing TPL-001 through TPL-006.
Douglas Hohlbaugh, Vice Chair Standards Development Manager	FirstEnergy Corp. 76 South Main Street 10th Floor Akron, Ohio 44308	(330) 384-4698 hohlbaughdg@firstenergycorp.com	Doug Hohlbaugh holds a Bachelor of Science in Electrical Engineering from Akron University (1989) and a Professional Engineering license in the state of Ohio. His 20 plus years experience in the electric utility industry has involved the transmission business of FirstEnergy with a focus on transmission planning. His work experience includes various technical positions in transmission and distribution, as well as sales and marketing experience with FirstEnergy's (FE)unregulated energy services. His existing responsibilities include the Reliability Standards Development Lead of the FirstEnergy FERC Compliance Department including oversight of newly proposed and/or revised Reliability Standards governing the bulk electric transmission system. The responsibilities include overseeing and ensuring timely implementation of all new Reliability Standard development projects at both the North American Electric Reliability Corporation (NERC) and Reliability First Corporation (RFC) having impact on a variety of FE business units which support the reliable operation of the bulk transmission system.
D. Darrin Church Principal Engineer Bulk Transmission Planning	Tennessee Valley Authority 1101 Market Street MR 5G-C Chattanooga, Tennessee 37402-2801	423) 751-6899 (423) 751-3453 Fx ddchurch@tva.gov	Darrin Church is a Principal Bulk Planning Engineer in TVA's Transmission Planning Department. Darrin has 15 years experience in Bulk Transmission Planning along with 5 years previous experience in planning relaying and protection schemes. Responsibilities include ensuring reliability of TVA's 500 kV, 230 kV, 161 kV, and 115 kV transmission systems which include initiating capital projects required to maintain an adequate and reliable transmission system per NERC Reliability Standards.

Drafting Team Roster
Project 2006-02 Assess Transmission and Future Needs

William Harm Senior Consultant	PJM Interconnection, L.L.C. 955 Jefferson Ave Valley Forge Corporate Center Norristown, Pennsylvania 19403-2497	(610) 666-8868 harm@pjm.com	Bill Harm has over 35 years of industry experience with PJM through various assignments involving real time operation, operations planning, and transmission planning. Mr. Harm's current responsibilities involve performance assessment and policy development responsibilities. He either has or continues to represent PJM in various industry forums and groups, including RFC, NERC, and the ISO/RTO forums. He earned a Bachelor and Masters of Science Degree in Electrical Engineering from Drexel University and is a registered professional Engineer in the Commonwealth of PA.
Julius Horvath Director System Planning	Lone Star Transmission, LLC	(512)236-3135 julius.horvath@ lonestar- transmission.co m	Julius Horvath is currently the Director of System Planning at Lone Star Transmission, LLC, in Austin, Texas. Julius has over ten years of utility experience at the Bonneville Power Administration, Wind Energy Transmission Texas, LLC and the Lower Colorado River Authority in Transmission Planning prior to Lone Star. Julius is a Registered Professional Engineer in the State of Texas.
Robert A. Jones Project Manager, Stability Studies	Southern Company Services P.O. Box 2641 Birmingham, Alabama 35291	(205) 257-6148 rajones@ southernco.com	Robert Jones obtained a BSEE degree from the University of Alabama in 1973 and a MSEE degree from University of Alabama – Birmingham in 1978. He has worked for 37 years for Southern Company Services. Eighteen of those years have been in Transmission Planning. The last 15 years, he has been responsible for stability studies for Southern Company.
Brian K. Keel Manager, Transmission System Planning	Salt River Project MS POB100 PO Box 52025 Phoenix, Arizona 85072	602-236-0970 brian.keel@ srpnet.com	Brian Keel has a Bachelor and Master Degrees in Electrical Engineering, specializing in power systems, from the University of Illinois. Brian was employed by Duke Power for over one year and PSI Energy for 8 years. Brian has been at SRP since 1998 and is currently the Manager of Transmission System Planning. Brian has Chaired four groups within WECC mainly concentrating on transmission reliability. Brian is a current member of the NERC TADS Work Group.
R. W. Mazur Manager System Planning Department	Manitoba Hydro 12-1146 Waverly Street P.O. Box 815 Winnipeg, Manitoba R3C 2P4	(204) 474-3113 rwmazur@ hydro.mb.ca	Ronald W. Mazur obtained his Bachelor of Science in Electrical Engineering degree in 1971, and his Masters of Science in Electrical Engineering degree in 1989, both from the University of Manitoba. Ron Mazur is a registered professional engineer with the Association of Professional Engineers and Geoscientists of Manitoba. Ron joined Manitoba Hydro in 1974, where he worked in station design for 5 years, and in system performance (operations) for 6 years, and in system planning since 1986. He is currently the Manager of the System Planning Department responsible for the expansion planning of Manitoba Hydro's transmission system (100 kV and above) and the HVDC system. Ron is a Canadian representative on the NERC Planning Committee, and Chair of the Planning Committee of the Midwest Reliability Organization.

Drafting Team Roster
Project 2006-02 Assess Transmission and Future Needs

Thomas C. Mielnik Manager Electric System Planning	MidAmerican Energy Co. 106 East Second Street Davenport, Iowa 52808	(563) 333-8129 tcmielnik@ midamerican.co m	Thomas Mielnik has over 37 years experience in Electric Utility Planning. He has been the Manager of Electric System Planning for MEC from 1995 to the present. He was a member of the NERC ATC Working Group from 1996 to 1999 and is a Registered Professional Engineer.
Bernie M Pasternack, President, P.E.	Transmission Strategies 4347 Harborough Rd Upper Arlington, Ohio 43220	(614) 459-5806 bmpasternack@ att.net	Bernie Pasternack was employed by the AEP Service Corporation for over 41 years, where he spent his entire career in various aspects of transmission planning and asset management. After retiring from AEP in June 2010, he formed his own consulting practice, providing services to the electric utility industry. He holds BEE and MSEE degrees from Rensselaer Polytechnic Institute and an MBA from Fairleigh Dickinson University. Before retiring from AEP, Bernie was responsible for the planning and management of AEP's transmission assets. Bernie was also responsible for providing input to policy making decisions relative to AEP's transmission strategy and business plan. During his career, Bernie has made significant contributions to a variety of industry organizations including IEEE, CIGRE, EPRI, EEI, ECAR/RFC, and NERC. He was a member of the EEI Transmission Policy TF and AEP's representative on the Reliability First Corporation Reliability Committee. Bernie has also played an active role in many NERC activities over the past twenty years, including its Planning Committee and a number of its subcommittees, working groups, and standards drafting teams.
Bob Pierce Senior Engineer	Duke Energy 526 South Church Street MC EC10Q Charlotte, North Carolina 28201-1006	(980) 373-6480 bob.pierce@ duke- energy.com	Robert (Bob) Pierce is a Consulting Engineer at Duke Energy where he specializes in Bulk System Planning, NERC standards, and FERC regulations. He holds a B.S. in Nuclear Engineering from Pennsylvania State University and a M.S. in Electrical Engineering from the University of North Carolina-Charlotte. Mr. Pierce is a registered Professional Engineer with 13 years Transmission Planning experience and a total of 31 years of power system experience.

Drafting Team Roster
Project 2006-02 Assess Transmission and Future Needs

Chifong L. Thomas Principal Transmission Planning Engineer	Pacific Gas and Electric Company (now at Bright Source Energy)		Chifong Thomas is currently the Senior Director, Energy Markets and Strategy at Bright Source Energy, Inc. However, during the drafting of this standard, she was a Principal Transmission Planning Engineer at Pacific Gas and Electric Company (PG&E). She has more than 39 years of electric utility experience, more than 37 of which is in electric transmission planning. She has both conducted and supervised transmission planning studies to develop plans for the PG&E transmission system from 60 kV to 500 kV. She has participated in developing methodologies, policies and strategic plans, and in contract negotiations. Ms Thomas has also served as an expert witness in various regulatory and judicial forums. She has served on various technical organizations and work groups, including WECC, NERC Standards Drafting Teams, and Industry Advisory Committees of the California Energy Commission and of EPRI. She has also served on the Technical Advisory Committee (Electrical Engineering) to the California Board of Registration for Professional Engineers and Land Surveyors. Ms. Thomas holds a Bachelor of Science Degree in Electrical Engineering from Washington State University and is a registered Electrical Engineer in the State of California. She is also a senior member of the IEEE.
Dana Walters Manager Transmission Planning, Process, & Policy	National Grid 40 Sylvan Road Waltham, Massachusetts 01581	781-907-2501 dana.walters@us.ngrid.com	Dana Walters is a Manager in the Transmission Planning group at National Grid. Mr. Walters has 34 year of experience in the Electric Utility industry. Most of his experience involves various aspects of Transmission Planning. This includes topics such as analytical studies of thermal, stability, short circuit, generator interconnections, and lightning protection. Other areas of experience include involvement in Investment Planning, tariff design, Consulting, Production Cost analysis, and Distribution Planning. In his role as a Transmission Planner, Mr. Walters has been involved in numerous committees and working groups at the NERC, NPCC, and ISO levels. Mr. Walters has a Masters in Engineering Management from Northeastern University and a Bachelor in Electrical Engineering with a focus in Power Systems also from Northeastern University. Mr. Walters is a registered professional engineer in New Hampshire and is a member of IEEE.

From: Margaret Mayora
To: grpStaff
Subject: FW: New NERC Related Matters (10.19.2011)
Date: Thursday, October 20, 2011 5:17:32 PM

Fyi.

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From: McCarthy, Catherine P. [mailto:CMcCarthy@deweyleboeuf.com]
Sent: Thursday, October 20, 2011 5:04 PM
To: cmccarthy@deweyleboeuf.com
Subject: New NERC Related Matters (10.19.2011)

1. Petition of NERC for Approval of a Revised Transmission Planning System Performance Requirements Reliability Standard and Five New Glossary Terms and Retirement of Four Existing Reliability Standards (RM12-1)

On October 19, 2011, NERC submitted TPL-001-2 Reliability Standard to FERC for approval. The standard relates to transmission planning performance requirements for reliable Bulk Electric System ("BES") operations across normal and Contingency conditions. TPL-001-2 — Transmission System Planning Performance Requirements. The standard will serve as a foundation for annual planning assessments conducted by Planning Coordinators and Transmission Planners to plan the BES reliably in response to a range of potential contingencies. The standard is intended to present clear, measurable, and enforceable Requirements that each Planning Coordinator and Transmission Planner must follow when planning its System. In replacing previous standards, TPL-001-2 introduces significant revisions including increased specificity of data requirements and modeling conditions. For example, sensitivity studies varying one or more modeling conditions by a sufficient amount to stress the system will be required.

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==========
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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

TIME ERROR CORRECTION RELIABILITY STANDARD	))	**Docket No. RM09-13-000**

MOTION TO FURTHER DEFER ACTION

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August 11, 2011

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

TIME ERROR CORRECTION RELIABILITY STANDARD	))	**Docket No. RM09-13-000**

MOTION TO FURTHER DEFER ACTION

I. INTRODUCTION

Pursuant to Rule 212 of the Federal Energy Regulatory Commission's ("FERC" or "the Commission") Rules of Practice and Procedure, 18 C.F.R. §385.212, the North American Electric Reliability Corporation ("NERC")[1] hereby submits this Motion to Further Defer Action regarding NERC's request to approve the BAL-004-1 Time Error Correction Reliability Standard.[2] The continuing need to perform Time Error Correction is an issue under review by NERC and its stakeholders. New technologies have supplanted the need for time management via power system frequency, leading to the industry question the justification for continuing Time Error Corrections.

Given recent outcomes during the advance preparation of a planned Field Trial during which suspension of Time Error Corrections would occur, it became clear to NERC that research and analysis regarding Time Error Correction needs to continue prior to moving that Field Trial forward. NERC has postponed its Field Trial (originally planned to commence in mid-July 2010) pending further review. Accordingly, NERC continues to believe that action on NERC's

[1] The Federal Energy Regulatory Commission ("FERC" or "Commission") certified NERC as the electric reliability organization ("ERO") in its Order issued on July 20, 2006 in Docket No. RR06-1-000. *North American Electric Reliability Corporation*, "Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing," 116 FERC ¶ 61,062 (July 20, 2006).
[2] *Time Error Correction Reliability Standard*, Comments of the North American Electric Reliability Corporation in Response to Notice of Proposed Rulemaking, Docket No. RM09-13-000 (April 28, 2010).

BAL-004-1 Petition at this time would be premature. To that end, NERC requests that the Commission continue to defer action regarding the BAL-004-1 Time Error Correction standard. NERC's Operation Committee and its subject matter expert team reviewing the Time Error Correction elimination Field Trial preparations are in the process of reviewing the findings to date, including public reaction to the planned trial. NERC will provide an update prior to the end of this year, indicating next steps and plans for moving forward on the potential elimination of Time Error Correction.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to:

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*Persons to be included on FERC's official service list. NERC requests waiver of FERC's rules and regulations to permit the inclusion of more than two people on the service list.

III. BACKGROUND

The Commission approved the current Time Error Correction Reliability Standard, BAL-004-0, on March 16, 2007, as part of Order No. 693.[3] Approximately two years later, NERC filed a request for Commission approval of a revised version of the BAL-004-1 Reliability Standard.[4] In response, the Commission issued a Notice of Proposed Rulemaking on March 18, 2010, that proposed to remand the standard and direct NERC to make specific changes to address Commission concerns ("NOPR").[5] NERC and several other entities submitted comments to the Commission regarding the NOPR. General support for the Commission's NOPR proposal seemed lacking, as reflected in comments from NERC, the Edison Electric Institute, the Midwest Independent Transmission System Operator, Inc., and the ISO/RTO Council. No entity submitted comments in direct support of the NOPR.

In its comments, NERC noted that its Balancing Authority Controls Standards Drafting Team (BACSDT) was considering whether eliminating Time Error Corrections altogether might be beneficial to reliability. NERC stated the reasons regarding why Time Error Corrections may in fact be obsolete, and recommended the Commission hold a technical conference to discuss Time Error Corrections and their possible elimination.

On August 20, 2010, NERC submitted a Motion to Defer Action on the BAL-004-1 Reliability Standard.[6] In the motion, NERC noted that ongoing testing and analysis of Time Error Correction may lead to NERC's withdrawal of the request for the approval of BAL-004-1 and the retirement of BAL-004-0, and that issuing a final rule would be premature at this stage in the

---

[3] *Mandatory Reliability Standards for the Bulk-Power System*, 118 FERC ¶ 61,218, FERC Stats. & Regs. ¶ 31,242 (2007) at PP 382-386 ("Order No. 693"), *order on reh'g, Mandatory Reliability Standards for the Bulk-Power System*, 120 FERC ¶ 61,053 ("Order No. 693-A") (2007).
[4] *North American Electric Reliability Corporation*, Petition of the North American Electric Reliability Corporation for Approval of BAL-004-1 Reliability Standard, Docket No. RM06-16-000 (March 11, 2009).
[5] *Time Error Correction Reliability Standard*, 130 FERC ¶ 61,201, (March 18, 2010).
[6] *Motion to Defer Action*, Docket No. RM09-13-000 (August 20, 2011)

process. NERC requested the Commission to defer action until August 20, 2011. In the motion, NERC stated that it would submit a status report six months from the date of the motion. In February 22, 2011, NERC filed an informational status report, fulfilling that commitment.[7]

As August 20, 2011 approaches, NERC has made significant progress in developing and moving forward with a Field Trial to determine if Time Error Corrections can be eliminated. However, concerns have been identified in two of the four interconnections related to market rules and monitoring hardware that must be resolved prior to initiating such a Field Trial. The Field Trial, originally scheduled to commence on or around July 15, 2011, has been postponed pending further discussion at the September 2011 meeting of NERC's Operating Committee. At that meeting, discussion will occur regarding the proper approach for moving forward. Options may include testing the possible elimination of Time Error Corrections on a smaller scope, further delay of the testing, closer coordination with NIST and FERC, and other approaches.

NERC has received a number of questions and concerns regarding the impact the Field Test will have on appliances, motors, and other devices. To a large extent, these questions are based on a perception that NERC is going to allow instantaneous frequency performance to become less stringently controlled than is currently required, and that consumers will expect to see frequency deviations of +/- 5 Hertz or more. This is clearly incorrect, and NERC has no intention of relaxing entities' obligations to control frequency. In addition to these concerns, NERC has also received comments from various industries and government agencies. While significant outreach has occurred within the electric industry, given the numerous potential audiences beyond this effort, additional efforts are needed with additional audiences depending upon the outcome of the September meeting.

[7] *North American Electric Reliability Corporation Status Report Regarding BAL-004-1 Time Error Correction Reliability Standard*, Docket No. RM09-13-000 (February 22, 2011)

NERC believes it is appropriate to continue to move forward cautiously. Accordingly, the above concerns will be discussed at the next meeting of NERC's Operating Committee, and considered when evaluating next steps for the Field Test.

IV. MOTION

In this filing, NERC respectfully requests that the Commission further defer action on NERC's BAL-004-1 filing. As discussed above, NERC originally planned to initiate its Time Error Correction Elimination Field Trial on July 15, 2011, but postponed that effort when two interconnections identified market rule and technology changes that would be needed prior to implementing the Field Trial. NERC and its stakeholders are in the process of researching and analyzing the appropriate next steps. Because Time Error Correction is a process that has broad-reaching effects, NERC believes it is critical that any action taken with regard to the elimination of Time Error Correction be pursued with due care.

NERC anticipates that if elimination of Time Error Correction moves forward, NERC will withdraw its request for approval of the BAL-004-1 Reliability Standard, and ultimately retire the currently approved BAL-004-0 Reliability Standard entirely. Accordingly, taking action that would further entrench this practice within the operation of the bulk power system would be premature and potentially detrimental to bulk power system reliability.

Therefore, NERC requests that the Commission continue to defer action on the BAL-004-1 standard. NERC will provide a status report with any necessary recommendations on or before December 15, 2011.

V. CONCLUSION

NERC respectfully requests that FERC defer action on BAL-004-1 as discussed above, to allow further research and analysis to be performed by NERC.

Respectfully submitted,

/s/ Holly A. Hawkins

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Assistant General Counsel for Standards and Critical Infrastructure Protection
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CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 11th day of August, 2011.

/s/ Holly A Hawkins
Holly A. Hawkins
Attorney for North American Electric Reliability Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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*Persons to be included on FERC's official service list. NERC requests waiver of FERC's rules and regulations to permit the inclusion of more than two people on the service list.

III. BACKGROUND

The Commission approved the current Time Error Correction Reliability Standard, BAL-004-0, on March 16, 2007, as part of Order No. 693.[3] Approximately two years later, NERC filed a request for Commission approval of a revised version of the BAL-004-1 Reliability Standard.[4] In response, the Commission issued a Notice of Proposed Rulemaking on March 18, 2010, that proposed to remand the standard and direct NERC to make specific changes to address Commission concerns ("NOPR").[5] NERC and several other entities submitted comments to the Commission regarding the NOPR. General support for the Commission's NOPR proposal seemed lacking, as reflected in comments from NERC, the Edison Electric Institute, the Midwest Independent Transmission System Operator, Inc., and the ISO/RTO Council. No entity submitted comments in direct support of the NOPR.

In its comments, NERC noted that its Balancing Authority Controls Standards Drafting Team (BACSDT) was considering whether eliminating Time Error Corrections altogether might be beneficial to reliability. NERC stated the reasons regarding why Time Error Corrections may in fact be obsolete, and recommended the Commission hold a technical conference to discuss Time Error Corrections and their possible elimination.

On August 20, 2010, NERC submitted a Motion to Defer Action on the BAL-004-1 Reliability Standard.[6] In the motion, NERC noted that ongoing testing and analysis of Time Error Correction may lead to NERC's withdrawal of the request for the approval of BAL-004-1 and the retirement of BAL-004-0, and that issuing a final rule would be premature at this stage in the

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[3] *Mandatory Reliability Standards for the Bulk-Power System*, 118 FERC ¶ 61,218, FERC Stats. & Regs. ¶ 31,242 (2007) at PP 382-386 ("Order No. 693"), *order on reh'g, Mandatory Reliability Standards for the Bulk-Power System*, 120 FERC ¶ 61,053 ("Order No. 693-A") (2007).
[4] *North American Electric Reliability Corporation*, Petition of the North American Electric Reliability Corporation for Approval of BAL-004-1 Reliability Standard, Docket No. RM06-16-000 (March 11, 2009).
[5] *Time Error Correction Reliability Standard*, 130 FERC ¶ 61,201, (March 18, 2010).
[6] *Motion to Defer Action*, Docket No. RM09-13-000 (August 20, 2011)

process. NERC requested the Commission to defer action until August 20, 2011. In the motion, NERC stated that it would submit a status report six months from the date of the motion. In February 22, 2011, NERC filed an informational status report, fulfilling that commitment.[7]

As August 20, 2011 approaches, NERC has made significant progress in developing and moving forward with a Field Trial to determine if Time Error Corrections can be eliminated. However, concerns have been identified in two of the four interconnections related to market rules and monitoring hardware that must be resolved prior to initiating such a Field Trial. The Field Trial, originally scheduled to commence on or around July 15, 2011, has been postponed pending further discussion at the September 2011 meeting of NERC's Operating Committee. At that meeting, discussion will occur regarding the proper approach for moving forward. Options may include testing the possible elimination of Time Error Corrections on a smaller scope, further delay of the testing, closer coordination with NIST and FERC, and other approaches.

NERC has received a number of questions and concerns regarding the impact the Field Test will have on appliances, motors, and other devices. To a large extent, these questions are based on a perception that NERC is going to allow instantaneous frequency performance to become less stringently controlled than is currently required, and that consumers will expect to see frequency deviations of +/- 5 Hertz or more. This is clearly incorrect, and NERC has no intention of relaxing entities' obligations to control frequency. In addition to these concerns, NERC has also received comments from various industries and government agencies. While significant outreach has occurred within the electric industry, given the numerous potential audiences beyond this effort, additional efforts are needed with additional audiences depending upon the outcome of the September meeting.

[7] *North American Electric Reliability Corporation Status Report Regarding BAL-004-1 Time Error Correction Reliability Standard*, Docket No. RM09-13-000 (February 22, 2011)

NERC believes it is appropriate to continue to move forward cautiously. Accordingly, the above concerns will be discussed at the next meeting of NERC's Operating Committee, and considered when evaluating next steps for the Field Test.

IV. MOTION

In this filing, NERC respectfully requests that the Commission further defer action on NERC's BAL-004-1 filing. As discussed above, NERC originally planned to initiate its Time Error Correction Elimination Field Trial on July 15, 2011, but postponed that effort when two interconnections identified market rule and technology changes that would be needed prior to implementing the Field Trial. NERC and its stakeholders are in the process of researching and analyzing the appropriate next steps. Because Time Error Correction is a process that has broad-reaching effects, NERC believes it is critical that any action taken with regard to the elimination of Time Error Correction be pursued with due care.

NERC anticipates that if elimination of Time Error Correction moves forward, NERC will withdraw its request for approval of the BAL-004-1 Reliability Standard, and ultimately retire the currently approved BAL-004-0 Reliability Standard entirely. Accordingly, taking action that would further entrench this practice within the operation of the bulk power system would be premature and potentially detrimental to bulk power system reliability.

Therefore, NERC requests that the Commission continue to defer action on the BAL-004-1 standard. NERC will provide a status report with any necessary recommendations on or before December 15, 2011.

V. CONCLUSION

NERC respectfully requests that FERC defer action on BAL-004-1 as discussed above, to allow further research and analysis to be performed by NERC.

Respectfully submitted,

/s/ Holly A. Hawkins

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CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 11th day of August, 2011.

/s/ Holly A Hawkins
Holly A. Hawkins
Attorney for North American Electric Reliability Corporation

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

August 31, 2011

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: ***North American Electric Reliability Corporation,***
Docket No. RM06-16-000

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits this filing in compliance with Paragraph 629 of the Federal Energy Regulatory Commission's ("FERC") Order No. 693. Order No. 693 requires that NERC provide a quarterly informational filing regarding the timeframe to restore power to the auxiliary power systems of U.S. nuclear power plants following a blackout as determined during simulations and drills of system restoration plans. This filing contains the referenced material pertaining to the second quarter of 2011.

NERC's filing consists of the following:

- This transmittal letter;
- A table of contents for the entire filing;
- A narrative description summarizing the data collected;
- Official Data Request to Fulfill FERC Order No. 693 Requirements: Restoration of Nuclear Power Plant Off-site Power Sources (**Exhibit A**); and
- Restoration of Nuclear Power Plant Off-site Power Sources Data: 2nd Quarter 2011 (**Exhibit B**).

Please contact the undersigned if you have any questions.

Respectfully submitted,

/s/ Andrew M. Dressel
Andrew M. Dressel

Attorney for North American Electric Reliability Corporation

Critical Energy Infrastructure Information Has Been Redacted From This Public Version

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

MANDATORY RELIABILITY STANDARDS FOR THE BULK POWER SYSTEM	**)** **)**	**Docket No. RM06-16-000**

SECOND QUARTER 2011 COMPLIANCE FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IN RESPONSE TO PARAGRAPH 629 OF ORDER No. 693

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August 31, 2011

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EXHIBIT A – Official Data Request to Fulfill FERC Order No. 693 Requirements: Restoration of Nuclear Power Plant Off-site Sources

EXHIBIT B – Restoration of Nuclear Power Plant Off-site Power Sources Data: 2nd Quarter 2011

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

MANDATORY RELIABILITY STANDARDS FOR THE BULK POWER SYSTEM	**)** **)**	**Docket No. RM06-16-000**

SECOND QUARTER 2011 COMPLIANCE FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IN RESPONSE TO PARAGRAPH 629 OF ORDER No. 693 AND REQUEST TO TERMINATE COMPLIANCE FILING OBLIGATION

I. INTRODUCTION

In its March 16, 2007 Order,[1] the Federal Energy Regulatory Commission ("FERC" or "Commission") directed the North American Electric Reliability Corporation ("NERC") to provide a quarterly informational filing regarding the timeframe to restore power to the auxiliary power systems of U.S. nuclear power plants following a blackout as determined during simulations and drills of system restoration plans. This filing includes information for the second quarter of 2011.

[1] *Mandatory Reliability Standards for the Bulk-Power System*, 118 FERC ¶ 61,218, FERC Stats. & Regs. ¶ 31,242 (2007) (Order No. 693), *Order on reh'g, Mandatory Reliability Standards for the Bulk-Power System*, 120 FERC ¶ 61,053 (Order No. 693-A) (2007).

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:

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III. SUMMARY OF RESTORATION OF NUCLEAR POWER PLANT OFF-SITE POWER SOURCES DATA

Background

In response to comments offered by the U.S. Nuclear Regulatory Commission during the Notice of Proposed Rulemaking process, FERC expressed, in Order No. 693, its concern regarding the role and priority that nuclear power plants should have in bulk power system restoration plans. FERC addressed the concern in the discussion of the EOP-005-1 — System Restoration Plans Reliability Standard. Specifically, in Paragraph 629 of Order No. 693, FERC directed NERC as follows:

> The Commission directs the ERO to gather data, pursuant to §39.5(f) of the Commission's regulations, from simulations and drills of system restoration on the time it takes to restore power to the auxiliary power

> systems of nuclear power plants under its data gathering authority and report that information to the Commission on a quarterly basis.

EOP-005-1, Requirement R11 and sub-requirement R11.4 identify the expected priority for restoring off-site power to nuclear stations. They state:

> **R11.** Following a disturbance in which one or more areas of the Bulk Electric System become isolated or blacked out, the affected Transmission Operators and Balancing Authorities shall begin immediately to return the Bulk Electric System to normal.
>
> **R11.4.** The affected Transmission Operators shall give high priority to restoration of off-site power to nuclear stations.

Importantly, while the requirement provides the instruction to give high priority to off-site power restoration, it does not specify target timeframes.

NERC, in its role as the Electric Reliability Organization ("ERO") and in accordance with 18 C.F.R. § 39.2(d), is required to provide information as necessary to FERC in order to implement section 215 of the Federal Power Act. As such, users, owners and operators of the bulk power system are required to provide the ERO with information in support of this same objective.

To collect the data necessary to respond to the FERC directive for nuclear power plant off-site power source data, NERC issued a data request following a process that was, at that time, drafted as a proposed rule of procedure. That procedure required NERC to post a proposed ERO data request for industry comment, followed by NERC Board of Trustees approval, before issuing it as a formal data request.[2] NERC posted the "nuclear data request" for a 30-day industry comment period that began on June 26, 2007. NERC reviewed the comments received and presented a final version of the data request that was adopted by the NERC Board of Trustees at its August 2, 2007 meeting.

[2] FERC has since approved Section 1600 of the Rules of Procedure, known as the Data Rule, which establishes the process for issuing ERO data requests.

The data presented in **Exhibit B** to this filing contains critical energy infrastructure information. Specifically, the information set forth in **Exhibit B** to the instant filing includes critical energy infrastructure information as defined by FERC Rules of Practice and Procedure (18 C.F.R. Part 388), FERC Orders, and NERC Rules of Procedure. The information pertains to proprietary or business design information, including design information related to vulnerabilities of critical energy infrastructure information that is not publicly available. Accordingly, the information set forth in **Exhibit B** has been redacted from the public filing. In accordance with the FERC Rules of Practice and Procedure, 18 C.F.R. § 388.112, a non-public version of the information redacted from the public filing is being provided separately. NERC requests that the confidential, non-public information be provided special treatment in accordance with the above regulation.

The ERO data request for nuclear power plant off-site power source restoration data, as approved by the NERC Board of Trustees, is found in **Exhibit A**. Following Board of Trustees approval, NERC began to collect nuclear data from U.S. Transmission Operators during the fourth quarter 2007 and will continue to collect the data quarterly until otherwise directed by FERC. This filing represents data captured for the second quarter of 2011.

The specific data requested of the Transmission Operators requests the following information:

- Reporting entity;
- Name of exercise, drill or simulation;
- Date of exercise, drill or simulation;
- Name of nuclear plant;

- Unit designation (each unit must be included separately);
- Identifier of off-site power source;
- Time duration when off-site power sources are lost to the restoration of first off-site power source (For this request, the loss of off-site power sources is the simulated physical interruption of power in support of EOP-005-1 requirements); and
- Discussion of scenario assumptions or constraints impacting the restoration of the initial off-site power source to the nuclear power plant.

In addition, the following clarifying language was included in the data request to guide the Transmission Operators when supplying the requested data.

> Simulations, drills, or exercises that are implemented for individualized operator training requirements are not included in this request. Simulations, drills, and exercises conducted to support the requirements of EOP-005-1 are included in this request. This request is not intended to require additional simulations or studies to those conducted to satisfy EOP-005-1 requirements.

It is important to note that EOP-005 focuses on restoration plans and does not contain any requirement for restoration plans specific to nuclear plants. Hence, the reporting conducted under this data request so far will not result in a tabulation resulting in reports for each US nuclear plant.

Exhibit B presents the raw data collected through this period of observation. As noted above, for the public version of this report, **Exhibit B** has been redacted to remove the actual raw data collected through the period of observation, in accordance with the data survey, and in recognition that the information requested constitutes confidential critical energy infrastructure information. Specifically, **Exhibit B** contains information that, if released, could identify system weaknesses and pose a risk of attack on existing infrastructure. NERC respectfully requests that the critical energy infrastructure

information be protected consistent with national energy security objectives and in accordance with the cited regulation.

NERC has not analyzed this data to identify the impact of the reported off-site power source restoration times relative to the ability of the U.S. nuclear power plants to remain in a mode that permits a timely return to service. NERC will utilize the information contained herein to ensure applicable entities are supporting their reliability standard obligations as defined in EOP-005-1 relative to the priority of off-site power source restoration to nuclear power plants in plans for system restoration.

Summary of Data

There are a total of 104 nuclear units in the U.S. All of these units have reported the requested information as directed. In the second quarter of 2011, Transmission Operators conducted a total of twenty-three (23) individual exercises, drills, or simulations during this period that included the restoration of off-site power sources to eighteen (18) units, with many events impacting more than one nuclear unit.[3] Transmission Operators conduct these exercises, drills, and simulations in support of EOP-005-1 and report their results to their respective Regional Entities. The Regional Entities then report their findings to NERC.

In total, thirty-eight (38) off-site power source restoration "events" are included in the raw data presented in **Exhibit B** of this filing. Of the thirty-eight (38) events, there were thirty-three (33)[4] potential initial off-site source restorations (some units have

[3] For example, an entity conducted one system restoration exercise on June 10, 2011 that involved the restoration of offsite power sources to two nuclear units. In the summary chart that follows below, each offsite power source restoration "event" is reported separately for purposes of data analysis.
[4] Not all units provided data for off-site sources beyond the first source restored. The data included represents only the units that provided the data and does not include the entire spectrum of off-site sources beyond the initial source for the rest of the units.

multiple off-site sources). The remaining five (5) events included in the data involved the restoration of a subsequent off-site source beyond the first source restored. Of the five (5) events, one (1) subsequent source was simulated to be restored the two to four hour window. The remainder of the subsequent sources (4) were restored in more than ten hours.

Prior to the first quarter 2011 filing, there were twelve (12) nuclear units that had not been reported as being involved in a drill, exercise or simulation during the term of this data request (2007 through 2011). NERC contacted the Transmission Operators responsible for these 12 nuclear plants to determine whether drills, exercises or simulations have been conducted regarding the time it takes to restore off-site power to the nuclear plant. Each Transmission Operator has now reported conducting at least one drill, exercise, or simulation. One entity reported an exercise that occurred in November of 2010 that included three (3) units. Another entity reported twelve (12) exercises in the first quarter of 2011 that included two (2) units. Other entities reported exercises conducted in the second quarter of 2011 that included seven (7) additional units. Restoration times for these eleven (11) units ranged from 24 minutes in a table top simulation to eleven (11) hours in a powerflow simulation exercise.

NERC categorized the restoration of first off-site sources in two-hour windows. Over eighty-seven (87) percent (29 of 33) of the initial off-site power source restorations occurred within the first four hours following the simulated blackout event, with over fifty-five (55) percent (18 of 33) occurring in two hours or less. Eleven (11) sources were simulated to be restored in the 2 to 4 hour window.

Total Number Offsite Power Source Restoration Events Included in EOP-005-1 Exercises, Drills or Simulations	38

Potential first off-site source restorations	33
Exercises, Drills, or Simulations in which the first off-site source was restored in 2 hours or less following the loss of power	18
Exercises, Drills, or Simulations in which the first off-site source was restored 2-4 hours following the loss of power	11
Exercises, Drills, or Simulations in which the first off-site source was restored 4-6 hours following the loss of power	0
Exercises, Drills or Simulations in which the first off-site source was restored 6-8 hours following the loss of power	3
Exercises, Drills, or Simulations in which the first off-site source was restored 8-10 hours following the loss of power	0
Exercises, Drills or Simulations in which the first off-site source was restored more than 10 hours following the loss of power	1
Exercises, Drills, or Simulations that did not achieve the restoration of the first off-site power source to a nuclear power plant or that did not report a time for source restoration	0

IV. CONCLUSION

NERC respectfully requests that FERC accept this informational filing for the second quarter of 2011 in accordance with FERC's directive that NERC provide information regarding the time it takes to restore off-site power sources to nuclear power plants following a blackout as determined by drills and simulations.

Respectfully submitted,

/s/ Andrew M. Dressel

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CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 31st day of August, 2011.

/s/ Andrew M. Dressel
Andrew M. Dressel

Attorney for North American Electric Reliability Corporation

Critical Energy Infrastructure Information Has Been Redacted From This Public Version

Exhibit A

Official Data Request to Fulfill FERC Order No. 693 Requirements: Restoration of Nuclear Power Plant Off-site Power Sources

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Gerry Adamski
Vice President and
Director of Standards

August 24, 2007

TRANSMISSION OPERATOR CONTACT
TITLE
COMPANY
ADDRESS
CITY, STATE ZIP CODE (TNR, 12pt)

Dear XXXXX:

Official Data Request to Fulfill FERC Order No. 693 Requirements
Restoration of Nuclear Power Plant Off-site Power Sources

Pursuant to the authority granted by FERC Order 672 and as implemented in Title 18, Section 39.2 of the Code of Federal Regulations, NERC as the appointed electric reliability organization issues this official data request as described in **Attachment 1**.

The legal basis in the United States for this authority is explained in FERC's Order 672, paragraph 114:

> 114. The Commission agrees with commenters that, to fulfill its obligations under this Final Rule, the ERO or a Regional Entity will need access to certain data from users, owners and operators of the Bulk-Power System. Further, the Commission will need access to such information as is necessary to fulfill its oversight and enforcement roles under the statute. Section 39.2 of the regulations will include the following requirement:
>
> > (d) Each user, owner or operator of the Bulk-Power System within the United States (other than Alaska and Hawaii) shall provide the Commission, the Electric Reliability Organization and the applicable Regional Entity such information as is necessary to implement section 215 of the Federal Power Act as determined by the Commission and set out in the Rules of the Electric Reliability Organization and each applicable Regional Entity. The Electric Reliability Organization and each Regional Entity shall provide the Commission such information as is necessary to implement section 215 of the Federal Power Act.

Within the United States, failure to comply with an official data request would constitute a violation of FERC regulations. Enforcement action is available to FERC to deal with

violations of its regulations. This is authority FERC could exercise, not authority available to NERC. NERC's Compliance Monitoring and Enforcement Program, including the ability to impose penalties and sanctions, is limited to violations of reliability standards.

Please note the following additional pieces of information relative to this data request:

- An Excel spreadsheet (attached) to serve as a template for providing the requested information.
- Regional entities are requested to submit the requested information to sarcomm@nerc.net.

Thank you for your support of this effort. Please contact me should you have any questions.

Sincerely,

Enclosure

cc: James D. Castle, Chairman, Operating Reliability Subcommittee
Regional Entity Management Group

Exhibit A
Restoration of Nuclear Power Plant Offsite Power Source Data Request

Background

In paragraph 629 of Order No. 693, FERC directs NERC to provide an informational filing regarding the timeframe to restore auxiliary power to nuclear power plants following a blackout as determined during simulations and drills of system restoration plans:

> 629. "In addition the Commission directs the ERO to gather data, pursuant to § 39.5(f) of the Commission's regulations, from simulations and drills of system restoration on the time it takes to restore power to the auxiliary power systems of nuclear power plants under its data gathering authority and report that information to the Commission on a quarterly basis."

Description of Data Requested

This request is an ongoing request that begins in the fourth quarter of 2007. If an exercise, drill, or simulation includes the restoration of one or more offsite power sources to a nuclear power plant, the following information is to be prepared and provided *for each offsite power source* in a format developed and provided by NERC:

- Reporting entity
- Name of exercise, drill, or simulation
- Date of exercise, drill, or simulation
- Name of nuclear plant
- Unit designation (each unit must be included separately)
- Identifier of offsite power source
- Time duration when offsite power sources are lost to the restoration of first offsite power source. (For this request, the loss of offsite power sources is the simulated physical interruption of power in support of EOP-005-1 requirements.)
- Discussion of scenario assumptions or constraints impacting the restoration of the initial offsite power source to the nuclear power plant

Simulations, drills, or exercises that are implemented for individualized operator training requirements are not included in this request. Simulations, drills, and exercises conducted to support the requirements of EOP-005-1 are included in this request. This request is not intended to require additional simulations or studies to those conducted to satisfy EOP-005-1 requirements.

The individual data submissions should be submitted to the regional entity who will compile the data in a consolidated format. The regional entity will then forward the complied data to NERC's director of standards on a quarterly basis.

To comply with FERC directives, NERC will make a quarterly filing with FERC that includes the compiled data.

How the Data Will Be Used
The data will be provided to FERC per its directive in Order 693. FERC agrees with issues raised by the Nuclear Regulatory Commission (NRC) concerning the role and priority nuclear power plants should have in system restorations, and directs the collection of this data to aid in its review of this issue.

How the Data Will Be Collected and Validated
The regional entities are requested to coordinate the collection and composite presentation of the requested data from its member participants. Transmission operators responsive to this request are expected to validate the data to be correct prior to submittal.

Reporting Entities
Each transmission operator in the United States who has a nuclear power plant tied to a transmission line that it controls and who is participating in an exercise, drill, or simulation in support of the EOP-005-1 standard will report. Transmission operators that do not have a nuclear power plant tied to a transmission line it controls are exempt from this request.

Transmission operators outside the United States subject to EOP-005-1 are voluntarily encouraged to submit this information as well. NERC will seek permission from these non-U.S. entities for inclusion of its data in the information filed with FERC.

Due Date for the Information
If a transmission operator subject to this data request conducts a drill, simulation, or exercise that includes restoration of the initial offsite power source to a nuclear power plant, the transmission operator is to submit the requested information to its regional entity by the fifteenth of the month; following the end of the previous three-month quarter. The regional entity is to provide a quarterly report of all such submissions by April 30, July 31, October 31, and January 31 for the three-month period that concludes on these dates. This data request begins in the fourth quarter of 2007.

If no drill, exercise, or simulation meeting the criteria described above is conducted during a quarter, no submission by the transmission operator and regional entity is required. This data request does not direct transmission operators to conduct quarterly exercises, drills, or simulations to satisfy this data request. It does require the data to be reported if such a simulation, drill, or exercise is conducted.

Restrictions on Disseminating Data (Confidential/CEII)
NERC will provide this data to FERC per its Order No. 693 directives. This information will be treated as critical energy infrastructure information when submitted to FERC.

Estimate on Burden Imposed to Collect Data
There will be ongoing costs for the staff of responsible entities to respond and for regional entities to collect, compile, and report to NERC the requested data.

Exhibit B

Restoration of Nuclear Power Plant Off-site Source Data: 2nd Quarter 2011

Critical Energy Infrastructure Information Has Been Redacted From This Public Version

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 40

[Docket No. RM10–29–000; Order No. 753]

Electric Reliability Organization Interpretation of Transmission Operations Reliability Standard

September 15, 2011.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: Under section 215 of the Federal Power Act (FPA), the Federal Energy Regulatory Commission approves the North American Electric Reliability Corporation's proposed interpretation of Reliability Standard, TOP–001–1, Requirement R8, which pertains to the restoration of real and reactive power during a system emergency.

DATES: *Effective Date:* This rule will become effective November 21, 2011.

FOR FURTHER INFORMATION CONTACT:
Robert T. Stroh (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, Telephone: (202) 502–8473.
Eugene Blick (Technical Information), Office of Electric Reliability, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, Telephone: (202) 502–8066.
David O'Connor (Technical Information), Office of Electric Reliability, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, Telephone: (202) 502–6695.

SUPPLEMENTARY INFORMATION: Before Commissioners: Jon Wellinghoff, Chairman; Marc Spitzer, Philip D. Moeller, John R. Norris, and Cheryl A. LaFleur.

Final Rule

1. Under section 215 of the Federal Power Act (FPA),[1] the Federal Energy Regulatory Commission approves the North American Electric Reliability Corporation's (NERC) proposed interpretation of Requirement R8 in Commission-approved NERC Reliability Standard TOP–001–1—Reliability Responsibilities and Authorities.

I. Background

2. Section 215 of the FPA requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval. Approved Reliability Standards are enforced by the ERO, subject to Commission oversight, or by the Commission independently.

3. Pursuant to section 215 of the FPA, the Commission established a process to select and certify an ERO[2] and, subsequently, certified NERC as the ERO.[3] On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 Reliability Standards filed by NERC, including Reliability Standard TOP–001–1.[4]

4. NERC's Rules of Procedure provide that a person that is ''directly and materially affected'' by Bulk-Power System reliability may request an interpretation of a Reliability Standard.[5] The ERO's ''standards process manager'' will assemble a team with relevant expertise to address the requested interpretation and also form a ballot pool. NERC's Rules provide that, within 45 days, the team will draft an interpretation of the Reliability Standard, with subsequent balloting. If approved by ballot, the interpretation is appended to the Reliability Standard and filed with the applicable regulatory authority for regulatory approval.

A. Reliability Standard TOP–001–1

5. Reliability Standard TOP–001–1 (Reliability Responsibilities and Authorities) centers on the responsibilities of balancing authorities and transmission operators during a system emergency. Specifically, the stated purpose of Reliability Standard TOP–001–1 is to ensure reliability entities have clear decision-making authority and capabilities to take appropriate actions or direct the actions of others to return the transmission system to normal conditions during an emergency. Requirement R8 of the standard provides:

> During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.[6]

B. NERC Proposed Interpretation

6. On July 16, 2010, NERC submitted its petition for approval for an interpretation of Requirement R8 in Commission-approved Reliability Standard TOP–001–1. The Petition explains that NERC received a request from Florida Municipal Power Pool (FMPP) seeking an interpretation of Reliability Standard TOP–001–1, Requirement R8. Specifically, FMPP requested clarification on several aspects of Requirement R8. FMPP asked the following:

> Balancing real power is not a function of a [Transmission Operator] and balancing reactive power is not a function of a [Balancing Authority]. For Requirement R8 is the Balancing Authority responsibility to immediately take corrective action to restore Real Power Balance and is the [Transmission Operator] responsibility to immediately take corrective action to restore Reactive Power Balance?[7]

7. Consistent with the NERC Rules of Procedure, NERC stated that it assembled a team to respond to the request for interpretation and presented the proposed interpretation to industry ballot, using a process similar to the process it uses for the development of Reliability Standards.[8]

8. In response to FMPP's interpretation request, NERC provided the following:

> The answer to both questions is yes. According to the NERC Glossary of Terms Used in Reliability Standards, the Transmission Operator is responsible for the reliability of its ''local'' transmission system, and operates or directs the operations of the transmission facilities. Similarly, the Balancing Authority is responsible for maintaining load-interchange-generation balance, i.e., real power balance. In the context of this requirement, the Transmission Operator is the functional entity that balances reactive power. Reactive power balancing can be accomplished by issuing instructions to the Balancing Authority or Generator Operators to alter reactive power injection. Based on NERC Reliability Standard BAL–005–1b Requirement R6, the Transmission Operator has no requirement to

[1] 16 U.S.C. 824o (2006).

[2] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards,* Order No. 672, FERC Stats. & Regs. ¶ 31,204, order on reh'g, Order No. 672–A, FERC Stats. & Regs. ¶ 31,212 (2006).

[3] *North American Electric Reliability Corp.,* 116 FERC ¶ 61,062, *order on reh'g & compliance,* 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc.* v. *FERC,* 564 F.3d 1342 (D.C. Cir. 2009).

[4] *Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g,* Order No. 693–A, 120 FERC ¶ 61,053 (2007).

[5] NERC Rules of Procedure, Appendix 3A, Reliability Standards Development Procedure, Version 6.1, at 27–29 (2010).

[6] Reliability Standard TOP–001–1, Requirement R8.

[7] NERC Petition at 5.

[8] NERC Reliability Standards Development Procedure at 27–29.

compute an Area Control Error (ACE) signal or to balance real power. Based on NERC Reliability Standard VAR–001–1 Requirement R8, the Balancing Authority is not required to resolve reactive power balance issues. According to TOP–001–1\ Requirement R3, the Balancing Authority is only required to comply with Transmission Operator or Reliability Coordinator instructions to change injections of reactive power.[9]

NERC stated that the interpretation was developed and approved by industry stakeholders and approved by the NERC Board of Trustees (Board).

9. The NERC petition explained that the interpretation is consistent with the stated purpose of the Reliability Standard, which is to ensure reliability entities have clear decision-making authority and capabilities to take appropriate actions or direct the actions of others to return the transmission system to normal conditions during an emergency. NERC added that the interpretation clarifies the responsibilities of balancing authorities and transmission operators during a system emergency by referencing the *NERC Glossary of Terms Used in Reliability Standards* as well as other relevant Reliability Standards.[10]

10. On February 14, 2011, NERC made a supplemental filing in response to a Commission staff data request.[11] With regard to whether Requirement R8 obligates a joint response in a system emergency, NERC explained that Requirement R8 does not use the word ''joint'' or otherwise infer joint responsibility during system emergencies. Rather, NERC responded that the balancing authority and transmission operator have separate responsibilities to restore real and reactive power balance during system emergencies. NERC also stated that the use of ''and'' between the two entities should not construe communication or coordination. NERC added that the Blackout Report[12] correctly identifies communication and coordination issues as reliability issues and that communication and coordination are addressed in the Communications (COM) Reliability Standards.[13]

II. Notice of Proposed Rulemaking

11. On April 21, 2011, the Commission issued a Notice of Proposed Rulemaking (NOPR) proposing to approve NERC's interpretation of Reliability Standard TOP–001–1, Requirement R8.[14] In the NOPR, the Commission stated that it believed that the ERO has presented a reasonable interpretation consistent with the language of the Reliability Standard. In addition, the NOPR noted that a balancing authority and transmission operator each have coordination and communication functions that are necessary for maintaining real and reactive power balance.

12. In response to the NOPR, NERC filed comments supporting the Commission's proposed approval of the interpretation. No comments were filed opposing the Commission's proposal to approve NERC's interpretation.

III. Commission Determination

13. The Commission adopts the NOPR proposal and approves the interpretation of TOP–001–1, Requirement R8. The Commission finds that NERC's interpretation is just, reasonable, not unduly discriminatory or preferential, and in the public interest.

14. The interpretation supports the stated purpose of the Reliability Standard, i.e., ensuring that reliability entities have clear decision-making authority and capabilities to take appropriate actions or direct the actions of others to return the transmission system to normal conditions during an emergency.[15] The interpretation also clarifies the responsibilities of a balancing authority and transmission operator during a system emergency. Further, the language is consistent with the language of the requirement. Accordingly, the Commission approves the ERO's interpretation of TOP–001–1, Requirement R8.

15. We agree, as discussed in the interpretation, that the balancing authority is responsible for restoring real power balance during a system emergency and the transmission operator is responsible for restoring reactive power balance during a system emergency. However, during a system emergency, communication and coordination between the transmission operator and balancing authority can be essential to restore real and reactive power balance. For example, during an emergency, the balancing authority may rely on the real power output of a generator to fulfill its responsibility, while the transmission operator may expect the same generator unit to reduce real power to generate greater reactive power output.[16]

16. NERC acknowledges the need for such communication and coordination.[17] NERC maintains that this coordination and communication is required through two currently-effective Communication Reliability Standards: (1) COM–001–1.1—Telecommunications and (2) COM–002–2—Communication and Coordination.[18]

17. We agree with NERC that the currently effective COM Reliability Standards provide for such communication and coordination. For example, Reliability Standard COM–002–2, Requirement R1 provides that transmission operators, balancing authorities and generator operators must have communication links with one another and must be staffed to address a real-time emergency. Reliability Standard EOP–001–0, Requirements R3, R4.3, and R7 also contain provisions relevant to the need for communication and coordination in emergencies.[19] These provisions require balancing authorities and transmission operators to develop plans to mitigate operating emergencies including coordination among adjacent transmission operators and balancing authorities.

18. Accordingly, for the reasons discussed above, we approve NERC's proposed interpretation of TOP–001–1, Requirement R8.

IV. Information Collection Statement

19. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping requirements (collections of information) imposed by an agency.[20] The information contained here is also

[9] *Id.* at 5–6.

[10] *Id.* at 6.

[11] Response of the North American Electric Reliability Corporation to Request for Additional Information Regarding Interpretation to Reliability Standard TOP–001–1, Requirement R8 (NERC Response).

[12] *Final Report on the August 14, 2003 Blackout in the United States and Canada* (Blackout Report).

[13] NERC Response at 4–7.

[14] *Electric Reliability Organization Interpretation of Transmission Operations Reliability Standard,* Notice of Proposed Rulemaking, 76 FR 23222 (Apr. 26, 2011), FERC Stats. & Regs. ¶ 32,674 (2011) (NOPR).

[15] *Id.* at 6.

[16] The Blackout Report described such a scenario, explaining that a generator unit tripped because the unit's protection system detected the VAR output, i.e., reactive power, exceeded the unit's capability. Blackout Report at 27. The Blackout Report also explained that no generator units were asked to reduce their real power output to produce more reactive power. *Id.* at 47.

[17] NERC Response at 6–7.

[18] NERC Response at 6–7. NERC also identifies several ongoing Reliability Standards projects that are intended to strengthen the requirements pertaining to communication and coordination between entities.

[19] *See* NOPR, FERC Stats. & Regs. ¶ 32,674 at P 14. On July 13, 2011, the Commission approved EOP–001–2 Reliability Standard, replacing EOP–001–0 effective July 1, 2013. *Mandatory Reliability Standards for Interconnection Reliability Operating Limits; System Restoration Reliability Standards,* 136 FERC ¶ 61,030 (2011). The applicable Requirements in EOP–001–2 relevant to the need for communication and coordination in emergencies are Requirements R2, R3.3, and R6.

[20] 5 CFR 1320.11.

subject to review under section 3507(d) of the Paperwork Reduction Act of 1995.[21]

20. As stated above, the Commission approved, in Order No. 693, Reliability Standard TOP–001–1 that is the subject of the current rulemaking. This Final Rule approves the interpretation of the previously approved Reliability Standard, which was developed by NERC as the ERO. The interpretation, as clarified, relates to an existing Reliability Standard, and the Commission does not expect it to affect entities' current reporting burden.[22] Accordingly, we will submit this Final Rule to OMB for informational purposes only.

21. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, e-mail: *DataClearance@ferc.gov,* Phone: (202) 502–8663, fax: (202) 273–0873].

V. Environmental Analysis

22. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[23] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[24] The actions proposed herein fall within this categorical exclusion in the Commission's regulations.

VI. Regulatory Flexibility Act

23. The Regulatory Flexibility Act of 1980 (RFA)[25] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a final rule and that minimize any significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[26] The SBA has established a size standard for electric utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million megawatt hours.[27] The RFA is not implicated by this Final Rule because the interpretations discussed herein will not have a significant economic impact on a substantial number of small entities.

24. The Commission approved Reliability Standard TOP–001–1 in 2007 in Order No. 693. The Final Rule in the immediate docket addresses an interpretation of Requirement R8 of previously-approved TOP–001–1. The interpretation clarifies current compliance obligations of balancing authorities and transmission operators and therefore, does not create an additional regulatory impact on small entities.

VII. Document Availability

25. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (*http://www.ferc.gov*) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5 p.m. eastern time) at 888 First Street, NE., Room 2A, Washington, DC 20426.

26. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

27. User assistance is available for eLibrary and the FERC's website during normal business hours from FERC Online Support at 202–502–6652 (toll free at 1–866–208–3676) or e-mail at *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659. E-mail the Public Reference Room at *public.referenceroom@ferc.gov.*

VIII. Effective Date and Congressional Notification

28. These regulations are effective November 21, 2011. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

List of Subjects in 18 CFR Part 40

Electric power, Electric utilities, Reporting and recordkeeping requirements.

By the Commission.

Kimberly D. Bose,

Secretary.

[FR Doc. 2011–24088 Filed 9–19–11; 8:45 am]

BILLING CODE 6717–01–P

[21] 44 U.S.C. 3507(d).

[22] *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1901–1907.

[23] *Regulations Implementing the National Environmental Policy Act* of 1969, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Preambles 1986–1990 ¶ 30,783 (1987).

[24] 18 CFR 380.4(a)(2)(ii).

[25] 5 U.S.C. 601–612.

[26] 13 CFR 121.101.

[27] 13 CFR 121.201, Section 22, Utilities, & n.1.

DEPARTMENT OF DEFENSE

Office of the Secretary

[Docket ID: DoD–2011–OS–0004]

32 CFR Part 311

Privacy Act of 1974; Implementation

AGENCY: Office of the Secretary, DoD.

ACTION: Direct final rule with request for comments.

SUMMARY: The Office of the Secretary of Defense is exempting those records contained in DMDC 14 DoD, entitled ''Defense Clearance and Investigations Index (DCII)'', pertaining to investigatory material compiled for law enforcement purposes to enable OSD components to conduct certain investigations and relay law enforcement information without compromise of the information, protect investigative techniques and efforts employed, and identities of confidential sources who might not otherwise come forward and who furnished information under an express promise that the sources' identity would be held in confidence. The exemption will allow DoD to provide protection against notification of investigatory material including certain reciprocal investigations and counterintelligence information, which might alert a subject to the fact that an investigation of that individual is taking place, and the disclosure of which would weaken the on-going investigation, reveal investigatory techniques, and place confidential informants in jeopardy who furnished information under an express promise that the sources' identity would be held in confidence. Further,

20110915-3033 FERC PDF (Unofficial) 09/15/2011

136 FERC ¶ 61,176
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM10-29-000; Order No. 753]

Electric Reliability Organization Interpretation of Transmission Operations Reliability Standard

(Issued September 15, 2011)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: Under section 215 of the Federal Power Act (FPA), the Federal Energy Regulatory Commission approves the North American Electric Reliability Corporation's proposed interpretation of Reliability Standard, TOP-001-1, Requirement R8, which pertains to the restoration of real and reactive power during a system emergency.

EFFECTIVE DATE: This rule will become effective [sixty (60) days after publication in the **FEDERAL REGISTER**].

FOR FURTHER INFORMATION CONTACT:

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Federal Energy Regulatory Commission
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SUPPLEMENTARY INFORMATION:

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136 FERC ¶ 61,176
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Marc Spitzer, Philip D. Moeller,
John R. Norris, and Cheryl A. LaFleur.

Electric Reliability Organization Interpretation of Transmission Operations Reliability Standard — Docket No. RM10-29-000

ORDER NO. 753

FINAL RULE

(Issued September 15, 2011)

1. Under section 215 of the Federal Power Act (FPA),[1] the Federal Energy Regulatory Commission approves the North American Electric Reliability Corporation's (NERC) proposed interpretation of Requirement R8 in Commission-approved NERC Reliability Standard TOP-001-1 — Reliability Responsibilities and Authorities.

I. Background

2. Section 215 of the FPA requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval. Approved Reliability Standards are enforced by the ERO, subject to Commission oversight, or by the Commission independently.

[1] 16 U.S.C. § 824o (2006).

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3. Pursuant to section 215 of the FPA, the Commission established a process to select and certify an ERO[2] and, subsequently, certified NERC as the ERO.[3] On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 Reliability Standards filed by NERC, including Reliability Standard TOP-001-1.[4]

4. NERC's Rules of Procedure provide that a person that is "directly and materially affected" by Bulk-Power System reliability may request an interpretation of a Reliability Standard.[5] The ERO's "standards process manager" will assemble a team with relevant expertise to address the requested interpretation and also form a ballot pool. NERC's Rules provide that, within 45 days, the team will draft an interpretation of the Reliability Standard, with subsequent balloting. If approved by ballot, the interpretation is appended to the Reliability Standard and filed with the applicable regulatory authority for regulatory approval.

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[2] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[3] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g & compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[4] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[5] NERC Rules of Procedure, Appendix 3A, Reliability Standards Development Procedure, Version 6.1, at 27-29 (2010).

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A. Reliability Standard TOP-001-1

5. Reliability Standard TOP-001-1 (Reliability Responsibilities and Authorities) centers on the responsibilities of balancing authorities and transmission operators during a system emergency. Specifically, the stated purpose of Reliability Standard TOP-001-1 is to ensure reliability entities have clear decision-making authority and capabilities to take appropriate actions or direct the actions of others to return the transmission system to normal conditions during an emergency. Requirement R8 of the standard provides:

> During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.[6]

B. NERC Proposed Interpretation

6. On July 16, 2010, NERC submitted its petition for approval for an interpretation of Requirement R8 in Commission-approved Reliability Standard TOP-001-1. The Petition explains that NERC received a request from Florida Municipal Power Pool (FMPP) seeking an interpretation of Reliability Standard TOP-001-1, Requirement R8. Specifically, FMPP requested clarification on several aspects of Requirement R8. FMPP asked the following:

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[6] Reliability Standard TOP-001-1, Requirement R8.

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> Balancing real power is not a function of a [Transmission Operator] and balancing reactive power is not a function of a [Balancing Authority]. For Requirement R8 is the Balancing Authority responsibility to immediately take corrective action to restore Real Power Balance and is the [Transmission Operator] responsibility to immediately take corrective action to restore Reactive Power Balance?[7]

7. Consistent with the NERC Rules of Procedure, NERC stated that it assembled a team to respond to the request for interpretation and presented the proposed interpretation to industry ballot, using a process similar to the process it uses for the development of Reliability Standards.[8]

8. In response to FMPP's interpretation request, NERC provided the following:

> The answer to both questions is yes. According to the NERC Glossary of Terms Used in Reliability Standards, the Transmission Operator is responsible for the reliability of its "local" transmission system, and operates or directs the operations of the transmission facilities. Similarly, the Balancing Authority is responsible for maintaining load-interchange-generation balance, i.e., real power balance. In the context of this requirement, the Transmission Operator is the functional entity that balances reactive power. Reactive power balancing can be accomplished by issuing instructions to the Balancing Authority or Generator Operators to alter reactive power injection. Based on NERC Reliability Standard BAL-005-1b Requirement R6, the Transmission Operator has no requirement to compute an Area Control Error (ACE) signal or to balance real power. Based on NERC Reliability Standard VAR-001-1 Requirement R8, the Balancing Authority is not required to resolve reactive power balance issues. According to TOP-001-1 \ Requirement R3, the Balancing Authority is only required to comply

[7] NERC Petition at 5.

[8] NERC Reliability Standards Development Procedure at 27-29.

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> with Transmission Operator or Reliability Coordinator instructions to change injections of reactive power.[9]

NERC stated that the interpretation was developed and approved by industry stakeholders and approved by the NERC Board of Trustees (Board).

9. The NERC petition explained that the interpretation is consistent with the stated purpose of the Reliability Standard, which is to ensure reliability entities have clear decision-making authority and capabilities to take appropriate actions or direct the actions of others to return the transmission system to normal conditions during an emergency. NERC added that the interpretation clarifies the responsibilities of balancing authorities and transmission operators during a system emergency by referencing the *NERC Glossary of Terms Used in Reliability Standards* as well as other relevant Reliability Standards.[10]

10. On February 14, 2011, NERC made a supplemental filing in response to a Commission staff data request.[11] With regard to whether Requirement R8 obligates a joint response in a system emergency, NERC explained that Requirement R8 does not use the word "joint" or otherwise infer joint responsibility during system emergencies. Rather, NERC responded that the balancing authority and transmission operator have

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[9] *Id*. at 5-6.

[10] *Id*. at 6.

[11] Response of the North American Electric Reliability Corporation to Request for Additional Information Regarding Interpretation to Reliability Standard TOP-001-1, Requirement R8 (NERC Response).

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separate responsibilities to restore real and reactive power balance during system emergencies. NERC also stated that the use of "and" between the two entities should not construe communication or coordination. NERC added that the Blackout Report[12] correctly identifies communication and coordination issues as reliability issues and that communication and coordination are addressed in the Communications (COM) Reliability Standards.[13]

II. Notice of Proposed Rulemaking

11. On April 21, 2011, the Commission issued a Notice of Proposed Rulemaking (NOPR) proposing to approve NERC's interpretation of Reliability Standard TOP-001-1, Requirement R8.[14] In the NOPR, the Commission stated that it believed that the ERO has presented a reasonable interpretation consistent with the language of the Reliability Standard. In addition, the NOPR noted that a balancing authority and transmission operator each have coordination and communication functions that are necessary for maintaining real and reactive power balance.

12. In response to the NOPR, NERC filed comments supporting the Commission's proposed approval of the interpretation. No comments were filed opposing the Commission's proposal to approve NERC's interpretation.

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[12] *Final Report on the August 14, 2003 Blackout in the United States and Canada* (Blackout Report).

[13] NERC Response at 4-7.

[14] *Electric Reliability Organization Interpretation of Transmission Operations Reliability Standard*, Notice of Proposed Rulemaking, 76 FR 23222 (Apr. 26, 2011), FERC Stats. & Regs. ¶ 32,674 (2011) (NOPR).

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III. Commission Determination

13. The Commission adopts the NOPR proposal and approves the interpretation of TOP-001-1, Requirement R8. The Commission finds that NERC's interpretation is just, reasonable, not unduly discriminatory or preferential, and in the public interest.

14. The interpretation supports the stated purpose of the Reliability Standard, i.e., ensuring that reliability entities have clear decision-making authority and capabilities to take appropriate actions or direct the actions of others to return the transmission system to normal conditions during an emergency.[15] The interpretation also clarifies the responsibilities of a balancing authority and transmission operator during a system emergency. Further, the language is consistent with the language of the requirement. Accordingly, the Commission approves the ERO's interpretation of TOP-001-1, Requirement R8.

15. We agree, as discussed in the interpretation, that the balancing authority is responsible for restoring real power balance during a system emergency and the transmission operator is responsible for restoring reactive power balance during a system emergency. However, during a system emergency, communication and coordination between the transmission operator and balancing authority can be essential to restore real and reactive power balance. For example, during an emergency, the balancing authority may rely on the real power output of a generator to fulfill its responsibility, while the

[15] *Id*. at 6.

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transmission operator may expect the same generator unit to reduce real power to generate greater reactive power output.[16]

16. NERC acknowledges the need for such communication and coordination.[17] NERC maintains that this coordination and communication is required through two currently-effective Communication Reliability Standards: (1) COM-001-1.1 – Telecommunications and (2) COM-002-2 – Communication and Coordination.[18]

17. We agree with NERC that the currently effective COM Reliability Standards provide for such communication and coordination. For example, Reliability Standard COM-002-2, Requirement R1 provides that transmission operators, balancing authorities and generator operators must have communication links with one another and must be staffed to address a real-time emergency. Reliability Standard EOP-001-0, Requirements R3, R4.3, and R7 also contain provisions relevant to the need for communication and coordination in emergencies.[19] These provisions require balancing authorities and

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[16] The Blackout Report described such a scenario, explaining that a generator unit tripped because the unit's protection system detected the VAR output, i.e., reactive power, exceeded the unit's capability. Blackout Report at 27. The Blackout Report also explained that no generator units were asked to reduce their real power output to produce more reactive power. *Id*. at 47.

[17] NERC Response at 6-7.

[18] NERC Response at 6-7. NERC also identifies several ongoing Reliability Standards projects that are intended to strengthen the requirements pertaining to communication and coordination between entities.

[19] *See* NOPR, FERC Stats. & Regs. ¶ 32,674 at P 14. On July 13, 2011, the Commission approved EOP-001-2 Reliability Standard, replacing EOP-001-0 effective July 1, 2013. *Mandatory Reliability Standards for Interconnection Reliability Operating*

(continued…)

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transmission operators to develop plans to mitigate operating emergencies including coordination among adjacent transmission operators and balancing authorities.

18. Accordingly, for the reasons discussed above, we approve NERC's proposed interpretation of TOP-001-1, Requirement R8.

IV. Information Collection Statement

19. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping requirements (collections of information) imposed by an agency.[20] The information contained here is also subject to review under section 3507(d) of the Paperwork Reduction Act of 1995.[21]

20. As stated above, the Commission approved, in Order No. 693, Reliability Standard TOP-001-1 that is the subject of the current rulemaking. This Final Rule approves the interpretation of the previously approved Reliability Standard, which was developed by NERC as the ERO. The interpretation, as clarified, relates to an existing Reliability Standard, and the Commission does not expect it to affect entities' current reporting burden.[22] Accordingly, we will submit this Final Rule to OMB for informational purposes only.

Limits; System Restoration Reliability Standards, 136 FERC ¶ 61,030 (2011). The applicable Requirements in EOP-001-2 relevant to the need for communication and coordination in emergencies are Requirements R2, R3.3, and R6.

[20] 5 C.F.R § 1320.11.

[21] 44 U.S.C. § 3507(d).

[22] *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1901-1907.

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21. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, e-mail: DataClearance@ferc.gov, Phone: (202) 502-8663, fax: (202) 273-0873].

V. Environmental Analysis

22. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[23] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[24] The actions proposed herein fall within this categorical exclusion in the Commission's regulations.

VI. Regulatory Flexibility Act

23. The Regulatory Flexibility Act of 1980 (RFA)[25] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a final rule and that minimize any significant

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[23] *Regulations Implementing the National Environmental Policy Act of* 1969, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Preambles 1986-1990 ¶ 30,783 (1987).

[24] 18 C.F.R. § 380.4(a)(2)(ii).

[25] 5 U.S.C. § 601-612.

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economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[26] The SBA has established a size standard for electric utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million megawatt hours.[27] The RFA is not implicated by this Final Rule because the interpretations discussed herein will not have a significant economic impact on a substantial number of small entities.

24. The Commission approved Reliability Standard TOP-001-1 in 2007 in Order No. 693. The Final Rule in the immediate docket addresses an interpretation of Requirement R8 of previously-approved TOP-001-1. The interpretation clarifies current compliance obligations of balancing authorities and transmission operators and therefore, does not create an additional regulatory impact on small entities.

VII. Document Availability

25. In addition to publishing the full text of this document in the *Federal Register*, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (http://www.ferc.gov) and in FERC's Public Reference Room during normal business

[26] 13 C.F.R. § 121.101.

[27] 13 C.F.R. § 121.201, Section 22, Utilities, & n.1.

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hours (8:30 a.m. to 5:00 p.m. eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

26. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

27. User assistance is available for eLibrary and the FERC's website during normal business hours from FERC Online Support at 202-502-6652 (toll free at 1-866-208-3676) or e-mail at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

VIII. Effective Date and Congressional Notification

28. These regulations are effective [insert date 60 days from publication in the **Federal Register**]. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

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List of subjects in 18 CFR Part 40

Electric power, Electric utilities, Reporting and recordkeeping requirements.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

Document Content(s)

RM10-29-000a.DOC.....1-15

extending from 4.8 miles west to 10 miles east of the VORTAC and within a 6.7-mile radius of Monmouth Executive Airport and within 1.8 miles each side of the Colts Neck VOR/DME 167° radial extending from the Monmouth Executive Airport 6.7-mile radius to the VOR/DME and within 4 miles each side of the 312° bearing from Monmouth Executive airport extending from the 6.7-mile radius of the airport to 9 miles northwest of the airport and within a 6.5-mile radius of Robert J. Miller Air Park and within 1.3 miles each side of the Coyle VORTAC 044° radial extending from the 6.5-mile radius to the VORTAC, excluding the portions that coincide with the Atlantic City, NJ, Princeton, NJ. Old Bridge NJ, Philadelphia, PA, Class E airspace areas.

Issued in College Park, Georgia, on September 9, 2011.

Mark D. Ward,

Manager, Operations Support Group, Eastern Service Center, Air Traffic Organization.

[FR Doc. 2011–24348 Filed 9–21–11; 8:45 am]

BILLING CODE 4910–13–P

FEDERAL TRADE COMMISSION

16 CFR Part 310

Telemarketing Sales Rule

AGENCY: Federal Trade Commission.

ACTION: Correcting amendments.

SUMMARY: The Federal Trade Commission published a final amended Telemarketing Sales Rule in the **Federal Register** on August 10, 2010 (75 FR 48458), with new provisions to address the telemarketing of debt relief services. This document makes technical corrections in that final rule.

DATES: Effective on September 22, 2011.

FOR FURTHER INFORMATION CONTACT: Karen S. Hobbs, Attorney, Division of Marketing Practices, Bureau of Consumer Protection, Federal Trade Commission, Washington, DC 20580, (202) 326–3587.

SUPPLEMENTARY INFORMATION: This document makes technical corrections in the Telemarketing Sales Rule.

List of Subjects in 16 CFR Part 310

Telemarketing, Trade practices.

Accordingly, 16 CFR part 310 is corrected by making the following correcting amendments:

PART 310—TELEMARKETING SALES RULE

■ 1. The authority citation for part 310 continues to read as follows:

Authority: 15 U.S.C. 6101–6108.

§ 310.4 [Amended]

■ 2. In § 310.4:

■ a. Amend the last sentence of paragraph (a)(7) by removing ''(a)(6)(i)'' and adding in its place ''(a)(7)(i)''.

■ b. Amend paragraph (a)(7)(i)(B) by removing ''(a)(6)(i)(A)'' and adding in its place ''(a)(7)(i)(A)''.

■ c. Amend the introductory text of paragraph (a)(7)(ii) by removing ''(a)(6)(i)'' and adding in its place ''(a)(7)(i)''.

■ d. Amend paragraph (a)(7)(ii)(B) by removing ''(a)(6)(ii)(A)'' and adding in its place A(a)(7)(ii)(A)''.

By direction of the Commission.

Donald S. Clark,

Secretary.

[FR Doc. 2011–24361 Filed 9–21–11; 8:45 am]

BILLING CODE 6750–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 40

[Docket No. RM10–6–000; Order No. 754]

Interpretation of Transmission Planning Reliability Standard

AGENCY: Federal Energy Regulatory Commission, Energy.

ACTION: Final rule.

SUMMARY: On November 17, 2009, the North American Electric Reliability Corporation (NERC) submitted a petition requesting approval of NERC's interpretation of Requirement R1.3.10 of Commission-approved transmission planning Reliability Standard TPL–002–0 (System Performance Following Loss of a Single Bulk Electric System Element). In a March 2010 Notice of Proposed Rulemaking (NOPR), the Commission proposed to reject NERC's proposed interpretation, and instead proposed an alternative interpretation of Requirement R1.3.10 of Reliability Standard TPL–002–0. As a result of the comments received in response to the proposal, the Commission declines to adopt the NOPR proposal and approves NERC's proposed interpretation. In addition, as proposed by several commenters, the Commission directs NERC and Commission staff to initiate a process to identify any reliability issues, as discussed below.

DATES: *Effective Date:* This rule will become effective October 24, 2011.

FOR FURTHER INFORMATION CONTACT:

Ron LeComte (Legal Information), Office of General Counsel, 888 First Street, NE., Washington, DC 20426. *ron.lecomte@ferc.gov.*

Eugene Blick (Technical Information), Office of Electric Reliability, 888 First Street, NE., Washington, DC 20426. *eugene.blick@ferc.gov.*

Lauren Rosenblatt (Legal Information), Office of Enforcement, 888 First Street, NE., Washington, DC 20426. *lauren.rosenblatt@ferc.gov.*

SUPPLEMENTARY INFORMATION: 136 FERC ¶ 61,186

Before Commissioners: Jon Wellinghoff, Chairman; Marc Spitzer, Philip D. Moeller, John R. Norris, and Cheryl A. LaFleur.

Issued September 15, 2011

1. On November 17, 2009, the North American Electric Reliability Corporation (NERC) submitted a petition requesting approval of NERC's interpretation of Requirement R1.3.10 of Commission-approved transmission planning Reliability Standard TPL–002–0 (System Performance Following Loss of a Single Bulk Electric System Element). In a March 2010 Notice of Proposed Rulemaking (NOPR),[1] the Commission proposed to reject NERC's proposed interpretation, and instead proposed an alternative interpretation of Requirement R1.3.10 of Reliability Standard TPL–002–0. As a result of the comments received in response to the proposal, the Commission declines to adopt the NOPR proposal and approves NERC's proposed interpretation of Requirement R1.3.10 of Reliability Standard TPL–002–0. In addition, as proposed by several commenters, the Commission directs NERC and Commission staff to initiate a process to identify any reliability issues, as discussed below.

I. Background

2. Section 215 of the Federal Power Act (FPA) requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval.[2] Specifically, the Commission may approve, by rule or order, a proposed Reliability Standard or modification to a Reliability Standard if it determines that the Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[3] Once approved, the Reliability Standards may be enforced by the ERO, subject to Commission oversight, or by the Commission independently.[4]

[1] *Interpretation of Transmission Planning Reliability Standards,* 75 FR 14386 (March 25, 2010), FERC Stats. & Regs. ¶ 32,655 (2010).

[2] 16 U.S.C. 824 (2006).

[3] *Id.* 824o(d)(2).

[4] *Id.* 824o(e)(3).

3. Pursuant to section 215 of the FPA, the Commission established a process to select and certify an ERO,[5] and subsequently certified NERC.[6] On April 4, 2006, NERC submitted to the Commission a petition seeking approval of 107 proposed Reliability Standards. On March 16, 2007, the Commission issued a final rule, Order No. 693,[7] approving 83 of the 107 Reliability Standards, including transmission planning Reliability Standards TPL–001–0 through TPL–004–0. In addition, pursuant to section 215(d)(5) of the FPA,[8] the Commission directed NERC to develop modifications to 56 of the 83 approved Reliability Standards, including TPL–002–0.[9]

4. NERC's Rules of Procedure provide that a person that is ''directly and materially affected'' by Bulk-Power System reliability may request an interpretation of a Reliability Standard.[10] In response, the ERO will assemble a team with relevant expertise to address the requested interpretation and also form a ballot pool. NERC's Rules of Procedure provide that, within 45 days, the team will draft an interpretation of the reliability standard and submit it to the ballot pool. If approved by the ballot pool and subsequently by the NERC Board of Trustees, the interpretation is appended to the Reliability Standard and filed with the applicable regulatory authorities for approval.

II. Transmission Planning Reliability Standards

5. Each of the TPL Reliability Standards, TPL–001–0 through TPL–004–0, requires the planning authorities and transmission planners (planner) to provide a ''valid assessment'' that would ''ensure that reliable systems are developed that meet specified performance requirements'' both in the near-term (years one through five) and in the longer-term (years six through ten, or as needed). For each of these TPL Reliability Standards, entities must adequately assess a range of operating conditions on their systems and plan to meet certain performance criteria that the TPL Reliability Standards specify for each of four classes of contingencies.[11] The principles that planners must apply to the design of the assessment and of the supporting studies are set forth in the Requirements of the specific TPL Reliability Standard.

6. Table I, which is incorporated into each of the TPL Reliability Standards, sets forth the different types of contingencies that planners must study in conjunction with critical system conditions. The performance that must be met before and after experiencing those contingencies is also defined in the Table I, including reliably meeting all projected customer demand and firm transfers for Category B contingencies.

7. Requirement R1 of Reliability Standard TPL–002–0 states:

> R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B.[12] To be valid, the Planning Authority and Transmission Planner assessments shall: * * *.

8. Requirement R1 proceeds with sub-Requirements R1.1 through R1.5, which provide the criteria that must be met to qualify the assessment directed by Requirement R1 as valid. In particular, Requirement R1.3 mandates that the assessment shall

> [b]e supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B. The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

Further, Requirement R1.3.10 requires the planner to

> [i]nclude the effects of existing and planned protection systems, including any backup or redundant systems.

III. NERC Proposed Interpretation

9. In the NERC Petition, NERC explained that it received a request from PacifiCorp for an interpretation of Reliability Standard TPL–002–0, Requirement R1.3.10, addressing three specific questions. The PacifiCorp questions and NERC interpretations were as follows:

Question 1: Does TPL–002–0 R1.3.10 require that all elements that are expected to be removed from service through normal operation of the protection systems be removed in simulations?

Response 1: TPL–002–0 requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL–002–0, R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations.

Question 2: Is a Category B disturbance limited to faults with [N]ormal [C]learing where the protection system operates as designed in the time expected with proper functioning of the protection system(s) or do Category B disturbances extend to protection system misoperations and failures?

Response 2: This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL–003–0—System Performance following Loss of Two or More Bulk Electric System Elements (Category C) and TPL–004–0—System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System (BES) Elements (Category D).

Question 3: Does TPL–002–0, R1.3.10 require that planning for Category B [C]ontingencies assume a [C]ontingency that results in something other than a [N]ormal [C]learing event even though the TPL–002–0 Table I—Category B matrix uses the phrase ''SLG or 3-Phase Fault, with Normal Clearing?''

Response 3: TPL–002–0, R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.[13]

10. In support of its request for approval, NERC stated that the proposed interpretation directly supports the reliability purpose of TPL–002–0 because it clarifies what is required for the ''System simulations'' cited in the main requirement without expanding

[5] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards,* Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g,* Order No. 672–A, FERC Stats. & Regs. ¶ 31,212 (2006).

[6] *North American Electric Reliability Corp.,* 116 FERC ¶ 61,062, *order on reh'g & compliance,* 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc.* v. *FERC,* 564 F.3d 1342 (DC Cir. 2009).

[7] *Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g,* Order No. 693–A, 120 FERC ¶ 61,053 (2007).

[8] 16 U.S.C. 824o(d)(5).

[9] Order No. 693, FERC Stats & Regs. ¶ 31,242 at P 1797.

[10] NERC Rules of Procedure, Appendix 3A, Reliability Standards Development Procedure, Version 6.1, at 27–29 (2010).

[11] Reliability Standards TPL–001–0 through TPL–004–0 each includes the same Table I, titled ''Transmission System Standards—Normal and Emergency Conditions,'' which identifies the classes of contingencies as Category A through Category D. Reliability Standard TPL–002–0 addresses Category B contingencies.

[12] Category B contingencies are defined in Table I of the Reliability Standard.

[13] NERC Petition at 10. In support for its request for an interpretation, PacifiCorp states that ''[i]f TPL–002–0, R1.3.10 requires that planning for Category B Contingencies must assume failure or misoperation of all existing and planned protection systems, protection system failures previously identified as Category C [Ø] Contingencies or Category D [Ø] Contingencies would now become Category B Contingencies * * *.'' *Id.* at Appendix A at 1–2.

the reach of the standard.[14] NERC maintained that the proposed interpretation clearly identifies what needs to be done—that all elements expected to be removed from service through normal operation of the protection system must be removed in simulations and that only normal clearing is required in the simulations. NERC stated that the proposed interpretation clearly distinguishes that misoperations and failures of the protection system are not part of Reliability Standard TPL–002–0, but are addressed in other standards. NERC stated that the interpretation will result in ensuring that an adequate level of reliability for the Bulk-Power System will be achieved and maintained by providing clarity and certainty in support of the objective.

IV. Commission NOPR

11. The Commission proposed to reject NERC's proposed interpretation and proposed an alternative interpretation. The Commission's proposed interpretation would have required modeling of the non-operation of non-redundant primary protection systems to be in compliance with Requirement R1.3.10 of Reliability Standard TPL–002–0. In the NOPR, the Commission stated that a planner would perform an assessment of its portion of the interconnected transmission system through computer modeling and simulations, in which the planner first creates base cases. Using these base cases as a starting point, the planner then assesses the performance of the system and tests the base cases by subjecting them to various Category B Contingencies outlined in Table I with normal clearing. The Commission's proposed interpretation would have found that Requirement R1.3.10 of TPL–002–0 requires planners to study, in their system assessments, the non-operation of non-redundant primary protection systems in order to ascertain whether and how reliance on the as-designed backup or redundant protection systems affects reliability.[15]

12. The Commission proposed that its interpretation of R1.3.10 of Reliability Standard TPL–002–0 would apply prospectively from the effective date of any Final Rule and no entity will be subject to financial penalties for having operated in a manner inconsistent with this proposed interpretation prior to the effective date of any Final Rule.

V. Comments

13. Twenty-seven entities provided comments on the Commission's proposed interpretation.[16] Almost uniformly, comments support NERC's proposed interpretation.[17] In general, commenters [18] state that the non-operation of a primary protection system is not studied under TPL–002–0, but rather under TPL–003–0 and TPL–004–0 as an unplanned event with delayed clearing.[19] Commenters contend that only planned protection system outages (maintenance outages) should be addressed under TPL–002–0.[20] In addition, commenters assert that the Commission's interpretation would require the installation of fully redundant protection systems at an estimated cost of $24 billion and require significant construction efforts spanning 10 to 20 years.[21] Commenters contend that TPL–002–0 relates to Normal Clearing and not Delayed Clearing in which a protection system failure has occurred or fails to operate.

14. NERC explains that the pre-2007 voluntary transmission planning standard was broken into four mandatory Version 0 Standards linked by the performance categories of Table I. Thus, according to NERC, some continuity was lost and, as a result, sub-requirements such as Requirement R1.3.10 that appear in TPL–002–0 through TPL–004–0 have very limited applicability in the context of TPL–002–0. NERC explains that Requirement R1.3.10 of TPL–002–0 is a valid requirement for judging system performance, but only in those cases where the system is being studied to determine its ability to perform when a given primary protection system or one of its components is out of service for maintenance (Requirement R1.3.12).

A. Supplemental Comments

15. The Trade Associations submitted supplemental comments, with additional comments in support filed by NERC. The Trade Associations reiterate their request that the Commission approve, without change, NERC's proposed interpretation of Reliability Standard TPL–002–0 Requirement R1.3.10. The Trade Associations also state that, based on outreach meetings with Commission staff, there may be a system protection issue that merits further exploration by technical experts. Thus, the Trade Associations suggest that the Commission take the following two actions. First, instruct Commission Reliability Staff to meet with NERC and its appropriate subject matter experts to: (a) Explore Staff's concerns and identify whether there is a further system protection issue warranting additional actions, and (b) if so, define the issue's scope and assess its importance. The Trade Associations state such exchange of views among technical experts would be intended to facilitate the subject matter experts' ability to recommend appropriate actions within NERC. Second, direct NERC to submit an informational filing within six months to explain its view as to whether there is a further system protection issue that needs to be addressed and if so, what forum and process should be used to address that issue and what priority it should be accorded relative to other reliability initiatives planned by NERC.[22]

16. NERC supports the Trade Associations' proposal to give NERC, Commission staff, and technical experts the opportunity to further examine whether there may be a potential system protection issue that needs to be addressed. NERC states that it would make an informational filing with the Commission regarding whether there is a further system protection issue that needs to be addressed and if so, what forum and process should be used to address that issue and what priority it should be accorded relative to other reliability initiatives planned by NERC.

[14] *Id.* at 11.

[15] *Interpretation of Transmission Planning Reliability Standards,* FERC Stats. & Regs. ¶ 32,655, at P 15 (2010).

[16] A list of commenters is provided in Appendix 1.

[17] Commenters including NERC, Trade Associations (Edison Electric Institute, American Public Power Association, National Rural Electric Cooperative Association, Electric Power Supply Association, Transmission Access Policy Study Group, and Canadian Electricity Association), Florida Reliability Coordinating Council and others indicate support for NERC's interpretation of Requirement R1.3.10 of TPL–002–0. In contrast, the International Transmission Companies (ITC) commented that the Commission's proposal ''establishes an additional level of good utility practice'' and ''is a reasonable and rational approach to evaluate system consequences, under Requirement R1.3.10 of TPL–002–0, regarding element outages and clearing times associated with non-operation of the primary protection system.'' However, given the corrective actions that would be required to comply with the Commission's proposal, ITC requests that the Commission allow an appropriate amount of time for compliance.

[18] *See, e.g.,* NERC comments at 7–8; Trade Association Comments at 19–23.

[19] Planned outages are modeled as one of the base case conditions (categories) and studied to achieve the performance requirements of Category B (single contingencies), Table I. Protection system failures are addressed by performance requirements of Category C (two or more contingencies) and misoperations are addressed by Category D (extreme events).

[20] Requirement R.1.3.12 of TPL–002–0 requires the planner to consider the planned (including maintenance) outage of protection systems at demand levels for which such outages are performed.

[21] *See* Trade Associations comments at 31–34.

[22] Trade Associations Supplemental Comments at 3 (footnote omitted).

17. NERC requests that the Commission approve the proposed interpretation of Reliability Standard TPL–002–0 Requirement R1.3.10, as filed.

VI. Discussion

18. In the NOPR, the Commission proposed to find that Reliability Standard TPL–002–0, Requirement R1.3.10 requires the study of the non-operation of non-redundant primary protection systems. Based on the comments received, the Commission accepts NERC's interpretation of TPL–002–0, Requirement R1.3.10, that finds that the requirement does not require the study of non-operation of non-redundant primary protection systems. Because we find NERC's proposed interpretation to be just and reasonable, we, therefore, decline to adopt the NOPR proposal.

19. We agree with the Trade Associations that there may be a system protection issue that merits further exploration by technical experts. The comments received in response to the Commission's NOPR and Commission staff outreach discussions indicate that there may have been a misunderstanding that the Commission's proposed interpretation would have established a full redundancy requirement for all primary protection systems. The Commission clarifies that it did not intend to require full redundancy. Rather, the Commission believes that there is an issue concerning the study of the non-operation of non-redundant primary protection systems; *e.g.,* the study of a single point of failure on protection systems. The Commission agrees with commenters that this issue does not have to be addressed in TPL–002–0, Requirement R1.3.10.

20. Accordingly, consistent with the supplemental comments of the Trade Associations, we direct Commission staff to meet with NERC and its appropriate subject matter experts to explore this reliability concern, including where it can best be addressed, and identify any additional actions necessary to address the matter. Further, we direct NERC to make an informational filing within six months of the date of the issuance of this Final Rule explaining whether there is a further system protection issue that needs to be addressed and, if so, what forum and process should be used to address that issue and what priority it should be accorded relative to other reliability initiatives planned by NERC.[23]

VII. Information Collection Statement

21. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping (collections of information) imposed by an agency.[24] The information contained here is also subject to review under section 3507(d) of the Paperwork Reduction Act of 1995.[25]

22. As stated above, the Commission previously approved, in Order No. 693, the Reliability Standard that is the subject of the current Final Rule. This Final Rule accepts an interpretation of the currently approved Reliability Standard and does not change this standard. The interpretation of the current Reliability Standard at issue in this final rule is not expected to change the reporting burden or the information collection requirements. The informational filing required of NERC is part of currently active collection FERC–725 and does not require additional approval by OMB.[26]

23. We will submit this final rule to OMB for informational purposes only.

24. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426 [*Attention:* Ellen Brown, Office of the Executive Director, *e-mail: data.clearance@ferc.gov, phone:* (202) 502–8663, or fax: (202) 273–0873].

VIII. Environmental Analysis

25. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[27] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[28] The actions proposed herein fall within this categorical exclusion in the Commission's regulations.

IX. Regulatory Flexibility Act

26. The Regulatory Flexibility Act of 1980 (RFA)[29] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a proposed rule and that minimize any significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[30] The SBA has established a size standard for electric utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million megawatt hours.[31] The RFA is not implicated by this Final Rule because the interpretation accepted herein does not modify the existing burden or reporting requirements. With no changes to the Reliability Standard as approved, the Commission certifies that this Final Rule will not have a significant economic impact on a substantial number of small entities.

X. Document Availability

27. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (*http://www.ferc.gov*) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington DC 20426.

28. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

29. User assistance is available for eLibrary and the FERC's Web site during normal business hours from FERC Online Support at (202) 502–6652 (toll free at 1–866–208–3676) or e-mail at

[23] This filing requirement has been approved by the Office of Management and Budget under FERC–725, OMB Control No. 1902–0225. This filing does not change the existing burden or reporting requirements imposed on NERC under FERC–725.

[24] 5 CFR 1320.11.

[25] 44 U.S.C. 3507(d).

[26] *See supra* n. 23.

[27] *Regulations Implementing the National Environmental Policy Act of 1969,* Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987).

[28] 18 CFR 380.4(a)(2)(ii).

[29] 5 U.S.C. 601–612.

[30] 13 CFR 121.201.

[31] *Id.* n. 1.

ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659. E-mail the Public Reference Room at *public.referenceroom@ferc.gov.*

XI. Effective Date and Congressional Notification

30. This final rule is effective 30 days from publication in **Federal Register**. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB that this rule is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

List of Subjects in 18 CFR Part 40

Applicability, Mandatory reliability standards.

By the Commission.

Kimberly D. Bose,

Secretary.

Note: The following appendix will not appear in the Code of Federal Regulations.

Appendix 1

List of Commenters

American Transmission Company LLC
Avista Corporation
Black Hills Power, Inc.
Bonneville Power Administration
Constellation Energy Group, Inc.[32]
Department of Interior, Office of Environmental Policy and Compliance
Entergy Services, Inc.
Exelon Corporation
Florida Reliability Coordinating Council
Independent Electricity System Operator and Hydro One Networks
International Transmission Company[33]
ISO/RTO Council
Kansas City Power & Light Company, KCP&L Greater Missouri Operations Company
Manitoba Hydro
Modesto Irrigation District
National Grid
New England States Committee on Electricity
North American Electric Reliability Corporation
Pacific Gas and Electric Company
Public Power Council[34]
Reliability First Corporation
San Diego Gas & Electric Company
Southern Company Services, Inc.[35]
Trade Associations[36]
Tampa Electric Company
Virginia Electric and Power Company, doing business as Dominion Virginia Power
Wisconsin Electric Power Company

[32] Baltimore Gas & Electric Company, Constellation Energy Commodities Group, Inc., Constellation Energy Control and Dispatch, LLC, Constellation NewEnergy, Inc., and Constellation Power Source Generation, Inc., and Constellation Energy Nuclear Group, LLC.

[33] *ITCTransmission,* Michigan Electric Transmission Company, LLC, ITC Midwest LLC, and ITC Great Plains, LLC.

[34] Public Power Council includes Washington Rural Electric Cooperative Association, Idaho Consumer-Owned Utilities Association, Oregon PUD Association, Northwest Public Power Association, Oregon Rural Electric Cooperative Association, PNGC Power, Western Public Agencies Group, Western Montana Electric G&T Cooperative, Inc., Oregon Municipal Electric Utilities Association, Washington PUD Association, Northwest Requirements Utilities.

[35] Alabama Power Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company.

[36] The Trade Association includes the Edison Electric Institute, the American Public Power Association, Canadian Electricity Association, the National Rural Electric Cooperative Association, the Transmission Access Policy Study Group, and the Electric Power Supply Association.

[FR Doc. 2011–24408 Filed 9–21–11; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 660

[Docket No. 0912281446–0111–02]

RIN 0648–XA709

Fisheries Off West Coast States; Coastal Pelagic Species Fisheries; Closure

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Temporary rule; closure.

SUMMARY: NMFS is prohibiting directed fishing for Pacific sardine off the coasts of Washington, Oregon and California. This action is necessary because the directed harvest allocation total for the third seasonal period (September 15–December 31) is projected to be reached by the effective date of this rule. From the effective date of this rule until January 1, 2012, Pacific sardine may be harvested only as part of the live bait fishery or incidental to other fisheries; the incidental harvest of Pacific sardine is limited to 30-percent by weight of all fish per trip. Fishing vessels must be at shore and in the process of offloading at 12:01 a.m. Pacific Daylight Time, on the date of closure.

DATES: Effective 12:01 a.m. Pacific Daylight Time Wednesday, September 21, 2011, through 11:59 p.m. Pacific Standard Time, December 31, 2011.

FOR FURTHER INFORMATION CONTACT: Joshua Lindsay, Southwest Region, NMFS, (562) 980–4034.

SUPPLEMENTARY INFORMATION: This document announces that based on the best available information recently obtained from the fishery and information on past effort, the directed fishing harvest allocation for the third allocation period (September 15–December 31) will be reached and therefore directed fishing for Pacific sardine is being closed until January 1, 2012. Fishing vessels must be at shore and in the process of offloading at the time of closure. From 12:01 am on the date of closure through December 31, 2011, Pacific sardine may be harvested only as part of the live bait fishery or incidental to other fisheries, with the incidental harvest of Pacific sardine limited to 30-percent by weight of all fish caught during a trip.

NMFS manages the Pacific sardine fishery in the U.S. exclusive economic zone (EEZ) off the Pacific coast (California, Oregon, and Washington) in accordance with the Coastal Pelagic Species (CPS) Fishery Management Plan (FMP). Annual specifications published in the **Federal Register** establish the harvest guideline (HG) and allowable harvest levels for each Pacific sardine fishing season (January 1–December 31). If during any of the seasonal allocation periods the applicable adjusted directed harvest allocation is projected to be taken only incidental harvest is allowed, and for the remainder of the period, any incidental Pacific sardine landings will be counted against that period's incidental set aside. In the event that an incidental set-aside is projected to be attained, all fisheries will be closed to the retention of Pacific sardine for the remainder of the period via appropriate rulemaking.

Under 50 CFR 660.509, if the total HG or these apportionment levels for Pacific sardine are reached at any time, NMFS is required to close the Pacific sardine fishery via appropriate rulemaking and keep it closed until it re-opens either per the allocation scheme or the beginning of the next fishing season. In accordance with section 660.509, the Regional Administrator shall publish a notice in the **Federal Register** announcing the date of the closure of the directed fishery for Pacific sardine.

The above in-season harvest restrictions are not intended to affect the prosecution of the live bait portion of the Pacific sardine fishery.

Classification

This action is required by 50 CFR 660.509 and is exempt from Office of Management and Budget review under Executive Order 12866.

NMFS finds good cause to waive the requirement to provide prior notice and opportunity for public comment pursuant to the authority set forth at 5 U.S.C. 553(b)(B) for the closure of the directed harvest of Pacific sardine. For

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136 FERC ¶ 61,186
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM10-6-000; Order No. 754]

Interpretation of Transmission Planning Reliability Standard

(Issued September 15, 2011)

AGENCY: Federal Energy Regulatory Commission

ACTION: Final Rule.

SUMMARY: On November 17, 2009, the North American Electric Reliability Corporation (NERC) submitted a petition requesting approval of NERC's interpretation of Requirement R1.3.10 of Commission-approved transmission planning Reliability Standard TPL-002-0 (System Performance Following Loss of a Single Bulk Electric System Element). In a March 2010 Notice of Proposed Rulemaking (NOPR), the Commission proposed to reject NERC's proposed interpretation, and instead proposed an alternative interpretation of Requirement R1.3.10 of Reliability Standard TPL-002-0. As a result of the comments received in response to the proposal, the Commission declines to adopt the NOPR proposal and approves NERC's proposed interpretation. In addition, as proposed by several commenters, the Commission directs NERC and Commission staff to initiate a process to identify any reliability issues, as discussed below.

EFFECTIVE DATE: This rule will become effective 30 days after publication in the FEDERAL REGISTER.

FOR FURTHER INFORMATION CONTACT:

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ron.lecomte@ferc.gov

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Washington, DC 20426
lauren.rosenblatt@ferc.gov

SUPPLEMENTARY INFORMATION:

20110915-3057 FERC PDF (Unofficial) 09/15/2011

136 FERC ¶ 61,186
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Marc Spitzer, Philip D. Moeller,
John R. Norris, and Cheryl A. LaFleur.

Interpretation of Transmission Planning Reliability Standard — Docket No. RM10-6-000

ORDER NO. 754

FINAL RULE

(Issued September 15, 2011)

1. On November 17, 2009, the North American Electric Reliability Corporation (NERC) submitted a petition requesting approval of NERC's interpretation of Requirement R1.3.10 of Commission-approved transmission planning Reliability Standard TPL-002-0 (System Performance Following Loss of a Single Bulk Electric System Element). In a March 2010 Notice of Proposed Rulemaking (NOPR),[1] the Commission proposed to reject NERC's proposed interpretation, and instead proposed an alternative interpretation of Requirement R1.3.10 of Reliability Standard TPL-002-0. As a result of the comments received in response to the proposal, the Commission declines to adopt the NOPR proposal and approves NERC's proposed interpretation of Requirement R1.3.10 of Reliability Standard TPL-002-0. In addition, as proposed by

[1] *Interpretation of Transmission Planning Reliability Standards*, 75 FR 14386 (March 25, 2010), FERC Stats. & Regs. ¶ 32,655 (2010).

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several commenters, the Commission directs NERC and Commission staff to initiate a process to identify any reliability issues, as discussed below.

I. Background

2. Section 215 of the Federal Power Act (FPA) requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval.[2] Specifically, the Commission may approve, by rule or order, a proposed Reliability Standard or modification to a Reliability Standard if it determines that the Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[3] Once approved, the Reliability Standards may be enforced by the ERO, subject to Commission oversight, or by the Commission independently.[4]

3. Pursuant to section 215 of the FPA, the Commission established a process to select and certify an ERO,[5] and subsequently certified NERC.[6] On April 4, 2006, NERC

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[2] 16 U.S.C. 824 (2006).

[3] *Id.* 824o(d)(2).

[4] *Id*. 824o(e)(3).

[5] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[6] *North American Electric Reliability Corp*., 116 FERC ¶ 61,062, *order on reh'g & compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

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submitted to the Commission a petition seeking approval of 107 proposed Reliability Standards. On March 16, 2007, the Commission issued a final rule, Order No. 693,[7] approving 83 of the 107 Reliability Standards, including transmission planning Reliability Standards TPL-001-0 through TPL-004-0. In addition, pursuant to section 215(d)(5) of the FPA,[8] the Commission directed NERC to develop modifications to 56 of the 83 approved Reliability Standards, including TPL-002-0.[9]

4. NERC's Rules of Procedure provide that a person that is "directly and materially affected" by Bulk-Power System reliability may request an interpretation of a Reliability Standard.[10] In response, the ERO will assemble a team with relevant expertise to address the requested interpretation and also form a ballot pool. NERC's Rules of Procedure provide that, within 45 days, the team will draft an interpretation of the reliability standard and submit it to the ballot pool. If approved by the ballot pool and subsequently by the NERC Board of Trustees, the interpretation is appended to the Reliability Standard and filed with the applicable regulatory authorities for approval.

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[7] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[8] 16 U.S.C. 824o(d)(5).

[9] Order No. 693, FERC Stats & Regs. ¶ 31,242 at P 1797.

[10] NERC Rules of Procedure, Appendix 3A, Reliability Standards Development Procedure, Version 6.1, at 27-29 (2010).

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II. Transmission Planning Reliability Standards

5. Each of the TPL Reliability Standards, TPL-001-0 through TPL-004-0, requires the planning authorities and transmission planners (planner) to provide a "valid assessment" that would "ensure that reliable systems are developed that meet specified performance requirements" both in the near-term (years one through five) and in the longer-term (years six through ten, or as needed). For each of these TPL Reliability Standards, entities must adequately assess a range of operating conditions on their systems and plan to meet certain performance criteria that the TPL Reliability Standards specify for each of four classes of contingencies.[11] The principles that planners must apply to the design of the assessment and of the supporting studies are set forth in the Requirements of the specific TPL Reliability Standard.

6. Table I, which is incorporated into each of the TPL Reliability Standards, sets forth the different types of contingencies that planners must study in conjunction with critical system conditions. The performance that must be met before and after experiencing those contingencies is also defined in the Table I, including reliably meeting all projected customer demand and firm transfers for Category B contingencies.

[11] Reliability Standards TPL-001-0 through TPL-004-0 each includes the same Table I, titled "Transmission System Standards – Normal and Emergency Conditions," which identifies the classes of contingencies as Category A through Category D. Reliability Standard TPL-002-0 addresses Category B contingencies.

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7. Requirement R1 of Reliability Standard TPL-002-0 states:

> R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B.[[12]] To be valid, the Planning Authority and Transmission Planner assessments shall: ….

8. Requirement R1 proceeds with sub-Requirements R1.1 through R1.5, which provide the criteria that must be met to qualify the assessment directed by Requirement R1 as valid. In particular, Requirement R1.3 mandates that the assessment shall

> [b]e supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B. The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

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[12] Category B contingencies are defined in Table I of the Reliability Standard.

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Further, Requirement R1.3.10 requires the planner to

> [i]nclude the effects of existing and planned protection systems, including any backup or redundant systems.

III. NERC Proposed Interpretation

9. In the NERC Petition, NERC explained that it received a request from PacifiCorp for an interpretation of Reliability Standard TPL-002-0, Requirement R1.3.10, addressing three specific questions. The PacifiCorp questions and NERC interpretations were as follows:

> Question 1: Does TPL-002-0 R1.3.10 require that all elements that are expected to be removed from service through normal operation of the protection systems be removed in simulations?
>
> Response 1: TPL-002-0 requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0, R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations.
>
> Question 2: Is a Category B disturbance limited to faults with [N]ormal [C]learing where the protection system operates as designed in the time expected with proper functioning of the protection system(s) or do Category B disturbances extend to protection system misoperations and failures?

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Response 2: This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System (BES) Elements (Category D).

Question 3: Does TPL-002-0, R1.3.10 require that planning for Category B [C]ontingencies assume a [C]ontingency that results in something other than a [N]ormal [C]learing event even though the TPL-002-0 Table I - Category B matrix uses the phrase "SLG or 3-Phase Fault, with Normal Clearing?"

Response 3: TPL-002-0, R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.[13]

[13] NERC Petition at 10. In support for its request for an interpretation, PacifiCorp states that "[i]f TPL-002-0, R1.3.10 requires that planning for Category B Contingencies must assume failure or misoperation of all existing and planned protection systems, protection system failures previously identified as Category C [] Contingencies or Category D [] Contingencies would now become Category B Contingencies ...." *Id.* at Appendix A at 1-2.

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10. In support of its request for approval, NERC stated that the proposed interpretation directly supports the reliability purpose of TPL-002-0 because it clarifies what is required for the "System simulations" cited in the main requirement without expanding the reach of the standard.[14] NERC maintained that the proposed interpretation clearly identifies what needs to be done – that all elements expected to be removed from service through normal operation of the protection system must be removed in simulations and that only normal clearing is required in the simulations. NERC stated that the proposed interpretation clearly distinguishes that misoperations and failures of the protection system are not part of Reliability Standard TPL-002-0, but are addressed in other standards. NERC stated that the interpretation will result in ensuring that an adequate level of reliability for the Bulk-Power System will be achieved and maintained by providing clarity and certainty in support of the objective.

IV. Commission NOPR

11. The Commission proposed to reject NERC's proposed interpretation and proposed an alternative interpretation. The Commission's proposed interpretation would have required modeling of the non-operation of non-redundant primary protection systems to be in compliance with Requirement R1.3.10 of Reliability Standard TPL-002-0. In the NOPR, the Commission stated that a planner would perform an assessment of its portion of the interconnected transmission system through computer modeling and simulations,

[14] *Id.* at 11.

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in which the planner first creates base cases. Using these base cases as a starting point, the planner then assesses the performance of the system and tests the base cases by subjecting them to various Category B Contingencies outlined in Table I with normal clearing. The Commission's proposed interpretation would have found that Requirement R1.3.10 of TPL-002-0 requires planners to study, in their system assessments, the non-operation of non-redundant primary protection systems in order to ascertain whether and how reliance on the as-designed backup or redundant protection systems affects reliability.[15]

12. The Commission proposed that its interpretation of R1.3.10 of Reliability Standard TPL-002-0 would apply prospectively from the effective date of any Final Rule and no entity will be subject to financial penalties for having operated in a manner inconsistent with this proposed interpretation prior to the effective date of any Final Rule.

V. Comments

13. Twenty-seven entities provided comments on the Commission's proposed interpretation.[16] Almost uniformly, comments support NERC's proposed interpretation.[17]

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[15] *Interpretation of Transmission Planning Reliability Standards*, FERC Stats. & Regs. ¶ 32,655, at P 15 (2010).

[16] A list of commenters is provided in Appendix 1.

[17] Commenters including NERC, Trade Associations (Edison Electric Institute, American Public Power Association, National Rural Electric Cooperative Association, Electric Power Supply Association, Transmission Access Policy Study Group, and Canadian Electricity Association), Florida Reliability Coordinating Council and others indicate support for NERC's interpretation of Requirement R1.3.10 of TPL-002-0. In contrast, the International Transmission Companies (ITC) commented that the

(continued…)

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In general, commenters[18] state that the non-operation of a primary protection system is not studied under TPL-002-0, but rather under TPL-003-0 and TPL-004-0 as an unplanned event with delayed clearing.[19] Commenters contend that only planned protection system outages (maintenance outages) should be addressed under TPL-002-0.[20] In addition, commenters assert that the Commission's interpretation would require the installation of fully redundant protection systems at an estimated cost of $24 billion and require significant construction efforts spanning 10 to 20 years.[21] Commenters contend that TPL-002-0 relates to Normal Clearing and not Delayed Clearing in which a protection system failure has occurred or fails to operate.

Commission's proposal "establishes an additional level of good utility practice" and "is a reasonable and rational approach to evaluate system consequences, under Requirement R1.3.10 of TPL-002-0, regarding element outages and clearing times associated with non-operation of the primary protection system." However, given the corrective actions that would be required to comply with the Commission's proposal, ITC requests that the Commission allow an appropriate amount of time for compliance.

[18] *See*, *e.g.*, NERC comments at 7-8; Trade Association Comments at 19-23.

[19] Planned outages are modeled as one of the base case conditions (categories) and studied to achieve the performance requirements of Category B (single contingencies), Table I. Protection system failures are addressed by performance requirements of Category C (two or more contingencies) and misoperations are addressed by Category D (extreme events).

[20] Requirement R.1.3.12 of TPL-002-0 requires the planner to consider the planned (including maintenance) outage of protection systems at demand levels for which such outages are performed.

[21] *See* Trade Associations comments at 31-34.

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14. NERC explains that the pre-2007 voluntary transmission planning standard was broken into four mandatory Version 0 Standards linked by the performance categories of Table I. Thus, according to NERC, some continuity was lost and, as a result, sub-requirements such as Requirement R1.3.10 that appear in TPL-002-0 through TPL-004-0 have very limited applicability in the context of TPL-002-0. NERC explains that Requirement R1.3.10 of TPL-002-0 is a valid requirement for judging system performance, but only in those cases where the system is being studied to determine its ability to perform when a given primary protection system or one of its components is out of service for maintenance (Requirement R1.3.12).

A. Supplemental Comments

15. The Trade Associations submitted supplemental comments, with additional comments in support filed by NERC. The Trade Associations reiterate their request that the Commission approve, without change, NERC's proposed interpretation of Reliability Standard TPL-002-0 Requirement R1.3.10. The Trade Associations also state that, based on outreach meetings with Commission staff, there may be a system protection issue that merits further exploration by technical experts. Thus, the Trade Associations suggest that the Commission take the following two actions. First, instruct Commission Reliability Staff to meet with NERC and its appropriate subject matter experts to: (a) explore Staff's concerns and identify whether there is a further system protection issue warranting additional actions, and (b) if so, define the issue's scope and assess its importance. The Trade Associations state such exchange of views among technical experts would be intended to facilitate the subject matter experts' ability to recommend appropriate actions

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within NERC. Second, direct NERC to submit an informational filing within six months to explain its view as to whether there is a further system protection issue that needs to be addressed and if so, what forum and process should be used to address that issue and what priority it should be accorded relative to other reliability initiatives planned by NERC.[22]

16. NERC supports the Trade Associations' proposal to give NERC, Commission staff, and technical experts the opportunity to further examine whether there may be a potential system protection issue that needs to be addressed. NERC states that it would make an informational filing with the Commission regarding whether there is a further system protection issue that needs to be addressed and if so, what forum and process should be used to address that issue and what priority it should be accorded relative to other reliability initiatives planned by NERC.

17. NERC requests that the Commission approve the proposed interpretation of Reliability Standard TPL-002-0 Requirement R1.3.10, as filed.

VI. Discussion

18. In the NOPR, the Commission proposed to find that Reliability Standard TPL-002-0, Requirement R1.3.10 requires the study of the non-operation of non-redundant primary protection systems. Based on the comments received, the Commission accepts NERC's interpretation of TPL-002-0, Requirement R1.3.10, that finds that the

[22] Trade Associations Supplemental Comments at 3 (footnote omitted).

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requirement does not require the study of non-operation of non-redundant primary protection systems. Because we find NERC's proposed interpretation to be just and reasonable, we, therefore, decline to adopt the NOPR proposal.

19. We agree with the Trade Associations that there may be a system protection issue that merits further exploration by technical experts. The comments received in response to the Commission's NOPR and Commission staff outreach discussions indicate that there may have been a misunderstanding that the Commission's proposed interpretation would have established a full redundancy requirement for all primary protection systems. The Commission clarifies that it did not intend to require full redundancy. Rather, the Commission believes that there is an issue concerning the study of the non-operation of non-redundant primary protection systems; e.g., the study of a single point of failure on protection systems. The Commission agrees with commenters that this issue does not have to be addressed in TPL-002-0, Requirement R1.3.10.

20. Accordingly, consistent with the supplemental comments of the Trade Associations, we direct Commission staff to meet with NERC and its appropriate subject matter experts to explore this reliability concern, including where it can best be addressed, and identify any additional actions necessary to address the matter. Further, we direct NERC to make an informational filing within six months of the date of the issuance of this Final Rule explaining whether there is a further system protection issue that needs to be addressed and, if so, what forum and process should be used to address

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that issue and what priority it should be accorded relative to other reliability initiatives planned by NERC.[23]

VII. Information Collection Statement

21. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping (collections of information) imposed by an agency.[24] The information contained here is also subject to review under section 3507(d) of the Paperwork Reduction Act of 1995.[25]

22. As stated above, the Commission previously approved, in Order No. 693, the Reliability Standard that is the subject of the current Final Rule. This Final Rule accepts an interpretation of the currently approved Reliability Standard and does not change this standard. The interpretation of the current Reliability Standard at issue in this final rule is not expected to change the reporting burden or the information collection requirements. The informational filing required of NERC is part of currently active collection FERC-725 and does not require additional approval by OMB.[26]

23. We will submit this final rule to OMB for informational purposes only.

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[23] This filing requirement has been approved by the Office of Management and Budget under FERC-725, OMB Control No. 1902-0225. This filing does not change the existing burden or reporting requirements imposed on NERC under FERC-725.

[24] 5 CFR 1320.11.

[25] 44 U.S.C. 3507(d).

[26] *See supra* n.23.

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24. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, e-mail: data.clearance@ferc.gov, phone: (202) 502-8663, or fax: (202) 273-0873].

VIII. Environmental Analysis

25. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[27] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[28] The actions proposed herein fall within this categorical exclusion in the Commission's regulations.

IX. Regulatory Flexibility Act

26. The Regulatory Flexibility Act of 1980 (RFA)[29] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a proposed rule and that minimize any significant

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[27] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987).

[28] 18 CFR 380.4(a)(2)(ii).

[29] 5 U.S.C. 601-612.

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economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[30] The SBA has established a size standard for electric utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million megawatt hours.[31] The RFA is not implicated by this Final Rule because the interpretation accepted herein does not modify the existing burden or reporting requirements. With no changes to the Reliability Standard as approved, the Commission certifies that this Final Rule will not have a significant economic impact on a substantial number of small entities.

X. Document Availability

27. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (http://www.ferc.gov) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington DC 20426.

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[30] 13 CFR 121.201.

[31] *Id.* n.1.

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28. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

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XI. Effective Date and Congressional Notification

30. This final rule is effective 30 days from publication in Federal Register. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB that this rule is not a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

List of subjects in 18 CFR Part 40

Applicability
Mandatory Reliability Standards
Availability of Reliability Standards

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

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Appendix 1
List of Commenters

American Transmission Company LLC
Avista Corporation
Black Hills Power, Inc.
Bonneville Power Administration
Constellation Energy Group, Inc.[32]
Department of Interior, Office of Environmental Policy and Compliance
Entergy Services, Inc.
Exelon Corporation
Florida Reliability Coordinating Council
Independent Electricity System Operator and Hydro One Networks
International Transmission Company[33]
ISO/RTO Council
Kansas City Power & Light Company, KCP&L Greater Missouri Operations Company
Manitoba Hydro
Modesto Irrigation District
National Grid
New England States Committee on Electricity
North American Electric Reliability Corporation
Pacific Gas and Electric Company
Public Power Council[34]

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[32] Baltimore Gas & Electric Company, Constellation Energy Commodities Group, Inc., Constellation Energy Control and Dispatch, LLC, Constellation NewEnergy, Inc., and Constellation Power Source Generation, Inc., and Constellation Energy Nuclear Group, LLC.

[33] ITC*Transmission*, Michigan Electric Transmission Company, LLC, ITC Midwest LLC, and ITC Great Plains, LLC.

[34] Public Power Council includes Washington Rural Electric Cooperative Association, Idaho Consumer-Owned Utilities Association, Oregon PUD Association, Northwest Public Power Association, Oregon Rural Electric Cooperative Association, PNGC Power, Western Public Agencies Group, Western Montana Electric G&T Cooperative, Inc., Oregon Municipal Electric Utilities Association, Washington PUD Association, Northwest Requirements Utilities.

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List of Commenters Continued

Reliability First Corporation
San Diego Gas & Electric Company
Southern Company Services, Inc.[35]
Trade Associations[36]
Tampa Electric Company
Virginia Electric and Power Company, doing business as Dominion Virginia Power
Wisconsin Electric Power Company

[35] Alabama Power Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company.

[36] The Trade Association includes the Edison Electric Institute, the American Public Power Association, Canadian Electricity Association, the National Rural Electric Cooperative Association, the Transmission Access Policy Study Group, and the Electric Power Supply Association.

Document Content(s)

RM10-6-000.DOC.....1-21

From:	Ben Li Associates
To:	Guy V. Zito; rsc
Subject:	RE: NERC: Order No. 754 Approving Interpretation of TPL-002-0 issued following FERC Sunshine Open Meeting
Date:	Thursday, September 15, 2011 2:53:00 PM

Yes, Guy, what a pleasant no-surprise.

FERC may have succumbed to pressure or simply came to realization that the industry had a point. At any rate, the industry comments helped serve the purpose, and those long hours spent in drafting, editing and discussing draft comments in various arenas really paid off.

Ben

-----Original Message-----
From: Guy V. Zito [mailto:gzito@npcc.org]
Sent: Thursday, September 15, 2011 1:51 PM
To: rsc
Subject: Fwd: NERC: Order No. 754 Approving Interpretaion of TPL-002-0 issued following FERC Sunshine Open Meeting

FYI

Guy

Sent from my iPhone

Begin forwarded message:

From: Elizabeth Heenan <Elizabeth.Heenan@nerc.net<mailto:Elizabeth.Heenan@nerc.net>>
Date: September 15, 2011 1:41:12 PM EDT
To: reg_corresp_notif
<reg_corresp_notif@listserv.nerc.com<mailto:reg_corresp_notif@listserv.nerc.com>>
Subject: NERC: Order No. 754 Approving Interpretaion of TPL-002-0 issued following FERC Sunshine Open Meeting
Reply-To: Elizabeth Heenan <Elizabeth.Heenan@nerc.net<mailto:Elizabeth.Heenan@nerc.net>>

To NERC Management and Regional Entity Executives:

Attached please find Order No. 754 V Order Approving Interpretation of TPL-002-0 - System Performance Following Loss of a Single Bulk Electric System Element, issued today following the FERC Sunshine Open Meeting in Docket No. RM10-6-000 (Agenda Item E-4).

Thank you,

Elizabeth A. Heenan
Legal Assistant
North American Electric Reliability Corporation 1120 G Street NW Suite 990 Washington, DC 20005
Phone: (202) 393-3998
Direct: (202) 383-2634
Fax: (202) 393-3955

Y

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136 FERC ¶ 61,185
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Marc Spitzer, Philip D. Moeller,
John R. Norris, and Cheryl A. LaFleur.

Transmission Relay Loadability Reliability Standard Docket No. RM08-13-004

ORDER NO. 733-B

ORDER DENYING RECONSIDERATION AND GRANTING CLARIFICATION IN PART AND DENYING CLARIFICATION IN PART

(Issued September 15, 2011)

1. In this order, the Commission addresses requests for clarification or reconsideration of Order No. 733-A, which addressed requests for rehearing and clarification of our Final Rule on the North American Electric Reliability Corporation's (NERC) Reliability Standard PRC-023-1 regarding "relay loadability."[1] The petitioners seek further clarification of several matters that were clarified in Order No. 733-A. We address these requests substantively and, in part, grant clarification and, in part, deny requests for clarification.

2. In addition, the petitioners seek clarification or reconsideration regarding certain issues arising from the Final Rule, Order No. 733 that should have been raised at an earlier stage of this proceeding, on rehearing. These arguments are rejected as untimely requests for rehearing of Order No. 733. The petitioners also seek to augment the record by submitting expert affidavits and request that the Commission clarify or reconsider Order No. 733-A in light of the supplemented record. As discussed below, we reject the attempt to expand the record at this late stage of the proceeding. While we reject the untimely arguments and affidavits on procedural grounds, we nonetheless review these matters in a summary manner and deny the requests on substantive grounds.

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[1] *Transmission Relay Loadability Reliability Standard*, Order No. 733, 130 FERC ¶ 61,221 (2010), *order on reh'g and clarification*, Order No. 733-A, 134 FERC ¶ 61,127 (2011).

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I. Background

3. On March 18, 2010, the Commission issued Order No. 733, which approved Reliability Standard PRC-023-1 (Transmission Relay Loadability) submitted to the Commission by NERC, the Commission-certified Electric Reliability Organization (ERO) for the United States. The Reliability Standard requires transmission owners, generator owners, and distribution providers to set load-responsive phase protection relays[2] according to specific criteria in order to ensure that the relays reliably detect and protect the electric network from all fault conditions but do not limit transmission loadability[3] or inhibit system operators' ability to protect system reliability. Pursuant to section 215(d)(5) of the Federal Power Act (FPA),[4] the Commission directed the ERO to develop certain modifications to PRC-023-1 and to develop a new Reliability Standard that requires the use of protective relay systems that can differentiate between faults and stable power swings and, when necessary, phase-out relays that cannot meet this requirement.

4. On February 17, 2011, the Commission issued Order No. 733-A providing clarifications and granting rehearing, in part, and denying rehearing, in part. Among other matters addressed in the order, the Commission clarified its directives to modify PRC-023-1 to include a mandatory test for planning coordinators to use to identify which facilities below 200 kV are critical to the reliability of the bulk electric system (and therefore subject to the Standard) and to revise Attachment A to make the Standard applicable to supervisory relays. Additionally, the Commission clarified a directive requiring NERC to develop a new Reliability Standard addressing stable power swings by requiring the use of protective relays that can differentiate between faults and stable power swings and, when necessary, phase-out relays that cannot meet this requirement. The Commission also offered clarification regarding the applicability of the Standard to backup protective relays located at a generator step-up transformer.

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[2] Load-responsive protection relays are a category of protective relays that detect and initiate the removal of faults on an electric system. They are designed to read electrical measurements, such as current, voltage, and frequency, and can be set to recognize certain measurements as indicating a fault. When a protective relay detects a fault on an element of the system that it is protecting, it sends a signal to an interrupting device (such as a circuit breaker) to disconnect the element from the rest of the system.

[3] Loadability refers to the ability of protective relays to refrain from operating under load conditions.

[4] 16 U.S.C. § 824o(d)(5) (2006).

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5. In addition, Order No. 733-A articulated the structure established by section 215 of the FPA by which the Commission, and not solely the ERO, has the responsibility and authority to identify reliability gaps. The ERO is authorized to address reliability matters through its Reliability Standards development process, and the Commission through its review of proposed Reliability Standards and authority to direct modifications or new Standards that address specific issues necessary to carry out the purposes of section 215.

II. Request for Clarification of Reconsideration

6. On March 21, 2011, the Edison Electric Institute and the National Rural Electric Cooperative Association (collectively, EEI/NRECA) jointly filed a timely motion and the American Public Power Association and the Transmission Access Policy Study Group (collectively, APPA/TAPS) together filed a motion, in both instances, requesting clarification or reconsideration of Order No. 733-A.[5]

7. In general, both motions assert the Commission based its directives on a faulty understanding of the Blackout Report[6] or an incorrect characterization of relay engineering. Both motions also reprise issues addressed in Order No. 733-A relating to the Commission exceeding its statutory authority by failing to give "due weight" to the technical expertise of the ERO and by giving overly prescriptive directives. Finally, EEI/NRECA seek clarification or reconsideration of language that they characterize as suggesting that the Commission expects 100 percent relay security and of the Commission's directive regarding generator relays.

III. Discussion

8. Below, we address the following five matters that are appropriately before us as requests for clarification of Order No. 733-A: (1) stable power swings; (2) due weight to the ERO; (3) scope of Commission directives; (4) expected relay performance; and (5) relays located at generators. On these matters, we grant clarification, in part, and deny clarification, in part.

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[5] EEI/NRECA March 21, 2011 Joint Request for Clarification at 1 (EEI/NRECA Request); APPA/TAPS March 21, 2011 Motion at 1 (APPA/TAPS Motion). EEI/NRECA and APPA/TAPS are collectively referred to herein as the Trade Associations.

[6] U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* (Apr. 2004) (Blackout Report), *available at* https://reports.energy.gov/BlackoutFinal-Web.pdf.

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9. In addition, certain arguments raised in the requests for clarification and/or reconsideration do not pertain to clarifications made by the Commission in Order No. 733-A. Likewise, EEI/NRECA submit two affidavits to support their pleadings. As discussed below, we reject the untimely pleadings and affidavits on procedural grounds. As we explain, however, even if these pleadings and affidavits were properly before us, they would not cause us to revisit our previous decisions.[7]

A. Stable Power Swings

10. Reliability Standard PRC-023-1 applies to steady state[8] relay loadability without regard to dynamic conditions or stable power swings.[9] Rather than ordering the ERO to modify PRC-023-1 to address stable power swings, Order No. 733 directed the ERO to develop a new Reliability Standard that requires the use of protective relay systems that can differentiate between faults and stable power swings and, when necessary, phase-out relays that cannot meet this requirement. In Order No. 733-A, the Commission reaffirmed its belief that not addressing stable power swings constitutes a gap in the current Reliability Standards, clarified its expectations regarding phasing-out zone 3 relays,[10] and affirmed that the ERO has flexibility in how it addresses the directive.

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[7] We address the arguments in these pleadings and affidavits on the merits below, in a section titled "Untimely Arguments."

[8] The steady state of a power system is an operating condition assumed for analysis purposes in which all the operating quantities that characterize the system's operating condition can be considered to be constant. As stated in the Blackout Report on page 76, "[t]he electric power system constantly experiences small power oscillations that do not lead to system instability." As a practical matter, therefore, the power system never achieves a steady state condition because there are always movements or changes in power flows, voltages or frequencies simply due to load ramping, generation dispatches, planned or unplanned removal of facilities, and tripping or inadvertent tripping of facilities due to system disturbances.

[9] Stable power swings are oscillations in power flow(s) on an electric system that do not result in instability and arise from an event or disturbance such as changes in load, scheduled or unscheduled removal of transmission or generation facilities, or a fault.

[10] Reliability Standard PRC-023-1 addresses Recommendation 21A of the Blackout Report, which pertains to zone 3 relays. The most common system protective device for transmission lines is the impedance relay, also known as a distance relay. A protective system using distance relays consists of two or three relays, each of which looks at a particular "zone" of the transmission line. Zone 3 relays, and zone 2 relays set

(continued…)

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11. EEI/NRECA assert the Blackout Report does not support the need for a Reliability Standard addressing stable power swings. They believe the Blackout Report neither recommends that such a Standard be created, nor does its analysis support such a Standard. According to EEI/NRECA, relays tripped during the August 2003 Blackout not because of the inability of relays to distinguish faults from stable power swings, but because of faults and severe over-loading conditions without faults. In response to the Commission's statement regarding protection system applications currently used to block tripping of relay elements during stable power swings,[11] EEI/NRECA identify technical limitations of certain protection schemes mentioned by the Commission in Order No. 733-A. They claim that a Reliability Standard that requires relays to distinguish between stable power swings and faults threatens to decrease Bulk-Power System reliability.[12] Finally, they assert that the Commission has inserted "dynamic loadability" conditions into PRC-023-1 thus introducing "a concept unknown in the industry" and contradicting the intent of the Reliability Standard. For these reasons, the Trade Associations seek clarification of the rationale supporting the directives.

Commission Determination

12. The Commission addressed this issue in both Order Nos. 733 and 733-A[13] and is not persuaded that further clarification is necessary. The Blackout Report summarizes

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to operate like zone 3 relays (zone 3/zone 2 relays), can provide remote circuit breaker failure and backup protection for remote distance faults on a transmission line. These relays are typically set to reach 100 percent of the protected transmission line with a margin of more than 100 percent of the longest line (including any series elements such as transformers) that emanates from the remote buses. The zone 3/zone 2 relay trips when the apparent impedance (measured by the current and voltage seen by the relay) falls within a designated zone for a specified length of time. In tripping, it causes circuit breakers to operate and thereby isolates the protected elements. Blackout Report at 74; Order No. 733, 130 FERC ¶ 61,221 at P 4 n.8.

[11] "We also believe that [the] claim that relays cannot distinguish between actual faults and stable power swings appears to ignore the fact that there are protection system applications currently in use for such purposes, i.e., 'power swing block' applications that are applied to block tripping of distance relay elements during stable power swings." Order No. 733-A, 134 FERC ¶ 61,127 at P 112 (footnote omitted).

[12] EEI/NRECA Request at 13–14.

[13] Order No. 733, 130 FERC ¶ 61,221 at P 130–173; Order No. 733-A, 134 FERC ¶ 61,127 at P 100–113.

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how the August 2003 Blackout cascade was triggered, identifies the role played by zone 3/zone 2 relays operating unnecessarily when faults did not exist,[14] and recommends addressing the problem of such relays tripping unnecessarily.[15] It takes no position, however, on whether to address the problem based on either a steady-state loading approach or a stable power swings approach. Had the Blackout Report taken a position as to how to address the problem of relays tripping unnecessarily, the Commission would nevertheless be authorized by section 215(d)(5) of the FPA to identify gaps in reliability and direct the ERO to submit a new Reliability Standard or a modification to an existing Standard to address such gaps. The ERO designed Reliability Standard PRC-023-1 to address the steady-state aspects of relay loadability,[16] but did not address the aspects of the problem associated with stable power swings. The Commission identified the failure to address stable power swings as a gap in the current Reliability Standards that must be addressed and directed that it be addressed in a separate Reliability Standard.[17]

13. As we explained in Order No. 733, the Commission's concern that stable power swings should not cause unnecessary relay operations is consistent with good planning practices and considerations as documented by the NERC's predecessor, the North American Electric Reliability Council.[18] According to its published *NERC Planning Standards* approved by the ERO's predecessor's Board of Trustees in 1997, good planning practice dictates that protection design systems are to be designed to have generation and transmission protection systems avoid tripping for stable power swings on the interconnected transmission system.[19]

14. EEI/NRECA assert that the August 2003 Blackout was the result of severe over-loading conditions and not the result of an inability on the part of relays to distinguish faults from stable power swings. The general nature of their assertion suggests that lines tripped because the current exceeded the lines' ratings just as a household circuit breaker, which is sensitive only to current, trips to prevent thermal damage. But, in fact,

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[14] Blackout Report at 73.

[15] *Id.* at 158.

[16] *See* Order No. 733, 130 FERC ¶ 61,221 at P 132, 173.

[17] *Id.* P 150–153; Order No. 733-A, 134 FERC ¶ 61,127 at P 104.

[18] Order No. 733, 130 FERC ¶ 61,221 at P 151.

[19] North American Electric Reliability Council, *NERC Planning Standards* 49 (1997).

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transmission lines can tolerate thermal heating for limited periods without experiencing problems.[20] Moreover, based on steady-state load flow analysis, the Blackout Report indicates the Sammis-Star line, loss of which marked the turning point at which system problems initiated a cascade, only encountered loading above 120 percent of its normal rating[21] but tripped because its protective relays registered low apparent impedance.[22]

15. The Blackout Report details how, upon the initial tripping of FirstEnergy's lines, the redistributed power flows increased the current flowing over the remaining operational lines, thus, aggravating voltage declines.[23] Because current increases in inverse proportion to the decrease in voltage for a given amount of power, as the current rose, the voltage on the lines fell. Zone 3/zone 2 relays, looking for line faults, operated when the apparent impedance (voltage divided by current) seen by the relays fell within one of the relays' operating zones for the appropriate amount of time delay.[24] Once lines in the Cleveland-Akron area tripped, the disrupted power flow on these tripped lines were redistributed to other lines including critical 345 kV lines in Michigan, in turn causing depressed voltages and increased currents which, when seen by zone 3/zone 2 relays, led to further tripping of lines.[25] Based on these facts, an assertion that the lines tripped simply because of overloading in the absence of stable power swings would represent an incomplete picture. Instead, the Blackout Report states that "[p]ower swings and voltage

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[20] North American Electric Reliability Council, *NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts* 12 (February 10, 2004) (NERC Actions Report), *reprinted in* Blackout Report, Appendix D, at 204 ("Many of the zone 3 relays that operated during the August 14 cascading outage were not set with adequate margins above their emergency thermal ratings. For the short times involved, thermal heating is not a problem and the lines should not be tripped for overloads."); s*ee also* Blackout Report at 82.

[21] Blackout Report at 64 fig. 5.12.

[22] *Id.* at 69 ("Unlike the previous three 345-kV lines, which tripped on short circuits to ground due to tree contacts, Sammis-Star tripped because it protective relays saw low apparent impedance (depressed voltage divided by abnormally high line current)—i.e., the relay reacted as if the high flow was due to a short circuit.").

[23] *Id.* at 81.

[24] *Id.* at 80.

[25] *Id.* at 75.

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fluctuations . . . can cause other lines to detect high currents and low voltage that appear to be faults, even if faults do not actually exist on these other lines."[26]

16. Moreover, the North American Electric Reliability Council acknowledged the role of power swings in the misoperation of relays during the August 2003 Blackout. In its Recommendation 8 appended to the Blackout Report in Appendix D, it acknowledged the role power swings played in causing zone 3 relays to operate for overload conditions:

> First, beginning with the Sammis-Star line trip, most of the remaining line trips during the cascade phase were the result of the operation of a zone 3 relay for a perceived overload (a combination of high amperes and low voltage) on the protected line. If used, zone 3 relays typically act as an overreaching backup to zone 1 and zone 2 relays, and are not intentionally set to operate on a line overload. However, under extreme conditions of low voltages and *large power swings* as seen on August 14, zone 3 relays can operate for overload conditions and propagate the outage to a wider area by essentially causing the system to "break up."[27]

In response to the Commission's request for comment on whether the ERO should develop a modification to PRC-023-1 or a separate Reliability Standard to address stable power swings, NERC replied, in part, that "[r]eliability of the power system requires secure protective relay settings to avoid operation during *stable power swings* and dependable tripping for faults and unstable power swings. . . . FERC is appropriately concerned with the effect of stable power swings upon load responsive relays."[28] And in a document that the ERO described as representing the technical justification for ongoing revisions to the Reliability Standard addressing coordination of system protection among operating entities,[29] NERC's System Protection and Control Subcommittee states "[t]he

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[26] *Id.* at 73.

[27] NERC Actions Report at 12, *reprinted in* Blackout Report at 204 (emphasis added).

[28] North American Electric Reliability Corp. August 17, 2009 Comments in Response to Notice of Proposed Rulemaking (NERC Comments) Docket No. RM08-13-000, at 24–25 (emphasis added).

[29] *Id.* at 21.

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impedance relay *must not operate for stable system swings*."[30] The Commission's directive is, therefore, supported by the record and is not arbitrary and capricious.[31]

17. In response to the Commission's Notice of Proposed Rulemaking,[32] some commenters disputed the value of the protection schemes capable of distinguishing between faults and stable power swings mentioned by the Commission, and argued that the applications identified by the Commission were less reliable than the methods used in distance relays. In Order No. 733, we noted that the protection systems discussed in the NOPR were merely examples of systems that can differentiate between faults and stable power swings. Regarding the Trade Associations' concern that the directive may result in reduced reliability, we repeat what we responded to those NOPR commenters in Order No. 733: "We leave it to the ERO to determine the appropriate protection systems to be discussed in the new Reliability Standard through application of its technical expertise."[33]

18. Our directive does not require the elimination of the currently used impedance (or distance) relays as backup protection. Nor does it mandate use of a particular technology or an absolute obligation to prevent protection relays from operating unnecessarily during power stable swings. Our directive instead requires "the creation of a Reliability Standard that addresses protection systems vulnerable to stable power swings (resulting from Category B and Category C contingencies) that will result in inappropriate

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[30] North American Electric Reliability Corp., *Technical Reference Document, Power Plant and Transmission System Protection Coordination* 26 (2009) (emphasis added) (subsequently revised in July 2010 without alteration to cited material).

[31] The ERO has continued to support the reliability objective associated with developing a Reliability Standard to address operation of protective relays in response to stable power swings. North American Electric Reliability Corporation, Informational Filing in Response to Order No. 733-A on Rehearing, Clarification, and Request for an Extension of Time, Docket No. RM08-13-000 at 7 (filed July 21, 2011) (NERC Informational Filing).

[32] *Transmission Relay Loadability Reliability Standard*, Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,642 (2009) (NOPR).

[33] Order No. 733, 130 FERC ¶ 61,221 at P 167; *see also* Order No. 733-A, 134 FERC ¶ 61,127 at 108 ("[t]hrough the application of its technical expertise, and the balancing of stakeholder interests, the ERO's Reliability Standard development process is the appropriate forum to discover and address any unintended consequences arising from the use of protective relays systems").

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tripping."[34] A new Reliability Standard addressing stable power swings will interact with existing Facilities Design, Connections and Maintenance (FAC), Interconnection Reliability Operations and Coordination (IRO), Protection and Control (PRC), Transmission Operations (TOP), and Transmission Planning (TPL) Reliability Standards. These Reliability Standards interact to promote Reliable Operations. As we said in Order No. 733:

> these interactions require limits to be established for all system elements, interconnected systems to be operated within these limits, operators to take immediate action to mitigate operation outside of these limits, and protective relays to refrain from operating until the observed condition on their protected element exceeds these limits. Protection relays include primary and backup relays. If zone 2/zone 3 relays are used by entities as part of their protection systems designed to achieve the system performance, they can remain as backup protection as long as they do not inadvertently trip non-faulted facilities due to stable power swings.[35]

19. As to EEI/NRECA's assertion that our directive contradicts the intent of the Reliability Standard by inserting dynamic-related criteria into PRC-023-1, we note that our directive was to fill a gap not intended to be covered by this Reliability Standard by creating a *new* Reliability Standard to address stable power swings. In its response to the NOPR, NERC commented that rather than modifying PRC-023-1, stable power swings should be addressed in a separate Reliability Standard.[36] NERC further requested that we provide the ERO adequate time to undertake the effort to develop requirements that promote the overall reliability of the power system while avoiding unintended consequences. The Commission, accordingly, did not direct that stable power swings be addressed in PRC-023-1. Instead, we agreed with the ERO that this subject could appropriately be handled in a separate Reliability Standard and directed the ERO to submit an action plan and timeline to address this issue.

20. Therefore, based on the rationale provided above, we do not provide the clarification sought by the Trade Associations.

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[34] Order No. 733-A, 134 FERC ¶ 61,127 at 107.

[35] Order No. 733, 130 FERC ¶ 61,221 at P 166.

[36] NERC Comments at 25.

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B. Due Weight

Order No. 733-A

21. In Order No. 733-A, the Commission reaffirmed that the ERO has discretion in how to comply with a Commission directive.[37] The Commission explained that "[t]he ERO is not required to adopt the Commission's guidance into the Reliability Standard, but is required to develop its response to the Commission's concerns through the stakeholder evaluation process contained within the Reliability Standard development process."[38]

22. In discussing concerns raised on rehearing regarding the Commission's application of due weight, the Commission explained:

> We find no difficulty in reading section 215(d)(2) in harmony with section 215(d)(5). Section 215(d)(2) requires the Commission to give due weight to the technical expertise of the ERO when the Commission reviews a Standard or modification proposed by the ERO. Section 215(d)(5) authorizes the Commission to direct a modification to a Standard if it judges that such a modification is necessary. There is no contradiction in the Commission giving due weight to the technical expertise of the ERO and still finding that there is a "specific matter" that the ERO must address. EEI's argument tends to diminish the significance of the Commission's authority to direct modifications under section 215(d)(5) because it fails to recognize that the Commission, and not just the ERO, has the responsibility and authority to identify "specific matters" that it considers appropriate to carry out section 215. Section 215 establishes a paradigm by which both the Commission and the ERO are responsible for identifying reliability gaps—the ERO through its Reliability Standards development process, where it can independently identify areas of concern and develop Standards to address them; and the Commission through its review of proposed Reliability Standards and authority to direct modifications or new Standards that address specific issues necessary to effectuate the purposes of section 215.[39]

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[37] Order No. 733-A, 134 FERC ¶ 61,127 at P 12; *see generally id.* "Authority Under Section 215(d) of the FPA" at P 8–30.

[38] *Id.* P 12.

[39] *Id.* P 25 (citation omitted); s*ee also id.* P 23–27.

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Requests for Clarification

23. EEI/NRECA state that an essential part of the reliability regime established by section 215 of the FPA is the requirement that the Commission give due weight to the technical expertise of the ERO. They argue that the Commission failed to give due weight to the ERO's technical expertise regarding *how* to address the transmission relay loadability concerns raised in the Blackout Report. EEI/NRECA contend that the Commission's directives in this proceeding necessarily determined that the ERO had not sufficiently addressed the recommendations of the Blackout Report on loadability issues. But, they argue, "where the ERO has proposed a rational technical basis for why the proposed Reliability Standard meets the purpose of the Standard, the obligation to give 'due weight' should act to prevent the Commission from second-guessing the conclusions of the ERO, even if the Commission believes it would have proposed a different Reliability Standard."[40]

24. EEI/NRECA further assert that a directive begins with a determination that the proposed Reliability Standard is technically deficient, thus, overruling the ERO's conclusions on the proper way to protect the Bulk-Power System. EEI/NRECA contend that, the Commission's duty to give due weight to the ERO's expertise requires that "the Commission must respect the technical expertise of the ERO not only in *how* to address the underlying concern, but also with regards [sic] to w*hether* there is an additional underlying concern on that issue that needs to be addressed."[41]

25. According to EEI/NRECA, a proposed Reliability Standard is the product of the ERO's technical judgment with respect to both what it contains and what it omits. With this premise, any directive addressing the context of the proposed Standard must overcome the obligation to accord due weight to the ERO's technical judgment. Accordingly, EEI/NRECA argue that Order No. 733-A errs in asserting that the Commission's authority to direct a modification under section 215(d)(5) of the FPA is not constrained by the requirement in section 215(d)(2)[42] that it give due weight to the technical expertise of the ERO.[43]

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[40] EEI/NRECA Request at 22.

[41] *Id.* at 25.

[42] 16 U.S.C. § 824o(d)(2) (2006).

[43] Order No. 733-A, 134 FERC ¶ 61,127 at P 25.

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26. In giving guidance with respect to a specific directive, the Commission has stated that it will consider an alternative provided that the ERO can show that its alternative addresses the Commission's underlying reliability concern in an equally efficient and effective manner as the Commission's suggested approach.[44] For the Trade Associations, the requirement that the ERO's alternative approach must be equally effective and efficient as the Commission's proposal is not supported by Section 215, and adds additional and unwarranted restrictions on the ERO's statutory role.[45]

Commission Determination

27. We deny the EEI/NRECA request for clarification on this issue. While EEI/NRECA add some new nuance to the matter, their petition essentially revisits a matter that we have adequately addressed previously in this and other Commission proceedings.[46] However, we address the matter below because of the ongoing concern regarding the Commission's authority to issue directives pursuant to section 215(d)(5) of the FPA and how that dovetails with another statutory provision that the Commission give "due weight" to the ERO's technical expertise.

28. Section 215(d)(5) of the FPA grants the Commission the authority to direct the ERO to develop a Reliability Standard or a modification to a Reliability Standard that addresses a specific matter if the Commission considers such a new or modified Reliability Standard appropriate.[47] While EEI/NRECA are correct in stating that the Commission must give due weight to the technical expertise of the ERO when the Commission reviews a Standard or modification proposed by the ERO, their argument fails to recognize that the Commission, upon its own motion, is authorized to identify matters it considers appropriate to carry out section 215. The Commission has the

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[44] *Id.* P 13; Order No. 733, 130 FERC ¶ 61,221 at P 18.

[45] EEI/NRECA Request at 23; APPA/TAPS Motion at 5.

[46] *See* Order No. 733-A, 134 FERC ¶ 61,127 at P 8–12, 22-27; *see also Revision to Electric Reliability Organization Definition of Bulk Electric System*, Order No. 743-A, 134 FERC ¶ 61,210, at P 14–16, 26–31 (2011); *North American Electric Reliability Corp.*,132 FERC ¶ 61,218, at P 30–36, 53 (2010).

[47] Section 215(d)(5) of the FPA states: "The Commission, upon its own motion or upon complaint, may order the Electric Reliability Organization to submit to the Commission a proposed reliability standard or a modification to a reliability standard that addresses a specific matter if the Commission considers such a new or modified reliability standard appropriate to carry out this section."

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responsibility and authority to identify specific matters that it considers appropriate to carry out section 215.[48]

29. We are not persuaded by EEI/NRECA's argument that a proposed Reliability Standard is owed due weight both to the matters addressed in the Standard and to related matters that are omitted from the Standard without any explanation in the record. The petitioners' approach is incongruous with the language of section 215(d)(2) of the FPA, which states that "the Commission shall give due weight to the technical expertise of the Electric Reliability Organization with respect to the *content* of a proposed standard or modification to a reliability standard…" (emphasis added). EEI/NRECA argue that an unexplained omission is an exercise of the ERO's technical expertise and thus entitled to due weight. We disagree, and find that it is unreasonable to read the statute as requiring the Commission to give due weight to an omission when there is no evidence in the record to explain that omission. Without such evidence, the Commission would have no basis for evaluating the reasoning behind the omission or for determining whether the omission prevented the proposed Reliability Standard from satisfying the statutory standard of review. Thus, the Commission must give due weight to an omission when the ERO explains the technical basis behind the omission in an initial filing, response to a Commission data request, supplemental filing, comments on a notice of proposed rulemaking, or other filing in the record. We do not read section 215(d)(2) as requiring the Commission to give due weight to an unexplained omission, especially in circumstances where, as here, the Commission identifies the omission as an area of concern and provides the ERO with an opportunity to comment on whether the concern is justified, and if so, whether the Commission's proposed remedy is appropriate. Consequently, we reject EEI/NRECA's argument.

30. Moreover, EEI/NRECA imply that the due weight owed the ERO prevents the Commission from issuing directives to augment or modify a Standard. We disagree with any such implication. We believe it is important to explain the Commission's application of due weight, as well as its section 215(d)(5) authority, in the context of this proceeding. In Order No. 733, the Commission directed the ERO to develop a new or modified Reliability Standard to address several concerns identified by the Commission. For example, Reliability Standard PRC-023 does not address stable power swings. The Commission found that this omission constitutes a reliability gap and directed the ERO to develop a new Standard that addresses this matter.[49] Furthermore, in its comments in response to the reliability gap identified by the Commission in the NOPR, the ERO

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[48] Order No. 733-A, 134 FERC ¶ 61,127 at P 25.

[49] Order No. 733, 130 FERC ¶ 61,221 at P 150; Order No. 733-A, 134 FERC ¶ 61,127 at P 104.

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affirmed the need to address stable power swings.[50] In this circumstance, it is reasonable for the Commission to exercise its section 215(d)(5) authority to direct the ERO to develop a new or modified Reliability Standard that addresses the Commission's concern.

31. Similarly, Reliability Standard PRC-023-01 states that the Standard applies to transmission lines operated at 200 kV and above and "transmission lines operated at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System."[51] The Reliability Standard, however, does not provide any criteria for defining or identifying transmission lines that are "critical" to reliability. In its comments on the NOPR, NERC submitted its guidance for identifying operationally significant 100kV–200kV facilities, but after careful review and giving due weight to the ERO's submission, the Commission concluded that the guidance would identify some, but likely not all, critical sub-200 kV facilities. In particular, the Commission found that while NERC's guidance would identify all critical facilities between regions and sub-regions, it would not necessarily identify the critical facilities within a sub-region or a company.[52] In light of this, the Commission directed the ERO pursuant to section 215(d)(5) of the FPA, to develop a mandatory test to identify which sub-200 kV facilities could trip on relay loadability and contribute to a cascading outage.[53] The Commission's Final Rule also articulated what an appropriate set of criteria would accomplish and a suggested set of criteria for determining "critical" transmission lines in the 100 kV to 200 kV range. The Commission, however, made clear that other approaches would be acceptable provided that they satisfied the underlying reliability concerns. Again we believe that this is an appropriate exercise of the Commission's 215(d)(5) authority, and does not deny due weight to the ERO's technical expertise.[54]

32. In another exercise of its section 215(d)(5) authority, the Commission directed the ERO to modify PRC-023-1 by removing supervisory relays from Attachment A's list of

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[50] *See* NERC Comments at 24.

[51] PRC-023-1 A.4.1.2.

[52] Order No. 733, 130 FERC ¶ 61,221 at P 75-76.

[53] Order No. 733-A, 134 FERC ¶ 61,127 at P 39, *citing* Order No. 733, 130 FERC ¶ 61,221 at P 69.

[54] The ERO acknowledged the need for some criteria in its comments on the NOPR. *See* NERC Comments at 12 ("NERC recognizes the need for consistent criteria across North American [sic] for making these determinations regarding 100 kV to 200 kV circuits.").

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protection systems excluded from the requirements of the Reliability Standard. The Commission, however, made it clear that it did not prescribe this specific change as an exclusive solution to its reliability concern.[55] The ERO gave no technical rationale for the exclusion in its initial filing, but in response to the NOPR justified the exclusion on the basis that it is preferable to trip one line for loss of communications than not to trip the line at all.[56] In this instance, the Commission, after giving due weight to the ERO's technical expertise, was not persuaded that the ERO had offered a reasonable rationale for the exclusion of supervisory relays.[57] Even with this concern, the Commission determined that the proposed Reliability Standard PRC-023-1 was just and reasonable, not unduly discriminatory or preferential and in the public interest, and approved the Standard. However, as a separate matter, the Commission exercised its authority pursuant to section 215(d)(5) of the FPA and directed the ERO to address the Commission's concern regarding supervisory relays.

33. We disagree with the Trade Associations' argument that the Commission is adding an unwarranted restriction on the ERO by requiring any alternative to its guidance to be "equally effective and efficient" as the Commission's suggested approach. The Commission addressed this same issue raised by NRECA in another docket. Our Order No. 743-A noted that section 215(d)(2) of the FPA establishes the standard of review the Commission is to use in reviewing the content of an ERO proposed Reliability Standard.[58] The statute specifies that the "Commission may approve, by rule or order, a proposed reliability standard or modification to a reliability standard if it determines that the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[59] The Commission then dismissed NRECA's argument by stating:

> Certainly, whether a proposed Reliability Standard provides for an adequate level of reliability is included in the factors used in determining whether the proposal is just and reasonable, but it is not the standard of review. The Commission's statement that any alternative proposal must be "as effective

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[55] Order No. 733, 130 FERC ¶ 61,221 at P 264.

[56] NERC Comments at 35.

[57] *See* Order No. 733, 130 FERC ¶ 61,221 at P 267–269 (explaining the Commission's concerns regarding the exclusion of supervisory relays).

[58] *Revision to Electric Reliability Organization Definition of Bulk Electric System*, Order No. 743-A, 134 FERC ¶ 61,210, at P 14 (2011).

[59] 16 U.S.C. ¶ 824o(d)(2).

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> as, or more effective than, the Commission's proposed approach" must not "result in a reduction in reliability" provides guidance regarding the Commission's view of what is necessary to produce not only an adequate level of reliability but also a result that accords with the section 215(d)(2) review criterion.[60]

34. Accordingly, for the reasons discussed above, we deny the Trade Associations' request for clarification on this issue.

C. Scope of Commission Directives

35. In Order No. 733-A, the Commission addressed arguments on rehearing that Order No. 733 prescribed the specific technical content of certain modifications and, thereby, exceeded the Commission's authority. In response, the Commission clarified in Order No. 733-A that it did not require the ERO to adopt the precise content of Commission guidance in order to satisfy the concern identified by the Commission.[61] Rather, the guidance was given to inform the ERO and industry as to the underpinnings of the Commission's concerns.[62]

36. APPA/TAPS ask the Commission to clarify that its directive to make Reliability Standard PRC-023-1 applicable to supervisory relays does not foreclose the ERO developing a more tailored approach to addressing the Standard's applicability.

37. The Trade Associations assert that the scope of the directives clarified in Order No. 733-A belies the Commission's claim that the ERO has discretion in how it addresses the Commission's underlying reliability concern. The directives, EEI/NRECA claim, direct the ERO *how* to address the Commission's concerns and in so doing, exceed the statutory authority of the Commission to grant directives on a "specific matter." For example, according to EEI/NRECA, rather than simply state its concern that reliability is compromised by excluding supervisory relays from the scope of PRC-023-1, the Commission directed the ERO to (1) remove the exclusion of supervisory relays from the Reliability Standard, and (2) add supervisory relays to the list of protective functions described as within the scope of the Standard.

38. EEI/NRECA point to the directive to develop a test to determine sub-200 kV critical assets as another example in which the Commission restricted the ERO's

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[60] Order No. 743-A, 134 FERC ¶ 61,210 at P 16 (citations omitted).

[61] *E.g.*, Order No. 733-A, 134 FERC ¶ 61,127 at P 10–13, 23, 48.

[62] *Id.* P 12.

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discretion by identifying specific elements that it would consider appropriate for such a test. They argue that although the Final Rule explicitly provides room for discretion, the ERO remains constrained by the Commission's restrictions on the manner in which it is permitted to address the Commission's underlying concerns. EEI/NRECA argue that, by so limiting the ERO's scope to address an identified reliability concern, the Commission exceeded its authority under the FPA and impinged on the ERO's authority to draft and propose Reliability Standards.

Commission Determination

39. In response to APPA/TAPS, we clarify our directive pertaining to supervisory relays. In Order No. 733-A, the Commission discussed its directive to make supervisory relays subject to Reliability Standard PRC-023-1 and stated:

> As discussed in Order No. 733, and previously in this section, the Commission is concerned with supervisory relays set below the rating of the line being continuously energized and thus no longer able to act as a check on the protection system the relays are supervising. . . . The ERO did not provide any technical rationale for excluding any load responsive phase protection systems from the requirements of PRC-023-1. Having directed the ERO to modify PRC-023-1 in a specific manner, we will accept an alternative method that addresses the Commission's concern provided such alternative is demonstrably adequate in addressing the Commission's underlying concern as efficiently and effectively as the Commission's proposal.[63]

The Commission clarifies that its directive regarding the applicability of the Reliability Standard to supervisory relays does not foreclose the development of an approach tailored to eliminate application of the standard to some supervisory relays but not to others, where technically justified.[64] In other words, the revised standard only need apply to a subset of supervisory relays.

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[63] *Id.* P 133-134.

[64] Concurrent with the issuance of this order, we are also issuing a Notice of Proposed Rulemaking in Docket No. RM11-16-000, pertaining to NERC's proposed revisions to Reliability Standard PRC-023-2. In that proceeding, the Commission proposes to approve NERC's modified Reliability Standard, which includes a provision pertaining to supervisory relays. *See Transmission Relay Loadability Reliability Standard*, Notice of Proposes Rulemaking, 136 FERC ¶ 61,187 at P 28-29, 39 (2011).

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40. The Commission declines to grant clarification as to the other issues raised regarding the scope of the Commission's directives. EEI/NRECA's arguments seem to presuppose that the use of the term "specific matter" in section 215(d)(5) necessarily means a single, unitary matter.[65] Thus, they argue that the Commission should have articulated its concern regarding a test for sub-200 kV facilities as a single issue: the lack of a uniform test for critical sub-200 kV facilities. Instead, the Commission articulated its concern as follows:

> [I]n order to provide the necessary assurance that the Standard would achieve its purpose, the test must include or be consistent with the system simulations and assessments that are already required by the existing TPL Reliability Standards, meet the system performance levels for all Category of Contingencies used in transmission planning, set forth some definition of desirable system performance, and describe the steady state and dynamic base cases that the planning coordinator must use in identifying facilities in the 100 kV to 200 kV range that are subject to PRC-023-1.[66]

As we said in Order No. 733-A, these <u>are</u> the elements that constitute the Commission's reliability concern. When the Commission's concern is manifold, it serves no purpose to pretend it is simple and deny the ERO the ability to understand the full extent of the Commission's concern. If the Commission foregoes giving a precise statement of its concern, the ERO may not know how to appropriately respond.[67]

41. We find our view to be consistent with the statutory language that authorizes the Commission to order the ERO to submit a new Reliability Standard or a modification to address a "specific matter" the Commission considers appropriate. If the Commission were to adopt the Trade Associations' reading of the statute, the Commission would be constrained to articulate its reliability concerns such as those quoted above one at a time, thus compelling an inefficient succession of directed modifications to the Reliability Standard.

D. <u>Expectation as to Relay Operation</u>

42. EEI/NRECA seek clarification as to whether the Commission expects relays to never operate during non-fault conditions. Order No. 733-A discussed an argument made

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[65] *See* EEI/NRECA Request at 29–30.

[66] Order No. 733-A, 134 FERC ¶ 61,127 at P 22.

[67] *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 185.

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by EEI that it would be better for relays to trip for certain known but uncommon, non-fault conditions rather than risk not tripping for another condition. As part of its response to this argument, the Commission said that "a protection relay, as an integral part of the Bulk-Power System, must not operate during non-fault conditions, regardless of how few times the relay may actually operate."[68] EEI/NRECA assert this statement suggests the Commission wants 100 percent security and seek clarification that the Commission does not expect that relays will never operate during non-fault condition.[69]

43. Order No. 733-A addressed this matter in the context of stable power swings, when the Commission said "we do not direct the development of a Reliability Standard containing an absolute obligation to prevent protection relays from operating unnecessarily. . . ."[70] We clarify that the language identified by EEI/NRECA is the design condition expected of such protection relay systems and not an expectation that such a design will always achieve its objective 100 percent of the time. In other words, we do not expect perfect relay operation. However, the design and implementation of relay systems pursuant to Reliability Standard PRC-023 should duly consider the appropriate balance between security and dependability as they strive to avoid settings that will result in relay operation under non-fault conditions.[71] Accordingly, we grant clarification of this issue.

E. Relays Located at Generators

44. In Order No. 733, the Commission distinguished between two roles for protection relays located at the generator terminal on the low-voltage side of a generator step-up transformer. Such relays can: (1) provide backup protection for a Bulk-Power System element such as a transmission line outside of the generator zone of protection, or (2) provide backup protection for the generator and step-up transformer.[72] The Commission stated that those relays that provide backup protection to transmission lines

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[68] Order No. 733-A, 134 FERC ¶ 61,127 at P 131.

[69] EEI/NRECA Request at 33–34.

[70] Order No. 733-A, 134 FERC ¶ 61,127 at P 107.

[71] Relay dependability and security are not synonymous. The dependability of a relay addresses whether the relay will trip during a fault; security addresses whether the relay will not trip in the absence of a fault. *See* Order No. 733-A, 134 FERC ¶ 61,127 at P 127.

[72] Order No. 733, 130 FERC ¶ 61,221 at P 113.

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and transformers are subject to Reliability Standard PRC-023-1.[73] In Order No. 733-A, the Commission clarified that it does not intend the Reliability Standard to apply to backup protective relays connected to current transformers at the neutral end of the generator.[74] Order No. 733-A also noted that Attachment A to PRC-023-1 explicitly excludes generator protection relays that are susceptible to load, but Attachment A does not exclude any other type of relay physically located on the low-voltage side of a generator step-up transformer.[75] Thus, the Commission concluded that, by its very terms, the Reliability Standard applies to generator protection relays located at the generator step-up transformer.[76]

45. Order No. 733-A states that Reliability Standard PRC-023-1 applies to relays which, though "they may be connected to current transformers located at the generator terminal or on the low-voltage side of the generator step-up transformer, are set to provide backup protection for Bulk-Power System elements."[77] EEI/NRECA characterize this statement as being in conflict with the Commission's stated expectation that "the ERO will develop [a] Reliability Standard addressing generator loadability as a new Reliability Standard with its own individual timeline, and not as a revision to an existing Standard"[78] and request clarification of this apparent conflict.

46. EEI/NRECA also argue that relays that sense in the direction of the transmission system serve to protect the thermal limits of the generating asset rather than loadability of the transmission system. Since the generator operates at a lower power capacity than the transmission system, EEI/NRECA claim that setting the relay in accordance with Reliability Standard PRC-023-1 may not adequately protect the generating asset. Moreover, because the relays are applied at the generating terminals and not the transmission lines, they do not restrict transmission loadability. Finally, EEI/NRECA assert that failure to clarify the scope of PRC-023-1 will change the function of these relays from protection of generation assets to supporting transmission loadability.

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[73] *See id.* P 112.

[74] Order No. 733-A, 134 FERC ¶ 61,127 at P 93.

[75] *Id.*

[76] *Id.*

[77] *Id.* P 94 (citation omitted).

[78] *Id.* P 95, *citing* Order No. 733, 130 FERC ¶ 61,221 at P 106.

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Commission Determination

47. The orders in this proceeding state that Reliability Standard PRC-023-1 applies to relays set to provide primary or backup protection to transmission elements rather than to generators.[79] We see no conflict between this statement and the stated expectation that the ERO will develop a new Reliability Standard addressing generator relay loadability. The Commission addressed EEI/NRECA's perceived conflict in Order No. 733 when it stated:

> Our statement that such relays are subject to the Reliability Standard is not in conflict with the use of a protection system to protect the generator/step-up transformer in the context of other industry standards, such as IEEE Standard C37.102, or with the exclusion in section 3.4 of Attachment A to PRC-023-1 of generator relays that are susceptible to load. The relays that we referred to in the NOPR, while they may be physically located at the generator terminal or on the low-voltage side of the generator step-up transformer, are applied to provide backup protection for Bulk-Power System elements. This application is different from "generator relays," which are also physically located at the generator, but are applied to protect the generator.[80]

48. Further, we disagree with EEI/NRECA's broad claim that all relays sensing in the direction of the transmission system serve to protect the thermal limits of the generating assets and that our assertion as to the scope of PRC-023-1 changes the function of these relays from protecting generation assets to supporting transmission loadability. Certainly, some relays sensing in the direction of the transmission system are set to protect generating assets, but our statement regarding PRC-023-1's applicability was not directed at those relays. Instead, we address only that subset of relays set to provide backup protection for Bulk-Power System elements.

49. While such relays may be few in number, distance relays can be physically located at the generator terminal on the low-voltage side of a step-up transformer, sensing in the direction of the transmission system, and function as backup protection for a Bulk-Power System fault (i.e., for a transmission line outside of the generator zone of protection) in case the transmission system relays fail to clear a fault.[81] This understanding is

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[79] *Id*. P 94, 98; Order No. 733, 130 FERC ¶ 61,221 at P 112.

[80] Order No. 733, 130 FERC ¶ 61,221 at P 114 (citation omitted).

[81] *Id.* P 113.

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confirmed in NERC's Technical Reference Document, *Power Plant and Transmission System Protection and Coordination*, written by industry experts and approved by NERC's Planning Committee. This document states that "[t]he generator impedance relay can be set to provide trip dependability for faults on transmission lines when relays fail."[82] In such instances, where the relay is set to trip for faults on transmission lines, the relay must be coordinated with generator protection devices, but the relay is designed to trip the step-up transformer and generator in order to stop current flowing from the generator to the faulted line when transmission line relays fail.[83]

50. Because relays can be set to trip for faults on transmission lines, they can restrict transmission loadability notwithstanding that they are applied at the generator rather than on the transmission system. If the relay can inappropriately trip the step-up transformer and generator under non-fault conditions, it can leave other generators to shoulder its share of the system load.

51. EEI/NRECA assert that, because a generator operates at a lower power capacity than the transmission facility to which it is connected, setting a relay in accordance with Reliability Standard PRC-023-1 may not adequately protect the generating asset. This assertion appears to be contradicted by the above-quoted statement in the NERC Technical Reference Document, but it does not conflict with the Commission's statements in Order No. 733 and Order No. 733-A. The Commission has not stated that a relay whose function is to protect the generating asset is subject to PRC-023-1. In Order No. 733, the Commission declined to extend the Reliability Standard to generator step-up and auxiliary transformer loadability, agreeing with the ERO that the matter could appropriately be addressed in a separate Reliability Standard.[84] In the context contemplated by EEI/NRECA's argument, where the relay is set to protect generating elements, the relay may be set in whatever manner is appropriate to achieve its intended purpose.

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[82] North American Electric Reliability Corp., *Technical Reference Document, Power Plant and Transmission System Protection Coordination* 34 (2009). The Reference Document then continues to describe the technical details on how the generator impendence relay should be set to provide trip dependability for faults on transmission lines.

[83] *See id.* at 35.

[84] Order No. 733, 130 FERC ¶ 61,221 at P 104; s*ee also* Order No. 733-A, 134 FERC ¶ 61,127 at P 98.

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52. Accordingly, we deny the EEI/NRECA request for clarification of the Commission's statements regarding the applicability of Reliability Standard PRC-023-1 to relays located at a generator terminal that serve to protect Bulk-Power System elements.

F. Untimely Arguments

53. The Trade Associations assert the Commission's directives regarding (a) creation of a uniform test to identify critical sub-200 kV facilities, (b) subjecting supervisory relays to PRC-023-1, and (c) creation of a new Reliability Standard addressing protective relays that can differentiate between stable power swings and faults are based on errors of fact. These directives, they assert, reflect a misunderstanding of protection system engineering and of the Blackout Report. EEI/NRECA argue that, to the extent the Commission failed to consider the negative reliability implications of the directives, reached conclusions contrary to the findings or recommendations of the Blackout Report, or exceeded a mere difference of opinion regarding the directives' engineering implications, the directives are arbitrary and capricious.

54. While Order No. 733-A offered clarifications of the Commission's earlier directives regarding creating a uniform test to identify critical sub-200 kV facilities and subjecting supervisory relays to PRC-023-1, the arguments raised in the Trade Associations' motions do not arise as a result of new information set forth in our clarifications. Instead, they attempt to revisit the technical basis for the Commission's directives. The Trade Associations should have raised these arguments in response to the NOPR. Failing that, the arguments should have been raised on rehearing prior to the issuance of Order No. 733-A.

55. The Commission does not allow rehearing of an order denying rehearing.[85] Any other result would lead to never-ending litigation as every response by the Commission to a party's arguments would allow yet another opportunity for rehearing unless presumably that response were word-for-word identical to what the Commission earlier said.[86]

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[85] *See, e.g.*, *Bridgeport Energy, LLC*, 114 FERC ¶ 61,265 (2006) (*Bridgeport*); *Cargill Power Markets, LLC et al.*, 114 FERC ¶ 61,093 (2006); *Southern Company Services, Inc*., 111 FERC ¶ 61,329 (2005); *AES Warrior Run, Inc. v. Potomac Edison Company d/b/a Allegheny Power*, 106 FERC ¶ 61,181 (2004); *Southwestern Public Service Co*., 65 FERC ¶ 61,088, at 61,533 (1993).

[86] *See, e.g.*, *Bridgeport*, 114 FERC ¶ 61,265 at P 8, *citing Canadian Association of Petroleum Producers v. FERC*, 254 F.3d 289, 296 (D.C. Cir. 2001) (rejecting the notion of "infinite regress" that would "serve no useful end").

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Litigation before the Commission cannot be allowed to drag on indefinitely – at some point it must end – and so the Commission does not allow parties to seek rehearing of an order denying rehearing. As the U.S. Court of Appeals for the District of Columbia Circuit has explained, even "an improved rationale" does not justify a further request for rehearing.[87]

56. Matters that do not arise as a result of a modification of Order No. 733 by Order No. 733-A should have been raised previously in a motion for rehearing of Order No. 733 and are therefore rejected based on the procedural defect.

57. Further, in support of their arguments, EEI/NRECA append to their motion two affidavits of Thomas E. Wiedman (Wiedman Affidavit) and William J. Miller (Miller Affidavit) addressing the Blackout Report and various engineering matters such as the role and function of supervisory relays. These issues were first addressed in the NOPR and should have been raised in comments to it.[88] These issues were also addressed in the Order No. 733[89] and again in Order No. 733-A.[90] The Commission looks with disfavor on parties raising issues for the first time on rehearing because other parties are not permitted to respond to a request for rehearing.[91] The introduction of such material is "disruptive to the administrative process because it has the effect of moving the target for parties seeking a final administrative decision."[92] The Trade Associations should have raised these concerns in comments to the NOPR or on rehearing of Order No. 733 and do

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[87] *Southern Natural Gas Co. v. FERC*, 877 F.2d 1066, 1073 (D.C. Cir. 1989) (*Southern*) (citing *Tennessee Gas Pipeline Co. v. FERC*, 871 F.2d 1099, 1109-10 (D.C. Cir. 1989)); s*ee also Londonderry Neighborhood Coalition v. FERC*, 273 F.3d 416, 423-24 (1st Cir. 2001).

[88] *E.g.*, NOPR, FERC Stats. & Regs. ¶ 32,642 at P 11, 30–45, 54–60, 78–80.

[89] *E.g.*, Order No. 733, 130 FERC ¶ 61,221 at P 47–97, 150–173, 250-272.

[90] *E.g.*, Order No. 733-A, 134 FERC ¶ 61,127 at P 14–17, 22, 30-39, 48–65, 104–113, 129–134.

[91] *Westar Energy, Inc.*, 134 FERC ¶ 61,176, at P 23 (2011), *citing Calpine Oneta Power v. American Elec. Power Serv. Corp.*, 114 FERC ¶ 61,030 (2006); *Midwest Indep. Transmission Sys. Op., Inc.*, 112 FERC ¶ 61,211, at P 34 (2005) (citing *Baltimore Gas & Elec. Co.*, 91 FERC ¶ 61,270 (2000) and *Baltimore Gas & Elec. Co.*, 92 FERC ¶ 61,043, at 61,114 (2000)).

[92] *Midwest Indep. Transmission Sys. Op., Inc.*, 112 FERC ¶ 61,211 at P 34.

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not explain why they failed to provide the material contained in the affidavits at an earlier stage in this proceeding. Therefore, we reject the affidavits and disregard all citations to extra-record evidence.

58. While we reject the untimely arguments and affidavits on procedural grounds, we nonetheless review these matters and, in the alternative, deny the requests on substantive grounds. Accordingly, below, we review in summary fashion the following issues denied as untimely requests for rehearing that are raised either in the EEI/NRECA Request or in the supporting affidavits: (1) identification of critical sub-200 kV transmission facilities; (2) supervisory relays; (3) due weight owed to the ERO's recommendation; and (4) stable power swings. While some arguments regarding the weight owed to the ERO's recommendations were timely raised and are discussed above, the arguments addressed below are rejected as procedurally defective since they do not arise out of a clarification made in Order No. 733-A. Similarly, though we have already addressed stable power swings above, we return to that subject to address matters raised out-of-time in the Wiedman Affidavit.

1. Identification of Critical Sub-200 kV Transmission Facilities

EEI/NRECA Arguments

59. EEI/NRECA argue that the Commission's directive to create a uniform test to identify critical sub-200 kV facilities is not supported by the Blackout Report. In particular, EEI/NRECA, relying on the Wiedman affidavit, question the accuracy of the Order No. 733-A statement that critical facilities between 100 and 200 kV must be identified and subject to PRC-023 "to prevent a recurrence of the undesirable system performance that occurred during the August 2003 blackout."[93] While Order No. 733-A refers to the tripping of thirteen lines during a four minute period, EEI/NRECA argue the tripping of the 138 kV lines would have happened regardless of whether they were subject to the loadability requirements of PRC-023-1.[94]

60. EEI/NRECA rely on the Wiedman affidavit's statements that the Blackout Report indicates that the steady state loadability of transmission relays at 345 kV were at issue. Mr. Wiedman avers that, since PRC-023 protects the loadability of the 345 kV lines, the 138 kV lines tripped due to system conditions directly related to the 345 kV line trips in the immediate vicinity.[95] Wiedman posits that, if the 345 kV lines did not trip (because

[93] EEI/NRECA at 7; Wiedman Affidavit P 42.

[94] EEI/NRECA at 7-8.

[95] Wiedman Affidavit P 9.

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the relays were properly set pursuant to PRC-023), the control room operators at FirstEnergy would have had sufficient time to manually shed load and arrest a potential cascade.[96] Thus, according to the affidavit, inclusion of the 138 kV facilities in PRC-023 would not have improved performance during the 2003 blackout.

Commission Determination

61. We are unpersuaded by EEI/NRECA's reasoning. First, while NERC's predecessor organization, the North American Electric Reliability Council, recommended that transmission owners evaluate the settings of zone 3 relays on all transmission lines of 230 kV and higher, it was the U.S. – Canada Task Force, with technical advice from the Electric System Working Group,[97] that recommended that the review be broadened to include operationally significant 115 kV and 138 kV lines.[98] Moreover, NERC, utilizing industry experts in the standards drafting process, developed Reliability Standard PRC-023-1, which requires planning coordinators to determine which 100-200 kV facilities are critical to the reliability of the bulk electric system in order to identify facilities to be subject to the Standard. The Commission directive pertained to the development of a uniform test for planning coordinators to apply when identifying such facilities.

62. Second, EEI/NRECA assert that the basis for the directive to develop a uniform test is found in a flawed analysis of the events of the August 2003 Blackout, quoting Mr. Wiedman's assertion that "[t]he inclusion of sub-200 kV facilities in the PRC-023 would not have improved performance during the August 2003 Blackout."[99] But Order No. 733-A explained that the 138 kV lines at issue did not trip as a result of the matters addressed by Reliability Standard PRC-023-1.[100] Rather than the specific role played by

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[96] Wiedman Affidavit P 49.

[97] *See generally* Blackout Report, Appendix A, Members of the U.S.-Canada Power System Outage Task Force and its Three Working Groups, (composition of Task Force and the Electric System Working Group), and Appendix B, Description of Outage Investigation and Process for Development of Recommendations, at 175-187.

[98] Blackout Report at 156.

[99] EEI/NRECA Request at 8.

[100] Order No. 733-A, 134 FERC ¶ 61,127 at P 35 *citing* Order No. 733, 130 FERC ¶ 61,221 at P 52 ("The cascade of 138 kV lines was precipitated by faults caused by tree contact, not protective relays, and would not have been prevented if PRC-023-1 had been in effect before the blackout.").

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relays on sub-200 kV facilities during the August 2003 Blackout, the Commission's concern was the inclusiveness of the test.[101] After its examination of the August 2003 Blackout, the U.S. – Canada Task Force determined that zone 3 relays on operationally significant 100-200 kV circuits should be evaluated because they were one of the causes for a portion of the blackout. The Task Force adopted a methodical approach addressing each of the factors that played a role in a blackout since in order to achieve the reliability goal, all the causes must be addressed.

63. Accordingly, were these issues timely raised and not barred from consideration, we would nevertheless deny EEI/NRECA's request for clarification regarding the directive to develop a uniform test to identify critical sub-200 kV facilities.

2. Supervisory Relays

EEI/NRECA Arguments

64. EEI/NRECA argue that the overbroad nature of the Commission's directive on supervisory relays is based on an incorrect characterization of relay engineering and would likely lead to a reduction in reliability. Adding supervisory relays to the scope of the Standard, they contend, would add costs while threatening to harm reliability. The Miller Affidavit purports to survey supervisory relays applied for both voltage and current supervision on a variety of protection systems in normal operation and, in one instance, during protection system failures. Mr. Miller, however, states that experienced engineers generally agree with applying Reliability Standard PRC-023 to phase overcurrent supervisory elements associated with current-based communication-assisted schemes where the scheme is capable of tripping for a loss of communication.[102]

Commission Determination

65. We do not dispute the observations concerning many technical applications raised in the Miller Affidavit. The Commission's reliability concern arises from an actual incident, and the Miller Affidavit supports application of PRC-023 to the protection scheme involved in that event. As a result of that incident, we concluded that it is inappropriate to exclude all supervising relays from the scope of PRC-023. The concern EEI/NRECA raises about our directive regarding supervising relays should be ameliorated by our clarification made above that the directive does not foreclose the

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[101] Order No. 733-A, 134 FERC ¶ 61,127 at P 22 (*citing* Order No. 733, 130 FERC ¶ 61,221 at P 49-50, 77-78).

[102] Miller Affidavit at 8.

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development of a tailored approach that applies the Standard to some supervising relays but not to others.

3. Due Weight Owed to the ERO's Recommendation Regarding Implementation of Blackout Report's Recommendations

EEI/NRECA Arguments

66. EEI/NRECA contend that the Commission's directives regarding PRC-023-1 are not supported by the Blackout Report, but the proposed Reliability Standard does satisfy the Blackout Report's recommendations. They argue that, had proposed Reliability Standard PRC-023-1 been properly implemented prior to August 2003, the 345 kV Sammis-Star line would not have tripped and the control room operators at FirstEnergy should then have had enough time to manually shed load thus averting the cascade. EEI/NRECA further argue that proposed Reliability Standard PRC-023-1 is therefore an appropriate exercise of NERC's technical expertise and deserves deference.

Commission Determination

67. The Commission does not share the same confidence that PRC-023-1, properly implemented, would have allowed system operators to prevent the cascade that followed the tripping of the Sammis-Star line. In filing Reliability Standard PRC-023-1 for Commission approval, the ERO was only prepared to say:

> [i]t is difficult to be certain about the effects that this proposed reliability standard would have had on the end-state of the blackout. Considered in concert with other activities that have been precipitated by the blackout investigation, it seems clear that the events of the blackout would have taken a very different course and that relay loadability would not have been as pivotal a factor as seen on August 14, 2003.[103]

Similarly, Order No. 733-A states that "[t]o assert, as Order No. 733 does, that one cannot definitely conclude on the present record that PRC-023-1 would have prevented the spread of the blackout…by no means is intended to minimize the significance of relay loadability."[104]

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[103] NERC, Petition for of PRC-023-1 Reliability Standard, Docket No. RM08-13-000, at 7 (filed July 30, 2008).

[104] Order No. 733-A, 134 FERC ¶ 61,127 at P 38 (citation omitted).

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68. Nevertheless, even if one were to assume the accuracy of EEI/NRECA's claim regarding PRC-023-1, it would not foreclose the Commission from making directives with respect to the subject matter of the Reliability Standard. The standard for review of proposed Reliability Standards or modifications to existing Standards is not, as presented by EEI/NRECA, an inquiry into whether they are "needed to prevent the re-occurrence of events such as those that occurred during the August 2003 [b]lackout."[105] A directive is authorized under section 215(d)(5) if it is appropriate to carry out the purposes of section 215 of the FPA. Thus, while the technical expertise of the ERO must be given due weight, the fact that compliance with a proposed Reliability Standard would have mitigated the August 2003 Blackout does not prevent the Commission making directives to address identified gaps in reliability associated with the Standard.

69. Accordingly, were this issue timely raised and not barred from consideration, we would nevertheless deny EEI/NRECA's request for clarification regarding whether the Commission properly gave due weight to the ERO's technical expertise.

4. Stable Power Swings

Wiedman Affidavit

70. In his affidavit, Mr. Wiedman argues the tripping of lines that occurred during the August 2003 Blackout was not the result of the inability of relays to distinguish between faults and stable power swings but rather was the result of loading conditions on extra high-voltage power lines. During the time after the Sammis-Star line tripped and the system separated, the Blackout-Report does not refer to any line trip as the result of either a stable or an unstable power swing. Furthermore, he argues, the Commission's directive does not sufficiently reflect the threat to reliability posed by the modification of existing relay settings.

Commission Determination

71. We agree with Mr. Wiedman that the Blackout Report does not identify lines as tripping because of stable or unstable power swings during the period between the Sammis-Star tripping and the system separating, nor does the report identify steady state current flows as the cause of relays tripping. His affidavit simply fails to address how it came to be that zone 3 relays tripped without stable power swings. He asserts that the Galion-Ohio Central-Muskingum 345 kV line tripped by its zone 3 relay because of a load current that was well above its emergency line conductor rating, and that several 138 kV lines tripped, mostly by zone 3 or zone 2 impedance relays, as they experienced levels

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[105] EEI/NRECA Request at 19.

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of line overload.[106] But he fails to address how, absent a stable or unstable power swing, the line current rose to the point that the impedance encroached those zone 3 relays' operating zones.

72. Mr. Wiedman's assertion that the zone 3 relay on the Sammis-Star line tripped when experiencing a voltage of 95 percent of normal and a current just barely above its thermal rating is troubling. Such conditions are essentially within normal operation, and tripping would only occur if the impedance, as seen by the zone 3 relays, encroached into the operating zone of the relay. Stable power swings can cause relays to unreliably detect fault conditions. Mr. Wiedman does not deny this; he only argues the Blackout Report does not explicitly state stable power swings were the cause of any given line tripping while failing to acknowledge the Report's statements about the impact of power swings.[107] The ERO and the Blackout Report confirm the threat posed by stable power swings to system reliability.[108] We are unpersuaded by Mr. Wiedman's arguments.

73. As for Mr. Wiedman's assertion that the Commission's directive regarding stable power swings downplays the threat to reliability posed by the modification of existing relay settings, we note that the examples he gives would fail to meet the Reliability Standard PRC-001's requirement that protective systems be coordinated. There are alternative approaches to addressing our directive that Mr. Wiedman does not mention. We are therefore not convinced that the ERO's response to our directive will result in a diminution of reliability. Accordingly, were these issues timely raised and not barred from consideration, we would nevertheless deny EEI/NRECA's request for clarification regarding stable power swings.

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[106] Wiedman Affidavit at 1-11.

[107] *E.g*., Blackout Report at 73 ("Power swings and voltage fluctuations caused by [a few initiating events as seen on August 14, 2003,] can cause other lines to detect high currents and low voltages that appear to be faults, even if faults do not actually exist on those other lines."); Blackout Report at 80 ("The Sammis-Star line tripped at 16:05:57 EDT on a zone 3 impedance relay although there were no faults occurring at the time, because increased real and reactive power flow caused the apparent impedance to be within the impedance circle (reach) of the relay.").

[108] *See* Section II.B. Stable Power Swings, *supra*. In addition, in its Informational Filing, the ERO states that it has unpublished analysis that show some of the lines that tripped during the August 2003 Blackout were due to stable power swings. NERC Informational Filing at 6-7.

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The Commission orders:

(A) The requests for clarification are hereby granted, in part, and denied, in part, as discussed in the body of this order.

(B) The requests for reconsideration are hereby denied.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Document Content(s)

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136 FERC 61,208
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Marc Spitzer, Philip D. Moeller,
John R. Norris, and Cheryl A. LaFleur.

North American Electric Reliability Corporation Docket No. RD11-5-000

ORDER APPROVING INTERPRETATION OF RELIABILITY STANDARDS

(Issued September 26, 2011)

1. On April 15, 2011, the North American Electric Reliability Corporation (NERC) filed a petition seeking Commission approval of an interpretation of Requirements R1 and R3 of Reliability Standard PRC-004-1 (Analysis and Mitigation of Transmission and Generation Protection System Misoperations) and Requirements R1 and R2 of Reliability Standard PRC-005-1 (Transmission and Generation Protection System Maintenance and Testing). The Commission approves NERC's interpretation, effective as of the date of this order.

I. Background

2. On March 16, 2007, pursuant to section 215(d) of the Federal Power Act (FPA),[1] the Commission issued Order No. 693 approving 83 Reliability Standards proposed by NERC, including PRC-004-1 and PRC-005-1.[2]

3. NERC's Rules of Procedure provide that all persons "directly and materially affected" by Bulk-Power System reliability may request an interpretation of a Reliability Standard.[3] In response to a request, NERC assembles a team with relevant expertise to

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[1] 16 U.S.C. § 824o(d) (2006).

[2] *See Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[3] NERC Rules of Procedure, Appendix 3A, Reliability Standards Development Procedure Version 7, at 30 (2010); NERC Rules of Procedure, Appendix 3A, Standards Process Manual, at 27 (2010). NERC states that it initially developed the interpretation

(continued…)

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address the requested interpretation and forms an industry ballot pool. NERC's Rules of Procedure provide that, within 45 days, the team will draft an interpretation of the Reliability Standard, with subsequent balloting. If approved by industry ballot and the NERC Board of Trustees, the interpretation is appended to the Reliability Standard and filed with the applicable regulatory authority for approval. When the subject Reliability Standard is next revised, the interpretation is incorporated into the Reliability Standard.

II. NERC Filing

4. NERC states that on March 25, 2009, the Y-W Electric Association and Tri-State Generation and Transmission Association requested an interpretation from NERC for the term "transmission Protection System" as it appears in Requirements R1 and R3 of PRC-004-1 and Requirements R1 and R2 of PRC-005-1 and "specifically whether protection for a radially-connected transformer protection system energized from the BES [bulk electric system] is considered a transmission Protection System and is subject to these standards."[4]

Requirements R1 and R3 of PRC-004-1

5. Requirements R1 and R3 of PRC-004-1 address a responsible entity's obligation to analyze transmission Protection System misoperations and to develop and implement corrective actions to avoid future misoperations. The specific language of Requirements R1 and R3 is:

> R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1.
>
> R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.

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under the Reliability Standards Development Procedure Version 7 until it was superseded by the current Standards Process Manual on September 3, 2010. Petition at 4 n.4.

[4] Petition at 7.

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Requirements R1 and R2 of PRC-005-1

6. Requirements R1 and R2 of PRC-005-1 address a responsible entity's obligation to maintain and test Protection Systems that affect the reliability of the bulk electric system. The specific language of Requirements R1 and R2 is:

> R1. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include: . . .
>
> R2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include: . . .

NERC Interpretation

7. NERC interprets "transmission Protection System," as it appears in Requirements R1 and R3 of PRC-004-1 and Requirements R1 and R2 of PRC-005-1, to mean "any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES."[5] In addition, NERC's proposed interpretation states that "[a] Protection System for a radially connected transformer energized from the BES would be considered a transmission Protection System and subject to these standards only if the protection trips an interrupting device that interrupts current supplied directly from the BES and the transformer is a BES element."[6]

8. NERC requests that the Commission approve the interpretation and that it be made effective immediately upon approval, consistent with the Commission's procedures.

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[5] *Id.* at 7.

[6] *Id.*

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III. Procedural Matters

9. Notice of NERC's filing was published in the *Federal Register*, 76 Fed. Reg. 34,224 (2011), with interventions and protests due on or before July 1, 2011. A motion to intervene was timely filed by American Municipal Power, Inc. No comments or protests were filed.

IV. Discussion

A. Preliminary Matters

10. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2011), American Municipal Power, Inc.'s timely, unopposed motion to intervene serves to make it a party to this proceeding.

B. Commission Determination

11. The Commission approves NERC's interpretation as it is consistent with the intent of Requirements R1 and R3 of PRC-004-1 and Requirements R1 and R2 of PRC-005-1. The interpretation clarifies that the Requirements are "applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the [BES] and trips an interrupting device that interrupts current supplied directly from the BES."[7] This interpretation is consistent with the Commission's understanding that a "transmission Protection System" is installed for the purpose of detecting and isolating faults affecting the reliability of the bulk electric system through the use of current interrupting devices. The Commission further understands that the "interrupting device" referred to in the interpretation is a device that has the performance capability to interrupt full fault current associated with the protected bulk electric system facilities.

The Commission orders:

NERC's proposed interpretation of Requirements R1 and R3 of PRC-004-1 and Requirements R1 and R2 of PRC-005-1 is hereby approved, effective as of the date of this order, as discussed in the body of this order.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

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[7] *Id.* at 10.

Document Content(s)

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	**)** **)**	**Docket No. RR10-1-001**

ANNUAL REPORT OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION ON WIDE-AREA ANALYSIS OF TECHNICAL FEASIBILITY EXCEPTIONS

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September 28, 2011

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Exhibit A – Supporting Spreadsheets

I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC")[1] hereby provides the first Annual Report on Wide-Area Analysis of Technical Feasibility Exceptions ("TFEs") in compliance with Paragraphs 220 and 221 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") Order No. 706,[2] FERC's January 21, 2010 Order Approving TFE Procedures and Ordering Compliance Filing,[3] and Appendix 4D of the NERC Rules of Procedure.

In Order No. 706, NERC was directed to submit an annual report to the Commission that provides a wide-area analysis regarding use of the TFEs ("Annual Report") and the effect on Bulk-Power System reliability. In FERC's January 21 Order, FERC renewed its directive and ordered NERC to modify Appendix 4D of the NERC Rules of Procedure to direct the inclusion of specific criteria in the Annual Report. Currently, Appendix 4D of the NERC Rules of Procedure, as approved by FERC, requires NERC to submit its first Annual Report covering the initial period from January 1, 2010 through June 30, 2011. By this informational filing, NERC submits the Annual Report, in accordance with Order No. 706, FERC's January 21 Order, and Appendix 4D of the NERC Rules of Procedure.

In support of this first Annual Report, NERC submits supporting spreadsheets detailing the TFE data provided to NERC by the Regional Entities. (*See,* **Exhibit A**).

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[1] The Federal Energy Regulatory Commission ("FERC" or "Commission") certified NERC as the electric reliability organization ("ERO") in its order issued on July 20, 2006 in Docket No. RR06-1-000. *North American Electric Reliability Corporation*, "Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing," 116 FERC ¶ 61,062 (July 20, 2006).

[2] Mandatory Reliability Standards for Critical Infrastructure Protection, 122 FERC ¶ 61,040 (January 18, 2008) ("Order No. 706").

[3] *Order Approving Technical Feasibility Exception Procedures and Ordering Compliance Filing*, 130 FERC ¶ 61,050 (January 21, 2010) ("January 21 Order").

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to:

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III. DISCUSSION

A. Background

In Order No. 706, FERC approved eight Critical Infrastructure Protection ("CIP") Reliability Standards and directed NERC to develop a set of conditions or criteria that a responsible entity must follow when relying on the TFE contained in specific Requirements of the CIP Reliability Standards.[4] The criteria to determine a "technical feasibility" exception are

[4] *Mandatory Reliability Standards for Critical Infrastructure Protection*, 122 FERC ¶ 61,040 at P 178 (January 18, 2008) ("Order No. 706").

intended to address "long-life equipment in place that is not readily compatible with a modern environment where cyber security issues are an acknowledged concern."[5]

Order No. 706 also provides:

> The annual report must address, at a minimum, the frequency of the use of such provisions, the circumstances or justifications that prompt their use, the interim mitigation measures used to address vulnerabilities, and efforts to eliminate future reliance on the exception. . . [T]he report should contain aggregated data with sufficient detail for the Commission to understand the frequency with which specific provisions are being invoked as well as high level data regarding mitigation and remediation plans over time and by region . . . .[6]

On October 20, 2009, NERC submitted a petition for approval to amend the NERC Rules of Procedure to include: (i) a new Section 412, Requests for Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Reliability Standards; and (ii) a new Appendix 4D, Procedure for Requesting and Receiving Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Standards.[7]

Under the proposed TFE procedure, Appendix 4D provides that a TFE request must demonstrate that strict compliance with an applicable requirement, evaluated in the context of the Responsible Entity's covered asset that is the subject of the TFE request, is not technically feasible or is operationally infeasible. A covered asset is defined in Appendix 4D as: "A Cyber Asset or Critical Cyber Asset that is subject to an Applicable Requirement."[8]

The NERC-proposed TFE procedure also required an Annual Report that would include, at a minimum: (i) the frequency of use of the TFE Request process, (ii) categorization of the

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[5] *Id.* at P 180.
[6] *Id.* at P 220.
[7] *Petition for Approval of Amendments to the Rules of Procedure of the North American Electric Reliability Corporation – New Section 412 and Appendix 4D, "Procedure for Requesting and Receiving Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Standards,"* Docket No. RR10-1-000 (October 29, 2009) ("NERC Petition").
[8] Section 2.9, Appendix 4D of the NERC Rules of Procedure.

submitted and approved TFE Requests to date by broad categories, (iii) categorization of the circumstances or justifications on which the approved TFEs to date were submitted and approved, (iv) categorization of the compensating measures and mitigating measures implemented and maintained by Responsible Entities, (v) a discussion of Compliance Audit results and findings concerning the implementation and maintenance of compensating measures and mitigating measures, (vi) assessments, and (vii) discussion of efforts to eliminate future reliance on TFEs.

In addition, the NERC proposal required that information on the frequency of use of the TFE process include: (a) the numbers of TFE requests that have been submitted, accepted/rejected, and approved/disapproved, (b) the number of approved TFEs that are still in effect as of on or about the date of the Annual Report, (c) the numbers of approved TFEs that reached their expiration dates, or were terminated, and (d) the number of approved TFEs that are scheduled to reach expiration date during the ensuing year.[9]

On January 21, 2010, FERC issued an order approving NERC's proposed TFE procedures and directing a compliance filing.[10] With respect to the information to be included in the Annual Report, the January 21 Order directed that:

> … NERC's report must also distinguish the number of TFEs approved from the number of assets with approved TFEs. In addition, in NERC's annual report the information required by section 12.1(iii) and (iv) must be detailed enough to allow the Commission to evaluate the level of consistency among the Regional Entities in both the justification for granting TFEs and the accepted mitigation measures among similar approved TFEs. This information should be provided to the Commission in such a way as to avoid security concerns accompanying individual asset identification. Further, NERC's annual report also should include for each TFE request that was granted an Effective Date beyond the outer limits to be set forth in sections 5.1.5 and 5.2.6, due to exceptional circumstances, the number of days the request was not subject to imposition of any

[9] NERC Petition at Appendix 4D, § 12.1(i).
[10] January 21 Order at P 14.

> findings of violations or imposition of penalties or sanctions under section 5.3.[11]

On April 21, 2010, NERC submitted a compliance filing in response to the January 21 Order that included a revised Appendix 4D. On October 1, 2010, FERC issued an order directing NERC to, among other things, revise section 12.1, "Contents of Annual Report."

On December 23, 2010, NERC filed another compliance filing revising Appendix 4D in response to FERC's October 1, 2010 Order.[12] In its April 12, 2011 Order, FERC accepted NERC's December 23, 2010 filing as compliant with its directives.[13] Therefore, Appendix 4D now provides that NERC must report annually on the consistency within the TFE process and on the criteria of TFE requests. Specifically, Section 11.2.4 of Appendix 4D, which provides reporting requirements regarding consistency within the TFE process, and Section 13, which provides criteria to be included in each annual report, state:

> **Section 11.2.4**
> NERC will submit to the FERC and to other Applicable Governmental Entities an annual informational report containing the following information concerning the manner in which Regional Entities have made determinations to approve or disapprove TFE Requests based on the criteria of Section 3.1:
>
> (i) whether any issues were identified during the period covered by the informational report with respect to the consistency of the determinations made based on the criteria in Section 3.1, either within a Regional Entity or among Regional Entities;
>
> (ii) a description of any such identified consistency issues;
>
> (iii) how each consistency issue was resolved;
>
> (iv) the numbers of TFE Requests for which reconsideration was requested pursuant to Section 5.2.9 based on purported inconsistencies in determinations applying the criteria in Section 3.1 and the numbers of such

[11] January 21 Order at P 57.
[12] *Compliance Filing of the North American Electric Reliability Corporation in Response to October 1, 2010 Commission Order Concerning Appendix 4D to the NERC Rules Of Procedure – "Procedure for Requesting and Receiving Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Standards"* Docket No. RR10-1-001 (December 23, 2010)
[13] *Order on Compliance Filing*, 135 FERC ¶ 61,026 (April 12, 2011).

requests which resulted in TFE Requests being approved, disapproved and rejected; and

(v) whether NERC has developed or is in a position to develop a uniform framework for Regional Entities to use to appraise the reliability benefits of Strict Compliance when making determinations based on the criteria in Section 3.1(iv) and (vi).

Section 13

(i) The frequency of use of the TFE Request process, disaggregated by Regional Entity and in the aggregate for the United States and for the jurisdictions of other Applicable Governmental Authorities, including (A) the numbers of TFE Requests that have been submitted, accepted/rejected, and approved/disapproved during the preceding year and cumulatively since the effective date of this Appendix, (B) the numbers of unique Covered Assets for which TFEs have been approved, (C) the numbers of approved TFEs that are still in effect as of on or about the date of the Annual Report; (D) the numbers of approved TFEs that reached their Expiration Dates or were terminated during the preceding year; and (E) the numbers of approved TFEs that are scheduled to reach their Expiration Dates during the ensuing year;

(ii) Categorization of the submitted and approved TFE Requests to date by broad categories such as the general nature of the TFE Request, the Applicable Requirements covered by submitted and approved TFE Requests, and the types of Covered Assets that are the subject of submitted and approved TFE Requests;

(iii) Categorization of the circumstances or justifications on which the approved TFEs to date were submitted and approved, by broad categories such as the need to avoid replacing existing equipment with significant remaining useful lives, unavailability of suitable equipment to achieve Strict Compliance in a timely manner, or conflicts with other statutes and regulations applicable to the Responsible Entity;

(iv) Categorization of the compensating measures and mitigating measures implemented and maintained by Responsible Entities pursuant to approved TFEs, by broad categories of compensating measures and mitigating measures and by types of Covered Assets;

(v) For each TFE Request that was rejected or disapproved, and for each TFE that was terminated, but for which, due to exceptional circumstances as determined by the Regional Entity, the Effective Date was later than the latest date specified in Section 5.1.5, 5.2.6, or 9.3, as applicable, a statement of the number of days the Responsible Entity was not subject to imposition of findings of violations of the Applicable Requirement or imposition of penalties or sanctions pursuant to Section 5.3.

(vi) A discussion, on an aggregated basis, of Compliance Audit results and findings concerning the implementation and maintenance of compensating measures and mitigating measures, and the implementation of steps and the conduct of research and analyses to achieve Strict Compliance with the Applicable Requirements, by Responsible Entities in accordance with approved TFEs;

(vii) Assessments, by Regional Entity (and for more discrete areas within a Regional Entity, if appropriate) and in the aggregate for the United States and for the jurisdictions of other Applicable Governmental Authorities, of the wide-area impacts on the reliability of the Bulk Electric System of approved TFEs in the aggregate, including the compensating measures and mitigating measures that have been implemented; and

(viii) Discussion of efforts to eliminate future reliance on TFEs.

Each of these criteria is addressed below in Section III.B.

B. Summary of Annual Report

In accordance with Appendix 4D of the NERC Rules of Procedure, Regional Entities submit confidential quarterly reports to NERC regarding the types of Covered Assets for which TFE Requests are approved. In addition to providing quarterly reports, each Regional Entity submitted responses to the eight criteria identified in Section 13.1 of Appendix 4D to be included in the Annual Report. NERC has compiled and analyzed the vast amount of TFE data provided by the Regional Entities in preparation for this Annual Report.

The following is a summary of the TFE data reported by each Regional Entity for the eight criteria. **Exhibit A** to this filing provides a detailed breakdown of the compiled TFE data for criteria (i) through (v). The exhibit includes both aggregated information for the ERO and disaggregated information by Regional Entity.

1. **Criterion (i): The frequency of use of the TFE Request process, disaggregated by Regional Entity and in the aggregate for the United States and for the jurisdictions of other Applicable Governmental Authorities, including (A) the numbers of TFE Requests that have been submitted, accepted/rejected, and approved/disapproved during the preceding year and cumulatively since the effective date of this Appendix, (B) the numbers of unique Covered Assets for which TFEs have been approved, (C) the numbers of approved TFEs that are still in effect as of on or about the date of the Annual Report; (D) the numbers of approved TFEs that reached their Expiration Dates or were terminated during the preceding year; and (E) the numbers of approved TFEs that are scheduled to reach their Expiration Dates during the ensuing year;**

The total aggregate number of TFE requests that were in the initial stages of the review process as of June 30, 2011, is 5,288. A breakdown of TFE requests at this stage by Regional Entity is: FRCC (339), MRO (314), NPCC (0), RFC (1,173), SERC (751), SPP-RE (225), TRE (569), and WECC (1,917).

The total aggregate number of TFE requests that have been accepted since the process was initiated on January 1, 2010 is 3,492. A breakdown of TFE Requests accepted by Regional Entity is: FRCC (297), MRO (311), NPCC (27), RFC (1,065), SERC (662), SPP-RE (222), TRE (539), and WECC (369). Table 1 below provides the aggregate number of TFEs accepted, and indicates that TFEs are most frequently accepted for Reliability Standard CIP-007, Requirement (R) 4.[14]

[14] CIP-007, R 4 provides:

> R4. Malicious Software Prevention —The Responsible Entity shall use anti-virus software and other malicious software ("malware") prevention tools, where technically feasible, to detect, prevent, deter, and mitigate the introduction, exposure, and propagation of malware on all Cyber Assets within the Electronic Security Perimeter(s).

Table 1

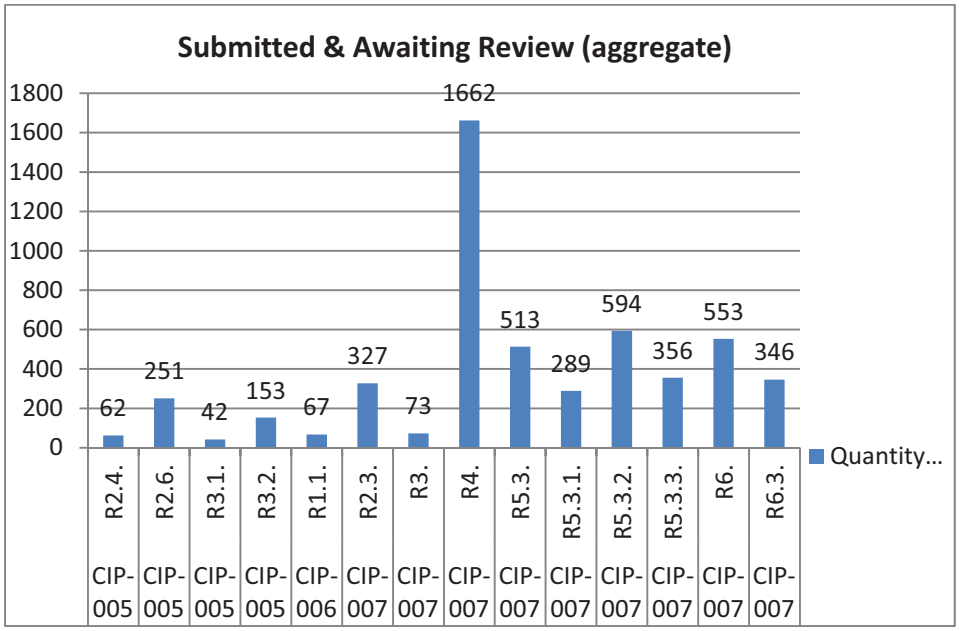

The total number of TFE requests that have been rejected is 448. A breakdown of TFE Requests rejected by Regional Entity is: FRCC (6), MRO (1), NPCC (2), RFC (105), SERC (62), SPP-RE (1), TRE (30), and WECC (241).

The total number of TFE Requests that have been accepted and approved are 3,369. A breakdown of the TFE Requests accepted and approved by Regional Entity is: FRCC (199), MRO (304), NPCC (385), RFC (943), SERC (362), SPP-RE (146), TRE (459), and WECC (568). As shown in Table 2 below, TFEs for CIP-007, R4, are the most frequently accepted and approved TFEs.

Table 2

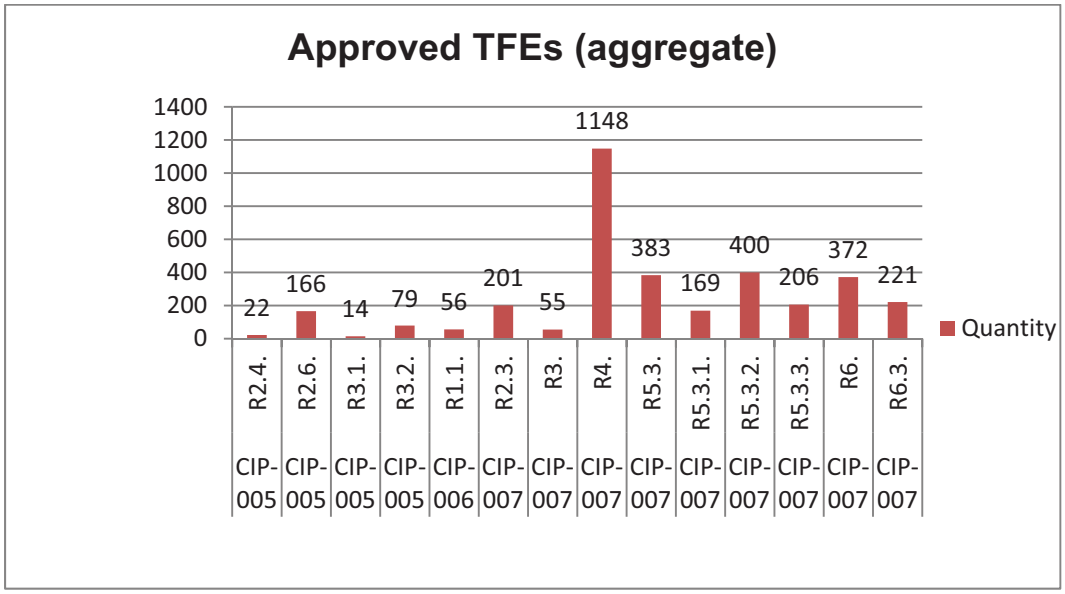

The total number of TFE Requests that have been accepted and disapproved is 782. A breakdown of the TFE Requests accepted and disapproved by Regional Entity is as follows: FRCC (30), MRO (7), NPCC (0), RFC (53), SERC (160), SPP-RE (41), TRE (80), and WECC (411). "Accepted and disapproved" means that the proposed TFE met the initial filing requirements for acceptance, but upon subsequent detailed review was determined not to qualify.

To date, the number of unique Covered Assets for which TFEs have been approved is 68,323. A breakdown of approved Covered Assets by Regional Entity is: FRCC (1,988), MRO (7,577), NPCC (9,715), RFC (22,116), SERC (9,535), SPP-RE (2,433), TRE (7,647), and WECC (7,311).

The numbers of approved TFEs that are active and still in effect as of this report are 2,416. A breakdown of TFE Requests active and still in effect by Regional Entity is: FRCC (195), MRO (235), NPCC (385), RFC (771), SERC (368), SPP-RE (104), TRE (324), and WECC (34).

The number of approved TFEs that reached their expiration dates or were terminated during the preceding year is 565. A breakdown of TFE requests that reached their expiration dates or were terminated by Regional Entity is: FRCC (4), MRO (79), NPCC (26), RFC (172), SERC (15), SPP-RE (119), TRE (135), and WECC (15).

The number of approved TFEs that are scheduled to reach their expiration dates during the ensuing year is 166. A breakdown of TFE Requests to reach their expiration dates during the ensuing year by Regional Entity is: FRCC (3), MRO (23), NPCC (4), RFC (80), SERC (17), SPP-RE (8), TRE (5), and WECC (26).

2. Criteria (ii): Categorization of the submitted and approved TFE Requests to date by broad categories such as the general nature of the TFE Request, the Applicable Requirements covered by submitted and approved TFE Requests, and the types of Covered Assets that are the subject of submitted and approved TFE Requests.

As indicated in the Table 3 below, CIP-007, R4, includes the single largest category of TFE's, with 5,063 submitted and approved Covered Assets. CIP-007, R5 – when combining CIP-007, R5, R5.3.1, R5.3.2, and R5.3.3 – also accounts for 7,048 of the total submitted and approved Covered Assets. A significant amount of Covered Assets were also submitted and approved for CIP-005, R2 (868) and CIP-007, R3 (465).

The three largest categories of submitted and approved Covered Assets include: Network Data Communications Devices (3,215), Industrial Process Control Systems (3,064), and Servers (2,403). As one Regional Entity (FRCC) reported, the ubiquitous presence of Microsoft Windows operating system has been an issue for Responsible Entities in meeting password requirements. Moreover, Regional Entities report that TFEs for CIP-007, R4, include multiple devices that will likely not have anti-malware available in the near future. (*e.g.*, relays, remote terminal units (RTU), programmable logic controllers (PLC), and printers).

Table 3

Asset Categories (per Part A of TFE request)	Quantity of TFEs - submitted & approved														
	CIP-005				CIP-006	CIP-007									
	R2.4	R2.6	R3.1	R3.2	R1.1	R2.3	R3.2	R4	R5.3	R5.3.1	R5.3.2	R5.3.3	R6	R6.3	Total
Data Storage Device	0	16	0	3	0	3	2	104	12	33	52	5	13	10	270
Digital Protective Control Device	0	1	0	0	0	5	0	20	4	1	6	2	7	1	70
Electronic Access Control System	6	74	0	12	6	2	6	249	7	9	28	16	3	1	482
Electronic Access Monitoring System	3	16	5	2	2	0	2	212	9	13	66	25	8	0	387
Industrial Process Control System	0	10	0	6	0	558	2	644	592	17	60	54	588	563	3214
Mainframe Computer	2	0	0	0	0	0	0	2	0	0	1	0	0	0	5
Network Data Communications Devices	5	44	3	24	7	38	12	1631	459	34	217	38	470	233	3440
PC Laptop	2	4	0	0	5	16	31	21	136	2	90	14	4	8	353
Peripheral Device	0	5	0	3	0	27	1	99	52	35	35	21	81	52	489
Physical Access Control System	3	127	3	15	2	7	2	135	82	12	43	20	16	14	528
Physical Access Monitoring System	1	10	3	16	11	9	2	74	21	14	36	12	8	7	227
Physical Security Perimeter	0	1	0	2	21	1	0	7	0	1	3	1	1	1	46
Relay	0	4	0	0	0	7	0	218	16	2	15	7	13	4	315
RTU	0	8	0	9	0	17	0	240	22	7	9	7	33	19	427
Servers	1	1	3	1	4	30	396	980	250	19	564	34	60	61	2475
Telecommunications Device	3	20	0	11	4	22	1	51	4	23	26	12	29	16	247
Transmitters	0	0	0	0	0	4	0	4	2	2	2	0	4	0	21
Valve Controllers	0	0	0	0	0	0	0	1	0	0	0	0	0	0	1
Other	0	18	8	3	120	45	3	211	55	64	110	70	108	84	1040
Total	33	405	32	135	185	868	465	5303	1779	322	1418	374	1573	1145	14037

3. Criteria (iii): Categorization of the circumstances or justifications on which the approved TFEs to date were submitted and approved, by broad categories such as the need to avoid replacing existing equipment with significant remaining useful lives, unavailability of suitable equipment to achieve Strict Compliance in a timely manner, or conflicts with other statutes and regulations applicable to the Responsible Entity.

In Table 4 below, the categories of circumstances or justifications on which the TFEs to date were submitted and approved include:

- Not technically possible (2,814)
- Operationally infeasible (227)
- Precluded by technical limitations (774)
- Adverse effect on BES reliability (41)
- Cannot achieve by compliance date (94)
- Excessive cost that exceeds reliability benefit (21)
- Conflicts with other statutory or regulatory requirement(74)
- Unacceptable safety risks (3)

When assessing proposed TFEs, the Regional Entities considered the criteria that each Responsible Entity used as the basis for each request. A large majority of TFEs (nearly 3,000) cited "not technically possible" as the basis for the request. The figures below show the aggregate percentages for each of the cited categories:

- Not technically possible 71%
- Precluded by technical limitations 19%
- Operationally infeasible 6%
- Cannot achieve by compliance date 2%
- Adverse effect on BES reliability 1%
- Excessive cost that exceeds reliability benefit <1%
- Conflicts with other statutory or regulatory requirement <1%
- Unacceptable safety risks <1%

Table 4

Asset Categories (per Part A of TFE request)	Aggregate - Approved TFEs - Basis								
	Not technically possible	Operationally infeasible	Precluded by technical limitations	Adverse effect on BES reliability	Cannot achieve by compliance date	Unacceptable safety risks	Conflicts with other statutory or regulatory requirement	Excessive cost that exceeds reliability benefit	Total
Data Storage Device	88	4	8	0	9	0	0	0	109
Digital Protective Control Device	40	0	1	0	3	0	2	0	46
Electronic Access Control System	208	9	38	0	4	0	1	5	265
Electronic Access Monitoring System	127	4	77	2	6	0	0	1	217
Industrial Process Control System	230	21	85	11	5	0	0	0	352
Mainframe Computer	3	2	0	0	0	0	0	0	5
Network Data Communications Device	725	30	113	3	32	0	1	2	906
PC Laptop	43	33	28	5	2	0	0	2	113
Peripheral Device	214	1	40	0	2	0	3	0	260
Physical Access Control System	164	10	37	0	0	0	0	1	212
Physical Access Monitoring System	112	9	38	0	0	0	0	1	160
Physical Security Perimeter	19	5	11	0	1	0	2	1	39
Relay	76	2	5	0	1	0	2	0	86
RTU	149	8	6	0	0	0	0	0	163
Server	194	66	88	19	23	3	0	1	394
Telecommunications Device	153	5	4	0	1	0	0	2	165
Transmitters	6	0	0	0	0	0	0	0	6
Valve Controllers	1	0	0	0	0	0	0	0	1
Other	262	18	195	1	5	0	3	5	489
Total	2814	227	774	41	94	3	14	21	3988

4. Criteria (iv): Categorization of the compensating measures and mitigating measures implemented and maintained by Responsible Entities pursuant to approved TFEs, by broad categories of compensating measures and mitigating measures and by types of Covered Assets.

Several Regional Entities reported that Responsible Entities employ multiple strategies to protect Covered Assets that are unable to meet applicable Reliability Standards. The principal strategies employed include protecting devices with physical and logical security controls. A significant portion of compensating and mitigating measures involved firewalls, the use of Intrusion Detection and Intrusion Prevention (IDS/IPS) systems, and strong access policies.

Responsible Entities may use similar compensating and mitigating measures, but implementation of those measures amongst those Responsible Entities can vary. For example, an entity with a security center manned 24-hours a day may rely on security personnel so that only authorized personnel can gain access to a device. Another entity that does not have round-the-clock coverage in its security center may use physical monitoring, but also rely on security cameras and motion detectors.

Table 5 below shows the categorization of mitigation and compensation measures. The largest category is Electronic Security Perimeter (ESP) (2,386). Other significant compensating and mitigating measures deployed include Physical Security Perimeter (PSP) (1,582), Authentication (795), IDS/IPS (502), and System Status Monitoring (338).

Table 5

Asset categories (per Part A of TFE request)	Aggregate - Approved TFEs - Risk Mitigation/Compensation Strategies									
	ESP	PSP	IDS/ IPS	Training	System Status Monitoring	Malware Prevention	Authentication	Encryption	Physical Monitoring	Total
Data Storage Device	64	54	26	8	23	19	22	0	5	221
Digital Protective Control Device	23	24	12	1	7	5	16	0	5	93
Electronic Access Control System	140	97	38	30	47	21	62	5	17	457
Electronic Access Monitoring System	110	105	18	54	38	42	64	2	21	454
Industrial Process Control System	253	178	42	28	103	42	77	0	32	755
Mainframe Computer	1	1	1	0	1	1	2	0	1	8
Network Data Communications Device	536	345	135	77	196	117	163	3	65	1637
PC Laptop	52	34	14	10	28	15	19	1	6	179
Peripheral Device	194	105	40	27	64	14	28	0	8	480
Physical Access Control System	124	78	8	20	22	13	35	11	17	328
Physical Access Monitoring System	92	48	11	21	14	9	33	3	28	259
Physical Security Perimeter	3	5	0	2	2	2	3	2	18	37
Relay	60	53	13	1	20	12	36	3	12	210
RTU	108	83	22	0	35	18	25	1	17	309
Server	225	125	53	72	54	39	83	1	26	678
Telecommunications Device	96	81	17	1	31	14	20	1	3	264
Transmitters	6	7	1	0	0	0	0	0	0	14
Valve Controllers	1	1	0	0	1	0	0	0	0	3
Other	298	158	51	97	142	33	107	3	57	946
Total	2386	1582	502	449	828	416	795	36	338	7332

5. Criteria (v) – For each TFE Request that was rejected or disapproved, and for each TFE that was terminated, but for which, due to exceptional circumstances as determined by the Regional Entity, the Effective Date was later than the latest date specified in Section 5.1.5, 5.2.6, or 9.3, as applicable, a statement of the number of days the Responsible Entity was not subject to imposition of findings of violations of the Applicable Requirement or imposition of penalties or sanctions pursuant to Section 5.3.

All eight Regional Entities (FRCC, MRO, NPCC, RFC, SERC, SPP-RE, TRE, and WECC) reported that there were no instances of rejection, disapproval, or termination of TFE requests, where the effective date was extended past the latest date specified in Section 5.1.5, 5.2.6, or 9.3, as applicable, of Appendix 4D to the NERC Rules of Procedure.

6. Criteria 6 - A discussion, on an aggregated basis, of Compliance Audit results and findings concerning the implementation and maintenance of compensating measures and mitigating measures, and the implementation of steps and the conduct of research and analyses to achieve Strict Compliance with the Applicable Requirements, by Responsible Entities in accordance with approved TFEs.

The TFE Procedure, in conjunction with the Compliance Monitoring and Enforcement Program (CMEP), is the framework that Regional Entities utilize to review and audit TFE requests. During a compliance audit where TFEs are in scope, the subject Responsible Entity is *not* evaluated against the applicable standard for which a TFE was accepted and approved. Instead, the Responsible Entity is evaluated against the alternative compliance obligations assumed by the Responsible Entity in the approved TFE request (*i.e.*, compensating and mitigating measures).

Seven of the eight Regional Entities (FRCC, MRO, NPCC, RFC, SERC, SPP-RE, and WECC) have conducted Compliance Audits where approved or terminated TFEs were in scope. Generally, Regional Entities found that Responsible Entities are managing and maintaining their TFEs within the procedural requirements of Appendix 4D. Only two Regional Entities (MRO

and RFC) have issued audit findings against approved TFEs to be processed as potential violations through the CMEP.

7. Criteria 7- Assessments, by Regional Entity (and for more discrete areas within a Regional Entity, if appropriate) and in the aggregate for the United States and for the jurisdictions of other Applicable Governmental Authorities, of the wide-area impacts on the reliability of the Bulk Electric System of approved TFEs in the aggregate, including the compensating measures and mitigating measures that have been implemented.

The wide-area impact of approved TFEs on the reliability of the BES, in the aggregate, has been minimal. The issues identified by the Regional Entities, as a result of the assessment, include: implementation of anti-virus software and malware prevention tools, as required by CIP-007 R4; implementation passwords or specific password criteria, as required by CIP-007 R5.3, R5.3.1, R5.3.2 and R5.3.3; and inability to monitor or log system events related to Cyber Security, as required by CIP-007 R6 and R6.3.

Each Regional Entity reported similar experiences with the execution and management of the TFE process and the manner in which it impacted the reliability of the BES. In general, the mitigating and compensating measures of approved TFEs that were implemented in lieu of strict compliance with applicable CIP Reliability Standards accomplished the stated alternate compliance objective.

Regional Entities reported that a large majority of Responsible Entities have implemented multiple compensating and mitigating measures for Covered Assets. As a result, the level of security for the BES achieved through the TFE process is comparable to strict compliance with the applicable Reliability Standards. As previously noted, the primary compensating and mitigating measures deployed by Regional Entities include the following Covered Asset protections: ESP, PSP, Authentication, IDS/IPS, and System Status Monitoring.

The following is a summary of the Regional Entity data submitted for Criteria 7.

a) FRCC Region

FRCC reported that it has had over 400 "actionable" TFEs submitted, amended, or resubmitted since the program's inception. While the range of TFEs submitted to FRCC includes all possible requirements, and represents nearly every device type, most TFEs have been identified by the entity as minimal impact to the BES. FRCC has concurred with the majority of those assessments.

Generally, FRCC has found that Responsible Entities are diligent in applying compensating and mitigating measures that are appropriate to the potential impact those systems could have on reliability. Compensating and mitigating measures have typically utilized multiple strategies, ranging from physical isolation of a device to logical isolation behind firewalls that have strict rules, require two factor authentication, and use Intrusion Detection or Intrusion Prevention devices or both. According to FRCC, these efforts have helped ensure that the net effect is equal to or better than strict compliance.

FRCC also reported that Responsible Entities have increased awareness of cyber security requirements through various measures. During compliance audits and spot checks, FRCC determined that the overall effort placed on securing the Critical Cyber Assets (CCAs) has been substantial.

b) MRO Region

MRO has received and processed 314 TFEs, not including Canadian Entity submittals and TFE amendments. After assessing the impact on the reliability of the BES, MRO identified the following three risk areas where Covered Assets cannot:

- Implement anti-virus software and malware prevention tools required by CIP-007 R4. In the MRO footprint these represent 35% of the approved TFEs and 37.5% of all

Covered Assets. Of the TFEs submitted regarding CIP-007 R4, Network and Data Communications devices represent 30% of the Covered Assets.

- Implement passwords or specific password criteria required by CIP-007 R5.3, R5.3.1, R5.3.2 and R5.3.3. In the MRO footprint these Requirements combined represent 30% of the approved TFEs and 15% of the Covered Assets. No specific Covered Asset category represents a large percentage of the Covered Assets submitted against TFEs for these Requirements. The numbers are spread across a wide variety of device types.

- Monitor or log system events related to Cyber Security required by CIP-007 R6 and R6.3. In the MRO footprint, these Requirements combined represent 15% of the approved TFEs and 30% of all Covered Assets. No specific Covered Asset category that represents a large percentage of the Covered Assets submitted against TFEs for these Requirements. The numbers are spread across a wide variety of device types.

The three risk areas identified by MRO represent 80% of its TFEs, and 82.5% of the Covered Assets in TFEs submitted to MRO. According to MRO, an analysis of the device types indicates that most are legacy or proprietary equipment that were never designed or produced with the capability to implement various security controls as defined in applicable CIP Requirements.

MRO concluded that Responsible Entities have implemented a defense-in-depth security model when deploying compensating and mitigating measures. The majority of MRO TFEs detail multiple compensating and mitigating measures deployed or being deployed to achieve at least a comparable level of security for the BES, as would strict compliance with applicable Requirements. The four primary compensating and mitigating measures deployed in the MRO Region are detailed below with their frequency of use: ESP (27.5%), PSP (21%), IDS/IPS (14.5%), and System Status Monitoring (13.5%).

c) NPCC Region

The majority of the TFEs submitted to NPCC were found to have minimal impact to the BES. NPCC determined that the compensating and mitigating measures for those devices further minimizes the exposure of those assets for which the TFEs have been filed. The Part B Substantive Reviews conducted by NPCC revealed that most Responsible Entities have implemented multiple compensating and mitigating measures thereby affording the Responsible Entities a defense-in-depth security model.

d) ReliabilityFirst Region

Reliability*First* Corporation (RFC) has received and processed 1,173 TFEs from Responsible Entities not including TFE amendments. Based upon an assessment of the impact on the reliability of the BES, RFC identified the risk areas where Covered Assets cannot:

- Implement antivirus software and malware prevention tools required by CIP-007 R4. In the RFC footprint these represent 33% of the approved TFEs and 29% of all Covered Assets. Of the TFEs submitted against Requirement CIP-007 R4, Network and Data Communications Devices represent 30% of the Covered Assets.

- Implement passwords or specific password criteria required by CIP-007 R5.3, R5.3.1, R5.3.2 and R5.3.3. In the RFC footprint these Requirements combined represent 41.5% of the approved TFEs and 43% of the Covered Assets. No one Covered Asset category that represents a large percentage of the Covered Assets submitted against TFEs for these Requirements. The numbers are spread across a wide variety of device types.

- Monitor or log system events related to Cyber Security as required by CIP-007 R6 and R6.3. In the RFC footprint these Requirements combined represent 13% of the approved TFEs and 13.5% of all Covered Assets. No one Covered Asset category that represents a large percentage of the Covered Assets submitted against TFEs for these Requirements. The numbers are spread across a wide variety of device types.

The three risk areas identified by RFC represent 87.5% of the TFEs with 85.5% of the Covered Assets in TFEs submitted to ReliabilityFirst. An analysis of the device types indicates that numerous legacy or proprietary equipment were never designed or produced with the capability to implement various security controls as defined in Applicable CIP Requirements.

RFC generally reported that Responsible Entities have implemented a defense-in-depth security model when deploying compensating and mitigating measures. Moreover, RFC found that most TFEs detail multiple compensating and mitigating measures deployed or being deployed to achieve at least a comparable level of security for the BES, as would strict compliance with the applicable requirement. The four primary compensating and mitigating measures deployed to mitigate risks are detailed below with their frequency of use: ESP (33.5%), PSP (19%), IDS/IPS (12%), and System Status Monitoring (15.5%).

e) <u>SERC Region</u>

SERC received and processed 751 TFEs from Responsible Entities within its footprint. Generally, SERC reported that Responsible Entities have implemented effective protective measures that have resulted in limiting reliability impact on the BES. However, SERC reports that the TFE process is burdensome for the Responsible Entities and for Regional resources. For instance, significant resources are spent submitting and reviewing TFEs on certain types of devices that are widely known to be unable to support a feature that is required by applicable CIP Reliability Standards (*e.g.*, anti-virus software on a network printer).

f) <u>SPP-RE Region</u>

In the SPP-RE Region, Responsible Entities reported no significant risks to the reliability of the BES as a result of approved TFEs, such as the loss of situation awareness, system

visibility, or system control. According to SPP-RE, the implementation of compensating and mitigating measures achieve a comparable or better level of protection as strict compliance offsets any potential risks, so that TFEs have a minimal impact on the reliability of the BES within the SPP-RE footprint.

Typical compensating and mitigating measures that have been implemented by Responsible Entities within the SPP RE region include: ESP, PSP, IDS/IPS, Training, Status Monitoring, Host-Based Malware Prevention (where Covered Assets cannot implement antivirus or anti-malware tools, they are protected by all other cyber assets within a defined ESP having these security controls installed and managed), Enhanced Authentication (Access to Covered Assets and all Cyber Assets that reside within a defined ESP are protected by multi-factor authentication services such as RSA SecurID, digital certificates, or biometrics), Data Encryption (when mandatory controls cannot be implemented, data is encrypted between CCAs to protect data confidentiality and integrity), and Physical Monitoring.

g) <u>Texas RE Region</u>

Texas RE received and processed 569 TFEs from Responsible Entities within its footprint. Based upon Texas RE's assessment, the wide-area impact of TFEs on the reliability of the BES is minimal. However, Texas RE reported that the TFE process is burdensome and has not increased the security or reliability of the BES. With respect to compensating and mitigating measures for TFEs, Texas RE did not report any impacts on the BES.

h) <u>WECC Region</u>

WECC received and processed 1,917 TFEs from Responsible Entities within its footprint. WECC reported that the TFE process is not fully developed and is overly burdensome for both

the Regional and Registered Entities. According to WECC, the value of the TFE process to the BES and reliable operations is minimal. With respect to compensating and mitigating measures for TFEs, WECC did not report any impacts on the BES.

8. Criterion 8 - Discussion of efforts to eliminate future reliance on TFEs.

Regional Entities (FRCC, MRO, NPCC, RFC, and WECC) report that many efforts are being considered to eliminate future reliance on TFEs:

- Upgrade or replace Covered Assets that will enable implementation of security controls defined in CIP Standards and Requirements;
- Remove CCAs that covered by approved TFEs that reside within defined ESPs;
- Retire legacy systems that are now subject to coverage by an approved TFE; and
- Implement previously unused or unidentified functionality on Covered Assets that will achieve strict compliance with the Applicable Requirement.

Where applicable, upgrades of Covered Assets will result in strict compliance without having to rely on TFEs. According to one Regional Entity (NPCC), Responsible Entities have researched the means to achieve strict compliance and reduce the number of TFEs required, but many of the devices for which TFEs are submitted cannot and may never be able to achieve strict compliance with the standards as written.

In addition, efforts such as forming committees and discussion groups to determine where a new or existing device should reside, training IT personnel on the expectations of applicable Reliability Standards, and coordination with the Regional Entity compliance monitoring and enforcement staff regarding the need for TFEs, has led to the continuing decline of the number of devices that rely on a TFE for compliance. Moreover, non-essential devices are also being evaluated for continued inclusion within a defined ESP. Where a device does not need to reside within the ESP for operational necessity, Covered Assets have been relocated

outside the ESP, eliminating the need for a TFE and reducing residual risk to devices remaining within the ESP.

The primary barriers identified by Regional Entities to eliminating TFEs include: 1) revising Reliability Standards, 2) certifying vendors, and 3) retaining legacy systems. With respect to revising applicable standards, some regions (notably SERC) report that it can be difficult to establish a minimum threshold, and provide flexibility for technology and changes in security. For example, the current password standards are very specific (*e.g.*, requiring at least six characters) in some cases, but standards can be strengthened to define the required complexity and to allow for strong, non-password technologies such as biometrics or two-factor authentication. With respect to vendors, there is support for developing requirements to use products that are certified as meeting an appropriate security standard. Many legacy systems in operation were built to last, not necessarily built to be compatible with enhanced security features. Applying those types of enhanced security features often means that properly operating equipment would need to be replaced with more modern, secure models. Therefore, in order to eliminate the need for a TFE, replacement costs may become a barrier to implementing enhanced security features.

C. Consistency in Approval and Disapproval of TFE Requests

Appendix 4D of the NERC Rules of Procedure require NERC and the Regional Entities to engage in the activities "for the purpose of assuring consistency in the review, approval and disapproval of TFE Requests…."[15] Also, as noted above, Section 11.2.4 requires that NERC submit with each Annual Report certain information concerning the manner in which Regional Entities have made determinations to approve or disapprove TFE Requests:

[15] Section 11 of Appendix 4D of the NERC Rules of Procedure.

Section 11.2.4
(i) whether any issues were identified during the period covered by the informational report with respect to the consistency of the determinations made based on the criteria in Section 3.1, either within a Regional Entity or among Regional Entities;

(ii) a description of any such identified consistency issues;

(iii) how each consistency issue was resolved;

(iv) the numbers of TFE Requests for which reconsideration was requested pursuant to Section 5.2.9 based on purported inconsistencies in determinations applying the criteria in Section 3.1 and the numbers of such requests which resulted in TFE Requests being approved, disapproved and rejected; and

(v) whether NERC has developed or is in a position to develop a uniform framework for Regional Entities to use to appraise the reliability benefits of Strict Compliance when making determinations based on the criteria in Section 3.1(iv) and (vi).

NERC has not received any reports of inconsistency either in assessing the accuracy or validity of TFEs submitted by Responsible Entities, or in the decisions approving or rejecting TFEs. Specifically, no requests were received from Responsible Entities asserting "that the approval, disapproval or rejection by a Regional Entity of a TFE Request submitted by the Responsible Entity constitutes an inconsistent application of the criteria specified in Section 3.1 as compared to other determinations of TFE Requests made by the same Regional Entity or another Regional Entity for the same type of Covered Assets…."[16]

NERC and the Regional Entities formed a group of "TFE Managers" to serve as the committee to review approved and disapproved TFE Requests for consistency. Primary and alternate representatives from each region, facilitated by NERC staff, met regularly to discuss common concerns. Those representatives also led the efforts at their respective regions for receiving, reviewing, and reporting TFE-related data.

[16] Section 5.2.8 of Appendix 4D of the NERC Rules of Procedure.

In addition to the TFE Managers' regularly scheduled conference calls and face-to-face meetings, the TFE Managers communicated regularly by email, and discussed consistency issues at workshops and other meetings. Potential inconsistencies were commonly discussed in a roundtable fashion until a consensus was reached on the pertinent issues.

The TFE management effort also included the development of common tools and processes for the Responsible Entities to use when submitting TFE requests. Specifically, NERC worked with the Regional Entities to leverage their existing portals (used for tracking other compliance-related data) to include confidential TFE processes. The TFE Managers also developed templates for quarterly and annual reports that Responsible Entities submit to NERC.

Appendix 4D requires NERC to develop a "uniform framework for Regional Entities to use to appraise the reliability benefits of Strict Compliance when making determinations based on the criteria in Section 3.1(iv) and (vi)." Those criteria pertain to TFEs that cite safety risks or issues that outweigh the reliability benefits, or that cite the incurrence of costs that far exceed the benefits to reliability.

The TFE management approach outlined above is used for TFE requests citing safety risks; however, very few such TFE requests have been submitted. Of the 3,369 approved TFEs, only 3 cited "safety risks" as a basis, while 21 pointed to "excessive costs." The TFEs that cited safety risks came from an entity with servers used to manage EMS applications that could cause equipment malfunctions if anti-virus software was installed. The Responsible Entity felt that it would ultimately create an unsafe operating condition. In this particular case, however, the Regional Entity determined that other basis categories also could have been cited (*e.g.*, operationally infeasible or adverse effect on reliability), so the region accepted the request as submitted.

Examples of approved TFE requests that cited excessive costs include:

- Unprotected wiring that provides a communication link between discrete electronic security perimeters and not within an ESP for which increased physical security would add no significant reliability benefit.
- A"six wall boundary" around a Physical Security Perimeter had a gap between the top of the wall and the hard ceiling. The opening was needed for proper operation of the building's HVAC system, so the Responsible Entity implemented other physical security measures as an alternative.

For TFE requests that asserted that costs exceeded the benefits to reliability, auditors not only conducted standard interviews with subject matter experts and assessments of compensating or mitigating measures, but also analyzed cost studies provided by Responsible Entities.

IV. CONCLUSION

For the foregoing reasons, NERC respectfully requests that the Commission accept this Annual Report as compliant with the directives contained in Order No. 706 and Appendix 4D of NERC's Rules of Procedure.

Respectfully submitted,

/s/ Willie L. Phillips

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CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 28th day of September, 2011.

/s/ Willie L. Phillips
Willie L. Phillips
Attorney for North American Electric Reliability Corporation

September 28, 2011

Annual Report—Wide-Area Analysis of Technical Feasibility Exceptions

Exhibit A: Supporting Spreadsheets

1. Program Information

Period Covered:	Jan 1, 2010--Jun 30, 2011		Date of Report:	28-Sep-11	
	Number of entities subject to compliance with CIP Standards	Number of entities subject to CIP compliance that have claimed CCAs	Number of entities w/ CCAs that have requested TFEs	TFE Manager	Alternate
FRCC	31	7	7	Steve Kruse	Carlos Valiente
MRO	87	22	19	Steen Fjalstad	Tom Tierney
NPCC	227	47	36	Marie Kozub Peter Scalici	David Cerasoli
RFC	216	51	55	Bob Yates	Ray Sefchik
SERC	245	24	20	Matt Stryker	Mike Almeyda
SPP	95	15	13	Shon Austin	Kevin Perry
TRE	305	23	17	Bill Beaver	Kevin Bunch
WECC	358	52	52	Brent Castagnetto	Kim Israelsson
TOTAL	1564	241	219		

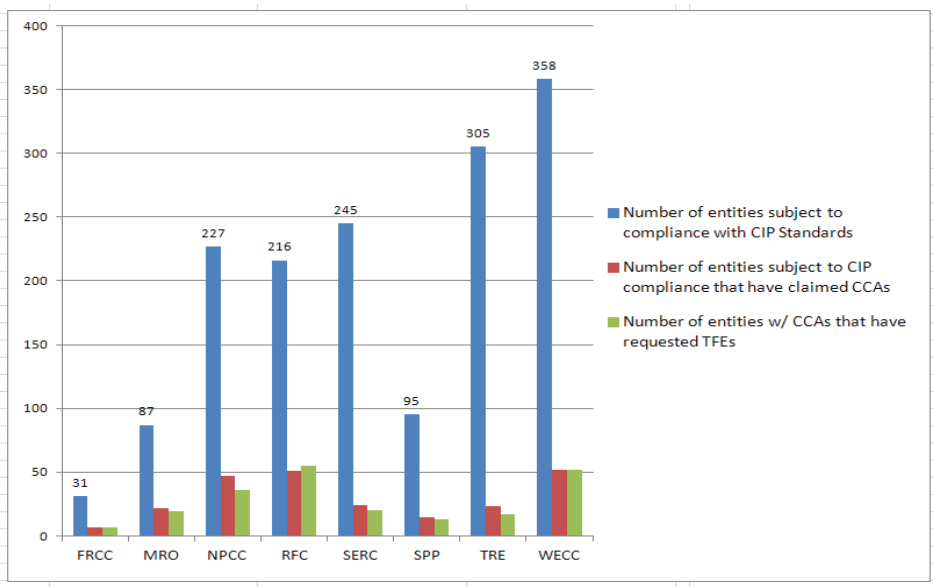

2a. TFE Requests (Aggregate)

Aggregate -- TFE Status

State	CIP Requirement	Total	# of Covered Assets
a. Initial submission & Pending			
CIP-005	R2.4.	62	826
CIP-005	R2.6.	251	3131
CIP-005	R3.1.	42	517
CIP-005	R3.2.	153	1353
CIP-006	R1.1.	67	2099
CIP-007	R2.3.	327	9033
CIP-007	R3.	73	1709
CIP-007	R4.	1662	42241
CIP-007	R5.3.	513	17229
CIP-007	R5.3.1.	289	6592
CIP-007	R5.3.2.	594	15456
CIP-007	R5.3.3.	356	12590
CIP-007	R6.	553	14273
CIP-007	R6.3.	346	7755
b. Accepted (5.1)			
CIP-005	R2.4.	22	393
CIP-005	R2.6.	166	1641
CIP-005	R3.1.	14	102
CIP-005	R3.2.	79	564
CIP-006	R1.1.	56	965
CIP-007	R2.3.	201	6024
CIP-007	R3.	55	1673
CIP-007	R4.	1148	24730
CIP-007	R5.3.	383	11621
CIP-007	R5.3.1.	169	3435
CIP-007	R5.3.2.	400	9425
CIP-007	R5.3.3.	206	9498
CIP-007	R6.	372	8639
CIP-007	R6.3.	221	4418
c. Rejected (5.1)			
CIP-005	R2.4.	20	270
CIP-005	R2.6.	15	401
CIP-005	R3.1.	17	348
CIP-005	R3.2.	23	303
CIP-006	R1.1.	1	3
CIP-007	R2.3.	26	990
CIP-007	R3.	2	38
CIP-007	R4.	62	2827
CIP-007	R5.3.	31	836
CIP-007	R5.3.1.	48	1678
CIP-007	R5.3.2.	85	3236
CIP-007	R5.3.3.	64	2255
CIP-007	R6.	35	973
CIP-007	R6.3.	19	976

Aggregate -- TFE Status

State	CIP Requirement	Total	# of Covered Assets
d. Approved (5.2)			
CIP-005	R2.4.	25	356
CIP-005	R2.6.	170	1435
CIP-005	R3.1.	16	111
CIP-005	R3.2.	85	651
CIP-006	R1.1.	44	802
CIP-007	R2.3.	173	5500
CIP-007	R3.	60	1953
CIP-007	R4.	1225	23721
CIP-007	R5.3.	317	7388
CIP-007	R5.3.1.	149	2033
CIP-007	R5.3.2.	350	6919
CIP-007	R5.3.3.	195	4266
CIP-007	R6.	331	8322
CIP-007	R6.3.	229	4866
e. Disapproved (5.2)			
CIP-005	R2.4.	5	18
CIP-005	R2.6.	51	1253
CIP-005	R3.1.	3	12
CIP-005	R3.2.	31	220
CIP-006	R1.1.	11	1103
CIP-007	R2.3.	57	1982
CIP-007	R3.	14	330
CIP-007	R4.	182	4525
CIP-007	R5.3.	91	1883
CIP-007	R5.3.1.	62	1655
CIP-007	R5.3.2.	79	2088
CIP-007	R5.3.3.	56	794
CIP-007	R6.	83	2586
CIP-007	R6.3.	57	1237
f. Terminated/expired prior to June 30, 2011 (ON schedule or earlier due to the Responsible Entity's efforts) (9.0)			
CIP-005	R2.4.	6	155
CIP-005	R2.6.	43	260
CIP-005	R3.1.	3	17
CIP-005	R3.2.	31	179
CIP-006	R1.1.	7	24
CIP-007	R2.3.	34	616
CIP-007	R3.	22	349
CIP-007	R4.	163	1110
CIP-007	R5.3.	54	974
CIP-007	R5.3.1.	31	200
CIP-007	R5.3.2.	46	469
CIP-007	R5.3.3.	33	327
CIP-007	R6.	65	472
CIP-007	R6.3.	41	206

Aggregate -- TFE Status

State	CIP Requirement	Total	# of Covered Assets
g. Terminated prior to June 30, 2011 (EARLIER THAN scheduled by Region's direction) (9.0)			
CIP-005	R2.4.	0	0
CIP-005	R2.6.	0	0
CIP-005	R3.1.	0	0
CIP-005	R3.2.	0	0
CIP-006	R1.1.	0	0
CIP-007	R2.3.	0	0
CIP-007	R3.	0	0
CIP-007	R4.	0	0
CIP-007	R5.3.	0	0
CIP-007	R5.3.1.	0	0
CIP-007	R5.3.2.	0	0
CIP-007	R5.3.3.	0	0
CIP-007	R6.	0	0
CIP-007	R6.3.	0	0
h. TFEs scheduled to terminate between July 1, 2011 and June 30, 2012			
CIP-005	R2.4.	5	66
CIP-005	R2.6.	3	22
CIP-005	R3.1.	1	18
CIP-005	R3.2.	5	43
CIP-006	R1.1.	2	2
CIP-007	R2.3.	14	469
CIP-007	R3.	9	100
CIP-007	R4.	48	684
CIP-007	R5.3.	18	141
CIP-007	R5.3.1.	6	72
CIP-007	R5.3.2.	26	281
CIP-007	R5.3.3.	13	168
CIP-007	R6.	13	485
CIP-007	R6.3.	3	38
i. Active TFEs (includes those scheduled to terminate after			
CIP-005	R2.4.	18	255
CIP-005	R2.6.	112	1115
CIP-005	R3.1.	10	96
CIP-005	R3.2.	46	460
CIP-006	R1.1.	37	768
CIP-007	R2.3.	105	4519
CIP-007	R3.	45	1658
CIP-007	R4.	916	19793
CIP-007	R5.3.	244	6290
CIP-007	R5.3.1.	103	1691
CIP-007	R5.3.2.	282	6317
CIP-007	R5.3.3.	142	3846
CIP-007	R6.	214	6970
CIP-007	R6.3.	142	4279

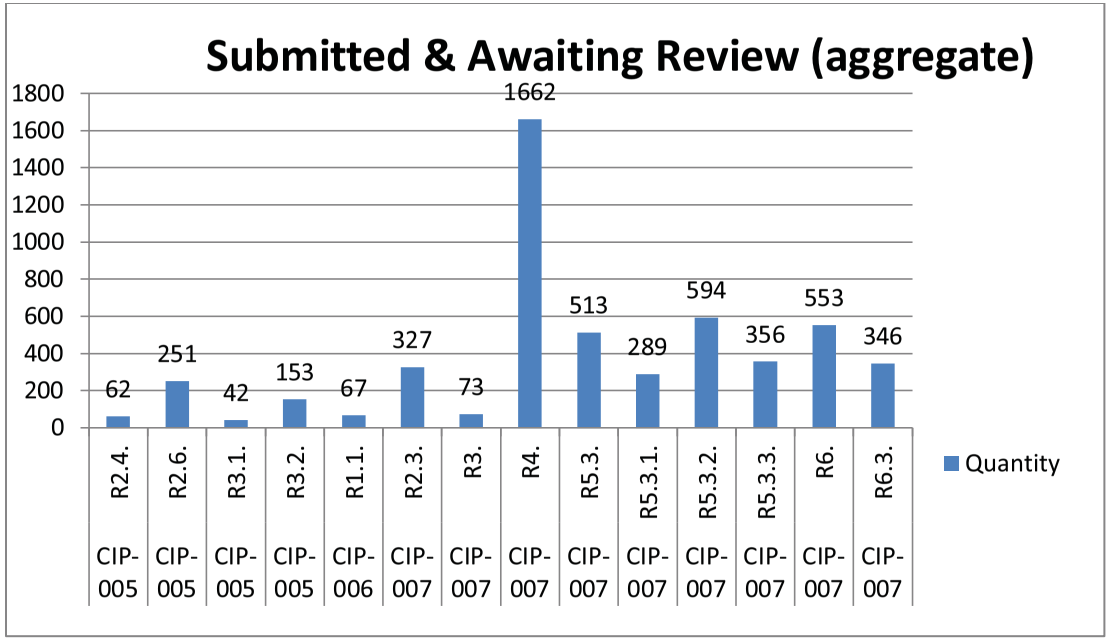
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1800
1600
1400
1200
1000
800
600
400
200
0
62
251
42
153
67
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1662
513
289
594
356
553
346
R2.4.
R2.6.
R3.1.
R3.2.
R1.1.
R2.3.
R3.
R4.
R5.3.
R5.3.1.
R5.3.2.
R5.3.3.
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Quantity

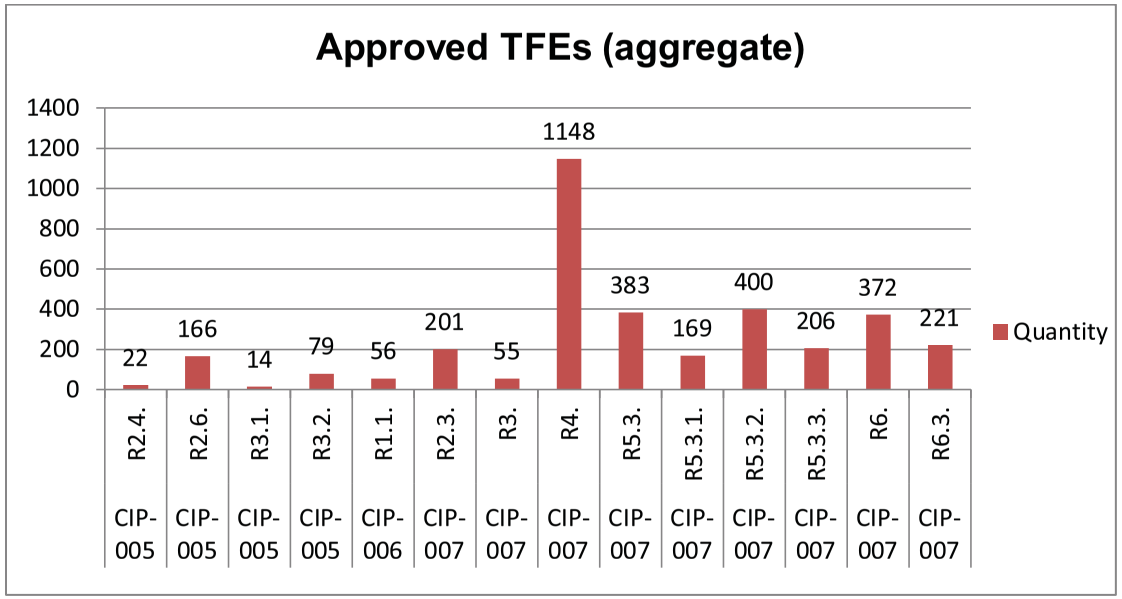
Approved TFEs (aggregate)
1400
1200
1000
800
600
400
200
0
22
166
14
79
56
201
55
1148
383
169
400
206
372
221
R2.4.
R2.6.
R3.1.
R3.2.
R1.1.
R2.3.
R3.
R4.
R5.3.
R5.3.1.
R5.3.2.
R5.3.3.
R6.
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CIP-005
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CIP-007
CIP-007
Quantity

2b. TFE Requests, Status (by Region)

		FRCC		MRO		NPCC		RFC		SERC		SPP		TRE		WECC	
State	CIP Standard Requirement	Total	# of Covered	Total	# of Covered	Total	# of Covered	Total	# of Covered	Total	# of Covered	Total	# of Covered	Total	# of Covered	Total	# of Covered
a. Initial submission & Pending Review (4.0)																	
CIP-005	R2.4.	1	2	6	157			6	231	2	6			8	27	39	403
CIP-005	R2.6.	10	80	9	120			43	821	20	310	19	70	56	402	94	1328
CIP-005	R3.1.							13	103			1	10			28	404
CIP-005	R3.2.	3	24	7	53			8	65	5	9	9	39	47	397	74	766
CIP-006	R1.1.	10	124	8	516			16	20	16	282	1	1	6	22	10	1,134
CIP-007	R2.3.	29	480	17	280			43	2969	52	1735	7	210	36	593	143	2,766
CIP-007	R3.	8	216	13	301			13	404	12	462	7	69	3	46	17	211
CIP-007	R4.	81	950	105	2856			407	8199	191	5267	97	1416	134	2133	647	21,420
CIP-007	R5.3.	38	626	25	466			151	3894	124	2523	15	287	30	584	130	8,849
CIP-007	R5.3.1.	19	225	11	56			51	1219	50	2010	9	91	44	648	105	2,343
CIP-007	R5.3.2.	47	733	29	305			162	4314	111	5297	25	523	58	1190	162	3,094
CIP-007	R5.3.3.	23	665	36	395			95	3278	21	1203	8	139	46	676	127	6,234
CIP-007	R6.	34	371	32	1223			111	3423	90	2663	17	491	57	867	212	5,235
CIP-007	R6.3.	36	314	16	989			54	1038	57	1783	10	252	44	444	129	2,935
b. Accepted (5.1)																	
CIP-005	R2.4.	1	2	6	157			4	184	2	6	0	0	8	27	1	17
CIP-005	R2.6.	7	64	8	112	1	1	40	575	22	322	19	70	56	402	13	95
CIP-005	R3.1.							11	85	0	0	1	10			2	7
CIP-005	R3.2.	1	16	6	27			7	51	6	22	8	27	43	348	8	73
CIP-006	R1.1.	10	124	7	515			16	20	15	275	1	1	6	22	1	8
CIP-007	R2.3.	23	308	17	280			42	2625	43	1505	7	210	32	578	37	518
CIP-007	R3.	2	4	13	301			19	786	11	467	7	69	3	46	0	0
CIP-007	R4.	75	825	105	2856	13	119	378	7165	180	4241	95	1156	129	2109	173	6,259
CIP-007	R5.3.	35	606	25	466	3	15	144	3551	110	2448	16	293	28	578	22	3,664
CIP-007	R5.3.1.	16	199	11	56	2	13	45	969	34	919	9	91	41	637	11	551
CIP-007	R5.3.2.	44	707	29	305	1	1	138	3768	96	2640	24	598	53	1157	15	249
CIP-007	R5.3.3.	20	628	36	395	2	13	80	2970	9	157	8	123	42	661	9	4,551
CIP-007	R6.	30	347	32	1223	3	37	97	2846	78	2147	17	440	54	855	61	744
CIP-007	R6.3.	33	301	16	989	2	35	44	766	56	1385	10	252	44	444	16	246
c. Rejected (5.1)																	
CIP-005	R2.4.									0	0					20	270
CIP-005	R2.6.							2	244	0	0					13	157
CIP-005	R3.1.							2	18	0	0					15	330
CIP-005	R3.2.	2	8	1	26			1	14	1	1			4	49	14	205
CIP-006	R1.1.					1	3			0	0					0	0
CIP-007	R2.3.							1	344	8	97			4	15	13	534
CIP-007	R3.									1	7					1	31
CIP-007	R4.	2	87					26	937	8	83	1	2	5	17	20	1701
CIP-007	R5.3.							6	250	2	56			2	6	21	524
CIP-007	R5.3.1.							6	250	11	840			3	11	28	577
CIP-007	R5.3.2.					1	26	24	546	9	2308			5	33	46	323
CIP-007	R5.3.3.	1	31					15	308	10	1013			4	15	34	888
CIP-007	R6.	1	13					12	283	10	90			3	12	9	575
CIP-007	R6.3.							10	272	2	62			0	0	7	642

3a. TFE Requests, Device Categories (Aggregate)

asset categories (per Part A of TFE request)	Aggregate - Quantity of TFEs submitted & approved													
	CIP-005				CIP-006	CIP-007								
	R2.4	R2.6	R3.1	R3.2	R1.1	R2.3	R3.2	R4	R5.3	R 5.3.1	R5.3.2	R5.3.3	R6	R6.3
Data Storage Device	0	19	0	3	0	3	2	113	13	33	52	6	14	12
Digital Protective Control Device	0	1	0	0	0	7	0	28	6	2	7	4	14	1
Electronic Access Control System	9	82	0	17	6	3	7	290	9	9	28	16	5	1
Electronic Access Monitoring System	3	17	6	7	2	1	2	226	10	13	66	25	9	0
Industrial Process Control System	0	12	0	6	0	568	3	673	605	24	71	61	613	578
Mainframe Computer	2	0	0	0	0	0	0	2	0	0	1	0	0	0
Network Data Communications Device	6	52	6	31	7	61	12	1751	466	42	223	42	494	247
PC Laptop	2	4	0	0	5	22	31	23	137	3	93	16	6	11
Peripheral Device	0	9	0	6	0	31	1	122	59	38	37	21	100	65
Physical Access Control System	3	131	3	16	2	10	2	151	89	16	49	24	17	15
Physical Access Monitoring System	1	10	3	16	11	10	2	76	21	14	36	12	8	7
Physical Security Perimeter	0	2	0	2	23	1	0	10	0	1	4	1	1	1
Relay	0	4	0	1	0	7	0	226	16	5	19	9	17	11
RTU	0	9	1	11	0	23	1	263	25	8	10	7	49	20
Server	1	6	4	3	4	39	397	1018	252	21	569	38	61	62
Telecommunications Device	4	21	0	11	4	23	1	63	7	23	26	12	33	19
Transmitters	0	0	0	0	0	4	0	5	2	2	3	0	5	0
Valve Controllers	0	0	0	0	0	0	0	1	0	0	0	0	0	0
Other	2	26	9	5	121	55	4	262	62	68	124	80	127	95

3b(1). TFE Requests, Device Categories (by Region)

FRCC

asset categories	Quantity of TFEs submitted & approved													
	CIP-005				CIP-006	CIP-007								
	R2.4	R2.6	R3.1	R3.2	R1.1	R2.3	R3.2	R4	R5.3	R 5.3.1	R5.3.2	R5.3.3	R6	R6.3
Data Storage Device	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Digital Protective Control Device	0	0	0	0	0	2	0	2	0	0	2	0	1	1
Electronic Access Control System	1	1	0	0	1	0	0	8	1	0	1	1	0	0
Electronic Access Monitoring System	0	1	0	0	1	0	0	5	0	1	2	0	0	0
Industrial Process Control System	0	0	0	0	0	1	0	2	5	1	2	2	2	3
Mainframe Computer	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Network Data Communications Device	1	1	0	0	2	2	0	26	6	2	8	1	3	3
PC Laptop	0	0	0	0	2	0	0	1	2	0	2	1	0	0
Peripheral Device	0	0	0	0	0	2	0	7	2	3	3	1	5	4
Physical Access Control System	0	3	0	1	1	0	0	5	2	1	3	1	0	0
Physical Access Monitoring System	0	2	0	1	1	0	0	3	1	1	3	1	1	1
Physical Security Perimeter	0	1	0	1	1	0	0	1	0	1	2	1	0	0
Relay	0	0	0	0	0	2	0	2	1	0	0	0	2	2
RTU	0	0	0	0	0	0	0	1	1	0	0	0	1	1
Server	0	0	0	0	1	4	0	9	6	3	11	3	4	6
Telecommunications Device	0	0	0	0	2	0	0	0	0	0	0	0	0	0
Transmitters	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Valve Controllers	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	4	3	0	3	2	1	1	1	4	3

MRO

asset categories	Quantity of TFEs submitted & approved													
	CIP-005				CIP-006	CIP-007								
	R2.4	R2.6	R3.1	R3.2	R1.1	R2.3	R3.2	R4	R5.3	R 5.3.1	R5.3.2	R5.3.3	R6	R6.3
Data Storage Device	0	1	0	0	0	0	1	7	0	0	0	1	1	1
Digital Protective Control Device	0	0	0	0	0	0	0	2	0	1	1	2	1	0
Electronic Access Control System	2	4	0	0	0	0	4	20	1	1	3	2	2	1
Electronic Access Monitoring System	2	5	0	1	0	0	1	8	2	2	3	3	1	0
Industrial Process Control System	0	0	0	0	0	0	0	13	12	0	1	8	11	0
Mainframe Computer	0	0	0	0	0	0	0	1	0	0	1	0	0	0
Network Data Communications Device	1	0	0	2	1	4	5	45	5	4	10	8	6	5
PC Laptop	0	0	0	0	0	2	4	0	0	0	2	5	0	0
Peripheral Device	0	0	0	0	0	0	0	9	1	0	0	0	4	2
Physical Access Control System	0	4	0	2	0	2	2	6	1	0	3	0	4	1
Physical Access Monitoring System	0	2	0	2	0	1	1	5	0	0	4	0	3	1
Physical Security Perimeter	0	0	0	0	2	1	0	3	0	0	1	0	1	1
Relay	0	0	0	0	0	0	0	2	1	1	1	1	1	1
RTU	0	0	0	0	0	1	0	3	1	0	1	0	1	1
Server	1	0	0	1	0	4	6	10	2	0	6	6	1	1
Telecommunications Device	0	0	0	0	1	1	1	5	1	1	2	1	1	1
Transmitters	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Valve Controllers	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	5	6	0	14	6	2	5	7	6	5

3b(2). TFE Requests, Device Categories (by Region)

NPCC

asset categories	Quantity of TFEs submitted & approved													
	CIP-005				CIP-006	CIP-007								
	R2.4	R2.6	R3.1	R3.2	R1.1	R2.3	R3.2	R4	R5.3	R 5.3.1	R5.3.2	R5.3.3	R6	R6.3
Data Storage Device	0	0	0	0	0	0	0	2	0	0	0	0	1	1
Digital Protective Control Device	0	0	0	0	0	0	0	7	1	0	0	0	0	0
Electronic Access Control System	1	1	0	4	0	0	0	32	0	0	1	0	1	0
Electronic Access Monitoring System	1	1	0	0	0	0	0	14	0	2	4	0	1	0
Industrial Process Control System	0	2	0	0	0	10	0	16	8	1	1	1	7	6
Mainframe Computer	0	0	0	0	0	0	0	1	0	0	0	0	0	0
Network Data Communications Device	1	10	0	1	0	3	0	63	3	2	5	0	8	5
PC Laptop	0	1	0	0	0	2	0	5	1	0	2	0	1	1
Peripheral Device	0	1	0	0	0	1	0	16	2	3	3	3	7	4
Physical Access Control System	0	3	0	2	1	0	0	15	2	0	1	1	2	2
Physical Access Monitoring System	0	1	0	1	0	0	0	6	0	0	1	1	0	0
Physical Security Perimeter	0	0	0	0	0	0	0	2	0	0	0	0	0	0
Relay	0	0	0	0	0	2	0	0	1	1	4	0	0	0
RTU	0	1	0	0	0	5	0	12	4	1	2	1	6	5
Server	0	0	0	0	0	3	0	24	4	0	1	0	0	2
Telecommunications Device	0	0	0	0	0	0	0	5	1	0	0	0	1	2
Transmitters	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Valve Controllers	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other	0	1	0	0	1	5	0	36	4	1	3	1	10	6

RFC

asset categories	Quantity of TFEs submitted & approved													
	CIP-005				CIP-007									
	R2.4	R2.6	R3.1	R3.2	R1.1	R2.3	R3.2	R4	R5.3	R 5.3.1	R5.3.2	R5.3.3	R6	R6.3
Data Storage Device	0	1	0	0	0	0	1	12	6	3	5	2	4	3
Digital Protective Control Device	0	0	0	0	0	1	0	5	1	0	3	0	2	0
Electronic Access Control System	0	6	0	0	0	2	2	41	2	0	11	9	0	0
Electronic Access Monitoring System	0	7	5	1	0	0	0	52	4	4	19	19	2	0
Industrial Process Control System	0	3	0	0	0	12	2	30	25	8	17	13	19	8
Mainframe Computer	2	0	0	0	0	0	0	0	0	0	0	0	0	0
Network Data Communications Device	1	11	3	3	0	7	5	128	48	11	28	21	23	7
PC Laptop	2	0	0	0	0	1	3	7	3	0	11	2	3	0
Peripheral Device	0	0	0	0	0	2	0	13	4	5	5	5	7	6
Physical Access Control System	0	1	3	4	0	0	0	6	3	3	12	3	5	6
Physical Access Monitoring System	0	0	3	3	0	0	0	6	0	3	9	3	4	5
Physical Security Perimeter	0	0	0	0	15	0	0	1	0	0	0	0	0	0
Relay	0	4	0	0	0	3	0	12	4	0	7	6	6	0
RTU	0	1	0	0	0	3	0	13	3	0	0	1	11	3
Server	0	0	3	0	0	4	8	43	25	3	34	14	3	1
Telecommunications Device	0	1	0	0	1	0	0	3	1	0	0	0	0	0
Transmitters	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Valve Controllers	0	0	0	0	0	0	0	1	0	0	0	0	0	0
Other	0	10	8	3	0	7	2	66	14	21	50	44	27	22

3b(3). TFE Requests, Device Categories (by Region)

SERC

asset categories	Quantity of TFEs submitted & approved													
	CIP-005				CIP-006	CIP-007								
	R2.4	R2.6	R3.1	R3.2	R1.1	R2.3	R3.2	R4	R5.3	R 5.3.1	R5.3.2	R5.3.3	R6	R6.3
Data Storage Device	0	10	0	0	0	2	0	74	3	27	44	0	4	4
Digital Protective Control Device	0	0	0	0	0	0	0	0	2	0	0	0	0	0
Electronic Access Control System	1	49	0	8	5	0	0	121	3	3	5	0	0	0
Electronic Access Monitoring System	0	0	0	0	1	0	0	121	3	0	30	0	4	0
Industrial Process Control System	0	0	0	0	0	532	0	571	535	0	32	23	541	541
Mainframe Computer	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Network Data Communications Device	0	5	0	0	4	9	0	1285	377	5	150	0	399	196
PC Laptop	0	0	0	0	3	9	24	0	129	0	64	0	0	0
Peripheral Device	0	0	0	0	0	16	0	36	32	12	12	0	44	26
Physical Access Control System	0	110	0	0	0	0	0	89	74	0	10	2	0	0
Physical Access Monitoring System	0	0	0	0	10	0	0	37	20	0	7	0	0	0
Physical Security Perimeter	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Relay	0	0	0	0	0	0	0	198	8	0	0	0	0	0
RTU	0	0	0	0	0	0	0	199	9	0	0	0	6	6
Server	0	0	0	0	3	12	380	875	210	8	491	6	50	50
Telecommunications Device	0	0	0	0	0	12	0	20	0	12	12	0	12	0
Transmitters	0	0	0	0	0	4	0	4	2	2	2	0	4	0
Valve Controllers	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other	0	6	0	0	106	19	0	75	21	33	42	8	51	47

SPP

asset categories	Quantity of TFEs submitted & approved													
	CIP-005				CIP-006	CIP-007								
	R2.4	R2.6	R3.1	R3.2	R1.1	R2.3	R3.2	R4	R5.3	R 5.3.1	R5.3.2	R5.3.3	R6	R6.3
Data Storage Device	0	1	0	1	0	0	0	1	0	0	0	0	1	0
Digital Protective Control Device	0	1	0	0	0	0	0	1	0	0	0	0	1	0
Electronic Access Control System	0	8	0	0	0	0	0	6	0	4	5	3	0	0
Electronic Access Monitoring System	0	1	0	0	0	0	0	3	0	0	2	1	0	0
Industrial Process Control System	0	0	0	0	0	1	0	3	1	0	0	0	0	0
Mainframe Computer	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Network Data Communications Device	0	4	0	2	0	2	2	27	6	1	8	2	5	0
PC Laptop	0	0	0	0	0	0	0	4	0	0	3	1	0	7
Peripheral Device	0	1	0	1	0	0	1	3	0	0	0	0	1	1
Physical Access Control System	0	0	0	2	0	0	0	0	0	0	1	1	0	0
Physical Access Monitoring System	0	0	0	2	0	0	0	0	0	0	2	1	0	0
Physical Security Perimeter	0	0	0	1	1	0	0	0	0	0	0	0	0	0
Relay	0	0	0	0	0	0	0	1	0	0	1	0	2	1
RTU	0	0	0	0	0	0	0	2	0	0	0	0	1	0
Server	0	1	0	0	0	1	0	6	0	3	9	2	0	0
Telecommunications Device	0	1	0	0	0	0	0	4	1	1	3	2	0	0
Transmitters	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Valve Controllers	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	2	0	7	3	2	2	2	4	0

3b(4). TFE Requests, Device Categories (by Region)

TRE

asset categories	Quantity of TFEs submitted & approved													
	CIP-005				CIP-006	CIP-007								
	R2.4	R2.6	R3.1	R3.2	R1.1	R2.3	R3.2	R4	R5.3	R 5.3.1	R5.3.2	R5.3.3	R6	R6.3
Data Storage Device	0	3	0	2	0	1	0	8	3	3	3	2	2	1
Digital Protective Control Device	0	0	0	0	0	2	0	3	0	0	0	0	2	0
Electronic Access Control System	1	5	0	0	0	0	0	21	0	1	2	1	0	0
Electronic Access Monitoring System	0	1	0	0	0	0	1	9	0	4	6	2	0	0
Industrial Process Control System	0	5	0	6	0	2	0	9	6	7	7	7	8	5
Mainframe Computer	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Network Data Communications Device	1	13	0	16	0	11	0	57	14	9	8	6	26	17
PC Laptop	0	3	0	0	0	2	0	4	1	2	6	5	0	0
Peripheral Device	0	3	0	2	0	6	0	15	11	12	12	12	13	9
Physical Access Control System	3	6	0	4	0	5	0	14	0	8	13	12	5	5
Physical Access Monitoring System	1	5	0	7	0	8	1	17	0	10	10	6	0	0
Physical Security Perimeter	0	0	0	0	2	0	0	0	0	0	0	0	0	0
Relay	0	0	0	0	0	0	0	3	1	0	2	0	2	0
RTU	0	6	0	9	0	8	0	10	4	6	6	5	7	3
Server	0	0	0	0	0	2	2	13	3	2	12	3	2	1
Telecommunications Device	3	18	0	11	0	9	0	14	0	9	9	9	15	13
Transmitters	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Valve Controllers	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other	0	1	0	0	4	3	1	10	5	4	7	7	6	1

WECC

asset categories	Quantity of TFEs submitted & approved													
	CIP-005				CIP-006	CIP-007								
	R2.4	R2.6	R3.1	R3.2	R1.1	R2.3	R3.2	R4	R5.3	R 5.3.1	R5.3.2	R5.3.3	R6	R6.3
Data Storage Device	0	3	0	0	0	0	0	9	1	0	0	1	1	2
Digital Protective Control Device	0	0	0	0	0	2	0	8	2	1	1	2	7	0
Electronic Access Control System	3	8	0	5	0	1	1	41	2	0	0	0	2	0
Electronic Access Monitoring System	0	1	1	5	0	1	0	14	1	0	0	0	1	0
Industrial Process Control System	0	2	0	0	0	10	1	29	13	7	11	7	25	15
Mainframe Computer	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Network Data Communications Device	1	8	3	7	0	23	0	120	7	8	6	4	24	14
PC Laptop	0	0	0	0	0	6	0	2	1	1	3	2	2	3
Peripheral Device	0	4	0	3	0	4	0	23	7	3	2	0	19	13
Physical Access Control System	0	4	0	1	0	3	0	16	7	4	6	4	1	1
Physical Access Monitoring System	0	0	0	0	0	1	0	2	0	0	0	0	0	0
Physical Security Perimeter	0	1	0	0	2	0	0	3	0	0	1	0	0	0
Relay	0	0	0	1	0	0	0	8	0	3	4	2	4	7
RTU	0	1	1	2	0	6	1	23	3	1	1	0	16	1
Server	0	5	1	2	0	9	1	38	2	2	5	4	1	1
Telecommunications Device	1	1	0	0	0	1	0	12	3	0	0	0	4	3
Transmitters	0	0	0	0	0	0	0	1	0	0	1	0	1	0
Valve Controllers	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other	2	8	1	2	1	10	1	51	7	4	14	10	19	11

4. Approved TFE Requests, Basis for Submission (Aggregate)

asset categories (per Part A of TFE request)	Aggregate							
	Aggregate - Approved TFEs - Basis							
	Not technically possible	Operationally infeasible	Precluded by technical limitations	Adverse effect on BES reliability	Cannot achieve by compliance date	Unacceptable safety risks	Conflicts with other statutory or regulatory	Excessive cost that exceeds reliability benefit
Data Storage Device	88	4	8	0	9	0	0	0
Digital Protective Control Device	40	0	1	0	3	0	2	0
Electronic Access Control System	208	9	38	0	4	0	1	5
Electronic Access Monitoring System	127	4	77	2	6	0	0	1
Industrial Process Control System	230	21	85	11	5	0	0	0
Mainframe Computer	3	2	0	0	0	0	0	0
Network Data Communications Device	725	30	113	3	32	0	1	2
PC Laptop	43	33	28	5	2	0	0	2
Peripheral Device	214	1	40	0	2	0	3	0
Physical Access Control System	164	10	37	0	0	0	0	1
Physical Access Monitoring System	112	9	38	0	0	0	0	1
Physical Security Perimeter	19	5	11	0	1	0	2	1
Relay	76	2	5	0	1	0	2	0
RTU	149	8	6	0	0	0	0	0
Server	194	66	88	19	23	3	0	1
Telecommunications Device	153	5	4	0	1	0	0	2
Transmitters	6	0	0	0	0	0	0	0
Valve Controllers	1	0	0	0	0	0	0	0
Other	262	18	195	1	5	0	3	5

5. Approved TFE Requests, Mitigating/Compensating Strategies (Aggregate)

Asset categories (per Part A of TFE request)	Aggregate								
	Aggregate - Approved TFEs - Risk Mitigation/Compensation Strategies								
	ESP	PSP	IDS/IPS	Training	System Status Monitoring	Malware Prevention	Authentication	Encryption	Physical Monitoring
Data Storage Device	64	54	26	8	23	19	22	0	5
Digital Protective Control Device	23	24	12	1	7	5	16	0	5
Electronic Access Control System	140	97	38	30	47	21	62	5	17
Electronic Access Monitoring System	110	105	18	54	38	42	64	2	21
Industrial Process Control System	253	178	42	28	103	42	77	0	32
Mainframe Computer	1	1	1	0	1	1	2	0	1
Network Data Communications Device	536	345	135	77	196	117	163	3	65
PC Laptop	52	34	14	10	28	15	19	1	6
Peripheral Device	194	105	40	27	64	14	28	0	8
Physical Access Control System	124	78	8	20	22	13	35	11	17
Physical Access Monitoring System	92	48	11	21	14	9	33	3	28
Physical Security Perimeter	3	5	0	2	2	2	3	2	18
Relay	60	53	13	1	20	12	36	3	12
RTU	108	83	22	0	35	18	25	1	17
Server	225	125	53	72	54	39	83	1	26
Telecommunications Device	96	81	17	1	31	14	20	1	3
Transmitters	6	7	1	0	0	0	0	0	0
Valve Controllers	1	1	0	0	1	0	0	0	0
Other	298	158	51	97	142	33	107	3	57

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Reliability Technical Conference Docket No. AD12-1-000

NOTICE OF TECHNICAL CONFERENCE

(October 7, 2011)

Take notice that the Federal Energy Regulatory Commission will hold a Technical Conference on Tuesday, November 29, 2011, from 1:00 p.m. to 5:00 p.m. and Wednesday, November 30, 2011, from 9:00 a.m. to 4:00 p.m. This Commissioner-led conference will be held in the Commission Meeting Room at the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426. The conference will be open for the public to attend, and advance registration is not required.

The purpose of the conference is to discuss policy issues related to reliability of the Bulk-Power System. The conference will explore the progress made on the priorities for addressing risks to reliability that were identified in earlier Commission technical conferences. The conference also will discuss emerging issues, including processes used by planning authorities and other entities to identify reliability concerns that may arise in the course of compliance with Environmental Protection Agency regulations, and the tools and processes (including tariffs and market rules) available to address any identified reliability concerns.

The agenda for this conference will be issued at a later date. Information on this event will be posted on the Calendar of Events on the Commission's web site, www.ferc.gov, prior to the event.

Commission conferences are accessible under section 508 of the Rehabilitation Act of 1973. For accessibility accommodations, please send an email to accessibility@ferc.gov or call toll free 1-866-208-3372 (voice) or 202-208-1659 (TTY), or send a FAX to 202-208-2106 with the required accommodations.

For more information about this conference, please contact:

Sarah McKinley
Office of External Affairs
Federal Energy Regulatory Commission
888 First Street, N.E.
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(202) 502-8368
sarah.mckinley@ferc.gov

Nathaniel J. Davis, Sr.,
Deputy Secretary.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426
OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RR11-3-000

October 17, 2011

Schiff Hardin LLP
1666 K Street, N.W., Suite 300
Washington, D.C. 20036-4390

Attention: Owen E. MacBride
Attorney for North American Electric Reliability Corporation

Reference: Petition for Approval of Amendments to Delegation Agreement with Northeast Power Coordinating Council, Inc.

Dear Mr. MacBride:

1. On May 25, 2011, the North American Electric Reliability Corporation (NERC) submitted a petition requesting approval of amendments to the Delegation Agreement between NERC and Northeast Power Coordinating Council, Inc. (NPCC), specifically amendments to NPCC's Bylaws and Regional Reliability Standards Development Procedure.

2. The amendments to the NPCC Bylaws: (1) establish a hybrid Board of Directors comprised of stakeholder directors and independent directors; (2) reduce the total number of stakeholder directors; (3) reduce the number of stakeholder membership sectors by combining two existing sectors; (4) establish procedures for electing the stakeholder directors and the independent directors; and (5) revise the composition of the NPCC Hearing Body for compliance matters. The amendments to the NPCC Regional Reliability Standards Development Procedure are conforming changes in light of the Bylaws amendments.

3. Notice of this filing was issued on May 25, 2011, with comments, protests or motions to intervene due on or before June 15, 2011. No protests or adverse comments were filed.

4. NERC's uncontested filing is accepted pursuant to the relevant authority delegated to the Director, Office of Electric Reliability, under 18 C.F.R. § 375.303 (2011), effective January 1, 2012.

5. This action shall not be construed as accepting any other contingency plan pursuant to 18 C.F.R. § 375.303(a)(1)(i) or any other data or report pursuant to C.F.R. § 375.303(b)(3)(iv). This action shall not be construed as approving any other application including Electric Reliability Organization or Regional Entity Rules or procedures pursuant to 18 C.F.R. § 375.303(a)(2)(i). Such acceptance or approval shall not be deemed as recognition of any claimed right or obligation associated therewith; and such acceptance or approval is without prejudice to any findings or orders which have been or which may hereafter be made by the Commission in any proceeding now or pending or hereafter instituted by or against NERC.

6. This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713.

Sincerely,

Joseph H. McClelland, Director
Office of Electric Reliability

From: Elizabeth Heenan
To: reg_corresp_notif
Subject: NERC: FERC Orders Issued Following Sunshine Open Meeting
Date: Thursday, October 20, 2011 11:57:21 AM
Attachments: Order_Approving_PRC-002-NPCC-01_2011.10.20.pdf
Order_Approving_Interp_TOP-002-2a_2011.10.20.pdf

To NERC Management and Regional Entity Executives:

Attached please find two orders issued today following FERC's Sunshine Open Meeting.

Agenda Item E-7: RD11-8-000 – Order Approving Regional Reliability Standard PRC-002-NPCC-01. This order approves the Regional Reliability Standard and the accompanying implementation plan.

Agenda Item E-6: RD11-9-000 – Order Approving Interpretation of Reliability Standard. This order approves the interpretation of R10 of TOP-002-2a - Normal Operations Planning standard. The standard will now be referred to as TPL-002-2b

Additional orders will be sent as they are issued.

Thank you.

Elizabeth A. Heenan

Legal Assistant
North American Electric Reliability Corporation
1120 G Street NW
Suite 990
Washington, DC 20005
Cell: (202) 420-8795
Direct: (202) 383-2634
Fax: (202) 393-3955

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20111020-3017 FERC PDF (Unofficial) 10/20/2011

137 FERC ¶ 61,061
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
and Cheryl A. LaFleur.

North American Electric Reliability Corporation Docket No. RD11-9-000

ORDER APPROVING INTERPRETATION OF RELIABILITY STANDARD

(Issued October 20, 2011)

1. On April 15, 2011, the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), submitted a petition for Commission approval of an interpretation of Requirement R10 of Transmission Operations (TOP) Reliability Standard TOP-002-2a (Normal Operations Planning). This Reliability Standard requires, in pertinent part, each balancing authority and transmission operator to maintain plans to evaluate options and establish procedures for the reliable operation of the Bulk-Power System for current day and future operations, as well as coordinate current day and future operations with neighboring balancing authorities and transmission operators. Requirement R10, the subject of NERC's Petition, addresses the planning required to meet all System Operating Limits and Interconnection Reliability Operating Limits. NERC also requests that the Standard including the interpretation, which would be referred to as Reliability Standard TOP-002-2b, be made effective immediately upon the issuance of an order in this proceeding.

2. In this order, the Commission finds that NERC's proposed interpretation of Requirement R10 of Reliability Standard TOP-002-2a is just, reasonable, not unduly discriminatory or preferential, and in the public interest. Therefore, the Commission approves the interpretation, referred to as Reliability Standard TOP-002-2b, effective as of the date of this order.

I. Background

3. Section 215 of the Federal Power Act (FPA) requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval. Once approved, the Reliability Standards may be

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enforced by the ERO, subject to Commission oversight, or by the Commission independently.[1]

4. Pursuant to section 215 of the FPA, the Commission established a process to select and certify an ERO[2] and, subsequently, certified NERC as the ERO.[3] On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 Reliability Standards filed by NERC, including Reliability Standard TOP-002-2.[4] On December 2, 2009, the Commission approved TOP-002-2a, an interpretation submitted by NERC on Requirement R11.[5]

5. NERC's Rules of Procedure provide that a person that is "directly and materially affected" by Bulk-Power System reliability may request an interpretation of a Reliability Standard.[6] The ERO's "standards process manager" will assemble a team with relevant expertise to address the requested interpretation and also form a ballot pool. NERC's Rules provide that, within 45 days, the team will draft an interpretation of the Reliability Standard, with subsequent balloting. If approved by ballot, the interpretation is appended to the Reliability Standard and submitted to the Board of Trustees. Once approved by the Board of Trustees, the Reliability Standard with the interpretation is filed with the applicable regulatory authority for regulatory approval.

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[1] *See* 16 U.S.C. § 824o(e) (2006).

[2] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approva,l and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[3] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g & compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[4] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[5] *North American Electric Reliability Corp.*, 129 FERC ¶ 61,191 (2009).

[6] NERC Rules of Procedure, Appendix 3A, Reliability Standards Development Procedure, Version 6.1, at 27-29 (2010).

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II. NERC Petition

6. In its April 15, 2011 Petition,[7] NERC requests Commission approval of a proposed interpretation of Requirement R10 of Reliability Standard TOP-002-2a (Normal Operations Planning). The stated purpose of Reliability Standard TOP-002-2a is to ensure that current operations plans and procedures are prepared for reliable operations, including responses to unplanned events. Requirement R10, the subject of the proposed interpretation, requires:

> Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).

7. The Petition explains that NERC received a request from Florida Municipal Power Pool (FMPP) seeking an interpretation of Requirement R10 of Reliability Standard TOP-002-2a. Specifically, FMPP asked:

> In Requirement 10 is the requirement of the BA to plan to maintain load-interchange-generation balance under the direction of the TOPs meeting all SOLs and IROLs?

8. In response to FMPP's interpretation request, NERC provided the following interpretation:

> Yes. As stated in the NERC *Glossary of Terms used in Reliability Standards*, the Balancing Authority is responsible for integrating resource plans ahead of time, maintaining load-interchange-generation balance within a Balancing Authority Area, and supporting Interconnection frequency in real time. The Balancing Authority does not possess the Bulk Electric System information necessary to manage transmission flows (MW, MVAR or Ampere) or voltage. Therefore, the Balancing Authority must follow the directions of the Transmission Operator to meet all SOLs and IROLs.

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[7] *North American Electric Reliability Corp*., April 15, 2011 Petition for Approval of an Interpretation of Requirement R10 of Reliability Standard TOP-002-2a (Petition).

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9. In the Petition, NERC explains that the interpretation is consistent with the stated purpose of the Reliability Standard, which is to ensure that current operations plans and procedures are prepared for reliable operation, including response to unplanned events. The *NERC Glossary of Terms used in Reliability Standards* (NERC Glossary) definitions for balancing authority and transmission operator are referenced along with an explanation that the balancing authority does not possess information needed to manage flows or voltage, thus requiring the balancing authority to follow direction of the transmission operator or reliability coordinator. Further, the Petition states that when balancing authority actions do not resolve targeted transmission issues, the transmission operator or reliability coordinator is responsible for directing alternative actions.[8]

III. Notice of Filing, Interventions and Comments

10. On August 22, 2011, notice of NERC's filing was published in the *Federal Register* with interventions and protests due on or before September 14, 2011.[9] A motion to intervene was timely filed by American Municipal Power, Inc. (AMP). Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure,[10] the timely, unopposed motion to intervene serves to make AMP a party to this proceeding.

IV. Commission Determination

11. The Commission finds that the ERO's interpretation of Requirement R10 of Reliability Standard TOP-002-2a is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[11]

12. The interpretation supports the stated purpose of the Reliability Standard, i.e., current operational plans and procedures are essential for an entity to be prepared for reliable operations, including responses to unplanned events. The interpretation also clarifies the responsibilities of the balancing authority with regard to normal operations planning. Further, the language of the interpretation is consistent with the language of

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[8] *Id.* 6-7.

[9] 76 Fed. Reg. 52,325 (2011).

[10] 18 C.F.R. § 385.214 (2011).

[11] 16 U.S.C. § 824(d)(2).

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the requirement. Accordingly, the Commission approves the ERO's interpretation of Requirement R10 of Reliability Standard TOP-002-2a.

13. We agree with NERC that the balancing authority is responsible for integrating resource plans ahead of time, maintaining load-interchange-generation balance within a balancing authority area, and supporting interconnection frequency in real time under the definition of Balancing Authority found in the NERC Glossary.[12] Additionally, the Commission notes that communication and coordination between the balancing authority and transmission operator can be essential in normal operations planning under TOP-002-2a, Requirement R10 to "plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs)."[13]

14. Accordingly, the Commission approves Reliability Standard TOP-002-2b, effective as of the date of this order.

V. Information Collection Statement

15. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping requirements (collections of information) imposed by an agency.[14] The information contained here is also subject to review under section 3507(d) of the Paperwork Reduction Act of 1995.[15]

16. The Commission approved Reliability Standard TOP-002-2, the subject of this order, in Order No. 693.[16] This order proposes to approve the interpretation of the previously approved Reliability Standard, which was developed by NERC as the ERO. The interpretation relates to an existing Reliability Standard, and the Commission does

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[12] Petition at 6.

[13] *See* Reliability Standard TOP-002-2a, Requirement R10; *see generally Electric Reliability Organization Interpretation of Transmission Operations Reliability Standard*, Order No. 753, 136 FERC ¶ 61,176, at P 15-17 (2011).

[14] 5 C.F.R. § 1320.11 (2011).

[15] 44 U.S.C. § 3507(d).

[16] Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

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not expect it to affect entities' current reporting burden.[17] Accordingly, we will submit this Final Rule to OMB for informational purposes only.

The Commission Orders:

(A) NERC's interpretation is hereby approved, as discussed in the body of this order.

By the Commission. Commissioner Spitzer is not participating.

(S E A L)

Kimberly D. Bose,
Secretary.

[17] 5 C.F.R. § 1320.3(b)(2).

Document Content(s)

RD11-9-000.DOC.....1-6

137 FERC ¶ 61,071
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
and Cheryl A. LaFleur.

North American Electric Reliability Corporation Docket No. RR11-7-000

ORDER ACCEPTING 2012 BUSINESS PLAN AND BUDGET OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

(Issued October 20, 2011)

1. On August 24, 2011, the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO),[1] filed its 2012 business plan and budget, as well as the 2012 business plans and budgets of each Regional Entity and of the Western Interconnection Regional Advisory Body (WIRAB).[2] As discussed below, the Commission accepts the business plan and budget of NERC and the business plans and budgets of the Regional Entities and WIRAB, as well as the associated attachments and updates. NERC is authorized to issue billing invoices to fund the fiscal year 2012 operations of the Regional Entities, WIRAB, and itself.

I. Background

A. Regulatory History

2. Section 215 of the Federal Power Act (FPA) requires the Commission-certified ERO to develop mandatory and enforceable Reliability Standards, subject to Commission

[1] *North American Electric Reliability Corp*., 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[2] NERC's business plan and budget combined with the Regional Entities' business plans and budgets are collectively referred to herein as NERC's "Application." The eight Regional Entities include: Florida Reliability Coordinating Council (FRCC); Midwest Reliability Organization (MRO); Northeast Power Coordinating Council, Inc. (NPCC); Reliability*First* Corporation (RFC); SERC Reliability Corporation (SERC); Southwest Power Pool Regional Entity (SPP RE); Texas Reliability Entity (Texas RE); and Western Electricity Coordinating Council (WECC).

review and approval.[3] Specifically, section 215(c)(2)(B) of the FPA provides that the ERO must have rules that "allocate equitably reasonable dues, fees, and other charges among end users for all activities under this section."[4]

3. On February 3, 2006, the Commission issued Order No. 672 to implement the requirements of section 215 of the FPA, which generally provides for Commission authorization of funding for "statutory" functions, i.e., those functions carried out pursuant to section 215 of the FPA.[5] Among other things, Order No. 672 sets forth requirements for funding the ERO and the approval of an ERO business plan and budget.[6] Moreover, the Commission's regulations require the ERO to file with the Commission the ERO's proposed annual budget for statutory and non-statutory activities 130 days before the beginning of its fiscal year.[7] Further, the ERO's filing must contain the annual budgets of each Regional Entity for statutory and non-statutory activities and provide supporting materials, including the ERO's and each Regional Entity's complete business plan and budget organizational chart. The filing must also explain the proposed collection of all dues, fees, and charges, as well as the proposed expenditure of funds collected.

4. In an October 2006 order, the Commission conditionally accepted NERC's 2007 business plan and budget for its first year of operation as the ERO and provided NERC guidance on future business plan and budget submissions.[8] Subsequently, the Commission provided additional guidance on future business plan and budget submissions when it conditionally accepted NERC's 2008, 2009, 2010, and 2011 business plans and budgets.[9]

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[3] 16 U.S.C. § 824o (2006).

[4] *Id.* § 824o(c)(2)(B).

[5] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204 (2006), *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[6] Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 197.

[7] 18 C.F.R. § 39.4(b) (2011).

[8] *North American Electric Reliability Corp*., 117 FERC ¶ 61,091 (2006), *order on reh'g*, 119 FERC ¶ 61,059 (2007).

[9] *North American Electric Reliability Corp*., 121 FERC ¶ 61,057 (2007); *North American Electric Reliability Corp*., 125 FERC ¶ 61,056 (2008) (2009 Budget Order), *order granting clarification*, 126 FERC ¶ 61,021 (2009) (2009 Budget Clarification

(continued…)

B. NERC's 2012 ERO Business Plan and Budget Application

5. NERC's Application contains its proposed business plan and budget for the year ending December 31, 2012, as well as the proposed business plans and budgets of WIRAB and each of NERC's eight Regional Entities for the year ending December 31, 2012.

6. The proposed assessment for statutory activities for 2012 in the United States, Canada, and Mexico is $160,942,119, which includes $50,661,272 for NERC funding; $110,037,998 for Regional Entity funding; and $242,849 for WIRAB funding. NERC states that the portion allocable for the United States statutory activities of NERC, the Regional Entities and WIRAB is $144,102,400.

7. NERC's Application indicates that it will continue to allocate costs to end users in the United States based on Net Energy for Load (NEL) from 2010. NERC states that it will calculate and bill the assessments to certain entities, referred to as "designees," based on NEL values that include the NEL for other load-serving entities served by the designee or for which the "designee" has otherwise agreed to accept responsibility for assessments.[10] Further, NERC states that the calculation and billing of assessments to "designees" is not a departure from the principle that the ERO funding requirement should be recovered from load-serving entities based on NEL, but rather is a matter of administrative convenience and efficiency.[11]

8. In addition to the NERC and Regional Entity business plans and budgets, NERC has included various attachments in this filing, including: "Discussion of Comments Received During Development of NERC's 2012 Business Plan and Budget" (Attachment 12), "Calculation of Adjustments to the Alberta Electric System Operator 2012 NERC Assessment, the Ontario Independent Electric System Operator 2012 NERC Assessment, the New Brunswick System Operator 2012 Assessment and the Québec 2012 NERC Assessment" (Attachment 13), "Status Report on the Achievement of NERC's 2011 Goals" (Attachment 14), "Metrics Comparing Regional Entity Operations Based on the 2011 Projections and 2012 Budgets" (Attachment 15), "Metrics on NERC and Regional

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Order), *order on compliance*, 128 FERC ¶ 61,025 (2009) (2009 Budget Compliance Order); *North American Electric Reliability Corp.*, 129 FERC ¶ 61,040 (2009) (2010 Budget Order); *North American Electric Reliability Corp.*, 133 FERC ¶ 61,062 (2010) (2011 Budget Order).

[10] NERC Application at 21, n.35; *see also id.*, Attachment 2 (NERC Business Plan and Budget), Appendix 2C.

[11] *Id.* at 21, n.35.

Entity Administrative (Indirect) Costs Based on the 2012 Budgets" (Attachment 16), and "Status Report on Progress in Processing Violations of Reliability Standards" (Attachment 17).

C. Financial Performance Audit of NERC

9. On August 22, 2011, the Commission's Division of Audits in the Office of Enforcement informed NERC by letter that it was commencing an audit of NERC pursuant to section 215 of the FPA.[12] The audit letter stated that the financial performance audit will evaluate "NERC's budget formulation, administration, and execution . . . will focus on the costs and resources used to achieve program objectives . . . [and] will cover the period from August 23, 2006 to the present."[13]

II. Notice and Responsive Pleadings

10. Notice of NERC's August 24, 2011 Filing was published in the *Federal Register*, 76 Fed. Reg. 54,755 (2011), with interventions and protests due on or before September 14, 2011. A motion to intervene was timely filed by American Municipal Power, Inc. Motions to intervene and comments were timely filed by American Public Power Association (APPA) and Edison Electric Institute (EEI). Both APPA's and EEI's comments support Commission approval of NERC's 2012 business plan and budget.

III. Discussion

A. Preliminary Matters

11. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2011), the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

B. Substantive Issues

1. NERC Business Plan and Budget

a. NERC Application

12. NERC states that its 2012 business plan and budget was developed under a rigorous process that provided ample opportunity for review by the Finance and Audit Committee of the NERC Board of Trustees and allowed for stakeholder comment during the process. NERC explains that its principal goals in 2012 include: (1) developing

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[12] 16 U.S.C. § 824o (2006); 18 C.F.R. § 39.2(d) (2011).

[13] The August 22, 2011 Audit Letter to NERC is available on the Commission's eLibrary document retrieval system in Docket No. FA11-21-000.

clear, results-based reliability standards; (2) promoting a culture of industry learning and reliability excellence; (3) providing effective measures of reliability and risk performance; (4) facilitating effective management of critical infrastructure tasks; (5) ensuring effective and timely compliance and mitigation; (6) providing an effective and efficient ERO enterprise; and (7) instilling a high degree of trust and confidence in the ERO.[14]

13. NERC's 2012 business plan and budget are based on the following statutory program areas: (1) Reliability Standards; (2) Compliance Enforcement and Organization Registration and Certification; (3) Reliability Assessment and Performance Analysis; (4) Training, Education and Personnel Certification; and (5) Situational Awareness and Infrastructure Security.[15] For NERC's five statutory program areas, NERC describes the program, identifies the program's goals and objectives, and provides the number of full-time equivalent employees (FTE), as well as the amount budgeted for 2012. NERC also provides 2011 approved budget data and 2012 projected data for comparison.

14. NERC's proposed total budget for 2012 is $53,112,272, a decrease of $614,193 or 1.1 percent over the 2011 budget requirement of $53,726,465. NERC's proposed 2012 net funding requirement is $50,661,272 (i.e., total budget less funding from other sources), of which $46,132,189 is allocated to the United States.[16] The net funding requirement allocated to the United States is an increase of $12,874,197, or 38.7 percent, over the 2011 budget proposal.[17] NERC states that its proposed total U.S. net funding requirement is equivalent to $0.0000115 per kWh, based on the aggregate NEL of the United States in 2010.[18]

15. In contrast to the 2011 budget proposal, NERC does not propose to set aside funds for its Working Capital Reserve in the 2012 budget proposal. NERC projects a Working

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[14] NERC Application at 6.

[15] *Id.* at 19; *see also* Attachment 1.

[16] NERC Application at 19.

[17] The substantial increase in the net funding requirement allocated to the United States is explained in large part by the fact that the 2012 budget proposal does not rely on penalty payments to otherwise reduce the net funding requirement because it received no penalty payment during the period July 1, 2010 through June 30, 2011. By contrast, the 2011 budget proposal included $10,175,000 in penalty payments received from registered entities during the period July 1, 2009 through June 30, 2010, thus reducing the net funding requirement for that period. NERC Application at 18.

[18] *Id*. at 19.

Capital Reserve of $1,798,578 at December 31, 2011.[19] Moreover, NERC states that under the terms of the lease for its new Atlanta headquarters, rent is abated for a significant portion of 2012 and that it maintains a $4,000,000 line of credit with a major financial institution.[20]

16. As shown in the table below, NERC proposes a 2012 staffing level of 176.75 FTEs, which is an increase of 26 FTEs over the 2011 budget staff level of 150.75 FTEs.

NERC Program	**2012 Budget**[21]	**Direct FTEs**[22]	**Change in FTEs from 2011 Budget**
Reliability Standards	$9,156,601	24.92	4.84
Compliance Monitoring and Enforcement and Organization Registration and Certification	$19,514,535	55.66	8.58
Reliability Assessment and Performance Analysis	$6,968,860	16.5	2.75
Training, Education and Operator Certification	$3,098,129	6.75	.5
Situational Awareness and Infrastructure Security	$14,374,147	25.17	-0.66
Administrative Services[23]		47.75	10

[19] *Id.* at 53-54.

[20] *Id.*

[21] The amounts projected for each program area are the total direct funding for Canada, Mexico, and United States. NERC Application, Attachment 2 at 6 (Table 1).

[22] NERC Application, Attachment 2 at 24.

[23] The budgeted amount for each program includes the total cost for administrative services ($19,922,828), which is allocated to each program based on the number of FTEs budgeted for that program. NERC Application at 19.

Contribution to Working Capital Reserve	$0		
Total Budget	$53,112,272	176.75	26
Less other funding sources	($2,451,000)		
Net Funding Requirement	$50,661,272		

b. Commission Determination

17. The Commission accepts NERC's business plan and budget. We find that NERC's budget is reasonable and the associated costs of NERC's jurisdictional functions are equitably allocated among end users.[24]

2. Regional Entity Business Plans and Budgets

18. NERC's Application includes the 2012 Business and Budget Plan of each Regional Entity. NERC states that it reviewed the Regional Entity business plans and budgets and concludes that each Regional Entity proposes necessary and adequate resources to carry out its delegated functions.[25] The Commission has reviewed each Regional Entity budget, and has determined that each submission reasonably supports the level of expenditures identified in the budget.

19. We are satisfied that the Regional Entities have focused on adequately staffing and funding all of their program areas to perform the delegated, statutory functions. Accordingly, the Commission accepts the Regional Entity business plans and budgets.

3. WIRAB Budget

20. WIRAB's total budget for 2012 is $614,677, which is a $1,793 decrease over its 2011 budget. WIRAB proposes to fund its 2012 budget through its Working Capital Reserve and interest income and, therefore, its statutory funding for 2012 will be $242,849 for 2012 (of which $205,937 will be allocable to the United States). WIRAB states that it will employ 2.75 FTEs for 2012, an increase of .25 FTEs over 2011.

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[24] 16 U.S.C. § 824o(c)(1)(B) (2006). The Commission is currently undertaking an audit of NERC's financial performance. Any issues discovered in the course of the audit will be addressed with NERC as part of that process.

[25] NERC Application at 23-24.

21. Based on the information provided by WIRAB, the Commission concludes that WIRAB's 2012 budget is reasonable and, accordingly, the Commission accepts the WIRAB 2012 budget.

4. Other Matters

a. Background

22. In the 2011 Budget Order, the Commission directed NERC to make additions to Attachments 15 and 16 regarding metrics used to analyze the Regional Entities operations in future business plan and budget filings.[26] Specifically, the Commission directed NERC to include an analysis of the current fiscal year in addition to the "Metrics for Budget Submission" for the next budget year, specifically a "projected" versus "budgeted" amount.[27]

b. NERC Application

23. As in past budget proposals, NERC provides two sets of metrics in Attachments 15 and 16. NERC states that Attachment 15 "depict[s] and compare[s] the Regional Entities' total statutory budgets and staffing, [Compliance Monitoring and Enforcement Program (CMEP)] budgets and staffing, total statutory budget and CMEP budget dollars per registered entity and per registered function, registered entities and registered functions per statutory FTE and per CMEP FTE, numbers of 'small,' 'medium' and 'large' non-CIP compliance audits and 'small' and 'large' CIP compliance audits, and cost per compliance audit by type and size of audit."[28] Further, NERC states that the metrics in Attachment 16 "focus[] on the NERC and Regional Entity administrative (indirect) costs and staffing relative to total and direct program costs and staffing."[29] In response to the Commission's directive regarding additional metrics in the 2011 Budget Order, NERC states that Attachment 15 now "has been expanded to include metrics based on the NERC and Regional Entity 2011 projections included in their respective 2012 Business Plans and Budgets."[30]

24. For future budget proposals, NERC asks the Commission to discontinue the requirement directed in the 2011 Budget Order that NERC and the Regional Entities

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[26] 2011 Budget Order, 133 FERC ¶ 61,062 at P 38.

[27] *Id.*

[28] NERC Application at 79.

[29] *Id.*

[30] *Id.* at 80.

present metrics based on current year financial projections. NERC states that although NERC and the Regional Entities present current year "projections" in their business plans and budgets, these "projections" are not prepared with the level of consistency used to prepare the entities' annual budgets and therefore, make the usefulness of any comparison using this information questionable. NERC states that it has not developed a set of guidelines and criteria with the Regional Entities for making such decisions and, as a result, the comparison of those metrics to the metrics based on the budgets for the upcoming year does not provide meaningful comparative information. Further, the comparison could be misleading because the two sets of underlying numbers are not necessarily prepared with the same levels of consistency. In addition, NERC states that it already prepares and files a detailed report with the Commission comparing their final, actual, audited statutory costs to their budgeted costs for the preceding year, with explanations of significant variances on a total entity basis and on a line item basis by program, and includes metrics based on both budgeted costs and actual costs for the preceding year.

c. Commission Determination

25. The Commission agrees that the additional metrics developed in response to the 2011 Budget Order, i.e., the "Metric Based on 2011 Regional Entity Projections" presented in Attachment 15 of NERC's Application, are of limited value and should be discontinued in future business plan and budget filings.[31] NERC should continue to provide the metrics on Regional Entity operations in Attachments 15 and 16 that it has historically provided.

26. In reaching this determination, the Commission considered the following arguments raised in NERC's Application: (1) NERC and the Regional Entities have not developed a set of guidelines and criteria to ensure that the information contained in the projection figures are consistent from Regional Entity to Regional Entity; (2) the "projected" figures contained in the 2012 business plan and budget filing as well as the "projected" figures contained in earlier business plan and budget filings were likely not developed or reported consistently among the Regional Entities; and (3) utilizing four or five months worth of reportable data from the first two quarters of the year and extrapolating from that information for the full year is difficult and could result in a flawed analysis due to the cyclical nature of certain activities.[32] The Commission agrees that these factors diminish the value of NERC's comparative analysis with respect to the

[31] We refer specifically to the metrics and analyses that discuss comparisons between the current year projections of Regional Entity Operations to the upcoming year's Regional Entity Budgets. NERC Application, Attachment 15 at 24-25.

[32] NERC Application at 81-83.

directive in the 2011 Budget Order, thus rendering it an unnecessary step for NERC in developing and analyzing the Regional Entities' business plans and budgets in the future.

27. In light of the foregoing discussion, the Commission finds it appropriate to discontinue the requirement (directed in the 2011 Budget Order) that NERC provide comparative metrics based on Regional Entity projections. As it has historically done, NERC should continue to file metrics in Attachments 15 and 16 of its business plan and budget as they relate to current year budget information.

The Commission orders:

(A) NERC's 2012 business plan and budget is hereby accepted, as discussed in the body of this order.

(B) The Regional Entity 2012 business plans and budgets are hereby accepted, as discussed in the body of this order.

(C) The WIRAB Budget is hereby approved for funding, as discussed in the body of this order.

By the Commission. Chairman Wellinghoff concurring with a separate statement attached.
Commissioner Spitzer is not participating.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Order Accepting 2012 Budget Plan and Budget of the North American Electric Reliability Corporation	Docket No. RR11-07-000

(Issued October 20, 2011)

WELLINGHOFF, Chairman, *concurring*:

As we note in the order, the Commission is currently undertaking, for the first time, a financial audit of NERC. The audit includes, among other things, a comprehensive and detailed analysis of the data and information underlying NERC's 2012 budget and business plan. In my view, there is no legal barrier to the Commission's ability to revisit NERC's 2012 budget and business plan in light of the results of the audit.

For this reason, I concur with this order.

_____
Jon Wellinghoff
Chairman

Comment Period Opens
Proposed Amendments to NERC Rules of Procedure Section 509, Section 1703 and Appendix 5C

Comment Period Ends October 27, 2011

The North American Electric Reliability Corporation (NERC) is proposing changes to its Rules of Procedure (ROP) and associated Appendices.

NERC is requesting comments on a proposed revision to the NERC Rules of Procedure to add new sections 509 and 1703, as well as, Appendix 5C: *Procedure For Requesting and Receiving An Exception From The Application Of The NERC Definition of Bulk Electric System.* The comment period begins September 13, 2011 and ends October 27, 2011.

The proposed revisions are in response to FERC Orders 743 and 743A where NERC was directed to revise the definition of the Bulk Electric System (BES) and to develop a proposed exemption process. The proposed amendments would effectuate the exemption process directive by creating a new ERO rule implementing an exceptions process.

Under this process entities would be allowed to pursue either including within the BES an Element or Elements that would otherwise be excluded by application of the BES Definition or excluding from the BES an Element or Elements that would otherwise be included by application of the BES Definition. This exception process was developed with the participation of interested stakeholders who believe it to be practical in application and less burdensome than the NOPR proposal where a Regional Entity would have sought ERO and Commission approval before exempting each facility rated at 100kV or above from compliance with the Reliability Standards.

Materials Included in this Request for Comments

- Proposed new Section 509: Exceptions to the Definition of the Bulk Electric System
- Proposed new Section 1703: Challenges to NERC Determinations of BES Exception Requests under ROP Section 509
- Proposed new Appendix 5C: *Procedure for Requesting and Receiving An Exception From the Application of The NERC Definition of Bulk Electric System* (clean and redline showing changes from the May 2011 posting)

Additional Materials Included for information

- Consideration of comments from May 2011 posting
- BES Exception Request flowchart and timelines
- Exception Request Form template

Submission of Comments

Comments are due **October 27, 2011,** and must be submitted electronically using the form provided.

1. The ROP team believes the proposed amendments represent a process that balances the need for effective and efficient reliability administration with due process and clarity of expectations. Do you agree? **Please comment why or why not…If not please offer your proposed revision.**
   - ☒ ***Yes***
   - ☐ **No**
   - ☐ **Comments:**

2. The ROP team believes the proposed amendments represent a process that is consistent, repeatable, and verifiable. Do you agree? **Please comment why or why not…If not, please offer your proposed revision.**
   - ☐ ***Yes***
   - ☒ **No**
   - ☐ **Comments:** There is a very noticeable gap and lack of transparency on how the exception application will be evaluated and processed. Suggest the ROP team develop a reference/guidance document in order to assist Registered Entities, Regional Entities, and the ERO on how and on what basis an exception application would or should be processed.

3. The ROP team believes the proposed amendments represent a process that supports consistent treatment of transmission lines that cross international borders. Do you agree? **Please comment Please comment why or why not…If not, please offer your proposed revision.**
   - ☒ ***Yes***
   - ☐ **No**
   - ☐ **Comments:**

4. The ROP team believes the proposed amendments represent a process that helps alleviate concerns about a "one-size fits all" approach. Do you agree? **Please comment why or why not…If not, please offer your proposed revision.**
   - ☒ ***Yes***
   - ☐ **No**
   - ☐ **Comments:**

5. The ROP team believes the proposed amendments represent a process that allowed commenters to raise and address a number of their substantive concerns. Do you agree? **Please comment Please comment why or why not…If not, please offer your proposed revision.**
   - ☐ ***Yes***
   - ☒ **No**

☐ **Comments:** Refer to the response to Question 2.

6. Do you have any other comments not covered above?

☐ **Comments:** Sections 4.5.3 and 4.6 discuss the disclosure of confidential information mandated by or under the rules, laws, or acts within the United States. Suggest that alternate language be used for clarity, or adequate provisions be provided to include other jurisdictions, such as Canada.

SAMPLE FORM:
REQUEST FOR EXCEPTION TO THE BULK ELECTRIC SYSTEM DEFINITION

The information that must be submitted for an Exception Request is specified in Section 4.5 of the BES Exception Process (Appendix 5C to the NERC ROP).

This Sample Form is not intended to be the only way such information might be gathered, and each Regional Entity may develop a method or methods (electronic, hard copy, etc.) for submission of such information consistent with the Regional Entity's other submission forms.

This Sample Form is intended only to provide a possible example of a form that could be used for the submission of all the information required for a Request. There is no intention to attach this or any other form to Appendix 5C.

The substance of the information required shall not be changeable, but the only part of this form which must be used verbatim is Section III.B, **Detailed Information to Support an Exception Request**. That Part was designed under the Standards Development Process.

SAMPLE FORM:
REQUEST FOR EXCEPTION TO THE BULK ELECTRIC SYSTEM DEFINITION

Section I: General Information – Suitable for Public Posting

Request for: ☐ Inclusion ☐ Exclusion Submittal Date: _____

Type of Request: ☐ Original ☐ Amended (ID of Original Request _____)

Name of Submitting Entity: _____
Submitting Entity NERC Compliance Registry ID (if assigned): _____
Entity Address (1): _____
Entity Address (2): _____
City/Town: _____ State, Zip Code: _____
Is this request being filed in conjunction with other requests? ☐ Yes ☐ No
If so, identify the other Submitting Entity(ies): _____
Is the Submitting Entity filing a similar Request with another Regional Entity(ies)? ☐ Yes ☐ No
If so, which Regional Entity(ies) _____

Element(s) Description (check all that apply):
☐ Transmission ☐ Generation
☐ Substation ☐ Generator
☐ Network ☐ Generator facility
☐ Radial ☐ Generator interconnection facility
☐ Other (please explain)
_____

Status under the BES Definition for which this Exception Request is being submitted:[1]
☐ Included under Core Definition (No specific Inclusions or Exclusions apply)
☐ Not included under Core Definition (No specific Inclusions or Exclusions apply)
☐ Included under I1 ☐ Excluded under E1
☐ Included under I2 ☐ Excluded under E2
☐ Included under I3 ☐ Excluded under E3
☐ Included under I4 ☐ Excluded under E4
☐ Included under I5

Is Submitting Entity the Owner of Element(s)? ☐ Yes ☐ No
If No, provide the following:
Name of Owner: _____
Owner's NERC Compliance Registry ID (if assigned): _____
Is the Submitting Entity a (check all that apply):
☐ Regional Entity
☐ Reliability Coordinator
☐ Balancing Authority
☐ Transmission Operator
☐ Planning Coordinator
☐ Transmission Planner

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[1] Entities that have Element(s) designated as excluded under the BES definition and designations, do not have to file a Request under the Exception Procedure for an exclusion.

SAMPLE FORM:
REQUEST FOR EXCEPTION TO THE BULK ELECTRIC SYSTEM DEFINITION

Section II: Detailed Information – Treated as Confidential; Shared with Specified Entities[2]

Submitting Entity Contact Information
Contact's Name:_____ Phone: _____
Title: _____
E-mail: _____ Fax: _____

With respect to the Element(s) to which this Request applies, supply the NCR number for each of the following in whose scope of responsibility the Element(s) resides:

Reliability Coordinator: _____
Balancing Authority: _____
Transmission Operator: _____
Planning Coordinator: _____
Transmission Planner: _____

By submitting this Request, the following responsible, authorized representative of the Submitting Entity's senior management certifies that the representative has read the Exception Request on behalf of the Submitting Entity and that the Submitting Entity believes approval of the Exception Request is warranted pursuant to the criteria in Section 3.1 of Appendix 5C of the NERC Rules of Procedure. The representative further certifies that a copy of Sections I. and II. of this Request has been sent to each PC, RC, TOP, TP and BA that has (or will have upon inclusion in the BES) the Elements covered by this Request within its scope of responsibility. If the Submitting Entity is not the Owner, the representative also certifies that the Submitting Entity conferred with the Owner regarding the reason for the requested Exception, but could not reach agreement regarding the submission of the Request.

Name of senior management representative so certifying:_____
Title:_____

If Submitting Entity is not the Owner, Owner Contact Information, to the extent available:
Contact's Name:_____ Phone: _____
Title: _____ Cell: _____
E-mail: _____ Fax: _____

If the Submitting Entity is not the Owner, summarize the basis for your interest in this Request:

_____
_____
_____

Provide a brief statement of the basis, consistent with Section 3.1 of Appendix 5C of the NERC Rules of Procedure, on which the Submitting Entity contends the Exception Request should be approved.

_____
_____

[2] At the time of submitting this Request, the Submitting Entity shall also submit Section I and Section II to each PC, RC, TOP, TP and BA that has (or will have upon inclusion in the BES) the Elements covered by this Request within its scope of responsibility.

SAMPLE FORM:
REQUEST FOR EXCEPTION TO THE BULK ELECTRIC SYSTEM DEFINITION

List of Elements for which Request is being made, identified by terminal connections (including location(s), voltage level(s) and unit capacity(-ies)). This information should be sufficient to identify the physical location and electrical designation of the Element(s) so that the Request can be processed.

_____
_____
_____
_____
_____
_____
_____
_____
_____
_____
_____
_____
_____
_____

Note: The Submitting Entity(ies) should mark all information for which it seeks confidentiality according to Section 1500 of the NERC Rules of Procedure.

SAMPLE FORM:
REQUEST FOR EXCEPTION TO THE BULK ELECTRIC SYSTEM DEFINITION

Section III: Detailed Engineering Information – Submitted Only to Regional Entity

A. Classified Information Requirements.

A Request for Exception should include the following as applicable:

1. If the Exception Request is supported, in whole or in part, by Classified National Security Information, NRC Safeguards Information, and/or Protected FOIA Information, a statement identifying which of these categories each such item of information falls into and explaining why each such item of information is Classified National Security Information, NRC Safeguards Information, and/or Protected FOIA Information.
2. If the Submitting Entity is prohibited by law from disclosing any Classified National Security Information, NRC Safeguards Information and/or Protected FOIA Information to any person who is not an Eligible Reviewer (such as, for example, the restriction on access to Classified National Security Information specified in Section 4.1 of Executive Order No. 12958, as amended), the Exception Request shall identify the Classified National Security Information, NRC Safeguards Information and/or Protected FOIA Information that is subject to such restrictions on disclosure and shall identify the criteria which a person must meet in order to be an Eligible Reviewer of the Classified National Security Information, NRC Safeguards Information and/or Protected FOIA Information.

B. Detailed Information to Support an Exception Request

(The remainder of this sample form is comprised of the material drafted by the BES Definition Team and is subject to revisions in accordance with future changes that team may adopt. Comments on this Section III. B can be made to the BES Definition Standard Drafting Team.)

General Instructions:

A one-line breaker diagram identifying the facility for which the exception is requested must be supplied with every application. The diagram(s) supplied should also show the Protection Systems at the interface points associated with the Elements for which the exception is being requested.

Entities are required to supply the data and studies needed to support their submittal. Studies should:

- Be based on an Interconnection-wide base case that is suitably complete and detailed to reflect the facility's electrical characteristics and system topology
- Clearly document all assumptions used
- Address key performance measures of BES reliability through steady-state power flow, and transient stability analysis as necessary to support the entity's application, consistent with the methodologies described in the Transmission Planning (TPL) standard and commensurate with the scope of the request

Supporting statements for your position from other entities are encouraged.

List any attached supporting documents:

SAMPLE FORM:

REQUEST FOR EXCEPTION TO THE BULK ELECTRIC SYSTEM DEFINITION

For Transmission Facilities:

1. Is there generation connected to the facility?

   ☐ Yes ☐ No

   If yes, what are the individual gross nameplate values of each unit?

   Description/Comments:

2. How does the facility impact permanent Flowgates in the Eastern Interconnection, major transfer paths within the Western Interconnection, or a comparable monitored facility in the ERCOT Interconnection or the Quebec Interconnection?

   Please list the Flowgates or paths considered in your analysis along with any studies or assessments that illustrate the degree of impact:

3. Is the facility included in an Interconnection Reliability Operating Limit (IROL) in the Eastern Interconnection, ERCOT Interconnection, or Quebec Interconnection or a major transfer path rating in the Western Interconnection?

   ☐ Yes ☐ No

   Please provide the appropriate list for your operating area:

4. How does an outage of the facility impact the over-all reliability of the BES? Please provide study results that demonstrate the most severe system impact of the outage of the facility and the rationale for your response:

SAMPLE FORM:
REQUEST FOR EXCEPTION TO THE BULK ELECTRIC SYSTEM DEFINITION

5. Is the facility used for off-site power supply to a nuclear power plant as designated in a mutually agreed upon Nuclear Plant Interface Requirement (NPIR)?

   ☐ Yes ☐ No

   Description/Comments:

6. Is the facility part of a Cranking Path associated with a Blackstart Resource?

   ☐ Yes ☐ No

   Description/Comments:

7. Does power flow through this facility into the BES?

   ☐ Yes ☐ No

   If yes, ☐ under 10% of the calendar year ☐ 10% - 25% of the calendar year
   ☐ 25% - 50% of the calendar year ☐ More than 50% of the calendar year

   If yes, then using metered or SCADA data for the most recent consecutive two calendar year period, what is the minimum and maximum magnitude of the power flow out of the facility and describe the conditions when this could occur?

SAMPLE FORM:
REQUEST FOR EXCEPTION TO THE BULK ELECTRIC SYSTEM DEFINITION

For Generation Facilities:

1. What is the MW value of the host Balancing Authority's most severe single Contingency and what is the generator's, or generator facility's, percent of this value?

   Please provide the values and a reference to supporting documents:

2. Is the generator or generator facility used to provide Ancillary Services?

   ☐ Yes ☐ No

   Describe what Ancillary Services the generator or generator facility is supplying:

3. Is the generator designated as a must run unit?

   ☐ Yes ☐ No

   Please provide the appropriate reference for your operating area:

4. How does an outage of the generator impact the over-all reliability of the BES? Please provide study results that demonstrate the most severe system impact of the outage of the generator and the rationale for your response:

5. Does the generator use the BES to deliver its actual or scheduled output, or a portion of its actual or scheduled output, to Load?

   ☐ Yes ☐ No

   Description/Comments:

Comment Period Opens
Proposed Amendments to NERC Rules of Procedure Section 509, Section 1703 and Appendix 5C

Comment Period Ends October 27, 2011

The North American Electric Reliability Corporation (NERC) is proposing changes to its Rules of Procedure (ROP) and associated Appendices.

NERC is requesting comments on a proposed revision to the NERC Rules of Procedure to add new sections 509 and 1703, as well as, Appendix 5C: *Procedure For Requesting and Receiving An Exception From The Application Of The NERC Definition of Bulk Electric System.* The comment period begins September 13, 2011 and ends October 27, 2011.

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Under this process entities would be allowed to pursue either including within the BES an Element or Elements that would otherwise be excluded by application of the BES Definition or excluding from the BES an Element or Elements that would otherwise be included by application of the BES Definition. This exception process was developed with the participation of interested stakeholders who believe it to be practical in application and less burdensome than the NOPR proposal where a Regional Entity would have sought ERO and Commission approval before exempting each facility rated at 100kV or above from compliance with the Reliability Standards.

Materials Included in this Request for Comments

- Proposed new Section 509: Exceptions to the Definition of the Bulk Electric System
- Proposed new Section 1703: Challenges to NERC Determinations of BES Exception Requests under ROP Section 509
- Proposed new Appendix 5C: *Procedure for Requesting and Receiving An Exception From the Application of The NERC Definition of Bulk Electric System* (clean and redline showing changes from the May 2011 posting)

Additional Materials Included for information

- Consideration of comments from May 2011 posting
- BES Exception Request flowchart and timelines
- Exception Request Form template

Submission of Comments

Comments are due **October 27, 2011,** and must be submitted electronically using the form provided.

1. The ROP team believes the proposed amendments represent a process that balances the need for effective and efficient reliability administration with due process and clarity of expectations. Do you agree? **Please comment why or why not…If not please offer your proposed revision.**

   ☐ ***Yes***

   ☒ **No**

   ☒ **Comments:** The process still needs simplification in order to be efficient. The whole process may take over 22 months to be concluded as shown by the flowcharts.

NERC has failed to address the specific requirements of a key FERC directive contained in Orders No. 743 and 743-A. These Rules of Procedure amendments potentially violate the jurisdictional boundary set between Transmission and local distribution in Federal Power Act (FPA), Section 215, 824(o) and in those Orders.

The Regions and NERC must first screen all Elements and facilities presented for exception for the presence of "facilities used in the distribution of electric energy." In our view, and that of FERC, these local distribution facilities must be excluded from the Bulk Electric System (BES) as is specifically required in FPA, Section 215, 824(o), and through reference to the FPA by FERC in Order Nos. 743 and 743-A. This local distribution exclusion from the BES should be automatic upon presentation of appropriate proofs. Only then may NERC apply its various administrative procedures and technical criteria for exempting jurisdictional Transmission Elements and Facilities from the BES, where they may be found ***not*** "necessary for operating an interconnected electric energy transmission network."

NERC should adopt, in the proposed amendments to the RoP, the FERC Seven Factor test as the 'first screen' used for identifying and excluding any and all "facilities used in the distribution of electric energy." Filing Entities presenting such appropriate proofs should not need to present further evidence to demonstrate that such Elements and facilities are eligibility for exclusion from the BES.

The presentation of a local distribution determination by a jurisdictional Federal, State or Provincial body, that such Elements or facilities are "facilities used in the distribution of electric energy," represents appropriate proof and is sufficient for said Elements and facilities to be excluded from the BES.

Supporting Discussion:

Federal Power Act (FPA), Section 215, 824(o), Definitions differentiates between jurisdictional Transmission and non-jurisdictional local distribution as follows:

(a) Definitions- For purposes of this section:
(1) The term `bulk-power system' means--
(A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and
(B) electric energy from generation facilities needed to maintain transmission system reliability.
The term does not include facilities used in the local distribution of electric energy.

In FERC Order 743-A the Commission stated

> 69. We agree … that the Seven Factor Test could be relevant and possibly is a logical starting point for determining which facilities are local distribution for reliability purposes"

By adopting this FERC Seven Factor test, the BES SDT will have fulfilled its obligation to respond to these FERC mandates relating to "local distribution" as stated in FERC Order 743:

> "Determining where the line between 'transmission' and 'local distribution' lies," (¶37),
>
> "To the extent that any individual line would be considered to be local distribution, that line would not be considered part of the bulk electric system" (¶39), to establish
>
> "[A] means to track and review facilities that are classified as local distribution to ensure accuracy and consistent application of the definition" (¶119).

Supporting References:

FERC Order 743 observed some believe that "the Commission's [and by extension NERC's] proposal exceeds its jurisdiction by encompassing local distribution facilities that are not necessary for operating the interconnected transmission network." [FERC Order 743, ¶27.]

In this regard FERC Order 743 states:

> At ¶37, Congress specifically exempted "facilities used in the local distribution of electric energy" from the definition. … Determining where the line between "transmission" and "local distribution" lies, which includes an inquiry into which lower voltage "transmission" facilities are necessary to operate the interconnected transmission system, should be part of the exemption process the ERO develops.
>
> And at ¶39, To the extent that any individual line would be considered to be local distribution, that line would not be considered part of the bulk electric system.
>
> And at ¶119, … [W]e believe that it would be beneficial for the ERO in maintaining a list of exempted facilities, to consider including a means to track and review facilities that are classified as local distribution to ensure accuracy and consistent application of the definition. Similarly, the ERO could track exemptions for radial facilities. [Emphasis added]

Note that in ¶119 the Commission clearly distinguishes between "radial facilities" and "local distribution" just as it differentiates between jurisdictional radials and non-jurisdictional local distribution facilities in footnote 82:

> [82] As discussed further below, the Commission uses the term "exclusion" herein when discussing facilities expressly excluded by the statute (*i.e.*, local distribution) and the term "exemption" when referring to the exemption process NERC will develop for use with facilities other than local distribution that may be exempted from compliance with the mandatory Reliability Standards for other reasons.

2. The ROP team believes the proposed amendments represent a process that is consistent, repeatable, and verifiable. Do you agree? **Please comment why or why not…If not, please offer your proposed revision.**

   ☐ ***Yes***

   ☒ **No**

   ☒ **Comments:** There is a very noticeable gap and lack of transparency on how the exception application will be evaluated and processed. Suggest the ROP team develop a

reference/guidance document in order to assist Registered Entities, Regional Entities, and the ERO on how and on what basis an exception application would or should be processed.

While the proposed process is repeatable, it is difficult to evaluate if the process will be verifiable because it will depend, for example, how the RE conducts its review of an Exception request.

Refer to the responses to Question #1.

In addition, we believe that there is a substantial need to provide Applicants greater clarity and improved transparency with regard to how their exception applications will be evaluated by Regional Entities and NERC. Absent some guidance we are concerned that Regional variances will arise during application of the Exception Process within the eight NERC regions.

We, therefore, recommend that the RoP Drafting Team and/or the BES Standard Drafting Team develop an Applicant's and Evaluator's Guidance document to assist Applicants, Regional Entities, and NERC in preparing and evaluating exception applications. For example, the Federal Power Act provides Congress' vision for a reliable transmission system. Federal Power Act (FPA), Section 215, 824(o), Definitions states,

> (4) The term `**reliable operation**' means operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.

We recommend that NERC and the Regions specifically adopt this Congressional guidance, defining 'reliable operation,' as their overriding Technical Principles when evaluating Exception Process applications concerning jurisdictional Transmission Elements and facilities.

3. The ROP team believes the proposed amendments represent a process that supports consistent treatment of transmission lines that cross international borders. Do you agree? **Please comment Please comment why or why not…If not, please offer your proposed revision.**

☒ ***Yes***

☐ **No**

☒ **Comments:** The Procedure for requesting and receiving an exception from the application of the NERC definition of BES may not be applicable because of the obligation to submit to the applicable Governmental Authorities in Canada. NERC will have to take into consideration that other procedures exist under Canadian jurisdiction which may be quite different from the one proposed.

Also, footnote 2 in section 1.2 presumes automatic adherence of Canadian Authorities or the need for its procedure to be submitted to NERC. Instead, it will be necessary that NERC and Canadian Authorities, with the Canadian Entities involved, to come to a common understanding of differences, and come to some agreement. Those exchanges should aim

to ensure reliability across the border while respecting proper jurisdictions. It could be done by addressing reliability in bulk power transfer within (intra) or between (inter) two Balancing Authority Areas, and monitored facilities included in an Interconnection Reliability Operating Limit (IROL). Other criteria must be left to the discretion of the applicable jurisdiction.

4. The ROP team believes the proposed amendments represent a process that helps alleviate concerns about a "one-size fits all" approach. Do you agree? **Please comment why or why not…If not, please offer your proposed revision.**

   ☒ ***Yes***

   ☐ **No**

   ☒ **Comments:** As stated previously, the Procedure need to be made more efficient, recognize that applicable Governmental Authorities in Canada may adopt different approaches or methodologies for addressing exceptions to the NERC BES definition.

   Refer to the responses to Question #1.

5. The ROP team believes the proposed amendments represent a process that allowed commenters to raise and address a number of their substantive concerns. Do you agree? **Please comment Please comment why or why not…If not, please offer your proposed revision.**

   ☐ ***Yes***

   ☒ **No**

   ☒ **Comments:** Refer to the response to Question 2.

6. Do you have any other comments not covered above?

   ☐ **Comments:** Sections 4.5.3 and 4.6 discuss the disclosure of confidential information mandated by or under the rules, laws, or acts within the United States. Suggest that alternate language be used for clarity, or adequate provisions be provided to include other jurisdictions, such as Canada.

   As stated in previous responses, the Procedure needs to be made more efficient and that it needs to be recognized that applicable Governmental Authorities in Canada may adopt different approaches or methodologies for addressing exceptions to the NERC BES definition. In addition, before implementing this process, NERC will have to ensure that it fits all applicable Governmental Authorities frameworks as it is addressed in the proposed Section 1703 - Challenges to NERC Determinations of BES Exception Requests under ROP Section 509.

PROCEDURE FOR REQUESTING AND RECEIVING AN EXCEPTION FROM THE APPLICATION OF THE NERC DEFINITION OF BULK ELECTRIC SYSTEM

~~1.0 INTRODUCTION~~

~~1.1. Purpose~~

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1.0 INTRODUCTION

1.1. Purpose

The NERC definition of the Bulk Electric System uses specific terms and thresholds that, in most cases, should appropriately identify Elements and groups of Elements that are appropriately classified as part of the Bulk Electric System. Conversely, the BES Definition should, in most cases, exclude Elements that are not part of the Bulk Electric System. In certain cases, however, it is anticipated that the BES Definition will classify certain Elements as part of the Bulk Electric System that are not necessary for the Reliable Operation of the interconnected bulk transmission system and that it will classify certain Elements as non-Bulk Electric System that are necessary for the Reliable Operation of the interconnected bulk power transmission system.

This Appendix to the Rules of Procedure of the North American Electric Reliability Corporation ~~(NERC)~~ provides the procedure ~~("Exception Procedure")~~ by which an entity may request and receive an Exception from the application of the ~~NERC definition of the Bulk Electric System ("BES").~~ BES Definition. Such an Exception ~~herein~~ may have the effect of either including within the BES an Element or Elements that would otherwise be excluded by application of the ~~NERC definition of the BES ("~~BES Definition~~")~~ or excluding from the BES an Element or Elements that would otherwise be included by application of the BES Definition. This Appendix is intended to implement authorization granted by FERC to allow such Exceptions from the BES Definition.[1]

An entity must request and obtain an Exclusion Exception pursuant to an Exception Request under this Exception Procedure before any Element that is included in the BES by application of the BES Definition shall be excluded from the BES.- Likewise, an entity must request and obtain an Inclusion Exception pursuant to an Exception Request under this Exception Procedure before any Element that is excluded from the BES by application of the BES Definition shall be included in the BES.

~~An entity unable to determine~~During the pendency of an Exception Request, the status of an Element ~~by~~(s) that is the subject of an Exception Request shall remain as it is determined based on application of the BES Definition ~~also may submit an Exception Request under this Exception Procedure to obtain~~. This status will continue until all appeals to all Applicable Governmental Authorities are completed. An entity that is planning a ~~determination~~connection of ~~whether the~~a new Element ~~is or is not within the BES.~~ for which it believes an Exception would be appropriate may request an Exception prior to commercial operation of the Element.

The ~~owner~~Owner of the Element to which the Exception Request applies ~~("Owner")~~ or, with respect to an Element owned by another Registered Entity, any ~~applicable~~ Regional Entity,

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[1] *Revision to Electric Reliability Organization Definition of Bulk Electric System*, 133 FERC ¶ 61,150 ("Order No. 743~~,~~") (2010), *Order on Reh'g, Revision to Electric Reliability Organization Definition of Bulk Electric System,* 134 FERC ¶61,210 ("Order No. 743-A~~,~~") (2011).

Planning ~~Coordinator,~~Authority ("PA"), Reliability Coordinator ~~or~~ ("RC"), Transmission Operator ("TOP"), Transmission Planner ("TP") or Balancing Authority ("BA") that has (or will have upon inclusion of the Elements in the BES) the Elements covered by an Exception Request within its Scope of Responsibility may submit an Exception Request for the Element as provided in this Exception Procedure.

1.2. Authority

This Appendix is a NERC Rule of Procedure and an Electric Reliability Organization Rule. As such, this Appendix has been approved by (i) the NERC Board of Trustees and (ii) FERC or other Applicable Governmental ~~Entity in Canada or Mexico.~~ Authority. Any future revisions to this Appendix must be adopted in accordance with Article XI, section 2 of the NERC *Bylaws* and Section 1400 of the NERC *Rules of Procedure*, including approval by the NERC Board of Trustees and by FERC, in order to become effective.

Applicable Governmental ~~Entities~~Authorities in Canada or Mexico may adopt this Exception Procedure in its entirety or in part with its own deviation[2], ensuring there will be no adverse impact on the interconnected transmission system. Cross-border Regional Entities shall implement this Exception Procedure in a manner consistent with their memoranda of understanding, legislation, or governing contracts with applicable entities and Applicable Governmental Authorities concerning compliance monitoring and enforcement activities in particular states and provinces.

1.3 Obligations of Canadian and Mexican Entities and Cross-Border Regional Entities

A Registered Entity that is a Canadian Entity or a Mexican Entity seeking an Exception shall work with the Regional Entity, NERC, and Applicable Governmental Authorities in Canada or Mexico, as appropriate, to the extent permitted under applicable ~~federal, state or provincial~~ laws, and without being obligated to authorize the disclosure of information prohibited by applicable federal, state or provincial law from disclosure to FERC or other Applicable Governmental Authorities in the U.S., in order to comply with the requirements of

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[2] Canadian jurisdictions and relevant governmental authority should adopt the same or similar technical principles as exception criteria and follow the NERC process or ~~any other~~its process ~~agreed with the~~and submit it to NERC and/or applicable Cross-Border RE. ~~.~~ If and when there are any deviation(s) from the these principles or process, ~~the application~~it must:

(a) describe the deviations from the technical principles and process along with justifications, and

(b) demonstrate and confirm that any of the following ~~element~~Element or path are not excluded as part of the exception process, which

i. transfer bulk power within (intra) or between (inter) two Balancing Authority Areas; and

ii. are monitored facilities included in an Interconnection Reliability Operating Limit (IROL)

iii. excluded ~~element~~Element(s) are not necessary for the operation of transmission system.

this Exception Procedure or similar procedure adopted ~~as per~~pursuant to section 1.2~~.~~. A Canadian Entity or a Mexican Entity shall not be required to subject itself to United States federal or state laws not otherwise applicable to the entity in order to utilize this Exception Procedure to obtain an Exception.

2.0. DEFINITIONS

For purposes of this Appendix, the following terms shall be defined as set forth in this Section 2.0. Capitalized terms used in this Appendix that are not defined in this Section 2.0 shall have the meanings as defined in, as applicable, (i) the NERC *Glossary of Terms Used in Reliability Standards*, ~~or~~ (ii) Section 1.0 of the NERC *Uniform Compliance Monitoring and Enforcement Program*, Appendix 4C to the NERC *Rules of Procedure*, ~~or (iii) Section 1501 of the NERC *Rules of Procedure*.~~(iii) page 20 of the Organization Registration and Certification Manual, or (iv) Section 1501 of the NERC *Rules of Procedure*. [Note: FYI, consistent with what has been posted in the "Definitions and Capitalization" package, this lead-in paragraph would be replaced with the following text: "For purposes of this Appendix, capitalized terms shall have the definitions set forth in Appendix 2 to the Rules of Procedure. For ease of reference, the definitions of the following terms that are used in this Appendix are also set forth below."]

2.1 Acceptance of the Exception Request~~:~~ (or Acceptance): The determination by a Regional Entity that an eligible (in accordance with Section 4.1) Exception Request contains all the Required Information ~~in order to be reviewed for substance.~~ so that it can undergo substantive review.

2.2 Approval of the Exception Request~~:~~ (or Approval): The determination by NERC that an Exception Request meets the criteria to receive ~~an~~the requested Exception.

2.3 BES: ~~The~~ Bulk Electric System.

2.4 BES ~~DEFINITION:~~ Definition: The NERC definition of the Bulk Electric System~~.~~ as set forth in the NERC *Glossary of Terms Used in Reliability Standards*..

2.5 Canadian Entity: A Registered Entity that is organized under Canadian federal or provincial law.

2.6 Classified National Security Information: Required Information that has been determined to be protected from unauthorized disclosure pursuant to Executive Order No. 12958, as amended, and/or the regulations of the NRC at 10 C.F.R. §95.35; or pursuant to any comparable provision of Canadian federal or provincial law.

2.7 Disapproval of the Exception Request~~:~~ (or Disapproval): The determination by NERC that an Exception Request does not meet the criteria to receive ~~an~~the requested Exception.

2.8 Eligible Reviewer: A person who has the required security clearances or other qualifications, or who otherwise meets the applicable criteria, to have access to Confidential

Information, Classified National Security Information, NRC Safeguards Information or Protected FOIA Information, as applicable to the particular information to be reviewed.

~~**2.9 Exception**: A determination that (i) an Element that falls within the BES Definition should be excluded from the BES, or (ii) an Element that falls outside the BES Definition should be included in the BES, in either case based on application of the technical criteria in this Appendix.~~

~~**2.10 Exception**~~

2.9 Exception: Either an Inclusion Exception or and Exclusion Exception.

2.10 Exception Procedure: The procedure set forth in this Appendix.

2.11 Exception Request: A request made by a Submitting Entity in accordance with this Appendix for an Exception.

2.12 Exception Request Form: The form adopted by each Regional Entity, in accordance with a template ~~approved~~provided by NERC, for use by Submitting Entities in submitting ~~an~~ Exception Requests; provided, that the Exception Request~~.~~ Form must include Section III.B as adopted by NERC.

2.13 Exclusion Exception: A determination that an Element that falls within the BES Definition should be excluded from the BES.

2.14 FERC: The United States Federal Energy Regulatory Commission.

2.~~14~~ 15 FOIA: The U.S. Freedom of Information Act, 5 U.S.C. §552.

2.~~15~~ 16 Inclusion Exception: A determination that an Element that falls outside the BES Definition should be included in the BES.

2.17 Lead ~~Submitting~~ Entity: The entity that submits Exception Request information that is common to a group of Submitting Entities that are submitting Exception Requests jointly.

2.~~16~~ 18 Mexican Entity: A Registered Entity that is organized under Mexican law.

2.19 NRC: The United States Nuclear Regulatory Commission.

2.~~17~~ 20 NRC Safeguards Information: Required Information that is subject to restrictions on disclosure pursuant to 42 U.S.C. §2167 and the regulations of the NRC at 10 C.F.R. §73.21-73.23; or pursuant to comparable provisions of Canadian federal or provincial law.

2.~~18~~ 21 Owner: The ~~Owner~~owner(s) of an Element or Elements that is or may be determined to be part of the BES as a result of either the application of the BES Definition or an

Exception, or another entity, such as an operator, authorized to act on behalf of the ~~Owner~~owner of the Element or Elements in the context of an Exception Request.

2.~~19 Part A Required Information~~~~: Required Information that is to be provided in Part A of a Submitting Entity's Exception Request.~~

~~**2.20 Part B Required Information**: Required Information that is to be provided in Part B of a Submitting Entity's Exception Request.~~

~~**2.21**~~ **22 Protected FOIA Information:**- Required Information, held by a governmental entity, that is subject to an exemption from disclosure under FOIA ~~(~~[5 U.S.C. §552(e~~)),~~)], under any similar state or local statutory provision, or under any comparable provision of Canadian federal or provincial law, which would be lost were the Required Information to be placed into the public domain.

2.~~22~~ 23 Recommendation:- Regional Entity's report to NERC containing the Regional Entity's evaluation concerning whether or to what extent an Exception Request should be approved.

~~**2.23 Registered Entity:** An entity that is registered for a reliability function in the NERC *Compliance Registry.*~~

2.24 Rejection of the Exception Request~~:~~ (or Rejection): The determination by the Regional Entity that an Exception Request is not an eligible (in accordance with Section 4.1) Exception Request or does not contain all the Required Information in order to be reviewed for substance.

~~**2.25**~~ **Required Information:**- Information required to be provided in an Exception Request, as specified in Section 4.0 of this Appendix.

2~~:~~.26 ~~**Submitting Entity:**~~ **Scope of Responsibility:** The registered functions of a PA, RC, TOP, TP or BA and the geographical or electric region in which the PA, RC, TOP, TP or BA operates to perform its registered functions, or with respect to a Regional Entity, it's Regional Entity Region.

2.27 Submitting Entity: The entity that submits an Exception Request ~~Form.~~ .

2.28 Technical Review Panel: A panel established pursuant to Section 5.3 of this Appendix.

3.0. BASIS FOR APPROVAL OF AN EXCEPTION

3.1. Grounds for an Exception

(a) Exclusion Exception

An entity may request and obtain ~~approval~~ Approval from NERC for an Exclusion Exception on the grounds that ~~application of the terms of the BES Definition, evaluated in the context or environment of~~ the Element ~~or Elements~~(s) for which the Exception Request is filed~~: *[This draft presumes there will be a separate* ***Technical Principles for Demonstrating BES Exceptions*** *document, which*~~ is ~~*currently being drafted and posted for comment separately by the BES SDT; if not, the detailed criteria could be*~~ included ~~*here. In any case the details would be stated again on the form(s) to be completed by the Submitting Entity.]*~~

~~(i) would exclude from the BES an Element(s) that . . . ; or~~

~~would include~~ within the BES ~~an Element(s) that . . . ; or~~based on application of the BES Definition but is not necessary for the Reliable Operation of the interconnected bulk power transmission system as evidenced by Required Information provided pursuant to **Detailed Information to Support an Exception Request (**Section III.B of the Exception Request Form).

~~(iii) would be inconclusive regarding whether the subject Element or Elements are part of the BES.~~

(b) Inclusion Exception

An entity may request and obtain Approval from NERC for an Inclusion Exception on the grounds that the Element(s) for which the Exception Request is filed is not included within the BES based on application of the BES Definition but is necessary for the Reliable Operation of the interconnected bulk power transmission system as evidenced by Required Information provided pursuant to **Detailed Information to Support an Exception Request** (Section III.B of the Exception Request Form).

3.2.~~–~~ Burden

The burden to provide a sufficient basis for ~~approval~~Approval of an Exception Request in accordance with the provisions of this ~~Appendix~~Exception Procedure is on the ~~entity submitting the Exception Request ("the~~ Submitting Entity~~").~~ . It is the responsibility of the Regional Entity, subject to oversight by NERC as provided in this ~~Appendix, to~~ Exception Procedure, to evaluate the request and make ~~an initial recommendation as to whether~~ a Recommendation to NERC regarding its Approval. No single piece of evidence provided as part of an Exception Request ~~has met the criteria for approval.~~ or response to a question will be solely dispositive in the determination of whether an Exception Request shall be approved or disapproved.

4.0. FORM, CONTENTS, AND SUBMISSION OF AN EXCEPTION REQUEST

~~4.1~~4.1. Eligible Submitting Entities

The Owner of an Element may submit an Exception Request for either an Inclusion Exception or an Exclusion Exception regarding that Element. A Regional Entity, PA, RC, TOP, TP, or BA that has (or will have upon inclusion in the BES) the Elements covered by an Exception Request within its Scope of Responsibility may submit an Exception Request for the inclusion in the BES of an Element or Elements owned by a Registered Entity , provided that before doing so, (i) the Submitting Entity conferred with the Owner about the reasons for an Exception, and (ii) could not reach agreement regarding the submission of such an Exception Request. (If the Owner agrees with submitting an Exception Request, the Owner should be the Submitting Entity.) Only a Regional Entity may submit an Exception Request for the inclusion in the BES of an Element or Elements owned by an Owner that is not a Registered Entity. Only an Owner or a Regional Entity may submit an Exception Request for the exclusion from the BES of an Element. When a Regional Entity requests an Exception, the Regional Entity shall submit its Exception Request to NERC, in which case, NERC will perform the duties and responsibilities of the "Regional Entity" specified in this Appendix.

With respect to an Element that crosses a boundary between Regional Entities, (1) the Submitting Entity will submit the Exception Request to both (or all) Regional Entities, which will cooperate to process the Exception Request pursuant to section 5.1 below, or (2) the Regional Entities must jointly submit an Exception Request to NERC (neither Regional Entity shall be allowed to submit such Exception Request unilaterally).

4.2. Separate Submissions for Each Exception Request

A separate Exception Request shall be submitted for each Element or set of connected Elements for which the Submitting Entity seeks an Exception. The scope of an Exception Request shall cover the terminal connections of the Element or set of Elements as identified in the Exception Request. Where the ~~entity~~Submitting Entity seeks Exception from the BES Definition for multiple, similar Elements (either at the same location or at different locations within the geographic boundaries of a Regional Entity) on the same basis, the Exception Requests for all such Elements may be included in one ~~submission~~ Exception Request with all such Elements or sets of connected Elements separately identified. A single Exception Request may not be submitted for separate Elements within the geographic boundaries of more than one Regional Entity.

Multiple ~~entities~~Submitting Entities may jointly file Exception Requests for ~~similarly situated~~similar Elements for which they are requesting Exceptions on the same basis ~~under Section 3.1.~~ . In such a situation, the ~~entities~~Submitting Entities will submit a package comprised of a complete Exception Request Form for ~~one entity (the "~~a Lead Entity~~"),~~, and an Exception Request Form for each other ~~entity~~Submitting Entity that (1) provides the ~~entity's~~Submitting Entity's differing individual information to the extent such is required (e.g., contact information, identification, and location of Element(s), etc.), and (2) otherwise references the pertinent portions of the complete Exception Request Form filed by the Lead Entity (e.g., status under application of the ~~terms of the~~ BES Definition, basis for an Exception under Section 3.1, etc~~.) ~~.). For any Exception Request filed by multiple ~~entities~~Submitting Entities as provided in this Section, the Lead Entity shall be considered the "Submitting Entity" for purposes of the Regional Entity's and NERC's notices and actions in accordance with the remainder of this ~~Appendix.~~

Exception Procedure. However, any Owner nonetheless may take any action otherwise appropriate for a Submitting Entity (e.g., respond to a Recommendation, submit an appeal, etc.).

~~A Regional Entity, Planning Coordinator, Reliability Coordinator or Balancing Authority may submit an Exception Request with respect to an Element or Elements owned by another Registered Entity (the "Owner"), provided that before doing so, (i) the entity confers with the Owner about the reasons for an Exception, and (ii) the Owner disagreed with submitting such an Exception Request. If a Regional Entity seeks an Exception, the Regional Entity shall submit its Exception Request to NERC, in which case, NERC will perform the duties and responsibilities of the "Regional Entity" specified in this Appendix.~~

~~4.2~~4.3. Withdrawal of an Exception Request

A Submitting Entity may withdraw an Exception Request at any time prior to NERC Approval or disapproval of the Exception Request.

4.4. Form and Format of Exception Request

An Exception Request shall consist of ~~two parts, each~~three sections, all of which must be submitted to the applicable Regional Entity~~, with a copy to the Owner if different than the Submitting Entity~~ . If the Submitting Entity is not the Owner [i.e., is a Regional Entity, PA, RC, TOP, TP, or BA that has (or will have upon inclusion of the Element in the BES) the Elements covered by an Exception Request within its Scope of Responsibility], it shall at the same time provide a copy of the Exception Request to the Owner (or if the Owner is unknown, to the operator of the Element(s~~)~~)) to which the Exception Request applies~~), in a secure electronic form using the Exception Request Form:~~.

~~(i) Part A of the Exception Request is the identification of the Element(s) for which a Submitting Entity is requesting an Exception and of its status under the application of the terms of the BES Definition. Part A Required Information must be submitted as part of the Exception Request Form.~~

~~(ii) Part B of the Exception Request contains the detailed material to support an Exception Request and includes the documents, drawings, and other information necessary to provide the details and justification for the requested Exception. In accordance with the *[Technical Principles for Demonstrating BES Exceptions document]*, certain Part B Required Information must be submitted with the Exception Request Form, and additional Part B Required Information must be available at a location for review by the Regional Entity beginning on the date the Exception Request is submitted.~~

~~(iii) A Regional Entity may also require a Submitting Entity to submit all or a portion of the additional Part B Required Information to the Regional Entity, provided that (A) the information can be filed in a secure manner that does not compromise the confidentiality of any Confidential Information, Classified National Security Information, NRC Safeguards Information and/or Protected FOIA Information, and (B) the Submitting~~

~~Entity shall not be required to file with a Regional Entity any Part B Required Information if the Submitting Entity is not assured of such security , or to the extent that such filing is prohibited by law; provided that the information shall still be available at a location for review as provided in Section 4.2(ii). The Regional Entity is under no obligation to issue a Recommendation regarding an Exception Request without documentation sufficient to grant such an approval.~~

~~4.3~~4.5. Required Information to be Included in the Exception Request

~~4.3~~5.1. ~~Part A~~ Section I of an Exception Request shall contain the ~~Part A~~ Required Information specified in this Section 4.~~3~~5.1 ~~and shall be submitted to~~. At the ~~Regional~~same time the Submitting Entity ~~using~~submits the Exception Request Form~~. Consistent with the summary nature of the Part A Required Information~~ to the Regional Entity, the Submitting Entity shall submit a copy of Section I to each PA, RC, TOP, TP, and BA that has (or will have upon inclusion in the BES) the Elements covered by an Exception Request ~~Form provides checklists~~within its Scope of ~~responses to be selected by the Submitting Entity and/or limited space for narrative descriptions for the Part A Required Information listed below.~~ Responsibility. Failure to provide all ~~Part A~~Section I Required Information ~~will~~may result in ~~rejection~~Rejection of the Exception Request as incomplete. ~~The Part A Required Information shall consist of the following information:~~

1. Name and address of ~~entity submitting the Exception Request (“~~Submitting Entity~~”).~~.

2. Submitting Entity NERC Compliance Registry ID (if yet assigned).

3. Name of the Owner, if different than the Submitting Entity~~, and certification by the Submitting Entity that it conferred with the Owner regarding the reason for the requested Exception, but that the Owner disagreed with submitting such an Exception Request.~~

4. Owner’s NERC Compliance Registry ID (if yet assigned).

5. Exception Request submittal date.

6. Whether the Exception Request is an original Exception Request or an amended Exception Request; and if it is an amended Exception Request, the identification number(s) of the original Exception Request and any previous amendments.

7. ~~Name, mailing address, phone number, facsimile number and E-mail address of the Submitting Entity’s technical contact person for~~Whether the Exception Request~~.~~

~~8. To the extent known by the Submitting Entity, name, mailing address, phone number, facsimile number and E-mail address of the Owner’s technical contact~~

person for the Exception Request, if the Owner is different from the Submitting Entity.

9. Status under the BES Definition of the Element(s) for which the Exception is being requested. *[On the form, this would be a checklist of the various parts of the BES Definition,*submitted in conjunction with *perhaps some space for specific, relevant details. "Unable to determine status" would be one option.]*Requests by other Submitting Entities. If so, the names of the other Submitting Entities.

10. The type(s) of Element(s) for which the Exception is being requested.

11. Identification and location(s) of Element(s) for which the Exception is being requested.

12.8. Whether the Submitting Entity is filing a similar Exception Request(s) with one or more other Regional Entities, and if yes, the name(s) of the other Regional Entity(ies).

9. The type(s) of Element(s) for which the Exception is being requested.

10. Status, based on application of the BES Definition, of the Element(s) for which the Exception is being requested.

4.35.2 Part B**.** Section II of an Exception Request shall contain the Part B Required Information specified in this Section 4.35.2. Failure to include all Part BAt the same time the Submitting Entity submits the Exception Request Form to the Regional Entity, the Submitting Entity shall submit a copy of Section II to each PA, RC, TOP, TP, and BA that has (or will have upon inclusion of the Element(s) in the BES) the Elements covered by an Exception Request within its Scope of Responsibility. Failure to provide all Section II Required Information may result in rejectionRejection of the Exception Request. The information provided should be comprehensive, as opposed to the summary information provided on Part A, and should include any supporting documents, as required by the *[*incomplete.

Section II Required Information will not be publicly posted or disclosed to third parties except for persons involved in reviewing the Exception Request.

1. Identification and location(s) of Element(s) for which the Exception is being requested.

2. Name, title, phone number, facsimile number, and E-mail address of the Submitting Entity's technical *criteria document].* contact person for the Exception Request.

3. Certification by the Submitting Entity (if other than Owner) that it conferred with the Owner regarding the reason for the requested Exception, but could not reach agreement regarding the submission of an Exception Request.

4. To the extent known by the Submitting Entity, name, mailing address, phone number, facsimile number, and E-mail address of the Owner's technical contact person for the Exception Request, if the Owner is different from the Submitting Entity.

~~1.~~5. Identification of PA, RC, TOP, TP, and BA that has (or will have upon inclusion in the BES) the Elements covered by the Exception Request within its Scope of Responsibility, and certification by the Submitting Entity that it has sent copies of Sections I and II to each such entity.

6. A statement of the basis~~, consistent with Section 3.1 of this Appendix,~~ on which the Submitting Entity contends the Exception Request should be approved, ~~with supporting documentation for such basis~~ and if the Submitting Entity is not the Owner, a statement of the basis of the Submitting Entity's reason for submitting the Exception Request.

7. A statement, signed and dated by an authorized representative of the Submitting Entity's senior management stating that the representative has read the Exception Request on behalf of the Submitting Entity and that the Submitting Entity believes Approval of the Exception Request is warranted.

4.5.3 Section III of an Exception Request shall contain the **Detailed Information to Support an Exception Request** as specified on the Exception Request Form. Failure to include all Section III Required Information may result in Rejection of the Exception Request. The Submitting Entity may designate all or part of the Section III Required Information as ~~required by the *[technical criteria document]*, or an explanation of the reason for the inability to determine the subject Element's or Elements' status by application of the terms of the BES Definition~~Confidential Information.

1. If the Exception Request is supported, in whole or in part, by Classified National Security Information, NRC Safeguards Information, and/or Protected FOIA Information, Section III shall include a statement identifying which of these categories each such item of information falls into and explaining why each such item of information is Classified National Security Information, NRC Safeguards Information, and/or Protected FOIA Information.

2. If the Submitting Entity is prohibited by law from disclosing any Classified National Security Information, NRC Safeguards Information and/or Protected FOIA Information to any person who is not an Eligible Reviewer (such as, for example, the restriction on access to Classified National Security Information specified in Section 4.1 of Executive Order No. 12958, as amended), ~~the Exception Request~~Section III shall identify the Classified National Security Information, NRC Safeguards Information and/or Protected FOIA Information that is subject to such restrictions on disclosure and shall identify the criteria which a person must meet in order to be an Eligible Reviewer of the Classified

National Security Information, NRC Safeguards Information and/or Protected FOIA Information.

4. ~~A statement, signed and dated by a responsible, authorized representative of the Submitting Entity's senior management stating that the representative has read the Exception Request on behalf of the Submitting Entity and that the Submitting Entity believes approval of the Exception Request is warranted pursuant to the criteria in Section 3.1 of this Appendix.~~

5.4~~.3.3~~ The Owner of the Element(s) to which the Exception Request applies, if different than the Submitting Entity, may file a response to supplement, correct or disagree with all or any part of an Exception Request ~~Form~~. Any PA, RC, TOP, TP, and BA that has (or will have upon inclusion of the Element(s) in the BES) the Elements covered by an Exception Request within its Scope of Responsibility may also provide input to the RE regarding the request. If in order to evaluate an Exception Request, the Owner, PA, RC, TOP, TP or BA wishes to obtain any Required Information in Section III of the Exception Request, the Owner PA, RC, TOP, TP or BA may submit to the Regional Entity a request stating its reason for wanting to review such information, and the Regional Entity may provide such information if the Regional Entity believes such review may assist the Regional Entity's review; if any of such Section III Required Information has been designated Confidential Information, prior to being provided the Confidential Information, the Owner, PA, RC, TOP, TP or BA shall execute a confidentiality agreement in a form established by the Regional Entity. Any response provided pursuant to this section 4.5.4 must be submitted to the Regional Entity with copies to the Submitting Entity and the Owner, if different from the Submitting Entity, within forty-five (45) days after ~~receiving a copy of~~the date the Exception Request Form was submitted to the Regional Entity.

4.~~4~~6 Access to Confidential Information, Classified National Security Information, NRC Safeguards Information, and Protected FOIA Information Included in Required Information

4.~~4~~6.1. Upon reasonable advance notice from a Regional Entity, and subject to Section 4.~~4~~6.2, a Submitting Entity or Owner must provide the Regional Entity (~~i~~a) with access to Confidential Information, Classified National Security Information, NRC Safeguards Information, and Protected FOIA Information included in the ~~Part B Required Information~~Exception Request, and (~~ii~~b) with access for purposes of making a physical review and inspection ~~to~~of the Element or Elements for which an Exception Request has been submitted.

4.~~4~~6.2. If the Submitting Entity or Owner is prohibited by law from disclosing any Confidential Information, Classified National Security Information, NRC Safeguards Information, or Protected FOIA Information to any person who is not an Eligible Reviewer (such as, for example, the restriction on access to Classified National Security Information specified in Section 4.1 of Executive Order No. 12958, as amended), then such Confidential Information, Classified National Security Information, NRC Safeguards Information, or Protected FOIA Information shall only be reviewed by a representative or

representatives of the Regional Entity ~~(~~which may include contractors~~)~~, who are Eligible Reviewers.

~~4.~~4.~~4~~6.3. The Regional Entity, as applicable, will work cooperatively with the Submitting Entity and/or Owner to provide necessary levels of protection for information identified in Section 1500 of the NERC Rules of Procedure and to access Protected FOIA Information in a way that does not waive or extinguish the exemption of the Protected FOIA Information from disclosure. If the Regional Entity shares any Confidential Information with a third party it shall do so subject to restrictions in applicable law under appropriate confidentiality agreements.

5.0 REVIEW, ACCEPTANCE OR REJECTION, AND RECOMMENDATION REGARDING EXCEPTION REQUESTS

The Regional Entity's Evaluation of the Exception Request will consist of two stages:

(a) During the first stage, the Regional Entity shall conduct an initial screening to determine whether to accept or reject the Exception Request; and

(b) During the second stage, the Regional Entity shall conduct a substantive review to determine its Recommendation to NERC as to whether or not the Exception Request should be approved.

If the Regional Entity determines at any time that for a specified period of time, the Regional Entity will be unable to complete initial screenings of Exception Requests within the time provided by Section 5.1.3(a) and/or substantive reviews of Exception Requests within the time provided in Section 5.2.2, the Regional Entity, based on consultation with NERC, shall establish an alternative time period objective and work plan for completing initial screenings and substantive reviews of Exception Requests during the specified period of time. The alternative time period objective and work plan shall be publicized by posting on the Regional Entity's website.

5.1. Initial Screening of Exception Request for Acceptance or Rejection

~~5.1~~5.1.1. Upon receipt of an Exception Request, the Regional Entity ~~(i)~~ will assign a unique identifier to the Exception Request, and ~~(ii)~~ will review the Exception Request to determine that the Exception Request is ~~for an exception~~from an eligible (in accordance with Section 4.1) Submitting Entity for an Exception from the application of the ~~terms of the~~ BES Definition and that all Required Information has been provided~~, as required by the *[Technical Criteria Document]*.~~ . If the Exception Request indicates that the Submitting Entity has submitted a similar Exception Request to one or more other Regional Entities, the Regional Entities shall coordinate their actions undertaken pursuant to this Section 5.0. If the Exception Request is for an Element that crosses boundaries between or among Regional Entities, the Regional Entities shall cooperatively determine a lead Regional Entity to assess the request in a single process yielding a single Recommendation to NERC.

5.1.2. The unique identifier assigned to the Exception Request will be in the form of XXXX-YYYY-NERCID-ExceptionZZZZZ, where "XXXX" is the year in which the Exception Request is received by the Regional Entity (*e.g.*, "2011"); "YYYY" is the acronym for the Regional Entity within whose geographic boundaries the relevant Element or Elements are located[3]; NERCID is the Submitting Entity's NERC Compliance Registry ID (or an abbreviation of its name if an ID is not yet assigned); and "ZZZZZ" is the sequential number of the Exception Requests received by the Regional Entity in that year. If the Exception Request is amended or resubmitted, "-AZ" will be added to the end of the identifier, where "Z" is the number of the amendment to the Exception Request.

5.1.3. ~~(a)~~ The Regional Entity will typically complete its initial screening of the Exception Request Form and any ~~responsive document filed by an Owner~~Owner's response submitted pursuant to Section 4.5.4 no later than either sixty (60) ~~calendar~~ days after receiving the Exception Request or, if the Submitting Entity is not the Owner, thirty (30) ~~calendar~~ days after receiving any ~~responsive document from the Owner~~Owner's response, whichever is later.

~~(b) If the Regional Entity determines at any time that for a specified period of time, the Regional Entity will be unable to complete initial screenings of Exception Requests within the time provided by Section 5.1.3(a) after receipt and substantive reviews of Exception Requests within six months after receipt, the Regional Entity, based on consultation with NERC, shall establish an alternative time period objective and work plan for completing initial screenings and substantive reviews of Exception Requests during the specified period of time. The alternative time period objective and work plan shall be publicized by posting on the Regional Entity's Website.~~

5.1.4. If, based on its initial screening, the Regional Entity determines the Exception Request is from an eligible (in accordance with Section 4.1) Submitting Entity for an Exception from the ~~application of the terms of the~~ BES Definition ~~(or for a determination of undeterminable status),~~ , and that all ~~Part A~~ Required Information has been provided~~, and that the Part B Required Information provides the types and scope of information required to be submitted in accordance with Section 4.2(ii) of this Appendix~~, the Regional Entity shall accept the Exception Request as complete and send a notice of such Acceptance to the Submitting Entity, with a copy to the Owner, if different than the Submitting Entity, and to NERC.

5.1.5. (a) If the Regional Entity determines, ~~(A)~~ based on its review of the ~~Part A Required Information provided by the Submitting Entity~~Exception Request, that the Exception Request (i) is not from an eligible (in accordance with Section 4.1) Submitting Entity for an Exception from ~~the~~ application of the ~~terms of the~~ BES Definition ~~(of for a determination of~~

[3] The acronyms to be used are: FRCC (Florida Reliability Coordinating Council); MRO (Midwest Reliability Organization); NPCC (Northeast Power Coordinating Council); RFC (Reliability*First* Corporation); SERC (SERC Reliability Corporation); SPP (Southwest Power Pool Regional Entity); TRE (Texas ~~Regional Entity/Texas~~ Reliability Entity); and WECC (Western Electricity Coordinating Council), and NERC in cases where the Exception Request is submitted to NERC.

~~otherwise undeterminable status),~~, and/or (ii) does not contain all ~~Part A Required Information, and/or (B) based on its review of the Part B Required Information provided by the Submitting Entity that the Exception Request does not provide the types and scope of information required in accordance with Section 4.2(ii) of this Appendix~~Required Information, the Regional Entity shall reject the Exception Request as incomplete and send a notice of such Rejection to the Submitting Entity, with a copy to the Owner, if different than the Submitting Entity, and to NERC~~,~~. To the extent feasible, if an Exception Request Form is missing ~~Part A or Part B information that the Regional Entity believes may be readily available to the Submitting Entity~~Required Information, the Regional Entity shall not reject the Exception Request until (1) it has contacted the Submitting Entity to request that the Exception Request Form be supplemented with ~~such information, and (2) the Submitting Entity has failed to submit such information within a reasonable period of time.~~ the missing Required Information, and (2) the Submitting Entity has failed to submit such Required Information within thirty (30) days or such additional period of time as the Regional Entity may allow at its discretion based on the circumstances, and (3) the Regional Entity has received the opinion from a Technical Review Panel pursuant to Section 5.3. When a Submitting Entity submits supplemental Required Information in response to a request under this section 5.1.5(a), the time for the Regional Entity to perform its initial screening will be extended for fifteen (15) days after receipt of the supplemental Required Information.

~~-~~(b)~~-~~ If the Regional Entity rejects the Exception Request in accordance with Section 5.1.5 (a), the Regional Entity's notice shall explain the reason for the Rejection~~ and identify any Part A Required Information or Part B Required Information that was not provided in the Exception Request Form.~~. The Regional Entity shall at the same time provide the Submitting Entity (and Owner if different) a copy of the Technical Review Panel's opinion. The Submitting Entity may~~ (i) at any time after a Rejection, submit an amended Exception Request to the Regional Entity correcting any deficiencies, or (ii),~~ within thirty (30) days after receipt of the Rejection, ~~ask~~appeal to NERC ~~to direct Reconsideration of the Exception Request~~ in accordance with Section ~~8~~7.0 of this ~~Appendix~~Exception Procedure to reverse the Rejection and to direct the Regional Entity to proceed with a substantive review of the Exception Request.

~~5.1.6.~~ The Regional Entity may either accept the Exception Request in its entirety, reject the Exception Request in its entirety, or if the Exception Request is for more than one Element, may accept it with respect to a subset of the Elements and reject it with respect to the remainder based on the similarity of the evidence presented for the Exception Request.

5.2 Substantive Review of Exception Request for Approval or Disapproval

~~5.2.1~~ After Acceptance of an Exception Request, the Regional Entity shall conduct a substantive review to evaluate whether or to what extent the Exception Request ~~meets the criteria for an Exception specified in Section 3.1 of this Appendix.~~ should be approved. As part of its substantive review, depending on the circumstances of the Exception Request, the Regional Entity may request access to and review the ~~Part B~~ Required Information, including any Confidential Information, Classified National Security Information, NRC Safeguards Information, and Protected FOIA Information that is necessary to support the Exception Request; may conduct one or more physical inspections of the relevant Element(s) and its (their) context

and surrounding Elements and Facilities; may request additional information from the Submitting Entity ~~or~~, Owner, or applicable PAs, RCs, BAs, TOPs and TPs; and may engage in further discussions concerning possible revisions to the Exception Request.

~~**5.2.2.** The~~ **5.2.2.** Upon Acceptance of the Exception Request, the Regional Entity and Submitting Entity (and Owner, if different) shall confer to establish milestones in order to complete ~~its~~the substantive review of the Exception Request ~~and~~within six months after Acceptance of the Exception Request or within an alternative time period under Section 5.0, at the conclusion of which the Regional Entity shall issue a notice (in accordance with Sections 5.2.~~4 or 5.2.5~~3) stating its Recommendation that the Exception Request be approved or disapproved~~, within six months after acceptance of the Exception Request or within an alternative time period as specified in~~. Such notice shall include the Regional Entity's evaluation of whether and to what extent the Exception Request should be approved in its entirety or be disapproved in its entirety, or, if the Exception Request is for more than one Element, to be approved with respect to a ~~work plan established under Section 5.1.3(b).~~ subset of the Elements and disapproved with respect to the remainder of the Elements. In ~~addition~~the case of extraordinary circumstances, the Regional Entity and Submitting Entity (and Owner, if different) may agree to extend the period of substantive review for individual Exception Requests ~~by issuing a notice to the Submitting Entity, with a copy to the Owner if different than the Submitting Entity and to NERC, stating~~; the revised date by which the Regional Entity will issue its Recommendation concerning the Exception Request~~.~~ shall be stated in a notice issued by the Regional Entity.

~~**5.2.3.** The~~**5.2.3.** Upon completion of its substantive review of the Exception Request, the Regional Entity shall issue a Recommendation to NERC, with a copy to the Submitting Entity and to the Owner if different than the Submitting Entity, including ~~its~~the Regional Entity's evaluation of whether and to what extent the Exception Request ~~meets the criteria~~qualifies to be approved in its entirety or be disapproved in its entirety, or if the Exception Request is for more than one Element, to be approved with respect to a subset of the Elements and disapproved with respect to the remainder~~.~~ of the Elements. The Recommendation shall set forth the basis on which the Regional Entity arrived at its Recommendation. With the Recommendation, the Regional Entity will also send NERC copies of the Exception Request Form and all other information ~~supplied~~considered by the ~~Submitting~~Regional Entity ~~and Owner if different than the Submitting Entity.~~ in arriving at its Recommendation.

5.2.4 The Regional Entity shall not recommend Disapproval of the Exception Request in whole or in part without first submitting the Exception Request for review to a Technical Review Panel and receiving its opinion, in accordance with Section 5.3.

5.3 Technical Review Panel

Each Regional Entity shall establish provisions for a Technical Review Panel consisting of not less than five (5) individuals. Panel members shall comply with Subsection 7 of Section 403 of the NERC Rules of Procedure, shall not have participated in the review of the Exception Request, and shall have the required technical background to evaluate Exception Requests. When the Regional Entity intends either pursuant to Section 5.1.5.(a) to reject an Exception Request, in

whole or in part, or pursuant to Section 5.2.2 to issue a Recommendation of Disapproval, in whole or in part, the Technical Review Panel must first review the Regional Entity's proposed determinations and provide an opinion, a copy of which shall be provided to the Submitting Entity (and Owner if different) in the event the Regional Entity decides to reject or disapprove, as applicable, the Exception Request. The Regional Entity will not be bound by the opinion of the Technical Review Panel, but such evaluation shall become part of the record associated with the Exception Request and shall be provided to NERC.

6.0 SUPPLEMENTATION OF AN EXCEPTION REQUEST PRIOR TO A RECOMMENDATION

A Submitting Entity or Owner at any time prior to the Regional Entity issuing its Recommendation may supplement a pending Exception Request that is under review by a Regional Entity, either at the request of the Regional Entity or at the Submitting Entity's or Owner's own ~~decision~~initiative, for the purpose of providing additional or revised Required Information. The Submitting Entity or Owner shall submit a written explanation of what Required Information is being added or revised and the purpose of the supplementation. Supplementing a pending Exception Request may, in the Regional Entity's discretion, ~~extend~~reset the time period for the Regional Entity's initial screening or substantive review, as applicable, of the Exception Request.

7.0 ~~RECONSIDERATION~~APPEAL OF REJECTION OF AN EXCEPTION REQUEST ~~APPLICATION BASED ON ITS COMPLETENESS~~

~~A~~The Submitting Entity~~, or Owner if different than the Submitting Entity,~~ may submit to the NERC Director of Compliance Operations, with a copy to the Regional Entity and Owner if different, information that ~~the entity believes~~ demonstrates that the insufficiencies in an Exception Request Form identified in the notice of Rejection by ~~a~~the Regional Entity pursuant to Section 5.1.5 are incorrect ~~and~~ or otherwise do not warrant Rejection of the Exception Request, and that the Exception Request should be ~~considered on its merits by a~~ accepted and proceed to substantive review. ~~An entity's~~ A Submitting Entity's submission to NERC under this Section 7.0 shall be in writing ~~and~~, shall ~~(i)~~ provide the Exception Request which received the ~~rejection~~Rejection (using the identifier assigned to the Exception Request pursuant to Section 5.1.2), ~~(ii) provide a copy of the Regional Entity's notice of Rejection of the Exception Request, and (iii)~~ and shall set forth a description of the errors that the ~~entity~~ Submitting Entity believes are in the notice~~.~~ of Rejection. The ~~entity's~~Submitting Entity's submission must ~~provide a clear and compelling demonstration (1)~~ demonstrate that it is eligible (in accordance with Section 4.1) to submit the Exception Request ~~is for an Exception as provided by Section 3.1~~ and ~~(2)~~ that all ~~Part A~~ Required Information ~~and Part B Required Information~~ for ~~such an~~the Exception Request has been provided. ~~Within forty-five (45) calendar days after receiving the submission,~~ NERC will review the ~~entity's~~Submitting Entity's submission and the reports submitted by the Regional Entity or Regional Entities pursuant to Section 5.1.5 with respect to the Exception Request, and if NERC determines that the Submitting Entity is eligible (in accordance with Section 4.1) to submit the Exception Request ~~is for an Exception pursuant to Section 3.1 (or for a determination of undeterminable status),~~, that all ~~Part A~~ Required Information has been provided, and that the ~~Part B Required Information provides the types and scope of information required~~Exception Request should proceed to ~~be submitted in accordance with Section 4.2(ii) of this Appendix~~substantive review, NERC shall ~~direct~~, within forty-five (45) days after receiving the submission, issue a decision directing the Regional Entity ~~to reconsider its rejection and~~ to proceed to a substantive review of the Exception Request in accordance with Section 5.2. NERC will send a written notice to the ~~entity~~ Submitting Entity, the Owner if different, and the Regional Entity stating ~~either~~ that NERC ~~has determined to direct reconsideration by~~either

directs the Regional Entity to proceed to a substantive review or that NERC ~~has determined~~does not ~~to~~ direct ~~reconsideration by the Regional Entity, as applicable~~such a review.

8.0 APPROVAL OR DISAPPROVAL OF AN EXCEPTION REQUEST

Following the ~~submission~~date of ~~a~~the Regional Entity's Recommendation to NERC, a Submitting Entity or Owner will have thirty (30) ~~calendar~~ days to submit a comment in support of or opposition to the Recommendation. ~~For no more than ninety days after receiving the Recommendation or seventy five days after receiving a comment on the Recommendation, whichever is longer, a~~ A team of three ~~NERC Reliability Assessment and Performance Analysis personnel~~persons with the required technical background to evaluate Exception Requests shall review the ~~Exception Request Form~~Recommendation and ~~supporting~~accompanying materials~~, the Recommendation and any comments, and~~ provided by the Regional Entity pursuant to Section 5.2.3, the Technical Review Panel opinion (if any), and any comment submitted by the Submitting Entity or Owner. This review shall be completed within ninety (90) days after NERC receives the Recommendation. NERC may choose to ask the Regional Entity, Submitting Entity and Owner, if different than the Submitting Entity, to appear at a NERC office for interviews or discussion regarding any questions. ~~By the end of such~~ In lieu of appearing in person at a NERC office, appearances may be, upon the mutual agreement of NERC, the Regional Entity, the Submitting Entity and/or Owner, conducted by a conference call, teleconferencing, or webinar. By the end of the ninety-day review period, the team shall issue a decision on behalf of NERC either to ~~Approve~~approve or to ~~Disapprove~~disapprove the Exception Request. If the Exception Request concerns more than one Element, ~~NERC~~the review team's decision may ~~Approve~~approve the Exception Request in its entirety, ~~Disapprove~~disapprove the Exception Request in its entirety, or ~~Approve~~approve some portion of the Exception Request and ~~Disapprove~~disapprove the remaining portion. The decision shall be in writing ~~and identify~~, shall be based on the team's independent consideration of the full record, and state the basis for the decision. If the decision of the team was not unanimous, the ~~writing~~written decision shall note that fact and include the basis on which the minority disagreed. The decision of the review team shall be the decision of NERC with respect to Approval or Disapproval of the Exception Request.

Documentation used to substantiate the ~~conclusions of NERC~~decision related to an Exception Request shall be retained by ~~the~~ NERC for a minimum of six (6) years or as long as the Exception is in effect, whichever is longer, unless a different retention period is otherwise identified, for the purposes of future audits of this procedure.

9.0 APPEAL OF APPROVAL OR DISAPPROVAL OF AN EXCEPTION REQUEST

~~**9.1**~~

A Submitting Entity or Owner aggrieved by NERC's ~~approval~~Approval or ~~disapproval~~Disapproval of an Exception Request or termination of an Exception may, within ~~twenty one (21) calendar~~thirty (30) days following ~~receipt~~the date of NERC's decision, ~~file an appeal with the NERC Board of Trustees by sending a letter to NERC's General Counsel stating the desire to do so, with copies to the other parties to the Exception Request process. The appeal~~

~~shall state the basis~~ challenge such determination pursuant to Section 1703 of the ~~objection to NERC's decision.~~

~~**9.2** NERC, the Regional Entity(ies), the~~ NERC Rules of Procedure. If neither a Submitting Entity ~~and the~~nor Owner ~~are encouraged to resolve any disagreements informally, and the entities involved may make use of alternative dispute resolution procedures at any time during the course of the matter, and in connection therewith to agree to toll the time~~ challenges, within such period ~~for consideration of the appeal.~~

~~**9.3** A panel appointed by the NERC Board of Trustees for that purpose shall decide the appeal within ninety (90) days. The panel shall consist of at least three appointees, one of whom must be a member of the NERC staff, who are knowledgeable about the types of Elements for~~ , NERC's determination with respect to any Element to which the Exception Request ~~was made and do not have a direct financial or business interest in the outcome of the appeal. The panel may request additional information from the Regional Entity(ies), the Submitting Entity and the Owner.~~

~~**9.4** The panel will provide a written decision regarding the appeal, including a basis for its decision, and NERC shall notify the Regional Entity(ies), the Submitting Entity and the Owner, that the appeal was granted~~ or ~~denied and~~the Exception applies, such determination shall ~~provide a copy~~become effective with respect to such Element on the thirty-first day following the date of the ~~written~~NERC decision ~~of the panel~~.

~~**9.5** The Submitting Entity and/or the Owner, if aggrieved by the decision of the panel may request that the NERC Board of Trustees Compliance Committee review the decision by filing its request for review and a statement of reasons with NERC's Chief Reliability Officer within 14 days of the panel decision. Within forty-five (45) days after receiving the request for review, the Board of Trustees Compliance Committee will provide a written decision regarding the appeal, including a basis for its decision; provided that the Board of Trustees Compliance Committee may, in its discretion, decline to review the decision of the panel, in which case the decision of the panel shall be the final NERC decision.~~

~~**9.6** A record of the appeals process shall be maintained by NERC.~~

~~**9.7** A Submitting Entity or Owner aggrieved by the decision of the Board of Trustees C ompliance Committee may appeal to FERC or the Applicable Canadian Governmental Authority within 21 days after notification of the final appellate decision.~~

~~10.0~~ 10.0 IMPLEMENTATION PERIOD FOR EXCEPTIONS

10.1 Inclusion Exceptions

In the case of an Element not included in the BES by application of the BES Definition but for which an Inclusion Exception is approved, the Owner shall submit a proposed implementation plan to the Regional Entity detailing the schedule for complying with any NERC Reliability Standards applicable to the newly included Element. The Regional Entity and Owner

shall confer to agree upon such schedule. If the Regional Entity and Owner are unable to agree on the implementation plan, the Regional Entity Board or a Board-appointed committee shall specify a reasonable implementation schedule.

10.2 Denials of Exception Requests for Exclusion

(a) In the case of a newly-constructed or installed Element which is included in the BES by application of the BES Definition but for which an Exception Request for an Exclusion Exception was submitted at least twelve (12) months before commercial operation of the Element, but which Exception Request is either still pending or has been disapproved at the time of commercial operation, the Owner shall submit a proposed implementation plan to the Regional Entity detailing the schedule for complying with any NERC Reliability Standards applicable to the newly constructed or installed Element. The Regional Entity and Owner shall confer to agree upon such schedule. If the Regional Entity and Owner are unable to agree on the implementation plan, the Regional Entity Board or a Board-appointed committee shall specify a reasonable implementation schedule.

(b) In the case of an Element which is included in the BES based on application of the current BES Definition but was not included in the BES under the BES Definition in effect immediately prior to the current BES Definition, and for which an Exception Request for an Exclusion Exception was submitted no more than twelve (12) months after the current BES Definition became effective, but which Exception Request has been rejected or disapproved, the Owner shall submit a proposed implementation plan to the Regional Entity detailing the schedule for complying with any NERC Reliability Standards applicable to the newly included Element. The Regional Entity and Owner shall confer to agree upon such schedule. If the Regional Entity and Owner are unable to agree on the implementation plan, the Regional Entity Board or a Board-appointed committee shall specify a reasonable implementation schedule.

11.0 TERMINATION OF AN APPROVED EXCEPTION

~~10~~11.1 An Exception Request typically will be ~~granted~~approved without a specified date of termination~~,~~ but will be subject to ~~periodic~~ review to verify continuing justification for the Exception.

~~**10.2** Registered Entities~~**11.2** Submitting Entity(ies) shall notify the appropriate Regional Entity, with a copy to NERC, within ninety (90) days after learning of any change of condition which would affect the ~~Part A or Part B Required Information regarding an Element(s) to which an Exception applies.~~basis stated by NERC in its decision pursuant to Section 8.0 approving the Exception Request. NERC shall review such notification and determine whether to direct the Regional Entity to perform a substantive review (pursuant to Section 5.2) to verify continuing justification for the Exception and to issue a Recommendation to NERC.

~~10~~11.3 ~~Registered Entities~~Submitting Entity(ies) shall ~~self~~ certify[4] periodically to the appropriate Regional Entity that the basis for ~~Elements~~an Element being included or excluded in the BES through the Exception ~~remain~~remains valid and in connection with each certification, shall provide the Regional Entity with any changes to ~~Part A~~Section I or Section II Required

[4] ~~Self~~ The certification shall consider the effect on the basis for the Exception ~~resulting from system~~of changes such as load growth and topological changes, as well as the effect on system limits and impacts as a result of the contingencies listed in Table 1 of ~~the~~each applicable NERC TPL ~~standards~~Reliability Standard.

Information. ~~Such self~~ The certification shall be due on the first day of the first quarter twenty~~-~~-four (24) months after the date on which the Exception Request was approved~~,~~ and every twenty-four ~~months~~ (24) months thereafter, ~~so~~as long as the Exception remains in effect.~~-~~ If such certification is not provided, the Exception ~~will terminate~~is subject to termination ninety (90) days after ~~such~~the date the certification was due~~.~~

~~**10.4** NERC and~~, and the Regional Entity shall send the Submitting Entity and ~~FERC shall be notified of necessary changes to the BES list consistent with the notification provisions described in this section~~NERC written notice of such termination.

11.4 If the Regional Entity obtains information through means other than those described in Sections 11.2 and 11.3 that indicates an Exception may no longer be warranted, the Regional Entity shall provide such information to NERC. NERC shall review the information and determine whether to direct the Regional Entity to perform a substantive review (pursuant to Section 5.2) to verify continuing justification for the Exception and to issue a Recommendation to NERC.

11.5 If the Regional Entity's Recommendation following a substantive review pursuant to Section 11.2 or 11.4 is that the Exception shall be terminated, NERC shall (i) issue a written notice to the Submitting Entity and Owner, if different, that the Exception is under review for possible termination, (ii) allow the Submitting Entity and/or Owner, as applicable, thirty (30) days from the date of the notice to submit comments or information to NERC to show that the Exception continues to be justified and should remain in effect, and (iii) cause the Recommendation to be reviewed in accordance with Section 8.0 of this Appendix. If the conclusion of the review is that the Exception should be terminated, NERC shall send a written notice to the Submitting Entity and Owner, if different, stating that the Exception is terminated and the reasons for the termination. When an Element will be included in the BES as a result of the termination of an Exclusion Exception under this Section, an implementation plan detailing the schedule for complying with any NERC Reliability Standards applicable to the newly included Element will be developed in accordance with Section 10.1 as if it were an inclusion exception.

11.6 Upon request by the Regional Entity, the Submitting Entity(ies) and/or Owner if different shall provide within thirty (30) calendar days the most recent versions of any Section III Required Information so requested.

BES Element Exception Process

Section 4.0 - Form, content and submission on an exception request

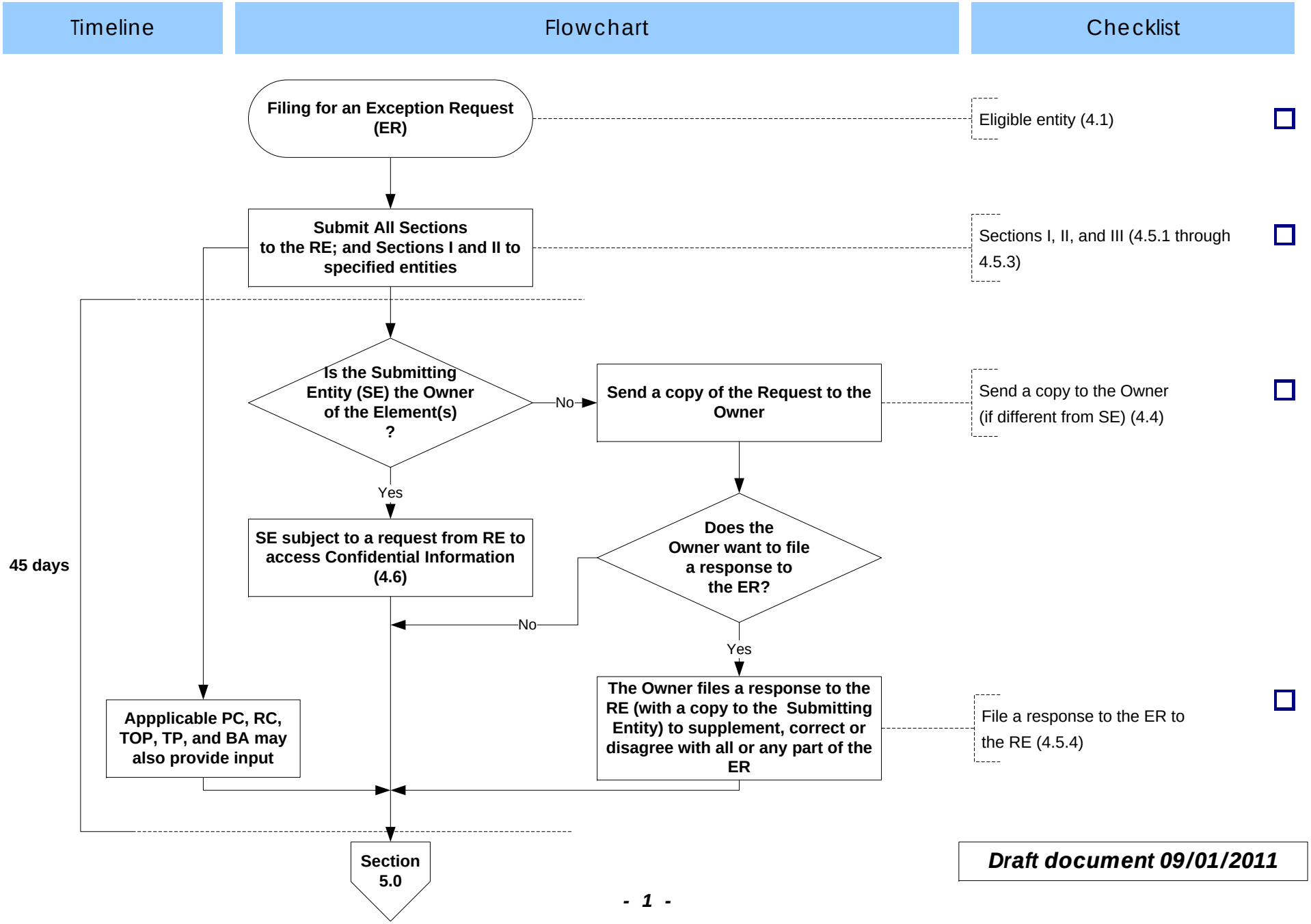

Draft document 09/01/2011

BES Element Exception Process

Section 5.0 – Review, acceptance or rejection, and reccomendation regarding ER

FIRST STAGE

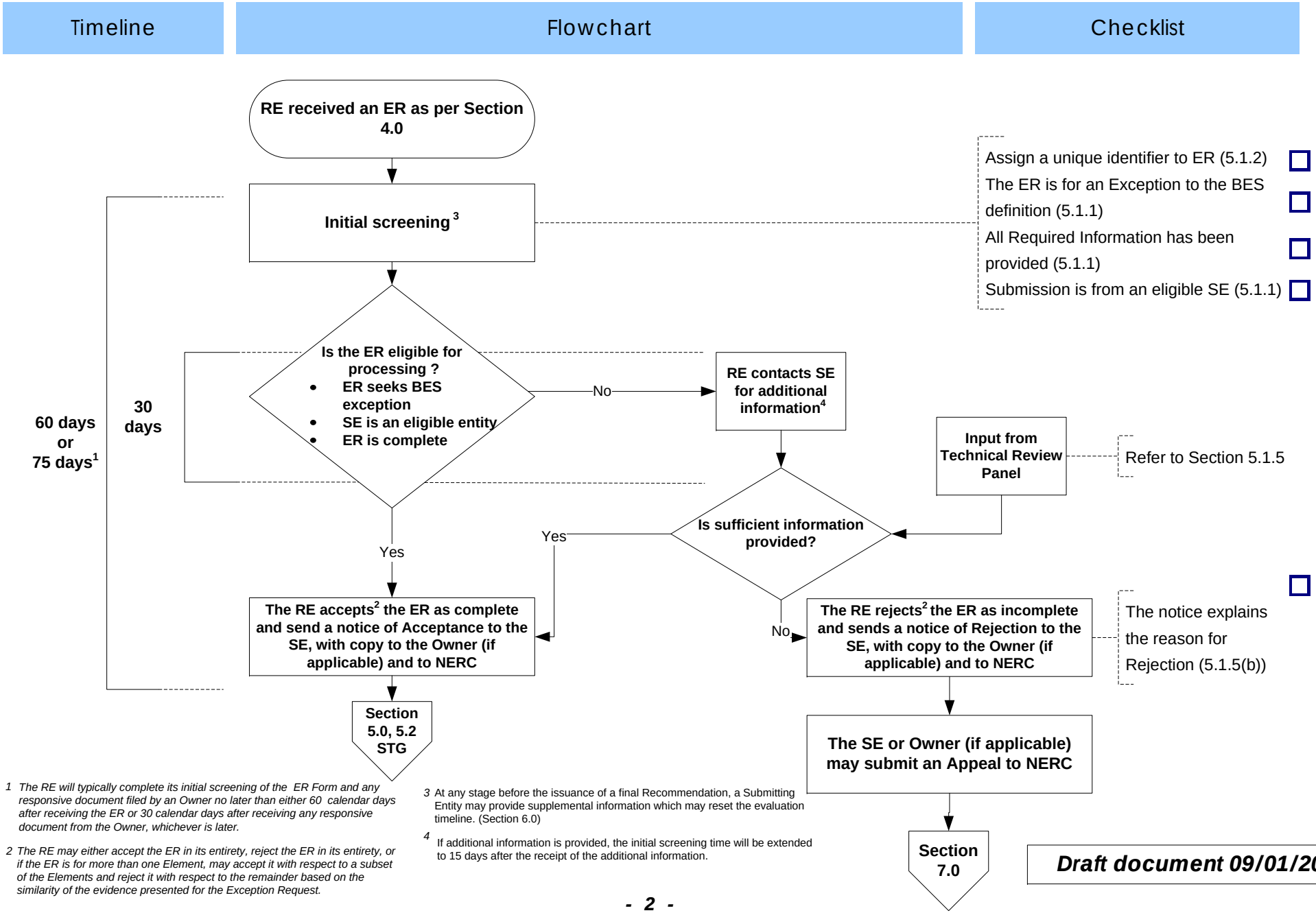

1 *The RE will typically complete its initial screening of the ER Form and any responsive document filed by an Owner no later than either 60 calendar days after receiving the ER or 30 calendar days after receiving any responsive document from the Owner, whichever is later.*

2 *The RE may either accept the ER in its entirety, reject the ER in its entirety, or if the ER is for more than one Element, may accept it with respect to a subset of the Elements and reject it with respect to the remainder based on the similarity of the evidence presented for the Exception Request.*

3 At any stage before the issuance of a final Recommendation, a Submitting Entity may provide supplemental information which may reset the evaluation timeline. (Section 6.0)

4 If additional information is provided, the initial screening time will be extended to 15 days after the receipt of the additional information.

Draft document 09/01/2011

BES Element Exception Process

Section 5.0 – Review, acceptance or rejection, and reccomendation regarding ER

SECOND STAGE

Timeline	Flowchart	Checklist
6 months	The RE conducts a substansive review[5]	
	RE and SE confer to set milestones	Refer to Section 5.2.2.
	Input from Technical Review Panel	Refer to Section 5.2.4.
	The RE issues a Recommendation to NERC and SE (and Owner if different from the SE)	The notice is in accordance with Sections 5.2.2 and 5.2.3 ☐ The Recommendation (5.2.3): ☐ - includes an evaluation - states the Elements covered - States the basis of the Recommendation - includes information considered by the RE in arriving at its Recommendation
	Section 8.0	

5 At any stage, pursuant to section 6.0, before the issuance of a final Recommendation a Submitting Entity may provide supplemental information which may reset the evaluation timeline.

Draft document 09/01/2011

BES Element Exception Process

Section 7.0 – Appeal of Rejection of an ER Application based on its completeness

Timeline	Flowchart	Checklist

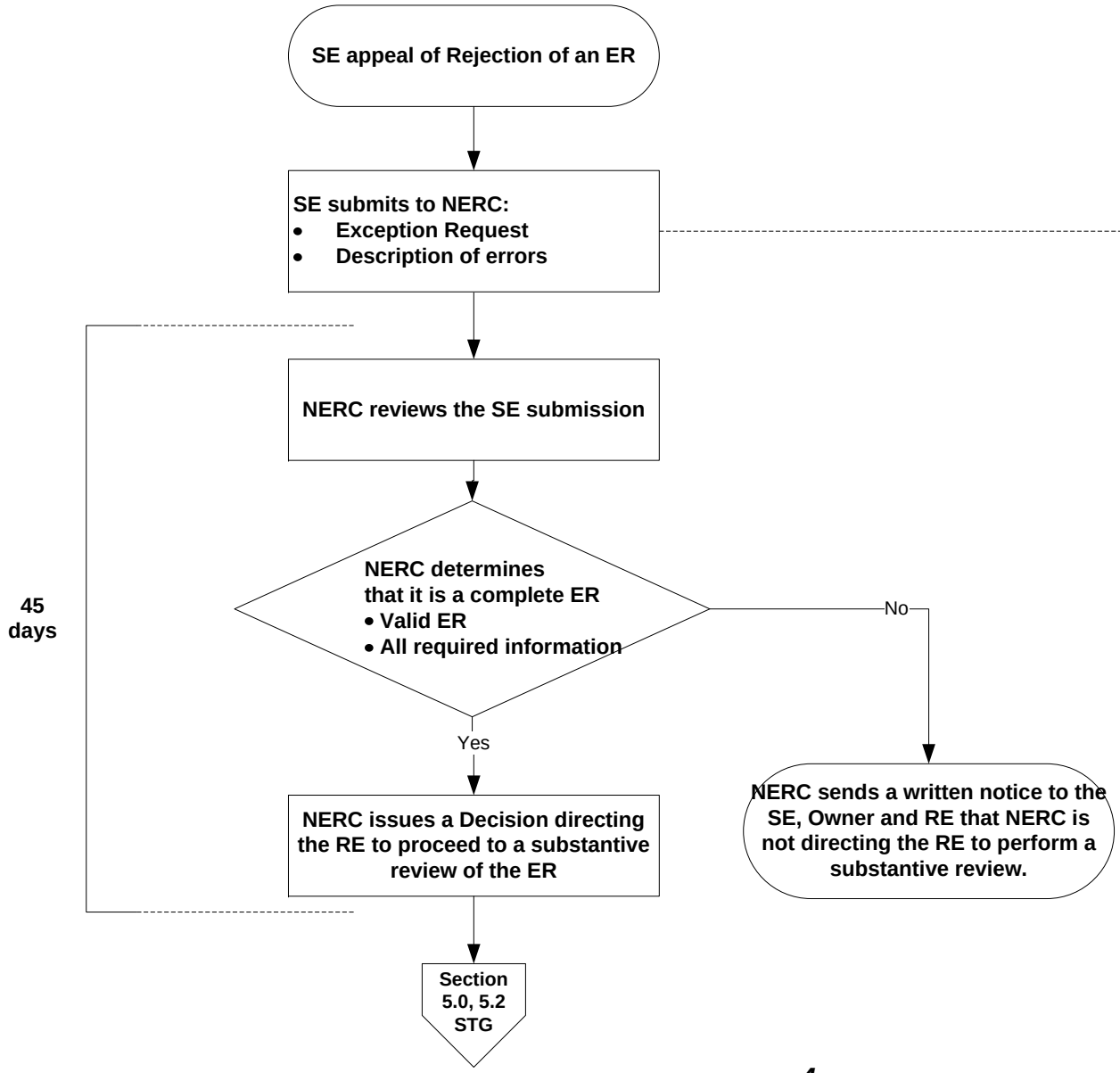

Submission shall (7.0):
- be written ☐
- provide the ER identifier ☐
- set forth a description of the errors that the SE believes are in the notice ☐

Information that demonstrates the insufficiencies identified by the RE are incorrect. ☐

Draft document 09/01/2011

BES Element Exception Process

Section 8.0 – Approval or Disapproval of an ER

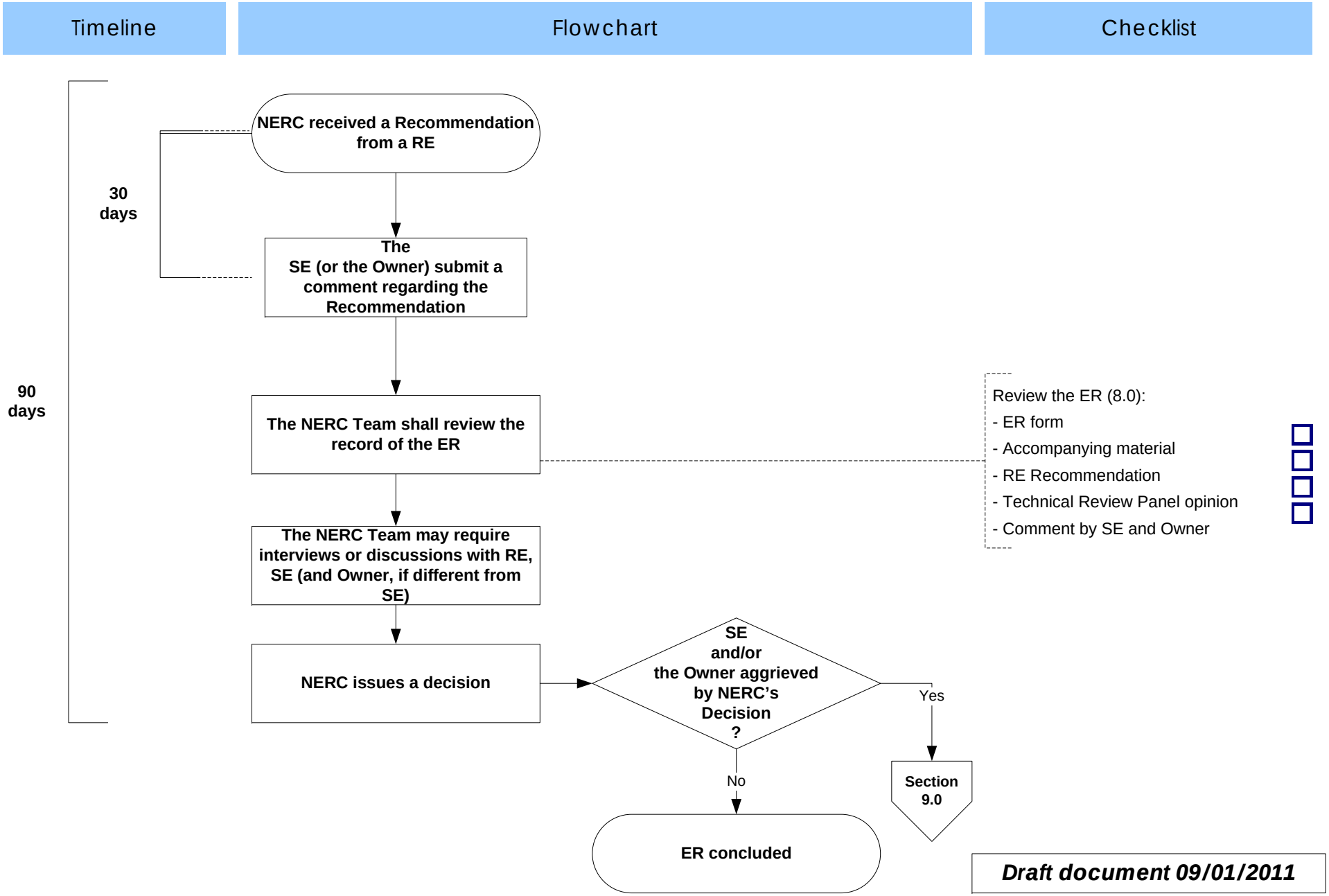

Draft document 09/01/2011

BES Element Exception Process

Section 9 – NERC BOT Review of a Decision

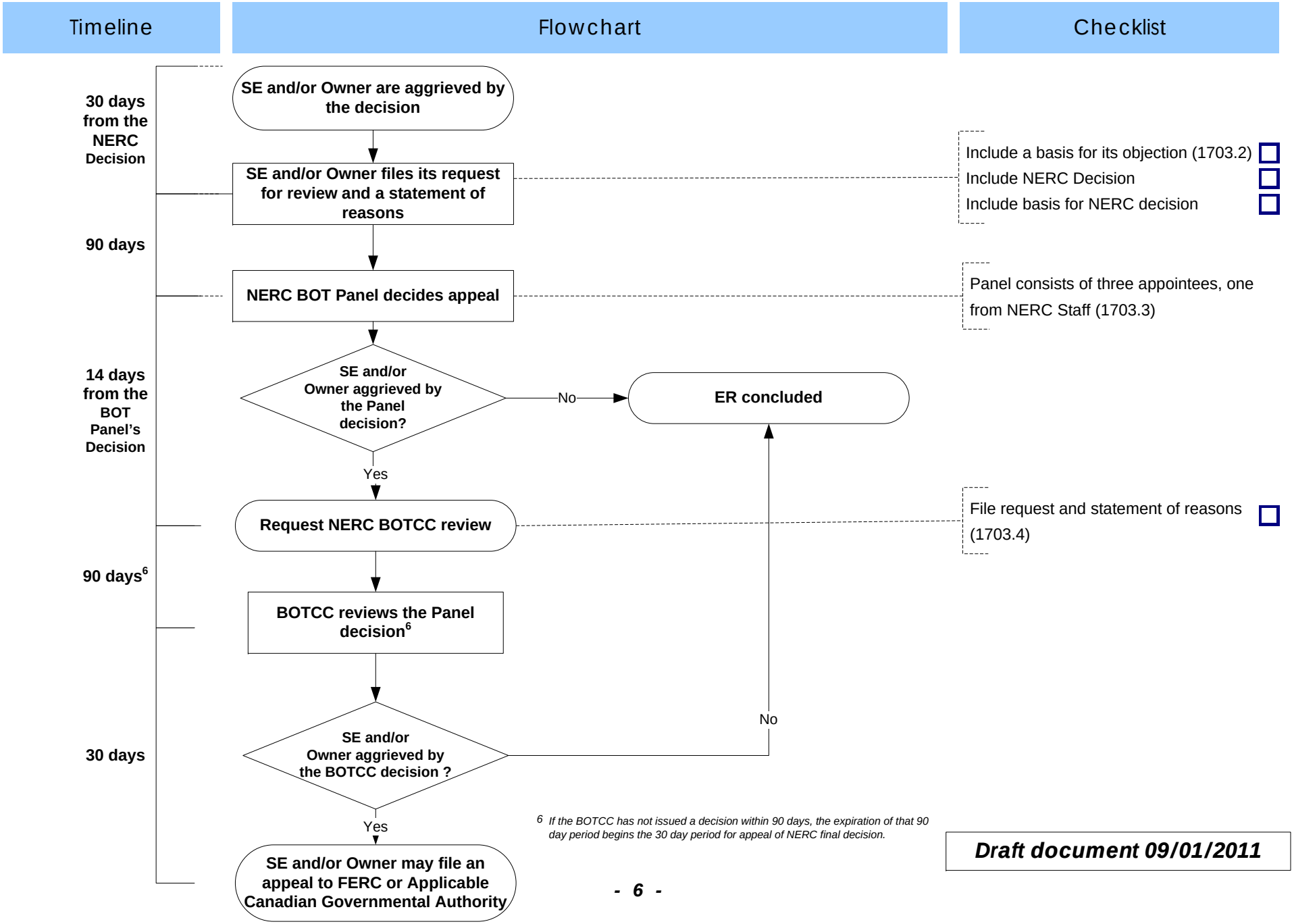

6 *If the BOTCC has not issued a decision within 90 days, the expiration of that 90 day period begins the 30 day period for appeal of NERC final decision.*

Draft document 09/01/2011

1703. Challenges to NERC Determinations of BES Exception Requests under ROP Section 509

1. This Section 1703 establishes the procedures to be followed when a Submitting Entity or Owner wishes to challenge a determination by NERC to approve or to disapprove an Exception Request or to terminate an Exception under Section 509.

2. A Submitting Entity (or Owner if different) aggrieved by the decision of NERC to approve or disapprove an Exception Request or to terminate an Exception with respect to any Element may, within 30 days following the date of the decision, file an appeal with the NERC Director of Compliance Operations, with copies to the Regional Entity and the Submitting Entity or Owner if different. The appeal shall state the basis of the objection to the decision of NERC. The Regional Entity, and the Submitting Entity or Owner if different may file a response to the appeal within 30 days following the date the appeal is filed with NERC.

3. The NERC Board of Trustees shall appoint a standing panel to decide appeals from NERC decisions to approve or to disapprove Exception Requests or to terminate Exceptions. The standing panel, which may contain alternates, shall consist of at least three appointees, one of whom must be a member of the NERC staff, who are knowledgeable about Bulk Electric System reliability (including but not limited to operations and planning), who were not involved at any earlier stage of the review of the Exception Request or the Exception, and who do not have a direct financial or business interest in the outcome of the appeal. The panel shall consider the entire record of the Exception Request or the termination of the Exception and decide the appeal within 90 days after being assigned the appeal by NERC.

4. The Submitting Entity, or Owner if different, aggrieved by the decision of the panel may request that the NERC Board of Trustees Compliance Committee review the decision by filing a request for review and a statement of reasons with NERC's Chief Reliability Officer within 30 days following the date of the panel decision. The Board of Trustees Compliance Committee may, in its discretion, decline to review the decision of the panel, in which case the decision of the panel shall be the final NERC decision. Within 90 days of date of submission of the request for review under this Section 1703.4, the Board of Trustees Compliance Committee may either: (a) issue a decision on the merits, which shall be the final NERC decision, or (b) issue a notice declining to review the decision of the panel, in which case the decision of the panel shall be the final NERC decision. If no written decision or notice declining review is issued within 90 days following the date of submission of the request for review, the appeal shall be deemed to have been denied by the NERC Board of Trustees Compliance Committee and this will have the same effect as a notice declining review.

5. The Submitting Entity, or Owner if different, may appeal the final NERC decision to, or seek review of the final NERC decision by, the Applicable Governmental Authority(ies), in accordance with the legal authority and rules and procedures of the Applicable Governmental Authority(s). Any such appeal shall be filed within thirty (30) days following the date of the decision or of the notice

declining review of the NERC Board of Trustees Compliance Committee or the expiration of the 90 day period specified in Section 1703.4, whichever is applicable, or within such other time period as is provided for in the legal authority, rules or procedures of the Applicable Governmental Authority.

registered in a CFR that registers as responsible for any reliability standard or requirement/sub requirement of a reliability standard shall inform the point of contact of its registration.

New Section 509: "Exceptions to the Definition of the Bulk Electric System"

Appendix 5C sets forth the procedures by which (i) an entity may request a determination that an Element that falls within the definition of the Bulk Electric System should be exempted from being considered a part of the Bulk Electric System, or (ii) an entity may request that an Element that falls outside of the definition of the Bulk Electric System should be considered a part of the Bulk Electric System.

From:	Kenneth Lotterhos
To:	Philip A. Fedora; Guy V. Zito; Lee R. Pedowicz
Cc:	Ed Schwerdt
Subject:	RE: BES RoP comments
Date:	Monday, October 24, 2011 2:34:29 PM
Importance:	High

All:

Both Phil and I propose the following changes to the section 8 language pertaining to the ERO review panel recognizing NERC's concern that they have limited resources to devote to this effort but retaining the elements we would like in the NERC review panel composition.

"A team of three persons appointed by the NERC BOT, one of which shall be from the ERO, with the required technical background who were not involved at any earlier stage of the review of the Exception Request nor have a direct financial or business interest in the outcome, to evaluate Exception Requests shall review the Recommendation and accompanying materials . . . ."

This language will assure independence of the ERO review panel, assure that the required technical expertise is met, and recognize NERC's resource limitations.

Background:

Here is the former Section 8 language:

"a team of three NERC Reliability Assessment and Performance Analysis personnel shall review the Exception Request Form and supporting materials . . . ."

As compared to the new Section 8 language:

"A team of three persons with the required technical background to evaluate Exception Requests shall review the Recommendation and accompanying materials . . . ."

The proposed 1703 appeal process for the appeal panel requires:

"The standing panel, which may contain alternates, shall consist of at least three appointees, one of whom must be a member of the NERC staff, who are knowledgeable about Bulk Electric System reliability (including but not limited to operations and planning), who were not involved at any earlier stage of the review of the Exception Request or the Exception, and who do not have a direct financial or business interest in the outcome of the appeal.

Sincerely,

Ken

From: Philip A. Fedora [mailto:pfedora@npcc.org]
Sent: Monday, October 24, 2011 12:34 PM
To: Guy V. Zito; Lee R. Pedowicz
Cc: Kenneth Lotterhos; Ed Schwerdt
Subject: BES RoP comments
Importance: High

Guy & Lee:

See thread below – please add these suggestions to NPCC's BES RoP response, due October 27th;

Ken – can you send the Section 8 suggested wording change we discussed last week?

Thanks,

Phil

From: Kenneth Lotterhos [mailto:klotterhos@navigant.com]
Sent: Monday, October 24, 2011 12:15 PM
To: Philip A. Fedora
Subject: RE: Five to Three

Hi Phil. "Not less than three" sounds like it should work with the ROP. It would match the size of the NERC review panel. I floated the idea of using the more descriptive language in 1703 (previous section 8 language) for section 8 on Friday's call and Carter and Mark will have it as part of the November ROP discussions. It would be good if there were comments submitted, preferably by more than one entity, that I can point to when the issue comes up.

Starting on my answers to the comments on the Technical Criteria this afternoon – fun, fun.

Ken

From: Philip A. Fedora [mailto:pfedora@npcc.org]
Sent: Monday, October 24, 2011 11:51 AM
To: Kenneth Lotterhos
Cc: Ed Schwerdt
Subject: Five to Three

Hi Ken:

As we discussed last week, Ed also agrees that a five member Regional Technical Review Panel should not be required; it should be revised to say:

"Each Regional Entity shall establish provisions for a Technical Review Panel consisting of not less than three (3) individuals … "

this wouldn't preclude a Region having more than three, but wouldn't mandate five.

By the way, how did the suggestion of reverting back to the previous language Section 8 regarding the NERC team's composition pan out?

Phil

From: Philip A. Fedora
Sent: Friday, October 14, 2011 1:24 PM
To: fortem@coned.com
Cc: 'Kenneth Lotterhos'; Ed Schwerdt
Subject: From the current proposed RoP draft(s) (provided for industry comment)

5.3 Technical Review Panel
Each Regional Entity shall establish provisions for a Technical Review Panel consisting of not less than five (5) individuals. Panel members shall comply with Subsection 7 of Section 403 of the NERC Rules of Procedure, shall not have participated in the review of the Exception Request, and shall have the required technical background to evaluate Exception Requests. When the Regional Entity intends either pursuant to Section 5.1.5.(a) to reject an Exception Request, in whole or in part, or pursuant to Section 5.2.2 to issue a Recommendation of Disapproval, in whole or in part, the Technical Review Panel must first review the Regional Entity's proposed determinations and provide an opinion, a copy of which shall be provided to the Submitting Entity (and Owner if different) in the event the Regional Entity decides to reject or disapprove, as applicable, the Exception Request. The Regional Entity will not be bound by the opinion of the Technical Review Panel, but such evaluation shall become part of the record associated with the Exception Request and shall be provided to NERC.

8.0 APPROVAL OR DISAPPROVAL OF AN EXCEPTION REQUEST

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NERC, the Regional Entity, the Submitting Entity and/or Owner, conducted by a conference call,
teleconferencing, or webinar. By the end of the ninety-day review period, the team shall issue a
decision on behalf of NERC either to approve or to disapprove the Exception Request. If the Exception Request concerns more than one Element, the review team's decision may approve the
Exception Request in its entirety, disapprove the Exception Request in its entirety, or approve some portion of the Exception Request and disapprove the remaining portion. The decision shall
be in writing, shall be based on the team's independent consideration of the full record, and state
the basis for the decision. If the decision of the team was not unanimous, the written decision shall note that fact and include the basis on which the minority disagreed. The decision of the review team shall be the decision of NERC with respect to Approval or Disapproval of the Exception Request.

Documentation used to substantiate the decision related to an Exception Request shall be retained by NERC for a minimum of six (6) years or as long as the Exception is in effect, whichever is longer, unless a different retention period is otherwise identified, for the purposes
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Company Registration Number: UK Ltd. 3641719
Registered in Delaware, USA
Registered Office Address: 30 South Wacker Drive, Suite 3400, Chicago, Illinois 60606

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Navigant Consulting, Inc.
Company Registration Number: UK Ltd. 3641719
Registered in Delaware, USA
Registered Office Address: 30 South Wacker Drive, Suite 3400, Chicago, Illinois 60606

From:	Kenneth Lotterhos
To:	Philip A. Fedora; Guy V. Zito; Lee R. Pedowicz
Cc:	Ed Schwerdt
Subject:	RE: BES RoP comments
Date:	Monday, October 24, 2011 12:35:44 PM

I'll find it and sent it to all on this email.

Ken

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Sent: Monday, October 24, 2011 12:34 PM
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Cc: Kenneth Lotterhos; Ed Schwerdt
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Company Registration Number: UK Ltd. 3641719
Registered in Delaware, USA
Registered Office Address: 30 South Wacker Drive, Suite 3400, Chicago, Illinois 60606

From: Lee R. Pedowicz
To: rscmembers; donald.e.nelson@state.ma.us; rjfalsetti@cogeco.ca
Subject: Comment Form--Project 2011-INT-01 - Interpretation of MOD-028-1 for FPL
Date: Tuesday, October 04, 2011 7:43:33 AM
Attachments: Unofficial_Word_Proj_2011-INT-01_100311--due_11-16-11.docx
Standards_Announcement_2011_INT-01_100311.pdf
MOD-028-2_Redline_to_last_approved_20110930.pdf
MOD-028-2_Clean_20110930.pdf
SAR_for_MOD-028_Rapid_Revision.pdf
MOD-028-2_Imp_Plan_20110930.pdf
Request_for_Interpretation_Form_FPL_MOD-028.pdf

Good morning.

Attached is a Word version of the Comment Form for Project 2011-INT-01 – Interpretation of MOD-028-1 for FPL, and supporting materials. Please let me know your comments by the close of business November 9, 2011. Comments are due to NERC November 16, 2011.

Thanks.

Lee

Implementation Plan

Approvals Requested
MOD-028-2 – Area Interchange Methodology

Prerequisite Approvals
None.

Functional Entities Required to Comply with the Standard

- Each Transmission Operator that uses the Area Interchange Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.
- Each Transmission Service Provider that uses the Area Interchange Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.

Effective Date

New or Revised Standards
MOD-028-2 – Area Interchange Methodology
In those jurisdictions where regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter beginning no less than 60 days after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter beginning no less than 60 days after Board of Trustees approval.

Standards for Retirement
MOD-028-1 – Area Interchange Methodology
Midnight of the day immediately prior to the Effective Date of MOD-028-2 in the particular Jurisdiction in which the new standard is becoming effective.

A. Introduction

1. Title: Area Interchange Methodology

2. Number: MOD-028-~~1~~2

3. Purpose: To increase consistency and reliability in the development and documentation of Transfer Capability calculations for short-term use performed by entities using the Area Interchange Methodology to support analysis and system operations.

4. Applicability:

4.1. Each Transmission Operator that uses the Area Interchange Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.

4.2. Each Transmission Service Provider that uses the Area Interchange Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.

5. Proposed Effective Date: ~~First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.~~In those jurisdictions where regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter beginning no less than 60 days after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter beginning no less than 60 days after Board of Trustees approval.

B. Requirements

R1. Each Transmission Service Provider shall include in its Available Transfer Capability Implementation Document (ATCID), at a minimum, the following information relative to its methodology for determining Total Transfer Capability (TTC): *[Violation Risk Factor: ~~Lower~~PENDING] [Time Horizon: Operations Planning]*

1.1. Information describing how the selected methodology has been implemented, in such detail that, given the same information used by the Transmission Operator, the results of the TTC calculations can be validated.

1.2. A description of the manner in which the Transmission Operator will account for Interchange Schedules in the calculation of TTC.

1.3. Any contractual obligations for allocation of TTC.

1.4. A description of the manner in which Contingencies are identified for use in the TTC process.

1.5. The following information on how source and sink for transmission service is accounted for in ATC calculations including:

1.5.1. Define if the source used for Available Transfer Capability (ATC) calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation

1.5.2. Define if the sink used for ATC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation

1.5.3. The source/sink or POR/POD identification and mapping to the model.

1.5.4. If the Transmission Service Provider's ATC calculation process involves a grouping of generation, the ATCID must identify how these generators participate in the group.

R2. When calculating TTC for ATC Paths, the Transmission Operator shall use a Transmission model that contains all of the following: *[Violation Risk Factor: ~~Lower~~PENDING] [Time Horizon: Operations Planning]*

2.1. Modeling data and topology of its Reliability Coordinator's area of responsibility. Equivalent representation of radial lines and facilities 161 kV or below is allowed.

2.2. Modeling data and topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination areas.

2.3. Facility Ratings specified by the Generator Owners and Transmission Owners.

R3. When calculating TTCs for ATC Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's area. The Transmission Operator shall also include the following data associated with Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed: [*Violation Risk Factor: ~~Lower~~PENDING*] [*Time Horizon: Operations Planning*]

3.1. ~~For on-peak and off-peak intra-day and next-day~~For TTCs, use the following (as well as any other values and additional parameters as specified in the ATCID):

3.1.1. Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.

3.1.2. A daily or hourly load forecast for ~~the applicable period being calculated~~TTCs used in current-day and next-day ATC calculations.

3.1.3. A Daily load forecast for TTCs used in ATC calculations for days two through 31.

~~**3.1.2.**~~**3.1.4.** A monthly load forecast for TTCs used in ATC calculations for months two through 13 months TTCs.

~~**3.1.3.**~~**3.1.5.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

~~**3.2.** For days two through 31 TTCs and for months two through 13 TTCs, use the following (as well as any other values and internal parameters as specified in the ATCID):~~

~~**3.2.1.** Expected generation and Transmission outages, additions, and Retirements, included as specified in the ATCID.~~

~~**3.2.2.** Daily load forecast for the days two through 31 TTCs being calculated and monthly forecast for months two through 13 months TTCs being calculated.~~

~~**3.2.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.~~

R4. When calculating TTCs for ATC Paths, the Transmission Operator shall meet all of the following conditions: *[Violation Risk Factor: ~~Lower~~PENDING] [Time Horizon: Operations Planning]*

4.1. Use all Contingencies meeting the criteria described in the ATCID.

4.2. Respect any contractual allocations of TTC.

4.3. Include, for each time period, the Firm Transmission Service expected to be scheduled as specified in the ATCID (filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers) for the Transmission Service Provider, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed modeling the source and sink as follows:

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate representation" in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point, an "equivalence," or an "aggregate representation" in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.

- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point shall as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate representation" in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can not be mapped to a discretely modeled point, an "equivalence," or an "aggregate representation" in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider to which the power is to be delivered as the sink.
- If the sink, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider to which the power is being delivered as the sink.

R5. Each Transmission Operator shall establish TTC for each ATC Path as defined below: *[Violation Risk Factor: ~~Lower~~PENDING] [Time Horizon: Operations Planning]*

5.1. At least once within the seven calendar days prior to the specified period for TTCs used in hourly and daily ATC calculations.

5.2. At least once per calendar month for TTCs used in monthly ATC calculations.

5.3. Within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a transformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage, provided such outage is expected to last 24 hours or longer.

R6. Each Transmission Operator shall establish TTC for each ATC Path using the following process: *[Violation Risk Factor: ~~Lower~~PENDING] [Time Horizon: Operations Planning]*

6.1. Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either:

- A System Operating Limit is reached on the Transmission Service Provider's system, or
- A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater[1].

[1] The Transmission operator may honor distribution factors less than 5% if desired.

6.2. If the limit in step R6.1 can not be reached by adjusting any combination of load or generation, then set the incremental Transfer Capability by the results of the case where the maximum adjustments were applied.

6.3. Use (as the TTC) the lesser of:

- The sum of the incremental Transfer Capability and the impacts of Firm Transmission Services, as specified in the Transmission Service Provider's ATCID, that were included in the study model, or
- The sum of Facility Ratings of all ties comprising the ATC Path.

6.4. For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Service Provider so the TTC does not exceed each Transmission Service Provider's contractual rights.

R7. The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: *[Violation Risk Factor: ~~Lower~~PENDING] [Time Horizon: Operations Planning]*

7.1. One calendar day after its determination for TTCs used in hourly and daily ATC calculations.

7.2. Seven calendar days after its determination for TTCs used in monthly ATC calculations.

R8. When calculating Existing Transmission Commitments (ETCs) for firm commitments (ETC_F) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: ~~Lower~~PENDING] [Time Horizon: Operations Planning]*

$$ETC_F = NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Where:

$NITS_F$ is the firm capacity set aside for Network Integration Transmission Service (including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources) on ATC Paths that serve as interfaces with other Balancing Authorities.

GF_F is the firm capacity set aside for Grandfathered Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or safe harbor tariff on ATC Paths that serve as interfaces with other Balancing Authorities.

PTP_F is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

ROR_F is the capacity reserved for roll-over rights for Firm Transmission Service contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

OS_F is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.

R9. When calculating ETC for non-firm commitments (ETC_{NF}) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: [Violation Risk Factor: ~~Lower~~*PENDING*] [Time Horizon: Operations Planning]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

$NITS_{NF}$ is the non-firm capacity set aside for Network Integration Transmission Service (i.e., secondary service , including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources) reserved on ATC Paths that serve as interfaces with other Balancing Authorities.

GF_{NF} is the non-firm capacity reserved for Grandfathered Non-Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or safe harbor tariff on ATC Paths that serve as interfaces with other Balancing Authorities.

PTP_{NF} is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

OS_{NF} is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Non-Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.

R10. When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall utilize the following algorithm: *[Violation Risk Factor: ~~Lower~~PENDING] [Time Horizon: Operations Planning]*

$$ATC_F = TTC - ETC_F - CBM - TRM + Postbacks_F + counterflows_F$$

Where:

ATC_F is the firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC_F is the sum of existing firm Transmission commitments for the ATC Path during that period.

CBM is the Capacity Benefit Margin for the ATC Path during that period.

TRM is the Transmission Reliability Margin for the ATC Path during that period.

$Postbacks_F$ are changes to firm ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

counterflows$_F$ are adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

R11. When calculating non-firm ATC for a ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: ~~Lower~~PENDING] [Time Horizon: Operations Planning]*

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + counterflows_{NF}$$

Where:

ATC_{NF} is the non-firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC_F is the sum of existing firm Transmission commitments for the ATC Path during that period.

ETC_{NF} is the sum of existing non-firm Transmission commitments for the ATC Path during that period.

CBM_S is the Capacity Benefit Margin for the ATC Path that has been scheduled without a separate reservation during that period.

TRM_U is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

$Postbacks_{NF}$ are changes to non-firm ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

$counterflows_{NF}$ are adjustments to non-firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

C. Measures

M1. Each Transmission Service Provider shall provide its current ATCID that has the information described in R1 to show compliance with R1. (R1)

M2. Each Transmission Operator shall provide evidence including the model used to calculate TTC as well as other evidence (such as Facility Ratings provided by facility owners, written documentation, logs, and data) to show that the modeling requirements in R2 were met. (R2)

M3. Each Transmission Operator shall provide evidence, including scheduled outages, facility additions and retirements, (such as written documentation, logs, and data) that the data described in R3 and R4 were included in the determination of TTC as specified in the ATCID. (R3)

M4. Each Transmission Operator shall provide the contingencies used in determining TTC and the ATCID as evidence to show that the contingencies described in the ATCID were included in the determination of TTC. (R4)

M5. Each Transmission Operator shall provide copies of contracts that contain requirements to allocate TTCs and TTC values to show that any contractual allocations of TTC were respected as required in R4.2. (R4)

M6. Each Transmission Operator shall provide evidence (such as copies of coordination agreements, reservations, interchange transactions, or other documentation) to show that firm reservations were used to estimate scheduled interchange, the modeling of scheduled interchange was based on the rules described in R4.3, and that estimated scheduled interchange was included in the determination of TTC. (R4)

M7. Each Transmission Operator shall provide evidence (such as logs and data and dated copies of requests from the Transmission Service Provider to establish TTCs at specific intervals) that TTCs have been established at least once in the calendar week prior to the specified period for TTCs used in hourly and daily ATC calculations, at least once per calendar month for TTCs used in monthly ATC calculations, and within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a autotransformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage; provided such outage is expected to last 24 hours or longer in duration per the specifications in R5.(R5)

M8. Each Transmission Operator shall provide evidence (such as written documentation) that TTCs have been calculated using the process described in R6. (R6)

M9. Each Transmission Operator shall have evidence including a copy of the latest calculated TTC values along with a dated copy of email notices or other equivalent evidence to show that it provided its Transmission Service Provider with the most current values for TTC in accordance with R7. (R7)

M10. The Transmission Service Provider shall demonstrate compliance with R8 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R8 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-028-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R8 to calculate its firm ETC. (R8)

M11. The Transmission Service Provider shall demonstrate compliance with R9 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R9 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-028-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R8 to calculate its non-firm ETC. (R9)

M12. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in

R10. Such documentation must show that only the variables allowed in R10 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R10)

M13. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R11. Such documentation must show that only the variables allowed in R11 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R11)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

For entities that do not work for the Regional Entity~~.~~

, the Regional Entity shall serve as the Compliance ~~**Monitoring Period and Reset**~~Enforcement Authority.
~~Not applicable.~~

For functional entities that work for their Regional Entity, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to calculate TTC and evidence of the previous version to show compliance with R2.

- The Transmission Operator shall retain evidence to show compliance with R3 for the most recent 12 months or until the model used to calculate TTC is updated, whichever is longer.
- The Transmission Operator shall retain evidence to show compliance with R4, R5, R6 and R7 for the most recent 12 months.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R8 and R9 for the most recent 14 days; evidence to show compliance in calculating daily values required in R8 and R9 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R8 and R9 for the most recent 60 days.
- The Transmission Service Provider shall retain evidence to show compliance with R10 and R11 for the most recent 12 months.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Service Provider has an ATCID but it is missing one of the following: ▪ R1.1 ▪ R1.2 ▪ R1.3 ▪ R1.4 ▪ R1.5 (any one or more of its sub-subrequirements)	The Transmission Service Provider has an ATCID but it is missing two of the following: ▪ R1.1 ▪ R1.2 ▪ R1.3 ▪ R1.4 ▪ R1.5 (any one or more of its sub-subrequirements)	The Transmission Service Provider has an ATCID but it is missing three of the following: ▪ R1.1 ▪ R1.2 ▪ R1.3 ▪ R1.4 ▪ R1.5 (any one or more of its sub-subrequirements)	The Transmission Service Provider has an ATCID but it is missing more than three of the following: ▪ R1.1 ▪ R1.2 ▪ R1.3 ▪ R1.4 ▪ R1.5 (any one or more of its sub-subrequirements)
R2.	The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.	The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.	One or both of the following: • The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission Operator did not use a Transmission model that includes modeling data and topology (or equivalent representation) for one adjacent Reliability Coordinator Area.	One or more of the following: • The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission Operator's model includes equivalent representation of non-radial facilities greater than 161 kV for its own Reliability Coordinator Area. • The Transmission Operator did not use a Transmission model that includes modeling data and topology (or equivalent representation) for two or more adjacent Reliability Coordinator

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Areas.
R3.	The Transmission Operator did not include in the TTC process one to ten expected generation and Transmission outages, additions or retirements as specified in the ATCID.	The Transmission Operator did not include in the TTC process eleven to twenty-five expected generation and Transmission outages, additions or retirements as specified in the ATCID.	The Transmission Operator did not include in the TTC process twenty-six to fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID.	One or more of the following: • The Transmission Operator did not include in the TTC process more than fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID. • The Transmission Operator did not include the Load forecast or unit commitment in its TTC calculation as described in R3.
R4.	The Transmission Operator did not model reservations' sources or sinks as described in ~~R5~~R4.3 for more than zero reservations, but not more than 5% of all reservations; or 1 reservation, whichever is greater.	The Transmission Operator did not model reservations' sources or sinks as described in ~~R5~~R4.3 for more than 5%, but not more than 10% of all reservations; or 2 reservations, whichever is greater.	The Transmission Operator did not model reservations' sources or sinks as described in ~~R5~~R4.3 for more than 10%, but not more than 15% of all reservations; or 3 reservations, whichever is greater.	One or more of the following: • The Transmission Operator did not include in the TTC calculation the contingencies that met the criteria described in the ATCID. • The Transmission Operator did not respect contractual allocations of TTC. • The Transmission Operator did not model reservations' sources or sinks as described in R4.3 for more than 15% of all reservations; or more than 3 reservations, whichever is greater. • The Transmission Operator did not use firm reservations to estimate interchange or did not

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				utilize that estimate in the TTC calculation as described in R4.3.
R5.	One or more of the following: • The Transmission Operator did not establish TTCs for use in hourly or daily ATCs within 7 calendar days but did establish the values within 10 calendar days • The Transmission Operator did not establish TTCs for use in monthly ATCs during a calendar month but did establish the values within the next consecutive calendar month	One or more of the following: • The Transmission Operator did not establish TTCs for use in hourly or daily ATCs in 10 calendar days but did establish the values within 13 calendar days • The Transmission Operator did not establish TTCs for use in monthly ATCs during a two consecutive calendar month period but did establish the values within the third consecutive calendar month	One or more of the following: • The Transmission Operator did not establish TTCs for used in hourly or daily ATCs in 13 calendar days but did establish the values within 16 calendar days • The Transmission Operator did not establish TTCs for use in monthly ATCs during a three consecutive calendar month period but did establish the values within the fourth consecutive calendar month	One or more of the following: • The Transmission Operator did not establish TTCs for used in hourly or daily ATCs in 16 calendar days • The Transmission Operator did not establish TTCs for use in monthly ATCs during a four or more consecutive calendar month period • The Transmission Operator did not establish TTCs within 24 hrs of the triggers defined in R5.3
R6.	N/A	N/A	N/A	The Transmission Operator did not calculate TTCs per the process specified in R6.
R7.	One or more of the following: • The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than one calendar day after their determination, but not been more than two calendar days after their determination.	One or more of the following: • The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than two calendar days after their determination, but not been more than three calendar days after their determination.	One or more of the following: • The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than three calendar days after their determination, but not been more than four calendar days after their determination.	One or more of the following: • The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than four calendar days after their determination. • The Transmission Operator did not provide its Transmission Service Provider with its ATC

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	• The Transmission Operator has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than seven calendar days after their determination, but not more than 14 calendar days since their determination.	• The Transmission Operator has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 14 calendar days after their determination, but not been more than 21 calendar days after their determination.	• The Transmission Operator has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 21 calendar days after their determination, but not been more than 28 calendar days after their determination.	Path TTCs used in hourly or daily ATC calculations. • The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 28 calendar days after their determination. • The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations.
R8.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.
R9.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 15% of the value calculated in	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 25% of the value calculated in	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 35% of the value calculated in	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.	the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater...	the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.	or 45MW, whichever is greater.
R10.	The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).
R11.	The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Note: A valid interpretation request is one that requests additional clarity about one or more requirements in approved NERC reliability standards, but does not request approval as to how to comply with one or more requirements.

When completed, email this form to:
laura.hussey@nerc.net
For questions about this form or for assistance in completing the form, call Laura Hussey at 404-446-2579.

Request for an Interpretation of a Reliability Standard	
Date submitted: 5/13/2011	
Contact information for person requesting the interpretation:	
Name: Don McInnis	
Organization: Florida Power & Light	
Telephone: 305-442-5272	E-mail: don.mcinnis@fpl.com
Identify the standard that needs clarification:	
Standard Number (include version number, e.g. PRC-001-1): MOD-028-1	
Standard Title: Area Interchange Methodology	
Identify specifically what requirement needs clarification:	
Requirement Number and Text of Requirement: **R3.1** For on-peak and off-peak intra-day and next-day TTCs, use the following (as well as any other values and additional parameters as specified in the ATCID):	
Identify the nature of clarification that is requested: (Check as many as applicable)	
☒ Clarify the required performance ☒ Clarify the conditions under which the performance is required ☐ Clarify which functional entity is responsible for performing an action in a requirement ☐ Clarify the reliability outcome the requirement is intended to produce Please explain the clarification needed: *By using the words "on-peak", "off-peak", and "intra-day" this requirement implies there would have to be separate TTC numbers for different portions of the current day. However, R5 of MOD28 establishes the calculation frequencies and only requires an update to TTC once within the 7 days prior to the specified period where they are used in an ATC calculation. The*	

clarification needed is on the ATC Drafting Team's intent with respect to the quantity and timing of individual TTC calculations needed for use in the ATC calculations.
Identify the material impact associated with this interpretation:
Identify the material impact to your organization or others, if known, caused by the lack of clarity or an incorrect interpretation of this standard. *Adherence to the implied intra day calculation requirement of R3.1 is resulting in additional work and creating coordination issues with other parties which are not calculating intra day TTC values.*

Standard Authorization Request Form

Request Date	August 30, 2011

SAR Requester Information	**SAR Type** (Check a box for each one that applies.)	
Individual, Group, or Committee Name Andrew Rodriquez	☐	New Standard
Primary Contact (if Group or Committee) Andrew Rodriquez	☒	Revision to existing Standard
Company or Group Name NERC	☐	Withdrawal of existing Standard
E-mail andy.rodriquez@nerc.net	☐	Project Identified in Reliability Standards Development Plan (Project Number and Name:)
Telephone 404-446-2560	☐	Modification to NERC Glossary term or addition of new term

Brief Description of Proposed Standard Modifications/Actions (In three sentences or less, summarize the proposed actions a drafting team will be responsible for implementing.)

This SAR proposes to modify MOD-028-1 R3.1 to address an ambiguity in the standard.

Need (Explain why the Standard is being developed or modified. Clearly indicate why the actions being proposed are needed for maintaining or improving bulk power system reliability, including an assessment of the reliability and market interface impacts. This is similar to the Purpose statement in a Reliability Standard.)
N/A

Goals (Describe what must be accomplished in order to meet the above need. This section would become the Requirements in a Reliability Standard.)
N/A

Objectives and/or Potential Future Metrics (Describe what the potential measure or criteria for success may be for determining the successful implementation of this request. Provide ideas for potential metrics to be developed and monitored in the future relative to this request, if any.)
N/A

Detailed Description (In three paragraphs or more, provide a detailed description of the

proposed actions a drafting team will be responsible for executing so that the team can efficiently implement this request. While you will check applicability boxes on the following page, this description must include proportional identification of to whom the standard should apply among industry participants.)

Sub-requirement R3.1 of MOD-028-1 states the following:

> **R3.1** For on-peak and off-peak intra-day and next-day TTCs, use the following (as well as any other values and additional parameters as specified in the ATCID):

NERC received a request to interpret this sub-requirement. The requester stated:

> *By using the words "on-peak", "off-peak", and "intra-day" this requirement implies there would have to be separate TTC numbers for different portions of the current day. However, R5 of MOD28 establishes the calculation frequencies and only requires an update to TTC once within the 7 days prior to the specified period where they are used in an ATC calculation. The clarification needed is on the ATC Drafting Team's intent with respect to the quantity and timing of individual TTC calculations needed for use in the ATC calculations. Adherence to the implied intra day calculation requirement of R3.1 is resulting in additional work and creating coordination issues with other parties which are not calculating intra day TTC values.*

While the Interpretation team was preparing its Interpretation, the Standards Committee requested the Interpretation Team use a "rapid modification" approach to clarify the requirement in question directly. The Interpretation Team is proposing the attached modification to the standard in lieu of an Interpretation.

Because FERC has not yet rules on the VRFs for this standard, they have been marked as PENDING in order to not distract from the discussion of the modification.

OPTIONAL: Technical Analysis Performed to Support Justification (Provide the results of any technical study or analysis performed to justify this request. Alternatively, if deemed necessary, propose a technical study or analysis that should be performed prior to a related standard development project being initiated in response to this request.)
N/A

Reliability Functions

The Standard(s) May Apply to the Following Functions (Check box for each one that applies.)		
☐	Regional Entity	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☒	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.

☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles (Check box for all that apply.)	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.
Does the proposed Standard(s) comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*	
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes	
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes	
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes	

4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation

Related Projects

Project ID and Title	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

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Standards Announcement

Project 2011-INT-01 Interpretation of MOD-028-1 for FPL
Ballot Pool Window Open: October 4 – November 2, 2011
Formal Comment Period Open: October 4 – November 16, 2011
Initial Ballot Window: November 7 – November 16, 2011

Now available

In May 2011, Florida Power & Light Company (FPL) requested an interpretation of MOD-028-1 – Area Interchange Methodology, Requirement R3.1. The request asks for clarification of the timing and frequency of Total Transfer Capability (TTC) calculations needed for Available Transfer Capability (ATC) calculations. At its July 2011 meeting the Standards Committee approved (with FPL's approval) addressing FPL's request for interpretation through a rapid revision to the MOD-028-1 standard. As envisioned, making a permanent revision to the standard makes more efficient use of industry resources than providing clarity first through an interpretation and then later through a revision to the standard.

A drafting team appointed by the Standards Committee has posted FPL's request for interpretation, a SAR identifying the revisions necessary to address the requested clarification, a draft MOD-028-2 (clean and redline showing changes to the last approved version of the standard), and an associated implementation plan, for a formal 45-day comment period through 8 p.m. Eastern on Wednesday, November 16, 2011. Because the revisions are narrowly focused on addressing the clarification requested by FPL, the Standards Committee approved waiving the initial 30-day formal comment period. A ballot pool is open through **8 a.m. Eastern on Wednesday, November 2**.

Ballot Pool Open through 8 a.m. Eastern on Wednesday, November 2
A ballot pool is being formed for balloting the revisions to MOD-028-2. The Standards Committee has authorized posting the standard and implementation plan for a 45-day formal comment period with an initial ballot conducted during the last 10 days of that comment period. (The Standards Committee authorized waiving the initial 30-day formal comment period because the revisions to MOD-028 are narrowly focused on addressing the clarification requested in FPL's request for interpretation.)

The ballot pool is open through 8 a.m. Eastern on November 2, 2011, and the ballot window will be open from 8 a.m. Eastern on Monday, November 7 through 8 p.m. Eastern on Wednesday, November 16, 2011.

Instructions for Joining the Ballot Pool for Project 2011-INT-01
Registered Ballot Body members may join the ballot pool to be eligible to vote in the upcoming ballot at the following page: https://standards.nerc.net/BallotPool.aspx

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-2011-INT-01_in@nerc.com

Instructions for Commenting

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

An initial ballot of MOD-028-2 and its associated implementation plan will begin on Monday, November 7, 2011 and end at 8 p.m. Eastern on Wednesday, November 16, 2011.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
116-390 Village Blvd.
Princeton, NJ 08540
609.452.8060 | www.nerc.com

From: Guy V. Zito
To: rscmembers
Subject: FW: Comments on Interpretation of COM-002
Date: Wednesday, October 05, 2011 10:00:18 AM

RSC Members,

Please see below. I had discussions with enforcement, and audit on this today. Let's discuss at the next RSC meeting October, 26-27 in Boston. Lee- Agenda item…

Thanks,

Guy V. Zito
Asst. Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

From: John Muir
Sent: Wednesday, October 05, 2011 8:21 AM
To: Salvatore Buffamante; Walter Cintron
Cc: Guy V. Zito; Lee R. Pedowicz; Ben Eng
Subject: Comments on Interpretation of COM-002

Gentlemen,

I don't know who is responsible for providing NPCC's comments to the Interpretation that is posted for vote and comments, but here are mine. I disagree with the interpretation that …

COM-002-2 R2 does not specify the conditions under which a directive is issued, nor does it define directive. It only provides that the requirements be followed when a directive is issued to address a real-time emergency. Routine operating instructions during normal operations would not require the communications protocols for repeat backs as specified in R2.

The purpose addresses three separate needs. Emergency conditions are only referenced in regard to capabilities and staffing.

Purpose: To ensure Balancing Authorities, Transmission Operators, and Generator Operators have adequate communications and that these communications capabilities are staffed and available for addressing a real-time emergency condition. To ensure communications by operating personnel are effective.

Who - Balancing Authorities, Transmission Operators, and Generator Operators

What –

- Ensure adequate communications
- Ensure communications capabilities are staffed and available for addressing a real-time emergency condition
- Ensure communications by operating personnel are effective

There is no reference to 'emergency' in R2. R2 addresses adequate and effective communications, not staffing and availability.

R2:
Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall issue directives in a clear, concise, and definitive manner; shall ensure the recipient of the directive repeats the information back correctly; and shall acknowledge the response as correct or repeat the original statement to resolve any misunderstandings.

Who - Balancing Authorities, Transmission Operators, and Generator Operators
What –

- issue directives in a clear, concise, and definitive manner;
- ensure the recipient of the directive repeats the information back correctly;
- acknowledge the response as correct or repeat the original statement to resolve any misunderstandings

John

From:	Guy V. Zito
To:	John Muir; Salvatore Buffamante; Walter Cintron
Cc:	Lee R. Pedowicz; Ben Eng
Subject:	RE: Comments on Interpretation of COM-002
Date:	Wednesday, October 05, 2011 7:49:25 PM

Thanks for your thoughts John. TFCO will be discussing this at their meeting tomorrow and Friday and also the RSC later this month. I will keep all posted as information becomes available.

Guy V. Zito
Assistant Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10 th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

From: John Muir
Sent: Wednesday, October 05, 2011 8:21 AM
To: Salvatore Buffamante; Walter Cintron
Cc: Guy V. Zito; Lee R. Pedowicz; Ben Eng
Subject: Comments on Interpretation of COM-002

Gentlemen,

I don't know who is responsible for providing NPCC's comments to the Interpretation that is posted for vote and comments, but here are mine. I disagree with the interpretation that …

COM-002-2 R2 does not specify the conditions under which a directive is issued, nor does it define directive. It only provides that the requirements be followed when a directive is issued to address a real-time emergency. Routine operating instructions during normal operations would not require the communications protocols for repeat backs as specified in R2.

The purpose addresses three separate needs. Emergency conditions are only referenced in regard to capabilities and staffing.

Purpose: To ensure Balancing Authorities, Transmission Operators, and Generator Operators have adequate communications and that these communications capabilities are staffed and available for addressing a real-time emergency condition. To ensure communications by operating personnel are effective.

Who - Balancing Authorities, Transmission Operators, and Generator Operators
What –

- Ensure adequate communications
- Ensure communications capabilities are staffed and available for addressing a real-time emergency condition
- Ensure communications by operating personnel are effective

There is no reference to 'emergency' in R2. R2 addresses adequate and effective communications, not staffing and availability.

R2:

Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall issue directives in a clear, concise, and definitive manner; shall ensure the recipient of the directive repeats the information back correctly; and shall acknowledge the response as correct or repeat the original statement to resolve any misunderstandings.

Who - Balancing Authorities, Transmission Operators, and Generator Operators

What –

- issue directives in a clear, concise, and definitive manner;
- ensure the recipient of the directive repeats the information back correctly;
- acknowledge the response as correct or repeat the original statement to resolve any misunderstandings

John

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Note: an Interpretation cannot be used to change a standard.

Request for an Interpretation of a Reliability Standard

Date submitted: October 1, 2009

Date accepted: October 2, 2009

Contact information for person requesting the interpretation:

Name: Kathleen Goodman

Organization: ISO/RTO Council – Standards Review Committee

Telephone: (413) 535-4111

E-mail: kgoodman@iso-ne.com

Identify the standard that needs clarification:

Standards Numbers (include version number): COM-002-2

Standards Titles: Communications and Coordination

Identify specifically what requirement needs clarification:

Requirement Number and Text of Requirement:

R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall issue directives in a clear, concise, and definitive manner; shall ensure the recipient of the directive repeats the information back correctly; and shall acknowledge the response as correct or repeat the original statement to resolve any misunderstandings.

Clarification needed:

Please clarify whether routine operating instructions are "directives" or whether "directives" are limited to actual and anticipated emergency operating conditions.

Identify the material impact associated with this interpretation:

Identify the material impact to your organization or others caused by the lack of clarity or an incorrect interpretation of this standard.

There are at least two potential material impacts to registered entities caused by lack of clarity or an incorrect interpretation of this term.
First, sometimes Regional Entities, for compliance purposes, will seek corroboration from RCs, BAs, and TOPs about whether other registered entities follow their "directives." Obtaining clarity that routine operating instructions do not constitute directives for purposes

of administering compliance with the NERC Standards will help RCs, BAs and TOPs (as well as functional entities receiving such "directives") to determine when the need exists for, and the conditions under which, an entity must adhere to Requirement R2 of COM-002 to complete a 3-part communication, and to make decisions about how to retain records that may assist Regional Entities in conducting investigations and/or audits of registered entities. Second, some BAs utilize electronic dispatch instructions, during routine operations as well as during emergency operations, for more reliable and efficient dispatch of generating units. Through such systems, larger numbers of generators can be given dispatch instructions more quickly, and dispatch instructions can be given to effectuate small changes in generator output.
Changing communication protocols for day-to-day, non-emergency instructions may require operators to revisit how they communicate with other registered entities, which may reduce the reliability of the system.

Project 2009-22: Response to Request for an Interpretation of NERC Standard COM-002-2 R2 for the ISO/RTO Council – Standards Review Committee

The following interpretation of NERC Standard COM-002-2 – Communications and Coordination R2 was developed by the Operating Personnel Communications Protocols Standard Drafting Team.

Requirement Number and Text of Requirement

R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall issue directives in a clear, concise, and definitive manner; shall ensure the recipient of the directive repeats the information back correctly; and shall acknowledge the response as correct or repeat the original statement to resolve any misunderstandings.

Question

Please clarify whether routine operating instructions are "directives" or whether "directives" are limited to actual and anticipated emergency operating conditions.

Response

COM-002-2 R2 does not specify the conditions under which a directive is issued, nor does it define directive. It only provides that the requirements ~~to~~ be followed when a directive is issued ~~during~~to address a real-time emergency. ~~Routine operating instructions can be directives. COM-002-2 does not apply to all directives. The purpose statement for COM-002-2 is "To ensure Balancing Authorities, Transmission Operators, and Generator Operators have adequate communications and that these communications capabilities are staffed and available for addressing a real-time emergency condition. To ensure communications by operating personnel are effective." As such,~~ Routine operating instructions during normal operations would not require the communications protocols for repeat backs as specified in R2.

~~This requirement addresses verbal communication, so electronic communication would not fall under COM-002-2 R2.~~

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Standards Announcement

Project 2010-07 Generator Requirements at the Transmission Interface
Ballot Pool Forming October 5 – November 4, 2011
Formal Comment Period October 5 – November 18, 2011
Initial Ballot Windows Open November 9 – 18, 2011

Available Now

The SDT has reviewed comments received during a 30-day formal comment period that took place earlier this year, from June 17-July 17, 2011, and thanks to all those who provided feedback during that comment period. The SDT has incorporated many of the suggested changes into its latest proposed standards, as explained in the posted Consideration of Comments.

This is the second formal comment period and initial ballot period for three standards included in Project 2010-07. Revised drafts of FAC-001-1 and two versions of FAC-003 – FAC-003-3 and FAC-003-X – along with minor modifications to PRC-004-2.1, have been posted for a formal comment period and initial ballot that will end on Friday, November 18, 2011. Note that FAC-003-X shows changes to the last approved version of the standard, while FAC-003-3 shows changes to the last version being developed by the Project 2007-07 drafting team to incorporate Requirements for Generator Owners in those standards.

PRC-004-2.1 is being posted for the first time with this posting, and is also being posted for a formal 45-day comment period with an initial ballot. Because the changes are very limited, the Standards Committee waived the initial formal comment period for this standard.

Instructions for Joining the Ballot Pool for Project 2010-07
Registered Ballot Body members may join the ballot pool to be eligible to vote in the upcoming ballots at the following page: Join Ballot Pool

During the pre-ballot windows, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) One ballot pool list server has been set up and can be used for communication on each of the standards being balloted for this project. The list server is: bp-2010-07_FAC-001-1_in@nerc.com

Instructions for Commenting

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

Separate ballots will be conducted for each standard. These ballot windows will begin on Wednesday, November 9, 2011 and end at 8 p.m. Eastern on Friday, November 18, 2011. NOTE: There is only one ballot pool to join for this project. There will be four separate ballots, one for each standard, and individuals who join this single ballot pool will be eligible to vote in all four ballots. This was done to make the process simpler for those who are voting. If you have any questions, please contact Monica Benson at monica.benson@nerc.net.

Background

The purpose of Project 2010-07 is to ensure that all generator-owned Facilities are appropriately covered under NERC's Reliability Standards. While many Generator Owners and Generator Operators operate Facilities, commonly known as generator interconnection Facilities, that are considered by some entities to be transmission, these are most often radial Facilities that are not part of the integrated grid. As such, they should not be subject to the same standards applicable to Transmission Owners and Transmission Operators who own and operate Transmission Elements and Facilities that are part of the integrated grid.

As part of the BES, generators so affect the overall reliability of the BES. But registering a Generator Owner or Generator Operator as a Transmission Owner or Transmission Operator, as has been the solution in some cases in the past, may decrease reliability by diverting the Generator Owner's or Generator Operator's resources from the operation of the equipment that actually produces electricity – the generation equipment itself.

The drafting team's goal is to ensure that an adequate level of reliability is maintained in the BES by clearly describing which standards need to be applied to generator interconnection Facilities that are not already applicable to Generator Owners or Generator Operators. This can be accomplished by properly applying FAC-001, FAC-003, and PRC-004 to Generator Owners as proposed in the redline standards posted for comment.

Before reviewing the standards, the drafting team encourages all stakeholders to read the technical justification resource document it has provided to describe its rationale and its work thus far.

Additional information is available on the project page.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Technical Justification: FAC-001-1

Project 2010-07 Generator Requirements at the Transmission Interface

In response to the June 17-July 17, 2011 formal posting of the proposed standard changes in Project 2010-07, the standard drafting team (SDT) received stakeholder comments on FAC-001-1 expressing concern about the feasibility of a Generator Owner receiving and executing an interconnection request on one of its interconnection Facilities, as well as concern about the market-related processes that would go along with such an interconnection request. In this technical justification document, the SDT seeks to further clarify its rationale for making the proposed FAC-001-1 applicable to qualifying Generator Owners.

While the SDT understands that interconnection requests for Generator Owner Facilities are still relatively rare, in the past (for instance, 134 FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities. The SDT acknowledges that FERC does not have jurisdiction over all Generator Owners, but realizes that the potential exists for a third party to request to interconnect its planned generator with an existing generator interconnection Facility (whose use at the time of the request is solely to transmit capacity, energy, and ancillary services from the existing generator).

The SDT discussed the various ways such an interconnection could occur and agrees that if the third party interconnection could be accomplished without the need for the existing Generator Owner to develop its own connection requirements and system performance requirements and determine impacts on the interconnected transmission systems, this standard need not apply to the Generator Owner. And the SDT agrees that in many cases, these connection requirements, system performance requirements, and determined impacts on the interconnected transmission systems are currently determined by entities registered as either a Transmission Owner, Transmission Planner, and/or Transmission Service Provider. However, the SDT remains convinced (based on the orders cited above) that there may be occasions where FERC or another regulatory agency compels the Generator Owner to allow a third party to interconnect its planned generator with an existing generator interconnection Facility. Where this occurs, the SDT feels it is necessary for the existing owner of that generator interconnection Facility to provide connection requirements to the third party that requests interconnection. The SDT also believes, and many comments seem to support, that performance requirements and a determination of impact to the interconnected transmission systems need to be evaluated by some entity. The question becomes which entity.

The SDT can only work within the standards development process. We cannot address other regulatory issues such as FERC-mandated open transmission access (Order 888 and subsequent) or state or provincial jurisdiction over generation or transmission assets. While we acknowledge these

mechanisms exists and may come into play in the scenarios described in the proposed FAC-001-1, we as the SDT can only deal within the context of reliability standards. For this reason, R2 indicates that FAC-001-1 applies only when a Generator Owner has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility.
The SDT's reasoning here is that if the owner of the existing generator interconnection Facility agrees, or is compelled, to allow a third party to interconnect, and can do so using existing agreements, contracts, and/or tariffs (and thereby avoid having an executed Agreement to evaluate the reliability impact of interconnecting third party Facility to the Generator Owner's existing Facility), and thus avoid having to develop its own connection requirements or perform impact studies, it will. In this example, it is likely that the existing Transmission Owner, Transmission Planner, and/or Transmission Service Provider processes and Agreements will be utilized and the purpose of FAC-001-1 will be met without applying this standard to the Generator Owner.

If, on the other hand, the owner of the existing generator interconnection Facility agrees, or is compelled, to allow a third party to interconnect, but cannot do so without having to develop its own connection requirements or perform impact studies, the SDT believes that the potential for a reliability gap exists. This might occur, for instance, if the owner of an existing generator interconnection Facility was compelled to allow interconnection and to implement open transmission access. In this example, (under FERC Order 888 and subsequent orders), the existing interconnection owner becomes a Transmission Service Provider and is required to have an Open Access Transmission Tariff (OATT). FERC's pro forma OATT requires the Transmission Service Provider to, among other things, perform system impact and feasibility studies. In order to do so, such studies must be coordinated with other Transmission Service Providers and Transmission Planners. And, to further complicate the issue, the SDT has been informed that in Texas, a Generator Owner is not allowed to own transmission.

Clearly, these issues are complex and not all are within the jurisdiction of federal or provincial regulators. For these reasons, the SDT took the only approach it found workable. If, and only if, the existing owner of a generator interconnection Facility has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to its existing generation Facility would the proposed FAC-001-1 apply. The SDT believes that this is most likely to occur if the owner of an existing generator interconnection Facility is compelled to allow a third party to interconnect and adopt open transmission access. However, the SDT cannot be certain this is the only example and it therefore proposes to add this new requirement to FAC-001-1. In doing so, the SDT acknowledges that the Generator Owner may not, at the time it agrees or is compelled to allow a third party to interconnect, have the necessary expertise to conduct the required interconnect studies to meet this standard. However, the SDT believes that, upon executing such Agreement, the Generator Owner will have to acquire such expertise. How the Generator Owner chooses to do so is not for the SDT to determine. The SDT is tasked with identifying potential reliability gaps and addressing such gaps through the standards development process.

The SDT does agree with many comments asking that the Generator Owner not be required to maintain its connection requirements, and there was robust discussion among the team and observers. Some were concerned that, without an obligation to maintain, there would not be a review to ensure compliance with NERC Reliability Standards and applicable Regional Entity, subregional, Power Pool, and individual Transmission Owner planning criteria. Others were concerned that the third party requesting interconnection might not actually interconnect, but the owner of the existing generator interconnection Facility would, having executed an evaluation agreement, be forever obligated to maintain connection requirements. In the end, the SDT agreed that if the owner of the existing generator interconnection Facility adopted open access or was determined to be providing "transmission service" it was likely that its existing registration would be re-evaluated and that the issue would be more appropriately addressed at that time. The SDT has therefore agreed to remove maintenance requirements for Generator Owners from both Requirement R2 and Requirement R4 in the proposed FAC-001-1.

We hope that you have found this explanation of our rationale helpful, but if you have further suggestions for improvement or clarity, please submit them in your comments on this latest posting.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Technical Justification

Project 2010-07 Generator Requirements at the Transmission Interface

Background

As part of its work on Project 2010-07—Generator Requirements at the Transmission Interface, the standard drafting team (SDT) reviewed 34 reliability standards and 102 requirements to determine what changes are necessary to close a reliability gap with respect to what is commonly known as the generator interconnection Facility. The majority of these standards and requirements had been addressed in the *Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface* (Ad Hoc Report), and additional standards have been reviewed, and will continued to be reviewed, as a result of informal discussions with NERC and FERC staffs.

The basis for standard modifications recommended by the Ad Hoc Group for Generator Requirements at the Transmission Interface (Ad Hoc Group) was a few fundamental clarifications to the definitions of Generator Owner, Generator Operator, and Transmission, along with the creation of new definitions: one for Generator Interconnection Facility and one for Generator Interconnection Operational Interface. The Ad Hoc Group proposed the addition of these two new definitions to 26 standards encompassing 29 requirements (new and old), along with some modifications to FAC-003 to make it applicable to Generator Owners under certain circumstances.

Since the publication of the Ad Hoc Report, various entities have challenged these modifications and the recommended creation of the new definitions. The SDT has developed a more focused approach than that of the Ad Hoc Group: to propose recommendations whereby radial interconnection Facilities (at or above 100 kV) that are owned and operated by generating entities will be included in a small set of standards and requirements previously only applicable to Transmission Owners. The SDT agrees completely with the Ad Hoc Group's conclusion that Generator Owners and Operators of these radial generator tie-line Facilities (at voltages equal to or greater than 100 kV) should not be registered as Transmission Owners and Transmission Operators in order to maintain reliability on the Bulk Electric System (BES).

The SDT's justification for this strategy is rooted in the very title of its standards project: "Generator Requirements at the Transmission Interface." That is, the goal and scope of the project has always been to determine the responsibilities of those Generator Owners and Generator Operators that own or operate an interconnection Facility (in some cases labeled a "transmission Facility") between the generator and the interface with the portion of the BES where Transmission Owners and Transmission Operators take over ownership and operating responsibility. These kinds of Generator Owners and Generator Operators do not own or operate Facilities that are part of the interconnected system; rather, they own and operate radial Facilities that are connected to the boundary of the

interconnected system and as such have a limited role in providing reliability compared to those that operate in a networked fashion beyond the point of interconnection.

While some argue that these interconnecting portions of a Generator Owner's Facilities could be defined as Transmission and thus require the Generator Owner and Generator Operator for the Facility to be classified and registered as a Transmission Owner and Transmission Operator, the SDT does not believe this is necessary to provide an appropriate level of reliability for the BES. Just as important, such classification and registration could actually cause a reduction in reliability. Generator Owners and Generator Operators do not need, and in some cases may be prohibited from having, a wide-area view and responsibility for the integrated transmission system. Requiring Generator Owners and Generator Operators to have such responsibilities would require significant training, would require substantially more data and modeling responsibilities, and would detract from the entities' primary functions: to own and operate their generation equipment – including any Facilities owned and operated at voltages of 100 kV or greater that connect to the interconnected system – in a reliable manner.

Additionally, the SDT believes that the industry is much more aware today of the need to include all elements (owned and operated at 100 kV or higher) of a generator Facility in the procedures and compliance program of the registered entity that owns or has operational responsibility of those elements. Industry awareness was raised substantially at the time the October 17, 2010 Facility Ratings Recommendation to Industry was issued (which included Generator Owners and specifically addressed interconnection Facilities in the Q&A document). While this applies to a specific NERC Recommendation, the SDT considers this compelling evidence that the paradigm for thinking about generator interconnection Facilities is shifting.

All of this has led the SDT to its current conclusions to modify FAC-001, FAC-003, and PRC-004. The SDT does not believe any further modifications to standards are necessary to maintain an appropriate level of reliability based on the revised assumption that while generator Facilities (at 100 kV and above) will be considered by some to be transmission, Generator Owners and Generator Operators should not be registered as Transmission Owners and Transmission Operators simply as a result of the ownership and operation of such Facilities. Because the majority of commenters support the SDT's current recommendation to not adopt new terms, the SDT has elected to focus on its standard changes and to postpone discussions on revisions to existing, or creation of new, definitions until the standards have been successfully balloted.

Below, the SDT discusses the changes it has proposed for FAC-001, FAC-003, and PRC-004 and then provides justification for not modifying any additional standards that had been proposed for substantive modification in the Ad Hoc Report.

Review of SDT's Proposed Standard Changes

FAC-001-1—Facility Connection Requirements

While some stakeholders have questioned the modifications in the proposed FAC-001-1, the SDT remains convinced that there is the potential for a reliability gap if this standard is not modified so that it applies to a Generator Owner if and when it executes an Agreement to evaluate the reliability impact of interconnecting a third party Facility to its existing generation interconnection Facility. The intent of this modified language is to start the compliance clock when the Generator Owner executes an Agreement to perform the reliability assessment required in FAC-002-1. This step is expected to occur if a Generator Owner is compelled by a regulatory body to allow such interconnection. Assuming that a regulatory body would require a Generator Owner to evaluate such an interconnection request, the SDT expects the Generator Owner and the third party to execute some form of an Agreement. The SDT intentionally excluded a specific reference to the form of Agreement (such as a feasibility study) in deference to stakeholder suggestions to avoid comingling of commercial and reliability issues in reliability standards.

The SDT acknowledges that the scenario described in the proposed FAC-001-1 may be rare, but in the past (for instance, FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities, and the SDT thinks it is important to clarify the responsibilities related to such a request in NERC's Reliability Standards. And, while the SDT acknowledges that such regulatory action might also result in the Generator Owner being registered for other functions, such as Transmission Owner, Transmission Planner, and/or Transmission Service Provider, it decided the proposed revision provides appropriate reliability coverage until any additional registration is required and does not impact any Generator Owner that never executes an Agreement as described in the standard.

FAC-003-X and FAC-003-3—Vegetation Management

The SDT and most stakeholders agree with the Ad Hoc Group recommendation that FAC-003 be applicable to Generator Owners that own a generation interconnection if that Facility contains overhead conductors. The Ad Hoc Group originally excluded such a Facility from this requirement if its length is less than two spans (generally one half mile from the generator property line). After reviewing formal comments, the SDT agreed to revise the exclusion so that it applies to a Facility if its length is "one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard" to approximate line of sign from a fixed point. Other than revising this exclusion, the SDT applied the same criteria to the Generator Owner as applies to the Transmission Owner in the current FERC approved version of this standard as well as one approved by stakeholders (under Project 2007-07) in February 2011. The SDT is communicating with NERC staff and the Project 2007-07 SDT to ensure that changes to this standard will be coordinated before submitting to NERC's Board of Trustees, but feels compelled to continue to posting both versions until the outcome of Project 2007-07 efforts is clearer.

PRC-004-2.1—Analysis and Mitigation of Transmission and Generation Protection System Misoperations

After examining all standards it had previously reviewed, the SDT elected to propose a slight change to PRC-004-2.1. While the SDT rejected other opportunities to "drop" the phrase "generator interconnection Facility" into requirements because it is not typically the best way to add clarity, in the case of PRC-004-2, the SDT fears that the phrasing of R2 ("The Generator Owner shall analyze its generator Protection System Misoperations…") could lead to some confusion about whether an interconnection Facility is included. Thus, the SDT proposes adding "and generator interconnection Facility" as redlined in the draft standard. Because there is no change in applicability, and because the SDT believes that most Generator Owners already interpret the standard in this manner, we consider this to be a minor and not substantive change employed only to add clarity.

Review of Other Substantive Standard Modifications from the Ad Hoc Report

To ensure that no reliability gaps were left when the SDT shifted its strategy from the original strategy of the Ad Hoc Group, the SDT reviewed all standards for which the Ad Hoc Group had proposed changes, and again discussed whether making these standards applicable to Generator Owners or Generator Operators would increase reliability with respect to generator requirements at the transmission interface. Below, the SDT provides its reasons for not proposing the substantive changes that were included in the Ad Hoc Report (that is, a change in applicability or new requirement, beyond simply adding the text "including its Generator Interconnection Facility" to an existing requirement). As Project 2010-07 continues, the SDT will work with FERC staff, NERC staff, and industry groups to determine if its list of proposed standards is supported industry-wide, and whether other standards need to be considered.

EOP-003-1—Load Shedding Plans

For **EOP-003-1**, the Ad Hoc Group originally proposed that Generator Operators be added to the requirement that requires Transmission Operators and Balancing Authorities to coordinate automatic load-shedding throughout their areas. The SDT determined that this addition was unnecessary because PRC-001 already includes the requirement that Transmission Operators coordinate their underfrequency load shedding programs with underfrequency isolation of generating units, which infers that Generator Operators need to provide their underfrequency settings to their respective Transmission Operator. Further, Generator Operators typically do not have the technical expertise or access to the data necessary for the high-level coordination that this standard requires.

IRO-005-2—Reliability Coordination – Current Day Operations

The SDT chose not to adopt the revision to **IRO-005-2** proposed by the Ad Hoc Group. This revision would have added a new requirement that would read, "The Generator Operator shall immediately inform the Transmission Operator of the status of the Special Protection System, including any degradation or potential failure to operate as expected for SPS relay or control equipment under its control." The SDT initially arrived at this decision because of the planned retirement of IRO-005-2. In subsequent meetings, the SDT also reached the conclusion that there is no reliability gap as PRC-001-1 R2 already requires the Generator Operator to notify reliability entities of relay or equipment failures.

The SDT believes that a Special Protection System is a form of protection system and therefore any degradation or potential failure to operate as expected would be required to be reported by the Generator Operator to reliability entities (Balancing Authorities, Transmission Operators, and Reliability Coordinators).

Personnel Performance, Training, and Qualifications (PER) Standards

The SDT also chose not to propose the revisions to **PER-001-0—Operating Personnel Responsibility and Authority** or **PER-002-0—Operating Personnel Training** that were proposed by the Ad Hoc Group. For PER-001-0, the Ad Hoc Group had proposed adding a new R2 that would read "Each Generator Operator shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Generation Facility and Generation Interconnection Facility, and the responsibility and authority to follow the directives of reliability authorities including the Transmission Operator and Balancing Authority." To PER-002-0, the Ad Hoc Group proposed adding the Generator Operator to R1 ("Each Transmission Operator, Generator Operator, and Balancing Authority shall be staffed with adequately trained operating personnel") and adding a new R3 that would read: "Each Generator Operator shall implement an initial and continuing training program for all operating personnel that are responsible for operating the Generator Interconnection Facility that verifies the personnel's ability and understanding to operate the equipment in a reliable manner."

These proposed changes to the PER standards have little to do with responsibilities that relate specifically to a generator interconnection Facility. Issues related to the training of Generator Operators existed separately from the work of Project 2010-07, and the SDT agrees that its scope limits its efforts to standards that are directly related to generator requirements at the transmission interface. The SDT also cites past FERC Orders as proof that this issue is not within the scope of Project 2010-07. In Order 693, FERC directed NERC to "expand the applicability of the personnel training Reliability Standard, PER-002-0, to include (i) generator operators centrally-located at a generation control center with a direct impact on the reliable operation of the Bulk-Power System..." In Order 742, FERC reaffirmed this, stating that it is "not modifying the Order No. 693 directive regarding training for certain generator operator dispatch personnel, nor are we expanding a generator operator's responsibilities."

Centrally-located generator operators working at a generation control center typically dispatch the output from multiple generating units. As such, they can be called upon to comply with orders from their Balancing Authority that may have a significant impact on the reliable operation of the BES. Their training would be covered by proposed change to PER-002-0 and Order 742. Generator Operators who deal with interconnection facilities at individual generating plants, on the other hand, typically do not receive reliability-based orders specific to the interconnection Facilities and are therefore not covered by Order 742. Further, the SDT believes there is no reliability gap as Generator Operators are, under

currently approved reliability standards, required to follow directives issued by a Balancing Authority, Reliability Coordinator or Transmission Operator.

These items are clearly important ones for the Commission, but the SDT does not think it is appropriate to fold modifications to these PER standards into the scope of its work until it is specifically directed to do so. For now, modifications to PER-002-0 based on Order 693 directives are already included in NERC's Issue Database (P. 52-53) to be addressed by a future project. PER-001-0 is not addressed in the Issues Database, but the Project 2007-03 drafting team has proposed that the standard be retired.

Transmission Operations (TOP) Standards

For TOP standards, the Ad Hoc Group proposed a number of new requirements that the SDT does not see as supportive of reliability. This set of standards was somewhat difficult to analyze, as the Project 2007-03—Real-time Transmission Operations drafting team has made significant changes to TOP-001 through TOP-008, resulting in three proposed TOP standards where are currently eight (see the project's Implementation Plan). The Project 2010-07 reviewed both the FERC-approved TOP standards and the fifth draft of the modified standards in Project 2007-03 to determine whether it needed to propose any additional changes to cover radial generator interconnection Facilities. In addition, the Project 2010-07 SDT contacted the Project 2010-07 to get its opinion as to whether there might be any reliability gaps related to generator interconnection facilities. No such changes will be proposed for the reasons outlined below.

The Ad Hoc Group proposed adding two new requirements to **TOP-001-1—Reliability Responsibilities and Authority**. The first was proposed as R9 and read: "The Generator Operator shall coordinate the operation of its Generator Interconnection Facility with the Transmission Operator to whom it interconnects in order to preserve Interconnection reliability…" The SDT does not agree that this change is necessary. TOP-002-2 R3 (proposed to be covered in the future by TOP-003-2, as outlined in Project 2007-03's Implementation Plan) already requires the Generator Operator to coordinate its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. These entities are, in turn, required to coordinate with their respective Transmission Operator. Additionally, TOP-002-2 R4 (proposed to be covered in the future by TOP-003-2, as outlined in Project 2007-03's Implementation Plan) requires each Balancing Authority and Transmission Operator to coordinate with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator. With these requirements, Generator Operators are already required to provide necessary operations information to Transmission Operators. To require the same thing in TOP-001-1 would be redundant.

The second new requirement proposed by the Ad Hoc Group for TOP-001-1 was R10, which was to read: "The Transmission Operator shall have decision-making authority over operation of the Generator Interconnection Operational Interface at all times in order to preserve Interconnection reliability." As cited above, TOP-002-2 R3 (proposed to be covered in the future by TOP-003-2, as

outlined in Project 2007-03's Implementation Plan) already requires the Generator Operator to coordinate with its interconnecting Transmission Operator. Further, TOP-001-1 R3 (proposed to be covered in the future in the proposed IRO-001-2 R2 and R3) already requires the Generator Operator to comply with reliability directives issued by the Transmission Operator. These requirements effectively give the Transmission Operator decision-making authority over operation of all generator Facilities up to the point of interconnection. To require the same thing in TOP-001-1 would be redundant.

The Ad Hoc Group also proposed a new requirement, R7, for **TOP-004-2—Transmission Operations** that would read: "The Generator Operator shall operate its Generator Interconnection Facility within its applicable ratings." The SDT does not agree that a reliability gap exists, because an operator has a fiduciary obligation to protect a Facility for which it is operationally responsible. FAC-008-1—Facility Ratings Methodology and FAC-009-1—Establish and Communicate Facility Ratings already infer that the reason for establishing a ratings methodology and communicating facility ratings to the Reliability Coordinator, Planning Authority, Transmission Planner, and Transmission Operator is "…for use in reliable planning and operation of the Bulk Electric System." Further, TOP-004-2 is proposed to be retired under the work of the Project 2007-03 drafting team. Its requirements will either be deleted or assigned elsewhere.

The Ad Hoc team proposed to add a new requirement, R5, to **TOP-008-1—Response to Transmission Limit Violations** that would read "The Generator Operator shall disconnect the Generator Interconnection Facility when safety is jeopardized or the overload or abnormal voltage or reactive condition persists and generating equipment or the Generator Interconnection Facility is endangered. In doing so, the Generator Operator shall notify its Transmission Operator and Balancing Authority impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter." The SDT sees no reliability benefit to adding this requirement. TOP-001-1 R7 ("Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless…") and its parts give the Generator Operator authority over its Facilities, which would include the generator interconnection Facility. If there is an outage, R7.1 requires the Generator Operator to notify and coordinate with its Transmission Operator, which is required to notify the Reliability Coordinator and other affected Transmission Operators. And as with TOP-004-2, the Project 2007-03 drafting team has proposed to deleting all of TOP-008-1's requirements and retiring the standard.

Conclusion

The Project 2010-07 SDT is confident that the changes it has proposed address the reliability gap that exists with respect to the responsibilities of Generator Owners and Generator Operations that own radial interconnection Facilities. The changes to FAC-001 and FAC-003 (and now PRC-004) have been supported by stakeholders during comment periods, and there has been no strong support for bringing other standards into the scope of this project.

That said, the SDT recognizes the success of its work depends on stakeholders, NERC, and FERC agreeing that generator requirements at the transmission interface are covered under NERC Reliability Standards, both for the sake of reliability and to prevent further unwarranted registration of Generator Owners and Generator Operators as Transmission Owners and Transmission Operators. If the SDT's work does not close the gap in the eyes of all parties, that work will have been unsuccessful, so the SDT is considering all feedback it receives with request to this project. While it is posting changes to only FAC-001, FAC-003, and PRC-004, and stands by that decision, it will continue to consider whether glossary term additions/modifications and modifications to other standards could enhance the reliability impact of this project. Based on conversations with NERC and FERC staff, and review of FERC's Order Denying Compliance Registry Appeals of Cedar Creek Wind Energy and Milford Wind Corridor Phase I (135 FERC ¶ 61,241), the SDT is discussing whether it should consider the following requirements for further review: EOP-005-1 R1, R2, R6, R7; FAC-014-2 R2; PER-003-1 R1, R1.1, R1.2; PRC-001-1 R2, R2.2, R4, R6; PRC-004-1 R1; TOP-001 R1; TOP-004-2 R6, R6.1, R6.2, R6.3, R6.4; and TOP-006-1 R3. The SDT is actively seeking stakeholder feedback as to whether, in light of these orders, it should consider additional standards and or new or modifications to existing definitions as it proceeds with its work.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan for FAC-001-1 – Facility Connection Requirements

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

Revision to Sections of Approved Standards and Definitions

There are no proposed revisions to requirements in other already approved standards. FAC-001-0 – Facility Connection Requirements will be retired ~~when~~at midnight the day before FAC-001-1 becomes effective.

Compliance with Standard

Since this version of the standard imposes no changes to Transmission Owners from those in the FERC-approved version of the standard, the expectation is that Transmission Owners will maintain their current state of compliance. Thus, the standard is effective for Transmission Owners upon approval, as detailed below.

The proposed changes to the FERC-approved version of this standard only address Generator Owner applicability and requirements (add Generator Owner to section 4.2, introduce a new requirement (R2), and modify ~~two~~one existing ~~requirements~~requirement (now R3~~ and R4~~)). Therefore, this implementation plan only identifies a compliance timeframe for Generator Owners to which this standard will apply.

Effective Date

There are two effective dates associated with this standard:

> In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner and Regional Entity become effective upon Board of Trustees' adoption.
>
> In those jurisdictions where regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities. In those jurisdictions where no regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after Board of Trustees' adoption.

A. Introduction

1. Title: **Facility Connection Requirements**

2. Number: FAC-001-~~0~~ 1

3. Purpose: To avoid adverse impacts on reliability, Transmission Owners and Generator Owners must establish Facility connection and performance requirements.

4. Applicability:

4.1. Transmission Owner

4.2. Applicable Generator Owner

4.2.1 Generator Owner within an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.

5. Effective Date: ~~April 1, 2005~~

5.1. In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner and Regional Entity become effective upon Board of Trustees' adoption.

5.2. In those jurisdictions where regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities. In those jurisdictions where no regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after Board of Trustees' adoption.

B. Requirements

R1. The Transmission Owner shall document, maintain, and publish Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional ~~Reliability Organization~~Entity, subregional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements. The Transmission Owner's Facility connection requirements shall address connection requirements for:

1.1. Generation Facilities,

1.2. Transmission Facilities, and

1.3. End-user Facilities

[VRF – Medium]

R2. Each applicable Generator Owner shall, within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission ~~Owner's~~ System (under FAC-002-1), document and publish its Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, subregional,

Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements.

[VRF – Medium]

R3. Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) shall address~~, but are not limited to,~~ the following items~~:~~ in its Facility connection requirements:

3.1. Provide a written summary of its plans to achieve the required system performance as described ~~above~~in Requirements R1 or R2 throughout the planning horizon:

3.1.1. Procedures for coordinated joint studies of new Facilities and their impacts on the interconnected Transmission Systems.

3.1.2. Procedures for notification of new or modified Facilities to others (those responsible for the reliability of the interconnected Transmission Systems) as soon as feasible.

3.1.3. Voltage level and MW and MVAR capacity or demand at point of connection.

3.1.4. Breaker duty and surge protection.

3.1.5. System protection and coordination.

3.1.6. Metering and telecommunications.

3.1.7. Grounding and safety issues.

3.1.8. Insulation and insulation coordination.

3.1.9. Voltage, Reactive Power, and power factor control.

3.1.10. Power quality impacts.

3.1.11. Equipment Ratings.

3.1.12. Synchronizing of Facilities.

3.1.13. Maintenance coordination.

3.1.14. Operational issues (abnormal frequency and voltages).

3.1.15. Inspection requirements for existing or new Facilities.

3.1.16. Communications and procedures during normal and emergency operating conditions.

[VRF – Medium]

R4. The Transmission Owner shall maintain and update its Facility connection requirements as required. The Transmission Owner shall make documentation of these requirements available

to the users of the transmission system, the Regional ~~Reliability Organization~~Entity, and ~~NERC~~ERO on request (five business days).

[VRF – Medium]

C. Measures

M1. The Transmission Owner shall make available (to its Compliance ~~Monitor) for inspection~~Enforcement Authority) evidence that it met all the requirements stated in ~~Reliability Standard FAC-001-0_~~Requirement R1.

M2. Each Generator Owner that has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission ~~Owner~~System shall make available (to its Compliance ~~Monitor) for inspection~~Enforcement Authority) evidence that it met all requirements stated in ~~Reliability Standard FAC-001-0_~~Requirement R2.

M3. ~~The~~Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) shall make available (to its Compliance ~~Monitor) for inspection~~Enforcement Authority) evidence that it met all ~~the~~ requirements stated in ~~Reliability Standard FAC-001-0_R3~~Requirement R3.

~~M3.~~M4. The Transmission Owner shall make available (to its Compliance Enforcement Authority) evidence that it met all the requirements stated in Requirement R4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

Compliance Monitor: Regional ~~Reliability Organization.~~Entity

1.2. Compliance Monitoring ~~Period~~ and ~~Reset Timeframe~~Enforcement Processes:

~~On request (five business days).~~

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3. Data Retention

~~None specified.~~

The Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Owner shall retain evidence of Requirement R1, Measure M1, Requirement R3, Measure M3, and Requirement R4, Measure M4 from its last audit.

The Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain evidence of Requirement R2, Measure M2, and Requirement R3, Measure M3 from its last audit.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels ~~of Non-Compliance~~

~~**2.1. Level 1:** Facility connection requirements were provided for generation, transmission, and end-user facilities, per Reliability Standard FAC-001-0_R1, but the document(s) do not address all of the requirements of Reliability Standard FAC-001-0_R2.~~

~~**2.2. Level 2:** Facility connection requirements were not provided for all three categories (generation, transmission, or end-user) of facilities, per Reliability Standard FAC-001-0_R1, but the document(s) provided address all of the requirements of Reliability Standard FAC-001-0_R2.~~

~~**2.3. Level 3:** Facility connection requirements were not provided for all three categories (generation, transmission, or end-user) of facilities, per Reliability Standard FAC-001-0_R1, and the document(s) provided do not address all of the requirements of Reliability Standard FAC-001-0_R2.~~

~~**2.4. Level 4:** No document on facility connection requirements was provided per Reliability Standard FAC-001-0_R3.~~

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Not Applicable.	The Transmission Owner failed to do one of the following: Document or maintain or publish Facility connection requirements as specified in the Requirement	The Transmission Owner failed to do one of the following: Failed to include (2) of the components as specified in R1.1, R1.2 or R1.3 OR	The Transmission Owner did not develop Facility connection requirements.

		OR Failed to include one (1) of the components as specified in R1.1, R1.2 or R1.3.	Failed to document or maintain or publish its Facility connection requirements as specified in the Requirement **and** failed to include one (1) of the components as specified in R1.1, R1.2 or R1.3.	
R2	The Generator Owner failed to document and publish Facility connection requirements until more than 45 calendar days but less than or equal to 60 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.	The Generator Owner failed to document and publish Facility connection requirements until more than 60 calendar days but less than or equal to 70 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.	The Generator Owner failed to document and publish Facility connection requirements until more than 70 calendar days but less than or equal to 80 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.	The Generator Owner failed to document and publish Facility connection requirements until more than 80 days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.
R3	The responsible entity's Facility connection requirements failed to address one of the Parts listed in Requirement R3, Part 3.1.1 R3.1.6.	The responsible entity's Facility connection requirements failed to address two of the Parts listed in Requirement R3, Part 3.1.1 R3.1.6.	The responsible entity's Facility connection requirements failed to address three of the Parts listed in Requirement R3, Part 3.1.1 R3.1.6.	The responsible entity's Facility connection requirements failed to address four or more of the Parts listed in Requirement R3, Part 3.1.1 R3.1.6.
R4	The responsible entity made the requirements available more than five business days but less than or equal to 10 business days after a request.	The responsible entity made the requirements available more than 10 business days but less than or equal to 20 business days after a request.	The responsible entity made the requirements available more than 20 business days less than or equal to 30 business days after a request.	The responsible entity made the requirements available more than 30 business days after a request.

E. **Regional Differences**

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Added requirements for Generator Owner and brought overall standard format up to date	Revision under Project 2010-07

The drafting team limited its modifications to those associated with expanding the scope to include the Generator Owner and bringing the format up to date.

A. Introduction

1. Title: **Facility Connection Requirements**

2. Number: FAC-001-1

3. Purpose: To avoid adverse impacts on reliability, Transmission Owners and Generator Owners must establish Facility connection and performance requirements.

4. Applicability:

4.1. Transmission Owner

4.2. Applicable Generator Owner

4.2.1 Generator Owner within an executed Agreement to evaluate the reliability impact of interconnecting ~~another Facility to its existing generation Facility~~a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.

5. Effective Date:

5.1. In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner and Regional Entity become effective upon Board of Trustees' adoption.

5.2. In those jurisdictions where regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities. In those jurisdictions where no regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after Board of Trustees' adoption.

B. Requirements

R1. The Transmission Owner shall document, maintain, and publish Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, subregional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements. The Transmission Owner's Facility connection requirements shall address connection requirements for:

1.1. Generation Facilities,

1.2. Transmission Facilities, and

1.3. End-user Facilities

[VRF – Medium]

R2. Each applicable Generator Owner shall, within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System ~~of executing an Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility~~ (under FAC-002-1), ~~shall~~ document and publish its ~~and thereafter maintain~~ Facility connection requirements to ensure compliance with NERC Reliability

Standards and applicable Regional Entity, subregional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements.

[VRF – Medium]

R3. Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) ~~with Facility connection requirements and each Transmission Owner~~ shall ~~have Facility connection requirements that~~ address the following items in its Facility connection requirements:

3.1. Provide a written summary of its plans to achieve the required system performance as described in Requirements R1 ~~and~~ or R2 throughout the planning horizon:

3.1.1. Procedures for coordinated joint studies of new Facilities and their impacts on the interconnected Transmission Systems.

3.1.2. Procedures for notification of new or modified Facilities to others (those responsible for the reliability of the interconnected Transmission Systems) as soon as feasible.

3.1.3. Voltage level and MW and MVAR capacity or demand at point of connection.

3.1.4. Breaker duty and surge protection.

3.1.5. System p~~P~~rotection and coordination.

3.1.6. Metering and telecommunications.

3.1.7. Grounding and safety issues.

3.1.8. Insulation and insulation coordination.

3.1.9. Voltage, Reactive Power, and power factor control.

3.1.10. Power quality impacts.

3.1.11. Equipment Ratings.

3.1.12. Synchronizing of Facilities.

3.1.13. Maintenance coordination.

3.1.14. Operational issues (abnormal frequency and voltages).

3.1.15. Inspection requirements for existing or new Facilities.

3.1.16. Communications and procedures during normal and emergency operating conditions.

[VRF – Medium]

R4. The Transmission Owner shall~~Each applicable Generator Owner with Facility connection requirements (in accordance with Requirement R2) and each Transmission Owner shall maintain Facility connection requirements and~~ maintain and update its Facility connection

requirements as required. The Transmission Owner shall- make documentation of these requirements available to the users of the t~~T~~ransmission s~~S~~ystem, the Regional Entity, and ERO on request (five business days).

[VRF – Medium]

C. Measures

M1. The Transmission Owner shall make available (to its Compliance Enforcement Authority) evidence that it met all the requirements stated in Requirement R1.

M2. Each Generator Owner that has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System ~~that executes an Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility~~ shall make available (to its Compliance Enforcement Authority) evidence that it met all requirements stated in Requirement R2.

M3. Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) ~~Each applicable Generator Owner with Facility connection requirements and each Transmission Owner~~ shall make available (to its Compliance Enforcement Authority) evidence that it met all requirements stated in Requirement R3.

M4. ~~Each applicable Generator Owner with Facility connection requirements and each~~The Transmission Owner shall make available (to its Compliance Enforcement Authority) evidence that it met all the requirements stated in Requirement R4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Compliance Monitor: Regional Entity

1.2. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3. Data Retention

The Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Owner shall retain evidence of Requirement R1, Measure M1, Requirement R3, Measure M3, and Requirement R4, Measure M4 from its last audit.

The Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain evidence of Requirement R2, Measure M2, and Requirement R3, Measure M3~~, and Requirement R4, Measure M4~~ from its last audit.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Not Applicable.	The Transmission Owner failed to do one of the following: Document or maintain or publish Facility connection requirements as specified in the Requirement OR Failed to include one (1) of the components ~~and~~ as specified in R1.1, R1.2 or R1.3.	The Transmission Owner failed to do one of the following: ~~Document or maintain or publish its Facility connection requirements as specified in the Requirement~~ ~~OR~~ Failed to include (2) of the components as specified in R1.1, R1.2 or R1.3 OR Failed to document or maintain or publish its Facility connection requirements as specified in the Requirement **and** failed to include one (1) of the components as specified in R1.1, R1.2 or R1.3.	The Transmission Owner did not develop Facility connection requirements.

R2	The ~~responsible entity~~Generator Owner failed to document and publish ~~and thereafter maintain~~ Facility connection requirements until more than 45 calendar days but less than or equal to 60 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.~~executing an Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility.~~	The Generator Owner ~~responsible entity~~ failed to document and publish ~~and thereafter maintain~~ Facility connection requirements until more than 60 calendar days but less than or equal to 70 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.~~executing an Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility.~~	The Generator Owner ~~responsible entity~~ failed to document and publish ~~and thereafter maintain~~ Facility connection requirements until more than 70 calendar days but less than or equal to 80 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.~~executing an Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility.~~	The Generator Owner ~~responsible entity~~ failed to document and publish ~~and thereafter maintain~~ Facility connection requirements until more than 80 days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.~~executing an Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility.~~
R3	The responsible entity's Facility connection requirements failed to address one of the Parts listed in Requirement R3, Part 3.1.1 R3.1.6~~subrequirements~~.	The responsible entity's Facility connection requirements failed to address two of the Parts listed in Requirement R3, Part 3.1.1 R3.1.6~~subrequirements~~.	The responsible entity's Facility connection requirements failed to address three of the Parts listed in Requirement R3, Part 3.1.1 R3.1.6~~sub-requirements~~.	The responsible entity's Facility connection requirements failed to address four or more of the Parts listed in Requirement R3, Part 3.1.1 R3.1.6~~subrequirements~~. ~~OR~~ ~~The responsible entity does not have Facility connection requirements.~~
R4	The responsible entity made the requirements available more than	The responsible entity made the requirements available more than 10	The responsible entity made the requirements available more than 20	The responsible entity made the requirements

	five business days but less than or equal to 10 business days after a request.	business days but less than or equal to 20 business days after a request.	business days less than or equal to 30 business days after a request.	available more than 30 business days after a request.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Added requirements for Generator Owner and brought overall standard format up to date	Revision under Project 2010-07

Implementation Plan for FAC-003-3 – Transmission Vegetation Management

Prerequisite Approvals

There are a number of scenarios that could occur regarding the approval of FAC-003-2 – Vegetation Management must be implemented that would affect the implementation of FAC-003-3.

If FAC-003-2 is filed with applicable regulatory authorities and approved before FAC-003-3 is filed with applicable regulatory authorities, then when and if FAC-003-3 is approved by applicable regulatory authorities, the implementation plan and effective dates for Transmission Owners in FAC-003-2 will be transferred into this implementation plan. The "clock" for calculating effective dates for Transmission Owners will still have started at the time specified in FAC-003-2 (based on the approval date of that standard can). Generator Owners will be implemented required to comply with the implementation plan as outlined below.

If applicable regulatory authorities elect to approve only FAC-003-3 and not FAC-003-2, the original implementation plan for Transmission Owners as outlined in FAC-003-2 will be transferred into this implementation plan. Generator Owners will be required to comply with the implementation plan as outlined below. The "clocks" for calculating the effective dates for both Transmission Owners and Generator Owners will begin at the same time.

If applicable regulatory authorities approve FAC-003-2 and FAC-003-3 at the same time, the implementation plan and effective dates for Transmission Owners in FAC-003-2 will be transferred into this implementation plan and FAC-003-2 will be immediately retired. Generator Owners will be required to comply with the implementation plan as outlined below. The "clocks" for calculating the effective dates for both Transmission Owners and Generator Owners will begin at the same time.

Revision to Sections of Approved Standards and Definitions

There are no proposed revisions to requirements in other already approved standards. All requirements and the two revised definitions in the proposed standard FAC-003-2 will be retired when at midnight the day before FAC-003-3 becomes effective.

There are two revised definitions in the proposed standard:

Right-of-Way (ROW)

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either

construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.

Vegetation Inspection

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

There is one new definition in the proposed standard:

Minimum Vegetation Clearance Distance (MVCD)
The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

The current glossary definitions of Right-of-Way and Vegetation Inspection, or the glossary definitions of Right-of-Way and Vegetation Inspection in FAC-003-2, if that standard has been approved, will be retired at midnight the day before FAC-003-3 (and with it, the above definitions of Right-of-Way and Vegetation Inspection) becomes effective. The above definition of Minimum Vegetation Clearance Distance will be added to the NERC glossary upon approval of FAC-003-3, or the above definition of Minimum Vegetation Clearance Distance will replace (and thus force the retirement, at midnight the day before FAC-003-3 is approved) of the same definition in FAC-003-2, if FAC-003-2 has been approved.

Compliance with Standard

~~There are no changes to~~As outlined above under "Prerequisite Approvals," the ~~requirements applicable to~~ inclusion of Transmission Owners ~~already proposed~~ in this implementation plan will depend on order in which regulatory authorities approved FAC-003-2~~,~~ and ~~the expectation is that Transmission Owners will maintain their current state of compliance. Thus, the standard is effective for Transmission Owners upon approval, as detailed below.~~

~~The proposed changes to Version 2 of the standard only address Generator Owner applicability and requirements (add Generator Owner to sections 4.1.2 and 4.~~FAC-003-3~~ and add applicable Generator Owner to all requirements).~~. Therefore, this implementation plan only identifies a compliance timeframe for Generator Owners to which this standard will apply.

To reach compliance with the standard, a Generator Owner will have to perform a full review of as-built drawings and determine which generation interconnection Facilities require a Transmission

Vegetation Management Plan (TVMP) and inspection as specified by NERC Reliability Standard FAC-003-3. In general, Generator Owners do not have staff that are qualified and experienced to create a TVMP, perform Right-of-Way inspections, and perform any required tree trimming (as is required by FAC-003-3 Requirement 1.3). Once a complete inventory is created, the Generator Owner will begin the process of gathering information for the TVMP. In instances where the generation interconnection Facilities are owned by a partnership, a majority or operating partner will need to obtain partnership approval to proceed with procurement of a TVMP expert, and later a tree trimming crew. Typically, a request for proposal to hire TVMP consultant is initiated which could take several weeks in order to obtain sufficient bids (and also satisfy Sarbanes Oxley requirements). Once all bids have been received, a contract with a TVMP consultant is signed. At this point, the TVMP consultant and Generator Owner staff will develop the TVMP, which needs to take into account local growth conditions, types of vegetation and other aspects required by FAC-003. Once the TVMP is developed, Generator Owner staff and the TVMP consultant will need to perform a Right-of-Way inspection (as required in FAC-003-3 Requirement 1), usually done using GPS, LIDAR and other tools by experienced and qualified staff.

Once a Right-of-Way inspection is completed and clearances are required, the Generator Owner will need to issue a request for proposal to hire a tree trimming crew that is qualified and experienced to perform required clearance trimming. Once all bids have been received, a contract with a tree trimming crew is signed. When the tree trimming crew is acquired, the crew will need to familiarize themselves with the entity's TVMP and required clearances. The Generator Owner will typically need to schedule any required outages in order for the tree trimming crew to perform the needed clearance trimming. This action would also include the implementation of the work plan as required in FAC-003-3 Requirement 2. During scheduled outages, if required, the tree trimming crew will perform any required clearances and document the activities.

Another typical action is the Generator Owner establishing a system for maintaining TVMP-related activities, including maintenance of inspection and clearance documentation (as required in FAC-003-3 Requirement 1.2). On an ongoing basis, in addition to performing inspections and clearances as required by the entity's TVMP, the Generator Owner will need to ensure that the training and qualification requirements for the standard are met. The entity will also need to maintain documentation of all FAC-003-3 activities for compliance period of one year to meet compliance with the standard.

Again, due to a typical lack of experience and qualifications required by FAC-003-3, compliance with this standard by a Generator Owner may take as long as two years – in part because many entities will have generator interconnection Facilities in various parts of the country which may require several instances of TVMP and numerous Right-of-Way inspections.

Effective Date

There are ~~three~~two effective dates associated with this implementation plan:

The first ~~effective date applies to Transmission Owners.~~

> ~~In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner become effective upon Board of Trustees' adoption.~~

~~The second~~ effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

> In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The ~~third~~second effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

> In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

~~Exceptions:~~
Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or ~~as~~designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being ~~subject~~an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to ~~this standard.~~become an element of an IROL or an element of a Major WECC Transfer Path.

2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.

3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.

4. An existing transmission line operated at 200kV or higher ~~that~~which is newly acquired by an asset owner and which was not previously subject to this standard~~,~~ becomes subject to this standard 12 months after the acquisition date~~ of the line.~~.

5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SC approved SAR for initial posting (January 11, 2007).
2. SAR posted for comment (January 15–February 14, 2007).
3. SAR posted for comment (April 10–May 9, 2007).
4. SC authorized moving the SAR forward to standard development (June 27, 2007).
5. First draft of proposed standard posted (October 27, 2008-November 25, 2008)).
6. Second draft of revised standard posted (September 10, 20-October 24, 2009).
7. Third draft of revised standard posted (March 1, 2010-March 31, 2010).
8. Fourth draft of revised standard posted (June 17, 2010-July 17, 2010).
9. Fifth draft of revised standard posted (February 18, 2011-February 28, 2011)
10. Sixth draft of revised standard posted (September xx – 2011)

Proposed Action Plan and Description of Current Draft

This is the fourth posting of the proposed revisions to the standard in accordance with Results-Based Criteria and the sixth draft overall.

Future Development Plan

Anticipated Actions	Anticipated Date
Recirculation ballot of standards.	September 2011
Receive BOT approval	November 2011

Effective Dates

There are two effective dates associated with this standard.

The first effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

> In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The second effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

> In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

~~This standard becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval is required. Where no regulatory approval is required, the standard becomes effective on the first calendar day of the first calendar quarter one year after Board of Trustees adoption.~~

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.

2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.

3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.

4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.

5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

Version History

Version	Date	Action	Change Tracking
1	TBA	1. Added "Standard Development Roadmap." 2. Changed "60" to "Sixty" in section A, 5.2. 3. Added "Proposed Effective Date: April 7, 2006" to footer. 4. Added "Draft 3: November 17, 2005" to footer.	01/20/06
1	April 4, 2007	Regulatory Approval — Effective Date	New
23	September 29, 2011	Using the latest draft of FAC-003-2 from the Project 2007-07 SDT, modified proposed definitions and Applicability to include Generator Owners of a certain length.	Revision under Project 2010-07

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Right-of-Way (ROW)
The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.

The current glossary definition of this NERC term is modified to address the issues set forth in Paragraph 734 of FERC Order 693.

Vegetation Inspection
The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the applicable Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.

Current definition of Vegetation Inspection: The systematic examination of a transmission corridor to document vegetation conditions.

Minimum Vegetation Clearance Distance (MVCD)
The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.

FAC-003-2 is currently under development under Project 2007-07. The project is nearing its final stages, but the Project 2010-07 drafting team does not want to assume that the project will be approved by NERC's Board or Trustees (BOT) or FERC. Thus, the Project 2010-07 drafting team has developed two sets of proposed changes: one to this version, the latest draft of Version 2 as proposed by the Project 2007-07 team, and one to FAC-003-1, the current FERC-approved version of the standard.

If FAC-003-2 is approved by NERC's BOT, the Project 2010-07 drafting team will likely proceed with the modifications seen in this standard. These changes would be submitted for stakeholder approval and balloted as FAC-003-3. Several scenarios that could play out based on the order of the approval of these versions of the standards are addressed in the FAC-003-3 implementation plan.

If, however, FAC-003-2 remains under development, the Project 2010-07 drafting team will proceed with changes to FAC-003-1 to avoid further delay of its project goals. Changes to FAC-003-1 would address the addition of Generator Owners to the applicability, the proposal of modifications to the NERC defined term Right-of-Way to include applicable Generator Owners, and some formatting changes to bring the standard up to date. These changes would not be comprehensive; rather, they would aim to include the generator interconnection Facility in the standard with as few other changes as possible.

A. Introduction

1. Title: Transmission Vegetation Management

2. Number: FAC-003-3~~2~~

3. Purpose: To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

4. Applicability

4.1. Functional Entities:

4.1.1. Applicable Transmission Owners

4.1.1.1. Transmission Owners that own Transmission Facilities defined in 4.2.

4.1.2. Applicable Generator Owners

4.1.2.1. Generator Owners that own generation Facilities defined in 4.3

~~**4.1.**~~

~~4.1.1 **Transmission Owners**~~

4.2. **Transmission Facilities:** Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities:

4.2.1. ~~4.2.1.~~ Each overhead transmission line operated at 200kV or higher.

4.2.2. ~~4.2.2.~~ Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.

4.2.3. ~~4.2.3.~~ Each overhead transmission line operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

Rationale: The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. ~~3) NERC has a project in place to address at a later date the applicability of this standard to Generation Owners.~~ 3~~4~~) Specifically

4.2.4. ~~4.2.4.~~ Each overhead transmission line identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

4.3. **Generation Facilities:** Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[2], state, provincial, public, private, or tribal entities:

4.3.1. Overhead transmission lines that extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating switchyard and are:

~~Rationale: The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards,~~

4.3.1.1. Operated at 200kV or higher; or

4.3.1.2. Operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.

4.3.1.3. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies."*

[2] EPAct 2005 section 1211c: *"Access approvals by Federal agencies."*

Enforcement:

The Requirements within a Reliability Standard govern and will be enforced. The Requirements within a Reliability Standard define what an entity must do to be compliant and binds an entity to certain obligations of performance under Section 215 of the Federal Power Act. Compliance will in all cases be measured by determining whether a party met or failed to meet the Reliability Standard Requirement given the specific facts and circumstances of its use, ownership or operation of the bulk power system.

Measures provide guidance on assessing non-compliance with the Requirements. Measures are the evidence that could be presented to demonstrate compliance with a Reliability Standard Requirement and are not intended to contain the quantitative metrics for determining satisfactory performance nor to limit how an entity may demonstrate compliance if valid alternatives to demonstrating compliance are available in a specific case. A Reliability Standard may be enforced in the absence of specified Measures.

Entities must comply with the "Compliance" section in its entirety, including the Administrative Procedure that sets forth, among other things, reporting requirements.

The "Guideline and Technical Basis" section, the Background section and text boxes with "Examples" and "Rationale" are provided for informational purposes. They are designed to convey guidance from NERC's various activities. The "Guideline and Technical Basis" section and text boxes with "Examples" and "Rationale" are not intended to establish new Requirements under NERC's Reliability Standards or to modify the Requirements in any existing NERC Reliability Standard. Implementation of the "Guideline and Technical Basis" section, the Background section and text boxes with "Examples" and "Rationale" is not a substitute for compliance with Requirements in NERC's Reliability Standards."

5. Background:

5.1.1. This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

5.1.2. a) Performance-based — defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome*?

5.1.3. b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system*?

5.1.4. c) Competency-based — defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system*?

5.1.5. The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

5.1.6. For this standard, the requirements have been developed as follows:

5.1.7. Performance-based: Requirements 1 and 2

5.1.8. Competency-based: Requirement 3

5.1.9. Risk-based: Requirements 4, 5, 6 and 7

5.1.10. R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). R4 serves

as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

5.1.11. Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term "public lands" includes municipal lands, village lands, city lands, and a host of other governmental entities.

5.1.12. This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

5.1.13. This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

5.1.14. Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

B. Requirements and Measures

R1. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below[3] [*Violation Risk Factor: High*] [*Time Horizon: Real-time*]:

1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage[4],
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage[5],
3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[4],
4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage[4].

M1. Each applicable Transmission Owner

Rationale for R1 and R2:
Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of ~~a~~ an applicable Transmission Owner's or applicable Generator Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.

2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.

3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.

4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

[3] This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner ~~a Transmission Owner~~ subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.

[4] If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

[5] Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

and applicable Generator Owner ~~Transmission Owner~~ has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

R2. Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[2] [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time*]:

1. An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage[3],
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage[4],
3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[4],
4. An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage[4]

M2. Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)

R3. Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following:

3.1 Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;

3.2 Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

[*Violation Risk Factor: Lower*] [*Time Horizon: Long Term Planning*]:

Rationale

The documentation provides a basis for evaluating the competency of the applicable Transmission Owner's or applicable Generator Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating

M3. The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

R4. Each applicable Transmission Owner and applicable Generator Owner~~Transmission Owner~~, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time*].

Rationale

This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ and the control center when a critical situation is confirmed.

M4. Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

R5. When a applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ is constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner~~Transmission Owner~~ shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

Rationale

Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

M5. Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

R6. Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW[6] [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

Rationale

Inspections are used by applicable Transmission Owners and applicable Generator Owners~~Transmission Owners~~ to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors

[6] When the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a

M6. Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

R7. Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

Rationale

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

- Change in expected growth rate/ environmental factors
- Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner[7]
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Emerging technologies

time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

[7] Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.

M7. Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

C. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

1.2 Regional Entity Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, Measures M1, M2, M3, M5, M6 and M7 for three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3 Compliance Monitoring and Enforcement Processes:

5.1.15. Compliance Audit

5.1.16. Self-Certification

5.1.17. Spot Checking

5.1.18. Compliance Violation Investigation

5.1.19. Self-Reporting

Complaint

Periodic Data Submittal

1.4 Additional Compliance Information

Periodic Data Submittal: The applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner~~Transmission Owner~~.

A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners~~Transmission Owners~~, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Real-time	High	The ~~Transmission Owner~~responsible entity failed to manage vegetation in a manner such that the responsible entity~~Transmission Owner~~ had an encroachment into the MVCD observed in Real-time, absent a Sustained Outage.	The responsible entity ~~Transmission Owner~~ failed to manage vegetation in a manner such that the responsible entity ~~Transmission Owner~~ had an encroachment into the MVCD due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage.	The responsible entity ~~Transmission Owner~~ failed to manage vegetation in a manner such that the responsible entity ~~Transmission Owner~~ had an encroachment into the MVCD due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage.	The responsible entity ~~Transmission Owner~~ failed to manage vegetation in a manner such that the responsible entity ~~Transmission Owner~~ had an encroachment into the MVCD due to a grow-in that caused a vegetation-related Sustained Outage.
R2	Real-time	Medium	The responsible entity ~~Transmission Owner~~ failed to manage vegetation in a manner such that the responsible entity~~Transmission Owner~~ had an encroachment into the MVCD observed in Real-time, absent a Sustained Outage.	The responsible entity ~~Transmission Owner~~ failed to manage vegetation in a manner such that the responsible entity ~~Transmission Owner~~ had an encroachment into the MVCD due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage.	The responsible entity ~~Transmission Owner~~ failed to manage vegetation in a manner such that the responsible entity~~Transmission Owner~~ had an encroachment into the MVCD due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage.	The responsible entity ~~Transmission Owner~~ failed to manage vegetation in a manner such that the responsible entity ~~Transmission Owner~~ had an encroachment into the MVCD due to a grow-in that caused a vegetation-related Sustained Outage.
R3	Long-Term Planning	Lower		The responsible entity ~~Transmission Owner~~ has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates,	The responsible entity ~~Transmission Owner~~ has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating	The responsible entity ~~Transmission Owner~~ does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the

				vegetation control methods, and inspection frequency, for the responsible entity's ~~Transmission Owner's~~ applicable lines. (Requirement R3, Part 3.2)	and all Rated Electrical Operating Conditions, for the responsible entity's ~~Transmission Owner's~~ applicable lines. Requirement R3, Part 3.1)	responsible entity's ~~Transmission Owner's~~ applicable lines.
R4	Real-time	Medium			The responsible entity ~~Transmission Owner~~ experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The responsible entity ~~Transmission Owner~~ experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5	Operations Planning	Medium				The responsible entity ~~Transmission Owner~~ did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6	Operations Planning	Medium	The responsible entity ~~Transmission Owner~~ failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The responsible entity ~~Transmission Owner~~ failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity ~~Transmission Owner~~ failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity ~~Transmission Owner~~ failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7	Operations Planning	Medium	The responsible entity ~~Transmission Owner~~ failed to complete 5% or less of its annual	The responsible entity ~~Transmission Owner~~ failed to complete more than 5% and up to and including 10% of its	The responsible entity ~~Transmission Owner~~ failed to complete more than 10% and up to and including 15% of its	The responsible entity ~~Transmission Owner~~ failed to complete more than 15% of its annual vegetation work plan for

			vegetation work plan for its applicable lines (as finally modified).	annual vegetation work plan for its applicable lines (as finally modified).	annual vegetation work plan for its applicable lines (as finally modified).	its applicable lines (as finally modified).

D. Regional Differences

None.

E. Interpretations

None.

F. Associated Documents

Guideline and Technical Basis (attached).

Guideline and Technical Basis

Effective dates:

The first two sentences of the Effective Dates section is standard language used in most NERC standards to cover the general effective date and is sufficient to cover the vast majority of situations. Five special cases are needed to cover effective dates for individual lines which undergo transitions after the general effective date. These special cases cover the effective dates for those lines which are initially becoming subject to the standard, those lines which are changing their applicability within the standard, and those lines which are changing in a manner that removes their applicability to the standard.

Case 1 is needed because the Planning Coordinators may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2011 may identify a line to have that designation beginning in PY 2021, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. The table below has some explanatory examples of the application.

Date that Planning Study is completed	PY the line will become an IROL element	Date 1	Date 2	Effective Date The latter of Date 1 or Date 2
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Case 2 is needed because a line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Case 3 is needed because a line operating at 200 kV or above that once was designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network. Such changes result in the need to apply R1 to that line until that date is reached and then to apply R2 to that line thereafter.

Case 4 is needed because an existing line that is to be operated at 200 kV or above can be acquired by an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner~~Transmission Owner~~, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network which will thereafter make the line subject to the standard.

Case 5 is needed because an existing line that is operated below 200 kV can be acquired by an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner~~Transmission owner~~, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network. In this special case the line upon acquisition was designated as an element of an Interconnection Reliability Operating Limit (IROL) or an element of a Major WECC Transfer Path.

Defined Terms:

Explanation for revising the definition of ROW:
The current NERC glossary definition of Right of Way has been modified to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This modified definition represents a slight but significant departure from the strict legal definition of "right of way" in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the revised definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

Explanation for revising the definition of Vegetation Inspections:

The current glossary definition of this NERC term is being modified to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

Explanation of the definition of the MVCD:

The MVCD is a calculated minimum distance that is derived from the Gallet Equations. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 below provides MVCD values for various voltages and altitudes. Details of the equations and an example calculation are provided in Appendix 1 of the Technical Reference Document.

Requirements R1 and R2:

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element of an IROL or Major WECC Transfer Path. R2 is applicable to all other lines that are not elements of IROLs, and not elements of Major WECC Transfer Paths.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations as described more fully in the Technical Reference document.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner ~~Transmission Operator~~ or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's ~~Transmission Owner's~~ inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will prevent transmission outages.

If the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

Requirement R3: R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below. In the Technical Reference document more figures and explanations of conductor dynamics are provided.

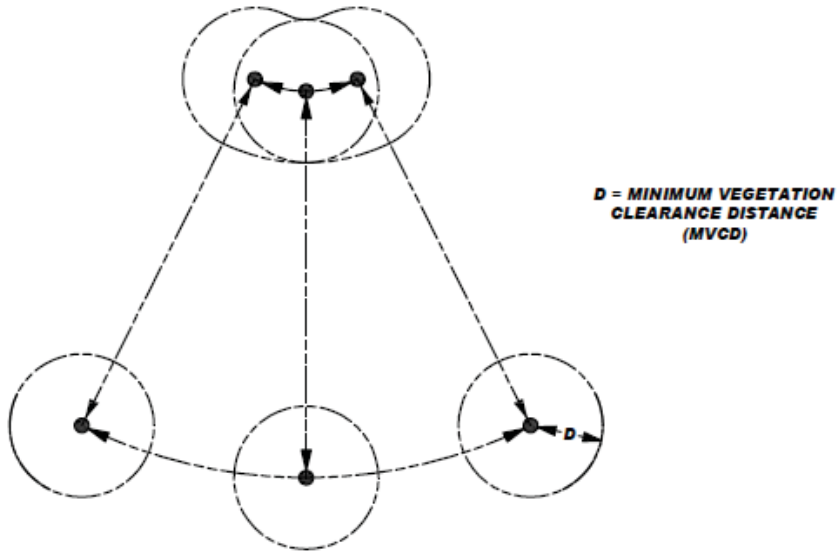

Figure 1

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

Requirement R4:

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner's~~ employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners ~~Transmission Owners~~ may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5:
R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's ~~Transmission Owner's~~ rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6:
R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner's ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The "Low VSL" for R6 would apply in this example.

Requirement R7:
R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ is required to complete its an annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a "span-by-span", or even a "line-by-line" detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

For example, when an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ identifies 1,000 miles of applicable transmission lines to be completed in the applicable Transmission Owner's or applicable Generator Owner's ~~Transmission Owner's~~ annual plan, the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ will be responsible completing those identified miles. If a applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be: 1000 – 100 (deferred miles) = 900 modified annual plan, or 900 / 900 = 100% completed annual miles. If an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be: 1000 – 875 = 125 miles failed to complete then, 125 miles (not completed) / 1000 total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner's or applicable Generator Owner's ~~Transmission Owner's~~ system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.

In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner's or applicable Generator Owner's ~~Transmission Owner's~~ easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners ~~Transmission Owners~~ may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner~~Transmission Owner~~, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[8]
For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)	(AC) Maximum System Voltage (kV)[9]	MVCD (feet) Over sea level up to 500 ft	MVCD (feet) Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft
765	800	8.2ft	8.33ft	8.61ft	8.89ft	9.17ft	9.45ft	9.73ft	10.01ft	10.29ft	10.57ft	10.85ft	11.13ft
500	550	5.15ft	5.25ft	5.45ft	5.66ft	5.86ft	6.07ft	6.28ft	6.49ft	6.7ft	6.92ft	7.13ft	7.35ft
345	362	3.19ft	3.26ft	3.39ft	3.53ft	3.67ft	3.82ft	3.97ft	4.12ft	4.27ft	4.43ft	4.58ft	4.74ft
287	302	3.88ft	3.96ft	4.12ft	4.29ft	4.45ft	4.62ft	4.79ft	4.97ft	5.14ft	5.32ft	5.50ft	5.68ft
230	242	3.03ft	3.09ft	3.22ft	3.36ft	3.49ft	3.63ft	3.78ft	3.92ft	4.07ft	4.22ft	4.37ft	4.53ft
161*	169	2.05ft	2.09ft	2.19ft	2.28ft	2.38ft	2.48ft	2.58ft	2.69ft	2.8ft	2.91ft	3.03ft	3.14ft
138*	145	1.74ft	1.78ft	1.86ft	1.94ft	2.03ft	2.12ft	2.21ft	2.3ft	2.4ft	2.49ft	2.59ft	2.7ft
115*	121	1.44ft	1.47ft	1.54ft	1.61ft	1.68ft	1.75ft	1.83ft	1.91ft	1.99ft	2.07ft	2.16ft	2.25ft
88*	100	1.18ft	1.21ft	1.26ft	1.32ft	1.38ft	1.44ft	1.5ft	1.57ft	1.64ft	1.71ft	1.78ft	1.86ft
69*	72	0.84ft	0.86ft	0.90ft	0.94ft	0.99ft	1.03ft	1.08ft	1.13ft	1.18ft	1.23ft	1.28ft	1.34ft

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

[8] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[9] Where applicable lines are operated at nominal voltages other than those listed, t~~T~~he applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ should use the maximum system voltage to determine the appropriate clearance for that line.

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[7]
For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)	(AC) Maximum System Voltage (kV)[8]	MVCD meters Over sea level up to 152.4 m	MVCD meters Over 152.4 m up to 304.8 m	MVCD meters Over 304.8 m up to 609.6m	MVCD meters Over 609.6m up to 914.4m	MVCD meters Over 914.4m up to 1219.2m	MVCD meters Over 1219.2m up to 1524m	MVCD meters Over 1524 m up to 1828.8 m	MVCD meters Over 1828.8m up to 2133.6m	MVCD meters Over 2133.6m up to 2438.4m	MVCD meters Over 2438.4m up to 2743.2m	MVCD meters Over 2743.2m up to 3048m	MVCD meters Over 3048m up to 3352.8m
765	800	2.49m	2.54m	2.62m	2.71m	2.80m	2.88m	2.97m	3.05m	3.14m	3.22m	3.31m	3.39m
500	550	1.57m	1.6m	1.66m	1.73m	1.79m	1.85m	1.91m	1.98m	2.04m	2.11m	2.17m	2.24m
345	362	0.97m	0.99m	1.03m	1.08m	1.12m	1.16m	1.21m	1.26m	1.30m	1.35m	1.40m	1.44m
287	302	1.18m	0.88m	1.26m	1.31m	1.36m	1.41m	1.46m	1.51m	1.57m	1.62m	1.68m	1.73m
230	242	0.92m	0.94m	0.98m	1.02m	1.06m	1.11m	1.15m	1.19m	1.24m	1.29m	1.33m	1.38m
161*	169	0.62m	0.64m	0.67m	0.69m	0.73m	0.76m	0.79m	0.82m	0.85m	0.89m	0.92m	0.96m
138*	145	0.53m	0.54m	0.57m	0.59m	0.62m	0.65m	0.67m	0.70m	0.73m	0.76m	0.79m	0.82m
115*	121	0.44m	0.45m	0.47m	0.49m	0.51m	0.53m	0.56m	0.58m	0.61m	0.63m	0.66m	0.69m
88*	100	0.36m	0.37m	0.38m	0.40m	0.42m	0.44m	0.46m	0.48m	0.50m	0.52m	0.54m	0.57m
69*	72	0.26m	0.26m	0.27m	0.29m	0.30m	0.31m	0.33m	0.34m	0.36m	0.37m	0.39m	0.41m

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[7]
For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)
	Over sea level up to 500 ft	Over 500 ft up to 1000 ft	Over 1000 ft up to 2000 ft	Over 2000 ft up to 3000 ft	Over 3000 ft up to 4000 ft	Over 4000 ft up to 5000 ft	Over 5000 ft up to 6000 ft	Over 6000 ft up to 7000 ft	Over 7000 ft up to 8000 ft	Over 8000 ft up to 9000 ft	Over 9000 ft up to 10000 ft	Over 10000 ft up to 11000 ft
	(Over sea level up to 152.4 m)	(Over 152.4 m up to 304.8 m	(Over 304.8 m up to 609.6m)	(Over 609.6m up to 914.4m	(Over 914.4m up to 1219.2m	(Over 1219.2m up to 1524m	(Over 1524 m up to 1828.8 m)	(Over 1828.8m up to 2133.6m)	(Over 2133.6m up to 2438.4m)	(Over 2438.4m up to 2743.2m)	(Over 2743.2m up to 3048m)	(Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

Notes:

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet Equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 uses the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-01 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 per unit. This value is a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the

maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet Equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet "wet" formulas are not vastly different when the same transient overvoltage factors are used; the "wet" equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

While EPRI is currently trying to establish empirical data for spark-over distances to live vegetation, there are no spark-over formulas currently derived expressly for vegetation to conductor minimum distances. Therefore the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.
The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

Comparison of spark-over distances computed using Gallet wet equations vs. IEEE 516-2003 MAID distances

(AC) Nom System Voltage (kV)	(AC) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	Table 7 (Table D.5 for feet) IEEE 516-2003 MAID (ft) @ Alt. 3000 feet
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan for FAC-003-X – Transmission Vegetation Management Program

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

Revision to Sections of Approved Standards and Definitions

There are no proposed revisions to requirements in other already approved standards. FAC-003-1 will be retired ~~when~~at midnight the day before FAC-003-~~2~~X becomes effective.

There is one revised definition in the proposed standard:

> **Right-of-Way:** A corridor of land on which electric lines may be located. The Transmission Owner or applicable Generator Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

The current glossary definition of Right-of-Way will be retired at midnight the day before FAC-003-X (and with it, the above definition of Right-of-Way) becomes effective.

Compliance with Standard

There are no changes to the requirements applicable to Transmission Owners already in effect in FAC-003-1, and the expectation is that Transmission Owners will maintain their current state of compliance. Thus, the standard is effective for Transmission Owners upon approval, as detailed below.

The proposed changes to FAC-003-1 only address Generator Owner applicability and requirements (add Generator Owner to section 4.3 and add applicable Generator Owner to all requirements). Therefore, this implementation plan only identifies a compliance timeframe for Generator Owners to which this standard will apply.

To reach compliance with the standard, a Generator Owner will have to perform a full review of as-built drawings and determine which generation interconnection Facilities require a Transmission Vegetation Management Plan (TVMP) and inspection as specified by NERC Reliability Standard FAC-003-X. In general, Generator Owners do not have staff that are qualified and experienced to create a TVMP and implement annual plans for vegetation management. Once a complete inventory is created, the Generator Owner will begin the process of gathering information for the TVMP. In instances where the generation interconnection Facilities are owned by a partnership, a majority or operating partner will need to obtain partnership approval to proceed with procurement of a TVMP expert, and later a tree trimming crew. Typically, a request for proposal to hire TVMP consultant is initiated, which could take several weeks in order to obtain sufficient bids (and also satisfy Sarbanes Oxley requirements). Once all bids have been received, a

contract with a TVMP consultant is signed. At this point, the TVMP consultant and Generator Owner staff will develop the TVMP, which needs to take into account local growth conditions, types of vegetation and other aspects required by FAC-003-X. Once the TVMP is developed, Generator Owner staff and the TVMP consultant will need to perform a Right-of-Way inspection, usually done using GPS, LIDAR and other tools by experienced and qualified staff.

Once a Right-of-Way inspection is completed and clearances are required, the Generator Owner will need to issue a request for proposal to hire a tree trimming crew that is qualified and experienced to perform required clearance trimming. Once all bids have been received, a contract with a tree trimming crew is signed. When the tree trimming crew is acquired, the crew will need to familiarize themselves with the entity's TVMP and required clearances. The Generator Owner will typically need to schedule any required outages in order for the tree trimming crew to perform the needed clearance trimming. This action would also include the implementation of the work plan. During scheduled outages, if required, the tree trimming crew will perform any required clearances and document the activities.

Another typical action is the Generator Owner establishing a system for maintaining TVMP-related activities, including maintenance of inspection and clearance documentation. On an ongoing basis, in addition to performing inspections and clearances as required by the entity's TVMP, the Generator Owner will need to ensure that the training and qualification requirements for the standard are met. The entity will also need to maintain documentation of all FAC-003-X activities for compliance period of one year to meet compliance with the standard.

Again, due to a typical lack of experience and qualifications required by FAC-003-X, compliance with this standard by a Generator Owner may take as long as two years – in part because many entities will have generator interconnection Facilities in various parts of the country which may require several instances of TVMP and numerous Right-of-Way inspections.

Effective Date

There are three effective dates associated with this implementation plan:

The first effective date applies to Transmission Owners.

> In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner become effective upon Board of Trustees' adoption.

The second effective date allows Generator Owners time to prepare a formal transmission vegetation management program as outlined in Requirement R1.

> In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The third effective date allows entities time to comply with Requirements R2, R3, and R4.

> In those jurisdictions where regulatory approval is required, Requirements R2, R3, and R4 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R2, R3, and R4 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary. When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.

Right-of-Way (ROW)

A corridor of land on which electric lines may be located. The applicable Transmission Owner or applicable Generator Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

The current glossary definition of this NERC term was modified to include applicable Generator Owners.

FAC-003-2 is currently under development under Project 2007-07. The project is nearing its final stages, but the Project 2010-07 drafting team does not want to assume that the project will be approved by NERC's Board or Trustees (BOT) or FERC. Thus, the Project 2010-07 drafting team has develop two sets of proposed changes: one to this version, FAC-003-1, the current FERC-approved version of the standard, and one to FAC-003-2, the latest draft of Version 2 as proposed by the Project 2007-07 team

If FAC-003-2 is approved by NERC's BOT, the Project 2010-07 drafting team will likely proceed with the modifications it has proposed in the redline to that version of the standard. These changes would be submitted for stakeholder approval and balloted as FAC-003-3. FAC-003-2 would be retired once FAC-003-03 was approved.

If, however, FAC-003-2 remains under development, the Project 2010-07 drafting team will proceed with the changes to FAC-003-1 seen below to avoid further delay of its project goals. Changes to FAC-003-1 would address the addition of Generator Owners to the applicability section, modifications to the NERC defined terms Right-of-Way to include Generator Owners, and some formatting changes to bring the standard up to date. These changes would not be comprehensive; rather, they would aim to include the generator interconnection Facility in the standard with as few other changes as possible.

A. Introduction

1. **Title:** **Transmission Vegetation Management Program**

2. **Number:** FAC-003-~~1~~X

3. **Purpose:** To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation-related outages of the transmission systems to the respective Regional ~~Reliability Organizations (RRO~~Entity (RE) and the North American Electric Reliability Council (NERC).

Within the text of NERC Reliability Standard FAC-003-X, "transmission line(s)" and "applicable line(s)" can also refer to the generation Facilities as referenced in 4.4 and its subsections.

4. **Applicability:**

4.1. Regional Entity.

~~**4.1.**~~**4.2.** Applicable Transmission Owner~~.~~

~~**4.2.**Regional Reliability Organization.~~

4.2.1. ~~This standard shall apply to all~~Transmission Owner that owns overhead transmission lines operated at 200 kV and above and to any lower voltage lines designated by the ~~RRO~~RE as critical to the reliability of the electric system in the region.

4.3. Applicable Generator Owner

4.3.1. Generator Owner that owns an overhead transmission line(s) that extends greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard up to the point of interconnection with the a Transmission Owner's Facility and is operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.

5. Effective Dates:

~~**5.1.** One calendar year from the date of adoption by the NERC Board of Trustees for Requirements 1 and 2.~~

~~**5.2.** Sixty calendar days from the date of adoption by the NERC Board of Trustees for Requirements 3 and 4.~~

~~B. **Requirements**~~

~~The Transmission~~There are three effective dates associated with this implementation plan:

The first effective date applies to Transmission Owners.

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner become effective upon Board of Trustees' adoption.

The second effective date allows Generator Owners time to prepare a formal transmission vegetation management program as outlined in Requirement R1.

In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The third effective date allows entities time to comply with Requirements R2, R3, and R4.

In those jurisdictions where regulatory approval is required, Requirements R2, R3, and R4 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R2, R3, and R4 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

B. Requirements

R1. Each applicable Transmission Owner or applicable Generator Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the applicable Transmission Owner's or applicable Generator Owner's objectives, practices, approved procedures, and work specifications[1].

R1.1. The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the applicable Transmission Owner's or applicable Generator Owner's transmission lines.

R1.2. ~~The~~Each applicable Transmission Owner or applicable Generator Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the

[1] ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.

effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the applicable Transmission Owner or applicable Generator Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.

R1.2.1. Clearance 1 — The applicable Transmission Owner or applicable Generator Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the applicable Transmission Owner or applicable Generator Owner plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.

R1.2.2. Clearance 2 — The applicable Transmission Owner or applicable Generator Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These applicable Transmission Owner-specific or applicable Generator Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.

R1.2.2.1 Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.

R1.2.2.2 Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.

R1.3. All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner or Generator Owner, to perform their duties.

R1.4. Each applicable Transmission Owner or applicable Generator Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner or applicable Generator Owner is restricted from attaining the clearances specified in Requirement 1.2.1.

R1.5. Each Transmission Owner or applicable Generator Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action

(temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.

~~The~~*[VRF – High]*

R2. Each applicable Transmission Owner or applicable Generator Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each applicable Transmission Owner or applicable Generator Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.

~~The~~*[VRF – High]*

R3. Each applicable Transmission Owner or applicable Generator Owner shall report quarterly to its ~~RRO~~Regional Entity, or the ~~RRO's~~Regional Entity's designee, sustained transmission line outages determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation.

R3.1. Multiple sustained outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of outages within a 24-hour period.

R3.2. The applicable Transmission Owner or applicable Generator Owner is not required to report to the ~~RRO~~Regional Entity, or the ~~RRO's~~Regional Entity's designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).

R3.3. The outage information provided by the applicable Transmission Owner or applicable Generator Owner to the ~~RRO~~Regional Entity, or the ~~RRO's~~Regional Entity's designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

R3.4. An outage shall be categorized as one of the following:

R3.4.1. Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;

R3.4.2. Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;

R3.4.3. Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.

[VRF – Lower]

R4. The ~~RRO~~Regional Entity shall report the outage information provided to it by applicable Transmission ~~Owner's~~Owners or applicable Generator Owners, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the ~~RRO~~Regional Entity as a result of any of the reported outages.

[VRF – Lower]

C. Measures

M1. ~~The~~Each applicable Transmission Owner or applicable Generator Owner has a documented TVMP, as identified in Requirement 1.

M1.1. ~~The~~Each applicable Transmission Owner or applicable Generator Owner has documentation that the applicable Transmission Owner or applicable Generator Owner performed the vegetation inspections as identified in Requirement 1.1.

M1.2. ~~The~~Each applicable Transmission Owner or applicable Generator Owner has documentation that describes the clearances identified in Requirement 1.2.

M1.3. ~~The~~Each applicable Transmission Owner or applicable Generator Owner has documentation that the personnel directly involved in the design and implementation of the applicable Transmission Owner's or applicable Generator Owner TVMP hold the qualifications identified by the Transmission Owner or applicable Generator Owner as required in Requirement 1.3.

M1.4. ~~The~~Each applicable Transmission Owner or applicable Generator Owner has documentation that it has identified any areas not meeting the applicable Transmission Owner's or applicable Generator Owner's standard for vegetation management and any mitigating measures the Transmission Owner or applicable Generator Owner has taken to address these deficiencies as identified in Requirement 1.4.

M1.5. ~~The~~Each applicable Transmission Owner or applicable Generator Owner has a documented process for the immediate communication of imminent threats by vegetation as identified in Requirement 1.5.

M2. ~~The~~Each applicable Transmission Owner or applicable Generator Owner has documentation that the Transmission Owner implemented the work plan identified in Requirement 2.

M3. ~~The~~ Each applicable Transmission Owner or applicable Generator Owner has documentation that it has supplied quarterly outage reports to the ~~RRO~~Regional Entity, or the ~~RRO's~~Regional Entity's designee, as identified in Requirement 3.

M4. The ~~RRO~~Regional Entity has documentation that it provided quarterly outage reports to NERC as identified in Requirement 4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

~~RRO~~

~~NERC~~

Compliance Monitor:

- Regional Entity for the Transmission Owner and Generator Owner
- Electric Reliability Organization or another Regional Entity approved by the ERO and FERC or other applicable government authorities

1.2. Compliance Monitoring ~~Period~~ and ~~Reset~~Enforcement Processes:

~~One calendar Year~~

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3. Data Retention

~~Five Years~~

The applicable Transmission Owner and applicable Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The applicable Transmission Owner and applicable Generator Owner shall retain evidence of Requirement 1, Measure 1, Requirement 2, Measure 2, and Requirement 3, Measure 3 from its last audit.

1.4. Additional Compliance Information

~~The Transmission Owner shall demonstrate compliance through self-certification submitted to the compliance monitor (RRO) annually that it meets the requirements of NERC Reliability Standard FAC-003-1. The compliance monitor shall conduct an on-site audit every five years or more frequently as deemed appropriate by the compliance monitor to review documentation related to Reliability Standard FAC-003-1. Field audits of ROW vegetation conditions may be conducted if determined to be necessary by the compliance monitor.~~

None.

2. Violation Severity Levels ~~of Non-Compliance~~

~~**2.1.Level 1:**~~

~~**2.1.1.**The TVMP was incomplete in one of the requirements specified in any subpart of Requirement 1, or;~~

~~**2.1.2.**Documentation of the annual work plan, as specified in Requirement 2, was incomplete when presented to the Compliance Monitor during an on-site audit, or;~~

~~**2.1.3.**The RRO provided an outage report to NERC that was incomplete and did not contain the information required in Requirement 4.~~

~~**2.2.Level 2:**~~

~~**2.2.1.**The TVMP was incomplete in two of the requirements specified in any subpart of Requirement 1, or;~~

~~**2.2.2.**The Transmission Owner was unable to certify during its annual self-certification that it fully implemented its annual work plan, or documented deviations from, as specified in Requirement 2.~~

~~**2.2.3.**The Transmission Owner reported one Category 2 transmission vegetation-related outage in a calendar year.~~

~~**2.3.Level 3:**~~

~~**2.3.1.**The Transmission Owner reported one Category 1 or multiple Category 2 transmission vegetation-related outages in a calendar year, or;~~

~~**2.3.2.**The Transmission Owner did not maintain a set of clearances (Clearance 2), as defined in Requirement 1.2.2, to prevent flashover between vegetation and overhead ungrounded supply conductors, or;~~

~~**2.3.3.**The TVMP was incomplete in three of the requirements specified in any subpart of Requirement 1.~~

~~**2.4.Level 4:**~~

~~**2.4.1.**The Transmission Owner reported more than one Category 1 transmission vegetation-related outage in a calendar year, or;~~

~~**2.4.2.**The TVMP was incomplete in four or more of the requirements specified in any subpart of Requirement 1.~~

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity did not include and keep current one of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current two of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current three of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current all required elements of the TVMP, as directed by the requirement.
R1.1	N/A	N/A	The applicable entity TVMP did not define a schedule, as directed by the requirement, or the type of ROW vegetation inspections, as directed by the requirement.	The applicable entity TVMP did not define a schedule, as directed by the requirement, nor the type of ROW vegetation inspections, as directed by the requirement.
R1.2	N/A	N/A	N/A	The responsible entity, in its TVMP, failed to

				identify and document clearances between vegetation and any overhead, ungrounded supply conductors. OR The responsible entity, in its TVMP, failed to take into consideration transmission line voltage, or the effects of ambient temperature on conductor sag under maximum design loading, or the effects of wind velocities on conductor sway. OR The responsible entity, in its TVMP, failed to establish Clearance 1 or Clearance 2 values.
R1.2.1	N/A	N/A	N/A	The responsible entity failed to determine and document an appropriate clearance distance to be achieved at the time of transmission vegetation management work taking into account local conditions and the expected time frame in

				which the responsible entity expects to return for future vegetation management work. OR The responsible entity documented a Clearance 1 value that was smaller than its Clearance 2 value.
R1.2.2	N/A	N/A	N/A	The responsible entity failed to determine and document Clearance 2 values taking into account local conditions and the expected time frame in which the responsible entity expects to return for future vegetation management work.
R1.2.2.1	N/A	N/A	N/A	Where transmission system transient overvoltage factors were known, clearances were not derived from Table 5, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.
R1.2.2.2	N/A	N/A	N/A	Where transmission system transient overvoltage factors are known, clearances were not derived from Table 7, IEEE

				516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.
R1.3	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, one of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, 5% or less of those persons did not hold appropriate qualifications and training to perform their duties.	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, two of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 5% up to (and including) 10%of those persons did not hold appropriate qualifications and training to perform their duties.	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, three of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 10% up to (and including) 15%of those persons did not hold appropriate qualifications and training to perform their duties.	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, more than three of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 15% of those persons did not hold appropriate qualifications and training to perform their duties.
R1.4	N/A	N/A	N/A	The responsible entity's TVMP does not include mitigation measures to achieve sufficient clearances where restrictions to the ROW are in effect.
R1.5	N/A	N/A	N/A	The responsible entity did not establish or did not document a process for the immediate communication of vegetation conditions that present an

				imminent threat of line outage, as directed by the requirement.
R2	The responsible entity did not meet one of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	The responsible entity did not meet two of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	The responsible entity did not meet the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	The responsible entity does not have an annual plan for vegetation management. OR The responsible entity has not implemented the annual plan for vegetation management.
R3	The responsible entity failed to provide a quarterly outage report, but did not experience any reportable outages. OR The responsible entity provided a quarterly report, but failed to report in the manner specified by one or more of the following subcomponents of Requirement R3: R3.1 or R3.2.	The responsible entity provided a quarterly report, but failed to include information required by R3.3.	The responsible entity provided a quarterly outage report, but failed to include a reportable Category 3 outage as described in R3.4.3.	The responsible entity experienced reportable outages but failed to provide a quarterly report. OR The responsible entity provided a quarterly outage report, but failed to include a reportable Category 1 (as described in R3.4.1) or Category 2 outage (as described in R3.4.2).
R4	N/A	N/A	N/A	N/A

E. **Regional Differences**

None Identified.

Version History

Version	Date	Action	Change Tracking
1	TBA	1. Added "Standard Development Roadmap." 2. Changed "60" to "Sixty" in section A, 5.2. 3. Added "Proposed Effective Date: April 7, 2006" to footer. 4. Added "Draft 3: November 17, 2005" to footer.	01/20/06
X	May 16, 2011	Made standard applicable to certain qualifying Generator Owners and brought overall standard format up to date	Revision under Project 2010-07

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary. When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.

Right-of-Way (ROW)

The current glossary definition of this NERC term was modified to include applicable Generator Owners.

A corridor of land on which electric lines may be located. The applicable Transmission Owner or applicable Generator Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

FAC-003-2 is currently under development under Project 2007-07. The project is nearing its final stages, but the Project 2010-07 drafting team does not want to assume that the project will be approved by NERC's Board or Trustees (BOT) or FERC. Thus, the Project 2010-07 drafting team has develop two sets of proposed changes: one to this version, FAC-003-1, the current FERC-approved version of the standard, and one to FAC-003-2, the latest draft of Version 2 as proposed by the Project 2007-07 team

If FAC-003-2 is approved by NERC's BOT, the Project 2010-07 drafting team will likely proceed with the modifications it has proposed in the redline to that version of the standard. These changes would be submitted for stakeholder approval and balloted as FAC-003-3. FAC-003-2 would be retired once FAC-003-03 was approved.

If, however, FAC-003-2 remains under development, the Project 2010-07 drafting team will proceed with the changes to FAC-003-1 seen below to avoid further delay of its project goals. Changes to FAC-003-1 would address the addition of Generator Owners to the applicability section, modifications to the NERC defined terms Right-of-Way to include Generator Owners, and some formatting changes to bring the standard up to date. These changes would not be comprehensive; rather, they would aim to include the generator interconnection Facility in the standard with as few other changes as possible.

A. Introduction

1. Title: **Transmission Vegetation Management Program**

2. Number: FAC-003-X

3. Purpose: To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation-related outages of the transmission systems to the respective Regional Entity (RE) and the North American Electric Reliability Council (NERC).

Within the text of NERC Reliability Standard FAC-003-X, "transmission line(s)" and "applicable line(s)" can also refer to the generation Facilities as referenced in 4.4 and its subsections.

4. Applicability:

4.1. Regional Entity.

4.2. Applicable Transmission Owner

4.2.1. Transmission Owner that owns overhead transmission lines operated at 200 kV and above and to any lower voltage lines designated by the RE as critical to the reliability of the electric system in the region.

4.3. Applicable Generator Owner

4.3.1. Generator Owner that owns an overhead ~~Facility~~ transmission line(s) that extends greater than one ~~half~~ mile or 1.609 kilometers beyond the fenced area of the ~~switchyard, generating station or generating substation~~ generating station switchyard up to the point of interconnection with ~~the Transmission system~~a Transmission Owner's Facility and is operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.

5. Effective Dates:

There are three effective dates associated with this implementation plan:

The first effective date applies to Transmission Owners.

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner become effective upon Board of Trustees' adoption.

The second effective date allows Generator Owners time to prepare a formal transmission vegetation management program as outlined in Requirement R1.

In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The third effective date allows entities time to comply with Requirements R2, R3, and R4.

In those jurisdictions where regulatory approval is required, Requirements R2, R3, and R4 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R2, R3, and R4 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

B. Requirements

R1. Each applicable Transmission Owner or applicable Generator Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the applicable Transmission Owner's or applicable Generator Owner's objectives, practices, approved procedures, and work specifications[1].

R1.1. The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the applicable Transmission Owner's or applicable Generator Owner's transmission lines.

R1.2. Each applicable Transmission Owner or applicable Generator Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the applicable Transmission Owner or applicable Generator Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.

R1.2.1. Clearance 1 — The applicable Transmission Owner or applicable Generator Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon

[1] ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.

local conditions and the expected time frame in which the applicable Transmission Owner or applicable Generator Owner plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.

R1.2.2. Clearance 2 — The applicable Transmission Owner or applicable Generator Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These applicable Transmission Owner-specific or applicable Generator Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.

R1.2.2.1 Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.

R1.2.2.2 Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.

R1.3. All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner or Generator Owner, to perform their duties.

R1.4. Each applicable Transmission Owner or applicable Generator Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner or applicable Generator Owner is restricted from attaining the clearances specified in Requirement 1.2.1.

R1.5. Each Transmission Owner or applicable Generator Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.

[VRF – High]

R2. Each applicable Transmission Owner or applicable Generator Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into

consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each applicable Transmission Owner or applicable Generator Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.

[VRF – High]

R3. Each applicable Transmission Owner or applicable Generator Owner shall report quarterly to its Regional Entity, or the Regional Entity's designee, sustained transmission line outages determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation.

R3.1. Multiple sustained outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of outages within a 24-hour period.

R3.2. The applicable Transmission Owner or applicable Generator Owner is not required to report to the Regional Entity, or the Regional Entity's designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).

R3.3. The outage information provided by the applicable Transmission Owner or applicable Generator Owner to the Regional Entity, or the Regional Entity's designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

R3.4. An outage shall be categorized as one of the following:

R3.4.1. Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;

R3.4.2. Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;

R3.4.3. Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.

[VRF – Lower]

R4. The Regional Entity shall report the outage information provided to it by applicable Transmission Owners or applicable Generator Owners, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported outages.

[VRF – Lower]

C. Measures

M1. Each applicable Transmission Owner or applicable Generator Owner has a documented TVMP, as identified in Requirement 1.

M1.1. Each applicable Transmission Owner or applicable Generator Owner has documentation that the applicable Transmission Owner or applicable Generator Owner performed the vegetation inspections as identified in Requirement 1.1.

M1.2. Each applicable Transmission Owner or applicable Generator Owner has documentation that describes the clearances identified in Requirement 1.2.

M1.3. Each applicable Transmission Owner or applicable Generator Owner has documentation that the personnel directly involved in the design and implementation of the applicable Transmission Owner's or applicable Generator Owner TVMP hold the qualifications identified by the Transmission Owner or applicable Generator Owner as required in Requirement 1.3.

M1.4. Each applicable Transmission Owner or applicable Generator Owner has documentation that it has identified any areas not meeting the applicable Transmission Owner's or applicable Generator Owner's standard for vegetation management and any mitigating measures the Transmission Owner or applicable Generator Owner has taken to address these deficiencies as identified in Requirement 1.4.

M1.5. Each applicable Transmission Owner or applicable Generator Owner has a documented process for the immediate communication of imminent threats by vegetation as identified in Requirement 1.5.

M2. Each applicable Transmission Owner or applicable Generator Owner has documentation that the Transmission Owner implemented the work plan identified in Requirement 2.

M3. Each applicable Transmission Owner or applicable Generator Owner has documentation that it has supplied quarterly outage reports to the Regional Entity, or the Regional Entity's designee, as identified in Requirement 3.

M4. The Regional Entity has documentation that it provided quarterly outage reports to NERC as identified in Requirement 4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Compliance Monitor:

- Regional Entity for the Transmission Owner and Generator Owner
- Electric Reliability Organization or another Regional Entity ~~for the Regional Entity~~approved by the ERO and FERC or other applicable government authorities

1.2. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3. Data Retention

The applicable Transmission Owner and applicable Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The applicable Transmission Owner and applicable Generator Owner shall retain evidence of Requirement 1, Measure 1, Requirement 2, Measure 2, and Requirement 3, Measure 3 from its last audit.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity did not include and keep current one of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current two of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current three of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current all required elements of the TVMP, as directed by the requirement.
R1.1	N/A	N/A	The applicable entity TVMP did not define a schedule, as directed by the requirement, or the type of ROW vegetation inspections, as directed by the requirement.	The applicable entity TVMP did not define a schedule, as directed by the requirement, nor the type of ROW vegetation inspections, as directed by the requirement.
R1.2	N/A	N/A	N/A	The responsible entity, in its TVMP, failed to identify and document clearances between vegetation and any overhead, ungrounded supply conductors. OR The responsible

				entity, in its TVMP, failed to take into consideration transmission line voltage, or the effects of ambient temperature on conductor sag under maximum design loading, or the effects of wind velocities on conductor sway. OR The responsible entity, in its TVMP, failed to establish Clearance 1 or Clearance 2 values.
R1.2.1	N/A	N/A	N/A	The responsible entity failed to determine and document an appropriate clearance distance to be achieved at the time of transmission vegetation management work taking into account local conditions and the expected time frame in which the responsible entity expects to return for future vegetation management work. OR The responsible entity documented a Clearance 1 value that was

				smaller than its Clearance 2 value.
R1.2.2	N/A	N/A	N/A	The responsible entity failed to determine and document Clearance 2 values taking into account local conditions and the expected time frame in which the responsible entity expects to return for future vegetation management work.
R1.2.2.1	N/A	N/A	N/A	Where transmission system transient overvoltage factors were known, clearances were not derived from Table 5, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.
R1.2.2.2	N/A	N/A	N/A	Where transmission system transient overvoltage factors are known, clearances were not derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.
R1.3	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, one of those persons did not hold	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, two of those persons did not hold	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, three of those persons did not hold	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, more than three of those persons did not

	appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, 5% or less of those persons did not hold appropriate qualifications and training to perform their duties.	appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 5% up to (and including) 10%of those persons did not hold appropriate qualifications and training to perform their duties.	appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 10% up to (and including) 15%of those persons did not hold appropriate qualifications and training to perform their duties.	hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 15% of those persons did not hold appropriate qualifications and training to perform their duties.
R1.4	N/A	N/A	N/A	The responsible entity's TVMP does not include mitigation measures to achieve sufficient clearances where restrictions to the ROW are in effect.
R1.5	N/A	N/A	N/A	The responsible entity did not establish or did not document a process for the immediate communication of vegetation conditions that present an imminent threat of line outage, as directed by the requirement.
R2	The responsible entity did not meet one of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining	The responsible entity did not meet two of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining	The responsible entity did not meet the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining	The responsible entity does not have an annual plan for vegetation management. OR The responsible entity has not implemented the

	documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	annual plan for vegetation management.
R3	The responsible entity failed to provide a quarterly outage report, but did not experience any reportable outages. OR The responsible entity provided a quarterly report, but failed to report in the manner specified by one or more of the following subcomponents of Requirement R3: R3.1 or R3.2.	The responsible entity provided a quarterly report, but failed to include information required by R3.3.	The responsible entity provided a quarterly outage report, but failed to include a reportable Category 3 outage as described in R3.4.3.	The responsible entity experienced reportable outages but failed to provide a quarterly report. OR The responsible entity provided a quarterly outage report, but failed to include a reportable Category 1 (as described in R3.4.1) or Category 2 outage (as described in R3.4.2).
R4	N/A	N/A	N/A	N/A

E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
1	TBA	1. Added "Standard Development Roadmap." 2. Changed "60" to "Sixty" in section A, 5.2. 3. Added "Proposed Effective Date: April 7, 2006" to footer.	01/20/06

		4. Added "Draft 3: November 17, 2005" to footer.	
X	May 16, 2011	~~Added~~ Made standard applicable to certain qualifying ~~requirements for~~ Generator Owners and brought overall standard format up to date	Revision under Project 2010-07

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan for PRC-004-2.1— Analyis of Transmission and Generation Protection System Misoperations

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

Revision to Sections of Approved Standards and Definitions

There are no proposed revisions to requirements in other already approved standards. PRC-004-2 will be retired when PRC-004-2.1 becomes effective.

Compliance with Standard

The proposed change to Requirement R2 is a clarifying change. While there was no reliability gap in the previous version of the standard, if applied literally, there was the possibility for the misperception that the Generator Owner was only responsible for analyzing its generator Protection System Misoperations, exclusive of its generator interconnection Facility. The errata change to R2 makes clear that generator interconnection Facilities are also part of Generator Owners' responsibility in the context of this standard.

Because the change is merely a clarifying change, no additional time for compliance is needed.

Effective Date

In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustees' adoption.

Standard PRC-004-2.1 – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

A. Introduction

1. **Title:** Analysis and Mitigation of Transmission and Generation Protection System Misoperations

2. **Number:** PRC-004-2.1

3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.

4. **Applicability**

   4.1. Transmission Owner.

   4.2. Distribution Provider that owns a transmission Protection System.

   4.3. Generator Owner.

5. **(Proposed) Effective Date:** In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustees' adoption.

   ~~The first day of the first calendar quarter, one year after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year after Board of Trustees' adoption.~~

B. Requirements

R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

R2. The Generator Owner shall analyze its generator and generator interconnection Facility Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.

C. Measures

M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Entity's procedures.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

The Compliance Monitor shall retain any audit data for three years.

1.5. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Violation Severity Levels (no changes)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
2	TBD	Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised.
3	XX	Errata change: Edited R2 to add “…and	Revision under Project

		generator interconnection Facility…"	2010-07

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance Application Notice — 0010

~~Compliance Application:~~ Definition of "Annual" and Implementation of Annual Requirements

Posted: April 19, 2011
Revised: ~~August~~Month XX, 2011

Primary Interest Groups
~~ERO Auditors, Investigators and~~ Compliance Enforcement Authority (~~Auditors~~CEA)[1]
NERC
Regional ~~Entities~~Entity
Registered Entities subject to ~~Reliability~~ reliability ~~Standards~~ standards containing a requirement to repeat some performance on an annual basis (annual requirement)

Issue: What is the~~The~~ definition of "annual," and how do registered entities implement that definition ~~implementation of annual requirements~~?
~~NERC received a request for clarification of the definition of the term "annual" and guidance regarding the implementation of annual requirements.~~This CAN provides instruction to ~~Auditors~~CEAs on how to assess compliance when a standard requires an "annual" activity.

~~**Reliability Objective**To maintain reliability through the consistent application of the annual requirements contained in NERC Reliability Standards. The intent of most annual requirements is to ensure that entities perform a particular task on a regular basis, with an established maximum interval between the occasions when the task is performed. Intervals that are too long degrade the value of the activity in protecting reliability.~~**Background**
Without clear guidance, registered entities determined their own definition of the term "annual," which is contained in a multitude of standards, without certainty that the definition or implementation of the requirements established compliance with the applicable ~~Reliability~~ reliability ~~Standards~~standards. The intent of most annual requirements is to ensure that entities perform a particular task on a regular basis, with an established maximum interval between the occasions when the task is performed. Intervals that are too long ~~degrade~~affect the ability of the ~~the value of the~~ activity ~~in~~to protect~~ing~~ reliability.

Compliance Application

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard requirements.~~This includes any person authorized to determine a Possible Violation of NERC Reliability Standard requirements.~~

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DRAFT

NERC has established clarity for the term "annual," as well as parameters for ~~Auditors~~CEAs to assess compliance regarding the implementation of a registered entity's definition of an annual requirement. The registered entity's definition ~~will~~ may apply to standards that require an annual action or event, unless a standard contains a definition. In cases where the standard contains a definition of the term "annual" or "annually," that definition remains and is applicable to that standard. In cases where the standard specifies how annual requirements are implemented, that language remains and is applicable to that standard. This CAN does not supersede or change any language contained in a standard.

In all standards where the term "annual" is not defined, ~~Auditors~~CEAs are to determine if the registered entity ~~may determine~~established its own definition of annual within the parameters provided below. ~~Auditors~~CEAs are instructed to look for a reg~~ional~~istered entity's ~~must~~ documented definition of annual ~~in order to provide that definition~~ as the basis for determining compliance. ~~Auditors~~ CEAs are to verify whether a registered entity documented either ~~may document~~ one definition of annual across all standards that do not specify how an annual requirement is implemented, or ~~a registered entity may document~~ a definition for each individual standard.

~~Auditors~~CEAs are to verify that a registered entity defined "annual" pursuant to the guidelines below: ~~A registered entity may define "annual" as:~~

a) ~~Annual - w~~Within a calendar year, with the calendar year beginning on January 1 and ending on December 31 (Calendar Year).

In this option, ~~Auditors~~CEAs are to verify that the activity or event ~~must be~~is conducted at least once ~~in~~ every Calendar Year. A best practice is that the activities or events should not be too far apart. For example, a registered entity's documentation may state that there should be no more than 15 months between the events required by the standard. ~~Auditors~~CEAs are instructed not to find a Possible Violation if a registered entity has not instituted this best practice, but this may invoke questions about a registered entity's culture of compliance.

Or:~~While including these parameters is not required, it is a best practice that demonstrates a concern for reliability.~~

b) Rolling 12 months – the activity or event ~~must~~ is~~have been~~ conducted at least once within the last 12-month period.

Or:

c) CEAs ~~are to allow for~~ should verify whether ~~Registered~~ registered entities ~~may to~~ have documented another definition of "annual"[2] along with~~and~~ procedures that define ~~its~~ their implementation of annual requirements ~~that differ from the options contained in this CAN~~. However, ~~Auditors~~CEAs are to verify that any alternative documented method

[2] For example, a registered entity may define "annual" as "at least once within the last 12-month period" and may include a grace period of two months. In this situation, the activity or event ~~must~~ is still to be conducted at least once ~~in~~ every Calendar Year.

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~~must~~ demonstrates that the required activity was conducted at least once ~~in~~ every Calendar Year.

Regardless of the registered entity's documented definition of annual, ~~it~~ that definition will not supersede any requirement stated in the standard.

This definition of annual will be in effect throughout the ERO, will supersede any prior definition and is in effect until the term "annual" is defined in each standard.

Effective Period for CAN

This revised CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance from April 19, 2011, regardless of the start date of the violation. It will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

For any enforcement action in process and for audits that have been initiated,[3] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.

Evidence of Compliance ~~Guidance~~

~~Auditors~~CEAs are to assess compliance based on an entity's implementation of one of the below situations:

- ~~An auditor~~A CEA is instructed not to find noncompliance or a possible violation if a registered entity is following its own documented definition of annual[4] and its own documented implementation plan for annual requirements~~, a registered entity will be determined to be compliant in regard to the annual requirement of a standard~~.
- ~~An auditor~~A CEA is instructed to look for evidence that a registered entity has and adheres to its own documented definition of annual and its own documented implementation plan for annual requirements~~ but is not adhering to either~~. If an entity does not adhere to its definition, ~~an Auditor~~a CEA is instructed to find the registered entity ~~will be found~~ non-compliant, ~~*with the annual requirement of the standard at issue, unless the entity is conducting the required activity*~~*unless* ~~or~~ the entity conducts the annual activity ~~event~~ at least once ~~in~~ every Calendar Year.
- If a registered entity does not have a documented definition of annual and its own documented implementation plan for annual requirements, ~~an Auditor~~a CEA is to assess the entity's compliance ~~will be determined~~ based upon ~~option~~ Option ~~(a~~A~~)~~ contained ~~herein~~above~~, which is that~~: that the activity or event ~~must have been~~is conducted at least once ~~within~~ each Calendar Year.

[3] "Initiated" means that a registered entity has received notification of the upcoming audit.

[4] Provided that, as indicated above, ~~The~~ the registered entity's definition of annual ~~must is to provide for~~causes the activity or event to occur at least once ~~in~~ every Calendar Year.

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Revision History

Posted Date	Action	Revision
April 19. 2011	Posted Final CAN	
~~August~~Month XX, 2011	Posted Revised CAN	Revised target audience to CEA

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance Application Notice — 0011

~~Compliance Application:~~ PRC-005-1 R2 New Equipment

Posted: April 19, 2011
Revised: ~~August~~Month XX, 2011

Primary Interest Groups
~~ERO Auditors, Investigators and~~ Compliance Enforcement ~~Authorities~~ Authority (~~Auditors~~CEA)[1]
NERC
Regional ~~Entities~~Entity
Transmission Owner~~s~~ (TO)
Generator Owner~~s~~ (GO)
Distribution Provider~~s~~ (DP) that owns a transmission Protection System

Issue: Should CEAs review ~~Does PRC-005 require~~ evidence of the pre-operational testing[2] of a registered entity's protective system equipment in connection with PRC-005 issues?
For the purpose of aiding ~~an Auditor~~a CEA, this CAN provides instruction for assessing whether **new** ~~all transmission and generation~~ Protection System equipment~~s~~ affecting the reliability of the Bulk ~~Electric~~ Power System (BP~~E~~S) ~~have~~ has been maintained and tested within the intervals defined in a registered entity's program.

Compliance Application
In order to determine compliance with PRC-005-1 R2, ~~Auditors~~ CEAs are instructed to look for evidence that substantiates the last date a registered entity tested and maintained its Protection System[3] devices.

PRC-005-1 R2 ~~requires~~provides, in pertinent part:

> ***R2.*** *Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization[4] on request (within 30 calendar days). The documentation of the program implementation shall include:*

---

[1] ~~This includes any person authorized to determine a Possible Violation of NERC Reliability Standard requirements~~ Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard requirements.
[2] The "pre-operational test" means the last testing a registered entity conducts on the Protection System device before the device is put into service.
[3] The *NERC Glossary of Terms Used in Reliability Standards* defines Protection System as "Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry."

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DRAFT

R2.1. *Evidence Protection System devices were maintained and tested within the defined intervals.*

R2.2. *Date each Protection System device was last tested/maintained.*

Without evidence demonstrating that new equipment was tested and was in appropriate condition to enter into service (the start date), ~~an auditor~~a CEA cannot assess ~~the date~~when the registered entity's ~~used as a starting point to determine when its first~~ maintenance or testing must occur.

As soon as the entity conducts its pre-operational testing,[5] ~~and puts the protective scheme into service,~~[6] the interval ~~has begun~~begins for its maintenance and testing program.[7] The completion of the pre-operational testing is the point in time that the registered entity is aware of the operating condition of the equipment and thus is the date that should be used as the start~~ing point~~ date for the equipment's maintenance and testing interval. As pre-operational testing may occur over a period of time, the CEA should verify ~~registered entity should use~~ the date that the pre-operational testing was completed for the equipment at issue.

The next maintenance and testing date to be verified by the CEA would be at some specific period of time ~~in the future from that~~after the start date, as defined by the registered entity's maintenance and testing program.

Effective Period for CAN

This revised CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance from April 19, 2011, regardless of the start date of the violation. It will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

For any enforcement action in process and for audits that have been initiated,[8] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.
~~This CAN is effective upon posting as final on the NERC Web site, and is to be used by CEAs to apply compliance for any Possible Violations discovered from the posting date forward, regardless of the date of the violation. It supersedes all prior communications and will remain in effect until a future CAN~~

[4] For this standard, the Regional Reliability Organization refers to the Regional Entity.
[5] Pre-operational testing may also be referred to as "commissioning tests."
[6] ~~The registered entity's Protection System maintenance and testing program is only applicable for Protection System devices in service; however the date the equipment was placed in-service is not the date that should be used for the starting point of the maintenance and testing interval, unless the equipment was placed into service on the same date the pre-operational testing was completed.~~
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[8] "Initiated" means that a registered entity has received notification of the upcoming audit.

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Evidence of Compliance ~~Guidance~~

To determine evidence of the start~~ing~~ ~~point~~ date for a registered entity's equipment's maintenance and testing interval, ~~an Auditor~~a CEA is instructed to look for:

1. the date the registered entity completed its equipment's pre-operational testing, and
2. evidence that the equipment was deemed operational and cleared for entry into service.

In the event that a registered entity has equipment that changes status such that it becomes subject to the standard (such as a radial line becoming a non-radial line), ~~an Auditor~~a CEA is instructed to look for either:

1. the date existing Protection System devices were last maintained or tested, or
2. the date new Protection System devices completed pre-operational testing

as the start date for determining the equipment's maintenance and testing interval under the registered entity's maintenance and testing program.

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance Application Notice — 0011

~~Compliance Application:~~ PRC-005-1 R2 New Equipment

Posted: April 19, 2011
Revised: ~~August~~Month XX, 2011

Primary Interest Groups
~~ERO Auditors, Investigators and~~ Compliance Enforcement ~~Authorities~~ Authority (~~Auditors~~CEA)[1]
NERC
Regional ~~Entities~~Entity
Transmission Owner~~s~~ (TO)
Generator Owner~~s~~ (GO)
Distribution Provider~~s~~ (DP) that owns a transmission Protection System

Issue: Should CEAs review ~~Does PRC-005 require~~ evidence of the pre-operational testing[2] of a registered entity's protective system equipment in connection with PRC-005 issues?
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Compliance Application
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PRC-005-1 R2 ~~requires~~provides, in pertinent part:

> ***R2.*** *Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization[4] on request (within 30 calendar days). The documentation of the program implementation shall include:*

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Revision History

Posted Date	Action	Revision
April 19, 2011	Posted Final CAN	
~~August~~Month XX, 2011	Posted Revised CAN	Revised target audience to CEA

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance Application Notice — 0013

PRC-023~~-1~~ R1 and R2 Effective Dates for Switch-On-To-Fault Schemes

Posted: June 17, 2011
Revised: ~~August~~Month XX, 2011

Primary Interest Groups
Compliance Enforcement Authorit~~ies~~y (CEA)[1]
NERC
Regional ~~Entities~~Entity
Transmission Owners (TO), Generation Owners (GO), Distribution Providers (DP) and Planning Coordinators (PC) with load-responsive phase protection systems subject to NERC Reliability Standard PRC-023~~-1~~[2]

Issue: What are the Effective Dates for ~~Switch~~switch-~~On~~on-~~To~~to-~~Fault~~ fault (SOTF) ~~Schemes~~schemes?
For the purpose of aiding a CEA, this CAN clarifies the ~~effective~~ Effective ~~dates~~ Dates for ~~switch-on-to-fault~~SOTF schemes included on 1) transmission lines operated at 200 kV and above, and 2) transformers with low voltage terminals connected at 200 kV and above, under PRC-023~~-1~~ Requirement (R) 1 and R2.

Background
Points 5.1.1 and 5.1.2 of the introduction to the standard set forth the effective dates for equipment applicable to R1 and R2. The language reads:

> ***5.1.1*** *For circuits described in 4.1.1[3] and 4.1.3[4] above (except for switch-on-to-fault schemes) — the beginning of the first calendar quarter following applicable regulatory approvals.*
>
> ***5.1.2*** *For circuits described in 4.1.2[5] and 4.1.4[6] above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter 39 months following applicable regulatory approvals.*

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[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard requirements.

[2] ~~PRC-023-1 was approved by the Federal Energy Regulatory Commission in Order No. 733, which was effective on May 17, 2010. *See* Transmission Relay Loadability Reliability Standard, Order No. 733, 130 FERC ¶ 61,221 (2010).~~

[3] Transmission lines operated at 200 kV and above.

[4] Transformers with low voltage terminals connected at 200 kV and above.

[5] Transmission lines operated at 100 kV to 200 kV as designated by the PC as critical to the reliability of the Bulk Power System (BPS).

[6] Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the PC as critical to the reliability of the BPS.

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The ~~standard~~ Standard ~~drafting~~ Drafting ~~team~~ Team included a parenthetical in PRC-023~~-1~~ R5.1.2 to address comments from industry participants that "[t]he schedule for ~~Switch~~switch-~~On~~on-~~To~~to-~~Fault~~ fault (SOTF) protections applied on elements 200 kV and above is the same as the Beyond Zone 3 schedule for the phase protections referenced in section A.4.1.2 and A.4.1.4 applied on elements 100 kV to 200 kV. The Effective Date for the ~~Standard~~ standard should be modified to include all SOTF protections in the Effective Date in Section A.5.1.2."

Compliance Application

The ~~effective~~ Effective ~~date~~ Date for ~~switch-on-to-fault~~SOTF schemes included on- 1) transmission lines operated at 200 kV and above, and 2) transformers with low voltage terminals connected at 200 kV and above, is the beginning of the first calendar quarter 39 months following applicable regulatory approvals. CEAs are to assess compliance as of the applicable ~~effective~~ Effective ~~date~~Date.

To summarize, the ~~effective~~ Effective ~~dates~~ Dates corresponding to the applicable equipment under points 5.1.1 and 5.1.2 of the introduction to PRC-023~~-1~~ are as follows:

Equipment	Effective Date	US Effective Date
Transmission lines operated at 200 kV and above (except ~~switch-on-to-fault~~SOTF schemes)	the beginning of the first calendar quarter following applicable regulatory approvals	July 1, 2010
Transformers with low voltage terminals connected at 200 kV and above (except ~~switch-on-to-fault~~SOTF schemes)		
Transmission lines operated at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.	the beginning of the first calendar quarter 39 months following applicable regulatory approvals	October 1, 2013
Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System		
~~Switch-on-to-fault~~SOTF schemes on all applicable facilities specified in the applicability sections A.4.1.1 – A.4.1.4~~.~~		

Effective Period of CAN

This revised CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance from June 17, 2011, regardless of the start date of the violation. It will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

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This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.
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Revision History

[7] "Initiated" means that a registered entity has received notification of the upcoming audit.
~~[8] "Initiated" means that a registered entity has received notification of the upcoming audit.~~

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Posted Date	Action	Revision
June 17, 2011	Posted Final CAN	
~~August~~Month XX, 2011	Posted Revised CAN	Revised target audience to CEA

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Compliance Application Notice — 0015

Unavailability of NERC Software Tools

Posted: July 19, 2011

~~Reposted~~Revised: ~~August~~Month XX, 2011

Primary Interest Groups
Compliance Enforcement Authority (CEA)[1]
NERC
Regional ~~Entities~~ Entity ~~(RE)~~
Registered entities using a NERC Software Tool to fulfill a NERC Reliability Standard requirement(s)
~~ERO Auditors, Investigators and Compliance Enforcement Authorities (Auditors)~~[2]

Issue: What are the ~~P~~performance obligations for a registered entity when a NERC Software Tool[3] is unavailable?
For the purpose of aiding ~~an auditor~~a CEA, this CAN provides instruction for assessing ~~whether~~a registered entit~~ies~~y's ~~have~~ ~~NERC received a request to clarify a registered entity's~~ performance obligations ~~that require the use of NERC Software Tools and what types of acceptable alternative evidence an Auditor is to verify~~ when a NERC Software Tool ~~has been~~is~~was~~ unavailable.

~~**Reliability Objective**~~
~~To foster compliance with the NERC Reliability Standards through clear communication of performance obligations~~

Background

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard requirements.
[2] ~~This includes any person authorized to determine a Possible Violation of NERC Reliability Standard requirements.~~
[3] A NERC Software Tool is a NERC software application, which includes but is not limited to, applications such as the Reliability Coordinator Information System, the NERC Interchange Distribution Calculator (IDC) tool, NERCnet or applicable NERC web pages.

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~~Auditors~~A CEA ~~are~~is to verify that registered entities ~~may are~~be using -NERC Software Tools~~s~~ to perform tasks as required by the NERC Reliability Standards. There are three situations under which this may be ~~occurring~~required:

1. A NERC Reliability Standard requires the use of a NERC Software Tool; however, there are other means available to accomplish the requirements.

   For example: EOP-002-2.1 Attachment 1 requires the use of the Reliability Coordinator Information System (RCIS); IRO-006-4.1 Attachment 1 requires posting information on applicable NERC web pages and requires the use of the RCIS.

2. A NERC Reliability Standard does not require the use of a NERC Software Tool (*i.e.*, does not name a NERC Software Tool), but a NERC Software Tool is the only way to accomplish the requirement.

   For example: EOP-005-1 R11.3 requires affected Balancing Authorities to immediately review the Interchange Schedules. ~~Auditors~~CEAs in the Eastern Interconnection should be aware that the NERC IDC Tool is the only tool available for registered entities to accomplish this requirement.

3. A NERC Reliability Standard does not require the use of a NERC Software Tool (*i.e.*, does not name a NERC Software Tool) and there are other means available to accomplish the requirements. Nevertheless, some registered entities may be relying upon a NERC Software Tool to accomplish a NERC Reliability Standard's requirements.

   For example: IRO-002-2 R4, R5 and R6, and IRO-003-2 R1 and R2 are Reliability Standard Requirements that do not specify a tool; however, registered entities may rely upon NERC Inter-~~regional~~ Regional Security Network (NERC ISN), aka NERCnet, to accomplish the requirements.

Compliance Application

NERC is addressing this issue as directed by FERC in Order No. 693[4] through the Standards Development Process in Project 2009-02: Real-~~time~~ Time Reliability Monitoring and Analysis Capabilities. As stated in the Standard Authorization Request (SAR) Form:

> *The scope of the SAR is to establish requirements for the monitoring and analysis capabilities provided to System Operators and used to support Real-T~~t~~ime System Operations. The SAR addresses availability parameters, performance metrics, and procedures for failure notification,*

[4] "… the Commission clarifies that the Commission's intent is to have the ERO develop a requirement that identifies capabilities, not actual tools or products." *Mandatory Reliability Standards for the Bulk -Power System*, FERC Stats. & Regs. ¶ 31,242 at P 906 (2007) (Order No. 693), *reh'g denied*, 120 FERC ¶ 61,053 (2007) (Order No. 693-A). *See also* Order No. 693 at P 1660 "We adopt our proposal to require the ERO to develop a modification related to the provision of a minimum set of analytical tools. In response to LPPC and others, we note that our intent was not to identify specific sets of tools, but rather the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System. In response to APPA that the inclusion of specific analytical tools is counterproductive because the tools will become obsolete, we note that we are not seeking specific analytical tools, but rather minimum capabilities."

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maintenance coordination, and change management. The intent is to describe 'what' needs to be done but not 'how' to do it.

Project 2009-02 is in progress to resolve language in standards that require the use of NERC Software Tools; however, until such time that a revised standard would change the below ~~guidance~~compliance monitoring instructions, ~~Auditors~~a CEA is ~~are~~ to consider the following ~~will be considered in the determination of a violation~~~~evidence~~for assessing compliance:[5]

1. **During the time that a NERC Software Tool is not available and a NERC Reliability Standard:**
   a. **requires the use of a NERC Software Tool and**
   b. **other means of accomplishing the requirements are available**

   A~~n Auditor~~CEA is to verify that a registered entity ~~would be required to~~ used an ~~back-up tool or~~ alternate method[6] or back-up tool ~~of~~for accomplishing the ~~requirements~~[7] ~~in order to be compliant with the standard at issue~~requirements.

   ~~An Auditor is to verify that the registered entity is always expected to have a~~has a ~~back-up tool or alternate method of accomplishing a standard's requirements, to be prepared for situations where its primary tool is unavailable (regardless if it is a NERC Software Tool or not).~~

2. **During the time a NERC Software Tool is not available and a NERC Reliability Standard:**
   a. **does not require the use of a NERC Software Tool, but**
   b. **a NERC Software Tool is the only way to accomplish the requirement**

   In this situation, a~~An~~ CEA is not to ~~Auditor shall not~~ verify whether a registered entity ~~would not be required to have a back-up tool~~has an ~~or~~ alternate method or back-up tool ~~to accomplish the requirements because t~~~~when t~~~~here is not an available alternative~~. However, a ~~Auditors~~CEA ~~are~~is to verify evidence that the registered entity took necessary actions to act in the best interest of the ~~Interconnection~~ interconnection at all times[8] and accomplished the requirements of the ~~Standard~~ standard at issue.

3. **Where a NERC Software Tool is not available and a NERC Reliability Standard:**
   a. **does not require the use of a NERC Software Tool by naming a NERC Software Tool, however**
   b. **a registered entity relies upon a NERC Software Tool, although there are other tools available**

[5] Future revisions to any standard resulting from Project 2009-02 may or may not include a change to CAN-0015~~this Compliance Application Notice~~.
[6] CEAs are to look for alternate methods that may include basic processes such as email notifications or phone records that indicate the entity called the applicable party with the required information.
[7] ~~Auditors are to look for alternate methods that may include basic processes such as email notifications or phone records that indicate the entity called the applicable party with the required information.~~
[8] *See* NERC Reliability Standard IRO-005-2 R16 for specific applicability to Reliability Coordinators.

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A CEA is to verify that a registered entity used an alternate method[9] or back-up tool for accomplishing the requirements.

~~An Auditor is to verify that registered entity would be required to have a back-up tool or alternate method of accomplishing the requirements is implemented by the registered entity in order to be compliant with the Standard at issue.~~

~~As stated in scenario #1, a registered entity is always expected to have a back-up tool or alternate method of accomplishing a Standard's requirements, where one is available, for situations where its primary software tool is unavailable (regardless if it is a NERC Software Tool or not).~~

Effective Period for CAN

This revised CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance from July 19, 2011, regardless of the start date of the violation. It will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

For any enforcement action in process and for audits that have been initiated,[10] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.
~~This CAN is effective upon posting as final on the NERC Web site, and is to be used by Auditors to apply compliance for any Possible Violations discovered from the posting date forward, regardless of the date of the violation. It supersedes all prior communications and will remain in effect until a future CAN supersedes it or until such time that a future version of the standard or interpretation addresses this specific issue and is enforceable, or until it is superseded by a future CAN that addresses this particular Standard and Requirement.~~

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[9] CEAs are to look for alternate methods that may include basic processes such as email notifications or phone records that indicate the entity called the applicable party with the required information.
[10] "Initiated" means that a registered entity has received notification of the upcoming audit.

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Revision History

Posted Date	Action	Revision
July 19, 2011	Posted Final CAN	
Month XX, 2011	Posted Revised CAN	Revised target audience to CEAs

~~*This document is designed to convey compliance guidance from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this compliance application notice is not a substitute for compliance with requirements in NERC's Reliability Standards.*~~

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Compliance Application Notice — 0022

~~Compliance Application:~~ VAR-002-1.1b R1 and R3 Generator Operation in Manual Mode

Posted: June 17, 2011
Revised: Month XX, 2011

Primary Interest Groups
Compliance Enforcement Authority (CEA)[1]
NERC
Regional ~~Entities~~ Entity ~~(RE)~~
Generator Operator~~s~~ (GOP)
Generator Owner~~s~~ (GO)

Issue: ~~Generator Operation in Manual Mode~~
~~NERC received requests for clarification regarding whether a~~May generators ~~may~~ be operated in manual mode during start-up?
For the purpose of aiding a CEA, this CAN provides guidance regarding the start-up of generators in manual mode
~~Reliability Objective~~
~~The reliability objective is to ensure generators provide the reactive and voltage control necessary~~ to ensure that voltage levels, reactive flows and reactive resources are maintained within applicable Facility Ratings ~~to protect equipment and the reliable operation of the Interconnection~~.

~~Background~~
~~The standard requires that each generator connected to the interconnected transmission system be operated in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage).~~

Compliance Application
VAR-002-1.1b R1 and VAR-001-1[2] R4 provide direction on operating in automatic voltage control mode:

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard and requirements.
[2] VAR-001-2 was approved by the NERC Board of Trustees on October 5, 2010. It was approved by FERC on January 10, 2011 and will become effective on October 1, 2011. There were no changes to R4 in version 2.
~~[2] VAR-001-2 was approved by the NERC Board of Trustees on October 5, 2010. It was approved by FERC on January 10, 2011 and will become effective on October 1, 2011. There were no changes to R4 in version 2.~~

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VAR-002-1.1b R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.

VAR-001-1 R4. …The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and ***direct the Generator Operator to comply with the schedule in automatic voltage control mode*** *(AVR in service and controlling voltage). [Emphasis added]*

CEAs are instructed to ~~determine~~verify ~~whether~~that ~~Therefore, while~~ a registered entity ~~has been directed to, and is expected to,~~ operated its generators in automatic voltage control mode unless the registered entity ***notified its TOP***, in which case ~~a~~ the registered entity may have operated a generator in manual mode or any mode other than automatic, ~~***provided it has notified its Transmission Operator,***~~ ~~and~~ provided it ~~is able to~~ compl~~y~~ied with the voltage or Reactive Power schedule while not operating in automatic voltage control mode.

CEAs are to verify whether a registered entity opted to provide a blanket notification to its TOP regarding when it would be operating in a mode other than automatic voltage control mode. If the registered entity acted on this option, the CEA is to verify that the registered entity's TOP ~~accepted~~received the blanket notification in lieu of separate notifications for each change in status. ~~At the Transmission Operator's sole discretion, a registered entity may notify the Transmission Operator in advance of specific instances (such as start up and shut down) that it will operate its generator in a mode other than automatic voltage control mode.~~

CEAs are to determine whether, ~~i~~in the event that a registered entity ~~does~~ did not notify its ~~Transmission Operator~~ TOP in advance of operating its generator in a mode other than automatic voltage control mode, ~~it must~~the registered entity, pursuant to VAR-002-1.1b R3,[3] ~~notify~~ notified its ~~Transmission Operator~~TOP ~~of the change~~ as soon as was possible, but within 30 minutes of the change.

~~As stated in~~Per VAR-002-1.1b R3, CEAs are to determine whether a registered entity ~~must~~ notif~~y~~ied the ~~Transmission Operator~~ TOP every time it ~~makes~~ made a change (except in the case of providing advance notice)—*i.e.*, whether the ~~Generator Operator~~GOP ~~must have notify~~ notified the ~~Transmission Operator~~TOP when the generator ~~is~~ was taken out of automatic voltage control mode, ~~**AND**~~ **and** the ~~Generator Operator~~GOP ~~must have notify~~ notified the ~~Transmission Operator~~TOP when the generator ~~is~~ was returned to automatic voltage control mode.

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VAR-001-1 R4 and VAR-002-1.1b R2 provide direction on maintaining the voltage and Reactive Power schedule:

[3] VAR-002-1.1b R3 provides: Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:

R3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.

R3.2. A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.

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VAR-001-1 R4. Each Transmission Operator shall specify a voltage or Reactive Power schedule[1] at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and ***direct the Generator Operator to comply with the schedule*** *in automatic voltage control mode (AVR in service and controlling voltage). [Emphasis added]*

[1] The voltage schedule is a target voltage to be maintained within a tolerance band during a specified period.

VAR-002-1.1b R2. Unless ***exempted*** *by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings[1]) as directed by the Transmission Operator. [Emphasis added]*

[1] When a Generator is operating in manual control, reactive power capability may change based on stability considerations and this will lead to a change in the associated Facility Ratings.

~~Therefore, a registered entity must comply with the voltage or Reactive Power schedule, regardless of whether the registered entity is operating in automatic voltage control mode or manual mode (MVAR control mode), unless exempted by the Transmission Operator.~~

Effective Period for CAN

This revised CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance from June 17, 2011, regardless of the start date of the violation. It will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

For any enforcement action in process and for audits that have been initiated,[4] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.
~~This CAN is effective upon posting on the NERC web site and will remain in effect until such time that a future version of the standard or an interpretation addresses this specific issue and is enforceable.~~

~~**Providing**~~ **Evidence of Compliance**

CEAs are to assess the following to attain reasonable assurance of the entity's compliance
~~A registered entity must be able to provide evidence to its compliance enforcement authority/auditor of~~:

1. ~~its~~ a registered entity's notifications to its ~~Transmission Operator~~TOP that it would not be operating in automatic voltage control mode; and
2. ~~its~~ a registered entity's notifications to its ~~Transmission Operator~~TOP of any change in status or capability; and

[4] "Initiated" means that a registered entity has received notification of the upcoming audit.

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3. ~~its~~ a registered entity's compliance with the voltage and Reactive Power schedule whenever it was not operating in automatic voltage control mode.

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Revision History

Posted Date	Action	Revision
June 17, 2011	Posted Final CAN	
Month XX, 2011	Posted Revised CAN	Revised target audience to CEAs

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Compliance Application Notice — 0024

CIP-002–CIP-009 R3 Routable Protocols and Data Diode Devices

~~Compliance Application:~~

Posted [DATE]

Primary Interest Groups
Compliance Enforcement Authority (CEA)[1]
NERC
Regional ~~Entities~~ Entity (RE)
Reliability Coordinator~~s~~ (RC)
Transmission Owner (TO)
Transmission Operator~~s~~ (TOP)
Balancing ~~Authorities~~ Authority (BA)
Generator Owner (GO)
Generator Operator~~s~~ (GOP)
Load Serving Entity (LSE)
Interchange Authority (IA)
Transmission Service Provider (TSP)

Issue: ~~Whether~~ Can data diodes' communication characteristics allow a Cyber Asset to be excluded from NERC Critical Infrastructure Protection (CIP) Standards?~~.~~
For the purpose of aiding a CEA, this CAN provides instruction for assessing whether ~~NERC received a request for clarification of whether~~ the communication characteristics of data diode devices can be used to exclude non-critical Cyber Assets from consideration as Critical Cyber Assets (CCA) when a routable protocol is implemented~~, thereby making them inapplicable to NERC Reliability Standards CIPCIP-002 through CIP-009Standards~~.

~~**Reliability Objective**~~
~~The reliability objective is to effectively determine which Cyber Assets are to be determined to be Critical Cyber Assets, and therefore must implement all the requirements contained in CIP-003 through CIP-009.~~

CAN Summary
CEAs are to verify whether a registered entity has properly identified~~include CCAs during CIP audits~~ CCAs ~~When~~ when a routable protocol is implemented. CEAs are instructed to find that ~~, because~~ data diode

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard requirements.

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devices that use routable protocols cannot be used to exclude assets ~~CCAs~~ from compliance with CIP standards as CCAs ~~CCAs from CIP Standard audits~~.

Background

CIP-002 (versions 1, 2 and 3) requires the identification of Critical Assets and associated CCAs. CIP-002 R3.1 provides that~~,~~ ~~in order for~~ a Cyber Asset associated with a Critical Asset ~~to~~ must be designated a CCA~~, it must~~if it uses a routable protocol[2] to communicate outside the Electronic Security Perimeter (ESP).

Data diode devices provide a "one-way" (uni-directional) path for data to flow across the ESP. Several commercial products are available that perform this function, each of which operates in a slightly different way from the others. However, nearly all commercially available stand--alone data diode devices provide for connectivity to IP networks on each side of the stand--alone data diode device. This IP connectivity is assumed to be implemented primarily to minimize the impact to the "internal" Cyber Assets. It is further assumed that, in the context of the CIP standards, the stand--alone data diode devices will be implemented to transmit data from the ~~"Critical Cyber Asset"~~CCA portion of the network to the "outside" portion of the network in a write-only direction from the CCA portion of the network.

An easy way to assess this is to determine if any of the network interfaces on the stand-alone data diode device are configured with IP addresses. If the stand-alone data diode device has an IP address, it is "using" a routable protocol.

Another type of data diode device consists of network interface cards ~~which~~that are installed into existing Cyber Assets, and which provide the same uni-directional communication as stand-alone data diode devices. For purposes of this CAN, these will be ref~~v~~erred to as "embedded data diode devices" to distinguish them from stand-alone data diode devices. ~~In this case, like that using a legacy connection, the data does not use a routable connection to cross the ESP.~~

Since data diode devices can only transmit data in a single direction, normal flow control that is typically handled by the TCP layer in a TCP/IP network cannot be accomplished. The sending Cyber Asset cannot guarantee that the receiving Cyber Asset has received the data. If the data is relied upon for essential functions such as control systems, this lack of communication status feedback may be unacceptable.

Similarly, most control systems require not only the transmission of data, but also the receipt of data requests and control commands. A data diode device implemented in a write-only direction as an ESP access control point will not allow data requests, control commands, communication status feedback or set points from external supervisory systems such as SCADA systems.

Compliance Application

CIP-002-3 R3 provides, in pertinent part:

> ***R3.*** *Critical Cyber Asset Identification — using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control*

[2] The most commonly implemented example of a routable protocol is IP (Internet Protocol). Other routable protocols exist, notably the OSI protocol, but the use of these other routable protocols is extremely limited in North America.

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centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002-3, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:

R3.1. *The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,*

R3.2. *The Cyber Asset uses a routable protocol within a control center; or,*

R3.3. *The Cyber Asset is dial-up accessible.*

NERC Reliability Standard CIP-002 requires the identification of Critical Assets and associated CCAs. The plain language of ~~standard~~ CIP-002 R3.1 does not discuss directionality of data flow~~,~~ —only whether the Cyber Asset~~CA~~ communicates to external systems (to communicate outside the Electronic Security Perimeter) using a routable protocol.

Therefore, under the current ~~version of the CIP Standards~~~~standards~~subrequirement of R3.1, the ~~only~~ relevant criteria for determining whether non-critical CAs are to be classified as CCAs is the use of a routable protocol to communicate outside the Electronic Security Perimeter. Stand--alone ~~D~~data diode devices receive and transmit data through an IP network, which is a routable protocol. ~~Data diode~~Therefore, despite the use of ~~T~~these devices, the CAs that use a routable protocol to communicate outside the ESP must be identified as CCAs. ~~do not provide an exclusion of CIP Standards for CCAs within the defined ESP.~~ The use of a routable protocol to communicate to Cyber Assets outside the ESP will subject these assets to CIP Standards as CCAs.

Effective Period for CAN

This CAN is effective upon posting as final on the NERC Web site, and is to be used by CEAs to assess compliance from the posting date forward, regardless of the start date of any non-compliance or Possible Violation. It supersedes all prior communications and will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

For any enforcement action in process and for audits that have been initiated,[3] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.
~~CAN-0024 is effective upon posting on the NERC Web site and will remain in effect until such time that a future version of the standard or interpretation addresses this specific issue becomes enforceable. CAN-0024 could be superseded by a future CAN that addresses this particular Standard and Requirement.~~

Providing Evidence of Compliance

A CEA is to ~~assess~~consider the following to obtain reasonable assurance of the entity's compliance:
~~A registered entity must be able to provide an auditor or Compliance Enforcement Authority (CEA):~~

[3] "Initiated" means that a registered entity has received notification of the upcoming audit.

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- Evidence of ~~its~~ the registered entity's assessment as to whether a Cyber Asset was determined to be a CCA, based upon whether the Cyber Asset:
  - Is ~~Associated~~ associated with a Critical Asset,
  - Is e~~E~~ssential to the reliable operation of the Critical Asset, and
  - Meets the connectivity qualification described in CIP-002 R3.1, R3.2 and R3.3 (i.e., uses routable protocols to communicate to Cyber Assets outside the Electronic Security Perimeter).
- If the Cyber Asset was deemed not to be a CCA, the CEA should verify whether ~~evidence~~:
  - ~~that n~~No routable protocols were used to communicate to Cyber Assets outside the ~~Electronic Security Perimeter~~ESP, and
  - ~~the~~ The cyber asset ~~was not~~is not dial-up accessible.

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This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

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~~*demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.*~~

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~~Revision History~~

~~Posted Date~~		~~Revision~~
~~Month XX, 20XX~~	~~Posted Final CAN~~	
~~Month XX, 20XX~~	~~Posted Revised CAN~~	~~Revised target audience to CEAs~~

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From:	Brian Hogue
To:	Lee R. Pedowicz
Cc:	Guy V. Zito
Subject:	FW: draft minutes on CAN-0024
Date:	Monday, October 24, 2011 10:19:18 AM
Attachments:	TFIST_Meeting_Minutes_20111018_draft01.pdf

Lee –

The TFIST consensus comments on CAN-0024 are attached. Also I pasted them here

----------< cut here >----------

Agreed that CAN-0024 expands the Standard and should not be supported.

Agreed that this CAN's wording conflicts with the CIPC Guideline on Identifying Critical Cyber
Assets pages 35-36 (and drawings 3 & 4).

If CAN-0024 only to applies to "stand-alone" devices with interfaces both internal and external
to the ESP, and with both interfaces communicating using routable protocols, that would be
acceptable. This would be better stated by replacing this paragraph (second paragraph on
page 2 of 4 of the clean CAN-0024):

> "An easy way to assess this is to determine if any of the network interfaces on the
> stand-alone data diode device are configured with IP addresses. If the stand-alone data
> diode device has an IP address, it is 'using' a routable protocol."

With the following:

> "An easy way to assess this is to determine if both the internal and outside network
> interfaces on the stand-alone data diode device are configured with Routable Protocol.
> If the stand-alone data diode device has Routable Protocol on both interfaces, it is
> 'using' a routable protocol to communicate outside the Electronic Security Perimeter."

In addition, the following two paragraphs (also page 2 of the clean CAN-0024) should be
deleted because the CAN's purpose is not to comment on whether a particular solution is
technically feasible or acceptable. Recommend deleting

> "Since data diode devices can only transmit data in a single direction, normal flow
> control that is typically handled by the TCP layer in a TCP/IP network cannot

be
accomplished. The sending Cyber Asset cannot guarantee that the receiving Cyber
Asset has received the data. If the data is relied upon for essential functions such as
control systems, this lack of communication status feedback may be unacceptable."

and

"Similarly, most control systems require not only the transmission of data, but also the
receipt of data requests and control commands. A data diode device implemented in a
write-only direction as an ESP access control point will not allow data requests, control
commands, communication status feedback or set points from external supervisory
systems such as SCADA systems."

----------< cut here >----------

-brian

From: Brian Hogue
Sent: Monday, October 24, 2011 10:17 AM
To: tfist
Subject: draft minutes on CAN-0024

TFIST –

Attached are the consensus comments from last Tuesday's call on CAN-0024. These comments will be forwarded to RSC. If you have any corrections/improvements, email the group or me ASAP

-brian

Minutes of the conference call of the Task Force on Infrastructure Security & Technology, on October 18, 2011

Attendees

Greg Goodrich	NYISO
David Gordon	MMWEC
Rob Haromszeki	Hydro On
Brett Lewis	NYISO
Joe Pereira	ISO-NE
Benoit Tardif	HQT
Daniel Yagudayev	Con Ed
Javier Echevarria	NPCC
Frantz Roc	NPCC

1. **Introductions**
   Everyone introduced themselves.

2. **Anti-trust guidelines**
   Read the NPCC antitrust guidelines.

3. **Discussion**
   This conference call's purpose is reaching consensus comments on CAN-0024 which will be forwarded to RSC. This CAN's topic is data diodes and CIP-002-3 R3.

   Agreed that CAN-0024 expands the Standard and should not be supported.

   Agreed that this CAN's wording conflicts with the CIPC Guideline on Identifying Critical Cyber Assets pages 35-36 (and drawings 3 & 4).

   If CAN-0024 only to applies to "stand-alone" devices with interfaces both internal and external to the ESP, and with both interfaces communicating using routable protocols, that would be acceptable. This would be better stated by replacing this paragraph (second paragraph on page 2 of 4 of the clean CAN-0024):

   > "An easy way to assess this is to determine if any of the network interfaces on the stand-alone data diode device are configured with IP addresses. If the stand-alone data diode device has an IP address, it is 'using' a routable protocol."

   With the following:

   > "An easy way to assess this is to determine if both the internal and outside network interfaces on the stand-alone data diode device are configured with Routable Protocol. If the stand-alone data diode device has Routable Protocol on both interfaces, it is 'using' a routable protocol to communicate outside the Electronic Security Perimeter."

DRAFT

In addition, the following two paragraphs (also page 2 of the clean CAN-0024) should be deleted because the CAN's purpose is not to comment on whether a particular solution is technically feasible or acceptable. Recommend deleting

> “Since data diode devices can only transmit data in a single direction, normal flow control that is typically handled by the TCP layer in a TCP/IP network cannot be accomplished. The sending Cyber Asset cannot guarantee that the receiving Cyber Asset has received the data. If the data is relied upon for essential functions such as control systems, this lack of communication status feedback may be unacceptable."

and

> "Similarly, most control systems require not only the transmission of data, but also the receipt of data requests and control commands. A data diode device implemented in a write-only direction as an ESP access control point will not allow data requests, control commands, communication status feedback or set points from external supervisory systems such as SCADA systems."

DRAFT

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Compliance Application Notice — 0026

~~Compliance Application:~~ TOP-006 R3 Protection Relays

Posted: June 17, 2011
Revised: ~~[Date]~~Month XX, 2011

Primary Interest Groups
Compliance Enforcement Authority (CEA)[1]
NERC
Regional Entity~~ies~~
Transmission Operator~~s~~ (TOP)
Balancing Authority~~ies~~ (BA)
Reliability Coordinator~~s~~ (RC)

Issue: ~~Clarification~~ What is ~~of~~ the scope of "protective relays" under TOP-006 R3?
For the purpose of aiding a CEA, this CAN provides instruction for assessing whether each RC, TOP~~,~~ and BA ~~NERC received a request for clarification of whether a RC, TOP and BA, under TOP-006 Requirement (R) 3, needs to~~ provided appropriate technical information to its operating staff for all protective relays in its area whether or not it has the responsibility for or ownership of the protective relays.

~~**Reliability Objective**~~
~~To ensure that appropriate and current technical information pertaining to protective relaysing is provided to RC, TOP, and BA operating personnel.~~

Compliance Application
TOP-006 ~~-1 and TOP-006-2~~ provides, in pertinent part:

> ***R3.*** *Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel.*

CEAs are to verify that each RC, TOP and BA ~~must~~ has provided to its operating personnel the relevant characteristics (including the purpose and limitations) of:

1. the protective relays that are applied in the applicable entity's area, and

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard and requirements.

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2. the protective relays, regardless of whether another entity has ownership or maintenance responsibility, that may impact that entity (the RC, TOP or BA).

Effective Period for CAN

This revised CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance from June 17, 2011, regardless of the start date of the violation. It will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

For any enforcement action in process and for audits that have been initiated,[2] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.
~~This CAN covers version 1 and 2, is effective upon posting on the NERC Web site and will remain in effect until such time that a future version of the standard or interpretation addresses this specific issue and is enforceable. CAN-0026 could be superseded by a future CAN that addresses this particular Standard and Requirement.~~

~~Providing~~ Evidence of Compliance

CEAs are to verify ~~evidence of~~ that communication of technical information occurred between applicable entities' operating personnel ~~of technical information~~regarding ~~about~~:

a. the protective relays that are applied in the applicable entity's area, and

b. the protective relays, regardless of ownership or maintenance responsibility of the associated relays, that may impact that entity (the RC, TOP or BA).

This evidence could include but is not limited to~~,~~ operator logs, voice recordings and~~,~~ electronic communications~~, or other equivalent~~.

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[2] "Initiated" means that a registered entity has received notification of the upcoming audit.

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Revision History

Posted Date	Action	Revision
June 17, 2011	Posted Final CAN	
Month XX, 20XX	Posted Revised CAN	Revised target audience to CEAs

~~*This document is designed to convey compliance guidance from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time.*~~

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Compliance Application Notice — 0028

~~Compliance Application:~~ TOP-006 R1.2 Reporting Responsibilities

Posted: July 19, 2011
Re~~posted~~vised: ~~August~~Month XX, 2011

Primary Interest Groups
Compliance Enforcement Authority (CEA)[1]
NERC
Regional ~~Entities~~ Entity ~~(RE)~~
Transmission Operator~~s~~ (TOP)
Balancing ~~Authorities~~ Authority (BA)
Generator Operator~~s~~ (GOP)
Reliability Coordinator~~s~~ (RC)
~~ERO Auditors, Investigators and Compliance Enforcement Authorities (Auditors)~~[2]

Issue: What are resource reporting responsibilities for ~~the Balancing Authorities (~~BA~~s)~~ and ~~Transmission Operators (~~TOP~~)~~ s under TOP-006?
For the purpose of aiding a CEA, this CAN provides instruction for assessing whether ~~NERC received a request for clarification of whether~~ a BA or TOP ~~is responsible for reporting generation or transmission resources available for use to RCs and other affected BAs and TOPs under TOP-006 Requirement (R) 1.2.~~

~~NERC also received a request for clarification of whether a TOP~~has fulfilled the requirements ~~is responsible~~ for reporting transmission or generation resources available for use to RCs and other affected BAs and TOPs under TOP-006 R1.2.

~~**Reliability Objective**~~
~~For the purpose of aiding an auditor, this CAN provides instruction for assessing whether registered entities have reported the~~~~The Reliability Objective is to the current generation and transmission resource information to applicable entities are available~~in order ~~to monitor critical reliability parameters in real-time.~~

Background

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard and requirements.
[2] ~~This includes any person authorized to determine a Possible Violation of NERC Reliability Standard requirements.~~

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~~Auditors~~CEAs are to verify that ~~TOP-006 requires~~ BAs and TOPs have reported the availability of generation or transmission resources under TOP-006. ~~Auditors~~CEAs ~~should~~are to be aware that BAs are not responsible for reporting transmission resources.

Compliance Application

TOP-006 provides, in pertinent part:

> ***R1.*** *Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use.*
>
> …
>
> *R1.2. Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.*

~~Auditors~~CEAs are to assess compliance for the respo~~determine the respo~~nsible entity within the context of TOP-006 R1.2 as follows:

1. A BA is the responsible entity for the reporting of generation resources available for use to the appropriate RC and the other affected BAs and TOPs; and
2. A TOP is the responsible entity for the reporting of transmission resources available for use to the appropriate RC and the other affected BAs and TOPs.

Effective Period for CAN

This revised CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance from July 19, 2011, regardless of the start date of the violation. It will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

For any enforcement action in process and for audits that have been initiated,[3] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.

~~This CAN is effective upon posting as final on the NERC Web site, and is to be used by ERO Auditors to apply compliance for any Possible Violations discovered from the posting date forward, regardless of the date of the violation. It supersedes all prior communications and will remain in effect until a future CAN supersedes it or until such time that a future version of the standard or interpretation addresses this specific issue and is enforceable, or until it is superseded by a future CAN that addresses this particular Standard and Requirement.~~

~~This CAN covers Versions 1 and 2 of the standard, is effective upon posting on the NERC Web site and will remain in effect until such time that a future version of the standard or interpretation addresses this specific issue and is enforceable.~~

~~Providing~~ Evidence of Compliance

[3] "Initiated" means that a registered entity has received notification of the upcoming audit.

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A ~~Auditors~~CEA is to assess the following to obtain reasonable assurance of the entity's compliance: ~~are to verify evidence of compliance in the following ways~~~~BA and TOP must be able to provide an auditor or Compliance Enforcement Authority:~~

1. ~~That the BA and TOP have documented~~Evidence of its communications to its RC and~~,~~ other affected BAs and TOPs regarding the applicable generation or transmission resources available for use. This evidence could include but is not limited to:~~,~~ operator logs, voice recordings~~,~~ and electronic communications~~, or other equivalent~~. Each BA and TOP is to have at least 90 days of historical data (see section D. Compliance, subsection 1.3 Data Retention of TOP-006) as evidence to provide a CEA, and
2. Its ~~Auditors are to verify that each BA and TOP must have~~has at least 90 days of historical data as ~~evidence to provide an auditor or Compliance Enforcement Authority, including applicable~~ processes, procedures, or other corroborating evidence to demonstrate compliance for the remainder of the audit period.

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Revision History

Posted Date	Action	Revision
July 19, 2011	Posted Final CAN	
Month XX, 20XX	Posted Revised CAN	Revised target audience to CEAs

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Interpretation of CIP-006-1 Cyber Security – Physical Security of Critical Cyber Assets for Progress Energy

Request for Interpretation Received from Progress Energy on April 2, 2008:

Request:
Progress Energy requests a formal interpretation of CIP-006-1. R1.1.

In CIP_006-1, Requirement 1.1 states "Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets."

In CIP-005-1, Requirement 1 states "Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The Responsible Entity shall identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s)."

In CIP-002-1, Requirement 3 states "Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time interutility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:

R3.1. The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,

R3.2. The Cyber Asset uses a routable protocol within a control center; or,

R3.3. The Cyber Asset is dial-up accessible.

CIP-002-1 R3 defines Critical Cyber Assets as assets essential to the operation of Critical Asset and assets meeting one of the characteristics of R3.1, R3.2 or R3.3. It is unclear from the stated requirements the extent ESP wiring external to physical security perimeter must be protected within a six wall boundary. Progress Energy requests an interpretation as to the applicability of CIP-006-1 R1 to the aspects of the wiring that comprises the ESP.

CIP-006-1 Cyber Security – Physical Security of Critical Cyber Assets
R1. Physical Security Plan — The Responsible Entity shall create and maintain a physical security plan, approved by a senior manager or delegate(s) that shall address, at a minimum, the following:

R1.1. Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.

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The following revised interpretation of CIP-006-1 — Physical Security of Critical Cyber Assets Requirement R1.1 was developed by the ~~Cyber Security Order 706 SAR drafting team~~CIP Interpretation Drafting Team's Project 2008-10 Interpretation Drafting Team in response to industry comments received from the second initial ballot:

Interpretation of CIP-006-1 Requirement R1.1*: "…to ensure and document that all Cyber Assets within an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter. Progress Energy requests an interpretation as to the applicability of CIP-006-1 R1 to the aspects of the wiring that comprises the ESP.*

Revised Response:

~~The definition of Cyber Asset in the *NERC Glossary of Terms Used in Reliability Standards* includes communication networks. Physical media (wiring) is a component of a communication network within an Electronic Security Perimeter, but the wiring itself is not a separate Cyber Asset.~~

~~The specific situation described by Progress Energy involves physically separate Critical Cyber Assets connected by wiring inside the Electronic Security Perimeter. Since the connective wiring is inside the Electronic Security Perimeter, Requirement R1.1 of CIP-006-1 applies.~~

~~CIP-006-1 R1.1 also provides: "Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets." For wiring within the Electronic Security Perimeter that is external to a Physical Security Perimeter, the alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed ("six-wall") border: alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space; alternative logical control measures may include, but are not limited to data encryption, and/or circuit monitoring to detect unauthorized access or physical tampering.~~

CIP-006-1, Requirement R1.1 applies to "Cyber Assets," and the first test in determining whether it applies to wiring is to determine whether wiring is a "Cyber Asset."
The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definition of "Cyber Asset," Requirement R1.1 of CIP-006-1 does not apply to wiring.

This interpretation is limited to whether Requirement R1.1 applies to a particular circumstance (e.g, "wiring"), which makes it distinct from the interpretation in CIP-006-3c, appendix 3. The interpretation in CIP-006-3c, appendix 3, only applies when a completely enclosed ("six-wall") border cannot be established for a "Cyber Asset" within an Electronic Security Perimeter (ESP).

A. Introduction

1. Title: Cyber Security — Physical Security of Critical Cyber Assets

2. Number: CIP-006-3c

3. Purpose: Standard CIP-006-3 is intended to ensure the implementation of a physical security program for the protection of Critical Cyber Assets. Standard CIP-006-3 should be read as part of a group of standards numbered Standards CIP-002-3 through CIP-009-3.

4. Applicability:

4.1. Within the text of Standard CIP-006-3, "Responsible Entity" shall mean:

4.1.1 Reliability Coordinator

4.1.2 Balancing Authority

4.1.3 Interchange Authority

4.1.4 Transmission Service Provider

4.1.5 Transmission Owner

4.1.6 Transmission Operator

4.1.7 Generator Owner

4.1.8 Generator Operator

4.1.9 Load Serving Entity

4.1.10 NERC

4.1.11 Regional Entity

4.2. The following are exempt from Standard CIP-006-3:

4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3 Responsible Entities that, in compliance with Standard CIP-002-3, identify that they have no Critical Cyber Assets

5. Effective Date: The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Physical Security Plan — The Responsible Entity shall document, implement, and maintain a physical security plan, approved by the senior manager or delegate(s) that shall address, at a minimum, the following:

R1.1. All Cyber Assets within an Electronic Security Perimeter shall reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to such Cyber Assets.

R1.2. Identification of all physical access points through each Physical Security Perimeter and measures to control entry at those access points.

R1.3. Processes, tools, and procedures to monitor physical access to the perimeter(s).

R1.4. Appropriate use of physical access controls as described in Requirement R4 including visitor pass management, response to loss, and prohibition of inappropriate use of physical access controls.

R1.5. Review of access authorization requests and revocation of access authorization, in accordance with CIP-004-3 Requirement R4.

R1.6. A visitor control program for visitors (personnel without authorized unescorted access to a Physical Security Perimeter), containing at a minimum the following:

R1.6.1. Logs (manual or automated) to document the entry and exit of visitors, including the date and time, to and from Physical Security Perimeters.

R1.6.2. Continuous escorted access of visitors within the Physical Security Perimeter.

R1.7. Update of the physical security plan within thirty calendar days of the completion of any physical security system redesign or reconfiguration, including, but not limited to, addition or removal of access points through the Physical Security Perimeter, physical access controls, monitoring controls, or logging controls.

R1.8. Annual review of the physical security plan.

R2. Protection of Physical Access Control Systems — Cyber Assets that authorize and/or log access to the Physical Security Perimeter(s), exclusive of hardware at the Physical Security Perimeter access point such as electronic lock control mechanisms and badge readers, shall:

R2.1. Be protected from unauthorized physical access.

R2.2. Be afforded the protective measures specified in Standard CIP-003-3; Standard CIP-004-3 Requirement R3; Standard CIP-005-3 Requirements R2 and R3; Standard CIP-006-3 Requirements R4 and R5; Standard CIP-007-3; Standard CIP-008-3; and Standard CIP-009-3.

R3. Protection of Electronic Access Control Systems — Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall reside within an identified Physical Security Perimeter.

R4. Physical Access Controls — The Responsible Entity shall document and implement the operational and procedural controls to manage physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. The Responsible Entity shall implement one or more of the following physical access methods:

- Card Key: A means of electronic access where the access rights of the card holder are predefined in a computer database. Access rights may differ from one perimeter to another.
- Special Locks: These include, but are not limited to, locks with “restricted key” systems, magnetic locks that can be operated remotely, and “man-trap” systems.
- Security Personnel: Personnel responsible for controlling physical access who may reside on-site or at a monitoring station.
- Other Authentication Devices: Biometric, keypad, token, or other equivalent devices that control physical access to the Critical Cyber Assets.

R5. Monitoring Physical Access — The Responsible Entity shall document and implement the technical and procedural controls for monitoring physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. Unauthorized access attempts shall be reviewed immediately and handled in accordance with the procedures specified in Requirement CIP-008-3. One or more of the following monitoring methods shall be used:

- Alarm Systems: Systems that alarm to indicate a door, gate or window has been opened without authorization. These alarms must provide for immediate notification to personnel responsible for response.
- Human Observation of Access Points: Monitoring of physical access points by authorized personnel as specified in Requirement R4.

R6. Logging Physical Access — Logging shall record sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week. The Responsible Entity shall implement and document the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent:

- Computerized Logging: Electronic logs produced by the Responsible Entity's selected access control and monitoring method.
- Video Recording: Electronic capture of video images of sufficient quality to determine identity.
- Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access as specified in Requirement R4.

R7. Access Log Retention — The Responsible Entity shall retain physical access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008-3.

R8. Maintenance and Testing — The Responsible Entity shall implement a maintenance and testing program to ensure that all physical security systems under Requirements R4, R5, and R6 function properly. The program must include, at a minimum, the following:

R8.1. Testing and maintenance of all physical security mechanisms on a cycle no longer than three years.

R8.2. Retention of testing and maintenance records for the cycle determined by the Responsible Entity in Requirement R8.1.

R8.3. Retention of outage records regarding access controls, logging, and monitoring for a minimum of one calendar year.

C. Measures

M1. The Responsible Entity shall make available the physical security plan as specified in Requirement R1 and documentation of the implementation, review and updating of the plan.

M2. The Responsible Entity shall make available documentation that the physical access control systems are protected as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation that the electronic access control systems are located within an identified Physical Security Perimeter as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation identifying the methods for controlling physical access to each access point of a Physical Security Perimeter as specified in Requirement R4.

M5. The Responsible Entity shall make available documentation identifying the methods for monitoring physical access as specified in Requirement R5.

M6. The Responsible Entity shall make available documentation identifying the methods for logging physical access as specified in Requirement R6.

M7. The Responsible Entity shall make available documentation to show retention of access logs as specified in Requirement R7.

M8. The Responsible Entity shall make available documentation to show its implementation of a physical security system maintenance and testing program as specified in Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entities.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep documents other than those specified in Requirements R7 and R8.2 from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

1.5.1 The Responsible Entity may not make exceptions in its cyber security policy to the creation, documentation, or maintenance of a physical security plan.

1.5.2 For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall not be required to comply with Standard CIP-006-3 for that single access point at the dial-up device.

2. Violation Severity Levels (Under development by the CIP VSL Drafting Team)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
2		Modifications to remove extraneous information from the requirements, improve readability, and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Replaced the RRO with RE as a responsible entity. Modified CIP-006-1 Requirement R1 to clarify that a physical security plan to protect Critical Cyber Assets must be documented, maintained, implemented, and approved by the senior manager. Revised the wording in R1.2 to identify all "physical" access points. Added Requirement R2 to CIP-006-2 to clarify the requirement to safeguard the Physical Access Control Systems and exclude hardware at the Physical Security Perimeter access point, such as electronic lock control mechanisms and badge readers from the requirement. Requirement R2.1 requires the Responsible Entity to protect the Physical Access Control Systems from unauthorized access. CIP-006-1 Requirement R1.8 was moved to become CIP-006-2 Requirement R2.2. Added Requirement R3 to CIP-006-2, clarifying the requirement for Electronic Access Control Systems to be safeguarded within an identified Physical Security Perimeter. The sub requirements of CIP-006-2 Requirements R4, R5, and R6 were changed from formal requirements to bulleted lists of options consistent with the intent of the requirements. Changed the Compliance Monitor to Compliance Enforcement Authority.	
3		Updated version numbers from -2 to -3 Revised Requirement 1.6 to add a Visitor Control program component to the Physical Security Plan, in response to FERC order issued September 30, 2009. In Requirement R7, the term "Responsible Entity" was capitalized.	
	11/18/2009	Updated Requirements R1.6.1 and R1.6.2 to be responsive to FERC Order RD09-7	
3	12/16/09	Approved by NERC Board of Trustees	Update
1a	Board approved 02/12/ 2008	Interpretation of R1 and Additional Compliance Information Section 1.4.4 (Appendix 1)	Interpretation (Project 2007-27)
1b/2b	Board approved 08/05/2009	Interpretation of R4 (Appendix 2)	Interpretation (Project 2008-15)
3c	Board approved 02/16/2010	Interpretation of R1 and R1.1 (Appendix 3)	Interpretation (Project 2009-13)

Appendix 1

Interpretation of Requirement R1.1.

Request: *Are dial-up RTUs that use non-routable protocols and have dial-up access required to have a six-wall perimeters or are they exempted from CIP-006-1 and required to have only electronic security perimeters? This has a direct impact on how any identified RTUs will be physically secured.*

Interpretation:

Dial-up assets are Critical Cyber Assets, assuming they meet the criteria in CIP-002-1, and they must reside within an Electronic Security Perimeter. However, physical security control over a critical cyber asset is not required if that asset does not have a routable protocol. Since there is minimal risk of compromising other critical cyber assets dial-up devices such as Remote Terminals Units that do not use routable protocols are not required to be enclosed within a "six-wall" border.

CIP-006-1 — Requirement 1.1 requires a Responsible Entity to have a physical security plan that stipulate cyber assets that are within the Electronic Security Perimeter also be within a Physical Security Perimeter.

> **R1. Physical Security Plan — The Responsible Entity shall create and maintain a physical security plan, approved by a senior manager or delegate(s) that shall address, at a minimum, the following:**
>
> **R1.1. Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.**

CIP-006-1 — Additional Compliance Information 1.4.4 identifies dial-up accessible assets that use non-routable protocols as a special class of cyber assets that are not subject to the Physical Security Perimeter requirement of this standard.

> **1.4. Additional Compliance Information**
>
> **1.4.4 For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall not be required to comply with Standard CIP-006 for that single access point at the dial-up device.**

Appendix 2

The following interpretation of CIP-006-1a — Cyber Security — Physical Security of Critical Cyber Assets, Requirement R4 was developed by the standard drafting team assigned to Project 2008-14 (Cyber Security Violation Severity Levels) on October 23, 2008.

Request:

1. *For physical access control to cyber assets, does this include monitoring when an individual leaves the controlled access cyber area?*
2. *Does the term, "time of access" mean logging when the person entered the facility or does it mean logging the entry/exit time and "length" of time the person had access to the critical asset?*

Interpretation:

No, monitoring and logging of access are only required for ingress at this time. The term "time of access" refers to the time an authorized individual enters the physical security perimeter.

Requirement Number and Text of Requirement

R4. Logging Physical Access — Logging shall record sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week. The Responsible Entity shall implement and document the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent:

- **R4.1. Computerized Logging: Electronic logs produced by the Responsible Entity's selected access control and monitoring method.**
- **R4.2. Video Recording: Electronic capture of video images of sufficient quality to determine identity.**
- **R4.3. Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access as specified in Requirement R2.3.**

Appendix 3

Requirement Number and Text of Requirement
R1. Physical Security Plan — The Responsible Entity shall create and maintain a physical security plan, approved by a senior manager or delegate(s) that shall address, at a minimum, the following: R1.1. Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.
Question
If a completely enclosed border cannot be created, what does the phrase, "to control physical access" require? Must the alternative measure be physical in nature? If so, must the physical barrier literally prevent physical access e.g. using concrete encased fiber, or can the alternative measure effectively mitigate the risks associated with physical access through cameras, motions sensors, or encryption? Does this requirement preclude the application of logical controls as an alternative measure in mitigating the risks of physical access to Critical Cyber Assets?
Response
For Electronic Security Perimeter wiring external to a Physical Security Perimeter, the drafting team interprets the Requirement R1.1 as not limited to measures that are "physical in nature." The alternative measures may be physical or logical, on the condition that they provide security equivalent or better to a completely enclosed ("six-wall") border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering.

Unofficial Comment Form for Interpretation of CIP-006-x for Progress Energy (Project 2008-10)

Please **DO NOT** use this form to submit comments. Please use the electronic comment form to submit comments on the interpretation of CIP-006-x for Progress Energy (Project 2008-10). The electronic comment form must be completed by **November 21, 2011.**

Project Page

If you have questions please contact Steven Noess at steven.noess@nerc.net or by telephone at 404-446-9691.

Background Information

The last successive ballot to this interpretation closed on October 12, 2009. Since that date, a project team from the CIP Interpretation Drafting Team reviewed and responded to the comments received from the last successive ballot and made revisions to the interpretation. The project team revised the interpretation pursuant to NERC Guidelines for Interpretation Drafting Teams (available here).

The interpretation drafting team determined that the interpretation must limit itself to the question asked: whether CIP-006-1, Requirement R1.1, applies to the aspects of wiring that comprises the ESP. The interpretation drafting team revised the interpretation from the last successive ballot accordingly.

The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but the interpretation drafting team determined that it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definition of "Cyber Asset," the interpretation drafting team interpreted that Requirement R1.1 of CIP-006-1 does not apply to wiring.

The team furthermore acknowledges and notes in its revised interpretation that a different interpretation, appended to CIP-006-3c as appendix 3, applies to the "alternative measures" question "where a completely enclosed ('six-wall') border cannot be established" for "Cyber Assets within an Electronic Security Perimeter." The interpretation drafting team has determined that such analysis is beyond the scope of this interpretation. CIP-006-1 R1.1 applies to "Cyber Assets" and this interpretation is limited to whether wiring is a "Cyber Asset." A secondary analysis of "acceptable alternative measures where a completely enclosed ('six-wall') border cannot be established" does not apply.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

Please review the request for an interpretation, the associated standard, and the draft interpretation and then answer the following questions.

1. The NERC Board of Trustees indicated that the interpretation process **should not** be used to address requests for a decision on **"how"** a reliability standard applies to a registered entity's particular facts and circumstances. Do you believe this request for an interpretation is asking for clarity on the meaning of a requirement or clarity on the application of a requirement?

   ☒ The request is asking for clarity on the **meaning** of a requirement.

☐ The request is asking for clarity on the **application** of a requirement.

Comments:

2. The NERC Board of Trustees indicated that in deciding whether or not to approve a proposed interpretation, it will use a standard of strict construction and not seek to expand the reach of the standard to correct a perceived gap or deficiency in the standard. Do you believe this interpretation expands the reach of the standard?

☐ The interpretation **expands** the reach of the standard.

☒ The interpretation **does not expand** the reach of the standard.

Comments:

3. Do you agree with this interpretation? If not, why not.

☒ Yes

☐ No

Comments:

4. Are there any other comments you would like to add that haven't been covered in the previous questions, please add them here.

Comments: No comments

		Applicable	
Standard	**Req**	**TO**	**TOP**
EOP-005[1]			
EOP-005-1	R1		X
EOP-005-1	R2		X
EOP-005-1	R5		X
EOP-005-1	R6		X
EOP-005-1	R7		X
EOP-005-1 is effective			
until 8/2013, when			
EOP-005-2 is effective.			
R13 - R18 applies to GOPs.			
FAC-001[2]			
FAC-001-0	R1	X	
FAC-001-0	R1.1	X	
FAC-001-0	R1.2	X	
FAC-001-0	R1.3	X	
FAC-001-0	R2	X	
FAC-001-0	R2.1	X	
FAC-001-0	R2.1.1	X	
FAC-001-0	R2.1.2	X	
FAC-001-0	R2.1.3	X	
FAC-001-0	R2.1.4	X	
FAC-001-0	R2.1.5	X	
FAC-001-0	R2.1.6	X	

		Applicable	
Standard	**Req**	**TO**	**TOP**
FAC-001 Continued			
FAC-001-0	R2.1.7	X	
FAC-001-0	R2.1.8	X	
FAC-001-0	R2.1.9	X	
FAC-001-0	R2.1.10	X	
FAC-001-0	R2.1.11	X	
FAC-001-0	R2.1.12	X	
FAC-001-0	R2.1.13	X	
FAC-001-0	R2.1.14	X	
FAC-001-0	R2.1.15	X	
FAC-001-0	R2.1.16	X	
FAC-001-0	R3.	X	
FAC-003[3]			
FAC-003-1	R1	X	
FAC-003-1	R1.1	X	
FAC-003-1	R1.2	X	
FAC-003-1	R1.2.1	X	
FAC-003-1	R1.2.2	X	
FAC-003-1	R1.2.2.1	X	
FAC-003-1	R1.2.2.2	X	
FAC-003-1	R1.3	X	
FAC-003-1	R1.4	X	
FAC-003-1	R1.5	X	

		Applicable	
Standard	**Req**	**TO**	**TOP**
FAC-003 Continued			
FAC-003-1	R2.	X	
FAC-003-1	R3	X	
FAC-003-1	R3.1	X	
FAC-003-1	R3.2	X	
FAC-003-1	R3.3	X	
FAC-003-1	R3.4	X	
FAC-003-1	R3.4.1	X	
FAC-003-1	R3.4.2	X	
FAC-003-1	R3.4.3	X	
FAC-014-2[4]			
FAC-014-2	R2		X
PER-002[5]			
PER-002-0	R2		X
PER-002-0	R3		X
PER-002-0	R3.1		X
PER-002-0	R3.2		X
PER-002-0	R3.3		X
PER-002-0	R3.4		X
PER-002-0	R4		X

		Applicable	
Standard	**Req**	**TO**	**TOP**
PRC-001[6]			
PRC-001-1	R2		X
PRC-001-1	R2.2		X
PRC-001-1	R4		X
PRC-004[7]			
PRC-004-1	R1	X	
PRC-004-1	R3	X	
PRC-005-1[8]			
PRC-005-1	R1	X	
PRC-005-1	R2	X	
TOP-001-1[9]			
TOP-001-1	R1		X
TOP-004-1[10]			
TOP-004-1	R6		X
TOP-006-1[11]			
TOP-006-1	R3		X
TOP-006-1	R6		X

[1] EOP-005			[5] PER-002-0 The registered entity will develop an appropriate training program that contains the necessary elements for the GO/GOP operating a transmission facility to understand fully the impacts of the operation on the BPS, such as equipment involved, including protection systems, the coordination aspects with the TO/TOP to which it is connected, and the protocols for and impacts of operating facilities associated with the transmission facility. The objective of this training is to ensure that the GO/GOP is completely aware of its obligations to follow the directives of the appropriate TOP and has personnel with the skills and training to execute these obligations in the best interest of reliability	[7]PRC-004-1 R1 & R3 requires analysis and reporting of misops.	
If GOP has blackstart capability, then EOP-005 applies, GOP restoration plan would require coordination with TOP per the TOP Blackstart Restoration Plan. The GOP would start its blackstart resources to provide necessary real and reactive power to its generating resources per interconnecting TOP directives.		[2] FAC-001 would be an included requirement if another Entity wishes to connect to the Generator Lead 'Transmission line'. If a study is contracted, requirement would apply.		[8] PRC-005-1 TO ….that owns a transmission Protection System shall …. analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan; and reporting the misops.	
In addition, if GOP has blackstart capability the interconnection TOP will have included this capability in its restoration planning for its area of responsibility.		[3] FAC-003-1 would apply for a facility that has a generator transmission line leading to the inter-connection point with at least three tower structures which includes two adjacent spans; or includes a visual impediment.		[9] TOP-001-1 R1 ensures personnel assigned to operate BES transmission facilities have clear and unambiguous authority to operate those facilities.	
If GOP does not have blackstart capability, GOP restoration plan is dependent upon provision of real and reactive power service from interconnecting TOP, per VAR-001 and VAR-002 requiring the GOP to follow the directives of the interconnecting TOP, compliance with this standard/requirments is not required.		[4] FAC-014-2 In the event an RC directs the establishment of an SOL, the SOL must be established in accordance with the RC's SOL Methodology.	[6] PRC-001-R2 requires notification and corrective action for relay or equipment failure R4 coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities	[10] TOP-004-1 R6 ensures formal policies and procedures are formulated to provide for coordination of activities that may impact reliability.	[11] TOP-006-1 R3 ensures technical information is provided to the responsible personnel; R6 ensures correct and accurate data to TOP and BA.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

NERC Compliance Process Directive #2011-CAG-001

Directive Regarding Generator Transmission Leads

Version 1.0

DRAFT

DATE, 2011 | Public Process Announcement

Introduction and Purpose

This directive provides interim guidance to address the following reliability gap, which was identified early in the mandatory compliance and enforcement period: a Generator Owner (GO) and/or Generator Operator (GOP) owned and/or operated transmission facilities that were not registered for the NERC Reliability Standards that cover Transmission Owners (TO) and/or Transmission Operators (TOP). As a result of this reliability gap, NERC and the Regional Entities (RE) began registering GO/GOPs that owned and/or operated transmission facilities as TO/TOPs, in addition to their registration as GO/GOP. The ERO has been evaluating whether a subset of the TO/TOP standards and requirements rather than the full suite of TO/TOP standards should be developed to apply to certain of these entities.

In accordance with section 8c of the Regional Delegation Agreements (RDA),[1] this *Directive Regarding Generation Connection Leads* (Directive) is provided to the Regional Entities (RE) to ensure consistency in the application of NERC Reliability Standards and Requirements for a GO and/or GOP that is registered or should be registered as a TO and/or TOP in accordance with the NERC Statement of Compliance Registry Criteria.[2] This directive is an interim solution because it supports the longer term efforts of reliability standard drafting teams charged with revising NERC Reliability Standards specifically associated with generator transmission leads, such as the *Generator Requirements at the Transmission Interface (GO/TO)* Standards Drafting Team.[3] Additionally, Project 2010-07 Generator Requirements at the Transmission Interface Background Resource Document and this directive are preceded by and built upon the work reflected in the *Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface* completed November 16, 2009.[4]

Attachment 1 of this Directive provides examples of typical generator transmission leads. Based upon the RE's risk assessment of the registered entity, as noted above, the RE can determine that standards and requirements may need to be added to or excluded from the list of Reliability Standards set forth in Appendix 1 to the Memorandum of Understanding (MOU) with respect to a particular registered entity. This Directive specifically recognizes the need for flexibility between the Regional Entity and the

[1] The current RDAs are located on NERC's website: http://www.nerc.com/page.php?cid=1%7C9%7C119%7C181.
[2] http://www.nerc.com/files/Appendix_5B-StatementOfComplianceRegistryCriteria.pdf
[3] Project 2010-07 "Generator Requirements at the Transmission Interface," available at: http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html.
[4] "Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface,"available at: http://www.nerc.com/files/GO-TO_Final_Report_Complete_2009Nov16.pdf.

registered entity to reach agreement on the final list of applicable Reliability Standards which will be attached to the executed MOU. The list may be increased if the Regional Entity determines, based on the entity's specific facts and circumstances, merit it, or decreased if the entity provides to the Regional Entity technical or physical justification why the standard/requirement should not apply. If agreement cannot be reached, the entity will be registered in accordance with the criteria specified in the ROP Appendix 5B '*Statement of Compliance Registry Criteria*.'. The Regional Entity also has flexibility to prioritize the order in registering specific GO/GOPs as TO/TOPs.

This interim measure is not intended to prejudge, and should not be read as prejudging, the outcome of the Standard Development Process Projects. In identifying the minimum applicable NERC Reliability Standards listed in Appendix 1 to the MOU, NERC is taking into account physical and technical limitations, as well as reliability considerations, that support applicability of a subset of reliability standards to registered entities with generator transmission leads.

Background

The ERO recognized a gap in reliability as it relates to particular types of transmission facilities that connect generators directly to the bulk power system (BPS) in the event such entities are not registered as TOs/TOPs. This gap is realized in the following standards:

- (EOP) System Restoration
- (FAC) Connerction Requirements
- (FAC) Vegetation Management
- (PER) Specific training
- (PRC) System Protection Coordination
- (TOP) System Relay Protection

For transmission facilities identified above, Project 2010-07 states that "such Facilities are only to be included in the reliability standards requirements applicable to the Generator Owner or Generator Operator. To ensure that responsibility for the generator interconnection Facilities is included in all necessary standards, however, a select number of standards need to have Generator Owners added to their applicability."[5]

Since a GO/GOP does not operate a generator transmission lead similarly to the manner in which a traditional utility operates other transmission facilities, an interim solution is to apply a more limited subset of TO/TOP reliability standards to GOs/GOPs until the efforts of the longer term reliability standard drafting teams are completed.

Since June 2007 (date of mandatory and enforceable NERC Standards under FERC Order 693)[6], three registration appeals have been decided in which FERC upheld the registrations of GOs/GOPs as TOs/TOPs and recognized the ability to consider a modified set of applicable NERC Reliability

[5] http://www.nerc.com/docs/standards/sar/2010-07_Project_2010-07_Background_Resource_Document_061711.pdf
[6] Docket No. RM06-16-000; Order No. 693 Issued March 16, 2007 "Mandatory Reliability Standards for the Bulk-Power System"

Standards. These registration appeals involved New Harquahala Generating Company, LLC, (New Harquahala)[7], Cedar Creek Wind Energy, LLC (Cedar Creek)[8] and Milford Wind Corridor Phase I, LLC (Milford).[9] NERC's request for clarification or rehearing on the FERC Cedar Creek and Milford order concerning applicability of standards outside the standards development process is currently pending.[10]

Applicability

GOs/GOPs that have the following characteristics based on the factual circumstances will have the opportunity to work with their RE and enter into an MOU that identifies the list of applicable standards as a TO/TOP:

1. has blackstart capability, or
2. a facility that is/has some portion operated at 100 kV or higher and has interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities, or
3. meets the criteria for registration as a TO/TOP as set forth in the NERC Statement of Registry Criteria, or
4. a facility that has some portion operated at 100 kV or higher and has a generator transmission line leading to the inter-connection that has a visual impediment to the inter-connection or has at least three tower structures that include the one connecting span at each end tower.

Process

As discussed above, a GO/GOP that owns or operates a transmission facility that connects the generator to the BPS must comply with a limited set of NERC Reliability Standards and Requirements applicable to TOs and TOPs under the conditions listed below and more fully detailed in the MOU and its Appendix 1, List of Applicable Standards.

Entities that execute an MOU will have six months from the date that the MOU is executed to come into compliance with the applicable standards identified in the executed MOU. During the six-month period, entities are encouraged to identify and mitigate any risks to the BPS. After the six-month implementation period, entities will be registered as a TO and/or TOP and and required to comply with and be subject to Uniform Compliance Monitoring and Enforcement Program[11] (CMEP) provisions for compliance with respect to the reliability standards and associated requirements identified in the MOU. A pro forma MOU is included as Attachment 2, with its Appendix 1.

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[7] 123 FERC ¶ 61,173(May 16, 2008).
[8] 135 FERC ¶ 61,241 (June 16, 2011).
[9] 135 FERC ¶ 61,241 (June 16, 2011).
[10] 135 FERC ¶ 61,241 at p. 7 ("In short, the Commission should clarify that the minimum lists of Reliability Standards included in the June 16 Order are not intended to prejudge either the outcome of the Reliability Standards development process for Project 2010-07, or the Reliability Standards that should apply to Cedar Creek and Milford in advance of the Commission-ordered negotiations.").
[11] http://www.nerc.com/files/Appendix4C_Uniform_CMEP_20110101.pdf

Scheduling of audits for GO/GOPs also registered as a TO/TOPs[12] will be scheduled at the discretion of the RE.[13]

For those GO/GOP entities that have already been registered as TO/TOPs, those entities may request that the list of standards and requirements applied to their TO/TOP obligations be reevaluated by the RE. For those entities with agreed applicability lists that FERC has approved, FERC approval of a change in the list of applicable standards will be required before any changes are implemented.

Concurrent with the end of the six-month implementation period, certification[14] of the entity as a TOP may be accomplished via a desktop process such as webinar and telephone conference presentations.

An alternative into which the GO/GOP may enter is the Coordinated Functional Registration or other duly executed legal agreement for the TO/TOP function. NERC has provided guidance to facilitate a better understanding of the compliance responsibility, registration, and accountability for entities that delegate the performance of reliability related tasks to a third party, specifically NERC Compliance Public Bulletin #2010-004.[15]

Attachments

Attachment 1: Typical Generation Transmission Tie Lines Diagrams

Attachment 2: Pro Forma MOU

Appendix 1: List of Applicable Standards Including Technical Rationale

Contact Information

If you have any questions please contact:

Jim Hughes
Manager of Organization Registration and Certification
North American Electric Reliability Corporation (NERC)
3353 Peachtree Rd. NE North Tower Suite 600
Atlanta, GA 30326
404-446-2574
jim.hughes@nerc.net

[12] CMEP 3.1.4.1 Reliability Standards A Compliance Audit shall include those Reliability Standards applicable to the Registered Entity that are identified in the NERC Implementation Plan for the current year.

[13] CMEP 3.1.3 Frequency of Compliance Audits ……an unscheduled Compliance Audit of any Registered Entity (i) may be initiated at any time by the Compliance Enforcement Authority if reasonably determined to be necessary to ensure the Registered Entity's compliance with Reliability Standards.

[14] The TOP function is a 'certifiable' function in accordance with the NERC Rules of Procedure (RoP) Section 500 and Appendix 5A *Organization Registration and Certification Manual*.

[15] NERC Compliance Public Bulletin #2010-004 "Guidance for Entities that Delegate Reliability Tasks to a Third Party Entity" available at http://www.nerc.com/files/2010-004%20v1%200.pdf.

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RELIABILITY CORPORATION

NERC Compliance Process Directive #2011-CAG-001

Directive Regarding Generator Transmission Leads

Attachment 1

Typical Generator Transmission Leads One-Line Diagrams

RELIABILITY | ACCOUNTABILITY

Glossary of Icons

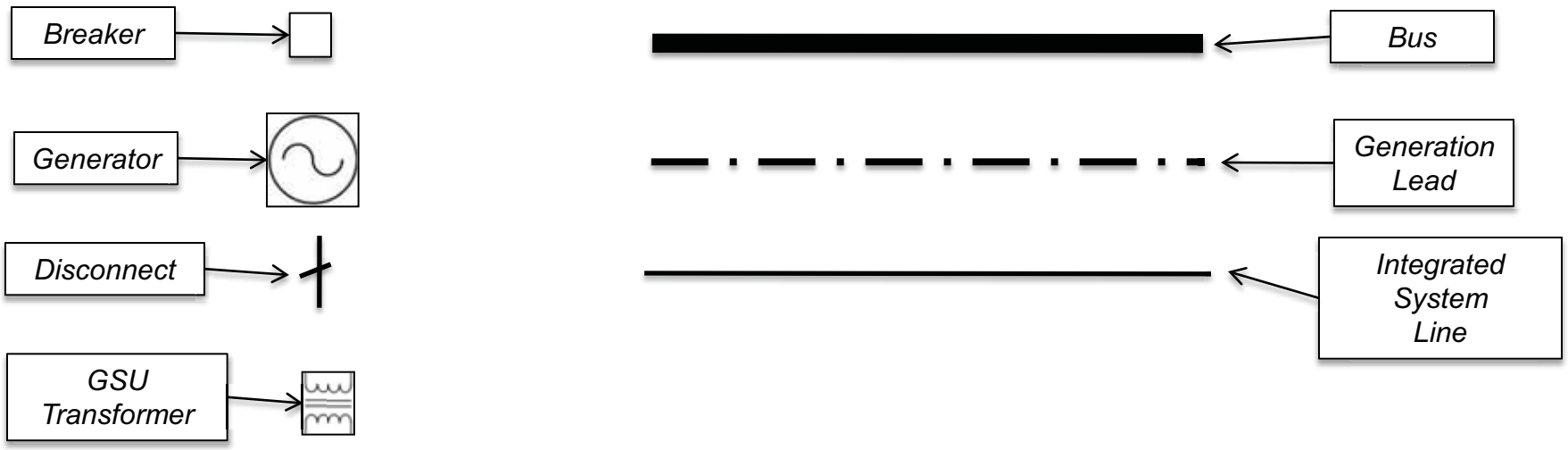

Single Generator Transmission Lead 1a

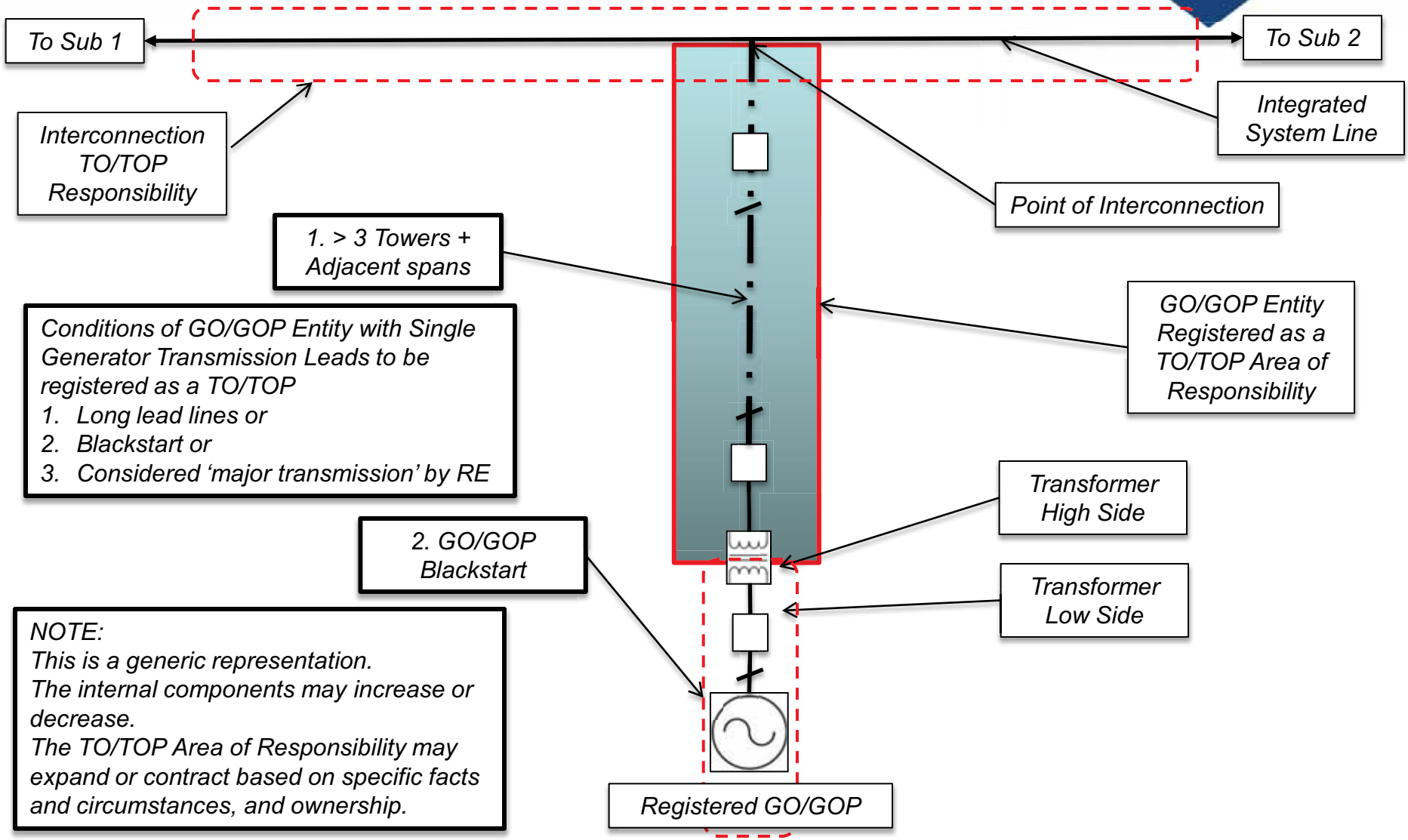

Conditions of GO/GOP Entity with Single Generator Transmission Leads to be registered as a TO/TOP

1. Long lead lines or
2. Blackstart or
3. Considered 'major transmission' by RE

NOTE:
This is a generic representation.
The internal components may increase or decrease.
The TO/TOP Area of Responsibility may expand or contract based on specific facts and circumstances, and ownership.

Multiple Generator Transmission Leads

2a

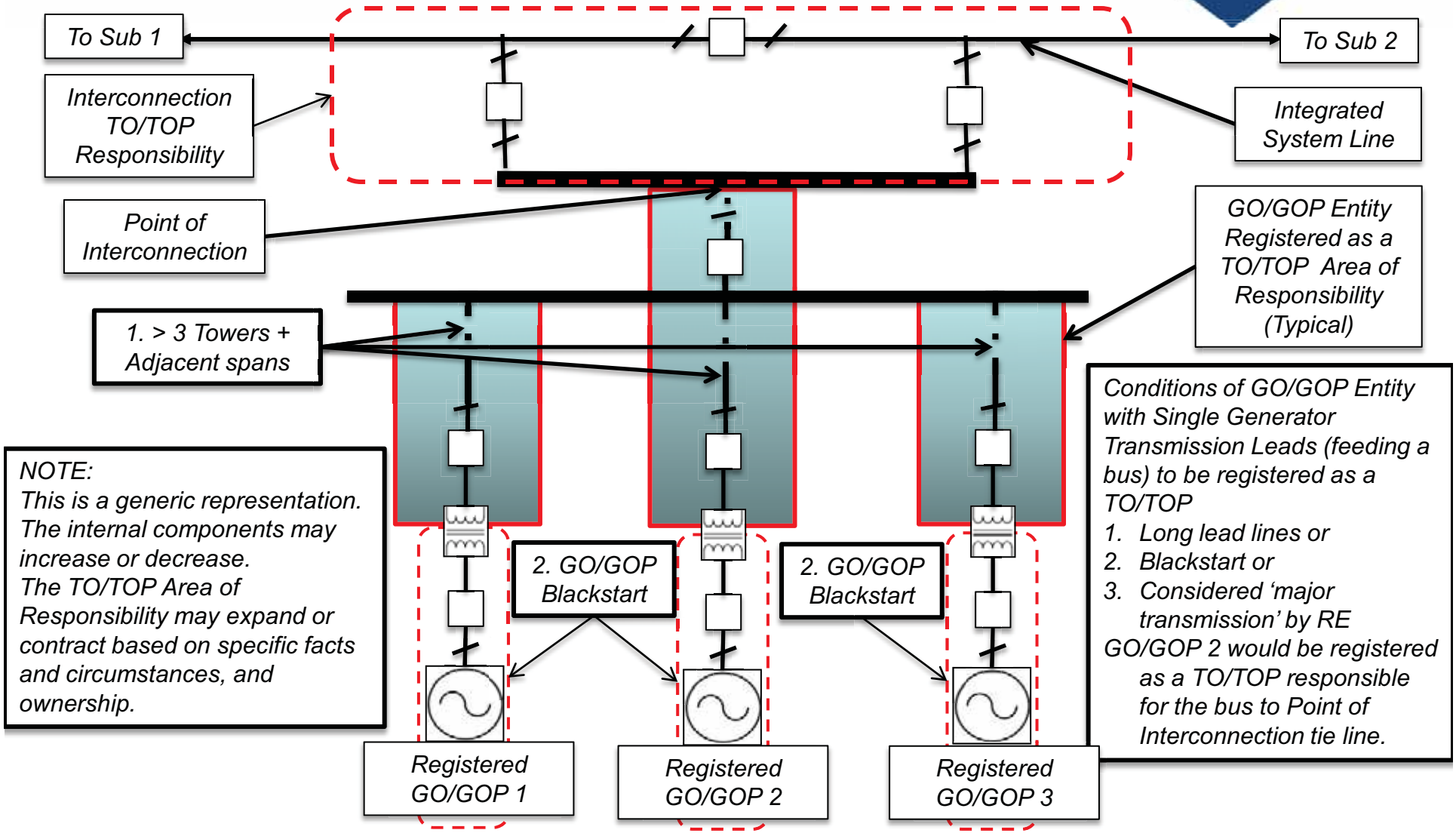

NOTE:
This is a generic representation. The internal components may increase or decrease.
The TO/TOP Area of Responsibility may expand or contract based on specific facts and circumstances, and ownership.

Conditions of GO/GOP Entity with Single Generator Transmission Leads (feeding a bus) to be registered as a TO/TOP

1. Long lead lines or
2. Blackstart or
3. Considered 'major transmission' by RE

GO/GOP 2 would be registered as a TO/TOP responsible for the bus to Point of Interconnection tie line.

MEMORANDUM OF UNDERSTANDING
REGARDING TO and TOP COMPLIANCE OBLIGATIONS

This Memorandum of Understanding ("Memorandum" or "MOU) is between **[Entity]**, **and** the (Regional Entity) ("RE") as delegate of the North American Electric Reliability Corporation ("NERC") in the registration and compliance monitoring and enforcement processes**.** **[Entity]** and RE are referred to herein as "Party" or "Parties" as the case may be. NERC is not a party to this MOU, but the Parties enter into this MOU with the understanding that NERC is aware of the Parties' intent to execute this MOU and have its terms apply to **[Entity]'s** and RE's activities associated with Reliability Standards and the Compliance Monitoring and Enforcement Program.

This MOU sets forth Reliability Standards that will be applied to **[Entity]** associated with its registration as a Transmission Owner ("TO") and/or Transmission Operator ("TOP") as well as the Reliability Standards which will be applicable to [Entity] until either of the Parties terminate this MOU as provided for herein.

RECITALS

WHEREAS, the Energy Policy Act of 2005 was signed into law in August 2005, which added a new Section 215 to the Federal Power Act giving the Federal Energy Regulatory Commission ("FERC") authority over developing and enforcing reliability standards for the Bulk Power System;

WHEREAS, in Docket RR06-1-000, 116 FERC ¶ 61,062 FERC certified NERC as the Electric Reliability Organization ("ERO");

WHEREAS, in Docket RM06-16-000, 118 FERC ¶ 61,218 ("Order No. 693") and in Docket RM06-22-000, 122 FERC ¶ 61,040 ("Order No. 706"), and in other orders, FERC has approved various Reliability Standards applicable to users, owners and operators of the Bulk Power System developed by NERC, and FERC intends to approve additional Reliability Standards;

WHEREAS, NERC, through the RE Delegation Agreement, as amended from time to time, has delegated authority to RE for the purposes of proposing Reliability Standards to the ERO and enforcing Reliability Standards within the RE's footprint;

WHEREAS, TOs and TOPs are required to register with NERC in accordance with the NERC Statement of Compliance Registry Criteria and to comply with specified Reliability Standards applicable to them;

WHEREAS, **[Entity]** is a user, owner, or operator of the bulk power system and is or could be registered by NERC as a [TO and/or TOP] on the NERC Compliance Registry;

WHEREAS, the application of various TO and TOP applicable Reliability Standards to entities such as [Entity] is a matter currently being reviewed and subject to change, see NERC Project 2010-07 Generator Requirements at the Transmission Interface, and, in the interim, as part of the registration and compliance monitoring and enforcement processes, the Parties wish to specifically identify the NERC and RE reliability standards and requirements for which **[Entity]** will be subject to compliance monitoring and enforcement processes, pending completion of any Reliability Standards modifications that may result from the above referenced or similar Projects or until this MOU is terminated by a Party as provided herein;

UNDERSTANDINGS

NOW THEREFORE, in view of the recitals set forth above, which the Parties acknowledge and agree are accurate representations of the facts and are hereby incorporated by reference, the Parties mutually acknowledge the following understandings.

1. DEFINITIONS.

Unless otherwise defined herein, all capitalized terms shall have the meaning set forth in the FERC-approved NERC Glossary of Terms, the NERC Functional Model, the RE/NERC Delegation Agreement, the Compliance Monitoring and Enforcement Program ("CMEP"), and the NERC Rules of Procedure.

"Minimum Applicable Reliability Standard" means a Reliability Standard for which **[Entity]**, in its capacity as a [TO and/or TOP], is or will be subject to the compliance monitoring and enforcement activities specified in the CMEP. **[Entity]**'s Minimum Applicable Reliability Standards are identified at Appendix 1 of this MOU.

"Reliability Standard" means a mandatory Reliability Standard approved by FERC under Section 215 of the Federal Power Act to provide for reliable operation of the Bulk Power System. This definition includes NERC and RE Regional Reliability Standards which have been approved by FERC.

2. SCOPE OF THIS MEMORANDUM

This MOU is applicable to **[Entity]'s** registration as a **[TO and/or TOP]**. To the extent that **[Entity]** may also be registered for other functions, this MOU is not applicable to those functions.

3. RELIABILITY STANDARDS

The Minimum Applicable Reliability Standards are set forth in Appendix 1 to this MOU. RE will update Appendix 1 on an annual basis to reflect FERC approved modifications, deletions and additions to the Minimum Applicable Reliability Standards. RE, in its sole discretion, may include a Reliability Standard to the Appendix 1 list of Minimum Applicable Reliability Standards if the Reliability Standard for any reason becomes applicable to the TO or TOP function subsequent to execution of this MOU.

[Entity's] compliance with any Minimum Applicable Reliability Standard set forth in Appendix 1, or to be included in an Appendix 1 at a future date, shall occur within the time period or on the date arising from FERC approval of such Reliability Standard. If any such time period or date has passed as of the date of execution of this MOU or [Entity] is unable to comply with any Minimum Applicable Reliability Standard within the time period or on the date applicable to a Minimum Applicable Reliability Standard, the processes set forth in the CMEP are applicable to any **[Entity]** non-compliance with such Applicable Reliability Standard.

4. THIRD PARTY PERFORMANCE OF TASKS ASSOCIATED WITH RELIABILITY STANDARD REQUIREMENTS

It is understood that an **[Entity]** may enter into agreements to use qualified third party contractors or agents to meet its obligations under Reliability Standards. Although an entity may enter into such agreements, the ultimate responsibility for ensuring compliance with Reliability Standard requirements remains with the registered entity.

5. CHANGE IN COMPLIANCE RESPONSIBILITY OR REGISTRATION STATUS OF ENTITY

[Entity]'s compliance responsibilities and obligations treated in this MOU may be assigned to another Registered Entity only with written RE approval and under applicable law. Should the status of **[Entity]** as a **[TO and/or TOP]** change for any reason, including but not limited to acquisition, transfer, sale or other transaction involving **[Entity]** or its facilities, **[Entity]** will promptly notify RE.

6. AUDITS AND ENFORCEMENT

[Entity] understands that its compliance with Minimum Applicable Reliability Standards is subject to audit, enforcement and possible mitigation, penalties or sanctions pursuant to Section 215 of the Federal Power Act and related regulations, orders and policies of FERC, NERC and RE. RE may monitor, assess, and enforce compliance with applicable Reliability Standards using any and all available monitoring, assessment and enforcement activities allowed by NERC and FERC.

7. GENERAL TERMS AND CONDITIONS

7.1 Dispute Resolution. Any dispute regarding an enforcement action asserting non-compliance with any Minimum Applicable Reliability Standard will be resolved in accordance with Section 5.0 of the CMEP.

7.2 Liability. Except for corrective action, penalties and sanctions assessed pursuant to applicable law, no Party to this MOU will be liable to any other party for any indirect, special, incidental or consequential losses, damages, claims, liabilities, costs or expenses (including attorneys fees and court costs) arising from the performance or non-performance of its obligations explicitly arising under the operation of this MOU.

7.3 Confidentiality. RE acknowledges that for the purposes of this MOU and in its activities monitoring and enforcing Minimum Applicable Reliability Standards, it may receive information from **[Entity]** that has been marked "Confidential" in accordance with Section 1500 of the NERC Rules of Procedure. Where so marked, RE will protect such information from disclosure in accordance with the procedures set forth at Section 1500 of the NERC Rules of Procedure ("ROP") and Section 9.0 of the CMEP. However, nothing contained in the body of this MOU is intended to constitute Confidential Information as defined in NERC ROP 1501. This MOU will not be treated as confidential; RE may release this MOU to third parties upon request, with written notification of said release to **[Entity]**.

7.4 No Contract or Third Party Beneficiaries. This MOU is intended to document the Parties' mutual understandings. This MOU is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities including the Parties or any Third Party.

7.5 Multiple Counterparts. This MOU may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

7.6 No Partnership. This MOU will not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party will have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, another Party.

7.7 Governing Law. The interpretation of this MOU will be governed by the law of [**to be determined**], excluding its conflicts of law rules, except if a federal party is involved, in which case federal law will apply as if performed within the state of [to be determined].

7.8 Notices.
Any written notice provided in this MOU will be transmitted via electronic mail to the persons identified in herein followed with a hard copy delivered in person, sent by overnight mail or United States certified mail within three (3) days of the electronic mail transmission. Electronic mail notice will be deemed effective upon transmission unless the Party sending the electronic mail learns that delivery was unsuccessful, in which case notice is deemed effective upon service of the hard copy. Any Party may at any time, by at least fifteen (15) days notice to the other Party, change the designation or address of a person specified herein. Such a change will not constitute an amendment to this MOU. Notices under this section pertain only to this MOU and do not affect or alter any notification requirements or timelines specified in the NERC ROP or the CMEP.

Notices shall be sent to: XXXXXX

8.0 TERMINATION

RE or **[Entity]** may terminate this MOU at any time by providing written notice within XXXX days. Violations of applicable Reliability Standards as of the termination date survive this termination provision. In addition, violations committed prior the termination date but discovered after the termination date also survive termination of the agreement. Finally, termination does not affect registration as a TO/TOP.

IN WITNESS WHEREOF, the Parties have executed this MOU and it is effective as of date of the last signature below.

Dated: RE

By _____

Dated: **[Entity]**

By _____

APPENDIX 1

APPLICABLE RELIABILITY STANDARDS

From:	Margaret Mayora
To:	Stanley E. Kopman; Walter Cintron
Cc:	grpStaff
Subject:	NERC Draft Directive Regarding Generator Leads
Date:	Thursday, October 20, 2011 11:58:54 AM
Attachments:	NERC_Draft_Directive.pdf

Stanley and Walter:

Below is a summary of the NERC draft directive regarding generator leads from NPCC's D.C. counsel.

Please note that the deadline for comments has been extended from October 28th to November 15th.

Margaret

MARGARET MAYORA
COMPLIANCE ATTORNEY
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas - 10th Floor
New York, NY 10018
(T) 212 840-1070; (F) 212 302-2782

From: McCarthy, Catherine P. [mailto:CMcCarthy@deweyleboeuf.com]
Sent: Thursday, October 20, 2011 11:24 AM
To: cmccarthy@deweyleboeuf.com
Subject: NERC Draft Directive Regarding Generator Leads

We provided a short summary of the attached NERC draft directive earlier. Below is some additional analysis on this important NERC item that is likely to be significant for many generators.

NERC Issues Draft Directive Regarding Generator Leads

On October 6, 2011, the North American Electric Reliability Corporation ("NERC") released for comment a draft Directive regarding generator lead lines. The draft Directive would create a bright-line test that would require many Generator Owners/ Operators to be registered as Transmission Owners/ Operators. The purpose of the draft Directive is to provide interim guidance until reliability standards are drafted to address what NERC perceives to be a "reliability gap" stemming from the fact that Generator Owners/ Operators that own or operate transmission facilities are currently not required to comply with many of the reliability standards applicable to Transmission Owners/ Operators.

The draft Directive takes into consideration the June 6, 2011 Federal Energy Regulatory Commission ("FERC") order[1][1] that upheld two NERC determinations that Cedar Creek Wind Energy, LLC ("Cedar Creek") and Milford Wind Corridor Phase I ("Milford Wind"), Generator Owners/ Operators, were properly registered as a Transmission Owners/ Operators by the Western Electricity Coordinating Council. Requests for rehearing on the order are pending before FERC. NERC is soliciting comments on the draft Directive and has established a deadline for comments of October 28, 2011.

As a result of the perceived reliability gap identified above, Regional Entities began registering Generator Owners/ Operators that owned and/or operated transmission facilities as Transmission

Owners and/ Operators *in addition* to their registration as Generator Owners/ Operators. NERC is evaluating whether a subset of Transmission Owner/ Operator standards and requirements should apply in such cases. Typically, the generation facilities at issue were those facilities needed to interconnect the generator to the grid. For example, the transmission at issue for Cedar Creek and Milford Wind were generation tie line interconnection facilities connected to the Bulk-Power System. The draft Directive appears to be broad and would seem to apply to Generator Owners/ Operators with one or more of the following characteristics:

- Own/Operate a generation facility with blackstart capability that has single or multiple generator transmission leads; or
- Has associated transmission facilities that are/have some portion operated at 100kV or higher and are interconnected with neighboring Generator Operator(s), Transmission Operators and Balancing Authorities; or
- Meet the criteria for registration as a Transmission Owners and/ or Operators as set forth in the NERC Statement of Registry; or
- Have transmission facilities with some portion operated at 100kV or higher and has a generator transmission line leading to the interconnection that has a visual impediment to the interconnection or has at least three tower structures that include the one connecting span at each end tower.[2][2]

The draft Directive contains a pro forma Memorandum of Understanding ("MOU") that would be negotiated and executed between Regional Entities and Registered Entities. Registered Entities that execute a MOU will have six months from the date that the MOU is executed to become compliant with the applicable standards. After the six months, Registered Entities will be registered as a Transmission Owner and/or Operator and will be required to comply with the requirements identified in the MOU.

It is not clear whether NERC would have the authority to implement the draft Directive without prior FERC approval. Additionally, the pro forma MOU allows Regional Entities to negotiate terms which may lead to inconsistencies with how the requirements are applied in different regions, and also allows the Regional Entity to terminate the MOU at any time which would likely subject a Registered Entity to all of the Transmission Owner and/ or Transmission Operator Reliability Standards.

---

[1][1] Cedar Creek Wind Energy, LLC and Milford Wind Corridor Phase I, LLC, 135 FERC ¶ 61, 241 (June 16, 2011).

[2][2] See diagrams attached to the draft Directive.

From: Goodman, Kathleen
To: Guy V. Zito; Lee R. Pedowicz
Subject: FW: NERC: Draft Directive Regarding Generator Transmission Leads
Date: Tuesday, October 18, 2011 1:28:00 PM

I think we should look at…

From: Stacia-Ann Chambers [mailto:Stacia-Ann.Chambers@nerc.net]
Sent: Monday, October 17, 2011 9:49 AM
To: trades
Subject: NERC: Draft Directive Regarding Generator Transmission Leads

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Announcement

Draft Directive Regarding Generator Transmission Leads

October 17, 2011

Click here for: Draft Directive
Click here for: Attachment 1 – Examples of Typical Generation Transmission Tie Lines
Click here for: Attachment 2 – Pro Forma Memorandum of Understanding (MOU)
Click here for: Appendix 1 to the MOU – Applicable Standards

Ladies and Gentlemen:

The Draft NERC Compliance Process Directive, regarding Generator Transmission Leads, is provided for industry review and comment. The Directive will provide guidance to address the reliability gap that exists between GO/GOPs that own/operate transmission facilities (meeting the NERC Statement of Compliance Registry Criteria) but are not registered as TO/TOPs.

As a result of this reliability gap, NERC and the Regional Entities (RE) began registering

GO/GOPs that owned and/or operated transmission facilities as TO/TOPs in addition to their registration as GO/GOP. The ERO is evaluating whether a subset of TO/TOP standards and requirements should apply in such cases.

Four documents are provided:

1. Draft Directive
2. Attachment 1- Examples of Typical Generation Transmission Tie Lines
3. Attachment 2 – Pro Forma Memorandum of Understanding (MOU)
4. Appendix 1 to the MOU – Applicable Standards

Further, this Directive takes into consideration the FERC order concerning the registration appeal of Cedar Creek and Milford and FERC's determination regarding a minimum set of applicable standards to each entity. Requests for rehearing of the order are pending. Appendix 1 is subject to the outcome of the order on rehearing.

This Directive does not prejudge the outcome of the Standards Development Process.

NERC would appreciate industry comments, consolidated by the industry trade association and forum representatives this announcement is delivered to, no later than November 15, 2011. Please provide detailed technical justifications for revisions that you propose to Appendix 1.

Please forwards your comments to:

- Jim Hughes
- Jack Wiseman
- Stacia-Ann Chambers

Thank you for your assistance.

For more information or assistance, please contact Jim Hughes or Jack Wiseman (via email).

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-

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance Application Notice — 0020

~~Compliance Application:~~ TPL-002, TPL-003, TPL-004 and TOP-002 Equipment Maintenance Outages

Posted: [DATE]

Primary Interest Groups
Compliance Enforcement Authority (CEA)[1]
NERC
Regional Entity~~ies~~
Registered Entities subject to TPL-002, TPL-003, TPL-004 and TOP-002

Issue: What ~~other planned~~[2] maintenance outages should be addressed under the ~~TOP~~ TPL standards ~~or~~ versus under the TOP~~PL~~ s~~S~~tandards?~~.~~
For the purpose of aiding a CEA, this CAN provides instruction for a assessing ~~NERC received a request for further clarification~~[3] ~~of~~ whether maintenance outages, including Protection Systems, must be included ~~in operational planning studies under TOP-002 or~~ in transmission planning assessments under TPL-002, TPL-003, and TPL-004 or in operational planning studies under TOP-002.[4]

Summary of Compliance Application Notice
A CEA is to verify that ~~P~~planned maintenance outages, including planned outages for the maintenance and testing of Protection Systems, ~~that are known and scheduled in the planning timeframe, must be~~were considered in TPL assessments. An outage is "planned" when it is included on an approved Transmission Operator (TOP) or Balancing Authority (BA) outage schedule. Therefore, a CEA is to verify that any outages that were included on the approved,

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard requirements.
~~[2] "Planned" is not interchangeable with the term "scheduled." "Planned" refers to an activity that is known and therefore can be considered in the planning horizon; "scheduled" means that the activity has been given a specific date or dates upon which the activity will be conducted.~~
~~[3] FERC approved an interpretation for TOP-002-2 on December 2, 2009 in the *Order on Reliability Standard Interpretation*, 129 FERC ¶ 61,191 (2009) and an interpretation for TPL-002 and TPL-003 on April 23, 2010; in the *Order on Reliability Standard Interpretation*, 131 FERC ¶ 61,068 (2010).~~
[4] FERC approved an interpretation for TOP-002-2 on December 2, 2009 in the *Order on Reliability Standard Interpretation*, 129 FERC ¶ 61,191 (2009) and an interpretation for TPL-002 and TPL-003 on April 23, 2010; in the *Order on Reliability Standard Interpretation*, 131 FERC ¶ 61,068 (2010).

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DRAFT

applicable TOP or BA outage schedule more than 12 months out from the time the TPL assessment was conducted were included in the entity's TPL assessments.

However, a CEA is to verify that ~~A~~all ~~planned~~ maintenance outages, including maintenance and testing of Protection Systems ~~that are known and scheduled in the operations timeframe~~, ~~must be~~were included in the entity's operational planning studies under the TOP standard.

~~**Reliability Objective**~~
~~The rReliability Oobjective is to ensure the interconnected BES BPS transmission system is planned such that the nNetwork can be :~~
~~Operated to address current system conditions and ensure acceptable reliability performance at all times, including during planned Protection System maintenance outages.~~
~~1) Operated to address current system conditions, including the impacts on system reliability that may result from planned protection system maintenance.~~

Background
TPL-002, TPL-003 and TPL-004
TPL-002, -003 and -004 addresses planning for the near term (years 1 through 5). TPL-002 and TPL-003 also address planning for the longer term (years 6 through 10).

The three standards contain similar requirements specifying that the *Planning Authority*[5] and *Transmission Planner (TP)* shall each demonstrate, through a valid assessment, that its portion of the interconnected transmission system is evaluated for the risks and consequences of contingencies, and to be valid, the assessment shall Include the planned (including maintenance) outage of any bulk electric equipment (including Protection Systems or their components) at those demand levels for which planned (including maintenance) outages are performed (*see* TPL-002-0 R1.3.12, TPL-003-0 R1.3.12 and TPL-004-0 R1.3.9).

TOP-002
TOP-002 addresses planning for current-day, next-day, and seasonal operations.

This standard requires that the ~~*Balancing Authority*~~*BA* and ~~*Transmission Operator*~~*TOP* will plan to meet unscheduled changes in system configuration (R6) and perform seasonal, next-day, and current-day Bulk Electric System studies to determine System Operating Limits (SOLs) (R11).

General Discussion

~~**Compliance Application**~~
~~TPL-002/TPL-003/TPL-004~~

[5] The Planning Authority was renamed "Planning Coordinator" in the Functional Model dated February 13, 2007. TPL -002, TPL-003 and TPL-004 use the former "Planning Authority" name; the Functional Model terminology was a change in name only and did not affect responsibilities.

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~~TPL-002-0 provides, in pertinent part:~~

> ~~***R1.3.*** *Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).*[6] *...*~~
>
> > ~~***R1.3.12****. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.*~~

~~*TPL-003-0 provides, in pertinent part:*~~

> ~~***R1.3*** *Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).*[7] *...*~~
>
> > ~~***R1.3.12****. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.*~~

~~*TPL-004-0 provides, in pertinent part:*~~

> ~~***R1.3.*** *Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).*[8] *...*~~
>
> > ~~***R1.3.9.*** *Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.*~~
>
> ~~Outages to be included in TPL assessments~~

---

[6] ~~Consistent with applicable FERC precedent, the term 'Regional Reliability Organization' in this context refers to the Regional Entity. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). *See* paragraph 157 of Order 693.~~

[7] ~~*See* footnote 45.~~

[8] ~~*See* footnote 45.~~

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~~TPL assessments must include all planned and scheduled equipment maintenance outages, including Protection System maintenance outages, that are to occur within the near-term (years one through five) and longer-term (years six through ten) planning horizons.~~

~~The distinction between planned maintenance outages that must be included in the TPL assessment versus the TOP operational studies is in how far in advance of the outage that it is scheduled. At some point, all maintenance outages are planned and scheduled. If an outage, including a Protection System maintenance outage, is scheduled more than 12 months in advance then that outage would fall within the TPL planning horizon and would be required to be evaluated as a planned outage pursuant to R1.3.12 of the TPL-002-0 and TPL-003-0 standards and R1.3.9 of TPL-004-0.~~

Although there are situations in which maintenance outages are planned and scheduled more than 12 months in advance, more often maintenance is placed on an approved TOP or BA outage schedule in the operating horizon, less than 1 year out from the planned maintenance. Most maintenance plans ~~have to~~ are~~be~~ developed and therefore the associated outages are planned ~~scheduled~~with less lead time. In this case, the lead time makes it impractical for inclusion in planning studies under the TPL timeframe.

~~much sooner to when the outages are expected to occur. This does not circumvent the requirements of TPL—maintenance scheduling in the operating horizon is driven by requirements to coordinate the actual work and to study system conditions that are as close as possible to those expected when the maintenance outage occurs. The scheduling is fluid in real time as managers schedule work crews, procure equipment, and perform other tasks pertaining to the maintenance.~~ Additionally, since maintenance outage windows typically occur in the spring and fall months, multiple outages may be scheduled concurrently if reliability considerations permit them to be scheduled.[9] Therefore, if an outage is required for Protection System maintenance and testing, it may be planned in the operating horizon and tagged on to an outage required for another purpose. ~~The Transmission Operator has the additional responsibility of resolving any potential scheduling conflicts that develop, with the Reliability Coordinator performing any required arbitration. Due to the need to schedule these outages close to the time the outage is taken, the TPL planners would not be aware of them at the time the long-term planning studies are being conducted. Any planning study performed under the TPL standard 12 months prior to the outage(s) would have little value to the Transmission Operators scheduling outages.~~

All Protection System maintenance outages must be evaluated in the TOP planning timeframe through operating studies in order to accurately assess the system impact in the context of ~~existing~~ system topology and expected generation dispatch. ~~, and other outages.~~ Results of any Protection System outages that were analyzed in the TPL planning horizon may be helpful to the

[9] The Transmission Operator has the responsibility of resolving scheduling conflicts resulting in detected reliability impacts with the Reliability Coordinator pursuant to TOP-001-1 R7.2; TOP-002-2a R1, R2 and R11; TOP-003-0 R1.2 and R3; TOP-004-2 R2, R3, R6 and R6.3; IRO-005-4 R1 and IRO-010.a R1 and R3.

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~~Transmission Operator~~TOP in designing his ~~analysis~~operating study analysis, but those TPL studies are typically done with all lines assumed to be in service. ~~Statistically, t~~That is never the case in the operating horizon.

For example, if a transmission line has fully functional and equivalent A and B protection packages, one of those may be removed from service without requiring an outage. ~~fully redundant Protection Systems are~~ When fully functional and equivalent A and B protection packages are available, planned maintenance and testing can be performed on one of these Protection Systems without a loss of protection, and no outage of the protected system element is needed. Therefore, these outages need not be included in the transmission assessment. ~~However, when fully redundant protection is not available, outages of the protected system element may be required in order to perform the planned Protection System maintenance and testing. If the maintenance was known and scheduled in the TPL planning horizon, the maintenance outage would be included in the TPL assessments. Regardless if the Protection System maintenance and testing is included in the TPL assessments, the Transmission Operator must analyze the impact of system performance in context of all other outages that will be ongoing at the time of the planned maintenance, and thus must be included in the operational studies under the TOP standard.~~

Compliance Application

TPL-002-0 provides, in pertinent part:

> ***R1.3.*** *Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).*[10] *…*
>
> > ***R1.3.12****. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.*

TPL-003-0 provides, in pertinent part:

> ***R1.3*** *Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).*[11] *…*

[10] Consistent with applicable FERC precedent, the term 'Regional Reliability Organization' in this context refers to the Regional Entity. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). *See* paragraph 157 of Order 693.
[11] *See* footnote 4.

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> ***R1.3.12**. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.*

TPL-004-0 provides, in pertinent part:

> ***R1.3.** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).*[12] *…*
>
> > ***R1.3.9.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.*

Outages to be included in TPL assessments

A CEA is to verify that a registered entity's TPL assessments include all "planned" equipment maintenance outages, including Protection System maintenance outages, that are to occur within the near-term (years one through five) and longer-term (years six through ten) planning horizons.

A CEA is to use the following to determine whether the outage is "planned" in the TPL planning horizon as required by the standard:

1. if it is included on an approved, applicable TOP or BA outage schedule; and
2. if the outage was included on the approved, applicable TOP or BA outage schedule more than 12 months out from the time the TPL assessment was conducted.

~~However, if a registered entity's equipment persistently fails, the registered entity cannot plan on the equipment being in service. Therefore, the registered entity must include the equipment in the TPL planning horizon as "not available."~~

TOP-002-2 R11

TOP-002-2 R11 provides:

> ***R11.** The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators,*

[12] *See* footnote 4.

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Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.

Outages to be included in TOP evaluations

Under R11, a CEA is to verify that the ~~Transmission Operator~~TOP ~~must~~ incorporated **all** ~~planned and scheduled~~ maintenance outages – including short duration Protection System outages – in its current-day, next-day, and seasonal operational planning studies to properly account for current system conditions as discussed above.

~~Additionally, the Transmission Operator must determine if its operational planning studies may or may not require additional evaluation (such as the assessments conducted by the planners under the TPL standard) conducted under the TOP current-day, next-day, and seasonal planning horizon.~~

Effective Period for CAN

This CAN is effective upon posting as final on the NERC Web site, and is to be used by CEAs to assess compliance from the posting date forward, regardless of the start date of any non-compliance or Possible Violation. It supersedes all prior communications and will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

For any enforcement action in process and for audits that have been initiated,[13] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.

~~Compliance Guidance~~Providing Evidence of Compliance

TPL-002, TPL-003, TPL-004

A CEA is to assess the following to obtain reasonable assurance of the entity's compliance: ~~A registered entity must be able to provide an auditor or Compliance Enforcement Authority:~~

1. Evidence that a valid assessment for its portion of the interconnected transmission system had been completed~~,~~ and included any ~~planned and scheduled~~ outages of bulk electric equipment, including maintenance outages for equipment or Protection Systems that were included on an approved, applicable TOP or BA outage schedule during the planning timeframe.

TOP-002 R11

A CEA is to assess the following to obtain reasonable assurance of the entity's compliance:
~~A registered entity must be able to provide an auditor or Compliance Enforcement Authority:~~

[13] "Initiated" means that a registered entity has received notification of the upcoming audit.

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1. Evidence that its current-day, next-day, and seasonal operational planning studies evaluated all ~~planned and scheduled~~[14] maintenance outages, including Protection Systems maintenance outages.

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This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

[14] ~~Balancing Authorities and Transmission Operators are required to plan for unscheduled outages under TOP-002 R6, which provides: "Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, sub-regional and local reliability requirements.~~

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance Application Notice — 0030

~~Compliance Application:~~ Attestations

Posted [DATE]

Primary Interest Groups
Compliance Enforcement Authority (CEA)[1]
NERC
Regional ~~Entities~~ Entity ~~(RE)~~
Registered ~~Entities~~Entity

Issue: When is an attestation ~~is~~ suitable evidence of compliance~~.~~?
For the purpose of aiding a CEA, this CAN provides instruction for assessing ~~NERC received a request for clarification regarding~~ the appropriate situations and uses of attestations as evidence of compliance with a reliability standard.

~~**Reliability Objective**~~
~~Attestations may be appropriate, in certain circumstances, to demonstrate an entity's compliance for the audit period.~~

Background
An attestation is a written statement of fact, voluntarily made under an oath or affirmation and signed by the author~~, and witnessed for authenticity by a notary public~~. In certain situations where documentation is not available, attestations~~, coupled with corroborating evidence,~~ may be provided to ~~auditors and Compliance Enforcement Authorities (~~CEAs~~)~~ to demonstrate compliance. As with any other piece of evidence, the persuasive value of an attestation will be determined by the ~~auditors and~~ CEAs reviewing it.

Compliance Application
A CEA is not to accept an attestation as a substitute for the registered entity's obligation to have maintained adequate records. However, ~~There~~ there ~~are a limited~~~~limited~~may be ~~number~~ circumstances~~,~~ ~~provided below,~~ ~~where~~ in which ~~CEAs are instructed to accept~~ a written attestation may be accepted ~~is acceptable~~ as evidence of compliance, particularly if corroborating evidence is available. ~~Below are examples of situations in which an attestation would be acceptable.~~

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard and requirements.

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DRAFT

~~In these examples described below,~~ CEAs are instructed to accept attestations. ~~and to request~~ ~~c~~Corroborating evidence as outlined in the three examples ~~outlined~~ below is preferred~~and request certain corroborating evidence~~. If no corroborating evidence is available, CEAs are not precluded from accepting an attestation but must evaluate the facts and circumstances to determine whether the attestation by itself constitutes sufficient evidence. CEAs are also instructed to accept attestations when an attestation is required or acceptable pursuant to a standard or a compliance communication, such as another CAN or Bulletin. In every case in which an attestation is accepted~~situations~~, ~~auditors and~~ CEAs ~~may~~ are to evaluate the persuasive value of an attestation depending on the quality and specificity of the statements, and any corroborating evidence. ~~A CEA is not to accept~~ A~~an attestation is as not a substitution for the registered entity's obligation to have maintained adequate records.~~

1. A CEA is instructed to ~~find~~accept ~~A~~an attestation ~~would be considered appropriateacceptable when~~ in the case that evidence is not available or is not complete due to a force majeure event~~, among other things, due to events outside of the entity's control, such as records being destroyed by a force majeure event~~ including, but not limited to, natural disasters and ~~catastrophic~~ computer malfunctions. ~~In the event that an entity suffers a loss of evidence from events that it cannot control, such as a fire, flood, other natural disaster or event causing the loss of information, CEAs are instructed to accept an attestation from the entity.~~

2. CEAs are instructed to accept ~~A~~attestations ~~would also be appropriate to~~in support of an entity's position that an event or situation did not occur. An example of this scenario is if an entity is to perform a duty upon receiving communication. In order to support the entity's position that it did not receive any communication that would require performance, a CEA is to look for evidence such as a blank log book, showing that no communication occurred, and/or statements from entities to support the entity's attestation.

~~1.~~3. Finally, a CEA is instructed to ~~consider~~accept an attestation ~~would be appropriate~~ in situations ~~where~~in which the evidence retention period for audit purposes is longer than the document retention period in a standard, consistent with Bulletin #2011-001, Data Retention.[2]

~~When an entity needs to provide evidence to show that an event did not occur, an attestation can be submitted. An example of this scenario is if an entity must perform a duty when it received a communication. In order to support the entity's position that it did not receive any communication that would require performance, the entity could provide a blank log book showing that no communication occurred and/or statements from entities that would have provided the requesting communicationto support the entity's attestation.~~

~~In the event that an entity suffers a loss of evidence from events that it cannot control, such as a fire, flood, other natural disaster or event causing the loss of information, an attestation can be used for audit purposes. The registered entity may still be found to be out of compliance, but the surrounding circumstances, e.g., the event that resulted in the unavailability of the evidence occurred without fault~~

[2] ~~-~~*See* Public Notice – NERC Compliance Process Bulletin #2011-001, Data Retention, located at http://www.nerc.com/page.php?cid=3|22.

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~~of the entity, could be considered a mitigating factor in the determination of an assessed penalty. Auditors and CEA will evaluate force majeure situations on a case-by-case basis.~~

~~In all cases in which an attestation is provided, the auditors~~CEAs ~~will~~ are to ~~evaluate both the attestation and the quality of the corroborating evidence when~~and the entity providing the attestation may ~~evaluating~~ still be found ~~to be out of compliance.~~

Effective Period for CAN

This CAN is effective upon posting as final on the NERC Web site, and is to be used by CEAs to assess compliance from the posting date forward, regardless of the start date of any non-compliance or Possible Violation. ~~It supersedes all prior communications and will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.~~

For any enforcement action in process and for audits that have been initiated,[3] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN. ~~This CAN is effective upon final posting on the NERC Web site, and will be used by ERO auditors to apply compliance for any Possible Violations discovered from the posting date forward, regardless of the date of the violation. It supersedes all prior communications and will remain in effect until a future CAN supersedes it or until such time that a future version of the standard or an interpretation addresses this specific issue and is enforceable.~~

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~~Providing~~ Evidence of Compliance

A CEA is to assess the following, in addition to an attestation, to obtain reasonable assurance of the entity's compliance (as indicated above~~,~~; however, if no corroborating evidence is available, ~~the~~a CEA must evaluate the facts and circumstances to determine whether the attestation by itself constitutes sufficient evidence):

~~When providing attestations in the above situations, a registered entity would need to provide supporting evidence as follows:~~

1. For incomplete records, a CEA is to look for ~~registered entity must provide~~ all applicable records in ~~its~~ a registered entity's possession.

2. To support a position that an event did not occur, a CEA is to look for ~~registered entity must provide~~:

    a. Log books or records (either hardcopy or electronic) that show a blank entry or lack of an entry,

    b. A documented process to demonstrate how an event or request would have been recorded,

[3] "Initiated" means that a registered entity has received notification of the upcoming audit.

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c. Additional statements from other internal operating personnel or from other entities that have actual knowledge of the event,~~,~~ or

d. Other corroborating evidence to show that an event did not occur.

~~2.~~

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3. In the event that the evidence retention period for audit purposes is longer than the document retention period in a standard, a CEA is instructed to ~~to accept an attestation or may look for other forms of corroborating evidence as~~look for the type of evidence outlined in Bulletin #2011-001, Data Retention.[4]

~~3. When no evidence remains from a force majeure event, registered entities must provide records associated with the event's occurrence as well as a list of the actualsummary of the types of data that was lost due to the event.~~

CEAs may accept
~~Registered entities may use~~attestations based on the ~~NERC~~ sample ~~Attestation~~ attestation ~~Form~~ form that is attached to this CAN, or ~~they may use their own~~other forms of attestation or affidavit documents provided by registered entities. The attached form is meant to be used as a guideline and is not a mandatory format for submitting an attestation to an auditor.

For more information please contact:

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This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.
~~*This document is designed to convey compliance guidance from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the NERC Reliability Standards as they may be amended from*~~

[4] *See* Public Notice – NERC Compliance Process Bulletin #2011-001, Data Retention, located at http://www.nerc.com/page.php?cid=3|22.

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~~*time to time. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose NERC compliance personnel from accepting a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of this Compliance Application Notice is not a substitute for compliance with requirements in NERC's Reliability Standards.*~~

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(Sample Attestation Form)

[Add Registered Entity Letterhead]

Registered Entity Name: (NERC ID# NCR######)

County of:

City of:

ATTESTATION

I, [NAME], certify that I am [TITLE], [REGISTERED ENTITY]; that I am authorized to execute this ~~Affidavit~~attestation; that I am familiar with the [REGISTERED ENTITY]'s attached statements; that, to the best of my information, knowledge and belief, the statements and supporting documents appended to this ~~verification~~ attestation are true and correct as of the date of signing ~~and will be updated on a continuing basis until final resolution~~.

[SIGNATURE]
[NAME]
[TITLE]
[REGISTERED ENTITY]
[CONTACT INFORMATION – ADDRESS, PHONE, FAX, E-MAIL]

~~Subscribed and sworn to before me on the [DAY] day of [MONTH][YEAR].~~

~~[SIGNATURE]~~
~~Notary Public~~

~~My Commission Expires:~~

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CIP 706 DT Meeting, Sept 2011.

Purpose of the meeting is to finish all the draft standards to submit for a quality review to NERC staff. The group intends to review each requirement from each standard. The SDT leadership is not supportive of a lot of changes to be proposed at this meeting. The SDT will review and finalize the implementation plan for quality review and also the "change justification" and "mapping document" for each standard. At the end of the meeting there will be individual assignments given to each DT member and some observers in order to meet the tight schedule.

October meeting will be a review of the results of the Quality Review

Anticipated posting for November 3rd. NERC staff indicated that the filing must be completed by third quarter 2012.

Industry updates

- DOE/NIST/Risk Management Process currently posted for comment, it is version 1 of the guideline.
- NERC Cyber Attack TF went through a scenario/exercise and reviewed potential vulnerability and solutions. Document will be made available for public comment within approximately 30 days. Report should be published by the end of the 2011 which will describe what scenario was looked at what was discovered and if any gaps were identified. The results will go to the Electricity Sector.
- NERC GridEx November 16-17. Planning complete with active exercise with participants and observers. Send Scott Mix an email to participate. It will be similar to the govt. exercises and was developed by asset owner SMEs. It is intended to provide a realistic simulation of what may happen. Will consist of emails, notifications, responses.
- NERC GridSecCon- October 18-20, New Orleans, two day agenda-high level government speakers. On the 18 will be an INL training course as well as SANs and industrial control systems training. Conference will be $250 and be 19th and 20th. Information is on the NERC website
- FERC NOPR published last week and is soliciting comments for 60 days from when it is published in the Federal Registry(perhaps next week) proposing to accept Version 4 and soliciting comments. The NOPR mentions expectations regarding deadlines of the CIP 706 directives and expresses concern with a stakeholder process that may not achieve approvals of the Version 5. FERC is strongly urging comment submission and the staff seem to be waivering and not supportive or critical of it.

Process for the Version 5 will be as follows. Preparation for Quality review this week to take place. It will be reviewed from a Compliance, Legal and Process related point of view. There are 50 volunteers currently who will be engaged in the review for a number of 2 day sessions preceded by a plenary session. The SDT will meet in October to review the determinations of the quality review teams. The SDT will have approximately 2 weeks to review the results of the Quality review. Posting will occur after SC approval, November 3 remains the goal. The standards and the definition will be posted concurrently but will be balloted individually and the definitions will be balloted separately. One consolidated

comment form will be posted that will apply to all the posted materials. To the extent that comments are captured, repeating comments on forms and also during the ballot are not necessary. The SDT and NERC staff are the urging the team not to encourage stakeholders to send in their comments to NERC only once and not to submit repetitious comments. Some on the SDT are not supportive of the individual ballots. The FERC filing will have "all" the approved standards and complete set. NERC staff noted that they will not move the set forward until all are approved. SDT does not agree with the approach. The NERC staff believes that there is time for 3 ballots. One failed and two successful- initial, successive and recirc. All standards must be approved before moving them to the BOT. If some are approved and some are not, then those approved will be held in abeyance until all are approved. Staff will take concerns back to management at NERC. NERC staff is adamant that it is more manageable and makes the revisions more efficient. The team seems very confused and agitated over this. John Lim will call Allen Moser.

Standards templates and QR process was discussed. The standards were placed in a Results Based Template format. VRFs are carried forward from version 3, some Time Horizons are in two categories for the same requirement. The VSLs are carried forward and many are binary in nature. Evidence retention was generally "since last audit" or for three years, whichever is longer. Also NERC indicated that NERC will post and file two versions with the FERC, one a crisp clean requirements only version and another that is the results based with the supporting ancilliary information. There is a "mapping" document available which documents where the Version 5 standards came from. There is a "Directive" document that describes how the FERC 706 FERC Directives were addressed. These documents will be available shortly, perhaps by the end of the meeting.

Applicability was discussed at length. Appears to be consistent with Registry Criteria for DPs and LSEs, i.e. if one owns UFLS, UVLS, SPS or Transmission Protection Systems. Concerns over the expansion of the scope of coverage for DPs, i.e. electromechanical stand-alone relays exist and in large numbers that have no communications. The UFLS must be part of the BES Cyber system. There is concern that without specifics there will be too many relays and assets that will be brought in to the compliance assessment.

FERC is concerned that everything that is IP connected will provide an "attack vector" in to the systems. SDT is concerned that in order to protect all the IP connected equipment will cause the scope of the CIP standards to expand drastically and include almost everything. Low level IP connections and their protection appears in the NOPR.

CIP Senior Manager approval is only required for CIP-002 and 003 and in all other places CIP Senior Manager or "Delegate" is acceptable for anything except a "Policy". Team needs to be specific what authorization is acceptable and where. Will revise standards.

Control Centers that perform functions for RC s, BA s, GO s or TO s they will be classified as high irrespective if they are not controlling BES assets. SDT did not like this and believes it exceeds the NOPR requirements. Much discussion about run of river units that could be in the 10s of MW range being now classified as a "high" Impact facility. Also discussed was how to handle "storm" or emergency

operations centers. There needs to be some more clarification on what applies where in exceptional circumstances.

The SDT is making some substantive changes and it is acknowledged that the standards could be better but the time to continue to refine the standards before the QR does not allow much more revision. Also the SDT is having issues with the definitions, some of which were developed in response to the FERC 706 Directives issued.

SDT was pressing on FERC staff in the room what an acceptable and reasonable password policy would be for the standards. Group seems to be leaning towards 8 characters from the previous 6 and not specifying timeframes. FERC Staff seems uncomfortable with not putting timeframes or an upward boundary. Chair indicated password entropy is the context of this standard would be a failure. FERC staff would be supportive of a TFE if devices were not capable or other extraneous situations were out there.

SDT expressed concern over a suitable test environment for a simulated Disaster Recovery. FERC staff mentioned something about a “regional exercise”??

From: Guy V. Zito
To: rscmembers
Subject: FW: PRC-024 standard
Date: Thursday, September 29, 2011 11:11:44 AM

RSC Members please note the below. Further reason to get our UFLS standard moving. I think moving this variance through may be difficult for reasons below.

Guy V. Zito
Asst. Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

-----Original Message-----
From: Guy V. Zito
Sent: Thursday, September 29, 2011 10:53 AM
To: phan.si_truc@hydro.qc.ca
Cc: clermont.sylvain@hydro.qc.ca; Lee R. Pedowicz; dusseault.marc@hydro.qc.ca; boisvert.Martin@hydro.qc.ca
Subject: RE: PRC-024 standard

Si Truc,

Of course the RSC is available to assist in this effort. I do however think a better approach would be to promote and move forward the NPCC Regional UFLS standard which already contains the requirements for Quebec. Also the Variance is not a Regional one because it is not Region wide, rather it would be an entity variance which may pose issues. Let's discuss further at our meeting in October. In addition I had a conversation internally and was informed by compliance staff that once the NPCC Regional UFLS standard is in place the auditors will be auditing to that, not the NERC continent wide UFLS.

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212-302-2782 fax

-----Original Message-----
From: Phan.Si_Truc@hydro.qc.ca [mailto:Phan.Si_Truc@hydro.qc.ca]
Sent: Thursday, September 29, 2011 10:33 AM
To: Guy V. Zito
Cc: clermont.sylvain@hydro.qc.ca; Lee R. Pedowicz; dusseault.marc@hydro.qc.ca; boisvert.Martin@hydro.qc.ca
Subject: RE: PRC-024 standard
Importance: High

Guy,

Attached the Quebec's comments in order to add a Quebec variance in the PRC-024 standard.
This variance is the continuation of compliance with the PRC-006 Continental and regional standard.

We also ask NPCC to assume the role in the application because our comments were always ignored by the NERC PRC-024 drafting team since 2009.
If necessary, I will present the Quebec variance in detail at our next face-to-face meeting.
Regards,

Si-Truc PHAN, ing.
Normes de Fiabilité & Encadrements Contrôle de réseau / Reliability Standards & Operating Procedures
Dir. Contrôle des mouvements d'énergie 19e Tour Est, Complexe Desjardins, H5B 1H7 Hydro-Québec TransÉnergie
Tel:(514) 879-4100 # 3610

-----Message d'origine-----
De : Guy V. Zito [mailto:gzito@npcc.org] Envoyé : vendredi 16 septembre 2011 15:30 À : Phan, Si Truc Cc : Clermont, Sylvain; Lee R. Pedowicz; Dusseault, Marc; Boisvert, Martin Objet : RE: PRC-024 standard

OK let me know if you want the RSC to assume a role in the application or need assistance Si Truc

Have a good weekend.

Guy V. Zito

Assistant Vice President-Standards

Northeast Power Coordinating Council, Inc.

1040 Avenue of the Americas, 10 th Floor

New York, NY 10018

212-840-1070

212-302-2782 fax

From: Phan.Si_Truc@hydro.qc.ca [Phan.Si_Truc@hydro.qc.ca]

Sent: Friday, September 16, 2011 3:02 PM

To: Lee R. Pedowicz; Guy V. Zito

Cc: clermont.sylvain@hydro.qc.ca; dusseault.marc@hydro.qc.ca; boisvert.Martin@hydro.qc.ca

Subject: PRC-024 standard

Good afternoon gents,

I've just to let you know than HQ TransEnergie will submit the request to NERC for a Quebec Interconnection's variance in order to uniformize with the same graph in the PRC-006 UFLS.

We will present more in detail the reason to our NPCC committee TFSS, TFSP and SS-38.

I will inform to our RSC group at the next meeting.

Si-Truc PHAN, ing.

Normes de Fiabilité & Encadrements Contrôle de réseau / Reliability Standards & Operating Procedures

Dir. Contrôle des mouvements d'énergie

19e Tour Est, Complexe Desjardins, H5B 1H7

Hydro-Québec TransÉnergie

Tel:(514) 879-4100 # 3610

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From: Guy V. Zito
To: isen.widjaja@ieso.ca; dusseault.marc@hydro.qc.ca; david.conroy@cmpco.com
Cc: phan.si_truc@hydro.qc.ca; pilot.mario@hydro.qc.ca; aubut.noel@hydro.qc.ca; tfss; rscmembers; ss38-members
Subject: RE: PRC-024 Regional Variance ?
Date: Tuesday, October 04, 2011 4:19:28 PM

Thank you Isen.

I will discuss further with HQ at the upcoming RSC meeting.

Guy V. Zito
Assistant Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10 th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

From: Widjaja, Isen [isen.widjaja@ieso.ca]
Sent: Tuesday, October 04, 2011 4:05 PM
To: Guy V. Zito; dusseault.marc@hydro.qc.ca; david.conroy@cmpco.com
Cc: phan.si_truc@hydro.qc.ca; pilot.mario@hydro.qc.ca; aubut.noel@hydro.qc.ca; tfss; rscmembers; ss38-members
Subject: RE: PRC-024 Regional Variance ?

Guy,

After some discussion within SS-38, the only reason to have a variance would be to enforce the more restrictive NPCC UFLS generator trip settings curve.

If you believe that this does not need to be re-iterated in the NERC standard through a variance, and is suitably covered by the NPCC standard, then the SS-38 working group does not believe NPCC should seek a variance.

Isen

From: Guy V. Zito [mailto:gzito@npcc.org]
Sent: October 3, 2011 9:58 AM
To: dusseault.marc@hydro.qc.ca; david.conroy@cmpco.com
Cc: phan.si_truc@hydro.qc.ca; pilot.mario@hydro.qc.ca; aubut.noel@hydro.qc.ca; tfss; rscmembers
Subject: RE: PRC-024 Regional Variance ?
Importance: High

Marc,

I am aware of this. I am seeking alternatives to submission of this to the NERC standard. First, it isn't region-wide but rather an "entity" variance. Also the NPCC UFLS standard will address some of the issue. In addition, when the final PRC-024 approved standard is filed with the Regie there may be some avenue regarding how to implement in the Quebec Interconnection. To the extent we can avoid keeping a Quebec variance out of the NERC "arena" I think we should as it will complicate and potentially jeopardize Quebec's ability to continue to do this should it fail in a NERC

continent wide ballot. I will be discussing potential approaches further at the upcoming RSC meeting in Boston on October 25-26 with Sylvain Clemont and Si Truc Phan.

Best Regards,

Guy V. Zito
Asst. Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

From: Dusseault.Marc@hydro.qc.ca [mailto:Dusseault.Marc@hydro.qc.ca]
Sent: Monday, October 03, 2011 9:01 AM
To: david.conroy@cmpco.com
Cc: phan.si_truc@hydro.qc.ca; pilot.mario@hydro.qc.ca; aubut.noel@hydro.qc.ca; tfss
Subject: RE: PRC-024 Regional Variance ?

Dave,

HQT is asking for a PRC-024 variance.

Regards,

Marc Dusseault, eng.
Manager - Orientation of the Main Transmission System
Hydro-Québec TransÉnergie
Tel.: (514) 879-4496
E-mail: dusseault.marc@hydro.qc.ca

De : Conroy, David M. [mailto:David.Conroy@cmpco.com]
Envoyé : lundi 3 octobre 2011 08:37
À : NPCC TFSS Mail Exploder (tfss@npcc.org)
Objet : FW: PRC-024 Regional Variance ?
Importance : Haute

> Do any TFSS or SS-38 members believe NPCC should seek a regional variance for PRC-024?
> If so, please reply by tomorrow.
> Donal, please forward to the SS-38 members.
>
> ---
>
> **From:** Guy V. Zito [mailto:gzito@npcc.org]
> **Sent:** Monday, October 03, 2011 7:23 AM
> **To:** Conroy, David M.
> **Cc:** Donal J. Kidney
> **Subject:** FW: PRC-024 Regional Variance ?
> **Importance:** High
>
> Dave,

Any further comment on the below issue I inquired about?

I don't think there would be a variance required and TFSP has responded below as well. Please let me know.

Thanks,

Guy V. Zito
Asst. Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

From: Verner, Daren [mailto:DVerner@nbpower.com]
Sent: Saturday, October 01, 2011 7:12 AM
To: Guy V. Zito
Cc: tfsp-members; Quoc
Subject: FW: PRC-024 Regional Variance ?
Importance: High

Guy,

TFSP believes that a variance is not required as the NPCC curve is below the proposed curve (more stringent), however TFSS should be consulted for this recommendation.

Regards
TFSP

From: Guy V. Zito [mailto:gzito@npcc.org]
Sent: September-06-11 12:40 PM
To: tfsp
Cc: rsc; tfco-all; tfcp; tfss
Subject: PRC-024 Regional Variance ?
Importance: High

The Generator Verification Standard Drafting Team at NERC has asked the regions if they need any regional variance for the attached draft standard. WECC has indicated they need one. Please provide a review and let me know by the end of September. The team is meeting in October.

Thanks,

Guy V. Zito
Asst. Vice President-Standards
Northeast Power Coordinating Council, Inc.

1040 Avenue of the Americas, 10th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

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From: Guy V. Zito
To: Jack Alvarez; Philip A. Fedora
Cc: grpStaff
Subject: RE: NERC: MEETING MATERIALS AVAILABLE: TIS/SPCS Joint Meetings -- September 27-29, 2011 Atlanta, GA
Date: Thursday, September 29, 2011 8:15:14 PM

Jack,

There is mention in your notes of teams having something regarding a revised SPS definition for mid-November. Is that a SAR and draft definition? The new definition needs to go through the standards development process and be posted for comment and approved by stakeholders. Ultimately it will require NERC BOT approval, filing with FERC etc. There were numerous issues entities are experiencing today, was there any discuss of what the interim plan might be to try to promote more audit consistency, i.e. a CANs?

Thanks for the notes,

Guy

From: Jack Alvarez
Sent: Thursday, September 29, 2011 7:37 PM
To: Philip A. Fedora
Cc: grpStaff
Subject: RE: NERC: MEETING MATERIALS AVAILABLE: TIS/SPCS Joint Meetings -- September 27-29, 2011 Atlanta, GA

See attached SPCS-TIS meeting agenda/my meeting notes/NPCC presentation/group's summary matrix workbook.

Jack Alvarez
NPCC
Senior Engineer
Phone # 212 840-1070
Fax # 212 302-2782
Email - jalvarez@npcc.org

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From: Philip A. Fedora
Sent: Wednesday, September 21, 2011 2:09 PM
To: Jack Alvarez
Cc: Ed Schwerdt; Guy V. Zito; Quoc
Subject: FW: NERC: MEETING MATERIALS AVAILABLE: TIS/SPCS Joint Meetings -- September 27-29, 2011 Atlanta, GA

Jack:

Please make arrangements to represent NPCC at this meeting next week (see below) – as you can see from the Agenda, they want to discuss the SPS definition and SPS Regional practices.

Thanks,

Phil

From: Michelle Marx [mailto:Michelle.Marx@nerc.net]
Sent: Wednesday, September 21, 2011 12:35 PM
To: ero-rapa
Subject: NERC: MEETING MATERIALS AVAILABLE: TIS/SPCS Joint Meetings -- September 27-29, 2011 Atlanta, GA

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Meeting Materials Available

Transmission Issues Subcommittee/System Protection and Control Subcommittee Joint Meetings

September 27, 2011 | 8:00-5:00 p.m. Eastern
September 28, 2011 | 8:00-5:00 p.m. Eastern

September 29, 2011 | 8:00-12:00 p.m. Eastern (TIS & SPCS meeting separately)

SPCS, TIS, and ERO-RAPA Members,

Please note the following information and please forward to anyone from your region that is not a member of SPCS, TIS, or ERO-RAPA that is planning to attend the joint SPCS/TIS meeting in Atlanta to participate in the discussion regarding assessment of the Special Protection System definition and related reliability standards.

- All attendees are required to register for the meeting. Attendees may register for either the SPCS or TIS meeting by following the links on the NERC calendar. Attendees that are not members of the SPCS or TIS may register for either meeting.

Click Here for: Meeting Registration
Click Here for: Meeting Details

- Attendees are requested to check in at the 6th floor reception desk.

- An agenda for the joint meeting on September 27-28 is posted at:
Click Here for: Joint Meeting Agenda

- Three additional documents are attached for reference. These documents are provided as a record of discussion that led to our assignment and are provided for reference purposes only. The SPCS and

TIS may consider these documents during discussion, but it is up to the SPCS and TIS to identify the issues to be addressed in the assessment.

1. A proposed SPS criteria developed by MRO – this document was used to facilitate the initial ERO-RAPA discussion that eventually led to our assignment.
2. A summary of regional SPS criteria developed by MRO – this document also was used to facilitate the initial ERO-RAPA discussion.
3. Comments from the North American Transmission Forum – this document provides Transmission Forum input regarding topics identified in the MRO documents.

- ReadyTalk information will be provided prior to the meeting for members unable to attend in-person.

I look forward to your participation next week.

Thanks,

Phil

For more information or assistance, please contact Phil Tatro

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

RELIABILITY | ACCOUNTABILITY

Y

NPCC Requirements for Special Protection Systems

Jack Alvarez – Senior Engineer

Presented at the Joint NERC SPCS and TIS Meeting
September 27-29, 2011

Use of SPSs (NPCC Directory 1)

In Transmission Planning

- Special protection systems (SPS) shall be used judiciously.
- A SPS may be used to provide protection for infrequent contingencies, or for temporary conditions that may exist such as project delays, unusual combinations of system demand and equipment outages or availability, or specific equipment maintenance outages.
- A SPS may also be applied to preserve system integrity in the event of severe facility outages and extreme contingencies.
- The decision to employ a SPS shall take into account the complexity of the scheme and the consequences of correct or incorrect operation as well as its benefits.

In Transmission Operation

- When adequate bulk power system facilities are not available, SPS may be employed to maintain system security.

SPS Definition (Criteria A-7)

- Special Protection System (SPS) – A protection system designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted elements. Such action may include changes in load, generation, or system configuration to maintain system stability, acceptable voltages or power flows. However, the following are not considered SPSs:
  - Automatic underfrequency load shedding,
  - Automatic undervoltage load shedding, and
  - Manual or automatic locally controlled shunt devices.

Types of SPS (Directory 7)

- Type I
- Type II
- Type III

Type I

- A Special Protection System which recognizes or anticipates abnormal system conditions resulting from design and operating criteria contingencies, and whose misoperation or failure to operate would have a significant adverse impact outside of the local area.

Type II

- A Special Protection System which recognizes or anticipates abnormal system conditions resulting from extreme contingencies or other extreme causes, and whose misoperation or failure to operate would have a significant adverse impact outside of the local area.

Type III SPS

- Special Protection System whose mis-operation or failure to operate results in no significant adverse impact outside the local area.

NPCC Processes for Review of SPSs (Directory 1)

- Proposed new or modified SPS submitted for review by Task Forces (TFCP, TFCO, and TFSS)
- Periodic Transmission Reviews submitted by Planning Coordinators

Proposed New or Modified SPS

- Proposed new or modified SPS submitted for review by Task Forces
  - Task Forces confirm the Type of SPS
  - Type I and II SPSs are submitted to TFSP for protection design review (NPCC Directory 7)
  - Type I and II SPSs are submitted to RCC for approval. Type III SPSs are submitted to RCC for information.
- SPS Database Updated Annually

Periodic Transmission Reviews

- PCs submit to NPCC periodic Transmission Reviews that include among other things, reviews of all the existing, new, and modified SPSs included in its transmission plan. Review may focus on the new and modified SPSs, and just those existing SPSs that may have been impacted by system changes since they were last reviewed.
  - For Type I and Type II SPSs, discuss and/or refer to appropriate load flow and stability studies analyzing the consequences.
  - For Type III SPSs, discuss and/or refer to load flow and stability studies demonstrating that this is still the case for the time period being reviewed.
  - For instances where a SPS which was formerly Type III, is identified as Type I or Type II for the time period being reviewed, the TFSS notifies the Task Forces on Coordination of Planning, System Protection and Coordination of Operation to coordinate the review of the SPS.

TFSP Review of Type I and Type II SPS for Conformance with Directory 7

- Review of Type I SPSs focuses mainly on the Dependability – designed with sufficient redundancy such that the Special Protection System is capable of performing its intended function while itself experiencing a single failure.
- Review of Type II SPS focuses mainly on the Security - designed to avoid false operation while itself experiencing a credible failure.

Subject	FRCC	MRO	NPCC
SPS Definition	NERC definition	NERC definition	Regional definition; conceptually the same as NERC
- Exclusions	automatic synchronizing relays; shunt reactive support switching controls		Manual or automatic locally controlled shunt devices.
- Inclusions			
Current Applications other than stability, voltage, thermal	none	SSR	Generating torsional concerns associated with reclosing
Voltage threshold?	100 kV and above	none	none
Differentiate based on contingency categories	No	No	Yes; B/C vs D
Differentiate for wide-area vs local	No	No	Yes
Differentiate for temporary vs permanent	No	No	No
Classifications	No	No	Type I (B/C wide-area); Type II (D wide-area); Type III (local-area)

Classification basis	N/A	N/A	Local area — An electrically confined or radial portion of the system. The geographic size and number of system elements contained will vary based on system characteristics. A local area may be relatively large geographically with relatively few buses in a sparse system, or be relatively small geographically with a relatively large number of buses in a densely networked system.
Redundancy requirements	per PRC-012	per PRC-012	Type I required to be redundant; Type II and Type III not required to be redundant

NERC definition: An automatic system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to he isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar) or system configuration to maintain system stabilitiy, and acceptable voltage.

RFC	SERC	SPP
NERC definition	NERC definitions with clarifications	NERC definitions with clarifications
	shunt capacitors and reactor switching; fault conditions that must be isolated including bus break-up/back-up/breaker failure; LTCs; automated actions that could be performed by operator; tripping islanded generator; relays that protect for specific equipment damage (overloads, overcurrent, hot-spot, reclose blocking, etc.)	shall not require operator action; systems used to contol and monitor facilities below 100 kV
	SPSs must be installed to address a TPL-001, -002, or -003 violation or to address a problem associated with a TPL-004 contingency that the PC or TP determines is necessary to mitigate	
none	none	none
none	none	100 kV
No	No	No
No	No	No
No	No	No
No	No	No

N/A	N/A	N/A
per PRC-012	per PRC-012	per PRC-012

TRE	WECC	Concensus
Regional definition; conceptually the same as NERC	NERC definition	Modify NERC definition
		automatic reclosing; shunt reactive support switching controls locally applied based on local measurements;
		to be classified as an SPS the scheme must be installed to address a TPL-001, -002, or -003 violation or to address a problem associated with a TPL-004 contingency that the PC or TP determines is necessary to mitigate
none	SSR	
none	none	
No	Yes; B/C vs D	Yes; B/C vs D
Yes	Yes	
Yes; exit strategy strategy required or justification for permanent	No	
Type I (wide-area); Type II (local-area)	Wide-area, local-area, safety net	

per PRC-012	Wide-area and local-area required to be redundant; safety nets not required to be redundnant	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Agenda
System Protection and Control Subcommittee
Transmission Issues Subcommittee
Joint Meeting

September 27, 2011 | 8 a.m. -5 p.m. EDT
September 28, 2011 | 8 a.m. -5 p.m. EDT

NERC Atlanta Headquarters
3353 Peachtree Rd. NE
Suite 600, North Tower
Atlanta, GA 30326

Please check in at the 6th floor reception desk.

Administrative (Tuesday: 8:00 a.m. – 8:15 a.m.)

a. Welcome and Introductions
b. Host Arrangements and Safety
c. Antitrust Compliance Guidelines/Open Meeting Notice
d. Review and Approval of Agenda

Agenda

1. **Special Protection System Review** (Tuesday: 8:15 a.m. – Wednesday: 12:00 p.m.)
   a. Review scope of work
   b. Overview of SPS definition and SPS-related reliability standards
   c. Regional presentations of present practices applying the SPS definition and SPS-related reliability standards
      - Develop matrix of issues, highlighting commonality and differences
   d. Establish teams to assess the SPS definition and related reliability standards
   e. Breakout sessions for team meetings
   f. Team reports
   g. Develop schedule and next steps

2. **Response of Protective Relays to Power Swings** (Wednesday: 1:00 p.m. – 5:00 p.m.)
   a. Review draft report
   b. Discuss concepts for identifying elements with relays subject to operating during power swings
   c. Discuss proposed methods for screening protective relay settings
   d. Identify any additional subject matter that should be covered in the report
   e. Develop schedule and next steps

NOTE: The SPCS and TIS will meet separately on September 29 to discuss items of interest specific to each subcommittee.

<u>"System Protection and Control Subcommittee" (SPCS) and "Transmission Issues Subcommittee" (TIS) Meeting Notes</u>

Jack Alvarez – Sr. Engineer, RAPA

Date – September 27 -28, 2011

Meeting Location – NERC Atlanta Headquarters

- NERC Planning Committee (PC) requested that the two working groups (SPCS and TIS) meet together to review and prepare a definition of what a Special Protection System (SPS) is.
    - Expectation is to have a report with recommendations back to the PC for their March 2012 meeting.
    - It was noted that the TIS subcommittee was renamed the "System Analysis and Modeling Subcommittee" (SAMS).
    - The meeting was called for as part of the revision of the PRC 12 to 16 Standards.
- NERC believes that the definition of an SPS varies widely across the Regions.
    - **It was noted that the purpose of the meeting was not to draft a "SPS" Standard but to describe what an SPS is.**
- Representatives from the Regions gave brief presentations summarizing what their area's definition of an SPS was; how they were defined; and their respective processes for reviewing an SPS were.
    - The objective of the presentations was to gather information on the similarities or significant differences between the Regions with respect to the NERC definition of an SPS.
        - A summary matrix was developed, however, it was noted that the Regional definitions of an SPS did not vary much from the basic NERC definition. (see attachment)
        - One of the questions asked of each Region was "did any of their SPSs trip load", and everyone said that they did have such systems. The Canadian Areas have many Type III SPS which trip load.
        - A significant question that was asked by NERC as to whether or not an Energy Management System (EMS) is considered an SPS.
        - Another question that raised considerable discussion was the definition of what "wide area vs. local area" coverage by an SPS was.

- NPCC presentation is attached.

- **Basic conclusion was that the NERC definition of an SPS needed to be modified.**
    - Individuals were selected (some volunteered) and formed into “teams” to participate in the development of a new NERC definition of an SPS with the expectation of having something developed by mid-November 2011.

docket(s). For assistance with any FERC Online service, please e-mail *FERCOnlineSupport@ferc.gov.* or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: September 26, 2011.

Kimberly D. Bose,

Secretary.

[FR Doc. 2011–25214 Filed 9–29–11; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Notice of Commission Staff Attendance

The Federal Energy Regulatory Commission hereby gives notice that members of the Commission's staff may attend the following meeting related to the transmission planning activities of the Midwest Independent Transmission System Operator, Inc. (MISO):

MISO Planning Advisory Committee, September 28, 2011, 10 a.m.–4 p.m., Local Time.

The above-referenced meeting will be held at:

MISO Headquarters, 720 City Center Drive, Carmel, IN 46032.

The above-referenced meeting is open to the public.

Further information may be found at *http://www.misoenergy.org.*

The discussions at the meeting described above may address matters at issue in the following proceedings:

Docket No. ER10–1791, *Midwest Independent Transmission System Operator, Inc.*

Docket No. ER11–3728, *Midwest Independent Transmission System Operator, Inc.*

Docket No. EL11–56, *FirstEnergy Service Company.*

Docket No. OA08–53, *Midwest Independent Transmission System Operator, Inc.*

For more information, contact Christopher Miller, Office of Energy Markets Regulation, Federal Energy Regulatory Commission at (317) 249–5936 or *christopher.miller@ferc.gov.*

Dated: September 26, 2011.

Kimberly D. Bose,

Secretary.

[FR Doc. 2011–25215 Filed 9–29–11; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. RD10–8–000]

North American Electric Reliability Corporation; Notice of Technical Conference

Take notice that the Federal Energy Regulatory Commission (Commission) will hold a staff-led Technical Conference to discuss issues related to the interpretations of Reliability Standard CIP–006–2 in the above-referenced docket. The Technical Conference will be held on Tuesday, October 25, 2011, from 9 a.m. to 1 p.m. (EST) in the Commission Meeting Room at the Commission's headquarters at 888 First Street, NE., Washington, DC 20426. The Technical Conference will be open for the public to attend and advance registration is not required.

The Technical Conference will explore the risks of leaving dial-up intelligent electronic devices that are part of the Bulk-Power System and that use non-routable protocols physically unprotected. The Commission is interested in: (1) Information on the number of Bulk-Power System assets that are networked using non-routable protocols; (2) the proportion of those assets that are currently physically unprotected; (3) the risks associated with leaving such assets physically unprotected; and (4) methods for mitigating such risks.

The Technical Conference will also explore monitoring physical access not only when authorized personnel enter a controlled access area, such as the physical security perimeter to critical cyber assets, but also when authorized personnel leave the controlled access area. The Commission is interested in the level of security attained by monitoring both physical ingress and egress into controlled access areas.

Those interested in speaking at the conference should notify the Commission by close of business October 7, 2011 by completing an online form describing the topics that they wish to address: *https://www.ferc.gov/whats-new/registration/naerc-10-25-speaker-form.asp.* Due to time constraints, we may not be able to accommodate all those interested in speaking. The Commission will issue a subsequent notice that will provide the detailed agenda, including panel speakers.

A free webcast of this event is available through *http://www.ferc.gov.* Anyone with Internet access who desires to view this event can do so by navigating to www.ferc.gov's Calendar of Events and locating this event in the calendar. The event will contain a link to its webcast. The Capitol Connection provides technical support for the free webcasts. It also offers access to this event via television in the DC area and via phone bridge for a fee.

FERC conferences are accessible under section 508 of the Rehabilitation Act of 1973. For accessibility accommodations please send an e-mail to *accessibility@ferc.gov* or call toll free (866) 208–3372 (voice) or (202) 502–8659 (TTY), or send a fax to (202) 208–2106 with the requested accommodations.

For further information please contact Sarah McKinley at (202) 502–8368 or *sarah.mckinley@ferc.gov.*

Dated: September 26, 2011.

Kimberly D. Bose,

Secretary.

[FR Doc. 2011–25212 Filed 9–29–11; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

[FRL–9473–6; Docket ID No. EPA–HQ–ORD–2011–0050]

Draft Integrated Science Assessment for Ozone and Related Photochemical Oxidants

AGENCY: Environmental Protection Agency.

ACTION: Notice of Public Comment Period.

SUMMARY: The U.S. Environmental Protection Agency (EPA) is announcing the availability of the second external review draft of a document titled, ''Second External Review Draft Integrated Science Assessment for Ozone and Related Photochemical Oxidants'' (EPA/600/R–10/076B). The document was prepared by the National Center for Environmental Assessment (NCEA) within EPA's Office of Research and Development as part of the review of the national ambient air quality standards (NAAQS) for ozone.

EPA is releasing this draft document to seek review by the Clean Air Scientific Advisory Committee (CASAC) and the public (meeting date and location to be specified in a separate Federal Register notice). The draft document does not represent and should not be construed to represent any final EPA policy, viewpoint, or determination. EPA will consider any public comments submitted in response to this notice when revising the document.

CAN Comment Form
Compliance Application Notice – 00_ _

Please complete the CAN Comment Form and email it to cancomments@nerc.net.

Commenter Information

Name:

Phone Number:

Email Address:

Entity Represented:

Region:

Primary Interest Groups

Are you suggesting a change to the groups mentioned? Yes / No
If yes, explain what change and why:

Issue

Are you suggesting a change to the issue statement of the CAN? Yes / No
If yes, explain what change and why:

Background

Are you suggesting a change to the background statement of the CAN? Yes / No

If yes, explain what change and why:

Compliance Application

Are you suggesting a change to the compliance application section of the CAN? Yes / No

If yes, explain what change and why:

Effective Period for CAN

Are you suggesting a change to the effective period of the CAN? Yes / No

If yes, explain what change and why:

Evidence of Compliance

Are you suggesting a change to the evidence of compliance mentioned in the CAN? Yes / No

If yes, explain what change and why:

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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-Ballot Results
-Registered Ballot Body
-Proxy Voters

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Ballot Results

Ballot Name:	Project 2007-09 MOD-026-1 Initial Ballot_June 2011_in
Ballot Period:	7/22/2011 - 8/1/2011
Ballot Type:	Initial
Total # Votes:	287
Total Ballot Pool:	318
Quorum:	**90.25 % The Quorum has been reached**
Weighted Segment Vote:	46.53 %
Ballot Results:	**The standard will proceed to a successive ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	85	1	45	0.643	25	0.357	6	9
2 - Segment 2.	6	0.4	0	0	4	0.4	1	1
3 - Segment 3.	68	1	25	0.439	32	0.561	8	3
4 - Segment 4.	25	1	9	0.45	11	0.55	2	3
5 - Segment 5.	75	1	32	0.5	32	0.5	2	9
6 - Segment 6.	42	1	17	0.486	18	0.514	2	5
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.4	2	0.2	2	0.2	3	1
9 - Segment 9.	2	0.2	0	0	2	0.2	0	0
10 - Segment 10.	7	0.7	4	0.4	3	0.3	0	0
Totals	**318**	**6.7**	**134**	**3.118**	**129**	**3.582**	**24**	**31**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	View
1	Arizona Public Service Co.	Robert Smith	Abstain	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California NCR11118	Kevin Smith	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph	Negative	

1	BC Hydro and Power Authority	Patricia Robertson	Negative	View
1	Beaches Energy Services	Joseph S Stonecipher	Negative	View
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	View
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	View
1	CenterPoint Energy Houston Electric	Dale Bodden	Affirmative	
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Vero Beach	Randall McCamish	Negative	View
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	View
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Negative	View
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor	Affirmative	
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	View
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	Kansas City Power & Light Co.	Michael Gammon		
1	Keys Energy Services	Stanley T Rzad	Negative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Los Angeles Department of Water & Power	Ly M Le	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	View
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	Minnkota Power Coop. Inc.	Richard Burt	Negative	View
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	Northeast Utilities	David Boguslawski	Negative	View
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Negative	View
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	PacifiCorp	Colt Norrish		
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	View
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	View
1	Public Utility District No. 1 of Chelan County	Chad Bowman	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Negative	View
1	SCE&G	Henry Delk, Jr.		

1	Seattle City Light	Pawel Krupa	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert Schaffeld	Negative	View
1	Southwest Transmission Cooperative, Inc.	James Jones	Negative	View
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	View
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock	Abstain	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	View
2	Independent Electricity System Operator	Kim Warren	Negative	View
2	ISO New England, Inc.	Kathleen Goodman	Negative	View
2	Midwest ISO, Inc.	Marie Knox	Negative	View
2	Southwest Power Pool	Charles H Yeung		
3	AEP	Michael E DeLoach	Affirmative	
3	Alabama Power Company	Richard J. Mandes	Negative	View
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	View
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Clewiston	Lynne Mila	Negative	
3	City of Farmington	Linda Jacobson	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Negative	View
3	City of Redding	Bill Hughes	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Lisa Cleary	Affirmative	
3	ComEd	Bruce Krawczyk	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	View
3	Consumers Energy	David A. Lapinski	Abstain	
3	Cowlitz County PUD	Russell A Noble	Negative	View
3	CPS Energy	Jose Escamilla	Negative	View
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Dominion Resources Services	Michael F. Gildea	Negative	View
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	
3	Entergy	Joel T Plessinger	Abstain	
3	FirstEnergy Solutions	Kevin Querry	Negative	View
3	Florida Municipal Power Agency	Joe McKinney	Negative	View
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Abstain	
3	Georgia Power Company	Anthony L Wilson	Negative	View
3	Georgia Systems Operations Corporation	William N. Phinney	Abstain	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Negative	
3	Gulf Power Company	Paul C Caldwell	Negative	View
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	
3	JEA	Garry Baker		
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	View
3	Manitoba Hydro	Greg C. Parent	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Don Horsley	Negative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	View
3	Nebraska Public Power District	Tony Eddleman	Negative	View
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Negative	View
3	Ocala Electric Utility	David Anderson	Negative	

3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	View
3	PacifiCorp	John Apperson	Negative	
3	Platte River Power Authority	Terry L Baker	Negative	View
3	Potomac Electric Power Co.	Robert Reuter	Abstain	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	View
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	View
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	View
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	View
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Negative	
4	City of Clewiston	Kevin McCarthy	Negative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Abstain	
4	Cowlitz County PUD	Rick Syring	Negative	View
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas W. Richards		
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres	Affirmative	View
4	Indiana Municipal Power Agency	Jack Alvey	Negative	View
4	Integrys Energy Group, Inc.	Christopher Plante	Negative	View
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	View
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	View
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steven McElhaney	Negative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Negative	View
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Associated Electric Cooperative, Inc.	Brad Haralson	Affirmative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Negative	View
5	Black Hills Corp	George Tatar	Negative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	Chelan County Public Utility District #1	John Yale	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Redding	Paul Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	
5	City of Tallahassee	Brian Horton	Negative	
5	Cleco Power	Stephanie Huffman	Negative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	

5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	View
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Negative	View
5	Cowlitz County PUD	Bob Essex	Negative	View
5	CPS Energy	Robert Stevens	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Negative	View
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Negative	View
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	Negative	View
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Gainesville Regional Utilities	Karen C Alford	Negative	
5	Great River Energy	Preston L Walsh	Negative	
5	Green Country Energy	Greg Froehling		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik		
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	View
5	Liberty Electric Power LLC	Daniel Duff	Negative	View
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	View
5	Manitoba Hydro	S N Fernando	Negative	View
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	View
5	Muscatine Power & Water	Mike Avesing	Negative	View
5	Nebraska Public Power District	Don Schmit	Negative	View
5	New York Power Authority	Gerald Mannarino		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	View
5	Occidental Chemical	Michelle R DAntuono	Negative	View
5	Pacific Gas and Electric Company	Richard J. Padilla	Negative	View
5	PacifiCorp	Sandra L. Shaffer	Negative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	View
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Fossil LLC	Mikhail Falkovich	Negative	View
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	View
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	View
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Siemens PTI	Edwin Cano	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	View
5	Tenaska, Inc.	Scott M Helyer	Negative	View
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.		
5	Wisconsin Electric Power Co.	Linda Horn	Negative	View
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
6	AEP Marketing	Edward P. Cox	Affirmative	View
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	View
6	Arizona Public Service Co.	Justin Thompson		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Abstain	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	View
6	Constellation Energy Commodities Group	Brenda Powell	Negative	View

6	Dominion Resources, Inc.	Louis S. Slade	Negative	View
6	Duke Energy Carolina	Walter Yeager	Negative	
6	Entergy Services, Inc.	Terri F Benoit		
6	Exelon Power Team	Pulin Shah	Negative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	View
6	Florida Municipal Power Pool	Thomas Washburn	Negative	View
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Negative	View
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	MidAmerican Energy Co.	Dennis Kimm		
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Scott L Smith	Negative	View
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Negative	View
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	View
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Negative	View
6	Sacramento Municipal Utility District	Claire Warshaw	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet		
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8		James A Maenner	Abstain	
8		Roger C Zaklukiewicz	Negative	View
8		Merle Ashton		
8		Edward C Stein	Affirmative	
8		Brendan Kirby	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Negative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Negative	View
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Negative	View
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Negative	View
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Negative	View
10	Texas Reliability Entity	Larry D Grimm	Negative	View
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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A New Jersey Nonprofit Corporation

From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Revised Standards Announcement - Project 2007-09 Generator Verification | Revised Ballot Results of Two Initial Ballots
Date: Tuesday, August 09, 2011 4:49:42 PM
Attachments: 2007-09_Full_Record_MOD-026_final.pdf
2007-09_Full_Record_PRC-024-1_final.pdf

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Revised: Standards Announcement
Project 2007-09 Generator Verification
Results of Two Initial Ballots and Non-binding Polls

Update now available at: https://standards.nerc.net/Ballots.aspx

Initial ballots of two standards, MOD-026-1 – Verification of Models and Data for Generator Excitation System Functions, and PRC-024-1– Generator Frequency and Voltage Protective Relay Settings, and concurrent, non-binding polls of the associated VRFs and VSLs concluded on Monday, August 1, 2011.

Revised Ballot Results for MOD-026-1 and PRC-024-1

Updated voting statistics for each standard are listed in the table below, and the Ballot Results Web page provides a link to the detailed results.

Standard	Ballot Results	Non-binding Poll Results
MOD-026-1 – Verification of Models and Data for Generator Excitation System Functions	Quorum: 90.25% Approval: 46.53%	88.75% of those who registered to participate provided an opinion or abstention; 56% of those who provided an opinion indicated support for the VRFs and VSLs
PRC-024-1– Generator Performance During Frequency and Voltage Excursions	Quorum: 90.82% Approval: 18.23%	88.35% of those who registered to participate provided an opinion or abstention; 20.79% of those who provided an opinion indicated support for the VRFs and VSLs

Reason for Revisions

We announced the ballot and non-binding poll results on August 5, 2011 and became aware yesterday that one company submitted a vote via e-mail that was not received by the process administrator due to a problem with NERC's IT systems. The NERC IT department has been made aware of the situation and is researching the cause. We will provide stakeholders with an alternative method of submitting e-mail ballot which will be highlighted in any future ballot announcement. It is important to note that all votes submitted through NERC's electronic balloting application have been received.

The only time votes are accepted via e-mail is for an entity that has registered someone in a ballot pool who is not in that role. When the ballot pool member is no longer available to cast a ballot for the entity, we make every effort to allow the entity to continue to participate in the ballot pool by manually entering the vote for the person designated as his/her replacement. Our software, in its current format does not update ballot pools when an entity's Registered Ballot Body member changes, which forces us to enter these ballots through the manual process.

We are committed to maintaining an accurate record of this ballot. If you sent your votes via e-mail, please review the attached ballot results to ensure that your votes are included (or view the project page for the updated posted results: http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html).

If you find that your entity's votes were not posted, please call Monica Benson at 404-446-2573. You will need to send verification of any e-mail vote showing that the ballot was sent before the close of the ballot window, which will be forwarded to our IT department for review.

Thank you for your patience and understanding as we make any necessary voting result updates to ensure that accurate voting records are posted.

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower

Atlanta, GA 30326
404-446-2560 | www.nerc.com

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Ballot Results

Ballot Name:	Project 2007-09 PRC-024-1 Initial Ballot June 2011_in
Ballot Period:	7/22/2011 - 8/1/2011
Ballot Type:	Initial
Total # Votes:	287
Total Ballot Pool:	316
Quorum:	**90.82 % The Quorum has been reached**
Weighted Segment Vote:	18.23 %
Ballot Results:	**The standard will proceed to a successive ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	82	1	16	0.232	53	0.768	5	8
2 - Segment 2.	6	0.4	0	0	4	0.4	1	1
3 - Segment 3.	68	1	8	0.131	53	0.869	4	3
4 - Segment 4.	25	1	3	0.158	16	0.842	3	3
5 - Segment 5.	76	1	10	0.154	55	0.846	2	9
6 - Segment 6.	42	1	3	0.083	33	0.917	2	4
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.6	3	0.3	3	0.3	1	1
9 - Segment 9.	2	0.2	0	0	2	0.2	0	0
10 - Segment 10.	7	0.7	2	0.2	5	0.5	0	0
Totals	**316**	**6.9**	**45**	**1.258**	**224**	**5.642**	**18**	**29**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Negative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	View
1	Arizona Public Service Co.	Robert Smith	Abstain	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott J Kinney	Negative	View
1	Balancing Authority of Northern California NCR11118	Kevin Smith	Negative	View
1	Basin Electric Power Cooperative	David Rudolph	Negative	

1	BC Hydro and Power Authority	Patricia Robertson	Negative	View
1	Beaches Energy Services	Joseph S Stonecipher	Negative	View
1	Bonneville Power Administration	Donald S. Watkins	Negative	View
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	View
1	CenterPoint Energy Houston Electric	Dale Bodden	Negative	
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	View
1	City of Vero Beach	Randall McCamish	Negative	View
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	
1	Colorado Springs Utilities	Paul Morland	Negative	View
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	View
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	Entergy Services, Inc.	Edward J Davis	Negative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor	Affirmative	
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Ronald D. Schellberg	Negative	View
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	View
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	Kansas City Power & Light Co.	Michael Gammon		
1	Keys Energy Services	Stanley T Rzad	Negative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Los Angeles Department of Water & Power	Ly M Le	Negative	View
1	Lower Colorado River Authority	Martyn Turner	Negative	View
1	Manitoba Hydro	Joe D Petaski	Affirmative	View
1	MEAG Power	Danny Dees	Negative	View
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	Minnkota Power Coop. Inc.	Richard Burt	Negative	View
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Negative	
1	Northeast Utilities	David Boguslawski	Negative	View
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Omaha Public Power District	Doug Peterchuck	Negative	View
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Negative	View
1	PacifiCorp	Colt Norrish		
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Negative	View
1	Portland General Electric Co.	John T Walker	Negative	View
1	Potomac Electric Power Co.	David Thorne	Negative	
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	View
1	Progress Energy Carolinas	Sammy Roberts	Negative	View
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	View
1	Public Utility District No. 1 of Chelan County	Chad Bowman	Negative	View
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	View
1	Salt River Project	Robert Kondziolka	Negative	View
1	Santee Cooper	Terry L. Blackwell	Negative	
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Negative	View
1	Snohomish County PUD No. 1	Long T Duong	Negative	View

1	South California Edison Company	Steven Mavis	Negative	View
1	Southern Company Services, Inc.	Robert Schaffeld	Negative	View
1	Southwest Transmission Cooperative, Inc.	James Jones	Negative	View
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	View
1	Tennessee Valley Authority	Larry Akens	Negative	View
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Negative	View
1	Western Farmers Electric Coop.	Forrest Brock	Abstain	
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	
2	Alberta Electric System Operator	Mark B Thompson	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	
2	Independent Electricity System Operator	Kim Warren	Negative	View
2	ISO New England, Inc.	Kathleen Goodman	Negative	View
2	Midwest ISO, Inc.	Marie Knox	Negative	View
2	Southwest Power Pool	Charles H Yeung		
3	AEP	Michael E DeLoach	Negative	
3	Alabama Power Company	Richard J. Mandes	Negative	View
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Negative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Negative	
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	View
3	Bonneville Power Administration	Rebecca Berdahl	Negative	
3	City of Clewiston	Lynne Mila	Negative	
3	City of Farmington	Linda Jacobson	Negative	View
3	City of Green Cove Springs	Gregg R Griffin	Negative	View
3	City of Redding	Bill Hughes	Negative	View
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Lisa Cleary	Negative	View
3	ComEd	Bruce Krawczyk	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	View
3	Consumers Energy	David A. Lapinski	Abstain	
3	Cowlitz County PUD	Russell A Noble	Negative	View
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	
3	Dominion Resources Services	Michael F. Gildea	Negative	View
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	
3	Entergy	Joel T Plessinger	Negative	
3	FirstEnergy Solutions	Kevin Querry	Negative	View
3	Florida Municipal Power Agency	Joe McKinney	Negative	View
3	Florida Power Corporation	Lee Schuster	Negative	View
3	Gainesville Regional Utilities	Kenneth Simmons	Abstain	
3	Georgia Power Company	Anthony L Wilson	Negative	View
3	Georgia Systems Operations Corporation	William N. Phinney	Abstain	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Negative	
3	Gulf Power Company	Paul C Caldwell	Negative	View
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	View
3	JEA	Garry Baker		
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	View
3	Manitoba Hydro	Greg C. Parent	Affirmative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Don Horsley	Negative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Negative	View
3	Muscatine Power & Water	John S Bos	Negative	View
3	Nebraska Public Power District	Tony Eddleman	Negative	View
3	New York Power Authority	Marilyn Brown	Negative	
3	Northern Indiana Public Service Co.	William SeDoris	Negative	View
3	Ocala Electric Utility	David Anderson	Negative	
3	Orlando Utilities Commission	Ballard K Mutters	Negative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	
3	Pacific Gas and Electric Company	John H Hagen	Negative	View

3	PacifiCorp	John Apperson	Negative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Negative	
3	Progress Energy Carolinas	Sam Waters	Negative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	View
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange	Negative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	View
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	View
3	Salt River Project	John T. Underhill	Negative	View
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Negative	View
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Southern California Edison Co.	David Schiada	Negative	View
3	Tacoma Public Utilities	Travis Metcalfe	Negative	View
3	Tennessee Valley Authority	Ian S Grant	Negative	View
3	Wisconsin Electric Power Marketing	James R Keller	Negative	View
3	Xcel Energy, Inc.	Michael Ibold	Negative	View
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	View
4	American Municipal Power	Kevin Koloini	Negative	
4	City of Clewiston	Kevin McCarthy	Negative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Negative	View
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Abstain	
4	Cowlitz County PUD	Rick Syring	Negative	View
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas W. Richards		
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	View
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	View
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	View
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Negative	View
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	View
4	Seattle City Light	Hao Li	Negative	View
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steven McElhaney	Negative	
4	Tacoma Public Utilities	Keith Morisette	Negative	View
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
5	AEP Service Corp.	Brock Ondayko	Negative	View
5	Amerenue	Sam Dwyer	Negative	View
5	Arizona Public Service Co.	Edward Cambridge	Negative	
5	Associated Electric Cooperative, Inc.	Brad Haralson	Affirmative	
5	Avista Corp.	Edward F. Groce	Negative	View
5	BC Hydro and Power Authority	Clement Ma	Negative	View
5	Black Hills Corp	George Tatar	Negative	View
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	
5	BrightSource Energy, Inc.	Chifong Thomas	Negative	View
5	Chelan County Public Utility District #1	John Yale	Negative	View
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Redding	Paul Cummings	Negative	View
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Negative	View
5	City of Tallahassee	Brian Horton	Negative	
5	Cleco Power	Stephanie Huffman	Negative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Negative	View
5	Colorado Springs Utilities	Jennifer Eckels	Negative	View
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	View
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Negative	View
5	Cowlitz County PUD	Bob Essex	Negative	View

5	CPS Energy	Robert Stevens	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Negative	View
5	Duke Energy	Dale Q Goodwine	Negative	View
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Negative	View
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	Negative	View
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Gainesville Regional Utilities	Karen C Alford	Negative	
5	Great River Energy	Preston L Walsh	Negative	
5	Green Country Energy	Greg Froehling		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik		
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	View
5	Liberty Electric Power LLC	Daniel Duff	Negative	View
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Tom Foreman	Negative	View
5	Luminant Generation Company LLC	Mike Laney	Negative	View
5	Manitoba Hydro	S N Fernando	Affirmative	View
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Negative	View
5	MidAmerican Energy Co.	Christopher Schneider	Negative	View
5	Muscatine Power & Water	Mike Avesing	Negative	View
5	Nebraska Public Power District	Don Schmit	Negative	View
5	New York Power Authority	Gerald Mannarino		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	View
5	Occidental Chemical	Michelle R DAntuono	Negative	View
5	Pacific Gas and Electric Company	Richard J. Padilla	Negative	View
5	PacifiCorp	Sandra L. Shaffer	Negative	View
5	Platte River Power Authority	Roland Thiel	Negative	View
5	PPL Generation LLC	Annette M Bannon	Negative	View
5	Progress Energy Carolinas	Wayne Lewis	Negative	View
5	PSEG Fossil LLC	Mikhail Falkovich	Negative	View
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	View
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	View
5	Sacramento Municipal Utility District	Bethany Hunter	Negative	View
5	Salt River Project	Glen Reeves	Negative	View
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Negative	View
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Siemens PTI	Edwin Cano	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	View
5	Southern California Edison Co.	Denise Yaffe	Negative	
5	Southern Company Generation	William D Shultz	Negative	View
5	Tenaska, Inc.	Scott M Helyer	Affirmative	
5	Tennessee Valley Authority	David Thompson	Negative	View
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	View
5	U.S. Bureau of Reclamation	Martin Bauer P.E.		
5	Westar Energy	Bo Jones	Negative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	View
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
6	AEP Marketing	Edward P. Cox	Negative	View
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	View
6	Arizona Public Service Co.	Justin Thompson		
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	City of Austin dba Austin Energy	Lisa L Martin	Abstain	
6	City of Redding	Marvin Briggs	Negative	View
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	View
6	Constellation Energy Commodities Group	Brenda Powell	Negative	View
6	Dominion Resources, Inc.	Louis S. Slade	Negative	View
6	Duke Energy Carolina	Walter Yeager	Negative	

6	Entergy Services, Inc.	Terri F Benoit	Negative	
6	Exelon Power Team	Pulin Shah	Negative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	View
6	Florida Municipal Power Pool	Thomas Washburn	Negative	View
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Negative	View
6	Los Angeles Department of Water & Power	Brad Packer	Negative	
6	Luminant Energy	Brad Jones	Negative	View
6	Manitoba Hydro	Daniel Prowse	Affirmative	View
6	MidAmerican Energy Co.	Dennis Kimm		
6	New York Power Authority	William Palazzo	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	Omaha Public Power District	David Ried	Negative	
6	PacifiCorp	Scott L Smith	Negative	View
6	Platte River Power Authority	Carol Ballantine	Negative	View
6	PPL EnergyPlus LLC	Mark A Heimbach	Negative	View
6	Progress Energy	John T Sturgeon	Negative	View
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	View
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Negative	View
6	Sacramento Municipal Utility District	Claire Warshaw	Negative	View
6	Salt River Project	Steven J Hulet	Negative	View
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet		
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Negative	View
6	South California Edison Company	Lujuanna Medina	Negative	View
6	Tampa Electric Co.	Benjamin F Smith II	Negative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	View
6	Xcel Energy, Inc.	David F. Lemmons	Negative	View
8		James A Maenner	Affirmative	
8		Roger C Zaklukiewicz	Negative	View
8		Merle Ashton		
8		Edward C Stein	Affirmative	
8		Brendan Kirby	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Negative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Negative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Negative	View
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Negative	View
10	Midwest Reliability Organization	James D Burley	Negative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Negative	View
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	View
10	SERC Reliability Corporation	Carter B. Edge	Negative	View
10	Texas Reliability Entity	Larry D Grimm	Negative	View
10	Western Electricity Coordinating Council	Steven L. Rueckert	Negative	View

Legal and Privacy : 609.452.8060 voice : 609.452.9550 fax : 116-390 Village Boulevard : Princeton, NJ 08540-5721
Washington Office: 1120 G Street, N.W. : Suite 990 : Washington, DC 20005-3801

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A New Jersey Nonprofit Corporation

From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Revised Standards Announcement - Project 2007-09 Generator Verification | Revised Ballot Results of Two Initial Ballots
Date: Tuesday, August 09, 2011 4:49:42 PM
Attachments: 2007-09_Full_Record_MOD-026_final.pdf
2007-09_Full_Record_PRC-024-1_final.pdf

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Revised: Standards Announcement
Project 2007-09 Generator Verification
Results of Two Initial Ballots and Non-binding Polls

Update now available at: https://standards.nerc.net/Ballots.aspx

Initial ballots of two standards, MOD-026-1 – Verification of Models and Data for Generator Excitation System Functions, and PRC-024-1– Generator Frequency and Voltage Protective Relay Settings, and concurrent, non-binding polls of the associated VRFs and VSLs concluded on Monday, August 1, 2011.

Revised Ballot Results for MOD-026-1 and PRC-024-1

Updated voting statistics for each standard are listed in the table below, and the Ballot Results Web page provides a link to the detailed results.

Standard	Ballot Results	Non-binding Poll Results
MOD-026-1 – Verification of Models and Data for Generator Excitation System Functions	Quorum: 90.25% Approval: 46.53%	88.75% of those who registered to participate provided an opinion or abstention; 56% of those who provided an opinion indicated support for the VRFs and VSLs
PRC-024-1– Generator Performance During Frequency and Voltage Excursions	Quorum: 90.82% Approval: 18.23%	88.35% of those who registered to participate provided an opinion or abstention; 20.79% of those who provided an opinion indicated support for the VRFs and VSLs

Reason for Revisions

We announced the ballot and non-binding poll results on August 5, 2011 and became aware yesterday that one company submitted a vote via e-mail that was not received by the process administrator due to a problem with NERC's IT systems. The NERC IT department has been made aware of the situation and is researching the cause. We will provide stakeholders with an alternative method of submitting e-mail ballot which will be highlighted in any future ballot announcement. It is important to note that all votes submitted through NERC's electronic balloting application have been received.

The only time votes are accepted via e-mail is for an entity that has registered someone in a ballot pool who is not in that role. When the ballot pool member is no longer available to cast a ballot for the entity, we make every effort to allow the entity to continue to participate in the ballot pool by manually entering the vote for the person designated as his/her replacement. Our software, in its current format does not update ballot pools when an entity's Registered Ballot Body member changes, which forces us to enter these ballots through the manual process.

We are committed to maintaining an accurate record of this ballot. If you sent your votes via e-mail, please review the attached ballot results to ensure that your votes are included (or view the project page for the updated posted results: http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html).

If you find that your entity's votes were not posted, please call Monica Benson at 404-446-2573. You will need to send verification of any e-mail vote showing that the ballot was sent before the close of the ballot window, which will be forwarded to our IT department for review.

Thank you for your patience and understanding as we make any necessary voting result updates to ensure that accurate voting records are posted.

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower

Atlanta, GA 30326
404-446-2560 | www.nerc.com

You have received this email because you are a registered representative in the Registered Ballot Body.

Project 2007-17 — Protection System Maintenance & Testing — PRC-005
FirstEnergy Ballot (Negative) and Comments

While FirstEnergy (FE) has supported the proposed PRC-005-2 standard and voted affirmative in the previous ballot, we remain concerned with the proposed draft version of Requirement R3 as well as the SDT developed statements in the Supplementary Reference & FAQ. The SDT's approach sends industry the wrong message; a message that entities should not go beyond what is in the text of the standards and that in some cases they can even be found non-compliant by failing to meet their own more stringent internal practice. Therefore, we regrettably change our position to **NEGATIVE** at this time.

The NERC reliability standards aim to ensure an Adequate Level of Reliability (ALR). If NERC's reliability standard establishes that an ALR is achieved by a maximum allowable relay maintenance period of every 6 years in a time-based Protection System Maintenance Program (PSMP), then an entity striving to complete its maintenance every 4 years should not be found non-compliant for completing it in 5 years. The overall NERC CMEP strategy reinforced in CAN Webinars and NERC Workshops is that "auditors must audit to the standard", however, the approach taken by the SDT within Requirement R3 language and the Supplementary Reference and FAQ document are contrary to this position.

On page 26 of the Supplementary Reference and FAQ document it states "*If your PSMP (plan) requires more activities then you must perform and document to this higher standard.*" Similarly, page 27 states "*If your PSMP (plan) requires activities more often than the Tables maximum then you must perform and document those activities to your more stringent standard.*" Requirement R3 states that an entity must "implement and follow its PSMP".

FE is concerned that NERC is discouraging entities to go beyond the standards to enhance the reliability of the BES. In responding to an industry comment, the Commission in Order 693 states "*While we appreciate that many entities may perform at a higher level than that required by the Reliability Standards, and commend them for doing so, the Commission is focused on what is required under the Reliability Standards, we do not require that they exceed the Reliability Standards.*"[1] Of course an entity can adjust its time-based PSMP to say something like ... "The preferred interval maintenance is every X years not to exceed Y years as stated in Table 1.x of PRC-005-2." However, a registered entity should not be subject to fines when they have actually complied with the maximum allowable time intervals permitted, but did not "cover themselves" in their procedure text. Positions like this are "compliance for compliance sake" and not based on a reliability gap.

FE appreciates the SDT's hard-work and generally supports the standard from a technical standpoint. In addition to our primary concern of ensuring auditing to the actual requirements contained within a reliability standard we also offer the following suggested revision to Table [xx] as follows:
[Additional FE Comments here];

[1] FERC Order 693, Par. 278

DRAFT

We appreciate the SDT's careful consideration of the feedback provided. Should you have any question please feel free to contact Doug Hohlbaugh, Manager, Standards Development at 330-384-4698.

DRAFT

Project 2007-17 — Protection System Maintenance & Testing — PRC-005
FirstEnergy Ballot (Negative) and Comments

PROPOSED CHANGES TO PRC-005-2

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish and implement a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2. *Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

The PSMP shall:

1.1. Address all Protection System component types.

1.2. Identify which maintenance method (time-based, performance-based (per PRC-005 Attachment A), or a combination) is used to address each Protection System component type. All batteries associated with the station dc supply component type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.

1.3. Identify the associated maintenance intervals for time-based programs, to be no less frequent than the intervals established in Table 1-1 through 1-5, Table 2, and Table 3.

1.4. Include all applicable monitoring attributes and related maintenance activities applied to each Protection System component type to consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall ~~implement and follow its PSMP and~~ initiate resolution of any unresolved maintenance issues. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

Adjustments to measures will also be required to match the above proposed requirements.

DRAFT

Project 2007-17 — Protection System Maintenance & Testing — PRC-005
FirstEnergy Ballot (Negative) and Comments

PROPOSED CHANGES TO SUPPLEMENTARY REFERENCE & FAQ

Furthermore, we ask that the team remove the following text from the Supplementary Reference document:

1. Page 26 - The bullet "If your PSMP (plan) requires more activities then you must perform and document to this higher standard."

2. Page 27 – The bullet "If your PSMP (plan) requires activities more often than the Tables maximum then you must perform and document those activities to your more stringent standard."

3. Page 27 – The paragraph "It has been noted here that an entity may have a PSMP that is more stringent than PRC-005-2. There may be any number of reasons that an entity chooses a more stringent plan than the minimums prescribed within PRC-005-2, most notable of which is an entity using performance based maintenance methodology. (Another reason for having a more stringent plan than is required could be a regional entity could have more stringent requirements.) Regardless of the rationale behind an entity's more stringent plan, it is incumbent upon them to perform the activities, and perform them at the stated intervals, of the entity's PSMP. A quality PSMP will help assure system reliability and adhering to any given PSMP should be the goal."

   FE Comment:

   - The reference to more stringent "regional requirements" is unnecessary as it does not pertain to this NERC standard. If a regional entity finds need for more stringent expectations that exceed this NERC standard, then the approved regional standard would govern to those expectations, not this continent-wide NERC standard. Alternatively, a region could choose to pursue an entity variance to this standard to establish unique regional differences.
   - The reference to a performance based maintenance plan may be valid for defining need for more frequent maintence/testing of select equipment. A condition-based plan may as well, however, condition-based and performance – based programs will likely be implemented to justify extending maintenance intervals not shorten them. However, an entity electing a **time-based program** should be audited to the actual requirements within the standard. The standard and accompanying reference document should be clear on this point.

DRAFT

From:	Guy V. Zito
To:	tfsp
Cc:	rscmembers
Subject:	FW: FE Comments - PRC-005-2 Ballot and Comment Period - Ending Sept 28
Date:	Thursday, September 15, 2011 10:19:24 AM
Attachments:	DRAFT-FE Comments_PRC-005-2 Ballot Comments_Rev1_091411 rev2_clean.pdf
Importance:	High

TFSP Members,

Attached for your consideration is a statement from First Energy on an issue that has been previously raised by the NPCC RSC during its deliberations on the PRC standard. Please consider when reviewing the draft standard posted for comment through September 28th with a ballot taking place the last ten days of that comment period.

RSC requests any consensus input by **September 19th** in order to develop a ballot recommendation for the northeast.

Thanks,

Guy V. Zito
Asst. Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

From: hohlbaughdg@firstenergycorp.com [mailto:hohlbaughdg@firstenergycorp.com]
Sent: Wednesday, September 14, 2011 5:20 PM
To: Guy V. Zito
Subject: FE Comments - PRC-005-2 Ballot and Comment Period - Ending Sept 28

Guy:

I believe NPCC has expressed similar concerns in prior comments and ballots. Passing along FirstEnergy's draft comments and ballot position (negative) for your information.

Feel free to share with other NPCC interested parties if you wish.

Thanks,

Doug

Doug Hohlbaugh
Manager, Standards Development
FirstEnergy Corp.
76 South Main Street
Akron, OH 44308

330-384-4698 (office)
330-608-8097 (mobile)
330-761-4388 (fax)

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From: Guy V. Zito
To: tfsp
Subject: FW: NERC Recirc. Ballot PRC-005
Date: Thursday, September 15, 2011 12:55:54 PM
Attachments: Standard_PRC-005-_redline.pdf
Importance: High

TFSP,

Please see below the request for comments and recommendation for PRC-005 emailed earlier.

Thanks,

Guy V. Zito
Asst. Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

From: Guy V. Zito
Sent: Tuesday, September 06, 2011 7:37 AM
To: tfsp
Cc: rscmembers
Subject: NERC Recirc. Ballot PRC-005
Importance: High

TFSP Members,

Attached is the redline PRC-005-2 showing changes the drafting team made since the initial ballot, and failed recirculation ballot. Of note are:

- the definition "Unresolved Maintenance Issue" replacing "Maintenance Correctable Issue"
- New Table 3 "**Maintenance Activities and Intervals for distributed UFLS and UVLS Systems"**
- Increased maintenance cycle for batteries

For the initial ballot, NPCC RSC had recommended a "Yes" vote to the members. Please review the standard and notify me if any issues were introduced which should be commented on or would change our previous recommendation. Further materials and information may be found at:

http://www.nerc.com/filez/standards/Protection_System_Maintenance_Project_2007-17.html

I would like your consensus TFSP **comments and recommendation by 9/14**-for the RSC's consideration. This second Recirculation Ballot period opens on 9/19 and closes at 8PM on 9/28.

Thanks for your attention to this matter,

Guy V. Zito
Asst. Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

From:	Guy V. Zito
To:	rsballot
Cc:	rsc
Subject:	FW: NERC: Standards Announcement - Project 2007-17 Protection System Maintenance and Testing Ballot Window and Non-Binding Poll Window Now Open | Sept 19 – 28, 2011
Date:	Wednesday, September 21, 2011 12:41:56 PM
Importance:	High

NPCC Members of the NERC Registered Ballot Body,

The NPCC Regional Standards Committee, in conjunction with the Task Force on System Protection, have completed a review of the subject standard currently posted for ballot through 8:00 pm September 28, 2011. The RSC recommends an "**Affirmative Vote**" to accept.

An issue was raised regarding requiring an entity to adhere to their protection system maintenance program, PSMP. If an entity has a maintenance program in place that has shorter intervals, i.e. more stringent than those in the appendix of the standard, and the entity misses completing a maintenance, the entity will be found non-compliant irrespective of the entity to demonstrate they still were within the intervals listed in the actual standard. NPCC will submit a comment to raise this.

If you have any questions please contact me.

Thanks,

Guy V. Zito
Assistant Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10 th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

From: Eleanor Crouch [Eleanor.Crouch@nerc.net]
Sent: Monday, September 19, 2011 9:26 AM
To: Eleanor Crouch
Subject: NERC: Standards Announcement - Project 2007-17 Protection System Maintenance and Testing Ballot Window and Non-Binding Poll Window Now Open | Sept 19 – 28, 2011

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2007-17 Protection System Maintenance and Testing Now Open: Ballot Window and Non-Binding Poll Window September 19 – 28, 2011

Now available at: https://standards.nerc.net/CurrentBallots.aspx

An initial ballot of PRC-005-2 Protection System Maintenance, and a concurrent non-binding poll of the associated VRFs and VSLs, are open Monday, September 19, 2011 through **8:00 p.m. Eastern on Wednesday, September 28, 2011.**

PRC-005-2 was posted for a recirculation ballot that ended June 30, 2011. The standard narrowly failed to achieve ballot pool approval, and in accordance with the Standards Processes Manual, the project has been reinitiated. Because the project is not new to stakeholders, the

Standards Committee has waived the initial 30-day comment period and directed that the first posting be for a formal 45-day comment period with an initial ballot conducted during the last ten days of the comment period.

The drafting team has posted the SAR, a clean copy of PRC-005-2, its Implementation Plan and associated VRFs and VSLs, and a Supplemental Reference and FAQ on the project web page: http://www.nerc.com/filez/standards/Protection_System_Maintenance_Project_2007-17.html

Redlines have also been posted showing changes made to the standard, implementation plan, and Supplemental Reference and FAQ since the standard was posted for recirculation ballot in June 2011.

Note that PRC-005-2 reflects the merging of the following standards into a single standard, making it impractical to post a redline of proposed PRC-005-2 that shows the changes to the last approved version of the standard.

- PRC-005-1 — Transmission and Generation Protection System Maintenance and Testing
- PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Program
- PRC-011-0 — UVLS System Maintenance and Testing
- PRC-017-0 — Special Protection System Maintenance and Testing

The last approved versions of PRC-005-1, PRC-008-0, PRC-011-0, and PRC-017-0 have been posted on the project's web page for easy reference at:
http://www.nerc.com/filez/standards/Protection_System_Maintenance_Project_2007-17.html

A mapping document showing the disposition of requirements from each of these standards has also been posted.

Instructions for Casting Ballots and Opinions in Non-binding Polls
Members of the ballot pool associated with this project may log in and submit their vote the standard and opinion for the non-binding poll of VRFs and VSLs at:
https://standards.nerc.net/CurrentBallots.aspx.

Special Instructions for Submitting Comments With a Ballot
A formal comment period is open through **8:00 p.m. Eastern on Wednesday, September 28, 2011.**

Comments submitted with ballots are extremely valuable to help the drafting team revise its work. In an effort to reduce the burden on stakeholders providing comments, the drafting team requests that all comments (both those submitted with a ballot and those submitted by stakeholders not balloting) be submitted through the electronic comment form. This will ensure that stakeholders only provide a single set of comments, but have an opportunity to notify the drafting team if they have provided comments.

When submitting a ballot with comments, submit the comments through the electronic form and then simply record a "Comments submitted" in the comments field of the ballot to indicate that comments were submitted.

An off-line unofficial copy of the questions listed in the comment form is posted on the project page. Please note that comments submitted during the formal comment period, the ballot for the standard, and the non-binding poll for the VRFs and VSLs all use the same electronic form, and it is NOT necessary for ballot pool members to submit more than one set of comments (one during the comment period; a second with a ballot; a third with a non-binding poll).

Next Steps
The drafting team will consider all comments received, and decide whether to make additional revisions to the standards.

Project Background

The proposed PRC-005-2 – Protection System Maintenance standard addresses FERC directives from FERC Order 693, as well as issues identified by stakeholders. In accordance with the FERC directives, this draft standard establishes requirements for a time-based maintenance program, where all relevant devices are maintained according to prescribed maximum intervals. It further establishes requirements for a condition-based maintenance program, where the hands-on maintenance intervals are adjusted to reflect the known and reported condition of the relevant devices. For a performance-based maintenance program, it ascertains where the hands-on maintenance intervals are adjusted to reflect the historical performance of the relevant devices.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Eleanor Crouch at eleanor.crouch@nerc.net.

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From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement - Project 2007-17 Protection System Maintenance & Testing | Initial Ballot Results
Date: Tuesday, October 18, 2011 4:06:40 PM

Standards Announcement

Project 2007-17 Protection System Maintenance & Testing Initial Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

Ballot Results for PRC-005-2 Protection System Maintenance
An initial ballot of PRC-005-2 Protection System Maintenance, and a concurrent non-binding poll of the associated VRFs and VSLs, concluded on September 28, 2011.

Voting statistics for the standard are listed below, and the Ballot Results webpage provides a link to the detailed results.

Quorum: 84.86 %
Approval: 61.10 %

Non-binding Poll Results for Associated VRF and VSLs
Of those who registered to participate, 83.13% provided an opinion or abstention; 68.68% of those who provided an opinion indicated support for the VRFs and VSLs that were proposed.

Next Steps
The drafting team will consider all comments received, and decide whether to make additional revisions to the standards.

Project Background
The proposed PRC-005-2 – Protection System Maintenance standard addresses FERC directives from FERC Order 693, as well as issues identified by stakeholders. In accordance with the FERC directives, this draft standard establishes requirements for a time-based maintenance program, where all relevant devices are maintained according to prescribed maximum intervals. It further establishes requirements for a condition-based maintenance program, where the hands-on maintenance intervals are adjusted to reflect the known and reported condition of the relevant devices. For a performance-based maintenance program, it ascertains where the hands-on maintenance intervals are adjusted to reflect the historical performance of the relevant devices.

PRC-005-2 was posted for a recirculation ballot that ended June 30, 2011. The standard narrowly failed to achieve ballot pool approval, and in accordance with the Standards Processes Manual, the project has been reinitiated. Because the project is not new to stakeholders, the Standards Committee waived the initial 30-day comment period and directed that the standard

be posted for a formal 45-day comment period with an initial ballot conducted during the last ten days of the comment period.

Additional information is available on the project webpage.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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From: Lee R. Pedowicz
To: rscmembers; donald.e.nelson@state.ma.us; rjfalsetti@cogeco.ca
Subject: FW: NERC: Standards Announcement | Technical Difficulties on Balloting and Comment Portion NERC Webpages
Date: Tuesday, September 27, 2011 10:18:34 AM

Good morning.

For information.

Lee

From: Monica Benson [mailto:Monica.Benson@nerc.net]
Sent: Tuesday, September 27, 2011 10:10 AM
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement | Technical Difficulties on Balloting and Comment Portion NERC Webpages

Standards Announcement

To: Members of the NERC Registered Ballot Body

We are experiencing technical difficulties and at this time the balloting and comment portion of the NERC webpages are unavailable. We are working diligently to correct the problem.

The following ballots and comment periods are affected:

- Project 2007-17: Protection System Maintenance & Testing – Initial Ballot & Non-Binding Poll VRFs and VSLs; Comment Period
- Project 2010-17: Definition of Bulk Electric System – Two Initial Ballots and Three Comment Periods

We will be extending the Project 2007-17: Protection System Maintenance & Testing Initial Ballot and Non-Binding Poll, as well as the comment period, by one additional day, now ending September 29, 2011.

We will let you know as soon as the issue has been resolved and will decide whether any other adjustments to ballot or comment periods are necessary once we have additional information on the length of the disruption.

Thank you for your patience.

Standards staff

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Standards Committee approves ~~SAR for~~ posting SAR and draft standard on ~~June 5, 2007~~August 11, 2011.
2. ~~The SAR was posted for comment from June 11, 2007–July 10, 2007.~~
3. ~~The SC approves development of the standard on August 13, 2007.~~
4. ~~First posting of revised standard on July 24, 2009.~~
5. ~~Second posting of revised standard on June 11, 2010~~
6. ~~Third posting of revised standard on November 17, 2010~~
7. ~~Fourth posting of revised standard on April 13, 2011~~

Description of Current Draft:

This is the ~~fifth~~ first draft of the Standard. This standard merges previous standards PRC-005-1, PRC-005-1a, PRC-008-0, PRC-011-0, and PRC-017-0. It also addresses FERC comments from Order 693, and addresses observations from the NERC System Protection and Control Task Force, as presented in *NERC SPCTF Assessment of Standards: PRC-005-1 — Transmission and Generation Protection System Maintenance and Testing, PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs, PRC-011-0 — UVLS System Maintenance and Testing, PRC-017-0 — Special Protection System Maintenance and Testing.*

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for combined ~~30~~45-day comment and ballot.	~~July~~ September ~~5~~ – ~~August~~ October~~4~~, 2011
2. Conduct ~~successive~~ initial ballot	~~July~~ October~~26 – August 4~~, 2011
3. Drafting Team Responds to Comments	~~August~~ November~~4~~ – Dec~~Sept~~ember ~~6~~, 2011

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific component includes one or more of the following activities:

- Verify — Determine that the component is functioning correctly.
- Monitor — Observe the routine in-service operation of the component.
- Test — Apply signals to a component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Detect visible signs of component failure, reduced performance and degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

Protection System (NERC Board of Trustees Approved Definition)

- Protective relays which respond to electrical quantities,
- ~~communications~~ Communications systems necessary for correct operation of protective functions,
- ~~voltage~~ Voltage and current sensing devices providing inputs to protective relays,
- ~~station~~ Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- ~~control~~ Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

The following terms are defined for use only within PRC-005-2, and should remain with the standard upon approval rather than being moved to the Glossary of Terms.

~~Maintenance Correctable~~Unresolved Maintenance Issue – ~~Failure of a component to operate within design parameters such that the~~A deficiency that cannot be corrected during the performance of the maintenance activity~~. Therefore this issue~~ and requires follow-up corrective action.

Segment – Protection Systems or components ~~-~~of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a segment. A segment must contain at least sixty (60) individual components.

Component Type - Any one of the five specific elements of the Protection System definition.

Component – A component ~~-~~is any individual discrete piece of equipment included in a Protection System, including but not limited to a protective relay or current sensing device. The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others

test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

Countable Event – A component which has failed and requires repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5 and Table 3 which requires corrective action, or a Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System component configuration errors, or Protection System application errors are not included in Countable Events.

A. Introduction

1. Title: **Protection System Maintenance**

2. Number: PRC-005-2

3. Purpose: To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.

4. Applicability:

4.1. Functional Entities:

4.1.1 Transmission Owners

4.1.2 Generator Owners

4.1.3 Distribution Providers

4.2. Facilities:

4.2.1 Protection Systems that are installed for the purpose of detecting faults on BES Elements (lines, buses, transformers, etc.)

4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.

4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.

4.2.4 Protection Systems installed as a Special Protection System (SPS) for BES reliability.

4.2.5 Protection Systems for generator Facilities that are part of the BES, including:

4.2.5.1 Protection Systems that act to trip the generator either directly or via generator lockout or auxiliary tripping relays.

4.2.5.2 Protection Systems for generator step-up transformers for generators that are part of the BES.

4.2.5.3 Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).

4.2.5.4 Protection Systems for generator-connected station service transformers for generators that are part of the BES.

5. Effective Date: See Implementation Plan

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2. *Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

The PSMP shall:

1.1. Address all Protection System **component types.**

1.2. Identify which maintenance method (time-based,

Component Type *- Any one of the five specific elements of the Protection System definition.*

performance-based (per PRC-005 Attachment A), or a combination) is used to address each Protection System component type. All batteries associated with the station dc supply component type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.

1.3. Identify the associated maintenance intervals for time-based programs, to be no less frequent than the intervals established in Table 1-1 through 1-5~~ and~~ , Table 2, and Table 3.

1.4. Include all applicable monitoring attributes and related maintenance activities applied to each Protection System component type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, ~~and~~ Table 2, and Table 3.

***~~Maintenance Correctable~~Unresolved Maintenance* Issue -** *~~Failure of a component to operate within design parameters such that the~~ A deficiency that cannot be corrected during the performance of the maintenance activity~~. Therefore this issue~~ and requires follow-up corrective action.*

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement and follow its PSMP and initiate resolution of any ~~identified **maintenance correctable**~~**unresolved maintenance issues**.
[Violation Risk Factor: High] [Time Horizon: Operations Planning]

C. Measures

M1. Each Transmission Owner, Generator Owner and Distribution Provider shall have a current documented Protection System Maintenance Program that addresses all component types of its Protection Systems, as required by Requirement R1. For each Protection System component type, the documentation shall include the type of maintenance program applied (time-based, performance-based, or a combination of these maintenance methods), maintenance activities, maintenance intervals, and, for component types that use monitoring to extend the intervals, the appropriate monitoring attributes as specified in Requirement R1, Parts 1.1 through 1.4.

M2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a performance-based maintenance program shall have evidence that its current performance-based maintenance program is in accordance with Requirement R2, which may include but is not limited to equipment lists, dated maintenance records, and dated analysis records and results.

M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has implemented the Protection System Maintenance Program and initiated resolution of ~~identified Maintenance Correctable Issues~~unresolved maintenance issues in accordance with Requirement R3, which may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Entity

1.2. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3. Data Retention

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to demonstrate compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program including the documentation that specifies the type of maintenance program applied for each Protection System component type.

For Requirement R2 and Requirement R3, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System **components**, or all performances of each distinct maintenance activity for the Protection System component since the previous scheduled audit date, whichever is longer.

Component – *A component is any individual discrete piece of equipment included in a Protection System, including but not limited to a protective relay or current sensing device. The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.*

The Compliance Enforcement Authority shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's PSMP failed to specify whether one component type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.2)	The responsible entity's PSMP failed to address one component type included in the definition of 'Protection System' (Part 1.1) OR The responsible entity's PSMP failed to specify whether two component types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.2)	The responsible entity's PSMP failed to address two component types included in the definition of 'Protection System' (Part 1.1) OR The responsible entity's PSMP failed to include station batteries in a time-based program (Part 1.2) OR The responsible entity failed to include all maintenance activities or intervals relevant for the identified monitoring attributes specified in Tables 1-1 through 1-5, ~~and~~ Table 2, and Table 3. (Part 1.3 and 1.4)	The responsible entity has not established a PSMP. OR The responsible entity's PSMP failed to address three or more component types included in the definition of 'Protection System' (Part 1.1) OR The responsible entity failed to specify whether three or more component types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.2).
R2	The responsible entity uses performance-based maintenance intervals in its PSMP but has: 1) Failed to reduce countable events to less than 4% within three years OR 2) Failed to annually document program activities, results, maintenance dates, or countable events for 5% or less of components in any individual segment	NA	The responsible entity uses performance-based maintenance intervals in its PSMP but has failed to reduce countable events to less than 4% within four years.	The responsible entity uses performance-based maintenance intervals in its PSMP but has: 1) Failed to establish the entire technical justification described within R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce countable events to less than 4% within five years OR 3) Failed to annually document program activities, results, maintenance dates, or countable

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				events for over 5% of components in any individual segment OR 4) Maintained a segment with less than 60 components OR 5) Failed to: • Annually update the list of components, OR • Perform maintenance on the greater of 5% of the segment population or 3 components, OR • Annually analyze the program activities and results for each segment.
R3	The responsible entity has failed to implement and follow scheduled program on 5% or less of total Protection System components. OR The responsible entity has failed to initiate resolution on 5% or less of ~~identified maintenance correctable~~unresolved maintenance issues.	The responsible entity has failed to implement and follow scheduled program on greater than 5%, but no more than 10% of total Protection System components OR The responsible entity has failed to initiate resolution on greater than 5%, but less than or equal to 10% of ~~identified~~ unresolved maintenance~~maintenance correctable~~ issues.	The responsible entity has failed to implement and follow scheduled program on greater than 10%, but no more than 15% of total Protection System components OR The responsible entity has failed to initiate resolution on greater than 10%, but less than or equal to 15% of ~~identified~~unresolved maintenance issues.	The responsible entity has failed to implement and follow scheduled program on greater than 15% of total Protection System components OR The responsible entity has failed to initiate resolution on greater than 15% of ~~identified~~ unresolved maintenance~~maintenance correctable~~ issues.

E. Regional Variances

None

F. Supplemental Reference Document

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program..

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — July~~February~~ 2011.

Version History

Version	Date	Action	Change Tracking
2	TBD	Complete revision, absorbing maintenance requirements from PRC-005-1, PRC-005-1a, PRC-008-0, PRC-011-0, PRC-017	Complete revision

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**[1]	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 calendar years	Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self diagnosis and alarming (see Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. • Alarming for power supply failure (see Table 2).	12 calendar years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

[1] For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error. (See Table 2) • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure. (See Table 2) • Alarming for change of settings. (See Table 2)	12 calendar years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 1-2 Component Type - Communications Systems Excluding distributed UFLS and UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.	~~3~~ 4 calendar months	Verify that the communications system is functional.
	6 calendar years	Verify that the channel meets performance criteria pertinent to the communications technology applied (~~e.g~~e.g. ~~-~~signal level, reflected power, or data error rate). Verify essential signals to and from other Protection System components.

Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function. (See Table 2)	12 calendar years	Verify that the channel meets performance criteria pertinent to the communications technology applied (~~e.g~~e.g. signal level, reflected power, or data error rate). Verify essential signals to and from other Protection System components.
Any communications system with continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2)	No periodic maintenance specified	None.

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any voltage and current sensing devices not having monitoring attributes of the category below.	12 calendar years	Verify that current and voltage signal values are provided to the protective relays.
Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2).	No periodic maintenance specified	None.

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station dc supply using **Vented Lead-Acid (VLA) batteries** not having monitoring attributes of Table 1-4(f). Protection System Station dc supply for distribution breakersnon-BES interrupting devices for UFLS or UVLSSPS or non-distributed UVLS systems are excluded (see Table 1-4(e)).	3 4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible • Physical condition of battery rack
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as designed by evaluating the measured cell/unit internal ohmic values to station battery baseline. -or- Verify that the station battery can perform as designed by conducting a performance, service, or modified performance capacity test of the entire battery bank.

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station dc supply **with Valve Regulated Lead-Acid (VRLA) batteries** not having monitoring attributes of Table 1-4(f). Station dc supply for non-BES interrupting devices ~~distribution breakers~~ for ~~UFLS or UVLS~~SPS or non-distributed UFLS and UVLS systems are excluded (see Table 1-4(e)).	~~3~~ 4 Calendar Months	Verify: • Station dc supply voltage Inspect: • For unintentional grounds
	6 Calendar Months	Inspect: • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Physical condition of battery rack
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as designed by evaluating the measured cell/unit internal ohmic values to station battery baseline. -or- Verify that the station battery can perform as designed by conducting a performance, service, or modified performance capacity test of the entire battery bank

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding UFLS and non-distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station dc supply **Nickel-Cadmium (NiCad) batteries** not having monitoring attributes of Table 1-4(f). Station dc supply for non-BES interrupting devices distribution breakers for UFLS or UVLSSPS or non-distributed UFLS and UVLS systems are excluded (see Table 1-4(e)).	3 4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells. • Physical condition of battery rack
	6 Calendar Years	Verify that the station battery can perform as designed by conducting a performance service, or modified performance capacity test of the entire battery bank.

Table 1-4(d) Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage Excluding UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f). Protection System Station dc supply for non-BES interrupting devices distribution breakers for UFLS, UVLS and SPS or non-distributed UFLS and UVLS systems are excluded (see Table 1-4(e)).	3 4 Calendar Months	Verify: • Station dc supply voltage Inspect: • For unintentional grounds
	18 Calendar Months	Inspect: Condition of non-battery based dc supply
	6 Calendar Years	Verify that the dc supply can perform as designed when ac power is not present.

Table 1-4(e) Component Type – Protection System Station dc Supply for non-BES Interrupting Device for SPS and non-distributed UVLS and UFLS systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any Protection System dc supply for tripping only non-BES interrupting devices as part of a ~~UFLS, UVLS or~~ SPS or non-distributed UVLS and UFLS system and not having monitoring attributes of Table 1-4(f).	When control circuits are verified (See Table 1-5)	Verify~~:~~ ~~•~~ Station dc supply voltage

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure. (See Table 2)	No periodic maintenance specified	No periodic verification of station dc supply voltage is required.
Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2)		No periodic inspection of the electrolyte level for each cell is required.
Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2)		No periodic inspection of unintentional dc grounds is required.
Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2)		No periodic verification of float voltage of battery charger is required
Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2)		No periodic verification of the battery continuity is required.
Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2)		No periodic verification of the intercell and terminal connection resistance is required.
Any lead acid battery based station dc supply with internal ohmic value monitoring, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2)		.No periodic measurement and evaluation relative to baseline of battery cell/unit internal ohmic values is required to verify the station battery can perform as designed .
Any Valve Regulated Lead-Acid (VRLA) station battery with monitoring and alarming of each cell/unit internal Ohmic value. (See Table 2)		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA battery is required.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and UVLS (see Table 3) **Note:** Table requirements apply to all Control Circuitry components of Protection Systems, ~~UVLS and UFLS Systems,~~ and SPSs except as noted.		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices ~~(excluding UFLS or UVLS systems).~~	6 calendar years	Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.
~~Trip coils of circuit breakers and interrupting devices in UFLS or UVLS systems.~~Unmonitored control circuitry associated with SPS	~~No periodic maintenance specified~~12 calendar years	~~None.~~Verify all paths of the control circuits essential for proper operation of the SPS.
Electromechanical lockout and/or tripping auxiliary devices which are directly in a trip path from the protective relay to the interrupting device trip ~~coil .~~coil.	6 calendar years	Verify electrical operation of electromechanical trip and auxiliary devices.
Unmonitored control circuitry associated with protective functions.	12 calendar years	Verify all paths of the ~~control and~~ trip circuits through the trip coil(s) of the circuit breakers or other interrupting devices~~circuits~~.
Control circuitry whose continuity and energization or ability to operate are monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5, alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any alarm path through which alarms in Tables 1-1 through 1-5 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the "Alarm Path with monitoring" category below. Alarms are reported within 24 hours of DETECTION to a location where corrective action can be initiated.	12 Calendar Years	Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated.
Alarm Path with monitoring: The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.	No periodic maintenance specified	~~No periodic maintenance specified~~None.

Table 3 Maintenance Activities and Intervals for distributed UFLS and UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 calendar years	Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self diagnosis and alarming (See Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. Alarming for power supply failure (See Table 2).	12 calendar years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error. (See Table 2) • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure. (See Table 2) Alarming for change of settings. (See Table 2)	12 calendar years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.
Voltage and/or current sensing devices associated with UFLS or UVLS systems.	12 calendar years	Verify that current and/or voltage signal values are provided to the protective relays.
Protection System dc supply for tripping only non-BES interrupting devices as part of a UFLS or UVLS system.	12 calendar years	Verify Protection System dc supply voltage
Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices.	12 calendar years	Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic).
Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems.	12 calendar years	Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.
Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices.	No periodic maintenance specified	None.
Trip coils of non-BES interrupting devices in UFLS or UVLS systems.	No periodic maintenance specified	None.

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

Purpose: To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

To establish the technical justification for the initial use of a performance-based PSMP:

1. Develop a list with a description of components included in each designated segment of the Protection System component population, with a minimum **segment** population of 60 components.
2. Maintain the components in each segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5 and Table 3 until results of maintenance activities for the segment are available for a minimum of 30 individual components of the segment.

> **Segment** – *Protection Systems or components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a segment. A segment must contain at least sixty (60) individual components.*

3. Document the maintenance program activities and results for each segment, including maintenance dates and countable events for each included component.
4. Analyze the maintenance program activities and results for each segment to determine the overall performance of the segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each segment such that the segment experiences **countable events** on no more than 4% of the components within the segment, for the greater of either the last 30 components maintained or all components maintained in the previous year.

> **Countable Event** – *A component which has failed and requires repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5 and Table 3 which requires corrective action, or a Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System component configuration errors, or Protection System application errors are not included in Countable Events.*

To maintain the technical justification for the ongoing use of a performance-based PSMP:

1. At least annually, update the list of Protection System components and segments and/or description if any changes occur within the segment.
2. Perform maintenance on the greater of 5% of the components (addressed in the performance based PSMP) in each segment or 3 individual components within the segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each segment to determine the overall performance of the segment.

4. Using the prior year's data, determine the maximum allowable maintenance interval for each segment such that the segment experiences countable events on no more than 4% of the components within the segment, for the greater of either the last 30 components maintained or all components maintained in the previous year.
5. If the components in a Protection System segment maintained through a performance-based PSMP experience 4% or more countable events, develop, document, and implement an action plan to reduce the countable events to less than 4% of the segment population within 3 years.

From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement - Project 2007-17 Protection System Maintenance & Testing | Initial Ballot Results
Date: Tuesday, October 18, 2011 4:06:40 PM

Standards Announcement

Project 2007-17 Protection System Maintenance & Testing Initial Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

Ballot Results for PRC-005-2 Protection System Maintenance
An initial ballot of PRC-005-2 Protection System Maintenance, and a concurrent non-binding poll of the associated VRFs and VSLs, concluded on September 28, 2011.

Voting statistics for the standard are listed below, and the Ballot Results webpage provides a link to the detailed results.

Quorum: 84.86 %
Approval: 61.10 %

Non-binding Poll Results for Associated VRF and VSLs
Of those who registered to participate, 83.13% provided an opinion or abstention; 68.68% of those who provided an opinion indicated support for the VRFs and VSLs that were proposed.

Next Steps
The drafting team will consider all comments received, and decide whether to make additional revisions to the standards.

Project Background
The proposed PRC-005-2 – Protection System Maintenance standard addresses FERC directives from FERC Order 693, as well as issues identified by stakeholders. In accordance with the FERC directives, this draft standard establishes requirements for a time-based maintenance program, where all relevant devices are maintained according to prescribed maximum intervals. It further establishes requirements for a condition-based maintenance program, where the hands-on maintenance intervals are adjusted to reflect the known and reported condition of the relevant devices. For a performance-based maintenance program, it ascertains where the hands-on maintenance intervals are adjusted to reflect the historical performance of the relevant devices.

PRC-005-2 was posted for a recirculation ballot that ended June 30, 2011. The standard narrowly failed to achieve ballot pool approval, and in accordance with the Standards Processes Manual, the project has been reinitiated. Because the project is not new to stakeholders, the Standards Committee waived the initial 30-day comment period and directed that the standard

be posted for a formal 45-day comment period with an initial ballot conducted during the last ten days of the comment period.

Additional information is available on the project webpage.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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From: Lee R. Pedowicz
To: rscmembers; donald.e.nelson@state.ma.us; rjfalsetti@cogeco.ca
Subject: FW: NERC: Standards Announcement | Technical Difficulties on Balloting and Comment Portion NERC Webpages
Date: Tuesday, September 27, 2011 10:18:34 AM

Good morning.

For information.

Lee

From: Monica Benson [mailto:Monica.Benson@nerc.net]
Sent: Tuesday, September 27, 2011 10:10 AM
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement | Technical Difficulties on Balloting and Comment Portion NERC Webpages

Standards Announcement

To: Members of the NERC Registered Ballot Body

We are experiencing technical difficulties and at this time the balloting and comment portion of the NERC webpages are unavailable. We are working diligently to correct the problem.

The following ballots and comment periods are affected:

- Project 2007-17: Protection System Maintenance & Testing – Initial Ballot & Non-Binding Poll VRFs and VSLs; Comment Period
- Project 2010-17: Definition of Bulk Electric System – Two Initial Ballots and Three Comment Periods

We will be extending the Project 2007-17: Protection System Maintenance & Testing Initial Ballot and Non-Binding Poll, as well as the comment period, by one additional day, now ending September 29, 2011.

We will let you know as soon as the issue has been resolved and will decide whether any other adjustments to ballot or comment periods are necessary once we have additional information on the length of the disruption.

Thank you for your patience.

Standards staff

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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Atlanta, GA 30326
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You have received this email because you are a registered representative in the Registered Ballot Body.

From:	Monica Benson
To:	monica.benson@nerc.net
Subject:	NERC: Standards Announcement - Project 2007-17 Protection System Maintenance and Testing | Formal Comment Period Open Aug 15 – Sept 28, 2011 | Ballot Pool Windows Open Through Sept 14, 2011
Date:	Monday, August 15, 2011 10:34:10 AM

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2007-17 Protection System Maintenance and Testing
Formal Comment Period Open Aug 15 – Sept 28, 2011
Ballot Pool Windows Open Through Sept 14, 2011
Initial Ballot and Non-Binding Poll: Sept 19 – 28, 2011

Now available at: http://www.nerc.com/filez/standards/Protection_System_Maintenance_Project_2007-17.html

The Standards Committee has authorized posting the SAR for Project 2007-17 Protection System Maintenance and Testing, along with the draft standard PRC-005-2 — Protection System Maintenance and associated implementation plan, for a formal 45-day comment period.

PRC-005-2 was posted for a recirculation ballot that ended June 30, 2011. The standard narrowly failed to achieve ballot pool approval, and in accordance with the Standard Processes Manual, the project has been reinitiated. An initial ballot and concurrent non-binding poll will be conducted during the last 10 days of the 45-day comment period. A new ballot pool is being formed during the first 30-days of the 45-day comment period. Because the project is not new to stakeholders, the Standards Committee has waived the initial 30-day comment period and asked the drafting team to conduct a webinar during the comment period.

Instructions for Joining the New Ballot Pool for Project 2007-17

The ballot pool windows are open through **8 a.m. Eastern on Wednesday, September 14, 2011**.

Registered Ballot Body members may join the ballot pools to be eligible to vote in the upcoming ballot and non-binding poll at the following page: https://standards.nerc.net/BallotPool.aspx

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for the initial ballot pool is: bp-2007-17_PSMT_IN2_in@nerc.com. The list serve for the non-binding poll is: bp-2007-17_nb_0811_in@nerc.com

Any member who wishes to participate in the non-binding poll of the associated violation risk factor (VRF) and violation severity levels (VSLs) must also join this pool. We have discontinued the practice of automatically populating the ballot pool for the non-binding poll with all those who joined the pool to vote on the standard. Thus, anyone wishing to vote on the standard and also wishes to cast an opinion in the non-binding poll of the VRFs and VSLs must join both ballot pools.

Instructions for Submitting Comments

A formal comment period is open through **8 p.m. Eastern on Wednesday, September 28, 2011.**

Please use this electronic comment form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net.

Documents for this project, including the SAR, a clean copy of PRC-005-2, its Implementation Plan, and Supplemental Reference and FAQ along with an off-line unofficial copy of the questions listed in the comment forms are posted at the following site: http://www.nerc.com/filez/standards/Protection_System_Maintenance_Project_2007-17.html

Redlines have also been posted showing changes made to the standard, implementation plan, and Supplemental Reference and FAQ since the standard was posted for recirculation ballot in June.

The drafting team considered whether revisions to the SAR were needed but did not revise the SAR, so the SAR that is posted is the same SAR that was posted for comment when Project 2007-17 was first initiated, except that the date has been updated.

Note that PRC-005-2 reflects the merging of the following standards into a single standard, making it impractical to post a redline of proposed PRC-005-2 that shows the changes to the last approved version of the standard.

- PRC-005-1 — Transmission and Generation Protection System Maintenance and Testing
- PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Program
- PRC-011-0 — UVLS System Maintenance and Testing
- PRC-017-0 — Special Protection System Maintenance and Testing

The last approved versions of PRC-005-1, PRC-008-0, PRC-011-0, and PRC-017-0 have been posted on the project's web page for easy reference at:

http://www.nerc.com/filez/standards/Protection_System_Maintenance_Project_2007-17.html

Next Steps – Webinar, Initial Ballot and Non-binding Poll of VRFs and VSLs

The drafting team plans to conduct a webinar during the comment period to review PRC-005-2 and address questions. Additional details will be announced when they are available.

An initial ballot of the revised standard and its associated implementation plan, and a new non-binding poll of the revised VRFs and VSLs will be conducted during the last 10 days of the comment period, beginning on Monday, September 19 through Wednesday, September 28, 2011.

Project Background

The proposed PRC-005-2 – Protection System Maintenance standard addresses FERC directives from FERC Order 693, as well as issues identified by stakeholders. In accordance with the FERC directives, this draft standard establishes requirements for a time-based maintenance program, where all relevant devices are maintained according to prescribed maximum intervals. It further establishes requirements for a condition-based maintenance program, where the hands-on maintenance intervals are adjusted to reflect the known and reported condition of the relevant devices. For a performance-based maintenance program, it ascertains where the hands-on maintenance intervals are adjusted to reflect the historical performance of the relevant devices.

Standards Development Process

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September 16, 2011

NERC Member Representatives Committee
Industry Stakeholders

Upcoming Ballot on BES Definition

The NERC Member Representatives Committee (MRC) and Board of Trustees (BOT) had active and fruitful discussions at their August 3-4, 2011 meetings regarding NERC's efforts to develop a revised definition of Bulk Electric System (BES) as directed by the Federal Energy Regulatory Commission (FERC) in Order 743 and Order 743-A.

The net result of those discussions and subsequent consideration by the BES Definition Standard Drafting Team and NERC Standards Committee was a decision to separate the original development effort into two phases, as described in the Drafting Team's "Bulk Electric System Definition Project – Fact Sheet." NERC chairman, John Q. Anderson, in his September 1, 2011 letter to Standards Committee chairman, Allen Mosher, thanked the committee and the BES Definition Standard Drafting Team for their timely efforts, indicating that this action "fulfills all of our expectations regarding the resolution that the Board approved at its August 4, 2011 meeting."

As explained in the Fact Sheet, the Drafting Team received many suggestions during the initial posting of the draft BES Definition that were deemed to fall outside the narrow scope of the regulatory directives in the FERC orders. These industry suggestions deserve serious and thorough consideration and will get that attention in the second phase of the project as now defined.

Scott Helyer, MRC vice chair, and I fully support this phased approach and believe that it strikes an appropriate balance that will allow NERC to fully address the issues raised in the FERC orders and at the same time keep high priority attention on possible changes to the Statement of Compliance Registry Criteria that have been suggested by the industry. As officers of a representative group of the industry, we will continue to support pursuing phase 2 of this project plan on a high priority basis. We also strongly encourage the industry to cast their ballots on the merits of the proposed BES Definition and supporting documents as an adequate response to the FERC orders and not as a referendum on the project plan.

The BES Standard Drafting Team and the associated Rules of Procedure Drafting Team will be holding a webinar on September 28, 2011, 1 – 4 p.m. ET, to discuss both phases of the overall project plan and the specifics of the proposed BES Definition and Rules changes that will be balloted beginning September 30.

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I encourage all of you to take advantage of this webinar to gain a fuller understanding of the decision to divide this project into two phases, the proposed BES Definition to satisfy the FERC orders, and the plan to address the remaining suggestions during Phase 2 of the project.

Please contact me and/or Scott Helyer if you have any questions about the new project plan or to express any concerns with the approach being taken.

Sincerely,

William J. Gallagher
Chairman, NERC Member Representatives Committee

cc: NERC Standards Committee
BES Definition Standard Drafting Team

From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement - Project 2010-17 Definition of Bulk Electric System | Initial Ballot Results
Date: Wednesday, October 12, 2011 10:51:45 AM

Standards Announcement

Project 2010-17 Definition of Bulk Electric System
Initial Ballot Results

Now available

Ballot Results for Definition of Bulk Electric System

The two ballots windows for Project 2010-17 Definition of Bulk Electric System (BES): the first for the definition of Bulk Electric System and associated implementation plan, and the second for the draft application form titled Detailed Information to Support an Exception Request referenced in the Rules of Procedure Exception Process closed at 8 p.m. Eastern on Monday, October 10, 2011.

Voting statistics for each ballot are listed below, and the Ballot Results Web page provides a link to the detailed results.

BES Definition	Technical Criteria to Support a BES Exception Request
Quorum: 92.97%	Quorum: 89.53%
Approval: 71.68%	Approval: 64.03%

Next Steps

The drafting team will consider all comments received, and decide whether to make additional revisions to the definition of Bulk Electric System, the associated implementation plan, and the application form titled *Detailed Information to Support an Exception Request* referenced in the Rules of Procedure Exception Process. The drafting team is working to meet the regulatory deadline established in FERC Orders 743 and 743A (filing by January 25, 2012).

The Standards Committee and NERC Board of Trustees have recommended that the drafting team address issues such as generation thresholds in a second phase of this project. This approach will ensure that the drafting team has sufficient time to adequately consider and develop a sound technical basis for an approach, and will allow the drafting team to meet the regulatory deadline in FERC Orders 743 and 743A (filing by January 25, 2012). The drafting team has posted a **draft** Supplemental Standards Authorization Request (SAR) for information purposes only; the SAR will be posted for comment at a future time. Additionally, the drafting team has posted a Fact Sheet, which provides an up to date review of the project scope, project plan - phased approach, current status and upcoming events, on the project webpage.

Project Background

On November 18, 2010 FERC issued Order 743 (amended by Order 743A) and directed NERC to revise the definition of Bulk Electric System so that the definition encompasses all Elements and Facilities necessary for the reliable operation and planning of the interconnected bulk power system. Additional specificity will reduce ambiguity and establish consistency across all Regions

in distinguishing between BES and non-BES Elements and Facilities.

In addition, NERC was directed to develop a process for identifying any Elements or Facilities that should be excluded from the BES. NERC is working to address these directives with two activities – the definition of Bulk Electric System is being revised through the standard development process and a BES Definition Exception Process is being developed as proposed modifications to the Rules of Procedure. The proposed modifications have been posted for a comment period through October 27, 2011. The work of the BES Definition Exception Process has been publicly posted at: http://www.nerc.com/filez/standards/Rules_of_Procedure-RF.html.

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Date: Wednesday, October 12, 2011 10:51:45 AM

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From: Guy V. Zito
To: Philip A. Fedora; Ed Schwerdt
Cc: Gerard J. Dunbar; Lee R. Pedowicz
Subject: RE: NERC: Standards Announcement - Project 2010-17 Definition of Bulk Electric System | Initial Ballot Results
Date: Wednesday, October 12, 2011 10:46:31 AM

Section 321 will be used very sparingly and with great care. It was developed as a last resort for FERC issued "Directives" that the industry won't accept standards for.

Guy V. Zito
Assistant Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10 th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

From: Philip A. Fedora
Sent: Wednesday, October 12, 2011 10:39 AM
To: Ed Schwerdt
Cc: Guy V. Zito; Gerard J. Dunbar; Lee R. Pedowicz
Subject: FW: NERC: Standards Announcement - Project 2010-17 Definition of Bulk Electric System | Initial Ballot Results

FYI - Phil

From: Kenneth Lotterhos [mailto:klotterhos@navigant.com]
Sent: Wednesday, October 12, 2011 10:36 AM
To: Philip A. Fedora
Subject: FW: NERC: Standards Announcement - Project 2010-17 Definition of Bulk Electric System | Initial Ballot Results

Hi Phil,

Looks like the BES definition got the needed 2/3 but the Technical Criteria fell short. I guess rule 321 will come up in the Technical Criteria context (above 60%) but depending on the comments received I'm not sure that the Board would have the stomach to file it with a recommendation for approval.

P16 of the order you sent around outlines the options, but given the timeframe many will not be feasible (e.g., Technical Conference etc.).

The prospects look dismal and discussion of what to do may take up a good deal of meeting time next week. The SDT leadership should develop a game plan before going into the SDT meeting.

More fun – ha ha!

Sincerely,

Ken

From: Ed Dobrowolski [mailto:Ed.Dobrowolski@nerc.net]
Sent: Wednesday, October 12, 2011 10:22 AM
To: dbessdt_plus
Subject: FW: NERC: Standards Announcement - Project 2010-17 Definition of Bulk Electric System | Initial Ballot Results

FYI

Edd

Edward J. Dobrowolski
NERC
Standards Development Coordinator
1.609.947.3673

Mark Twain: "Travel is fatal to prejudice, bigotry, and narrow-mindedness."

From: Monica Benson
Sent: Wednesday, October 12, 2011 10:21 AM
To: Monica Benson
Subject: NERC: Standards Announcement - Project 2010-17 Definition of Bulk Electric System | Initial Ballot Results

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Standards Announcement

Project 2010-17 Definition of Bulk Electric System Initial Ballot Results

Now available

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In addition, NERC was directed to develop a process for identifying any Elements or Facilities that should be excluded from the BES. NERC is working to address these directives with two activities – the definition of Bulk Electric System is being revised through the standard development process and a BES Definition Exception Process is being developed as proposed modifications to the Rules of Procedure. The proposed modifications have been posted for a comment period through October 27, 2011. The work of the BES Definition Exception Process has been publicly posted at: http://www.nerc.com/filez/standards/Rules_of_Procedure-RF.html.

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From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement - Project 2007-07 Transmission Vegetation Management Recirculation Ballot Results
Date: Friday, October 14, 2011 5:08:23 PM

Standards Announcement

Project 2007-07 Transmission Vegetation Management Recirculation Ballot Results

Now available

Ballot Results for FAC-003-2 Transmission Vegetation Management
A recirculation ballot on revisions to FAC-003-2 – Transmission Vegetation Management concluded on Thursday, October 13, 2011. The standard was approved by the associated ballot pool.

Voting statistics for the standard are listed in the table below, and the Ballot Results Web page provides a link to the detailed results.

Standard	Ballot Results
FAC-003-2 – Transmission Vegetation Management	Quorum: 87.17% Approval: 86.25 %

Next Steps
The standard will be presented to the NERC Board of Trustees for adoption.

Background
FAC-003-1 is being revised to address several fill-in-the-blank requirements, directives from Order 693, and issues raised by stakeholders. A successive ballot closed in February 2011 and achieved a quorum of 79.28% and an approval of 79.34%. The drafting team has posted its consideration of comments from the successive ballot and has posted answers to a set of questions posed by Standards Committee chairman Allen Mosher.

Documents for this project, including clean and redline to the last posted versions of the standard, implementation plan, and technical reference and the drafting team's responses to the technical, policy, and regulatory questions posed by Chairman Mosher have been posted on the project webpage.

Standards Process
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You have received this email because you are a registered representative in the Registered Ballot Body.

From: Lee R. Pedowicz
To: rscmembers; donald.e.nelson@state.ma.us; rjfalsetti@cogeco.ca
Subject: FW: NERC: Standards Announcement - Project 2007-07 Vegetation Management | Now Open: Recirculation Ballot October 4-13, 2011
Date: Tuesday, October 04, 2011 11:19:11 AM

Good morning.

For information.

Lee

From: Monica Benson [mailto:Monica.Benson@nerc.net]
Sent: Tuesday, October 04, 2011 10:10 AM
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement - Project 2007-07 Vegetation Management | Now Open: Recirculation Ballot October 4-13, 2011

Standards Announcement

Project 2007-07 Vegetation Management
Now Open: Recirculation Ballot October 4-13, 2011

Now available

Project 2007-07 – Vegetation Management
A recirculation ballot window for FAC-003-2 – Transmission Vegetation Management and its associated implementation plan is open through **8 p.m. on Thursday, October 13, 2011**.

Instructions
Members of the ballot pool associated with this project may log in and submit their votes.

In the recirculation ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their prior votes. A ballot pool member who failed to cast a ballot during the last ballot window may cast a ballot in the recirculation ballot window. If a ballot pool member does not participate in the recirculation ballot, that member's last vote cast in the successive ballot that ended on February 28, 2011 will be carried over and used to determine if there are sufficient affirmative votes for this standard to pass.

Background
FAC-003-1 is being revised to address several fill-in-the-blank requirements, directives from Order 693, and issues raised by stakeholders. A successive ballot closed in February 2011 and achieved a quorum of 79.28% and an approval of 79.34%. The drafting team has posted its consideration of comments from the successive ballot and has been working to address a set of questions posed by Standards Committee chairman Allen Mosher, aimed at documenting the technical justification for the proposed requirements and verifying that the team has addressed the associated directives from Order 693

Documents for this project, including clean and redline to the last posted versions of the standard, implementation plan, and technical reference and the drafting team's responses to

the technical, policy, and regulatory questions posed by Chairman Mosher have been posted on the project webpage.

Next Steps

Voting results will be posted and announced after the ballot window closes. If the recirculation ballot achieves a quorum and ballot pool approval, the standard will be presented to the NERC Board of Trustees for adoption.

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You have received this email because you are a registered representative in the Registered Ballot Body.

From:	Monica Benson
To:	monica.benson@nerc.net
Subject:	NERC: Standards Announcement - Project 2007-17 Protection System Maintenance and Testing | Formal Comment Period Open Aug 15 – Sept 28, 2011 | Ballot Pool Windows Open Through Sept 14, 2011
Date:	Monday, August 15, 2011 10:34:10 AM

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Standards Announcement

Project 2007-17 Protection System Maintenance and Testing
Formal Comment Period Open Aug 15 – Sept 28, 2011
Ballot Pool Windows Open Through Sept 14, 2011
Initial Ballot and Non-Binding Poll: Sept 19 – 28, 2011

Now available at: http://www.nerc.com/filez/standards/Protection_System_Maintenance_Project_2007-17.html

The Standards Committee has authorized posting the SAR for Project 2007-17 Protection System Maintenance and Testing, along with the draft standard PRC-005-2 — Protection System Maintenance and associated implementation plan, for a formal 45-day comment period.

PRC-005-2 was posted for a recirculation ballot that ended June 30, 2011. The standard narrowly failed to achieve ballot pool approval, and in accordance with the Standard Processes Manual, the project has been reinitiated. An initial ballot and concurrent non-binding poll will be conducted during the last 10 days of the 45-day comment period. A new ballot pool is being formed during the first 30-days of the 45-day comment period. Because the project is not new to stakeholders, the Standards Committee has waived the initial 30-day comment period and asked the drafting team to conduct a webinar during the comment period.

Instructions for Joining the New Ballot Pool for Project 2007-17

The ballot pool windows are open through **8 a.m. Eastern on Wednesday, September 14, 2011**.

Registered Ballot Body members may join the ballot pools to be eligible to vote in the upcoming ballot and non-binding poll at the following page: https://standards.nerc.net/BallotPool.aspx

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for the initial ballot pool is: bp-2007-17_PSMT_IN2_in@nerc.com. The list serve for the non-binding poll is: bp-2007-17_nb_0811_in@nerc.com

Any member who wishes to participate in the non-binding poll of the associated violation risk factor (VRF) and violation severity levels (VSLs) must also join this pool. We have discontinued the practice of automatically populating the ballot pool for the non-binding poll with all those who joined the pool to vote on the standard. Thus, anyone wishing to vote on the standard and also wishes to cast an opinion in the non-binding poll of the VRFs and VSLs must join both ballot pools.

Instructions for Submitting Comments

A formal comment period is open through **8 p.m. Eastern on Wednesday, September 28, 2011.**

Please use this electronic comment form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net.

Documents for this project, including the SAR, a clean copy of PRC-005-2, its Implementation Plan, and Supplemental Reference and FAQ along with an off-line unofficial copy of the questions listed in the comment forms are posted at the following site: http://www.nerc.com/filez/standards/Protection_System_Maintenance_Project_2007-17.html

Redlines have also been posted showing changes made to the standard, implementation plan, and Supplemental Reference and FAQ since the standard was posted for recirculation ballot in June.

The drafting team considered whether revisions to the SAR were needed but did not revise the SAR, so the SAR that is posted is the same SAR that was posted for comment when Project 2007-17 was first initiated, except that the date has been updated.

Note that PRC-005-2 reflects the merging of the following standards into a single standard, making it impractical to post a redline of proposed PRC-005-2 that shows the changes to the last approved version of the standard.

- PRC-005-1 — Transmission and Generation Protection System Maintenance and Testing
- PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Program
- PRC-011-0 — UVLS System Maintenance and Testing
- PRC-017-0 — Special Protection System Maintenance and Testing

The last approved versions of PRC-005-1, PRC-008-0, PRC-011-0, and PRC-017-0 have been posted on the project's web page for easy reference at:

http://www.nerc.com/filez/standards/Protection_System_Maintenance_Project_2007-17.html

Next Steps – Webinar, Initial Ballot and Non-binding Poll of VRFs and VSLs

The drafting team plans to conduct a webinar during the comment period to review PRC-005-2 and address questions. Additional details will be announced when they are available.

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Unofficial Comment Form for 1st Draft of the Standard for Protection System Maintenance and Testing Project 2007-17

Please **DO NOT** use this form. Please use the electronic comment form to submit comments on the 1st draft of the PRC-005-2 standard for Protection System Maintenance and Testing. Comments must be submitted by **September 28, 2011.** If you have questions please contact Al McMeekin at al.mcmeekin@nerc.net or by telephone at 803-530-1963.

http://www.nerc.com/filez/standards/Protection_System_Maintenance_Project_2007-17.html

Background Information:
This project recently failed to receive two-thirds weighted stakeholder approval on recirculation ballot. The Standards Committee directed that the Standard Drafting Team post the SAR and standard for a 45-day comment period with an initial ballot conducted during the last 10 days. During the posting period, the Standard Drafting Team plans to conduct a Webinar to discuss recently-presented industry comments and how they are addressed in the draft standard.

The Protection System Maintenance and Testing Standard Drafting Team (PSMT SDT) has made several changes to the fifth posting of PRC-005-2 based on comments received from industry. The changes include:

- Revising the term, "Maintenance Correctable Issue" to "Unresolved Maintenance Issue".
- Revising the "3 calendar months" interval for various station dc supply and communications system maintenance activities to "4 calendar months".
- The maintenance activities and intervals for distributed UFLS and UVLS systems were extracted from Table 1-1 through 1-5 and placed into a new Table 3 to more clearly illustrate the requirements related to these systems, which are often implemented on the distribution system.
- Modifying the VSLs and VRFs to reflect the changes listed above.
- Revising the Supplemental Reference and FAQ document to reflect changes made to the draft standard and to address additional issues raised within comments.
- Revising the Implementation Plan.

The PSMT SDT would like to receive industry comments on this standard.

For questions 1-5, please provide specific comments related to the individual question. Please reserve question 6 for general comments not related to questions 1-5.

1. Do you have any comments regarding the existing SAR for this project?

   ☒ Yes
   ☐ No

Comments: Maintenance and testing of protection systems is the final step in the process that begins with the calculation of settings. The calculation of settings is followed by the application of those settings to the equipment. Maintenance and testing ensures that the settings given to testing personnel have been applied as given. This Standard addresses the Maintenance and Testing of protection systems. It should also address the need to validate the accuracy of the settings given to the field. A statement should be added to the SAR to address this need.

2. In response to comments, the term "Maintenance Correctable Issue" was revised to "Unresolved Maintenance Issue". Do you agree with this change? If you do not agree, please provide specific suggestions for improvement.

   ☐ Yes

   ☐ No

   Comments:

3. In response to comments, the SDT revised the previous "3 calendar months" interval to "4 calendar months" for communications systems and station dc supply. Do you agree with this change? If you do not agree, please provide specific suggestions for improvement.

   ☐ Yes

   ☐ No

   Comments:

4. The SDT extracted the maintenance activities and intervals for distributed UFLS and UVLS systems from Table 1-1 through 1-5 and placed them into a new Table 3 to more clearly illustrate the requirements related to these systems. Do you agree with this change? If you do not agree, please provide specific suggestions for improvement.

   ☐ Yes

   ☐ No

   Comments:

5. The SDT has revised the "Supplementary Reference" document which is supplied to provide supporting discussion for the Requirements within the standard. Do you agree with the changes? If not, please provide specific suggestions for change.

   ☐ Yes

   ☐ No

   Comments:

6. If you have any other comments on this Standard that you **have not already provided in response to the prior questions**, please provide them here.

   Comments: The focus of the industry is on the field procedures necessary to ensure that protection systems are maintained and tested. This includes the verification that settings have been applied correctly. The accuracy of the settings calculated needs to be validated, and that step should be considered for inclusion in this Standard.

From: Lee R. Pedowicz
To: "cancomments@nerc.net"
Cc: rscmembers; rjfalsetti@cogeco.ca; donald.e.nelson@state.ma.us
Subject: Comments--Compliance Application Notice (CAN) Process, CAN-0016 CIP-001 R1 Sabotage Reporting Procedure
Date: Tuesday, September 06, 2011 2:06:42 PM

Good afternoon.

Below are the comments from NPCC representing 18 registered entities.

Contributors

	Contributor	Organization	Region	Segment
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
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COMPLIANCE APPLICATION NOTICE (CAN) PROCESS

Introduction

NPCC members submit the following comments in response to the North American Reliability Corporation's ("NERC") August 15, 2011 request regarding the Compliance Application Notice Process Version 4.

Summary of Comments

NPCC members support NERC's proposed modifications to the CAN Process that ensure the process will be implemented consistent with the limited intent and scope of that Process to:

1. Respect the FERC recognition that Industry-driven *Reliability Standards Development Process* "are sufficiently clear as to be enforceable and do not create due process concerns."
2. Recognize that the CANS Process is not meant to address "gaps and ambiguities" in the approved standards, and that CANS shall not introduce any new standard, requirement or measure not explicitly mandated <u>by a given standard</u>
    a. CANS must not be used to implement rights and obligations, policies, best practices or NERC's subjective belief of what is required by a standard where any of the foregoing exceed the scope of the standards;
    b. CANS must not be used to close perceived "gaps" in standards;
    c. CANS: 1) are limited to establishing "consistency in the application of compliance criteria across all CEAs..." 2) are limited to identifying non-exclusive instructions for determining "safe-harbor" evidence that is acceptable to demonstrate compliance (i.e. not defining the one and only measurement, just instructions for identifying evidence that if met will demonstrate compliance)
    d. CANs are temporary CMEP administration aides to facilitate consistent CMEP results that will expire if and when the underlying issue is addressed by an interpretation and/or standard revision becomes effective.
3. CANS are a NERC staff initiative and not part of the Standards Development Process and therefore not enforceable.

General Discussion

The ERO has begun to use statements from Order 693 as rationale for exercising its authority within different programs. Order 693 stated that the approved standards were sufficient to ensure reliability, but also recognized that clarity issues may arise. The Order directed the use of the ERO's approved Reliability Standard Development Process to resolve those issues. It did not establish or direct NERC to establish a CAN Process to provide clarity.

During the CANS Webinar, staff stated that the CAN process is the only tool they have to effect changes. That is not true and is not consistent with Order 693. To

the extent NERC continues to use the CAN process, it must be used for the limited purposes it was intended to address. The current revisions to the Process appear to realign the process with its limited purpose and that the CAN process is not a tool for standard clarification. To the extent the revised process is administered consistent with these principles, NPCC members believe it represents an improvement over the current operation of the program.

NPCC members support the concept to implement the CANS program as defined by the Compliance Application Notice (Can) Process manual and, by implication, to return the NERC Interpretation Process to its role of providing business practice justification for ambiguous terms, processes or procedures, as contained in the approved Standards Requirements.

NPCC members agree that the CANS Process is a NERC staff process. As such, CANs cannot and must not change, modify or interpret a FERC and Canadian Regulator approved standard, requirement or measure. The CANs are designed to resolve conflicts by and among Compliance Enforcement personnel on what is acceptable non-exclusive evidence for compliance; a CAN should not limit/restrict the scope of acceptable evidence. If a standard intends to specifically limit how an entity must comply with its obligations, those specifics must be developed in the Standards Development Process.

NPCC members note that the applicability of the CAN process is correctly limited to NERC and the regions, and, as such, provides instructions for auditors' to follow. It is not designed to mandate any particular obligations with respect to industry behaviour. Based on industry requests in the CAN process, it appears that certain entities wish to use the CAN process to mitigate their compliance risk by telling them exactly what they need to do under the standard to comply. As discussed above, that is not the purpose of the CAN process, nor does NERC have the authority to implement the process in that manner. Applying the CAN Process consistent with its original design and intent will enable entities to conduct themselves in a manner that results in the "safe-harbor" evidence reflected in a CAN, which facilitates their ability to comply with the standards in a manner that reduces risk. NERC must administer the CAN Process consistent with its limited purposes. Any attempt to do otherwise would be beyond the scope of NERC's authority as the ERO. Additionally, because CANs are not part of the standards and cannot be the sole means of assessing compliance, enforcement actions cannot be based on alleged violations of a CAN.

Other comments related specifically to the document:
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Add Item "e":
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   a. A CAN provides instructions to CEAs regarding the boundaries within which to assess compliance with effective standards and requirements
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The introductory paragraph under Scope states that "there are multiple ways for a registered entity to meet the requirements of a standard, a range of acceptable compliance actions."

The use of the term "boundaries" is open-ended. How is it determined that the way an entity
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In the CAN Process section (page 6), Section A. Issue Identification, Item 1, what defines a large corporation, and why must it have "entities in multiple Regional Entities"? Also, the sentence immediately following Item 4 reads: "CAN issues may relate to specific standards and requirements…" Why may? On p. 3 the Introduction states "Compliance Application Notices (CANs) were created by NERC…in regard to compliance monitoring with NERC Reliability Standards" which clearly states the relationship between CANs and Standards. What else might a CAN relate to? The paragraph in Section B (top of page 7) beginning with "After the CAN issues are reviewed and it has been determined…" refers to priority being determined based on its impact to reliability, etc. The final sentence reads : "CANs are developed in the order that will help the most registered entities at the moment." One CAN may have a very significant reliability impact on a minimum number of entities, and another CAN with not so significant reliability impact on a much greater number of entities, but it still helps them. Which CAN has the priority?
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In the Expiration or Removal of CANs section on page 8, recommend adding:

"A CAN may be retired if replaced by a subsequent, more up-to-date CAN. CANs may also be withdrawn or retired when the issue initiating the CAN is no longer valid or relevant, e.g., when the underlying reliability standard is consolidated into others."

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For all occurrences throughout the document replace BPS with BES, BES being the NERC defined term.

CAN-0016 CIP-001 R1 Sabotage Reporting Procedure

The CAN process is intended to provide guidance to industry and CEA staff with respect to acceptable evidence to demonstrate compliance. It is not designed to interpret the substantive scope of a standard and/or requirement. Accordingly, a CAN should not, and indeed cannot, expand the substantive scope of a standard/requirement, either directly (*e.g*. via the explicit inclusion of an obligation that doesn’t exist in a requirement) or indirectly (*e.g*. by mandating the provision of compliance evidence that forces registered entities to engage in activities / establish processes that are not otherwise required under a standard/requirement). Substantive changes must occur pursuant to the FERC approved Standards revision process. This is explicitly recognized in each CAN, which state: *This document is designed to convey compliance guidance from NERC’s various activities. It is not intended to establish new requirements under NERC’s Reliability Standards or to modify the requirements in any existing NERC Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time.*

The plain language of CIP-001 R1 is clear. It states:

> **R1.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the recognition of and for making their operating personnel aware of sabotage events on its facilities and multi-site sabotage affecting larger portions of the Interconnection.

All that is required for compliance is the existence of sabotage procedures that provide for the recognition and communication of sabotage events. The requirement does not prescribe the substance of those procedures, nor does it impose performance obligations relative to the procedures. The substantive details of the procedures are determined by the registered entities.

The scope of CIP-001 R1 is supported by the applicable compliance measure, which states:

> **M1.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have and provide upon request a procedure (either electronic or hard copy) as defined in Requirement 1

Consistent with the scope of R1, all that is required by M1 to demonstrate compliance is to have procedures and provide them upon request. There are no specific plan details that must be included to demonstrate compliance, nor does the measure require any sort of

performance evidence. This is understandable in that neither NERC, FERC nor the Industry have yet established a continent-wide approach with respect to: (a) how to define "sabotage", or (b) what measures relating to "performance" are appropriately standardized.

In addition to going beyond the scope of the requirements/measurements, CAN-0016 also suffers from the same shortcomings of its prior version. Although not explicit, as in the first version of CAN-0016, this version still implies that it applies to non-BPS facilities. The CAN states that the emphasis is to enable registered entity personnel to recognize sabotage that "may impact the reliability of the BPS". This raises the same jurisdictional concern at issue in the prior version.

NERC's jurisdiction is circumscribed by Section 215 of the FPA, which limits reliability oversight to the BPS. Accordingly, the scope of all NERC standards, including CIP-001, is limited to BPS facilities. Sabotage events that "may impact" the BPS could be interpreted by CEA staff to include non-BPS facilities if such personnel believe that an event on a non-BPS facility could somehow impact a BPS facility. The CAN should be revised to clearly state that procedures required by CIP-001 are only relevant to BPS facilities.

The revised CAN-0016 therefore impermissibly: 1) exceeds the scope of the requirement and measures; 2) exceeds NERC's jurisdictional authority, by adding additional requirements to an existing FERC-approved Standard and indicates that the CEAs should audit against the CAN; and 3) establishes the CAN as the exclusive means of demonstrating compliance.

Lee Pedowicz
Manager, Reliability Standards
NPCC
212-840-1070 xt7061

From: Jordan Erwin
To: canonly
Subject: NERC Compliance Operations Announcement Regarding CANs
Date: Monday, August 15, 2011 4:57:43 PM

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

This email provides notice of the following activity on NERC Compliance Application Notices page on the NERC Web site, which is located at: http://www.nerc.com/page.php?cid=3|22|354.

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COMPLIANCE APPLICATION NOTICES (CANs)

-

-

In response to industry and at the request of the NERC Board of Trustees, NERC is making some refinements to the CAN process and to CANs that are currently posted as final. Today's posting includes the revised CAN process and CAN-0016. Additional CANs will be revised in the near future.

-

Processes and Tools Postings:

1. The Compliance Application Notice (CAN) Process, Version 4 has been posted in the "Compliance Application Notices Processes and Tools" section. This document is provided as a redline to Version 3 of the CAN Process (posted on July 8, 2011) and is provided for industry comments. **Comments are due September 6, 2011.**

   Changes include:
   1. targeted CANs to Compliance Enforcement Authorities (ERO Auditors, Investigators and Enforcement staff);
   2. added language to clarify the scope of a CAN;
   3. clarified that entities with an equally efficient or effective method of compliance may not be found non-compliant;
   4. clarified the order of actions a registered entity may pursue to contest a CAN;
   5. and added two levels of review for contested CANs.

CANs Posted for Industry Comments:

This revised CAN, listed below, has been posted for industry comments in the "Draft Compliance Application Notices for Industry Review" section. This is a CAN was previously posted as a Final CAN (on June 16, 2011). It has been revised to target Compliance Enforcement Authorities and add clarification. **Comments are due September 6, 2011.**

1. CAN-0016 CIP-001 R1 *Sabotage Reporting Procedure*
   - Clean Version
   - Redline Version

Thank you for including the CAN number in the title of your email and identifying the number of registered entities that are represented in your comments.

Please submit comments or questions to cancomments@nerc.net. For further information, please contact Valerie Agnew at 404-446-2566 or by e-mail at Valerie.Agnew@nerc.net.

North American Electric Reliability Corporation
3353 Peachtree Road, NE
Suite 600, North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com

Y

Y

From: Lee R. Pedowicz
To: "cancomments@nerc.net"
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Lee Pedowicz
Manager, Reliability Standards
NPCC
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Date: Monday, August 15, 2011 4:57:43 PM

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In response to industry and at the request of the NERC Board of Trustees, NERC is making some refinements to the CAN process and to CANs that are currently posted as final. Today's posting includes the revised CAN process and CAN-0016. Additional CANs will be revised in the near future.

-

Processes and Tools Postings:

1. The Compliance Application Notice (CAN) Process, Version 4 has been posted in the "Compliance Application Notices Processes and Tools" section. This document is provided as a redline to Version 3 of the CAN Process (posted on July 8, 2011) and is provided for industry comments. **Comments are due September 6, 2011.**

   Changes include:
   1. targeted CANs to Compliance Enforcement Authorities (ERO Auditors, Investigators and Enforcement staff);
   2. added language to clarify the scope of a CAN;
   3. clarified that entities with an equally efficient or effective method of compliance may not be found non-compliant;
   4. clarified the order of actions a registered entity may pursue to contest a CAN;
   5. and added two levels of review for contested CANs.

CANs Posted for Industry Comments:

This revised CAN, listed below, has been posted for industry comments in the "Draft Compliance Application Notices for Industry Review" section. This is a CAN was previously posted as a Final CAN (on June 16, 2011). It has been revised to target Compliance Enforcement Authorities and add clarification. **Comments are due September 6, 2011.**

1. CAN-0016 CIP-001 R1 *Sabotage Reporting Procedure*
   - Clean Version
   - Redline Version

Thank you for including the CAN number in the title of your email and identifying the number of registered entities that are represented in your comments.

Please submit comments or questions to cancomments@nerc.net. For further information, please contact Valerie Agnew at 404-446-2566 or by e-mail at Valerie.Agnew@nerc.net.

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Y

Y

Please **DO NOT** use this form to submit comments on the 2nd draft of the Definition of the Bulk Electric System (Project 2010-17). Use the electronic comment form **only** to submit comments. Comments must be submitted by **October 10, 2011.**

If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Background Information
Definition of the BES (Project 2010-17)

The SDT responded to the comments received for the first posting of the definition for this project by clarifying the core definition, inclusions, and exclusions to meet the concerns of the industry. The SDT has also utilized a variety of other inputs including work that was done by regional entities such as WECC, NPCC, RFC, and FRCC in coming up with the present definition. Another input was FERC Orders No. 743 and 743a which provided several specific directives on clarifying the existing definition. It should be noted that the revised definition does not address functional entity registration or standards requirements applicability. Those are separate issues.

The core definition represents a true bright-line; but, it is clear that by itself, it does not cover all of the known situations and configurations that are needed for a complete definition. Therefore, the SDT developed several specific inclusions and exclusions that will be added to the core definition to complete it. At the present time, the SDT has drafted five specific inclusions and four specific exclusions.

Inclusions represent those items that are included as part of the Bulk Electric System (BES) where they would not have been included as part of the simple core definition. The reasons that the SDT has added these items are as follows:

- I1 – Since transformers have windings operating at different voltages, it was felt that clarification was required so as to more explicitly identify which transformers were to be included in the BES. The SDT believes that the present draft provides this needed clarification.
- I2 – This inclusion represents a merger of the original Inclusion I2 and the original Inclusion I3 concerning generation thresholds.
- I3 – Blackstart units are considered vital to the overall operation of the BES. Consequently, the SDT has included Blackstart Resources. However, due to industry comments, the SDT has deleted the inclusion of Cranking Paths.
- I4 – This item was added in order to accommodate the effects of variable generation on the BES. The intent of this configuration is to include variable generation (e.g., wind and solar resources) with an aggregate rating greater than 75 MVA and was considered different enough from what was proposed in Inclusion I2 as to warrant a separate inclusion statement in order to provide greater clarity in this area.
- I5 – This is a new inclusion brought about by industry comments to clarify the inclusion of Reactive Power devices.

In addition to inclusions, in order to complete the picture, specific exclusions also need to be considered. The SDT has currently drafted four specific exclusions:

- E1 – This item was added to address the basic issue of radial systems. Radial exclusion was part of the existing definition and was supported moving forward in all of the regional work as well as Order No. 743 (and Order No. 743a). The SDT has

clarified this exclusion in response to industry comments by deleting the automatic interruption device.

- E2 – This item was added to address the situation of behind-the-meter generation. The wording is basically extracted from the ERO Statement of Compliance Registry Criteria.
- E3 – Local networks were added to the exclusion list after considerable discussions among the SDT and various registered entities that have configurations meeting these conditions. The SDT believes that any network that simply supports distribution should be excluded from the BES. The SDT has clarified the language for the exclusion and added a 300 kV upper limit.
- E4 – The SDT has added an exclusion for Reactive Power devices used solely by retail customers for their own use as a result of comments received.

Several commenters objected to simply carrying through the generation and voltage thresholds from the ERO Statement of Compliance Registry Criteria as part of the revised definition. However, no respondents provided technical justifications for changing these values. Furthermore, the scope of this project deals mainly with responding to FERC Orders 743 and 743a which clearly stated that the intent of the order was to maintain the status quo and to only address those urgent issues identified in the order. Hence, the tight schedule that was provided in the order. After consulting with the NERC Board of Trustees and the NERC Standards Committee, the SDT has decided to forgo any attempt at changing generation or voltage thresholds at this time. There simply isn't enough time or resources to do those topics justice with the mandated schedule. Therefore, the focus of the SDT efforts will be to address the directives in Orders 743 and 743a. However, this does not mean that the issues will be dropped. Both the NERC Board of Trustees and the NERC Standards Committee have endorsed the idea that the Project 2010-17 SDT take a phased approach to this project with a new Standards Authorization Request (SAR) to address generation thresholds as well as several other issues that have arisen from SDT deliberations. Issues such as what is necessary for the reliable operation of the BES, whether the BES needs to be a contiguous, possible interconnection difference, who is a user of the BES, and correlation of the definition of BES and the ERO Statement of Compliance Registry Criteria will be addressed with this new SAR. The proposed SAR has been posted for information purposes only concurrent with the second posting of this project. A formal comment period will follow.

In parallel with the definition project, another team has been set up to develop a change to the NERC Rules of Procedure (RoP) to allow for entities to technically justify excluding Elements from the BES that might otherwise be included according to the proposed definition. This same process would be used by Registered Entities to justify including Elements in the BES that might otherwise be excluded according to the proposed definition. This RoP team will develop the process for seeking an exemption from the definition but the DBESSDT will develop the criteria necessary for applying for an exemption through the standards development process. The DBESSDT developed exception criteria is posted separately but simultaneously to the second posting of the definition.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

The SDT has asked one specific question for each specific aspect of the definition.

1. The SDT has made clarifying changes to the core definition in response to industry comments. Do you agree with these changes? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   Yes: X

   No:

   Comments:

2. The SDT has revised the specific inclusions to the core definition in response to industry comments. Do you agree with Inclusion I1 (transformers)? If you do not support this change or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   Yes:

   No: X

   Comments: More specific description is needed for the equipment intended to be included in I1. For example, is it intended to include autotransformers, PARs, primary, secondary, tertiary windings, etc.? There will be difficulty applying the definition to facilities without this detail. Suggest rewording to: All transformers (including auto-transformers, voltage regulators, and phase angle regulators and all windings) with primary and secondary terminals operated at or above 100kV, and generator step-up (GSU) transformers with one terminal operated at or above 100KV, unless excluded by E1 or E3.

3. The SDT has revised the specific inclusions to the core definition in response to industry comments. Do you agree with Inclusion I2 (generation) including the reference to the ERO Statement of Compliance Registry Criteria? If you do not support this change or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   Yes:

   No: X

   Comments: In deference to direction given to the Drafting Team, Inclusion I2 should remove the reference to the Statement of Compliance Registry Criteria. The current

language induces circular arguments without a true governing document. The definition should drive what appears in the registration criteria. I2 should be revised to read: "Generating resources with a gross nameplate rating of 20MVA or greater, or generating plant/facility connected at a common bus, with an aggregate nameplate rating of 75MVA or greater and is directly connected to a BES Element." This is consistent with the proposed I2 and the current Compliance Registry Criteria. Ultimately the definition should be the governing document and provide the details of what generation should be included. It is understood that Phase 2 of this project will address this.

4. The SDT has revised the specific inclusions to the core definition in response to industry comments. Do you agree with Inclusion I3 (blackstart)? If you do not support this change or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   Yes:

   No: X

   Comments: Eliminating I3 should be considered based on the availability and performance expectations of black start resources being ensured by existing standards, and unless they meet the BES definition under the I2 inclusion they do not have any reliability impact on BES operation.

   If I3 is retained, suggest rewording Inclusion I3 to read as follows: Black start resources material to and designated as part of the Transmission Operator's restoration plan.

5. The SDT has revised the specific inclusions to the core definition in response to industry comments. Do you agree with Inclusion I4 (dispersed power)? If you do not support this change or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   Yes:

   No: X

   Comments: Suggest the term "common point" needs clarification and/or definition (is risk of single mode failure intended, i.e. where all the resources could be lost for a single event?). Suggest the following wording: "connected at a common point through a dedicated step-up transformer with a high-side voltage of 100 KV or above."

   Dispersed power producing sources such as wind and solar should not be included as BES elements because of the variable and intermittent nature of these resources. If these dispersed power producing resources had dedicated energy storage facilities only

then that could make them BES elements. Generally the collector systems for these resources (from the bulk transmission system reliability perspective) do not differ from distribution systems which are excluded from the BES.

6. The SDT has added specific inclusions to the core definition in response to industry comments. Do you agree with Inclusion I5 (reactive resources)? If you do not support this change or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   Yes:

   No: X

   Comments: Technical studies need to be conducted to confirm reactive resource impacts on the reliability of the BES. The inclusion of reactive resources is a significant expansion of the current BES definition and therefore requires technical justification for inclusion. Inclusion I5 as written is confusing with a reference to Inclusion I1 in the definition. Suggest removing references to reactive resources from Phase 1 until technical justification can be demonstrated (as part of Phase 2).

7. The SDT has revised the specific exclusions to the core definition in response to industry comments. Do you agree with Exclusion E1 (radial system)? If you do not support this change or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   Yes:

   No: X

   Comments: E1 can be simplified by not dividing in three subsets of a, b and c. The end result is that a Radial system is excluded if it does not have more than 75 MVA aggregate non-retail generation. There seems to be an error with reference to I3. Black start unit paths are not designated as BES and were taken out in this version under I3 so E1 and E3 should not reference I3. This contradicts the radial or LN exclusion from I3. Suggest deleting the reference to I3 in E1 and E3 because this reference is in contradiction to I3. I3 does not require a path to be BES, but it implied that a radial cannot be excluded if there is a black start unit on the radial.

   Further clarification is needed to the language in the Note referring to the "Normally Open switch". The E1 reference Note should be re-worded to state "Radial systems shall be assessed with all normally open switching devices in their open positions." Explanatory figures should be included to illustrate the system configurations addressed.

   Black start unit paths must be considered in the construction of E1. In E1c, what is meant by "non-retail"?

8. The SDT has revised the specific exclusions to the core definition in response to industry comments. Do you agree with Exclusion E2 (behind-the-meter generation)? If you do not support this change or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

Yes:

No: X

Comments: Why are references to Balancing Authority, Generator Owner, and Generator Operator included in E2 which is part of the BES definition? The wording of Exclusion E2 should be consistent with the Statement of Compliance Registry Criteria in Section III.c.4.

9. The SDT has revised the specific exclusions to the core definition in response to industry comments. Do you agree with Exclusion E3 (local network)? If you do not support this change or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   Yes:

   No: X

   Comments: What is the technical justification for 300kv and higher? Local Network is capitalized (network not capitalized at the beginning of E3) throughout E3, yet it is not defined in the NERC Glossary. The installed generation limit in a Local Network should be addressed in Phase 2. Any studies supporting E3 should be made available.

10. The SDT has added specific exclusions to the core definition in response to industry comments. Do you agree with Exclusion E4 (reactive resources)? If you do not support this change or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

    Yes:

    No: X

    Comments: Consider using other wording to replace "retail". The statement "owned or operated by the retail customer" is confusing and arguably inaccurate and should be revised. Refer to comments related to reactive resources for Question 6 regarding Inclusion I5. Retail and non-retail generation should be defined.

11. Are there any other concerns with this definition that haven't been covered in previous questions and comments remembering that the exception criteria are posted separately for comment?

    Yes: X

    No:

Comments: Technical bases have not been provided for the proposed definition of the BES. Additionally, the cost impacts have not been assessed and weighed against the potential benefits of this proposal.

There is confusion arising from the construction and interactions of the Inclusion, and Exclusion sections. System diagrams, put in a separate guidance document, would help in understanding. The situation of using Exceptions to understand Exclusions must be avoided. Suggest consider incorporating Inclusions directly, and leave the Exclusions as is format wise.

The Implementation period discusses a 24 month timeframe (the Order suggests 18) from when the standard becomes effective to begin Compliance obligations. If construction is required to become compliant or meet performance requirements with standards, or CIP Version 5 standards increase the amount of BES assets this will be insufficient when considering budgeting, designing, siting requirements, and permitting.

Concern exists over the paradigm that the definition should "mirror" the NERC Compliance Registry Criteria regarding who is registered. Some RSC members believe the definition should drive any changes to the registry criteria and not the criteria perpetuating the thresholds in the definition. However, there is a need to confirm that Phase 2 of this project will address this.

The Inclusions and Exclusions listed need clarifications and perhaps diagrams and accompanying guidelines to clarify and explain the intent.

Comment Form for 2nd Draft of Project 2010-17: Definition of BES (BES) Technical Principles for Demonstrating BES Exceptions

Please **DO NOT** use this form to submit comments on the second draft of the Project 2010-17: Definition of the Bulk Electric System (BES) Exception Criteria. Use the electronic comment form **only** to submit comments on the second draft Exception Criteria. Comments must be submitted by **October 10, 2011.**

If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Background Information
Definition of the BES (Project 2010-17)
Technical Principles for Demonstrating BES Exceptions

In parallel with the definition project, another stakeholder team outside the standards development process has been set up to develop a change to the NERC Rules of Procedure (RoP) to allow for entities to apply for excluding Elements from the BES that might otherwise be included according to the proposed definition and designations. This same process would be used by Registered Entities to justify including Elements in the BES that might otherwise be excluded according to the proposed definition and designations. The RoP team will develop the process for seeking an exception from the definition and designations, but the Definition of the BES Standards Drafting Team (DBESSDT), through the standards development process, has developed the criteria necessary for applying for an exception.

The exception process has been set up as a checklist of items that an entity requesting an exception should supply to the Regional Entity as the first step in the process described in the Rules of Procedure. The same checklist will be utilized for exceptions dealing with inclusions or exclusions. The intent of the SDT is to standardize the types of information that must be supplied when seeking an exception to the extent possible. This will allow for the Regional Entities to process the requests based on standardized evidence and for the ERO to make the eventual decision on the request based on this standardized evidence. This is a significant departure from the first posting on this topic. Based on industry response from that posting and further analysis the SDT has abandoned the initial exclusion criteria and developed this new methodology that it believes will provide more clarity and continuity to the process. The initial proposal was dependent on a comparison of an entity's characteristics to a defined value and/or limit. However, it has become apparent that it is not feasible to establish continent-wide values and/or limits due to differences in operational characteristics. The new process requires an entity to clarify the characteristics of the facilities in question and to document the operational performance as appropriate through submittal of the Detailed Information to Support an Exception Request along with any other supporting documentation for the exception being sought. The appropriate Regional Entity will review the submittal to validate information, make a recommendation of whether or not to support the exclusion or inclusion, and then file the request and recommendation with the ERO as established in the Rules of Procedure as presently being drafted and posted for comment. An ERO panel as described in the Rules of Procedure presently being drafted and posted for comment will then make the decision on the exception. At this point, the engineering judgment of the ERO panel will be utilized. Using the request document to dictate the type of supporting material that needs to be supplied plus having a common panel perform the evaluations will result in an open, transparent, and consistent process.

Technical Principles for Demonstrating BES Exceptions

The SDT is seeking industry feedback on the approach being presented. Comments received from this posting will help to determine the final criteria that the industry will be required to adhere to. Therefore, industry feedback is vital to the development process.

It should be noted that the actual application process is described in the Rules of Procedure document that will be posted separately from the exception criteria document.

You do not have to answer all questions. Enter all comments in simple text format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Page one of the 'Detailed Information to Support an Exception Request' contains general instructions. Do you agree with the instructions presented or is there information that you believe needs to be on page one that is missing? Please be as specific as possible with your comments.

   Yes:

   No: X

   Comments:

   How an exception application will be assessed by the RE and NERC is not addressed in the document. Stakeholders need to know how the exception application will be evaluated and processed. Suggest that the SDT develop a reference or a guidance document as part of the RoP that will provide guidance to Registered Entities, Regional Entities and the ERO on how an exception application will be processed. Of particular concern is the lack of clarity and specificity with respect to what analyses and study results are required under the third bullet on page 1 and under question 4 on both pages 2 and 4. This lack of clarity and specificity will lead to inconsistent application of the Technical Principles by both Registered Entities and Regional Entities.

   We recommend the following: the impact and performance analyses required by the 3rd bullet on page 1 and by #4 on pages 2 and 4 should be stipulated to be all analyses, scenarios, and contingencies required under NERC Standard TPL-002-1 with the "exception element" removed from the base system model. Entities shall report on all key performance measures of BES reliability specified in the TPL-002-1 attributable to the removed "exception element".

   On page 1 under General Instructions, it is stated that:

   > "A one-line breaker diagram identifying the facility for which the exception is requested must be supplied with every application. The diagram(s) supplied should also show the Protection Systems at the interface points associated with the Elements for which the exception is being requested."

   What is meant by interface points?

2. Pages two and three of the Detailed Information to Support an Exception Request contain a checklist of items that deal with transmission facilities. Do you agree with the information being requested or is there information that you believe needs to be on page two or three that is missing? Please be as specific as possible with your comments.

   Yes:

   No: X

Comments:

For question 2 on page 2 For Transmission Facilities:

- What standards will define the "impact"?
- What is a material impact and a non-material impact?
- What kinds and types of impacts are acceptable/unacceptable?
- How are impacts determined?

Question 6 on page 3 reads "Is the facility part of a Cranking Path associated with a Blackstart Resource?", suggest removing the reference to "Cranking Path" because the Drafting Team does not require that the BES be contiguous, and black start resource Cranking Paths were deleted from Inclusion I3.

Question 7 on page 3 asks, "Does power flow through this facility into the BES?" This can only apply to a Local Network with two or more connections to the BES. No power should normally flow through a Local Network (or Radial system) to another portion of the BES. There may be occasional, brief reverse power flows may be acceptable during short periods under abnormal operating conditions.

Question 7 also requests "data for the most recent consecutive two calendar year period." Why is two years worth of data necessary? One year of data would be sufficient.

From Question 7, "what is the minimum and maximum magnitude of the power flow out of the facility …" What is intended by the use of magnitude?

Suggest that the Drafting Team adopt the FERC Seven Factor test for question 7.

Suggest deleting the "% of the calendar year" check boxes in favor of a statement either that power does not flow through the Local Network, or alternatively, a blank space for reporting the net peak MWs and MWHs transferred annually through the facility, and the percentage of these transferred amounts to the peak and annual MWH demands served by the Local Network. Suggest requesting only one year (8,760 hours) of data covering four seasons, including Summer and Winter capability periods.

3. Page four of the 'Detailed Information to Support an Exception Request' contains a checklist of items that deal with generation facilities. Do you agree with the information being requested or is there information that you believe needs to be on page four that is missing? Please be as specific as possible with your comments.

   Yes:

   No: X

   Comments:

   This Application generally applies to traditionally fueled generating facilities. Application form and justifications would be required for non-traditional resources such as solar and wind?

Question 2 on page 4 asks, "Is the generator or generator facility used to provide Ancillary Services?" If some of these Generator check list items are market-related and not reliability-related, they should not be present.

If the Ancillary Services are reliability-related, please explain their relation to BES reliability.

Suggest inserting the word "reliability" before the words "must run" in question 3.

Question 5 on page 4 asks, "Does the generator use the BES to deliver its actual or scheduled output, or a portion of its actual or scheduled output, to Load?" This could mean the generator may serve local loads through non-BES facilities. In order to serve these local loads the generator would need to be connected to a Radial system, a Local Network or to local distribution facilities. Is this what is intended? Were there any other possibilities envisioned by the BES SDT?

4. Do you have concerns about an entity's ability to obtain the data they would need to file the 'Detailed Information to Support an Exception Request'? If so, please be specific with your concerns so that the SDT can fully understand the problem.

   Yes: ☐
   No: ☒

- Comments:

  According to the Applicability section, the TPL Reliability Standards are only applicable to the Planning Coordinator (PC) and the Transmission Planner (TP). Was it the BES SDT's assumption that Applicants would have the PC or TP run studies for them, or that all Applicants would gain access to those models and run the models themselves? (Ref. TPL-002-1b, Applicability: Planning Authority, and Transmission Planner.)

5. Are there other specific characteristics that you feel would be important for presenting a case and which are generic enough that they belong in the request? If so, please identify them here and provide suggested language that could be added to the document.

   Yes: ☒

   No: ☐

   Comments:

   There is no guidance provided as to how the information asked for in this form will be evaluated, and what the decision making process will entail. As such, a

reference document should be developed and provide some guidance how to evaluate applications.

Suggest that the BES SDT adopt the FERC Seven Factor test.

6. Are you aware of any conflicts between the proposed approach and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, or jurisdictional issue? If so, please identify them here and provide suggested language changes that may clarify the issue.

   Yes: ☐
   No: ☒
   Comments:

7. Are there any other concerns with the proposed approach for demonstrating BES Exceptions that haven't been covered in previous questions and comments (bearing in mind that the definition itself and the proposed Rules of Procedure changes are posted separately for comments)? Please be as specific as possible with your comments.

   Yes: ☐
   No: ☒
   Comments:

From: Alex Zak
To: Alex Zak
Subject: NERC: Comment Period Opens for Proposed Changes to NERC Rules of Procedure and All Appendices
Date: Friday, September 02, 2011 5:30:01 PM

Proposed Changes to NERC Rules of Procedure and All Appendices

Announcement: Comment Period Opens for Proposed Changes to NERC Rules of Procedure and All Appendices

September 2, 2011

Click Here for access to the proposed changes: (NERC Rules of Procedure webpage)

The North American Electric Reliability Corporation (NERC) is proposing changes to its Rules of Procedure and associated Appendices.

NERC requests comments on proposed revisions to the NERC Rules of Procedure and all existing Appendices to the Rules of Procedure (3A, 3B, 3C, 4A, 4B, 4C, 4D, 4E, 5A, 5B, 6 and 8), as well as proposed new Appendix 2, *Definitions of Terms Used in the Rules of Procedure*. These documents are now available at: http://www.nerc.com/page.php?cid=1|8|169.

Comments are due October 17, 2011, and must be submitted electronically to ROPcomments@nerc.net. NERC intends to submit these changes to the NERC Board of Trustees for approval at its November 3, 2011 meeting. Although the comment period does not close until October 17, 2011, commenters are respectfully requested to submit their comments sooner than October 17, if possible, in order to provide additional time for NERC staff and the Regional Entities to consider them.

For further information, please contact Catherine Sills at catherine.sills@nerc.net.

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From: Wendy Sandberg
To: Wendy Sandberg
Subject: NERC Announcement: 2012-2014 Reliability Standards Development Plan - Posted for Comment
Date: Monday, September 12, 2011 4:36:13 PM
Attachments: image003.png

Announcement

2012-2014 Reliability Standards Development Plan Posted for Comment

September 12-26, 2011

NERC is in the process of developing the 2012-2014 Reliability Standard Development Plan (the Plan). The Plan will be developed over the next several months, and will provide status updates for projects in development, identify the next projects scheduled for initiation, designate projects for further research, and catalog all proposed projects for future development.

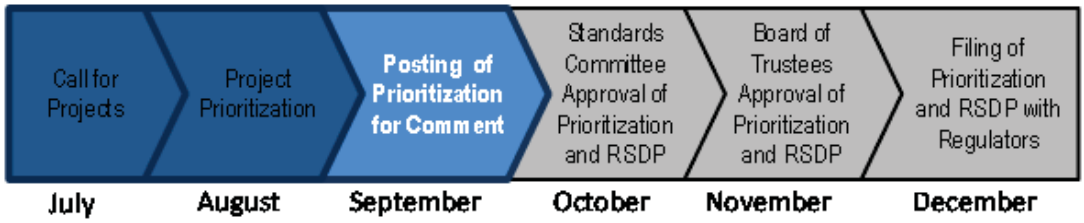

The Standards Committee has been evaluating projects, and has developed an initial prioritization. NERC staff has used this to develop the first draft of the Plan. The Plan has been posted for review and industry comment at the following location:

2012-2014 Reliability Standards Development Plan DRAFT

While this effort is intended to develop an industry consensus for what projects to move forward, any work plan is unlikely to be seen as perfect in the eyes of all constituents. Accordingly, while we encourage stakeholders to make any comments they believe to be appropriate, we also ask that the main focus of review and comment be on any significant concerns with the prioritization and work plan. Is there anything in the prioritization that is significantly below where it should be ranked? Is there anything in the Plan we deferred that can't wait? Of course, all comments and suggestions are appreciated.

Comment Form

If you have any general questions or comments on the development of the Plan, please feel free to contact Andy Rodriquez, NERC's Director of Standards Development at andy.rodriquez@nerc.net

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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reliability Standards Development Plan

2012-2014

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RELIABILITY | ACCOUNTABILITY

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Chapter 1 – Executive Summary

This document provides an update on the status of Standards Development work at NERC, as well as a forecast of work being planned for 2012-2014. The document has several sections:

- Chapter 1 contains this Executive Summary
- Chapter 2 contains introductory remarks from the Chair of the Standards Committee and NERC's Vice-President and Director of Standards
- Chapter 3 provides a general update on Standards Activities in 2011
- Chapter 4 provides a summary of the development of this document and he implementation of projects in general.
- Chapter 5 provides a summary of the Work Plan
- Appendix 1 shows the prioritization scores used in the development of the Work Plan
- Appendix 2 shows the Work Plan in Gantt chart form
- Appendix 3 provides brief summaries of all the projects proposed within the Work Plan

Chapter 2 – A Joint Letter from the Chair of the Standards Committee and NERC's Vice-President and Director of Standards

<to be added>

Chapter 3 - General

This is the Reliability Standards Development Plan (the "Plan") for years 2012-2014. The Plan provides several items of information to its readers:

- Information regarding the state of Standards at NERC, changes in Standards, and challenges facing Standards in the years to come
- Status updates regarding standards and related projects currently in development
- A forecast of Standards Development work scheduled for the next three years
- An overview of the process used to prioritize work and assign resources to Standards development projects

NERC Standards staff endeavors to maintain a complete, updated set of Standards information on the NERC website, which can be found at www.nerc.com.

The Standards Program continues to manage its ongoing load of work in order to move toward the target work load levels identified in early 2011. Progress is being made in this area; however, some projects expected to be completed in 2011 are still in active development. This is largely due to unforeseen complications regarding achieving consensus and managing overall product quality.

Status Updates

2011 Reorganization and Hiring

In early 2011, NERC performed a minor reorganization of the Standards staff in order to ensure appropriate focus on key areas. A new position, Director of Regulatory Initiatives, was established to ensure overall coordination between NERC and its various regulators. NERC also established a Manager of Standards Information, with the primary focus of ensuring that information posted on the NERC website accurately reflects the current body of Standards and associated compliance information. Additional staff was hired into the Standards Process and Standards Development teams to better support the volume of work ongoing within the Standards Program.

Completed Standards Development Projects

In 2011, NERC completed development of the following projects.

- 2006-02 Assess Transmission and Future Needs (BOT approved, awaiting filing)
- 2007-04 Certifying System Operators (filed with regulators)
- 2007-07 Vegetation Management [**projection as of September 2011**]

- 2008-06 Cyber Security Order 706 Version 4 (filed with regulators)
- 2009-06 Facility Ratings (filed with regulators)
- 2010-10 FAC 729 (filed with regulators)
- 2010-11 TPL Table 1 Footnote B (filed with regulators)
- 2010-13 Relay Loadability Order Phase 1 (filed with regulators)

Progress on Version Zero Standards

The set of Version 0 standards included 110 standards. Of the 110 standards, NERC withdrew three, and the Federal Energy Regulatory Commission (FERC) ruled on the remaining 107 as follows:

- 27 were approved without any directives to modify the associated standard
- 56 were approved with directives to modify the associated standard
- 24 were not approved, pending provision of additional information.

Of the 56 that were approved with directives, progress in revising those standards includes:

- 7 have been approved by FERC
- 9 have been submitted and are pending FERC approval
- 18 are associated with projects under active development
- 22 are associated with projects that are either inactive or not started

Of the 24 that were not approved pending submittal of additional information, progress in revising those standards includes:

- 8 have been approved by FERC
- 4 have been submitted and are pending FERC approval
- 2 are associated with projects under active development
- 10 are associated with projects that are either inactive or not started

As of September 1, 2011, there are 103 Reliability Standards with 1220 requirements that are mandatory and enforceable in the United States.[1]

[1] The data included in this paragraph does not include Regional Reliability Standards.

Interpretations of Reliability Standards

Entities required to comply with a reliability standard have the right to request a formal interpretation of a requirement in a standard. Interpretation projects generally are narrower in scope than other standards projects, but like standards, interpretations are drafted by a drafting team and posted for industry review and ballot. From 2006 to 2011, NERC processed 43 interpretation requests. In addition, NERC received a number of requests for interpretation that were absorbed into standards development projects because drafting teams could not prepare the interpretations without expanding the requirements of the approved standard.

Progress on Regulatory Directives

Since NERC became the Electric Reliability organization (ERO), FERC has issued 44 Orders containing approximately 655 directives related to NERC Reliability Standards. Of the approximately 655 directives issued since 2007, NERC has completed projects associated with approximately 44% of these directives and continues to make substantial progress in addressing the remaining directives focusing first on those that have the greatest impact on reliability.

A significant number of the directives ordered by FERC for implementation by NERC (as the FERC-approved ERO) specify that NERC submit or modify a Reliability Standard that addresses a specific matter, as permitted under Section 215(d)(5) of the Federal Power Act. Other directives order NERC to make changes in its procedural rules. Still other directives order NERC to consider the views of various commenters when NERC next revises a particular Reliability Standard.

NERC processes these various types of directives consistent with its Rules of Procedure (including Appendices 3A- Standard Processes Manual and 3C Procedure for Coordinating Reliability Standards). Specifically, when a regulatory order or rule is issued, that order is reviewed and any directives within the order related to standards development are added to the NERC Standards Issues Database and categorized. NERC then seeks to associate each directive with a specific standard. Projects and the associated Standards, along with the associated regulatory directives, are then prioritized for revision using the prioritization process described elsewhere in this document.

In 2011, NERC developed and filed the first NERC Standards Report, Status and Timetable for Addressing Regulatory Directives. This report is to be filed annually with FERC on or before March 31 of each year consistent with in accordance with Section 321.6 of the NERC Rules of Procedure (“Rule 321”) that was approved by the FERC on March 17, 2011. The progress against the directives issued is outlined in the aforementioned report.

Rapid Development and Rapid Revision Projects

NERC’s Standards Committee (SC) has tentatively identified two ways to accelerate project development while staying within the boundaries established in the Standard Processes Manual. Both approaches are consistent with the original vision of standards development when the ERO was being developed.

The first, called "Rapid Development," utilizes a small team of professionals to draft a standard over a short, but intensive period of time. The standard is then submitted with its associated SAR and the project moves directly into the first formal comment phase. Under this model, it may be possible to develop and ballot a standard within a period less than a year. The SC is evaluating the approach as part of Project 2010.05.1 Phase 1 of Protection Systems: Misoperations. Initial results have provided useful lessons learned, including the need to carefully select members of the small team to ensure not just subject matter expertise, but balance of interests as well.

The second approach, called "Rapid Revision," takes a similar approach, but is focused on dealing with concerns identified during the Interpretation process. If an interpretation drafting team identifies simple modifications to a standard that can more effectively address an interpretation request than an interpretation can alone, the team may elect to make such changes and submit them with an associated SAR. Following SC review, the changes may move directly to comment and ballot. This approach is being tested with project 2011-INT-01 Interpretation of MOD-028-1 R3.1 for Florida Power and Light.

Challenges facing Standards

Five-Year Review Obligation

As part of its ANSI accreditation, NERC has committed to review each of its standards for modification once every five years. While not giving the appearance of being onerous, this obligation has proven challenging to meet. 2012 marks the fifth year since NERC's first set of standards became mandatory and enforceable in the United States; many of those standards are now due for that five-year review. However, the work load of the ERO remains high, and prioritization has resulted in a deferral f the work required for these five-year reviews except when already associated with a project of reliability value.

Product Quality

As NERC's and the industry's experience with standards has continued, it has become increasingly clear that minor problems with the quality of standards can have significant repercussions when it comes to clarity and compliance. NERC has undertaken efforts to improve the quality of its work products, and will continue to do so in 2012. Steps being taken include creating technical writer positions, enhanced training for staff, and developing additional internal quality assurance processes.

Standards Program Throughput

One continuing challenge is the ability to not only produce quality products, but to do so consistently and regularly. While in some cases limited by necessity due to the scarcity of industry resources available in the workforce, the Standards Program continues to look for ways to improve the efficiency of its processes and its ability to demonstrate tangible progress in standards development on a regular basis. In 2012, Standards staff will be implementing enhanced document management capabilities, as well as portfolio-level project controls to ensure optimal use of resources and overall consistency of throughput. This more global

"portfolio view" was used to in part to develop this Plan, but additional improvements are expected in 2012 as well. As such, it should be noted that this, in addition to the normal variables associated with consensus-based product development, may lead to changes in the schedules used to develop the forecasts within this document

Conclusion

The Standards Program continues to make changes to improve its overall effectiveness, and looks forward to additional improvements in 2012. The SC's work on this Plan has appropriately focused the industry on standards development to ensure the best progress in improving reliability, addressing concerns in a timely manner, and assisting with implementation complexity, all while making sure to consider the implications of cost. NERC believes this approach correctly balances the needs of the industry with the public interest, and will continue to work with the industry to ensure the continued protection of reliability in North America.

Chapter 4 – Project Development Overview

Project Prioritization and Plan Development

This year, NERC continued use of the Prioritization Tool (the Tool) developed by the Standards Committee (SC) in late 2010 and early 2011 to help determine how best to assign resources and perform work. Following the finalization of the 2011-2013 Plan, the Standards Committee's Process Subcommittee (SCPS) began to work on improving the Tool for use in the development of the 2012-2014 Plan.

Similar to last year, the Tool utilizes a simple scoring mechanism to identify key considerations for use in determining project priority. Revisions were made to the tool in response to comments received during the development of the 2011-2013 Plan. Changes included the elimination and consolidation of scores that seemed to overlap or be redundant, removal of the "Project Percent Complete" evaluations (as there is currently no intention of moving projects into Informal Development, as was considered during the development of the 2011-2013 Plan), the addition of a score to account for projects related to the NERC President's Top Priority Issues for Bulk Power System Reliability, and trial testing of a new metric that accounts for "cost considerations." In addition, the tool was modified to allow a more sophisticated analysis of each of the key drivers in project prioritization. This allowed the SC to consider each of those factors separately, as well as in aggregate, to determine how best to allocate resources.

During the month of July 2011, NERC solicited the industry at-large for additional projects for consideration in the 2012-2014 Plan. NERC received nine submissions, resulting in the creation of six new projects. NERC created one project to account for the remaining Order 729 directives yet to be resolved, and one project to account for issues with the MOD-029-01 standard that will need to be addressed at some point in the future. NERC created four additional projects to account for projects to modify standard based on NERC's five-year review obligation, as identified in its Rules of Procedure.

In August, the SC began reviewing each of these projects, assigning them various scores based on input from constituents within their respective segments. NERC staff assembled the results in September, and an initial Prioritization and Work Plan was approved for posting at the September meeting of the SC. This Work Plan assumed an overall throughput capability of thirteen projects in development concurrently, and divided that capability into three areas:

- Reliability Projects – those projects expected to be the most beneficial to Reliability. Capacity for eight concurrent projects was assigned to this area.
- Time-Sensitive Projects – those projects with time sensitivity, such as those responsive to FERC orders with specified deadlines, as well as those projects needed to meet the ERO's five-year review obligation. Capacity for three concurrent projects was assigned to this area.

- Practicality Projects – those projects that improve the overall effectiveness of NERC's Reliability Standards, including addressing failed interpretations, improving the clarity of often violated standards, and other such general improvements. Capacity for two concurrent projects was assigned to this area.

The Work Plan identified each project and the amount of work associated with it, then allocated projects in their respective areas in order or priority as resources came available. Some projects were identified that needed additional research, and were scheduled for initiation with sufficient time to allow such work to be completed. Additionally, some projects require specific expertise. To the extent such needs were identified, that expertise was managed to ensure the volume of work did not exceed the resource capacity. For example, projects related to protection systems were generally not started until another project related to protection systems was completed.

This Work Plan, along with the prioritization itself and this document in draft form, were posted for industry comment in September. Comments were received and considered at the October 2011 SCPS meeting; the final prioritization and Plan was approved by the SC at its October meeting. The Plan was presented to NERC' Board of Trustees and was approved at the Board's November meeting.

Project Implementation

Standards development projects at NERC proceed through a specific set of steps, identified in NERC's Standard Processes Manual. In general, the process can be summarized as follows:

- Initiation – projects are identified, and simple problem statements are developed. These problem statements are used to assist in the overall project prioritization effort described above.
- Planning – projects are further developed to determine their scope and merits. The drafting of a formal Standards Authorization Request (SAR) occurs in this step, as well as the development of communication plans if deemed to be necessary. In some cases, this step may occur concurrently with the initial steps of Execution and Control.
- Execution and Control – once the SC has approved a project for moving into this phase, standards or other work products are produced and the project begins moving forward in earnest. A detailed project schedule is developed, and standards are drafted, posted for comment, and balloted, culminating in review by NERC's Board of Trustees for adoption.
- Closing – Following action by NERC's Board of Trustees, the project is reviewed and analyzed for "lessons learned." Public information is updated as necessary, and any associated regulatory filings are made.

For more information on the specific details of each step in the implementation of projects to develop NERC Reliability Standards, readers are directed to various resources posted at the NERC Standards Resources page:

http://www.nerc.com/commondocs.php?cd=2

Chapter 5 – Project Work Plan Summary

This chapter summarizes the Reliability Standards Development Plan (the "Plan") for years 2012-2014. The following is based on the Standards Committee's Prioritization of Projects (included as Appendix 1) and the associated staff-developed Work Plan (included as Appendix 2). A detailed summary of projects is included as Appendix 3.

Projects for 2012-2014

NERC intends to continue development of the following projects in 2012. These are Active projects, and are expected to continue until completion. Although there are other projects that ranked higher this year than some of these projects, the Standards Committee believes that the industry has committed to completing these projects, and given that the workload is reaching a manageable size, moving any of these projects into informal development would be counterproductive.

The projects below have been color coded, to indicate their focus area (Reliability, Time Sensitivity, or Practicality). While most projects impact al three of these areas in some way, this is intended to illustrate the primary consideration driving its consideration.

Existing Active Projects:

- 2006-06 Reliability Coordination. This project ranked #13 in Reliability Priority.
- 2007-02 Operating Personnel Communication Protocols. This project ranked #5 in Reliability Priority.
- 2007-03 Real-time Transmission Operations. This project ranked #4 in Practicality Priority.
- 2007-06 Protection System Coordination. This project ranked #4 in Reliability Priority.
- 2007-07 Vegetation Management.
- 2007-09 Generator Verification.
- 2007-12 Frequency Response. This project ranked #10 in Reliability Priority, and was tied for #2 in Time Sensitivity Priority.
- 2007-17 Protection System Maintenance and Testing. This project ranked #3 in Reliability Priority.
- 2008-06 Cyber Security – Order 706. This project ranked #1 in Reliability Priority.
- 2009-01 Disturbance and Sabotage Reporting. This project ranked #7 in Reliability Priority.
- 2010-05.1 Phase 1 of Protection Systems: Misoperations. This project ranked #8 in Reliability Priority.
- 2010-07 Generator Requirements at the Transmission Interface. This project ranked #13 in Practicality Priority, and was tied for #2 in Time Sensitivity Priority.
- 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves. This project ranked #1 in Time Sensitivity Priority, and #2 in Practicality Priority.

- 2010-17 Definition of Bulk Electric System. This project ranked #10 in Reliability Priority, and was tied for #2 in Time Sensitivity Priority.

NERC intends to initiate development of the following additional projects in 2012. These projects have been assigned based on priority, but constrained by the need to have a limited number of projects under active development at any given time. Project 2010-05.2 is not schedule to start until later in 2012 due to the need for subject matter expertise in misoperations, which is already committed to Phase 1 of the project. 2012-04 is not starting until later in 2012 due to the need for subject matter expertise in protection system testing, which is already committed to Project 2007-17.

While this Plan is a reasonable approach to Standards development, it cannot account for unforeseen events. The Plan is subject to modification in response to factors such as delays in the completion of current projects, the need to complete background research prior to initiation of standards development work, unforeseen regulatory directives, and factors such new or emerging reliability risks to the Bulk Electric System. Changes to the Plan during its execution are not only possible, but likely, and should be expected.

Additional Projects in 2012:

- 2008-02 Undervoltage Load Shedding. This project ranked #14 in Reliability Priority, and is expected to be started upon the completion of 2006-06 Reliability Coordination.
- 2009-02 Real-time Monitoring and Analysis Capabilities. This project ranked #1 in Practicality Priority, and is expected to be started upon the completion of 2007-03 Real-time Transmission Operations.
- 2009-03 Emergency Operations. This project ranked #3 in Practicality Priority, and is expected to be started upon the completion of 2008-06 Cyber Security – Order 706.
- 2010-01 Support Personnel Training. This project ranked #15 in Reliability Priority, and is expected to be started upon the completion of 2009-01 Disturbance and Sabotage Reporting.
- 2010-05.2 Phase 2 of Protection Systems: SPS and RAS. This project ranked #11 in Reliability Priority, and is expected to be started upon the completion of the first phase of the project, 2010-05.1 Phase 1 of Protection Systems: Misoperations.
- 2010-13.2 Phase 2 of Relay Loadability: Generation. This project has been identified as having a higher priority, as it has a FERC deadline. While this was accounted for in the Prioritization, the SC agreed that this should take precedence over the 5-year review projects considered in the Prioritization. This project is expected to be started upon the completion of 2007-12 Frequency Response.
- 2012-04 Protection System Commissioning Testing. This project ranked #9 in Reliability Priority, and is expected to be started upon the completion of 2007-17 Protection System Maintenance and Testing

NERC intends to initiate development of the following projects in 2013. As noted above, these projects have generally been assigned based on priority and constrained by the need to have a limited number of projects under active development at any given time. 2012-06 is not starting until 2013 due to the need for subject matter expertise in reserves and in generator characteristics, which are already committed to projects 2010-14.1 and 2007-09, respectively. 2009-07 is not starting until 2013 due to the need for subject matter expertise in protection systems, which is already committed to project 2007-06.

Additional Projects in 2013:

- 2007-11 Disturbance Monitoring. This project is expected to start upon completion of 2010-17 Definition of Bulk Electric System.
- 2008-01 Voltage and Reactive Panning and Control. This project ranked #6 in practicality, and is expected to start upon completion of 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves
- 2008-12 Coordinate Interchange Standards. This project is expected to start upon completion of 2010-07 Generator Requirements at the Transmission Interface.
- 2009-07 Reliability of Protection Systems. This project ranked #2 in Reliability Priority, and is expected to start upon completion of 2007-06 Protection System Coordination.
- 2010-14.2 Project 2010-14.2 Phase 2 of Balancing Authority Reliability-based Control: Time Error, AGC, and Inadvertent. This project is expected to start upon completion of 2009-02 Real-time Monitoring and Analysis Capabilities.
- 2012-01 Equipment Monitoring and Diagnostic Devices. This project is expected to start upon completion of 2007-02 Operating Personnel Communication Protocols.
- 2012-06 Generator Capabilities. This project ranked #6 in Reliability Priority, and is expected to start upon completion of both 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves and 2007-09 Generator Verification.

NERC intends to initiate development of the following projects in 2014. These projects have been identified as having a lower priority, although some are associated with the 5-year review obligation. In general, these projects are not projected to be initiated until 2014 due to the need to limit the number of projects active at any given time. 2010-13.3 is not projected to start until 2014 due to the need for subject matter expertise in relay loadability, which is already committed to Phase 2 of the project.

Additional Projects in 2014:

- 2009-04 Phasor Measurements. This project is expected to start upon completion of 2009-03 Emergency Operations.

- 2009-05 Resource Adequacy Assessments. This project is expected to start upon completion of 2012-04 Protection System Commissioning Testing.
- 2010-03 Modeling Data. This project is expected to start upon completion of 2008-01 Voltage and Reactive Panning and Control.
- 2010-04 Demand Data. This project is expected to start upon completion of 2010-05.2 Phase 2 of Protection Systems: SPS and RAS.
- 2010-08 Functional Glossary Model Revisions. This project is expected to start upon completion of 2010-01 Support Personnel Training.
- 2010-13.3 Phase 3 of Relay Loadability: Stable Power Swings. This project is expected to start upon completion of the second phase of this project, 2010-13.2 Phase 2 of Relay Loadability: Generation.
- 2010-16 Definition of System Operator. This project is expected to start upon completion of 2012-04 Protection System Commissioning Testing.
- 2012-05 ATC Revisions - Order 729. This project is expected to start upon completion of 2008-12 Coordinate Interchange Standards.

Projects for 2015 and Beyond

NERC intends to develop the following projects in 2015 or later, which is beyond the scope of this Plan. These projects have been identified as having a lower priority, although some are associated with the 5-year review obligation. There is also some question as to whether or not they will provide sufficient value to be cost justified at this time. They have been included for completeness and to ensure that they are recognized as necessary projects.

It should be noted that several of these projects are related to NERC's ongoing obligation to review its standard every five years, as required in the Rules of Procedure. This is discussed in more detail in the General chapter.

- 2010-02 Connecting New Facilities to the Grid
- 2012-02 Physical Protection
- 2012-03 PRC-004 VSLs
- 2012-07 Obsolescence Review
- 2012-08 Glossary Updates
- 2012-09 IRO Review
- 2012-11 FAC Review
- 2012-12 PER Review
- 2012-13 NUC Review

- 2012-14 Risk Analysis

The following two projects were identified as potential projects for consideration, but not included in the prioritization. If necessary, they will be evaluated mid-year on an ad-hoc basis; otherwise, they will be considered in the prioritization process for the 2013-2015 Reliability Standards Development Plan.

- 2006-06.2 Phase 2 of Reliability Coordination
- 2012-15 Flow Limited Paths

Appendix 1 - Prioritization

The following pages show the project rankings in each of the three primary categories: Reliability, Time Sensitivity, and Practicality. The assignment of scores was based on the mean of individual scores provide by members of the Standards Committee. Scores highlighted in red indicate areas where the members of the SC were divided regarding how to assign a particular score.

Following the identification of potential projects, this prioritization is the next step in the creation of the Reliability Standards Development Plan, and provides a starting point for further discussion. The prioritization is used to create the Work Plan which follows as Appendix 2.

NERC Standards Committee
Project Prioritization Worksheet

STANDARDS COMMITTEE
Reliability Standard Project Prioritization

RELIABILITY SORT

Project Number and Name	Short Description	(E) Addresses an ERO Strategic Priority (to be completed by NERC Staff) 50 = Yes 0 = No	(F) Addresses a reliability risk not covered by an existing standard 100 = Severe risk 75 = High risk 50 = Moderate risk 25 = Low risk 0 = N/A	(G) Improves one or more existing standards: 100 = Significantly 75 = Moderately 50 = Incrementally 25 = Minimally 0 = N/A	(H) Cost of Implementation The cost of complying with the standard is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	(I) Cost of Administration The cost to demonstrate and verify compliance is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	(J) Time Sensitivity (to be competed by NERC Staff) Number of months until due date, if any	(K) Addresses compliance issues from NERC Staff or Stakeholders 50 =Significant issues 25 = Moderate issues 10 = Minimal issues 0 = N/A	(L) Addresses a failed interpretation or SDT inability to develop an interpretation related to a lack of clarity that is 50 = Significant 25 = Moderate 10 = Minimal 0 = N/A	(M) Other Practicality Concern (Explanation for the rating must be indicated in the column to the right) (0 to 50)	(N) Explanation	Reliability Score (0 - 250)	Cost Consideration Score (0 - 100)	Time Sensitivity Score (0 - 100)	Practicality Score (0 - 150)	Reliability Ranking	Cost Consideration Ranking	Time Sensitivity Ranking	Practicality Ranking
Project 2008-06 Cyber Security - Order 706 (ACTIVE)	13 - The project requires modifications to CIP-002 thru CIP-009 to bring the standards into conformance with the ERO Rules of Procedure and to address the directives from FERC Order 706.	50	70.8	100	87.5	75	48	45.8	45.8			**220.8**	**52**	**22**	**91.6**	1	17	29	5
Project 2009-07 Reliability of Protection Systems	20 - Requires facility owners to have protection system equipment installed such that, if there were a failure to a specified component of that protection system, the failure would not prevent meeting the BES performance identified in the TPL standards. Related to System Protection Initiative. New standard(s).	50	83.3	87.5	66.7	41.7	0	12.5	25			**220.8**	**66**	**0**	**37.5**	2	3	33	17
Project 2007-17 Protection System Maintenance & Testing (ACTIVE)	10 - Intended to consolidate several standards into a single maintenance and testing standard: PRC-005 (Transmission and Generation Protection System Maintenance and Testing), PRC-008-0 (Underfrequency Load Shedding Equipment Maintenance Programs), PRC-011-0 (UVLS System Maintenance and Testing), and PRC-017-0 (Special Protection System Maintenance and Testing). Standards PRC-008-0, PRC-011-0, and PRC-017-0 would then be withdrawn. Related to System Protection Initiative.	50	50	100	60	50	5	45.8	25			**200**	**60**	**94**	**70.8**	3	7	2	9
Project 2007-06 System Protection Coordination (ACTIVE)	5 - Requires upgrading and expanding the existing requirements from PRC-001 to identify criteria for determining where to install protection system devices and for requiring the installation of those devices to protect the reliability of the bulk electric system. PRC-027. Related to System Protection Initiative.	50	62.5	83.3	55	45	5	12.5	41.7			**195.8**	**61**	**94**	**54.2**	4	6	3	14
Project 2007-02 Operating Personnel Communications Protocols (ACTIVE)	3 - Requires developing new requirements in support of blackout recommendation #26 to ensure that real-time system operators use standard communication protocols during normal and emergency operations. COM-003.	50	75	70.8	25	25	5	4.2	0			**195.8**	**74**	**94**	**4.2**	5	1	4	27
Project 2012-06 Generator Capabilities	40 - For all synchronous generators, specify minimum droop settings and frequency response performance. Require proven voltage support and reactive response to a specific level. Related to Frequency Response Initiative. Related to BAL-003 and the Continent Wide Reserve Policy. New standard(s).	50	50	91.7	62.5	37.5	0	0	0			**191.7**	**60**	**0**	**0**	6	8	34	30
Project 2009-01 Disturbance and Sabotage Reporting (ACTIVE)	15 - This project will entail revision to existing standards CIP-001 and EOP-004. The standards may be merged to eliminate redundancy and provide clarity on sabotage events. EOP-004 has some 'fill-in-the-blank' components to eliminate. The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards. EOP-004, CIP-001 and CIP-008.	50	66.7	58.3	16.7	16.7	5	50	25			**175**	**73**	**94**	**75**	7	2	5	7
Project 2010-05.1 Phase 1 of Protection Systems: Misoperations (ACTIVE)	25 - Modify current PRC-003 and -004 standards and definitions related to Protection System Misoperations to support a good metric for measurement of Protection System performance and ensure the reliability of the bulk power system. Does not include SPS and RAS. Related to System Protection Initiative.	50	62.5	62.5	33.3	37.5	5	50	25			**175**	**64**	**94**	**75**	8	4	6	8
Project 2012-04 Protection System Commissioning Testing	38 - Establish minimum level of required commissioning testing prior to putting protection systems into service. Related to System Protection Initiative. New standard(s).	50	50	70.8	41.7	50	0	0	0			**170.8**	**57**	**0**	**0**	9	9	35	31
Project 2010-17 Definition of BES (ACTIVE)	34 - Define the BES as per FERC Order 743.	0	87.5	75	81.3	75	5	37.5	29.2			**162.5**	**52**	**94**	**66.7**	10	18	7	11
Project 2010-05.2 Phase 2 of Protections Systems: SPS and RAS	26 - Modify current PRC-012, -014, and -016 standards and definitions related to SPS/RAS Misoperations to support a good metric for measurement of Protection System performance and ensure the reliability of the bulk power system. May include additional updates to PRC-004 as well. Related to System Protection Initiative.	50	45.8	62.5	40	45	5	33.3	12.5			**158.3**	**56**	**94**	**45.8**	11	10	8	16
Project 2010-07 Generator Requirements at the Transmission Interface (ACTIVE)	27 - This project proposes changes to the requirements and the addition of new requirements to add significant clarity to Generator Owners and Generator Operators regarding their reliability standard obligations at the interface with the interconnected grid. Multiple standards.	0	75	75	66.7	66.7	5	50	8.3			**150**	**54**	**94**	**58.3**	12	15	9	13
Project 2006-06 Reliability Coordination (ACTIVE)	2 - Requires upgrading and expanding existing requirements that address reliability coordinator actions to prevent instability, uncontrolled separation or cascading outages. COM-001, COM-002, IRO-001, IRO-002, IRO-005, IRO-014, IRO-015, IRO-016, and IRO-003.	50	33.3	66.7	37.5	37.5	5	4.2	25			**150**	**56**	**94**	**29.2**	13	11	10	18
Project 2008-02 Undervoltage Load Shedding	12 - Consider consolidating PRC-010-0 (Assessment of the Design and Effectiveness of UVLS Program) and (PRC-022-1 — Under-Voltage Load Shedding Program Performance). Currently missing are any criteria for identifying where UVLS should be installed. The team will utilize the FIDVR (Fault-Induced Delayed Voltage Recovery) Technical Reference Paper in the development of requirements. Related to System Protection Initiative.	50	29.2	70.8	83.3	50	5	0	0			**150**	**42**	**94**	**0**	14	24	11	32

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Reliability Standard Project Prioritization

RELIABILITY SORT

Project Number and Name	Short Description	(E) Addresses an ERO Strategic Priority (to be completed by NERC Staff) 50 = Yes 0 = No	(F) Addresses a reliability risk not covered by an existing standard 100 = Severe risk 75 = High risk 50 = Moderate risk 25 = Low risk 0 = N/A	(G) Improves one or more existing standards: 100 = Significantly 75 = Moderately 50 = Incrementally 25 = Minimally 0 = N/A	(H) Cost of Implementation The cost of complying with the standard is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	(I) Cost of Administration The cost to demonstrate and verify compliance is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	(J) Time Sensitivity (to be competed by NERC Staff) Number of months until due date, if any	(K) Addresses compliance issues from NERC Staff or Stakeholders 50 =Significant issues 25 = Moderate issues 10 = Minimal issues 0 = N/A	(L) Addresses a failed interpretation or SDT inability to develop an interpretation related to a lack of clarity that is 50 = Significant 25 = Moderate 10 = Minimal 0 = N/A	(M) Other Practicality Concern (Explanation for the rating must be indicated in the column to the right) (0 to 50)	(N) Explanation	Reliability Score (0 - 250)	Cost Consideration Score (0 - 100)	Time Sensitivity Score (0 - 100)	Practicality Score (0 - 150)	Reliability Ranking	Cost Consideration Ranking	Time Sensitivity Ranking	Practicality Ranking
Project 2010-01 Support Personnel Training	21 - Require the use of a systematic approach to determining training needs of generator operators and operations planning and support staff with a direct impact on the reliable operations of the bulk power system. New standard(s).	50	45.8	50	85	41.7	0	0	0			**145.8**	**42**	**0**	**0**	15	25	36	33
Project 2008-01 Voltage and Reactive Planning and Control (INFORMAL)	11 - This project supports a blackout recommendation. Industry debate is needed on whether there should be a North American standard that requires a specific amount of reserves, or whether requirements for specific reserves should continue to be addressed at the regional level. The requirements in the existing standards need to be upgraded to be more specific in defining voltage and reactive power schedules. Consideration should be given to adding a requirement for the Reliability Coordinator to monitor and take action if reactive power falls outside identified limits.. VAR-001 and -002.	0	66.7	75	54.2	30	5	33.3	8.3	50	Addressing Reactive Requirements key to reliability of system. Length of Time since the reliability need was identified -- Project was identified to address a Blackout Recommendation (elapsed time = 7 years) and FERC Order 693 directives (elapsed time = 4-1/2 years). Subsequently, NERC Transmission Issues Subcommittee.	**141.7**	**64**	**94**	**91.6**	16	5	12	6
Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Control: Reserves (ACTIVE)	31 - The project includes of modifications to BAL-001 and BAL-002 to support Frequency Response project. Includes Continent-wide Reserve Policy. 5 Year review of BAL-001. Related to Frequency Response Initiative.	0	50	87.5	81.3	31.3	1	8.3	45.8	40	There is a significant disagreement between FERC Staff, NERC Staff and the industry as to what is required under BAL-002. There could also be significant cost savings to the industry if the revisions to BAL-001 were to be realized.	**137.5**	**56**	**100**	**94.1**	17	12	1	2
Project 2010-13-3 Phase 3 of Relay Loadability: Stable Power Swings	30 - Address concerns with Stable Power Swings as identified in the FERC Order on Relay Loadability. Related to System Protection Initiative New standard(s).	50	41.7	41.7	81.3	68.8	36	5	12.5	50	Relay performance during "stable" swings is complex. Restraint from tripping during stable swings must be balanced with the necessity of separation during unstable swings. The FERC order ignores this.	**133.4**	**33**	**42**	**67.5**	18	35	27	10
Project 2007-12 Frequency Response (ACTIVE)	9 - Requires entities to provide data needed to model each interconnection's frequency response, as well as establishes Frequency Response Obligation. Related to Frequency Response Initiative. BAL-003.	0	50	79.2	50	75	5	16.7	10	36.7	Frequency response has declined over the years. This issue is a high priority for FERC.	**129.2**	**51**	**94**	**63.4**	19	20	13	12
Project 2007-09 Generator Verification (ACTIVE)	7 - Requires upgrading existing requirements for generators to verify their capabilities to ensure that accurate data is used in model to assess the bulk electric system. MOD-025, -026, -027, PRC-019 and -024.	0	66.7	62.5	75	45.8	5	10	0			**129.2**	**52**	**94**	**10**	20	19	14	24
Project 2010-13.2 Phase 2 of Relay Loadability: Generation (INFORMAL)	29 - Draft new standard PRC-025-1 Generator Relay Loadability in compliance with the FERC Order 733 issued March 18, 2010. Related to System Protection Initiative.	50	29.2	50	62.5	50	12	0	0			**129.2**	**42**	**82**	**0**	21	26	24	34
Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities (INFORMAL)	16 - The project will establish requirements for the functionality, performance, and management of Real-time tools for Reliability Coordinators, Transmission Operators, and Balancing Authorities for use by their System Operators in support of reliable System operations. New standard(s).	0	66.7	58.3	90	85	27	37.5	10	50	Getting industry buy in to the development of the tool required.	**125**	**38**	**57**	**97.5**	22	31	25	1
Project 2007-07 Vegetation Management (ACTIVE)	6 - Project 2007-07 Vegetation Management Requires upgrading the existing requirements for entities to implement a vegetation management program to prevent transmission outages that adversely impact the reliability of the bulk electric system. FAC-003.	50	4.2	58.3	58.3	45	5	0	0	50	Results-Based Proof-of-Concept	**112.5**	**40**	**94**	**50**	23	29	15	15
Project 2009-03 Emergency Operations (INFORMAL)	17 - This set of EOP standards may be merged into a single standard. There are some requirements in IRO-001 that may be improved and merged into the new EOP standard. EOP-001, -002, -003, IRO-001.	0	37.5	70.8	45	45	5	12.5	29.2	50	Getting the industry to agree to combining the standards into one or two instead of four.	**108.3**	**55**	**94**	**91.7**	24	13	16	3
Project 2012-01 Equipment Monitoring and Diagnostic Devices	35 - Consider the development of reliability standards for the application of major equipment monitoring and diagnostic devices and procedures. New standard(s).	0	25	70.8	87.5	62.5	0	0	0			**95.8**	**36**	**0**	**0**	25	34	37	35
Project 2007-11 Disturbance Monitoring (INFORMAL)	8 - Requires upgrading and expanding existing requirements for entities to install disturbance monitoring equipment and report disturbance data to ensure information is available to analyze bulk power system disturbances. PRC-002, PRC-018.	0	25	70	75	66.7	5	0	0	25	High Regional Priority	**95**	**38**	**94**	**25**	26	32	17	20
Project 2010-03 Modeling Data	23 - Requires merging, upgrading and expanding existing requirements for entities to provide data used to model the bulk electric system. Related to Blackout recommendation and Modeling Initiative. MOD-010 thru -015.	0	41.7	45.8	33.3	33.3	5	0	0			**87.5**	**55**	**94**	**0**	27	14	18	36
Project 2007-03 Real-time Transmission Operations (ACTIVE)	4 - Requires upgrading and expanding existing requirements that address transmission operator responsibilities to ensure the real-time operating reliability of the transmission assets within the transmission operator's area. PER-001, TOP-001- through TOP-008	0	4.2	66.7	33.3	50	5	50	41.7			**70.9**	**47**	**94**	**91.7**	28	21	19	4
Project 2008-12 Coordinate Interchange Standards (INFORMAL)	14 - Revise the set of Coordinate Interchange standards to 1) ensure that each requirement is assigned to an owner, operator or user of the bulk power system, and not to a tool used to coordinate interchange, 2) to address the Interchange Subcommittee's concerns related to the Dynamic Transfers and Pseudo-ties, and 3) to address previously identified stakeholder comments and applicable directives from Order 693. INT-001 through -010.	0	45.8	25	41.7	41.7	5	25	1.7			**70.8**	**47**	**94**	**26.7**	29	22	20	19
Project 2009-04 Phasor Measurements	18 - Supports a blackout recommendation. Several industry studies were issued that need to be analyzed to determine appropriate requirements for a NERC standard. Related to North-American Synchro-Phasor Initiative. New standard(s).	0	66.7	0	50	33.3	0	0	0			**66.7**	**46**	**0**	**0**	30	23	38	37

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Reliability Standard Project Prioritization

RELIABILITY SORT

Project Number and Name	Short Description	(E) Addresses an ERO Strategic Priority (to be completed by NERC Staff) 50 = Yes 0 = No	(F) Addresses a reliability risk not covered by an existing standard 100 = Severe risk 75 = High risk 50 = Moderate risk 25 = Low risk 0 = N/A	(G) Improves one or more existing standards: 100 = Significantly 75 = Moderately 50 = Incrementally 25 = Minimally 0 = N/A	(H) Cost of Implementation The cost of complying with the standard is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	(I) Cost of Administration The cost to demonstrate and verify compliance is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	(J) Time Sensitivity (to be competed by NERC Staff) Number of months until due date, if any	(K) Addresses compliance issues from NERC Staff or Stakeholders 50 =Significant issues 25 = Moderate issues 10 = Minimal issues 0 = N/A	(L) Addresses a failed interpretation or SDT inability to develop an interpretation related to a lack of clarity that is 50 = Significant 25 = Moderate 10 = Minimal 0 = N/A	(M) Other Practicality Concern (Explanation for the rating must be indicated in the column to the right) (0 to 50)	(N) Explanation	Reliability Score (0 - 250)	Cost Consideration Score (0 - 100)	Time Sensitivity Score (0 - 100)	Practicality Score (0 - 150)	Reliability Ranking	Cost Consideration Ranking	Time Sensitivity Ranking	Practicality Ranking
Project 2009-05 Resource Adequacy Assessments	19 - Implements recommendations from the Resource and Transmission Adequacy Task Force (RTATF) Report and the Gas/Electricity Interdependency Task Force Report, approved by the NERC Board on June 15, 2004, related to resource adequacy. New standard(s).	50	8.3	0	33.3	25	0	0	0			**58.3**	**38**	**0**	**0**	31	33	39	38
Project 2012-02 Physical Protection	36 - Consider the development of reliability standards for the safety and protection of essential equipment, buildings and people located in power generation, transmission, or distribution system locations in order to mitigate the associated reliability risks to the bulk power system. New standard(s).	0	45.8	8.3	91.7	83.3	0	0	0			**54.1**	**20**	**0**	**0**	32	37	40	39
Project 2010-04 Demand Data	24 - As envisioned, this project will result in two standards — with MOD-016 through MOD-020 being merged into a single standard, and MOD-021 remaining as a separate standard. The requirements need to be more specific to clearly identify the format, etc., for providing data.	0	0	50	18.8	18.8	5	0	0			**50**	**53**	**94**	**0**	33	16	21	40
Project 2010-16 Definition of System Operator	33 - Refine definition of "System Operator" to exclude the Generator Operator, as all other "System Operators" have a more wide-area view.	0	8.3	25	33.3	37.5	0	4.2	0			**33.3**	**41**	**0**	**4.2**	34	27	41	28
Project 2010-08 Functional Model Glossary Revisions	28 - The Functional Model Working Group (FMWG) has received many comments and questions from stakeholders concerning the differences in definitions between the Functional Model and the NERC Glossary of Terms Used in Reliability Standards. This project is designed to address these comments and make the definitions of functional entities consistent between the Functional Model and the NERC Glossary of Terms Used in Reliability Standards.	0	0	29.2	33.3	33.3	0	0	0	10	Foundational piece of ERO	**29.2**	**41**	**0**	**10**	35	28	42	25
Project 2010-02 Connecting New Facilities to the Grid	22 - Ensure that all of the elements that should be addressed when a new facility is connected to the grid are included in the revised standard. FAC-001 and -002.	0	0	25	33.3	33.3	5	0	0			**25**	**40**	**94**	**0**	36	30	22	41
Project 2012-14 Risk Analysis	47 - Require entities to have and maintain a checklist of potential threats to the power system that must be addressed by each TOP/BA. The checklist should include things like GMD, voltage collapse, and other extreme events. New standard(s).	0	25	0	100	50	0	0	0			**25**	**19**	**0**	**0**	37	38	43	42
Project 2012-07 Obsolescence Review	41 - Require all TOs and GOs to periodically review their electronic, electric, mechanical, and other control systems, as well as protection systems, to replace obsolete equipment. New standard(s).	0	25	0	100	75	0	0	0			**25**	**13**	**0**	**0**	38	39	44	43
Project 2010-14.1 Phase 2 of Balancing Authority Reliability-based Control: Time Error, AGC, and Inadvertent (INFORMAL)	32 - The project includes elimination of Time Error Corrections, 5-year review of BAL-005, miscellaneous clean up and modification to BAL-006.	0	4.2	0	50	50	5	0	25			**4.2**	**26**	**94**	**25**	39	36	23	21
Project 2012-11 FAC Review	44 - 5-Year Review of FAC-010, -011, -014	0	0	0	50	50	27	0	0			**0**	**0**	**57**	**0**	40	40	26	44
Project 2012-05 ATC-Revisions - Order 729	39 - Respond to directives in Order 729 related to ATC Standards. Perform 5-year review of MOD-001, -004, -008, -029, and -030. Also includes MOD-028.	0	0	0	50	50	51	0	25			**0**	**0**	**17**	**25**	41	43	31	22
Project 2012-09 IRO Review	43 - 5-Year review of IRO-006, -008, -009, and -010.	0	0	0	50	50	54	16.7	8.3			**0**	**0**	**12**	**25**	42	44	32	23
Project 2012-13 NUC Review	46 - 5-Year Review of NUC-001.	0	0	0	25	25	39	0	0			**0**	**0**	**37**	**0**	43	41	28	45
Project 2012-12 PER Review	45 - 5-Year Review of PER-003, -004 and -005.	0	0	0	50	50	49	0	0			**0**	**0**	**20**	**0**	44	42	30	46
Project 2012-03 PRC-004 VSLs	37 - Update VSLs to address the situation where Corrective Action Plans were developed or documented, but not fully implemented. PRC-004.	0	0	0	25	50	0	8.3	0			**0**	**0**	**0**	**8.3**	45	45	45	26
Project 2012-08 Glossary Updates	42 - Per FERC Order 693, define Bulk Power System, Reliability Standard, and Reliable Operation. Modify definition of Generator Operator and Transmission Operator.	0	0	0	75	75	0	4.2	0			**0**	**0**	**0**	**4.2**	46	46	46	29
2006-06.2 Phase 2 of Reliability Coordination	NA - Address specific directives from FERC Order 693 related to reliability standard IRO-003-2 - Reliability Coordination - Wide-Area View											**0**	**0**	**0**	**0**	47	47	47	47
2012-15 Flow Limited Paths	NA - Address concerns identified with MOD-029 and its treatment of flow-limited paths.											**0**	**0**	**0**	**0**	48	48	48	48

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TIME SENSITIVITY SORT

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Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Control: Reserves (ACTIVE)	3.1 - The project includes of modifications to BAL-001 and BAL-002 to support Frequency Response project. Includes Continent-wide Reserve Policy. 5 Year review of BAL-001. Related to Frequency Response Initiative.	0	50	87.5	81.3	31.3	1	8.3	45.8	40	There is a significant disagreement between FERC Staff, NERC Staff and the industry as to what is required under BAL-002. There could also be significant cost savings to the industry if the revisions to BAL-001 were to be realized.	**137.5**	**56**	**100**	**94.1**	17	12	1	2
Project 2007-02 Operating Personnel Communications Protocols (ACTIVE)	3 - Requires developing new requirements in support of blackout recommendation #26 to ensure that real-time system operators use standard communication protocols during normal and emergency operations. COM-003.	50	75	70.8	25	25	5	4.2	0			**195.8**	**74**	**94**	**4.2**	5	1	2	27
Project 2009-01 Disturbance and Sabotage Reporting (ACTIVE)	15 - This project will entail revision to existing standards CIP-001 and EOP-004. The standards may be merged to eliminate redundancy and provide clarity on sabotage events. EOP-004 has some 'fill-in-the-blank' components to eliminate. The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards. EOP-004, CIP-001 and CIP-008.	50	66.7	58.3	16.7	16.7	5	50	25			**175**	**73**	**94**	**75**	7	2	3	7
Project 2010-05.1 Phase 1 of Protection Systems: Misoperations (ACTIVE)	25 - Modify current PRC-003 and -004 standards and definitions related to Protection System Misoperations to support a good metric for measurement of Protection System performance and ensure the reliability of the bulk power system. Does not include SPS and RAS. Related to System Protection Initiative.	50	62.5	62.5	33.3	37.5	5	50	25			**175**	**64**	**94**	**75**	8	4	4	8
Project 2008-01 Voltage and Reactive Planning and Control (INFORMAL)	11 - This project supports a blackout recommendation. Industry debate is needed on whether there should be a North American standard that requires a specific amount of reserves, or whether requirements for specific reserves should continue to be addressed at the regional level. The requirements in the existing standards need to be upgraded to be more specific in defining voltage and reactive power schedules. Consideration should be given to adding a requirement for the Reliability Coordinator to monitor and take action if reactive power falls outside identified limits. VAR-001 and -002.	0	66.7	75	54.2	30	5	33.3	8.3	50	Addressing Reactive Requirements key to reliability of system. Length of Time since the reliability need was identified -- Project was identified to address a Blackout Recommendation (elapsed time = 7 years) and FERC Order 693 directives (elapsed time = 4-1/2 years). Subsequently, NERC Transmission Issues Subcommittee.	**141.7**	**64**	**94**	**91.6**	16	5	5	6
Project 2007-06 System Protection Coordination (ACTIVE)	5 - Requires upgrading and expanding the existing requirements from PRC-001 to identify criteria for determining where to install protection system devices and for requiring the installation of those devices to protect the reliability of the bulk electric system. PRC-027. Related to System Protection Initiative.	50	62.5	83.3	55	45	5	12.5	41.7			**195.8**	**61**	**94**	**54.2**	4	6	6	14
Project 2007-17 Protection System Maintenance & Testing (ACTIVE)	10 - Intended to consolidate several standards into a single maintenance and testing standard: PRC-005 (Transmission and Generation Protection System Maintenance and Testing), PRC-008-0 (Underfrequency Load Shedding Equipment Maintenance Programs), PRC-011-0 (UVLS System Maintenance and Testing), and PRC-017-0 (Special Protection System Maintenance and Testing). Standards PRC-008-0, PRC-011-0, and PRC-017-0 would then be withdrawn. Related to System Protection Initiative.	50	50	100	60	50	5	45.8	25			**200**	**60**	**94**	**70.8**	3	7	7	9
Project 2010-05.2 Phase 2 of Protections Systems: SPS and RAS	26 - Modify current PRC-012, -014, and -016 standards and definitions related to SPS/RAS Misoperations to support a good metric for measurement of Protection System performance and ensure the reliability of the bulk power system. May include additional updates to PRC-004 as well. Related to System Protection Initiative.	50	45.8	62.5	40	45	5	33.3	12.5			**158.3**	**56**	**94**	**45.8**	11	10	8	16
Project 2006-06 Reliability Coordination (ACTIVE)	2 - Requires upgrading and expanding existing requirements that address reliability coordinator actions to prevent instability, uncontrolled separation or cascading outages. COM-001, COM-002, IRO-001, IRO-002, IRO-005, IRO-014, IRO-015, IRO-016, and IRO-003.	50	33.3	66.7	37.5	37.5	5	4.2	25			**150**	**56**	**94**	**29.2**	13	11	9	18
Project 2009-03 Emergency Operations (INFORMAL)	17 - This set of EOP standards may be merged into a single standard. There are some requirements in IRO-001 that may be improved and merged into the new EOP standard. EOP-001, -002, -003, IRO-001.	0	37.5	70.8	45	45	5	12.5	29.2	50	Getting the industry to agree to combining the standards into one or two instead of four.	**108.3**	**55**	**94**	**91.7**	24	13	10	3
Project 2010-03 Modeling Data	23 - Requires merging, upgrading and expanding existing requirements for entities to provide data used to model the bulk electric system. Related to Blackout recommendation and Modeling Initiative. MOD-010 thru -015.	0	41.7	45.8	33.3	33.3	5	0	0			**87.5**	**55**	**94**	**0**	27	14	11	36
Project 2010-07 Generator Requirements at the Transmission Interface (ACTIVE)	27 - This project proposes changes to the requirements and the addition of new requirements to add significant clarity to Generator Owners and Generator Operators regarding their reliability standard obligations at the interface with the interconnected grid. Multiple standards.	0	75	75	66.7	66.7	5	50	8.3			**150**	**54**	**94**	**58.3**	12	15	12	13
Project 2010-04 Demand Data	24 - As envisioned, this project will result in two standards — with MOD-016 through MOD-020 being merged into a single standard, and MOD-021 remaining as a separate standard. The requirements need to be more specific to clearly identify the format, etc., for providing data.	0	0	50	18.8	18.8	5	0	0			**50**	**53**	**94**	**0**	33	16	13	40

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STANDARDS COMMITTEE
Reliability Standard Project Prioritization

TIME SENSITIVITY SORT

Project Number and Name	Short Description	(E) Addresses an ERO Strategic Priority (to be completed by NERC Staff) 50 = Yes 0 = No	(F) Addresses a reliability risk not covered by an existing standard 100 = Severe risk 75 = High risk 50 = Moderate risk 25 = Low risk 0 = N/A	(G) Improves one or more existing standards: 100 = Significantly 75 = Moderately 50 = Incrementally 25 = Minimally 0 = N/A	(H) Cost of Implementation The cost of complying with the standard is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	(I) Cost of Administration The cost to demonstrate and verify compliance is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	(J) Time Sensitivity (to be competed by NERC Staff) Number of months until due date, if any	(K) Addresses compliance issues from NERC Staff or Stakeholders 50 =Significant issues 25 = Moderate issues 10 = Minimal issues 0 = N/A	(L) Addresses a failed interpretation or SDT inability to develop an interpretation related to a lack of clarity that is 50 = Significant 25 = Moderate 10 = Minimal 0 = N/A	(M) Other Practicality Concern (Explanation for the rating must be indicated in the column to the right) (0 to 50)	(N) Explanation	Reliability Score (0 - 250)	Cost Consideration Score (0 - 100)	Time Sensitivity Score (0 - 100)	Practicality Score (0 - 150)	Reliability Ranking	Cost Consideration Ranking	Time Sensitivity Ranking	Practicality Ranking
Project 2010-17 Definition of BES (ACTIVE)	34 - Define the BES as per FERC Order 743.	0	87.5	75	81.3	75	5	37.5	29.2			**162.5**	**52**	**94**	**66.7**	10	18	14	11
Project 2007-09 Generator Verification (ACTIVE)	7 - Requires upgrading existing requirements for generators to verify their capabilities to ensure that accurate data is used in model to assess the bulk electric system. MOD-025, -026, 027; PRC-019 and -024.	0	66.7	62.5	75	45.8	5	10	0			**129.2**	**52**	**94**	**10**	20	19	15	24
Project 2007-12 Frequency Response (ACTIVE)	9 - Requires entities to provide data needed to model each interconnection's frequency response, as well as establishes Frequency Response Obligation. Related to Frequency Response Initiative. BAL-003.	0	50	79.2	50	75	5	16.7	10	36.7	Frequency response has declined over the years. This issue is a high priority for FERC.	**129.2**	**51**	**94**	**63.4**	19	20	16	12
Project 2007-03 Real-time Transmission Operations (ACTIVE)	4 - Requires upgrading and expanding existing requirements that address transmission operator responsibilities to ensure the real-time operating reliability of the transmission assets within the transmission operator's area. PER-001, TOP-001- through TOP-008	0	4.2	66.7	33.3	50	5	50	41.7			**70.9**	**47**	**94**	**91.7**	28	21	17	4
Project 2008-12 Coordinate Interchange Standards (INFORMAL)	14 - Revise the set of Coordinate Interchange standards to 1) ensure that each requirement is assigned to an owner, operator or user of the bulk power system, and not to a tool used to coordinate interchange, 2) to address the Interchange Subcommittee's concerns related to the Dynamic Transfers and Pseudo-ties, and 3) to address previously identified stakeholder comments and applicable directives from Order 693. INT-001 through -010.	0	45.8	25	41.7	41.7	5	25	1.7			**70.8**	**47**	**94**	**26.7**	29	22	18	19
Project 2008-02 Undervoltage Load Shedding	12 - Consider consolidating PRC-010-0 (Assessment of the Design and Effectiveness of UVLS Program) and (PRC-022-1 — Under-Voltage Load Shedding Program Performance). Currently missing are any criteria for identifying where UVLS should be installed. The team will utilize the FIDVR (Fault-Induced Delayed Voltage Recovery) Technical Reference Paper in the development of requirements. Related to System Protection Initiative.	50	29.2	70.8	83.3	50	5	0	0			**150**	**42**	**94**	**0**	14	24	19	32
Project 2007-07 Vegetation Management (ACTIVE)	6 - Project 2007-07 Vegetation Management Requires upgrading the existing requirements for entities to implement a vegetation management program to prevent transmission outages that adversely impact the reliability of the bulk electric system. FAC-003.	50	4.2	58.3	58.3	45	5	0	0	50	Results-Based Proof-of-Concept	**112.5**	**40**	**94**	**50**	23	29	20	15
Project 2010-02 Connecting New Facilities to the Grid	22 - Ensure that all of the elements that should be addressed when a new facility is connected to the grid are included in the revised standard. FAC-001 and -002.	0	0	25	33.3	33.3	5	0	0			**25**	**40**	**94**	**0**	36	30	21	41
Project 2007-11 Disturbance Monitoring (INFORMAL)	8 - Requires upgrading and expanding existing requirements for entities to install disturbance monitoring equipment and report disturbance data to ensure information is available to analyze bulk power system disturbances. PRC-002, PRC-018.	0	25	70	75	66.7	5	0	0	25	High Regional Priority	**95**	**38**	**94**	**25**	26	32	22	20
Project 2010-14.1 Phase 2 of Balancing Authority Reliability-based Control: Time Error, AGC, and Inadvertent (INFORMAL)	32 - The project includes elimination of Time Error Corrections, 5-year review of BAL-005, miscellaneous clean up and modification to BAL-006.	0	4.2	0	50	50	5	0	25			**4.2**	**26**	**94**	**25**	39	36	23	21
Project 2010-13.2 Phase 2 of Relay Loadability: Generation (INFORMAL)	29 - Draft new standard PRC-025-1 Generator Relay Loadability in compliance with the FERC Order 733 issued March 18, 2010. Related to System Protection Initiative.	50	29.2	50	62.5	50	12	0	0			**129.2**	**42**	**82**	**0**	21	26	24	34
Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities (INFORMAL)	16 - The project will establish requirements for the functionality, performance, and management of Real-time tools for Reliability Coordinators, Transmission Operators, and Balancing Authorities for use by their System Operators in support of reliable System operations. New standard(s).	0	66.7	58.3	90	85	27	37.5	10	50	Getting industry buy in to the development of the tool required.	**125**	**38**	**57**	**97.5**	22	31	25	1
Project 2012-11 FAC Review	44 - 5-Year Review of FAC-010, -011, -014	0	0	0	50	50	27	0	0			**0**	**0**	**57**	**0**	40	40	26	44
Project 2010-13-3 Phase 3 of Relay Loadability: Stable Power Swings	30 - Address concerns with Stable Power Swings as identified in the FERC Order on Relay Loadability. Related to System Protection Initiative New standard(s).	50	41.7	41.7	81.3	68.8	36	5	12.5	50	Relay performance during "stable" swings is complex. Restraint from tripping during stable swings must be balanced with the necessity of separation during unstable swings. The FERC order ignores this.	**133.4**	**33**	**42**	**67.5**	18	35	27	10
Project 2012-13 NUC Review	46 - 5-Year Review of NUC-001.	0	0	0	25	25	39	0	0			**0**	**0**	**37**	**0**	43	43	28	45
Project 2008-06 Cyber Security - Order 706 (ACTIVE)	13 - The project requires modifications to CIP-002 thru CIP-009 to bring the standards into conformance with the ERO Rules of Procedure and to address the directives from FERC Order 706.	50	70.8	100	87.5	75	48	45.8	45.8			**220.8**	**52**	**22**	**91.6**	1	17	29	5
Project 2012-12 PER Review	45 - 5-Year Review of PER-003, -004 and -005.	0	0	0	50	50	49	0	0			**0**	**0**	**20**	**0**	44	44	30	46
Project 2012-05 ATC-Revisions - Order 729	39 - Respond to directives in Order 729 related to ATC Standards. Perform 5-year review of MOD-001, -004, -008, -029, and -030. Also includes MOD-028.	0	0	0	50	50	51	0	25			**0**	**0**	**17**	**25**	41	41	31	22
Project 2012-09 IRO Review	43 - 5-Year review of IRO-006, -008, -009, and -010.	0	0	0	50	50	54	16.7	8.3			**0**	**0**	**12**	**25**	42	42	32	23

NERC Standards Committee
Project Prioritization Worksheet

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Reliability Standard Project Prioritization

TIME SENSITIVITY SORT

Project Number and Name	Short Description	(E) Addresses an ERO Strategic Priority (to be completed by NERC Staff) 50 = Yes 0 = No	(F) Addresses a reliability risk not covered by an existing standard 100 = Severe risk 75 = High risk 50 = Moderate risk 25 = Low risk 0 = N/A	(G) Improves one or more existing standards: 100 = Significantly 75 = Moderately 50 = Incrementally 25 = Minimally 0 = N/A	(H) Cost of Implementation The cost of complying with the standard is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	(I) Cost of Administration The cost to demonstrate and verify compliance is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	(J) Time Sensitivity (to be competed by NERC Staff) Number of months until due date, if any	(K) Addresses compliance issues from NERC Staff or Stakeholders 50 =Significant issues 25 = Moderate issues 10 = Minimal issues 0 = N/A	(L) Addresses a failed interpretation or SDT inability to develop an interpretation related to a lack of clarity that is 50 = Significant 25 = Moderate 10 = Minimal 0 = N/A	(M) Other Practicality Concern (Explanation for the rating must be indicated in the column to the right) (0 to 50)	(N) Explanation	Reliability Score (0 - 250)	Cost Consideration Score (0 - 100)	Time Sensitivity Score (0 - 100)	Practicality Score (0 - 150)	Reliability Ranking	Cost Consideration Ranking	Time Sensitivity Ranking	Practicality Ranking
Project 2009-07 Reliability of Protection Systems	20 - Requires facility owners to have protection system equipment installed such that, if there were a failure to a specified component of that protection system, the failure would not prevent meeting the BES performance identified in the TPL standards. Related to System Protection Initiative. New standard(s).	50	83.3	87.5	66.7	41.7	0	12.5	25			220.8	66	0	37.5	2	3	33	17
Project 2012-06 Generator Capabilities	40 - For all synchronous generators, specify minimum droop settings and frequency response performance. Require proven voltage support and reactive response to a specific level. Related to Frequency Response Initiative. Related to BAL-003 and the Continent Wide Reserve Policy. New standard(s).	50	50	91.7	62.5	37.5	0	0	0			191.7	60	0	0	6	8	34	30
Project 2012-04 Protection System Commissioning Testing	38 - Establish minimum level of required commissioning testing prior to putting protection systems into service. Related to System Protection Initiative. New standard(s).	50	50	70.8	41.7	50	0	0	0			170.8	57	0	0	9	9	35	31
Project 2009-04 Phasor Measurements	18 - Supports a blackout recommendation. Several industry studies were issued that need to be analyzed to determine appropriate requirements for a NERC standard. Related to North-American Synchro-Phasor Initiative. New standard(s).	0	66.7	0	50	33.3	0	0	0			66.7	46	0	0	30	23	36	37
Project 2010-01 Support Personnel Training	21 - Require the use of a systematic approach to determining training needs of generator operators and operations planning and support staff with a direct impact on the reliable operations of the bulk power system. New standard(s).	50	45.8	50	85	41.7	0	0	0			145.8	42	0	0	15	25	37	33
Project 2010-16 Definition of System Operator	33 - Refine definition of "System Operator" to exclude the Generator Operator, as all other "System Operators" have a more wide-area view.	0	8.3	25	33.3	37.5	0	4.2	0			33.3	41	0	4.2	34	27	38	28
Project 2010-08 Functional Model Glossary Revisions	28 - The Functional Model Working Group (FMWG) has received many comments and questions from stakeholders concerning the differences in definitions between the Functional Model and the NERC Glossary of Terms Used in Reliability Standards. This project is designed to address these comments and make the definitions of functional entities consistent between the Functional Model and the NERC Glossary of Terms Used in Reliability Standards.	0	0	29.2	33.3	33.3	0	0	0	10	Foundational piece of ERO	29.2	41	0	10	35	28	39	25
Project 2009-05 Resource Adequacy Assessments	19 - Implements recommendations from the Resource and Transmission Adequacy Task Force (RTATF) Report and the Gas/Electricity Interdependency Task Force Report, approved by the NERC Board on June 15, 2004, related to resource adequacy. New standard(s).	50	8.3	0	33.3	25	0	0	0			58.3	38	0	0	31	33	40	38
Project 2012-01 Equipment Monitoring and Diagnostic Devices	35 - Consider the development of reliability standards for the application of major equipment monitoring and diagnostic devices and procedures. New standard(s).	0	25	70.8	87.5	62.5	0	0	0			95.8	36	0	0	25	34	41	35
Project 2012-02 Physical Protection	36 - Consider the development of reliability standards for the safety and protection of essential equipment, buildings and people located in power generation, transmission, or distribution system locations in order to mitigate the associated reliability risks to the bulk power system. New standard(s).	0	45.8	8.3	91.7	83.3	0	0	0			54.1	20	0	0	32	37	42	39
Project 2012-14 Risk Analysis	47 - Require entities to have and maintain a checklist of potential threats to the power system that must be addressed by each TOP/BA. The checklist should include things like GMD, voltage collapse, and other extreme events. New standard(s).	0	25	0	100	50	0	0	0			25	19	0	0	37	38	43	42
Project 2012-07 Obsolescence Review	41 - Require all TOs and GOs to periodically review their electronic, electric, mechanical, and other control systems, as well as protection systems, to replace obsolete equipment. New standard(s).	0	25	0	100	75	0	0	0			25	13	0	0	38	39	44	43
Project 2012-03 PRC-004 VSLs	37 - Update VSLs to address the situation where Corrective Action Plans were developed or documented, but not fully implemented. PRC-004.	0	0	0	25	50	0	8.3	0			0	0	0	8.3	45	45	45	26
Project 2012-08 Glossary Updates	42 - Per FERC Order 693, define Bulk Power System, Reliability Standard, and Reliable Operation. Modify definition of Generator Operator and Transmission Operator.	0	0	0	75	75	0	4.2	0			0	0	0	4.2	46	46	46	29
2006-06.2 Phase 2 of Reliability Coordination	NA - Address specific directives from FERC Order 693 related to reliability standard IRO-003-2 - Reliability Coordination - Wide-Area View											0	0	0	0	47	47	47	47
2012-15 Flow Limited Paths	NA - Address concerns identified with MOD-029 and its treatment of flow-limited paths.											0	0	0	0	48	48	48	48

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Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities (INFORMAL)	16 - The project will establish requirements for the functionality, performance, and management of Real-time tools for Reliability Coordinators, Transmission Operators, and Balancing Authorities for use by their System Operators in support of reliable System operations.. New standard(s).	0	66.7	58.3	90	85	27	37.5	10	50	Getting industry buy in to the development of the tool required.	125	38	57	97.5	22	31	25	1
Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Control: Reserves (ACTIVE)	31 - The project includes of modifications to BAL-001 and BAL-002 to support Frequency Response project. Includes Continent-wide Reserve Policy. 5 Year review of BAL-001. Related to Frequency Response Initiative.	0	50	87.5	81.3	31.3	1	8.3	45.8	40	There is a significant disagreement between FERC Staff, NERC Staff and the industry as to what is required under BAL-002. There could also be significant cost savings to the industry if the revisions to BAL-001 were to be realized.	137.5	56	100	94.1	17	12	1	2
Project 2009-03 Emergency Operations (INFORMAL)	17 - This set of EOP standards may be merged into a single standard. There are some requirements in IRO-001 that may be improved and merged into the new EOP standard. EOP-001, -002, -003, IRO-001.	0	37.5	70.8	45	45	5	12.5	29.2	50	Getting the industry to agree to combining the standards into one or two instead of four.	108.3	55	94	91.7	24	13	10	3
Project 2007-03 Real-time Transmission Operations (ACTIVE)	4 - Requires upgrading and expanding existing requirements that address transmission operator responsibilities to ensure the real-time operating reliability of the transmission assets within the transmission operator's area. PER-001, TOP-001- through TOP-008	0	4.2	66.7	33.3	50	5	50	41.7			70.9	47	94	91.7	28	21	17	4
Project 2008-01 Voltage and Reactive Planning and Control (INFORMAL)	11 - This project supports a blackout recommendation. Industry debate is needed on whether there should be a North American standard that requires a specific amount of reserves, or whether requirements for specific reserves should continue to be addressed at the regional level. The requirements in the existing standards need to be upgraded to be more specific in defining voltage and reactive power schedules. Consideration should be given to adding a requirement for the Reliability Coordinator to monitor and take action if reactive power falls outside identified limits.. VAR-001 and -002.	0	66.7	75	54.2	30	5	33.3	8.3	50	Addressing Reactive Requirements key to reliability of system. Length of Time since the reliability need was identified -- Project was identified to address a Blackout Recommendation (elapsed time = 7 years) and FERC Order 693 directives (elapsed time = 4-1/2 years). Subsequently, NERC Transmission Issues Subcommittee.	141.7	64	94	91.6	16	5	5	5
Project 2008-06 Cyber Security - Order 706 (ACTIVE)	13 - The project requires modifications to CIP-002 thru CIP-009 to bring the standards into conformance with the ERO Rules of Procedure and to address the directives from FERC Order 706.	50	70.8	100	87.5	75	48	45.8	45.8			220.8	52	22	91.6	1	17	29	6
Project 2009-01 Disturbance and Sabotage Reporting (ACTIVE)	15 - This project will entail revision to existing standards CIP-001 and EOP-004. The standards may be merged to eliminate redundancy and provide clarity on sabotage events. EOP-004 has some 'fill-in-the-blank' components to eliminate. The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards. EOP-004, CIP-001 and CIP-008.	50	66.7	58.3	16.7	16.7	5	50	25			175	73	94	75	7	2	3	7
Project 2010-05.1 Phase 1 of Protection Systems: Misoperations (ACTIVE)	25 - Modify current PRC-003 and -004 standards and definitions related to Protection System Misoperations to support a good metric for measurement of Protection System performance and ensure the reliability of the bulk power system. Does not include SPS and RAS. Related to System Protection Initiative.	50	62.5	62.5	33.3	37.5	5	50	25			175	64	94	75	8	4	4	8
Project 2007-17 Protection System Maintenance & Testing (ACTIVE)	10 - Intended to consolidate several standards into a single maintenance and testing standard: PRC-005 (Transmission and Generation Protection System Maintenance and Testing), PRC-008-0 (Underfrequency Load Shedding Equipment Maintenance Programs), PRC-011-0 (UVLS System Maintenance and Testing), and PRC-017-0 (Special Protection System Maintenance and Testing). Standards PRC-008-0, PRC-011-0, and PRC-017-0 would then be withdrawn. Related to System Protection Initiative.	50	50	100	60	50	5	45.8	25			200	60	94	70.8	3	7	7	9
Project 2010-13-3 Phase 3 of Relay Loadability: Stable Power Swings	30 - Address concerns with Stable Power Swings as identified in the FERC Order on Relay Loadability. Related to System Protection Initiative New standard(s).	50	41.7	41.7	81.3	68.8	36	5	12.5	50	Relay performance during "stable" swings is complex. Restraint from tripping during stable swings must be balanced with the necessity of separation during unstable swings. The FERC order ignores this.	133.4	33	42	67.5	18	35	27	10
Project 2010-17 Definition of BES (ACTIVE)	34 - Define the BES as per FERC Order 743.	0	87.5	75	81.3	75	5	37.5	29.2			162.5	52	94	66.7	10	18	14	11
Project 2007-12 Frequency Response (ACTIVE)	9 - Requires entities to provide data needed to model each interconnection's frequency response, as well as establishes Frequency Response Obligation. Related to Frequency Response Initiative. BAL-003.	0	50	79.2	50	75	5	16.7	10	36.7	Frequency response has declined over the years. This issue is a high priority for FERC.	129.2	51	94	63.4	19	20	16	12
Project 2010-07 Generator Requirements at the Transmission Interface (ACTIVE)	27 - This project proposes changes to the requirements and the addition of new requirements to add significant clarity to Generator Owners and Generator Operators regarding their reliability standard obligations at the interface with the interconnected grid. Multiple standards.	0	75	75	66.7	66.7	5	50	8.3			150	54	94	58.3	12	15	12	13

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Project 2007-06 System Protection Coordination (ACTIVE)	5 - Requires upgrading and expanding the existing requirements from PRC-001 to identify criteria for determining where to install protection system devices and for requiring the installation of those devices to protect the reliability of the bulk electric system. PRC-027. Related to System Protection Initiative.	50	62.5	83.3	55	45	5	12.5	41.7			**195.8**	**61**	**94**	**54.2**	4	6	6	14
Project 2007-07 Vegetation Management (ACTIVE)	6 - Project 2007-07 Vegetation Management Requires upgrading the existing requirements for entities to implement a vegetation management program to prevent transmission outages that adversely impact the reliability of the bulk electric system. FAC-003.	50	4.2	58.3	58.3	45	5	0	0	50	Results-Based Proof-of-Concept	**112.5**	**40**	**94**	**50**	23	29	20	15
Project 2010-05.2 Phase 2 of Protections Systems: SPS and RAS	26 - Modify current PRC-012, -014, and -016 standards and definitions related to SPS/RAS Misoperations to support a good metric for measurement of Protection System performance and ensure the reliability of the bulk power system. May include additional updates to PRC-004 as well. Related to System Protection Initiative.	50	45.8	62.5	40	45	5	33.3	12.5			**158.3**	**56**	**94**	**45.8**	11	10	8	16
Project 2009-07 Reliability of Protection Systems	20 - Requires facility owners to have protection system equipment installed such that, if there were a failure to a specified component of that protection system, the failure would not prevent meeting the BES performance identified in the TPL standards. Related to System Protection Initiative. New standard(s).	50	83.3	87.5	66.7	41.7	0	12.5	25			**220.8**	**66**	**0**	**37.5**	2	3	33	17
Project 2006-06 Reliability Coordination (ACTIVE)	2 - Requires upgrading and expanding existing requirements that address reliability coordinator actions to prevent instability, uncontrolled separation or cascading outages. COM-001, COM-002, IRO-001, IRO-002, IRO-005, IRO-014, IRO-015, IRO-016, and IRO-003.	50	33.3	66.7	37.5	37.5	5	4.2	25			**150**	**56**	**94**	**29.2**	13	11	9	18
Project 2008-12 Coordinate Interchange Standards (INFORMAL)	14 - Revise the set of Coordinate Interchange standards to 1) ensure that each requirement is assigned to an owner, operator or user of the bulk power system, and not to a tool used to coordinate interchange, 2) to address the Interchange Subcommittee's concerns related to the Dynamic Transfers and Pseudo-ties, and 3) to address previously identified stakeholder comments and applicable directives from Order 693. INT-001 through -010.	0	45.8	25	41.7	41.7	5	25	1.7			**70.8**	**47**	**94**	**26.7**	29	22	18	19
Project 2007-11 Disturbance Monitoring (INFORMAL)	8 - Requires upgrading and expanding existing requirements for entities to install disturbance monitoring equipment and report disturbance data to ensure information is available to analyze bulk power system disturbances. PRC-002, PRC-018.	0	25	70	75	66.7	5	0	0	25	High Regional Priority	**95**	**38**	**94**	**25**	26	32	22	20
Project 2010-14.1 Phase 2 of Balancing Authority Reliability-based Control: Time Error, AGC, and Inadvertent (INFORMAL)	32 - The project includes elimination of Time Error Corrections, 5-year review of BAL-005, miscellaneous clean up and modification to BAL-006.	0	4.2	0	50	50	5	0	25			**4.2**	**26**	**94**	**25**	39	36	23	21
Project 2012-05 ATC - Revisions - Order 729	39 - Respond to directives in Order 729 related to ATC Standards. Perform 5-year review of MOD-001, -004, -008, -029, and -030. Also includes MOD-028.	0	0	0	50	50	51	0	25			**0**	**0**	**17**	**25**	41	41	31	22
Project 2012-09 IRO Review	43 - 5-Year review of IRO-006, -008, -009, and -010.	0	0	0	50	50	54	16.7	8.3			**0**	**0**	**12**	**25**	42	42	32	23
Project 2007-09 Generator Verification (ACTIVE)	7 - Requires upgrading existing requirements for generators to verify their capabilities to ensure that accurate data is used in model to assess the bulk electric system. MOD-025, -026, 027; PRC-019 and -024.	0	66.7	62.5	75	45.8	5	10	0			**129.2**	**52**	**94**	**10**	20	19	15	24
Project 2010-08 Functional Model Glossary Revisions	28 - The Functional Model Working Group (FMWG) has received many comments and questions from stakeholders concerning the differences in definitions between the Functional Model and the NERC Glossary of Terms Used in Reliability Standards. This project is designed to address these comments and make the definitions of functional entities consistent between the Functional Model and the NERC Glossary of Terms Used in Reliability Standards.	0	0	29.2	33.3	33.3	0	0	0	10	Foundational piece of ERO	**29.2**	**41**	**0**	**10**	35	28	39	25
Project 2012-03 PRC-004 VSLs	37 - Update VSLs to address the situation where Corrective Action Plans were developed or documented, but not fully implemented. PRC-004.	0	0	0	25	50	0	8.3	0			**0**	**0**	**0**	**8.3**	45	45	45	26
Project 2007-02 Operating Personnel Communications Protocols (ACTIVE)	3 - Requires developing new requirements in support of blackout recommendation #26 to ensure that real-time system operators use standard communication protocols during normal and emergency operations. COM-003.	50	75	70.8	25	25	5	4.2	0			**195.8**	**74**	**94**	**4.2**	5	1	2	27
Project 2010-16 Definition of System Operator	33 - Refine definition of "System Operator" to exclude the Generator Operator, as all other "System Operators" have a more wide-area view.	0	8.3	25	33.3	37.5	0	4.2	0			**33.3**	**41**	**0**	**4.2**	34	27	38	28
Project 2012-08 Glossary Updates	42 - Per FERC Order 693, define Bulk Power System, Reliability Standard, and Reliable Operation. Modify definition of Generator Operator and Transmission Operator.	0	0	0	75	75	0	4.2	0			**0**	**0**	**0**	**4.2**	46	46	46	29
Project 2010-03 Modeling Data	23 - Requires merging, upgrading and expanding existing requirements for entities to provide data used to model the bulk electric system. Related to Blackout recommendation and Modeling Initiative. MOD-010 thru -015.	0	41.7	45.8	33.3	33.3	5	0	0			**87.5**	**55**	**94**	**0**	27	14	11	30

NERC Standards Committee
Project Prioritization Worksheet

STANDARDS COMMITTEE Reliability Standard Project Prioritization		(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	PRACTICALITY SORT							
Project Number and Name	Short Description	Addresses an ERO Strategic Priority (to be completed by NERC Staff) 50 = Yes 0 = No	Addresses a reliability risk not covered by an existing standard 100 = Severe risk 75 = High risk 50 = Moderate risk 25 = Low risk 0 = N/A	Improves one or more existing standards: 100 = Significantly 75 = Moderately 50 = Incrementally 25 = Minimally 0 = N/A	Cost of Implementation The cost of complying with the standard is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	Cost of Administration The cost to demonstrate and verify compliance is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	Time Sensitivity (to be competed by NERC Staff) Number of months until due date, if any	Addresses compliance issues from NERC Staff or Stakeholders 50 =Significant issues 25 = Moderate issues 10 = Minimal issues 0 = N/A	Addresses a failed interpretation or SDT inability to develop an interpretation related to a lack of clarity that is 50 = Significant 25 = Moderate 10 = Minimal 0 = N/A	Other Practicality Concern (Explanation for the rating must be indicated in the column to the right) (0 to 50)	Explanation	Reliability Score (0 - 250)	Cost Consideration Score (0 - 100)	Time Sensitivity Score (0 - 100)	Practicality Score (0 - 150)	Reliability Ranking	Cost Consideration Ranking	Time Sensitivity Ranking	Practicality Ranking
Project 2010-04 Demand Data	24 - As envisioned, this project will result in two standards — with MOD-016 through MOD-020 being merged into a single standard, and MOD-021 remaining as a separate standard. The requirements need to be more specific to clearly identify the format, etc., for providing data.	0	0	50	18.8	18.8	5	0	0			**50**	**53**	**94**	**0**	33	16	13	31
Project 2008-02 Undervoltage Load Shedding	12 - Consider consolidating PRC-010-0 (Assessment of the Design and Effectiveness of UVLS Program) and (PRC-022-1 — Under-Voltage Load Shedding Program Performance). Currently missing are any criteria for identifying where UVLS should be installed. The team will utilize the FIDVR (Fault-Induced Delayed Voltage Recovery) Technical Reference Paper in the development of requirements. Related to System Protection Initiative.	50	29.2	70.8	83.3	50	5	0	0			**150**	**42**	**94**	**0**	14	24	19	32
Project 2010-02 Connecting New Facilities to the Grid	22 - Ensure that all of the elements that should be addressed when a new facility is connected to the grid are included in the revised standard. FAC-001 and -002.	0	0	25	33.3	33.3	5	0	0			**25**	**40**	**94**	**0**	36	30	21	33
Project 2010-13.2 Phase 2 of Relay Loadability: Generation (INFORMAL)	29 - Draft new standard PRC-025-1 Generator Relay Loadability in compliance with the FERC Order 733 issued March 18, 2010. Related to System Protection Initiative.	50	29.2	50	62.5	50	12	0	0			**129.2**	**42**	**82**	**0**	21	26	24	34
Project 2012-11 FAC Review	44 - 5-Year Review of FAC-010, -011, -014.	0	0	0	50	50	27	0	0			**0**	**0**	**57**	**0**	40	40	26	35
Project 2012-13 NUC Review	46 - 5-Year Review of NUC-001.	0	0	0	25	25	39	0	0			**0**	**0**	**37**	**0**	43	43	28	36
Project 2012-12 PER Review	45 - 5-Year Review of PER-003, -004 and -005.	0	0	0	50	50	49	0	0			**0**	**0**	**20**	**0**	44	44	30	37
Project 2012-06 Generator Capabilities	40 - For all synchronous generators, specify minimum droop settings and frequency response performance. Require proven voltage support and reactive response to a specific level. Related to Frequency Response Initiative. Related to BAL-003 and the Continent Wide Reserve Policy. New standard(s).	50	50	91.7	62.5	37.5	0	0	0			**191.7**	**60**	**0**	**0**	6	8	34	38
Project 2012-04 Protection System Commissioning Testing	38 - Establish minimum level of required commissioning testing prior to putting protection systems into service. Related to System Protection Initiative. New standard(s).	50	50	70.8	41.7	50	0	0	0			**170.8**	**57**	**0**	**0**	9	9	35	39
Project 2009-04 Phasor Measurements	18 - Supports a blackout recommendation. Several industry studies were issued that need to be analyzed to determine appropriate requirements for a NERC standard. Related to North-American Synchro-Phasor Initiative. New standard(s).	0	66.7	0	50	33.3	0	0	0			**66.7**	**46**	**0**	**0**	30	23	36	40
Project 2010-01 Support Personnel Training	21 - Require the use of a systematic approach to determining training needs of generator operators and operations planning and support staff with a direct impact on the reliable operations of the bulk power system. New standard(s).	50	45.8	50	85	41.7	0	0	0			**145.8**	**42**	**0**	**0**	15	25	37	41
Project 2009-05 Resource Adequacy Assessments	19 - Implements recommendations from the Resource and Transmission Adequacy Task Force (RTATF) Report and the Gas/Electricity Interdependency Task Force Report, approved by the NERC Board on June 15, 2004, related to resource adequacy. New standard(s).	50	8.3	0	33.3	25	0	0	0			**58.3**	**38**	**0**	**0**	31	33	40	42
Project 2012-01 Equipment Monitoring and Diagnostic Devices	35 - Consider the development of reliability standards for the application of major equipment monitoring and diagnostic devices and procedures. New standard(s).	0	25	70.8	87.5	62.5	0	0	0			**95.8**	**36**	**0**	**0**	25	34	41	43
Project 2012-02 Physical Protection	36 - Consider the development of reliability standards for the safety and protection of essential equipment, buildings and people located in power generation, transmission, or distribution system locations in order to mitigate the associated reliability risks to the bulk power system. New standard(s).	0	45.8	8.3	91.7	83.3	0	0	0			**54.1**	**20**	**0**	**0**	32	37	42	44
Project 2012-14 Risk Analysis	47 - Require entities to have and maintain a checklist of potential threats to the power system that must be addressed by each TOP/BA. The checklist should include things like GMD, voltage collapse, and other extreme events. New standard(s).	0	25	0	100	50	0	0	0			**25**	**19**	**0**	**0**	37	38	43	45
Project 2012-07 Obsolescence Review	41 - Require all TOs and GOs to periodically review their electronic, electric, mechanical, and other control systems, as well as protection systems, to replace obsolete equipment. New standard(s).	0	25	0	100	75	0	0	0			**25**	**13**	**0**	**0**	38	39	44	46
2006-06.2 Phase 2 of Reliability Coordination	NA - Address specific directives from FERC Order 693 related to reliability standard IRO-003-2 - Reliability Coordination - Wide-Area View											**0**	**0**	**0**	**0**	47	47	47	47
2012-15 Flow Limited Paths	NA - Address concerns identified with MOD-029 and its treatment of flow-limited paths.											**0**	**0**	**0**	**0**	48	48	48	48

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Committee Process for Standards Project Identification, Prioritization, and Monitoring

to ensure the reliability of the bulk power system

Revised July 2011

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Objective

This document presents a Standards Committee process for identifying, prioritizing, and monitoring NERC standards development projects, taking into account the various drivers for project initiation and the industry's resource constraints. The process provides the flexibility to accommodate new projects and to adjust project priority and completion schedule in response to changing conditions.

Changes in this Revision

When first used in developing the 2011-2013 Reliability Standard Development Plan (RSDP), the Standards Committee solicited feedback on the use of this tool. Stakeholders submitted several comments and suggestions that the Standards Committee deferred until the development of this revision. In response to those comments and suggestions, as well as other feedback received during the development of this revision, the Standards Committee made the following changes:

- Elimination of the perceived duplication between the process of assigning a score based on the number and type of regulatory directives assigned (previously column G) and the process of assigning scores for "Reliability Gap" (previously column H) and "Reliability Improvement" (previously column I). Some concern has been expressed that ranking the priority of directives assigned to a project based on their reliability impact and then additionally rating a project on its reliability impact was "double counting."
- Addition of a score to account for projects that address ERO Strategic Priorities
- Consolidation of all deadlines (regulatory directive based (previously column F), 5-year review based (column K), or otherwise) into one single new "Time Sensitivity" score. While previously, the Standards Committee felt that time limits derived from directives should be given special consideration, further discussion has led to the questioning of that assertion. Instead, all time limits will be considered, and the Standards Committee may elect to use its judgment to make additional modifications to project prioritization results based on specific knowledge or situations.
- Elimination of the "Project Percent Complete" (previously column N) evaluation
- Addition of two preliminary "cost" considerations
- Modification of the scoring mechanism, such that the "total" score is now the sum of the four subject area scores. In two cases, subject matter scores are no longer simple summations, but instead are determined based on slightly more complex equations.
- The ability to rank projects based on different factors (Reliability, Cost Considerations, Time Sensitivity, Practicality, or all factors combined)

Background

Since the startup of the ERO, the number of standards development projects has been significant. Coupled with the increasing number of requests for interpretations and directives issued by regulatory authorities, the industry has experienced a rapid and sustained increase in standards development related workload. The standards development process allows for any individual to propose a new project or request an interpretation. While the Standards Committee can exercise its discretion to delay the start of any project to cope with increased workload and to better manage standard projects to achieve timely completion, additional flexibility beyond just withholding the start of a project is needed.

At its April 2010 meeting, the NERC Standards Committee endorsed a proposal to develop a structured process to assist in managing standards development projects from the project planning stage through submission of a completed standard to the NERC Board of Trustees. The process outlined in this document takes into account industry resource constraints and changing conditions as new projects emerge and as issues are encountered during the course of standard development. It is expected that this process will occur on an annual basis. Projects that are requested mid-cycle will be scored and evaluated as described in Section 7.

1. **Identifying the List of Standards Projects**

   In general, standard projects may be initiated for a variety of reasons, including:

   a. **To meet a deadline.** These deadlines may include the five-year standard revision cycle requirement, regulatory-imposed deadlines, or other time-based commitments.

   b. **To address a Reliability Need** — Industry participants, regulators, NERC staff or the Board of Trustees identify the need for a new standard or revision to an existing standard to meet a reliability need or fill a reliability gap

   c. **To address practical implementation issues.**— Industry participants, NERC and Regional Entity staff identify quality and clarity gaps in NERC's existing reliability standards that need to be remedied to ensure consistent industry compliance. These may be indentified through compliance, through the need for interpretations, or through other means (for example, Regional Entities and stakeholders may propose continent-wide NERC standards that will avoid the need to develop regional standards which will be phased out when the NERC standards are put in place).

   The list of standards projects will include all current projects, all projects in informal development, and all new projects that have yet to be initiated.

   Although any stakeholder can submit a Standards Authorization Request at any time, NERC will generally solicit project candidates for a fixed period of time prior to beginning its annual prioritization. Requests received outside that window of time will be considered for prioritization either at the next annual prioritization or on a case by case basis.

2. **Identifying NERC Project Capacity**

NERC is only able to manage a finite number of projects at a given point in time, due to the limitations of both staff and industry resources. In general, NERC can accommodate 10-12 projects on an ongoing basis. Because some projects are more complex than others, NERC's Standards Committee will work with NERC staff to determine the total capacity for NERC Standards Development. NERC staff will remain responsible for the actual assignment of staff resources to projects.

3. **Identifying the Project Portfolio Mix**

Because there are many legitimate reasons for initiating projects, a simple ranking based on priorities is not sufficient. Although focusing on those projects with the greatest reliability need is important, it does not recognize the practical considerations or the time sensitivity of each project. For example, a project with a low reliability impact may nonetheless be associated with a regulatory imposed deadline; or a project may not directly improve reliability, but make a standard much easier to comprehend and implement successfully.

To address this, the Standards Committee allocates Project Capacity to three programs within the Standards Development portfolio: Time Sensitive projects, Practicality projects, and Reliability projects. This allocation is determined by the Standards Committee each year as the Reliability Standards Development Plan is being drafted. For example, assuming that the SC will pursue a total of 12 projects in 2012, this could result in capacity being allocated for three Time-sensitive projects, three Practicality projects, and six Reliability projects.

4. **Evaluating Each Project**

Each project identified will be evaluated in several areas. Members of the Standards Committee will provide the majority of the evaluation data, while NERC staff will only provide information regarding Time-Sensitivity and alignment with ERO Strategic Priorities (columns E and J in Attachment A).

Each representative on the Standards Committee will provide their recommendations for the values assigned to specific areas of each project. NERC will then aggregate and analyze this information and present it to the Standards Committee for review. In general, the arithmetic mean of all Standards Committee input will be used to set the "score" to be used in the prioritization. So if three members selected 50, 75, and 100 out of a possible total 100, the arithmetic mean would be 75.

However, in those cases where significant disagreement is noted between Standards Committee members, further discussion will occur among the Standards Committee to determine if additional changes should be considered. "Significant" disagreement shall be defined as more than 50% of the Standards Committee members participating having scores that are different from the mean by more than 30% of the maximum value for that particular score. So for example, if three members selected 0, 50, and 100, the mean would be 50. However, 66% (two) of the members would have chosen values that were different from the mean by more than 30% (50 points), so further discussion would be required to reconcile the difference.

5. **Determining Cost Considerations**
As a first step, all projects will be evaluated for cost considerations. This is accomplished by comparing the "reliability" value to the "cost" value. The calculation of this value is explained in Attachment A's explanation of Column P.

Cost is measured in two areas – the cost to the industry to comply with the standard, and the cost to the industry to demonstrate compliance with the standard. The first area should be focused on the incremental upgrades and investments needed to meet the standard (e.g., equipment purchases, software upgrades, training), while the second area should consider the cost of retaining data and documents, auditing and audit preparation, and reporting.

Projects with a score of less than 50 will generally having a lower benefit relative to cost. When contemplating projects for the Reliability Program area, those with a lower benefit should be carefully considered prior to being initiated. However, a lower benefit should generally not by itself preclude a project from consideration.

6. **Determining Projects for Each Program**
For each of the three portfolio program areas (Time Sensitive, Reliability, or Practicality), the Standards Committee will prioritize the list of projects and assign the top priority projects to the programs until program capacity is eliminated.

Following this, the Standards Committee will review any projects that are in progress but are not currently assigned to one of the three portfolio programs. In general, the Standards Committee will displace lower priority projects within the program with projects currently in progress – effectively "filling" the programs with active work before adding new work. However, the Standards Committee may, if it so chooses, halt an existing project in order to move a project that it deems more critical forward.

Next, the Standards Committee will review project interdependencies. If a high-priority project is expected to move forward, and relies on a lower-priority project for completion, then that lower-priority project should displace a higher-priority project to ensure the dependency is honored.

Finally, the Standards Committee will eliminate any duplicate projects that appear in more than one program. The Standards Committee shall make the determination regarding in which program a project should reside. As these duplicate projects are eliminated, other projects may return or be added to the program.

Additionally, the Prioritization will develop a list of potential projects for further research and planning. This list of potential projects will be brought to the Standing Committees for their assistance such that they may be considered in the following year for initiation.

7. **Adding New Projects Intra-year and Adjusting Project Priority**

When a new project emerges and is evaluated outside the annual prioritization, the resulting point scores may indicate that the new project should have priorities higher than other projects currently under active development. It is generally assumed that ongoing projects should have highest priority and should continue development work regardless of other projects' emergence. However, both emerging reliability issues and regulatory directives may lead the Standards Committee to direct that one or more projects that are currently assigned to a program be put on hold until resources become available and development work can be restarted.

The Standards Committee will decide if any of the ongoing projects should be stopped or deferred and advise the respective Standard Drafting Teams (SDTs) accordingly, or develop other remedial actions to launch the new projects and continue with all ongoing projects. If it determines that none of the ongoing projects should be stopped and the new projects should be launched, but no resource relief can be provided, the Standards Committee will bring the situation, along with options and recommendations, to the Board of Trustees for its attention and direction.

8. **Developing Projects Schedules**

The time required to complete a standard development project varies from one project to another depending on the scope of work and the complexity of the issues to be addressed. While the SAR proponents generally have a good grasp of the time required to complete a standard project from the formation of the SDT to balloting, the SDT itself may have more intimate knowledge of the technical issues involved and hence a better feel of the time needed to complete its assigned project. Further, since SDT members are industry volunteers that are committed to their projects, it is desirable and appropriate that the SDTs provide inputs into their project schedules and milestone events.

In general, NERC staff together with the Standards Committee will develop an initial project schedule based on past experience, complexity of the standards and other considerations such as available expertise, compliance deadlines, etc. Then, the SDT will be given the opportunity to review and adjust the project schedule at its initial meetings, and present a revised schedule, if necessary, to the Standards Committee for consideration. Once approved by the Standards Committee, the SDT will take ownership of the project and its schedule, and monitor and report project progress to the Standards Committee on an as-needed basis.

9. **Monitoring Projects**

The SDTs are responsible for monitoring all milestone events and completion schedules for their assigned projects. If at any time the milestone dates for a project are expected to be missed, the responsible SDT should report to the Standards Committee, and present options to put the project back on schedule or request accepting delays with supporting rationale. Where necessary, the SDT may seek the Standards Committee's endorsement or advice for other remedial actions including additional resource support, resolution of contentious issues, accepting an extension of the project schedule, or other actions deemed appropriate.

Such reporting should be made at least two months prior to a milestone date in danger of being missed, and at least four months prior to the scheduled completion date (end of re-circulation balloting) that is in danger of being missed. The Standards Committee will act upon receiving a report from the SDT of potential slippage. In its deliberation, it will assess impacts of implementing any remedial actions on the status of other ongoing or pending projects.

From time to time, the Standards Committee may request the Chair or a representative of an SDT to report on the progress of a project even though there is no indication of a potential slippage.

10. **Project Identification, Prioritization and Management Flow Diagram**
A flow diagram showing the process described in 1 to 9 is shown below.

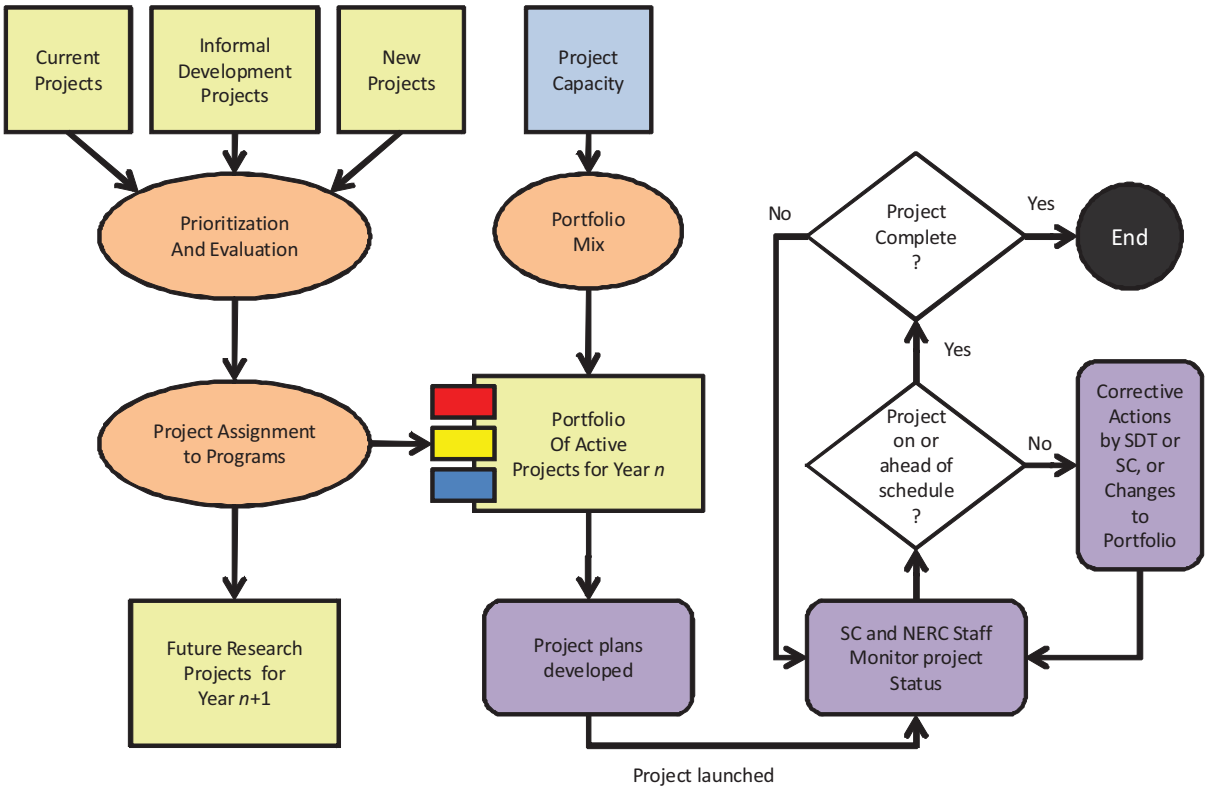

Attachment A – Project Prioritization Tool Details

Below is a detailed description of the values and calculations used in the Project Prioritization Tool.

Rows

Row 1 Contains general information and macro buttons.

The ***"Sort"*** macro buttons simply sorts rows 3 through 250 in descending order of the associated column and re-establishes the rankings listed in columns B, T, U, V, W, and X as appropriate.

The ***Click Here to Insert a Row*** macro button shifts all existing data down one row to insert a blank row in row 3. Data will then need to be entered into the new row.

Row 2 Contains the column headers.

Columns

Column A Blank.

Column B ***Priority Number:*** The relative ranking or each project as a result of the most recent "Total" Sort performed.

Column C ***Project Number and Name***

Column D ***Short Description*** (of the Project)

Column E ***Addresses an ERO Strategic Priority***. If the project is expected to aid in meeting one of the ERO's identified strategic priorities, then 50 points are added to the project reliability score. This value is assigned by NERC staff, and is used to calculate the **Reliability Score.**

Column F ***Addresses a reliability risk not covered by an existing standard.*** This value is subjective in nature, and will be determined based on the consensus of the Standards Committee. In general, this value is intended to capture "gaps" in the reliability standards, and should consider factors such as how the project relates to instability, separation, or a cascading sequence of failures; how it relates to an adequate level of reliability; and how wide the impact of the project is. A "*Fill-in-the-blank"* standard would be one possible example of a "gap." This value is used to calculate the **Reliability Score.** It is also used with Columns G, H, and I in the calculation used to determine the **Cost Consideration Score.**

100 = Severe risk

75 = High risk

50 = Moderate risk

25 = Low risk

0 = N/A

Column G ***Improves one or more existing standards.*** This value is subjective in nature, and will be determined based on the consensus of the Standards Committee. In general, this value is intended to capture ways of improving the effectiveness of existing standards to provide improved reliability, such as raising the minimum level of compliance or adding additional requirements. This value is used to calculate the **Reliability Score.** It is also used with Columns F, H, and I in the calculation used to determine the **Cost Consideration Score.** The project is expected to improve reliability:

100 = Significantly

75 = Moderately

50 = Incrementally

25 = Minimally

0 = N/A

Column H ***Cost of Implementation.*** This value is subjective in nature, and will be determined based on the consensus of the Standards Committee. This value is used with Columns F, G, and I in the calculation of the **Cost Consideration Score,** and should consider such items as equipment purchases or upgrades, training, and similar costs. In other words, what would it cost the industry to become compliant with the standard? When considered in aggregate, the cost of complying with the standard is expected to be:

100 = Very high

75 = High

50 = Average

25 = Low

0 = Very Low

Column I ***Cost of Administration.*** This value is subjective in nature, and will be determined based on the consensus of the Standards Committee. This value is used with Columns F, G, and H in the calculation of the **Cost Consideration Score,** and should consider things such as the cost to retain data, the cost to document, and the cost of compliance staff evaluating data. In other words, what would it cost the industry (including applicable entities, regions, and NERC) to prove that the standard is being complied with? When considered in aggregate, the cost to demonstrate and verify compliance is expected to be:

100 = Very high

75 = High

50 = Average

25 = Low

0 = Very Low

Column J ***Time Sensitivity.*** Number of months until due date, if any, from the time the prioritization is effective. For example, in 2012, this should be the number of months from January 2012 to the due date. This value is assigned by NERC staff, and is used to calculate the **Time Sensitivity Score.** 0 indicates no deadline exists within the subsequent 60 months.

Column K ***Addresses compliance issues from NERC Staff or Stakeholders.*** This value is subjective in nature, and will be determined based on the consensus of the Standards Committee. For example, if Compliance had idenfied a frequently violated standard, or standards for which one or more CAN's had been developed, or standard which has been identified by stakeholders as being difficult to comprehend. This value is used to calculate the **Practicality Score.**

50 =Significant issues

25 = Moderate issues

10 = Minimal issues

0 = N/A

Column L ***Addresses a failed interpretation or SDT inability to develop an interpretation.*** This value is subjective in nature, and will be determined based on the consensus of the Standards Committee. This value is used to calculate the **Practicality Score.** The interpretation is needed to address a lack of clarity that is:

50 = Significant

25 = Moderate

10 = Minimal

0 = N/A

Column M ***Other Practicality Concern.*** This value is subjective in nature, and will be determined based on the consensus of the Standards Committee. An example of a project that would have points assigned here is the Vegetation Management project because of it being used at the prototype results based standard. Additional considerations would be the breadth of impact to registered entities, projects with active field trials, the length of time project has been in the queue, and projects that clarify a standard or delete redundant requirements. Addressing "*Fill-in-the-blank"* standard would be another area where practicality might drive a need to develop a standard by eliminating the potential for duplicate work among the regions. Between 0 and 50. This value is used to calculate the **Practicality Score**, and must be accompanied by an explanation of the relative value provided in Column N.

Column N ***Explanation:*** the explanation of the value set in column M.

Column O ***Reliability Score.*** The sum of columns E, F, and G. Between 0 and 250.

Column P ***Cost Consideration Score.*** Calculated based on the sum of columns F and G less the sum of the columns H and I, then scaled to produce a value between 0 and 100. Projects with no reliability benefit are automatically scored as 0.

Column Q ***Time Sensitivity Score.*** Calculated by dividing the number of months in column J by sixty, subtracting that value from one, and then multiplying by 100 and rounding. If the number of months is zero or greater than 60, then the score is set at 0. This results in projects with a closer deadline having a higher priority.

Column R ***Practicality Score.*** The sum of columns K, L, and M. Between 0 and 150.

Column S ***Total Score.*** The sum of the **Reliability Score, Cost Consideration Score, Time Sensitivity Score,** and **Practicality Score.** Based on total scores, results in a weighted score with approximately the following distribution of weights:

Reliability 41.6%
Cost Consideration 16.7%
Time Sensitivity 16.7%
Practicality 25%

Columns T-X ***Rankings.*** The numbers show the rankings for each area, and color codes the cells based on the following:

- The top *n* projects, where *n* is the number at the top of the column for columns U, W, and X
- All projects with a Cost Consideration Score greater than or equal to *n*, where *n* is the number at the top of column V.

Appendix 2 – Work Plan

The following page shows the schedule of work in Gantt chart format. Projects for which the Standing Committees will be asked to provide research are identified with blue Gantt chart bars, and have been tentatively allocated a year duration for research (pending feedback from the Standing Committees).

Following the Prioritization, the Work Plan is the next step in the creation of the Reliability Standards Development Plan. It is used primarily to identify project predecessors and ensure resource allocations are consistent and manageable. Once complete, it identifies the estimated start and completion of all projects over the three-year period.

ID	Task Name
1	**Reliability Projects: 8 Slots**
2	**Project 2008-06 Cyber Security - Order 706 (ACTIVE)**
3	**Project 2007-17 Protection System Maintenance & Testing (ACTIVE)**
4	**Project 2007-02 Operating Personnel Communications Protocols (ACTIVE)**
5	**Project 2007-06 System Protection Coordination (ACTIVE)**
6	**Project 2009-01 Disturbance and Sabotage Reporting (ACTIVE)**
7	**Project 2010-05.1 Phase 1 of Protection Systems: Misoperations (ACTIVE)**
8	**Project 2006-06 Reliability Coordination (ACTIVE)**
9	**Project 2007-09 Generator Verification (ACTIVE)**
10	***Project 2012-04 Protection System Commissioning Testing***
11	Standing Committee Research
12	Standards Development
13	Project 2008-02 Undervoltage Load Shedding
14	**Project 2010-05.2 Phase 2 of Protections Systems: SPS and RAS**
15	Standing Committee Research
16	Standards Development
17	**Project 2010-01 Support Personnel Training**
18	Standing Committee Research
19	Standards Development
20	Project 2009-03 Emergency Operations (INFORMAL)
21	**Project 2012-06 Generator Capabilities**
22	Standing Committee Research
23	Standards Development
24	**Project 2009-07 Reliability of Protection Systems**
25	Standing Committee Research
26	Standards Development
27	**Project 2012-01 Equipment Monitoring and Diagnostic Devices**
28	Standing Committee Research
29	Standards Development
30	**Project 2009-04 Phasor Measurements**
31	Standing Committee Research
32	Standards Development
33	Project 2009-05 Resource Adequacy Assessments
34	Project 2010-16 Definition of System Operator
35	Project 2010-08 Functional Model Glossary Revisions
36	**Project 2010-13.3 Phase 3 of Relay Loadability: Stable Power Swings**
37	Standing Committee Research
38	Standards Development
39	**Time-Sensitive Projects - 3 Slots**
40	**Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Control: Reserves (ACTIVE)**
41	**Project 2010-17 Definition of BES (ACTIVE)**
42	**Project 2007-12 Frequency Response (ACTIVE)**
43	Project 2010-13.2 Phase 2 of Relay Loadability: Generation (INFORMAL)
44	Project 2008-01 Voltage and Reactive Planning and Control (INFORMAL)
45	Project 2007-11 Disturbance Monitoring (INFORMAL)
46	**Project 2010-03 Modeling Data**
47	Standing Committee Research
48	Standards Development
49	**Project 2010-04 Demand Data**
50	Standing Committee Research
51	Standards Development
52	**Project 2010-02 Connecting New Facilities to the Grid**
53	Standing Committee Research
54	Standards Development
55	**Practicality Projects - 2 Slots**
56	**Project 2010-07 Transmission Requirements at the Generator Interface (ACTIVE)**
57	**Project 2007-03 Real-time Transmission Operations (ACTIVE)**
58	Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities (INFORMAL)
59	Project 2008-12 Coordinate Interchange Standards (INFORMAL)
60	Project 2010-14.2 Phase 2 of Balancing Authority Reliability-based Control: Time Error, AGC, and Inadvertent (INFORMAL)
61	Project 2012-05 ATC-Revisions - Order 729
62	**Excess Beyond Capacity for 2012-2014**
63	**Project 2007-07 Vegetation Management (ACTIVE)**
64	Project 2012-02 Physical Protection
65	Project 2012-03 PRC-004 VSLs
66	Project 2012-08 Glossary Updates
67	Project 2012-07 Obsolescence Review
68	Project 2012-09 IRO Review
69	Project 2012-11 FAC Review
70	Project 2012-12 PER Review
71	Project 2012-13 NUC Review
72	Project 2012-14 Risk Analysis
73	*2006-06.2 Phase 2 of Reliability Coordination*
74	*2012-15 Flow Limited Paths*

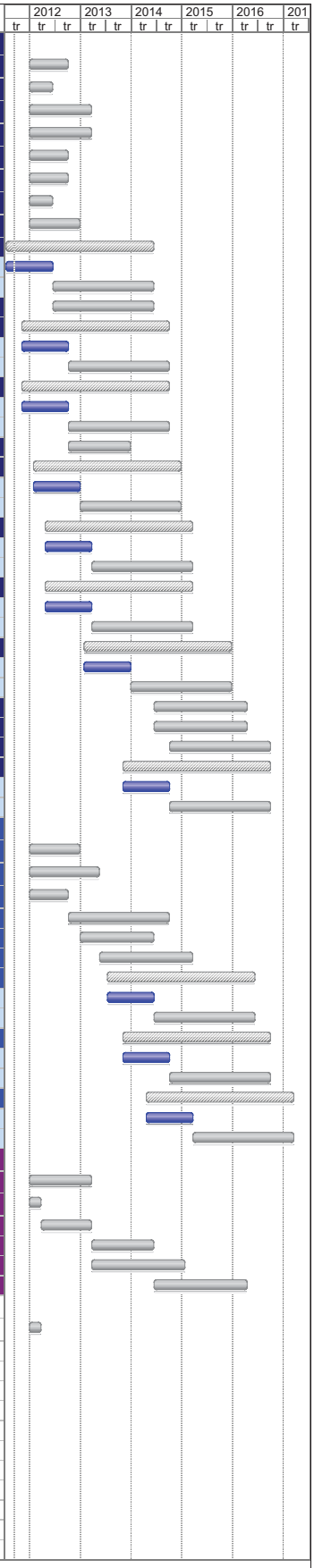

Appendix 3 – Project Summaries

The following are detailed summaries of the projects discussed earlier within this plan.

DEVELOPMENT 2012

Project 2006-06 Reliability Coordination

Summary:

This project ensures that the reliability-related requirements applicable to the Reliability Coordinator are clear, measurable, unique and enforceable, and that this set of requirements is sufficient to maintain reliability of the Bulk Electric System. Most of the requirements in this set of standards were translated from Operating Policies as part of the Version 0 process. There have been suggestions for improving these requirements, and the drafting team is considering comments submitted by stakeholders, drafting teams and FERC in determining what changes should be proposed. The drafting team is reviewing all of the requirements in this set of standards and making a determination whether to:

- Modify the requirement to improve clarity and measurability while removing ambiguity
- Move the requirement (into another project or Standard, or to the certification process)
- Eliminate the requirement (because it is redundant or doesn't support BPS reliability).

Standards affected:

COM-001, COM-002, IRO-001- IRO-002, IRO-005, IRO-014, IRO-015, IRO-016

Status:

This project's SAR was finalized on May 2, 2007. The draft standards have been posted several times. The NERC Board of Trustees adopted IRO-002-3, IRO-005-4 and IRO-014-2, along with a conforming change to IRO-001-1.1 associated with IRO-014-2 (creating IRO-001-2) on August 4, 2011. The Board also approved the retirement of IRO-015-1 and IRO-016-1. The drafting team is continuing development on COM-001-2, COM-002-3, and additional revisions to IRO-001, which will become IRO-001-3. It is estimated this project will complete in Q2 2012.

FUTURE CONSIDERATION

Project 2006.06.2 Phase 2 of Reliability Coordination: IRO-003

Summary:

This project will address directives from Order 693 related to the inclusion of measures in IRO-003 and the determination of "critical facilities."

Standards affected:

IRO-003

Status:

A SAR was developed and was finalized on July 14, 2010. However, no additional work has occurred for this project at this time. At this time, no estimate for starting the project has been identified.

DEVELOPMENT 2012

Project 2007-02 Operating Personnel Communication Protocols

Summary:

This project is reviewing COM-003 to ensure the standard is complete, appropriately scoped, and enforceable. The project is also considering other general improvements and stakeholder comments received during the initial development of the standards, as well as other comments received from Electric Reliability Organization (ERO) regulatory authorities. This also satisfies the NERC requirement for five-year review of the standard.

This standard will require the use of specific communication protocols, especially for communications during alerts and emergencies. The standard will be applicable to transmission operators, balancing authorities, reliability coordinators, generator operators and distribution providers. Requirements will include protocols for communicating changes to realtime operating states and protocols for issuing and responding to operating directives.

Standards affected:

COM-003

Status:

This project's SAR was finalized on June 8, 2007. A draft standard was posted November 20, 2009 through January 15, 2010. Subsequently, this team was put on hold for an extended period of time. The project was restarted in 2011, and the team is reviewing comments and preparing to post a new version of the standard. It is estimated this project will complete in Q1 2013.

DEVELOPMENT 2012

Project 2007-03 Real-time Transmission Operations

Summary:

This project is clarifying requirements for real-time operations of the Bulk Electric System in the several standards, as well as providing other general improvements. It will consider stakeholder comments received during the initial development of the standards, as well as and other comments received from ERO regulatory authorities. This also satisfies the NERC requirement for five-year review of the standards.

Standards affected:

PER-001, TOP-001, TOP-002, TOP-003, TOP-004, TOP-004, TOP-005¸ TOP-006, TOP-007, TOP-008

Status:

This project's SAR was finalized November 1, 2007. The standards have been posted several times for public comment. The standards were most recently posted for Initial Ballot from May 31, 2011 through June 9, 2011. It is estimated this project will complete in Q1 2012.

DEVELOPMENT 2012

Project 2007-06 System Protection Coordination

Summary:

This project is reviewing PRC-001-1 to assure that Protection System application and performance issues are coordinated among all related entities. It will ensure the applicable entities within the standard correctly reflect the functional responsibilities, as described in the NERC Functional Model. The project will also incorporate other general improvements, address directives received from ERO regulatory authorities, and consider the observations and recommendations developed by the NERC SPCTF. As necessary, the project will coordinate the transfer of monitoring-related requirements to appropriate other standards through coordination with project 2006-06 Reliability Coordination.

Standards affected:

PRC-001, PRC-027 (New)

Status:

This project's SAR was finalized on July 27, 2007. A draft standard was posted from September 9, 2009 through October 26, 2009. Several interim drafts have been developed since that time. A new results-based version of the standard is in development. It is estimated this project will complete in Q1 2013.

DEVELOPMENT 2012

Project 2007-07 Vegetation Management

Summary:

This project will address some 'fill-in-the-blank' components of the existing standard, wchih were created in 2006 (prior to mandatory and enforceable standards). The project also will investigate applicability to lower voltae transmission lines, address the issue of clearances for lines on both federal and non-federal lands, consider revising the definition of right of way to encompass required clearance areas, and review the suitability of the IEEE 516-2003 standard for minimum vegetation clearance. This also satisfies the NERC requirement for five-year review of the standard.

Standards affected:

FAC-003

Status:

This project's SAR was finalized June 27, 2007. The standards have been posted several times for public comment. The standards were most recently posted for Successive Ballot from February 18, 2011 through February 28, 2011. The team has drafted a revised standard and has requested it be posted for Recirculation Ballot. It is estimated this project will complete in Q1 2012.

DEVELOPMENT 2012

Project 2007-09 Generator Verification

Summary:

This project will create or modify standards to ensure that generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator protective relays and generator voltage regulator controls and limit functions. It will also ensure that generator models accurately reflect the generator's capabilities and operating characteristics.

Standards affected:

MOD-024, MOD-025, MOD-026, MOD-027, PRC-019, PRC-024

Status:

This project's SAR was finalized June 14, 2007. The standards have been posted several times for public comment. Two of the standards were most recently posted for Initial Ballot from July 22, 2011 through August 1, 2011. Three other standards were posted for comment June 12, 2011 through July 15, 2011. It is estimated this project will complete in Q4 2012.

PENDING 2013

Project 2007-11 Disturbance Monitoring

Summary:

Purpose

This project establishes and clarifies requirements for the installation of Disturbance Monitoring Equipment (DME) and reporting of disturbance data to facilitate analyses of events and verify system models. The project will review PRC-002 and each of the current regional programs developed in accordance with that standard, including any other associated programs and/or requirements related to or contained with the disturbance monitoring program documentation. The project will then determine which requirements should be continent-wide requirements and which requirements should be included in regional standards.

Standards affected:

PRC-002, PRC-018

Status:

This project's SAR was finalized May 21, 2007. An initial draft standard was posted from February 2, 2009, to March 18, 2009. This project was moved to informal development in 2011. It is estimated this project will start in Q2 2013 and complete in Q1 2015.

DEVELOPMENT 2012

Project 2007-12 Frequency Response

Summary:

Purpose:
This project will modify the BAL-003 Standard to require sufficient Frequency Response from the Balancing Authority to maintain Interconnection Frequency within predefined bounds. It will also ensure the standard provides consistent methods for measuring Frequency Response and determining the Frequency Bias Setting.

Standards affected:

BAL-003

Status:

This project's SAR was finalized June 30, 2007. The standard has been posted once for public comment, and is expected to be posted for comment in Q4 of 2011. The project is expected to complete in Q2, 2012.

DEVELOPMENT 2012

Project 2007-17 Protection System Maintenance and Testing

Summary:

This project will modify the standards related to ensuring all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested. The project will respond to various FERC directives contained in Order 693, as well as make general improvements to the standard.

Standards affected:

PRC-005, PRC-008, PRC-011, PRC-017

Status:

This project's SAR was finalized May 7, 2007. The standards have been posted several times for public comment. The standards were most recently posted for Initial Ballot from September 19, 2011 through September 28, 2011. It is estimated this project will complete in Q2 2012.

PENDING 2013

Project 2008-01 Voltage and Reactive Planning and Control

Summary:

This project will revise the VAR Standards to require that appropriate functional entities develop and coordinate voltage and reactive planning and operating criteria to ensure that there are sufficient reactive resources, and voltage and reactive margins, to manage the risk of voltage instability. The project will also will address the FERC directives in Order 693 associated with these standards. Review and modifications to the existing VAR standards will also consider the Transmission Issues Subcommittee's "Reactive Support & Control Whitepaper" dated 05/18/2009.

Standards affected:

VAR-001, VAR-002

Status:

This project's SAR was finalized April of 2011. This project was moved into informal development in 2011, prior to posting any daft of the standard. It is estimated this project will begin in Q1 2013 and complete in Q2 2014.

PENDING 2012

Project 2008-02 Undervoltage Load Shedding

Summary:

This project will improve the existing standards on Under Voltage Load Shedding (UVLS) to ensure that load is shed when needed to prevent voltage collapse and voltage instability in the Bulk Electric System. The existing standards will be consolidated, and specific criteria for UVLS programs and assessments of those UVLS programs should be added. 'Fill-in-the-blank' elements should be eliminated, and concerns related to Fault-Induced Delayed Voltage Recovery' will be reviewed and addressed.

Standards affected:

PRC-010, PRC-022

Status:

This standard has a proposed SAR that was posted for comment from January 20, 2010, through February 19, 2010. It is estimated this project will start in Q3 2012 and complete in Q2 2014.

DEVELOPMENT 2012

Project 2008-06 Cyber Security – Order 706

Summary:

This project establishes standards to protect the critical cyber assets (including hardware, software, data, and communications networks) essential to the reliable operations of the bulk power system. Currently the project is focused on Version 5 of the standards, which is focused on addressing the remaining directives in Order 706.

Standards affected:

CIP-002, CIP-003, CIP-004, CIP-005, CIP-006, CIP-007, CIP-008, CIP-009, CIP-010 (New), CIP-011 (New)

Status:

This project's SAR was finalized June 9, 2008. Older versions of the standard have been posted, balloted, and approved several times. Version 5 of the standards has not yet been posted for comment. It is estimated this project will complete in Q3 2012.

PENDING 2013

Project 2008-12 Coordinate Interchange Standards

Summary:

This project will revise the set of Coordinate Interchange standards to ensure that each requirement is assigned to an owner, operator or user of the bulk power system, and not to a tool used to coordinate interchange; to address the Interchange Subcommittee concerns related to the Dynamic Transfers and Pseudo-ties; and to address previously identified stakeholder comments. The project will also consider adding requirements to have backup capability for use when the interchange transaction tool fails.

Standards affected:

INT-001, INT-003, INT-004, INT-005, INT-006, INT-007, INT-008, INT-009, INT-010

Status:

This project's SAR was finalized December 1, 2008. An initial draft set of standards was developed and posted for comment from November 10, 2009 through December 9, 2009. However, the project was moved into informal development in 2011. It is estimated this project will start in Q2 2013 and complete in Q2 2014.

DEVELOPMENT 2012

Project 2009-01 Disturbance and Sabotage Reporting

Summary:

Purpose:

This project entails revisions to existing standards CIP-001-1 – Sabotage Reporting and EOP-004-1 – Disturbance Reporting. The project will eliminate redundancy and provide clarity on sabotage events. Additionally, EOP-004 will be reviewed to eliminate any 'fill-in-the-blank' components.

Standards affected:

CIP-001, EOP-004

Status:

This project's SAR was finalized August 13, 2009. The standard has been posted for comment twice, and is being prepared for Initial Ballot. It is estimated this project will complete in Q3 2012.

PENDING 2012

Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities

Summary:

This project will create new or revised standards to establish requirements for the monitoring and analysis capabilities provided to System Operators to support Real-time System Operations. The project will address availability parameters, performance metrics, and procedures for failure notification, maintenance coordination, and change management.

Standards affected:

New

Status:

This project's SAR was finalized March 31, 2010. The project team posted a White Paper created to illustrate the concepts it intends to pursue as the project unfolds. This posting solicited comments from February 16, 2011, through April 4, 2011. This project was moved to informal development in 2011. It is estimated this project will start in Q2 2012 and complete in Q1 2013.

PENDING 2012

Project 2009-03 Emergency Operations

Summary:

This project will review the EOP-001, EOP-002, and EOP-003 standards and associated interpretations to ensure the requirements are clear and unambiguous. Many of the requirements in this set of standards were translated from Operating Policies as part of the Version 0 process; suggestions for improvement have been submitted by stakeholders, other drafting teams, and FERC staff.

Standards affected:

EOP-001, EOP-002, EOP-003

Status:

This project's SAR was finalized November 5, 2010. Prior to the development of an initial draft standard, this project was moved to informal development. It is estimated this project will start in Q3 2012 and complete in Q4 2013.

2014 PENDING RESEARCH

Project 2009-04 Phasor Measurements

Summary:

This project will review several industry studies to determine if there should be phasor requirements developed for a NERC standard. This project is related to the North-American Synchro-Phasor Initiative, and supports a blackout recommendation.

Standards affected:

New

Status:

This is a new project, which will require SAR development and research. It is estimated this project will start in Q1 2014 and complete in Q4 2015.

PENDING 2014

Project 2009-05 Resource Adequacy Assessments

Summary:

This project will implement certain recommendations related to resource adequacy from the *Resource and Transmission Adequacy Task Force (RTATF) Report* and the *Gas/Electricity Interdependency Task Force Report,* approved by the NERC Board on June 15, 2004. The project will create a standard with requirements to perform resource adequacy assessments, using metrics that take into account various factors (including, but not limited to, fuel deliverability). The standard would also make the results of the assessments available to the industry, NERC, and appropriate regulatory agencies.

Standards affected:

New

Status:

This project's SAR was finalized August 17. 2007. Prior to the development of an initial draft standard, this project was moved to informal development in 2011. It is estimated this project will start in Q3 2014 and complete in Q2 2016.

2013 PENDING RESEARCH

Project 2009-07 Reliability of Protection Systems

Summary:

This project will ensure Protection Systems are designed and installed with redundancy where appropriate, such that if there were a failure to a specified component of that protection system, the failure would not prevent meeting the BES performance identified in the TPL standards.

Standards affected:

New

Status:

This project has an initial draft of a SAR which was posted for comment January 20, 2009, through February 18, 2009. Comment responses have not been prepared, and the SAR has not been finalized. It is estimated this project will start in Q1 2013 and complete in Q1 2015.

2012 PENDING RESEARCH

Project 2010-01 Support Personnel Training

Summary:

This project will develop a standard that requires the use of a systematic approach to determining training needs of generator operators and operations planning and support staff with a direct impact on the reliable operations of the bulk power system.

Standards affected:

New

Status:

This is a new project, which will require SAR development and research. It is estimated this project will start in Q3 2012 and complete in Q3 2014.

FUTURE CONSIDERATION, PENDING RESEARCH

Project 2010-02 Connecting New Facilities to the Grid

Summary:

22 - Ensure that all of the elements that should be addressed when a new facility is connected to the grid are included in the revised standard. FAC-001 and -002.

Standards affected:

FAC-001, FAC-002

Status:

This is a new project, which will require SAR development and research. It is estimated this project will start in Q2 2015 and complete in Q1 2017.

2014 PENDING RESEARCH

Project 2010-03 Modeling Data

Summary:

This project will consider merging, upgrading and expanding existing requirements for entities to provide data used to model the bulk electric system. This project is related the Modeling Initiative, and supports a blackout recommendation.

Standards affected:

MOD-010, MOD-011, MOD-012, MOD-013, MOD-014, MOD-015, PRC-013, PRC-015

Status:

This is a new project, which will require SAR development and research. It is estimated this project will start in Q3 2014 and complete in Q2 2016.

2014 PENDING RESEARCH

Project 2010-04 Demand Data

Summary:

This project will consolidate MOD-016 through MOD-020 into a single standard, with MOD-021 remaining as a separate standard. Requirements will be made be more specific to clearly identify the format for providing data, and modifications will made in support if previously received industry comments and regulatory directives.

Standards affected:

MOD-016, MOD-017, MOD-018, MOD-019, MOD-020, MOD-021

Status:

This is a new project, which will require SAR development and research. It is estimated this project will start in Q3 2014 and complete in Q3 2016.

DEVELOPMENT 2012

Project 2010-05.1 Phase 1 of Protection Systems: Misoperations

Summary:

This project addresses a key element for Bulk Electric System (BES) reliability: the correct performance of Protection Systems. Monitoring BES Protection System events to identify and correct the root causes of Misoperations will improve overall Protection System performance. The project will revise the definition of Misoperation and redraft the standard to be more clear and unambiguous.

Standards affected:

PRC-003, PRC-004

Status:

This project's SAR was finalized June 9, 2011. An initial draft of the standard was posted for comment from June 10, 2011 through July 11, 2011. A second draft is being prepared for posting and initial ballot. It is estimated this project will complete in Q3 2012.

2012 PENDING RESEARCH

Project 2010-05.2 Phase 2 of Protection Systems: SPS and RAS

Summary:

This project will moodily the current standards and definitions related to SPS/RAS Misoperations to support a good metric for measurement of Protection System performance and to ensure the reliability of the bulk power system. This project is related to the System Protection Initiative.

Standards affected:

PRC-012, PRC-014, PRC-016.

Status:

This project has a draft SAR, but it has not yet been posted for comment. It is estimated this project will start in Q4 2012 and complete in Q3 2014.

DEVELOPMENT 2012

Project 2010-07 Generator Requirements at the Transmission Interface

Summary:

This project will develop any needed changes to the Reliability Standards to provide clarity to Generator Owners and Generator Operators regarding their reliability standard obligations at the interface with the interconnected grid. The project will review standard for applicability, propose changes as necessary, and ensure that requirements that should apply to all generators, regardless of interconnection configuration, are implemented effectively.

Standards affected:

FAC-001, FAC-003, PRC-004, others as needed

Status:

This project's SAR was finalized November 30, 2010. A draft set of standards was developed and posted from June 17, 2011 through July 17, 2011. Discussion and coordination between NERC, FERC , and the members of the project team are ongoing to ensure adequate coverage of all reliability needs. It is estimated this project will complete in Q1 2013.

FUTURE CONSIDERATION

Project 2010-08 Functional Glossary Model Revisions

Summary:

This project will ensure the definitions of various functional entities between the Functional Model, the NERC Glossary of Terms, and the NERC Statement of Compliance Registration Criteria are consistent.

Standards affected:

TBD

Status:

The Functional Model Working Group (FMWG) is responding to comments received from the first posting of the SAR. It is estimated this project will start in Q4 2014 and complete in Q3 2016.

PENDING 2012

Project 2010-13.2 Phase 2 of Relay Loadability: Generation

Summary:

This project is being created in response to directives included in FERC Order 733. The project will draft a new standard to address generator relay loadability.

Standards affected:

New

Status:

This project's SAR was finalized November 1, 2010. Prior to the development of an initial draft, this project was moved to informal development in 2011. It is estimated this project will start in Q4 2012 and complete in Q3 2014.

2014 PENDING RESEARCH

Project 2010-13.3 Phase 3 of Relay Loadability: Stable Power Swings

Summary:

This project is being created in response to directives includes in FERC Order 733. The project will draft a new standard to address protective relay operations due to power swings.

Standards affected:

New

Status:

This is a new project, which will require SAR development and research. It is estimated this project will start in Q4 2014 and complete in Q3 2016.

DEVELOPMENT 2012

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves

Summary:

This project will review the standard related to Control Performance and Disturbance control, and propose modifications or new standards as necessary. This project includes the testing and analysis of the new Balancing Authority ACE Limit (BAAL) metric, as well as the development of a continent-wide reserve policy to support BAL-01, BAL-002, and BAL-003.

Standards affected:

BAL-001, BAL-002, New

Status:

This project was created by merging two existing teams. As such, there are two SARS associated with the project – one that was finalized on November 7, 2007, and one that was finalized on December 3, 2007. The combined effort was moved into informal development in 2011, but restarted to coordinate with project 2007-12 Frequency Response. It is estimated this project will complete in Q4 2012.

PENDING 2013

Project 2010-14.2 Project 2010-14.2 Phase 2 of Balancing Authority Reliability-based Control: Time Error, AGC, and Inadvertent

Summary:

This project will consider the Time Error Correction standard, AGC, standard, and Inadvertent Accounting standard to determine what changes, if any, are necessary to ensure the standards are clear and unambiguous. In some cases, the standard may no longer be necessary.

Standards affected:

BAL-004, BAL-005, BAL-006

Status:

This project is currently in informal development. Based on its priority, it has been identified in the 2012-2014 Work Plan to begin in Q2 2013 and complete in Q1 2015.

PENDING 2014

Project 2010-16 Definition of System Operator

Summary:

This project will remove the 'Generator Operator' from the current definition of System Operator. This will more accurately establish the responsibilities and expectations of the Generator Operator consistent with the current manner in which the bulk electric system is operated.

Standards affected:

TBD

Status:

A proposed SAR and revision to the definition of System Operator was posted for a 30-day formal comment period from November 3, 2010 through December 3, 2010. It is estimated this project will start in Q3 2014 and complete in Q1 2016.

DEVELOPMENT 2012

Project 2010-17 Definition of Bulk Electric System

Summary:

This project will revise the definition of Bulk Electric System (BES) to address various Federal Energy Regulatory Commissions (FERC) concerns the definition must be modified to encompass all Elements and Facilities necessary for the reliable operation and planning of the interconnected bulk power system. These concerns have been identified in FERC Order 693 issued on March 16, 2007 and in Order 743 issued on November 18, 2010 (Order 743). The project will also consider additional modifications (beyond those established in the regulatory directives) to improve clarity, to reduce ambiguity and to establish consistency across all Regions in distinguishing between BES and non-BES Elements and Facilities.

Standards affected:

Multiple

Status:

This project's SAR was finalized March 25, 2011. The draft definition has been posted twice, with the most recent posting done concurrently with an initial ballot from September 30, 2011, to October 02 2011. The first part of this project is expected to complete in Q1 of 2012. The remainder of this project is estimated to complete in Q2 2013.

2013 PENDING RESEARCH

Project 2012-01 Equipment Monitoring and Diagnostic Devices

Summary:

This project will consider the development of reliability standards for the application of major equipment monitoring and diagnostic devices and procedures, with the intent of identifying potential equipment failures prior to their occurrence. This will provide more time to address failing systems and avoid or minimize long lead times.

Standards affected:

New

Status:

This is a new project, which will require SAR development and research. It is estimated this project will start in Q2 2013 and complete in Q1 2015.

FUTURE CONSIDERATION

Project 2012-02 Physical Protection

Summary:

This project will develop standards for the safety and protection of essential equipment, buildings and people located in power generation, transmission, or distribution system locations in order to mitigate the associated reliability risks to the bulk power system.

Standards affected:

New

Status:

This is a new project, which will require SAR development and research. At this time, no estimate for starting the project has been identified.

FUTURE CONSIDERATION

Project 2012-03 PRC-004 VSLs

Summary:

This project will address a problem identified in the VSLs of PRC-004. Currently, the VSLs do not address the case where a Corrective Acton Plan was developed or documented, but not fully implemented.

Standards affected:

PRC-004

Status:

This is a new project, which will require SAR development. At this time, no estimate for starting the project has been identified.

2012 PENDING RESEARCH

Project 2012-04 Protection System Commissioning Testing

Summary:

This project will address a gap in reliability related to protection systems by creating a standard that requires commissioning testing. Improper or inadequate commissioning testing practices are a common cause of protection system Misoperation. However, the current set of approved NERC reliability standards does not address the testing of protection system equipment *before* that equipment is placed into initial service. Creating a commissioning standard would also enhance the effectiveness of the mandatory auditing program.

Standards affected:

New

Status:

This is a new project, which will require SAR development and research. It is estimated this project will start in Q2 2012 and complete in Q2 2014.

PENDING 2014

Project 2012-05 ATC Revisions - Order 729

Summary:

This project will respond to the remaining directives in Order 729.

Standards affected:

MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, MOD-030

Status:

This is a new project, which will require SAR development. It is estimated this project will start in Q3 2014 and complete in Q1 2016.

2013 PENDING RESEARCH

Project 2012-06 Generator Capabilities

Summary:

This project will develop standards to ensure generator performance. The project should consider requirements that specify governor droop, frequency response, and reactive response.

Standards affected:

New

Status:

This is a new project, which will require SAR development and research. It is estimated this project will start in Q1 2013 and complete in Q4 2014.

FUTURE CONSIDERATION

Project 2012-07 Obsolescence Review

Summary:

This project will create a standard that requires Generator and Transmission Owners periodically review their control and protection systems to identity and electronic, electrical, or mechanical devices that have become obsolete.

Standards affected:

New

Status:

This is a new project, which will require SAR development and research. At this time, no estimate for starting the project has been identified.

FUTURE CONSIDERATION

Project 2012-08 Glossary Updates

Summary:

This project will respond to FERC directives to either create or modify the following definitions: Transmission Operator, Generator Operator, Bulk Power System, Reliable Operation, and Reliability Standard.

Standards affected:

TBD

Status:

This is a new project, which will require SAR development. At this time, no estimate for starting the project has been identified.

FUTURE CONSIDERATION

Project 2012-09 IRO Review

Summary:

This project will perform the five-year review of several IRO standards, pursuant to NERC's Rules of Procedure.

Standards affected:

IRO-006, IRO-006-EAST, IRO-008, IRO-009, and IRO-010

Status:

This is a new project, which will require SAR development. At this time, no estimate for starting the project has been identified.

FUTURE CONSIDERATION

Project 2012-11 FAC Review

Summary:

This project will perform the five-year review of several FAC standards, pursuant to NERC's Rules of Procedure.

Standards affected:

FAC-010, FAC-011, FAC-014

Status:

This is a new project, which will require SAR development. At this time, no estimate for starting the project has been identified.

FUTURE CONSIDERATION

Project 2012-12 PER Review

Summary:

This project will perform the five-year review of several PER standards, pursuant to NERC's Rules of Procedure.

Standards affected:

PER-003, PER-004, PER-005

Status:

This is a new project, which will require SAR development. At this time, no estimate for starting the project has been identified.

FUTURE CONSIDERATION

Project 2012-13 NUC Review

Summary:

This project will perform the five-year review of the NUC standard, pursuant to NERC's Rules of Procedure.

Standards affected:

NUC-001

Status:

This is a new project, which will require SAR development. At this time, no estimate for starting the project has been identified.

FUTURE CONSIDERATION

Project 2012-14 Risk Analysis

Summary:

This project will develop a standard that requires entities to have and maintain a checklist of potential threats to the power system that must be addressed by each TOP/BA. The checklist would include things like GMD, voltage collapse, and other extreme events.

Standards affected:

New

Status:

This is a new project, which will require SAR development and research. At this time, no estimate for starting the project has been identified.

FUTURE CONSIDERATION

Project 2012-15 Flow Limited Paths

Summary:

The MOD-029 standard includes a provision which, if left uncorrected, could in certain scenarios result in significantly over-conservative ATC values being calculated. This project will address this problem.

Standards affected:

MOD-029

Status:

This is a new project, which will require SAR development and research. At this time, no estimate for starting the project has been identified.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form for 2012-2014 Reliability Standards Development Plan

Please **DO NOT** use this form, but use the electronic comment form to provide comments on the 2012-2014 Reliability Standards Development Plan (the Plan). The electronic comment form must be completed and submitted **by 8:00 p.m. ET, September 26, 2011**.

If you have questions please contact Andy Rodriquez or by telephone at (404) 446-2560.

Reliability Standards Development Plan

Background Information

NERC is in the process of developing the 2012-2014 Reliability Standard Development Plan (the Plan). The Plan will be developed over the next several months, and will provide status updates for projects in development, identify the next projects scheduled for initiation, designate projects for further research, and catalog all proposed projects for future development.

The Standards Committee (SC) has been evaluating projects, and has developed an initial prioritization. NERC staff has used this to develop the first draft of the Plan. While this effort is intended to develop an industry consensus for what projects to move forward, any work plan is unlikely to be seen as perfect in the eyes of all constituents. Accordingly, while we encourage stakeholders to make any comments they believe to be appropriate, we also ask that the main focus of review and comment be on any significant concerns with the prioritization and work plan. Is there anything in the prioritization that is significantly below where it should be ranked? Is there anything in the Plan we deferred that can't wait? Of course, all comments and suggestions are appreciated.

1. Is there anything in the prioritization that is significantly below where it should be ranked? If yes, please explain.

   ☐ Yes
   ☐ No
   Comments:

2. Is there anything in the Plan we deferred that can't wait? If yes, please explain.

   ☐ Yes
   ☐ No
   Comments:

3. For six projects, the SC had disagreements regarding the appropriate score for certain key values. The projects are listed below. For specific information, see the projects, the referenced columns, and the specific cells (highlighted in red) in Appendix 1 of the Plan document. Do you believe these projects and their associated priorities are adequately reflected in the Plan? If no, please explain.
   - Project 2007-17 Protection System Maintenance and Testing (column L)
   - Project 2008-01 Voltage and Reactive Planning and Control (column K)
   - Project 2009-01 Disturbance and Sabotage Reporting (column L)
   - Project 2009-03 Emergency Operations (column F)
   - Project 2009-07 Reliability of Protection Systems (column L)
   - Project 2010-17 Definition of Bulk Electric System (column L)

   ☐ Yes
   ☐ No
   Comments:

4. Please provide any additional comments you would care to offer.

   Comments: Editorial comments: Page 1--in the fourth bullet down, "he" should be replaced with "the". Page 7--in the paragraph entitled "Five-Year Review Obligation", fourth sentence, replace "f" with "of". Page 14--the second bullet under "Additional Projects in 2013:", replace "Panning" with "Planning".

   On page 4, in the section "Completed Standards Development Projects", 2007-07 Vegetation Management should be removed if it hasn't been Board of Trustees approved.

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Compliance Application Notice – 0006

EOP-005-1 R7 Verification of Restoration

~~Original CAN Posting~~Posted: October 25, 2010
Revised ~~CAN Posted~~: Month XX, 2011

Primary Interest Groups
~~ERO Auditors, Investigators and~~ Compliance Enforcement Authorityies (~~Auditors~~CEA)[1]
NERC
Regional Entitiesy
Balancing Authorityies (BA)
Transmission Operators (TOP)

Issue: In regards to evidentiary requirements regarding actual testing or by simulation, what constitutes an actual test and what constitutes a simulation?
For the purpose of aiding a ~~Auditor~~CEA, this CAN provides instruction for assessing whether:

1) an entity has verified its restoration procedure "by actual testing or by simulation," as required by ~~EOP-005-1 R7~~EOP-005-1 R7, and

2) the use of a third-party vendor impacts ~~the~~a registered entity's obligation to coordinate its restoration plan.

~~Registered entities and Regional Entities request that NERC provide informal guidance on the following issues:~~

~~Does the size of an entity determine whether it is required to use actual testing or simulation to verify its restoration procedure?~~

~~What constitutes a test?~~

~~What constitutes a simulation?~~

~~What types of evidence may demonstrate that a registered entity has verified its restoration procedure "by actual testing or by simulation," as required by EOP-005-1 R7?~~

~~How does the use of a third-party vendor impact the registered entity's obligation to coordinate its restoration plan, as required by EOP-005-1 R4?~~

~~**Reliability Objective**~~

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard and requirements. ~~This includes any person authorized to determine non-compliance or a Possible Violation or non-compliance of NERC Reliability Standard requirements.~~

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404.446.2560 | www.nerc.com

DRAFT

~~The reliability objective of EOP-005-1 R7 is to ensure that the registered entity has verified, by actual testing or by simulation, that its restoration procedure can restore its portion of the Bulk Power System (BPS) in the event of a partial or total BPS shut down.~~

Compliance Application

EOP-005-1 R7 provides, in pertinent part:

> ***R7****. Each Transmission Operator and Balancing Authority shall verify the restoration procedure by actual testing or by simulation.*

~~Auditors~~CEAs are instructed to obtain evidence that a registered entity ~~must provide evidence to demonstrate to the Compliance Enforcement Authority that it~~ ~~has~~ verified its restoration procedure by actual testing or by simulation.

A ~~Auditor~~CEA is not to assess ~~The standard does not provide~~ the circumstances under which actual testing or simulation ~~must~~ is to occur. Rather, ~~—~~ a CEA ~~Auditor~~ is to focus solely on the registered entity's testing or simulation that verifies the adequacy of the entity's restoration procedure.

The size of an entity **does not** determine whether actual testing or simulation is required; therefore, ~~Auditors~~CEAs are to assess whether registered entities have~~may~~ verified their procedures by actual testing, simulation, or some combination of the two, by the ~~guidance~~instructions ~~for appropriate testing or simulation~~ provided below.

Regarding actual testing: Actual testing is an option that a TOP or BA may use to verify steps of the restoration~~a~~ procedure~~, such as ,~~ ~~operating Bulk Electric System Elements~~ to demonstrate the TOP's or BA's ability to establish a Cranking Path with clearly identified generator start up loads ~~and then~~ for the TOP ~~and~~ or BA to start~~ing~~ a generating unit using that Cranking Path. The intent is to demonstrate that the Cranking Path can be successfully established.~~The intent is to simulate and verify that the Cranking Path can be successfully~~ ~~and efficiently established within an acceptable voltage and frequency range.~~

Actual testing may also include use of the restoration procedure to restore a portion of the system where the responsible entity uses logs, historial~~n~~ data, and other documentation to verify that the step(s) of the restoration procedure[2] worked, based on actual operations (including things such as verification of fuel sources). While the actual testing may be different from what is expected to occur in an actual restoration, ~~an Auditor~~a CEA is to ~~verify that~~assess whether the ~~aspects~~ attributes necessary to verify the adequacy of the system restoration procedure ~~must be~~are included.

~~CEAs~~

Regarding simulation: Simulation is an option that the ~~Transmission Operator~~TOP or ~~Balancing Authority~~BA can use to verify its restoration procedure. Simulation can include electronic simulation, which is a simulation of what is expected to actually occur during system restoration. Simulations may be conducted at a control center using the system operator's workstation or other facilities. Simulation

[2] ~~Auditors~~~~CEAs~~Restoration procedures are a guide to use during a restoration event and not a sequence of tasks to be performed in a numerical order. System conditions and other activities in other areas of the system will affect the restoration process.

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can also include a walk-through simulation of a restoration procedure that has been tested using previous electronic simulation methods. In both cases, ~~an Auditor~~a CEA is to verify that the restoration scope and the results of the simulation ~~must~~ are ~~be~~ close enough to what would actually occur ~~so~~ that decisions made during the simulation would be effective in actual restoration.

An ***electronic simulation*** can include ~~the use of~~an engineering analysis, ~~using~~ which uses engineering analytical methods and practices that provide results that are consistent with actual measurements to verify the restoration procedure. The analysis is performed in a simulation environment, and the restoration procedure is verified by showing that the steps in the restoration procedure do not place ~~Load~~ load and generation out of balance. The level of simulation required depends on the actual restoration procedure, the facilities being simulated, and the contingencies considered. This may require the use of ~~load~~ power flows[3] to verify steady state conditions; transient stability analysis to verify the dynamic performance; electromagnetic transient analysis to verify switching operations; and an overall analysis to tie the results of these studies into a coherent determination ~~if~~ of whether the proposed restoration actually achieves its desired goal.

A ***walk-through simulation of the actual equipment*** using the restoration procedure without actually performing the actions can include, but is not limited to, the use of ~~things~~ equipment such as control room consoles, control panel illustrations, one line diagrams, or other diagrams that identify system components. The walk-through simulation can verify some ~~aspects~~ attributes of the procedure by simulating procedure steps, such as staff pointing to physical breakers, one line drawings, light indicators and stating expected results when actions are taken. This type of simulation relies on the results of engineering studies performed using the same system conditions as proposed in the restoration procedure to verify expected steady state, transient stability and electromagnetic transient results. Regardless of the type of simulation, the desired outcome is to verify that the restoration procedure is viable in the event of a partial or total shutdown of the Bulk Power System (BPS).

A ***simulated restoration exercise that takes place without actual equipment***[4] (whether by electronic or walk-through simulation) would not normally be considered verification "by actual testing or simulation," as required by the standard. However, under certain circumstances, a registered entity may fulfill the requirement by conducting a simulation restoration exercise(s) that takes place without actual equipment. For a walk-through simulation conducted without actual equipment, the ~~Auditor~~CEA is instructed to verify that the registered entity ~~must provide the ERO Auditor or Compliance Enforcement Authority~~ has ~~with~~ a letter from either its BA or a TOP whose restoration procedure includes the registered entity, stating that:

1. the registered entity does not have a technical component to its restoration plan and
2. the registered entity's restoration is included in the BA's or TOP's restoration plan.

Regarding outsourcing of reliability requirements and coordination: A BA or TOP may use a third party to conduct a simulation of its restoration procedure. The third party may be a contractor or another registered entity, such as ~~as another~~a TOP. In such cases, ~~an Auditor~~a CEA is to verify that the registered

3 "power flows" refers to powe flow studies which, for the purpose of the CAN, is interchangeable with load flow studies.
4 Simulated restoration exercises conducted without actual equipment may be considered "tabletop exercises."

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entity ~~must have~~has a copy of the restoration procedure applicable to its facilities, documentation to show that the restoration procedure was ~~tested~~verified by simulation, and the ~~test~~ simulation results.

Additional information on compliance responsibility and accountability regarding the delegations of performance of reliability-related tasks is contained in the "NERC Compliance Public Bulletin #2010-004 Guidance for Entities that Delegate Reliability Tasks to a Third Party Entity."[5]

Effective Period for CAN

This revised CAN supersedes the original CAN, as well as all prior communications. ~~Auditors~~CEAs are to use this CAN to assess compliance from October 25, 2010, regardless of the start date of the violation. It will remain in effect until such time that a future version of ~~the~~a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN~~ and is enforceable~~.

For any enforcement action in process and for audits that have been initiated,[6], a CEA~~Regional Entity~~ will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.

~~**Non-exclusive list of Evidence**~~**Providing Evidence of Compliance**

~~Auditors~~CEAs are to ~~consider the following non-exclusive list of evidence that has been used to meet~~to ~~demonstrate a registered entity has fulfilled the requirements of R7~~assess the following to obtain reasonable assurance of the entity's compliance:

- engineering analytical methods and practices;
- ~~load~~ power flows to verify steady state conditions;
- transient stability analysis to verify the dynamic performance; and
- electromagnetic transient analysis to verify switching operations.

~~Auditors~~CEAs are to verify that all of the evidence ~~duplicates~~ replicates actual events. Additionally, ~~Auditors~~CEAs may accept ~~registered entities may use~~ actual responses to system disturbances, long-term dynamics, ~~one lines,~~ or other modeling tools or techniques not listed in this notice to ~~demonstrate~~ obtain a reasonable assurance that a registered entity is compliant with this requirement.

For more information please contact:

Michael Moon
Director of Compliance Operations
michael.moon@nerc.net
404-446-2567

[5] ~~http://www.nerc.com/files/2010-004%20v1%200.pdf~~http://www.nerc.com/files/2010-004%20v1%200.pdf

Field Code Changed

[6] "Initiated" means that a registered entity has received notification of the upcoming audit.

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This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

Revision History

Posted Date	Action	Revision
October 25, 2010	Posted Final CAN	
~~[DATE]~~~~August~~Month XX, 2011	Posted Revised CAN	Revised to provide for simulated restoration exercise that takes place without actual equipment and target audience to ~~Auditors~~CEAs

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From: Lee R. Pedowicz
To: "cancomments@nerc.net"
Cc: rscmembers; tfist
Subject: Draft CANs Posted for Comment and Retirement of CAN-0001 though 0004--NPCC Response
Date: Wednesday, September 21, 2011 11:00:38 AM

Good morning.

Below are the comments from NPCC representing 22 registered entities on the subject CANs.

Contributors

	Contributor	Organization	Region	Segment
1.	Ray A'Brial	Central Hudson	NPCC	1
2.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
3.	Rob Antonishen	Ontario Power Generation	NPCC	5
4.	Michael Bilheimer	The United Illuminating Company	NPCC	1
5.	Gregory Campoli	New York Independent System Operator	NPCC	2
6.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
7.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
8.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
9.	Brian Evans-Mongeon	Utility Services	NPCC	8
10.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
11.	Kathleen Goodman	ISO - New England	NPCC	2
12.	Greg Goodrich	New York Independent System Operator	NPCC	2
13.	David Gordon	Massachusetts Municipal Wholesale Electric Company	NPCC	5
14.	Chantel Haswell	FPL Group, Inc.	NPCC	5
15.	John Helme	Utility Services	NPCC	8
16.	Brian Hogue	Northeast Power Coordinating Council	NPCC	10
17.	David Kiguel	Hydro One Networks Inc.	NPCC	1
18.	Brett Lewis	New York Independent System Operator	NPCC	2
19.	John Lim	Consolidated Edison Co. of New York, Inc.	NPCC	1
20.	Michael R. Lombardi	Northeast Utilities	NPCC	1
21.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
22.	Jerry Mannarino	New York Power Authority	NPCC	5
23.	Bruce Metruck	New York Power Authority	NPCC	6

24.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
25.	Robert Pellegrini	The United Illuminating Company	NPCC	1
26.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
27.	Michael Puscas	Northeast Utilities	NPCC	1
28.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
29.	Saurabh Saksena	National Grid	NPCC	1
30.	Michael Schiavone	National Grid	NPCC	1
31.	Wayne Sipperly	New York Power Authority	NPCC	5
32.	Donald Weaver	New Brunswick System Operator	NPCC	2
33.	Ben Wu	Orange and Rockland Utilities	NPCC	1
34.	Daniel Yagudayev	Consolidated Edison Co. of New York, Inc.	NPCC	1
35.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
36.	Guy Zito	Northeast Power Coordinating Council	NPCC	10

-

CAN-0005 CIP-002-3 R3 Critical Cyber Asset Designation for System Operator Laptops

The following needs to be addressed:

The following statement from page 2:

> From page 2, "CEAs are to verify that system operator laptops with the capability and purpose of controlling Critical Assets remotely (either in normal operations or in emergencies) are designated as CCAs under CIP-002-3 Requirement R3."

Should be changed to:

> "CEAs are to verify that System Operator laptops with the capability and purpose of controlling Critical Assets remotely (either in normal operations or in emergencies) are designated as CCAs under CIP-002-3 Requirement R3 if the laptops are essential to the operation of the Critical Asset, and if the laptops have at least one of the characteristics of CIP-002 R3.1, R3.2 or R3.3."

System Operator is capitalized since it is a defined term in the NERC Glossary of Terms. The use of the term System Operator is intended to be the System Operator in a control center, not a system operator that might have electric power system control responsibilities.

Clarification of “essential” is necessary to eliminate any confusion in this CAN.

CAN-0007 CIP-004-2 R4.2 & CIP-004-3 R4.2 Revocation of Access to CCAs

-

Following are comments on CAN-0007:

- “May” is used several times in statements throughout the document. Suggest replacing “may” with “can” or “could” for more clarity.
- On page 2 of the redline, change “(i.e. local and remote or primary and secondary)” to “(i.e., local, remote, primary, or secondary)”. This makes the wording easier to understand.
- On pages 1 and 3 of the CAN, the wording “CEAs are to identify whether entities revoked access to CCAs…”, to “CEAs are to look for evidence that registered entities revoked access…”. “Look for evidence” is more explicit and appropriate to use in this context rather than “identify”.
- On the NERC Website for Compliance Application Notices, in the Compliance Application Notices Section, CAN-0007 has a December 2, 2010 posted date. In the Draft Compliance Application Notices for Industry Review Section the CAN-0007 documents have an October 25, 2010 posted date.

Lee Pedowicz
Manager, Reliability Standards
NPCC
212-840-1070 xt7061

From: John G. Mosier Jr.
To: Lee R. Pedowicz; co11
Subject: Draft Letter---CAN-006 Questions by CO-11
Date: Sunday, October 23, 2011 2:57:31 PM
Attachments: 20111023_JGM-MM_CAN-006_Observations.doc

Lee,

As discussed during your teleconference with CO-11, attached is a proposed letter for the RSC asking for further clarification on CAN-006. CO-11 members: any further comments?

Thanks,

Jerry

NPCC, Inc.
NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

DRAFT

October nn, 2011

Mr. Michael Moon
Director of Compliance Operations
North American Electric Reliability Corporation
3353 Peachtree Road NE
Atlanta Financial Center-North Tower
Suite 600-Sixth Floor
Atlanta, Georgia 30326

Re: Request for Clarification on Compliance Application Notice 0006: EOP-005-1, Requirement 7, "Verification of Restoration"

Dear Mr. Moon:

Further clarification is sought regarding Compliance Application Notice 0006: EOP-005-1, Requirement 7, "Verification of Restoration." The CAN broadly addresses restoration simulations as follows:

> "Regarding simulation: Simulation is an option that the TOP or BA can use to verify its restoration procedure. Simulation can include electronic simulation, which is a simulation of what is expected to actually occur during system restoration. Simulations may be conducted at a control center using the system operator's workstation or other facilities. Simulation can also include a walk-through simulation of a restoration procedure that has been tested using previous electronic simulation methods. In both cases, a CEA is to verify that the restoration scope and the results of the simulation are close enough to what would actually occur that decisions made during the simulation would be effective in actual restoration."

This describes the restoration exercises which are typically conducted throughout North America and certainly reflects the understanding of NPCC in applying Requirement 7. However, the CAN goes on to state:

> "A ***simulated restoration exercise that takes place without actual equipment*** [4] (whether by electronic or walk-through simulation) would not normally be considered verification "by actual testing or simulation," as required by the standard."
>
> [4] Simulated restoration exercises conducted without actual equipment may be considered "tabletop exercises."

It appears that the second statement effectively refutes the first and casts doubt on the acceptance of the simulated restoration exercises to meet Requirement 7.

In addition, there is some doubt in demonstrating compliance as summarized in the CAN:

> **"Providing Evidence of Compliance**
>
> CEAs are to assess the following to obtain reasonable assurance of the entity's compliance:
>
> - engineering analytical methods and practices;
> - power flows to verify steady state conditions;
> - transient stability analysis to verify the dynamic performance; and
> - electromagnetic transient analysis to verify switching operations.
>
> CEAs are to verify that all of the evidence replicates actual events."

The language of the CAN infers that information in ALL of the bullets is necessary to achieve compliance. Is this in fact the case.

Your assistance in this important effort is appreciated.

Very truly yours,

J. G. Mosier, Jr.

John G. Mosier, Jr.
Assistant Vice President-System Operations

JGM:cd

cc: Members, NPCC Restoration Working Group (CO-11)
Members, NPCC Task Force on Coordination of Operation
Members, NPCC Regional Standards Committee
Members, NPCC Compliance Committee

From: Lee R. Pedowicz
To: "cancomments@nerc.net"
Cc: rscmembers; donald.e.nelson@state.ma.us; rjfalsetti@cogeco.ca
Subject: FW: Compliance Application Notices (CAN) Announcement: New CAN Template, five DRAFT CANs for Industry Review, and CANs Status posted to NERC Compliance"s Website--NPCC Comments
Date: Friday, October 14, 2011 6:46:19 AM

Good morning.

Below are the comments from NPCC representing 21 registered entities on the subject Compliance Application Notice.

Contributors

	Contributor	Organization	Region	Segment
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Brian Evans-Mongeon	Utility Services	NPCC	8
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Chantel Haswell	FPL Group, Inc.	NPCC	5
10.	Brian Hogue	Northeast Power Coordinating Council	NPCC	10
11.	David Kiguel	Hydro One Networks Inc.	NPCC	1
12.	Michael R. Lombardi	Northeast Utilities	NPCC	1
13.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
14.	Bruce Metruck	New York Power Authority	NPCC	6
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Saurabh Saksena	National Grid	NPCC	1
20.	Michael Schiavone	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New	NPCC	3

		York, Inc.		
25.	Guy Zito	Northeast Power Coordinating Council	NPCC	10

CAN-0009: Facility Rating and Design Specifications, FAC-008 and FAC-009

CAN-0009 is adding requirements as described following.

FAC-008 R1 stipulates the things that need to be included in the methodology used for developing Facility Ratings. It does not specifically reference conductor clearances. Yet the CAN (page 3) says:

"Therefore, in order for a CEA to determine whether a registered entity's Facility Ratings were established pursuant to the entity's FRM, the CEA is to first verify whether the entity's FRM addresses design criteria for Transmission Facilities, including clearances, and if so, whether the design criteria and clearances that are included are:"

Continuing, it then goes on to say "Additionally, where an entity's Facility Ratings include the FRM requirement, the Facilities are to be constructed to the actual clearances and/or design criteria specified in the entity's FRM. If the Facilities in the field are not constructed to design specifications and/or within acceptable tolerances for clearances, or the CEA may find a non-compliance with FAC-009 R1. "

Even though the requirement didn't specifically mention clearances, the auditors are instructed to check that the clearances in the field meet the design clearance requirement. That is not in the requirement. The requirements are straightforward: develop a methodology in accordance with FAC-008 R1, develop ratings per that methodology (FAC-009 R1), and communicate the ratings (FAC-009 R2).

Lee Pedowicz
Manager, Reliability Standards
NPCC
212-840-1070 xt7061

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda
Project 2008-06 Cyber Security Order 706 - Industry Webinar

August 24, 2011 | 11:00 a.m. - 12:30 p.m. ET
Meeting Location: Industry Webinar
Dial-in: 1.800.698.9012 | Access Code: 8816510 | Broadcast Audio: 234090

11:00 – 11:05 a.m.	Welcome and Opening Remarks
11:05 – 11:15 a.m.	Cyber Security Order 706 Drafting Team Schedule Update
11:15 – 11:55 a.m.	CIP-002 to CIP-011 Version 5 Revisions
11:55 a.m. – 12:00 p.m.	Implementation Plan
12:00 – 12:30 p.m.	Questions and Answers
12:30 p.m.	Adjourn

116-390 Village Blvd.
Princeton, NJ 08540
609.452.8060 | www.nerc.com

From: Wendy Sandberg
To: Wendy Sandberg
Subject: NERC Announcement: Project 2007-17 Nomination Period Open
Date: Wednesday, August 31, 2011 3:25:32 PM

Standards Announcement

Project 2007-17 Protection System Maintenance and Testing Drafting Team – Nomination Period Open

September 1-23, 2011

The Standards Committee is seeking additional industry experts to serve on the Protection System Maintenance and Testing Drafting Team. While anyone may submit a nomination to participate on this team, the specific focus of this solicitation is to add members that represent smaller entities. This team is drafting revisions to PRC-005-1 Transmission and Generation Protection System Maintenance and Testing.

Nominees should have experience in developing, managing, or supporting a maintenance program or a testing program for one or more of the following:

- Generator protection systems
- Transmission protection systems
- Under-frequency load shedding equipment
- Under-voltage load shedding equipment
- Special protection systems

If you are interested in serving on this drafting team, please complete this nomination form **by September 23, 2011**.

Further details are included on the Project 2007-17 project page:
Project 2007-17 Protection System Maintenance

Standards Process
The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Sandberg or at (404) 446-2560.

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NERC. Reliability. Accountability.

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Notes de Sylvain

Board of Trustees
August 4, 2011 | 8:00 a.m.-12:00 p.m.PT
Vancouver Marriott Pinnacle
1128 West Hastings Street
Vancouver, BC VE 4R5 Canada

Introductions and Chair's Remarks
NERC Antitrust Compliance Guidelines

Consent Agenda* — Approve
1. Minutes
    a. May 24, 2011 Conference Call
    b. May 11, 2011 Meeting
2. Committee Membership Appointments and Changes
3. Future Meetings

The agenda is approved.

Regular Agenda
4. President's Report

Gerry Cauley reconfirms after many discussions yesterday that NERC made mistakes with the CANs. He needs to get back with staff and work on these. He will work and correct the current ones and accept the idea of the Task Force as proposed during the MRC to establish a long term solution. Gerry would like to ensure there is an interim process/solution in place if an entity wishes to challenge a CAN. Step one would include submitting challenge to NERC President. Step two would involve an appeal to the Board Compliance Committee.

Some trustee commented that effort should go on fixing the standards. Other commented about the need to be cautious about task force and do not support this idea because the process is good and there were only mistakes. A task force would create bureaucracy.

Revised CANs and a guideline document will be posted and will go through rounds of comments.

About the changes to the RoP, he acknowledges that NERC needs to do a better job at communicating the need for these changes. Because of the deadline to file with FERC, he suggests we split the proposed changes and put them in different timelines. The changes that have been in the work for long time would be submitted with the initial timeline and the new ones would be explained better.

Gerry adds the improvements to compliance enforcement presented yesterday are a good step forward. He acknowledges that NERC needs to improve communication on these

proposals with FERC and entities. It is clear we must bring everyone on board. Members have similar concerns to MRC about the need for details and the filing to FERC.

Gerry still has concerns about the SDT's work. The Board may or may not be faced with tough decisions. It would be helpful if we had SDT provide greater clarify on definition as envisioned and the technical justification, so that Board can evaluate its risk. We'd like to be able to do this prior to next meeting in November. He sSuggests that the Board meets sometime in mid-September, and the SDT could bring the definition in its current form and present the justification.

Joe McLelland from FERC followed with interest yesterday. This is a very important order. The Commission had in mind:

- *Parallel flows*
- *TLRs*
- *Significant amount of generation*
- *Regional discretion*

The Commission would not be looking at anything additional. The re-designation from 25-70 MVA is not something the Commission ordered and might be expecting.

The filing should be responsive to the Commission directives. Anything extra is not something the Commission is expected. Submitting these extras probably complicates matters for the Commission.

For trustees it may be a question of strategy as the Commission was not looking to expand but more for consistency. So a filing in two parts, one responding to the directives and one based on merits (technical justifications) like the 75 MVA. David Goulding states that we don't need to wait for a directive to act on things we are convinced are important to reliability like a level of generation.

Gerry Cauley introduces resolution calling for SDT to submit draft and justification by September 9; motion gives SDT and SC freedom to assess all options and discussions, and determine a strategy for moving forward.

The SDT asks whether it means delays of their schedule and seek clarification on what exactly the Board is expecting from the SDT. Gerry says the Board is not ready to make the call that the SDT is right or wrong but needs to see the technical justifications.

5. Reliability Standards*
   a. Project 2006-02 Assess Transmission Future Needs and Develop Transmission Plans
      1. TPL-001-2 – Transmission System Planning Performance Requirements — Approve

         Approved without any discussion.

b. Project 2006-06 Reliability Coordination

1. IRO-002-3 — Reliability Coordination – Analysis Tools — Approve
2. IRO-005-4 — Reliability Coordination - Current Day Operations — Approve
3. IRO-014-2 — Coordination Among Reliability Coordinators — Approve

All were approved without discussion.

c. Overview of Selected Standards in Process – Regulatory and Development Issues — Discuss

1. FAC-003 – Development Status and Issues

Successive ballot conducted last Feb and received more than 79% weighted segment approval. The team, even with this level of support, wants to address comments.

2. TPL-Footnote B – Regulatory Status and Issues

FERC still reviewing the data submitted.

3. CIP-002 -4 – Regulatory Status and Issues

FERC issued data request in April soliciting additional information.

6. Planning Committee Strategic Plan and Charter — Approve

The PC developed a strategic plan to sustain alignment with ERO strategic objectives to address reliability planning issues.

The proposed changes:

- *Reorganize PC subgroups around strategic work objectives*
  - *Unwind groups that are no longer needed*
  - *Reform subgroups contributing to strategic objectives*
- *Support NERC's standards and compliance activities*
  - *Technical input into NERC standards process*
  - *Technical review of CANs*
- *Support industry forums*

Gerry Cauley commends the committee and the staff. It provides a good model to other committees. The Board approved the Strategic Plan and the Revised Charter.

7. Generating Availability Data System: Section 1600 Data Request — Approve

The task force recommends that GADS data be provided from all NERC Compliance Registry Generator Owners, following Section 1600, Requests for Data or Information under NERC's Rules of Procedures.

GADS data confidentiality will be covered under NERC's Rules of ProcedureSection 1500, Confidential Information.

The resolution is approved without discussion.

8. 2011 Risk Assessment of Reliability Performance — Approve

Approved without discussion.

9. Regional Delegation Agreement Metrics — Approve

Approved without discussion.

10. Regulatory Update — Review

NERC standard made enforceable in Nova Scotia and final stage in Québec.

Standing Committee Reports (Agenda Item 11)*

- a. Compliance and Certification Committee
  - i. Committee Report
  - ii. Request For Action
- b. Critical Infrastructure Protection Committee
- c. Member Representatives Committee
- d. Operating Committee
- e. Personnel Certification Governance Committee
- f. Planning Committee
- g. Standards Committee
- h. Electricity Sub-Sector Coordinating Council

Forum and Group Reports (Agenda Item 12)

a. North American Energy Standards Board
b. Regional Entity Management Group
c. North American Transmission Forum
d. North American Generator Forum

Board Committee Reports

13. Corporate Governance and Human Resources
14. Compliance
15. Nominating
16. Finance and Audit
    a. Review and approval of NERC and Regional Entity 2012 Business Plans and Budgets and Assessments to LSEs

    The Business Plans and Budgets were approved without discussion.

    b. Review Risk Management Framework

More discussions is required.

17. Standards Oversight and Technology

NPCC, Inc.
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1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

August 11, 2011

To: **NPCC Board of Directors**

From: **Harvey J. Reed**

Re: **NERC Meetings of the Member Representatives Committee and Board of Trustees – August 3rd and 4th**

Ladies and Gentlemen:

A review of the above referenced meetings is provided below for your information.

Member Representatives Committee – August 3rd

I. Remarks by Gerry Cauley, NERC President and CEO

1. This is the 5 year ERO Landmark. Along the way mistakes have been made and adjustments have been needed. This is part of a learning process.
2. The focus going forward will be on compliance programs, standards and critical infrastructure, which needs to lead to having an impact on reliability.
3. The ERO is shifting from enforcement having a one size fits all to one in which supports the goals of the organization in a more effective manner.
4. Allowing more judgment and discretion in the enforcement process is the key to signaling to all what is most important. This requires a qualified and trained staff to carry out the audit function. If the ERO is successful, the focus of the audits will be on the right things to insure reliability.
5. Going forward the ERO needs to be able to evaluate performance, effectiveness. To accomplish that it is important to correctly identify the key issues and underlying causes.

II. Nominating Committee Report – All three of the Board Members whose terms are up for renewal would like to be reappointed. Unless there is an issue with a Board Member, the committee intends to nominate the existing board members and not conduct a search.

III. Compliance Enforcement Improvement Initiatives - This is a sea change in the way the ERO approaches enforcement, since it allows the auditors and the registered entity to find, fix, track, and report without going through the entire process, which will save resources at all levels in the ERO and stakeholders, which can be appropriately focused on the important issues. To accomplish this auditor guidelines and training are required.

1. This is one of the most important initiatives that NERC is undertaking. It is essential to implement the initiative successfully, since it is designed to focus the ERO resources on the most important reliability issues facing the industry.
2. Comments
    a. Need to have a means of evaluating performance and make whatever mid-course corrections are necessary so that this important initiative is successful
    b. Important to provide efficiencies to all stakeholders and Regional Entities so that the entire compliance process runs efficiently by focusing resources on the correct issues. FERC needs to appreciate that the prosecutorial discretion will improve efficiency and effectiveness of the ERO.
    c. Concerns expressed about consistency of enforcement across Regional Entities. Although it was recognized that there is always a tension between making things perfectly consistent at the cost of needless work by all and giving the Regional Entities and NERC the ability to exercise discretion in enforcement.
    d. Gerry Cauley – NERC needs industry support to convince FERC that this is correct approach to enforcement.

IV. BES/Adequate Level of Reliability

1. Report presented on the status of the BES drafting team and rules of procedure team.
2. Key policy issue is whether or not the drafting team can complete its work on time to make filing while providing technical justification for move from 20 MVA to 75 MVA threshold for generation.
3. Gerry Cauley – Would we better off separating the move to 75 MVA into a separate SAR and focus the BES effort on completing the FERC directives on time?
4. Ken Pederson questioned whether it is likely that the drafting team can complete its work on time if they continued to try to complete both the directives and the technical justification for the move to 75 MVA. Similarly, other Board members were concerned that continuing with the move to 75 MVA could threaten filing the BES on a timely basis.

V. Compliance Application Notices and Standards Interpretations - Gerry Cauley indicated that this was a well intentioned process in which some mistakes were made. This included some overreaching by NERC staff and NERC can not make standards or change standards with CANs. These errors will be corrected. However, this does not change NERC's responsibility to give instructions to auditors and to effectively and efficiently administer the audit process.

VI. Proposed Changes to Rules of Procedure - David Cook, General Counsel, explained the initiative as one in which FERC directives were comingled with changes that NERC believes are necessary. He explained that penalties for not answering a data request would not be applied to GADs data base collection of data. There was a discussion of whether or not NERC had the legal authority to impose penalties for a registered entity not answering a data request.

VII. Reports

1. Status of NERC Security Initiatives
2. Regional Delegation Agreement Metrics
3. Event Analysis Activities
4. Budget

Board of Trustees Meeting – August 4th

I. Presidents Report - Comments by Gerry Cauley

1. CAN's – NERC has made mistakes. NERC Staff will review all CAN's and revise those that need to be revised so that they are guides to auditors. These guides will be based on the principle that rather than pinpoint an answer, the guides will provide a range of outcomes that are reasonable. These revised CAN's will be developed in a transparent process that provides for feedback from stakeholders. NERC will send out drafts for comment. If stakeholders still have concerns with CAN, appeal to Gerry Cauley and if stakeholders are still concerned about the CAN, stakeholders should appeal to Board Compliance Committee (BOTCC).
    a. Paul Barber – Assuming that the CAN's get rewritten and are guides, this process is OK. However, NERC should not lose focus on fixing standards. Other Board members echoed the sentiment.
    b. Tom Berry – suggested that in addition to the procedure outlined by Gerry Cauley that a certification process be set up for auditors. Gerry Cauley did not object, but wants to focus on fixing CAN's first.
2. Proposed changes to Rules of Procedure (ROP) - NERC needs to do a better job of communicating. The posting should have contained more explanation. NERC will separate those changes to ROP that emanate from FERC directives from the others and put them on a separate track with better communications.
3. New Enforcement Process – The new process is trying to reduce the enforcement backlog by streamlining the compliance process in the front end. The proposal is good, but NERC needs to do a better job of communicating the benefits and impacts to reliability.
    a. Board believes the proposal is very important and supports NERC's efforts to get the process filed, but filing should be timely.
4. BES definition – Is concerned that the move to 75 MVA would introduce new elements into meeting FERC directives and risk both meeting the deadline and challenges from FERC. This risk could be mitigated by separating the 75 MVA issue from the BES definition filing and then deal with the technical justification for 75 MVA later. The standard drafting team (SDT) should provide input to the Board sooner than November. Suggested that SDT should report to Board in special Board meeting in mid-September to assess the risk to making the filing deadline and gaining FERC approval.
    a. Joe McCleland - FERC was specific in what it was looking for and spelled it out in the order. NERC could put new items in filing, but that would complicate FERC's review.
    b. Board expressed concern with going forward and wants to consider separating the 75 MVA issue.

c. Gerry Cauley – Offered motion to direct the SDT to consider the comments, provide the Board with best technical justification for the 75 MVA and the best standard available by a mid-September special Board meeting. Motion was approved by Board.

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II. Reliability Standards

a. Transmission standard – approved
b. Reliability Coordination Standards – approved

III. Planning Committee Strategic Plan and Charter - approved

IV. GADS – Section 1600 mandatory data request – approved

V. 2011 Risk Assessment of Reliability Performance - approved

VI. Regional Delegation Agreement Metrics - approved

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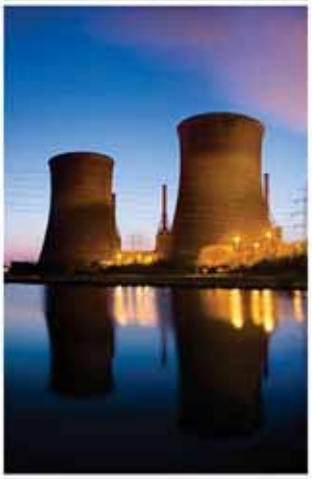

Announcement

NERC Board Focuses on Improving Efforts; Approves Four Standards

August 10, 2011

VANCOUVER – The North American Electric Reliability Corporation (NERC) had its quarterly Board of Trustees meeting on August 4 in Vancouver. Gerry Cauley, president and chief executive officer of NERC, welcomed NERC Board of Trustees; Federal Energy Regulatory Commission staff; and industry stakeholders.

Entering its fifth year as the electric reliability organization, NERC continues to strive for excellence by evolving and adapting to better meet the mission of ensuring the reliability of the bulk power system.

"A mature organization is constantly using the experience it gains to develop better procedures and make course corrections as needed," Cauley said. "We have strong standards and processes in place, and we will use our gained knowledge to make them even stronger."

To continue toward reliability excellence, NERC committed to reviewing its Compliance Application Notice program. NERC staff will review and revise existing CANs to ensure they provide clear, concise guidance for auditors to use consistently across the Regions. A process guide document also is being developed to provide more transparency to the effort. The board will review the CAN process again in November.

Also discussed was progress on the bulk electric system definition. The board directed the Standards Committee and the standard drafting team to consider feedback received during meeting while drafting the BES standard, and to submit a draft of the proposed standard and technical justification to the board by September 9.

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NERC introduced a new compliance enforcement initiative that differentiates issues of noncompliance based on the level of potential risk to the reliability of the bulk power system. The new enforcement initiative is designed to refocus efforts on reliability excellence, eliminate undue regulatory burdens, streamline paperwork requirements, increase caseload processing, and encourage continued timely and thorough self-reporting and mitigation.

The board approved four standards - *Project 2006-02 Assess Transmission Future Needs and Develop Transmission Plans* (TPL-001-2) and *Project 2006-06 Reliability Coordination* (IRO-002-3, IRO-005-4 and IRO-014-2); as well as the Planning Committee's strategic plan and revised charter, which better aligns activities with NERC's enterprise strategic plan.

Also approved were the *Generating Availability Data System: Mandatory Reporting of Conventional Generation Performance Data* report; the Regional Delegation Agreement metrics and the *2011 Risk Assessment of Reliability Performance* report.

The next board meeting is November 3 in Atlanta.

###

The North American Electric Reliability Corporation's mission is to ensure the reliability of the North American bulk power system. NERC is the electric reliability organization (ERO) certified by the Federal Energy Regulatory Commission to establish and enforce reliability standards for the bulk-power system. NERC has equivalent relationships with provincial and federal authorities in Canada. NERC develops and enforces reliability standards; assesses adequacy annually via a 10-year forecast, and summer and winter forecasts; monitors the bulk power system; and educates, trains and certifies industry personnel. Learn more at www.nerc.com

Notes de Sylvain

NERC
Member Representatives Committee
August 3, 2011 | 1–5 p.m. PT
Vancouver Marriott Pinnacle
1128 West Hastings Street
Vancouver, BC VE 4R5 Canada

Introductions and Chairman's Remarks
Antitrust Compliance Guidelines and Public Meeting Notice
Consent Agenda — Approve

1. Minutes
2. Future Meetings

The consent agenda is approved.

Regular Agenda

3. Welcome to Vancouver

Greg Reimer, Executive v-p Transmission, BC Hydro welcomes everyone.

4. Remarks by Gerry Cauley, NERC President and CEO

Gerry says that we now have past the 5 years mark of being certified as the ERO. Most of our programs have been built in the course of these 5 years. We are engaging and reporting progress with stakeholders at these meetings. It is part of the due process of building the ERO and the programs. The real question is: "Are we having an impact on reliability and on compliance?"

He says that we can show some progress. Setting up and running good programs is not the end. We are starting to see a shift from one size fits all approach to how can we engage industry and what we need to focus on. Priority, judgement, discretion is not about going light. We try to signal as much as we can that we need to be smarter and transparent. Training of the staff is important. This also ties to the budget. How do we move from growing ERO to focusing on the right things? We are now looking at effectiveness and at getting the ability to identify key risks.

5. Report on NERC Board Nominating Committee

David Goulding reports on the members of the committee. Every retiring member expressed the will to be back.

6. Compliance Enforcement Improvement Initiatives

Following the presentation at the CC, the MRC members discuss the proposed improvements. It would be important for NERC to submit for review to the stakeholders what will be submitted to FERC. We need more details on how it will work because the devil may be in the details. This is something we must be successful at. We can't continue on the actual path. So let's not be picky. There is a discussion about the importance of consistency.

Gerry insists that this initiative really needs broad support.

7. Status of NERC Security Initiatives*
    a. Critical Infrastructure Protection (CIP) Standards
    b. Electricity Sector Information Sharing and Analysis Center Authorities and Responsibilities
    c. Training, Exercises, and Outreach
    d. Status of Proposed Cybersecurity Legislation in Congress
    e. Electricity Sub-Sector Coordinating Council (ESCC) Coordinated Action Plan

Regarding the CIP Standards:

- *CIP Version 4 Status: being reviewed by FERC*
- *CIP Version 5 Status: posting for comment and ballot planned for November 2011. Anticipate industry approval in 2Q 2012 and submission to regulators 3Q 2012*

As for the Cybersecurity legislations in Congress:

- *NERC CEO Gerry Cauley has testified 4 times since February 2011 to 4 different Congressional committees on the topic of cybersecurity*
- *The Senate Energy and Natural Resource Committee passed the Senate Grid Cybersecurity Act on May 26th*
- *The House Energy and Commerce Committee is considering action on "The GRID Act"*
- *The House and Senate Homeland Security Committees are considering comprehensive approach with DHS as lead*
- *White House cybersecurity bill*

Some of the issues that ESCC is dealing with:

- *Spare Equipment Database Task Force*
    - *Voluntary versus mandatory participation*
- *Geomagnetic Disturbance Task Force*
    - *Full transparency regarding transformer impact assessments*
    - *Continued government funding of GMD observational satellites*

8. MRC BES/ALR Policy Issues Task Force Report to the Board*
    a. Bulk Electric System (BES) Definition and Rules of Procedure Standard Drafting Team Reports

b. Policy Issues Related to BES Definition
c. Policy Issues Related to Adequate Level of Reliability (ALR) Definition

Peter Heidrich, the BES SDT Chair presented an overview of the accomplishments of the SDT. There is a meeting with FERC's staff next week and after the SDT will meet. The last comments period generated comments from 279 different people from 213 companies representing 10 of the 10 industry segments. He indicated the main changes resulting from these comments. On the exception, comments from 75 different people from 45 companies representing 8 of the 10 industry segments were received. The revised BES definition with exception criteria (inclusions and exclusions), the Exception process and the technical principles will be posted for comments in September.

Gerry Cauley states that it is important the Board get engaged in the process. He would not like the SDT to come to the Board with a dilemma (the generation level, the 75 MVA question and its relation to registration). He asks if this could be separated from the current effort? Gerry asks if the MRC wishes to advice the Board on this?

The chairman of the Board, John Anderson, is concerned that, at this point, the discussion is interfering with the SDT's job. He believes the SDT should continue its work and get the results. If the MRC wants to get into that then why do we have a SDT? So unless the MRC wishes to express that the SDT is out of the way, we should let them do their work.

9. Compliance Application Notices in the Context of Standards and Interpretations Development

The CANs are for bridging the gap between compliance and standards. NERC continues dialog with the industry. We do not want to overreach. We will continue to solicit feedback from industry in a variety of forums.

Gerry Cauley talks about trying to tune the programs. NERC may have made mistakes in some CANs, especially with the wording (in using "must"). He acknowledges that industry takes seriously what comes out of NERC. The program was well intended. We have breaches. We can fix it in matters of days. My commitment to the Board is certainly to fix this before the next Board. I may have been silent, but I monitored the traffic. We will always have to give instructions. We will always need this even if we call this something else.

Barry Lawson on behalf of EEI and other trade organizations says we very much support effort by NERC to provide consistency between auditors and regions. The CANs process in some instances have provided this beneficial guidance. On some other CANs have changed the meaning of a standard, interpreted a standard or added language to standard outside of the standard process. CANs should not be used to clarify unclear standards. That should be done in the standard process. When an entity has a legitimate concern about how to comply after a CAN, it lacks any

mechanism to appeal. CAN could benefit from subject matter experts in the industry, but currently can't. The trade association recommend that a task force be formed and reports in November on how the benefits can be achieved. It would be composed of NERC and industry.

SERC wants to commend NERC to seek input from industry member before CANs are issued and appreciates Gerry's remarks. Not only CANs can inform auditors but also industry. Part of the need for the CANs is that many standards don't yet have the required clarity.

Paul Murphy from IESO states that: ISO/RTO sector supports formation of a task force. In terms of what the Board can do to provide immediate relief, we would welcome clear principles as to what CANs are intended to achieve. Board guidance on interpretation bulletins was quite useful, so something similar would be valuable here.

10. Regional Delegation Agreement Metrics Proposal

The goal is to measure NERC and Regional Entity performance under Regional Delegation Agreements, Rules of Procedure, and applicable regulations, so the success of the ERO enterprise.

No input is provided by the MRC.

11. Event Analysis Activities*

a. February 2011 Cold Snap Report
b. Release of Event Analysis Reports to the Industry

Following these events, the final report on track for late summer 2011 and the ERO will scrutinize events analysis execution for internal improvement opportunities.

The event analysis is getting bogged down by the compliance investigation component in which lawyers start to get involved. One suggestion is to get just the fact out quickly and do the compliance investigation after.

12. Case Study on Culture of Reliability Excellence

A case study from Dominion is presented. It is about the Surry Nuclear Power Station Tornado Damage on April 16, 2011.

13. Upcoming MRC Officer Elections and MRC Nominations

The terms of Paul Murphy (IESO), Julius Pataky (BC Hydro), Carmine Marcello (Hydro One) and Lorne Milford (Manitoba Hydro) expires in 2012. Except for Camine, for which we don't know, they all wish to run again.

14. Proposed Changes to Rules of Procedure

Most members commented that they fail to see what is the problem that these changes is trying to solve. D. Cook said that they will have a good reason when this will be presented to the Board in November.

15. 2012 Business Plan and Budget and 2012 Regional Entity Business Plans and Budget

The key changes to this version of the budget are:

- *Increased focus on priorities, deferral or elimination of lower priority items*
- *Commitment to significantly improve compliance enforcement framework and Standards setting process*
- *Recognition of need for strategy and guidelines for SAFNR*
- *Reduction of $1.7M in Contracts/Consultants*
- *Changes in personnel related costs*
  - *Reduction of 2 FTEs (1-Compliance and 1-EA)*
  - *Reduction of merit pool from 3 to 2 percent*
  - *Freeze on Senior Management base salary*
  - *Reduction in meetings, travel and benefit costs*
  - *Revised assumptions on employee benefit costs*

The result is

- *$190.5k (0.4%) increase in cost of existing operations*
- *2012 incremental resource requirement of $4.2M (8.6%)*
- *Total projected 2012 budget increase of $4.4M (9%)*
- *No additional working capital funding*
- *$.6M reduction in Total Funding Requirement versus 2011*
- *7.9% below forecast in 2011 three-year plan*

Increase in assessment for Canadians: -10,3%

16. Future Agenda Items
17. Update on Regulatory Matters

Negotiation of the second agreement among NERC, the Régie and NPCC regarding implementation of mandatory standards in Québec has been completed and the agreement is under consideration by the provincial government. The Régie has issued a preliminary decision regarding adoption of mandatory standards for Québec.

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August 11, 2011

To: **NPCC Board of Directors**

From: **Harvey J. Reed**

Re: **NERC Meetings of the Member Representatives Committee and Board of Trustees – August 3rd and 4th**

Ladies and Gentlemen:

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4. Allowing more judgment and discretion in the enforcement process is the key to signaling to all what is most important. This requires a qualified and trained staff to carry out the audit function. If the ERO is successful, the focus of the audits will be on the right things to insure reliability.
5. Going forward the ERO needs to be able to evaluate performance, effectiveness. To accomplish that it is important to correctly identify the key issues and underlying causes.

II. Nominating Committee Report – All three of the Board Members whose terms are up for renewal would like to be reappointed. Unless there is an issue with a Board Member, the committee intends to nominate the existing board members and not conduct a search.

III. Compliance Enforcement Improvement Initiatives - This is a sea change in the way the ERO approaches enforcement, since it allows the auditors and the registered entity to find, fix, track, and report without going through the entire process, which will save resources at all levels in the ERO and stakeholders, which can be appropriately focused on the important issues. To accomplish this auditor guidelines and training are required.

1. This is one of the most important initiatives that NERC is undertaking. It is essential to implement the initiative successfully, since it is designed to focus the ERO resources on the most important reliability issues facing the industry.
2. Comments
    a. Need to have a means of evaluating performance and make whatever mid-course corrections are necessary so that this important initiative is successful
    b. Important to provide efficiencies to all stakeholders and Regional Entities so that the entire compliance process runs efficiently by focusing resources on the correct issues. FERC needs to appreciate that the prosecutorial discretion will improve efficiency and effectiveness of the ERO.
    c. Concerns expressed about consistency of enforcement across Regional Entities. Although it was recognized that there is always a tension between making things perfectly consistent at the cost of needless work by all and giving the Regional Entities and NERC the ability to exercise discretion in enforcement.
    d. Gerry Cauley – NERC needs industry support to convince FERC that this is correct approach to enforcement.

IV. BES/Adequate Level of Reliability

1. Report presented on the status of the BES drafting team and rules of procedure team.
2. Key policy issue is whether or not the drafting team can complete its work on time to make filing while providing technical justification for move from 20 MVA to 75 MVA threshold for generation.
3. Gerry Cauley – Would we better off separating the move to 75 MVA into a separate SAR and focus the BES effort on completing the FERC directives on time?
4. Ken Pederson questioned whether it is likely that the drafting team can complete its work on time if they continued to try to complete both the directives and the technical justification for the move to 75 MVA. Similarly, other Board members were concerned that continuing with the move to 75 MVA could threaten filing the BES on a timely basis.

V. Compliance Application Notices and Standards Interpretations - Gerry Cauley indicated that this was a well intentioned process in which some mistakes were made. This included some overreaching by NERC staff and NERC can not make standards or change standards with CANs. These errors will be corrected. However, this does not change NERC's responsibility to give instructions to auditors and to effectively and efficiently administer the audit process.

VI. Proposed Changes to Rules of Procedure - David Cook, General Counsel, explained the initiative as one in which FERC directives were comingled with changes that NERC believes are necessary. He explained that penalties for not answering a data request would not be applied to GADs data base collection of data. There was a discussion of whether or not NERC had the legal authority to impose penalties for a registered entity not answering a data request.

VII. Reports

1. Status of NERC Security Initiatives
2. Regional Delegation Agreement Metrics
3. Event Analysis Activities
4. Budget

Board of Trustees Meeting – August 4th

I. Presidents Report - Comments by Gerry Cauley

1. CAN's – NERC has made mistakes. NERC Staff will review all CAN's and revise those that need to be revised so that they are guides to auditors. These guides will be based on the principle that rather than pinpoint an answer, the guides will provide a range of outcomes that are reasonable. These revised CAN's will be developed in a transparent process that provides for feedback from stakeholders. NERC will send out drafts for comment. If stakeholders still have concerns with CAN, appeal to Gerry Cauley and if stakeholders are still concerned about the CAN, stakeholders should appeal to Board Compliance Committee (BOTCC).
    a. Paul Barber – Assuming that the CAN's get rewritten and are guides, this process is OK. However, NERC should not lose focus on fixing standards. Other Board members echoed the sentiment.
    b. Tom Berry – suggested that in addition to the procedure outlined by Gerry Cauley that a certification process be set up for auditors. Gerry Cauley did not object, but wants to focus on fixing CAN's first.
2. Proposed changes to Rules of Procedure (ROP) - NERC needs to do a better job of communicating. The posting should have contained more explanation. NERC will separate those changes to ROP that emanate from FERC directives from the others and put them on a separate track with better communications.
3. New Enforcement Process – The new process is trying to reduce the enforcement backlog by streamlining the compliance process in the front end. The proposal is good, but NERC needs to do a better job of communicating the benefits and impacts to reliability.
    a. Board believes the proposal is very important and supports NERC's efforts to get the process filed, but filing should be timely.
4. BES definition – Is concerned that the move to 75 MVA would introduce new elements into meeting FERC directives and risk both meeting the deadline and challenges from FERC. This risk could be mitigated by separating the 75 MVA issue from the BES definition filing and then deal with the technical justification for 75 MVA later. The standard drafting team (SDT) should provide input to the Board sooner than November. Suggested that SDT should report to Board in special Board meeting in mid-September to assess the risk to making the filing deadline and gaining FERC approval.
    a. Joe McCleland - FERC was specific in what it was looking for and spelled it out in the order. NERC could put new items in filing, but that would complicate FERC's review.
    b. Board expressed concern with going forward and wants to consider separating the 75 MVA issue.

c. Gerry Cauley – Offered motion to direct the SDT to consider the comments, provide the Board with best technical justification for the 75 MVA and the best standard available by a mid-September special Board meeting. Motion was approved by Board.

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II. Reliability Standards

a. Transmission standard – approved
b. Reliability Coordination Standards – approved

III. Planning Committee Strategic Plan and Charter - approved

IV. GADS – Section 1600 mandatory data request – approved

V. 2011 Risk Assessment of Reliability Performance - approved

VI. Regional Delegation Agreement Metrics - approved

Notes de Sylvain

NERC
Member Representatives Committee
August 3, 2011 | 1–5 p.m. PT
Vancouver Marriott Pinnacle
1128 West Hastings Street
Vancouver, BC VE 4R5 Canada

Introductions and Chairman's Remarks
Antitrust Compliance Guidelines and Public Meeting Notice
Consent Agenda — Approve

1. Minutes
2. Future Meetings

The consent agenda is approved.

Regular Agenda

3. Welcome to Vancouver

Greg Reimer, Executive v-p Transmission, BC Hydro welcomes everyone.

4. Remarks by Gerry Cauley, NERC President and CEO

Gerry says that we now have past the 5 years mark of being certified as the ERO. Most of our programs have been built in the course of these 5 years. We are engaging and reporting progress with stakeholders at these meetings. It is part of the due process of building the ERO and the programs. The real question is: "Are we having an impact on reliability and on compliance?"

He says that we can show some progress. Setting up and running good programs is not the end. We are starting to see a shift from one size fits all approach to how can we engage industry and what we need to focus on. Priority, judgement, discretion is not about going light. We try to signal as much as we can that we need to be smarter and transparent. Training of the staff is important. This also ties to the budget. How do we move from growing ERO to focusing on the right things? We are now looking at effectiveness and at getting the ability to identify key risks.

5. Report on NERC Board Nominating Committee

David Goulding reports on the members of the committee. Every retiring member expressed the will to be back.

6. Compliance Enforcement Improvement Initiatives

Following the presentation at the CC, the MRC members discuss the proposed improvements. It would be important for NERC to submit for review to the stakeholders what will be submitted to FERC. We need more details on how it will work because the devil may be in the details. This is something we must be successful at. We can't continue on the actual path. So let's not be picky. There is a discussion about the importance of consistency.

Gerry insists that this initiative really needs broad support.

7. Status of NERC Security Initiatives*
    a. Critical Infrastructure Protection (CIP) Standards
    b. Electricity Sector Information Sharing and Analysis Center Authorities and Responsibilities
    c. Training, Exercises, and Outreach
    d. Status of Proposed Cybersecurity Legislation in Congress
    e. Electricity Sub-Sector Coordinating Council (ESCC) Coordinated Action Plan

Regarding the CIP Standards:

- *CIP Version 4 Status: being reviewed by FERC*
- *CIP Version 5 Status: posting for comment and ballot planned for November 2011. Anticipate industry approval in 2Q 2012 and submission to regulators 3Q 2012*

As for the Cybersecurity legislations in Congress:

- *NERC CEO Gerry Cauley has testified 4 times since February 2011 to 4 different Congressional committees on the topic of cybersecurity*
- *The Senate Energy and Natural Resource Committee passed the Senate Grid Cybersecurity Act on May 26th*
- *The House Energy and Commerce Committee is considering action on "The GRID Act"*
- *The House and Senate Homeland Security Committees are considering comprehensive approach with DHS as lead*
- *White House cybersecurity bill*

Some of the issues that ESCC is dealing with:

- *Spare Equipment Database Task Force*
    - *Voluntary versus mandatory participation*
- *Geomagnetic Disturbance Task Force*
    - *Full transparency regarding transformer impact assessments*
    - *Continued government funding of GMD observational satellites*

8. MRC BES/ALR Policy Issues Task Force Report to the Board*
    a. Bulk Electric System (BES) Definition and Rules of Procedure Standard Drafting Team Reports

b. Policy Issues Related to BES Definition
c. Policy Issues Related to Adequate Level of Reliability (ALR) Definition

Peter Heidrich, the BES SDT Chair presented an overview of the accomplishments of the SDT. There is a meeting with FERC's staff next week and after the SDT will meet. The last comments period generated comments from 279 different people from 213 companies representing 10 of the 10 industry segments. He indicated the main changes resulting from these comments. On the exception, comments from 75 different people from 45 companies representing 8 of the 10 industry segments were received. The revised BES definition with exception criteria (inclusions and exclusions), the Exception process and the technical principles will be posted for comments in September.

Gerry Cauley states that it is important the Board get engaged in the process. He would not like the SDT to come to the Board with a dilemma (the generation level, the 75 MVA question and its relation to registration). He asks if this could be separated from the current effort? Gerry asks if the MRC wishes to advice the Board on this?

The chairman of the Board, John Anderson, is concerned that, at this point, the discussion is interfering with the SDT's job. He believes the SDT should continue its work and get the results. If the MRC wants to get into that then why do we have a SDT? So unless the MRC wishes to express that the SDT is out of the way, we should let them do their work.

9. Compliance Application Notices in the Context of Standards and Interpretations Development

The CANs are for bridging the gap between compliance and standards. NERC continues dialog with the industry. We do not want to overreach. We will continue to solicit feedback from industry in a variety of forums.

Gerry Cauley talks about trying to tune the programs. NERC may have made mistakes in some CANs, especially with the wording (in using "must"). He acknowledges that industry takes seriously what comes out of NERC. The program was well intended. We have breaches. We can fix it in matters of days. My commitment to the Board is certainly to fix this before the next Board. I may have been silent, but I monitored the traffic. We will always have to give instructions. We will always need this even if we call this something else.

Barry Lawson on behalf of EEI and other trade organizations says we very much support effort by NERC to provide consistency between auditors and regions. The CANs process in some instances have provided this beneficial guidance. On some other CANs have changed the meaning of a standard, interpreted a standard or added language to standard outside of the standard process. CANs should not be used to clarify unclear standards. That should be done in the standard process. When an entity has a legitimate concern about how to comply after a CAN, it lacks any

mechanism to appeal. CAN could benefit from subject matter experts in the industry, but currently can't. The trade association recommend that a task force be formed and reports in November on how the benefits can be achieved. It would be composed of NERC and industry.

SERC wants to commend NERC to seek input from industry member before CANs are issued and appreciates Gerry's remarks. Not only CANs can inform auditors but also industry. Part of the need for the CANs is that many standards don't yet have the required clarity.

Paul Murphy from IESO states that: ISO/RTO sector supports formation of a task force. In terms of what the Board can do to provide immediate relief, we would welcome clear principles as to what CANs are intended to achieve. Board guidance on interpretation bulletins was quite useful, so something similar would be valuable here.

10. Regional Delegation Agreement Metrics Proposal

The goal is to measure NERC and Regional Entity performance under Regional Delegation Agreements, Rules of Procedure, and applicable regulations, so the success of the ERO enterprise.

No input is provided by the MRC.

11. Event Analysis Activities*

a. February 2011 Cold Snap Report
b. Release of Event Analysis Reports to the Industry

Following these events, the final report on track for late summer 2011 and the ERO will scrutinize events analysis execution for internal improvement opportunities.

The event analysis is getting bogged down by the compliance investigation component in which lawyers start to get involved. One suggestion is to get just the fact out quickly and do the compliance investigation after.

12. Case Study on Culture of Reliability Excellence

A case study from Dominion is presented. It is about the Surry Nuclear Power Station Tornado Damage on April 16, 2011.

13. Upcoming MRC Officer Elections and MRC Nominations

The terms of Paul Murphy (IESO), Julius Pataky (BC Hydro), Carmine Marcello (Hydro One) and Lorne Milford (Manitoba Hydro) expires in 2012. Except for Camine, for which we don't know, they all wish to run again.

14. Proposed Changes to Rules of Procedure

Most members commented that they fail to see what is the problem that these changes is trying to solve. D. Cook said that they will have a good reason when this will be presented to the Board in November.

15. 2012 Business Plan and Budget and 2012 Regional Entity Business Plans and Budget

The key changes to this version of the budget are:

- *Increased focus on priorities, deferral or elimination of lower priority items*
- *Commitment to significantly improve compliance enforcement framework and Standards setting process*
- *Recognition of need for strategy and guidelines for SAFNR*
- *Reduction of $1.7M in Contracts/Consultants*
- *Changes in personnel related costs*
  - *Reduction of 2 FTEs (1-Compliance and 1-EA)*
  - *Reduction of merit pool from 3 to 2 percent*
  - *Freeze on Senior Management base salary*
  - *Reduction in meetings, travel and benefit costs*
  - *Revised assumptions on employee benefit costs*

The result is

- *$190.5k (0.4%) increase in cost of existing operations*
- *2012 incremental resource requirement of $4.2M (8.6%)*
- *Total projected 2012 budget increase of $4.4M (9%)*
- *No additional working capital funding*
- *$.6M reduction in Total Funding Requirement versus 2011*
- *7.9% below forecast in 2011 three-year plan*

Increase in assessment for Canadians: -10,3%

16. Future Agenda Items
17. Update on Regulatory Matters

Negotiation of the second agreement among NERC, the Régie and NPCC regarding implementation of mandatory standards in Québec has been completed and the agreement is under consideration by the provincial government. The Régie has issued a preliminary decision regarding adoption of mandatory standards for Québec.

From: Guy V. Zito
To: rsc
Subject: FW: NOMINATION PERIOD OPENS: Member Representatives Committee - Sector Election
Date: Tuesday, September 13, 2011 7:09:58 AM

Member Reps. Committee is now open for nomination for all sectors. See below...

Thanks,

Guy V. Zito, NPCC

From: Sara Minges [Sara.Minges@nerc.net]
Sent: Monday, September 12, 2011 5:25 PM
To: Sara Minges
Subject: NOMINATION PERIOD OPENS: Member Representatives Committee - Sector Election

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Nomination Period Opens – Sector Election:

Member Representatives Committee

Now Available at: MRC Sector Nomination Form
Click here for: MRC Nominations and Elections webpage

In accordance with Article VIII, Section 3 of the NERC Bylaws, NERC is holding its annual elections to replace the Member Representatives Committee Sector members whose terms expire in February 2012. The annual sector elections will fill the one open seat of each of the twelve sectors of the Member Representatives Committee. The newly elected representatives' terms will expire in February 2014.

Please review the Steps for Nominating and Electing Members to the Member Representatives Committee during your sectors' election. Also, to be eligible for nomination for election as a sector representative, the nominee's organization must be registered as a member of NERC from that sector.

Timeline:

September 12 - Nomination Period Opens
November 11 - Nomination Period Closes
December 12 - Election Period Opens
December 22 - Election Period Ends

For more information or assistance, please contact Sara Minges or at (202) 383-2627.

3353 Peachtree Road NE

Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

RELIABILITY | ACCOUNTABILITY

Sara Minges
Legal Assistant
North American Electric Reliability Corporation
1120 G Street, NW, Suite 990
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Direct Dial: 202-383-2627
Email: Sara.Minges@nerc.net
****
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To unsubscribe send a blank email to leave-1270654-39208.98eac8c94409e17058b6e89bfa4b2626@listserv.nerc.com

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Nomination Form for NERC Member Representatives Committee Sector Members

Nominations are due by November 11, 2011

Information about you, the nominator		
1. Name	Your first and last name.	
2. E-mail Address	Your E-mail address.	
3. Phone Number	Your phone number.	
4. NERC Member Name	Who you work for or represent. Must be a NERC member.	
5. Membership Sector	Which of the 12 membership sectors the member belongs to.	**…**
Information about the person you are nominating, the nominee		
6. Name	Nominee's name.	
7. E-mail Address	Nominee's E-mail address (optional).	
8. NERC Member Name	Who the nominee works for or represents. Must be a NERC member.	
9. Membership Sector	Which of the 12 membership sectors the member belongs to. **Must be the same as Item 5 above.**	**…**
10. Title	Nominee's business title.	
11. Job description	Brief explanation of the nominee's responsibilities.	
12. Willingness to serve, and additional information	The nominee is willing to attend all committee meetings, bring the sector's opinions and interests to the table, and keep the sector constituents informed about MRC activities, discussions, and decisions.	☐ **Yes**
	Additional information about the nominee that would help the sectors' members decide to elect this person. (A sentence or two).	

How to Submit your Nomination

1. Send this form by E-mail to sara.minges@nerc.net as an attachment
2. Or you can fax the nomination form to:

   Sara Minges
   202-393-3955
3. Save a copy of your nomination form for your records.

Notes de Sylvain
NERC Compliance Committee
August 3, 2011 | 10:30 a.m.-Noon PT
Vancouver Marriott Pinnacle
1128 West Hastings Street
Vancouver, BC VE 4R5 Canada

Compliance Enforcement Improvement Initiatives

A presentation on the enforcement improvement was made.

The goals of the suggested improvements are:

- Refocus industry efforts on achieving reliability excellence through attention to matters posing greatest risks to reliability
- Reduce undue regulatory burdens on users, owners, and operators
- Improve caseload processing

The improvements proposed are:

- Enforcement discretion
    - Decline to pursue matters through to a Notice of Penalty
    - Applied in both compliance monitoring and enforcement processing
    - All issues of concern must still be addressed
- Streamlined Notices of Penalty (NOP)
    - Spreadsheet NOP format
- Dismissal reporting

All instances will be mitigated. It now needs to be filed with FERC.

Gerry Cauley wants to make sure that we all realize the significance of the proposal. He applauds the initiative and the work done by the regions with staff. It will become an exercise in judgement.

The improvements are well received and welcome as a step forward. Members believe in will streamline the process and reduce the documentation burden. Auditor training will be a key factor. It shows leadership and willingness to be bold on NERC's part. This is part of focusing on efficiency and results, and not just process and punishment. We hope to gain support of stakeholders, but recognize there will be apprehension at the onset with a new way of doing business. It is not without risk. It is just doing our job better.

PJM offers support for the improvements. The details need to be clarified and the auditor will need to lean to deal with this situation.

EEI is very supportive of find and fix; we want to keep things out of the pipeline and appreciate efforts to support that; we want to support this, but think we need a little bit more to go; if there's a way stakeholders can see the details in advance of submission to FERC, that would be helpful.

APPA likewise with EEI, we need to see a detailed proposal before we can support it; members support broad conceptual outline.

Notes de Sylvain

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Vancouver Marriott Pinnacle
1128 West Hastings Street
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September 13, 2011 | 1-5 p.m. CDT
September 14, 2011 | 8-noon CDT

Sheraton St. Louis City Center Hotel & Suite
400 S. 14th Street
St. Louis, MO 63103
(314) 613-6400

Administrative

a. Welcome and Introductions – Chair - Jeff Mitchell

b. Arrangements and Schedule of Events – new Secretary – John Moura

c. Announcement of Quorum – Achieved

d. NERC Antitrust Compliance Guidelines and Public Announcement - Reviewed

e. Future Meetings – Dec 13-14, 2011, Atlanta, Georgia - March 7-8, 2012, Phoenix AZ

f. Agenda Approved

Agenda

1. **Consent Agenda - Approved**
   a. June 7-8 and July 11 Teleconference Draft Meeting Minutes:
   PC_Draft_Meeting_Minutes_Toronto_June_2011
   PC_Draft_Teleconference_Minutes_July_11_2011
   b. Integration of Variable Generation's Task 1.8 report "Potential Bulk System Reliability Impacts of Distributed Resources"
2. Chairman's Remarks
   a. Jeff Mitchell reported on:
      - the BES Definition
        - Phase 1 – to meet directives of FERC Order;
        - Phase 2 – address other identified issues – the OC/PC will be providing some of the technical justification for those identified issues (SAMS/TIS) to help out the Standards process, as called for in the PC Strategic plan.
      - Standards Impact – help the SC with their prioritization and technical justification supporting the reliability benefits of the NERC Standards. The EXCOM will get this started initially.

3. Information Only
   a. Development of Interconnection-wide Models – Timeline & Issue
      Mark Lauby gave the presentation "Interconnection Model Improvements" provided in the Agenda package.
   b. Update on ALR activities
      Mark Lauby reviewed the status report provided in the Agenda package.
   c. TVA tornado damage – Tim Ponseti – VP Transmission Planning &Compliance (TVA)
      Video Clip/presentation of the April 27, 2011 event
   d. Surry Nuclear Plant tornado damage
      Carl Eng gave a presentation reviewing the impact of the tornado on the Surry Nuclear Plant.
   e. Event Analysis Working Group
      Jacquie Smith provided an overview of the EAWG Update using slides to be provided to the PC. She explained progress made to date – reviewed events by categories – 17 lessons learned released to date, +20 more by the end of the year (for example, related to freeze conditions).

      EA program Update (WG meets on the Monday before the OC/PC meetings)

      60-70 responses to EA survey:
      - ✓ Concerns over Reporting vs. Compliance
        - Have a table defining reportable events compared to that required by EA process
        - Consolidate criteria/content with OE-417 reporting
        - Separate/equivalent form for Canadian entity reporting (not given to DOE)
        - Modify EA language from "require" to strongly encourage"
      - ✓ Event Categories – define Cat 0/ clarify wording
      - ✓ Release of detailed EA report – mark lesson learned with contact info (regional rep) for follow-up – w/o breaching confidentiality
      - ✓ CIP Events – those with operational impact; CIP vulnerabilities treated under different process
      - ✓ EA Process Document – target completion by October 1, 2011
      - ✓ ROP changes introduced to BOT November 2011
      - ✓ ROP changes voted on by BOT in February 2012
      - ✓ Continued focus on developing and publishing Lessons Learned.

      <u>PC Discussion</u>

      Putting out too many lessons learned (not actionable) creates a lot of noise which makes it difficult to glean the important ones.

Committee Matters

a. Approved – Recommendations on Consolidating Reliability Assessments and Performance Analysis Reports and Measures

John Moura reviewed the materials provided in the Agenda package.

- ✓ Performance Analysis – State of Reliability Report (name TBD) ALR Metrics to include IRI/SRI Metrics, TADS, GADS, DADS, Spare Equipment, Operations (Frequency, RC), Security (CIP) reports, post-Seasonal Assessment
- ✓ Reliability Assessment - LTRA, Summer Reliability, Winter Reliability, Special Reliability Assessment(s), as required
- ✓ April – PAS Annual report
- ✓ May – Summer Reliability Assessment
- ✓ October - LTRA
- ✓ November – Winter Reliability Assessment

PC Discussion

May require a Section 1600 request to move some of the TADS data collection dates to match the proposed PAS schedule (expected to be fully functional for year 2012).

Include performance of Spare Equipment data base project that does not divulge confidential information.

Q: Is this the time to think about handing over seasonal assessments responsibility to the OC?
A: Timely question – An option to be discussed tomorrow with the OC's Leadership.
Mark Lauby - Goal is to get the metrics reported on a quarterly basis, to avoid stale data; requires coordination of data submittals.

Q: Is a report necessary, if the metrics and standards are reported in a timely, ongoing manner.
A: John Moura responded that a report requirement provides a focal point for the effort.

b. PC Approved the Core Principles, OC/PC Organizational Structure to support NERC Alerts, and the Organizational Structure for Coordinating NERC Alerts as outlined in Attachment 1 of the Agenda package.

Mark Lauby reviewed the proposal provided in the Agenda package.

c. Appointment – Executive Committee membership

Jeff Mitchell –looking for two nominations – Stuart and Ron agree to continue to serve – Scott "struggling to keep up" but would continue absent any other interest.

PC EXCOM Nominations received and accepted:

- ✓ Mark Westendorf - ISO/RTO
- ✓ Stuart Nelson – State/Municipal

- ✓ Ron Mazur – Federal/Provincial
- ✓ Noman Williams - SPP

d. Review – PC Next -Steps and Future Work Plan actions required – Jeff Mitchell

i. Previously approved the following changes in Planning Committee Subgroups: Disband the following groups with PC thanks and appreciation:

- ✓ Resource Issues Subcommittee
- ✓ Data Coordination Working Group
- ✓ Load Forecasting Working Group
- ✓ Loss-of-Load Expectation Working Group
- ✓ Reliability Fundamentals Working Group

The following Subcommittee changes:

- ✓ Transmission Issues Subcommittee named the System Analysis and
- ✓ Modeling Subcommittee (SAMS)
- ✓ Merge the Data Coordination Subcommittee and Reliability Metrics Working Group becomes the Performance Analysis Subcommittee (PAS)

The conversion of the following Task Forces to Working Groups

- ✓ Model Validation Task Force, reporting to the SAMS
- ✓ Demand Response Data Task Force, reporting to the PAS
- ✓ Generator Availability Data System Task Force, reporting to PAS
- ✓ Approved the following changes in working group reporting:
- ✓ Transmission Availability Data System Working Group, reporting to PAS
- ✓ Events Analysis Working Group, reporting to PAS

ii. Consider Approval the following Chairs and Vice Chairs, for each subgroup (action at the December PC meeting) (suggestion - perhaps subgroup chairs/vice chairs should be PC members?):

- ✓ System Analysis and Modeling Subcommittee (SAMS): Chair Mark Byrd
- ✓ Performance Analysis Subcommittee (PAS): Chair Bill Adams, Vice Chair Jerry Rust
- ✓ Model Validation Working Group: Chair Jose Conti
- ✓ Demand Response Data Working Group: Chair Sharon Bauer
- ✓ Generator Availability Data System Working Group: Chair TBD

All other Subcommittee and Working Group Chairs and Vice Chairs are asked to serve out their current terms, to be no longer than two years from the time they started. If this two year term has already lapsed, then a new Chair/Vice Chair should be proposed to the PC.

iii. Draft subgroups' scopes

To be finalized at the December PC meeting – just an initial cut to get started. This is the opportunity for the PC and the respective subgroups involved to make the changes that they believe they need to make.

Also presented – the RAS proposal for the Reliability Assessment Data Coordination Group – SME who understand the data collection and availability, and continue liaison with the DOE EIA.

e. Discussion - Starting in 2012, PC to hold 3 meetings each year for2 days (with ½ day for Joint Sessions) compared to 4 meetings for 1 day (with ½ day for Joint Session one time per year)

Jeff Mitchell Example – Day-and-a-half Meetings
Day 1 – Separate OC & PC Ex Com meetings
1-5 (w or w/o Lunch)
Ex Com 9-11 [REMG 11:00]
Day 2 – Separate OC & PC meetings
8-5 (with lunch) [REMG 7-8 am]
Day 3 – Joint OC/PC/CIPC & CIPC Only
8-12
Jointly voted items covered first, informational other
CIPC only meeting would begin at 1 pm

One-day Meetings
Day 1 Separate OC & PC & Ex Com
4-7 (or other times)
Day 2 Separate OC and PC Meetings
8-5 (with lunch)
Day 3 – Joint OC/PC/CIPC & CIPC-only
8-12
Jointly voted items covered first, informational other
CIPC only meeting would begin at 1 pm

Jeff Mitchell – why? - economy of peoples travel time, reduction of NERC meeting room expenses.

<u>PC Discussion</u>

- ✓ Be mindful of those traveling from the West Coast
- ✓ Coordination with NERC BOT meetings
- ✓ Don't clobber set State/Federal regulatory meetings (NARUC, FERC)

- ✓ Tear down the wall between the OC/PC for common Agenda Item discussion/votes
- ✓ Webinars may or may not be as effective as face-face meetings (precludes side-bar interactions)
- ✓ Decide by December (in order to allow time to plan regional/other internal company reviews and discussions prior to the NERC meetings)
- ✓ Requires a vote – all three committees would have to agree to the change.

f. Discussion - Merging Planning and Operating Committees

Jeff Mitchell – been attending these meetings for 10 years now, this is the third time this topic has been brought up. Was to be an Agenda Item at the last MRC meetng, but because it wasn't discussed at the OC/PC, they tabled it. In Reliability First, we have one technical committee, which seems to work. Why? – again efficiency in travel/cost of hotel.

PC Discussion

- ✓ MRO just split their one group into two.
- ✓ Concern over the size of the group, covering different specialized topics, very different issues.
- ✓ Do have some common issues, beneficial to hear the discussions between the planners and operators.
- ✓ Perhaps Middle ground – take votes at joint meeting?
- ✓ Some efficiency to hear the other groups concerns – rather than giving the same presentation four times.
- ✓ Bob Cummings – trying to vote jointly was a real mess from a parliamentary point of view the first time NERC tried it (Glossary of Terms was brought before the joint NERC session. Someone moved to vote on it – challenge on Roberts Rules regarding not allowed to vote jointly – this would have to be resolved prior to trying it again).
- ✓ Put the responsibility where it belongs – for instance, the seasonal assessments do not belong at the PC – that will gain efficiencies.
- ✓ Today – the joint sessions are just informational – because you go back to your home committee to debate. Somehow have to figure a way to have the debates and votes take place there.
- ✓ Can have a separate OC vote, PC vote and CIPC vote (not just a collective group vote)
- ✓ Have the joint meeting in the middle, so the CIPC people are not stranded.

No motion for a PC recommendation at this time.

4.0 Subgroups

a. Reliability Assessment Subcommittee
Mark Kuras highlighted the materials in the Agenda package – repeated pitch for the Reliability Assessment Data Working Group reporting to RAS – Thanks expressed to Chuck for chairing the DCWG.

- ✓ Review and Provide Feedback on DRAFT Special Reliability Assessment: Gas / Electric Interdependencies – PHASE I - Draft Report Comments from PC Members are due to NERC via assessments@nerc.net by COB on October 5, 2011.
  DRAFT Special Reliability Assessment: Gas / Electric Interdependencies - Primer On Existing Environment *PHASE I - Draft Report* – Note report not posted as of September 12th.

- ✓ Review and Provide Feedback on DRAFT Special Reliability Assessment: Gas / Electric Interdependencies – PHASE II - Work Plan Comments from PC Members are due to NERC via assessments@nerc.net by COB on September 21, 2011.
  DRAFT Special Reliability Assessment: Gas / Electric Interdependencies - *PHASE II - Work Plan*

- ✓ **Approved - 2010/2011 Post-Winter Reliability Assessment Report – As discussed: (Include Canada in Figure 1, etc.)**
  2010/2011 Post-Winter Reliability Assessment Report

- ✓ Review and Provide Feedback on DRAFT 2012 Special Reliability Assessment: Reliability Impacts of U.S. Environmental Regulations Scope - Comments from PC Members are due to NERC via assessments@nerc.net by COB on October 5, 2011.
  - All five FERC commissioners are to testify before the House Energy & Commerce Committee Wednesday on the reliability impact of recent EPA regulations.
  - President Obama delayed the Environmental Protection Agency's (EPA's) smog rule, saying that he had underscored the importance of reducing regulatory burdens and uncertainty. The decision has dealt a blow to environmental groups—which are contemplating legal action—and won the Democratic president praise from Republicans and industry groups
    DRAFT 2012 Special Reliability Assessment: Reliability Impacts of Environmental Regulations - Scope

- ✓ The following schedule (for PC) remains for the 2011 LTRA:
  - September 30 Draft Report to PC, OC, MRC for Comment
  - October 11 PC Comments due to NERC
  - October 17 Final Draft Report to PC
  - October 25 PC Webinar to Approve Report
  - October 31 Final draft to NERC Board of Trustees (BOT)
  - November 18 BOT Meeting to Approve LTRA
  - November 28 Target release and electronic publication of report

- ✓ The 2011/2012 Winter Reliability Assessment is currently being developed. The following schedule (for PC) remains:
  - November 3 Report sent to PC/OC/MRC for review and comment
  - November 9 Comments due back to NERC
  - November 11 Final Report sent to PC for approval
  - November 14 PC Webinar to approve report
  - November 15 Report send to BOT for approval
  - November 28 BOT Meeting for approval
  - November 29 Publish final report

b. Reliability Metrics Working Group

Provide feedback by September 30, 2011 on the responses to the comments received on the Integrated Reliability Index (IRI) whitepaper. The comment and response document is available at: IRI Whitepaper Comments and Responses.

Bill Adams, RMWG Chair gave the RMWG presentation provided in the Agenda package. Future items to consider;

- ✓ Consolidation of GADS, TADS and DADS metrics/reports
- ✓ TADs related metrics
- ✓ ERO-RAPA relay mis-operation

c. Geo-Magnetic Disturbance Task Force

Review and provide Feedback – PRELIMINARY DRAFT (expected to be posted by October 3) report from Geomagnetic Disturbance Task Force by October 14, 2011.

GMD Preliminary Report

Don Watkins highlighted the following information from the presentation provided in the Agenda package:

- ✓ Preliminary Draft Report out by October 3rd, with a short comment period (by October 14th)

- ✓ Need for generator equipment SMEs
- ✓ Coordination with NOAA for more advanced notification
- ✓ Power Flows that include the impedance of the earth to model ground currents
- ✓ Standardize GMD data formats/periodicity
- ✓ System stability – relay actions needed for the system to survive – controlled system shut down during extreme HILF events

PC Discussion

- ✓ Dave Goulding commented that pre-emptive actions would likely be second guessed as not being necessary by many "after the fact."
- ✓ Dave Goulding asked if CIGRE/other international groups participate.
  A: Several international groups interact with NOAA, and some outreach through e-mail notification occurs – agreed that more outreach should be undertaken by NERC in the future.
- ✓ Probability of an event occurrence
  A: Transformers sturdier than initially thought – better to identify the planning and operating options required to reconfigure and protect the system. Have developed a model for a 100 year event, in favor of the previous assertion that it would be ten times the HQ event – this assertion has now been recognized as "speculative."
- ✓ Generator SME
  A: Need to have a person with generator expertise review the information to determine applicability

d. Transmission Issues Subcommittee

PC Approved (two against) – Interconnection Criteria for Frequency Response Requirements – Determination of Interconnection Frequency Response Obligations (IFRO) – including changes brought forward at meeting:

- Change reference to "Category D" instead of "Category C" to be consistent with new TPL standard.
- Bruce units 3-8 MW = 4,324 MW
- Check of reference to the RS recommendation (from their report)
- Largest contingency in Ontario is Darlington Plant (3,500 MW)

Frequency Response Criteria Report for BAL-003 for use by Standards Drafting Team use

Bob Cummings gave the overview presentation provided in the Agenda materials

e. System Protection and Control Subcommittee

Technical Reference Document, Use of Circuit Breaker Position Indication in Breaker Failure Protection. PC comments to Phil Tatro by Sept 30th – will be resubmitted at the December PC for approval.

SPCS guideline: "Use of Circuit Breaker Position Indication in Breaker Failure Protection"

Jonathan Sykes, SPCS Chair gave the presentation provided in the Agenda package.

f. Spare Equipment Database Task Force
PC Approved (one abstention) the SEDTF report to the PC entitled Special Report: Spare Equipment Database Report. In addition, the report recommends the PC also approve implementation of the SED program as described in the report.

Dale Burmester gave the presentation provided in the Agenda package.

Four Primary Recommendations

- ✓ Participation:
  Voluntary by ALL NERC registered TOs and GOs
  Even if TO or GO has no spares
- ✓ Content: Long-lead time (6 months-plus) transformers including:
  Transmission: low side rating of 100kV or higher & max nameplate rating of 100 MVA or higher (all 3 phases)
  GSU: high side voltage of 100kV or higher and max nameplate rating of 75 MVA or higher (all 3 phases)
- ✓ 24x7 online program operated by NERC vendor: start 2012
- ✓ Confidentiality: Secure database
  Mandatory SED confidentiality agreement

Next Steps – report to be submitted for approval at the NERC November BOT meeting.

PC Discussion

- What about 230/69 kV transformers?
  A: Include in the future
- What are the contractual agreements?
  A: No obligations, no standard contracts – a data base just a vehicle to get interested parties together
- Coordination with other groups (like the Transmission Forum)
  A: EEI group is participating, will reach out to others

- Voluntary, but monitoring with quarterly reports – expect to become mandatory?
  A: It would be up to the PC to make that recommendation
- Regional Entity coordination role?
  A: Expect regional entities to participate in HILF war room teleconference calls

Additional Agenda Item

John Moura - with new PC leadership/secretary – how better to deliver the work product for PC meetings?

- ✓ Post information brought to the meeting ideally before being presented, or during meeting if developed "just in time"
- ✓ Organize/consolidate the web links instead of distributing them in the Agenda, Agenda Item, footnotes, etc.
- ✓ When commenting on drafts, difficult to see what has changed in previous drafts

Jeff Mitchell thanked Dave Goulding for attending, and encouraged continuing NERC BOT participation in future PC meetings.

Meeting Adjourned at 10:17 am on September 14th

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda
Standards and Compliance Workshop

October 26-28, 2011

JW Marriott Atlanta-Buckhead
3300 Lenox Road
Atlanta, GA 30326
(404) 262-3344

Wednesday, October 26	Presentation	Presenter
10:00 a.m.-12:00 p.m.	NERC Standards 101	**Maureen Long**, Director of Standards Process, and **Mallory Huggins**, Standards Specialist
12:00-1:00 p.m.	Lunch for NERC 101 participants	--
1:00-1:40 p.m.	President's Remarks	**Gerry Cauley**, President and CEO
1:40-2:30 p.m.	Standards Development Updates (Reliability Standards Development Plan; Prioritization; Version 0; Active Projects)	**Andy Rodriquez**, Director of Standards Development
2:30-3:15 p.m.	Cliff Notes for Standards Participation	**Maureen Long**, Director of Standards Process, and **Laura Hussey**, Standards Process Manager
3:15-3:30 p.m.	Break	--
3:30-4:30 p.m.	Feedback Loops: Events Analysis, Compliance, and Standards	**Earl Shockley**, Director of Events Analysis and Operations, **Mike Moon**, Director of Compliance Operations, and **Herb Schrayshuen**, VP and Director of Standards
4:30-5:00 p.m.	General Q&A Session	**Mike Moon**, Director of Compliance Operations, and **Herb Schrayshuen**, VP and Director of Standards

Thursday, October 27	Presentation	Presenter
8:00-9:00 a.m.	FERC Commissioner Remarks	**Commissioner Cheryl LaFleur**
9:00-9:30 a.m.	Rapid Development Project: Project 2010-05.1—Phase 1 of Protection Systems: Misoperations	**Maureen Long**, Director of Standards Process
9:30-10:00 a.m.	Interpretations	**Laura Hussey**, Standards Process Manager
10:00-10:15 a.m.	Break	--
10:15 a.m.-12:00 p.m.	Compliance and Enforcement Initiative and the Future Impact on Standards Development	**Rebecca Michael**, Associate General Counsel and Acting Director of Enforcement, and **Mike Moon**, Director of Compliance Operations
12:00-1:00 p.m.	Lunch	--
1:00-3:00 p.m.	Project 2010-017— Definition of Bulk Electric System	**Pete Heidrich**, Chair of Project 2010-17—Definition of BES, Standard Drafting Team, and **Carter Edge**, Chair of Project 2010-17—Definition of BES, Rules of Procedure
3:00-3:15 p.m.	Break	--
3:15-4:00 p.m.	ERO 2012 Implementation Plan and Actively Monitored List	**Kyle Howells,** Compliance Auditor
4:00-5:00 p.m.	Compliance Application Notices (CANs)	**Ben Engelby,** Senior Compliance Specialist, and **Caroline Clouse,** Compliance Specialist

Friday, October 28	Presentation	Presenter
8:00-9:00 a.m.	Website Update and Available NERC Resources	**Kristin Iwanechko**, Manager of Standards Information, and **Caroline Clouse**, Compliance Specialist
9:00-10:00 a.m.	CIP Version 5	**Steve Noess**, Standards Development Advisor
10:00-10:15 a.m.	Break	--
10:15-11:00 a.m.	Critical Infrastructure Protection (CIP) Initiatives at NERC	**Brian Harrell**, Manager of CIP Standards, Training, and Awareness
11:00-11:30 a.m.	Auditors and Compliance Enforcement Authority Training	**Peter Knoetgen**, Director of Training and Accreditation
11:30 a.m.-12:00 p.m.	General Q&A Session	**Mike Moon**, Director of Compliance Operations, and **Herb Schrayshuen**, VP and Director of Standards

From: Eleanor Crouch
To: Eleanor Crouch
Subject: Updated- NERC Workshop Announcement and Agenda: Standards and Compliance Workshop Announcement - October 26-28,2011 | Atlanta, GA
Date: Wednesday, October 19, 2011 12:58:44 PM

Updated Workshop Announcement

Standards and Compliance Workshop

October 26-28, 2011 | Atlanta, GA

Click here for: Agenda-Standards and Compliance Workshop – **Updated Agenda**
Click here for: Workshop Details and Hotel Registration Information – **New Area Hotels Now Available!**
Click here for: NERC Standards 101 - Registration
Click here for : Three-Day Workshop Registration
Click here for: Original Announcement

For more information or assistance, please contact **Eleanor Crouch** at eleanor.crouch@nerc.net or at **404-446-2572**.

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You have received this email because you are a registered representative in the Registered Ballot Body.

Regional Reliability Standards Evaluation Procedure

Version 2.0

September 30, 2011

Version 2.0 of the Regional Reliability Standards Evaluation Procedure is the revised version of the procedure for evaluating regional reliability standards which have been submitted to the North American Electric Reliability Corporation (NERC) for approval, revision, or withdrawal by a Regional Entity.

3353 Peachtree Road NE, Suite 600, Atlanta, GA 30326
Phone: 404.446.2560 ▪ www.nerc.com

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Introduction

Purpose

This procedure addresses both NERC's and the Regional Entities responsibilities during the development process, approval by the NERC Board of Trustees and approval by FERC in the United States and applicable authorizes in Canada and Mexico before regional reliability standards becoming mandatory and enforceable.

This procedure outlines NERC's responsibilities of (a) interaction with Regional Entities during the regional reliability standard development process and (b) evaluation of regional reliability standards that have been developed through a North American Electric Reliability Corporation (NERC) approved regional reliability standards development procedure and submitted to NERC by a Regional Entity for approval.

This document also provides the Regional Entities responsibilities to (a) notify NERC of a potential regional reliability standard (b) provide required documentation for the quality review, NERC BOT approval, and governmental authorities filings and (c) prepare the FERC Filing in conjunction with NERC Legal.

Once a regional reliability standard has been approved by FERC and applicable authorities in Canada and Mexico, the regional reliability standard shall be made part of the body of NERC reliability standards and shall be enforced upon all applicable bulk power system owners, operators, and users within the applicable Regional Entity's region, regardless of membership in the region.

Regional reliability standards shall provide for as much uniformity as possible relative to NERC reliability standards across the interconnected bulk power system of the North American continent. A regional reliability standard shall be more stringent than a continent-wide reliability standard, shall cover matters not covered by a continent-wide reliability standard, or shall be necessitated by a physical difference in the bulk power system.

Background

NERC is a nonprofit corporation. NERC was certified by the Federal Energy Regulatory Commission (FERC) as the Electric Reliability Organization (ERO) on July 20, 2006. NERC's predecessor organization, the North American Electric Reliability Council, was formed in 1968 as a result of the Northeast blackout in 1965 to promote the reliability of the bulk power system of North America. NERC works with all stakeholder segments of the electric industry, including Regional Entities, to develop standards for the reliable planning and operation of the bulk power system.

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While NERC reliability standards are intended to promote reliability, they must at the same time accommodate competitive electricity markets. Reliability is a necessity for electricity markets, and robust electricity markets can support reliability.

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Principles

Need for Guiding Principles

The NERC Board of Trustees has adopted reliability principles and market interface principles to define the purpose, scope, and nature of reliability standards. As these principles are fundamental to reliability and the market interface, these principles provide a constant beacon to guide the development of reliability standards. The Board of Trustees may modify these principles from time to time, as necessary, to adapt its vision for reliability standards.

Individuals and committees that are responsible for the regional reliability standards development procedure for each of the regional entities shall consider these reliability and market interface principles in the execution of those duties.

Reliability Principles

NERC reliability standards are based on certain reliability principles that define the foundation of reliability for North American bulk power system. Each regional reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power system. Each regional reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Market Principles

Recognizing that bulk power system reliability and electricity markets are inseparable and mutually interdependent, all regional reliability standards shall be consistent with market interface principles. Consideration of market interface principles is intended to ensure that reliability standards are written such that they achieve their reliability objective without causing undue restrictions or adverse impacts on competitive electricity markets.

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Elements of a Reliability Standard

Definition of a Reliability Standard

A reliability standard defines certain obligations or requirements of entities that own, operate, plan, and use the bulk power system of North America. The obligations or requirements must be material to reliability and measurable. A reliability standard is defined as follows:

> "Reliability standard" means a requirement to provide for reliable operation of the bulk-power system, including without limiting the foregoing, requirements for the operation of existing bulk-power system facilities, including cyber security protection, and including the design of planned additions or modifications to such facilities to the extent necessary for reliable operation of the bulk-power system; but shall not include any requirement to enlarge bulk-power system facilities or to construct new transmission capacity or generation capacity[1].

A Regional Entity may develop, through its own NERC-approved regional reliability standard development procedure, regional reliability standards that go beyond, add detail to, or implement NERC reliability standards, or that cover matters not addressed in NERC reliability standards.

Characteristics and Elements of a Regional Reliability Standard

To ensure as much uniformity as possible between regional and continent-wide reliability standards across the interconnected bulk power system of the North American continent, the characteristics and elements of regional reliability standards must be consistent with the characteristics and elements of continent-wide reliability standards as described in NERC's Reliability Standards Development Procedure.

Please reference the Standard Processes Manual (SPM) on the Standards page of the NERC site for additional information on elements of reliability standards.

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Roles in the Evaluation of Regional Reliability Standards

Approval, Revision, or Withdrawal of a Regional Reliability Standard

Only Regional Entities shall be permitted to submit a regional reliability standard to NERC for approval, revision, or withdrawal.

Roles in the Evaluation of a Regional Reliability Standard

Board of Trustees — The NERC Board of Trustees shall consider for adoption as reliability standards the regional reliability standards that have been approved by the applicable Regional Entity's Board of Directors. Once the NERC Board of Trustees adopts a regional reliability standard as a reliability standard, NERC will file the standard with the applicable regulatory authorities to propose the standard be made mandatory and enforceable.

NERC Committees, Subcommittees, Working Groups, and Task Forces — The committees, subcommittees, working groups, and task forces within NERC shall advise NERC as to the technical aspects of a proposed regional reliability standard. (Note: The Regional Entity requesting action on a specific regional reliability standard shall be permitted to present to the applicable NERC groups the technical aspects of the regional standard and the justification for the Regional Entity's request for such action.)

Manager of Regional Standards — The NERC regional reliability standards evaluation process shall be administered by NERC's Manager of Regional Standards. The Manager of Regional Standards is responsible for ensuring that the development and revision of regional reliability standards is in accordance with the NERC's Electric Reliability Organization Rules of Procedure, Section 300. The Manager of Regional Standards works to ensure the integrity of the process and completeness of the regional reliability standards. The Manager of Regional Standards facilitates all steps in NERC's review and approval of proposed regional reliability standards.

NERC and Regional Entity Members — The members of NERC and the Regional Entities may initiate new or revised regional reliability standards and may comment on proposed standards as delineated in the respective regional reliability standards development procedures.

Regional Entity — A Regional Entity is responsible for submitting a proposed regional reliability standard to NERC for approval, revision, or withdrawal. The Regional Entity is responsible for responding to comments and for requesting that a proposed regional reliability standard be forwarded to the NERC Board of Trustees for adoption.

Regional Entity Standard Drafting Team — A team of technical experts, appointed by the Regional Entity, that:

- develops the details of the regional reliability standard,
- considers and responds to comments, and
- participates in industry forums to help build consensus on the regional reliability standard.

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Standards Development Advisor – The Standards Development Advisor is a member of NERC staff who works closely with their assigned Regional Entity Standard Drafting Team throughout the development of a regional reliability standard. The Standard Development Advisor attends drafting team meetings, performs informal quality reviews, facilitates the formal quality review, provides the formal quality review feedback, facilitates the NERC comment period and provides technical advice from the NERC staff when needed.

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Regional Reliability Standards Evaluation Procedure

Overview

This regional reliability standards evaluation procedure is dictated by NERC's Electric Reliability Organization Rules of Procedure, Section 300.

Note:

- The term "days" below refers to calendar days.
- Standard Authorization Request (SAR) is the naming convention used in this document for the request to develop, revise, or withdraw a regional reliability standard, which is submitted to the Regional Entity to request development of a regional standard. A SAR may be approved or rejected by the Regional Entity pursuant to applicable procedures.

Regional Entity notifies NERC

The Regional Entity's notification and submission of a regional SAR to NERC is the first step in the process for NERC evaluation of a regional reliability standard. The Regional Entity is requested to send the SAR to the Manager of Regional Standards at nerc-rss@nerc.com.

The purpose for the Regional Entity to provide the SAR to NERC prior to its approval by the Region is to allow NERC time to review the SAR in conjunction with the continent-wide standards current and pending projects. There may be instances where a variance could be added to a continent-wide standard or where a continent-wide standard is on the horizon for the same standard as the submitted regional SAR.

NERC Review

NERC will review the SAR and provide a response back within 15 days. The response will inform the Regional Entity of the results of the review of the SAR against continent-wide standards and current and pending NERC projects. The Regional Entity can then make the decision whether to continue with the SAR project.

Approved SAR

Once the SAR is approved by the Regional Entity using its Regional Reliability Standard Development Process, the Regional Entity will provide the approved SAR to the NERC Standard Development Advisor assigned to the project.

NERC will post the SAR to the Regional Reliability Standards Under Development page.

NERC Roles and Responsibilities

NERC will follow the development of the new, revised, or withdrawn regional reliability standard. A regional NERC Standards Development Advisor will be assigned to the project.

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In order to stay involved in the development process, NERC requests that the Regional Entity include the Standard Development Advisor assigned to the project on the standard drafting team email distribution list.

NERC shall perform informal quality reviews during the development of the regional standard and will provide the results to the Regional Entity. The Regional Entity can request an informal quality review at any time. NERC will provide feedback from the informal quality review within 10 days of a request.

During the development process, NERC shall evaluate whether a proposed regional reliability standard has been developed in accordance with all applicable procedural requirements and whether the Regional Entity has considered and attempted to resolve all stakeholder objections. NERC staff may ask one of the NERC Committees, Subcommittees, Working Groups, or Task Forces to comment as to the technical aspects of the submitted request. The NERC Standard Development Advisor shall coordinate this work so that comments from NERC and related groups are submitted during regional comment periods in accordance with the region's standard development process.

Conduct Quality Review

A formal quality review shall be performed prior to posting the regional standard for regional ballot (and prior to the first 45-day comment period posted by NERC). The Regional Entity shall request the formal quality review prior to requesting the first 45 day comment period by NERC.

NERC shall coordinate a formal quality review of the "final draft" of the standard, implementation plan, VRFs and VSLs to assess whether the documents are within the scope of the SAR, whether the standard is clear and enforceable as written, and whether the standard meets the criteria specified in NERC's Benchmarks for Excellent Standards and criteria for governmental approval of standards, VRFs and VSLs. This review shall be completed within 30 days of receipt of the final version of the documents from the Regional Entity. The detailed results of this review shall be provided to the Regional Entity.

The formal quality review shall be performed prior to the regional standard being submitted for region ballot and taken to Regional Entity's Board of Directors for review and approval.

The Regional Entity will need to provide the following documents for the formal quality review:

- Approved SAR
- Regional Standard
- Justification for VRFs and VSLs
- Implementation Plan
- Technical Justification
- Mapping Document – Optional (Required if developing a new version of an approved standard)
- Issues Table – Optional (Required for resolution for FERC/Stakeholder issues)

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Technical Review

The Regional Entity can also request an informal technical review at any time, or NERC may conduct a review on its own initiative. The Standards Development Advisor handling the project will request that a NERC internal technical expert review the regional standard. The SME will provide questions, concerns, and recommendations. If requested, the SME will attend drafting teams meetings. NERC shall endeavor to submit its technical comments, if any, on a proposed regional standard during a regularly posted comment period in accordance with regional procedures.

Regional Variances

The same formal quality review procedure will be followed for regional variances.

Please reference the Standard Processes Manual on the Standards page of the NERC site for information on regional variances.

Expediting a Regional Reliability Standard

If the Regional Entity is expediting the regional reliability standard following their regional standards development process, the formal quality review can be performed in parallel with the first 45-day formal comment period.

Notification of Regional Entity Post for Comment (Optional)

The Regional Entity may request NERC send a notification to industry that the regional standard or variance has been posted on the Regional Entity's site for comment. This would allow the Regional Entity to obtain comments from outside its regional footprint on the technical merits of its regional standard or variance.

Conduct Formal NERC Comment Period(s)

Proposed new or revised regional standards will require a minimum of one 45-day public comment period where the new or modified standard, its associated VRFs and VSLs, and implementation plan or the proposal to retire a standard and its associated VRFs and VSLs and implementation plan are posted by NERC for continent-wide review. This NERC comment period may be conducted after the region process is completed, or concurrently with the "final" region comment and ballot periods.

The intent of the public comment period is to solicit specific feedback on the final draft of the regional standard, VRFs and VSLs, and implementation plan.

Below are the questions asked of stakeholders during the NERC comment period on a Regional Reliability Standard:

1. Do you agree the proposed standard is being developed using the associated Regional Reliability Standards Development Procedure?

2. Does the proposed standard pose a significant adverse impact on reliability or commerce of the interconnection and neighboring regions?
3. Does the proposed standard pose a serious and substantial threat to public health, safety, welfare, or national security?
4. Does the proposed standard create a serious and substantial burden on competitive markets within the interconnection and neighboring regions that is not necessary for reliability?
5. Does the proposed regional reliability standard meet at least one of the following criteria?
    a. The proposed standard has more specific criteria for the same requirements covered in a continent-wide standard.
    b. The proposed standard has requirements that are not included in the corresponding continent-wide reliability standard.
    c. The proposed regional difference is necessitated by a physical difference in the bulk power system.
6. If you have any other comments that you have not already provided in the response to prior questions, please provide them here.

Since the need for the regional reliability standards was established at the regional level, comments at this stage in the evaluation of a regional reliability standard will be permitted only on whether the proposed regional reliability standard meets the criteria listed above. The comments may include recommendations to accept or reject the standard and reasons for that recommendation.

Documents required for NERC Comment Period:

- Regional Standard
- Implementation Plan

The first 45-day public comment period by NERC may be concurrent with the final public comment period in the Regional Entity's regional standard develop process, as long as the formal quality review has been completed. The NERC comment period may also be conducted after final region approval of a regional standard or variance.

Once NERC has verified that the Regional Entity has submitted a complete request for approval, revision, or withdrawal of a regional reliability standard, NERC will set the posting start and end dates for the purpose of soliciting public comments. The posting of the proposed regional reliability standard will be linked to the Regional Entity's standards development documentation for reference.

Comments will be accepted online using an internet-based application along with other electronic means as necessary. Comments on the proposed regional reliability standard will be accepted for at least one 45-day period from the notice of posting.

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Consideration of the Comments

NERC will assemble the comments on the proposed regional reliability standard and supply the assembled comments to the Regional Entity. NERC will provide the assembled comments to the Regional Entity within ten days of the end of the public comment period.

The Regional Entity (generally including the regional Standard Drafting Team) shall give prompt consideration to the assembled comments in an effort to resolve all expressed objections. The Regional Entity shall provide to NERC a response to every comment contained in the assembled comments and identify any refinements made to the proposed regional reliability standard that were made in response to the comments received. The Regional Entity will summarize comments that were rejected by the Regional Entity and identify the reason(s) that the comments were rejected, in part or whole. The Regional Entity will supply the reply comments to NERC electronically within 30 days of receiving the assembled comments. The Regional Entity's reply comments will be posted on NERC's website within 14 days of receipt by NERC.

Based on comments received, the Regional Entity may determine there is an opportunity to improve the standard. In this case, the Regional Entity may revise the proposed standard and request another posting. Although there is no predetermined limit on the number of times a proposed regional reliability standard may be revised and posted, the Regional Entity should ensure the potential benefits of another posting outweigh the burden on the Regional Entity and stakeholders.

Prior to NERC Board of Trustees Review

The Manager of Regional Standards, in conjunction with the Regional Entity, will be responsible for preparing the Regional Standard for presentation to the NERC Board of Trustees for review and approval. The Regional Entity shall provide any additional documentation and information needed for submittal to the NERC Board of Trustees, as requested by NERC staff. The documentation must be received at least 60 days prior to the NERC Board of Trustees meeting. NERC staff shall review the documentation for completeness, and shall prepare a recommendation to present to the NERC Board.

NERC Board of Trustees Review

From a NERC Regional Standards perspective, a regional reliability standard is ready to be proposed to the NERC Board of Trustees after (a) a formal quality review has been performed and reviewed by the Regional Entity, (b) at least one 45-day comment period has been held at the NERC level, and (c) the regional reliablity standard has been approved by the Regional Entity's Board of Directors.

At a regular or special meeting, the Board of Trustees shall consider adoption of the proposed regional reliability standard. The Board of Trustees shall consider the Regional Entity's request, NERC staff's recommendation for action on the regional reliability standard, any stakeholder comments, and the Regional Entity's consideration of comments in determining whether to adopt the regional reliability standard as a NERC reliability standard. The Board of Trustees shall adopt

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or reject a proposed regional reliability standard, but may not modify a proposed regional reliability standard. If the Board of Trustees chooses not to adopt a regional reliability standard, it shall provide its reasons for not doing so.

Implementation of Regional Reliability Standard

The effective date of a regional reliability standard will be proposed in the standard implementation plan; however, the actual effective date will be contingent on obtaining the applicable regulatory approvals.

Governmental Approvals

Once the Board of Trustees has adopted a regional reliability standard or the revision or retirement of a regional reliability standard, the Board of Trustees will direct the standard to be filed with applicable governmental authorities in the United States, Canada, and Mexico for approval.

All approved documents shall be filed for approval with the applicable governmental authorities.

Petition Filing

The preparation for the petition filing involves a coordinated effort between many parties. NERC Legal Staff will prepare the shell petition. The Regional Entity will fill in the information required in the shell petition and produce the necessary attachments. The Regional Standards Staff will coordinate the process and assemble the document for final legal review. Generally, regulatory authorities will approve regional reliability standards that are either (1) more stringent than the continent-wide Reliability Standard, including a standard that addresses matters that the continent-wide Reliability Standard does not; or (2) regional reliability standards that are necessitated by a physical difference in the bulk power system. The petition must demonstrate how the regional reliability standard meets the regulatory and legal requirements for approval of a standard. Specifically, the petition must state the reliability need for the regional reliability standard, how the standard satisfies that need, and how the standard addresses any outstanding regulatory directives. If the standard is a revision to an existing standard the Regional Entity must explain how the new version of the standard improves upon the previous version of the standard. NERC will provide the petition "shell" for the Regional Entity's standards and legal staff to use as a guide to complete the petition by. NERC legal staff will work with the Regional Entity's legal staff to ensure that the filing document is complete.

Regional Reliability Standard Approved

Once a regional reliability standard is approved by applicable governmental agencies, all bulk power system owners, operators, and users within the region are required to comply with the standard in accordance with applicable statutes, regulations and agreements. The NERC staff will notify the Regional Entity of the regulatory decision. If accepted for filing, the regional reliability standard will be forwarded to the regional/NERC compliance programs within 10 business days for entrance into the ERO's compliance monitoring and enforcement program in accordance with the schedule included in the standard's associated implementation plan.

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ProcessDiagram

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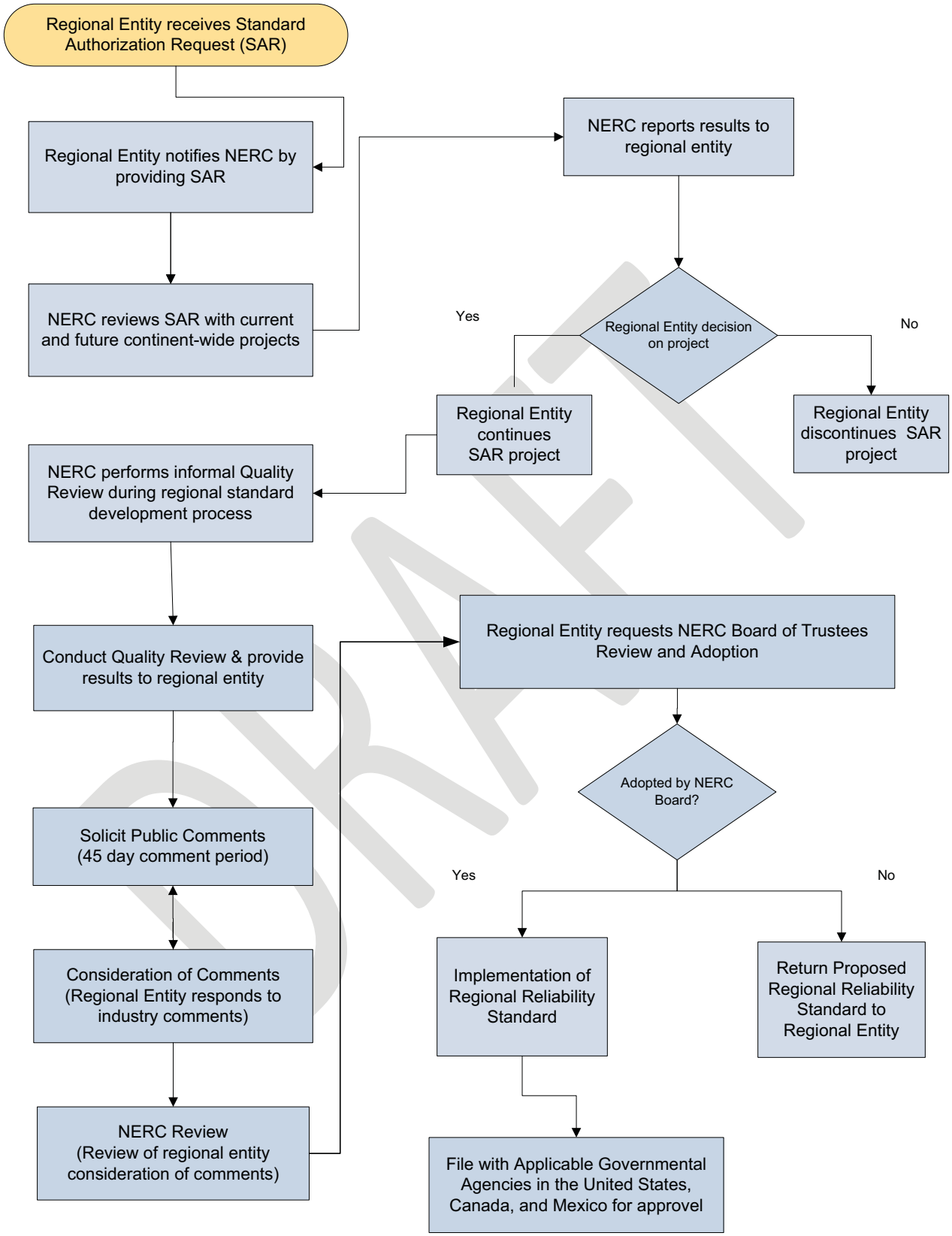
Regional Entity receives Standard Authorization Request (SAR)
Regional Entity notifies NERC by providing SAR
NERC reviews SAR with current and future continent-wide projects
NERC reports results to regional entity
Regional Entity decision on project
Yes
No
Regional Entity continues SAR project
Regional Entity discontinues SAR project
NERC performs informal Quality Review during regional standard development process
Conduct Quality Review & provide results to regional entity
Regional Entity requests NERC Board of Trustees Review and Adoption
Adopted by NERC Board?
Solicit Public Comments (45 day comment period)
Yes
No
Consideration of Comments (Regional Entity responds to industry comments)
Implementation of Regional Reliability Standard
Return Proposed Regional Reliability Standard to Regional Entity
NERC Review (Review of regional entity consideration of comments)
File with Applicable Governmental Agencies in the United States, Canada, and Mexico for approvel

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Special Procedures

Urgent Actions

Under certain conditions, the Regional Entity may designate a proposed regional reliability standard or revision to a regional reliability standard as requiring urgent action. Urgent action may be appropriate when a delay in implementing a proposed regional reliability standard or revision can materially impact reliability of the bulk power system. The Regional Entity must use its judgment carefully to ensure an urgent action is truly necessary and not simply an expedient way to change or implement a standard.

The Regional Entity will submit a request for approval, revision, or withdrawal of a regional reliability standard to NERC's regional standards staff. The request must include a justification for urgent action. If the Regional Entity designates the request as an urgent action item, then NERC will post the request for public comment. This posting requires a minimum 30-day posting period instead of the standard 45 days. NERC and the Regional Entity will use reasonable efforts to expedite the process, with the goal of completing the NERC regional reliability standards evaluation process in 60 days or less, including obtaining Board of Trustees approval. The petition(s) seeking approval from applicable regulatory agencies will be filed within 45 days after Board approval.

Appeals

The appeals process is outlined in the Standard Processes Manual on the Standards page of the NERC site.

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Maintenance of Regional Reliability Standards Evaluation Procedure

Requests to Revise the Regional Reliability Standards Evaluation Procedure

Any person or entity may submit a written request to modify the Regional Reliability Standards Evaluation Procedure. NERC shall oversee the handling of the request. NERC shall prioritize all requests, merge related requests, and respond to each requestor within 90 days.

On-line Standards Information System

NERC shall be responsible for maintaining an electronic database of information regarding currently proposed and currently in effect regional reliability standards. This information shall include current regional reliability standards in effect, proposed revisions to regional reliability standards, and proposed new regional reliability standards. This information shall provide a record, for at a minimum the previous five years, of the review and approval process for each regional reliability standard, including public comments received and the associated responses during the approval process. This information shall be available through public internet access.

Archived Standards Information

NERC shall be responsible for maintaining a historical record of regional reliability standards information that is no longer maintained on-line. For example, regional reliability standards that expired or were replaced may be removed from the on-line system. Archived information shall be retained indefinitely as practical, but in no case less than five years or one complete standard cycle from the date on which the standard was no longer in effect. Archived records of regional reliability standards information shall be available electronically within 30 days following the receipt by NERC of a request from a Regional Entity.

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From: Barbara Nutter
To: rsg
Subject: NERC: Regional Reliability Standards Evaluation Procedure
Date: Friday, September 30, 2011 1:42:08 PM
Attachments: NERC Regional Reliability Evaluation Procedure_093011_Clean.doc

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Dear RSG:

Attached is a clean version of the Regional Reliability Standards Evaluation Procedure Revision 2 dated September 30, 2011. Per comments received and discussion at the last RSG meeting changes have been made in the following areas:

- Purpose
- Regional Variances
- Notification of Regional Entity Post for Comment (Optional)
- Conduct Formal NERC Comment Period
- Prior to NERC Board of Trustees Review
- Petition Filing
- Appeals

Items that still need performed:

- Correct page numbering in Table of Contents
- Add section numbering
- Update to new template

Please review the document prior to the next RSG meeting on October 6, 2011. We will vote on approval for implementation of Revision 2 during the October meeting.

If you have any questions, please feel free to contact me.

Thank you,

Barb Nutter

Standards Development Advisor - Regional Standards
North American Electric Reliability Corporation
barbara.nutter@nerc.net
404.446.9692 - office
609.651.6037 - cell

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Ben's Notes (in italic) of Standards Committee Meeting

Thursday, August 11, 2011 | 1–5 p.m. Eastern

1. **Administrative Items**
   a. Introductions and Quorum* (A. Mosher)

      Proxy: Nathan Mitchell for Allen Mosher, John Huge for John Anderson.

      From the BoT, Ken Peterson and Tom Barry joined the call.

   b. Conference Call Reminder **(Maureen)**

   c. NERC Antitrust Compliance Guidelines* (M. Long)

   d. Meeting Agenda — **Approve** (A. Mosher)

      Approved without changes.

   e. Waiver of 5-day Rule — **Approve** (A. Mosher)

      Action on EEI/NRECA's request for interpretation of CIP-001, R1 (Item 3f).

2. **Consent Agenda**
   a. July 13-14, 2011 Standards Committee Meeting Minutes* — **Approve**

   b. July 26, 2011 Standards Committee Executive Committee Meeting Minutes*— **Ratify**

   c. Project 2009-01 – Disturbance and Sabotage Reporting – accept the resignation of the chair; appoint a new chair and vice chair* (Confidential)

   d. Project 2007-09 – Generator Verification – accept a resignation and appoint a replacement* (Confidential)

   e. Critical Infrastructure Protection Interpretation Drafting Team – appoint additional members* (Confidential)

      Above approved in one motion.

3. **High Priority Projects, Activities, and Action Items**
   a. Status of Projects Identified as High Priority* (A. Rodriquez)

      Andy provided an update. No new issues.

   b. Status of BES Definition Projects

Pete Heidrich and several SDT members dialed in to provide an update. The BES SDT proposed to post the draft definition without the piece that would raise the 20 MVA/unit to 75 MVA at this time. However, the industry comments and proposal for this change need to be duly addressed. The SDT proposed to submit a revised SAR to address the 20/75 MVA proposal after the initial definition is approved. The SDT will work with the SC to prepare a position paper to the BoT by September 7 to layout options and propose best ways forward in meeting the FERC deadline to file a revised definition by January 2012.

c. Rapid revision to MOD-028 (A. Rodriquez)

The SC directed the SDT to develop a rapid revision. Andy indicated that a rapid change may not be appropriate for this request. The SC suggested that the IDT has several options which, among others, would include proposing an interpretation and suggesting a normal standard development project be initiated to fully address the issues brought up by the request. The SC will wait for the IDT's proposal.

d. Project Prioritization Schedule (A. Rodriquez)

Andy will try to send a first draft priority list (using the latest tool) to the SC in a couple of weeks. The SC will either call a special meeting or work on the proposed list at its September meeting, then hold a webminar presenting the project priority in mid September and invite industry comments. The SC will then finalize the priority list at its October meeting and prepare for a presentation at the November BoT meeting.

e. Status of Outstanding Interpretations* (L. Hussey)

Ben asked about the status of the COM-002 interpretation and expressed a concern that several months have passed and the IDT hasn't developed response to comments and post a revised interpretation for balloting. Staff indicated that the IDT has been tied up with standard development work but has a plan to attend to the RFI at its August/September meeting.

f. EEI and NRECA Request for Interpretation* (L. Hussey)

EEI and NRECA jointly filed a Request for interpretation on CIP-001-1 R1 seeking clarification on the word "facilities". They filed the request after the final CAN-016 was posted in which the term "facilities" was not defined. The SCEC discussed the RFI and decided that a proper interpretation could not be drafted within the BoT guideline. A change to the standard, which is underway in the Sabotage and Disturbance Reporting project (EOP-004), or a revise CAN would be a more appropriate project. Staff was directed to ask the requesters if they would accept a revised CAN with clarification of the "facilities" issue. At the SC meeting, such an indication hadn't come forth but staff indicated that they expect a positive respond by the requesters was imminent.

Mike Gildea suggested (moved) that the SC move forward with forming the interpretation drafting team with the understanding that if indeed the requesters withdraw the request, no further work would be done. However, staff pointed out that after an IDT is formed, the requesters will no longer be able to withdraw the request. Gildea changed his motion as follows:

Motion passed to start preparing for soliciting IRT nominations, with actions withheld for 2 weeks pending a response from the requesters.

4. Standards Process

a. Letter from Tom Galloway regarding Interpretations and Compliance Application Notices*

The CANs discussions at the August 4 BoT meeting took care of most of the issues raised by the SC. However, the SC will continue to monitor the CAN process development, and may revisit some of the issues raised in the letter (and Galloway's response) as appropriate.

b. Election of Standards Committee Members *

Election to start sometime in September. Segments that choose to use a special election procedure need to submit the procedure to Maureen. Still no words from FERC regarding approval of the RoP that contained the revised election procedure which would allow less than 75% to reach a quorum for bi-election, and moving the officers to neutral, non-voting positions.

c. Project Prioritization Tool and Reference Document *

The SC approved posting of the tool and the reference document before the webminar as information only. Andy was asked to work with Mike Gildea and his Communication and Planning Subcommittee to communicate posting and webminar announcement.

d. PRC-005-2 – Authorize Posting SAR and Standard (To be sent separately)

5. Coordination

a. Report from Member Representative Committee, Standards Oversight and Technology Committee and Board of Trustees Meetings (A. Mosher and H. Schrayshuen)

<u>From the SOTC Meeting</u>

- *SOTC expressed a concern that based on current forecast, very few projects are scheduled for completion in 2013. This needs to be discussed in the context of prioritization. Andy indicated that while he agreed this does not have good optics, we need to figure out at a higher level how we want to deal with the logistical problem of managing the triple constraint (schedule, resources and scope). We are looking to control scope in a limited fashion by phasing projects, but we still have little control over volunteer resources. So if we are going to control schedule, we are going to have to be more aggressive about managing the scope of projects. If we want to tackle big issues, though, we are going to have to recognize that the scope is fixed, resources are fixed – and with those limits, the schedule just takes as long as it takes. Ben agreed with this view. Manipulating the schedule to force a number of projects to be completed within a specific time frame can be counter-productive, witnessed by past failures of some rushed projects.*
- *Integrating Regional standards processing. Tom Berry indicated that this needs to be worked out between NERC Management, the Regional Executives and the SC. Staff will take a first stab at it.*
- *Some SOTC members expressed a desire to add flexibility to the standards development process following the SC's decision in July to move the PRC-005 project back to square one despite it failed by a small margin. The Standards Committee's Process Committee was charged to explore ways to add flexibility.*

<u>From the MRC/BOT Meetings</u>

- *At the BoT meeting, Tom Berry motioned to move FAC-003 toward for approval in November and asked the SC to explore options to achieve this. Andy indicated that the SDT appeared to have worked out quite a bit of technical justification to support the latest draft. He expected to receive the package sometime next week. The SC was hoping that the QR will find the revised standard and justification to be acceptable for posting for balloting.*
- *There was general discussion at the BoT meeting on how to integrate the pleading development earlier in the Standard Development process. One idea was to have various skill sets on SDTs - more lawyers for instance. Andy indicated that his aligns well with what we are already working on internally at NERC, an effort where Legal gets involved earlier and learns the project inside and out. Holly and Andy will further discuss legal's involvement to help standard development recognizing the SDT has final responsibility and decision of the technical content of the standards.*
- *The BoT's request to receive a report/proposal paper from the SC/SDT regarding the BES definition was discussed under Item 3b.*

b. Coordination with Regulatory and Governmental Authorities (H. Hawkins)

Holly provided an update. Nothing major worth noting.

c. Coordination with Regional Managers (H. Schrayshuen)

Herb provided an update. Nothing major worth noting.

6. Discussion Items

a. Standards Committee Meeting Locations for 2012

Denver, among other offered locations, was picked for the July 2012 meeting.

b. Standards Committee Meeting with SDT Leadership October 11, 2011*

Maureen will draft a letter for Allen inviting the SDT chairs and vice-chairs, and those SC members who can arrive a day early to attend the October 11 meeting.

7. Informational Items

a. Drafting Team Vacancies*

SC noted the specific areas that some SDTs are lacking representations.

b. SAR Form *

A revised SAR form(very minor change) is now being used.

8. Executive Committee Actions (M. Long)

a. Pre-authorize the Standards Committee's Executive Committee to take action on items identified during the meeting — **Pre-authorize**

- *Handle any additional nominations to some SDTs.*
- *Handle the EEI/NRECA RFI as needed.*

9. Adjourn

Background

1. Administrative Items

a. **Introductions** — Allen Mosher will lead the introduction of committee members and determine if there is a quorum.

b. **Conference Call Reminder** — Participants are reminded that the conference call meeting is public and open to all interested parties. The access number was posted on the NERC website and widely distributed. Speakers on the call should keep in mind that the listening audience may include members of the press and representatives of various governmental authorities, in addition to the expected participation by industry stakeholders.

c. **NERC Antitrust Compliance Guidelines** — Maureen Long will review the NERC Antitrust Compliance Guidelines provided in **Attachment 1c**. It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition. It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.

d. **Meeting Agenda** — Allen Mosher will review the meeting agenda and ask for modifications before the agenda is approved.

e. **Waiver of 5-day Rule** — If there are items submitted to the Standards Committee for action with less than five days notice, those items cannot be added to the agenda without the unanimous consent of the members present. If any items fall into this category Allen Mosher will ask the Standards Committee to vote on waiving the 5-day rule.

2. Consent Agenda

The consent agenda allows the Standards Committee to approve routine items that would normally not need discussion. Any Standards Committee member may ask the chair to remove an item from the consent agenda for formal discussion.

The chair will ask the committee to approve, ratify, acknowledge, or appoint as appropriate the following from the consent agenda:

a. July 13-14, 2011 Standards Committee Meeting Minutes

b. July 26, 2011 Standards Committee Executive Committee Meeting Minutes

c. Project 2009-01 – Disturbance and Sabotage Reporting – accept the resignation of the chair; appoint a new chair and vice chair

d. Project 2007-09 – Generator Verification – accept a resignation and appoint a replacement

e. Critical Infrastructure Protection Interpretation Drafting Team – appoint additional members

3. High Priority Projects, Activities and Action Items

a. Status of Projects Identified as High Priority

Andy Rodriquez will review the status of the following high priority projects:

Projects Behind Schedule:

Project 2007-07 Vegetation Management - Project delayed significantly due to concerns regarding VSL assignments for R1/R2 and technical content in the draft that could be viewed as weakening the standard. The issues of Active Transmission Line Right of Way, Critical Clearance Zone, Gallet equations, and compliance elements underwent significant debate. The team expects to return documents to NERC on or around August 5, 2011 for assembly into a package for Quality Review prior to recirculation ballot. Due to the late stage in development, no additional actions to bring standard back on schedule are available beyond continuing to work toward completion.

Project 2007-17 Protection System Maintenance and Testing – Project delayed due to a failed recirculation ballot. A new project schedule is under development.

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves – The project was delayed due to its prioritization assignment, but Phase I was moved into formal development. A new project schedule is under development.

Project 2010-07 Generator Requirements at the Transmission Interface – The project was delayed approximately one month due to the recent Milford/Cedar Creek Order and concerns associated with that Order. The team is evaluating options for moving forward.

Project 2007-02 Operating Personnel Communication Protocols – Additional work required to address previous response to comments from 1/10/2010 has led to a one-month delay in project. The team continues to work on moving forward as soon as possible.

b. Status of BES Definition Projects

Peter Heidrich and Herbert Schrayshuen will provide updates on the status of the various teams working on this project.

c. Rapid Revision to MOD-028

During its July 2011 meeting, the Standards Committee voted to allow staff to ask the MOD-028 interpretation requester (Florida Power & Light Co. or FPL) if it would accept a 'rapid revision' to the standard as an alternative to the formal interpretation. FPL has indicated it will accept the outcome of the rapid revision process as an alternative to a formal interpretation. Andy Rodriquez will report on the status of this project.

d. Project Prioritization Schedule

Andy Rodriquez provided a list of projects for inclusion in the next version of the Reliability Standard Development Plan 2012-2014 and the following schedule for prioritizing those projects:

- August 11 – Present list of projects to SC
- August 22 – Provide SC with NERC staff recommendations
- August 22- September 2 - SC members provides their recommendations
- September 8 – SC reviews prioritization results, approves Prioritization for posting
- September 12-26 – Public posting of Prioritization, RSDP for comment
- October 3 – Draft RSDP and Prioritization send to BOT for review
- October 12-13 – SC Final approval of Prioritization for use in the RSDP
- November 3 – BOT approval of Final RSDP and Prioritization
- December – Filing of RSDP and Prioritization

e. **Status of Outstanding Interpretations**

Laura Hussey will provide an update on the status of outstanding interpretations.

f. **EEI and NRECA Request for Interpretation**

The standards staff presented the Standards Committee's Executive Committee with a request for interpretation that was jointly submitted by EEI and NRECA. The request is associated with CIP-001, Requirement R1 and seeks clarity on the meaning of "its facilities."

> R1: Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have the procedures for the recognition of and for making their operating personnel aware of sabotage events on its facilities and multi-site sabotage affecting larger portions of the interconnection.

A CAN was issued on this standard and requirement that included the following statement:

> The registered entity would be considered non-compliant with the standard if its Sabotage Reporting Procedure excludes any of its facilities from its procedure, including but not limited to non-BES facilities.

Michael Moon reported that the CAN was issued in response to a Notice of Penalty (see pages 4, 5) associated with an entity that developed a procedure that specifically excluded reporting of events on non-BES facilities.

The standard is currently under revision as part of Project 2009-01 – Disturbance and Sabotage Reporting. That project is combining requirements from CIP-001 and EOP-004 into a new version of EOP-004. The Project 2009-01 plans to post its standard for a parallel comment and ballot period in August.

Recommendation:

While this is a valid request for clarity on the meaning of a requirement, the standard lacks information to provide clarity on what was meant by use of the term, "its facilities" in CIP-001, Requirement R1. The standards staff recommends advising the requesters that there is not sufficient information in the body of the standard to develop an interpretation under the strict construction guidance provided by the Board of Trustees and advising the requesters that the standard is under revision and additional clarity will be provided with the revised standard.

4. Standards Process

a. **Letter from Tom Galloway regarding Interpretations and Compliance Application Notices**

The Standards Committee sent Tom Galloway a letter expressing concerns about Compliance Application Notices and Mr. Galloway provided a written response to the letter from the Standards Committee. The committee will review the information in the letter and any action resulting from the August 3, 2011 Member Representative Committee where CANs will be discussed.

b. **Election of Standards Committee Members**

Maureen Long will review the process for electing Standards Committee members. While the Board of Trustees approved revisions to the election procedure and these have been filed for approval, FERC has not yet ruled on these.

c. **Project Prioritization Tool and Reference Document**

Ben Li will provide an update on the revisions to the Project Prioritization Tool and associated reference document and will seek the Standards Committee's approval of both.

d. **PRC-005-2 – Authorize Posting SAR and Standard (To be sent separately)**

The drafting team working on the PRC-005-2 – Protection System Maintenance standard has been working to update its standard, using information from the failed recirculation ballot. The team is expected to submit a SAR and proposed standard with a request to post both for a formal parallel comment and initial ballot period.

5. Coordination

a. **Report from Member Representative Committee, Standards Oversight and Technology Committee and Board of Trustees Meetings (A. Mosher and H. Schrayshuen)**

Allen Mosher and Herbert Schrayshuen will report on their observations and actions taken during the August 3-4, 2011 MRC and BOT meetings.

b. **Coordination with Regulatory and Governmental Authorities**

Holly Hawkins will provide an update on regulatory activities since the last Standards Committee meeting.

c. **Coordination with Regional Managers**

Herb Schrayshuen will provide an update on the work of the Regional Standards Group.

6. Discussion Items

a. **Standards Committee Meeting Locations**

The Standards Committee has confirmed meeting space for its January, April and October face-to-face meetings. Three locations have space for the July meeting and the committee will be asked to select one of these locations during the meeting.

- January 11-12– San Diego
- April 11-12– Tampa
- July 11-12– Carmel, Denver, or Charlotte
- October 10-11– Miami

b. **Standards Committee Meeting with SDT Leadership October 11, 2011**

During its July 2011 meeting, the Standards Committee expressed a desire to invite the leadership of active drafting teams to a meeting on October 11, 2011. The Standards Committee will review the suggestions that arose from the meeting with drafting team leadership in 2010 to identify suggestions that have been adopted and suggestions that deserve additional attention.

7. Informational Items

a. **Drafting Team Vacancies**

b. **Updated SAR Form**

8. Executive Committee Actions

a. **Pre-authorize the Standards Committee's Executive Committee to Take action**

If potential action items are identified before the close of the August Standards Committee meeting, the Standards Committee will be asked to preauthorize the Standards Committee to act on these items if they are submitted before September 8, 2011.

9. Adjourn

Outstanding Action Items from March, April, May, June, and July SC Meetings							
Activity	Entire Standards Committee	Executive Committee	Standards Committee Officers	Process Subcommittee	Comm. & Planning Subcommittee	Staff	Status
03132011_6_Review process for replacing drafting team members (when an employee appointed to a drafting team changes jobs, some entities recommend another employee as a replacement; some teams working on lower priority projects are recommending drafting team replacements)s				Subcommittee			Open
03132011_8_ Develop a proposal to integrate the consideration of reliability improvements versus costs into standard development and approval. – are there simple questions we can ask stakeholders in comment forms for cost benefit feedback				Subcommittee			Process Subcommittee reported this is in progress – monitoring NPCC actions
04132011_10_Share Pro Forma VSLs with NERC and Regional enforcement and legal staffs; if supported share with FERC staff; if supported file with FERC				Terry Bilke			In progress
07132011_1_Update project web pages with latest project						Andy Rodriquez	

Outstanding Action Items from March, April, May, June, and July SC Meetings							
Activity	Entire Standards Committee	Executive Committee	Standards Committee Officers	Process Subcommittee	Comm. & Planning Subcommittee	Staff	Status
schedules							
07132011_2_Consult with David Cook on final location of BES Definition Technical Principles						Andrew Dressel	
07132011_3_Work with the CCC's SIS to identify opportunities for improved coordination on RSAW development				Jim Stanton			
07132011_4_Send a "hold the date" notice to SDT chairs and coordinators/advisors for Tuesday, October 11 2011						Maureen Long	

From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Standards Committee Announcement | 2012 - 2013 SC Elections
Date: Tuesday, October 11, 2011 4:15:07 PM

2012-2013 SC Elections
Standards Committee

Click Here for: Nomination Form (Under **2012-2013 Term Elections** Heading)

Registered Ballot Body members and others interested in NERC Reliability Standards are encouraged to submit nominations for industry segment representatives on the Standards Committee (SC). With reliability standards mandatory for all bulk power system owners, operators, and users in North America, the SC's oversight role is increasingly important. The Standards Committee consists of two members from each of the ten Industry Segments that make up the Registered Ballot Body, with at least two members representing Canada. The Standards Committee is elected by stakeholders, and reports directly to the Board of Trustees. The Standards Committee meets monthly, either by conference call or in face-to-face meetings. Members who cannot travel to the meetings may participate by conference call. The Standards Committee Charter provides a description of the Standards Committee's responsibilities.

Each of the ten Industry Segments has a position[1] to fill for a two-year term ending December 31, 2012.

Any Industry Segment that intends to use a special procedure to elect its Standards Committee representatives must provide a copy of its procedure and evidence that the use of the procedure was ratified by at least two-thirds of the registered entities in that segment to Monica Benson at monica.benson@nerc.net.

As reference, the following Standards Committee members have a term that expires at the end of 2011:

Segment 1 – Carol Sedewitz
Segment 2 – Ben Li
Segment 4 – Allen Mosher
Segment 6 – Alice Ireland
Segment 7 – Frank McElvain
Segment 8 – Jim Stanton
Segment 9 – Klaus Lambeck
Segment 10 –Linda Campbell

In addition to the above, there is a vacancy in both Segment 3 and Segment 5.

Anyone may submit a nomination. However, the nominee must be from an entity registered in the particular segment for which the nomination is received. Instructions are provided in the Election of Members of the NERC Standards Committee Procedure.

Please submit completed SC nomination forms to monica.benson@nerc.net no later than **November 1, 2011**. An election of segment representatives will be conducted immediately after the

nominations period is closed.

Questions may be addressed to Monica Benson or 404-446-2573.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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[1] One of the current Canadian members has a term that expires at the end of 2010. In accordance with the Standards Committee Charter, if the regular election of Standards Committee members does not result in at least two Canadian members being elected, the Canadian nominees receiving the next highest percentage of votes within his or her respective Segment(s) will be designated as members, as needed to achieve a total of two Canadian members.

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Standards Committee Nomination Form

2012-2013 Term

The Standards Committee (SC) has two representatives from each of the ten industry segments. (If the regular election of Standards Committee members does not result in at least two Canadian members being elected, the Canadian nominees receiving the next highest percentage of votes within their respective Segment(s) will be designated as members, as needed to achieve a total of two Canadian members.) The SC representatives are elected by the segment they represent. The SC reports to the NERC Board of Trustees and oversees the development of NERC Reliability Standards by performing the following tasks governed by the Standard Processes Manual and the Standards Committee Charter:

- Manages standard development
- Manages the standards process
- Reviews the effectiveness of the balloting process
- Coordinates with the compliance program
- Coordinates with NAESB
- Coordinates with the NERC Board of Trustees, regulators and industry groups, and stakeholders

Any person may nominate any other person to serve on the SC, with the limitation that the nominee must be employed by or an agent of an entity that is registered in that segment of the Registered Ballot Body. The nominee is not required to be the RBB representative from that organization.

Nominations will be accepted for all positions listed below. Please note that Segment 10 has a separate procedure for election of representatives to the SC. Election of representatives for all other segments is governed by the default Election of Members of the NERC Standards Committee Procedure.

You may use this form to nominate candidates for any of the nine segments that use the default SC election procedure. You may submit more than one nomination. Please, however, use one form per nomination. You are welcome to nominate yourself.

Which Industry Segment will this candidate represent? (Check one.)		
☐	Segment 1	Transmission Owners
☐	Segment 2	Regional Transmission Organizations and Independent System Operators
☐	Segment 3	Load-serving Entities
☐	Segment 4	Transmission-dependent Utilities
☐	Segment 5	Electric Generators

☐	Segment 6	Electricity Brokers, Aggregators, and Marketers
☐	Segment 7	Large Electricity End Users
☐	Segment 8	Small Electricity End Users
☐	Segment 9	Federal, State, and Provincial Regulatory or other Government Entities

Nominee's name and contact information.	
Name	
Job Title	
Organization	
Telephone	
E-mail	
Mailing Address	

Has the nominee been contacted to verify willingness to serve on the SC?	Yes ☐	No ☐

Person making this nomination (if different from nominee).	
Name	
Organization	
Telephone	
E-mail	

Please provide a brief summary of the nominee's qualifications for this SC position. (The summary should be no longer than a single page of single-spaced text.

Please complete this form no later than November 1, 2011 and send to Monica Benson at monica.benson@nerc.net.

From: Lee R. Pedowicz
To: Guy V. Zito
Cc: John G. Mosier Jr.; John Muir; Gerard J. Dunbar
Subject: CO-11 Meeting Call In
Date: Tuesday, October 04, 2011 9:23:00 AM

Good morning.

I called in to the CO-11 Meeting this morning as Jerry asked, and the following was discussed regarding CANs, CAN-0006 EOP-005-1 R7 Verification of Restoration in particular:

- I explained the CANs comment process from the RSC perspective--how I distribute the CANs to the RSC, and then send the consensus comments to NERC.
- There was a discussion about the "authority" of CANs, and what they're supposed to do, and the impact of CANs on audits. CANs raise more questions than provide answers.
- There were a lot of compliance questions, so I asked John Muir to call in and join the discussion. He provided helpful information on how auditors use the CANs. He said that auditors are supposed to be familiar with CANs, use the CANs, and audit to the CANs--CANs not being requirements, but clarifications of the requirements.
- CANs are not "formal" documents--how can entities be expected to comply with CANs? And if so, a more formal procedure needs to be put in place for managing CANs.
- CO-11 mentioned getting their concerns over CAN-0006 to Mike Moon. Individuals can always send E-mails to him directly, but from a NPCC perspective the RSC submits the CANs comments.
- To ensure Working Group, Task force or other NPCC input to CANs, I suggested that when CANs are posted for comment I distribute to the affected parties within NPCC beyond the RSC and Compliance. CO-11 thought it was a good idea.
- Jerry said that he will send me a letter addressing CO-11's concerns.
- Jerry asked that we include a discussion of CANs at the next RSC Meeting.

Lee

CAN Number (If a CAN has been numbered, it is under development)	CAN Requestor	Status	Standard	Project Subject	Item Description/Driver for Request (NERC has tried to identify these issues without identifying regions or registered entities; the description is a summary at the time of quarterly prioritization. It may not include all the related information currently identified with each possible CAN; NERC will document other information related to each within that CANs development history. Items listed here may require more than one CAN per standard or a group of similar issues into one CAN, depending on efficiencies, other NERC-wide efforts, etc.)
5		Industry Comments/ Industry Redline	CIP-002-3 R3	Laptops remotely controlling BES assets are designated CCA	Registered entities and Regional Entities requested clarity regarding whether system operator laptops with the capability and purpose of controlling Bulk Electric System assets remotely (whether in normal operations or in emergencies) should be designated as Critical Cyber Assets (CCAs).
6		Industry Comments/ Industry Redline	EOP-005-1 R7	Verification of Restoration Procedure by Actual Testing or by Simulation	Evidentiary Requirements regarding Actual Testing or by Simulation
7		Industry Comments/ Industry Redline	CIP-004-2 R4.2 CIP-004-3 R4.2	Revocation of Access (physical and electronic) to Critical Cyber Assets	Registered Entities and Regional Entities requested clarity about the extent and timing of revocation of access to Critical Cyber Assets (CCAs) required in CIP-004 R4.2. Specifically, clarity was sought on what constitutes revocation, access (physical and electronic), and what constitutes revocation of access to CCAs under different entity-specific scenarios.
8		Industry Comments/ Industry Redline	PRC-005-1 R2	Pre-June 18 evidence	NERC Compliance received a request for clarification on PRC-005-1 R2 regarding the monitored timeframes for gathering evidence pre-June 2007 when determining compliance with an entity's maintenance and testing program. What is the validity of a regional auditor to ask for evidence pre June 2007 even though there was no obligation to retain records until at least June 17, 2007?
9		Industry Comments/ Industry Redline	FAC-008 R1 FAC-009 R1, R2	Facilities not Matching Design Specifications	Field construction not matching design specifications
10		Industry Comments/ Industry Redline	Definition of "Annual"	Definition of "Annual"	The definition of “annual” and implementation of annual requirements

11		Industry Comments/ Industry Redline	PRC-005-1 R2	New Equipment	NERC Compliance received a request for clarification on PRC-005-1 R2 regarding gatheriing evidence of initial testing for new equipment
12		Industry Comments/ Industry Redline	Requirement of periodic action by Effective Date	Requirement of periodic action by Effective Date	Registered entities and Regional Entities have requested that NERC provide clarification on whether a registered entity must provide evidence that it completed a periodic action or event required by a NERC Reliability Standard (Standard) prior to the registered entity's Effective Date for the Standard.
13		Industry Comments/ Industry Redline	PRC-023	R1 and R2	Identification of the Effective Date for some Equipment
15		Industry Comments/ Industry Redline	EOP-002-2 Attachment 1; EOP-005-1 R11.3; IRO-002-2 R4, R5, R6; IRO-003-2 R1, R2; IRO-005-3 R1; and IRO-006-4.1 R1.4.1	NERC Tools	NERC Compliance received a request for clarification on a suite of reliability standards that require the use of a NERC tool. What is a registered entity's performance obligation to a standard's requirements when a NERC Tool is unavailable? EOP-005-1 R11.3: NERC Compliance received a request for clarification regarding "working with" and the applicability.
16		Industry Comments/ Industry Redline	CIP-001 R1	Non-BES Facilities	Is a registered entity required to include non-BES facilities in its Sabotage Reporting Procedure?
17		Industry Comments/ Industry Redline	CIP-007-3 R5	Password controls	Is a CEA is to verify that technical controls, procedural controls, or both are implemented in assessing compliance with CIP-007 Requirement (R) 5?
18		Industry Comments/ Industry Redline	FAC-008 R1.2.1	1.2.1	What is included in "terminal equipment"?
19		In Development	CIP-007-3 R3	Security Patches	Is a registered entity required to have a technical control for password configuration or would a manual solution meet the requirement? How would a manual solution be audited? NERC Compliance received a request for clarification for when and under what conditions a TFE is required.

20		Industry Comments/ Industry Redline	TPL-002a R6 & R11 TPL-002.0b R1.3.12 TPL-003a R1.3.12 TPL-004 R	Eval of Maintenance Outages	NERC received a request for clarification of whether maintenance outages, including Protection Systems, must be included in operational planning studies under TOP-002 or in transmission planning assessments under TPL-002, TPL-003, and TPL-004.
21		In Development	COM-002	Definition of a Directive	NERC received a request for clarification of the definition of a “directive,” whether it applies to both non-emergency and emergency situations, and the required use of three-part communications.
22		Industry Comments/ Industry Redline	VAR-002-1.1b R1	Startup in Manual Mode	NERC received requests for clarification regarding whether a generator may be operated in manual mode during start-up.
23		In Development	CIP-005 R3 CIP-006 R6 CIP-007 R6	Logging System Failures	NERC received a request for clarification of whether any exception exists for an entity that cannot log access 100% of the time, 24 hours per day, seven days per week, and if not, whether the entity needs to file a self-report of non-compliance any time the access logging system fails.
24		Industry Comments/ Industry Redline	CIP-002-1 R3.1	Data Diodes	NERC received a request for clarification of whether the communication characteristics of data diode devices can be used to exclude non-critical Cyber Assets (CA) from consideration as Critical Cyber Assets (CCA) when a routable protocol is implemented, thereby making them inapplicable to CIP Standards.
25		In Development	EOP-001-1 R2.4	BA Restoration Plans	NERC received the following question: When a BA is not a registered TOP, how does it comply with EOP-001-0 R3.4 (U.S.) or EOP-001-1 R2.4 (Canada), which require BAs to have a set of plans for system restoration?
26		Industry Comments/ Industry Redline	TOP-006-1 R3	Protective Relays	NERC received a request for clarification of whether a RC, TOP and BA, under TOP-006 Requirement (R) 3, needs to provide appropriate technical information to its operating staff for all protective relays in its area whether or not it has the responsibility or ownership of the protective relays.
27		In Development	TOP-003-1 R2	Generator Outages	NERC received a request to clarify whether TOP-003 R2 requires the BA to plan and coordinate scheduled outages of generators within the BA’s area.

28		Industry Comments/ Industry Redline	TOP-006-1 R1.2	BA v. TOP Reporting	NERC Compliance received a request for clarity regarding the BA and TOP applicability.
29		Industry Comments/ Industry Redline	PRC-004-1 R2 R3	Misoperations	NERC received a request for clarification regarding whether entities must develop and implement Corrective Action Plans (CAPs) for, and maintain a record of, all Misoperations or only those that must be reported to NERC/RAPA.
30		Industry Comments/ Industry Redline	Attestations	Attestations	NERC received a request for clarification regarding the appropriate situations and uses of attestations as evidence of compliance with a reliability standard.
31		Industry Comments/ Industry Redline	CIP-005 CIP-006 CIP-006 R1.1	Physical Security Access Points	NERC received a request to define the entry point metric definition of the access points on the perimeter. NERC also received a request for clarification for an acceptable entry point into a Physical Security Perimeter (PSP) of Critical Cyber Assets (CCA), as well as acceptable opening dimensions.
32		In Development	EOP-008	Above and Beyond Security Measures	NERC received a request for clarification regarding whether an entity will be considered non-compliant if the measures it has implemented to comply with the requirement(s) of a Standard 1. meet the intent of the Standard and 2. exceed or are superior to the requirement of the Standard, 3. but do not meet the actual requirements of a given Standard.

33		In Development	PRC-023 R1.8; • R1.9 • (R1.1; R1.6; R1.7)	Load questions	NERC Compliance received a request for clarity on: -"load remote to system" - "generation remote to load" - if there is a 4-hour load rating or can a seasonal facility rating be used for R1.1 -in a Directional Comparison Blocking (DCB) Scheme, does the reverse looking zone need to comply with PRC-23 loadability requirements? -R2 of the PRC-023-1 standard has an effective date of July 1, 2010 and if an entity chooses to apply R1.6, R1.7, R1.8, R1.9, R1.12, or R1.13, how can this be a valid choice until they have the appropriate agreement from it PC, TOP and RC? -what is the process that requires every entity that falls under this standard to be included with unknown PA/PC in their respective regions? Some registered entities do not know who, if anybody, is their PA/PC., and upon contacting some TOPs, BAs, etc. in their area that are registered as a PA/PC to ask if they would serve as their PA/PC and were rebuffed. -the use of PC for PA and IC or IA in NERC Reliability Standards until a FERC Filing/Order is in effect.
34		In Development	EOP-002-2.1 R1 IRO-001-1.1 R3 TOP-001-1 R1	Authority Letters	NERC received a request to clarify what criteria auditors consider when reviewing an authority letter.
35		In Development	Periodic Data Submittals	Periodic Data Submittals	NERC received a request for clarification of whether violations would be mitigated if they were included in periodic data submittals.
36		In Development	PRC-023	Applicability	This is in regards to PRC-023 and its applicability to Generator Owners that are not also transmission owners and/or distribution providers as stated in FERC Order 733.
37		In Development	Roll-up Violations	Roll-up Violations	NERC received a request for clarification regarding whether the finding of non-compliance of one requirement would be applied across other Standards to which that requirement applies
38		In Development	PER-002 R4	Training Hours	NERC received a request for clarification of how many training hours equals the required five days of training per PER-002 R4.

39		Industry Comments/Industry Redline	DOE 417	DOE Form OE-417	The Department of Energy's (DOE) new online process for submitting the OE-417 disturbance reporting form does not automatically issue a copy to NERC or the Regions.
40		In Development	BAL-003 R2	FERC Discrepancy - Frequency Bias Value	NERC received a request for clarification on the proper approach to determine Frequency Bias Setting.
41		In Development	IRO-004 R1	FERC Discrepancy - Complete Dynamic Modeling	NERC received a request for clarification on whether complete dynamic modeling is required for next-day assessments.
42		In Development	PRC-001 R1 PRC-001 R2 PRC-001 R4	FERC Discrepancy - Purpose Limits of Protection System Schemes	R1: Clarity on the use of the term "Generator Operator" (Not GOP's responsibility in company to know protection system)
43		In Development	PRC-005 R2	FERC Discrepancy - Maintenance and Testing Procedure & Consistency Issues fm Key Reliability Standard Spot Check	NERC received several requests for clarification on what types of evidence are typically used to demonstrate compliance with Protection Systems[1] maintenance and testing in certain compliance areas
44		In Development	TOP-001 R1 TOP-001 R2 TOP-001 R5 TOP-001-1 R8	FERC Discrepancy - System Emergency and Emergency Conditions	NERC received a request for clarification on the definition of system emergency.
45		In Development	TPL-002 R1.3.10 TPL-003 R1.3.10 TPL-004 R1.3.7	Power Flow Models and Protection Systems Include Relay Devices as N-1	NERC received a request for clarification regarding the inconsistencies identified in the Key Reliability Standard Spot Check.

46		In Development	PER-002 and PER-003	Local v. Remote Operators	Remote (or local) control center operators are not certified; NERC position is that the main control center needs to be and that remote operators do not need to be.
47		In Development	PRC-004	Relay in Abnormal Condition	Does operation of a relay during an abnormal condition constitute a misoperation?
48		In Development	COM-001 R1.1-R1.4	Telecommuncation Redundancy	A single point of failure is not a automatic failure to comply with R1.1 - 1.3. If a facility is not sufficiently redundant, an entity is not automatically out of compliance with all R1 sub requirements but only R1.4.
49		In Development	TOP-002 R14	Intentional Delays Notifying BA and RC	Define "Intentional Time Delay"
50		In Development	BAL-002-0 R3, R1.1, R3.1, R4, R4.2	Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification.	NERC received a request for clarification regarding the inconsistencies identified in the Key Reliability Standard Spot Check.
51		In Development	CIP-004-2 R3 TOP-002-2a R2, R6, R8, R10, R19 TOP-002-2 R11	Background Checks System Conditions	Clarification of CIP-004-2 for Army Corps of Engineers; 7-yr Criminal Background Check? Asks for clarity on acceptable sources of ID verification, periodicity of ID verifications and 7-yr criminal checks; use gov't I-9; R6: Clarification of whether it is the responsibility of the BA to plan to meet CPS and DCS under unscheduled changes in the system configuration and generation dispatch. R2, R8, and R19: Clarity on BA obligations; the request for clarity seems to try to change the standard; "What do I have to do to comply?" R6 and R10: BA and TOP applicability.

52		In Development	BAL-001-1 R1, BAL-002	Error Control	Clarification of whether the WECC Automatic Time Error Control Procedure (WATEC) violates Requirement 1 of BAL-001-0. Also see Standard's list for clarification "which disturbances are excluded from compiance evaluation".
53		In Development		New Generation Facility	Whether an entity must be registered before connection and any testing
54		In Development	PRC-008-1	UFLS Equipment	NERC should consider officially defining UFLS equipment as a Protection System or explicitly list what is included as part of UFLS equipment in order to remove confusion concerning this terminology. Adapt compliance applications for PRC-005 to the standard
55		In Development	PRC-017-0 R1.1	define protection system	Include control circuitry as part of an SPS or formally regard an SPS to fall under the definition of a Protection System
56		In Development	CIP-003 R1	Enforcing Subrequirements in Standards	If an entity may have one or more policies for any standard to demonstrate / define how it meets the requirements and sub-requirements how within the policy or policies the entity must clearly address each of the components laid out in the requirement and sub-requirements.
57		In Development	PRC-011	UVLS	Adapt compliance applications for PRC-005 to the standard
58		In Development	PRC-017	SPS	Adapt compliance applications for PRC-005 to the standard
		RED= HIGH PRIORITY			
		In Queue	EOP-003-1 R3 & R5	Applicability	NERC Compliance received a request for clarity regarding the BA and TOP applicability with regard to compliance with the standard. Also - does this just apply to automatic load shedding or does it also apply to manual load shedding? (see interpretation list) it is fixed in the standard - as of 4/28 it has been approved by the BOT and is pending FERC filing

		In Queue	IRO-002-1 R3	Applicability	Clarity requested from a region on the RC, BA, and TOP applicability
		YELLOW= MEDIUM PRIORITY			
		In Queue	EOPs	Evidence Consistency	NERC Compliance received a request for clarification regarding communication capability, access, and verification using, RCIS, WECCnet, and FRCC
		In Queue	TPL-003	Application	Application of Table 1 in TPL-003 and proper modeling of contingency events (ie: Category C vs. D)
		In Queue	PRC-005-2	Define	Definition of a Calendar Year (CAN-0010)
		In Queue	various	RRO requirements	Clarity on the RRO requirements and references in the currently approved NERC standards - ERCOT
		In Queue	PRC-001		Internal Direction/Potential CAN discussion -Oceanview CI PRC-001
		In Queue	EOP-004-1 Attachment 2	Clarity, Scope	NERC Compliance received a request for clarity regarding the difference between the FERC approved standard that includes an older version of the DOE disturbance reporting requirement form (Attachment 2), and the current DOE form to reconcile the differences in required time for reporting. Entities need to align with the DOE but know how to plan for compliance with this difference.
		In Queue	IRO-006-4.1 R3	Applicability	Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification.
		In Queue	MOD-018	Applicability	Definition of a "non-member."
		In Queue	Definition of BPS	Intrepretation of BPS definition	Application of current BPS definition in regard to attributing “one transmission source” to “load”
		In Queue	RRO stnds	Clarity, Consistency	NERC Compliance received a request for clarity regarding the proper use of RRO.
		GREEN= LOWER PRIORITY			

		In Queue	FAC-003-1 R1	TVMP Changes	NERC received multiple requests for clarification on FAC-003-1 R1 regarding the allowable timeframe for implementation when an entity changes one TVMP plan based on normal trend to another TVMP plan based on clear cut. Once changed is the entity bound to implement immediately? Does the stnd provide for entities to have a transition period while changing TVMP plan? When they change a program, see below for TOP-002 and combine for one CAN
		In Queue	TOP-002	Evidence	NERC Compliance received a request for clarification regarding different approaches to compliance when either the standard is less stringent than the registered entity's procedure or the auditing approach goes above what the standard requires. When a standard requires a registered entity to develop and implement its own plan, the auditor will audit to the registered entity's plan, even if it is superior to the requirements in the standard.

Reasoning		**ISSUES THAT HAVE BEEN ADDRESSED/Retired CANs**			
AML Corrected		Adressed	BAL-005-0.1b R1	Applicability	Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification.
Issue too Broad		Adressed	CIP-002	CCAs	NERC Compliance received a request for clarification regarding different approaches to compliance and the scope of obligations on entities.
Covered by CAN-0012 and CAN-0010		Adressed	CIP-005 R4	Cyber Vulnerability Assessment	NERC Compliance received a request for clarification on whether or not it is it appropriate to enforce this standard as requiring the entity to have performed a CVA prior to their Compliance Date.
AML Corrected		Adressed	COM-001-1.1 R6	Applicability	Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification.
AML Corrected		Adressed	EOP-002-2.1 R7.2, R9	Applicability	Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification.
Submitted to Standards Issue Database		Adressed	FAC-003	Embedded References	NERC Compliance received a request for clarification about using IEEE standard by references in an enforceable standard when that IEEE standard has such stringent copyrights that can't be included in standard for auditors to audit to.
CAN not appropriate vehicle but will hold for future		Adressed	FAC-008	Submitted Example of Excellence	NERC Compliance received a request for a best practice example of how to approach facility ratings.
AML Corrected		Adressed	FAC-014-2 R2 and R4	Applicability	Inadvertent errors between stnds and compliance data sheets and database.
AML Corrected		Adressed	TOP-001-1 R7.1	Applicability	Inadvertent errors between stnds and compliance data sheets and database.
AML Corrected		Adressed	TOP-003-0 R1.2	Applicability	Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification.

AML Corrected		Adressed	TOP-005-1.1 R2 and R3	Applicability	Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification.
Discussed in Bulletin 2011-002 Audit Notifications		Adressed	PRC-008 R2	Evidence	NERC Compliance received a request for clarification on audit notifications and "data requests" for this standard.
1 - Material covered in subsequent order		Adressed	INT-004-2 R1	Correction to VRF Matrix	This document provides notice of a correction in the Violation Risk Factor Matrix regarding compliance applicability of INT-004-2 R1.
2- Material covered in subsequent order		Retired	TOP-003-0 R1.3	Correction to VRF Matrix	This document provides notice of a correction in the Violation Risk Factor Matrix and the 2010 Actively Monitored Standards spreadsheet regarding compliance applicability of TOP-003-0 R1.3.

To request a CAN, please complete the CAN Template Form, clearly identifying the area of concern as well as your suggested solution, and submit the form to cancomments@nerc.net.

Compliance Application Notice – 00XX

List applicable Standard and Requirement:

Primary Interest Groups

Compliance Enforcement Authority (CEA)[1]
NERC
Regional Entity
List applicable functional entities [BA, TOP, GOP, etc.]:

Issue: How are CEAs applying compliance according to NERC Reliability Standard [insert standard here]? (Form as a question)

Background

Provide any background necessary to understand the issue:

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard requirements.

Compliance Application
[Standard and Requirement] provides, in pertinent part:

[insert standard and requirement]

[Insert compliance instruction to CEAs, how the standard should be applied in a compliance setting] E.g., CEAs are to verify that registered entities are fulfilling the requirements of the standard by:

Effective Period for CAN
Provide recommendation:

Evidence of Compliance
[List acceptable forms of evidence here] E.g., A CEA is to assess the following to obtain reasonable assurance of the entity's compliance:

For more information please contact:

Michael Moon
Director of Compliance Operations
michael.moon@nerc.net
404-446-2567

Valerie Agnew
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Ben Engelby
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Caroline Clouse
Compliance Specialist
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404-446-2588

This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

CAN Prioritization Form
Industry Suggestions for Order of Priority

Please complete the CAN Prioritization Form and email it to cancomments@nerc.net.

Contact Information

Name:

Phone Number:

Email Address:

Entity Represented:

Region:

Please rank the criticality of potential CANs from the list located on the NERC Compliance Application Notice Web site, "CAN Status" spreadsheet: http://www.nerc.com/files/CANs%20Status.pdf.

CAN Number	Standard	Importance Level (High, Medium or Low)

If desired, provide rationale for your ranking:

Optional Information:

Provide any input to be considered in the development of this Compliance Application Notice:

CAN Comment Form
Compliance Application Notice – 00_ _

Please complete the CAN Comment Form and email it to cancomments@nerc.net.

Commenter Information

Name:

Phone Number:

Email Address:

Entity Represented:

Region:

Primary Interest Groups

Are you suggesting a change to the groups mentioned? Yes / No
If yes, explain what change and why:

Issue

Are you suggesting a change to the issue statement of the CAN? Yes / No
If yes, explain what change and why:

Background

Are you suggesting a change to the background statement of the CAN? Yes / No

If yes, explain what change and why:

Compliance Application

Are you suggesting a change to the compliance application section of the CAN? Yes / No

If yes, explain what change and why:

Effective Period for CAN

Are you suggesting a change to the effective period of the CAN? Yes / No

If yes, explain what change and why:

Evidence of Compliance

Are you suggesting a change to the evidence of compliance mentioned in the CAN? Yes / No

If yes, explain what change and why:

Reliability Standards Suggestions

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards and improvements to the standard development process. Please use this form to submit your suggestions related to NERC's Reliability Standards, Reliability Standards Development Plan (RSDP), or standard processes in general. NERC will consider all input received for future development projects, revisions of the RSDP, or wherever else appropriate.

Please return all completed forms via email to andy.rodriquez@nerc.net with the words "Standards Suggestions" in the subject line.

Submitter Information	Suggestion…	
Individual, Group, or Committee Name:	☐	**…for consideration by a drafting team assigned to an active project**
Company or Group Name:	☐	**…for consideration in a future project already identified in the RSDP**
Email:	☐	**…to create a new project for inclusion in the RSDP**
Telephone:	☐	**…to modify the Standard Development Process**
Date Submitted:	☐	**…related to another issue or topic**

Suggestion Detail
Notes: 1. Please be as specific as possible. 2. Where applicable, please identify the specific element(s) of the standard (e.g. Requirement R1.2, Section D1.1, Measure M1, etc.) to which the suggestion pertains. 3. Where practical, please provide an example to clearly identify the issue. 4. Please provide an idea for improvement, including suggested alternative language where possible.
Standard or Project Number (if applicable):
Standard or Project Title (if applicable):
Other Identifying Information (e.g., step in the standard process):
Problem or Concern:
Example:
Suggestion:
Intended Outcome (e.g., describe how the suggestion would improve reliability, make the standard clearer for auditors, etc.):
Additional Information:

Thank you for taking the time to submit your suggestion for improving the reliability of the bulk power system through improved reliability standards and standard processes!

Compliance Application Notice (CAN) High-Level Review Request Form

To submit a request for a higher level of review, please complete this Request Form and email it to:

1. For CEO Higher Level Review: Gerry.Cauley@nerc.net and cancomments@nerc.net
2. For subsequent BOTCC Higher Level Review: cancomments@nerc.net

Date:

Requesting Entity/Trade Organization (list all represented Entities or attach a list):

CAN Number:

Standard and Requirement:

Please indicate the nature of your request for review:

Jurisdictional_____ Other Legal_____ Beyond Scope_____ Technical_____

Errata/Grammar_____ Creates an evidentiary burden_____ Other_____

For NERC CEO Review

1. Please fully describe your reason for requesting the NERC CEO higher level review.

2. If you believe the compliance application should be modified, please provide your recommendation for modification.

3. Add any additional comments here.

For NERC BOTCC Review

Note: NERC CEO Review must be completed prior to submission for NERC BOTCC Review

4. Please fully describe your reason for requesting the BOTCC higher level review (i.e. the basis of disagreement with the CEO determination or any remaining issue to be resolved).

5. Add any additional comments here.

(For NERC use only):

Level of Review: CEO_____ Date: _____ BOTCC_____ Date:_____

NERC Chief Executive Officer review date:
Disposition of CEO review

NERC Board of Trustees Compliance Committee (BOTCC) review date, if applicable:
Disposition of BOTCC review, if applicable

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance Application Notice (CAN) Process

October 14, 2011

RELIABILITY | ACCOUNTABILITY

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Introduction

Compliance Applications Notices (CANs) were created by NERC to fulfill ERO obligations under FERC Order 693[1] to provide compliance guidance to Compliance Enforcement Authority (CEA)[2] staff and to provide transparency to industry in regard to compliance monitoring[3] with NERC Reliability Standards. CANs encourage accountability for both CEAs and registered entities and were issued in response to requests for compliance guidance from industry stakeholders.

ERO Basis and Authority

NERC is the FERC-certified ERO and is accountable to the Commission and the industry for providing compliance guidance with regard to NERC Reliability Standards. The ERO's implementation of a thorough compliance program and appropriate enforcement actions, and providing continuing education and information campaigns to assist the industry sustain compliance, will enhance reliability of the Bulk Power System (BPS).

In FERC Order No. 693,[4] several commenters argued that the NERC Reliability Standards were not comprehensive in nature and requested relief from monetary penalties and compliance with the standards. FERC responded, "As discussed in our standard-by-standard review, each reliability standard that we approve contains requirements that are sufficiently clear as to be enforceable and do not create due process concerns."[5]

Further, the Commission agreed with NERC that, even if some clarification of a particular NERC Reliability Standard would be desirable at the outset, making it mandatory allows the ERO and the Regional Entities to provide that clarification on a going-forward basis while still requiring compliance with NERC Reliability Standards.[6]

In addition, NERC and the industry are accountable for the development of NERC Reliability Standards, as articulated in the 2005 Federal Power Act[7] and FERC Order No. 672,[8] which duly recognize the requisite collective expertise, experience and judgment of all parties involved to develop and improve standards.

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[1] FERC Order 693, Docket No. RM06-16-000.

[2] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard requirements.

[3] The Three-Year ERO Performance Assessment stated that NERC should "evaluate and implement ways to make registered entities more aware of means currently available to them to obtain guidance on how to comply with reliability standards and how to demonstrate compliance." Appendix A – Progress in Implementing Specific NERC Actions from the Three-Year ERO Performance Assessment – March 16, 2011, p. 19.

[4] FERC Order No. 693, Docket No. RM06-16-000.

[5] *Id.* at Paragraph 274.

[6] "NERC can maximize consistency and appropriateness of treatment in compliance matters most efficiently if it has the ability to advise or provide direction…at an early stage…" FERC Order on NERC Three-Year Assessment, Docket Nos. RR09-7-000 and AD10-14-000, §216.

[7] Section 215.d.2 located at http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=109_cong_bills&docid=f:h6enr.txt.pdf.

[8] See P. 324 located at http://www.nerc.com/files/final_rule_reliability_Order_672.pdf

Purpose

There are two significant and mutually reinforcing purposes of a CAN:

1. To *establish consistency* in the application of compliance criteria among all CEAs; and
2. To *provide transparency* to industry on how CEAs are to apply compliance with a NERC Reliability Standard.

NERC received numerous industry comments requesting detailed compliance clarification of the NERC Reliability Standards. Below is a sampling of comments[9] that NERC received during the comment periods of the NERC Three-Year Assessment[10] and the Notice of Proposed Rulemaking (NOPR) of FERC Order No. 693. This feedback from industry factored significantly in the decision for NERC to implement CANs.

- NERC "need[s] to provide more information and guidance to registered entities concerning the compliance and enforcement process. This includes providing guidance on what it takes to comply with and demonstrate compliance with Reliability Standards, eliminating the backlog of audit reports and enforcement violations so that more precedents are available to industry, and providing more uniformity and consistency in audits between Regional Entities and different audit teams."[11]

- "A clear communication channel is fundamental to the success of the ERO. Connecting the feedback from different program areas, such as compliance monitoring and enforcement, reliability assessments and event analysis will prove valuable."[12]

- "Without a designated communication process, the most efficient and effective compliance process is not in place between compliance staff and registered entities. Currently, each company and Regional Entity struggles with this problem on an inefficient, case-by-case basis. Hence, the [CAN] process NERC is recommending will increase efficiency and use less resources."[13]

- "Some commenters argue that certain Reliability Standards require additional specificity or else users, owners and operators will not understand the consequences of a violation."[14]

NERC appreciates interaction from Industry during comment periods, and channels of communication remain open at all times if questions or concerns regarding a particular CAN arise.

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[9] Commenters included industry trade associations that represent over 70 percent of utility customers in North America.
[10] Comments submitted during the NERC Three-Year Assessment comment period.
[11] *Id.*
[12] *Id.*
[13] *Id.*
[14] FERC Order No. 693, Docket No. RM06-16-000.

Scope

A CAN is not a formal interpretation of a NERC Reliability Standard. Further, a CAN cannot modify or change an interpretation or NERC Reliability Standard. CANs instruct CEAs to assess compliance by using either a specific method, or, if there are multiple ways for a registered entity to meet the requirements of a standard, a range of acceptable compliance actions.

Concisely stated, a CAN is based on the following four principles:

a. A CAN provides instructions to CEAs regarding the boundaries within which to assess compliance with effective standards and requirements
b. A CAN cannot expand a standard
c. A CAN cannot add new requirements
d. A CAN applies to any facilities that affect the reliability of the BPS

The CAN process includes several crosschecks with other NERC programs and departments, including a review by NERC legal staff and the NERC Executive Approval Team.[15] CANs provide timely compliance instruction to CEAs to ensure consistent application of the standards. In the event that CEA practices vary, the posted CAN establishes a benchmark that all CEAs must adopt. By making instructions to CEAs transparent to industry, CANs also include the benefit of informing registered entities what to expect during an audit.

CAN Process

The CAN process is designed to give CEAs instruction on specific compliance applications in an expeditious manner. NERC follows several steps when developing CANs, including identifying issues that need clarification, prioritizing the issues, researching and developing CANs, providing the Regional Entities and industry time to comment, and submitting CANs to the Commission for review before posting them on the NERC Web site as final.

A. <u>Issue Identification</u>

NERC receives CAN topics through a variety of avenues, such as:

1. Industry comments received from individual registered entities, trade associations, and large corporations that have entities in multiple Regional Entities;
2. Regional Entities and issues they observe;

[15] Chief Executive Officer, Senior Vice President and General Counsel, Senior Vice President and Chief Reliability Officer, Vice President and Director of Standards, Vice President and Director of Reliability Assessments, Vice President and Chief Security Officer, Associate General Counsel (693), Assistant General Counsel (CIP), Director of Compliance Operations, Director of Events Analysis and Investigations, Director of Training, Director of Situation Awareness and Director of Compliance Enforcement.

3. NERC in various oversight activities in CMEP and standards development; and

4. Other regulatory bodies at the national or provincial level.

NERC tracks the category source[16] of the CAN request and includes it on the CAN Status spreadsheet posted on the NERC Compliance Application Notices web page.

CAN issues may relate to specific standards and requirements, crosscutting issues that cover various standards and requirements, or compliance monitoring processes and procedures. NERC encourages any interested party to submit an issue by sending a completed Appendix 1 – CAN Template to cancomments@nerc.net.

B. Determination of Whether a CAN is the Appropriate Vehicle

Once NERC receives an issue, it reviews the issue to determine whether a CAN is the appropriate vehicle to resolve it. In this relevance determination, NERC analyzes several factors, including the number of entities that may be affected, the impact to reliability of the BPS, whether there are questions regarding compliance monitoring, if there are perceived inconsistencies in audit practices among Regional Entities, and if there is a need for clarity among industry stakeholders. NERC considers all requests for clarification, but in order for a CAN to be drafted, the issue must apply to multiple entities, multiple issues, or broad issues that apply to many industry members.

If NERC determines that a CAN is not the appropriate vehicle to resolve the issue, NERC will determine if there is another vehicle. For example, if the issue is a question regarding the mandatory and effective date of a revision to a standard, a bulletin/public notice may be a better vehicle.

C. Prioritization of CANs

After NERC reviews the CAN issues has determined that a CAN is the appropriate vehicle to address the issue, the CAN is listed on the CAN Status spreadsheet, posted on the NERC Web site[17] and assigned a priority level.

There are several components that determine the priority of a CAN:

- Factors surrounding the issue
- Input from the Standards Committee (SC) and the Certification and Compliance Committee (CCC)
- Input from industry

NERC determines the priority of the CAN based on factors surrounding the issue, which may include the significance of the issue,[18] its impact to reliability of the BPS, its urgency, the number of violations

[16] A category would not identify the name of source and would be a broad designation such as Registered Entity type, Regional Entity, Trade Association, etc. .

[17] The complete list of CAN issues and prioritization can be found on the NERC web site: http://www.nerc.com/files/CANs%20Status.pdf.

that have occurred due to the issue, the standard and requirement, and the number of registered entities that are affected.

NERC will solicit input from the SC and the CCC regarding prioritization and any initial input on the issue.

Industry may also provide input as to the prioritization of a CAN and any initial comments on the issue by submitting a completed Appendix 2 – Industry Prioritization Recommendation Form to NERC's cancomments@nerc.net. The posting on the CAN Status spreadsheet will provide information so that interested parties can submit a prioritization request or initial comments on the issue.

The priority level of a CAN may change based upon 1) a change to the factors surrounding the issue, 2) the identification of a higher priority CAN to be developed, or 3) input from either the SC, CCC, or industry.

D. Development Process

After an issue has been identified and a priority assigned, NERC begins the CAN development process. Before any drafting is done, NERC reviews the issue. The first step is a review of the NERC Reliability Standard in its entirety, including applicable FERC orders, approved standards interpretations, the standards drafting team's intent, investigation of how CEAs are currently applying compliance, and any other existing communications and guidance. NERC also reviews the input that was received during the prioritization process.

NERC then conducts research that includes obtaining technical information from subject matter specialists, standards drafting teams, CEAs and Regional Entities. The input from subject matter specialists may include soliciting input from stakeholder committees or their subcommittes, as appropriate. NERC conducts this research to determine the level of consistency that exists in regard to the issue.

When NERC has concluded the research and a draft CAN is complete, they present it to the NERC Executive Approval Team for the first level of approval.

E. Regional Entity Comment Period

Following NERC Executive Approval Team approval, the NERC sends the CAN to the Regional Entities for verification of the compliance application. The Regional Entities, as a part of the ERO, are involved throughout the development process. At this point, NERC gives the Regional Entities a period of five days to conduct a review of the drafted document prior to posting. This provides the Regional Entities an opportunity to identify any issues or concerns that occurred in the editing of the draft that would prevent the CAN from moving forward in the process. In the event that a Regional Entity discovers

[18] One determination of significance of the issue is whether the issue is related to one of the NERC identified high risk factors for the reliability of the BPS: (1) Misoperations of relay protection and control systems; (2) Human errors by field personnel; (3) Ambiguous or incomplete voice communications; (4) Right-of-way maintenance; (5) Changing resource mix; (6) Integration of new technologies; (7) Preparedness for high-impact, low frequency events; and (8) Non-traditional threats via cyber-security vulnerabilities.

content in the CAN that is technically incorrect or any other issue that should prevent the CAN from moving forward, the Regional Entity will notify NERC.

In the event that the Regional Entities support progression of the CAN, it will be posted on the NERC Web site for industry comment. The Regional Entities may provide additional comments throughout the industry comment period.

F. Industry Comment Period

The industry period lasts 21 days, and extensions of time may be granted upon request. Registered entities or their representatives may submit comments via Appendix 3 - the CAN Comment Form.[19] In order to keep the CAN process transparent, NERC posts all industry comments on the NERC Web site.

After the comment period, NERC staff analyzes all comments received and reviews the CAN for potential changes based on the comments. NERC provides rationale for any changes made or not made to the CAN and posts the rationale on the NERC Web site.

Industry comments are especially important when the compliance application varies, as the CAN will establish a consistent application. Industry, in this context, includes registered entities, their trade associations or forums, and NERC stakeholder committees, as appropriate.

G. Final Review and Posting

NERC presents the final draft of the CAN to the NERC Executive Approval Team for a second review of the CAN, including any modifications that were made, or were not made, after industry comments. Upon approval by the NERC Executive Approval Team, NERC sends the CAN to FERC staff and Canadian Regulators[20] for review, after which NERC posts it as final on the NERC web site.

When NERC posts the CAN, an email announcement goes out to all registered entities and CEAs.

H. Webinars and Training

NERC conducts webinars after CANs are posted as final on the NERC Web site to provide an opportunity for questions from industry and CEAs. The webinar slides are posted on the NERC Web site.

NERC also provides training for CEAs and industry to develop awareness of the CANs and consistency in the use of the compliance application. NERC presents recently posted CANs and the CAN process at trade forums, compliance workshops and committee meetings.

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[19] See Appendix 3 for the CAN Comment Form.

[20] As requested by each Province.

I. Expiration or Removal of CANs

CANs are retired when a revised standard or interpretation that addresses the compliance application issue in the CAN is approved by FERC and becomes enforceable. Further, a CAN may be revoked or revised if a higher level of review directs the CAN to be withdrawn or modified, or additional information is brought forward to demonstrate that the CAN is incorrect.

Benefits of CANs

The advantages of issuing a CAN are significant. CEAs receive instruction so compliance monitoring of the NERC Reliability Standards is conducted consistently. The result of the transparent process provides registered entities with visibility into how compliance will be applied. Additionally, CANs are generated in a relatively short time period compared to a much lengthier formal process.

A. Provide Formal Feedback to Standards

For each CAN that NERC drafts, NERC submits the issues raised to applicable Standards Development Teams and the standards issue database, to be considered in ongoing or future standards projects, revisions to existing standards, or the initiation of new standards. All of the decisions concerning standards development rest with the stakeholders through the actions of the Standards Committee.

B. Time to Develop

The timeline for CAN development from issue identification to final posting is measured in terms of months–typically three to six months. This process is designed to be much more responsive than either the formal Standards Interpretation Process or the Standards Development Process,[21] which may take 18 - 36 months, plus FERC approval time.

CAN Issues and Concerns

During the development of the CAN process, NERC received issues and concerns from industry stakeholders. This section highlights some concerns and provides answers to the questions received.

- *NERC received comments that CANs overreach the standards*. CANs give the necessary instruction to CEAs in order to monitor compliance to the standards in a consistent manner. CANs are temporary in nature and will be retired when a standard or interpretation that addresses the issues therein becomes effective.

- *NERC received comments that the CAN process circumvents the standards process*. The CAN process and the standards process serve different purposes. The Standards Development Process, codified by the Federal Power Act of 2005, Section 215, creates mandatory and enforceable regulation. The CAN process provides instruction on how CEAs are to assess compliance with that

[21] See the NERC Rules of Procedure, Appendix 3A, Standards Process Manual, Effective September 3, 2010.

regulation. Therefore, NERC must balance the long-term standards development process with the day-to-day compliance monitoring and enforcement responsibilities as the FERC-certified ERO.

Contesting a CAN

NERC's belief is that transparent, open communication of compliance applications provides an opportunity to formally address areas of concern. When industry takes issue with the application identified in a CAN, there are several existing processes available for formal resolution. In accordance with the NERC Rules of Procedure, a registered entity may contest a violation that was assessed due to the application of a CAN.

A registered entity or its representatives (requestor) may (in order of hierarchy):

1. Submit technical evidence in support of a request to NERC to have a CAN changed or removed.
    a. NERC will acknowledge receipt of the issue and will keep the requestor informed of progress. Folowing NERC's determination, if the requestor is not satisfied with the change to the CAN, then the requestor may:
2. Propose a change to the standard through a request for a formal interpretation[22] or a Standard Authorization Request (SAR); or
3. Request a higher-level review of the CAN[23]
    a. The first level of review would be conducted by NERC's Chief Executive Officer.
    b. If a registered entity is not satisfied with the results of the first level of review, the registered entity may request a second level of review by the NERC Board of Trustees Compliance Committee (BOTCC).

The higher-level review of the CAN may result in three options for disposition: (1) affirm the CAN as written, (2) make recommended changes to CAN, or (3) withdraw the CAN. If the CAN is modified or withdrawn, there will be an announcement to industry and to ERO Compliance Enforcement Authorities to announce the change.

The higher-level review will begin when the registered entity or its representative submits the CAN Higher-Level Review Form (Appendix 5) to NERC. NERC's Chief Executive Officer or his designee will have 14 days to review the CAN and determine whether it will be affirmed, modified or withdrawn.

If a registered entity or its representative decides to pursue the higher level of review to the Board of Trustees Compliance Committee (BOTCC), they must submit a second request for higher-level review by completing additional information and submitting a revised Appendix 5. The BOTCC will review the comments and the applicable CAN at the next available time during its monthly BOTCC meeting and

[22] A formal interpretation is conducted through the Standards Development Process. As such, it is formally filed with FERC and will result in an order issued by FERC Commissioners.

[23] See Appendix 5 for the CAN Higher-level Review Form.

make a determination whether to uphold the CAN. The BOTCC will review the complete record and determine whether to either uphold the CAN, direct the CAN to be modified or withdraw the CAN.

Summary

Compliance Application Notices fulfill NERC's obligation as the ERO to provide a consistent compliance monitoring program under FERC Order No. 693. CANs carry out the requests of industry for clarification and provide timely compliance guidance in a transparent manner. CANs not only assist CEAs in monitoring compliance, but the industry benefits from understanding what the issues are and how to prepare for an upcoming audit. The CAN process is evolving, and changes have been made to the program based on feedback from industry stakeholders, Regional Entities, and the NERC Board of Trustees.

Version History

Version	Date	Action
0	May 2010	Initial Draft
1	December 10, 2010	Updated CAN Process
2	April 14, 2011	Updated CAN Process with detailed steps
3	July 8, 2011	Updated CAN Process to include specific industry requests
4	August 15, 2011	Updated Purpose Section, Contesting a CAN Section, based on Board of Trustee recommendations.
5	October 14, 2011	Updated CAN Prioritization Process, Regional Entity comment section, industry comment section, CAN higher-level review section, and added Appendices 1-5.

Industry Comments for CAN-0016 CIP-001 R1 Sabotage Reporting Procedure

*One or more of these responses came from a trade organization or an ISO/RTO that represents multiple entities.

Comment Topics	Main Points	Total # of Responses on this Topic	Industry Suggestions	Response
CAN doesn't answer the question	There are many other issues addressed but not "what facilities should be included in a registered entity's sabotage reporting procedure?"	19*	State which facilities are to be included; permit registered entities to use the NERC Glossary definition of "Facilities" as a specific application of the undefined word "facilities" as used in CIP-001-1.	The CAN was revised to make the answer to the question clearer. A CEA is to assess a possible non-compliance when a registered entity's sabotage reporting procedure specifically excludes facilities that have the potential to impact the reliability of the BPS. Registered entities are encouraged to identify their facilities that may, if subject to sabotage, impact the BPS.
Add language to Examples #1 and #2	Add: "...on its facilities and multi-site sabotage affecting larger portions of the Interconnection;" to the end of #1 and #2.	1	The language makes the examples "correct."	The standard specifies "...on its facilities and multi-site sabotage affecting larger portions of the Interconnection" and thus is incorporated into the examples, so no further language was deemed necessary.
CAN out of scope	The new draft CAN-0016 should only address the fact that CIP-001 does not apply to non-BES facilities. No other aspects of CIP-001 should be addressed in this CAN.	70*	The CAN should not require that all personnel working for a registered entity are qualified to analyze an event and determine if the intent is sabotage or just vandalism or theft.	The CAN was revised to state that CEA staff are to verify all personnel aware of the sabotage reporting procedures. The CAN shifted to focus on the purpose of the standard - i.e. that registered entities are to have a sabotage reporting procedure. The CAN clarifies that a registered entity must have a procedure for recognizing potential sabotage events on its facilities and multi-site sabotage affecting larger portions of the Interconnection and that a CEA is to find a possible non-compliance if a registered entity specifically excludes any those facilities that, if subject to a potential sabotage event, could impact the reliability of the BPS. This CAN further clarifies that a CEA must verify that a registered entity has implemented its sabotage reporting procedure. While the term "operating personnel" is not defined, the comments received suggest that this designates a subset of employees and only those employees are subject to the standard. The standard does not dilineate a subset of employees, but applies to the functional entity.
BPS vs BES	References to BPS should be changed to BES.	35		According to Section 39 of the Energy Policy Act of 2005, NERC defines the Interconnected Power Grid as the Bulk Power System. Unless otherwise restricted by a standard, it is applicable to the BPS. This standard does not provide such a restriction. There is currently a Standards Drafting Team defining "BES," and there may be more guidance to follow.
Footnote 1	Footnote #1 should only be in effect for CIP-001 Version 1a, which is the most current version	1	Rewrite footnote	This Footnote has changed based on comments.
Footnote 5	Footnote 5 in the new draft CAN-0016 adds the requirement of obtaining the opinion of expert personnel. This is not in the standard language and should be removed from the CAN.	13	Don't make requirements not in the Standard	This Footnote has changed based on comments.
Footnote 7	Footnote 7 capitalizes sabotage reporting procedure. Need to be consistent throughout the CAN. Since sabotage reporting procedure is not a NERC defined term, it should not be capitalized.	1	Uncapitalize "Sabotage Reporting Procedure"	Sabotage reporting procedure is no longer capitalized.
Define "operating personnel" and "sabotage event"	CIP-001 R1 (as well as R3 and indirectly R2) apply to "operating personnel" whereas the draft revised CAN-0016 appears to expand the applicability of CIP-001 R1 to all "personnel" and/or "employees" of the registered entity.	24*	Language needs to be clarified	"Operating personnel" and "sabotage event" are not defined glossary terms. Based on comments, these definitions will be submitted to the Standards Issue Database. While the term "operating personnel" is not defined in the NERC Glossary, the comments received suggest that this designates a subset of employees and only those employees are subject to the standard. The standard does not dilineate a subset of employees, but applies to the functional entity.
Remove Language	(1) The "implementation" language should be removed from the CAN. (2) The section for the CEA to provide guidance to identify noncompliance, "b. responded to this compliance guidance only in preparation for an audit." This should be removed or clarified as to how this is determined by the CEA.	10*		(1) The CAN clarifies that a CEA is to verify that a registered entity has implemented its sabotage reporting procedure. The standard states, "shall have procedures" and there is a reasonable presumption that having a procedure requires more than a document, it requires implementation of the procedure. (2) In the effort to provide instruction to the CEA, the ERO endeavored to give registered entities an opportunity to make adjustments to their sabotage reporting procedure. The CEA will make its determination based on specific facts and circumstances, including the amount of time between the issuance of the CAN and when the registered entity modified its sabotage reporting procedure, and the length of time between the entity's modification and notification of its audit. It would be reasonably expected that an entity would review and update its sabotage reporting procedure at least annually and when prompted by guidance from a Compliance Enforcement Authority.
Need more time to respond	21 days not long enough	3		The CAN process allows 21 days for Industry comments; however, NERC will accept extensions upon request.
Implementation of CAN	Under the Effective Period for CAN section, no timeframe is provided to implement the CAN. As currently written, a registered entity's sabotage reporting procedure must contain the elements outlined in this CAN upon posting. A registered entity needs adequate time following a posting to revise procedures to incorporate the compliance application provided by the approved (i.e., posted) CAN.	6		CANs provide instructions to CEAs regarding how to assess compliance with enforceable Standards. CANs are to be used by CEAs when they are posted as Final on the NERC Web site. CANs are instruction to CEAs on a going-forward basis and registered entities are encouraged to update their sabotage reporting procedure as guidance is provided. The CAN provides instruction for a CEA to verify a registered entity's most recent document to provide an entity the opportunity to make any adjustments necessary to its process.
FERC/Jurisdiction	As written, footnote 4 goes beyond FERC jurisdiction.	2*		CIP-001 was drafted prior to the mandatory and effective date of the standards and the subsequent approval of the NERC glossary. At the time of drafting, the distinction between BPS and BES was not considered and the term "facilities" was not changed (capitalized) at the time the defintion was approved in the NERC glossary. Therefore, at this point in time, it is not considered to be a defined term. NERC has a responsibility to maintain the reliable operation of the BPS, as defined in Section 215.a.4 of the Federal Power Act.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Revised ~~DRAFT~~ Compliance Application Notice — 0016

~~CIP-001[1] R1~~CIP-001 R1 – Sabotage Reporting Procedure ~~Applicability to Non-BES Facilities~~

Posted: June 17, 2011
Reposted: October 14, 2011

Primary Interest Groups
Compliance Enforcement Authorit~~ies~~y (CEA)[2]
NERC
Regional ~~Entities~~Entity
Registered ~~Entities~~ Entity

Issue: What ~~The inclusion of~~ facilities should be included in a registered entity's sabotage reporting procedure?
For the purpose of aiding a CEA, this CAN provides instruction for assessing whether registered entities have developed sabotage reporting procedures that fulfill the requirements of CIP-001.

~~NERC received a request to clarify whether registered entities were required to include either BES or non-BES facilities in their Sabotage Reporting Procedures in order to be compliant with the NERC Reliability Standard CIP-001 Requirement (R) 1.~~

~~Reliability Objective~~
~~The reliability objective is to foster compliance with the NERC Reliability Standards through clear communication of performance obligations.~~

~~Background~~
~~Registered entities have requested clarification as to whether the Sabotage Reporting Procedures required by CIP-001-1 R1 must include a list of registered entity's facilities and whether excluding any of its facilities, specifically non-BES facilities, constitutes noncompliance with the requirement.~~

[1] ~~This CAN is in effect for CIP-001 Versions 0, 1 and 1a, and will remain in effect until the issue is addressed by a future version of the standard. In Canada, this CAN is in effect for applicable versions of CIP-001 pursuant to each Canadian Province's corresponding Memorandum of Understanding (MOU), which may be accessed on the NERC Web site.~~
[2] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard requirements.

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DRAFT

~~CEA~~ Compliance Application

~~The~~ CIP-001~~-1 R1~~[3] ~~reads~~provides, in pertinent part:

> ***R1.*** *Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the recognition of and for making their operating personnel aware of sabotage events on its facilities[4] and multi-site sabotage affecting larger portions of the Interconnection.*

Therefore, ~~to be compliant with~~CEAs are instructed to verify: ~~CIP-001-1 R1:~~[5]

1. a registered entity ~~is required to have~~ has procedures for the recognition of sabotage events;[6]
2. a registered entity has procedures for personnel recognizing a sabotage event to make the entity's operating personnel aware of the sabotage event(s);
3. pursuant to its procedures, a registered entity's ~~employees~~ personnel ~~should be~~are able to recognize sabotage events that happen on the registered entity's facilities; and
4. pursuant to its procedures, a registered entity's ~~employees~~ personnel ~~should~~ are able to recognize sabotage events that happen across multiple sites that would affect larger portions ~~or~~ of the ~~interconnection~~Interconnection.

The emphasis of the standard is for the registered entity's ~~employees~~ personnel to be able to recognize a sabotage event(s) that may impact[7] the reliability of the ~~b~~Bulk ~~p~~Power ~~s~~System (BPS) and to make operating personnel aware of a recognized sabotage event(s). A CEA is to verify that the entity's procedure provides sufficient detail as to how it ~~will~~ determines whether 1) events are sabotage-related and 2) the event has the potential to impact the reliability of the BPS.

When assessing compliance, CEAs are not to consider a registered entity's determinations regarding whether events were sabotage-related or whether the events were reported. A CEA is to verify whether

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[3] Pursuant to section 215 of the Federal Power Act (FPA), the Commission approved CIP-001-1 in FERC Order No. 693. *Mandatory Reliability Standards for the Bulk Power System*, FERC Stats. & Regs. ¶ 31,242 (2007) (Order No. 693), *rehearing denied*, 120 FERC ¶ 61,053 (2007) (Order No. 693-A).

[4] The standard includes the word "facilities," which is not capitalized and therefore does not denote an identified term. *The NERC Glossary of Terms Used in Reliability Standards* defines "Facility" as "A set of electrical equipment that operates as a single Bulk Electric System Element (*e.g.*, a line, a generator, a shunt compensator, transformer, *etc.*)."

[5] ~~In Order No. 672, the Commission concluded that it is appropriate for each user, owner and operator of the Bulk Power System to be required to abide by any such Commission-approved Rules and added a subsection (b) to 18 C.F.R. section 39.2, stating: (b) All entities subject to the Commission's reliability jurisdiction under section 39.2(a) shall comply with applicable Reliability Standards, the Commission's regulations, and applicable Electric Reliability Organization Rules and Regional Entity Rules made effective under this part. *See* FERC 18 C.F.R. Part 39; *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards* (Order No. 672), III FERC Stats. & Regs. ¶ 31,204 (2006).~~

[6] ~~CEAs' verification of a registered entity's sabotage reporting procedure is to include flexibility for a registered entity to have established procedures that appropriately address the expertise of employees across the company. However, CEAs are to verify that registered entities must have a procedure where, at a minimum, employees that are not aware of how to recognize potential experts sabotage events are trained aware ofto spot unusual events that could potentially be sabotage related and obtain the opinion of expert trained employeespersonnel.~~

[7] Examples may include but are not limited to: events or activities that may threaten the reliability of the BPS, create a threat to the reliability of the BPS or impede the utilities ability to reliably operate the BPS.

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the registered entity made the determination and reporting decision according to the entity's sabotage reporting procedure.

While a registered entity's sabotage reporting procedure may ~~include~~ require personnel to be aware ~~awareness~~ of specific items for a particular facility, a CEA is not to consider whether a registered entity ~~is not required to~~ listed any ~~all~~ of its facilities in its sabotage reporting procedure when assessing compliance. If an employee is ~~properly trained~~aware of how to recognize a sabotage event, the employee ~~should willis to~~will be able to ~~be able~~ recognize a sabotage event regardless of where on, or in, the registered entity's facilities it occurred. However, a CEA is to assess a possible non-compliance when a registered entity's sabotage reporting procedure specifically excludes facilities that have the potential to impact the reliability of the BPS.

~~The registered entity would be considered non-compliant with the standard if its Sabotage Reporting Procedure **excludes** any of its facilities from its procedure, including but not limited to non-BES facilities.~~

Effective Period for CAN

This revised CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance from June 17, 2011, regardless of the start date of the violation. It will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

~~This CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance is effective for CIP-001 upon posting the posting of this CAN on the NERC Web site. It supersedes all prior communications and It will remain in effect until a future CAN supersedes it or until such time that a future version of a standard or interpretation addresses this specific issue and is enforceable.~~.

It is anticipated that EOP-004-2, in Standards Development Project 2009-1 Disturbance and Sabotage Reporting, will ultimately define sabotage reporting obligations in CIP-001-1a after industry approval, BOT approval and FERC approval.

CEAs are instructed to assess compliance by the registered entity's current[8] sabotage reporting procedure and the facts and circumstances surrounding that procedure. For example:

1. If, following the posting of this CAN, a registered entity's sabotage reporting procedure contains the elements specified by the standard and outlined in this CAN, CEAs ~~will~~are to evaluate ~~look at~~ the entity's current sabotage reporting procedure. The CEA is not to look further back in time to determine non-compliance or a Possible Violation because prior versions of the entity's sabotage reporting procedure did not include each of the elements identified in this CAN, or specifically excluded certain facilities that, if subjected to a sabotage event, could impact the BPS.
2. ~~However t~~The CEA is to identify non-compliance and a Possible Violation if a registered entity:
    a. did not respond to ~~this~~ compliance guidance and therefore its current sabotage reporting procedure specifically excludes facilities that, if subjected to a sabotage event, could impact the BPS; or

[8] "Current" means the ~~S~~sabotage ~~R~~reporting ~~P~~procedure in effect at the time of the audit.

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b. responded to this compliance guidance only in preparation for an upcoming audit. In this situation a CEA is to look at the entity's previous versions of its sabotage reporting procedure and make an assessment of the registered entity's actions based on the content in its revised sabotage reporting procedure as well as the facts and circumstances surrounding the revision.

For any enforcement action in process and for audits that have been initiated,[9] a ~~Regional Entity will~~CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether this CAN should be applied.

~~Providing~~ Evidence of Compliance

A CEA is to assess the following to obtain reasonable assurance of the entity's compliance:~~An Auditor is to request:~~

1. evidence of the entity's sabotage reporting procedure, including how it will identify sabotage events that impact the reliability of the BPS, and
2. evidence that the entity is following its procedure, including a list of events that were analyzed. For example:
   - If a registered entity had a sabotage event or activity, the entity could demonstrate how it followed its procedure to:
     1. recognize a sabotage event that may have an impact on the BPS, and
     2. make its operating personnel aware of the event.
   - If a registered entity had a suspect event or activity that the entity determined was not due to sabotage or would not have an impact on the BPS, it could demonstrate how it followed its sabotage procedure to make that determination.
   - If a registered entity did not have a sabotage event or activity, the entity could demonstrate that its employees ~~were~~are ~~trained~~aware ~~on~~ of its procedure and would be able to implement the procedure if such an event or activity occurred. An entity may also provide an attestation that no suspect events or activities had occurred.

~~are impact the reliability of the BPS and~~

~~evidence that the entity is following its procedure.~~

~~Therefore, if a registered entity includes language in its Sabotage Reporting Procedure that non-BES, or any other, facilities are **excluded** from its procedure the registered entity would be non-compliant with CIP-001-1 R1.~~

For more information please contact:

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[9] "Initiated" means that a registered entity has received notification of the upcoming audit.

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This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

~~*This document is designed to convey compliance guidance from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time.*~~

Revision History

Posted Date	Action	Revision
June 17, 2011	Posted Final CAN	
October 14, 2011	Posted Revised CAN	Supersedes prior CAN; incorporates direction of NERC Board of Trustees

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NERC Compliance Process Bulletin #2011-006

CIP Implementation Plan Table 3 Entities
Posted: October 19, 2011

Background

Process Bulletin #2011-006 has been issued to document that the "Implementation Plan for Newly Identified Critical Cyber Assets and Newly Registered Entities," which can be found as a link on the NERC Web site under the CIP Standards, is the version in effect for use for entities that registered after 2007.

Clarification of Changes

Effective April 1, 2010, Table 4 of the Implementation Plan for Cyber Security Standards CIP-002-1 through CIP-009-1 became obsolete and is no longer in effect. It was superseded by the "Implementation Plan for Newly Identified Critical Cyber Assets and Newly Registered Entities," and applies to Cyber Security Standards CIP-002-2 through CIP-009-2 and CIP-002-3 through CIP-009-3. It is available at the following link:
http://www.nerc.com/docs/standards/sar/Imp-Plan_Newly_Identified_CCA_RE_clean_last_approval_2009Nov19.pdf.

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This document is designed to convey compliance guidance from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time.

NPCC, Inc.
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Date: August 24, 2011

To: NPCC Board of Directors
From: Philip A. Fedora - Assistant Vice President – Reliability Services
Subject: Summary of the August 2011 Definition of BES Drafting Team meetings

The NERC Definition of Bulk Electric System (BES) Drafting Team (Project 2010-17) met on August 8th with FERC Staff, face-to-face on August 9-11, and via teleconference on August 18th. Publically available materials regarding BES drafting Team meetings are posted on the NERC website at: http://www.nerc.com/filez/standards/Project2010-17_BES.html.

August 8th Meeting with FERC Staff

FERC staff again indicated they were comfortable with the general approach the BES Drafting Team has taken - a core BES definition followed by the Inclusions and Exclusions, but reemphasized that that main points of Order No. 743 need to be remembered during the course of the project:

- ✓ The revised definition should eliminate regional discretion.
- ✓ All eight regions, including NPCC, need to be consistent with respect to the definition.
- ✓ Registration "status quo" should be observed.

Feedback from FERC Staff

Generator Capacity Threshold - There was a high level FERC concern expressed about proposed elimination of the 20 MVA units. This was seen as beyond the scope and intent of the Order No. 743. A suggestion was made that such changes would be more appropriate in a future project.

Radial Exclusion – Normally Open Switch - FERC staff indicated they were comfortable with the concept but concerned with what "normally open" means. They asked the BES Drafting Team to consider explaining the meaning of "normally open" in order to provide sufficient guidance to auditors.

Radial Exclusion – Hard Tap "status quo" - FERC staff reiterated their position that the BES Order called for maintaining the status quo, and asked if the BES Drafting Team was aware of any Regions that did not include hard taps in the BES. The BES Drafting Team replied that their understanding was that there could be variations.

Local Network (LN) Exclusion - FERC staff asked if a review had been performed on the LN Technical Justification document. The BES Drafting Team replied that no review had been performed as yet since the document was just recently sent out for BES Drafting Team review and comment. FERC staff stated that they thought the document was headed in the right direction but that it needed more substance. One particular concern was where the LN begins and ends.

Impact of the proposed BES Definition - FERC staff asked about impact of the proposed BES Definition with respect to NPCC. They were referred to the data supplied with the NPCC BES compliance filing in 2009. For example, there are 1,175 transmission elements 100 kV and above in New York State; approximately 850 to 900 of those elements could likely be included applying the initial posted BES definition. For comparison, 199 transmission elements in New York are

currently identified as BES, based on the current NPCC A-10 methodology. NPCC generation registration is consistent with the NERC Compliance Registry generator thresholds.

BES Exception Application Form - FERC staff previewed their specific suggestions regarding the BES Exception Application Form.

BES Drafting Team Questions to FERC Staff
The BES Drafting Team questioned what 'validate' means – would the ERO be expected to rerun analyses submitted for a BES exception? FERC staff replied that they did not anticipate having the ERO rerun the analyses, but that they did expect the ERO to do enough 'due diligence' to validate the information/recommendations they receive.

The BES Drafting Team asked where any "Technical Justification" documents should reside in the filing. FERC staff responded that they would like to see major findings in the filing letter with technical justification white papers as a separate attachment, but not in an appendix where they may "get lost."

The BES Drafting Team asked whether a guidance document on the BES definition itself was expected. FERC staff stated since that the BES definition is "bright-line" no guidance document is necessary.

The BES Drafting Team asked about interpretation of NERC Standard requirement applicability for BES units identified as 20 MVA and 800 MVA, for example. FERC staff stated that this was a valid question but that the scope of this question did not allow it to be answered here. The BES Order was interested in preserving the status quo. This issue would be better addressed by other NERC initiatives.

The BES Drafting Team inquired concerning language in other FERC documents that refers to 20 MVA units as a "Large Generators" and asked how that reference would be reconciled against the BES definition. FERC staff stated that they have not linked Large Generator Interconnection Agreements (or Small Generator Interconnection Agreements) to the NERC Reliability Standards.

August 8-11 BES Drafting Team Meeting

Technical Justification for the proposed elimination of 20 MVA Generation - After considering the feedback from the NERC Board of Trustees, the NERC Standards Committee, and the Regional Entity Managers, the BES Drafting Team decided to forgo any attempt at changing BES generation thresholds at this time. It was agreed that there wasn't enough time or resources to provide the required technical justification, given the mandated schedule. It was agreed that the primary focus of the BES Drafting Team efforts should be to address the directives in FERC Orders 743 and 743a.

BES Project 2010-17 will take a phased approach with a new BES Standards Authorization Request (SAR) to address generation thresholds as well as several other issues that have been identified through industry review of the initial BES definition posting.

The BES Drafting Team then discussed the changes to the following documents, considering the comments and suggestions provided by FERC staff, consistent with the phased approach:

- ✓ Local Network (LN) technical Justification
- ✓ BES Exception Application Form
- ✓ Response to industry Technical Principles comments
- ✓ Questions for the Second BES Posting
- ✓ Review of Applicable NERC Standards

August 18th NERC Standards Committee (SC) Meeting

The BES Chair and several BES Drafting Team members provided an update regarding the BES Definition project. It was reported that the BES Drafting Team will not be proposing any change to the existing thresholds for generation in the next posting; the revised BES Definition will refer to the existing generator thresholds as specified in Section III (c) of the NERC Registration Criteria. Considering raising/changing the BES generation threshold will be a addressed in a separate "Phase 2" BES definition effort to be defined by a revised BES SAR currently being developed by the BES Drafting and to be pursued in the future, after the initial definition is approved, in order to allow industry time to first understand the Phase I materials. Issues identified but not addressed in Phase 1 will be included in the "Phase 2" SAR.

The SC was very supportive of adoption of this phased approach. The BES Drafting Team will work with the SC to prepare a position paper to the NERC BOT by September 7th to present options and propose best ways forward in meeting the FERC deadline to file a revised definition by January 2012. Some Phase 2 activities may proceed in parallel.

August 18th BES Drafting Team Teleconference

The BES Drafting Team finalized its response to comments received from the first posting of the BES Definition and the BES Technical Principles (now BES Exception Application Form); questions for second posting BES comment forms were also finalized.

The Technical Justification associated with the Local Network BES Definition (Exclusion E3) was discussed and finalized.

Proposed revisions to new BES SAR (Phase 2) were discussed and agreed upon by the BES Drafting Team for submittal to the NERC Standards Committee for their consideration. The new BES SAR (Phase 2) will be posted for information only at this time. Once the revised BES definition is finalized, the new BES SAR will be formally posted for industry comment.

Bulk Electric System Definition, as submitted for NERC Quality Review:

Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

Inclusions:

- **I1** - Transformers with primary and secondary terminals operated at 100 kV or higher unless excluded under Exclusion E1 or E3.
- **I2** - Generating resource(s) (with gross aggregate nameplate rating per the ERO Statement of Compliance Registry Criteria) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above.
- **I3** - Blackstart Resources identified in the Transmission Operator's restoration plan.
- **I4** - Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above.
- **I5** –Static or dynamic devices dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1.

Exclusions:

- **E1** - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:
    a) Only serves Load. Or,

b) Only includes generation resources, not identified in Inclusion I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,

c) Where the radial system serves Load and includes generation resources, not identified in Inclusion I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

Note – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

- **E2** - A generating unit or multiple generating units that serve all or part of retail customer Load with electric energy on the customer's side of the retail meter if: (i) the net capacity provided to the BES does not exceed75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.
- **E3** - Local networks (LN): A group of contiguous transmission Elements operated at or above 100 kV but less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customer Load and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:

  a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusion I3 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating) ;

  b) Power flows only into the LN: The LN does not transfer energy originating outside the LN for delivery through the LN; and

  c) Not part of a Flowgate or transfer path: The LN does not contain a monitored Facility of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).
- **E4** – Reactive Power devices owned and operated by the retail customer solely for its own use.

Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.

<u>Next Steps</u>

- ✓ Following NERC Quality Review, second posting/initial ballot of BES Definition and associated documents no later than by September 2, 2011;
- ✓ BES Definition, associated documents, and the BES Rules of Procedure industry-wide NERC Webinar scheduled for Wednesday, September 28, 2011 from 1:00 p.m. to 5:00 p.m. ET;
- ✓ BES Drafting Team to meet November 8-10, 2011 to respond to comments received from the second posting/initial ballot.

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Notes
Project 2010-17 Definition of Bulk Electric System

Thursday, August 18, 2011 | 1:00 p.m. – 5:00 p.m. ET

Administration

1. Introductions & Quorum

   The Chair brought the call to order at 1:00 p.m. ET on Thursday, August 18, 2011. Call participants were:

Members		
Jennifer Dering, NYPA	Phil Fedora, NPCC	Ajay Garg, Hydro One
Pete Heidrich, FRCC, Chair	John Hughes, ELCON	Barry Lawson, NRECA, Vice Chair
Jeff Mitchell, RFC	Jerry Murray, OR PUC	Rich Salgo, Sierra Pacific
Jason Snodgrass, GTC	Jennifer Sterling, Exelon	Jonathan Sykes, PG&E
Ed Dobrowolski, NERC		
Observers		
Ena Agbedia, FERC	Neil Burbure, FERC	Frank Cain, LCEC
Lam Chung, Manitoba Hydro	Mark Cole	Frank Cumpton, BG&E
Paul Cummings, Redding	Michelle D'Antuono, Occidental	Richard Dearman, TVA
Andy Dressel, NERC Legal	Tom Duffy, CH	Jeff Gindling, Duke
Bill Harm, PJM	Nick Henery, FERC	Ken Lotterhos, Navigant
John Martinsen, Snohomish	Susan Morris, FERC	Wilket Ng, Con Ed
David O'Connor, FERC	Nitin Sem, BG&E	Ken Shortt, Pacificorp

Tim Soles, Occidental	Bob Stroh, FERC	

2. NERC Anti-trust Guidelines and Conference Call Warning – Ed Dobrowolski

   The NERC Anti-trust Guidelines were presented and the conference call warning was delivered. No questions were raised.

3. Review Agenda and Meeting Objectives – Pete Heidrich

   The agenda was approved as issued.

   The objective of the call was to finalize the documents needed for the second posting submittal.

Agenda

1. **Finalize First Posting Response to Comments**

   a. BES Definition

      Prior to reviewing the responses, the SDT reviewed the definition itself. Changes were made to Inclusions I2 and I4.

      In Inclusion I2, the SDT thought the existing wording presented a circular reference to the ERO Statement of Compliance Registry Criteria (SCRC) and that this could cause confusion in the industry. The wording was adjusted to provide clarity.

      In Inclusion I4, the reference to the ERO SCRC was deleted and the 75 MVA threshold was returned. This is a new concept so it is not found currently in the ERO SCRC so the reference would have been problematic. The 75 MVA threshold is consistent with the ERO SCRC however.

      The SDT members were concerned about submitting a new SAR versus revising the present SAR. Logistically, the right path to take was a new SAR as it would be problematic to ask industry to approve a revised SAR at the same time they were voting on the output of the original SAR. A new SAR, posted for information only at this time, to show the industry the path that would be followed was consistent with the approach suggested by the NERC Standards Committee. The SDT was worried that a new SAR would mean a new SDT. As the existing SDT is committed to this project and wants to see it through to the end, they wanted to make certain that they wouldn't be dismissed at the end of Phase 1. Words were added to the response to show the intent of the SDT.

   b. BES Technical Principles

      The SDT accepted the responses as distributed.

2. **Finalize Questions for Second Posting Comment Forms**

a. BES Definition

The changes suggested in the last SDT meeting were accepted as is.

A reference to the tie to the ERO SCRC was added to question 3.

b. BES Technical Principles

The changes suggested in the last SDT meeting were accepted as is.

A line for description/comments was added to Transmission Q5 and Q6 similar to the other questions.

A question was raised as to whether it was correct to refer to the BES in the questions. It was stated that this might be a circular reference and cause confusion. The SDT did not make a change in this regard as the feeling was that at this point the BES was defined and there shouldn't be any confusion. This is not the same as using the term in its own definition.

There was some concern that industry might interpret the questions incorrectly by assuming that a single 'yes' or 'no' response could invalidate a request. That is not the intent of the SDT. The intent is that the entire document will be taken into consideration and that the answer to any individual question will just be one piece of the information leading to a decision. A statement will be added to the ERO Rules of Procedure draft to clearly state the intent of the SDT.

AI – Ken Lotterhos will forward a request to place a statement in the ERO Rules of Procedure clearing up any possible misconceptions about a single response invalidating a request for exception.

3. Finalize Technical Justification for the LN – Rich Salgo

Rich provided an overview of the changes made since the last SDT meeting:

- Added a bullet in the summary and a section to the text describing the tie to the 300 kV EHV limit in TPL-001-2
- Deleted the requirement by requirement analysis
- Deleted the PTDF example
- Added a new PTDF and LODF section to illustrate how the local network interacts with the BES
- Emphasized that power always flows in to the local network
- Added a real world example in the appendix with names changed to protect confidentiality – the LODF will be added to the appendix if the SDT approves the concept

The SDT approved the LODF concept and Rich will add it to the document. The SDT asked for several changes to the paper:

- The appendix should be incorporated in a single document with the text to facilitate comprehension of the industry
- The drawings in the appendix need a legend
- A clear delineation of the local network is needed
- There should be a note that the arrows are proportional to the flow on the line

Rich will make the suggested changes and submit the document for inclusion in the second posting by noon Friday, August 19, 2011.

AI – Rich Salgo will revise the local network technical justification document with the SDT suggested changes by noon on Friday, August 19, 2011.

This document is solely for the purpose of justifying Exclusion E3. It is not asking anyone to perform studies or do any analysis. It is not part of the exception process although it could be used as a model for what needs to be submitted for those seeking inclusion/exclusion through that process.

4. Finalize Revisions to SAR

The SDT made changes to emphasize the phased nature of the project moving forward.

The new SAR will be posted for information only at this time. Once the revised definition gets through the pipeline, the new SAR will be formally posted and questions will be asked of industry.

5. Next Steps – Pete Heidrich

The next step is to submit the documents to NERC Quality Review. Ed Dobrowolski will clean up the documents and make the submittal on Friday, August 19, 2011.

AI – Ed Dobrowolski will clean up the documents for the second posting and submit to NERC Quality Review.

6. Future Meetings

a. Face-to-face meeting on Tuesday, September 20 through Thursday, September 22, 2011. This meeting was cancelled.

b. Industry webinar on Wednesday, September 28, 2011 from 1:00 p.m. to 5:00 p.m. ET.

c. Face-to-face meeting on Tuesday, November 8, 2011 through Thursday, November 10, 2011 to respond to comments. Dates based on proposed posting date. Location TBD.

7. Action Items & Schedule – Ed Dobrowolski

The following action items were developed during this call:

- Ken Lotterhos will forward a request to place a statement in the ERO Rules of Procedure clearing up any possible misconceptions about a single response invalidating a request for exception.
- Rich Salgo will revise the local network technical justification document with the SDT suggested changes by noon on Friday, August 19, 2011.
- Ed Dobrowolski will clean up the documents for the second posting and submit to NERC Quality Review.

The project is on schedule at this time.

8. Adjourn

The Chair thanked the members and observers for their hard work in meeting the schedule and adjourned the call at 5:30 p.m.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda
Project 2010-17 Definition of Bulk Electric System

Monday, August 8, 2011 | 1:00 p.m. - 5:00 p.m. ET
Meeting Location: FERC 888 First St. NE Washington, DC 20426

Administration

1. Introductions

   The Chair brought the meeting to order at 1:15 p.m. ET on Monday, August 8, 2011 at the FERC offices in Washington, DC. Meeting attendees were:

Members		
Phil Fedora, NPCC	Ajay Garg, Hydro One	Pete Heidrich, FRCC, Chair
John Hughes, ELCON	Jeff Mitchell, RFC	Jerry Murray, OR PUC
Rich Salgo, Sierra Pacific	Jason Snodgrass, GTC	Jennifer Sterling, Exelon
Jonathan Sykes, PG&E	Ed Dobrowolski, NERC Coordinator	
Observers		
Paul Cummings, Redding	Frank Cumpton, BG&E	Andy Dressel, NERC Legal
Carter Edge, SERC	Jeff Gindling, Duke	Bill Harm, PJM
John Martinsen, Snohomish	Willie Phillips, NERC Legal	Tim Soles, Occidental
Sam Stonerock, SCE	Phil Tatro, NERC	Dave Taylor, NERC
FERC Staff		
Kal Ayoub	Neil Burbure	Jonathan First
Dennis Fuentes	Randy Johanning	Susan Morris
David O'Connor	Christy Walsh	Zak Zaremski

2. NERC Anti-trust Guidelines and Conference Call Warning – Ed Dobrowolski

   The NERC Anti-trust Guidelines were read and the conference call warning was delivered.

3. FERC Disclaimer

   FERC staff stated that they were not speaking on behalf of the Commission.

4. Review Agenda and Meeting Objectives – Susan Morris & Pete Heidrich

   The agenda was accepted as posted. The objective of the meeting was to hear FERC staff's concerns about the proposed BES definition and for the SDT to ask any questions they might have of FERC staff.

Agenda

1. **Discussion Points**

   a. Generator Capacity Threshold

      FERC staff stated that the current registration criteria is 20 and 75, the original draft was 20/75, and that they understood that the proposed revision is just 75. They acknowledged that the SDT is working on a technical justification for the change. However, they pointed out that the key points of the order were to remove regional discretion, apply the definition equally in all 8 regions, maintain the status quo,, and that the Commission was satisfied with the registration criteria and definition application except in NPCC. They stated that adding more elements would add to registration and make a vote problematic but deleting elements will add angst to regulators. There is a high level concern about the elimination of the 20 MVA units. This is seen as beyond the scope and intent of the order. A suggestion was made that such changes might be more appropriate in a future project.

      The SDT questioned how FERC might use the proposed definition.

      FERC staff replied that they saw the definition as drawing a universe of facilities subject to mandatory standards but that some elements such as UFLS or control centers won't be BES elements but will support BES elements. The definition is needed to support that position.

      NERC staff responded that the definition is a baseline with specific standards carving out pieces of the BES in applicability decisions.

      Ajay Garg stated that the 20 MVA deletion should not be an issue because standards can be written against non-BES elements as discussed at the MRC and clarified by NERC staff. The focus should be on providing the best definition possible as a starting point.

The SDT pointed out that they are responsible for responding to industry concerns as stated in the comments. The comments indicated a desire to change the threshold. To date, the schedule has not been jeopardized by considering this change and the technical justification associated with it. The SDT should be allowed to move forward with their work. The next posting can't be made without the accompanying technical justification for changes.

b. Radial Exclusion – Normally Open Switch

FERC staff stated that they are comfortable with the concept but concerned with what normally open means. They feel it is too broad, vague, difficult to enforce, and ambiguous.

The SDT questioned the ambiguity concept as industry has a clear meaning of normally open. For example, it is clearly marked on drawings.

FERC staff felt that this might cause confusion in other standards.

The SDT stated that normally open switches can change from time to time but not every day. The general thought would be to stay with language that industry knows and train others (a smaller set) as necessary.

FERC staff questioned whether the SDT could come up with wording in a footnote to explain what normally open means. Something along the lines of 'normally open shows in drawings' might be all that is needed. This would provide guidance to auditors.

The SDT responded that this might be possible and that they will consider this at their next meeting.

c. Radial Exclusion – Hard Tap status quo

FERC staff asked if the SDT was aware of any regions that did not include hard taps in the BES.

The SDT replied that they don't know for certain but that it is their understanding that there are variations.

FERC staff then asked if the current language specifically included or excluded hard taps.

The SDT replied that the current language is silent on this topic.

FERC staff reiterated their position that the Order called for maintaining the status quo.

FERC staff asked the SDT RFC member how hard taps were handled within RFC.

The RFC representative replied that they don't currently explicitly state that hard taps are included in the BES but some are included.

NERC staff responded that there is no perfect answer to this question. If the tap is at 100 kV then it is likely to be included but a survey would be required to know all of the situations across the continent.

FERC staff stated that they are not advocating a survey but that they had some concerns after a statement that was made by a large utility at a recent SDT meeting that they had 400 hard taps that would now be excluded.

The representative of the specific utility in question clarified the statement referenced by FERC staff. They did not state that they had 400 hard taps which would now be excluded. What they said was that they had approximately 400 taps which are classified as distribution. The utility generally follows the RFC rules for hard tap radial classification.

FERC staff acknowledged the clarification and then asked the RFC representative if they had any concerns about the proposed definition with respect to hard taps.

The RFC representative replied that they normally consider the hard taps impact on the BES in making their determination. Protection system issues are a part of this analysis.

FERC staff asked RFC if they were comfortable with the proposed definition in this regard.

The RFC representative stated that they were neither comfortable nor uncomfortable as the revised definition is quiet on the topic.

d. Local Network Exclusion

FERC staff asked if a review had been performed on the technical justification document.

The SDT replied that no review had been performed as yet since the document was just sent out.

FERC staff stated that they thought the document was headed in the right direction but that it needed more substance. One particular concern was where the LN begins and ends.

The SDT stated that the LN is a parallel path to the BES at 100 kV but that it is only serving local load and therefore not a true parallel path in the traditional sense. The start and end points are determined by where the parallel path begins and ends.

FERC staff stated that analysis will be needed for an LN.

The SDT replied that the work is not finished at this time but that preliminary analysis showed that the LN exclusion was not creating any reliability gaps.

FERC staff questioned the inclusion of transfer distribution factors in the justification. These factors are different in the east and west. The east uses 5% which also keys the markets.

The SDT reiterated that the work is in its preliminary stages and is just the starting point for the full discussion.

FERC staff stated that they would be looking for additional information on how to specify an LN and asked if a footnote could be added to the definition pointing to the technical justification paper.

FERC staff also asked about an NPCC study in this area.

The NPCC member of the SDT replied that the referenced study was part of an NPCC compliance filing in 2009 on the BES topic. The particular information for New York and New England is not public information. However, the study showed that there were approximately 1175 elements over 100 kV in the area. 900 to 950 of those elements would be included in the BES under the current proposal. Under the old NPCC methodology where they only considered cascading, 199 elements would be considered BES.

e. Exception Application Form

FERC staff pointed out that in the last SDT meeting, some SDT members asked about providing a guidance document on this topic.

The SDT replied that they have not dismissed the idea of providing such a document but that the current proposal has added language that should provide some guidance.

FERC staff had some specific suggestions for improving the form.

The SDT agreed to review all of the specific items in their upcoming meeting.

2. SDT Questions to FERC Staff

The SDT questioned what 'validate' means to FERC staff. Does this mean that the ERO would have to rerun the analysis submitted for an exception?

FERC staff replied that they did not anticipate having the ERO rerun the analysis but that they did expect the ERO to do enough to validate the data they receive.

The SDT asked where technical justification documents should reside in the eventual filing.

FERC staff would like to see major findings in the filing letter with technical justification white papers as a separate attachment and not in an appendix where they can get lost.

The SDT asked whether FERC staff was expecting a guidance document on the definition itself.

FERC staff stated that the definition is a bright-line so no guidance document should be necessary.

The SDT asked how FERC staff could support the same definition requirements for 20 MVA units and 800 MVA units.

FERC staff stated that this was a valid question with several possible options for how to fix the problem but that the scope of this project probably won't allow it to be answered here. The Order was interested in preserving the status quo. Other problems should be solved in other projects.

The SDT pointed to language in other FERC documents that cited 20 MVA as a large generator and asked how that applied to the definition.

FERC staff stated that they have never linked Large Generator Interconnection Agreements (or Small Generator Interconnection Agreements) to standards.

3. **Next Steps – Pete Heidrich**

   The SDT will discuss FERC staff concerns as part of the next SDT meeting.

4. **Action Items – Ed Dobrowolski**

   No specific action items were identified during this meeting.

5. **Adjourn**

   The Chair thanked FERC staff for the opportunity to meet and discuss the issues and adjourned the meeting at 3:00 p.m. ET.

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Notes
Project 2010-17 Definition of Bulk Electric System

Tuesday, August 9, 2011 | 8:00 a.m. - 5:00 p.m. ET
Wednesday, August 10, 2011 | 8:00 a.m. – 5:00 p.m. ET
Thursday, August 11, 2011 | 8:00 a.m. – 5:00 p.m. ET
Meeting Location: ELCON 1111 19th St. NW Washington, DC 20036

Administration

1. Introductions

The Chair called the meeting to order at 8:00 a.m. ET on Tuesday, August 9, 2011 at the ELCON offices in Washington, DC. Meeting participants were:

Members		
Brian Evans-Mongeon, Utility Services	Phil Fedora, NPCC	Ajay Garg, Hydro One
Pete Heidrich, FRCC, Chair	John Hughes, ELCON	Jeff Mitchell, RFC
Jerry Murray, OR PUC	Rich Salgo, Sierra Pacific	Jason Snodgrass, GTC
Jennifer Sterling, Exelon	Jonathan Sykes, PG&E	Ed Dobrowolski, NERC
Observers		
Neil Burbure, FERC	Paul Cummings, City of Redding	Frank Cumpton, BG&E
Richard Dearman, TVA	Tom Duffy, CH	Carter Edge, SERC
Dennis Fuentes, FERC	Jeff Gindling, Duke	Bill Harm, PJM
Jonathan Hayes, SPP	John Martinsen, Snohomish	Susan Morris, FERC
Steve Myers, ERCOT	David O'Connor, FERC	Alain Pageau, HQ
Ken Shortt, Pacificorp	Tim Soles, Occidental	Sam Stonerock, SCE
Bob Stroh, FERC	Phil Tatro, NERC	Orhan Yildiz, EIA

Zack Zaremski, FERC		

2. NERC Anti-trust Guidelines and Conference Call Warning – Ed Dobrowolski

   The NERC Anti-trust Guidelines and conference call warning were delivered. There were no questions.

3. Review Agenda and Meeting Objectives – Pete Heidrich

   An item was added to the agenda for a report on the recent RE Managers/MRC/BOT meetings from Pete Heidrich.

   The objective of the meeting was to finalize a number of the SDT documents in preparation for the second posting.

Agenda

1. **Review of RE Managers/MRC/BOT Meetings – Pete Heidrich**

   Seven out of the eight regions do not support the deletion of 20 MVA units. SERC is the only region that supports the deletion.

   FERC is emphasizing that they expect the SDT to focus on the directives in the Order.

   The MRC expressed their dislike of the 20 MVA deletion as well as the statement on local distribution in the core. The MRC also expressed concern with the ability of the SDT to develop technically sound justifications for the elimination of the 20 MVA and the local network exclusion. Without the appropriate technical justification the MRC sees the deletion of the 20 MVA units as guaranteeing failure of the project.

   The current wording of the local distribution statement in the core is seen as setting up jurisdictional disputes. David Cook of NERC Legal distributed a letter to the SDT leadership which was shared with the entire SDT providing a suggested change to the wording of the definition in this regard. The SDT reviewed the proposal and accepted the proposed change.

   The MRC asked Pete Heidrich if all of the changes undertaken by the SDT were in direct response to directives in the Order. The answer was 'no.'

   The MRC felt that the local network exclusion will require a strong technical justification complete with a thorough analysis for the next posting.

   The general feeling at the meeting was that the ERO needs to show the Commission that it can get the job done when given a specific order.

   The BOT focused on eliminating regional entity discretion and addressing directives. They requested a progress report containing all technical justifications no later than September 9, 2011.

FERC brought up the issue of hard taps on radials. They felt that the present draft alters the scope of the BES in this regard and will change the status quo. They stated that they were not looking for substantive changes to the BES as part of this project.

The BOT suggested a two phase approach. In phase one, the emphasis would be on maintaining the status quo – stay with the 20 and 75 MVA thresholds and delete the local network exclusion. Phase two could tackle those issues and any other contentious topics.

Pete walked away from the meeting with the impression that the BOT would not approve the current proposed definition.

The phased approach would allow time for the SDT to go out to technical committees for assistance in gathering the data needed for technical justifications of positions. It was stressed by the BOT that changes must show a positive impact on reliability and not just that there was no negative impact.

Both the BOT and the MRC stated that they see a tight coupling of the definition and registry criteria.

The SDT was not appreciative of what they saw as interference in their work by the BOT/MRC. The SDT feels that industry is supportive of the current proposal.

The states seem confused by what is going on. They are not certain what revising the definition will accomplish or how it will affect users of the BES. The SDT stated that short of specific applicability in an individual standard, the definition of the BES determines what standards apply to.

If the SDT decides to adopt the phased approach, a new or revised SAR will be required.

2. Review of Meeting with FERC Staff – Pete Heidrich

At the meeting with FERC staff on Monday, August 9, 2011, FERC staff expressed concerns with several areas of the proposed definition and process. Notes from that meeting were distributed separately. The SDT stated that they would review the identified concerns as part of the agenda for this meeting. Items reviewed were:

- Generation thresholds – This item will be reviewed under agenda item #3 and FERC staff concerns will be included in the discussion.
- Normally open switch – Language was added to provide clarity. FERC staff indicated that this change was being viewed positively.
- Hard taps – The SDT stated that as written, the proposed definition would exclude hard taps as long as they qualified for the exclusion (Exclusion E1) and all of its parts. This might result in a change to the status quo but it will do so while providing additional clarity to the situation. The status quo is inconsistent and applied with discretion.

- Exception process form – This item will be reviewed under agenda item #6 and specific comments from FERC staff will be considered at that time.

3. Report from Sub-team on 20/75 MVA Issue – Jonathan Sykes

Jonathan provided a high level overview of the technical justification for deleting generating units between 20 and 75 MVA from the BES definition.

The paper states that the sub-team does not feel that registration depends on the definition. They see the two as loosely coupled. Users will still be required to register and entities will still be registered. Approximately 5% of installed generation would be excluded from consideration under the proposed definition based on the evidence gathered to date. Case studies with the excluded generation out of the study have all solved so far with no reliability issues although WECC did have to bring on reserves. Therefore, the sub-team feels that units between 20 and 75 MVA are not needed for reliability.

It was pointed out that formal studies still need to be made and that these studies may result in slightly different values but shouldn't change the end result.

The SDT provided the following comments:

- Were a set of consistent assumptions used throughout?
- What happens with the most severe single contingency situation with these units out of the BES?
- No data was presented from several parts of the country.
- Study data must be available, not just end results in text.
- The report doesn't justify the selection of 75 MVA.
- It would be beneficial to provide examples from recent operations such as the Texas situation this past winter to show that there would be no ill effect from excluding these units.
- The assumption that registration can continue as is contradicts the position of the MRC/BOT.
- The paper states that deletion of the units will save money for entities but this may not be true as those units are already registered and under standards.

The SDT stated that the technical justification must be provided for the second posting and that in order for that to happen, the final draft needed to be available for review by August 16, 2011. The sub-team accepted this condition and asked for a vote of the SDT to determine if they should continue their work or whether the SDT wanted to drop back to the status quo approach suggested by the BOT. The SDT voted 6-5 to continue with the sub-team work effort and approach.

The sub-team then drafted a formal data request to be sent to all regions requesting studies to be done in the next few days so that they could present their report to the SDT as scheduled. Numerous questions arose at this time as to what exactly was being requested. It became evident that the studies would not be ready in time.

The sub-team came back to the SDT with an alternate proposal:

- Remove all generator thresholds from the inclusions.
- Leave the generation limits in the exclusions.
- Create a SAR to capture the generation threshold issue at a minimum for future development.

Several SDT members were concerned that the new SAR wouldn't be approved and the issues would end up getting lost. However, it was pointed out that everyone involved, including the BOT, was supportive of such an approach and the chances of the SAR being turned down were almost certainly non-existent.

The SDT voted 10-1 to adopt this revised approach.

On the next day, several SDT members pointed out what they considered a fatal flaw in the proposed wording of the revised definition and inclusions under this approach. As a result of the discussions on this topic, a compromise position was adopted that placed a reference to the current ERO Statement of Compliance Registry Criteria in the inclusion.

This approach will necessitate the creation of a new SAR to address the generation threshold issue at a minimum going forward. The SDT brainstormed ideas for inclusion in the new SAR and provide them to Pete Heidrich who volunteered to draft the SAR for review on the next SDT conference call.

The list of items for consideration included the need for a contiguous BES, generation thresholds, demarcation between transmission, generation, and distribution, associated support equipment for the BES, and items derived from FERC Order 693

AI – Pete Heidrich will draft a new SAR to address the issues generated at the August 9, 2011 SDT meeting and distribute the document so that it can be reviewed on the August 18, 2011 SDT conference call.

4. Report from Sub-team for LN Issue – Rich Salgo

Rich presented a high level overview of the position paper.

The basic premise of the sub-team is that if all three conditions for Exclusion E3 are met, then the system in question is definitely distribution and not transmission. The situation is not unlike the radial system exclusion in concept. The sub-team has studied the existing standards and does not see any effect as a result of this definition.

The SDT was concerned that the paper read more like a narrative text and didn't contain any technical analysis. There were also comments raised about the last section of the paper that talked about distribution factors. The SDT didn't feel that this was a germane issue and should probably be eliminated.

The question arose as to why Exclusion E3 was needed now that the statement on distribution facilities was added to the core and if the local network exclusion was truly a bright-line. The sub-team pointed out that Order 743 gave the SDT the opportunity to define distribution and that Exclusion E3 was a particular example of such a determination that will have wide-spread application. The bright-line question is not black and white. Some degree of 'analysis' is required to prove the point but the sub-team pointed out that it was all readily available data that entities already have for other reasons.

The SDT asked for specific real-world examples of local networks with the names changed to protect confidentiality. The SDT also requested that the report cover the issue of the 300 kV limit as well as addressing ties to the TPL and CIP methodologies.

The sub-team will have the final draft report ready for review on the next SDT conference call so that it can be submitted for the second posting.

AI – The LN Sub-team will distribute their final draft to the SDT for review on the August 18, 2011 conference call.

5. **Reports on Informal In-house Tests of Exception Criteria**

Several SDT members reported on their findings when they ran an informal test of the new form at their respective companies.

Lee County filled out the form and submitted it to FRCC. Lee County reported no problems in filling out the form or providing the data. FRCC is still reviewing the submittal.

Exelon asked about the possibility of adding an 'other' category to pick up any loose ends that didn't fit cleanly under either transmission or generation.

Con Edison asked for several wording changes based on their dry runs that were accepted by the SDT.

6. **Finalize Exception Criteria**

After discussions with Carter Edge, Chair of the RoP team, the SDT deleted page 1 of the form as it was duplicative of what has already been developed by the RoP team. It was also determined that the SDT did not need to address the issue of data retention as this topic has already been covered by the RoP team. The RoP team will need to change some of their crafted language to coordinate with the new approach to the exception criteria adopted by the SDT.

In addition to cleaning up the text in general, questions were added on off-site nuclear power supply and cranking paths. Protection system diagrams were added to the required data.

7. **Finalize Industry Comments to Technical Principles**

   All of the authors accepted the final draft of the document.

8. **Finalize Questions for Second Posting**

   The preamble to the documents needs to be changed to bring in the concept of the new SAR.

   On the definition document, questions 9 & 10 were basically identical and one will be deleted. The questions should emphasize 'revised' instead of 'added.'

   On the criteria document, a question will be added to determine if sufficient information for making a decision is being requested.

9. **Discuss Applicability of Standards – Pete Heidrich**

   The spreadsheet was updated as requested at the last SDT meeting. Pete provided an overview of his analysis which indicates no affect on standards due to the revised definition. As part of his analysis, he expanded the search to include pending standards and specific applicability for each standard with no change to the results. SDT members are encouraged to review the results in detail and to distribute any comments, questions, or suggestions through the mail server. Unless someone does come up with something new to discuss, this issue is closed.

   AI – SDT members should review the applicability spreadsheet and send any comments, questions, or suggestions to the mail server for SDT consideration.

10. **Discuss Review of Pending Standards – Pete Heidrich**

    See item #9 for discussion of this issue.

11. **Next Steps – Pete Heidrich**

    With the new approach adopted at this meeting, the responses to comments for the first posting of the definition need to be updated. Ed Dobrowolski will do the update and distribute them to the individual authors for review. Full SDT review will take place on the next SDT conference call. Several other documents will need to be updated as well and Ed will handle all changes.

    The SDT discussed the possibility of developing a guidance document for the exception process. A meeting was tentatively scheduled for September 20 – 22, 2011 in Tampa, FL to develop such a document.

    AI – Ed Dobrowolski to update all documents needed for the second posting and distribute them to the SDT for final review on the August 18, 2011 conference call.

12. **Future Meetings**

a. Conference call and web ex to finalize all second posting documents on August 18, 2011 from 1:00 p.m. – 5:00 p.m. ET.

b. (Tentative) Face-to-face meeting on September 20 – 22, 2011 in Tampa, FL to develop a guidance document for the exception process.

c. Face-to-face meeting on Tuesday, November 8, 2011 through Thursday, November 10, 2011. Dates based on proposed posting date. Location TBD.

d. Schedule meetings and conference calls as necessary.

13. Action Items & Schedule – Ed Dobrowolski

The following action items were developed during this meeting:

- Pete Heidrich will draft a new SAR to address the issues generated at the August 9, 2011 SDT meeting and distribute the document so that it can be reviewed on the August 18, 2011 SDT conference call.
- The LN Sub-team will distribute their final draft to the SDT for review on the August 18, 2011 conference call.
- SDT members should review the applicability spreadsheet and send any comments, questions, or suggestions to the mail server for SDT consideration.
- Ed Dobrowolski to update all documents needed for the second posting and distribute them to the SDT for final review on the August 18, 2011 conference call.

If the documents can be finalized on the August 18, 2011 conference call, the submittal to NERC Quality Review can be made on time and the project will remain on schedule.

Pete Heidrich reminded the MRC/BOT that the milestone for determining whether an extension to the project timeframe will be needed has always been tied to the results of the initial ballot. The upcoming posting is a combined 45-day posting and combined initial ballot. If the posting is made on schedule, the results will be known in late October.

14. Adjourn

The Chair thanked ELCON for their hospitality and adjourned the meeting at 2:30 p.m. on Thursday, August 11, 2011.

August 24, 2011

John Q. Anderson
Chairman
NERC Board of Trustees

Dear Chairman Anderson:

At the NERC Board of Trustees August 4, 2011 meeting, the Board approved the following Resolution on Definition of Bulk Electric System:

> In furtherance of the Board's oversight of the standards development process and in anticipation of the Board's ultimate responsibility to determine whether the revised definition of "Bulk Electric System" that emerges from the standards development process should be approved and filed with the Federal Energy Regulatory Commission no later than January 25, 2012, as NERC's response to the directives in Order No. 743, the Board:
>
> (1) directs the Standards Committee and the Standard Drafting Team to consider the feedback heard at the August 4, 2011 board meeting regarding the development of the Bulk Electric System definition; and
>
> (2) further directs that the Standards Committee submit to the Board by September 9, 2011:
>
> (a) the draft of the proposed Bulk Electric System definition as it exists on that date;
>
> (b) the best justification that the Standard Drafting Team has prepared to support the change in generator threshold from 20 MVA to 75 MVA; and
>
> (c) an options paper that addresses possible options for moving forward with the development of the proposed definition and responding to the Commission by the January 25, 2012 deadline; and
>
> (3) expects the Standards Drafting Team to continue its work on the Bulk Electric System definition.

The Drafting Team (DT) for Project 2010-17 Definition of the Bulk Electric System met the week of August 7, 2011 and determined that it was highly unlikely that the DT could develop an adequate technical justification to support revision of the single unit generator threshold criteria (20 to 75 MVA) in the time frame established by Order 743. The team revised its proposed definition and provided us with an update to its action plan that reflects adoption of the guidance provided by the Member Representatives Committee and Board of Trustees.

- Attachment A is a copy of the latest draft of the proposed definition of Bulk Electric System as of August 19, 2011. The revised definition is silent on generator threshold; there is no proposed change from 20 MVA to 75 MVA.
- Attachment B is a copy of the letter provided by the drafting team's chair, Peter Heidrich, on August 23, 2011 relative to the status of the project.
- Attachment C is a copy of the team's proposed action plan for moving this project forward to meet the applicable Commission directives by January 25, 2012. This includes splitting the

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project into two phases, with phase 1 focused solely on meeting the Commission's relevant directives. Phase 2 will address other issues, including the generator threshold issue, raised by stakeholders or during drafting team deliberations.

It is our view that the drafting team's proposed course of action meets the intent of the Board's August 4 Resolution that the Standards Committee and the Standard Drafting Team consider the feedback heard at the August 4, 2011 Board meeting regarding the development of the Bulk Electric System definition and that the drafting team continue its work on the Bulk Electric System definition. The team expects to post its latest documents for a stakeholder comment period starting on August 25, 2011.

Sincerely yours,

Allen Mosher
Chair, Standards Committee

Cc: Herbert Schrayshuen
Standards Committee
BES Definition SDT

Project 2010-17 Definition of Bulk Electric System

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment 12/17/10 – 1/21/11
2. SC authorized moving the SAR forward to standard development 3/25/11
3. First posting of definition 4/28/11 – 5/27/11
4. First posting of criteria 5/11/11 – 6/10/11

Description of Current Draft

This draft is the second posting of the revised definition of the Bulk Electric System (BES). It is for a 45-day formal comment and parallel voting period.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period	April 28, 2011
45-day Formal Comment Period with Parallel Initial Ballot	September 2011
Recirculation ballot	December 2011
BOT adoption	January 2011

Effective Dates

This definition shall become effective on the first day of the second calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the definition will go into effect on the first day of the second calendar quarter after Board of Trustees adoption. Compliance obligations for Elements included by the definition shall begin 24 months after the applicable effective date of the definition.

Version History

Version	Date	Action	Change Tracking
1	TBD	Respond to FERC Order No. 743 to clarify the definition of the Bulk Electric System	N/A

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Bulk Electric System (BES): Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

Inclusions:

- **I1** - Transformers with primary and secondary terminals operated at 100 kV or higher unless excluded under Exclusion E1 or E3.
- **I2** - Generating resource(s) (with gross aggregate nameplate rating per the ERO Statement of Compliance Registry Criteria) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above.
- **I3** - Blackstart Resources identified in the Transmission Operator's restoration plan.
- **I4** - Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above.
- **I5** –Static or dynamic devices dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1.

Exclusions:

- **E1** - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:
    a) Only serves Load. Or,
    b) Only includes generation resources, not identified in Inclusion I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,
    c) Where the radial system serves Load and includes generation resources, not identified in Inclusion I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

  Note – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

- **E2** - A generating unit or multiple generating units that serve all or part of retail customer Load with electric energy on the customer's side of the retail meter if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.
- **E3** - Local networks (LN): A group of contiguous transmission Elements operated at or above 100 kV but less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customer Load and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:
    a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusion I3 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating) ;
    b) Power flows only into the LN: The LN does not transfer energy originating outside the LN for delivery through the LN; and
    c) Not part of a Flowgate or transfer path: The LN does not contain a monitored Facility of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).
- **E4** – Reactive Power devices owned and operated by the retail customer solely for its own use.

Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.

FRCC
Florida Reliability Coordinating Council, Inc.

FLORIDA RELIABILITY COORDINATING COUNCIL, INC.
1408 N. WESTSHORE BLVD., SUITE 1002
TAMPA, FLORIDA 33607-4512
PHONE 813.289.5644 • FAX 813.289.5646
WWW.FRCC.COM

August 23, 2011

Allen Mosher, Chair of NERC Standards Committee
Ben Li, Vice Chair of NERC Standards Committee
Herbert Schrayshuen, Vice President and Director of Standards, NERC

RE: Project 2010-17 Definition of the Bulk Electric System - Action Plan

Gentlemen;

This letter provides the Standards Committee, the Board of Trustees and NERC staff with the Drafting Team's action plan for Project 2010-17 Definition of the Bulk Electric System (BES). The project is currently on schedule to complete the revision of the definition of the BES, the development of the associated Implementation Plan and all documents supporting the Rules of Procedure Exception Process by January 25, 2012, in response to the directives established by the Commission (FERC) in Order Nos. 743 and 743-A.

The drafting team submitted the following documents for quality review on Friday, August 19, 2011, in preparation for the next scheduled posting. The goal is to post the documents for stakeholder formal comment and initial ballot no later than September 2, 2011:

- Draft BES Definition
  - Responses to the initial posting of definition
  - Technical Justification for the Local Network exclusion (E3)
  - Second posting comment form for definition
- Draft Technical Principles for Demonstrating BES Exceptions (evidence document to support Rules of Procedure Process)
  - Responses to the initial posting of Technical Principles document
  - Second posting comment form for Technical Principles
- Draft Implementation Plan
- Table identifying how the team addressed applicable FERC directives
- Phase 2 SAR (to be posted for informational purposes only)

I have attached the latest action plan for successful completion of this project in phases which encompasses the MRC and BOT recommendations.

Sincerely,

Peter A. Heidrich
Chair, Project 2010-17 Definition of the Bulk Electric System Drafting Team

cc: NERC Board of Trustees
NERC Standards Committee

August 23, 2011 Action Plan for Completion of Project 2010-17 – Definition of Bulk Electric System

The Standard Drafting Team (SDT) for Project 2010-17 Definition of the Bulk Electric System met the week of August 7, 2011 and determined that the feasibility of developing an adequate technical justification for the revision of the single unit generator threshold criteria (20 to 75 MVA) is highly unlikely in the time frame established by Order No. 743 (filing deadline of January 25, 2012). Therefore the SDT adopted the recommendations of the Member Representatives Committee (MRC) and the NERC Board of Trustees (BOT) and developed the following plan to meet the schedule for addressing the directives established by the Commission (FERC) in Order Nos. 743 and 743-A while also addressing concerns raised by SDT members and concerns received from stakeholders through the standard development process.

- The SDT revised the draft definition to eliminate any change in the generation thresholds. To accomplish this, the SDT has chosen to remain silent as to the actual values associated with the generator thresholds for units and referenced the ERO Statement of Compliance Registry Criteria for additional clarification. This will ensure that the current 'status-quo' application of the BES definition and the registration process will continue as it is today.
- The SDT developed a second Standard Authorization Request (SAR) for the project (Project 2010-17 Definition of the Bulk Electric System) to establish a phased approach where *phase 1* addresses the directives from Order Nos. 743 and 743-A and *phase 2* will address the concerns raised by SDT members and stakeholders through the Standard Development Process.
- The SDT finalized the revised draft BES definition and all associated documents for a 45-day concurrent posting (formal comment period and initial ballot) scheduled to begin no later than September 2, 2011. The SDT also prepared a revised version of the "*Technical Principles for Demonstrating BES Exceptions*[1]" for posting (formal comment period and initial ballot) in parallel with the posting of the BES definition.

[1] The "*Technical Principles for Demonstrating BES Exceptions*" was developed to supplement the Rules of Procedure Exception Process by providing guidance to the ERO, the Regional Entities and the industry on the detailed information and evidence necessary to support a BES Definition exception request.

Bulk Electric System Definition Project - Fact Sheet

From the Standards Committee
The Standards Committee has approved a multi-phased approach to the BES Definition Project and is committed to keeping this project on its "High Priority" project list and committed to continuing development work, without pause, with the same Project 2010-17 drafting team, through completion of Phase II. This document provides key facts on this important project.

Project Scope
On November 18, 2010, the Federal Energy Regulatory Commission (FERC) issued Order 743 (subsequently clarified in Order 743-A) and directed NERC to revise the definition of Bulk Electric System (BES) so that the definition encompasses all elements and facilities necessary for the reliable operation and planning of the interconnected bulk power system. Additional directives include the retention of the radial exclusion, the elimination of regional discretion which exists in the current definition and the development of a process for identifying any elements or facilities that should be excluded from the BES. The Commission has established a filing deadline of January 25, 2012 for all portions of the project.

NERC is working to address these directives with two activities – the definition of Bulk Electric System (BES) is being revised through the standard development process and a BES Definition Exception Process is being developed as a proposed modification to the Rules of Procedure.

This project includes several work products which have been developed in parallel to meet the January 25th deadline:

- A revised *Bulk Electric System definition* developed by the Project 2010-17 Definition of Bulk Electric System standards drafting team (Project 2010-17 SDT).
- A BES definition *Implementation Plan* also developed by the Project 2010-17 SDT.
- A new *Appendix 5C* to NERC's Rules of Procedure that addresses the *process for requesting BES exceptions*, drafted by NERC staff and an industry stakeholder team drawn from BES SDT nominees.
- An application form titled *Detailed Information to Support an Exception Request* which identifies potential forms of evidence that can be utilized to support the exception request. This form is referenced in the Rules of Procedure Exception Process and was developed by the Project 2010-17 SDT.

Current Status
The proposed definition of BES and its implementation plan are currently posted for a 45-day concurrent posting (formal comment period and initial ballot) through October 10, 2011, as is the draft

application form (*Detailed Information to Support an Exception Request*). Entities wanting to participate in the ballot for the definition of BES or the ballot for the application form *must* join the respective ballot pools by September 26, 2011. The initial ballot will take place from September 30-October 10, 2011.

The definition includes a default threshold of 100 kV augmented by a list of five categories of facilities that are included in the BES and a list of four categories of facilities that are excluded from the BES. The definition was designed to create a "bright line" definition of facilities to be included as part of the BES that can be consistently applied across North America.

The draft Rules of Procedure Exception Process will be posted for comment in mid-September. This is being processed following the NERC procedure for making a change to the Rules of Procedure (described in Section 1400 of the NERC Rules of Procedure).

Standard Development Project Subdivided Into Two Phases

During the initial posting of the draft BES definition for industry comment, the Project 2010-17 SDT received many suggestions that fall outside the narrow scope of the regulatory directives in FERC Order No. 743 (as clarified in Order No. 743-A). The following is a list of the areas of concern already identified by the SDT members and stakeholders through the standard development process:

- Thresholds for generation resources
- Reliability benefit of a contiguous BES
- Points of demarcation between transmission, generation, and distribution
- Scope of equipment supporting reliable operation of the BES
- Relationship between BES definition and ERO Statement of Compliance Registry Criteria

The Project 2010-17 SDT and NERC staff believe these suggestions deserve serious consideration and fall within the scope of the current project. The SDT initially thought it could address a number of the above suggestions within a project schedule that would meet the Order No. 743 filing deadline of January 25, 2012. However, upon consideration of policy input and direction received from the Member Representatives Committee and the NERC Board of Trustees, the Project 2010-17 SDT quickly determined that developing an adequate technical justification for these additional revisions to the BES definition was highly unlikely in the time frame established by Order No. 743.

The SDT recognizes its obligation to fully respond to both FERC regulatory directives, address all stakeholder concerns, and produce a fully-supported technical justification for the proposed definition, while meeting regulatory expectations for a timely filing. After consideration of policy direction from the Member Representatives Committee and the NERC Board of Trustees and consultation with NERC staff, the SDT concluded that seeking a time extension at this time is not a viable alternative for three reasons:

- NERC has to demonstrate that it can work effectively, using its standard development process, to address tough reliability issues in a timely manner. A request for an extension may be perceived as a failure of NERC to work with stakeholders to solve complex reliability issues in a timely manner.
- If a request for an extension were requested, FERC is not under any obligation to respond within any specific timeframe, and may not respond before the documents must be submitted; the drafting team has to proceed without delay to meet the January 25, 2012 filing deadline.
- There is not sufficient technical information immediately available to support resolution of the issues raised by stakeholders and identified above. Developing that information will take time. To build a defensible case for adoption for some of the proposals, a significant effort is needed to collect information from stakeholders and then analyze that information and develop specific proposals. A firm technical foundation is essential to the success of any proposal that would change current practice. Before submitting a proposal to approve a new threshold for generator resources, for example, NERC must produce strong evidence that changing the threshold will not adversely impact reliability.

For these reasons, the Project 2010-17 SDT adopted the recommendations of the Member Representatives Committee and the NERC Board of Trustees and developed the following plan of subdividing Project 2010-17 Definition of Bulk Electric System into multiple phases. This establishes the best way to meet the FERC deadline while also giving serious consideration to issues raised by stakeholders. The first phase of this project, which is currently in development, will address the directives established by FERC in Order Nos. 743 and 743-A. The second phase of this project will address concerns raised by SDT members and concerns received from stakeholders through the standard development process. Commenters have been informed that the issues identified above will be fully addressed in the next phase of Project 2010-17 Definition of Bulk Electric System.

The Standards Committee, the Members Representatives Committee and the NERC Board of Trustees recognize the significance of the project and have taken steps to ensure the project's overall success by supporting the partitioning of Project 2010-17 Definition of Bulk Electric System, as described above, into multiple phases as the best way to meet the FERC deadline while also giving serious consideration to issues raised by stakeholders.

Upcoming Webinar

The Rules of Procedure team and the drafting team for Project 2010-17 Definition of Bulk Electric System, will jointly provide a webinar on September 28, 2011 from 1-4 p.m. Eastern to walk through the proposed addition to the Rules of Procedure; the application form proposed to collect evidence to support a request for an exception to the definition of BES; the proposed definition of BES; and the associated implementation plan. Register here for this webinar: http://www.nerc.com/page.php?cid=6|83|355.

From:	Philip A. Fedora
To:	rcc
Cc:	jtfc; Philip Raymond
Subject:	FW: BES Definition Project - Revised Fact Sheet
Date:	Friday, September 23, 2011 3:52:52 PM
Attachments:	BES_Definition_Fact_Sheet_20110920_final.pdf
Importance:	High

Attached is a revised version of the Bulk Electric System Definition Project – Fact Sheet.

Several minor revisions have been made to clarify issues to be addressed during Phase 2 of the project and to identify some of the major improvements made to the draft definition (i.e. radial system clarifications and the local network exclusion) beyond simply responding to the directives in Order Nos. 743 & 743-A.

This version has been dated 9-20-2011 and has replaced the previous version on the Project Page on the NERC website.

Don – please distribute to the NYSRC-EC, FYI.

Thanks,

Phil

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Bulk Electric System Definition Project - Fact Sheet

From the Standards Committee

The Standards Committee has approved a multi-phased approach to the Bulk Electric System (BES) Definition Project and is committed to keeping this project on its "High Priority" project list and committed to continuing development work, without pause, with the same Project 2010-17 drafting team, through completion of Phase II. This document provides key facts on this important project.

Project Scope

On November 18, 2010, the Federal Energy Regulatory Commission (FERC) issued Order 743 (subsequently clarified in Order 743-A) and directed NERC to revise the definition of BES so that the definition encompasses all elements and facilities necessary for the reliable operation and planning of the interconnected bulk power system. Additional directives include the retention of the radial exclusion, the elimination of regional discretion which exists in the current definition and the development of a process for identifying any elements or facilities that should be excluded from the BES. The Commission has established a filing deadline of January 25, 2012 for all portions of the project.

NERC is working to address these directives with two activities – the definition of Bulk Electric System (BES) is being revised through the standard development process and a BES Definition Exception Process is being developed as a proposed modification to the Rules of Procedure.

This project includes several work products which have been developed in parallel to meet the January 25th deadline:

- A revised *Bulk Electric System definition* developed by the Project 2010-17 Definition of Bulk Electric System standards drafting team (SDT) (Project 2010-17 SDT).
- A BES definition *Implementation Plan* also developed by the Project 2010-17 SDT.
- A new *Appendix 5C* to NERC's Rules of Procedure that addresses the *process for requesting BES exceptions*, drafted by NERC staff and an industry stakeholder team drawn from BES SDT nominees.
- An application form titled *Detailed Information to Support an Exception Request* which identifies potential forms of evidence that can be utilized to support the exception request. This form is referenced in the Rules of Procedure Exception Process and was developed by the Project 2010-17 SDT.

Current Status

The proposed definition of BES and its implementation plan are currently posted for a 45-day concurrent posting (formal comment period and initial ballot) through October 10, 2011, as is the draft application form (*Detailed Information to Support an Exception Request*). Entities wanting to participate in the ballot for the definition of BES or the ballot for the application form *must* join the respective ballot pools by September 26, 2011. The initial ballot will take place from September 30-October 10, 2011.

The definition includes a default threshold of 100 kV augmented by a list of five categories of facilities that are included in the BES and a list of four categories of facilities that are excluded from the BES. In addition, the drafting team has clarified what is meant by 'radial' and drafted a specific exclusion for local networks serving a distribution function. The definition was designed to create a "bright line" definition of facilities to be included as part of the BES that can be consistently applied across North America.

The draft Rules of Procedure Exception Process is posted for comment through October 27, 2011. This is being processed following the NERC procedure for making a change to the Rules of Procedure (described in Section 1400 of the NERC Rules of Procedure).

Standard Development Project Subdivided Into Two Phases

During the initial posting of the draft BES definition for industry comment, the Project 2010-17 SDT received many suggestions that fall outside the narrow scope of the regulatory directives in FERC Order No. 743 (as clarified in Order No. 743-A). The following is a list of the areas of concern already identified by the SDT members and stakeholders through the standard development process:

- 100 kV bright-line voltage threshold
- Thresholds for generation resources
- Reliability benefit of a contiguous BES
- Points of demarcation between transmission, generation, and distribution
- Scope of equipment supporting reliable operation of the BES
- Relationship between BES definition and ERO Statement of Compliance Registry Criteria

The Project 2010-17 SDT and NERC staff believe these suggestions deserve serious consideration and fall within the scope of the current project. The SDT initially thought it could address a number of the above suggestions within a project schedule that would meet the Order No. 743 filing deadline of January 25, 2012. However, upon consideration of policy input and direction received from the Member Representatives Committee and the NERC Board of Trustees, the Project 2010-17 SDT quickly determined that developing an adequate technical justification for these additional revisions to the BES definition was highly unlikely in the time frame established by Order No. 743.

The SDT recognizes its obligation to fully respond to both FERC regulatory directives, address all stakeholder concerns, and produce a fully-supported technical justification for the proposed definition, while meeting regulatory expectations for a timely filing. After consideration of policy direction from the Member Representatives Committee and the NERC Board of Trustees and consultation with NERC staff, the SDT concluded that seeking a time extension at this time is not a viable alternative for three reasons:

- NERC has to demonstrate that it can work effectively, using its standard development process, to address tough reliability issues in a timely manner. A request for an extension may be perceived as a failure of NERC to work with stakeholders to solve complex reliability issues in a timely manner.
- If a request for an extension were requested, FERC is not under any obligation to respond within any specific timeframe, and may not respond before the documents must be submitted; the drafting team has to proceed without delay to meet the January 25, 2012 filing deadline.
- There is not sufficient technical information immediately available to support resolution of the issues raised by stakeholders and identified above. Developing that information will take time. To build a defensible case for adoption for some of the proposals, a significant effort is needed to collect information from stakeholders and then analyze that information and develop specific proposals. A firm technical foundation is essential to the success of any proposal that would change current practice. Before submitting a proposal to approve a new threshold for generator resources, for example, NERC must produce strong evidence that changing the threshold will not adversely impact reliability.

For these reasons, the Project 2010-17 SDT adopted the recommendations of the Member Representatives Committee and the NERC Board of Trustees and developed the following plan of subdividing Project 2010-17 Definition of Bulk Electric System into multiple phases. This establishes the best way to meet the FERC deadline while also giving serious consideration to issues raised by stakeholders. The first phase of this project, which is currently in development, will address the directives established by FERC in Order Nos. 743 and 743-A. The second phase of this project will address concerns raised by SDT members and concerns received from stakeholders through the standard development process. Commenters have been informed that the issues identified above will be fully addressed in the next phase of Project 2010-17 Definition of Bulk Electric System.

The Standards Committee, the Members Representatives Committee and the NERC Board of Trustees recognize the significance of the project and have taken steps to ensure the project's overall success by supporting the partitioning of Project 2010-17 Definition of Bulk Electric System, as described above, into multiple phases as the best way to meet the FERC deadline while also giving serious consideration to issues raised by stakeholders.

Upcoming Webinar

The Rules of Procedure team and the drafting team for Project 2010-17 Definition of Bulk Electric System, will jointly provide a webinar on September 28, 2011 from 1-4 p.m. Eastern to walk through the proposed addition to the Rules of Procedure; the application form proposed to collect evidence to support a request for an exception to the definition of BES; the proposed definition of BES; and the associated implementation plan. Register here for this webinar: http://www.nerc.com/page.php?cid=6|83|355.

From:	De Graffenried, Christopher
To:	Guy V. Zito; Lee R. Pedowicz
Cc:	yostp@coned.com
Subject:	FW: NARUC Resolution on BES Definition
Date:	Thursday, August 04, 2011 10:49:41 AM

Guy - Per your request.

Resolution on Maintaining State Authority to
Ensure Reliable Electric Service at Reasonable Rates

WHEREAS, State commissions are charged with ensuring retail ratepayers receive safe, reliable electric service at just and reasonable rates; *and*

WHEREAS, State commissions have a statutory obligation to ensure that the electric utilities operate and maintain the entire electric system in a reliable manner; *and*

WHEREAS, Electric utilities regulated by State commissions operate the bulk power and local distribution electric systems; *and*

WHEREAS, When there is a failure of facilities or operations, at either the bulk power or local distribution level, service to retail ratepayers can be interrupted; *and*

WHEREAS, State regulatory commissioners must balance the needs of ratepayers, utilities, and the electric system operations, planning, and maintenance; *and*

WHEREAS, Costs associated with reliability standards (both investments and compliance) are ultimately borne by retail ratepayers; *and*

WHEREAS, The North American Electric Reliability Corporation (NERC) and the Federal Energy Regulatory Commission (FERC) authority to set and enforce standards for reliable operation of the bulk power system is defined by Federal Power Act (FPA) Section 215, which explicitly exempts "facilities used in the local distribution of electric energy" from the bulk power system and limits NERC authority to develop standards to the bulk power system; *and*

WHEREAS, While recognizing that the electric system is a contiguous set of facilities, the facilities comprising the electric system must be designated as either part of the bulk power system or local distribution system for statutory administration consistent with the FPA; *and*

WHEREAS, The design of the bulk systems and design of the local distribution systems are both complicated and varied and, as such, standards designed for the bulk system applied to the local distribution system can be inappropriate and overly costly and can undermine the reliability of the entire system; *now, therefore be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners, convened at its 2011 Summer Committee Meetings in Los Angeles, California, urges NERC and FERC to respect the statutory limits of their authority under FPA 215 and not attempt to overreach into State jurisdictional local distribution facilities when defining the bulk system or setting reliability standards; *and be it further*

RESOLVED, That new and revised NERC standards should demonstratively provide

reliability
benefits to consumers that justify their costs; *and be it further*
19
RESOLVED, That NARUC and State commissions should be vigilant in monitoring NERC and
FERC activities to ensure new and revised standards are consistent with FPA 215, enhance reliability, and benefit ratepayers.

Sponsored by the Committee on Electricity
Adopted by the NARUC Board of Directors July 20, 2011

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2010-17 Definition of Bulk Electric System

Peter Heidrich, FRCC – BES Definition Drafting Team Chair
Carter Edge, SERC – ROP Drafting Team Chair

September 28, 2011

RELIABILITY | ACCOUNTABILITY

Topics

- Expanded Project Plan
- Bulk Electric System (BES) Definition
  - Significant Revisions
- Rules of Prodedure (ROP) Exception Process (Appendix 5C)
- Exception Application Form
  - Detailed Information to Support an Exception Request
- Implementation Plan
- Near-term Project Milestones

Project Plan - Phased Approach

- **Phase 1** - Addresses directives from Orders No. 743 & 743-A:
  - Modify the Definition of BES
    - Eliminate "as defined by Regions" language
    - Eliminate "generally defined as" language
  - Develop an Exception Process
  - Develop Regional Transition Plans
  - Filing Due Date of January 25, 2012

Project Plan - Phased Approach

- **Phase 2** - Addresses concerns identified through the Standards Development Process:
  - Reliability benefit of a contiguous BES
  - 100 kV bright-line voltage threshold
  - "Points of Demarcation" between Transmission, Generation, and Distribution
  - Threshold for Generation Resources
  - Scope of the equipment which supports the reliable operation of the BES
  - Relationship between the BES definition and the ERO Statement of Compliance Registry Criteria

Project Plan - Phased Approach

- Why two phases?
  - A strong, factual, technical justification is **essential** if we are to gain FERC approval for any changes to things such as generator thresholds
  - Need time to run studies and produce technical justifications to support proposals
  - BES Definition due January 25, 2012

Project Plan - Phased Approach

- Current Posting
  - Includes DRAFT Standard Authorization Request to establish Phase 2 of the project
  - Titled: NERC Glossary of Terms – Phase 2: Revision of the BES definition
  - Posted for informational purposes ONLY
  - Will be posted for comment later in the project

Project Plan - Phased Approach

- NERC Standards Committee
  - Approved the multi-phased approach
  - Committed to keeping this project on its “High Priority” project list
  - Committed to continuing development work with the current Standard Drafting Team (SDT) through completion of Phase 2
  - Committed to supplying resources to complete technical research

Project Plan - Phased Approach

- Additional Information
  - BES Definition Project - Fact Sheet

    BES Definition Fact Sheet

BES Definition – Significant Revisions*

- Exclusion of Local Distribution Facilities
- Generation Threshold Values
- Local Networks (High Voltage Limit)
- Reactive Resources

* Based on comments from 279 different people from 213 companies representing 10 of the 10 Industry Segments

BES Definition

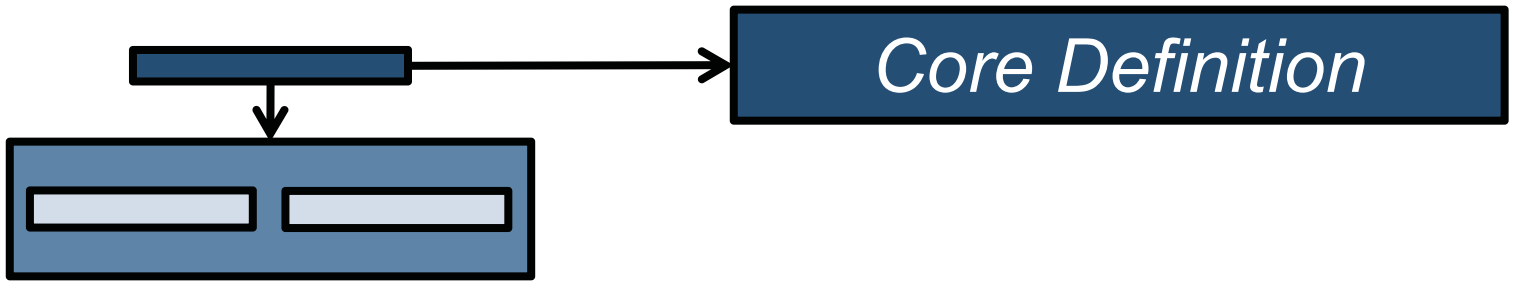

Bulk Electric System (BES):

Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

BES Designation Criteria Inclusions

- **I1** - Transformers with primary and secondary terminals operated at 100 kV or higher unless excluded under Exclusion E1 or E3.

BES Designation Criteria Inclusions

- **I2** - Generating resource(s) (with gross individual or gross aggregate nameplate rating per the ERO Statement of Compliance Registry Criteria) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above.

BES Designation Criteria Inclusions

- **I3** - Blackstart Resources identified in the Transmission Operator's restoration plan.

BES Designation Criteria Inclusions

- **I4** - Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above.

BES Designation Criteria Inclusions

- I5 - Static or dynamic devices dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1.

BES Designation Criteria Exclusions

- **E1** - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:
  - Only serves Load. Or,
  - Only includes generation resources, not identified in Inclusion I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,
  - Where the radial system serves Load and includes generation resources, not identified in Inclusion I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

Note - A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

BES Designation Criteria Exclusions

- **E2** - A generating unit or multiple generating units that serve all or part of retail customer Load with electric energy on the customer's side of the retail meter if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.

BES Designation Criteria Exclusions

- **E3** - Local networks (LN): A group of contiguous transmission Elements operated at or above 100 kV but less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customer Load and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:
  - Limits on connected generation
  - Power flows only into the LN
  - Not part of a Flowgate or transfer path

BES Designation Criteria Exclusions

- E4 – Reactive Power devices owned and operated by the retail customer solely for it's own use.

ROP – Exception Process

- What's Posted (Through October 27, 2011)
  - For Comment
    - New Rule 509
    - New Rule 1703
    - New Appendix 5D
  - For Information
    - Process Flow Diagrams
    - Exception Request Form (Sample)

ROP – Exception Process

- New Rule 509 - Exceptions to the Definition of the BES
  - "Appendix 5C sets forth the procedures by which (i) an entity may request a determination that an Element that falls within the definition of the Bulk Electric System should be exempted from being considered a part of the Bulk Electric System, or (ii) an entity may request that an Element that falls outside of the definition of the Bulk Electric System should be considered a part of the Bulk Electric System."

ROP – Exception Process

- New Rule 1703 - Challenges to NERC Determinations of BES Exception Requests under ROP
  - Leverages existing (proposed) appeals process
  - NERC's decision to Approve, Disapprove, or Terminate
  - 30 days to appeal
  - 90 days for review panel to decide
  - May request BOTCC review panel decision

ROP – Exception Process

- New Appendix 5C
  - Entity determination of status is a prerequisite for requesting an exception
  - Section 4: Who's and What's
    - Who can submit request?
    - Who to submit a request to?
    - What to submit?
    - Who "approves"?
    - What happens if I disagree?
  - Section 5: What to Expect

ROP – Exception Process

- Initial Screening
  - Region "accepts or rejects" the request for substantive review
    - Eligible submitter?
    - Request for Exception?
    - Required Information provided?

ROP – Exception Process

- Substantive Review
  - Region recommends "Approval or Disapproval" of request to NERC based on:
    - "…necessary for the Reliable Operation of the interconnected bulk power transmission system as evidenced by Required Information provided"

ROP – Exception Process

- NERC Decision
  - NERC receives the request record with a recommendation from the Regional Entity
    - States the basis for the recommendation
    - Includes information considered by the RE in arriving at its Recommendation
  - Submitting Entity or Owner has opportunity to comment in support or opposition to the recommendation
  - NERC decision final if not appealed

ROP – Exception Process

- Implementation Plans for Requests
  - Status "as is" when going through the process
  - Some implementation may be necessary for:
    - New Inclusion Exceptions
    - Denials of Exception Requests for Exclusion
      - Newly-constructed or installed Element
      - Was not included in the BES under the BES Definition in effect

Exception Process Technical Principles*

- Reliability benefits of an Element cannot be determined by a single study or analysis of a single parameter
- Not feasible to establish continent-wide values and/or limits

*Based on comments from 75 different people from 45 companies representing 8 of the 10 Industry Segments

Exception Process Technical Principles

- The SDT has adopted a new approach:
  - "Detailed Information to Support an Exception Request" Application Form
  - Targeted questions for Transmission and Generation addressing the facility characteristics with guidance on the type of supporting evidence to accompany request
  - No hard numbers to guide the evaluation
  - Engineering judgment will be utilized to perform the evaluation of the evidence in a consistent, repeatable, and verifiable process

Application Form – General Instructions

- Entities are required to provide:
  - A one-line breaker diagram identifying the facility and the Protection Systems at the interface points for which the exception is requested
  - The data and studies needed to support their submittal. Studies should:
    - Be based on an Interconnection-wide base case
    - Clearly document all assumptions used
    - Address key performance measures of BES reliability through steady-state power flow and transient stability analysis
  - Support for your position from other entities (if available)

Application Form – For Transmission Facilities

1. Is there generation connected to the facility?
2. How does the facility impact permanent Flowgates in the Eastern Interconnection, major transfer paths within the Western Interconnection, or a comparable monitored facility in the ERCOT Interconnection or the Quebec Interconnection?
3. Is the facility included in an IROL in the Eastern Interconnection, ERCOT Interconnection, or Quebec Interconnection or a major transfer path rating in the Western Interconnection?

Application Form – For Transmission Facilities

4. How does an outage of the facility impact the over-all reliability of the BES?
5. Is the facility used for off-site power supply to a nuclear power plant as designated in a mutually agreed upon Nuclear Plant Interface Requirement (NPIR)?
6. Is the facility part of a Cranking Path associated with a Blackstart Resource?
7. Does power flow through this facility into the BES?

Application Form – For Generation Facilities

1. What is the MW value of the host Balancing Authority's most severe single Contingency and what is the generator's, or generator facility's, percent of this value?
2. Is the generator or generator facility used to provide Ancillary Services?
3. Is the generator designated as a must run unit?
4. How does an outage of the generator impact the over-all reliability of the BES?
5. Does the generator use the BES to deliver its actual or scheduled output, or a portion of its actual or scheduled output, to Load?

Implementation Plan

- Effective Dates:
  - This definition shall become effective on the first day of the second calendar quarter after applicable regulatory approval
  - In those jurisdictions where no regulatory approval is required the definition shall go into effect on the first day of the second calendar quarter after Board of Trustees adoption

Implementation Plan

- Compliance Obligations:
  - Compliance obligations for Elements included by the definition shall begin 24 months after the applicable effective date of the definition
  - SDT believes that the timeframe is needed to:
    - Effectively produce reasonable transition plans
    - Submit any necessary registration changes
    - File for exceptions
    - Provide training

Near-term Project Milestones

- Concurrent Posting (through October 10, 2011)
  - Revised BES definition with designations (inclusions and exclusions)
  - Implementation Plan
  - "Detailed Information to Support an Exception Request" Application Form
  - DRAFT SAR Phase 2 (Information Only)
- ROP BES Exception Process (Comment Period ends October 27, 2011)

Question & Answer

Website: http://www.nerc.com/filez/standards/Project2010-17_BES.html

From: Clermont.Sylvain@hydro.qc.ca
To: Guy V. Zito; Lee R. Pedowicz; rscmembers
Cc: paquet.pierre@hydro.qc.ca; david.kiguel@HydroOne.com; alden.briggs@nbso.ca; brian.rivard@ieso.ca
Subject: BES Vote
Date: Monday, October 17, 2011 4:37:58 PM

Guy, Lee,

Following the vote and the comments on the BES definition and technical principal, I would appreciate if, at the next meeting of the RSC, we could have a discussion on the process that lead to NPCC vote.

As you are aware, NPCC casted a vote opposite to the vote of all its Canadian members and of some of its US members as well (like ISONE and NYPA, for example). We, at HQT believes it would be interesting and pertinent to have a discussion on the process that led to such a vote.

Our representative will make a similar request at the next RCC face-to-face meeting.

I thank you for your usual good cooperation. And I will gladly see you in Boston next week.

Sylvain Clermont, ing. M.Ing.
Chef Réseaux voisins / Manager Neighboring Systems
Direction Commercialisation et Affaires réglementaires
Tél. : 514 879-4648
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NPCC, Inc.
NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

Date: October 20, 2011

To: NPCC Board of Directors
From: Philip A. Fedora - Assistant Vice President – Reliability Services
Subject: Summary of the October 18-20, 2011 Definition of BES Drafting Team meeting

The NERC Definition of Bulk Electric System (BES) Drafting Team (Project 2010-17) met face-to-face on October 18-20, 2011. Publically available materials regarding BES Drafting Team meetings are posted on the NERC website at: http://www.nerc.com/filez/standards/Project2010-17_BES.html.

BES Definition
The BES Drafting Team posted a second draft of the BES Definition and associated implementation plan for a formal 45-day comment period and ballot, through 8 p.m. Eastern on Monday, October 10, 2011. The ballot achieved Quorum (92.97%) with 71.68% approval. There were 113 sets of comments, including comments from more than 75 different people from approximately 45 companies representing eight of the 10 Industry Segments.

The BES Drafting Team discussed responses to the comments received and considered any corresponding resulting changes to the BES Definition.

BES Exception Request
The BES Drafting Team also posted a draft application form titled 'Detailed Information to Support an Exception Request' referenced in the Rules of Procedure Exception Process for the same formal 45-day comment period and ballot. The ballot achieved Quorum (89.53%) with 64.05% approval. There were 72 sets of comments, including comments from approximately 137 different people from approximately 83 companies representing all ten Industry Segments.

The BES Drafting Team discussed responses to the comments received and considered any corresponding resulting changes.

NERC Rules of Procedure
NERC is requesting public comments through October 27, 2011 on the second draft of a new procedure for facility-by-facility determinations of inclusions or exclusions to the Bulk Electric System resolved through exceptions to the BES definition. This exception process is proposed to be included in the NERC Rules of Procedure as Appendix 5C.

Next Steps
The BES Definition Drafting Team will continue its review of the comments received and finalize its responses on the Draft BES Definition and Rules of Procedure Exception Process by November 4th; following a NERC quality check, the documents are expected to be posted for a Recirculation Ballot on November 14th.

Future BES Drafting Team Meeting(s)
November 8, 2011 11:00 a.m. – tentative conference call (if needed)

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137 FERC ¶ 61,043
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
and Cheryl A. LaFleur.

North American Electric Reliability Corporation Docket No. RD11-8-000

ORDER APPROVING REGIONAL RELIABILITY STANDARD

(Issued October 20, 2011)

1. On May 31, 2011, the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), submitted a petition for Commission approval of the Northeast Power Coordinating Council's (NPCC) Protection and Control (PRC) regional Reliability Standard PRC-002-NPCC-01 (Disturbance Monitoring) and two associated new definitions. The regional Reliability Standard requires transmission owners and generator owners to provide recording capability necessary to monitor the response of the Bulk-Power System to system disturbances, including scheduled and unscheduled outages; requires each reliability coordinator to establish requirements for its area's dynamic disturbance recording needs; and establishes disturbance data reporting requirements.

2. In this order, we approve regional Reliability Standard PRC-002-NPCC-01, finding that it is just, reasonable, not unduly discriminatory or preferential, and in the public interest. Also, we approve NERC's requested implementation plan which provides staggered effective dates, i.e., the date on which applicable entities are subject to mandatory compliance, with full compliance required within four years of regulatory approval.

I. Background

3. Section 215 of the Federal Power Act (FPA) requires the ERO to develop mandatory and enforceable Reliability Standards, which provide for the reliable operation of the Bulk-Power System, subject to Commission review and approval.[1] Section 215(d)(2) of the FPA states that the Commission may approve, by rule or order, a proposed Reliability Standard or modification to a Reliability Standard if it determines that the Reliability Standard is just, reasonable, not unduly discriminatory or preferential,

[1] 16 U.S.C. § 824o(d) (2006).

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and in the public interest. Once approved, the Reliability Standard may be enforced by the ERO, subject to Commission oversight, or by the Commission independently.[2]

4. Reliability Standards that the ERO proposes to the Commission may include Reliability Standards that are developed by a Regional Entity.[3] On April 19, 2007, the Commission approved delegation agreements between NERC and eight Regional Entities, including NPCC.[4] In the Delegation Agreement Order, the Commission accepted NPCC as a Regional Entity and accepted NPCC's Standards Development Manual, which sets forth the process for NPCC's development of regional Reliability Standards.[5] The NPCC region is a less than interconnection-wide region, and its standards apply only to that part of the Eastern Interconnection within the NPCC geographical footprint.

5. In Order No. 672, the Commission urged uniformity of Reliability Standards, but recognized a potential need for regional differences.[6] Accordingly, the Commission stated that:

> As a general matter, we will accept the following two types of regional differences, provided they are otherwise just, reasonable, not unduly discriminatory or preferential and in the public interest, as required under the statute: (1) a regional difference that is more stringent than the continent-wide Reliability Standard, including a regional difference that addresses matters that the continent-wide Reliability Standard does not; and (2) a regional Reliability Standard that is necessitated by a physical difference in the Bulk-Power System.[7]

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[2] *See* 16 U.S.C. § 824o(e).

[3] *Id.* § 824o(e)(4).

[4] *See North American Electric Reliability Corp.*, 119 FERC ¶ 61,060, at P 316-350 (Delegation Agreement Order), *order on reh'g*, 120 FERC ¶ 61,260 (2007).

[5] *Id.* P 302.

[6] *Rules Concerning Certification of the Electric Reliability Organization; Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 290, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[7] Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 291.

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6. On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 Reliability Standards filed by the ERO.[8] In that order, the Commission determined that it would not take action on certain proposed Reliability Standards that required supplemental information from regional reliability organizations. Such Reliability Standards refer to regional criteria or procedures that had not been submitted to the Commission for approval and, as such, are referred to as "fill-in-the-blank" standards. Pending Reliability Standard PRC-002-1 (Define Regional Disturbance Monitoring and Reporting) is one such fill-in-the-blank standard and, therefore, is not enforceable. NERC's continent-wide, fill-in-the-blank standard PRC-002-1 would require regional reliability organizations to establish: (i) installation requirements for sequence of event recording, fault recording, and dynamic disturbance recording, and (ii) reporting requirements for recorded disturbance data. Because PRC-002-1 is an unenforceable and unapproved fill-in-the-blank standard, NPCC's proposed regional Reliability Standard PRC-002-NPCC-01 is intended to fill the reliability gap related to disturbance monitoring and reporting by establishing enforceable disturbance monitoring and reporting requirements for the NPCC region.

II. NERC Petition and Notice of Filing

7. In its May 31, 2011 petition,[9] NERC requests Commission approval of proposed regional Reliability Standard PRC-002-NPCC-01 (Disturbance Monitoring) and two associated new definitions. NERC states that PRC-002-NPCC-01 is intended to ensure that adequate disturbance data is available to facilitate bulk electric system event analyses and thereby improve system reliability by promoting improved system design and operations.

8. The standard is applicable to transmission owners, generator owners, and reliability coordinators and contains 17 requirements that identify the proper locations for sequence of events recorders, fault recorders, and dynamic disturbance recorders within the NPCC region and specify the data to be captured and reported by this equipment.

9. Sequence of events recorders capture the sequences of events for monitored changes of state in equipment and protection systems occurring in substations, switchyards, or power plants. Requirement R1 requires that each transmission owner and

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[8] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[9] *North American Electric Reliability Corp.*, May 31, 2011 Petition for Approval of Proposed NPCC Regional Reliability Standard PRC-002-NPCC-01 — Disturbance Monitoring (NERC Petition).

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generator owner provide sequence of events recording capability at specified locations either through installation of sequence of events recorders or as part of another device such as a remote terminal unit or a generator plant digital (or distributed) control system.

10. Fault recorders capture and store power system waveforms that can be used to analyze transients and abnormalities in system frequency. Requirement R2 requires each transmission owner to provide fault recording capability for specified elements of the Bulk-Power System, and Requirement R3 requires that each transmission owner have fault recording capability that determines the "Current Zero Time" for loss of bulk electric system transmission elements. "Current Zero Time" is a new defined term used in PRC-002-NPCC-01 to mean the precise time of circuit interruption. It is defined as "the time of the final current zero on the last phase to interrupt."

11. Requirement R4 requires each generator owner to provide fault recording capability for "Generating Plants" at and above 200 MVA and connected through a generator step-up transformer to a bulk electric system element, unless such recording capability is provided by the transmission owner. "Generating Plants" is a new term defined as "one or more generators at a single physical location whereby a single contingency can affect all the generators at that location." The term appears in this Requirement and in Requirement R1's description of where sequence of event recording capability is to be located. It is used to clarify that, for the sake of efficiency, one sequence of event recorder or a single fault recorder may be used where it will capture all the information from a single contingency affecting all the generators at a single location, and multiple recorders would be redundant.

12. Because certain data are necessary for post-event analysis, Requirement R5 requires each transmission owner and generator owner to record for faults sufficient electrical quantities for each monitored bulk electric system element to determine: (i) three phase-to-neutral voltages; (ii) three phase currents and neutral currents; (iii) polarizing currents and voltages, if used; (iv) frequency; and (v) real and reactive power. Requirement R6 sets out the recording specifications required of the fault recording equipment in order to ensure the monitored data is captured in sufficient detail for it to be meaningfully used in analyses.

13. Dynamic disturbance recorders monitor power system conditions when the system experiences dynamic events such as low frequency oscillations, or frequency or voltage excursions. Requirement R7 requires each reliability coordinator to establish dynamic disturbance recording needs for its area in accordance with specified recording requirements, and Requirement R8 requires that dynamic disturbance recorders function continuously. To capture system disturbance data with sufficient detail for use in post-event analyses, Requirement R9 specifies the minimal recording duration, sample rate and trigger events for dynamic disturbance recorders. Requirement R10 requires each reliability coordinator to establish requirements to ensure that certain specified data are monitored or derived where dynamic disturbance recorders are installed.

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14. Requirement R11 requires each reliability coordinator to document additional settings and deviations from the required trigger settings described in Requirement R9 and the required list of monitored quantities described in Requirement R10 and to report these settings and deviations to the Regional Entity upon request. Requirement R12 requires each reliability coordinator to specify its dynamic disturbance recording requirements, including trigger settings, to transmission owners and generator owners.

15. Each transmission owner and generator owner that receives a request from its reliability coordinator to install a dynamic disturbance recorder is required, under Requirement R13, to acquire and install the recorder in accordance with an implementation schedule agreed to with the reliability coordinator. They also are required by Requirement R14 to establish a maintenance and testing program for their stand alone disturbance monitoring equipment (i.e., equipment whose only purpose is disturbance monitoring). The Requirement lists elements of such a program.

16. Requirement R15 requires that each reliability coordinator, transmission owner, and generator owner share data within 30 days upon request, and each generator owner must provide recorded disturbance data from disturbance monitoring equipment within 30 days of receipt of a request for information from NERC, the Regional Entity, the reliability coordinator, or transmission or generator owners within NPCC. Requirement R16 specifies the format requirements for data files. Requirement R17 requires each reliability coordinator, transmission owner and generator owner to maintain, record and provide to the Regional Entity, upon request, specified data regarding the disturbance monitoring equipment installed to meet regional Reliability Standard PRC-002-NPCC-01.

17. Notice of NERC's filing was published in the *Federal Register*, 76 Fed. Reg. 40,350 (2011), with interventions and protests due on or before August 1, 2011. No motion to intervene or protest was received.

III. <u>Discussion</u>

18. The Commission approves regional Reliability Standard PRC-002-NPCC-01 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. To that end, the Commission finds that PRC-002-NPCC-01 satisfies the Order No. 672 factors on how the Commission determines whether a regional Reliability Standard is just and reasonable in that PRC-002-NPCC-01: (1) is clear and unambiguous regarding what is required and who is required to comply (transmission owners, generator owners, and reliability coordinators within the NPCC region); (2) has clear and objective measures for compliance and achieves a reliability goal (namely, ensuring that adequate disturbance data is available to facilitate bulk electric system event analyses); and (3) is "more stringent" than NERC's existing unapproved and unenforceable continent-wide disturbance monitoring and reporting standard, PRC-002-1.

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19. Regional Reliability Standard PRC-002-NPCC-01 includes two new defined terms that apply only to the NPCC region: "Current Zero Time" and "Generating Plant." The two proposed regional terms do not conflict with any existing terms in the NERC Glossary of Terms. Accordingly, the Commission approves the inclusion of the two regional terms related to PRC-002-NPCC-01 in the NERC Glossary specifically as NPCC regional terms.

20. The Commission finds that the NERC's violation risk factors and violation severity levels for regional Reliability Standard PRC-002-NPCC-01 are consistent with the Commission's established guidelines.[10] We therefore approve the assigned violation risk factors and violation severity levels.

21. As requested by NERC, the Commission approves the implementation plan for regional Reliability Standard PRC-002-NPCC-01.

IV. Information Collection Statement

22. The Office of Management and Budget (OMB) regulations require approval of certain information collection requirements imposed by agency actions.[11] Upon approval of a collection of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirement of this order will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number. The Paperwork Reduction Act (PRA)[12] requires each federal agency to seek and obtain OMB approval before undertaking a collection of information directed to ten or more persons, or continuing a collection for which OMB approval and validity of the control number are about to expire.[13]

23. The Commission will submit these reporting and recordkeeping requirements to OMB for its review and approval under section 3507(d) of the PRA.[14] Comments are

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[10] *See North American Electric Reliability Corp.*, 119 FERC ¶ 61,145, *order on reh'g*, 120 FERC ¶ 61,145, at P 8-13 (2007); *North American Electric Reliability Corp.*, 123 FERC ¶ 61,284, at P 20-35, *order on reh'g & compliance*, 125 FERC ¶ 61,212 (2008); *North American Electric Reliability Corp.*, 135 FERC ¶ 61,166 (2011).

[11] 5 C.F.R. § 1320.10.

[12] 44 U.S.C . § 3501-20.

[13] 44 U.S.C. 3502(3)(A)(i), 44 U.S.C. § 3507(a)(3).

[14] 44 U.S.C. 3507(d).

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solicited within sixty days of the date this order is published in the *Federal Register* on the Commission's need for this information, whether the information will have practical utility, the accuracy of provided burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques. Comments should be submitted following the Commission's submission guidelines at http://www.ferc.gov/help/submission-guide.asp and should reference Docket No. RD11-8-000.

24. This Order approves regional Reliability Standard PRC-002-NPCC-01 (Disturbance Monitoring) which introduces new mandatory and enforceable requirements for the applicable entities. It generally identifies the evidence that will be used to monitor compliance. NPCC presently has criteria addressing monitoring equipment and published guidance addressing maintenance and testing of such equipment. The Disturbance Monitoring Equipment Criteria[15] seek the same or equivalent information identified in Reliability Standard PRC-002-NPCC-01, and NPCC's guidance establishes maintenance and testing expectations similar to those imposed by the regional Reliability Standard.[16] Thus, it is currently usual and customary for affected entities within NPCC to create, maintain and store some of the same or equivalent information identified in Reliability Standard PRC-002-NPCC-01. Therefore, many of the requirements contained in PRC-002-NPCC-01 do not impose new burdens on the affected entities.[17]

25. Several requirements contained in regional Reliability Standard PRC-002-NPCC-01 do introduce entirely new responsibilities for the applicable entities. Each such requirement is discussed below. Requirement R13 requires that each transmission owner and generator owner retain evidence that it acquired and installed dynamic disturbance recorders in accordance with the specifications requested by the reliability coordinator, and that the generator owner, transmission owner, and reliability coordinator retain evidence that they agreed on an implementation schedule. Requirement R14 requires that each transmission owner and generator owner establish a maintenance and testing program for stand-alone disturbance monitoring equipment. Sub-requirements 14.5 specifies that the program must require active analog quantities to be verified monthly, and Sub-requirement 14.7 requires that if failed units cannot be returned to service within

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[15] Disturbance Monitoring Equipment Criteria (Aug. 2007), *available at* https://www.npcc.org/Standards/Criteria/A-15.pdf (Disturbance Monitoring Criteria).

[16] Guide for Application of Disturbance Recording Equipment (Sept. 2006), *available at* https:/www.npcc.org/Standards/Guides/B-26.pdf (Application Guide).

[17] 5 C.F.R. § 1320.3(b)(2) (2011).

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90 days, the owner must record its efforts to restore the equipment to service. These components of the program have not been included in NPCC's current Disturbance Monitoring Criteria or Application Guide. Requirement R17 requires each reliability coordinator, transmission owner, and generator owner to maintain and record specific data on installed disturbance monitoring equipment, and submit the data to the Regional Entity upon request. Under the Disturbance Monitoring Criteria, the reliability coordinator was not obligated to maintain these records or provide the records to the Regional Entity.

26. Public Reporting Burden: The estimate below regarding the number of respondents is based on the NERC compliance registry as of August 29, 2011. According to the NERC compliance registry, there are 35 transmission owners, 136 generation owners, and five reliability coordinators in the NPCC region. However, under NERC's compliance registration program, entities may be registered for multiple functions, so these numbers incorporate some double counting. The net number of entities responding will be approximately 167 entities registered as a transmission owner, generation owner, or reliability coordinator. This includes eight entities registered as both a generation owner and transmission owner, as well as one entity registered as both a transmission owner and a reliability coordinator.

27. We estimate that annually, approximately one entity within NPCC will have to procure dynamic disturbance recording capability. Based on Commission staff outreach and analysis, we estimate the total acquisition and installation cost will range between $150,000 and $750,000. We also estimate that an entity will experience a unit failure greater than 90 days once every five years. Therefore, 20 percent of NPCC's 163 generator owners and transmission owners will experience a unit failure of this duration each year. The estimated burden for the requirements in this Order follow:

PRC-002-NPCC-01	**Number of Respondents Annually (1)**	**Number of Responses Per Respondent (2)**	**Average Burden Hours Per Response (3)**	**Total Annual Hours (1x2x3)**

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R13: GO[18] and TO to document acquisition and installation of dynamic disturbance recorders. GO, TO, and RC to develop and employ implementation schedule	1	1	*Record Retention*	10	10
R14.5: GO and TO maintenance and testing program for stand-alone disturbance monitoring equipment includes monthly verification of active analog quantities	163	12	*Record Retention*	5	9,780
R14.7: GO and TO requirement to return failed units to service in 90 days. Record kept of efforts if greater than 90 days	33	1	*Reporting (assessment and dist. of records)*	10	330
			Record Retention	10	330
R17: RC maintains data on equipment, and provide to RE upon request	5	1	*Reporting (assessment and dist. of data)*	5	25
			Record Retention	10	50
Total			***Reporting (assessment and dist)***		**355**
			Record Retention		**10,170**

[18] For purposes of this chart, generation owner is abbreviated to GO, transmission owner is abbreviated to TO, and reliability coordinator is abbreviated to RC.

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Information Collection Costs: The Commission seeks comments on the costs to comply with these requirements and recordkeeping burden associated with regional Reliability Standard PRC-002-NPCC-01.

- Total Annual Hours for Collection: (Reporting and Record Retention) = 10,525 hours.
- Total Estimated Annual Record Retention Cost[19] = 10,170 hours @ $28/hour = $ 284,360
- Total Estimated Annual Reporting Cost = 355 hours @ $120/hour = $ 42,600
- Total Estimated Annual Compliance Cost (acquisition and installation of dynamic disturbance recorders) = $750,000
- Total Estimated Annual Cost = $1,077,640
- Title: NPCC Regional Reliability Standards
- Action: Proposed Collection FERC-725I.
- OMB Control No: To be determined.
- Respondents: Business or other for profit, and/or not for profit institutions.
- Frequency of Responses: On occasion.
- Necessity of the Information: This proposed rule would approve a new regional Reliability Standard that requires entities within the NPCC region to identify the proper locations for sequence of events recorders, fault recorders, and dynamic disturbance recorders and specify the data to be captured and reported by this equipment.
- Internal review: The Commission has reviewed the requirements pertaining to the proposed regional Reliability Standard and determined that the proposed requirements are necessary to meet the statutory provisions of the Energy Policy Act of 2005. These requirements conform to the Commission's plan for efficient information collection, communication and management within the energy industry. The Commission has assured itself, by means of internal review, that there is specific objective support for the burden estimates associated with the information requirements.

28. Interested persons may obtain information on the reporting requirements by contacting: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, e-mail: DataClearance@ferc.gov, Phone: (202) 502-8663, fax: (202) 273-0873].

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[19] The hourly reporting cost is based on the estimated cost of an engineer to implement the requirements of the rule. The record retention cost comes from Commission staff research on record retention requirements.

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The Commission orders:

Regional Reliability Standard PRC-002-NPCC-01, its assigned VRFs and VSLs, inclusion of the terms “Current Zero Time” and “Generating Plant” in the NERC Glossary of Terms Used in Reliability Standards, and the implementation plan proposed by NERC are herby approved, as discussed in this order.

By the Commission. Commissioner Spitzer is not participating.

(S E A L)

Kimberly D. Bose,
Secretary.

Document Content(s)

RD11-8-000.DOC.....1-11

Introduction

1. **Title:** **Disturbance Monitoring**
2. **Number:** PRC-002-NPCC-1
3. **Purpose:** Ensure that adequate disturbance data is available to facilitate Bulk Electric System event analyses. All references to equipment and facilities herein unless otherwise noted will be to Bulk Electric System (BES) elements.
4. **Applicability:**
   - **4.1.** Transmission Owner
   - **4.2.** Generator Owner
   - **4.3.** Reliability Coordinator
5. **(Proposed) Effective Date:** To be established.

A. Requirements

R1. Each Transmission Owner and Generator Owner shall provide Sequence of Event (SOE) recording capability by installing Sequence of Event recorders or as part of another device, such as a Supervisory Control And Data Acquisition (SCADA) Remote Terminal Unit (RTU), a generator plant Digital (or Distributed) Control System (DCS) or part of Fault recording equipment. This capability shall: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

1.1 Be provided at all substations and at locations where circuit breaker operation affects continuity of service to radial Loads greater than 300MW, or the operation of which drops 50MVA Nameplate Rating or greater of Generation, or the operation of which creates a Generation/Load island.

Be provided at generating units above 50MVA Nameplate Rating or series of generating units utilizing a control scheme such that the loss of 1 unit results in a loss of greater than 50MVA Nameplate Capacity, and at Generating Plants above 300MVA Name Plate Capacity.

1.2 Monitor the following at each location listed in 1.1:

1.2.1 Transmission and Generator circuit breaker positions

1.2.2 Protective Relay tripping for all Protection Groups that operate to trip circuit breakers identified in 1.2.1.

1.2.3 Teleprotection keying and receive

R2. Each Transmission Owner shall provide Fault recording capability for the following Elements at facilities where Fault recording equipment is required to be installed as per R3: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

2.1 All transmission lines.

2.2 Autotransformers or phase-shifters connected to busses.

2.3 Shunt capacitors, shunt reactors.

2.4 Individual generator line interconnections.

2.5 Dynamic VAR Devices.

2.6 HVDC terminals.

R3. Each Transmission Owner shall have Fault recording capability that determines the Current Zero Time for loss of Bulk Electric System (BES) transmission Elements. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R4. Each Generator Owner shall provide Fault recording capability for Generating Plants at and above 200 MVA Capacity and connected through a generator step up (GSU) transformer to a Bulk Electric System Element unless Fault recording capability is already provided by the Transmission Owner. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R5. Each Transmission Owner and Generator Owner shall record for Faults, sufficient electrical quantities for each monitored Element to determine the following: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

5.1 Three phase-to-neutral voltages. (Common bus-side voltages may be used for lines.)

5.2 Three phase currents and neutral currents.

5.3 Polarizing currents and voltages, if used.

5.4 Frequency.

5.5 Real and reactive power.

R6. Each Transmission Owner and Generator Owner shall provide Fault recording with the following capabilities: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

6.1 Each Fault recorder record duration shall be a minimum of one (1) second.

6.2 Each Fault recorder shall have a minimum recording rate of 16 samples per cycle.

6.3 Each Fault recorder shall be set to trigger for at least the following:

6.3.1 Monitored phase overcurrents set at 1.5 pu or less of rated CT secondary current or Protective Relay tripping for all Protection Groups.

6.3.2 Neutral (residual) overcurrent set at 0.2 pu or less of rated CT secondary current.

6.3.3 Monitored phase undervoltage set at 0.85 pu or greater.

6.4 Document additional triggers and deviations from the settings in 6.3.2 and 6.3.3 when local conditions dictate.

R7. Each Reliability Coordinator shall establish its area's requirements for Dynamic Disturbance Recording (DDR) capability that: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

7.1 Provides a minimum of 1 DDR per 3,000 MW of peak Load.

7.2 Records dynamic disturbance information with consideration of the following facilities/locations:

7.2.1 Major Load centers.

7.2.2 Major Generation clusters.

7.2.3 Major voltage sensitive areas.

7.2.4 Major transmission interfaces.

7.2.5 Major transmission junctions.

7.2.6 Elements associated with Interconnection Reliability Operating Limits (IROLs).

7.2.7 Major EHV interconnections between operating areas.

R8. Each Reliability Coordinator shall specify that DDRs installed, after the approval of this standard, function as continuous recorders. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R9. Each Reliability Coordinator shall specify that DDRs are installed with the following capabilities: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

9.1 A minimum recording time of sixty (60) seconds per trigger event.

9.2 A minimum data sample rate of 960 samples per second, and a minimum data storage rate for RMS quantities of six (6) data points per second.

9.3 Each DDR shall be set to trigger for at least one of the following (based on manufacturers' equipment capabilities):

9.3.1 Rate of change of Frequency.

9.3.2 Rate of change of Power.

9.3.3 Delta Frequency (recommend 20 mHz change).

9.3.4 Oscillation of Frequency.

R10. Each Reliability Coordinator shall establish requirements such that the following quantities are monitored or derived where DDRs are installed: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

10.1 Line currents for most lines such that normal line maintenance activities do not interfere with DDR functionality.

10.2 Bus voltages such that normal bus maintenance activities do not interfere with DDR functionality.

10.3 As a minimum, one phase current per monitored Element and two phase-to-neutral voltages of different Elements. One of the monitored voltages shall be of the same phase as the monitored current.

10.4 Frequency.

10.5 Real and reactive power.

R11. Each Reliability Coordinator shall document additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10, and report this to the Regional Entity (RE) upon request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R12. Each Reliability Coordinator shall specify its DDR requirements including the DDR setting triggers established in R9 to the Transmission Owners and Generator Owners. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R13. Each Transmission Owner and Generator Owner that receives a request from the Reliability Coordinator to install a DDR shall acquire and install the DDR in accordance with R12. Reliability Coordinators, Transmission Owners, and Generator Owners shall mutually agree on an implementation schedule. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R14. Each Transmission Owner and Generator Owner shall establish a maintenance and testing program for stand alone DME (equipment whose only purpose is disturbance monitoring) that includes: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

14.1 Maintenance and testing intervals and their basis.

14.2 Summary of maintenance and testing procedures.

14.3 Monthly verification of communication channels used for accessing records remotely (if the entity relies on remote access and the channel is not monitored to a control center staffed around the clock, 24 hours a day, 7 days a week (24/7)).

14.4 Monthly verification of time synchronization (if the loss of time synchronization is not monitored to a 24/7 control center).

14.5 Monthly verification of active analog quantities.

14.6 Verification of DDR and DFR settings in the software every six (6) years.

14.7 A requirement to return failed units to service within 90 days. If a DME device will be out of service for greater than 90 days the owner shall keep a record of efforts aimed at restoring the DME to service.

R15. Each Reliability Coordinator, Transmission Owner and Generator Owner shall share data within 30 days upon request. Each Reliability Coordinator, Transmission Owner, and Generator Owner shall provide recorded disturbance data from DMEs within 30 days of receipt of the request in each of the following cases: *[Violation Risk Factor: Lower] [Time Horizon: Operations]*

15.1 NERC, Regional Entity, Reliability Coordinator.

15.2 Request from other Transmission Owners, Generator Owners within NPCC.

R16. Each Reliability Coordinator, Transmission Owner and Generator Owner shall submit the data files conforming to the following format requirements: *[Violation Risk Factor: Lower] [Time Horizon: Operations]*

16.1 The data files shall be capable of being viewed, read, and analyzed with a generic COMTRADE analysis tool as per the latest revision of IEEE Standard C37.111.

16.2 Disturbance Data files shall be named in conformance with the latest revision of IEEE Standard C37.232.

16.3 Fault Recorder and DDR Files shall contain all monitored channels. SOE records shall contain station name, date, time resolved to milliseconds, SOE point name, status.

R17. Each Reliability Coordinator, Transmission Owner and Generator Owner shall maintain, record and provide to the Regional Entity (RE), upon request, the following data on the DMEs installed to meet this standard: *[Violation Risk Factor: Lower] [Time Horizon: Operations]*

17.1 Type of DME.

17.2 Make and model of equipment.

17.3 Installation location.

17.4 Operational Status.

17.5 Date last tested.

17.6 Monitored Elements.

17.7 All identified channels.

17.8 Monitored electrical quantities.

B. Measures

M1. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it provided Sequence of Event recording capability in accordance with 1.1 and 1.2. (R1)

M2. Each Transmission Owner shall have, and provide upon request, evidence that it provided Fault recording capability in accordance with 2.1 to 2.6. (R2)

M3. Each Transmission Owner shall have, and provide upon request, evidence that it provided Fault recording capability that determined the Current Zero Time for loss of Bulk Electric System (BES) transmission Elements in accordance with R3.

M4. Each Generator Owner shall have, and provide upon request, evidence that it provided Fault recording capability for its Generating Plants at and above 200 MVA Capacity in accordance with R4.

M5. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it records for Faults, sufficient electrical quantities for each monitored Element to determine the parameters listed in 5.1 to 5.5. (R5)

M6. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it provided Fault recording capability in accordance with 6.1 to 6.4. (R6)

M7. Each Reliability Coordinator shall have, and provide upon request, evidence that it established its area's requirements for Dynamic Disturbance Recording (DDR) capability in accordance with 7.1 and .2. (R7)

M8. Each Reliability Coordinator shall have, and provide upon request, evidence that DDRs installed after the approval of this standard function as continuous recorders. (R8)

M9. Each Reliability Coordinator shall have, and provide upon request, evidence that it developed DDR setting triggers to include the parameters listed in 9.1 to 9.3. (R9)

M10. Each Reliability Coordinator shall have, and provide upon request, evidence that DDRs monitor the Elements listed in 10.1 through 10.5. (R10)

M11. Each Reliability Coordinator shall have, and provide upon request, evidence that it documented additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10. (R11)

M12. Each Reliability Coordinator shall have, and provide upon request, evidence that it specified its DDR requirements which included the DDR setting triggers established in R9 to the Transmission Owners and Generator Owners in the Reliability Coordinator's area. (R12)

M13. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it acquired and installed the DDRs in accordance with the specifications contained in the Reliability Coordinator's request, and a mutually agreed upon implementation schedule. (R13)

M14. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it has a maintenance and testing program for stand alone DME

(equipment whose only purpose is disturbance monitoring) that meets the requirements in 14.1 through 14.7. (R14)

M15. Each Reliability Coordinator, Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it provided recorded disturbance data from DMEs within 30 days of the receipt of the request from the entities listed in 15.1 and 15.2. (R15)

M16. Each Reliability Coordinator, Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it submitted the data files in a format that meets the requirements in 16.1 through 16.3. (R16)

M17. Each Reliability Coordinator, Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it maintained a record of and provided to NPCC when requested, the data on DMEs installed meeting the requirements 17.1 through 17.8. (R17)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

NPCC Compliance Committee

1.2. Compliance Monitoring Period and Reset Time Frame

Not Applicable

1.3. Data Retention

The Transmission Owner and Generator Owner shall keep evidences for three calendar years for Measures 1, 5, 6, 13, 16 and 17.

The Transmission Owner shall keep evidence for three years for Measures 2 and 3.

The Generator Owner shall keep evidence for three years for Measure 4.

The Reliability Coordinator shall keep evidence for three years for Measures 7, 8, 9, 10, 11, 12, 16 and 17.

The Transmission Owner and Generator Owner shall keep evidences for twenty-four calendar months for Measures 14 and 15.

The Reliability Coordinator shall keep evidence for twenty-four calendar months for Measure 15.

If a Transmission Owner, Generator Owner or Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit and all subsequent record.

1.4. Compliance Monitoring and Assessment Processes

- Self-Certifications
- Spot Checking
- Compliance Audits
- Self-Reporting
- Compliance Violation Investigations
- Complaints

1.5. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1 The Transmission Owner or Generator Owner provided the Sequence of Event recording capability meeting the bulk of R1 but missed…	Up to and including 10% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.	More than 10% and up to and including 20% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.	More than 20% and up to and including 30% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.	More than 30% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R2 The Transmission Owner provided the Fault recording capability meeting the bulk of R2 but missed…	Up to and including 10% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.	More than 10% and up to and including 20% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.	More than 20% and up to and including 30% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.	More than 30% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.
R3 The Transmission Owner failed to provide…	Not applicable.	Not applicable.	Not applicable.	Fault recording capability that determines the current zero time for loss of transmission Elements.
R4 The Generator Owner failed to provide Fault recording capability at…	Up to and including 10% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.	More than 10% and up to and including 20% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.	More than 20% and up to 30% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.	More than 30% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5 The Transmission Owner or Generator Owner failed to record for the Faults…	Up to and including 10% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.	More than 10% and up to and including 20% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.	More than 20% and up to and including 30% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.	More than 30% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.
R6 The Transmission Owner or Generator Owner failed …	To provide Fault recording capability for up to and including 10% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of capabilities identified in 6.1 through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in 6.3 through 6.4 for up to 2 locations.	To provide Fault recording capability for more than 10% and up to and including 20% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of capabilities identified in 6.1 through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in 6.3 through 6.4 for more than two (2) and up to and including five (5) locations.	To provide Fault recording capability for more than 20% and up to and including 30% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of 6.1 through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in 6.3 through 6.4 for more than five (5) and up to and including ten (10) locations.	To provide Fault recording capability for more than 30% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of capabilities identified in 6.1 through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in 6.3 through 6.4 for more than ten (10) locations.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7 The Reliability Coordinator failed to establish its area's requirements for…	Up to and including 10% of the required DDR coverage for its area as per 7.1and 7.2.	More than 10% and up to and including 20% of the required DDR coverage for its area as per 7.1 and 7.2.	More than 20% and up to and including 30% of the required DDR coverage for its area as per 7.1 and 7.2.	More than 30% of the required DDR coverage for its area as per 7.1 and 7.2.
R8 The Reliability Coordinator failed to specify that DDRs installed…	Not applicable.	Not applicable.	Not applicable.	Function as continuous recorders.
R9 The Reliability Coordinator failed to specify that DDRs are installed without…	Not applicable.	Not applicable.	Not applicable.	The capabilities listed in 9.1 through 9.3.
R10 The Reliability Coordinator failed to ensure that the quantities listed in 10.1 through 10.5 are monitored or derived…	Not applicable.	Not applicable.	Not applicable.	Where DDRs are installed.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R11 The Reliability Coordinator failed to document and report to the Regional Entity upon request additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10 for…	Up to two (2) facilities within the Reliability Coordinator's area that have a DDR.	More than two (2) and up to five (5) facilities within the Reliability Coordinator's area that have a DDR.	More than five (5) and up to ten (10) facilities within the Reliability Coordinator's area that have a DDR.	More than ten (10) facilities within the Reliability Coordinator's area that have a DDR.
R12 The Reliability Coordinator failed to specify to the Transmission Owners and Generator Owners its DDR requirements including the DDR setting triggers established in R9 but missed…	Not applicable.	Not applicable.	Not applicable.	Established setting triggers.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R13 The Transmission Owner or Generator Owner failed to comply with the Reliability Coordinator's request installing the DDR in accordance with R12 for…	Up to and including 10% of the requirement set of the Reliability Coordinator's request to install DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR.	More than 10% and up to 20% of the requirement set requested by the Reliability Coordinator for installing DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR.	More than 20% and up to 30% of the requirement set requested by the Reliability Coordinator for installing DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR.	More than 30% of the requirement set requested by the Reliability Coordinator and installing DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR OR The Reliability Coordinator, Transmission Owners, and Generator Owners failed to mutually agree on an implementation schedule.
R14 The Transmission Owner or Generator Owner…	Established a maintenance and testing program for stand alone DME but provided incomplete data for any one (1) of 14.1 through 14.7.	Established a maintenance and testing program for stand alone DME but provided incomplete data for more than one (1) and up to and including three (3) of 14.1 through 14.7.	Established a maintenance and testing program for stand alone DME but provided incomplete data for more than three (3) and up to and including six (6) of 14.1 through 14.7.	Did not establish any maintenance and testing program for DME; OR The Transmission Owner or Generator Owner established a maintenance and testing program for DME but did not provide any data that meets all of 14.1 through 14.7.
R15 The Reliability Coordinator, Transmission Owner or Generator Owner provided recorded disturbance data from DMEs but was late for…	Up to and including fifteen (15) days in meeting the requests of an entity, or entities in 15.1, or 15.2.	More than fifteen (15) days but less than and including thirty (30) days in meeting the requests of an entity, or entities in 15.1 or 15.2.	More than 30 days but less than and including forty-five (45) days in meeting the requests of an entity, or entities in 15.1 or 15.2.	More than forty-five (45) days in meeting the requests of an entity, or entities in 15.1 or 15.2.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R16 The Reliability Coordinator, Transmission Owner or Generator Owner failed to submit…	Up to and including two (2) data files in a format that meets the applicable format requirements in 16.1 through 16.3.	More than two (2) and up to and including five (5) data files in a format that meets the applicable format requirements in 16.1 through 16.3.	More than five (5) and up to and including ten (10) data files in a format that meets the applicable format requirements in 16.1 through 16.3.	More than ten (10) data files in a format that meets the applicable format requirements in 16.1 through 16.3.
R17 The Reliability Coordinator, Transmission Owner or Generator Owner failed to maintain or provide to the Regional Entity , upon request…	Up to and including two (2) of the items in 17.1 through 17.8.	More than two (2) and up to and including four (4) of the items in 17.1 to 17.8.	More than four (4) and up to and including six (6) of the items in 17.1 through 17.8.	More than six (6) of the items in 17.1 through 17.8.

D. Associated Documents

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. RSAR forwarded to the RSC for review July 22, 2008.
2. RSC authorized the SAR to be forwarded to the RCC for Task Force assignment Aug. 21, 2008.
3. RCC to appointed TFSP as the Lead Task Force Sept. 4, 2008.
4. First draft posted on the NPCC website Nov. 5, 2008 for 45 day comment period.
5. Second draft posted on the NPCC website June 2, 2009 for 45 day comment period.
6. Third draft posted for Pre-Ballot Review Nov. 24, 2009.
7. Ballot began Dec. 17, 2009; Standard approved by NPCC Membership Jan. 6, 2010.
8. Presented to, and approved by the NPCC Board of Directors Feb. 9, 2010.

Description of Current Draft:

This is the draft of the standard approved by the NPCC Board of Directors.

Future Development Plan:

Anticipated Action	Date
Consolidate comments--submit to TFSP	May 28, 2009
Post response to comments, and second version of standard	June 1, 2009
Post response to comments, and third version of standard	Sept. 9, 2009
For Pre-Ballot Review	Nov. 24, 2009
Posting of Notification of Ballot	Dec. 2, 2009
Ballot period begins	Dec. 17, 2009
NPCC Membership approval	Jan. 6, 2010
NPCC Board of Directors approval	Feb. 9, 2010
NERC approval	Nov. 4, 2010

Definitions of Terms Used in Standard

This section includes all newly defined terms used in the proposed Standard. Terms already defined in the NERC glossaries are not repeated here. The new definitions listed below become approved when the proposed Standard is approved. The terms will be listed and defined in the NPCC Section of the NERC Glossary. The NPCC Section will list terms specific to the NPCC region.

In the Standard, defined terms are indicated with their first letters capitalized.

Current Zero Time: The time of the final current zero on the last phase to interrupt.

Generating Plant: One or more generators at a single physical location whereby any single contingency can affect all the generators at that location.

Implementation Plan for PRC-002-NPCC-1

Disturbance Monitoring

Draft

Background

In developing the Implementation Plan for PRC-002-NPCC-1 the Standard Drafting Team considered the following:

1. The requirements listed in this Regional Standard are intended to cover all aspects of the utilization of Disturbance Monitoring equipment. The intent of the Standard is to be more stringent than the continent wide Standard under development at NERC. After the approved NERC continent wide Standard is issued, PRC-002-NPCC-1 will be revisited to eliminate any redundancies.

2. The refueling outage schedules of nuclear plants will be considered when determining their compliance.

3. Any implementation plan will be impacted by the resource availability and approval processes of the Reliability Coordinators, Transmission Owners, and Generator Owners.

4. It is assumed the Reliability Coordinators have already established their DDR needs. If not, "time zero" will be after the Reliability Coordinator issues the locations and needs for additional DDR equipment.

Effective Dates

1. Within two (2) years of FERC and Canadian entities' approvals, entities shall be 50 percent compliant at facilities required to have DME capabilities by:

   a. Installing Sequence of Events (SOE) capability at 50 percent of the facilities that previously had no SOE capability (percent complete will be based on the number of facilities completed)
   b. Installing additional SOE capability to facilities with existing SOEs such that 50 percent of the total required capability is complete (percent complete will be based on the number of SOE points required)

c. Installing Fault Recording capability at 50 percent of the facilities that previously had no Fault Recording capability (percent complete will be based on the number of facilities completed)
d. Installing additional Fault Recording capability to facilities with existing Fault Recording capability such that 50 percent of the required capability is complete (percent complete will be based on the number of traces required)
e. Installing Dynamic Disturbance Recording (DDR) capability at 50 percent of the facilities that previously had no DDR capability (percent complete will be based on the number of facilities completed versus those required by the Reliability Coordinator)
f. Installing additional DDR capability to facilities with existing DDR capability such that 50 percent of the required capability is complete (percent complete will be based on the number of elements as required by the Reliability Coordinator)

2. Within three (3) years of FERC and Canadian entities' approvals, entities shall be 75 percent compliant at facilities required to have DME capabilities by:

a. Installing SOE capability at 75 percent of the facilities that previously had no SOE capability (percent complete will be based on the number of facilities completed)
b. Installing additional SOE capability to facilities with existing SOEs such that 75 percent of the total required capability is complete (percent complete will be based on the number of SOE points required)
c. Installing Fault Recording capability at 75 percent of the facilities that previously had no Fault Recording capability (percent complete will be based on the number of facilities completed)
d. Installing additional Fault Recording capability to facilities with existing Fault Recording capability such that 75 percent of the required capability is complete (percent complete will be based on the number of traces required)
e. Installing DDR capability at 75 percent of the facilities that previously had no DDR capability (percent complete will be based on the number of facilities completed versus those required by the Reliability Coordinator)
f. Installing additional DDR capability to facilities with existing DDR capability such that 75 percent of the required capability is complete (percent complete will be based on the number of elements as required by the Reliability Coordinator)

3. Within four (4) years of FERC and Canadian entities' approvals, all (100 percent) SOE, Fault Recording, and DDR capability shall be installed to satisfy the requirements of this Standard.

Reference

NPCC Criteria:

A-5 Bulk Power System Protection Criteria

A-7 NPCC Glossary of Terms

A-10 Classification of Bulk Power System Elements

A-15 Disturbance Monitoring Equipment Criteria

NPCC Guides:

B-26 Guide for Application of Disturbance Recording Equipment

B-28 Draft Guideline for Generator Sequence of Event Monitoring

SP-6 Synchronized Event Data Reporting

A NPCC Directory will be developed for Disturbance Monitoring. It will contain supporting information and details from the Criteria and Guides that are not incorporated in the Standard.

From: Lee R. Pedowicz
To: general
Cc: "rrswg_plus@nerc.com"; rsc-members; dmsdt; rjfalsetti@cogeco.ca; donald.e.nelson@state.ma.us; kal.ayoub@ferc.gov; stephanie.monzon@nerc.net
Subject: NPCC Regional Standard PRC-002-NPCC-01 Disturbance Monitoring--NERC Approval
Date: Thursday, November 04, 2010 10:55:00 AM

Good morning.

I want to take this opportunity to thank everyone who participated in the balloting for NPCC Disturbance Monitoring PRC-002-NPCC-01 Standard's VSL Table. Balloting closed Oct. 31, 2010, and I am pleased to report that the VSL Table passed. The results can be viewed by going to the link:

https://www.npcc.org/member/Home.aspx

Also, I was just informed that the NERC Board of Trustees today has approved the Standard and its Implementation Plan. The next step is for the Standard package to be submitted to FERC and the Canadian authorities for their approvals.

Thanks again to everyone for their help.

Lee Pedowicz
Manager, Reliability Standards
NPCC

From: Guy V. Zito
To: grpStaff
Subject: NPCC"s first Regional Standard DME
Date: Friday, October 14, 2011 10:29:27 AM

To All

The NPCC DME standard is on the meeting agenda for next week's FERC sunshine meeting. We are hoping for a very favorable outcome. We have had a number of teleconferences with FERC staff in the last few weeks and I met with a member of staff again yesterday. I will keep you all informed.

Thanks,
Guy

Sent from my iPhone

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
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PRC-006-NPCC-1
Automatic Underfrequency Load Shedding

Cost Effectiveness Questions

October 3, 2011

NPCC is addressing the convergence of the final approval milestones of the UFLS Regional Standard and the development of the Cost Effectiveness Analysis Procedure with a posting designed to evaluate the cost effectiveness of the standards requirements.

All responses will be held individually confidential and aggregated to provide the industry with raw total cost effectiveness information for the standard's ballot. Send your responses via E-mail to NPCCstandard@npcc.org by Nov. 2, 2011.

1) **On a requirement by requirement basis, are the Requirements effective in achieving the reliability objective of the Standard and if not, why?**

2) **Are there alternative ways to achieve the draft Standard's reliability objective? If so, what alternatives are there and which requirements would they replace? This must be supported by studies done or be demonstrable.**

3) **On a requirement by requirement basis, do the draft requirements in the Standard achieve or contribute to a level of reliability that is "adequate", i.e. acceptable? If so, how? If not, why not?**

4) **Is there any adverse impact to reliability or any other existing standard, NPCC Regional Criteria, or in-process project draft Standard(s), of which your organization is aware?**

5) **Describe the size of your organization in broad general terms, e.g. GO-Total installed MWs, TOs circuit miles by kV and total load served, etc.**

6) **What are the gross anticipated one-time and ongoing costs of implementing the Standard as presently drafted (labor and materials)? Is there a cost recovery mechanism in place for your organization, i.e. markets or tariffs?**

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

October 3, 2011

NPCC Full and General Members;

NPCC and its stakeholders have recently received the endorsement of a Regional Standard on Automatic Underfrequency Load Shedding (PRC-006-NPCC-01) from the *Reliability Coordinating Committee (RCC*).

The draft standard, which was developed based on the recommendations contained within the NPCC UFLS program assessments conducted in 2006 by the *SS38 Working Group on Inter-Area Dynamic Analysis* and approved by the RCC in November of 2007, also incorporates the performance attributes of the existing NPCC Directory #12 and its associated implementation plan.

During the development of this standard industry concerns have increasingly recognized the need to understand the potential costs of implementing reliability standards.

In response to these concerns, NPCC has initiated an effort to perform an evaluation of such costs and the effectiveness of a standard's requirements.

Recently, an initial draft of a Cost Effectiveness Analysis Procedure was developed and posted in the NPCC Open Process to solicit industry comment on its content.

Accordingly, NPCC will address the convergence of the final approval milestones of the UFLS Regional Standard and the development of the Cost Effectiveness Analysis Procedure with a posting designed to evaluate the cost effectiveness of the standards requirements.

Please find attached a copy of PRC-006-NPCC-01 which has been developed by the *NPCC Standard Drafting Team (SDT)* under the direction of the *Task Force on System Studies (TFSS).* Also, attached are a set of questions requesting information on recovery mechanisms, technical feasibility and which focus on cost effectiveness within the framework of the existing approved UFLS implementation schedule.

The standard, its implementation plan and the cost questions have all been posted on the NPCC website for a 30 day comment period and are available to receive your comments until November 2, 2011 at:

https://www.npcc.org/Standards/Regional%20Standards%20General/Forms/Public%20List.aspx

All responses will be held individually confidential and aggregated to provide the industry with raw total cost effectiveness information for the standard's ballot.

Please contact me with any questions regarding the NPCC UFLS draft standard, NPCC Regional Standard Development Procedure or the draft NPCC Cost Effectiveness Analysis Procedure.

Respectfully,

Guy V. Zito
Asst. Vice President-Standards, Chair Regional Standards Committee
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10th Floor
New York, NY 10018
212-840-1070

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. NPCC Regional Standards Committee (RSC) authorized posting UFLS RSAR development on August 20, 2008.
2. UFLS RSAR posted on NPCC website on August 25, 2008.
3. NPCC Reliability Coordinating Committee (RCC) approved the Task Force on System Studies (TFSS) as the lead task force to initiate drafting a UFLS Regional Standards on September 4, 2008.
4. NPCC UFLS Regional Standard Drafting Team initial meeting on January 27, 2009.
5. First draft posted on the NPCC Website July 13, 2009 for a 45 day comment period.
6. Second draft posted on the NPCC Website May 26, 2010 for a 45 day comment period.
7. Third draft posted on the NPCC Website May 6, 2011 for a 45 day comment period.

Description of Current Draft:

This is the third draft of the proposed standard.

Future Development Plan:

Anticipated Action	Anticipated Date
1. Post the initial draft of the standard for 45 day comment period.	July 13, 2009 to August 27, 2009
2. Respond to comments on the first posting and post revised standard and implementation plan for a 45 day comment period.	September 2009 to May 2010 May 26, 2010 to July 9th, 2010
3. Respond to comments on the 2nd posting.	July 2010 to October 2010
4. Obtain RSC approval to move the standard forward to balloting.	November 2010
5. Post the standard and implementation plan for a 30 day pre ballot review.	December 2010

6. Conduct a ten day ballot.	December 2010
7. Respond to ballot comments and post revised standard and implementation plan for a 45 day comment period.	May, 2011.
8. Respond to comments on the 3rd posting.	July 2011
9. Obtain RSC approval to move the standard forward to balloting.	August 2011
10. Post the standard and implementation plan for a 30 day pre ballot review.	August 2011
11. Conduct a ten day ballot.	September 2011
12. Membership Approval.	September 2011.

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the NERC Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the NPCC Glossary.

In the standards, defined terms are indicated with its first letter capitalized.

A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**
2. **Number:** PRC-006-NPCC-1
3. **Purpose:** To provide a regional reliability standard that ensures the development of an effective automatic underfrequency load shedding (UFLS) program in order to preserve the security and integrity of the bulk power system during declining system frequency events in coordination with the NERC UFLS reliability standard characteristics.
4. **Applicability:**
   - **4.1.** Generator Owner
   - **4.2.** Planning Coordinator
   - **4.3.** Distribution Provider
   - **4.4.** Transmission Owner
5. **(Proposed) Effective Date:** To be established.

B. Requirements

R1 Each Planning Coordinator shall establish requirements for entities aggregating their UFLS programs for each anticipated island and requirements for compensatory load shedding based on islanding criteria (required by the NERC PRC Standard on UFLS). [Violation Risk Factor:Medium] [Time Horizon: Long Term Planning]

R2 Each Planning Coordinator shall, within 30 days of completion of its system studies required by the NERC PRC Standard on UFLS, identify to the Regional Entity the generation facilities within its Planning Coordinator Area necessary to support the UFLS program performance characteristics. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

R3 Each Planning Coordinator shall provide to the Transmission Owner, Distribution Provider, and Generator Owner within 30 days upon written request the requirements for entities aggregating the UFLS programs and requirements for compensatory load shedding program derived from each Planning Coordinator's system studies as determined by Requirement R1. [Violation Risk Factor:Low] [Time Horizon: Long Term Planning]

R4 Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall implement an automatic UFLS program reflecting normal operating conditions excluding outages for its Facilities based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 4, or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1 and acting as a single entity, provide an aggregated automatic UFLS program that sheds their coincident peak aggregated net Load, based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R5 Each Distribution Provider or Transmission Owner that must arm its load to trip on underfrequency in order to meet its requirements as specified and by doing so exceeds the tolerances and/or deviates from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Requirement R4 above, as applicable depending on its total peak net Load shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

5.1 Inform its Planning Coordinator of the need to exceed the stated tolerances or the number of stages as shown in UFLS Attachment C, Table 1 if applicable and

5.2 Provide its Planning Coordinator with a technical study that demonstrates that the Distribution Providers or Transmission Owners specific deviations from the requirements of UFLS Attachment C, Table 1 will not have a significant adverse impact on the bulk power system.

5.3 Inform its Planning Coordinator of the need to exceed the stated tolerances of UFLS Attachment C, Table 2 or Table 3, and in the case of Attachment C, Table 2 only, the need to deviate from providing two stages of UFLS, if applicable, and

5.4 Provide its Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or Transmission Owner to comply with UFLS Attachment C Table 2 or Attachment C Table 3.

R6 Each Distribution Provider and Transmission Owner in the Québec Interconnection portion of NPCC shall implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 5 or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R7 Each Distribution Provider and Transmission Owner shall set each underfrequency relay that is part of its region's UFLS program with the following minimum time delay:

7.1 Eastern Interconnection – 100 ms

7.2 Québec Interconnection – 200 ms

[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R8 Each Planning Coordinator shall develop and review once per calendar year settings for inhibit thresholds (such as but not limited to voltage, current and time) to be utilized within its region's UFLS program. [Violation Risk Factor:Medium] [Time Horizon: Long Term Planning]

R9 Each Planning Coordinator shall provide each Transmission Owner and Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds within 30 days of the initial determination of those inhibit thresholds and within 30 days of any changes to those thresholds. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

R10 Each Distribution Provider and Transmission Owner shall implement the inhibit threshold settings based on the notification provided by the Planning Coordinator in accordance with Requirement R11. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

R11 Each Distribution Provider and Transmission Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with R11. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

R12 Each Transmission Owner and Distribution Provider shall annually provide documentation, with no more than 15 months between updates, to its Planning Coordinator of the actual net Load that would have been shed by the UFLS relays at each UFLS stage coincident with their integrated hourly peak net Load during the previous year, as determined by measuring actual metered Load through the switches that would be opened by the UFLS relays. [Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]

R13 Each Generator Owner shall set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted in Requirements R18 and R21. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R14 Each Generator Owner shall transmit the generator underfrequency trip setting and time delay to its Planning Coordinator within 45 days of the Planning Coordinator's request. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

R15 Each Generator Owner with a new generating unit, scheduled to be in service on or after the effective date of this Standard, or an existing generator increasing its net capability by greater than 10% shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

15.1 Design measures to prevent the generating unit from tripping directly or indirectly for underfrequency conditions above the appropriate generator tripping threshold curve in Figure 1.

15.2 Design auxiliary system(s) or devices used for the control and protection of auxiliary system(s), necessary for the generating unit operation such that they will not trip the generating unit during underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1.

R16 Each Generator Owner of existing non-nuclear units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1 shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

16.1 Set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations.

16.2 Transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinator.

16.3 Have compensatory load shedding, as provided by a Distribution Provider or Transmission Owner that is adequate to compensate for the loss of their generator due to early tripping.

R17 Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall apply the criteria described in Attachment A to determine the compensatory load shedding that is required in Requirement R15.3 for generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R18 Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall apply the criteria described in Attachment B to determine the compensatory load shedding that is required in Requirement R15.3 for generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R19 Each Generator Owner of existing nuclear generating plants with units that have underfrequency relay threshold settings above the Eastern Interconnection generator tripping curve in Figure 1, based on their licensing design basis, shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

19.1 Set the underfrequency protection to operate at as low a frequency as possible in accordance with the plant design and licensing limitations but not greater than 57.8Hz.

19.2 Set the frequency trip setting upper tolerance to no greater than + 0.1 Hz.

19.3 Transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the Planning Coordinator.

R20 The Planning Coordinator shall update its UFLS program database as specified by the NERC PRC Standard on UFLS. This database shall include the following information: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

20.1 For each UFLS relay, including those used for compensatory load shedding, the amount and location of load shed at peak, the corresponding frequency threshold and time delay settings.

20.2 The buses at which the Load is modeled in the NPCC library power flow case.

20.3 A list of all generating units that may be tripped for underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, including the frequency trip threshold and time delay for each protection system.

20.4 The location and amount of additional elements to be switched for voltage control that are coordinated with UFLS program tripping.

20.5 A list of all UFLS relay inhibit functions along with the corresponding settings and locations of these relays.

R21 Each Planning Coordinator shall notify each Distribution Provider, Transmission Owner, and Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program performance characteristics as specified by the NERC PRC Standard on UFLS.[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R22 Each Distribution Provider, Transmission Owner and Generator Owner shall implement the load distribution changes based on the notification provided by the Planning Coordinator in accordance with Requirement R25. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R23 Each Distribution Provider, Transmission Owner and Generator Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with Requirement R25. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

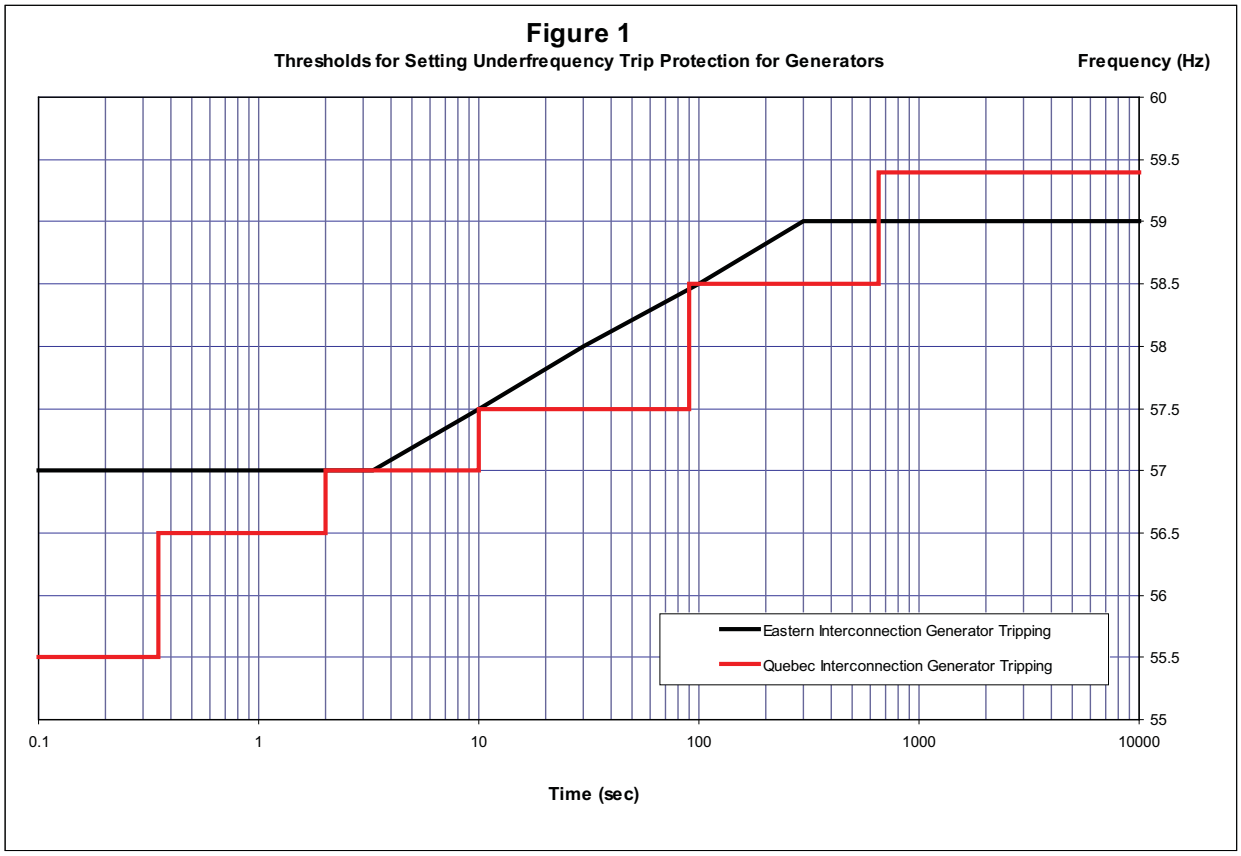
Figure 1
Thresholds for Setting Underfrequency Trip Protection for Generators
Frequency (Hz)
60
59.5
59
58.5
58
57.5
57
56.5
56
55.5
55
0.1
1
10
100
1000
10000
Time (sec)
Eastern Interconnection Generator Tripping
Quebec Interconnection Generator Tripping

C. Measures

M1 Each Planning Coordinator shall have evidence such as reports, system studies and/or real time power flow data captured from actual system events and other dated documentation that demonstrates it meets Requirement R1.

M2. Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets requirement R2.

M3 Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets Requirement R3.

M4 Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall have evidence such as documentation or reports containing the location and amount of load to be tripped, and the corresponding frequency thresholds, on those circuits included in its UFLS program to achieve the individual and cumulative percentages identified in Requirement R4.

M5 Each Distribution Provider or Transmission Owner shall have evidence such as reports, analysis, system studies and dated documentation that demonstrates that it meets Requirement R5.

M6 Each Distribution Provider and Transmission Owner in the Québec Interconnection shall have evidence such as documentation or reports containing the location and amount of load to be tripped and the corresponding frequency thresholds on those circuits included in its UFLS program to achieve the load values identified in Table 4 of Requirement R6.

M7 Each Distribution Provider and Transmission Owner shall have evidence such as documentation or reports that their underfrequency relays have been set with the minimum time delay, in accordance with Requirement R7.

M8 Each Planning Coordinator shall have evidence such as reports, system studies or analysis that demonstrates that it meets Requirement R8.

M9 Each Planning Coordinator shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R9.

M10 Each Distribution Provider and Transmission Owner shall provide evidence such as test reports, data sheets or other documentation that demonstrates that it meets Requirement R10.

M11 Each Distribution Provider and Transmission Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates that it meets Requirement R11.

M12 Each Distribution Provider and Transmission Owner shall provide evidence such as reports, spreadsheets or other dated documentation submitted to its Planning Coordinator that indicates the frequency set point, the net amount of load shed and the percentage of its peak load at each stage of its UFLS program coincident with the integrated hourly peak of the previous year that demonstrates that it meets Requirement R12.

M13 Each Generator Owner shall provide evidence such as reports, data sheets, spreadsheets or other documentation that demonstrates that it meets Requirement R13.

M14 Each Generator Owner shall provide evidence such as emails, letters or other dated documentation that demonstrates that it meets Requirement R14.

M15 Each Generator Owner shall provide evidence such as reports, data sheets, specifications, memorandum or other documentation that demonstrates that it meets Requirement R15.

M16 Each Generator Owner with existing non-nuclear units in service prior to the effective date of this Standard which have underfrequency tripping that is not compliant with Requirement R12 shall provide evidence such as reports, spreadsheets, memorandum or dated documentation demonstrating that it meets Requirement R16.

M17 Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall provide evidence such as emails, memorandum or other documentation that demonstrates that it followed the methodology described in Attachment A and meets Requirement R17.

M18 Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall provide evidence such as emails, memorandum, or other documentation that demonstrates that it followed the methodology described in Attachment B and meets Requirement R18.

M19 Each Generator Owner of nuclear units that have been specifically identified by NPCC as having generator trip settings above the generator trip curve in Figure 1 shall provide evidence such as letters, reports and dated documentation that demonstrates that it meets Requirement R19.

M20 Each Planning Coordinator shall provide evidence such as spreadsheets, system studies, or other documentation that demonstrates that it meets the requirements of Requirement R20.

M21 Each Planning Coordinator shall provide evidence such as emails, memorandum or other dated documentation that it meets Requirement R21.

M22 Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as reports, spreadsheets or other documentation that demonstrates that it meets Requirement R22.

M23 Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates it meets Requirement 23.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

NPCC Compliance Committee

1.2. Compliance Monitoring Period and Reset Time Frame

Not Applicable

1.3. Data Retention

The Distribution Provider and Transmission Owner shall keep evidences for three calendar years for Measures 4, 5, 6,7,10, 11, and 12.

The Planning Coordinator shall keep evidence for three calendar years for Measures 1, 2, 3, 8, 9, 20, and 21.

The Planning Coordinator in Ontario, Quebec, and the Maritime Provinces shall keep evidence for three calendar years for Measure 17.

The Distribution Provider, Transmission Owner, and Generator Owner shall keep evidences for three calendar years for Measures 18, 22, and 23.

The Generator Owner shall keep evidence for three calendar years for Measures 13, 14, 15, 16, and 19.

1.4. Compliance Monitoring and Assessment Processes

Self -Certifications.

Spot Checking.

Compliance Audits.

Self- Reporting.

Compliance Violation Investigations.

Complaints.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	**N/A**	Planning Coordinator did not establish requirements for entities aggregating their UFLS programs. or Did not establish requirements for compensatory load shedding.	Planning Coordinator did not establish requirements for entities aggregating their UFLS programs and did not establish requirements for compensatory load shedding.
R2	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 30 days but less than 41 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 40 days but less than 51 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 50 days but less than 61 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 60 days after completion of the system studies. or The Planning Coordinator did not identify the generation facilities within its Planning Coordinator Area necessary to support the UFLS program.
R3	The Planning Coordinator provided the requested information, but did so more than 30 days but less than 41 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 40 days but less than 51 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 50 days but less than 61 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 60 days after the request. or The Planning Coordinator failed to provide the requested information.

				t
R4	N/A	N/A	N/A	The Distribution Provider or Transmission Owner failed to implement an automatic UFLS program reflecting normal operating conditions excluding outages, for its Facilities or collectively implemented by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on frequency thresholds, total nominal operating time, and amounts specified in the appropriate included tables.
R5	N/A	The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not inform the Planning Coordinator of the need to exceed the stated tolerances of UFLS Table 2 or Table 3, and in the case of Table	The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Atachment C, as applicable depending on their total peak net Load, but did not provide the Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or	The Distribution Provider or Transmission Owner did not arm its load to trip on underfrequency in order to meet its minimum obligations and in doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load.

		2 only, the need to deviate from providing two stages of UFLS.	Transmission Owner to comply with the appropriate table.	
R6	N/A	N/A	T	The Distribution Provider or Transmission Owner in the Québec Interconnection portion of NPCC did not implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4 or did not collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4.
R7	N/A	N/A	N/A	The Distribution Provider or Transmission Owner failed to set

				an underfrequency relay that is part of its region's UFLS program as specified in Requirement R7.
R8		N/A	The Planning Coordinator developed inhibit thresholds as specified in Requirement R9 but did not perform the review once per calendar year.	The Planning Coordinator did not develop inhibit thresholds as specified in Requirement R9.
R9	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 30 days but less than 41 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 40 days but less than 51 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 50 days but less than 61 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 60 days after the initial determination or any subsequent change to the inhibit thresholds. or The Planning Coordinator did not provide to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds.
R10	N/A	N/A	N/A	The Distribution Provider or Transmission Owner did not implement the inhibit threshold based on the notification provided by the Planning Coordinator in accordance with Requirement R9.

R11	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator. or The Distribution Provider or Transmission Owner did not develop its implementation plan.
R12				The Transmission Owner or Distribution Provider did not provide documentation to its Planning Coordinator of actual net load data or updates to the data that would be shed by the UFLS relays, as determined by measuring actual metered load through the switches that would be opened by the UFLS relays, that were armed to shed at each UFLS stage coincident with their integrated hourly peak during the previous year.
R13	N/A	N/A	N/A	The Generator Owner did not set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted.

R14	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 45 days and less than 56 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 55 days and less than 66 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 65 days and less than 76 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 75days after the Planning Coordinator's request. or The Generator Owner did not transmit the generator underfrequency trip setting and time delay to its Planning Coordinator.
R15	N/A	N/A	The Generator Owner did not fulfill the obligation of Requirement R15, Part 15.1 OR did not fulfill the obligation of Requirement R15, Part 15.2.	The Generator Owner did not fulfill the obligation of Requirement R15, Part 15.1 and did not fulfill the obligation of Requirement R15, Part 15.2.
R16	N/A	The Generator Owner did not fulfill the obligation of Requirement R16, Part 16.2.	The Generator Owner did not fulfill the obligation of Requirement R16, Part 16.1 OR did not fulfill the obligation of Requirement R16, Part 16.3.	The Generator Owner did not fulfill the obligation of Requirement R16, Part 16.1 and did not fulfill the obligation of Requirement R16, Part 16.3.

R17	N/A	N/A	N/A	The Planning Coordinator did not apply the methodology described in Attachment A to determine the compensatory load shedding that is required.
R18	N/A	N/A	N/A	The Generator Owner, Distribution Provider, or Transmission Owner did not apply the methodology described in Attachment B to determine the compensatory load shedding that is required.
R19	N/A	The Generator Owner did not fulfill the obligation of Requirement R19, Part 19.3.	The Generator Owner did not fulfill the obligation of Requirement R19, Part 19.1 OR did not fulfill the obligation of Requirement R19, Part 19.2.	The Generator Owner did not fulfill the obligation of Requirement R19, Part 19.1 and did not fulfill the obligation of Requirement R19, Part 19.2.
R20	The Planning Coordinator did not have data in its database for one of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for two of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for three of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for four or more of the parameters listed in Requirement 20, Parts 20.1 through 20.5.

R21	N/A	N/A	N/A	The Planning Coordinator did not notify a Distribution Provider, Transmission Owner, or Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program requirements.
R22	N/A	N/A	N/A	The Distribution Provider, Transmission Owner, or Generator Owner did not implement the load distribution changes based on the notification provided by the Planning Coordinator.
R23	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator. or The Distribution Provider. Transmission Owner or Generator Owner did not develop its implementation plan.

PRC-006-NPCC-1 Attachment A

Compensatory Load Shedding Criteria for Ontario, Quebec, and the Maritime Provinces:

The Planning Coordinator in Ontario, Quebec and the Maritime provinces is responsible for establishing the compensatory load shedding requirements for all existing non-nuclear units in its NPCC area with underfrequency protections set to trip above the appropriate curve in Figure 1. In addition, it is the Planning Coordinator's responsibility to communicate these requirements to the appropriate Distribution Provider or Transmission Owner and to ensure that adequate compensatory load shedding is provided in all islands identified in Requirement R1 in which the unit may operate.

The methodology below provides a set of criteria for the Planning Coordinator to follow for determining compensatory load shedding requirements:

1. The Planning Coordinator shall identify, compile and maintain an updated list of all existing non-nuclear generating units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1. The list shall include the following information for each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 All islands within which the unit may operate, as identified in Requirement R1

2. For each generating unit identified in (1) above, the Planning Coordinator shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 Arrange for a Distribution Provider or Transmission Owner that owns UFLS relays within the island(s) identified by the Planning Coordinator in Requirement R1 within which the generator may operate to provide compensatory load shedding.

    2.2 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4..

    2.3 The compensatory load shedding shall be provided at the UFLS program stage (or threshold stage for Quebec) with a frequency threshold setting that corresponds to the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1 during an underfrequency event. If the highest

frequency at which the subject generator will trip above the appropriate curve in Figure 1 does not correspond to a specific UFLS program stage threshold setting, the compensatory load shedding shall be provided at the UFLS program stage with a frequency threshold setting that is higher than the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1.

2.4 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-1 Attachment B

Compensatory Load Shedding Criteria for ISO-NE and NYISO:

The Generator Owner in the New England states or New York State are responsible for establishing a compensatory load shedding program for all existing non-nuclear units with underfrequency protection set to trip above the appropriate curve in Figure 1 of this standard. The Generator Owner shall follow the methodology below to determine compensatory load shedding requirements:

1. The Generator Owner shall identify and compile a list of all existing non-nuclear generating units in service prior to the effective date of this standard that has underfrequency protection set to trip above the appropriate curve in Figure 1. The list shall include the following information associated with each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 Smallest island within which the unit may operate as identified by the Planning Coordinator in Requirement R1 of this Standard.

2. For each generating unit identified in (1) above, the Generator Owner shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 In cases where a Distribution Provider or Transmission Owner has coordinated protection settings with the Generator Owner to cause the generator to trip above the appropriate curve in Figure 1, the Distribution Provider or Transmission Owner is responsible to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

    2.2 In cases where a Generator Owner has a generator that cannot physically meet the set points defined by the appropriate curve in Figure 1, the Generator Owner shall arrange for a Distribution Provider or Transmission Owner to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

    2.3 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4.

2.4 The compensatory load shedding shall be provided at the UFLS program stage with the frequency threshold setting at or closest to but above the frequency at which the subject generator will trip.

2.5 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-1 Attachment C

UFLS Table 1: Eastern Interconnection

Distribution Providers and Transmission Owners with 100 MW or more of peak net Load shall implement a UFLS program with the following attributes:

Frequency Threshold (Hz)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
59.5	0.30	6.5 – 7.5	6.5 – 7.5
59.3	0.30	6.5 – 7.5	13.5 – 14.5
59.1	0.30	6.5 – 7.5	20.5 – 21.5
58.9	0.30	6.5 – 7.5	27.5 – 28.5
59.5	10.0	2 – 3	29.5 – 31.5

UFLS Table 2: Eastern Interconnection

Distribution Providers and Transmission Owners with 50 MW or more and less than 100 MW of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time(s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	14-25	14-25
2	59.1	0.30	14-25	28-50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

UFLS Table 3: Eastern Interconnection

Distribution Providers and Transmission Owners with 25 MW or more and less than 50 MW of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	28-50	28-50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

UFLS Table 4: Quebec Interconnection

	Rate	Frequency (Hz)	MW at peak (*Load must be fixed at all times.)	Mvar at peak	Total Nominal Operating Time (s) [2]
Threshold Stage 1	——	58.5	1000*	1000	0.30
Threshold Stage 2	——	58.0	800*	800	0.30
Threshold Stage 3	——	57.5	800	800	0.30
Threshold Stage 4	——	57.0	800	800	0.30
Threshold Stage 5 (anti-stall)	——	59.0	500	500	20.0
Slope Stage 1	-0.3 Hz/s	58.5	400	400	0.30
Slope Stage 2	-0.4 Hz/s	59.8	800*	800	0.30
Slope Stage 3	-0.6 Hz/s	59.8	800*	800	0.30
Slope Stage 4	-0.9 Hz/s	59.8	800	800	0.30

2. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communications time, and the rated breaker interrupting time. The underfrequency relay operating time shall be measured from the time when the frequency passes through the frequency threshold set point.

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PRC-006-NPCC-1 Automatic Underfrequency Load Shedding

Implementation Plan

Background:

The purpose of this draft Regional Standard is to ensure the development and maintenance of an effective and coordinated Automatic Underfrequency Load Shedding program in order to preserve the reliability and integrity of the bulk power system during declining system frequency events.

In the developing the Implementation Plan for PRC-006-NPCC-01 the Standard Drafting Team considered the following:

1. The requirements listed in this Regional Standard are intended to cover all aspects of the UFLS program. The Regional Standard Drafting Team (RSDT) coordinated its development with the draft NERC UFLS Standard PRC-006. The intent of this Regional Standard is to be more stringent than the continent wide standard while incorporating specific program characteristics into the requirements.
2. The Implementation Plan for this standard is based, in part, on the timelines reflected in the existing and ongoing Implementation Plan for NPCC Directory #12 absent the annual milestones required by Directory #12.

Effective Dates:

Eastern Interconnection & Québec Interconnection Portions of NPCC Excluding the Independent Electricity System Operator (IESO) Planning Coordinator Area of NPCC in Ontario, Canada.

1. The effective date for requirements R1, R2, R3, R4, R5, R6, and R7 is the first day of the first calendar quarter following applicable regulatory approval but no earlier than Jan 1, 2016 to allow for the existing implementation plan to be completed.

2. The effective date for requirements R8 through R23 is the first day of the first calendar quarter two years following applicable governmental and regulatory approval.

Independent Electricity System Operator (IESO) Planning Coordinator's Area of NPCC in Ontario, Canada

1. Effective the first day of the first calendar quarter following applicable governmental and regulatory approval but no earlier than April 1, 2017.

References:

- 2006 Assessment of UFLS Adequacy Part 3 Assessment of Program Modifications.
- SS38 Underfrequency Load Shedding Support Studies

NPCC Criteria:

- Directory #12 Underfrequency Load Shedding Program Requirements.
- A-7 NPCC Glossary of Terms.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. NPCC Regional Standards Committee (RSC) authorized posting UFLS RSAR development on August 20, 2008.
2. UFLS RSAR posted on NPCC website on August 25, 2008.
3. NPCC Reliability Coordinating Committee (RCC) approved the Task Force on System Studies (TFSS) as the lead task force to initiate drafting a UFLS Regional Standards on September 4, 2008.
4. NPCC UFLS Regional Standard Drafting Team initial meeting on January 27, 2009.
5. First draft posted on the NPCC Website July 13, 2009 for a 45 day comment period.
6. Second draft posted on the NPCC Website May 26, 2010 for a 45 day comment period.
7. Third draft posted on the NPCC Website May 6, 2011 for a 45 day comment period.

Description of Current Draft:

This is the third draft of the proposed standard.

Future Development Plan:

Anticipated Action	Anticipated Date
1. Post the initial draft of the standard for 45 day comment period.	July 13, 2009 to August 27, 2009
2. Respond to comments on the first posting and post revised standard and implementation plan for a 45 day comment period.	September 2009 to May 2010 May 26, 2010 to July 9th, 2010
3. Respond to comments on the 2nd posting.	July 2010 to October 2010
4. Obtain RSC approval to move the standard forward to balloting.	November 2010
5. Post the standard and implementation plan for a 30 day pre ballot review.	December 2010

6. Conduct a ten day ballot.	December 2010
7. Respond to ballot comments and post revised standard and implementation plan for a 45 day comment period.	May, 2011.
8. Respond to comments on the 3rd posting.	July 2011
9. Obtain RSC approval to move the standard forward to balloting.	August 2011
10. Post the standard and implementation plan for a 30 day pre ballot review.	August 2011
11. Conduct a ten day ballot.	September 2011
12. Membership Approval.	September 2011.

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the NERC Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the NPCC Glossary.

In the standards, defined terms are indicated with its first letter capitalized.

A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**
2. **Number:** PRC-006-NPCC-1
3. **Purpose:** To provide a regional reliability standard that ensures the development of an effective automatic underfrequency load shedding (UFLS) program in order to preserve the security and integrity of the bulk power system during declining system frequency events in coordination with the NERC UFLS reliability standard characteristics.
4. **Applicability:**
   - **4.1.** Generator Owner
   - **4.2.** Planning Coordinator
   - **4.3.** Distribution Provider
   - **4.4.** Transmission Owner
5. **(Proposed) Effective Date:** To be established.

B. Requirements

R1 Each Planning Coordinator shall establish requirements for entities aggregating their UFLS programs for each anticipated island and requirements for compensatory load shedding based on islanding criteria (required by the NERC PRC Standard on UFLS). [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

R2 Each Planning Coordinator shall, within 30 days of completion of its system studies required by the NERC PRC Standard on UFLS, identify to the Regional Entity the generation facilities within its Planning Coordinator Area necessary to support the UFLS program performance characteristics. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

R3 Each Planning Coordinator shall provide to the Transmission Owner, Distribution Provider, and Generator Owner within 30 days upon written request the requirements for entities aggregating the UFLS programs and requirements for compensatory load shedding program derived from each Planning Coordinator's system studies as determined by Requirement R1. [Violation Risk Factor: Low] [Time Horizon: Long Term Planning]

R4 Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall implement an automatic UFLS program reflecting normal operating conditions excluding outages for its Facilities based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3, or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1 and acting as a single entity, provide an aggregated automatic UFLS program that sheds their coincident peak aggregated net Load, based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R5 Each Distribution Provider or Transmission Owner that must arm its load to trip on underfrequency in order to meet its requirements as specified and by doing so exceeds the tolerances and/or deviates from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Requirement R4 above, as applicable depending on its total peak net Load shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

5.1 Inform its Planning Coordinator of the need to exceed the stated tolerances or the number of stages as shown in UFLS Attachment C, Table 1 if applicable and

5.2 Provide its Planning Coordinator with a technical study that demonstrates that the Distribution Providers or Transmission Owners specific deviations from the requirements of UFLS Attachment C, Table 1 will not have a significant adverse impact on the bulk power system.

5.3 Inform its Planning Coordinator of the need to exceed the stated tolerances of UFLS Attachment C, Table 2 or Table 3, and in the case of Attachment C, Table 2 only, the need to deviate from providing two stages of UFLS, if applicable, and

5.4 Provide its Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or Transmission Owner to comply with UFLS Attachment C Table 2 or Attachment C Table 3.

R6 Each Distribution Provider and Transmission Owner in the Québec Interconnection portion of NPCC shall implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4 or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R7 Each Distribution Provider and Transmission Owner shall set each underfrequency relay that is part of its region's UFLS program with the following minimum time delay:

7.1 Eastern Interconnection – 100 ms

7.2 Québec Interconnection – 200 ms

[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R8 Each Planning Coordinator shall develop and review once per calendar year settings for inhibit thresholds (such as but not limited to voltage, current and time) to be utilized within its region's UFLS program. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

R9 Each Planning Coordinator shall provide each Transmission Owner and Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds within 30 days of the initial determination of those inhibit thresholds and within 30 days of any changes to those thresholds. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

R10 Each Distribution Provider and Transmission Owner shall implement the inhibit threshold settings based on the notification provided by the Planning Coordinator in accordance with Requirement R9. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

R11 Each Distribution Provider and Transmission Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with R9. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

R12 Each Transmission Owner and Distribution Provider shall annually provide documentation, with no more than 15 months between updates, to its Planning Coordinator of the actual net Load that would have been shed by the UFLS relays at each UFLS stage coincident with their integrated hourly peak net Load during the previous year, as determined by measuring actual metered Load through the switches that would be opened by the UFLS relays. [Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]

R13 Each Generator Owner shall set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted in Requirements R16 and R19. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R14 Each Generator Owner shall transmit the generator underfrequency trip setting and time delay to its Planning Coordinator within 45 days of the Planning Coordinator's request. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

R15 Each Generator Owner with a new generating unit, scheduled to be in service on or after the effective date of this Standard, or an existing generator increasing its net capability by greater than 10% shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

15.1 Design measures to prevent the generating unit from tripping directly or indirectly for underfrequency conditions above the appropriate generator tripping threshold curve in Figure 1.

15.2 Design auxiliary system(s) or devices used for the control and protection of auxiliary system(s), necessary for the generating unit operation such that they will not trip the generating unit during underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1.

R16 Each Generator Owner of existing non-nuclear units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1 shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

16.1 Set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations.

16.2 Transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinator.

16.3 Have compensatory load shedding, as provided by a Distribution Provider or Transmission Owner that is adequate to compensate for the loss of their generator due to early tripping.

R17 Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall apply the criteria described in Attachment A to determine the compensatory load shedding that is required in Requirement R17.3 for generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R18 Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall apply the criteria described in Attachment B to determine the compensatory load shedding that is required in Requirement R17.3 for generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R19 Each Generator Owner of existing nuclear generating plants with units that have underfrequency relay threshold settings above the Eastern Interconnection generator tripping curve in Figure 1, based on their licensing design basis, shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

19.1 Set the underfrequency protection to operate at as low a frequency as possible in accordance with the plant design and licensing limitations but not greater than 57.8Hz.

19.2 Set the frequency trip setting upper tolerance to no greater than + 0.1 Hz.

19.3 Transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the Planning Coordinator.

R20 The Planning Coordinator shall update its UFLS program database as specified by the NERC PRC Standard on UFLS. This database shall include the following information: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

20.1 For each UFLS relay, including those used for compensatory load shedding, the amount and location of load shed at peak, the corresponding frequency threshold and time delay settings.

20.2 The buses at which the Load is modeled in the NPCC library power flow case.

20.3 A list of all generating units that may be tripped for underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, including the frequency trip threshold and time delay for each protection system.

20.4 The location and amount of additional elements to be switched for voltage control that are coordinated with UFLS program tripping.

20.5 A list of all UFLS relay inhibit functions along with the corresponding settings and locations of these relays.

R21 Each Planning Coordinator shall notify each Distribution Provider, Transmission Owner, and Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program performance characteristics as specified by the NERC PRC Standard on UFLS.[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R22 Each Distribution Provider, Transmission Owner and Generator Owner shall implement the load distribution changes based on the notification provided by the Planning Coordinator in accordance with Requirement R21. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R23 Each Distribution Provider, Transmission Owner and Generator Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with Requirement R21. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

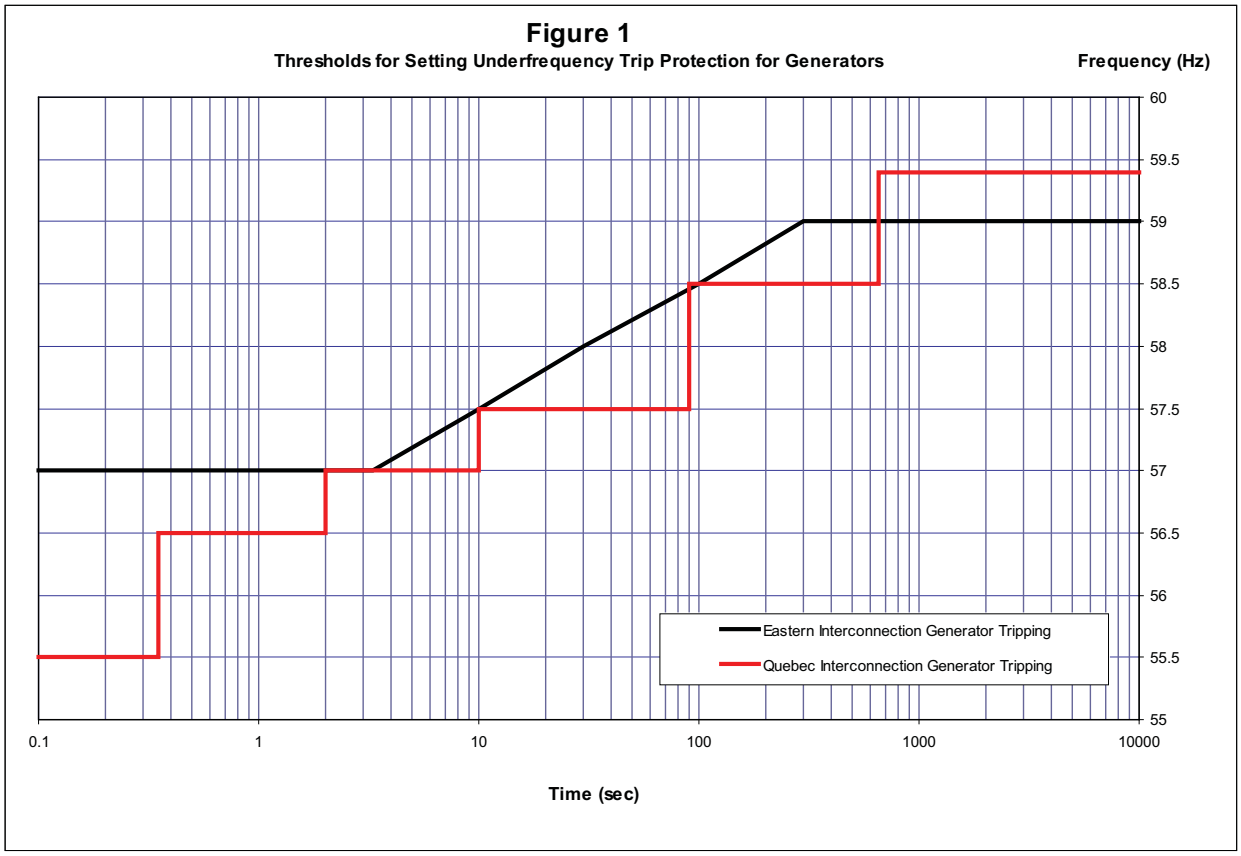
Figure 1
Thresholds for Setting Underfrequency Trip Protection for Generators
Frequency (Hz)
60
59.5
59
58.5
58
57.5
57
56.5
56
55.5
55
0.1
1
10
100
1000
10000
Time (sec)
Eastern Interconnection Generator Tripping
Quebec Interconnection Generator Tripping

C. Measures

M1 Each Planning Coordinator shall have evidence such as reports, system studies and/or real time power flow data captured from actual system events and other dated documentation that demonstrates it meets Requirement R1.

M2. Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets requirement R2.

M3 Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets Requirement R3.

M4 Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall have evidence such as documentation or reports containing the location and amount of load to be tripped, and the corresponding frequency thresholds, on those circuits included in its UFLS program to achieve the individual and cumulative percentages identified in Requirement R4. (Attachment C Tables 1-3).

M5 Each Distribution Provider or Transmission Owner shall have evidence such as reports, analysis, system studies and dated documentation that demonstrates that it meets Requirement R5.

M6 Each Distribution Provider and Transmission Owner in the Québec Interconnection shall have evidence such as documentation or reports containing the location and amount of load to be tripped and the corresponding frequency thresholds on those circuits included in its UFLS program to achieve the load values identified in Table 4 of Requirement R6. (Attachment C Table 4).

M7 Each Distribution Provider and Transmission Owner shall have evidence such as documentation or reports that their underfrequency relays have been set with the minimum time delay, in accordance with Requirement R7.

M8 Each Planning Coordinator shall have evidence such as reports, system studies or analysis that demonstrates that it meets Requirement R8.

M9 Each Planning Coordinator shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R9.

M10 Each Distribution Provider and Transmission Owner shall provide evidence such as test reports, data sheets or other documentation that demonstrates that it meets Requirement R10.

M11 Each Distribution Provider and Transmission Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates that it meets Requirement R11.

M12 Each Distribution Provider and Transmission Owner shall provide evidence such as reports, spreadsheets or other dated documentation submitted to its Planning Coordinator that indicates the frequency set point, the net amount of load shed and the percentage of its peak load at each stage of its UFLS program coincident with the integrated hourly peak of the previous year that demonstrates that it meets Requirement R12.

M13 Each Generator Owner shall provide evidence such as reports, data sheets, spreadsheets or other documentation that demonstrates that it meets Requirement R13.

M14 Each Generator Owner shall provide evidence such as emails, letters or other dated documentation that demonstrates that it meets Requirement R14.

M15 Each Generator Owner shall provide evidence such as reports, data sheets, specifications, memorandum or other documentation that demonstrates that it meets Requirement R15.

M16 Each Generator Owner with existing non-nuclear units in service prior to the effective date of this Standard which have underfrequency tripping that is not compliant with Requirement R13 shall provide evidence such as reports, spreadsheets, memorandum or dated documentation demonstrating that it meets Requirement R16.

M17 Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall provide evidence such as emails, memorandum or other documentation that demonstrates that it followed the methodology described in Attachment A and meets Requirement R17.

M18 Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall provide evidence such as emails, memorandum, or other documentation that demonstrates that it followed the methodology described in Attachment B and meets Requirement R18.

M19 Each Generator Owner of nuclear units that have been specifically identified by NPCC as having generator trip settings above the generator trip curve in Figure 1 shall provide evidence such as letters, reports and dated documentation that demonstrates that it meets Requirement R19.

M20 Each Planning Coordinator shall provide evidence such as spreadsheets, system studies, or other documentation that demonstrates that it meets the requirements of Requirement R20.

M21 Each Planning Coordinator shall provide evidence such as emails, memorandum or other dated documentation that it meets Requirement R21.

M22 Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as reports, spreadsheets or other documentation that demonstrates that it meets Requirement R22.

M23 Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates it meets Requirement 23.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

NPCC Compliance Committee

1.2. Compliance Monitoring Period and Reset Time Frame

Not Applicable

1.3. Data Retention

The Distribution Provider and Transmission Owner shall keep evidences for three calendar years for Measures 4, 5, 6,7,10, 11, and 12.

The Planning Coordinator shall keep evidence for three calendar years for Measures 1, 2, 3, 8, 9, 20, and 21.

The Planning Coordinator in Ontario, Quebec, and the Maritime Provinces shall keep evidence for three calendar years for Measure 17.

The Distribution Provider, Transmission Owner, and Generator Owner shall keep evidences for three calendar years for Measures 18, 22, and 23.

The Generator Owner shall keep evidence for three calendar years for Measures 13, 14, 15, 16, and 19.

1.4. Compliance Monitoring and Assessment Processes

Self -Certifications.

Spot Checking.

Compliance Audits.

Self- Reporting.

Compliance Violation Investigations.

Complaints.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	**N/A**	Planning Coordinator did not establish requirements for entities aggregating their UFLS programs. or Did not establish requirements for compensatory load shedding.	Planning Coordinator did not establish requirements for entities aggregating their UFLS programs and did not establish requirements for compensatory load shedding.
R2	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 30 days but less than 41 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 40 days but less than 51 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 50 days but less than 61 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 60 days after completion of the system studies. or The Planning Coordinator did not identify the generation facilities within its Planning Coordinator Area necessary to support the UFLS program.
R3	The Planning Coordinator provided the requested information, but did so more than 30 days but less than 41 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 40 days but less than 51 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 50 days but less than 61 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 60 days after the request. or The Planning Coordinator failed to provide the requested information.

R4	N/A	N/A	N/A	The Distribution Provider or Transmission Owner failed to implement an automatic UFLS program reflecting normal operating conditions excluding outages, for its Facilities or collectively implemented by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on frequency thresholds, total nominal operating time, and amounts specified in the appropriate included tables.
R5	N/A	The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not inform the Planning Coordinator of the need to exceed the stated tolerances of UFLS Table 2 or Table 3, and in the case of Table	The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not provide the Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or	The Distribution Provider or Transmission Owner did not arm its load to trip on underfrequency in order to meet its minimum obligations and in doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load.

		2 only, the need to deviate from providing two stages of UFLS.	Transmission Owner to comply with the appropriate table.	
R6	N/A	N/A	T	The Distribution Provider or Transmission Owner in the Québec Interconnection portion of NPCC did not implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4 or did not collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4.
R7	N/A	N/A	N/A	The Distribution Provider or Transmission Owner failed to set

				an underfrequency relay that is part of its region's UFLS program as specified in Requirement R7.
R8		N/A	The Planning Coordinator developed inhibit thresholds as specified in Requirement R8 but did not perform the review once per calendar year.	The Planning Coordinator did not develop inhibit thresholds as specified in Requirement R8.
R9	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 30 days but less than 41 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 40 days but less than 51 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 50 days but less than 61 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 60 days after the initial determination or any subsequent change to the inhibit thresholds. or The Planning Coordinator did not provide to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds.
R10	N/A	N/A	N/A	The Distribution Provider or Transmission Owner did not implement the inhibit threshold based on the notification provided by the Planning Coordinator in accordance with Requirement R9.

R11	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator. or The Distribution Provider or Transmission Owner did not develop its implementation plan.
R12				The Transmission Owner or Distribution Provider did not provide documentation to its Planning Coordinator of actual net load data or updates to the data that would be shed by the UFLS relays, as determined by measuring actual metered load through the switches that would be opened by the UFLS relays, that were armed to shed at each UFLS stage coincident with their integrated hourly peak during the previous year.
R13	N/A	N/A	N/A	The Generator Owner did not set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted.

R14	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 45 days and less than 56 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 55 days and less than 66 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 65 days and less than 76 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 75days after the Planning Coordinator's request. or The Generator Owner did not transmit the generator underfrequency trip setting and time delay to its Planning Coordinator.
R15	N/A	N/A	The Generator Owner did not fulfill the obligation of Requirement R15; Part 15.1 OR did not fulfill the obligation of Requirement R15, Part 15.2.	The Generator Owner did not fulfill the obligation of Requirement R15, Part 15.1 and did not fulfill the obligation of Requirement R15, Part 15.2.
R16	N/A	The Generator Owner did not fulfill the obligation of Requirement R16, Part 16.2.	The Generator Owner did not fulfill the obligation of Requirement R16; Part 16.1 OR did not fulfill the obligation of Requirement R16, Part 16.3.	The Generator Owner did not fulfill the obligation of Requirement R16, Part 16.1 and did not fulfill the obligation of Requirement R16, Part 16.3.

R17	N/A	N/A	N/A	The Planning Coordinator did not apply the methodology described in Attachment A to determine the compensatory load shedding that is required.
R18	N/A	N/A	N/A	The Generator Owner, Distribution Provider, or Transmission Owner did not apply the methodology described in Attachment B to determine the compensatory load shedding that is required.
R19	N/A	The Generator Owner did not fulfill the obligation of Requirement R19, Part 19.3.	The Generator Owner did not fulfill the obligation of Requirement R19; Part 19.1 OR did not fulfill the obligation of Requirement R19, Part 19.2.	The Generator Owner did not fulfill the obligation of Requirement R19, Part 19.1 and did not fulfill the obligation of Requirement R19, Part 19.2.
R20	The Planning Coordinator did not have data in its database for one of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for two of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for three of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for four or more of the parameters listed in Requirement 20, Parts 20.1 through 20.5.

R21	N/A	N/A	N/A	The Planning Coordinator did not notify a Distribution Provider, Transmission Owner, or Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program requirements.
R22	N/A	N/A	N/A	The Distribution Provider, Transmission Owner, or Generator Owner did not implement the load distribution changes based on the notification provided by the Planning Coordinator.
R23	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator. or The Distribution Provider. Transmission Owner or Generator Owner did not develop its implementation plan.

PRC-006-NPCC-1 Attachment A

Compensatory Load Shedding Criteria for Ontario, Quebec, and the Maritime Provinces:

The Planning Coordinator in Ontario, Quebec and the Maritime provinces is responsible for establishing the compensatory load shedding requirements for all existing non-nuclear units in its NPCC area with underfrequency protections set to trip above the appropriate curve in Figure 1. In addition, it is the Planning Coordinator's responsibility to communicate these requirements to the appropriate Distribution Provider or Transmission Owner and to ensure that adequate compensatory load shedding is provided in all islands identified in Requirement R1 in which the unit may operate.

The methodology below provides a set of criteria for the Planning Coordinator to follow for determining compensatory load shedding requirements:

1. The Planning Coordinator shall identify, compile and maintain an updated list of all existing non-nuclear generating units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1. The list shall include the following information for each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 All islands within which the unit may operate, as identified in Requirement R1

2. For each generating unit identified in (1) above, the Planning Coordinator shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 Arrange for a Distribution Provider or Transmission Owner that owns UFLS relays within the island(s) identified by the Planning Coordinator in Requirement R1 within which the generator may operate to provide compensatory load shedding.

    2.2 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4..

    2.3 The compensatory load shedding shall be provided at the UFLS program stage (or threshold stage for Quebec) with a frequency threshold setting that corresponds to the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1 during an underfrequency event. If the highest

frequency at which the subject generator will trip above the appropriate curve in Figure 1 does not correspond to a specific UFLS program stage threshold setting, the compensatory load shedding shall be provided at the UFLS program stage with a frequency threshold setting that is higher than the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1.

2.4 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-1 Attachment B

Compensatory Load Shedding Criteria for ISO-NE and NYISO:

The Generator Owner in the New England states or New York State are responsible for establishing a compensatory load shedding program for all existing non-nuclear units with underfrequency protection set to trip above the appropriate curve in Figure 1 of this standard. The Generator Owner shall follow the methodology below to determine compensatory load shedding requirements:

1. The Generator Owner shall identify and compile a list of all existing non-nuclear generating units in service prior to the effective date of this standard that has underfrequency protection set to trip above the appropriate curve in Figure 1. The list shall include the following information associated with each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 Smallest island within which the unit may operate as identified by the Planning Coordinator in Requirement R1 of this Standard.

2. For each generating unit identified in (1) above, the Generator Owner shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 In cases where a Distribution Provider or Transmission Owner has coordinated protection settings with the Generator Owner to cause the generator to trip above the appropriate curve in Figure 1, the Distribution Provider or Transmission Owner is responsible to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

    2.2 In cases where a Generator Owner has a generator that cannot physically meet the set points defined by the appropriate curve in Figure 1, the Generator Owner shall arrange for a Distribution Provider or Transmission Owner to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

    2.3 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4.

2.4 The compensatory load shedding shall be provided at the UFLS program stage with the frequency threshold setting at or closest to but above the frequency at which the subject generator will trip.

2.5 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-1 Attachment C

UFLS Table 1: Eastern Interconnection

Distribution Providers and Transmission Owners with 100 MW or more of peak net Load shall implement a UFLS program with the following attributes:

Frequency Threshold (Hz)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
59.5	0.30	6.5 – 7.5	6.5 – 7.5
59.3	0.30	6.5 – 7.5	13.5 – 14.5
59.1	0.30	6.5 – 7.5	20.5 – 21.5
58.9	0.30	6.5 – 7.5	27.5 – 28.5
59.5	10.0	2 – 3	29.5 – 31.5

UFLS Table 2: Eastern Interconnection

Distribution Providers and Transmission Owners with 50 MW or more and less than 100 MW of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time(s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	14-25	14-25
2	59.1	0.30	14-25	28-50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

UFLS Table 3: Eastern Interconnection

Distribution Providers and Transmission Owners with 25 MW or more and less than 50 MW of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	28-50	28-50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

UFLS Table 4: Quebec Interconnection

	Rate	Frequency (Hz)	MW at peak (*Load must be fixed at all times.)	Mvar at peak	Total Nominal Operating Time (s) [2]
Threshold Stage 1	——	58.5	1000*	1000	0.30
Threshold Stage 2	——	58.0	800*	800	0.30
Threshold Stage 3	——	57.5	800	800	0.30
Threshold Stage 4	——	57.0	800	800	0.30
Threshold Stage 5 (anti-stall)	——	59.0	500	500	20.0
Slope Stage 1	-0.3 Hz/s	58.5	400	400	0.30
Slope Stage 2	-0.4 Hz/s	59.8	800*	800	0.30
Slope Stage 3	-0.6 Hz/s	59.8	800*	800	0.30
Slope Stage 4	-0.9 Hz/s	59.8	800	800	0.30

2. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communications time, and the rated breaker interrupting time. The underfrequency relay operating time shall be measured from the time when the frequency passes through the frequency threshold set point.

Regional Standards Committee--- Authorization to Post Cl

Transmission Owners			Y	N
David Kiguel	Hydro One	416-345-5313	**X**	
Chris de Graffenried	Con Ed	212-460-2925	**X**	
Mike Schviavone	Natl Grid	315-460-2472	**X**	
Randy Mac Donald	NB	506-458-4653	**X**	
Robert Pellegrini	UI	203-499-2413	Left Phone Message/Sent Email	
Sylvain Clermont	HQ	514-879-4648	Left Phone Message/Sent Email	
Mike Lombardi	NU	860-665-6619	**X**	
Ben Wu	O&R	845-577-3713	Left Phone Message/Sent Email	

EAP and Pre Ballot for UFLS PRC -006-01

			Regional St
Reliability Coordinators			Y
Don Weaver	NB	506-458-4640	**X**
Greg Campoli	NYISO	518-356-6159	**X**
Kathleen Goodman	ISO NE	413-535-4111	Left Phone
Si Truc Phan	HQ	514-879-4100	Bad Numbe
Tina Teng	IESO	905 855 6282 (KC)	Left Phone
Kurtis Chong	IESO	905-855-6282	Left Phone

andards Committee--- Authorization to Post CEAP and Pre Ballot for UFLS PRC -006-01

N

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			Regional St
LSE			Y
Peter Yost	Con Ed	212-460-2889	**X**
Saurabh Saksena	Natl Grid	781-907-3226	Left Phone

andards Committee--- Authorization to Post CEAP and Pre Ballot for UFLS PRC -006-01

N

Message/Sent Email

			Regional St
GO			Y
Wayne Sipperly	NYPA	914-287-3753	**X**
Mike Garton	Dominion	804-819-2336	**X**
David Ramkalawan	OPG	416-592-6089	**X**
Chantel Haswell	FPL	561-694-3129	Requested

andards Committee--- Authorization to Post CEAP and Pre Ballot for UFLS PRC -006-01

N

Vote

			Regional St
Marketers			Y
Bruce Metruck	NYPA	315-792-8213	**X**
Brian Evans Mongeon	US	802-552-4022	**X**

andards Committee--- Authorization to Post CEAP and Pre Ballot for UFLS PRC -006-01

N

			Regional St
State			Y
Diane Barney	NYPSC	518-486-2943	Did Not Co

andards Committee--- Authorization to Post CEAP and Pre Ballot for UFLS PRC -006-01

N

ntact…non voting Member

			Regional St
Sub Regions			Y
Al Adamson	NYSRC	518-355-1937	Did Not Co

andards Committee--- Authorization to Post CEAP and Pre Ballot for UFLS PRC -006-01

N

ntact…non voting Member

NPCC, Inc.
NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

PRC-006-NPCC-1 Automatic Underfrequency Load Shedding

Implementation Plan

Background:

The purpose of this draft Regional Standard is to ensure the development and maintenance of an effective and coordinated Automatic Underfrequency Load Shedding program in order to preserve the reliability and integrity of the bulk power system during declining system frequency events.

In the developing the Implementation Plan for PRC-006-NPCC-01 the Standard Drafting Team considered the following:

1. The requirements listed in this Regional Standard are intended to cover all aspects of the UFLS program. The Regional Standard Drafting Team (RSDT) coordinated its development with the draft NERC UFLS Standard PRC-006. The intent of this Regional Standard is to be more stringent than the continent wide standard while incorporating specific program characteristics into the requirements.
2. The Implementation Plan for this standard is based, in part, on the timelines reflected in the existing and ongoing Implementation Plan for NPCC Directory #12 absent the annual milestones required by Directory #12.

Effective Dates:

Eastern Interconnection & Québec Interconnection Portions of NPCC Excluding the Independent Electricity System Operator (IESO) Planning Coordinator Area of NPCC in Ontario, Canada.

1. The effective date for requirements R1, R2, R3, R4, R5, R6, and R7 is the first day of the first calendar quarter following applicable regulatory approval but no earlier than Jan 1, 2016 to allow for the existing implementation plan to be completed.

2. The effective date for requirements R8 through R23 is the first day of the first calendar quarter two years following applicable governmental and regulatory approval.

Independent Electricity System Operator (IESO) Planning Coordinator's Area of NPCC in Ontario, Canada

1. Effective the first day of the first calendar quarter following applicable governmental and regulatory approval but no earlier than April 1, 2017.

References:

- 2006 Assessment of UFLS Adequacy Part 3 Assessment of Program Modifications.
- SS38 Underfrequency Load Shedding Support Studies

NPCC Criteria:

- Directory #12 Underfrequency Load Shedding Program Requirements.
- A-7 NPCC Glossary of Terms.

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October 3, 2011

NPCC Full and General Members;

Please find attached a draft of the NPCC Regional Standard PRC-006-NPCC-1 *Automatic Underfrequency Load Shedding* which has been posted to the NPCC Website for a 30 day pre-ballot review until November 2, 2011.

The Task Force on System Studies (TFSS) and the Reliability Coordinating Council (RCC) has each endorsed this draft and on September 30, 2011 the Regional Standards Committee (RSC) authorized a 30 day pre-ballot review and subsequent ballot period.

A separate notification will be provided to NPCC Members announcing the start of the formal 10 day ballot period.

This Standard has been developed in accordance with the FERC approved NPCC Regional Standard Development Procedure.

Additionally, and in order to facilitate the approval of this standard by the ERO, NERC requested NPCC Staff to submit the Standard to a Quality Review. The focus of this review eliminated instances of potential double jeopardy with the NERC PRC Standard and other clarifications to facilitate compliance.

Also attached and posted on the NPCC Website are the draft Implementation Plan and the UFLS Regional Standard Drafting Team's Responses to Comments from the third posting of the Standard.

The draft Standard and its supporting documents may be viewed at:

https://www.npcc.org/Standards/SitePages/DevStandardDetail.aspx?DevDocumentId=4

Note that the Cost Effectiveness Questions for PRC-006-NPCC-1 have also been posted on the NPCC Website Standards - Regional Standards General:

https://www.npcc.org/Standards/Regional%20Standards%20General/Forms/Public%20List.aspx

All responses to the Cost Effectiveness questions will be held individually confidential and aggregated to provide the industry with raw total cost effectiveness information for the standard's ballot. Send your responses via E-mail to NPCCstandard@npcc.org by Nov. 2, 2011.

Please contact me with any questions regarding content or the NPCC Regional Standard Development Procedure.

Respectfully,

Guy V. Zito
Asst. Vice President-Standards, Chair Regional Standards Committee
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10th Floor
New York, NY 10018
212-840-1070

Information in a Regional Standard Authorization Request (RSAR)

The tables below identify information to be submitted in a Regional Standard Authorization Request to the NPCC Regional Standards Process Manager, NPCCstandard@npcc.org . The NPCC Regional Standards Process Manager shall be responsible for implementing and maintaining this form as needed to support the information requirements of the standards process.

Regional Standard Authorization Request Form

Title of Proposed Standard:	Regional Reserve Sharing
Request Date:	November 1, 2010

RSAR Requester Information

		RSAR Type (Check box for one of these selections.)	
Name:	Lee Pedowicz		
Company:	Northeast Power Coordinating Council	☒	New Standard
Telephone:	212-840-1070	☐	Revision to Existing Standard
Fax:	212-302-2782	☐	Withdrawal of Existing Standard
Email:	lpedowicz@npcc.org	☐	Urgent Action

Purpose (Describe the purpose of the proposed standard – what the standard will achieve in support of reliability.**)** The purpose of this standard is to establish the requirements for Balancing Authorities within NPCC that participate in Reserve Sharing Groups to assist each other in meeting their reserve obligations, and to satisfy the requirements of NERC Standard BAL-002 Disturbance Control Performance.
Industry Need (Provide a detailed statement justifying the need for the proposed standard, along with any supporting documentation**.)** A Reserve Sharing Group is intended to maintain, allocate and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. This standard will establish the NPCC requirements for Balancing Authorities that participate in the NPCC Regional Reserve Sharing Group to assist each other in meeting their ten minute reserve requirement, and to utilize their contingency reserves to balance resources and demand, and to return the Interconnection frequency to within defined limits following a reportable disturbance.
Brief Description (Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.**)** This Standard will define the requirements for: • Balancing Authority registration • power contribution during events requiring Regional Reserve Sharing • Balancing Authority reporting • physical deliverability • the Regional Reserve Sharing Coordinator • requesting assistance

Reliability Functions

The Standard will Apply to the Following Functions (Check all applicable boxes.)		
☐	Reliability Coordinator	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
☒	Balancing Authority	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules.

☐	Planning Authority	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
☐	Transmission Service Provider	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.
☐	Transmission Owner	The entity that owns and maintains transmission facilities.
☐	Transmission Operator	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.
☐	Transmission Planner	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.
☐	Resource Planner	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.
☐	Generator Operator	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
☐	Generator Owner	Entity that owns and maintains generating units.
☐	Purchasing-Selling Entity	The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.
☐	Distribution Provider	Provides and operates the "wires" between the transmission system and the customer.
☐	Load-Serving Entity	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check all boxes that apply.)*	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.
☒	5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.
☒	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.
Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*	
Recognizing that reliability is an Common Attribute of a robust North American economy:	
1. A reliability standard shall not give any market participant an unfair competitive advantage.Yes	
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes	
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes	
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes	

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft a standard based on this description.)

This Standard shall specify the requirements for Balancing Authorities that participate in the NPCC Reserve Sharing Group by:

- mandating Regional Reserve Sharing Group registration
- having TFCO approve participant registration, and the registration of the Regional Reserve Sharing Coordinator
- defining a participant Balancing Authority's contribution towards its ten minute reserve requirement
- defining that Regional Reserve Sharing Energy is available in predetermined blocks
- stipulating the information that a Balancing Authority must report
- defining the Regional Reliability Sharing Energy parameters for use by the Regional Reserve Sharing Coordinator
- having the contingent Balancing Authority request Regional Reliability Standard assistance, and the Regional Reserve Sharing Coordinator's response
- specifying the actions required by the Reserve Sharing Coordinator, and the Balancing Authorities upon termination of the Regional Reserve Sharing Energy implementation
- addressing actions to be taken should contingencies occur when Regional Reserve Sharing is in progress

The RRS Participation Form will be included as an appendix.

Related Standards

Standard No.	Explanation
BAL-002-1	Disturbance Control Performance

-t

Related SARs or RSARs

SAR ID	Explanation

From: Barbara Nutter
To: Lee R. Pedowicz
Subject: FW: NERC Announcement: BAL-002-NPCC-01 Regional Reserve Sharing Groups - Nomination Period Open
Date: Tuesday, October 18, 2011 10:19:35 AM
Importance: High

From: Wendy Sandberg
Sent: Tuesday, October 18, 2011 10:13 AM
To: Wendy Sandberg
Subject: NERC Announcement: BAL-002-NPCC-01 Regional Reserve Sharing Groups - Nomination Period Open
Importance: High

Regional Reliability Standards Announcement

BAL-002-NPCC-01 Regional Reserve Sharing Groups – Nomination Period Open

October 12 – November 10, 2011

NPCC has begun the development of BAL-002-NPCC-01, Regional Reserve Sharing Groups. At the November 30, 2010 meeting of the NPCC Reliability Coordinating Committee, the NPCC Task Force on Coordination of Operation was charged as the lead Task Force responsible for drafting this standard. In accordance with the NPCC Regional Reliability Standards Development Procedure, NPCC is soliciting for any *additional* interested candidates to assist with the drafting of the standard. The anticipated workload is 4-6 "in-person" meetings and 4-6 teleconferences. The Regional Standards Committee (RSC) will review additional qualified candidates who self nominate and NPCC will notify the nominees in December, 2011 of the RSC determination.

If you are interested in serving on this drafting team, please complete this nomination form **by November 10, 2011**.

Further details are included on the NPCC page:
BAL-002-NPCC-01 - Regional Reserve Sharing Groups

Regional Reliability Standards Development Procedure
The NPCC Regional Reliability Standards Development Procedure contains all the procedures governing the NPCC regional standards development process. The success of the Regional standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Howard Gugel (via email) or at (609) 651-2269 or Wendy Sandberg (via email) or at (404) 446-9735.

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From:	Lee R. Pedowicz
To:	general
Cc:	grpStaff; tfco-all; rscmembers; rsg; donald.e.nelson@state.ma.us; rjfalsetti@cogeco.ca
Subject:	Solicitation for additional NPCC Regional Standard Drafting Team Members for "Regional Reserve Sharing Groups", BAL-002-NPCC-01
Date:	Wednesday, October 12, 2011 11:50:00 AM
Attachments:	NPCC DT Self NominationFormRRSG--10-12-11.doc
Importance:	High

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

October 12, 2011

Subject: Solicitation for additional NPCC Regional Standard Drafting Team Members for Regional Reserve Sharing Groups BAL-002-NPCC-01

Dear Sir/Madam,

NPCC has begun the development of the subject Regional Standard. At the November 30, 2010 meeting of the NPCC Reliability Coordinating Committee, the NPCC Task Force on Coordination of Operation was charged as the lead Task Force responsible for drafting this standard. In accordance with the NPCC Regional Reliability Standards Development Procedure, NPCC is soliciting for any *additional* interested candidates to assist with the drafting of the standard. The anticipated workload is 4-6 "in-person" meetings and 4-6 teleconferences. Attached is a self nomination form to be completed and returned by any interested persons no later than November 11, 2011. The Regional Standards Committee (RSC) will review additional qualified candidates who self nominate and NPCC will notify the nominees in December, 2011 of the RSC determination. Please distribute this email to any potential interested candidates. This information will also be posted on the NPCC Website.

Sincerely,

Lee Pedowicz
Manager, Reliability Standards
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New York, NY 10018
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(212) 302-2782 FAX

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
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October 26th, 2011

Members Regional Standards Committee

Re: NPCC Glossary of Terms

Ladies and Gentlemen:

A new NPCC Glossary of Terms has been developed from the existing *NPCC A7 Glossary of Terms* document and is presented to the Regional Standards Committee (RSC) for approval.

The new *Glossary of Terms* is intended to be a repository of all NPCC defined terms and was translated from the A7 Glossary which will be retired.

The Glossary was posted to the NPCC Open Process from July 28th, 2011 through Sept. 12, 2011and all comments have been addressed by NPCC Staff. The new Glossary replicates all terms currently found in the A7 and none of the A7 definitions have been changed. However, during the Open Process NPCC received suggestions on the organization and formatting of the Glossary and several of these suggestions have been adopted.

The Glossary is organized into two sections, one containing all terms used within NPCC Directories and a second section containing all remaining terms found in the existing A7document but not used in any Directories.

Additionally, and within each of the Glossary's sections, terms that are defined differently in the NERC Glossary have been highlighted.

A significant difference between the new Glossary and the A7 will be the manner in which new or revised terms are approved. As described in the Directory Development Manual, the entire Glossary will no longer be subject to the Open Process to consider a new or revised term. Instead the process of establishing or revising a NPCC defined term will be considered a revision to the Directory in which the term resides in order to capture the context of its use within the document.

The development of the NPCC Glossary was based on Phase 1 of the NPCC Directory project, which involved initial translations of NPCC documents into Directory format. Ultimately and as part of Phase 2 of the project, NPCC Task Forces will be asked to review instances where two separate definitions (NERC and NPCC) exist to determine whether the NPCC definition is warranted and to address issues such as capitalizing instead of bolding within NPCC documents.

Accordingly, the *NPCC Glossary of Terms* is presented to the RSC for its consideration and approval.

Upon RSC approval the Glossary will be presented to the Reliability Coordinating Council (RCC) for information and posted on the Documents section of the NPCC website, after which the existing A7 Glossary will be retired.

Very truly yours,

Gerry Dunbar
Manager, Reliability Criteria
Northeast Power Coordinating Council, Inc.

cc: RSC, Regional Standards Committee

Note: Terms highlighted in blue are those that are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
Actual Interchange		Metered electric **power** that flows from one entity to another.	D5
Applicable emergency limits		These limits depend on the duration of the occurrence, and on the policy of the various member systems of NPCC regarding loss of life to equipment, voltage limitations, etc. **Emergency** limits are those which can be utilized for the time required to take corrective action, but in no case less than five minutes. The limiting condition for voltages should recognize that voltages should not drop below that required for suitable system **stability** performance, and should not adversely affect the operation of the **bulk power system**. The limiting condition for equipment loadings should be such that cascading outages will not occur due to operation of protective devices upon the failure of facilities. (Various definitions of equipment **ratings** are found elsewhere in this glossary.)	D1 D7
Area		An **Area** (when capitalized) refers to one of the following: New England, New York, Ontario, Quebec or the Maritimes (New Brunswick, Nova Scotia and Prince Edward Island); or, as the situation requires, area (lower case) may mean a part of a system or more than a single system. Within NPCC, Areas (capitalized) operate as **control areas** as defined by the North American Electric Reliability Council (NERC) (the definition can be found in this glossary).	D1 D7 D8 D12
Area Control Error	**ACE**	The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error. (Source: NERC Glossary of Terms)	D2 D5 D8

Term	Acronym	Definition	Directories that use this term
Automatic Generation Control	**AGC**	Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction. (Source: NERC Glossary of Terms)	D2 D5 D8
Basic Minimum Power System		Consists of one or more generating stations, transmission lines, and substations operating in the form of an island for the purpose of initiating the restoration process. The Reliability Coordinator and Transmission Operator shall each identify its area's basic minimum power system(s) within its system restoration plan.	D8
Bipolar		Operation of HVdc with two **poles** of opposite polarity with negligible ground current.	D1
Blackstart Capability		The ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering **power** without assistance from the electric system.	D8
Bulk Power System	**BPS**	The interconnected electrical systems within northeastern North America comprised of system **elements** on which **faults** or **disturbances** can have a **significant adverse impact** outside of the **local area.**	D1 D2 D3 D4 D7 D9 D10
Cable		An underground or underwater circuit.	D4 D5 D7 D8

Term	Acronym	Definition	Directories that use this term
Capacity		The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of **generation**, transmission, or other electrical equipment.	D1 D2 D5 D8
Commutation Failure		A fault in a thyristor valve group where the current transfer from one valve to the next is interrupted.	D4
Component		Refers to components of equipment or protection systems rather than **elements** of a **power** system. See **Element**.	D1 D3 D7
Contingency		An event, usually involving the loss of one or more **elements**, which affects the power system at least momentarily.	D1 D2 D5 D7
Converter		An operative unit comprised of either a rectifier or inverter bridge connected to an ac system through transformers and switching devices with the associated control equipment.	D4
Converter Transformer		A **power** transformer which transfers the energy from the thyristor valves to the connected ac system and vice-versa.	D4
Critical Components		Equipment required for continued and proper operation of a **key facility** in the event of a total loss of grid supply. Critical components include but are not limited to the following: ▪ blackstart generating units; ▪ substation backup power supplies; ▪ control center and telecommunication center backup power supplies and computer systems; ▪ control center and telecommunication center computer room HVAC; ▪ telecommunication facilities backup power supplies.	D8

Term	Acronym	Definition	Directories that use this term
Declared Capability (of a generator or generating facility)		The facility ratings submitted by the Generator Owner to the respective Transmission Operator as per NERC Standard FAC-009.	D10
Delayed Fault Clearing		Fault clearing consistent with correct operation of a breaker failure protection system and its associated breakers, or of a backup protection system with an intentional time delay. (Source: NERC Glossary of Terms)	D1
Demand		1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer. (Source: NERC Glossary of Terms)	D1 D5
Disturbance		Severe oscillations or severe step changes of current, voltage and/or frequency usually caused by **faults**.	D1 D2 D4 D5 D7
Disturbance Monitoring Equipment	**DME**	Devices capable of monitoring and recording system data pertaining to a Disturbance. Such devices include the following categories of recorders2 • Sequence of event recorders which record equipment response to the event; • Fault recorders, which record actual waveform data replicating the system primary voltages and currents. This may include protective relays; • Dynamic Disturbance Recorders (DDRs), which record incidents that portray power system behavior during dynamic events such as low-	D4

Term	Acronym	Definition	Directories that use this term
		frequency (0.1 Hz – 3 Hz) oscillations and abnormal frequency or voltage excursions (Source: NERC Glossary of Terms)	
Economic Dispatch		The allocation of demand to individual generating units on line to effect the most economical production of electricity. (Source: NERC Glossary of Terms)	D2
Element		Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components. (Source: NERC Glossary of Terms)	D1 D2 D4 D5 D7 D9 D10
Emergency		Any abnormal system condition that requires automatic or manual action to prevent or limit loss of transmission facilities or **generation** supply that could adversely affect the **reliability** of the electric system. NPCC Specific Definition: **Emergency** — An **Emergency** is considered to exist in an Area if **firm load** may have to be shed.	D1 D2 D4 D5 D7
Emergency Regional Reserve Redispatch		The regional coordination of actions to enhance **reliability** among **Areas** in response to a **Regional Reserve Deficiency.**	D5
Emergency Regional Reserve Dispatch Energy		Electrical energy that is received and delivered among **Areas** in response to a **Regional Reserve Deficiency** to enhance regional **reliability.**	D5
Emergency Transfer		The amount of **power** transfer allowed between **Areas** or within an **Area**	D2

Term	Acronym	Definition	Directories that use this term
Capability		when ope**rating** to meet NPCC **emergency** criteria contingencies [as defined in Directory #1].	
Energize		To make a piece of equipment or circuit alive.	D4
Fault		An electrical **short circuit**.	D1 D4 D7
Firm Capacity		Capacity that is as firm as the seller's native **load** unless modified by contract. Associated energy may or may not be taken at option of purchaser. Supporting **reserve** is carried by the seller.	D1
Firm Load		That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions. (Source: Firm Demand defined in NERC Glossary of Terms)	D1 D2
First Contingency Loss		The largest **capacity** outage including any assigned Ten-Minute Reserve which would result from the loss of a single **element.**	D5
Forced Outage		1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. 2. The condition in which the equipment is unavailable due to unanticipated failure. (Source: NERC Glossary of Terms)	D1
Generation (Electricity)		The process of producing electrical energy from other forms of energy; also, the amount of electric energy produced, usually expressed in kilowatthours (kWh) or megawatthours (MWh). Gross Generation — The electrical output at the terminals of the generator, usually expressed in megawatts (MW).	D1 D2 D4 (Appendix A) D5 D7 (Appendices) D12

Term	Acronym	Definition	Directories that use this term
		Net Generation — Gross generation minus station service or unit service **power** requirements, usually expressed in megawatts (MW).	
Generation Facility		Generating units, which are modeled as a single entity by the Transmission Operator.	D8 D9 D10
Generation Rejection		The process of deliberately removing preselected **generation** from a **power** system, or initiating HVdc power runback, in response to a **contingency** or an abnormal condition in order to maintain the integrity of the system. Synonym: Generator Dropping.	D1 D7
Gross Real Power Capability (of a generator or generating facility)		The maximum megawatt output at the generator terminals, at the normally expected system conditions for that seasonal capability period.	D9
Gross Reactive Power Capability (of a generator or generating facility)		The maximum lagging and leading reactive capability at the generator terminals and at a specified Gross Real Power output for a specific seasonal capability period.	D10
Grounded		Connected to earth or some extended conducting body that serves instead of the earth, whether the connection is intentional or accidental.	D4 D7
Harmonic		A sinusoidal component of a periodic wave or quantity having a frequency that is an integral multiple of the fundamental frequency. Note: For example, a component, the frequency of which is twice the fundamental frequency, is called a second harmonic.	D4
HVdc Link		A high Voltage direct current connection between two **power** systems often used to interconnect two asynchronous **power** systems.	D4
Inadvertent Interchange		The difference between the Balancing Authority's Net Actual Interchange and Net Scheduled Interchange. (IA – IS) (Source: NERC Glossary of Terms)	D5

Term	Acronym	Definition	Directories that use this term
Interconnection		When capitalized, any one of the five major electric system networks in North America: Eastern, Western, ERCOT, Québec, and Alaska. When not capitalized, the facilities that connect two systems or **Control Areas**. Additionally, an interconnection refers to the facilities that connect a nonutility generator to a **Control Area** or system.	D1 D2 D5 D8 D12
Interchange		Energy transfers that cross Balancing Authority boundaries. (Source: NERC Glossary of Terms)	D1 (Appendix B) D2 D5
Interchange Schedule		An agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction. (Source: NERC Glossary of Terms)	D1 D5
Interface		The specific set of transmission **elements** between two areas or between two areas comprising one or more electrical systems.	D1 (Appendices)
Interruptible Load		Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment. (Source: NERC Glossary of Terms)	D1 (Appendix D) D5
Island		A portion of a **power** system or several power systems that is electrically separated from the interconnection due to the disconnection of transmission system **elements.**	D1 D8 D12
Key Facilities		Facilities required to establish a **basic minimum power system** following a system blackout. These facilities are essential to the restoration plan of the **Control Area** and include generating stations having blackstart units and other selected generating stations, transmission **elements** which are	D8

Term	Acronym	Definition	Directories that use this term
		part of the **basic minimum power system,** control centers and telecommunication centers and telecommunication facilities which are necessary to support **protection** and control facilities, voice and data between and within control centers and voice and data between control centers and key generating / transmission substations.	
Load		An end-use device or customer that receives power from the electric system. (Source: NERC Glossary of Terms)	D1 D2 D3 D4 D5 D7 (Appendices) D8 D9 D10 D12
Load Relief		**Load** reduction accomplished by **voltage reduction** and/or **load shedding**.	D1
Load Shedding		The process of deliberately removing (either manually or automatically) preselected customers' **load** from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages.	D2 D3 D4 D12
Local area		An electrically confined or radial portion of the system. The geographic size and number of system elements contained will vary based on system characteristics. A local area may be relatively large geographically with relatively few buses in a sparse system, or be relatively small geographically with a relatively large number of buses in a densely networked system.	D1 D4

Term	Acronym	Definition	Directories that use this term
Maintenance Outage		The removal of equipment from service **availability** to perform work on specific **elements** that can be deferred, but requires the equipment be removed from service before the next planned outage. Typically, a Maintenance Outage may occur anytime during the year, have a flexible start date, and may or may not have a predetermined duration.	D1
Net Capacity		The maximum capacity (or effective **rating**), modified for ambient limitations, that a generating unit, **power** plant, or electric system can sustain over a specified period, less the capacity used to supply the **demand** of station service or auxiliary needs.	D1
Net Real Power Capability (of a generator or generating facility)		The Gross Real Power Capability, less the auxiliary real power loads necessary to operate the generator at maximum real power output.	D9
Net Reactive Power Capability (of a generator or generating facility)		The **Gross Reactive Power Capability** adjusted for any applicable losses and auxiliary loads incurred up to the point of interconnection and at a specified Gross Real Power output for a specific seasonal capability period.	D10
Normal Fault Clearing		Fault clearing consistent with correct operation of the **protection system** and with the correct operation of all circuit breakers or other automatic switching devices intended to operate in conjunction with that **protection system.**	D1
Normal (Precontingency) Operating Procedures		Operating procedures that are normally invoked by the **system operator** to alleviate potential facility overloads or other potential system problems in anticipation of a **contingency**.	D1 (Appendix F)
Normal Transfer Capability		The amount of **power** transfer allowed between **Areas** or within an **Area** when operating to meet NPCC normal criteria contingencies [as defined in Directory #1].	D1 D2
Operating Capability		The maximum load carrying ability of generating equipment or other electrical apparatus under specified conditions for a given time interval.	D9

Term	Acronym	Definition	Directories that use this term
Operating Limit		The maximum value of the most critical system operation parameter(s) which meet(s): (a) pre-**contingency** criteria as determined by equipment loading capability and acceptable voltage conditions; (b) **stability** criteria; (c) post-**contingency** loading and voltage criteria.	D1 (Appendix C) D2 D5
Operating Capacity		The **capacity** claimed for any generating source recognizing any temporary deratings, governor load limits, proven maximum loading rates, starting times and equipment limitations including transmission **operating limits**.	D5
Operating Procedures		A set of policies, practices, or system adjustments that may be automatically or manually implemented by the **system operator** within a specified time frame to maintain the operational integrity of the interconnected electric systems.	D1 D5 D7
Operating Reserve		The sum of **ten-minute** and **thirty-minute reserve**.	D1 D2
Phase Shifting Transformer		A transformer that advances or retards the phase angle relationship of one circuit with respect to another to control **power** flow. Synonyms: Phase angle regulator, phase shifter.	D1 D2 D4
Pilot Protection		A form of line protection that uses a communication channel as a means to compare electrical conditions at the terminals of a line.	D4
Planned Outage		Removing the equipment from service **availability** for inspection and/or general overhaul of one or more major equipment groups. This outage usually is scheduled well in advance.	D1
Pole (HVdc term)		A rectifier and an inverter, with associated filter banks and control equipment, tied together by a transmission line or bus.	D1
Power		See definitions for Real Power and Reactive Power.	D8
Power Swing		A transient change in the **power** flows on a system, usually of an oscillatory nature.	D1 D4 (Appendix A)

Term	Acronym	Definition	Directories that use this term
Protected element		The power system **element** protected by the subject **protection system**. Examples: Line, bus, transformer, generator.	D4
Protection		The provisions for detecting power system **faults** or abnormal conditions and taking appropriate automatic corrective action.	D1 D2 D3 D4 D7
Protection group		A fully integrated assembly of **protective relays** and associated equipment that is designed to perform the specified protective functions for a power system **element**, independent of other groups. Notes: (a) Variously identified as Main Protection, Primary Protection, Breaker Failure Protection, Back-Up Protection, Alternate Protection, Secondary Protection, A Protection, B Protection, Group A, Group B, System 1 or System 2. (b) Pilot protection is considered to be one protection group.	D1 D3 D4 D7
Protection System		Element Basis One or more protection groups; including all equipment such as instrument transformers, station wiring, circuit breakers and associated trip/close modules, and communication facilities; installed at all terminals of a power system **element** to provide the complete protection of that **element**. Terminal Basis One or more protection groups, as above, installed at one terminal of a power system **element**, typically a transmission line.	D1 D3 D4 D7

Term	Acronym	Definition	Directories that use this term
Protective relay		A **relay** that detects a power system **fault** or abnormal condition and initiates appropriate control system action.	D3 D4
Rating		The operational limits of an electric system, facility, or **element** under a set of specified conditions.	D1 D5
Reactive Power		The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, **synchronous condensers**, or electrostatic equipment such as capacitors. Reactive power directly influences electric system voltage. It is usually expressed in kilovars (kVAr) or megavars (MVAr).	D1 D2 D10
Real Power		The rate of producing, transferring, or using electrical energy, usually expressed in kilowatts (kW) or megawatts (MW).	D1 D2 D9 D10
Reclosing		Autoreclosing — The automatic closing of a circuit breaker in order to restore an **element** to service following automatic tripping of the circuit breaker. Autoreclosing does not include automatic closing of capacitor or reactor circuit breakers. High-speed autoreclosing — The autoreclosing of a circuit breaker after a necessary time delay (less than one second) to permit **fault** arc deionization with due regard to coordination with all **relay** protective systems. This type of autoreclosing is generally not supervised by voltage magnitude or phase angle.	D1

Term	Acronym	Definition	Directories that use this term
		Manual Reclosing — The closing of a circuit breaker by operator action after it has been tripped by **protective relays**. Operator initiated closing commands may originate from local control or from remote (supervisory) control. Either local or remote close commands may be supervised or unsupervised. Supervision — A closing command is said to be supervised if closing is permitted to occur only if certain prerequisite conditions are met (e.g., **synchronism-check**). Synchronism-check — refers to the determination that acceptable voltages exist on the two sides of the breaker and the phase angle between them is within a specified limit for a specified time.	
Regional Reserve Deficiency		When two or more **Areas** are deficient in **ten minute reserve** after all **Area** coordinated actions have been deployed, including acquiring emergency energy and/or capacity but excluding the shedding of firm load.	D5
Relay		An electrical device designed to respond to input conditions in a prescribed manner and after specified conditions are met to cause contact operation or similar abrupt change in associated electric control circuits. (Also: see **protective relay**).	D1 D3 D4 D7 D12
Reliability		The degree of performance of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system — Adequacy and **Security.** Adequacy — The ability of the electric system to supply the aggregate electrical **demand** and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled	D1 D2 D5 D9 D10

Term	Acronym	Definition	Directories that use this term
		outages of system **elements**. Security — The ability of the electric system to withstand **disturbances** such as electric **short circuits** or unanticipated loss of system **elements.**	
Reportable Events		**System disturbances** involving losses of **load**, **generation** or transmission facilities within NPCC **Control Areas** which equal or exceed the following criteria are reportable events: (1) Actual net **interchange** deviations equal to or greater than 500 MW (Maritime: 300 MW). (2) Loss of **generation** or **load** equal to or greater than 500 MW (Maritime: 300 MW). (3) System frequency deviations equal to or greater than 0.03 Hz (Hydro-Quebec: 0.5 Hz). (System frequency deviations that occur for events outside of the NPCC are reported for analysis of frequency response, but are not included in the reporting for the NERC Disturbance Control Standard.)	D5
Reserve		In normal usage, reserve is the amount of capacity available in excess of the demand	D1 D2 D5
Reserve on Automatic Generation Control (AGC)		That portion of **synchronized reserve** which is under the command of an automatic controller to respond to **load** without need for manual action.	D5
Reserve Requirement		That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area supply adequacy.	D2 D5
Resource		Resource refers to the total contributions provided by supply-side and **demand**-side facilities and/or actions. Supply-side facilities include utility and non-utility **generation** and purchases from neighboring systems. **Demand**-side facilities include measures for reducing **load**, such as conservation, **demand** management, and **interruptible load.**	D1 D2 D5 D8 D9 D10

Term	Acronym	Definition	Directories that use this term
Scheduled Interchange		The algebraic sum of all Interchange Schedules across a given path or between Balancing Authorities for a given period or instant in time. (Source: Net Scheduled Interchange defined in NERC Glossary of Terms)	D5
Second Contingency Loss		The largest **capacity** outage which would result from the loss of a single **element** after allowing for the First Contingency Loss.	D5
Short Circuit		An abnormal connection (including an arc) of relatively low impedance, whether made accidentally or intentionally, between two points of different potential. *Note:* The term **fault** or short-circuit **fault** is used to describe a short circuit.	D4 D7
Short Time Emergency Rating	**STE**	The maximum loading of electrical equipment which can be sustained for 15 minutes based on nominal ambient conditions and recognizing preloading conditions.	D1 (Appendix C)
Significant Adverse Impact		With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from **faults** or **disturbances**, shall be deemed as having **significant adverse impact**: a. instability; • any instability that cannot be demonstrably contained to a well-defined **local area**. • any loss of synchronism of generators that cannot be demonstrably contained to a well-defined **local area** b. unacceptable system dynamic response; • an oscillatory response to a **contingency** that is not demonstrated to be clearly positively damped within 30 seconds of the initiating event. c. unacceptable equipment tripping • tripping of an un-faulted **bulk power system** element (element that	D1 (Appendix E) D5

Term	Acronym	Definition	Directories that use this term
		has already been classified as **bulk power system**) under planned system configuration due to operation of a **protection system** in response to a stable **power swing** • operation of a Type I or Type II **Special Protection System** in response to a condition for which its operation is not required d. voltage levels in violation of applicable **emergency** limits; e. loadings on transmission facilities in violation of applicable **emergency** limits.	
Single Contingency		A single event, which may result in the loss of one or more **elements.**	D5
Special Protection System	**SPS**	A **protection system** designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted **elements**. Such action may include changes in **load**, **generation**, or system configuration to maintain system **stability**, acceptable voltages or **power** flows. Automatic underfrequency **load shedding** as defined in the *Emergency Operation Criteria* A-3, is not considered an SPS. Conventionally switched, locally controlled shunt devices are not SPSs.	D1 D3 D4 (Appendix A) D7
Stability		The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances. (Source: NERC Glossary of Tems)	D1 D4
Static Var Compensator	**SVC**	A combination of controlled shunt reactors and switched capacitor banks, used to affect the **reactive power** flow of the system or to regulate the system voltage.	D1 (Appendix G) D2 D4
Synchronize		The process of connecting two previously separated alternating current apparatuses or systems after matching frequency, voltage, phase angles, etc. (e.g., paralleling a generator to the electric system).	D8
Synchronized Reserve		The unused portion of generating capacity which is synchronized to the system and ready to pick up **load** to claimed capacity and capacity which	D5

Term	Acronym	Definition	Directories that use this term
		can be made available by curtailing pumping hydro units.	
Synchronous Condenser		A synchronous machine which operates without mechanical load to supply or absorb **reactive power** for voltage control purposes.	D2 D10
System Disturbance		An event characterized by one or more of the following phenomena: the loss of **power** system **stability**; cascading outages of circuits; oscillations; abnormal ranges of frequency or voltage or both.	D1 D2 D4 D5 D7
System Operator		An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time. (Source: NERC Glossary of Terms)	D2 D3 D8
Teleprotection		A form of **protection** that uses a communication channel.	D4 D7
Ten-Minute Reserve		The sum of **synchronized** and non-**synchronized reserve** that is fully available in ten minutes.	D1 D5
Thirty-Minute Reserve		The sum of **synchronized** and non-**synchronized reserve** that can be utilized in thirty minutes, excluding capacity assigned to **ten-minute reserve**.	D5
Tie Line		A circuit connecting two Balancing Authority Areas.	D1 D2 (Appendix B) D5
Tie Line Bias		A mode of operation under automatic **generation** control in which the **area control error** is determined by the actual net **interchange** minus the biased scheduled net **interchange.**	D2
Total Transfer Capability	**TTC**	The amount of electric **power** that can be transferred over the interconnected transmission network in a *reliable* manner based on *all* of the following conditions:	D5

Term	Acronym	Definition	Directories that use this term
		1. For the existing or planned system configuration, and with **normal** (**precontingency**) **operating procedures** in effect, all facility loadings are within normal **ratings** and all voltages are within normal limits. 2. The electric systems are capable of absorbing the dynamic **power swings**, and remaining stable, following a **disturbance** that results in the loss of any single electric system **element**, such as a transmission line, transformer, or generating unit. 3. After the dynamic **power swings** subside following a **disturbance** that results in the loss of any single electric system **element** as described in 2 above, and after the operation of any automatic operating systems, but before any post-**contingency** operator-initiated system adjustments are implemented, all transmission facility loadings are within **emergency ratings** and all voltages are within **emergency** limits 4. With reference to condition 1 above, in the case where precontingency facility loadings reach normal thermal **ratings** at a transfer level below that at which any first **contingency** transfer limits are reached, the transfer capability is defined as that transfer level at which such normal **ratings** are reached. 5. In some cases, individual system, **power pool,** subregional, or Regional planning criteria or guides may require consideration of specified multiple contingencies, such as the outage of transmission circuits using common towers or rights-of-way, in the determination of transfer capability limits. If the resulting transfer limits for these multiple **contingencies** are more restrictive than the single contingency considerations described above, the more restrictive **reliability** criteria or guides must be observed.	

Term	Acronym	Definition	Directories that use this term
Transfer Capability		The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from "Area A" to "Area B" is not generally equal to the transfer capability from "Area B" to "Area A." (Source: NERC Glossary of Terms)	D1 D2 D5
Transient Stability		The ability of an electric system to maintain synchronism between its parts when subjected to a **disturbance** and to regain a state of equilibrium following that disturbance.	D1
Verified Capability (of a generator or generating facility)		The capability as demonstrated by the methods specified in NPCC Directories and accepted by the Transmission Operator.	D9 D10
Voltage Reduction		A means to reduce the **demand** by lowering the customer's voltage.	D1 D2 (Appendix B) D5 (Appendix 3)
Voltage Regulating Transformer		A transformer that increases or decreases the voltage magnitude relationship of one circuit with respect to another, most often used to control voltage but also to control **reactive power** flow.	D1
With Due Regard To Reclosing		This phrase means that before any manual system adjustments, recognition will be given to the type of **reclosing** (i.e., manual or automatic) and the kind of **protection.**	D1

vNote: Terms highlighted in blue are those that are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
Actual Interchange		Metered electric **power** that flows from one entity to another.	D5
Applicable emergency limits		These limits depend on the duration of the occurrence, and on the policy of the various member systems of NPCC regarding loss of life to equipment, voltage limitations, etc. **Emergency** limits are those which can be utilized for the time required to take corrective action, but in no case less than five minutes. The limiting condition for voltages should recognize that voltages should not drop below that required for suitable system **stability** performance, and should not adversely affect the operation of the **bulk power system**. The limiting condition for equipment loadings should be such that cascading outages will not occur due to operation of protective devices upon the failure of facilities. (Various definitions of equipment **ratings** are found elsewhere in this glossary.)	D1 D7
Area		An **Area** (when capitalized) refers to one of the following: New England, New York, Ontario, Quebec or the Maritimes (New Brunswick, Nova Scotia and Prince Edward Island); or, as the situation requires, area (lower case) may mean a part of a system or more than a single system. Within NPCC, Areas (capitalized) operate as **control areas** as defined by the North American Electric Reliability Council (NERC) (the definition can be found in this glossary).	D1 D7 D8 D12
Area Control Error	**ACE**	~~See NERC definition.~~ The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error. (Source: NERC Glossary of Terms)	D2 D5 D8

Term	Acronym	Definition	Directories that use this term
Automatic Generation Control	**AGC**	~~See NERC definition.~~ Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction. (Source: NERC Glossary of Terms)	D2 D5 D8
Basic Minimum Power System		Consists of one or more generating stations, transmission lines, and substations operating in the form of an island for the purpose of initiating the restoration process. The Reliability Coordinator and Transmission Operator shall each identify its area's basic minimum power system(s) within its system restoration plan.	D8
Bipolar		Operation of HVdc with two **poles** of opposite polarity with negligible ground current.	D1
Blackstart Capability		The ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering **power** without assistance from the electric system.	D8
Bulk ~~p~~Power ~~s~~System	**BPS**	The interconnected electrical systems within northeastern North America comprised of system **elements** on which **faults** or **disturbances** can have a **significant adverse impact** outside of the **local area.**	D1 D2 D3 D4 D7 D9 D10
Cable		An underground or underwater circuit.	D4 D5 D7

Term	Acronym	Definition	Directories that use this term
			D8
~~**Capability, Operating**~~		~~The maximum load carrying ability of generating equipment or other electrical apparatus under specified conditions for a given time interval.~~	~~D9~~
Capacity		The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of **generation**, transmission, or other electrical equipment.	D1 D2 D5 D8
Commutation Failure		A fault in a thyristor valve group where the current transfer from one valve to the next is interrupted.	D4
Component		Refers to components of equipment or protection systems rather than **elements** of a **power** system. See **Element**.	D1 D3 D7
Contingency		An event, usually involving the loss of one or more **elements**, which affects the power system at least momentarily.	D1 D2 D5 D7
Converter		An operative unit comprised of either a rectifier or inverter bridge connected to an ac system through transformers and switching devices with the associated control equipment.	D4
Converter Transformer		A **power** transformer which transfers the energy from the thyristor valves to the connected ac system and vice-versa.	D4
Critical Components		Equipment required for continued and proper operation of a **key facility** in the event of a total loss of grid supply. Critical components include but are not limited to the following: ▪ blackstart generating units; ▪ substation backup power supplies; ▪ control center and telecommunication center backup power supplies and computer systems; ▪ control center and telecommunication center computer room HVAC;	D8

Term	Acronym	Definition	Directories that use this term
		and ▪ telecommunication facilities backup power supplies. ▪	
Declared Capability (of a generator or generating facility)		~~(of a generator or generating facility)~~ The facility ratings submitted by the Generator Owner to the respective Transmission Operator as per NERC Standard FAC-009.	D10
Delayed Fault Clearing		~~See NERC definition.~~ Fault clearing consistent with correct operation of a breaker failure protection system and its associated breakers, or of a backup protection system with an intentional time delay. (Source: NERC Glossary of Terms)	D1
Demand		~~See NERC definition.~~ 1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer. (Source: NERC Glossary of Terms)	D1 D5
Disturbance		Severe oscillations or severe step changes of current, voltage and/or frequency usually caused by **faults**.	D1 D2 D4 D5 D7
Disturbance Monitoring Equipment	**DME**	~~See NERC definition.~~ Devices capable of monitoring and recording system data pertaining to a Disturbance. Such devices include the following categories of recorders2 • Sequence of event recorders which record equipment response to the	D4

Term	Acronym	Definition	Directories that use this term
		event; • Fault recorders, which record actual waveform data replicating the system primary voltages and currents. This may include protective relays; • Dynamic Disturbance Recorders (DDRs), which record incidents that portray power system behavior during dynamic events such as low-frequency (0.1 Hz – 3 Hz) oscillations and abnormal frequency or voltage excursions (Source: NERC Glossary of Terms)	
Economic Dispatch		~~See NERC definition.~~ The allocation of demand to individual generating units on line to effect the most economical production of electricity. (Source: NERC Glossary of Terms)	D2
Element		~~See NERC definition.~~ Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components. (Source: NERC Glossary of Terms)	D1 D2 D4 D5 D7 D9 D10
Emergency		Any abnormal system condition that requires automatic or manual action to prevent or limit loss of transmission facilities or **generation** supply that could adversely affect the **reliability** of the electric system. NPCC Specific Definition:	D1 D2 D4 D5 D7

Term	Acronym	Definition	Directories that use this term
		Emergency — An **Emergency** is considered to exist in an Area if **firm load** may have to be shed.	
Emergency Regional Reserve Redispatch		The regional coordination of actions to enhance **reliability** among **Areas** in response to a **Regional Reserve Deficiency.**	D5
Emergency Regional Reserve Dispatch Energy		Electrical energy that is received and delivered among **Areas** in response to a **Regional Reserve Deficiency** to enhance regional **reliability.**	D5
Emergency Transfer Capability		The amount of **power** transfer allowed between **Areas** or within an **Area** when ope**rating** to meet NPCC **emergency** criteria contingencies [as defined in Directory #1].	D2
Energize		To make a piece of equipment or circuit alive.	D4
Fault		An electrical **short circuit**.	D1 D4 D7
Firm Capacity		Capacity that is as firm as the seller's native **load** unless modified by contract. Associated energy may or may not be taken at option of purchaser. Supporting **reserve** is carried by the seller.	D1
Firm Load		~~See NERC definition on Firm Demand.~~ That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions. (Source: Firm Demand defined in NERC Glossary of Terms)	D1 D2
First Contingency Loss		The largest **capacity** outage including any assigned Ten-Minute Reserve which would result from the loss of a single **element.**	D5
Forced Outage		1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. 2. The condition in which the equipment is unavailable due to unanticipated	D1

Term	Acronym	Definition	Directories that use this term
		failure. (Source: NERC Glossary of Terms)	
Generation (Electricity)		The process of producing electrical energy from other forms of energy; also, the amount of electric energy produced, usually expressed in kilowatthours (kWh) or megawatthours (MWh). Gross Generation — The electrical output at the terminals of the generator, usually expressed in megawatts (MW). Net Generation — Gross generation minus station service or unit service **power** requirements, usually expressed in megawatts (MW).	D1 D2 D4 (Appendix A) D5 D7 (Appendices) D12
Generation Facility		Generating units, which are modeled as a single entity by the Transmission Operator.	D8 D9 D10
Generation Rejection		The process of deliberately removing preselected **generation** from a **power** system, or initiating HVdc power runback, in response to a **contingency** or an abnormal condition in order to maintain the integrity of the system. Synonym: Generator Dropping.	D1 D7
Gross Real Power Capability (of a generator or generating facility)		~~(of a generator or generating facility) –~~ The maximum megawatt output at the generator terminals, at the normally expected system conditions for that seasonal capability period.	D9
Gross Reactive Power Capability (of a generator or generating facility)		The maximum lagging and leading reactive capability at the generator terminals and at a specified Gross Real Power output for a specific seasonal capability period.	D10
Grounded		Connected to earth or some extended conducting body that serves instead of the earth, whether the connection is intentional or accidental.	D4 D7

Term	Acronym	Definition	Directories that use this term
Harmonic		A sinusoidal component of a periodic wave or quantity having a frequency that is an integral multiple of the fundamental frequency. Note: For example, a component, the frequency of which is twice the fundamental frequency, is called a second harmonic.	D4
HVdc Link		A high Voltage direct current connection between two **power** systems, often used to interconnect two asynchronous **power** systems.	D4
Inadvertent Interchange		~~See NERC definition.~~ The difference between the Balancing Authority's Net Actual Interchange and Net Scheduled Interchange. (IA – IS) (Source: NERC Glossary of Terms)	D5
Interconnection		When capitalized, any one of the five major electric system networks in North America: Eastern, Western, ERCOT, Québec, and Alaska. When not capitalized, the facilities that connect two systems or **Control Areas**. Additionally, an interconnection refers to the facilities that connect a nonutility generator to a **Control Area** or system.	D1 D2 D5 D8 D12
Interchange		~~See NERC definition.~~ Energy transfers that cross Balancing Authority boundaries. (Source: NERC Glossary of Terms)	D1 (Appendix B) D2 D5
Interchange Schedule		~~See NERC definition.~~ An agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction. (Source: NERC Glossary of Terms)	D1 D5
Interface		The specific set of transmission **elements** between two areas or between two areas comprising one or more electrical systems.	D1 (Appendices)

Term	Acronym	Definition	Directories that use this term
Interruptible Load		~~See NERC definition.~~ Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment. (Source: NERC Glossary of Terms)	D1 (Appendix D) D5
Island		A portion of a **power** system or several power systems that is electrically separated from the interconnection due to the disconnection of transmission system **elements.**	D1 D8 D12
Key Facilities		Facilities required to establish a **basic minimum power system** following a system blackout. These facilities are essential to the restoration plan of the **Control Area** and include generating stations having blackstart units and other selected generating stations, transmission **elements** which are part of the **basic minimum power system,** control centers and telecommunication centers and telecommunication facilities which are necessary to support **protection** and control facilities, voice and data between and within control centers and voice and data between control centers and key generating / transmission substations.	D8
Load		~~See NERC definition.~~ An end-use device or customer that receives power from the electric system. (Source: NERC Glossary of Terms)	D1 D2 D3 D4 D5 D7 (Appendices) D8 D9 D10 D12
Load Relief		**Load** reduction accomplished by **voltage reduction** and/or **load shedding**.	D1

Term	Acronym	Definition	Directories that use this term
Load Shedding		The process of deliberately removing (either manually or automatically) preselected customers' **load** from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages.	D2 D3 D4 D12
Local area		An electrically confined or radial portion of the system. The geographic size and number of system elements contained will vary based on system characteristics. A local area may be relatively large geographically with relatively few buses in a sparse system, or be relatively small geographically with a relatively large number of buses in a densely networked system.	D1 D4
Maintenance Outage		The removal of equipment from service **availability** to perform work on specific **elements** that can be deferred, but requires the equipment be removed from service before the next planned outage. Typically, a Maintenance Outage may occur anytime during the year, have a flexible start date, and may or may not have a predetermined duration.	D1
Net Capacity		The maximum capacity (or effective **rating**), modified for ambient limitations, that a generating unit, **power** plant, or electric system can sustain over a specified period, less the capacity used to supply the **demand** of station service or auxiliary needs.	D1
Net Real Power Capability (of a generator or generating facility)		~~(of a generator or generating facility)~~ The Gross Real Power Capability, less the auxiliary real power loads necessary to operate the generator at maximum real power output.	D9
Net Reactive Power Capability (of a generator or generating facility)		The **Gross Reactive Power Capability** adjusted for any applicable losses and auxiliary loads incurred up to the point of interconnection and at a specified Gross Real Power output for a specific seasonal capability period.	D10

Term	Acronym	Definition	Directories that use this term
Normal ~~f~~Fault ~~c~~Clearing		Fault clearing consistent with correct operation of the **protection system** and with the correct operation of all circuit breakers or other automatic switching devices intended to operate in conjunction with that **protection system.**	D1
Normal (Precontingency) Operating Procedures		Operating procedures that are normally invoked by the **system operator** to alleviate potential facility overloads or other potential system problems in anticipation of a **contingency**.	D1 (Appendix F)
Normal Transfer Capability		The amount of **power** transfer allowed between **Areas** or within an **Area** when operating to meet NPCC normal criteria contingencies [as defined in Directory #1].	D1 D2
Operating Capability		The maximum load carrying ability of generating equipment or other electrical apparatus under specified conditions for a given time interval.	D9
Operating Limit		The maximum value of the most critical system operation parameter(s) which meet(s): (a) pre-**contingency** criteria as determined by equipment loading capability and acceptable voltage conditions; (b) **stability** criteria; (c) post-**contingency** loading and voltage criteria.	D1 (Appendix C) D2 D5
Operating Capacity		The **capacity** claimed for any generating source recognizing any temporary deratings, governor load limits, proven maximum loading rates, starting times and equipment limitations including transmission **operating limits**.	D5
Operating Procedures		A set of policies, practices, or system adjustments that may be automatically or manually implemented by the **system operator** within a specified time frame to maintain the operational integrity of the interconnected electric systems.	D1 D5 D7
Operating Reserve		The sum of **ten-minute** and **thirty-minute reserve**.	D1 D2
~~**Operator, System**~~		~~See NERC definition on System Operator~~	~~D2~~ ~~D3~~ ~~D8~~
~~**Forced Outage**~~		~~See NERC definition.~~	~~D1~~

Term	Acronym	Definition	Directories that use this term
Phase Shifting Transformer		A transformer that advances or retards the phase angle relationship of one circuit with respect to another to control **power** flow. Synonyms: Phase angle regulator, phase shifter.	D1 D2 D4
Pilot Protection		A form of line protection that uses a communication channel as a means to compare electrical conditions at the terminals of a line.	D4
Planned Outage		Removing the equipment from service **availability** for inspection and/or general overhaul of one or more major equipment groups. This outage usually is scheduled well in advance.	D1
Pole (HVdc term)		A rectifier and an inverter, with associated filter banks and control equipment, tied together by a transmission line or bus.	D1
Power		See definitions for Real Power and Reactive Power.	D8
Power Swing		A transient change in the **power** flows on a system, usually of an oscillatory nature.	D1 D4 (Appendix A)
Protected element		The power system **element** protected by the subject **protection system**. Examples: Line, bus, transformer, generator.	D4
Protection		The provisions for detecting power system **faults** or abnormal conditions and taking appropriate automatic corrective action.	D1 D2 D3 D4 D7
Protection group		A fully integrated assembly of **protective relays** and associated equipment that is designed to perform the specified protective functions for a power system **element**, independent of other groups. Notes:	D1 D3 D4 D7

Term	Acronym	Definition	Directories that use this term
		(a) Variously identified as Main Protection, Primary Protection, Breaker Failure Protection, Back-Up Protection, Alternate Protection, Secondary Protection, A Protection, B Protection, Group A, Group B, System 1 or System 2. (b) Pilot protection is considered to be one protection group.	
Protection System		Element Basis One or more protection groups; including all equipment such as instrument transformers, station wiring, circuit breakers and associated trip/close modules, and communication facilities; installed at all terminals of a power system **element** to provide the complete protection of that **element**. Terminal Basis One or more protection groups, as above, installed at one terminal of a power system **element**, typically a transmission line.	D1 D3 D4 D7
Protective relay		A **relay** that detects a power system **fault** or abnormal condition and initiates appropriate control system action.	D3 D4
Rating		The operational limits of an electric system, facility, or **element** under a set of specified conditions.	D1 D5
Reactive Power		The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, **synchronous condensers**, or electrostatic equipment such as capacitors. Reactive power directly influences electric system voltage. It is usually expressed in	D1 D2 D10

Term	Acronym	Definition	Directories that use this term
		kilovars (kVAr) or megavars (MVAr).	
~~**Reactive Power Capability (of a generator or generating facility), Gross**~~		~~The maximum lagging and leading reactive capability at the generator terminals and at a specified Gross Real Power output for a specific seasonal capability period.~~	~~D10~~
~~**Reactive Power Capability (of a generator or generating facility), Net**~~		~~The **Gross Reactive Power Capability** adjusted for any applicable losses and auxiliary loads incurred up to the point of interconnection and at a specified Gross Real Power output for a specific seasonal capability period.~~	~~D10~~
Real Power		The rate of producing, transferring, or using electrical energy, usually expressed in kilowatts (kW) or megawatts (MW).	D1 D2 D9 D10
Reclosing		Autoreclosing — The automatic closing of a circuit breaker in order to restore an **element** to service following automatic tripping of the circuit breaker. Autoreclosing does not include automatic closing of capacitor or reactor circuit breakers. High-speed autoreclosing — The autoreclosing of a circuit breaker after a necessary time delay (less than one second) to permit **fault** arc deionization with due regard to coordination with all **relay** protective systems. This type of autoreclosing is generally not supervised by voltage magnitude or phase angle. Manual Reclosing — The closing of a circuit breaker by operator action after it has been tripped by **protective relays**. Operator initiated closing commands may originate from local control or from remote (supervisory) control. Either local or remote close commands may be supervised or unsupervised. Supervision — A closing command is said to be supervised if closing is permitted to occur only if certain prerequisite conditions are met (e.g.,	D1

Term	Acronym	Definition	Directories that use this term
		synchronism-check). Synchronism-check — refers to the determination that acceptable voltages exist on the two sides of the breaker and the phase angle between them is within a specified limit for a specified time.	
Regional Reserve Deficiency		When two or more **Areas** are deficient in **ten minute reserve** after all **Area** coordinated actions have been deployed, including acquiring emergency energy and/or capacity but excluding the shedding of firm load.	D5
Relay		An electrical device designed to respond to input conditions in a prescribed manner and after specified conditions are met to cause contact operation or similar abrupt change in associated electric control circuits. (Also: see **protective relay**).	D1 D3 D4 D7 D12
Reliability		The degree of performance of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system — **Adequacy** and **Security.** Adequacy — The ability of the electric system to supply the aggregate electrical **demand** and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system **elements**. Security — The ability of the electric system to withstand **disturbances** such as electric **short circuits** or unanticipated loss of system **elements.**	D1 D2 D5 D9 D10
Reportable Events		**System disturbances** involving losses of **load**, **generation** or transmission facilities within NPCC **Control Areas** which equal or exceed the following criteria are reportable events:	D5

Term	Acronym	Definition	Directories that use this term
		(1) Actual net **interchange** deviations equal to or greater than 500 MW (Maritime: 300 MW). (2) Loss of **generation** or **load** equal to or greater than 500 MW (Maritime: 300 MW). (3) System frequency deviations equal to or greater than 0.03 Hz (Hydro-Quebec: 0.5 Hz). (System frequency deviations that occur for events outside of the NPCC are reported for analysis of frequency response, but are not included in the reporting for the NERC Disturbance Control Standard.)	
Reserve		In normal usage, reserve is the amount of capacity available in excess of the demand	D1 D2 D5
Reserve on Automatic Generation Control (AGC)		That portion of **synchronized reserve** which is under the command of an automatic controller to respond to **load** ~~**demands**~~ without need for manual action.	D5
Reserve Requirement		That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area supply adequacy.	D2 D5
Resource		Resource refers to the total contributions provided by supply-side and **demand**-side facilities and/or actions. Supply-side facilities include utility and non-utility **generation** and purchases from neighboring systems. **Demand**-side facilities include measures for reducing **load**, such as conservation, **demand** management, and **interruptible load.**	D1 D2 D5 D8 D9 D10
Scheduled Interchange		~~See NERC definition on Net Scheduled Interchange.~~ The algebraic sum of all Interchange Schedules across a given path or between Balancing Authorities for a given period or instant in time. (Source: Net Scheduled Interchange defined in NERC Glossary of Terms)	D5
Second Contingency Loss		The largest **capacity** outage which would result from the loss of a single	D5

Term	Acronym	Definition	Directories that use this term
		element after allowing for the First Contingency Loss.	
Short Circuit		An abnormal connection (including an arc) of relatively low impedance, whether made accidentally or intentionally, between two points of different potential. *Note:* The term **fault** or short-circuit **fault** is used to describe a short circuit.	D4 D7
Short Time Emergency ~~(STE)~~ Rating	**STE**	The maximum loading of electrical equipment which can be sustained for 15 minutes based on nominal ambient conditions and recognizing preloading conditions.	D1 (Appendix C)
Significant ~~a~~Adverse ~~i~~Impact		With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from **faults** or **disturbances**, shall be deemed as having **significant adverse impact**: a. instability; • any instability that cannot be demonstrably contained to a well-defined **local area**. • any loss of synchronism of generators that cannot be demonstrably contained to a well-defined **local area** b. unacceptable system dynamic response; • an oscillatory response to a **contingency** that is not demonstrated to be clearly positively damped within 30 seconds of the initiating event. c. unacceptable equipment tripping • tripping of an un-faulted **bulk power system** element (element that has already been classified as **bulk power system**) under planned system configuration due to operation of a **protection system** in response to a stable **power swing** • operation of a Type I or Type II **Special Protection System** in response to a condition for which its operation is not required	D1 (Appendix E) D5

Term	Acronym	Definition	Directories that use this term
		d. voltage levels in violation of applicable **emergency** limits; e. loadings on transmission facilities in violation of applicable **emergency** limits.	
Single Contingency		A single event, which may result in the loss of one or more **elements.**	D5
Special Protection System	**SPS**	A **protection system** designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted **elements**. Such action may include changes in **load**, **generation**, or system configuration to maintain system **stability**, acceptable voltages or **power** flows. Automatic underfrequency **load shedding** as defined in the *Emergency Operation Criteria* A-3, is not considered an SPS. Conventionally switched, locally controlled shunt devices are not SPSs.	D1 D3 D4 (Appendix A) D7
Stability		~~See NERC definition.~~ The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances. (Source: NERC Glossary of Tems)	D1 D4
Static Var Compensator	**SVC**	A combination of controlled shunt reactors and switched capacitor banks, used to affect the **reactive power** flow of the system or to regulate the system voltage.	D1 (Appendix G) D2 D4
Synchronize		The process of connecting two previously separated alternating current apparatuses or systems after matching frequency, voltage, phase angles, etc. (e.g., paralleling a generator to the electric system).	D8
Synchronized Reserve		The unused portion of generating capacity which is synchronized to the system and ready to pick up **load** to claimed capacity and capacity which can be made available by curtailing pumping hydro units.	D5
Synchronous Condenser		A synchronous machine which operates without mechanical load to supply or absorb **reactive power** for voltage control purposes.	D2 D10

Term	Acronym	Definition	Directories that use this term
System Disturbance		An event characterized by one or more of the following phenomena: the loss of **power** system **stability**; cascading outages of circuits; oscillations; abnormal ranges of frequency or voltage or both.	D1 D2 D4 D5 D7
System Operator		An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time. (Source: NERC Glossary of Terms)	D2 D3 D8
Teleprotection		A form of **protection** that uses a communication channel.	D4 D7
Ten-~~m~~Minute ~~r~~Reserve		The sum of **synchronized** and non-**synchronized reserve** that is fully available in ten minutes.	D1 D5
Thirty-Minute Reserve		The sum of **synchronized** and non-**synchronized reserve** that can be utilized in thirty minutes, excluding capacity assigned to **ten-minute reserve**.	D5
Tie Line		~~See NERC definition.~~ A circuit connecting two Balancing Authority Areas.	D1 D2 (Appendix B) D5
Tie Line Bias		A mode of operation under automatic **generation** control in which the **area control error** is determined by the actual net **interchange** minus the biased scheduled net **interchange.**	D2
Total Transfer Capability	**TTC**	The amount of electric **power** that can be transferred over the interconnected transmission network in a *reliable* manner based on *all* of the following conditions: 1. For the existing or planned system configuration, and with **normal** (**precontingency**) **operating procedures** in effect, all facility loadings	D5

Term	Acronym	Definition	Directories that use this term
		are within normal **ratings** and all voltages are within normal limits. 2. The electric systems are capable of absorbing the dynamic **power swings**, and remaining stable, following a **disturbance** that results in the loss of any single electric system **element**, such as a transmission line, transformer, or generating unit. 3. After the dynamic **power swings** subside following a **disturbance** that results in the loss of any single electric system **element** as described in 2 above, and after the operation of any automatic operating systems, but before any post-**contingency** operator-initiated system adjustments are implemented, all transmission facility loadings are within **emergency ratings** and all voltages are within **emergency** limits 4. With reference to condition 1 above, in the case where precontingency facility loadings reach normal thermal **ratings** at a transfer level below that at which any first **contingency** transfer limits are reached, the transfer capability is defined as that transfer level at which such normal **ratings** are reached. 5. In some cases, individual system, **power pool,** subregional, or Regional planning criteria or guides may require consideration of specified multiple contingencies, such as the outage of transmission circuits using common towers or rights-of-way, in the determination of transfer capability limits. If the resulting transfer limits for these multiple **contingencies** are more restrictive than the single contingency considerations described above, the more restrictive **reliability** criteria or guides must be observed.	
Transfer Capability		~~See NERC definition.~~ The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system	D1 D2 D5

Term	Acronym	Definition	Directories that use this term
		conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from "Area A" to "Area B" is not generally equal to the transfer capability from "Area B" to "Area A." (Source: NERC Glossary of Terms)	
Transient Stability		The ability of an electric system to maintain synchronism between its parts when subjected to a **disturbance** and to regain a state of equilibrium following that disturbance.	D1
Verified Capability (of a generator or generating facility)		~~(of a generator or generating facility)~~ The capability as demonstrated by the methods specified in NPCC ~~this~~ Directories ~~y~~ and accepted by the Transmission Operator.	D9 D10
Voltage Reduction		A means to reduce the **demand** by lowering the customer's voltage.	D1 D2 (Appendix B) D5 (Appendix 3)
Voltage Regulating Transformer		A transformer that increases or decreases the voltage magnitude relationship of one circuit with respect to another, most often used to control voltage but also to control **reactive power** flow.	D1
With ~~d~~Due ~~r~~Regard ~~t~~To ~~r~~Reclosing		This phrase means that before any manual system adjustments, recognition will be given to the type of **reclosing** (i.e., manual or automatic) and the kind of **protection.**	D1

Note: Terms highlighted in blue are those that are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Documents that use this term
Automatic Operating Systems		**Special protection systems**, remedial action schemes, or other operating systems installed on the electric systems that require *no intervention* on the part of **system operators**.	
Auto-reclosing		The automatic closing of a circuit breaker in order to restore an **element** to service following automatic tripping of the circuit breaker. Auto-reclosing does not include automatic closing of capacitor or reactor circuit breakers.	
Available Transfer Capability	**ATC**	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. ATC is defined as the Total Transfer Capability (TTC), less the **Transmission Reliability Margin (TRM)**, less the sum of existing transmission commitments (which includes retail customer service) and the **Capacity Benefit Margin (CBM)**.	
Availability		A measure of time a generating unit, transmission line, or other facility is capable of providing service, whether or not it actually is in service. Typically, this measure is expressed as a percent available for the period under consideration.	
Average Demand		The electric energy delivered over any interval of time as determined by dividing the total energy by the units of time in the interval.	
Base load Capacity		Capacity used to serve an essentially constant level of customer **demand**. Base load generating units typically operate whenever they are available.	
Billing Demand		The demand upon which customer billing is based as specified in a rate schedule or contract. It may be based on the contract year, a contract minimum, or a previous maximum and, therefore, does not necessarily coincide with the actual measured demand of the billing period.	
Bottled Energy/Power/Capacity		Energy/Power/Capacity which is available at the source but which cannot be delivered to the point of use because of restrictions in the transmission	

Term	Acronym	Definition	Documents that use this term
		system. Also referred to as Locked-In Energy/Power/Capacity.	
Capacity Benefit Margin	**CBM**	CBM is defined as that amount of transmission transfer capability reserved by **load** serving entities to ensure access to **generation** from interconnected systems to meet **generation reliability** requirements.	
Coincident Demand		The sum of two or more demands that occur in the same demand interval.	
Contingency Reserve Adjustment Factor		A factor used in determining the additional **ten-minute reserve** that each **Area**, not meeting the DCS requirement for a given quarter, must carry. It is calculated using the following formula: $CRA_{quarter} = 2 -$ {the average percentage DCS (expressed as a decimal) for the quarter of measurement}	
Continuous Rating		The rating – as defined by the equipment owner – that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or **element** can support or withstand indefinitely without loss of equipment life. (Normally not used in NPCC)	
Contract Demand		The amount of **capacity** that a supplier agrees to make available for delivery to a particular entity and which the entity agrees to purchase.	
Control Area		An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling **generation** to maintain its net **interchange schedule** with other Control Areas and contributing to frequency regulation of the **Interconnection.**	
Demand Interval		The time period during which electric energy is measured, usually in 15-, 30-, or 60-minute increments.	
Double Element Contingency		A **contingency** involving the loss of two **elements**.	

Term	Acronym	Definition	Documents that use this term
Emergency Rating		The rating – as defined by the equipment owner – that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units, that a system, facility, or **element** can support or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.	
Firm Demand		That portion of the Contract Demand that a **power** supplier is obligated to provide except when system **reliability** is threatened or during **emergency** conditions.	
First Contingency Incremental Transfer Capability	**FCITC**	The amount of **power**, incremental above normal base **power** transfers, that can be transferred over the transmission network in a reliable manner based on the following conditions: 1. For the existing or planned system configuration, and with normal (pre-**contingency) operating procedures** in effect, all facility loadings are within normal **ratings** and all voltages are within normal limits. 2. The electric systems are capable of absorbing the dynamic **power swings**, and remaining stable, following a **disturbance** that results in the loss of any single electric **element**, such as a transmission line, transformer, or generating unit. 3. After the dynamic **power swings** subside following a **disturbance** that results in the loss of any single electric system **element** as described in 2 above, and after the operation of automatic operating systems, but before any post-**contingency** operator-initiated system adjustments are implemented, all transmission facility loadings are within **emergency ratings** and all voltages are within **emergency** limits.	
First Contingency Total Transfer Capability	**FCTTC**	The algebraic sums of the FCITC values and the appropriate total interregional transfers assumed in the base load flow model used for the	

Term	Acronym	Definition	Documents that use this term
		FCITC calculations.	
Forced Outage Rate		The hours a generating unit, transmission line, or other facility is forced out of service, divided by the sum of the hours it is removed from service, plus the total number of hours the facility was connected to the electricity system expressed as a percent.	
Harmonic Current		A periodic component of current having a frequency that is an integral multiple of that currents fundamental frequency. Harmonic currents are normally measured in amperes or in percent of the fundamental frequency current, generally at specific frequencies, such as second and third harmonics. Harmonic currents can, for example, be generated by HVdc converters, **Static Var Compensators** (SVC) and geomagnetically induced currents (GIC).	
High Speed Fault Clearing		Fault clearing consistent with correct operation of high-speed relays and the associated circuit breakers without intentional time delay. *Notes:* The specified time for high-speed relays in present practice is 50 milliseconds (three cycles on a 60Hz basis) or less. [IEEE C37.100-1981]. For planning purposes, a total clearing time of six cycles or less is considered high speed.	
High-Speed Auto reclosing		The auto reclosing of a circuit breaker after a necessary time delay (less than one second) to permit **fault** arc deionization with due regard to coordination with all **relay** protective systems. This type of auto reclosing is generally not supervised by voltage magnitude or phase angle.	
Integrated Demand		The average of the instantaneous demands over the demand interval.	
Interchange Scheduling		The actions taken by scheduling entities to arrange transfer of electric **power**. The schedule consists of an agreement on the amount, start and end times, ramp rate, and degree of firmness.	
Instantaneous Demand		The rate of energy delivered at a given instant.	
Limiting Contingency		The **contingency** which establishes the **transfer capability**.	

Term	Acronym	Definition	Documents that use this term
Load Cycle		The normal pattern of **demand** over a specified time period associated with a device or circuit.	
Long Time Emergency (LTE) Rating		The maximum rating of electrical equipment based on nominal ambient conditions and recognizing the nominal **load cycle** for a long period such as 24 hours.	
Manual Reclosing		The closing of a circuit breaker by operator action after it has been tripped by **protective relays**. Operator initiated closing commands may originate from local control or from remote (supervisory) control. Either local or remote close commands may be supervised or unsupervised.	
Negative Shared Activation Reserve Energy		Energy received by an assisting **Area** from a contingent **Area** for an eligible **resource** loss having a concurrent effective loss of demand that exceeds the loss of energy from the **resource** loss, and is implemented at a zero time ramp rate immediately following allocation notification, maintained until the Contingent **Area** requests a return to normal but not longer than thirty minutes, and ramped out at a ten-minute ramp rate following communications initiated by the Contingent **Area** which have resulted in mutually established **interchange schedules.**	
Non coincident Demand		The sum of two or more demands that occur in different demand intervals.	
Non recallable Available Transfer Capability	**NATC**	Total Transmission Capability less the **Transmission Reliability Margin**, less non recallable reserved transmission service (including the **Capacity Benefit Margin**).	
Non-Synchronized Reserve		That portion of **operating capacity**, which is available for synchronizing to the network and that capacity which can be made available by applying load management techniques such as curtailing **interruptible loads** or implementing **voltage reductions**.	
Normal Incremental Transfer Capability	**NITC**	The amount of electric **power**, incremental above normal base power transfers, that can be transferred between two areas of the interconnected transmission systems under conditions where pre-**contingency** loadings reach the normal thermal **rating** of a facility prior to any first **contingency** transfer limits being reached. When this occurs, NITC replaces FCITC as	

Term	Acronym	Definition	Documents that use this term
		the most limiting transfer capability.	
Normal Rating		The rating – as defined by the equipment owner – that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or **element** can support or withstand through the daily **demand** cycles without loss of equipment life.	
NPCC Emergency Criteria Contingencies		The set of contingencies to be observed when operating the **bulk power system** under **emergency** conditions.	
NPCC Normal Criteria Contingencies		The set of contingencies to be observed when operating the **bulk power system** under normal conditions.	
Peak Demand		The highest electric **power** requirement occurring in a given period (e.g., an hour, a day, month, season, or year). For an electric system, it is equal to the sum of the metered net outputs of all generators within a system and the metered line flows into the system, less the metered line flows out of the system.	
Peaking Capacity		Capacity used to serve **peak demand**. Peaking generating units operate a limited number of hours per year, and their capacity factor is normally less than 20%.	
Permanent Fault		A fault which prevents the affected **element** from being returned to service until physical actions are taken to effect repairs or to remove the cause of the fault.	
Pole (of an ac switching device)		That portion of the device associated exclusively with one electrically separated conducting path of the main circuit of the device.	
Post contingency Operating Procedures		Operating procedures that may be invoked by the **system operator** to mitigate or alleviate system problems after a **contingency** has occurred.	
Power		Apparent Power — The product of the volts and amperes. It comprises both *real* and *reactive* power, usually expressed in kilo volt amperes (kVA) or megavoltamperes (MVA).	
Power Pool		Two or more interconnected electric systems operated and/or planned to supply **power** for their combined **demand** requirements.	

Term	Acronym	Definition	Documents that use this term
Recallable Available Transmission Capability	**RATC**	Total Transmission Capability less the **Transmission Reliability Margin**, less recallable transmission service, less non-recallable transmission service (including the **Capacity Benefit Margin**).	
Reclosing *This term by itself is not defined in the NPCC glossary.*		*Need to develop this definition.*	
Regional Reserve Sharing		Procedure that allows participating **Areas** to reduce the requirement for **reserve** within its **Area** due to the availability and deliverability of **reserve** from other **Areas.**	
Regional Reserve Sharing Energy		Energy delivered to a contingent **Area** from assisting **Areas** that is converted from delivered **Shared Activation Reserve Energy** after the **Shared Activation Reserve Energy** has been delivered for 30 minutes; maintained until the Contingent **Area** requests a return to normal but not longer than sixty minutes, and ramped out at a ten-minute ramp rate following communications initiated by the Contingent **Area** which have resulted in mutually established **interchange schedules.**	
Shared Activation Reserve Energy		Energy delivered from an assisting **Area** to a contingent **Area** that is implemented at a zero time ramp rate immediately following allocation notification, maintained until the Contingent **Area** requests a return to normal but not longer than thirty minutes, and ramped out at a ten-minute ramp rate following communications initiated by the Contingent **Area** which have resulted in mutually established **interchange schedules.**	
Single Element Contingency		A **contingency** involving the loss of one **element**.	
Small-Signal Stability		The ability of the electric system to withstand small changes or **disturbances** without the loss of synchronism among the synchronous machines in the system.	
Stability Limit		See NERC definition.	

Term	Acronym	Definition	Documents that use this term
Supervision		A closing command is said to be supervised if closing is permitted to occur only if certain prerequisite conditions are met (e.g., **synchronism-check**).	
Supervisory Control		A form of remote control comprising an arrangement for the selective control of remotely located facilities by an electrical means over one or more communications media.	
Surge		See NERC definition.	
Synchronism-check		Refers to the determination that acceptable voltages exist on the two sides of the breaker and the phase angle between them is within a specified limit for a specified time.	
Synchronism-check Relay		A verification **relay** whose function is to operate when two input voltages satisfy predetermined operating parameters.	
Transient Fault		A fault which occurs for a short or limited time, or which disappears when the faulted **element** is separated from all electrical sources and which does not require repairs to be made before the **element** can be returned to service either manually or automatically.	
Transmission Reliability Margin	**TRM**	TRM is defined as that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.	
Wheeling		The contracted use of electrical facilities of one or more entities to transmit electricity for another entity.	

NPCC Glossary of Terms Not Used by any Directories (References to existing NPCC documents to be provided) Draft: ~~June 21, 2011~~October 4, 2011

Note: Terms highlighted in blue are those that are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Documents that use this term
Automatic Operating Systems		**Special protection systems**, remedial action schemes, or other operating systems installed on the electric systems that require *no intervention* on the part of **system operators**.	
Autoreclosing		The automatic closing of a circuit breaker in order to restore an **element** to service following automatic tripping of the circuit breaker. Autoreclosing does not include automatic closing of capacitor or reactor circuit breakers.	
Available Transfer Capability	**ATC**	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. ATC is defined as the Total Transfer Capability (TTC), less the **Transmission Reliability Margin (TRM)**, less the sum of existing transmission commitments (which includes retail customer service) and the **Capacity Benefit Margin (CBM)**.	
Availability		A measure of time a generating unit, transmission line, or other facility is capable of providing service, whether or not it actually is in service. Typically, this measure is expressed as a percent available for the period under consideration.	
Average Demand		The electric energy delivered over any interval of time as determined by dividing the total energy by the units of time in the interval.	
Baseload Capacity		Capacity used to serve an essentially constant level of customer **demand**. Baseload generating units typically operate whenever they are available.	
Billing Demand		The demand upon which customer billing is based as specified in a rate schedule or contract. It may be based on the contract year, a contract minimum, or a previous maximum and, therefore, does not necessarily coincide with the actual measured demand of the billing period.	
Bottled Energy/Power/Capacity		Energy/Power/Capacity which is available at the source but which cannot be delivered to the point of use because of restrictions in the transmission	

Term	Acronym	Definition	Documents that use this term
		system. Also referred to as Locked-In Energy/Power/Capacity.	
Capacity Benefit Margin	**CBM**	CBM is defined as that amount of transmission transfer capability reserved by **load** serving entities to ensure access to **generation** from interconnected systems to meet **generation reliability** requirements.	
Coincident Demand		The sum of two or more demands that occur in the same demand interval.	
Contingency Reserve Adjustment Factor		A factor used in determining the additional **ten-minute reserve** that each **Area**, not meeting the DCS requirement for a given quarter, must carry. It is calculated using the following formula: $CRA_{quarter} = 2 -$ {the average percentage DCS (expressed as a decimal) for the quarter of measurement}	
Continuous Rating		The rating – as defined by the equipment owner – that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or **element** can support or withstand indefinitely without loss of equipment life. (Normally not used in NPCC)	
Contract Demand		The amount of **capacity** that a supplier agrees to make available for delivery to a particular entity and which the entity agrees to purchase.	
Control Area		An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling **generation** to maintain its net **interchange schedule** with other Control Areas and contributing to frequency regulation of the **Interconnection.**	
Demand Interval		The time period during which electric energy is measured, usually in 15-, 30-, or 60-minute increments.	
Double Element Contingency		A **contingency** involving the loss of two **elements**.	

Term	Acronym	Definition	Documents that use this term
Emergency Rating		The rating – as defined by the equipment owner – that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units, that a system, facility, or **element** can support or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.	
Firm Demand		That portion of the Contract Demand that a **power** supplier is obligated to provide except when system **reliability** is threatened or during **emergency** conditions.	
First Contingency Incremental Transfer Capability	**FCITC**	The amount of **power**, incremental above normal base **power** transfers, that can be transferred over the transmission network in a reliable manner based on the following conditions: 1. For the existing or planned system configuration, and with normal (pre-**contingency) operating procedures** in effect, all facility loadings are within normal **ratings** and all voltages are within normal limits. 2. The electric systems are capable of absorbing the dynamic **power swings**, and remaining stable, following a **disturbance** that results in the loss of any single electric **element**, such as a transmission line, transformer, or generating unit. 3. After the dynamic **power swings** subside following a **disturbance** that results in the loss of any single electric system **element** as described in 2 above, and after the operation of automatic operating systems, but before any post-**contingency** operator-initiated system adjustments are implemented, all transmission facility loadings are within **emergency ratings** and all voltages are within **emergency** limits.	
First Contingency Total Transfer Capability	**FCTTC**	The algebraic sums of the FCITC values and the appropriate total interregional transfers assumed in the base load flow model used for the	

Term	Acronym	Definition	Documents that use this term
		FCITC calculations.	
Forced Outage Rate		The hours a generating unit, transmission line, or other facility is forced out of service, divided by the sum of the hours it is removed from service, plus the total number of hours the facility was connected to the electricity system expressed as a percent.	
Harmonic ~~c~~Current		A periodic component of current having a frequency that is an integral multiple of that currents fundamental frequency. Harmonic currents are normally measured in amperes or in percent of the fundamental frequency current, generally at specific frequencies, such as second and third harmonics. Harmonic currents can, for example, be generated by HVdc converters, **Static Var Compensators** (SVC) and geomagnetically induced currents (GIC).	
High ~~s~~Speed ~~f~~Fault ~~c~~Clearing		Fault clearing consistent with correct operation of high-speed relays and the associated circuit breakers without intentional time delay. *Notes:* The specified time for high-speed relays in present practice is 50 milliseconds (three cycles on a 60Hz basis) or less. [IEEE C37.100-1981]. For planning purposes, a total clearing time of six cycles or less is considered high speed.	
High-~~s~~Speed ~~a~~Autoreclosing		The autoreclosing of a circuit breaker after a necessary time delay (less than one second) to permit **fault** arc deionization with due regard to coordination with all **relay** protective systems. This type of autoreclosing is generally not supervised by voltage magnitude or phase angle.	
Integrated Demand		The average of the instantaneous demands over the demand interval.	
Interchange Scheduling		The actions taken by scheduling entities to arrange transfer of electric **power**. The schedule consists of an agreement on the amount, start and end times, ramp rate, and degree of firmness.	
Instantaneous Demand		The rate of energy delivered at a given instant.	
Limiting Contingency		The **contingency** which establishes the **transfer capability**.	

Term	Acronym	Definition	Documents that use this term
Load Cycle		The normal pattern of **demand** over a specified time period associated with a device or circuit.	
Long Time Emergency (LTE) Rating		The maximum rating of electrical equipment based on nominal ambient conditions and recognizing the nominal **load cycle** for a long period such as 24 hours.	
Manual Reclosing		The closing of a circuit breaker by operator action after it has been tripped by **protective relays**. Operator initiated closing commands may originate from local control or from remote (supervisory) control. Either local or remote close commands may be supervised or unsupervised.	
Negative Shared Activation Reserve Energy		Energy received by an assisting **Area** from a contingent **Area** for an eligible **resource** loss having a concurrent effective loss of demand that exceeds the loss of energy from the **resource** loss, and is implemented at a zero time ramp rate immediately following allocation notification, maintained until the Contingent **Area** requests a return to normal but not longer than thirty minutes, and ramped out at a ten-minute ramp rate following communications initiated by the Contingent **Area** which have resulted in mutually established **interchange schedules.**	
Noncoincident Demand		The sum of two or more demands that occur in different demand intervals.	
Nonrecallable Available Transfer Capability	**NATC**	Total Transmission Capability less the **Transmission Reliability Margin**, less nonrecallable reserved transmission service (including the **Capacity Benefit Margin**).	
Non-Synchronized Reserve		That portion of **operating capacity**, which is available for synchronizing to the network and that capacity which can be made available by applying load management techniques such as curtailing **interruptible loads** or implementing **voltage reductions**.	
Normal Incremental Transfer Capability	**NITC**	The amount of electric **power**, incremental above normal base power transfers, that can be transferred between two areas of the interconnected transmission systems under conditions where pre-**contingency** loadings reach the normal thermal **rating** of a facility prior to any first **contingency** transfer limits being reached. When this occurs, NITC replaces FCITC as	

Term	Acronym	Definition	Documents that use this term
		the most limiting transfer capability.	
Normal Rating		The rating – as defined by the equipment owner – that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or **element** can support or withstand through the daily **demand** cycles without loss of equipment life.	
NPCC Emergency Criteria Contingencies		The set of contingencies to be observed when operating the **bulk power system** under **emergency** conditions.	
NPCC Normal Criteria Contingencies		The set of contingencies to be observed when operating the **bulk power system** under normal conditions.	
Peak Demand		The highest electric **power** requirement occurring in a given period (e.g., an hour, a day, month, season, or year). For an electric system, it is equal to the sum of the metered net outputs of all generators within a system and the metered line flows into the system, less the metered line flows out of the system.	
Peaking Capacity		Capacity used to serve **peak demand**. Peaking generating units operate a limited number of hours per year, and their capacity factor is normally less than 20%.	
Permanent Fault		A fault which prevents the affected **element** from being returned to service until physical actions are taken to effect repairs or to remove the cause of the fault.	
Pole (of an ac switching device)		That portion of the device associated exclusively with one electrically separated conducting path of the main circuit of the device.	
Postcontingency Operating Procedures		Operating procedures that may be invoked by the **system operator** to mitigate or alleviate system problems after a **contingency** has occurred.	
Power		Apparent Power — The product of the volts and amperes. It comprises both *real* and *reactive* power, usually expressed in kilovoltamperes (kVA) or megavoltamperes (MVA).	
Power Pool		Two or more interconnected electric systems operated and/or planned to supply **power** for their combined **demand** requirements.	

Term	Acronym	Definition	Documents that use this term
Recallable Available Transmission Capability	**RATC**	Total Transmission Capability less the **Transmission Reliability Margin**, less recallable transmission service, less non-recallable transmission service (including the **Capacity Benefit Margin**).	
Reclosing *This term by itself is not defined in the NPCC glossary.*		*Need to develop this definition.*	
Regional Reserve Sharing		Procedure that allows participating **Areas** to reduce the requirement for **reserve** within its **Area** due to the availability and deliverability of **reserve** from other **Areas.**	
Regional Reserve Sharing Energy		Energy delivered to a contingent **Area** from assisting **Areas** that is converted from delivered **Shared Activation Reserve Energy** after the **Shared Activation Reserve Energy** has been delivered for 30 minutes; maintained until the Contingent **Area** requests a return to normal but not longer than sixty minutes, and ramped out at a ten-minute ramp rate following communications initiated by the Contingent **Area** which have resulted in mutually established **interchange schedules.**	
Shared Activation Reserve Energy		Energy delivered from an assisting **Area** to a contingent **Area** that is implemented at a zero time ramp rate immediately following allocation notification, maintained until the Contingent **Area** requests a return to normal but not longer than thirty minutes, and ramped out at a ten-minute ramp rate following communications initiated by the Contingent **Area** which have resulted in mutually established **interchange schedules.**	
Single Element Contingency		A **contingency** involving the loss of one **element**.	
Small-Signal Stability		The ability of the electric system to withstand small changes or **disturbances** without the loss of synchronism among the synchronous machines in the system.	
Stability Limit		See NERC definition.	

Term	Acronym	Definition	Documents that use this term
Supervision		A closing command is said to be supervised if closing is permitted to occur only if certain prerequisite conditions are met (e.g., **synchronism-check**).	
Supervisory Control		A form of remote control comprising an arrangement for the selective control of remotely located facilities by an electrical means over one or more communications media.	
Surge		See NERC definition.	
Synchronism-check		Refers to the determination that acceptable voltages exist on the two sides of the breaker and the phase angle between them is within a specified limit for a specified time.	
Synchronism-check Relay		A verification **relay** whose function is to operate when two input voltages satisfy predetermined operating parameters.	
Transient Fault		A fault which occurs for a short or limited time, or which disappears when the faulted **element** is separated from all electrical sources and which does not require repairs to be made before the **element** can be returned to service either manually or automatically.	
Transmission Reliability Margin	**TRM**	TRM is defined as that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.	
Wheeling		The contracted use of electrical facilities of one or more entities to transmit electricity for another entity.	

October 19, 2011

NPCC Composite Responses to Comments Received on the NPCC Glossary of Terms

NPCC would like to thank those who provided comments on the draft NPCC Glossary of Terms which was posted to the Open Process from July 28, 2011 through September 12, 2011. The NPCC responses to individual comments are provided below.

Summary:

Below is a summary of the key comments and NPCC's responses:

1. Some commenters expressed a concern over the inconsistent approach adopted for listing and defining the Terms associated with Real Power Capability and Reactive Power Capability. The term of the latter (Reactive Power Capability) has been changed in order to make it consistent with the term for Real Power Capability.

2. Some commenters suggested that all terms have their definitions presented in the Glossary table as opposed to simply making a reference to the document that contains the definition, i.e. the NERC Glossary of Terms. This suggestion has been adopted and a note has been added to cite the source document.

3. A number of editorial changes have been made as per commenters' suggestions,

4. Terms that are not used in any Directories are put in a different group than those that are used by at least one Directory. However, there are terms that are not used in any Directories but are included in the definition of another term that is used by at least one Directory. (For example: the term "availability" is not used in any Directories, but is referenced in the defined term "Maintenance Outage".)

   Some commenter's suggested that a term that is included in the definition of another term which is used in a Directory be also grouped under "Glossary of Terms used by Directories". NPCC has not adopted this approach at this time since this needs to be assessed in the context of the future structure of terms

used in NPCC documents and the treatment of terms not used in any NPCC documents.

This is outside the scope of the current phase of NPCC Glossary of Terms development. Nonetheless, the suggestion will be forwarded to the respective Task Forces for consideration as we move to the next phase of glossary development.

5. Some commenters suggested that Terms used by Directories be changed from "bolded" to "capitalized" so as to be consistent with the approach adopted by NERC and other standards setting organizations.

   However, the posted NPCC Glossary of Terms used by Directories is a first step toward grouping all terms in the proper places and to remove redundancy among terms defined in the Directories and the A-07 document. In the future, revisions to terms used in all NPCC documents will undergo a comprehensive review to arrive at the most appropriate structure.

   Additionally, defined terms are bolded in all Directories, A, B and C documents and capitalizing the terms listed in the NPCC Glossary of Terms used in Directories while leaving terms used in NPCC documents bolded may create confusion. Therefore, this suggestion has not been adopted at this time.

   Nonetheless, NPCC will consider changing all defined terms from bolded to capitalized to be consistent with the approach adopted by NERC and others. This issue will be presented to the lead Task Forces for the Directories and A, B and C documents for their consideration.

6. Some commenters suggested material or structure changes that would require further deliberation as we move into the next phase of Glossary of Terms development. NPCC will forward these suggestions to the appropriate Task Forces for their consideration as each Directory is updated or as we move into next phase of Glossary development.

Specific responses to individual comments are provided below.

Comments from Michael Falvo - IESO:

We appreciate the opportunity to comment on the draft NPCC Glossary of Terms which was posted on July 28, 2011. We offer these comments:

1. The definition of Declared Capability appearing in the draft glossary is the same as that contained in the approved version of Directory 9. However, the approved version of Directory 10 contains a different definition. The Directory 10 definition states:

"Declared Capability (of a generator or generating facility) – The values submitted by the Generator Owner to the respective Transmission Operator."

It is not clear which definition is correct so this matter needs to be resolved.

NPCC Response:

Comment accepted: The identified inconsistency will be brought to the attention of the lead Task Force for D9 and D10 to develop a resolution as these Directories are revised.

2. Additionally, the text "(of a generator or generating facility)" should be moved from the Definition column to the Term column.

NPCC Response:

Comment accepted: The text has been moved to the Term column.

3. There is an inconsistency in how the terms Gross and Net Real Power Capability are listed in the glossary when compared with the terms Reactive Power Capability, Gross and Net. This must be addressed. While there are arguments for listing the terms in either format, for ease of locating a given term we prefer listing the definitions in alphabetical order of the entire name, i.e. "Gross Real Power Capability" and "Net Real Power Capability".

NPCC Response:

Comment accepted: Changes to the Gross and Net Reactive Power Capabilities have been made as suggested.

4. Additionally, the text "(of a generator or generating facility)" should be moved from the Definition column to the Term column and unbolded.

NPCC Response:

Comment accepted: The text has been moved to the Term column.

5. Several NPCC defined terms listed below should also be highlighted to indicate that they are different from similar defined terms in the NERC Glossary:

   Interconnection
   Operating Procedures (the NERC defined term is actually Operating Procedure)
   Protection System
   Rating
   Reactive Power
   Real Power
   Available Transfer Capability
   Capacity Benefit Margin
   Emergency Rating
   Firm Demand
   Normal Rating
   Peak Demand
   Transmission Reliability Margin

NPCC Response:

Comment accepted: We have highlighted these terms as suggested.

6. NERC standard PRC-005-2 which is currently under development contains a proposed definition of "Component". It may be worth including a footnote indicating that this NERC definition is currently under development.

NPCC Response:

Comment rejected: Since this term is not currently defined in the NERC Glossary and the NPCC term is not referencing the NERC term, we do not think that adding the suggested footnote is needed or appropriate at this time.

7. Finally, in the "Term" column, there are approximately nine instances where capitalization of the defined term is required for overall consistency.

NPCC Response:

Comment accepted: We have revised all the non-capitalized terms to achieve consistency.

8. We also support the review of the NPCC Glossary of Terms as part of the Phase 2 reformatting of each Directory, to determine whether maintenance of the NPCC definition is warranted in cases where a NERC definition also exists.

NPCC Response:

Thank you for the comment.

Comments from Daniel Rogers - LIPA:

1. NPCC does not define "misoperation" or "protection system misoperation" in the Glossary of Terms. Should it be assumed that it is the intent of NPCC to reference the NERC definition of "protection system misoperation" where required as it has in the NPCC C-45, Analysis & Reporting of Protection System Misoperations?

NPCC Response:

Comment accepted: NPCC will reque**st** the lead Task Forces of those Directories that contain the term "misoperation", currently not defined, to review the need for defining it with reference to the NERC definition.

Comments from Mike Garton - Dominion:

Dominion finds acceptable NPCC's intent to establish a new Glossary of Terms with two sections; one for A criteria terms and another for B and C terms. Dominion does however offer the following recommendations for consideration:

1. In the NPCC Glossary of Terms Used by Directories; there should be a legend to reflect why the terms are highlighted in blue (because the NPCC definition of this term is different than the NERC definition).

NPCC Response:

Comment accepted: A note has been added at the top of the table as suggested.

2. Add a revision history to both Directory documents.

NPCC Response:

Thank you for the comment. NPCC will consider this as we develop the next version.

Comments from Shaina Dadah - National Grid

The following comments are submitted by Northeast Utilities for the NPCC Glossary of Terms.

1. We support the new format of the NPCC Glossary of terms and NPCC's intent to retire the A7 document. In addition, we suggest that all terms specified in the glossary have the definition given along with the term, rather than referencing other documents. Should the definition come from another source; we recommend that it be cited.

    a. Example: As the glossary is presented in the draft:

Term	Acronym	Definition	Directories that use this term
Area Control Error	ACE	See NERC Definition	D2 D5 D8

We would prefer that it reads as follows:

Term	Acronym	Definition	Directories that use this term
Area Control Error	ACE	The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error. (NERC Glossary of Terms, 2008)	D2 D5 D8

NPCC Response:

Comment accepted: This approach has been adopted. Definitions for all terms are provided in the table, including those that are the same as NERC's, with the appropriate source cited.

Comments from John Seelke – PSEG Services Corporation

PSEG member companies of NPCC (PSEG Energy Resources & Trade LLC, PSEG Power Connecticut LLC, PSEG Power New York Inc) support the development of a new NPCC Glossary. We have these comments:

1. Capitalize proposed NPCC Glossary terms and remove all bolded terms. This should be the final end goal. However, since more NPCC terms may be added later from Criteria A-07 (which is NPCC's current Glossary), in the interim, NPCC terms that are defined in the proposed Glossary should be capitalized, while those in A-07 can remain be bolded. That approach would help user distinguish what's been changed and what's left to be changed.

NPCC Response:

Comment rejected: The proposed NPCC Glossary essentially replicates all existing terms listed in A-07.

Presently, defined terms are bolded in all NPCC documents including Directories, A, B and C documents and capitalizing the terms listed in the NPCC Glossary of Terms used in Directories while leaving terms used in NPCC documents bolded may create confusion. Therefore, this suggestion has not been adopted at this time.

Nonetheless, NPCC will consider changing all defined terms from bolded to capitalize to be consistent with the approach adopted for NERC standards. This issue will be presented to the lead Task Forces for the Directories and A, B and C documents for their consideration.

2. Definition principles. Here are some suggested NPCC Glossary principles:
    a. Improve unclear definitions. For example, "applicable emergency limits" should have each term capitalized per the comment above regarding capitalization. Also capitalize "stability" and "bulk power system," which are NPCC proposed Glossary terms. Finally, this definition would benefit from some redrafting to make it more coherent, including looking at the definition of "Operating Limit" which incorporates similar concepts.

NPCC Response:

Thank you for the comment. NPCC will present this to the lead Task Forces for consideration along with your other suggestion to capitalize defined terms, as indicated above.

b. Adopt a NERC Glossary definition where possible. Per the e-mail sent by Gerry Dunbar, we note that this will be done in Phase II, and we agree it's needed. It would help if NPCC adopted the same definition for the same term used by NERC.

NPCC Response:

Thank you for the comment.

Comments from Ted Dahill – National Grid

As requested, below are my comments on the 'NPCC Glossary of Terms Used or Not Used by Directories'. I was not able to provide a red-line version since you sent a 'PDF' file.

My format is the 'Term' being defined then my comment on the 'Definition'.

- General comment - suggest when use 'See NERC definition' we provide generic reference to the NERC website to help people start looking for the definition.

NPCC Response:

Comment accepted. Another commenter suggested that the NERC definitions be provided in the definition box. NPCC agrees with that commenter to adopt this more user-friendly approach and have made the corresponding changes. This should address your concern.

- Area - 'control areas' is not defined but is in the second file of 'terms not used in the directories' so should be moved in to the 'used in the directories' file.

NPCC Response:

Thank you for the comment.

The term "control area" is not used in any Directories, but is defined in the A-07 document and referenced in the defined term "area". The intent of developing the proposed initial NPCC Glossary, among others, is to identify terms that have been defined and the documents that they are used (or not used) without revising them or determining whether or not terms not used need to be removed. As we begin developing Phase II Directories, we will review the terms "area" and "control area" (and any other terms used or otherwise) to determine if they are still applicable in today's environment where control area is no longer an appropriate term to use when it has been essentially replaced with Balancing Area, Transmission Operator Area, Reliability Coordination Area, etc.

- Energize - suggest changing the word ' alive' to 'capable of conducting electric power

NPCC Response:

Thank you for the comment. Change to the definition must be posted for members' commenting and balloting so we are unable to make any changes at this time. Your suggestion will be forwarded to the attention of and appropriate action by the lead Task Force of the Directory that first uses this term.

- Interconnection - 'Control Areas' is not defined but is in the second file of 'terms not used in the directories' so should be moved in to the 'used in the directories' file.

NPCC Response:

Thank you for the comment. The term "control area" is not used in any Directories, but is defined in the A-07 document and referenced in the defined term "area". The intent of developing the proposed initial NPCC Glossary, among others, is to identify terms that have been defined and the documents that they are used (or not used) without revising them or determining whether or not terms not used need to be removed. As we begin developing Phase II Directories, we will review the terms

“area” and “control area” (and any other terms used or otherwise) to determine if they are still applicable in today’s environment where control area is no longer an appropriate term to use when it has been essentially replaced with Balancing Area, Transmission Operator Area, Reliability Coordination Area, etc.

- Maintenance Outage - 'availability' is not defined but is in the second file of 'terms not used in the directories' so should be moved in to the 'used in the directories' file.

NPCC Response:

Thank you for the comment. The term “availability” is not used in any Directories, but is defined in the A-07 document and referenced in the defined term “Maintenance Outage”, which is used in Directory 1. As we begin developing Phase II Directories, we will review the need to keep the term “availability”. Your suggestion will be brought to the attention of and appropriate action by the lead Task Force of Directory 1.

- Normal (Pre-contingency Operating Procedure - 'system operator' referenced but provide definition as 'Operator, System' with NERC reference. NERC's Glossary of Terms has it as 'System Operator'. Suggest changing the 'Operator, System' to 'System Operator and relocate in file as appropriate.

NPCC Response:

Comment accepted. “Operator, System” changed to “System Operator” and relocated the term.

- Planned Outage - 'availability' not defined - see 'Maintenance Outage' above.

NPCC Response:

Thank you for the comment. Please see our response to your comment on Maintenance Outage, above.

- Reactive Power Capability (of a generator or generating facility), Net - 'Gross Reactive Power Capability' is not defined in either file. Should add definition after the 'Gross Real Power Capability' definition.

NPCC Response:

Comment accepted. Other commenters also pointed this out. NPCC has made changes to arrive at a consistent treatment of the Gross and Net Real and Reactive Power Capability terms.

- Reclosing - reference '**synchronism-check**' that is then defined within the 'Reclosing' definition. Suggest making 'synchronism-check- a separate defined term as it is referenced other places - such as in the 'Supervision' definition.

NPCC Response:

Thank you for the comment. The term "synchronism-check" is not used in any Directories, but is defined in the A-07 document and referenced in the defined term "Reclosing", which is used in Directory 1. As we begin developing Phase II Directories, we will review the need to keep the term "synchronism-check". Your suggestion will be brought to the attention of and appropriate action by the lead Task Force of Directory 1.

- Reportable Events - 'Control Areas' is not defined - see 'Area' above.

NPCC Response:

Thank you for the comment. The term "control area" is not used in any Directories, but is defined in the A-07 document and referenced in the defined term "area". The intent of developing the proposed initial NPCC Glossary, among others, is to identify terms that have been defined and the documents that they are used (or not used) without revising them or determining whether or not terms not used need to be removed. As we begin developing Phase II Directories, we will review the terms "area" and "control area" (and any other terms used or otherwise) to determine if they are still applicable in today's environment where control area is no longer an appropriate term to use when it has been essentially replaced with Balancing Area, Transmission Operator Area, Reliability Coordination Area, etc.

- Reserve on Automatic Generation Control (AGC) - 'load demand' is bold and not define. Suggest use either 'load' or 'demand' both of which are defined using NERC reference.

NPCC Response:

Comment accepted: We have removed the word "demand".

- Ten-minute Reserve - refer to 'non-synchronized' which is not a defined term. Suggest removing the bolding from the 'non' so will refer back to the ''synchronized' definition.

NPCC Response:

Comment accepted. Suggested change has been made.

- Thirty-minute Reserve - see 'Ten-minute Reserve' issue.

NPCC Response:

Comment accepted. Suggested change has been made.

- Total Transfer Capability - in point 1, suggest changing 'normal (pre-**contingency) operating procedures**' to all bold and drop the hyphen to agree with the defined term.

NPCC Response:

Comment accepted. Suggested change has been made.

- Total Transfer Capability - in point 3, the term 'emergency ratings' is not defined but is in the second file of 'terms not used in the directories' so suggest moving the definition into the 'used in the directories'. An alternative would be to add the term into the glossary with a reference to the NERC definitions.

NPCC Response:

Thank you for the comment. The term "emergency rating" is not used in any Directories, but is defined in the A-07 document and referenced in the defined term "Total Transfer Capability", which is used in Directory D5. Further, "emergency rating" by itself is not defined but the "Short Term Emergency Rating" is defined and used in Directory 1. As we begin developing Phase II Directories, we will request the lead Task Forces for Directories 1 and 5 to assess the need to define emergency rating as a separate term.

- Total Transfer Capability - in point 5, the term 'power pool' is not defined but is in the second file of 'terms not used in the directories' so should be moved in to the 'used in the directories' file'.

NPCC Response:

Thank you for the comment. The term "power pool" is not used in any Directories, but is defined in the A-07 document and referenced in the defined term "Total Transfer Capability", which is used in Directory 5. As we begin developing Phase II Directories, we will review the need to keep the terms "power pool. Your suggestion will be brought to the attention of and appropriate action by the lead Task Force of Directory 5.

As for the file of 'Not Used by any Directories', beside the referenced changes above (moving definitions back into the 'used' file:

- Available Transfer Capability - would use of the NERC definition satisfy NPCC's needs or are TRM and CBM specific terms that need referencing?

NPCC Response:

Comment accepted. The NPCC term Available Transfer Capability is defined differently than the NERC terms. We will highlight this in the NPCC Glossary table. Further, the terms TRM and CBM are defined differently from the NERC terms. We have highlighted them to indicate the difference.

- Average Demand - delete the '-' from the 'Term' column

NPCC Response:

Comment accepted. "-" has been deleted from the Term column.

- Peaking Capacity - refers to '**peak demand**' which is not a defined term in either file. Suggest adding into the 'used in directories' file with a reference to the NERC definition.

NPCC Response:

Thank you for the comment. Peak Demand is defined in the A-07 document but is not used in any Directories. Consistent with the approach we presented in the cover

letter when we posted the NPCC Glossary, we would keep these terms as defined but not used in any Directories for now. As we begin developing Phase II Directories and start reviewing terms used in the A, B and C document, we will review these terms and determine where to list them under the NPCC Glossary.

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Cost Effectiveness Analysis Procedure "CEAP" For NPCC Regional Reliability Standards

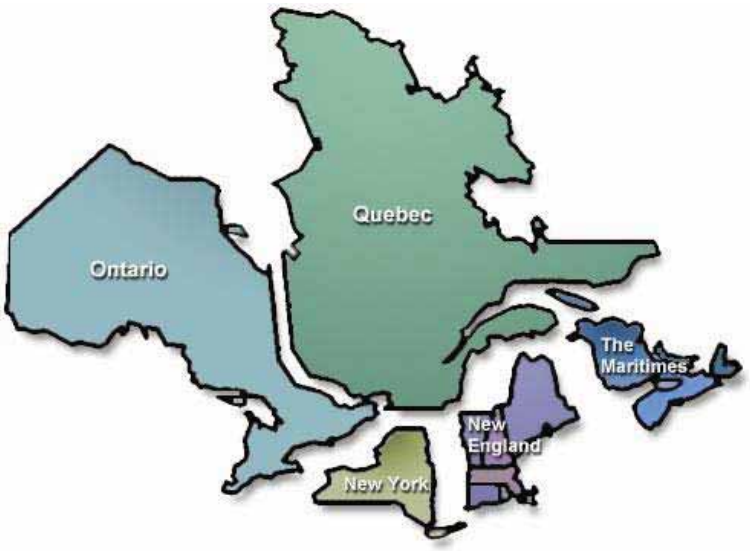

Approved by the NPCC Regional Standards Committee
XX/XX/2011
Approved by NPCC Board of Directors
XX/XX/2011

I. EXECUTIVE SUMMARY

During a 2010 FERC technical conference the Commission recognized that "reliability does not come without cost", and significant interest was expressed in development of a process to identify costs for draft reliability Standards and the ability of the proposed standards to achieve their reliability objective(s) in a cost effective manner. In addition, the NPCC Board of Directors (BOD), in its consideration of Regional Standards, expressed concern regarding what a Standard's implementation may cost the industry and the relevant incremental reliability improvement (benefits) that implementation of that Standard may yield. Therefore, the NPCC BOD directed NPCC Staff to develop a methodology to assess the cost and benefit of Standards. This NPCC Cost Effectiveness Analysis Procedure (CEAP) establishes a process to address those concerns.

The CEAP introduces two assessments of the estimated industry wide costs of requirements in a proposed draft Standard into that Standard's development process. The procedure, conducted in parallel with the drafting process, is designed so it does not delay the development of the Standard, but adds supporting information and background for the NPCC stakeholders, ballot body and the NPCC Board of Directors. In addition to providing a "snapshot" looking at the cost of the proposal, the CEAP will also solicit input from an independent and wider range of technical perspectives of the industry as well as NPCC's technical groups to determine if any unintended adverse impacts may be created with respect to other Regional or Continent wide Standards, should the draft Standard be approved.

The NPCC CEAP will be utilized to perform an analysis of the cost benefit of the proposed requirements in NPCC's Regional Standards as they are developed, and prior to their approval by the NPCC Board of Directors. Implementation of the CEAP will be coordinated with the steps outlined in the NPCC Regional Standards Development Procedure for developing a Regional Standard.

The process incorporates two separate phases of reviews,

> First to be conducted is a Cost Benefit Analysis (CBA) that will be based on the responses to an initial set of questions posed to the industry during the Regional Standard Authorization Request (RSAR) stage to determine if the Standard project should be pursued. A cost benefit analysis is an assessment to determine and compare the relative costs and benefits of a particular course of action. Questions posed during the RSAR stage to the industry will focus on potential costs and benefits. Questions posed during the RSAR phase will also determine if the Standard, in the view of stakeholders, would achieve an Adequate Level of Reliability (ALR) or go "beyond" that to achieve some optimum or premium level of reliability. Once this information is gathered, the NPCC Regional Standards Committee (RSC) will review this information and make a determination whether or not to pursue the development of the standard.[1] The CBA might lead to the

[1] For example, if the RSAR in question addresses Geomagnetic Disturbances (GMD) and hardening the grid, questions could be posed at the onset of the process on what a cost might be to protect all the transformers (potentially billions of dollars) and what the probability of experiencing a severe GMD, based on past history is (extremely low for continent wide outage).

conclusion that a technical guideline or whitepaper might be a preferred undertaking as opposed to a mandatory Standard in a given area.

Second will be the Cost Effectiveness Analysis (CEA). The Cost Effectiveness Analysis is an analytical tool whose purpose is to provide information about the relative cost of different approaches to eliminating disparities, increasing life expectancy, or any program or initiative. This will involve two sets of questions. One to solicit industry opinion on the technical feasibility to achieve the reliability objective of the Standard with its requirements, and second will be to solicit cost, cost recovery, resource and estimated time to implement compliance to the draft Standard. These will be done on a requirement by requirement basis, and questions will ideally be posted once the draft Standard's requirements have firmed up later in the Standard development process. The RSC will evaluate all information provided and produce a CEAP report that will be posted along with the NPCC Standard during balloting. Information in the report will be aggregated and presented on a region-wide basis along with either a recommendation, or a list of potential issues for stakeholder consideration.

All cost information submitted by entities will be reviewed and compiled by NPCC Staff prior to being made public, or presented to the RSC. Market issues of individual stakeholders may exist or be revealed through the responses to the CEAP questions. Necessary confidentialities will be maintained, and no market sensitive information will be revealed.

II. BACKGROUND

The purpose of the Northeast Power Coordinating Council, Inc. ("NPCC"), is to enhance the reliability of the international, interconnected bulk power system in Northeastern North America through the development of more stringent and specific Regional Reliability Standards. Additionally NPCC will perform compliance assessment and enforcement of continent wide and Regional Reliability Standards pursuant to the execution and implementation of a Regional Delegation Agreement with the Electric Reliability Organization ("ERO") and applicable Canadian Memoranda of Understanding. These agreements are backstopped by the Federal Energy Regulatory Commission ("FERC") and Canadian Provincial governmental authorities. In the development and enforcement of Regional Reliability Standards, NPCC, to the extent possible, facilitates attainment of fair, effective, efficient, and competitive electric markets.

General Membership in NPCC is voluntary and is open to any person or entity, including any entity participating in the Registered Ballot Body of the ERO that has an interest in the reliable operation of the Northeastern North American bulk power system.

III. NPCC PROCEDURE FOR COST EFFECTIVENESS ANALYSIS OF PROPOSED NPCC REGIONAL STANDARDS.

1) Before accepting a NPCC Regional Standard Authorization Request (RSAR), the Regional Standards Committee (RSC) posts the CBA questions in Appendix B for

stakeholder review and response. Following receipt of the responses to the CBA questions, the RSC will compile the information obtained and determine whether or not to accept the RSAR and authorize posting of the notification of intent to develop a standard along with the responses to the Cost Benefit Analysis (CBA) questions in Appendix B. If the RSC determines that the CBA responses do not support a standard's development, the RSC will determine if a technical guideline or white paper be developed to address the reliability objective by the appropriate task force or working group. The RSC will also issue a formal notice explaining why the RSAR was not accepted.

2) During the NPCC Regional Standards development process, a NPCC Regional Standard Drafting Team (RSDT) will deliberate on whether the requirements in a Standard are developed enough to begin the CEA process and request that the RSC initiate the second phase (CEA) of the process.

3) The RSC, upon approval of the RSDT's request to initiate Phase two of the CEAP, will develop a CEAP Guidance Procedure document (see Appendix A for template) outlining the expectations for the CEAP, and conduct the assessment as follows:

    a. Approve a set of surveys that must be conducted to determine the appropriate impact (i.e. operational, costs, resources, etc.) of the proposed Standard's requirements on a requirement by requirement basis. The RSC will judge whether or not sufficient stakeholder responses were received to provide valid results for analysis. If the number of responses received was not adequate the RSC will determine what course of action to take, ranging from accepting the limited information received, to the reissuance of the surveys. The surveys should be such that their results provide:

        i. Indication of what cost would be associated with the individual requirements in the Standard, if approved. The approximate costs would be aggregated by the RSC and based on surveys for the entire Region, and also by the Reliability Coordinator, Province, etc. to provide more information on how universal the impact may be.
        ii. Indication of the entities' estimates of what resources and timeframes might be needed to comply with a Standard's requirements and provide information on the time the entities might need to implement the requirements of the Standard, and develop documentation regarding compliance. This input would consider not only technical but budgetary concerns. The timeframe would provide further input to the RSDT's Implementation Plan.
        iii. Identification of potential alternative reliability requirements that could more cost-effectively achieve the same benefits of reliability

improvements , and provide justifications, as well as any potential adverse impacts or unintended consequences, if any, that may result directly, or indirectly.
iv. Identification of any market issues that may exist and how they could affect the Standard's requirements or applicability.

b. Approve the assignment of a particular survey to NPCC Task Forces (TF) or Working Groups (WG) and the scope of activities expected as per the Cost Effectiveness Analysis (CEA) Guidance Document, or utilize the standard set of questions in Appendix B.
c. Upon completion of the surveys and analysis, the RSC will~~, and if necessary utilize resources outside of the RSC to~~ conduct an assessment of cost and perceived effectiveness of the draft Standard's requirements to achieve the identified reliability benefit of the Standard's objective and develop a recommendation.

4) Upon TF (or WG) completion of the CEAP and all RSC requested tasks the TF (or WG) will submit the information, results and recommendations to the RSC.

5) The RSC will review the TF recommendations, information, and suggested follow up actions and will determine a course of action.

6) The RSC will communicate the outcome of their deliberations to the RSDT along with one of the following actions:
   a. Revise the Standard to address the results of the CEAP.
   b. Accept the Standard "as is" to move forward through the remainder of the process (go to Step 7).
   c. Hold the Standard in abeyance until such time as additional guidance can be provided regarding whether or how to continue.
   d. Decide not to pursue the development of certain requirements or the entire Standard due to cost effectiveness considerations.

7) Upon acceptance by the RSC of the CEAP and determination that the Standard is cost effective by virtue of information provided in the RCC report and any other input that may be available, the remainder of the NPCC Standards Development Process will be followed. The results of the CEAP will be posted along with the draft Standard and Implementation Plan along with any other pertinent information for the information of the stakeholders during ballot.

8) The NPCC Assistant Vice President of Standards will present the results of the CEAP to the NPCC Board of Directors at the same time the Standard is presented for approval.

Appendix A

CEAP Guidance Procedure

Date RSC Accepted SDT request to initiate CEA_____

Draft Standard Title/Project Number_____

Standard Type (i.e. Planning- TPL, Protection-PRC, etc.)_____

NPCC Subject Matter Experts (RSC, RCC, TF or WG) _____
(Cost and Technical consideration--assigned gathering of data/surveys)

Applicability (i.e. TOP, GO, TO, etc.)_____

Suggested Additional Outreach for Survey_____
(Gen. Forum, NATF, etc.)

Standard Templates Survey Questions or Custom_____

Assigned Group for Custom Survey(s), if applicable (RSC, TF, or etc.)_____

RSC approves Survey data requests (Date) _____

Date Survey sent to stakeholders for 30 day comment period_____

RSC analyzes Survey results and develops a recommendation_____

RSC posts the results of the CEAP along with the Ballot materials_____

1) <u>CEAP Phase 1 Cost Benefit Analysis (CBA)</u>
RSAR proposed (but not yet accepted) Date_____

Results of RSC Evaluation of CBA Responses (Proceed? Y/N) _____

Date RSC initiates Phase 1 CEAP, CBA_____

2) CEAP Phase 2 Cost Effectiveness Analysis (CEA)

Appendix B

Typical CBA Questions (Phase 1 of CEAP, to be included upon notification of intention to develop an NPCC Regional Standard and posting of RSAR)

1) **Does the proposed Standard fill a reliability "gap"? ~~and i~~Is the Standard needed to fill a reliability gap? Provide supporting information if the abnswer to either question is yes. If not, why not (probabilistic data may be used to make a determination)?**
2) **If the Standard meets a "reliability related" need would it achieve an adequate level of reliability "ALR" or exceed this ALR? If so, how? If not why?**
3) **What approximate one-time and ongoing estimated potential costs would be associated with compliance with the proposed Standard?~~the implementation and maintenance of a Standard in this area?~~**
4) **Is there an alternate way of achieving the reliability objective of this proposed Standard?**
5) **Would a technical guideline or "best practices" whitepaper be effective in achieving a desired outcome to meet the reliability need, as opposed to a "region wide" Standard?**
6) **What are the benefits of the proposed standard/requirements?**

Typical CEAP Technical Survey Questions (Phase 2 of CEAP, may be included in SDT postings for comments or done separately as part of the CEAP);

1) **On a requirement by requirement basis, are the Requirements effective in achieving the reliability objective of the Standard and if not, why?**
2) **Are there alternative ways to achieve the draft Standard's reliability objective? If so, what alternatives are there and which requirements would they replace?**

3) **On a requirement by requirement basis, do the draft requirements in the Standard achieve or contribute to a level of reliability that is "adequate", i.e. acceptable? If so, how? If not, why not?**
4) **Are there additional "efficiencies" that could be realized for any requirement(s)? If so, which requirements, what "efficiencies", and how realized?**
5) **Is there any adverse impact to reliability or any other existing standard, NPCC Regional Criteria, or in-process project draft Standard(s), of which your organization is aware?**
6) **What would the probabilistic risk be for an event/issue to occur which would otherwise be addressed by this Standard? (i.e. High, Medium, or Low)**

<u>Typical CEAP Cost and Implementation Questions</u> (Phase 2 of CEAP, may be included in SDT postings for comments or done separately as part of the CEAP);

1) **Describe the size of your organization in broad general terms, e.g. GO-Total installed MWs, TOs circuit miles by kV and total load served, etc.**
2) **What are the gross anticipated one-time and ongoing costs of implementing the Standard as presently drafted (labor and materials)?**
3) **If the Standard were not implemented, what would be the potential cost incurred if the perceived reliability risk was not mitigated, or the projected outcome, (i.e. lack of maintenance of UFLS could render it inoperable and lead to cascading)?**
4) **How long would it take your organization to implement full compliance to the Standard as written? What would affect the implementation (i.e. outage scheduling, availability of materials, human resources, etc.)?**

NPCC Cost Effectiveness Analysis Procedure "CEAP"

RSC Conducts Phase 1 CBA, upon RSC approval to continue-

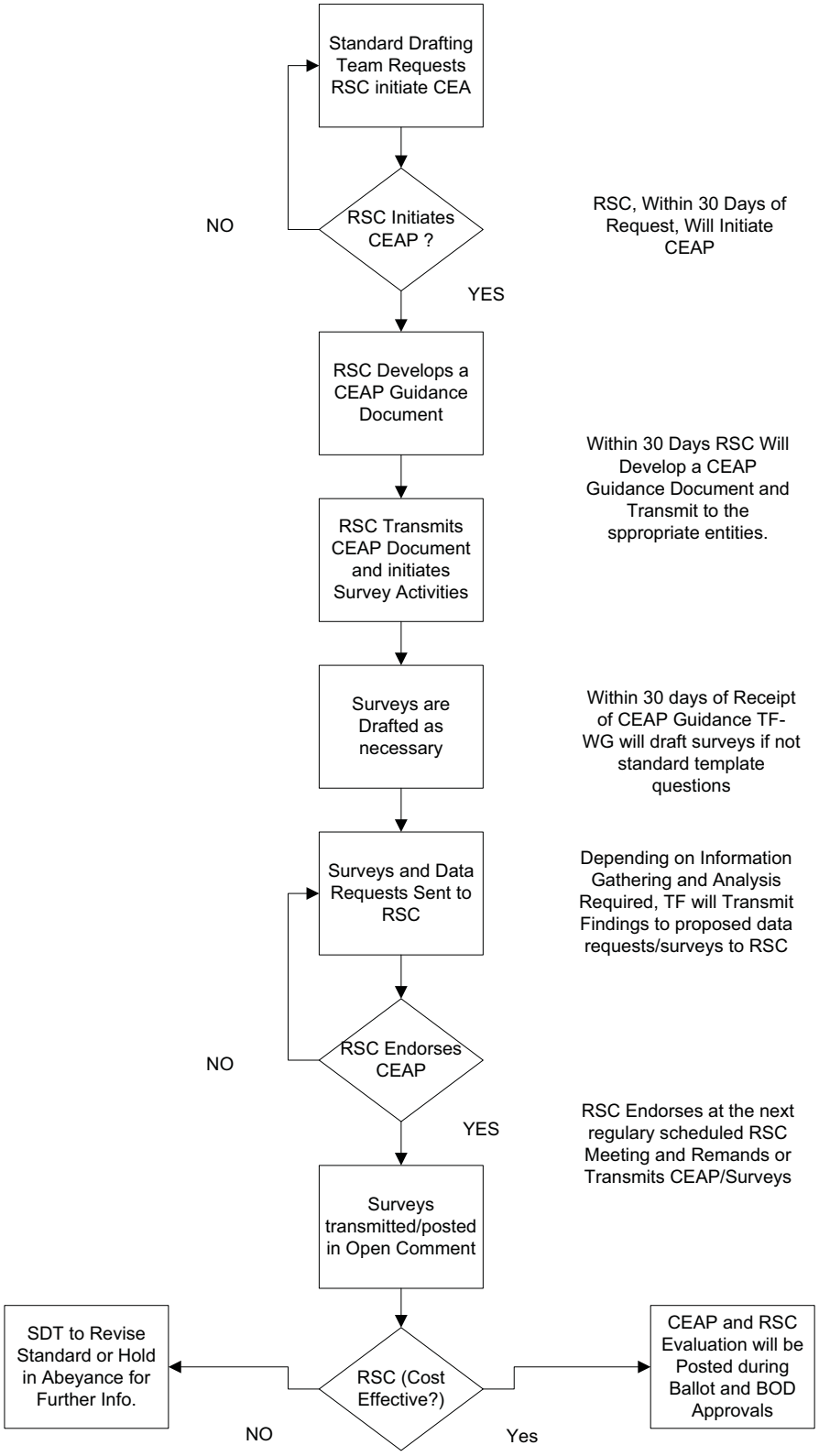

October 5, 2011

NPCC, Inc.

1040 Avenue of the Americas - 10th Floor, New York, NY 10018-3703

NPCC RSC Triage Process for Standards Related Matters

Objective: The NPCC RSC Triage Process is intended to be used to clearly identify the process that NPCC will utilize to evaluate continent-wide, regional standards and related matters. It is meant to ensure consistency, and that the proper resources are employed to review the technical subject matter and the proper policy level in order to ensure a sufficient review is done.

1) The Triage process will begin upon NPCC becoming aware of continent-wide or regional (NPCC, FRCC, etc.) standards related activity.
2) Because of the variability of deadlines for standards related activities, the NSS will develop a timeline for each activity to meet externally imposed "due dates".
3) NPCC Standards Staff (NSS) reviews the activity and determines the subject matter expertise required for the review.
4) NSS will solicit the appropriate NPCC Staff for an internal review and compile any NPCC Staff recommendations.
5) NSS will forward to the RSC Executive Committee (EXCom) the notification of the standards activity, NPCC Staff recommendations, potential affected entities, and suggest the Subject Matter Experts "SME"/ Task Force "TF"(s) required to perform an evaluation.
6) EXCom reviews the notification and the NSS recommendation for SME review and appropriately accepts, rejects or modifies (including an alternate course of action) the recommendation.
7) NSS will make a formal request to the SME (TF) (copying the RCC) for review and comment and clearly indicate the analysis required and the recommended response type-- i.e. ballot recommendation, comment, opinion on a field test result, white paper opinion, etc., as well as a date by which the review must be completed. The TF or WG to which the analysis and review has been delegated to will respond to the NSS by the date indicated in the request.
8) NSS will also, and as necessary depending on the issue, discuss with the RSC the initiation of the Cost Effectiveness review procedure.
9) NSS will then compile all the information from the SME TF, NPCC Staff internal recommendations and any Cost Effectiveness information available and review for major issues and items or requirements that should prevent the activity from being continued.
10) NSS will then submit the information gathered to the RSC for their review and consensus.
11) Any RSC member, alternate, NPCC Staff (refer to Step 4 above), or member of the NSS may initiate a teleconference request to resolve or discuss outstanding concerns.
12) As necessary any remaining concerns will be brought to the SME/TF for resolution.
13) Upon the conclusion of RSC discussions, and either consensus or confirmation of outstanding issues, NSS will respond to the notification as required by either submission of comment,

DRAFT

making a ballot recommendation to the membership of NPCC, or notifying the members of the issues that exist that preclude a consensus position.

14) Documentation of the final response and supporting materials will be posted in the appropriate location on the NPCC Website.

DRAFT

NPCC RSC Triage Process for Standards Related Matters

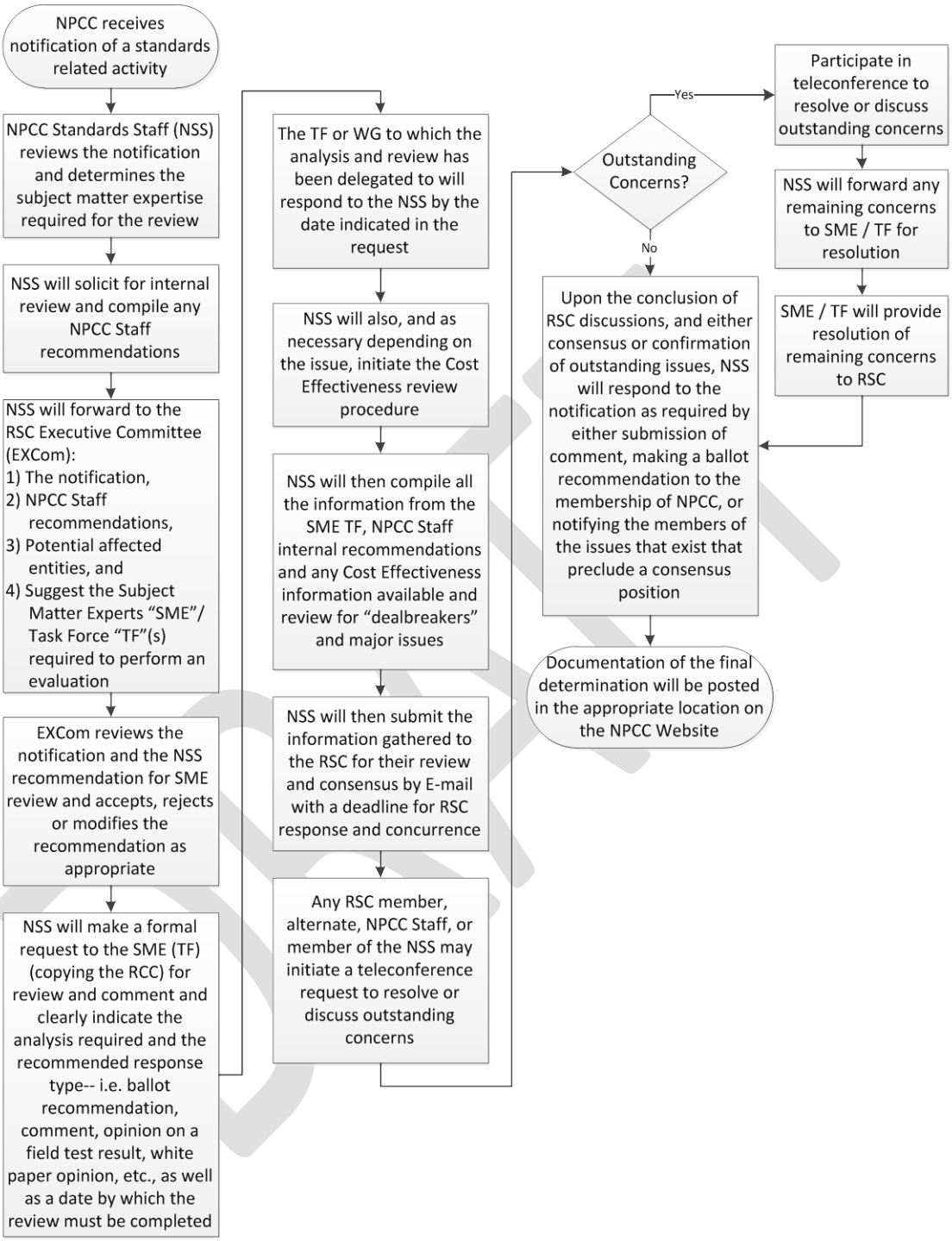

From:	Guy V. Zito
To:	clermont.sylvain@hydro.qc.ca; Lee R. Pedowicz; rscmembers; rjfalsetti@cogeco.ca; donald.e.nelson@state.ma.us; michael.jones@us.ngrid.com
Cc:	phan.si_truc@hydro.qc.ca
Subject:	RE: Triage Process
Date:	Wednesday, August 17, 2011 11:29:29 PM

It is implicit to the RSC ExCom's action on the individual items requiring review Sylvain. We can discuss further at the October RSC meeting. Thanks for reviewing and your support of this.

Best Regards,

Guy V. Zito
Assistant Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10 th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

From: Clermont.Sylvain@hydro.qc.ca [Clermont.Sylvain@hydro.qc.ca]
Sent: Wednesday, August 17, 2011 9:44 AM
To: Lee R. Pedowicz; rscmembers; rjfalsetti@cogeco.ca; donald.e.nelson@state.ma.us; michael.jones@us.ngrid.com
Cc: phan.si_truc@hydro.qc.ca
Subject: RE: Triage Process

First this is a very good idea.

The only comment I would have is that there doesn't seem to be any step to assign priority and assess the "importance" or the alignment with our priorities. How do we determine that we have higher priorities relative to the work force available. We may choose to focus our attention to what matters the most. I don't see that in the process.

Maybe I'm misreading ?

Sylvain Clermont, ing.
Chef Réseaux voisins / Manager Neighboring Systems
Direction Commercialisation et Affaires réglementaires
Hydro-Québec TransÉnergie
Complexe Desjardins | Tour de l'est, 19e étage
C.P. 10 000, succ. pl. Desjardins
Montréal (Québec) | H5B 1H7
Tel: (514) 879-4648 | Cell: (514) 710-8736

De : Lee R. Pedowicz [mailto:lpedowicz@npcc.org]
Envoyé : 17 août 2011 06:45
À : rscmembers; rjfalsetti@cogeco.ca; donald.e.nelson@state.ma.us; michael.jones@us.ngrid.com
Objet : FW: Triage Process

Good morning.

Reminder.

Lee

From: Lee R. Pedowicz
Sent: Friday, August 05, 2011 9:45 AM
To: rscmembers; rjfalsetti@cogeco.ca; david.ramkalawan@opg.com; donald.e.nelson@state.ma.us; michael.jones@us.ngrid.com; david.conroy@cmpco.com; dverner@nbpower.com; alden.briggs@nbso.ca; dave.daley@nbso.ca; ggoodrich@nyiso.com
Subject: Triage Process

Good morning.

As discussed at this week's RSC Meeting, attached is a copy of the Triage Process on which I've included the comments received to date. Please review and let me know any additional thoughts by August 19, 2011. The plan is have this put on the agenda for the September RCC Meeting.

Lee

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NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1515 BROADWAY, NEW YORK, NY 10036-8901 TELEPHONE: (212) 840-1070 FAX: (212) 302-2782

Draft for RSC Approval

October 26, 2011

Northeast Power Coordinating Council, Inc.

Directory Development and Revision Manual

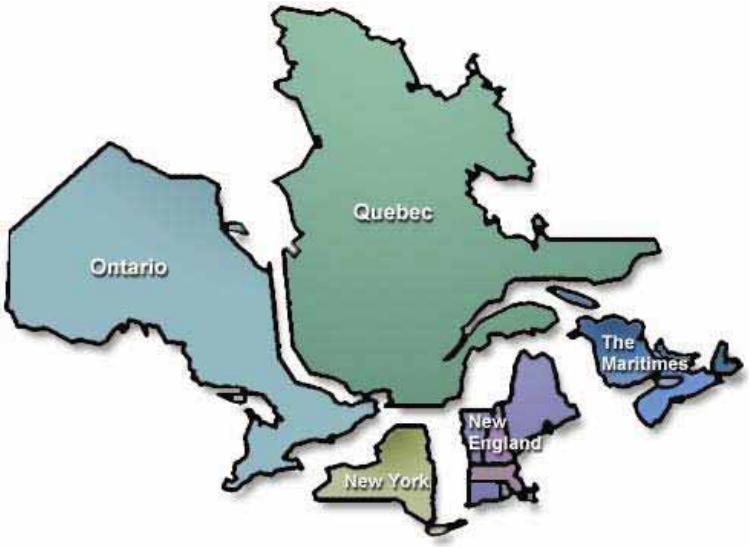

Approved by the Reliability Standards Committee

October XX, 2011

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0		Effective Date	New

NPCC

DIRECTORY DEVELOPMENT and REVISION MANUAL

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I. EXECUTIVE SUMMARY

The purpose of the Northeast Power Coordinating Council, Inc. ("NPCC") is to enhance the reliability of the international, interconnected bulk power system in Northeastern North America through the development of more stringent and regionally specific criteria.

NPCC Directories have been developed in order to provide a consistent and comprehensive set of reliability requirements for the Northeast, while consolidating related information for NPCC Criteria, Guidelines, Procedures as well as FERC and NERC approved Regional Standards into one document.

NPCC Directories and the criteria contained within, apply only to NPCC Full Members. However, there may be additional requirements within tariffs or interconnection agreements that hold non Members responsible for complying with the criteria within each Directory.

This document is intended to provide guidance to NPCC Task Forces and NPCC Full Members when establishing a new or revised Directory or when retiring or consolidating an existing Directory and will also clarify the roles and responsibilities of the NPCC Task Forces responsible for Directory content.

II. Introduction

The NPCC Regional Standards Committee (RSC) working with the lead Task Force for each Directory has overall responsibility for managing the Directory project.

The Directories are organized to demonstrate that NPCC regional criteria are more specific than and/or more stringent than and consistent with NERC Reliability Standards.

Each Directory contains an Introduction, along with sections that identify NERC ERO Standard and NPCC Regional Standard Requirements that are associated with the Directory.

Additionally, each Directory is comprised of a section that describes the NPCC regionally specific criteria and was developed from the related NPCC ‘A’ documents. The appropriate Type ‘B’ Guideline and Type ‘C’ Procedure documents are included within each Directory as Appendices.

A mapping document has been provided on the Directory page of the NPCC Website and has been organized in a manner that provides guidance on where a Directory's content originated (A Criteria, B Guideline, or C Procedure).

1. https://www.npcc.org/Standards/Directories/Directory_Mapping.pdf.

The mapping document provides tracking of specific content language from documents that were translated or replaced by Directories and their Appendices.

Phase 1 of the Directory Project was initiated by the NPCC Reliability Coordinating Council in order to demonstrate consistency with NERC Standards and to effectively group documents together according to functional topics.

During Phase 1 an initial translation of the existing criteria document was performed in addition to identifying and eliminating language within the criteria that duplicated existing NERC Reliability Standards.

Additionally, Functional Model language was introduced and the corresponding 'B' Guidelines and 'C' Procedures were incorporated into each Directory as appendices.

The resulting Directory created a single source reference for all entities while providing a method to demonstrate consistency with NERC Standards.

Phase 2 of the Directory Project was initiated in order to reformat the Criteria section of each document into specific and measurable NERC style requirements which will promote the NPCC Regional criteria as more specific or more stringent within each Directory.

Phase 2 will also facilitate the development of the NPCC Criteria Compliance Enforcement Program (CCEP) by providing the respective requirements of that program.

Although the Regional Standards Committee is responsible for the overall Directory program, individual Directories are under the control of a lead NPCC Task Force which is responsible for coordinating review among all other Task Forces which have jurisdiction over either a portion of the criteria or one or more of the Appendices in the Directory.

.

III. TASK FORCE ROLES and RESPONSIBILITIES

With the development of the Directories it has been recognized that in certain cases the jurisdictional boundaries of Task Force ownership have been crossed and additional guidance when coordinating Directory review among Task Forces is necessary.

In general, revisions and interpretations to a Directory shall be coordinated by the Lead Task Force of the document.

Revisions to a Directory can be initiated in a fully bi-directional manner; that is either by the Lead Task Force responsible for the document or by another Task Force who is responsible for some portion (criteria or appendices) of the document.

This process will allow each Directory to remain under the control of the respective Lead Task Force which has the necessary expertise to keep each document current and accurate while also providing a means to coordinate component review of those segments of the Directory that may be under the control of another Task Force.

The Lead Task Force can initiate a full revision of the Directory in accordance with the *NPCC Reliability Assessment Program* (NRAP) date of approval or some need to revise the criteria section of the document.

https://www.npcc.org/Library/NRAP/Forms/Public%20List.aspx

The Lead Task Force will also notify other Task Forces under whose jurisdiction either a portion of the criteria or Appendices exists in order to coordinate the total document review and revision.

Similarly, a Task Force which is not the Lead Task Force of the Directory, but is responsible for some portion of the document, shall coordinate a necessary revision to their section of the document through the Lead Task Force of the Directory.

IV. DIRECTORY DEVELOPMENT AND REVISION PROCEDURE

1. NEW DIRECTORY

Any NPCC Full Member may request the development of a new Directory. The request shall be made to the NPCC Manager of Reliability Criteria via email and shall contain the background and justification for the development of the new Directory. The NPCC Manager of Reliability Criteria shall forward the request to the Regional Standards Committee (RSC) in order for the RSC to review the request and assign its development to the appropriate NPCC Task Force.

The Lead Task Force responsible for developing the new Directory shall draft an initial version of the document consistent with the Directory template in Attachment A.

The NPCC Manager of Reliability Criteria shall post the draft Directory to the NPCC Open Process for 45 days.

At the conclusion of the 45 day Open Process, the Lead Task Force will discuss the comments submitted and post responses to comments on the NPCC Open Process portal.

If the responses to comments received on the draft result in substantive changes to the document, then the revised draft shall be reposted to the Open Process for a successive 45 day posting period.

If no substantive changes are developed which would require additional postings of a revised draft, the new Directory is presented to the Reliability Coordinating Council (RCC) for approval.

Upon RCC approval the document is submitted for a ballot to the NPCC Full Member Representatives along with the RCC recommendation of approval.[1]

The process for establishing a new Directory is represented below in Figure 1:

[1] Approval of a new Directory requires a 2/3rd majority of Full Member voting representatives in accordance with the NPCC Bylaws.

Figure 1 New Directory:

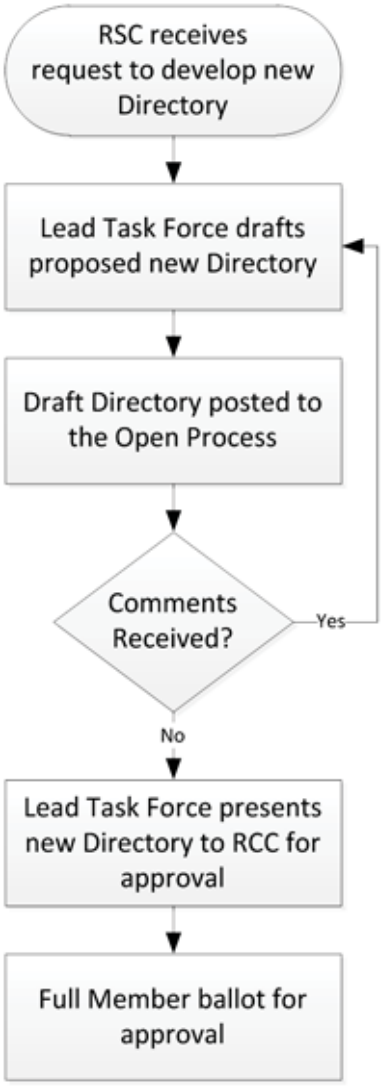

2. DIRECTORY REVISIONS

a. Revisions to the Criteria Section of a Directory

Any NPCC Full Member may request a revision to the criteria within a Directory. A request to revise the criteria section of an NPCC Directory shall be submitted to the Lead Task Force responsible for the document.

The Lead Task Force shall notify each affected NPCC Task Force which has jurisdiction over either a portion of the criteria or one or more of the appendices within the Directory that a request to revise the criteria in the document has been received.

The Lead Task Force shall review the request to revise the criteria and shall also consider conforming changes to appendices as a result of the criteria revision if necessary.

The NPCC Manager of Reliability Criteria shall post the Directory containing the revised criteria to the NPCC Open Process review for 45 days.

At the conclusion of the 45 day Open Process, the Lead Task Force will discuss the comments submitted and post responses to comments on the NPCC Open Process portal.

If the responses to the comments received on the criteria revision result in substantive changes to the document, then the revised Directory criteria shall be reposted to the Open Process for a successive 45 day posting period.

If no substantive changes are developed which would require additional postings of a revised draft of the Directory, then the Directory is presented to the Reliability Coordinating Council (RCC) for approval.

Upon RCC approval the document is submitted for a ballot to the NPCC Full Member Representatives along with the RCC recommendation of approval.

Approval of the revised Directory criteria requires a 2/3rd majority of Full Member voting representatives in accordance with the NPCC Bylaws.

The process for revisions to the criteria in an existing Directory is represented below in Figure 2:

Figure 2 Revisions to Criteria:

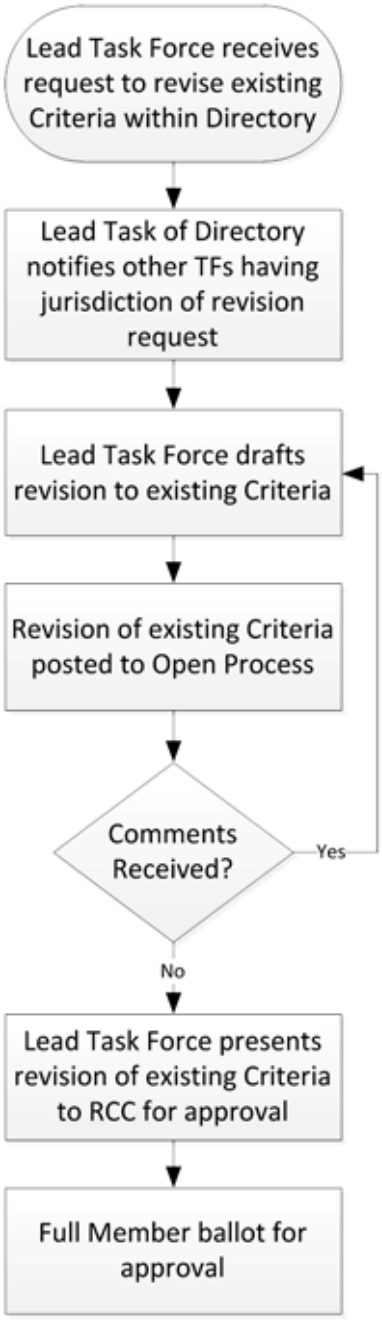

b. Revisions to the Appendix Section of a Directory

Any NPCC Full Member may request an Appendix within a Directory to be revised or retired. Revisions or retirements of Appendices shall only require RCC approval.

A request to revise or retire an Appendix of a NPCC Directory shall be submitted to the Task Force responsible for the Appendix.

The Task Force responsible for the Appendix shall notify the Lead Task Force of the Directory that a request to revise or retire an appendix within the document has been received.

The Lead Task Force of the Directory shall be responsible for notifying all Task Forces which have jurisdiction over either the criteria or one or more of the other Appendices within the Directory that a request to revise or retire an appendix has been received.

After the Task Force responsible for the revised Appendix request reviews the subject appendix they will forward the Directory containing the draft revised Appendix to the Lead Task Force of the Directory.

The Lead Task Force shall be responsible for posting the Directory which contains the revised or retired Appendix to the NPCC Open Process review for 45 days. Additionally, although the entire Directory will be posted to the open process, the Lead Task Force will limit the comments solicited to only the subject Appendix.

At the conclusion of the 45 day Open Process, the Lead Task Force will forward the comments submitted on the Appendix to the Task Force responsible for the revised or retired Appendix.

If the responses to the comments received on the revised or retired Appendix result in substantive change (s) to the Appendix, then the Directory containing the revised or retired Appendix shall be reposted to the Open Process for a successive 45 day review period by the Lead Task Force of the entire Directory; if no substantive changes are developed which would require additional postings the entire Directory containing the draft of the revised or retired Appendix will be presented to the Reliability Coordinating Council (RCC) for approval.

The process for revisions to the appendices within an existing Directory is represented below in Figure 3:

Figure 3 Revisions to Appendices:

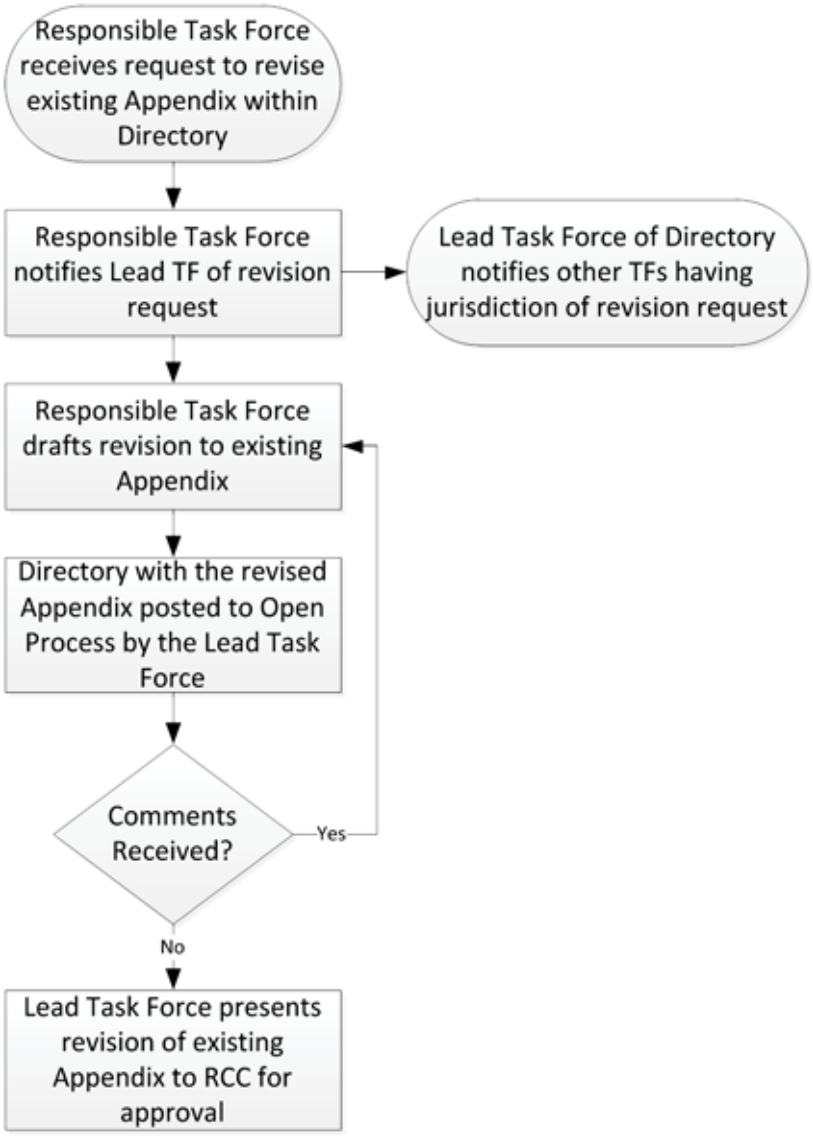

c. Revisions to the NPCC Glossary of Terms

The NPCC Glossary of Terms contains the definitions of all terms found within the NPCC Directories, Criteria, Guidelines, and Procedures and which are not already defined in the NERC Glossary of Terms or are regionally specific. The Glossary of Terms is intended to be a repository of all NPCC defined terms and contains the Full Member approved definition of that term as developed by the Task Force responsible for the Directory in which the term resides.

The Glossary is organized into two sections, one containing all defined terms within the Directories (including Appendices) which support the NPCC Criteria and another section for definitions found within remaining B and C documents.

The process of establishing or revising a NPCC defined term shall be considered a revision to the Directory in which the term resides in order to capture the context of its use within the document.

Accordingly, the entire Glossary is not subject to the Open Process for a revision to an individual definition.

The development and review of a new definition or a revision to an existing NPCC specific definition contained within the Glossary will be coordinated by the Lead Task Force for the Directory in which the defined term resides.

Any NPCC Full Member may request that a new or revised term be added to the NPCC Glossary of Terms by forwarding a request to the Lead Task Force for the Directory in which the defined term resides.

When the subject term resides in multiple Directories, the requestor shall forward the request to each of the Task Forces for the Directories in which the defined term resides and the individual Task Forces shall coordinate their review of the request, by assigning one of the Task Forces as the Lead Task Force for the review.

After the Lead Task Force in which the defined term resides has completed its review they will post the subject Directory containing the new or revised term to the NPCC Open Process for 45 days. When the new or revised term appears in multiple Directories, the designated Lead Task Force for the review shall include in the posting notice a comprehensive list of references to all occurrences of the defined term in other NPCC Directories, including each Directory in which the term resides.

At the conclusion of the 45 day Open Process, if responses to comments received on the new or revised term result in further substantive change to the term, then the Directory containing the new or revised term shall be reposted to the Open Process for a successive 45 day posting period by the Lead Task Force for the subject Directory; if no substantive changes to the term are developed which would require an additional posting, then the Directory containing the new or revised term will be presented to the Reliability Coordinating Council (RCC) by the Lead Task Force for approval.

Upon RCC recommendation the Directory containing the new or revised term will be balloted by the Full Members.

Upon Full Member approval of the new or revised term the Glossary will be updated by the Lead Task Force of the document in which the term resides.

The process for revisions to the appendices within an existing Directory is represented below in Figure 4:

Figure 4 Revisions to the NPCC Glossary of Terms:

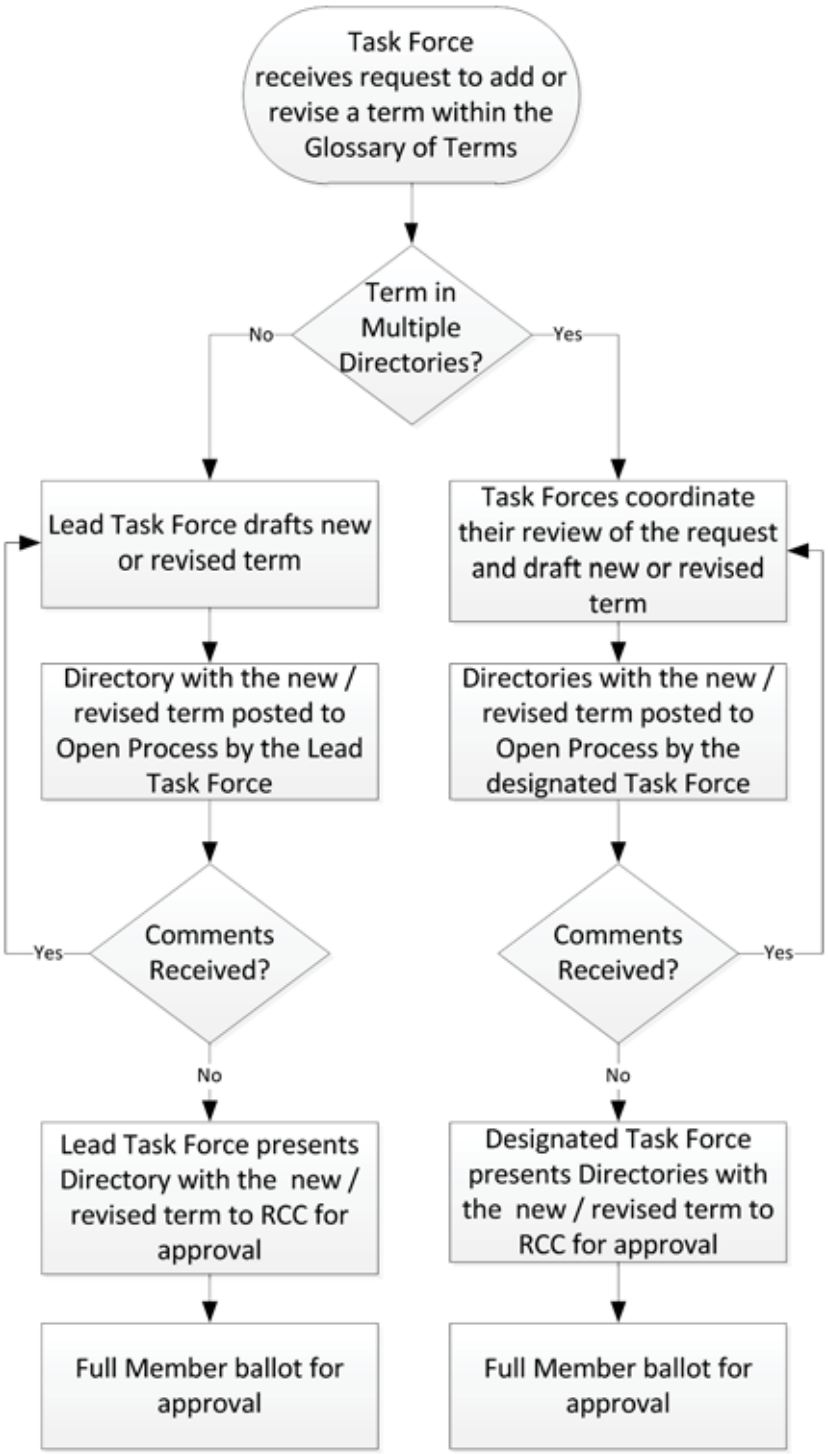

3. MAINTENANCE of LINKS and ERRATA

The maintenance of Links and minor Errata changes to a Directory or its Appendices shall be the responsibility of NPCC Standards staff.

Errata and Link revisions are updated as needed and require only the Lead TF approval prior to publishing.

NPCC staff will also maintain a record of the change on the Directory Revision History page within the document.

V. DIRECTORY INTERPRETATION PROCESS

Any NPCC Full Member may request an interpretation of the criteria within a Directory.

The NPCC Full Member seeking the interpretation shall submit a *Request for Criteria Interpretation* form [2] to the NPCC Manager of Reliability Criteria explaining the clarification required and the specific circumstances surrounding the request.

The NPCC Manager of Reliability Criteria shall review the request and work with the originator to insure that it is clearly written and properly formatted before forwarding to the NPCC Task Force designated as the Lead Task Force for the subject Directory.

The Lead Task Force shall notify each NPCC Task Force which has jurisdiction over either another portion of the criteria and /or one or more of the appendices within the subject Directory, that a *Request for Criteria Interpretation* has been received. The Lead Task Force shall also forward the request to the affected Task Force(s).

As soon as practical the Lead Task Force for the Directory or the Task Force having jurisdiction shall review the request among its Members and provide a response to the NPCC Manager of Reliability Criteria, who shall forward the response to the NPCC Member requesting the interpretation.

The response to a Directory interpretation request shall provide the requested explanation without expanding on the criteria and should be sufficiently concise to eliminate ambiguity on how to comply with the criteria.

[2] The Request for Interpretation Form is included in Appendix B of this document.

The NPCC Manager of Reliability Criteria shall review the interpretation provided by the Lead Task Force or the Task Force having jurisdiction to insure that it is clear and provides the requested explanation without expanding on the criteria.

The detailed results of the *Request for Criteria Interpretation* shall be retained by the Lead Task Force and the NPCC Standards Staff along with a recommendation on whether the language within the document should be revised in order to provide additional clarity.

VI. DIRECTORY FORMAT AND VERSION CONTROL

Each Directory will be formatted in accordance with the Directory Template in Appendix A of this document.

The Task Force Revision Review Record on the cover page of each Directory shall contain the date of the most recent version of the Directory as approved by the Full Members of NPCC.

The Revision History record on page 2 of each Directory shall contain a record of all revisions to the document, including maintenance of errata and links.

References:

2. https://www.npcc.org/Standards/Directories/Directory_Flowchart.pdf.

3. https://www.npcc.org/Standards/Directories/Directory_Mapping.pdf.

Appendix A

DIRECTORY FORMAT TEMPLATE

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

NPCC
Regional Reliability Reference Directory # XX

Task Force XXXXX Revision Review Record:
XX/XX, 20XX

Adopted by the Members of the Northeast Power Coordinating Council, Inc. June 26th, 2009 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0		Effective Date	New

Format for NPCC Directories (Phase 2)

Effective Dates (Denotes date of adoption by the Membership)

Revision History (Depicts revision history and tracks key changes)

Table of Content (Self explanatory)

A. Introduction

1. **Title:** Self-explanatory

2. **Directory #:** Self-explanatory

3. **Objective:** What reliability objective is this Directory intended to meet (i.e., achieving specific performance target/outcome, mitigating particular risks, establishing the minimum capability level, etc.)

4. **Effective Date:** Which parts of the Directory become effective on which dates.

5. **Background:** Information related to this creation or revision of this Directory, e.g., which A, B or C documents are mapped into this Directory; the general basis of the Directory, etc.

6. **Applicability:** Which entities are assigned reliability requirements and/or what facilities need to conform with the stipulated criteria.

B. NERC ERO Reliability Standard Requirements

A list of the NERC standards associated with this Directory.

C. NPCC Regional Reliability Standard Requirements

A list of NPCC Regional Standards associated with this Directory.

D. NPCC Full Member, More Stringent Requirements, Criteria and Measures

Requirements

The requirements and criteria that the applicable entities or facilities must comply with.

.

E. Compliance

Compliance with the requirements set forth in this Directory will be in accordance with the NPCC Criteria Compliance and Enforcement Program (CCEP).

Measures and corresponding Levels of Non Compliance for these requirements are contained within the compliance template associated with this Directory.

Prepared by:	Task Force XX (Lead Task Force for the Directory)
Review and Approval:	Revision to any portion of this Directory will in accordance with the NPCC Directory Development and Revision Manual and will be posted by the Lead Task Force in the NPCC Open Process for a 45 day review and comment period. Upon satisfactorily addressing all of the comments in this forum, the Directory will be sent to the RCC for its approval. Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC. Bylaws" in effect at the time the ballots are cast. Revisions pertaining to the Appendices or any other portion of the document such as links, glossary terms, etc., only RCC Members will need to conduct the final approval ballot of the document. This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

Appendix B

NPCC Request for Criteria Interpretation

Note: an Interpretation cannot be used to revise a Directory.

Request for an Interpretation of a Directory
Date interpretation request submitted: Date interpretation response provided:
Contact information for person requesting the interpretation:
Name:
Organization:
Telephone:
E-mail:
Identify the Directory that needs clarification:
Directory Number :
Directory Title:
Identify specifically what portion of the Criteria needs clarification:
Text of Requirement:
Identify the material impact associated with this interpretation:

Identify the material impact to your organization or others caused by the lack of clarity or an incorrect interpretation of this Directory:

Submit completed Request for Criteria Interpretation forms to the NPCC Manager of Reliability Criteria.

Interpretation: Response to Request for an Interpretation of Directory XX for the XXXX Corporation
The following interpretation of Directory was developed by the Task Force on XXXXX
Directory Number and Text of Requirement
Question 1
Response to Question 1
Question 2
Response to Question 2

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1515 BROADWAY, NEW YORK, NY 10036-8901 TELEPHONE: (212) 840-1070 FAX: (212) 302-2782

Draft

October 26, 2011~~July 27, 2011~~

Northeast Power Coordinating Council, Inc.

Directory Development and Revision Manual

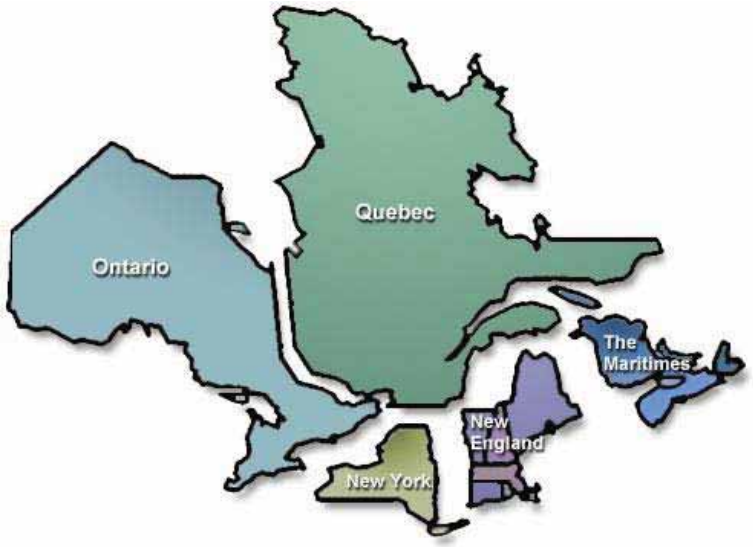

Approved by the Reliability Coordinating Council

XXXX, XX, 20XX

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0		Effective Date	New

NPCC

DIRECTORY DEVELOPMENT and REVISION MANUAL

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I. EXECUTIVE SUMMARY

The purpose of the Northeast Power Coordinating Council, Inc. ("NPCC") is to enhance the reliability of the international, interconnected bulk power system in Northeastern North America through the development of more stringent and regionally specific criteria.

NPCC Directories have been developed in order to provide a consistent and comprehensive set of reliability requirements for the Northeast, while consolidating related information for NPCC Criteria, Guidelines, Procedures as well as FERC and NERC approved ~~nd~~ Regional Standards into one document.

NPCC Directories and the criteria contained within, apply only to NPCC Full Members. However, there may be additional agreements within tariffs or interconnection agreements that hold non Members ~~other entities~~ responsible for complying with the criteria within each Directory.

This document is intended to provide guidance to NPCC Task Forces and NPCC Full Members when establishing a new or revised Directory or when retiring or consolidating an existing Directory and will also clarify the roles and responsibilities of the NPCC Task Forces responsible for Directory content.

II. Introduction

The NPCC Regional Standards Committee (RSC) working with the lead Task Force for each Directory has overall responsibility for managing the Directory project.

The Directories are organized to demonstrate that NPCC regional criteria are ~~at once~~ more specific than or ~~,~~ more stringent than ~~-~~and are also ~~and~~ consistent with NERC Reliability Standards.

Each Directory contains an Introduction, along with sections that identify NERC ERO Standard and NPCC Regional Standard Requirements that are associated with the Directory.

Additionally, each Directory is comprised of a section that describes the NPCC regionally ~~more stringent or more~~ specific criteria and was developed from the related NPCC ‘~~’~~A’ documents. The appropriate Type ‘B’ Guideline and Type ‘C’ Procedure documents are included within each Directory as Appendices.

A mapping document has been provided on the Directory page of the NPCC Website and has been organized in a manner that provides guidance on where a Directory's content originated. (A Criteria, B Guideline, or C Procedure).

1. https://www.npcc.org/Standards/Directories/Directory_Mapping.pdf.

The mapping document provides tracking of specific content language from documents that were translated or replaced by Directories and their Appendices.

Phase 1 of the Directory Project was initiated by the NPCC Reliability Coordinating Council in order to demonstrate consistency with NERC Standards and to effectively group documents together according to functional topics.

During Phase 1 an initial translation of the existing criteria document was performed in addition to identifying and eliminating language within the criteria that duplicated existing NERC Reliability Standards.

Additionally, Functional Model language was introduced and the corresponding 'B' Guidelines and 'C' Procedures were incorporated into each Directory as appendices.

The resulting Directory created a single source reference for all entities ~~NPCC Members~~ while providing a method to demonstrate consistency with NERC Standards.

Phase 2 of the Directory Project was initiated in order to reformat the Criteria section of each document into specific and measurable NERC style requirements which will promote the NPCC Regional criteria as more specific or more stringent within each Directory.

Phase 2 will also facilitate the development of the NPCC Criteria Compliance Enforcement Program (CCEP) by providing the respective requirements and measures of that program.

Although the Regional Standards Committee is responsible for the overall Directory program, individual ~~Each~~ Directories~~y~~ are ~~is~~ under the control of a lead NPCC Task Force which is responsible for coordinating ~~the~~ review and posting of the document among all other Task Forces which have jurisdiction over either a portion of the criteria or one or more of the Appendices in the Directory.

~~A mapping document has been provided on the Directory page of the NPCC Website and has been organized in a manner that provides guidance on where a Directory's content originated. (A Criteria, B Guideline, or C Procedure).~~

~~The mapping document provides tracking of specific content language from documents that were translated or replaced by Directories and their Appendices~~.

III. TASK FORCE ROLES and RESPONSIBILITIES

With the development of the Directories it has been recognized that in certain cases the jurisdictional boundaries of Task Force ownership have been crossed and additional guidance when coordinating Directory review among Task Forces is necessary.

In general, revisions and interpretations to a Directory shall be coordinated by the Lead Task Force of the document.

Revisions to a Directory can be initiated in a fully bi-directional manner; that is either by the Lead Task Force responsible for the document or by another Task Force who is responsible for some portion (criteria or appendices) of the document.

This process will allow each Directory to remain under the control of the respective Lead Task Force which has the necessary expertise to keep each document current and accurate while also providing a means to coordinate component review of those segments of the Directory that may be under the control of another Task Force.

The Lead Task Force can initiate a full revision of the Directory in accordance with the *NPCC Reliability Assessment Program* (NRAP) date of approval or some need to revise the criteria section of the document.

https://www.npcc.org/Library/NRAP/Forms/Public%20List.aspx

The Lead Task Force will also notify other Task Forces under whose jurisdiction either a portion of the criteria or Appendices exists in order to coordinate the total document review and revision.

Similarly, a Task Force which is not the Lead Task Force of the Directory, but is responsible for some portion of the document, shall coordinate a necessary revision to their section of the document through the Lead Task Force of the Directory.

III.IV. DIRECTORY DEVELOPMENT AND REVISION PROCEDURE

1. NEW DIRECTORY

Any NPCC Full Member may request the development of a new Directory. The request shall be made to the NPCC Manager of Reliability Criteria via email and shall contain the background and justification for the development of the new Directory. The NPCC Manager of Reliability Criteria shall forward the request to the Regional Standards Committee (RSC) in order for the -RSC which to shall review the request and assign its development to the appropriate NPCC Task Force.

The Lead Task Force responsible for developing the new Directory, shall draft an initial version of the document consistent with the Directory template in Attachment A.consistent with the format of existing approved Directories, shall draft an initial version of the document using Phase 2 formatting.

The NPCC Manager of Reliability CriteriaStandards staff shall post the draft new Directory to the NPCC Open Process portal for review. (for 45 days.)

At the conclusion of the 45 day Open Process, the Lead Task Force will discuss the comments submitted and post the responses to comments on the NPCC Open Process portal.

If the responses to comments received on the draft result in substantive changes to the document, then the revised draft shall be reposted to the Open Process for a successive 45 day posting period.

I; if no substantive changes are developed which would require additional postings of a revised the draft, of the new Directory is presented to the Reliability Coordinating Council (RCC) for approval.

Upon RCC approval the document is submitted for a ballot to the NPCC Full Member Representatives along with the RCC recommendation of approval.[1]

---

[1] Approval of a new Directory requires a 2/3rd majority of Full Member voting representatives in accordance with the NPCC Bylaws.

The process for establishing a new Directory is represented below in Figure 1:

Figure 1 New Directory:

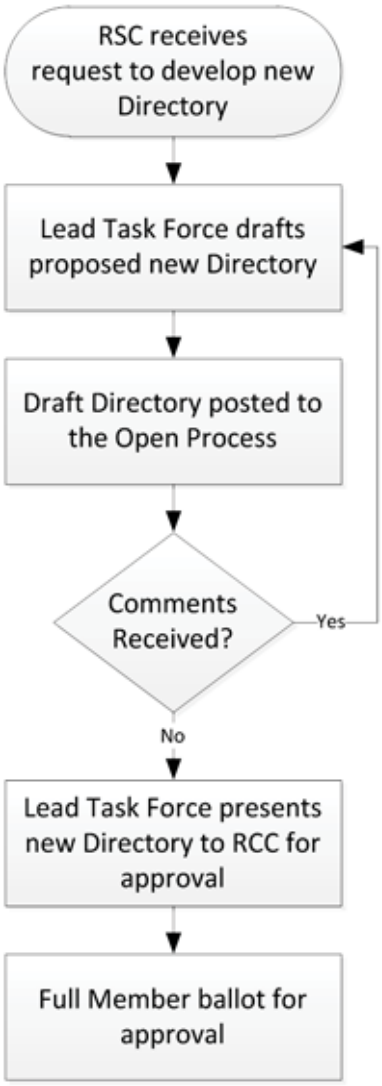

~~Approval of a new Directory requires a 2/3rd majority of Full Member voting representatives in accordance with the NPCC Bylaws.~~

2. DIRECTORY REVISIONS

a. ~~a.~~ Revisions to the Criteria Section of a Directory

Any NPCC Full Member may request a revision to the criteria within a Directory. A request to revise the criteria section of an NPCC Directory shall be submitted to the L~~l~~ead Task Force responsible for the document.

The Lead Task Force shall notify each affected NPCC Task Force which has jurisdiction over either a ~~another~~ portion of the criteria or one or more of the appendices within the Directory that a request to revise the criteria in the document has been received.

The Lead Task Force shall review the request to revise the criteria and shall also consider conforming changes to appendices as a result of the criteria revision if necessary.

The NPCC Manager of Reliability Criteria ~~Lead Task Force~~ shall post the Directory containing the revised criteria to the NPCC Open Process review for 45 days.

At the conclusion of the 45 day Open Process, the Lead Task Force will discuss the comments submitted and post ~~the~~ responses to comments on the NPCC Open Process portal.

If the responses to the comments received on the criteria revision result in substantive changes to the document, then the revised Directory criteria shall be reposted to the Open Process for a successive 45 day posting period.~~;~~

I~~ i~~f no substantive changes are developed which would require additional postings of a revised ~~the~~ draft of the ~~revised~~ Directory, then the Directory ~~criteria~~ is presented to the Reliability Coordinating Council (RCC) for approval.

Upon RCC approval the document is submitted for a ballot to the NPCC Full Member Representatives along with the RCC recommendation of approval.

Approval of the revised Directory criteria requires a 2/3rd majority of Full Member voting representatives in accordance with the NPCC Bylaws.

The process for revisions to the criteria in an existing Directory is represented below in Figure 2:

Figure 2 Revisions to Criteria:

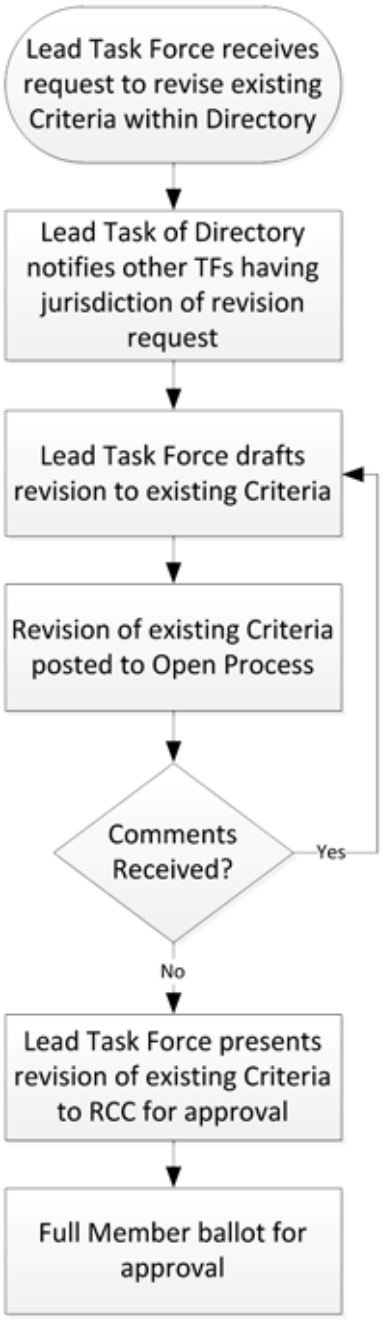

b. Revisions to the Appendix Section of a Directory

Any NPCC Full Member may request an Appendix within a Directory to be revised or retirement. Revisions or retirements of pertaining to the Appendices shall only require RCC approval.

A request to revise or retire an Appendix of a NPCC Directory shall be submitted to the Task Force responsible for the Appendix.

The Task Force responsible for the Appendix shall notify the Lead Task Force of the Directory that a request to revise or retire an appendix within the document has been received.

The Lead Task Force of the Directory shall be responsible for notifying all Task Forces which have jurisdiction over either the criteria or one or more of the other Appendices within the Directory that a request to revise or retire an appendix has been received.

After the Task Force responsible for the revised Appendix request reviews the subject appendix they will forward the Directory containing the draft revised Appendix to the Lead Task Force of the Directory.

The Lead Task Force shall be responsible for posting the Directory which contains the revised or Appendixretired Appendix to the NPCC Open Process review for 45 days. Additionally, although the entire Directory will be posted to the open process, the Lead Task Force will limit the comments solicited to only the subject Appendix.

At the conclusion of the 45 day Open Process, the Lead Task Force will forward the comments submitted on the Appendix to the Task Force responsible for the revised or retired Appendix.

If the responses to the comments received on the revised or retired Appendix result in substantive change (s) to the Appendix, then the Directory containing the revised or retired Appendix shall be reposted to the Open Process for a successive 45 day review posting period by the Lead Task Force of the entire Directory; if no substantive changes are developed which would require additional postings the entire Directory containing the draft of the revised or retired Appendix will be presented to the Reliability Coordinating Council (RCC) for approval.

The process for revisions to the appendices within an existing Directory is represented below in Figure 3:

Figure 3 Revisions to Appendices:

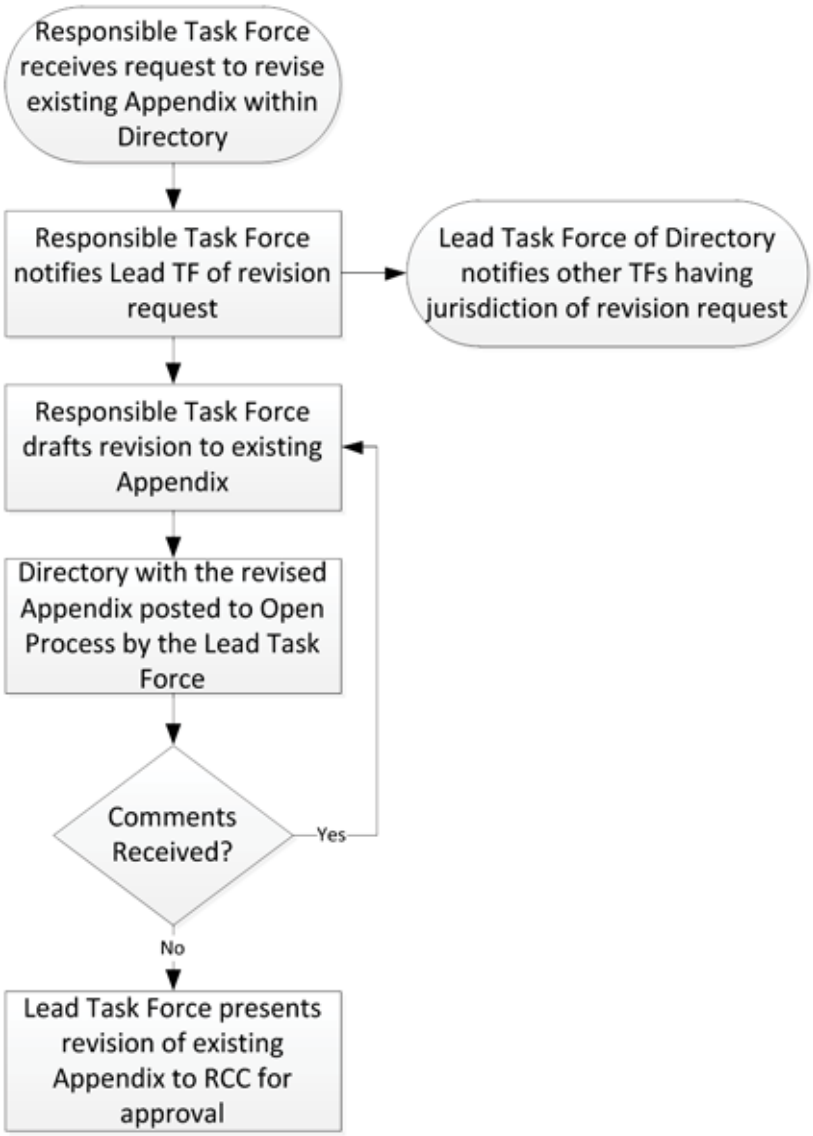

c. Revisions to the NPCC Glossary of Terms

The NPCC Glossary of Terms contains the definitions of all terms found within the NPCC Directories, Criteria, Guidelines, and Procedures and which are not already defined in the NERC Glossary of Terms or are regionally specific. The Glossary of Terms is intended to be a repository of all NPCC defined terms and contains the Full Member approved definition of that term as developed by the Task Force responsible for the Directory in which the term resides.

The Glossary is ~~has been~~ organized into two sections, one containing all defined terms within the Directories (including Appendices) ~~and~~ which support the NPCC Criteria~~;~~ and another section for definitions found within remaining ~~the~~ B and C documents. ~~efinitions.~~

~~The NPCC Glossary of Terms is intended to be a repository of all NPCC defined terms and contains the Full Member approved definition of that term as developed by the Task Force responsible for the Directory in which the term resides.~~

The process of establishing or revising a NPCC defined term shall be considered a revision to the Directory in which the term resides in order to capture the context of its use within the document.

Accordingly, the entire Glossary is not subject to the Open Process for a revision to an individual definition.

The development and review of a new definition or a revision to an existing NPCC specific definition contained within the Glossary will be coordinated by the Lead Task Force for the Directory in which the defined term resides.

Any NPCC Full Member may request that a new or revised term be added to the NPCC Glossary of Terms by forwarding a request to the Lead Task Force for the Directory in which the defined term resides.

When the subject term resides in multiple Directories, the requestor shall forward the request to each of the ~~Lead~~ Task Forces for the Directories in which the defined term resides and the individual Task Forces shall coordinate their review of the request, by assigning one of the Task Forces as the Lead Task Force for the review.~~.~~

After the Lead Task Force in which the defined term resides has completed its review they will post the subject Directory containing the new or revised term to the NPCC Open Process for 45 days. When the new or revised term appears in multiple Directories, the ~~The~~ designated Lead Task Force for the review, shall include in the posting notice ~~will also provide~~ a comprehensive list of references to all occurrences of the defined term in other NPCC Directories, including each Directory in which the term resides.~~background if necessary on other NPCC Directories in which the term appears.~~ .

At the conclusion of the 45 day Open Process, if responses to comments received on the new or revised term result in further substantive change to the term, then the Directory containing the new or revised term shall be reposted to the Open Process for a successive 45 day posting period by the Lead Task Force for the subject Directory; if no substantive changes to the term are developed which would require an additional posting, then the Directory containing the new or revised term will be presented to the Reliability Coordinating Council (RCC) by the Lead Task Force for approval.

Upon RCC recommendation the Directory containing the new or revised term will be balloted by the Full Members.

~~Finally, and~~ U~~u~~pon Full Member approval of the~~-~~ new or revised NPCC term in accordance with the NPCC By- Laws the Glossary will be updated by the Lead Task Force of the document in which the term resides.

The process for revisions to the appendices within an existing Directory is represented below in Figure 4:

Figure 4 Revisions to the NPCC Glossary of Terms:

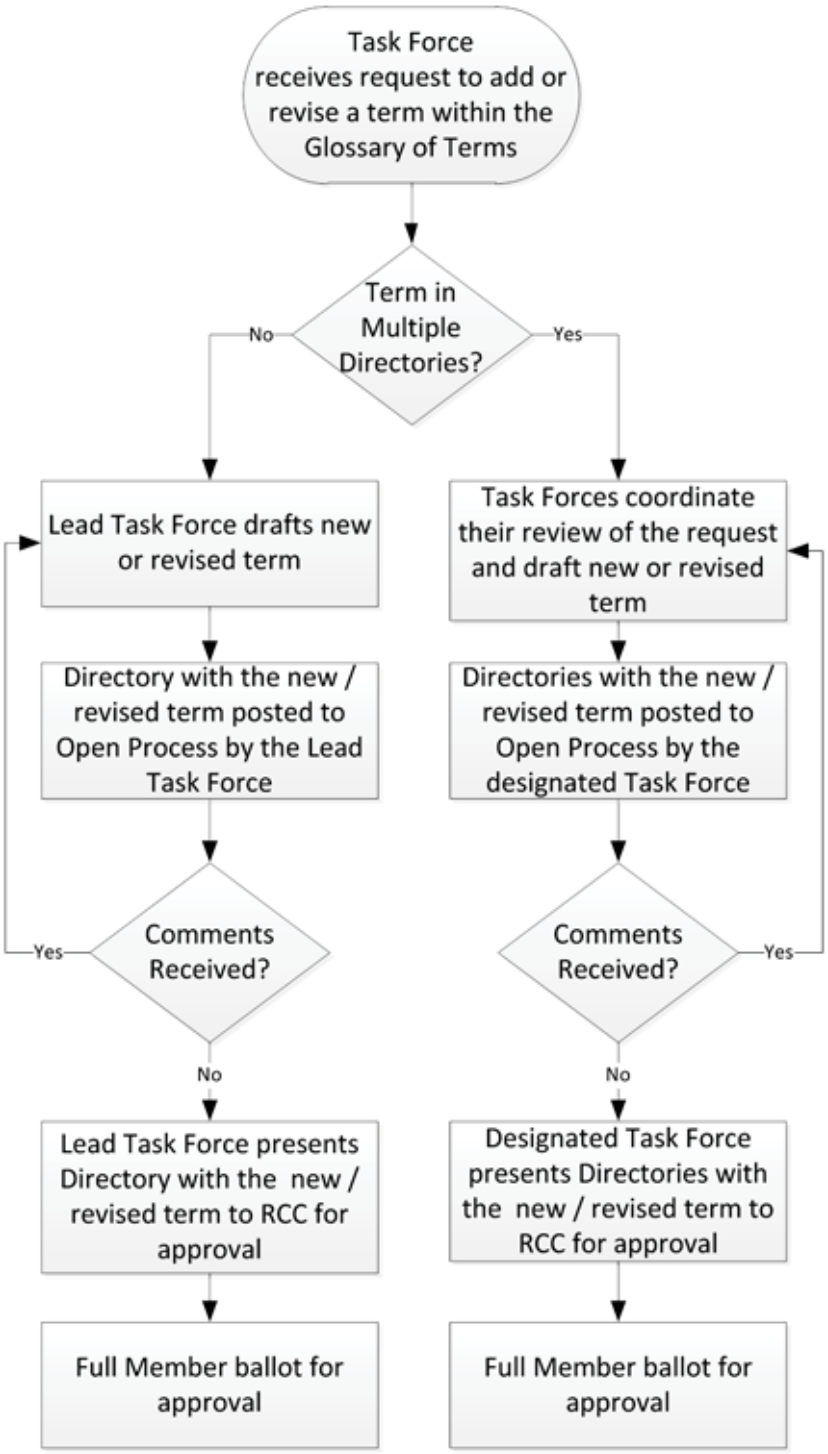

3. MAINTENANCE of LINKS and ERRATA

The maintenance of Links and minor Errata changes to a Directory or its Appendices shall be the responsibility of NPCC Standards staff.

Errata and Link revisions are updated as needed and require only the Lead TF approval prior to publishing.

NPCC staff will also maintain a record of the change on the Directory Revision History page within the document.

~~IV.~~V. DIRECTORY INTERPRETATION PROCESS

Any NPCC Full Member may request an interpretation of the criteria within a Directory.

The NPCC Full Member seeking the interpretation shall submit a *Request for Criteria Interpretation* form [2] to the NPCC Manager of Reliability Criteria ~~NPCC Standards staff~~ explaining the clarification required and the specific circumstances surrounding the request.

The NPCC Manager of Reliability Criteria~~Standards staff~~ shall review the request and work with the originator to insure that it is clearly written and properly formatted, before forwarding to the NPCC Task Force designated as the Lead Task Force for the subject Directory.

The Lead Task Force shall notify each NPCC Task Force which has jurisdiction over either another portion of the criteria and /or one or more of the appendices within the subject ~~the~~ Directory, that a *Request for Criteria Interpretation* has been received. The Lead Task Force shall also ~~and~~ forward the request to the affected Task Force(s). ~~having jurisdiction~~.

As soon as practical the Lead Task Force for the Directory or the Task Force having jurisdiction shall review the request among its Members and provide a response to the NPCC Manager of Reliability Criteria ~~Standards Staff~~, who shall forward the response to the NPCC Member requestiong the interpretation.~~.~~

The response to a Directory interpretation request shall provide the requested explanation without expanding on the criteria and should be sufficiently concise to eliminate ambiguity ~~nor~~ on how to ~~should it explain how~~ to comply with the criteria.

[2] The Request for Interpretation Form is included in Appendix B of this document.

The NPCC Manager of Reliability Criteria~~Standards Staff~~ shall review the interpretation provided by the Lead Task Force or the Task Force having jurisdiction to insure that it is clear and provides the requested explanation without expanding on the criteria.

The detailed results of the *Request for Criteria Interpretation* shall be retained by the Lead Task Force and the NPCC Standards Staff along with a recommendation on whether the language within the document should be revised in order to provide additional clarity.

~~V. TASK FORCE ROLES and RESPONSIBILITIES~~

~~With the development of the Directories it has been recognized that in certain cases the jurisdictional boundaries of Task Force ownership have been crossed and additional guidance when coordinating Directory review among Task Forces is necessary.~~

~~In general, revisions and interpretations to a Directory shall be coordinated by the Lead Task Force of the document.~~

~~Revisions to a Directory can be initiated in a fully bi-directional manner; that is either by the Lead Task Force responsible for the document or by another Task Force who is responsible for some portion (criteria or appendices) of the document.~~

~~This process will allow each Directory to remain under the control of the respective Lead Task Force which has the necessary expertise to keep each document current and accurate while also providing a means to coordinate component review of those segments of the Directory that may be under the control of another Task Force.~~

~~The Lead Task Force can initiate a full revision of the Directory in accordance with the *NPCC Reliability Assessment Program* (NRAP) date of approval or some need to revise the criteria section of the document.~~

~~The Lead Task Force will also notify other Task Forces under whose jurisdiction either a portion of the criteria or Appendices exists in order to coordinate the total document review and revision.~~

~~Similarly, a Task Force which is not the Lead Task Force of the Directory, but is responsible for some portion of the document, shall coordinate a necessary revision to their section of the document through the Lead Task Force of the Directory.~~

~~However, in all cases the subsequent Open Process posting and approval process will be coordinated by the Lead Task Force responsible for the overall Directory.~~

~~Additionally, and in order to promote consistency and to simplify the Directory process, revisions to both B- Guideline and C-Procedure documents which have been incorporated within a Directory as an Appendix will require RCC approval.~~

VI. DIRECTORY FORMAT AND VERSION CONTROL

Each Directory will be formatted in accordance with the Directory Template in Appendix A of this document.

The Task Force Revision Review Record on the cover page of each Directory shall contain the date of the most recent version of the Directory as approved by the Full Members of NPCC.

The Revision History record on page 2 of each Directory shall contain a record of all revisions to the document, including maintenance of errata and links.

References:

2. https://www.npcc.org/Standards/Directories/Directory_Flowchart.pdf.

3. https://www.npcc.org/Standards/Directories/Directory_Mapping.pdf.

Appendix A

DIRECTORY FORMAT TEMPLATE

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

NPCC
Regional Reliability Reference Directory # XX

Task Force XXXXX Revision Review Record:
XX/XX, 20XX

Adopted by the Members of the Northeast Power Coordinating Council, Inc. June 26th, 2009 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

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0		Effective Date	New

Format for NPCC Directories (Phase 2)

Effective Dates (Denotes date of adoption by the Membership)

Revision History (Depicts revision history and tracks key changes)

Table of Content (Self explanatory)

A. Introduction

1. **Title:** Self-explanatory

2. **Directory #:** Self-explanatory

3. **Objective:** What reliability objective is this Directory intended to meet (i.e., achieving specific performance target/outcome, mitigating particular risks, establishing the minimum capability level, etc.)

   The key driver(s) for the criteria in this Directory is (are) ….. For example: specifying the design and operating criteria of BPS, stipulating the maintenance criteria for protection systems, etc.

4. **Effective Date:** Which parts of the Directory become effective on which dates.

5. **Background:** Information related to this creation or revision of this Directory, e.g., which A, B or C documents are mapped into this Directory; the general basis of the Directory, etc.

6. **Applicability:** Which entities are assigned reliability requirements and/or what facilities need to conform with the stipulated criteria.

B. NERC ERO Reliability Standard Requirements

A list of the NERC standards that are associated with this Directory.

C. NPCC Regional Reliability Standard Requirements

A list of NPCC Regional Standards that are associated with this Directory.

D. NPCC Full Member, More Stringent Requirements, Criteria and Measures Requirements

The requirements and criteria that the applicable entities or facilities must comply with. The requirements and criteria should be written to clearly stipulate the specific performance targets, expected outcome, the risks to be avoided or the capabilities to be achieved to meet the stated objective, and the conditions under which the requirements and criteria are to be complied with.

.

E. Compliance

Compliance with the requirements set forth in this Directory will be in accordance with the NPCC Criteria Compliance and Enforcement Program (CCEP).

Measures and corresponding Levels of Non Compliance for these requirements are contained within the compliance template associated with this Directory.

Appendix A - Guideline and Procedure

The guidelines and procedures that the applicable entities should generally follow to meet the requirements and criteria specified in the Directory.

Prepared by: Task Force XX (Lead Task Force for the Directory)

Review and Approval: Revision to any portion of this Directory will in accordance with the NPCC Directory Development and Revision Manual and will be posted by the Lead Task Force in the NPCC Open Process for a 45 day review and comment period. Upon satisfactorily addressing all of the comments in this forum, the Directory will be sent to the RCC for its approval.

Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC. Bylaws" in effect at the time the ballots are cast.

Revisions pertaining to the Appendices or any other portion of the document such as links, glossary terms, etc., only RCC Members will need to conduct the final approval ballot of the document.

This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

~~Appendix A~~

~~DIRECTORY FORMAT TEMPLATE~~

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

~~NPCC~~
~~Regional Reliability Reference Directory # XX~~

~~Task Force XXXXX Revision Review Record:~~
~~XX/XX, 20XX~~

~~Adopted by the Members of the Northeast Power Coordinating Council, Inc. June 26th, 2009 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.~~

~~Revision History~~

~~Version~~	~~Date~~	~~Action~~	~~Change Tracking (New, Errata or Revisions)~~
~~0~~		~~Effective Date~~	~~New~~

~~Table of Content~~

~~Title Page 1~~

~~Revision History 2~~

~~Table of Content 3~~

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~~2.0 Terms Defined in This Directory 4~~

~~3.0 NERC ERO Reliability Standard Requirements 5~~

~~4.0 NPCC Regional Reliability Requirements 5~~

~~5.0 NPCC Full Member More Stringent Requirements 5~~

~~6.0 Measures and Assessments 8~~

~~7.0 Compliance Monitoring 8~~

~~Appendix A~~

~~1.0 Introduction~~

~~1.1 Title~~

~~1.2 Directory Number XX~~

~~1.3 Objective~~

~~1.4 Effective Date XX/XX, 20XX~~

~~1.5 Background~~

~~1.6 Applicability~~

~~1.6.1 Functional Entities~~

~~Balancing Authorities~~
~~Transmission Operators~~

~~2.0 Terms Defined in this Directory~~

~~The definitions of terms found in this Directory appearing in bold typeface can be found in the Appendix A.~~

~~3.0 NERC ERO Reliability Standard Requirements~~

~~The NERC ERO Reliability Standards containing Requirements that are associated with this Directory include, but may not be limited to:~~

~~4.0 NPCC Regional Reliability Standard Requirements~~

~~None.~~

~~5.0 NPCC Full Member, More Stringent Criteria~~

~~These Criteria are in addition to, or more stringent or more specific than the NERC or any Regional Reliability standard requirements.~~

~~6.0 Measures and Assessments~~

~~None developed at this time.~~

~~7.0 Compliance Monitoring~~

~~Adherence to these Criteria shall be reported by the responsible entity in a manner and form designated by the Compliance Committee.~~

~~Prepared by:~~ ~~Task Force XX~~

~~Review and Approval:~~ ~~Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45-day review and comment period. Upon satisfactorily addressing all the comments in this forum, the Directory document will be sent to the remaining Task Forces for their recommendation to seek RCC approval.~~

~~Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC Bylaws" in effect at the time the ballots are cast.~~

~~Revisions pertaining to the Appendices or any other portion of the document such as Links, glossary of terms, etc., will only require RCC Members' approval. Errata may be corrected by the Lead Task Force at any time and provide the appropriate notifications to the NPCC Inc. membership.~~

~~This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.~~

~~**References:**~~

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

Appendix B

NPCC Request for Criteria Interpretation

Note: an Interpretation cannot be used to revise a Directory.

Request for an Interpretation of a Directory
Date interpretation request submitted: Date interpretation response provided:~~revised version submitted:~~
Contact information for person requesting the interpretation:
Name:
Organization:
Telephone:
E-mail:
Identify the Directory that needs clarification:
Directory Number :
Directory Title:
Identify specifically what portion of the Criteria needs clarification:
Text of Requirement:
Identify the material impact associated with this interpretation:

Identify the material impact to your organization or others caused by the lack of clarity or an incorrect interpretation of this Directory:

Submit completed Request for Criteria Interpretation forms to the NPCC Manager of Reliability Criteria.

Interpretation: Response to Request for an Interpretation of Directory XX for the XXXX Corporation
The following interpretation of Directory was developed by the Task Force on XXXXX
Directory Number and Text of Requirement
Question 1
Response to Question 1
Question 2
Response to Question 2

October 17, 2011

NPCC composite responses to comments received on the Directory Development and Revision Manual

NPCC would like to thank those who provided comments on the draft Directory Development and Revision Manual which was posted to the Open Process from July 28, 2011 through September 12, 2011. The NPCC responses to individual comments are provided below.

NPCC Response to Comments Received in NPCC Open Process Posting of the Directory Development and Revision Manual.

Comments from Michael Falvo - IESO:

We appreciate the opportunity to comment on the draft NPCC Directory development and Revision Manual which was posted on July 28, 2011. We offer these comments:

1. Section III, 1. New Directory

We suggest providing a template or form for making a request to develop a directory, similar to an RSAR. This would ensure consistency in the information provided in support of the request.
We presume that some technical justification would have to be provided by the requestor in support of the request. There seems to be no provision to terminate the process if sufficient justification for development of a Directory cannot be provided. Does this need to be catered for and if so, who would make this decision (NPCC Staff, the RSC or the Lead Task Force) and on what basis?

NPCC Response:

Comment rejected. *Based on the anticipated number of future requests to develop new Directories an email to the RSC should be sufficient. However, the language in the Manual was revised to reflect that such a request could be made via email and that it should contain* the *background and justification for the development of the new Directory.*

2. Section III, 2c Revisions to NPCC Glossary of Terms

It is not clear whether all of the Directories in which a defined term subject to revision appears, will be posted for comment. Please clarify.
Where the only change to a Directory is the defined term itself, we do not see the benefit of posting the Directory for comment unless the intention is to highlight all occurrences of the term in the Directory. Please clarify. As an alternative approach, we suggest for consideration providing a comprehensive list of references to all occurrences of the defined term in the various NPCC documents.

NPCC Response:

Comment accepted. *The language in the Manual will be revised to clarify how a posting of a new or revised defined term should be handled when the term appears in multiple Directories. In such cases, the posting notice for the Directory that is posted will also provide a comprehensive list of references to all occurrences of the defined term in other NPCC Directories.*

3. Section IV, Directory Interpretation Process

This process does not indicate how NPCC Standards Staff will deal with Requests for Criteria Interpretation that turn out to be questions on how to comply with criteria. Will NPCC Standards Staff have the authority to screen Requests and re-direct them to NPCC Compliance Staff? Please clarify.

NPCC Response:

Comment rejected. *A request for Criteria Interpretation that may also be a question on how to comply with the criteria can be handled in a similar manner as a Request for Criteria Interpretation. The response from the Task Force should be sufficiently precise to eliminate ambiguity. The language in the Manual was modified in order to provide further clarification on this point.*

Comments from Mike Garton- Dominion:

Dominion provides the following comments on the NPCC Directory Development and Revision Manual:

1. Section III (Directory Development and Revision Procedure) – This section only involves the Regional Standards Committee (RSC) on a review of a request for a new Directory. Why is the RSC not involved with reviewing requests for revisions to a Directory or the NPCC Glossary of Terms?

   NPCC Response:

   Comment rejected. *The section of the Manual that addresses the development of a new Directory and assigns the Regional Standards Committee (RSC) with the authority to develop a new Directory is consistent with the RSC's responsibility to manage the overall NPCC Directory project. Individual Task Forces are responsible for Directory content and language including the definition of terms and are better positioned to manage proposed revisions. The RSC manages and coordinates issues that impact the Directory project on a more comprehensive level.*

2. Should the RSC be involved in reviewing the documents prior to open process posting?

   NPCC Response:

   Comment rejected*. See the response to Comment #1.*

3. Only a new Directory requires posting by the NPCC Standards staff. Please explain.

   NPCC Response:

   Comment accepted*. The section on New Directories and Directory Revisions will be revised to specify that the NPCC Manager of Reliability Criteria will post the document.*

4. Section IV (Directory Interpretation Process) – This section requires a request for interpretation to be submitted to "NPCC Standards staff." Please provide clarification on how and to whom the request would be submitted.

`NPCC Response:

Comment accepted. *See the response to Comment #3.*

5. Revision requests for a Directory or the Glossary of Terms are not required to be submitted to the NPCC Standards staff. Please explain the difference in handling/processing.

NPCC Response:

Comment rejected. *The Lead Task Force for each Directory is responsible for Directory content including the definition of terms and language revisions and are better positioned to manage proposed revisions.*

6. Section IV (Directory Interpretation Process) – This section requires clarification with respect to processing an interpretation. Specifically, how does it get approved, does it go through open process review, is it attached to the Directory, etc.?

NPCC Response:

Comment rejected. *The Interpretation is provided by the NPCC Lead Task Force for the Directory and which is comprised of subject matter experts who collectively are responsible for the content. The interpretation is not a revision to the document and therefore is not subject to an Open Process posting.*
Additionally, Section IV addresses archiving and potential revision protocol as a result of the interpretation.

7. The draft document should contain a revision history.

NPCC Response:

Comment accepted. *A revision history will be added to the document.*

Comments from Richard Burke – ISO-NE:

Comments:

1. Introduction - As discussed at the CCEP Working Group of the NPCC Compliance Committee the need for measures is not supported given the Levels of Non-Compliance addressing the failure to comply with specific criteria. Consider removing any mention of the development of measures as part of Phase II of this program.

   NPCC Response:

   Comment accepted*. Criteria language reformatted as part of the Phase 2 development of the NPCC Directories will be concise enough to preclude the use of Measures within each Directory when evaluating levels of non compliance.*

2. Directory Development and Revision Procedure - Given the many steps required to approve a new Directory or to revise an existing Directory, it is suggested that flow charts be appended to each specific section of this document to graphically depict the necessary steps and time frames. (See the NERC CMEP flow charts and/or the NPCC CCEP Process Document for examples of this graphical aid.)

   NPCC Response:

   Comment accepted*. Flow Charts will be developed and inserted into the Manual.*

Comments from John Seelke, P.E. - PSEG Services Corporation

PSEG's Comments re: July 27, 2011 draft NPCC Directory Development and Revision Manual

PSEG member companies of NPCC (PSEG Energy Resources & Trade LLC, PSEG Power Connecticut LLC, PSEG Power New York Inc) support the development of directories that will consolidate NPCC Criteria, Guidelines, Procedures and Regional Standards into individual topic-based documents. We have these comments:

1. The manual would benefit if the NPCC flowchart for directory approval and revisions was incorporated into the manual. See https://www.npcc.org/Standards/Directories/Directory_Flowchart.pdf.

   NPCC Response:

   Comment accepted. *A link to the subject flowchart will be included in the Manual.*

2. While the mapping document that maps current guidelines, criteria, and procedures is mentioned on page 3, it would be helpful if a link to that document was provided in manual. See https://www.npcc.org/Standards/Directories/Directory_Mapping.pdf.

   NPCC Response:

   Comment Accepted*. A link to the mapping document will be included in the Manual.*

3. In conjunction with comment #2 above, it would be helpful if the prior guidelines, criteria, and procedures that are incorporated into directories were kept in an archived section of the Website for user reference.

   NPCC Response:

   Comment rejected. *Presently there is no plan to establish an archived section on the NPCC website as described. However, prior guidelines, criteria, procedures or*

other retired documents can be obtained by sending an email request to the NPCC Manager of Reliability Criteria.

Comments from Christopher L. de Graffenried- Consolidated Edison Company of NY, Inc.

Con Edison's comments on the draft NPCC document "Directory Development and Revision Manual." Clearly, this Manual is needed to help keep the Directories up-to-date with the sometimes rapidly evolving NERC Reliability Standards which they reference.

1. P. 5 states: "This document is intended to provide guidance when establishing a new or revised Directory." I would add a section on the Retirement and Consolidation of Directories, where for example NERC's Reliability Standards grow to encompass the previously more stringent NPCC requirements or where two or more NERC Reliability Standards are collapsed into one, e.g., TPL-001-2.

   NPCC Response:

   Comment accepted. *The language in the subject paragraph will be revised to include circumstances when a Directory is retired or incorporated.*

2. P. 5 fix the minor typographical error where it states: "the related NPCC'A' documents" and replace with the related NPCC [added space, corrected single quote] 'A' documents."

   NPCC Response:

   Comment accepted. *Minor typographical error corrected.*

3. P. 6, Phase 2 – Should NERC's performance-based approach be specifically adopted in this manual?

NPCC Response:

Comment rejected. *Directory content reformatted into NERC Style requirements are in general Risk Based and are consistent with the development of regionally specific criteria within NPCC.*

4. P. 7, Posting – Should the Lead Task Force have an opportunity to offer a Webinar explaining the posting and responding to questions?

NPCC Response:

Comment rejected. *A Task Force can elect to hold a Webinar at the discretion of the individual Committee if its Members feel it will be productive in explaining issues surrounding individual postings.*

P. 8, under b. Revisions to the Appendix Section of a Directory it states: "Revisions pertaining to the Appendices shall only require RCC approval." It is not clear why the process for modification of an Appendix would necessarily be different or any less rigorous than a change in the Directory language. For example, the Appendices to the UFLS Directory #12 contain the specific generator tripping frequency performance envelopes/criteria, and serve are a key part of the Directory's requirements.

NPCC Response:

Comment rejected. *The distinction between the approval for a change in the language of an Appendix, all of which have been developed from legacy B and C documents, and a change in the language of the (criteria section) of a Directory is consistent with NPCC document A1 Criteria for Review and Approval of Documents. Regarding Directory #12 the performance attributes are included in the criteria section of the document.*

P. 9, NPCC Glossary of Terms – Once the NERC BES Definition is promulgated, NPCC will need something to differentiate its A-10 based facilities from BES facilities. This might require development of a new term. The term BPS is ambiguous as it is the same wording (and abbreviation) as is used in the wider "bulk power system" term defined by and used in FPA Section 215, 824(o).

NPCC Response:

Comment accepted. *The various designations used to distinguish different elements of the power system can lead to confusion and ambiguity. NPCC will consider this issue in other forums in the future.*

P. 9 – 10, It states: "Finally, and upon Full Member approval of the new or revised NPCC term the Glossary ..." Comment: We did not see a requirement for a 2/3rds ballot approval. What is the requirement? Is it a 50% simple majority or 2/3rds? Whatever it is, shouldn't we say what the approval requirement is for this ballot?

NPCC Response:

Comment accepted*. Full Member approval will be in accordance with the Voting Requirements as described in the NPCC Bylaws. The language in the Manual will be revised accordingly.*

5. P. 18, The Request for Interpretation (RFI) appears to be modeled after the NERC RFI. Will or should NPCC also have CAN's process to supplement RFI's during the three-year update cycle on p. 17 ("This Directory will be updated at least once every three years …")?

NPCC Response:

Comment rejected. *The Interpretation process was developed to provide guidance to NPCC Members and NPCC Staff when responding to such inquiries. The process is expected to be sufficient in order address these circumstances when they arise.*

Comments from Michael Lombardi- NU

1. Change 'Requirement' to Criteria. The term 'Requirement' is commonly associated with NERC Standards and 'Criteria' is more commonly associated with NPCC Directories.

   NPCC Response:

   Comment rejected. *The NPCC criteria will still be promoted within the document, although the criteria have been reformatted into NERC style requirements.*

2. Is the Regional Standard referenced here the same as a Standard approved by NERC and FERC? If it is, it would be beneficial to indicate as such, otherwise more specified terminology would be beneficial.

   NPCC Response:

   Comment accepted. *Manual language will be revised to clarify that the Regional Standards referenced have been approved by FERC and NERC..*

3. To whom would this document provide guidance? i.e. a Task Force, a member, a Full Member etc.

   NPCC Response:

   Comment accepted. *Manual language will be revised to provide additional clarity.*

4. This wording indicates that the Directory either provides more stringent or more specific criteria, which is more vague than the previous statement (bolded above) indicating that the Criteria are more stringent and specific and consistent with NERC.

NPCC Response:

Comment accepted. *Manual language will be revised to provide a more consistent reference.*

5. This section may be better suited as a note to the Directory Phase 1 discussion.

NPCC Response:

Comment accepted.

6. Where is a NPCC Full Member Defined?

NPCC Response:

Thank you for the Comment. *The definition of a NPCC Full Member can be found in the NPCC By-Laws.*

https://www.npcc.org/Library/Business%20Plan%20Bylaws/Approved%20Bylaws%20of%20NPCC%20Inc%207-24-07.pdf

7. How shall the request be made, an email, a form, a letter? Is there a point of contact on the RSC this request should be made to? Where can a Full Member go to find out who is on the RSC to make the request?

NPCC Response:

Comment accepted. *Manual language will be revised to provide additional clarity. The RSC roster is available in the NPCC Directory.*

8. Is there a time line for this? What happens if they deny the request?

NPCC Response:

Comment rejected. The RSC review and assignment of a Task Force to review such a request would occur at its subsequent meeting following receipt of the request. The NPCC Manager of Reliability Criteria would notify the entity making the request if the RSC decides not to develop the new Directory.

9. Will there be template to aid in this?

NPCC Response:

Thank you for the Comment. *A Directory 'template' is attached to this Manual.*

10. How long does this process take?

NPCC Response:

Thank you for the Comment. *This process can vary depending on the extent of the comments and the workload of the Task Force.*

11. What constitutes "substantive"? Who makes this determination?

NPCC Response:

Thank you for the Comment. *If the performance attributes of the criteria have changed as a result of revisions made in response to comments then those 'changes' would be considered substantive. Typically, such a change is evident and is made by the Task Force managing the revisions.*

12. This section may be better served as a note to the previous statement.

NPCC Response:

Comment accepted. *This section moved to a note of the previous statement.*

13. How does a Directory get recommended for obsolescence? Is it because the contents are now covered by other Directories or Regional Standards or NERC Standards?

NPCC Response:

Thank you for the Comment. *Yes. (In some cases a Regional Standard may replace an existing Directory, or Directory content may be moved to another Directory to promote efficiency, or as NERC Standards become more robust they could supplant a Directory). When a Directory is impacted by changes that render it obsolete, the Lead Task Force of the Directory will present its recommendation for modification or retirement to the RCC, which in turn approves a Full Member ballot.*

14. When criteria are revised, how do the appendices get reviewed by the Task Forces responsible for them to make sure the Appendices are still applicable and/or need to be updated?

NPCC Response:

Comment accepted. *Manual language will be revised to consider conforming changes to appendices as a result of the criteria revision.*

15. How is the Lead Task Force Determined? Is this indicated by the 'prepared by xyz Task force' at the end of the Directory? Also, how is a revision request made {email, phone, etc} and how does a Full Member get contact information for the Lead Task Force?

NPCC Response:

Thank you for the Comment*. The Lead Task Force is responsible for the criteria within the Directory and is typically comprised of general SME's experienced in that area from the region. The 'prepared by xyz Task Force' is a reflection of that Directory's Lead Task Force.*

A request to revise the criteria can be made to the Chairperson of the Lead Task Force via email or through the Full Members representative on the respective Task Force.

The roster of all NPCC committees including Task Forces can be found in the NPCC Directory.

16. Is there a way to get a request to revise the Criteria and this to be denied?

NPCC Response:

Thank you for the Comment. *The Lead Task Force will consider the request among its members and will arrive at a consensus on the merits of such a request. Should the TF agree with the request to revise the criteria the proposed revision will be posted to the open process. The entity making the request is entitled to present its request to the TF, however after vetting the request if the TF does not support the proposed revision the entity making the request will be notified of the TF decision and the background informing the decision.*

17. Again, what constitutes substantive and who makes the determination as to what is or is not substantive?

NPCC Response:

Thank you for the Comment*. Please see the response to Question #11.*

18. This may be better served as a note.

NPCC Response:

Comment accepted*. Subject language moved to a footnote.*

19. How are requests to make an Appendix obsolete handled?

NPCC Response:

Comment accepted*. Manual language will be revised to include circumstances when an Appendix is retired. In general the process of retiring an Appendix will follow the process of revising an existing appendix.*

20. Who does this request go to, and by what method of communication? How does the Full Member find the appropriate contact information to make request?

NPCC Response:

Comment accepted*. A request to revise an appendix shall be submitted to the Task Force responsible for the Appendix. In cases where the TF responsible for the Appendix is not the Lead TF for the Directory, the TF responsible for the Appendix will be noted on the Appendix. All NPCC Directories and the appendices within will be reviewed to insure that the TF responsible for the appendices is apparent.*

An email to the chairperson of the TF responsible for the appendix.

The roster of all NPCC committees including Task Forces can be found in the NPCC Directory.

21. Why is only RCC's approval needed?

NPCC Response:

Thank you for the Comment. *The Appendices within NPCC Directories are all former B Procedure or C Guideline documents. The requirement for RCC approval of B and C documents (as opposed to a Full Member approval ballot) is described in NPCC document A1 Criteria for Review and Approval of Documents.*

22. Will the whole Directory be posted or will only the Appendix be posted? If the whole Directory is posted comments may be made in regards to Directory rather than just the revised the Appendix.

NPCC Response:

Comment accepted. *Manual language will be revised to limit comments received in the open process to only the subject appendix and not the entire Directory.*

23. Is there a separate process for requesting an interpretation of a definition?

NPCC Response:

Thank you for the Comment. *No. A request for an interpretation of a Glossary Definition is the same as the Directory Interpretation Process.*

24. Due to the NPCC Glossary of Terms relying on the NERC Glossary for some definitions, will the NPCC Glossary contain a link and/or reference to the NERC Glossary?

NPCC Response:

Comment accepted. *The NPCC Glossary will have extensive references to the NERC Glossary.*

25. This is a little confusing because the discussion above indicates that B & C documents were incorporated into Directories as Appendices.

NPCC Response:

Comment accepted. *Not all B and C documents have been incorporated into Directories. However, the Manual language will be revised to provide more clarity.*

26. What happens when the Term resides in more than one Directory/Appendix where there is more than one Task Force responsible?

NPCC Response:

Comment accepted. *The Task Forces will coordinate the review of the term among all the Lead Task Forces of Directories in which the term resides, by assigning a Lead Task Force to coordinate the review. The Manual language will be revised to provide more clarity.*

27. If the term resides in more than one Directory does that mean more than one Directory revision is going to occur? If so, how is a Lead, Lead Task force etc. appointed to coordinate the contextual review of a Term change in multiple Directories?

NPCC Response:

Thank you for the Comment. *When the term resides in more than one Directory, the Task Forces will coordinate the review of the NPCC defined term by assigning a Lead Task Force to coordinate the review among the TF's. Each TF individually will examine the context of the term within the Directory it has jurisdiction over. The TF designated to coordinate the review of the term shall include in the posting notice a comprehensive list of references to all occurrences of the defined term in other NPCC Directories, including each Directory in which the term resides.*

28. Similar comment as above regarding how to make a request.

NPCC Response:

Thank you for the Comment. *See response to Question #20.*

29. Should the entire Directory be posted for review for a revision and/or addition of an NPCC Glossary Term even though the Directory does not materially change? It may be more efficient and effective to post the Term for review with background on impacted NPCC documents, once the review completed then have take comments on the revision/addition itself.

NPCC Response:

Comment rejected. *NPCC will post the entire Directory in order to provide the context in which the term or proposed revision resides.*

30. May Errata and Link change recommendations be made by Members?

NPCC Response:

Comment rejected*. NPCC Members may bring the suggested errata and link change recommendations to the attention of members of the NPCC Standards Staff, however it is the responsibility of the NPCC Standards Staff to maintain links and errata changes.*

31. Which NPCC Staff?

NPCC Response:

Thank you for the Comment*. See response to Question #30. Manual will be revised to provide clarity.*

32. It may be beneficial to define "Full Member" and "Member" in the Glossary of Terms.

NPCC Response:

Comment rejected*. The definition of Full and General Member can be found in the NPCC Bylaws.*

33. How does a Member find contact information for the staff?

NPCC Response:

Thank you for the Comment*. The roster of all NPCC Staff can be found in the NPCC Directory.*

34. Is there a more specific guideline?

NPCC Response:

Thank you for the Comment*. Depending on the number of agenda items, such a request is addressed by the Task Force at its next quarterly meeting.*

35. A suggested approach would be to make the Interpretation an Addendum to the affected Directory to keep the related material together and allow the Interpretation to be retired if addressed in future Directory revisions.

NPCC Response:

Comment rejected*. The results of the interpretation will be available from the Task Force or NPCC Standards staff.*

36. A better place for this discussion may be with the discussion of Full Members regarding initiating revisions, requests for new Directories…Interpretations etc. above.

NPCC Response:

Comment accepted*. This section relocated within the topic.*

37. Will there be a link to this document?

NPCC Response:

Comment accepted*. A link to the document will be provided.*

38. This same information is provided in Section 2.b: Revisions to an Appendix.

NPCC Response:

Comment accepted*. These paragraphs deleted.*

39. NU recommends including a Revision number along with the date of revision.

NPCC Response:

Thank you for the Comment*. The Revision history record on page 2 of each Directory contains the Revision number and date of each revision.*

40. It may be beneficial to term this as "More Stringent Criteria" or instead label this section as "NPCC Full Member Criteria"

NPCC Response:

Thank you for the Comment*. A revised Directory template which reflects the format developed for Phase 2 of the Directory project will be utilized in the Manual. This section of the document will be identified as: NPCC Full Member, More Stringent Requirements and Criteria.*

41. Would it be simpler to reference solely the NPCC Glossary so only one Document with Definitions needs to be updated as opposed to having an Appendix A in each Directory?

NPCC Response:

Comment accepted. *A revised Directory template which reflects the format developed for Phase 2 of the Directory project will be utilized in the Manual. NPCC and NERC defined terms will reside in the NPCC Glossary instead of an Appendix within the individual Directories.*

42. The user of the Directory may be better served by showing or mapping of Directory Content to the ERO standard and requirement, which the Directory fulfills.

NPCC Response:

Thank you for the comment. *A document which maps NERC requirements to individual NPCC documents is available and NPCC will consider making a link to this document available.*

43. This is inconsistent with what is in the Table of Contents.

NPCC Response:

Comment accepted*. Revised Directory template does not contain highlighted inconsistency.*

44. In Section II Paragraph 2, there is a claim that the Directory Criteria are more specific, and more stringent, which is inconsistent with the or statement here.

NPCC Response:

Comment accepted. *Revised manual language in Section II Paragraph 2 to clarify that criteria is either more stringent or more specific.*

45. Which Compliance Committee? NPCC?

NPCC Response:

Comment accepted. *Revised Directory template does not contain highlighted inconsistency.*

46. Is this the Lead to be considered the Lead Task Force that owns the Directory?

NPCC Response:

Comment accepted. *Revised Directory template will clarify the Lead Task Force responsible for the Directory.*

47. Should there be a reference to the NPCC Directory Development and Revision Manual?

NPCC Response:

Comment accepted. *A reference to the Directory Development and Revision Manual will be added.*

48. It would be helpful if this form provided some directions as to where this may be submitted, such as a Task Force email.

NPCC Response:

Comment accepted. *Additional information providing direction on where to send the request will be added to the form.*

49. It would be beneficial to have fields available for capturing Dates for when the response to request for interpretation was provided back to entity requesting the interpretation, along with date of providing interpretation to the rest of the NPCC body.

NPCC Response:

Comment accepted. *The form will be revised to provide a field indicating the date on which the entity was provided with a response.*

Comments from Ted Dahill - National Grid

1. I am assuming final version will include page number references

   NPCC Response:

   Comment accepted. *Page number references will be provided in the document.*

2. Are we implying that NPCC will always seek to develop reliability requirements that are more stringent than NERC's? Would expect as ERO Standards are revised/developed then NPCC Directories will be eliminated – PRC-006-NPCC and Directory 12 as example.

   NPCC Response:

   Comment accepted. *NPCC will continue to promote regionally more stringent or specific on BPS A-10 elements.*

3. I suggest deleting the reference to 'Regional Standards to avoid confusion with Regional Reliability Standards, such as PRC-006-NPCC-1. The term 'Regional Standards' is generally used as a reference to the ERO process where need a 'regional standard' to satisfy the 'ERO approved continent-wide requirements'.

   NPCC Response:

   Comment rejected. *The reference to Regional Standards is appropriate since in some circumstances a Directory could remain in force with a Regional Standard.*

4. Suggest using 'requirements' instead of 'criteria' as a means of that the NPCC 'requirements' exceed the associated ERO standard requirements.

   NPCC Response:

   Comment rejected. *The NPCC criteria will still be promoted within the document, although the criteria have been reformatted into NERC style requirements.*

5. Want to emphasis that any entity operating within the NPCC region has access to these documents.

   NPCC Response:

   Comment accepted. *Manual language will be revised to provide a broader reference.*

6. I thought it was the RSC's responsibility to coordinate all reliability activities. Is this true? If so, need to ensure RSC is involved to control annual work plan activities.

   NPCC Response:

   Comment accepted. *Manual language will be revised to clarify the RSC role.*

7. Is this what we really want? I thought the RSC was responsible for coordinating all NERC related reliability standards and NPCC Directory related activities to ensure consistency. The RSC has the ability to coordinate the activities of all NPCC Task Forces to reach a common goal. I would be concerned that Task Forces working on their own might cause development/revision problems? I think all development/revision of Directories should go through the RSC for consistency purposes and to monitor the projected work load of the Task Forces.

   NPCC Response:

   Comment rejected. *RSC is responsible for the overall Directory project and closely monitors the status of individual directories including revisions. However, the individual Task Forces comprised of NPCC subject matter experts are better positioned to initiate revisions to critical criteria wording.*

8. Suggest using the word 'a'.

   NPCC Response:

   Comment accepted. *Manual language will be revised.*

9. Again, recommend coordinating through the RSC.

   NPCC Response:

   Comment rejected. *See response to Question #7.*

10. Question, would only the revised Appendix be submitted to the RCC or would the total directory be submitted such that the total document has a revised approval date while the Directory's 'change history' identifies why the revision was developed.

    NPCC Response:

    Comment accepted. *The entire Directory would be submitted to the RCC. However, unlike a revision to the criteria section of a Directory, the revision to an Appendix would not require Full Member approval. Additionally, for any revision the Revision History and the Task Force Review Record will be updated.*

11. Suggest moving this paragraph up to link it to the opening paragraph.

    NPCC Response:

    Comment accepted.

12. Again, I suggest having the RSC be the contact and lead for any changes. IF it is the RSC, then will need to modify references to Lead Task Force below.

    NPCC Response:

    Comment rejected. *See response to Question #7.*

13. Is this still a valid statement? Thought were using 'Criteria Compliance and Enforcement Program (CCEP)'. See NPCC documents CCEP-1 and CCEP-2.

    NPCC Response:

    Comment rejected. *The NPCC Reliability Assessment Program (NRAP) is NPCC's comprehensive reliability program.*
    Directory (criteria) reviews and their milestones are part of the NRAP.

Modified Violation Severity Levels for MOD-024-RFC-01.1

Req. Number	VIOLATION SEVERITY LEVEL			
	LOWER	MODERATE	HIGH	SEVERE
R1	N/A	N/A	The Generator Operator failed to verify the Real Power capability of a unit for summer periods in accordance with the periodicity specified per Requirement R1.1 through R1.5. OR The Generator Operator failed to verify the Real Power capability of a unit for winter periods in accordance with the periodicity specified per Requirement R1.1 through R1.5.	The Generator Operator failed to verify the Real Power capability of a unit for summer and winter periods in accordance with the periodicity specified per Requirement R1.1 through R1.5.
R2	The Generator Operator failed to verify its unit with all normal auxiliary equipment needed for normal operation in service as specified per Requirement R2.1.	N/A	The Generator Operator failed to perform the Summer verification by recording data for the specified continuous hours of normal operation during the Summer Peak Period per Requirement R2.2 (R2.2.1, R2.2.2, R2.2.3 or R2.2.4), R2.3 or R2.4.	The Generator Operator failed to reschedule a verification when the transmission system can support it when a verification test was scheduled and was not performed because the transmission system could not support it as specified per Requirement R2.5. OR The Generator Operator failed to reschedule a verification within six months of the

				resolution of the issue, when a verification was scheduled and was not performed because of a generating plant operational issue as specified per Requirement R2.6.
R3	N/A	N/A	The Generator Operator recorded the Real Power requirements of auxiliary loads during the verifications required by Requirement R2 on a simplified key one-line diagram but the diagram failed to record one (1) of the following existing auxiliary Real Power loads: Generator Step-Up (GSU), auxiliary, station service or standby (start-up) transformers as specified per Requirement R3. OR The Generator Operator failed to include Real Power consumption by common service load that shall be prorated among the appropriate units in the plant which will represent the consumption normally experienced during the system's peak load period of the day as specified per Requirement R3.1.	The Generator Operator recorded the Real Power requirements of auxiliary loads during the verifications required by Requirement R2 on a simplified key one-line diagram but the diagram failed to record two (2) or more of the following existing auxiliary Real Power loads: Generator Step-Up (GSU), auxiliary, station service or standby (start-up) transformers as specified per Requirement R3. OR The Generator Operator failed to record the Real Power requirements of auxiliary loads during the verifications required by Requirement R2 on a simplified key one-line diagram as specified per Requirement R3. OR If metering does not exist, the

				Generator Operator failed to use engineering analysis, per Requirement R3.2, to record the Real Power requirements of auxiliary loads during the verifications required by Requirement R2 on a simplified key one-line diagram as specified per Requirement R3.
R4	N/A	The Generator Operator documented an ambient conditions normalization methodology(ies) but provided its ambient conditions normalization methodology(ies) for inspection and technical review by those Resource Planners, Planning Coordinators and Transmission Planners, more than 15 business days but less than or equal to 25 business days of a request as specified per Requirement R4.1.1. OR The Generator Operator documented and provided an ambient conditions normalization methodology(ies) as specified in Requirement R4.1.1, and provided a written response to	The Generator Operator used local ambient conditions that reflect the fifty percent probability of occurrence (the median) of local temperature, humidity and cooling water temperature (whichever is applicable) conditions at the time of the Planning Coordinator's summer and winter peak load, measured at or near the generator's location but failed to include one (1) of the items as specified per Requirement R4.3.1, R4.3.2 or R4.3.3.	The Generator Operator failed to perform a normalization to median ambient conditions, of the recorded data in Requirement R2, before reporting the gross and Low Side Net Real Power capability as specified per Requirement R4. OR The Generator Operator documented an ambient conditions normalization methodology(ies) but provided its ambient conditions normalization methodology(ies) for inspection and technical review by those Resource Planners, Planning Coordinators and Transmission Planners, more than 25 business days of a request as specified per Requirement

		that commenting entity more that 45 calendar days but less than 55 calendar days of receipt of those comments as specified per Requirement R4.1.2.		R4.1.1. OR The Generator Operator documented and provided an ambient conditions normalization methodology(ies) as specified in Requirement R4.1.1, and provided a written response to that commenting entity more than 55 calendar days of receipt of those comments as specified per Requirement R4.1.2. OR The Generator Operator failed to document an ambient conditions normalization methodology(ies) to adjust the recorded Real Power capability readings from the operational tracking or test as specified per Requirement R4.1. OR The Planning Coordinator failed to make available to each Generator Operator the current and previous 15 years of annual summer and winter peak load dates and times

				within six months of the end of each summer and winter Peak Period as specified per Requirement R4.2. OR The Generator Operator used local ambient conditions that reflect the fifty percent probability of occurrence (the median) of local temperature, humidity and cooling water temperature (whichever is applicable) conditions at the time of the Planning Coordinator's summer and winter peak load, measured at or near the generator's location but failed to include two (2) or more of the items as specified per Requirement R4.3.1, R4.3.2 or R4.3.3.
R5	The Generator Operator provided the data (as specified per Requirement R5.1, R5.2 and R5.3) from the most recent Real Power capability verification but provided the data more than 30 calendar days but less than or equal to 40 calendar days following the predetermined schedule.	The Generator Operator provided the data (as specified per Requirement R5.1, R5.2 and R5.3) from the most recent Real Power capability verification but provided the data more than 40 calendar days but less than or equal to 50 calendar days following the predetermined schedule.	The Generator Operator provided the data (as specified per Requirement R5.1, R5.2 and R5.3) from the most recent Real Power capability verification but provided the data more than 50 calendar days but less than or equal to 60 calendar days following the predetermined schedule. OR	The Generator Operator provided the data (as specified per Requirement R5.1, R5.2 and R5.3) from the most recent Real Power capability verification but provided the data more than 60 calendar days following the predetermined schedule. OR The Generator Operator

			The Generator Operator provided the data from the most recent Real Power capability verification within the predetermined schedule but failed to include one (1) of the items as specified per Requirement R5.1, R5.2 and R5.3.	provided the data from the most recent Real Power capability verification within the predetermined schedule but failed to include two (2) or more of the items as specified per Requirement R5.1, R5.2 and R5.3. OR The Generator Operator failed to provide the data from the most recent Real Power capability verification as specified per Requirement R5.

Modified Violation Severity Levels for MOD-024-RFC-01.1

Req. Number	VIOLATION SEVERITY LEVEL			
	LOWER	MODERATE	HIGH	SEVERE
R1	N/A	N/A	The Generator Operator failed to verify the Real Power capability of a unit for summer periods in accordance with the periodicity specified per Requirement R1.1 through R1.5. OR The Generator Operator failed to verify the Real Power capability of a unit for winter periods in accordance with the periodicity specified per Requirement R1.1 through R1.5.	The Generator Operator failed to verify the Real Power capability of a unit for summer and winter periods in accordance with the periodicity specified per Requirement R1.1 through R1.5.
R2	The Generator Operator failed to verify its unit with all normal auxiliary equipment needed for normal operation in service as specified per Requirement R2.1.	N/A	The Generator Operator failed to perform the Summer verification by recording data for the specified continuous hours of normal operation during the Summer Peak Period per Requirement R2.2 (R2.2.1, R2.2.2, R2.2.3 or R2.2.4), R2.3 or R2.4.	The Generator Operator failed to reschedule a verification when the transmission system can support it when a verification test was scheduled and was not performed because the transmission system could not support it as specified per Requirement R2.5. OR The Generator Operator failed to reschedule a verification within six months of the

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OR¶
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The Generator Operator verified the summer gross Real Power capability by operational tracking or test for the as specified period of time under Requirement R2.2 but failed to verify run-of-river hydro as specified per Requirement R2.4.

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				resolution of the issue, when a verification was scheduled and was not performed because of a generating plant operational issue as specified per Requirement R2.6.
R3	N/A	N/A	The Generator Operator recorded the Real Power requirements of auxiliary loads during the verifications required by Requirement R2 on a simplified key one-line diagram but the diagram failed to record one (1) of the following existing auxiliary Real Power loads: Generator Step-Up (GSU), auxiliary, station service or standby (start-up) transformers as specified per Requirement R3. OR The Generator Operator failed to include Real Power consumption by common service load that shall be prorated among the appropriate units in the plant which will represent the consumption normally experienced during the system's peak load period of the day as specified per Requirement R3.1.	The Generator Operator recorded the Real Power requirements of auxiliary loads during the verifications required by Requirement R2 on a simplified key one-line diagram but the diagram failed to record two (2) or more of the following existing auxiliary Real Power loads: Generator Step-Up (GSU), auxiliary, station service or standby (start-up) transformers as specified per Requirement R3. OR The Generator Operator failed to record the Real Power requirements of auxiliary loads during the verifications required by Requirement R2 on a simplified key one-line diagram as specified per Requirement R3. OR If metering does not exist, the

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				Generator Operator failed to use engineering analysis, per Requirement R3.2, to record the Real Power requirements of auxiliary loads during the verifications required by Requirement R2 on a simplified key one-line diagram as specified per Requirement R3.
R4	N/A	The Generator Operator documented an ambient conditions normalization methodology(ies) but provided its ambient conditions normalization methodology(ies) for inspection and technical review by those Resource Planners, Planning Coordinators and Transmission Planners, more than 15 business days but less than or equal to 25 business days of a request as specified per Requirement R4.1.1. OR The Generator Operator documented and provided an ambient conditions normalization methodology(ies) as specified in Requirement R4.1.1, and provided a written response to	The Generator Operator used local ambient conditions that reflect the fifty percent probability of occurrence (the median) of local temperature, humidity and cooling water temperature (whichever is applicable) conditions at the time of the Planning Coordinator's summer and winter peak load, measured at or near the generator's location but failed to include one (1) of the items as specified per Requirement R4.3.1, R4.3.2 or R4.3.3.	The Generator Operator failed to perform a normalization to median ambient conditions, of the recorded data in Requirement R2, before reporting the gross and Low Side Net Real Power capability as specified per Requirement R4. OR The Generator Operator documented an ambient conditions normalization methodology(ies) but provided its ambient conditions normalization methodology(ies) for inspection and technical review by those Resource Planners, Planning Coordinators and Transmission Planners, more than 25 business days of a request as specified per Requirement

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The Generator Operator documented an ambient conditions normalization methodology(ies) but failed to provide its ambient conditions normalization methodology(ies) for inspection and technical review by those Resource Planners, Planning Coordinators and Transmission Planners, within 15 business days of the receipt of a request as specified per Requirement R4.1.1.¶
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The Generator Operator documented an ambient conditions normalization methodology(ies) but failed to provide a written response to that commenting entity within 45 calendar days of receipt of those comments as specified per Requirement R4.1.2.¶
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		that commenting entity more that 45 calendar days but less than 55 calendar days of receipt of those comments as specified per Requirement R4.1.2.		R4.1.1. OR The Generator Operator documented and provided an ambient conditions normalization methodology(ies) as specified in Requirement R4.1.1, and provided a written response to that commenting entity more than 55 calendar days of receipt of those comments as specified per Requirement R4.1.2. OR The Generator Operator failed to document an ambient conditions normalization methodology(ies) to adjust the recorded Real Power capability readings from the operational tracking or test as specified per Requirement R4.1. OR The Planning Coordinator failed to make available to each Generator Operator the current and previous 15 years of annual summer and winter peak load dates and times

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				within six months of the end of each summer and winter Peak Period as specified per Requirement R4.2. OR The Generator Operator used local ambient conditions that reflect the fifty percent probability of occurrence (the median) of local temperature, humidity and cooling water temperature (whichever is applicable) conditions at the time of the Planning Coordinator's summer and winter peak load, measured at or near the generator's location but failed to include two (2) or more of the items as specified per Requirement R4.3.1, R4.3.2 or R4.3.3.
R5	The Generator Operator provided the data (as specified per Requirement R5.1, R5.2 and R5.3) from the most recent Real Power capability verification but provided the data more than 30 calendar days but less than or equal to 40 calendar days following the predetermined schedule.	The Generator Operator provided the data (as specified per Requirement R5.1, R5.2 and R5.3) from the most recent Real Power capability verification but provided the data more than 40 calendar days but less than or equal to 50 calendar days following the predetermined schedule.	The Generator Operator provided the data (as specified per Requirement R5.1, R5.2 and R5.3) from the most recent Real Power capability verification but provided the data more than 50 calendar days but less than or equal to 60 calendar days following the predetermined schedule. OR	The Generator Operator provided the data (as specified per Requirement R5.1, R5.2 and R5.3) from the most recent Real Power capability verification but provided the data more than 60 calendar days following the predetermined schedule. OR The Generator Operator

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			The Generator Operator provided the data from the most recent Real Power capability verification within the predetermined schedule but failed to include one (1) of the items as specified per Requirement R5.1, R5.2 and R5.3.	provided the data from the most recent Real Power capability verification within the predetermined schedule but failed to include two (2) or more of the items as specified per Requirement R5.1, R5.2 and R5.3. OR The Generator Operator failed to provide the data from the most recent Real Power capability verification as specified per Requirement R5.

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MOD-024-RFC-01.1 Violation Severity Level (VSL) Justification

This document provides the justification for assignment of VSLs, identifying how each proposed VSL meets NERC's criteria and FERC's Guidelines. NERC's criteria for setting VSLs and FERC's four guidelines (G1-G4) for setting VSLs are provided at the end of this document.

VSL Justifications		
R1	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	The Generator Operator failed to verify the Real Power capability of a unit for summer periods in accordance with the periodicity specified per Requirement R1.1 through R1.5. OR The Generator Operator failed to verify the Real Power capability of a unit for winter periods in accordance with the periodicity specified per Requirement R1.1 through R1.5.
	Proposed Severe VSL	The Generator Operator failed to verify the Real Power capability of a unit for summer and winter periods in accordance with the periodicity specified per Requirement R1.1 through R1.5.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSLs for the stated requirement are not based on numeric gradations. Instead, they are based on whether an entity failed to perform a summer, winter or any verification during the specified periodicity. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance.*
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	*The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline 2B.*
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding	*The VSL aligns with the language of the requirement, and does not add to nor take away from it. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*

	Requirement	
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignments comply with Guideline 4, because they are based on a single violation of a Reliability Standard and are not based on a cumulative number of violations of the same requirement over a period of time.*

VSL Justifications		
R2	Proposed Lower VSL	The Generator Operator failed to verify its unit with all normal auxiliary equipment needed for normal operation in service as specified per Requirement R2.1.
	Proposed Moderate VSL	N/A
	Proposed High VSL	The Generator Operator failed to perform the Summer verification by recording data for the specified continuous hours of normal operation during the Summer Peak Period per Requirement R2.2 (R2.2.1, R2.2.2, R2.2.3 or R2.2.4), R2.3 or R2.4.
	Proposed Severe VSL	The Generator Operator failed to reschedule a verification when the transmission system can support it when a verification test was scheduled and was not performed because the transmission system could not support it as specified per Requirement R2.5. OR The Generator Operator failed to reschedule a verification within six months of the resolution of the issue, when a verification was scheduled and was not performed because of a generating plant operational issue as specified per Requirement R2.6.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSLs for the stated requirement are not based on numeric gradations. Instead, they are based on not complying with certain parts of the requirement. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance.*
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	*The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline 2B.*

	Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	*The VSL aligns with the language of the requirement, and does not add to nor take away from it. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignments comply with Guideline 4, because they are based on a single violation of a Reliability Standard and are not based on a cumulative number of violations of the same requirement over a period of time.*

VSL Justifications		
R3	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	The Generator Operator recorded the Real Power requirements of auxiliary loads during the verifications required by Requirement R2 on a simplified key one-line diagram but the diagram failed to record one (1) of the following existing auxiliary Real Power loads: Generator Step-Up (GSU), auxiliary, station service or standby (start-up) transformers as specified per Requirement R3. OR The Generator Operator failed to include Real Power consumption by common service load that shall be prorated among the appropriate units in the plant which will represent the consumption normally experienced during the system's peak load period of the day as specified per Requirement R3.1.
	Proposed Severe VSL	The Generator Operator recorded the Real Power requirements of auxiliary loads during the verifications required by Requirement R2 on a simplified key one-line diagram but the diagram failed to record two (2) or more of the following existing auxiliary Real Power loads: Generator Step-Up (GSU), auxiliary, station service or standby (start-up) transformers as specified per Requirement R3. OR The Generator Operator failed to record the Real Power requirements of auxiliary loads during the verifications required by Requirement R2 on a simplified key one-line diagram as specified per Requirement R3.

		OR If metering does not exist, the Generator Operator failed to use engineering analysis, per Requirement R3.2, to record the Real Power requirements of auxiliary loads during the verifications required by Requirement R2 on a simplified key one-line diagram as specified per Requirement R3.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSLs for the stated requirement are not based on numeric gradations. Instead, they are based on the number items the entity had failed to include in the simplified key one-line diagram but the diagram. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance.*
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	*The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline 2B.*
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	*The VSL aligns with the language of the requirement, and does not add to nor take away from it. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignments comply with Guideline 4, because they are based on a single violation of a Reliability Standard and are not based on a cumulative number of violations of the same requirement over a period of time.*

VSL Justifications		
R4	Proposed Lower VSL	N/A
	Proposed Moderate VSL	The Generator Operator documented an ambient conditions normalization methodology(ies) but provided its ambient conditions normalization methodology(ies) for inspection and technical review by those Resource

		Planners, Planning Coordinators and Transmission Planners, more than 15 business days but less than or equal to 25 business days of a request as specified per Requirement R4.1.1. OR The Generator Operator documented and provided an ambient conditions normalization methodology(ies) as specified in Requirement R4.1.1, and provided a written response to that commenting entity more that 45 calendar days but less than 55 calendar days of receipt of those comments as specified per Requirement R4.1.2.
	Proposed High VSL	The Generator Operator used local ambient conditions that reflect the fifty percent probability of occurrence (the median) of local temperature, humidity and cooling water temperature (whichever is applicable) conditions at the time of the Planning Coordinator's summer and winter peak load, measured at or near the generator's location but failed to include one (1) of the items as specified per Requirement R4.3.1, R4.3.2 or R4.3.3.
	Proposed Severe VSL	The Generator Operator failed to perform a normalization to median ambient conditions, of the recorded data in Requirement R2, before reporting the gross and Low Side Net Real Power capability as specified per Requirement R4. OR The Generator Operator documented an ambient conditions normalization methodology(ies) but provided its ambient conditions normalization methodology(ies) for inspection and technical review by those Resource Planners, Planning Coordinators and Transmission Planners, more than 25 business days of a request as specified per Requirement R4.1.1. OR The Generator Operator documented and provided an ambient conditions normalization methodology(ies) as specified in Requirement R4.1.1, and provided a written response to that commenting entity more than 55 calendar days of receipt of those comments as specified per Requirement R4.1.2. OR The Generator Operator failed to document an ambient conditions normalization methodology(ies) to adjust the recorded Real Power capability readings from the operational tracking or test as specified per Requirement R4.1. OR The Planning Coordinator failed to make available to each Generator Operator the current and previous 15 years of annual summer and winter peak load dates and times within six months of the end of each summer and

		winter Peak Period as specified per Requirement R4.2. OR The Generator Operator used local ambient conditions that reflect the fifty percent probability of occurrence (the median) of local temperature, humidity and cooling water temperature (whichever is applicable) conditions at the time of the Planning Coordinator's summer and winter peak load, measured at or near the generator's location but failed to include two (2) or more of the items as specified per Requirement R4.3.1, R4.3.2 or R4.3.3.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSLs for the stated requirement are not based on numeric gradations. Instead, they are based on the number of days the entity was late and based on specific sub-requirements in which an entity did not comply with. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance.*
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	*The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline 2B.*
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	*The VSL aligns with the language of the requirement, and does not add to nor take away from it. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignments comply with Guideline 4, because they are based on a single violation of a Reliability Standard and are not based on a cumulative number of violations of the same requirement over a period of time.*

VSL Justifications		
R5	Proposed Lower VSL	The Generator Operator provided the data (as specified per Requirement R5.1, R5.2 and R5.3) from the most recent Real Power capability verification but provided the data more than 30 calendar days but less than or equal to 40 calendar days following the predetermined schedule.
	Proposed Moderate VSL	The Generator Operator provided the data (as specified per Requirement R5.1, R5.2 and R5.3) from the most recent Real Power capability verification but provided the data more than 40 calendar days but less than or equal to 50 calendar days following the predetermined schedule.
	Proposed High VSL	The Generator Operator provided the data (as specified per Requirement R5.1, R5.2 and R5.3) from the most recent Real Power capability verification but provided the data more than 50 calendar days but less than or equal to 60 calendar days following the predetermined schedule. OR The Generator Operator provided the data from the most recent Real Power capability verification within the predetermined schedule but failed to include one (1) of the items as specified per Requirement R5.1, R5.2 and R5.3.
	Proposed Severe VSL	The Generator Operator provided the data (as specified per Requirement R5.1, R5.2 and R5.3) from the most recent Real Power capability verification but provided the data more than 60 calendar days following the predetermined schedule. OR The Generator Operator provided the data from the most recent Real Power capability verification within the predetermined schedule but failed to include two (2) or more of the items as specified per Requirement R5.1, R5.2 and R5.3. OR The Generator Operator failed to provide the data from the most recent Real Power capability verification as specified per Requirement R5.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSLs for the stated requirement are not based on numeric gradations. Instead, they are based on the number of days the entity was late and are also based on the number of items an entity failed to provide. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance.*
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the	*The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline 2B.*

	Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	*The VSL aligns with the language of the requirement, and does not add to nor take away from it. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignments comply with Guideline 4, because they are based on a single violation of a Reliability Standard and are not based on a cumulative number of violations of the same requirement over a period of time.*

NERC's Criteria for VSLs:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC's VSL Guidelines:

VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance (Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.)

VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties (A violation of a "binary" type requirement must be a "Severe" VSL. Avoid using ambiguous terms such as "minor" and "significant" to describe noncompliant performance.)

VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement (VSLs should not expand on what is required in the requirement.)

VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations (. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.)

Modified Violation Severity Levels for MOD-024-RFC-01.1

Req. Number	VIOLATION SEVERITY LEVEL			
	LOWER	MODERATE	HIGH	SEVERE
R1	N/A	N/A	The Generator Operator failed to verify the Real Power capability of a unit for summer periods in accordance with the periodicity specified per Requirement R1.1 through R1.5. OR The Generator Operator failed to verify the Real Power capability of a unit for winter periods in accordance with the periodicity specified per Requirement R1.1 through R1.5.	The Generator Operator failed to verify the Real Power capability of a unit for summer and winter periods in accordance with the periodicity specified per Requirement R1.1 through R1.5.
R2	The Generator Operator failed to verify its unit with all normal auxiliary equipment needed for normal operation in service as specified per Requirement R2.1.	N/A	The Generator Operator failed to perform the Summer verification by recording data for the specified continuous hours of normal operation during the Summer Peak Period per Requirement R2.2 (R2.2.1, R2.2.2, R2.2.3 or R2.2.4), R2.3 or R2.4.	The Generator Operator failed to reschedule a verification when the transmission system can support it when a verification test was scheduled and was not performed because the transmission system could not support it as specified per Requirement R2.5. OR The Generator Operator failed to reschedule a verification within six months of the

				resolution of the issue, when a verification was scheduled and was not performed because of a generating plant operational issue as specified per Requirement R2.6.
R3	N/A	N/A	The Generator Operator recorded the Real Power requirements of auxiliary loads during the verifications required by Requirement R2 on a simplified key one-line diagram but the diagram failed to record one (1) of the following existing auxiliary Real Power loads: Generator Step-Up (GSU), auxiliary, station service or standby (start-up) transformers as specified per Requirement R3. OR The Generator Operator failed to include Real Power consumption by common service load that shall be prorated among the appropriate units in the plant which will represent the consumption normally experienced during the system's peak load period of the day as specified per Requirement R3.1.	The Generator Operator recorded the Real Power requirements of auxiliary loads during the verifications required by Requirement R2 on a simplified key one-line diagram but the diagram failed to record two (2) or more of the following existing auxiliary Real Power loads: Generator Step-Up (GSU), auxiliary, station service or standby (start-up) transformers as specified per Requirement R3. OR The Generator Operator failed to record the Real Power requirements of auxiliary loads during the verifications required by Requirement R2 on a simplified key one-line diagram as specified per Requirement R3. OR If metering does not exist, the

				Generator Operator failed to use engineering analysis, per Requirement R3.2, to record the Real Power requirements of auxiliary loads during the verifications required by Requirement R2 on a simplified key one-line diagram as specified per Requirement R3.
R4	N/A	The Generator Operator documented an ambient conditions normalization methodology(ies) but provided its ambient conditions normalization methodology(ies) for inspection and technical review by those Resource Planners, Planning Coordinators and Transmission Planners, more than 15 business days but less than or equal to 25 business days of a request as specified per Requirement R4.1.1. OR The Generator Operator documented and provided an ambient conditions normalization methodology(ies) as specified in Requirement R4.1.1, and provided a written response to	The Generator Operator used local ambient conditions that reflect the fifty percent probability of occurrence (the median) of local temperature, humidity and cooling water temperature (whichever is applicable) conditions at the time of the Planning Coordinator's summer and winter peak load, measured at or near the generator's location but failed to include one (1) of the items as specified per Requirement R4.3.1, R4.3.2 or R4.3.3.	The Generator Operator failed to perform a normalization to median ambient conditions, of the recorded data in Requirement R2, before reporting the gross and Low Side Net Real Power capability as specified per Requirement R4. OR The Generator Operator documented an ambient conditions normalization methodology(ies) but provided its ambient conditions normalization methodology(ies) for inspection and technical review by those Resource Planners, Planning Coordinators and Transmission Planners, more than 25 business days of a request as specified per Requirement

		that commenting entity more that 45 calendar days but less than 55 calendar days of receipt of those comments as specified per Requirement R4.1.2.		R4.1.1. OR The Generator Operator documented and provided an ambient conditions normalization methodology(ies) as specified in Requirement R4.1.1, and provided a written response to that commenting entity more than 55 calendar days of receipt of those comments as specified per Requirement R4.1.2. OR The Generator Operator failed to document an ambient conditions normalization methodology(ies) to adjust the recorded Real Power capability readings from the operational tracking or test as specified per Requirement R4.1. OR The Planning Coordinator failed to make available to each Generator Operator the current and previous 15 years of annual summer and winter peak load dates and times

				within six months of the end of each summer and winter Peak Period as specified per Requirement R4.2. OR The Generator Operator used local ambient conditions that reflect the fifty percent probability of occurrence (the median) of local temperature, humidity and cooling water temperature (whichever is applicable) conditions at the time of the Planning Coordinator's summer and winter peak load, measured at or near the generator's location but failed to include two (2) or more of the items as specified per Requirement R4.3.1, R4.3.2 or R4.3.3.
R5	The Generator Operator provided the data (as specified per Requirement R5.1, R5.2 and R5.3) from the most recent Real Power capability verification but provided the data more than 30 calendar days but less than or equal to 40 calendar days following the predetermined schedule.	The Generator Operator provided the data (as specified per Requirement R5.1, R5.2 and R5.3) from the most recent Real Power capability verification but provided the data more than 40 calendar days but less than or equal to 50 calendar days following the predetermined schedule.	The Generator Operator provided the data (as specified per Requirement R5.1, R5.2 and R5.3) from the most recent Real Power capability verification but provided the data more than 50 calendar days but less than or equal to 60 calendar days following the predetermined schedule. OR	The Generator Operator provided the data (as specified per Requirement R5.1, R5.2 and R5.3) from the most recent Real Power capability verification but provided the data more than 60 calendar days following the predetermined schedule. OR The Generator Operator

			The Generator Operator provided the data from the most recent Real Power capability verification within the predetermined schedule but failed to include one (1) of the items as specified per Requirement R5.1, R5.2 and R5.3.	provided the data from the most recent Real Power capability verification within the predetermined schedule but failed to include two (2) or more of the items as specified per Requirement R5.1, R5.2 and R5.3. OR The Generator Operator failed to provide the data from the most recent Real Power capability verification as specified per Requirement R5.

MOD-024-RFC-01.1 Violation Severity Level (VSL) Justification

This document provides the justification for assignment of VSLs, identifying how each proposed VSL meets NERC's criteria and FERC's Guidelines. NERC's criteria for setting VSLs and FERC's four guidelines (G1-G4) for setting VSLs are provided at the end of this document.

VSL Justifications		
R1	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	The Generator Operator failed to verify the Real Power capability of a unit for summer periods in accordance with the periodicity specified per Requirement R1.1 through R1.5. OR The Generator Operator failed to verify the Real Power capability of a unit for winter periods in accordance with the periodicity specified per Requirement R1.1 through R1.5.
	Proposed Severe VSL	The Generator Operator failed to verify the Real Power capability of a unit for summer and winter periods in accordance with the periodicity specified per Requirement R1.1 through R1.5.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSLs for the stated requirement are not based on numeric gradations. Instead, they are based on whether an entity failed to perform a summer, winter or any verification during the specified periodicity. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance.*
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	*The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline 2B.*
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding	*The VSL aligns with the language of the requirement, and does not add to nor take away from it. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*

	Requirement	
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignments comply with Guideline 4, because they are based on a single violation of a Reliability Standard and are not based on a cumulative number of violations of the same requirement over a period of time.*

VSL Justifications		
R2	Proposed Lower VSL	The Generator Operator failed to verify its unit with all normal auxiliary equipment needed for normal operation in service as specified per Requirement R2.1.
	Proposed Moderate VSL	N/A
	Proposed High VSL	The Generator Operator failed to perform the Summer verification by recording data for the specified continuous hours of normal operation during the Summer Peak Period per Requirement R2.2 (R2.2.1, R2.2.2, R2.2.3 or R2.2.4), R2.3 or R2.4.
	Proposed Severe VSL	The Generator Operator failed to reschedule a verification when the transmission system can support it when a verification test was scheduled and was not performed because the transmission system could not support it as specified per Requirement R2.5. OR The Generator Operator failed to reschedule a verification within six months of the resolution of the issue, when a verification was scheduled and was not performed because of a generating plant operational issue as specified per Requirement R2.6.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSLs for the stated requirement are not based on numeric gradations. Instead, they are based on not complying with certain parts of the requirement. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance.*
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	*The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline 2B.*

	Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	*The VSL aligns with the language of the requirement, and does not add to nor take away from it. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignments comply with Guideline 4, because they are based on a single violation of a Reliability Standard and are not based on a cumulative number of violations of the same requirement over a period of time.*

VSL Justifications		
R3	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	The Generator Operator recorded the Real Power requirements of auxiliary loads during the verifications required by Requirement R2 on a simplified key one-line diagram but the diagram failed to record one (1) of the following existing auxiliary Real Power loads: Generator Step-Up (GSU), auxiliary, station service or standby (start-up) transformers as specified per Requirement R3. OR The Generator Operator failed to include Real Power consumption by common service load that shall be prorated among the appropriate units in the plant which will represent the consumption normally experienced during the system's peak load period of the day as specified per Requirement R3.1.
	Proposed Severe VSL	The Generator Operator recorded the Real Power requirements of auxiliary loads during the verifications required by Requirement R2 on a simplified key one-line diagram but the diagram failed to record two (2) or more of the following existing auxiliary Real Power loads: Generator Step-Up (GSU), auxiliary, station service or standby (start-up) transformers as specified per Requirement R3. OR The Generator Operator failed to record the Real Power requirements of auxiliary loads during the verifications required by Requirement R2 on a simplified key one-line diagram as specified per Requirement R3.

		OR If metering does not exist, the Generator Operator failed to use engineering analysis, per Requirement R3.2, to record the Real Power requirements of auxiliary loads during the verifications required by Requirement R2 on a simplified key one-line diagram as specified per Requirement R3.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSLs for the stated requirement are not based on numeric gradations. Instead, they are based on the number items the entity had failed to include in the simplified key one-line diagram but the diagram. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance.*
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	*The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline 2B.*
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	*The VSL aligns with the language of the requirement, and does not add to nor take away from it. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignments comply with Guideline 4, because they are based on a single violation of a Reliability Standard and are not based on a cumulative number of violations of the same requirement over a period of time.*

VSL Justifications		
R4	Proposed Lower VSL	N/A
	Proposed Moderate VSL	The Generator Operator documented an ambient conditions normalization methodology(ies) but provided its ambient conditions normalization methodology(ies) for inspection and technical review by those Resource

		Planners, Planning Coordinators and Transmission Planners, more than 15 business days but less than or equal to 25 business days of a request as specified per Requirement R4.1.1. OR The Generator Operator documented and provided an ambient conditions normalization methodology(ies) as specified in Requirement R4.1.1, and provided a written response to that commenting entity more that 45 calendar days but less than 55 calendar days of receipt of those comments as specified per Requirement R4.1.2.
	Proposed High VSL	The Generator Operator used local ambient conditions that reflect the fifty percent probability of occurrence (the median) of local temperature, humidity and cooling water temperature (whichever is applicable) conditions at the time of the Planning Coordinator's summer and winter peak load, measured at or near the generator's location but failed to include one (1) of the items as specified per Requirement R4.3.1, R4.3.2 or R4.3.3.
	Proposed Severe VSL	The Generator Operator failed to perform a normalization to median ambient conditions, of the recorded data in Requirement R2, before reporting the gross and Low Side Net Real Power capability as specified per Requirement R4. OR The Generator Operator documented an ambient conditions normalization methodology(ies) but provided its ambient conditions normalization methodology(ies) for inspection and technical review by those Resource Planners, Planning Coordinators and Transmission Planners, more than 25 business days of a request as specified per Requirement R4.1.1. OR The Generator Operator documented and provided an ambient conditions normalization methodology(ies) as specified in Requirement R4.1.1, and provided a written response to that commenting entity more than 55 calendar days of receipt of those comments as specified per Requirement R4.1.2. OR The Generator Operator failed to document an ambient conditions normalization methodology(ies) to adjust the recorded Real Power capability readings from the operational tracking or test as specified per Requirement R4.1. OR The Planning Coordinator failed to make available to each Generator Operator the current and previous 15 years of annual summer and winter peak load dates and times within six months of the end of each summer and

		winter Peak Period as specified per Requirement R4.2. OR The Generator Operator used local ambient conditions that reflect the fifty percent probability of occurrence (the median) of local temperature, humidity and cooling water temperature (whichever is applicable) conditions at the time of the Planning Coordinator's summer and winter peak load, measured at or near the generator's location but failed to include two (2) or more of the items as specified per Requirement R4.3.1, R4.3.2 or R4.3.3.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSLs for the stated requirement are not based on numeric gradations. Instead, they are based on the number of days the entity was late and based on specific sub-requirements in which an entity did not comply with. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance.*
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	*The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline 2B.*
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	*The VSL aligns with the language of the requirement, and does not add to nor take away from it. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignments comply with Guideline 4, because they are based on a single violation of a Reliability Standard and are not based on a cumulative number of violations of the same requirement over a period of time.*

VSL Justifications		
R5	Proposed Lower VSL	The Generator Operator provided the data (as specified per Requirement R5.1, R5.2 and R5.3) from the most recent Real Power capability verification but provided the data more than 30 calendar days but less than or equal to 40 calendar days following the predetermined schedule.
	Proposed Moderate VSL	The Generator Operator provided the data (as specified per Requirement R5.1, R5.2 and R5.3) from the most recent Real Power capability verification but provided the data more than 40 calendar days but less than or equal to 50 calendar days following the predetermined schedule.
	Proposed High VSL	The Generator Operator provided the data (as specified per Requirement R5.1, R5.2 and R5.3) from the most recent Real Power capability verification but provided the data more than 50 calendar days but less than or equal to 60 calendar days following the predetermined schedule. OR The Generator Operator provided the data from the most recent Real Power capability verification within the predetermined schedule but failed to include one (1) of the items as specified per Requirement R5.1, R5.2 and R5.3.
	Proposed Severe VSL	The Generator Operator provided the data (as specified per Requirement R5.1, R5.2 and R5.3) from the most recent Real Power capability verification but provided the data more than 60 calendar days following the predetermined schedule. OR The Generator Operator provided the data from the most recent Real Power capability verification within the predetermined schedule but failed to include two (2) or more of the items as specified per Requirement R5.1, R5.2 and R5.3. OR The Generator Operator failed to provide the data from the most recent Real Power capability verification as specified per Requirement R5.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSLs for the stated requirement are not based on numeric gradations. Instead, they are based on the number of days the entity was late and are also based on the number of items an entity failed to provide. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance.*
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the	*The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline 2B.*

	Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	*The VSL aligns with the language of the requirement, and does not add to nor take away from it. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignments comply with Guideline 4, because they are based on a single violation of a Reliability Standard and are not based on a cumulative number of violations of the same requirement over a period of time.*

NERC's Criteria for VSLs:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC's VSL Guidelines:

VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance (Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.)

VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties (A violation of a "binary" type requirement must be a "Severe" VSL. Avoid using ambiguous terms such as "minor" and "significant" to describe noncompliant performance.)

VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement (VSLs should not expand on what is required in the requirement.)

VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations (. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.)

From:	anthony.jablonski@rfirst.org
To:	rsg
Subject:	ANNOUNCEMENT: ReliabilityFirst PRC-006-RFC-01 (UFLS) Draft Standard Posted for 7th 30-Day Public Comment Period (September 28, 2011 thru October 27, 2011)
Date:	Tuesday, September 27, 2011 4:57:22 PM

Ladies and Gentlemen:

Announcement: 30-Day Comment Period Opens September 28, 2011 thru October 27, 2011

The Reliability*First* Automatic Underfrequency Load Shedding Requirements (PRC-006-RFC-01) draft standard will be posted for the 7th 30-Day Comment Period beginning September 28, 2011 through October 27, 2011. The Reliability*First* UFLS SDT has performed a review of the NERC PRC-006-1 standard and draft PRC-006-RFC-01 requirements to ensure the Reliability*First* requirements are either more stringent than the NERC PRC-006-1 reliability standard, adds additional detail, or address matters that the NERC PRC-006-1 reliability standard does not cover (subsequently a number of requirements have been remove from the draft PRC-006-RFC-01 standard) . Similar to the NERC PRC-006-1 standard, the Reliability*First* PRC-006-RFC-01 standard is applicable to the Planning Coordinator which is required to develop the overall UFLS program based on performance criterion contained in the NERC standard. The Reliability*First* standard goes further and prescribes; with more certainty, aspects that the Planning Coordinator's UFLS program must contain, further details on certain procedural matters with respect to how islands are addressed, and assessment of UFLS program implementation. The Reliability*First* UFLS SDT has developed a UFLS Whitepaper which further details the need and basis for the regional PRC-006-RFC-01 standard.

The draft PRC-006-RFC-01 standard and supporting documents has also gone through a formal NERC Quality Review which assessed whether the draft standard is within the scope of the SAR, whether the draft standard is clear and enforceable as written, and whether the standard meets the criteria specified in NERC's Benchmarks for Excellent Standards and criteria for governmental approval of standards, VRFs and VSLs. The Reliability*First* UFLS SDT subsequently modified the draft 7 NERC PRC-006-1 standard (and supporting documents) based on comments received through the 6th comment posting period, SDT review of the NERC PRC-006-1 standard and recommendations received via the NERC Quality Review.

The 7th draft Reliability*First* PRC-006-RFC-01 standard (clean and redline), draft Implementation Plan, UFLS Whitepaper, responses to comments received via the 6th comment period and the 7th comment posting period questions can be found on the PRC-006-RFC-01 webpage. Also listed on the RSVP website is a detailed description on how to post a comment.

Also, per the current Reliability*First* Standards Development Procedure, entities may join the Ballot Pool for PRC-006-RFC-01 standard through the close of business of the seventh day of the 15-Day pre-ballot posting period. Please NOTE – participation in recent Reliability*First* Category Ballots has been sparse. It is very important that all interested entities join the Ballot Pool and participate in this future Category Ballot. A detailed description on how to join the Ballot Pool is located on the Reliability*First* RSVP site located under the "Help Files" section of the RSVP homepage.

Once again we would like to thank you for your participation in the Reliability*First* Standards process. If you have any questions, please contact Anthony Jablonski anthony.jablonski@rfirst.org at 330-247-3054. Thank you and have a great day.

Regards,

Anthony Jablonski
Standards Process Manager
Reliability*First* Corporation
Anthony.Jablonski@rfirst.org
Office: (330) 247-3054
Cell: (330) 933-5609

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Y

Y

From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Regional Reliability Standards Announcement | Comment Period Open for PRC-006-RFC-01- October 3 – November 2, 2011
Date: Monday, October 03, 2011 10:52:23 AM

Regional Reliability Standards Announcement

Comment Period Open for PRC-006-RFC-01
October 3 – November 2, 2011

Now available

Proposed Standard for the Reliability*First* Corporation (RFC)
RFC has requested NERC to post regional reliability standard PRC-006-RFC-01 — Automatic Underfrequency Load Shedding for a 30-day industry review as permitted by the NERC Rules of Procedure.

Instructions
Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the regional standards development page.

Background
The Reliability*First* UFLS Standard: PRC-006-RFC-01 is being developed to establish Reliability*First* Regional requirements for Automatic Underfrequency Load Shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.

Regional Reliability Standards Development Process
Section 300 of the *Rules of Procedure for the Electric Reliability Organization* governs the regional reliability standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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Monthly NERC, NAESB, Regional Entity Update

Creating a Culture of Compliance

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BACKGROUND

Outlined below is recent standards and compliance activity at NERC, NAESB and the Regional Entities. If you have comments for MISO consideration send them to standards&compliance@misoenergy.org

To facilitate communication regarding particular issues, two exploder lists have been created. The lists are titled, NERC_NAESB Monthly Update (join this list to receive this monthly report on NERC, NAESB, and Regional Activities), and Standards Collaboration (join this list to participate in meetings and receive communications on collaborating on comments to new and revised standards).

To join, please go to https://extranet.midwestiso.org. If you do not have an existing account, you will need to create one. Once you have created an account, click on "update account information," and check the box for the exploder/s you would like to join.

DEADLINES

NERC/NAESB/Regional Deadline Table		
Due Date	**Deliverable**	**Entity**
9/1/11	Open of Drafting Team Nomination Period for Project 2007-17: Protection System Maintenance and Testing	NERC
9/8/11	Close of Category Ballot for Modified VSLs MOD-024-RFC-01.1: Generator Verification – Real Power	RFC
9/14/11	Close of Ballot Pool Window for Project 2007-17: Protection System Maintenance and Testing	NERC
9/15/11	Data Submittal - BAL-001-0- Real Power Balancing Control Performance (CPS 1 & CPS 2): August, 2011	RFC
9/15/11	Data Submittal - BAL-006-1.1 - Inadvertent Interchange – August, 2010	RFC/ NERC
9/19/11	Open of Initial Ballot and Non-Binding Poll for Project 2007-17: Protection System Maintenance and Testing	NERC
9/23/11	Close of Drafting Team Nomination Period for Project 2007-17: Protection System Maintenance and Testing	NERC
9/26/11	Close of Two Ballot Pool Windows for Project 2010-17: BES Definition	NERC
9/28/11	Close of Formal Comment Period for Project 2007-17: Protection System Maintenance and Testing	NERC
9/28/11	Close of Initial Ballot and Non-Binding Poll for Project 2007-17: Protection System Maintenance and Testing	NERC
9/30/11	Open of Two Ballot Window for Project 2010-17: BES Definition	NERC
10/10/11	Close of Two Formal Comment Periods for Project 2010-17: BES Definition	NERC
10/10/11	Close of Two Ballot Windows for Project 2010-17: BES Definition	NERC
10/15/11	Data Submittal - BAL-001-0- Real Power Balancing Control Performance (CPS 1 & CPS 2): September, 2011	RFC
10/15/11	Data Submittal - BAL-006-1.1 - Inadvertent Interchange – September, 2010	RFC/ NERC
10/15/11	Data Submittal – BAL-002-0 Disturbance Control Performance	RFC

FERC

FERC Orders of Note

August 2, 2011

Order Approving Reliability Standard CIP-001-2a Sabotage Reporting with a Regional Variance for TRE Docket No. RD11-6-000

August 22, 2011

Notice of FERC Audit of NERC Docket No. FA11-21-000

August 25, 2011

Letter Order Approving Standards Process Manual Compliance Filing Docket No. RR10-12-001

August 29, 2011

Order on Notices of Penalty – July 28 and July 29, 2011 Notices of Penalty Docket Nos. NP11-229-000 – NP11-253-000

Order Initiating Review of Notice of Penalty Docket No. NP11-238-000

Order Approving Stipulation and Consent Agreement – Grand River Dam Authority Docket No. IN11-7-000

NERC Filings to FERC

August 11, 2011

Motion to Further Defer Action on Time Error Correction Reliability Standard Docket No. RM09-13-000

August 24, 2011

Request of NERC for Acceptance of 2012 Business Plan and Budget and the 2012 Business Plans and Budget of Regional Entities and for Approval of Proposed Assessments to Fund Budgets Docket No. RR11-___-000

NERC

Standards Under Development

Click Picture for Link to NERC Reliability Standards Under Development Page

Reliability Standards Under Development			
Project	**Action**	**Start Date**	**End Date**
Current and Pending Ballots (Sorted by End Date)			
Project 2007-17 — Protection System Maintenance & Testing — PRC-005	Initial Ballot	09/19/11	09/28/11
Project 2007-17 — Protection System Maintenance & Testing — PRC-005	Non-Binding Poll VRFs and VSLs	09/19/11	09/28/11
Project 2010-17 — Definition of Bulk Electric System — Initial Ballot of Definition of BES	Initial Ballot	09/30/11	10/10/11
Project 2010-17 — Definition of Bulk Electric System — Initial Ballot of Detailed Information to Support BES Exceptions Request	Initial Ballot	09/30/11	10/10/11
Join Ballot Pools (Ballot Pool Windows Close at 8 a.m. EST)			
Project 2007-17 — Protection System Maintenance & Testing — PRC-005	Join Initial Ballot	08/15/11	09/14/11
Project 2007-17 — Protection System Maintenance & Testing — PRC-005	Join Non-Binding Poll	08/15/11	09/14/11
Project 2010-17 — Definition of Bulk Electric System — Initial Ballot of Definition of BES	Join Initial Ballot	08/26/11	09/26/11
Project 2010-17 — Definition of Bulk Electric System — Initial Ballot of Detailed Information to Support BES Exceptions Request	Join Initial Ballot	08/26/11	09/26/11
Posted for Comment (Closes at 8 p.m. EST) (Sorted by End Date)			
Project 2007-17 — Protection System Maintenance & Testing — PRC-005	Comment Form	08/15/11	09/28/11
Project 2010-17 — Definition of Bulk Electric System — Initial Ballot of Definition of BES	Comment Form	08/26/11	10/10/11
Project 2010-17 — Definition of Bulk Electric System — Initial Ballot of Detailed Information to Support BES Exceptions Request	Comment Form	08/26/11	10/10/11

NERC

Ballot Results

See more information on the NERC Ballot Results web page

Initial Ballot Results

- Project 2007-09: Generator Verification

Voting statistics are listed below

MOD-026-1: Verification of Models and Data for Generator Excitation System Functions

Quorum: 90.25%

Approval: 46.53%

Non-Binding Poll Results for VRFs and VSLs

Quorum: 88.75%

Approval: 56%

PRC-024-1: Generator Performance During Frequency and Voltage Excursions

Quorum: 90.82%

Approval: 18.23%

Non-Binding Poll Results for VRFs and VSLs

Quorum: 88.35%

Approval: 20.79%

Recirculation Ballot Results

- Project 2006-06: Reliability Coordination

Voting statistics are listed below

IRO-002-3: Reliability Coordination Analysis Tools

Quorum: 94.13%

Approval: 76.99%

Non-Binding Poll Results for VRFs and VSLs

Quorum: 75.37%

Approval: 93%

IRO-005-4: Reliability Coordination – Current Day Operations

Quorum: 94.13%

Approval: 75.17%

Non-Binding Poll Results for VRFs and VSLs

Quorum: 75.66%

Approval: 93%

IRO-014-2: Coordination Among Reliability Coordinators

Quorum: 94.13%

Approval: 76.27%

Non-Binding Poll Results for VRFs and VSLs

Quorum: 75.37%

Approval: 89%

Successive Ballot Results

- None

Final Ballot Results

- None

NERC Miscellaneous News

- NERC has modified their Mandatory Effective Dates webpage for U.S. Reliability Standards. Users can now view: Mandatory standards subject to enforcement, Standards subject to future enforcement, Standards pending regulatory approval, Inactive standards
- NERC has announced a new enforcement initiative for processing violations of Reliability Standards. The new process is designed to refocus efforts on reliability excellence, eliminate undue regulatory burdens, streamline paperwork requirements, increase caseload processing, and encourage continued timely and thorough self-reporting mitigation. Read the full announcement here.
- Slides and recording from NERC's Technical Webinar: Project 2008-06: Cyber Security Order 706 – Draft Version 5 (CIP-002 – CIP-011) have been posted for viewing.
- Slides and recording from NERC's Webinar: Project 2007-09 Generator Verification have been posted for viewing
- NERC has made revisions to the 2012 Actively Monitored List (AML) of Reliability Standards. This version supersedes the 2012 AML posted on August 1, 2011. The greatest change for 2012 is the use of a three-tiered approach to compliance auditing. The latest AML can be found here.
- NERC has announced the development of ERO Best Practices publications. These highlight registered entities that are recognized by NERC as having practices that add significant reliability benefit. The new best practice is titled "Event Analysis – Best Practices"
- NERC and FERC have released a task force report on the southwest outages that occurred during the extreme cold weather of the first week of February 2011. You can read the full outage report here.
- Five new lessons learned have been posted on the NERC website under "Events Analysis – Lessons Learned"
- The full summary of NERC's quarterly Board of Trustees meeting can be found here
- The July 2011 NERC Newsletter can be found here.

REGIONAL ENTITIES

Reliability*First*

- The August RFC Newsletter can be found here.
- RFC CMEP Update

2011 RFC Compliance Monitoring Schedule

2011 CIP Audit Schedule Rev. 13.xls

Midwest Reliability Organization (MRO)

- Find the July/August edition of the MRO Midwest Reliability Matters Newsletter Here.
- Find the MRO Standards page here.
- Find the MRO Compliance page here.

SERC

- SERC has posted the most recent Lessons Learned document. The July feature is FAC-008-1 and IRO-014-1. To view the Lessons Learned, click Here.
- See the latest SERC news here.
- Find the SERC Standards page here.

NAESB

NAESB Subcommittee Information

WEQ Business Practices Subcommittee (BPS)

- Information on the *Business Practices Subcommittee* is posted at: http://www.naesb.org/weq/weq_bps.asp

- The *Business Practices Subcommittee* has an exploder list which is used for the subcommittee to exchange information between meetings. To sign-up for this exploder list follow the instructions at: http://www.naesb.org/pdf3/weq_bps_exploder.pdf

WEQ OASIS Subcommittee:

- Information on the *OASIS Subcommittee* is posted at: http://www.naesb.org/weq/weq_oasis.asp

- The *OASIS Subcommittee* has an exploder list which is used for the subcommittee to exchange information between meetings. To sign-up for this exploder list follow the instructions at: http://www.naesb.org/pdf4/weq_oasis_exploder.pdf

WEQ Joint Electric Scheduling Subcommittee (JESS):

- Information on the Joint Electric Scheduling Subcommittee is posted at: http://www.naesb.org/weq/weq_jess.asp

- The *Joint Electric Scheduling Subcommittee* has an exploder list which is used for the subcommittee to exchange information between meetings. To sign-up for this exploder list follow the instructions at: http://www.naesb.org/pdf4/weq_jess_exploder.pdf:

WEQ Standards Review Subcommittee (SRS):

- Information on the *Standards Review Subcommittee* is posted at: http://www.naesb.org/weq/weq_standards_review.asp

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COMPLIANCE CALENDAR

September 2011						
Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
			1	2	3	4
5	6	7	8	9 NERC Webinar Project 2012-2014 Reliability Standards Development Plan 1:30 – 2:30 PM	10	11
12	13	14	15 NERC Webinar 2012 CMEP Implementation Plan 3:00 – 4:00 PM	16	17	18
19	20	21	22 NERC Webinar Project 2010-07 1:00 – 5:00 PM	23	24	25
26	27	28 NERC Webinar Project 2010-17: Definition of BES 1:00 – 4:00 PM ET	29	30		

Future Meetings

- NERC
  - Dec 6, 2011: NERC Compliance Workshop, Atlanta, GA
  - For the complete NERC Meeting schedule, see: http://www.nerc.net/meetings/
- RFC
  - For the complete RFC Meeting schedule, see: https://www.rfirst.org/Pages/Calendar.aspx
- MRO
  - For the complete MRO Meeting schedule, see http://www.midwestreliability.org/meetings.html
- SERC
  - For the complete SERC Meeting schedule, see: http://www.serc1.org/Application/UpcomingMeetingsView.aspx

Monthly NERC, NAESB, Regional Entity Update

Creating a Culture of Compliance

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NAESB
Subcommittee Information

COMPLIANCE CALENDAR
Upcoming meeting information for NERC and Regional Entities

BACKGROUND

Outlined below is recent standards and compliance activity at NERC, NAESB and the Regional Entities. If you have comments for MISO consideration send them to standards&compliance@misoenergy.org

To facilitate communication regarding particular issues, two exploder lists have been created. The lists are titled, NERC_NAESB Monthly Update (join this list to receive this monthly report on NERC, NAESB, and Regional Activities), and Standards Collaboration (join this list to participate in meetings and receive communications on collaborating on comments to new and revised standards).

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DEADLINES

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10/15/11	Data Submittal - BAL-006-1.1 - Inadvertent Interchange – September, 2010	RFC/ NERC
10/15/11	Data Submittal – BAL-002-0 Disturbance Control Performance	RFC
10/17/11	Close of Comment Period for Proposed Changes to NERC Rules of Procedures and All Appendices	NERC
10/27/11	Close of Comment Period for Rules of Procedure Modifications to Support BES Exception Requests for Project 2010-17 BES Definition	NERC
10/27/11	Close of Comment Period for ReliabilityFirst PRC-006-RFC-01 (UFLS) draft standard	RFC
10/28/11	Close of Comment Period for Cybersecurity Risk Management Process Guideline	DOE
11/15/11	Data Submittal - BAL-001-0- Real Power Balancing Control Performance (CPS 1 & CPS 2): September, 2011	RFC
11/15/11	Data Submittal - BAL-006-1.1 - Inadvertent Interchange – September, 2010	RFC/ NERC

FERC

FERC Orders of Note

September 9, 2011

Order on Notice of Penalty – NP11-184-000 Docket No. NP11-184-000

Order on Notices of Penalty – August 11, 2011 Notices of Penalty Docket Nos. NP11-254-000 through NP11-259-000

September 15, 2011

Notice of Proposed Rulemaking on Transmission Relay Loadability Standard PRC-023-2 Docket No. RM11-16-000

Order No. 754 – Order Approving Interpretation of TPL-002-0 Requirement R1.3.10 Docket No. RM10-6-000, Order No. 754

Order No. 753 – Order on ERO Interpretation of Transmission Operations Reliability Standard TOP-001-1 Requirement R8 Docket No. RM10-29-000, Order No. 753

Order Approving Personnel Performance, Training, and Qualification Reliability Standard PER-003-1 Docket No. RD11-7-000

Order No. 733-B – Order Denying Reconsideration and Granting Clarification in Part and Denying Clarification in Part Docket No. RM08-13-004

Notice of Proposed Rulemaking on Version 4 CIP Reliability Standards Docket No. RM11-11-000

September 21, 2011

Notice of Technical Conference on Penalty Guidelines Docket No. PL10-4-000

September 26, 2011

Order Approving Interpretations to PRC-004-1 and PRC-005-1 Docket No. RD11-5-000

Notice of Technical Conference Regarding CIP-006-2 Docket No. RD10-8-000

September 30, 2011

Order on Notices of Penalty – August 31, 2011 Notices of Penalty Docket Nos. NP11-260-000 through NP11266-000

NERC Filings to FERC

September 09, 2011

Petition for Approval of Interpretations to Requirements of Reliability Standards EOP-001-0 and EOP-001-2 – Emergency Operations Planning Docket No. RM11-__-000

September 13, 2011

Joint Motion for Extension of Time Docket Nos. RC11-1-000 and RC11-2-000

September 19, 2011

Additional Comments in Support of NP11-238 Docket No. NP11-238-000

September 28, 2011

First Annual Annual Report of nERC on Wide-Area Analysis of Technical Feasibility Exceptions Docket No. RR10-1-001

September 30, 2011

Petition Requesting Approval of NEW Enforcement Mechanisms and Submittal of Initial Find Fix and Track (FFT) Informational Filing Docket No. RC11-___-000

NERC

Standards Under Development

Click Picture for Link to NERC Reliability Standards Under Development Page

Reliability Standards Under Development			
Project	**Action**	**Start Date**	**End Date**
Current and Pending Ballots (Sorted by End Date)			
Project 2010-17 – Definition of Bulk Electric System – Initial Ballot of Definition of BES	Initial Ballot	09/30/11	10/10/11
Project 2010-17 – Definition of Bulk Electric System – Initial Ballot of Detailed Information to Support BES Exceptions Request	Initial Ballot	09/30/11	10/10/11
Interpretation 2011-INT-01 – Interpretation of MOD-028 for Florida Power & Light Company	Coming Soon		
Join Ballot Pools (Ballot Pool Windows Close at 8 a.m. Eastern)			
Interpretation 2011-INT-01 – Interpretation of MOD-028 for Florida Power & Light Company	Coming Soon		
Posted for Comment (Closes at 8 p.m. Eastern) (Sorted by End Date)			
Project 2010-17 – Definition of Bulk Electric System – Initial Ballot of Definition of BES	Comment Form	08/26/11	10/10/11
Project 2010-17 – Definition of Bulk Electric System – Initial Ballot of Detailed Information to Support BES Exceptions Request	Comment Form	08/26/11	10/10/11
Project 2010-17 – Definition of Bulk Electric System-Comment Period for Rules of Procedure Modifications to Support BES Exceptions	Comment Form	09/13/11	10/27/11
Interpretation 2011-INT-01 – Interpretation of MOD-028 for Florida Power & Light Company	Coming Soon		

NERC

Ballot Results

See more information on the NERC Ballot Results web page

Initial Ballot Results

- None

Recirculation Ballot Results

- None

Successive Ballot Results

- None

Final Ballot Results

- None

NERC Miscellaneous News

- Slides and Recording for NERC's Webinar: Project 2010-17 Definition of Bulk Electric System and Rules of Procedure have been posted.
- Slides and Recording for NERC's Webinar: Project 2007-17 Protection System Maintenance and Testing have been posted.
- Slides for NERC's Webinar: 2012 CMEP Implementation Plan and Actively Monitored List have been posted.
- NERC has posted its September 15th Dismissal Analysis.
- NERC has released a report "2011 Risk Assessment of Reliability Performance", to provide feedback and trend information to stakeholders on reliability performance.
- NERC has posted the Key Reliability Standard Spot Check (KRSSC) Program Report.
- NERC has announced the development of ERO Best Practices publications. These highlight registered entities that are recognized by NERC as having practices that add significant reliability benefit. The new best practice is titled "Event Analysis – Best Practices"
- Three new lessons learned have been posted on the NERC website under "Events Analysis – Lessons Learned"
- The September 2011 NERC Newsletter can be found here.

REGIONAL ENTITIES

Reliability*First*

- MOD-024-RFC-01.1 Modified VSLs Category Ballot Results

Voting statistics are listed below

Quorum: 87.5%

Affirmative Votes: 26

Negative Votes: 1

Abstentions: 1

Total Votes Cast: 28

The proposed MOD-024-RFC-01.1 Modified VSLs and supporting documents can be found here.

- The RFC BOD has retired the Legacy MAAC Document A-3, MAAC Document A-4, MAIN GUIDE 10 AND MAIN GUIDE 10- Appendix B, effective November 1, 2011.
- The RFC BOD has retired EOP-007-RFC-01: System Restoration Plans, effective July 1, 2013.
- The September RFC Newsletter can be found here.
- RFC CMEP Update

2011 RFC Compliance Monitoring Schedule

2011 CIP Audit Schedule Rev. 13.xls

Midwest Reliability Organization (MRO)

- Find the September/October edition of the MRO Midwest Reliability Matters Newsletter Here.
- Find the MRO Standards page here.
- Find the MRO Compliance page here.

SERC

- See the latest SERC news here.
- Find the SERC Standards page here.

NAESB

NAESB Subcommittee Information

WEQ Business Practices Subcommittee (BPS)

- Information on the *Business Practices Subcommittee* is posted at: http://www.naesb.org/weq/weq_bps.asp

- The *Business Practices Subcommittee* has an exploder list which is used for the subcommittee to exchange information between meetings. To sign-up for this exploder list follow the instructions at: http://www.naesb.org/pdf3/weq_bps_exploder.pdf

WEQ OASIS Subcommittee:

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WEQ Joint Electric Scheduling Subcommittee (JESS):

- Information on the Joint Electric Scheduling Subcommittee is posted at: http://www.naesb.org/weq/weq_jess.asp

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WEQ Standards Review Subcommittee (SRS):

- Information on the *Standards Review Subcommittee* is posted at: http://www.naesb.org/weq/weq_standards_review.asp

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COMPLIANCE CALENDAR

October 2011						
Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
					1	2
3	4	5	6 NERC Webinar Project 2010-07 1:00 – 3:00	7	8	9
10	11	12	13	14	15	16
17	18	19 RFC Reliability Workshop	20 RFC Reliability Workshop	21	22	23
24	25	26 NERC Standards and Compliance Workshop	27 NERC Standards and Compliance Workshop	28 NERC Standards and Compliance Workshop	29	30
31						

Future Meetings

- NERC
  - Dec 6, 2011: NERC Compliance Workshop, Atlanta, GA
  - For the complete NERC Meeting schedule, see: http://www.nerc.net/meetings/
- RFC
  - For the complete RFC Meeting schedule, see: https://www.rfirst.org/Pages/Calendar.aspx
- MRO
  - For the complete MRO Meeting schedule, see http://www.midwestreliability.org/meetings.html
- SERC
  - For the complete SERC Meeting schedule, see: http://www.serc1.org/Application/UpcomingMeetingsView.aspx

Ben Eng

From: Ben Eng
Sent: Tuesday, September 27, 2011 10:29 AM
Subject: 2011 3rd Quarter - Protection System Misoperation Reports

(this email being re-sent with a corrected link to procedure, templates and background. Sorry for any inconvenience)

To Primary Compliance Contact (PCC),

This is a reminder that the list of 3rd Quarter reportable Protection System Misoperations is due on 10/20/11.

This reminder is being sent to you as the PCC of a TO, GO and/or DP that has protection systems. As such, your organization(s) may have quarterly misoperations and commensurate actions to report. If you are not the Technical Contact for the annual self-certification to PRC-004, then please contact the person who is responsible, or who is your Subject Matter Expert, and have them address this notification. If your organization has already submitted 3rd quarter misoperation reports to NPCC, or stated by email that you had none to report, then no further action is required on your part.

Misoperation Report Submittals vs. Compliance

Quarterly misoperation reporting is not the same as certification of compliance to NERC Standard PRC-004, *Analysis and Mitigation of Transmission and Generation Protection System*. Self-certification of compliance to PRC-004, for the reporting period Jan-Dec 2011, takes place on January 20, 2012.
However the submittal of misoperation reports (if applicable), analyses, corrective action plans and implementation of same, can be used as supporting evidence for compliance with PRC-004.

Due Dates

The due dates for quarterly misoperation reporting are desired data submittal due dates so that the NPCC System Protection SP-7 Working Group is afforded adequate time to review the misoperation report submittals. Missing the due date for quarterly misoperation reporting does not mean you are non-compliant with NERC standard PRC-004. The compliance due date is January 20, 2012 as stated above.

- For your information, the SP-07 working group has met several times to review the submitted misoperations for 1st and 2nd Quarters 2011. The results of their review are submitted to NERC. If you have 1st or 2nd Quarter 2011 misoperation information which has not been provided to NPCC, please do so with the 3rd Quarter submittals

.

What Information to Submit? How to Submit It?

NOTE: Do not use the NPCC CDAA application at this time for quarterly misoperation reporting. It has not been modified to accommodate attachment/submittal of the template. When its features have been upgraded, you shall be notified.

- If you had **no** 3rd Quarter misoperations to report, or do not own protection systems, please send me an **email** listing your organization and stating that your organization had no 3rd Quarter misoperations, or do not own protection systems. There is no need to complete and send the Misoperations Reporting Template.

- If you had any 3rd Quarter misoperations to report, please follow the instructions in the Misoperation Reporting Guide (first document) found at this link:

https://www.npcc.org/Compliance/CDAA/Forms/Public%20List.aspx

  - Complete the blank reporting template (Ref. 8.10).
    - One template is used to capture all reportable misoperations in the 3rd Quarter for your registered function.
    - If you are registered for more than one function, please submit a separate template with all misoperations for that function (i.e. One template for TO misoperations, one template for GO misoperations)
  - Email or FTP (file transfer protocol) the completed template to me at beng@npcc.org

- If you had any 1st or 2nd Quarter misoperations which have **not been provided to NPCC**, please do so immediately by completing the template and sending it to me. Please use "No" in the Resubmittal Check" column (1st column on template)

- If you have updated status (analysis, corrective action plan development or implementation) for previously submitted 1st or 2nd Quarter misoperations, please submit them with your 3rd Quarter misoperations on the same template and denote them by entering "Yes" in the "Resubmittal Check" column (1st column) of the template.

More Information:

At the link provided above, there are additional notable references describing the overview, rationale and details regarding Misoperation Reporting:

- Definitions and scope and other particulars of reportable misoperations (Appendix A of Ref. 8.5, ERO RAPA letter to Regional Executives),

- NERC Webinar Presentation - Consistent Protection System Misoperation Reporting (Ref. 8.8)

- Questions and Answers about Consistent Protection System Misoperation Reporting (Ref. 8.9)

If you have any additional questions, feel free to email them to me or call me at 212-205-7054.
Thank you,

Ben Eng
NPCC
Manager, Compliance Audits

From:	Ben Eng
To:	Lee R. Pedowicz
Cc:	Quoc
Subject:	RSC Agenda Item 28 - Protection System Misoperation Reporting
Date:	Thursday, October 20, 2011 2:21:19 PM
Attachments:	2011_Q3_MisopReportReminder.pdf

Lee

Apologies for not getting back to you re: your RSC agenda. The wording for Item 28 is still true but you can replace the Details section with the following bulleted list and the attached sample notification letter:

- The process is in place to capture misoperation reports. Improvements to the process are planned.
- Initial notification for 3rd Quarter Misoperation Reports sent about 3 weeks prior to the due date.
- Follow up reminder sent the week before the due date
- The notification contained the link to the pertinent materials on the new NPCC website
- SP-7 has been compiling and reviewing the misoperations and formalizing reports to NERC as scheduled.
- Ensuring that all reportable misoperations that happen in NPCC's footprint has been the biggest challenge.

Ben Eng
NPCC
Manager, Compliance Audits

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

Exhibit A

List of Approved Directories and Criteria

Criteria Document Type, Number	Title	Date of Full Member Approval
Directory 1	Design and Operation of the Bulk Power System	December 1, 2009
Directory 2	Emergency Operations	October 21, 2008
Directory 3	Maintenance Criteria for Bulk Power System Protection	July 11, 2008
Directory 4	Bulk Power System Protection Criteria	December 1, 2009
Directory 7	Special Protection Systems	December 27, 2007
Directory 8	System Restoration	October 21, 2008
Directory 9	Verification of Generator Gross and Net Real Power Capability	December 22, 2008
Directory 10	Verification of Generator Gross and Net Reactive Power Capability	December 22, 2008
Directory 12	Underfrequency Load Shedding Program Requirements	March 3, 2010
Criteria A6	Operating Reserve Criteria	December 29, 2008
Criteria A7	Glossary of Terms	July 17, 2007
Criteria A8	Reliability Compliance Enforcement Program	December 20, 2007
Criteria A10	Classification of Bulk Power System Elements	December 1, 2009
Criteria A15	Disturbance Monitoring Equipment Criteria	August 23, 2007

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Exhibit B

Summary of Approved Directories and Criteria

Directory 1, **Design and Operation of the Bulk Power System**
Approved, December 1, 2009

The objective of these criteria is to provide a "design-based approach" to ensure the bulk power system is designed and operated to a level of reliability such that the loss of a major portion of the system, or unintentional separation of a major portion of the system, will not result from any design contingencies referenced in Sections 5.4.1 and 5.4.2. In NPCC the technique for assuring the reliability of the bulk power system is to require that it be designed and operated to withstand representative contingencies as specified in this Directory. Analyses of simulations of these contingencies include assessment of the potential for widespread cascading outages due to overloads, instability or voltage collapse. Loss of small portions of a system (such as radial portions) may be tolerated provided these do not jeopardize the reliability of the remaining bulk power system.
Criteria described in this document are to be used in the design and operation of the bulk power system. These criteria are applicable to all entities which are part of or make use of the bulk power system.

The characteristics of a reliable bulk power system include adequate resources and transmission to reliably meet projected customer electricity demand and energy requirements as prescribed in this document and include:

a. Consideration of a balanced relationship among the fuel type, capacity, physical characteristics (peaking/base load/etc.), and location of resources.

b. Consideration of a balanced relationship among transmission system elements to avoid excessive dependence on any one transmission circuit, structure, right-of-way, or substation.

c. Transmission systems should provide flexibility in switching arrangements, voltage control, and other control measures.

Directory 2, **Emergency Operations**
Approved, October 21, 2008

The purpose of this Directory is to present the basic factors to be considered in formulating plans and procedures to be followed in an emergency or during conditions which could lead to an emergency, in order to facilitate mutual assistance and coordination within NPCC and adjacent areas.
The objectives in formulating plans related to emergency operating conditions are:

1. To avoid the interruption of service to firm load to the extent possible.

2. To minimize the occurrence of system disturbances.

3. To contain any system disturbance and limit its effects to the area initially affected.

4. To minimize the effects of any system disturbances on customers.

5. To avoid damages to system elements.

6. To avoid hazard to the public.

Directory 3, **Maintenance Criteria for Bulk Power System Protection**
Approved, July 11, 2008

The purpose of this Directory is to present the basic maintenance requirements for bulk power system protection systems. It is recognized that responsible entities may choose to apply more rigid requirements because of local considerations.

Directory 4, **Bulk Power System Protection Criteria**
Approved, December 1, 2009

The purpose of this Directory is to provide the protection criteria, for protection of the NPCC bulk power system. It is not a design specification.

Directory 7, **Special Protection Systems**
Approved, December 27, 2007

Provide the basic criteria for Special Protection Systems such that the Bulk Power System in NPCC Inc. member Areas is operated reliably.

The documents outlines the approval process that an entity must go through when installing an SPS on the NPCC Bulk Power System. NPCC also categorizes the SPS into Type 1, 2 or 3 depending on the impact such device could have on the Bulk Power System. Type 1 SPSs, which could have the greatest impact on Bulk Power System operation must receive a higher level of examination, analysis and approvals within the NPCC Committee and Task Force structure. Greater study and documentation is required for these Type 1 SPSs.

Directory 8, **System Restoration**
Approved, October 21, 2008

The purpose of this Directory is to present the basic criteria with which each applicable entity must plan for and perform power system restoration following a major or a total blackout.
Compliance to the criteria set forth in this Directory document by each applicable entity assures the capabilities to perform power system restoration.
The functional requirements and performance of operational monitoring and control systems, operator voice communications and data telecommunications are beyond the scope of this Directory, except particular requirements for system restoration.
On an annual basis, the NPCC Inc. Task Force on Coordination of Operation shall review and accept each applicable entity's restoration plan for viability and coordination with other operating entities. The composite of the individual restoration plans, once reviewed and accepted by NPCC, comprises NPCC's regional restoration plan.

Directory 9, **Verification of Generator Gross and Net Real Power Capability**
Approved, December 22, 2008

This Directory presents the minimum criteria for verifying the Gross Real Power Capability and Net Real Power Capability of generators or generating facilities. Compliance to the criteria set forth in this Directory by each applicable entity assures accuracy of information used in the steady-state models to assess the reliability of the NPCC bulk power system. This Directory has been developed to

ensure that the requirements specified in NERC Standard MOD-024-1, "Verification of Generator Gross and Net Real Power Capability" are met by NPCC and its applicable members responsible for meeting the NERC Reliability Standards.

Directory 10, **Verification of Generator Gross and Net Reactive Power Capability**
Approved, December 22, 2008

This Directory presents the minimum criteria for verifying the Gross Reactive Power Capability and Net Reactive Power Capability of generators or generating facilities.
Compliance to the criteria set forth in this Directory by each applicable entity assures accuracy of information used in the steady-state models to assess the reliability of the NPCC bulk power system. This directory has been developed to ensure that the requirements specified in NERC Standard MOD-025-1, "Verification of Generator Gross and Net Reactive Power Capability" are met by NPCC and its applicable members responsible for meeting the NERC standards.

Directory 12, **Underfrequency Load Shedding Program Requirements**
Approved, March 3, 2010

This Directory presents the basic criteria for the design and implementation of under frequency load shedding programs to ensure that declining frequency is arrested and recovered in accordance with established NPCC performance requirements to prevent system collapse due to load-generation imbalance.

Criteria A6, **Operating Reserve Criteria**
Approved, December 29, 2008

In the continuous operation of electric power systems, operating capacity is required to meet forecast demand, including an allowance for error, to provide protection against equipment failure which has a reasonably high probability of occurrence, and to provide adequate regulation of frequency and tie line power flow. The operating capacity in excess of that required for actual load is commonly referred to as operating reserve.
This document establishes standard terminology and minimum requirements governing the amount, availability, distribution, and shared activation of operating reserve.
The objective is to facilitate a high level of reliability in the NPCC Region that is, as a minimum, consistent with the Operating Policies and Standards specified by

the North American Electric Reliability Council (NERC).

Criteria A7, **Glossary of Terms**
Approved, July 17, 2007

This document provides specific NPCC regional term definitions of those terms not listed in the NERC Glossary.

Criteria A8, **Reliability Compliance Enforcement Program**
Approved, December 20, 2007

The NPCC Inc. Reliability Compliance and Enforcement Program (the Program) described in this document is to be used to assess and enforce compliance with NPCC Inc. reliability criteria in such a way that the reliability objective stated above will be achieved. Actions taken by NPCC Inc. under the Program, including the imposition of sanctions, where applicable, shall in no way be construed as an acceptable alternative to the Member's continued obligation to comply with NPCC Inc. Criteria, Guides and Procedures. As such the Member, as stated in the NPCC Inc. Bylaws, remains responsible for providing its plan and schedule to achieve compliance. It is further noted that the Program requirements are applicable only to the elements of the bulk power system as classified by NPCC Inc. in Document A-10.

Criteria A10, **Classification of Bulk Power System Elements**
December 1, 2009

NPCC defines specific requirements applicable to design, operation, and protection of the bulk power system. The object of this Classification of Bulk Power System Elements (Document A-10) is to provide the methodology to identify the bulk power system elements, or parts thereof, of the interconnected NPCC Region.

The methodology in this document is used to classify elements of the bulk power system and may result in elements being added to or removed from the NPCC Bulk Power System List. The methodology in this document is based on the following:

Results of an analysis done on a bus basis can be applied to identify which elements, or portions thereof, connected to the bus are part of the bulk power system.

Elements shall not automatically be included or excluded from the bulk power system based on voltage class. Application of this methodology may be omitted at buses that can be logically excluded from the bulk power system based on study results at other buses tested using this methodology. If a bus is determined to be bulk power system, all other buses with elements connected to that bus must be tested.

Elements shall be evaluated based on this methodology when significant changes occur on the system that could change an element's bulk power system status; the evaluation may be limited to the affected part of the system.

Areas and facility owners may adopt methodologies that exceed the requirements set forth in this document for their own purposes. However, only elements classified as bulk power system as a result of testing described in this document shall be included on the NPCC's list of bulk power system elements. NPCC criteria and compliance monitoring shall consider only the system elements listed on NPCC's list of bulk power system elements.

The Classification of Bulk Power System Elements is based on three defined terms: bulk power system, local area and significant adverse impact.

Criteria A15, **Disturbance Monitoring Equipment Criteria**
Approved, August 23, 2007

A prompt and accurate sequence of events must be established following a disturbance to provide timely analysis and reporting of the disturbance. The importance of Disturbance Monitoring Equipment (DME) in monitoring performance of protection equipment and validation of system simulation models has long been recognized in NPCC criteria. This document provides the application and functional requirements for NPCC DME, in accordance with NERC Reliability Standards PRC-002 and PRC-018.

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Exhibit C

Approved Directories and Criteria

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NPCC
Regional Reliability Reference Directory # 1
Design and Operation of the Bulk Power System

Task Force on Coordination of Planning Revision Review Record:
December 01, 2009

Adopted by the Members of the Northeast Power Coordinating Council, Inc., on December 01, 2009 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

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Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)

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1.0 Introduction

1.1 Title - Design and Operation of the Bulk Power System

1.2 Directory Number 1

1.3 Objective

The objective of these criteria is to provide a "design-based approach" to ensure the **bulk power system** is designed and operated to a level of reliability such that the loss of a major portion of the system, or unintentional separation of a major portion of the system, will not result from any design **contingencies** referenced in Sections 5.4.1 and 5.4.2. In NPCC the technique for assuring the reliability of the **bulk power system** is to require that it be designed and operated to withstand representative **contingencies** as specified in this Directory. Analyses of simulations of these **contingencies** include assessment of the potential for widespread cascading outages due to overloads, instability or voltage collapse. Loss of small portions of a system (such as radial portions) may be tolerated provided these do not jeopardize the reliability of the remaining **bulk power system**.

Criteria described in this document are to be used in the design and operation of the **bulk power system.** These criteria are applicable to all entities which are part of or make use of the **bulk power system**.

The characteristics of a reliable **bulk power system** include adequate **resources** and transmission to reliably meet projected customer electricity demand and energy requirements as prescribed in this document and include:

a. Consideration of a balanced relationship among the fuel type, capacity, physical characteristics (peaking/base **load**/etc.), and location of **resources**.

b. Consideration of a balanced relationship among transmission system **elements** to avoid excessive dependence on any one transmission circuit, structure, right-of-way, or substation.

c. Transmission systems should provide flexibility in switching arrangements, voltage control, and other control measures

1.4 Effective Date - December 01, 2009

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1.5 Background

This Directory was developed from the NPCC A-2 criteria document - Basic Criteria for the Design and Operation of Interconnected Power Systems (May 6, 2004 version). Guidelines and Procedures for consideration in the implementation of this Directory are provided in the Appendices.

1.6 Applicability

1.6.1 Functional Entities

Reliability Coordinators
Transmission Operators
Balancing Authorities
Planning Coordinators
Transmission Planners
Resource Planners

2.0 Terms Defined in this Directory

Terms appearing in bold typeface in this Directory (including the Appendices) are defined in Appendix A.

3.0 NERC ERO Reliability Standard Requirements

The NERC ERO Reliability Standards containing requirements that are associated with this Directory include, but may not be limited to:

3.1 EOP-001-0 - Emergency Operations Planning
3.2 FAC-011-2 - System Operating Limits Methodology for the Operations Horizon
3.3 IRO-002-1 - Reliability Coordination - Facilities
3.4 IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators
3.5 MOD-010-0 - Steady-State Data for Transmission System Modeling and Simulation
3.6 MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures
3.7 MOD-012-0 — Dynamics Data for Transmission System Modeling and Simulation
3.8 MOD-013-1 — RRO Dynamics Data Requirements and Reporting Procedures
3.9 MOD-014-0 — Development of Interconnection-Specific Steady State System Models
3.10 MOD-015-0 — Development of Interconnection-Specific Dynamics System Models
3.11 MOD-016-1 — Actual and Forecast Demands, Net Energy for Load,

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Controllable DSM
3.12 TOP-001-1 — Reliability Responsibilities and Authorities
3.13 TOP-002-2 — Normal Operations Planning
3.14 TOP-003-0 — Planned Outage Coordination
3.15 TOP-004-2 — Transmission Operations
3.16 TPL-001-0 — System Performance Under Normal Conditions
3.17 TPL-002-0 — System Performance Following Loss of a Single BES Element NPCC Regional Reliability Standard Requirements
3.18 TPL-003-0 — System Performance Following Loss of Two or More BES Elements
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3.20 TPL-005-0 — Regional and Interregional Self-Assessment Reliability Reports
3.21 TPL-006-0 — Assessment Data from Regional Reliability Organizations
3.22 VAR-001-1 — Voltage and Reactive Control

4.0 NPCC regional Reliability Standards Requirements

None

5.0 NPCC Full Member, More Stringent Criteria

NPCC provides a forum for coordinating the design and operations of its five Reliability Coordinator Areas. NPCC shall conduct regional and interregional studies, and assess and monitor Planning Coordinator Area studies and Reliability Coordinator operations to assure conformance to these criteria through committees, task forces, and working groups.

It is the responsibility of each Reliability Coordinator to ascertain that their portion of the **bulk power system** is operated in conformance with these criteria. It is the responsibility of each Transmission Planner and Planning Coordinator to ascertain that their portion of the **bulk power system** is designed in conformance with these criteria

5.1 General Requirements

Specific system conditions may require Planning Coordinators or Reliability Coordinators to develop criteria which are more stringent than those set out herein. Any constraints imposed by these more stringent criteria will be observed. It is also recognized that these Criteria are not necessarily applicable to those **elements** that are not a part of the **bulk power system** or in the portions of a system where instability or overloads will not jeopardize the reliability of the remaining **bulk power system.**

5.1.1 Design Criteria

These design criteria will be used in the assessment of the **bulk power system** by each of the NPCC Transmission Planners and Planning Coordinators, and in the reliability testing at the Transmission Operator, Reliability Coordinator and Regional Council levels.

Design studies shall assume **power** flow conditions utilizing transfers, **load** and generation conditions which stress the system. Transfer capability studies shall be based on the **load** and generation conditions expected to exist for the period under study. All **reclosing** facilities shall be assumed in service unless it is known that such facilities will be rendered inoperative.

S**pecial protection systems (SPS)** shall be used judiciously and when employed shall be installed, consistent with good system design and operating criteria found in Directory #7 – *Special Protection Systems*.

A SPS may be used to provide protection for infrequent **contingencies**, or for temporary conditions that may exist such as project delays, unusual combinations of system demand and equipment outages or availability, or specific equipment maintenance outages. A **SPS** may also be applied to preserve system integrity in the event of severe facility outages and extreme **contingencies.** The decision to employ a **SPS** shall take into account the complexity of the scheme and the consequences of correct or incorrect operation as well as its benefits.

The requirements of **special protection systems** are defined in the NPCC *Bulk Power System Protection Criteria*, (Document A-5), and the *Special Protection Systems*, (Directory #7).

5.1.2 Operating Criteria

Coordination among and within the Reliability Coordinator Areas of NPCC is essential to the reliability of interconnected operations. Timely information concerning system conditions shall be transmitted by the NPCC Reliability Coordinators to other NPCC Reliability Coordinators, adjacent Reliability Coordinators or other entities as needed to assure reliable operation of the **bulk power system**.

The operating criteria represent the application of the design criteria to inter-Reliability Coordinator Area, intra- Reliability Coordinator Area operation.

The operating criteria define the minimum level of reliability that shall apply to inter-Reliability Coordinator Area operation. Where inter-Reliability Coordinator Area reliability is affected, each Reliability

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Coordinator shall establish limits and operate so that the **contingencies** stated in Section 5.5.1 and 5.5.2 can be withstood without causing a **significant adverse impact** on other Reliability Coordinator Areas.

When adequate **bulk power system** facilities are not available, **special protection systems** (SPS) may be employed to maintain system security.

Two categories of transmission transfer capabilities, normal and **emergency**, are applicable. Normal transfer capabilities are to be observed unless an **emergency** is declared.

5.1.3 Data Exchange Requirements for Modeling and System Analysis

It is the responsibility of NPCC and NPCC Members to protect the proprietary nature of the following information and to ensure it is used only for purposes of efficient and reliable system design and operation. Also, any sharing of such information must not violate anti-trust laws.

For reliability purposes, Reliability Coordinators shall share and coordinate forecast system information and real time information to enable and enhance the analysis and modeling of the interconnected **bulk power system** by security application software on energy management systems. Each Registered Entity within an NPCC Reliability Coordinator Area shall provide needed information to its Reliability Coordinator as required. Analysis and modeling of the interconnected power system is required for reliable design and operation. Data needed to analyze and model the electric system and its component facilities must be developed, maintained, and made available for use in interconnected operating and planning studies, including data for fault level analysis.

Reliability Coordinators and Registered Entities shall maintain and submit, as needed, data in accordance with applicable NPCC Procedures.

Data submitted for analysis representing physical or control characteristics of equipment shall be verified through appropriate methods. System analysis and modeling data must be reviewed annually, and verified on a periodic basis. Generation equipment, and its component controllers, shall be tested to verify data.

5.2 Resource Adequacy – Design Criteria

The probability (or risk) of disconnecting **firm load** due to resource deficiencies shall be, on average, not more than one day in ten years as

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determined by studies conducted for each Resource Planning and Planning Coordinator Area. Compliance with this criterion shall be evaluated probabilistically, such that the loss of **load** expectation (LOLE) of disconnecting **firm load** due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or **load** relief from available operating procedures.

5.3 Resource Adequacy – Operating Criteria

Each Balancing Authority shall have procedures in place to schedule outages and deratings of **resources** in such a manner that the available **resources** will be adequate to meet the Resource Planner's and Planning Coordinator's forecasted demand and **reserve** requirements, in accordance with the NPCC *Operating Reserve Criteria* (Document A-6).

For consistent evaluation and reporting of **resource** adequacy, it is necessary to measure the net capability of generating units and **loads** utilized as a **resource** of each Planning Coordinator Area.

5.4 Transmission Design Criteria

The portion of the **bulk power system** in each Planning Coordinator Area and in each Transmission Planning Area shall be designed with sufficient transmission capability to serve forecasted demand under the conditions noted in Sections 5.4.1 and 5.4.2. These criteria will also apply after any critical generator, transmission circuit, transformer, series or shunt compensating device or HVdc pole has already been lost, assuming that the Planning Coordinator Area generation and **power** flows are adjusted between outages by the use of **ten-minute reserve** and where available, phase angle regulator control and HVdc control.

Anticipated transfers of **power** from one Planning Coordinator Area to another, as well as within Planning Coordinator Areas, shall be considered in the design of transmission facilities. Transmission transfer capabilities shall be determined in accordance with the conditions noted in Sections 5.4.1 and 5.4.2.

5.4.1 Stability Assessment

Stability of the **bulk power system** shall be maintained during and following the most severe of the **contingencies** stated below, with due regard to **reclosing**. For each of the **contingencies** below that involve a fault, **stability** shall be maintained when the simulation is based on

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fault clearing initiated by the **"system A" protection group**, and also shall be maintained when the simulation is based on **fault clearing** initiated by the **"system B" protection group**.

a. A permanent three-phase fault on any generator, transmission circuit, transformer or bus section with **normal fault clearing**.

b. Simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with **normal fault clearing**. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded. Other similar situations can be excluded on the basis of acceptable risk, provided that the Reliability Coordinating Committee specifically accepts each request for exclusion.

c. A permanent phase to ground fault on any transmission circuit, transformer, or bus section with **delayed fault clearing**.

d. Loss of any **element** without a fault.

e. A permanent phase to ground fault on a circuit breaker with **normal fault clearing**. (**Normal fault clearing** time for this condition may not always be high speed.)

f. Simultaneous permanent loss of both poles of a direct current bipolar facility without an ac fault

g. The failure of a circuit breaker to operate when initiated by a **SPS** following: loss of any **element** without a fault; or a permanent phase to ground fault, with **normal fault clearing**, on any transmission circuit, transformer or bus section.

5.4.2 Steady State Assessment

a. Each Transmission Planner shall design its system in accordance with these criteria and its own voltage control procedures and criteria, and coordinate these with adjacent Transmission Planner Areas**.** Adequate **reactive power** resources and appropriate controls shall be installed in each Transmission Planner Area to maintain voltages within

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normal limits for pre-**disturbance** conditions, and within **applicable emergency limits** for the system conditions that exist following the **contingencies** specified in 5.4.1.

b. Line and equipment loadings shall be within normal limits for pre-**disturbance** conditions and within **applicable emergency limits** for the system conditions that exist following the **contingencies** specified in 5.4.1.

5.4.3 Fault Current Assessment

Each Transmission Planner and Planning Coordinator shall establish procedures and implement a system design that ensures equipment capabilities are adequate for fault current levels with all transmission and generation facilities in service for all potential operating conditions, and coordinate these procedures with adjacent Planning Coordinator Areas.

5.5 Transmission Operating Criteria

Scheduled outages of facilities that affect inter-Reliability Coordinator Area reliability shall be coordinated sufficiently in advance of the outage to permit the affected Reliability Coordinators to maintain reliability. Each Reliability Coordinator shall notify adjacent Reliability Coordinators of scheduled or forced outages of any facility on the NPCC Transmission Facilities Notification List and of any other condition which may impact on inter-Reliability Coordinator Area reliability. Work on facilities which impact inter-Reliability Coordinator Area reliability shall be expedited to minimize the time that the facilities are out of service.

Individual Reliability Coordinator Areas shall be operated in a manner such that the **contingencies** noted in Section 5.5.1 and 5.5.2 can be withstood and do not adversely affect other Reliability Coordinator Areas.

Appropriate adjustments shall be made to Reliability Coordinator Area operations to accommodate the impact of **protection group** outages, including the outage of a **protection group** which is part of a Type I **special protection system**. For typical periods of forced outage or maintenance of a **protection group**, it can be assumed, unless there are indications to the contrary, that the remaining **protection** will function as designed. If the **protection group** will be out of service for an extended period of time, additional adjustments to operations may be appropriate considering other system conditions and the consequences of possible failure of the remaining **protection group**.

5.5.1 Normal Transfers

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Pre-**contingency** voltages, line and equipment loadings shall be within normal limits. Unless specific instructions describing alternate action are in effect, normal transfers shall be such that manual **reclosing** of a faulted **element** can be carried out before any manual system adjustment, without affecting the **stability** of the **bulk power system**.

Stability of the **bulk power system** shall be maintained during and following the most severe of the **contingencies** stated below, with due regard to **reclosing.** For each of the **contingencies** stated below that involves a fault, **stability** shall be maintained when the simulation is based on **fault clearing** initiated by the **"system A" protection group**, and also shall be maintained when the simulation is based on **fault clearing** initiated by the **"system B" protection group**.

a. A permanent three-phase fault on any generator, transmission circuit, transformer or bus section, with **normal fault clearing**.

b. Simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with **normal fault clearing**. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded. Other similar situations can be excluded on the basis of acceptable risk, provided that the Reliability Coordinating Committee specifically accepts each request for exclusion.

c. A permanent phase to ground fault on any transmission circuit, transformer, or bus section with **delayed fault clearing**.

d. Loss of any **element** without a fault.

e. A permanent phase to ground fault on a circuit breaker, with **normal fault clearing**. (**Normal fault clearing** time for this condition may not always be high speed.)

f. Simultaneous permanent loss of both poles of a direct current bipolar facility without an ac fault.

g. The failure of a circuit breaker to operate when initiated by a **SPS** following: loss of any **element**

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without a fault; or a permanent phase to ground fault, with **normal fault clearing**, on any transmission circuit, transformer or bus section.

Reactive power resources shall be maintained in each Reliability Coordinator Area in order to maintain voltages within normal limits for pre-**disturbance** conditions, and within **applicable emergency limits** for the system conditions that exist following the **contingencies** specified in the foregoing. Adjoining Reliability Coordinators shall mutually agree upon procedures for inter-Reliability Coordinator Area voltage control.

Line and equipment loadings shall be within normal limits for pre-**disturbance** conditions and within **applicable emergency limits** for the system conditions that exist following the **contingencies** specified in the foregoing.

Since **contingencies** b, c, e, f, and g, are not confined to the loss of a single **element**, individual Transmission Operators and Reliability Coordinators may choose to permit a higher post **contingency** flow on remaining facilities than for **contingencies** a and d. This is permissible providing operating procedures are documented to accomplish corrective actions; the loadings are sustainable for at least the anticipated time required to effect such action, and other Transmission Operator Areas or Reliability Coordinator Areas will not be subjected to the higher flows without prior agreement.

5.5.2 Emergency Transfers

When **firm load** cannot be supplied within normal limits in a Transmission Operator Area, or a portion of a Transmission Operator Area, transfers may be increased to the point where pre-**contingency** voltages, line and equipment loadings are within **applicable emergency limits**. **Emergency** transfer levels may require generation adjustment before manually **reclosing** faulted **elements**.

Stability of the **bulk power system** shall be maintained during and following the most severe of the following **contingencies**, and with due regard to **reclosing**:

a. A permanent three-phase fault on any generator, transmission circuit, transformer or bus section, with **normal fault clearing**.

b. The loss of any **element** without a fault.

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Immediately following the most severe of these **contingencies**, voltages, line and equipment loadings will be within **applicable emergency limits**.

5.5.3 Post Contingency Operation

Immediately after the occurrence of a **contingency**, the status of the **bulk power system** must be assessed and transfer levels must be adjusted, if necessary, to prepare for the next **contingency**. If the readjustment of generation, **load** resources, phase angle regulators, and direct current facilities is not adequate to restore the system to a secure state, then other measures such as voltage reduction and shedding of firm **load** may be required. System adjustments shall be completed as quickly as possible, but in all cases within 30 minutes after the occurrence of the **contingency**.

Voltage reduction need not be initiated and firm **load** need not be shed to observe a post **contingency** loading requirement until the **contingency** occurs, provided that adequate response time for this action is available after the **contingency** occurs and other measures will maintain post **contingency** loadings within **applicable emergency limits**.

Emergency measures, including the pre-**contingency** disconnection of **firm load** if necessary, must be implemented to limit transfers to within the requirements of 5.5.2 above.

5.5.4 Operation under High Risk Conditions

Operating to the **contingencies** listed in Sections 5.5.1 and 5.5.2 is considered to provide an acceptable level of **bulk power system** security. Under certain unusual conditions, such as severe weather, the expectation of occurrence of some **contingencies**, and the associated consequences, may be judged to be temporarily, but significantly, greater than the long-term average expectation. When these conditions, referred to as high risk conditions, are judged to exist in a Transmission Operator Area, consideration should be given to operating in a more conservative manner than that required by the provisions of Sections 5.5.1 and 5.5.2.

5.6 Extreme Contingency Assessment

Extreme **contingency** assessment recognizes that the **bulk power system** can be subjected to events which exceed, in severity, the **contingencies** listed in Section 5.4.1. One of the objectives of extreme **contingency** assessment is to

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determine, through planning studies, the effects of extreme **contingencies** on system performance. This is done in order to obtain an indication of system strength, or to determine the extent of a widespread system **disturbance**, even though extreme **contingencies** do have low probabilities of occurrence.

The specified extreme **contingencies** listed below are intended to serve as a means of identifying some of those particular situations that could result in a widespread **bulk power system disturbance**. It is the responsibility of each Planning Coordinator Area to identify any additional extreme **contingencies** to be assessed.

Assessment of the extreme **contingencies** listed below shall examine post **contingency** steady state conditions, as well as **stability**, overload, cascading outages and voltage collapse. Pre-**contingency load** flows chosen for analysis shall reflect reasonable **power** transfer conditions within or between Planning Coordinator Areas.

Analytical studies shall be conducted to determine the effect of the following extreme **contingencies**:

a. Loss of the entire capability of a generating station.

b. Loss of all transmission circuits emanating from a generating station, switching station, dc terminal or substation

c. Loss of all transmission circuits on a common right-of-way.

d. Permanent three-phase fault on any generator, transmission circuit, transformer, or bus section, with **delayed fault clearing** and with due regard to **reclosing**.

e. The sudden dropping of a large **load** or major **load** center.

f. The effect of severe **power** swings arising from **disturbances** outside the Council's interconnected systems.

g. Failure of a **special protection system**, to operate when required following the normal **contingencies** listed in Section 5.4.1.

h. The operation or partial operation of a **special protection system** for an event or condition for which it was not intended to operate.

i. Sudden loss of fuel delivery system to multiple plants, (i.e. gas pipeline **contingencies**, including both gas transmission lines and gas mains.)

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Note: The requirement of this section is to perform extreme **contingency** assessments. In the case where extreme **contingency** assessment concludes there are serious consequences, an evaluation of implementing a change to design or operating practices to address such **contingencies** shall be conducted.

5.7 Extreme System Conditions Assessment

The **bulk power system** can be subjected to wide range of other than normal system conditions that have low probability of occurrence. One of the objectives of extreme system conditions assessment is to determine, through planning studies, the impact of these conditions on expected steady-state and dynamic system performance. This is done in order to obtain an indication of system robustness or to determine the extent of a widespread system **disturbance**. Each Transmission Planner and Planning Coordinator has the responsibility to incorporate special simulation testing to assess the impact of extreme system conditions.

Analytical studies shall be conducted to determine the effect of design **contingencies** under the following extreme conditions:

a. Peak **load** conditions resulting from extreme weather conditions with applicable **rating** of electrical **elements**.

b. Generating unit(s) fuel shortage, (i.e. gas supply adequacy)

After due assessment of extreme system conditions, measures may be utilized, where appropriate, to mitigate the consequences that are indicated as a result of testing for such system conditions. .

Prepared by: Task Force on Coordination of Planning

Review and Approval: Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45 day review and comment period. Upon satisfactorily addressing all the comments in this forum, the Directory document will be sent to the remaining Task Forces for their recommendation to seek RCC approval.

Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC. Bylaws" in effect at the time the ballots are cast.

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Revisions pertaining to the Appendices or any other portion of the document such as Links glossary terms, etc., only RCC Members will need to conduct the final approval ballot of the document.

This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

References:

NPCC Glossary of Terms (Document A-7)
Bulk Power System Protection Criteria (NPCC Document A-5)
Emergency Operations (NPCC Directory #2)
Special Protection Systems (Directory #7))

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Appendix A - Definition of Terms

Applicable emergency limits - These limits depend on the duration of the occurrence, and on the policy of the various member systems of NPCC regarding loss of life to equipment, voltage limitations, etc.

Emergency limits are those which can be utilized for the time required to take corrective action, but in no case less than five minutes.

The limiting condition for voltages should recognize that voltages should not drop below that required for suitable system **stability** performance, and should not adversely affect the operation of the **bulk power system**.

The limiting condition for equipment loadings should be such that cascading outages will not occur due to operation of protective devices upon the failure of facilities. (Various definitions of equipment **ratings** are found elsewhere in this glossary.)

Bulk power system **-** The interconnected electrical systems within north-eastern North America comprising **generation** and transmission facilities on which **faults** or **disturbances** can have a **significant adverse impact** outside of the local area. In this context, local areas are determined by the Council members.

Contingency - An event, usually involving the loss of one or more **elements,** which affects the **power** system at least momentarily.

NPCC Specific Definitions:

NPCC Emergency Criteria **Contingencies** - The set of **contingencies** to be observed when operating the **bulk power system** under **emergency** conditions. (Document C-1; also reference Document A-2, Section 6.2 - Emergency Transfers.)

NPCC Normal Criteria **Contingencies** - The set of **contingencies** to be observed when operating the **bulk power system** under normal conditions. (Document C-1; also reference Document A-2, Section 6.1 - Normal Transfers.)

Double Element Contingency - A **contingency** which involves the loss of two **elements**. (Document C-1)

Single Contingency - A single event which may result in the loss of one or more **elements.**

Single Element Contingency - A **contingency** involving the loss of one **element**. (Document C-1)

Limiting Contingency - The **contingency** which establishes the **transfer capability**. (Document C-1)

First Contingency Loss - The largest **capacity** outage including any assigned Ten-Minute Reserve which would result from the loss of a single **element** (Documents A-6 and C-1)

Second Contingency Loss - The largest **capacity** outage which would result from the loss of a single **element** after allowing for the First Contingency Loss. (Documents A-6 and C-1)

Disturbance - Severe oscillations or severe step changes of current, voltage and/or frequency usually caused by **faults**.

System Disturbance - An event characterized by one or more of the following phenomena: the loss of **power** system **stability**; cascading outages of circuits; oscillations; abnormal ranges of frequency or voltage or both.

Element - Any electric device with terminals that may be connected to other electric devices, such as a generator, transformer, circuit, circuit breaker, or bus section.

Limiting Element - The element that is either operating at its appropriate **rating** or would be, following a limiting **contingency** and, as a result, establishes a system limit.

Emergency - Any abnormal system condition that requires automatic or manual action to prevent or limit loss of transmission facilities or **generation** supply that could adversely affect the **reliability** of the electric system.

Specific to NPCC: An **Emergency** is considered to exist in an Area if **firm load** may have to be shed.

Fault Clearing

Delayed fault clearing - Fault clearing consistent with correct operation of a breaker failure **protection group** and its associated breakers, or of a backup **protection group** with an intentional time delay.

High speed fault clearing - Fault clearing consistent with correct operation of high speed relays and the associated circuit breakers without intentional time delay.
Notes: The specified time for high-speed relays in present practice is 50 milliseconds (three cycles on a 60Hz basis) or less. [IEEE C37.100-1981]. For planning purposes, a total clearing time of six cycles or less is considered high speed.

Normal fault clearing - Fault clearing consistent with correct operation of the **protection system** and with the correct operation of all circuit breakers or other automatic switching devices intended to operate in conjunction with that **protection system**.

Load - The electric **power** used by devices connected to an electrical generating system. (IEEE Power Engineering). Also see **Demand**.

<u>NPCC Specific Definitions:</u>

Firm Load - Loads that are not **Interruptible Loads**.

Interruptible Load - Loads that are interruptible under the terms specified in a contract.

Power

Apparent Power - The product of the volts and amperes. It comprises both *real* and *reactive* power, usually expressed in kilovoltamperes (kVA) or megavoltamperes (MVA).

Reactive Power - The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, **synchronous condensers**, or electrostatic equipment such as capacitors. Reactive power directly influences electric system voltage. It is usually expressed in kilovars (kVAr) or megavars (MVAr).

Real Power - The rate of producing, transferring, or using electrical energy, usually expressed in kilowatts (kW) or megawatts (MW).

Protection - The provisions for detecting power system **faults** or abnormal conditions and taking appropriate automatic corrective action.

Protection group - A fully integrated assembly of **protective relays** and associated equipment that is designed to perform the specified protective functions for a power system **element**, independent of other groups.

Notes:
(a) Variously identified as Main Protection, Primary Protection, Breaker Failure Protection, Back-Up Protection, Alternate Protection, Secondary Protection, A Protection, B Protection, Group A, Group B, System 1 or System 2.

(b) Pilot protection is considered to be one protection group. Protection system
Element Basis One or more protection groups; including all equipment such as instrument transformers, station wiring, circuit breakers and associated trip/close modules, and communication facilities; installed at all terminals of a power system **element** to provide the complete protection of that **element**.

Terminal Basis
One or more protection groups, as above, installed at one terminal of a power system **element**, typically a transmission line.

Pilot Protection - A form of line protection that uses a communication channel as a means to compare electrical conditions at the terminals of a line.

Rating - The operational limits of an electric system, facility, or **element** under a set of specified conditions.

Reclosing

Autoreclosing - The automatic closing of a circuit breaker in order to restore an **element** to service following automatic tripping of the circuit breaker. Autoreclosing does not include automatic closing of capacitor or reactor circuit breakers.

High-speed autoreclosing - The autoreclosing of a circuit breaker after a necessary time delay (less than one second) to permit **fault** arc deionization with due regard to coordination with all **relay** protective systems. This type of autoreclosing is generally not supervised by voltage magnitude or phase angle.

Manual Reclosing - The closing of a circuit breaker by operator action after it has been tripped by **protective relays**. Operator initiated closing commands may originate from local control or from remote (supervisory) control. Either local or remote close commands may be supervised or unsupervised.

Supervision- A closing command is said to be supervised if closing is permitted to occur only if certain prerequisite conditions are met (e.g., **synchronism-check**).

Synchronism-check - refers to the determination that acceptable voltages exist on the two sides of the breaker and the phase angle between them is within a specified limit for a specified time.

Relay - An electrical device designed to respond to input conditions in a prescribed manner and after specified conditions are met to cause contact operation or similar abrupt change in associated electric control circuits. (Also: see **protective relay**).

Reliability - The degree of performance of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system — **Adequacy** and **Security**.

Adequacy — The ability of the electric system to supply the aggregate electrical **demand** and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system **elements**.

Security — The ability of the electric system to withstand **disturbances** such as electric **short circuits** or unanticipated loss of system **elements**.

Reserve - In normal usage, reserve is the amount of **capacity** available in excess of the **demand**

Reserve Requirement - That capability above firm system **demand** required to provide for regulation, **load** forecasting error, equipment forced and scheduled outages, and local area supply **adequacy**

NPCC Specific Definitions:

Non-Synchronized Reserve — That portion of operating capacity which is available by synchronizing a generator to the network, and that capacity which can be made available by reducing load that is dependent on starting a generator to replace energy that is supplied from the grid. Non-Synchronized Reserve also includes the capacity achieved through the implementation of voltage reduction. (Documents A-6 and C-1)

Operating Reserve - The sum of **ten-minute** and **thirty-minute reserve**. (Documents A-3, A-6, and A-1)

Reserve on **Automatic Generation Control (AGC)** - That portion of **synchronized reserve** which is under the command of an automatic controller to respond to **load demands** without need for manual action. (Documents A-6 and C-1)

Synchronized Reserve - The unused capacity from resources that are synchronized to the system and ready to achieve claimed capacity (Documents A-6 and C-1)

Ten-minute reserve - The sum of **synchronized** and **non-synchronized reserve** that is fully available in ten minutes. (Documents A-6 and C-1)

Thirty-Minute Reserve - The sum of synchronized and non-synchronized reserve that can be utilized within thirty minutes of receiving an activation request, excluding capacity assigned to ten minute reserve. (A-6, C-1)

Resource - Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load.

Significant adverse impact - With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from **faults** or **disturbances**, shall be deemed as having **significant adverse impact**:

a. instability:
- any instability that cannot be demonstrably contained to a well defined local area,
- any loss of synchronism of generators that cannot be demonstrably contained to a well-defined local area.

b. unacceptable system dynamic response:

- an oscillatory response to a contingency that is not demonstrated to be clearly positively damped within 30 seconds of the initiating event.

c. unacceptable equipment tripping:

- tripping of an un-faulted **bulk power system** element (element that has already been classified as **bulk power system**) under planned system configuration due to operation of a protection system in response to a stable power swing,
- the operation of a Type I or Type II **Special Protection System** in response to a condition for which its operation is not required

d. voltage levels in violation of **applicable emergency limits**;

e. loadings on transmission facilities in violation of **applicable emergency limits**.

Special Protection System (SPS) – A protection system designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted elements. Such action may include changes in load, generation, or system configuration to maintain system stability, acceptable voltages or power flows. Automatic underfrequency load shedding as defined in the NPCC Directory #2 - Emergency Operations - is not considered a SPS. Conventionally switched, locally controlled shunt devices are not **special protection systems**.

Stability - The ability of an electric system to maintain a state of equilibrium during normal and abnormal system conditions or **disturbances**.

Small-Signal Stability - The ability of the electric system to withstand small changes or **disturbances** without the loss of synchronism among the synchronous machines in the system.

Transient Stability - The ability of an electric system to maintain synchronism between its parts when subjected to a **disturbance**, and to regain a state of equilibrium following that **disturbance**.

Appendix B - Guidelines and Procedures for NPCC Area Transmission Reviews

1.0 Introduction

NPCC has established a Reliability Assessment Program to bring together work done by NPCC, Transmission Planners and Planning Coordinators relevant to the assessment of **bulk power system reliability**. As part of the Reliability Assessment Program, the Task Force on System Studies (TFSS) is charged on an ongoing basis with conducting periodic reviews of the **reliability** of the planned bulk power transmission system of each Planning Coordinator Area of NPCC and the transmission interconnections to other Planning Coordinator Areas. The purpose of these reviews is to determine whether each Planning Coordinator Area's planned bulk power transmission system is in conformance with the NPCC *Design and Operation of the Bulk Power System* (Directory #1). Since it is the intention of the NPCC that the *Basic Criteria* in Directory #1 be consistent with the NERC *Standards*, conformance with the NPCC *Basic Criteria* in Directory #1 assures consistency with the NERC *Standards*.

To assist the TFSS in carrying out this charge, each NPCC Planning Coordinator shall conduct an annual assessment of the **reliability** of the planned bulk power transmission system within the Planning Coordinator Area and the transmission interconnections to other Planning Coordinator Areas (an Area Transmission Review), in accordance with these Guidelines, and present a report of this assessment to the TFSS for review. Each Planning Coordinator is also responsible for providing an annual report to the Compliance Committee in regard to its Area Transmission Review in accordance with the *NPCC Reliability Compliance and Enforcement Program* (Document A-8).

The NPCC role in monitoring conformance with the NPCC *Basic Criteria* in Directory #1 is limited to those instances where non-conformance could result in adverse consequences to more than one Planning Coordinator Area. If in the process of conducting the **reliability** review; problems of an intra-Reliability Coordinator Area nature are identified, NPCC shall inform the affected systems and the Planning Coordinator within which the systems are located, but follow-up concerning resolution of the problem shall be the Planning Coordinators responsibility and not that of NPCC. The affected Planning Coordinator will notify NPCC on a timely basis as to the resolution of the identified problem. If the problem is of an inter-Reliability Coordinator Area nature, NPCC shall inform the affected Planning Coordinators and, further, shall take an active role in following-up resolution of the identified problem.

2.0 Purpose of Area Review Presentation

The purpose of the presentation associated with an Area Transmission Review is to demonstrate that the Planning Coordinators planned transmission system, based on its projection of available **resources**, is in conformance with the NPCC *Basic Criteria* in Directory #1. By such a presentation, the Task Force will satisfy itself that the criteria have been met and, in general, that the **reliability** of the NPCC Interconnected Systems will be maintained. Analysis of this material should include a review of **Special Protection Systems**, as well as an assessment of the potential for widespread cascading due to overloads, instability or voltage collapse. In addition, the potential consequences of failure or misoperation of Dynamic Control Systems (DCS), which include Transmission Control Devices as defined in the NERC *Standards*, should be addressed.

This review by the TFSS does not alter Planning Coordinators and/or Company responsibilities with respect to their system's conformity with the NPCC *Basic Criteria* in Directory #1.

3.0 The Study Year to be considered

It is suggested that a study year of 4 to 6 years from the reporting date is a realistic one, both from the viewpoint of minimum lead times required for construction, and the ability to alter plans or facilities. The reviews may be conducted for a longer term beyond 6 years to address identified marginal conditions that may have longer lead-time solutions

4.0 Types and Frequency of Reviews

Each Planning Coordinator is required to present an annual transmission review to TFSS. However, the review presented by the Planning Coordinator may be one of three types: a Comprehensive (or Full) Review, an Intermediate (or Partial) Review, or an Interim Review.

A Comprehensive Review is a thorough assessment of the Planning Coordinator's entire bulk power transmission system, and includes sufficient analyses to fully address all aspects of an Area Transmission Review as described in Section 5.0. A Comprehensive Review is required of each Planning Coordinator at least every five years. TFSS may require a Planning Coordinator to present a Comprehensive Review in less than five years if changes in the Planning Coordinator's planned facilities or forecasted system conditions (system changes) warrant it.

In the years between Comprehensive Reviews, Planning Coordinators may conduct

either an Interim Review, or an Intermediate Review, depending on the extent of the Planning Coordinator's system changes since its last Comprehensive Review. If the system changes are relatively minor, the Planning Coordinator may conduct an Interim Review. In an Interim Review, the Planning Coordinator provides a summary of the changes in planned facilities and forecasted system conditions since its last Comprehensive Review and a brief discussion and assessment of the impact of those changes on the bulk power transmission system. No new analyses are required for an Interim Review.

If the Planning Coordinator's system changes since its last Comprehensive Review are moderate or concentrated in a portion of the Planning Coordinator's system, the Planning Coordinator may conduct an Intermediate Review. An Intermediate Review covers all the elements of a Comprehensive Review, but the analyses may be limited to addressing only those issues considered to be of significance, considering the extent of the system changes. If the system changes are major or pervasive, the Planning Coordinator should conduct a Comprehensive Review.

In March of each year, each Planning Coordinator shall present to the TFSS a proposal for the type of review to be conducted that year. TFSS will consider each Planning Coordinator's proposal and either indicate their concurrence, or require the Planning Coordinator to conduct a more extensive review if the Task Force feels that such is warranted based on the Planning Coordinator's system changes since its last Comprehensive Review. Area Interim Review reports shall be presented to TFSS by the end of that calendar year, and Area Intermediate and Comprehensive Review reports shall be presented to TFSS by April of the following year.

5.0 Format of Presentation – Comprehensive and Intermediate Review

Introduction

- Reference the most recent Area Comprehensive Review and any subsequent Intermediate or Interim reviews as appropriate.
- Describe the type and scope of this review.
- For a Comprehensive Review, describe the existing and planned **bulk power system** facilities included in this review.
- Describe changes in system facilities, schedules and **loads** since the most recent Comprehensive Review.
- Include maps and one-line diagrams of the system showing proposed changes as necessary.
- Describe the selected demand levels over the range of forecast system demands.

- Discuss projected firm transfers and interchange schedules.

Study results demonstrating conformance with Section 5.4 of NPCC Directory #1, *Design and Operation of the Bulk Power System* entitled, "Transmission Design Criteria", which includes evaluation of contingencies after any critical generator, transmission circuit, transformer, series or shunt compensating device or HVDC pole has already been lost.

a) Discuss the scope of the analyses. The analyses conducted for a Comprehensive Review should be thorough, but an Intermediate Review may focus on specific areas of the system, specific system conditions, or a more limited set of "critical" **contingencies**.

b) Steady State Assessment

- Discuss the **load** model, power factor, demand side management, and other modeling assumptions used in the analysis. Discuss the methodology used in voltage assessments. (An Intermediate Review may refer to the discussion from the last Comprehensive Review.)

- Provide supporting information on the **contingencies** selected for evaluation and an explanation of why the remaining simulations would produce less severe results.

- Include plots of "base case" **load** flows with all lines in service for the various conditions studied, e.g., peak, off-peak, and heavy transfers.

- Discuss the **load** flows showing the effects of major planned changes on the system.

- Discuss applicable transfer limits between contiguous areas.

- Discuss the adequacy of voltage performance and voltage control capability for the planned bulk power transmission system.

- Include in the study the planned (including maintenance) outage of any bulk electric equipment (including **protection** systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

c) Stability Assessment

Discuss and/or refer to significant studies showing the effect on the system of **contingencies** as specified in Section 5.4.1 of NPCC Directory #1, *Design and Operation of the Bulk Power System*, entitled "Stability Assessment" and report on the most severe **contingencies** in the following manner:

- Provide supporting information on the **contingencies** selected for evaluation and an explanation of why the remaining simulations would produce less severe results.
- Nature of fault, **elements** switched, switching times.
- Plots of angles versus time for significant machines, HVdc and SVC response, voltages at significant buses and significant interface flows.
- Include the effects of existing and planned **protection systems**, including any backup or redundant systems.
- Include the effects of existing and planned control devices.
- Include in the study the planned (including maintenance) outage of any bulk electric equipment (including **protection systems** or their components) at those demand levels for which planned (including maintenance) outages are performed.

For a Comprehensive or Intermediate Review, discuss the **load** model and other modeling assumptions used in the analysis. (An Intermediate Review may refer to the discussion from the last Comprehensive Review.)

d) Fault Current Assessment

- Discuss the methodology and assumptions used in the fault current assessment. (An Intermediate Review may refer to the discussion from the last Comprehensive Review.)
- Discuss instances where fault levels exceed equipment capabilities and measures to mitigate such occurrences.
- Discuss changes to fault levels at stations adjacent to other Planning Coordinator Areas.

Extreme Contingency Assessment

a) Discuss the scope of the analyses. The analyses conducted for a Comprehensive Review should be thorough, but an Intermediate Review may focus on specific areas of the system, specific system conditions, or a more limited set of "critical" **contingencies**.

b) Provide supporting information on the extreme **contingencies** selected for evaluation and an explanation of why the remaining simulations would produce less severe results.

c) Discuss and/or refer to significant **load** flow studies showing the base case and the post fault conditions for the **contingencies** as specified in Section 5.6 of Directory #1 entitled "Extreme Contingency Assessment". Report on the most severe **contingencies** tested.

d) Discuss and/or refer to significant **stability** studies showing the effect on the system of **contingencies** as specified in Section 5.6 of Directory #1. Report on the most severe **contingencies** tested.

e) In the case where **contingency** assessment concludes serious consequences, conduct an evaluation of implementing a change to address such **contingencies**.

Extreme System Condition Assessment

a) Discuss the scope of the analyses.

b) Discuss and/or refer to significant **load** flow studies showing the effect on the steady state performance of extreme system conditions as specified in Section 5.7 of Directory #1, entitled "Extreme System Condition Assessment". Report on the most severe system conditions and **contingencies** tested.

c) Provide supporting information on the **contingencies** selected for evaluation and an explanation of why the remaining simulations would produce less severe results.

d) Discuss and/or refer to significant **stability** studies showing the effect on the dynamic performance of extreme system conditions as specified in Section 5.7 of Directory #1. Report on the most severe system conditions and **contingencies** tested.

e) In the case where extreme condition assessment concludes serious consequences, conduct an evaluation of implementing measures to mitigate such consequences.

Review of Special Protection Systems (SPSs)

a) Discuss the scope of review. A Comprehensive Review should review all the existing, new, and modified **SPSs** included in its transmission plan. An Intermediate Review may focus on the new and modified **SPSs**, and just those existing **SPSs** that may have been impacted by system changes since they were last reviewed.

b) For those **SPSs** whose failure or misoperation has an inter-Planning Coordinator Area or interregional effect, discuss and/or refer to appropriate **load** flow and **stability** studies analyzing the consequences.

c) For those **SPSs** whose failure or misoperation has only local or inter-company consequences, discuss and/or refer to **load** flow and **stability** studies demonstrating that this is still the case for the time period being reviewed.

d) For instances where a **SPS** which was formerly considered to have only local consequences is identified as having the potential for inter-Planning Coordinator Area effects, for the time period being reviewed, the TFSS should notify the Task Forces on Coordination of Planning, System Protection and Coordination of Operation. In such instances a complete review of the **SPS** should be made, as per the *Procedure for NPCC Review of New or Modified Bulk Power System Special Protection Systems (SPS)* in Directory #7.

Review of Dynamic Control Systems (DCSs)

For those DCSs whose failure or misoperation may have an inter-Planning Coordinator Area or interregional effect, discuss and/or refer to appropriate **stability** studies analyzing the consequences of such failure or misoperation in accordance with the Joint Working Group (JWG)-1 report, "Technical Considerations and Suggested Methodology for the Performance Evaluation of Dynamic Control Systems". A Comprehensive Review should address all potentially impactive existing and new DCSs, but an Intermediate Review may focus on new DCSs and just those existing DCSs that may have been impacted by system changes since they were last reviewed.

Review of Exclusions to the *Basic Criteria*.

Review any exclusions granted under the NPCC *Guidelines for Requesting Exclusions to Sections 5.4.1(b) and 5.5.1(b) Directory #1 Design and Operation of the Bulk Power System* (Appendix F). A Comprehensive Review should address all exclusions, but an Intermediate Review may focus

on just those exclusions that may have been impacted by system changes since they were last reviewed.

Overview Summary of System Performance for Year Studied

6.0 Format of Presentation - Interim Review

Introduction of Interim Review

Reference the most recent Comprehensive Review and any subsequent Intermediate or Interim Reviews as appropriate.

Changes in Facilities (Existing and Planned) and Forecasted System Conditions Since the Last Comprehensive Review.

a) **Load** Forecast

b) Generation **Resources**

c) Transmission Facilities

d) **Special Protection Systems**

e) Dynamic Control Systems

f) Exclusions

Brief Impact Assessment and Overview Summary

The Planning Coordinator will provide a brief assessment of the impact of these changes on the **reliability** of the interconnected **bulk power system**, based on engineering judgment and internal and joint system studies as appropriate.

7.0 Documentation

The documentation required for a Comprehensive or Intermediate Review should be in the form of a report addressing each of the **elements** of the above presentation format. The report should be accompanied by the Planning Coordinator'**s bulk power system** map and one-line diagram, summary tables, figures, and appendices, as appropriate. The report may include references to other studies performed by the Planning Coordinator or by utilities within the Planning Coordinator Area that are relevant to the Area review, with appropriate excerpts from those studies.

The documentation required for an Interim Review should be in the form of a

summary report (normally not exceeding 5 pages), containing a description of system changes and a brief assessment on their impact on the **reliability** of the interconnected **bulk power system**.

8.0 Task Force Follow-Up Procedures

8.1 Once a Planning Coordinator has presented its Review report to the TFSS, TFSS will review the Planning Coordinator's report and any supporting documentation and:

a. Consider whether to accept the report as complete and in full conformance with these Guidelines. If the report is found to be unacceptable, TFSS will indicate to the Planning Coordinator the specific areas of deficiency, and request the Planning Coordinator to address those deficiencies.

b. Consider their concurrence with the results and conclusion(s) of the Planning Coordinator's Review. If there is not concurrence, TFSS will indicate to the Planning Coordinator the specific areas of disagreement, and work with the Planning Coordinator to try to achieve concurrence. If agreement has not been reached within a reasonable period of time, TFSS shall prepare a summary of the results of its review, including a discussion of the Planning Coordinators of disagreement.

8.2 If the results of the Area Review indicates that the Planning Coordinator's planned bulk power transmission system is not in conformance with NPCC Directory #1, TFSS will request the Planning Coordinator to develop a plan to achieve conformance with the Criteria.

8.3 If the Area Review indicates an overall **bulk power system** reliability concern (not specific to the Planning Coordinator's planned bulk power transmission system), TFSS will consider what additional studies may be necessary to address the concern, and prepare a summary discussion and recommendation to the Task Force on Coordination of Planning.

8.4 Upon completion of an Area Review, TFSS will report the results of the review to the Task Force on Coordination of Planning and to the Reliability Coordinating Committee.

Appendix C - Procedure for Testing and Analysis of Extreme Contingencies

1.0 Introduction

Extreme **Contingencies** (ECs) are tested "as a measure of system strength", in order to identify potential patterns of weakness in the bulk power transmission system. This procedure for the testing and analysis of ECs should be used when testing ECs for NPCC studies or studies submitted for NPCC review.

This procedure applies to **reliability** studies that consider the overall performance of the interconnected systems of the NPCC Planning Coordinator Areas. It principally applies to NPCC - wide studies of the **bulk power system**, and generally does not apply to studies normally conducted by NPCC Planning Coordinators that concentrate on individual or a limited number of facilities. This procedure applies to NPCC Overall and Area Transmission Reviews, and may be applicable to other **reliability** studies conducted by the Planning Coordinators, and even to individual facility investigations, where such studies and investigations consider the overall performance of the interconnected systems of the NPCC Planning Coordinator Areas. Certain Transmission Planners or Planning Coordinators may elect to completely mitigate the effects of specific ECs.

Finally, this procedure should be followed in multi-regional **reliability** studies in which NPCC is an active participant, to the extent that this is possible within the framework of such multi-regional efforts.

2.0 Choosing Contingencies for Testing

The ECs are defined in the NPCC Directory #1- Design and Operation of the **Bulk Power System**, and in the NERC Standards. Testing should focus on those ECs expected to have the greatest potential effect on the interconnected system. Particular attention should be paid to contingencies which would result in major angular power shifts, e.g., interruption of shorter transmission paths carrying heavy power flows, leaving longer transmission paths as the only remaining paths. Additionally, contingencies which would result in reversal of major power transfers, e.g., loss of major ties in a neighboring region or Area when said region or Area was transferring power away from the area of interest, should be considered for their impact in subjecting the system to severe power swings (reference EC type “f”). In considering specific **contingencies** to be investigated in an NPCC **reliability** study, all relevant testing done at the Planning Coordinator level should first be reviewed.

In general, a **contingency** in a particular Planning Coordinator Area should be studied, if requested by any other Planning Coordinator, based on a reasonable surmise that the requesting Planning Coordinator may be adversely affected.

3.0 Modeling Assumptions

The assumed generation dispatch is a major consideration in all EC testing. In general, EC testing should use a dispatch pattern considered to be highly probable for the year and **load** level being studied. Intra-Reliability Coordinator Area inter-Reliability Coordinator Area and, where appropriate, inter-regional transfers should be simulated at a level which is experienced or expected at least 75% of the time on a flow duration basis, up to the maximum operating limit for the interfaces being tested. It is not the NPCC intent to test the worst imaginable extreme, but EC tests should be severe.

Each Planning Coordinator shall specify the appropriate Planning Coordinator **load** representation (e.g. active and reactive power as a function of voltage) for use in NPCC **reliability** studies. This applies to long term stability tests or post-transient loadflows as well as **transient stability** tests.

4.0 Evaluating Individual Test Results

A question in evaluating the results of a particular test run is - “Does the system "pass" or "fail" for this **contingency**?” While in the final analysis this is a matter of informed engineering judgment, factors which should be considered include:

1. Lines or transformers loaded above **short time emergency ratings**,

2. Buses with voltage levels in violation of **applicable emergency limits**, (which vary depending on the location within the system),

3. Magnitude and geographic distribution of such overloads and voltage violations across the system,

4. Transient generator angles, frequencies, voltages and power,

5. Operation of Dynamic Control Systems and **Special Protection Systems** (SPS),

6. Oscillations that could cause generators to lose synchronism or lead to dynamic instability,

7. net loss of source resulting from any combination of loss of synchronism of one or more units, generation rejection or runback initiated by SPS, or any other defined system separation,

8. Identification of the extent of the Planning Coordinator Area (s) involved for any indicated instability or islanding (the involvement of more than one

Planning Coordinator Area, should be a major consideration),

9. **Relay** operations or the proximity of apparent impedance trajectories to **relay** trip characteristics,

10. The angle across opened breakers,

11. Adequacy of computer simulation models and data.

Finally, a judgment should be attempted as to whether a "failure" is symptomatic of a basic system weakness, or just sensitivity to a particular EC. For example, should failures turn up for several EC tests in a particular part of the system, it is likely that a basic system weakness has been identified.

The loss of portions of the system should not necessarily be considered a failed result, provided that these losses do not jeopardize the integrity of the overall **bulk power system**.

NPCC study groups should avoid characterizations like "successful" and "unsuccessful" when commenting on individual runs. Rather, the specific initial conditions directly causing or related to the failure, the complete description of the nature of the failure (e.g., voltage collapse, instability, system separation, as well as the facilities involved), and the extent of potential impact on other Planning Coordinator Areas should be reported.

5.0 Evaluating the Results of a Program of EC Testing

The NPCC Directory #1 document - "*Design and Operation of* ***Bulk Power System***", calls for testing of Extreme **Contingencies** (EC) "as a measure of system strength." The results of all NPCC **reliability** studies are made available to the Planning Coordinators as a guide for planners and designers in the conduct of their future work. The focus of NPCC reports, then, should be on indicating those portions of the system in which basic system weaknesses may be developing, rather than on the results of one specific **contingency**.

Any patterns of weaknesses should be identified, which may include reference to earlier NPCC **reliability** studies and/or Planning Coordinator or member system investigations. There is also a need to distinguish between a "failed" test which indicates sensitivity only to a particular **contingency** run and a "failed" test which indicates a more general system weakness (always keeping in mind the severity of possible consequences of the **contingency**). Actions taken by member systems or Planning Coordinators to reduce the probability of occurrence or mitigate the consequences of the **contingency** should also be cited.

NPCC follow-up, after publication of a final report, is appropriate only for instances

of possible general system weakness. In these instances, the results should be specifically referred to the affected Planning Coordinator or Planning Coordinators for further and more detailed investigation with subsequent reporting to NPCC.

Appendix D - Guidelines for Area Review of Resource Adequacy

1.0 Introduction

NPCC has established a Reliability Assessment Program to bring together work done by the NPCC and Planning Coordinators relevant to the assessment of **bulk power system reliability**. As part of the Reliability Assessment Program, each Planning Coordinator submits to the Task Force on Coordination of Planning its resource adequacy assessment consistent with these guidelines. The Task Force is charged, on an ongoing basis, with reviewing and recommending NPCC Reliability Coordinating Committee approval of these reviews of **resource** adequacy of each Planning Coordinator Area of NPCC.

Resources refer to the total contributions provided by supply-side and demand-side facilities and actions. Supply-side facilities include all generation sources within a Planning Coordinator Area and firm capacity backed purchases from neighboring systems. Demand-side facilities include measures for reducing or shifting **load**, such as conservation, **load** management, interruptible **loads**, dispatchable **loads** and small identified generation which is not metered at the control centers.

The NPCC role in monitoring conformance with the NPCC Directory #1 - *Design and Operation of Bulk Power System* is essential because under this criterion, each Planning Coordinator determines its resource requirements by considering interconnection assistance from other Planning Coordinators, on the basis that adequate **resources** will be available in those Planning Coordinator Areas. Because of this reliance on interconnection assistance, inadequate **resources** in one Planning Coordinator Area could result in adverse consequences in another Planning Coordinator Area.

It is recognized that all Planning Coordinators may not necessarily express their own **resource** adequacy criterion as stated in the NPCC Basic Criteria in Directory #1. However, the NPCC Basic Criteria provides a reference point against which a Planning Coordinator's **resource** adequacy criterion can be compared.

The NPCC will not duplicate reviews and studies completed by member systems and Planning Coordinators**.** The NPCC may reference these reviews in appropriate NPCC reports.

2.0 Purpose of Presentation

The purpose of the presentation associated with a **resource** adequacy review is to show that each Planning Coordinator's proposed **resources** are in accordance with the NPCC Directory #1 - *Design and Operation of the Bulk Power System*.
By such a presentation, the Task Force will satisfy itself that the proposed **resources** of each NPCC Planning Coordinator will meet the NPCC Resource Adequacy -

Design Criteria, as defined NPCC Directory #1, over the time period under consideration. The review by the Task Force on Coordination of Planning does not replace Planning Coordinator and/or company responsibility to assess their systems in conformity with the NPCC Basic Criteria in Directory #1.

3.0 Time Period to be Considered

The time period to be considered for a Planning Coordinator's Comprehensive **Resource** Review will be five years and be undertaken every three years. In subsequent years, the Planning Coordinator shall conduct Annual Interim Reviews that will cover, at a minimum, the remaining years studied in the Comprehensive Review. Based on the results of the Annual Interim Review, the Task Force may recommend that the Planning Coordinator conduct the next Comprehensive Review at a date earlier than specified above. Comprehensive and Interim reviews are normally expected to be presented to the Task Force before the beginning of the first time period covered by the assessment.

4.0 Format of Presentation and Report – Comprehensive Review

Each Planning Coordinator should include in its presentations and in the accompanying report documentation, as a minimum, the information listed below. At its own discretion, the Planning Coordinator may discuss other related issues not covered specifically by these guidelines.

4.1 Executive Summary

4.1.1 Briefly illustrate the major findings of the review.

4.1.2 Provide a table format summary of major assumptions and results.

4.2 Table of Contents

4.2.1 Include listing of all tables and figures.

4.3 Introduction

4.3.1 Reference the previous NPCC Area Review.

4.3.2 Compare the proposed **resources** and **load** forecast covered in this NPCC review with that covered in the previous review

4.4 Resource Adequacy Criterion

4.4.1 State the Planning Coordinator's **resource** adequacy criterion.

4.4.2 State how the Planning Coordinator criterion is applied; e.g., **load** relief steps.

4.4.3 Summarize **resource** requirements to meet the criteria for the time period under consideration. If interconnections to other Planning Coordinators and regions are considered in determining this requirement, indicate the value of the interconnections in terms of megawatts.

4.4.4 If the Planning Coordinator criterion is different from the NPCC criterion, provide either an estimate of the **resources** required to meet the NPCC criteria or a statement as to the comparison of the two criteria.

4.4.5 Discuss **resource** adequacy studies conducted since the previous Area Review, as appropriate.

4.5 Resource Adequacy Assessment

4.5.1 Evaluate proposed **resources** versus the requirement to reliably meet projected electricity demand assuming the Planning Coordinator's most likely **load** forecast.

4.5.2 Evaluate proposed **resources** versus the requirement to reliably meet projected electricity demand assuming the Planning Coordinator's high **load** growth scenario.

4.5.3 Discuss the impact of **load** and **resource** uncertainties on projected Planning Coordinator Area **reliability** and discuss any available mechanisms to mitigate potential **reliability** impacts.

4.5.4 Review the impacts that major proposed changes to market rules may have on Planning Coordinator Area **reliability**.

4.6 Proposed Resource Capacity Mix

4.6.1 Discuss any **reliability** impacts resulting from the proposed **resources** fuel supply and transportation or environmental considerations.

4.6.2 Describe available mechanisms to mitigate any potential **reliability** impacts of **resource** fuel supply, demand resource response, transportation issues and/or environmental considerations.

4.6.3 Discuss any **reliability** impacts related to an **Area**'s compliance with state, Federal or Provincial requirements (such as environmental, renewable energy, or greenhouse gas reductions).

5.0 Format of Presentation and Report – Annual Interim Review

The Annual Interim Review should include a reference to the most recent Comprehensive Review; a listing of major changes in: facilities and system conditions, **load** forecast, generation resources availability; related fuel supply and transportation information, environmental considerations, demand response programs, transfer capability and **emergency** operating procedures. In addition, the assessment should also include a comparison of major changes in market rules, implementation of new rules, locational requirements, and installed capacity requirements. Finally, the report should include a brief impact assessment and an overall summary.

The Planning Coordinator will provide a brief assessment of the impact of these changes on the **reliability** of the interconnected **bulk power system**. This assessment should be based on engineering judgment, internal system studies and appropriate joint interconnected studies. To the extent that engineering judgment or existing studies can be used to clearly demonstrate that a Planning Coordinator Area is expected to meet the NPCC resource adequacy criterion, detailed system LOLE studies are not required.

The documentation for the Annual Interim Review should be in the form of a summary report (normally not exceeding three to five pages.)

Sections A and B should describe the **reliability** model and program used for the **resource** adequacy studies discussed in Section 4.5. Section C should describe the Task Force follow-up procedures.

A. <u>Description of Resource Reliability Model</u>

1.1 Load Model

1.1.1 Description of the **load** model and basis of period **load** shapes.

1.1.2 How **load** forecast uncertainty is handled in model.

1.1.3 How the electricity demand and energy projections of interconnected entities within the Planning Coordinator Area that are not members of the Planning Coordinator Area are addressed.

1.1.4 How the effects (demand and energy) of demand-side management programs (e.g., conversion, interruptible demand, direct control **load** management, demand (**load**) response programs) are addressed.

1.2 Supply Side **Resource** Representation

1.2.1 Resource Ratings

1.2.1.1 Definitions.

1.2.1.2 Procedure for verifying **ratings**. Reference NPCC Document B-9, *Guide for Rating Generating Capability*.

1.2.2 Unavailability Factors Represented

1.2.2.1 Type of unavailability factors represented; e.g., forced outages, planned outages, partial derating, etc.

1.2.2.2 Source of each type of factor represented and whether generic or individual unit history provides basis for existing and new units.

1.2.2.3 Maturity considerations, including any possible allowance for in-service date uncertainty.

1.2.2.4 Tabulation of typical unavailability factors.

1.2.3 Purchase and Sale Representation.

1.2.3.1. Describe characteristics and level of dependability of transactions.

1.2.4 Retirements.

1.2.4.1 Summarize proposed retirements.

1.3 Representation of Interconnected System in Multi-Area **Reliability** Analysis, including which Planning Coordinator Areas and regions are considered, interconnection capacities assumed, and how expansion plans of other Planning Coordinators and regions are considered.

1.4 Modeling of Variable and Limited Energy Sources.

1.5 Modeling of Demand Side Resources and Demand (**Load**) Response Programs.

1.5.1 Description should include how such factors as in-service date uncertainty, **rating**, availability, performance and duration are addressed.

1.6 Modeling of all **Resources**.

1.6.1 Description should include how such factors as in-service date uncertainty; capacity value, availability, **emergency** assistance, scheduling and deliverability are addressed.

1.7 Other assumptions i.e., internal transmission limitations, maintenance over-runs, fuel supply and transportation and environmental constraints.

1.8 Incorporate the **reliability** impacts of market rules.

B. Other Factors, If Any, Considered in Establishing Reserve Requirement Documentation

The documentation required to meet the requirements of the above format should be in the form of summaries of studies performed within a Planning Coordinator Area, including references to applicable reports, summaries of reports or submissions made to regulatory agencies.

C. Task Force Follow-Up Procedures

Once a specific Planning Coordinator has made a presentation or a series of presentations to the Task Force on Coordination of Planning, the latter shall:

1. Prepare a brief summary of key issues discussed during the presentation.

2. Note where further information was requested and the results of such further interrogations.

3. Note the specific items that require additional study and indicate the responsibilities for undertaking these studies.

4. Recommend approval to the Reliability Coordinating Committee.

Appendix E - Guidelines for Requesting Exclusions to Sections 5.4.1 (B) and 5.5.1 (B) of NPCC Directory #1 – *Design and Operation of the Bulk Power System*

1.0 Introduction

The Northeast Power Coordinating Council (NPCC) was formed to promote the **reliability** and efficiency of electric service of the interconnected **bulk power system** of the members of the NPCC by extending the coordination of their system design and operations as cited in the NPCC Memorandum of Agreement. Towards that end, the Member Systems of NPCC adopted the *Basic Criteria for Design and Operation of Interconnected Power Systems* (Directory #1 – *Design and Operation of the Bulk Power System*), which establishes the minimum standards for design and operation of the interconnected **bulk power system** of NPCC. In accordance with those standards, the **bulk power system** should be designed and operated so as to withstand certain specific **contingencies**.

One such **contingency**, listed under Section 5.4.1(b), Transmission Design Criteria - **Stability** Assessment, and under Section 5.5.1(b), Transmission Operating Criteria - Normal Transfers, involves "simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with normal **fault clearing**." Although this **contingency** is normally included in the NPCC Criteria, the Basic Criteria in Directory #1 define specific conditions for which a multiple circuit tower situation is an acceptable risk and, therefore, can be excluded.

Directory #1 also allows for requests for exclusion from this **contingency**, on the basis of acceptable risk, for other instances of multi-circuit tower construction. All exclusions must be approved by the Reliability Coordinating Committee (RCC). An acceptance of a request for exclusion is dependent on the successful demonstration that such exclusion is an acceptable risk. These guidelines describe the procedure to be followed and the supporting documentation required when requesting exclusion, and establishes a procedure for periodic review of exclusions of record.

2.0 Documentation

The documentation supporting a request for exclusion to Sections 5.1(b) and 6.1(b) of the Basic Criteria must include the following:

2.1 A description of the facilities involved, including geographic location, length and type of construction, and electrical connections to the rest of the interconnected power system;

2.2 Relevant design information pertinent to the assessment of acceptable risk, which might include: details of the construction of the facilities, geographic or

atmospheric conditions, or any other factors that influence the risk of sustaining a multi-circuit **contingency**;

2.3 An assessment of the consequences of the occurrence of a multi-circuit **contingency**, including, but not limited to, a discussion of levels of exposure and probability of occurrence of **significant adverse impact** outside the local area;

2.4 For existing facilities, the historical outage performance, including cause, for multi-circuit **contingencies** on the specific facility (facilities) involved as compared to that of other multi-circuit tower facilities;

2.5 For planned facilities, the estimated frequency of multi-circuit **contingencies** based on the historical performance of facilities of similar construction located in an area with similar geographic climate and topography.

3.0 Procedure for obtaining an Exclusion

The following procedure shall be used in obtaining exclusion to Sections 5.4.1(b) or 5.5.1(b) of Directory #1:

3.1 The entity requesting the exclusion (the Requestor) shall submit the request and supporting documentation to the Task Force on System Studies (TFSS) after acceptance has been granted by the Requestor's own Planning Coordinator, if such process is applicable.

3.2 TFSS shall review the request, verify that the documentation requirements have been met, and determine the acceptability of the request.

3.3 If TFSS deems the request acceptable, TFSS shall request the Task Force on Coordination of Planning (TFCP), the Task Force on Coordination of Operation (TFCO), and the Task Force on System Protection (TFSP) to review the request. The Requestor shall provide copies of the request and supporting documentation to the other Task Forces as directed by TFSS. If additional information is requested by the other Task Forces as part of their assessment, the Requestor will provide this information directly to the interested Task Force, with a copy to the TFSS. The other Task Forces shall review the request and indicate their acceptance or non-acceptance to TFSS.

3.4 If any of the four Task Forces determines the request is not acceptable, TFSS will respond to the Requestor with the determination and inform the RCC and the other Task Forces of the decision.

3.5 TFSS shall notify TFCP, TFCO, and TFSP of an exclusion that has been accepted by the Task Forces and the basis for the exclusion. The TFSS will then make a recommendation to the RCC regarding the exclusion.

3.6 The NPCC Policy for Alternative Dispute Resolution is available for use if the decision is unacceptable to the Requestor.

Upon acceptance of the requested exclusion by the RCC, TFSS shall so notify the Requestor and update a summary list of the exclusions. The summary list and supporting documents shall be maintained by NPCC.

4.0 Periodic Review of Exclusions of Record

Exclusions shall be reviewed within the Planning Coordinator's transmission reviews as provided in *Guidelines for NPCC Area Transmission Reviews* (NPCC Directory #1 – Appendix C). This review shall verify that the basis for each exclusion is still valid. TFSS shall notify TFCP, TFCO, TFSP, and the RCC when a Planning Coordinator's transmission review has determined exclusion is no longer applicable, and revise the exclusion summary list accordingly.

Appendix F – Procedure for Operational Planning Coordination

1.0 Introduction

The Reliability Coordinators (RC) of the Northeast Power Coordinating Council, Inc. (NPCC) require access to the security data specified in this procedure in order to adequately assess the reliability of the NPCC bulk power system. All users of the electric systems, including market participants, must supply such data to the NPCC Reliability Coordinators. Coordination among and within the Reliability Coordinator Areas (RC Area) of NPCC is essential to the reliability of interconnected operations. Timely information concerning system conditions should be transmitted by the NPCC RC Areas to other RC Areas as needed to assure reliable operation of the **bulk power system**. One aspect of this coordination is to ensure that adjacent RC Areas and neighboring systems are advised on a regular basis of expected operating conditions, including generator, transmission and **system protection**, including Type I **special protection system,** outages that may materially reduce the ability of an RC Area to contribute to the reliable operation of the interconnected system, or to receive and/or render assistance to another RC Area. To the extent practical, the coordination of outage schedules is desirable in order to limit the severity of such impacts.

To ensure that there is effective coordination for system **reliability** concerns, this document establishes procedures for the exchange of information regarding load/capacity forecasts, including firm sales and firm purchases, generator outage schedules, and transmission outage schedules for those facilities that may have an adverse impact on other RC Area(s). It also details general action that may be taken to improve the communication of problems as well as specific topics that may be discussed in regularly scheduled, pre-arranged conference call meetings or in conference calls arranged in anticipation of problems such as capacity deficiency or inadequate light load margin in one or more RC Areas.

Participants and other recipients of the information provided by this process must adhere to the NERC *Confidentiality Agreement for Electric System Operating Reliability Data*.

2.0 Load/Capacity Forecasts

2.1 Twice yearly, by May 15th and November 15th respectively, the Operations Planning Working Group (CO 12) will perform a summer and winter assessment for the next season. The methodology and format of the seasonal report will be presented in NPCC Document C-45, "CO-12 Seasonal Assessment Methodology," currently under development.

The results will be reviewed by the NPCC Task Force on Coordination of Operation (TFCO) and the NPCC Reliability Coordinating Committee (RCC) in advance of the spring and autumn meetings of both groups.

2.2 Each week, each RC Area will review its weekly net resource capacity margin, as defined in Attachment A, for the twelve weeks to follow and forward the information to the NPCC Staff for distribution to all NPCC RC Areas. If an NPCC RC Area identifies a deficiency or light load condition, the RC Area should identify the cause(s) and mitigation measures that have been implemented, or will be implemented, to manage the issue.

3.0 Generator Outage Coordination

3.1 Each RC Area should exchange current and expected critical generation outages.

4.0 Transmission Outage Coordination

4.1 Advance Planning of Transmission Facility Outages

NPCC Document A-2, *Basic Criteria for Design and Operation of Interconnected Power Systems,* requires that scheduled outages of transmission facilities that affect **reliability** between RC Areas be coordinated sufficiently in advance of the outage to permit the affected RC Area to maintain **reliability**. For the purposes of this procedure, each RC should exchange critical transmission outages as identified in coordination agreements with their interconnected neighbors and jointly develop and maintain a Facilities Notification List.

4.2 Facilities Notification List

The NPCC Facilities Notification List, Attachment D, has two components:

1) the NPCC Transmission Facilities Notification List; and
2) the list of NPCC Type I **special protection systems**.

The Facilities Notification List is developed by each RC Area and specifies all facilities that, if removed from service, may have a significant, direct or indirect impact on another RC Area's transfer capability. The cause of such impact might include stability, voltage, and/or thermal considerations.

Prior to October 1st of each year, each RC Area will review and update its Facilities Notification List and coordinate necessary changes with other appropriate NPCC RC Areas. Prior to January 1st, and after review by the TFCO, the approved, updated Facilities Notification List will be posted on the NPCC secure website.

The Task Force on System Protection develops yearly the list of NPCC Type 1 **special protection systems** with input from the Task Force on System Studies.

It should be noted that revisions to the Facilities Notification List only will not follow the NPCC Process for Open Review due to the secure nature of the information contained, and Attachment D is not openly published with this Procedure.

A temporary reconfiguration of the network may result in an outage to one or more facilities not listed in Attachment D having an impact on other NPCC RC Areas. It is the responsibility of the RC experiencing the condition to notify impacted RCs in a timely manner and provide updated status reports during the condition.

4.3 Notifications of Work

4.3.1 Notification requirements should be defined in interconnected coordination agreements. The time frames identified below are the minimum notification requirements.

4.3.2 The initiating RC will advise affected RCs of all applications for outages of facilities on the Facilities Notification List, including those which have been planned.

All outages to equipment listed in the Facilities Notification List should be planned with as much lead time as practical.

Normally, notification for work on facilities covered by this instruction will be submitted to the appropriate RC Areas at least two (2) working days prior to the time the facility is to be taken out of service.

When an RC Area receives an outage notification from another RC Area, prompt attention will be given to the notification and appropriate comments rendered. Analysis will be conducted by each RC Area in accordance with internal procedures.

4.3.3 An RC Area will not normally remove from service any transmission facility, which might have a **reliability** impact on an RC Area without prior notification to and appropriate review by that RC Area. In the event of an **emergency** condition, each RC Area may take action as deemed appropriate. Other RC Areas should be notified immediately.

An RC Area will make every effort to reschedule routine (non-emergency) transmission outages that severely degrade the reliability of an adjacent RC Area or neighboring system.

4.3.4 Each RC Area will advise the other affected RC Areas of any protection outage associated with RC Area tie line facilities. Coordination agreements may identify additional reporting

requirements associated with protection outages.

5.0 Data Providers

NPCC entities are to provide the data in order to adequately assess the reliability of the NPCC bulk power system.

6.0 Specific Communications

Conditions in an RC Area that may have an impact on another RC Area should be communicated in a clear and timely manner. Specific communications are conducted as follows:

6.1 Weekly

Each Thursday a conference call will be initiated by the NPCC Staff to discuss operations expected during the seven-day period starting with the following Sunday. Operations personnel from the NPCC RC Areas will participate. In advance of the conference call, each RC Area will prepare the data specified in Attachments A and B, and forward it to the NPCC Staff a minimum of one hour in advance of the scheduled call. The completed "NPCC Weekly Conference Call Generating Capacity Worksheet," Attachment B, together with the list of "Twelve Weeks Projections of Net Margins," Attachment C, will be forwarded to the conference call participants by the NPCC Staff.

Each RC will review its weekly capacity margins for the next twelve week period. If a deficiency or light load condition is identified, the RC will identify the cause of the deficiency or light load condition and discuss proposed mitigation measures.

The NPCC Staff will prepare Conference Call Notes that will be forwarded to the conference call participants and members of the TFCO by the following Friday afternoon.

If a deficiency or light load condition, or if adverse system operating conditions are expected within the next week, any RC Area may recommend that an Emergency Preparedness Conference Call (NPCC Document C-01) take place at an appropriate time.

Items of particular concern that should be discussed during the weekly conference call are described in Attachment C.

6.2 Emergency Preparedness Conference Call

Whenever adverse system operating or weather conditions are expected, any RC Area may request the NPCC Staff to arrange an Emergency Preparedness Conference Call (NPCC Document C-01) to discuss operating details with appropriate operations management personnel from the NPCC RC Areas and neighboring systems.

6.3 Daily Conference Calls

Each of the NPCC Reliability Coordinator Area control rooms participate in a regularly scheduled daily conference call. The goal of this call is to alert NPCC Reliability Coordinators of any potential emerging problems. Subjects for discussion are limited to credible events which could impact the ability of a Reliability Coordinator to serve its load and meet its operating reserve obligations, or which would impose a burden to the Interconnection.

Procedure for Operational Planning Coordination – Attachment A

Load and Capacity Table Instructions

and

Generating Capacity Worksheet Instructions

Week Beginning	The seven day period for which data is to be reported is defined as starting with the Sunday following the conference call through the following Saturday.
Installed Generating Capacity (Line Item 1)	Include all available generation at its maximum demonstrated capability for the appropriate seasonal capability period.
Firm Purchases (Line Item 2)	Include only those transactions where capacity is delivered. Exclude "energy only" transactions.
Firm Sales (Line Item 3)	Include only those transactions where capacity is delivered. Exclude "energy only" transactions.
Net Capacity (Line Item 4)	Add Installed Generating Capacity and Firm Purchases. Subtract Firm Sales. (Line 1+Line 2-Line3)
Peak Load Forecast (Line Item 5)	The peak load forecast should be the best estimate of the RC Area's maximum peak load exposure anticipated for the week reported.
Available Reserve (Line Item 6)	Subtract Peak Load Forecast from Net Capacity. (Line 4-Line5.)
Demand Side Management (Line Item 7)	Include only maximum capability which can be obtained by operator initialization within four (4) hours.

Attachment A (continued)	
Known Unavailable Capability (Line Item 8)	Include all known outages, as well as those deratings or unit outages presently forced out, unavailable, on extended cold standby or which are anticipated to remain out of service. This would also include capacity unavailable due to transmission constraints.
Net Reserve (Line Item 9)	Available Reserve plus Demand Side Management minus Known Unavailable Capacity. (Line 6+Line 7-Line 8)
Required Operating Reserve (Line Item 10)	The methodology used by each RC Area in calculating operating reserve must, as a minimum, meet the requirements of NPCC Document A-06, "Operating Reserve Criteria." Methodologies differing from the A-06 requirements should be clarified in Attachment B, "NPCC Weekly Conference Call Generating Capacity Worksheet," under the tab for "Operating Reserve."
Gross Margin (Line Item 11)	Subtract Required Operating Reserve from Net Reserve. (Line 9-Line 10)
Unplanned Outages (Line Item 12)	Estimate the amount of generating capacity which will be unavailable. This quantity should be based on historical averages for forced outages and deratings.
Net Resource Capacity Margin (Line Item 13)	Subtract Unplanned Outages from Gross Margin. A positive value reflects surplus reserve. A negative value reflects a deficiency. (Line 11-Line 12)
Forecast High / Low Temperatures and Days (Line Item 14)	Include the expected high and low temperatures for the RC Area for the week, and indicate the day on which they are expected to occur.

Attachment A (continued)	
Seasonal High / Low Temperatures (Line Item 15)	Include the expected high and low forecast seasonal temperatures for the RC Area.
Minimum Load Forecast (Line Item 16)	The minimum load forecast should be the best estimate of the RC Area's minimum load exposure anticipated for the week reported.
Minimum Resources (Line Item 17)	The Minimum Resources are the Reliability Coordinator Area's total expected on-line generator minimum output capability and must-take purchases.
Light Load Margin (Line Item 18)	Subtract Minimum Resources from Minimum Load Forecast. A negative number indicates a light load condition. (Line 16-Line 17)

Procedure for Operational Planning Coordination – Attachment B

NPCC Weekly Conference Call Generating Capacity Worksheet

The "NPCC Weekly Conference Call Generating Capacity Worksheet" is an active Excel spreadsheet used each week to assist in the calculation of the data discussed during the weekly conference call. A blank template, in Microsoft Office Excel 2003, is available from the NPCC office.

Procedure for Operational Planning Coordination - Attachment C

CONDITIONS FOR DISCUSSION

Items of particular concern that should be discussed during a conference call include, but are not limited to, the following:

- anticipated weather;
- largest first and second contingencies;
- operating reserve requirements and expected available operating reserve;
- capacity deficiencies;
- potential fuel shortages or potential supply disruptions which could lead to energy shortfalls;
- light load margins;
- general and specific voltage conditions throughout each system or RC Area;
- status of short term contracts and other scheduled arrangements, including those that impact on operating reserves;
- additional capability available within twelve hours and four hours;
- generator outages that may have a significant impact on an adjacent RC Area or neighboring system;
- transmission outages that might have an adverse impact on internal and external energy transfers;
- potential need for emergency transfers;
- expected transfer limits and limiting elements;
- a change or anticipated change in the normal operating configuration of the system, such as the temporary modification of relay protection schemes so that the usual and customary levels of protection will not be provided, or the arming of special protection systems not normally armed, or the application of abnormal operating procedures; and
- update of the abnormal status of NPCC Type I special protection systems forced out of service.

Attachment D

NPCC Facilities Notification List

Attachment D is not publicly available due to the confidential nature of the information presented.

Appendix G - Procedures for Inter Reliability Coordinator Area Voltage Control

1.0 Introduction

This Procedure provides general principles and guidance for effective inter-Transmission Operator Area voltage control, consistent with the NPCC, Directory #1, "Design and Operation of the Bulk Power System," and applicable NERC Standards. Specific methods to implement this Procedure may vary among Transmission Operators, depending on local requirements. Coordinated inter- Transmission Operator Area voltage control is necessary to regulate voltages to protect equipment from damage and prevent voltage collapse. Coordinated voltage regulation reduces electrical losses on the network and lessens equipment degradation. Local control actions are generally most effective for voltage regulation. Occasions arise when adjacent Transmission Operators can assist each other to compensate for deficiencies or excesses of **reactive power** and improve voltage profiles and system security.

2.0 Principles

Each Transmission Operator develops, and operates in accordance with, its own voltage control procedures and criteria which are consistent with NPCC, Inc. Criteria and NERC Standards. Adjacent Transmission Operators should be familiar with the respective criteria and procedures of their neighboring Transmission Operators should mutually agree upon procedures for inter- Transmission Operator Area voltage control. Whether inter- Transmission Operator Area voltage control is carried out through specific or general procedures, the following should be considered and applied:

2.1 To effectively coordinate voltage control, location and placement of metering for **reactive power** resources and voltage controller status should be consistent between adjacent Transmission Operators.

2.2 the availability of **voltage regulating transformers** in the proximity of **tie lines**;

2.3 voltage levels, limits, and regulation requirements for stations on either side of an inter- Transmission Operator Area interface;

2.4 the circulation of **reactive power** (export at one tie point in exchange for import at another);

2.5 **tie line** reactive losses as a function of real **power** transfer;

2.6 reactive **reserve** of on-line generators;

2.7 shunt reactive device availability and switching strategy; and

2.8 **static VAR compensator** availability, reactive **reserve**, and control strategy.

3.0 Procedure

Transmission Operators maintain normal voltage conditions, in accordance with their own individual or joint operating policies, procedures and applicable interconnection agreements. In the event the system state changes to an abnormal voltage condition, the Transmission Operator in which the abnormal condition is originating should immediately take corrective action. If the corrective control actions are ineffective, or the Transmission Operator has insufficient reactive resources to control the problem, assistance may be requested from other Transmission Operators.

3.1 Normal Voltage Conditions

The **bulk power system** is operating with Normal Voltage Conditions when:

- actual voltages are within applicable normal (pre-**contingency**) voltage ranges; and
- expected post-**contingency** voltages are within applicable post-**contingency** minimum and maximum levels following the most severe **contingency** specified in Directory #1 "Design and Operation of the Bulk Power System."

Each Transmission Operator should maintain a mix of static and dynamic resources, including reactive **reserves**.

3.1.1 Providing that it is feasible to regulate reactive flows on its **tie lines**, each Transmission Operator should establish a mutually agreed upon voltage profile with adjacent Transmission Operators and with other neighboring systems. This voltage profile should conform to the provisions of the relevant interconnection agreements and may provide for:

- The minimum and maximum voltage at stations at or near terminals of inter-Transmission Operator Area tie lines;
- The receipt of reactive flow at one tie point in exchange for delivery at another;
- The sharing of the reactive requirements of **tie lines** and series regulating equipment (either equally or in proportion to line lengths, etc.); and
- The transfer of **reactive power** from one Transmission Operator to another.

This voltage profile, adjusted for changes in operating conditions, should be considered as the basis for determining which Transmission Operator should implement necessary measures to alleviate abnormal voltage conditions affecting more than one Transmission Operator as discussed in 3.2.10 below.

3.1.2 Each Transmission Operator should anticipate voltage trends and initiate corrective action in advance of critical periods of heavy and light **loads**.

4.0 Procedure for Triennial Monitoring and Reporting of Inter-Area Voltage Control

4.1 On, or shortly before, the first of July, the TFCO Secretary will write to each TFCO member, requesting a written response by the end of July in the form of:

a) A copy of any new procedures and principles between the reporting Reliability Coordinator and adjacent Reliability Coordinators providing detailed application, or,

b) a copy of any new understanding, such as the minutes of an operating committee meeting between Reliability Coordinators, indicating that such detailed application is not required, and why;

c) a copy of any revisions to the procedures and principles, or understandings currently on file at NPCC, that exists between the reporting Reliability Coordinator and adjacent Reliability Coordinators;

d) a response indicating no change to existing procedures and principles, or understandings currently on file at NPCC.

4.2 The TFCO Secretary will draft a report summarizing the extent to which responses indicated conformance with the NPCC Procedures, and will forward it to TFCO members at least two weeks prior to the October TFCO meeting.

4.3 Following TFCO review and adoption, the TFCO Chairman will forward the report to the Chairman of the Reliability Coordinating Committee (RCC) recommending acceptance or other action as deemed appropriate. This will normally be forwarded three weeks prior to the next regularly scheduled RCC meeting.

NPCC, Inc.
NORTHEAST POWER COORDINATING COUNCIL, INC.
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NPCC
Regional Reliability Reference Directory # 2
Emergency Operations

Task Force on Coordination of Operations Revision Review Record:
October 21, 2008

Adopted by the Members of the Northeast Power Coordinating Council, Inc. this October 21, 2008 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

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Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	10/21/08	Effective Date	New
1	6/26/09	Transfer Auto UFLS language to D#12	Revision
2	8/19/09	Removed references to Automatic UFLS in Section 7 to reflect transfer of Automatic UFLS language to D#12.	Errata

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Appendix A

Appendix B

1.0 Introduction

1.1 Title Emergency Operations

1.2 Directory Number 2

1.3 Objective

The purpose of this Directory is to present the basic factors to be considered in formulating plans and procedures to be followed in an emergency or during conditions which could lead to an emergency, in order to facilitate mutual assistance and coordination within NPCC and adjacent areas.

The objectives in formulating plans related to emergency operating conditions are:

1. To avoid the interruption of service to firm **load** to the extent possible.
2. To minimize the occurrence of **system disturbances**.
3. To contain any **system disturbance** and limit its effects to the area initially affected.
4. To minimize the effects of any **system disturbances** on customers.
5. To avoid damages to system **elements**.
6. To avoid hazard to the public.

1.4 Effective Date **October 21, 2008**

1.5 Background

This Directory was developed from the NPCC A-03 Emergency Operations Criteria and associated B-3 Guideline and C-20 Procedure documents. Guidelines and procedures for consideration in the implementation of this Directory are provided in Appendix B.

1.6 Applicability

1.6.1 Functional Entities

Reliability Coordinators
Balancing Authorities
Transmission Operators
Generator Operators

2.0 Terms Defined in this Directory

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The definitions of terms found in this Directory appearing in bold typeface can be found in the Appendix A.

3.0 NERC ERO Reliability Standard Requirements

The NERC ERO Reliability Standards containing Requirements that are associated with this Directory include, but may not be limited to:

3.1 BAL-005: Automatic Generation Control
3.2 COM-001: Telecommunications
3.3 COM-002: Communications and Coordination
3.4 EOP-001: Emergency Operations Planning
3.5 EOP-002: Capacity and Energy Emergency
3.6 EOP-003: Load Shedding Plans
3.7 PRC-006: Development and Documentation of RRO's UFLS Programs
3.8 PRC-007: Assuring Consistency with Regional UFLS Requirements
3.9 TOP-001: Reliability Responsibilities and Authorities
3.10 TOP-004: Transmission Operations
3.11 TOP-006: Monitoring System Controls
3.12 IRO-003: Reliability Coordination – Wide Area View
3.13 IRO-005: Reliability Coordinator – Current Day Operation
3.14 IRO-015: Notification and Information Exchange Between RCs
3.15 IRO-016: Coordination of Real Time Activities Between RCs
3.16 BAL-001: Real Power Balancing Control Performance
3.17 BAL-002: Disturbance Control Performance
3.18 BAL-003: Frequency Response and Bias

4.0 NPCC Regional Reliability Standard Requirements

None.

5.0 NPCC Full Member, More Stringent Criteria

These Criteria are in addition, more stringent or more specific than the NERC or any Regional Reliability standard requirements

5.1 General Criteria

Normal Transfer Capabilities shall be observed unless there is insufficient **capacity** or voltage support in a Balancing Authority or Transmission Operator area**,** in which case **Emergency Transfer Capabilities** may be used prior to shedding firm **load. Emergency transfer capabilities** shall not be exceeded.

The circumstances under which each of these system operating limits are

applied shall be clearly indicated by written instructions.

5.2 Manual **Load Shedding** Requirement

Each Balancing Authority shall have the capability of manually shedding at least fifty percent of its area **load** in ten minutes or less. Manual **load shedding** plans shall not interrupt **bulk power system** elements.

5.2.1 Manual **load shedding** procedures shall be reviewed at least annually by the Balancing Authority and Transmission Operator, to ensure that the proper amount of **load** can be shed within the time limits prescribed.

5.2.2 Studies shall be performed by the affected Transmission Operator to ensure satisfactory voltage and loading conditions after manual **load shedding**.

6.0 Measures and Assessments

None developed at this time.

7.0 Compliance Monitoring

The monitoring of manual **load shedding** requirements (Section 5.2) will be carried out by the NPCC Compliance Committee.

Prepared by: Task Force on Coordination of Operation

Review and Approval: Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45 day review and comment period. Upon satisfactorily addressing all the comments in this forum, the Directory document will be sent to the remaining Task Forces for their recommendation to seek RCC approval.

Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC Bylaws" in effect at the time the ballots are cast.

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Revisions pertaining to the Appendices or any other portion of the document such as Links, glossary of terms, etc., will only require RCC Members' approval. Errata may be corrected by the Lead Task Force at any time and provide the appropriate notifications to the NPCC Inc. membership.

This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

References: None

Appendix A
Definition of Terms[1]

Automatic Generation Control (AGC) — Equipment that automatically adjusts a **Control Area**'s **generation** to maintain its **interchange schedule** plus its share of frequency regulation.

The following AGC modes are typically available:

a. **Tie Line Bias** Control — Automatic generation control with both frequency and net **interchange** terms of **Area Control Error** considered.

b. Constant Frequency (Flat Frequency) Control — Automatic generation control with the net **interchange** term of **Area Control Error** ignored. This Automatic Generation Control mode attempts to maintain the desired frequency without regard to **interchange**.

c. Constant Net **Interchange** (Flat **Tie Line**) Control — Automatic generation control with the frequency term of **Area** Control Error ignored. This Automatic Generation Control mode attempts to maintain net **interchange** at the desired level without regard to frequency.

Bulk power system — The interconnected electrical systems within northeastern North America comprising **generation** and transmission facilities on which **faults** or **disturbances** can have a **significant adverse impact** outside of the local area. In this context, local areas are determined by the Council members.

Capacity — The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of **generation**, transmission, or other electrical equipment.

Element — Any electric device with terminals that may be connected to other electric devices, such as a generator, transformer, circuit, circuit breaker, or bus section. Limiting Element — The element that is either operating at its appropriate **rating** or would be following a limiting **contingency** and, as a result, establishes a system limit.

Emergency — Any abnormal system condition that requires automatic or manual action

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[1] These terms will be moved and grouped under a separate Directory when all other Directories are developed.

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to prevent or limit loss of transmission facilities or **generation** supply that could adversely affect the **reliability** of the electric system.

Specific to NPCC, an **Emergency** is considered to exist in an Area if **firm load** may have to be shed.

Emergency Transfer Capability — The amount of **power** transfer allowed between **Areas** or within an **Area** when operating to meet NPCC **emergency** criteria contingencies.

Generation (Electricity) — The process of producing electrical energy from other forms of energy; also, the amount of electric energy produced, usually expressed in kilowatt-hours (kWh) or megawatt hours (MWh).

Gross Generation — The electrical output at the terminals of the generator, usually expressed in megawatts (MW).

Net Generation — Gross generation minus station service or unit service **power** requirements, usually expressed in megawatts (MW).

Interchange — Electric **power** or energy that flows from one entity to another.

Interchange Schedule — An agreed-upon transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of **power** and energy between the contracting parties and the **Control Area**(s) involved in the transaction.

Interface — The specific set of transmission **elements** between two areas or between two areas comprising one or more electrical systems.

Island — A portion of a **power** system or several power systems that is electrically separated from the interconnection due to the disconnection of transmission system **elements**.

Load — The electric **power** used by devices connected to an electrical generating system. (IEEE Power Engineering). Also see **Demand**.

<u>NPCC Specific Definitions:</u>

Firm Load — Loads that are not **Interruptible Loads**.

Interruptible Load — Loads that are interruptible under the terms specified in a contract.

Load Shedding — The process of deliberately removing (either manually or automatically) preselected customers' **load** from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall

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customer outages.

Normal Transfer Capability — The amount of **power** transfer allowed between **Areas** or within an **Area** when operating to meet NPCC normal criteria contingencies.

Protective relay — A **relay** that detects a power system **fault** or abnormal condition and initiates appropriate control system action.

Real Power — The rate of producing, transferring, or using electrical energy, usually expressed in kilowatts (kW) or megawatts (MW).

Reactive Power — The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, **synchronous condensers**, or electrostatic equipment such as capacitors. Reactive power directly influences electric system voltage. It is usually expressed in kilovars (kVAr) or megavars (MVAr).

Relay — An electrical device designed to respond to input conditions in a prescribed manner and after specified conditions are met to cause contact operation or similar abrupt change in associated electric control circuits. (Also: see **protective relay**).

Reliability - The degree of performance of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system — **Adequacy** and **Security**.

Adequacy - The ability of the electric system to supply the aggregate electrical **demand** and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system **elements**.

Security - The ability of the electric system to withstand **disturbances** such as electric **short circuits** or unanticipated loss of system **elements**.

Special protection system (SPS) – A **protection system** designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted **elements**. Such action may include changes in **load**, **generation**, or system configuration to maintain system **stability**, acceptable voltages or power flows. Automatic underfrequency **load shedding** as defined in this Directory, is not considered a **Special Protection System**. Conventionally switched, locally controlled shunt devices are not **Special Protection Systems**.

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System Disturbance - An event characterized by one or more of the following phenomena: the loss of **power** system **stability**; cascading outages of circuits; oscillations; abnormal ranges of frequency or voltage or both.

Operator, System - Person responsible for operating control of the **bulk power system** in an **Area** of NPCC or an adjoining system interconnected with NPCC. This could be a Security Coordinator, a **Control Area** Operator or in some cases a bulk power utility operator (e.g. NYPA, Niagara Mohawk, etc)

Voltage Reduction - A means to reduce the **demand** by lowering the customer's voltage.

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Appendix B
Guideline and Procedure for Emergency Operation

1.0 Introduction

This Appendix provides the guidelines and procedures for anticipating and operating under emergency conditions. These guidelines and procedures are intended to provide specific instructions to the **System Operator** during such conditions in an NPCC Balancing Authority area or Transmission Operator area or Reliability Coordinator area with an objective to minimize, when possible, the impact of an evolving event and to prevent, contain and control an **emergency**.

2.0 Minimizing the Impact of Events

2.1 It is recognized that provisions are made in the design of a power system for the satisfactory performance of the system during certain **faults** or incidents of **equipment** failure. It is also recognized that the power system should be operated in a prescribed manner to withstand these contingencies.

2.2 When planning for near term forecast conditions, each Balancing Authority and Transmission Operator should develop operating strategies that provide for sufficient generation and transmission to meet the following objectives:

2.2.1 **Operating reserve** requirements.

2.2.2 **Automatic generation control** and frequency control requirements.

2.2.3 Line/tie line loadings within applicable normal operating limits.

2.2.4 **Bulk power system** voltage within normal limits**.**

2.3 When operating conditions deviate from the boundaries that are planned for, a Balancing Authority area or a Transmission Operator area may experience abnormal operating conditions. If such conditions persist, the Balancing Authority or the Transmission Operator may need to declare and enter into an **emergency.** When operating under abnormal and emergency conditions, the guideline and procedure as presented in Sections 3.0 to 6.0 should be followed.

3.0 Operating Under Abnormal Voltage Conditions

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3.1 The **bulk power system** is operating with abnormal voltage conditions when:

3.1.1 actual voltages are outside applicable normal (pre-contingency) voltage ranges.

3.1.2 expected post-contingency voltages violate applicable post-contingency minimum and maximum levels following applicable NPCC Normal or Emergency Criteria Contingencies.

Transmission Operators that anticipate or experiencing an abnormal voltage condition should follow the procedures specified in Section 3.2.

3.2 Correction of Abnormal Voltage Conditions

Abnormal voltage conditions in a Transmission Operator area can be caused by changes within the Transmission Operating area or external Transmission Operator areas, or by changes in load-generation-interchange balance in external Balancing Authority areas. In determining the appropriate steps to correct abnormal voltage conditions, attempts should be made to identify the root cause of the problems.

3.2.1 If a Transmission Operator area is experiencing abnormal voltage conditions, the Transmission Operator should implement the steps in Section 3.2.2 and 3.2.3 to return voltages to normal condition.

3.2.2 If the **bulk power system** voltage is rapidly decaying, the Balancing Authority or Transmission Operator area, if identifiable, causing the decay should immediately implement all possible action, including the shedding of **firm load**, to correct the problem. All other Transmission Operator areas experiencing the rapid voltage decay should immediately implement all possible action, including the shedding of **firm load**, to correct the problem, until such time that the Balancing Authority or Transmission Operator area causing the decay has implemented actions to correct the problem.

3.2.3 When a Transmission Operator anticipates or is experiencing an abnormal, but stable, or gradually changing **bulk power system** voltage condition, it should implement steps to correct the situation. Recognizing that voltage problems are most effectively corrected by control actions as close to the source as possible, the Transmission Operator should use its own resources, but may request assistance from adjacent Transmission Operator areas. Provided below is a guide for the implementation of potential control actions with the

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provision that individual steps may be eliminated if considered ineffective for the particular situation.

3.2.3.1 The Transmission Operator area anticipating or experiencing the abnormal **bulk power system** voltage condition should implement the following control actions, where effective and as available, in accordance with the Transmission Operator's voltage control procedures:

3.2.3.1.1 adjust transformer taps.

3.2.3.1.2 switch capacitors/reactors.

3.2.3.1.3 adjust static VAR compensators.

3.2.3.1.4 utilize full reactive capability of on-line generators.

3.2.3.1.5 deploy synchronous condensers.

3.2.3.1.6 other actions as local voltage control procedures allow.

3.2.3.1.7 dispatch additional generation.

3.2.3.2 If the steps in Section 3.2.3.1 are insufficient to correct the problem, adjacent Transmission Operators should be advised of the need to depart from normal reactive schedules and should be requested to provide assistance if this will be effective. The adjacent Transmission Operators should assist by using some or all of the control actions listed in Section 3.2.3.1 where effective and as available, in accordance with their respective voltage control procedures.

3.2.3.3 If the steps in Sections 3.2.3.1 and 3.2.3.2 are insufficient to correct the problem, the Transmission Operator experiencing the abnormal voltage condition should take the following actions, where effective and as available, in accordance with its voltage control procedure:

3.2.3.3.1 request the Balancing Authority to modify economy transactions with other Balancing

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Authority areas, and/or deviate from economic dispatch.

3.2.3.3.2 operate hydraulic units as synchronous condensers, where possible.

3.2.3.3.3 reschedule pumped hydro units to generate or motor over the critical period.

3.2.3.3.4 purchase energy.

3.2.3.3.5 reduce generator **real power** output to increase reactive capability.

3.2.3.3.6 start additional generation.

3.2.3.3.7 switch out internal transmission lines provided system operating limits are not violated.

3.2.3.4 If the steps listed in Section 3.2.3.3 fail to correct the problem, the Transmission Operator experiencing the **bulk power system** voltage problem should request adjacent Transmission Operators to assist by using some or all of the steps listed in Section 3.2.3.3 where effective and as available.

3.2.3.5 If the steps listed in Section 3.2.3.3 and 3.2.3.4 are insufficient to correct the problem, the Transmission Operator experiencing the problem should implement voltage reduction procedures if this will improve transmission voltage levels. If, after this step, additional assistance is required, adjacent Transmission Operators should be requested to reduce customer supply voltage if this will be effective, providing the Transmission Operator in difficulty has already taken this step.

3.2.3.6 If the problem is low voltage and it persists after the steps up to Section 3.2.3.5 are exhausted, or if the **bulk power system** voltage is rapidly decaying, the Transmission Operator in difficulty will shed **firm load** as required.

3.2.4 When assistance is provided by an adjacent Balancing Authority and/or Transmission Operator, Emergency Transfer Criteria must not be exceeded.

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3.2.5 If two or more Transmission Operators are experiencing voltage problems simultaneously, they will assist each other as above to the extent feasible. If the problem is so severe as to require the shedding of **firm load**, the shedding should be done to the extent required to control the situation. Transmission Operators that have mutually agreed upon a normal schedule of **reactive power** flow should adhere to this schedule to the extent possible.

3.2.6 If the abnormal voltage is caused by conditions external to NPCC, the following steps should be implemented by the NPCC Transmission Operator experiencing abnormal voltage conditions as required and appropriate.

3.2.6.1 Using available voltage and **reactive power** flow information, determine which system is causing the abnormal voltage or the trend toward abnormal voltage.

3.2.6.2 Establish communication with the system causing the abnormal voltage

3.2.6.3 All NPCC Transmission Operators in a position to assist should take any available action to relieve the abnormal voltage condition, excluding the shedding of **firm load** or opening transmission circuits. Assistance should normally only be requested after similar action has been implemented by the requesting Transmission Operator(s).

3.2.6.4 If the action in 3.2.6.3 above is insufficient, the Transmission Operator experiencing the difficulty should promptly take all steps necessary to relieve the abnormal voltage condition, including shedding **firm load** and/or opening transmission circuits.

4.0 Actions to Contain an Emergency

If preventative measures as outlined under Sections 2.0 and/or 3.0 have not been adequate, the Balancing Authority or the Transmission Operator experiencing the abnormal conditions may need to declare and enter into an **emergency**. Actions to contain the emergency should then be taken. These actions should apply to both the Balancing Authority area and Transmission Operator area causing the emergency (if identifiable) and the Balancing Authority area and Transmission Operator area experiencing the emergency. The following is thus a continuation of the preventative and corrective measures implemented in Sections 2.0 and/or 3.0 above. Sections 4.1 and 4.2 apply to scenarios in which operation in one Balancing

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Authority area or Transmission Operator area is having an adverse impact on the reliability of another Balancing Authority or Transmission Operator area. Section 4.3 applies to the scenario that a Balancing Authority is experiencing difficulties in controlling frequency and/or ACE due to capacity/energy shortfall.

4.1 Action of a Balancing Authority and Transmission Operator Experiencing a Transmission **Emergency**

If a Transmission Operator area is in a transmission emergency because of conditions in another Transmission Operator area, it should implement any of the following actions that removes or lessens the threat to its reliability.

4.1.1 Attempt to identify the specific cause(s) and communicate with relevant Transmission Operator. Request assistance if required.

4.1.2 Manually shed **firm load** or reject **generation** as appropriate.

4.1.3 Communicate (if time permits and only if beneficial) to the adjacent Transmission Operator that the tie lines will be opened if immediate action is not taken to alleviate the **emergency**.

4.1.4 Open tie lines to prevent damage to equipment, if necessary.

4.1.5 If a Balancing Authority area is experiencing a capacity or **emergency**, it should issue the appropriate NERC Energy Emergency Alert level and follow procedures in NERC Standard *Emergency Preparedness and Operations* EOP-002-0 *Attachment 1*.

4.2 Action of a Balancing Authority or Transmission Operator Causing the Transmission **Emergency**

If operation in a Balancing Authority or Transmission Operator area is having an adverse reliability impact in another area, the Balancing Authority and Transmission Operator are required by NERC and NPCC Standards to respond to requests for assistance from the area in difficulty that remove or lessen the threat to its reliability, including:

4.2.1 Attempt to identify the specific cause(s) and communicate with relevant Balancing Authority or Transmission Operator. Request assistance if required.

4.2.2 Manually shed **firm load** until transmission loading and voltage return to acceptable values at all known problem locations.

4.2.3 Open or close tie lines as required.

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4.2.4 Issue the appropriate NERC Energy Emergency Alert level and follow procedures in NERC Standard *Emergency Preparedness and Operations* EOP-002-0 *Attachment 1.*

4.3 Actions of a Balancing Authority to control Frequency and operate under a Capacity/Energy Emergency

A Balancing Authority area may from time to time experience difficulty in controlling frequency or ACE. Under these situations, the Balancing Authority should consider implementing the following actions.

4.3.1 Large Frequency Deviation

When a large frequency excursion occurs during normal operations, Balancing Authority areas connected synchronously to the Eastern Interconnection shall continue to operate in the tie line bias area control mode unless continued operation in the tie line bias area control mode would have an adverse impact on reliability.

4.3.2 Manual **Load Shedding** for Capacity Shortage and Frequency Control

Each Balancing Authority should normally carry out the following unless an alternative plan is submitted for review by the NPCC Task Forces on Coordination of Operation and System Studies and approved by the NPCC Reliability Coordinating Committee:

4.3.2.1 The first half of the **load** shed manually should not include load which is part of any automatic load shedding plan unless following manual **load shedding**, the requirements of Section 5.2.1 of this Directory can still be met.

4.3.2.2 The plan should include the capability of shedding **load** proportionately over the whole system, unless operating requirements limit load shedding to one part of a system.

4.3.3 Suspension of Tie Line Bias Area Control Mode

Balancing Authority areas connected synchronously to the Eastern Interconnection should continue to operate in the tie line bias area control mode unless reliability concerns such as but not limited to those shown below require alternative actions:

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4.3.3.1 The Balancing Authority area loses synchronism with the Eastern Interconnection.

4.3.3.2 The Balancing Authority area is uncertain whether it is still connected to the Eastern Interconnection.

4.3.3.3 Values included in the ACE equation are suspect and may result in significant errors in control signals issued.

4.3.3.4 Continued operation in the tie line bias area control mode is, or has a reasonable probability of, adversely affecting reliability.

In this case, an alternative area control mode should be implemented.

4.3.4 Use of Alternative Balancing Authority Control Mode

Balancing Authority areas connected synchronously to the Eastern Interconnection should develop alternative AGC operation strategies to address the concerns of 4.3.1 and 4.3.2 above as needed

4.3.5 Sustained Negative Area Control Error (ACE) Causing A Burden

If a Balancing Authority area has a negative ACE that cannot be returned to zero within fifteen minutes with regulation resources presently available and other planned energy resource deployments due to a known and persisting shortage, and the Balancing Authority area is burdening other Balancing Authority areas or Interconnection frequency, then the Balancing Authority should implement **load shedding** sufficient to return ACE to zero and perform the following notifications:

4.3.5.1 Inform the senior shift authority in each of the other affected Balancing Authorities of the NPCC.

4.3.5.2 Initiate, or request NPCC Staff to initiate, an NPCC Emergency Preparedness Conference Call, as defined in NPCC Reference Document RD-01, *NPCC Emergency Preparedness Conference Call Procedures – NPCC Security Conference Call Procedures*.

4.3.5.3 Issue the appropriate NERC Energy Emergency Alert level and follow procedures in NERC Standard *Emergency Preparedness and Operations* EOP-002-0 *Attachment 1*.

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5.0 Correction of Transmission Loading if Exceeding Limits

5.1 When a Transmission Operator area is experiencing internal circuit or tie line loading in excess of applicable system operating limits, the following steps should be implemented as required and appropriate based on industry-wide and/or local procedures (assistance from the Reliability Coordinators may be required to implement some of these actions):

5.1.1 Implement local congestion management procedures including but not limited to:

5.1.1.1 adjust internal **generation,**

5.1.1.2 transfer **load**,

5.1.1.3 adjust phase angle regulators (phase shifters), and

5.1.1.4 redeploy reactive resources:

5.1.2 Restore out-of-service transmission facilities where possible.

5.1.3 Recall **generation** and transmission **element** outages.

5.1.4 Discontinue **generation** and transmission **element** commissioning.

5.1.5 Activate/implement voltage reduction.

5.1.6 Utilize the NERC TLR process.

5.1.7 Operate to **emergency condition limits**.

5.1.8 Establish communication with areas inside and/or outside NPCC and request relief.

5.1.9 All Balancing Authorities and Transmission Operators in a position to assist should take any available action, excluding **load shedding**, to keep loading from exceeding applicable system operating limits. Assistance should normally only be requested after similar action has been implemented by the requesting Transmission Operator.

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5.1.10 The Balancing Authority or Transmission Operator causing the overload (if identifiable) should adjust **generation** or perform other actions up to and including **load shedding** to keep loading below applicable system operating limits.

5.1.11 The Transmission Operator experiencing the overload should, when effective, reconfigure the system or implement **load shedding** to return the load on **elements** to within applicable system operating limits.

6.0 Generation Tripping at Low Frequency

During a declining frequency event in a Balancing Authority area, generators may trip by underfrequency trip protection. This may aggravate the already declining frequency, possibly leading to a collapse of the area. To arrest the frequency decline, the loss in generation may need to be compensated for by **load shedding**.

6.1 Generator Tripping at Frequency Below the Curve in Figure 1

If the frequency decays below the curve shown in Figure 1 of this Directory, steps may be taken to protect generating equipment, including separation from the system with or without **load**. In such cases isolation onto a generator's own auxiliaries is preferred to facilitate rapid resynchronization as soon as system conditions permit. For time periods exceeding 300 seconds, manual load shedding may need to be implemented to correct the low frequency problem.

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NPCC
Regional Reliability Reference Directory # 3
Maintenance Criteria for Bulk Power System Protection

Task Force on System Protection Revision Review Record:
July 11, 2008

Adopted by the Members of the Northeast Power Coordinating Council, Inc. this July 11, 2008 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

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Revision History

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Appendix A

Appendix B

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1.0 Introduction

1.1 Title Maintenance Criteria for BPS Protection

1.2 Directory Number 3

1.3 Objective

The purpose of this Directory is to present the basic maintenance requirements for **bulk power system protection systems**. It is recognized that responsible entities may choose to apply more rigid requirements because of local considerations.

1.4 Effective Date July 11, 2008

1.5 Background

This Directory was developed from the NPCC A-04 Maintenance Criteria for Bulk Power System Protection and B-23 Guideline document. Guidelines and procedures for consideration in the implementation of this Directory are provided in Appendix B.

1.6 Applicability

1.6.1 Functional Entities[1]

Transmission Owners
Generator Owners
Distribution Providers

1.6.2 Facilities

These criteria shall apply to all **protection** of the NPCC **bulk power system**, including Type I **special protection systems** and **protection** required for the NPCC Automatic Underfrequency **Load Shedding** Program.

Automatic underfrequency **load shedding protection systems** and generator underfrequency tripping **relays** are not generally located at **bulk power system** stations; however, they have a direct effect on the operation of the **bulk power system** during major **emergencies**, and as such, they are subject to this Criteria.

[1] Any of these entities that own a transmission protection system and/or a Underfrequency Load Shedding (UFLS) facility/program

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2.0 Terms Defined in this Directory

The definitions of terms found in this Directory appearing in bold typeface can be found in Document A-07, NPCC Glossary of Terms.

3.0 NERC Reliability Standard Requirements

The NERC Reliability Standards containing Requirements that are associated with this Directory include:

3.1 PRC-005-1 – Transmission and Generation Protection System Maintenance and Testing
3.2 PRC-008-0 - Implementation and Documentation of UFLS Equipment Maintenance Program
3.3 PRC-011-0 – UVLS System Maintenance and Testing
3.4 PRC-012-0 – Special Protection System Review Procedure
3.5 PRC-017-0 – Special Protection System Maintenance and Testing

4.0 NPCC Regional Reliability Standard Requirements

None developed at this time.

5.0 NPCC Full Member, More Stringent Criteria

5.1 General Criteria

Minimum periodic testing of each **protection group** shall be conducted to verify that the **protection group** is capable of performing its intended **protection** function. Such testing shall include **protection** assembly testing (as illustrated in attached Figure 1) and **protection group** system testing. To assure satisfactory operation of the protective equipment as a system, test procedures and test facilities must ensure that related tests properly overlap.

5.2 **Protection** Assembly Testing Requirements

Refer to Figure 1, equipment marked as [1]

The following **Protection** Assembly testing shall be performed on an interval not exceeding that specified in Table 1 for **bulk power system protection groups**:

5.2.1 Make visual inspections,

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5.2.2 Verify inputs and outputs,

5.2.3 Confirm that the intended version of software is installed (microprocessor-based **relays**),

5.2.4 Verify correct **protection** operation,

5.2.5 Verify the integrity of current and voltage transformers and associated circuitry. This verifies that the correct secondary quantities are input to the **relay**. For microprocessor **relays**, verify the internal analog inputs with an independent source.

TABLE 1
INTERVALS FOR PROTECTION ASSEMBLY TESTING

	Non-Self Monitored **Protection Assembly** Note (1)	Microprocessor-Based **Protection Assembly** Note (2)	Microprocessor-Based **Protection Assembly** Note (3)
All **Protection Groups**	**4 years**	**6 years**	**8 years**

Notes:

(1) Non-Self Monitored **protection** assemblies include electromechanical **relays** and solid state **relays**.

(2) Microprocessor-based **protection** assemblies where the principal fault-sensing and logic components include self monitoring or self checking, and the failure alarm is monitored to an Operator.

(3) Microprocessor-based **protection** assemblies as per Note (2), plus additional self monitoring or self checking of ac voltage and current input integrity, and the failure alarm is monitored to an Operator.

5.3 **Protection Group** DC Circuits Testing Requirements

Refer to Figure 1, equipment marked as [2]

Tests performed in Section 5.2 above verify the operation of the ac signaling, measuring **relays,** and verify a **protection** assemblies' ability to initiate a trip output(s). However, to verify operation of the **protection group** as a system, DC circuit testing is required. These tests verify the **protection** equipment operation from the trip outputs of the protection assembly up to breaker trip coils. DC circuit testing can be achieved by verifying overlapping **protection group** equipment zones, normally bound

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by test switches, or by test tripping the **protection group.**

DC circuit test tripping shall be performed on an interval not exceeding that specified in Table 2 for **bulk power system protection groups**:

TABLE 2
INTERVALS FOR DC CIRCUIT TEST TRIPPING

	Non-Monitored	Monitored Note (1)
DC Circuit Tripping	4 years	6 years

Note (1): Trip coil and DC circuit continuity is continuously monitored to an Operator.

5.4 Battery Banks and Chargers Testing Requirements

Refer to Figure 1, equipment marked as [5]

Voltage verification of the station battery(s) shall be performed on an interval not exceeding that specified in Table 3 for **bulk power system protection groups**:

TABLE 3
BATTERY BANKS AND CHARGER TESTING

	Non-Monitored	Monitored Note (1)
Battery Voltage	Every month	Continuous

Note (1): Battery Voltage alarms are continuously monitored to an Operator

5.5 Breaker Test Tripping Requirements

Refer to Figure 1, equipment marked as [4]

The ability of the breaker(s) to trip via each trip coil shall be verified every two years. Nuclear plants can complete these tests at an interval not to exceed three years.

5.6 Telecommunication Testing Requirements

Refer to Figure 1, equipment marked as [3a] and [3b]

5.6.1 Terminal Equipment

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Telecommunications terminal equipment shall be tested on the same time interval as the protection assemblies as per Table 1 above.

5.6.2 Channel Health

For trip equipment which uses frequency shift keying (FSK) mode of communication, such as Power Line Carrier systems, the ability to perform its intended trip function shall be verified every twelve months. This testing is not required for telecommunication systems that continuously verify this functionality to an Operator – alarmed and monitored.

The signal adequacy shall be tested every month and the ability of a channel to perform its intended function shall be verified every twelve months on telecommunication systems that are not continuously monitored. An example of such a system is on/off Power Line Carrier.

5.7 Underfrequency Load Shedding and Generator Trip Testing Requirements

Protection group DC circuit tests for protection required by the NPCC Automatic Underfrequency **Load Shedding** Program need not be performed more frequently than the protection group DC circuit tests for other **protection** on the same breaker. Because of the distributed nature of this **load shedding protection**, random failures to trip do not compromise the objectives of the NPCC Automatic Underfrequency **Load Shedding** Program.

The successful operation of the NPCC Automatic Underfrequency **Load Shedding** Program requires the proper coordination of generator underfrequency tripping, as described in Directory 2. For generators rated 20 MW and above, the correct calibration of generator underfrequency tripping **relays** shall be verified at an interval not exceeding that specified in Table 1.

6.0 Measures and Assessments

None developed at this time.

7.0 Compliance Monitoring

Adherence to requirements in this Directory must be reported in a manner and form designated by the Compliance Committee. Exceptions to the requirements

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stipulated herein are acceptable if the exceptions are completely removed within five (5) months of the end of the calendar year in which the testing is due. The intervals specified in this document refer to calendar year in which testing is due regardless of the date.

Prepared by:	Task Force on System Protection
Review and Approval:	Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45 day review and comment period. Upon satisfactorily addressing all the comments in this forum, the Directory document will be sent to the remaining Task Forces for their recommendation to seek RCC approval. Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC. Bylaws" in effect at the time the ballots are cast. Revisions pertaining to the Appendices or any other portion of the document such as Links glossary terms, etc., only RCC Members will need to conduct the final approval ballot of the document. This Directory will be updated at least once every 3 years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.
References:	NPCC Glossary of Terms (Document A-7)

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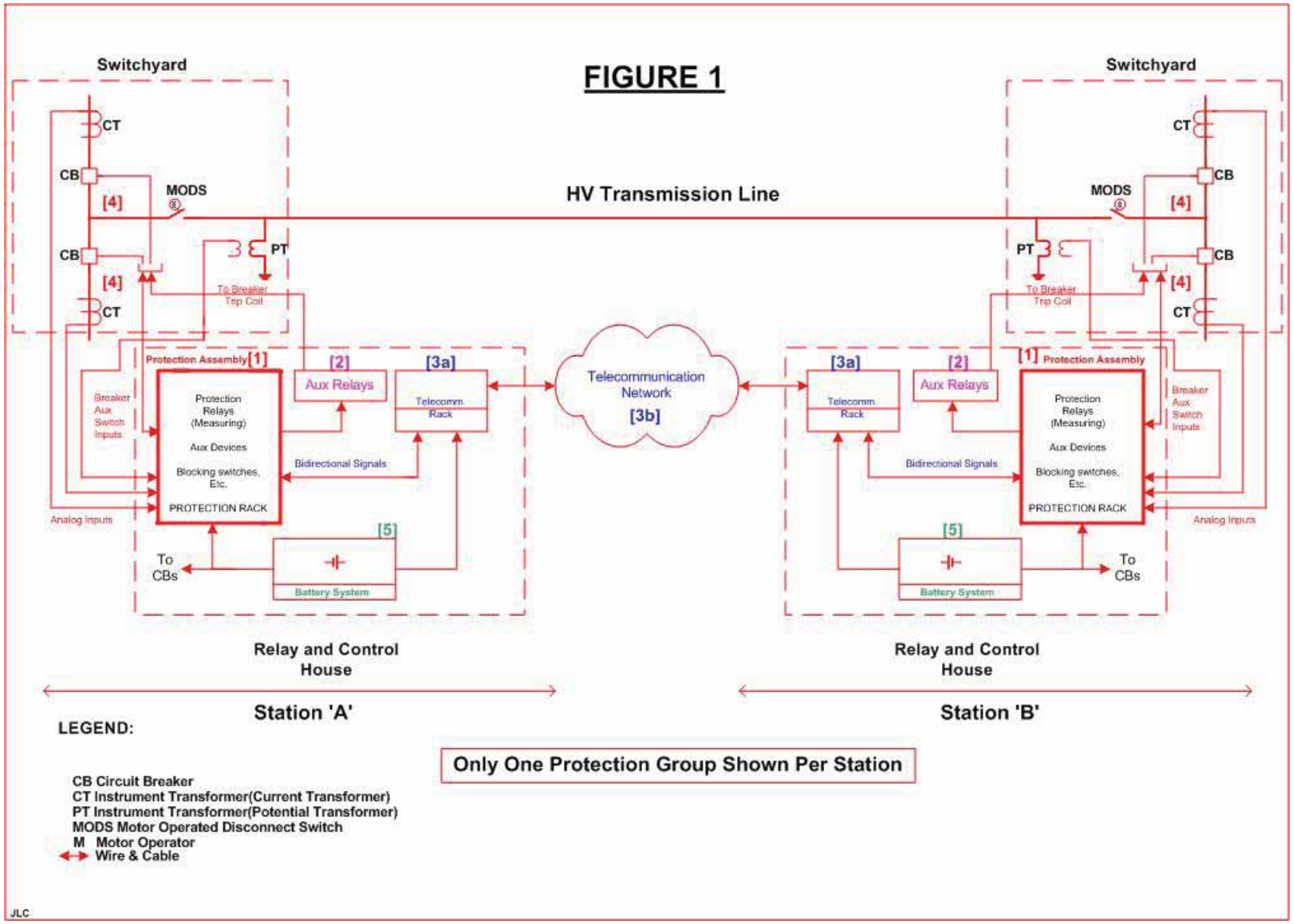

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Appendix A
Definition of Terms

Bulk power system - The interconnected electrical systems within northeastern North America comprising **generation** and transmission facilities on which faults or disturbances can have a significant adverse impact outside of the local area. In this context, local areas are determined by the Council members.

Element — any electric device with terminals that may be connected to other electric devices, such as a generator, transformer, circuit, circuit breaker, or bus section. Limiting Element — the element that is either operating at its appropriate **rating** or would be following a limiting **contingency** and, as a result, establishes a system limit.

Load — the electric **power** used by devices connected to an electrical generating system. (IEEE Power Engineering). Also see **Demand**.

NPCC Specific Definitions:

Firm Load — Loads that are not **Interruptible Loads**.

Interruptible Load — Loads that are interruptible under the terms specified in a contract.

Load Shedding — the process of deliberately removing (either manually or automatically) preselected customers' **load** from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages.

Protection - The provisions for detecting power system **faults** or abnormal conditions and taking appropriate automatic corrective action.

Protection group — a fully integrated assembly of **protective relays** and associated equipment that is designed to perform the specified protective functions for a power system **element**, independent of other groups.

Notes:

(a) Variously identified as Main **Protection**, Primary **Protection**, Breaker Failure **Protection**, Back-Up **Protection**, Alternate **Protection**, Secondary **Protection**, A **Protection**, B **Protection**, Group A, Group B, System 1 or System 2.

(b) Pilot **protection** is considered to be one **protection group.**

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Protection system

Element Basis

One or more **protection** groups; including all equipment such as instrument transformers, station wiring, circuit breakers and associated trip/close modules, and communication facilities; installed at all terminals of a power system **element** to provide the complete **protection** of that **element**.

Terminal Basis

One or more **protection** groups, as above, installed at one terminal of a power system **element**, typically a transmission line.

Pilot **Protection** — a form of line **protection** that uses a communication channel as a means to compare electrical conditions at the terminals of a line.

Relay — an electrical device designed to respond to input conditions in a prescribed manner and after specified conditions are met to cause contact operation or similar abrupt change in associated electric control circuits. (Also: see **protective relay**).

Special protection system (SPS) – A **protection system** designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted **elements**. Such action may include changes in **load**, **generation,** or system configuration to maintain system **stability**, acceptable voltages or power flows. Automatic underfrequency **load shedding** as defined in the *Emergency Operation Criteria* A-3, is not considered a **Special Protection System**. Conventionally switched, locally controlled shunt devices are not **Special Protection Systems**

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Appendix B
Guideline and Procedure for Maintenance of Bulk Power System Protection

1.0 Introduction

This Appendix provides the guidelines and procedures for consideration in the implementation of this Directory.

2.0 General

2.1 Generator Under-frequency Tripping

For generators rated less than 20 MW, consideration may be given to verifying the calibration of generator underfrequency **relays** at an interval not exceeding that specified in Table 1.

3.0 Microprocessor-based Protective Relays

The use of computer based technology for **protective relays** has influenced what is considered sufficient for periodic maintenance of microprocessor-based **relays**. The purpose of this document is to provide guidance for the maintenance of microprocessor-based **protective relays** as required in Section 5.2 and in notes (2) and (3) of Table 1 of this Directory.

This Section applies only to the maintenance of microprocessor-based **protective relays** (**Protection** Assembly Testing Requirements, verify correct **protection** operation). It does not include other **protection** maintenance that is still required, as outlined in the remaining Sections of this Directory.

This Section is not intended to be a maintenance procedure, but rather a guide for member systems to develop their maintenance procedures.

3.1 Testing of Microprocessor-Based Relays

For the purposes of maintenance testing, microprocessor-based **relays** or Intelligent Electronic Devices (IEDs), can be viewed as being composed of four sections:

3.1.1 Analog Input Section;
3.1.2 Digital Input/Output Section;
3.1.3 Processor Section; and;
3.1.4 Power supply Section

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3.2 Analog Input Section

Measurements of magnitude and angle (calculate where not available directly) of metered values should be compared with known quantities. This supposes that the device uses the same hardware for both protection and metering. If this is not the case, then a calibration test should be conducted to verify the analog inputs.

It is not sufficient to compare the magnitudes as measured by the IED. The input section has filtering with active and passive components, which are vulnerable to change over time and cause changes in the phase characteristics of the channel. Measuring and recording of the phase angle readings is, therefore, required.

3.3 Digital Input and Output Sections

Each digital input and output that is utilized should be verified for proper functions.

3.3.1 Inputs

Operation of all used physical inputs should be verified by applying the DC control voltage, and observing associated display, or the computer interface.

3.3.2 Outputs

Outputs of the IED should be verified either by:

3.3.2.1 Asserting the output element using appropriate relay commands and observe the status of the output relay, or;

3.3.2.2 Where such features are not available, the appropriate output contact can be verified by asserting the associated logic settings that permit contact operation.

3.4 Processor Section

The processor section samples the analog and digital inputs, executes the algorithm and logic, and provides the outputs. It includes program memory, non-volatile memory for settings and volatile memory for sequence of events and oscillography. The processor section also

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performs self-checking.

All of the downloaded settings and the firmware version should be compared with the official copy of the protection settings to verify that the **relay** contains the intended settings, and it is working with the intended version of firmware.

3.5 Power Supply Section

Most microprocessor-based IEDs provide measurement of the power supply voltages and/or continuously monitor the power supply voltages, and provide a **relay** failure alarm if they go out of limits. Where these values are accessible, they should be checked against specified ranges. Alternatively, the alarm should be checked on loss of dc voltage to the power supply.

3.6 Integrity Testing

This test is intended to verify the integrity of operation of the **relay** program execution and the processing of the phase voltages and current signals. Verify the correct operation of one of the three-phase protection elements, or a single phase, for a single-phase **relay**. As an example, for a distance **relay**, test one of a zone's A-G, B-G, and C-G elements.

3.7 Multi-Processor Based IEDs

Most **relays** are designed using a single processor; however, some **relay** designs use multiple processors. If the processing is divided among several processors, then tests should be conducted to include testing of functions that are executed in the respective processors. The manufacturer and/or manual should be consulted to verify hardware configuration. As an example, if a **relay** uses two processors, one each for phase and ground elements, then integrity testing should be repeated for phase and ground elements respectively.

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NPCC
Regional Reliability Reference Directory # 4
Bulk Power System Protection Criteria

Task Force on System Protection Revision Review Record:
December 01, 2009

Adopted by the Members of the Northeast Power Coordinating Council, Inc. December 01, 2009 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

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1.0 Introduction

1.1 Title Protection Criteria

1.2 Directory Number 4

1.3 Objective

The purpose of this Directory is to provide the **protection** criteria, for **protection** of the NPCC **bulk power system**. It is not a design specification.

1.4 Effective Date December 01, 2009

1.5 Background

This Directory was developed from the draft NPCC A-05 Bulk Power Protection Criteria document dated December 4, 2008 and approved B-05, B-07, B-24 and C-22 documents. Guidelines and procedures for consideration in the implementation of this Directory are provided in Appendix A.

1.6 Applicability

1.6.1 Functional Entities

Transmission Owners
Generator Owners

1.6.2 Facilities

1.6.2.1 New Facilities

These criteria shall apply to all new Bulk Power System (BPS) facilities.

1.6.2.2 Existing Facilities

It is the responsibility of individual companies to assess the **protection systems** at existing facilities and to make modifications which are required to meet the intent of these criteria as follows.

1.6.2.2.1 Planned Renewal or Upgrade to Existing BPS Facilities

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It is recognized that there may be portions of the **bulk power system,** which existed prior to each member's adoption of the *Bulk Power System Protection Criteria* (Document A-5) that do not meet these criteria. However, if **protection systems** or sub-systems of these facilities are replaced as part of a planned renewal or upgrade to the facility and do not meet all of these criteria, then an assessment shall be conducted for those criteria that are not met.

The result of this assessment shall be reported, It is recommended this reporting be in accordance with the procedure stipulated in Section 4.0 of Appendix A of this Directory and using the appropriate portion of the "Protection System Review forms" (formerly C-22 forms), for review and disposition by the TFSP, or in a form consistent with the intent of the procedure.

1.6.2.2.2 Facility Classification Upgraded to **Bulk Power System**.

These criteria apply to all existing facilities which become classified as **bulk power system**. A mitigation plan shall be required to bring such a facility into compliance with these criteria.

Where the owner of the **protection system** has determined that the cost and risks involved to implement physical separation, as per Section 5.12, cannot be justified, the reason for this determination and an assessment shall be reported to the TFSP.

It is recommended this reporting be in accordance with the procedure stipulated in Section 4.0 of Appendix A of this Directory and using the appropriate portion of the "Protection System Review forms" (formerly C-22 forms), for review and disposition by the TFSP, or in a form consistent with the intent of

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the procedure.

1.6.2.2.3 Additions to **Bulk Power System** Facilities

If a **bulk power system element** is added to an existing **bulk power system** facility that is recognized under Section 1.6.2.2.1, Planned Renewal or Upgrade to Existing Facilities, these criteria apply to the **protection systems** for the new **element**.

1.6.2.2.4 "In-Kind" Replacement of **Bulk Power System** Equipment

If a **bulk power system element** (e.g., breaker, transformer, capacitor bank, reactor, etc.) or a **protective relay** is replaced "in kind" as a result of an unplanned event, then it is not required to upgrade the associated **protection system** to comply with these criteria.

1.6.2.2.5 Change in **Bulk Power System** Facility Status

When a facility was originally on the BPS list of April 2007 and has been shown to be non-BPS but later was determined to be BPS again, Section 1.6.2.2.1 would apply. When the facility returns to BPS status, it shall be maintained in accordance with Directory #3 within two years timeframe.

1.6.3 Responsibility

Whenever changes are anticipated in generating sources, transmission facilities, or operating conditions, Generator Owners and Transmission Owners shall review those **protection system** applications (i.e., settings, ac and dc supplies) which can reasonably be expected to be impacted by those changes.

2.0 Terms Defined in this Directory

The definitions of terms found in this Directory appearing in bold typeface, can be found in Document A-07, NPCC *Glossary of Terms*.

3.0 NERC ERO Reliability Standard Requirements

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The NERC ERO Reliability Standards containing requirements that are associated with this Directory include, but may not be limited to:

3.1 PRC-001
3.2 PRC-002
3.3 PRC-012

4.0 NPCC Regional Reliability Standard Requirements

None.

5.0 NPCC Full Member, More Stringent Criteria

These Criteria are in addition, more stringent or more specific than the NERC or any Regional Reliability standard requirements.

5.1 General Criteria

The intent of the criteria established in this Directory is to ensure dependable and secure operation of the **protection systems** for **Bulk Power System** facilities. For those **protective relays** intended for removal of **faults** from the **bulk power system**, dependability is paramount, and the redundancy provisions of the criteria shall apply. For **Protective relays** installed for reasons other than **fault** sensing such as overload, etc., security is paramount, and the redundancy provisions of the criteria do not apply. The relative effect on the **bulk power system** of a failure of a **protection system** to operate when desired versus an unintended operation shall be weighed carefully in selecting design parameters as follows.

5.2 Criteria for Dependability

5.2.1 Except as identified otherwise in these criteria, all elements of the **bulk power system** shall be protected by two protection **groups**, each of which is independently capable of performing the specified protective function for that **element.** This requirement also applies during energization of the **element.**

5.2.2 Except as identified otherwise in these criteria, the two **protection groups** shall not share the same component**.**

5.2.3 Means shall be provided to trip all necessary local and remote breakers in the event that a breaker fails to clear a fault. This **protection** need not be duplicated.

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5.3 Criteria for Security

Protection systems shall be designed to isolate only the faulted **element**, except in those circumstances where additional **elements** are tripped intentionally to preserve system integrity, or where isolating additional **elements** has no impact outside the local area.

5.4 Criteria for Dependability and Security

5.4.1 The thermal capability of all **protection system** components shall be adequate to withstand rated maximum short time and continuous loading of the associated **protected elements**.

5.4.2 Communication link availability, critical switch positions, and trip circuit integrity, shall be monitored to allow prompt attention by appropriate operating authorities.

5.4.3 When remote access to **protection systems** is possible, the design shall include security measures to minimize the probability of unauthorized access to the protection systems.

5.4.4 Short Circuit Models used to assess **protection** scheme design and to develop **protection** settings shall take into account minimum and maximum fault levels and mutual effects of parallel transmission lines. Details of neighboring systems shall be modeled wherever they can affect results significantly.

5.5 Operating Time Criteria

Bulk power system protection shall take corrective action within times determined by studies with due regard to security, dependability and selectivity.

5.6 Current Transformer Criteria

Current transformers (CTs) associated with **protection systems** shall have adequate steady-state and transient characteristics for their intended function as follows:

5.6.1 The output of each current transformer secondary winding shall be designed to remain within acceptable limits for the connected burdens under all anticipated **fault** currents to ensure correct operation of the **protection system**.

5.6.2 The thermal and mechanical capabilities of the CT at the operating

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tap shall be adequate to prevent damage under maximum **fault** conditions and normal or **emergency** system loading conditions.

5.6.3 For **protection groups** to be independent, they shall be supplied from separate current transformer secondary windings.

5.6.4 Interconnected current transformer secondary wiring shall be grounded at only one point.

5.6.5 Current transformers shall be connected so that adjacent **protection** zones overlap.

5.7 Voltage Transformer and Potential Devices Criteria

Voltage transformers and potential devices associated with **protection systems** shall have adequate steady-state and transient characteristics for their intended functions as follows:

5.7.1 Voltage transformers and potential devices shall have adequate volt-ampere capacity to supply the connected burden while maintaining their **relay** accuracy over their specified primary voltage range.

5.7.2 The two **protection groups** protecting an element shall be supplied from separate voltage sources. The two protection groups may be supplied from separate secondary windings on one transformer or potential device, provided all of the following requirements are met:

5.7.2.1 Complete loss of one or more phase voltages does not prevent all tripping of the protected **element**;

5.7.2.2 Each secondary winding has sufficient capacity to permit fuse **protection** of the circuit;

5.7.2.3 Each secondary winding circuit is adequately fuse protected.

5.7.3 The wiring from each voltage transformer secondary winding shall not be grounded at more than one point.

5.8 Batteries and Direct Current (DC) Supply Criteria

DC supplies associated with **protection** shall be designed to have a high degree of dependability as follows:

5.8.1 No single battery or dc power supply failure shall prevent both

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independent **protection groups** from performing the intended function. Each battery shall be provided with its own charger. Physical separation shall be maintained between the two station batteries or dc power supplies used to supply the independent **protection groups**.

5.8.2 Each station battery shall have sufficient capacity to permit operation of the station, in the event of a loss of its battery charger or the ac supply source, for the period of time necessary to transfer the **load** to the other station battery or re-establish the supply source. Each station battery and its associated charger shall have sufficient capacity to supply the total dc **load** of the station.

5.8.3 A transfer arrangement shall be provided to permit connecting the total **load** to either station battery without creating areas where, prior to failure of either a station battery or a charger, a single event can disable both dc supplies.

5.8.4 The battery chargers and all dc circuits shall be protected against short circuits. All protective devices shall be coordinated to minimize the number of dc circuits interrupted.

5.8.5 Dc systems shall be continuously monitored or annunciated to detect abnormal voltage levels (both high and low), dc grounds, and loss of ac to the battery chargers, in order to allow prompt attention by the appropriate operating authorities.

5.8.6 **Protection group** dc sources shall be continuously monitored to detect loss of voltage in order to allow prompt attention by the appropriate operating authorities.

5.9 Station Service ac Supply Criteria

On **bulk power system** facilities there shall be two sources of station service ac supply, each capable of carrying at least all the critical **loads** associated with **protection systems**.

5.10 Circuit Breaker

No single trip coil failure shall prevent both independent **protection groups** from performing the intended function. The design of a breaker with two trip coils shall be such that the breaker will operate if both trip coils are energized simultaneously. The correct operation of this design shall be verified by tests.

5.11 Teleprotection Criteria

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5.11.1 Communication facilities required for **teleprotection** shall be designed to have a level of performance consistent with that required of the **protection system**, and shall meet the following:

5.11.1.1 Where each of the two **protection groups** protecting the same **bulk power system element** requires a communication channel, the equipment and channel for each **protection group** shall be separated physically and designed to minimize the risk of both **protection groups** being disabled simultaneously by a single event or condition.

5.11.1.2 **Teleprotection** equipment shall be monitored to detect loss of equipment and/or channels to allow prompt attention by the appropriate operating authorities.

5.11.1.3 **Teleprotection** equipment shall be provided with means to test for proper signal adequacy.

5.11.1.4 **Teleprotection** equipment shall be powered by the substation batteries or other sources independent from the power system.

5.11.1.5 Except as identified otherwise in these criteria, the two **teleprotection** groups shall not share the same component.

5.11.1.5.1 The use of a single communication tower for the radio communication systems used by two **protection groups** protecting a single **element** is permitted as long as directional diversity of the communication signals is achieved.

5.12 Environment

5.12.1 Each separate **protection group** and **teleprotection** protecting the same system **element** shall be on different non-adjacent vertical mounting assemblies or enclosures.

5.12.2 Wiring for separate **protection groups** and **teleprotections** protecting the same system **element** shall not be in the same cable.

5.12.3 Cabling for separate **protection groups** and **teleprotections** protecting the same system **element** shall be physically separated. This can be accomplished by being in different raceways, trays,

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trenches, etc.

5.12.4 In the event a common raceway is used, cabling for separate **protection groups** protecting the same system **element** shall be separated by a fire barrier.

5.13 Grounding Criteria

Station grounding is critical to the correct operation of **protection systems**. The design of the ground grid directly impacts proper **protection system** operation and the probability of false operation from **fault** currents or transient voltages. Each member shall have established as part of its substation design procedures or specifications, a mandatory method of designing the substation ground grid, which:

5.13.1 Can be traced to a recognized calculation methodology

5.13.2 Considers cable shielding

5.13.3 Considers equipment grounding

5.14 Transmission Line Protection Criteria

5.14.1 **Protection system** settings shall not constitute a loading limitation as per NERC requirement/standard. In cases where NERC approved exceptions are used the limits thus imposed shall be adhered to as system operating constraints.

5.14.2 A **pilot protection** shall be so designed that its failure or misoperation will not affect the operation of any other **pilot protection** on that same **element**.

5.15 Breaker Failure Protection Criteria

Means shall be provided to trip all necessary local and remote breakers in the event that a breaker fails to clear a **fault**, as follows.

5.15.1 Breaker failure **protection** shall be initiated by each of the **protection groups** which trip the breaker, with the optional exception of a breaker failure **protection** in an adjacent zone.

5.15.2 Fault current detectors shall be used to determine if a breaker has failed to interrupt a **fault.**

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5.16 Generating Station Protection Criteria

All under- and over-frequency **protection systems** designed to disconnect generators from the power system shall be coordinated with automatic under frequency **load shedding** programs, in accordance with the *Emergency Operation Criteria* (Directory #2).

5.17 Automatic Under frequency Load Shedding Protection System Criteria

5.17.1 The requirements and guides for the operation of these **Protection Systems** are detailed in the *Emergency Operation Criteria* (Directory #2). The guideline for automatic under frequency **load shedding protective relaying** design is provided in Appendix A of this Directory.

5.18 HVdc System Protection Criteria

5.18.1 The ac portion of an HVdc converter station, up to the valve-side terminals of the converter transformers, shall be protected in accordance with these criteria.

5.18.2 Multiple commutation failures, unordered power reversals, and **faults** in the converter bridges and the dc portion of the HVdc link which are severe enough to disturb the **bulk power system** shall be detected by more than one independent control or **protection group** and appropriate corrective action shall be taken, in accordance with the considerations in these criteria.

5.19 Protection System Testing and Maintenance Criteria

5.19.1 **Protection systems** shall be maintained in accordance with the *Maintenance Criteria for Bulk Power System Protection* (Directory #3).

5.19.2 The design of **protection systems** both in terms of circuitry and physical arrangement shall facilitate periodic testing and maintenance.

5.19.3 Each **protection group** shall be functionally tested to verify the dependability and security aspects of the design, when initially placed in service and when modifications are made.

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5.20 Analysis of Protection Performance Requirements

5.20.1 **Bulk power system** automatic operations shall be analyzed to determine proper **protection system** performance. Corrective measures shall be taken promptly if a **protection group** fails to operate or operates incorrectly.

5.20.2 Event and fault recording capability shall be provided to the extent required to permit analysis of **system disturbances** and **protection system** performance.

5.20.3 Internal clocks in event and **fault** recording equipment shall be time synchronized to within 2 milliseconds or less of Universal Coordinated Time scale. The time zone shall be clearly identified as either universal time zone or local time zone.

5.20.4 Each **protective relay** which trips **Bulk Power System** equipment shall provide separate target indication.

6.0 Measures and Assessments

None developed at this time.

7.0 Compliance Monitoring

7.1 Each member shall provide the Task Force on System Protection (TFSP) with advance notification of any of the member's new **bulk power system protection systems**, or significant changes in the member's existing **bulk power system protection systems**.

7.2 Each member shall also provide the TFSP with advance notification of non-member **protection** facilities as required per *NPCC Bylaws*.

7.3 Each new or revised **protection system** shall be reported to the TFSP. It is recommended this reporting be in accordance with the procedure detailed in Section 4.0 of Appendix A of this Directory, or in a form consistent with the intent of the procedure.

7.4 Adherence to these Criteria shall be reported by the responsible entity in a manner and form designated by the Compliance Committee.

Prepared by: Task Force on System Protection

Review and Approval: Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45 day review

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and comment period. Upon satisfactorily addressing all the comments in this forum, the Directory document will be sent to the remaining Task Forces for their recommendation to seek RCC approval.

Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC. Bylaws" in effect at the time the ballots are cast.

Revisions pertaining to the Appendices or any other portion of the document such as Links glossary terms, etc., only RCC Members will need to conduct the final approval ballot of the document.

This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

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Appendix A
Guideline and Procedure for Bulk Power System Protection

1.0 Introduction

This Appendix provides the guidance for consideration in the implementation of the **bulk power system Protection** criteria stipulated in this Directory, and the procedure on reporting new and revised **bulks power system protection** facilities.

2.0 Design Considerations

2.1 General Considerations

In general, the function of a **protection system** is to limit the severity and extent of **system disturbances** and possible damage to system equipment.

The Directory's criteria objectives can be met only if **protection systems** have a high degree of dependability and security. In this context dependability relates to the degree of certainty that a **protection system** will operate correctly when required to operate. Security relates to the degree of certainty that a **protection system** will not operate when not required to operate.

Often increased security (fewer unintended operations) results in decreased dependability (more failures to operate), and vice versa. As an example, consideration is given to the consequence of applying permissive line **protection** schemes, which often are more secure, but less dependable, than blocking line protection schemes. The relative effect on the **bulk power system** of a failure of a **protection system** to operate when desired versus an unintended operation should be weighed carefully in selecting design parameters. Considerations for specific aspects of **protection** design are provided below.

2.2 Issues Affecting Dependability

2.2.1 Some portions of **elements** may not in themselves be part of the **bulk power system**. Those portions do not require two **protection groups**.

2.2.2 Two identical measuring **relays** should not be used in independent **protection groups** due to the risk of simultaneous failure of both groups because of design deficiencies or equipment problems.

2.2.3 In addition to the separation requirements in the criteria, areas of common exposure should be kept to a minimum to reduce the possibility of both **protection groups** being disabled by a single

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event such as fire, excavation, water leakage, and other such incidents.

2.2.4 On installations where free-standing or column-type current transformers are provided on one side of the breaker only, resulting in a **protection** blind spot, **protection** should be provided to detect a **fault** to ground on the primaries of such current transformers. When frame ground **protection** is used, then frame ground and breaker failure **protections** are the two local independent **protections** for the blind spot between the current transformer and the circuit breaker. Neither of these **protections** need be duplicated. Both of these **protections** should be designed so as to not be disabled by the same failure. The frame ground **protection** and breaker failure **protection** will in fact provide independent **protections** for the blind spot.

2.3 Issues Affecting Security

2.3.1 For **faults** external to the protected zone, each **protection group** should be designed either to not operate, or to operate selectively with other groups and with breaker failure **protection**.

2.3.2 For planned system conditions, **protection systems** should not operate to trip for stable power swings.

2.4 Issues Affecting Dependability and Security

2.4.1 **Protection systems** should be no more complex than required for any given application.

2.4.2 The components and software used in **protection systems** should be of proven quality, as demonstrated either by actual experience or by stringent tests under simulated operating conditions.

2.4.3 **Protection systems** should be designed to minimize the possibility of component failure or malfunction due to electrical transients and interference or external effects such as vibration, shock and temperature.

2.4.4 **Protection system** circuitry and physical arrangements should be designed so as to minimize the possibility of incorrect operations due to personnel error.

2.4.5 **Protection system** automatic self-checking facilities should be designed so as to not degrade the performance of the **protection**

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system.

2.4.6 Consideration should be given to the consequences of loss of instrument transformer voltage inputs to **protection systems**.

2.4.7 **Protection systems**, including intelligent electronic devices (IEDs) and communication systems used for **protection**, should comply with applicable industry standards for utility grade **protection** service. Utility Grade **Protection System** Equipment are equipment that are suitable for protecting transmission power system elements, that are required to operate reliably, under harsh environments normally found at substations. Utility grade equipment should meet the applicable sections of all or some of the following types of industry standards, to ensure their suitability for such applications:

- IEEE C37.90.1-2002 (oscillatory surge and fast transient)
- IEEE C37.90.1-2002 (service conditions)
- IEC 60255-22-1, 2005 (1 MHz burst, i.e. oscillatory)
- IEC 61000-4-12, 2001 (oscillatory surge)
- IEC 61000-4-4, 2004 (EFT)
- IEC 60255-22-4, 2002 (EFT)
- IEEE C37.90.2-2004 (narrow-band radiation)
- IEC 60255-22-3, 2000 (narrow-band radiation)
- IEC 61000-4-3, 2002 (narrow-band radiation)
- IEEE 1613 (communications networking devices in Electric power Substations)

2.5 Operating Time

Adequate time margin should be provided taking into account study inaccuracies, differences in equipment, and **protection** operating times. In cases where clearing times are deliberately extended, consideration should be given to the following:

- Effect on system **stability** or reduction of **stability** margins.
- Possibility of causing or increasing damage to equipment and subsequent extended repair and/or outage time.
- Effect of **disturbances** on service to customers.

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2.6 Current Transformer

None.

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2.7 Voltage Transformers and Potential Devices

Voltage transformer installations should be designed with due regard to ferroresonance.

2.7.1 Special attention should be given to the physical properties (e.g. resistance to corrosion, moisture, fatigue) of the fuses used in **protection** voltage circuits.

2.8 Batteries and Direct Current (dc) Supply

2.8.1 The circuitry between each battery and its first protective device cannot be protected and therefore should be designed so as to minimize the possibility of electrical short circuit.

2.8.2 The design for the regulation of the dc voltage should be such that, under all anticipated charging and loading conditions, voltage within acceptable limits will be supplied to all devices, while minimizing ac ripple and voltage transients.

2.9 Station Service ac Supply

None.

2.10 Circuit Breakers

The indication of the circuit breaker position in **protection systems** should be designed to reliably mimic the main contact position.

2.11 Teleprotection

2.11.1 **Teleprotection** systems should be designed to prevent unwanted operations such as those caused by equipment or personnel.

2.11.2 Two identical **teleprotection** equipments should not be used in independent **protection groups**, due to the risk of simultaneous failure of both groups because of design deficiencies or equipment problems.

2.11.3 Areas of common exposure should be kept to a minimum to reduce the possibility of both groups being disabled by a single event such as fire, excavation, water leakage, and other such incidents.

2.11.4 **Teleprotection** systems should be designed to mitigate the effects of signal interference from other communication sources and to

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assure adequate signal transmission during **bulk power system disturbances**.

2.12 Environment

Means should be employed to maintain environmental conditions that are favorable to the correct performance of **protection systems.**

2.13 Grounding

None.

2.14 Transmission Lines Protection

For planned system conditions, line **protection systems** associated with transmission facilities should not operate to trip for stable **power swings**.

2.15 Breaker Failure Protection

2.15.1 It is not necessary to duplicate the breaker failure **protection** itself.

2.15.2 Auxiliary switches may also be required in instances where the **fault** currents are not large enough to operate the **fault** current detectors. In addition, auxiliary switches may be necessary for high-speed detection of a breaker failure condition.

2.16 Generating Station Protection

2.16.1 Each **protection system** should be designed to minimize the effects to **the bulk power system** of **faults** and **disturbances**, while itself experiencing a single failure.

2.16.2 Generators should be protected to limit possible damage to the equipment. The following are some of the abnormal (not necessarily **fault**) conditions that should be detected:

- Unbalanced phase currents, loss of excitation
- Overexcitation, generator out of step, field ground
- inadvertent energization.

2.16.2.1 **Protections** for the above conditions, which are applied for equipment **protection**, need not be duplicated.

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2.16.2.2 When a directional over current or distance **relay** is applied to remove the generator for slowly cleared **faults** on the external system, such **protection** is a backup and need not be duplicated.

2.16.2.3 The apparatus should be protected when the generator is starting up or shutting down as well as running at normal speed; this may require additional **relays** as the normal **relays** may not function satisfactorily at low frequencies.

2.16.2.4 Generator **protection systems** should not operate for stable **power swings** except when that particular generator is out of step with the remainder of the system. This does not apply to **Special Protection Systems** designed to trip the generator as part of an overall plan to maintain **stability** of the power system.

2.16.2.5 Loss of excitation and out of step **relays** should be set with due regard to the performance of the excitation system.

2.16.2.6 It is recognized that the overall **protection** of a generator involves non-electrical considerations that have not been included as a part of the criteria in this Directory.

2.16.2.7 All over frequency, overvoltage and under voltage **protection systems** designed to disconnect generators from the power system should be coordinated with automatic under frequency **load shedding** programs.

2.17 Automatic Under frequency Load Shedding Protection Systems

2.17.1 Automatic under frequency **load shedding protection systems** are not generally located at **bulk power system** stations; however, they have a direct effect on the operation of the **bulk power system** during major **emergencies**.

2.17.2 Automatic under frequency **load shedding protection** need not be duplicated.

2.17.3 Under frequency **relays** which operate at a discrete frequency value are called "under frequency threshold **relays**." Selection of under frequency sensing devices should be on a threshold basis. Alternatively, rate of change of frequency **load shedding** may be used when the requirements of the Balancing Authority indicate that this method will achieve the intent of the **load shedding** program.

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Appropriate studies are necessary to determine the application and settings of the rate of change of frequency **relays** for a particular Balancing Authority area.

2.17.4 In order for each Balancing Authority within NPCC to **shed** approximately the same proportion of **load**, given the same frequency condition, all styles and manufacture of under frequency **relays** should trip at essentially the same time. For electromechanical **relays**, time delay depends on rate of frequency decline, and it is not possible to achieve uniform response for different rates of decline. The recommendations in this guideline are based on the goal of a uniform response at a rate of frequency decline of 0.2 Hz per second.

2.17.5 Additional Application Considerations

2.17.5.1 Where undesired under frequency **relay** operation can be caused by decaying frequency due to isolated generation or motor load, additional supervising undercurrent or voltage **relays** may be used to prevent misoperation.

2.17.5.2 Where the AC voltage source for an under frequency **relay** is derived from a potential device connected to a cable circuit, care should be taken to estimate the voltage present during deenergization of the circuit. The natural frequency of the decaying cable voltage may be less than 60 Hz, and thus cause an incorrect **relay** operation.

2.17.5.3 The AC Voltage Inhibit feature available on some relays may be useful as a security tool to restrain operation during cable deenergization, depending on the voltage decay time constant

2.17.5.4 Due regard should be given to the expected power system voltage during events for which the underfrequency **relays** are expected to operate. The **relay's** minimum AC voltage operating characteristic should not inhibit proper **relay** operation, nor should the Voltage Inhibit feature, where it exists, be set to prevent proper operation.

2.17.6 Settings and Maintenance Recommendations

2.17.6.1 Pickup Time Delay Settings

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Pickup and time delay settings of underfrequency threshold **relays** should be applied in accordance with the requirements specified in Section 5.2 and Section 5.4 of *Emergency Operation Criteria* (Directory #2).

2.17.6.2 Relay Performance Considerations

Any underfrequency **relay** which has been found to have drifted more than ±0.2 Hz from its set point or ±0.1 seconds from its time delay should be recalibrated and then retested in six months. If, at that time, the **relay** has drifted ±0.2 Hz or more from its set point or ±0.1 seconds or more from its fixed time delay, the cause of the drift should be corrected or the **relay** should be replaced.

2.17.6.3 Maintenance

Underfrequency **load shedding relays** have a direct effect on the operation of the **bulk power system** during major **emergencies**. These **relays** should be maintained in accordance with requirements stipulated in *Maintenance Criteria for Bulk Power System Protection* (Directory 3), even though they are usually located in non-**bulk power system** stations**.**

2.18 HVdc Systems Protection

2.18.1 Converter terminals should be protected to avoid excessive equipment stresses and to minimize equipment damage and outage time. These **protections** are usually specific to the design of the converter station(s) and are determined by the manufacturer to comply with availability guarantees. The followings are some conditions which should be detected:

- ac and dc undervoltage,
- ac and dc overvoltage,
- valve misfire,
- excessive harmonics on the dc,
- dc ground **faults** and open circuits,
- dc switching device failures,
- thyristor failures,
- valve and snubber circuit overloads.

2.18.2 The overall **protection** and control of an HVdc link may also involve the initiation of actions in response to abnormal conditions

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on the ac interconnected system. The control and **protection systems** associated with such conditions are not considered part of the HVdc systems **protection**.

2.19 Protection System Testing and Maintenance

Test facilities and test procedures should be designed such that they do not compromise the independence of **protection groups** protecting the same **bulk power system element**. Test devices or switches should be used to eliminate the necessity for removing or disconnecting wires during testing.

2.20 Analysis of Protection System

Insofar as possible, each active protective function within a **protective relay** should provide separate target information.

2.21 Transmission Station Protection

2.21.1 The **protection systems** should operate properly for the anticipated range of currents.

2.21.2 For planned system conditions, all station **protection systems** should not operate for **load** current or stable **power swings.**

2.21.3 **Load** responsive **protection relays** applied to transmission autotransformers should allow all possible load ability, consistent with equipment **protection** requirements.

2.21.4 Fault pressure or Buchholz **relays** used on transformers, phase shifters or regulators should be applied so as to minimize the likelihood of their misoperation due to through **faults**.

2.22 Capacitor Banks

2.22.1 Each **protection system** should be designed to minimize the effects to the **bulk power system** of **faults** and **disturbances**, while itself experiencing a single failure.

2.22.2 Capacitor bank **protection** should be applied with due consideration for capacitor bank transients, power system voltage unbalance, and system harmonics.

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Appendix A

2.22.3 Protection may be provided to minimize the impact of failures of individual capacitor units on the remaining capacitor units, however, these types of **protections** do not need to be duplicated:

a. Overvoltage Protection
b. Individual fuses for each capacitor unit
c. Overvoltage Protection for each capacitor units

2.23 Static Var Compensation (SVC) Protection

2.23.1 The low voltage branch circuits contain the reactive controlling equipment, filters, etc. These may include all or some of the following:

a. Thyristor Controlled Reactors (TCR)
b. Thyristor Switched Capacitors (TSC)
c. Switched or Fixed Capacitors
d. Harmonic Filters

2.23.2 **Protection** for the branch circuits that are not part of the **bulk power system** need not be duplicated. **Protection** for these branch circuits should be applied with due consideration for capacitor bank transients, power system voltage unbalance, and system harmonics.

2.23.3 **Protection** against abnormal non-**fault** conditions within the SVC via control of the TSC and TCR valves should be designed so as to not interfere with the proper operation of the SVC.

2.24 Logic System

The design should recognize the effects of contact races, spurious operation due to battery grounds, dc transients, radio frequency interference or other such influences.

It is recognized that timing is often critical in logic schemes. Operating times of different devices vary. Known timing differences should be accounted for in the overall design.

2.25 Microprocessor-Based Equipment and Software

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Appendix A

A **protection system** may incorporate microprocessor-based equipment. Information from this equipment may support other functions such as power system operations. In such cases, the software and the interface should be designed so as to not degrade the **protection system** functions.

2.26 Control Cable, Wiring and Ancillary Control Devices

Control cables and wiring and ancillary control devices should be highly dependable and secure. Due consideration should be given to published codes and standards, fire hazards, current-carrying capacity, voltage drop, insulation level, mechanical strength, routing, shielding, grounding and environment.

2.27 Environment

Means should be employed to maintain environmental conditions that are favorable to the correct performance of **protection systems**.

3.0 Guideline for Application of Remote Access to Protection System

The following guideline is established for the application of remote access to **protection system** Intelligent Electronic Devices (IEDs), such as relays, programmable logic controllers (PLC), and teleprotection equipment that have remote access capabilities, and are designed and configured for remote access applications. It is intended to assist in meeting the requirement stipulated in Section 5.1.3.3 of this Directory, and Section 3.3.1.6 of the *Special Protection System Criteria* (Directory 7).

This guideline assumes that appropriate physical measures are in place, and that they meet all applicable standards.

3.1 Definitions for Use in this Guideline Only

The flowing defined terms are used for illustration of the guideline presented in this Section only. These terms are not defined in Appendix A of this Directory, or any other NPCC documents.

IED - Intelligent Electronic Device, normally computer based, equipped with digital communication abilities, some examples are **protective relays**, RTUs, SERs, DFRs, PLCs, data concentrators, telecommunications equipment, and general monitoring equipment.

PLC - Programmable Logic Controller, used to create and implement logical actions and automation.

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Appendix A

Remote Access - accessing a device from a remote geographical area via a communications link; once accessed, provides similar local device functionality, at a distance.

Authenticate - to prove to be genuine or is an approved user.

Intrusion - An unauthorized electronic entry into an IED. Access normally provides user access to the functionality of the device.

Cryptography – is the study and application of codes and ciphers. Codes or encryption is used to transform data into a form that is not directly usable. Decryption transforms encrypted data using a decryption key back into the original useful form.

VPN – Virtual Private Network. It uses encryption to provide a private channel between private networks using a public network as its carrier i.e., two users using the Internet to provide confidentiality, integrity, and authentication.

3.2 Governing Principles

The industry has become more reliant on computer technology for power **system protection**, control, communications, and automation of its power system. Electromechanical and solid-state technologies are being replaced with microprocessor devices, offering, among other functions, local and remote communications access. **Protection system** IEDs are employed to protect, and or operate power system elements. Unauthorized access to an IED could result in interruption of electric service, damage to the power system equipment, major **disturbances**, or a danger to life and property. **Protection system** IEDs also contain a large amount of information that utility personnel have come to rely on, including telemetry, power system **disturbance** analysis, fault location, preventive maintenance information, as well as asset condition and optimization data. However, this technology has also created vulnerabilities that are similar to those seen in traditional computer networks. Therefore, the following should be the governing principles of any cyber security program:

- Prevent penetration from cyber attacks.
- Prevent local and remote access to critical cyber assets by non-authorized personnel.
- Monitor cyber assets to detect unauthorized access or attempts to access.
- Limit exposure.

3.3 Guideline

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Appendix A

3.3.1 Authentication

One of the foundations of the cyber security program is controlled, or secure, access. This dictates that some form of user authentication be used. Three common means of authenticating a user's identity are:

3.3.1.1 Something the user knows, such as passwords, or IP addresses.

3.3.1.2 Something the user has, such as a key, or cryptographic token.

3.3.1.3 Something the user is, such as fingerprints and voiceprints

At minimum, at least two factors of authentication should be used, e.g., passwords, and a destination – telephone number, or an IP address. The use of more factors such as encryption, etc. will result in providing more secure authentication. However, most present day and legacy **protection system** IEDs do not yet support this technology. Existing equipment often contains some level of security features. At a minimum, they usually provide multi-level passwords. These features should be activated as a first step in security implementation

3.3.2 Substation IED Access Point

A list of all substation IEDs that have remote electronic access configured should be compiled and maintained. This list should also include the access method(s) (e.g., dial-in, WAN, etc), the associated phone numbers and/or IP address, passwords, and other pertinent data.

3.3.3 Approved Remote Access Authorization List

A list of approved users, and the station IEDs they are authorized to access, should be established and maintained. It is vital that all such access information be classified as confidential, and managed as such.

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Appendix A

3.3.4 Remote Access Configuration

Protection system IEDs should be configured to afford remote access only where needed and approved, and then, only when proper authentication is provided.

3.3.5 Password

Most **protection system** IEDs offer multiple access levels, each with separate passwords. Normally, a "view" only level is provided which allows a user to extract and or view information only. An alternate access level is provided to allow trained and authorized users to "make" settings and configuration changes, and initiate breaker operations. It is this level of access that is susceptible to an intrusion which could cause the most damage to the power system. Only limited users should have access to this level by considering the followings:

3.3.5.1 Establish multi-tiered passwords with different privileges for different classes of users.

3.3.5.2 Default passwords should be changed when remote access is configured.

3.3.5.3 Make sure that all IEDs have "strong" passwords, i.e., passwords that are not dictionary words, not easily guessable, not blank, or have no password at all. It is recommended that all passwords contain a combination of letters and numbers, and should be at least six characters long.

3.3.6 Logging/Alarming

When remote connections are used to access the relay beyond "view-only" mode, this should be alarmed and/or logged where possible.

3.3.7 Controlling Authority Approval

For both local and remote communications, excluding viewing, notification and approval of the Controlling Authority should be required to access in-service **protection system** IEDs. Only authorized users, as per Sections 3.3.3 and 3.3.5 above, should have remote access capabilities.

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Appendix A

3.3.8 Disable User Function

Often, **protection system** IEDs are put into service with functions that are not used. These functions can create vulnerabilities, and therefore, should be disabled if possible.

3.4 Other Available Higher Level Authentication Factors and Some General Good Practices

As stated in Section 3.3.1, a minimum of two factors of authentication should be used. However, the use of more factors will result in providing more secure authentication. This Section is intended to provide additional factors and practices that could be implemented where warranted, and where the technology allows.

3.4.1 For WAN based access systems, implement Virtual Private Network (VPN) technology. VPN technology is also applicable when using ISDN, DSL, and cable.

3.4.2 Limit, as far as possible, dependence on the public telephone network for substation communications to IEDs. Instead, use secure communications facilities whenever possible.

3.4.3 Call back (where the IED device or modem hangs up on the original caller and calls back on a second line to a preconfigured phone number) may be utilized as a portion of an IED's security to prevent unauthorized access. This security measure added to other security measures will improve the IEDs security. Security can be further enhanced by using a different telephone line for the return call.

3.4.4 For dial-up modem access, use a hardware lock and key dongle on the analog phone line at each modem and the lock and key combination will act as a gatekeeper. When a call is initiated, the lock at the called modem will verify the existence of a valid key at the calling modem Time.

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Appendix A

3.4.5 Isolation from the Business/Corporate Network

Isolation of the substation **protection system** IEDs from the Corporate Network should be provided where possible. Data can be transferred from the substation IEDs to a server connected to a Corporate Network via appropriate firewalls. This practice is warranted because most Corporate Networks are Internet connected and therefore are exposed to external users.

4.0 Procedure for Reporting New and Revised **Protection Systems**

Paragraph 7.1 of this criteria states that **Protection system** owners shall provide the Task Force on System Protection (TFSP) with advance notification of any of their new **bulk power system protection** facilities, or significant changes in their existing **bulk power system protection** facilities. Paragraph 7.2 of this criteria states that **Protection system** owners shall also provide the TFSP with advance notification of non-member **protection** facilities as required per NPCC Bylaws . Notification will be made to the TFSP early in the engineering design stage.

4.1 Additional Requirements for Presentation and Review

4.1.1 A presentation will be made to the TFSP on new facilities or a modification to an existing facility when requested by either a member entity or the TFSP.

4.1.2 A presentation will be made to the TFSP when the design of the **protection** facility deviates from the criteria set forth in this Directory.

4.1.3 A presentation will be made to the TFSP when a member entity is in doubt as to whether a design meets the **protection** criteria set forth in this Directory.

4.2 Data Required for Presentation and Review of Proposed Protection Facilities

4.2.1 The **protection system** owner will advise the TFSP of the basic design of the proposed system. The data will be supplied on the "Protection System Review Forms" (formerly C-22 forms) as listed below, accompanied by a geographical map, a one-line diagram of all affected areas, and the associated **protection** and control function diagrams. A physical layout of **protection** panels and batteries for the purpose of illustrating physical separation will also be included.

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Appendix A

Protection System Details
Line Relaying (Phase)
Line Relaying (Ground)
Transformer/Reactor Relaying
Generator Relaying
Bus Relaying
Shunt Capacitors and Filters Relaying
HVdc Converter Relaying
Special Protection Systems
Communication links
Equipment Details
Current Transformers
Voltage Transformers
Station Battery
Physical Separation
Breakers
Disturbance Monitoring Equipment
Transmission Relay Loadability
Exception Request

4.2.2 The proposed **protection system** will be explained with due emphasis on any special conditions or design restrictions existing on the particular power system.

4.3 Procedure for Presentation

4.3.1 The **protection system** owner will arrange to have a technical presentation made to the TFSP

4.3.2 To facilitate scheduling, the chairman of the TFSP will be notified approximately four months prior to the desired date of presentation.

4.3.3 Copies of materials to be presented will be distributed to TFSP members 30 days prior to the date of the presentation.

4.4 TFSP Procedures

4.4.1 The TFSP will review the material presented and develop a position statement concerning the proposed **protection system**. This statement will indicate one of the following:

4.4.1.1 The need for additional information to enable the TFSP to reach a decision.

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Appendix A

4.4.1.2 Acceptance of the member statement of conformance to the Protection Criteria.

4.4.1.3 Acceptance of the submitted proposal

4.4.1.4 Conditional acceptance of the submitted proposal*.

4.4.1.5 Rejection of the submitted proposal*.

* Position Statements 4.4.1.4 and 4.4.1.5 will include an indication of areas of departure from the intent of the **protection** criteria and suggestions for modifications to bring the **protection system** into conformance with the NPCC criteria.

4.4.2 The results of the TFSP review will be documented in the following manner:

4.4.2.1 A position statement will be included in the minutes of the meeting at which the proposed **protection system** was reviewed.

4.4.2.2 If necessary, a letter outlining areas of nonconformance with the **protection** criteria stipulated in this Directory and recommendations for correction will be submitted to the **protection system** owner. If necessary, the matter will be brought to the attention of the RCC.

4.4.2.3 The Task Force will maintain a record of all the reviews it has conducted.

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NPCC
Regional Reliability Reference Directory # 7
Special Protection Systems

Task Force on System Protection Revision Review Record
December 27, 2007

Adopted by the Members of the Northeast Power Coordinating Council Inc., this December 27, 2007, based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 and as amended to date.

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Introduction

1.1 Title Special Protection Systems

1.2 Directory Number 7

1.3 Objective

Provide the basic criteria for **Special Protection Systems** such that the **Bulk Power System** in NPCC Inc. member **Areas** is operated reliably.

1.4 Effective Date Immediately upon Approval by the NPCC Full Members

1.5 Background

This directory establishes the basic **protection** criteria for **Special Protection Systems**. It is not intended to be a design specification. It is recognized that responsible entities in certain **Areas** may choose to apply more rigid criteria because of local considerations.

Guidance for consideration in the implementation of these criteria is provided in Appendix A, and the procedure for reviewing new and revised **Special Protection Systems** is provided in Appendix B.

1.6 Applicability

1.6.1 Functional Entities

Transmission Owner, Generator Owner, Distribution Provider

1.6.2 Facilities

1.6.2.1 New Facilities

The standard requirements and criteria stipulated in this Directory apply to all new Type I and Type II **Special Protection Systems** (SPSs) as defined below. In the application of Type II SPSs, their security is the prime concern (see Section 3.3.1 of this document). As such, Sections 3.3.1.1, 3.3.2.3, 3.3.3.2, 3.3.6 and 3.3.8.1 in this document do not apply to Type II.

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1.6.2.2 Existing Facilities

It is the responsibility of individual Transmission Owners (TO), Generator Owners (GO) and Distribution Providers (DP) to assess their existing **Special Protection Systems** and to make modifications which are required to meet the intent of these standards as follows:

a. Planned Renewal or Upgrade to Existing Facilities It is recognized that there may be **SPSs,** which existed prior to each TO's, GO's and DP's adoption of the *Special Protection System Criteria* that do not meet these criteria. If any **Special Protection Systems** or sub-systems of these facilities are replaced as part of a planned renewal or upgrade to the facility and do not meet all of these criteria, then an assessment shall be conducted for those criteria that are not met. The result of this assessment shall be reported on TFSP Form #1-5.

b. SPS Re-classified to Type I or Type II

These requirements apply to all existing SPSs which are reclassified as Type I or Type II due to system changes. A mitigation plan shall be required to bring such a SPS into compliance with these criteria.

c. In-kind Replacement of SPS Equipment

If SPS equipment is replaced "in-kind" as a result of an un-planned event, then it is not required to upgrade the associated protection system to comply with these criteria.

1.6.3 Classification of **Special Protection Systems**

Special Protection Systems are sub-divided into three types. Reference can be made to the NPCC *Basic Criteria for Design and Operation of Interconnected Power Systems* (Document A-2) where design criteria contingencies are described in Section 5.0; operating criteria contingencies, in Section 6.0; and extreme contingencies, in Section 7.0 of Document A-2.

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Type I	A **Special Protection System** which recognizes or anticipates abnormal system conditions resulting from design and operating criteria **contingencies**, and whose misoperation or failure to operate would have a **significant adverse impact** outside of the local area. The corrective action taken by the **Special Protection System** along with the actions taken by other **protection systems** are intended to return power system parameters to a stable and recoverable state.
Type II	A **Special Protection System** which recognizes or anticipates abnormal system conditions resulting from extreme **contingencies** or other extreme causes, and whose misoperation or failure to operate would have a **significant adverse impact** outside of the local area.
Type III	**Special Protection System** whose misoperation or failure to operate results in no **significant adverse impact** outside the local area. The practices contained in this document for a Type I SPS should be considered but are not required for a Type III SPS. It should be recognized that a Type III SPS may, due to system changes, become Type I or Type II.

2.0 Terms Defined in this Directory

The following terms are defined in this Directory. Their definitions are provided in Attachment 1.

Bulk Power System
Contingency
Fault
Operating Procedures
Protection
Special Protection System (SPS)
Teleprotection

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3.0 Requirements

3.1 The NERC ERO Reliability Standards containing Requirements that are associated with this Directory include, but may not be limited to:

3.1.1 PRC-012-0 — Special Protection System Review Procedure

3.1.2 PRC-013-0 Special Protection System Database

3.1.3 PRC-014-0 — Special Protection System Assessment

3.1.4 PRC-015-0 — Special Protection System Data and Documentation

3.1.5 PRC-016-0 — Special Protection System Misoperations

3.1.6 PRC-017-0 - Special Protection System Maintenance and Testing

3.2 NPCC Regional Reliability Standard Requirements

None at this time. To be developed.

3.3 NPCC "Full Member", More Stringent Criteria

3.3.1 General Criteria

A **Special Protection System** shall be designed to recognize or anticipate the specific power system conditions associated with the intended function.

Due consideration shall be given to dependability and security. The relative effect on the **bulk power system** of a failure of an SPS to operate when desired versus an unintended operation shall be weighed carefully in selecting design parameters as follows:

3.3.1.1 To enhance dependability, a **Special Protection System** shall be designed with sufficient redundancy such that the **Special Protection System** is capable of performing its intended function while itself experiencing a single failure.

3.3.1.2 Multiple protection groups that are used to obtain redundancy within a **Special Protection System** shall not share the same component.

3.3.1.3 A **Special Protection System** shall be designed to avoid false operation while itself experiencing a credible failure.

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3.3.1.4 The thermal capability of all **Special Protection System** components shall be adequate to withstand the maximum short time and continuous loading conditions to which the associated power system elements may be subjected.

3.3.1.5 Communication link availability, critical control switch and test switch positions, and trip circuit integrity, shall be monitored to allow prompt attention by appropriate operating authorities.

3.3.1.6 When remote access to **Special Protection Systems** is possible, the design shall include security measures to minimize the probability of unauthorized access to the **Special Protection System**.

3.3.1.7 An SPS shall be designed to take corrective action within times determined by studies with due regard to security, dependability and selectivity.

3.3.1.8 Status of SPS arming shall be monitored to allow prompt attention by appropriate operating authorities.

3.3.1.9 An SPS shall be equipped with means to enable its arming and to independently verify the arming.

3.3.2 Current Transformer Criteria

Current transformers (CTs) associated with **Special Protection Systems** shall have adequate steady-state and transient characteristics for their intended function.

3.3.2.1 The output of each current transformer secondary winding shall be designed to remain within acceptable limits for the connected burdens under all anticipated currents, including **fault** currents, to ensure correct operation of the **Special Protection System**.

3.3.2.2 The thermal and mechanical capabilities of the CT at the operating tap shall be adequate to prevent damage under maximum **fault** conditions and normal or **emergency** system loading conditions.

3.3.2.3 For **protection groups** to be independent, they shall be supplied from separate current transformer secondary windings.

3.3.2.4 Interconnected current transformer secondary wiring shall be grounded at only one point.

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3.3.3 Voltage Transformer and Potential Device Criteria

Voltage transformers and potential devices associated with **Special Protection Systems** shall have adequate steady-state and transient characteristics for their intended functions.

3.3.3.1 Voltage transformers and potential devices shall have adequate volt-ampere capacity to supply the connected burden while maintaining their **relay** accuracy over their specified primary voltage range.

3.3.3.2 If a **Special Protection System** is designed to have multiple **protection groups** at a single location for redundancy, each of the **protection groups** shall be supplied from separate voltage sources. The **protection groups** may be supplied from separate secondary windings on one transformer or potential device, provided all of the following requirements are met:

. Complete loss of one or more phase voltages does not prevent operation of both SPS protection groups;
. Each secondary winding has sufficient capacity to permit fuse **protection** of the circuit;
. Each secondary winding circuit is adequately fuse protected.

3.3.3.3 The wiring from each voltage transformer secondary winding shall not be grounded at more than one point.

3.3.3.4 Voltage transformer installations should be designed with due regard to ferroresonance.

3.3.4 Battery and Direct Current (dc) Supply Criteria

dc supplies associated with a **Special Protection System** shall be designed to have a high degree of dependability as follows.

3.3.4.1 If a **Special Protection System** is designed to have multiple **protection groups** at a single location for redundancy, no single battery or dc power supply failure shall prevent the independent **protection groups** from performing the intended function. Each battery shall be provided with its own charger.

3.3.4.2 Each battery shall have sufficient capacity to permit operation of the **Special Protection System**, in the event of a loss of its battery charger or the ac supply source, for the period of time necessary to transfer the load to

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the other battery or re-establish the supply source.

3.3.4.3 The battery chargers and all dc circuits shall be protected against short circuits. All protective devices should be coordinated to minimize the number of dc circuits interrupted.

3.3.4.4 dc battery systems shall be continuously monitored to detect abnormal voltage levels (both high and low), dc grounds, and loss of ac to the battery chargers in order to allow prompt attention by the appropriate operating authorities.

3.3.4.5 **Special Protection System** dc supply circuits shall be continuously monitored to detect loss of voltage in order to allow prompt attention by the appropriate operating authorities.

3.3.5 Station Service ac Supply Criteria

If a **Special Protection System** is designed to have multiple **protection groups** at a single location for redundancy, there shall be two sources of station service ac supply, each capable of carrying at least all the critical loads associated with the **Special Protection System**.

3.3.6 Circuit Breakers Criteria

Where **Special Protection System** redundancy is achieved by use of independent **protection groups** tripping the same circuit breakers without overarming, each circuit breaker shall be equipped with two independent trip coils.

3.3.7 Teleprotection Criteria

Communication facilities required for **teleprotection** shall be designed to have a level of performance consistent with that required of the **Special Protection System**, and shall meet the following:

3.3.7.1 Where the design of a **Special Protection System** is composed of multiple **protection groups** for redundancy and each group requires a communication channel, the equipment and channel for each group shall be separated physically and designed to minimize the risk of more than one **protection group** being disabled simultaneously by a single event or condition.

3.3.7.2 **Teleprotection** equipment shall be monitored to detect loss of equipment and/or channel to allow prompt attention by the appropriate operating authorities.

3.3.7.3 **Teleprotection** systems shall be designed to assure adequate signal transmission

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during **bulk power system** disturbances, and shall be provided with means to test for proper signal adequacy.

3.3.7.4 **Teleprotection** equipment shall be powered by the substation batteries or other sources independent from the power system.

3.3.7.5 Except as identified otherwise in these criteria, the two **teleprotection** groups shall not share the same component. The use of a single communication tower for the radio communication systems used by the two SPS groups is permitted.

3.3.8 Physical Separation/Environment Criteria

3.3.8.1 In addition to the physical separation as referenced in sections 3.3.1.2 and 3.3.9.5, if a **Special Protection System** is designed to have multiple **protection groups** at a single location for redundancy, each separate protection group and **Teleprotection** of an SPS shall be on different non-adjacent vertical mounting assemblies or enclosures.

3.3.8.2 In the event a common raceway is used, cabling for separate groups of an SPS shall be separated by a fire barrier.

3.3.9 Grounding Criteria

Station grounding is critical to the correct operation of **Special Protection Systems**. The design of the ground grid directly impacts proper **Special Protection System** operation and probability of false operation from **fault** currents or transient voltages.

3.3.9.1 Each TO, GO and DP shall have established as part of its substation design procedures or specifications, a mandatory method of designing the substation ground grid, which:

. Can be traced to a recognized calculation methodology
. Considers cable shielding
. Considers equipment grounding

3.3.10 Provision for Breaker Failure Criteria

Type I SPS shall include breaker failure **protection** for each circuit breaker whose operation is critical to the adequacy of the action taken by the SPS with due regard to the power system conditions this SPS is required to detect. Options for breaker failure **protection**:

3.3.10.1 A design which recognizes that the breaker has not achieved or will not achieve the

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intended function required by the **Special Protection System** and which takes independent action to achieve that function. This provision needs not be duplicated and can be combined with conventional breaker failure schemes if appropriate.

3.3.10.2 Overarming the **Special Protection System** such that adequate action is taken even if a single breaker fails.

3.3.10.3 The redundancy afforded by actions taken by other independent schemes or devices.

3.3.11 Testing and Maintenance Criteria

3.3.11.1 Each SPS shall be maintained in accordance with the Maintenance Criteria for Bulk Power System Protection (Document A-4).

3.3.11.2 The design of an SPS both in terms of circuitry and physical arrangement shall facilitate periodic testing and maintenance.

3.3.11.3 Test facilities or test procedures shall be designed such that they do not compromise the independence of the redundant design aspects of the SPS.

3.3.11.4 An SPS shall be functionally tested when initially placed in service and when modifications are made.

3.3.11.5 If a segmented testing approach is used, test procedures and test facilities shall be designed to ensure that related tests properly overlap. Proper overlap is ensured if each portion of circuitry is seen to perform its intended function, such as operating a relay, from either a real or test stimulus, while observing some common reliable downstream indicator.

3.3.11.6 All positive combinations of input logic shall be tested regardless of the maintenance strategy used.

3.3.11.7 Sufficient testing shall be employed to ensure that timing races do not exist within hardwired or electronic logic, and that the SPS operating time is within design limits.

3.3.11.8 Each time the SPS is maintained, its hardware shall be tested in conjunction with the control facilities, related computer equipment, software and **operating procedures** to ensure compatibility and correct operation.

3.3.12 Analysis of SPS Performance

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3.3.12.1 **Bulk power system** automatic operations shall be analyzed to determine proper **Special Protection System** performance. Corrective measures must be taken promptly if the **Special Protection System** or a **protection group** within the SPS fails to operate or operates incorrectly.

3.3.12.2 Event recording capability shall be provided to permit analysis of system operations and **Special Protection System** performance.

4.0 Measures and Assessments

None developed at this time.

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Prepared by:	Lead Task Force- Task Force on System Protection
Review and Approval:	Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45 day review and comment period. Upon satisfactorily addressing all the comments in this forum, the Directory document will be sent to the remaining Task Forces for their recommendation to seek RCC approval. Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC Inc. Bylaws" in effect at the time the ballots are cast. Revisions pertaining to the Appendices or any other portion of the document such as Links, Glossary Terms, etc., will only require RCC Member approval of the document. Errata may be corrected by the Lead Task Force at any time and provide the appropriate notifications to the NPCC Inc. membership. This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC Regional Reliability Standards and other NPCC documents.
References:	NPCC RRS PRC-XXX-X (Future NPCC Regional Standard) Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2) Emergency Operation Criteria (Document A-3) Maintenance Criteria for Bulk Power System Protection (Document A-4) NPCC Glossary of Terms (Document A-7)

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Attachment 1
Definition of Terms

Bulk power system - The interconnected electrical systems within northeastern North America comprising **generation** and transmission facilities on which **faults** or **disturbances** can have a **significant adverse impact** outside of the local area. In this context, local areas are determined by the Council members.

Contingency – An event, usually involving the loss of one or more **elements,** which affects the **power** system at least momentarily.

Fault – An electrical short circuit.

Permanent Fault — A fault which prevents the affected **element** from being returned to service until physical actions are taken to effect repairs or to remove the cause of the fault.

Transient Fault — A fault which occurs for a short or limited time, or which disappears when the faulted **element** is separated from all electrical sources and which does not require repairs to be made before the **element** can be returned to service either manually or automatically.

Operating Procedures -A set of policies, practices, or system adjustments that may be automatically or manually implemented by the system operator within a specified time frame to maintain the operational integrity of the interconnected electric systems.

Automatic Operating Systems — **Special protection systems**, remedial action schemes, or other operating systems installed on the electric systems that require *no intervention* on the part of **system operators**.

Normal (Precontingency) Operating Procedures — Operating procedures that are normally invoked by the **system operator** to alleviate potential facility overloads or other potential system problems in anticipation of a **contingency**.

Postcontingency Operating Procedures — Operating procedures that may be invoked by the **system operator** to mitigate or alleviate system problems after a **contingency** has occurred.

Protection -The provisions for detecting power system **faults** or abnormal conditions and taking appropriate automatic corrective action.

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Protection group — A fully integrated assembly of **protective relays** and associated equipment that is designed to perform the specified protective functions for a power system **element**, independent of other groups.

Notes:

(a) Variously identified as Main **Protection**, Primary **Protection**, Breaker Failure **Protection**, Back-Up **Protection**, Alternate **Protection**, Secondary **Protection**, A **Protection**, B **Protection**, Group A, Group B, System 1 or System 2.

(b) Pilot **protection** is considered to be one **protection group.**

Protection system

Element Basis

One or more **protection** groups; including all equipment such as instrument transformers, station wiring, circuit breakers and associated trip/close modules, and communication facilities; installed at all terminals of a power system **element** to provide the complete **protection** of that **element**.

Terminal Basis

One or more **protection** groups, as above, installed at one terminal of a power system **element**, typically a transmission line.

Pilot **Protection** — A form of line **protection** that uses a communication channel as a means to compare electrical conditions at the terminals of a line.

Significant adverse impact — With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from **faults** or **disturbances**, shall be deemed as having **significant adverse impact**:

a. instability;
. any instability that cannot be demonstrably contained to a well defined local area.
. any loss of synchronism of generators that cannot be demonstrably contained to a well-defined local area

b. unacceptable system dynamic response;
. an oscillatory response to a **contingency** that is not demonstrated to be clearly positively damped within 30 seconds of the initiating event.

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c. unacceptable equipment tripping
- tripping of an un-faulted **bulk power system** element (element that has already been classified as **bulk power system**) under planned system configuration due to operation of a **protection** system in response to a stable power swing
- operation of a Type I or Type II **Special Protection System** in response to a condition for which its operation is not required

d. voltage levels in violation of applicable **emergency** limits;

e. loadings on transmission facilities in violation of applicable **emergency** limits;

Special protection system (SPS) – A **protection system** designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted **elements**. Such action may include changes in **load**, **generation**, or system configuration to maintain system **stability**, acceptable voltages or power flows. Automatic underfrequency **load shedding** as defined in the *Emergency Operation Criteria* A-3, is not considered a **Special Protection System**. Conventionally switched, locally controlled shunt devices are not **Special Protection Systems**.

Teleprotection - A form of **protection** that uses a communication channel

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Appendix A
Guidance for Consideration in SPS Design

Introduction

This Appendix provides the guidance for consideration in the implementation of the **Special Protection System** design criteria stipulated in Section 3.3 of this Directory.

The general objective for any SPS is to perform its intended function (generator rejection, load rejection, etc.) in a dependable and secure manner. In this context, dependability relates to the degree of certainty that the SPS will operate correctly when required to operate. Security relates to the degree of certainty that the SPS will not operate when not required to operate.

The relative effects on the **bulk power system** of a failure to operate when desired versus an unintended operation should be weighed carefully in selecting design parameters. For example, the choice of duplication as a means of providing redundancy improves the dependability of the SPS but can also jeopardize security in that it may increase the probability of an unintended operation. This general objective can be met only if the SPS can dependably respond to the specific conditions for which it is intended to operate and differentiate these from other conditions for which action must not take place.

Close coordination should be maintained among system planning, design, operating, maintenance and **protection** functions, since both initially and throughout their life cycle, SPSs are a multi-discipline concern.

2.0 Considerations Affecting Dependability

2.1 Redundancy is normally provided by duplication. Some aspects of duplication may be achieved by overarming, which is defined as providing for more corrective action than would be necessary if no failures are considered. The redundancy requirements for an SPS apply only with respect to its response to the conditions it is required to detect.

2.2 For a **Special Protection System** that is composed of multiple **protection groups**, the risk of simultaneous failure of more than one **protection group** because of design deficiencies or equipment failure should be considered, particularly if identical equipment is used in each **protection group**. The extent and nature of these failures should be recognized in the design and operation of the **Special Protection System.**

2.3 Area of common exposure should be kept to a minimum to reduce the possibility of all groups being disabled by a single event such as fire, evacuation, water leakage, and other such incidents.

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3.0 Considerations Affecting Security

3.1 An SPS should be designed to operate only for conditions which require its specific protective or control actions.

3.2 **Special Protection Systems** should be no more complex than required for any given application.

3.3 The components and software used in **Special Protection Systems** should be of proven quality, as demonstrated either by actual experience or by stringent tests under simulated operating conditions.

3.4 **Special Protection Systems** should be designed to minimize the possibility of component failure or malfunction due to electrical transients and interference or external effects such as vibration, shock and temperature

3.5 **Special Protection Systems**, including intelligent electronic devices (IEDs) and communication systems used for **protection**, should comply with applicable industry standards for utility grade **protection** service. Utility Grade **Protection** System Equipment are equipment that are suitable for protecting transmission power system elements, that are required to operate reliably, under harsh environments normally found at substations. Utility grade equipment should meet the applicable sections of all or some of the following types of industry standards, to ensure their suitability for such applications:

- IEEE C37.90.1-2002 (oscillatory surge and fast transient)
- IEEE C37.90.1-2002 (service conditions)
- IEC 60255-22-1, 2005 (1 MHz burst, i.e. oscillatory)
- IEC 61000-4-12, 2001 (oscillatory surge)
- IEC 61000-4-4, 2004 (EFT)
- IEC 60255-22-4, 2002 (EFT)
- IEEE C37.90.2-2004 (narrow-band radiation)
- IEC 60255-22-3, 2000 (narrow-band radiation)
- IEC 61000-4-3, 2002 (narrow-band radiation)
- IEEE 1613 (communications networking devices in Electric power Substations)

3.6 **Special Protection System** circuitry and physical arrangements should be carefully designed so as to minimize the possibility of incorrect operations due to personnel error.

3.7 **Special Protection System** automatic self-checking facilities should be designed so as to not degrade the performance of the **Special Protection System**.

3.8 Consideration should be given to the consequences of loss of instrument transformer voltage inputs to **Special Protection Systems**.

3.9 Consideration should be given to the effect of the means of arming on overall security and dependability of the **Special Protection System**. Arming should have a level of security and dependability commensurate with the requirements of the SPS.

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4.0 Considerations Affecting Performance

4.1 Control Cable, Wiring and Ancillary Control Device

Control cables and wiring and ancillary control devices should be highly dependable and secure. Due consideration should be given to published codes and standards, fire hazards, current-carrying capacity, voltage drop, insulation level, mechanical strength, routing, shielding, grounding and environment.

4.2 Environment

Means should be employed to maintain environmental conditions that are favorable to the correct performance of **Special Protection Systems.**

5.0 Operating Time of an SPS

Adequate time margin should be provided taking into account study inaccuracies, differences in equipment, and **protection** operating times.

6.0 Arming of an SPS

Arming is the selection, which may be external to the **Special Protection System**, of desired output action based on power system conditions and recognized contingencies. Arming requirements of a Special Protection System are normally based upon the results of system studies which take into account recognized contingencies, operating policies/procedures and current power system load/generation conditions. For a simple **Special Protection System**, arming may be an on/off function. A **Special Protection System** can be armed either automatically or manually.

6.1 Automatic arming is implemented without human intervention.

6.2 Arming manually if the recognition, decision or implementation requires human intervention. Sufficient time with adequate margin for recognition, analysis and the taking of corrective action should be allowed.

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7.0 Maintenance Considerations

7.1 Additional periodic maintenance is recommended on the following **protection** equipment:

- On continuously monitored analog **teleprotection** channels, verify signal adequacy every twelve months.
- On non-monitored analog **teleprotection** channels, verify signal adequacy every month.
- On digital **teleprotection** systems, which are inherently monitored, verify local function every two years.
- On batteries and chargers, verify proper operation and general condition every month.
- On circuit breakers, verify ability to trip via each trip coil every two years, with due regard to critical trip paths between sensing relays and the breaker trip coils.

7.2 It is the responsibility of each TO, GO and DP to evaluate its own particular circumstances and determine if any additional maintenance should be performed on its system. More extensive maintenance may be required but not limited to:

- during the initial break-in period,
- where **protection** systems are exposed to abnormal conditions such as temperature extremes, vibration, corrosive atmosphere, etc.,
- when the operating condition of **protection** system control wiring is suspect..

7.3 The design of a **Special Protection System** both in terms of circuitry and physical arrangement should facilitate periodic testing and maintenance in a manner that mitigates the risk of inadvertent operation. As a **Special Protection System** may be complex and may interface with other protection systems or control systems, special attention should be placed on ensuring that test devices and test interfaces properly support a clearly defined maintenance strategy.

7.4 Proper overlap is ensured if each portion of circuitry is seen to perform its intended function, such as operating a relay, from either a real or test stimulus, while observing some common reliable downstream indicator.

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7.5 Whenever practicable, some of the maintenance testing requirements may be met by analyzing and documenting the detailed performance of the **Special Protection System** during actual events to demonstrate that the specific testing requirements have been fulfilled. Such an approach can reduce the probability of false operation during maintenance while effectively reducing the extent of planned maintenance.

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Appendix B
Procedure for Review of Special Protection Systems

Introduction

This Appendix provide the procedure to follow to obtain concurrence from NPCC if an entity concludes that a new **Special Protection System** or a modification of an existing **Special Protection System** will be required which affects the **bulk power system**. The procedure is also shown on the attached flow chart.

2.0 NPCC Review and Concurrence

2.1 Allowing for sufficient lead time to ensure an orderly review, the entity will notify the chairman of the Task Force on Coordination of Planning (TFCP) of its proposal to install a new **Special Protection System** or modify an existing **Special Protection System**. The entity will send copies of the complete notification to TFCO and TFSP. This notification will include statements that describe possible failure modes and whether misoperation, unintended operation or failure of the **Special Protection System** would have local, inter-company, inter-**Area** or inter-Regional consequences, when the **Special Protection System** is planned for service, how long it is expected to remain in service, the specific **contingency**(s) for which it is designed to operate and whether the **Special Protection System** will be designed according to the NPCC *Bulk Power System Protection Criteria* (Document A-5) and the *Special Protection System Criteria* and Standards requirements listed in this docment.

2.2 If the **Special Protection System** is expected to have only local consequences, TFCP will request that the Task Force on System Studies (TFSS) and the Task Force on System Protection (TFSP) review the proposal.

2.2.1 TFSP will be notified of the proposed **Special Protection System**. TFSP will advise TFCP of any concerns.

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2.2.2 TFSS will review the analyses that the proposing entity has performed. A presentation may be required from the proposing entity. The purpose of the review will be to confirm that there are no adverse inter-**Area** or inter-Regional consequences of either a failure of the **Special Protection System** to operate when and how it is required or an inadvertent or unintended operation of the **Special Protection System**. If necessary, TFSS will request that the proposing entity conduct additional analyses.

2.2.3 If the TFSS review confirms the **Special Protection System** has only local consequences, TFSS will send the information to TFCP. If TFCP concurs, they will then notify the proposing entity of NPCC's conclusions that the **Special Protection System** has only local consequences. TFCP will also notify the Reliability Coordinating Committee (RCC), all the Task Forces, the Compliance Committee (CC), the proposing entity and other Members that concurrence has been given to the proposing entity to modify an existing **Special Protection System** or install a new **Special Protection System**, at which time, the **Special Protection System** may be deployed.

2.2.4 If the TFSS review concludes that the **Special Protection System** could have inter-**Area** or inter-Regional consequences, they will inform the TFCP. Upon receipt of the TFSS conclusion or if TFCP separately determines the **Special Protection System** could have inter-**Area** or inter-Regional consequences, TFCP will arrange for an overall NPCC review as detailed in Step 3.

2.2.5 TFSS will update the NPCC **Special Protection System** list/database.

2.3 If the proposing entity expects the **Special Protection System** to have inter-**Area** or inter-Regional consequences, or if the TFSS or TFCP review concludes this to be the case, TFCP will request the Task Force on Coordination of Operation (TFCO), the Task Force on System Protection (TFSP) and TFSS to review it. Each of the Task Forces may require a presentation from the proposing entity.

2.3.1 TFSP will confirm the failure modes of the **Special Protection System**, including actions of back-up **protection**, and whether or not the **Special Protection System** complies with NPCC system **protection** standards. TFSP will review whether the new or modified **Special Protection System** is in conformance with the NPCC *Bulk Power System Protection Criteria* (Document A-5) and the *Special*

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Protection System Criteria and Standards requirments listed in this document and forward a summary of their findings to TFCO, TFCP and TFSS. This summary will include a statement as to whether the **Special Protection System** is in conformance with the *Bulk Power System Protection Criteria* (Document A-5) and the *Special Protection System Criteria* and Standards requirments listed in this document and whether the Task Force has any objections to its modification or installation.

2.3.2 TFSS will review the analysis that the proposing entity has performed. The purpose of the review will be to assess the **Special Protection System** is in conformance with the *Basic Criteria for Design and Operation of Interconnected Power Systems* (Document A-2) and to determine the inter-**Area** or inter-Regional consequences of either a failure of the **Special Protection System** to operate when and how it is required or an inadvertent or unintended operation of the **Special Protection System**. If necessary, TFSS will request that the proposing entity conduct additional studies. When their review is completed, TFSS will forward a summary of their findings to TFCO, TFCP and TFSP. This summary will include a statement as to whether the **Special Protection System** is in conformance with the *Basic Criteria* (A-2) and whether the Task Force has any objections to its modification or installation.

2.3.3 TFCO will review the operability of the **Special Protection System** and forward a summary of their findings to TFCP, TFSS and TFSP. This summary will include a statement as to whether the Task Force has any objections to its modification or installation.

2.3.4 TFCP will prepare an overall summary for the RCC. This summary will include the findings of the other Task Forces and whether there are any objections to the modification of the existing **Special Protection System** or the installation of the new **Special Protection System** and as a minimum, include the following information:

. Function, i.e. GR-generation rejection etc.
. Identification
. Initiating condition
. Action(s) resulting
. Name of the **Special Protection System**, and owner, identification number
. Arming, i.e. percentage of time, system conditions for which it's needed, manual vs. automatic, etc.
. Reason for the installation
. Comments, explanations, such as "temporary until such time…"
. Company, owner
. SPS Number, drawn by NPCC staff
. Current Status, i.e. New, Changed or Removed
. Type Determination

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- Determinations of the Task Forces' analyses
- Consequences of operation, misoperation and failure to operate
- Approximate of load or generation rejected by **Special Protection System** operation
- Proposed date of deployment
- Proposed date of retirement/deactivation

2.3.5 The RCC will review the summary report and act on the proposal to modify an existing **Special Protection System** or install a new **Special Protection System**. The RCC may also remand the review of the **Special Protection System** back to the TFCP if further analyses are determined to be needed.

2.3.6 The TFCP will notify the RCC, all the Task Forces, the CC, the proposing entity and other Members of the outcome of the review. Upon NPCC approval of the type and compliance with Criteria, the **Special Protection System** may be deployed.

2.3.7 The TFSS will then update the NPCC **Special Protection System** list/database.

3.0 Presentation and Review of Special Protection Systems

Each new or modified Type I or Type II **Special Protection System** shall be reported to the Task Force on System Protection in accordance with the following presentation and review procedure.

3.1 A presentation will be made to the TFSP on new facilities or a modification to an existing facility when requested by an NPCC Member or the TFSP.

3.2 A presentation will be made to the TFSP when the design of the **protection** facility deviates from the *Bulk Power System Protection Criteria* (Document A-5).

3.3 A presentation will be made to the TFSP when an NPCC Member is in doubt as to whether a design meets the *Protection Criteria*.

3.4 Data Required for Presentation and Review of Proposed **Special Protection System:**

3.4.1 The TO, GO or DP will advise the TFSP of the basic design of the proposed system. The data will be supplied on the attached forms, accompanied by a geographical map, a one-line diagram of all affected areas, and the associated **protection** and control function diagrams. A physical layout of **protection** panels and batteries for the purpose of illustrating physical separation will also be included.

3.4.2 The proposed **protection** system will be explained with due emphasis on

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any special conditions or design restrictions existing on the particular power system:

3.5 Procedure for Presentation:

3.5.1 The TO, GO or DP will arrange to have a technical presentation made to the TFSP.

3.5.2 To facilitate scheduling, the chairman of the TFSP will be notified approximately four months prior to the desired date of presentation.

3.5.3 Copies of materials to be presented will be distributed to TFSP members 30 days prior to the date of the presentation.

3.6 Review by TFSP

The TFSP will review the material presented and develop a position statement concerning the proposed **protection** system. This statement will indicate one of the following:

3.6.1 The need for additional information to enable the TFSP to reach a decision.

3.6.2 Acceptance of the TO, GO or DP statement of conformance to the *Protection Criteria*.

3.6.3 Acceptance of the submitted proposal.

3.6.4 *Conditional acceptance of the submitted proposal.

3.6.5 *Rejection of the submitted proposal

* Position Statements to include an indication of areas of departure from the intent of the *protection criteria* and suggestions for modifications to bring the **protection** system into conformance with the NPCC criteria.

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3.6.6 The results of the TFSP review will be documented in the following manner.

. A position statement will be included in the minutes of the meeting at which the proposed **protection** system was reviewed.
. If necessary, a letter outlining areas of nonconformance with the NPCC *Protection Criteria* and recommendations for correction will be submitted to the TO, GO or DP.
. The Task Force will maintain a record of all the reviews it has conducted.

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PROCEDURE FOR NPCC REVIEW OF NEW OR MODIFIED BULK POWER SYSTEM SPECIAL PROTECTION SYSTEMS (SPS)

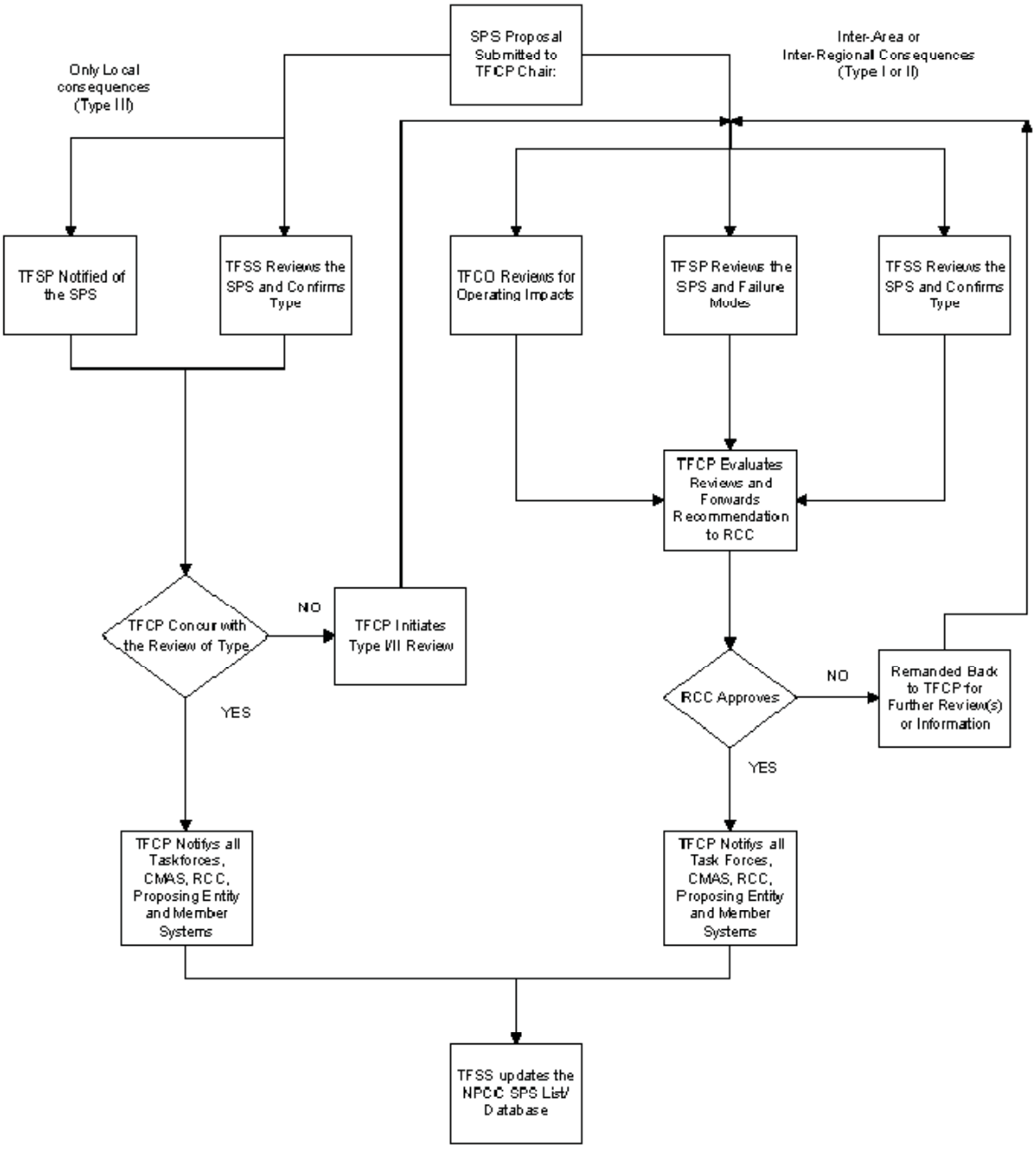

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NPCC, Inc.

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NPCC
Regional Reliability Reference Directory # 8
System Restoration

Task Force on Coordination of Operations Revision Review Record:
October 21, 2008

Adopted by the Members of the Northeast Power Coordinating Council, Inc. this October 22, 2008, based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

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Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	10/21/08	Effective Date	New
1	1/30/09	Sect. 3.1 & 3.2 updated current Version of NERC Standards EOP-005 &EOP-006	Errata

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Appendix A

Appendix B

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1.0 Introduction

1.1 Title System Restoration

1.2 Directory Number 8

1.3 Objective

The purpose of this Directory is to present the basic criteria with which each applicable entity must plan for and perform power system restoration following a major or a total blackout.

Compliance to the criteria set forth in this Directory document by each applicable entity assures the capabilities to perform power system restoration.

The functional requirements and performance of operational monitoring and control systems, **operator** voice communications and data telecommunications are beyond the scope of this Directory, except particular requirements for system restoration.

On an annual basis, the NPCC Inc. Task Force on Coordination of Operation shall review and accept each applicable entity's restoration plan for viability and coordination with other operating entities. The composite of the individual restoration plans, once reviewed and accepted by NPCC, comprises NPCC's regional restoration plan.

1.4 Effective Date **October 21, 2008**

1.5 Background

This Directory was developed from the draft NPCC A-12 System Restoration Criteria document (January 10, 2008 version) and associated C-35 Procedure document. Guidelines and procedures for consideration in the implementation of this Directory are provided in Appendix B.

1.6 Applicability

1.6.1 Functional Entities

Reliability Coordinators
Transmission Operators
Balancing Authorities
Transmission Owners
Generator Owners

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2.0 Terms Defined in this Directory

The definitions of terms found in this Directory appearing in bold typeface, including those terms used in Appendix B, can be found in the Appendix A.

3.0 NERC ERO Reliability Standard Requirements

The NERC ERO Reliability Standards containing requirements that are associated with this Directory include, but may not be limited to:

3.1 EOP-005-1
3.2 EOP-006-1

4.0 NPCC Regional Reliability Standard Requirements

None.

5.0 NPCC Full Member, More Stringent Criteria

These Criteria are in addition to and more stringent or more specific than the NERC or any Regional Reliability standard requirements.

5.1 System Restoration Plan Requirements

Each Reliability Coordinator and Transmission Operator shall develop and maintain a system restoration plan for its operating area[1] that meets NERC requirements. In addition, the restoration plan shall:

5.1.1 identify the operating area's **basic minimum power system**(s);

5.1.2 address the priority of restoring off-site power to nuclear plants;

5.1.3 identify interconnection points with adjacent operating areas;

5.1.4 identify **synchronization** parameters;

5.1.5 address coordination of system restoration with neighboring operating areas;

5.1.6 provide for the reenergization of transmission systems to major generating stations , including inter-area tie points;

5.1.7 address electrical **island** stabilization;

[1] Operating area means the Reliability Coordinating area or the Transmission Operator area as defined in the NERC Functional Model.

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5.1.8 identify adequate on-site fuel resources for any supplementary generators (e.g., a diesel generator) used to sustain the supply of station service in whole or in part necessary for operating **key facilities**.

5.2 **Basic Minimum Power System** Determination Requirements

5.2.1 The **basic minimum power system** shall consist of one or more generating stations, transmission lines, and substations operating in the form of an **island** for the purpose of initiating the restoration process. The Reliability Coordinator and Transmission Operator shall each identify its area's **basic minimum power system**(s) within its system restoration plan.

5.2.2 A Reliability Coordinator and Transmission Operator may utilize more than one **basic minimum power system** to initiate the restoration process. In determining such a system(s), the Reliability Coordinator and the Transmission Operator shall involve all affected parties or entities.

5.2.3 The **basic minimum power system** shall include the capability to:

5.2.3.1 utilize **blackstart** generators;

5.2.3.2 form an electrical **island**;

5.2.3.3 **synchronize** electrical **islands;** and

5.2.3.4 permit the continuation of the system restoration plan.

5.3 Identification of **Key Facilities** and Associated **Critical Components**

5.3.1 The Reliability Coordinator shall identify the **key facilities**.

5.5.2 The Transmission Owners and Generator Owners of the **key facility** shall identify the associated **critical components.**

5.4 Power System Restoration Event Analysis

5.4.1 Reliability Coordinator Restoration Evaluation

Following an event where the system restoration plan was invoked, the Reliability Coordinator shall report on the performance of its restoration plan..

5.4.2 Transmission Operator Restoration Evaluation

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Following an event where the system restoration plan was invoked, the Transmission Operator shall report on the performance of its restoration plan.

5.5 Testing Requirements for Facilities Associated with Interconnection Points

Each Transmission Owner of facilities that connect the **basic minimum power system** to interconnection points as agreed to by adjacent areas shall have a maintenance and testing program for the associated equipment required for continued and proper operation in the event of a total loss of grid supply. Upon request, a summary of the maintenance and testing records shall be provided to the Reliability Coordinator.

5.6 Testing Requirements for Facilities Associated with Offsite Power to Nuclear Generating Plants

Each Transmission Owner of facilities that connect the **basic minimum power system** to nuclear plants shall have a maintenance and testing program for the associated equipment required for continued and proper operation in the event of a total loss of grid supply. Upon request, a summary of the maintenance and testing records shall be provided to the Reliability Coordinator.

5.7 Testing Requirements for Critical Components Associated with Key Facilities

Each Transmission Owner and Generator Owner of a **key facility** shall:

- maintain a list of **critical components** associated with each **key facility**;
- perform the tests outlined in Table 1;
- maintain records of the test results; and
- provide the above upon request to the Reliability Coordinator and Transmission Operator.

Note that the occurrence of an actual successful event can be considered as a completed test, provided it can be demonstrated that the operation of the facility during the event met the test objectives and performance of these criteria.

The NPCC Compliance Committee stipulates the reporting requirements by the Transmission Owner and Generator Owner.

5.7.1 Reporting on Failure of Critical Components Associated with Key Facilities

The Transmission Operator shall report to its Reliability Coordinator, failure of a test or the failure of **critical components** associated with

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key facilities:

5.7.1.1 As soon as possible and no later than 15 minutes after its control room has confirmed the loss of functionality at **a key facility** due to the failure of **critical components**. Loss of functionality at a **key facility** is defined as the loss of operability which can negatively impact the restoration plan. Examples of such conditions are:

- Loss of equipment control;
- Complete loss of AC or DC service supply;
- Loss of Blackstart facilities

5.7.1.2 As soon as possible and no later than 24 hours after their control room staff becomes aware of the failure of **critical components** associated with **key facilities** which results in a loss of redundancy at a **key facility**. Examples of such conditions are:

- Loss of a redundant AC or DC service supply;
- Loss of redundant Blackstart facilities

The report shall identify remedial actions to be undertaken, including the date by which the work is to be completed.

5.7.2 Blackstart Generating Unit Startup Test (Reference: Table 1; Test BS-1)

5.7.2.1 The Generator Owner having generating facilities designated as having **blackstart capability** shall annually verify the facilities' **blackstart capability** without dependencies on **power** sources unavailable during a partial or complete system blackout. Once the facility has been started, it shall continue to demonstrate its capability to operate in a stable condition while isolated from the **power** system for a minimum of ten minutes. The number of units within a generating facility that shall be **blackstarted** for this test is determined by the Reliability Coordinator and Transmission Operator as needed by their respective system restoration plans.

5.7.2.2 Each Reliability Coordinator and Transmission Operator shall ensure that the Generator Owner of a blackstart **generation** facility included in its restoration plan complete a successful blackstart test consistent with the objectives of its system restoration plan.

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5.7.2.3 Operations voice communications and system control and data acquisition (SCADA) that are required for **blackstart** shall be verified to operate adequately without dependency on the interconnected system or other unrelated unit support for any source of station service.

5.7.3 Backup Pressurization System of Underground Transmission Cables Test (Reference: Table 1; Test UG-1)

Certain underground transmission cables require the capability to pressurize the insulating medium to maintain dielectric strength. The capability to do so during a **blackout** is essential to maintain the availability of such underground cables for service and to preclude any damage to the cables upon energizing. The Transmission Owner shall test the underground transmission cable's capability either by testing the cable's backup pressurization system or by powering the cable's normal pressurizing system from a backup power source (e.g. backup generator). This test shall be conducted every six (6) months by demonstrating that the required pressures can be maintained for a minimum of thirty (30) minutes.

5.7.4 Substation and Telecommunication Backup Power Supplies - Batteries and Generators Test (Reference: Table 1; Tests ST-1 to ST-6)

Transmission Owners shall test the backup power supplies in substations and telecommunication sites that are identified as **critical components** as specified below. Separate backup power arrangements for these substations and sites shall be separately identified in the **critical components** listing, and shall be inspected and tested individually.

The required tests are as follows:

5.7.4.1 Battery charger and batteries shall be inspected annually and meet the Transmission Owner's / Transmission Operator's battery integrity standards. (Reference: Table 1; Test ST-1)

5.7.4.2 Interruption of AC supply to a battery charger shall be carried out annually to ensure a battery picks up and carries **load**. Alternatively, a discharge test may be performed. (Reference: Table 1; Test ST-2)

5.7.4.3 The Transmission Owner's design and commissioning requirements must ensure that all **critical component loads** are supplied from batteries and battery charger as part of the engineering and design. If, and when, modifications are

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made, and/or every five years, the Transmission Owner shall reconfirm through its design review and/or through testing that all **critical component loads** are connected to the battery and the battery charger. (Reference: Table 1; Test ST-3)

5.7.4.4 Performance testing of batteries in substations and telecommunication sites shall be done at least once every five (5) years. A recognized discharge (load) test will be conducted at least once every five years for a minimum of two hours. The success of this test is when average and individual cell voltages do not drop below prescribed design limits for the specific battery type. (Reference: Table 1; Test ST-4)

5.7.4.5 For substations and telecommunication sites provided with backup power generators, a startup and run test shall be performed monthly for a minimum run time of fifteen (15) minutes. (Reference: Table 1; Test ST-5)

5.7.4.6 For substations and telecommunication sites provided with automatically started backup power generators, the Transmission Owner shall verify that the generators will pickup the required **load** during the loss of station service, a startup, transfer and run test simulating the loss of station service will be performed annually for a duration of at least thirty (30) minutes. (Reference: Table 1; Test ST-6) For manually started back-up emergency generators, the Transmission Owner shall verify manual start of the generator and stable operation for thirty (30) minutes. (Reference: Table 1; Test ST-6)

5.7.5 Control Center and Telecommunication Center Facilities Test (Reference: Table 1; Tests CC-1 To CC-5)

5.7.5.1 Each Reliability Coordinator, Transmission Operator and Balancing Authority shall test its facilities in the control centers and the telecommunication centers to demonstrate the computer systems will be functional when required for system restoration, without dependencies on power sources unavailable during a partial or complete system blackout. The uninterruptible power supply (UPS) systems in control centers and telecommunication centers shall be tested annually by interrupting AC supply and verifying that all **critical component loads** are supplied for a time that is sufficient for backup power sources to restore the AC input to the UPS. (Reference: Table 1; Test CC-1)

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5.7.5.2 Performance testing of batteries in control centers and telecommunication sites shall be done at least once every five (5) years. A recognized discharge (load) test will be conducted at least once every five years for a minimum of two hours. The success of this test is when average and individual cell voltages do not drop below prescribed design limits for the specific battery type. (Reference: Table 1; Test CC-2)

5.7.5.3 For control centers and telecommunication centers provided with a backup power generator, a startup and run test shall be performed monthly for at least fifteen (15) minutes. (Reference: Table 1; Test CC-3)

5.7.5.4 For control centers and telecommunication centers provided with a backup power generator, verification that the generators will pick up the required **load** (including heating, ventilation and air conditioning (HVAC) for computer systems) during the loss of station service shall be provided. A startup, transfer and run test simulating the loss of station service shall be performed annually for a duration of at least thirty (30) minutes. During the test, the operation of the auxiliaries shall be verified. (Reference: Table 1; Test CC-4)

5.7.5.5 Each Reliability Coordinator, Transmission Operator and Balancing Authority shall test its computer redundancy features every six (6) months to ensure computer systems continue to function adequately. (Reference: Table 1; Test CC-5)

6.0 Measures and Assessments

M1. Each Reliability Coordinator and Transmission Operator shall have a dated, documented System restoration plan developed in accordance with Section 5.1, "System Restoration Plans."

M2. Each Reliability Coordinator shall have documentation identifying the Basic Minimum Power System for its area, in accordance with Section 5.2, that incorporates the components and the Key Facilities identified in Section 5.3.

M3. Each Transmission Owner and Generator Owner shall have documentation identifying the Critical Components of Key Facilities in its area or facility, in accordance with Section 5.3.

M4. If there has been a Disturbance in which elements of the restoration plan have been utilized, each Reliability Coordinator and Transmission Operator involved shall provide evidence of conducting an event analysis in accordance with Section 5.4.

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M5. Each Transmission Owner shall provide self-certification of a maintenance and testing program for the associated equipment required for continued and proper operation of facilities between interconnection points and the Basic Minimum Power System, in accordance with Section 5.5.

M6. Each Transmission Owner shall provide self-certification of a maintenance and testing program for the associated equipment required for continued and proper operation of facilities between nuclear plants and the Basic Minimum Power System, in accordance with Section 5.6.

M7. Each Transmission Operator shall ensure Transmission Owners and Generator Owners of a key facility test these facilities in accordance with Section 5.7.

7.0 Compliance Monitoring

Adherence to these Criteria shall be reported by the responsible entity in a manner and form designated by the Compliance Committee.

Prepared by: Task Force on Coordination of Operation and Task Force on System Studies

Review and Approval: Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45 day review and comment period. Upon satisfactorily addressing all the comments in this forum, the Directory document will be sent to the remaining Task Forces for their recommendation to seek RCC approval.

Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC. Bylaws" in effect at the time the ballots are cast.

Revisions pertaining to the Appendices or any other portion of the document such as Links glossary terms, etc., only RCC Members will need to conduct the final approval ballot of the document.

This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

References: None

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Table 1 - Standard Test Procedures for key facilities
and associated critical components required for system restoration

Table 1 - Standard Test Procedures for key facilities and associated critical components required for system restoration				
Test No.	**Critical Component**	**Test**	**Test Frequency and Duration**	**Criteria for Successful Test**
BS-1	Blackstart Generating Units	Startup test of generating unit **blackstart capability** without dependencies on the power system	Frequency: annual Duration: 10 minutes of stable operation	Successful startup and 10 minutes of stable operation All operating aids and auxiliary systems are independent.
UG-1	Pressurization system of underground transmission Cables	Test backup pressurization system by switching from normal to backup pressurization scheme or test cable's normal pressurization system from a backup power source (e.g. backup generator)	Frequency: every 6 months Duration: minimum of 30 minutes; verify that backup pressurization system or backup generator is able to maintain dielectric strength of insulating medium for the expected time required for restoration	Maintains safe dielectric pressure for the minimum test period Backup pressurization system or backup generator can maintain dielectric fluid pressure for the expected time required for system restoration

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Table 1 - Standard Test Procedures for key facilities and associated critical components required for system restoration				
Test No.	**Critical Component**	**Test**	**Test Frequency and Duration**	**Criteria for Successful Test**
ST-1	Battery charger and batteries in substation and Telecommunication site	Check battery integrity as per Transmission Owner / Operator maintenance practices	Frequency: annually	Meet Transmission Owner / Operator battery integrity standards
ST-2	Battery charger and batteries in substation and Telecommunication site	Interruption of AC supplies to battery charger to ensure that battery picks up and carries **load**	Frequency: annually	Maintain acceptable voltage levels for the duration of the test
ST-3	Battery charger and batteries in substation and Telecommunication site	Confirm by design review and/or testing that all critical **loads** are connected to the battery via commissioning requirements and when modifications are made or if practicable, interruption of AC station service.	Frequency: once every 5 years or when modifications are made	Confirm that all critical **loads** are supplied from battery charger and batteries.

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Table 1 - Standard Test Procedures for key facilities and associated critical components required for system restoration				
Test No.	**Critical Component**	**Test**	**Test Frequency and Duration**	**Criteria for Successful Test**
ST-4	Batteries in substation and telecommunication site	Perform recognized performance test of battery capacity including discharge (load) test	Frequency: at least once every five years Duration: minimum 2 hours	The success of this test is when average/individual cell voltage does not drop below prescribed design limits for the specific battery type.
ST-5	Backup generator in substation and Telecommunication site	Startup and run test for backup generator	Frequency: monthly Duration: minimum of 15 minutes	Successful startup followed by 15 minutes of stable operation
ST-6	Backup generator in substation and Telecommunication site	Backup generator startup, transfer and run test to simulate loss of station service	Frequency: annually Duration: minimum of 30 minutes	- Successful startup (automatically started type) - Transfer scheme operates correctly (automatically started type) - 30 minutes of stable operation supplying critical **loads** (both automatically and manually started backup generators)

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Table 1 - Standard Test Procedures for key facilities and associated critical components required for system restoration				
Test No.	**Critical Component**	**Test**	**Test Frequency and Duration**	**Criteria for Successful Test**
CC-1	Uninterruptible power supply (UPS) system in control center and Telecommunication center	Interruption of AC supply to UPS to ensure it can continue to support all critical **loads**	Frequency: annually Duration: for a time that is sufficient for backup power sources to restore AC supply to the UPS	No impact on computer or telecommunication functions during testing
CC-2	Batteries in control center and telecommunication center	Perform recognized performance test of battery capacity including discharge (load) test	Frequency: at least once every five years Duration: minimum 2 hours	The success of this test is when average/individual cell voltage does not drop below prescribed design limits for the specific battery type.
CC-3	Backup generator in control center and Telecommunication center	Startup and run test for backup generator	Frequency: monthly Duration: minimum of 15 minutes	Successful startup followed by 15 minutes of stable operation

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Table 1 - Standard Test Procedures for key facilities and associated critical components required for system restoration				
Test No.	**Critical Component**	**Test**	**Test Frequency and Duration**	**Criteria for Successful Test**
CC-4	Backup generator in control center and Telecommunication center	Backup generator startup, transfer and run test to simulate loss of station service	Frequency: annually Duration: minimum of 30 minutes	- Successful startup - Transfer scheme operates correctly - 30 minutes of stable operation supplying **loads** critical to system restoration - When HVAC system restarts, ambient temperature is in the range of equipment working temperature
CC-5	Computer systems	Verify computer redundancy or (n-1) check by failing over the EMS	Redundancy check every 6 months	- No impact on computer functions during testing. - Successful switching / testing without equipment failure.

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Appendix A
Definition of Terms[2]

Area — An **Area** (when capitalized) refers to one of the following: New England, New York, Ontario, Quebec or the Maritimes (New Brunswick, Nova Scotia and Prince Edward Island); or, as the situation requires, area (lower case) may mean a part of a system or more than a single system. Within NPCC, Areas (capitalized) operate as **control areas** as defined by the North American Electric Reliability Council (NERC) (the definition can be found on page 6 of this glossary).

Area Control Error — The instantaneous difference between actual and net **scheduled interchange**, taking into account the effects of frequency bias.

Automatic Generation Control (AGC) — Equipment that automatically adjusts a **Control Area**'s **generation** to maintain its **interchange schedule** plus its share of frequency regulation.

Basic Minimum Power System —Consists of one or more generating stations, transmission lines, and substations operating in the form of an island for the purpose of initiating the restoration process. The Reliability Coordinator and Transmission Operator shall each identify its area's basic minimum power system(s) within its system restoration plan.

Bipolar — Operation of **HVdc** with two **poles** of opposite polarity with negligible ground current.

Blackstart Capability — The ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering **power** without assistance from the electric system.

Critical Component — Equipment required for continued and proper operation of a **key facility** in the event of a total loss of grid supply. Critical components include but are not limited to the following:

- blackstart generating units;
- substation backup power supplies;
- control center and telecommunication center backup power supplies and computer systems;
- control center and telecommunication center computer room HVAC;
- telecommunication facilities backup power supplies.; and
- cable pressurization systems at or between key facilities shall be tested.

Disturbance – Severe oscillations or severe step changes of current, voltage and/or

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frequency usually caused by **faults**.

System Disturbance — An event characterized by one or more of the following phenomena: the loss of **power** system **stability**; cascading outages of circuits; oscillations; abnormal ranges of frequency or voltage or both.

Emergency — Any abnormal system condition that requires automatic or manual action to prevent or limit loss of transmission facilities or **generation** supply that could adversely affect the **reliability** of the electric system.

Specific to NPCC: An **Emergency** is considered to exist in an Area if **firm load** may have to be shed.

Energize — To make a piece of equipment or circuit alive.

First Contingency Loss — The largest **capacity** outage including any assigned Ten-Minute Reserve which would result from the loss of a single **element**

HVdc Link — A high Voltage direct current connection between two **power** systems, often used to interconnect two asynchronous **power** systems.

Interconnection — When capitalized, any one of the five major electric system networks in North America: Eastern, Western, ERCOT, Québec, and Alaska. When not capitalized, the facilities that connect two systems or **Control Areas**. Additionally, an interconnection refers to the facilities that connect a non-utility generator to a **Control Area** or system.

Interface — The specific set of transmission **elements** between two areas or between two areas comprising one or more electrical systems.

Island — A portion of a **power** system or several power systems that is electrically separated from the interconnection due to the disconnection of transmission system **elements**.

Key Facilities — Facilities required to establish a **basic minimum power system** following a system blackout. These facilities are essential to the restoration plan of the **Control Area** and include generating stations having blackstart units and other selected generating stations, transmission **elements** which are part of the **basic minimum power system,** control centers and telecommunication centers and telecommunication facilities which are necessary to support **protection** and control facilities, voice and data between and within control centers and voice and data between control centers and key generating / transmission substations.

Load — The electric **power** used by devices connected to an electrical generating system. (IEEE Power Engineering). Also see **Demand**.

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NPCC Specific Definitions:

Firm Load — Loads that are not **Interruptible Loads**.

Interruptible Load — Loads that are interruptible under the terms specified in a contract.

Load Shedding — The process of deliberately removing (either manually or automatically) preselected customers' **load** from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages.

Operator, System - Person responsible for operating control of the **bulk power system** in an **Area** of NPCC or an adjoining system interconnected with NPCC. This could be a Security Coordinator, a **Control Area** Operator or in some cases a bulk power utility operator (e.g. NYPA, Niagara Mohawk, etc)

Power

Apparent Power — The product of the volts and amperes. It comprises both *real* and *reactive* power, usually expressed in kilovoltamperes (kVA) or megavoltamperes (MVA).

Reactive Power — The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, **synchronous condensers**, or electrostatic equipment such as capacitors. Reactive power directly influences electric system voltage. It is usually expressed in kilovars (kVAr) or megavars (MVAr).

Real Power — The rate of producing, transferring, or using electrical energy, usually expressed in kilowatts (kW) or megawatts (MW).

Rating — The operational limits of an electric system, facility, or **element** under a set of specified conditions.

Reclosing

Autoreclosing — The automatic closing of a circuit breaker in order to restore an **element** to service following automatic tripping of the circuit breaker. Autoreclosing does not include automatic closing of capacitor or reactor circuit breakers.

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High-speed autoreclosing — The autoreclosing of a circuit breaker after a necessary time delay (less than one second) to permit **fault** arc deionization with due regard to coordination with all **relay** protective systems. This type of autoreclosing is generally not supervised by voltage magnitude or phase angle.

Manual Reclosing — The closing of a circuit breaker by operator action after it has been tripped by **protective relays**. Operator initiated closing commands may originate from local control or from remote (supervisory) control. Either local or remote close commands may be supervised or unsupervised.

Supervision — A closing command is said to be supervised if closing is permitted to occur only if certain prerequisite conditions are met (e.g., **synchronism-check**).

Synchronism-check — refers to the determination that acceptable voltages exist on the two sides of the breaker and the phase angle between them is within a specified limit for a specified time.

Reserve — In normal usage, reserve is the amount of **capacity** available in excess of the **demand**

Reserve Requirement — That capability above firm system **demand** required to provide for regulation, **load** forecasting error, equipment forced and scheduled outages, and local area supply **adequacy**

Synchronize — The process of connecting two previously separated alternating current apparatuses or systems after matching frequency, voltage, phase angles, etc. (e.g., paralleling a generator to the electric system).

Synchronism-check Relay — A verification **relay** whose function is to operate when two input voltages satisfy predetermined operating parameters.

Tie Line — A circuit connecting two or more **Control Areas** or systems of an electric system

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Appendix B
Guideline and Procedure for Blackstart and System Restoration

1.0 Introduction

This Appendix provides the guidelines and procedures to the Reliability Coordinator, Transmission Operator and Balancing Authority to manage system restoration events that affect the NPCC member Areas and adjoining operating areas. This Procedure does not prescribe or supplant the specific restoration plans developed by each Reliability Coordinator and Transmission Operator within NPCC. This Procedure is structured to stipulate restoration actions on the part of the responsible entity, and includes the following broad categories:

1. A quick reference of each Reliability Coordinator and Transmission Operator area's restoration plan;
2. Actions to stabilize remaining electrical islands;
3. Assessment of conditions prior to interconnecting;
4. Establishing interconnections;
5. Actions to remain stable following an interconnection; and
6. Training and testing to validate plans.

Although the risk of a complete **power** system shutdown in North America is minimized by operating to reliability standards specified by NERC, NPCC and appropriate authorities within the region, there remains a requirement to be prepared for the worst case scenario. NERC and NPCC require that all Reliability Coordinators and Transmission Operators maintain viable system restoration plans and restoration capabilities.

The Reliability Coordinators and Transmission Operators within NPCC have detailed individual restoration plans that meet both NERC and NPCC requirements. These Plans address the possibility of a complete system blackout by calling for the building of a **basic minimum power system** from designated **key facilities**. The ultimate goal of this rebuilding process is to reconnect electrical areas to reestablish a fully interconnected system. At the same time, these restoration plans recognize that it is impossible to predict the extent to which each individual Reliability Coordinator and Transmission Operator area will be disrupted in a blackout event, nor the specific order in which facilities will become available for service after a system collapse. These partial blackout scenarios have been addressed by the prescription of technical guidelines that can be used to restore the **power** system following any type of blackout event.

In recognition of the fact that it is impossible to predict the extent of a blackout event nor the ensuing order of resource availability, this document does not attempt to provide specific procedures as to when and where to reconnect NPCC's Reliability Coordinator and Transmission Operator areas and neighboring operating areas. Instead, it provides

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technical guidelines for **system operators** to reconnect the Reliability Coordinator and Transmission Operator areas and provide mutual assistance in a manner that reestablishes interconnected operation in a responsibly expeditious manner.

To preclude compromising the physical and cyber security of critical assets, specific information related to facilities is to be treated as confidential and thus restricted from the public domain. Access to such information is permitted only through controlled mechanisms on a "need to know" basis.

2.0 Minimizing the Impact of Events

Within NPCC, the Reliability Coordinator and Transmission Operator restoration plans are developed in accordance with all relevant NPCC Criteria and NERC Standards and reflect the best practices of the industry concerning power system restoration. These restoration plans provide specific direction for recovery from a total or major blackout; and they also provide general guidelines for partial blackouts. Each restoration plan establishes the following major priorities:

2.1 Establish the **basic minimum power system** within the Reliability Coordinator and Transmission Operator area;

2.2 Provide AC supply to nuclear generating units and non-blackstart generating units;

2.3 Restore enough **load** to stabilize generating units and transmission conditions; and

2.4 Establish inter-area **tie lines**.

Table 2-1 below summarizes, at a very high level, the restoration plans of each NPCC Reliability Coordinator and Transmission Operator area; Table 2-2 following similarly summarizes the restoration plans of adjoining Reliability Coordinator and Transmission Operator areas. Attachments 1 to 7 provide a detailed overview of the restoration plans of each of these areas.

Table 2-1 NPCC Reliability Coordinator and Transmission Operator Area

				Priority in

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RC and TOP Area[3]	Type of Restoration Plan	Primary Priority	Secondary Priority	Restoring Interconnections
Maritimes Area (New Brunswick System Operator)	Detailed switching plans and duties of the control centers are documented using defined and / or alternate paths.	Restore AC station service to nuclear generating site.	Restore AC supply to station service to all other plants and transmission substations.	At the earliest opportunity in a controlled fashion.
New England Area (ISO-NE)	The ISO-NE and Local Control Centers have a coordinated set of restoration plans. Detailed paths are defined to restore from a complete blackout. Technical guides are prescribed to restore from partial blackouts. Plans identify where and when ties between electrical **islands** can be made.	Restore AC Station Service to nuclear generation sites.	Restore AC Supply to generating stations, transmission stations and control centers.	Interconnections are made when technically viable. Procedures advocate interconnecting early.
New York Area (NYISO)	In the event of a complete system shutdown the plan defines a specific switching sequence along with general guidelines to restore the system. In the event of a partial system shutdown only the applicable guidelines and steps are followed.	Restore the **basic minimum power system** to expedite restoration of AC station service to nuclear generating sites.	Load restoration, but when limited energy is available within the NY system, preference is given to generating station start-up.	High priority given to establishment of **tie line** operation.
Ontario Area (IESO)	Strategies for restoration	Restore AC station	Restore AC Supply to Critical **Loads**	At the earliest opportunity in a

[3] All member Areas in NPCC are registered as the Reliability Coordinator and Transmission Operator. Hence, only the member Areas names are shown in this column to indicate they represent both the RC and the TOP.

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	established at time of incident based on, sources of potential for restart / blackstart, equipment availability and restoration plan priorities. "Rules of Thumb" developed to guide operators through stages of restoration. IESO directs restoration to create multiple **islands** simultaneously. There are 8 recognized restoration paths within 4 electrical **island** strategy diagrams for reference.	service to nuclear generating sites.	(AC & DC station service) for Switchyards, Substations, Generating Stations, Control Centers and interdependent infrastructure (i.e. telecommunications).	controlled fashion.
Québec Area (HQTE)	The available restoration paths allow for the partition of the main system into five **basic minimum power systems**.	Restore AC station service to nuclear plant and critical facilities of the five **basic minimum power systems**.	Restore AC station service to all other facilities.	Emphasis placed on restoring the Gatineau and the Abitibi-Témiscamingue islands from Ontario sources and Gaspé Island from New-Brunswick sources. Otherwise Interconnections are made when technically viable.

Table 2-2 Adjacent Reliability Coordinator/Transmission Operator Areas

				Priority in

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RC (TOP) Area[4]	Type of Restoration Plan	Primary Priority	Secondary Priority	Restoring Interconnections
MISO (Manitoba)	Manitoba uses a defined path approach for system restoration applied over two restoration areas, the Northern collector system and the remainder of the **bulk power system**. The **bulk power system** is further subdivided into two areas that are paralleled at predefined locations.	The primary priority for restoration is to restore station service to the valve group on the Southern system.	Secondary priorities are to restore station service to the specified **HVdc bipolar pole** within time limits and to restore station service to the remainder of plants in the Southern system and in the Northern system to the **HVdc** collector plants.	There are no specified priority **tie lines**, but any available **tie lines** are used as an anchor for the system.
MISO (Michigan)	The portion of Michigan adjacent to Ontario uses a defined path approach for system restoration. Alternate paths are also defined.	The primary priority for restoration is to restore AC Station service to nuclear plants and to establish a cranking path to provide start up **power** to all other plants and connect them together.	A secondary priority is to return the City of Detroit to normal **power**.	It is a priority to reestablish interconnected operation if the **tie lines** are available. Re establishing **tie lines** with Ontario is a special consideration due to their proximity to the 120 kV system and plants.
MISO (Minnesota)	Minnesota uses a defined path approach utilizing the 115 kV system.	The primary priority for restoration is to provide start up **power** to major generating plants.	The secondary priority is to provide station light and **power** to remaining stations.	Interconnected operation is reestablished with neighboring jurisdictions as soon as **tie lines** become available, with **tie lines** to

[4] MISO is registered as a Reliability Coordinator, whereas its members Manitoba, Michigan and Minnesota are registered as Transmission Operators, which are indicated in brackets. PJM is registered as an RC and a TOP.

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				Manitoba being the priority.
PJM	Each member company of PJM has its own restoration plan. PJM will coordinate and direct all transmission tie connections to external RC and TOP areas.	Restore off site **power** supply to nuclear plants.	Restore AC supply to switchyards, hydroelectric and fossil sites.	The restoration of **tie lines** will be evaluated as the facilities become available.

3.0 Voice Communication Overview

3.1 The ability to communicate is essential to the restoration process. The options for direct voice communications between control centers include the following:

3.1.1 Public Switched Telephone Networks (PSTN)

1. NERC Hot Line
2. Cellular Telephones

3.1.2 Direct Ring Down Circuits

3.1.3 Utility Owned Voice Channels

3.1.4 Satellite Telephones

3.2 Alternative means of communication to the PSTN can include direct ring down circuits and satellite telephones. All NPCC member **Areas** are Reliability Coordinators (and Transmission Operators), and therefore they are members of the NERC Hotline; the telephones associated with this service operate through the PSTN. Finally, cellular telephones are available for use in all Reliability Coordinator areas, although they have proven to be unreliable during major events due to excessive phone traffic.

Communication paths directly between Reliability Coordinator and Transmission Operator areas within NPCC (referred to as primary paths) contain multiple communications media options. In the improbable event that all primary paths between two areas are interrupted, alternate communication paths, where possible, have been identified. If available, a communication media on the direct or primary path between the Reliability Coordinator and Transmission Operator areas should be used at all times unless otherwise directed by the Reliability Coordinators and Transmission Operators to use an alternate path for coordination among them.

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4.0 Actions to Stabilize Remaining Electrical **Islands**

4.1 Immediate Actions to Stabilize Conditions Within Electrical **Islands**

After a significant **power system disturbance**, electrical **islands** can result due to the separation and survival of sub-areas from the **Interconnection**. It is imperative to immediately monitor and assess conditions within these electrical **islands** and take any warranted actions to stabilize their operation. Actions taken to stabilize the **islands** may include the switching of reactive control devices, **generation** dispatch actions, transmission switching or **load shedding** to secure thermal, voltage or frequency conditions.

4.2 Requirement for Manual Generation Dispatch

If the **power** system has been severely disrupted, economic dispatch signals may be inaccurately calculated by energy management system software or may be ineffective in their application. Consequently, the Reliability Coordinator and Transmission Operator may request the Balancing Authority to suspend use of economic dispatch signals and change over to manual dispatch orders.

4.3 **Tie Line** Regulation

The Balancing Authority should appropriately select flat frequency or **tie line** bias control to stabilize frequency depending on the status of their **tie lines**. If a Balancing Authority area is electrically isolated, the flat frequency control mode should be implemented. If two or more Balancing Authority areas have remained connected, combinations of different control modes may have to be explored. Use of flat frequency control by the largest area and tie line bias control by other smaller connected areas could produce the best frequency regulation.

4.4 Inadvertent **Synchronization** of Electrical **Islands**

The Transmission Operator should recognize that the circuit breakers of transmission circuits that opened during the event, and whose terminals are **energized** within separate electrical **islands**, may automatically **reclose**. This action can be done by automatic **synchronism-check relays** that were actually installed for a separate purpose, namely the supervision of steady state angles across, and appropriate **reclosure** of, an open circuit whose terminals are **synchronized**. The unintentional byproduct of **reclosing** two electrical **islands** through **synchronism-check relays**, whose frequencies and voltages happen to match for a sufficient period of time, may be followed by the immediate trip of the circuit as the **islands** continue to pull away from each other, and the circuit is too weak to hold them together. The Transmission Operator should recognize and address this potential inadvertent automatic **reclosing**. Furthermore, it

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should also consider the potential for manual inadvertent **reclosure** of circuits between electrical **islands** and take any necessary actions to preclude or prepare for an inadvertent **reclosure**. If warranted, it should consider blocking the circuit breaker automatic **reclosure.**

5.0 Assessment of Conditions Prior to Interconnecting

When assistance is required from an external Reliability Coordinator or Transmission Operator area, communications between the requesting and assisting Reliability Coordinator and Transmission Operator areas must ensure that there is a sufficient level of understanding of:

1. Existing system conditions after stabilization, and;
2. Types of assistance that may be sought after synchronization.

The existing system conditions to be assessed include, but are not limited to, the following:

1. **Load**;
2. **Synchronized Generation**;
3. Prevailing Voltage and Frequency;
4. System Topology;
5. System Operating **Reserves**;
6. System Reactive **Reserves**; and
7. **First Contingency Loss**.

The types of assistance may include, but are not limited to, the following:

1. Start-up for **Generation**;
2. Frequency Control;
3. **Tie Line** Regulation; and
4. System **Reserves** and Restoration of **Loads**.

Assessment of these technical considerations will identify the conditions under which a **tie line** will be established and maintained, reducing the risk of a subsequent separation and the loss of **load** and / or **generation**.

These guidelines are offered to guide **system operators** on technical considerations prior to agreeing to mutually assist a neighbor in an **emergency** in order to maintain the reliability of their operating areas (or portion thereof) while enabling such assistance to occur. It is recognized that, in cases where interconnection agreements are in place together with jointly agreed to operating procedures governing mutual assistance in an **emergency**, their requirements should be met in conjunction with implementing the actions offered in this document.

It must be understood that any assistance agreed to between the operating areas is based on acceptable conditions identified and agreed to by the **system operators.**

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Once the assessment of conditions prior to interconnecting is completed, and if **resources** are available, the **assisting** operating area should be prepared to assist to the maximum extent that is reliably possible.

5.1 Inadvertent Synchronization of Electrical Islands

Relaying and **reclosing** on **tie lines** should be assessed. While the operation of protection **relaying** may not be significantly impacted by the presence of an unusually sparse transmission system, **system operators** may want to disable any automatic **reclosing** on **tie lines**, especially if only one **tie line** is in service, or if only a few remote, low voltage **tie lines** are in service.

5.2 Tie Line Regulation

Prior to interconnecting, **system operators** within the operating areas on either side of the tie line must determine whether the areas are already interconnected to any other systems and, if so, what are the interconnection point(s). If **synchronization** is needed, it will be easier to make frequency adjustments in the smaller system.

System operators should also discuss the conditions under which interconnection points may be deliberately opened. Acceptable ranges of deviations in **tie line** flows caused by system restoration activities should be established using direction from Section 6.0, "Mutual Assistance Guidelines." Restoration activities should strive to follow these guidelines as conditions permit on the system. At the same time, **system operators** must appreciate the levels of post-**contingency tie line** flows that could occur (and have to be temporarily sustained) and be ready to delay restoration activities to restore tie line security in response to a **contingency**.

5.3 Assessment of Reserves Prior to Synchronizing Electrical Islands

Prior to **synchronizing** electrical **islands** between operating areas, an assessment of the **reserves** should be made such that the **reserves** for the new electrical **island** can be determined and additional **reserves** be made available if required or an activation plan be adopted for **contingency** recovery.

Considerations to be assessed prior to **synchronizing** the electrical **islands** include, but are not limited to, the following:

1. What is the largest single **contingency** loss?
2. Are operating **reserves** adequate to cover the loss?
3. What is the amount of spinning **reserve**?
4. Is a **load shedding** plan being utilized for **reserve**?
5. If **reserves** are activated, will any transmission facilities be overloaded?
6. If either of the largest **contingency** losses in the two **islands** occurs after the

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combined **island** is formed, will the interconnection circuit(s) be able to accommodate the resultant **power** flows within their **rating(s)**?

It is recommended to place additional interconnection circuits in service once the initial **synchronization** of the two electrical **islands** has been accomplished to guard against the contingent loss of the path and provide additional transfer capability between the two operating areas.

5.4 Frequency Control

The energy management systems of the NPCC Balancing Authorities utilize the following control mechanisms to perform interconnected regulation using **Automatic Generation Control (AGC)** applications:

1. **Flat Tie Line**

   Only the **tie line** mismatch between **scheduled interchange** and **actual interchange** flow is used to determine **area control error (ACE)**.

2. **Flat Frequency**

   Only frequency deviation is used to determine the **ACE**.

3. **Tie Line Bias**

   Both frequency deviation and **tie line** mismatch are used to determine the **ACE**.

Following a major **system disturbance**, Balancing Authorities must determine the status of their respective **Automatic Generation Control (AGC)** systems, and, if still in service, whether its continuing functioning is desired.

When **synchronizing** electrical **islands** between, the smaller **island** can more readily adjust its frequency to match that of the larger **island**. Once synchronized, the Balancing Authorities should appropriately select flat frequency or **tie line bias** control to stabilize frequency depending on the status of their **tie lines**. If two or more Balancing Authority areas have remained connected, or have re-**synchronized** with each other, combinations of different control modes should be explored. If the above control modes are incorrectly applied, the resulting control actions could actually have a negative impact on the Balancing Authority areas.

For instance, if the larger of the Balancing Authority areas was in flat frequency control (as it should be), and the adjacent smaller Balancing Authority area was in flat **tie line** control, the smaller area would not provide its frequency response as it should for additional **contingencies**, because the **AGC** would be controlling to **tie line** deviations only. Its generators would initially provide some frequency

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response, but the **AGC** control would back them down to maintain the **tie line** on schedule, thereby negating the frequency response contribution of the smaller areas. The use of flat frequency control by the largest Balancing Authority area, and **tie line bias** control by other smaller connected Balancing Authority areas should produce the best frequency regulation.

Each Balancing Authority should determine if economic dispatch continues to be accurate and / or effective, and if it is determined that it is no longer viable, the Balancing Authority should switch to manual dispatch of **generation**.

The Balancing Authority should determine if **tie line** regulation continues to be accurate and / or effective by determining the following:

1. The external Balancing Authority area to which it is connected
2. The relative sizes of the Balancing Authority area(s) to which it is connected

If it is determined that the Balancing Authority area remains tied to the massive **Eastern Interconnection**, the Balancing Authority may use normal **tie line** regulation (**tie line bias**). However, if only two Balancing Authority areas, or a few Balancing Authority areas, remain tied together, the concerned Balancing Authorities should:

1. Use flat frequency control in the largest Balancing Authority area
2. Use tie line bias control in the smaller Balancing Authority area(s)

5.5 Synchronization or Paralleling of Electrical Islands

It is desirable to **synchronize** electrical **islands** between operating areas to enhance the stability of both by gaining electrical inertia (generators and motor **loads**).

Considerations to be assessed prior to **synchronizing** the electrical **islands** include, but are not limited to:

1. Determining which circuit and circuit breaker to use to **synchronize** the electrical **islands,** then apply the guidelines of Section 7.1, “Synchronous Ties” in this Appendix; and
2. Estimating the total nominal generator synchronized capacity that will exist in the new combined electrical **island** after it is **synchronized** such that the size of single shot **load** restoration can be determined and agreed to by both operating areas as outlined in Section 5.6 below.

If a major **system disturbance** has completely separated two operating areas, the **reclosing** of their first **synchronous** interconnection will require **synchronization** of the two areas. If the two areas have already **synchronized** and established a **tie line**, before energizing any additional **tie lines**, the Reliability Coordinator

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and/or the Transmission Operator should assess the electrical configurations on either side of the **tie line** under consideration and determine if its **reclosing** will simply parallel the existing **tie lines(s)**, or if **synchronization** is required. The principles in section 7.0, "Principles of Restoring Inter-area **Ties Lines**," in this Appendix should be followed.

5.6 Provision of External Restoration Service

External restoration service may be provided to an adjacent blacked-out Reliability Coordinator or Transmission Operator area. When the assisting area has strong **tie lines** remaining with the Eastern **Interconnection**, load restoration should be limited to the tie capability to the area to be restored.

When the assisting area is itself an electrical island, it is necessary to limit the incremental amount of load to be restored to 5 % of the total **synchronized** nominal **capacity** of the generators in the electrical **island**. It is important to note that this constraint is based on the nominal **synchronized capacity** of the generator, representing the inertia of the machine, and not on the actual output of the generator. This is to preclude the resulting frequency and voltage transients from operating any underfrequency **load shedding relays**, generator underfrequency protection **relays** or line protection **relays**.

Caution should be exercised in marginal situations due to cold **load** pickup, which, when **energizing** feeder **loads**, can be two to five times their normal **load**.

Additional considerations to be assessed prior to providing assistance include, but are not limited to, the following:

1. Are there any large station service motor **loads** (As an example, boiler feed pumps **synchronous** motors can draw four to five times the rated running **load** on start up.)?
2. In **energizing** transmission lines to generating stations, will customer **loads** be restored, and, if so, what will be their expected MWs?
3. Will long transmission lines or high voltage cables be energized? If so, what is the expected charging current in MVAR?
4. State any restrictions on the MW or MVAR flow on the Reliability Coordinator's or Transmission Operator's **tie line**(s) that will be used to provide the assistance

5.7 Radially Energize and Restore a Portion of an Adjacent Area's System

Situations can occur where it is desirable for an operating area to supply generating stations, substations and customer **load** in an adjacent operating area. In doing so, caution must be exercised in determining points of separation between the two systems.

Considerations to be assessed prior to providing the assistance include, but are not

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limited to the following:

1. Determine the current **load** expected to be supplied.
2. Determine the expected peak **load**.
3. Determine the **generation** available.
4. Identify real or reactive restrictions (MW and / or MVAR) on the interconnected circuit(s) used to provide the assistance.
5. If sourced from an electrical island, then the considerations of Section 5.6 are applicable.
6. Determine the expected duration of this arrangement, if known, until the assisted area is in a position to return normal configuration.

6.0 Establishing Interconnection via Inter-Area Tie Lines

When two systems are to be interconnected, options may be available as to where the interconnection may take place. When these options exist, it is up to the Reliability Coordinator or the Transmission Operator to determine the best location and voltage level to govern the interconnection

6.1 Synchronous Tie Line

When synchronizing Reliability Coordinator or Transmission Operator areas, the following guidelines should be followed:

Synchronize at locations where:

1. **Synchronism-check relays** and / or manual synchroscopes are available;
2. Voltage control **resources** are at, or in close proximity to, the open points;
3. **Generation** sources are easily manipulated or controlled; and
4. Good multi-party communications are available between the personnel directing the **synchronization**, the personnel controlling the **synchronizing** breaker, and the personnel controlling the **generation** facilities on both sides of the open points.

For locations where manual **synchronizations** are performed, the voltage magnitude of the two systems to be paralleled should be matched as closely as possible. A rule of thumb would be to close the paralleling circuit breaker with not more than a 3% voltage difference between the two **islands**. After any warranted coarse adjustments are made within each **island**, the **island** with the dynamic voltage control device closest to the **synchronizing** location should perform final voltage adjustments. If possible, the smaller **island** should have the slightly higher voltage.

The frequency of the two systems must also be closely matched before **synchronization**. First, the difference in the frequencies of the two systems should be no greater than 20 degrees of relative phase angle rotation per second,

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or one full synchroscope revolution in 18 seconds. The smaller or incoming island should adjust the frequency and be running at the slightly higher frequency. Finally, the synchroscope phasing should be done as close to the 12 o'clock position as possible, and certainly within ± 20º (approximately ± 3 minutes) of vertical upon the closing of the breaker.

Where available, automatic, programmable **synchronism-check relays** can be used for **synchronizing islands** or **tie lines** if known to be effective. The Transmission Operator's operating personnel may still have to work to achieve adequate voltage and frequency matches on either side of these automatic **relays** to allow their operation. Consequently, the required operating conditions for these automatic **relays** should be known by the Transmission Operator's operating personnel.

6.2 Non-Synchronous Tie Lines

Non-synchronous **tie lines**, such as **HVdc tie lines** or variable frequency transformers, can present special concerns during system restoration.

The start-up of older model asynchronous **HVdc tie line**s must be left until the later stages of system restoration when a strong AC system is in place to support:

1. AC / **HVdc commutation**;
2. short circuit requirements; and
3. the switching of large MVAR devices.

Newer technology **HVdc tie lines** and variable frequency transformers may be reliably **energized** or started even with weak, partially restored AC power systems.

Each Transmission Operator should develop and maintain the criteria for the restoration of each of their **HVdc tie lines** and variable frequency transformers. These criteria will take into consideration the capabilities of the equipment to operate effectively in a weakened power system.

The Transmission Operator should consider situations where non-synchronous **tie lines** have remained in service following the event. The operating personnel should determine if these facilities can remain in-service without having a negative impact on the restoration procedures due to their ability to remain stable.

7.0 Considerations to Remain Stable Following Interconnection

Once interconnected, the increase in **tie line** flow(s) into an **island**, in response to a **generation contingency** within the **island**, is proportional to the relative amounts of generating **capacity** in each island. The resulting flow can be estimated as follows:

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{(the MW size of the islanded generation contingency) times (the MW size of the island)} divided by {the MW size of the combined synchronized system}

The size is best based on the total **capacity** of **synchronized generation**, but this value is hard to determine, and therefore **load** can be used as an approximate substitute. This information, combined with the considerations addressed in Sections 6.1 through 6.3 in this Appendix, will help operating personnel establish secure flows on **tie lines**.

7.1 Frequency Considerations

In general, once operating areas are tied together and receiving or supplying assistance, operating personnel should continue restoration efforts in a manner that prevents excessive frequency or voltage deviations. The target for maximum transient frequency swings while receiving assistance is 59.5 to 60.5 Hz. Before performing switching that would introduce **load** or **generation resources**, operating personnel should check and, if needed, take action to ensure that steady state system frequency prior to switching is at a level that will avoid excessive frequency excursions immediately after switching.

7.2 Voltage Considerations

Operating personnel should also discuss desired voltage levels that would be sustainable during the event. The general voltage range for maximum voltage deviation while receiving assistance is 5% of nominal transmission voltages.

7.3 Thermal Considerations

Operating personnel should be aware of three key parameters noted below. The specific amounts for each facility need to be communicated between the Interconnecting operating areas. These amounts may be revised as system condition change.

7.3.1 Maximum Tie Line Interface Export Loading

It is the maximum **tie-line** or **interface** loadings possible based on equipment **ratings** and operation to provide **contingency** coverage.

Some operating area ties points consist of multiple circuits in parallel and are constrained by the thermal capability of the facilities making up the interface. It should be expected that the **tie line** interface loading of these interfaces will not exceed:

1. The normal continuous rating of any single facility making up the interface; or

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2. The appropriate emergency rating of any facility, as a result of the worst contingency impacting the interface.

7.3.2 Maximum Tie Line Interface Loading Rate

It is the maximum loading rate of a **tie line** or **interface** as allowed by the assisting operating area.

The typical maximum **tie line interface** loading rates may range from 15 MW per minute to 50 MW per minute, depending on the **tie line** configuration.

7.3.3 Maximum Tie Line Interface Deviation for Step Changes in **Load** or **Generation**

This is the parameter that indicates the maximum step change allowed, from a mutually agreed to schedule flow, on a **tie line** or **interface**.

These deviations are typically the lesser of:

1. 5% of the synchronized capacity, or
2. The cumulative effect of the loading rates of **generation** within the operating area adjacent to the interconnection point.

The typical maximum **tie line** interface deviation for step changes in **load** or **generation** may range from 15 MW to 100 MW

8.0 Training and Exercises

To maintain the ability of the Reliability Coordinator, Transmission Operator and Balancing Authority operating personnel to respond effectively to a **power** system emergency, they are certified and trained within NPCC in accordance with all NERC requirements. In addition to operator training conducted within a given NPCC member operating entity, exercises serve as a means to demonstrate and sustain this ability. Exercises can also be referred to as drills or simulations. When such activities include operating personnel working together from more than one NPCC operating entity**,** or with jurisdictions external to the NPCC, inter-area coordination of the emergency response of the operating personnel is greatly enhanced.

Each Reliability Coordinator, Transmission Operating and Balancing Authority within NPCC conducts regular system restoration exercises for their operating personnel and support staff. These exercises focus primarily on procedures specific to the concerned operating area. The NPCC Dispatcher Training Working Group (Working Group CO-02) develops and conducts semiannual training seminars. Exercises conducted as part of the NPCC Working Group CO-02 training program involve operating personnel from multiple Reliability Coordinators, Transmission Operators and Balancing Authorities within NPCC and therefore can help to also evaluate the coordination of each operating

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area's restoration plans.

Exercises may include:

1. Simulated emergency response activities;
2. Table top simulations;
3. Exercise participants participating from their normal work headquarters;
4. Minimal to zero coaching by exercise coordinators; and
5. Interventions into the conduct of the exercise by exercise coordinators, usually being limited to that necessary to run the exercise and interjecting complications and changed conditions to add credibility and challenge.

Exercises are typically conducted by dedicated exercise coordinators.

For purposes of evaluating the exercise against its objectives, a post exercise assessment, is usually conducted, with feedback gathered to support the creation of an evaluation report to disseminate lessons learned.

The specific requirements for any coordinated inter-area exercise will be determined by the NPCC Inter-Control Area Restoration Coordination Working Group (Working Group CO-11), with input from the NPCC Dispatcher Training Working Group and relevant operating personnel critiques. Coordinated inter-area exercises should be considered as an additional step when a Reliability Coordinator or transmission Operator is scheduling its own internal restoration exercise in order to foster and sustain inter-area coordination in performing system restoration.

In general, both the individual entity's and NPCC's exercises should include experiences and lessons learned from actual restoration events.

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Attachment 1[5]

Maritimes Area Restoration Overview

Objective

This restoration summary is a brief overview of how the Maritimes **Area** restores the **power** system following a complete blackout of the Maritimes **Area**. It does not attempt to cover details of the individual system restoration plans or all the possible blackout scenarios.

Background

The Maritimes **Area** consists of three Canadian provinces: New Brunswick (NB), Nova Scotia (NS) and Prince Edward Island (PEI), as well as a radially connected portion of the state of Maine {Northern Maine Independent System Administrator (NMISA)}. The New Brunswick System Operator (NBSO) is the Reliability Coordinator for the Maritimes **Area**, and as such coordinates **synchronization** between the systems within the **Area**, and / or with adjacent **Areas**.

Each entity within the Maritimes **Area** operates its own electrical grid. NB is connected to NS via two 138 kV lines and one 345 kV line. NB is connected to PEI via two 138 kV cables. Northern Maine ISA is radially connected to NB via two 138 kV lines and three 69 kV lines. There is no direct connection from NS to PEI. In 2004, the total Maritime peak load was approximately 6,000 MW.

Basic Plan

The restoration plan assumes no assistance from adjacent **Areas**. Each entity within the Maritimes **Area** has **blackstart capability** and, therefore, individually establishes their **power** system according to their detailed switching plans. Each system uses the "open all breaker" method in the beginning of the restoration process. When the **power** systems are established and stable, the electrical islands will **synchronize** with each other. The Reliability Coordinator in NB will coordinate the **synchronization** between NB and NS, NB and PEI, NB and NMISA, as well as the load pick-up in any system from this point on until the systems are fully established. At any time throughout the restoration process, NB may **synchronize** with an adjacent **Area**.

[5] Attachments 1 to 7 have been developed for some time by NPCC member Areas, MISO and PJM, and have not been revised for this Directory. Hence, the term Area(s) instead of the functional entities as described in the NERC Functional Model may still appear in some of the attachments. It is expected that changes to replace "Area" will occur over time when these attachments are revised in the future.

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Attachment 2

New England Area Restoration Overview

Introduction

This procedure addresses restoration of the **bulk power system** (115 kV and above) after a partial or complete system blackout. Expeditious restoration of the **bulk power system** depends on independent actions and interactions by NEPOOL Participants, Local Control Centers and the ISO New England Inc. (ISO). Depending on the expanse of the blackout (local area or widespread) numerous Participant and Local Control Center restoration procedures, and this procedure, may need to be implemented simultaneously.

During system restoration, a high priority must be given to the restoration of off-site AC **power** sources to nuclear generators. Also, technical aspects of system restoration (i.e. unit startups, load pickups, switching surges, voltages, frequency, **synchronization** of islands, etc.) will be crucial. Recognizing these concerns, this procedure and all Local Control Center and Participant restoration procedures have been developed in a coordinated fashion.

Responsibilities

A. Local Control Centers

1. Determine the extent of the blackout within each Local Control Center and inform the ISO as soon as possible of existing generation and transmission capabilities. (The ISO will determine the extent of the blackout within New England and adjacent power systems and inform the Local Control Centers.)

2. Implement Local Control Center restoration procedures (including necessary coordination with the ISO and adjacent Local Control Centers).

3. Should communications with the ISO fail, 345 kV circuits and inter-Local Control Center and inter-**Area tie lines** may be **energized** if prudent to total system restoration, and if communications between the affected parties exist.

B. ISO New England

1. Determine the extent of the blackout throughout New England and adjacent power systems and inform all Local Control Centers of existing **generation** and transmission capabilities.

2. Implement the ISO restoration procedure (including necessary coordination with the Local Control Centers and adjacent power systems).

3. If the blackout is severe and unit dispatch must be temporarily returned to the Local Control Centers, be prepared to assist the Local Control Centers with the loading function if the Local Control Centers request such assistance.

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4. Authorize the closing of inter-Local Control Center and inter-**Area** transmission lines.

5. Once inter-Local Control Center or inter-**Area tie lines** are **energized**, oversee and coordinate **load** pickups within the interconnected parties.

6. Select priority for start-up **power** supply to generating stations when the choice is to supply a station in one Local Control Center or a station in another Local Control Center from the same source.

7. Direct **load shedding**, if necessary, to enable continued reliable restoration of interconnected parties or the closing of inter-Local Control Center or inter-**Area tie lines**.

8. Monitor **bulk power system** transmission and generation facilities and, as practical, take action to promote system reliability.

System Restoration Guidelines

The following lists guidelines regarding the technical aspects of system restoration that are provided in New England restoration procedures:

A. Restoration of Off-Site AC Power to Nuclear Generators
B. Opening Circuit Breakers and Switches
C. Reviewing Load Tap Changer (LTC) Positions
D. Generator Start Ups and MW Loading
E. Spinning Reserves
F. Load Pickups
G. Transmission Line Charging
H. Voltage Schedules at Generators
I. Circuit Energizations
J. Synchronization
K. Inter-Local Control Center Ties
L. Inter-Area Ties

Recognizing the numerous scenarios of possible system blackouts (the expanse of the blackout and resources available for restoration), knowledge of these guidelines is important. They represent a general-purpose tool for system restoration. More specific guidelines for restoration of the 345 kV system in the event of a complete blackout are also provided in the New England restoration procedures. The specific actions in these guides reflect the general guidelines. Where appropriate, the Local Control Center and the ISO procedures have been coordinated.

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Attachment 3

New York Area Restoration Overview

Introduction

This procedure establishes the guidelines to be used in the restoration of the New York state power system following a major disturbance. Since the exact extent or nature of the disturbance cannot be predicted, the procedure is presented as a general guide.

1. In the event of a complete system shutdown, the Transmission Providers are trained and expected to work from a planned sequence of steps to develop a 345 kV back bone system across the state.
2. If a partial shutdown occurs, or if a portion of the NYS Power System becomes isolated, the Transmission Owners shall execute only those steps required to restore the area in which the outage exists.

Prompt restoration of the NYISO total customer **load** is best accomplished by the restoration of the New York state power system. Although some customer **load** may be picked up during this procedure to maintain stability and voltage levels, priority must be assigned to the restoration of the major transmission **tie lines**. Each Transmission Owner may restore **load** within its area in accordance with its own restoration plan, but **load** restoration must not delay the restoration of inter-and intra-**Area tie lines**.

Throughout the restoration process, it is the objective of these procedures that the restored facilities be operated in accordance with the operating criteria of the NY State Reliability Council, the New York ISO, the Northeast Power Coordinating Council and the North American Electric Reliability Council.

Each Transmission Owner is responsible for performing the actions listed below in the substations and facilities within its jurisdiction. As these actions are carried out, the Transmission Owner shall inform the NYISO Shift Supervisor, who is responsible for overall coordination of the restoration procedure.

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Attachment 4

Ontario Area Restoration Overview

Operational Authority Structure

In accordance with the Ontario Electricity Act of 1998, the Independent Electricity System Operator (IESO) is responsible for managing the reliability of the IESO controlled grid, operating a competitive marketplace for electricity and mitigating the impacts of electricity **emergencies** on public health and safety.

To accomplish the above, the IESO directs the operation of the IESO controlled grid in accordance with operating agreements with the Ontario Transmission Operators. These agreements identify what transmission system **elements** are included in the IESO controlled grid and the terms and conditions by which the IESO directs their operation. The IESO has no direct physical control of the devices that comprise the transmission system.

The IESO administers Ontario's market rules by which market participants are bound by their participation agreements to fulfill specified obligations necessary for reliability.

To operate the interconnections to fulfill its obligations to the Electricity Act, NERC and the Northeast Power Coordinating Council, the IESO has interconnection agreements and associated joint operating procedures with adjacent Reliability Coordinators and Transmission Operators.

To operate the marketplace, the IESO runs an automated dispatch every five minutes. The dispatch algorithm achieves the most **economic dispatch** in accordance with submitted bids and offers and scheduled transactions given the prevailing electrical security constraints. The dispatch algorithm simultaneously solves for **operating reserve**.

The IESO can manually dispatch generators by direct voice communication to generator operators when circumstances dictate this be done to manage reliability.

As defined in the NERC functional model, the IESO is a Reliability Coordinator, Transmission Operator, Balancing Authority, Interchange Authority, Transmission Service Provider, Market Operator and Compliance Monitor.

Overview of System Restoration Plan for Ontario

The Ontario Power System Restoration Plan (OPSRP) is structured to address what is needed to enable successful system restoration in four related subject areas:

1. Operational;
2. Testing;
3. Training; and
4. Administration.

The primary objective of the Ontario Power System Restoration Plan (OPSRP) is to restore the

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IESO controlled grid to a secure operating state, to the maximum extent possible, based on the equipment that returns to service after a partial or complete blackout.

The OPSRP priorities are to restore critical station service to the nuclear plants, other generating and transmission facilities, operational control centers and telecommunication installations. This is given top priority to minimize reliance on stored energy systems (batteries, compressed air systems, etc.). **Islands** containing nuclear and fossil generators are **synchronized** at the earliest opportunity in an effort to increase the chances of their survival by expediting their return to service.

Since the post-**contingency** system configuration is not predictable, the plan was designed to be sufficiently flexible to be applicable to the wide range of possible configurations. The OPSRP does not require a step by step restoration of predefined paths; rather, its successful implementation is predicated on strategies, procedures, identified limitations and rules of thumb to overcome them (based on worst case scenarios) that give the **system operators** guidance for each stage of the restoration. The OPSRP focuses on controlling voltage and frequency deviations to magnitudes that are non-impactive and on reducing the exposure to additional disturbances.

Subsequent to the post disturbance assessment and actions to stabilize any surviving electrical **islands**, the four stages of system restoration are:

1. Recovery of generation;
2. **Energizing** transmission lines;
3. Load restoration (initially to lower voltage), and
4. S**ynchronizing** electrical **islands**.

By off line study, modeling and engineering analysis, rules of thumb have been developed to guide **system operators** in overcoming the constraints that are encountered during each of the above four stages of system restoration.

The OPSRP also specifies mandatory independent actions by Restoration Participants to carry out the following:

1. Maintain the availability of generators post disturbance;
2. Shed load on underfrequency;
3. Open circuit breakers that are off potential in preparation for system restoration;
4. Restore station service at step-down transformer stations; and
5. Synchronize bypass their units at speed no load (SNL) to sustain their in plant station service, including the switching of any units from condense mode to generate mode.

Should any adjacent interconnected system be stable and secure, or an electrical **island** within Ontario survive, the IESO controlled grid would be restored using this source of potential. Should Ontario lack a source of restart potential from the aforementioned sources, the OPSRP relies on designated blackstart sites. Certified blackstart service providers must perform an annual test, including the energization of one of the transmission circuits out of the generating station. Their performance is strictly monitored by the IESO for adherence to their ancillary service contract. In addition, it is estimated that, as a minimum, one fossil / nuclear unit at each

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station is expected to survive, and all available generating sources are expected to aid in the restoration process.

The large size of the IESO-controlled grid led to dividing the system into smaller areas for the purpose of restoration after a complete system shutdown. Depending upon the post-**contingency** configurations and **resources**, the plan can be implemented in whole or in part. The IESO can manage the simultaneous creation of, and restoration of, a number of electrical **islands**. Once formed, these **islands** are **synchronized** together, or are **synchronized** with adjacent areas, in a controlled fashion.

To guide operations staff, the OPSRP contains high level system restoration path diagrams for eight potential paths, and four restoration strategy diagrams for Ontario as a whole in accordance with four large electrical islands. Additionally the IESO has introduced two way communications guidelines to enhance the effectiveness of operational communications with the operations staff of nuclear and fossil generating stations.

Administration to Sustain Emergency Response Capabilities

The IESO has implemented all identified opportunities for improvement identified in the various blackout investigations following the power system collapse of August, 2003.

In consideration of the 1998 ice storm and the advent of Ontario's competitive marketplace in 2002, the associated market rules were strengthened in the area of **emergency** preparedness. As a consequence, Ontario requires all market participants to file an Emergency Preparedness Plan, and those participants that operate facilities impactive to the restoration process must file and certify a restoration plan attachment. There are currently ninety-six Restoration Participants in Ontario as of April 2005. To maintain Ontario's collective level of emergency preparedness, the IESO annually conducts large scale exercises supported by localized tabletop drill and training sessions with many of the Restoration Participants.

All OPSRP revisions are achieved with input from all Restoration Participants in Ontario, and the OPSRP fully conforms to NERC and NPCC requirements.

The OPSRP also covers the training requirements for operations staff, testing requirements of facilities, restoration tests (blackstart**s**) and simulations conducted through tabletop exercises and large scale exercises. All are critical elements to the success of any system restoration plan.

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Attachment 5

Québec Area Restoration Overview

1.0 Introduction

Every utility takes, in designing and operating its system, all the necessary precautions to limit **contingencies** leading to a blackout of the system. However, the possibility of such a shutdown still exists, and the utilities must have a plan to restore their system and resume normal operation.

Note: The information contained in this document derives from the system restoration plan of Hydro-Québec TransÉnergie which consists primarily of hydroelectric generation. Therefore some of the information might not be applicable to a different system, and some features particular to fully thermal systems might not have been covered in this text.

2.0 Objective

To allow restoration of the system, safely, in the shortest possible time.

3.0 Methodology

The design of the restoration plan contains the following elements:

1. Basic plan;
2. Regular follow-up;
3. Personnel and material required; and
4. Testing of **critical components** associated with **key facilities**.

3.1 Basic Plan

The primary priority of the basic restoration plan is the restoration of AC station service to the nuclear plant.

If a blackout occurs, the configuration of the system has to be examined to identify possible restoration paths allowing the partition of the main system into **basic minimum power systems** (BMPS). A BMPS consists of one or more generating stations, transmission lines and substations. These BMPSs are stand alone and can be restored independently. To restore the total system, the **system operator** in charge of the restoration process will select one BMPS as the main system upon which all the other BMPSs are to be **synchronized**. While waiting for that **synchronization**, as much **load** as its **generation** capacity permits continues to be independently restored in each BMPS.

A special case is recognized if a subsystem stays synchronous or can be rapidly **synchronized** with a neighboring utility, its final integration to the main system

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will be carried out according to the rules governing exchanges between the two systems, in accordance with the relevant operating agreement.

The selection of the restoration paths is based on practical criteria. The plan is also subject to technical criteria and a number of precautions required for a smooth restoration process. Taking into account these three factors will ensure an optimal restoration procedure having the minimum risk and the shortest duration.

3.2 Follow-up

The following activities are required to ensure the continuous validity of the plan.

3.2.1 Daily Follow-up of the System Configuration

Once the restoration plan is set up, it must be constantly updated to keep track of equipment outages. Some equipment is designated as necessary for the restoration process (i.e., they are within, or directly affect, the restoration path), and a listing is produced and continually updated. If any such equipment is unavailable, an analysis is performed to identify alternate paths or equipment. Some of these substitutes may already be part of the **key facilities** list, but it is important to analyze each occurrence of simultaneous outages and validate the alternative options accordingly.

Also, an assessment of the yearly maintenance schedule avoids situations that could affect the restoration process.

3.2.2 System Expansion Plan

The impacts of additions and modifications must be assessed and their impact on the restoration procedure thoroughly evaluated.

3.2.3 Presentation of the Plan

The total blackout of a system being an infrequent and sudden event, it is important to keep the operations staff up to date regarding the plan. A formal presentation is scheduled at least once a year with all the operations personnel concerned.

3.3 Personnel and Material

To ensure fast and efficient application of the plan, proper logistics is required.

3.3.1 Personnel

One **system operator** is selected to be in charge of the restoration process, and his role is clearly defined, along with the role of all other people

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involved in the process.

Backup Team

Each control center, system control center and remote control center must have a multidisciplinary backup team able to solve any problem that might occur during the process. This team includes experts in the following fields: operating procedures, **power** system analysis, electrical apparatus, automatic controls and remote systems, **protective relaying**, telecommunications and computer controlled systems.

A list of the backup team, with the phone numbers, is prepared and continuously updated. It is available at all control centers.

3.3.2 Material

Emergency Procedures

The plan must be broken down into a set of **emergency** procedures for each **key facility**. These procedures state in a short and precise way the operations that are to be performed to isolate the station (preliminary operations) and then to initiate the restoration process. They do not include technical or administrative information. Their application is compulsory.

Following a blackout, the procedures are to be applied step by step. Any abnormal event preventing the application of one procedure must be reported to the **system operator** in charge. No modification is allowed without his permission, since all these procedures are part of a coordinated plan and depend on operations performed before and after that particular operation.

To facilitate the restoration process, system control and remote system control sets of **emergency** procedures summarize the main steps to follow.

Blackstart Procedures:

These procedures state in a short and precise way the operations to be performed, to start generating units designated as having **blackstart capability** and used to initiate the BMPS restoration process.

Restoration Process Diagram:

A diagram of the restoration plan, showing all the BMPSs, will assist the on-shift **system operator** to implement the plan in a step-by-step manner in case of computer deficiencies.

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Key facilities and Critical Components Lists:

These lists are continuously kept up to date.

Audio Communication System:

An instantaneous and efficient means for the **system operator** in charge to communicate with each station.

Automated Functions:

The control centers using computer operating systems use the following functions:

1. **Blackout Function**

   To avoid computer overload due to the avalanche of alarms and status changes following the system shutdown, this function should be active only for a very short time and be very selective to allow posting of all the major alarms.

2. **Reset Function**

   This function allows the operation, through the remote control center, of any critical circuit breaker in order to speed up the restoration process.

3. **Load Restoration Function**

   This function permits the automatic recording of the progress of the **load** restoration, station by station, for each subsystem.

4.0 Testing of Critical Components Associated With Key Facilities

Testing of **critical components** associated with **key facilities** shall be performed at a frequency and for a duration that is sufficient to reasonably ensure that the **critical components** will function properly when isolated from all **power** sources not available during a partial or complete system blackout. As a minimum, this frequency and duration of testing is stated in NPCC Document A-03, "Emergency Operation Criteria."

5.0 Control of the Restoration Process

5.1 Control Centers

As soon as the shutdown of the system is acknowledged, all remote control center **system operators** and neighboring **system operators** are notified. Application of

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the **emergency** procedures is initiated at once. The corporate **emergency** response hierarchy is immediately informed of the situation and the following actions are initiated:

1. Backup teams are called in;
2. Other **system operators** are called in;
3. An operator is dispatched to every unattended key facility;
4. An inventory of all unavailable equipment (already out before the blackout and equipment which failed during the event) is set and transmitted to the **system operator** in charge and to his backup team;
5. Information or questions unrelated to the restoration process are not forwarded to the control centers. Only authorized personnel involved in the restoration process are allowed in the control rooms;
6. The **system operator** follows carefully the restoration of the BMPS and checks that all is done according to the plan. Any reported discrepancy is addressed and transmitted to the backup team for analysis. The team then formulates alternate solutions;
7. Voltage and frequency profiles are the preferred monitoring indicators to speed up or to slow down the **load** restoration;
8. **Synchronization** of the different BMPSs is coordinated by the **system operator**. **Load** restoration is stopped during **synchronization** of the BMPS;
9. **Synchronization** of the different subsystems is coordinated by the **system operator**;
10. The next step is to continue **load** restoration until all the **load** is back on the system;
11. The last step is to resume normal operation and **reenergize** the **tie lines** with neighboring utilities.

5.2 Individual Facility

After the blackout has occurred, determine:

1. Tripped equipment;
2. **Energized** or in service equipment;
3. Breakers which have remained closed;
4. Unavailable equipment;
5. Proceed with **emergency** procedures; and
6. Contact the remote control **system operator** in charge to report any problem.

6.0 Debriefing

As soon as possible after the event a meeting is held to identify any problem, malfunction or difficulty observed during the restoration process.

A final report is prepared to disclose any difficulty encountered and propose corrective actions.

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Attachment 6

External Power Systems-Midwest ISO Restoration Overview

Operational Authority Structure

The Midwest ISO (MISO) reliability footprint is divided into three regions (Central, East and West). The Central and East regions are handled in the Carmel, Indiana, office, with the West region controlled from the St. Paul, Minnesota, office. Both offices have the same Reliability Coordinator (RC) authority.

The East Region deals with MECS (Michigan Electric Coordinated System), which in turn directs the ITC (International Transmission Company) on operational matters. The MECS is the Balancing Authority, and the ITC is the Transmission Owner.

The West Region deals with Minnesota Power and Manitoba Hydro, both of which are Balancing Authorities and Transmission Owners.

The MISO dispatches all **generation** for its member companies, and it has functional control of their operations, meaning that the MISO has the authority to direct actions to be taken by the Balancing Authorities and / or Transmission Owners. The MISO does not have the capability to physically control equipment on the system (this is done by the Transmission Owner). The MISO approves transmission access request, and the MISO scheduling coordinates schedules on a footprint wide basis.

Emergency Preparedness

The MISO reliability coordinators and real-time operational staff handle system **emergencies** according to NERC guidelines and internal MISO procedures. Information for dissemination to public entities comes from the MISO real-time management; this is then provide to the MISO public relations department which issues the information for public consumption.

System Restoration Summary

The MISO has detailed coordinated restoration plans. These are reviewed yearly with participation from the MISO member companies. MISO uses a sub-regional structure and philosophy to coordinate and plan for restoration. There are nine identified sub-regions in the MISO footprint that are geographical and electrical in nature. This allows for response to be flexible depending on where the restoration needs exist. The MISO system restoration plan contains all pertinent infrastructure information involved in restoration, including blackstart unit locations, synchroscope locations, critical paths, critical **loads**, etc. Given that the location or magnitude of a system separation cannot be predicted, the MISO plan and structure give it the ability to respond to any given restoration situation. The MISO also has developed an interconnection checklist to ensure **island** stability and enhance successful **synchronizing** when tying **islands** together. The MISO also has data collection forms that are utilized during

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restoration to allow for quick assessment and dissemination of information during actual restoration events.

Plans are practiced yearly through exercises to assess the response plan, Reliability Coordinator action, Balancing Authority operator action and Transmission Operator reaction to a system separation event. Past exercises have focused on operator understanding of the restoration plan, concepts of restoration, testing all aspects of communication protocols among operating entities (e.g. Reliability Coordinator to Reliability Coordinator, Reliability Coordinator to Transmission Operator and Balancing Authority, Transmission Operator to Transmission Operator, etc.), island operation, and interconnections.

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Attachment 7

External Power Systems-PJM Restoration Overview

In the PJM RTO, during the initial stages of a restoration, each Load Serving Entity is responsible for restoring its own customer **load** with internal **generation** or through coordinated efforts with other Transmission / Generation Owner. After a subsystem is stabilized, requests from neighboring entities for cranking **power** are a higher priority than restoring additional customer **load** of the supplying **Load** Serving Entity / Transmission Owner. Any **Load** Serving Entity / Transmission Owner that is not operating in parallel with adjacent **Load** Serving Entities / Transmission Owners is free to restore or shed **load** in any manner or at any rate it may deem reasonable.

Local Control Centers that share common transmission or **generation** facilities (345 kV or below) must develop pre-arranged plans for the priority operation of these facilities during restoration. These plans include the maintenance of good communications during the period of the **emergency**.

The PJM dispatcher immediately establishes communications with the Transmission Owners and adjacent operating areas experiencing the disturbance to establish the extent and severity of the separation. If direct communication channels are not functioning, communications are established via whatever means are available (i.e., routing calls through alternate channels, outside phone lines, radio communications, and / or PJM Satellite Phone System).

PJM Operator Responsibilities During the Restoration Process

The PJM System Operator has certain responsibilities regardless of the stage of the system restoration process. Transmission Owners will have primary responsibility of restoring their transmission system until such time as PJM is returning to normal operation and resumes authority over the transmission system. PJM actions during a system restoration include:

1. PJM will coordinate all interchange schedules with external operating areas.
2. PJM will coordinate and direct all restoration of the 500 kV transmission system.
3. PJM will develop and calculate **area control error** (ACE) as required when appropriate data is available to perform this calculation.
4. PJM will coordinate and direct all transmission tie connections to external operating areas.
5. PJM will identify opportunities for interconnection between PJM internal Transmission Owners and / or neighboring operating areas.
6. PJM will collect system status information and provide status updates to members on system restoration status.
7. PJM will conduct periodic System Operations Subcommittee (SOS) conference calls, as appropriate.

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The following table presents the general steps that are performed to restore the PJM RTO following separation:

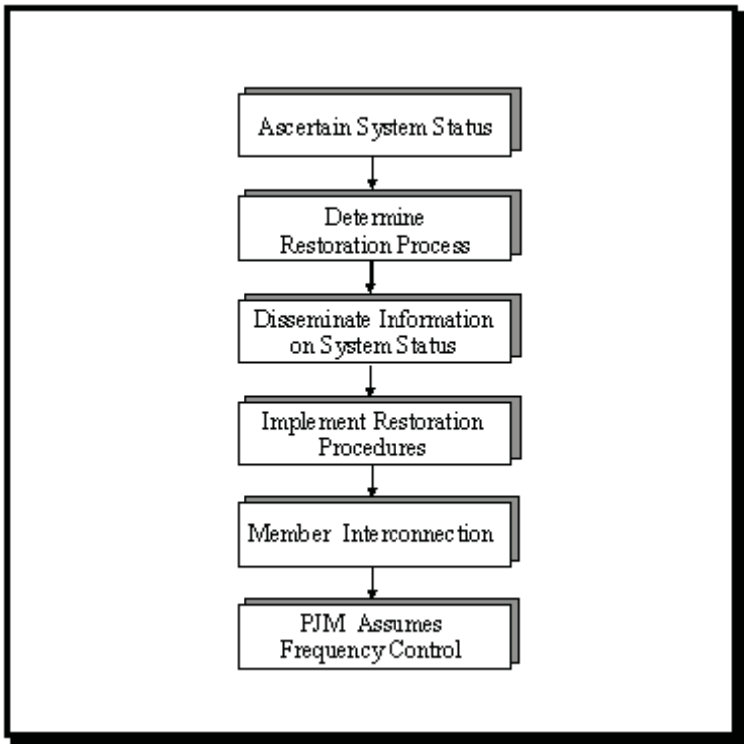

Ascertain System Status

After a system disturbance occurs that results in a significant loss of customer **load** in a widespread area, it is important to determine transmission and **generation** loss, equipment damage, and the extent of the service interruption.

Determine Restoration Process

The purpose of this step is to develop and implement a restoration strategy. This step is performed after the status of the PJM RTO is determined.

Disseminate Information

The purpose of this step is to provide updated information of the system status to appropriate personnel. After system restoration plans are established and implemented, all participants must be apprised of system conditions.

Implement Restoration Procedure

The purpose of this step is to direct the restart of Generation Owners internal **generation** and **load** on-line **generation** in planned steps while maintaining system **load**, scheduled frequency, voltage control and **reserves**. This step is performed when a Transmission

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Owner / Generation Owner is in a completely isolated or blacked-out condition and must restart their system without outside assistance.

Member Interconnection

The purpose of this step is to provide guidelines for the Transmission Owners to interconnect and control frequency, **tie line**, voltage schedules, share **reserves** and coordinate **emergency** procedures. This step is performed after the Transmission Owners have restarted and desire to interconnect and share reserves or Transmission Owners have coordinated plans to restart while interconnected.

PJM Assumes Frequency Control

This occurs when the control of an interconnected area is too burdensome for any one Local Control Center

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NPCC
Regional Reliability Reference Directory # 9
Verification of Generator
Gross and Net Real Power Capability

Task Force on Coordination of Operations Revision Review Record:
December 22, 2008

Adopted by the Members of the Northeast Power Coordinating Council, Inc. this December 22, 2008 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

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Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	12/22/2008		New
1	07/07/2009	Included FAC-008 in Section 3.0	Errata

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Appendix A

Appendix B

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1.0 Introduction

1.1 Title Verification of Generator Gross and Net Real Power Capability

1.2 Directory Number 9

1.3 Objective

This Directory presents the minimum criteria for verifying the **Gross Real Power Capability** and **Net Real Power Capability** of generators or generating facilities.

Compliance to the criteria set forth in this Directory by each applicable entity assures accuracy of information used in the steady-state models to assess the reliability of the NPCC bulk power system. This Directory has been developed to ensure that the requirements specified in NERC Standard MOD-024-1, "Verification of Generator Gross and Net Real Power Capability" are met by NPCC and its applicable members responsible for meeting the NERC Reliability Standards.

1.4 **Effective Date** **December 22, 2008**

1.5 Background

This Directory was developed from the draft NPCC A-13 Verification of Generator Gross and Net Real Power Capability Criteria document whose technical content was approved by the Reliability Coordinator Committee on March 5,2008 for conversion into a Directory.

1.6 Applicability

1.6.1 Functional Entities

Generator Owners
Transmission Operators (in whose area the generator or generation facility resides)

2.0 Terms Defined in this Directory

The definitions of terms appearing in bold typeface in this Directory can be found in Appendix A.

3.0 NERC ERO Reliability Standard Requirements

The NERC ERO Reliability Standards containing requirements that are associated with

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this Directory include:

3.1 MOD-024-1 -Verification of Generator Gross and Net Real Power Capability
3.2 TOP-002-2 - Normal Operations Planning
3.3 FAC-008-1 - Facility Ratings Methodology
3.4 FAC-009-1 - Establish and Communicate Facility Ratings

4.0 NPCC Regional Reliability Standard Requirements

None.

5.0 NPCC Specific Criteria

5.1 Developing the List of Generators or Generation Facilities to be Verified

The Transmission Operator shall identify and maintain documentation of those generators and generation facilities subject to periodic seasonal **Gross Real Power Capability** and **Net Real Power Capability** verification. The documentation maintained by the Transmission Operator shall at least include the following:

5.1.1 Listing of all generators or generation facilities and their D**eclared Gross Real Power Capability** and **Net Real Power Capability**.

5.1.2 Listing of all generators' or generation facilities' V**erified Gross Real Power Capability** and **Net Real Power Capability**, verification date and method of verification.

5.1.3 Listing for each generator's or generation facility's discrepancies between a Generator Owner's declared and verified **Gross Real Power Capability** and **Net Real Power Capability** (Sections 5.2.2 and 5.6.1.3), the reason for such discrepancies and a Generator Owner's plan to address the discrepancies.

5.1.4 Copies of Generator Owner supplied **Gross Real Power Capability** and **Net Real Power Capability** testing, manufacturer data, performance tracking or operating historical data, certification documentation, as specified by the Transmission Operator.

5.1.5 Listing of generators exempted from the verification requirements and the basis for their exemption (see Section 5.5).

5.2 Establishing the Generator Real Power Capability Verification Program

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5.2.1 The Transmission Operator shall establish and maintain a program to periodically verify the **Gross Real Power Capability** and **Net Real Power Capability** of all generators and generation facilities that are subject to periodic seasonal **Gross Real Power Capability** and **Net Real Power Capability** verification.

5.2.2 The Transmission Operator shall establish requirements for a Generator Owner to notify the Transmission Operator within a specified time period when its generator or generation facility cannot achieve the **Declared Gross** or **Net Real Power Capability** because of equipment issues. The Transmission Operator shall specify a time frame for the Generator Owner to address this discrepancy.

5.2.3 The Transmission Operator shall report annually to NPCC about the status of its program including any changes in verification process related to verification of **Gross Real Power Capability** and **Net Real Power Capability**, and provide copies of any changes to its verification process to the Generator Owners and NPCC within 30 days of issue.

5.3 Implementing the Generator Real Power Capability Verification Program

The Transmission Operator shall request the Generator Owners to verify the seasonal **Gross Real Power Capability** and **Net Real Power Capability** of their generators or generation facilities that are subject to periodic seasonal **Gross Real Power Capability** and **Net Real Power Capability** verification in accordance with the verification schedule specified in Section 5.3.1. The two (2) capability seasons are defined as summer and winter as specified by the Transmission Operator.

5.3.1 Generator and generation facility **Gross Real Power Capability** and **Net real Power Capability** shall be re-verified every three (3) years or as required by the Transmission Operator.

5.3.1.1 If a Transmission Operator determines that only one seasonal generating capability value will suffice for NPCC Bulk Power System reliability analysis, then periodic verification will be required only for that particular season.

5.3.1.2 If a Transmission Operator determines that the difference between **Gross Real Power** and **Net Real Power Capability** of a generator or generation facility is insignificant for NPCC Bulk Power System reliability analysis, then periodic verification will be required for only one numerical value.

5.4 Verification Criteria for Generator and Generation Facility Real Power Capability

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The Generator Owners shall comply with the Transmission Operator's requests for periodic verification of **Gross Real Power Capability** and **Net Real Power Capability** of their generators or generation facilities. The Generator Owners shall apply the following criteria to verify the **Gross Real Power Capability** and **Net Real Power Capability** of their generators or generation facilities according to their types, as specified by the Transmission Operator.

5.4.1 Thermal Generators

The verification of **Gross Real Power Capability** and **Net Real Power Capability** of a generator shall be determined on the basis of operation for no less than one hour.

The verification of a thermal generator's capability can include testing, use of operating historical data, commissioning data (for new generators only) and performance tracking data acquired during the same seasonal capability testing period.

5.4.2 Internal Combustion Generators and Gas Turbine Generators

The verification of **Gross Real Power Capability** and **Net Real Power Capability** for internal combustion generators and gas turbine generators shall correspond to the ambient conditions normally expected for the seasonal period for which the **Gross Real Power Capability** and **Net Real Power Capabilities** are being claimed for no less than one hour.

The verification of internal combustion and gas turbine generator's capability can include testing, use of operating historical data, commissioning data (for new generators only) and performance tracking data acquired during the same seasonal capability period.

5.4.3 Hydro Generators

5.4.3.1 Hydro capability shall be determined on a generation facility or an individual generator basis.

5.4.3.2 The **Gross Real Power Capability** and **Net Real Power Capability** shall be determined on the basis of the availability of sufficient water at an adequate head to provide the output for no less than one hour.

5.4.3.3 The verification of a Hydro generator's capability can include testing, use of operating historical data, commissioning data (for new generators only) and performance tracking data acquired during the same seasonal capability period.

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5.4.4 Combined Cycle Generators

5.4.4.1 Combined cycle generator capability shall be determined on a generation facility, individual generator or on a generator stage basis.

5.4.4.2 The verification of **Gross Real Power Capability** and **Net Real Power Capability** for combined cycle generators shall correspond to the ambient conditions normally expected for the seasonal period for which the Gross Real Power Capability and Net Real Power Capabilities are being claimed for no less than one hour.

5.4.4.3 The verification of a combined cycle generator's capability can include testing, use of operating historical data, commissioning data (for new generators only) and performance tracking data acquired during the same seasonal capability period.

5.4.5 Intermittent Power Sources

For intermittent power resources (wind, solar, tidal or geo-thermal generators) the manufacturer's data, performance tracking and operating historical data shall be used to determine generator or generation facility **Gross Real Power Capability** and **Net Real Power Capability**.

5.4.6 Multiple Generator facilities Forming a Generation Facility

The verification of **Gross Real Power Capability** and **Net Real Power Capability** for multiple generator facilities when limited by common elements shall be based on the real power capability of the facility and not the sum of the capabilities of the individual generators.

5.4.7 Consideration of Other Limitations

The Generator Owner shall identify any equipment or other factor that will limit the capability of the generator or generation facility to meet its **Declared Gross Real Power Capability** and **Net Real Power Capability.**

5.5 Exemption of Generators or Generation Facilities from Verification Testing

5.5.1 The Generator Owner shall notify the Transmission Operator and request for exemption if it cannot conduct seasonal capability testing on a generator or generation facility for any of the reasons listed below. For

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existing generators, the Generator Owner shall submit generator operation records, manufacturer data, or performance tracking for the same previous seasonal verification period for this generator or generation facility. For new generators only, the Generator Owner shall submit commissioning data.

1. Adverse impact on transmission system reliability

2. Potential damage to transmission system or generator equipment

3. Environment conditions

4. Governmental regulatory or operating license limitations

5.5.2 The Transmission Operator shall, within 30 days of receiving notification by a Generator Owner that it cannot perform verification testing for the required seasonal period, notify the Generator Owner that its generator will be exempted from the seasonal capability testing.

5.6 Documenting and Reporting Verified Generator and Generation Facility Gross and Net Real Power Capabilities

5.6.1 Each Generator Owner shall, as specified by the Transmission Operator:

5.6.1.1 Provide generator or generation facility **Declared Gross Real Power Capability** and **Net Real Power Capability** to the Transmission Operator.

5.6.1.2 Provide evidence, upon request, to the Transmission Operator that generator or generation facility **Gross Real Power Capability** and **Net Real Power Capability** have been verified.

5.6.1.3 Report to the Transmission Operator any discrepancies between **Declared** and **Verified Gross Real Power Capability** or **Net Real Power Capability** within a time frame specified by the Transmission Operator as required in Section 5.2.2, and develop and implement a plan to resolve the discrepancies.

5.6.1.4 Determine and report the generator or generation facility real power seasonal auxiliary **loads** (including common station **loads**) to the Transmission Operator.

5.6.2 The Transmission Operator shall:

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5.6.2.1 Document any discrepancies between system modeling and generator verified capabilities, the reason for such discrepancies and resolve the discrepancy with the Generator Owner.

5.6.2.2 Specify a time frame for the Generator Owner to address the discrepancy between the **Declared** and **Verified Gross Real Power Capability** or **Net Real Power Capability** of its generators or generation facilities.

5.6.2.3 Report to NPCC annually any discrepancies between **Declared** and **Verified Gross Real Power Capability** or **Net Real Power Capability**.

6.0 Measures and Assessments

None developed at this time.

7.0 Program Validation and Compliance Monitoring

The NPCC Task Force on Coordination of Operation shall annually validate that each Transmission Operator has implemented the **Gross Real Power Capability** and **Net Real Power Capability** verification program.

The NPCC Compliance Committee shall conduct periodic compliance audits to review the effectiveness of the Transmission Operator's **Gross Real Power Capability** and **Net Real Power Capability** verification program and ensure compliance to the criteria in this Directory by the responsible entities.

Adherence to these criteria shall be reported by each responsible entity in a manner and form designated by the Compliance Committee.

Prepared by: Task Force on Coordination of Operation / Task Force on Coordination of Planning

Review and Approval: Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45 day review and

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comment period. Upon satisfactorily addressing all the comments in this forum, the Directory document will be sent to the remaining Task Forces for their recommendation to seek RCC approval.

Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC. Bylaws" in effect at the time the ballots are cast.

Revisions pertaining to the Appendices or any other portion of the document such as links, glossary terms, etc., only RCC Members will need to conduct the final approval ballot of the document.

This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

References: NPCC Glossary of Terms (Document A-7)

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Appendix A
Definition of Terms[1]

Declared Capability (of a generator or generating facility) – The facility ratings submitted by the Generator Owner to the respective Transmission Operator as per NERC Standard FAC-009.

Gross Real Power Capability (of a generator or generating facility) – The maximum megawatt output at the generator terminals, at the normally expected system conditions for that seasonal capability period.

Load — The electric **power** used by devices connected to an electrical generating system. (IEEE Power Engineering). Also see **Demand**.

Interruptible Load — Loads that are interruptible under the terms specified in a contract.

NPCC Specific Definitions:

Net Real Power Capability (of a generator or generating facility) – The Gross Real Power Capability, less the auxiliary real power loads necessary to operate the generator at maximum real power output.

Verified Capability (of a generator or generating facility) – The capability as demonstrated by the methods specified in this Directory and accepted by the Transmission Operator.

Appendix B

Basic Flow Chart for Verification of Generator Gross and Net Real Power Capability

[1] These terms will be moved and grouped under a separate Directory when all other Directories are developed.

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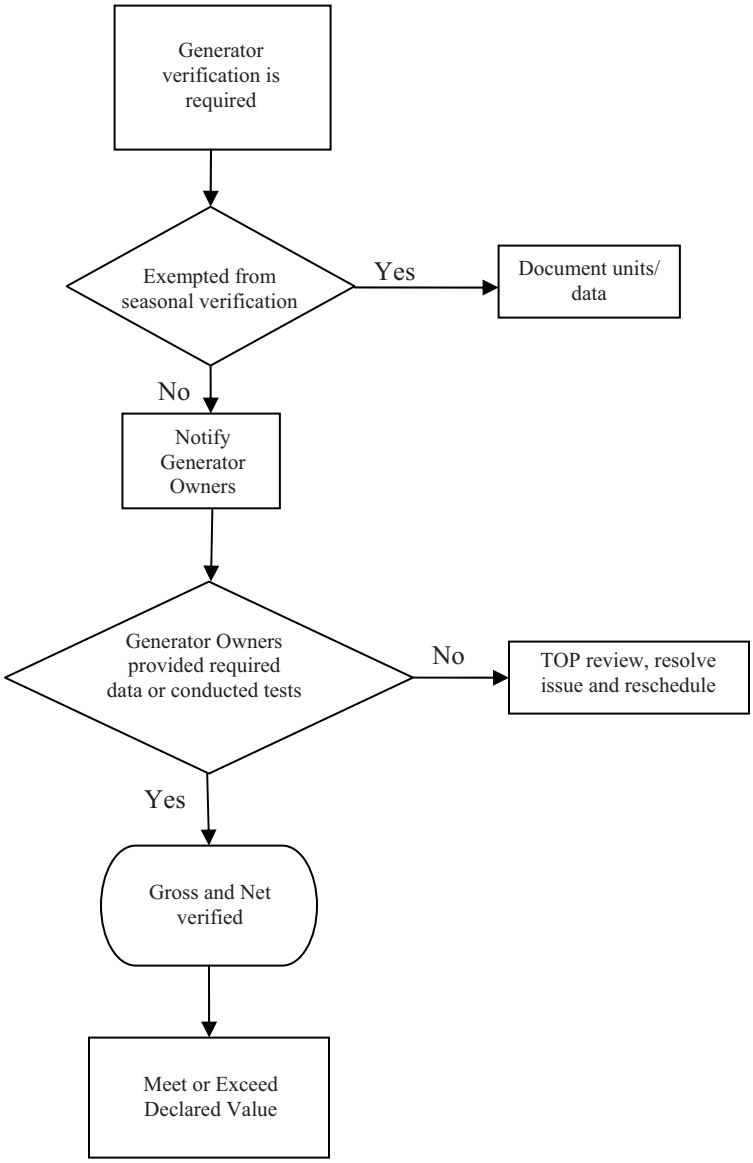

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NPCC, Inc.

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NPCC

Regional Reliability Reference Directory # 10
Verification of Generator
Gross and Net Reactive Power Capability

Task Force on Coordination of Operations Revision Review Record:
December 22, 2008

Adopted by the Members of the Northeast Power Coordinating Council, Inc. this December 22, 2008, based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

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Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	12/22/08		New
1	07/07/09	Included FAC-008 in Section 3.0	Errata

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Appendix A

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This document, when downloaded or printed, becomes UNCONTROLLED. Users should check the NPCC website for the current CONTROLLED version of this document.

1.0 Introduction

1.1 Title Verification of Generator Gross and Net Reactive Power Capability

1.2 Directory Number 10

1.3 Objective

This Directory presents the minimum criteria for verifying the **Gross Reactive Power Capability** and **Net Reactive Power Capability** of generators or generating facilities.

Compliance to the criteria set forth in this Directory by each applicable entity assures accuracy of information used in the steady-state models to assess the reliability of the NPCC bulk power system. This directory has been developed to ensure that the requirements specified in NERC Standard MOD-025-1, "Verification of Generator Gross and Net Reactive Power Capability" are met by NPCC and its applicable members responsible for meeting the NERC standards.

1.4 Effective Date **December 22, 2008**

1.5 Background

This Directory was developed from the draft NPCC A-14 Verification of Generator Gross and Net Reactive Power Capability Criteria document whose technical content was approved by the Reliability Coordinator Committee on March 5, 2008 for conversion into a Directory.

1.6 Applicability

1.6.1 Functional Entities

Generator Owners

Transmission Operators (in whose **area** the generator or generation facility resides)

2.0 Terms Defined in this Directory

The definitions of terms appearing in bold typeface in this Directory can be found in Appendix A.

3.0 NERC ERO Reliability Standard Requirements

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The NERC ERO Reliability Standards containing requirements that are associated with this Directory include:

3.1 MOD-025-1 - Verification of Generator Gross and Net Reactive Power Capability
3.2 TOP-002-2 - Normal Operations Planning
3.3 FAC-008-1- Facility Ratings Methodolgy
3.4 FAC-009-1 - Establish and Communicate Facility Ratings

4.0 NPCC Regional Reliability Standard Requirements

None.

5.0 NPCC Specific Requirements

5.1 Developing The List of Generators or Generation Facilities to be Verified

The Transmission Operator shall identify and maintain documentation of those generators and generation facilities subject to periodic seasonal **Gross Reactive Power Capability** and **Net Reactive Power Capability** verification. The documentation maintained by the Transmission Operator shall at least include the following:

5.1.1 Listing of all generators or generation facilities and their **Declared Gross Reactive Power Capability** and **Net Reactive Power Capability** and seasonal auxiliary load reactive power requirements. (Reference Appendix B-2).

5.1.2 Listing of all generators' or generation facilities' **Verified Gross Reactive Power Capability** and **Net Reactive Power Capability**, verification date and method of verification.

5.1.3 Listing of each generator's or generation facility's discrepancies between a Generator Owner's **Declared** and **Verified Gross Reactive Power Capability** and **Net Reactive Power Capability**, the reason for such discrepancies and a Generator Owner's plan to address the discrepancies.

5.1.4 Copies of Generator Owner supplied **Gross Reactive Power Capability** and **Net Reactive Power Capability** testing, manufacturer data, performance tracking or operating historical data, certification documentation, as specified by the Transmission Operator.

5.1.5 Listing of generators exempted from the verification requirements and the basis for their exemption (see Section 5.5).

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5.2 Establishing the Generator Reactive Power Capability Verification Program

5.2.1 The Transmission Operator shall establish and maintain a program in accordance with the criteria outlined in this Document to periodically verify the **Gross Reactive Power Capability** and **Net Reactive Power Capability** of all generators and generation facilities that are subject to periodic seasonal **Gross Reactive Power Capability** and **Net Reactive Power Capability** verification.

5.2.2 The Transmission Operator shall establish requirements for a Generator Owner to notify its Transmission Operator within a specified time period when its generator or generation facility cannot achieve the **Declared Reactive Power Capability** because of equipment issues.

5.2.3 The Transmission Operator shall report annually to NPCC about the status of its program including any changes in the verification process related to verification of **Gross Reactive Power Capability** and **Net Reactive Power Capability** and provide copies of any changes to its verification process to the Generator Owners and NPCC within 30 days of issue.

5.3 Implementing the Generator Reactive Power Capability Verification Program

The Transmission Operator shall request the Generator Owners to verify the seasonal **Gross Reactive Power Capability** and **Net Reactive Power Capability** of their generators or generation facilities that are subject to periodic seasonal **Gross Reactive Power Capability** and **Net Reactive Power Capability** verification in accordance with the verification schedule specified in Section 5.3.1. The two (2) capability seasons are defined as summer and winter as specified by the Transmission Operator.

5.3.1 Generator and generation facility **Gross Reactive Power Capability** and **Net Reactive Power Capability** shall be re-verified every five (5) years or as required by the Transmission Operator.

5.3.1.1 If a Transmission Operator determines that only one seasonal generating capability value will suffice for NPCC Bulk Power System reliability analysis, then periodic verification will be required only for that particular season.

5.3.1.2 If a Transmission Operator determines that the difference between **Gross Reactive Power** and **Net Reactive Power Capability** of a generator or generation facility is insignificant for NPCC Bulk Power System reliability analysis, then periodic verification will be required for only one numerical value.

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5.3.1.3 If a Transmission Operator determines that only lagging or leading **Gross Reactive Power** and **Net Reactive Power Capability** of a generator or generation facility is required for NPCC Bulk Power System reliability analysis, then periodic verification will be required only for that specific reactive power capability value.

5.3.2 A Generator Owner shall notify the Transmission Operator within a specified time period when its generator or generation facility cannot achieve the **Declared Capability** because of equipment issues. The Transmission Operator shall specify a time frame for the Generator Owner to re-verify a generator or generation facility that could not meet its **Declared Capability**.

5.3.3 The Transmission Operator shall specify the real power level at which the verification shall be performed, recognizing that the verification of lagging and leading reactive power capabilities should normally be performed during on-peak and off-peak hours, respectively.

5.3.4 The Transmission Operator shall specify those intermittent or small generating units whose capability may be represented by verification results of a single unit.

5.4 Verification Criteria for Generator or Generation Facility Reactive Power Capability

The Generator Owners shall comply with the Transmission Operator's requests for periodic verification of **Gross Reactive Power Capability** and **Net Reactive Power Capability** of their generators or generation facilities, and apply the following criteria to verify the **Gross Reactive Power Capability** and **Net Reactive Power Capability** of their generators or generation facilities according to their types. The verification can include testing, use of performance tracking with any required supplemental engineering analysis, or commissioning data (for new generators only) acquired during the same seasonal capability period, as specified by the Transmission Operator.

5.4.1 Thermal Generators, Internal Combustion Generators, Gas Turbine Generators, Combined Cycle and Hydro Generators

The verification of **Gross Reactive Power Capability** and **Net Reactive Power Capability** of a generator or a generator operated as a synchronous condenser shall be determined from the average leading reactive power output for at least a 15 consecutive minute period and average lagging reactive power output for a 60 consecutive minute period.

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5.4.2 Intermittent Power Resources

For intermittent power resources (wind, tidal or geo-thermal generators) the manufacturers' or commissioning data can be used until sufficient performance tracking data is available to verify generator or generation facilities lagging and leading reactive capabilities.

5.4.3 Multiple Generator Facilities Forming a Generation Facility

The verification of **Gross Reactive Power Capability** and **Net Reactive Power Capability** for multiple generator facilities when limited by common elements shall be based on the reactive power capability of the facility and not the sum of the capabilities of the individual generators.

5.4.4 Consideration of Other Limitations

The Generator Owner shall identify any equipment or other factor that will limit the capability of the generator or generation facility to meet its **Declared Gross Reactive Power Capability** and **Net Reactive Power Capability.**

5.4.5 If the generator or generator facility is unable to demonstrate it's **Declared** lagging or leading seasonal **Gross Reactive Power** and **Net Reactive Power Capability** during testing or by use of performance data, the Transmission Operator and Generator Owner shall evaluate the cause of the limitation. The Transmission Operator shall document the reasons that prevented the generator or generation facility from achieving its **Declared Capability** and determine if retesting is required during that seasonal period.

5.5 Exemption of Generators or Generation Facilities from Verification Testing

5.5.1 The Generator Owner shall notify the Transmission Operator and request an exemption if it cannot conduct seasonal capability testing on a generator or generation facility for any of the reasons listed below. For existing generators, the Generator Owner shall submit certified generator operation records, manufacturer data, or performance tracking for the same previous seasonal verification period for this generator or generation facility. For new generators only, the Generator Owner shall submit commissioning data.

1. Adverse impact on transmission system reliability

2. Potential damage to transmission system or generator equipment

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3. Governmental regulatory or operating license limitations

5.5.2 The Transmission Operator shall, within 30 days of receiving notification by a Generator Owner that it cannot perform verification testing for the required seasonal period, notify the Generator Owner that its generator shall be exempted from the seasonal capability testing and coordinate with the Generator Owner to reschedule the verification testing for the next seasonal verification period.

5.5.3 The generator or generation facility exempted from seasonal capability testing shall submit generator performance tracking records, manufacturers or commissioning data (for new generators only) from the previous applicable seasonal verification period. Engineering analysis may be used in conjunction with performance tracking data to justify any difference between a generator's or generation facility's declared capability and previous seasonal performance data.

5.6 Documenting and Reporting Verified Generator or Generation Facility Gross and Net Reactive Power Capabilities

5.6.1 Each Generator Owner shall, as specified by the Transmission Operator:

5.6.1.1 Provide generator or generation facility **Declared Gross Reactive Power Capability** and **Net Reactive Power Capability** to the Transmission Operator;

5.6.1.2 Provide generator or generation facility **Verified Gross Reactive Power Capability** and **Net Reactive Power Capability** to the Transmission Operator.

5.6.1.3 Report to the Transmission Operator any discrepancies between declared and **Verified Gross Reactive Power Capability** or **Net Reactive Power Capability** within time frame specified by the Transmission Operator as required in Section 5.2.2, and develop and implement a plan to resolve the discrepancies.

5.6.1.4 Determine and report to the Transmission Operator the generator or generation facilities reactive power seasonal auxiliary **loads.**

5.6.1.5 Retain **Gross Reactive Power** and **Net Reactive Power Capability** testing results, commissioning data or performance tracking data with any supplemental engineering analysis to support any of the data for the current and most recent prior verification period.

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5.6.2 The Transmission Operator shall:

5.6.2.1 Document any discrepancies between system modeling and generator **Verified Capabilities** and the reason for such discrepancies.

5.6.2.2 Specify a time frame for the Generator Owner to address the discrepancy between the declared and **Verified Gross Reactive Power Capability** or **Net Reactive Power Capability** of its generators or generation facilities.

5.6.2.3 Report to NPCC annually any discrepancies between declared and **Verified Gross Reactive Power Capability** or **Net Reactive Power Capability**.

6.0 Measures and Assessments

None developed at this time.

7.0 Program Validation and Compliance Monitoring

The NPCC Task Force on Coordination of Operation shall annually validate that each Transmission Operator has implemented the **Gross Reactive Power Capability** and **Net Reactive Power Capability** verification program.

The NPCC Compliance Committee shall conduct periodic compliance audits to review the effectiveness of the Transmission Operator's **Gross Reactive Power Capability** and **Net Reactive Power Capability** verification program, and ensure compliance to the criteria in this Directory by the responsibility entities.

Adherence to these criteria shall be reported by each responsible entity in a manner and form designated by the Compliance Committee.

Prepared by: Task Force on Coordination of Operation / Task Force on Coordination of Planning

Review and Approval: Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45 day review and comment period. Upon satisfactorily addressing all the comments in this forum, the Directory document will be sent to the remaining Task

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Forces for their recommendation to seek RCC approval.

Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC. Bylaws" in effect at the time the ballots are cast.

Revisions pertaining to the Appendices or any other portion of the document such as Links glossary terms, etc., only RCC Members will need to conduct the final approval ballot of the document.

This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

References: NPCC Glossary of Terms (Document A-7)

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Appendix A
Definition of Terms[1]

Declared Capability (of a generator or generating facility) – The values submitted by the Generator Owner to the respective Transmission Operator.

Generation Facility – generating units, which are modeled as a single entity by the Transmission Operator.

Gross Reactive Power Capability (of a generator or generating facility) – The maximum lagging and leading reactive capability at the generator terminals and at a specified Gross Real Power output for a specific seasonal capability period.

Gross Real Power Capability (of a generator or generating facility) – The maximum megawatt output at the generator terminals, at the normally expected system conditions for that seasonal capability period.

Net Reactive Power Capability (of a generator or generating facility) – the **Gross Reactive Power Capability** adjusted for any applicable losses and auxiliary loads incurred up to the point of interconnection and at a specified Gross Real Power output for a specific seasonal capability period.

Net Real Power Capability (of a generator or generating facility) – The Gross Real Power Capability, less the auxiliary real power loads necessary to operate the generator at maximum real power output.

Load — The electric **power** used by devices connected to an electrical generating system. (IEEE Power Engineering). Also see **Demand**.

NPCC Specific Definitions:

Firm Load — Loads that are not **Interruptible Loads**.

Interruptible Load — Loads that are interruptible under the terms specified in a contract.

Power

Apparent Power — The product of the volts and amperes. It comprises both *real* and *reactive* power, usually expressed in kilovoltamperes (kVA) or megavoltamperes (MVA).

Reactive Power — The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied

[1] These terms will be moved and grouped under a separate Directory when all other Directories are developed.

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to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, **synchronous condensers**, or electrostatic equipment such as capacitors. Reactive power directly influences electric system voltage. It is usually expressed in kilovars (kVAr) or megavars (MVAr).

Real Power — The rate of producing, transferring, or using electrical energy, usually expressed in kilowatts (kW) or megawatts (MW).

Verified Capability (of a generator or generating facility) – The capability as demonstrated by the methods specified in this Directory and accepted by the Transmission Operator.

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APPENDIX B-1

Basic Flow Chart for Verification of Generator Gross and Net Reactive Power Capability

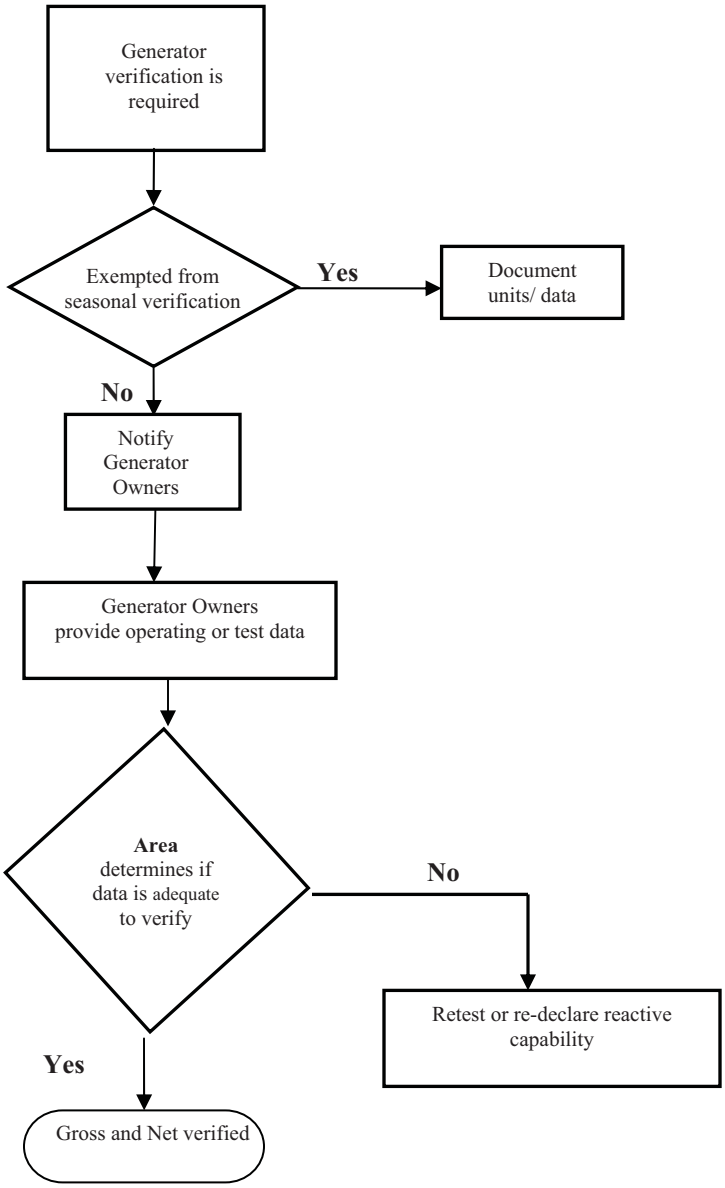

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APPENDIX B-2 – Generator Reactive Capability Form

GENERATOR REACTIVE CAPABILITY DATA FORM

1. Data Preparation Documentation*

Generator Facility Name	Unit No.	Facility ID	Generator Owner	Primary Contact
Big Generator Station	1	12234	Big Power	Jim Smith
Prepared By	**Date prepared:**	**Effective Date**	**Contact Tel**	**Contact e-mail**
John Doe	01/05/2007	01/10/2007	XXX-XXX-XXXX	john@bigpower.com

Auxiliary Reactive Power Requirements	Summer MVAR	Winter MVAR
	20	15

Reactive Data*

Seasonal Data	Declared Real and Reactive Capability						Verified Reactive Capability and Season			Verification Method (T, P,C** as applicable)	Date Verified
	Summer			Winter			Winter				Date
	Gross MW	Gross MVAR	Net MVAR	Gross MW	Gross MVAR	Net MVAR	Gross MW	Gross MVAR	Net MVAR		
Lagging Capability	500	120	120	525	100	100	520	110	110	P	03/15/2007
Leading Capability	500	250	230	525	240	225	525	200 (1)	185(1)	T	01/25/2007

Data inputted for illustration purposes, ***** T- Testing; P- Performance Tracking; C-Commissioning data***

Notes and Limitations:	(1) Full MVAR capability could not be achieved because of system voltage restriction. Engineering analysis was provided to demonstrate unit was capable of declared values.

Generating unit capability curve. *Please attach a .jpg image from the generating unit capability D curve*

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NPCC
Regional Reliability Reference Directory # 12
Under frequency Load Shedding Program Requirements

Task Force on Coordination of Operations Revision Review Record:
June 26th, 2009
March 3rd, 2010

Adopted by the Members of the Northeast Power Coordinating Council, Inc. June 26th, 2009 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	6/26/09	Effective Date	New
1	3/03/10	Sections 5.2.2 and 5.2.3 revised to consider small entity participation.	Revision

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1.0 Introduction

1.1 Title Under frequency Load Shedding Program

1.2 Directory Number 12

1.3 Objective

This Directory presents the basic criteria for the design and implementation of under frequency **load shedding** programs to ensure that declining frequency is arrested and recovered in accordance with established NPCC performance requirements to prevent system collapse due to load-generation imbalance.

1.4 Effective Date **June 26th, 2009**

The effective date of this Directory also is the initial date of a six-year implementation plan for under frequency **load shedding** program in the portion of NPCC in the Eastern Interconnection and a two-year implementation plan in the Québec Interconnection.

1.5 Background

This Directory was developed from the automatic Under frequency **Load Shedding** requirements in NPCC Directory #2, Emergency Operations, and the recommendations and implementation plans provided in the study reports: 2006 Assessment of Under frequency Load Shedding Adequacy Part III – Assessment of Program Modifications and 2008 Assessment of Under frequency Load Shedding Adequacy – Québec Area, approved by the Reliability Coordinating Committee on November 19, 2008.

1.6 Applicability

1.6.1 Functional Entities

Balancing Authorities
Transmission Operators
Generator Owners

2.0 Terms Defined in this Directory

The definitions of terms found in this Directory appearing in bold typeface can be found in the Appendix A.

3.0 NERC ERO Reliability Standard Requirements

The NERC ERO Reliability Standards containing Requirements that are associated with this Directory include, but may not be limited to:

3.1 EOP-003: Load Shedding Plans
3.2 PRC-006: Development and Documentation of Regional UFLS Programs
3.3 PRC-007: Assuring Consistency with Regional UFLS Program Requirements

4.0 NPCC Regional Reliability Standard Requirements

None.

5.0 NPCC Full Member, More Stringent Criteria

These Criteria are in addition to, or more stringent or more specific than the NERC or any Regional Reliability standard requirements.

5.1 Under frequency Load Shedding Program – General Criteria

The intent of the NPCC automatic Under frequency **Load Shedding** program is to ensure that declining frequency is arrested and recovered in accordance with established NPCC performance requirements stipulated in this document, as follows:

5.1.1 Frequency decline is arrested at no less than 58.0 Hz for the portions of NPCC in the Eastern Interconnection and 56.0 Hz for the portion of NPCC in the Québec Interconnection.

5.1.2 Frequency does not remain below 58.5 Hz for greater than 10 seconds, and does not remain below 59.5 Hz for greater than 30 seconds, for a generation deficiency of up to 25% of the **load**.

5.2 Under frequency Load Shedding Program – Eastern Interconnection specific Requirements

Each Balancing Authority in the NPCC portion of the Eastern Interconnection shall develop an automatic Under frequency **Load Shedding** Program that meets the following requirements, unless an alternative plan is submitted by the Balancing Authority for review by the NPCC Task Forces on Coordination of Operation and System Studies and approved by the NPCC Reliability Coordinating Committee:

5.2.1 The program shall consist of five stages of **load shedding** to be provided by entities with 100 MW or more of end-use load connected to its facilities with the following attributes:

	Threshold Setting	Block Size	Total Operating Time (1)
Stage 1	59.5 Hz	7 percent	300 ms
Stage 2	59.3 Hz	7 percent	300 ms
Stage 3	59.1 Hz	7 percent	300 ms
Stage 4	58.9 Hz	7 percent	300 ms
Stage 5 (anti-stall)	59.5 Hz	2 percent	10 s

Notes:

(1) Total operating time is the load-weighted average for all **load** within a Balancing Authority area, with maximum deviation for any load limited to ±50 ms.

5.2.2 The program shall consist of two stages of **load shedding** to be provided by entities with 50 MW or more and less than 100 MW of end-use load connected to its facilities with the following attributes:

	Threshold Setting	Block Size	Total Operating Time (1)
Stage 1	59.5 Hz	14 percent	300 ms
Stage 2	59.1 Hz	14 percent	300 ms

Notes:

(1) Total operating time is the load-weighted average for all **load** within a Balancing Authority area, with maximum deviation for any load limited to ±50 ms.

5.2.3 The program shall consist of one stage of **load shedding** to be provided by entities with 25 MW or more and less than 50 MW of end-use load connected to its facilities with the following attributes:

	Threshold Setting	Block Size	Total Operating Time (1)
Stage 1	59.5 Hz	28 percent	300 ms

Notes:

(1) Total operating time is the load-weighted average for all **load** within a Balancing Authority area, with maximum deviation for any load limited to ±50 ms.

5.2.4 Entities with less than 25 MW of end-use load connected to its facilities are exempt from providing UFLS.

5.2.5 Entities with less than 100 MW of end-use load connected to its facilities may collectively implement by mutual agreement with one or more entities within the same island[1]identified an aggregated automatic UFLS program that sheds load based on the frequency thresholds in section 5.2.1 as an alternative to implementing the applicable program in section 5.2.2 or 5.2.3.

5.2.6 Under frequency threshold **relays** shall be set to a nominal total operating time of 300 ms, from the time when frequency passes through the set point to the time of circuit breaker contact opening (including any communications time delay), with a minimum relay operating time to be no less than 100 ms when the rate of frequency decay is 0.2 Hz per second.

5.3 Under frequency Load Shedding Program – Québec Interconnection Specific Requirements

The Balancing Authority in the Québec Interconnection shall develop an automatic Under frequency **Load Shedding** Program that meets the following requirements, unless an alternative plan is submitted by the Balancing Authority for review by the NPCC Task Forces on Coordination of Operation and System Studies and approved by the NPCC Reliability Coordinating Committee:

[1] BA shall identify the appropriate island for entities participating in the program.

5.3.1 The program shall consist of five threshold stages and four rate-of-change (slope) stages of **load shedding** as depicted in Table 2.

Table 2 – UFLS Parameters for the Québec Interconnection Portion of NPCC

	Rate	Frequency	MW at System Peak	Mvar at System Peak	Total Operating Time
Threshold Stage 1	——	58.5 Hz	1000 MW (1)	1000 Mvar	300 ms
Threshold Stage 2	——	58.0 Hz	800 MW (1)	800 Mvar	300 ms
Threshold Stage 3	——	57.5 Hz	800 MW	800 Mvar	300 ms
Threshold Stage 4	——	57.0 Hz	800 MW	800 Mvar	300 ms
Threshold Stage 5 (anti-stall)	——	59.0 Hz	500 MW	500 Mvar	20 s
Slope Stage 1	-0.3 Hz/s	58.5 Hz	400 MW	400 Mvar	300 ms
Slope Stage 2	-0.4 Hz/s	59.8 Hz	800 MW (1)	800 Mvar	300 ms
Slope Stage 3	-0.6 Hz/s	59.8 Hz	800 MW (1)	800 Mvar	300 ms
Slope Stage 4	-0.9 Hz/s	59.8 Hz	800 MW	800 Mvar	300 ms

Notes:

(1) These stages shed fixed load independent of system load level.

(2) The amount of load shedding in this table includes load shedding to compensate for generators that trip above the curve in Figure 1.

5.4 Generator Under frequency Protection Requirements

Generators shall not be tripped for under-frequency conditions in the area above the curve in Figure 1, except as provided for in Sections 5.4.1 and 5.4.2.

5.4.1 It is recognized that, in special cases, requirements may dictate generator trip in the region above the curve. In those cases, the Generator Owner shall so notify its Balancing Authority and shall ensure through alternate arrangements, that automatic **load shedding** additional to the amount set out in Section 5.2 and in Section 5.3, equivalent (+/- 5%) to the amount of **generation** to be

tripped, is provided. Such cases shall be reviewed by the Task Force on Coordination of Operation

5.4.2 Generator Owners shall not increase the under frequency trip settings or make other modifications to the existing exempt generators (that trip above the curve in Figure 1) that may cause these generators to, directly or indirectly, trip at a higher frequency.

5.5 UFLS Program Assessment Requirements

5.5.1 Studies shall be performed by the associated Transmission Operator to ensure satisfactory voltage and loading conditions after automatic **load shedding**.

5.5.2 The Task Force on System Studies shall conduct a triennial study to coordinate the Automatic Under frequency **Load Shedding** Program among the NPCC Balancing Authorities.

6.0 Measures and Assessments

None developed at this time.

7.0 Compliance Monitoring

Adherence to these Criteria shall be reported by the responsible entity in a manner and form designated by the Compliance Committee.

Prepared by: Task Force on System Studies

Review and Approval: Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45 day review and comment period. Upon satisfactorily addressing all the comments in this forum, the Directory document will be sent to the remaining Task Forces for their recommendation to seek RCC approval.

Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC Bylaws" in effect at the time the ballots are cast.

Revisions pertaining to the Appendices or any other portion of

the document such as Links, glossary of terms, etc., will only require RCC Members' approval. Errata may be corrected by the Lead Task Force at any time and provide the appropriate notifications to the NPCC Inc. membership.

This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

References: NPCC Directory #2 – Emergency Operations.

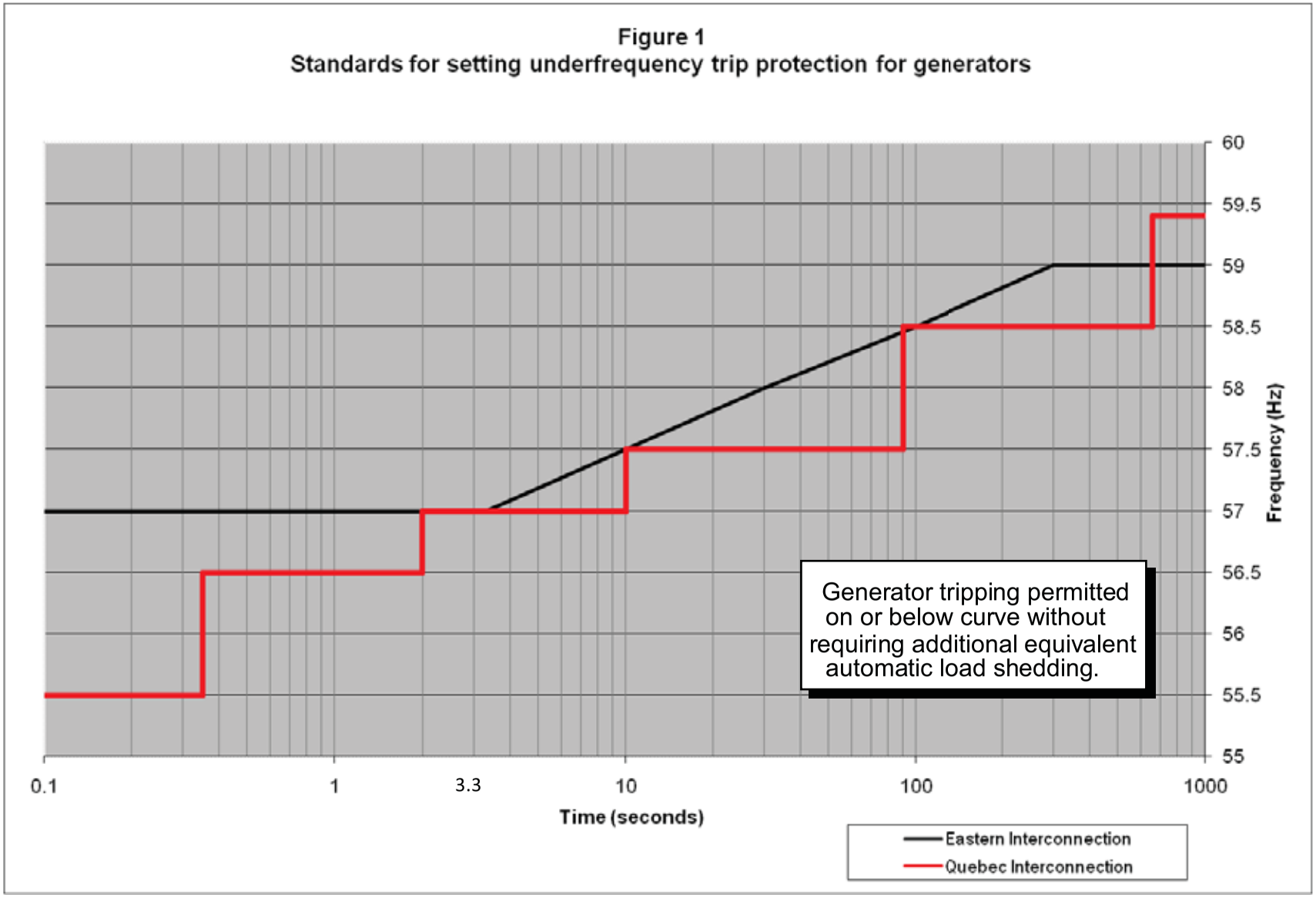
Figure 1
Standards for setting underfrequency trip protection for generators
60
59.5
59
58.5
58
57.5
57
56.5
56
55.5
55
Frequency (Hz)
0.1
1
3.3
10
100
1000
Time (seconds)
Generator tripping permitted on or below curve without requiring additional equivalent automatic load shedding.
Eastern Interconnection
Quebec Interconnection

Appendix A
Definition of Terms[2]

Bulk power system — The interconnected electrical systems within northeastern North America comprised of system **elements** on which **faults** or **disturbances** can have a **significant adverse impact** outside of the **local area**.

Island — A portion of a **power** system or several power systems that is electrically separated from the interconnection due to the disconnection of transmission system **elements**.

Load — The electric **power** used by devices connected to an electrical generating system. (IEEE Power Engineering). Also see **Demand**.

<u>NPCC Specific Definitions:</u>

Firm Load — Loads that are not **Interruptible Loads**.

Interruptible Load — Loads that are interruptible under the terms specified in a contract.

Load Shedding — The process of deliberately removing (either manually or automatically) preselected customers' **load** from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages.

Relay — An electrical device designed to respond to input conditions in a prescribed manner and after specified conditions are met to cause contact operation or similar abrupt change in associated electric control circuits. (Also: see **protective relay**).

---

[2] These terms will be moved and grouped under a separate Directory when all other Directories are developed.

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Operating Reserve Criteria

Adopted by the Members of the Northeast Power Coordinating Council March 30, 1972, based on recommendation by the Operating Procedure Coordinating Committee and the System Design Coordinating Committee, in accordance with paragraph IV, subheading (a), of NPCC's *Memorandum of Agreement* dated January 19, 1966 as amended to date.

Revised: September 24, 1976
Revised: May 18, 1979
Revised: May 14, 1980
Revised: November 5, 1982
Revised: December 30, 1986
Reviewed: October 10, 1990
Revised: August 26, 1992
Revised: February 14, 1996
Revised: September 1998
Revised: November 7, 2001
Revised: November 14, 2002
Revised: February 6, 2006
Revised: July 17, 2007
Revised: December 29, 2008

1.0 Purpose

In the continuous operation of electric power systems, **operating capacity** is required to meet forecast demand, including an allowance for error, to provide protection against equipment failure which has a reasonably high probability of occurrence, and to provide adequate regulation of frequency and **tie line** power flow. The **operating capacity** in excess of that required for actual load is commonly referred to as **operating reserve**.

This document establishes standard terminology and minimum requirements governing the amount, availability, distribution, and shared activation of **operating reserve**.

The objective is to facilitate a high level of **reliability** in the NPCC Region that is, as a minimum, consistent with the Operating Policies and Standards specified by the North American Electric Reliability Council (NERC).

2.0 Definitions

Please refer to the *NPCC Glossary of Terms* (NPCC Document A-07). Terms found in the Glossary are bolded here.

3.0 Minimum Requirements

3.1 **Ten-Minute Reserve** Requirement

The **ten-minute reserve** available to each **Area** shall at least equal **its first contingency loss** multiplied by the **Contingency Reserve Adjustment Factor** for the most recently completed quarter. **Ten-minute reserve** shall be sustainable as specified in section 3.7 below.

Each **Area** shall restore its **ten-minute reserve** within 105 minutes if it becomes deficient as a result of a contingency that is a **reportable event**, as described in NPCC Document C-09, *Monitoring Procedures For Operating Reserve Criteria*. Each **Area** shall restore its **ten-minute reserve** as soon as possible, and within 90 minutes if it becomes deficient and the deficiency is not a result of a contingency that is a **reportable event**. If an **Area** foresees that it cannot restore its **ten-minute reserve** within the times specified above, or extends beyond these times, a NERC Energy Emergency Alert of the appropriate level shall be declared. This requirement shall be maintained at all times, except as noted in NPCC Document C-20, *Procedures During Abnormal Operating Conditions*.

3.2 **Thirty-Minute Reserve** Requirement

The **thirty-minute reserve** available to each **Area** shall at least equal one-half its **second contingency loss**. **Thirty-minute reserve** shall be sustainable as specified in section 3.7 below.

Each **Area** shall restore its **thirty-minute reserve** within four hours if it becomes deficient. If an **Area** forecasts a deficiency in **thirty-minute reserve** for more than four hours into the future, the **Area** shall take corrective actions to eliminate the deficiency. This requirement shall be maintained at all times, except as noted in NPCC Document C-20, *Procedures During Abnormal Operating Conditions*.

3.3 Regulating Reserve Requirement

The **reserve** on **Automatic Generation Control** in each **Area** shall be sufficient to meet NERC control performance standards.

Except during significant frequency excursions as provided in *NPCC Regional Reliability Reference Directory #2 Emergency Operations*, **automatic generation control** equipment shall remain in service at all possible times to provide immediate response to sudden load changes or loss of generating equipment.

3.4 **Synchronized Reserve** Requirement

100 percent of an **Area**'s **ten-minute reserve** requirement shall be **synchronized reserve** except as described below. An **Area** shall adjust its **synchronized reserve** requirement based on its ability to recover from **reportable events** within fifteen minutes.

This **synchronized reserve** requirement may be decreased to a minimum of 25 percent of the **ten-minute reserve** requirement based upon the **Area**'s past performance in returning its **Area Control Error** (ACE) to precontingency values, or to zero, within fifteen minutes following loss of **resource**, in accordance with the following relationship:

The **synchronized reserve** requirement shall be decreased by 10 percent of the ten-minute requirement for every time a **control area** successfully returns its ACE to precontingency values, or to zero, following a **reportable event** where the **resource** loss is equal to or less than the magnitude of the **first contingency loss**. Successful recoveries that occur in the same month as a failure shall not be counted that month towards a reduced **synchronized reserve** requirement. However, successful recoveries subsequent to a failure can be counted in the next month provided there are no failures in that month.

The **synchronized reserve** requirement shall increase by 20 percent of the **ten-minute reserve** requirement for every time a **control area** fails to return its ACE to precontingency values or to zero within fifteen minutes following a **reportable event** where the **resource** loss is equal to or less than the magnitude of the **first contingency loss**. The maximum **synchronized reserve** requirement shall be 100 percent of the **Area**'s **ten-minute reserve** requirement.

Changes in the **synchronized reserve** requirement shall be calculated at the end of each month and shall be applied at the beginning of the next month.

3.5 Compliance with NERC Disturbance Control Standard (DCS)

Areas within NPCC shall calculate and report compliance with the Disturbance Control Standard as stipulated in Document C-09, *Monitoring Procedures for Operating Reserve Criteria.* The evaluation of DCS compliance for an Area shall utilize the NERC Disturbance Recovery Period of fifteen minutes and shall meet the DCS requirement 100% of the time for reportable disturbances. Each Control Area not meeting the DCS during a given quarter shall increase its **ten-minute reserve** requirement for the calendar quarter (offset by a month) by the **Contingency Reserve Adjustment Factor**.

3.6 Distribution of **Reserve**

Operating reserve available to an **Area** shall be distributed so as to ensure that it can be utilized without exceeding individual **element** ratings or transfer limitations.

3.7 Sustainability of **Reserve**

"**Synchronized Reserve, Ten Minute Reserve and Thirty Minute Reserve** acquired by an Area, if activated, shall be sustainable for at least one hour from the time of activation. Areas shall determine their sustainability requirement for regulating reserve based on their ability to achieve compliance with relevant standards, with due consideration of their operating characteristics."

3.8 Activation Of Inter-**Area** Reserve

When an **Area** acquires **operating reserve** from another **Area**, the provider of the **operating reserve** shall deliver an increase in energy equal to the amount of **operating reserve** acquired when the acquiring **Area** requests its activation. Unless the provider experiences its own contingency, the provider shall not initiate the curtailment of an existing or planned energy sale to any **Area** to support the activation of the **operating reserve** that was acquired until the contingent **Area** has recovered from the contingency. **Operating reserve** acquired from another **Area** shall be sustainable as specified in section 3.7 above.

3.9 Shared Activation Of **Ten-Minute Reserve**

Recovery from a sudden large loss of **generation** can be achieved faster by jointly activating **reserve** in several areas. NPCC and PJM have implemented such an arrangement in order to:

- more quickly relieve the initial stress placed on the interconnected transmission system following a large loss of **generation** or energy purchase
- effect an improvement in **reliability** achieved by the faster recovery
- assist in achieving compliance with the NERC Disturbance Control Standard (DCS)

Implementation of Shared Activation of **Ten-Minute Reserve** is described in NPCC document C-12, *Procedure for Shared Activation of Ten-Minute Reserve.* The provision for assistance via the Shared Activation Of Ten-Minute Reserve Procedure shall be a **reportable event**, except as noted in NPCC Document C-12. A portion of the energy being provided by assisting **Areas** as described in NPCC Document C-12 may be extended beyond the time limits specified therein as **Regional Reserve Sharing Energy,** as specified in NPCC Document C-38, *Procedure For Operating Reserve Assistance.*

3.10 Resource-Specific Requirements

3.10.1 **Synchronized Reserve**, **Ten Minute Reserve**, and **Thirty Minute Reserve** cannot be provided from loads where the same capacity is included in demand response programs and would result in double counting the same capacity.

3.10.2 Loads cannot provide **Synchronized Reserve** if the reduction in load is dependent on starting a generator to replace energy that is supplied from the grid.

3.10.3 To be eligible to provide **Synchronized Reserve**, **Ten Minute Reserve**, or **Thirty Minute Reserve**, the **Resource** shall meet the metering and testing requirements of the relevant **Area**(s).

3.10.4 To be eligible to provide **Synchronized Reserve**, **Ten Minute reserve**, or **Thirty Minute Reserve**, the **Resource** shall continuously meet the dispatch instruction requirements of the relevant **Area**(s).

3.10.5 To be eligible to provide **Synchronized Reserve**, **Ten Minute reserve**, or **Thirty Minute Reserve**, the **Resource** shall meet the requirements specified by the relevant **Area**(s) for operating limits and response rate, so that available reserve shall be computed accurately.

4.0 Procedures

4.1 Scheduling

4.1.1 Each **Area** shall ensure that sufficient **resources** are available such that its requirements for **operating reserve** are met at all times.

4.1.2 An **Area** shall meet its requirement for **operating reserve** using **resources** within the **Area** or obtain deliverable **capacity** from outside the **Area**.

4.1.3 Additional resources shall be made available to ensure the adequacy of operating reserve considering various sources of uncertainty such as, but not limited to, errors in the load forecast.

4.2 Daily Operation

4.2.1 Energy associated with **operating reserve** may be interchanged with the understanding that it is immediately recallable. The energy associated with reserve that is utilized to meet **AGC** requirements to provide satisfactory system regulation shall not be sold.

An **Area** acquiring energy sold out of the operating reserve of another **Area**:

- will not use this energy to augment its reserve. Resources displaced by the energy must remain available to cover for the curtailment of said energy at any time.
- must adjust its **ten-minute reserve** requirement to cover the larger of the **Area**'s **first contingency loss**, or the largest sum of such energy purchases, which could be withdrawn at the same time due to a single contingency or event.

An **Area** acquiring energy not sold out of the **operating reserve** of another **Area** is the only **Area** that can use this energy to augment its reserve. The providing **Area** is obligated to advise the acquiring **Area** of any change in the surplus status of the energy.

4.2.2 When an **Area** foresees it will be unable to provide its **operating reserve** requirements, appropriate measures, as contained in NPCC Document C-20, *Procedures During Abnormal Operating Conditions*, shall be implemented.

4.2.3 When an **Area** experiences a **contingency** in excess of its **first contingency loss**, it may request other **Areas**, via the NYISO Shift Supervisor, to activate an appropriate amount of their **ten-minute reserve**.

4.2.4 When **ten-minute reserve** in NPCC is fully utilized, appropriate measures by the deficient **Area**, as contained in *NPCC Regional Reliability Reference Directory #2 Emergency Operations* shall be implemented.

5.0 Responsibilities

5.1 Each **Area** is responsible for observing the criteria and procedures contained herein, identifying a loss of **capacity** within its **Area** and activating **operating reserve** available to that **Area**.

5.2 Each **Area** is responsible for periodically auditing **operating reserve** status and availability to ensure proper response at all times.

5.3 The NPCC Task Force on Coordination of Operation (TFCO) is responsible for monitoring the application of these criteria.

5.4 The NPCC Control Performance Working Group (CO-1) shall monitor total NPCC reserves as part of the ongoing **Area** Trouble Report process detailed in Procedure C-09, *Monitoring Procedures for Operating Reserve Criteria*, and report to the TFCO if levels drop below the historical norms within the NPCC region.

5.5 The NPCC Control Performance Working Group (CO-1) shall monitor compliance with the Control Performance Standards on a monthly basis and report its findings to the TFCO and NERC.

5.6 For reportable frequency deviation events, the NPCC Control Performance Working Group (CO-1) shall initiate the required data collection and reporting as required by NPCC Procedure C-11, *Monitoring Procedures for Interconnected System Frequency Response* and NERC Frequency Response Characteristic Surveys.

Lead Task Force: Task Force on Coordination of Operation

Review frequency: 3 years

References: *NPCC Regional Reliability Reference Directory #2 Emergency Operations* (NPCC Directory D#2)

NPCC Glossary of Terms (NPCC Document A-07)

Monitoring Procedures for Operating Reserve Criteria (NPCC Document C-09)

Monitoring Procedures for Interconnected System Frequency Response (NPCC Document C-11)

Procedure for Shared Activation of Ten-Minute Reserve (NPCC

Document C-12)

Procedures During Abnormal Operating Conditions (NPCC Document C-20)

Procedure for Operating Reserve Assistance (NPCC Document C-38)

NERC Standard BAL-001-0a "Real Power Balancing Control Performance"

NERC Standard BAL-002 "Disturbance Control Performance"

NERC Standard BAL-003-0a "Frequency Response and Bias"

NERC Standard BAL-004-1 "Time Error Correction"

NERC Standard BAL-005-0b "Automatic Generation Control"

NERC Standard BAL-006-1 "Inadvertent Interchange"

NERC Performance Standard Reference Document

Document A-7

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NPCC Glossary of Terms

Adopted by the Members of the Northeast Power Coordinating Council in September 1998 based on recommendations by the Reliability Coordinating Committee, in accordance with paragraph IV, subheading (a), of NPCC's Memorandum of Agreement dated January 19, 1966 as amended to date.

Partially Revised:	November 1, 2002
Partially Revised	November 14, 2002
Partially Revised	February 6, 2006
Partially Revised	April 30, 2007
Partially Revised	July 17, 2007

1.0 Introduction

The *NPCC Glossary of Terms* (the Glossary) originated as Appendix A to the *Criteria for Review and Approval of Documents* (Document A-1). It includes terms from NPCC Criteria (A), Guideline (B) and Procedure (C) Documents, as well as the North American Electric Reliability Council (NERC) *Glossary of Terms,* August 1996. The IEEE *Standard Dictionary of Electrical and Electronics Terms*, Sixth Edition, has also been used as a source for some definitions.

In general, only one entry is presented for each term, and where applicable, the definition from the *NERC Glossary of Terms* is used. All entries are listed alphabetically, and related sub-definitions are listed in alphabetic order under a main definition. For example, listed under **Fault** are the sub-definitions for Permanent Fault and Transient Fault. In a number of cases, where the main definition originated in the NERC *Glossary of Terms*, NPCC Specific Definitions have been added.

1.1 Applicability

The terms in the Glossary should be used in NPCC Documents ONLY with the defined meaning, so as to avoid ambiguity and confusion.

1.2 Bolding

Terms that are defined in the Glossary have been bolded when they appear in other definitions. However, a defined term is not bolded in its own definition.

1.3 Source Identification

The source of each definition is indicated just above the dividing line between items. For example, the following notation indicates that the NERC definition is used, and that similar A-1 and C-1 definitions are available:

NERC (A-1, C-1)

2.0 The Glossary

Applicable emergency limits — These limits depend on the duration of the occurrence, and on the policy of the various member systems of NPCC regarding loss of life to equipment, voltage limitations, etc.

Emergency limits are those which can be utilized for the time required to take corrective action, but in no case less than five minutes.

The limiting condition for voltages should recognize that voltages should not drop below that required for suitable system **stability** performance, and should not adversely affect the operation of the **bulk power system**.

The limiting condition for equipment loadings should be such that cascading outages will not occur due to operation of protective devices upon the failure of facilities. (Various definitions of equipment **ratings** are found elsewhere in this glossary.)

A-1

Area — An **Area** (when capitalized) refers to one of the following: New England, New York, Ontario, Quebec or the Maritimes (New Brunswick, Nova Scotia and Prince Edward Island); or, as the situation requires, area (lower case) may mean a part of a system or more than a single system. Within NPCC, Areas (capitalized) operate as **control areas** as defined by the North American Electric Reliability Council (NERC) (the definition can be found on page 6 of this glossary).

A-1 (A-3, A-6, C-1)

Area Control Error — The instantaneous difference between actual and net **scheduled interchange**, taking into account the effects of frequency bias.

NERC (C-1)

Automatic Generation Control (AGC) — Equipment that automatically adjusts a **Control Area**'s **generation** to maintain its **interchange schedule** plus its share of frequency regulation.

The following AGC modes are typically available:

a. **Tie Line Bias** Control — Automatic generation control with both frequency and net **interchange** terms of **Area Control Error** considered.

Automatic Generation Control (AGC) – continued

b. Constant Frequency (Flat Frequency) Control — Automatic generation control with the net **interchange** term of **Area Control Error** ignored. This Automatic Generation Control mode attempts to maintain the desired frequency without regard to **interchange**.

c. Constant Net **Interchange** (Flat **Tie Line**) Control — Automatic generation control with the frequency term of **Area** Control Error ignored. This Automatic Generation Control mode attempts to maintain net **interchange** at the desired level without regard to frequency.

NERC (A-3, C-1)

Availability — A measure of time a generating unit, transmission line, or other facility is capable of providing service, whether or not it actually is in service. Typically, this measure is expressed as a percent available for the period under consideration.

NERC (C-1)

Basic Minimum Power System — Consists of one or more generating stations, transmission lines, and substations operating in the form of an **island**. Such a system can be restarted independently and later **synchronized** to other **islands** or the main grid. The transmission **elements** included in the basic minimum power system connect the units which have **blackstart capability** to those units without **blackstart capability** which have been designated in the restoration plan to be restarted in the first stages of the restoration process. Also included are selected tie lines and corresponding substations, which are considered essential to the formation of a larger power system. The intent is to focus on the ability to create smaller electrical systems or islands, which can be expanded and synchronized to other such islands and the main grid.

A-3

Bipolar — Operation of HVdc with two **poles** of opposite polarity with negligible ground current.

A-2

Blackstart Capability — The ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering **power** without assistance from the electric system.

NERC (A-3, C-1)

Bottled Energy/Power/Capacity — Energy/Power/Capacity which is available at the source but which cannot be delivered to the point of use because of restrictions in the transmission system. Also referred to as Locked-In Energy/Power/Capacity.

A-10, (C-1)

Bulk power system — The interconnected electrical systems within northeastern North America comprised of system **elements** on which **faults** or **disturbances** can have a **significant adverse impact** outside of the **local area**.

A-1 (A-3, C-1, NERC)

Cable — An underground or underwater circuit.

C-13

Capability, Operating — The maximum load carrying ability of generating equipment or other electrical apparatus under specified conditions for a given time interval.

C-1

Capacity — The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of **generation**, transmission, or other electrical equipment.

Baseload Capacity — Capacity used to serve an essentially constant level of customer **demand**. Baseload generating units typically operate whenever they are available.

Firm Capacity — Capacity that is as firm as the seller's native **load** unless modified by contract. Associated energy may or may not be taken at option of purchaser. Supporting **reserve** is carried by the seller.

Intermediate Capacity — Capacity intended to operate fewer hours per year than **baseload capacity** but more than peaking capacity. Typically, such generating units have a capacity factor of 20% to 60%.

Net Capacity — The maximum capacity (or effective **rating**), modified for ambient limitations, that a generating unit, **power** plant, or electric system can sustain over a specified period, less the capacity used to supply the **demand** of station service or auxiliary needs.

Peaking Capacity — Capacity used to serve **peak demand**. Peaking generating units operate a limited number of hours per year, and their capacity factor is normally less than 20%.

NERC (C-1)

Capacity Benefit Margin (CBM) — See under **Transfer Capability.**

Commutation Failure — A fault in a thyristor valve group where the current transfer from one valve to the next is interrupted.

A-5, C-15

Component — refers to components of equipment or protection systems rather than **elements** of a **power** system. See **Element**.

A-5, B-11

Contingency — An event, usually involving the loss of one or more **elements**, which affects the **power** system at least momentarily.

NPCC Specific Definitions:

NPCC Emergency Criteria Contingencies — The set of contingencies to be observed when operating the **bulk power system** under **emergency** conditions. (C-1, also reference Document A-2, Section 6.2, Emergency Transfers.)

NPCC Normal Criteria Contingencies — The set of contingencies to be observed when operating the **bulk power system** under normal conditions. (C-1, also reference Document A-2, Section 6.1, Normal Transfers.)

Double Element Contingency — A **contingency** involving the loss of two **elements**.(C-1)

Single Contingency — A single event, which may result in the loss of one or more **elements.**

Single Element Contingency — A **contingency** involving the loss of one **element**.(C-1)

Limiting Contingency — The **contingency** which establishes the **transfer capability**. (C-1)

Contingency--continued

First Contingency Loss — The largest **capacity** outage including any assigned Ten-Minute Reserve which would result from the loss of a single **element** (A-6, C-1)

Second Contingency Loss — The largest **capacity** outage which would result from the loss of a single **element** after allowing for the First Contingency Loss. (A-6, C-1)

NERC (except as indicated)

Contingency Reserve Adjustment Factor — A factor used in determining the additional **ten-minute reserve** that each **Area**, not meeting the DCS requirement for a given quarter, must carry. It is calculated using the following formula:

$CRA_{quarter} = 2 -$ {the average percentage DCS (expressed as a decimal) for the quarter of measurement}

A-6

Control Area — An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling **generation** to maintain its net **interchange schedule** with other Control Areas and contributing to frequency regulation of the **Interconnection**.

NERC (C-1)

Converter — An operative unit comprised of either a rectifier or inverter bridge connected to an ac system through transformers and switching devices with the associated control equipment.

A-5

Converter Transformer — A **power** transformer which transfers the energy from the thyristor valves to the connected ac system and vice-versa.

A-5

Critical Components — Equipment required for continued and proper operation of a **key facility** in the event of a total loss of AC supply. Critical components include but are not limited to blackstart generating units, substation backup power supplies, control center and telecommunication center backup power supplies and computer systems, control center and telecommunication center computer room air conditioning and telecommunication facilities backup power supplies.

A-3

Demand — The rate at which energy must be generated or otherwise provided to supply an electric **power** system. Types of Demand include:

Instantaneous Demand — The rate of energy delivered at a given instant.

Average Demand — The electric energy delivered over any interval of time as determined by dividing the total energy by the units of time in the interval.

Integrated Demand — The average of the instantaneous demands over the demand interval.

Demand Interval — The time period during which electric energy is measured, usually in 15-, 30-, or 60-minute increments.

Peak Demand — The highest electric **power** requirement occurring in a given period (e.g., an hour, a day, month, season, or year). For an electric system, it is equal to the sum of the metered net outputs of all generators within a system and the metered line flows into the system, less the metered line flows out of the system.

Coincident Demand — The sum of two or more demands that occur in the same demand interval.

Noncoincident Demand — The sum of two or more demands that occur in different demand intervals.

Contract Demand — The amount of **capacity** that a supplier agrees to make available for delivery to a particular entity and which the entity agrees to purchase.

Firm Demand — That portion of the Contract Demand that a **power** supplier is obligated to provide except when system **reliability** is threatened or during **emergency** conditions.

Billing Demand — The demand upon which customer billing is based as specified in a rate schedule or contract. It may be based on the contract year, a contract minimum, or a previous maximum and, therefore, does not necessarily coincide with the actual measured demand of the billing period.

NERC (C-1)

Disturbance – Severe oscillations or severe step changes of current, voltage and/or frequency usually caused by **faults**.

Disturbance--continued

System Disturbance — An event characterized by one or more of the following phenomena: the loss of **power** system **stability**; cascading outages of circuits; oscillations; abnormal ranges of frequency or voltage or both.

A-3 (NERC, C-1)

Economic Dispatch — The optimization of the incremental cost of delivered **power** by allocating generating requirements among the on-control units with consideration of such factors as incremental generating costs and incremental transmission losses.

B-3, C-18 (IEEE definition PE 94-1991)

Element — Any electric device with terminals that may be connected to other electric devices, such as a generator, transformer, circuit, circuit breaker, or bus section.

Limiting Element — The element that is either operating at its appropriate **rating** or would be following a limiting **contingency** and, as a result, establishes a system limit.

NERC (slightly modified)

Emergency — Any abnormal system condition that requires automatic or manual action to prevent or limit loss of transmission facilities or **generation** supply that could adversely affect the **reliability** of the electric system.

NPCC Specific Definition:

Emergency — An **Emergency** is considered to exist in an Area if **firm load** may have to be shed. (TFCO)

C-38

Emergency Regional Reserve Redispatch — The regional coordination of actions to enhance **reliability** among **Areas** in response to a **Regional Reserve Deficiency**.

C-38

Emergency Regional Reserve Redispatch Energy — Electrical energy that is received and delivered among **Areas** in response to a **Regional Reserve Deficiency** to enhance regional **reliability.**

NERC (except as indicated)

Energize — To make a piece of equipment or circuit alive.

A-5 and B-1

Fault — An electrical **short circuit**.

Permanent Fault — A fault which prevents the affected **element** from being returned to service until physical actions are taken to effect repairs or to remove the cause of the fault.

Fault--continued

Transient Fault — A fault which occurs for a short or limited time, or which disappears when the faulted **element** is separated from all electrical sources and which does not require repairs to be made before the **element** can be returned to service either manually or automatically.

C-1 (NERC)

Fault Clearing

Delayed fault clearing — Fault clearing consistent with correct operation of a breaker failure **protection group** and its associated breakers, or of a backup **protection group** with an intentional time delay.

High speed fault clearing — Fault clearing consistent with correct operation of high-speed relays and the associated circuit breakers without intentional time delay. *Notes:* The specified time for high-speed relays in present practice is 50 milliseconds (three cycles on a 60Hz basis) or less. [IEEE C37.100-1981]. For planning purposes, a total clearing time of six cycles or less is considered high speed.

Normal fault clearing — Fault clearing consistent with correct operation of the **protection system** and with the correct operation of all circuit breakers or other automatic switching devices intended to operate in conjunction with that **protection system**.

A-1 (C-1)

Generation (Electricity) — The process of producing electrical energy from other forms of energy; also, the amount of electric energy produced, usually expressed in kilowatthours (kWh) or megawatthours (MWh).

Gross Generation — The electrical output at the terminals of the generator, usually expressed in megawatts (MW).

Net Generation — Gross generation minus station service or unit service **power** requirements, usually expressed in megawatts (MW).

NERC (C-1)

Generation Rejection — The process of deliberately removing preselected **generation** from a **power** system, or initiating HVdc power runback, in response to a **contingency** or an abnormal condition in order to maintain the integrity of the system. Synonym: Generator Dropping.

A-3 (C-1)

Grounded — Connected to earth or some extended conducting body that serves instead of the earth, whether the connection is intentional or accidental.

A-5

Harmonic — A sinusoidal component of a periodic wave or quantity having a frequency that is an integral multiple of the fundamental frequency. Note: For example, a component, the frequency of which is twice the fundamental frequency, is called a second harmonic.

A-5

Harmonic current — A periodic component of current having a frequency that is an integral multiple of that currents fundamental frequency. Harmonic currents are normally measured in amperes or in percent of the fundamental frequency current, generally at specific frequencies, such as second and third harmonics. Harmonic currents can, for example, be generated by HVdc converters, **Static Var Compensators** (SVC) and geomagnetically induced currents (GIC).

C-15

HVdc Link — A high Voltage direct current connection between two **power** systems, often used to interconnect two asynchronous **power** systems.

A-5

Inadvertent Interchange — The difference between a **Control Area**'s net **actual interchange** and net **scheduled interchange**.

NERC (C-1)

Interconnection — When capitalized, any one of the five major electric system networks in North America: Eastern, Western, ERCOT, Québec, and Alaska. When not capitalized, the facilities that connect two systems or **Control Areas**. Additionally, an interconnection refers to the facilities that connect a nonutility generator to a **Control Area** or system.

NERC

Interchange — Electric **power** or energy that flows from one entity to another.

Actual Interchange — Metered electric **power** that flows from one entity to another.

Interchange Schedule — An agreed-upon transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of **power** and energy between the contracting parties and the **Control Area**(s) involved in the transaction.

Interchange Scheduling — The actions taken by scheduling entities to arrange transfer of electric **power**. The schedule consists of an agreement on the amount, start and end times, ramp rate, and degree of firmness.

Scheduled Interchange — Electric **power** scheduled to flow between entities, usually the net of all sales, purchases, and **wheeling** transactions between those areas at a given time. .

NERC (C-1)

Interface — The specific set of transmission **elements** between two areas or between two areas comprising one or more electrical systems.

NERC (C-1)

Island — A portion of a **power** system or several power systems that is electrically separated from the interconnection due to the disconnection of transmission system **elements**.

NERC (A-3, C-1)

Key Facilities — Facilities required to establish a **basic minimum power system** following a system blackout. These facilities are essential to the restoration plan of the **Control Area** and include generating stations having blackstart units and other selected generating stations, transmission **elements** which are part of the **basic minimum power system,** control centers and telecommunication centers and telecommunication facilities which are necessary to support **protection** and control facilities, voice and data between and within control centers and voice and data between control centers and key generating / transmission substations.

A-3

Load — The electric **power** used by devices connected to an electrical generating system. (IEEE Power Engineering). Also see **Demand**.

NPCC Specific Definitions:

Firm Load — Loads that are not **Interruptible Loads**.

Interruptible Load — Loads that are interruptible under the terms specified in a contract.

(Referenced in A-3)

Load Cycle — The normal pattern of **demand** over a specified time period associated with a device or circuit.

NERC (C-1)

Load Relief — **Load** reduction accomplished by **voltage reduction** and/or **load shedding**.

A-3 (C-1)

Load Shedding — The process of deliberately removing (either manually or automatically) preselected customers' **load** from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages.

A-10

Local area — An electrically confined or radial portion of the system. The geographic size and number of system elements contained will vary based on system

characteristics. A local area may be relatively large geographically with relatively few buses in a sparse system, or be relatively small geographically with a relatively large number of buses in a densely networked system.

C-38

Negative Shared Activation Reserve Energy — Energy received by an assisting **Area** from a contingent **Area** for an eligible **resource** loss having a concurrent effective loss of demand that exceeds the loss of energy from the **resource** loss, and is implemented at a zero time ramp rate immediately following allocation notification, maintained until the Contingent **Area** requests a return to normal but not longer than thirty minutes, and ramped out at a ten-minute ramp rate following communications initiated by the Contingent **Area** which have resulted in mutually established **interchange schedules.**

NERC (A-3, C-1)

Operating Limit — The maximum value of the most critical system operation parameter(s) which meet(s): (a) pre-**contingency** criteria as determined by equipment loading capability and acceptable voltage conditions; (b) **stability** criteria; (c) post-**contingency** loading and voltage criteria.

A-3 (C-1)

Operating Capacity — The **capacity** claimed for any generating source recognizing any temporary deratings, governor load limits, proven maximum loading rates, starting times and equipment limitations including transmission **operating limits**.

A-6

Operating Procedures — A set of policies, practices, or system adjustments that may be automatically or manually implemented by the **system operator** within a specified time frame to maintain the operational integrity of the interconnected electric systems.

Automatic Operating Systems — **Special protection systems**, remedial action schemes, or other operating systems installed on the electric systems that require *no intervention* on the part of **system operators**.

Normal (Precontingency) Operating Procedures — Operating procedures that are normally invoked by the **system operator** to alleviate potential facility overloads or other potential system problems in anticipation of a **contingency**.

Postcontingency Operating Procedures — Operating procedures that may be invoked by the **system operator** to mitigate or alleviate system problems after a **contingency** has occurred.

NERC

Operator, System — Person responsible for operating control of the **bulk power system** in an **Area** of NPCC or an adjoining system interconnected with NPCC. This could be a Security Coordinator, a **Control Area** Operator or in some cases a bulk power utility operator (e.g. NYPA, Niagara Mohawk, etc)

A-3

Outage

Forced Outage — The removal from service of a generating unit, transmission line, or other facility for **emergency** reasons or a condition in which the equipment is unavailable due to unanticipated failure.

Forced Outage Rate — The hours a generating unit, transmission line, or other facility is forced out of service, divided by the sum of the hours it is removed from service, plus the total number of hours the facility was connected to the electricity system expressed as a percent.

Maintenance Outage — The removal of equipment from service **availability** to perform work on specific **elements** that can be deferred, but requires the equipment be removed from service before the next planned outage. Typically, a Maintenance Outage may occur anytime during the year, have a flexible start date, and may or may not have a predetermined duration.

Planned Outage — Removing the equipment from service **availability** for inspection and/or general overhaul of one or more major equipment groups. This outage usually is scheduled well in advance.

NERC (C-1)

Phase Shifting Transformer — A transformer that advances or retards the phase angle relationship of one circuit with respect to another to control **power** flow. Synonyms: Phase angle regulator, phase shifter.

A-2, C-25

Pole (of an ac switching device) — That portion of the device associated exclusively with one electrically separated conducting path of the main circuit of the device.

B-1 (IEEE definition C37.100-1992)

Pole (HVdc term) — A rectifier and an inverter, with associated filter banks and control equipment, tied together by a transmission line or bus.

A-2, A-6, C-20

Power

Apparent Power — The product of the volts and amperes. It comprises both *real* and *reactive* power, usually expressed in kilovoltamperes (kVA) or megavoltamperes (MVA).

Reactive Power — The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, **synchronous condensers**, or electrostatic equipment such as capacitors. Reactive power directly influences electric system voltage. It is usually expressed in kilovars (kVAr) or megavars (MVAr).

Real Power — The rate of producing, transferring, or using electrical energy, usually expressed in kilowatts (kW) or megawatts (MW).

NERC (C-1)

Power Pool — Two or more interconnected electric systems operated and/or planned to supply **power** for their combined **demand** requirements.

NERC (slightly modified)

Power Swing — A transient change in the **power** flows on a system, usually of an oscillatory nature.

A-2 and A-5

Protected element — The power system **element** protected by the subject **protection system**.

Examples: Line, bus, transformer, generator.

A-1

Protection — The provisions for detecting power system **faults** or abnormal conditions and taking appropriate automatic corrective action.

Protection group — A fully integrated assembly of **protective relays** and associated equipment that is designed to perform the specified protective functions for a power system **element**, independent of other groups.

Protection--continued

Notes:

(a) Variously identified as Main Protection, Primary Protection, Breaker Failure Protection, Back-Up Protection, Alternate Protection, Secondary Protection, A Protection, B Protection, Group A, Group B, System 1 or System 2.

(b) Pilot protection is considered to be one protection group.

Protection system

Elem ent Basis

One or more protection groups; including all equipment such as instrument transformers, station wiring, circuit breakers and associated trip/close modules, and communication facilities; installed at all terminals of a power system **element** to provide the complete protection of that **element**.

Term inal Basis

One or more protection groups, as above, installed at one terminal of a power system **element**, typically a transmission line.

Pilot Protection — A form of line protection that uses a communication channel as a means to compare electrical conditions at the terminals of a line.

A-1

Protective relay — A **relay** that detects a power system **fault** or abnormal condition and initiates appropriate control system action.

A-1 (C-1)

Rating — The operational limits of an electric system, facility, or **element** under a set of specified conditions.

Continuous Rating — The rating – as defined by the equipment owner – that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or **element** can support or withstand indefinitely without loss of equipment life. (Normally not used in NPCC)

Rating--continued

Normal Rating — The rating – as defined by the equipment owner – that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or **element** can support or withstand through the daily **demand** cycles without loss of equipment life.

Emergency Rating — The rating – as defined by the equipment owner – that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units, that a system, facility, or **element** can support or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

NPCC Specific Definitions:

Long Time Emergency (LTE) Rating — The maximum rating of electrical equipment based on nominal ambient conditions and recognizing the nominal **load cycle** for a long period such as 24 hours. (C-1)

Short Time Emergency (STE) Rating — The maximum loading of electrical equipment which can be sustained for 15 minutes based on nominal ambient conditions and recognizing preloading conditions. (C-1)

NERC (except as indicated)

Reclosing

Autoreclosing — The automatic closing of a circuit breaker in order to restore an **element** to service following automatic tripping of the circuit breaker. Autoreclosing does not include automatic closing of capacitor or reactor circuit breakers.

High-speed autoreclosing — The autoreclosing of a circuit breaker after a necessary time delay (less than one second) to permit **fault** arc deionization with due regard to coordination with all **relay** protective systems. This type of autoreclosing is generally not supervised by voltage magnitude or phase angle.

Manual Reclosing — The closing of a circuit breaker by operator action after it has been tripped by **protective relays**. Operator initiated closing commands may originate from local control or from remote (supervisory) control. Either local or remote close commands may be supervised or unsupervised.

Supervision — A closing command is said to be supervised if closing is permitted to occur only if certain prerequisite conditions are met (e.g., **synchronism-check**).

Reclosing--continued

Synchronism-check — refers to the determination that acceptable voltages exist on the two sides of the breaker and the phase angle between them is within a specified limit for a specified time.

C-38

Regional Reserve Deficiency — When two or more **Areas** are deficient in **ten minute reserve** after all **Area** coordinated actions have been deployed, including acquiring emergency energy and/or capacity but excluding the shedding of firm load.

C-38

Regional Reserve Sharing — Procedure that allows participating **Areas** to reduce the requirement for **reserve** within its **Area** due to the availability and deliverability of **reserve** from other **Areas**.

A-6 and C-38

Regional Reserve Sharing Energy — Energy delivered to a contingent **Area** from assisting **Areas** that is converted from delivered **Shared Activation Reserve Energy** after the **Shared Activation Reserve Energy** has been delivered for 30 minutes; maintained until the Contingent **Area** requests a return to normal but not longer than sixty minutes, and ramped out at a ten-minute ramp rate following communications initiated by the Contingent **Area** which have resulted in mutually established **interchange schedules.**

B-1 and C-1

Relay — An electrical device designed to respond to input conditions in a prescribed manner and after specified conditions are met to cause contact operation or similar abrupt change in associated electric control circuits. (Also: see **protective relay**).

A-1

Reliability — The degree of performance of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system — **Adequacy** and **Security**.

Reliability-continued

Adequacy — The ability of the electric system to supply the aggregate electrical **demand** and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system **elements**.

Security — The ability of the electric system to withstand **disturbances** such as electric **short circuits** or unanticipated loss of system **elements**.

NERC (slightly modified)

Reportable Events — **System disturbances** involving losses of **load**, **generation** or transmission facilities within NPCC **Control Areas** which equal or exceed the following criteria are reportable events:

(1) Actual net **interchange** deviations equal to or greater than 500 MW (Maritime: 300 MW).

(2) Loss of **generation** or **load** equal to or greater than 500 MW (Maritime: 300 MW).

(3) System frequency deviations equal to or greater than 0.03 Hz (Hydro-Quebec: 0.5 Hz). (System frequency deviations that occur for events outside of the NPCC are reported for analysis of frequency response, but are not included in the reporting for the NERC Disturbance Control Standard.)

A-6 (also see NERC DAWG *System Disturbances* Reports)

Reserve — In normal usage, reserve is the amount of **capacity** available in excess of the **demand**

Reserve Requirement — That capability above firm system **demand** required to provide for regulation, **load** forecasting error, equipment forced and scheduled outages, and local area supply **adequacy**.

NPCC Specific Definitions:

Non-Synchronized Reserve — That portion of **operating capacity** which is available by synchronizing a generator to the network, and that capacity which can be made available by reducing load that is dependent on starting a generator to replace energy that is supplied from the grid. Non-Synchronized Reserve also includes the capacity achieved through the implementation of **voltage reduction**. (A-6, C-1)

Reserve--continued

Operating Reserve — The sum of **ten-minute** and **thirty-minute reserve**. (A-3, A-6, C-1)

Reserve on **Automatic Generation Control (AGC)** — That portion of **synchronized reserve** which is under the command of an automatic controller to respond to **load demands** without need for manual action. (A-6, C-1)

Synchronized Reserve — The unused capacity from resources that are synchronized to the system and ready to achieve claimed capacity (A-6, C-1)

Ten-minute reserve — The sum of **synchronized** and **non-synchronized reserve** that is fully available in ten minutes. (A-6, C-1)

Thirty-Minute Reserve — The sum of **synchronized** and **non-synchronized reserve** that can be utilized within thirty minutes of receiving an activation request, excluding capacity assigned to **ten minute reserve**. (A-6, C-1)

Resource — Resource refers to the total contributions provided by supply-side and **demand**-side facilities and/or actions. Supply-side facilities include utility and non-utility **generation** and purchases from neighboring systems. **Demand**-side facilities include measures for reducing **load**, such as conservation, **demand** management, and **interruptible load**.

C-38

Shared Activation Reserve Energy — Energy delivered from an assisting **Area** to a contingent **Area** that is implemented at a zero time ramp rate immediately following allocation notification, maintained until the Contingent **Area** requests a return to normal but not longer than thirty minutes, and ramped out at a ten-minute ramp rate following communications initiated by the Contingent **Area** which have resulted in mutually established **interchange schedules.**

A-1

Short Circuit — An abnormal connection (including an arc) of relatively low impedance, whether made accidentally or intentionally, between two points of different potential. *Note:* The term **fault** or short-circuit **fault** is used to describe a short circuit.

A-10, IEEE C37.100-1981

Significant adverse impact — With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from **faults** or **disturbances**, shall be deemed as having **significant adverse impact**:

a. instab ility;
- any instability that cannot be demonstrably contained to a well-defined local area.
- any loss of synchronism of generators that cannot be demonstrably contained to a well-defined local area

b. unacceptable system dynamic response;
- an oscillatory response to a contingency that is not demonstrated to be clearly positively damped within 30 seconds of the initiating event.

c. unacceptable equipment tripping
- tripping of an un-faulted bulk power system element (element that has already been classified as bulk power system) under planned system configuration due to operation of a protection system in response to a stable power swing
- operation of a Type I or Type II Special Protection System in response to a condition for which its operation is not required

d. voltage levels in violation of applicable **emergency** limits;

e. loadings on transmission facilities in violation of applicable **emergency** limits;

A-1

Special Protection System (SPS) – A **protection system** designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted **elements**. Such action may include changes in **load**, **generation**, or system configuration to maintain system **stability**, acceptable voltages or **power** flows. Automatic underfrequency **load shedding** as defined in the *Emergency Operation Criteria* A-3, is not considered an SPS. Conventionally switched, locally controlled shunt devices are not SPSs.

A-1

Stability — The ability of an electric system to maintain a state of equilibrium during normal and abnormal system conditions or **disturbances**.

Small-Signal Stability — The ability of the electric system to withstand small changes or **disturbances** without the loss of synchronism among the synchronous machines in the system.

Transient Stability — The ability of an electric system to maintain synchronism between its parts when subjected to a **disturbance** and to regain a state of equilibrium following that disturbance.

NERC (slightly modified) (C-1)

Stability Limit — The maximum **power** flow possible through some particular point in the system while maintaining **stability** in the entire system or the part of the system to which the stability limit refers.

NERC (C-1)

Static Var Compensator (SVC) — A combination of controlled shunt reactors and switched capacitor banks, used to affect the **reactive power** flow of the system or to regulate the system voltage.

A-5, B-3, C-5 and C-18

Supervision — see **Reclosing**

Supervisory Control — A form of remote control comprising an arrangement for the selective control of remotely located facilities by an electrical means over one or more communications media.

NERC (C-1)

Surge — A transient variation of current, voltage, or **power** flow in an electric circuit or across an electric system.

NERC (C-1)

Synchronism-check — see **Reclosing**

Synchronism-check Relay — A verification **relay** whose function is to operate when two input voltages satisfy predetermined operating parameters.

B-1

Synchronize — The process of connecting two previously separated alternating current apparatuses or systems after matching frequency, voltage, phase angles, etc. (e.g., paralleling a generator to the electric system).

NERC (slightly modified) (C-1)

Synchronous Condenser — A synchronous machine which operates without mechanical load to supply or absorb **reactive power** for voltage control purposes.

B-3, C-15

Teleprotection — A form of **protection** that uses a communication channel.

A-1

Tie Line — A circuit connecting two or more **Control Areas** or systems of an electric system.

NERC A-3 (C-1)

Tie Line Bias — A mode of operation under automatic **generation** control in which the **area control error** is determined by the actual net **interchange** minus the biased scheduled net **interchange**.

NERC (C-1)

Transfer Capability — The measure of the ability of interconnected electric systems to move or transfer **power** *in a reliable manner* from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric **power**, generally expressed in megawatts (MW). In this context, "area" may be an individual electric system, **power pool**, **Control Area**, subregion, or NERC Region, or a portion of any of these. Transfer capability is directional in nature. That is, the transfer capability from "Area A" to "Area B" is *not* generally equal to the transfer capability from "Area B" to "Area A."

Available Transfer Capability (ATC) — A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. ATC is defined as the Total Transfer Capability (TTC), less the **Transmission Reliability Margin (TRM)**, less the sum of existing transmission commitments (which includes retail customer service) and the Capacity Benefit Margin (CBM).

Nonrecallable Available Transfer Capability (NATC) — Total Transmission Capability less the **Transmission Reliability Margin**, less nonrecallable reserved transmission service (including the Capacity Benefit Margin).

Recallable Available Transmission Capability (RATC) — Total Transmission Capability less the **Transmission Reliability Margin**, less recallable transmission service, less non-recallable transmission service (including the Capacity Benefit Margin).

Total Transfer Capability (TTC) — The amount of electric **power** that can be transferred over the interconnected transmission network in a *reliable* manner based on *all* of the following conditions:

1. For the existing or planned system configuration, and with normal (pre-**contingency**) **operating procedures** in effect, all facility

loadings are within normal **ratings** and all voltages are within normal limits.

2. The electric systems are capable of absorbing the dynamic **power swings**, and remaining stable, following a **disturbance** that results in the loss of any single electric system **element**, such as a transmission line, transformer, or generating unit.

3. After the dynamic **power swings** subside following a **disturbance** that results in the loss of any single electric system **element** as described in 2 above, and after the operation of any automatic operating systems, but before any post-**contingency** operator-initiated system adjustments are implemented, all transmission facility loadings are within **emergency ratings** and all voltages are within **emergency** limits.

4. With reference to condition 1 above, in the case where precontingency facility loadings reach normal thermal **ratings** at a transfer level below that at which any first **contingency** transfer limits are reached, the transfer capability is defined as that transfer level at which such normal **ratings** are reached.

5. In some cases, individual system, **power pool**, subregional, or Regional planning criteria or guides may require consideration of specified multiple contingencies, such as the outage of transmission circuits using common towers or rights-of-way, in the determination of transfer capability limits. If the resulting transfer limits for these multiple contingencies are more restrictive than the single **contingency** considerations described above, the more restrictive **reliability** criteria or guides must be observed. See Available Transfer Capability [shown above].

Capacity Benefit Margin (CBM) — CBM is defined as that amount of transmission transfer capability reserved by **load** serving entities to ensure access to **generation** from interconnected systems to meet **generation reliability** requirements.

Transmission Reliability Margin (TRM) — TRM is defined as that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

First Contingency Incremental Transfer Capability (FCITC) — The amount of **power**, incremental above normal base **power** transfers, that can be transferred over the transmission network in a reliable manner based on the following conditions:

First Contingency Incremental Transfer Capoability--continued

1. For the existing or planned system configuration, and with normal (pre-**contingency**) **operating procedures** in effect, all facility loadings are within normal **ratings** and all voltages are within normal limits.

2. The electric systems are capable of absorbing the dynamic **power swings**, and remaining stable, following a **disturbance** that results in the loss of any single electric **element**, such as a transmission line, transformer, or generating unit.

3. After the dynamic **power swings** subside following a **disturbance** that results in the loss of any single electric system **element** as described in 2 above, and after the operation of automatic operating systems, but before any post-**contingency** operator-initiated system adjustments are implemented, all transmission facility loadings are within **emergency ratings** and all voltages are within **emergency** limits.

First Contingency Total Transfer Capability (FCTTC) — The algebraic sums of the FCITC values and the appropriate total interregional transfers assumed in the base load flow model used for the FCITC calculations.

Normal Incremental Transfer Capability (NITC) — The amount of electric **power**, incremental above normal base power transfers, that can be transferred between two areas of the interconnected transmission systems under conditions where pre-**contingency** loadings reach the normal thermal **rating** of a facility prior to any first **contingency** transfer limits being reached. When this occurs, NITC replaces FCITC as the most limiting transfer capability.

NPCC Specific Definitions:

Transfer Capability — An **operating limit** relating to the permissible **power** transfer between specified areas of the transmission system. (C-1)

Emergency Transfer Capability — The amount of **power** transfer allowed between **Areas** or within an **Area** when ope**rating** to meet NPCC **emergency** criteria contingencies [as defined in the *Basic Criteria for Design and Operation of Interconnected Power Systems* (Document A-2).] (A-3, C-1)

Normal Transfer Capability — The amount of **power** transfer allowed between **Areas** or within an **Area** when operating to meet NPCC normal criteria contingencies [as defined in Document A-2.] (A-3, C-1)

NERC (except as indicated)

Transmission Reliability Margin (TRM) — See under **Transfer Capability**

Voltage Reduction — A means to reduce the **demand** by lowering the customer's voltage.

NERC (C-1)

Voltage Regulating Transformer — A transformer that increases or decreases the voltage magnitude relationship of one circuit with respect to another, most often used to control voltage but also to control **reactive power** flow.

B-3

Wheeling — The contracted use of electrical facilities of one or more entities to transmit electricity for another entity.

NERC (C-1)

With due regard to reclosing — This phrase means that before any manual system adjustments, recognition will be given to the type of **reclosing** (i.e., manual or automatic) and the kind of **protection**.

A-1

Compiled by the Joint Glossary Working Group under the auspices of the Task Force on Coordination of Planning.

Reviewed for concurrence by: TFCO, TFEMT, TFSP and TFSS

Review frequency: 1 year

References: *Criteria for Review and Approval of Documents* (Document A-1)

Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2)

Emergency Operation Criteria (Document A-3)

Bulk Power System Protection Criteria (Document A-5)

Operating Reserve Criteria (Document A-6)

Guide for the Application of Autoreclosing to the Bulk Power System (Document B-1)

Guidelines for Inter-AREA Voltage Control (Document B-3)

Special Protection System Guideline (Document B-11)

Glossary of Standard Operating Terms (Document C-1)

Monitoring Procedures for Emergency Operation Criteria (Document C-5)

Operational Planning Coordination (Document C-13)

Procedures for Solar Magnetic Disturbances on Electrical Power Systems (Document C-15)

Procedure for Testing and Analysis of Extreme Contingencies (Document C-18)

Procedures During Abnormal Operating Conditions (Document C-20)

Procedure to Collect Real Time Data for Inter-Area Dynamic Analysis (Document C-25)

The North American Electric Reliability Council (NERC) *Glossary of Terms,* August 1996.

The IEEE *Standard Dictionary of Electrical and Electronics Terms*, Sixth Edition.

Document A-8

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1515 BROADWAY, NEW YORK, NY 10036-8901 TELEPHONE: (212) 840-1070 FAX: (212) 302-2782

NPCC Inc.
Reliability Compliance and Enforcement Program

Adopted by the Members of the Northeast Power Coordinating Council on mm, dd, yyyy, based on recommendation by the Reliability Coordinating Committee, in accordance with paragraph VIII, subheading (a), of NPCC Inc. Bylaws dated May 18, 2006 as amended to date.

Revised: November 7, 2001
Revised: April 30, 2004
Revised: January 30, 2006
Revised: December 20, 2007

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Note:

Terms in bold typeface are defined in the *NPCC Inc. Glossary of Terms* (Document A-7)

1.0 Introduction

The purpose of the Northeast Power Coordinating Council Inc. is to promote the reliable and efficient operation of the interconnected **bulk power systems** in Northeastern North America through the establishment of criteria, coordination of system planning, design and operations, and assessment and enforcement of compliance with such criteria. In the development of reliability criteria, NPCC Inc., to the extent possible, facilitates attainment of fair, effective and efficient competitive electric markets.

The NPCC Inc. Reliability Compliance and Enforcement Program (the Program) described in this document is to be used to assess and enforce compliance with NPCC Inc. **reliability** criteria in such a way that the **reliability** objective stated above will be achieved. Actions taken by NPCC Inc. under the Program, including the imposition of sanctions, where applicable, shall in no way be construed as an acceptable alternative to the Member's continued obligation to comply with NPCC Inc. Criteria, Guides and Procedures. As such the Member, as stated in the NPCC Inc. Bylaws, remains responsible for providing its plan and schedule to achieve compliance. It is further noted that the Program requirements are applicable only to the elements of the **bulk power system** as defined by NPCC Inc. This definition can be found in the *NPCC Glossary of Terms* (Document A-7). The Program is applicable to all Full Members of the Council who have by virtue of their membership in NPCC Inc. agreed, under Section IX, Sub-section A (2) (f) of the NPCC Inc. Bylaws , to submit such data and reports as required and described in the Program.

The Program is designed to be consistent with the concept that compliance assessment and enforcement is most effectively accomplished by the entities that are closest to the complying party. The Program establishes the following assessment structure: NPCC Inc. will assess and enforce compliance to those standards and criteria for which the **Areas** have the reporting responsibilities, and the **Areas** will assess and enforce compliance to those standards and criteria for which the market participants have reporting responsibilities. It is expected that the **Areas** will have compliance processes in place that involve the market participants. The specific standards and criteria covered by this Program are described in Appendix A, which will be amended annually as required.

1.1 Non- member Facilities

A Member, through whose facilities a non-member connects with or proposes to connect with the NPCC Inc. **bulk power system** shall use its best efforts to assure that the arrangements for such connection are consistent with NPCC Inc. criteria in accordance with the provisions and requirements of the NPCC Inc. Bylaws.

2.0 Reliability Criteria

2.1 Development of Criteria

The criteria utilized in assessing compliance have been developed by NPCC Inc. consistent with the North American Electric Reliability Council broad-based standards. NPCC Inc. has implemented its Open Process as a means of assuring that the development and modification of these criteria are non-discriminatory. The process provides the opportunity for industry input into the establishment of such criteria.

2.2 Obligations of Members

Appendix A of this document sets forth the compliance requirements to which each Member has agreed for the current enforcement year.

2.3 Review of Appendix A Requirements

CMAS, in conjunction with the appropriate NPCC Inc. Task Forces, shall annually review the requirements included in Appendix A to assure that the effectiveness of the Reliability Compliance and Enforcement Program is maintained. Whenever an NPCC Inc. Criteria Document is due for a periodic review, the appropriate Task Force shall also review any associated compliance template in Appendix A to assure consistency of compliance implementation with the revised Criteria and shall inform the CMAS whether or not a template change is required.

The various NPCC Inc. Task Forces have a responsibility to make a recommendation for any additional requirements to be included in the RCEP or for the removal of an existing requirement from the RCEP. Such addition or removal of a requirement must be communicated to the CMAS as a proposed Amendment to Appendix A. Based on the Task Force's recommendation, CMAS submits the proposed Amendment for endorsement by the RCC and approval by the NPCC members.

3.0 Reporting and Disclosure

3.1 Area Reporting

Each **Area** furnishes to CMAS via the NPCC Inc. web-based Compliance Application, as per the established schedule, a compliance submittal for each of the requirements described in the annual NPCC Inc. Compliance Program Schedule.

NPCC Inc. has established a lateness policy with associated sanctions. The policy is detailed in Section 4.2 of A-8.

3.2 Area Disclosure

When an alleged violation is suspected, the name of the Area (not the individual party) will be reported to NPCC Inc. CMAS will track alleged violations and report to the RCC. Upon confirmation and completion of the due process within the Area, the Area shall disclose the name the participant responsible for the violation to the RCC if the participant is a member of NPCC Inc., or if a participant is not a member of NPCC Inc, the Area shall disclose the name of the participant responsible for the violation in accordance with the Area's disclosure procedure.

4.0 Compliance Assessment and Enforcement Process

The compliance assessment and enforcement process is described below in terms of the functional entities that will be responsible for the process. In addition, the *Guidelines for the Implementation of the NPCC Inc. Compliance Program* (Document B-22) diagrams and describes in detail the processes utilized by the Program and other pertinent details related to the Program.

4.1 Compliance Monitoring and Assessment Subcommittee (CMAS)

CMAS, as a standing subcommittee of the Reliability Coordinating Committee (RCC), has the responsibility to perform independent compliance monitoring and assessment functions and to recommend the appropriate compliance violation sanctions to the RCC.

CMAS establishes the Program requirements and schedule and submits them to the RCC for approval. Once approved, CMAS is responsible for managing the Program, making periodic reports to the RCC, and seeking RCC approvals when necessary.

NPCC Inc. Task Forces are utilized to develop compliance templates and to perform many of the technical assessments required in the Program. The results of these assessments are forwarded to CMAS for compliance review.

CMAS employs, whenever practical, the use of self-certification forms as a means of streamlining the reporting process. The *Review Process for NPCC Inc. Reliability Compliance Assessment and Enforcement Program*

(Document C-32) will be utilized to verify compliance reporting. The review process, which requires selected **Areas** to present detailed information related to selected requirements, assures accurate and efficient execution of the Program. CMAS establishes an annual schedule for the review process that is approved by the RCC.

CMAS conducts its compliance assessment and submits its report to the RCC for review and approval. CMAS will also provide a sanction recommendation for compliance violations where appropriate.

4.2 Reliability Coordinating Committee (RCC)

The RCC, a standing committee of NPCC Inc., reviews the compliance report submittals received from CMAS. Prior to a final compliance determination, the RCC may remand the report back to CMAS for clarification. Once the RCC has made a final compliance determination, any dispute regarding the technical compliance assessment will be submitted to the Enforcement Panel (EP).

The RCC also reviews any sanction recommendations received from CMAS. Prior to endorsing them, the RCC may remand the sanction recommendations back to CMAS for further clarification before forwarding them to the EP.

4.3 Enforcem ent Panel (EP)

The NPCC Inc. EP members shall adhere to the *Enforcement Panel Code of Conduct* and the *NPCC Administrative Procedures for Conducting an Enforcement Panel Hearing*.

The NPCC Inc. EP will receive either an undisputed RCC determination of a compliance violation including a sanction recommendation, an undisputed RCC determination with a disputed sanction recommendation or a disputed compliance violation from the RCC. The EP has full discretion to implement sanctions.

The **Area** shall notify the EP as to whether it will accept or dispute the sanction. If the **Area** accepts the sanction, the EP issues the appropriate sanction letter.

If, however, the Area disputes the sanction or the EP receives a disputed compliance violation, an EP hearing will be held in accordance with the approved hearing procedures. Non-voting regulatory observers, who are members of NPCC Inc., are permitted at Enforcement Panel hearings and may offer comments as appropriate but may not participate in any deliberations. A

regulatory observer is not permitted to participate in an Enforcement Panel hearing involving an entity subject to the regulator's jurisdiction.

The EP, which consists of five-members, functions independently from the NPCC Inc. Board of Directors (BODs). The panel will be made up of two Transmission Provider representatives, two Transmission Customer representatives, and a NPCC Inc. Staff Member. In addition, one alternate Transmission Customer member and one alternate Transmission Provider member will be elected. The alternate member shall provide substitute for a sitting member when there is potential conflict of interest. The EP members will elect a Chair.

The BODs will solicit nominations for participation on the EP from the NPCC Inc. Membership. Members of the EP will be elected by the NPCC Inc. membership from a list of candidates proposed by the BODs. An EP member shall not be a member of the CMAS.

4.4 Board of Directors

The NPCC Inc. BODs will provide oversight to the assessment and enforcement process through administration of the Program. The BODs will monitor the RCC compliance-related activities, EP final reports including sanction determinations and the results of any cases resolved through the NPCC Inc. ADR process in order to determine the success of the Program and whether changes are desirable.

4.5 Arbitration

An **Area** ("Disputing Area") may only seek review of an EP Final Report by invoking the arbitration provision described below:

a. Within 15 calendar days of submission for arbitration of any dispute related to a determination of non-compliance with a reliability criterion and/or the assessment of a sanction, the Chairman of the EP and the Disputing Area shall select a single arbitrator. If the Chairman of the EP and the Disputing Area are unable to agree on an arbitrator, they shall select an arbitrator from a list of qualified arbitrators maintained by the NPCC Inc. Each NPCC Inc. **Area** may submit one name of an arbitrator to be included on such list. All arbitrators included on such list are knowledgeable with respect to electric utility industry matters.

   The EP and the Disputing Area shall select the arbitrator from such list by (a) agreement, or in the absence of agreement, (b) striking names

from the list in turn (beginning with the party requesting arbitration) until only the selected arbitrator remains. The arbitrator selected will not be an employee, director or officer of either the NPCC Inc. or the Disputing Area or any Affiliate thereof. Potential arbitrators who are employees, directors or officers of Members of the NPCC Inc., but who are not themselves officers of the NPCC Inc. or members of the EP, will not be considered to be employees, directors or officers of the NPCC Inc. The arbitrator must agree in writing to be bound by the confidentiality obligations applicable to the NPCC Inc. Staff.

b. All arbitration proceedings shall be held in New York City, unless an alternate location is agreed to by the parties. The NPCC Inc. Staff will facilitate any such arbitration proceedings.

c. The arbitrator shall provide the EP and the Disputing Area the opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association. The NPCC Inc. shall submit to the arbitrator evidences including reports provided by the CMAS to the RCC, the RCC Final Compliance Determination and the EP Final Report, and the data and information provided by the **Area** and by other **Areas** to the CMAS. The EP and the Disputing Area shall be afforded a reasonable opportunity to rebut any such evidence. The arbitrator shall create and maintain an evidentiary record of sufficient detail to render an informed decision.

   During the arbitration process, the NPCC Inc. and the Disputing Area shall make funds available to the arbitrator as required by the arbitrator to pursue the arbitration. Such funds shall be shared equally by the NPCC Inc. and the Disputing Area, and at the conclusion of the arbitration shall be reimbursed as specified in (g) below.

d. In any arbitration, either the EP or the Disputing Area may raise any issue regarding the technical assessment and or sanction determination, including the factual basis for the technical assessment and or sanction, or whether the procedures specified in this document were properly followed. Neither the EP nor the Disputing Area, however, may dispute the validity of the reliability criteria used in the RCEP.

e. If an arbitrator hearing a dispute between the NPCC Inc. and the Disputing Area determines that data from another **Area** are relevant to the consideration of such dispute, the arbitrator shall so notify such other **Area**, and such other **Area** shall have 15 calendar days, or a mutually agreeable extension thereof, to provide the requested data.

f. As soon as practicable, but no later than 90 calendar days after initial selection of the arbitrator, the arbitrator shall issue to the EP and the Disputing Area a written decision resolving the dispute and explaining the basis for the conclusion. Such decision shall include findings of fact to support the arbitrator's conclusion. Such decision shall be final and binding on the parties.

   Any and all costs associated with the arbitration (not including attorney and expert witness fees which shall be borne by the respective parties) shall be borne by the party whose arbitration position was not selected by the arbitrator, unless the NPCC Inc. and the Disputing Area agree to an alternative method of allocating costs. If the arbitration decision differs from the positions of both the EP and the Disputing Area, the arbitrator shall specify how the costs are to be allocated. Such cost allocation shall include reimbursement of any funds provided to the arbitrator by the NPCC Inc. and the Disputing Area pursuant to the description contained in (c) above.

4.6 Appeal to Applicable Governmental Authority

Either the NPCC Inc. or the **Area** ("Disputing Area") may apply to applicable Governmental Authority to hear an appeal of any arbitrator's decision resulting from implementation of the NPCC Inc. ADR process. Such an appeal shall be filed at applicable Governmental Authority within fifteen (15) calendar days of the arbitrator's decision. The NPCC Inc. and the Disputing Area agree that in any appeal to applicable Governmental Authority either NPCC Inc. or the Disputing **Area** may address any issues raised in the arbitration or the EP proceeding, including the factual basis for the technical assessment or sanction or whether the procedures were properly followed. Neither NPCC Inc. nor the Disputing **Area**, however, may raise issues regarding the validity of the reliability standard and criteria in RCEP. Any appeal from an arbitrator's decision to the appropriate Governmental Authority shall be based solely upon the record assembled by the arbitrator, unless otherwise determined by appropriate Governmental Authority. Each of the NPCC Inc. and the Disputing **Area** in connection with such an appeal to appropriate Governmental Authority shall be solely responsible for its own cost incurred. Any initiation of a Governmental Authority appeal by the NPCC Inc. pursuant to this section 3.5 must be authorized by the NPCC Inc. Board of Directors.

5.0 Sanctions

5.1 Violations of Reliability Criteria

Table 1 defines the sanctions for violations to the criteria as described in the Compliance Templates shown in Appendix A. Not all Compliance Templates require all four levels of non-compliance. Except where noted, when there is an inconsistency between the template and the referenced criteria, the criteria shall prevail.

Table 1 - NPCC Inc. Non-Compliance Sanctions

Level of Non-Compliance	Sanctions
1	Letter to the relevant functional head (operations, planning) of the **Area**
2	Letter to the Chief Executive of the **Area** with copy to the relevant functional head, other NPCC Inc. **Areas**, the NPCC Inc. Task Force Chairs, the NPCC Inc. Reliability Coordinating Committee, the NPCC Inc. Board of Directors and NPCC Inc. Member Representatives.
3	Letter to the Board of Directors of the **Area** with copies to the Chief Executive of the **Area**, the relevant functional head of the **Area**, other NPCC Inc. **Areas**, the NPCC Inc. Task Force Chairs, the NPCC Inc. Reliability Coordinating Committee, the NPCC Inc. Board of Directors, NPCC Inc. Member Representatives, and Regional Managers of adjacent reliability Councils. Post on NPCC Inc. Web site
4	Same as Level 3 with copies to State/Provincial regulatory authorities, State Governor and Legislators

5.2 Policy on Lateness

All compliance reports are to be received by NPCC Inc. on time in accordance with the due dates established by CMAS. All reports are to be provided in easily readable electronic format.

Sanctions shall be applied if a complete report is not received by CMAS after a grace period of ten calendar days has expired. CMAS shall assess the following level of non-compliance for lateness:

Level 1	After 10 calendar day grace period
Level 2	After 30 calendar days following due date
Level 3	After 60 calendar days following due date
Level 4	After 90 calendar days following due date or report never received

Levels are defined in Table 1.

6.0 RCEP Data Retention Requirements

For the purposes of NPCC Inc. RCEP, a minimum of three years of data shall be retained that fully supports certification towards an NPCC Inc. criteria document or compliance template. This requirement may be superseded by data retention requirements where specified in other NPCC Inc. criteria documents or compliance templates.

Lead Subcommittee:	Compliance Monitoring and Assessment Subcommittee
Reviewed for concurrence by:	TFCP, TFCO, TFSP, TFSS, TFIST
Review frequency:	Annually
References:	*NPCC Inc. Bylaws*
	NPCC Inc. Glossary of Terms (Document A-7)
	Guidelines for Implementation of the NPCC Inc. Compliance Program (Document B-22*)*
	Review Process for NPCC Inc. Reliability Compliance and Enforcement Program (Document C-32)

APPENDIX A

Compliance Templates and Monitoring

Compliance Template A2-1

Area Transmission Review

Standard: The interconnected transmission systems shall be planned, designed, and constructed to reliably meet projected customer electricity demand and energy requirements in accordance with NPCC Inc. *Basic Criteria for Design and Operation of Interconnected Power Systems* (Document A-2). Studies shall be conducted in accordance with NPCC Inc. *Guidelines for NPCC Area Transmission Reviews*, Document B-4

References: NPCC Inc. *Basic Criteria for Design and Operation of Interconnected Power Systems* (Document A-2) and NPCC Inc. *Guidelines for NPCC Inc. Area Transmission Reviews* (Document B-4)

Responsibilities

Reporting Responsibility: **Areas**

Frequency of Reporting: Annually

Compliance Monitoring and Assessment Responsibility: NPCC Inc.

Enforcement Responsibility: NPCC Inc.

Full (100%) Compliance

An annual Area Transmission Review Report, including all supporting documentation in accordance with Document B-4 was submitted to TFSS and the Area's planned **bulk power system** meets the requirements of Document A-2. For and Interim or Intermediate Review, the Area must submit its report to TFSS no later than the end of the year in which the review was initiated. For a comprehensive Review, the Area must submit its report to TFSS no later than April 1st of the following year after which the review was initiated.

Non-Compliance

Level 1: An Area Transmission Review was submitted, but was incomplete in meeting the requirements of Document B-4.

Level 2: **An** Area Transmission Review was submitted. However, the **Area**'s planned **bulk power system** was found to be noncompliant with the A-2 criteria in one or more instances. The **Area** submitted an acceptable plan and schedule for addressing the instances of noncompliance.

Level 3: An Area Transmission Review was submitted. However, the **Area**'s planned **bulk power system** was found to be noncompliant with the A-2 criteria in one or more instances, and that either the **Area** failed to submit a plan and schedule to meet the requirements, or that the **Area** submitted such a plan, but it was found to be unacceptable.

Level 4: An Area Transmission Review was not submitted. Please refer to Section 5.2, Policy on Lateness.

Compliance Template A3-1

Underfrequency Load Shedding

Standard: Each NPCC Inc. **Area** shall plan and implement an Underfrequency Load Shedding Program as specified in section 4.6 of the NPCC Inc. *Emergency Operation Criteria* (Document A-3).

References: NPCC Inc. Documents A-3.

Responsibilities

Reporting Responsibility: **Areas**

Frequency of Reporting: Annually

Compliance Monitoring and Assessment Responsibility: NPCC Inc.

Enforcement Responsibility: NPCC Inc.

Full (100%) Compliance

The Area load-shedding program fully complies with the requirements of the NPCC Inc. *Emergency Operation Criteria* (Document A-3), Section 4.6.

Non-Compliance

Level 1: Deficiencies in Area load shedding capability were reported and a plan was submitted by the Area to correct the deficiencies. Deficiencies were corrected within five (5) months of the end of the current reporting period, or

The implementation of the Area's UFLS program is incomplete or inconsistent in one or more requirements of Document A-3, Section 4.6 (4.6.1, 4.6.2, or 4.6.3), but is consistent with the required **total** amount of load shedding, or

The amount of load shedding is less than 100% but greater than 95% of the Area's requirement of any of the load steps.

Level 2: Deficiencies in Area load shedding capability were reported and a plan was submitted by the Area to correct the deficiencies. Deficiencies were corrected within twelve (12) months of the end of the current reporting period, or

The amount of load shedding is less than 95% but greater than 90% of the Area's requirement in any of the load steps

Level 3: Deficiencies in Area load shedding capability were reported with no plan for correction within twelve (12) months of the end of the current reporting period, or

deficiencies from the immediately previous reporting period were not corrected by the end of the current reporting period, or

The amount of load shedding is less than 90% but greater 85% of the Area's requirement in any of the load steps.

Level 4: An Area load shedding capability report was not submitted or deficiencies from more than one previous reporti ng period w ere not corre cted by the end of the current reporting period. Please refer to Section 5.2, Policy on Lateness, or

The amount of load shedding is less than 85% of the Area's requirement in any of the load steps.

Compliance Template A3-3

Key Facility and Critical Components List

Standard: Each **Area** shall maintain an inventory of **key facilities** and their **critical components** required for the energization of the **basic minimum power system** to ensure a successful system restoration. (Section 4.11 of the NPCC Inc. *Emergency Operation Criteria,* Document A-3)

References: NPCC Inc. *Emergency Operation Criteria* (Document A-3)

Responsibilities

Reporting Responsibility: **Areas**

Frequency of Reporting: Annually

Compliance Monitoring and Assessment Responsibility: NPCC Inc.

Enforcement Responsibility: NPCC Inc.

Full (100%) Compliance

Each **Area** shall provide to NPCC Inc. , on a confidential basis, their current **key facilities** and **critical components** list annually. The list shall identify **critical components** associated with the following applicable **key facility** categories:

1. Blackstart generating stations.
2. Underground transmission cables.
3. Substation and Telecommunication sites.
4. Control Center and Telecommunication Center facilities.

Non-Compliance

Level 1: None.

Level 2: A **key facility** and **critical component** list was provided but NPCC Inc. Inter-Area Restoration Coordination Working Group (CO-11) found that it did not fully support the energization of the **basic minimum power system**.

Level 3: The **Area** did not maintain a current **key facility** and **critical components** list.

Level 4: None.

A-4 Compliance

Bulk Power System Protection Minimum Maintenance

Standard: Protection system owners shall implement a protection system maintenance and testing program that fulfills the requirements of the NPCC *Maintenance Criteria for Bulk Power System Protection* (Document A-4).

References: Document A-4.

Responsibilities

Area shall enforce market participants' compliance to A-4 Criteria in accordance with the **Area**'s policy and procedure.

Full (100%) Compliance

Exceptions to Document A-4 requirements are acceptable if the exceptions are completely removed within five (5) months of the end of the current reporting period.

Compliance Template A6-1

Ten-Minute Operating Reserve

Standard: Each **CONTROL AREA** shall operate its MW power **resources** to provide for a level of **OPERATING RESERVE**. Following loss of **resources**, a **CONTROL AREA** shall take appropriate steps to return its **AREA CONTROL ERROR** (ACE) to zero or its pre-disturbance level in accordance with the NPCC Inc. Operating Reserve Criteria (Document A-6). Each **CONTROL AREA** will maintain at all times sufficient **OPERATING RESERVE** to cover its **first contingency loss**.

Reference: NPCC Inc. *Operating Reserve Criteria* (Documents A-6)

Responsibilities

Reporting Responsibility: **Control Areas**

Frequency of Reporting: Monthly by the end of the following month

Compliance Monitoring and Assessment Responsibility: NPCC Inc.

Enforcement Responsibility: NPCC Inc.

Full (100%) Compliance

Control Area meets the **Ten-Minute Reserve** requirement as described in Sections 3.1 and 3.4 of A-6, except during emergency operations resulting from a capacity deficiency.

Non-Compliance

Level 1: Failure to meet the **Ten-Minute Reserve** requirement as described above once during the past twelve (12) months.

Level 2: Failure to meet the **Ten-Minute Reserve** requirements as described above twice during the past twelve (12) months.

Level 3: Failure to meet the **Ten-Minute Reserve** requirements as described above three times during the past twelve (12) months.

Level 4: Failure to meet the **Ten-Minute Reserve** requirements as described above four or more times during the past twelve (12) months.

Document A-10

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

Classification of Bulk Power System Elements

Adopted by the Members of the Northeast Power Coordinating Council Inc., this Dec. 1, 2009 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Inc. Bylaws dated May 18, 2006 as amended to date.

1.0 Introduction

NPCC defines specific requirements applicable to design, operation, and **protection** of the **bulk power system**. The object of this *Classification of **Bulk Power System Elements*** (Document A-10) is to provide the methodology to identify the **bulk power system elements**, or parts thereof, of the interconnected NPCC Region.

The methodology in this document is used to classify **elements** of the **bulk power system** and may result in **elements** being added to or removed from the NPCC **Bulk Power System** List. The methodology in this document is based on the following:

- Results of an analysis done on a bus basis can be applied to identify which **elements,** or portions thereof, connected to the bus are part of the **bulk power system**.

- **Elements** shall not automatically be included or excluded from the **bulk power system** based on voltage class. Application of this methodology may be omitted at buses that can be logically excluded from the **bulk power system** based on study results at other buses tested using this methodology. If a bus is determined to be **bulk power system**, all other buses with elements connected to that bus must be tested.

- **Elements** shall be evaluated based on this methodology when significant changes occur on the system that could change an **element**'s **bulk power system** status; the evaluation may be limited to the affected part of the system.

- **Areas** and facility owners may adopt methodologies that exceed the requirements set forth in this document for their own purposes. However, only **elements** classified as **bulk power system** as a result of testing described in this document shall be included on the NPCC's list of **bulk power system elements**. NPCC criteria and compliance monitoring shall consider only the system **elements** listed on NPCC's list of **bulk power system elements**.

The Classification of **Bulk Power System Elements** is based on three defined terms: **bulk power system**, **local area** and **significant adverse impact**.

2.0 Definitions

Terms in italics in this document are defined in this section.

Terms in bold are defined in the *NPCC Glossary of Terms* (Document A-7).

2.1 *Bus*

Within this document the term *bus* refers to a junction with sensing or **protection** equipment within a substation or switching station at which the terminals of two or more **elements** are connected, regardless of whether circuit breakers are provided. In this context, *bus* may not have a direct correlation to the use of this term in substation design or a power flow data set.

In some configurations a *bus* may include more than one physical *bus*, such as in a breaker-and-a-half arrangement or a single-line-single-breaker arrangement in which two physical *buses* are connected through a *bus*-tie breaker. The examples in Figure 1 depict two of many possible configurations where two physical *buses* are tested as a single *bus*. *Buses* that are separated by normally open *bus*-tie breakers are considered as separate *buses*. The termination of line sections through switches should not be considered as a *bus* requiring testing unless the switches are activated as part of a **protection system** for the line which they sectionalize as part of normal **protection system** actions.

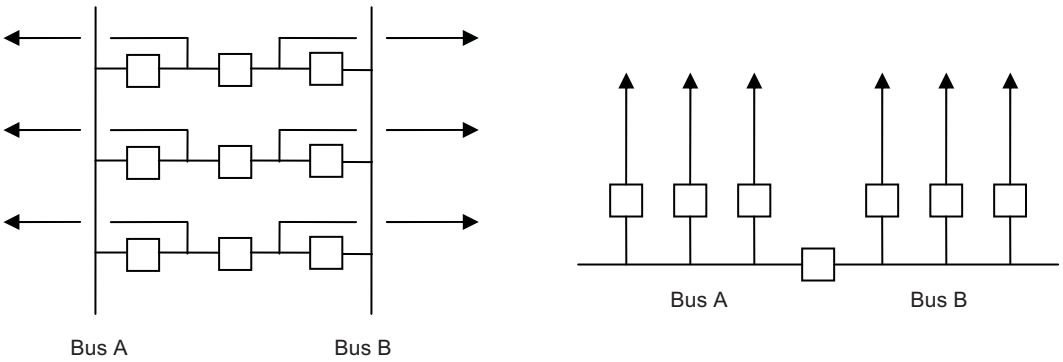

Figure 1 – Configurations where *Bus* A and *Bus* B are tested as one *bus*.

In some configurations **elements** may not be terminated to the *bus* through circuit breakers, such as the generator *bus* for a unit connected generator or a *bus* between a transmission line and transformer that are switched as a single circuit. The examples in Figure 2 depict two of many configurations where two physical *buses* are tested as separate *buses*.

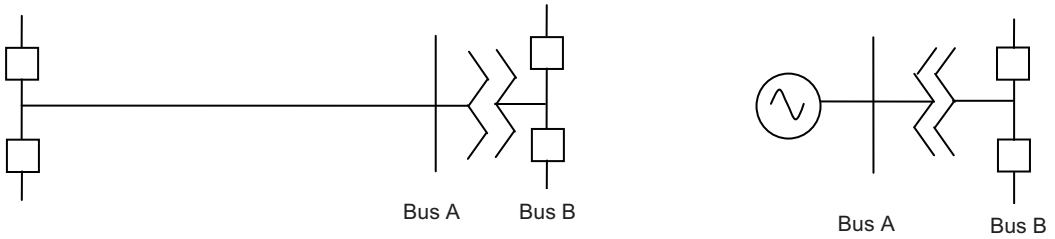

Figure 2 – Configurations where *Bus* A and *Bus* B are tested as two separate *buses*.

2.2 *Uncleared Locally*

Within this document the phrase *uncleared locally* is used to denote failure of the **protection** including **Special Protection Systems** for the *bus* under test to initiate tripping of all associated interrupting devices regardless of their location.

Protection located at other *buses* is assumed to operate as designed when that **protection** cannot be disabled by failure of a single component in common with the **protection** at the *bus* under test. For example, consider the case where the **protection** for **elements** connected to higher voltage level and lower voltage level *buses* in the same station share a dc source, and an independent dc source is provided for second **protection groups** associated with **elements** connected to the higher voltage level *bus*. In this case, it is acceptable when testing the lower voltage level *bus* to assume correct operation of any **protection groups** associated with **elements** connected to the higher voltage level *bus* capable of detecting the **fault** and supplied by the independent dc source.

In cases where circuit breakers are not provided at the terminals of the **element** at the *bus* under test (as shown in Figure 2, *bus* A), *uncleared locally* includes a failure to clear a **fault** by circuit breakers located at another *bus* within the same substation, unless back-up **protection** at that other *bus* using an independent dc source would detect the **fault** and initiate clearing.

3.0 Classification of Bulk Power System Elements

3.1 Testing Conditions and Assumptions

Studies conducted for the purpose of determining the **elements** of the **bulk power system** shall assume the following conditions:

3.1.1. Power flow transfers, **load** and **generation** patterns expected to exist for the period under study which stress the system in a manner critical to the classification of the *bus* to be tested. All **reclosing** facilities rendered inoperative.

3.1.2. Operation of **Special Protection Systems**, undervoltage **load shedding** and underfrequency **load shedding** modeled as designed.

3.1.3. Load models used in the **Transient Stability** Test are consistent with **Area** practices for the studies of rotor angle stability.

3.1.4. Load models used for steady state testing are either constant MVA or are based on actual system testing with LTC movement.

3.1.5. Stability simulation runs until the system response can be clearly determined.

3.1.6. Generic or detailed relay models to monitor, after tripping of remote terminals, the potential for tripping of un-faulted **elements**.

3.2 Test Methodology

Both **transient stability** and steady-state tests are used to determine the impact on system performance resulting from power system **faults**.

Testing is based on application of a *bus* **fault** at a single voltage level that is *uncleared locally*. Tripping of un-faulted **elements** associated with clearing the test **fault** does not constitute a **significant adverse impact**.

Depending on system configuration or topology, testing only **faults** at *buses* can fail to uncover **significant adverse impacts** arising from a design criteria contingency involving the loss of two adjacent transmission circuits on a common tower. Hence, specific tests in 1c and 2c below are designed to assess this contingency for its potential **significant adverse impact** outside of the **local area**.

A **transient stability** test may be done first to identify *buses* at which **faults** may cause a **significant adverse impact** outside of the **local area**.

For those *buses* which are not classified as **bulk power system** in the **transient stability** test, a steady-state test is used to identify *buses* at which **faults** may cause a **significant adverse impact** outside of the **local area**.

Step 1 - Transient Stability Test

Simulate the **transient stability** condition of a three-phase **fault** with delayed clearing at the *bus* under test (step 1a). If the test results in a positive **bulk power system** determination, more detailed testing (step 1b) may be applied to obtain a more precise determination.

1a. Apply a three-phase **fault** for at least 10 seconds at the *bus* that is being tested. Do not open any of the **elements** connected to the *bus* for the duration of the **fault**. After 10 seconds, simulate tripping of all terminals of each **element** connected to the *bus* under test. In cases where there is no **fault** interrupting device at the remote terminal of an **element**, open all terminals of all **elements** between the *bus* under test and the interrupting device(s) that will open to clear the **fault**. This test is performed as an efficient, but conservative method for evaluating the impacts of:

- *bus* **faults** which would result in faster clearing time, and
- **faults** off the *bus*.

It is recognized that due to the conservative nature of this test some **elements** could be classified unnecessarily as part of the **bulk power system**. If the above test results in a positive **bulk power system** determination, the following additional testing may be utilized to obtain a more precise determination. Subsequent testing utilizes design clearing times for the conditions being tested, as stated below.

1b. Apply a three-phase **fault** at the *bus*, which is *uncleared locally* and trip the remote terminals of all **elements** that will open to clear the **fault**. Remote clearing times shall be based on design **fault clearing** times, assuming no communications from the station under test to the remote terminals.

Transformers and other **elements** connected to the *bus* shall only be tripped by operation of independent remote **protection groups** capable of clearing a **fault** on the *bus* under test.

Some **protection groups** (e.g. directional comparison blocking) at remote terminals may provide high-speed **fault clearing** for faults at the bus under test. In order to test the effects of longer **fault clearing** times for fault conditions when these remote **protection**

groups would not provide high speed **fault clearing**, for either test (1a) or (1b) above:

- High-speed **fault clearing** at remote terminals must be ignored; or
- Testing must vary the placement of the 3-phase **fault** on the elements connected to the bus under test to include locations beyond the reach of the high-speed tripping relay element at the remote terminal.

However, the **protective relay** settings may be reviewed to determine whether the *bus* could be classified as not part of the **bulk power system** if faster remote **fault** clearing can be achieved. If **protective relay** settings are modified, an assessment shall be conducted to ensure that the faster clearing time does not compromise the security of the **protection system**. Until the **protective relay** settings are modified, the *bus* must be classified as **bulk power system**.

1c. The test above is meant to cover the majority of design criteria contingencies. However, the **elements** associated with the *bus* under test must be reviewed to ensure adverse consequences resulting from a design criteria contingency involving the loss of two adjacent transmission circuits on a common tower are not overlooked.

If a circuit terminating at the *bus* under test shares a multiple circuit tower with an adjacent circuit that does not terminate at the *bus* under test, the adjacent circuit design contingency must also be assessed. In such cases, simultaneous permanent phase to ground **faults** on different phases of each of two adjacent transmission circuits shall be applied at critical common tower locations. The **fault** on the circuit associated with the *bus* under test which is *uncleared locally*, shall be simulated with **normal fault clearing** at the remote terminal and on the adjacent circuit.

If the **fault** has a **significant adverse impact** outside of the **local area**, the *bus* is classified as part of the **bulk power system**.

For *buses* not classified as part of **bulk power system** in Step 1, continue with the Steady State Test in step 2.

Step 2 - Steady State Test

Simulate the post-**contingency** steady-state conditions based on one of the

following outcomes of the **fault** applied to the *bus* under test:

2a. If the **fault** was cleared based on design **fault clearing** times in the **Transient Stability** Test, open the same **elements** that were opened to clear the **fault** in the Transient Test. Post-**contingency** conditions shall reflect operation of all automatic devices.

2b. If the **fault** was not cleared based on design **fault clearing** times in the **Transient Stability** Test, assume that the **fault** propagates to the nearest location where it can be detected by independent **protection groups** and open the **elements** that would be opened by the **protection groups** to clear the **fault**. Note that because **fault clearing** will occur at interrupting devices capable of clearing the **fault**, it may be necessary to open multiple **elements** between the *bus* under test and the relevant interrupting devices, for example, a transmission line and transformer in series as shown in Figure 2.

2c. As in Step 1, the steady state test above is meant to cover the majority of design criteria contingencies. However, the **elements** associated with the *bus* under test must be reviewed to ensure adverse consequences resulting from a design criteria contingency involving the loss of two adjacent transmission circuits on a common tower are not overlooked. The post-contingency analysis must assess the loss of any adjacent circuit on common towers with a circuit terminating at the *bus* under test in addition to the **elements** associated with the *bus* under test.

Voltages and thermal loading will be assessed for **significant adverse impact** outside of the **local area** following automatic actions. In cases where a power flow solution is not obtained, other techniques shall be used to assess the impact of the event on the power system.

If the **fault** has a **significant adverse impact** outside of the **local area**, the *bus* is classified as part of the **bulk power system**.

Note that Step 2 can be done prior to Step 1. If a *bus* is classified as part of the **bulk power system** by the Steady State Test (Step 2), the **Transient Stability** Test (Step 1) need not be done for that *bus*.

3.3 Utilization of Test Results to Classify on an **Element**-by-**Element** Basis**.**

Classification of **bulk power system elements** is achieved by applying the results of the above tests to the **elements** connected to the tested *bus*.

An **element** with only one terminal such as a generator, shunt reactor, or capacitor bank, is classified as part of the **bulk power system** if the *bus* at which it is connected is classified as part of the **bulk power system**.

An **element** with multiple terminals such as a transformer or transmission line is classified as part of the **bulk power system** if any terminal of the **element** is connected to a *bus* that is classified as part of the **bulk power system**. The **bulk power system** classification may be limited to only a portion of the **element** if all of the following conditions are met:

- At least one terminal is connected to a *bus* that is not part of the **bulk power system**.
- The Steady State Test has been applied at the *buses* connected to all terminals of the **element** and none of these *buses* have been classified as part of the **bulk power system** based on results of the Steady State Test.
- The **Transient Stability** Test has been applied between the terminals of the **element** to identify those portions of the **element** for which the **Transient Stability** Test will not result in a **significant adverse impact** outside of the **local area**.

3.4 Documentation

Documentation for **Bulk Power System** classification shall include:

3.4.1 The rationale for the test conditions and assumptions used that are not listed above in 3.1.

3.4.2 The criteria used in evaluating the result of the testing including but not limited to stability, voltage, and thermal performance.

3.4.3 Detailed result of the testing shall be provided upon request.

4.0 Application and List Maintenance

Each **Area** shall be responsible for the application of the *Classification of* **Bulk Power System** *Elements* as described in this document and shall submit proposed changes and supporting documentation to the Task Force on System Studies (TFSS).

The "NPCC **Bulk Power System** List" will be maintained by the TFSS. Additions to and removals from the NPCC **Bulk Power System** List will be submitted by TFSS to the Reliability Coordinating Committee (RCC) for approval.

4.1 Addition of **Elements** to the **Bulk Power System** List

When application of this methodology identifies an **element** that was not part of the **bulk power system** should be classified as a **bulk power system element**, documentation of the analysis shall be presented to the TFSS. Once classification of the **element** is recommended by TFSS and approved by the RCC the **element** will be added to the NPCC **Bulk Power System** List with the appropriate comments and information. All task forces and the Compliance Committee will be notified once an **element** is approved by the RCC to be added to the **Bulk Power System List**. Within three months of an element being added to the **Bulk Power System** List, a plan and schedule for achieving compliance shall be provided to TFSP for review and acceptance. TFSP may require modifications to the proposed plan and schedule.

4.2 Removal of **Elements** from the **Bulk Power System** List

When application of this methodology identifies a **bulk power system element** that no longer should be classified as a **bulk power system element**, documentation of the analysis shall be submitted to the TFSS. If reclassification of the **element** is recommended by TFSS and approved by the RCC, the **element** will be removed from the NPCC **Bulk Power System** List.

Lead Task Force:	Task Force on Coordination of Planning
Reviewed for concurrence by:	TFSS, TFCO, TFSP, and TFIST
Review frequency:	4 years
References:	*Basic Criteria for Design and Operation of Interconnected Power Systems* (Document A-2)
	NPCC Glossary of Terms (Document A-7)

Document A-15

NPCC, Inc.

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Disturbance Monitoring Equipment Criteria

Adopted by the Members of the Northeast Power Coordinating Council on August 23, 2007 based on recommendation by the Reliability Coordinating Committee, in accordance with paragraph IX, subheading (A), of the Amended and Restated Bylaws of Northeast Power Coordinating Council dated July 24, 2007 as amended to date.

Note:

Terms in bold typeface are defined in the *NPCC Glossary of Terms* (Document A-7)

1.0 Introduction

A prompt and accurate sequence of events must be established following a **disturbance** to provide timely analysis and reporting of the **disturbance**. The importance of Disturbance Monitoring Equipment (DME) in monitoring performance of **protection** equipment and validation of system simulation models has long been recognized in NPCC criteria. This document provides the application and functional requirements for NPCC DME, in accordance with NERC Reliability Standards PRC-002 and PRC-018.

2.0 General

The term Disturbance Monitoring Equipment (DME) is defined in the NERC Glossary, listed as Reference 1, and is repeated below for convenience:

Disturbance Monitoring Equipment (DME) - Devices capable of monitoring and recording system data pertaining to a Disturbance. Such devices include the following categories of recorders:

- Sequence of event (SOE) recorders which record equipment response to the event
- Fault recorders, which record actual waveform data replicating the system primary voltages and currents. This may include protective relays.
- Dynamic Disturbance Recorders (DDRs), which record incidents that portray power system behavior during dynamic events such as low frequency (0.1 Hz – 3 Hz) oscillations and abnormal frequency or voltage excursions.

Footnote: Phasor Measurement Units (PMUs) and any other equipment that meets the functional requirements of DMEs may qualify as DMEs.

In this document, the terms DME, Sequence of Events Recorders, Fault Recorders, and DDRs all refer to functional capability and not to discrete devices.

All of the following applies to all new installations, and modifications to existing installations. Existing DMEs are required to be upgraded to meet these Criteria in accordance with the schedule called for in NERC Standard PRC-018-1.

This document shall be provided to the affected Reliability Coordinators (RCs), Transmission Owners (TOs), and Generator Owners (GOs) within 30 calendar days of its approval.

The TO and GO shall each install DMEs in accordance with these criteria. DMEs shall be provided to permit analysis and reporting of system protection performance,

monitoring of system protection performance, and validation of system simulation models.

3.0 Sequence Of Event Recording

3.1. Sequence of Event recording is the responsibility of transmission owners and **generation** owners. This capability can be provided as part of another device, such as a Supervisory Control And Data Acquisition (SCADA) Remote Terminal Unit (RTU), a generator plant Digital (or Distributed) Control System (DCS) or part of **fault** recording equipment.

3.2. Sequence of Event recorders shall be provided at all **bulk power system** substations and at generating units above 50 MW **capacity**, and at generating plants above 300 MW **capacity**

3.3. Sequence of Events recording shall monitor the following at each location:

- Transmission and Generator circuit breaker positions
- **Protective Relay** tripping for all **protection groups**
- **Teleprotection** keying & receive

4.0 Fault Recording

4.1 **Fault** recording is the responsibility of transmission owners and **generation** owners. When adding or replacing a DFR at an existing BPS facility, the TO or GO should complete a notification in accordance with Document C-22.

4.2 **Fault** recording shall be provided by the TO to determine the current zero time for loss of **BPS** transmission **elements**. The current zero time shall be reported as the time of the final current zero on the last phase to interrupt.

4.3 **Fault** recording capability shall be provided by the GO for generating units above 200 MW **capacity**.

4.4 **Fault** recorders shall monitor the following **elements** at each location where **fault** recorders are installed:

- All **BPS** Transmission Lines
- Autotransformers or phase-shifters connected to **BPS** busses
- Shunt capacitors 345 kV and above
- Individual generator interconnections
- Dynamic Var Devices
- HVDC Terminals

- A Transmission Owner may optionally include the monitoring of transformers serving load from a **BPS** bus.

4.5 Electrical quantities to be recorded for each monitored **element** shall be sufficient to determine the following:

- Three phase-to-neutral voltages. (Common bus-side voltages may be used for lines.)
- Three phase currents and neutral currents.
- Polarizing currents and voltages, if used.
- Frequency.
- Active and reactive power.

4.6 **Fault** recorder record duration shall be a minimum of one (1) second.

4.7 **Fault** recorder minimum recording rate shall be 16 samples per cycle.

4.8 As a minimum, **fault** recorders shall be set to trigger for all the following functions:

- **Protective Relay** tripping for all **protection groups**
- Neutral (residual) overcurrent set at 0.2 pu rated CT secondary current
- Phase undervoltage set at 0.85 pu

4.9 When local conditions require different settings or additional functions, such situations shall be documented.

5.0 Dynamic Disturbance Recording (DDR) Capability

5.1 Where the DDR capability is deemed necessary by the Reliability Coordinator, the Reliability Coordinator shall provide guidance in setting triggers and shall monitor the performance of the DDR devices.

5.2 On an **Area** basis, there shall be at least ten (10) DDRs per 30,000 MW of peak **load**, distributed throughout the system, and installed at various types of locations, with consideration given to the following factors:

- Major **load** centers
- Major **generation** clusters
- Major voltage sensitive areas
- Major transmission interfaces
- Major transmission junctions
- **Elements** associated with Interconnection Reliability Operating Limits (IROLs)

- Major EHV interconnections between control areas.

5.3 An evaluation of the need for a DDR should be made upon each new major **BPS** installation and upon each bulk power system station addition or expansion where a **fault** recorder replacement project is being made. (A field for this purpose will be included in the next revision of Document C-22.)

5.4 DDRs shall monitor the following **elements** at each location where dynamic recorders are installed:

- Most lines such that normal maintenance activities do not interfere with DDR requirements.
- Bus voltages

5.5 As a minimum, DDRs shall monitor one phase current per monitored **element** and two phase-to-neutral voltages of different **elements**. One of the monitored voltages shall be of the same phase as the monitored current.

5.6 Electrical quantities to be recorded for each monitored **element** shall be sufficient to determine the following:

- Voltage, current, and frequency
- Active and reactive power

5.7 DDRs installed after January 1, 2009 shall function as continuous recorders.

5.8 Each device shall sample data at a rate of at least 960 samples per second (16 samples per cycle and shall store the RMS value of electrical quantities at a rate of at least 6 data points per second.)

5.9 The following DDR triggers shall be considered where available based on manufacturers capability:

- Rate of change of Frequency
- Rate of change of Power
- Delta Frequency 20 mHz change
- Oscillation of Frequency

5.10 When local conditions require different settings or additional functions, such situations shall be documented.

5.11 When DDR triggers are used, duration of triggered records shall be a minimum of sixty (60) seconds.

6.0 Data

6.1 Recorded **disturbance** data from DMEs shall be forwarded within 30 days of receipt of the request in each of the following cases:

- Request from NERC **Disturbance** Investigation Team
- Request from NPCC **Disturbance** Investigation Team
- Reliability Coordinator Request

6.2 Data forwarded shall be archived in its native format for a period of 3 years by the TO or GO.

6.3 **Disturbance** data files shall be provided in a format which is capable of being viewed, read, and analyzed with a generic COMTRADE analysis tool (8).

6.4 Disturbance Data files shall be named in conformance with IEEE C37.232 Recommended Practice for Naming Time Sequence Data Files.

6.5 **Fault** Recorder and DDR Files shall contain all monitored channels. SOE records shall contain station, date, time resolved to milliseconds, SOE point name, status.

6.6 Recorded data from each **disturbance** shall be retrievable for 10 calendar days. This requirement does not apply to **relays** unless those **relays** are designated as DME.

6.7 The TO and GO shall each maintain and be ready to report to NPCC on request the following data on the DMEs installed to meet this standard:

- Type of DME
- Make and model of equipment
- Installation location
- Operational Status
- Date last tested
- Monitored **Elements**
- Monitored Devices
- Monitored Electrical Quantities

7.0 Time Synchronization

Internal clocks in DME devices shall be time synchronized to within 2 milliseconds or less of Coordinated Universal Time (UTC) scale. The time zone shall be clearly identified as either universal time zone or local time zone.

8.0 Maintenance And Testing

Each TO, and GO shall establish a maintenance and testing program for DME (guidance for maintenance and testing is provided in Document B-26) that includes:

- Maintenance and testing intervals and their basis.
- Summary of maintenance and testing procedures.

Prepared by: Task Force on System Protection

Review frequency: 3 years

References:

NERC "Glossary of Terms Used in Reliability Standards," November 1, 2006, available at www.nerc.com

NERC Standard PRC-002-1, "Define Regional Disturbance Monitoring and Reporting Requirements," adopted by NERC BOT on 08/02/06 and effective on 05/-2/07, available at www.nerc.com.

NERC Standard PRC-018-1, "Disturbance Monitoring Equipment Installation and Data Reporting," adopted by NERC BOT on 08/02/06 with effective dates phased in over four year period beginning 08/02/06, available at www.nerc.com.

NPCC Glossary of Terms (Document A-07)
NPCC Guide to Time Synchronization of Substation Equipment (Document B-25)
NPCC Guide for Application of Disturbance Recording Equipment (Document B-26)
SP-6 Report

IEEE C37.111-1999, "IEEE Standard Common Format for Transient Data Exchange for Power Systems."

IEEE C37.232, "IEEE Recommended Practice for Naming Time Sequence Data Files." This document was submitted for publication in February 2007. Refer questions to TFSP.

BEFORE THE
NOVA SCOTIA UTILITY AND REVIEW BOARD
OF THE PROVINCE OF NOVA SCOTIA

NORTHEAST POWER)
COORDINATING COUNCIL, INC.)

APPLICATION FOR APPROVAL OF REGIONAL RELIABILITY CRITERIA

The Northeast Power Coordinating Council, Inc. ("NPCC") hereby applies for approval of the Regional Reliability Criteria set out in Exhibit C by the Nova Scotia Utility and Review Board ("NSUARB") on behalf of the Province of Nova Scotia. NPCC is a signatory to the May 11, 2010 Memorandum of Understanding ("MOU") with Nova Scotia Power Incorporated ("NSPI") and the North American Reliability Corporation ("NERC") setting forth the framework in relation to the approval and implementation of mandatory NERC Reliability Standards and NPCC Regional Reliability Criteria in Nova Scotia and other related matters. The MOU supports a prior memorandum of understanding between NSUARB and NERC reflecting the mutual desire for a continuing and cooperative relationship in improving reliability of the North American bulk power system and the exchange of experience, information and data related to that system. In furtherance of the goals of that prior memorandum and pursuant to the terms of the MOU, NPCC respectfully submits this filing for approval of Regional Reliability Criteria.[1]

[1] More specifically, the MOU, at section 2, provides that "NERC will prepare a consolidated filing for NSUARB approval which includes all approved NERC Reliability Standards. Concurrently, NPCC will prepare a consolidated filing for NSUARB approval which includes all NPCC Regional Reliability Criteria."

NPCC, one of eight Regional Entities in North America, is responsible for promoting and enhancing the reliability and efficient operation of the international interconnected bulk power system in Northeastern North America. NPCC, as a cross-border Regional Entity, has been delegated authority within the United States ("U.S.") from NERC, a not-for-profit corporation that is certified[2] by the U.S. Federal Energy Regulatory Commission ("FERC") as the "electric reliability organization" under Section 215 of the Federal Power Act. That delegation is memorialized in the Amended and Restated Regional Delegation Agreement that was approved by the FERC on June 5, 2007. Among other things, NPCC exercises its delegated authority by:

- Actively participating in the development of North American Reliability Standards for the bulk power system, and, as needed, development of Regional Reliability Standards applicable within the NPCC international region
- Monitoring and enforcing approved Reliability Standards, including the registration of responsible entities, and, as needed, certification of such entities
- Assessing the present and future reliability of the bulk power system
- Providing operational coordination and situational awareness support
- Performing event analysis and identifying lessons learned to improve reliability
- Providing effective training and education of reliability personnel
- Promoting the protection of critical electric infrastructure.

[2] Through its enactment of the Energy Policy Act of 2005 ("the Act"), the U.S. Congress entrusted FERC with the duties of approving and enforcing rules in the U.S. to ensure the reliability of the Nation's bulk power system, and with the duties of certifying an electric reliability organization ("ERO") that would be charged with developing and enforcing mandatory Reliability Standards, subject to FERC approval. On July 20, 2006, FERC certified NERC as the ERO, charged with developing mandatory and enforceable Reliability Standards, which are subject to FERC review and approval.

In Canada, NPCC has signed Memoranda of Understanding and Agreements with applicable Canadian Provincial regulatory and/or governmental authorities to support the approval and application of mandatory Standards and Criteria in the Canadian jurisdictions of Ontario, Quebec, New Brunswick and Nova Scotia.

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Exhibit C -- Approved Directories and Criteria

I. INTRODUCTION

NPCC is filing this notice to provide the Province of Nova Scotia a description of the fourteen Regional Reliability Criteria proposed for adoption in the province. These criteria are listed and summarized in Exhibits A and B, respectively. Exhibit C includes the criteria that are currently published and these appear in two formats: Criteria documents (denominated with the prefix "A") and Directories. The Criteria document format pre-dates the Directory format; NPCC is currently in the process of converting the Criteria documents, and their associated criteria, into Directory documents and retiring the Criteria document once the resulting Directory is approved. Upon completion of this multi-year project, only NPCC Directories will exist. These Directories contain not only the criteria but also additional supporting guidance documents on how an entity may achieve the criteria's reliability objective. In addition, the Directories utilize the most recent NERC Functional Model language to identify to which functions the criteria apply and also have any redundancy to NERC Reliability Standards removed. The NPCC Directory documents also have been reviewed to ensure that there no inconsistency exists with any NERC Reliability Standard.

All NPCC Reliability Criteria in this filing have been approved by a vote of the Full Members of NPCC, including NSPI, on the dates listed in Exhibit A, based on recommendations by the NPCC Reliability Coordinating Committee, in accordance with the version of the NPCC Bylaws that were in effect at the time of the individual Reliability Criteria's approval, as amended to date. Under the NPCC Bylaws, each Full

Member of NPCC voluntarily agrees to plan, design and operate its bulk power system in compliance with NPCC Reliability Criteria.

In support of its request for approval by the NSUARB of the Reliability Criteria, NPCC submits the following information: (1) a listing of the Reliability Criteria approved by the Full Members of NPCC (Exhibit A), which are currently effective; (2) a summary of the current effective Reliability Criteria approved by Full Members of NPCC, including the criteria's purpose and applicability (Exhibit B); and (3) copies of the Reliability Criteria approved by Full Members of NPCC (Exhibit C).

II. NOTICES AND COMMUNICATIONS

Notices and communications regarding this Application may be addressed to:

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III. REQUEST FOR APPROVAL OF RELIABILITY CRITERIA

This section provides a summary of NPCC's proposed Regional Reliability Standard to be filed at a later date and existing Regional Reliability Criteria.

A. NPCC's Filing of Proposed Regional Reliability Standard

Pursuant to the execution and implementation of a Regional Delegation Agreement with the ERO and applicable Canadian Memoranda of Understanding or Agreements that are backstopped by the FERC and Canadian Provincial governmental and/or regulatory authorities, NPCC has been delegated the authority by the ERO to create Regional Reliability Standards to enhance the reliability of the international, interconnected bulk power system in Northeastern North America. These Regional Reliability Standards are more specific and/or more stringent than the ERO Reliability Standards. Regional Standards are developed and revised according to a NERC ERO and FERC approved ***NPCC Regional Reliability Standards Development Procedure***. In the development and enforcement of Regional Reliability Standards, NPCC, to the extent possible, facilitates attainment of fair, effective, efficient, and competitive electric markets while providing an open, transparent, fair and inclusive process that has no financial barriers to participation. Anyone can submit a ***Regional Standards Authorization Request*** to develop a new, or revise an existing Regional Standard.

These Standards will, in all cases, not be inconsistent with or less stringent than any requirements of the NERC/ERO Reliability Standards. Each Regional Reliability Standard shall enable or support one or more of the NERC reliability principles, thereby

ensuring that each Regional Standard serves a purpose in support of the reliability of the regional bulk power system. Each Regional Reliability standard shall also be consistent with all of pertinent reliability principles and criteria, thereby ensuring that no Regional Reliability standard undermines reliability through an unintended consequence.

Currently, NPCC has one Regional Reliability Standard approved by the General Members, including NSPI, which is on file with NERC. The standard, PRC-002-NPCC-1 Disturbance Monitoring is scheduled for NERC approval in 2010 and ultimately will be filed with FERC and the applicable Provincial Canadian regulatory and/or governmental authorities for approvals. Three other standards are in various stages of development and will be the subject of future filings with the NSUARB.

B. Overview of NPCC's Regional Reliability Criteria

The reliability criteria are contained in the Directories and Criteria documents listed below:

Directory # 1, – Design and Operation of the Bulk Power System
Directory # 2, - Emergency Operations
Directory # 3, - Maintenance Criteria for Bulk Power System Protection
Directory # 4, - Bulk Power System Protection Criteria
Directory #7, - Special Protection Systems
Directory # 8, - System Restoration
Directory # 9, - Generator Gross/Net Real Power Capability
Directory # 10, - Generator Gross/Net Reactive Power Capability
Directory # 12, - Underfrequency Load Shedding Program Requirements
Criteria A-6, - Operating Reserve Criteria
Criteria A-7, - Glossary of Terms

Criteria A-8, - Reliability Enforcement and Compliance Program
Criteria A-10, - Classification of Bulk Power System Elements
Criteria A-15, - Disturbance Monitoring Equipment Criteria

The NPCC-approved Regional Reliability Criteria are found in Section 5 of each of the above listed Directories and in the main body of the text appearing in the Criteria documents. The Directories also include contextual information associated with the criteria, including guidelines and procedures that are recommended to meet the reliability objectives found in the criteria portions of the directories. These Directories with their associated criteria and Criteria documents were adopted by the Full Members of NPCC on the dates indicated in Exhibit A, based on recommendation by the NPCC Reliability Coordinating Committee, in accordance with the NPCC Bylaws in effect at the time of their approval, as amended to date.

"Executive level" summaries of the pertinent aspects of the submitted Directories and Criteria documents appear in Exhibit B.

VI. CONCLUSION

By this filing, NPCC requests that the NSUARB approve the application of the Regional Reliability Criteria appearing in the Directories and Criteria documents in Exhibit C. NPCC looks forward to working with the Province of Nova Scotia to make its Regional Reliability Criteria mandatory and enforceable in Nova Scotia.

NPCC also requests the Province to provide feedback on the adequacy of the information provided with this filing and guidance on the appropriate information to be included in future filings.

Respectfully submitted,

/s/ Edward A. Schwerdt

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BEFORE THE
NOVA SCOTIA UTILITY AND REVIEW BOARD
OF THE PROVINCE OF NOVA SCOTIA

NORTH AMERICAN ELECTRIC	**)**
RELIABILITY CORPORATION	**)**

APPLICATION FOR APPROVAL OF RELIABILITY STANDARDS OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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Exhibit E -- Future Reliability Standards and List of Effective Dates for Approval

Exhibit F -- Matrix of Violation Risk Factors for Approval

Exhibit G -- Matrix of Violation Severity Levels for Approval

Exhibit H -- NERC Approved Reliability Standards Pending at FERC

I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC")[1] hereby applies for approval by the Nova Scotia Utility and Review Board ("NSUARB") of the proposed Reliability Standards set out in Exhibits C and E, as mandatory and enforceable for users, owners, and operators of the bulk power system within the Province of Nova Scotia.

NERC has been certified[2] as the "electric reliability organization" under Section 215 of the Federal Power Act.[3] The 113 Reliability Standards contained in Exhibits C and E have been approved as mandatory and enforceable for users, owners, and operators within the U.S. by FERC. NERC's Reliability Standards are now mandatory in the Canadian Provinces of Alberta, British Columbia, New Brunswick, Ontario, and Saskatchewan. The legislative framework is in place to make those standards mandatory and enforceable in Manitoba and Québec as well.

NERC has entered into a Memorandum of Understanding ("MOU") with NSUARB[4] and a separate MOU with Nova Scotia Power Incorporated ("NSPI"), and the Northeast Power Coordinating Council, Inc. ("NPCC"),[5] which became effective on December 22, 2006 and May 11, 2010, respectively. The May 11, 2010 MOU sets forth the mutual understandings of NERC, NSPI, and NPCC regarding the approval and

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[1] The Federal Energy Regulatory Commission ("FERC") certified NERC as the electric reliability organization ("ERO") in its order issued July 20, 2006 in Docket No. RR06-1-000. 116 FERC ¶ 61,062 (2006) ("ERO Certification Order").

[2] Through enactment of the Energy Policy Act of 2005, the U.S. Congress entrusted FERC with the duties of approving and enforcing rules in the U.S. to ensure the reliability of the Nation's bulk power system, and with the duties of certifying an ERO. On July 20, 2006, FERC certified NERC as the ERO, charged with developing mandatory and enforceable Reliability Standards, which are subject to FERC review and approval.

[3] 16 U.S.C. § 824o(f) (2006).

[4] *See* Memorandum of Understanding between Nova Scotia Utility and Review Board and North American Electric Reliability Corporation (signed December 22, 2006).

[5] *See* Memorandum of Understanding between Nova Scotia Power Incorporated and the Northeast Power Coordinating Council, Inc. and the North American Electric Reliability Corporation (signed May 11, 2010).

implementation of NERC Reliability Standards and NPCC Regional Reliability Criteria in Nova Scotia and other related matters. The May 11, 2010 MOU also requires NERC to make the instant filing requesting approval by Nova Scotia of the FERC approved, current and future effective NERC Reliability Standards.

In support of its request for approval by the NSUARB of the proposed Reliability Standards, NERC submits the following information: (1) a listing of the Reliability Standards approved by FERC that are currently effective (*see* Exhibit A); (2) a summary of the current effective Reliability Standards approved by FERC, including each standard's purpose, applicability, ballot body approval percentages, and other pertinent information (*see* Exhibit B); (3) the Reliability Standards approved by FERC and the associated NERC Glossary of Terms (*see* Exhibits C and E), for which approval is sought in this request;[6] (4) the critical infrastructure protection ("CIP") implementation plan for Version 2 of the CIP Reliability Standards (*see* Exhibit D); (5) the associated Violation Risk Factors ("VRF") (*see* Exhibit F); (6) the associated Violation Severity Levels ("VSL") (*see* Exhibit G); and (7) a list of additional Reliability Standards approved by the NERC Board of Trustees that are pending before FERC (*see* Exhibit H).[7,8]

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[6] The NERC Glossary of Terms includes Regional definitions that do not apply to the Province of Nova Scotia.

[7] NERC will file a subsequent request for approval of those standards with the NSUARB, once FERC has taken final action.

[8] In addition to the standards pending with FERC, there are NPCC Regional Reliability Standards pending with NERC. Refer to the following link for the status of these Regional Reliability Standards: http://www.nerc.com/filez/regional_standards/regional_reliability_standards_under_development.html

II. NOTICES AND COMMUNICATIONS

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III. REQUEST FOR APPROVAL OF RELIABILITY STANDARDS

This section provides a summary of NERC's existing Reliability Standards.

A. NERC Filing of All Proposed Reliability Standards

NERC is filing all FERC approved Reliability Standards for approval by the NSUARB. The Reliability Standards, in the instant filing, are provided in two parts. The first part consists of Reliability Standards that are currently mandatory and enforceable in the U.S. This part is referred to in the filing as current effective Reliability Standards (*see* Exhibit C). The second part consists of the Reliability Standards that FERC has approved, but will take effect later this year and in January 2011. This part is referred to in the filing as future effective Reliability Standards (*see* Exhibit E).

NERC also requests that the NSUARB approve the associated VRFs and VSLs, as set out in Exhibits F and G. VRFs assess the impact to reliability of violating a specific requirement. The risk factor is one of several elements used to determine an appropriate sanction when the corresponding requirement is violated. Each requirement must have an associated VRF of High, Medium, or Lower. VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL – Severe, High, Moderate and Lower. Some requirements do not have multiple degrees of noncompliant performance and may have only one, two, three or four VSLs. VRFs in conjunction with VSLs are considered in the determination of the possible base penalty range for a violation of a Reliability Standard requirement.

NERC has not included in this filing the full developmental record for the standards, which consists of the draft standards, comments received, responses to the comments by the drafting teams, and the full voting record, because the record for each standard may consist of several thousand pages. NERC will make the full developmental record available to the NSUARB and other interested parties upon request and as needed.

Further, NERC acknowledges the importance of the active participation of the electricity sector participants from the Province in NERC's Standard Development Process, as recognized in its MOU with the NSUARB. Having the proposed Reliability Standards approved or recognized by governmental authorities in the United States and Canada will reinforce the importance of these standards and will have a positive impact with regard to the reliability performance of all bulk power system users, owners, and operators.

NERC will continue to consult with the NSUARB on a regular basis to appropriately account for Canadian and provincial issues, reflecting the international nature of the North American bulk power system.

B. Overview of Reliability Standards

NERC Reliability Standards define the requirements for reliably planning and operating the North American bulk power system. These standards are developed by industry stakeholders using a balanced, open, fair and inclusive process managed by the NERC Standards Committee. The Standards Committee is facilitated by NERC staff and comprised of representatives from ten electricity stakeholder segments. Stakeholders, through the balloting process, and the NERC Board of Trustees have approved the standards provided in Exhibits C and E.

Collectively, the 113 Reliability Standards define overall acceptable performance with regard to the operation, planning, and design of the North American bulk power system. The standards address a full range of reliability objectives, including: real-time balancing of generation with demand to maintain frequency at 60 hertz; operating equipment within thermal, voltage and stability limits; operating to withstand the failure of any single facility and to avoid cascading failures following credible multiple contingency events; vegetation management in transmission rights-of-way; critical infrastructure protection; voice and data communications; relay protection for both generation and transmission equipment; system modeling and analysis; under frequency load shedding; emergency planning including system restoration and blackstart; and personnel training and certification.

C. Detailed Description of Proposed Reliability Standards

The Reliability Standards presented in Exhibits C and E are grouped by topical area, as summarized below.

Resource and Demand Balancing (BAL) – balancing resources and demand to maintain interconnection frequency within limits.

Critical Infrastructure Protection (CIP) – critical infrastructure protection, including cyber security protection and sabotage reporting.

Communications (COM) – communications for interconnected operations.

Emergency Preparedness and Operations (EOP) – emergency preparation, including load shedding and system restoration.

Facilities Design, Connections, and Maintenance (FAC) – facility connection requirements, facility ratings, system operating limits, and transfer capabilities; maintain equipment and rights-of-way, including vegetation management.

Interchange Scheduling and Coordination (INT) – schedule and coordinate uses of the bulk power system.

Interconnection Reliability Operations and Coordination (IRO) – coordinate interconnected operations, including interconnection limits and interconnection-wide transmission loading relief or congestion management.

Modeling, Data, and Analysis (MOD) – model system performance for planning, reliability assessment and analysis, and forecasting.

Nuclear (NUC) – coordinate between Nuclear Plant Generator Operators and Transmission Entities for the purpose of ensuring nuclear plant safe operation and shutdown.

Personnel Performance, Training, and Qualifications (PER) – qualification and training of operating personnel.

Protection and Control (PRC) – installation and maintenance of system protection equipment, including under-frequency load shedding and, where applicable, under-voltage load shedding.

Transmission Operations (TOP) – operation of transmission facilities within established ratings and the transmission system within operating limits.

Transmission Planning (TPL) – design and planning the system to withstand single contingencies, to avoid cascading outages following credible multiple contingencies, and to meet other performance criteria.

Voltage and Reactive (VAR) – maintain reactive resources and control system voltages to maintain equipment within voltage limits.

The NERC Glossary of Terms used in Reliability Standards – most recently updated April 20, 2010 - lists each term that is defined for use in one or more of NERC's continent-wide or Regional Reliability Standards and adopted by the NERC Board of Trustees.

Most of the terms identified in the glossary were adopted as part of the development of NERC's initial set of Reliability Standards, called the "Version 0" standards. Subsequent to the development of the Version 0 standards, new definitions have been developed following NERC's Reliability Standards Development Process and approved by the NERC Board of Trustees and by FERC.

More detail on each standard proposed for approval is included in Exhibit B. Specifically, Exhibit B includes each Reliability Standard's purpose, applicability, ballot body approval percentages, and the base standard approval percentage where the approval percentage between the base standard and current effective standard differ due to unsubstantial changes. Such changes include errata, interpretation, and conforming changes; addition of missing measures and compliance elements; and the removal of a regional waiver for the Western Interconnection. Also the NERC Board of Trustees and FERC approval dates are included in this exhibit.

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IV. BACKGROUND ON THE PROCESS FOR DEVELOPMENT OF RELIABILITY STANDARDS

By way of background, NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Reliability Standards Development Procedure, which is incorporated into the Rules of Procedure as Appendix 3A (collectively referred to as "Standards Development Process"). NERC's rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards. The development process is open to any person or entity with a legitimate interest in the reliability of the bulk power system. NERC considers the comments of all stakeholders, and a vote of stakeholders and the NERC Board of Trustees is required to approve a Reliability Standard for submission to FERC and the other appropriate regulatory authorities.

The Reliability Standards set out in Exhibits C and E have been developed and approved by industry stakeholders using NERC's Standards Development Process, and were approved by NERC and FERC.

NERC has diligently adhered to its Standards Development Process, which has been certified by the American National Standards Institute ("ANSI") as being open, inclusive, balanced and fair. Users, owners, and operators of the bulk power system that must comply with the standards, as well as the end users who benefit from a reliable supply of electricity and the public in general, can be assured that a standard is just,

reasonable and not unduly discriminatory or preferential because the standards are developed through a procedure with the following attributes:

1. **Openness** — Participation shall be open to all persons who are directly and materially affected by the reliability of the North American bulk power system. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in NERC or any other organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.

2. **Transparency** — The process shall be transparent to the public.

3. **Consensus-building** — The process shall build and document consensus for each standard, both with regard to the need and justification for the standard and the content of the standard.

4. **Fair Balance of Interests** — The process shall fairly balance interests of all stakeholders and shall not be dominated by any single interest category.

5. **Due Process** — Development of standards shall provide reasonable notice and opportunity for any person with a direct and material interest to express views on a proposed standard and the basis for those views, and to have that position considered in the development of the standards.

6. **Timeliness** — Development of standards shall be timely and responsive to new and changing priorities for reliability of the bulk power system.

These provisions of NERC's Standards Development Process ensure that substantial opportunity exists for all potentially affected parties to identify why they believe the proposed standard is or is not just and reasonable, or is or is not unduly discriminatory or preferential.

A. Benchmarks of an Excellent Reliability Standard

To translate the attributes stated above into objective measures, NERC has adopted ten benchmarks for use in the development of Reliability Standards. NERC believes these benchmarks, described below, define the essential attributes of a

technically sound Reliability Standard. NERC encourages the NSUARB to take these benchmarks into account as it considers approval of the proposed standards.

1. **Applicability —** Each Reliability Standard shall clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted. Such functional classes[9] include: reliability coordinators, balancing authorities, transmission operators, transmission owners, generator operators, generator owners, interchange authorities, transmission service providers, market operators, planning authorities, transmission planners, resource planners, load-serving entities, purchasing-selling entities, and distribution providers. Each reliability standard shall also identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area. As applicable, a standard may also identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 megawatts or greater, or transmission facilities energized at 200 kilovolts or greater.
2. **Purpose** — Each reliability standard shall have a clear statement of the purpose of the standard. The purpose shall describe how the standard contributes to the reliability of the bulk power system.
3. **Performance Requirements** — Each reliability standard shall state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practice and

[9] These functional classes of entities are derived from NERC's reliability functional model. When a standard identifies a class of entities to which it applies, that class must be defined in the NERC Glossary of Terms Used in Reliability Standards.

the public interest. Each requirement is not a "lowest common denominator" compromise, but instead achieves an objective that is the best approach for bulk power system reliability, taking account of the costs and benefits of implementing the proposal.

4. **Measurability —** Each performance requirement shall be stated so as to be objectively measurable by a third party with knowledge or expertise in the area. Each performance requirement shall have one or more associated measures used to objectively evaluate compliance with the requirement. If performance can be practically measured quantitatively, metrics shall be provided to determine satisfactory performance.
5. **Technical Basis in Engineering and Operations** — Each Reliability Standard shall be based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in the particular field.
6. **Completeness** — Reliability standards shall be complete and self-contained. The standards shall not depend on external information to determine the required level of performance.
7. **Consequences for Noncompliance** — In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, the consequences of violating a standard are clearly known to the responsible entities.
8. **Clear Language** — Each Reliability Standard shall be stated using clear and unambiguous language. Responsible entities, using reasonable judgment and in

keeping with good utility practice, are able to arrive at a consistent interpretation of the required performance.

9. **Practicality** — Each reliability standard shall establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter.
10. **Consistent Terminology** — To the extent possible, reliability standards shall use a set of standard terms and definitions that are approved through the NERC reliability standards development process.

The information to justify that each standard meets these ten benchmarks is principally developed by evaluating the comments received from stakeholders during the development of the standard. The results of this evaluation are reviewed by the Standards Committee prior to the standards being sent to the Board of Trustees for approval.

NERC Standards Development Process also makes allowance for appropriate regional differences, which have been incorporated into and made a part of the NERC Reliability Standards. Regional Entities, regional transmission organizations, market operators and other bulk power system users, owners, and operators, and users may need to request approval for a variance from a NERC Reliability Standard. For example, there may be a need for a variance based on a physical difference in the bulk power system.

Variances require NERC approval and are incorporated into the NERC Reliability Standards. NERC may grant variances on an entity, regional, or regional and Interconnection-wide basis through the applicable procedure described in the Standards Development Process. Variances should be identified and considered when a Standard

Authorization Request is posted for comment. They should also be considered in the drafting of a standard, with the intent to make any necessary variances a part of the initial development of a standard.

V. COMPETENCY AS AN ACCREDITED STANDARDS DEVELOPER

A. NERC's Experience as a Standards Developer

NERC and its predecessor, the North American Electric Reliability Council, have been promoting and evaluating bulk power system reliability and developing Reliability Standards for more than 40 years. NERC was formed as a voluntary electric reliability organization shortly after the 1965 blackout in the northeastern United States and eastern Canada. Since its inception, NERC has adopted operating policies and planning standards to ensure the reliability of the bulk power system in North America.

B. ANSI-Accredited Open Standards Process

NERC Standards Development Process is open and allows direct participation by all stakeholders. The process is based on the principles of ANSI, which accredited NERC as a standards developer on March 24, 2003. NERC's process is based on building consensus for each standard among reliability stakeholders across nine stakeholder segments. NERC ensures its process is open, inclusive of all interested parties, balanced, and fair.

The experience in the initial several years of the ANSI-accredited process has been that stakeholders have repeatedly demonstrated a willingness and ability to develop

and approve tough new standards, with most of the standards being approved by wide margins. The due process and "consider every minority comment" approach has improved the quality of standards as compared to the historical approach of developing standards within a technical committee. Broader diversity of views has added technical rigor to the standards and is a hallmark of the open process.

C. Technical Expertise to Develop Standards

A cornerstone of NERC, since its inception, has been the direct participation of volunteer industry experts who are the front-line practitioners in their fields. At any point in time there are more than 2,500 individuals participating in various NERC groups and activities. Additionally, the Regional Entities collectively engage many more experts in support of programs and activities to promote reliable bulk power system.

As is the case for most national and international technical standards development bodies, the NERC Standards Development Process depends on the standard drafting teams of experts to develop the standards, combined with peer review of the standards through a public comment process. Each drafting team has ownership and control of the standard through the development phase, subject to oversight by the Standards Committee to assure that the ANSI-accredited process is being correctly followed and the drafting team has been diligent in addressing all comments on the proposed standards.

To ensure the technical capabilities of each drafting team, the Standards Committee publicly solicits nominations for volunteer experts to work on each standard development project. Each project has a written set of qualifications and identified areas of expertise needed for the development of the standards. Sometimes a particular

standard can require unique types of expertise. For example, the drafting team for standard FAC-003-1 — Transmission Vegetation Management Program, had more than a dozen experts, each with 15 to 35 years experience as certified arborists and forestry professionals. The Standards Committee reviews the qualifications of each candidate and appoints a drafting team that collectively has the expertise necessary to develop the particular standards assigned to the group. When gaps are noted in the necessary areas of expertise, the Standards Committee will follow with additional requests for volunteers and NERC staff will assist by recruiting individuals with known expertise in the missing areas.

An additional source of technical expertise applied in the development of Reliability Standards comes through peer review and comment on drafts of the Standards Authorization Requests and the proposed standards.

The existing NERC Reliability Standards Development Procedure, which engages industry experts on standards drafting teams, provides a highly effective approach to harnessing the technical expertise of industry in the development of Reliability Standards. Experience thus far demonstrates that the process works well because the drafting teams and the industry as a whole are committed to strong standards that hold bulk power system users, owners, and operators accountable for reliability.

D. Standards Development Due Process

NERC's Standards Development Process explicitly provides for reasonable notice and opportunity for public comment, due process, openness and balance of interests.

As a result, NERC's Standards Development Process has the following principal attributes:

- Any member or committee of NERC, any member or committee of a regional entity, or any person or entity directly and materially affected by the reliability of the North American bulk power system may propose a Reliability Standard, revision to a standard, or withdrawal of a standard.
- NERC publicly notices each standard request and receives comment on the scope and justification for the proposed standard for a 30-day period. Notice of proposed standard provides an opportunity for participation by all persons that may be directly and materially affected.
- Once there is consensus on the scope and justification for the proposed standard, the Standards Committee authorizes development of the standard and appoints a drafting team.
- The drafting team applies their engineering and operating expertise to draft the standard based on sound technical criteria.
- Draft standards are posted for public comment for a defined period. If, based on comments received, the drafting team believes it can substantively improve a standard and increase consensus for a standard, the drafting team will revise the draft standard and post it again for comment. This step may be repeated, although experience indicates that even the most complex standards converge within two or three postings. More narrowly defined projects can be completed with a single posting for comment.

- Each standard is reviewed to determine if field testing is necessary. Typically field testing is required when new engineering or operational methods are proposed that have not been validated through practical experience.
- Once the drafting team has addressed all stakeholder comments and determined the standard would not be substantively improved by seeking further comment, the drafting team recommends the standard for a ballot of the stakeholders. The Standards Committee authorizes a ballot of the standard once it has verified the drafting team has met all of the procedural requirements and fairly considered all comments. The Standards Committee will remand the draft standard to the drafting team if the drafting team did not satisfactorily complete the process or did not sufficiently consider the inputs of commenters. Conversely, the drafting team may at any time conclude there is no consensus for the standard and recommend the Standards Committee terminate the development of the standard.
- A ballot pool for the proposed standard is formed at least 30 days prior to the start of the ballot and is open to all interested parties that have joined the Registered Ballot Body to vote on standards.
- Approval of a new Reliability Standard or revision to an existing Reliability Standard requires a quorum of at least 75 percent of the members of the ballot pool and a two-thirds majority of the weighted segment votes in the affirmative. The use of a weighted segment voting calculation ensures that there is a "balance of interests in the development and approval of Reliability Standards" among the ten stakeholder segments. The use of a supermajority for approval ensures strong

support for the standard. The summary pages contained in Exhibit B provide the ballot pool approval percentages for each standard.

- If there are any negative votes in the first ballot with reasons specified, the ballot pool will be presented an opportunity to change or add a vote during a second 10-day ballot period. The reasons given for the negative votes on the first ballot, and the responses of the drafting team, are presented to the members of the ballot pool to allow them to reconsider their vote based on objections given on the first vote. This ensures that all objections are heard and considered before approval of a standard.[10]
- New Reliability Standards or revisions to Reliability Standards approved by the ballot pool are submitted to the Board of Trustees for approval. The Board of Trustees must adopt or reject a proposed standard and may not modify a proposed standard. If the Board of Trustees chooses not to adopt a proposed standard, it must provide its reasons for not doing so. NERC's Bylaws require that the board has within its membership sufficient technical expertise to provide oversight of technical matters of NERC, including the development of standards.
- All standards development activities, including meetings of the drafting teams and the Standards Committee, are open.
- All standards actions are publicly noticed and drafts of standards, comments received, and responses to comments are publicly posted and become a permanent part of the development record for each standard.

[10] This "recirculation" ballot is a requirement of ANSI accreditation for the purpose of ensuring no person's views are excluded from consideration in the approval of a standard.

- Each standard is subject to appeal in the event an entity has a substantive or procedural complaint regarding the development, approval, revision, reaffirmation or withdrawal of a Reliability Standard. The appeals procedure is provided in the Reliability Standards Process Manual. The Standards Committee, a body elected by the stakeholder segments,[11] provides oversight of the Reliability Standards development process to ensure stakeholder interests are fairly represented.

[11] The Standards Committee is a representative committee consisting of two representatives that are democratically elected by each of the ten stakeholder segments. Additionally, there is a requirement that at least two of the members be Canadian.

VI. CONCLUSION

By this filing, NERC requests that the NSUARB approve the Reliability Standards and NERC Glossary of Terms used in Reliability Standards, as set out in Exhibits C and E. NERC also requests that the NSUARB approve the VRFs and VSLs associated with those standards, as set out in Exhibits F and G.

NERC looks forward to working with the Province of Nova Scotia to make its Reliability Standards mandatory and enforceable in Nova Scotia.

NERC also requests the Province to provide feedback on the adequacy of the information provided with this filing and guidance on the appropriate information to be included in future filings.

Respectfully submitted,

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Exhibit A

List of Current Reliability Standards

Current Effective Standard	Effective Date of Standard[1]	Current Effective Standard	Effective Date of Standard	Current Effective Standard	Effective Date of Standard
BAL-001-0.1a	June 18, 2007	FAC-013-1	June 18, 2007	PER-002-0	June 18, 2007
BAL-002-0	June 18, 2007	FAC-014-2	April 29, 2009	PER-003-0	June 18, 2007
BAL-003-0.1b	June 18, 2007	INT-001-3	June 18, 2007	PER-004-1	June 18, 2007
BAL-004-0	June 18, 2007	INT-003-2	June 18, 2007	PRC-001-1	June 18, 2007
BAL-005-0.1b	June 18, 2007	INT-004-2	June 18, 2007	PRC-004-1	June 18, 2007
BAL-006-1.1	June 18, 2007	INT-005-2	August 27, 2008	PRC-005-1	June 18, 2007
CIP-001-1	June 18, 2007	INT-006-2	August 27, 2008	PRC-007-0	June 18, 2007
CIP-002-2	April 1, 2010	INT-007-1	June 18, 2007	PRC-008-0	June 18, 2007
CIP-003-2	April 1, 2010	INT-008-2	August 27, 2008	PRC-009-0	June 18, 2007
CIP-004-2	April 1, 2010	INT-009-1	June 18, 2007	PRC-010-0	June 18, 2007
CIP-005-2	April 1, 2010	INT-010-1	June 18, 2007	PRC-011-0	June 18, 2007
CIP-006-2	April 1, 2010	IRO-001-1.1	June 18, 2007	PRC-015-0	June 18, 2007
CIP-007-2a	April 1, 2010	IRO-002-1	June 18, 2007	PRC-016-0.1	June 18, 2007
CIP-008-2	April 1, 2010	IRO-003-2	June 18, 2007	PRC-017-0	June 18, 2007
CIP-009-2	April 1, 2010	IRO-004-1	June 18, 2007	PRC-018-1	June 18, 2007
COM-001-1.1	June 18, 2007	IRO-005-2	June 18, 2007	PRC-021-1	June 18, 2007
COM-002-2	June 18, 2007	IRO-006-4.1	April 23, 2009	PRC-022-1	June 18, 2007
EOP-001-0	June 18, 2007	IRO-014-1	June 18, 2007	TOP-001-1	June 18, 2007
EOP-002-2.1	June 18, 2007	IRO-015-1	June 18, 2007	TOP-002-2a	June 18, 2007
EOP-003-1	June 18, 2007	IRO-016-1	June 18, 2007	TOP-003-0	June 18, 2007
EOP-004-1	June 18, 2007	MOD-006-0.1	June 18, 2007	TOP-004-2	June 18, 2007
EOP-005-1	June 18, 2007	MOD-007-0	June 18, 2007	TOP-005-1.1	June 18, 2007
EOP-006-1	June 18, 2007	MOD-010-0	June 18, 2007	TOP-006-1	June 18, 2007
EOP-008-0	June 18, 2007	MOD-012-0	June 18, 2007	TOP-007-0	June 18, 2007
EOP-009-0	June 18, 2007	MOD-016-1.1	June 18, 2007	TOP-008-1	June 18, 2007
FAC-001-0	June 18, 2007	MOD-017-0.1	June 18, 2007	TPL-001-0.1	June 18, 2007
FAC-002-0	June 18, 2007	MOD-018-0	June 18, 2007	TPL-002-0a	June 18, 2007
FAC-003-1	June 18, 2007	MOD-019-0.1	June 18, 2007	TPL-003-0a	June 18, 2007
FAC-008-1	June 18, 2007	MOD-020-0	June 18, 2007	TPL-004-0	June 18, 2007
FAC-009-1	June 18, 2007	MOD-021-0.1	June 18, 2007	VAR-001-1	June 18, 2007
FAC-010-2.1	April 29, 2009	NUC-001-2	April 1, 2010	VAR-002-1.1a	August 2, 2007
FAC-011-2	April 29, 2009	PER-001-0.1	June 18, 2007		

[1] The effective date is associated with the Base Standard. *See* Exhibit B for the effective date of the current effective standard.

Exhibit B

Summary of Each Current Reliability Standard

Standard BAL-001-0.1a — Real Power Balancing Control Performance: To maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time.

Applicability:

- Balancing Authorities

On October 29, 2008, BAL-001-0.1a was approved by the NERC Board of Trustees.
On May 13, 2009, BAL-001-0.1a was approved by the Federal Energy Regulatory Commission.

Version BAL-001-0.1a resulted from errata and interpretation changes. On January 7, 2005, the base standard BAL-001-0 was approved by the registered ballot body by a 95.5% affirmative vote.

Standard BAL-002-0 — Disturbance Control Performance: The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of load and because Contingency Reserve activation does not typically apply to the loss of load, the application of DCS is limited to the loss of supply and does not apply to the loss of load.

Applicability:

- Balancing Authorities
- Reserve Sharing Groups (Balancing Authorities may meet the requirements of Standard 002 through participation in a Reserve Sharing Group.)
- Regional Reliability Organizations

On January 7, 2005, BAL-002-0 was approved by the registered ballot body by a 95.5% affirmative vote.
On February 8, 2005, BAL-002-0 was approved by the NERC Board of Trustees.
On March 16, 2007, BAL-002-0 was approved by the Federal Energy Regulatory Commission.

Standard BAL-003-0.1b — Frequency Response and Bias: This standard provides a consistent method for calculating the Frequency Bias component of ACE.

Applicability:

- Balancing Authorities

On October 29, 2008, BAL-003-0.1b was approved by the NERC Board of Trustees.
On May 13, 2009, BAL-003-0.1b was approved by the Federal Energy Regulatory Commission.

Version BAL-003-0.1b resulted from errata and interpretation changes. On January 7, 2005, the base standard BAL-003-0 was approved by the registered ballot body by a 95.5% affirmative vote.

Standard BAL-004-0 — Time Error Correction: The purpose of this standard is to ensure that Time Error Corrections are conducted in a manner that does not adversely affect the reliability of the Interconnection.

Applicability:

- Reliability Coordinators
- Balancing Authorities

On January 7, 2005, BAL-004-0 was approved by the registered ballot body by a 95.5% affirmative vote.
On February 8, 2005, BAL-004-0 was approved by the NERC Board of Trustees.
On March 16, 2007, BAL-004-0 was approved by the Federal Energy Regulatory Commission.

Standard BAL-005-0.1b — Automatic Generation Control: This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved.

Applicability:

- Balancing Authorities
- Generator Operators
- Transmission Operators
- Load Serving Entities

On October 29, 2008, BAL-005-0.1b was approved by the NERC Board of Trustees.
On May 13, 2009, BAL-005-0.1b was approved by the Federal Energy Regulatory Commission.

Version BAL-005-0.1b resulted from errata and interpretation changes. On January 7, 2005, the base standard BAL-005-0 was approved by the registered ballot body by a 95.5% affirmative vote.

Standard BAL-006-1.1 — Inadvertent Interchange: This standard defines a process for monitoring Balancing Authorities to ensure that, over the long term, Balancing Authority Areas do not excessively depend on other Balancing Authority Areas in the Interconnection for meeting their demand or Interchange obligations.

Applicability:

- Balancing Authorities

On October 29, 2008, BAL-006-1.1 was approved by the NERC Board of Trustees.
On May 13, 2009, BAL-006-1.1 was approved by the Federal Energy Regulatory Commission.

Version BAL-006-1.1 resulted from errata changes. On April 26, 2006, the base standard BAL-006-1 was approved by the registered ballot body by a 95.81% affirmative vote.

Standard CIP-001-1 — Sabotage Reporting: Disturbances or unusual occurrences, suspected or determined to be caused by sabotage, shall be reported to the appropriate systems, governmental agencies, and regulatory bodies.

Applicability:

- Reliability Coordinators
- Balancing Authorities
- Transmission Operators
- Generator Operators
- Load Serving Entities

On October 29, 2006, CIP-001-1 was approved by the registered ballot body by a 69.48% affirmative vote.
On November 1, 2006, CIP-001-1 was approved by the NERC Board of Trustees.
On March 16, 2007, CIP-001-1 was approved by the Federal Energy Regulatory Commission.

Version CIP-001-1 resulted from the addition of missing measures and compliance elements. On January 7, 2005, the base standard CIP-001-0 was approved by the registered ballot body by a 95.5% affirmative vote.

Standard CIP–002–2 — Cyber Security — Critical Cyber Asset Identification: NERC Standards CIP-002-2 through CIP-009-2 provide a cyber security framework for the identification and protection of Critical Cyber Assets to support reliable operation of the Bulk Electric System.

These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the assets needed to manage Bulk Electric System reliability, and the risks to which they are exposed.

Business and operational demands for managing and maintaining a reliable Bulk Electric System increasingly rely on Cyber Assets supporting critical reliability functions and processes to communicate with each other, across functions and organizations, for services and data. This results in increased risks to these Cyber Assets.

Standard CIP-002-2 requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment.

Applicability:
Within the text of Standard CIP-002-2, "Responsible Entity" shall mean:

- Reliability Coordinator
- Balancing Authority
- Interchange Authority
- Transmission Service Provider
- Transmission Owner
- Transmission Operator
- Generator Owner
- Generator Operator
- Load Serving Entity
- NERC
- Regional Entity

The following are exempt from Standard CIP-002-2:

- Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
- Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

On April 27, 2009, CIP-002-2 was approved by the registered ballot body by an 88.32% affirmative vote.
On May 6, 2009, CIP-002-2 was approved by the NERC Board of Trustees.
On September 30, 2009, CIP-002-2 was approved by the Federal Energy Regulatory Commission.

This Reliability Standard has an associated Implementation Plan that provides the complete list of dates for compliance with the requirements (*see* Exhibit E).

Standard CIP–003–2 — Cyber Security — Security Management Controls: Standard CIP-003-2 requires that Responsible Entities have minimum security management controls in place to protect Critical Cyber Assets. Standard CIP-003-2 should be read as part of a group of standards numbered Standards CIP-002-2 through CIP-009-2.

Applicability:
Within the text of Standard CIP-003-2, "Responsible Entity" shall mean:

- Reliability Coordinator
- Balancing Authority
- Interchange Authority
- Transmission Service Provider
- Transmission Owner
- Transmission Operator
- Generator Owner
- Generator Operator
- Load Serving Entity
- NERC
- Regional Entity

The following are exempt from Standard CIP-003-2:

- Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
- Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
- Responsible Entities that, in compliance with Standard CIP-002-2, identify that they have no Critical Cyber Assets shall only be required to comply with CIP-003-2 Requirement R2.

On April 27, 2009, CIP-003-2 was approved by the registered ballot body by an 88.32% affirmative vote.
On May 6, 2009, CIP-003-2 was approved by the NERC Board of Trustees.
On September 30, 2009, CIP-003-2 was approved by the Federal Energy Regulatory Commission.

This Reliability Standard has an associated Implementation Plan that provides the complete list of dates for compliance with the requirements (*see* Exhibit E).

Standard CIP–004–2 — Cyber Security — Personnel & Training: Standard CIP-004-2 requires that personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including contractors and service vendors, have an appropriate level of personnel risk assessment, training, and security awareness. Standard CIP-004-2 should be read as part of a group of standards numbered Standards CIP-002-2 through CIP-009-2.

Applicability:

Within the text of Standard CIP-004-2, "Responsible Entity" shall mean:

- Reliability Coordinator
- Balancing Authority
- Interchange Authority
- Transmission Service Provider
- Transmission Owner
- Transmission Operator
- Generator Owner
- Generator Operator
- Load Serving Entity
- NERC
- Regional Entity

The following are exempt from Standard CIP-004-2:

- Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
- Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
- Responsible Entities that, in compliance with Standard CIP-002-2, identify that they have no Critical Cyber Assets.

On April 27, 2009, CIP-004-2 was approved by the registered ballot body by an 88.32% affirmative vote.
On May 6, 2009, CIP-004-2 was approved by the NERC Board of Trustees.
On September 30, 2009, CIP-004-2 was approved by the Federal Energy Regulatory Commission.

This Reliability Standard has an associated Implementation Plan that provides the complete list of dates for compliance with the requirements (*see* Exhibit E).

Standard CIP–005–2 — Cyber Security — Electronic Security Perimeter(s): Standard CIP-005-2 requires the identification and protection of the Electronic Security Perimeter(s) inside which all Critical Cyber Assets reside, as well as all access points on the perimeter. Standard CIP-005-2 should be read as part of a group of standards numbered Standards CIP-002-2 through CIP-009-2.

Applicability:
Within the text of Standard CIP-005-2, "Responsible Entity" shall mean:

- Reliability Coordinator
- Balancing Authority
- Interchange Authority
- Transmission Service Provider
- Transmission Owner
- Transmission Operator
- Generator Owner
- Generator Operator
- Load Serving Entity
- NERC
- Regional Entity

The following are exempt from Standard CIP-005-2:

- Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
- Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
- Responsible Entities that, in compliance with Standard CIP-002-2, identify that they have no Critical Cyber Assets.

On April 27, 2009, CIP-005-2 was approved by the registered ballot body by an 88.32% affirmative vote.
On May 6, 2009, CIP-005-2 was approved by the NERC Board of Trustees.
On September 30, 2009, CIP-005-2 was approved by the Federal Energy Regulatory Commission.

This Reliability Standard has an associated Implementation Plan that provides the complete list of dates for compliance with the requirements (*see* Exhibit E).

Standard CIP-006-2 — Cyber Security — Physical Security of Critical Cyber Assets: Standard CIP-006-2 is intended to ensure the implementation of a physical security program for the protection of Critical Cyber Assets. Standard CIP-006-2 should be read as part of a group of standards numbered Standards CIP-002-2 through CIP-009-2.

Applicability:
Within the text of Standard CIP-006-2, "Responsible Entity" shall mean:

- Reliability Coordinator
- Balancing Authority
- Interchange Authority
- Transmission Service Provider
- Transmission Owner
- Transmission Operator
- Generator Owner
- Generator Operator
- Load Serving Entity
- NERC
- Regional Entity

The following are exempt from Standard CIP-006-2:

- Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
- Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
- Responsible Entities that, in compliance with Standard CIP-002-2, identify that they have no Critical Cyber Assets.

On April 27, 2009, CIP-006-2 was approved by the registered ballot body by an 88.32% affirmative vote.
On May 6, 2009, CIP-006-2 was approved by the NERC Board of Trustees.
On September 30, 2009, CIP-006-2 was approved by the Federal Energy Regulatory Commission.

This Reliability Standard has an associated Implementation Plan that provides the complete list of dates for compliance with the requirements (*see* Exhibit E).

Standard CIP–007–2a — Cyber Security — Systems Security Management: Standard CIP-007-2 requires Responsible Entities to define methods, processes, and procedures for securing those systems determined to be Critical Cyber Assets, as well as the other (non-critical) Cyber Assets within the Electronic Security Perimeter(s). Standard CIP-007-2 should be read as part of a group of standards numbered Standards CIP-002-2 through CIP-009-2.

Applicability:
Within the text of Standard CIP-007-2, "Responsible Entity" shall mean:

- Reliability Coordinator
- Balancing Authority
- Interchange Authority
- Transmission Service Provider
- Transmission Owner
- Transmission Operator
- Generator Owner
- Generator Operator
- Load Serving Entity
- NERC
- Regional Entity

The following are exempt from Standard CIP-007-2:

- Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
- Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
- Responsible Entities that, in compliance with Standard CIP-002-2, identify that they have no Critical Cyber Assets.

On September 21, 2009, CIP-007-2a was approved by the registered ballot body by a 100% affirmative vote.
On November 5, 2009, CIP-007-2a was approved by the NERC Board of Trustees.
On March 18, 2010, CIP-007-2a was approved by the Federal Energy Regulatory Commission.

Version CIP-007-2a resulted from an interpretation. On April 27, 2009, the base standard CIP-007-2 was approved by the registered ballot body by an 88.32% affirmative vote.

This Reliability Standard has an associated Implementation Plan that provides the complete list of dates for compliance with the requirements (*see* Exhibit E).

Standard CIP–008–2 — Cyber Security — Incident Reporting and Response Planning: Standard CIP-008-2 ensures the identification, classification, response, and reporting of Cyber Security Incidents related to Critical Cyber Assets. Standard CIP-008-2 should be read as part of a group of standards numbered Standards CIP-002-2 through CIP-009-2.

Applicability:
Within the text of Standard CIP-008-2, "Responsible Entity" shall mean:

- Reliability Coordinator
- Balancing Authority
- Interchange Authority
- Transmission Service Provider
- Transmission Owner
- Transmission Operator
- Generator Owner
- Generator Operator
- Load Serving Entity
- NERC
- Regional Entity

The following are exempt from Standard CIP-008-2:

- Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
- Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
- Responsible Entities that, in compliance with Standard CIP-002-2, identify that they have no Critical Cyber Assets.

On April 27, 2009, CIP-008-2 was approved by the registered ballot body by an 88.32% affirmative vote.
On May 6, 2009, CIP-008-2 was approved by the NERC Board of Trustees.
On September 30, 2009, CIP-008-2 was approved by the Federal Energy Regulatory Commission.

This Reliability Standard has an associated Implementation Plan that provides the complete list of dates for compliance with the requirements (*see* Exhibit E).

Standard CIP–009–2 — Cyber Security — Recovery Plans for Critical Cyber Assets: Standard CIP-009-2 ensures that recovery plan(s) are put in place for Critical Cyber Assets and that these plans follow established business continuity and disaster recovery techniques and practices. Standard CIP-009-2 should be read as part of a group of standards numbered Standards CIP-002-2 through CIP-009-2.

Applicability:
Within the text of Standard CIP-009-2, "Responsible Entity" shall mean:

- Reliability Coordinator
- Balancing Authority
- Interchange Authority
- Transmission Service Provider
- Transmission Owner
- Transmission Operator
- Generator Owner
- Generator Operator
- Load Serving Entity
- NERC
- Regional Entity

The following are exempt from Standard CIP-009-2:

- Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
- Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
- Responsible Entities that, in compliance with Standard CIP-002-2, identify that they have no Critical Cyber Assets.

On April 27, 2009, CIP-009-2 was approved by the registered ballot body by an 88.32% affirmative vote.
On May 6, 2009, CIP-009-2 was approved by the NERC Board of Trustees.
On September 30, 2009, CIP-009-2 was approved by the Federal Energy Regulatory Commission.

This Reliability Standard has an associated Implementation Plan that provides the complete list of dates for compliance with the requirements (*see* Exhibit E).

Standard COM-001-1.1 — Telecommunications: Each Reliability Coordinator, Transmission Operator and Balancing Authority needs adequate and reliable telecommunications facilities internally and with others for the exchange of Interconnection and operating information necessary to maintain reliability.

Applicability:

- Transmission Operators
- Balancing Authorities
- Reliability Coordinators
- NERCNet User Organizations

On October 29, 2008, COM-001-1.1 was approved by the NERC Board of Trustees.
On May 13, 2009, COM-001-1.1 was approved by the Federal Energy Regulatory Commission.

Version COM-001-1.1 resulted from errata changes. On January 7, 2005, the base standard COM-001-0 was approved by the registered ballot body by a 95.5% affirmative vote.

Standard COM-002-2 — Communication and Coordination: To ensure Balancing Authorities, Transmission Operators, and Generator Operators have adequate communications and that these communications capabilities are staffed and available for addressing a real-time emergency condition. To ensure communications by operating personnel are effective.

Applicability:

- Reliability Coordinators
- Balancing Authorities
- Transmission Operators
- Generator Operators

On October 29, 2006, COM-002-2 was approved by the registered ballot body by a 69.48% affirmative vote.
On November 1, 2006, COM-002-2 was approved by the NERC Board of Trustees.
On March 16, 2007, COM-002-2 was approved by the Federal Energy Regulatory Commission.

Version COM-002-2 resulted from the addition of missing measures and compliance elements and conforming changes resulting from an update to another standard. On January 7, 2005, the base standard COM-002-0 was approved by the registered ballot body by a 95.5% affirmative vote.

Standard EOP-001-0 — Emergency Operations Planning - Each Transmission Operator and Balancing Authority needs to develop, maintain, and implement a set of plans to mitigate operating emergencies. These plans need to be coordinated with other Transmission Operators and Balancing Authorities, and the Reliability Coordinator.

Applicability:

- Balancing Authorities
- Transmission Operators

On January 7, 2005, EOP-001-0 was approved by the registered ballot body by a 95.5% affirmative vote.
On February 8, 2005, EOP-001-0 was approved by the NERC Board of Trustees.
On March 16, 2007, EOP-001-0 was approved by the Federal Energy Regulatory Commission.

Standard EOP-002-2.1 — Capacity and Energy Emergencies: To ensure Reliability Coordinators and Balancing Authorities are prepared for capacity and energy emergencies.

Applicability:

- Balancing Authorities
- Reliability Coordinators
- Load-Serving Entities

On October 29, 2008, EOP-002-2.1 was approved by the NERC Board of Trustees.
On May 13, 2009, EOP-002-2.1 was approved by the Federal Energy Regulatory Commission.

Version EOP-002-2.1 resulted from errata changes. On January 7, 2005, the base standard EOP-002-0 was approved by the registered ballot body by a 95.5% affirmative vote.

Standard EOP-003-1 — Load Shedding Plans: A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.

Applicability:

- Transmission Operators
- Balancing Authorities

On October 29, 2006, EOP-003-1 was approved by the registered ballot body by a 69.48% affirmative vote.
On November 1, 2006, EOP-003-1 was approved by the NERC Board of Trustees.
On March 16, 2007, EOP-003-1 was approved by the Federal Energy Regulatory Commission.

Version EOP-003-1 resulted from the addition of missing measures and compliance elements. On January 7, 2005, the base standard EOP-003-0 was approved by the registered ballot body by a 95.5% affirmative vote.

Standard EOP-004-1 — Disturbance Reporting: Disturbances or unusual occurrences that jeopardize the operation of the Bulk Electric System, or result in system equipment damage or customer interruptions, need to be studied and understood to minimize the likelihood of similar events in the future.

Applicability:

- Reliability Coordinators
- Balancing Authorities
- Transmission Operators
- Generator Operators
- Load Serving Entities
- Regional Reliability Organizations

On October 29, 2006, EOP-004-1 was approved by the registered ballot body by a 69.48% affirmative vote.
On November 1, 2006, EOP-004-1 was approved by the NERC Board of Trustees.
On March 16, 2007, EOP-004-1 was approved by the Federal Energy Regulatory Commission.

Version EOP-004-1 resulted from the addition of missing measures. On January 7, 2005, the base standard EOP-004-0 was approved by the registered ballot body by a 95.5% affirmative vote.

Standard EOP-005-1 — System Restoration Plans: To ensure plans, procedures, and resources are available to restore the electric system to a normal condition in the event of a partial or total shut down of the system.

Applicability:

- Transmission Operators
- Balancing Authorities

On April 26, 2006, EOP-005-1 was approved by the registered ballot body by a 96.58% affirmative vote.
On May 2, 2006, EOP-005-1 was approved by the NERC Board of Trustees.
On March 16, 2007, EOP-005-1 was approved by the Federal Energy Regulatory Commission.

Standard EOP-006-1 — Reliability Coordination — System Restoration: The Reliability Coordinator must have a coordinating role in system restoration to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.

Applicability:

- Reliability Coordinator

On October 29, 2006, EOP-006-1 was approved by the registered ballot body by a 69.48% affirmative vote.
On November 1, 2006, EOP-006-1 was approved by the NERC Board of Trustees.
On March 16, 2007, EOP-006-1 was approved by the Federal Energy Regulatory Commission.

Version EOP-006-1 resulted from the addition of missing measures and compliance elements. On January 7, 2005, the base standard EOP-006-0 was approved by the registered ballot body by a 95.5% affirmative vote.

Standard EOP-008-0 — Plans for Loss of Control Center Functionality: Each reliability entity must have a plan to continue reliability operations in the event its control center becomes inoperable.

Applicability:

- Transmission Operators
- Balancing Authorities
- Reliability Coordinators

On January 7, 2005, EOP-008-0 was approved by the registered ballot body by a 95.5% affirmative vote.
On February 8, 2005, EOP-008-0 was approved by the NERC Board of Trustees.
On March 16, 2007, EOP-008-0 was approved by the Federal Energy Regulatory Commission.

Standard EOP-009-0— Documentation of Blackstart Generating Unit Test Results: A system Blackstart Capability Plan (BCP) is necessary to ensure that the quantity and location of system blackstart generators are sufficient and that they can perform their expected functions as specified in overall coordinated Regional System Restoration Plans.

Applicability:

- Generator Operator
- Generator Owner

On January 7, 2005, EOP-009-0 was approved by the registered ballot body by a 95.5% affirmative vote.
On February 8, 2005, EOP-009-0 was approved by the NERC Board of Trustees.
On March 16, 2007, EOP-009-0 was approved by the Federal Energy Regulatory Commission.

Standard FAC-001-0 — Facility Connection Requirements: To avoid adverse impacts on reliability, Transmission Owners must establish facility connection and performance requirements.

Applicability:

- Transmission Owner

On January 7, 2005, FAC-001-0 was approved by the registered ballot body by a 95.5% affirmative vote.
On February 8, 2005, FAC-001-0 was approved by the NERC Board of Trustees.
On March 16, 2007, FAC-001-0 was approved by the Federal Energy Regulatory Commission.

Standard FAC-002-0 — Coordination of Plans for New Generation, Transmission, and End-User Facilities: To avoid adverse impacts on reliability, Generator Owners and Transmission Owners and electricity end-users must meet facility connection and performance requirements.

Applicability:

- Generator Owner
- Transmission Owner
- Distribution Provider
- Load-Serving Entity
- Transmission Planner
- Planning Authority

On January 7, 2005, FAC-002-0 was approved by the registered ballot body by a 95.5% affirmative vote.
On February 8, 2005, FAC-002-0 was approved by the NERC Board of Trustees.
On March 16, 2007, FAC-002-0 was approved by the Federal Energy Regulatory Commission.

Standard FAC-003-1 — Transmission Vegetation Management Program: To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation related outages of the transmission systems to the respective Regional Reliability Organizations (RRO) and the North American Electric Reliability Council (NERC).

Applicability:

- Transmission Owner
- Regional Reliability Organization
- This standard shall apply to all transmission lines operated at 200 kV and above and to any lower voltage lines designated by the RRO as critical to the reliability of the electric system in the region.

On January 27, 2006, FAC-003-1 was approved by the registered ballot body by an 89% affirmative vote.
On February 7, 2006, FAC-003-1 was approved by the NERC Board of Trustees.
On March 16, 2007, FAC-003-1 was approved by the Federal Energy Regulatory Commission.

Standard FAC-008-1 — Facility Ratings Methodology: To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

Applicability:

- Transmission Owner
- Generator Owner

On November 28, 2005, FAC-008-1 was approved by the registered ballot body by a 93% affirmative vote.
On February 7, 2006, FAC-008-1 was approved by the NERC Board of Trustees.
On March 16, 2007, FAC-008-1 was approved by the Federal Energy Regulatory Commission.

Standard FAC-009-1 — Establish and Communicate Facility Ratings: To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

Applicability:

- Transmission Owner
- Generator Owner

On November 28, 2005, FAC-009-1 was approved by the registered ballot body by a 93% affirmative vote.
On February 7, 2006, FAC-009-1 was approved by the NERC Board of Trustees.
On March 16, 2007, FAC-009-1 was approved by the Federal Energy Regulatory Commission.

Standard FAC-010-2.1 — System Operating Limits Methodology for the Planning Horizon: To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

Applicability:

- Planning Authority

On November 5, 2009, FAC-010-2.1 was approved by the NERC Board of Trustees.
On April 19, 2010, FAC-010-2.1 was approved by the Federal Energy Regulatory Commission.

Version FAC-010-2.1 resulted from errata changes. On June 22, 2008, the base standard FAC-010-2 was approved by the registered ballot body by a 95.21% affirmative vote.

Standard FAC-011-2 — System Operating Limits Methodology for the Operations Horizon: To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

Applicability:

- Reliability Coordinator

On June 22, 2008, FAC-011-2 was approved by the registered ballot body by a 95.21% affirmative vote.
On June 24, 2008 FAC-011-2 was approved by the NERC Board of Trustees.
On March 20, 2009, FAC-011-2 was approved by the Federal Energy Regulatory Commission.

Standard FAC-013-1 — Establish and Communicate Transfer Capabilities: To ensure that Transfer Capabilities used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

Applicability:

- Reliability Coordinator required by its Regional Reliability Organization to establish inter-regional and intra-regional Transfer Capabilities
- Planning Authority required by its Regional Reliability Organization to establish inter-regional and intra-regional Transfer Capabilities

On November 28, 2005, FAC-013-1 was approved by the registered ballot body by a 90% affirmative vote.
On February 7, 2006, FAC-013-1 was approved by the NERC Board of Trustees.
On March 16, 2007, FAC-013-1 was approved by the Federal Energy Regulatory Commission.

Standard FAC-014-2 — Establish and Communicate System Operating Limits: To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

Applicability:

- Reliability Coordinator
- Planning Authority
- Transmission Planner
- Transmission Operator

On June 22, 2008, FAC-014-2 was approved by the registered ballot body by a 95.21% affirmative vote.
On June 24, 2008, FAC-014-2 was approved by the NERC Board of Trustees.
On March 20, 2009, FAC-014-2 was approved by the Federal Energy Regulatory Commission.

Standard INT-001-3 — Interchange Information: To ensure that Interchange information is submitted to the NERC-identified reliability analysis service.

Applicability:

- Purchase-Selling Entities
- Balancing Authorities

On August 22, 2007, INT-001-3 was approved by the registered ballot body by a 99.17% affirmative vote.
On October 9, 2007, INT-001-3 was approved by the NERC Board of Trustees.
On July 21, 2008, INT-001-3 was approved by the Federal Energy Regulatory Commission.

Version INT-001-3 resulted from the addition of missing measures and compliance elements; and the removal of a Regional waiver in the Western Interconnection. On March 24, 2006, the base standard INT-001-1 was approved by the registered ballot body by a 77.89% affirmative vote.

Standard INT-003-2 — Interchange Transaction Implementation: To ensure Balancing Authorities confirm Interchange Schedules with Adjacent Balancing Authorities prior to implementing the schedules in their Area Control Error (ACE) equations.

Applicability:

- Balancing Authorities

On October 29, 2006, INT-003-2 was approved by the registered ballot body by a 69.48% affirmative vote.
On November 1, 2006, INT-003-2 was approved by the NERC Board of Trustees.
On March 16, 2007, INT-003-2 was approved by the Federal Energy Regulatory Commission.

Version INT-003-2 resulted from the addition of missing measures and compliance elements. On March 24, 2006, the base standard INT-003-1 was approved by the registered ballot body by a 77.89% affirmative vote.

Standard INT-004-2 — Dynamic Interchange Transaction Modifications: To ensure Dynamic Transfers are adequately tagged to be able to determine their reliability impacts.

Applicability:

- Balancing Authorities
- Reliability Coordinators
- Transmission Operators
- Purchasing-Selling Entities

On August 22, 2007, INT-004-2 was approved by the registered ballot body by a 99.17% affirmative vote.
On October 9, 2007, INT-004-2 was approved by the NERC Board of Trustees.
On July 21, 2008, INT-004-2 was approved by the Federal Energy Regulatory Commission.

Version INT-004-2 resulted from the removal of a Regional waiver in the Western Interconnection. On March 24, 2006, the base standard INT-004-1 was approved by the registered ballot body by a 77.89% affirmative vote.

Standard INT-005-2 — Interchange Authority Distributes Arranged Interchange: To ensure that the implementation of Interchange between Source and Sink Balancing Authorities is distributed by an Interchange Authority such that Interchange information is available for reliability assessments.

Applicability:

- Interchange Authority

On March 30, 2007, INT-005-2 was approved by the registered ballot body by a 96.82% affirmative vote.
On May 2, 2007, INT-005-2 was approved by the NERC Board of Trustees.
On July 21, 2008, INT-005-2 was approved by the Federal Energy Regulatory Commission.

Standard INT-006-2 — Response to Interchange Authority: To ensure that each Arranged Interchange is checked for reliability before it is implemented.

Applicability:

- Balancing Authority
- Transmission Service Provider

On March 30, 2007, INT-006-2 was approved by the registered ballot body by a 96.82% affirmative vote.
On May 2, 2007, INT-006-2 was approved by the NERC Board of Trustees.
On July 21, 2008, INT-006-2 was approved by the Federal Energy Regulatory Commission.

Standard INT-007-1 — Interchange Confirmation: To ensure that each Arranged Interchange is checked for reliability before it is implemented.

Applicability:

- Interchange Authority

On March 24, 2006, INT-007-1 was approved by the registered ballot body by a 77.89% affirmative vote.
On May 2, 2006, INT-007-1 was approved by the NERC Board of Trustees.
On March 16, 2007, INT-007-1 was approved by the Federal Energy Regulatory Commission.

Standard INT-008-2 — Interchange Authority Distributes Status: To ensure that the implementation of Interchange between Source and Sink Balancing Authorities is coordinated by an Interchange Authority.

Applicability:

- Interchange Authority

On March 30, 2007, INT-008-2 was approved by the registered ballot body by a 96.82% affirmative vote.
On May 2, 2007, INT-008-2 was approved by the NERC Board of Trustees.
On July 21, 2008, INT-008-2 was approved by the Federal Energy Regulatory Commission.

Standard INT-009-1 — Implementation of Interchange: To ensure that the implementation of Interchange between Source and Sink Balancing Authorities is coordinated by an Interchange Authority such that the Balancing Authorities implement the Interchange exactly as agreed upon in the Interchange confirmation process.

Applicability:

- Balancing Authority

On March 24, 2006, INT-009-1 was approved by the registered ballot body by a 77.89% affirmative vote.
On May 2, 2006, INT-009-1 was approved by the NERC Board of Trustees.
On March 16, 2007, INT-009-1 was approved by the Federal Energy Regulatory Commission.

Standard INT-010-1 — Interchange Coordination Exemptions: Allow certain types of Interchange schedules to be initiated or modified by reliability entities, and to be exempt from compliance with other Interchange Standards under abnormal operating conditions.

Applicability:

- Balancing Authority
- Reliability Coordinator

On March 24, 2006, INT-010-1 was approved by the registered ballot body by a 77.89% affirmative vote.
On May 2, 2006, INT-010-1 was approved by the NERC Board of Trustees.
On March 16, 2007, INT-010-1 was approved by the Federal Energy Regulatory Commission.

Standard IRO-001-1.1 — Reliability Coordination — Responsibilities and Authorities: Reliability Coordinators must have the authority, plans, and agreements in place to immediately direct reliability entities within their Reliability Coordinator Areas to re-dispatch generation, reconfigure transmission, or reduce load to mitigate critical conditions to return the system to a reliable state. If a Reliability Coordinator delegates tasks to others, the Reliability Coordinator retains its responsibilities for complying with NERC and regional standards. Standards of conduct are necessary to ensure the Reliability Coordinator does not act in a manner that favors one market participant over another.

Applicability:

- Reliability Coordinators
- Regional Reliability Organizations
- Transmission Operator
- Balancing Authorities
- Generator Operators
- Transmission Service Providers
- Load-Serving Entities
- Purchasing-Selling Entities

On October 29, 2008, IRO-001-1.1 was approved by the NERC Board of Trustees.
On May 13, 2009, IRO-001-1.1 was approved by the Federal Energy Regulatory Commission.

Version IRO-001-1.1 resulted from errata changes. On January 7, 2005, the base standard IRO-001-0 was approved by the registered ballot body by a 95.5% affirmative vote.

Standard IRO-002-1 — Reliability Coordination — Facilities: Reliability Coordinators need information, tools and other capabilities to perform their responsibilities.

Applicability:

- Reliability Coordinators

On October 29, 2006, IRO-002-1 was approved by the registered ballot body by a 69.48% affirmative vote.
On November 1, 2006, IRO-002-1 was approved by the NERC Board of Trustees.
On March 16, 2007, IRO-002-1 was approved by the Federal Energy Regulatory Commission.

Version IRO-002-1 resulted from the addition of missing measures and compliance elements. On January 7, 2005, the base standard IRO-002-0 was approved by the registered ballot body by a 95.5% affirmative vote.

Standard IRO-003-2 — Reliability Coordination — Wide-Area View: The Reliability Coordinator must have a wide-area view of its own Reliability Coordinator Area and that of neighboring Reliability Coordinators.

Applicability:

- Reliability Coordinators

On October 29, 2006, IRO-003-2 was approved by the registered ballot body by a 69.48% affirmative vote.
On November 1, 2006, IRO-003-2 was approved by the NERC Board of Trustees.
On March 16, 2007, IRO-003-2 was approved by the Federal Energy Regulatory Commission.

Version IRO-003-2 resulted from the addition of missing measures and compliance elements; and conforming changes resulting from updates to other standards. On January 7, 2005, the base standard IRO-003-0 was approved by the registered ballot body by a 95.5% affirmative vote.

Standard IRO-004-1 — Reliability Coordination — Operations Planning: Each Reliability Coordinator must conduct next-day reliability analyses for its Reliability Coordinator Area to ensure the Bulk Electric System can be operated reliably in anticipated normal and Contingency conditions. System studies must be conducted to highlight potential interface and other operating limits, including overloaded transmission lines and transformers, voltage and stability limits, etc. Plans must be developed to alleviate System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) violations.

Applicability:

- Reliability Coordinators
- Balancing Authorities
- Transmission Operators
- Transmission Service Providers
- Transmission Owners
- Generator Owners
- Generator Operators
- Load-Serving Entities

On November 28, 2005, IRO-004-1 was approved by the registered ballot body by a 98% affirmative vote.
On February 7 2006, IRO-004-1 was approved by the NERC Board of Trustees.
On March 16, 2007, IRO-004-1 was approved by the Federal Energy Regulatory Commission.

Version IRO-004-1 includes only conforming changes resulting from updates to other standards. On January 7, 2005, the base standard IRO-004-0 was approved by the registered ballot body by a 95.5% affirmative vote.

Standard IRO-005-2 — Reliability Coordination — Current Day Operations: The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.

Applicability:

- Reliability Coordinators
- Balancing Authorities
- Transmission Operators
- Transmission Service Providers
- Generator Operators
- Load-Serving Entities
- Purchasing-Selling Entities

On October 29, 2006, IRO-005-2 was approved by the registered ballot body by a 69.48% affirmative vote.
On November 1, 2006, IRO-005-2 was approved by the NERC Board of Trustees.
On January 22, 2009, IRO-005-2 was approved by the Federal Energy Regulatory Commission.

Version IRO-005-2 resulted from the addition of missing measures and compliance elements; and conforming changes resulting from updates to other standards. On January 7, 2005, the base standard IRO-005-0 was approved by the registered ballot body by a 95.5% affirmative vote.

Standard IRO-006-4.1 — Reliability Coordination — Transmission Loading Relief (TLR): The purpose of this standard is to provide Interconnection-wide transmission loading relief procedures that can be used to prevent or manage potential or actual SOL and IROL violations to maintain reliability of the Bulk Electric System.

Applicability:

- Reliability Coordinators
- Transmission Operators
- Balancing Authorities

On April 15, 2009, IRO-006-4.1 was approved by the Standards Committee and went to the NERC Board of Trustees for informational purposes on May 6, 2009.
On December 10, 2009, IRO-006-4.1 was approved by the Federal Energy Regulatory Commission.

Version IRO-006-4.1 resulted from errata changes. On September 23, 2007, the base standard IRO-006-4 was approved by the registered ballot body by a 92.33% affirmative vote.

Standard IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators: To ensure that each Reliability Coordinator's operations are coordinated such that they will not have an Adverse Reliability Impact on other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.

Applicability:

- Reliability Coordinator

On November 28, 2005, IRO-014-1 was approved by the registered ballot body by a 98% affirmative vote.
On February 7, 2006, IRO-014-1 was approved by the NERC Board of Trustees.
On March 16, 2007, IRO-014-1 was approved by the Federal Energy Regulatory Commission.

Standard IRO-015-1 — Notifications and Information Exchange Between Reliability Coordinators: To ensure that each Reliability Coordinator's operations are coordinated such that they will not have an Adverse Reliability Impact on other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.

Applicability:

- Reliability Coordinators

On November 28, 2005, IRO-015-1 was approved by the registered ballot body by a 98% affirmative vote.
On February 7, 2006, IRO-015-1 was approved by the NERC Board of Trustees.
On March 16, 2007, IRO-015-1 was approved by the Federal Energy Regulatory Commission.

Standard IRO-016-1 — Coordination of Real-time Activities Between Reliability Coordinators: To ensure that each Reliability Coordinator's operations are coordinated such that they will not have an Adverse Reliability Impact on other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.

Applicability:

- Reliability Coordinator

On November 28, 2005, IRO-016-1 was approved by the registered ballot body by a 98% affirmative vote.
On February 7, 2006, IRO-016-1 was approved by the NERC Board of Trustees.
On March 16, 2007, IRO-016-1 was approved by the Federal Energy Regulatory Commission.

Standard MOD-006-0.1 — Procedures for the Use of Capacity Benefit Margin Values: To promote the consistent and uniform use of transmission Transfer Capability margins calculations among transmission system users.

Applicability:

- Transmission Service Provider

On October 29, 2008, MOD-006-0.1 was approved by the NERC Board of Trustees.
On May 13, 2009, MOD-006-0.1 was approved by the Federal Energy Regulatory Commission.

Version MOD-006-0.1 resulted from errata changes. On January 7, 2005, the base standard MOD-006-0 was approved by the registered ballot body by a 95.5% affirmative vote.

Standard MOD-007-0 — Documentation of the Use of Capacity Benefit Margin: To promote the consistent and uniform application of Transfer Capability margin calculations among transmission system users by developing methodologies for calculating Capacity Benefit Margin (CBM). This methodology shall comply with NERC definitions for CBM, the NERC Reliability Standards, and applicable Regional criteria.

Applicability:

- Transmission Service Provider

On January 7, 2005, MOD-007-0 was approved by the registered ballot body by a 95.5% affirmative vote.
On February 8, 2005 MOD-007-0 was approved by the NERC Board of Trustees.
On March 16, 2007, MOD-007-0 was approved by the Federal Energy Regulatory Commission.

Standard MOD-010-0 — Steady-State Data for Modeling and Simulation of the Interconnected Transmission System: To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the Interconnected Transmission Systems.

Applicability:

- Transmission Owners specified in the data requirements and reporting procedures of MOD-011-0_R1
- Transmission Planners specified in the data requirements and reporting procedures of MOD-011-0_R1
- Generator Owners specified in the data requirements and reporting procedures of MOD-011-0_R1
- Resource Planners specified in the data requirements and reporting procedures of MOD-011-0_R1

On January 7, 2005, MOD-010-0 was approved by the registered ballot body by a 95.5% affirmative vote.
On February 8, 2005, MOD-010-0 was approved by the NERC Board of Trustees.
On March 16, 2007, MOD-010-0 was approved by the Federal Energy Regulatory Commission.

Standard MOD-012-0 — Dynamics Data for Modeling and Simulation of the Interconnected Transmission System: To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems.

Applicability:

- Transmission Owners specified in the data requirements and reporting procedures of MOD-013-0_R1
- Transmission Planners specified in the data requirements and reporting procedures of MOD-013-0_R1
- Generator Owners specified in the data requirements and reporting procedures of MOD-013-0_R1
- Resource Planners specified in the data requirements and reporting procedures of MOD-013-0_R1

On January 7, 2005, MOD-012-0 was approved by the registered ballot body by a 95.5% affirmative vote.
On February 8, 2005, MOD-012-0 was approved by the NERC Board of Trustees.
On March 16, 2007, MOD-012-0 was approved by the Federal Energy Regulatory Commission.

Standard MOD-016-1.1 — Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management: Ensure that accurate, actual Demand data is available to support assessments and validation of past events and databases. Forecast Demand data is needed to perform future system assessments to identify the need for system reinforcements for continued reliability. In addition, to assist in proper real-time operating, Load information related to controllable Demand-Side Management (DSM) programs is needed.

Applicability:

- Planning Authority
- Regional Reliability Organization

On October 29, 2008, MOD-016-1.1 was approved by the NERC Board of Trustees.
On May 13, 2009, MOD-016-1.1 was approved by the Federal Energy Regulatory Commission.

Version MOD-016-1.1 resulted from errata changes. On April 26, 2006, the base standard MOD-016-1 was approved by the registered ballot body by a 99.8% affirmative vote.

Standard MOD-017-0.1 — Aggregated Actual and Forecast Demands and Net Energy for Load: To ensure that assessments and validation of past events and databases can be performed, reporting of actual Demand data is needed. Forecast demand data is needed to perform future system assessment to identify the need for system reinforcement for continued reliability. In addition to assist in proper real-time operating, load information related to controllable Demand-Side Management programs is needed.

Applicability:

- Load-Serving Entity
- Planning Authority
- Resource Planner

On October 29, 2008, MOD-017-0.1 was approved by the NERC Board of Trustees.
On May 13, 2009, MOD-017-0.1 was approved by the Federal Energy Regulatory Commission.

Version MOD-017-0.1 resulted from errata changes. On January 7, 2005, the base standard MOD-017-0 was approved by the registered ballot body by a 95.5% affirmative vote.

Standard MOD-018-0 — Treatment for Nonmember Demand Data and How Uncertainties are Addressed in Forecasts Demand Data and Net Energy for Load: To ensure that Assessments and validation of past events and databases can be performed, reporting of actual demand data is needed. Forecast demand data is needed to perform future system assessments to identify the need for system reinforcement for continued reliability. In addition, to assist in proper real-time operating, load information related to controllable Demand-Side Management programs is needed.

Applicability:

- Load-Serving Entity
- Planning Authority
- Transmission Planner
- Resource Planner

On January 7, 2005, MOD-018-0 was approved by the registered ballot body by a 95.5% affirmative vote.
On February 8, 2005, MOD-018-0 was approved by the NERC Board of Trustees.
On March 16, 2007, MOD-018-0 was approved by the Federal Energy Regulatory Commission.

Standard MOD-019-0.1 — Reporting of Interruptible Demands and Direct Control Load Management Data: To ensure that assessments and validation of past events and databases can be performed, reporting of actual demand data is needed. Forecast demand data is needed to perform future system assessments to identify the need for system reinforcement for continued reliability. In addition, to assist in proper real-time operating, load information related to controllable Demand-Side Management programs is needed.

Applicability:

- Load-Serving Entity
- Planning Authority
- Transmission Planner
- Resource Planner

On October 29, 2008, MOD-019-0.1 was approved by the NERC Board of Trustees.
On May 13, 2009, MOD-019-0.1 was approved by the Federal Energy Regulatory Commission.

Version MOD-019-0.1 resulted from errata changes. On January 7, 2005, the base standard MOD-019-0 was approved by the registered ballot body by a 95.5% affirmative vote.

Standard MOD-020-0 — Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators: To ensure that assessments and validation of past events and databases can be performed, reporting of actual demand data is needed. Forecast demand data is needed to perform future system assessments to identify the need for system reinforcement for continued reliability. In addition to assist in proper real-time operating, load information related to controllable Demand-Side Management programs is needed.

Applicability:

- Load-Serving Entity
- Transmission Planner
- Resource Planner

On January 7, 2005, MOD-020-0 was approved by the registered ballot body by a 95.5% affirmative vote.
On February 8, 2005, MOD-020-0 was approved by the NERC Board of Trustees.
On March 16, 2007, MOD-020-0 was approved by the Federal Energy Regulatory Commission.

Standard MOD-021-0.1 — Documentation of the Accounting Methodology for the Effects of Controllable Demand-Side Management in Demand and Energy Forecasts: To ensure that assessments and validation of past events and databases can be performed, reporting of actual Demand data is needed. Forecast demand data is needed to perform future system assessments to identify the need for system reinforcement for continued reliability. In addition, to assist in proper real-time operating, load information related to controllable Demand-Side Management (DSM) programs is needed.

Applicability:

- Load-Serving Entity
- Transmission Planner
- Resource Planner

On April 15, 2009, MOD-021-0.1 was approved by the Standards Committee and went to the NERC Board of Trustees for informational purposes on May 6, 2009.
On December 10, 2009, MOD-021-0.1 was approved by the Federal Energy Regulatory Commission.

Version MOD-021-0.1 resulted from errata changes. On January 7, 2005, the base standard MOD-021-0 was approved by the registered ballot body by a 95.5% affirmative vote.

Standard NUC-001-2 — Nuclear Plant Interface Coordination: This standard requires coordination between Nuclear Plant Generator Operators and Transmission Entities for the purpose of ensuring nuclear plant safe operation and shutdown.

Applicability:

- Nuclear Plant Generator Operator.
- Transmission Entities shall mean all entities that are responsible for providing services related to Nuclear Plant Interface Requirements (NPIRs). Such entities may include one or more of the following:
    - Transmission Operators
    - Transmission Owners
    - Transmission Planners
    - Transmission Service Providers
    - Balancing Authorities
    - Reliability Coordinators
    - Planning Coordinators
    - Distribution Providers
    - Load-serving Entities
    - Generator Owners
    - Generator Operators

On July 20, 2009, NUC-001-2 was approved by the registered ballot body by a 96.94% affirmative vote.
On August 5, 2009, NUC-001-2 was approved by the NERC Board of Trustees.
On January 21, 2010, NUC-001-2 was approved by the Federal Energy Regulatory Commission.

Standard PER-001-0.1 — Operating Personnel Responsibility and Authority: Transmission Operator and Balancing Authority operating personnel must have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.

Applicability:

- Transmission Operators
- Balancing Authorities

On April 15, 2009, PER-001-0.1 was approved by the Standards Committee and went to the NERC Board of Trustees for informational purposes on May 6, 2009.
On December 10, 2009, PER-001-0.1 was approved by the Federal Energy Regulatory Commission.

Version PER-001-0.1 resulted from errata changes. On January 7, 2005, the base standard PER-001-0 was approved by the registered ballot body by a 95.5% affirmative vote.

Standard PER-002-0 — Operating Personnel Training: Each Transmission Operator and Balancing Authority must provide their personnel with a coordinated training program that will ensure reliable system operation.

Applicability:

- Balancing Authority
- Transmission Operator

On January 7, 2005, PER-002-0 was approved by the registered ballot body by a 95.5% affirmative vote.
On February 8, 2005, PER-002-0 was approved by the NERC Board of Trustees.
On March 16, 2007, PER-002-0 was approved by the Federal Energy Regulatory Commission.

Standard PER-003-0 — Operating Personnel Credentials: Certification of operating personnel is necessary to ensure minimum competencies for operating a reliable Bulk Electric System.

Applicability:

- Transmission Operators
- Balancing Authorities
- Reliability Coordinators

On January 7, 2005, PER-003-0 was approved by the registered ballot body by a 95.5% affirmative vote.
On February 8, 2005, PER-003-0 was approved by the NERC Board of Trustees.
On March 16, 2007, PER-003-0 was approved by the Federal Energy Regulatory Commission.

Standard PER-004-1 — Reliability Coordination — Staffing: Reliability Coordinators must have sufficient, competent staff to perform the Reliability Coordinator functions.

Applicability:

- Reliability Coordinators

On October 29, 2006, PER-004-1 was approved by the registered ballot body by a 69.48% affirmative vote.
On November 1, 2006, PER-004-1 was approved by the NERC Board of Trustees.
On March 16, 2007, PER-004-1 was approved by the Federal Energy Regulatory Commission.

Version PER-004-1 resulted from the addition of missing measures and compliance elements. On January 7, 2005, base standard PER-004-0 was approved by the registered ballot body by a 95.5% affirmative vote.

Standard PRC-001-1 — System Protection Coordination: To ensure system protection is coordinated among operating entities.

Applicability:

- Balancing Authorities
- Transmission Operators
- Generator Operators

On October 29, 2006, PRC-001-1 was approved by the registered ballot body by a 69.48% affirmative vote.
On November 1, 2006, PRC-001-1 was approved by the NERC Board of Trustees.
On March 16, 2007, PRC-001-1 was approved by the Federal Energy Regulatory Commission.

Version PRC-001-1 resulted from the addition of missing measures and compliance elements. On January 7, 2005, the base standard PRC-001-0 was approved by the registered ballot body by a 95.5% affirmative vote.

Standard PRC-004-1 — Analysis and Mitigation of Transmission and Generation Protection System Misoperations: Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.

Applicability:

- Transmission Owner
- Distribution Provider that owns a transmission Protection System
- Generator Owner

On February 3, 2006, PRC-004-1 was approved by the registered ballot body by a 96% affirmative vote.
On February 7, 2006, PRC-004-1 was approved by the NERC Board of Trustees.
On March 16, 2007, PRC-004-1 was approved by the Federal Energy Regulatory Commission.

Standard PRC-005-1 — Transmission and Generation Protection System Maintenance and Testing: To ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested.

Applicability:

- Transmission Owner
- Generator Owner
- Distribution Provider that owns a transmission Protection System

On February 3, 2006, PRC-005-1 was approved by the registered ballot body by a 96% affirmative vote.
On February 7, 2006, PRC-005-1 was approved by the NERC Board of Trustees.
On March 16, 2007, PRC-005-1 was approved by the Federal Energy Regulatory Commission.

Standard PRC-007-0 — Assuring Consistency of Entity Underfrequency Load Shedding Programs with Regional Reliability Organization's Underfrequency Load Shedding Program Requirements: Provide last resort System preservation measures by implementing an Under Frequency Load Shedding (UFLS) program.

Applicability:

- Transmission Owner required by its Regional Reliability Organization to own a UFLS program
- Transmission Operator required by its Regional Reliability Organization to operate aUFLS program
- Distribution Provider required by its Regional Reliability Organization to own or operate a UFLS program
- Load-Serving Entity required by its Regional Reliability Organization to operate a UFLS program

On January 7, 2005, PRC-007-0 was approved by the registered ballot body by a 95.5% affirmative vote.
On February 8, 2005, PRC-007-0 was approved by the NERC Board of Trustees.
On March 16, 2007, PRC-007-0 was approved by the Federal Energy Regulatory Commission.

Standard PRC-008-0 — Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Programs: Provide last resort system preservation measures by implementing an Under Frequency Load Shedding (UFLS) program.

Applicability:

- Transmission Owner required by its Regional Reliability Organization to have a UFLS program
- Distribution Provider required by its Regional Reliability Organization to have a UFLS program

On January 7, 2005, PRC-008-0 was approved by the registered ballot body by a 95.5% affirmative vote.
On February 8, 2005, PRC-008-0 was approved by the NERC Board of Trustees.
On March 16, 2007, PRC-008-0 was approved by the Federal Energy Regulatory Commission.

Standard PRC-009-0 — Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event: Provide last resort System preservation measures by implementing an Under Frequency Load Shedding (UFLS) program.

Applicability:

- Transmission Owner required by its Regional Reliability Organization to own a UFLS program
- Transmission Operator required by its Regional Reliability Organization to operate a
- UFLS program
- Load-Serving Entity required by the Regional Reliability Organization to operate a UFLS program**.**
- Distribution Provider required by the Regional Reliability Organization to own or operate a UFLS program

On January 7, 2005, PRC-009-0 was approved by the registered ballot body by a 95.5% affirmative vote.
On February 8, 2005, PRC-009-0 was approved by the NERC Board of Trustees.
On March 16, 2007, PRC-009-0 was approved by the Federal Energy Regulatory Commission.

Standard PRC-010-0 — Technical Assessment of the Design and Effectiveness of Undervoltage Shedding Program: Provide System preservation measures in an attempt to prevent system voltage collapse or voltage instability by implementing an Undervoltage Load Shedding (UVLS) program.

Applicability:

- Load-Serving Entity that operates a UVLS program
- Transmission Owner that owns a UVLS program
- Transmission Operator that operates a UVLS program
- Distribution Provider that owns or operates a UVLS program

On January 7, 2005, PRC-010-0 was approved by the registered ballot body by a 95.5% affirmative vote.
On February 8, 2005, PRC-010-0 was approved by the NERC Board of Trustees.
On March 16, 2007, PRC-010-0 was approved by the Federal Energy Regulatory Commission.

Standard PRC-011-0 — Undervoltage Load Shedding System Maintenance and Testing: Provide system preservation measures in an attempt to prevent system voltage collapse or voltage instability by implementing an Undervoltage Load Shedding (UVLS) program.

Applicability:

- Transmission Owner that owns a UVLS system
- Distribution Provider that owns a UVLS system

On January 7, 2005, PRC-011-0 was approved by the registered ballot body by a 95.5% affirmative vote.
On February 8, 2005, PRC-011-0 was approved by the NERC Board of Trustees.
On March 16, 2007, PRC-011-0 was approved by the Federal Energy Regulatory Commission.

Standard PRC-015-0 — Special Protection System Data and Documentation: To ensure that all Special Protection Systems (SPS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.

Applicability:

- Transmission Owner that owns an SPS
- Generator Owner that owns an SPS
- Distribution Provider that owns an SPS

On January 7, 2005, PRC-015-0 was approved by the registered ballot body by a 95.5% affirmative vote.
On February 8, 2005, PRC-015-0 was approved by the NERC Board of Trustees.
On March 16, 2007, PRC-015-0 was approved by the Federal Energy Regulatory Commission.

Standard PRC-016-0.1 — Special Protection System Misoperations: To ensure that all Special Protection Systems (SPS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.

Applicability:

- Transmission Owner that owns an SPS
- Generator Owner that owns an SPS
- Distribution Provider that owns an SPS

On October 29, 2008, PRC-016-0.1 was approved by the NERC Board of Trustees.
On May 13, 2009, PRC-016-0.1 was approved by the Federal Energy Regulatory Commission.

Version PRC-016-0.1 resulted from errata changes. On January 7, 2005, the base standard PRC-016-0 was approved by the registered ballot body by a 95.5% affirmative vote.

Standard PRC-017-0 — Special Protection System Maintenance and Testing: To ensure that all Special Protection Systems (SPS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.

Applicability:

- Transmission Owner that owns an SPS
- Generator Owner that owns an SPS
- Distribution Provider that owns an SPS

On January 7, 2005, PRC-017-0 was approved by the registered ballot body by a 95.5% affirmative vote.
On February 8, 2005, PRC-017-0 was approved by the NERC Board of Trustees.
On March 16, 2007, PRC-017-0 was approved by the Federal Energy Regulatory Commission.

Standard PRC-018-1 — Disturbance Monitoring Equipment Installation and Data Reporting:
Ensure that Disturbance Monitoring Equipment (DME) is installed and that Disturbance data is reported in accordance with regional requirements to facilitate analyses of events.

Applicability:

- Transmission Owner
- Generator Owner

On July 15, 2006, PRC-018-1 was approved by the registered ballot body by a 92.47% affirmative vote.
On August 2, 2006, PRC-018-1 was approved by the NERC Board of Trustees.
On March 16, 2007, PRC-018-1 was approved by the Federal Energy Regulatory Commission.

Standard PRC-021-1 — Under-Voltage Load Shedding Program Data: Ensure data is provided to support the Regional database maintained for Under-Voltage Load Shedding (UVLS) programs that were implemented to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES).

Applicability:

- Transmission Owner that owns a UVLS program
- Distribution Provider that owns a UVLS program

On February 3, 2006, PRC-021-1 was approved by the registered ballot body by a 99% affirmative vote.
On February 7, 2006, PRC-021-1 was approved by the NERC Board of Trustees.
On March 16, 2007, PRC-021-1 was approved by the Federal Energy Regulatory Commission.

Standard PRC-022-1 — Under-Voltage Load Shedding Program Performance: Ensure that Under Voltage Load Shedding (UVLS) programs perform as intended to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES).

Applicability:

- Transmission Operator that operates a UVLS program
- Distribution Provider that operates a UVLS program
- Load-Serving Entity that operates a UVLS program

On February 3, 2006, PRC-022-1 was approved by the registered ballot body by a 99% affirmative vote.
On February 7, 2006, PRC-022-1 was approved by the NERC Board of Trustees.
On March 16, 2007, PRC-022-1 was approved by the Federal Energy Regulatory Commission.

Standard TOP-001-1 — Reliability Responsibilities and Authorities: To ensure reliability entities have clear decision-making authority and capabilities to take appropriate actions or direct the actions of others to return the transmission system to normal conditions during an emergency.

Applicability:

- Balancing Authorities
- Transmission Operators
- Generator Operators
- Distribution Providers
- Load Serving Entities

On October 29, 2006, TOP-001-1 was approved by the registered ballot body by a 69.48% affirmative vote.
On November 1, 2006, TOP-001-1 was approved by the NERC Board of Trustees.
On March 16, 2007, TOP-001-1 was approved by the Federal Energy Regulatory Commission.

Version TOP-001-1 resulted from the addition of missing measures and compliance elements. On January 7, 2005, the base standard TOP-001-0 was approved by the registered ballot body by a 95.5% affirmative vote.

Standard TOP-002-2a — Normal Operations Planning: Current operations plans and procedures are essential to being prepared for reliable operations, including response for unplanned events.

Applicability:

- Balancing Authority
- Transmission Operator
- Generator Operator
- Load Serving Entity
- Transmission Service Provider

On December 19, 2008, TOP-002-2a was approved by the registered ballot body by a 97.47% affirmative vote.
On February 10, 2009, TOP-002-2a was approved by the NERC Board of Trustees.
On December 2, 2009, TOP-002-2a was approved by the Federal Energy Regulatory Commission.

Version TOP-002-2a resulted from interpretation changes; and the addition of missing measures and compliance elements. On January 7, 2005, the base standard TOP-002-0 was approved by the registered ballot body by a 95.5% affirmative vote.

Standard TOP-003-0 — Planned Outage Coordination: Scheduled generator and transmission outages that may affect the reliability of interconnected operations must be planned and coordinated among Balancing Authorities, Transmission Operators, and Reliability Coordinators.

Applicability:

- Generator Operators
- Transmission Operators
- Balancing Authorities
- Reliability Coordinators

On January 7, 2005, TOP-003-0 was approved by the registered ballot body by a 95.5% affirmative vote.
On February 8, 2005, TOP-003-0 was approved by the NERC Board of Trustees.
On March 16, 2007, TOP-003-0 was approved by the Federal Energy Regulatory Commission.

Standard TOP-004-2 — Transmission Operations: To ensure that the transmission system is operated so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single Contingency and specified multiple Contingencies.

Applicability:

- Transmission Operators

On October 23, 2006 and October 29, 2006, TOP-004-2 was approved by the registered ballot body by 71.66% and 69.48% affirmative votes, respectively.[1]
On November 1, 2006, TOP-004-2 was approved by the NERC Board of Trustees.
On January 22, 2009, TOP-004-2 was approved by the Federal Energy Regulatory Commission.

Version TOP-004-2 resulted from conforming changes; and the addition of missing measures and compliance elements. On January 7, 2005, the base standard TOP-004-0 was approved by the registered ballot body by a 95.5% affirmative vote.

[1] There were two versions of the TOP-004-1 that were approved by the registered ballot body. The project that was balloted on October 23, 2006 had changes associated with the version one FAC-010, FAC-011 and FAC-014 Reliability Standards. The project that was balloted on October 29, 2006 had changes associated with adding measures and compliance elements.

Standard TOP-005-1.1 — Operational Reliability Information: To ensure reliability entities have the operating data needed to monitor system conditions within their areas.

Applicability:

- Transmission Operators
- Balancing Authorities
- Reliability Coordinators
- Purchasing Selling Entities

On October 29, 2008, TOP-005-1.1 was approved by the NERC Board of Trustees.
On May 13, 2009, TOP-005-1.1 was approved by the Federal Energy Regulatory Commission.

Version TOP-005-1.1 resulted from errata changes. On January 7, 2005, the base standard TOP-005-0 was approved by the registered ballot body by a 95.5% affirmative vote.

Standard TOP-006-1 — Monitoring System Conditions: To ensure critical reliability parameters are monitored in real-time.

Applicability:

- Transmission Operators
- Balancing Authorities
- Generator Operators
- Reliability Coordinators

On October 29, 2006, TOP-006-1 was approved by the registered ballot body by a 69.48% affirmative vote.
On November 1, 2006, TOP-006-1 was approved by the NERC Board of Trustees.
On March 16, 2007, TOP-006-1 was approved by the Federal Energy Regulatory Commission.

Version TOP-006-1 resulted from the addition of missing measures and compliance elements. On January 7, 2005, the base standard TOP-006-0 was approved by the registered ballot body by a 95.5% affirmative vote.

Standard TOP-007-0 — Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations: This standard ensures SOL and IROL violations are being reported to the Reliability Coordinator so that the Reliability Coordinator may evaluate actions being taken and direct additional corrective actions as needed.

Applicability:

- Transmission Operators
- Reliability Coordinators

On January 7, 2005, TOP-007-0 was approved by the registered ballot body by a 95.5% affirmative vote.
On February 8, 2005, TOP-007-0 was approved by the NERC Board of Trustees.
On March 16, 2007, TOP-007-0 was approved by the Federal Energy Regulatory Commission.

Standard TOP-008-1 — Response to Transmission Limit Violations: To ensure Transmission Operators take actions to mitigate SOL and IROL violations.

Applicability:

- Transmission Operators

On October 29, 2006, TOP-008-1 was approved by the registered ballot body by a 69.48% affirmative vote.
On November 1, 2006, TOP-008-1 was approved by the NERC Board of Trustees.
On March 16, 2007, TOP-008-1 was approved by the Federal Energy Regulatory Commission.

Version TOP-008-1 resulted from the addition of missing measures and compliance elements. On January 7, 2005, the base standard TOP-008-0 was approved by the registered ballot body by a 95.5% affirmative vote.

Standard TPL-001-0.1 — System Performance Under Normal (No Contingency) Conditions (Category A): System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

Applicability:

- Planning Authority
- Transmission Planner

On October 29, 2008, TPL-001-0.1 was approved by the NERC Board of Trustees.
On May 13, 2009, TPL-001-0.1 was approved by the Federal Energy Regulatory Commission.

Version TPL-001-0.1 resulted from errata changes. On January 7, 2005, the base standard TPL-001-0 was approved by the registered ballot body by a 95.5% affirmative vote.

Standard TPL-002-0a — System Performance Following Loss of a Single Bulk Electric System Element (Category B): System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

Applicability:

- Planning Authority
- Transmission Planner

On July 7, 2008, TPL-002-0a was approved by the registered ballot body by 79.13% and 78.31% affirmative votes.[2]
On July 30, 2008, TPL-002-0a was approved by the NERC Board of Trustees.
On April 23, 2010, TPL-002-0a was approved by the Federal Energy Regulatory Commission.

Version TPL-002-0a resulted from interpretation changes. On January 7, 2005, the base standard TPL-002-0 was approved by the registered ballot body by a 95.5% affirmative vote.

[2] There were two projects associated with this standard because there were two requests for interpretation for TPL-002-0. The Ameren request for interpretation resulted in the registered ballot body affirmative vote of 79.13% and the Midwest Independent Transmission System Operator, Inc. request for interpretation resulted in the registered ballot body affirmative vote of 78.31%.

Standard TPL-003-0a — System Performance Following Loss of Two or More Bulk Electric System Elements (Category C): System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

Applicability:

- Planning Authority
- Transmission Planner

On July 7, 2008, TPL-003-0a was approved by the registered ballot body by 79.13% and 78.31% affirmative votes.[3]
On July 30, 2008, TPL-003-0a was approved by the NERC Board of Trustees.
On April 23, 2010, TPL-003-0a was approved by the Federal Energy Regulatory Commission.

Version TPL-003-0a resulted from interpretation changes. On January 7, 2005, the base standard TPL-003-0 was approved by the registered ballot body by a 95.5% affirmative vote.

[3] There were two projects associated with this standard because there were two requests for interpretation for TPL-003-0. The Ameren request for interpretation resulted in the registered ballot body affirmative vote of 79.13% and the Midwest Independent System Operator, Inc. request for interpretation resulted in the registered ballot body affirmative vote of 78.31%.

Standard TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D): System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

Applicability:

- Planning Authority
- Transmission Planner

On January 7, 2005, TPL-004-0 was approved by the registered ballot body by a 95.5% affirmative vote.
On February 8, 2005, TPL-004-0 was approved by the NERC Board of Trustees.
On March 16, 2007, TPL-004-0 was approved by the Federal Energy Regulatory Commission.

Standard VAR-001-1 — Voltage and Reactive Control: To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in real time to protect equipment and the reliable operation of the Interconnection.

Applicability:

- Transmission Operators
- Purchasing-Selling Entities

On July 15, 2006, VAR-001-1 was approved by the registered ballot body by a 92.1% affirmative vote.
On August 2, 2006, VAR-001-1 was approved by the NERC Board of Trustees.
On March 16, 2007, VAR-001-1 was approved by the Federal Energy Regulatory Commission.

Standard VAR-002-1.1a — Generator Operation for Maintaining Network Voltage Schedules: To ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and the reliable operation of the Interconnection.

Applicability:

- Generator Operator
- Generator Owner

On October 29, 2008, VAR-002-1.1a was approved by the NERC Board of Trustees.
On May 13, 2009, VAR-002-1.1a was approved by the Federal Energy Regulatory Commission.

Version VAR-002-1.1a resulted from errata and interpretation changes. On July 15, 2006, the base standard VAR-002-1 was approved by the registered ballot body by a 92.1% affirmative vote.

Exhibit C

Current Reliability Standards and NERC Glossary of Terms for Approval

A. Introduction

1. **Title**: **Real Power Balancing Control Performance**
2. **Number**: BAL-001-0.1a
3. **Purpose**: To maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time.
4. **Applicability**:

   4.1. Balancing Authorities.
5. **Effective Date:** May 13, 2009

B. Requirements

R1. Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit ε_1^2 is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating Committee.

$$AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right] \le \in_1^2 \;\; or \;\; \frac{AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right]}{\in_1^2} \le 1$$

The equation for ACE is:

$ACE = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME}$

where:

- NI_A is the algebraic sum of actual flows on all tie lines.
- NI_S is the algebraic sum of scheduled flows on all tie lines.
- B is the Frequency Bias Setting (MW/0.1 Hz) for the Balancing Authority. The constant factor 10 converts the frequency setting to MW/Hz.
- F_A is the actual frequency.
- F_S is the scheduled frequency. F_S is normally 60 Hz but may be offset to effect manual time error corrections.
- I_{ME} is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net tie line flows (NI_A) and the hourly net interchange demand measurement (megawatt-hour). This term should normally be very small or zero.

R2. Each Balancing Authority shall operate such that its average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit, referred to as L_{10}.

$$AVG_{10-\text{minute}}(ACE_i) \le L_{10}$$

where:

$$L_{10}=1.65\in_{10}\sqrt{(-10B_i)(-10B_s)}$$

ε_{10} is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average Frequency Error based on frequency performance over a given year. The bound, ε_{10}, is the same for every Balancing Authority Area within an Interconnection, and B_s is the sum of the Frequency Bias Settings of the Balancing Authority Areas in the respective Interconnection. For Balancing Authority Areas with variable bias, this is equal to the sum of the minimum Frequency Bias Settings.

R3. Each Balancing Authority providing Overlap Regulation Service shall evaluate Requirement R1 (i.e., Control Performance Standard 1 or CPS1) and Requirement R2 (i.e., Control Performance Standard 2 or CPS2) using the characteristics of the combined ACE and combined Frequency Bias Settings.

R4. Any Balancing Authority receiving Overlap Regulation Service shall not have its control performance evaluated (i.e. from a control performance perspective, the Balancing Authority has shifted all control requirements to the Balancing Authority providing Overlap Regulation Service).

C. Measures

M1. Each Balancing Authority shall achieve, as a minimum, Requirement 1 (CPS1) compliance of 100%.

CPS1 is calculated by converting a compliance ratio to a compliance percentage as follows:

CPS1 = (2 - CF) * 100%

The frequency-related compliance factor, CF, is a ratio of all one-minute compliance parameters accumulated over 12 months divided by the target frequency bound:

$$CF = \frac{CF_{12-\text{month}}}{(\in_1)^2}$$

where: ε_1 is defined in Requirement R1.

The rating index $CF_{12\text{-month}}$ is derived from 12 months of data. The basic unit of data comes from one-minute averages of ACE, Frequency Error and Frequency Bias Settings.

A clock-minute average is the average of the reporting Balancing Authority's valid measured variable (i.e., for ACE and for Frequency Error) for each sampling cycle during a given clock-minute.

$$\left(\frac{ACE}{-10B}\right)_{\text{clock-minute}} = \frac{\left(\dfrac{\sum ACE_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}\right)}{\text{-10B}}$$

$$\Delta F_{\text{clock-minute}} = \frac{\sum \Delta F_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}$$

The Balancing Authority's clock-minute compliance factor (CF) becomes:

$$CF_{\text{clock-minute}} = \left[\left(\frac{ACE}{-10B} \right)_{\text{clock-minute}} * \Delta F_{\text{clock-minute}} \right]$$

Normally, sixty (60) clock-minute averages of the reporting Balancing Authority's ACE and of the respective Interconnection's Frequency Error will be used to compute the respective hourly average compliance parameter.

$$CF_{\text{clock-hour}} = \frac{\sum CF_{\text{clock-minute}}}{n_{\text{clock-minute samples in hour}}}$$

The reporting Balancing Authority shall be able to recalculate and store each of the respective clock-hour averages (CF clock-hour average-month) as well as the respective number of samples for each of the twenty-four (24) hours (one for each clock-hour, i.e., hour-ending (HE) 0100, HE 0200, ..., HE 2400).

$$\text{CF}_{\text{clock-hour average-month}} = \frac{\sum_{\text{days-in-month}} [(\text{CF}_{\text{clock-hour}})(n_{\text{one-minute samples in clock-hour}})]}{\sum_{\text{days-in month}} [n_{\text{one-minute samples in clock-hour}}]}$$

$$\text{CF}_{\text{month}} = \frac{\sum_{\text{hours-in-day}} [(\text{CF}_{\text{clock-hour average-month}})(n_{\text{one-minute samples in clock-hour averages}})]}{\sum_{\text{hours-in day}} [n_{\text{one-minute samples in clock-hour averages}}]}$$

The 12-month compliance factor becomes:

$$\text{CF}_{\text{12-month}} = \frac{\sum_{\text{i=1}}^{12} (CF_{\text{month-i}})(n_{(\text{one-minute samples in month})-\text{i}})]}{\sum_{\text{i=1}}^{12} [n_{(\text{one-minute samples in month})\text{-i}}]}$$

In order to ensure that the average ACE and Frequency Deviation calculated for any one-minute interval is representative of that one-minute interval, it is necessary that at least 50% of both ACE and Frequency Deviation samples during that one-minute interval be present. Should a sustained interruption in the recording of ACE or Frequency Deviation due to loss of telemetering or computer unavailability result in a one-minute interval not containing at least 50% of samples of both ACE and Frequency Deviation, that one-minute interval shall be excluded from the calculation of CPS1.

M2. Each Balancing Authority shall achieve, as a minimum, Requirement R2 (CPS2) compliance of 90%. CPS2 relates to a bound on the ten-minute average of ACE. A compliance percentage is calculated as follows:

$$CPS2 = \left[1 - \frac{\text{Violations}_{\text{month}}}{(\text{Total Periods}_{\text{month}} - \text{Unavailable Periods}_{\text{month}})} \right] * 100$$

The violations per month are a count of the number of periods that ACE clock-ten-minutes exceeded L_{10}. ACE clock-ten-minutes is the sum of valid ACE samples within a clock-ten-minute period divided by the number of valid samples.

Violation clock-ten-minutes

$$= 0 \text{ if } \left| \frac{\sum ACE}{n_{\text{samples in 10-minutes}}} \right| \le L_{10}$$

$$= 1 \text{ if } \left| \frac{\sum ACE}{n_{\text{samples in 10-minutes}}} \right| > L_{10}$$

Each Balancing Authority shall report the total number of violations and unavailable periods for the month. L_{10} is defined in Requirement R2.

Since CPS2 requires that ACE be averaged over a discrete time period, the same factors that limit total periods per month will limit violations per month. The calculation of total periods per month and violations per month, therefore, must be discussed jointly.

A condition may arise which may impact the normal calculation of total periods per month and violations per month. This condition is a sustained interruption in the recording of ACE.

In order to ensure that the average ACE calculated for any ten-minute interval is representative of that ten-minute interval, it is necessary that at least half the ACE data samples are present for that interval. Should half or more of the ACE data be unavailable due to loss of telemetering or computer unavailability, that ten-minute interval shall be omitted from the calculation of CPS2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar month.

1.3. Data Retention

The data that supports the calculation of CPS1 and CPS2 (Appendix 1-BAL-001-0) are to be retained in electronic form for at least a one-year period. If the CPS1 and CPS2 data for a Balancing Authority Area are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved. Each Balancing Authority shall retain for a rolling 12-month period the values of: one-minute average ACE (ACE_i), one-minute average Frequency Error, and, if using variable bias, one-minute average Frequency Bias.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance – CPS1

2.1. Level 1: The Balancing Authority Area's value of CPS1 is less than 100% but greater than or equal to 95%.

2.2. Level 2: The Balancing Authority Area's value of CPS1 is less than 95% but greater than or equal to 90%.

2.3. Level 3: The Balancing Authority Area's value of CPS1 is less than 90% but greater than or equal to 85%.

2.4. Level 4: The Balancing Authority Area's value of CPS1 is less than 85%.

3. Levels of Non-Compliance – CPS2

3.1. Level 1: The Balancing Authority Area's value of CPS2 is less than 90% but greater than or equal to 85%.

3.2. Level 2: The Balancing Authority Area's value of CPS2 is less than 85% but greater than or equal to 80%.

3.3. Level 3: The Balancing Authority Area's value of CPS2 is less than 80% but greater than or equal to 75%.

3.4. Level 4: The Balancing Authority Area's value of CPS2 is less than 75%.

E. Regional Differences

1. The ERCOT Control Performance Standard 2 Waiver approved November 21, 2002.

F. Associated Documents

1. Appendix 2 – Interpretation of Requirement R1 (October 23, 2007).

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	BOT Approval	New
0	April 1, 2005	Effective Implementation Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	July 24, 2007	Corrected R3 to reference M1 and M2 instead of R1 and R2.	Errata
0a	December 19, 2007	Added Appendix 2 – Interpretation of R1 approved by BOT on October 23, 2007	Revised
0a	January 16, 2008	In Section A.2., Added "a" to end of standard number. In Section F, corrected automatic numbering from "2" to "1" and removed "approved" and added parenthesis to "(October 23, 2007)."	Errata
0	January 23, 2008	Reversed errata change from July 24, 2007	Errata
0.1a	October 29, 2008	Board approved errata changes; updated version number to "0.1a"	Errata
0.1a	May 13, 2009	Approved by FERC	

Appendix 1-BAL-001-0
CPS1 and CPS2 Data

CPS1 DATA	Description	Retention Requirements
ε_1	A constant derived from the targeted frequency bound. This number is the same for each Balancing Authority Area in the Interconnection.	Retain the value of ε_1 used in CPS1 calculation.
ACE_i	The clock-minute average of ACE.	Retain the 1-minute average values of ACE (525,600 values).
B_i	The Frequency Bias of the Balancing Authority Area.	Retain the value(s) of B_i used in the CPS1 calculation.
F_A	The actual measured frequency.	Retain the 1-minute average frequency values (525,600 values).
F_S	Scheduled frequency for the Interconnection.	Retain the 1-minute average frequency values (525,600 values).

CPS2 DATA	Description	Retention Requirements
V	Number of incidents per hour in which the absolute value of ACE clock-ten-minutes is greater than L_{10}.	Retain the values of V used in CPS2 calculation.
ε_{10}	A constant derived from the frequency bound. It is the same for each Balancing Authority Area within an Interconnection.	Retain the value of ε_{10} used in CPS2 calculation.
B_i	The Frequency Bias of the Balancing Authority Area.	Retain the value of B_i used in the CPS2 calculation.
B_s	The sum of Frequency Bias of the Balancing Authority Areas in the respective Interconnection. For systems with variable bias, this is equal to the sum of the minimum Frequency Bias Setting.	Retain the value of B_s used in the CPS2 calculation. Retain the 1-minute minimum bias value (525,600 values).
U	Number of unavailable ten-minute periods per hour used in calculating CPS2.	Retain the number of 10-minute unavailable periods used in calculating CPS2 for the reporting period.

Appendix 2

Interpretation of Requirement 1

Request: *Does the WECC Automatic Time Error Control Procedure (WATEC) violate Requirement 1 of BAL-001-0?*

Interpretation:

Requirement 1 of BAL-001 — Real Power Balancing Control Performance, is the definition of the area control error (ACE) equation and the limits established for Control Performance Standard 1 (CPS1).

BAL-001-0

R1. Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit ε12 is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating Committee.

- The WATEC procedural documents ask Balancing Authorities to maintain raw ACE for CPS reporting and to control via WATEC-adjusted ACE.
- As long as Balancing Authorities use raw (unadjusted for WATEC) ACE for CPS reporting purposes, the use of WATEC for control is not in violation of BAL-001 Requirement 1.

Introduction

1. **Title:** **Disturbance Control Performance**
2. **Number:** BAL-002-0
3. **Purpose:**
   The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of load and because Contingency Reserve activation does not typically apply to the loss of load, the application of DCS is limited to the loss of supply and does not apply to the loss of load.
4. **Applicability:**
   - **4.1.** Balancing Authorities
   - **4.2.** Reserve Sharing Groups (Balancing Authorities may meet the requirements of Standard 002 through participation in a Reserve Sharing Group.)
   - **4.3.** Regional Reliability Organizations
5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.

R1.1. A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such cases, the Reserve Sharing Group shall have the same responsibilities and obligations as each Balancing Authority with respect to monitoring and meeting the requirements of Standard BAL-002.

R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including:

R2.1. The minimum reserve requirement for the group.

R2.2. Its allocation among members.

R2.3. The permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve.

R2.4. The procedure for applying Contingency Reserve in practice.

R2.5. The limitations, if any, upon the amount of interruptible load that may be included.

R2.6. The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by multiple Balancing Authorities.

R3. Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS.

R3.1. As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency. All Balancing Authorities and Reserve Sharing Groups shall review, no less frequently

than annually, their probable contingencies to determine their prospective most severe single contingencies.

R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:

R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.

R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee.

R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Balancing Authority.) Compliance may be demonstrated by either of the following two methods:

R5.1. The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

or

R5.2. The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

R6. A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period for its Interconnection.

R6.1. The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period.

R6.2. The default Contingency Reserve Restoration Period is 90 minutes. This period may be adjusted to better suit the reliability targets of the Interconnection based on analysis approved by the NERC Operating Committee.

C. Measures

M1. A Balancing Authority or Reserve Sharing Group shall calculate and report compliance with the Disturbance Control Standard for all Disturbances greater than or equal to 80% of the magnitude of the Balancing Authority's or of the Reserve Sharing Group's most severe single contingency loss. Regions may, at their discretion, require a lower reporting threshold. Disturbance Control Standard is measured as the percentage recovery (R_i).

For loss of generation:

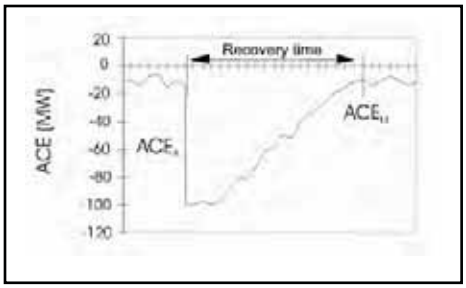

if $ACE_A < 0$
then

$$R_i = \frac{MW_{Loss} - \max(0, ACE_A - ACE_M)}{MW_{Loss}} * 100\%$$

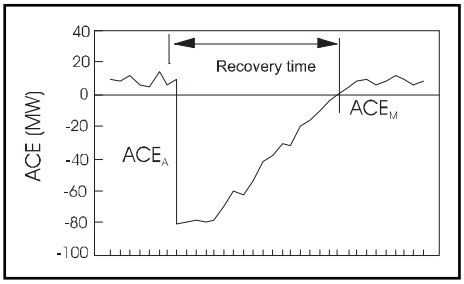

if $ACE_A \geq 0$
then

$$R_i = \frac{MW_{Loss} - \max(0, -ACE_M)}{MW_{Loss}} * 100\%$$

where:

- MW_{LOSS} is the MW size of the Disturbance as measured at the beginning of the loss,
- ACE_A is the pre-disturbance ACE,
- ACE_M is the maximum algebraic value of ACE measured within the fifteen minutes following the Disturbance. A Balancing Authority or Reserve Sharing Group may, at its discretion, set $ACE_M = ACE_{15\ min}$, and

The Balancing Authority or Reserve Sharing Group shall record the MW_{LOSS} value as measured at the site of the loss to the extent possible. The value should not be measured as a change in ACE since governor response and AGC response may introduce error.

The Balancing Authority or Reserve Sharing Group shall base the value for ACE_A on the average ACE over the period just prior to the start of the Disturbance (10 and 60 seconds prior and including at least 4 scans of ACE). In the illustration below, the horizontal line represents an averaging of ACE for 15 seconds prior to the start of the Disturbance with a result of ACE_A = - 25 MW.

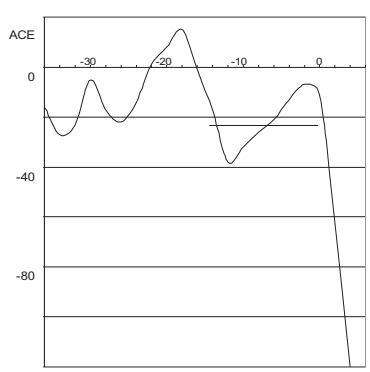

The average percent recovery is the arithmetic average of all the calculated R_i's for Reportable Disturbances during a given quarter. Average percent recovery is similarly calculated for excludable Disturbances.

D. Compliance

1. Compliance Monitoring Process

Compliance with the DCS shall be measured on a percentage basis as set forth in the measures above.

Each Balancing Authority or Reserve Sharing Group shall submit one completed copy of DCS Form, "NERC Control Performance Standard Survey – All Interconnections" to its Resources Subcommittee Survey Contact no later than the 10th day following the end of the calendar quarter (i.e. April 10th, July 10th, October 10th, January 10th). The Regional Reliability Organization must submit a summary document reporting compliance with DCS to NERC no later than the 20th day of the month following the end of the quarter.

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

Compliance for DCS will be evaluated for each reporting period. Reset is one calendar quarter without a violation.

1.3. Data Retention

The data that support the calculation of DCS are to be retained in electronic form for at least a one-year period. If the DCS data for a Reserve Sharing Group and Balancing Area are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved.

1.4. Additional Compliance Information

Reportable Disturbances – Reportable Disturbances are contingencies that are greater than or equal to 80% of the most severe single Contingency. A Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group may optionally reduce the 80% threshold, provided that normal operating characteristics are not being considered or misrepresented as contingencies. Normal operating characteristics are excluded because DCS only measures the recovery from sudden, unanticipated losses of supply-side resources.

Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

Multiple Contingencies within the Contingency Reserve Restoration Period – Additional Reportable Disturbances that occur after the end of the Disturbance Recovery Period but before the end of the Contingency Reserve Restoration Period shall be reported and included in the compliance evaluation. However, the Balancing Authority or Reserve Sharing Group can request a waiver from the Resources Subcommittee for the event if the contingency reserves were rendered inadequate by prior contingencies and a good faith effort to replace contingency reserve can be shown.

2. Levels of Non-Compliance

Each Balancing Authority or Reserve Sharing Group not meeting the DCS during a given calendar quarter shall increase its Contingency Reserve obligation for the calendar quarter (offset by one month) following the evaluation by the NERC or Compliance Monitor [e.g. for the first calendar quarter of the year, the penalty is applied for May, June, and July.] The increase shall be directly proportional to the non-compliance with the DCS in the preceding quarter. This adjustment is not compounded across quarters, and is an additional percentage of reserve needed beyond the most severe single Contingency. A Reserve Sharing Group may choose an allocation method for increasing its Contingency Reserve for the Reserve Sharing Group provided that this increase is fully allocated.

A representative from each Balancing Authority or Reserve Sharing Group that was non-compliant in the calendar quarter most recently completed shall provide written documentation verifying that the Balancing Authority or Reserve Sharing Group will apply the appropriate DCS performance adjustment beginning the first day of the succeeding month, and will continue to apply it for three months. The written documentation shall accompany the quarterly Disturbance Control Standard Report when a Balancing Authority or Reserve Sharing Group is non-compliant.

2.1. Level 1: Value of the average percent recovery for the quarter is less than 100% but greater than or equal to 95%.

2.2. Level 2: Value of the average percent recovery for the quarter is less than 95% but greater than or equal to 90%.

2.3. Level 3: Value of average percent recovery for the quarter is less than 90% but greater than or equal to 85%.

2.4. Level 4: Value of average percent recovery for the quarter is less than 85%.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, "10 min." to "Recovery time." Removed fourth bullet.	Errata

A. Introduction

1. **Title:** **Frequency Response and Bias**
2. **Number:** BAL-003-0.1b
3. **Purpose:** This standard provides a consistent method for calculating the Frequency Bias component of ACE.
4. **Applicability:**
   - **4.1.** Balancing Authorities.
5. **Effective Date:** May 13, 2009

B. Requirements

R1. Each Balancing Authority shall review its Frequency Bias Settings by January 1 of each year and recalculate its setting to reflect any change in the Frequency Response of the Balancing Authority Area.

- **R1.1.** The Balancing Authority may change its Frequency Bias Setting, and the method used to determine the setting, whenever any of the factors used to determine the current bias value change.
- **R1.2.** Each Balancing Authority shall report its Frequency Bias Setting, and method for determining that setting, to the NERC Operating Committee.

R2. Each Balancing Authority shall establish and maintain a Frequency Bias Setting that is as close as practical to, or greater than, the Balancing Authority's Frequency Response. Frequency Bias may be calculated several ways:

- **R2.1.** The Balancing Authority may use a fixed Frequency Bias value which is based on a fixed, straight-line function of Tie Line deviation versus Frequency Deviation. The Balancing Authority shall determine the fixed value by observing and averaging the Frequency Response for several Disturbances during on-peak hours.
- **R2.2.** The Balancing Authority may use a variable (linear or non-linear) bias value, which is based on a variable function of Tie Line deviation to Frequency Deviation. The Balancing Authority shall determine the variable frequency bias value by analyzing Frequency Response as it varies with factors such as load, generation, governor characteristics, and frequency.

R3. Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection reliability.

R4. Balancing Authorities that use Dynamic Scheduling or Pseudo-ties for jointly owned units shall reflect their respective share of the unit governor droop response in their respective Frequency Bias Setting.

- **R4.1.** Fixed schedules for Jointly Owned Units mandate that Balancing Authority (A) that contains the Jointly Owned Unit must incorporate the respective share of the unit governor droop response for any Balancing Authorities that have fixed schedules (B and C). See the diagram below.

R4.2. The Balancing Authorities that have a fixed schedule (B and C) but do not contain the Jointly Owned Unit shall not include their share of the governor droop response in their Frequency Bias Setting.

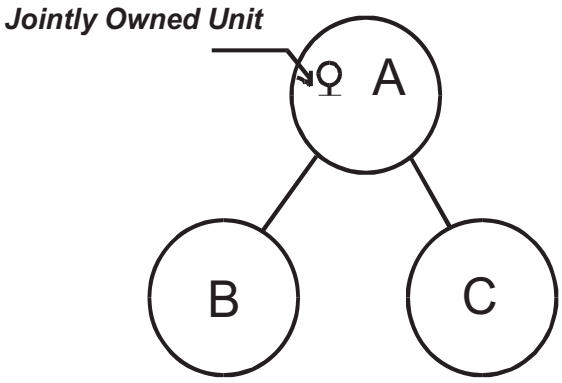

R5. Balancing Authorities that serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of the Balancing Authority's estimated yearly peak demand per 0.1 Hz change.

R5.1. Balancing Authorities that do not serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of its estimated maximum generation level in the coming year per 0.1 Hz change.

R6. A Balancing Authority that is performing Overlap Regulation Service shall increase its Frequency Bias Setting to match the frequency response of the entire area being controlled. A Balancing Authority shall not change its Frequency Bias Setting when performing Supplemental Regulation Service.

C. Measures

M1. Each Balancing Authority shall perform Frequency Response surveys when called for by the Operating Committee to determine the Balancing Authority's response to Interconnection Frequency Deviations.

D. Compliance

Not Specified.

E. Regional Differences

None identified.

F. Associated Documents

1. Appendix 1 – Interpretation of Requirement R3 (October 23, 2007).
2. Appendix 2 – Interpretation of Requirements R2, R2.2, R5, and R5.1 (February 12, 2008).

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0a	December 19,	Added Appendix 1 – Interpretation of R3	Addition

	2007	approved by BOT on October 23, 2007	
0a	January 16, 2008	Section F: added "1."; changed hyphen to "en dash." Changed font style for "Appendix 1" to Arial.	Errata
0b	February 12, 2008	Added Appendix 2 – Interpretation of R2, R2.2, R5, and R5.1 approved by BOT on February 12, 2008	Addition
0.1b	October 29, 2008	BOT approved errata changes; updated version number to "0.1b"	Errata
0.1b	May 13, 2009	FERC Approved – Updated Effective Date and footer	Addition

Appendix 1

Interpretation of Requirement 3

Request: *Does the WECC Automatic Time Error Control Procedure (WATEC) violate Requirement 3 of BAL-003-0?*

Interpretation:

Requirement 3 of BAL-003-0 — Frequency Response and Bias deals with Balancing Authorities using Tie-Line Frequency Bias as the normal mode of automatic generation control.

> **BAL-003-0**
> **R3.** Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection reliability.

- Tie-Line Frequency Bias is one of the three foundational control modes available in a Balancing Authority's energy management system. (The other two are flat-tie and flat-frequency.) Many Balancing Authorities layer other control objectives on top of their basic control mode, such as automatic inadvertent payback, CPS optimization, time control (in single BA Interconnections).
- As long as Tie-Line Frequency Bias is the underlying control mode and CPS1 is measured and reported on the associated ACE equation, there is no violation of BAL-003-0 Requirement 3:

$$ACE = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME}$$

Appendix 2

Interpretation of Requirements R2, R2.2, R5, R5.1

Request: *ERCOT specifically requests clarification that a Balancing Authority is entitled to use a variable bias value as authorized by Requirement R2.2, even though Requirement 5 seems not to account for the possibility of variable bias settings.*

Interpretation:

The consensus of the Resources Subcommittee is that BAL-003-0 — Frequency Response and Bias — Requirement R2 does not conflict with BAL-003-0 Requirement R5.

BAL-003-0 — Frequency Response and Bias Requirement 2 requires a Balancing Authority to analyze its response to frequency excursions as a first step in determining its frequency bias setting. The Balancing Authority may then choose a fixed bias (constant through the year) per Requirement 2.1, or a variable bias (varies with load, specific generators, etc.) per Requirement 2.2.

BAL-003-0

R2. Each Balancing Authority shall establish and maintain a Frequency Bias Setting that is as close as practical to, or greater than, the Balancing Authority's Frequency Response. Frequency Bias may be calculated several ways:

R2.1. The Balancing Authority may use a fixed Frequency Bias value which is based on a fixed, straight-line function of Tie Line deviation versus Frequency Deviation. The Balancing Authority shall determine the fixed value by observing and averaging the Frequency Response for several Disturbances during on-peak hours.

R2.2. The Balancing Authority may use a variable (linear or non-linear) bias value, which is based on a variable function of Tie Line deviation to Frequency Deviation. The Balancing Authority shall determine the variable frequency bias value by analyzing Frequency Response as it varies with factors such as load, generation, governor characteristics, and frequency.

BAL-003-0 — Frequency Response and Bias Requirement 5 sets a minimum contribution for all Balancing Authorities toward stabilizing interconnection frequency. The 1% bias setting establishes a minimum level of automatic generation control action to help stabilize frequency following a disturbance. By setting a floor on bias, Requirement 5 also helps ensure a consistent measure of control performance among all Balancing Authorities within a multi-Balancing Authority interconnection. However, ERCOT is a single Balancing Authority interconnection. The bias settings ERCOT uses do produce, on average, the best level of automatic generation control action to meet control performance metrics. The bias value in a single Balancing Authority interconnection does not impact the measure of control performance.

BAL-003-0

R5. Balancing Authorities that serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of the Balancing Authority's estimated yearly peak demand per 0.1 Hz change.

R5.1. Balancing Authorities that do not serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of its estimated maximum generation level in the coming year per 0.1 Hz change.

A. Introduction

1. **Title:** **Time Error Correction**
2. **Number:** BAL-004-0
3. **Purpose:**
   The purpose of this standard is to ensure that Time Error Corrections are conducted in a manner that does not adversely affect the reliability of the Interconnection.
4. **Applicability:**
   4.1. Reliability Coordinators
   4.2. Balancing Authorities
5. **Effective Date:** April 1, 2005

B. Requirements

R1. Only a Reliability Coordinator shall be eligible to act as Interconnection Time Monitor. A single Reliability Coordinator in each Interconnection shall be designated by the NERC Operating Committee to serve as Interconnection Time Monitor.

R2. The Interconnection Time Monitor shall monitor Time Error and shall initiate or terminate corrective action orders in accordance with the NAESB Time Error Correction Procedure.

R3. Each Balancing Authority, when requested, shall participate in a Time Error Correction by one of the following methods:

R3.1. The Balancing Authority shall offset its frequency schedule by 0.02 Hertz, leaving the Frequency Bias Setting normal; or

R3.2. The Balancing Authority shall offset its Net Interchange Schedule (MW) by an amount equal to the computed bias contribution during a 0.02 Hertz Frequency Deviation (i.e. 20% of the Frequency Bias Setting).

R4. Any Reliability Coordinator in an Interconnection shall have the authority to request the Interconnection Time Monitor to terminate a Time Error Correction in progress, or a scheduled Time Error Correction that has not begun, for reliability considerations.

R4.1. Balancing Authorities that have reliability concerns with the execution of a Time Error Correction shall notify their Reliability Coordinator and request the termination of a Time Error Correction in progress.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata

A. Introduction

1. **Title:** **Automatic Generation Control**

2. **Number:** BAL-005-0.1b

3. **Purpose:**

   This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved.

4. **Applicability:**

   4.1. Balancing Authorities

   4.2. Generator Operators

   4.3. Transmission Operators

   4.4. Load Serving Entities

5. **Effective Date:** May 13, 2009

B. Requirements

R1. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.

R1.1. Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.

R1.2. Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.

R1.3. Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a Balancing Authority Area.

R2. Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.

R3. A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications, and control equipment are employed to prevent such service from becoming a Burden on the Interconnection or other Balancing Authority Areas.

R4. A Balancing Authority providing Regulation Service shall notify the Host Balancing Authority for whom it is controlling if it is unable to provide the service, as well as any Intermediate Balancing Authorities.

R5. A Balancing Authority receiving Regulation Service shall ensure that backup plans are in place to provide replacement Regulation Service should the supplying Balancing Authority no longer be able to provide this service.

R6. The Balancing Authority's AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's ACE. Single Balancing Authorities operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control. If a Balancing Authority is unable to calculate ACE for more than 30 minutes it shall notify its Reliability Coordinator.

R7. The Balancing Authority shall operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become inoperative, the Balancing Authority shall use manual control to adjust generation to maintain the Net Scheduled Interchange.

R8. The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every six seconds.

R8.1. Each Balancing Authority shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide a minimum availability of 99.95%.

R9. The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.

R9.1. Balancing Authorities with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection may choose to omit the Interchange Schedule related to the HVDC link from the ACE equation if it is modeled as internal generation or load.

R10. The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.

R11. Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE.

R12. Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.

R12.1. Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment. Balancing Authorities shall ensure that megawatt-hour data is telemetered or reported at the end of each hour.

R12.2. Balancing Authorities shall ensure the power flow and ACE signals that are utilized for calculating Balancing Authority performance or that are transmitted for Regulation Service are not filtered prior to transmission, except for the Anti-aliasing Filters of Tie Lines.

R12.3. Balancing Authorities shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more Balancing Authorities to deliver the output of Jointly Owned Units or to serve remote load.

R13. Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the accuracy of its control equipment. The Balancing Authority shall adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error (I_{ME}) term of the ACE equation to compensate for any equipment error until repairs can be made.

R14. The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the Balancing Authority shall provide its operating personnel with real-time values for ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.

R15. The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority's control center and other critical locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.

R16. The Balancing Authority shall sample data at least at the same periodicity with which ACE is calculated. The Balancing Authority shall flag missing or bad data for operator display and archival purposes. The Balancing Authority shall collect coincident data to the greatest practical extent, i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time.

R17. Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	≤ 0.001 Hz
MW, MVAR, and voltage transducer	≤ 0.25 % of full scale
Remote terminal unit	≤ 0.25 % of full scale
Potential transformer	≤ 0.30 % of full scale
Current transformer	≤ 0.50 % of full scale

C. Measures

Not specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Balancing Authorities shall be prepared to supply data to NERC in the format defined below:

1.1.1. Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization CPS source data in daily CSV files with time stamped one minute averages of: 1) ACE and 2) Frequency Error.

1.1.2. Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization DCS source data in CSV files with time stamped scan rate values for: 1) ACE and 2) Frequency Error for a time period of two minutes prior to thirty minutes after the identified Disturbance.

1.2. Compliance Monitoring Period and Reset Timeframe

Not specified.

1.3. Data Retention

1.3.1. Each Balancing Authority shall retain its ACE, actual frequency, Scheduled Frequency, Net Actual Interchange, Net Scheduled Interchange, Tie Line meter error correction and Frequency Bias Setting data in digital format at the same scan rate at which the data is collected for at least one year.

1.3.2. Each Balancing Authority or Reserve Sharing Group shall retain documentation of the magnitude of each Reportable Disturbance as well as the ACE charts and/or samples used to calculate Balancing Authority or Reserve Sharing Group disturbance recovery values. The data shall be retained for one year following the reporting quarter for which the data was recorded.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

Not specified.

E. Regional Differences

None identified.

F. Associated Documents

1. Appendix 1 – Interpretation of Requirement R17 (February 12, 2008).

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0a	December 19, 2007	Added Appendix 1 – Interpretation of R17 approved by BOT on May 2, 2007	Addition
0a	January 16, 2008	Section F: added "1."; changed hyphen to "en dash." Changed font style for "Appendix 1" to Arial.	Errata
0b	February 12, 2008	Replaced Appendix 1 – Interpretation of R17 approved by BOT on February 12, 2008.	Replacement
0.1b	October 29, 2008	BOT approved errata changes; updated version number to "0.1b"	Errata
0.1b	May 13, 2009	FERC approved – Updated Effective Date and Footer	Addition

Appendix 1

Request: *PGE requests clarification regarding the measuring devices for which the requirement applies, specifically clarification if the requirement applies to the following measuring devices:*

- *Only equipment within the operations control room*
- *Only equipment that provides values used to calculate AGC ACE*
- *Only equipment that provides values to its SCADA system*
- *Only equipment owned or operated by the BA*
- *Only to new or replacement equipment*
- *To all equipment that a BA owns or operates*

BAL-005-1

R17. Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	≤ 0.001 Hz
MW, MVAR, and voltage transducer	≤ 0.25% of full scale
Remote terminal unit	≤ 0.25% of full scale
Potential transformer	≤ 0.30% of full scale
Current transformer	≤ 0.50% of full scale

Existing Interpretation Approved by Board of Trustees May 2, 2007

BAL-005-0, Requirement 17 requires that the Balancing Authority check and calibrate its control room time error and frequency devices against a common reference at least annually. The requirement to "annually check and calibrate" does not address any devices outside of the operations control room.

The table represents the design accuracy of the listed devices. There is no requirement within the standard to "annually check and calibrate" the devices listed in the table, unless they are included in the control center time error and frequency devices.

Interpretation:

As noted in the existing interpretation, BAL-005-1 Requirement 17 applies only to the time error and frequency devices that provide, or in the case of back-up equipment may provide, input into the reporting or compliance ACE equation or provide real-time time error or frequency information to the system operator. Frequency inputs from other sources that are for reference only are excluded. The time error and frequency measurement devices may not necessarily be located in the system operations control room or owned by the Balancing Authority; however the Balancing Authority has the responsibility for the accuracy of the frequency and time error measurement devices. No other devices are included in R 17. The other devices listed in the table at the end of R17 are for reference only and do not have any mandatory calibration or accuracy requirements.

New or replacement equipment that provides the same functions noted above requires the same calibrations. Some devices used for time error and frequency measurement cannot be calibrated as such. In this case, these devices should be cross-checked against other properly calibrated equipment and replaced if the devices do not meet the required level of accuracy.

A. Introduction

1. Title: **Inadvertent Interchange**

2. Number: BAL-006-1.1

3. Purpose:

This standard defines a process for monitoring Balancing Authorities to ensure that, over the long term, Balancing Authority Areas do not excessively depend on other Balancing Authority Areas in the Interconnection for meeting their demand or Interchange obligations.

4. Applicability:

4.1. Balancing Authorities.

5. Effective Date: Immediately after approval of applicable regulatory authorities

B. Requirements

R1. Each Balancing Authority shall calculate and record hourly Inadvertent Interchange.

R2. Each Balancing Authority shall include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. The Balancing Authority shall take into account interchange served by jointly owned generators.

R3. Each Balancing Authority shall ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities.

R4. Adjacent Balancing Authority Areas shall operate to a common Net Interchange Schedule and Actual Net Interchange value and shall record these hourly quantities, with like values but opposite sign. Each Balancing Authority shall compute its Inadvertent Interchange based on the following:

R4.1. Each Balancing Authority, by the end of the next business day, shall agree with its Adjacent Balancing Authorities to:

R4.1.1. The hourly values of Net Interchange Schedule.

R4.1.2. The hourly integrated megawatt-hour values of Net Actual Interchange.

R4.2. Each Balancing Authority shall use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month.

R4.3. A Balancing Authority shall make after-the-fact corrections to the agreed-to daily and monthly accounting data only as needed to reflect actual operating conditions (e.g. a meter being used for control was sending bad data). Changes or corrections based on non-reliability considerations shall not be reflected in the Balancing Authority's Inadvertent Interchange. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the Adjacent Balancing Authority(ies).

R5. Adjacent Balancing Authorities that cannot mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month shall, for the purposes of dispute resolution, submit a report to their respective Regional Reliability Organization Survey Contact. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy.

C. Measures

None specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Each Balancing Authority shall submit a monthly summary of Inadvertent Interchange. These summaries shall not include any after-the-fact changes that were not agreed to by the Source Balancing Authority, Sink Balancing Authority and all Intermediate Balancing Authority(ies).

1.2. Inadvertent Interchange summaries shall include at least the previous accumulation, net accumulation for the month, and final net accumulation, for both the On-Peak and Off-Peak periods.

1.3. Each Balancing Authority shall submit its monthly summary report to its Regional Reliability Organization Survey Contact by the 15th calendar day of the following month.

1.4. Each Balancing Authority shall perform an Area Interchange Error (AIE) Survey as requested by the NERC Operating Committee to determine the Balancing Authority's Interchange error(s) due to equipment failures or improper scheduling operations, or improper AGC performance.

1.5. Each Regional Reliability Organization shall prepare a monthly Inadvertent Interchange summary to monitor the Balancing Authorities' monthly Inadvertent Interchange and all-time accumulated Inadvertent Interchange. Each Regional Reliability Organization shall submit a monthly accounting to NERC by the 22nd day following the end of the month being summarized.

2. Levels of Non Compliance

A Balancing Authority that neither submits a report to the Regional Reliability Organization Survey Contact, nor supplies a reason for not submitting the required data, by the 20th calendar day of the following month shall be considered non-compliant.

E. Regional Differences

1. MISO RTO Inadvertent Interchange Accounting Waiver approved by the Operating Committee on March 25, 2004. This regional difference will be extended to include SPP effective May 1, 2006.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	April 6, 2006	Added following to "Effective Date:" and footer This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first.	Errata
1	May 2, 2006	Adopted by Board of Trustees	Revised
1	May 9, 2007	Removed "This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first." From the "Effective Date." and footer	Correction
1.1	October 29,	BOT adopted errata changes; updated	Errata

	2008	version number to 1.1	

A. Introduction

1. **Title:** **Sabotage Reporting**
2. **Number:** CIP-001-1
3. **Purpose:** Disturbances or unusual occurrences, suspected or determined to be caused by sabotage, shall be reported to the appropriate systems, governmental agencies, and regulatory bodies.
4. **Applicability**
   - **4.1.** Reliability Coordinators.
   - **4.2.** Balancing Authorities.
   - **4.3.** Transmission Operators.
   - **4.4.** Generator Operators.
   - **4.5.** Load Serving Entities.
5. **Effective Date:** January 1, 2007

B. Requirements

R1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the recognition of and for making their operating personnel aware of sabotage events on its facilities and multi-site sabotage affecting larger portions of the Interconnection.

R2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the communication of information concerning sabotage events to appropriate parties in the Interconnection.

R3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall provide its operating personnel with sabotage response guidelines, including personnel to contact, for reporting disturbances due to sabotage events.

R4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall establish communications contacts, as applicable, with local Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP) officials and develop reporting procedures as appropriate to their circumstances.

C. Measures

M1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have and provide upon request a procedure (either electronic or hard copy) as defined in Requirement 1

M2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have and provide upon request the procedures or guidelines that will be used to confirm that it meets Requirements 2 and 3.

M3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have and provide upon request evidence that could include, but is not limited to procedures, policies, a letter of understanding, communication records, or other equivalent evidence that will be used to confirm that it has established communications contacts with the applicable, local FBI or RCMP officials to communicate sabotage events (Requirement 4).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to verify compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Reliability Coordinator, Transmission Operator, Generator Operator, Distribution Provider, and Load Serving Entity shall have current, in-force documents available as evidence of compliance as specified in each of the Measures.

If an entity is found non-compliant the entity shall keep information related to the non-compliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. **Levels of Non-Compliance:**

2.1. **Level 1:** There shall be a separate Level 1 non-compliance, for every one of the following requirements that is in violation:

2.1.1 Does not have procedures for the recognition of and for making its operating personnel aware of sabotage events (R1).

2.1.2 Does not have procedures or guidelines for the communication of information concerning sabotage events to appropriate parties in the Interconnection (R2).

2.1.3 Has not established communications contacts, as specified in R4.

2.2. **Level 2:** Not applicable.

2.3. **Level 3:** Has not provided its operating personnel with sabotage response procedures or guidelines (R3).

2.4. **Level 4:**.Not applicable.

E. Regional Differences

None indicated.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Amended

A. Introduction

1. **Title:** Cyber Security — Critical Cyber Asset Identification

2. **Number:** CIP-002-2

3. **Purpose:** NERC Standards CIP-002-2 through CIP-009-2 provide a cyber security framework for the identification and protection of Critical Cyber Assets to support reliable operation of the Bulk Electric System.

   These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the assets needed to manage Bulk Electric System reliability, and the risks to which they are exposed.

   Business and operational demands for managing and maintaining a reliable Bulk Electric System increasingly rely on Cyber Assets supporting critical reliability functions and processes to communicate with each other, across functions and organizations, for services and data. This results in increased risks to these Cyber Assets.

   Standard CIP-002-2 requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment.

4. **Applicability:**

   4.1. Within the text of Standard CIP-002-2, "Responsible Entity" shall mean:

   4.1.1 Reliability Coordinator.

   4.1.2 Balancing Authority.

   4.1.3 Interchange Authority.

   4.1.4 Transmission Service Provider.

   4.1.5 Transmission Owner.

   4.1.6 Transmission Operator.

   4.1.7 Generator Owner.

   4.1.8 Generator Operator.

   4.1.9 Load Serving Entity.

   4.1.10 NERC.

   4.1.11 Regional Entity.

   4.2. The following are exempt from Standard CIP-002-2:

   4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

   4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required)

B. Requirements

R1. Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.

R1.1. The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.

R1.2. The risk-based assessment shall consider the following assets:

R1.2.1. Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.

R1.2.2. Transmission substations that support the reliable operation of the Bulk Electric System.

R1.2.3. Generation resources that support the reliable operation of the Bulk Electric System.

R1.2.4. Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration.

R1.2.5. Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.

R1.2.6. Special Protection Systems that support the reliable operation of the Bulk Electric System.

R1.2.7. Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.

R2. Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.

R3. Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002-2, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:

R3.1. The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,

R3.2. The Cyber Asset uses a routable protocol within a control center; or,

R3.3. The Cyber Asset is dial-up accessible.

R4. Annual Approval — The senior manager or delegate(s) shall approve annually the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of the senior manager or delegate(s)'s approval of the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)

C. Measures

M1. The Responsible Entity shall make available its current risk-based assessment methodology documentation as specified in Requirement R1.

M2. The Responsible Entity shall make available its list of Critical Assets as specified in Requirement R2.

M3. The Responsible Entity shall make available its list of Critical Cyber Assets as specified in Requirement R3.

M4. The Responsible Entity shall make available its approval records of annual approvals as specified in Requirement R4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entity.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep documentation required by Standard CIP-002-2 from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

1.5.1 None.

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
1	01/16/06	R3.2 — Change “Control Center” to “control center”	03/24/06
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
2	05/06/09	Adopted by NERC Board of Trustees	Revised

A. Introduction

1. **Title:** Cyber Security — Security Management Controls

2. **Number:** CIP-003-2

3. **Purpose:** Standard CIP-003-2 requires that Responsible Entities have minimum security management controls in place to protect Critical Cyber Assets. Standard CIP-003-2 should be read as part of a group of standards numbered Standards CIP-002-2 through CIP-009-2.

4. **Applicability:**

   4.1. Within the text of Standard CIP-003-2, "Responsible Entity" shall mean:

   4.1.1 Reliability Coordinator.

   4.1.2 Balancing Authority.

   4.1.3 Interchange Authority.

   4.1.4 Transmission Service Provider.

   4.1.5 Transmission Owner.

   4.1.6 Transmission Operator.

   4.1.7 Generator Owner.

   4.1.8 Generator Operator.

   4.1.9 Load Serving Entity.

   4.1.10 NERC.

   4.1.11 Regional Entity.

   4.2. The following are exempt from Standard CIP-003-2:

   4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

   4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

   4.2.3 Responsible Entities that, in compliance with Standard CIP-002-2, identify that they have no Critical Cyber Assets shall only be required to comply with CIP-003-2 Requirement R2.

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Cyber Security Policy — The Responsible Entity shall document and implement a cyber security policy that represents management's commitment and ability to secure its Critical Cyber Assets. The Responsible Entity shall, at minimum, ensure the following:

R1.1. The cyber security policy addresses the requirements in Standards CIP-002-2 through CIP-009-2, including provision for emergency situations.

R1.2. The cyber security policy is readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets.

R1.3. Annual review and approval of the cyber security policy by the senior manager assigned pursuant to R2.

R2. Leadership — The Responsible Entity shall assign a single senior manager with overall responsibility and authority for leading and managing the entity's implementation of, and adherence to, Standards CIP-002-2 through CIP-009-2.

R2.1. The senior manager shall be identified by name, title, and date of designation.

R2.2. Changes to the senior manager must be documented within thirty calendar days of the effective date.

R2.3. Where allowed by Standards CIP-002-2 through CIP-009-2, the senior manager may delegate authority for specific actions to a named delegate or delegates. These delegations shall be documented in the same manner as R2.1 and R2.2, and approved by the senior manager.

R2.4. The senior manager or delegate(s), shall authorize and document any exception from the requirements of the cyber security policy.

R3. Exceptions — Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and authorized by the senior manager or delegate(s).

R3.1. Exceptions to the Responsible Entity's cyber security policy must be documented within thirty days of being approved by the senior manager or delegate(s).

R3.2. Documented exceptions to the cyber security policy must include an explanation as to why the exception is necessary and any compensating measures.

R3.3. Authorized exceptions to the cyber security policy must be reviewed and approved annually by the senior manager or delegate(s) to ensure the exceptions are still required and valid. Such review and approval shall be documented.

R4. Information Protection — The Responsible Entity shall implement and document a program to identify, classify, and protect information associated with Critical Cyber Assets.

R4.1. The Critical Cyber Asset information to be protected shall include, at a minimum and regardless of media type, operational procedures, lists as required in Standard CIP-002-2, network topology or similar diagrams, floor plans of computing centers that contain Critical Cyber Assets, equipment layouts of Critical Cyber Assets, disaster recovery plans, incident response plans, and security configuration information.

R4.2. The Responsible Entity shall classify information to be protected under this program based on the sensitivity of the Critical Cyber Asset information.

R4.3. The Responsible Entity shall, at least annually, assess adherence to its Critical Cyber Asset information protection program, document the assessment results, and implement an action plan to remediate deficiencies identified during the assessment.

R5. Access Control — The Responsible Entity shall document and implement a program for managing access to protected Critical Cyber Asset information.

R5.1. The Responsible Entity shall maintain a list of designated personnel who are responsible for authorizing logical or physical access to protected information.

R5.1.1. Personnel shall be identified by name, title, and the information for which they are responsible for authorizing access.

R5.1.2. The list of personnel responsible for authorizing access to protected information shall be verified at least annually.

R5.2. The Responsible Entity shall review at least annually the access privileges to protected information to confirm that access privileges are correct and that they correspond with the Responsible Entity's needs and appropriate personnel roles and responsibilities.

R5.3. The Responsible Entity shall assess and document at least annually the processes for controlling access privileges to protected information.

R6. Change Control and Configuration Management — The Responsible Entity shall establish and document a process of change control and configuration management for adding, modifying, replacing, or removing Critical Cyber Asset hardware or software, and implement supporting configuration management activities to identify, control and document all entity or vendor-related changes to hardware and software components of Critical Cyber Assets pursuant to the change control process.

C. Measures

M1. The Responsible Entity shall make available documentation of its cyber security policy as specified in Requirement R1. Additionally, the Responsible Entity shall demonstrate that the cyber security policy is available as specified in Requirement R1.2.

M2. The Responsible Entity shall make available documentation of the assignment of, and changes to, its leadership as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation of the exceptions, as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation of its information protection program as specified in Requirement R4.

M5. The Responsible Entity shall make available its access control documentation as specified in Requirement R5.

M6. The Responsible Entity shall make available its change control and configuration management documentation as specified in Requirement R6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entity.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep all documentation and records from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

1.5.1 None

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Requirement R2 applies to all Responsible Entities, including Responsible Entities which have no Critical Cyber Assets. Modified the personnel identification information requirements in R5.1.1 to include name, title, and the information for which they are responsible for authorizing access (removed the business phone information). Changed compliance monitor to Compliance Enforcement Authority.	
2	05/06/09	Adopted by NERC Board of Trustees	Revised

A. Introduction

1. **Title:** Cyber Security — Personnel & Training

2. **Number:** CIP-004-2

3. **Purpose:** Standard CIP-004-2 requires that personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including contractors and service vendors, have an appropriate level of personnel risk assessment, training, and security awareness. Standard CIP-004-2 should be read as part of a group of standards numbered Standards CIP-002-2 through CIP-009-2.

4. **Applicability:**

   4.1. Within the text of Standard CIP-004-2, "Responsible Entity" shall mean:

   4.1.1 Reliability Coordinator.

   4.1.2 Balancing Authority.

   4.1.3 Interchange Authority.

   4.1.4 Transmission Service Provider.

   4.1.5 Transmission Owner.

   4.1.6 Transmission Operator.

   4.1.7 Generator Owner.

   4.1.8 Generator Operator.

   4.1.9 Load Serving Entity.

   4.1.10 NERC.

   4.1.11 Regional Entity.

   4.2. The following are exempt from Standard CIP-004-2:

   4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

   4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

   4.2.3 Responsible Entities that, in compliance with Standard CIP-002-2, identify that they have no Critical Cyber Assets.

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Awareness — The Responsible Entity shall establish, document, implement, and maintain a security awareness program to ensure personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets receive on-going reinforcement in sound security practices. The program shall include security awareness reinforcement on at least a quarterly basis using mechanisms such as:

- Direct communications (e.g. emails, memos, computer based training, etc.);
- Indirect communications (e.g. posters, intranet, brochures, etc.);

- Management support and reinforcement (e.g., presentations, meetings, etc.).

R2. Training — The Responsible Entity shall establish, document, implement, and maintain an annual cyber security training program for personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets. The cyber security training program shall be reviewed annually, at a minimum, and shall be updated whenever necessary.

R2.1. This program will ensure that all personnel having such access to Critical Cyber Assets, including contractors and service vendors, are trained prior to their being granted such access except in specified circumstances such as an emergency.

R2.2. Training shall cover the policies, access controls, and procedures as developed for the Critical Cyber Assets covered by CIP-004-2, and include, at a minimum, the following required items appropriate to personnel roles and responsibilities:

R2.2.1. The proper use of Critical Cyber Assets;

R2.2.2. Physical and electronic access controls to Critical Cyber Assets;

R2.2.3. The proper handling of Critical Cyber Asset information; and,

R2.2.4. Action plans and procedures to recover or re-establish Critical Cyber Assets and access thereto following a Cyber Security Incident.

R2.3. The Responsible Entity shall maintain documentation that training is conducted at least annually, including the date the training was completed and attendance records.

R3. Personnel Risk Assessment —The Responsible Entity shall have a documented personnel risk assessment program, in accordance with federal, state, provincial, and local laws, and subject to existing collective bargaining unit agreements, for personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets. A personnel risk assessment shall be conducted pursuant to that program prior to such personnel being granted such access except in specified circumstances such as an emergency.

The personnel risk assessment program shall at a minimum include:

R3.1. The Responsible Entity shall ensure that each assessment conducted include, at least, identity verification (e.g., Social Security Number verification in the U.S.) and seven-year criminal check. The Responsible Entity may conduct more detailed reviews, as permitted by law and subject to existing collective bargaining unit agreements, depending upon the criticality of the position.

R3.2. The Responsible Entity shall update each personnel risk assessment at least every seven years after the initial personnel risk assessment or for cause.

R3.3. The Responsible Entity shall document the results of personnel risk assessments of its personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets, and that personnel risk assessments of contractor and service vendor personnel with such access are conducted pursuant to Standard CIP-004-2.

R4. Access — The Responsible Entity shall maintain list(s) of personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including their specific electronic and physical access rights to Critical Cyber Assets.

R4.1. The Responsible Entity shall review the list(s) of its personnel who have such access to Critical Cyber Assets quarterly, and update the list(s) within seven calendar days of any change of personnel with such access to Critical Cyber Assets, or any change in the access rights of such personnel. The Responsible Entity shall ensure access list(s) for contractors and service vendors are properly maintained.

R4.2. The Responsible Entity shall revoke such access to Critical Cyber Assets within 24 hours for personnel terminated for cause and within seven calendar days for personnel who no longer require such access to Critical Cyber Assets.

C. Measures

M1. The Responsible Entity shall make available documentation of its security awareness and reinforcement program as specified in Requirement R1.

M2. The Responsible Entity shall make available documentation of its cyber security training program, review, and records as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation of the personnel risk assessment program and that personnel risk assessments have been applied to all personnel who have authorized cyber or authorized unescorted physical access to Critical Cyber Assets, as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation of the list(s), list review and update, and access revocation as needed as specified in Requirement R4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entity.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not Applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep personnel risk assessment documents in accordance with federal, state, provincial, and local laws.

1.4.2 The Responsible Entity shall keep all other documentation required by Standard CIP-004-2 from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.3 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
1	01/16/06	D.2.2.4 — Insert the phrase "for cause" as intended. "One instance of personnel termination for cause…"	03/24/06
1	06/01/06	D.2.1.4 — Change "access control rights" to "access rights."	06/05/06
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Reference to emergency situations. Modification to R1 for the Responsible Entity to establish, document, implement, and maintain the awareness program. Modification to R2 for the Responsible Entity to establish, document, implement, and maintain the training program; also stating the requirements for the cyber security training program. Modification to R3 Personnel Risk Assessment to clarify that it pertains to personnel having authorized cyber or authorized unescorted physical access to "Critical Cyber Assets". Removal of 90 day window to complete training and 30 day window to complete personnel risk assessments. Changed compliance monitor to Compliance Enforcement Authority.	
2	05/06/09	Adopted by NERC Board of Trustees	Revised

A. Introduction

1. **Title:** Cyber Security — Electronic Security Perimeter(s)

2. **Number:** CIP-005-2

3. **Purpose:** Standard CIP-005-2 requires the identification and protection of the Electronic Security Perimeter(s) inside which all Critical Cyber Assets reside, as well as all access points on the perimeter. Standard CIP-005-2 should be read as part of a group of standards numbered Standards CIP-002-2 through CIP-009-2.

4. **Applicability**

   4.1. Within the text of Standard CIP-005-2, "Responsible Entity" shall mean:

   4.1.1 Reliability Coordinator.

   4.1.2 Balancing Authority.

   4.1.3 Interchange Authority.

   4.1.4 Transmission Service Provider.

   4.1.5 Transmission Owner.

   4.1.6 Transmission Operator.

   4.1.7 Generator Owner.

   4.1.8 Generator Operator.

   4.1.9 Load Serving Entity.

   4.1.10 NERC.

   4.1.11 Regional Entity

   4.2. The following are exempt from Standard CIP-005-2:

   4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

   4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

   4.2.3 Responsible Entities that, in compliance with Standard CIP-002-2, identify that they have no Critical Cyber Assets.

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The Responsible Entity shall identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s).

R1.1. Access points to the Electronic Security Perimeter(s) shall include any externally connected communication end point (for example, dial-up modems) terminating at any device within the Electronic Security Perimeter(s).

R1.2. For a dial-up accessible Critical Cyber Asset that uses a non-routable protocol, the Responsible Entity shall define an Electronic Security Perimeter for that single access point at the dial-up device.

R1.3. Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points of these communication links within the Electronic Security Perimeter(s) shall be considered access points to the Electronic Security Perimeter(s).

R1.4. Any non-critical Cyber Asset within a defined Electronic Security Perimeter shall be identified and protected pursuant to the requirements of Standard CIP-005-2.

R1.5. Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall be afforded the protective measures as a specified in Standard CIP-003-2; Standard CIP-004-2 Requirement R3; Standard CIP-005-2 Requirements R2 and R3; Standard CIP-006-2 Requirement R3; Standard CIP-007-2 Requirements R1 and R3 through R9; Standard CIP-008-2; and Standard CIP-009-2.

R1.6. The Responsible Entity shall maintain documentation of Electronic Security Perimeter(s), all interconnected Critical and non-critical Cyber Assets within the Electronic Security Perimeter(s), all electronic access points to the Electronic Security Perimeter(s) and the Cyber Assets deployed for the access control and monitoring of these access points.

R2. Electronic Access Controls — The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for control of electronic access at all electronic access points to the Electronic Security Perimeter(s).

R2.1. These processes and mechanisms shall use an access control model that denies access by default, such that explicit access permissions must be specified.

R2.2. At all access points to the Electronic Security Perimeter(s), the Responsible Entity shall enable only ports and services required for operations and for monitoring Cyber Assets within the Electronic Security Perimeter, and shall document, individually or by specified grouping, the configuration of those ports and services.

R2.3. The Responsible Entity shall implement and maintain a procedure for securing dial-up access to the Electronic Security Perimeter(s).

R2.4. Where external interactive access into the Electronic Security Perimeter has been enabled, the Responsible Entity shall implement strong procedural or technical controls at the access points to ensure authenticity of the accessing party, where technically feasible.

R2.5. The required documentation shall, at least, identify and describe:

R2.5.1. The processes for access request and authorization.

R2.5.2. The authentication methods.

R2.5.3. The review process for authorization rights, in accordance with Standard CIP-004-2 Requirement R4.

R2.5.4. The controls used to secure dial-up accessible connections.

R2.6. Appropriate Use Banner — Where technically feasible, electronic access control devices shall display an appropriate use banner on the user screen upon all interactive access attempts. The Responsible Entity shall maintain a document identifying the content of the banner.

R3. Monitoring Electronic Access — The Responsible Entity shall implement and document an electronic or manual process(es) for monitoring and logging access at access points to the Electronic Security Perimeter(s) twenty-four hours a day, seven days a week.

R3.1. For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall implement and document monitoring process(es) at each access point to the dial-up device, where technically feasible.

R3.2. Where technically feasible, the security monitoring process(es) shall detect and alert for attempts at or actual unauthorized accesses. These alerts shall provide for appropriate notification to designated response personnel. Where alerting is not technically feasible, the Responsible Entity shall review or otherwise assess access logs for attempts at or actual unauthorized accesses at least every ninety calendar days.

R4. Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of the electronic access points to the Electronic Security Perimeter(s) at least annually. The vulnerability assessment shall include, at a minimum, the following:

R4.1. A document identifying the vulnerability assessment process;

R4.2. A review to verify that only ports and services required for operations at these access points are enabled;

R4.3. The discovery of all access points to the Electronic Security Perimeter;

R4.4. A review of controls for default accounts, passwords, and network management community strings;

R4.5. Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.

R5. Documentation Review and Maintenance — The Responsible Entity shall review, update, and maintain all documentation to support compliance with the requirements of Standard CIP-005-2.

R5.1. The Responsible Entity shall ensure that all documentation required by Standard CIP-005-2 reflect current configurations and processes and shall review the documents and procedures referenced in Standard CIP-005-2 at least annually.

R5.2. The Responsible Entity shall update the documentation to reflect the modification of the network or controls within ninety calendar days of the change.

R5.3. The Responsible Entity shall retain electronic access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008-2.

C. Measures

M1. The Responsible Entity shall make available documentation about the Electronic Security Perimeter as specified in Requirement R1.

M2. The Responsible Entity shall make available documentation of the electronic access controls to the Electronic Security Perimeter(s), as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation of controls implemented to log and monitor access to the Electronic Security Perimeter(s) as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation of its annual vulnerability assessment as specified in Requirement R4.

M5. The Responsible Entity shall make available access logs and documentation of review, changes, and log retention as specified in Requirement R5.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. **Compliance Enforcement Authority**

   1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

   1.1.2 ERO for Regional Entity.

   1.1.3 Third-party monitor without vested interest in the outcome for NERC.

   1.2. **Compliance Monitoring Period and Reset Time Frame**

   Not applicable.

   1.3. **Compliance Monitoring and Enforcement Processes**

   Compliance Audits

   Self-Certifications

   Spot Checking

   Compliance Violation Investigations

   Self-Reporting

   Complaints

   1.4. **Data Retention**

   1.4.1 The Responsible Entity shall keep logs for a minimum of ninety calendar days, unless: a) longer retention is required pursuant to Standard CIP-008-2, Requirement R2; b) directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

   1.4.2 The Responsible Entity shall keep other documents and records required by Standard CIP-005-2 from the previous full calendar year.

   1.4.3 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

   1.5. **Additional Compliance Information**

2. **Violation Severity Levels (To be developed later.)**

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
1	01/16/06	D.2.3.1 — Change “Critical Assets,” to “Critical Cyber Assets” as intended.	03/24/06
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment.	

		Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Revised the wording of the Electronic Access Controls requirement stated in R2.3 to clarify that the Responsible Entity shall "implement and maintain" a procedure for securing dial-up access to the Electronic Security Perimeter(s). Changed compliance monitor to Compliance Enforcement Authority.	
2	05/06/09	Adopted by NERC Board of Trustees	Revised

A. Introduction

1. **Title:** Cyber Security — Physical Security of Critical Cyber Assets

2. **Number:** CIP-006-2

3. **Purpose:** Standard CIP-006-2 is intended to ensure the implementation of a physical security program for the protection of Critical Cyber Assets. Standard CIP-006-2 should be read as part of a group of standards numbered Standards CIP-002-2 through CIP-009-2.

4. **Applicability:**

   4.1. Within the text of Standard CIP-006-2, "Responsible Entity" shall mean:

   4.1.1 Reliability Coordinator.

   4.1.2 Balancing Authority.

   4.1.3 Interchange Authority.

   4.1.4 Transmission Service Provider.

   4.1.5 Transmission Owner.

   4.1.6 Transmission Operator.

   4.1.7 Generator Owner.

   4.1.8 Generator Operator.

   4.1.9 Load Serving Entity.

   4.1.10 NERC.

   4.1.11 Regional Entity.

   4.2. The following are exempt from Standard CIP-006-2:

   4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

   4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

   4.2.3 Responsible Entities that, in compliance with Standard CIP-002-2, identify that they have no Critical Cyber Assets.

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Physical Security Plan — The Responsible Entity shall document, implement, and maintain a physical security plan, approved by the senior manager or delegate(s) that shall address, at a minimum, the following:

R1.1. All Cyber Assets within an Electronic Security Perimeter shall reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to such Cyber Assets.

R1.2. Identification of all physical access points through each Physical Security Perimeter and measures to control entry at those access points.

R1.3. Processes, tools, and procedures to monitor physical access to the perimeter(s).

R1.4. Appropriate use of physical access controls as described in Requirement R4 including visitor pass management, response to loss, and prohibition of inappropriate use of physical access controls.

R1.5. Review of access authorization requests and revocation of access authorization, in accordance with CIP-004-2 Requirement R4.

R1.6. Continuous escorted access within the Physical Security Perimeter of personnel not authorized for unescorted access.

R1.7. Update of the physical security plan within thirty calendar days of the completion of any physical security system redesign or reconfiguration, including, but not limited to, addition or removal of access points through the Physical Security Perimeter, physical access controls, monitoring controls, or logging controls.

R1.8. Annual review of the physical security plan.

R2. Protection of Physical Access Control Systems — Cyber Assets that authorize and/or log access to the Physical Security Perimeter(s), exclusive of hardware at the Physical Security Perimeter access point such as electronic lock control mechanisms and badge readers, shall:

R2.1. Be protected from unauthorized physical access.

R2.2. Be afforded the protective measures specified in Standard CIP-003-2; Standard CIP-004-2 Requirement R3; Standard CIP-005-2 Requirements R2 and R3; Standard CIP-006-2 Requirements R4 and R5; Standard CIP-007-2; Standard CIP-008-2; and Standard CIP-009-2.

R3. Protection of Electronic Access Control Systems — Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall reside within an identified Physical Security Perimeter.

R4. Physical Access Controls — The Responsible Entity shall document and implement the operational and procedural controls to manage physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. The Responsible Entity shall implement one or more of the following physical access methods:

- Card Key: A means of electronic access where the access rights of the card holder are predefined in a computer database. Access rights may differ from one perimeter to another.
- Special Locks: These include, but are not limited to, locks with “restricted key” systems, magnetic locks that can be operated remotely, and “man-trap” systems.
- Security Personnel: Personnel responsible for controlling physical access who may reside on-site or at a monitoring station.
- Other Authentication Devices: Biometric, keypad, token, or other equivalent devices that control physical access to the Critical Cyber Assets.

R5. Monitoring Physical Access — The Responsible Entity shall document and implement the technical and procedural controls for monitoring physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. Unauthorized access attempts shall be reviewed immediately and handled in accordance with the procedures specified in Requirement CIP-008-2. One or more of the following monitoring methods shall be used:

- Alarm Systems: Systems that alarm to indicate a door, gate or window has been opened without authorization. These alarms must provide for immediate notification to personnel responsible for response.
- Human Observation of Access Points: Monitoring of physical access points by authorized personnel as specified in Requirement R4.

R6. Logging Physical Access — Logging shall record sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week. The Responsible Entity shall implement and document the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent:

- Computerized Logging: Electronic logs produced by the Responsible Entity's selected access control and monitoring method.
- Video Recording: Electronic capture of video images of sufficient quality to determine identity.
- Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access as specified in Requirement R4.

R7. Access Log Retention — The responsible entity shall retain physical access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008-2.

R8. Maintenance and Testing — The Responsible Entity shall implement a maintenance and testing program to ensure that all physical security systems under Requirements R4, R5, and R6 function properly. The program must include, at a minimum, the following:

R8.1. Testing and maintenance of all physical security mechanisms on a cycle no longer than three years.

R8.2. Retention of testing and maintenance records for the cycle determined by the Responsible Entity in Requirement R8.1.

R8.3. Retention of outage records regarding access controls, logging, and monitoring for a minimum of one calendar year.

C. Measures

M1. The Responsible Entity shall make available the physical security plan as specified in Requirement R1 and documentation of the implementation, review and updating of the plan.

M2. The Responsible Entity shall make available documentation that the physical access control systems are protected as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation that the electronic access control systems are located within an identified Physical Security Perimeter as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation identifying the methods for controlling physical access to each access point of a Physical Security Perimeter as specified in Requirement R4.

M5. The Responsible Entity shall make available documentation identifying the methods for monitoring physical access as specified in Requirement R5.

M6. The Responsible Entity shall make available documentation identifying the methods for logging physical access as specified in Requirement R6.

M7. The Responsible Entity shall make available documentation to show retention of access logs as specified in Requirement R7.

M8. The Responsible Entity shall make available documentation to show its implementation of a physical security system maintenance and testing program as specified in Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entities.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep documents other than those specified in Requirements R7 and R8.2 from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

1.5.1 The Responsible Entity may not make exceptions in its cyber security policy to the creation, documentation, or maintenance of a physical security plan.

1.5.2 For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall not be required to comply with Standard CIP-006-2 for that single access point at the dial-up device.

2. Violation Severity Levels (Under development by the CIP VSL Drafting Team)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
2		Modifications to remove extraneous information from the requirements, improve readability, and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Replaced the RRO with RE as a responsible entity. Modified CIP-006-1 Requirement R1 to clarify that a physical security plan to protect Critical Cyber Assets must be documented, maintained, implemented and approved by the senior manager. Revised the wording in R1.2 to identify all "physical" access points. Added Requirement R2 to CIP-006-2 to clarify the requirement to safeguard the Physical Access Control Systems and exclude hardware at the Physical Security Perimeter access point, such as electronic lock control mechanisms and badge readers from the requirement. Requirement R2.1 requires the Responsible Entity to protect the Physical Access Control Systems from unauthorized access. CIP-006-1 Requirement R1.8 was moved to become CIP-006-2 Requirement R2.2. Added Requirement R3 to CIP-006-2, clarifying the requirement for Electronic Access Control Systems to be safeguarded within an identified Physical Security Perimeter. The sub requirements of CIP-006-2 Requirements R4, R5, and R6 were changed from formal requirements to bulleted lists of options consistent with the intent of the requirements. Changed the Compliance Monitor to Compliance Enforcement Authority.	
2	05/06/09	Adopted by NERC Board of Trustees	Revised

A. Introduction

1. Title: Cyber Security — Systems Security Management

2. Number: CIP-007-2a

3. Purpose: Standard CIP-007-2 requires Responsible Entities to define methods, processes, and procedures for securing those systems determined to be Critical Cyber Assets, as well as the other (non-critical) Cyber Assets within the Electronic Security Perimeter(s). Standard CIP-007-2 should be read as part of a group of standards numbered Standards CIP-002-2 through CIP-009-2.

4. Applicability:

4.1. Within the text of Standard CIP-007-2, "Responsible Entity" shall mean:

4.1.1 Reliability Coordinator.

4.1.2 Balancing Authority.

4.1.3 Interchange Authority.

4.1.4 Transmission Service Provider.

4.1.5 Transmission Owner.

4.1.6 Transmission Operator.

4.1.7 Generator Owner.

4.1.8 Generator Operator.

4.1.9 Load Serving Entity.

4.1.10 NERC.

4.1.11 Regional Entity.

4.2. The following are exempt from Standard CIP-007-2:

4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3 Responsible Entities that, in compliance with Standard CIP-002-2, identify that they have no Critical Cyber Assets.

5. Effective Date: April 1, 2010

B. Requirements

R1. Test Procedures — The Responsible Entity shall ensure that new Cyber Assets and significant changes to existing Cyber Assets within the Electronic Security Perimeter do not adversely affect existing cyber security controls. For purposes of Standard CIP-007-2, a significant change shall, at a minimum, include implementation of security patches, cumulative service packs, vendor releases, and version upgrades of operating systems, applications, database platforms, or other third-party software or firmware.

R1.1. The Responsible Entity shall create, implement, and maintain cyber security test procedures in a manner that minimizes adverse effects on the production system or its operation.

R1.2. The Responsible Entity shall document that testing is performed in a manner that reflects the production environment.

R1.3. The Responsible Entity shall document test results.

R2. Ports and Services — The Responsible Entity shall establish, document and implement a process to ensure that only those ports and services required for normal and emergency operations are enabled.

R2.1. The Responsible Entity shall enable only those ports and services required for normal and emergency operations.

R2.2. The Responsible Entity shall disable other ports and services, including those used for testing purposes, prior to production use of all Cyber Assets inside the Electronic Security Perimeter(s).

R2.3. In the case where unused ports and services cannot be disabled due to technical limitations, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.

R3. Security Patch Management — The Responsible Entity, either separately or as a component of the documented configuration management process specified in CIP-003-2 Requirement R6, shall establish, document and implement a security patch management program for tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).

R3.1. The Responsible Entity shall document the assessment of security patches and security upgrades for applicability within thirty calendar days of availability of the patches or upgrades.

R3.2. The Responsible Entity shall document the implementation of security patches. In any case where the patch is not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.

R4. Malicious Software Prevention — The Responsible Entity shall use anti-virus software and other malicious software ("malware") prevention tools, where technically feasible, to detect, prevent, deter, and mitigate the introduction, exposure, and propagation of malware on all Cyber Assets within the Electronic Security Perimeter(s).

R4.1. The Responsible Entity shall document and implement anti-virus and malware prevention tools. In the case where anti-virus software and malware prevention tools are not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.

R4.2. The Responsible Entity shall document and implement a process for the update of anti-virus and malware prevention "signatures." The process must address testing and installing the signatures.

R5. Account Management — The Responsible Entity shall establish, implement, and document technical and procedural controls that enforce access authentication of, and accountability for, all user activity, and that minimize the risk of unauthorized system access.

R5.1. The Responsible Entity shall ensure that individual and shared system accounts and authorized access permissions are consistent with the concept of "need to know" with respect to work functions performed.

R5.1.1. The Responsible Entity shall ensure that user accounts are implemented as approved by designated personnel. Refer to Standard CIP-003-2 Requirement R5.

R5.1.2. The Responsible Entity shall establish methods, processes, and procedures that generate logs of sufficient detail to create historical audit trails of individual user account access activity for a minimum of ninety days.

R5.1.3. The Responsible Entity shall review, at least annually, user accounts to verify access privileges are in accordance with Standard CIP-003-2 Requirement R5 and Standard CIP-004-2 Requirement R4.

R5.2. The Responsible Entity shall implement a policy to minimize and manage the scope and acceptable use of administrator, shared, and other generic account privileges including factory default accounts.

R5.2.1. The policy shall include the removal, disabling, or renaming of such accounts where possible. For such accounts that must remain enabled, passwords shall be changed prior to putting any system into service.

R5.2.2. The Responsible Entity shall identify those individuals with access to shared accounts.

R5.2.3. Where such accounts must be shared, the Responsible Entity shall have a policy for managing the use of such accounts that limits access to only those with authorization, an audit trail of the account use (automated or manual), and steps for securing the account in the event of personnel changes (for example, change in assignment or termination).

R5.3. At a minimum, the Responsible Entity shall require and use passwords, subject to the following, as technically feasible:

R5.3.1. Each password shall be a minimum of six characters.

R5.3.2. Each password shall consist of a combination of alpha, numeric, and "special" characters.

R5.3.3. Each password shall be changed at least annually, or more frequently based on risk.

R6. Security Status Monitoring — The Responsible Entity shall ensure that all Cyber Assets within the Electronic Security Perimeter, as technically feasible, implement automated tools or organizational process controls to monitor system events that are related to cyber security.

R6.1. The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for monitoring for security events on all Cyber Assets within the Electronic Security Perimeter.

R6.2. The security monitoring controls shall issue automated or manual alerts for detected Cyber Security Incidents.

R6.3. The Responsible Entity shall maintain logs of system events related to cyber security, where technically feasible, to support incident response as required in Standard CIP-008-2.

R6.4. The Responsible Entity shall retain all logs specified in Requirement R6 for ninety calendar days.

R6.5. The Responsible Entity shall review logs of system events related to cyber security and maintain records documenting review of logs.

R7. Disposal or Redeployment — The Responsible Entity shall establish and implement formal methods, processes, and procedures for disposal or redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005-2.

R7.1. Prior to the disposal of such assets, the Responsible Entity shall destroy or erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.

R7.2. Prior to redeployment of such assets, the Responsible Entity shall, at a minimum, erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.

R7.3. The Responsible Entity shall maintain records that such assets were disposed of or redeployed in accordance with documented procedures.

R8. Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of all Cyber Assets within the Electronic Security Perimeter at least annually. The vulnerability assessment shall include, at a minimum, the following:

R8.1. A document identifying the vulnerability assessment process;

R8.2. A review to verify that only ports and services required for operation of the Cyber Assets within the Electronic Security Perimeter are enabled;

R8.3. A review of controls for default accounts; and,

R8.4. Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.

R9. Documentation Review and Maintenance — The Responsible Entity shall review and update the documentation specified in Standard CIP-007-2 at least annually. Changes resulting from modifications to the systems or controls shall be documented within thirty calendar days of the change being completed.

C. Measures

M1. The Responsible Entity shall make available documentation of its security test procedures as specified in Requirement R1.

M2. The Responsible Entity shall make available documentation as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation and records of its security patch management program, as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation and records of its malicious software prevention program as specified in Requirement R4.

M5. The Responsible Entity shall make available documentation and records of its account management program as specified in Requirement R5.

M6. The Responsible Entity shall make available documentation and records of its security status monitoring program as specified in Requirement R6.

M7. The Responsible Entity shall make available documentation and records of its program for the disposal or redeployment of Cyber Assets as specified in Requirement R7.

M8. The Responsible Entity shall make available documentation and records of its annual vulnerability assessment of all Cyber Assets within the Electronic Security Perimeters(s) as specified in Requirement R8.

M9. The Responsible Entity shall make available documentation and records demonstrating the review and update as specified in Requirement R9.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entity.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep all documentation and records from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Responsible Entity shall retain security–related system event logs for ninety calendar days, unless longer retention is required pursuant to Standard CIP-008-2 Requirement R2.

1.4.3 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information.

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment and acceptance of risk. Revised the Purpose of this standard to clarify that Standard CIP-007-2 requires Responsible Entities to define methods,	

		processes, and procedures for securing Cyber Assets and other (non-Critical) Assets within an Electronic Security Perimeter. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. R9 changed ninety (90) days to thirty (30) days Changed compliance monitor to Compliance Enforcement Authority.	
2	05/06/09	Adopted by NERC Board of Trustees	Revised
2a	11/05/09	Added Appendix 2 — Interpretation of R2 approved by BOT on November 5, 2009	Interpretation
2a	03/18/10	Interpretation of CIP-007-1 Requirement R2 — FERC Approved, per footnote 11 of Order — to be appended to CIP-007-2, Effective Date April 1, 2010	Interpretation

Appendix 1

Requirement Number and Text of Requirement
R2. The Responsible Entity shall establish and document a process to ensure that only those ports and services required for normal and emergency operations are enabled.
Question
Does the term "port" mean a physical (hardware) or a logical (software) connection to a computer?
Response
The drafting team interprets the term “ports” used as part of the phrase “ports and services” to refer to logical ports, e.g., Transmission Control Protocol (TCP) ports, where interface with communication services occurs.

A. Introduction

1. **Title:** Cyber Security — Incident Reporting and Response Planning

2. **Number:** CIP-008-2

3. **Purpose:** Standard CIP-008-2 ensures the identification, classification, response, and reporting of Cyber Security Incidents related to Critical Cyber Assets. Standard CIP-008-2 should be read as part of a group of standards numbered Standards CIP-002-2 through CIP-009-2.

4. **Applicability**

   4.1. Within the text of Standard CIP-008-2, "Responsible Entity" shall mean:

   4.1.1 Reliability Coordinator.

   4.1.2 Balancing Authority.

   4.1.3 Interchange Authority.

   4.1.4 Transmission Service Provider.

   4.1.5 Transmission Owner.

   4.1.6 Transmission Operator.

   4.1.7 Generator Owner.

   4.1.8 Generator Operator.

   4.1.9 Load Serving Entity.

   4.1.10 NERC.

   4.1.11 Regional Entity.

   4.2. The following are exempt from Standard CIP-008-2:

   4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

   4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

   4.2.3 Responsible Entities that, in compliance with Standard CIP-002-2, identify that they have no Critical Cyber Assets.

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Cyber Security Incident Response Plan — The Responsible Entity shall develop and maintain a Cyber Security Incident response plan and implement the plan in response to Cyber Security Incidents. The Cyber Security Incident response plan shall address, at a minimum, the following:

R1.1. Procedures to characterize and classify events as reportable Cyber Security Incidents.

R1.2. Response actions, including roles and responsibilities of Cyber Security Incident response teams, Cyber Security Incident handling procedures, and communication plans.

R1.3. Process for reporting Cyber Security Incidents to the Electricity Sector Information Sharing and Analysis Center (ES-ISAC). The Responsible Entity must ensure that all reportable Cyber Security Incidents are reported to the ES-ISAC either directly or through an intermediary.

R1.4. Process for updating the Cyber Security Incident response plan within thirty calendar days of any changes.

R1.5. Process for ensuring that the Cyber Security Incident response plan is reviewed at least annually.

R1.6. Process for ensuring the Cyber Security Incident response plan is tested at least annually. A test of the Cyber Security Incident response plan can range from a paper drill, to a full operational exercise, to the response to an actual incident. Testing the Cyber Security Incident response plan does not require removing a component or system from service during the test.

R2. Cyber Security Incident Documentation — The Responsible Entity shall keep relevant documentation related to Cyber Security Incidents reportable per Requirement R1.1 for three calendar years.

C. Measures

M1. The Responsible Entity shall make available its Cyber Security Incident response plan as indicated in Requirement R1 and documentation of the review, updating, and testing of the plan.

M2. The Responsible Entity shall make available all documentation as specified in Requirement R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entity.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep documentation other than that required for reportable Cyber Security Incidents as specified in Standard CIP-008-2 for the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

1.5.1 The Responsible Entity may not take exception in its cyber security policies to the creation of a Cyber Security Incident response plan.

1.5.2 The Responsible Entity may not take exception in its cyber security policies to reporting Cyber Security Incidents to the ES ISAC.

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
2	05/06/09	Adopted by NERC Board of Trustees	Revised

A. Introduction

1. **Title:** Cyber Security — Recovery Plans for Critical Cyber Assets

2. **Number:** CIP-009-2

3. **Purpose:** Standard CIP-009-2 ensures that recovery plan(s) are put in place for Critical Cyber Assets and that these plans follow established business continuity and disaster recovery techniques and practices. Standard CIP-009-2 should be read as part of a group of standards numbered Standards CIP-002-2 through CIP-009-2.

4. **Applicability:**

   4.1. Within the text of Standard CIP-009-2, "Responsible Entity" shall mean:

   4.1.1 Reliability Coordinator

   4.1.2 Balancing Authority

   4.1.3 Interchange Authority

   4.1.4 Transmission Service Provider

   4.1.5 Transmission Owner

   4.1.6 Transmission Operator

   4.1.7 Generator Owner

   4.1.8 Generator Operator

   4.1.9 Load Serving Entity

   4.1.10 NERC

   4.1.11 Regional Entity

   4.2. The following are exempt from Standard CIP-009-2:

   4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

   4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

   4.2.3 Responsible Entities that, in compliance with Standard CIP-002-2, identify that they have no Critical Cyber Assets.

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Recovery Plans — The Responsible Entity shall create and annually review recovery plan(s) for Critical Cyber Assets. The recovery plan(s) shall address at a minimum the following:

R1.1. Specify the required actions in response to events or conditions of varying duration and severity that would activate the recovery plan(s).

R1.2. Define the roles and responsibilities of responders.

R2. Exercises — The recovery plan(s) shall be exercised at least annually. An exercise of the recovery plan(s) can range from a paper drill, to a full operational exercise, to recovery from an actual incident.

R3. Change Control — Recovery plan(s) shall be updated to reflect any changes or lessons learned as a result of an exercise or the recovery from an actual incident. Updates shall be communicated to personnel responsible for the activation and implementation of the recovery plan(s) within thirty calendar days of the change being completed.

R4. Backup and Restore — The recovery plan(s) shall include processes and procedures for the backup and storage of information required to successfully restore Critical Cyber Assets. For example, backups may include spare electronic components or equipment, written documentation of configuration settings, tape backup, etc.

R5. Testing Backup Media — Information essential to recovery that is stored on backup media shall be tested at least annually to ensure that the information is available. Testing can be completed off site.

C. Measures

M1. The Responsible Entity shall make available its recovery plan(s) as specified in Requirement R1.

M2. The Responsible Entity shall make available its records documenting required exercises as specified in Requirement R2.

M3. The Responsible Entity shall make available its documentation of changes to the recovery plan(s), and documentation of all communications, as specified in Requirement R3.

M4. The Responsible Entity shall make available its documentation regarding backup and storage of information as specified in Requirement R4.

M5. The Responsible Entity shall make available its documentation of testing of backup media as specified in Requirement R5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entities.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep documentation required by Standard CIP-009-2 from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Communication of revisions to the recovery plan changed from 90 days to 30 days. Changed compliance monitor to Compliance Enforcement Authority.	
2	05/06/09	Adopted by NERC Board of Trustees	Revised

A. Introduction

1. **Title:** **Telecommunications**
2. **Number:** COM-001-1.1
3. **Purpose:** Each Reliability Coordinator, Transmission Operator and Balancing Authority needs adequate and reliable telecommunications facilities internally and with others for the exchange of Interconnection and operating information necessary to maintain reliability.
4. **Applicability**
   - **4.1.** Transmission Operators.
   - **4.2.** Balancing Authorities.
   - **4.3.** Reliability Coordinators.
   - **4.4.** NERCNet User Organizations.
5. **Effective Date:** May 13, 2009

B. Requirements

R1. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall provide adequate and reliable telecommunications facilities for the exchange of Interconnection and operating information:

- **R1.1.** Internally.
- **R1.2.** Between the Reliability Coordinator and its Transmission Operators and Balancing Authorities.
- **R1.3.** With other Reliability Coordinators, Transmission Operators, and Balancing Authorities as necessary to maintain reliability.
- **R1.4.** Where applicable, these facilities shall be redundant and diversely routed.

R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall manage, alarm, test and/or actively monitor vital telecommunications facilities. Special attention shall be given to emergency telecommunications facilities and equipment not used for routine communications.

R3. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall provide a means to coordinate telecommunications among their respective areas. This coordination shall include the ability to investigate and recommend solutions to telecommunications problems within the area and with other areas.

R4. Unless agreed to otherwise, each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use English as the language for all communications between and among operating personnel responsible for the real-time generation control and operation of the interconnected Bulk Electric System. Transmission Operators and Balancing Authorities may use an alternate language for internal operations.

R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have written operating instructions and procedures to enable continued operation of the system during the loss of telecommunications facilities.

R6. Each NERCNet User Organization shall adhere to the requirements in Attachment 1-COM-001, "NERCNet Security Policy."

C. Measures

M1. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include, but is not limited to communication facility test-procedure documents, records of testing, and maintenance records for communication facilities or equivalent that will be used to confirm that it manages, alarms, tests and/or actively monitors vital telecommunications facilities. (Requirement 2 part 1)

M2. The Reliability Coordinator, Transmission Operator or Balancing Authority shall have and provide upon request evidence that could include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent, that will be used to determine compliance to Requirement 4.

M3. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request its current operating instructions and procedures, either electronic or hard copy that will be used to confirm that it meets Requirement 5.

M4. The NERCnet User Organization shall have and provide upon request evidence that could include, but is not limited to documented procedures, operator logs, voice recordings or transcripts of voice recordings, electronic communications, etc that will be used to determine if it adhered to the (User Accountability and Compliance) requirements in Attachment 1-COM-001. (Requirement 6)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

NERC shall be responsible for compliance monitoring of the Regional Reliability Organizations

Regional Reliability Organizations shall be responsible for compliance monitoring of all other entities

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)

- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 calendar days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

For Measure 1 each Reliability Coordinator, Transmission Operator, Balancing Authority shall keep evidence of compliance for the previous two calendar years plus the current year.

For Measure 2 each Reliability Coordinator, Transmission Operator, and Balancing Authority shall keep 90 days of historical data (evidence).

For Measure 3, each Reliability Coordinator, Transmission Operator, Balancing Authority shall have its current operating instructions and procedures to confirm that it meets Requirement 5.

For Measure 4, each Reliability Coordinator, Transmission Operator, Balancing Authority and NERCnet User Organization shall keep 90 days of historical data (evidence).

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor.

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

Attachment 1-COM-001— NERCnet Security Policy

2. Levels of Non-Compliance for Transmission Operator, Balancing Authority or Reliability Coordinator

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: There shall be a separate Level 3 non-compliance, for every one of the following requirements that is in violation:

2.3.1 The Transmission Operator, Balancing Authority or Reliability Coordinator used a language other then English without agreement as specified in R4.

2.3.2 There are no written operating instructions and procedures to enable continued operation of the system during the loss of telecommunication facilities as specified in R5.

2.4. Level 4: Telecommunication systems are not actively monitored, tested, managed or alarmed as specified in R2.

3. Levels of Non-Compliance — NERCnet User Organization

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

3.4. Level 4: Did not adhere to the requirements in Attachment 1-COM-001, NERCnet Security Policy.

E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	April 6, 2007	Requirement 1, added the word "for" between "facilities" and "the exchange."	Errata
1.1	October 29, 2008	BOT adopted errata changes; updated version number to "1.1"	Errata

Attachment 1-COM-001— NERCnet Security Policy

Policy Statement

The purpose of this NERCnet Security Policy is to establish responsibilities and minimum requirements for the protection of information assets, computer systems and facilities of NERC and other users of the NERC frame relay network known as "NERCnet." The goal of this policy is to prevent misuse and loss of assets.

For the purpose of this document, information assets shall be defined as processed or unprocessed data using the NERCnet Telecommunications Facilities including network documentation. This policy shall also apply as appropriate to employees and agents of other corporations or organizations that may be directly or indirectly granted access to information associated with NERCnet.

The objectives of the NERCnet Security Policy are:

- To ensure that NERCnet information assets are adequately protected on a cost-effective basis and to a level that allows NERC to fulfill its mission.
- To establish connectivity guidelines for a minimum level of security for the network.
- To provide a mandate to all Users of NERCnet to properly handle and protect the information that they have access to in order for NERC to be able to properly conduct its business and provide services to its customers.

NERC's Security Mission Statement

NERC recognizes its dependency on data, information, and the computer systems used to facilitate effective operation of its business and fulfillment of its mission. NERC also recognizes the value of the information maintained and provided to its members and others authorized to have access to NERCnet. It is, therefore, essential that this data, information, and computer systems, and the manual and technical infrastructure that supports it, are secure from destruction, corruption, unauthorized access, and accidental or deliberate breach of confidentiality.

Implementation and Responsibilities

This section identifies the various roles and responsibilities related to the protection of NERCnet resources.

NERCnet User Organizations

Users of NERCnet who have received authorization from NERC to access the NERC network are considered users of NERCnet resources. To be granted access, users shall complete a User Application Form and submit this form to the NERC Telecommunications Manager.

Responsibilities

It is the responsibility of NERCnet User Organizations to:

- Use NERCnet facilities for NERC-authorized business purposes only.
- Comply with the NERCnet security policies, standards, and guidelines, as well as any procedures specified by the data owner.

- Prevent unauthorized disclosure of the data.
- Report security exposures, misuse, or non-compliance situations via Reliability Coordinator Information System or the NERC Telecommunications Manager.
- Protect the confidentiality of all user IDs and passwords.
- Maintain the data they own.
- Maintain documentation identifying the users who are granted access to NERCnet data or applications.
- Authorize users within their organizations to access NERCnet data and applications.
- Advise staff on NERCnet Security Policy.
- Ensure that all NERCnet users understand their obligation to protect these assets.
- Conduct self-assessments for compliance.

User Accountability and Compliance

All users of NERCnet shall be familiar and ensure compliance with the policies in this document.

Violations of the NERCnet Security Policy shall include, but not be limited to any act that:

- Exposes NERC or any user of NERCnet to actual or potential monetary loss through the compromise of data security or damage.
- Involves the disclosure of trade secrets, intellectual property, confidential information or the unauthorized use of data.

  Involves the use of data for illicit purposes, which may include violation of any law, regulation or reporting requirement of any law enforcement or government body.

A. Introduction

1. **Title:** **Communication and Coordination**
2. **Number:** COM-002-2
3. **Purpose:** To ensure Balancing Authorities, Transmission Operators, and Generator Operators have adequate communications and that these communications capabilities are staffed and available for addressing a real-time emergency condition. To ensure communications by operating personnel are effective.
4. **Applicability**
   - **4.1.** Reliability Coordinators.
   - **4.2.** Balancing Authorities.
   - **4.3.** Transmission Operators.
   - **4.4.** Generator Operators.
5. **Effective Date:** January 1, 2007

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall have communications (voice and data links) with appropriate Reliability Coordinators, Balancing Authorities, and Transmission Operators. Such communications shall be staffed and available for addressing a real-time emergency condition.

R1.1. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator, and all other potentially affected Balancing Authorities and Transmission Operators through predetermined communication paths of any condition that could threaten the reliability of its area or when firm load shedding is anticipated.

R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall issue directives in a clear, concise, and definitive manner; shall ensure the recipient of the directive repeats the information back correctly; and shall acknowledge the response as correct or repeat the original statement to resolve any misunderstandings.

C. Measures

M1. Each Transmission Operator, Balancing Authority and Generator Operator shall have communication facilities (voice and data links) with appropriate Reliability Coordinators, Balancing Authorities, and Transmission Operators and shall have and provide as evidence, a list of communication facilities or other equivalent evidence that confirms that the communications have been provided to address a real-time emergency condition. (Requirement 1, part 1)

M2. The Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it notified its Reliability Coordinator, and all other potentially affected Balancing Authorities and Transmission Operators of a

condition that could threaten the reliability of its area or when firm load shedding was anticipated. (Requirement 1.1)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Balancing Authority, Transmission Operator and Generator Operator shall keep evidence of compliance for the previous two calendar years plus the current year. (Measure 1)

Each Balancing Authority and Transmission Operator shall keep 90 days of historical data. (Measure 2).

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor.

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Transmission Operator and Balancing Authority:

2.1. **Level 1:** Not applicable.

2.2. **Level 2:** Not applicable**.**

2.3. **Level 3:** Not applicable.

2.4. **Level 4:** Communication did not occur as specified in R1.1.

3. **Levels of Non-Compliance for Generator Operator:**

3.1. **Level 1:** Not applicable.

3.2. **Level 2:** Not applicable**.**

3.3. **Level 3:** Not applicable.

3.4. **Level 4:** Communication facilities are not provided to address a real-time emergency condition as specified in R1.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	February 7, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Adopted by Board of Trustees	Revised

A. Introduction

1. **Title:** **Emergency Operations Planning**

2. **Number:** EOP-001-0

3. **Purpose:** Each Transmission Operator and Balancing Authority needs to develop, maintain, and implement a set of plans to mitigate operating emergencies. These plans need to be coordinated with other Transmission Operators and Balancing Authorities, and the Reliability Coordinator.

4. **Applicability**

   4.1. Balancing Authorities.

   4.2. Transmission Operators.

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

R2. The Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes.

R3. Each Transmission Operator and Balancing Authority shall:

R3.1. Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.

R3.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.

R3.3. Develop, maintain, and implement a set of plans for load shedding.

R3.4. Develop, maintain, and implement a set of plans for system restoration.

R4. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include:

R4.1. Communications protocols to be used during emergencies.

R4.2. A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions.

R4.3. The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.

R4.4. Staffing levels for the emergency.

R5. Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001-0 when developing an emergency plan.

R6. The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.

R7. The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable:

R7.1. The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.

R7.2. The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.

R7.3. The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)

R7.4. The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.

C. Measures

M1. The Transmission Operator and Balancing Authority shall have its emergency plans available for review by the Regional Reliability Organization at all times.

M2. The Transmission Operator and Balancing Authority shall have its two most recent annual self-assessments available for review by the Regional Reliability Organization at all times.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframes

The Regional Reliability Organization shall review and evaluate emergency plans every three years to ensure that the plans consider the applicable elements of Attachment 1-EOP-001-0.

The Regional Reliability Organization may elect to request self-certification of the Transmission Operator and Balancing Authority in years that the full review is not done.

Reset: one calendar year.

1.3. Data Retention

Current plan available at all times.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: One of the applicable elements of Attachment 1-EOP-001-0 has not been addressed in the emergency plans.

2.2. Level 2: Two of the applicable elements of Attachment 1-EOP-001-0 have not been addressed in the emergency plans.

2.3. Level 3: Three of the applicable elements of Attachment 1-EOP-001-0 have not been addressed in the emergency plans.

2.4. Level 4: Four or more of the applicable elements of Attachment 1-EOP-001-0 have not been addressed in the emergency plans or a plan does not exist.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata

Attachment 1-EOP-001-0

Elements for Consideration in Development of Emergency Plans

1. Fuel supply and inventory — An adequate fuel supply and inventory plan that recognizes reasonable delays or problems in the delivery or production of fuel.

2. Fuel switching — Fuel switching plans for units for which fuel supply shortages may occur, e.g., gas and light oil.

3. Environmental constraints — Plans to seek removal of environmental constraints for generating units and plants.

4. System energy use — The reduction of the system's own energy use to a minimum.

5. Public appeals — Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.

6. Load management — Implementation of load management and voltage reductions, if appropriate.

7. Optimize fuel supply — The operation of all generating sources to optimize the availability.

8. Appeals to customers to use alternate fuels — In a fuel emergency, appeals to large industrial and commercial customers to reduce non-essential energy use and maximize the use of customer-owned generation that rely on fuels other than the one in short supply.

9. Interruptible and curtailable loads — Use of interruptible and curtailable customer load to reduce capacity requirements or to conserve the fuel in short supply.

10. Maximizing generator output and availability — The operation of all generating sources to maximize output and availability. This should include plans to winterize units and plants during extreme cold weather.

11. Notifying IPPs — Notification of cogeneration and independent power producers to maximize output and availability.

12. Requests of government — Requests to appropriate government agencies to implement programs to achieve necessary energy reductions.

13. Load curtailment — A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety, and welfare of the community. Address firm load curtailment.

14. Notification of government agencies — Notification of appropriate government agencies as the various steps of the emergency plan are implemented.

15. Notifications to operating entities — Notifications to other operating entities as steps in emergency plan are implemented.

A. Introduction

1. **Title**: **Capacity and Energy Emergencies**
2. **Number**: EOP-002-2.1
3. **Purpose**: To ensure Reliability Coordinators and Balancing Authorities are prepared for capacity and energy emergencies.
4. **Applicability**
   - **4.1.** Balancing Authorities.
   - **4.2.** Reliability Coordinators.
   - **4.3.** Load-Serving Entities.
5. **Effective Date:** May 13, 2009

B. Requirements

R1. Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate capacity and energy emergencies.

R2. Each Balancing Authority shall implement its capacity and energy emergency plan, when required and as appropriate, to reduce risks to the interconnected system.

R3. A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.

R4. A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load.

R5. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.

R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to:

- **R6.1.** Loading all available generating capacity.
- **R6.2.** Deploying all available operating reserve.
- **R6.3.** Interrupting interruptible load and exports.
- **R6.4.** Requesting emergency assistance from other Balancing Authorities.
- **R6.5.** Declaring an Energy Emergency through its Reliability Coordinator; and

R6.6. Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.

R7. Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall:

R7.1. Manually shed firm load without delay to return its ACE to zero; and

R7.2. Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0 "Energy Emergency Alert Levels."

R8. A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002-0 "Energy Emergency Alert Levels." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.

R9. When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources) as permitted in its transmission tariff (See Attachment 1-IRO-006-0 "Transmission Loading Relief Procedure" for explanation of Transmission Service Priorities):

R9.1. The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0.

R9.2. The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed.

R9.3. The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.

R9.4. The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.

C. Measures

M1. Each Reliability Coordinator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, job descriptions, signed agreements, authority letter signed by an appropriate officer of the company, or other equivalent evidence that will be used to confirm that it meets Requirement 1.

M2. If a Reliability Coordinator or Balancing Authority implements its Capacity and Energy Emergency plan, that entity shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts or other equivalent evidence that will be used to determine if the actions it took to relieve emergency

conditions were in conformance with its Capacity and Energy Emergency Plan. (Requirement 2)

M3. If a Balancing Authority experiences an operating Capacity or Energy Emergency it shall have and provide upon request evidence that could include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it met Requirement 3.

M4. If a Reliability Coordinator has any Balancing Authority within its Reliability Coordinator Area that has notified the Reliability Coordinator of a potential or actual Energy Emergency, the Reliability Coordinator involved in the event shall have and provide upon request evidence that could include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence to determine if it initiated an Energy Emergency Alert as specified in Requirement 8 and as detailed in Attachment 1-EOP-002 Energy Emergency Alert Levels.

M5. If a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources), the Reliability Coordinator involved in the event shall have and provide upon request evidence that could include, but is not limited to, NERC reports, EEA reports, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if that Reliability Coordinator met Requirements 9.2, 9.3 and 9.4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Timeframe

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

For Measure 1, each Reliability Coordinator and Balancing Authority shall keep The current in-force documents.

For Measure 2, 4 and 5 the Reliability Coordinator shall keep 90 days of historical data.

For Measure 3 the Balancing Authority shall keep 90 days of historical data.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor.

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for a Reliability Coordinator:

2.1. Level 1: Did not submit the report to NERC as required in R9.2.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 One or more of the actions of the Capacity and Energy Emergency Plans were not implemented as appropriate. (R2)

2.4.2 There is no evidence an Emergency Alert was issued as specified in R8

2.4.3 Failed to comply with R9.3 or R9.4

2.4.4 Did not provide evidence that it has the responsibility and clear decision-making authority in accordance with R1.

3. Levels of Non-Compliance for a Balancing Authority:

3.1. Level 1: Not applicable.

3.2. Level 2: Did not provide evidence that it has the responsibility and clear decision-making authority in accordance with R1.

3.3. Level 3: Not applicable.

3.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Failed to communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities when in an operating Capacity or Energy Emergency (R3).

3.4.2 One or more of the actions of the Capacity and Energy Emergency Plans were not implemented as appropriate (R2).

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	September 19, 2006	Changes R7. to refer to "Requirement 6" instead of "Requirement 7"	Errata
2	November 1, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Corrected numbering in Section A.4. "Applicability."	Errata
2	October 1, 2007	Added to Section 1 inadvertently omitted "4.3. Load-Serving Entities	Errata
2.1	October 29, 2008	BOT adopted errata changes; updated version number to "2.1"	Errata
2.1	May 13, 2009	FERC Approved	Revised

Attachment 1-EOP-002-2.1
Energy Emergency Alerts

Introduction

This Attachment provides the procedures by which a Load Serving Entity can obtain capacity and energy when it has exhausted all other options and can no longer provide its customers' expected energy requirements. NERC defines this situation as an "Energy Emergency." NERC assumes that a capacity deficiency will manifest itself as an energy emergency.

The Energy Emergency Alert Procedure is initiated by the Load Serving Entity's Reliability Coordinator, who declares various Energy Emergency Alert levels as defined in Section B, "Energy Emergency Alert Levels," to provide assistance to the Load Serving Entity.

The Load Serving Entity who requests this assistance is referred to as an "Energy Deficient Entity."

NERC recognizes that Transmission Providers are subject to obligations under FERC-approved tariffs and other agreements, and nothing in these procedures should be interpreted as changing those obligations.

A. General Requirements

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of a Balancing Authority, or 3) upon the request of a Load Serving Entity.

   1.1. **Situations for initiating alert.** An Energy Emergency Alert may be initiated for the following reasons:

   - When the Load Serving Entity is, or expects to be, unable to provide its customers' energy requirements, and has been unsuccessful in locating other systems with available resources from which to purchase, or
   - The Load Serving Entity cannot schedule the resources due to, for example, Available Transfer Capability (ATC) limitations or transmission loading relief limitations.

2. **Notification.** A Reliability Coordinator who declares an Energy Emergency Alert shall notify all Balancing Authorities and Transmission Providers in its Reliability Area. The Reliability Coordinator shall also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between Reliability Coordinators shall be held as necessary to communicate system conditions. The Reliability Coordinator shall also notify the other Reliability Coordinators when the alert has ended.

B. Energy Emergency Alert Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual energy emergencies in the Interconnection, NERC has established three levels of Energy Emergency

Alerts. The Reliability Coordinators will use these terms when explaining energy emergencies to each other. An Energy Emergency Alert is an emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC reliability standards or power supply contracts.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. Alert 1 — All available resources in use.

Circumstances:

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves, and
- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. Alert 2 — Load management procedures in effect.

Circumstances:

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity is no longer able to provide its customers' expected energy requirements, and is designated an Energy Deficient Entity.
- Energy Deficient Entity foresees or has implemented procedures up to, but excluding, interruption of firm load commitments. When time permits, these procedures may include, but are not limited to:
  - Public appeals to reduce demand.
  - Voltage reduction.
  - Interruption of non-firm end use loads in accordance with applicable contracts[1].
  - Demand-side management.
  - Utility load conservation measures.

During Alert 2, Reliability Coordinators, Balancing Authorities, and Energy Deficient Entities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The Energy Deficient Entity shall communicate its needs to other Balancing Authorities and market participants. Upon request from the Energy Deficient Entity, the respective Reliability Coordinator shall post the declaration of the alert level along with the name of the

[1] For emergency, not economic, reasons.

Energy Deficient Entity and, if applicable, its Balancing Authority on the NERC website.

2.2 Declaration period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators, Balancing Authority, and Transmission Providers**.**

2.3 Sharing information on resource availability. A Balancing Authority and market participants with available resources shall immediately contact the Energy Deficient Entity. This should include the possibility of selling non-firm (recallable) energy out of available Operating Reserves. The Energy Deficient Entity shall notify the Reliability Coordinators of the results.

2.4 Evaluating and mitigating transmission limitations. The Reliability Coordinators shall review all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) and transmission loading relief procedures in effect that may limit the Energy Deficient Entity's scheduling capabilities. Where appropriate, the Reliability Coordinators shall inform the Transmission Providers under their purview of the pending Energy Emergency and request that they increase their ATC by actions such as restoring transmission elements that are out of service, reconfiguring their transmission system, adjusting phase angle regulator tap positions, implementing emergency operating procedures, and reviewing generation redispatch options.

2.4.1 Notification of ATC adjustments. Resulting increases in ATCs shall be simultaneously communicated to the Energy Deficient Entity and the market via posting on the appropriate OASIS websites by the Transmission Providers.

2.4.2 Availability of generation redispatch options. Available generation redispatch options shall be immediately communicated to the Energy Deficient Entity by its Reliability Coordinator.

2.4.3 Evaluating impact of current transmission loading relief events. The Reliability Coordinators shall evaluate the impact of any current transmission loading relief events on the ability to supply emergency assistance to the Energy Deficient Entity. This evaluation shall include analysis of system reliability and involve close communication among Reliability Coordinators and the Energy Deficient Entity.

2.4.4 Initiating inquiries on reevaluating SOLs and IROLs. The Reliability Coordinators shall consult with the Balancing Authorities and Transmission Providers in their Reliability Areas about the possibility of reevaluating and revising SOLs or IROLs.

2.5 Coordination of emergency responses. The Reliability Coordinator shall communicate and coordinate the implementation of emergency operating responses.

2.6 Energy Deficient Entity actions. Before declaring an Alert 3, the Energy Deficient Entity must make use of all available resources. This includes but is not limited to:

2.6.1 All available generation units are on line. All generation capable of being on line in the time frame of the emergency is on line including quick-start and peaking units, regardless of cost.

2.6.2 Purchases made regardless of cost. All firm and non-firm purchases have been made, regardless of cost.

2.6.3 Non-firm sales recalled and contractually interruptible loads and demand-side management curtailed. All non-firm sales have been recalled, contractually interruptible retail loads curtailed, and demand-side management activated within provisions of the agreements.

2.6.4 Operating Reserves. Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.

3. Alert 3 — Firm load interruption imminent or in progress.

Circumstances:

- Balancing Authority or Load Serving Entity foresees or has implemented firm load obligation interruption. The available energy to the Energy Deficient Entity, as determined from Alert 2, is only accessible with actions taken to increase transmission transfer capabilities.

3.1 Continue actions from Alert 2. The Reliability Coordinators and the Energy Deficient Entity shall continue to take all actions initiated during Alert 2. If the emergency has not already been posted on the NERC website (see paragraph 2.1), the respective Reliability Coordinators will, at this time, post on the website information concerning the emergency.

3.2 Declaration Period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers.

3.3 Use of Transmission short-time limits. The Reliability Coordinators shall request the appropriate Transmission Providers within their Reliability Area to utilize available short-time transmission limits or other emergency operating procedures in order to increase transfer capabilities into the Energy Deficient Entity.

3.4 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator of the Energy Deficient Entity shall evaluate the risks of revising SOLs and IROLs on the

reliability of the overall transmission system. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Balancing Authority or Transmission Operator whose equipment would be affected. The resulting increases in transfer capabilities shall only be made available to the Energy Deficient Entity who has requested an Energy Emergency Alert 3 condition. SOLs and IROLs shall only be revised as long as an Alert 3 condition exists or as allowed by the Balancing Authority or Transmission Operator whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.4.1 Energy Deficient Entity obligations. The deficient Balancing Authority or Load Serving Entity must agree that, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include load shedding.

3.4.2 Mitigation of cascading failures. The Reliability Coordinator shall use its best efforts to ensure that revising SOLs or IROLs would not result in any cascading failures within the Interconnection.

3.5 Returning to pre-emergency Operating Security Limits. Whenever energy is made available to an Energy Deficient Entity such that the transmission systems can be returned to their pre-emergency SOLs or IROLs, the Energy Deficient Entity shall notify its respective Reliability Coordinator and downgrade the alert.

3.5.1 Notification of other parties. Upon notification from the Energy Deficient Entity that an alert has been downgraded, the Reliability Coordinator shall notify the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers that their systems can be returned to their normal limits.

3.6 Reporting. Any time an Alert 3 is declared, the Energy Deficient Entity shall submit the report enclosed in this Attachment to its respective Reliability Coordinator within two business days of downgrading or termination of the alert. Upon receiving the report, the Reliability Coordinator shall review it for completeness and immediately forward it to the NERC staff for posting on the NERC website. The Reliability Coordinator shall present this report to the Reliability Coordinator Working Group at its next scheduled meeting.

4. Alert 0 - Termination. When the Energy Deficient Entity believes it will be able to supply its customers' energy requirements, it shall request of its Reliability Coordinator that the EEA be terminated.

4.1. Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the affected Balancing Authorities and Transmission Operators. The Alert 0 shall also be posted on the NERC website if the original alert was so posted.

C. Energy Emergency Alert 3 Report

A Deficient Balancing Authority or Load Serving Entity declaring an Energy Emergency Alert 3 must complete the following report. Upon completion of this report, it is to be sent to the Reliability Coordinator for review within two business days of the incident.

Requesting Balancing Authority:

Entity experiencing energy deficiency (if different from Balancing Authority):

Date/Time Implemented:

Date/Time Released:

Declared Deficiency Amount (MW):

Total energy supplied by other Balancing Authority during the Alert 3 period:

Conditions that precipitated call for "Energy Deficiency Alert 3":

If "Energy Deficiency Alert 3" had not been called, would firm load be cut? If no, explain:

Explain what action was taken in each step to avoid calling for "Energy Deficiency Alert 3":

1. **All generation capable of being on line in the time frame of the energy deficiency was on line (including quick start and peaking units) without regard to cost.**

2. **All firm and nonfirm purchases were made regardless of cost.**

3. **All nonfirm sales were recalled within provisions of the sale agreement.**

4. **Interruptible load was curtailed where either advance notice restrictions were met or the interruptible load was considered part of spinning reserve.**

5. **Available load reduction programs were exercised (public appeals, voltage reductions, etc.).**

6. **Operating Reserves being utilized.**

Comments:

Reported By: **Organization:**

Title:

A. Introduction

1. **Title:** **Load Shedding Plans**
2. **Number:** EOP-003-1
3. **Purpose:** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.
4. **Applicability**
   - **4.1.** Transmission Operators.
   - **4.2.** Balancing Authorities.
5. **Effective Date:** January 1, 2007

B. Requirements

R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.

R2. Each Transmission Operator and Balancing Authority shall establish plans for automatic load shedding for underfrequency or undervoltage conditions.

R3. Each Transmission Operator and Balancing Authority shall coordinate load shedding plans among other interconnected Transmission Operators and Balancing Authorities.

R4. A Transmission Operator or Balancing Authority shall consider one or more of these factors in designing an automatic load shedding scheme: frequency, rate of frequency decay, voltage level, rate of voltage decay, or power flow levels.

R5. A Transmission Operator or Balancing Authority shall implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

R6. After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.

R7. The Transmission Operator and Balancing Authority shall coordinate automatic load shedding throughout their areas with underfrequency isolation of generating units, tripping of shunt capacitors, and other automatic actions that will occur under abnormal frequency, voltage, or power flow conditions.

R8. Each Transmission Operator or Balancing Authority shall have plans for operator-controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.

C. Measures

M1. Each Transmission Operator and Balancing Authority that has or directs the deployment of undervoltage and/or underfrequency load shedding facilities, shall have and provide upon request, its automatic load shedding plans.(Requirement 2)

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request its manual load shedding plans that will be used to confirm that it meets Requirement 8. (Part 1)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Additional Reporting Requirement

No additional reporting required.

1.4. Data Retention

Each Balancing Authority and Transmission Operator shall have its current, in-force load shedding plans.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.5. Additional Compliance Information

None.

2. Levels of Non-Compliance:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not Applicable.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Does not have an automatic load shedding plan as specified in R2.

2.4.2 Does not have manual load shedding plans as specified in R8.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised

A. Introduction

1. **Title:** **Disturbance Reporting**

2. **Number:** EOP-004-1

3. **Purpose:** Disturbances or unusual occurrences that jeopardize the operation of the Bulk Electric System, or result in system equipment damage or customer interruptions, need to be studied and understood to minimize the likelihood of similar events in the future.

4. **Applicability**

   4.1. Reliability Coordinators.

   4.2. Balancing Authorities.

   4.3. Transmission Operators.

   4.4. Generator Operators.

   4.5. Load Serving Entities.

   4.6. Regional Reliability Organizations.

5. **Effective Date:** January 1, 2007

B. Requirements

R1. Each Regional Reliability Organization shall establish and maintain a Regional reporting procedure to facilitate preparation of preliminary and final disturbance reports.

R2. A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity shall promptly analyze Bulk Electric System disturbances on its system or facilities.

R3. A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity experiencing a reportable incident shall provide a preliminary written report to its Regional Reliability Organization and NERC.

R3.1. The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity shall submit within 24 hours of the disturbance or unusual occurrence either a copy of the report submitted to DOE, or, if no DOE report is required, a copy of the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report form. Events that are not identified until some time after they occur shall be reported within 24 hours of being recognized.

R3.2. Applicable reporting forms are provided in Attachments 1-EOP-004 and 2-EOP-004.

R3.3. Under certain adverse conditions, e.g., severe weather, it may not be possible to assess the damage caused by a disturbance and issue a written Interconnection Reliability Operating Limit and Preliminary Disturbance Report within 24 hours. In such cases, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall promptly notify its Regional Reliability Organization(s) and NERC, and verbally provide as much information as is available at that

time. The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall then provide timely, periodic verbal updates until adequate information is available to issue a written Preliminary Disturbance Report.

R3.4. If, in the judgment of the Regional Reliability Organization, after consultation with the Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity in which a disturbance occurred, a final report is required, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall prepare this report within 60 days. As a minimum, the final report shall have a discussion of the events and its cause, the conclusions reached, and recommendations to prevent recurrence of this type of event. The report shall be subject to Regional Reliability Organization approval.

R4. When a Bulk Electric System disturbance occurs, the Regional Reliability Organization shall make its representatives on the NERC Operating Committee and Disturbance Analysis Working Group available to the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity immediately affected by the disturbance for the purpose of providing any needed assistance in the investigation and to assist in the preparation of a final report.

R5. The Regional Reliability Organization shall track and review the status of all final report recommendations at least twice each year to ensure they are being acted upon in a timely manner. If any recommendation has not been acted on within two years, or if Regional Reliability Organization tracking and review indicates at any time that any recommendation is not being acted on with sufficient diligence, the Regional Reliability Organization shall notify the NERC Planning Committee and Operating Committee of the status of the recommendation(s) and the steps the Regional Reliability Organization has taken to accelerate implementation.

C. Measures

M1. The Regional Reliability Organization shall have and provide upon request as evidence, its current regional reporting procedure that is used to facilitate preparation of preliminary and final disturbance reports. (Requirement 1)

M2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity that has a reportable incident shall have and provide upon request evidence that could include, but is not limited to, the preliminary report, computer printouts, operator logs, or other equivalent evidence that will be used to confirm that it prepared and delivered the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Reports to NERC within 24 hours of its recognition as specified in Requirement 3.1.

M3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and/or Load Serving Entity that has a reportable incident shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it provided information verbally as time permitted, when system conditions precluded the preparation of a report in 24 hours. (Requirement 3.3)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

NERC shall be responsible for compliance monitoring of the Regional Reliability Organizations.

Regional Reliability Organizations shall be responsible for compliance monitoring of Reliability Coordinators, Balancing Authorities, Transmission Operators, Generator Operators, and Load-serving Entities.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Regional Reliability Organization shall have its current, in-force, regional reporting procedure as evidence of compliance. (Measure 1)

Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and/or Load Serving Entity that is either involved in a Bulk Electric System disturbance or has a reportable incident shall keep data related to the incident for a year from the event or for the duration of any regional investigation, whichever is longer. (Measures 2 through 4)

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

See Attachments:

- EOP-004 Disturbance Reporting Form
- Table 1 EOP-004

2. Levels of Non-Compliance for a Regional Reliability Organization

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: No current procedure to facilitate preparation of preliminary and final disturbance reports as specified in R1.

3. Levels of Non-Compliance for a Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load- Serving Entity:

3.1. Level 1: There shall be a level one non-compliance if any of the following conditions exist:

3.1.1 Failed to prepare and deliver the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Reports to NERC within 24 hours of its recognition as specified in Requirement 3.1

3.1.2 Failed to provide disturbance information verbally as time permitted, when system conditions precluded the preparation of a report in 24 hours as specified in R3.3

3.1.3 Failed to prepare a final report within 60 days as specified in R3.4

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable

3.4. Level 4: Not applicable.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	May 23, 2005	Fixed reference to attachments 1-EOP-004-0 and 2-EOP-004-0, Changed chart title 1-FAC-004-0 to 1-EOP-004-0, Fixed title of Table 1 to read 1-EOP-004-0, and fixed font.	Errata
0	July 6, 2005	Fixed email in Attachment 1-EOP-004-0 from info@nerc.com to esisac@nerc.com.	Errata

0	July 26, 2005	Fixed Header on page 8 to read EOP-004-0	Errata
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	March 22, 2007	Updated Department of Energy link and references to Form OE-411	Errata

Attachment 1-EOP-004
NERC Disturbance Report Form

Introduction

These disturbance reporting requirements apply to all Reliability Coordinators, Balancing Authorities, Transmission Operators, Generator Operators, and Load Serving Entities, and provide a common basis for all NERC disturbance reporting. The entity on whose system a reportable disturbance occurs shall notify NERC and its Regional Reliability Organization of the disturbance using the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report forms. Reports can be sent to NERC via email (esisac@nerc.com) by facsimile (609-452-9550) using the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report forms. If a disturbance is to be reported to the U.S. Department of Energy also, the responding entity may use the DOE reporting form when reporting to NERC. Note: All Emergency Incident and Disturbance Reports (Schedules 1 and 2) sent to DOE shall be simultaneously sent to NERC, preferably electronically at esisac@nerc.com.

The NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Reports are to be made for any of the following events:

1. The loss of a bulk power transmission component that significantly affects the integrity of interconnected system operations. Generally, a disturbance report will be required if the event results in actions such as:
   a. Modification of operating procedures.
   b. Modification of equipment (e.g. control systems or special protection systems) to prevent reoccurrence of the event.
   c. Identification of valuable lessons learned.
   d. Identification of non-compliance with NERC standards or policies.
   e. Identification of a disturbance that is beyond recognized criteria, i.e. three-phase fault with breaker failure, etc.
   f. Frequency or voltage going below the under-frequency or under-voltage load shed points.
2. The occurrence of an interconnected system separation or system islanding or both.
3. Loss of generation by a Generator Operator, Balancing Authority, or Load-Serving Entity — 2,000 MW or more in the Eastern Interconnection or Western Interconnection and 1,000 MW or more in the ERCOT Interconnection.
4. Equipment failures/system operational actions which result in the loss of firm system demands for more than 15 minutes, as described below:
   a. Entities with a previous year recorded peak demand of more than 3,000 MW are required to report all such losses of firm demands totaling more than 300 MW.
   b. All other entities are required to report all such losses of firm demands totaling more than 200 MW or 50% of the total customers being supplied immediately prior to the incident, whichever is less.
5. Firm load shedding of 100 MW or more to maintain the continuity of the bulk electric system.

6. Any action taken by a Generator Operator, Transmission Operator, Balancing Authority, or Load-Serving Entity that results in:
   a. Sustained voltage excursions equal to or greater than ±10%, or
   b. Major damage to power system components, or
   c. Failure, degradation, or misoperation of system protection, special protection schemes, remedial action schemes, or other operating systems that do not require operator intervention, which did result in, or could have resulted in, a system disturbance as defined by steps 1 through 5 above.
7. An Interconnection Reliability Operating Limit (IROL) violation as required in reliability standard TOP-007.
8. Any event that the Operating Committee requests to be submitted to Disturbance Analysis Working Group (DAWG) for review because of the nature of the disturbance and the insight and lessons the electricity supply and delivery industry could learn.

NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report

☐ Check here if this is an Interconnection Reliability Operating Limit (IROL) violation report.

1.	Organization filing report.		
2.	Name of person filing report.		
3.	Telephone number.		
4.	Date and time of disturbance. Date:(mm/dd/yy) Time/Zone:		
5.	Did the disturbance originate in your system?	Yes ☐ No ☐	
6.	Describe disturbance including: cause, equipment damage, critical services interrupted, system separation, key scheduled and actual flows prior to disturbance and in the case of a disturbance involving a special protection or remedial action scheme, what action is being taken to prevent recurrence.		
7.	Generation tripped. MW Total List generation tripped		
8.	Frequency. Just prior to disturbance (Hz): Immediately after disturbance (Hz max.): Immediately after disturbance (Hz min.):		
9.	List transmission lines tripped (specify voltage level of each line).		
10.		FIRM	INTERRUPTIBLE
	Demand tripped (MW):		
	Number of affected Customers:		

	Demand lost (MW-Minutes):		
11.	Restoration time.	INITIAL	FINAL
	Transmission:		
	Generation:		
	Demand:		

Attachment 2-EOP-004
U.S. Department of Energy Disturbance Reporting Requirements

Introduction

The U.S. Department of Energy (DOE), under its relevant authorities, has established mandatory reporting requirements for electric emergency incidents and disturbances in the United States. DOE collects this information from the electric power industry on Form OE-417 to meet its overall national security and Federal Energy Management Agency's Federal Response Plan (FRP) responsibilities. DOE will use the data from this form to obtain current information regarding emergency situations on U.S. electric energy supply systems. DOE's Energy Information Administration (EIA) will use the data for reporting on electric power emergency incidents and disturbances in monthly EIA reports. In addition, the data may be used to develop legislative recommendations, reports to the Congress and as a basis for DOE investigations following severe, prolonged, or repeated electric power reliability problems.

Every Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity must use this form to submit mandatory reports of electric power system incidents or disturbances to the DOE Operations Center, which operates on a 24-hour basis, seven days a week. All other entities operating electric systems have filing responsibilities to provide information to the Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity when necessary for their reporting obligations and to file form OE-417 in cases where these entities will not be involved. EIA requests that it be notified of those that plan to file jointly and of those electric entities that want to file separately.

Special reporting provisions exist for those electric utilities located within the United States, but for whom Reliability Coordinator oversight responsibilities are handled by electrical systems located across an international border. A foreign utility handling U.S. Balancing Authority responsibilities, may wish to file this information voluntarily to the DOE. Any U.S.-based utility in this international situation needs to inform DOE that these filings will come from a foreign-based electric system or file the required reports themselves.

Form EIA-417 must be submitted to the DOE Operations Center if any one of the following applies (see Table 1-EOP-004-0 — Summary of NERC and DOE Reporting Requirements for Major Electric System Emergencies):

1. Uncontrolled loss of 300 MW or more of firm system load for more than 15 minutes from a single incident.
2. Load shedding of 100 MW or more implemented under emergency operational policy.
3. System-wide voltage reductions of 3 percent or more.
4. Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system.
5. Actual or suspected physical attacks that could impact electric power system adequacy or reliability; or vandalism, which target components of any security system. Actual or suspected cyber or communications attacks that could impact electric power system adequacy or vulnerability.

6. Actual or suspected cyber or communications attacks that could impact electric power system adequacy or vulnerability.
7. Fuel supply emergencies that could impact electric power system adequacy or reliability.
8. Loss of electric service to more than 50,000 customers for one hour or more.
9. Complete operational failure or shut-down of the transmission and/or distribution electrical system.

The initial DOE Emergency Incident and Disturbance Report (form OE-417 – Schedule 1) shall be submitted to the DOE Operations Center within 60 minutes of the time of the system disruption. Complete information may not be available at the time of the disruption. However, provide as much information as is known or suspected at the time of the initial filing. If the incident is having a critical impact on operations, a telephone notification to the DOE Operations Center (202-586-8100) is acceptable, pending submission of the completed form OE-417. Electronic submission via an on-line web-based form is the preferred method of notification. However, electronic submission by facsimile or email is acceptable.

An updated form OE-417 (Schedule 1 and 2) is due within 48 hours of the event to provide complete disruption information. Electronic submission via facsimile or email is the preferred method of notification. Detailed DOE Incident and Disturbance reporting requirements can be found at: http://www.oe.netl.doe.gov/oe417.aspx.

Table 1-EOP-004-0 Summary of NERC and DOE Reporting Requirements for Major Electric System Emergencies				
Incident No.	**Incident**	**Threshold**	**Report Required**	**Time**
1	Uncontrolled loss of Firm System Load	≥ 300 MW – 15 minutes or more	OE – Sch-1 OE – Sch-2	1 hour 48 hour
2	Load Shedding	≥ 100 MW under emergency operational policy	OE – Sch-1 OE – Sch-2	1 hour 48 hour
3	Voltage Reductions	3% or more – applied system-wide	OE – Sch-1 OE – Sch-2	1 hour 48 hour
4	Public Appeals	Emergency conditions to reduce demand	OE – Sch-1 OE – Sch-2	1 hour 48 hour
5	Physical sabotage, terrorism or vandalism	On physical security systems – suspected or real	OE – Sch-1 OE – Sch-2	1 hour 48 hour
6	Cyber sabotage, terrorism or vandalism	If the attempt is believed to have or did happen	OE – Sch-1 OE – Sch-2	1 hour 48 hour
7	Fuel supply emergencies	Fuel inventory or hydro storage levels ≤ 50% of normal	OE – Sch-1 OE – Sch-2	1 hour 48 hour
8	Loss of electric service	≥ 50,000 for 1 hour or more	OE – Sch-1 OE – Sch-2	1 hour 48 hour
9	Complete operation failure of electrical system	If isolated or interconnected electrical systems suffer total electrical system collapse	OE – Sch-1 OE – Sch-2	1 hour 48 hour
All DOE OE-417 Schedule 1 reports are to be filed within 60-minutes after the start of an incident or disturbance All DOE OE-417 Schedule 2 reports are to be filed within 48-hours after the start of an incident or disturbance				
All entities required to file a DOE OE-417 report (Schedule 1 & 2) shall send a copy of these reports to NERC simultaneously, but no later than 24 hours after the start of the incident or disturbance.				
Incident No.	**Incident**	**Threshold**	**Report Required**	**Time**
1	Loss of major system component	Significantly affects integrity of interconnected system operations	NERC Prelim Final report	24 hour 60 day

2	Interconnected system separation or system islanding	Total system shutdown Partial shutdown, separation, or islanding	NERC Prelim Final report	24 hour 60 day
3	Loss of generation	≥ 2,000 – Eastern Interconnection ≥ 2,000 – Western Interconnection ≥ 1,000 – ERCOT Interconnection	NERC Prelim Final report	24 hour 60 day
4	Loss of firm load ≥15-minutes	Entities with peak demand ≥3,000: loss ≥300 MW All others ≥200MW or 50% of total demand	NERC Prelim Final report	24 hour 60 day
5	Firm load shedding	≥100 MW to maintain continuity of bulk system	NERC Prelim Final report	24 hour 60 day
6	System operation or operation actions resulting in:	• Voltage excursions ≥10% • Major damage to system components • Failure, degradation, or misoperation of SPS	NERC Prelim Final report	24 hour 60 day
7	IROL violation	Reliability standard TOP-007.	NERC Prelim Final report	72 hour 60 day
8	As requested by ORS Chairman	Due to nature of disturbance & usefulness to industry (lessons learned)	NERC Prelim Final report	24 hour 60 day
All NERC Operating Security Limit and Preliminary Disturbance reports will be filed within 24 hours after the start of the incident. If an entity must file a DOE OE-417 report on an incident, which requires a NERC Preliminary report, the Entity may use the DOE OE-417 form for both DOE and NERC reports.				
Any entity reporting a DOE or NERC incident or disturbance has the responsibility to also notify its Regional Reliability Organization.				

A. Introduction

1. **Title:** **System Restoration Plans**
2. **Number:** EOP-005-1
3. **Purpose:** To ensure plans, procedures, and resources are available to restore the electric system to a normal condition in the event of a partial or total shut down of the system.
4. **Applicability**
   - **4.1.** Transmission Operators.
   - **4.2.** Balancing Authorities.
5. **Effective Date:** One year after BOT adoption.

B. Requirements

R1. Each Transmission Operator shall have a restoration plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shutdown of its system, including necessary operating instructions and procedures to cover emergency conditions, and the loss of vital telecommunications channels. Each Transmission Operator shall include the applicable elements listed in Attachment 1-EOP-005 in developing a restoration plan.

R2. Each Transmission Operator shall review and update its restoration plan at least annually and whenever it makes changes in the power system network, and shall correct deficiencies found during the simulated restoration exercises.

R3. Each Transmission Operator shall develop restoration plans with a priority of restoring the integrity of the Interconnection.

R4. Each Transmission Operator shall coordinate its restoration plans with the Generator Owners and Balancing Authorities within its area, its Reliability Coordinator, and neighboring Transmission Operators and Balancing Authorities.

R5. Each Transmission Operator and Balancing Authority shall periodically test its telecommunication facilities needed to implement the restoration plan.

R6. Each Transmission Operator and Balancing Authority shall train its operating personnel in the implementation of the restoration plan. Such training shall include simulated exercises, if practicable.

R7. Each Transmission Operator and Balancing Authority shall verify the restoration procedure by actual testing or by simulation.

R8. Each Transmission Operator shall verify that the number, size, availability, and location of system blackstart generating units are sufficient to meet Regional Reliability Organization restoration plan requirements for the Transmission Operator's area.

R9. The Transmission Operator shall document the Cranking Paths, including initial switching requirements, between each blackstart generating unit and the unit(s) to be started and shall provide this documentation for review by the Regional Reliability Organization upon request. Such documentation may include Cranking Path diagrams.

R10. The Transmission Operator shall demonstrate, through simulation or testing, that the blackstart generating units in its restoration plan can perform their intended functions as required in the regional restoration plan.

R10.1. The Transmission Operator shall perform this simulation or testing at least once every five years.

R11. Following a disturbance in which one or more areas of the Bulk Electric System become isolated or blacked out, the affected Transmission Operators and Balancing Authorities shall begin immediately to return the Bulk Electric System to normal.

R11.1. The affected Transmission Operators and Balancing Authorities shall work in conjunction with their Reliability Coordinator(s) to determine the extent and condition of the isolated area(s).

R11.2. The affected Transmission Operators and Balancing Authorities shall take the necessary actions to restore Bulk Electric System frequency to normal, including adjusting generation, placing additional generators on line, or load shedding.

R11.3. The affected Balancing Authorities, working with their Reliability Coordinator(s), shall immediately review the Interchange Schedules between those Balancing Authority Areas or fragments of those Balancing Authority Areas within the separated area and make adjustments as needed to facilitate the restoration. The affected Balancing Authorities shall make all attempts to maintain the adjusted Interchange Schedules, whether generation control is manual or automatic.

R11.4. The affected Transmission Operators shall give high priority to restoration of off-site power to nuclear stations.

R11.5. The affected Transmission Operators may resynchronize the isolated area(s) with the surrounding area(s) when the following conditions are met:

R11.5.1. Voltage, frequency, and phase angle permit.

R11.5.2. The size of the area being reconnected and the capacity of the transmission lines effecting the reconnection and the number of synchronizing points across the system are considered.

R11.5.3. Reliability Coordinator(s) and adjacent areas are notified and Reliability Coordinator approval is given.

R11.5.4. Load is shed in neighboring areas, if required, to permit successful interconnected system restoration.

C. Measures

M1. The Transmission Operator shall within 30 calendar days of a request, provide its Regional Reliability Organization with documentation of simulations or tests that demonstrate the blackstart units and Cranking Paths identified in the Transmission Operator's restoration plan can perform their intended functions as required in the regional restoration plan.

M2. The Transmission Operator shall within 30 calendar days of a request from its Regional Reliability Organization, make available documentation showing the number, size, and location of system blackstart generating units and the associated Cranking Paths for review at the Transmission Operator's location.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

The Transmission Operator must have its plan to reestablish its electric system available for review by the Regional Reliability Organization at all times.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

Self-Certification: Each Transmission Operator shall annually self-certify to the Regional Reliability Organization that the following criteria have been met:

1.4.1 The necessary operating instructions and procedures for restoring loads, including identification of critical load requirements.

1.4.2 A set of procedures for annual review for simulating and, where practical, actual testing and verification of the restoration plan resources and procedures.

1.4.3 Documentation must be retained in the personnel training records that operating personnel have been trained annually in the implementation of the plan and have participated in restoration exercises.

1.4.4 Any significant changes to the restoration plan must be reported to the Regional Reliability Organization.

1.4.5 The number, size, availability, and location of system blackstart generating units are sufficient to meet Regional Reliability Organization restoration plan requirements for the Transmission Operator's area

1.4.6 The Cranking Paths, including initial switching requirements, between each blackstart generating unit and the unit(s) to be started have been documented and this documentation is available for the Regional Reliability Organization's review.

1.4.7 The blackstart generating units in its restoration plan can perform their intended functions as required in the regional restoration plan.

2. Levels of Non-Compliance

2.1. Level 1: Plan exists but is not reviewed annually.

2.2. Level 2: Plan exists but does not address one of the elements listed in Attachment 1–EOP-005.

2.3. Level 3: Did not make available documentation showing the number, size, and location of system blackstart generating units and the associated Cranking Paths.

2.4. Level 4: There shall be a level four non-compliance if any of the following conditions exist:

2.4.1 Plan exists but does not address two or more of the requirements in Attachment 1 – EOP-005.

2.4.2 No restoration plan in place.

2.4.3 No simulation or test results as required in Requirement 10.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

Attachment 1 – EOP-005

Elements for Consideration in Development of Restoration Plans

The Restoration Plan must consider the following requirements, as applicable:

1. Plan and procedures outlining the relationships and responsibilities of the personnel necessary to implement system restoration.
2. The provision for a reliable black-start capability plan including: fuel resources for black start power for generating units, available cranking and transmission paths, and communication adequacy and protocol and power supplies.
3. The plan must account for the possibility that restoration cannot be completed as expected.
4. The necessary operating instructions and procedures for synchronizing areas of the system that have become separated.
5. The necessary operating instructions and procedures for restoring loads, including identification of critical load requirements.
6. A set of procedures for simulating and, where practical, actually testing and verifying the plan resources and procedures.
7. Documentation must be retained in the personnel training records that operating personnel have been trained annually in the implementation of the plan and have participated in restoration exercises.
8. The functions to be coordinated with and among Reliability Coordinators and neighboring Transmission Operators. (The plan should include references to coordination of actions among neighboring Transmission Operators and Reliability Coordinators when the plans are implemented.)
9. Notification shall be made to other operating entities as the steps of the restoration plan are implemented.

A. Introduction

1. **Title:** **Reliability Coordination – System Restoration**
2. **Number:** EOP-006-1
3. **Purpose:** The Reliability Coordinator must have a coordinating role in system restoration to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.
4. **Applicability**

   4.1. Reliability Coordinator.
5. **Effective Date:** January 1, 2007

B. Requirements

R1. Each Reliability Coordinator shall be aware of the restoration plan of each Transmission Operator in its Reliability Coordinator Area in accordance with NERC and regional requirements.

R2. The Reliability Coordinator shall monitor restoration progress and coordinate any needed assistance.

R3. The Reliability Coordinator shall have a Reliability Coordinator Area restoration plan that provides coordination between individual Transmission Operator restoration plans and that ensures reliability is maintained during system restoration events.

R4. The Reliability Coordinator shall serve as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators and Transmission Operators or Balancing Authorities not immediately involved in restoration.

R5. Reliability Coordinators shall approve, communicate, and coordinate the re-synchronizing of major system islands or synchronizing points so as not to cause a Burden on adjacent Transmission Operator, Balancing Authority, or Reliability Coordinator Areas.

R6. The Reliability Coordinator shall take actions to restore normal operations once an operating emergency has been mitigated in accordance with its restoration plan.

C. Measures

M1. Each Reliability Coordinator shall have and provide upon request a current copy of the restoration plan of each Transmission Operator in its Reliability Coordinator Area that will be used to confirm that it meets Requirement 1.

M2. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts, or other equivalent evidence that will be used to determine if the Reliability Coordinator monitored restoration progress and coordinated any needed assistance in accordance with Requirement 2.

M3. The Reliability Coordinator shall have and provide upon request a current copy of the Reliability Coordinator Area restoration plan that confirms that the Reliability Coordinator role of providing coordination between individual Transmission Operator restoration plans is included in the Reliability Coordinator Restoration Plan. (Requirement 3)

M4. The Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts, or other equivalent evidence that will be used to determine if it served as the primary contact to disseminate information to neighboring Reliability Coordinators and Transmission Operators and Balancing Authorities that were not immediately involved in restoration. (Requirement 4)

M5. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts, or other equivalent evidence that will be used to determine if it approved, communicated, and coordinated the re-synchronizing of major system islands or synchronizing points. (Requirement 5)

M6. The Reliability Coordinator shall have and provide upon request, evidence that could include, but is not limited to system restoration plan, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts, or other equivalent evidence that will be used to determine if it took actions to restore normal operations, once an operating emergency was mitigated, in accordance with its restoration plan. (Requirement 6)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the compliance monitor on a case-by-case basis.)

The Performance-Reset Period shall be twelve months from the last finding of non-compliance.

1.3. Data Retention

Each Reliability Coordinator shall have the current version of its Transmission Operator's restoration plans (Measure 1) and its current Reliability Coordinator Area restoration plan (Measure 3)

Each Reliability Coordinator shall keep historical data (evidence) gathered as a result of each major system disturbance requiring the implementation of system restoration plans and data gathered during the restoration period until normal system operation is resumed, for three years (Measure 2 , 4 , 5 and 6).

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance:

2.1. Level 1: Did not have one of the Transmission Operator restoration plans within the Reliability Coordinator's Area as specified in R1.

2.2. Level 2: Not applicable.

2.3. Level 3: There shall be a separate Level 3 non-compliance, for every one of the following requirements that is in violation:

2.3.1 Does not have a Reliability Coordinator Restoration plan that defines the requirement of the Reliability Coordinator to provide coordination between individual Transmission Operator restoration plans as specified in R3.

2.3.2 No evidence it served as the primary contact to disseminate information to neighboring Reliability Coordinators, Transmission Operators and Balancing Authorities that were not immediately involved in restoration. (Requirement 4).

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Did not have two or more of the Transmission Operator restoration plans within the Reliability Coordinator's Area as specified in R1.

2.4.2 Did not monitor restoration progress and coordinate assistance as specified in R2.

2.4.3 Did not approve, communicate, and coordinate the re-synchronizing of major system islands or synchronizing points as specified in R5.

2.4.4 Did not take action in accordance with its restoration plan to return to normal operations once an operating emergency was mitigated as specified in R6.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised

A. Introduction

1. **Title:** **Plans for Loss of Control Center Functionality**
2. **Number:** EOP-008-0
3. **Purpose:** Each reliability entity must have a plan to continue reliability operations in the event its control center becomes inoperable.
4. **Applicability**
   - **4.1.** Transmission Operators.
   - **4.2.** Balancing Authorities.
   - **4.3.** Reliability Coordinators.
5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have a plan to continue reliability operations in the event its control center becomes inoperable. The contingency plan must meet the following requirements:

- **R1.1.** The contingency plan shall not rely on data or voice communication from the primary control facility to be viable.
- **R1.2.** The plan shall include procedures and responsibilities for providing basic tie line control and procedures and for maintaining the status of all inter-area schedules, such that there is an hourly accounting of all schedules.
- **R1.3.** The contingency plan must address monitoring and control of critical transmission facilities, generation control, voltage control, time and frequency control, control of critical substation devices, and logging of significant power system events. The plan shall list the critical facilities.
- **R1.4.** The plan shall include procedures and responsibilities for maintaining basic voice communication capabilities with other areas.
- **R1.5.** The plan shall include procedures and responsibilities for conducting periodic tests, at least annually, to ensure viability of the plan.
- **R1.6.** The plan shall include procedures and responsibilities for providing annual training to ensure that operating personnel are able to implement the contingency plans.
- **R1.7.** The plan shall be reviewed and updated annually.
- **R1.8.** Interim provisions must be included if it is expected to take more than one hour to implement the contingency plan for loss of primary control facility.

C. Measures

M1. Evidence that the Reliability Coordinator, Transmission Operator or Balancing Authority has developed and documented a current contingency plan to continue the monitoring and operation of the electrical equipment under its control to maintain Bulk Electrical System reliability if its primary control facility becomes inoperable.

D. Compliance

1. **Compliance Monitoring Process**
   - **1.1. Compliance Monitoring Responsibility**

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

Periodic Review: Review and evaluate the plan for loss of primary control facility contingency as part of the three-year on-site audit process. The audit must include a demonstration of the plan by the Reliability Coordinator, Transmission Operator, and Balancing Authority.

Reset: One calendar year.

1.3. Data Retention

The contingency plan for loss of primary control facility must be available for review at all times.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: NA

2.2. Level 2: A contingency plan has been implemented and tested, but has not been tested in the past year or there are no records of shift operating personnel training.

2.3. Level 3: A contingency plan has been implemented, but does not include all of the elements contained in Requirements R1.1–R1.8.

2.4. Level 4: A contingency plan has not been developed, implemented, and tested.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata

A. Introduction

1. **Title:** **Documentation of Blackstart Generating Unit Test Results**
2. **Number:** EOP-009-0
3. **Purpose:** A system Blackstart Capability Plan (BCP) is necessary to ensure that the quantity and location of system blackstart generators are sufficient and that they can perform their expected functions as specified in overall coordinated Regional System Restoration Plans.
4. **Applicability:**
   - **4.1.** Generator Operator
   - **4.2.** Generator Owner
5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Generator Operator of each blackstart generating unit shall test the startup and operation of each system blackstart generating unit identified in the BCP as required in the Regional BCP (Reliability Standard EOP-007-0_R1). Testing records shall include the dates of the tests, the duration of the tests, and an indication of whether the tests met Regional BCP requirements.

R2. The Generator Owner or Generator Operator shall provide documentation of the test results of the startup and operation of each blackstart generating unit to the Regional Reliability Organizations and upon request to NERC.

C. Measures

M1. The Generator Operator shall have evidence it provided the test results specified in Reliability Standard EOP-009-0R1 as specified in Reliability Standard EOP-009-0_R2.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Timeframe

   Current test results: to the Regional Reliability Organization and upon request to NERC (30 calendar days).

   1.3. Data Retention

   None specified.

   1.4. Additional Compliance Information

   None

2. **Levels of Non-Compliance**

   2.1. Level 1: Startup and operation testing of each blackstart generating unit was performed, but the documentation was incomplete.

   2.2. Level 2: Not applicable.

2.3. Level 3: Startup and operation testing of a blackstart generating unit was only partially performed.

2.4. Level 4: Startup and operation testing of each blackstart generating unit was not performed.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Facility Connection Requirements**
2. **Number:** FAC-001-0
3. **Purpose:** To avoid adverse impacts on reliability, Transmission Owners must establish facility connection and performance requirements.
4. **Applicability:**
   - **4.1.** Transmission Owner
5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Transmission Owner shall document, maintain, and publish facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Reliability Organization, subregional, Power Pool, and individual Transmission Owner planning criteria and facility connection requirements. The Transmission Owner's facility connection requirements shall address connection requirements for:

- **R1.1.** Generation facilities,
- **R1.2.** Transmission facilities, and
- **R1.3.** End-user facilities

R2. The Transmission Owner's facility connection requirements shall address, but are not limited to, the following items:

- **R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
  - **R2.1.1.** Procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems.
  - **R2.1.2.** Procedures for notification of new or modified facilities to others (those responsible for the reliability of the interconnected transmission systems) as soon as feasible.
  - **R2.1.3.** Voltage level and MW and MVAR capacity or demand at point of connection.
  - **R2.1.4.** Breaker duty and surge protection.
  - **R2.1.5.** System protection and coordination.
  - **R2.1.6.** Metering and telecommunications.
  - **R2.1.7.** Grounding and safety issues.
  - **R2.1.8.** Insulation and insulation coordination.
  - **R2.1.9.** Voltage, Reactive Power, and power factor control.
  - **R2.1.10.** Power quality impacts.
  - **R2.1.11.** Equipment Ratings.
  - **R2.1.12.** Synchronizing of facilities.

R2.1.13. Maintenance coordination.

R2.1.14. Operational issues (abnormal frequency and voltages).

R2.1.15. Inspection requirements for existing or new facilities.

R2.1.16. Communications and procedures during normal and emergency operating conditions.

R3. The Transmission Owner shall maintain and update its facility connection requirements as required. The Transmission Owner shall make documentation of these requirements available to the users of the transmission system, the Regional Reliability Organization, and NERC on request (five business days).

C. Measures

M1. The Transmission Owner shall make available (to its Compliance Monitor) for inspection evidence that it met all the requirements stated in Reliability Standard FAC-001-0_R1.

M2. The Transmission Owner shall make available (to its Compliance Monitor) for inspection evidence that it met all requirements stated in Reliability Standard FAC-001-0_R2.

M3. The Transmission Owner shall make available (to its Compliance Monitor) for inspection evidence that it met all the requirements stated in Reliability Standard FAC-001-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (five business days).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Facility connection requirements were provided for generation, transmission, and end-user facilities, per Reliability Standard FAC-001-0_R1, but the document(s) do not address all of the requirements of Reliability Standard FAC-001-0_R2.

2.2. Level 2: Facility connection requirements were not provided for all three categories (generation, transmission, or end-user) of facilities, per Reliability Standard FAC-001-0_R1, but the document(s) provided address all of the requirements of Reliability Standard FAC-001-0_R2.

2.3. Level 3: Facility connection requirements were not provided for all three categories (generation, transmission, or end-user) of facilities, per Reliability Standard FAC-001-0_R1, and the document(s) provided do not address all of the requirements of Reliability Standard FAC-001-0_R2.

2.4. **Level 4:** No document on facility connection requirements was provided per Reliability Standard FAC-001-0_R3.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Coordination of Plans For New Generation, Transmission, and End-User Facilities**

2. **Number:** FAC-002-0

3. **Purpose:** To avoid adverse impacts on reliability, Generator Owners and Transmission Owners and electricity end-users must meet facility connection and performance requirements.

4. **Applicability:**

   4.1. Generator Owner

   4.2. Transmission Owner

   4.3. Distribution Provider

   4.4. Load-Serving Entity

   4.5. Transmission Planner

   4.6. Planning Authority

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Generator Owner, Transmission Owner, Distribution Provider, and Load-Serving Entity seeking to integrate generation facilities, transmission facilities, and electricity end-user facilities shall each coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority. The assessment shall include:

R1.1. Evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems.

R1.2. Ensurance of compliance with NERC Reliability Standards and applicable Regional, subregional, Power Pool, and individual system planning criteria and facility connection requirements.

R1.3. Evidence that the parties involved in the assessment have coordinated and cooperated on the assessment of the reliability impacts of new facilities on the interconnected transmission systems. While these studies may be performed independently, the results shall be jointly evaluated and coordinated by the entities involved.

R1.4. Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance in accordance with Reliability Standard TPL-001-0.

R1.5. Documentation that the assessment included study assumptions, system performance, alternatives considered, and jointly coordinated recommendations.

R2. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each retain its documentation (of its evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems) for three years and shall provide the documentation to the Regional Reliability Organization(s) and NERC on request (within 30 calendar days).

C. Measures

M1. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider's documentation of its assessment of the reliability impacts of new facilities shall address all items in Reliability Standard FAC-002-0_R1.

M2. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each have evidence of its assessment of the reliability impacts of new facilities and their connections on the interconnected transmission systems is retained and provided to other entities in accordance with Reliability Standard FAC-002-0_R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: RRO.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days).

1.3. Data Retention

Evidence of the assessment of the reliability impacts of new facilities and their connections on the interconnected transmission systems: Three years.

1.4. Additional Compliance Information

None

2. Levels of Non-Compliance

2.1. Level 1: Assessments of the impacts of new facilities were provided, but were incomplete in one or more requirements of Reliability Standard FAC-002_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Assessments of the impacts of new facilities were not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	January 13, 2006	Removed duplication of "Regional Reliability Organizations(s).	Errata

A. Introduction

1. **Title:** **Transmission Vegetation Management Program**

2. **Number:** FAC-003-1

3. **Purpose:** To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation-related outages of the transmission systems to the respective Regional Reliability Organizations (RRO) and the North American Electric Reliability Council (NERC).

4. **Applicability:**

   4.1. Transmission Owner.

   4.2. Regional Reliability Organization.

   4.3. This standard shall apply to all transmission lines operated at 200 kV and above and to any lower voltage lines designated by the RRO as critical to the reliability of the electric system in the region.

5. **Effective Dates:**

   5.1. One calendar year from the date of adoption by the NERC Board of Trustees for Requirements 1 and 2.

   5.2. Sixty calendar days from the date of adoption by the NERC Board of Trustees for Requirements 3 and 4.

B. Requirements

R1. The Transmission Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the Transmission Owner's objectives, practices, approved procedures, and work specifications[1].

R1.1. The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the Transmission Owner's transmission lines.

R1.2. The Transmission Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the Transmission Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.

R1.2.1. Clearance 1 — The Transmission Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the Transmission Owner plans to return for future

[1] ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.

vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.

R1.2.2. Clearance 2 — The Transmission Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These Transmission Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.

R1.2.2.1 Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.

R1.2.2.2 Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.

R1.3. All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner, to perform their duties.

R1.4. Each Transmission Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner is restricted from attaining the clearances specified in Requirement 1.2.1.

R1.5. Each Transmission Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.

R2. The Transmission Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each Transmission Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.

R3. The Transmission Owner shall report quarterly to its RRO, or the RRO's designee, sustained transmission line outages determined by the Transmission Owner to have been caused by vegetation.

R3.1. Multiple sustained outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of outages within a 24-hour period.

R3.2. The Transmission Owner is not required to report to the RRO, or the RRO's designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).

R3.3. The outage information provided by the Transmission Owner to the RRO, or the RRO's designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the Transmission Owner.

R3.4. An outage shall be categorized as one of the following:

R3.4.1. Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;

R3.4.2. Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;

R3.4.3. Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.

R4. The RRO shall report the outage information provided to it by Transmission Owner's, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the RRO as a result of any of the reported outages.

C. Measures

M1. The Transmission Owner has a documented TVMP, as identified in Requirement 1.

M1.1. The Transmission Owner has documentation that the Transmission Owner performed the vegetation inspections as identified in Requirement 1.1.

M1.2. The Transmission Owner has documentation that describes the clearances identified in Requirement 1.2.

M1.3. The Transmission Owner has documentation that the personnel directly involved in the design and implementation of the Transmission Owner's TVMP hold the qualifications identified by the Transmission Owner as required in Requirement 1.3.

M1.4. The Transmission Owner has documentation that it has identified any areas not meeting the Transmission Owner's standard for vegetation management and any mitigating measures the Transmission Owner has taken to address these deficiencies as identified in Requirement 1.4.

M1.5. The Transmission Owner has a documented process for the immediate communication of imminent threats by vegetation as identified in Requirement 1.5.

M2. The Transmission Owner has documentation that the Transmission Owner implemented the work plan identified in Requirement 2.

M3. The Transmission Owner has documentation that it has supplied quarterly outage reports to the RRO, or the RRO's designee, as identified in Requirement 3.

M4. The RRO has documentation that it provided quarterly outage reports to NERC as identified in Requirement 4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

RRO

NERC

1.2. Compliance Monitoring Period and Reset

One calendar Year

1.3. Data Retention

Five Years

1.4. Additional Compliance Information

The Transmission Owner shall demonstrate compliance through self-certification submitted to the compliance monitor (RRO) annually that it meets the requirements of NERC Reliability Standard FAC-003-1. The compliance monitor shall conduct an on-site audit every five years or more frequently as deemed appropriate by the compliance monitor to review documentation related to Reliability Standard FAC-003-1. Field audits of ROW vegetation conditions may be conducted if determined to be necessary by the compliance monitor.

2. Levels of Non-Compliance

2.1. Level 1:

2.1.1. The TVMP was incomplete in one of the requirements specified in any subpart of Requirement 1, or;

2.1.2. Documentation of the annual work plan, as specified in Requirement 2, was incomplete when presented to the Compliance Monitor during an on-site audit, or;

2.1.3. The RRO provided an outage report to NERC that was incomplete and did not contain the information required in Requirement 4.

2.2. Level 2:

2.2.1. The TVMP was incomplete in two of the requirements specified in any subpart of Requirement 1, or;

2.2.2. The Transmission Owner was unable to certify during its annual self-certification that it fully implemented its annual work plan, or documented deviations from, as specified in Requirement 2.

2.2.3. The Transmission Owner reported one Category 2 transmission vegetation-related outage in a calendar year.

2.3. Level 3:

2.3.1. The Transmission Owner reported one Category 1 or multiple Category 2 transmission vegetation-related outages in a calendar year, or;

2.3.2. The Transmission Owner did not maintain a set of clearances (Clearance 2), as defined in Requirement 1.2.2, to prevent flashover between vegetation and overhead ungrounded supply conductors, or;

2.3.3. The TVMP was incomplete in three of the requirements specified in any subpart of Requirement 1.

2.4. Level 4:

2.4.1. The Transmission Owner reported more than one Category 1 transmission vegetation-related outage in a calendar year, or;

2.4.2. The TVMP was incomplete in four or more of the requirements specified in any subpart of Requirement 1.

E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
Version 1	TBA	1. Added "Standard Development Roadmap." 2. Changed "60" to "Sixty" in section A, 5.2. 3. Added "Proposed Effective Date: April 7, 2006" to footer. 4. Added "Draft 3: November 17, 2005" to footer.	01/20/06

A. Introduction

1. **Title:** **Facility Ratings Methodology**

2. **Number:** FAC-008-1

3. **Purpose:** To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Transmission Owner

   4.2. Generator Owner

5. **Effective Date:** August 7, 2006

B. Requirements

R1. The Transmission Owner and Generator Owner shall each document its current methodology used for developing Facility Ratings (Facility Ratings Methodology) of its solely and jointly owned Facilities. The methodology shall include all of the following:

R1.1. A statement that a Facility Rating shall equal the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

R1.2. The method by which the Rating (of major BES equipment that comprises a Facility) is determined.

R1.2.1. The scope of equipment addressed shall include, but not be limited to, generators, transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.

R1.2.2. The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.

R1.3. Consideration of the following:

R1.3.1. Ratings provided by equipment manufacturers.

R1.3.2. Design criteria (e.g., including applicable references to industry Rating practices such as manufacturer's warranty, IEEE, ANSI or other standards).

R1.3.3. Ambient conditions.

R1.3.4. Operating limitations.

R1.3.5. Other assumptions.

R2. The Transmission Owner and Generator Owner shall each make its Facility Ratings Methodology available for inspection and technical review by those Reliability Coordinators, Transmission Operators, Transmission Planners, and Planning Authorities that have responsibility for the area in which the associated Facilities are located, within 15 business days of receipt of a request.

R3. If a Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides written comments on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings Methodology, the Transmission Owner or Generator Owner shall provide a written response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the

Facility Ratings Methodology and, if no change will be made to that Facility Ratings Methodology, the reason why.

C. Measures

M1. The Transmission Owner and Generator Owner shall each have a documented Facility Ratings Methodology that includes all of the items identified in FAC-008 Requirement 1.1 through FAC-008 Requirement 1.3.5.

M2. The Transmission Owner and Generator Owner shall each have evidence it made its Facility Ratings Methodology available for inspection within 15 business days of a request as follows:

M2.1 The Reliability Coordinator shall have access to the Facility Ratings Methodologies used for Rating Facilities in its Reliability Coordinator Area.

M2.2 The Transmission Operator shall have access to the Facility Ratings Methodologies used for Rating Facilities in its portion of the Reliability Coordinator Area.

M2.3 The Transmission Planner shall have access to the Facility Ratings Methodologies used for Rating Facilities in its Transmission Planning Area.

M2.4 The Planning Authority shall have access to the Facility Ratings Methodologies used for Rating Facilities in its Planning Authority Area.

M3. If the Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides documented comments on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings Methodology, the Transmission Owner or Generator Owner shall have evidence that it provided a written response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings Methodology and, if no change will be made to that Facility Ratings Methodology, the reason why.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Transmission Owner and Generator Owner shall self-certify its compliance to the Compliance Monitor at least once every three years. New Transmission Owners and Generator Owners shall each demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

The Transmission Owner and Generator Owner shall each keep all superseded portions of its Facility Ratings Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on the Facility Ratings Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Transmission Owner and Generator Owner shall each make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 Facility Ratings Methodology

1.4.2 Superseded portions of its Facility Ratings Methodology that had been replaced, changed or revised within the past 12 months

1.4.3 Documented comments provided by a Reliability Coordinator, Transmission Operator, Transmission Planner or Planning Authority on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings methodology, and the associated responses

2. Levels of Non-Compliance

2.1. Level 1: There shall be a level one non-compliance if any of the following conditions exists:

2.1.1 The Facility Ratings Methodology does not contain a statement that a Facility Rating shall equal the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

2.1.2 The Facility Ratings Methodology does not address one of the required equipment types identified in FAC-008 R1.2.1.

2.1.3 No evidence of responses to a Reliability Coordinator's, Transmission Operator, Transmission Planner, or Planning Authority's comments on the Facility Ratings Methodology.

2.2. Level 2: The Facility Ratings Methodology is missing the assumptions used to determine Facility Ratings or does not address two of the required equipment types identified in FAC-008 R1.2.1.

2.3. Level 3: The Facility Ratings Methodology does not address three of the required equipment types identified in FAC-008-1 R1.2.1.

2.4. Level 4: The Facility Ratings Methodology does not address both Normal and Emergency Ratings or the Facility Ratings Methodology was not made available for inspection within 15 business days of receipt of a request.

E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
1	01/01/05	1. Lower cased the word "draft" and "drafting team" where appropriate. 2. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 3. Changed "Timeframe" to "Time	01/20/05

		Frame" and "twelve" to "12" in item D, 1.2.	

A. Introduction

1. **Title:** **Establish and Communicate Facility Ratings**

2. **Number:** FAC-009-1

3. **Purpose:** To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Transmission Owner

   4.2. Generator Owner

5. **Effective Date:** October 7, 2006

B. Requirements

R1. The Transmission Owner and Generator Owner shall each establish Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings Methodology.

R2. The Transmission Owner and Generator Owner shall each provide Facility Ratings for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities to its associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) as scheduled by such requesting entities.

C. Measures

M1. The Transmission Owner and Generator Owner shall each be able to demonstrate that it developed its Facility Ratings consistent with its Facility Ratings Methodology.

M1.1 The Transmission Owner's and Generator Owner's Facility Ratings shall each include ratings for its solely and jointly owned Facilities including new Facilities, existing Facilities, modifications to existing Facilities and re-ratings of existing Facilities.

M2. The Transmission Owner and Generator Owner shall each have evidence that it provided its Facility Ratings to its associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) as scheduled by such requesting entities.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization

   1.2. Compliance Monitoring Period and Reset Time Frame

   Each Transmission Owner and Generator Owner shall self-certify its compliance to the Compliance Monitor annually. The Compliance Monitor may conduct a targeted audit once in each calendar year (January–December) and an investigation upon complaint to assess performance.

   The Performance-Reset Period shall be twelve months from the last finding of non-compliance.

1.3. Data Retention

The Transmission Owner and Generator Owner shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall retain audit data for three years.

1.4. Additional Compliance Information

The Transmission Owner and Generator Owner shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 Facility Ratings Methodology

1.4.2 Facility Ratings

1.4.3 Evidence that Facility Ratings were distributed

1.4.4 Distribution schedules provided by entities that requested Facility Ratings

2. Levels of Non-Compliance

2.1. Level 1: Not all requested Facility Ratings associated with existing Facilities were provided to the Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) in accordance with their respective schedules.

2.2. Level 2: Not all Facility Ratings associated with new Facilities, modifications to existing Facilities, and re-ratings of existing Facilities were provided to the Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) in accordance with their respective schedules.

2.3. Level 3: Facility Ratings provided were not developed consistent with the Facility Ratings Methodology.

2.4. Level 4: No Facility Ratings were provided to the Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), or Transmission Operator(s) in accordance with their respective schedules.

E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Lower cased the word “draft” and “drafting team” where appropriate. 2. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 3. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Planning Horizon**
2. **Number:** FAC-010-2.1
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**

   4.1. Planning Authority
5. **Effective Date:** April 19, 2010

B. Requirements

R1. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the planning horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3.2. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R2.5. Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.6. In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:

R2.6.1. Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.

R3. The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).

R3.2. Selection of applicable Contingencies.

R3.3. Level of detail of system models used to determine SOLs.

R3.4. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.5. Anticipated transmission system configuration, generation dispatch and Load level.

R3.6. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:

R4.1. Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.

R4.2. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.

R4.3. Each Transmission Planner that works in the Planning Authority's Planning Authority Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology.

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.

2.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.2	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1. OR The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.
R2	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance following single and multiple contingencies, but does not address the pre-contingency state (R2.1)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following single contingencies, but does not address multiple contingencies. (R2.5-R2.6)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following multiple contingencies, but does not meet the performance for response to single contingencies. (R2.2 –R2.4)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state but does not require that SOLs be set to meet the BES performance specified for response to single contingencies (R2.2-R2.4) and does not require that SOLs be set to meet the BES performance specified for response to multiple contingencies. (R2.5-R2.6)
R3	The Planning Authority has a methodology for determining SOLs that includes a description for all but one of the following: R3.1 through R3.6.	The Planning Authority has a methodology for determining SOLs that includes a description for all but two of the following: R3.1 through R3.6.	The Planning Authority has a methodology for determining SOLs that includes a description for all but three of the following: R3.1 through R3.6.	The Planning Authority has a methodology for determining SOLs that is missing a description of four or more of the following: R3.1 through R3.6.
R4	One or both of the following: The Planning Authority issued its SOL Methodology and changes	One of the following: The Planning Authority issued its SOL Methodology and changes	One of the following: The Planning Authority issued its SOL Methodology and changes	One of the following: The Planning Authority failed to issue its SOL Methodology and

Requirement	Lower	Moderate	High	Severe
	to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	changes to that methodology to more than three of the required entities. The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. The Planning Authority issued its SOL Methodology and changes to that methodology to all but

Requirement	Lower	Moderate	High	Severe
				four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.
R5	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days. OR The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer. OR The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

E. Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R2.5 and R2.6, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
1	November 1, 2006	Fixed typo. Removed the word "each" from the 1st sentence of section D.1.3, Data Retention.	01/11/07
2	June 24, 2008	Adopted by Board of Trustees; FERC Order 705	Revised
2		Changed the effective date to July 1, 2008 Changed "Cascading Outage" to "Cascading" Replaced Levels of Non-compliance with Violation Severity Levels	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2.1	November 5, 2009	Adopted by the Board of Trustees — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2.	Errata
2.1	April 19, 2010	FERC Approved — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2.	Errata

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Operations Horizon**
2. **Number:** FAC-011-2
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**

   4.1. Reliability Coordinator
5. **Effective Date:** April 29, 2009

B. Requirements

R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the operations horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

R2.3. In determining the system's response to a single Contingency, the following shall be acceptable:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

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[1] The Contingencies identified in FAC-011 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies

R2.3.3. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

R3.2. Selection of applicable Contingencies

R3.3. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.

R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.

R3.4. Level of detail of system models used to determine SOLs.

R3.5. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.6. Anticipated transmission system configuration, generation dispatch and Load level

R3.7. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:

R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.

R4.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.

R4.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.

2.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1. OR The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area.
R2	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)	Not applicable.	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)	The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)
R3	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but one of the following: R3.1 through R3.7.	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but two of the following: R3.1 through R3.7.	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but three of the following: R3.1 through R3.7.	The Reliability Coordinator has a methodology for determining SOLs that is missing a description of three or more of the following: R3.1 through R3.7.
R4	One or both of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was	One of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30	One of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60	One of the following: The Reliability Coordinator failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Reliability Coordinator issued its SOL Methodology and

Requirement	Lower	Moderate	High	Severe
	provided up to 30 calendar days after the effectiveness of the change.	calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to

Requirement	Lower	Moderate	High	Severe
				30 calendar days after the effectiveness of the change.
R5	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to October 1, 2008 Changed “Cascading Outage” to “Cascading” Replaced Levels of Non-compliance with Violation Severity Levels Corrected footnote 1 to reference FAC-011 rather than FAC-010	Revised
2	June 24, 2008	Adopted by Board of Trustees: FERC Order 705	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update

A. Introduction

1. **Title:** **Establish and Communicate Transfer Capabilities**

2. **Number:** FAC-013-1

3. **Purpose:** To ensure that Transfer Capabilities used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Reliability Coordinator required by its Regional Reliability Organization to establish inter-regional and intra-regional Transfer Capabilities

   4.2. Planning Authority required by its Regional Reliability Organization to establish inter-regional and intra-regional Transfer Capabilities

5. **Effective Date:** October 7, 2006

B. Requirements

R1. The Reliability Coordinator and Planning Authority shall each establish a set of inter-regional and intra-regional Transfer Capabilities that is consistent with its current Transfer Capability Methodology.

R2. The Reliability Coordinator and Planning Authority shall each provide its inter-regional and intra-regional Transfer Capabilities to those entities that have a reliability-related need for such Transfer Capabilities and make a written request that includes a schedule for delivery of such Transfer Capabilities as follows:

R2.1. The Reliability Coordinator shall provide its Transfer Capabilities to its associated Regional Reliability Organization(s), to its adjacent Reliability Coordinators, and to the Transmission Operators, Transmission Service Providers and Planning Authorities that work in its Reliability Coordinator Area.

R2.2. The Planning Authority shall provide its Transfer Capabilities to its associated Reliability Coordinator(s) and Regional Reliability Organization(s), and to the Transmission Planners and Transmission Service Provider(s) that work in its Planning Authority Area.

C. Measures

M1. The Reliability Coordinator and Planning Authority shall each be able to demonstrate that it developed its Transfer Capabilities consistent with its Transfer Capability Methodology.

M2. The Reliability Coordinator and Planning Authority shall each have evidence that it provided its Transfer Capabilities in accordance with schedules supplied by the requestors of such Transfer Capabilities.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility
   Regional Reliability Organization

   1.2. Compliance Monitoring Period and Reset Timeframe

   The Reliability Coordinator and Planning Authority shall each verify compliance through self-certification submitted to the Compliance Monitor annually. The Compliance

Monitor may conduct a targeted audit once in each calendar year (January–December) and an investigation upon a complaint to assess compliance.

The Performance-Reset Period shall be twelve months from the last finding of non-compliance.

1.3. Data Retention

The Planning Authority and Reliability Coordinator shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority and Reliability Coordinator shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 Transfer Capability Methodology.

1.4.2 Inter-regional and Intra-regional Transfer Capabilities.

1.4.3 Evidence that Transfer Capabilities were distributed.

1.4.4 Distribution schedules provided by entities that requested Transfer Capabilities.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: Not all requested Transfer Capabilities were provided in accordance with their respective schedules.

2.3. Level 3: Transfer Capabilities were not developed consistent with the Transfer Capability Methodology.

2.4. Level 4: No requested Transfer Capabilities were provided in accordance with their respective schedules.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Changed incorrect use of certain hyphens (-) to “en dash (–).” 2. Lower cased the word “draft” and “drafting team” where appropriate. 3. Changed Anticipated Action #5, page 1, from “30-day” to “Thirty-day.” 4. Added or removed “periods.”	01/20/05

A. Introduction

1. **Title:** **Establish and Communicate System Operating Limits**
2. **Number:** FAC-014-2
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
   - **4.1.** Reliability Coordinator
   - **4.2.** Planning Authority
   - **4.3.** Transmission Planner
   - **4.4.** Transmission Operator
5. **Effective Date:** April 29, 2009

B. Requirements

R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.

R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology.

R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL Methodology.

R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows:

R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:

R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL.

R5.1.2. The value of the IROL and its associated T_v.

R5.1.3. The associated Contingency(ies).

R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).

R5.2. The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.

R5.3. The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area.

R5.4. The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.

R6. The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits.

R6.1. The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits.

R6.2. If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.

C. Measures

M1. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each be able to demonstrate that it developed its SOLs (including the subset of SOLs that are IROLs) consistent with the applicable SOL Methodology in accordance with Requirements 1 through 4.

M2. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each have evidence that its SOLs (including the subset of SOLs that are IROLs) were supplied in accordance with schedules supplied by the requestors of such SOLs as specified in Requirement 5.

M3. The Planning Authority shall have evidence it identified a list of multiple contingencies (if any) and their associated stability limits and provided the list and the limits to its Reliability Coordinators in accordance with Requirement 6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each verify compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor may conduct a targeted audit once in each calendar year (January – December) and an investigation upon a complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last finding of non-compliance.

1.3. Data Retention

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology(ies)

1.4.2 SOLs, including the subset of SOLs that are IROLs and the IROLs supporting information

1.4.3 Evidence that SOLs were distributed

1.4.4 Evidence that a list of stability-related multiple contingencies and their associated limits were distributed

1.4.5 Distribution schedules provided by entities that requested SOLs

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	There are SOLs, for the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs, for the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs, for the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs for the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)
R2	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)
R3	There are SOLs, for the Planning Coordinator Area, but from 1% up to, but less than, 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs, for the Planning Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs for the Planning Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs, for the Planning Coordinator Area, but 75% or more of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)
R4	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but up to 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	The Transmission Planner has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 75% or more of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)
R5	The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all the requesting entities but missed meeting one or more of the schedules by less than 15	One of the following: The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but one of the requesting entities within the schedules provided.	One of the following: The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but two of the requesting entities within the schedules provided.	One of the following: The responsible entity failed to provide its SOLs (including the subset of SOLs that are IROLs) to more than two of the requesting entities within 45

Requirement	Lower	Moderate	High	Severe
	calendar days. (R5)	(R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 15 or more but less than 30 calendar days. (R5) OR The supporting information provided with the IROLs does not address 5.1.4	(R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 30 or more but less than 45 calendar days. (R5) OR The supporting information provided with the IROLs does not address 5.1.3	calendar days of the associated schedules. (R5) OR The supporting information provided with the IROLs does not address 5.1.1 and 5.1.2.
R6	The Planning Authority failed to notify the Reliability Coordinator in accordance with R6.2	Not applicable.	The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)	The Planning Authority did not identify the subset of multiple contingencies which result in stability limits. (R6) OR The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to more than one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to January 1, 2009 Replaced Levels of Non-compliance with Violation Severity Levels	Revised
2	June 24, 2008	Adopted by Board of Trustees: FERC Order	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update

A. Introduction

1. **Title: Interchange Information**
2. **Number:** INT-001-3
3. **Purpose:**
   To ensure that Interchange information is submitted to the NERC-identified reliability analysis service.
4. **Applicability:**
   4.1. Purchase-Selling Entities.
   4.2. Balancing Authorities.
5. **Effective Date:** August 27, 2008 (U.S.)
   NERC Board Approval: October 9, 2007

B. Requirements

R1. The Load-Serving, Purchasing-Selling Entity shall ensure that Arranged Interchange is submitted to the Interchange Authority for:

R1.1. All Dynamic Schedules at the expected average MW profile for each hour.

R2. The Sink Balancing Authority shall ensure that Arranged Interchange is submitted to the Interchange Authority:

R2.1. If a Purchasing-Selling Entity is not involved in the Interchange, such as delivery from a jointly owned generator.

R2.2. For each bilateral Inadvertent Interchange payback.

C. Measures

M1. The Purchasing-Selling Entity that serves the load shall have and provide upon request evidence that could include but is not limited to, its Interchange Transaction tags operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts or other equivalent evidence that will be used to confirm that Arranged Interchange was submitted to the Interchange Authority for all Dynamic Schedules at the expected average MW profile for each hour as specified in Requirement 1.

M2. Each Sink Balancing Authority shall have and provide upon request evidence that could include but is not limited to, Interchange Transaction tags operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts, or other equivalent evidence that will be used to confirm that Arranged Interchange was submitted to the Interchange Authority as specified in Requirements 2.1 and 2.2.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

The Purchasing-Selling Entity that serves load and Sink Balancing Authority shall each keep 90 days of historical data (evidence).

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Sink Balancing Authorities:

2.1. Level 1: One instance of not submitting Arranged Interchange to the Interchange Authority as specified in R2.1 and R2.2.

2.2. Level 2: Two instances of not submitting Arranged Interchange to the Interchange Authority as specified in R2.1 and 2.2.

2.3. Level 3: Three instances of not submitting Arranged Interchange to the Interchange Authority as specified in R2.1 and 2.2.

2.4. Level 4: Four or more instances of not submitting Arranged Interchange to the Interchange Authority as specified in R2.1 and 2.2.

3. Levels of Non-Compliance for Purchasing-Selling Entities that Serve Load:

3.1. Level 1: One instance of not submitting Arranged Interchange to the Interchange Authority as specified in R1.

3.2. **Level 2:** Two instances of not submitting Arranged Interchange to the Interchange Authority as specified in R1.

3.3. **Level 3:** Three instances of not submitting Arranged Interchange to the Interchange Authority as specified in R1.

3.4. **Level 4:** Four or more instances of not submitting Arranged Interchange to the Interchange Authority as specified in R1.

E. Regional Differences

1. MISO Energy Flow Information Waiver effective on July 16, 2003.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Adopted by Board of Trustees	Revised
3	October 9, 2008	Adopted by Board of Trustees (Remove WECC Waiver)	Revised
3	July 21, 2008	Regulatory Approval	Revised

A. Introduction

1. **Title:** **Interchange Transaction Implementation**
2. **Number:** INT-003-2
3. **Purpose:**

   To ensure Balancing Authorities confirm Interchange Schedules with Adjacent Balancing Authorities prior to implementing the schedules in their Area Control Error (ACE) equations.

4. **Applicability**

   4.1. Balancing Authorities.

5. **Effective Date:** January 1, 2007

B. Requirements

R1. Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation.

R1.1. The Sending Balancing Authority and Receiving Balancing Authority shall agree on Interchange as received from the Interchange Authority, including:

R1.1.1. Interchange Schedule start and end time.

R1.1.2. Energy profile.

R1.2. If a high voltage direct current (HVDC) tie is on the Scheduling Path, then the Sending Balancing Authorities and Receiving Balancing Authorities shall coordinate the Interchange Schedule with the Transmission Operator of the HVDC tie.

C. Measures

M1. Each Receiving and Sending Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, interchange transaction tags, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts, or other equivalent evidence that will be used to confirm that each Interchange Schedule's start and end time, and energy profile were confirmed prior to implementation in the Balancing Authority's ACE equation. (Requirement R1, R1.1, R1.1.1 & R1.1.2)

M2. Each Receiving and Sending Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, interchange transaction tags, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts, or other equivalent evidence that will be used to confirm that it coordinated the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in Requirement 1.2.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Balancing Authority shall keep 90 days of historical data (evidence).

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Balancing Authorities:

2.1. Level 1: There shall be a separate Level 1 non-compliance, if either of the following conditions exists:

2.1.1 One instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.

2.1.2 One instance of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2

2.2. **Level 2:** There shall be a separate Level 2 non-compliance, if either of the following conditions exists:

2.2.1 Two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1, and R1.1.2.

2.2.2 Two instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2

2.3. **Level 3:** There shall be a separate Level 3 non-compliance, if either of the following conditions exists:

2.3.1 Three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1, and R1.1.2.

2.3.2 Three instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2

2.4. **Level 4:** There shall be a separate Level 4 non-compliance, if either of the following conditions exists:

2.4.1 Four or more instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1, and R1.1.2.

2.4.2 Four or more instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2.

E. Regional Differences

1. MISO Scheduling Agent Waiver dated November 21, 2002.
2. MISO Enhanced Scheduling Agent Waiver dated July 16, 2003.
3. MISO Energy Flow Information Waiver dated July 16, 2003.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Adopted by Board of Trustees	Revised

A. Introduction

1. **Title:** **Dynamic Interchange Transaction Modifications**
2. **Number:** INT-004-2
3. **Purpose:** To ensure Dynamic Transfers are adequately tagged to be able to determine their reliability impacts.
4. **Applicability**
   - **4.1.** Balancing Authorities
   - **4.2.** Reliability Coordinators
   - **4.3.** Transmission Operators
   - **4.4.** Purchasing-Selling Entities
5. **Effective Date:** August 27, 2008 (U.S.)

   NERC Board Approval: October 9, 2007

B. Requirements

R1. At such time as the reliability event allows for the reloading of the transaction, the entity that initiated the curtailment shall release the limit on the Interchange Transaction tag to allow reloading the transaction and shall communicate the release of the limit to the Sink Balancing Authority.

R2. The Purchasing-Selling Entity responsible for tagging a Dynamic Interchange Schedule shall ensure the tag is updated for the next available scheduling hour and future hours when any one of the following occurs:

- **R2.1.** The average energy profile in an hour is greater than 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than ±10%.
- **R2.2.** The average energy profile in an hour is less than or equal to 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than ±25 megawatt-hours.
- **R2.3.** A Reliability Coordinator or Transmission Operator determines the deviation, regardless of magnitude, to be a reliability concern and notifies the Purchasing-Selling Entity of that determination and the reasons.

C. Measures

M1. The Sink Balancing Authority shall provide evidence that the responsible Purchasing-Selling Entity revised a tag when the deviation exceeded the criteria in INT-004 Requirement 2.

D. Compliance

1. **Compliance Monitoring Process**

   Periodic tag audit as prescribed by NERC. For the requested time period, the Sink Balancing Authority shall provide the instances when Dynamic Schedule deviation

exceeded the criteria in INT-004 R2 and shall provide evidence that the responsible Purchasing-Selling Entity submitted a revised tag.

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year without a violation from the time of the violation.

1.3. Data Retention

Three months.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: Not specified.

2.2. Level 2: Not specified.

2.3. Level 3: Not specified.

2.4. Level 4: Not specified.

E. Regional Differences

1. None

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Board of Trustees Approval	Revised
2	October 9, 2007	Board of Trustees Approval (Removal of WECC Waiver)	Revised
2	July 21, 2008	FERC Approval	Revised

A. Introduction

1. **Title:** **Interchange Authority Distributes Arranged Interchange**
2. **Number:** INT-005-2
3. **Purpose:** To ensure that the implementation of Interchange between Source and Sink Balancing Authorities is distributed by an Interchange Authority such that Interchange information is available for reliability assessments.
4. **Applicability:**

   4.1. Interchange Authority.
5. **Effective Date:** August 27, 2008. (U.S.)

   NERC Board Approval: May 2, 2007

B. Requirements

R1. Prior to the expiration of the time period defined in the Timing Table, Column A, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment to all reliability entities involved in the Interchange.

R1.1. When a Balancing Authority or Reliability Coordinator initiates a Curtailment to Confirmed or Implemented Interchange for reliability, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment only to the Source Balancing Authority and the Sink Balancing Authority.

C. Measures

M1. For each Arranged Interchange, the Interchange Authority shall be able to provide evidence that it has distributed the Arranged Interchange information to all reliability entities involved in the Interchange within the applicable time frame.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Time Frame

   The Performance-Reset Period shall be twelve months from the last non-compliance to Requirement 1.

   1.3. Data Retention

   The Interchange Authority shall keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

   1.4. Additional Compliance Information

   Each Interchange Authority shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

Subsequent to the initial compliance review, compliance may be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of noncompliant Interchange Authorities, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a specific complaint of failure to perform R1. Complaints must be lodged within 60 days of the incident. The Compliance Monitor will evaluate complaints.

Each Interchange Authority shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records for the audit period which indicate the Interchange Authority's distribution of all Arranged Interchange information to all reliability entities involved in an Interchange. The Compliance Monitor may request up to a three month period of historical data ending with the date the request is received by the Interchange Authority.

1.4.6 For specific complaints, only those data and system log records associated with the specific Interchange event contained in the complaint which indicate that the Interchange Authority distributed the Arranged Interchange information to all reliability entities involved in that specific Interchange.

2. Levels of Non-Compliance

2.1. Level 1: One occurrence[1] of not distributing information to all involved reliability entities as described in R1.

2.2. Level 2: Two occurrences[1] of not distributing information to all involved reliability entities as described in R1.

2.3. Level 3: Three occurrences[1] of not distributing information to all involved reliability entities as described in R1.

2.4. Level 4: Four or more occurrences[1] of not distributing information to all involved reliability entities as described in R1 or no evidence provided.

E. Regional Differences

None

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Approved by BOT	New

[1] This does not include instances of not distributing information due to extenuating circumstances approved by the Compliance Monitor.

2	May 2, 2007	Approved by BOT	Revised
2	July 21, 2008	Approved by FERC	Revised

Timing Table

Interchange Timeline with Minimum Reliability-Related Response Times

	A	B	C	D	
If Actual Arranged Interchange (RFI) is Submitted	**IA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments** **IA Verifies Reliability Data Complete**	**IA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**	**Minimum *Total* Reliability Period** **(Columns A through D)**
≤1 hour prior to ramp start	≤ 1 minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA for all Interconnections except WECC	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start	*15 minutes*
≤20 minutes prior to ramp start	≤ 1 minute from RFI submission	≤ 5 minutes from Arranged Interchange receipt from IA for WECC	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start	*10 minutes*
>20 minutes to ≤1 hour prior to ramp start	≤ 1 minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA for WECC	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start	*15 minutes*
>1 hour to < 4 hours prior to ramp start	≤ 1 minute from RFI submission	≤ 20 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start	*1 hour plus 1 minute*
≥ 4 hours prior to ramp start	≤ 1 minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start	*4 hours*

A. Introduction

1. **Title:** **Response to Interchange Authority**
2. **Number:** INT-006-2
3. **Purpose:** To ensure that each Arranged Interchange is checked for reliability before it is implemented.
4. **Applicability:**
   - **4.1.** Balancing Authority.
   - **4.2.** Transmission Service Provider.
5. **Effective Date:** August 27, 2008. (U.S.)

   NERC Board Approved: May 2, 2007

B. Requirements

R1. Prior to the expiration of the reliability assessment period defined in the Timing Table, Column B, the Balancing Authority and Transmission Service Provider shall respond to a request from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange.

- **R1.1.** Each involved Balancing Authority shall evaluate the Arranged Interchange with respect to:
  - **R1.1.1.** Energy profile (ability to support the magnitude of the Interchange).
  - **R1.1.2.** Ramp (ability of generation maneuverability to accommodate).
  - **R1.1.3.** Scheduling path (proper connectivity of Adjacent Balancing Authorities).
- **R1.2.** Each involved Transmission Service Provider shall confirm that the transmission service arrangements associated with the Arranged Interchange have adjacent Transmission Service Provider connectivity, are valid and prevailing transmission system limits will not be violated.

C. Measures

M1. The Balancing Authority and Transmission Service Provider shall each provide evidence that it responded, relative to transitioning an Arranged Interchange to a Confirmed Interchange, to each request from an Interchange Authority within the reliability assessment period defined in the Timing Table, Column B.

D. Compliance

1. **Compliance Monitoring Process**

   - **1.1. Compliance Monitoring Responsibility**
     Regional Reliability Organization.
   - **1.2. Compliance Monitoring Period and Reset Time Frame**

     The Performance-Reset Period shall be twelve months from the last non-compliance to Requirement 1.
   - **1.3. Data Retention**

The Balancing Authority and Transmission Service Provider shall each keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

1.4. Additional Compliance Information

The Balancing Authority and Transmission Service Provider shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

Subsequent to the initial compliance review, compliance may be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of non-compliant Interchange Authorities, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. The Compliance Monitor will evaluate complaints.

The Balancing Authority, and Transmission Service Provider shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records and agreements for the audit period which indicate a reliability entity identified in R1 responded to all instances of the Interchange Authority's communication under Reliability Standard INT-005 Requirement 1 concerning the pending transition of an Arranged Interchange to Confirmed Interchange. The Compliance Monitor may request up to a three month period of historical data ending with the date the request is received by the Balancing Authority, or Transmission Service Provider.

1.4.6 For specific complaints, agreements and those data and system log records associated with the specific Interchange event contained in the complaint which indicates a reliability entity identified in R1 has responded to the Interchange Authority's communication under INT-005 R1 concerning the pending transition of Arranged Interchange to Confirmed Interchange for that specific Interchange.

2. Levels of Non-Compliance

2.1. Level 1: One occurrence[1] of not responding to the Interchange Authority as described in R1.

2.2. Level 2: Two occurrences[1] of not responding to the Interchange Authority as described in R1.

[1] This does not include instances of not responding due to extenuating circumstances approved by the Compliance Monitor.

2.3. Level 3: Three occurrences[1] of not responding to the Interchange Authority as described in R1.

2.4. Level 4: Four or more occurrences[1] of not responding to the Interchange Authority as described in R1 or no evidence provided.

E. Regional Differences

None.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Approved by BOT	New
2	May 2, 2007	Approved by BOT	Revised
2	July 21, 2008	Approved by FERC	Revised

Timing Table

Interchange Timeline with Minimum Reliability-Related Response Times

	A	B	C	D	
If Actual Arranged Interchange (RFI) is Submitted	**IA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments** **IA Verifies Reliability Data Complete**	**IA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**	**Minimum *Total* Reliability Period** **(Columns A through D)**
≤1 hour prior to ramp start	≤ 1 minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA for all Interconnections except WECC	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start	*15 minutes*
≤20 minutes prior to ramp start	≤ 1 minute from RFI submission	≤ 5 minutes from Arranged Interchange receipt from IA for WECC	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start	*10 minutes*
>20 minutes to ≤1 hour prior to ramp start	≤ 1 minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA for WECC	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start	*15 minutes*
>1 hour to < 4 hours prior to ramp start	≤ 1 minute from RFI submission	≤ 20 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start	*1 hour plus 1 minute*
≥ 4 hours prior to ramp start	≤ 1 minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start	*4 hours*

A. Introduction

1. **Title:** **Interchange Confirmation**
2. **Number:** **INT-007-1**
3. **Purpose:** To ensure that each Arranged Interchange is checked for reliability before it is implemented.
4. **Applicability**

   4.1. Interchange Authority.
5. **Effective Date:** January 1, 2007

B. Requirements

R1. The Interchange Authority shall verify that Arranged Interchange is balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange by verifying the following:

R1.1. Source Balancing Authority megawatts equal sink Balancing Authority megawatts (adjusted for losses, if appropriate).

R1.2. All reliability entities involved in the Arranged Interchange are currently in the NERC registry.

R1.3. The following are defined:

R1.3.1. Generation source and load sink.

R1.3.2. Megawatt profile.

R1.3.3. Ramp start and stop times.

R1.3.4. Interchange duration.

R1.4. Each Balancing Authority and Transmission Service Provider that received the Arranged Interchange information from the Interchange Authority for reliability assessment has provided approval.

C. Measures

M1. For each Arranged Interchange, the Interchange Authority shall show evidence that it has verified the Arranged Interchange information prior to the dissemination of the Confirmed Interchange.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Time Frame

   The Performance-Reset Period shall be twelve months from the last noncompliance to Requirement 1.

   1.3. Data Retention

   The Interchange Authority shall keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

1.4. Additional Compliance Information

Each Interchange Authority shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

Subsequent to the initial compliance review, compliance may be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of noncompliant Interchange Authorities, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. Complaints will be evaluated by the Compliance Monitor.

Each Interchange Authority shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records for the audit period which indicate an Interchange Authority's verification that all Arranged Interchange was balanced and valid as defined in R1. The Compliance Monitor may request up to a three-month period of historical data ending with the date the request is received by the Interchange Authority.

1.4.6 For specific complaints, only those data and system log records associated with the specific Interchange event contained in the complaint which indicate an Interchange Authority's verification that an Arranged Interchange was balanced and valid as defined in R1 for that specific Interchange

2. Levels of Non-Compliance

2.1. Level 1: One occurrence[1] where Interchange-related data was not verified as defined in R1.

2.2. Level 2: Two occurrences where Interchange-related data was not verified as defined in R1.

2.3. Level 3: Three occurrences where Interchange-related data was not verified as defined in R1.

2.4. Level 4: Four or more occurrences where Interchange-related data was not verified as defined in R1.

E. Regional Differences

None

[1] This does not include instances of not verifying due to extenuating circumstances approved by the Compliance Monitor.

Version History

Version	Date	Action	Change Tracking

A. Introduction

1. **Title:** **Interchange Authority Distributes Status**
2. **Number:** INT-008-2
3. **Purpose:** To ensure that the implementation of Interchange between Source and Sink Balancing Authorities is coordinated by an Interchange Authority.
4. **Applicability:**

   4.1. Interchange Authority.
5. **Effective Date:** August 27, 2008. (U.S.)

   NERC Board Approval: May 2, 2007

B. Requirements

R1. Prior to the expiration of the time period defined in the Timing Table, Column C, the Interchange Authority shall distribute to all Balancing Authorities (including Balancing Authorities on both sides of a direct current tie), Transmission Service Providers and Purchasing-Selling Entities involved in the Arranged Interchange whether or not the Arranged Interchange has transitioned to a Confirmed Interchange.

R1.1. For Confirmed Interchange, the Interchange Authority shall also communicate:

R1.1.1. Start and stop times, ramps, and megawatt profile to Balancing Authorities.

R1.1.2. Necessary Interchange information to NERC-identified reliability analysis services.

C. Measures

M1. For each Arranged Interchange, the Interchange Authority shall provide evidence that it has distributed the final status and Confirmed Interchange information specified in Requirement 1 to all Balancing Authorities, Transmission Service Providers and Purchasing-Selling Entities involved in the Arranged Interchange within the time period defined in the Timing Table, Column C. If denied, the Interchange Authority shall tell all involved parties that approval has been denied.

M1.1 For each Arranged Interchange that includes a direct current tie, the Interchange Authority shall provide evidence that it has communicated the final status to the Balancing Authorities on both sides of the direct current tie, even if the Balancing Authorities are neither the Source nor Sink for the Interchange.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Time Frame

The Performance-Reset Period shall be twelve months from the last non-compliance to R1.

1.3. Data Retention

The Interchange Authority shall keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

1.4. Additional Compliance Information

Each Interchange Authority shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

Subsequent to the initial compliance review, compliance will be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of noncompliant Interchange Authorities, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. Complaints will be evaluated by the Compliance Monitor.

Each Interchange Authority shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records for the audit period which indicate the Interchange Authority's distribution of all Arranged Interchange final status and Confirmed Interchange information to all entities involved in an Interchange per R1. The Compliance Monitor may request up to a three-month period of historical data ending with the date the request is received by the Interchange Authority

1.4.6 For specific complaints, only those data and system log records associated with the specific Interchange event contained in the complaint which indicate that the Interchange Authority distributed the Arranged Interchange final status and Confirmed Interchange information to all entities involved in that specific Interchange.

2. Levels of Non-Compliance

2.1. Level 1: One occurrence[1] of not distributing final status and information as described in R1.

[1] This does not include instances of not distributing information due to extenuating circumstances approved by the Compliance Monitor.

2.2. Level 2: Two occurrences[1] of not distributing final status and information as described in R1.

2.3. Level 3: Three occurrences[1] of not distributing final status and information as described in R1.

2.4. Level 4: Four or more occurrences[1] of not distributing final status and information as described in R1 or no evidence provided.

E. Regional Differences

None.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Approved by BOT	New
2	May 2, 2007	Approved by BOT	Revised
2	July 21, 2008	Approved by FERC	Revised

Timing Table

	A	B	C	D	
If Actual Arranged Interchange (RFI) is Submitted	**IA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments** **IA Verifies Reliability Data Complete**	**IA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**	**Minimum *Total* Reliability Period** **(Columns A through D)**
≤1 hour prior to ramp start	≤ 1 minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA for all Interconnections except WECC	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start	*15 minutes*
≤20 minutes prior to ramp start	≤ 1 minute from RFI submission	≤ 5 minutes from Arranged Interchange receipt from IA for WECC	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start	*10 minutes*
>20 minutes to ≤1 hour prior to ramp start	≤ 1 minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA for WECC	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start	*15 minutes*
>1 hour to < 4 hours prior to ramp start	≤ 1 minute from RFI submission	≤ 20 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start	*1 hour plus 1 minute*
≥ 4 hours prior to ramp start	≤ 1 minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start	*4 hours*

A. Introduction

1. **Title:** **Implementation of Interchange**

2. **Number:** **INT-009-1**

3. **Purpose:** To ensure that the implementation of Interchange between Source and Sink Balancing Authorities is coordinated by an Interchange Authority such that the Balancing Authorities implement the Interchange exactly as agreed upon in the Interchange confirmation process.

4. **Applicability**

   4.1. Balancing Authority.

5. **Effective Date:** January 1, 2007

B. Requirements

R1. The Balancing Authority shall implement Confirmed Interchange as received from the Interchange Authority.

C. Measures

M1. The Balancing Authority shall provide evidence that Implemented Interchange matches Confirmed Interchange as submitted by the Interchange Authority.

M2. Evidence shall demonstrate that the Interchange was implemented in the Balancing Authority's Area Control Error (ACE) equation, or the system that calculates the ACE equation. Evidence may be on a net basis or an individual Interchange basis.

M3. Balancing Authorities that are interconnected with a direct current tie shall demonstrate that the Interchange was implemented in the ACE equation or modeled as an equivalent generator/load within its area.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Time Frame

   The Performance-Reset Period shall be twelve months from the last noncompliance to Requirement 1.

   1.3. Data Retention

   The Balancing Authority and Interchange Authority shall each keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

   1.4. Additional Compliance Information

   Each Balancing Authority shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

   Subsequent to the initial compliance review, compliance may be:

   1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of non-compliant Balancing Authorities, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. The Compliance Monitor will evaluate complaints.

The Balancing Authorities shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records for the audit period which indicate a Balancing Authority implemented all instances of the Interchange Authority's communication under R1 concerning the implementation of a Confirmed Interchange. The Compliance Monitor may request up to a three month period of historical data ending with the date the request is received by the Balancing Authority

1.4.6 For specific complaints, only those data and system log records associated with the specific Interchange event contained in the complaint which indicates a Balancing Authority implemented the Interchange Authority's communication under R1 concerning the implementation of the Confirmed Interchange for that specific Interchange.

2. Levels of Non-Compliance

2.1. Level 1: One occurrence[1] of not implementing a Confirmed Interchange as described in R1.

2.2. Level 2: Two occurrences[1] of not implementing a Confirmed Interchange as described in R1.

2.3. Level 3: Three occurrences[1] of not implementing a Confirmed Interchange as described in R1.

2.4. Level 4: Four or more occurrences[1] of not implementing a Confirmed Interchange as described in R1 or no evidence provided.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

[1] This does not include instances of not implementing due to extenuating circumstances approved by the Compliance Monitor.

A. Introduction

1. **Title:** **Interchange Coordination Exemptions**

2. **Number:** **INT-010-1**

3. **Purpose:** Allow certain types of Interchange schedules to be initiated or modified by reliability entities, and to be exempt from compliance with other Interchange Standards under abnormal operating conditions.

4. **Applicability**

   4.1. Balancing Authority.

   4.2. Reliability Coordinator.

5. **Effective Date:** January 1, 2007

B. Requirements

R1. The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement shall ensure that a request for an Arranged Interchange is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no request for Arranged Interchange is required.

R2. For a modification to an existing Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit the modified Arranged Interchange reflecting that modification within 60 minutes of the initiation of the event.

R3. For a new Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit an Arranged Interchange reflecting that Interchange schedule within 60 minutes of the initiation of the event.

C. Measures

M1. The Balancing Authority that uses its energy sharing agreement where the duration exceeds 60 minutes shall have evidence it submitted Arranged Interchange per Requirement 1.

M2. The Reliability Coordinator that directs a modification to an existing Interchange shall have evidence that a directive was issued to submit the Arranged Interchange in accordance with Requirement 2.

M3. The Reliability Coordinator that directs the initiation of a new Interchange shall have evidence that a directive was issued to submit the Arranged Interchange in accordance with Requirement 3.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Time Frame

   The Performance-Reset Period shall be twelve months from the last noncompliance to R1, R2, or R3.

1.3. Data Retention

The Balancing Authority and Reliability Coordinator shall each keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

1.4. Additional Compliance Information

Each Balancing Authority and Reliability Coordinator shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

Subsequent to the initial compliance review, compliance may be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of non-compliant Balancing Authorities and Reliability Coordinators, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. The Compliance Monitor will evaluate complaints.

The Balancing Authority and Reliability Coordinator shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records for the audit period which indicate a Balancing Authority or Reliability Coordinator acted in compliance with INT-010. The Compliance Monitor may request up to a three month period of historical data ending with the date the request is received by the Balancing Authority

1.4.6 For specific complaints, only those data and system log records associated with the specific Interchange event contained in the complaint which indicates a Balancing Authority or Reliability Coordinator failed to act in compliance with INT-010.

2. Levels of Non-Compliance

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions is present:

2.1.1 One occurrence of not submitting an Arranged Interchange as described in R1.

2.1.2 One occurrence of not directing the submittal of a new or modified Arranged Interchange as described in R2 or R3.

2.2. Level 2: There shall be a level two non-compliance if either of the following conditions is present:

2.2.1 Two occurrences of not submitting an Arranged Interchange as described in R1.

2.2.2 Two occurrences of not directing the submittal of a new or modified Arranged Interchange as described in R2 or R3.

2.3. Level 3: There shall be a level three non-compliance if either of the following conditions is present:

2.3.1 Three occurrences of not submitting an Arranged Interchange as described in R1.

2.3.2 Three occurrences of not directing the submittal of a new or modified Arranged Interchange as described in R2 or R3.

2.4. Level 4: There shall be a level three non-compliance if any of the following conditions is present:

2.4.1 Four or more occurrences of not submitting an Arranged Interchange as described in R1.

2.4.2 Four or more occurrences of not directing the submittal of a new or modified Arranged Interchange as described in Requirements 2 or 3.

2.4.3 No evidence provided.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

A. Introduction

1. **Title:** **Reliability Coordination — Responsibilities and Authorities**

2. **Number:** IRO-001-1.1

3. **Purpose:** Reliability Coordinators must have the authority, plans, and agreements in place to immediately direct reliability entities within their Reliability Coordinator Areas to re-dispatch generation, reconfigure transmission, or reduce load to mitigate critical conditions to return the system to a reliable state. If a Reliability Coordinator delegates tasks to others, the Reliability Coordinator retains its responsibilities for complying with NERC and regional standards. Standards of conduct are necessary to ensure the Reliability Coordinator does not act in a manner that favors one market participant over another.

4. **Applicability**

   4.1. Reliability Coordinators.

   4.2. Regional Reliability Organizations.

   4.3. Transmission Operator.

   4.4. Balancing Authorities.

   4.5. Generator Operators.

   4.6. Transmission Service Providers.

   4.7. Load-Serving Entities.

   4.8. Purchasing-Selling Entities.

5. **Effective Date:** May 13, 2009

B. Requirements

R1. Each Regional Reliability Organization, subregion, or interregional coordinating group shall establish one or more Reliability Coordinators to continuously assess transmission reliability and coordinate emergency operations among the operating entities within the region and across the regional boundaries.

R2. The Reliability Coordinator shall comply with a regional reliability plan approved by the NERC Operating Committee.

R3. The Reliability Coordinator shall have clear decision-making authority to act and to direct actions to be taken by Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System. These actions shall be taken without delay, but no longer than 30 minutes.

R4. Reliability Coordinators that delegate tasks to other entities shall have formal operating agreements with each entity to which tasks are delegated. The Reliability Coordinator shall verify that all delegated tasks are understood, communicated, and addressed within its Reliability Coordinator Area. All responsibilities for complying with NERC and regional standards applicable to Reliability Coordinators shall remain with the Reliability Coordinator.

R5. The Reliability Coordinator shall list within its reliability plan all entities to which the Reliability Coordinator has delegated required tasks.

R6. The Reliability Coordinator shall verify that all delegated tasks are carried out by NERC-certified Reliability Coordinator operating personnel.

R7. The Reliability Coordinator shall have clear, comprehensive coordination agreements with adjacent Reliability Coordinators to ensure that System Operating Limit or Interconnection Reliability Operating Limit violation mitigation requiring actions in adjacent Reliability Coordinator Areas are coordinated.

R8. Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator may implement alternate remedial actions.

R9. The Reliability Coordinator shall act in the interests of reliability for the overall Reliability Coordinator Area and the Interconnection before the interests of any other entity.

C. Measures

M1. Each Regional Reliability Organization shall have, and provide upon request, evidence that could include, but is not limited to signed agreements or other equivalent evidence that will be used to confirm that it established one or more Reliability Coordinators to continuously assess transmission reliability and coordinate emergency operations among the operating entities within the region and across the regional boundaries as described in Requirement 1.

M2. Each Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, job descriptions, signed agreements, an authority letter signed by an officer of the company, or other equivalent evidence that will be used to confirm that the Reliability Coordinator has the authority to act as described in Requirement 3.

M3. The Reliability Coordinator shall have and provide upon request current formal operating agreements with entities that have been delegated any Reliability Coordinator tasks (Requirement 4 Part 1).

M4. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, job descriptions, signed agreements, records of training sessions, monitoring procedures or other equivalent evidence that will be used to confirm that all delegated tasks are understood, communicated, and addressed within its Reliability Coordinator Area (Requirement 4 Part 2 and Requirement 5).

M5. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, records that show each operating person assigned to perform a Reliability Coordinator delegated task has a NERC Reliability Coordinator certification credential, or equivalent evidence confirming that delegated tasks were

carried out by NERC certified Reliability Coordinator operating personnel, as specified in Requirement 6.

M6. The Reliability Coordinator shall have and provide upon request as evidence, signed agreements with adjacent Reliability Coordinators that will be used to confirm that it will coordinate corrective actions in the event SOL and IROL mitigation actions within neighboring areas must be taken. (Requirement 7)

M7. Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, or other equivalent evidence that will be used to confirm that it did comply with the Reliability Coordinator's directives, or if for safety, equipment, regulatory or statutory requirements it could not comply, it informed the Reliability Coordinator immediately. (Requirement 8)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

NERC shall be responsible for compliance monitoring of the Regional Reliability Organization.
Regional Reliability Organizations shall be responsible for compliance monitoring of the Reliability Coordinators, Transmission Operators, Generator Operators, Distribution Providers, and Load Serving Entities.

1.2. Compliance Monitoring Period and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Regional Reliability Organization shall have its current, in-force document for Measure 1.

Each Reliability Coordinator shall have its current, in-force documents or the latest copy of a record as evidence of compliance to Measures 2 through 6.

Each Transmission Operator, Generator Operator, Transmission Service Provider, and Load Serving Entity shall keep 90 days of historical data (evidence) for Measure 7.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance: for a Regional Reliability Organization:

2.1. Level 1: Not applicable

2.2. Level 2: Not applicable

2.3. Level 3: Not applicable

2.4. Level 4: Does not have evidence it established one or more Reliability Coordinators to continuously assess transmission reliability and coordinate emergency operations among the operating entities within the region and across the regional boundaries as described in Requirement 1.

3. Levels of Non-Compliance for a Reliability Coordinator:

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable**.**

3.4. Level 4: There shall be a separate Level 4 non-compliance for every one of the following requirements that is in violation:

3.4.1 Does not have the authority to act as described in R3.

3.4.2 Does not have formal operating agreements with entities that have been delegated any Reliability Coordinator tasks, as specified in R4, Part 1.

3.4.3 Did not confirm that all delegated tasks are understood, communicated, and addressed within its Reliability Coordinator Area and that they are being performed in a manner that complies with NERC and regional standards for the delegated tasks as per R4, Part 2.

3.4.4 Did not verify that delegated tasks are being carried out by NERC Reliability Coordinator certified staff as specified in R6.

3.4.5 Does not have agreements with adjacent Reliability Coordinators that confirm that they will coordinate corrective actions in the event SOL and IROL mitigation actions must be taken (R7).

4. Levels of Non-Compliance for a Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: There shall be a separate Level 4 non-compliance for every one of the following requirements that is in violation:

4.4.1 Did not comply with a Reliability Coordinator directive for reasons other than safety, equipment, or regulatory or statutory requirements. (R8)

4.4.2 Did not inform the Reliability Coordinator immediately after it was determined that it could not follow a Reliability Coordinator directive. (R8)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	November 19, 2006	Changes "Distribution Provider" to "Transmission Service Provider"	Errata
1.1	October 29, 2008	– Removed "Proposed" from effective date; – BOT adopted errata changes; updated version number to "1.1"	Errata
1.1	May 13, 2009	FERC Approved	Revised

A. Introduction

1. **Title:** **Reliability Coordination — Facilities**
2. **Number:** IRO 002-1
3. **Purpose:** Reliability Coordinators need information, tools and other capabilities to perform their responsibilities.
4. **Applicability**

   4.1. Reliability Coordinators.
5. **Effective Date:** January 1, 2007

B. Requirements

R1. Each Reliability Coordinator shall have adequate communications facilities (voice and data links) to appropriate entities within its Reliability Coordinator Area. These communications facilities shall be staffed and available to act in addressing a real-time emergency condition.

R2. Each Reliability Coordinator shall determine the data requirements to support its reliability coordination tasks and shall request such data from its Transmission Operators, Balancing Authorities, Transmission Owners, Generation Owners, Generation Operators, and Load-Serving Entities, or adjacent Reliability Coordinators.

R3. Each Reliability Coordinator — or its Transmission Operators and Balancing Authorities — shall provide, or arrange provisions for, data exchange to other Reliability Coordinators or Transmission Operators and Balancing Authorities via a secure network.

R4. Each Reliability Coordinator shall have multi-directional communications capabilities with its Transmission Operators and Balancing Authorities, and with neighboring Reliability Coordinators, for both voice and data exchange as required to meet reliability needs of the Interconnection.

R5. Each Reliability Coordinator shall have detailed real-time monitoring capability of its Reliability Coordinator Area and sufficient monitoring capability of its surrounding Reliability Coordinator Areas to ensure that potential or actual System Operating Limit or Interconnection Reliability Operating Limit violations are identified. Each Reliability Coordinator shall have monitoring systems that provide information that can be easily understood and interpreted by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure.

R6. Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be critical to SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area.

R7. Each Reliability Coordinator shall have adequate analysis tools such as state estimation, pre- and post-contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays.

R8. Each Reliability Coordinator shall continuously monitor its Reliability Coordinator Area. Each Reliability Coordinator shall have provisions for backup facilities that shall be exercised if the main monitoring system is unavailable. Each Reliability Coordinator shall ensure SOL and IROL monitoring and derivations continue if the main monitoring system is unavailable.

R9. Each Reliability Coordinator shall control its Reliability Coordinator analysis tools, including approvals for planned maintenance. Each Reliability Coordinator shall have procedures in place to mitigate the effects of analysis tool outages.

C. Measures

M1. Each Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, a document that lists its voice communications facilities with Transmission Operators, Balancing Authorities and Generator Operators within its Reliability Coordinator Area and with neighboring Reliability Coordinators, that will be used to confirm that it has communication facilities in accordance with Requirements 1 and 4.

M2. Each Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, a data-link facility description document, computer print-out, training-document, or other equivalent evidence that will be used to confirm that it has data links with entities within its Reliability Coordinator Area and with neighboring Reliability Coordinators, as specified in Requirements 1 and 4.

M3. Each Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, a letter to Transmission Operators, Balancing Authorities, Transmission Owners, Generator Owners, Generator Operators, and Load-Serving Entities, or adjacent Reliability Coordinators, or other equivalent evidence that will be used to confirm that the Reliability Coordinator has requested the data required to support its reliability coordination tasks. (Requirement 2)

M4. Each Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection system communications performance or equivalent evidence to demonstrate that it has real-time monitoring capability of its Reliability Coordinator Area and monitoring capability of its surrounding Reliability Coordinator Areas to identify potential or actual System Operating Limit or Interconnection Reliability Operating Limit violations.

M5. Each Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, documentation from suppliers, operating and planning staff training documents, examples of studies, or other equivalent evidence to show that it has analysis tools in accordance with Requirement 7.

M6. Each Reliability Coordinator shall provide evidence such as equipment specifications, operating procedures, staff records of their involvement in training, or other equivalent

evidence to show that it has a backup monitoring facility that can be used to identify and monitor SOLs and IROLs. (Requirement 8)

M7. Each Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, a documented procedure or equivalent evidence that will be used to confirm that the Reliability Coordinator has the authority to veto planned outages to analysis tools, including final approvals for planned maintenance as specified in Requirement 9 Part 1.

M8. Each Reliability Coordinator shall have and provide upon request its current procedures used to mitigate the effects of analysis tool outages as specified in Requirement 9 Part 2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance. Monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Reliability Coordinator shall have current in-force documents used to show compliance with Measures 1 through 8.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for a Reliability Coordinator

2.1. Level 1: Not applicable.

2.2. Level 2: Did not confirm that the network used for data exchange to other Reliability Coordinators is secure as specified in R3.

2.3. Level 3: There shall be a separate Level 3 non-compliance, for every one of the following requirements that is in violation:

2.3.1 Has not requested the data required to support its reliability coordination tasks. (Requirement 2)

2.3.2 Does not control its Reliability Coordinator analysis tools, including the exercising of final approvals for planned maintenance (R7) or does not have current procedures in place to mitigate the effects of analysis tool outages as specified in R9.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Does not have or could not demonstrate the use of voice communication facilities (or show data links) to one or more Transmission Operators, Generator Operators or Balancing Authorities with authority over Bulk Electrical System equipment or with one or more neighboring Reliability Coordinators. (R1 and R4)

2.4.2 Does not have real-time monitoring capability of its Reliability Coordinator Area and surrounding Reliability Coordinator Areas as specified in R5.

2.4.3 Does not have a documented procedure for the use of its backup monitoring facilities. (R8)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised

A. Introduction

1. **Title:** **Reliability Coordination — Wide-Area View**
2. **Number:** IRO-003-2
3. **Purpose:** The Reliability Coordinator must have a wide-area view of its own Reliability Coordinator Area and that of neighboring Reliability Coordinators.
4. **Applicability**

   4.1. Reliability Coordinators.
5. **Effective Date:** January 1, 2007

B. Requirements

R1. Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.

R2. Each Reliability Coordinator shall know the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or IROL violation. Reliability Coordinators shall also know the status of any facilities that may be required to assist area restoration objectives.

C. Measures

M1. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors adjacent Reliability Coordinator Areas as necessary to ensure that, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organizations shall be responsible for compliance monitoring.

   1.2. Compliance Monitoring and Reset Time Frame

   One or more of the following methods will be used to assess compliance:

   - Self-certification (Conducted annually with submission according to schedule.)

- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Reliability Coordinator shall have current in-force documents used to show compliance with Measure 1.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for a Reliability Coordinator

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Did not produce acceptable evidence to confirm that it monitors adjacent Reliability Coordinator Areas as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	February 7, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Adopted by Board of Trustees	Revised

A. Introduction

1. **Title:** **Reliability Coordination — Operations Planning**

2. **Number:** IRO-004-1

3. **Purpose:** Each Reliability Coordinator must conduct next-day reliability analyses for its Reliability Coordinator Area to ensure the Bulk Electric System can be operated reliably in anticipated normal and Contingency conditions. System studies must be conducted to highlight potential interface and other operating limits, including overloaded transmission lines and transformers, voltage and stability limits, etc. Plans must be developed to alleviate System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) violations.

4. **Applicability**

   4.1. Reliability Coordinators.

   4.2. Balancing Authorities.

   4.3. Transmission Operators.

   4.4. Transmission Service Providers.

   4.5. Transmission Owners.

   4.6. Generator Owners.

   4.7. Generator Operators.

   4.8. Load-Serving Entities.

5. **Effective Date:** November 1, 2006

B. Requirements

R1. Each Reliability Coordinator shall conduct next-day reliability analyses for its Reliability Coordinator Area to ensure that the Bulk Electric System can be operated reliably in anticipated normal and Contingency event conditions. The Reliability Coordinator shall conduct Contingency analysis studies to identify potential interface and other SOL and IROL violations, including overloaded transmission lines and transformers, voltage and stability limits, etc.

R2. Each Reliability Coordinator shall pay particular attention to parallel flows to ensure one Reliability Coordinator Area does not place an unacceptable or undue Burden on an adjacent Reliability Coordinator Area.

R3. Each Reliability Coordinator shall, in conjunction with its Transmission Operators and Balancing Authorities, develop action plans that may be required, including reconfiguration of the transmission system, re-dispatching of generation, reduction or curtailment of Interchange Transactions, or reducing load to return transmission loading to within acceptable SOLs or IROLs.

R4. Each Transmission Operator, Balancing Authority, Transmission Owner, Generator Owner, Generator Operator, and Load-Serving Entity in the Reliability Coordinator Area shall provide information required for system studies, such as critical facility status, Load, generation, operating reserve projections, and known Interchange Transactions. This information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.

R5. Each Reliability Coordinator shall share the results of its system studies, when conditions warrant or upon request, with other Reliability Coordinators and with Transmission Operators,

Balancing Authorities, and Transmission Service Providers within its Reliability Coordinator Area. The Reliability Coordinator shall make study results available no later than 1500 Central Standard Time for the Eastern Interconnection and 1500 Pacific Standard Time for the Western Interconnection, unless circumstances warrant otherwise.

R6. If the results of these studies indicate potential SOL or IROL violations, the Reliability Coordinator shall direct its Transmission Operators, Balancing Authorities and Transmission Service Providers to take any necessary action the Reliability Coordinator deems appropriate to address the potential SOL or IROL violation.

R7. Each Transmission Operator, Balancing Authority, and Transmission Service Provider shall comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events.

C. Measures

M1. Evidence that the Reliability Coordinator conducted next-day contingency analyses for its Reliability Coordinator Area to ensure that the Bulk Electric System could be operated reliably in anticipated normal and Contingency conditions.

D. Compliance

1. Compliance Monitoring Process

Entities will be selected for an on-site audit at least every three years. For a selected 30-day period in the previous three calendar months prior to the on site audit, Reliability Coordinators will be asked to provide documentation showing that next-day reliability analyses were conducted each day to ensure the bulk power system could be operated in anticipated normal and Contingency conditions; and that they identified potential interface and other operating limits including overloaded transmission lines and transformers, voltage and stability limits, etc.

1.1. Compliance Monitoring Responsibility

Self-Certification: Each Reliability Coordinator must annually self-certify compliance to its Regional Reliability Organization with the completion of the studies and action plans in Requirements R1, R2 and R3.

Exception Reporting: Reliability Coordinators will prepare a monthly report to the Regional Reliability Organization for each month that system studies were not conducted, indicating the dates that studies were not done and the reason why.

1.2. Compliance Monitoring Period and Reset Time Frame

One year without a violation from the time of the violation.

1.3. Data Retention

Documentation shall be available for 3 months to provide verification that system studies were performed as required.

1.4. Additional Compliance Information

None identified.

2. Levels of Non-Compliance

2.1. Level 1: System studies were not conducted for one day in a calendar month and/or the action plans were not developed to maintain transmission loading within acceptable limits for potential interface and other IROL violations.

2.2. Level 2: System studies were not conducted for 2–3 days in a calendar month and/or the action plans were not developed to maintain transmission loading within acceptable limits for potential interface and other IROL violations.

2.3. Level 3: System studies were not conducted for 4–5 days in a calendar month and/or the action plans were not developed to maintain transmission loading within acceptable limits for potential interface and other IROL violations.

2.4. Level 4: System studies were not conducted for more than 5 days in a calendar month and/or the action plans were not developed to maintain transmission loading within acceptable limits for potential interface and other IROL violations.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata

A. Introduction

1. **Title:** **Reliability Coordination — Current Day Operations**

2. **Number:** IRO-005-2

3. **Purpose:** The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.

4. **Applicability**

   4.1. Reliability Coordinators.

   4.2. Balancing Authorities.

   4.3. Transmission Operators.

   4.4. Transmission Service Providers.

   4.5. Generator Operators.

   4.6. Load-Serving Entities.

   4.7. Purchasing-Selling Entities.

5. **Effective Date:** January 1, 2007

B. Requirements

R1. Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:

R1.1. Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading.

R1.2. Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.

R1.3. Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.

R1.4. System real and reactive reserves (actual versus required).

R1.5. Capacity and energy adequacy conditions.

R1.6. Current ACE for all its Balancing Authorities.

R1.7. Current local or Transmission Loading Relief procedures in effect.

R1.8. Planned generation dispatches.

R1.9. Planned transmission or generation outages.

R1.10. Contingency events.

R2. Each Reliability Coordinator shall be aware of all Interchange Transactions that wheel through, source, or sink in its Reliability Coordinator Area, and make that Interchange Transaction information available to all Reliability Coordinators in the Interconnection.

R3. As portions of the transmission system approach or exceed SOLs or IROLs, the Reliability Coordinator shall work with its Transmission Operators and Balancing Authorities to evaluate and assess any additional Interchange Schedules that would violate those limits. If a potential or actual IROL violation cannot be avoided through proactive intervention, the Reliability Coordinator shall initiate control actions or emergency procedures to relieve the violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall ensure all resources, including load shedding, are available to address a potential or actual IROL violation.

R4. Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.

R5. Each Reliability Coordinator shall identify the cause of any potential or actual SOL or IROL violations. The Reliability Coordinator shall initiate the control action or emergency procedure to relieve the potential or actual IROL violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall be able to utilize all resources, including load shedding, to address an IROL violation.

R6. Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.

R7. The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.

R8. Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.

R9. The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.

R10. As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities.

R11. The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.

R12. Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission

Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.

R13. Each Reliability Coordinator shall ensure that all Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities operate to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordinator Area will result in a SOL or IROL violation in another area of the Interconnection. In instances where there is a difference in derived limits, the Reliability Coordinator and its Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.

R14. Each Reliability Coordinator shall make known to Transmission Service Providers within its Reliability Coordinator Area, SOLs or IROLs within its wide-area view. The Transmission Service Providers shall respect these SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.

R15. Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.

R16. Each Reliability Coordinator shall confirm reliability assessment results and determine the effects within its own and adjacent Reliability Coordinator Areas. The Reliability Coordinator shall discuss options to mitigate potential or actual SOL or IROL violations and take actions as necessary to always act in the best interests of the Interconnection at all times.

R17. When an IROL or SOL is exceeded, the Reliability Coordinator shall evaluate the local and wide-area impacts, both real-time and post-contingency, and determine if the actions being taken are appropriate and sufficient to return the system to within IROL in thirty minutes. If the actions being taken are not appropriate or sufficient, the Reliability Coordinator shall direct the Transmission Operator, Balancing Authority, Generator Operator, or Load-Serving Entity to return the system to within IROL or SOL.

C. Measures

M1. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, a prepared report specifically detailing compliance to each of the bullets in Requirement 1, EMS availability, SCADA data collection system communications performance or equivalent evidence that will be used to confirm that it monitors the Reliability Coordinator Area parameters specified in Requirements 1.1 through 1.9.

M2. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Historical Tag Archive information, Interchange Transaction records, computer printouts, voice recordings or transcripts of voice recordings or equivalent evidence that will be used to confirm that it was aware of and made Interchange Transaction information available to all other Reliability Coordinators, as specified in Requirement 2.

M3. If a potential or actual IROL violation occurs, the Reliability Coordinator involved in the event shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, system

event logs, operator action notes or equivalent evidence that will be used to determine if it initiated control actions or emergency procedures to relieve that IROL violation within 30 minutes. (Requirement 3 Part 2 and Requirement 5)

M4. If one of its Balancing Authorities has insufficient operating reserves, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to computer printouts, operating logs, voice recordings or transcripts of voice recordings, or equivalent evidence that will be used to determine if the Reliability Coordinator directed and, if needed, assisted the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. (Requirement 4 Part 2 and Requirement 10)

M5. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to determine if it informed Transmission Operators and Balancing Authorities of Geo-Magnetic Disturbance (GMD) forecast information and provided assistance as needed in the development of any required response plans. (Requirement 6)

M6. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it disseminated information within its Reliability Coordinator Area in accordance with Requirement 7.

M7. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, computer printouts, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it monitored system frequency and Balancing Authority performance and directed any necessary rebalancing, as specified in Requirement 8 Part 1.

M8. The Transmission Operators and Balancing Authorities shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it utilized all resources, including firm load shedding, as directed by its Reliability Coordinator, to relieve an emergent condition. (Requirement 8 Part 2)

M9. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, operator logs or equivalent evidence that will be used to determine if it coordinated with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations including the coordination of pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities and Generator Operators. (Requirement 9 Part 1)

M10. If a large Area Control Error has occurred, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it identified sources of the Area Control Errors, and initiated corrective actions with the appropriate Balancing Authority if the problem was within the Reliability Coordinator's Area (Requirement 11 Part 1)

M11. If a Special Protection System is armed and that system could have had an inter-area impact, the Reliability Coordinator shall have and provide upon request evidence that could include,

but is not limited to, agreements with their Transmission Operators, procedural documents, operator logs, computer analysis, training modules, training records or equivalent evidence that will be used to confirm that it was aware of the impact of that Special Protection System on inter-area flows. (Requirement 12)

M12. If there is an instance where there is a disagreement on a derived limit, the Reliability Coordinator, Transmission Operator, Balancing Authority, Generator Operator, Load-serving Entity, Purchasing-selling Entity and Transmission Service Provider involved in the disagreement shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications or equivalent evidence that will be used to determine if it operated to the most limiting parameter. (Part 2 of Requirement 13)

M13. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, procedural documents, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it provided SOL and IROL information to Transmission Service Providers within its Reliability Coordinator Area. (Requirement 14, Part 1)

M14. The Transmission Service Providers shall have and provide upon request evidence that could include, but is not limited to, procedural documents, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it respected the SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.(Requirement 14 Part 2)

M15. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it issued alerts when it foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area, to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area as specified in Requirement 15 Part 1.

M16. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that upon receiving information such as an SOL or IROL violation, loss of reactive reserves, etc. it disseminated the information to its impacted Transmission Operators and Balancing Authorities as specified in Requirement 15 Part 2.

M17. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it notified all impacted Transmission Operators, Balancing Authorities and Reliability Coordinators when a transmission problem has been mitigated. (Requirement 15 Part 3)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

For Measures 1 and 11, each Reliability Coordinator shall have its current in-force documents as evidence.

For Measures 2–10 and Measure 13, and Measures 15 through 16, the Reliability Coordinator shall keep 90 days of historical data (evidence).

For Measure 8, the Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence).

For Measure 12, the Reliability Coordinator, Transmission Operator, Balancing Authority, and Transmission Service Provider shall keep 90 days of historical data (evidence).

For Measure 14, the Transmission Service Provider shall keep 90 days of historical data (evidence).

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for a Transmission Operator, Balancing Authority, Generator Operator, Load-serving Entity, Purchasing-selling Entity and Transmission Service Provider

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Did not follow the Reliability Coordinator's directives in accordance with R8 Part 2).

2.4.2 Did not operate to the most limiting parameter when a difference in derived limits existed. (R13 Part 2)

3. Levels of Non-Compliance for a Reliability Coordinator:

3.1. Level 1: Not applicable.

3.2. Level 2: Did not make Interchange Transaction information available to all other Reliability Coordinators in the Interconnection. (Requirement 2)

3.3. Level 3: There shall be a separate Level 3 non-compliance, for every one of the following requirements that is in violation:

3.3.1 Did not communicate to each of its Balancing Authorities and Transmission Operators to make them aware of GMD forecast information or did not assist in the development of any required response plans to a predicted GMD. (Requirement 6)

3.3.2 Did not disseminate information within its Reliability Coordinator Area. (Requirement 7)

3.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Does not meet one or more of the requirements as specified in requirement 1 (Requirements 1.1 through R1.9)

3.4.2 Did not make Interchange Transaction information available to all other Reliability Coordinators. (Requirement 2)

3.4.3 Did not initiate control actions or emergency procedures to relieve an IROL violation without delay, and no longer than 30 minutes. (Requirement 3 Part 2 and Requirement 5)

3.4.4 Did not direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. (Requirement 4 Part 2)

3.4.5 Did not monitor the system frequency or each of its Balancing Authorities performance or did not direct rebalancing to return to DCS and CPS compliance. (Requirement 8 Part 1)

3.4.6 Did not coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations. (Requirement 9)

3.4.7 When it identified a source of large Area Control Errors, it did not initiate corrective actions with the appropriate Balancing Authority if the problem was inside its Reliability Coordinator Area. (Requirement 11 part 1)

3.4.8 Did not provide evidence that it was aware of the impact of the operation of a Special Protection System on inter-area flows. (Requirement 12)

3.4.9 Did not operate to the most limiting parameter when a difference in derived limits existed. (Requirement 13 Part 2)

3.4.10 Did not provide Transmission Service Providers with SOLs or IROLs (within the Reliability Coordinator's wide-area view) (Requirement 14 Part 1)

3.4.11 Did not issue alerts when it foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area. (Requirement 15)

4. Levels of Non-Compliance for a Transmission Service Provider

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

4.4.1 Did not operate to the most limiting parameter when a difference in derived limits existed. (R13 Part 2)

4.4.2 Did not respect the SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.(Requirement 14 Part 2)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	February 2, 2006	Approved by Board of Trustees	Revised
2	August 31, 2006	Added three items that were inadvertently left out to "Applicability" section: 4.5 Generator Operators. 4.6 Load-Serving Entities. 4.7 Purchasing-Selling Entities	Errata
2	November 1, 2006	Approved by Board of Trustees	Revised

A. Introduction

1. **Title:** **Reliability Coordination — Transmission Loading Relief (TLR)**

2. **Number:** IRO-006-4.1

3. **Purpose:** The purpose of this standard is to provide Interconnection-wide transmission loading relief procedures that can be used to prevent or manage potential or actual SOL and IROL violations to maintain reliability of the Bulk Electric System.

4. **Applicability:**

   4.1. Reliability Coordinators.

   4.2. Transmission Operators.

   4.3. Balancing Authorities.

5. **Effective Date:** December 10, 2009

B. Requirements

R1. A Reliability Coordinator experiencing a potential or actual SOL or IROL violation within its Reliability Coordinator Area shall, with its authority and at its discretion, select one or more procedures to provide transmission loading relief. These procedures can be a "local" (regional, interregional, or sub-regional) transmission loading relief procedure or one of the following Interconnection-wide procedures: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

This requirement simply states; the RC has the authority to act, the RC should know at what limits he/she needs to act, the RC has pre-identified regional, interregional and sub-regional TLR procedures.

R1.1. The Interconnection-wide Transmission Loading Relief (TLR) procedure for use in the Eastern Interconnection provided in Attachment 1-IRO-006-4. The TLR procedure alone is an inappropriate and ineffective tool to mitigate an IROL violation due to the time required to implement the procedure. Other acceptable and more effective procedures to mitigate actual IROL violations include: reconfiguration, redispatch, or load shedding.

Comment: see FERC Order 693 paragraph 964 regarding recommendation for using tools other than TLR to mitigate an actual IROL.

R1.2. The Interconnection-wide transmission loading relief procedure for use in the Western Interconnection is the WECC Unscheduled Flow Reduction Procedure provided at: http://www.wecc.biz/documents/library/UFAS/UFAS_mitigation_plan_rev_2001-clean_8-8-03.pdf.

R1.3. The Interconnection-wide transmission loading relief procedure for use in ERCOT is provided as Section 7 of the ERCOT Protocols, posted at: http://www.ercot.com/mktrules/protocols/current.html

Note: the URL has changed.

R2. The Reliability Coordinator shall only use local transmission loading relief or congestion management procedures to which the Transmission Operator experiencing the potential or actual SOL or IROL violation is a party. [*Violation Risk Factor: Low*] [*Time Horizon: Operations Planning*]

R3. Each Reliability Coordinator with a relief obligation from an Interconnection-wide procedure shall follow the curtailments as directed by the Interconnection-wide procedure. A Reliability Coordinator desiring to use a local procedure as a substitute for curtailments as directed by the

Interconnection-wide procedure shall obtain prior approval of the local procedure from the ERO. [*Violation Risk Factor: Low*] [*Time Horizon: Operations Planning*]

R4. When Interconnection-wide procedures are implemented to curtail Interchange Transactions that cross an Interconnection boundary, each Reliability Coordinator shall comply with the provisions of the Interconnection-wide procedure. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

R5. During the implementation of relief procedures, and up to the point that emergency action is necessary, Reliability Coordinators and Balancing Authorities shall comply with applicable Interchange scheduling standards. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

Comment: R5 will be reviewed during Phase 3 of the TLR drafting team work. See white paper for explanation of the three phases of changes to this standard.

C. Measures

M1. Each Reliability Coordinator shall be capable of providing evidence (such as logs) that demonstrate when Eastern Interconnection, WECC, or ERCOT Interconnection-wide transmission loading relief procedures are implemented, the implementation follows the respective established procedure as specified in this standard (R1, R1.1, R1.2 and R1.3).

M2. Each Reliability Coordinator shall be capable of providing evidence (such as written documentation) that the Transmission Operator experiencing the potential or existing SOL or IROL violations is a party to the local transmission loading relief or congestion management procedures when these procedures have been implemented (R2).

M3. Each Reliability Coordinator shall be capable of providing evidence (such as NERC meeting minutes) that the local procedure has received prior approval by the ERO when such procedure is used as a substitute for curtailment as directed by the Interconnection-wide procedure (R3).

M4. Each Reliability Coordinator shall be capable of providing evidence (such as logs) that the responding Reliability Coordinator complied with the provisions of the Interconnection-wide procedure as requested by the initiating Reliability Coordinator when requested to curtail an Interchange Transaction that crosses an Interconnection boundary (R4).

M5. Each Reliability Coordinator and Balancing Authority shall be capable of providing evidence (such as Interchange Transaction Tags, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts) that they have complied with applicable Interchange scheduling standards INT-001, INT-003, and INT-004 during the implementation of relief procedures, up to the point emergency action is necessary (R5).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Compliance Monitoring Period: One calendar year.

Reset Period: One month without a violation.

1.3. Data Retention

The Reliability Coordinator shall maintain evidence for eighteen months for M1, M4, and M5.

The Reliability Coordinator shall maintain evidence for the duration the Transmission Operator is party to the procedure in effect plus one calendar year thereafter for M2.

The Reliability Coordinator shall maintain evidence for the approved duration of the procedure in effect plus one calendar year thereafter for M3.

1.4. Additional Compliance Information

Each Reliability Coordinator and Balancing Authority shall demonstrate compliance through self-certification submitted to its Compliance Monitor annually and reporting by exception. The Compliance Monitor may also use scheduled on-site reviews every three years, and investigations upon complaint, to assess performance.

Each Reliability Coordinator and Balancing Authority shall have the following available for its Compliance Monitor to inspect during a scheduled, on-site review or within 5 days of a request as part of an investigation upon complaint:

1.4.1 Operations logs, voice recordings or transcripts of voice recordings or other documentation providing the evidence of its compliance to all the requirements for all Interconnection-wide TLR procedures that it has implemented during the review period.

1.4.2 TLR reports.

2. Violation Severity Levels

2.1. Lower. There shall be a lower violation severity level if any of the following conditions exist:

2.1.1 For each TLR in the Eastern Interconnection, the Reliability Coordinator violates one (1) requirement of the applicable Interconnection-wide procedure (R1)

2.1.2 The Reliability Coordinators or Balancing Authorities did not comply with applicable Interchange scheduling standards during the implementation of the relief procedures, up to the point emergency action is necessary (R5).

2.1.3 When requested to curtail an Interchange Transaction that crosses an Interconnection boundary utilizing an Interconnection-wide procedure, the responding Reliability Coordinator did not comply with the provisions of the Interconnection-wide procedure as requested by the initiating Reliability Coordinator (R4).

2.2. Moderate. There shall be a moderate violation severity level if any of the following conditions exist:

2.2.1 For each TLR in the Eastern Interconnection, the Reliability Coordinator violated two (2) to three (3) requirements of the applicable Interconnection-wide procedure (R1).

2.3. High. There shall be a high violation severity level if any of the following conditions exist:

2.3.1 For each TLR in the Eastern Interconnection, the applicable Reliability Coordinator violated four (4) to five (5) requirements of the applicable Interconnection-wide procedure (R1).

2.4. Severe. There shall be a severe violation severity level if any of the following conditions exist:

2.4.1 For each TLR in the Eastern Interconnection, the Reliability Coordinator violated six (6) or more of the requirements of the applicable Interconnection-wide procedure (R1).

2.4.2 A Reliability Coordinator implemented local transmission loading relief or congestion management procedures to relieve congestion but the Transmission Operator experiencing the congestion was not a party to those procedures (R2).

2.4.3 A Reliability Coordinator implemented local transmission loading relief or congestion management procedures as a substitute for curtailment as directed by the Interconnection-wide procedure but the local procedure had not received prior approval from the ERO (R3).

2.4.4 While attempting to mitigate an existing IROL violation in the Eastern Interconnection, the Reliability Coordinator applied TLR as the sole remedy for an existing IROL violation.

2.4.5 While attempting to mitigate an existing constraint in the Western Interconnection using the "WSCC Unscheduled Flow Mitigation Plan", the Reliability Coordinator did not follow the procedure correctly.

2.4.6 While attempting to mitigate an existing constraint in ERCOT using Section 7 of the ERCOT Protocols, the Reliability Coordinator did not follow the procedure correctly.

E. Regional Differences

This section on Regional Differences is highlighted for transfer to NAESB following completion of the MISO/PJM/SPP field test as described in the white paper.

1. PJM/MISO Enhanced Congestion Management (Curtailment/Reload/Reallocation) Waiver approved March 25, 2004. To be retired upon completion of the field test, and in the interim the Regional Difference will be contained in both the NERC and NAESB standards.

2. Southwest Power Pool (SPP) Regional Difference – Enhanced Congestion Management (Curtailment/Reload/Reallocation). The SPP regional difference, which is equivalent to the PJM/MISO waiver, shall apply within the SPP region as follows:

This regional difference impacts actions on behalf of those SPP Balancing Authorities that are participating in the SPP market. This regional difference does not impact those Balancing Authorities for which SPP will continue to act as the Reliability Coordinator but that are not participating in the SPP market.

SPP shall calculate the impacts of SPP market flow on all facilities included in SPP's Coordinated Flowgate List. SPP shall conduct sensitivity studies to determine which external flowgates (outside SPP's footprint) are significantly impacted by the market flows of SPP's control zones (currently the balancing areas that exist today in the IDC). SPP shall perform studies to determine which external flowgates SPP will monitor and help control. An external flowgate selected by one of the studies will be considered a Coordinated Flowgate (CF).

In its calculation, SPP shall consider market flow impacts as the impacts of energy dispatched by the SPP market and self-dispatched energy serving load in the market footprint, but not tagged. SPP shall use a method equivalent to the PJM/MISO Market Flow Calculation methodology identified in the PJM/MISO waiver. Impacts of tagged transactions representing delivery of energy not dispatched by the SPP market and energy dispatched by the market but delivered outside the footprint will not be included in market flow.

SPP shall separate the market flow impacts for current hour and next hour into their appropriate priorities and shall provide those market flow impacts to the IDC. The market flows will be represented in the IDC and made available for curtailment under the appropriate TLR Levels. The market flow impacts will not be represented by conventional interchange transaction tags.

The SPP method will impact the following sections of the TLR Procedure:

Network and Native Load (NNL) Calculations — The SPP regional difference modifies Attachment 1-IRO-006-1 Section 5 "Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service" within the SPP region.

Section 5 of Attachment 1-IRO-006-1 requires that the "Per Generator Method without Counter Flow" methodology be utilized to calculate the portion of parallel flows on any Constrained Facility due to Network Integration (NI) transmission service and service to Native Load (NL) of each balancing authority.

SPP shall use a "Market Flow Calculation" methodology to calculate the portion of parallel flows on all facilities included in the RTO's "Coordinated Flowgate List" due to NI service or service to NL of each balancing authority.

The Market Flow Calculation differs from the Per Generator Method in the following ways:

- The contribution from all market area generators will be taken into account.
- In the Per Generator Method, only generators having a GLDF greater than 5% are included in the calculation. Additionally, generators are included only when the sum of the maximum generating capacity at a bus is greater than 20 MW. The market flow calculations will use all positively impacting flows down to 0% with no threshold. Counter flows will not be included in the market flow calculation.
- The contribution of all market area generators is based on the present output level of each individual unit.
- The contribution of the market area load is based on the present demand at each individual bus.

By expanding on the Per Generator Method, the market flow calculation evolves into a methodology very similar to the "Per Generator Method" method, while providing increased Interchange Distribution Calculator (IDC) granularity. Counter flows are also calculated and tracked in order to account for and recognize that the either the positive market flows may be reduced or counter flows may be increased to provide appropriate relief on a flowgate.

These NNL values will be provided to the IDC to be included and represented with the calculated NNL values of other Balancing Authorities for the purposes of identifying and obtaining required NNL relief across a flowgate in congestion under a TLR Level 5A/5B.

Pro Rata Curtailment of Non-Firm Market Flow Impacts — The SPP regional difference modifies Attachment 1-IRO-006-1 Appendix B "Transaction Curtailment Formula" within the SPP region.

Appendix B "Transaction Curtailment Formula" details the formula used to apply a weighted impact to each non-firm tagged Interchange Transaction (Priorities 1 thru 6) for the purposes of Curtailment by the IDC. For the purpose of Curtailment, the non-firm market flow impacts (Priorities 2 and 6) submitted to the IDC by SPP should be curtailed pro-rata as is done for Interchange Transaction using firm transmission service. This is because several of the values

needed to assign a weighted impact using the process listed in Appendix B will not be available:

- Distribution Factor (no tag to calculate this value from)
- Impact on Interface value (cannot be calculated without Distribution Factor)
- Impact Weighting Factor (cannot be calculated without Distribution Factor)
- Weighted Maximum Interface Reduction (cannot be calculated without Distribution Factor)
- Interface Reduction (cannot be calculated without Distribution Factor)
- Transaction Reduction (cannot be calculated without Distribution Factor)

While the non-firm market flow impacts submitted to the IDC are to be curtailed pro rata, the impacting non-firm tagged Interchange Transactions could still use the existing processes to assign the weighted impact value.

Assignment of Sub-Priorities — The SPP regional difference modifies Attachment 1-IRO-006-1 Appendix E "How the IDC Handles Reallocation", Section E2 "Timing Requirements", within the SPP region.

Under the header "IDC Calculations and Reporting" in Section E2 of Appendix E to Attachment 1-IRO-006-1, the following requirement exists: "In a TLR Level 3a the Interchange Transactions using Non-firm Transmission Service in a given priority will be further divided into four sub-priorities, based on current schedule, current active schedule (identified by the submittal of a tag ADJUST message), next-hour schedule, and tag status. Solely for the purpose of identifying which Interchange Transactions to be loaded under a TLR 3a, various MW levels of an Interchange Transaction may be in different sub-priorities. The sub-priorities are shown in the following table:

Priority	Purpose	Explanation and Conditions
S1	To allow a flowing Interchange Transaction to maintain or reduce its current MW amount in accordance with its energy profile.	The MW amount is the lowest between currently flowing MW amount and the next-hour schedule. The currently flowing MW amount is determined by the e-tag ENERGY PROFILE and ADJUST tables. If the calculated amount is negative, zero is used instead.
S2	To allow a flowing Interchange Transaction that has been curtailed or halted by TLR to reload to the lesser of its current-hour MW amount or next-hour schedule in accordance with its energy profile.	The Interchange Transaction MW amount used is determined through the e-tag ENERGY PROFILE and ADJUST tables. If the calculated amount is negative, zero is used instead.
S3	To allow a flowing Transaction to increase from its current-hour schedule to its next-hour schedule in accordance with its energy profile.	The MW amounts used in this sub-priority is determined by the e-tag ENERGY PROFILE table. If the calculated amount is negative, zero is used instead.
S4	To allow a Transaction that had never	The Transaction would not be allowed

	started and was submitted to the Tag Authority after the TLR (level 2 or higher) has been declared to begin flowing (i.e., the Interchange Transaction never had an active MW and was submitted to the IDC after the first TLR Action of the TLR Event had been declared.)	to start until all other Interchange Transactions submitted prior to the TLR with the same priority have been (re)loaded. The MW amount used is the sub-priority is the next-hour schedule determined by the e-tag ENERGY PROFILE table.

SPP shall use a "Market Flow Calculation" methodology to calculate the amount of energy flowing across all facilities included in the RTO's "Coordinated Flowgate List" that is associated with the operation of the SPP market. This energy is identified as "market flow."

These market flow impacts for current hour and next hour will be separated into their appropriate priorities and provided to the IDC by SPP. The market flows will then be represented and made available for curtailment under the appropriate TLR Levels.

Even though these market flow impacts (separated into appropriate priorities) will not be represented by conventional "tags," the impacts and their desired levels will still be provided to the IDC for current hour and next hour. Therefore, for the purposes of reallocation, a sub-priority (S1 thru S4) should be assigned to these market flow impacts by the NERC IDC as follows, using comparable logic as would be used if the impacts were in fact tagged transactions.

Priority	Purpose	Explanation and Conditions
S1	To allow existing market flow to maintain or reduce its current MW amount.	The currently flowing MW amount is the amount of market flow existing after the RTO has recognized the constraint for which TLR has been called. If the calculated amount is negative, zero is used instead.
S2	To allow market flow that has been curtailed or halted by TLR to reload to its desired amount for the current-hour.	This is the difference between the current hour unconstrained market flow and the current market flow. If the current-hour unconstrained market flow is not available, the IDC will use the most recent market flow since the TLR was first issued or, if not available, the market flow at the time the TLR was fist issued.
S3	To allow a market flow to increase to its next-hour desired amount.	This is the difference between the next hour and current hour unconstrained market flow.

To be retired upon completion of the field test, and in the interim the Regional Difference will be contained in both the NERC and NAESB standards.

F. Associated Documents

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	August 8, 2005	Revised Attachment 1	Revision
3	February 26, 2007	Revised Purpose and Attachment 1 related to NERC NAESB split of the TLR procedure	Revision
4	October 23, 2007	Approved by Board of Trustees	Revision
4.1	April 15, 2009	The URL in R1.2. was corrected.	Errata
4.1	December 10, 2009	Approved by FERC — Added approved effective date	Update

PLEASE NOTE: items designated for inclusion in the NAESB TLR business practice following completion of the standard revision were deleted. Please see the mapped document to see which items were move to NAESB and what future changes are expected.

Attachment 1 — IRO-006

Transmission Loading Relief Procedure — Eastern Interconnection

Purpose

This standard defines procedures for curtailment and reloading of Interchange Transactions to relieve overloads on transmission facilities modeled in the Interchange Distribution Calculator.

Applicability

This standard only applies to the Eastern Interconnection.

The flexibility for ISOs and RTOs to use redispatch is contained explicitly in the NAESB business practice Section 1.3.

1. Transmission Loading Relief (TLR) Procedure

1.1. Initiation only by Reliability Coordinator. A Reliability Coordinator shall be the only entity authorized to initiate the TLR Procedure.

1.1.1. Requesting relief on transmission facilities. Any Transmission Operator may request from its Reliability Coordinator relief on the transmission facilities it operates. A Reliability Coordinator shall review these requests for relief and determine the appropriate relief actions.

1.2. Mitigating SOL and IROL violations. A Reliability Coordinator may utilize the TLR Procedure to mitigate potential or existing System Operating Limit (SOL) violations or to prevent or mitigate Interconnection Reliability Operating Limit (IROL) violations on any transmission facility modeled in the IDC. However, the TLR procedure is an inappropriate and ineffective tool as a sole means to mitigate existing IROL violations due to the time required to implement the procedure. Reconfiguration, redispatch, and load shedding are more timely and effective in mitigating existing IROL violations

1.3. Sequencing of TLR Levels and taking emergency action. The Reliability Coordinator shall not be required to follow the TLR Levels in their numerical sequence (Section 2, "TLR Levels"). Furthermore, if a Reliability Coordinator deems that a transmission loading condition could jeopardize Bulk Electric System reliability, the Reliability Coordinator shall have the authority to enter TLR Level 6 directly, and immediately direct the Balancing Authorities or Transmission Operators to take such actions as redispatching generation, or reconfiguring transmission, or reducing load to mitigate the critical condition until Interchange Transactions can be reduced utilizing the TLR Procedure or other methods to return the system to a secure state.

1.4. Notification of TLR Procedure implementation. The Reliability Coordinator initiating the use of the TLR Procedure shall notify other Reliability Coordinators and Balancing Authorities and Transmission Operators, and must post the initiation and progress of the TLR event on the appropriate NERC web page(s).

This notification is automated in the Interchange Distribution Calculator (IDC) and populates a message on the NERC RCIS.

1.4.1. Notifying other Reliability Coordinators. The Reliability Coordinator initiating the TLR Procedure shall inform all other Reliability Coordinators via the Reliability Coordinator Information System (RCIS) that the TLR Procedure has been implemented.

Actions expected. The Reliability Coordinator initiating the TLR Procedure shall indicate the actions expected to be taken by other Reliability Coordinators.

1.4.2. Notifying Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify Transmission Operators and Balancing Authorities in its Reliability Area when entering and leaving any TLR level.

This notification is automated in the Interchange Distribution Calculator (IDC) and populates a message on the NERC RCIS.

1.4.3. Notifying Sink Balancing Authorities. The Reliability Coordinator for the sink Balancing Authority shall be responsible for directing the Sink Balancing Authority to curtail the Interchange Transactions as specified by the Reliability Coordinator implementing the TLR Procedure.

Notification order. Within a Transmission Service Priority level, the Sink Balancing Authorities whose Interchange Transactions have the largest impact on the Constrained Facilities shall be notified first if practicable.

1.4.4. Updates. At least once each hour, or when conditions change, the Reliability Coordinator implementing the TLR Procedure shall update all other Reliability Coordinators (via the RCIS). Transmission Operators and Balancing Authorities who have had Interchange Transactions impacted by the TLR will be updated by their Reliability Coordinator.

1.5. Obligations. All Reliability Coordinators shall comply with the request of the Reliability Coordinator who initiated the TLR Procedure, unless the initiating Reliability Coordinator agrees otherwise.

1.6. Consideration of Interchange Transactions. The administration of the TLR Procedure shall be guided by information obtained from the IDC.

1.6.1. Interchange Transactions not in the IDC. Reliability Coordinators shall also treat known Interchange Transactions that may not appear in the IDC in accordance with the procedures in this document.

1.6.2. Transmission elements not in IDC. When a Reliability Coordinator is faced with an overload on a transmission element that is not modeled in the IDC, the Reliability Coordinator shall use the best information available to curtail Interchange Transactions in order to operate the system in a reliable manner. The Reliability Coordinator shall use its best efforts to ensure that Interchange Transactions with a Transfer Distribution Factor of less than the Curtailment Threshold on the transmission element not modeled in the IDC are not curtailed.

1.6.3. Questionable IDC results. Any Reliability Coordinator who believes the curtailment list from the IDC for a particular TLR event is incorrect shall use its best efforts to communicate those adjustments necessary to bring the curtailment list into conformance with the principles of this Procedure to the initiating Reliability Coordinator. Causes of questionable IDC results may include:

- Missing Interchange Transactions that are known to contribute to the Constraint.
- Significant change in transmission system topology.
- TDF matrix error.

Impacts of questionable IDC results may include:

- Curtailment that would have no effect on, or aggravate the constraint.
- Curtailment that would initiate a constraint elsewhere.

If other Reliability Coordinators are involved in the TLR event, all impacted Reliability Coordinators shall be in agreement before any adjustments to the Curtailment list are made.

1.6.4. Curtailment that would cause a constraint elsewhere. A Reliability Coordinator shall be allowed to exempt an Interchange Transaction from Curtailment if that Reliability Coordinator is aware that the Interchange Transaction Curtailment directed by the IDC would cause a constraint to occur elsewhere. This exemption shall only be allowed after the Reliability Coordinator has consulted with the Reliability Coordinator who initiated the Curtailment.

1.7 Logging. The Reliability Coordinator shall complete the NERC Transmission Loading Relief Procedure Log whenever it invokes TLR Level 2 or above, and send a copy of the log via email to NERC within two business days of the TLR event for posting on the NERC website.

Creation and distribution of the TLR Procedure Log is now automated in the IDC.

1.8 TLR Event Review. The Reliability Coordinator shall report the TLR event to the Operating Reliability Subcommittee in accordance with TLR review processes established by NERC as required.

1.8.1 Providing information. Transmission Operators and Balancing Authorities within the Reliability Coordinator's Area, and all other Reliability Coordinators, including Transmission Operators and Balancing Authorities within their respective Reliability Areas, shall provide information, as requested by the initiating Reliability Coordinator, in accordance with TLR review processes established by NERC.

1.8.2 Market Committee reviews. The Market Committee may conduct reviews of certain TLR events based on the size and number of Interchange Transactions that are affected, the frequency that the TLR Procedure is called for a particular Constrained Facility, or other factors.

The Market Committee no longer exists and this requirement will be removed in Phase 3.

1.8.3 Operating Reliability Subcommittee reviews. The Operating Reliability Subcommittee shall conduct reviews to ensure proper implementation and for "lessons learned."

2. Transmission Loading Relief (TLR) Levels

Introduction
This section describes the various levels of the TLR Procedure. The description of each level begins with the circumstances that define the TLR Level, followed by the procedures to be followed.

The decision that a Reliability Coordinator makes in selecting a particular TLR Level often depends on the transmission loading condition and whether the Interchange Transaction is using Non-firm Point-to-Point Transmission Service or Firm Point-to-Point Transmission Service. There are further considerations that depend on whether the Constrained Facility is on or off the Contract Path. It is important to note that an Interchange Transaction using Firm Point-to-Point Transmission Service on all Contract Path links is considered a "firm" Interchange Transaction even if the Constrained Facility is off the Contract Path.

2.1. TLR Level 1 — Notify Reliability Coordinators of potential SOL or IROL Violations

2.1.1. The Reliability Coordinator shall use the following circumstances to establish the need for TLR Level 1**:**

- The transmission system is secure.
- The Reliability Coordinator foresees a transmission or generation contingency or other operating problem within its Reliability Area that could cause one or more transmission facilities to approach or exceed their SOL or IROL.

2.1.2. **Notification procedures**. The Reliability Coordinator shall notify all Reliability Coordinators via the Reliability Coordinator Information System (RCIS) as soon as the condition is foreseen. All affected Reliability Coordinators shall check to ensure that Interchange Transactions are posted in the IDC.

2.2. TLR Level 2 — Hold transfers at present level to prevent SOL or IROL Violations

2.2.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 2:

- The transmission system is secure.
- One or more transmission facilities are expected to approach, or are approaching, or are at their SOL or IROL.

2.3 TLR Level 3a — Reallocation of Transmission Service by curtailing Interchange Transactions using Non-firm Point-to-Point Transmission Service to allow Interchange Transactions using higher priority Transmission Service

2.3.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 3a:

- The transmission system is secure.
- One or more transmission facilities are expected to approach, or are approaching, or are at their SOL or IROL.
- Transactions using Non-firm Point-to-Point Transmission Service are flowing that are at or above the Curtailment Threshold on those facilities.

- The Transmission Provider has previously approved a higher priority Point-to-Point Transmission Service reservation over which a Transmission Customer wishes to begin an Interchange Transaction.

2.4. TLR Level 3b — Curtail Interchange Transactions using Non-Firm Transmission Service Arrangements to mitigate a SOL or IROL Violation

2.4.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 3b**:**

- One or more transmission facilities are operating above their SOL or IROL, or
- Such operation is imminent and it is expected that facilities will exceed their reliability limit unless corrective action is taken, or
- One or more Transmission Facilities will exceed their SOL or IROL upon the removal from service of a generating unit or another transmission facility.
- Transactions using Non-firm Point-to-Point Transmission Service are flowing that are at or above the Curtailment Threshold on those facilities.

2.5 TLR Level 4 — Reconfigure Transmission

2.5.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 4**:**

- One or more Transmission Facilities are above their SOL or IROL, or
- Such operation is imminent and it is expected that facilities will exceed their reliability limit unless corrective action is taken.

2.5.2. Reconfiguration procedures. The issuance of a TLR Level 4 shall result in the curtailment, in the current hour and the next hour, of all Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold that impact the Constrained Facilities. If a SOL or IROL violation is imminent or occurring, the Reliability Coordinator(s) shall request that the affected Transmission Operators reconfigure transmission on their system, or arrange for reconfiguration on other transmission systems, to mitigate the constraint.

2.6. TLR Level 5a — Reallocation of Transmission Service by curtailing Interchange Transactions using Firm Point-to-Point Transmission Service on a pro rata basis to allow additional Interchange Transactions using Firm Point-to-Point Transmission Service

2.6.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 5a**:**

- The transmission system is secure.
- One or more transmission facilities are at their SOL or IROL.
- All Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold have been curtailed.
- The Transmission Provider has been requested to begin an Interchange Transaction using previously arranged Firm Transmission Service that would result in a SOL or IROL violation.

- No further transmission reconfiguration is possible or effective.

2.7. TLR Level 5b — Curtail Interchange Transactions using Firm Point-to-Point Transmission Service to mitigate an SOL or IROL violation

2.7.1. The Reliability Coordinator shall use following circumstances to establish the need for entering TLR Level 5b**:**

- One or more Transmission Facilities are operating above their SOL or IROL, or
- Such operation is imminent, or
- One or more Transmission Facilities will exceed their SOL or IROL upon the removal from service of a generating unit or another transmission facility.
- All Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold have been curtailed.
- No further transmission reconfiguration is possible or effective.

formerly NERC section 3.3

2.8. Curtailment of Interchange Transactions Using Firm Transmission Service

2.8.1. The Reliability Coordinator shall direct the curtailment of Interchange Transactions using Firm Transmission Service that are at or above the Curtailment Threshold for the following TLR Levels:

2.8.1.1. TLR Level 5a. Enable additional Interchange Transactions using Firm Point-to-Point Transmission Service to be implemented after all Interchange Transactions using Non-firm Point-to-Point Service have been curtailed, or

2.8.1.2. TLR Level 5b. Mitigate a SOL or IROL violation that remains after all Interchange Transactions using Non-firm Transmission Service has been curtailed under TLR Level 3b, and following attempts to reconfigure transmission under TLR Level 4.

2.9. TLR Level 6 — Emergency Procedures

2.9.1 The Reliability Coordinator shall use following circumstances to establish the need for entering TLR Level 6**:**

- One or more Transmission Facilities are above their SOL or IROL.
- One or more Transmission Facilities will exceed their SOL or IROL upon the removal from service of a generating unit or another transmission facility.

2.9.2 **Implementing emergency procedures.** If the Reliability Coordinator deems that transmission loading is critical to Bulk Electric System reliability, the Reliability Coordinator shall immediately direct the Balancing Authorities and Transmission Operators in its Reliability Area to redispatch generation, or reconfigure transmission, or reduce load to mitigate the critical condition until Interchange Transactions can be reduced utilizing the TLR Procedures or other procedures to return the system to a secure state. All Balancing Authorities and Transmission Operators shall comply with all requests from their Reliability Coordinator.

2.10 TLR Level 0 — TLR concluded

2.10.1 Interchange Transaction restoration and notification procedures. The Reliability Coordinator initiating the TLR Procedure shall notify all Reliability Coordinators within the Interconnection via the RCIS when the SOL or IROL violations are mitigated and the system is in a reliable state, allowing Interchange Transactions to be reestablished at its discretion. Those with the highest transmission priorities shall be reestablished first if possible.

3. Requirements

3.1 The Reliability Coordinator shall be allowed to call a TLR 3b at any time to help mitigate a SOL or IROL violation.

3.2 The Reliability Coordinator shall Reallocate Interchange Transactions using Non-firm Point-to-Point Transmission for the next hour to maintain the desired flow using Reallocation in accordance with the following timing specification:

3.2.1 If issued prior to XX: 25, Non-firm Interchange Transactions will be curtailed to meet the desired current hour relief

4.2.1.1 At XX: 25 a Reallocation will be performed to maintain the desired flow at the top of the following hour

3.2.2 If issued after XX: 25, Non firm Interchange Transactions will be curtailed to meet the desired current hour relief and a Reallocation will be performed to maintain the target flow identified for the current hour.

3.2.3 Transactions must be in the IDC by the Approved-tag Submission Deadline for Reallocation.

3.3 The IDC shall issue ADJUST Lists to the Generation and Load Balancing Authority Areas and the Purchasing-Selling Entity who submitted the tag. The ADJUST List will include: (recommended to be moved to Attachment 2)

3.3.1 Interchange Transactions using Non-firm Point-to-Point Transmission Service that are to be curtailed or held during current and next hours. (recommended to be moved to Attachment 2)

3.3.2 Interchange Transactions using Firm Point-to-Point Transmission Service that were entered after XX:25 or issuance of TLR 3b (see Case 3 in Appendix F). (recommended to be moved to Attachment 2)

3.4 The Sink Balancing Authority shall send the ADJUST Lists back to the IDC as soon as possible to ensure the most accurate calculations for actions subsequent to the TLR 3b being called. (recommend to be moved to Attachment 2)

3.5 The Reliability Coordinator will no longer be required to call a TLR Level 3a as soon as the SOL or IROL violation that caused the TLR 3b to be called has been mitigated due to the inherent next hour Reallocation that takes place for the top of the next hour in the TLR Level 3b. (recommend to be moved to Attachment 2)

Appendices for Transmission Loading Relief Standard

PLEASE NOTE: items designated for inclusion in the NAESB TLR business practice following completion of the standard revision were deleted from this version of the NERC standard. Please see the mapped document to see which requirements were moved to NAESB and what future changes are expected. Appendices B, D, G, and the sub-priority portions of E-2 have been moved to NAESB, The appendices below (A, C, E, F) will be renumbered in the final standard.

Appendix A. Transaction Management and Curtailment Process.

Appendix C. Sample NERC Transmission Loading Relief Procedure Log.

Appendix E. How the IDC Handles Reallocation.

Section E1: Summary of IDC Features that Support Transaction Reloading/Reallocation.

Section E2: Timing Requirements.

Appendix F. Considerations for Interchange Transactions using Firm Point-to-Point Transmission Service.

Appendix A. Transaction Management and Curtailment Process

This flowchart depicts an overview of the Transaction Management and Curtailment process. Detailed decisions are not shown.

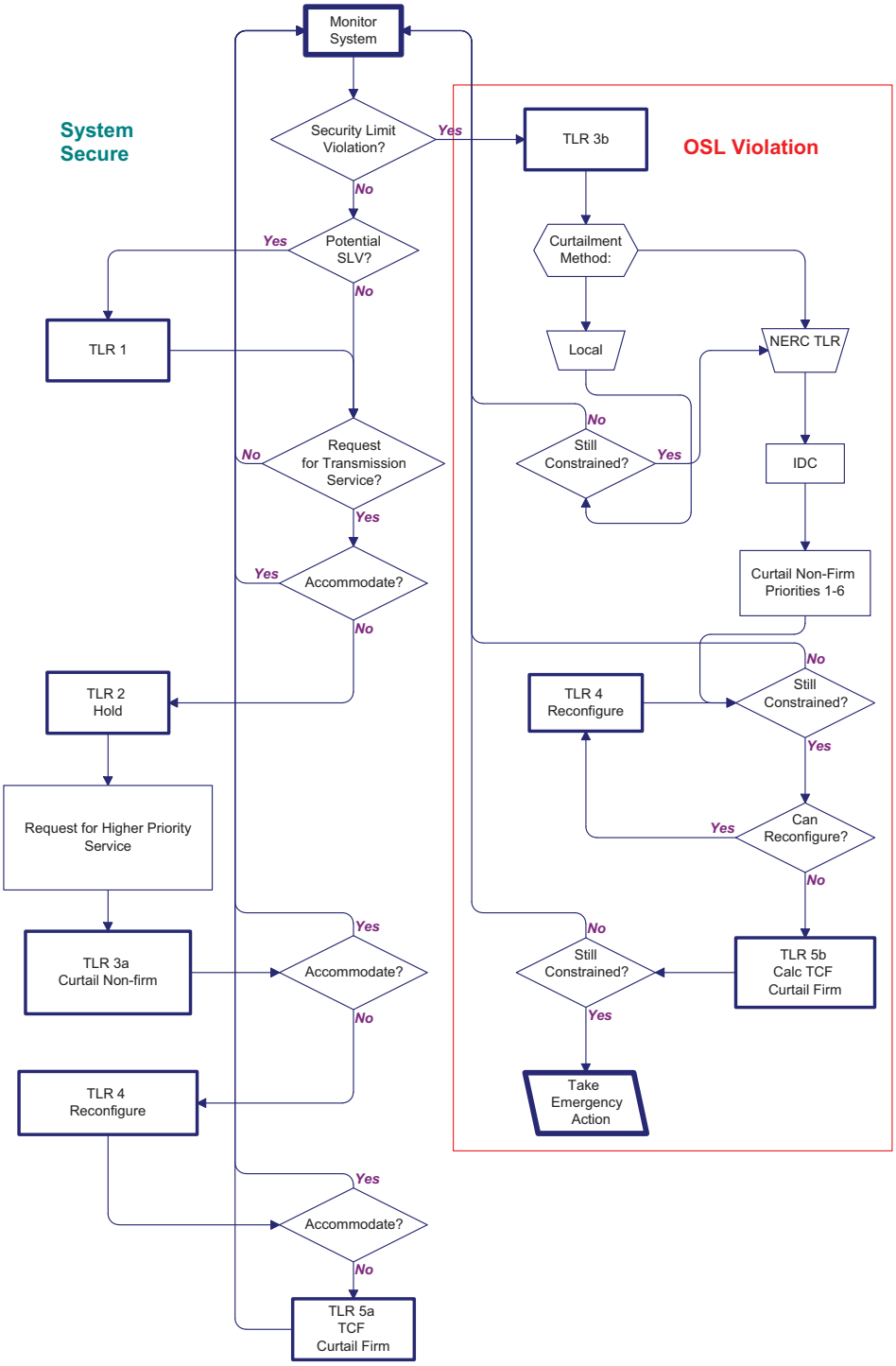

Appendix C. Sample NERC Transmission Loading Relief Procedure Log

SAVE FILE DIRECTORY:

NERC TRANSMISSION LOADING RELIEF (TLR) PROCEDURE LOG

FILE SAVED AS: .XLS

INCIDENT	DATE:	IMPACTED RELIABILITY COORDINATOR	ID NO:

INITIAL CONDITIONS

Limiting Flowgate (LIMIT)	Rating	Contingent Flowgate (CONT.)	ODF

TLR Levels

0: TLR Incident Canceled
1. Notify Reliability Coordinators of potential problems.
2: Halt additional transactions that contribute to the overload
3a and 3b: Curtail transactions using Non-firm Transmission Service
4. Reconfigure to continue firm transactions if needed.
5a and 5b: Curtail Transactions using Firm Transmission Service.
6: Implement emergency procedures.

Priorities

NX	Next Hour Market Service
NS	Service over secondary receipt and delivery points
NH	Hourly Service
ND	Daily Service
NW	Weekly Service
NM	Monthly Service
NN	Non-firm imports for native load and network customers from non-designated network resources
F	Firm Service

TLR ACTIONS

LEVEL	TIME	Priority	TLR 3,5 No. TX Curtail	TLR 3,5 MW Curtail	MW Flow Limiting Element Present	MW Flow Limiting Element Post Cont.	MW Flow Cont. Element Present	COMMENTS ABOUT ACTIONS

Appendix E. How the IDC Handles Reallocation

The IDC algorithms reflect the Reallocation and reloading principles in this Appendix, as well as the reporting requirements, and status display. The IDC will obtain the Tag Submittal Time from the Tag Authority and post the Reloading/Reallocation information to the NERC TLR website.

A summary of IDC features that support the Reallocation process is provided in Attachment E1. Details on the interface and display features are provided in Attachment E2. Refer to Version 1.7.095 NERC Transaction Information Systems Working Group (TISWG) *Electronic Tagging Functional Specification* for details about the E-Tag system.

E1. Summary of IDC Features that Support Transaction Reloading/Reallocation

The following is a summary of IDC features and E-Tag interface that support Reloading/Reallocation:

Information posted from IDC to NERC TLR website.

1. Restricted directions (all source/sink combinations that impact a Constrained Facility(ies) with TLR 2 or higher) will be posted to the NERC TLR website and updated as necessary.
2. TLR Constrained Facility status and Transfer Distribution Factors will continue to be posted to NERC TLR website.
3. Lowest priority of Interchange Transactions (marginal "bucket") to be Reloaded/Reallocated next-hour on each TLR Constrained Facility will be posted on NERC TLR website. This will provide an indication to the market of priority of Interchange Transactions that may be Reloaded/Reallocated the following hours.

IDC Logic, IDC Report, and Timing

1. The Reliability Coordinator will run the IDC the Reloading/Reallocation report at approximately 00:26. The IDC will prompt the Reliability Coordinator to enter a maximum loading value. The IDC will alarm if the Reliability Coordinator does not enter this value and issue a report by 00:30 or change from TLR 3a Level. The Report will be distributed to Balancing Authorities and Transmission Operators at 00:30. This process repeats every hour as long as the approved tag submission deadline for Reallocation is in effect (or until the TLR level is reduced to 1 or 0).
2. For Interchange Transactions in the restricted directions, tags must be submitted to the IDC by the approved tag submission deadline for Reallocation to be considered for Reallocation next-hour. The time stamp by the Tag Authority is regarded the official tag submission time.
3. Tags submitted to IDC after the approved tag submission deadline for Reallocation will not be allowed to start or increase but will be considered for Reallocation the next hour.
4. Interchange Transactions in restricted directions that are not indicated as "PROCEED" on the Reload/Reallocation Report will not be permitted to start or increase next hour.

Reloading/Reallocation Transaction Status

Reloading/Reallocation status will be determined by the IDC for all Interchange Transactions. The Reloading/Reallocation status of each Interchange Transaction will be listed on IDC reports and NERC TLR website as appropriate. An Interchange Transaction is considered to be in a restricted direction if it is at or above the Curtailment Threshold. Interchange Transactions below the Curtailment Threshold are unrestricted and free to flow subject to all applicable Reliability Standards and tariff rules.

1. **HOLD.** Permission has not been given for Interchange Transaction to start or increase and is waiting for the next Reloading/Reallocation evaluation for which it is a candidate. Interchange Transactions with E-tags submitted to the Tag Authority prior to TLR 2 or higher being declared (pre-tagged) will change to CURTAILED Status upon evaluation that does not permit them to start or increase.

Transactions with E-tags submitted to Tag Authority after TLR 2 or higher was declared (post-tagged) will retain HOLD Status until given permission to proceed or E-Tag expires.

2. **CURTAILED**. Transactions for which E-Tags were submitted to Tag Authority prior to TLR 2 or higher being declared (pre-tagged) and ordered to be curtailed totally, curtailed partially, not permitted to start, or not permitted to increase. Interchange Transactions (pre-tagged or post-tagged) that were flowing and ordered to be reduced or totally curtailed. The Balancing Authority will indicate to the IDC through the E-Tag adjustment table the Interchange Transaction's curtailed values.

3. **PROCEED**: Interchange Transaction is flowing or has been permitted to flow as a result of Reloading/Reallocation evaluation. The Balancing Authority will indicate through the E-Tag adjustment table to IDC if Interchange Transaction will reload, start, or increase next-hour per Purchasing-Selling Entity's energy schedule as appropriate.

Reallocation/Reloading Priorities

1. Interchange Transaction candidates are ranked for loading and curtailment by priority as per Section 4, "Principles for Mitigating Constraints On and Off the Contract Path." This is called the "Constrained Path Method," or CPM. (secondary, hourly, daily, … firm etc). Interchange Transactions are curtailed and loaded pro-rata within priority level per TLR algorithm.
2. Reloading/Reallocation of Interchange Transactions are prioritized first by priority per CPM. E-Tags must be submitted to the IDC by the approved tag submission deadline for Reallocation of the hour during which the Interchange Transaction is scheduled to start or increase to be considered for Reallocation.
3. During Reloading/Reallocation, Interchange Transactions using lower priority Transmission Service will be curtailed pro-rata to allow higher priority transactions to reload, increase, or start. Equal priority Interchange Transactions will not reload, start, or increase by pro-rata Curtailment of other equal priority Interchange Transactions.
4. Reloading of Interchange Transactions using Non-firm Transmission Service with CURTAILED Status will take precedence over starting or increasing of Interchange Transactions using Non-firm Transmission Service of the same priority with PENDING Statuses.
5. Interchange Transactions using Firm Point-to-Point Transmission Service will be allowed to start as scheduled under TLR 3a as long as their E-Tag was received by the IDC by the approved tag submission deadline for Reallocation of the hour during which the Interchange Transaction is due to start or increase, regardless of whether the E-tag was submitted to the Tag Authority prior to TLR 2 or higher being declared or not. If this is the initial issuance of the TLR 3a, Interchange Transactions using Firm Point-to-Point Transmission Service will be allowed to start as scheduled as long as their E-Tag was received by the IDC by the time the TLR is declared.

Total Flow Value on a Constrained Facility for Next Hour

1. The Reliability Coordinator will calculate the change in net flow on a Constrained Facility due to Reallocation for the next hour based on:

- Present constrained facility loading, present level of Interchange Transactions, and Balancing Authorities NNative Load responsibility (TLR Level 5a) impacting the Constrained Facility,
- SOLs or IROLs, known interchange impacts and Balancing Authority NNative Load responsibility (TLR Level 5a) on the Constrained Facility the next hour, and
- Interchange Transactions scheduled to begin the next hour.

2. The Reliability Coordinator will enter a maximum loading value for the constrained facility into the IDC as part of issuing the Reloading/Reallocation report.
3. The Reliability Coordinator is allowed to call for TLR 3a or 5a when approaching a SOL or IROL to allow maximum transactional flow next hour, and to manage flows without violating transmission limits.
4. The simultaneous curtailment and Reallocation for a Constrained Facility is allowed. This reduces the flow over the Constrained Facility while allowing Interchange Transactions using higher priority Transmission Service to start or increase the next hour. This may be used to accommodate change in flow next-hour due to changes other than Point-to-Point Interchange Transactions while respecting the priorities of Interchange Transactions flowing and scheduled to flow the next hour. The intent is to reduce the need for using TLR 3b, which prevents new Interchange Transactions from starting or increasing the next hour.
5. The Reliability Coordinator must allow Interchange Transactions to be reloaded as soon as possible. Reloading must be in an orderly fashion to prevent a SOL or IROL violation from (re)occurring and requiring holding or curtailments in the restricted direction.

E2. Timing Requirements

TLR Levels 3a and 5a Issuing/Processing Time Requirement

1. In order for the IDC to be reasonably certain that a TLR Level 3a or 5a re-allocation/reloading report in which all tags submitted by the approved tag submission deadline for Reallocation are included, the report must be generated no earlier than 00:25 to allow the 10-minute approval time for Transactions that start next hour.
2. In order to allow a Reliability Coordinator to declare a TLR Level 3a or 5a at any time during the hour, the TLR declaration and Reallocation/Reloading report distribution will be treated as independent processes by the IDC. That is, a Reliability Coordinator may declare a TLR Level 3a or 5a at any time during the course of an hour. However, if a TLR Level 3a or 5a is declared for the next hour prior to 00:25 (see Figure 5 at right), the Reallocation/Reloading report that is generated will be made available to the issuing Reliability Coordinator only for previewing purposes, and cannot be distributed to the other Reliability Coordinators or the market. Instead, the issuing Reliability Coordinator will be reminded by an IDC alarm at 00:25 to generate a new Reallocation/Reloading report that will include all tags submitted prior to the approved tag submission deadline for Reallocation.

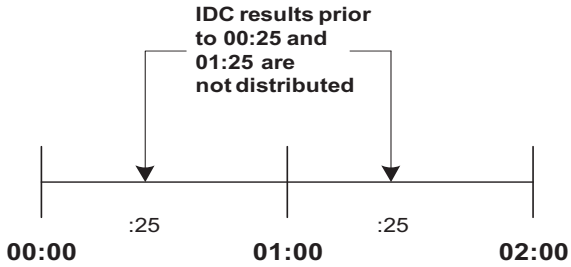

Figure 5 - IDC report may be run prior to 00:25, but results are not distributed.

3. A TLR Level 3a or 5a Reallocation/Reloading report must be confirmed by the issuing Reliability Coordinator prior to 00:30 in order to provide a minimum of 30 minutes for the Reliability Coordinators with tags sinking in its Reliability Area to coordinate the Reallocation and Reloading with the Sink Balancing Authorities. This provides only 5 minutes (from 00:25 to 00:30) for the issuing Reliability Coordinator to generate a Reallocation/Reloading report, review it, and approve it.
4. The TLR declaration time will be recorded in the IDC for evaluating transaction sub-priorities for Reallocation/Reloading purposes (see Subpriority Table, in the **IDC Calculations and Reporting** section below).

Re-Issuing of a TLR Level 2 or Higher

Each hour, the IDC will automatically remind the issuing Reliability Coordinator (via an IDC alarm) of a TLR level 2 or higher declared in the previous hour or earlier about re-issuing the TLR. The purpose of the reminder is to enable the Reliability Coordinator to Reallocate or reload currently halted or curtailed Interchange Transactions next hour. The reminder will be in the form of an alarm to the issuing Reliability Coordinator, and will take place at 00:25 so that, if the Reliability Coordinator re-issues the TLR as a TLR level 3a or 5a, all tags submitted prior to the approved tag submission deadline for Reallocation are available in the IDC.

IDC Assistance with Next Hour Point-to-Point Transactions

In order to assist a Reliability Coordinator in determining the MW relief required on a Constrained Facility for the next hour for a TLR level 3a or 5a, the IDC will calculate and present the total MW impact of all currently flowing and scheduled Point-to-Point Transactions for the next hour. In order to assist a Reliability Coordinator in determining the MW relief required on a Constrained Facility for the next hour during a TLR level 5a, the IDC will calculate and present the total MW impact of all currently flowing and scheduled Point-to-Point Transactions for the next hour as well as Balancing Authority with flows due to service to Network Customers and Native Load. The Reliability Coordinator will then be requested to provide the total incremental or decremental MW amount of flow through the Constrained Facility that can be allowed for the next hour. The value entered by the Reliability Coordinator and the IDC-calculated amounts will be used by the IDC to identify the relief/reloading amounts (delta

incremental flow value) on the constrained facility. The IDC will determine the Transactions to be reloaded, reallocated, or curtailed to make room for the Transactions using higher priority Transmission Service. The following examples show the calculation performed by IDC to identify the "delta incremental flow:"

Example 1

Flow to maintain on Facility	800 MW
Expected flow next hour from Transactions using Point-to-Point Transmission Service	950 MW
Contribution from flow next hour from service to Network customers and Native Load	-100 MW
Expected Net flow next hour on Facility	850 MW
Amount of Transactions using Point-to-Point Transmission Service to hold for Reallocation	850 MW – 800 MW = 50 MW
Amount to enter into IDC for Transactions using Point-to-Point Transmission Service	950 MW – 50 MW = 900 MW

Example 2

Flow to maintain on Facility	800 MW
Expected flow next hour from Transactions using Point-to-Point Transmission Service	950 MW
Contribution from flow next hour from service to Network customers and Native Load	50 MW
Expected Net flow next hour on Facility	1000 MW
Amount of Transactions using Point-to-Point Transmission Service to hold for Reallocation	1000 MW – 800 MW = 200 MW
Amount to enter into IDC for Transactions using Point-to-Point Transmission Service	950 MW – 200 MW = 750 MW

Example 3

Flow to maintain on Facility	800 MW
Expected flow next hour from Transactions using Point-to-Point Transmission Service	950 MW
Contribution from flow next hour from service to Network customers and Native Load	-200 MW
Expected Net flow next hour on Facility	750 MW
Amount of Transactions using Point-to-Point Transmission Service to hold for Reallocation	750 MW – 800 MW = -50 MW None are held

For a TLR levels 3b or 5b the IDC will request the Reliability Coordinator to provide the MW requested relief amount on the Constrained Facility, and will not present the current and next hour MW impact of Point-to-Point transactions. The Reliability Coordinator-entered requested relief amount will be used by the IDC to determine the Interchange Transaction Curtailments and flows due to service to Network Customers and Native Load (TLR Level 5b) in order to reduce the SOL or IROL violation on the Constrained Facility by the requested amount.

IDC Calculations and Reporting

At the time the TLR report is processed, the IDC will use all candidate Interchange Transactions for Reallocation that met the approved tag submission deadline for Reallocation plus those Interchange Transactions that were curtailed or halted on the previous TLR action of the same TLR event. The IDC will calculate and present an Interchange Transactions Halt/Curtailment list that will include reload and Reallocation of Interchange Transactions. The Interchange Transactions are prioritized as follows:

1. All Interchange Transactions will be arranged by Transmission Service Priority according to the Constrained Path Method. These priorities range from 1 to 6 for the various non-firm Transmission Service products (TLR levels 3a and 3b). Interchange Transactions using Firm Transmission Service (priority 7) are used only in TLR levels 5a and 5b. Next-Hour Market Service is included at priority 0 (Recommended to be placed in Attachment 2).

   Examples of Interchange Transactions using Non-firm Transmission Service sub-priority settings begin in the **Transaction Sub-priority Examples** following sections

2. All Interchange Transactions using Firm Transmission Service will be put in the same priority group, and will be Curtailed/Reallocated pro-rata, independent of their current status (curtailed or halted) or time of submittal with respect to TLR issuance (TLR level 5a). Under a TLR 5a, all Interchange Transactions using Non-firm Transmission Service that is at or above the Curtailment Threshold will have been curtailed and hence sub-prioritizing is not required.

All Interchange Transactions processed in a TLR are assigned one of the following statuses:

PROCEED:	The Interchange Transaction has started or is allowed to start to the next hour MW schedule amount.
CURTAILED:	The Interchange Transaction has started and is curtailed due to the TLR, or it had not started but it was submitted prior to the TLR being declared (level 2 or higher).
HOLD:	The Interchange Transaction had never started and it was submitted after the TLR being declared – the Interchange Transaction is held from starting next hour or the transaction had never started and it was submitted to the IDC after the Approved-Tag Submission Deadline – the Interchange Transaction is to be held from starting next hour and is not included in the Reallocation calculations until following hour.

Upon acceptance of the TLR Transaction Reallocation/reloading report by the issuing Reliability Coordinator, the IDC will generate a report to be sent to NERC that will include the PSE name and Tag ID of each Interchange Transaction in the IDC TLR report. The Interchange Transaction will be ranked according to its assigned status of HOLD, CURTAILED or PROCEED. The reloading/Reallocation report will be made available at NERC's public TLR website, and it is NERC's responsibility to format and publish the report.

Tag Reloading for TLR Levels 1 and 0

When a TLR Level 1 or 0 is issued, the Constrained Facility is no longer under SOL or IROL violation and all Interchange Transactions are allowed to flow. In order to provide the Reliability Coordinators with

a view of the Interchange Transactions that were halted or curtailed on previous TLR actions (level 2 or higher) and are now available for reloading, the IDC provides such information in the TLR report.

New Tag Alarming
Those Interchange Transactions that are at or above the Curtailment Threshold and are *not* candidates for Reallocation because the tags for those Transactions were not submitted by the approved tag submission deadline for Reallocation will be flagged as HOLD and must not be permitted to start or increase during the next hour. To alert Reliability Coordinators of those Transactions required to be held, the IDC will generate a report (for viewing within the IDC only) at various times. The report will include a list of all HOLD Transactions. In order not to overwhelm the Reliability Coordinator with alarms, only those who issued the TLR and those whose Transactions sink within their Reliability Area will be alarmed. An alarm will be issued for a given tag only once and will be issued for all TLR levels for which halting new Transactions is required: TLR Level 2, 3a, 3b, 5a and 5b.

Tag Adjustment
The Interchange Transactions with statuses of HOLD, CURTAILED or PROCEED must be adjusted by a Tag Authority or Tag Approval entity. Without the tag adjustments, the IDC will assume that Interchange Transactions were not curtailed/held and are flowing at their specified schedule amounts.

1. Interchange Transactions marked as CURTAILED should be adjusted to a cap equal to, or at the request of the originating PSE, less than the reallocated amount (shown as the MW CAP on the IDC report). This amount may be zero if the Transaction is fully curtailed.
2. Interchange Transaction marked as PROCEED should be adjusted to reload (NULL or to its MW level in accordance with its Energy Profile in the adjusted MW in the E-Tag) if the Interchange Transaction has been previously adjusted; otherwise, if the Interchange Transaction is flowing in full, the Tag Authority need not issue an adjust.
3. Interchange Transactions marked as HOLD should be adjusted to 0 MW.

Special Tag Status
There are cases in which a tag may be marked with a composite state of ATTN_REQD to indicate that tag Authority/Approval failed to communicate or there is an inconsistency between the validation software of different tag Authority/Approval entities. In this situation, the tag is no longer subject to passive approval and its status change to IMPLEMENT may take longer than 10 minutes. Under these circumstances, the IDC may have a tag that is issued prior to the Tag Submittal Deadline that will not be a candidate for Reallocation. Such tags, when approved by the Tag Authority, will be marked as HOLD and must be halted.

Transaction Sub-Priority Examples
The following describes examples of Interchange Transactions using Non-firm Transmission Service sub-priority setting for an Interchange Transaction under different circumstances of current-hour and next-hour schedules and active MW flowing as modified by tag adjust table in E-Tag.

Example 1 – Transaction curtailed, next-hour Energy Profile is higher

Energy Profile: Current hour	20 MW
Actual flow following curtailment: Current hour	10 MW
Energy Profile: Next hour	40 MW

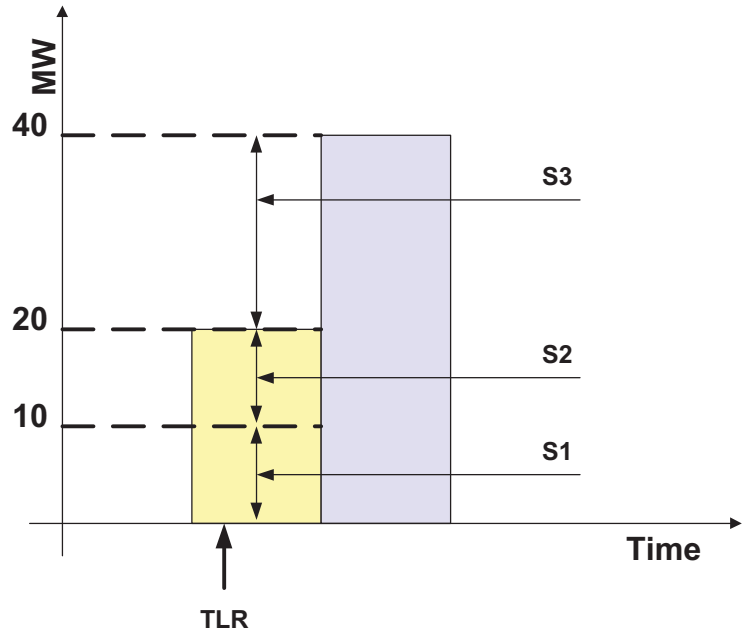

Sub-priorities for Transaction MW:

Sub-Priority	*MW Value*	*Explanation*
S1	10 MW	Maintain current curtailed flow
S2	+10 MW	Reload to current hour Energy Profile
S3	+20 MW	Load to next hour Energy Profile
S4		

Example 2 – Transaction curtailed, next-hour Energy Profile is lower

Energy Profile: Current hour	40 MW
Actual flow following curtailment: Current hour	10 MW
Energy Profile: Next hour	20 MW

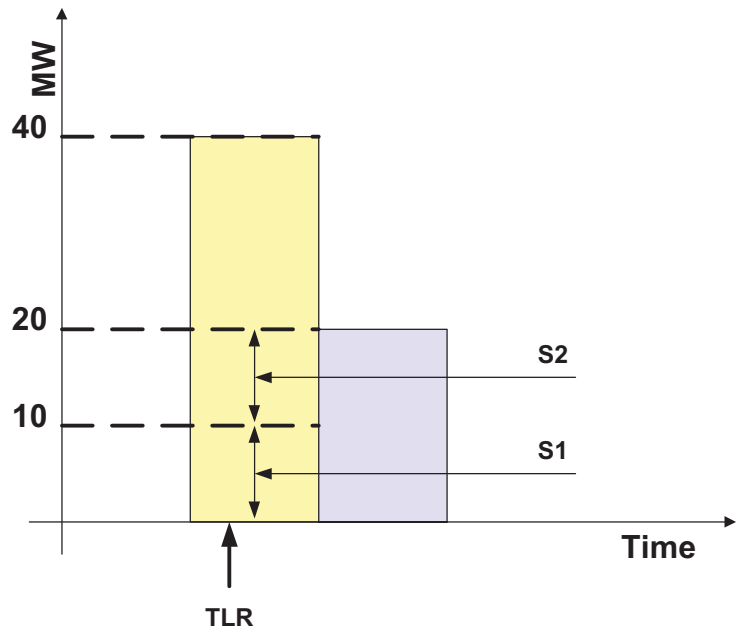

Sub-priorities for Transaction MW:

Sub-Priority	*MW Value*	*Explanation*
S1	10 MW	Maintain current curtailed flow
S2	+10 MW	Reload to *lesser* of current and next-hour Energy Profile
S3	+0 MW	Next-hour Energy Profile is 20MW, so no change in MW value
S4		

Example 3 – Transaction not curtailed, next-hour Energy Profile is higher

Energy Profile: Current hour	20 MW
Actual flow following curtailment: Current hour	20 MW (no curtailment)
Energy Profile: Next hour	40 MW

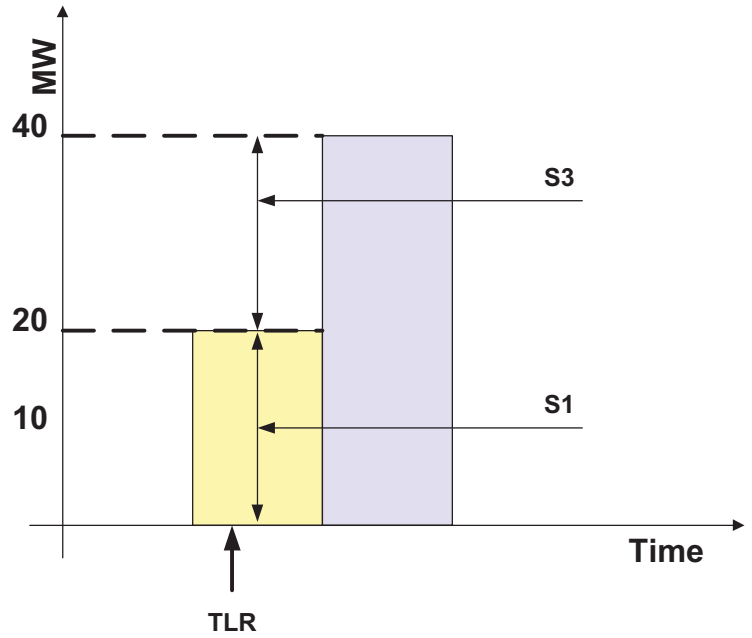

Sub-Priority	*MW Value*	*Explanation*
S1	20 MW	Maintain current flow (not curtailed)
S2	+0 MW	Reload to *lesser* of current and next-hour Energy Profile
S3	+20 MW	Next-hour Energy Profile is 40MW
S4		

Example 4 – Transaction not curtailed, next-hour Energy Profile is lower

Energy Profile: Current hour	40 MW
Actual flow following curtailment: Current hour	40 MW (no curtailment)
Energy Profile: Next hour	20 MW

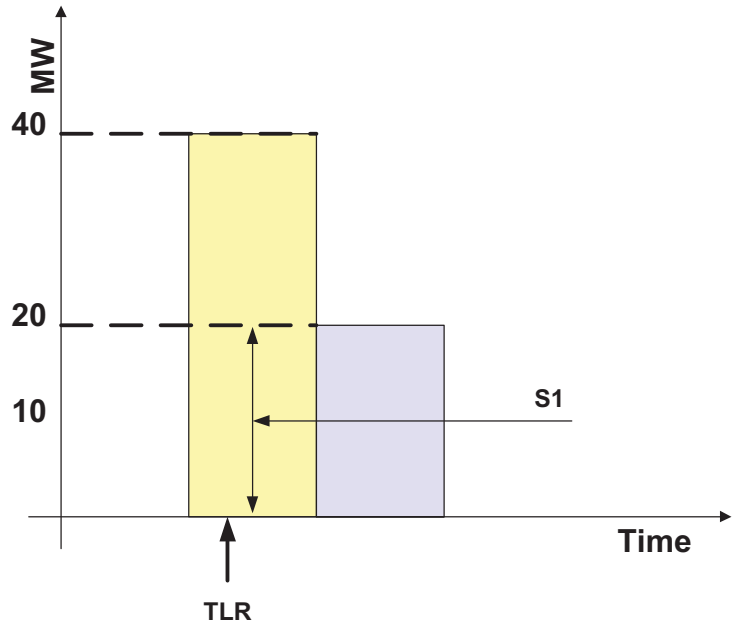

Sub-priorities for Transaction MW:

Sub-Priority	*MW Value*	*Explanation*
S1	20 MW	Reduce flow to next-hour Energy Profile (20MW)
S2	+0 MW	Reload to *lesser* of current and next-hour Energy Profile
S3	+0 MW	Next-hour Energy Profile is 20MW
S4		

Example 5 — TLR Issued before Transaction was scheduled to start

Energy Profile: Current hour	0 MW
Actual flow following curtailment: Current hour	0 MW (Transaction scheduled to start *after* TLR initiated)
Energy Profile: Next hour	20 MW

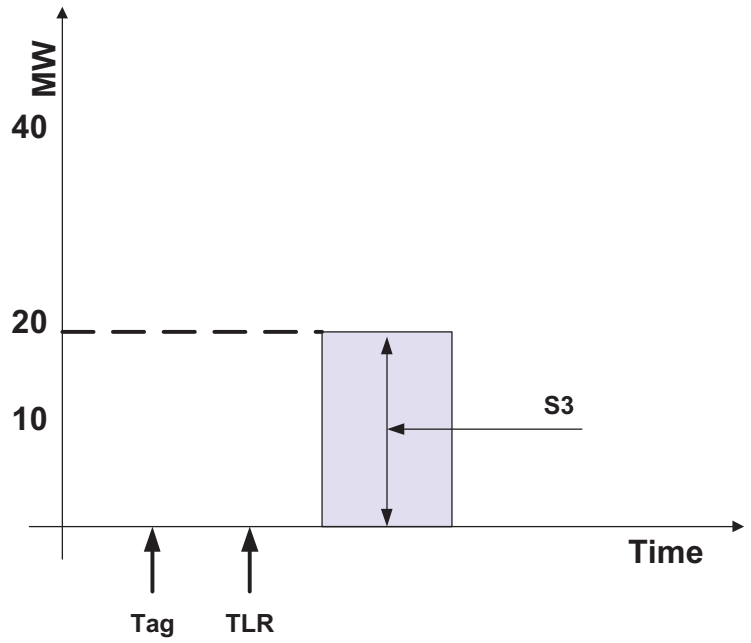

Sub-Priority	*MW Value*	*Explanation*
S1	0 MW	Transaction was not allowed to start
S2	+0 MW	Transaction was not allowed to start
S3	+20 MW	Next-hour Energy Profile is 20MW
S4	+0	Tag submitted prior to TLR

Appendix F. Considerations for Interchange Transactions

Using Firm Point-to-Point Transmission Service

The following cases explain the circumstances under which an Interchange Transaction using Firm Point-to-Point Transmission Service will be allowed to start as scheduled during a TLR 3b:

Case 1: TLR 3b is called between 00:00 and 00:25 and the Interchange Transaction using Firm Point-to-Point Transmission Service is submitted to IDC by 00:25.

The IDC will examine the current hour (00) and next hour (01) for all Interchange Transactions.

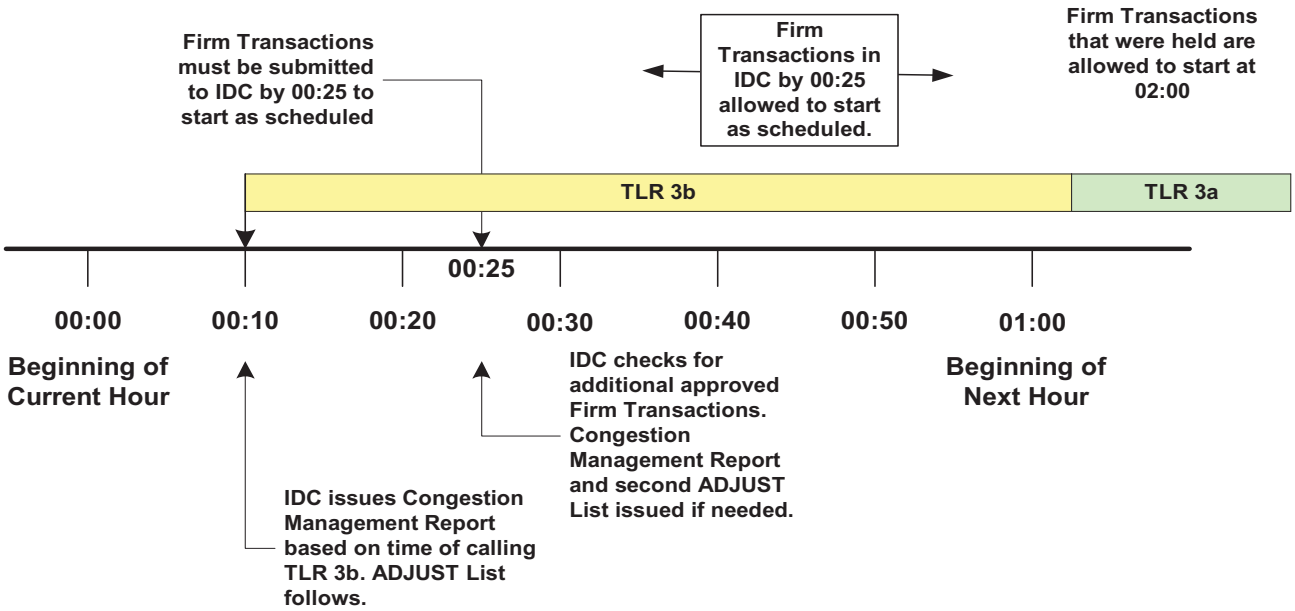

The IDC will issue an ADJUST List based upon the time the TLR 3b is called. The ADJUST List will include curtailments of Interchange Transactions using Non-firm Point-to-Point Transmission Service as necessary to allow room for those Interchange Transactions using Firm Point-to-Point Transmission Service to start as scheduled.

At 00:25, the IDC will check for additional Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC by that time and issue a second ADJUST List if those additional Interchange Transactions are found.

All existing or new Interchange Transactions using Non-firm Point-to-Point Transmission Service that are increasing or expected to start during the current hour or next hour will be placed on HALT or HOLD. There is no Reallocation of lower-priority Interchange Transactions using Non-firm Point-to-Point Transmission Service.

Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC by 00:25 will be allowed to start as scheduled.

Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC after 00:25 will be held.

Once the SOL or IROL violation is mitigated, the Reliability Coordinator shall call a TLR Level 3a (or lower). If a TLR Level 3a is called:

Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC by 00:25 will be allowed to start as scheduled at 02:00.

Interchange Transactions using Non-firm Point-to-Point Transmission Service that were held may then be reallocated to start at 02:00.

Case 2: TLR 3b is called after 00:25 and the Interchange Transaction using Firm Point-to-Point Transmission Service is submitted to the IDC no later than the time at which the TLR 3b is called.

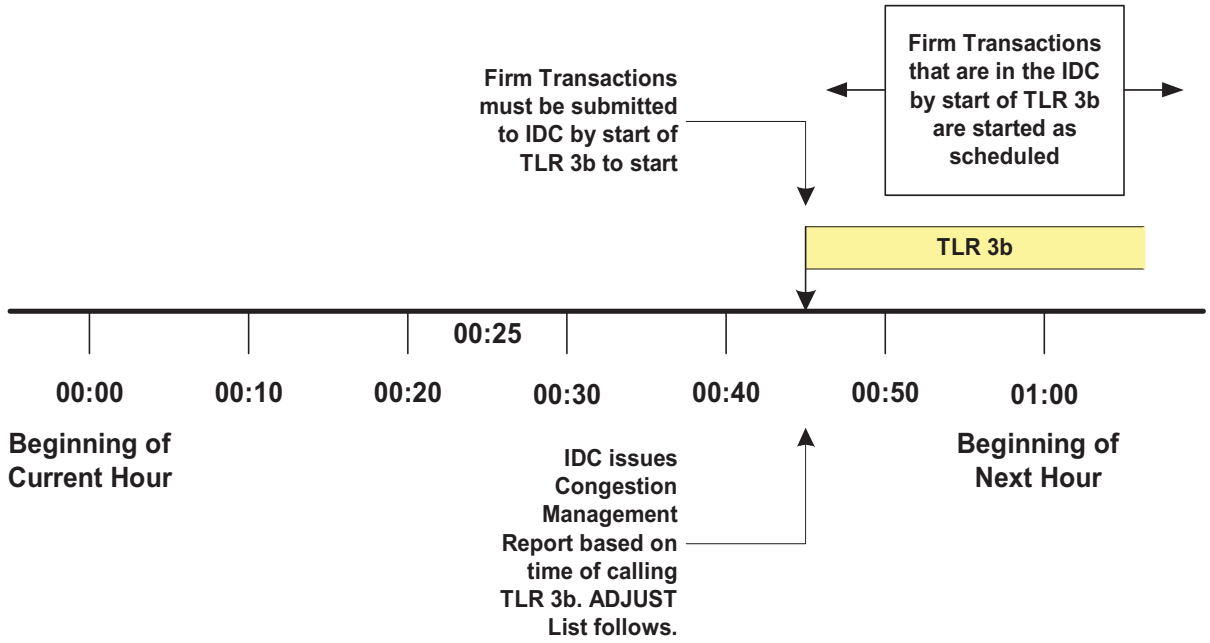

The IDC will examine the current hour (00) and next hour (01) for all Interchange Transactions.

The IDC will issue an ADJUST List at the time the TLR 3b is called. The ADJUST List will include additional curtailments of Interchange Transactions using Non-firm Point-to-Point Transmission Service as necessary to allow room for those Interchange Transactions using Firm Point-to-Point Transmission Service to start at as scheduled.

All existing or new Interchange Transactions using Non-firm Point-to-Point Transmission Service that are increasing or expected to start during the current hour or next hour will be placed on HALT or HOLD. There is no Reallocation of lower-priority Interchange Transactions using Non-firm Point-to-Point Transmission Service.

Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC by the time the TLR 3b was called will be allowed to start at as scheduled.

Interchange Transaction using Firm Point-to-Point Transmission Service that were submitted to the IDC after the TLR 3b was called will be held until the next issuance for TLR (either TLR 3b, 3a, or lower level).

Case 3. TLR 2 or higher is in effect, a TLR 3b is called after 00:25, and the Interchange Transaction using Firm Point-to-Point Transmission Service is submitted to the IDC by 00:25.

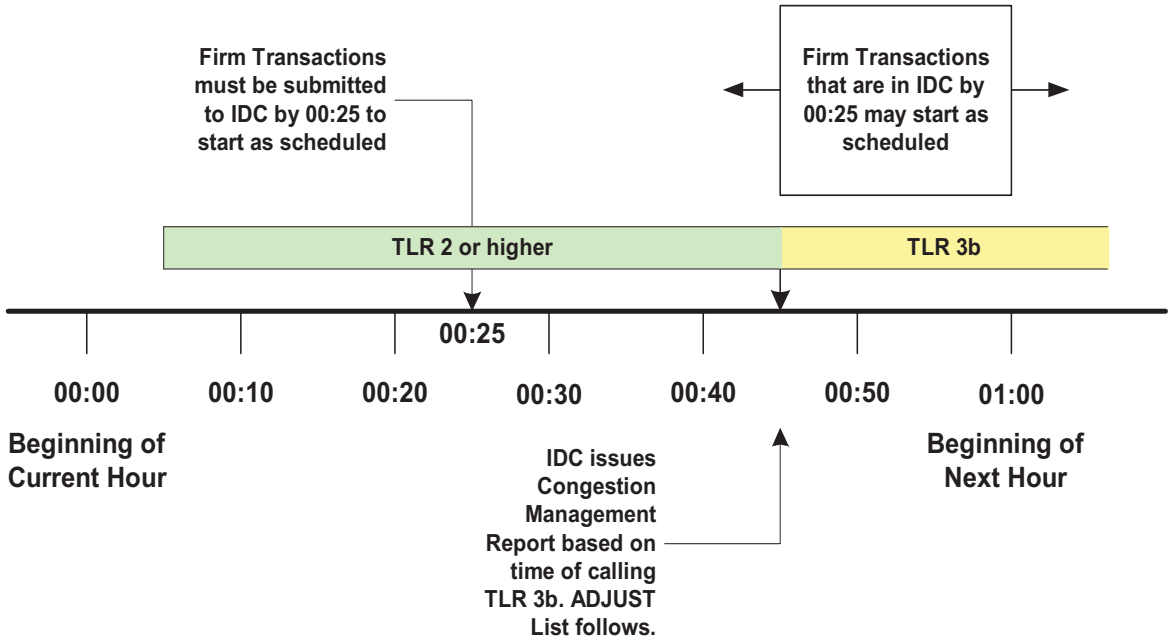

If a TLR 2 or higher has been issued and 3B is subsequently issued, then only those Interchange Transactions using Firm Point-to-Point Transmission Service that had been submitted to the IDC by 00:25 will be allowed to start as scheduled. All other Interchange Transactions are held.

Case 4. TLR 3b is called before 00:25 and the Interchange Transaction is submitted to the IDC by 00:25. TLR 3a is called at 00:40.

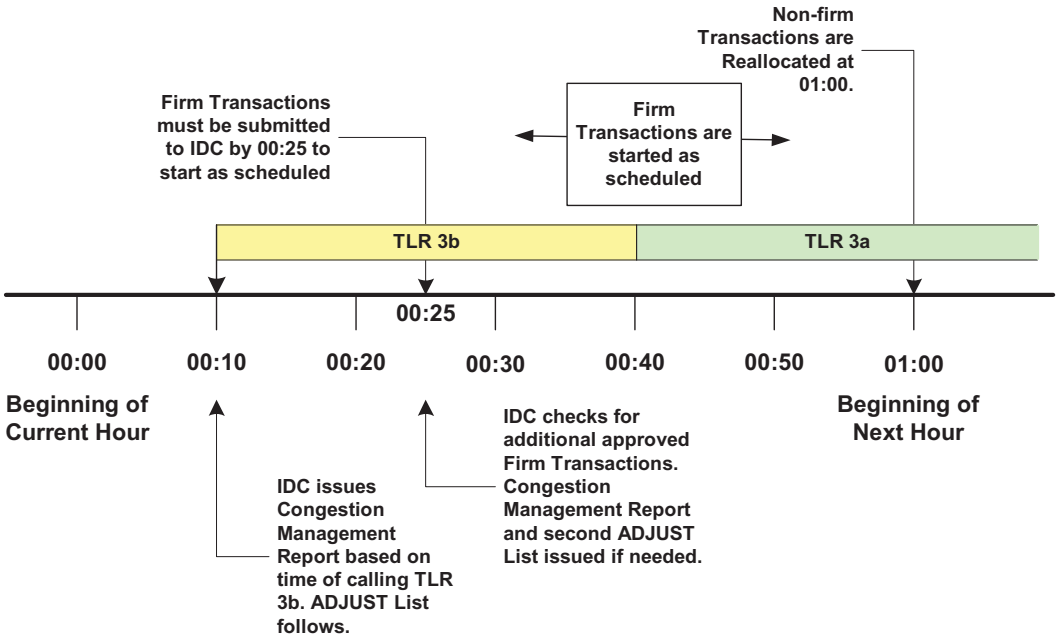

Same as Case 1, but TLR Level 3b ends at 00:40 and becomes TLR Level 3a.

All Interchange Transactions using Firm Point-to-Point Transmission Service will start as scheduled if in by the time the 3A is declared.

All Interchange Transactions using Non-firm Point-to-Point Transmission Service are reallocated at 01:00.

Case 5. TLR 3b is called before 00:25 and the Interchange Transaction is submitted to the IDC by 00:25. TLR 1 is called at 00:40.

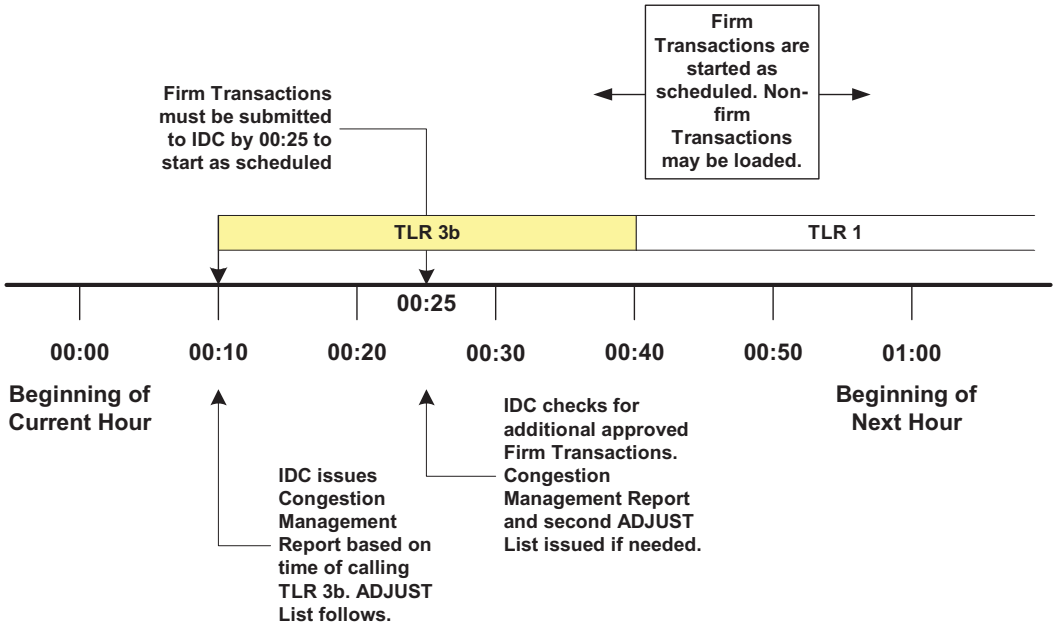

Same as Case 1, but TLR Level 3b ends at 00:40 and becomes TLR Level 1.

All Interchange Transactions using Firm Point-to-Point Transmission Service will start as scheduled.

All Interchange Transactions using Non-firm Point-to-Point Transmission Service may be loaded immediately.

A. Introduction

1. **Title:** **Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators**
2. **Number:** **IRO-014-1**
3. **Purpose:** To ensure that each Reliability Coordinator's operations are coordinated such that they will not have an Adverse Reliability Impact on other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.
4. **Applicability**

   4.1. Reliability Coordinator
5. **Effective Date:** November 1, 2006

B. Requirements

R1. The Reliability Coordinator shall have Operating Procedures, Processes, or Plans in place for activities that require notification, exchange of information or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall address Scenarios that affect other Reliability Coordinator Areas as well as those developed in coordination with other Reliability Coordinators.

R1.1. These Operating Procedures, Processes, or Plans shall collectively address, as a minimum, the following:

R1.1.1. Communications and notifications, including the conditions[1] under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and information to be exchanged with other Reliability Coordinators.

R1.1.2. Energy and capacity shortages.

R1.1.3. Planned or unplanned outage information.

R1.1.4. Voltage control, including the coordination of reactive resources for voltage control.

R1.1.5. Coordination of information exchange to support reliability assessments.

R1.1.6. Authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas.

R2. Each Reliability Coordinator's Operating Procedure, Process, or Plan that requires one or more other Reliability Coordinators to take action (e.g., make notifications, exchange information, or coordinate actions) shall be:

R2.1. Agreed to by all the Reliability Coordinators required to take the indicated action(s).

R2.2. Distributed to all Reliability Coordinators that are required to take the indicated action(s).

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[1] Examples of conditions when one Reliability Coordinator may need to notify another Reliability Coordinator may include (but aren't limited to) sabotage events, Interconnection Reliability Operating Limit violations, voltage reductions, insufficient resources, arming of special protection systems, etc.

R3. A Reliability Coordinator's Operating Procedures, Processes, or Plans developed to support a Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan shall include:

R3.1. A reference to the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.

R3.2. The agreed-upon actions from the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.

R4. Each of the Operating Procedures, Processes, and Plans addressed in Reliability Standard IRO-014 Requirement 1 and Requirement 3 shall:

R4.1. Include version control number or date.

R4.2. Include a distribution list.

R4.3. Be reviewed, at least once every three years, and updated if needed.

C. Measures

M1. The Reliability Coordinator's System Operators shall have available for Real-time use, the latest approved version of Operating Procedures, Processes, or Plans that require notifications, information exchange or the coordination of actions between Reliability Coordinators.

M1.1 These Operating Procedures, Processes, or Plans shall address:

M1.1.1 Communications and notifications, including the conditions under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and information to be exchanged with other Reliability Coordinators.

M1.1.2 Energy and capacity shortages.

M1.1.3 Planned or unplanned outage information.

M1.1.4 Voltage control, including the coordination of reactive resources for voltage control.

M1.1.5 Coordination of information exchange to support reliability assessments.

M1.1.6 Authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas.

M2. The Reliability Coordinator shall have evidence that these Operating Procedures, Processes, or Plans were:

M2.1 Agreed to by all the Reliability Coordinators required to take the indicated action(s).

M2.2 Distributed to all Reliability Coordinators that are required to take the indicated action(s).

M3. The Reliability Coordinator's Operating Procedures, Processes, or Plans developed (for its System Operators' internal use) to support a Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan received from another Reliability Coordinator shall:

M3.1 Be available to the Reliability Coordinator's System Operators for Real-time use,

M3.2 Include a reference to the associated source document, and

M3.3 Support the agreed-upon actions from the source document.

M4. The Reliability Coordinator's Operating Procedures, Processes, or Plans that addresses Reliability Coordinator-to-Reliability Coordinator coordination shall each include a version control number or date and a distribution list. The Reliability Coordinator shall have evidence that these Operating Procedures, Processes, or Plans were reviewed within the last three years.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

The Performance-Reset Period shall be one calendar year.

1.3. Data Retention

The Reliability Coordinator shall keep documentation for the prior calendar year and the current calendar year. The Compliance Monitor shall keep compliance data for a minimum of three years or until the Reliability Coordinator has achieved full compliance, whichever is longer.

1.4. Additional Compliance Information

The Reliability Coordinator shall demonstrate compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor shall also use a scheduled on-site review at least once every three years and investigations upon complaint. The Compliance Monitor shall conduct an investigation upon a complaint within 30 days of the alleged infraction's discovery date. The Compliance Monitor shall complete the investigation within 45 days after the start of the investigation. As part of an audit or investigation, the Compliance Monitor shall interview other Reliability Coordinators to identify Operating Procedures, Processes or Plans that were distributed to the Reliability Coordinator being audited to verify that these documents are available for Real-time use by the receiving Reliability Coordinator's System Operators.

The Reliability Coordinator shall have the following documents available for inspection during an on-site audit or within five business days of a request as part of an investigation upon a complaint:

1.4.1 The latest version of its Operating Procedures, Processes, or Plans that require notification, exchange of information, or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability.

1.4.2 Evidence of distribution of Operating Procedures, Processes, or Plans.

2. Levels of Non-Compliance

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions is present:

2.1.1 The latest versions of Operating Procedures, Processes, or Plans (identified through self-certification) that require notification, exchange of information, or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability do not include a version control number or date, and a distribution list.

2.1.2 The latest versions of Reliability Coordinator internal documents developed to support action(s) required as a result of other Reliability Coordinators do not include

both a reference to the source Operating Procedure, Process, or Plan and the agreed-upon actions from the source Operating Procedure, Process, or Plan.

2.2. Level 2: There shall be a level two non-compliance if any of the following conditions is present:

2.2.1 Documents required by this standard were not distributed to all entities on the distribution list.

2.2.2 Documents required by this standard were not available for System Operators' Real-time use.

2.2.3 Documents required by this standard do not address all required topics.

2.3. Level 3: Documents required by this standard do not address any of the six required topics in Reliability Standard IRO-014 R1.

2.4. Level 4: Not Applicable.

E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
Version 1	08/10/05	1. Changed incorrect use of certain hyphens (-) to "en dash (–)." 2. Hyphenated "30-day" when used as adjective. 3. Changed standard header to be consistent with standard "Title." 4. Initial capped heading "Definitions of Terms Used in Standard." 5. Added "periods" to items where appropriate. 6. Changed "Timeframe" to "Time Frame" in item D, 1.2. 7. Lower cased all words that are not "defined" terms — drafting team, self-certification. 8. Changed apostrophes to "smart" symbols. 9. Added comma in all word strings "Procedures, Processes, or Plans," etc. 10. Added hyphens to "Reliability Coordinator-to-Reliability Coordinator" where used as adjective. 11. Removed comma in item 2.1.2. 12. Removed extra spaces between words where appropriate.	01/20/06

A. Introduction

1. **Title:** **Notifications and Information Exchange Between Reliability Coordinators**

2. **Number:** **IRO-015-1**

3. **Purpose:** To ensure that each Reliability Coordinator's operations are coordinated such that they will not have an Adverse Reliability Impact on other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.

4. **Applicability**

   4.1. Reliability Coordinators

5. **Effective Date:** November 1, 2006

B. Requirements

R1. The Reliability Coordinator shall follow its Operating Procedures, Processes, or Plans for making notifications and exchanging reliability-related information with other Reliability Coordinators.

R1.1. The Reliability Coordinator shall make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas.

R2. The Reliability Coordinator shall participate in agreed upon conference calls and other communication forums with adjacent Reliability Coordinators.

R2.1. The frequency of these conference calls shall be agreed upon by all involved Reliability Coordinators and shall be at least weekly.

R3. The Reliability Coordinator shall provide reliability-related information as requested by other Reliability Coordinators.

C. Measures

M1. The Reliability Coordinator shall have evidence (such as operator logs or other data sources) it has followed its Operating Procedures, Processes, or Plans for notifying other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas.

M2. The Reliability Coordinator shall have evidence (such as operator logs or other data sources) that it participated in agreed upon (at least weekly) conference calls and other communication forums with adjacent Reliability Coordinators.

M3. The Reliability Coordinator shall have evidence that it provided requested reliability-related information to other Reliability Coordinators.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

The Performance Reset Period shall be one calendar year.

1.3. Data Retention

The Reliability Coordinator shall keep auditable documentation for a rolling 12 months. The Compliance Monitor shall keep compliance data for a minimum of three years or until the Reliability Coordinator has achieved full compliance — whichever is longer.

1.4. Additional Compliance Information

The Reliability Coordinator shall demonstrate compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor shall also use a scheduled on-site review at least once every three years and investigations upon complaint. The Compliance Monitor shall conduct an investigation upon a complaint within 30 days of the alleged infraction's discovery date. The Compliance Monitor shall complete the investigation within 45 days after the start of the investigation. As part of an audit or an investigation, the Compliance Monitor shall interview other Reliability Coordinators within the Interconnection and verify that the Reliability Coordinator being audited or investigated has been making notifications and exchanging reliability-related information according to agreed Operating Procedures, Processes, or Plans.

The Reliability Coordinator shall have the following available for its Compliance Monitor to inspect during a scheduled, on-site review or within five days of a request as part of an investigation upon complaint:

1.4.1 Evidence it has participated in agreed-upon conference calls or other communications forums.

1.4.2 Operating logs or other data sources that document notifications made to other Reliability Coordinators.

2. Levels of Non-Compliance

2.1. Level 1: Did not participate in agreed upon (at least weekly) conference calls and other communication forums with adjacent Reliability Coordinators.

2.2. Level 2: Did not notify other Reliability Coordinators as specified in its Operating Procedures, Processes, or Plans for making notifications but no Adverse Reliability Impacts resulted from the incident.

2.3. Level 3: Did not provide requested reliability-related information to other Reliability Coordinators.

2.4. Level 4: Did not notify other Reliability Coordinators as specified in its Operating Procedures, Processes, or Plans for making notifications and Adverse Reliability Impacts resulted from the incident.

E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
Version 1	08/10/05	1. Changed incorrect use of certain hyphens (-) to "en dash (–)."	01/20/06

		2. Hyphenated “30-day” and reliability-related when used as adjective. 3. Changed standard header to be consistent with standard “Title.” 4. Added “periods” to items where appropriate. 5. Initial capped heading “Definitions of Terms Used in Standard.” 6. Changed “Timeframe” to “Time Frame” in item D, 1.2. 7. Lower cased all words that are not “defined” terms — drafting team, and self-certification. 8. Changed apostrophes to “smart” symbols. 9. Added comma in all word strings “Procedures, Processes, or Plans,” etc. 10. Added hyphens to “Reliability Coordinator-to-Reliability Coordinator” where used as adjective. 11. Removed comma in item 2.1.2. 12. Removed extra spaces between words where appropriate.	

A. Introduction

1. **Title:** **Coordination of Real-time Activities Between Reliability Coordinators**

2. **Number:** **IRO-016-1**

3. **Purpose:** To ensure that each Reliability Coordinator's operations are coordinated such that they will not have an Adverse Reliability Impact on other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.

4. **Applicability**

   4.1. Reliability Coordinator

5. **Effective Date:** November 1, 2006

B. Requirements

R1. The Reliability Coordinator that identifies a potential, expected, or actual problem that requires the actions of one or more other Reliability Coordinators shall contact the other Reliability Coordinator(s) to confirm that there is a problem and then discuss options and decide upon a solution to prevent or resolve the identified problem.

R1.1. If the involved Reliability Coordinators agree on the problem and the actions to take to prevent or mitigate the system condition, each involved Reliability Coordinator shall implement the agreed-upon solution, and notify the involved Reliability Coordinators of the action(s) taken.

R1.2. If the involved Reliability Coordinators cannot agree on the problem(s) each Reliability Coordinator shall re-evaluate the causes of the disagreement (bad data, status, study results, tools, etc.).

R1.2.1. If time permits, this re-evaluation shall be done before taking corrective actions.

R1.2.2. If time does not permit, then each Reliability Coordinator shall operate as though the problem(s) exist(s) until the conflicting system status is resolved.

R1.3. If the involved Reliability Coordinators cannot agree on the solution, the more conservative solution shall be implemented.

R2. The Reliability Coordinator shall document (via operator logs or other data sources) its actions taken for either the event or for the disagreement on the problem(s) or for both.

C. Measures

M1. For each event that requires Reliability Coordinator-to-Reliability Coordinator coordination, each involved Reliability Coordinator shall have evidence (operator logs or other data sources) of the actions taken for either the event or for the disagreement on the problem or for both.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization

   1.2. Compliance Monitoring Period and Reset Time Frame

   The performance reset period shall be one calendar year.

1.3. Data Retention

The Reliability Coordinator shall keep auditable evidence for a rolling 12 months. In addition, entities found non-compliant shall keep information related to the non-compliance until it has been found compliant. The Compliance Monitor shall keep compliance data for a minimum of three years or until the Reliability Coordinator has achieved full compliance, whichever is longer.

1.4. Additional Compliance Information

The Reliability Coordinator shall demonstrate compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor shall use a scheduled on-site review at least once every three years. The Compliance Monitor shall conduct an investigation upon a complaint that is received within 30 days of an alleged infraction's discovery date. The Compliance Monitor shall complete the investigation and report back to all involved Reliability Coordinators (the Reliability Coordinator that complained as well as the Reliability Coordinator that was investigated) within 45 days after the start of the investigation. As part of an audit or investigation, the Compliance Monitor shall interview other Reliability Coordinators within the Interconnection and verify that the Reliability Coordinator being audited or investigated has been coordinating actions to prevent or resolve potential, expected, or actual problems that adversely impact the Interconnection.

The Reliability Coordinator shall have the following available for its Compliance Monitor to inspect during a scheduled, on-site review or within five working days of a request as part of an investigation upon complaint:

1.4.1 Evidence (operator log or other data source) to show coordination with other Reliability Coordinators.

2. Levels of Non-Compliance

2.1. Level 1: For potential, actual or expected events which required Reliability Coordinator-to-Reliability Coordinator coordination, the Reliability Coordinator did coordinate, but did not have evidence that it coordinated with other Reliability Coordinators.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: For potential, actual or expected events which required Reliability Coordinator-to-Reliability Coordinator coordination, the Reliability Coordinator did not coordinate with other Reliability Coordinators.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
Version 1	August 10, 2005	1. Changed incorrect use of certain hyphens (-) to "en dash (–)." 2. Hyphenated "30-day" and "Reliability Coordinator-to-Reliability Coordinator" when used as adjective.	01/20/06

		3. Changed standard header to be consistent with standard "Title." 4. Added "periods" to items where appropriate. 5. Initial capped heading "Definitions of Terms Used in Standard." 6. Changed "Timeframe" to "Time Frame" in item D, 1.2. 7. Lower cased all words that are not "defined" terms — drafting team, and self-certification. 8. Changed apostrophes to "smart" symbols. 9. Removed comma after word "condition" in item R.1.1. 10. Added comma after word "expected" in item 1.4, last sentence. 11. Removed extra spaces between words where appropriate.	

A. Introduction

1. **Title:** **Procedures for the Use of Capacity Benefit Margin Values**
2. **Number:** MOD-006-0.1
3. **Purpose:** To promote the consistent and uniform use of transmission Transfer Capability margins calculations among transmission system users.
4. **Applicability:**
   - **4.1.** Transmission Service Provider.
5. **Effective Date:** May 13, 2009

B. Requirements

R1. Each Transmission Service Provider shall document its procedure on the use of Capacity Benefit Margin (CBM) (scheduling of energy against a CBM reservation). The procedure shall include the following three components:

- **R1.1.** Require that CBM be used only after the following steps have been taken (as time permits): all non-firm sales have been terminated, Direct-Control Load Management has been implemented, and customer interruptible demands have been interrupted. CBM may be used to reestablish Operating Reserves.
- **R1.2.** Require that CBM shall only be used if the Load-Serving Entity calling for its use is experiencing a generation deficiency and its Transmission Service Provider is also experiencing Transmission Constraints relative to imports of energy on its transmission system.
- **R1.3.** Describe the conditions under which CBM may be available as Non-Firm Transmission Service.

R2. Each Transmission Service Provider shall make its CBM use procedure available on a web site accessible by the Regional Reliability Organizations, NERC, and transmission users..

C. Measures

M1. The Transmission Service Provider's procedure for the use of CBM (scheduling of energy against a CBM reservation) shall meet Reliability Standard MOD-006-0_R1.

M2. The Transmission Service Provider's procedure for the use of CBM (scheduling of energy against a CBM preservation) shall be available on a web site accessible by the Regional Reliability Organizations, NERC, and transmission users.

D. Compliance

1. **Compliance Monitoring Process**
   - **1.1. Compliance Monitoring Responsibility**
     Compliance Monitor: Regional Reliability Organizations
   - **1.2. Compliance Monitoring Period and Reset Timeframe**
     Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC compliance reporting process.
   - **1.3. Data Retention**

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: The Transmission Service Provider's procedure for use of CBM is available and addresses only two of the three requirements for such documentation as listed above under Reliability Standard MOD-006-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: The Transmission Service Provider's procedure for use of CBM addresses one or none of the three requirements as listed above under Reliability Standard MOD-006-0_R1, or is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	September 17, 2007	Corrected R1. — changed "preservation" to "reservation."	Errata
0.1	October 29, 2008	– Corrected Measure M1. — changed "preservation" to "reservation." – BOT adopted errata changes; changed version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved — Updated Effective date and footer	Revised

A. Introduction

1. **Title:** **Documentation of the Use of Capacity Benefit Margin**

2. **Number:** MOD-007-0

3. **Purpose:** To promote the consistent and uniform application of Transfer Capability margin calculations among transmission system users by developing methodologies for calculating Capacity Benefit Margin (CBM). This methodology shall comply with NERC definitions for CBM, the NERC Reliability Standards, and applicable Regional criteria.

4. **Applicability:**

   4.1. Transmission Service Provider

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Transmission Service Provider that uses CBM shall report (to the Regional Reliability Organization, NERC and the transmission users) the use of CBM by the Load-Serving Entities' Loads on its system, except for CBM sales as Non-Firm Transmission Service. (This use of CBM shall be consistent with the Transmission Service Provider's procedure for use of CBM.)

R2. The Transmission Service Provider shall post the following three items within 15 calendar days after the use of CBM for an Energy Emergency. This posting shall be on a web site accessible by the Regional Reliability Organizations, NERC, and transmission users.

R2.1. Circumstances.

R2.2. Duration.

R2.3. Amount of CBM used.

C. Measures

M1. The Transmission Service Provider shall have evidence that it posted an after-the-fact disclosure that energy was scheduled against a CBM preservation (for purposes other than Non-Firm Transmission Sales) on a website accessible by the Regional Reliability Organizations, NERC, and transmission users.

M2. If the Transmission Service Provider had energy scheduled against a CBM preservation (for purposes other than Non-Firm Transmission Sales) the Transmission Service Provider shall have evidence it posted an after-the-fact disclosure that includes the elements required by Reliability Standard MOD-007_R2.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: Regional Reliability Organizations.

   1.2. Compliance Monitoring Period and Reset Timeframe

   Within 15 calendar days of the use of CBM (excluding Non-Firm Transmission Sales)

   1.3. Data Retention

   None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: Information pertaining to the use of CBM during an Energy Emergency was provided, but was not made available on a web site accessible by the Regional Reliability Organizations, NERC, and transmission users, or meets only two of the three requirements as listed in Reliability Standard MOD-007-0_R2.

2.3. Level 3: Not applicable.

2.4. Level 4: After the use of CBM (excluding Non-Firm Transmission Sales), information pertaining to the use of CBM was provided but meets one or none of the three requirements as listed above under Reliability Standard MOD-007-0_R2, or no information was provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Steady-State Data for Modeling and Simulation of the Interconnected Transmission System**

2. **Number:** MOD-010-0

3. **Purpose:** To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the Interconnected Transmission Systems.

4. **Applicability:**

   4.1. Transmission Owners specified in the data requirements and reporting procedures of MOD-011-0_R1

   4.2. Transmission Planners specified in the data requirements and reporting procedures of MOD-011-0_R1

   4.3. Generator Owners specified in the data requirements and reporting procedures of MOD-011-0_R1

   4.4. Resource Planners specified in the data requirements and reporting procedures of MOD-011-0_R1

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Transmission Owners, Transmission Planners Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide appropriate equipment characteristics, system data, and existing and future Interchange Schedules in compliance with its respective Interconnection Regional steady-state modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-011-0_R1.

R2. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide this steady-state modeling and simulation data to the Regional Reliability Organizations, NERC, and those entities specified within Reliability Standard MOD-011-0_R1. If no schedule exists, then these entities shall provide the data on request (30 calendar days).

C. Measures

M1. The Transmission Owner, Transmission Planner, Generator Owner, and Resource Planner, (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall have evidence that it provided equipment characteristics, system data, and Interchange Schedules for steady-state modeling and simulation to the Regional Reliability Organizations and NERC as specified in Standard MOD-010-0_R1 and MOD-010-0_R2.

D. Compliance

1. Compliance Monitoring Process

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: Regional Reliability Organizations.

   1.2. Compliance Monitoring Period and Reset Timeframe

As specified within the applicable reporting procedures (Reliability Standard MOD-011-0_R2-M1). If no schedule exists, then on request (30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Steady-state data was provided, but was incomplete in one of the seven areas identified in Reliability Standard MOD-011-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Steady-state data was provided, but was incomplete in two or more of the seven areas identified in Reliability Standard MOD-011-0_R1.

2.4. Level 4: Steady-state data was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Dynamics Data for Modeling and Simulation of the Interconnected Transmission System.**

2. **Number:** MOD-012-0

3. **Purpose:** To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems.

4. **Applicability:**

   4.1. Transmission Owners specified in the data requirements and reporting procedures of MOD-013-0_R1

   4.2. Transmission Planners specified in the data requirements and reporting procedures of MOD-013-0_R1

   4.3. Generator Owners specified in the data requirements and reporting procedures of MOD-013-0_R1

   4.4. Resource Planners specified in the data requirements and reporting procedures of MOD-013-0_R1

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R1) shall provide appropriate equipment characteristics and system data in compliance with the respective Interconnection-wide Regional dynamics system modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-013-0_R1.

R2. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R1) shall provide dynamics system modeling and simulation data to its Regional Reliability Organization(s), NERC, and those entities specified within the applicable reporting procedures identified in Reliability Standard MOD-013-0_R1. If no schedule exists, then these entities shall provide data on request (30 calendar days).

C. Measures

M1. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R1) shall each have evidence that it provided equipment characteristics and system data for dynamics system modeling and simulation in accordance with Reliability Standard MOD-012-0_R1 and Reliability Standard MOD-012-0_R2.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

As specified within the applicable reporting procedures (Reliability Standard MOD-013-0). If no schedule exists, then on request (30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Dynamics data was provided, but was incomplete in one of the four areas identified in Reliability Standard MOD-013-0_R1.

2.2. Level 2: Not Applicable.

2.3. Level 3: Dynamics data was provided, but was incomplete in two or more of the four areas identified in Reliability Standard MOD-013-0_R1.

2.4. Level 4: Dynamics data was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	September 16, 2005	Changed references to MOD-013-0 R4 to MOD-013-0 R1 in Applicability, Requirements, and Measures (4 in all).	Errata

A. Introduction

1. **Title**: **Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management**

2. **Number:** MOD-016-1.1

3. **Purpose**: Ensure that accurate, actual Demand data is available to support assessments and validation of past events and databases. Forecast Demand data is needed to perform future system assessments to identify the need for system reinforcements for continued reliability. In addition, to assist in proper real-time operating, Load information related to controllable Demand-Side Management (DSM) programs is needed.

4. **Applicability**:

   4.1. Planning Authority.

   4.2. Regional Reliability Organization.

5. **Effective Date:** May 13, 2009

B. Requirements

R1. The Planning Authority and Regional Reliability Organization shall have documentation identifying the scope and details of the actual and forecast (a) Demand data, (b) Net Energy for Load data, and (c) controllable DSM data to be reported for system modeling and reliability analyses.

R1.1. The aggregated and dispersed data submittal requirements shall ensure that consistent data is supplied for Reliability Standards TPL-005, TPL-006, MOD-010, MOD-011, MOD-012, MOD-013, MOD-014, MOD-015, MOD-016, MOD-017, MOD-018, MOD-019, MOD-020, and MOD-021.

The data submittal requirements shall stipulate that each Load-Serving Entity count its customer Demand once and only once, on an aggregated and dispersed basis, in developing its actual and forecast customer Demand values.

R2. The Regional Reliability Organization shall distribute its documentation required in Requirement 1 and any changes to that documentation, to all Planning Authorities that work within its Region.

R2.1. The Regional Reliability Organization shall make this distribution within 30 calendar days of approval.

R3. The Planning Authority shall distribute its documentation required in R1 for reporting customer data and any changes to that documentation, to its Transmission Planners and Load-Serving Entities that work within its Planning Authority Area.

R3.1. The Planning Authority shall make this distribution within 30 calendar days of approval.

C. Measures

M1. The Planning Authority and Regional Reliability Organization's documentation for actual and forecast customer data shall contain all items identified in R1.

M2. The Regional Reliability Organization shall have evidence it provided its actual and forecast customer data reporting requirements as required in Requirement 2.

M3. The Planning Authority shall have evidence it provided its actual and forecast customer data and reporting requirements as required in Requirement 3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor for Planning Authority: Regional Reliability Organization.

Compliance Monitor for Regional Reliability Organization: NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

For the Regional Reliability Organization and Planning Authority: Current version of the documentation.

For the Compliance Monitor: Three years of audit information.

1.4. Additional Compliance Information

The Regional Reliability Organization and Planning Authority shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: Documentation does not address completeness and double counting of customer data.

2.2. Level 2: Documentation did not address one of the three types of data required in R1 (Demand data, Net Energy for Load data, and controllable DSM data).

2.3. Level 3: No evidence documentation was distributed as required.

2.4. Level 4: Either the documentation did not address two of the three types of data required in R1 (Demand data, Net Energy for Load data, and controllable DSM data) or there was no documentation.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	November 1, 2006	Corrected sequential numbering problem in Sections R2. and R3.	Errata
1.1	October 29, 2008	BOT adopted errata changes; updated version number to “1.1”	Errata
1.1	May 13, 2009	FERC Approved — Updated Effective Date and footer	Revised

A. Introduction

1. **Title:** **Aggregated Actual and Forecast Demands and Net Energy for Load**
2. **Number:** MOD-017-0.1
3. **Purpose:** To ensure that assessments and validation of past events and databases can be performed, reporting of actual Demand data is needed. Forecast demand data is needed to perform future system assessment to identify the need for system reinforcement for continued reliability. In addition to assist in proper real-time operating, load information related to controllable Demand-Side Management programs is needed.
4. **Applicability:**
   - **4.1.** Load-Serving Entity.
   - **4.2.** Planning Authority.
   - **4.3.** Resource Planner.
5. **Effective Date:** May 13, 2009

B. Requirements

R1. The Load-Serving Entity, Planning Authority and Resource Planner shall each provide the following information annually on an aggregated Regional, subregional, Power Pool, individual system, or Load-Serving Entity basis to NERC, the Regional Reliability Organizations, and any other entities specified by the documentation in Standard MOD-016-1_R1.

- **R1.1.** Integrated hourly demands in megawatts (MW) for the prior year.
- **R1.2.** Monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year.
- **R1.3.** Monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years.
- **R1.4.** Annual Peak hour forecast demands (summer and winter) in MW and annual Net Energy for load in GWh for at least five years and up to ten years into the future, as requested.

C. Measures

M1. Load-Serving Entity, Planning Authority, and Resource Planner shall each provide evidence to its Compliance Monitor that it provided load data per Standard MOD-017-0_R1.

D. Compliance

1. **Compliance Monitoring Process**
   - **1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually or as specified in the documentation (Standard MOD-016-1_R1.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. **Levels of Non-Compliance**

3. **Level 1:** Did not provide actual and forecast demands and Net Energy for Load data in one of the four areas as required in Reliability Standard MOD-017-0_R1.

4. **Level 2:** Did not provide actual and forecast demands and Net Energy for Load data in two of the four areas as required in Reliability Standard MOD-017-0_R1.

5. **Level 3:** Did not provide actual and forecast demands and Net Energy for Load data in three of the four areas as required in Reliability Standard MOD-017-0_R1.

6. **Level 4:** Did not provide actual and forecast demands and Net Energy for Load data in any of the areas as required in Reliability Standard MOD-017-0_R1.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 18, 2008	Revised R1. And D1.2. to reflect update in version from “MOD-016-0_R1” to MOD-016-1_R1.”	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved — Updated Effective Date and Footer	Revised

A. Introduction

1. **Title:** **Treatment of Nonmember Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load**

2. **Number:** MOD-018-0

3. **Purpose:** To ensure that Assessments and validation of past events and databases can be performed, reporting of actual demand data is needed. Forecast demand data is needed to perform future system assessments to identify the need for system reinforcement for continued reliability. In addition, to assist in proper real-time operating, load information related to controllable Demand-Side Management programs is needed.

4. **Applicability:**

   4.1. Load-Serving Entity

   4.2. Planning Authority

   4.3. Transmission Planner

   4.4. Resource Planner

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Load-Serving Entity, Planning Authority, Transmission Planner and Resource Planner's report of actual and forecast demand data (reported on either an aggregated or dispersed basis) shall:

R1.1. Indicate whether the demand data of nonmember entities within an area or Regional Reliability Organization are included, and

R1.2. Address assumptions, methods, and the manner in which uncertainties are treated in the forecasts of aggregated peak demands and Net Energy for Load.

R1.3. Items (MOD-018-0_R1.1) and (MOD-018-0_R1.2) shall be addressed as described in the reporting procedures developed for Standard MOD-016-0_R1.

R2. The Load-Serving Entity, Planning Authority, Transmission Planner and Resource Planner shall each report data associated with Reliability Standard MOD-018-0_R1 to NERC, the Regional Reliability Organization, Load-Serving Entity, Planning Authority, and Resource Planner on request (within 30 calendar days).

C. Measures

M1. The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each provide evidence to its Compliance Monitor that its actual and forecast demand data were addressed as described in the reporting procedures developed for Reliability Standard MOD-018-0_R1.

M2. The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each report current information for Reliability Standard MOD-018-0_R1 to NERC, the Regional Reliability Organization, Load-Serving Entity, Planning Authority, and Resource Planner on request (within 30 calendar days).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

On Request (within 30 calendar days).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Information for Reliability Standard MOD-018-0 item R1.1 or R1.2 was not provided.

2.2. Level 2: Information for Reliability Standards MOD-018-0 items R1.1 and R1.2 was not provided.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Reporting of Interruptible Demands and Direct Control Load Management**

2. **Number:** MOD-019-0.1

3. Purpose: To ensure that assessments and validation of past events and databases can be performed, reporting of actual demand data is needed. Forecast demand data is needed to perform future system assessments to identify the need for system reinforcement for continued reliability. In addition, to assist in proper real-time operating, load information related to controllable Demand-Side Management programs is needed.

4. **Applicability:**

   4.1. Load-Serving Entity.

   4.2. Planning Authority.

   4.3. Transmission Planner.

   4.4. Resource Planner.

5. **Effective Date:** May 13, 2009

B. Requirements

R1. The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each provide annually its forecasts of interruptible demands and Direct Control Load Management (DCLM) data for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions to NERC, the Regional Reliability Organizations, and other entities (Load-Serving Entities, Planning Authorities, and Resource Planners) as specified by the documentation in Reliability Standard MOD-016-1_R1.

C. Measures

M1. The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each provide evidence to its Compliance Monitor that it provided forecasts of interruptible demands and DCLM data per Reliability Standard MOD-019-0_R1.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Each Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Time Frame

   Annually or as specified in the documentation (Reliability Standard MOD-016-1_R1.)

   1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Did not provide forecasts of interruptible Demands and DCLM data as required in Standard MOD-019-0_R1.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
	February 8, 2005	Approved by BOT	Revised
0	July 24, 2007	Changed reference R1. and Dl.1.2. to "MOD-016-0_R1" to MOD-016-1_R1." (New version number.)	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1".	Errata
0.1	May 13, 2009	FERC Approved — Updated Effective Date and Footer	Revised

A. Introduction

1. **Title:** **Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators**

2. **Number:** MOD-020-0

3. **Purpose:** To ensure that assessments and validation of past events and databases can be performed, reporting of actual demand data is needed. Forecast demand data is needed to perform future system assessments to identify the need for system reinforcement for continued reliability. In addition to assist in proper real-time operating, load information related to controllable Demand-Side Management programs is needed.

4. **Applicability:**

   4.1. Load-Serving Entity

   4.2. Transmission Planner

   4.3. Resource Planner

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Load-Serving Entity, Transmission Planner, and Resource Planner shall each make known its amount of interruptible demands and Direct Control Load Management (DCLM) to Transmission Operators, Balancing Authorities, and Reliability Coordinators on request within 30 calendar days.

C. Measures

M1. The Load-Serving Entity, Transmission Planner, and Resource Planner each make known its amount of interruptible demands and DCLM to Transmission Operators, Balancing Authorities and Reliability Coordinators on request within 30 calendar days.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Timeframe

   On request (within 30 calendar days).

   1.3. Data Retention

   None specified.

   1.4. Additional Compliance Information

   None.

2. **Levels of Non-Compliance**

   2.1. Level 1: Interruptible Demands and DCLM data were provided to Reliability Coordinators, Balancing Authorities, and Transmission Operators, but were incomplete.

   2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Interruptible Demands and DCLM data were not provided to Reliability Coordinators, Balancing Authorities, and Transmission Operators.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Documentation of the Accounting Methodology for the Effects of Controllable Demand-Side Management in Demand and Energy Forecasts.**

2. **Number:** MOD-021-0.1

3. **Purpose:** To ensure that assessments and validation of past events and databases can be performed, reporting of actual Demand data is needed. Forecast demand data is needed to perform future system assessments to identify the need for system reinforcement for continued reliability. In addition, to assist in proper real-time operating, load information related to controllable Demand-Side Management (DSM) programs is needed.

4. **Applicability:**

   4.1. Load-Serving Entity

   4.2. Transmission Planner

   4.3. Resource Planner

5. **Effective Date:** December 10, 2009

B. Requirements

R1. The Load-Serving Entity, Transmission Planner and Resource Planner's forecasts shall each clearly document how the Demand and energy effects of DSM programs (such as conservation, time-of-use rates, interruptible Demands, and Direct Control Load Management) are addressed.

R2. The Load-Serving Entity, Transmission Planner and Resource Planner shall each include information detailing how Demand-Side Management measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load in the data reporting procedures of Standard MOD-016-0_R1.

R3. The Load-Serving Entity, Transmission Planner and Resource Planner shall each make documentation on the treatment of its DSM programs available to NERC on request (within 30 calendar days).

C. Measures

M1. The Load-Serving Entity, Transmission Planner and Resource Planner forecasts clearly document how the demand and energy effects of DSM programs (such as conservation, time-of-use rates, interruptible demands, and Direct Control Load Management) are addressed.

M2. The Load-Serving Entity, Transmission Planner and Resource Planner information detailing how Demand-Side Management measures are addressed in the forecasts of Peak Demand and annual Net Energy for Load are included in the data reporting procedures of Reliability Standard MOD-016-0_R1.

M3. The Load-Serving Entity, Planning Authority and Resource Planner shall each provide evidence to its Compliance Monitor that it provided documentation on the treatment of DSM programs to NERC as requested (within 30 calendar days).

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Documentation on the treatment of DSM programs in the demand and energy forecasts was provided, but was incomplete.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Documentation on the treatment of DSM programs in the demand and energy forecasts was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0.1	April 15, 2009	R1. – comma inserted after Load-Serving Entity	
0.1	December 10, 2009	Approved by FERC — Added effective date	Update

A. Introduction

1. **Title:** **Nuclear Plant Interface Coordination**

2. **Number:** NUC-001-2

3. **Purpose:** This standard requires coordination between Nuclear Plant Generator Operators and Transmission Entities for the purpose of ensuring nuclear plant safe operation and shutdown.

4. **Applicability:**

   4.1. Nuclear Plant Generator Operator.

   4.2. Transmission Entities shall mean all entities that are responsible for providing services related to Nuclear Plant Interface Requirements (NPIRs). Such entities may include one or more of the following:

   4.2.1 Transmission Operators.

   4.2.2 Transmission Owners.

   4.2.3 Transmission Planners.

   4.2.4 Transmission Service Providers.

   4.2.5 Balancing Authorities.

   4.2.6 Reliability Coordinators.

   4.2.7 Planning Coordinators.

   4.2.8 Distribution Providers.

   4.2.9 Load-serving Entities.

   4.2.10 Generator Owners.

   4.2.11 Generator Operators.

5. **Effective Date:** April 1, 2010

B. Requirements

R1. The Nuclear Plant Generator Operator shall provide the proposed NPIRs in writing to the applicable Transmission Entities and shall verify receipt [*Risk Factor: Lower*]

R2. The Nuclear Plant Generator Operator and the applicable Transmission Entities shall have in effect one or more Agreements[1] that include mutually agreed to NPIRs and document how the Nuclear Plant Generator Operator and the applicable Transmission Entities shall address and implement these NPIRs. [*Risk Factor: Medium*]

R3. Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall incorporate the NPIRs into their planning analyses of the electric system and shall communicate the results of these analyses to the Nuclear Plant Generator Operator. [*Risk Factor: Medium*]

R4. Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall: [*Risk Factor: High*]

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1. Agreements may include mutually agreed upon procedures or protocols in effect between entities or between departments of a vertically integrated system.

R4.1. Incorporate the NPIRs into their operating analyses of the electric system.

R4.2. Operate the electric system to meet the NPIRs.

R4.3. Inform the Nuclear Plant Generator Operator when the ability to assess the operation of the electric system affecting NPIRs is lost.

R5. The Nuclear Plant Generator Operator shall operate per the Agreements developed in accordance with this standard. [*Risk Factor: High*]

R6. Per the Agreements developed in accordance with this standard, the applicable Transmission Entities and the Nuclear Plant Generator Operator shall coordinate outages and maintenance activities which affect the NPIRs. [*Risk Factor: Medium*]

R7. Per the Agreements developed in accordance with this standard, the Nuclear Plant Generator Operator shall inform the applicable Transmission Entities of actual or proposed changes to nuclear plant design, configuration, operations, limits, protection systems, or capabilities that may impact the ability of the electric system to meet the NPIRs. [*Risk Factor: High*]

R8. Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall inform the Nuclear Plant Generator Operator of actual or proposed changes to electric system design, configuration, operations, limits, protection systems, or capabilities that may impact the ability of the electric system to meet the NPIRs. [*Risk Factor: High*]

R9. The Nuclear Plant Generator Operator and the applicable Transmission Entities shall include, as a minimum, the following elements within the agreement(s) identified in R2: [*Risk Factor: Medium*]

R9.1. Administrative elements:

R9.1.1. Definitions of key terms used in the agreement.

R9.1.2. Names of the responsible entities, organizational relationships, and responsibilities related to the NPIRs.

R9.1.3. A requirement to review the agreement(s) at least every three years.

R9.1.4. A dispute resolution mechanism.

R9.2. Technical requirements and analysis:

R9.2.1. Identification of parameters, limits, configurations, and operating scenarios included in the NPIRs and, as applicable, procedures for providing any specific data not provided within the agreement.

R9.2.2. Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs.

R9.2.3. Types of planning and operational analyses performed specifically to support the NPIRs, including the frequency of studies and types of Contingencies and scenarios required.

R9.3. Operations and maintenance coordination:

R9.3.1. Designation of ownership of electrical facilities at the interface between the electric system and the nuclear plant and responsibilities for operational control coordination and maintenance of these facilities.

R9.3.2. Identification of any maintenance requirements for equipment not owned or controlled by the Nuclear Plant Generator Operator that are necessary to meet the NPIRs.

R9.3.3. Coordination of testing, calibration and maintenance of on-site and off-site power supply systems and related components.

R9.3.4. Provisions to address mitigating actions needed to avoid violating NPIRs and to address periods when responsible Transmission Entity loses the ability to assess the capability of the electric system to meet the NPIRs. These provisions shall include responsibility to notify the Nuclear Plant Generator Operator within a specified time frame.

R9.3.5. Provision for considering, within the restoration process, the requirements and urgency of a nuclear plant that has lost all off-site and on-site AC power. .

R9.3.6. Coordination of physical and cyber security protection of the Bulk Electric System at the nuclear plant interface to ensure each asset is covered under at least one entity's plan.

R9.3.7. Coordination of the NPIRs with transmission system Special Protection Systems and underfrequency and undervoltage load shedding programs.

R9.4. Communications and training:

R9.4.1. Provisions for communications between the Nuclear Plant Generator Operator and Transmission Entities, including communications protocols, notification time requirements, and definitions of terms.

R9.4.2. Provisions for coordination during an off-normal or emergency event affecting the NPIRs, including the need to provide timely information explaining the event, an estimate of when the system will be returned to a normal state, and the actual time the system is returned to normal.

R9.4.3. Provisions for coordinating investigations of causes of unplanned events affecting the NPIRs and developing solutions to minimize future risk of such events.

R9.4.4. Provisions for supplying information necessary to report to government agencies, as related to NPIRs.

R9.4.5. Provisions for personnel training, as related to NPIRs.

C. Measures

M1. The Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, provide a copy of the transmittal and receipt of transmittal of the proposed NPIRs to the responsible Transmission Entities. (Requirement 1)

M2. The Nuclear Plant Generator Operator and each Transmission Entity shall each have a copy of the Agreement(s) addressing the elements in Requirement 9 available for inspection upon request of the Compliance Enforcement Authority. (Requirement 2 and 9)

M3. Each Transmission Entity responsible for planning analyses in accordance with the Agreement shall, upon request of the Compliance Enforcement Authority, provide a copy of the planning analyses results transmitted to the Nuclear Plant Generator Operator, showing incorporation of the NPIRs. The Compliance Enforcement Authority shall refer to the Agreements developed in accordance with this standard for specific requirements. (Requirement 3)

M4. Each Transmission Entity responsible for operating the electric system in accordance with the Agreement shall demonstrate or provide evidence of the following, upon request of the Compliance Enforcement Authority:

M4.1 The NPIRs have been incorporated into the current operating analysis of the electric system. (Requirement 4.1)

M4.2 The electric system was operated to meet the NPIRs. (Requirement 4.2)

M4.3 The Transmission Entity informed the Nuclear Plant Generator Operator when it became aware it lost the capability to assess the operation of the electric system affecting the NPIRs. (Requirement 4.3)

M5. The Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, demonstrate or provide evidence that the Nuclear Power Plant is being operated consistent with the Agreements developed in accordance with this standard. (Requirement 5)

M6. The Transmission Entities and Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, provide evidence of the coordination between the Transmission Entities and the Nuclear Plant Generator Operator regarding outages and maintenance activities which affect the NPIRs. (Requirement 6)

M7. The Nuclear Plant Generator Operator shall provide evidence that it informed the applicable Transmission Entities of changes to nuclear plant design, configuration, operations, limits, protection systems, or capabilities that would impact the ability of the Transmission Entities to meet the NPIRs. (Requirement 7)

M8. The Transmission Entities shall each provide evidence that it informed the Nuclear Plant Generator Operator of changes to electric system design, configuration, operations, limits, protection systems, or capabilities that would impact the ability of the Nuclear Plant Generator Operator to meet the NPIRs. (Requirement 8)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- For Measure 1, the Nuclear Plant Generator Operator shall keep its latest transmittals and receipts.

- For Measure 2, the Nuclear Plant Generator Operator and each Transmission Entity shall have its current, in-force agreement.
- For Measure 3, the Transmission Entity shall have the latest planning analysis results.
- For Measures 4.3, 6 and 8, the Transmission Entity shall keep evidence for two years plus current.
- For Measures 5, 6 and 7, the Nuclear Plant Generator Operator shall keep evidence for two years plus current.

If a Responsible Entity is found non-compliant it shall keep information related to the noncompliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

2.1. Lower: Agreement(s) exist per this standard and NPIRs were identified and implemented, but documentation described in M1-M8 was not provided.

2.2. Moderate: Agreement(s) exist per R2 and NPIRs were identified and implemented, but one or more elements of the Agreement in R9 were not met.

2.3. High: One or more requirements of R3 through R8 were not met.

2.4. Severe: No proposed NPIRs were submitted per R1, no Agreement exists per this standard, or the Agreements were not implemented.

E. Regional Differences

The design basis for Canadian (CANDU) NPPs does not result in the same licensing requirements as U.S. NPPs. NRC design criteria specifies that in addition to emergency on-site electrical power, electrical power from the electric network also be provided to permit safe shutdown. This requirement is specified in such NRC Regulations as 10 CFR 50 Appendix A — General Design Criterion 17 and 10 CFR 50.63 Loss of all alternating current power. There are no equivalent Canadian Regulatory requirements for Station Blackout (SBO) or coping times as they do not form part of the licensing basis for CANDU NPPs.
Therefore the definition of NPLR for Canadian CANDU units will be as follows:

Nuclear Plant Licensing Requirements (NPLR) are requirements included in the design basis of the nuclear plant and are statutorily mandated for the operation of the plant; when used in this standard, NPLR shall mean nuclear power plant licensing requirements for avoiding preventable challenges to nuclear safety as a result of an electric system disturbance, transient, or condition.

F. Associated Documents

Version History

Version	Date	Action	Change Tracking
1	May 2, 2007	Approved by Board of Trustees	New
2	To be determined	Modifications for Order 716 to Requirement R9.3.5	Revision

		and footnote 1; modifications to bring compliance elements into conformance with the latest version of the ERO Rules of Procedure.	
2	August 5, 2009	Adopted by Board of Trustees	Revised
2	January 22, 2010	Approved by FERC on January 21, 2010 Added Effective Date	Update

A. Introduction

1. **Title:** **Operating Personnel Responsibility and Authority**

2. **Number:** PER-001-0.1

3. **Purpose:** Transmission Operator and Balancing Authority operating personnel must have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

5. **Effective Date:** December 10, 2009

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.

C. Measures

M1. The Transmission Operator and Balancing Authority provide documentation that operating personnel have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System. These responsibilities and authorities are understood by the operating personnel. Documentation shall include:

M1.1 A written current job description that states in clear and unambiguous language the responsibilities and authorities of each operating position of a Transmission Operator and Balancing Authority. The job description identifies personnel subject to the authority of the Transmission Operator and Balancing Authority.

M1.2 The current job description is readily accessible in the control room environment to all operating personnel.

M1.3 A written current job description that states operating personnel are responsible for complying with the NERC reliability standards.

M1.4 Written operating procedures that state that, during normal and emergency conditions, operating personnel have the authority to take or direct timely and appropriate real-time actions. Such actions shall include shedding of firm load to prevent or alleviate System Operating Limit Interconnection or Reliability Operating Limit violations. These actions are performed without obtaining approval from higher-level personnel within the Transmission Operator or Balancing Authority.

D. Compliance

1. **Compliance Monitoring Process**

   Periodic Review: An on-site review including interviews with Transmission Operator and Balancing Authority operating personnel and document verification will be conducted every three years. The job description identifying operating personnel authorities and responsibilities will be reviewed, as will the written operating procedures or other documents delineating the authority of the operating personnel to take actions necessary to maintain the reliability of the Bulk Electric System during normal and emergency conditions.

1.1. Compliance Monitoring Responsibility

Self-certification: The Transmission Operator and Balancing Authority shall annually complete a self-certification form developed by the Regional Reliability Organization based on measures M1.1 to M1.4.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

Permanent.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: The Transmission Operator or Balancing Authority has written documentation that includes three of the four items in M1.

2.2. Level 2: The Transmission Operator or Balancing Authority has written documentation that includes two of the four items in M1.

2.3. Level 3: The Transmission Operator or Balancing Authority has written documentation that includes one of the four items in M1.

2.4. Level 4: The Transmission Operator or Balancing Authority has written documentation that includes none of the items in M1, or the personnel interviews indicate Transmission Operator or Balancing Authority do not have the required authority.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0.1	April 15, 2009	Replaced “position” with “job” on M1.1	Errata
0.1	December 10, 2009	Approved by FERC — added effective date	Update

A. Introduction

1. **Title:** **Operating Personnel Training**

2. **Number:** PER-002-0

3. **Purpose:** Each Transmission Operator and Balancing Authority must provide their personnel with a coordinated training program that will ensure reliable system operation.

4. **Applicability**

   4.1. Balancing Authority.

   4.2. Transmission Operator.

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall be staffed with adequately trained operating personnel.

R2. Each Transmission Operator and Balancing Authority shall have a training program for all operating personnel that are in:

R2.1. Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System.

R2.2. Positions directly responsible for complying with NERC standards.

R3. For personnel identified in Requirement R2, the Transmission Operator and Balancing Authority shall provide a training program meeting the following criteria:

R3.1. A set of training program objectives must be defined, based on NERC and Regional Reliability Organization standards, entity operating procedures, and applicable regulatory requirements. These objectives shall reference the knowledge and competencies needed to apply those standards, procedures, and requirements to normal, emergency, and restoration conditions for the Transmission Operator and Balancing Authority operating positions.

R3.2. The training program must include a plan for the initial and continuing training of Transmission Operator and Balancing Authority operating personnel. That plan shall address knowledge and competencies required for reliable system operations.

R3.3. The training program must include training time for all Transmission Operator and Balancing Authority operating personnel to ensure their operating proficiency.

R3.4. Training staff must be identified, and the staff must be competent in both knowledge of system operations and instructional capabilities.

R4. For personnel identified in Requirement R2, each Transmission Operator and Balancing Authority shall provide its operating personnel at least five days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.

C. Measures

M1. The Transmission Operator and Balancing Authority operating personnel training program shall be reviewed to ensure that it is designed to promote reliable system operations.

D. Compliance

1. Compliance Monitoring Process

Periodic Review: The Regional Reliability Organization will conduct an on-site review of the Transmission Operator and Balancing Authority operating personnel training program every three years. The operating personnel training records will be reviewed and assessed compared to the program curriculum.

1.1. Compliance Monitoring Responsibility

Self-certification: The Transmission Operator and Balancing Authority will annually provide a self-certification based on Requirements R1 through R4.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

Three years.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: N/A.

2.2. Level 2: The Transmission Operator or Balancing Authority operating personnel training program does not address all elements of Requirement R3.

2.3. Level 3: The Transmission Operator or Balancing Authority operating personnel training program does not address Requirement R4.

2.4. Level 4: A Transmission Operator or Balancing Authority has not provided a training program for its operating personnel.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Proposed Effective Date	Errata

A. Introduction

1. **Title:** **Operating Personnel Credentials**

2. **Number:** PER-003-0

3. **Purpose:** Certification of operating personnel is necessary to ensure minimum competencies for operating a reliable Bulk Electric System.

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

   4.3. Reliability Coordinators.

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Reliability Coordinator shall staff all operating positions that meet both of the following criteria with personnel that are NERC-certified for the applicable functions:

R1.1. Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System.

R1.2. Positions directly responsible for complying with NERC standards.

C. Measures

M1. Each Transmission Operator, Balancing Authority, and Reliability Coordinator shall have NERC-certified operating personnel on shift in required positions at all times with the following exceptions:

M1.1 While in training, an individual without the proper NERC certification credential may not independently fill a required operating position. Trainees may perform critical tasks only under the direct, continuous supervision and observation of the NERC-certified individual filling the required position.

M1.2 During a real-time operating emergency, the time when control is transferred from a primary control center to a backup control center shall not be included in the calculation of non-compliance. This time shall be limited to no more than four hours.

D. Compliance

1. **Compliance Monitoring Process**

   Periodic Review: An on-site review will be conducted every three years. Staffing schedules and certification numbers will be compared to ensure that positions that require NERC-certified operating personnel were covered as required. Certification numbers from the Transmission Operator, Balancing Authority, and Reliability Coordinator will be compared with NERC records.
   Exception Reporting: Any violation of the standard must be reported to the Regional Reliability Organization, who will inform the NERC Vice President-Compliance, indicating the reason for the non-compliance and the mitigation plans taken.

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar month without a violation.

1.3. Data Retention

Present calendar year plus previous calendar year staffing plan.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: The Transmission Operator, Balancing Authority, or Reliability Coordinator did not meet the requirement for a total time greater than 0 hours and up to 12 hours during a one calendar month period for each required position in the staffing plan.

2.2. Level 2: The Transmission Operator, Balancing Authority, or Reliability Coordinator did not meet the requirement for a total time greater than 12 hours and up to 36 hours during a one calendar month period for each required position in the staffing plan.

2.3. Level 3: The Transmission Operator, Balancing Authority, or Reliability Coordinator did not meet the requirement for a total time greater than 36 hours and up to 72 hours during a one-month calendar period for each required position in the staffing plan.

2.4. Level 4: The Transmission Operator, Balancing Authority, or Reliability Coordinator did not meet the requirement for a total time greater than 72 hours during a one calendar month period for each required position in the staffing plan.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Reliability Coordination — Staffing**
2. **Number:** PER-004-1
3. **Purpose:**

   Reliability Coordinators must have sufficient, competent staff to perform the Reliability Coordinator functions.
4. **Applicability**

   4.1. Reliability Coordinators.
5. **Effective Date:** January 1, 2007

B. Requirements

R1. Each Reliability Coordinator shall be staffed with adequately trained and NERC-certified Reliability Coordinator operators, 24 hours per day, seven days per week.

R2. All Reliability Coordinator operating personnel shall each complete a minimum of five days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.

R3. Reliability Coordinator operating personnel shall have a comprehensive understanding of the Reliability Coordinator Area and interactions with neighboring Reliability Coordinator Areas.

R4. Reliability Coordinator operating personnel shall have an extensive understanding of the Balancing Authorities, Transmission Operators, and Generation Operators within the Reliability Coordinator Area, including the operating staff, operating practices and procedures, restoration priorities and objectives, outage plans, equipment capabilities, and operational restrictions.

R5. Reliability Coordinator operating personnel shall place particular attention on SOLs and IROLs and inter-tie facility limits. The Reliability Coordinator shall ensure protocols are in place to allow Reliability Coordinator operating personnel to have the best available information at all times.

C. Measures

M1. The Reliability Coordinator shall have and provide upon request training records that confirm that each of its operating personnel has completed a minimum of five days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel, as specified in Requirement 2.

M2. Each Reliability Coordinator shall have and provide upon request evidence that could include but is not limited to, a documented training program and individual training records for each of its operating personnel or other equivalent evidence that will be used to confirm that it meets Requirements 3 and 4.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Reliability Coordinator shall keep evidence of compliance for the previous two calendar years plus the current year.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for a Reliability Coordinator

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 One or more of its shift operating personnel did not complete a minimum of five days per year of training and drills using realistic simulations of system emergencies in the past year. (R2)

2.4.2 No evidence operating personnel have a comprehensive understanding of the Reliability Coordinator Area and interactions with neighboring Reliability Coordinator Areas. (R3)

2.4.3 No evidence operating personnel have an extensive understanding of the Balancing Authorities, Transmission Operators, and Generation Operators within the Reliability Coordinator Area. (R4)

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised

A. Introduction

1. **Title:** **System Protection Coordination**
2. **Number:** PRC-001-1
3. **Purpose:**

   To ensure system protection is coordinated among operating entities.
4. **Applicability**

   4.1. Balancing Authorities

   4.2. Transmission Operators

   4.3. Generator Operators
5. **Effective Date:** January 1, 2007

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.

R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:

R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.

R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.

R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.

R4. Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the protection systems of others:

R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's protection systems.

R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' protection systems.

R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

C. Measures

M1. Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Special Protection Systems in its area. (Requirement 6 Part 1)

M3. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Special Protection Systems. (Requirement 6 Part 2)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will

have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measures 2 and 3.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Generator Operators:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.

3. Levels of Non-Compliance for Transmission Operators:

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

3.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Failed to provide evidence of coordination when installing new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities as specified in R3.2.

3.4.2 Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

4. Levels of Non-Compliance for Balancing Authorities:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	August 25, 2005	Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised

A. Introduction

1. **Title:** **Analysis and Mitigation of Transmission and Generation Protection System Misoperations**

2. **Number:** PRC-004-1

3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.

4. **Applicability**

   4.1. Transmission Owner.

   4.2. Distribution Provider that owns a transmission Protection System.

   4.3. Generator Owner.

5. **Effective Date:** August 1, 2006

B. Requirements

R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1.

R2. The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for PRC-003 R1.

R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.

C. Measures

M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Reliability Organization procedures developed for PRC-003 R1.

M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for PRC-003 R1.

M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Reliability Organization procedures developed for PRC-003 R1.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Transmission Owners and Distribution Providers that own a Transmission Protection System:

2.1. Level 1: Documentation of Misoperations is complete according to PRC-004 R1, but documentation of Corrective Action Plans is incomplete.

2.2. Level 2: Documentation of Misoperations is incomplete according to PRC-004 R1 and documentation of Corrective Action Plans is incomplete.

2.3. Level 3: Documentation of Misoperations is incomplete according to PRC-004 R1 and there are no associated Corrective Action Plans.

2.4. Level 4: Misoperations have not been analyzed and documentation has not been provided to the Regional Reliability Organization according to Requirement 3.

3. Levels of Non-Compliance for Generator Owners

3.1. Level 1: Documentation of Misoperations is complete according to PRC-004 R2, but documentation of Corrective Action Plans is incomplete.

3.2. Level 2: Documentation of Misoperations is incomplete according to PRC-004 R2 and documentation of Corrective Action Plans is incomplete.

3.3. Level 3: Documentation of Misoperations is incomplete according to PRC-004 R2 and there are no associated Corrective Action Plans.

3.4. Level 4: Misoperations have not been analyzed and documentation has not been provided to the Regional Reliability Organization according to R3.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06

A. Introduction

1. **Title:** **Transmission and Generation Protection System Maintenance and Testing**

2. **Number:** PRC-005-1

3. **Purpose:** To ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested.

4. **Applicability**

   4.1. Transmission Owner.

   4.2. Generator Owner.

   4.3. Distribution Provider that owns a transmission Protection System.

5. **Effective Date:** May 1, 2006

B. Requirements

R1. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:

R1.1. Maintenance and testing intervals and their basis.

R1.2. Summary of maintenance and testing procedures.

R2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:

R2.1. Evidence Protection System devices were maintained and tested within the defined intervals.

R2.2. Date each Protection System device was last tested/maintained.

C. Measures

M1. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System that affects the reliability of the BES, shall have an associated Protection System maintenance and testing program as defined in Requirement 1.

M2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System that affects the reliability of the BES, shall have evidence it provided documentation of its associated Protection System maintenance and testing program and the implementation of its program as defined in Requirement 2.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System, shall retain evidence of the implementation of its Protection System maintenance and testing program for three years.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Transmission Owner and any Distribution Provider that owns a transmission Protection System and the Generator Owner that owns a generation Protection System, shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: Documentation of the maintenance and testing program provided was incomplete as required in R1, but records indicate maintenance and testing did occur within the identified intervals for the portions of the program that were documented.

2.2. Level 2: Documentation of the maintenance and testing program provided was complete as required in R1, but records indicate that maintenance and testing did not occur within the defined intervals.

2.3. Level 3: Documentation of the maintenance and testing program provided was incomplete, and records indicate implementation of the documented portions of the maintenance and testing program did not occur within the identified intervals.

2.4. Level 4: Documentation of the maintenance and testing program, or its implementation, was not provided.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. 3. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/05

A. Introduction

1. **Title:** **Assuring Consistency of Entity Underfrequency Load Shedding Programs with Regional Reliability Organization's Underfrequency Load Shedding Program Requirements**

2. **Number:** PRC-007-0

3. **Purpose:** Provide last resort System preservation measures by implementing an Under Frequency Load Shedding (UFLS) program.

4. **Applicability:**

   4.1. Transmission Owner required by its Regional Reliability Organization to own a UFLS program

   4.2. Transmission Operator required by its Regional Reliability Organization to operate a UFLS program

   4.3. Distribution Provider required by its Regional Reliability Organization to own or operate a UFLS program

   4.4. Load-Serving Entity required by its Regional Reliability Organization to operate a UFLS program

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Transmission Owner and Distribution Provider, with a UFLS program (as required by its Regional Reliability Organization) shall ensure that its UFLS program is consistent with its Regional Reliability Organization's UFLS program requirements.

R2. The Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide, and annually update, its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a UFLS program database.

R3. The Transmission Owner and Distribution Provider that owns a UFLS program (as required by its Regional Reliability Organization) shall provide its documentation of that UFLS program to its Regional Reliability Organization on request (30 calendar days).

C. Measures

M1. Each Transmission Owner's and Distribution Provider's UFLS program shall be consistent with its associated Regional Reliability Organization's UFLS program requirements.

M2. Each Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program shall have evidence that it provided its associated Regional Reliability Organization and NERC with documentation of the UFLS program on request (30 calendar days).

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: The evaluation of the entity's UFLS program for consistency with its Regional Reliability Organization's UFLS program is incomplete or inconsistent in one or more requirements of Reliability Standard PRC-006-0_R1, but is consistent with the required amount of Load shedding.

2.2. Level 2: The amount of Load shedding is less than 95percent of the Regional requirement in any of the Load steps.

2.3. Level 3: The amount of Load shedding is less than 90percent of the Regional requirement in any of the Load steps.

2.4. Level 4: The evaluation of the entity's UFLS program for consistency with its Regional Reliability Organization's UFLS program was not provided or the amount of Load shedding is less than 85 percent of the Regional requirement on any of the Load steps.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program**

2. **Number:** PRC-008-0

3. **Purpose:** Provide last resort system preservation measures by implementing an Under Frequency Load Shedding (UFLS) program.

4. **Applicability:**

   4.1. Transmission Owner required by its Regional Reliability Organization to have a UFLS program

   4.2. Distribution Provider required by its Regional Reliability Organization to have a UFLS program

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall have a UFLS equipment maintenance and testing program in place. This UFLS equipment maintenance and testing program shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance.

R2. The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall implement its UFLS equipment maintenance and testing program and shall provide UFLS maintenance and testing program results to its Regional Reliability Organization and NERC on request (within 30 calendar days).

C. Measures

M1. Each Transmission Owner's and Distribution Provider's UFLS equipment maintenance and testing program contains the elements specified in Reliability Standard PRC-008-0_R1.

M2. Each Transmission Owner and Distribution Provider shall have evidence that it provided the results of its UFLS equipment maintenance and testing program's implementation to its Regional Reliability Organization and NERC on request (within 30 calendar days).

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Timeframe

   On request (within 30 calendar days).

   1.3. Data Retention

   None specified.

   1.4. Additional Compliance Information

   None.

2. Levels of Non-Compliance

2.1. Level 1: Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

2.2. Level 2: Complete documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.

2.3. Level 3: Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

2.4. Level 4: Documentation of the maintenance and testing program, or its implementation was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	September 26, 2005	Fixed reference in M1 from PRC-007-0_R1 to PRC-008-0_R1.	Errata

A. Introduction

1. **Title:** **Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event**

2. **Number:** PRC-009-0

3. **Purpose:** Provide last resort System preservation measures by implementing an Under Frequency Load Shedding (UFLS) program.

4. **Applicability:**

   4.1. Transmission Owner required by its Regional Reliability Organization to own a UFLS program

   4.2. Transmission Operator required by its Regional Reliability Organization to operate a UFLS program

   4.3. Load-Serving Entity required by the Regional Reliability Organization to operate a UFLS program

   4.4. Distribution Provider required by the Regional Reliability Organization to own or operate a UFLS program

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Transmission Owner, Transmission Operator, Load-Serving Entity and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall analyze and document its UFLS program performance in accordance with its Regional Reliability Organization's UFLS program. The analysis shall address the performance of UFLS equipment and program effectiveness following system events resulting in system frequency excursions below the initializing set points of the UFLS program. The analysis shall include, but not be limited to:

R1.1. A description of the event including initiating conditions.

R1.2. A review of the UFLS set points and tripping times.

R1.3. A simulation of the event.

R1.4. A summary of the findings.

R2. The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide documentation of the analysis of the UFLS program to its Regional Reliability Organization and NERC on request 90 calendar days after the system event.

C. Measures

M1. Each Transmission Owner's, Transmission Operator's, Load-Serving Entity's and Distribution Provider's documentation of the UFLS program performance following an underfrequency event includes all elements identified in Reliability Standard PRC-009-0_R1.

M2. Each Transmission Owner, Transmission Operator, Load-Serving Entity and Distribution Provider that owns or operate a UFLS program, shall have evidence it provided documentation of the analysis of the UFLS program performance following an underfrequency event as specified in Reliability Standard PRC-009-0_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

On request 90 calendar days after the system event.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Analysis of UFLS program performance following an actual underfrequency event below the UFLS set point(s) was incomplete in one or more elements in Reliability Standard PRC-009-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Analysis of UFLS program performance following an actual underfrequency event below the UFLS set point(s) was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Technical Assessment of the Design and Effectiveness of Undervoltage Load Shedding Program.**

2. **Number:** PRC-010-0

3. **Purpose:** Provide System preservation measures in an attempt to prevent system voltage collapse or voltage instability by implementing an Undervoltage Load Shedding (UVLS) program.

4. **Applicability:**

   4.1. Load-Serving Entity that operates a UVLS program

   4.2. Transmission Owner that owns a UVLS program

   4.3. Transmission Operator that operates a UVLS program

   4.4. Distribution Provider that owns or operates a UVLS program

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall periodically (at least every five years or as required by changes in system conditions) conduct and document an assessment of the effectiveness of the UVLS program. This assessment shall be conducted with the associated Transmission Planner(s) and Planning Authority(ies).

R1.1. This assessment shall include, but is not limited to:

R1.1.1. Coordination of the UVLS programs with other protection and control systems in the Region and with other Regional Reliability Organizations, as appropriate.

R1.1.2. Simulations that demonstrate that the UVLS programs performance is consistent with Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0.

R1.1.3. A review of the voltage set points and timing.

R2. The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall provide documentation of its current UVLS program assessment to its Regional Reliability Organization and NERC on request (30 calendar days).

C. Measures

M1. Each Transmission Owner's and Distribution Provider's UVLS program shall include the elements identified in Reliability Standard PRC-010-0_R1.

M2. Each Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall have evidence it provided documentation of its current UVLS program assessment to its Regional Reliability Organization and NERC as specified in Reliability Standard PRC-010-0_R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations. Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC Compliance Reporting process.

1.2. Compliance Monitoring Period and Reset Timeframe

Assessments every five years or as required by System changes.

Current assessment on request (30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: An assessment of the UVLS program did not address one of the three requirements listed in Reliability Standard PRC-010-0_R1.1 or an assessment of the UVLS program was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Undervoltage Load Shedding System Maintenance and Testing**
2. **Number:** PRC-011-0
3. **Purpose:** Provide system preservation measures in an attempt to prevent system voltage collapse or voltage instability by implementing an Undervoltage Load Shedding (UVLS) program.
4. **Applicability:**
   - **4.1.** Transmission Owner that owns a UVLS system
   - **4.2.** Distribution Provider that owns a UVLS system
5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Transmission Owner and Distribution Provider that owns a UVLS system shall have a UVLS equipment maintenance and testing program in place. This program shall include:

- **R1.1.** The UVLS system identification which shall include but is not limited to:
  - **R1.1.1.** Relays.
  - **R1.1.2.** Instrument transformers.
  - **R1.1.3.** Communications systems, where appropriate.
  - **R1.1.4.** Batteries.
- **R1.2.** Documentation of maintenance and testing intervals and their basis.
- **R1.3.** Summary of testing procedure.
- **R1.4.** Schedule for system testing.
- **R1.5.** Schedule for system maintenance.
- **R1.6.** Date last tested/maintained.

R2. The Transmission Owner and Distribution Provider that owns a UVLS system shall provide documentation of its UVLS equipment maintenance and testing program and the implementation of that UVLS equipment maintenance and testing program to its Regional Reliability Organization and NERC on request (within 30 calendar days).

C. Measures

M1. Each Transmission Owner and Distribution Provider that owns a UVLS system shall have documentation that its UVLS equipment maintenance and testing program conforms with Reliability Standard PRC-011-0_R1.

M2. Each Transmission Owner and Distribution Provider that owns a UVLS system shall have evidence it provided documentation of its UVLS equipment maintenance and testing program and the implementation of that UVLS equipment maintenance and testing program as specified in Reliability Standard PRC-011-0_R2.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (30 calendar days).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Documentation of the maintenance and testing program was complete, but records indicate implementation was not on schedule.

2.2. Level 2: Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

2.3. Level 3: Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

2.4. Level 4: Documentation of the maintenance and testing program, or its implementation, was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	October 12, 2005	Level 2 Non-Compliance: Changed “incomplete” to “complete” and inserted “not” between “was” and “on.”	Errata

A. Introduction

1. **Title:** **Special Protection System Data and Documentation**
2. **Number:** PRC-015-0
3. **Purpose:** To ensure that all Special Protection Systems (SPS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
   - **4.1.** Transmission Owner that owns an SPS
   - **4.2.** Generator Owner that owns an SPS
   - **4.3.** Distribution Provider that owns an SPS
5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall maintain a list of and provide data for existing and proposed SPSs as specified in Reliability Standard PRC-013-0_R1.

R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-0_R1 prior to being placed in service.

R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of SPS data and the results of Studies that show compliance of new or functionally modified SPSs with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).

C. Measures

M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it maintains a list of and provides data for existing and proposed SPSs as defined in Reliability Standard PRC-013-0_R1.

M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-0_R1 prior to being placed in service.

M3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it provided documentation of SPS data and the results of studies that show compliance of new or functionally modified SPSs with NERC standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).

D. Compliance

1. **Compliance Monitoring Process**
   - **1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: SPS owners provided SPS data, but was incomplete according to the Regional Reliability Organization SPS database requirements.

2.2. Level 2: SPS owners provided results of studies that show compliance of new or functionally modified SPSs with the NERC Planning Standards and Regional Reliability Organization criteria, but were incomplete according to the Regional Reliability Organization procedures for Reliability Standard PRC-012-0_R1.

2.3. Level 3: Not applicable.

2.4. Level 4: No SPS data was provided in accordance with Regional Reliability Organization SPS database requirements for Standard PRC-012-0_R1, or the results of studies that show compliance of new or functionally modified SPSs with the NERC Reliability Standards and Regional Reliability Organization criteria were not provided in accordance with Regional Reliability Organization procedures for Reliability Standard PRC-012-0_R1.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title: Special Protection System Misoperations**
2. **Number:** PRC-016-0.1
3. **Purpose:** To ensure that all Special Protection Systems (SPS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
   - **4.1.** Transmission Owner that owns an SPS.
   - **4.2.** Generator Owner that owns an SPS.
   - **4.3.** Distribution Provider that owns an SPS.
5. **Effective Date:** May 13, 2009

B. Requirements

R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall analyze its SPS operations and maintain a record of all misoperations in accordance with the Regional SPS review procedure specified in Reliability Standard PRC-012-0_R1.

R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall take corrective actions to avoid future misoperations.

R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).

C. Measures

M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it analyzed SPS operations and maintained a record of all misoperations in accordance with the Regional SPS review procedure specified in Reliability Standard PRC-012-0_R1.

M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it took corrective actions to avoid future misoperations.

M3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it provided documentation of the misoperation analyses and the corrective action plans to the affected Regional Reliability Organization and NERC on request (within 90 calendar days).

D. Compliance

1. **Compliance Monitoring Process**
   - **1.1. Compliance Monitoring Responsibility**

     Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

On request [within 90 calendar days of the incident or on request (within 30 calendar days) if requested more than 90 calendar days after the incident.]

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Documentation of SPS misoperations is complete but documentation of corrective actions taken for all identified SPS misoperations is incomplete.

2.2. Level 2: Documentation of corrective actions taken for SPS misoperations is complete but documentation of SPS misoperations is incomplete.

2.3. Level 3: Documentation of SPS misoperations and corrective actions is incomplete.

2.4. Level 4: No documentation of SPS misoperations or corrective actions.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	July 3, 2007	Change reference in Measure 1 from "PRC-016-0_R1" to "PRC-012-1_R1."	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised

A. Introduction

1. **Title:** **Special Protection System Maintenance and Testing**
2. **Number:** PRC-017-0
3. **Purpose:** To ensure that all Special Protection Systems (SPS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
   - **4.1.** Transmission Owner that owns an SPS
   - **4.2.** Generator Owner that owns an SPS
   - **4.3.** Distribution Provider that owns an SPS
5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have a system maintenance and testing program(s) in place. The program(s) shall include:

- **R1.1.** SPS identification shall include but is not limited to:
  - **R1.1.1.** Relays.
  - **R1.1.2.** Instrument transformers.
  - **R1.1.3.** Communications systems, where appropriate.
  - **R1.1.4.** Batteries.
- **R1.2.** Documentation of maintenance and testing intervals and their basis.
- **R1.3.** Summary of testing procedure.
- **R1.4.** Schedule for system testing.
- **R1.5.** Schedule for system maintenance.
- **R1.6.** Date last tested/maintained.

R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).

C. Measures

M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have a system maintenance and testing program(s) in place that includes all items in Reliability Standard PRC-017-0_R1.

M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it provided documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Timeframe:
On request (30 calendar days.)

1.2. Compliance Monitoring Period and Reset Timeframe

Compliance Monitor: Regional Reliability Organization.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

2.2. Level 2: Complete documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.

2.3. Level 3: Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

2.4. Level 4: Documentation of the maintenance and testing program, or its implementation, was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Disturbance Monitoring Equipment Installation and Data Reporting**

2. **Number:** PRC-018-1

3. **Purpose:** Ensure that Disturbance Monitoring Equipment (DME) is installed and that Disturbance data is reported in accordance with regional requirements to facilitate analyses of events.

4. **Applicability**

   4.1. Transmission Owner.

   4.2. Generator Owner.

5. **Effective Dates:** Phased in over four years after BOT adoption:

   Requirements 1 and 2:

   – 50% compliant two years after initial issuance of regional requirements per RELIABILITY STANDARD PRC-002 Requirement 5.

   – 75% compliant three years after initial issuance of regional requirements per reliability standard PRC-002 R5.

   – 100% compliant four years after initial issuance of regional requirements per reliability standard PRC-002 R5.

   Requirements 3 through 6:

   – 100% compliant six months after BOT adoption for already installed DME.

   – 100% compliant six months after installation for DMEs installed to meet Regional Reliability Organization requirements per reliability standard PRC-002 Requirements 1, 2 and 3.

B. Requirements

R1. Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard PRC-002 Requirements 1-3) shall have DMEs installed that meet the following requirements:

R1.1. Internal Clocks in DME devices shall be synchronized to within 2 milliseconds or less of Universal Coordinated Time scale (UTC)

R1.2. Recorded data from each Disturbance shall be retrievable for ten calendar days..

R2. The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization's installation requirements (reliability standard PRC-002 Requirements 1 through 3).

R3. The Transmission Owner and Generator Owner shall each maintain, and report to its Regional Reliability Organization on request, the following data on the DMEs installed to meet that region's installation requirements (reliability standard PRC-002 Requirements1.1, 2.1 and 3.1):

R3.1. Type of DME (sequence of event recorder, fault recorder, or dynamic disturbance recorder).

R3.2. Make and model of equipment.

R3.3. Installation location.

R3.4. Operational status.

R3.5. Date last tested.

R3.6. Monitored elements, such as transmission circuit, bus section, etc.

R3.7. Monitored devices, such as circuit breaker, disconnect status, alarms, etc.

R3.8. Monitored electrical quantities, such as voltage, current, etc.

R4. The Transmission Owner and Generator Owner shall each provide Disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements (reliability standard PRC-002 Requirement 4).

R5. The Transmission Owner and Generator Owner shall each archive all data recorded by DMEs for Regional Reliability Organization-identified events for at least three years.

R6. Each Transmission Owner and Generator Owner that is required by its Regional Reliability Organization to have DMEs shall have a maintenance and testing program for those DMEs that includes:

R6.1. Maintenance and testing intervals and their basis.

R6.2. Summary of maintenance and testing procedures.

C. Measures

M1. The Transmission Owner and Generator Owner shall each have evidence that DMEs it is required to have meet the functional requirements specified in Requirement 1 and are installed in accordance with its associated Regional Reliability Organization's requirements (R2).

M2. The Transmission Owner and Generator Owner shall each maintain the data listed in Requirements 3.1 through 3.8 for the DMEs installed to meet its Regional Reliability Organization's DME installation requirements.

M2.1 The Transmission Owner and Generator Owner shall each have evidence it provided this DME data to its Regional Reliability Organization within 30 calendar days of a request.

M3. The Transmission Owner and Generator Owner shall each have evidence it retained and provided recorded Disturbance data to entities in accordance with its associated Regional Reliability Organization's Disturbance data reporting requirements. (R4 R5)

M4. Each Transmission Owner and Generator Owner that is required to install DMEs to meet its Regional Reliability Organization's DME installation requirements, shall have an associated DME maintenance and testing program as defined in Requirement 6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Transmission Owner and Generator Owner shall each retain any Disturbance data provided to the Regional Reliability Organization (Requirement 4) for three years.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Transmission Owner and Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: There shall be a level one non-compliance if any of the following conditions is present:

2.1.1 DMEs that meet all the Regional Reliability Organization's installation requirements (in accordance with Requirement 2) were installed at 90% or more but not all of the required locations.

2.1.2 Recorded Disturbance data that meets all Regional Reliability Organization's Disturbance data requirements (in accordance with Requirement 4) was provided for 90% or more but not all of the required locations.

2.1.3 Data on required DMEs was incomplete (in accordance with R3)

2.1.4 Documentation of the DME maintenance and testing program provided was incomplete as required in R6, but records indicate maintenance and testing did occur within the identified intervals for the portions of the program that were documented.

2.2. Level 2: There shall be a level two non-compliance if any of the following conditions is present:

2.2.1 DMEs that meet all Regional Reliability Organization's installation requirements (in accordance with R2) were installed at 80% or more but less than 90% of the required locations.

2.2.2 Recorded Disturbance data that meets all Regional Reliability Organization's Disturbance data requirements (in accordance with R4) was provided for 80% or more but less than 90% of the required locations.

2.2.3 Recorded Disturbance data was not provided to all required entities (in accordance with R4)

2.2.4 Archived data was not retained for three years (in accordance with Requirement 5).

2.2.5 Documentation of the DME maintenance and testing program provided was complete as required in R6, but records indicate that maintenance and testing did not occur within the defined intervals.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions is present:

2.3.1 DMEs that meet all Regional Reliability Organization's installation requirements (in accordance with R2) were installed at 70% or more but less than 80% of the required locations.

2.3.2 Recorded Disturbance data that meets all Regional Reliability Organization's Disturbance data requirements (in accordance with R4) was provided for 70% or more but less than 80% of the required locations.

2.3.3 Documentation of the DME maintenance and testing program provided was incomplete as required in R6, and records indicate implementation of the documented portions of the maintenance and testing program did not occur within the identified intervals.

2.4. Level 4: There shall be a level four non-compliance if any one of the following conditions is present:

2.4.1 DMEs that meet all Regional Reliability Organization's installation requirements (in accordance with R2) were installed at less than 70% of the required locations.

2.4.2 Recorded Disturbance data that meets all Regional Reliability Organization's Disturbance data requirements (in accordance with R4) was provided for less than 70% of the required locations.

2.4.3 DMEs that meet all functional requirements (in accordance with R1) were not installed at all required locations.

2.4.4 Documentation of the DME maintenance and testing program was not provided, or no evidence that the testing program did occur within the identified intervals

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

A. Introduction

1. **Title:** **Under-Voltage Load Shedding Program Data**

2. **Number:** PRC-021-1

3. **Purpose:** Ensure data is provided to support the Regional database maintained for Under-Voltage Load Shedding (UVLS) programs that were implemented to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES).

4. **Applicability**

   4.1. Transmission Owner that owns a UVLS program.

   4.2. Distribution Provider that owns a UVLS program.

5. **Effective Date:** August 1, 2006

B. Requirements

R1. Each Transmission Owner and Distribution Provider that owns a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall annually update its UVLS data to support the Regional UVLS program database. The following data shall be provided to the Regional Reliability Organization for each installed UVLS system:

R1.1. Size and location of customer load, or percent of connected load, to be interrupted.

R1.2. Corresponding voltage set points and overall scheme clearing times.

R1.3. Time delay from initiation to trip signal.

R1.4. Breaker operating times.

R1.5. Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and Special Protection Systems.

R2. Each Transmission Owner and Distribution Provider that owns a UVLS program shall provide its UVLS program data to the Regional Reliability Organization within 30 calendar days of a request.

C. Measures

M1. Each Transmission Owner and Distribution Provider that owns a UVLS program shall have documentation that its UVLS data was updated annually and includes all items specified in Requirement 1.1 through 1.5.

M2. Each Transmission Owner and Distribution Provider that owns a UVLS program shall have evidence it provided the Regional Reliability Organization with its UVLS program data within 30 calendar days of a request.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Time Frame

   One calendar year.

   1.3. Data Retention

Each Transmission Owner and Distribution Provider that owns a UVLS program shall retain a copy of the data submitted over the past two years.

The Compliance Monitor shall retain all audit data for three years.

1.4. Additional Compliance Information

Transmission Owner and Distribution Provider shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: Did not update its UVLS data annually.

2.2. Level 2: UVLS data was provided, but did not address one of the items identified in R1.1 through R1.5.

2.3. Level 3: UVLS data was provided, but did not address two or more of the items identified in R1.1 through R1.5.

2.4. Level 4: Did not provide any UVLS data.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	12/01/05	1. Removed comma after 2004 in "Development Steps Completed," #1. 2. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 3. Added heading above table "Future Development Plan." 4. Lower cased the word "region," "board," and "regional" throughout document where appropriate. 5. Added or removed "periods" where appropriate. **6.** Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/05

A. Introduction

1. **Title:** **Under-Voltage Load Shedding Program Performance**

2. **Number:** **PRC-022-1**

3. **Purpose:** Ensure that Under Voltage Load Shedding (UVLS) programs perform as intended to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES).

4. **Applicability**

   4.1. Transmission Operator that operates a UVLS program.

   4.2. Distribution Provider that operates a UVLS program.

   4.3. Load-Serving Entity that operates a UVLS program.

5. **Effective Date:** May 1, 2006

B. Requirements

R1. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall analyze and document all UVLS operations and Misoperations. The analysis shall include:

R1.1. A description of the event including initiating conditions.

R1.2. A review of the UVLS set points and tripping times.

R1.3. A simulation of the event, if deemed appropriate by the Regional Reliability Organization. For most events, analysis of sequence of events may be sufficient and dynamic simulations may not be needed.

R1.4. A summary of the findings.

R1.5. For any Misoperation, a Corrective Action Plan to avoid future Misoperations of a similar nature.

R2. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall provide documentation of its analysis of UVLS program performance to its Regional Reliability Organization within 90 calendar days of a request.

C. Measures

M1. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall have documentation of its analysis of UVLS operations and Misoperations in accordance with Requirement 1.1 through 1.5.

M2. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall have evidence that it provided documentation of its analysis of UVLS program performance within 90 calendar days of a request by the Regional Reliability Organization.

D. Compliance

1. Compliance Monitoring Process

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall retain documentation of its analyses of UVLS operations and Misoperations for two years. The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

Transmission Operator, Load-Serving Entity, and Distribution Provider shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: Documentation of the analysis of UVLS performance was provided but did not include one of the five requirements in R1.

2.3. Level 3: Documentation of the analysis of UVLS performance was provided but did not include two or more of the five requirements in R1.

2.4. Level 4: Documentation of the analysis of UVLS performance was not provided.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	12/01/05	1. Removed comma after 2004 in "Development Steps Completed," #1. 2. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 3. Lower cased the word "region," "board," and "regional" throughout document where appropriate. 4. Added or removed "periods" where appropriate. 5. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06

A. Introduction

1. **Title:** **Reliability Responsibilities and Authorities**
2. **Number:** TOP-001-1
3. **Purpose:**

   To ensure reliability entities have clear decision-making authority and capabilities to take appropriate actions or direct the actions of others to return the transmission system to normal conditions during an emergency.

4. **Applicability**

   4.1. Balancing Authorities

   4.2. Transmission Operators

   4.3. Generator Operators

   4.4. Distribution Providers

   4.5. Load Serving Entities

5. **Effective Date:** January 1, 2007

B. Requirements

R1. Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.

R2. Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.

R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.

R4. Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.

R5. Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.

R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.

R7. Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless:

R7.1. For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.

R7.2. For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.

R7.3. When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.

R8. During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.

C. Measures

M1. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, signed agreements, an authority letter signed by an officer of the company, or other equivalent evidence that will be used to confirm that it has the authority, and has exercised the authority, to alleviate operating emergencies as described in Requirement 1.

M2. If an operating emergency occurs the Transmission Operator that experienced the emergency shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it took immediate actions to alleviate the operating emergency including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc. (Requirement 2)

M3. Each Transmission Operator, Balancing Authority, and Generator Operator shall have and provide upon request evidence such as operator logs, voice recordings or

transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it complied with its Reliability Coordinator's reliability directives. If the Transmission Operator, Balancing Authority or Generator Operator did not comply with the directive because it would violate safety, equipment, regulatory or statutory requirements, it shall provide evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that it immediately informed the Reliability Coordinator of its inability to perform the directive. (Requirement 3)

M4. Each Balancing Authority, Generator Operator, Distribution Provider and Load Serving Entity shall have and provide upon request evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it complied with its Transmission Operator's reliability directives. If the Balancing Authority, Generator Operator, Distribution Provider and Load Serving Entity did not comply with the directive because it would violate safety, equipment, regulatory or statutory requirements, it shall provide evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that it immediately informed the Transmission Operator of its inability to perform the directive. (Requirements 3 and 4)

M5. The Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it informed its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and took actions to avoid, when possible, or to mitigate an emergency. (Requirement 5)

M6. The Transmission Operator, Balancing Authority, and Generator Operator shall each have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it rendered assistance to others as requested, provided that the requesting entity had implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements. (Requirement 6)

M7. The Transmission Operator and Generator Operator shall each have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it notified either their Transmission Operator in the case of the Generator Operator, or other Transmission Operators, and the Reliability Coordinator when it removed Bulk Electric System facilities from service if removing those facilities would burden neighboring systems. (Requirement 7)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Transmission Operator shall have the current in-force document to show that it has the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area. (Measure 1)

Each Transmission Operator shall keep 90 days of historical data (evidence) for Measures 1 through 7, including evidence of directives issued for Measures 3 and 4.

Each Balancing Authority shall keep 90 days of historical data (evidence) for Measures 3, 4 and 6 including evidence of directives issued for Measures 3 and 4.

Each Generator Operator shall keep 90 days of historical data (evidence) for Measures 3, 4, 6 and 7 including evidence of directives issued for Measures 3 and 4.

Each Distribution Provider and Load-serving Entity shall keep 90 days of historical data (evidence) for Measure 4.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.4. Additional Compliance Information

None.

2. **Levels of Non-Compliance for a Balancing Authority:**

   2.1. **Level 1:** Not applicable.

   2.2. **Level 2:** Not applicable.

   2.3. **Level 3:** Not applicable.

   2.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

      2.4.1 Did not comply with a Reliability Coordinator's or Transmission Operator's reliability directive or did not immediately inform the Reliability Coordinator or Transmission Operator of its inability to perform that directive (R3)

      2.4.2 Did not render emergency assistance to others as requested, in accordance with R6.

3. **Levels of Non-Compliance for a Transmission Operator**

   3.1. **Level 1:** Not applicable.

   3.2. **Level 2:** Not applicable.

   3.3. **Level 3:** Not applicable.

   3.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

      3.4.1 Does not have the documented authority to act as specified in R1.

      3.4.2 Does not have evidence it acted with the authority specified in R1.

      3.4.3 Did not take immediate actions to alleviate operating emergencies as specified in R2.

      3.4.4 Did not comply with its Reliability Coordinator's reliability directive or did not immediately inform the Reliability Coordinator of its inability to perform that directive, as specified in R3.

      3.4.5 Did not inform its Reliability Coordinator and other potentially affected Transmission Operators of real time or anticipated emergency conditions as specified in R5.

      3.4.6 Did not take actions to avoid, when possible, or to mitigate an emergency as specified in R5.

      3.4.7 Did not render emergency assistance to others as requested, as specified in R6.

      3.4.8 Removed Bulk Electric System facilities from service under conditions other than those specified in R7.1, 7.2, and 7.3, and removing those facilities burdened a neighbor system.

4. **Levels of Non-Compliance for a Generator Operator:**

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

4.4.1 Did not comply with a Reliability Coordinator or Transmission Operator's reliability directive or did not immediately inform the Reliability Coordinator or Transmission Operator of its inability to perform that directive, as specified in R3.

4.4.2 Did not render all available emergency assistance to others as requested, unless such actions would violate safety, equipment, or regulatory or statutory requirements as specified in R6.

4.4.3 Removed Bulk Electric System facilities from service under conditions other than those specified in R7.1, 7.2, and 7.3, and burdened a neighbor system.

5. Levels of Non-Compliance for a Distribution Provider or Load Serving Entity

5.1. Level 1: Not applicable.

5.2. Level 2: Not applicable.

5.3. Level 3: Not applicable

5.4. Level 4: Did not comply with a Transmission Operator's reliability directive or immediately inform the Transmission Operator of its inability to perform that directive, as specified in R4.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised

A. Introduction

1. **Title:** **Normal Operations Planning**

2. **Number:** TOP-002-2a

3. **Purpose:** Current operations plans and procedures are essential to being prepared for reliable operations, including response for unplanned events.

4. **Applicability**

   4.1. Balancing Authority.

   4.2. Transmission Operator.

   4.3. Generator Operator.

   4.4. Load Serving Entity.

   4.5. Transmission Service Provider.

5. **Effective Date:** Immediately after approval of applicable regulatory authorities. FERC Approved 12/2/09

B. Requirements

R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.

R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.

R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.

R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.

R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.

R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.

R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.

R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.

R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.

R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).

R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.

R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.

R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.

R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:

R14.1. Changes in real and reactive output capabilities. (Retired August 1, 2007)

R14.1. Changes in real output capabilities. (Effective August 1, 2007)

R14.2. Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)

R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).

R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to:

R16.1. Changes in transmission facility status.

R16.2. Changes in transmission facility rating.

R17. Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.

R18. Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.

R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.

C. Measures

M1. Each Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, documented planning procedures, copies of current day plans, copies of seasonal operations plans, or other equivalent evidence that will be used to confirm that it maintained a set of current plans. (Requirement 1 Part 1).

M2. Each Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, copies of current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 5, 6, and 10.

M3. Each Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, copies of current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 7, 8, and 9.

M4. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, its next-day, and current-day Bulk Electric System studies used to determine SOLs or other equivalent evidence that will be used to confirm that its studies reflect current system conditions. (Requirement 11 Part 1)

M5. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that the results of Bulk Electric System studies were made available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator. (Requirement 11 Part 2)

M6. Each Generator Operator shall have and provide upon request evidence that, when requested by either a Transmission Operator or Balancing Authority, it performed a generating real and reactive capability verification and provided the results to the requesting entity in accordance with Requirement 13.

M7. Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that without any intentional time delay, it notified its Balancing Authority and Transmission Operator of changes in real and reactive capabilities and AVR status. (Requirement 14)

M8. Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, on request, it provided a forecast of expected real power output to assist in operations planning. (Requirement 15)

M9. Each Transmission Operators shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, without any intentional time delay, it notified its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics. (Requirement16)

M10. Each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider and Load Serving Entity shall have and provide upon request evidence that could include, but is not limited to, a list of interconnected transmission facilities and their line identifiers at each end or other equivalent evidence that will be used to confirm that it used uniform line identifiers when referring to transmission facilities of an interconnected network. (Requirement 18)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 calendar days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

For Measures 1 and 2, each Transmission Operator shall have its current plans and a rolling 6 months of historical records (evidence).

For Measures 1, 2, and 3 each Balancing Authority shall have its current plans and a rolling 6 months of historical records (evidence).

For Measure 4, each Transmission Operator shall keep its current plans (evidence).

For Measures 5 and 9, each Transmission Operator shall keep 90 days of historical data (evidence).

For Measures 6, 7 and 8, each Generator Operator shall keep 90 days of historical data (evidence).

For Measure 10, each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider, and Load-serving Entity shall have its current list interconnected transmission facilities and their line identifiers at each end or other equivalent evidence as evidence.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Balancing Authorities:

2.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Did not maintain an updated set of current-day plans as specified in R1.

2.4.2 Plans did not meet one or more of the requirements specified in R5 through R10.

3. Levels of Non-Compliance for Transmission Operators

3.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

3.2. Level 2: Not applicable.

3.3. Level 3: One or more of Bulk Electric System studies were not made available as specified in R11.

3.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Did not maintain an updated set of current-day plans as specified in R1.

3.4.2 Plans did not meet one or more of the requirements in R5, R6, and R10.

3.4.3 Studies not updated to reflect current system conditions as specified in R11.

3.4.4 Did not notify its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics as specified in R16.

4. Levels of Non-Compliance for Generator Operators:

4.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

4.4.1 Did not verify and provide a generating real and reactive capability verification and provide the results to the requesting entity as specified in R13.

4.4.2 Did not notify its Balancing Authority and Transmission Operator of changes in capabilities and characteristics as specified in R14.

4.4.3 Did not provide a forecast of expected real power output to assist in operations planning as specified in R15.

5. Levels of Non-Compliance for Transmission Service Providers and Load-serving Entities:

5.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

5.2. Level 2: Not applicable.

5.3. Level 3: Not applicable.

5.4. Level 4: Not applicable.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	June 14, 2007	Fixed typo in R11., (subject to …)	Errata
2a	February 10, 2009	Added Appendix 1 – Interpretation of R11 approved by BOT on February 10, 2009	Interpretation
2a	December 2, 2009	Interpretation of R11 approved by FERC on December 2, 2009	Same Interpretation

Appendix 1

Interpretation of Requirement R11

Requirement Number and Text of Requirement

Requirement R11: The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.

Question #1
Is the Transmission Operator required to conduct a "unique" study for each operating day, even when the actual or expected system conditions are identical to other days already studied? In other words, can a study be used for more than one day?

Response to Question #1
Requirement R11 mandates that each Transmission Operator review (i.e., study) the state of its Transmission Operator area both in advance of each day and during each day. Each day must have "a" study that can be applied to it, but it is not necessary to generate a "unique" study for each day. Therefore, it is acceptable for a Transmission Operator to use a particular study for more than one day.

Question #2
Are there specific actions required to implement a "study"? In other words, what constitutes a study?

Response to Question #2
The requirement does not mandate a particular type of review or study. The review or study may be based on complex computer studies or a manual reasonability review of previously existing study results. The requirement is designed to ensure the Transmission Operator maintains sensitivity to what is happening or what is about to happen.

Question #3
Does the term, "to determine SOLs" as used in the first sentence of Requirement R11 mean the "determination of system operating limits" or does it mean the "identification of potential SOL violations?"

Response to Question #3
TOP-002-2 covers real-time and near-real-time studies. Requirement R11 is meant to include both determining new limits and identifying potential "exceedances" of pre-defined SOLs. If system conditions indicate to the Transmission Operator that prior studies and SOLs may be outdated, TOP-002-2 mandates the Transmission Operator to conduct a study to identify SOLs for the new conditions. If the Transmission Operator determines that system conditions do not warrant a new study, the primary purpose of the review is to check that the previously defined (i.e., defined from the current SOLs in use, or the set defined by the planners) SOLs are not expected to be exceeded. As written, the standard provides the Transmission Operator discretion regarding when to look for new SOLs and when to rely on its current set of SOLs.

A. Introduction

1. **Title:** **Planned Outage Coordination**

2. **Number:** TOP-003-0

3. **Purpose:** Scheduled generator and transmission outages that may affect the reliability of interconnected operations must be planned and coordinated among Balancing Authorities, Transmission Operators, and Reliability Coordinators.

4. **Applicability**

   4.1. Generator Operators.

   4.2. Transmission Operators.

   4.3. Balancing Authorities.

   4.4. Reliability Coordinators.

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Generator Operators and Transmission Operators shall provide planned outage information.

R1.1. Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements.

R1.2. Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements.

R1.3. Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.

R2. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.

R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.

R4. Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.

C. Measures

M1. Evidence that the Generator Operator, Transmission Operator, Balancing Authority, and Reliability Coordinator reported and coordinated scheduled outage information as indicated in the requirements above.

D. Compliance

1. Compliance Monitoring Process

Each Regional Reliability Organization shall conduct a review every three years to ensure that each responsible entity has a process in place to provide planned generator and/or bulk transmission outage information to their Reliability Coordinator, and with neighboring Transmission Operators and Balancing Authorities.

Investigation: At the discretion of the Regional Reliability Organization or NERC, an investigation may be initiated to review the planned outage process of a monitored entity due to a complaint of non-compliance by another entity. Notification of an investigation must be made by the Regional Reliability Organization to the entity being investigated as soon as possible, but no later than 60 days after the event. The form and manner of the investigation will be set by NERC and/or the Regional Reliability Organization.

1.1. Compliance Monitoring Responsibility

A Reliability Coordinator makes a request for an outage to "not be taken" because of a reliability impact on the grid and the outage is still taken. The Reliability Coordinator must provide all its documentation within three business days to the Regional Reliability Organization. Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC Compliance Reporting process.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year without a violation from the time of the violation.

1.3. Data Retention

One calendar year.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: Each entity responsible for reporting information under Requirements R1 and R3 has a process in place to provide information to their Reliability Coordinator but does not have a process in place (where permitted by legal agreements) to provide this information to the neighboring Balancing Authority or Transmission Operator.

2.2. Level 2: N/A.

2.3. Level 3: N/A.

2.4. Level 4: There is no process in place to exchange outage information, or the entity responsible for reporting information under Requirements R1 to R3 does not follow the directives of the Reliability Coordinator to cancel or reschedule an outage.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata

A. Introduction

1. **Title:** **Transmission Operations**
2. **Number:** TOP-004-2
3. **Purpose:** To ensure that the transmission system is operated so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single Contingency and specified multiple Contingencies.
4. **Applicability:**

   4.1. Transmission Operators
5. **Proposed Effective Date:** Twelve months after BOT adoption of FAC-014.

B. Requirements

R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).

R2. Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.

R3. Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.

R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.

R5. Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.

R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including:

- **R6.1.** Monitoring and controlling voltage levels and real and reactive power flows.
- **R6.2.** Switching transmission elements.
- **R6.3.** Planned outages of transmission elements.
- **R6.4.** Responding to IROL and SOL violations.

C. Measures

M1. Each Transmission Operator that enters an unknown operating state for which valid limits have not been determined, shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, alarm program printouts, or other equivalent evidence that will be used to determine if it restored operations to respect proven reliable power system limits within 30 minutes as specified in Requirement 4.

M2. Each Transmission Operator shall have and provide upon request current policies and procedures that address the execution and coordination of activities that impact inter- and intra-Regional reliability for each of the topics listed in Requirements 6.1 through 6.6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Transmission Operator shall keep 90 days of historical data for Measure 1.

Each Transmission Operator shall have current, in-force policies and procedures, as evidence of compliance to Measure 2.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance:

2.1. Level 1: Not applicable.

2.2. Level 2: Did not have formal policies and procedures to address one of the topics listed in R6.1 through R6.4.

2.3. Level 3: Did not have formal policies and procedures to address two of the topics listed in R6.1 through R6.4.

2.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Did not restore operations to respect proven reliable power system limits within 30 minutes as specified in R4.

2.4.2 Did not have formal policies and procedures to address three or all of the topics listed in R6.1 through R6.4.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Added language from Missing Measures and Compliance Elements adopted by Board of Trustees on November 1, 2006	Revised
2	December 19, 2007	Updated to merge changes resulting from FAC-010-1, 011-1, and 014-1 standards approved by BOT on November 1, 2006. - Revised R3 and R6 with conforming changes made as errata to Levels of Non-compliance	Revised Errata

A. Introduction

1. **Title:** **Operational Reliability Information**
2. **Number:** TOP-005-1.1
3. **Purpose:** To ensure reliability entities have the operating data needed to monitor system conditions within their areas.
4. **Applicability**
   - **4.1.** Transmission Operators.
   - **4.2.** Balancing Authorities.
   - **4.3.** Reliability Coordinators.
   - **4.4.** Purchasing Selling Entities.
5. **Effective Date:** May 13, 2009

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall provide its Reliability Coordinator with the operating data that the Reliability Coordinator requires to perform operational reliability assessments and to coordinate reliable operations within the Reliability Coordinator Area.

R1.1. Each Reliability Coordinator shall identify the data requirements from the list in Attachment 1-TOP-005-0 "Electric System Reliability Data" and any additional operating information requirements relating to operation of the bulk power system within the Reliability Coordinator Area.

R2. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric System Reliability Data."

R3. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.

R4. Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.

C. Measures

M1. Evidence that the Reliability Coordinator, Balancing Authority, Transmission Operator, and Purchasing-Selling Entity is providing the information required, within the time intervals specified, and in a format agreed upon by the requesting entities.

D. Compliance

1. **Compliance Monitoring Process**
   - **1.1. Compliance Monitoring Responsibility**

Self-Certification: Entities shall annually self-certify compliance to the measures as required by its Regional Reliability Organization.

Exception Reporting: Each Region shall report compliance and violations to NERC via the NERC compliance reporting process.

1.2. Compliance Monitoring Period and Reset Time Frame

Periodic Review: Entities will be selected for operational reviews at least every three years. One calendar year without a violation from the time of the violation.

1.3. Data Retention

Not specified.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: Each entity responsible for reporting information under Requirements R1 to R4 is providing the requesting entities with the data required, in specified time intervals and format, but there are problems with consistency of delivery identified in the measuring process that need remedy (e.g., the data is not supplied consistently due to equipment malfunctions, or scaling is incorrect).

2.2. Level 2: N/A.

2.3. Level 3: N/A.

2.4. Level 4: Each entity responsible for reporting information under Requirements R1 to R4 is not providing the requesting entities with data with the specified content, timeliness, or format. The information missing is included in the requesting entity's list of data.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 6, 2007	Revised D.2.1 and D.2.4 reference "Requirements R1 to R5" "to Requirements R1 to R4."	Errata
1.1	October 29, 2008	BOT adopted errata changes; updated version number to "1.1"	Errata
1.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised

Attachment 1 — TOP-005-1.1

Electric System Reliability Data

This Attachment lists the types of data that Reliability Coordinators, Balancing Authorities, and Transmission Operators are expected to provide, and are expected to share with each other.

1. The following information shall be updated at least every ten minutes:

1.1. Transmission data. Transmission data for all Interconnections plus all other facilities considered key, from a reliability standpoint:

1.1.1 Status.

1.1.2 MW or ampere loadings.

1.1.3 MVA capability.

1.1.4 Transformer tap and phase angle settings.

1.1.5 Key voltages.

1.2. Generator data.

1.2.1 Status.

1.2.2 MW and MVAR capability.

1.2.3 MW and MVAR net output.

1.2.4 Status of automatic voltage control facilities.

1.3. Operating reserve.

1.3.1 MW reserve available within ten minutes.

1.4. Balancing Authority demand.

1.4.1 Instantaneous.

1.5. Interchange.

1.5.1 Instantaneous actual interchange with each Balancing Authority.

1.5.2 Current Interchange Schedules with each Balancing Authority by individual Interchange Transaction, including Interchange identifiers, and reserve responsibilities.

1.5.3 Interchange Schedules for the next 24 hours.

1.6. Area Control Error and frequency.

1.6.1 Instantaneous area control error.

1.6.2 Clock hour area control error.

1.6.3 System frequency at one or more locations in the Balancing Authority.

2. Other operating information updated as soon as available.

2.1. Interconnection Reliability Operating Limits and System Operating Limits in effect.

2.2. Forecast of operating reserve at peak, and time of peak for current day and next day.

2.3. Forecast peak demand for current day and next day.

2.4. Forecast changes in equipment status.

2.5. New facilities in place.

2.6. New or degraded special protection systems.

2.7. Emergency operating procedures in effect.

2.8. Severe weather, fire, or earthquake.

2.9. Multi-site sabotage.

A. Introduction

1. **Title:** **Monitoring System Conditions**
2. **Number:** TOP-006-1
3. **Purpose:**

   To ensure critical reliability parameters are monitored in real-time.
4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

   4.3. Generator Operators.

   4.4. Reliability Coordinators.
5. **Effective Date:** January 1, 2007

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use.

R1.1. Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.

R1.2. Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.

R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.

R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel.

R4. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.

R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.

R6. Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.

R7. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.

C. Measures

M1. The Generator Operator shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it informed its Host Balancing Authority and Transmission Operator of all generation resources available for use. (Requirement 1.1)

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it informed its Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use. (Requirement 1.2)

M3. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, computer printouts or other equivalent evidence that will be used to confirm that it monitored each of the applicable items listed in Requirement 2.

M4. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, printouts, training documents, description documents or other equivalent evidence that will be used to confirm that it has weather forecasts and past load patterns, available to predict the system's near-term load pattern. (Requirement 4)

M5. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, a description of its EMS alarm capability, training documents, or other equivalent evidence that will be used to confirm that important deviations in operating conditions and the need for corrective actions will be brought to the attention of its operators. (Requirement 5)

M6. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, a list of the frequency monitoring points available to the shift-operators or other equivalent evidence that will be used to confirm that it monitors system frequency. (Requirement 7)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)

- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Generator Operator shall keep 90 days of historical data (evidence) for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measure 2.

Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have current documents as evidence for Measure 3, 5 and 6..

Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have current documents as evidence of compliance to Measure 4.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Reliability Coordinators:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Does not monitor all of the applicable items listed in Requirement 2.

2.4.2 Did not have the information specified in R4.

2.4.3 Did not bring to the attention of its operators, important deviations in operating conditions and the need for corrective actions. (Requirement 5)

2.4.4 No evidence it monitors system frequency. (Requirement 7)

3. Levels of Non-Compliance for Generator Operators:

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

3.4. Level 4: Did not inform its Host Balancing Authority and/or the Transmission Operator of all generation resources available for use. (R1.1)

4. Levels of Non-Compliance for Transmission Operators and Balancing Authorities:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

4.4.1 Did not inform the Reliability Coordinator and/or other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use in accordance with R1.2.

4.4.2 Does not monitor all the applicable items listed in R2.

4.4.3 Did not have the information specified in R4.

4.4.4 Does not have monitoring to bring to the attention of operating personnel important deviations in operating conditions and the need for corrective actions as specified in R5.

4.4.5 No evidence it monitors system frequency. (R7).

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised

A. Introduction

1. **Title:** Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations

2. **Number:** TOP-007-0

3. **Purpose:**

   This standard ensures SOL and IROL violations are being reported to the Reliability Coordinator so that the Reliability Coordinator may evaluate actions being taken and direct additional corrective actions as needed.

4. **Applicability:**

   4.1. Transmission Operators.

   4.2. Reliability Coordinators.

5. **Effective Date:** April 1, 2005

B. Requirements

R1. A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits.

R2. Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.

R3. A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R2.

R4. The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.

C. Measures

M1. Evidence that the Transmission Operator informed the Reliability Coordinator when an IROL or SOL was exceeded and the actions taken to return the system to within limits.

M2. Evidence that the Transmission Operator returned the system to within IROL within 30 minutes for each incident that an IROL, or SOL that became an IROL due to changed system conditions, was exceeded.

M3. Evidence that the Reliability Coordinator evaluated actions and provided direction required to return the system to within limits.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   The Reliability Coordinator shall report any IROL violation exceeding 30 minutes to the Regional Reliability Organization and NERC within 72 hours. Each Regional Reliability Organization shall report any such violations to NERC via the NERC compliance reporting process. The Reliability Coordinator shall report any SOL violation that has become an IROL violation because of changed system conditions; i.e. exceeding the limit will require action to prevent:

1.1.1. System instability.

1.1.2. Unacceptable system dynamic response or equipment tripping.

1.1.3. Voltage levels in violation of applicable emergency limits.

1.1.4. Loadings on transmission facilities in violation of applicable emergency limits.

1.1.5. Unacceptable loss of load based on regional and/or NERC criteria.

1.2. Compliance Monitoring Period and Reset Timeframe

The reset period is monthly.

1.3. Data Retention

The data retention period is three months.

2. Levels of Non-Compliance

2.1. The Transmission Operator did not inform the Reliability Coordinator of an IROL or an SOL that has become an IROL because of changed system conditions, and the actions they are taking to return the system to within limits, or

2.2. The Transmission Operator did not take corrective actions as directed by the Reliability Coordinator to return the system to within the IROL within 30 minutes. (See Table 1-TOP-007-0 below.)

2.3. The limit violation was reported to the Reliability Coordinator, who did not provide appropriate direction to the Transmission Operator, resulting in an IROL violation in excess of 30 minutes duration.

Table 1-TOP-007-0 IROL and SOL Reporting Levels of Non-Compliance

Percentage by which IROL or SOL that has become an IROL is exceeded*	Limit exceeded for more than 30 minutes, up to 35 minutes.	Limit exceeded for more than 35 minutes, up to 40 minutes.	Limit exceeded for more than 40 minutes, up to 45 minutes.	Limit exceeded for more than 45 minutes.
Greater than 0%, up to and including 5%	Level 1	Level 2	Level 2	Level 3
Greater than 5%, up to and including 10%	Level 2	Level 2	Level 3	Level 3
Greater than 10%, up to and including 15%	Level 2	Level 3	Level 3	Level 4
Greater than 15%, up to and including 20%	Level 3	Level 3	Level 4	Level 4
Greater than 20%, up to and including 25%	Level 3	Level 4	Level 4	Level 4
Greater than 25%	Level 4	Level 4	Level 4	Level 4

*Percentage used in the left column is the flow measured at the end of the time period (30, 35, 40, or 45 minutes).

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata

A. Introduction

1. **Title:** **Response to Transmission Limit Violations**
2. **Number:** TOP-008-1
3. **Purpose:** To ensure Transmission Operators take actions to mitigate SOL and IROL violations.
4. **Applicability**

   4.1. Transmission Operators.
5. **Effective Date:** January 1, 2007

B. Requirements

R1. The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.

R2. Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.

R3. The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.

R4. The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.

C. Measures

M1. The Transmission Operator involved in an SOL or IROL violation shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications, alarm program printouts, or other equivalent evidence that will be used to determine if it took immediate steps to relieve the condition. (Requirement 1)

M2. The Transmission Operator that disconnects an overloaded facility shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications, alarm program print outs, or other equivalent evidence that will be used to determine if it disconnected an overloaded facility in accordance with Requirement 3 Part 1

M3. The Transmission Operator that disconnects an overloaded facility shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other

equivalent evidence that will be used to determine if it notified its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permitted, otherwise, immediately thereafter. (Requirement 3 Part 2)

M4. The Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, computer facilities documents, computer printouts, training documents, copies of analysis program results, operator logs or other equivalent evidence that will be used to confirm that it has sufficient information and analysis tools to determine the cause(s) of SOL violations. (Requirement 4 Part 1)

M5. The Transmission Operator that violates an SOL shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it used the results of these analyses to immediately mitigate the SOL violation. (Requirement 4 Part 3)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Transmission Operator shall keep 90 days of historical data (evidence) for Measure 1, 2 and 3.

Each Transmission Operator shall have current documents as evidence of compliance to Measures 4 and 5.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Transmission Operator

2.1. Level 1: Not applicable.

2.2. Level 2: Disconnected an overloaded facility as specified in R3 but did not notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, or immediately thereafter.

2.3. Level 3: Not applicable.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Did not take immediate steps to relieve an IROL or SOL violation in accordance with R1.

2.4.2 Did not disconnect an overloaded facility as specified in R3.

2.4.3 Does not have sufficient information and analysis tools to determine the cause(s) of SOL violations. (R4 Part 1)

2.4.4 Did not use the results of analyses to immediately mitigate an SOL violation. (R4 Part 3)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)
2. **Number:** TPL-001-0.1
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
4. **Applicability:**
   - **4.1.** Planning Authority
   - **4.2.** Transmission Planner
5. **Effective Date:** May 13, 2009

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-0_R1 and TPL-001-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually

1.3. Data Retention
None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

A. Introduction

1. Title: **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. Number: TPL-002-0a

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: April 23, 2010

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories,, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 and TPL-002-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0a	April 23, 2010	FERC approval of interpretation of TPL-002-0 R1.3.2	Interpretation

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-0a

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** April 23, 2010

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-0_R1 and TPL-003-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0a	April 23, 2010	FERC approval of interpretation of TPL-003-0 R1.3.12	Interpretation

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

A. Introduction

1. **Title:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. **Number**: TPL-004-0

3. **Purpose**: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability**:

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-0_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-0_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

A. Introduction

1. **Title:** **Voltage and Reactive Control**
2. **Number:** VAR-001-1
3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in real time to protect equipment and the reliable operation of the Interconnection.
4. **Applicability:**
   - **4.1.** Transmission Operators.
   - **4.2.** Purchasing-Selling Entities.
5. **Effective Date:** Six months after BOT adoption.

B. Requirements

R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators.

R2. Each Transmission Operator shall acquire sufficient reactive resources within its area to protect the voltage levels under normal and Contingency conditions. This includes the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.

R3. The Transmission Operator shall specify criteria that exempts generators from compliance with the requirements defined in Requirement 4, and Requirement 6.1.

- **R3.1.** Each Transmission Operator shall maintain a list of generators in its area that are exempt from following a voltage or Reactive Power schedule.
- **R3.2.** For each generator that is on this exemption list, the Transmission Operator shall notify the associated Generator Owner.

R4. Each Transmission Operator shall specify a voltage or Reactive Power schedule [1] at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (AVR in service and controlling voltage).

R5. Each Purchasing-Selling Entity shall arrange for (self-provide or purchase) reactive resources to satisfy its reactive requirements identified by its Transmission Service Provider.

R6. The Transmission Operator shall know the status of all transmission Reactive Power resources, including the status of voltage regulators and power system stabilizers.

- **R6.1.** When notified of the loss of an automatic voltage regulator control, the Transmission Operator shall direct the Generator Operator to maintain or change either its voltage schedule or its Reactive Power schedule.

R7. The Transmission Operator shall be able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow.

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[1] The voltage schedule is a target voltage to be maintained within a tolerance band during a specified period.

R8. Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including reactive generation scheduling; transmission line and reactive resource switching; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits.

R9. Each Transmission Operator shall maintain reactive resources to support its voltage under first Contingency conditions.

R9.1. Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when Contingencies occur.

R10. Each Transmission Operator shall correct IROL or SOL violations resulting from reactive resource deficiencies (IROL violations must be corrected within 30 minutes) and complete the required IROL or SOL violation reporting.

R11. After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.

R12. The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.

C. Measures

M1. The Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule as specified in Requirement 4 to each Generator Operator it requires to follow such a schedule.

M2. The Transmission Operator shall have evidence to show that, for each generating unit in its area that is exempt from following a voltage or Reactive Power schedule, the associated Generator Owner was notified of this exemption in accordance with Requirement 3.2.

M3. The Transmission Operator shall have evidence to show that it issued directives as specified in Requirement 6.1 when notified by a Generator Operator of the loss of an automatic voltage regulator control.

M4. The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with Requirement 11.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Transmission Operator shall retain evidence for Measures 1 through 4 for 12 months.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Transmission Operator shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: No evidence that exempt Generator Owners were notified of their exemption as specified under R3.2

2.2. Level 2: There shall be a level two non-compliance if either of the following conditions exists:

2.2.1 No evidence to show that directives were issued in accordance with R6.1.

2.2.2 No evidence that documentation was provided to Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with R11.

2.3. Level 3: There shall be a level three non-compliance if either of the following conditions exists:

2.3.1 Voltage or Reactive Power schedules were provided for some but not all generating units as required in R4.

2.4. Level 4: No evidence voltage or Reactive Power schedules were provided to Generator Operators as required in R4.

D. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	July 3, 2007	Added "Generator Owners" and "Generator Operators" to Applicability section.	Errata
1	August 23, 2007	Removed "Generator Owners" and "Generator Operators" to Applicability section.	Errata

A. Introduction

1. **Title:** **Generator Operation for Maintaining Network Voltage Schedules**

2. **Number:** VAR-002-1.1a

3. **Purpose:** To ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and the reliable operation of the Interconnection.

4. **Applicability**

   4.1. Generator Operator.

   4.2. Generator Owner.

5. **Effective Date:** May 13, 2009

B. Requirements

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings[1]) as directed by the Transmission Operator.

R2.1. When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.

R2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

R3. Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:

R3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.

R3.2. A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.

R4. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.

R4.1. For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:

R4.1.1. Tap settings.

R4.1.2. Available fixed tap ranges.

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[1] When a Generator is operating in manual control, reactive power capability may change based on stability considerations and this will lead to a change in the associated Facility Ratings.

R4.1.3. Impedance data.

R4.1.4. The +/- voltage range with step-change in % for load-tap changing transformers.

R5. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement.

R5.1. If the Generator Operator can't comply with the Transmission Operator's specifications, the Generator Operator shall notify the Transmission Operator and shall provide the technical justification.

C. Measures

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode as specified in Requirement 1.

M2. The Generator Operator shall have evidence to show that it controlled its generator voltage and reactive output to meet the voltage or Reactive Power schedule provided by its associated Transmission Operator as specified in Requirement 2.

M3. The Generator Operator shall have evidence to show that it responded to the Transmission Operator's directives as identified in Requirement 2.1 and Requirement 2.2.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any of the changes identified in Requirement 3.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in Requirements 4.1.1 through 4.1.4

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation as identified in Requirement 5.

M7. The Generator Operator shall have evidence that it notified its associated Transmission Operator when it couldn't comply with the Transmission Operator's step-up transformer tap specifications as identified in Requirement 5.1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Generator Operator shall maintain evidence needed for Measure 1 through Measure 5 and Measure 7 for the current and previous calendar years.

The Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. (Measure 6)

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Generator Owner and Generator Operator shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Generator Operator

2.1. Level 1: There shall be a Level 1 non-compliance if any of the following conditions exist:

2.1.1 One incident of failing to notify the Transmission Operator as identified in , R3.1, R3.2 or R5.1.

2.1.2 One incident of failing to maintain a voltage or reactive power schedule (R2).

2.2. Level 2: There shall be a Level 2 non-compliance if any of the following conditions exist:

2.2.1 More than one but less than five incidents of failing to notify the Transmission as identified in R1, R3.1,R3.2 or R5.1.

2.2.2 More than one but less than five incidents of failing to maintain a voltage or reactive power schedule (R2).

2.3. Level 3: There shall be a Level 3 non-compliance if any of the following conditions exist:

2.3.1 More than five but less than ten incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.

2.3.2 More than five but less than ten incidents of failing to maintain a voltage or reactive power schedule (R2).

2.4. Level 4: There shall be a Level 4 non-compliance if any of the following conditions exist:

2.4.1 Failed to comply with the Transmission Operator's directives as identified in R2.

2.4.2 Ten or more incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.

2.4.3 Ten or more incidents of failing to maintain a voltage or reactive power schedule (R2).

3. Levels of Non-Compliance for Generator Owner:

3.1.1 Level One: Not applicable.

3.1.2 Level Two: Documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage was missing two of the data types identified in R4.1.1 through R4.1.4.

3.1.3 Level Three: No documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage

3.1.4 Level Four: Did not ensure generating unit step-up transformer settings were changed in compliance with the specifications provided by the Transmission Operator as identified in R5.

E. Regional Differences

None identified.

F. Associated Documents

1. Appendix 1 – Interpretation of Requirements R1 and R2 (August 1, 2007).

Version History

Version	Date	Action	Change Tracking
1	May 15, 2006	Added "(R2)" to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.	July 5, 2006
1a	December 19, 2007	Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007	Revised
1a	January 16, 2007	In Section A.2., Added "a" to end of standard number. Section F: added "1."; and added date.	Errata
1.1a	October 29, 2008	BOT adopted errata changes; updated version number to "1.1a"	Errata
1.1a	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised

Appendix 1

Interpretation of Requirements R1 and R2

Request:

Requirement R1 of Standard VAR-002-1 states that Generation Operators shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (***automatic voltage regulator in service and controlling voltage***) unless the Generator Operator has notified the Transmission Operator.

Requirement R2 goes on to state that each Generation Operator shall maintain the generator voltage ***or Reactive Power output*** as directed by the Transmission Operator.

The two underlined phrases are the reasons for this interpretation request.

Most generation excitation controls include a device known as the Automatic Voltage Regulator, or AVR. This is the device which is referred to by the R1 requirement above. Most AVR's have the option of being set in various operating modes, such as constant voltage, constant power factor, and constant Mvar.

In the course of helping members of the WECC insure that they are in full compliance with NERC Reliability Standards, I have discovered both Transmission Operators and Generation Operators who have interpreted this standard to mean that AVR operation in the constant power factor or constant Mvar modes complies with the R1 and R2 requirements cited above. Their rational is as follows:

- The AVR is clearly in service because it is operating in one of its operating modes
- The AVR is clearly controlling voltage because to maintain constant PF or constant Mvar, it controls the generator terminal voltage
- R2 clearly gives the Transmission Operator the option of directing the Generation Operator to maintain a constant reactive power output rather than a constant voltage.

Other parties have interpreted this standard to require operation in the constant voltage mode only. Their rational stems from the belief that the purpose of the VAR-002-1 standard is to insure the automatic delivery of additional reactive to the system whenever a voltage decline begins to occur.

The material impact of misinterpretation of these standards is twofold.

- First, misinterpretation may result in reduced reactive response during system disturbances, which in turn may contribute to voltage collapse.
- Second, misinterpretation may result in substantial financial penalties imposed on generation operators and transmission operators who believe that they are in full compliance with the standard.

In accordance with the NERC Reliability Standards Development Procedure, I am requesting that a formal interpretation of the VAR-002-1 standard be provided. Two specific questions need to be answered.

- First, does AVR operation in the constant PF or constant Mvar modes comply with R1?
- Second, does R2 give the Transmission Operator the option of directing the Generation Owner to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

Interpretation:

1. First, does AVR operation in the constant PF or constant Mvar modes comply with R1?

   Interpretation: No, only operation in constant voltage mode meets this requirement. This answer is predicated on the assumption that the generator has the physical equipment that will allow such operation and that the Transmission Operator has not directed the generator to run in a mode other than constant voltage.

2. Second, does R2 give the Transmission Operator the option of directing the Generation Owner (sic) to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

   Interpretation: Yes, if the Transmission Operator specifically directs a Generator Operator to operate the AVR in a mode other than constant voltage mode, then that directed mode of AVR operation is allowed.

NERC Glossary of Terms

Glossary of Terms Used in NERC Reliability Standards
Updated April 20, 2010

Introduction:
This Glossary lists each term that was defined for use in one or more of NERC's continent-wide or Regional Reliability Standards and adopted by the NERC Board of Trustees from February 8, 2005 through February 16, 2010.

This reference is divided into two sections, and each section is organized in alphabetical order. The first section identifies all terms that have been adopted by the NERC Board of Trustees for use in continent-wide standards; the second section identifies all terms that have been adopted by the NERC Board of Trustees for use in regional standards. (WECC and ReliabilityFirst are the only Regions that have definitions approved by the NERC Board of Trustees. If other Regions develop definitions for approved Regional Standards using a NERC-approved standards development process, those definitions will be added to the Regional Definitions section of this glossary.)

Most of the terms identified in this glossary were adopted as part of the development of NERC's initial set of reliability standards, called the "Version 0" standards. Subsequent to the development of Version 0 standards, new definitions have been developed and approved following NERC's Reliability Standards Development Process, and added to this glossary following board adoption, with the "FERC approved" date added following a final Order approving the definition.

Immediately under each term is a link to the archive for the development of that term.

Definitions that have been adopted by the NERC Board of Trustees but have not been approved by FERC, or FERC has not approved but has directed be modified, are shaded in blue. Definitions that have been remanded or retired are shaded in orange.

Any comments regarding this glossary should be reported to the following: sarcomm@nerc.com with "Glossary Comment" in the subject line.

Continent-wide Definitions:

A....4
B....7
C....9
D....13
E....16
F....18
G....21
H....21
I....22
J....24
L....25
M....25
N....26
O....28
P....31
R....33
S....38
T....41
V....44
W....44

Regional Definitions

RFC Regional Definitions 45

WECC Regional Definitions 46

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Adequacy [Archive]		2/8/2005	3/16/2007	The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
Adjacent Balancing Authority [Archive]		2/8/2005	3/16/2007	A Balancing Authority Area that is interconnected another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
Adverse Reliability Impact [Archive]		2/7/2006	3/16/2007	The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection.
After the Fact [Archive]	ATF	10/29/2008	12/17/2009	A time classification assigned to an RFI when the submittal time is greater than one hour after the start time of the RFI.
Agreement [Archive]		2/8/2005	3/16/2007	A contract or arrangement, either written or verbal and sometimes enforceable by law.
Altitude Correction Factor [Archive]		2/7/2006	3/16/2007	A multiplier applied to specify distances, which adjusts the distances to account for the change in relative air density (RAD) due to altitude from the RAD used to determine the specified distance. Altitude correction factors apply to both minimum worker approach distances and to minimum vegetation clearance distances.
Ancillary Service [Archive]		2/8/2005	3/16/2007	Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider's transmission system in accordance with good utility practice. (*From FERC order 888-A.*)

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Anti-Aliasing Filter [Archive]		2/8/2005	3/16/2007	An analog filter installed at a metering point to remove the high frequency components of the signal over the AGC sample period.
Area Control Error [Archive]	ACE	2/8/2005	3/16/2007	The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error.
Area Interchange Methodology [Archive]		08/22/2008	11/24/2009	The Area Interchange methodology is characterized by determination of incremental transfer capability via simulation, from which Total Transfer Capability (TTC) can be mathematically derived. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC, and Postbacks and counterflows are added, to derive Available Transfer Capability. Under the Area Interchange Methodology, TTC results are generally reported on an area to area basis.
Arranged Interchange [Archive]		5/2/2006	3/16/2007	The state where the Interchange Authority has received the Interchange information (initial or revised).
Automatic Generation Control [Archive]	AGC	2/8/2005	3/16/2007	Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction.
Available Flowgate Capability [Archive]	AFC	08/22/2008	11/24/2009	A measure of the flow capability remaining on a Flowgate for further commercial activity over and above already committed uses. It is defined as TFC less Existing Transmission Commitments (ETC), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, and plus counterflows.

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Available Transfer Capability [Archive]	ATC	2/8/2005	3/16/2007	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin.
Available Transfer Capability [Archive]	ATC	08/22/2008	11/24/2009	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less Existing Transmission Commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, plus counterflows.
Available Transfer Capability Implementation Document [Archive]	ATCID	08/22/2008	11/24/2009	A document that describes the implementation of a methodology for calculating ATC or AFC, and provides information related to a Transmission Service Provider's calculation of ATC or AFC.
ATC Path [Archive]		08/22/2008	Not approved; Modification directed 11/24/09	Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path[1].

[1] See 18 CFR 37.6(b)(1)

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Balancing Authority [Archive]	BA	2/8/2005	3/16/2007	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
Balancing Authority Area [Archive]		2/8/2005	3/16/2007	The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.
Base Load [Archive]		2/8/2005	3/16/2007	The minimum amount of electric power delivered or required over a given period at a constant rate.
Blackstart Capability Plan [Archive]		2/8/2005 Approved Retirement when EOP-005-2 becomes effective 8/5/2009	3/16/2007	A documented procedure for a generating unit or station to go from a shutdown condition to an operating condition delivering electric power without assistance from the electric system. This procedure is only a portion of an overall system restoration plan.
Blackstart Resource [Archive]		8/5/2009		A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Block Dispatch [Archive]		08/22/2008	11/24/2009	A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, the capacity of a given generator is segmented into loadable "blocks," each of which is grouped and ordered relative to other blocks (based on characteristics including, but not limited to, efficiency, run of river or fuel supply considerations, and/or "must-run" status).
Bulk Electric System [Archive]		2/8/2005	3/16/2007	As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.
Burden [Archive]		2/8/2005	3/16/2007	Operation of the Bulk Electric System that violates or is expected to violate a System Operating Limit or Interconnection Reliability Operating Limit in the Interconnection, or that violates any other NERC, Regional Reliability Organization, or local operating reliability standards or criteria.
Business Practices [Archive]		08/22/2008	Not approved; Modification directed 11/24/09	Those business rules contained in the Transmission Service Provider's applicable tariff, rules, or procedures; associated Regional Reliability Organization or regional entity business practices; or NAESB Business Practices.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Capacity Benefit Margin [Archive]	CBM	2/8/2005	3/16/2007	The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Service Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.
Capacity Benefit Margin Implementation Document [Archive]	CBMID	11/13/2008	11/24/2009	A document that describes the implementation of a Capacity Benefit Margin methodology.
Capacity Emergency [Archive]		2/8/2005	3/16/2007	A capacity emergency exists when a Balancing Authority Area's operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements.
Cascading [Archive]		2/8/2005	3/16/2007	The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Cascading Outages [Archive]		11/1/2006 Withdrawn 2/12/2008	FERC Remanded 12/27/2007	~~The uncontrolled successive loss of Bulk Electric System Facilities triggered by an incident (or condition) at any location resulting in the interruption of electric service that cannot be restrained from spreading beyond a pre-determined area.~~
Clock Hour [Archive]		2/8/2005	3/16/2007	The 60-minute period ending at :00. All surveys, measurements, and reports are based on Clock Hour periods unless specifically noted.
Cogeneration [Archive]		2/8/2005	3/16/2007	Production of electricity from steam, heat, or other forms of energy produced as a by-product of another process.
Compliance Monitor [Archive]		2/8/2005	3/16/2007	The entity that monitors, reviews, and ensures compliance of responsible entities with reliability standards.
Confirmed Interchange [Archive]		5/2/2006	3/16/2007	The state where the Interchange Authority has verified the Arranged Interchange.
Congestion Management Report [Archive]		2/8/2005	3/16/2007	A report that the Interchange Distribution Calculator issues when a Reliability Coordinator initiates the Transmission Loading Relief procedure. This report identifies the transactions and native and network load curtailments that must be initiated to achieve the loading relief requested by the initiating Reliability Coordinator.
Constrained Facility [Archive]		2/8/2005	3/16/2007	A transmission facility (line, transformer, breaker, etc.) that is approaching, is at, or is beyond its System Operating Limit or Interconnection Reliability Operating Limit.
Contingency [Archive]		2/8/2005	3/16/2007	The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Contingency Reserve [Archive]		2/8/2005	3/16/2007	The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.
Contract Path [Archive]		2/8/2005	3/16/2007	An agreed upon electrical path for the continuous flow of electrical power between the parties of an Interchange Transaction.
Control Performance Standard [Archive]	CPS	2/8/2005	3/16/2007	The reliability standard that sets the limits of a Balancing Authority's Area Control Error over a specified time period.
Corrective Action Plan [Archive]		2/7/2006	3/16/2007	A list of actions and an associated timetable for implementation to remedy a specific problem.
Cranking Path [Archive]		5/2/2006	3/16/2007	A portion of the electric system that can be isolated and then energized to deliver electric power from a generation source to enable the startup of one or more other generating units.
Critical Assets [Archive]		5/2/2006	1/18/2008	Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.
Critical Cyber Assets [Archive]		5/2/2006	1/18/2008	Cyber Assets essential to the reliable operation of Critical Assets.
Curtailment [Archive]		2/8/2005	3/16/2007	A reduction in the scheduled capacity or energy delivery of an Interchange Transaction.
Curtailment Threshold [Archive]		2/8/2005	3/16/2007	The minimum Transfer Distribution Factor which, if exceeded, will subject an Interchange Transaction to curtailment to relieve a transmission facility constraint.
Cyber Assets [Archive]		5/2/2006	1/18/2008	Programmable electronic devices and communication networks including hardware, software, and data.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Cyber Security Incident [Archive]		5/2/2006	1/18/2008	Any malicious act or suspicious event that: • Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or, • Disrupts, or was an attempt to disrupt, the operation of a Critical Cyber Asset.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Delayed Fault Clearing [Archive]		11/1/2006	12/27/2007	Fault clearing consistent with correct operation of a breaker failure protection system and its associated breakers, or of a backup protection system with an intentional time delay.
Demand [Archive]		2/8/2005	3/16/2007	1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.
Demand-Side Management [Archive]	DSM	2/8/2005	3/16/2007	The term for all activities or programs undertaken by Load-Serving Entity or its customers to influence the amount or timing of electricity they use.
Direct Control Load Management [Archive]	DCLM	2/8/2005	3/16/2007	Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.
Dispatch Order [Archive]		08/22/2008	11/24/2009	A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, each generator is ranked by priority.
Dispersed Load by Substations [Archive]		2/8/2005	3/16/2007	Substation load information configured to represent a system for power flow or system dynamics modeling purposes, or both.
Distribution Factor [Archive]	DF	2/8/2005	3/16/2007	The portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Distribution Provider [Archive]		2/8/2005	3/16/2007	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.
Disturbance [Archive]		2/8/2005	3/16/2007	1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.
Disturbance Control Standard [Archive]	DCS	2/8/2005	3/16/2007	The reliability standard that sets the time limit following a Disturbance within which a Balancing Authority must return its Area Control Error to within a specified range.
Disturbance Monitoring Equipment [Archive]	DME	8/2/2006	3/16/2007	Devices capable of monitoring and recording system data pertaining to a Disturbance. Such devices include the following categories of recorders[2]: • Sequence of event recorders which record equipment response to the event • Fault recorders, which record actual waveform data replicating the system primary voltages and currents. This may include protective relays. • Dynamic Disturbance Recorders (DDRs), which record incidents that portray power system behavior during dynamic events such as low-frequency (0.1 Hz – 3 Hz) oscillations and abnormal frequency or voltage excursions

[2] Phasor Measurement Units and any other equipment that meets the functional requirements of DMEs may qualify as DMEs.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Dynamic Interchange Schedule or Dynamic Schedule [Archive]		2/8/2005	3/16/2007	A telemetered reading or value that is updated in real time and used as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.
Dynamic Transfer [Archive]		2/8/2005	3/16/2007	The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one Balancing Authority Area into another.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Economic Dispatch [Archive]		2/8/2005	3/16/2007	The allocation of demand to individual generating units on line to effect the most economical production of electricity.
Electrical Energy [Archive]		2/8/2005	3/16/2007	The generation or use of electric power by a device over a period of time, expressed in kilowatthours (kWh), megawatthours (MWh), or gigawatthours (GWh).
Electronic Security Perimeter [Archive]		5/2/2006	1/18/2008	The logical border surrounding a network to which Critical Cyber Assets are connected and for which access is controlled.
Element [Archive]		2/8/2005	3/16/2007	Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.
Emergency or BES Emergency [Archive]		2/8/2005	3/16/2007	Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System.
Emergency Rating [Archive]		2/8/2005	3/16/2007	The rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar or other appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.
Emergency Request for Interchange (Emergency RFI) [Archive]		10/29/2008	12/17/2009	Request for Interchange to be initiated for Emergency or Energy Emergency conditions.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Energy Emergency [Archive]		2/8/2005	3/16/2007	A condition when a Load-Serving Entity has exhausted all other options and can no longer provide its customers' expected energy requirements.
Equipment Rating [Archive]		2/7/2006	3/16/2007	The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady state, short-circuit and transient conditions, as permitted or assigned by the equipment owner.
Existing Transmission Commitments [Archive]	ETC	08/22/2008	11/24/2009	Committed uses of a Transmission Service Provider's Transmission system considered when determining ATC or AFC.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Facility [Archive]		2/7/2006	3/16/2007	A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)
Facility Rating [Archive]		2/8/2005	3/16/2007	The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.
Fault [Archive]		2/8/2005	3/16/2007	An event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection.
Fire Risk [Archive]		2/7/2006	3/16/2007	The likelihood that a fire will ignite or spread in a particular geographic area.
Firm Demand [Archive]		2/8/2005	3/16/2007	That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.
Firm Transmission Service [Archive]		2/8/2005	3/16/2007	The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.
Flashover [Archive]		2/7/2006	3/16/2007	An electrical discharge through air around or over the surface of insulation, between objects of different potential, caused by placing a voltage across the air space that results in the ionization of the air space.
Flowgate [Archive]		2/8/2005	3/16/2007	A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Flowgate [Archive]		08/22/2008	11/24/2009	1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.
Flowgate Methodology [Archive]		08/22/2008	11/24/2009	The Flowgate methodology is characterized by identification of key Facilities as Flowgates. Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the Total Flowgate Capability, and Postbacks and counterflows are added, to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs can be used to determine Available Transfer Capability (ATC).
Forced Outage [Archive]		2/8/2005	3/16/2007	1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. 2. The condition in which the equipment is unavailable due to unanticipated failure.
Frequency Bias [Archive]		2/8/2005	3/16/2007	A value, usually expressed in megawatts per 0.1 Hertz (MW/0.1 Hz), associated with a Balancing Authority Area that approximates the Balancing Authority Area's response to Interconnection frequency error.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Frequency Bias Setting [Archive]		2/8/2005	3/16/2007	A value, usually expressed in MW/0.1 Hz, set into a Balancing Authority ACE algorithm that allows the Balancing Authority to contribute its frequency response to the Interconnection.
Frequency Deviation [Archive]		2/8/2005	3/16/2007	A change in Interconnection frequency.
Frequency Error [Archive]		2/8/2005	3/16/2007	The difference between the actual and scheduled frequency. ($F_A - F_S$)
Frequency Regulation [Archive]		2/8/2005	3/16/2007	The ability of a Balancing Authority to help the Interconnection maintain Scheduled Frequency. This assistance can include both turbine governor response and Automatic Generation Control.
Frequency Response [Archive]		2/8/2005	3/16/2007	(Equipment) The ability of a system or elements of the system to react or respond to a change in system frequency. (System) The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Generator Operator [Archive]		2/8/2005	3/16/2007	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
Generator Owner [Archive]		2/8/2005	3/16/2007	Entity that owns and maintains generating units.
Generator Shift Factor [Archive]	GSF	2/8/2005	3/16/2007	A factor to be applied to a generator's expected change in output to determine the amount of flow contribution that change in output will impose on an identified transmission facility or Flowgate.
Generator-to-Load Distribution Factor [Archive]	GLDF	2/8/2005	3/16/2007	The algebraic sum of a Generator Shift Factor and a Load Shift Factor to determine the total impact of an Interchange Transaction on an identified transmission facility or Flowgate.
Generation Capability Import Requirement [Archive]	GCIR	11/13/2008	11/24/2009	The amount of generation capability from external sources identified by a Load-Serving Entity (LSE) or Resource Planner (RP) to meet its generation reliability or resource adequacy requirements as an alternative to internal resources.
Host Balancing Authority [Archive]		2/8/2005	3/16/2007	1. A Balancing Authority that confirms and implements Interchange Transactions for a Purchasing Selling Entity that operates generation or serves customers directly within the Balancing Authority's metered boundaries. 2. The Balancing Authority within whose metered boundaries a jointly owned unit is physically located.
Hourly Value [Archive]		2/8/2005	3/16/2007	Data measured on a Clock Hour basis.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Implemented Interchange [Archive]		5/2/2006	3/16/2007	The state where the Balancing Authority enters the Confirmed Interchange into its Area Control Error equation.
Inadvertent Interchange [Archive]		2/8/2005	3/16/2007	The difference between the Balancing Authority's Net Actual Interchange and Net Scheduled Interchange. ($I_A - I_S$)
Independent Power Producer [Archive]	IPP	2/8/2005	3/16/2007	Any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, cogenerators and small power producers and all other nonutility electricity producers, such as exempt wholesale generators, who sell electricity.
Institute of Electrical and Electronics Engineers, Inc. [Archive]	IEEE	2/7/2006	3/16/2007	
Interchange [Archive]		5/2/2006	3/16/2007	Energy transfers that cross Balancing Authority boundaries.
Interchange Authority [Archive]		5/2/2006	3/16/2007	The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.
Interchange Distribution Calculator [Archive]	IDC	2/8/2005	3/16/2007	The mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Interchange Schedule [Archive]		2/8/2005	3/16/2007	An agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction.
Interchange Transaction [Archive]		2/8/2005	3/16/2007	An agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries.
Interchange Transaction Tag or Tag [Archive]		2/8/2005	3/16/2007	The details of an Interchange Transaction required for its physical implementation.
Interconnected Operations Service [Archive]		2/8/2005	3/16/2007	A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected Bulk Electric Systems.
Interconnection [Archive]		2/8/2005	3/16/2007	When capitalized, any one of the three major electric system networks in North America: Eastern, Western, and ERCOT.
Interconnection Reliability Operating Limit [Archive]	IROL	2/8/2005	3/16/2007 Retired 12/27/2007	The value (such as MW, MVar, Amperes, Frequency or Volts) derived from, or a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages.
Interconnection Reliability Operating Limit [Archive]	IROL	11/1/2006	12/27/2007	A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading Outages that adversely impact the reliability of the Bulk Electric System.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Interconnection Reliability Operating Limit T_v [Archive]	IROL T_v	11/1/2006	12/27/2007	The maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit's T_v shall be less than or equal to 30 minutes.
Intermediate Balancing Authority [Archive]		2/8/2005	3/16/2007	A Balancing Authority Area that has connecting facilities in the Scheduling Path between the Sending Balancing Authority Area and Receiving Balancing Authority Area and operating agreements that establish the conditions for the use of such facilities
Interruptible Load or Interruptible Demand [Archive]		11/1/2006	3/16/2007	Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.
Joint Control [Archive]		2/8/2005	3/16/2007	Automatic Generation Control of jointly owned units by two or more Balancing Authorities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Limiting Element [Archive]		2/8/2005	3/16/2007	The element that is 1.)Either operating at its appropriate rating, or 2,) Would be following the limiting contingency. Thus, the Limiting Element establishes a system limit.
Load [Archive]		2/8/2005	3/16/2007	An end-use device or customer that receives power from the electric system.
Load Shift Factor [Archive]	LSF	2/8/2005	3/16/2007	A factor to be applied to a load's expected change in demand to determine the amount of flow contribution that change in demand will impose on an identified transmission facility or monitored Flowgate.
Load-Serving Entity [Archive]		2/8/2005	3/16/2007	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.
Misoperation [Archive]		2/7/2006	3/16/2007	▪ Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection. ▪ Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone). ▪ Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Native Load [Archive]		2/8/2005	3/16/2007	The end-use customers that the Load-Serving Entity is obligated to serve.
Net Actual Interchange [Archive]		2/8/2005	3/16/2007	The algebraic sum of all metered interchange over all interconnections between two physically Adjacent Balancing Authority Areas.
Net Energy for Load [Archive]		2/8/2005	3/16/2007	Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to Balancing Authority Areas through interchange. It includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities.
Net Interchange Schedule [Archive]		2/8/2005	3/16/2007	The algebraic sum of all Interchange Schedules with each Adjacent Balancing Authority.
Net Scheduled Interchange [Archive]		2/8/2005	3/16/2007	The algebraic sum of all Interchange Schedules across a given path or between Balancing Authorities for a given period or instant in time.
Network Integration Transmission Service [Archive]		2/8/2005	3/16/2007	Service that allows an electric transmission customer to integrate, plan, economically dispatch and regulate its network reserves in a manner comparable to that in which the Transmission Owner serves Native Load customers.
Non-Firm Transmission Service [Archive]		2/8/2005	3/16/2007	Transmission service that is reserved on an as-available basis and is subject to curtailment or interruption.
Non-Spinning Reserve [Archive]		2/8/2005	3/16/2007	1. That generating reserve not connected to the system but capable of serving demand within a specified time. 2. Interruptible load that can be removed from the system in a specified time.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Normal Clearing [Archive]		11/1/2006	12/27/2007	A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.
Normal Rating [Archive]		2/8/2005	3/16/2007	The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.
Nuclear Plant Generator Operator [Archive]		5/2/2007	10/16/2008	Any Generator Operator or Generator Owner that is a Nuclear Plant Licensee responsible for operation of a nuclear facility licensed to produce commercial power.
Nuclear Plant Off-site Power Supply (Off-site Power) [Archive]		5/2/2007	10/16/2008	The electric power supply provided from the electric system to the nuclear power plant distribution system as required per the nuclear power plant license.
Nuclear Plant Licensing Requirements (NPLRs) [Archive]		5/2/2007	10/16/2008	Requirements included in the design basis of the nuclear plant and statutorily mandated for the operation of the plant, including nuclear power plant licensing requirements for: 1) Off-site power supply to enable safe shutdown of the plant during an electric system or plant event; and 2) Avoiding preventable challenges to nuclear safety as a result of an electric system disturbance, transient, or condition.
Nuclear Plant Interface Requirements (NPIRs) [Archive]		5/2/2007	10/16/2008	The requirements based on NPLRs and Bulk Electric System requirements that have been mutually agreed to by the Nuclear Plant Generator Operator and the applicable Transmission Entities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Off-Peak [Archive]		2/8/2005	3/16/2007	Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand.
On-Peak [Archive]		2/8/2005	3/16/2007	Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of higher electrical demand.
Open Access Same Time Information Service [Archive]	OASIS	2/8/2005	3/16/2007	An electronic posting system that the Transmission Service Provider maintains for transmission access data and that allows all transmission customers to view the data simultaneously.
Open Access Transmission Tariff [Archive]	OATT	2/8/2005	3/16/2007	Electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission requiring the Transmission Service Provider to furnish to all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves.
Operating Plan [Archive]		2/7/2006	3/16/2007	A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Operating Procedure [Archive]		2/7/2006	3/16/2007	A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a system operator to take in removing a specific transmission line from service is an example of an Operating Procedure.
Operating Process [Archive]		2/7/2006	3/16/2007	A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process.
Operating Reserve [Archive]		2/8/2005	3/16/2007	That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.
Operating Reserve – Spinning [Archive]		2/8/2005	3/16/2007	The portion of Operating Reserve consisting of: • Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Operating Reserve – Supplemental [Archive]		2/8/2005	3/16/2007	The portion of Operating Reserve consisting of: • Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.
Operating Voltage [Archive]		2/7/2006	3/16/2007	The voltage level by which an electrical system is designated and to which certain operating characteristics of the system are related; also, the effective (root-mean-square) potential difference between any two conductors or between a conductor and the ground. The actual voltage of the circuit may vary somewhat above or below this value.
Operational Planning Analysis [Archive]		10/17/2008		An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).
Outage Transfer Distribution Factor [Archive]	OTDF	08/22/2008	11/24/2009	In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more system Facilities removed from service (outaged).
Overlap Regulation Service [Archive]		2/8/2005	3/16/2007	A method of providing regulation service in which the Balancing Authority providing the regulation service incorporates another Balancing Authority's actual interchange, frequency response, and schedules into providing Balancing Authority's AGC/ACE equation.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Participation Factors [Archive]		08/22/2008	11/24/2009	A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, generators are assigned a percentage that they will contribute to serve load.
Peak Demand [Archive]		2/8/2005	3/16/2007	1. The highest hourly integrated Net Energy For Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year). 2. The highest instantaneous demand within the Balancing Authority Area.
Performance-Reset Period [Archive]		2/7/2006	3/16/2007	The time period that the entity being assessed must operate without any violations to reset the level of non compliance to zero.
Physical Security Perimeter [Archive]		5/2/2006	1/18/2008	The physical, completely enclosed ("six-wall") border surrounding computer rooms, telecommunications rooms, operations centers, and other locations in which Critical Cyber Assets are housed and for which access is controlled.
Planning Authority [Archive]		2/8/2005	3/16/2007	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
Planning Coordinator [Archive]		08/22/2008	11/24/2009	See Planning Authority.
Point of Delivery [Archive]	POD	2/8/2005	3/16/2007	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction leaves or a Load-Serving Entity receives its energy.
Point of Receipt [Archive]	POR	2/8/2005	3/16/2007	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a Generator delivers its output.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Point to Point Transmission Service [Archive]	PTP	2/8/2005	3/16/2007	The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery.
Postback [Archive]		08/22/2008	Not approved; Modification directed 11/24/09	Positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.
Power Transfer Distribution Factor [Archive]	PTDF	08/22/2008	11/24/2009	In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system Facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer
Pro Forma Tariff [Archive]		2/8/2005	3/16/2007	Usually refers to the standard OATT and/or associated transmission rights mandated by the U.S. Federal Energy Regulatory Commission Order No. 888.
Protection System [Archive]		2/7/2006	3/17/07	Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry.
Pseudo-Tie [Archive]		2/8/2005	3/16/2007	A telemetered reading or value that is updated in real time and used as a "virtual" tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.
Purchasing-Selling Entity [Archive]		2/8/2005	3/16/2007	The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Ramp Rate or Ramp [Archive]		2/8/2005	3/16/2007	(Schedule) The rate, expressed in megawatts per minute, at which the interchange schedule is attained during the ramp period. (Generator) The rate, expressed in megawatts per minute, that a generator changes its output.
Rated Electrical Operating Conditions [Archive]		2/7/2006	3/16/2007	The specified or reasonably anticipated conditions under which the electrical system or an individual electrical circuit is intend/designed to operate
Rating [Archive]		2/8/2005	3/16/2007	The operational limits of a transmission system element under a set of specified conditions.
Rated System Path Methodology [Archive]		08/22/2008	11/24/2009	The Rated System Path Methodology is characterized by an initial Total Transfer Capability (TTC), determined via simulation. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from TTC, and Postbacks and counterflows are added as applicable, to derive Available Transfer Capability. Under the Rated System Path Methodology, TTC results are generally reported as specific transmission path capabilities.
Reactive Power [Archive]		2/8/2005	3/16/2007	The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).
Real Power [Archive]		2/8/2005	3/16/2007	The portion of electricity that supplies energy to the load.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reallocation [Archive]		2/8/2005	3/16/2007	The total or partial curtailment of Transactions during TLR Level 3a or 5a to allow Transactions using higher priority to be implemented.
Real-time [Archive]		2/7/2006	3/16/2007	Present time as opposed to future time. (From Interconnection Reliability Operating Limits standard.)
Real-time Assessment [Archive]		10/17/2008		An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data
Receiving Balancing Authority [Archive]		2/8/2005	3/16/2007	The Balancing Authority importing the Interchange.
Regional Reliability Organization [Archive]		2/8/2005	3/16/2007	1. An entity that ensures that a defined area of the Bulk Electric System is reliable, adequate and secure. 2. A member of the North American Electric Reliability Council. The Regional Reliability Organization can serve as the Compliance Monitor.
Regional Reliability Plan [Archive]		2/8/2005	3/16/2007	The plan that specifies the Reliability Coordinators and Balancing Authorities within the Regional Reliability Organization, and explains how reliability coordination will be accomplished.
Regulating Reserve [Archive]		2/8/2005	3/16/2007	An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Regulation Service [Archive]		2/8/2005	3/16/2007	The process whereby one Balancing Authority contracts to provide corrective response to all or a portion of the ACE of another Balancing Authority. The Balancing Authority providing the response assumes the obligation of meeting all applicable control criteria as specified by NERC for itself and the Balancing Authority for which it is providing the Regulation Service.
Reliability Adjustment RFI [Archive]		10/29/2008	12/17/2009	Request to modify an Implemented Interchange Schedule for reliability purposes.
Reliability Coordinator [Archive]		2/8/2005	3/16/2007	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
Reliability Coordinator Area [Archive]		2/8/2005	3/16/2007	The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.
Reliability Coordinator Information System [Archive]	RCIS	2/8/2005	3/16/2007	The system that Reliability Coordinators use to post messages and share operating information in real time.
Remedial Action Scheme [Archive]	RAS	2/8/2005	3/16/2007	See "Special Protection System"

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reportable Disturbance [Archive]		2/8/2005	3/16/2007	Any event that causes an ACE change greater than or equal to 80% of a Balancing Authority's or reserve sharing group's most severe contingency. The definition of a reportable disturbance is specified by each Regional Reliability Organization. This definition may not be retroactively adjusted in response to observed performance.
Request for Interchange [Archive]	RFI	5/2/2006	3/16/2007	A collection of data as defined in the NAESB RFI Datasheet, to be submitted to the Interchange Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority.
Reserve Sharing Group [Archive]		2/8/2005	3/16/2007	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.
Resource Planner [Archive]		2/8/2005	3/16/2007	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.
Response Rate [Archive]		2/8/2005	3/16/2007	The Ramp Rate that a generating unit can achieve under normal operating conditions expressed in megawatts per minute (MW/Min).

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Right-of-Way (ROW) [Archive]		2/7/2006	3/16/2007	A corridor of land on which electric lines may be located. The Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Scenario [Archive]		2/7/2006	3/16/2007	Possible event.
Schedule [Archive]		2/8/2005	3/16/2007	(Verb) To set up a plan or arrangement for an Interchange Transaction. (Noun) An Interchange Schedule.
Scheduled Frequency [Archive]		2/8/2005	3/16/2007	60.0 Hertz, except during a time correction.
Scheduling Entity [Archive]		2/8/2005	3/16/2007	An entity responsible for approving and implementing Interchange Schedules.
Scheduling Path [Archive]		2/8/2005	3/16/2007	The Transmission Service arrangements reserved by the Purchasing-Selling Entity for a Transaction.
Sending Balancing Authority [Archive]		2/8/2005	3/16/2007	The Balancing Authority exporting the Interchange.
Sink Balancing Authority [Archive]		2/8/2005	3/16/2007	The Balancing Authority in which the load (sink) is located for an Interchange Transaction. (This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)
Source Balancing Authority [Archive]		2/8/2005	3/16/2007	The Balancing Authority in which the generation (source) is located for an Interchange Transaction. (This will also be a Sending Balancing Authority for the resulting Interchange Schedule.)

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Special Protection System (Remedial Action Scheme) [Archive]		2/8/2005	3/16/2007	An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.
Spinning Reserve [Archive]		2/8/2005	3/16/2007	Unloaded generation that is synchronized and ready to serve additional demand.
Stability [Archive]		2/8/2005	3/16/2007	The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances.
Stability Limit [Archive]		2/8/2005	3/16/2007	The maximum power flow possible through some particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers.
Supervisory Control and Data Acquisition [Archive]	SCADA	2/8/2005	3/16/2007	A system of remote control and telemetry used to monitor and control the transmission system.
Supplemental Regulation Service [Archive]		2/8/2005	3/16/2007	A method of providing regulation service in which the Balancing Authority providing the regulation service receives a signal representing all or a portion of the other Balancing Authority's ACE.
Surge [Archive]		2/8/2005	3/16/2007	A transient variation of current, voltage, or power flow in an electric circuit or across an electric system.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Sustained Outage [Archive]		2/7/2006	3/16/2007	The deenergized condition of a transmission line resulting from a fault or disturbance following an unsuccessful automatic reclosing sequence and/or unsuccessful manual reclosing procedure.
System [Archive]		2/8/2005	3/16/2007	A combination of generation, transmission, and distribution components.
System Operating Limit [Archive]		2/8/2005	3/16/2007	The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings) • Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits) • Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability) • System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)
System Operator [Archive]		2/8/2005	3/16/2007	An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Telemetering [Archive]		2/8/2005	3/16/2007	The process by which measurable electrical quantities from substations and generating stations are instantaneously transmitted to the control center, and by which operating commands from the control center are transmitted to the substations and generating stations.
Thermal Rating [Archive]		2/8/2005	3/16/2007	The maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it sags to the point that it violates public safety requirements.
Tie Line [Archive]		2/8/2005	3/16/2007	A circuit connecting two Balancing Authority Areas.
Tie Line Bias [Archive]		2/8/2005	3/16/2007	A mode of Automatic Generation Control that allows the Balancing Authority to 1.) maintain its Interchange Schedule and 2.) respond to Interconnection frequency error.
Time Error [Archive]		2/8/2005	3/16/2007	The difference between the Interconnection time measured at the Balancing Authority(ies) and the time specified by the National Institute of Standards and Technology. Time error is caused by the accumulation of Frequency Error over a given period.
Time Error Correction [Archive]		2/8/2005	3/16/2007	An offset to the Interconnection's scheduled frequency to return the Interconnection's Time Error to a predetermined value.
TLR Log [Archive]		2/8/2005	3/16/2007	Report required to be filed after every TLR Level 2 or higher in a specified format. The NERC IDC prepares the report for review by the issuing Reliability Coordinator. After approval by the issuing Reliability Coordinator, the report is electronically filed in a public area of the NERC Web site.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Total Flowgate Capability [Archive]	TFC	08/22/2008	11/24/2009	The maximum flow capability on a Flowgate, is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated System Operating Limit.
Total Transfer Capability [Archive]	TTC	2/8/2005	3/16/2007	The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.
Transaction [Archive]		2/8/2005	3/16/2007	See Interchange Transaction.
Transfer Capability [Archive]		2/8/2005	3/16/2007	The measure of the ability of interconnected electric systems to move or transfer power *in a reliable manner* from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from "Area A" to "Area B" is *not g*enerally equal to the transfer capability from "Area B" to "Area A."
Transfer Distribution Factor [Archive]		2/8/2005	3/16/2007	See Distribution Factor.
Transmission [Archive]		2/8/2005	3/16/2007	An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Transmission Constraint [Archive]		2/8/2005	3/16/2007	A limitation on one or more transmission elements that may be reached during normal or contingency system operations.
Transmission Customer [Archive]		2/8/2005	3/16/2007	1. Any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service. 2. Any of the following responsible entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.
Transmission Line [Archive]		2/7/2006	3/16/2007	A system of structures, wires, insulators and associated hardware that carry electric energy from one point to another in an electric power system. Lines are operated at relatively high voltages varying from 69 kV up to 765 kV, and are capable of transmitting large quantities of electricity over long distances.
Transmission Operator [Archive]		2/8/2005	3/16/2007	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.
Transmission Operator Area [Archive]		08/22/2008	11/24/2009	The collection of Transmission assets over which the Transmission Operator is responsible for operating.
Transmission Owner [Archive]		2/8/2005	3/16/2007	The entity that owns and maintains transmission facilities.
Transmission Planner [Archive]		2/8/2005	3/16/2007	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Transmission Reliability Margin [Archive]	TRM	2/8/2005	3/16/2007	The amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.
Transmission Reliability Margin Implementation Document [Archive]	TRMID	08/22/2008	11/24/2009	A document that describes the implementation of a Transmission Reliability Margin methodology, and provides information related to a Transmission Operator's calculation of TRM.
Transmission Service [Archive]		2/8/2005	3/16/2007	Services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.
Transmission Service Provider [Archive]		2/8/2005	3/16/2007	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.
Vegetation [Archive]		2/7/2006	3/16/2007	All plant material, growing or not, living or dead.
Vegetation Inspection [Archive]		2/7/2006	3/16/2007	The systematic examination of a transmission corridor to document vegetation conditions.
Wide Area [Archive]		2/8/2005	3/16/2007	The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.

ReliabilityFirst Regional Definitions

The following definitions were developed for use in ReliabilityFirst Regional Standards.

RFC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Resource Adequacy [Archive]		08/05/2009		The ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses)
Net Internal Demand [Archive]		08/05/2009		Total of all end-use customer demand and electric system losses within specified metered boundaries, less Direct Control Management and Interruptible Demand
Peak Period [Archive]		08/05/2009		A period consisting of two (2) or more calendar months but less than seven (7) calendar months, which includes the period during which the responsible entity's annual peak demand is expected to occur
Year One [Archive]		08/05/2009		The planning year that begins with the upcoming annual Peak Period

WECC Regional Definitions

The following definitions were developed for use in WECC Regional Standards.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Area Control Error† [Archive]	ACE	3/12/2007	6/8/2007	Means the instantaneous difference between net actual and scheduled interchange, taking into account the effects of Frequency Bias including correction for meter error.
Automatic Generation Control† [Archive]	AGC	3/12/2007	6/8/2007	Means equipment that automatically adjusts a Control Area's generation from a central location to maintain its interchange schedule plus Frequency Bias.
Automatic Time Error Correction [Archive]		3/26/2008	5/21/2009	A frequency control automatic action that a Balancing Authority uses to offset its frequency contribution to support the Interconnection's scheduled frequency.
Average Generation† [Archive]		3/12/2007	6/8/2007	Means the total MWh generated within the Balancing Authority Operator's Balancing Authority Area during the prior year divided by 8760 hours (8784 hours if the prior year had 366 days).
Business Day† [Archive]		3/12/2007	6/8/2007	Means any day other than Saturday, Sunday, or a legal public holiday as designated in section 6103 of title 5, U.S. Code.
Disturbance† [Archive]		3/12/2007	6/8/2007	Means (i) any perturbation to the electric system, or (ii) the unexpected change in ACE that is caused by the sudden loss of generation or interruption of load.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Extraordinary Contingency† [Archive]		3/12/2007	6/8/2007	Shall have the meaning set out in Excuse of Performance, section B.4.c. language in section B.4.c: *means any act of God, actions by a non-affiliated third party, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, earthquake, explosion, accident to or breakage, failure or malfunction of machinery or equipment, or any other cause beyond the Reliability Entity's reasonable control; provided that prudent industry standards (e.g. maintenance, design, operation) have been employed; and provided further that no act or cause shall be considered an Extraordinary Contingency if such act or cause results in any contingency contemplated in any WECC Reliability Standard (e.g., the "Most Severe Single Contingency" as defined in the WECC Reliability Criteria or any lesser contingency).*
Frequency Bias† [Archive]		3/12/2007	6/8/2007	Means a value, usually given in megawatts per 0.1 Hertz, associated with a Control Area that relates the difference between scheduled and actual frequency to the amount of generation required to correct the difference.
Generating Unit Capability† [Archive]		3/12/2007	6/8/2007	Means the MVA nameplate rating of a generator.
Non-spinning Reserve† [Archive]		3/12/2007	6/8/2007	Means that Operating Reserve not connected to the system but capable of serving demand within a specified time, or interruptible load that can be removed from the system in a specified time.
Normal Path Rating† [Archive]		3/12/2007	6/8/2007	Is the maximum path rating in MW that has been demonstrated to WECC through study results or actual operation, whichever is greater. For a path with transfer capability limits that vary seasonally, it is the maximum of all the seasonal values.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Operating Reserve† [Archive]		3/12/2007	6/8/2007	Means that capability above firm system demand required to provide for regulation, load-forecasting error, equipment forced and scheduled outages and local area protection. Operating Reserve consists of Spinning Reserve and Nonspinning Reserve.
Operating Transfer Capability Limit† [Archive]	OTC	3/12/2007	6/8/2007	Means the maximum value of the most critical system operating parameter(s) which meets: (a) precontingency criteria as determined by equipment loading capability and acceptable voltage conditions, (b) transient criteria as determined by equipment loading capability and acceptable voltage conditions, (c) transient performance criteria, and (d) post-contingency loading and voltage criteria.
Primary Inadvertent Interchange [Archive]		3/26/2008	5/21/2009	The component of area (n) inadvertent interchange caused by the regulating deficiencies of the area (n).
Secondary Inadvertent Interchange [Archive]		3/26/2008	5/21/2009	The component of area (n) inadvertent interchange caused by the regulating deficiencies of area (i).
Spinning Reserve† [Archive]		3/12/2007	6/8/2007	Means unloaded generation which is synchronized and ready to serve additional demand. It consists of Regulating reserve and Contingency reserve (as each are described in Sections B.a.i and ii).
WECC Table 2† [Archive]		3/12/2007	6/8/2007	Means the table maintained by the WECC identifying those transfer paths monitored by the WECC regional Reliability coordinators. As of the date set out therein, the transmission paths identified in Table 2 are as listed in Attachment A to this Standard.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Functionally Equivalent Protection System [Archive]	FEPS	10/29/2008		A Protection System that provides performance as follows: • Each Protection System can detect the same faults within the zone of protection and provide the clearing times and coordination needed to comply with all Reliability Standards. • Each Protection System may have different components and operating characteristics.
Functionally Equivalent RAS [Archive]	FERAS	10/29/2008		A Remedial Action Scheme ("RAS") that provides the same performance as follows: • Each RAS can detect the same conditions and provide mitigation to comply with all Reliability Standards. • Each RAS may have different components and operating characteristics.
Security-Based Misoperation [Archive]		10/29/2008		A Misoperation caused by the incorrect operation of a Protection System or RAS. Security is a component of reliability and is the measure of a device's certainty not to operate falsely.
Dependability-Based Misoperation [Archive]		10/29/2008		Is the absence of a Protection System or RAS operation when intended. Dependability is a component of reliability and is the measure of a device's certainty to operate when required.
Commercial Operation [Archive]		10/29/2008		Achievement of this designation indicates that the Generator Operator or Transmission Operator of the synchronous generator or synchronous condenser has received all approvals necessary for operation after completion of initial start-up testing.
Qualified Transfer Path Curtailment Event [Archive]		2/10/2009		Each hour that a Transmission Operator calls for Step 4 or higher for one or more consecutive hours (See Attachment 1 IRO-006-WECC-1) during which the curtailment tool is functional.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Relief Requirement [Archive]		2/10/2009		The expected amount of the unscheduled flow reduction on the Qualified Transfer Path that would result by curtailing each Sink Balancing Authority's Contributing Schedules by the percentages listed in the columns of WECC Unscheduled Flow Mitigation Summary of Actions Table in Attachment 1 WECC IRO-006-WECC-1.
Transfer Distribution Factor [Archive]	TDF	2/10/2009		The percentage of USF that flows across a Qualified Transfer Path when an Interchange Transaction (Contributing Schedule) is implemented. [See the WECC Unscheduled Flow Mitigation Summary of Actions Table (Attachment 1 WECC IRO-006-WECC-1).]
Contributing Schedule [Archive]		2/10/2009		A Schedule not in the Qualified Transfer Path between a Source Balancing Authority and a Sink Balancing Authority that contributes unscheduled flow across the Qualified Transfer Path.
Qualified Transfer Path [Archive]		2/10/2009		A transfer path designated by the WECC Operating Committee as being qualified for WECC unscheduled flow mitigation.
Qualified Controllable Device [Archive]		2/10/2009		A controllable device installed in the Interconnection for controlling energy flow; the WECC Operating Committee has approved using the device for controlling the USF on the Qualified Transfer Paths.

Endnotes

[†] FERC approved the WECC Tier One Reliability Standards in the Order Approving Regional Reliability Standards for the Western Interconnection and Directing Modifications, 119 FERC ¶ 61,260 (June 8, 2007). In that Order, FERC directed WECC to address the inconsistencies between the regional definitions and the NERC Glossary in developing permanent replacement standards. The replacement standards designed to address the shortcomings were filed with FERC in 2009.

Exhibit D

Current Critical Infrastructure Protection Implementation Plan for Version 2

(Revised) Implementation Plan for Cyber Security Standards
CIP-002-1 through CIP-009-1

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

(Revised) Implementation Plan for Cyber Security Standards CIP-002-1 through CIP-009-1

The intent of the proposed Cyber Security Standards is to ensure that all entities responsible for the reliability of the Bulk Electric Systems in North America identify and protect Critical Cyber Assets that control or could impact the reliability of the Bulk Electric Systems. This implementation plan is based on the following assumptions:

- Cyber Security Standards CIP-002-1, CIP-003-1, CIP-004-1, CIP-005-1, CIP-006-1, CIP-007-1, CIP-008-1, and CIP-009-1 are approved by the ballot body and the NERC Board of Trustees no later than May 2, 2006.
- Responsible Entities have registered.
- Cyber Security Standards CIP-002-1 through CIP-009-1 become effective June 1, 2006.

To provide time for Responsible Entities to examine their policies and procedures, to assemble the necessary documentation, and to meet the requirements of these standards, compliance assessment will begin in 2007. The table below lists specific periods by which applicable Responsible Entities must be Auditably Compliant (defined below) with each requirement.

Implementation Schedule

The following tables identify when Responsible Entities must Begin Work (BW) to become compliant with a requirement, Substantially Compliant (SC) with a requirement, Compliant (C) with a requirement, and Auditably Compliant (AC) with a requirement. Begin Work means a Responsible Entity has developed and approved a plan to address the requirements of a standard, has begun to identify and plan for necessary resources, and has begun implementing the requirements. Substantially Compliant means an entity is well along in its implementation to becoming compliant with a requirement, but is not yet fully compliant. Compliant means the entity meets the full intent of the requirements and is beginning to maintain required "data," "documents," "documentation," "logs," and "records." Auditably Compliant means the entity meets the full intent of the requirement and can demonstrate compliance to an auditor, including 12-calendar-months of auditable "data," "documents," "documentation," "logs," and "records." Per the standards, each subsequent compliance-monitoring period will require the previous full calendar year of such material.

The implementation plan is broken into four tables as described below. The tables specify a compliance schedule for NERC Functional Model "entities," referred to as Responsible Entities in CIP-002 through CIP-009 standards. For organizations that are multiple Functional Model entities, each such Functional Model entity is required to demonstrate progress towards compliance according to the applicable table.

For instance, Table 1 applies to the Energy Control Center (Balancing Authority and Transmission Operator who were required to self-certify under Urgent Action Standard 1200) while the same organization's Generating Plant function (Generation Owners), would use Table 3. Likewise, this same organization's Transmission Provider function would use Table 2.

Table 1 defines the implementation schedule for Balancing Authorities (BA), Transmission Operators (TOP), and Reliability Coordinators (RC) that were required to self-certify compliance to NERC's Urgent Action Cyber Security Standard 1200 (UA 1200).

Table 2 defines the implementation schedule for Transmission Service Providers (TSP), those Transmission Operators (TOP) and Balancing Authorities that were not required to self-certify compliance to UA 1200, NERC, and the Regional Reliability Organizations.

Table 3 defines the implementation schedule for Responsible Entities required to register during 2006.

Table 4 defines the implementation schedule for Responsible Entities registering to a Functional Model function in 2007 and thereafter.

Table 1
Compliance Schedule for Standards CIP-002-1 through CIP-009-1
Balancing Authorities and Transmission Operators Required to Self-certify to UA Standard 1200, and Reliability Coordinators

	End of 2nd Qtr 2007		End of 2nd Qtr 2008		End of 2nd Qtr 2009		End of 2nd Qtr 2010	
Requirement	System Control Center	Other Facilities	System Control Center	Other Facilities	System Control Center	Other Facilities	System Control Center	Other Facilities
Standard CIP-002-1 — Critical Cyber Assets								
R1	SC	BW	C	SC	AC	C	AC	AC
R2	SC	BW	C	SC	AC	C	AC	AC
R3	SC	BW	C	SC	AC	C	AC	AC
R4	BW	BW	SC	SC	C	C	AC	AC
Standard CIP-003-1 — Security Management Controls								
R1	SC	BW	C	SC	AC	AC	AC	AC
R2	SC	SC	C	C	AC	AC	AC	AC
R3	SC	BW	C	SC	AC	C	AC	AC
R4	BW	BW	SC	SC	C	C	AC	AC
R5	BW	BW	SC	SC	C	C	AC	AC

Table 1 (cont.)

	End of 2nd Qtr 2007		End of 2nd Qtr 2008		End of 2nd Qtr 2009		End of 2nd Qtr 2010	
Requirement	System Control Center	Other Facilities	System Control Center	Other Facilities	System Control Center	Other Facilities	System Control Center	Other Facilities
R6	BW	BW	SC	SC	C	C	AC	AC
Standard CIP-004-1 — Personnel & Training								
R1	BW	BW	SC	SC	C	C	AC	AC
R2	SC	BW	C	SC	AC	C	AC	AC
R3	SC	BW	C	SC	AC	C	AC	AC
R4	SC	BW	C	SC	AC	C	AC	AC
Standard CIP-005-1 — Electronic Security								
R1	BW	BW	SC	SC	C	C	AC	AC
R2	BW	BW	SC	SC	C	C	AC	AC
R3	BW	BW	SC	SC	C	C	AC	AC
R4	BW	BW	SC	SC	C	C	AC	AC
R5	BW	BW	SC	SC	C	C	AC	AC
Standard CIP-006-1 — Physical Security								
R1	BW	BW	SC	SC	C	C	AC	AC
R2	BW	BW	SC	SC	C	C	AC	AC
R3	BW	BW	SC	SC	C	C	AC	AC
R4	BW	BW	SC	SC	C	C	AC	AC
R5	BW	BW	SC	SC	C	C	AC	AC
R6	BW	BW	SC	SC	C	C	AC	AC
Standard CIP-007-1 — Systems Security Management								
R1	SC	BW	C	SC	AC	C	AC	AC
R2	BW	BW	SC	SC	C	C	AC	AC
R3	BW	BW	SC	SC	C	C	AC	AC
R4	BW	BW	SC	SC	C	C	AC	AC
R5	BW	BW	SC	SC	C	C	AC	AC

Table 1 (cont.)

	End of 2nd Qtr 2007		End of 2nd Qtr 2008		End of 2nd Qtr 2009		End of 2nd Qtr 2010	
Requirement	System Control Center	Other Facilities	System Control Center	Other Facilities	System Control Center	Other Facilities	System Control Center	Other Facilities
R6	BW	BW	SC	SC	C	C	AC	AC
R7	BW	BW	SC	SC	C	C	AC	AC
R8	BW	BW	SC	SC	C	C	AC	AC
R9	BW	BW	SC	SC	C	C	AC	AC
Standard CIP-008-1 — Incident Reporting and Response Planning								
R1	SC	BW	C	SC	AC	C	AC	AC
R2	BW	BW	SC	SC	C	C	AC	AC
Standard CIP-009-1 — Recovery Plans								
R1	SC	BW	C	SC	AC	C	AC	AC
R2	SC	BW	C	SC	AC	C	AC	AC
R3	BW	BW	SC	SC	C	C	AC	AC
R4	BW	BW	SC	SC	C	C	AC	AC
R5	BW	BW	SC	SC	C	C	AC	AC

Table 2
Compliance Schedule for Standards CIP-002-1 through CIP-009-1
Transmission Providers, those Balancing Authorities and Transmission Operators
Not Required to Self-certify to UA Standard 1200,
NERC, and Regional Reliability Organizations.

	End of 2nd Qtr 2007	End of 2nd Qtr 2008	End of 2nd Qtr 2009	End of 2nd Qtr 2010
Requirement	All Facilities	All Facilities	All Facilities	All Facilities
Standard CIP-002-1 — Critical Cyber Assets				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
Standard CIP-003-1 — Security Management Controls				
R1	BW	SC	C	AC
R2	SC	C	AC	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
R5	BW	SC	C	AC
R6	BW	SC	C	AC
Standard CIP-004-1 — Personnel & Training				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
Standard CIP-005-1 — Electronic Security				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
R5	BW	SC	C	AC

Table 2 (cont.)

Standard CIP-006-1 — Physical Security				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
R5	BW	SC	C	AC
R6	BW	SC	C	AC
	Standard CIP-007-1 — Systems Security Management			
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
R5	BW	SC	C	AC
R6	BW	SC	C	AC
R7	BW	SC	C	AC
R8	BW	SC	C	AC
R9	BW	SC	C	AC
Standard CIP-008-1 — Incident Reporting and Response Planning				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
Standard CIP-009-1 — Recovery Plans				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
R5	BW	SC	C	AC

Table 3
Compliance Schedule for Standards CIP-002-1 through CIP-009-1
Interchange Authorities, Transmission Owners, Generator Owners, Generator Operators, and Load-Serving Entities

	December 31, 2006	December 31, 2008	December 31, 2009	December 31, 2010
Requirement	All Facilities	All Facilities	All Facilities	All Facilities
Standard CIP-002-1 — Critical Cyber Assets				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
Standard CIP-003-1 — Security Management Controls				
R1	BW	SC	C	AC
R2	SC	C	AC	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
R5	BW	SC	C	AC
R6	BW	SC	C	AC
Standard CIP-004-1 — Personnel & Training				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
Standard CIP-005-1 — Electronic Security				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
R5	BW	SC	C	AC

Table 3 (cont.)

	December 31, 2006	December 31, 2008	December 31, 2009	December 31, 2010
Requirement	All Facilities	All Facilities	All Facilities	All Facilities
Standard CIP-006-1 — Physical Security				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
R5	BW	SC	C	AC
R6	BW	SC	C	AC
Standard CIP-007-1 — Systems Security Management				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
R5	BW	SC	C	AC
R6	BW	SC	C	AC
R7	BW	SC	C	AC
R8	BW	SC	C	AC
R9	BW	SC	C	AC
Standard CIP-008-1 — Incident Reporting and Response Planning				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
Standard CIP-009-1 — Recovery Plans				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC

Table 3 (cont.)

	December 31, 2006	December 31, 2008	December 31, 2009	December 31, 2010
Requirement	All Facilities	All Facilities	All Facilities	All Facilities
R5	BW	SC	C	AC

Table 4
Compliance Schedule for Standards CIP-002-1 through CIP-009-1
For Entities Registering in 2007 and Thereafter.

	Upon Registration	Registration + 12 months	Registration + 24 months	Registration + 36 months
Requirement	All Facilities	All Facilities	All Facilities	All Facilities
Standard CIP-002-1 — Critical Cyber Assets				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
Standard CIP-003-1 — Security Management Controls				
R1	BW	SC	C	AC
R2	SC	C	AC	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
R5	BW	SC	C	AC
R6	BW	SC	C	AC
Standard CIP-004-1 — Personnel & Training				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC

Table 4 (cont.)

	Upon Registration	Registration + 12 months	Registration + 24 months	Registration + 36 months
Requirement	All Facilities	All Facilities	All Facilities	All Facilities
Standard CIP-005-1 — Electronic Security				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
R5	BW	SC	C	AC
Standard CIP-006-1 — Physical Security				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
R5	BW	SC	C	AC
R6	BW	SC	C	AC
Standard CIP-007-1 — Systems Security Management				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
R5	BW	SC	C	AC
R6	BW	SC	C	AC
R7	BW	SC	C	AC
R8	BW	SC	C	AC
R9	BW	SC	C	AC

Table 4 (cont.)

	Upon Registration	Registration + 12 months	Registration + 24 months	Registration + 36 months
Requirement	All Facilities	All Facilities	All Facilities	All Facilities
Standard CIP-008-1 — Incident Reporting and Response Planning				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
Standard CIP-009-1 — Recovery Plans				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
R5	BW	SC	C	AC

Implementation Plan for Newly Identified Critical Cyber Assets and Newly Registered Entities

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan for Newly Identified Critical Cyber Assets and Newly Registered Entities

This Implementation Plan applies to Cyber Security Standards CIP-002-2 through CIP-009-2 and CIP-002-3 through CIP-009-3.

The term "Compliant" in this Implementation Plan is used in the same way that it is used in the (Revised) Implementation Plan for Cyber Security Standards CIP-002-1 through CIP-009-1: "Compliant means the entity meets the full intent of the requirements and is beginning to maintain required "data," "documents," "documentation," "logs," and "records."

The Implementation Plan for Newly Identified Critical Cyber Assets and Newly Registered Entities (hereafter referred to as 'this Implementation Plan') defines the schedule for compliance with the requirements of either Version 2 or Version 3 of the NERC Reliability Standards CIP-003 through CIP-009[1] on Cyber Security for (a) newly Registered Entities and (b) newly identified Critical Cyber Assets by an existing Registered Entity after the Registered Entity's applicable *Compliant* milestone date has already passed.

There are no *Compliant* milestones specified in Table 2 of this Implementation Plan for compliance with NERC Standard CIP-002, since all Responsible Entities are required to be compliant with NERC Standard CIP-002 based on a previous or existing version-specific Implementation Plan[2].

Implementation Plan for Newly Identified Critical Cyber Assets

This Implementation Plan defines the *Compliant* milestone dates in terms of the number of calendar months after designation of the newly identified Cyber Asset as a Critical Cyber Asset, following the process stated in NERC Standard CIP-002. These *Compliant* Milestone dates are included in Table 2 of this Implementation Plan.

The term 'newly identified Critical Cyber Asset' is used when a Registered Entity has been required to be compliant with NERC Reliability Standard CIP-002 for at least one application of the risk-based Critical Asset identification methodology. Upon a subsequent annual application of the risk-based Critical Asset identification method in compliance with requirements of NERC Reliability Standard CIP-002, either a previously non-critical asset has now been determined to be a Critical Asset, and its associated essential Cyber Assets have now been determined to be Critical Cyber Assets, or Cyber Assets associated with an existing Critical Asset have now been identified as Critical Cyber Assets. These newly determined Critical Cyber Assets are referred to in this Implementation Plan as 'newly identified Critical Cyber Assets'.

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[1] The reference in this Implementation Plan to 'NERC Standards CIP-002 through CIP-009' is to all versions (i.e., Version 1, Version 2, and Version 3) of those standards. If reference to only a specific version of a standard or set of standards is required, a version number (i.e., '-1', '-2', or '-3') will be applied to that particular reference.

[2] Each version of NERC Standards CIP-002 through CIP-009 has its own implementation plan and/or designated effective date when approved by the NERC Board of Trustees or appropriate government authorities.

Table 2 defines the *Compliant* milestone dates for all of the requirements defined in the NERC Reliability Standards CIP-003 through CIP-009 in terms of the number of months following the designation of a newly identified Critical Cyber Asset a Responsible Entity has to become compliant with that requirement. Table 2 further defines the *Compliant* milestone dates for the NERC Reliability Standards CIP-003 through CIP-009 based on the 'Milestone Category', which characterizes the scenario by which the Critical Cyber Asset was identified.

For those NERC Reliability Standard requirements that have an entry in Table 2 annotated as *existing*, the designation of a newly identified Critical Cyber Asset has no bearing on its *Compliant* milestone date, since Responsible Entities are required to be compliant with those requirements as part of an existing CIP compliance implementation program[3], independent of the determination of a newly identified Critical Cyber Asset.

In all cases where a *Compliant* milestone is specified in Table 2 (i.e., not annotated as *existing*), the Responsible Entity is expected to have all audit records required to demonstrate compliance (i.e., to be 'Auditably Compliant'[4]) one year following the *Compliant* milestone listed in this Implementation Plan.

Implementation Plan for Newly Registered Entities

A newly Registered Entity is one that has registered with NERC in April 2008 or thereafter and has not previously undergone the NERC CIP-002 Critical Asset Identification Process. As such, it is presumed that no Critical Cyber Assets have been previously identified and no previously established CIP compliance implementation program exists. The *Compliant* milestone schedule defined in Table 3 of this Implementation Plan document defines the applicable compliance schedule for the newly Registered Entity to the NERC Reliability Standards CIP-002 through CIP-009.

Implementation Milestone Categories

The Implementation Plan milestones and schedule to achieve compliance with the NERC Reliability Standards CIP-002 through CIP-009 for newly identified Critical Cyber Assets and newly Registered Entities are provided in Tables 2 and 3 of this Implementation Plan document.

The Implementation Plan milestones defined in Table 2 are divided into categories based on the scenario by which the Critical Cyber Asset was newly identified. The scenarios that represent the milestone categories are briefly defined as follows:

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[3] The term 'CIP compliance implementation program' is used to mean that a Responsible Entity has programs and procedures in place to comply with the requirements of NERC Reliability Standards CIP-003 through CIP-009 for Critical Cyber Assets. All entities are required to be Compliant with NERC Reliability Standard CIP-002 according to a version specific Implementation Plan.

[4] The term 'Auditably Compliant' (AC) used in this Implementation Plan for newly identified Critical Cyber Assets and newly Registered Entities means "the entity meets the full intent of the requirement and can demonstrate compliance to an auditor, including 12-calendar-months of auditable 'data,' 'documents,' 'documentation,' 'logs,' and 'records.'" [see (Revised) Implementation Plan for Cyber Security Standards CIP-002-1 through CIP-009-1]. Since in all cases, the 'Auditably Compliant' dates are one calendar year following the 'Compliant' (C) date, the Auditably Compliant dates are not specified in this plan. The terms 'Begin Work' (BW) and 'Substantially Compliant' (SC) used in the Version 1 Implementation Plan are no longer used, and therefore are not referenced in this Implementation Plan.

1. A Cyber Asset is designated as the first Critical Cyber Asset by a Responsible Entity according to the process defined in NERC Reliability Standard CIP-002. No existing CIP compliance implementation program for Standards CIP-003 through CIP-009 is assumed to exist at the Responsible Entity. This category would also apply in the case of a newly Registered Entity (not resulting from a merger or acquisition), if any Critical Cyber Asset was identified according to the process defined in NERC Reliability Standard CIP-002.

2. An existing Cyber Asset becomes subject to the NERC Reliability Standards CIP-003 through CIP-009, *not due to a planned change in the electric system or Cyber Assets by the Responsibility Entity* (unplanned changes due to emergency response are handled separately). A CIP compliance implementation program already exists at the Responsible Entity.

3. A new or existing Cyber Asset becomes subject to the NERC Reliability Standards CIP-003 through CIP-009, *due to a planned change in the electric system or Cyber Assets by the Responsibility Entity*. A CIP compliance implementation program already exists at the Responsible Entity.

Note that the phrase 'Cyber Asset becomes subject to the NERC Reliability Standards CIP-003 through CIP-009' as used above applies to all Critical Cyber Assets, as well as other (non-critical) Cyber Assets within an Electronic Security Perimeter that must comply with the applicable requirements of NERC Reliability Standards CIP-003 through CIP-009.

Note also that the phrase 'planned change in the electric system or Cyber Assets by the Responsible Entity' refers to any changes of the electric system or Cyber Assets which were planned and implemented by the Responsible Entity.

For example, if a particular transmission substation has been designated a Critical Asset, but there are no Cyber Assets at that transmission substation, then there are no Critical Cyber Assets associated with the Critical Asset at the transmission substation. If an automation modernization activity is performed at that same transmission substation, whereby Cyber Assets are installed that meet the requirements as Critical Cyber Assets, then those newly identified Critical Cyber Assets have been implemented as a result of a planned change of the Critical Asset, and must therefore be in Compliance with NERC Reliability Standards CIP-003 through CIP-009 upon the commissioning of the modernized transmission substation.(Compliant Upon Commisioning below.)

If, however, a particular transmission substation with Cyber Assets does not meet the criteria as a Critical Asset, its associated Cyber Assets are *not* Critical Cyber Assets, as described in the requirements of NERC Reliability Standard CIP-002. Further, if an action is performed outside of that particular transmission substation, such as a transmission line is constructed or retired, a generation plant is modified changing its rated output, or load patterns shift resulting in corresponding transmission flow changes through that transmission substation, that unchanged transmission substation may become a Critical Asset based on established criteria or thresholds in the Responsible Entity's existing risk-based Critical Asset identification method (required by CIP-002 R1). (Note that the actions that cause the change in power flows may have been performed by a neighboring entity without the full knowledge of the affected Responsible

Entity.) Application of that risk-based Critical Asset Identification process is required annually (by CIP-002 R2), and, as such, it may not be immediately apparent that that particular transmission substation has become a Critical Asset until after the required annual application of the identification methodology. Category 1 Scenario below applies if there was no pre-existing Critical Cyber Assets subject to the standard, and therefore, there was no existing full CIP program. Category 2 Scenario below applies if a CIP program for existing Critical Cyber Assets has been implemented for that Registered Entity.

Figure 1 shows an overall process flow for determining which milestone category a Critical Cyber Asset identification scenario must follow. Following the figure is a more detailed description of each category.

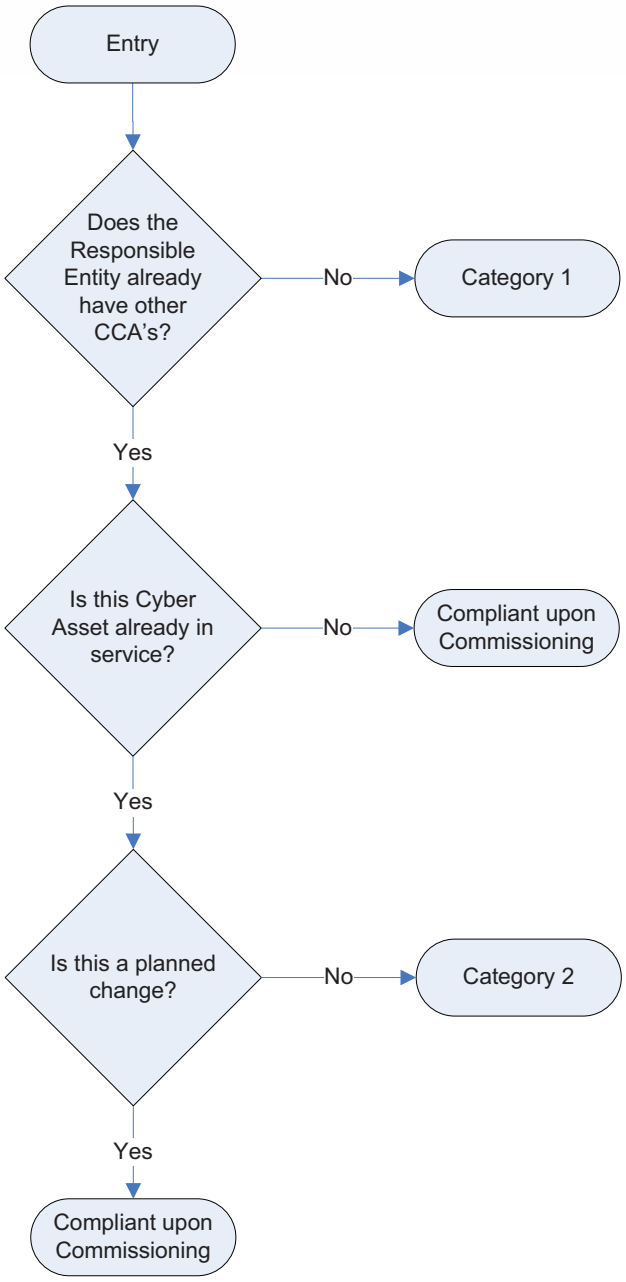

Figure 1: Category Selection Process Flow

Implementation Milestone Categories and Schedules

Based on the Critical Cyber Asset identification scenarios identified above, the implementation milestone categories and schedules for those scenarios are defined and distinguished below for entities with existing registrations in the NERC Compliance Registry. Scenarios resulting from the formation of newly Registered Entities are discussed in a subsequent section of this Implementation Plan.

1. **Category 1 Scenario**: A Responsible Entity that previously has undergone the NERC Reliability Standard CIP-002 Critical Asset identification process for at least one annual review and approval period without ever having previously identified any Critical Cyber Assets associated with Critical Assets, but has now identified one or more Critical Cyber Assets. As such, it is presumed that the Responsible Entity does not have a previously established CIP compliance implementation program.

   The *Compliant* milestones defined for this Category are defined in Table 2 (Milestone Category 1) of this Implementation Plan document.

2. **Category 2 Scenario**: A Responsible Entity has an established NERC Reliability Standards CIP compliance implementation program in place, and has newly identified additional existing Cyber Assets that need to be added to its Critical Cyber Asset list and therefore subject to compliance to the NERC Reliability CIP Standards due to unplanned changes in the electric system or the Cyber Assets. Since the Responsible Entity already has a CIP compliance implementation program, it needs only to implement the NERC Reliability CIP standards for the newly identified Critical Cyber Asset(s). The existing Critical Cyber Assets may remain in service while the relevant requirements of the NERC Reliability CIP Standards are implemented for the newly identified Critical Cyber Asset(s).

   This category applies only when additional in-service Critical Cyber Assets or applicable other Cyber Assets are *identified* as Critical Cyber Assets according to the process defined in the NERC Reliability Standard CIP-002. This category does not apply if the newly identified Critical Cyber Assets are not already in-service, or if the additional Critical Cyber Assets resulted from planned changes to the electric system or the Cyber Assets. In the case where the Critical Cyber Asset is not in service, the Responsible Entity must be compliant with the NERC Reliability Standards CIP-003 through CIP-009 upon commissioning of the new cyber or electric system assets (see "Compliant upon Commissioning" below).

   Unplanned changes due to emergency response, disaster recovery or system restoration activities are handled separately (see "Disaster Recovery and Restoration Activities" below).

3. **Compliant upon Commissioning**: When a Responsible Entity has an established NERC Reliability Standards CIP compliance implementation program and implements a new or replacement Critical Cyber Asset associated with a previously identified or newly

constructed Critical Asset, the Critical Cyber Asset shall be compliant when it is commissioned or activated. This scenario shall apply for the following scenarios:

a) 'Greenfield' construction of an asset that will be declared a Critical Asset (based on planning or impact studies) upon its commissioning or activation
b) Replacement or upgrade of an existing Critical Cyber Asset (or other Cyber Asset within an Electronic Security Perimeter) associated with a previously identified Critical Asset
c) Upgrade or replacement of an existing non-cyber asset with a Cyber Asset (e.g., replacement of an electro-mechanical relay with a microprocessor-based relay) associated with a previously identified Critical Asset and meets other criteria for identification as a Critical Cyber Asset
d) Planned addition of:
    i. a Critical Cyber Asset, or,
    ii. another (i.e., non-critical) Cyber Asset within an established Electronic Security Perimeter

In summary, this scenario applies in any case where a Critical Cyber Asset or applicable other Cyber Asset is being added or modified associated with an existing or new Critical Asset and where that Entity has an established NERC Reliability Standard CIP compliance implementation program.

A special case of a 'greenfield' construction exists where the asset under construction was planned and construction started under the assumption that the asset would not be a Critical Asset. During construction, conditions changed, and the asset will now be a Critical Asset upon its commissioning. In this case, the Responsible Entity must follow the Category 2 milestones from the date of the determination that the asset is a Critical Asset.

Since the assets must be compliant with the NERC Reliability Standards CIP-003 through CIP-009 upon commissioning, no implementation milestones or schedules are provided herein.

Disaster Recovery and Restoration Activities

A special case of restoration as part of a disaster recovery situation (such as storm restoration) shall follow the emergency provisions of the Responsible Entity's policy required by CIP-003 R1.1.

The rationale for this is that the primary task following a disaster is the restoration of the power system, and the ability to serve customer load. Cyber security provisions are implemented to support reliability and operations. If restoration were to be slowed to ensure full implementation of the CIP compliance implementation program, restoration could be hampered, and reliability could be harmed.

However, following the completion of the restoration activities, the entity is obligated to implement the CIP compliance implementation program at the restored facilities, and be able to

demonstrate full compliance in a spot-check or audit; or, file a self-report of non-compliance with a mitigation plan describing how and when full compliance will be achieved.

Newly Registered Entity Scenarios

Based on the Critical Cyber Asset identification scenarios identified above, the implementation milestone categories and schedules for those scenarios as they apply to newly Registered Entities are defined and distinguished below.

The following examples of business merger and asset acquisition scenarios may be helpful in explaining the expectations in each of the scenarios. Note that in each case, the predecessor Registered Entities are assumed to already be in compliance with NERC Reliability Standard CIP-002, and have existing risk-based Critical Asset identification methodologies.

1. **Newly Registered Entity Scenario 1 (Application of Category 1 Milestones):**

   A Merger of Two or More Registered Entities where None of the Predecessor Registered Entities has Identified any Critical Cyber Asset
   In the case of a business merger or asset acquisition, because there are no identified Critical Cyber Assets in any of the predecessor Registered Entities, a CIP compliance implementation program is not assumed to exist. The only program component required is the NERC Reliability Standard CIP-002 risk-based Critical Asset identification methodology implementation by each predecessor Responsible Entity.

   The merged Registered Entity has one calendar year from the effective date of the business merger asset acquisition to continue to operate the separate risk-based Critical Asset identification methodology implementation while determining how to either combine the risk-based Critical Asset identification methodologies, or at a minimum, operate separate risk-based Critical Asset identification methodologies under a common Senior Manager and governance structure. It would be preferred that a single program be the result of this analysis, however, Registered Entity-specific circumstances may dictate or allow multiple programs to continue separately. These decisions may be subject to review as part of compliance with NERC Reliability Standard CIP-002.

   The merged Registered Entity must ensure that it maintains the required 'annual application' of risk-based Critical Asset identification methodology(ies) as required in CIP-002 R2, even if that annual application timeframe is within the one calendar year allowed to determine if the merged Responsible Entity will combine the separate methodologies, or continue to operate them separately. Following the one calendar year allowance, the merged Responsible Entity must remain compliant with the program as it is determined to be implemented as a result of the one calendar year analysis of the disposition of the programs from the predecessor Responsible Entities.

   If either predecessor Registered Entities has identified Critical Assets (but without associated Critical Cyber Assets), the merged Registered Entity must continue to perform annual application of the risk-based Critical Asset identification methodology as required in CIP-002 R2, as well as to annually verify whether associated Cyber Assets meet the requirements as newly identified Critical Cyber Assets as required by CIP-002 R3. If

newly identified Critical Cyber Assets are found at any point in this process (i.e., during the one calendar year allowance period, or after that one calendar year allowance period), then the implementation milestones, categories and schedules of this Implementation Plan apply regardless of when this newly identified Critical Cyber Assets are determined, and independent of any merger and acquisition discussions contained in this Implementation Plan.

2. **Newly Registered Entity Scenario 2:**

A Merger of Two or More Registered Entities where Only One of the Predecessor Registered Entities has Identified at Least One Critical Cyber Asset
Since only one of the predecessor Registered Entities has previously identified Critical Cyber Assets, it is assumed that none of the other predecessor Registered Entities have CIP compliance implementation programs (since they are not required to have them). In this case, the CIP compliance implementation program from the predecessor Registered Entity with the previously identified Critical Cyber Asset would be expected to be implemented as the CIP compliance implementation program for the merged Registered Entity, and would be expected to apply to any Critical Cyber Assets identified after the effective date of the merger. Since the other predecessor Registered Entities did not have any Critical Cyber Assets, this should present no conflict in any CIP compliance implementation programs.

Note that the discussion of the disposition of any NERC Reliability Standard CIP-002 risk-based Critical Asset identification methodology from Scenario 1 above would apply in this case as well.

3. **Newly Registered Entity Scenario 3:**

A Merger of Two or More Registered Entities where Two or More of the Predecessor Registered Entities has Identified at Least One Critical Cyber Asset
This scenario is the most complicated of the three, since it applies to a merged Registered Entity that has more than one existing risk-based Critical Asset identification methodology and more than one CIP compliance implementation program, which are most likely not in complete agreement with each other. These differences could be due to any number of issues, ranging from something as 'simple' as selection of different anti-virus tools, to something as 'complicated' as risk-based Critical Asset identification methodology. This scenario will be discussed in two sections, the first dealing with the combination of risk-based Critical Asset identification methodologies; the second dealing with combining the CIP compliance implementation programs.

(a) **Combining the risk-based Critical Asset identification methodologies:** The merged Responsible Entity has one calendar year from the effective date of the business merger or asset acquisition to continue to operate the separate risk-based Critical Asset identification methodologies while determining how to either combine the risk-based Critical Asset identification methodologies, or at a minimum, operate the separate risk-based Critical Asset identification methodologies under a common Senior Manager and governance structure. It would be preferred that a single program be the result of this

analysis, however, Registered Entity specific circumstances may dictate or allow the two programs to continue separately. These decisions may be subject to review as part of compliance with NERC Reliability Standard CIP-002.

Registered Entities are encouraged when combining separate risk-based Critical Asset identification methodologies to ensure that, absent extraordinary circumstances, the resulting methodology produces a resultant list of Critical Assets that contains at least the same Critical Assets as were identified by all the predecessor Registered Entity's risk-based Critical Asset identification methodologies, as well as at least the same list of Critical Cyber Assets associated with the Critical Assets. The combined risk-based Critical Asset identification methodology and resultant Critical Asset list and Critical Cyber Asset list will be subject to review as part of compliance with NERC Reliability Standard CIP-002 R2 and R3. If additional Critical Assets are identified as a result of the application of the merged risk-based Critical Asset identification methodology, they should be treated as newly identified Critical Cyber Assets, as discussed elsewhere in this Implementation Plan, and subject to the CIP compliance implementation program merger determination as discussed next.

(b) Combining the CIP compliance implementation programs: The merged Responsible Entity has one calendar year from the effective date of the business merger to continue to operate the separate CIP compliance implementation programs while determining how to either combine the CIP compliance implementation programs, or at a minimum, operate the CIP compliance implementation programs under a common Senior Manager and governance structure.

Following the one year analysis period, if the decision is made to continue the operation of separate CIP compliance implementation programs under a common Senior Manager and governance structure, the merged Responsible Entity must update any required Senior Manager and governance issues, and clearly identify which CIP compliance implementation program components apply to each individual Critical Cyber Asset. This is essential to the implementation of the CIP compliance implementation program at the merged Responsible Entity, so that the correct and proper program components are implemented on the appropriate Critical Cyber Assets, as well as to allow the ERO compliance program (in a spot-check or audit) to determine if the CIP compliance implementation program has been properly implemented for each Critical Cyber Asset. Absent this clear identification, it would be possible for the wrong CIP compliance implementation program to be applied to a Critical Cyber Asset, or the wrong CIP compliance implementation program be evaluated in a spot-check or audit, leading to a possible technical non-compliance without real cause.

However, if after the one year analysis period, the decision is made to combine the operation of the separate CIP compliance implementation programs into a single CIP compliance implementation program, the merged Responsible Entity must develop a plan for merging of the separate CIP compliance implementation programs into a single CIP compliance implementation program, with a schedule and milestones for completion. The programs should be combined as expeditiously as possible, but without causing harm to reliability or operability of the Bulk power System. This 'merge plan' must be made

available to the ERO compliance program upon request, and as documentation for any spot-check or audit conducted while the merge plan is being performed. Progress towards meeting milestones and completing the merge plan will be verified during any spot-checks or audits conducted while the plan is being executed.

Example Scenarios

Note that there are no implementation milestones or schedules specified for a Responsible Entity that has a newly designated Critical Asset, but no newly designated Critical Cyber Assets. This situation exists because no action is required by the Responsible Entity upon designation of a Critical Asset without associated Critical Cyber Assets. Only upon designation of Critical Cyber Assets does a Responsible Entity need to become compliant with the NERC Reliability Standards CIP-003 through CIP-009.

As an example, Table 1 provides some sample scenarios, and provides the milestone category for each of the described situations.

Table 1: Example Scenarios

Scenarios	CIP Compliance Implementation Program:	
	No Program (note 1)	Existing Program
Existing Cyber Asset reclassified as Critical Cyber Asset due to change in assessment methodology	Category 1	Category 2
Existing asset becomes Critical Asset; associated Cyber Assets become Critical Cyber Assets	Category 1	Category 2
New asset comes online as a Critical Asset; associated Cyber Assets become Critical Cyber Asset	Category 1	Compliant upon Commissioning
Existing Cyber Asset moves into the Electronic Security Perimeter due to network reconfiguration	N/A	Compliant upon Commissioning
New Cyber Asset – never before in service and not a replacement for an existing Cyber Asset – added into a new or existing Electronic Security Perimeter	Category 1	Compliant upon Commissioning
New Cyber Asset replacing an existing Cyber Asset within the Electronic Security Perimeter	N/A	Compliant upon Commissioning
Planned modification or upgrade to existing Cyber Asset that causes it to be reclassified as a Critical Cyber Asset	Category 1	Compliant upon Commissioning
Asset under construction as an other (non-critical) asset becomes declared as a Critical Asset during construction	Category 1	Category 2
Unplanned modification such as emergency restoration invoked under a disaster recovery situation or storm restoration	N/A	Per emergency provisions as required by CIP-003 R1.1

Note: 1) assumes the entity is already compliant with CIP-002

Table 2 provides the compliance milestones for each of the two identified milestone categories.

Table 2: Implementation milestones for Newly Identified Critical Cyber Assets

CIP Standard Requirement	Milestone Category 1	Milestone Category 2
Standard CIP-002-2 — Critical Cyber Asset Identification		
R1	*N/A*	*N/A*
R2	*N/A*	*N/A*
R3	*N/A*	*N/A*
R4	*N/A*	*N/A*
Standard CIP-003-2 — Security Management Controls		
R1	24 months	*existing*
R2	*N/A*	*existing*
R3	24 months	*existing*
R4	24 months	6 months
R5	24 months	6 months
R6	24 months	6 months
Standard CIP-004-2 — Personnel and Training		
R1	24 months	*existing*
R2	24 months	18 months
R3	24 months	18 months
R4	24 months	18 months
Standard CIP-005-2 — Electronic Security Perimeter		
R1	24 months	12 months
R2	24 months	12 months
R3	24 months	12 months
R4	24 months	12 months
R5	24 months	12 months
Standard CIP-006-2 — Physical Security		
R1	24 months	12 months
R2	24 months	12 months
R3	24 months	12 months
R4	24 months	12 months
R5	24 months	12 months
R6	24 months	12 months
R7	24 months	12 months
R8	24 months	12 months

CIP Standard Requirement	Milestone Category 1	Milestone Category 2
Standard CIP-007-2 — Systems Security Management		
R1	24 months	12 months
R2	24 months	12 months
R3	24 months	12 months
R4	24 months	12 months
R5	24 months	12 months
R6	24 months	12 months
R7	24 months	12 months
R8	24 months	12 months
R9	24 months	12 months
Standard CIP-008-2 — Incident Reporting and Response Planning		
R1	24 months	6 months
R2	24 months	6 months
Standard CIP-009-2 — Recovery Plans for Critical Cyber Assets		
R1	24 months	6 months
R2	24 months	12 months
R3	24 months	12 months
R4	24 months	6 months
R5	24 months	6 months

Table 3[5] Compliance Schedule for Standards CIP-002-2 through CIP-009-2 or CIP-002-3 through CIP-009-3 For Entities Registering in April 2008 and Thereafter				
	Registration + 12 months	Registration + 24 months		
	All Facilities	All Facilities		
CIP-002-2 or CIP-002-3 — Critical Cyber Assets				
All Requirements		Compliant		
Standard CIP-003-2 or CIP-003-3 — Security Management Controls				
All Requirements Except R2		Compliant		
R2	Compliant			
Standard CIP-004-2 or CIP-004-3 — Personnel & Training				
All Requirements		Compliant		
Standard CIP-005-2 or CIP-005-3 — Electronic Security				
All Requirements		Compliant		
Standard CIP-006-2 or CIP-006-3 — Physical Security				
All Requirements		Compliant		
Standard CIP-007-2 or CIP-007-3 — Systems Security Management				
All Requirements		Compliant		
Standard CIP-008-2 or CIP-008-3 — Incident Reporting and Response Planning				
All Requirements		Compliant		
Standard CIP-009-2 or CIP-009-3 — Recovery Plans				
All Requirements		Compliant		

[5] Note: This table only specifies a 'Compliant' date, consistent with the convention used elsewhere in this Implementation Plan. The Compliant dates are consistent with those specified in Table 4 of the Version 1 Implementation Plan. Other compliance states referenced in the Version 1 Implementation Plan are no longer used.

Exhibit E

Future Reliability Standards and List of Effective Dates for Approval

Future Standards	Future Effective Date
CIP-002-3	10/1/2010 - See Exhibit D - CIP Implementation Plan
CIP-003-3	10/1/2010 - See Exhibit D - CIP Implementation Plan
CIP-004-3	10/1/2010 - See Exhibit D - CIP Implementation Plan
CIP-005-3	10/1/2010 - See Exhibit D - CIP Implementation Plan
CIP-006-3	10/1/2010 - See Exhibit D - CIP Implementation Plan
CIP-007-3	10/1/2010 - See Exhibit D - CIP Implementation Plan
CIP-008-3	10/1/2010 - See Exhibit D - CIP Implementation Plan
CIP-009-3	10/1/2010 - See Exhibit D - CIP Implementation Plan
INT-005-3	July 1, 2010
INT-006-3	July 1, 2010
INT-008-3	July 1, 2010
MOD-001-1	January 1, 2011
MOD-004-1	January 1, 2011
MOD-008-1	January 1, 2011
MOD-028-1	January 1, 2011
MOD-029-1	January 1, 2011
MOD-030-2	January 1, 2011
PRC-023-1	July 1, 2010 - Requirements R1 and R2 (Certain facilities and functions have a longer implementation window) November 17, 2011 - Requirement R3

A. Introduction

1. **Title:** Cyber Security — Critical Cyber Asset Identification

2. **Number:** CIP-002-3

3. **Purpose:** NERC Standards CIP-002-3 through CIP-009-3 provide a cyber security framework for the identification and protection of Critical Cyber Assets to support reliable operation of the Bulk Electric System.

   These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the assets needed to manage Bulk Electric System reliability, and the risks to which they are exposed.

   Business and operational demands for managing and maintaining a reliable Bulk Electric System increasingly rely on Cyber Assets supporting critical reliability functions and processes to communicate with each other, across functions and organizations, for services and data. This results in increased risks to these Cyber Assets.

   Standard CIP-002-3 requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment.

4. **Applicability:**

   4.1. Within the text of Standard CIP-002-3, "Responsible Entity" shall mean:

   4.1.1 Reliability Coordinator.

   4.1.2 Balancing Authority.

   4.1.3 Interchange Authority.

   4.1.4 Transmission Service Provider.

   4.1.5 Transmission Owner.

   4.1.6 Transmission Operator.

   4.1.7 Generator Owner.

   4.1.8 Generator Operator.

   4.1.9 Load Serving Entity.

   4.1.10 NERC.

   4.1.11 Regional Entity.

   4.2. The following are exempt from Standard CIP-002-3:

   4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

   4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required)

B. Requirements

R1. Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.

R1.1. The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.

R1.2. The risk-based assessment shall consider the following assets:

R1.2.1. Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.

R1.2.2. Transmission substations that support the reliable operation of the Bulk Electric System.

R1.2.3. Generation resources that support the reliable operation of the Bulk Electric System.

R1.2.4. Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration.

R1.2.5. Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.

R1.2.6. Special Protection Systems that support the reliable operation of the Bulk Electric System.

R1.2.7. Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.

R2. Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.

R3. Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002-3, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:

R3.1. The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,

R3.2. The Cyber Asset uses a routable protocol within a control center; or,

R3.3. The Cyber Asset is dial-up accessible.

R4. Annual Approval — The senior manager or delegate(s) shall approve annually the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of the senior manager or delegate(s)'s approval of the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)

C. Measures

M1. The Responsible Entity shall make available its current risk-based assessment methodology documentation as specified in Requirement R1.

M2. The Responsible Entity shall make available its list of Critical Assets as specified in Requirement R2.

M3. The Responsible Entity shall make available its list of Critical Cyber Assets as specified in Requirement R3.

M4. The Responsible Entity shall make available its approval records of annual approvals as specified in Requirement R4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entity.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep documentation required by Standard CIP-002-3 from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

1.5.1 None.

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
1	January 16, 2006	R3.2 — Change “Control Center” to “control center”	03/24/06
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3		Updated version number from -2 to -3	
3	12/16/09	Approved by the NERC Board of Trustees	Update

A. Introduction

1. **Title:** Cyber Security — Security Management Controls

2. **Number:** CIP-003-3

3. **Purpose:** Standard CIP-003-3 requires that Responsible Entities have minimum security management controls in place to protect Critical Cyber Assets. Standard CIP-003-3 should be read as part of a group of standards numbered Standards CIP-002-3 through CIP-009-3.

4. **Applicability:**

   4.1. Within the text of Standard CIP-003-3, "Responsible Entity" shall mean:

   4.1.1 Reliability Coordinator.

   4.1.2 Balancing Authority.

   4.1.3 Interchange Authority.

   4.1.4 Transmission Service Provider.

   4.1.5 Transmission Owner.

   4.1.6 Transmission Operator.

   4.1.7 Generator Owner.

   4.1.8 Generator Operator.

   4.1.9 Load Serving Entity.

   4.1.10 NERC.

   4.1.11 Regional Entity.

   4.2. The following are exempt from Standard CIP-003-3:

   4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

   4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

   4.2.3 Responsible Entities that, in compliance with Standard CIP-002-3, identify that they have no Critical Cyber Assets shall only be required to comply with CIP-003-3 Requirement R2.

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Cyber Security Policy — The Responsible Entity shall document and implement a cyber security policy that represents management's commitment and ability to secure its Critical Cyber Assets. The Responsible Entity shall, at minimum, ensure the following:

R1.1. The cyber security policy addresses the requirements in Standards CIP-002-3 through CIP-009-3, including provision for emergency situations.

R1.2. The cyber security policy is readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets.

R1.3. Annual review and approval of the cyber security policy by the senior manager assigned pursuant to R2.

R2. Leadership — The Responsible Entity shall assign a single senior manager with overall responsibility and authority for leading and managing the entity's implementation of, and adherence to, Standards CIP-002-3 through CIP-009-3.

R2.1. The senior manager shall be identified by name, title, and date of designation.

R2.2. Changes to the senior manager must be documented within thirty calendar days of the effective date.

R2.3. Where allowed by Standards CIP-002-3 through CIP-009-3, the senior manager may delegate authority for specific actions to a named delegate or delegates. These delegations shall be documented in the same manner as R2.1 and R2.2, and approved by the senior manager.

R2.4. The senior manager or delegate(s), shall authorize and document any exception from the requirements of the cyber security policy.

R3. Exceptions — Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and authorized by the senior manager or delegate(s).

R3.1. Exceptions to the Responsible Entity's cyber security policy must be documented within thirty days of being approved by the senior manager or delegate(s).

R3.2. Documented exceptions to the cyber security policy must include an explanation as to why the exception is necessary and any compensating measures.

R3.3. Authorized exceptions to the cyber security policy must be reviewed and approved annually by the senior manager or delegate(s) to ensure the exceptions are still required and valid. Such review and approval shall be documented.

R4. Information Protection — The Responsible Entity shall implement and document a program to identify, classify, and protect information associated with Critical Cyber Assets.

R4.1. The Critical Cyber Asset information to be protected shall include, at a minimum and regardless of media type, operational procedures, lists as required in Standard CIP-002-3, network topology or similar diagrams, floor plans of computing centers that contain Critical Cyber Assets, equipment layouts of Critical Cyber Assets, disaster recovery plans, incident response plans, and security configuration information.

R4.2. The Responsible Entity shall classify information to be protected under this program based on the sensitivity of the Critical Cyber Asset information.

R4.3. The Responsible Entity shall, at least annually, assess adherence to its Critical Cyber Asset information protection program, document the assessment results, and implement an action plan to remediate deficiencies identified during the assessment.

R5. Access Control — The Responsible Entity shall document and implement a program for managing access to protected Critical Cyber Asset information.

R5.1. The Responsible Entity shall maintain a list of designated personnel who are responsible for authorizing logical or physical access to protected information.

R5.1.1. Personnel shall be identified by name, title, and the information for which they are responsible for authorizing access.

R5.1.2. The list of personnel responsible for authorizing access to protected information shall be verified at least annually.

R5.2. The Responsible Entity shall review at least annually the access privileges to protected information to confirm that access privileges are correct and that they correspond with the Responsible Entity's needs and appropriate personnel roles and responsibilities.

R5.3. The Responsible Entity shall assess and document at least annually the processes for controlling access privileges to protected information.

R6. Change Control and Configuration Management — The Responsible Entity shall establish and document a process of change control and configuration management for adding, modifying, replacing, or removing Critical Cyber Asset hardware or software, and implement supporting configuration management activities to identify, control and document all entity or vendor-related changes to hardware and software components of Critical Cyber Assets pursuant to the change control process.

C. Measures

M1. The Responsible Entity shall make available documentation of its cyber security policy as specified in Requirement R1. Additionally, the Responsible Entity shall demonstrate that the cyber security policy is available as specified in Requirement R1.2.

M2. The Responsible Entity shall make available documentation of the assignment of, and changes to, its leadership as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation of the exceptions, as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation of its information protection program as specified in Requirement R4.

M5. The Responsible Entity shall make available its access control documentation as specified in Requirement R5.

M6. The Responsible Entity shall make available its change control and configuration management documentation as specified in Requirement R6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entity.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep all documentation and records from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

1.5.1 None

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Requirement R2 applies to all Responsible Entities, including Responsible Entities which have no Critical Cyber Assets. Modified the personnel identification information requirements in R5.1.1 to include name, title, and the information for which they are responsible for authorizing access (removed the business phone information). Changed compliance monitor to Compliance Enforcement Authority.	
3		Update version number from -2 to -3	
3	12/16/09	Approved by the NERC Board of Trustees	Update

A. Introduction

1. **Title:** Cyber Security — Personnel & Training

2. **Number:** CIP-004-3

3. **Purpose:** Standard CIP-004-3 requires that personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including contractors and service vendors, have an appropriate level of personnel risk assessment, training, and security awareness. Standard CIP-004-3 should be read as part of a group of standards numbered Standards CIP-002-3 through CIP-009-3.

4. **Applicability:**

   4.1. Within the text of Standard CIP-004-3, "Responsible Entity" shall mean:

   4.1.1 Reliability Coordinator.

   4.1.2 Balancing Authority.

   4.1.3 Interchange Authority.

   4.1.4 Transmission Service Provider.

   4.1.5 Transmission Owner.

   4.1.6 Transmission Operator.

   4.1.7 Generator Owner.

   4.1.8 Generator Operator.

   4.1.9 Load Serving Entity.

   4.1.10 NERC.

   4.1.11 Regional Entity.

   4.2. The following are exempt from Standard CIP-004-3:

   4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

   4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

   4.2.3 Responsible Entities that, in compliance with Standard CIP-002-3, identify that they have no Critical Cyber Assets.

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Awareness — The Responsible Entity shall establish, document, implement, and maintain a security awareness program to ensure personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets receive on-going reinforcement in sound security practices. The program shall include security awareness reinforcement on at least a quarterly basis using mechanisms such as:

- Direct communications (e.g., emails, memos, computer based training, etc.);
- Indirect communications (e.g., posters, intranet, brochures, etc.);
- Management support and reinforcement (e.g., presentations, meetings, etc.).

R2. Training — The Responsible Entity shall establish, document, implement, and maintain an annual cyber security training program for personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets. The cyber security training program shall be reviewed annually, at a minimum, and shall be updated whenever necessary.

R2.1. This program will ensure that all personnel having such access to Critical Cyber Assets, including contractors and service vendors, are trained prior to their being granted such access except in specified circumstances such as an emergency.

R2.2. Training shall cover the policies, access controls, and procedures as developed for the Critical Cyber Assets covered by CIP-004-3, and include, at a minimum, the following required items appropriate to personnel roles and responsibilities:

R2.2.1. The proper use of Critical Cyber Assets;

R2.2.2. Physical and electronic access controls to Critical Cyber Assets;

R2.2.3. The proper handling of Critical Cyber Asset information; and,

R2.2.4. Action plans and procedures to recover or re-establish Critical Cyber Assets and access thereto following a Cyber Security Incident.

R2.3. The Responsible Entity shall maintain documentation that training is conducted at least annually, including the date the training was completed and attendance records.

R3. Personnel Risk Assessment —The Responsible Entity shall have a documented personnel risk assessment program, in accordance with federal, state, provincial, and local laws, and subject to existing collective bargaining unit agreements, for personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets. A personnel risk assessment shall be conducted pursuant to that program prior to such personnel being granted such access except in specified circumstances such as an emergency.

The personnel risk assessment program shall at a minimum include:

R3.1. The Responsible Entity shall ensure that each assessment conducted include, at least, identity verification (e.g., Social Security Number verification in the U.S.) and seven-year criminal check. The Responsible Entity may conduct more detailed reviews, as permitted by law and subject to existing collective bargaining unit agreements, depending upon the criticality of the position.

R3.2. The Responsible Entity shall update each personnel risk assessment at least every seven years after the initial personnel risk assessment or for cause.

R3.3. The Responsible Entity shall document the results of personnel risk assessments of its personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets, and that personnel risk assessments of contractor and service vendor personnel with such access are conducted pursuant to Standard CIP-004-3.

R4. Access — The Responsible Entity shall maintain list(s) of personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including their specific electronic and physical access rights to Critical Cyber Assets.

R4.1. The Responsible Entity shall review the list(s) of its personnel who have such access to Critical Cyber Assets quarterly, and update the list(s) within seven calendar days of any change of personnel with such access to Critical Cyber Assets, or any change in the access rights of such personnel. The Responsible Entity shall ensure access list(s) for contractors and service vendors are properly maintained.

R4.2. The Responsible Entity shall revoke such access to Critical Cyber Assets within 24 hours for personnel terminated for cause and within seven calendar days for personnel who no longer require such access to Critical Cyber Assets.

C. Measures

M1. The Responsible Entity shall make available documentation of its security awareness and reinforcement program as specified in Requirement R1.

M2. The Responsible Entity shall make available documentation of its cyber security training program, review, and records as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation of the personnel risk assessment program and that personnel risk assessments have been applied to all personnel who have authorized cyber or authorized unescorted physical access to Critical Cyber Assets, as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation of the list(s), list review and update, and access revocation as needed as specified in Requirement R4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entity.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not Applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep personnel risk assessment documents in accordance with federal, state, provincial, and local laws.

1.4.2 The Responsible Entity shall keep all other documentation required by Standard CIP-004-3 from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.3 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
1	01/16/06	D.2.2.4 — Insert the phrase "for cause" as intended. "One instance of personnel termination for cause…"	03/24/06
1	06/01/06	D.2.1.4 — Change "access control rights" to "access rights."	06/05/06
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Reference to emergency situations. Modification to R1 for the Responsible Entity to establish, document, implement, and maintain the awareness program. Modification to R2 for the Responsible Entity to establish, document, implement, and maintain the training program; also stating the requirements for the cyber security training program. Modification to R3 Personnel Risk Assessment to clarify that it pertains to personnel having authorized cyber or authorized unescorted physical access to "Critical Cyber Assets". Removal of 90 day window to complete training and 30 day window to complete personnel risk assessments. Changed compliance monitor to Compliance Enforcement Authority.	
3		Update version number from -2 to -3	
3	12/16/09	Approved by NERC Board of Trustees	Update

A. Introduction

1. **Title:** Cyber Security — Electronic Security Perimeter(s)

2. **Number:** CIP-005-3

3. **Purpose:** Standard CIP-005-3 requires the identification and protection of the Electronic Security Perimeter(s) inside which all Critical Cyber Assets reside, as well as all access points on the perimeter. Standard CIP-005-3 should be read as part of a group of standards numbered Standards CIP-002-3 through CIP-009-3.

4. **Applicability**

   4.1. Within the text of Standard CIP-005-3, "Responsible Entity" shall mean:

   4.1.1 Reliability Coordinator.

   4.1.2 Balancing Authority.

   4.1.3 Interchange Authority.

   4.1.4 Transmission Service Provider.

   4.1.5 Transmission Owner.

   4.1.6 Transmission Operator.

   4.1.7 Generator Owner.

   4.1.8 Generator Operator.

   4.1.9 Load Serving Entity.

   4.1.10 NERC.

   4.1.11 Regional Entity

   4.2. The following are exempt from Standard CIP-005-3:

   4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

   4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

   4.2.3 Responsible Entities that, in compliance with Standard CIP-002-3, identify that they have no Critical Cyber Assets.

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The Responsible Entity shall identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s).

R1.1. Access points to the Electronic Security Perimeter(s) shall include any externally connected communication end point (for example, dial-up modems) terminating at any device within the Electronic Security Perimeter(s).

R1.2. For a dial-up accessible Critical Cyber Asset that uses a non-routable protocol, the Responsible Entity shall define an Electronic Security Perimeter for that single access point at the dial-up device.

R1.3. Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points of these communication links within the Electronic Security Perimeter(s) shall be considered access points to the Electronic Security Perimeter(s).

R1.4. Any non-critical Cyber Asset within a defined Electronic Security Perimeter shall be identified and protected pursuant to the requirements of Standard CIP-005-3.

R1.5. Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall be afforded the protective measures as a specified in Standard CIP-003-3; Standard CIP-004-3 Requirement R3; Standard CIP-005-3 Requirements R2 and R3; Standard CIP-006-3 Requirement R3; Standard CIP-007-3 Requirements R1 and R3 through R9; Standard CIP-008-3; and Standard CIP-009-3.

R1.6. The Responsible Entity shall maintain documentation of Electronic Security Perimeter(s), all interconnected Critical and non-critical Cyber Assets within the Electronic Security Perimeter(s), all electronic access points to the Electronic Security Perimeter(s) and the Cyber Assets deployed for the access control and monitoring of these access points.

R2. Electronic Access Controls — The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for control of electronic access at all electronic access points to the Electronic Security Perimeter(s).

R2.1. These processes and mechanisms shall use an access control model that denies access by default, such that explicit access permissions must be specified.

R2.2. At all access points to the Electronic Security Perimeter(s), the Responsible Entity shall enable only ports and services required for operations and for monitoring Cyber Assets within the Electronic Security Perimeter, and shall document, individually or by specified grouping, the configuration of those ports and services.

R2.3. The Responsible Entity shall implement and maintain a procedure for securing dial-up access to the Electronic Security Perimeter(s).

R2.4. Where external interactive access into the Electronic Security Perimeter has been enabled, the Responsible Entity shall implement strong procedural or technical controls at the access points to ensure authenticity of the accessing party, where technically feasible.

R2.5. The required documentation shall, at least, identify and describe:

R2.5.1. The processes for access request and authorization.

R2.5.2. The authentication methods.

R2.5.3. The review process for authorization rights, in accordance with Standard CIP-004-3 Requirement R4.

R2.5.4. The controls used to secure dial-up accessible connections.

R2.6. Appropriate Use Banner — Where technically feasible, electronic access control devices shall display an appropriate use banner on the user screen upon all interactive access attempts. The Responsible Entity shall maintain a document identifying the content of the banner.

R3. Monitoring Electronic Access — The Responsible Entity shall implement and document an electronic or manual process(es) for monitoring and logging access at access points to the Electronic Security Perimeter(s) twenty-four hours a day, seven days a week.

R3.1. For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall implement and document monitoring process(es) at each access point to the dial-up device, where technically feasible.

R3.2. Where technically feasible, the security monitoring process(es) shall detect and alert for attempts at or actual unauthorized accesses. These alerts shall provide for appropriate notification to designated response personnel. Where alerting is not technically feasible, the Responsible Entity shall review or otherwise assess access logs for attempts at or actual unauthorized accesses at least every ninety calendar days.

R4. Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of the electronic access points to the Electronic Security Perimeter(s) at least annually. The vulnerability assessment shall include, at a minimum, the following:

R4.1. A document identifying the vulnerability assessment process;

R4.2. A review to verify that only ports and services required for operations at these access points are enabled;

R4.3. The discovery of all access points to the Electronic Security Perimeter;

R4.4. A review of controls for default accounts, passwords, and network management community strings;

R4.5. Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.

R5. Documentation Review and Maintenance — The Responsible Entity shall review, update, and maintain all documentation to support compliance with the requirements of Standard CIP-005-3.

R5.1. The Responsible Entity shall ensure that all documentation required by Standard CIP-005-3 reflect current configurations and processes and shall review the documents and procedures referenced in Standard CIP-005-3 at least annually.

R5.2. The Responsible Entity shall update the documentation to reflect the modification of the network or controls within ninety calendar days of the change.

R5.3. The Responsible Entity shall retain electronic access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008-3.

C. Measures

M1. The Responsible Entity shall make available documentation about the Electronic Security Perimeter as specified in Requirement R1.

M2. The Responsible Entity shall make available documentation of the electronic access controls to the Electronic Security Perimeter(s), as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation of controls implemented to log and monitor access to the Electronic Security Perimeter(s) as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation of its annual vulnerability assessment as specified in Requirement R4.

M5. The Responsible Entity shall make available access logs and documentation of review, changes, and log retention as specified in Requirement R5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entity.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep logs for a minimum of ninety calendar days, unless: a) longer retention is required pursuant to Standard CIP-008-3, Requirement R2; b) directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Responsible Entity shall keep other documents and records required by Standard CIP-005-3 from the previous full calendar year.

1.4.3 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
1	01/16/06	D.2.3.1 — Change “Critical Assets,” to “Critical Cyber Assets” as intended.	03/24/06
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Revised the wording of the Electronic Access Controls requirement stated in R2.3 to clarify that the Responsible Entity	

		shall "implement and maintain" a procedure for securing dial-up access to the Electronic Security Perimeter(s). Changed compliance monitor to Compliance Enforcement Authority.	
3		Update version from -2 to -3	
3	12/16/09	Approved by the NERC Board of Trustees	Update

A. Introduction

1. **Title:** Cyber Security — Physical Security of Critical Cyber Assets

2. **Number:** CIP-006-3

3. **Purpose:** Standard CIP-006-3 is intended to ensure the implementation of a physical security program for the protection of Critical Cyber Assets. Standard CIP-006-3 should be read as part of a group of standards numbered Standards CIP-002-3 through CIP-009-3.

4. **Applicability:**

   4.1. Within the text of Standard CIP-006-3, "Responsible Entity" shall mean:

   4.1.1 Reliability Coordinator

   4.1.2 Balancing Authority

   4.1.3 Interchange Authority

   4.1.4 Transmission Service Provider

   4.1.5 Transmission Owner

   4.1.6 Transmission Operator

   4.1.7 Generator Owner

   4.1.8 Generator Operator

   4.1.9 Load Serving Entity

   4.1.10 NERC

   4.1.11 Regional Entity

   4.2. The following are exempt from Standard CIP-006-3:

   4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

   4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

   4.2.3 Responsible Entities that, in compliance with Standard CIP-002-3, identify that they have no Critical Cyber Assets

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Physical Security Plan — The Responsible Entity shall document, implement, and maintain a physical security plan, approved by the senior manager or delegate(s) that shall address, at a minimum, the following:

R1.1. All Cyber Assets within an Electronic Security Perimeter shall reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to such Cyber Assets.

R1.2. Identification of all physical access points through each Physical Security Perimeter and measures to control entry at those access points.

R1.3. Processes, tools, and procedures to monitor physical access to the perimeter(s).

R1.4. Appropriate use of physical access controls as described in Requirement R4 including visitor pass management, response to loss, and prohibition of inappropriate use of physical access controls.

R1.5. Review of access authorization requests and revocation of access authorization, in accordance with CIP-004-3 Requirement R4.

R1.6. A visitor control program for visitors (personnel without authorized unescorted access to a Physical Security Perimeter), containing at a minimum the following:

R1.6.1. Logs (manual or automated) to document the entry and exit of visitors, including the date and time, to and from Physical Security Perimeters.

R1.6.2. Continuous escorted access of visitors within the Physical Security Perimeter.

R1.7. Update of the physical security plan within thirty calendar days of the completion of any physical security system redesign or reconfiguration, including, but not limited to, addition or removal of access points through the Physical Security Perimeter, physical access controls, monitoring controls, or logging controls.

R1.8. Annual review of the physical security plan.

R2. Protection of Physical Access Control Systems — Cyber Assets that authorize and/or log access to the Physical Security Perimeter(s), exclusive of hardware at the Physical Security Perimeter access point such as electronic lock control mechanisms and badge readers, shall:

R2.1. Be protected from unauthorized physical access.

R2.2. Be afforded the protective measures specified in Standard CIP-003-3; Standard CIP-004-3 Requirement R3; Standard CIP-005-3 Requirements R2 and R3; Standard CIP-006-3 Requirements R4 and R5; Standard CIP-007-3; Standard CIP-008-3; and Standard CIP-009-3.

R3. Protection of Electronic Access Control Systems — Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall reside within an identified Physical Security Perimeter.

R4. Physical Access Controls — The Responsible Entity shall document and implement the operational and procedural controls to manage physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. The Responsible Entity shall implement one or more of the following physical access methods:

- Card Key: A means of electronic access where the access rights of the card holder are predefined in a computer database. Access rights may differ from one perimeter to another.
- Special Locks: These include, but are not limited to, locks with “restricted key” systems, magnetic locks that can be operated remotely, and “man-trap” systems.
- Security Personnel: Personnel responsible for controlling physical access who may reside on-site or at a monitoring station.
- Other Authentication Devices: Biometric, keypad, token, or other equivalent devices that control physical access to the Critical Cyber Assets.

R5. Monitoring Physical Access — The Responsible Entity shall document and implement the technical and procedural controls for monitoring physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. Unauthorized access attempts shall be reviewed immediately and handled in accordance with the procedures specified in Requirement CIP-008-3. One or more of the following monitoring methods shall be used:

- Alarm Systems: Systems that alarm to indicate a door, gate or window has been opened without authorization. These alarms must provide for immediate notification to personnel responsible for response.
- Human Observation of Access Points: Monitoring of physical access points by authorized personnel as specified in Requirement R4.

R6. Logging Physical Access — Logging shall record sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week. The Responsible Entity shall implement and document the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent:

- Computerized Logging: Electronic logs produced by the Responsible Entity's selected access control and monitoring method.
- Video Recording: Electronic capture of video images of sufficient quality to determine identity.
- Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access as specified in Requirement R4.

R7. Access Log Retention — The Responsible Entity shall retain physical access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008-3.

R8. Maintenance and Testing — The Responsible Entity shall implement a maintenance and testing program to ensure that all physical security systems under Requirements R4, R5, and R6 function properly. The program must include, at a minimum, the following:

R8.1. Testing and maintenance of all physical security mechanisms on a cycle no longer than three years.

R8.2. Retention of testing and maintenance records for the cycle determined by the Responsible Entity in Requirement R8.1.

R8.3. Retention of outage records regarding access controls, logging, and monitoring for a minimum of one calendar year.

C. Measures

M1. The Responsible Entity shall make available the physical security plan as specified in Requirement R1 and documentation of the implementation, review and updating of the plan.

M2. The Responsible Entity shall make available documentation that the physical access control systems are protected as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation that the electronic access control systems are located within an identified Physical Security Perimeter as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation identifying the methods for controlling physical access to each access point of a Physical Security Perimeter as specified in Requirement R4.

M5. The Responsible Entity shall make available documentation identifying the methods for monitoring physical access as specified in Requirement R5.

M6. The Responsible Entity shall make available documentation identifying the methods for logging physical access as specified in Requirement R6.

M7. The Responsible Entity shall make available documentation to show retention of access logs as specified in Requirement R7.

M8. The Responsible Entity shall make available documentation to show its implementation of a physical security system maintenance and testing program as specified in Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entities.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep documents other than those specified in Requirements R7 and R8.2 from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

1.5.1 The Responsible Entity may not make exceptions in its cyber security policy to the creation, documentation, or maintenance of a physical security plan.

1.5.2 For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall not be required to comply with Standard CIP-006-3 for that single access point at the dial-up device.

2. Violation Severity Levels (Under development by the CIP VSL Drafting Team)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
2		Modifications to remove extraneous information from the requirements, improve readability, and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Replaced the RRO with RE as a responsible entity. Modified CIP-006-1 Requirement R1 to clarify that a physical security plan to protect Critical Cyber Assets must be documented, maintained, implemented, and approved by the senior manager. Revised the wording in R1.2 to identify all "physical" access points. Added Requirement R2 to CIP-006-2 to clarify the requirement to safeguard the Physical Access Control Systems and exclude hardware at the Physical Security Perimeter access point, such as electronic lock control mechanisms and badge readers from the requirement. Requirement R2.1 requires the Responsible Entity to protect the Physical Access Control Systems from unauthorized access. CIP-006-1 Requirement R1.8 was moved to become CIP-006-2 Requirement R2.2. Added Requirement R3 to CIP-006-2, clarifying the requirement for Electronic Access Control Systems to be safeguarded within an identified Physical Security Perimeter. The sub requirements of CIP-006-2 Requirements R4, R5, and R6 were changed from formal requirements to bulleted lists of options consistent with the intent of the requirements. Changed the Compliance Monitor to Compliance Enforcement Authority.	
3		Updated version numbers from -2 to -3 Revised Requirement 1.6 to add a Visitor Control program component to the Physical Security Plan, in response to FERC order issued September 30, 2009. In Requirement R7, the term "Responsible Entity" was capitalized.	
	11/18/2009	Updated Requirements R1.6.1 and R1.6.2 to be responsive to FERC Order RD09-7	
3	12/16/09	Approved by NERC Board of Trustees	Update

A. Introduction

1. **Title:** Cyber Security — Systems Security Management

2. **Number:** CIP-007-3

3. **Purpose:** Standard CIP-007-3 requires Responsible Entities to define methods, processes, and procedures for securing those systems determined to be Critical Cyber Assets, as well as the other (non-critical) Cyber Assets within the Electronic Security Perimeter(s). Standard CIP-007-3 should be read as part of a group of standards numbered Standards CIP-002-3 through CIP-009-3.

4. **Applicability:**

   4.1. Within the text of Standard CIP-007-3, "Responsible Entity" shall mean:

   4.1.1 Reliability Coordinator.

   4.1.2 Balancing Authority.

   4.1.3 Interchange Authority.

   4.1.4 Transmission Service Provider.

   4.1.5 Transmission Owner.

   4.1.6 Transmission Operator.

   4.1.7 Generator Owner.

   4.1.8 Generator Operator.

   4.1.9 Load Serving Entity.

   4.1.10 NERC.

   4.1.11 Regional Entity.

   4.2. The following are exempt from Standard CIP-007-3:

   4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

   4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

   4.2.3 Responsible Entities that, in compliance with Standard CIP-002-3, identify that they have no Critical Cyber Assets.

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Test Procedures — The Responsible Entity shall ensure that new Cyber Assets and significant changes to existing Cyber Assets within the Electronic Security Perimeter do not adversely affect existing cyber security controls. For purposes of Standard CIP-007-3, a significant change shall, at a minimum, include implementation of security patches, cumulative service packs, vendor releases, and version upgrades of operating systems, applications, database platforms, or other third-party software or firmware.

R1.1. The Responsible Entity shall create, implement, and maintain cyber security test procedures in a manner that minimizes adverse effects on the production system or its operation.

R1.2. The Responsible Entity shall document that testing is performed in a manner that reflects the production environment.

R1.3. The Responsible Entity shall document test results.

R2. Ports and Services — The Responsible Entity shall establish, document and implement a process to ensure that only those ports and services required for normal and emergency operations are enabled.

R2.1. The Responsible Entity shall enable only those ports and services required for normal and emergency operations.

R2.2. The Responsible Entity shall disable other ports and services, including those used for testing purposes, prior to production use of all Cyber Assets inside the Electronic Security Perimeter(s).

R2.3. In the case where unused ports and services cannot be disabled due to technical limitations, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.

R3. Security Patch Management — The Responsible Entity, either separately or as a component of the documented configuration management process specified in CIP-003-3 Requirement R6, shall establish, document and implement a security patch management program for tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).

R3.1. The Responsible Entity shall document the assessment of security patches and security upgrades for applicability within thirty calendar days of availability of the patches or upgrades.

R3.2. The Responsible Entity shall document the implementation of security patches. In any case where the patch is not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.

R4. Malicious Software Prevention — The Responsible Entity shall use anti-virus software and other malicious software ("malware") prevention tools, where technically feasible, to detect, prevent, deter, and mitigate the introduction, exposure, and propagation of malware on all Cyber Assets within the Electronic Security Perimeter(s).

R4.1. The Responsible Entity shall document and implement anti-virus and malware prevention tools. In the case where anti-virus software and malware prevention tools are not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.

R4.2. The Responsible Entity shall document and implement a process for the update of anti-virus and malware prevention "signatures." The process must address testing and installing the signatures.

R5. Account Management — The Responsible Entity shall establish, implement, and document technical and procedural controls that enforce access authentication of, and accountability for, all user activity, and that minimize the risk of unauthorized system access.

R5.1. The Responsible Entity shall ensure that individual and shared system accounts and authorized access permissions are consistent with the concept of "need to know" with respect to work functions performed.

R5.1.1. The Responsible Entity shall ensure that user accounts are implemented as approved by designated personnel. Refer to Standard CIP-003-3 Requirement R5.

R5.1.2. The Responsible Entity shall establish methods, processes, and procedures that generate logs of sufficient detail to create historical audit trails of individual user account access activity for a minimum of ninety days.

R5.1.3. The Responsible Entity shall review, at least annually, user accounts to verify access privileges are in accordance with Standard CIP-003-3 Requirement R5 and Standard CIP-004-3 Requirement R4.

R5.2. The Responsible Entity shall implement a policy to minimize and manage the scope and acceptable use of administrator, shared, and other generic account privileges including factory default accounts.

R5.2.1. The policy shall include the removal, disabling, or renaming of such accounts where possible. For such accounts that must remain enabled, passwords shall be changed prior to putting any system into service.

R5.2.2. The Responsible Entity shall identify those individuals with access to shared accounts.

R5.2.3. Where such accounts must be shared, the Responsible Entity shall have a policy for managing the use of such accounts that limits access to only those with authorization, an audit trail of the account use (automated or manual), and steps for securing the account in the event of personnel changes (for example, change in assignment or termination).

R5.3. At a minimum, the Responsible Entity shall require and use passwords, subject to the following, as technically feasible:

R5.3.1. Each password shall be a minimum of six characters.

R5.3.2. Each password shall consist of a combination of alpha, numeric, and "special" characters.

R5.3.3. Each password shall be changed at least annually, or more frequently based on risk.

R6. Security Status Monitoring — The Responsible Entity shall ensure that all Cyber Assets within the Electronic Security Perimeter, as technically feasible, implement automated tools or organizational process controls to monitor system events that are related to cyber security.

R6.1. The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for monitoring for security events on all Cyber Assets within the Electronic Security Perimeter.

R6.2. The security monitoring controls shall issue automated or manual alerts for detected Cyber Security Incidents.

R6.3. The Responsible Entity shall maintain logs of system events related to cyber security, where technically feasible, to support incident response as required in Standard CIP-008-3.

R6.4. The Responsible Entity shall retain all logs specified in Requirement R6 for ninety calendar days.

R6.5. The Responsible Entity shall review logs of system events related to cyber security and maintain records documenting review of logs.

R7. Disposal or Redeployment — The Responsible Entity shall establish and implement formal methods, processes, and procedures for disposal or redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005-3.

R7.1. Prior to the disposal of such assets, the Responsible Entity shall destroy or erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.

R7.2. Prior to redeployment of such assets, the Responsible Entity shall, at a minimum, erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.

R7.3. The Responsible Entity shall maintain records that such assets were disposed of or redeployed in accordance with documented procedures.

R8. Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of all Cyber Assets within the Electronic Security Perimeter at least annually. The vulnerability assessment shall include, at a minimum, the following:

R8.1. A document identifying the vulnerability assessment process;

R8.2. A review to verify that only ports and services required for operation of the Cyber Assets within the Electronic Security Perimeter are enabled;

R8.3. A review of controls for default accounts; and,

R8.4. Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.

R9. Documentation Review and Maintenance — The Responsible Entity shall review and update the documentation specified in Standard CIP-007-3 at least annually. Changes resulting from modifications to the systems or controls shall be documented within thirty calendar days of the change being completed.

C. Measures

M1. The Responsible Entity shall make available documentation of its security test procedures as specified in Requirement R1.

M2. The Responsible Entity shall make available documentation as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation and records of its security patch management program, as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation and records of its malicious software prevention program as specified in Requirement R4.

M5. The Responsible Entity shall make available documentation and records of its account management program as specified in Requirement R5.

M6. The Responsible Entity shall make available documentation and records of its security status monitoring program as specified in Requirement R6.

M7. The Responsible Entity shall make available documentation and records of its program for the disposal or redeployment of Cyber Assets as specified in Requirement R7.

M8. The Responsible Entity shall make available documentation and records of its annual vulnerability assessment of all Cyber Assets within the Electronic Security Perimeters(s) as specified in Requirement R8.

M9. The Responsible Entity shall make available documentation and records demonstrating the review and update as specified in Requirement R9.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entity.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep all documentation and records from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Responsible Entity shall retain security–related system event logs for ninety calendar days, unless longer retention is required pursuant to Standard CIP-008-3 Requirement R2.

1.4.3 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information.

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment and acceptance of risk. Revised the Purpose of this standard to clarify that Standard CIP-007-2 requires Responsible Entities to define methods, processes, and procedures for securing Cyber Assets and other (non-Critical)	

		Assets within an Electronic Security Perimeter. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. R9 changed ninety (90) days to thirty (30) days Changed compliance monitor to Compliance Enforcement Authority.	
3		Updated version numbers from -2 to -3	
3	12/16/09	Approved by the NERC Board of Trustees	

A. Introduction

1. **Title:** Cyber Security — Incident Reporting and Response Planning

2. **Number:** CIP-008-3

3. **Purpose:** Standard CIP-008-3 ensures the identification, classification, response, and reporting of Cyber Security Incidents related to Critical Cyber Assets. Standard CIP-008-23 should be read as part of a group of standards numbered Standards CIP-002-3 through CIP-009-3.

4. **Applicability**

   4.1. Within the text of Standard CIP-008-3, "Responsible Entity" shall mean:

   4.1.1 Reliability Coordinator.

   4.1.2 Balancing Authority.

   4.1.3 Interchange Authority.

   4.1.4 Transmission Service Provider.

   4.1.5 Transmission Owner.

   4.1.6 Transmission Operator.

   4.1.7 Generator Owner.

   4.1.8 Generator Operator.

   4.1.9 Load Serving Entity.

   4.1.10 NERC.

   4.1.11 Regional Entity.

   4.2. The following are exempt from Standard CIP-008-3:

   4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

   4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

   4.2.3 Responsible Entities that, in compliance with Standard CIP-002-3, identify that they have no Critical Cyber Assets.

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Cyber Security Incident Response Plan — The Responsible Entity shall develop and maintain a Cyber Security Incident response plan and implement the plan in response to Cyber Security Incidents. The Cyber Security Incident response plan shall address, at a minimum, the following:

R1.1. Procedures to characterize and classify events as reportable Cyber Security Incidents.

R1.2. Response actions, including roles and responsibilities of Cyber Security Incident response teams, Cyber Security Incident handling procedures, and communication plans.

R1.3. Process for reporting Cyber Security Incidents to the Electricity Sector Information Sharing and Analysis Center (ES-ISAC). The Responsible Entity must ensure that all reportable Cyber Security Incidents are reported to the ES-ISAC either directly or through an intermediary.

R1.4. Process for updating the Cyber Security Incident response plan within thirty calendar days of any changes.

R1.5. Process for ensuring that the Cyber Security Incident response plan is reviewed at least annually.

R1.6. Process for ensuring the Cyber Security Incident response plan is tested at least annually. A test of the Cyber Security Incident response plan can range from a paper drill, to a full operational exercise, to the response to an actual incident.

R2. Cyber Security Incident Documentation — The Responsible Entity shall keep relevant documentation related to Cyber Security Incidents reportable per Requirement R1.1 for three calendar years.

C. Measures

M1. The Responsible Entity shall make available its Cyber Security Incident response plan as indicated in Requirement R1 and documentation of the review, updating, and testing of the plan.

M2. The Responsible Entity shall make available all documentation as specified in Requirement R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entity.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep documentation other than that required for reportable Cyber Security Incidents as specified in Standard CIP-008-3 for the previous full calendar year unless directed by its Compliance Enforcement

Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

1.5.1 The Responsible Entity may not take exception in its cyber security policies to the creation of a Cyber Security Incident response plan.

1.5.2 The Responsible Entity may not take exception in its cyber security policies to reporting Cyber Security Incidents to the ES ISAC.

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3		Updated Version number from -2 to -3 In Requirement 1.6, deleted the sentence pertaining to removing component or system from service in order to perform testing, in response to FERC order issued September 30, 2009.	
3	12/16/09	Approved by NERC Board of Trustees	Update

A. Introduction

1. **Title:** Cyber Security — Recovery Plans for Critical Cyber Assets

2. **Number:** CIP-009-3

3. **Purpose:** Standard CIP-009-3 ensures that recovery plan(s) are put in place for Critical Cyber Assets and that these plans follow established business continuity and disaster recovery techniques and practices. Standard CIP-009-3 should be read as part of a group of standards numbered Standards CIP-002-3 through CIP-009-3.

4. **Applicability:**

   4.1. Within the text of Standard CIP-009-3, "Responsible Entity" shall mean:

   4.1.1 Reliability Coordinator

   4.1.2 Balancing Authority

   4.1.3 Interchange Authority

   4.1.4 Transmission Service Provider

   4.1.5 Transmission Owner

   4.1.6 Transmission Operator

   4.1.7 Generator Owner

   4.1.8 Generator Operator

   4.1.9 Load Serving Entity

   4.1.10 NERC

   4.1.11 Regional Entity

   4.2. The following are exempt from Standard CIP-009-3:

   4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

   4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

   4.2.3 Responsible Entities that, in compliance with Standard CIP-002-3, identify that they have no Critical Cyber Assets.

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Recovery Plans — The Responsible Entity shall create and annually review recovery plan(s) for Critical Cyber Assets. The recovery plan(s) shall address at a minimum the following:

R1.1. Specify the required actions in response to events or conditions of varying duration and severity that would activate the recovery plan(s).

R1.2. Define the roles and responsibilities of responders.

R2. Exercises — The recovery plan(s) shall be exercised at least annually. An exercise of the recovery plan(s) can range from a paper drill, to a full operational exercise, to recovery from an actual incident.

R3. Change Control — Recovery plan(s) shall be updated to reflect any changes or lessons learned as a result of an exercise or the recovery from an actual incident. Updates shall be communicated to personnel responsible for the activation and implementation of the recovery plan(s) within thirty calendar days of the change being completed.

R4. Backup and Restore — The recovery plan(s) shall include processes and procedures for the backup and storage of information required to successfully restore Critical Cyber Assets. For example, backups may include spare electronic components or equipment, written documentation of configuration settings, tape backup, etc.

R5. Testing Backup Media — Information essential to recovery that is stored on backup media shall be tested at least annually to ensure that the information is available. Testing can be completed off site.

C. Measures

M1. The Responsible Entity shall make available its recovery plan(s) as specified in Requirement R1.

M2. The Responsible Entity shall make available its records documenting required exercises as specified in Requirement R2.

M3. The Responsible Entity shall make available its documentation of changes to the recovery plan(s), and documentation of all communications, as specified in Requirement R3.

M4. The Responsible Entity shall make available its documentation regarding backup and storage of information as specified in Requirement R4.

M5. The Responsible Entity shall make available its documentation of testing of backup media as specified in Requirement R5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entities.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep documentation required by Standard CIP-009-3 from the previous full calendar year unless directed by its Compliance

Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Communication of revisions to the recovery plan changed from 90 days to 30 days. Changed compliance monitor to Compliance Enforcement Authority.	
3		Updated version numbers from -2 to -3	
3	12/16/09	Approved by the NERC Board of Trustees	Update

A. Introduction

1. **Title:** **Interchange Authority Distributes Arranged Interchange**
2. **Number:** INT-005-3
3. **Purpose:** To ensure that the implementation of Interchange between Source and Sink Balancing Authorities is distributed by an Interchange Authority such that Interchange information is available for reliability assessments.
4. **Applicability:**

   4.1. Interchange Authority.
5. **Effective Date:** July 1, 2010

B. Requirements

R1. Prior to the expiration of the time period defined in the timing requirements tables in this standard, Column A, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment to all reliability entities involved in the Interchange.

R1.1. When a Balancing Authority or Reliability Coordinator initiates a Curtailment to Confirmed or Implemented Interchange for reliability, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment only to the Source Balancing Authority and the Sink Balancing Authority.

C. Measures

M1. For each Arranged Interchange, the Interchange Authority shall be able to provide evidence that it has distributed the Arranged Interchange information to all reliability entities involved in the Interchange within the applicable time frame.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Time Frame

   The Performance-Reset Period shall be twelve months from the last non-compliance to Requirement 1.

   1.3. Data Retention

   The Interchange Authority shall keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

   1.4. Additional Compliance Information

   Each Interchange Authority shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

   Subsequent to the initial compliance review, compliance may be:

   1.4.1 Verified by audit at least once every three years.

   1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of noncompliant Interchange Authorities, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a specific complaint of failure to perform R1. Complaints must be lodged within 60 days of the incident. The Compliance Monitor will evaluate complaints.

Each Interchange Authority shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records for the audit period which indicate the Interchange Authority's distribution of all Arranged Interchange information to all reliability entities involved in an Interchange. The Compliance Monitor may request up to a three month period of historical data ending with the date the request is received by the Interchange Authority.

1.4.6 For specific complaints, only those data and system log records associated with the specific Interchange event contained in the complaint which indicate that the Interchange Authority distributed the Arranged Interchange information to all reliability entities involved in that specific Interchange.

2. Levels of Non-Compliance

2.1. Level 1: One occurrence[1] of not distributing information to all involved reliability entities as described in R1.

2.2. Level 2: Two occurrences[1] of not distributing information to all involved reliability entities as described in R1.

2.3. Level 3: Three occurrences[1] of not distributing information to all involved reliability entities as described in R1.

2.4. Level 4: Four or more occurrences[1] of not distributing information to all involved reliability entities as described in R1 or no evidence provided.

E. **Regional Differences**

None

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Approved by BOT	New
2	May 2, 2007	Approved by BOT	Revised
3	April 8, 2010	Approved by FERC, Effective July 1, 2010	

[1] This does not include instances of not distributing information due to extenuating circumstances approved by the Compliance Monitor.

Timing Requirements for all Interconnections except WECC

		A	B	C	D
If Arranged Interchange (RFI)[2] is Submitted	**IA Assigned Time Classification**	**IA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments**	**IA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**
> 1 hour after the RFI start time	ATF	≤ 1 minute from RFI submission	Entities have up to 2 hours to respond.	≤ 1 minute from receipt of all Reliability Assessments	NA
< 15 minutes prior to ramp start and ≤ 1 hour after the RFI start time	Late	≤ 1 minute from RFI submission	Entities have up to 10 minutes to respond.	≤ 1 minute from receipt of all Reliability Assessments	≤ 3 minutes after receipt of confirmed RFI
< 1 hour and ≥ 15 minutes prior to ramp start	On- time	≤ 1 minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
≥ 1 hour to < 4 hours prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 20 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start

[2] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

Example of Timing Requirements for all Interconnections except WECC

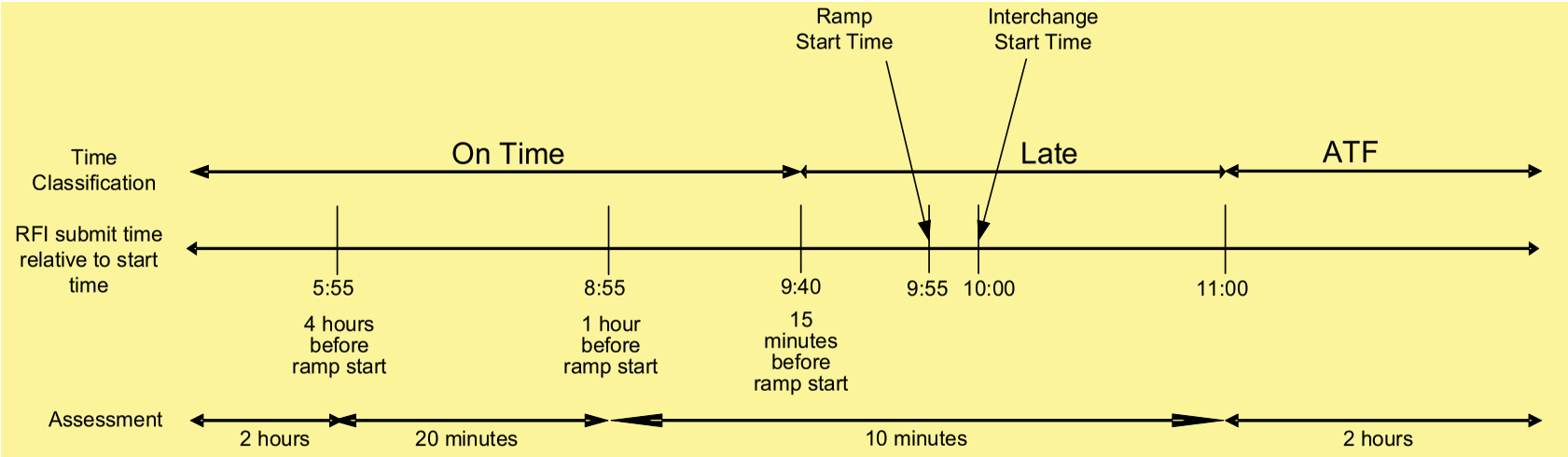

Timing Requirements for WECC

		A	B	C	D
If Arranged Interchange (RFI)[3] is Submitted	**IA Assigned Time Classification**	**IA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments**	**IA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF	≤ 1minute from RFI submission	Entities have up to 2 hours to respond.	≤ 1minute from receipt of all Reliability Assessments	NA
<10 minutes prior to ramp start and ≤1 hour after the start time	Late	≤ 1minute from RFI submission	Entities have up to 10 minutes to respond.	≤ 1minute from receipt of all Reliability Assessments	≤ 3 minutes after receipt of confirmed RFI
10 minutes prior to ramp start	On- time	≤ 1minute from RFI submission	≤ 5 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
11 minutes prior to ramp start	On- time	≤ 1minute from RFI submission	≤ 6 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
12 minutes prior to ramp start	On- time	≤ 1minute from RFI submission	≤ 7 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
13 minutes prior to ramp start	On- time	≤ 1minute from RFI submission	≤ 8 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
14 minutes prior to ramp start	On- time	≤ 1minute from RFI submission	≤ 9 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
<1 hour and ≥ 15 minutes prior to ramp start	On- time	≤ 1minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
≥ 1hour and < 4 hours prior to ramp start	On- time	≤ 1minute from RFI submission	< 20 minutes from Arranged interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On- time	≤ 1minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start
Submitted before 10:00 PPT with start time ≥ 00:00 PPT of following day	On- time	≤ 1minute from RFI submission	By 12:00 PPT of day the Arranged Interchange was received by the IA	≤ 1minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start

[3] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

Example of Timing Requirements for WECC

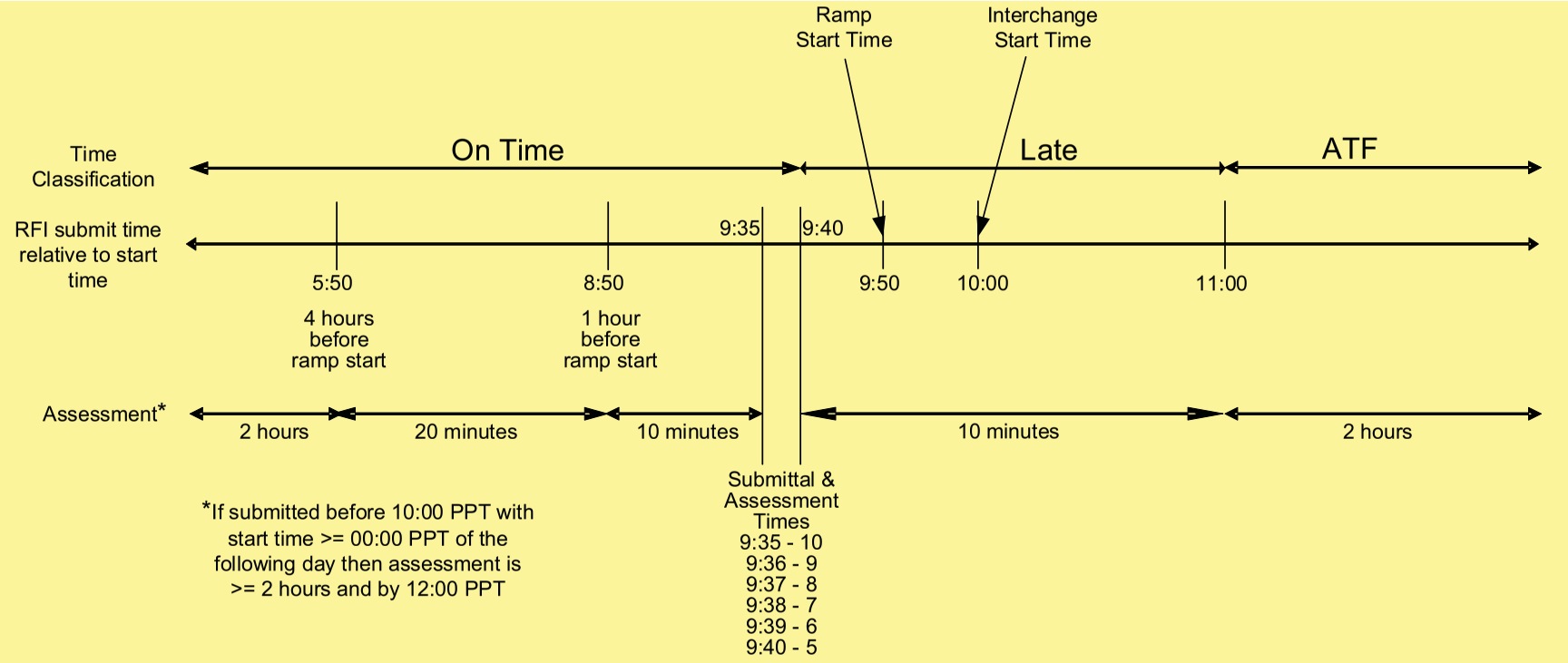

A. Introduction

1. Title: **Response to Interchange Authority**

2. Number: INT-006-3

3. Purpose: To ensure that each Arranged Interchange is checked for reliability before it is implemented.

4. Applicability:

4.1. Balancing Authority.

4.2. Transmission Service Provider.

5. Effective Date: July 1, 2010

B. Requirements

R1. Prior to the expiration of the reliability assessment period defined in the timing requirements tables in this standard, Column B, the Balancing Authority and Transmission Service Provider shall respond to each On-time Request for Interchange (RFI), and to each Emergency RFI and Reliability Adjustment RFI from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange.[1]

R1.1. Each involved Balancing Authority shall evaluate the Arranged Interchange with respect to:

R1.1.1. Energy profile (ability to support the magnitude of the Interchange).

R1.1.2. Ramp (ability of generation maneuverability to accommodate).

R1.1.3. Scheduling path (proper connectivity of Adjacent Balancing Authorities).

R1.2. Each involved Transmission Service Provider shall confirm that the transmission service arrangements associated with the Arranged Interchange have adjacent Transmission Service Provider connectivity, are valid and prevailing transmission system limits will not be violated.

C. Measures

M1. The Balancing Authority and Transmission Service Provider shall each provide evidence that it responded, relative to transitioning an Arranged Interchange to a Confirmed Interchange, to each On–time Request for Interchange (RFI), and to each Emergency RFI or Reliability Adjustment RFI from an Interchange Authority within the reliability assessment period defined in the Timing Table, Column B. The Balancing Authority and Transmission Service Provider need not provide evidence that it responded to any other requests.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility
Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

The Performance-Reset Period shall be twelve months from the last non-compliance to Requirement 1.

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[1] The Balancing Authority and Transmission Service Provider need not provide responses to any other requests.

1.3. Data Retention

The Balancing Authority and Transmission Service Provider shall each keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

1.4. Additional Compliance Information

The Balancing Authority and Transmission Service Provider shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

Subsequent to the initial compliance review, compliance may be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of non-compliant Interchange Authorities, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. The Compliance Monitor will evaluate complaints.

The Balancing Authority, and Transmission Service Provider shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records and agreements for the audit period which indicate a reliability entity identified in R1 responded to all instances of the Interchange Authority's communication under Reliability Standard INT-005 Requirement 1 concerning the pending transition of an Arranged Interchange to Confirmed Interchange. The Compliance Monitor may request up to a three month period of historical data ending with the date the request is received by the Balancing Authority, or Transmission Service Provider.

1.4.6 For specific complaints, agreements and those data and system log records associated with the specific Interchange event contained in the complaint which indicates a reliability entity identified in R1 has responded to the Interchange Authority's communication under INT-005 R1 concerning the pending transition of Arranged Interchange to Confirmed Interchange for that specific Interchange.

2. Levels of Non-Compliance

2.1. Level 1: One occurrence[2] of not responding to the Interchange Authority as described in R1.

2.2. Level 2: Two occurrences[1] of not responding to the Interchange Authority as described in R1.

2.3. Level 3: Three occurrences[1] of not responding to the Interchange Authority as described in R1.

[2] This does not include instances of not responding due to extenuating circumstances approved by the Compliance Monitor.

2.4. Level 4: Four or more occurrences[1] of not responding to the Interchange Authority as described in R1 or no evidence provided.

E. **Regional Differences**

None.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Approved by BOT	New
2	May 2, 2007	Approved by BOT	Revised
3	April 8, 2010	Approved by FERC, Effective July 1, 2010	

Timing Requirements for all Interconnections except WECC

		A	B	C	D
If Arranged Interchange (RFI)[3] is Submitted	**IA Assigned Time Classification**	**IA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments**	**IA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**
> 1 hour after the RFI start time	ATF	≤ 1 minute from RFI submission	Entities have up to 2 hours to respond.	≤ 1 minute from receipt of all Reliability Assessments	NA
< 15 minutes prior to ramp start and ≤ 1 hour after the RFI start time	Late	≤ 1 minute from RFI submission	Entities have up to 10 minutes to respond.	≤ 1 minute from receipt of all Reliability Assessments	≤ 3 minutes after receipt of confirmed RFI
< 1 hour and ≥ 15 minutes prior to ramp start	On- time	≤ 1 minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
≥ 1 hour to < 4 hours prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 20 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start

[3] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

Example of Timing Requirements for all Interconnections except WECC

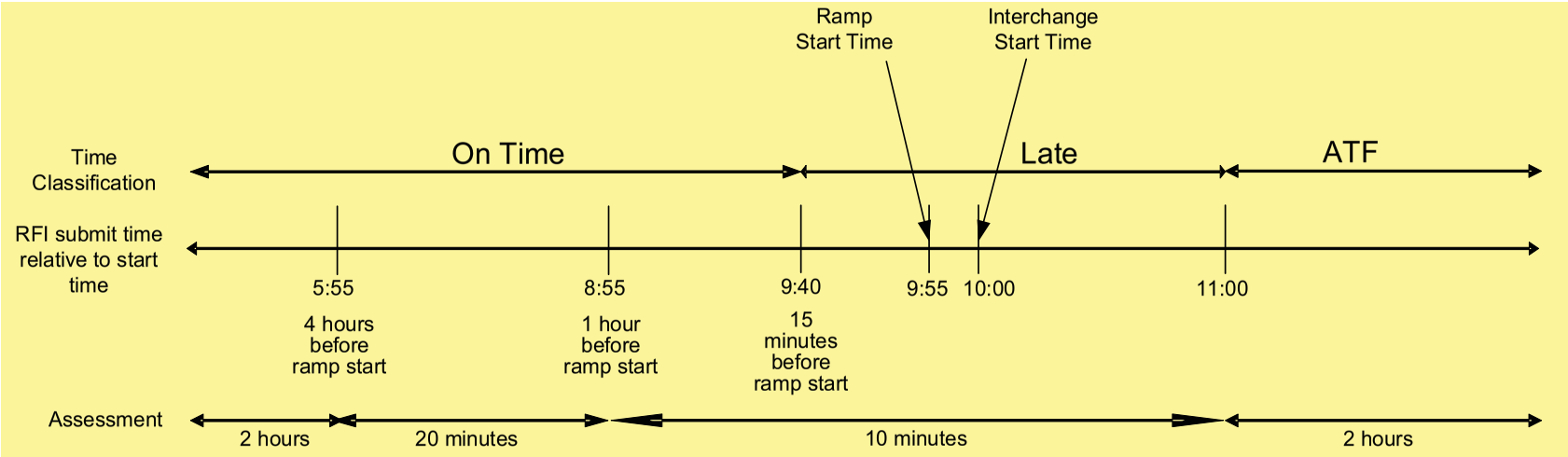

Timing Requirements for WECC

		A	B	C	D
If Arranged Interchange (RFI)[4] is Submitted	**IA Assigned Time Classification**	**IA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments**	**IA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF	≤ 1minute from RFI submission	Entities have up to 2 hours to respond.	≤ 1minute from receipt of all Reliability Assessments	NA
<10 minutes prior to ramp start and ≤1 hour after the start time	Late	≤ 1minute from RFI submission	Entities have up to 10 minutes to respond.	≤ 1minute from receipt of all Reliability Assessments	≤ 3 minutes after receipt of confirmed RFI
10 minutes prior to ramp start	On- time	≤ 1minute from RFI submission	≤ 5 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
11 minutes prior to ramp start	On- time	≤ 1minute from RFI submission	≤ 6 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
12 minutes prior to ramp start	On- time	≤ 1minute from RFI submission	≤ 7 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
13 minutes prior to ramp start	On- time	≤ 1minute from RFI submission	≤ 8 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
14 minutes prior to ramp start	On- time	≤ 1minute from RFI submission	≤ 9 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
<1 hour and ≥ 15 minutes prior to ramp start	On- time	≤ 1minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
≥ 1hour and < 4 hours prior to ramp start	On- time	≤ 1minute from RFI submission	< 20 minutes from Arranged interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On- time	≤ 1minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start
Submitted before 10:00 PPT with start time ≥ 00:00 PPT of following day	On- time	≤ 1minute from RFI submission	By 12:00 PPT of day the Arranged Interchange was received by the IA	≤ 1minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start

[4] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

Example of Timing Requirements for WECC

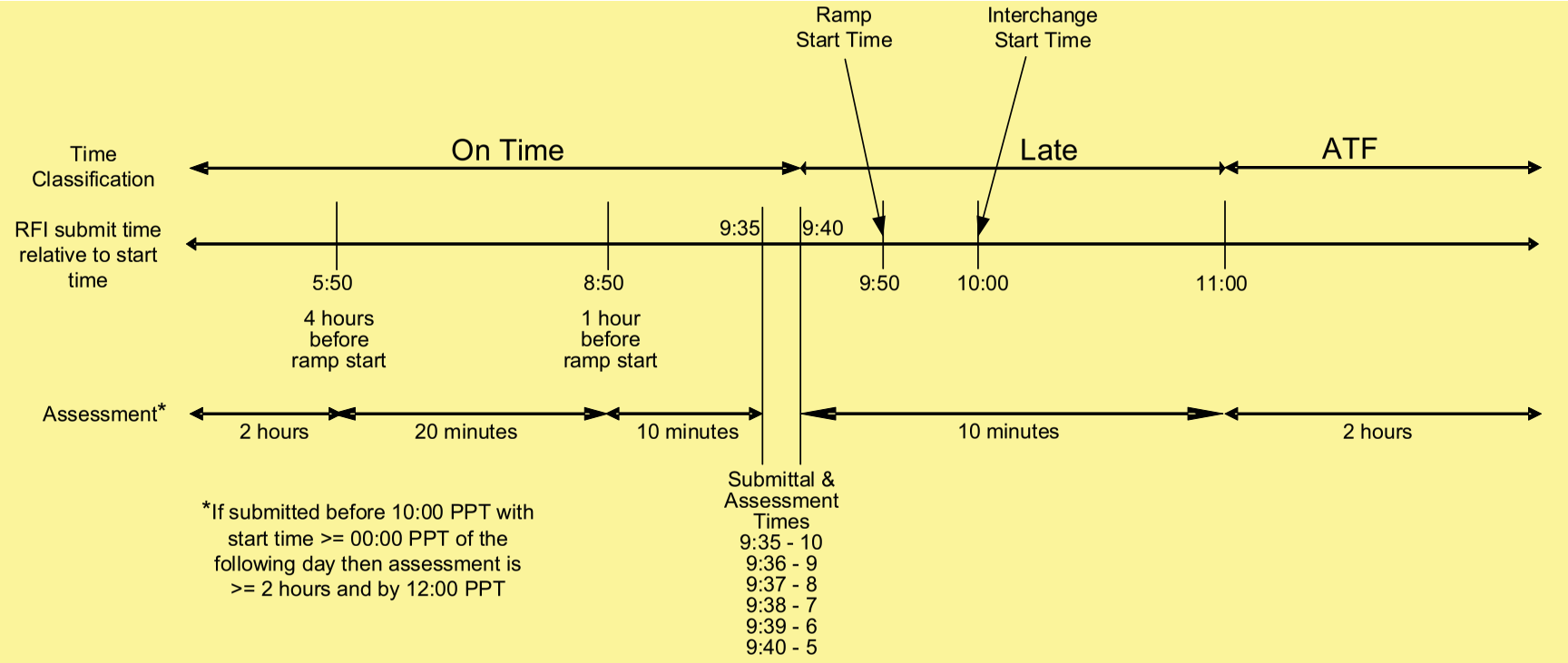

A. Introduction

1. **Title:** **Interchange Authority Distributes Status**
2. **Number:** INT-008-3
3. **Purpose:** To ensure that the implementation of Interchange between Source and Sink Balancing Authorities is coordinated by an Interchange Authority.
4. **Applicability:**

   4.1. Interchange Authority.
5. **Effective Date:** July 1, 2010

B. Requirements

R1. Prior to the expiration of the time period defined in the Timing Table, Column C, the Interchange Authority shall distribute to all Balancing Authorities (including Balancing Authorities on both sides of a direct current tie), Transmission Service Providers and Purchasing-Selling Entities involved in the Arranged Interchange whether or not the Arranged Interchange has transitioned to a Confirmed Interchange.

R1.1. For Confirmed Interchange, the Interchange Authority shall also communicate:

R1.1.1. Start and stop times, ramps, and megawatt profile to Balancing Authorities.

R1.1.2. Necessary Interchange information to NERC-identified reliability analysis services.

C. Measures

M1. For each Arranged Interchange, the Interchange Authority shall provide evidence that it has distributed the final status and Confirmed Interchange information specified in Requirement 1 to all Balancing Authorities, Transmission Service Providers and Purchasing-Selling Entities involved in the Arranged Interchange within the time period defined in the Timing Table, Column C. If denied, the Interchange Authority shall tell all involved parties that approval has been denied.

M1.1 For each Arranged Interchange that includes a direct current tie, the Interchange Authority shall provide evidence that it has communicated the final status to the Balancing Authorities on both sides of the direct current tie, even if the Balancing Authorities are neither the Source nor Sink for the Interchange.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Time Frame

   The Performance-Reset Period shall be twelve months from the last non-compliance to R1.

   1.3. Data Retention

The Interchange Authority shall keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

1.4. Additional Compliance Information

Each Interchange Authority shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

Subsequent to the initial compliance review, compliance will be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of noncompliant Interchange Authorities, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. Complaints will be evaluated by the Compliance Monitor.

Each Interchange Authority shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records for the audit period which indicate the Interchange Authority's distribution of all Arranged Interchange final status and Confirmed Interchange information to all entities involved in an Interchange per R1. The Compliance Monitor may request up to a three-month period of historical data ending with the date the request is received by the Interchange Authority

1.4.6 For specific complaints, only those data and system log records associated with the specific Interchange event contained in the complaint which indicate that the Interchange Authority distributed the Arranged Interchange final status and Confirmed Interchange information to all entities involved in that specific Interchange.

2. Levels of Non-Compliance

2.1. Level 1: One occurrence[1] of not distributing final status and information as described in R1.

2.2. Level 2: Two occurrences[1] of not distributing final status and information as described in R1.

2.3. Level 3: Three occurrences[1] of not distributing final status and information as described in R1.

[1] This does not include instances of not distributing information due to extenuating circumstances approved by the Compliance Monitor.

2.4. Level 4: Four or more occurrences[1] of not distributing final status and information as described in R1 or no evidence provided.

E. **Regional Differences**

None.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Approved by BOT	New
2	May 2, 2007	Approved by BOT	Revised
3	April 8, 2010	Approved by FERC, Effective July 1, 2010	

Timing Requirements for all Interconnections except WECC

		A	B	C	D
If Arranged Interchange (RFI)[2] is Submitted	**IA Assigned Time Classification**	**IA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments**	**IA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**
> 1 hour after the RFI start time	ATF	≤ 1 minute from RFI submission	Entities have up to 2 hours to respond.	≤ 1 minute from receipt of all Reliability Assessments	NA
< 15 minutes prior to ramp start and ≤ 1 hour after the RFI start time	Late	≤ 1 minute from RFI submission	Entities have up to 10 minutes to respond.	≤ 1 minute from receipt of all Reliability Assessments	≤ 3 minutes after receipt of confirmed RFI
< 1 hour and ≥ 15 minutes prior to ramp start	On- time	≤ 1 minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
≥ 1 hour to < 4 hours prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 20 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start

[2] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

Example of Timing Requirements for all Interconnections except WECC

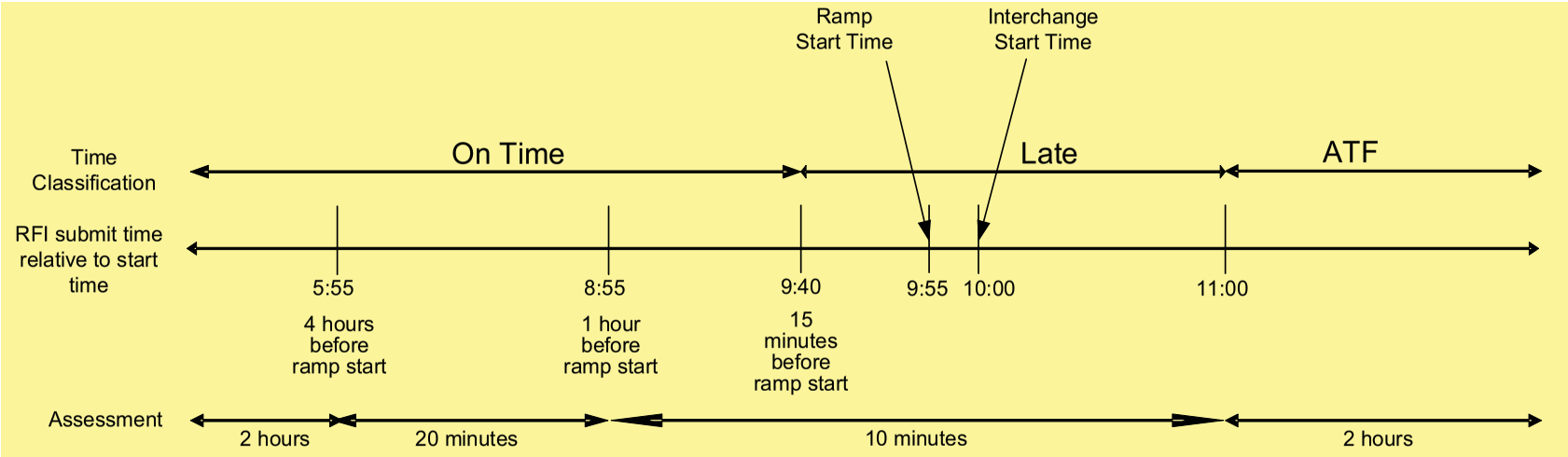

Timing Requirements for WECC

		A	B	C	D
If Arranged Interchange (RFI)[3] is Submitted	**IA Assigned Time Classification**	**IA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments**	**IA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF	≤ 1minute from RFI submission	Entities have up to 2 hours to respond.	≤ 1minute from receipt of all Reliability Assessments	NA
<10 minutes prior to ramp start and ≤1 hour after the start time	Late	≤ 1minute from RFI submission	Entities have up to 10 minutes to respond.	≤ 1minute from receipt of all Reliability Assessments	≤ 3 minutes after receipt of confirmed RFI
10 minutes prior to ramp start	On- time	≤ 1minute from RFI submission	≤ 5 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
11 minutes prior to ramp start	On- time	≤ 1minute from RFI submission	≤ 6 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
12 minutes prior to ramp start	On- time	≤ 1minute from RFI submission	≤ 7 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
13 minutes prior to ramp start	On- time	≤ 1minute from RFI submission	≤ 8 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
14 minutes prior to ramp start	On- time	≤ 1minute from RFI submission	≤ 9 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
<1 hour and ≥ 15 minutes prior to ramp start	On- time	≤ 1minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
≥ 1hour and < 4 hours prior to ramp start	On- time	≤ 1minute from RFI submission	< 20 minutes from Arranged interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On- time	≤ 1minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start
Submitted before 10:00 PPT with start time ≥ 00:00 PPT of following day	On- time	≤ 1minute from RFI submission	By 12:00 PPT of day the Arranged Interchange was received by the IA	≤ 1minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start

[3] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

Example of Timing Requirements for WECC

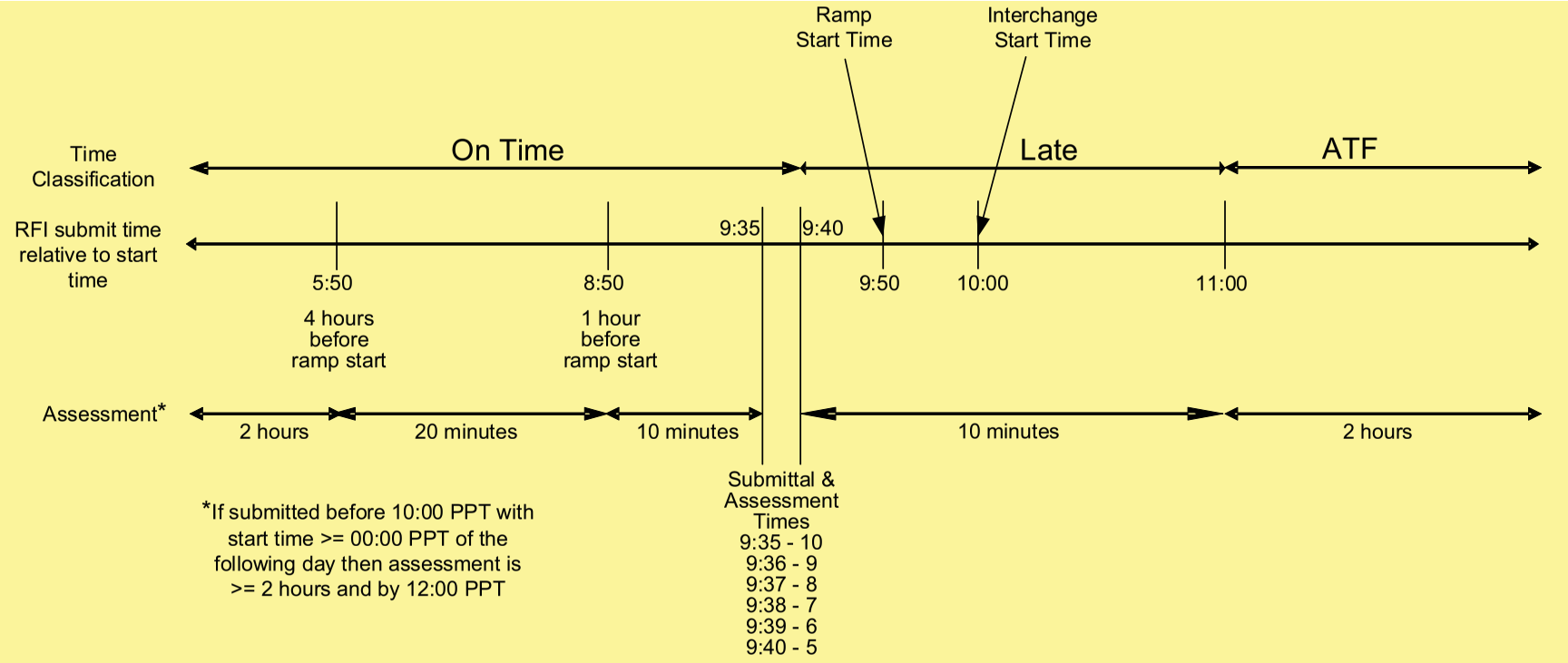

A. Introduction

1. **Title:** **Available Transmission System Capability**
2. **Number:** **MOD-001-1**
3. **Purpose:** To ensure that calculations are performed by Transmission Service Providers to maintain awareness of available transmission system capability and future flows on their own systems as well as those of their neighbors
4. **Applicability:**
   - **4.1.** Transmission Service Provider.
   - **4.2.** Transmission Operator.
5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.

B. Requirements

R1. Each Transmission Operator shall select one of the methodologies[1] listed below for calculating Available Transfer Capability (ATC) or Available Flowgate Capability (AFC) for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- The Area Interchange Methodology, as described in MOD-028
- The Rated System Path Methodology, as described in MOD-029
- The Flowgate Methodology, as described in MOD-030

R2. Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s): [*Violation Risk Factor: Lower* [*Time Horizon: Operations Planning*]

- **R2.1.** Hourly values for at least the next 48 hours.
- **R2.2.** Daily values for at least the next 31 calendar days.
- **R2.3.** Monthly values for at least the next 12 months (months 2-13).

R3. Each Transmission Service Provider shall prepare and keep current an Available Transfer Capability Implementation Document (ATCID) that includes, at a minimum, the following information: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- **R3.1.** Information describing how the selected methodology (or methodologies) has been implemented, in such detail that, given the same information used by the Transmission Service Provider, the results of the ATC or AFC calculations can be validated.

[1] All ATC Paths do not have to use the same methodology and no particular ATC Path must use the same methodology for all time periods.

R3.2. A description of the manner in which the Transmission Service Provider will account for counterflows including:

R3.2.1. How confirmed Transmission reservations, expected Interchange and internal counterflow are addressed in firm and non-firm ATC or AFC calculations.

R3.2.2. A rationale for that accounting specified in R3.2.

R3.3. The identity of the Transmission Operators and Transmission Service Providers from which the Transmission Service Provider receives data for use in calculating ATC or AFC.

R3.4. The identity of the Transmission Service Providers and Transmission Operators to which it provides data for use in calculating transfer or Flowgate capability.

R3.5. A description of the allocation processes listed below that are applicable to the Transmission Service Provider:

- Processes used to allocate transfer or Flowgate capability among multiple lines or sub-paths within a larger ATC Path or Flowgate.
- Processes used to allocate transfer or Flowgate capabilities among multiple owners or users of an ATC Path or Flowgate.
- Processes used to allocate transfer or Flowgate capabilities between Transmission Service Providers to address issues such as forward looking congestion management and seams coordination.

R3.6. A description of how generation and transmission outages are considered in transfer or Flowgate capability calculations, including:

R3.6.1. The criteria used to determine when an outage that is in effect part of a day impacts a daily calculation.

R3.6.2. The criteria used to determine when an outage that is in effect part of a month impacts a monthly calculation.

R3.6.3. How outages from other Transmission Service Providers that can not be mapped to the Transmission model used to calculate transfer or Flowgate capability are addressed.

R4. The Transmission Service Provider shall notify the following entities before implementing a new or revised ATCID: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R4.1. Each Planning Coordinator associated with the Transmission Service Provider's area.

R4.2. Each Reliability Coordinator associated with the Transmission Service Provider's area.

R4.3. Each Transmission Operator associated with the Transmission Service Provider's area.

R4.4. Each Planning Coordinator adjacent to the Transmission Service Provider's area.

R4.5. Each Reliability Coordinator adjacent to the Transmission Service Provider's area.

R4.6. Each Transmission Service Provider whose area is adjacent to the Transmission Service Provider's area.

R5. The Transmission Service Provider shall make available the current ATCID to all of the entities specified in R4. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R6. When calculating Total Transfer Capability (TTC) or Total Flowgate Capability (TFC) the Transmission Operator shall use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that time period. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R7. When calculating ATC or AFC the Transmission Service Provider shall use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that time period. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R8. Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

R8.1. Hourly values, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the ATC equation.

R8.2. Daily values, once per day.

R8.3. Monthly values, once per week.

R9. Within thirty calendar days of receiving a request by any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator for data from the list below solely for use in the requestor's ATC or AFC calculations, each Transmission Service Provider receiving said request shall begin to make the requested data available to the requestor, subject to the conditions specified in R9.1 and R9.2: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Expected generation and Transmission outages, additions, and retirements.
- Load forecasts.
- Unit commitments and order of dispatch, to include all designated network resources and other resources that are

Note that the North American Energy Standards Board (NAESB) is developing the companion standards that address the posting of ATC information, including supporting information such as that described in R9.

committed or have the legal obligation to run, as they are expected to run, in one of the following formats chosen by the data provider:

  - Dispatch Order
  - Participation Factors
  - Block Dispatch

- Aggregated firm capacity set-aside for Network Integration Transmission Service and aggregated non-firm capacity set aside for Network Integration Transmission Service (i.e. Secondary Service).
- Firm and non-firm Transmission reservations.
- Aggregated capacity set-aside for Grandfathered obligations
- Firm roll-over rights.
- Any firm and non-firm adjustments applied by the Transmission Service Provider to reflect parallel path impacts.
- Power flow models and underlying assumptions.
- Contingencies, provided in one or more of the following formats:
  - A list of Elements
  - A list of Flowgates
  - A set of selection criteria that can be applied to the Transmission model used by the Transmission Operator and/or Transmission Service Provider
- Facility Ratings.
- Any other services that impact Existing Transmission Commitments (ETCs).
- Values of Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) for all ATC Paths or Flowgates.
- Values of Total Flowgate Capability (TFC) and AFC for any Flowgates considered by the Transmission Service Provider receiving the request when selling Transmission service.
- Values of TTC and ATC for all ATC Paths for those Transmission Service Providers receiving the request that do not consider Flowgates when selling Transmission Service.
- Source and sink identification and mapping to the model.

R9.1. The Transmission Service Provider shall make its own current data available, in the format maintained by the Transmission Service Provider, for up to 13 months into the future (subject to confidentiality and security requirements).

R9.1.1. If the Transmission Service Provider uses the data requested in its transfer or Flowgate capability calculations, it shall make the data used available

R9.1.2. If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, but maintains that data, it shall make that data available

R9.1.3. If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, and does not maintain that data, it shall not be required to make that data available

R9.2. This data shall be made available by the Transmission Provider on the schedule specified by the requestor (but no more frequently than once per hour, unless mutually agreed to by the requester and the provider).

C. Measures

M1. The Transmission Operator shall provide evidence (such as a calculation, inclusion of the information in the ATCID, or other written documentation) that it has selected one of the specified methodologies per time period in R2 for use in determining Transfer Capabilities of those Facilities for each ATC Path within the Transmission Operator's operating area. (R1).

M2. The Transmission Service Provider shall provide ATC or AFC values and identification of the selected methodologies along with other evidence (such as written documentation, processes, or data) to show it calculated ATC or AFC for the following using the selected methodology or methodologies chosen as part of R1 (R2):

- There has been at least 48 hours of hourly values calculated at all times. (R2.1)
- There has been at least 31 consecutive calendar days of daily values calculated at all times. (R2.2)
- There has been at least the next 12 months of monthly values calculated at all times (Months 2-13). (R2.3)

M3. The Transmission Service Provider shall provide its current ATCID that contains all the information specified in R3. (R3)

M4. The Transmission Service Provider shall provide evidence (such as dated electronic mail messages, mail receipts, or voice recordings) that it has notified the entities specified in R4 before a new or revised ATCID was implemented. (R4)

M5. The Transmission Service Provider shall provide evidence (such as a demonstration) that the current ATCID is available to all of the entities specified in R4, as required by R5. (R5)

M6. The Transmission Operator shall provide a copy of the assumptions (such as contingencies, loop flow, generation re-dispatch, switching operating guides or data sources for load forecast and facility outages) used to calculate TTC or TFC as well as other evidence (such as copies of operations planning studies, models, supporting information, or data) to show that the assumptions used in determining TTC or TFC are no more limiting than those used in planning of operations for the corresponding time period studied. Alternatively the Transmission Operator may demonstrate that the same load flow cases are used for both TTC or TFC and Operations Planning.

When different inputs to the calculations are used because the calculations are performed at different times, such that the most recent information is used in any calculation, a difference in that input data shall not be considered to be a difference in assumptions. (R6)

M7. The Transmission Service Provider shall provide a copy of the assumptions (such as contingencies, loop flow, generation re-dispatch, switching operating guides or data sources for load forecast and facility outages) used to calculate ATC or AFC as well as other evidence (such as copies of operations planning studies, models, supporting information, or data) to show that the assumptions used in determining ATC or AFC are no more limiting than those used in planning of operations for the corresponding time period studied. Alternatively the Transmission Service Provider may demonstrate that the same load flow cases are used for both AFC and Operations Planning. When different inputs to the calculations are used because the calculations are performed at different times, such that the most recent information is used in any calculation, a difference in that input data shall not be considered to be a difference in assumptions. (R7)

M8. The Transmission Service Provider calculating ATC shall provide evidence (such as logs or data) that it has calculated the hourly, daily, and monthly values on at least the minimum frequencies specified in R8 or provide evidence (such as data, procedures, or software documentation) that the calculated values identified in the ATC equation have not changed. (R8)

M9. The Transmission Service Provider shall provide a copy of the dated request, if any, for ATC or AFC data as well as evidence to show it responded to that request (such as logs or data) within thirty calendar days of receiving the request, and the requested data items were made available in accordance with R9. (R9)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Operator shall maintain its current selected method(s) for calculating ATC or AFC and any methods in force since last compliance audit period to show compliance with R1.

- The Transmission Service Provider shall maintain evidence to show compliance with R2, R4, R6, R7, and R8 for the most recent calendar year plus the current year.
- The Transmission Service Provider shall maintain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R3.
- The Transmission Service Provider shall maintain evidence to show compliance with R5 for the most recent three calendar years plus the current year.
- The Transmission Operator shall maintain evidence to show compliance with R6 for the most recent calendar year plus the current year.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Transmission Operator did not select one of the specified methodologies for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area.
R2.	One or more of the following: ▪ The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 30 hours but less than the next 48 hours. ▪ Has calculated daily ATC or AFC values for more than the next 21 calendar days but less than the next 31 calendar days. ▪ Has calculated monthly ATC or AFC values for more than the next 9 months but less than the next 12 months.	One or more of the following: ▪ The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 20 hours but less than the next 31 hours. ▪ Has calculated daily ATC or AFC values for more than the next 14 calendar days but less than the next 22 calendar days. ▪ Has calculated monthly ATC or AFC values for more than the next 6 months but less than the next 10 months.	One or more of the following: ▪ The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 10 hours but less than the next 21 hours. ▪ Has calculated daily ATC or AFC values for more than the next 7 calendar days but less than the next 15 calendar days. ▪ Has calculated monthly ATC or AFC values for more than the next 3 months but less than the next 7 months.	One or more of the following: ▪ The Transmission Service Provider has calculated hourly ATC or AFC values for less than the next 11 hours. ▪ Has calculated daily ATC or AFC values for less than the next 8 calendar days. ▪ Has calculated monthly ATC or AFC values for less than the next 4 months. ▪ Did not use the selected methodology(ies) to calculate ATC.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	The Transmission Service Provider has an ATCID that does not incorporate changes made up to three months ago.	The Transmission Service Provider has an ATCID that does not incorporate changes made more than three months but not more than six months ago.	The Transmission Service Provider has an ATCID that does not incorporate changes made more than six months but not more than one year ago. **OR** The Transmission Service Provider has an ATCID, but it does not include one or two of the information items described in R3.	The Transmission Service Provider has an ATCID that does not incorporate changes made a year or more ago. **OR** The Transmission Service Provider does not have an ATCID, or its ATCID does not include three or more of the information items described in R3.
R4.	The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID after, but not more than 30 calendar days after, its implementation.	The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 30, but not more than 60, calendar days after its implementation.	The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 60, but not more than 90, calendar days after its implementation.	The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 90 calendar days after its implementation. **OR** The Transmission Service Provider did not notify one or more of the parties specified in R4 of a new or modified ATCID for more than 90 calendar days after its implementation.
R5.	N/A	N/A	N/A	The Transmission Service Provider did not make the ATCID available to the parties described in R4.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6.	The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than zero ATC Paths or Flowgates, but not more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater).	The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater), but not more than 10% of all ATC Paths or Flowgates or 2 ATC Paths or Flowgates (whichever is greater).	The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 10% of all ATC Paths or Flowgates or 2 ATC Path or Flowgate (whichever is greater), but not more than 15% of all ATC Paths or Flowgates or 3 ATC Paths or Flowgates (whichever is greater).	The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 15% of all ATC Paths or Flowgates or more than 3 ATC Paths or Flowgates (whichever is greater).
R7	The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than zero ATC Paths or Flowgates, but not more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater).	The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater), but not more than 10% of all ATC Paths or Flowgates or 2 ATC Paths or Flowgates (whichever is greater).	The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 10%, of all ATC Paths or Flowgates or 2 ATC Path or Flowgate (whichever is greater), but not more than 15% of all ATC Paths or Flowgates or 3 ATC Paths or Flowgates (whichever is greater).	The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 15% of all ATC Paths or Flowgates or more than 3 ATC Paths or Flowgates (whichever is greater).
R8.	One or more of the following: ▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the 175-hour per year requirement.	One or more of the following: ▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the 175-hour per year requirement.	One or more of the following: ▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the 175-hour per year requirement.	One or more of the following: ▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	▪ For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days. ▪ For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days.	▪ For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days. ▪ For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days.	For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days. ▪ For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days.	described in the ATC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days. ▪ For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days.
R9	N/A	The Transmission Service Provider made the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available more than 30 calendar days but less than 45 calendar days after receiving a request.	The Transmission Service Provider made the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available 45 calendar days or more but less than 60 calendar days after receiving a request.	The Transmission Service Provider did not make the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available for 60 calendar days or more after receiving a request.

A. Introduction

1. **Title:** **Capacity Benefit Margin**

2. **Number:** **MOD-004-1**

3. **Purpose:** To promote the consistent and reliable calculation, verification, preservation, and use of Capacity Benefit Margin (CBM) to support analysis and system operations.

4. **Applicability:**

   4.1. Load-Serving Entities.

   4.2. Resource Planners.

   4.3. Transmission Service Providers.

   4.4. Balancing Authorities.

   4.5. Transmission Planners, when their associated Transmission Service Provider has elected to maintain CBM.

5. **Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees.

B. Requirements

R1. The Transmission Service Provider that maintains CBM shall prepare and keep current a "Capacity Benefit Margin Implementation Document" (CBMID) that includes, at a minimum, the following information: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Long-term Planning*]

R1.1. The process through which a Load-Serving Entity within a Balancing Authority Area associated with the Transmission Service Provider, or the Resource Planner associated with that Balancing Authority Area, may ensure that its need for Transmission capacity to be set aside as CBM will be reviewed and accommodated by the Transmission Service Provider to the extent Transmission capacity is available.

R1.2. The procedure and assumptions for establishing CBM for each Available Transfer Capability (ATC) Path or Flowgate.

R1.3. The procedure for a Load-Serving Entity or Balancing Authority to use Transmission capacity set aside as CBM, including the manner in which the Transmission Service Provider will manage situations where the requested use of CBM exceeds the amount of CBM available.

R2. The Transmission Service Provider that maintains CBM shall make available its current CBMID to the Transmission Operators, Transmission Service Providers, Reliability Coordinators, Transmission Planners, Resource Planners, and Planning Coordinators that are within or adjacent to the Transmission Service Provider's area, and to the Load Serving Entities and Balancing Authorities within the Transmission Service Provider's

area, and notify those entities of any changes to the CBMID prior to the effective date of the change. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R3. Each Load-Serving Entity determining the need for Transmission capacity to be set aside as CBM for imports into a Balancing Authority Area shall determine that need by: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R3.1. Using one or more of the following to determine the GCIR:

- Loss of Load Expectation (LOLE) studies
- Loss of Load Probability (LOLP) studies
- Deterministic risk-analysis studies
- Reserve margin or resource adequacy requirements established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities

R3.2. Identifying expected import path(s) or source region(s).

R4. Each Resource Planner determining the need for Transmission capacity to be set aside as CBM for imports into a Balancing Authority Area shall determine that need by: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R4.1. Using one or more of the following to determine the GCIR:

- Loss of Load Expectation (LOLE) studies
- Loss of Load Probability (LOLP) studies
- Deterministic risk-analysis studies
- Reserve margin or resource adequacy requirements established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities

R4.2. Identifying expected import path(s) or source region(s).

R5. At least every 13 months, the Transmission Service Provider that maintains CBM shall establish a CBM value for each ATC Path or Flowgate to be used for ATC or Available Flowgate Capability (AFC) calculations during the 13 full calendar months (months 2-14) following the current month (the month in which the Transmission Service Provider is establishing the CBM values). This value shall: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R5.1. Reflect consideration of each of the following if available:

- Any studies (as described in R3.1) performed by Load-Serving Entities for loads within the Transmission Service Provider's area
- Any studies (as described in R4.1) performed by Resource Planners for loads within the Transmission Service Provider's area

- Any reserve margin or resource adequacy requirements for loads within the Transmission Service Provider's area established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities

R5.2. Be allocated as follows:

- For ATC Paths, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners
- For Flowgates, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners and the distribution factors associated with those paths or regions, as determined by the Transmission Service Provider

R6. At least every 13 months, the Transmission Planner shall establish a CBM value for each ATC Path or Flowgate to be used in planning during each of the full calendar years two through ten following the current year (the year in which the Transmission Planner is establishing the CBM values). This value shall: [*Violation Risk Factor: Lower*] [*Time Horizon: Long-term Planning*]

R6.1. Reflect consideration of each of the following if available:

- Any studies (as described in R3.1) performed by Load-Serving Entities for loads within the Transmission Planner's area
- Any studies (as described in R4.1) performed by Resource Planners for loads within the Transmission Planner's area
- Any reserve margin or resource adequacy requirements for loads within the Transmission Planner's area established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities

R6.2. Be allocated as follows:

- For ATC Paths, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners
- For Flowgates, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners and the distribution factors associated with those paths or regions, as determined by the Transmission Planner.

R7. Less than 31 calendar days after the establishment of CBM, the Transmission Service Provider that maintains CBM shall notify all the Load-Serving Entities and Resource Planners that determined they had a need for CBM on the Transmission Service Provider's system of the amount of CBM set aside. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R8. Less than 31 calendar days after the establishment of CBM, the Transmission Planner shall notify all the Load-Serving Entities and Resource Planners that determined they

had a need for CBM on the system being planned by the Transmission Planner of the amount of CBM set aside. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R9. The Transmission Service Provider that maintains CBM and the Transmission Planner shall each provide (subject to confidentiality and security requirements) copies of the applicable supporting data, including any models, used for determining CBM or allocating CBM over each ATC Path or Flowgate to the following: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Long-term Planning*]

R9.1. Each of its associated Transmission Operators within 30 calendar days of their making a request for the data.

R9.2. To any Transmission Service Provider, Reliability Coordinator, Transmission Planner, Resource Planner, or Planning Coordinator within 30 calendar days of their making a request for the data.

R10. The Load-Serving Entity or Balancing Authority shall request to import energy over firm Transfer Capability set aside as CBM only when experiencing a declared NERC Energy Emergency Alert (EEA) 2 or higher. [*Violation Risk Factor: Lower*] [*Time Horizon: Same-day Operations*]

R11. When reviewing an Arranged Interchange using CBM, all Balancing Authorities and Transmission Service Providers shall waive, within the bounds of reliable operation, any Real-time timing and ramping requirements. [*Violation Risk Factor: Medium*] [*Time Horizon: Same-day Operations*]

R12. The Transmission Service Provider that maintains CBM shall approve, within the bounds of reliable operation, any Arranged Interchange using CBM that is submitted by an "energy deficient entity[1]" under an EEA 2 if: [*Violation Risk Factor: Medium*] [*Time Horizon: Same-day Operations*]

R12.1. The CBM is available

R12.2. The EEA 2 is declared within the Balancing Authority Area of the "energy deficient entity," and

R12.3. The Load of the "energy deficient entity" is located within the Transmission Service Provider's area.

C. Measures

M1. Each Transmission Service Provider that maintains CBM shall produce its CBMID evidencing inclusion of all information specified in R1. (R1)

M2. Each Transmission Service Provider that maintains CBM shall have evidence (such as dated logs and data, copies of dated electronic messages, or other equivalent evidence) to show that it made the current CBMID available to the Transmission Operators, Transmission Service Providers, Reliability Coordinators, Transmission Planners, and Planning Coordinators specified in R2, and that prior to any change to the CBMID, it notified those entities of the change. (R2)

[1] See Attachment 1-EOP-002-0 for explanation.

M3. Each Load-Serving Entity that determined a need for Transmission capacity to be set aside as CBM shall provide evidence (including studies and/or requirements) that it met the criteria in R3. (R3)

M4. Each Resource Planner that determined a need for Transmission capacity to be set aside as CBM shall provide evidence (including studies and/or requirements) that it met the criteria in R4. (R4)

M5. Each Transmission Service Provider that maintains CBM shall provide evidence (such as studies, requirements, and dated CBM values) that it established 13 months of CBM values consistent with the requirements in R5.1 and allocated the values consistent with the requirements in R5.2. (Note that CBM values may legitimately be zero.) (R5)

M6. Each Transmission Planner with an associated Transmission Service Provider that maintains CBM shall provide evidence (such as studies, requirements, and dated CBM values) that it established CBM values for years two through ten consistent with the requirements in R6.1 and allocated the values consistent with the requirements in R6.2. Inclusion of GCIR based on R6.1 and R6.2 within the transmission base case meets this requirement. (Note that CBM values may legitimately be zero.) (R6)

M7. Each Transmission Service Provider that maintains CBM shall provide evidence (such as dated e-mail, data, or other records) that it notified the entities described in R7 of the amount of CBM set aside. (R7)

M8. Each Transmission Planner with an associated Transmission Service Provider that maintains CBM shall provide evidence (such as e-mail, data, or other records) that it notified the entities described in R8 of the amount of CBM set aside. (R8)

M9. Each Transmission Service Provider that maintains CBM and each Transmission Planner shall provide evidence including copies of dated requests for data supporting the calculation of CBM along with other evidences such as copies of electronic messages or other evidence to show that it provided the required entities with copies of the supporting data, including any models, used for allocating CBM as specified in R9. (R9)

M10. Each Load-Serving Entity and Balancing Authority shall provide evidence (such as logs, copies of tag data, or other data from its Reliability Coordinator) that at the time it requested to import energy using firm Transfer Capability set aside as CBM, it was in an EEA 2 or higher. (R10)

M11. Each Balancing Authority and Transmission Service Provider shall provide evidence (such as operating logs and tag data) that it waived Real-time timing and ramping requirements when approving an Arranged Interchange using CBM (R11)

M12. Each Transmission Service Provider that maintains CBM shall provide evidence including copies of CBM values along with other evidence (such as tags, reports, and supporting data) to show that it approved any Arranged Interchange meeting the criteria in R12. (R12)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority (CEA)

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

- The Transmission Service Provider that maintains CBM shall maintain its current, in force CBMID and any prior versions of the CBMID that were in force during the past three calendar years plus the current year to show compliance with R1.
- The Transmission Service Provider that maintains CBM shall maintain evidence to show compliance with R2, R5, R7, R9, and R12 for the most recent three calendar years plus the current year.
- The Load-Serving Entity shall each maintain evidence to show compliance with R3 and R10 for the most recent three calendar years plus the current year.
- The Resource Planner shall each maintain evidence to show compliance with R4 for the most recent three calendar years plus the current year.
- The Transmission Planner shall maintain evidence to show compliance with R6, R8, and R9 for the most recent three calendar years plus the current year.
- The Balancing Authority shall maintain evidence to show compliance with R10 and R11 for the most recent three calendar years plus the current year.
- The Transmission Service Provider shall maintain evidence to show compliance with R11 for the most recent three calendar years plus the current year.
- If an entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and subsequently submitted audit records.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting

- Complaints

1.5. Additional Compliance Information

None.

Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Service Provider that maintains CBM has a CBMID that does not incorporate changes that have been made within the last three months.	The Transmission Service Provider that maintains CBM has a CBMID that does not incorporate changes that have been made more than three, but not more than six, months ago. **OR** The CBM maintaining Transmission Service Provider's CBMID does not address one of the sub requirements.	The Transmission Service Provider that maintains CBM has a CBMID that does not incorporate changes that have been made more than six, but not more than twelve, months ago. **OR** The CBM maintaining Transmission Service Provider's CBMID does not address two of the sub requirements.	The Transmission Service Provider that maintains CBM has a CBMID that does not incorporate changes that have been made more than twelve months ago. **OR** The Transmission Service Provider that maintains CBM does not have a CBMID; **OR** The CBM maintaining Transmission Service Provider's CBMID does not address three of the sub requirements.
R2.	The Transmission Service Provider that maintains CBM notifies one or more of the entities specified in R2 of a change in the CBM ID after the effective date of the change, but not more than 30 calendar days after the effective date of the change.	The Transmission Service Provider that maintains CBM notifies one or more of the entities specified in R2 of a change in the CBM ID 30 or more calendar days but not more than 60 calendar days after the effective date of the change.	The Transmission Service Provider that maintains CBM notifies one or more of the entities specified in R2 of a change in the CBM ID 60 or more calendar days but not more than 90 calendar days after the effective date of the change. **OR** The Transmission Service Provider that maintains CBM made available the CBMID to at least one, but not all, of the entities specified in R2.	The Transmission Service Provider that maintains CBM notifies one or more of the entities specified in R2 of a change in the CBM ID more than 90 calendar days after the effective date of the change. **OR** The Transmission Service Provider that maintains CBM made available the CBMID to none of the entities specified in R2.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.		The Load-Serving Entity did not use one of the methods described in R3.1 **OR** The Load-Serving Entity did not identify paths or regions as described in R3.2		The Load-Serving Entity did not use one of the methods described in R3.1 **AND** The Load-Serving Entity did not identify paths or regions as described in R3.2
R4		The Resource Planner did not use one of the methods described in R4.1 **OR** The Resource Planner did not identify paths or regions as described in R4.2		The Resource Planner did not use one of the methods described in R4.1 **AND** The Resource Planner did not identify paths or regions as described in R4.2
R5.	The Transmission Service Provider that maintains CBM established CBM more than 13 months, but not more than 16 months, after the last time the values were established.	The Transmission Service Provider that maintains CBM established CBM more than 16 months, but not more than 19 months, after the last time the values were established. **OR** The Transmission Service Provider that maintains CBM did not consider one or more of the items described in R5.1 that was available. **OR** The Transmission Service Provider that maintains CBM did not base the allocation on one or more paths or regions as	The Transmission Service Provider that maintains CBM established CBM more than 19 months, but not more than 22 months, after the last time the values were established.	The Transmission Service Provider that maintains CBM established CBM more than 22 months after the last time the values were established. **OR** The Transmission Service Provider that maintains CBM failed to establish an initial value for CBM. **OR** The Transmission Service Provider that maintains CBM did not consider one or more of the items described in R5.1 that was available, and did not base the allocation on one or more

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		described in R5.2.		paths or regions as described in R5.2
R6.	The Transmission Planner with an associated Transmission Service Provider that maintains CBM established CBM for each of the years 2 through 10 more than 13 months, but not more than 16 months, after the last time the values were established.	The Transmission Planner with an associated Transmission Service Provider that maintains CBM established CBM for each of the years 2 through 10 more than 16 months, but not more than 19 months, after the last time the values were established. **OR** The Transmission Planner with an associated Transmission Service Provider that maintains CBM did not consider one or more of the items described in R6.1 that was available. **OR** The Transmission Planner with an associated Transmission Service Provider that maintains CBM did not base the allocation	The Transmission Planner with an associated Transmission Service Provider that maintains CBM established CBM for each of the years 2 through 10 more than 19 months, but not more than 22 months, after the last time the values were established.	The Transmission Planner with an associated Transmission Service Provider that maintains CBM established CBM for each of the years 2 through 10 more than 22 months after the last time the values were established. **OR** The Transmission Planner with an associated Transmission Service Provider that maintains CBM failed to establish an initial value for CBM for each of the years 2 through 10. **OR** The Transmission Planner with an associated Transmission Service Provider that maintains CBM did not consider one or more of the items described in

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		on one or more paths or regions as described in R6.2		R6.1 that was available, and did not base the allocation on one or more paths or regions as described in R6.2
R7.	The Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 31 or more days, but less than 45 days.	The Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 45 or more days, but less than 60 days.	The Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 60 or more days, but less than 75 days. **OR** The Transmission Service Provider that maintains CBM notified at least one, but not all, of the entities as required.	The Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 75 or more days, **OR** The Transmission Service Provider that maintains CBM notified none of the entities as required.
R8.	The Transmission Planner with an associated Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 31 or more days, but less than 45 days.	The Transmission Planner with an associated Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 45 or more days, but less than 60 days.	The Transmission Planner with an associated Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 60 or more days, but less than 75 days. **OR** The Transmission Planner with	The Transmission Planner with an associated Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 75 or more days, **OR** The Transmission Planner with an associated Transmission

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
			an associated Transmission Service Provider that maintains CBM notified at least one, but not all, of the entities as required.	Service Provider that maintains CBM notified none of the entities as required.
R9.	The Transmission Service Provider or Transmission Planner provided a requester specified in R9 with the supporting data, including models, used to allocate CBM more than 30, but not more than 45, days after the submission of the request.	The Transmission Service Provider or Transmission Planner provided a requester specified in R9 with the supporting data, including models, used to allocate CBM more than 45, but not more than 60, days after the submission of the request.	The Transmission Service Provider or Transmission Planner provided a requester specified in R9 with the supporting data, including models, used to allocate CBM more than 60, but not more than 75, days after the submission of the request. **OR** The Transmission Service Provider or Transmission Planner provided at least one, but not all, of the requesters specified in R9 with the supporting data, including models, used to allocate CBM.	The Transmission Service Provider or Transmission Planner provided a requester specified in R9 with the supporting data, including models, used to allocate CBM more than 75 days after the submission of the request. **OR** The Transmission Service Provider or Transmission Planner provided none of the requesters specified in R9 with the supporting data, including models, used to allocate CBM.
R10.	N/A	N/A	N/A	A Load-Serving Entity or Balancing Authority requested to schedule energy over CBM while not in an EEA 2 or higher.
R11.	N/A	N/A	N/A	A Balancing Authority or Transmission Service Provider denied an Arranged Interchange using CBM based on timing or ramping requirements without a reliability reason to do so.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R12.	N/A	N/A	N/A	The Transmission Service Provider failed to approve an Arranged Interchange for CBM that met the criteria described in R12 without a reliability reason to do so.

A. Introduction

1. **Title:** **Transmission Reliability Margin Calculation Methodology**
2. **Number:** **MOD-008-1**
3. **Purpose:** To promote the consistent and reliable calculation, verification, preservation, and use of Transmission Reliability Margin (TRM) to support analysis and system operations.
4. **Applicability:**

   4.1. Transmission Operators that maintain TRM.
5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees.

B. Requirements

R1. Each Transmission Operator shall prepare and keep current a TRM Implementation Document (TRMID) that includes, as a minimum, the following information: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R1.1. Identification of (on each of its respective ATC Paths or Flowgates) each of the following components of uncertainty if used in establishing TRM, and a description of how that component is used to establish a TRM value:

- Aggregate Load forecast.
- Load distribution uncertainty.
- Forecast uncertainty in Transmission system topology (including, but not limited to, forced or unplanned outages and maintenance outages).
- Allowances for parallel path (loop flow) impacts.
- Allowances for simultaneous path interactions.
- Variations in generation dispatch (including, but not limited to, forced or unplanned outages, maintenance outages and location of future generation).
- Short-term System Operator response (Operating Reserve actions).
- Reserve sharing requirements.
- Inertial response and frequency bias.

R1.2. The description of the method used to allocate TRM across ATC Paths or Flowgates.

R1.3. The identification of the TRM calculation used for the following time periods:

R1.3.1. Same day and real-time.

R1.3.2. Day-ahead and pre-schedule.

R1.3.3. Beyond day-ahead and pre-schedule, up to thirteen months ahead.

R2. Each Transmission Operator shall only use the components of uncertainty from R1.1 to establish TRM, and shall not include any of the components of Capacity Benefit Margin (CBM). Transmission capacity set aside for reserve sharing agreements can be included in TRM. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R3. Each Transmission Operator shall make available its TRMID, and if requested, underlying documentation (if any) used to determine TRM, in the format used by the Transmission Operator, to any of the following who make a written request no more than 30 calendar days after receiving the request. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- Transmission Service Providers
- Reliability Coordinators
- Planning Coordinators
- Transmission Planner
- Transmission Operators

R4. Each Transmission Operator that maintains TRM shall establish TRM values in accordance with the TRMID at least once every 13 months. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R5. The Transmission Operator that maintains TRM shall provide the TRM values to its Transmission Service Provider(s) and Transmission Planner(s) no more than seven calendar days after a TRM value is initially established or subsequently changed. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

C. Measures

M1. Each Transmission Operator shall produce its TRMID evidencing inclusion of all specified information in R1. (R1)

M2. Each Transmission Operator shall provide evidence including its TRMID, TRM values, CBM values, or other evidence, (such as written documentation, study reports, documentation of its CBM process, and supporting information) to demonstrate that its TRM values did not include any elements of uncertainty beyond those defined in R1.1 and to show that it did not include any of the components of CBM. (R2)

M3. Each Transmission Operator shall provide a dated copy of any request from an entity described in R3. The Transmission Operator shall also provide evidence (such as copies of emails or postal receipts that show the recipient, date and contents) that the requested documentation (such as work papers and load flow cases) was made available within the specified timeframe to the requestor. (R3)

M4. Each Transmission Operator shall provide evidence (such as logs, study report, review notes, or data) that it established TRM values at least once every thirteen months for each of the TRM time periods. (R4)

M5. Each Transmission Operator shall provide evidence (such as logs, email, website postings) that it provided their Transmission Service Provider(s) and Transmission Planner(s) with the updated TRM value as described in R5. (R5)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

The Transmission Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Operator shall have its current, in-force TRMID and any TRMIDs in force since last compliance audit period for R1.
- The Transmission Operator shall retain evidence to show compliance with R2, R3, and R5 for the most recent three calendar years plus the current year.
- The Transmission Operator shall retain evidence to show compliance with R4 for the most recent three calendar years plus the current year.
- If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Compliance Monitoring and Enforcement Processes

Any of the following may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Operator has a TRMID that does not incorporate changes made up to three months ago.	The Transmission Operator has a TRMID that does not incorporate changes that have been made three or more months ago but less than six months ago. **OR** The Transmission Operator's TRMID does not address one of the following: ▪ R1.1 ▪ R1.2 ▪ Any one or more of the following: ○ R1.3.1, R1.3.2 or R1.3.3	The Transmission Operator has a TRMID that does not incorporate changes that have been made six or more months ago but less than one year ago. **OR** The Transmission Operator's TRMID does not address two of the following: ▪ R1.1 ▪ R1.2 ▪ Any one or more of the following: ○ R1.3.1, R1.3.2 or R1.3.3	The Transmission Operator has a TRMID that does not incorporate changes that have been made one year ago or more. **OR** The Transmission Operator does not have a TRMID. **OR** The Transmission Operator's TRMID does not address three of the following: ▪ R1.1 ▪ R1.2 ▪ Any one or more of the following: ○ R1.3.1, R1.3.2 or R1.3.3
R2.	N/A	N/A	N/A	One or both of the following: ▪ The Transmission Operator included elements of uncertainty not defined in R1 in their establishment of TRM. ▪ The Transmission Operator included components of CBM in TRM.
R3.	The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in more than 30 days but less than 45 days.	The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in 45 days or more but less than 60 days.	The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in 60 days or more but less than 90 days.	The Transmission Operator did not make the TRMID available for 90 days or more.

R4	The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. Not more than 5% or 1 value (whichever is greater) were incorrect or missing.	The Transmission Operator did not establish TRM within thirteen months of the previous determination, and the last determination was not more than 15 months ago OR The Transmission Operator established TRM values on schedule BUT the values were incomplete. More than 5%, or 1 value (which ever is greater) were incorrect or missing, but not more than 10% or 2 values (whichever is greater).	The Transmission Operator did not establish TRM within 15 months of the previous determination, and the last determination was not more than 18 months ago. OR The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. More than 10% or 2 values (which ever is greater) were incorrect or missing, but not more than 15% or 3 values.	The Transmission Operator did not establish TRM OR The last determination of TRM was more than 18 months ago. OR The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. More than 15% or 3 values (which ever is greater) were incorrect or missing.
R5	The Transmission Operator did provide the TRM values to all entities specified in more then 7 days but less than 14 days. OR The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or did not match those determined in R4. Not more than 5% or 1 value (which ever is greater) were incorrect or missing.	The Transmission Operator did provide the TRM values to all entities specified in 14 days or more, but less than 30 days. OR The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or did not match those determined in R4. More than 5% or 1 value (which ever is greater) were incorrect or missing, but not more than 10% or 2 values (whichever is greater).	The Transmission Operator did provide the TRM values to all entities specified in 30 days or more, but less than 60 days. OR The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or did not match those determined in R4. More than 10% or 2 values (which ever is greater) were incorrect or missing, but not more than 15% or 3 values.	The Transmission Operator did not provide the TRM values to all entities specified within 60 days of the change. OR The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or did not match those determined in R4. More than 15% or 3 values (which ever is greater) were incorrect or missing.

A. Introduction

1. **Title: Area Interchange Methodology**

2. **Number: MOD-028-1**

3. **Purpose:** To increase consistency and reliability in the development and documentation of Transfer Capability calculations for short-term use performed by entities using the Area Interchange Methodology to support analysis and system operations.

4. **Applicability:**

   4.1. Each Transmission Operator that uses the Area Interchange Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.

   4.2. Each Transmission Service Provider that uses the Area Interchange Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.

B. Requirements

R1. Each Transmission Service Provider shall include in its Available Transfer Capability Implementation Document (ATCID), at a minimum, the following information relative to its methodology for determining Total Transfer Capability (TTC): *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R1.1. Information describing how the selected methodology has been implemented, in such detail that, given the same information used by the Transmission Operator, the results of the TTC calculations can be validated.

R1.2. A description of the manner in which the Transmission Operator will account for Interchange Schedules in the calculation of TTC.

R1.3. Any contractual obligations for allocation of TTC.

R1.4. A description of the manner in which Contingencies are identified for use in the TTC process.

R1.5. The following information on how source and sink for transmission service is accounted for in ATC calculations including:

R1.5.1. Define if the source used for Available Transfer Capability (ATC) calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation

R1.5.2. Define if the sink used for ATC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation

R1.5.3. The source/sink or POR/POD identification and mapping to the model.

R1.5.4. If the Transmission Service Provider's ATC calculation process involves a grouping of generation, the ATCID must identify how these generators participate in the group.

R2. When calculating TTC for ATC Paths, the Transmission Operator shall use a Transmission model that contains all of the following: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R2.1. Modeling data and topology of its Reliability Coordinator's area of responsibility. Equivalent representation of radial lines and facilities 161 kV or below is allowed.

R2.2. Modeling data and topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination areas.

R2.3. Facility Ratings specified by the Generator Owners and Transmission Owners.

R3. When calculating TTCs for ATC Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's area. The Transmission Operator shall also include the following data associated with Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R3.1. For on-peak and off-peak intra-day and next-day TTCs, use the following (as well as any other values and additional parameters as specified in the ATCID):

R3.1.1. Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.

R3.1.2. Load forecast for the applicable period being calculated.

R3.1.3. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

R3.2. For days two through 31 TTCs and for months two through 13 TTCs, use the following (as well as any other values and internal parameters as specified in the ATCID):

R3.2.1. Expected generation and Transmission outages, additions, and Retirements, included as specified in the ATCID.

R3.2.2. Daily load forecast for the days two through 31 TTCs being calculated and monthly forecast for months two through 13 months TTCs being calculated.

R3.2.3. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

R4. When calculating TTCs for ATC Paths, the Transmission Operator shall meet all of the following conditions: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R4.1. Use all Contingencies meeting the criteria described in the ATCID.

R4.2. Respect any contractual allocations of TTC.

R4.3. Include, for each time period, the Firm Transmission Service expected to be scheduled as specified in the ATCID (filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers) for the Transmission Service Provider, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed modeling the source and sink as follows:

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate representation" in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point, an "equivalence," or an "aggregate representation" in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point shall as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate representation" in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can not be mapped to a discretely modeled point, an "equivalence," or an "aggregate representation" in the Transmission Service Provider's Transmission model, use the immediately adjacent

Balancing Authority associated with the Transmission Service Provider to which the power is to be delivered as the sink.

- If the sink, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider to which the power is being delivered as the sink.

R5. Each Transmission Operator shall establish TTC for each ATC Path as defined below: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R5.1. At least once within the seven calendar days prior to the specified period for TTCs used in hourly and daily ATC calculations.

R5.2. At least once per calendar month for TTCs used in monthly ATC calculations.

R5.3. Within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a transformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage, provided such outage is expected to last 24 hours or longer.

R6. Each Transmission Operator shall establish TTC for each ATC Path using the following process: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R6.1. Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either:

- A System Operating Limit is reached on the Transmission Service Provider's system, or
- A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater[1].

R6.2. If the limit in step R6.1 can not be reached by adjusting any combination of load or generation, then set the incremental Transfer Capability by the results of the case where the maximum adjustments were applied.

R6.3. Use (as the TTC) the lesser of:

- The sum of the incremental Transfer Capability and the impacts of Firm Transmission Services, as specified in the Transmission Service Provider's ATCID, that were included in the study model, or
- The sum of Facility Ratings of all ties comprising the ATC Path.

R6.4. For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Service Provider so the TTC does not exceed each Transmission Service Provider's contractual rights.

[1] The Transmission operator may honor distribution factors less than 5% if desired.

R7. The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R7.1. One calendar day after its determination for TTCs used in hourly and daily ATC calculations.

R7.2. Seven calendar days after its determination for TTCs used in monthly ATC calculations.

R8. When calculating Existing Transmission Commitments (ETCs) for firm commitments (ETC_F) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$ETC_F = NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Where:

$NITS_F$ is the firm capacity set aside for Network Integration Transmission Service (including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources) on ATC Paths that serve as interfaces with other Balancing Authorities.

GF_F is the firm capacity set aside for Grandfathered Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or safe harbor tariff on ATC Paths that serve as interfaces with other Balancing Authorities.

PTP_F is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

ROR_F is the capacity reserved for roll-over rights for Firm Transmission Service contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

OS_F is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.

R9. When calculating ETC for non-firm commitments (ETC_{NF}) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

$NITS_{NF}$ is the non-firm capacity set aside for Network Integration Transmission Service (i.e., secondary service , including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources)

reserved on ATC Paths that serve as interfaces with other Balancing Authorities.

GF_{NF} is the non-firm capacity reserved for Grandfathered Non-Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or safe harbor tariff on ATC Paths that serve as interfaces with other Balancing Authorities.

PTP_{NF} is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

OS_{NF} is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Non-Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.

R10. When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall utilize the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$ATC_F = TTC - ETC_F - CBM - TRM + Postbacks_F + counterflows_F$$

Where:

ATC_F is the firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC_F is the sum of existing firm Transmission commitments for the ATC Path during that period.

CBM is the Capacity Benefit Margin for the ATC Path during that period.

TRM is the Transmission Reliability Margin for the ATC Path during that period.

$Postbacks_F$ are changes to firm ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

$counterflows_F$ are adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

R11. When calculating non-firm ATC for a ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + counterflows_{NF}$$

Where:

ATC_{NF} is the non-firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC_F is the sum of existing firm Transmission commitments for the ATC Path during that period.

ETC_{NF} is the sum of existing non-firm Transmission commitments for the ATC Path during that period.

CBM_S is the Capacity Benefit Margin for the ATC Path that has been scheduled without a separate reservation during that period.

TRM_U is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

$Postbacks_{NF}$ are changes to non-firm ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

$counterflows_{NF}$ are adjustments to non-firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

C. Measures

M1. Each Transmission Service Provider shall provide its current ATCID that has the information described in R1 to show compliance with R1. (R1)

M2. Each Transmission Operator shall provide evidence including the model used to calculate TTC as well as other evidence (such as Facility Ratings provided by facility owners, written documentation, logs, and data) to show that the modeling requirements in R2 were met. (R2)

M3. Each Transmission Operator shall provide evidence, including scheduled outages, facility additions and retirements, (such as written documentation, logs, and data) that the data described in R3 and R4 were included in the determination of TTC as specified in the ATCID. (R3)

M4. Each Transmission Operator shall provide the contingencies used in determining TTC and the ATCID as evidence to show that the contingencies described in the ATCID were included in the determination of TTC. (R4)

M5. Each Transmission Operator shall provide copies of contracts that contain requirements to allocate TTCs and TTC values to show that any contractual allocations of TTC were respected as required in R4.2. (R4)

M6. Each Transmission Operator shall provide evidence (such as copies of coordination agreements, reservations, interchange transactions, or other documentation) to show that firm reservations were used to estimate scheduled interchange, the modeling of scheduled interchange was based on the rules described in R4.3, and that estimated scheduled interchange was included in the determination of TTC. (R4)

M7. Each Transmission Operator shall provide evidence (such as logs and data and dated copies of requests from the Transmission Service Provider to establish TTCs at specific intervals) that TTCs have been established at least once in the calendar week prior to the specified period for TTCs used in hourly and daily ATC calculations, at least once per calendar month for TTCs used in monthly ATC calculations, and within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a autotransformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated

duration of the outage; provided such outage is expected to last 24 hours or longer in duration per the specifications in R5.(R5)

M8. Each Transmission Operator shall provide evidence (such as written documentation) that TTCs have been calculated using the process described in R6. (R6)

M9. Each Transmission Operator shall have evidence including a copy of the latest calculated TTC values along with a dated copy of email notices or other equivalent evidence to show that it provided its Transmission Service Provider with the most current values for TTC in accordance with R7. (R7)

M10. The Transmission Service Provider shall demonstrate compliance with R8 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R8 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-028-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R8 to calculate its firm ETC. (R8)

M11. The Transmission Service Provider shall demonstrate compliance with R9 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R9 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-028-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R8 to calculate its non-firm ETC. (R9)

M12. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R10. Such documentation must show that only the variables allowed in R10 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R10)

M13. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R11. Such documentation must show that only the variables allowed in R11 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R11)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset

Not applicable.

1.3. Data Retention

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to calculate TTC and evidence of the previous version to show compliance with R2.
- The Transmission Operator shall retain evidence to show compliance with R3 for the most recent 12 months or until the model used to calculate TTC is updated, whichever is longer.
- The Transmission Operator shall retain evidence to show compliance with R4, R5, R6 and R7 for the most recent 12 months.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R8 and R9 for the most recent 14 days; evidence to show compliance in calculating daily values required in R8 and R9 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R8 and R9 for the most recent 60 days.
- The Transmission Service Provider shall retain evidence to show compliance with R10 and R11 for the most recent 12 months.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Service Provider has an ATCID but it is missing one of the following: ▪ R1.1 ▪ R1.2 ▪ R1.3 ▪ R1.4 ▪ R1.5 (any one or more of its sub-subrequirements)	The Transmission Service Provider has an ATCID but it is missing two of the following: ▪ R1.1 ▪ R1.2 ▪ R1.3 ▪ R1.4 ▪ R1.5 (any one or more of its sub-subrequirements)	The Transmission Service Provider has an ATCID but it is missing three of the following: ▪ R1.1 ▪ R1.2 ▪ R1.3 ▪ R1.4 ▪ R1.5 (any one or more of its sub-subrequirements)	The Transmission Service Provider has an ATCID but it is missing more than three of the following: ▪ R1.1 ▪ R1.2 ▪ R1.3 ▪ R1.4 ▪ R1.5 (any one or more of its sub-subrequirements)
R2.	The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.	The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.	One or both of the following: • The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission Operator did not use a Transmission model that includes modeling data and topology (or equivalent representation) for one adjacent Reliability Coordinator Area.	One or more of the following: • The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission Operator's model includes equivalent representation of non-radial facilities greater than 161 kV for its own Reliability Coordinator Area. • The Transmission Operator did not use a Transmission model that includes modeling data and topology (or equivalent representation) for two or more adjacent Reliability Coordinator

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Areas.
R3.	The Transmission Operator did not include in the TTC process one to ten expected generation and Transmission outages, additions or retirements as specified in the ATCID.	The Transmission Operator did not include in the TTC process eleven to twenty-five expected generation and Transmission outages, additions or retirements as specified in the ATCID.	The Transmission Operator did not include in the TTC process twenty-six to fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID.	One or more of the following: • The Transmission Operator did not include in the TTC process more than fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID. • The Transmission Operator did not include the Load forecast or unit commitment in its TTC calculation as described in R3.
R4.	The Transmission Operator did not model reservations' sources or sinks as described in R5.3 for more than zero reservations, but not more than 5% of all reservations; or 1 reservation, whichever is greater.	The Transmission Operator did not model reservations' sources or sinks as described in R5.3 for more than 5%, but not more than 10% of all reservations; or 2 reservations, whichever is greater.	The Transmission Operator did not model reservations' sources or sinks as described in R5.3 for more than 10%, but not more than 15% of all reservations; or 3 reservations, whichever is greater.	One or more of the following: • The Transmission Operator did not include in the TTC calculation the contingencies that met the criteria described in the ATCID. • The Transmission Operator did not respect contractual allocations of TTC. • The Transmission Operator did not model reservations' sources or sinks as described in R4.3 for more than 15% of all reservations; or more than 3 reservations, whichever is greater. • The Transmission Operator did not use firm reservations to estimate interchange or did not

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				utilize that estimate in the TTC calculation as described in R4.3.
R5.	One or more of the following: • The Transmission Operator did not establish TTCs for use in hourly or daily ATCs within 7 calendar days but did establish the values within 10 calendar days • The Transmission Operator did not establish TTCs for use in monthly ATCs during a calendar month but did establish the values within the next consecutive calendar month	One or more of the following: • The Transmission Operator did not establish TTCs for use in hourly or daily ATCs in 10 calendar days but did establish the values within 13 calendar days • The Transmission Operator did not establish TTCs for use in monthly ATCs during a two consecutive calendar month period but did establish the values within the third consecutive calendar month	One or more of the following: • The Transmission Operator did not establish TTCs for used in hourly or daily ATCs in 13 calendar days but did establish the values within 16 calendar days • The Transmission Operator did not establish TTCs for use in monthly ATCs during a three consecutive calendar month period but did establish the values within the fourth consecutive calendar month	One or more of the following: • The Transmission Operator did not establish TTCs for used in hourly or daily ATCs in 16 calendar days • The Transmission Operator did not establish TTCs for use in monthly ATCs during a four or more consecutive calendar month period • The Transmission Operator did not establish TTCs within 24 hrs of the triggers defined in R5.3
R6.	N/A	N/A	N/A	The Transmission Operator did not calculate TTCs per the process specified in R6.
R7.	One or more of the following: • The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than one calendar day after their determination, but not been more than two calendar days after their determination. • The Transmission Operator	One or more of the following: • The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than two calendar days after their determination, but not been more than three calendar days after their determination. • The Transmission Operator	One or more of the following: • The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than three calendar days after their determination, but not been more than four calendar days after their determination. • The Transmission Operator	One or more of the following: • The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than four calendar days after their determination. • The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in hourly or

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than seven calendar days after their determination, but not more than 14 calendar days since their determination.	has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 14 calendar days after their determination, but not been more than 21 calendar days after their determination.	has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 21 calendar days after their determination, but not been more than 28 calendar days after their determination.	daily ATC calculations. • The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 28 calendar days after their determination. • The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations.
R8.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.
R9.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	more than 25% of the value calculated in the measure or 25MW, whichever is greater.	more than 35% of the value calculated in the measure or 35MW, whichever is greater...	more than 45% of the value calculated in the measure or 45MW, whichever is greater.	
R10.	The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).
R11.	The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).

A. Introduction

1. **Title:** **Rated System Path Methodology**
2. **Number:** **MOD-029-1**
3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Rated System Path Methodology to support analysis and system operations.
4. **Applicability:**

   4.1. Each Transmission Operator that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.

   4.2. Each Transmission Service Provider that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.
5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.

B. Requirements

R1. When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R1.1. The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:

R1.1.1. Includes at least:

R1.1.1.1. The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.

R1.1.1.2. All Transmission Operator areas contiguous with its own Transmission Operator area. (Equivalent representation is allowed.)

R1.1.1.3. Any other Transmission Operator area linked to the Transmission Operator's area by joint operating agreement. (Equivalent representation is allowed.)

R1.1.2. Models all system Elements as in-service for the assumed initial conditions.

R1.1.3. Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the studied area.

R1.1.4. Models phase shifters in non-regulating mode, unless otherwise specified in the Available Transfer Capability Implementation Document (ATCID).

R1.1.5. Uses Load forecast by Balancing Authority.

R1.1.6. Uses Transmission Facility additions and retirements.

R1.1.7. Uses Generation Facility additions and retirements.

R1.1.8. Uses Special Protection System (SPS) models where currently existing or projected for implementation within the studied time horizon.

R1.1.9. Models series compensation for each line at the expected operating level unless specified otherwise in the ATCID.

R1.1.10. Includes any other modeling requirements or criteria specified in the ATCID.

R1.2. Uses Facility Ratings as provided by the Transmission Owner and Generator Owner

R2. The Transmission Operator shall use the following process to determine TTC: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R2.1. Except where otherwise specified within MOD-029-1, adjust base case generation and Load levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the ATC Path while at the same time satisfying all planning criteria contingencies as follows:

R2.1.1. When modeling normal conditions, all Transmission Elements will be modeled at or below 100% of their continuous rating.

R2.1.2. When modeling contingencies the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its Emergency Rating.

R2.1.3. Uncontrolled separation shall not occur.

R2.2. Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction. If the TTC in the prevailing flow direction is dependant on a Special Protection System (SPS), set the TTC for the non-prevailing flow direction equal to the greater of the maximum flow that can be simulated in the non-prevailing flow direction or the maximum TTC that can be achieved in the prevailing flow direction without use of a SPS.

R2.3. For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R2.1.

R2.4. For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.

R2.5. The Transmission Operator shall identify when the TTC for the ATC Path being studied has an adverse impact on the TTC value of any existing path. Do this by modeling the flow on the path being studied at its proposed new

TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1. The Transmission Operator shall include the resolution of this adverse impact in its study report for the ATC Path.

R2.6. Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.

R2.7. For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken to have the path rated using a different method, set the TTC at that previously established amount.

R2.8. Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.

R3. Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R4. Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R5. When calculating ETC for firm Existing Transmission Commitments (ETC_F) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Where:

NL_F is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$NITS_F$ is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_F is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

PTP_F is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

ROR_F is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

OS_F is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

R6. When calculating ETC for non-firm Existing Transmission Commitments (ETC_{NF}) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

$NITS_{NF}$ is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_{NF} is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

PTP_{NF} is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

OS_{NF} is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

R7. When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_F = TTC - ETC_F - CBM - TRM + Postbacks_F + counterflows_F$$

Where

ATC_F is the firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC_F is the sum of existing firm commitments for the ATC Path during that period.

CBM is the Capacity Benefit Margin for the ATC Path during that period.

TRM is the Transmission Reliability Margin for the ATC Path during that period.

$Postbacks_F$ are changes to firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

$counterflows_F$ are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID.

R8. When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + counterflows_{NF}$$

Where:

ATC_{NF} is the non-firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC_F is the sum of existing firm commitments for the ATC Path during that period.

ETC_{NF} is the sum of existing non-firm commitments for the ATC Path during that period.

CBM_S is the Capacity Benefit Margin for the ATC Path that has been scheduled during that period.

TRM_U is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

$Postbacks_{NF}$ are changes to non-firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

$counterflows_{NF}$ are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and specified in its ATCID.

C. Measures

M1. Each Transmission Operator that uses the Rated System Path Methodology shall produce any Transmission model it used to calculate TTC for purposes of calculating ATC for each ATC Path, as required in R1, for the time horizon(s) to be examined. (R1)

M1.1. Production shall be in the same form and format used by the Transmission Operator to calculate the TTC, as required in R1. (R1)

M1.2. The Transmission model produced must include the areas listed in R1.1.1 (or an equivalent representation, as described in the requirement) (R1.1)

M1.3. The Transmission model produced must show the use of the modeling parameters stated in R1.1.2 through R1.1.10; except that, no evidence shall be required to prove: 1) utilization of a Special Protection System where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred. (R1.1.2 through R1.1.10)

M1.4. The Transmission Operator must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner. (R1.2)

M2. Each Transmission Operator that uses the Rated System Path Methodology shall produce the ATCID it uses to show where it has described and used additional modeling criteria in its ACTID that are not otherwise included in MOD-29 (R1.1.4, R.1.1.9, and R1.1.10).

M3. Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. (R2.7)

M4. Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)

M5. Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7and R8 for each ATC Path. (R3)

M6. Each Transmission Operator shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (R4)

M7. The Transmission Service Provider shall demonstrate compliance with R5 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R5 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-029-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the

originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R5 to calculate its firm ETC. (R5)

M8. The Transmission Service Provider shall demonstrate compliance with R5 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R6 and with data used to calculate this specified value for the designated time period. The data used must meet the requirements specified in the MOD-029 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R6 to calculate its non-firm ETC. (R6)

M9. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R7. Such documentation must show that only the variables allowed in R7 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R7)

M10. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

- The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:
- The Transmission Operator shall have its latest models used to determine TTC for R1. (M1)

- The Transmission Operator shall have the current, in force ATCID(s) provided by its Transmission Service Provider(s) and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1. (M2)
- The Transmission Operator shall retain evidence of any path and its rating that was established prior to January 1, 1994. (M3)
- The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R2. (M4)
- The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with R3 and R4. (M5 and M6)
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R5 and R6 for the most recent 14 days; evidence to show compliance in calculating daily values required in R5 and R6 for the most recent 30 days; and evidence to show compliance in calculating daily values required in R5 and R6 for the most recent sixty days. (M7 and M8)
- The Transmission Service Provider shall retain evidence for the most recent three calendar years plus the current year to show compliance with R7 and R8. (M9 and M10)
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Operator used a model that met all but one of the modeling requirements specified in R1.1. **OR** The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)	The Transmission Operator used a model that met all but two of the modeling requirements specified in R1.1. **OR** The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)	The Transmission Operator used a model that met all but three of the modeling requirements specified in R1.1. **OR** The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)	The Transmission Operator used a model that did not meet four or more of the modeling requirements specified in R1.1. **OR** The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)
R2	One or both of the following: • The Transmission Operator did not calculate TTC using one of the items in sub-requirements R2.1-R2.6. • The Transmission Operator does not include one required item in the study report required in R2.8.	One or both of the following: • The Transmission Operator did not calculate TTC using two of the items in sub-requirements R2.1-R2.6. • The Transmission Operator does not include two required items in the study report required in R2.8.	One or both of the following: • The Transmission Operator did not calculate TTC using three of the items in sub-requirements R2.1-R2.6. • The Transmission Operator does not include three required items in the study report required in R2.8.	One or more of the following: • The Transmission Operator did not calculate TTC using four or more of the items in sub-requirements R2.1-R2.6. • The Transmission Operator did not apply R2.7. • The Transmission Operator does not include four or more required items in the study report required in R2.8

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than zero ATC Paths, BUT, not more than 1% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 1% of all ATC Paths or 1 ATC Path (whichever is greater), BUT not more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater), BUT not more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL, for more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).
R4.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than seven, but not more than 14 calendar days after the report was finalized.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 14, but not more than 21 calendar days after the report was finalized.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 21, but not more than 28 calendar days after the report was finalized.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 28 calendar days after the report was finalized.
R5.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.
R6.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.	value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.	value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.	absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.
R7.	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).
R8.	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).

A. Introduction

1. **Title:** **Flowgate Methodology**

2. **Number:** **MOD-030-02**

3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Flowgate Methodology to support analysis and system operations.

4. **Applicability:**

   4.1.1 Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available Flowgate Capabilities (AFCs) on Flowgates.

   4.1.2 Each Transmission Service Provider that uses the Flowgate Methodology to calculate AFCs on Flowgates.

5. **Proposed Effective Date:** The date upon which MOD-030-01 is currently scheduled to become effective.

B. Requirements

R1. The Transmission Service Provider shall include in its "Available Transfer Capability Implementation Document" (ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

R1.1. The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations.

R1.2. The following information on how source and sink for transmission service is accounted for in AFC calculations including:

R1.2.1. Define if the source used for AFC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.

R1.2.2. Define if the sink used for AFC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.

R1.2.3. The source/sink or POR/POD identification and mapping to the model.

R1.2.4. If the Transmission Service Provider's AFC calculation process involves a grouping of generators, the ATCID must identify how these generators participate in the group.

R2. The Transmission Operator shall perform the following: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

R2.1. Include Flowgates used in the AFC process based, at a minimum, on the following criteria:

R2.1.1. Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator's system up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an OTDF of at least 5% and within the Transmission Operator's system are included as Flowgates.

R2.1.1.1. Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the

applicable time periods, including use of Special Protection Systems.

R2.1.1.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.

R2.1.1.3. If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.

R2.1.2. Results of a first Contingency transfer analysis from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) of at least 5% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology.

R2.1.2.1. Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Special Protection Systems.

R2.1.2.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.

R2.1.2.3. If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.

R2.1.3. Any limiting Element/Contingency combination at least within its Reliability Coordinator's Area that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, unless the limiting Element/Contingency combination is accounted for using another ATC methodology or was created to address temporary operating conditions.

R2.1.4. Any limiting Element/Contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:

R2.1.4.1. The coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and

- Any generator within the Transmission Service Provider's area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or
- A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area

adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.

- The Transmission Operator may utilize distribution factors less than 5% if desired.

R2.1.4.2. The limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.

R2.2. At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgate definitions at least once per calendar year.

R2.3. At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgates that have been requested as part of R2.1.4 within thirty calendar days from the request.

R2.4. Establish the TFC of each of the defined Flowgates as equal to:

- For thermal limits, the System Operating Limit (SOL) of the Flowgate.
- For voltage or stability limits, the flow that will respect the SOL of the Flowgate.

R2.5. At a minimum, establish the TFC once per calendar year.

R2.5.1. If notified of a change in the Rating by the Transmission Owner that would affect the TFC of a flowgate used in the AFC process, the TFC should be updated within seven calendar days of the notification.

R2.6. Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.

R3. The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

R3.1. Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the Generator Owners of the Facilities within the model.

R3.2. Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.

R3.3. Updated at least once per month for AFC calculations for months two through 13.

R3.4. Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and Facilities161kV or below is allowed.

R3.5. Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.

R4. When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the

Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.

- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.
- If the sink, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.

R5. When calculating AFCs, the Transmission Service Provider shall: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

R5.1. Use the models provided by the Transmission Operator.

R5.2. Include in the transmission model expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the applicable period of the AFC calculation for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.

R5.3. For external Flowgates, identified in R2.1.4, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.

R6. When calculating the impact of ETC for firm commitments (ETC_{Fi}) for all time periods for a Flowgate, the Transmission Service Provider shall sum the following: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

R6.1. The impact of firm Network Integration Transmission Service, including the impacts of generation to load, in the model referenced in R5.2 for the Transmission Service Provider's area, based on:

R6.1.1. Load forecast for the time period being calculated, including Native Load and Network Service load

R6.1.2. Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.

R6.2. The impact of any firm Network Integration Transmission Service, including the impacts of generation to load in the model referenced in R5.2 and has a distribution factor equal to or greater than the percentage[1] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed based on:

R6.2.1. Load forecast for the time period being calculated, including Native Load and Network Service load

R6.2.2. Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.

R6.3. The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider's area.

R6.4. The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts having a distribution factor equal to or greater than the percentage[2] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

R6.5. The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.

R6.6. The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage[3] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

R6.7. The impact of other firm services determined by the Transmission Service Provider.

R7. When calculating the impact of ETC for non-firm commitments (ETC_{NFi}) for all time periods for a Flowgate the Transmission Service Provider shall sum: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

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[1] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[2] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[3] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

R7.1. The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled for the Transmission Service Provider's area.

R7.2. The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, that have a distribution factor equal to or greater than the percentage[4] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

R7.3. The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.

R7.4. The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage[5] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

R7.5. The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider's area (i.e., secondary service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

R7.6. The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage[6] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

R7.7. The impact of other non-firm services determined by the Transmission Service Provider.

R8. When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$AFC_F = TFC - ETC_{Fi} - CBM_i - TRM_i + Postbacks_{Fi} + counterflows_{Fi}$$

Where:

AFC_F is the firm Available Flowgate Capability for the Flowgate for that period.

[4] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[5] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[6] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

TFC is the Total Flowgate Capability of the Flowgate.

ETC_{Fi} is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

CBM_i is the impact of the Capacity Benefit Margin on the Flowgate during that period.

TRM_i is the impact of the Transmission Reliability Margin on the Flowgate during that period.

$Postbacks_{Fi}$ are changes to firm AFC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

$counterflows_{Fi}$ are adjustments to firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

R9. When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$AFC_{NF} = TFC - ETC_{Fi} - ETC_{NFi} - CBM_{Si} - TRM_{Ui} + Postbacks_{NFi} + counterflows$$

Where:

AFC_{NF} is the non-firm Available Flowgate Capability for the Flowgate for that period.

TFC is the Total Flowgate Capability of the Flowgate.

ETC_{Fi} is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

ETC_{NFi} is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate during that period.

CBM_{Si} is the impact of any schedules during that period using Capacity Benefit Margin.

TRM_{Ui} is the impact on the Flowgate of the Transmission Reliability Margin that has not been released (unreleased) for sale as non-firm capacity by the Transmission Service Provider during that period.

$Postbacks_{NF}$ are changes to non-firm Available Flowgate Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

$counterflows_{NF}$ are adjustments to non-firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

R10. Each Transmission Service Provider shall recalculate AFC, utilizing the updated models described in R3.2, R3.3, and R5, at a minimum on the following frequency, unless none of the calculated values identified in the AFC equation have changed: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

R10.1. For hourly AFC, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the AFC equation.

R10.2. For daily AFC, once per day.

R10.3. For monthly AFC, once per week.

R11. When converting Flowgate AFCs to ATCs for ATC Paths, the Transmission Service Provider shall convert those values based on the following algorithm: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$ATC = \min(P)$$

$$P = \{PATC_1, PATC_2, \ldots PATC_n\}$$

$$PATC_n = \frac{AFC_n}{DF_{np}}$$

Where:

ATC is the Available Transfer Capability.

P is the set of partial Available Transfer Capabilities for all "impacted" Flowgates honored by the Transmission Service Provider; a Flowgate is considered "impacted" by a path if the Distribution Factor for that path is greater than the percentage[7] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider on an OTDF Flowgate or PTDF Flowgate.

$\mathbf{PATC_n}$ is the partial Available Transfer Capability for a path relative to a Flowgate *n.*

$\mathbf{AFC_n}$ is the Available Flowgate Capability of a Flowgate *n*.

$\mathbf{DF_{np}}$ is the distribution factor for Flowgate *n* relative to path *p*.

C. Measures

M1. Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates and information on how sources and sinks are accounted for in AFC calculations. (R1)

M2. The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)

M3. The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per calendar year. (R2.2)

M4. The Transmission Operator shall provide evidence (such as logs and dated requests) that it updated the list of Flowgates within thirty calendar days from a request. (R2.3)

M5. The Transmission Operator shall provide evidence (such as data or models) that it determined the TFC for each Flowgate as defined in R2.4. (R2.4)

M6. The Transmission Operator shall provide evidence (such as logs) that it established the TFCs for each Flowgate in accordance with the timing defined in R2.5. (R2.5)

M7. The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.6)

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[7] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

M8. The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)

M9. The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)

M10. The Transmission Service Provider shall provide evidence including the models received from Transmission Operators and other evidence (such as documentation and data) to show that it used the Transmission Operator's models in calculating AFC. (R5.1)

M11. The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation as specified in the ATCID. (R5.2)

M12. The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties on external Flowgates were used instead of those calculated by the Transmission Operator. (R5.3)

M13. The Transmission Service Provider shall demonstrate compliance with R6 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R6 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in this standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements defined in R6 to calculate its firm ETC. (R6)

M14. The Transmission Service Provider shall demonstrate compliance with R7 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R7 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in the standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements in R7 to calculate its non-firm ETC. (R7)

M15. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm AFCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

M16. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm AFCs, as required in R9. Such documentation must show that only the variables allowed in R9 were used to calculate non-firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the

value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R9)

M17. The Transmission Service Provider shall provide evidence (such as documentation, dated logs, and data) that it calculated AFC on the frequency defined in R10. (R10)

M18. The Transmission Service Provider shall provide evidence (such as documentation and data) when converting Flowgate AFCs to ATCs for ATC Paths, it follows the procedure described in R11. (R11)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to determine flowgates and TFC and evidence of the previous version to show compliance with R2 and R3.
- The Transmission Operator shall retain evidence to show compliance with R2.1, R2.3 for the most recent 12 months.
- The Transmission Operator shall retain evidence to show compliance with R2.2, R2.4 and R2.5 for the most recent three calendar years plus current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for 12 months or until the model used to calculate AFC is updated, whichever is longer.
- The Transmission Service Provider shall retain evidence to show compliance with R5, R8, R9, R10, and R11 for the most recent calendar year plus current year.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R6 and R7 for the most recent 14 days; evidence to show compliance in calculating daily values required in R6 and R7 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R6 and R7 for the most recent sixty days.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Service Provider does not include in its ATCID one or two of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.	The Transmission Service Provider does not include in its ATCID three of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.	The Transmission Service Provider does not include in its ATCID the information described in R1.1. **OR** The Transmission Service Provider does not include in its ATCID the information described in R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).	The Transmission Service Provider does not include in its ATCID the information described in R1.1 and R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).
R2.	One or more of the following: • The Transmission Operator established its list of Flowgates less frequently than once per calendar year, but not more than three months late as described in R2.2. • The Transmission Operator established its list of Flowgates more than thirty days, but not more than sixty days, following a request to create, modify or delete a flowgate as described in R2.3. • The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 7 days, but it has not been more than 14 days	One or more of the following: • The Transmission Operator did not include a Flowgate in their AFC calculations that met the criteria described in R2.1. • The Transmission Operator established its list of Flowgates more than three months late, but not more than six months late as described in R2.2. • The Transmission Operator established its list of Flowgates more than sixty days, but not more than ninety days, following a request to create, modify or delete a flowgate as described in R2.3. • The Transmission Operator	One or more of the following: • The Transmission Operator did not include two to five Flowgates in their AFC calculations that met the criteria described in R2.1. • The Transmission Operator established its list of Flowgates more than six months late, but not more than nine months late as described in R2.2. • The Transmission Operator established its list of Flowgates more than ninety days, but not more than 120 days, following a request to create, modify or delete a flowgate as described in R2.3. The Transmission Operator	One or more of the following: • The Transmission Operator did not include six or more Flowgates in their AFC calculations that met the criteria described in R2.1. • The Transmission Operator established its list of Flowgates more than nine months late as described in R2.2. • The Transmission Operator did not establish its list of internal Flowgates as described in R2.2. • The Transmission Operator established its list of Flowgates more than 120 days following a request to create, modify or delete a flowgate as described in

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	since the notification (R2.5.1) • The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs within seven days (one week) of their determination, but is has not been more than 14 days (two weeks) since their determination.	has not updated its Flowgate TFCs at least once within a calendar year, and it has been not more than 15 months since the last update. • The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 14 days, but it has not been more than 21 days since the notification (R2.5.1) • The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 14 days (two weeks) of their determination, but is has not been more than 21 days (three weeks) since their determination.	has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 15 months but not more than 18 months since the last update. • The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 21 days, but it has not been more than 28 days since the notification (R2.5.1) • The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 21 days (three weeks) of their determination, but is has not been more than 28 days (four weeks) since their determination.	R2.3. • The Transmission Operator did not establish its list of external Flowgates following a request to create, modify or delete an external flowgate as described in R2.3. • The Transmission Operator did not determine the TFC for a flowgate as described in R2.4. • The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 18 months since the last update. (R2.5) • The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 28 calendar days (R2.5.1) • The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 28 days (4 weeks) of their determination.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	One or more of the following: • The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission Operator did not update the model per R3.2 for one or more calendar days but not more than 2 calendar days • The Transmission Operator did not update the model for per R3.3 for one or more months but not more than six weeks	One or more of the following: • The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission Operator did not update the model per R3.2 for more than 2 calendar days but not more than 3 calendar days • The Transmission Operator did not update the model for per R3.3 for more than six weeks but not more than eight weeks	One or more of the following: • The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission Operator did not update the model per R3.2 for more than 3 calendar days but not more than 4 calendar days • The Transmission Operator did not update the model for per R3.3 for more than eight weeks but not more than ten weeks	One or more of the following: • The Transmission Operator did not update the model per R3.2 for more than 4 calendar days • The Transmission Operator did not update the model for per R3.3 for more than ten weeks • The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission operator did not include in the Transmission model detailed modeling data and topology for its own Reliability Coordinator area. • The Transmission operator did not include in the Transmission modeling data and topology for immediately adjacent and beyond Reliability Coordinator area.
R4.	The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than zero, but not more than	The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 5%, but not more than	The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 10%, but not more than	The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 15% of all reservations; or

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	5% of all reservations; or more than zero, but not more than 1 reservation, whichever is greater..	10% of all reservations; or more than 1, but not more than 2 reservations, whichever is greater..	15% of all reservations; or more than 2, but not more than 3 reservations, whichever is greater..	more than 3 reservations, whichever is greater..
R5.	The Transmission Service Provider did not include in the AFC process one to ten expected generation or Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.	The Transmission Service Provider did not include in the AFC process eleven to twenty-five expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.	The Transmission Service Provider did not include in the AFC process twenty-six to fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.	One or more of the following: • The Transmission Service Provider did not use the model provided by the Transmission Operator. • The Transmission Service Provider did not include in the AFC process more than fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. • The Transmission Service provider did not use AFC provided by a third party.
R6.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	25MW, whichever is greater..	35MW, whichever is greater.	45MW, whichever is greater.	
R7.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.
R8.	The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 5% of all Flowgates or 1 Flowgates (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 15% of all Flowgates or more than 3 Flowgates (whichever is greater).
R9.	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm AFC, or used additional elements, for more than zero Flowgates, but	The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 5% of all Flowgates	The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 10% of all	The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 15% of all

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	not more than 5% of all Flowgates or 1 Flowgate (whichever is greater).	or 1 Flowgate (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).	Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).	Flowgates or more than 3 Flowgates (whichever is greater).
R10	One or more of the following: ▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days. ▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days.	One or more of the following: ▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days. ▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days.	One or more of the following: ▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days. ▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days.	One or more of the following: ▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days. ▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R11.	N/A	N/A	N/A	The Transmission Service Provider did not follow the procedure for converting Flowgate AFCs to ATCs described in R11.

A. Regional Differences

None identified.

B. Associated Documents

Version History

Version	Date	Action	Change Tracking
2		Modified R2.1.1.3, R2.1.2.3, R2.1.3, R2.2, R2.3 and R11 Made conforming changes to M18 and VSLs for R2 and R11	Revised

A. Introduction

1. **Title: Transmission Relay Loadability**
2. **Number:** PRC-023-1
3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.
4. **Applicability:**

   4.1. Transmission Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined below:

   4.1.1 Transmission lines operated at 200 kV and above.

   4.1.2 Transmission lines operated at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.

   4.1.3 Transformers with low voltage terminals connected at 200 kV and above.

   4.1.4 Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.

   4.2. Generator Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined in 4.1.1 through 4.1.4.

   4.3. Distribution Providers with load-responsive phase protection systems as described in Attachment A, applied according to facilities defined in 4.1.1 through 4.1.4., provided that those facilities have bi-directional flow capabilities.

   4.4. Planning Coordinators.
5. **Effective Dates[1]:** TBD

   5.1. Requirement 1, Requirement 2:

   5.1.1 For circuits described in 4.1.1 and 4.1.3 above (except for switch-on-to-fault schemes) —the beginning of the first calendar quarter following applicable regulatory approvals.

   5.1.2 For circuits described in 4.1.2 and 4.1.4 above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter 39 months following applicable regulatory approvals.

   5.1.3 Each Transmission Owner, Generator Owner, and Distribution Provider shall have 24 months after being notified by its Planning Coordinator pursuant to R3.3 to comply with R1 (including all sub-requirements) for each facility that is added to the Planning Coordinator's critical facilities list determined pursuant to R3.1.

   5.2. Requirement 3: 18 months following applicable regulatory approvals.

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1 Temporary Exceptions that have already been approved by the NERC Planning Committee via the NERC System Protection and Control Task Force prior to the approval of this standard shall not result in either findings of non-compliance or sanctions if all of the following apply: (1) the approved requests for Temporary Exceptions include a mitigation plan (including schedule) to come into full compliance, and (2) the non-conforming relay settings are mitigated according to the approved mitigation plan.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (R1.1 through R1.13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees: [Violation Risk Factor: High] [Mitigation Time Horizon: Long Term Planning].

R1.1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

R1.2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[2] of a circuit (expressed in amperes).

R1.3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

R1.3.1. An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.

R1.3.2. An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.

R1.4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:

- 115% of the highest emergency rating of the series capacitor.
- 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with R1.3, using the full line inductive reactance.

R1.5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).

R1.6. Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability.

R1.7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

[2] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

R1.8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

R1.9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

R1.10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that they do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

R1.11. For transformer overload protection relays that do not comply with R1.10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater. The protection must allow this overload for at least 15 minutes to allow for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element. The setting should be no less than 100° C for the top oil or 140° C for the winding hot spot temperature[3].

R1.12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

R1.12.1. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

R1.12.2. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

R1.12.3. Include a relay setting component of 87% of the current calculated in R1.12.2 in the Facility Rating determination for the circuit.

R1.13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

R2. The Transmission Owner, Generator Owner, or Distribution Provider that uses a circuit capability with the practical limitations described in R1.6, R1.7, R1.8, R1.9, R1.12, or R1.13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator

[3] IEEE standard C57.115, Table 3, specifies that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and cautions that bubble formation may occur above 140 degrees C.

with the calculated circuit capability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

R3. The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities from 100 kV to 200 kV that must meet Requirement 1 to prevent potential cascade tripping that may occur when protective relay settings limit transmission loadability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

R3.1. The Planning Coordinator shall have a process to determine the facilities that are critical to the reliability of the Bulk Electric System.

R3.1.1. This process shall consider input from adjoining Planning Coordinators and affected Reliability Coordinators.

R3.2. The Planning Coordinator shall maintain a current list of facilities determined according to the process described in R3.1.

R3.3. The Planning Coordinator shall provide a list of facilities to its Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within 30 days of the establishment of the initial list and within 30 days of any changes to the list.

C. Measures

M1. The Transmission Owner, Generator Owner, and Distribution Provider shall each have evidence to show that each of its transmission relays are set according to one of the criteria in R1.1 through R1.13. (R1)

M2. The Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to the criteria in R1.6, R1.7, R1.8, R1.9, R1.12, or R.13 shall have evidence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R2)

M3. The Planning Coordinator shall have a documented process for the determination of facilities as described in R3. The Planning Coordinator shall have a current list of such facilities and shall have evidence that it provided the list to the approriate Reliability Coordinators, Transmission Operators, Generator Operators, and Distribution Providers. (R3)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

1.1.1 Compliance Enforcement Authority

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation for three years.

The Planning Coordinator shall retain documentation of the most recent review process required in R3. The Planning Coordinator shall retain the most recent list of facilities that are critical to the reliability of the electric system determined per R3.

The Compliance Monitor shall retain its compliance documentation for three years.

1.4. Additional Compliance Information

The Transmission Owner, Generator Owner, Planning Coordinator, and Distribution Provider shall each demonstrate compliance through annual self-certification, or compliance audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Enforcement Authority.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1		Evidence that relay settings comply with criteria in R1.1 though 1.13 exists, but evidence is incomplete or incorrect for one or more of the subrequirements.		Relay settings do not comply with any of the sub requirements R1.1 through R1.13 OR Evidence does not exist to support that relay settings comply with one of the criteria in subrequirements R1.1 through R1.13.
R2	Criteria described in R1.6, R1.7. R1.8. R1.9, R1.12, or R.13 was used but evidence does not exist that agreement was obtained in accordance with R2.			
R3		Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 31 days and 45 days after the list was established or updated.	Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 46 days and 60 days after list was established or updated.	Does not have a process in place to determine facilities that are critical to the reliability of the Bulk Electric System. OR Does not maintain a current list of facilities critical to the reliability of the Bulk Electric System, OR Did not provide the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers, or provided the list more than 60 days after the list was established or updated.

E. Regional Differences

None

F. Supplemental Technical Reference Document

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies

"Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, January 9, 2007, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/~filez/reports.html.

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	

Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

- **1.1.** Phase distance.
- **1.2.** Out-of-step tripping.
- **1.3.** Switch-on-to-fault.
- **1.4.** Overcurrent relays.
- **1.5.** Communications aided protection schemes including but not limited to:
  - **1.5.1** Permissive overreach transfer trip (POTT).
  - **1.5.2** Permissive under-reach transfer trip (PUTT).
  - **1.5.3** Directional comparison blocking (DCB).
  - **1.5.4** Directional comparison unblocking (DCUB).

2. This standard includes out-of-step blocking schemes which shall be evaluated to ensure that they do not block trip for faults during the loading conditions defined within the requirements.

3. The following protection systems are excluded from requirements of this standard:

- **3.1.** Relay elements that are only enabled when other relays or associated systems fail. For example:
  - Overcurrent elements that are only enabled during loss of potential conditions.
  - Elements that are only enabled during a loss of communications.
- **3.2.** Protection systems intended for the detection of ground fault conditions.
- **3.3.** Protection systems intended for protection during stable power swings.
- **3.4.** Generator protection relays that are susceptible to load.
- **3.5.** Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.
- **3.6.** Protection systems that are designed only to respond in time periods which allow operators 15 minutes or greater to respond to overload conditions.
- **3.7.** Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
- **3.8.** Relay elements associated with DC lines.
- **3.9.** Relay elements associated with DC converter transformers.

Exhibit F

Matrix of Violation Risk Factors for Approval

FERC Approved Standards

Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
BAL-001-0.1a	R1.	Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit ▯▯▯ a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating Committee. ***See Standard for Formula.***	MEDIUM
BAL-001-0.1a	R2.	Each Balancing Authority shall operate such that its average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit, referred to as L_{10}. ***See Standard for Formula.***	MEDIUM
BAL-001-0.1a	R3.	Each Balancing Authority providing Overlap Regulation Service shall evaluate Requirement R1 (i.e., Control Performance Standard 1 or CPS1) and Requirement R2 (i.e., Control Performance Standard 2 or CPS2) using the characteristics of the combined ACE and combined Frequency Bias Settings.	LOWER
BAL-001-0.1a	R4.	Any Balancing Authority receiving Overlap Regulation Service shall not have its control performance evaluated (i.e. from a control performance perspective, the Balancing Authority has shifted all control requirements to the Balancing Authority providing Overlap Regulation Service).	LOWER
BAL-002-0	R1.	Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.	HIGH
BAL-002-0	R1.1.	A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such cases, the Reserve Sharing Group shall have the same responsibilities and obligations as each Balancing Authority with respect to monitoring and meeting the requirements of Standard BAL-002.	HIGH
BAL-002-0	R2.	Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including:	MEDIUM
BAL-002-0	R2.1.	The minimum reserve requirement for the group.	HIGH
BAL-002-0	R2.2.	Its allocation among members.	LOWER

FERC Approved Standards

Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
BAL-002-0	R2.3.	The permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve.	LOWER
BAL-002-0	R2.4.	The procedure for applying Contingency Reserve in practice.	LOWER
BAL-002-0	R2.5.	The limitations, if any, upon the amount of interruptible load that may be included.	LOWER
BAL-002-0	R2.6.	The same portion of resource capacity (e.g., reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by multiple Balancing Authorities.	MEDIUM
BAL-002-0	R3.	Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS.	HIGH
BAL-002-0	R3.1.	As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency. All Balancing Authorities and Reserve Sharing Groups shall review, no less frequently than annually, their probable contingencies to determine their prospective most severe single contingencies.	HIGH
BAL-002-0	R4.	A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:	MEDIUM
BAL-002-0	R4.1.	A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.	MEDIUM
BAL-002-0	R4.2.	The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee.	<blank>
BAL-002-0	R5.	Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Balancing Authority.) Compliance may be demonstrated by either of the following two methods:	LOWER

FERC Approved Standards

Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
BAL-002-0	R5.1.	The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.	<blank>
BAL-002-0	R5.2.	The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.	<blank>
BAL-002-0	R6.	A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period for its Interconnection.	MEDIUM
BAL-002-0	R6.1.	The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period.	<blank>
BAL-002-0	R6.2.	The default Contingency Reserve Restoration Period is 90 minutes. This period may be adjusted to better suit the reliability targets of the Interconnection based on analysis approved by the NERC Operating Committee.	<blank>
BAL-002-WECC-1	R1.	Each Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group shall maintain as a minimum Contingency Reserve that is the sum of the following: [Time Horizon: Real-time Operations]	MEDIUM
BAL-002-WECC-1	R1.1.	The greater of the following:	
BAL-002-WECC-1	R1.1.1.	An amount of reserve equal to the loss of the most severe single contingency; or	
BAL-002-WECC-1	R1.1.2.	An amount of reserve equal to the sum of three percent of the load (generation minus station service minus Net Actual Interchange) and three percent of net generation (generation minus station service).	
BAL-002-WECC-1	R1.2.	If the Source Balancing Authority designates an Interchange Transaction(s) as part of its Non-Spinning Contingency Reserve, the Sink Balancing Authority shall carry an amount of additional Non-Spinning Contingency Reserve equal to the Interchange Transaction(s). This type of transaction cannot be designated as Spinning Reserves by the source BA. If the Source Balancing Authority does not designate the Interchange Transaction as part of its Contingency Reserve, the Sink Balancing Authority is not required to carry any additional Contingency Reserves under this Requirement.	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
BAL-002-WECC-1	R1.3.	If the Sink Balancing Authority is designating an Interchange Transaction(s) as part of its Contingency Reserve either Spinning or Non-Spinning, the Source Balancing Authority shall increase its Contingency Reserves equal in amount and type, to the capacity transaction(s) where the Sink Balancing Authority is designating the transaction(s) as a resource to meet its Contingency Reserve requirements. These types of transactions could be designated as either spinning or non-spinning reserves. If designated as Spinning Reserves, all of the requirements of section R2.1 & R2.2 must be met.	
BAL-002-WECC-1	R2.	Each Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group shall maintain at least half of the Contingency Reserve in R1.1 as Spinning Reserve. Any Spinning Reserve specified in R1 shall meet the following requirements. [Time Horizon: Real-time Operations]	HIGH
BAL-002-WECC-1	R2.1.	Immediately and automatically responds proportionally to frequency deviations, e.g. through the action of a governor or other control systems.	
BAL-002-WECC-1	R2.2.	Capable of fully responding within ten minutes.	
BAL-002-WECC-1	R3.	Each Reserve Sharing Group or Balancing Authority shall use the following acceptable types of reserve which must be fully deployable within 10 minutes of notification to meet R1: [Time Horizon: Real-time Operations]	MEDIUM
BAL-002-WECC-1	R3.1.	Spinning Reserve	
BAL-002-WECC-1	R3.2.	Interruptible Load;	
BAL-002-WECC-1	R3.3.	Interchange Transactions designated by the source Balancing Authority as non-spinning contingency reserve;	
BAL-002-WECC-1	R3.4.	Reserve held by other entities by agreement that is deliverable on Firm Transmission Service;	
BAL-002-WECC-1	R3.5.	An amount of off-line generation which can be synchronized and generating; or	
BAL-002-WECC-1	R3.6.	Load, other than Interruptible Load, once the Reliability Coordinator has declared a capacity or energy emergency.	
BAL-STD-002-0	WR1.	The reliable operation of the interconnected power system requires that adequate generating capacity be available at all times to maintain scheduled frequency and avoid loss of firm load following transmission or generation contingencies. This generating capacity is necessary to: supply requirements for load variations. replace generating capacity and energy lost due to forced outages of generation or transmission equipment. meet on-demand obligations. replace energy lost due to curtailment of interruptible imports. a. Minimum Operating Reserve. Each Balancing Authority shall maintain minimum Operating Reserve which is the sum of the following: (i) Regulating reserve. Sufficient Spinning Reserve, immediately responsive to Automatic Generation Control (AGC) to provide sufficient regulating margin to allow the Balancing Authority to meet NERC's Control Performance Criteria (see BAL-001-0). (ii) Contingency reserve. An amount of Spinning Reserve and Nonspinning Reserve (at least half of which must be Spinning Reserve), sufficient to meet the NERC Disturbance Control Standard BAL-002-0, equal to the greater of: (a) The loss of generating capacity due to forced outages of generation or transmission equipment that would result from the most severe single contingency; or (b) The sum of five percent of the load responsibility served by hydro generation and seven percent of the load responsibility served by thermal generation.	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
BAL-003-0.1b	R4.2.	The Balancing Authorities that have a fixed schedule (B and C) but do not contain the Jointly Owned Unit shall not include their share of the governor droop response in their Frequency Bias Setting. ***See Standard for Graphic.***	LOWER
BAL-003-0.1b	R1.	Each Balancing Authority shall review its Frequency Bias Settings by January 1 of each year and recalculate its setting to reflect any change in the Frequency Response of the Balancing Authority Area.	LOWER
BAL-003-0.1b	R1.1.	The Balancing Authority may change its Frequency Bias Setting, and the method used to determine the setting, whenever any of the factors used to determine the current bias value change.	LOWER
BAL-003-0.1b	R1.2.	Each Balancing Authority shall report its Frequency Bias Setting, and method for determining that setting, to the NERC Operating Committee.	LOWER
BAL-003-0.1b	R2.	Each Balancing Authority shall establish and maintain a Frequency Bias Setting that is as close as practical to, or greater than, the Balancing Authority's Frequency Response. Frequency Bias may be calculated several ways:	MEDIUM
BAL-003-0.1b	R2.1.	The Balancing Authority may use a fixed Frequency Bias value which is based on a fixed, straight-line function of Tie Line deviation versus Frequency Deviation. The Balancing Authority shall determine the fixed value by observing and averaging the Frequency Response for several Disturbances during on-peak hours.	LOWER
BAL-003-0.1b	R2.2.	The Balancing Authority may use a variable (linear or non-linear) bias value, which is based on a variable function of Tie Line deviation to Frequency Deviation. The Balancing Authority shall determine the variable frequency bias value by analyzing Frequency Response as it varies with factors such as load, generation, governor characteristics, and frequency.	LOWER
BAL-003-0.1b	R3.	Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection reliability.	MEDIUM
BAL-003-0.1b	R4.	Balancing Authorities that use Dynamic Scheduling or Pseudo-ties for jointly owned units shall reflect their respective share of the unit governor droop response in their respective Frequency Bias Setting.	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
BAL-003-0.1b	R4.1.	Fixed schedules for Jointly Owned Units mandate that Balancing Authority (A) that contains the Jointly Owned Unit must incorporate the respective share of the unit governor droop response for any Balancing Authorities that have fixed schedules (B and C). See the diagram below. ***See Standard for Graphic.***	LOWER
BAL-003-0.1b	R5.	Balancing Authorities that serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of the Balancing Authority's estimated yearly peak demand per 0.1 Hz change.	MEDIUM
BAL-003-0.1b	R5.1.	Balancing Authorities that do not serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of its estimated maximum generation level in the coming year per 0.1 Hz change.	MEDIUM
BAL-003-0.1b	R6.	A Balancing Authority that is performing Overlap Regulation Service shall increase its Frequency Bias Setting to match the frequency response of the entire area being controlled. A Balancing Authority shall not change its Frequency Bias Setting when performing Supplemental Regulation Service.	MEDIUM
BAL-004-0	R1.	Only a Reliability Coordinator shall be eligible to act as Interconnection Time Monitor. A single Reliability Coordinator in each Interconnection shall be designated by the NERC Operating Committee to serve as Interconnection Time Monitor.	LOWER
BAL-004-0	R2.	The Interconnection Time Monitor shall monitor Time Error and shall initiate or terminate corrective action orders in accordance with the NAESB Time Error Correction Procedure.	LOWER
BAL-004-0	R3.	Each Balancing Authority, when requested, shall participate in a Time Error Correction by one of the following methods:	MEDIUM
BAL-004-0	R3.1.	The Balancing Authority shall offset its frequency schedule by 0.02 Hertz, leaving the Frequency Bias Setting normal; or	LOWER
BAL-004-0	R3.2.	The Balancing Authority shall offset its Net Interchange Schedule (MW) by an amount equal to the computed bias contribution during a 0.02 Hertz Frequency Deviation (i.e. 20% of the Frequency Bias Setting).	LOWER
BAL-004-0	R4.	Any Reliability Coordinator in an Interconnection shall have the authority to request the Interconnection Time Monitor to terminate a Time Error Correction in progress, or a scheduled Time Error Correction that has not begun, for reliability considerations.	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
BAL-004-0	R4.1.	Balancing Authorities that have reliability concerns with the execution of a Time Error Correction shall notify their Reliability Coordinator and request the termination of a Time Error Correction in progress.	LOWER
BAL-004-WECC-01	R1.	Each BA that operates synchronously to the Western Interconnection shall continuously operate utilizing Automatic Time Error Correction (ATEC) in its Automatic Generation Control (AGC) system. ***See Standard for Formula***	MEDIUM
BAL-004-WECC-01	R1.2.	Large accumulations of primary inadvertent point to an invalid implementation of ATEC, loose control, metering or accounting errors. A BA in such a situation should identify the source of the error(s) and make the corrections, recalculate the primary inadvertent from the time of the error, adjust the accumulated primary inadvertent caused by the error(s), validate the implementation of ATEC, set Lmax equal to L10 and continue to operate with ATEC reducing the accumulation as system parameters allow.	
BAL-004-WECC-01	R2.	Each BA that is synchronously connected to the Western Interconnection and operates in any AGC operating mode other than ATEC shall notify all other BAs of its operating mode through the designated Interconnection communication system. Each BA while synchronously connected to the Western Interconnection will be allowed to have ATEC out of service for a maximum of 24 hours per calendar quarter, for reasons including maintenance and testing.	MEDIUM
BAL-004-WECC-01	R3.	BAs in the Western Interconnection shall be able to change their AGC operating mode between Flat Frequency (for blackout restoration); Flat Tie Line (for loss of frequency telemetry); Tie Line Bias; Tie Line Bias plus Time Error control (used in ATEC mode). The ACE used for NERC reports shall be the same ACE as the AGC operating mode in use.	MEDIUM
BAL-004-WECC-01	R4.	Regardless of the AGC operating mode each BA in the Western Interconnection shall compute its hourly Primary Inadvertent Interchange when hourly checkout is complete. If hourly checkout is not complete by 50 minutes after the hour, compute Primary Inadvertent Interchange with best available data. This hourly value shall be added to the appropriate accumulated Primary Inadvertent Interchange balance for either On-Peak or Off-Peak periods.	MEDIUM
BAL-004-WECC-01	R4.1.	Each BA in the Western Interconnection shall use the change in Time Error distributed by the Interconnection Time Monitor.	
BAL-004-WECC-01	R4.2.	All corrections to any previous hour Primary Inadvertent Interchange shall be added to the appropriate On- or Off-Peak accumulated Primary Inadvertent Interchange.	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
BAL-004-WECC-01	R4.3.	Month end Inadvertent Adjustments are 100% Primary Inadvertent Interchange and shall be added to the appropriate On- or Off-Peak accumulated Primary Inadvertent Interchange, unless such adjustments can be pinpointed to specific hours in which case R4.2 applies.	
BAL-004-WECC-01	R4.4.	Each BA in the Western Interconnection shall synchronize its Time Error to the nearest 0.001 seconds of the system Time Error by comparing its reading at the designated time each day to the reading broadcast by the Interconnection Time Monitor. Any difference shall be applied as an adjustment to its current Time Error.	
BAL-005-0.1b	R1.	All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.	<blank>
BAL-005-0.1b	R1.1.	Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.	MEDIUM
BAL-005-0.1b	R1.2.	Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.	MEDIUM
BAL-005-0.1b	R1.3.	Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a Balancing Authority Area.	MEDIUM
BAL-005-0.1b	R2.	Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.	HIGH
BAL-005-0.1b	R3.	A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications, and control equipment are employed to prevent such service from becoming a Burden on the Interconnection or other Balancing Authority Areas.	MEDIUM
BAL-005-0.1b	R4.	A Balancing Authority providing Regulation Service shall notify the Host Balancing Authority for whom it is controlling if it is unable to provide the service, as well as any Intermediate Balancing Authorities.	MEDIUM
BAL-005-0.1b	R5.	A Balancing Authority receiving Regulation Service shall ensure that backup plans are in place to provide replacement Regulation Service should the supplying Balancing Authority no longer be able to provide this service.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
BAL-005-0.1b	R6.	The Balancing Authority's AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's ACE. Single Balancing Authorities operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control. If a Balancing Authority is unable to calculate ACE for more than 30 minutes it shall notify its Reliability Coordinator.	MEDIUM
BAL-005-0.1b	R7.	The Balancing Authority shall operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become inoperative, the Balancing Authority shall use manual control to adjust generation to maintain the Net Scheduled Interchange.	MEDIUM
BAL-005-0.1b	R8.	The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every six seconds.	MEDIUM
BAL-005-0.1b	R8.1.	Each Balancing Authority shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide a minimum availability of 99.95%.	MEDIUM
BAL-005-0.1b	R9.	The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.	LOWER
BAL-005-0.1b	R9.1.	Balancing Authorities with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection may choose to omit the Interchange Schedule related to the HVDC link from the ACE equation if it is modeled as internal generation or load.	LOWER
BAL-005-0.1b	R10.	The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.	HIGH
BAL-005-0.1b	R11.	Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE.	MEDIUM
BAL-005-0.1b	R12.	Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
BAL-005-0.1b	R12.1.	Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment. Balancing Authorities shall ensure that megawatt-hour data is telemetered or reported at the end of each hour.	LOWER
BAL-005-0.1b	R12.2.	Balancing Authorities shall ensure the power flow and ACE signals that are utilized for calculating Balancing Authority performance or that are transmitted for Regulation Service are not filtered prior to transmission, except for the Anti-aliasing Filters of Tie Lines.	MEDIUM
BAL-005-0.1b	R12.3.	Balancing Authorities shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more Balancing Authorities to deliver the output of Jointly Owned Units or to serve remote load.	MEDIUM
BAL-005-0.1b	R13.	Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the accuracy of its control equipment. The Balancing Authority shall adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error (IME) term of the ACE equation to compensate for any equipment error until repairs can be made.	LOWER
BAL-005-0.1b	R14.	The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the Balancing Authority shall provide its operating personnel with real-time values for ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.	LOWER
BAL-005-0.1b	R15.	The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority's control center and other critical locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.	LOWER
BAL-005-0.1b	R16.	The Balancing Authority shall sample data at least at the same periodicity with which ACE is calculated. The Balancing Authority shall flag missing or bad data for operator display and archival purposes. The Balancing Authority shall collect coincident data to the greatest practical extent, i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
BAL-005-0.1b	R17.	Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below: ***See Standard for Values***	MEDIUM
BAL-006-1.1	R1.	Each Balancing Authority shall calculate and record hourly Inadvertent Interchange.	LOWER
BAL-006-1.1	R2.	Each Balancing Authority shall include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. The Balancing Authority shall take into account interchange served by jointly owned generators.	LOWER
BAL-006-1.1	R3.	Each Balancing Authority shall ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities.	LOWER
BAL-006-1.1	R4.	Adjacent Balancing Authority Areas shall operate to a common Net Interchange Schedule and Actual Net Interchange value and shall record these hourly quantities, with like values but opposite sign. Each Balancing Authority shall compute its Inadvertent Interchange based on the following:	LOWER
BAL-006-1.1	R4.1.	Each Balancing Authority, by the end of the next business day, shall agree with its Adjacent Balancing Authorities to:	LOWER
BAL-006-1.1	R4.1.1.	The hourly values of Net Interchange Schedule.	LOWER
BAL-006-1.1	R4.1.2.	The hourly integrated megawatt-hour values of Net Actual Interchange.	LOWER
BAL-006-1.1	R4.2.	Each Balancing Authority shall use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month.	LOWER
BAL-006-1.1	R4.3.	A Balancing Authority shall make after-the-fact corrections to the agreed-to daily and monthly accounting data only as needed to reflect actual operating conditions (e.g. a meter being used for control was sending bad data). Changes or corrections based on non-reliability considerations shall not be reflected in the Balancing Authority's Inadvertent Interchange. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the Adjacent Balancing Authority(ies).	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
BAL-006-1.1	R5.	Adjacent Balancing Authorities that cannot mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month shall, for the purposes of dispute resolution, submit a report to their respective Regional Reliability Organization Survey Contact. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy.	LOWER
CIP-001-1	R1.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall have procedures for the recognition of and for making their operating personnel aware of sabotage events on its facilities and multi site sabotage affecting larger portions of the Interconnection.	MEDIUM
CIP-001-1	R2.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall have procedures for the communication of information concerning sabotage events to appropriate parties in the Interconnection.	MEDIUM
CIP-001-1	R3.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall provide its operating personnel with sabotage response guidelines, including personnel to contact, for reporting disturbances due to sabotage events.	MEDIUM
CIP-001-1	R4.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall establish communications contacts, as applicable, with local Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP) officials and develop reporting procedures as appropriate to their circumstances.	MEDIUM
CIP-002-1	R1.	Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.	MEDIUM
CIP-002-1	R1.1.	The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.	LOWER
CIP-002-1	R1.2.	The risk-based assessment shall consider the following assets:	MEDIUM
CIP-002-1	R1.2.1.	Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.	LOWER
CIP-002-1	R1.2.2.	Transmission substations that support the reliable operation of the Bulk Electric System.	LOWER
CIP-002-1	R1.2.3.	Generation resources that support the reliable operation of the Bulk Electric System.	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-002-1	R1.2.4.	Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration.	LOWER
CIP-002-1	R1.2.5.	Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.	LOWER
CIP-002-1	R1.2.6.	Special Protection Systems that support the reliable operation of the Bulk Electric System.	LOWER
CIP-002-1	R1.2.7.	Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.	LOWER
CIP-002-1	R2.	Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.	HIGH
CIP-002-1	R3.	Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time interutility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:	HIGH
CIP-002-1	R3.1.	The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,	LOWER
CIP-002-1	R3.2.	The Cyber Asset uses a routable protocol within a control center; or,	LOWER
CIP-002-1	R3.3.	The Cyber Asset is dial-up accessible.	LOWER
CIP-002-1	R4.	Annual Approval — A senior manager or delegate(s) shall approve annually the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of the senior manager or delegate(s)'s approval of the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-002-2	R1.	Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.	MEDIUM
CIP-002-2	R1.1.	The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.	LOWER
CIP-002-2	R1.2.	The risk-based assessment shall consider the following assets:	MEDIUM
CIP-002-2	R1.2.1.	Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.	LOWER
CIP-002-2	R1.2.2.	Transmission substations that support the reliable operation of the Bulk Electric System.	LOWER
CIP-002-2	R1.2.3.	Generation resources that support the reliable operation of the Bulk Electric System.	LOWER
CIP-002-2	R1.2.4.	Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration.	LOWER
CIP-002-2	R1.2.5.	Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.	LOWER
CIP-002-2	R1.2.6.	Special Protection Systems that support the reliable operation of the Bulk Electric System.	LOWER
CIP-002-2	R1.2.7.	Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.	LOWER
CIP-002-2	R2.	Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.	HIGH
CIP-002-2	R3.	Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002-2, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:	HIGH
CIP-002-2	R3.1.	The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,	LOWER
CIP-002-2	R3.2.	The Cyber Asset uses a routable protocol within a control center; or,	LOWER
CIP-002-2	R3.3.	The Cyber Asset is dial-up accessible.	LOWER
CIP-002-2	R4.	Annual Approval — The senior manager or delegate(s) shall approve annually the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of the senior manager or delegate(s)'s approval of the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)	LOWER
CIP-002-3	R1.	Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-002-3	R1.1.	The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.	
CIP-002-3	R1.2.	The risk-based assessment shall consider the following assets:	
CIP-002-3	R1.2.1.	Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.	
CIP-002-3	R1.2.2.	Transmission substations that support the reliable operation of the Bulk Electric System.	
CIP-002-3	R1.2.3.	Generation resources that support the reliable operation of the Bulk Electric System.	
CIP-002-3	R1.2.4.	Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration.	
CIP-002-3	R1.2.5.	Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.	
CIP-002-3	R1.2.6.	Special Protection Systems that support the reliable operation of the Bulk Electric System.	
CIP-002-3	R1.2.7.	Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.	
CIP-002-3	R2.	Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.	
CIP-002-3	R3.	Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002-3, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:	
CIP-002-3	R3.1.	The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,	
CIP-002-3	R3.2.	The Cyber Asset uses a routable protocol within a control center; or,	
CIP-002-3	R3.3.	The Cyber Asset is dial-up accessible.	
CIP-002-3	R4.	Annual Approval — The senior manager or delegate(s) shall approve annually the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of the senior manager or delegate(s)'s approval of the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)	
CIP–003–1	R1.	Cyber Security Policy — The Responsible Entity shall document and implement a cyber security policy that represents management's commitment and ability to secure its Critical Cyber Assets. The Responsible Entity shall, at minimum, ensure the following:	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP–003–1	R1.1.	The cyber security policy addresses the requirements in Standards CIP-002 through CIP-009, including provision for emergency situations.	LOWER
CIP–003–1	R1.2.	The cyber security policy is readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets.	LOWER
CIP–003–1	R1.3.	Annual review and approval of the cyber security policy by the senior manager assigned pursuant to R2.	LOWER
CIP–003–1	R2.	Leadership — The Responsible Entity shall assign a senior manager with overall responsibility for leading and managing the entity's implementation of, and adherence to, Standards CIP-002 through CIP-009	MEDIUM
CIP–003–1	R2.1.	The senior manager shall be identified by name, title, business phone, business address, and date of designation.	LOWER
CIP–003–1	R2.2.	Changes to the senior manager must be documented within thirty calendar days of the effective date.	LOWER
CIP–003–1	R2.3.	The senior manager or delegate(s), shall authorize and document any exception from the requirements of the cyber security policy.	LOWER
CIP–003–1	R3.	Exceptions — Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and authorized by the senior manager or delegate(s).	LOWER
CIP–003–1	R3.1.	Exceptions to the Responsible Entity's cyber security policy must be documented within thirty days of being approved by the senior manager or delegate(s).	LOWER
CIP–003–1	R3.2.	Documented exceptions to the cyber security policy must include an explanation as to why the exception is necessary and any compensating measures, or a statement accepting risk.	LOWER
CIP–003–1	R3.3.	Authorized exceptions to the cyber security policy must be reviewed and approved annually by the senior manager or delegate(s) to ensure the exceptions are still required and valid. Such review and approval shall be documented.	LOWER
CIP–003–1	R4.	Information Protection — The Responsible Entity shall implement and document a program to identify, classify, and protect information associated with Critical Cyber Assets.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP–003–1	R4.1.	The Critical Cyber Asset information to be protected shall include, at a minimum and regardless of media type, operational procedures, lists as required in Standard CIP-002, network topology or similar diagrams, floor plans of computing centers that contain Critical Cyber Assets, equipment layouts of Critical Cyber Assets, disaster recovery plans, incident response plans, and security configuration information.	MEDIUM
CIP–003–1	R4.2.	The Responsible Entity shall classify information to be protected under this program based on the sensitivity of the Critical Cyber Asset information.	LOWER
CIP–003–1	R4.3.	The Responsible Entity shall, at least annually, assess adherence to its Critical Cyber Asset information protection program, document the assessment results, and implement an action plan to remediate deficiencies identified during the assessment.	LOWER
CIP–003–1	R5.	Access Control — The Responsible Entity shall document and implement a program for managing access to protected Critical Cyber Asset information.	LOWER
CIP–003–1	R5.1.	The Responsible Entity shall maintain a list of designated personnel who are responsible for authorizing logical or physical access to protected information.	LOWER
CIP–003–1	R5.1.1.	Personnel shall be identified by name, title, business phone and the information for which they are responsible for authorizing access.	LOWER
CIP–003–1	R5.1.2.	The list of personnel responsible for authorizing access to protected information shall be verified at least annually.	LOWER
CIP–003–1	R5.2.	The Responsible Entity shall review at least annually the access privileges to protected information to confirm that access privileges are correct and that they correspond with the Responsible Entity's needs and appropriate personnel roles and responsibilities.	LOWER
CIP–003–1	R5.3.	The Responsible Entity shall assess and document at least annually the processes for controlling access privileges to protected information.	LOWER
CIP–003–1	R6.	Change Control and Configuration Management — The Responsible Entity shall establish and document a process of change control and configuration management for adding, modifying, replacing, or removing Critical Cyber Asset hardware or software, and implement supporting configuration management activities to identify, control and document all entity or vendorrelated changes to hardware and software components of Critical Cyber Assets pursuant to the change control process.	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-003-2	R1.	Cyber Security Policy — The Responsible Entity shall document and implement a cyber security policy that represents management's commitment and ability to secure its Critical Cyber Assets. The Responsible Entity shall, at minimum, ensure the following:	MEDIUM
CIP-003-2	R1.1.	The cyber security policy addresses the requirements in Standards CIP-002-2 through CIP-009-2, including provision for emergency situations.	LOWER
CIP-003-2	R1.2.	The cyber security policy is readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets.	LOWER
CIP-003-2	R1.3.	Annual review and approval of the cyber security policy by the senior manager assigned pursuant to R2.	LOWER
CIP-003-2	R2.	Leadership — The Responsible Entity shall assign a single senior manager with overall responsibility and authority for leading and managing the entity's implementation of, and adherence to, Standards CIP-002-2 through CIP-009-2.	MEDIUM
CIP-003-2	R2.1.	The senior manager shall be identified by name, title, and date of designation.	LOWER
CIP-003-2	R2.2.	Changes to the senior manager must be documented within thirty calendar days of the effective date.	LOWER
CIP-003-2	R2.3.	Where allowed by Standards CIP-002-2 through CIP-009-2, the senior manager may delegate authority for specific actions to a named delegate or delegates. These delegations shall be documented in the same manner as R2.1 and R2.2, and approved by the senior manager.	LOWER
CIP-003-2	R2.4.	The senior manager or delegate(s), shall authorize and document any exception from the requirements of the cyber security policy.	LOWER
CIP-003-2	R3.	Exceptions — Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and authorized by the senior manager or delegate(s).	LOWER
CIP-003-2	R3.1.	Exceptions to the Responsible Entity's cyber security policy must be documented within thirty days of being approved by the senior manager or delegate(s).	LOWER
CIP-003-2	R3.2.	Documented exceptions to the cyber security policy must include an explanation as to why the exception is necessary and any compensating measures.	LOWER
CIP-003-2	R3.3.	Authorized exceptions to the cyber security policy must be reviewed and approved annually by the senior manager or delegate(s) to ensure the exceptions are still required and valid. Such review and approval shall be documented.	LOWER
CIP-003-2	R4.	Information Protection — The Responsible Entity shall implement and document a program to identify, classify, and protect information associated with Critical Cyber Assets.	MEDIUM
CIP-003-2	R4.1.	The Critical Cyber Asset information to be protected shall include, at a minimum and regardless of media type, operational procedures, lists as required in Standard CIP-002-2, network topology or similar diagrams, floor plans of computing centers that contain Critical Cyber Assets, equipment layouts of Critical Cyber Assets, disaster recovery plans, incident response plans, and security configuration information.	MEDIUM
CIP-003-2	R4.2.	The Responsible Entity shall classify information to be protected under this program based on the sensitivity of the Critical Cyber Asset information.	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-003-2	R4.3.	The Responsible Entity shall, at least annually, assess adherence to its Critical Cyber Asset information protection program, document the assessment results, and implement an action plan to remediate deficiencies identified during the assessment.	LOWER
CIP-003-2	R5.	Access Control — The Responsible Entity shall document and implement a program for managing access to protected Critical Cyber Asset information.	LOWER
CIP-003-2	R5.1.	The Responsible Entity shall maintain a list of designated personnel who are responsible for authorizing logical or physical access to protected information.	LOWER
CIP-003-2	R5.1.1.	Personnel shall be identified by name, title, and the information for which they are responsible for authorizing access.	LOWER
CIP-003-2	R5.1.2.	The list of personnel responsible for authorizing access to protected information shall be verified at least annually.	LOWER
CIP-003-2	R5.2.	The Responsible Entity shall review at least annually the access privileges to protected information to confirm that access privileges are correct and that they correspond with the Responsible Entity's needs and appropriate personnel roles and responsibilities.	LOWER
CIP-003-2	R5.3.	The Responsible Entity shall assess and document at least annually the processes for controlling access privileges to protected information.	LOWER
CIP-003-2	R6.	Change Control and Configuration Management — The Responsible Entity shall establish and document a process of change control and configuration management for adding, modifying, replacing, or removing Critical Cyber Asset hardware or software, and implement supporting configuration management activities to identify, control and document all entity or vendor-related changes to hardware and software components of Critical Cyber Assets pursuant to the change control process.	LOWER
CIP-003-3	R1.	Cyber Security Policy — The Responsible Entity shall document and implement a cyber security policy that represents management's commitment and ability to secure its Critical Cyber Assets. The Responsible Entity shall, at minimum, ensure the following:	
CIP-003-3	R1.1.	The cyber security policy addresses the requirements in Standards CIP-002-3 through CIP-009-3, including provision for emergency situations.	
CIP-003-3	R1.2.	The cyber security policy is readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets.	
CIP-003-3	R1.3.	Annual review and approval of the cyber security policy by the senior manager assigned pursuant to R2.	
CIP-003-3	R2.	Leadership — The Responsible Entity shall assign a single senior manager with overall responsibility and authority for leading and managing the entity's implementation of, and adherence to, Standards CIP-002-3 through CIP-009-3.	
CIP-003-3	R2.1.	The senior manager shall be identified by name, title, and date of designation.	
CIP-003-3	R2.2.	Changes to the senior manager must be documented within thirty calendar days of the effective date.	
CIP-003-3	R2.3.	Where allowed by Standards CIP-002-3 through CIP-009-3, the senior manager may delegate authority for specific actions to a named delegate or delegates. These delegations shall be documented in the same manner as R2.1 and R2.2, and approved by the senior manager.	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-003-3	R2.4.	The senior manager or delegate(s), shall authorize and document any exception from the requirements of the cyber security policy.	
CIP-003-3	R3.	Exceptions — Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and authorized by the senior manager or delegate(s).	
CIP-003-3	R3.1.	Exceptions to the Responsible Entity's cyber security policy must be documented within thirty days of being approved by the senior manager or delegate(s).	
CIP-003-3	R3.2.	Documented exceptions to the cyber security policy must include an explanation as to why the exception is necessary and any compensating measures.	
CIP-003-3	R3.3.	Authorized exceptions to the cyber security policy must be reviewed and approved annually by the senior manager or delegate(s) to ensure the exceptions are still required and valid. Such review and approval shall be documented.	
CIP-003-3	R4.	Information Protection — The Responsible Entity shall implement and document a program to identify, classify, and protect information associated with Critical Cyber Assets.	
CIP-003-3	R4.1.	The Critical Cyber Asset information to be protected shall include, at a minimum and regardless of media type, operational procedures, lists as required in Standard CIP-002-3, network topology or similar diagrams, floor plans of computing centers that contain Critical Cyber Assets, equipment layouts of Critical Cyber Assets, disaster recovery plans, incident response plans, and security configuration information.	
CIP-003-3	R4.2.	The Responsible Entity shall classify information to be protected under this program based on the sensitivity of the Critical Cyber Asset information.	
CIP-003-3	R4.3.	The Responsible Entity shall, at least annually, assess adherence to its Critical Cyber Asset information protection program, document the assessment results, and implement an action plan to remediate deficiencies identified during the assessment.	
CIP-003-3	R5.	Access Control — The Responsible Entity shall document and implement a program for managing access to protected Critical Cyber Asset information.	
CIP-003-3	R5.1.	The Responsible Entity shall maintain a list of designated personnel who are responsible for authorizing logical or physical access to protected information.	
CIP-003-3	R5.1.1.	Personnel shall be identified by name, title, and the information for which they are responsible for authorizing access.	
CIP-003-3	R5.1.2.	The list of personnel responsible for authorizing access to protected information shall be verified at least annually.	
CIP-003-3	R5.2.	The Responsible Entity shall review at least annually the access privileges to protected information to confirm that access privileges are correct and that they correspond with the Responsible Entity's needs and appropriate personnel roles and responsibilities.	
CIP-003-3	R5.3.	The Responsible Entity shall assess and document at least annually the processes for controlling access privileges to protected information.	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-003-3	R6.	Change Control and Configuration Management — The Responsible Entity shall establish and document a process of change control and configuration management for adding, modifying, replacing, or removing Critical Cyber Asset hardware or software, and implement supporting configuration management activities to identify, control and document all entity or vendor-related changes to hardware and software components of Critical Cyber Assets pursuant to the change control process.	
CIP-004-1	R1.	Awareness — The Responsible Entity shall establish, maintain, and document a security awareness program to ensure personnel having authorized cyber or authorized unescorted physical access receive on-going reinforcement in sound security practices. The program shall include security awareness reinforcement on at least a quarterly basis using mechanisms such as: Direct communications (e.g., emails, memos, computer based training, etc.); Indirect communications (e.g., posters, intranet, brochures, etc.); Management support and reinforcement (e.g., presentations, meetings, etc.).	LOWER
CIP-004-1	R2.	Training — The Responsible Entity shall establish, maintain, and document an annual cyber security training program for personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets, and review the program annually and update as necessary.	LOWER
CIP-004-1	R2.1.	This program will ensure that all personnel having such access to Critical Cyber Assets, including contractors and service vendors, are trained within ninety calendar days of such authorization.	MEDIUM
CIP-004-1	R2.2.	Training shall cover the policies, access controls, and procedures as developed for the Critical Cyber Assets covered by CIP-004, and include, at a minimum, the following required items appropriate to personnel roles and responsibilities:	MEDIUM
CIP-004-1	R2.2.1.	The proper use of Critical Cyber Assets;	LOWER
CIP-004-1	R2.2.2.	Physical and electronic access controls to Critical Cyber Assets;	LOWER
CIP-004-1	R2.2.3.	The proper handling of Critical Cyber Asset information; and,	LOWER
CIP-004-1	R2.2.4.	Action plans and procedures to recover or re-establish Critical Cyber Assets and access thereto following a Cyber Security Incident.	MEDIUM
CIP-004-1	R2.3.	The Responsible Entity shall maintain documentation that training is conducted at least annually, including the date the training was completed and attendance records.	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-004-1	R3.	Personnel Risk Assessment —The Responsible Entity shall have a documented personnel risk assessment program, in accordance with federal, state, provincial, and local laws, and subject to existing collective bargaining unit agreements, for personnel having authorized cyber or authorized unescorted physical access. A personnel risk assessment shall be conducted pursuant to that program within thirty days of such personnel being granted such access. Such program shall at a minimum include:	MEDIUM
CIP-004-1	R3.1.	The Responsible Entity shall ensure that each assessment conducted include, at least, identity verification (e.g., Social Security Number verification in the U.S.) and sevenyear criminal check. The Responsible Entity may conduct more detailed reviews, as permitted by law and subject to existing collective bargaining unit agreements, depending upon the criticality of the position.	LOWER
CIP-004-1	R3.2.	The Responsible Entity shall update each personnel risk assessment at least every seven years after the initial personnel risk assessment or for cause.	LOWER
CIP-004-1	R3.3.	The Responsible Entity shall document the results of personnel risk assessments of its personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets, and that personnel risk assessments of contractor and service vendor personnel with such access are conducted pursuant to Standard CIP-004.	LOWER
CIP-004-1	R4.	Access — The Responsible Entity shall maintain list(s) of personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including their specific electronic and physical access rights to Critical Cyber Assets.	LOWER
CIP-004-1	R4.1.	The Responsible Entity shall review the list(s) of its personnel who have such access to Critical Cyber Assets quarterly, and update the list(s) within seven calendar days of any change of personnel with such access to Critical Cyber Assets, or any change in the access rights of such personnel. The Responsible Entity shall ensure access list(s) for contractors and service vendors are properly maintained.	LOWER
CIP-004-1	R4.2.	The Responsible Entity shall revoke such access to Critical Cyber Assets within 24 hours for personnel terminated for cause and within seven calendar days for personnel who no longer require such access to Critical Cyber Assets.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-004-2	R1.	Awareness — The Responsible Entity shall establish, document, implement, and maintain a security awareness program to ensure personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets receive on-going reinforcement in sound security practices. The program shall include security awareness reinforcement on at least a quarterly basis using mechanisms such as: Direct communications (e.g. emails, memos, computer based training, etc.); Indirect communications (e.g. posters, intranet, brochures, etc.); Management support and reinforcement (e.g., presentations, meetings, etc.).	LOWER
CIP-004-2	R2.	Training — The Responsible Entity shall establish, document, implement, and maintain an annual cyber security training program for personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets. The cyber security training program shall be reviewed annually, at a minimum, and shall be updated whenever necessary.	LOWER
CIP-004-2	R2.1.	This program will ensure that all personnel having such access to Critical Cyber Assets, including contractors and service vendors, are trained prior to their being granted such access except in specified circumstances such as an emergency.	MEDIUM
CIP-004-2	R2.2.	Training shall cover the policies, access controls, and procedures as developed for the Critical Cyber Assets covered by CIP-004-2, and include, at a minimum, the following required items appropriate to personnel roles and responsibilities:	MEDIUM
CIP-004-2	R2.2.1.	The proper use of Critical Cyber Assets;	LOWER
CIP-004-2	R2.2.2.	Physical and electronic access controls to Critical Cyber Assets;	LOWER
CIP-004-2	R2.2.3.	The proper handling of Critical Cyber Asset information; and,	LOWER
CIP-004-2	R2.2.4.	Action plans and procedures to recover or re-establish Critical Cyber Assets and access thereto following a Cyber Security Incident.	MEDIUM
CIP-004-2	R2.3.	The Responsible Entity shall maintain documentation that training is conducted at least annually, including the date the training was completed and attendance records.	LOWER
CIP-004-2	R3.	Personnel Risk Assessment —The Responsible Entity shall have a documented personnel risk assessment program, in accordance with federal, state, provincial, and local laws, and subject to existing collective bargaining unit agreements, for personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets. A personnel risk assessment shall be conducted pursuant to that program prior to such personnel being granted such access except in specified circumstances such as an emergency. The personnel risk assessment program shall at a minimum include:	MEDIUM
CIP-004-2	R3.1.	The Responsible Entity shall ensure that each assessment conducted include, at least, identity verification (e.g., Social Security Number verification in the U.S.) and seven-year criminal check. The Responsible Entity may conduct more detailed reviews, as permitted by law and subject to existing collective bargaining unit agreements, depending upon the criticality of the position.	LOWER
CIP-004-2	R3.2.	The Responsible Entity shall update each personnel risk assessment at least every seven years after the initial personnel risk assessment or for cause.	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-004-2	R3.3.	The Responsible Entity shall document the results of personnel risk assessments of its personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets, and that personnel risk assessments of contractor and service vendor personnel with such access are conducted pursuant to Standard CIP-004-2.	LOWER
CIP-004-2	R4.	Access — The Responsible Entity shall maintain list(s) of personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including their specific electronic and physical access rights to Critical Cyber Assets.	LOWER
CIP-004-2	R4.1.	The Responsible Entity shall review the list(s) of its personnel who have such access to Critical Cyber Assets quarterly, and update the list(s) within seven calendar days of any change of personnel with such access to Critical Cyber Assets, or any change in the access rights of such personnel. The Responsible Entity shall ensure access list(s) for contractors and service vendors are properly maintained.	LOWER
CIP-004-2	R4.2.	The Responsible Entity shall revoke such access to Critical Cyber Assets within 24 hours for personnel terminated for cause and within seven calendar days for personnel who no longer require such access to Critical Cyber Assets.	MEDIUM
CIP-004-3	R1.	Awareness — The Responsible Entity shall establish, document, implement, and maintain a security awareness program to ensure personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets receive on-going reinforcement in sound security practices. The program shall include security awareness reinforcement on at least a quarterly basis using mechanisms such as: • Direct communications (e.g., emails, memos, computer based training, etc.); • Indirect communications (e.g., posters, intranet, brochures, etc.); • Management support and reinforcement (e.g., presentations, meetings, etc.).	
CIP-004-3	R2.	Training — The Responsible Entity shall establish, document, implement, and maintain an annual cyber security training program for personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets. The cyber security training program shall be reviewed annually, at a minimum, and shall be updated whenever necessary.	
CIP-004-3	R2.1.	This program will ensure that all personnel having such access to Critical Cyber Assets, including contractors and service vendors, are trained prior to their being granted such access except in specified circumstances such as an emergency.	
CIP-004-3	R2.2.	Training shall cover the policies, access controls, and procedures as developed for the Critical Cyber Assets covered by CIP-004-3, and include, at a minimum, the following required items appropriate to personnel roles and responsibilities:	
CIP-004-3	R2.2.1.	The proper use of Critical Cyber Assets;	
CIP-004-3	R2.2.2.	Physical and electronic access controls to Critical Cyber Assets;	
CIP-004-3	R2.2.3.	The proper handling of Critical Cyber Asset information; and,	
CIP-004-3	R2.2.4.	Action plans and procedures to recover or re-establish Critical Cyber Assets and access thereto following a Cyber Security Incident.	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-004-3	R2.3.	The Responsible Entity shall maintain documentation that training is conducted at least annually, including the date the training was completed and attendance records.	
CIP-004-3	R3.	Personnel Risk Assessment —The Responsible Entity shall have a documented personnel risk assessment program, in accordance with federal, state, provincial, and local laws, and subject to existing collective bargaining unit agreements, for personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets. A personnel risk assessment shall be conducted pursuant to that program prior to such personnel being granted such access except in specified circumstances such as an emergency. The personnel risk assessment program shall at a minimum include:	
CIP-004-3	R3.1.	The Responsible Entity shall ensure that each assessment conducted include, at least, identity verification (e.g., Social Security Number verification in the U.S.) and seven-year criminal check. The Responsible Entity may conduct more detailed reviews, as permitted by law and subject to existing collective bargaining unit agreements, depending upon the criticality of the position.	
CIP-004-3	R3.2.	The Responsible Entity shall update each personnel risk assessment at least every seven years after the initial personnel risk assessment or for cause.	
CIP-004-3	R3.3.	The Responsible Entity shall document the results of personnel risk assessments of its personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets, and that personnel risk assessments of contractor and service vendor personnel with such access are conducted pursuant to Standard CIP-004-3.	
CIP-004-3	R4.	Access — The Responsible Entity shall maintain list(s) of personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including their specific electronic and physical access rights to Critical Cyber Assets.	
CIP-004-3	R4.1.	The Responsible Entity shall review the list(s) of its personnel who have such access to Critical Cyber Assets quarterly, and update the list(s) within seven calendar days of any change of personnel with such access to Critical Cyber Assets, or any change in the access rights of such personnel. The Responsible Entity shall ensure access list(s) for contractors and service vendors are properly maintained.	
CIP-004-3	R4.2.	The Responsible Entity shall revoke such access to Critical Cyber Assets within 24 hours for personnel terminated for cause and within seven calendar days for personnel who no longer require such access to Critical Cyber Assets.	
CIP-005-1	R1.	Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The Responsible Entity shall identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s).	MEDIUM
CIP-005-1	R1.1.	Access points to the Electronic Security Perimeter(s) shall include any externally connected communication end point (for example, dial-up modems) terminating at any device within the Electronic Security Perimeter(s).	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-005-1	R1.2.	For a dial-up accessible Critical Cyber Asset that uses a non-routable protocol, the Responsible Entity shall define an Electronic Security Perimeter for that single access point at the dial-up device.	MEDIUM
CIP-005-1	R1.3.	Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points of these communication links within the Electronic Security Perimeter(s) shall be considered access points to the Electronic Security Perimeter(s).	MEDIUM
CIP-005-1	R1.4.	Any non-critical Cyber Asset within a defined Electronic Security Perimeter shall be identified and protected pursuant to the requirements of Standard CIP-005.	MEDIUM
CIP-005-1	R1.5.	Cyber Assets used in the access control and monitoring of the Electronic Security Perimeter(s) shall be afforded the protective measures as a specified in Standard CIP-003, Standard CIP-004 Requirement R3, Standard CIP-005 Requirements R2 and R3, Standard CIP-006 Requirements R2 and R3, Standard CIP-007, Requirements R1 and R3 through R9, Standard CIP-008, and Standard CIP-009.	MEDIUM
CIP-005-1	R1.6.	The Responsible Entity shall maintain documentation of Electronic SecurityPerimeter(s), all interconnected Critical and non-critical Cyber Assets within the Electronic Security Perimeter(s), all electronic access points to the Electronic Security Perimeter(s) and the Cyber Assets deployed for the access control and monitoring of these access points.	LOWER
CIP-005-1	R2.	Electronic Access Controls — The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for control of electronic access at all electronic access points to the Electronic Security Perimeter(s).	MEDIUM
CIP-005-1	R2.1.	These processes and mechanisms shall use an access control model that denies access by default, such that explicit access permissions must be specified.	MEDIUM
CIP-005-1	R2.2.	At all access points to the Electronic Security Perimeter(s), the Responsible Entity shall enable only ports and services required for operations and for monitoring Cyber Assets within the Electronic Security Perimeter, and shall document, individually or by specified grouping, the configuration of those ports and services.	MEDIUM
CIP-005-1	R2.3.	The Responsible Entity shall maintain a procedure for securing dial-up access to the Electronic Security Perimeter(s).	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-005-1	R2.4.	Where external interactive access into the Electronic Security Perimeter has been enabled, the Responsible Entity shall implement strong procedural or technical controls at the access points to ensure authenticity of the accessing party, where technically feasible.	MEDIUM
CIP-005-1	R2.5.	The required documentation shall, at least, identify and describe:	LOWER
CIP-005-1	R2.5.1.	The processes for access request and authorization.	LOWER
CIP-005-1	R2.5.2.	The authentication methods.	LOWER
CIP-005-1	R2.5.3.	The review process for authorization rights, in accordance with Standard CIP-004 Requirement R4.	LOWER
CIP-005-1	R2.5.4.	The controls used to secure dial-up accessible connections.	LOWER
CIP-005-1	R2.6.	Appropriate Use Banner — Where technically feasible, electronic access control devices shall display an appropriate use banner on the user screen upon all interactive access attempts. The Responsible Entity shall maintain a document identifying the content of the banner.	LOWER
CIP-005-1	R3.	Monitoring Electronic Access — The Responsible Entity shall implement and document an electronic or manual process(es) for monitoring and logging access at access points to the Electronic Security Perimeter(s) twenty-four hours a day, seven days a week.	MEDIUM
CIP-005-1	R3.1.	For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall implement and document monitoring process(es) at each access point to the dial-up device, where technically feasible.	MEDIUM
CIP-005-1	R3.2.	Where technically feasible, the security monitoring process(es) shall detect and alert for attempts at or actual unauthorized accesses. These alerts shall provide for appropriate notification to designated response personnel. Where alerting is not technically feasible, the Responsible Entity shall review or otherwise assess access logs for attempts at or actual unauthorized accesses at least every ninety calendar days.	MEDIUM
CIP-005-1	R4.	Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of the electronic access points to the Electronic Security Perimeter(s) at least annually. The vulnerability assessment shall include, at a minimum, the following:	MEDIUM
CIP-005-1	R4.1.	A document identifying the vulnerability assessment process;	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-005-1	R4.2.	A review to verify that only ports and services required for operations at these access points are enabled;	MEDIUM
CIP-005-1	R4.3.	The discovery of all access points to the Electronic Security Perimeter;	MEDIUM
CIP-005-1	R4.4.	A review of controls for default accounts, passwords, and network management community strings; and,	MEDIUM
CIP-005-1	R4.5.	Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.	MEDIUM
CIP-005-1	R5.	Documentation Review and Maintenance — The Responsible Entity shall review, update, and maintain all documentation to support compliance with the requirements of Standard CIP-005.	LOWER
CIP-005-1	R5.1.	The Responsible Entity shall ensure that all documentation required by Standard CIP-005 reflect current configurations and processes and shall review the documents and procedures referenced in Standard CIP-005 at least annually.	LOWER
CIP-005-1	R5.2.	The Responsible Entity shall update the documentation to reflect the modification of the network or controls within ninety calendar days of the change.	LOWER
CIP-005-1	R5.3.	The Responsible Entity shall retain electronic access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008.	LOWER
CIP-005-2	R1.	Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The Responsible Entity shall identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s).	MEDIUM
CIP-005-2	R1.1.	Access points to the Electronic Security Perimeter(s) shall include any externally connected communication end point (for example, dial-up modems) terminating at any device within the Electronic Security Perimeter(s).	MEDIUM
CIP-005-2	R1.2.	For a dial-up accessible Critical Cyber Asset that uses a non-routable protocol, the Responsible Entity shall define an Electronic Security Perimeter for that single access point at the dial-up device.	MEDIUM
CIP-005-2	R1.3.	Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points of these communication links within the Electronic Security Perimeter(s) shall be considered access points to the Electronic Security Perimeter(s).	MEDIUM
CIP-005-2	R1.4.	Any non-critical Cyber Asset within a defined Electronic Security Perimeter shall be identified and protected pursuant to the requirements of Standard CIP-005-2.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-005-2	R1.5.	Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall be afforded the protective measures as a specified in Standard CIP-003-2; Standard CIP-004-2 Requirement R3; Standard CIP-005-2 Requirements R2 and R3; Standard CIP-006-2 Requirement R3; Standard CIP-007-2 Requirements R1 and R3 through R9; Standard CIP-008-2; and Standard CIP-009-2.	MEDIUM
CIP-005-2	R1.6.	The Responsible Entity shall maintain documentation of Electronic Security Perimeter(s), all interconnected Critical and non-critical Cyber Assets within the Electronic Security Perimeter(s), all electronic access points to the Electronic Security Perimeter(s) and the Cyber Assets deployed for the access control and monitoring of these access points.	LOWER
CIP-005-2	R2.	Electronic Access Controls — The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for control of electronic access at all electronic access points to the Electronic Security Perimeter(s).	MEDIUM
CIP-005-2	R2.1.	These processes and mechanisms shall use an access control model that denies access by default, such that explicit access permissions must be specified.	MEDIUM
CIP-005-2	R2.2.	At all access points to the Electronic Security Perimeter(s), the Responsible Entity shall enable only ports and services required for operations and for monitoring Cyber Assets within the Electronic Security Perimeter, and shall document, individually or by specified grouping, the configuration of those ports and services.	MEDIUM
CIP-005-2	R2.3.	The Responsible Entity shall implement and maintain a procedure for securing dial-up access to the Electronic Security Perimeter(s).	MEDIUM
CIP-005-2	R2.4.	Where external interactive access into the Electronic Security Perimeter has been enabled, the Responsible Entity shall implement strong procedural or technical controls at the access points to ensure authenticity of the accessing party, where technically feasible.	MEDIUM
CIP-005-2	R2.5.	The required documentation shall, at least, identify and describe:	LOWER
CIP-005-2	R2.5.1.	The processes for access request and authorization.	LOWER
CIP-005-2	R2.5.2.	The authentication methods.	LOWER
CIP-005-2	R2.5.3.	The review process for authorization rights, in accordance with Standard CIP-004-2 Requirement R4.	LOWER
CIP-005-2	R2.5.4.	The controls used to secure dial-up accessible connections.	LOWER
CIP-005-2	R2.6.	Appropriate Use Banner — Where technically feasible, electronic access control devices shall display an appropriate use banner on the user screen upon all interactive access attempts. The Responsible Entity shall maintain a document identifying the content of the banner.	LOWER
CIP-005-2	R3.	Monitoring Electronic Access — The Responsible Entity shall implement and document an electronic or manual process(es) for monitoring and logging access at access points to the Electronic Security Perimeter(s) twenty-four hours a day, seven days a week.	MEDIUM
CIP-005-2	R3.1.	For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall implement and document monitoring process(es) at each access point to the dial-up device, where technically feasible.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-005-2	R3.2.	Where technically feasible, the security monitoring process(es) shall detect and alert for attempts at or actual unauthorized accesses. These alerts shall provide for appropriate notification to designated response personnel. Where alerting is not technically feasible, the Responsible Entity shall review or otherwise assess access logs for attempts at or actual unauthorized accesses at least every ninety calendar days.	MEDIUM
CIP-005-2	R4.	Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of the electronic access points to the Electronic Security Perimeter(s) at least annually. The vulnerability assessment shall include, at a minimum, the following:	MEDIUM
CIP-005-2	R4.1.	A document identifying the vulnerability assessment process;	LOWER
CIP-005-2	R4.2.	A review to verify that only ports and services required for operations at these access points are enabled;	MEDIUM
CIP-005-2	R4.3.	The discovery of all access points to the Electronic Security Perimeter;	MEDIUM
CIP-005-2	R4.4.	A review of controls for default accounts, passwords, and network management community strings;	MEDIUM
CIP-005-2	R4.5.	Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.	MEDIUM
CIP-005-2	R5.	Documentation Review and Maintenance — The Responsible Entity shall review, update, and maintain all documentation to support compliance with the requirements of Standard CIP-005-2.	LOWER
CIP-005-2	R5.1.	The Responsible Entity shall ensure that all documentation required by Standard CIP-005-2 reflect current configurations and processes and shall review the documents and procedures referenced in Standard CIP-005-2 at least annually.	LOWER
CIP-005-2	R5.2.	The Responsible Entity shall update the documentation to reflect the modification of the network or controls within ninety calendar days of the change.	LOWER
CIP-005-2	R5.3.	The Responsible Entity shall retain electronic access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008-2.	LOWER
CIP-005-3	R1.	Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The Responsible Entity shall identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s).	
CIP-005-3	R1.1.	Access points to the Electronic Security Perimeter(s) shall include any externally connected communication end point (for example, dial-up modems) terminating at any device within the Electronic Security Perimeter(s).	
CIP-005-3	R1.2.	For a dial-up accessible Critical Cyber Asset that uses a non-routable protocol, the Responsible Entity shall define an Electronic Security Perimeter for that single access point at the dial-up device.	
CIP-005-3	R1.3.	Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points of these communication links within the Electronic Security Perimeter(s) shall be considered access points to the Electronic Security Perimeter(s).	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-005-3	R1.4.	Any non-critical Cyber Asset within a defined Electronic Security Perimeter shall be identified and protected pursuant to the requirements of Standard CIP-005-3.	
CIP-005-3	R1.5.	Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall be afforded the protective measures as a specified in Standard CIP-003-3; Standard CIP-004-3 Requirement R3; Standard CIP-005-3 Requirements R2 and R3; Standard CIP-006-3 Requirement R3; Standard CIP-007-3 Requirements R1 and R3 through R9; Standard CIP-008-3; and Standard CIP-009-3.	
CIP-005-3	R1.6.	The Responsible Entity shall maintain documentation of Electronic Security Perimeter(s), all interconnected Critical and non-critical Cyber Assets within the Electronic Security Perimeter(s), all electronic access points to the Electronic Security Perimeter(s) and the Cyber Assets deployed for the access control and monitoring of these access points.	
CIP-005-3	R2.	Electronic Access Controls — The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for control of electronic access at all electronic access points to the Electronic Security Perimeter(s).	
CIP-005-3	R2.1.	These processes and mechanisms shall use an access control model that denies access by default, such that explicit access permissions must be specified.	
CIP-005-3	R2.2.	At all access points to the Electronic Security Perimeter(s), the Responsible Entity shall enable only ports and services required for operations and for monitoring Cyber Assets within the Electronic Security Perimeter, and shall document, individually or by specified grouping, the configuration of those ports and services.	
CIP-005-3	R2.3.	The Responsible Entity shall implement and maintain a procedure for securing dial-up access to the Electronic Security Perimeter(s).	
CIP-005-3	R2.4.	Where external interactive access into the Electronic Security Perimeter has been enabled, the Responsible Entity shall implement strong procedural or technical controls at the access points to ensure authenticity of the accessing party, where technically feasible.	
CIP-005-3	R2.5.	The required documentation shall, at least, identify and describe:	
CIP-005-3	R2.5.1.	The processes for access request and authorization.	
CIP-005-3	R2.5.2.	The authentication methods.	
CIP-005-3	R2.5.3.	The review process for authorization rights, in accordance with Standard CIP-004-3 Requirement R4.	
CIP-005-3	R2.5.4.	The controls used to secure dial-up accessible connections.	
CIP-005-3	R2.6.	Appropriate Use Banner — Where technically feasible, electronic access control devices shall display an appropriate use banner on the user screen upon all interactive access attempts. The Responsible Entity shall maintain a document identifying the content of the banner.	
CIP-005-3	R3.	Monitoring Electronic Access — The Responsible Entity shall implement and document an electronic or manual process(es) for monitoring and logging access at access points to the Electronic Security Perimeter(s) twenty-four hours a day, seven days a week.	
CIP-005-3	R3.1.	For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall implement and document monitoring process(es) at each access point to the dial-up device, where technically feasible.	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-005-3	R3.2.	Where technically feasible, the security monitoring process(es) shall detect and alert for attempts at or actual unauthorized accesses. These alerts shall provide for appropriate notification to designated response personnel. Where alerting is not technically feasible, the Responsible Entity shall review or otherwise assess access logs for attempts at or actual unauthorized accesses at least every ninety calendar days.	
CIP-005-3	R4.	Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of the electronic access points to the Electronic Security Perimeter(s) at least annually. The vulnerability assessment shall include, at a minimum, the following:	
CIP-005-3	R4.1.	A document identifying the vulnerability assessment process;	
CIP-005-3	R4.2.	A review to verify that only ports and services required for operations at these access points are enabled;	
CIP-005-3	R4.3.	The discovery of all access points to the Electronic Security Perimeter;	
CIP-005-3	R4.4.	A review of controls for default accounts, passwords, and network management community strings;	
CIP-005-3	R4.5.	Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.	
CIP-005-3	R5.	Documentation Review and Maintenance — The Responsible Entity shall review, update, and maintain all documentation to support compliance with the requirements of Standard CIP-005-3.	
CIP-005-3	R5.1.	The Responsible Entity shall ensure that all documentation required by Standard CIP-005-3 reflect current configurations and processes and shall review the documents and procedures referenced in Standard CIP-005-3 at least annually.	
CIP-005-3	R5.2.	The Responsible Entity shall update the documentation to reflect the modification of the network or controls within ninety calendar days of the change.	
CIP-005-3	R5.3.	The Responsible Entity shall retain electronic access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008-3.	
CIP-006-1	R1.	Physical Security Plan — The Responsible Entity shall create and maintain a physical security plan, approved by a senior manager or delegate(s) that shall address, at a minimum, the following:	MEDIUM
CIP-006-1	R1.1.	Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.	MEDIUM
CIP-006-1	R1.2.	Processes to identify all access points through each Physical Security Perimeter and measures to control entry at those access points.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-006-1	R1.3.	Processes, tools, and procedures to monitor physical access to the perimeter(s).	MEDIUM
CIP-006-1	R1.4.	Procedures for the appropriate use of physical access controls as described in Requirement R3 including visitor pass management, response to loss, and prohibition of inappropriate use of physical access controls.	MEDIUM
CIP-006-1	R1.5.	Procedures for reviewing access authorization requests and revocation of access authorization, in accordance with CIP-004 Requirement R4.	MEDIUM
CIP-006-1	R1.6.	Procedures for escorted access within the physical security perimeter of personnel not authorized for unescorted access.	MEDIUM
CIP-006-1	R1.7.	Process for updating the physical security plan within ninety calendar days of any physical security system redesign or reconfiguration, including, but not limited to, addition or removal of access points through the physical security perimeter, physical access controls, monitoring controls, or logging controls.	LOWER
CIP-006-1	R1.8.	Cyber Assets used in the access control and monitoring of the Physical Security Perimeter(s) shall be afforded the protective measures specified in Standard CIP-003, Standard CIP-004 Requirement R3, Standard CIP-005 Requirements R2 and R3, Standard CIP-006 Requirement R2 and R3, Standard CIP-007, Standard CIP-008 and Standard CIP-009.	LOWER
CIP-006-1	R1.9.	Process for ensuring that the physical security plan is reviewed at least annually.	LOWER
CIP-006-1	R2.	Physical Access Controls — The Responsible Entity shall document and implement the operational and procedural controls to manage physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. The Responsible Entity shall implement one or more of the following physical access methods:	MEDIUM
CIP-006-1	R2.1.	Card Key: A means of electronic access where the access rights of the card holder are predefined in a computer database. Access rights may differ from one perimeter to another.	MEDIUM
CIP-006-1	R2.2.	Special Locks: These include, but are not limited to, locks with “restricted key” systems, magnetic locks that can be operated remotely, and “man-trap” systems.	MEDIUM
CIP-006-1	R2.3.	Security Personnel: Personnel responsible for controlling physical access who may reside on-site or at a monitoring station.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-006-1	R2.4.	Other Authentication Devices: Biometric, keypad, token, or other equivalent devices that control physical access to the Critical Cyber Assets.	MEDIUM
CIP-006-1	R3.	Monitoring Physical Access — The Responsible Entity shall document and implement the technical and procedural controls for monitoring physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. Unauthorized access attempts shall be reviewed immediately and handled in accordance with the procedures specified in Requirement CIP-008. One or more of the following monitoring methods shall be used:	MEDIUM
CIP-006-1	R3.1.	Alarm Systems: Systems that alarm to indicate a door, gate or window has been opened without authorization. These alarms must provide for immediate notification to personnel responsible for response.	MEDIUM
CIP-006-1	R3.2.	Human Observation of Access Points: Monitoring of physical access points by authorized personnel as specified in Requirement R2.3.	LOWER
CIP-006-1	R4.	Logging Physical Access — Logging shall record sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week. The Responsible Entity shall implement and document the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent:	LOWER
CIP-006-1	R4.1.	Computerized Logging: Electronic logs produced by the Responsible Entity's selected access control and monitoring method.	LOWER
CIP-006-1	R4.2.	Video Recording: Electronic capture of video images of sufficient quality to determine identity.	LOWER
CIP-006-1	R4.3.	Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access as specified in Requirement R2.3.	LOWER
CIP-006-1	R5.	Access Log Retention — The Responsible Entity shall retain physical access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008.	LOWER
CIP-006-1	R6.	Maintenance and Testing — The Responsible Entity shall implement a maintenance and testing program to ensure that all physical security systems under Requirements R2, R3, and R4 function properly. The program must include, at a minimum, the following:	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-006-1	R6.1.	Testing and maintenance of all physical security mechanisms on a cycle no longer than three years.	MEDIUM
CIP-006-1	R6.2.	Retention of testing and maintenance records for the cycle determined by the Responsible Entity in Requirement R6.1.	LOWER
CIP-006-1	R6.3.	Retention of outage records regarding access controls, logging, and monitoring for a minimum of one calendar year.	LOWER
CIP-006-2	R1.	Physical Security Plan — The Responsible Entity shall document, implement, and maintain a physical security plan, approved by the senior manager or delegate(s) that shall address, at a minimum, the following:	MEDIUM
CIP-006-2	R1.1.	All Cyber Assets within an Electronic Security Perimeter shall reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to such Cyber Assets.	MEDIUM
CIP-006-2	R1.2.	Identification of all physical access points through each Physical Security Perimeter and measures to control entry at those access points.	MEDIUM
CIP-006-2	R1.3.	Processes, tools, and procedures to monitor physical access to the perimeter(s).	MEDIUM
CIP-006-2	R1.4.	Appropriate use of physical access controls as described in Requirement R4 including visitor pass management, response to loss, and prohibition of inappropriate use of physical access controls.	MEDIUM
CIP-006-2	R1.5.	Review of access authorization requests and revocation of access authorization, in accordance with CIP-004-3 Requirement R4.	MEDIUM
CIP-006-2	R1.6.	Continuous escorted access within the Physical Security Perimeter of personnel not authorized for unescorted access.	MEDIUM
CIP-006-2	R1.7.	Update of the physical security plan within thirty calendar days of the completion of any physical security system redesign or reconfiguration, including, but not limited to, addition or removal of access points through the Physical Security Perimeter, physical access controls, monitoring controls, or logging controls.	LOWER
CIP-006-2	R1.8.	Annual review of the physical security plan.	LOWER
CIP-006-2	R2.	Protection of Physical Access Control Systems — Cyber Assets that authorize and/or log access to the Physical Security Perimeter(s), exclusive of hardware at the Physical Security Perimeter access point such as electronic lock control mechanisms and badge readers, shall:	MEDIUM
CIP-006-2	R2.1.	Be protected from unauthorized physical access.	MEDIUM
CIP-006-2	R2.2.	Be afforded the protective measures specified in Standard CIP-003-3; Standard CIP-004-3 Requirement R3; Standard CIP-005-3 Requirements R2 and R3; Standard CIP-006-3a Requirements R4 and R5; Standard CIP-007-3; Standard CIP-008-3; and Standard CIP-009-3.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-006-2	R3.	Protection of Electronic Access Control Systems — Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall reside within an identified Physical Security Perimeter.	MEDIUM
CIP-006-2	R4.	Physical Access Controls — The Responsible Entity shall document and implement the operational and procedural controls to manage physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. The Responsible Entity shall implement one or more of the following physical access methods: --Card Key: A means of electronic access where the access rights of the card holder are predefined in a computer database. Access rights may differ from one perimeter to another. --Special Locks: These include, but are not limited to, locks with "restricted key" systems, magnetic locks that can be operated remotely, and "man-trap" systems. --Security Personnel: Personnel responsible for controlling physical access who may reside on-site or at a monitoring station. --Other Authentication Devices: Biometric, keypad, token, or other equivalent devices that control physical access to the Critical Cyber Assets.	MEDIUM
CIP-006-2	R5.	Monitoring Physical Access — The Responsible Entity shall document and implement the technical and procedural controls for monitoring physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. Unauthorized access attempts shall be reviewed immediately and handled in accordance with the procedures specified in Requirement CIP-008-3. One or more of the following monitoring methods shall be used: • Alarm Systems: Systems that alarm to indicate a door, gate or window has been opened without authorization. These alarms must provide for immediate notification to personnel responsible for response. • Human Observation of Access Points: Monitoring of physical access points by authorized personnel as specified in Requirement R4.	MEDIUM
CIP-006-2	R6.	Logging Physical Access — Logging shall record sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week. The Responsible Entity shall implement and document the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent: --Computerized Logging: Electronic logs produced by the Responsible Entity's selected access control and monitoring method. --Video Recording: Electronic capture of video images of sufficient quality to determine identity. --Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access as specified in Requirement R4.	LOWER
CIP-006-2	R7.	Access Log Retention — The responsible entity shall retain physical access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008-3.	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-006-2	R8.	Maintenance and Testing — The Responsible Entity shall implement a maintenance and testing program to ensure that all physical security systems under Requirements R4, R5, and R6 function properly. The program must include, at a minimum, the following:	MEDIUM
CIP-006-2	R8.1.	Testing and maintenance of all physical security mechanisms on a cycle no longer than three years.	MEDIUM
CIP-006-2	R8.2.	Retention of testing and maintenance records for the cycle determined by the Responsible Entity in Requirement R8.1.	LOWER
CIP-006-2	R8.3.	Retention of outage records regarding access controls, logging, and monitoring for a minimum of one calendar year.	LOWER
CIP-006-3	R1.	Physical Security Plan — The Responsible Entity shall document, implement, and maintain a physical security plan, approved by the senior manager or delegate(s) that shall address, at a minimum, the following:	
CIP-006-3	R1.1.	All Cyber Assets within an Electronic Security Perimeter shall reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to such Cyber Assets.	
CIP-006-3	R1.2.	Identification of all physical access points through each Physical Security Perimeter and measures to control entry at those access points.	
CIP-006-3	R1.3.	Processes, tools, and procedures to monitor physical access to the perimeter(s).	
CIP-006-3	R1.4.	Appropriate use of physical access controls as described in Requirement R4 including visitor pass management, response to loss, and prohibition of inappropriate use of physical access controls.	
CIP-006-3	R1.5.	Review of access authorization requests and revocation of access authorization, in accordance with CIP-004-3 Requirement R4.	
CIP-006-3	R1.6.	A visitor control program for visitors (personnel without authorized unescorted access to a Physical Security Perimeter), containing at a minimum the following:	
CIP-006-3	R1.6.1.	Logs (manual or automated) to document the entry and exit of visitors, including the date and time, to and from Physical Security Perimeters.	
CIP-006-3	R1.6.2.	Continuous escorted access of visitors within the Physical Security Perimeter.	
CIP-006-3	R1.7.	Update of the physical security plan within thirty calendar days of the completion of any physical security system redesign or reconfiguration, including, but not limited to, addition or removal of access points through the Physical Security Perimeter, physical access controls, monitoring controls, or logging controls.	
CIP-006-3	R1.8.	Annual review of the physical security plan.	
CIP-006-3	R2.	Protection of Physical Access Control Systems — Cyber Assets that authorize and/or log access to the Physical Security Perimeter(s), exclusive of hardware at the Physical Security Perimeter access point such as electronic lock control mechanisms and badge readers, shall:	
CIP-006-3	R2.1.	Be protected from unauthorized physical access.	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-006-3	R2.2.	Be afforded the protective measures specified in Standard CIP-003-3; Standard CIP-004-3 Requirement R3; Standard CIP-005-3 Requirements R2 and R3; Standard CIP-006-3 Requirements R4 and R5; Standard CIP-007-3; Standard CIP-008-3; and Standard CIP-009-3.	
CIP-006-3	R3.	Protection of Electronic Access Control Systems — Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall reside within an identified Physical Security Perimeter.	
CIP-006-3	R4.	Physical Access Controls — The Responsible Entity shall document and implement the operational and procedural controls to manage physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. The Responsible Entity shall implement one or more of the following physical access methods: • Card Key: A means of electronic access where the access rights of the card holder are predefined in a computer database. Access rights may differ from one perimeter to another. • Special Locks: These include, but are not limited to, locks with “restricted key” systems, magnetic locks that can be operated remotely, and “man-trap” systems. • Security Personnel: Personnel responsible for controlling physical access who may reside on-site or at a monitoring station. • Other Authentication Devices: Biometric, keypad, token, or other equivalent devices that control physical access to the Critical Cyber Assets.	
CIP-006-3	R5.	Monitoring Physical Access — The Responsible Entity shall document and implement the technical and procedural controls for monitoring physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. Unauthorized access attempts shall be reviewed immediately and handled in accordance with the procedures specified in Requirement CIP-008-3. One or more of the following monitoring methods shall be used: • Alarm Systems: Systems that alarm to indicate a door, gate or window has been opened without authorization. These alarms must provide for immediate notification to personnel responsible for response. • Human Observation of Access Points: Monitoring of physical access points by authorized personnel as specified in Requirement R4.	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-006-3	R6.	Logging Physical Access — Logging shall record sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week. The Responsible Entity shall implement and document the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent: • Computerized Logging: Electronic logs produced by the Responsible Entity's selected access control and monitoring method. • Video Recording: Electronic capture of video images of sufficient quality to determine identity. • Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access as specified in Requirement R4.	
CIP-006-3	R7.	Access Log Retention — The Responsible Entity shall retain physical access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008-3.	
CIP-006-3	R8.	Maintenance and Testing — The Responsible Entity shall implement a maintenance and testing program to ensure that all physical security systems under Requirements R4, R5, and R6 function properly. The program must include, at a minimum, the following:	
CIP-006-3	R8.1.	Testing and maintenance of all physical security mechanisms on a cycle no longer than three years.	
CIP-006-3	R8.2.	Retention of testing and maintenance records for the cycle determined by the Responsible Entity in Requirement R8.1.	
CIP-006-3	R8.3.	Retention of outage records regarding access controls, logging, and monitoring for a minimum of one calendar year.	
CIP-007-1	R1.	Test Procedures — The Responsible Entity shall ensure that new Cyber Assets and significant changes to existing Cyber Assets within the Electronic Security Perimeter do not adversely affect existing cyber security controls. For purposes of Standard CIP-007, a significant change shall, at a minimum, include implementation of security patches, cumulative service packs, vendor releases, and version upgrades of operating systems, applications, database platforms, or other third-party software or firmware.	MEDIUM
CIP-007-1	R1.1.	The Responsible Entity shall create, implement, and maintain cyber security test procedures in a manner that minimizes adverse effects on the production system or its operation.	MEDIUM
CIP-007-1	R1.2.	The Responsible Entity shall document that testing is performed in a manner that reflects the production environment.	LOWER
CIP-007-1	R1.3.	The Responsible Entity shall document test results.	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-007-1	R2.	Ports and Services — The Responsible Entity shall establish and document a process to ensure that only those ports and services required for normal and emergency operations are enabled.	MEDIUM
CIP-007-1	R2.1.	The Responsible Entity shall enable only those ports and services required for normal and emergency operations.	MEDIUM
CIP-007-1	R2.2.	The Responsible Entity shall disable other ports and services, including those used for testing purposes, prior to production use of all Cyber Assets inside the Electronic Security Perimeter(s).	MEDIUM
CIP-007-1	R2.3.	In the case where unused ports and services cannot be disabled due to technical limitations, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure or an acceptance of risk.	MEDIUM
CIP-007-1	R3.	Security Patch Management — The Responsible Entity, either separately or as a component of the documented configuration management process specified in CIP-003 Requirement R6, shall establish and document a security patch management program for tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).	LOWER
CIP-007-1	R3.1.	The Responsible Entity shall document the assessment of security patches and security upgrades for applicability within thirty calendar days of availability of the patches or upgrades.	LOWER
CIP-007-1	R3.2.	The Responsible Entity shall document the implementation of security patches. In any case where the patch is not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure or an acceptance of risk.	LOWER
CIP-007-1	R4.	Malicious Software Prevention — The Responsible Entity shall use anti-virus software and other malicious software (“malware”) prevention tools, where technically feasible, to detect, prevent, deter, and mitigate the introduction, exposure, and propagation of malware on all Cyber Assets within the Electronic Security Perimeter(s).	MEDIUM
CIP-007-1	R4.1.	The Responsible Entity shall document and implement anti-virus and malware prevention tools. In the case where anti-virus software and malware prevention tools are not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure or an acceptance of risk.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-007-1	R4.2.	The Responsible Entity shall document and implement a process for the update of anti-virus and malware prevention “signatures.” The process must address testing and installing the signatures.	MEDIUM
CIP-007-1	R5.	Account Management — The Responsible Entity shall establish, implement, and document technical and procedural controls that enforce access authentication of, and accountability for, all user activity, and that minimize the risk of unauthorized system access.	LOWER
CIP-007-1	R5.1.	The Responsible Entity shall ensure that individual and shared system accounts and authorized access permissions are consistent with the concept of “need to know” with respect to work functions performed.	MEDIUM
CIP-007-1	R5.1.1.	The Responsible Entity shall ensure that user accounts are implemented as approved by designated personnel. Refer to Standard CIP-003 Requirement R5.	LOWER
CIP-007-1	R5.1.2.	The Responsible Entity shall establish methods, processes, and procedures that generate logs of sufficient detail to create historical audit trails of individual user account access activity for a minimum of ninety days.	LOWER
CIP-007-1	R5.1.3.	The Responsible Entity shall review, at least annually, user accounts to verify access privileges are in accordance with Standard CIP-003 Requirement R5 and Standard CIP-004 Requirement R4.	MEDIUM
CIP-007-1	R5.2.	The Responsible Entity shall implement a policy to minimize and manage the scope and acceptable use of administrator, shared, and other generic account privileges including factory default accounts.	LOWER
CIP-007-1	R5.2.1.	The policy shall include the removal, disabling, or renaming of such accounts where possible. For such accounts that must remain enabled, passwords shall be changed prior to putting any system into service.	MEDIUM
CIP-007-1	R5.2.2.	The Responsible Entity shall identify those individuals with access to shared accounts.	LOWER
CIP-007-1	R5.2.3.	Where such accounts must be shared, the Responsible Entity shall have a policy for managing the use of such accounts that limits access to only those with authorization, an audit trail of the account use (automated or manual), and steps for securing the account in the event of personnel changes (for example, change in assignment or termination).	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-007-1	R5.3.	At a minimum, the Responsible Entity shall require and use passwords, subject to the following, as technically feasible:	LOWER
CIP-007-1	R5.3.1.	Each password shall be a minimum of six characters.	LOWER
CIP-007-1	R5.3.2.	Each password shall consist of a combination of alpha, numeric, and “special” characters.	LOWER
CIP-007-1	R5.3.3.	Each password shall be changed at least annually, or more frequently based on risk.	MEDIUM
CIP-007-1	R6.	Security Status Monitoring — The Responsible Entity shall ensure that all Cyber Assets within the Electronic Security Perimeter, as technically feasible, implement automated tools or organizational process controls to monitor system events that are related to cyber security.	LOWER
CIP-007-1	R6.1.	The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for monitoring for security events on all Cyber Assets within the Electronic Security Perimeter.	MEDIUM
CIP-007-1	R6.2.	The security monitoring controls shall issue automated or manual alerts for detected Cyber Security Incidents.	MEDIUM
CIP-007-1	R6.3.	The Responsible Entity shall maintain logs of system events related to cyber security, where technically feasible, to support incident response as required in Standard CIP-008.	MEDIUM
CIP-007-1	R6.4.	The Responsible Entity shall retain all logs specified in Requirement R6 for ninety calendar days.	LOWER
CIP-007-1	R6.5.	The Responsible Entity shall review logs of system events related to cyber security and maintain records documenting review of logs.	LOWER
CIP-007-1	R7.	Disposal or Redeployment — The Responsible Entity shall establish formal methods, processes, and procedures for disposal or redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005.	LOWER
CIP-007-1	R7.1.	Prior to the disposal of such assets, the Responsible Entity shall destroy or erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.	LOWER
CIP-007-1	R7.2.	Prior to redeployment of such assets, the Responsible Entity shall, at a minimum, erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-007-1	R7.3.	The Responsible Entity shall maintain records that such assets were disposed of or redeployed in accordance with documented procedures.	LOWER
CIP-007-1	R8.	Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of all Cyber Assets within the Electronic Security Perimeter at least annually. The vulnerability assessment shall include, at a minimum, the following:	LOWER
CIP-007-1	R8.1.	A document identifying the vulnerability assessment process;	LOWER
CIP-007-1	R8.2.	A review to verify that only ports and services required for operation of the Cyber Assets within the Electronic Security Perimeter are enabled;	MEDIUM
CIP-007-1	R8.3.	A review of controls for default accounts; and,	MEDIUM
CIP-007-1	R8.4.	Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.	MEDIUM
CIP-007-1	R9.	Documentation Review and Maintenance — The Responsible Entity shall review and update the documentation specified in Standard CIP-007 at least annually. Changes resulting from modifications to the systems or controls shall be documented within ninety calendar days of the change.	LOWER
CIP-007-2	R1.	Test Procedures — The Responsible Entity shall ensure that new Cyber Assets and significant changes to existing Cyber Assets within the Electronic Security Perimeter do not adversely affect existing cyber security controls. For purposes of Standard CIP-007-2, a significant change shall, at a minimum, include implementation of security patches, cumulative service packs, vendor releases, and version upgrades of operating systems, applications, database platforms, or other third-party software or firmware.	MEDIUM
CIP-007-2	R1.1.	The Responsible Entity shall create, implement, and maintain cyber security test procedures in a manner that minimizes adverse effects on the production system or its operation.	MEDIUM
CIP-007-2	R1.2.	The Responsible Entity shall document that testing is performed in a manner that reflects the production environment.	LOWER
CIP-007-2	R1.3.	The Responsible Entity shall document test results.	LOWER
CIP-007-2	R2.	Ports and Services — The Responsible Entity shall establish, document and implement a process to ensure that only those ports and services required for normal and emergency operations are enabled.	MEDIUM
CIP-007-2	R2.1.	The Responsible Entity shall enable only those ports and services required for normal and emergency operations.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-007-2	R2.2.	The Responsible Entity shall disable other ports and services, including those used for testing purposes, prior to production use of all Cyber Assets inside the Electronic Security Perimeter(s).	MEDIUM
CIP-007-2	R2.3.	In the case where unused ports and services cannot be disabled due to technical limitations, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.	MEDIUM
CIP-007-2	R3.	Security Patch Management — The Responsible Entity, either separately or as a component of the documented configuration management process specified in CIP-003-2 Requirement R6, shall establish, document and implement a security patch management program for tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).	LOWER
CIP-007-2	R3.1.	The Responsible Entity shall document the assessment of security patches and security upgrades for applicability within thirty calendar days of availability of the patches or upgrades.	LOWER
CIP-007-2	R3.2.	The Responsible Entity shall document the implementation of security patches. In any case where the patch is not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.	LOWER
CIP-007-2	R4.	Malicious Software Prevention — The Responsible Entity shall use anti-virus software and other malicious software (“malware”) prevention tools, where technically feasible, to detect, prevent, deter, and mitigate the introduction, exposure, and propagation of malware on all Cyber Assets within the Electronic Security Perimeter(s).	MEDIUM
CIP-007-2	R4.1.	The Responsible Entity shall document and implement anti-virus and malware prevention tools. In the case where anti-virus software and malware prevention tools are not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.	MEDIUM
CIP-007-2	R4.2.	The Responsible Entity shall document and implement a process for the update of anti-virus and malware prevention “signatures.” The process must address testing and installing the signatures.	MEDIUM
CIP-007-2	R5.	Account Management — The Responsible Entity shall establish, implement, and document technical and procedural controls that enforce access authentication of, and accountability for, all user activity, and that minimize the risk of unauthorized system access.	LOWER
CIP-007-2	R5.1.	The Responsible Entity shall ensure that individual and shared system accounts and authorized access permissions are consistent with the concept of “need to know” with respect to work functions performed.	MEDIUM
CIP-007-2	R5.1.1.	The Responsible Entity shall ensure that user accounts are implemented as approved by designated personnel. Refer to Standard CIP-003-2 Requirement R5.	LOWER
CIP-007-2	R5.1.2.	The Responsible Entity shall establish methods, processes, and procedures that generate logs of sufficient detail to create historical audit trails of individual user account access activity for a minimum of ninety days.	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-007-2	R5.1.3.	The Responsible Entity shall review, at least annually, user accounts to verify access privileges are in accordance with Standard CIP-003-2 Requirement R5 and Standard CIP-004-2 Requirement R4.	MEDIUM
CIP-007-2	R5.2.	The Responsible Entity shall implement a policy to minimize and manage the scope and acceptable use of administrator, shared, and other generic account privileges including factory default accounts.	LOWER
CIP-007-2	R5.2.1.	The policy shall include the removal, disabling, or renaming of such accounts where possible. For such accounts that must remain enabled, passwords shall be changed prior to putting any system into service.	MEDIUM
CIP-007-2	R5.2.2.	The Responsible Entity shall identify those individuals with access to shared accounts.	LOWER
CIP-007-2	R5.2.3.	Where such accounts must be shared, the Responsible Entity shall have a policy for managing the use of such accounts that limits access to only those with authorization, an audit trail of the account use (automated or manual), and steps for securing the account in the event of personnel changes (for example, change in assignment or termination).	MEDIUM
CIP-007-2	R5.3.	At a minimum, the Responsible Entity shall require and use passwords, subject to the following, as technically feasible:	LOWER
CIP-007-2	R5.3.1.	Each password shall be a minimum of six characters.	LOWER
CIP-007-2	R5.3.2.	Each password shall consist of a combination of alpha, numeric, and “special” characters.	LOWER
CIP-007-2	R5.3.3.	Each password shall be changed at least annually, or more frequently based on risk.	MEDIUM
CIP-007-2	R6.	Security Status Monitoring — The Responsible Entity shall ensure that all Cyber Assets within the Electronic Security Perimeter, as technically feasible, implement automated tools or organizational process controls to monitor system events that are related to cyber security.	LOWER
CIP-007-2	R6.1.	The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for monitoring for security events on all Cyber Assets within the Electronic Security Perimeter.	MEDIUM
CIP-007-2	R6.2.	The security monitoring controls shall issue automated or manual alerts for detected Cyber Security Incidents.	MEDIUM
CIP-007-2	R6.3.	The Responsible Entity shall maintain logs of system events related to cyber security, where technically feasible, to support incident response as required in Standard CIP-008-2.	MEDIUM
CIP-007-2	R6.4.	The Responsible Entity shall retain all logs specified in Requirement R6 for ninety calendar days.	LOWER
CIP-007-2	R6.5.	The Responsible Entity shall review logs of system events related to cyber security and maintain records documenting review of logs.	LOWER
CIP-007-2	R7.	Disposal or Redeployment — The Responsible Entity shall establish and implement formal methods, processes, and procedures for disposal or redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005-2.	LOWER
CIP-007-2	R7.1.	Prior to the disposal of such assets, the Responsible Entity shall destroy or erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-007-2	R7.2.	Prior to redeployment of such assets, the Responsible Entity shall, at a minimum, erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.	LOWER
CIP-007-2	R7.3.	The Responsible Entity shall maintain records that such assets were disposed of or redeployed in accordance with documented procedures.	LOWER
CIP-007-2	R8.	Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of all Cyber Assets within the Electronic Security Perimeter at least annually. The vulnerability assessment shall include, at a minimum, the following:	LOWER
CIP-007-2	R8.1.	A document identifying the vulnerability assessment process;	LOWER
CIP-007-2	R8.2.	A review to verify that only ports and services required for operation of the Cyber Assets within the Electronic Security Perimeter are enabled;	MEDIUM
CIP-007-2	R8.3.	A review of controls for default accounts; and,	MEDIUM
CIP-007-2	R8.4.	Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.	MEDIUM
CIP-007-2	R9.	Documentation Review and Maintenance — The Responsible Entity shall review and update the documentation specified in Standard CIP-007-2 at least annually. Changes resulting from modifications to the systems or controls shall be documented within thirty calendar days of the change being completed.	LOWER
CIP-007-3	R1.	Test Procedures — The Responsible Entity shall ensure that new Cyber Assets and significant changes to existing Cyber Assets within the Electronic Security Perimeter do not adversely affect existing cyber security controls. For purposes of Standard CIP-007-3, a significant change shall, at a minimum, include implementation of security patches, cumulative service packs, vendor releases, and version upgrades of operating systems, applications, database platforms, or other third-party software or firmware.	
CIP-007-3	R1.1.	The Responsible Entity shall create, implement, and maintain cyber security test procedures in a manner that minimizes adverse effects on the production system or its operation.	
CIP-007-3	R1.2.	The Responsible Entity shall document that testing is performed in a manner that reflects the production environment.	
CIP-007-3	R1.3.	The Responsible Entity shall document test results.	
CIP-007-3	R2.	Ports and Services — The Responsible Entity shall establish, document and implement a process to ensure that only those ports and services required for normal and emergency operations are enabled.	
CIP-007-3	R2.1.	The Responsible Entity shall enable only those ports and services required for normal and emergency operations.	
CIP-007-3	R2.2.	The Responsible Entity shall disable other ports and services, including those used for testing purposes, prior to production use of all Cyber Assets inside the Electronic Security Perimeter(s).	
CIP-007-3	R2.3.	In the case where unused ports and services cannot be disabled due to technical limitations, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-007-3	R3.	Security Patch Management — The Responsible Entity, either separately or as a component of the documented configuration management process specified in CIP-003-3 Requirement R6, shall establish, document and implement a security patch management program for tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).	
CIP-007-3	R3.1.	The Responsible Entity shall document the assessment of security patches and security upgrades for applicability within thirty calendar days of availability of the patches or upgrades.	
CIP-007-3	R3.2.	The Responsible Entity shall document the implementation of security patches. In any case where the patch is not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.	
CIP-007-3	R4.	Malicious Software Prevention — The Responsible Entity shall use anti-virus software and other malicious software ("malware") prevention tools, where technically feasible, to detect, prevent, deter, and mitigate the introduction, exposure, and propagation of malware on all Cyber Assets within the Electronic Security Perimeter(s).	
CIP-007-3	R4.1.	The Responsible Entity shall document and implement anti-virus and malware prevention tools. In the case where anti-virus software and malware prevention tools are not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.	
CIP-007-3	R4.2.	The Responsible Entity shall document and implement a process for the update of anti-virus and malware prevention "signatures." The process must address testing and installing the signatures.	
CIP-007-3	R5.	Account Management — The Responsible Entity shall establish, implement, and document technical and procedural controls that enforce access authentication of, and accountability for, all user activity, and that minimize the risk of unauthorized system access.	
CIP-007-3	R5.1.	The Responsible Entity shall ensure that individual and shared system accounts and authorized access permissions are consistent with the concept of "need to know" with respect to work functions performed.	
CIP-007-3	R5.1.1.	The Responsible Entity shall ensure that user accounts are implemented as approved by designated personnel. Refer to Standard CIP-003-3 Requirement R5.	
CIP-007-3	R5.1.2.	The Responsible Entity shall establish methods, processes, and procedures that generate logs of sufficient detail to create historical audit trails of individual user account access activity for a minimum of ninety days.	
CIP-007-3	R5.1.3.	The Responsible Entity shall review, at least annually, user accounts to verify access privileges are in accordance with Standard CIP-003-3 Requirement R5 and Standard CIP-004-3 Requirement R4.	
CIP-007-3	R5.2.	The Responsible Entity shall implement a policy to minimize and manage the scope and acceptable use of administrator, shared, and other generic account privileges including factory default accounts.	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-007-3	R5.2.1.	The policy shall include the removal, disabling, or renaming of such accounts where possible. For such accounts that must remain enabled, passwords shall be changed prior to putting any system into service.	
CIP-007-3	R5.2.2.	The Responsible Entity shall identify those individuals with access to shared accounts.	
CIP-007-3	R5.2.3.	Where such accounts must be shared, the Responsible Entity shall have a policy for managing the use of such accounts that limits access to only those with authorization, an audit trail of the account use (automated or manual), and steps for securing the account in the event of personnel changes (for example, change in assignment or termination).	
CIP-007-3	R5.3.	At a minimum, the Responsible Entity shall require and use passwords, subject to the following, as technically feasible:	
CIP-007-3	R5.3.1.	Each password shall be a minimum of six characters.	
CIP-007-3	R5.3.2.	Each password shall consist of a combination of alpha, numeric, and “special” characters.	
CIP-007-3	R5.3.3.	Each password shall be changed at least annually, or more frequently based on risk.	
CIP-007-3	R6.	Security Status Monitoring — The Responsible Entity shall ensure that all Cyber Assets within the Electronic Security Perimeter, as technically feasible, implement automated tools or organizational process controls to monitor system events that are related to cyber security.	
CIP-007-3	R6.1.	The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for monitoring for security events on all Cyber Assets within the Electronic Security Perimeter.	
CIP-007-3	R6.2.	The security monitoring controls shall issue automated or manual alerts for detected Cyber Security Incidents.	
CIP-007-3	R6.3.	The Responsible Entity shall maintain logs of system events related to cyber security, where technically feasible, to support incident response as required in Standard CIP-008-3.	
CIP-007-3	R6.4.	The Responsible Entity shall retain all logs specified in Requirement R6 for ninety calendar days.	
CIP-007-3	R6.5.	The Responsible Entity shall review logs of system events related to cyber security and maintain records documenting review of logs.	
CIP-007-3	R7.	Disposal or Redeployment — The Responsible Entity shall establish and implement formal methods, processes, and procedures for disposal or redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005-3.	
CIP-007-3	R7.1.	Prior to the disposal of such assets, the Responsible Entity shall destroy or erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.	
CIP-007-3	R7.2.	Prior to redeployment of such assets, the Responsible Entity shall, at a minimum, erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.	
CIP-007-3	R7.3.	The Responsible Entity shall maintain records that such assets were disposed of or redeployed in accordance with documented procedures.	
CIP-007-3	R8.	Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of all Cyber Assets within the Electronic Security Perimeter at least annually. The vulnerability assessment shall include, at a minimum, the following:	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-007-3	R8.1.	A document identifying the vulnerability assessment process;	
CIP-007-3	R8.2.	A review to verify that only ports and services required for operation of the Cyber Assets within the Electronic Security Perimeter are enabled;	
CIP-007-3	R8.3.	A review of controls for default accounts; and,	
CIP-007-3	R8.4.	Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.	
CIP-007-3	R9.	Documentation Review and Maintenance — The Responsible Entity shall review and update the documentation specified in Standard CIP-007-3 at least annually. Changes resulting from modifications to the systems or controls shall be documented within thirty calendar days of the change being completed.	
CIP–008–1	R1.	Cyber Security Incident Response Plan — The Responsible Entity shall develop and maintain a Cyber Security Incident response plan. The Cyber Security Incident Response plan shall address, at a minimum, the following:	LOWER
CIP–008–1	R1.1.	Procedures to characterize and classify events as reportable Cyber Security Incidents.	LOWER
CIP–008–1	R1.2.	Response actions, including roles and responsibilities of incident response teams, incident handling procedures, and communication plans.	LOWER
CIP–008–1	R1.3.	Process for reporting Cyber Security Incidents to the Electricity Sector Information Sharing and Analysis Center (ES ISAC). The Responsible Entity must ensure that all reportable Cyber Security Incidents are reported to the ES ISAC either directly or through an intermediary.	LOWER
CIP–008–1	R1.4.	Process for updating the Cyber Security Incident response plan within ninety calendar days of any changes.	LOWER
CIP–008–1	R1.5.	Process for ensuring that the Cyber Security Incident response plan is reviewed at least annually.	LOWER
CIP–008–1	R1.6.	Process for ensuring the Cyber Security Incident response plan is tested at least annually. A test of the incident response plan can range from a paper drill, to a full operational exercise, to the response to an actual incident.	LOWER
CIP–008–1	R2.	Cyber Security Incident Documentation — The Responsible Entity shall keep relevant documentation related to Cyber Security Incidents reportable per Requirement R1.1 for three calendar years.	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-008-2	R1.	Cyber Security Incident Response Plan — The Responsible Entity shall develop and maintain a Cyber Security Incident response plan and implement the plan in response to Cyber Security Incidents. The Cyber Security Incident response plan shall address, at a minimum, the following:	LOWER
CIP-008-2	R1.1.	Procedures to characterize and classify events as reportable Cyber Security Incidents.	LOWER
CIP-008-2	R1.2.	Response actions, including roles and responsibilities of Cyber Security Incident response teams, Cyber Security Incident handling procedures, and communication plans.	LOWER
CIP-008-2	R1.3.	Process for reporting Cyber Security Incidents to the Electricity Sector Information Sharing and Analysis Center (ES-ISAC). The Responsible Entity must ensure that all reportable Cyber Security Incidents are reported to the ES-ISAC either directly or through an intermediary.	LOWER
CIP-008-2	R1.4.	Process for updating the Cyber Security Incident response plan within thirty calendar days of any changes.	LOWER
CIP-008-2	R1.5.	Process for ensuring that the Cyber Security Incident response plan is reviewed at least annually.	LOWER
CIP-008-2	R1.6.	Process for ensuring the Cyber Security Incident response plan is tested at least annually. A test of the Cyber Security Incident response plan can range from a paper drill, to a full operational exercise, to the response to an actual incident. Testing the Cyber Security Incident response plan does not require removing a component or system from service during the test.	LOWER
CIP-008-2	R2.	Cyber Security Incident Documentation — The Responsible Entity shall keep relevant documentation related to Cyber Security Incidents reportable per Requirement R1.1 for three calendar years.	LOWER
CIP-008-3	R1.	Cyber Security Incident Response Plan — The Responsible Entity shall develop and maintain a Cyber Security Incident response plan and implement the plan in response to Cyber Security Incidents. The Cyber Security Incident response plan shall address, at a minimum, the following:	
CIP-008-3	R1.1.	Procedures to characterize and classify events as reportable Cyber Security Incidents.	
CIP-008-3	R1.2.	Response actions, including roles and responsibilities of Cyber Security Incident response teams, Cyber Security Incident handling procedures, and communication plans.	
CIP-008-3	R1.3.	Process for reporting Cyber Security Incidents to the Electricity Sector Information Sharing and Analysis Center (ES-ISAC). The Responsible Entity must ensure that all reportable Cyber Security Incidents are reported to the ES-ISAC either directly or through an intermediary.	
CIP-008-3	R1.4.	Process for updating the Cyber Security Incident response plan within thirty calendar days of any changes.	
CIP-008-3	R1.5.	Process for ensuring that the Cyber Security Incident response plan is reviewed at least annually.	
CIP-008-3	R1.6.	Process for ensuring the Cyber Security Incident response plan is tested at least annually. A test of the Cyber Security Incident response plan can range from a paper drill, to a full operational exercise, to the response to an actual incident.	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-008-3	R2.	Cyber Security Incident Documentation — The Responsible Entity shall keep relevant documentation related to Cyber Security Incidents reportable per Requirement R1.1 for three calendar years.	
CIP–009–1	R1.	Recovery Plans — The Responsible Entity shall create and annually review recovery plan(s) for Critical Cyber Assets. The recovery plan(s) shall address at a minimum the following:	MEDIUM
CIP–009–1	R1.1.	Specify the required actions in response to events or conditions of varying duration and severity that would activate the recovery plan(s).	MEDIUM
CIP–009–1	R1.2.	Define the roles and responsibilities of responders.	MEDIUM
CIP–009–1	R2.	Exercises — The recovery plan(s) shall be exercised at least annually. An exercise of the recovery plan(s) can range from a paper drill, to a full operational exercise, to recovery from an actual incident.	LOWER
CIP–009–1	R3.	Change Control — Recovery plan(s) shall be updated to reflect any changes or lessons learned as a result of an exercise or the recovery from an actual incident. Updates shall be communicated to personnel responsible for the activation and implementation of the recovery plan(s) within ninety calendar days of the change.	LOWER
CIP–009–1	R4.	Backup and Restore — The recovery plan(s) shall include processes and procedures for the backup and storage of information required to successfully restore Critical Cyber Assets. For example, backups may include spare electronic components or equipment, written documentation of configuration settings, tape backup, etc.	LOWER
CIP–009–1	R5.	Testing Backup Media — Information essential to recovery that is stored on backup media shall be tested at least annually to ensure that the information is available. Testing can be completed off site.	LOWER
CIP-009-2	R1.	Recovery Plans — The Responsible Entity shall create and annually review recovery plan(s) for Critical Cyber Assets. The recovery plan(s) shall address at a minimum the following:	MEDIUM
CIP-009-2	R1.1.	Specify the required actions in response to events or conditions of varying duration and severity that would activate the recovery plan(s).	MEDIUM
CIP-009-2	R1.2.	Define the roles and responsibilities of responders.	MEDIUM
CIP-009-2	R2.	Exercises — The recovery plan(s) shall be exercised at least annually. An exercise of the recovery plan(s) can range from a paper drill, to a full operational exercise, to recovery from an actual incident.	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
CIP-009-2	R3.	Change Control — Recovery plan(s) shall be updated to reflect any changes or lessons learned as a result of an exercise or the recovery from an actual incident. Updates shall be communicated to personnel responsible for the activation and implementation of the recovery plan(s) within thirty calendar days of the change being completed.	LOWER
CIP-009-2	R4.	Backup and Restore — The recovery plan(s) shall include processes and procedures for the backup and storage of information required to successfully restore Critical Cyber Assets. For example, backups may include spare electronic components or equipment, written documentation of configuration settings, tape backup, etc.	LOWER
CIP-009-2	R5.	Testing Backup Media — Information essential to recovery that is stored on backup media shall be tested at least annually to ensure that the information is available. Testing can be completed off site.	LOWER
CIP-009-3	R1.	Recovery Plans — The Responsible Entity shall create and annually review recovery plan(s) for Critical Cyber Assets. The recovery plan(s) shall address at a minimum the following:	
CIP-009-3	R1.1.	Specify the required actions in response to events or conditions of varying duration and severity that would activate the recovery plan(s).	
CIP-009-3	R1.2.	Define the roles and responsibilities of responders.	
CIP-009-3	R2.	Exercises — The recovery plan(s) shall be exercised at least annually. An exercise of the recovery plan(s) can range from a paper drill, to a full operational exercise, to recovery from an actual incident.	
CIP-009-3	R3.	Change Control — Recovery plan(s) shall be updated to reflect any changes or lessons learned as a result of an exercise or the recovery from an actual incident. Updates shall be communicated to personnel responsible for the activation and implementation of the recovery plan(s) within thirty calendar days of the change being completed.	
CIP-009-3	R4.	Backup and Restore — The recovery plan(s) shall include processes and procedures for the backup and storage of information required to successfully restore Critical Cyber Assets. For example, backups may include spare electronic components or equipment, written documentation of configuration settings, tape backup, etc.	
CIP-009-3	R5.	Testing Backup Media — Information essential to recovery that is stored on backup media shall be tested at least annually to ensure that the information is available. Testing can be completed off site.	
COM-001-1	R1.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide adequate and reliable telecommunications facilities for the exchange of Interconnection and operating information:	HIGH
COM-001-1.1	R1.1.	Internally.	HIGH
COM-001-1.1	R1.2.	Between the Reliability Coordinator and its Transmission Operators and Balancing Authorities.	HIGH

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
COM-001-1.1	R1.3.	With other Reliability Coordinators, Transmission Operators, and Balancing Authorities as necessary to maintain reliability.	HIGH
COM-001-1.1	R1.4.	Where applicable, these facilities shall be redundant and diversely routed.	HIGH
COM-001-1.1	R2.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall manage, alarm, test and/or actively monitor vital telecommunications facilities. Special attention shall be given to emergency telecommunications facilities and equipment not used for routine communications.	MEDIUM
COM-001-1.1	R3.	Each Reliability Coordinator, Transmission Operator and Balancing Authority shall provide a means to coordinate telecommunications among their respective areas. This coordination shall include the ability to investigate and recommend solutions to telecommunications problems within the area and with other areas.	LOWER
COM-001-1.1	R4.	Unless agreed to otherwise, each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use English as the language for all communications between and among operating personnel responsible for the real-time generation control and operation of the interconnected Bulk Electric System. Transmission Operators and Balancing Authorities may use an alternate language for internal operations.	MEDIUM
COM-001-1.1	R5.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have written operating instructions and procedures to enable continued operation of the system during the loss of telecommunications facilities.	LOWER
COM-001-1.1	R6.	Each NERCNet User Organization shall adhere to the requirements in Attachment 1-COM-001-0, “NERCNet Security Policy.”	LOWER
COM-002-2	R1.	Each Transmission Operator, Balancing Authority, and Generator Operator shall have communications (voice and data links) with appropriate Reliability Coordinators, Balancing Authorities, and Transmission Operators. Such communications shall be staffed and available for addressing a real-time emergency condition.	HIGH
COM-002-2	R1.1.	Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator, and all other potentially affected Balancing Authorities and Transmission Operators through predetermined communication paths of any condition that could threaten the reliability of its area or when firm load shedding is anticipated.	HIGH

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
COM-002-2	R2.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall issue directives in a clear, concise, and definitive manner; shall ensure the recipient of the directive repeats the information back correctly; and shall acknowledge the response as correct or repeat the original statement to resolve any misunderstandings.	MEDIUM
EOP-001-0	R1.	Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.	High
EOP-001-0	R2.	The Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes.	Medium
EOP-001-0	R3.	Each Transmission Operator and Balancing Authority shall:	Medium
EOP-001-0	R4.	Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include:	Medium
EOP-001-0	R5.	Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001-0 when developing an emergency plan.	Medium
EOP-001-0	R6.	The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.	Medium
EOP-001-0	R7.	The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable:	Medium
EOP-001-0	R3.1.	Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.	Medium
EOP-001-0	R3.2.	Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.	Medium
EOP-001-0	R3.3.	Develop, maintain, and implement a set of plans for load shedding.	Medium
EOP-001-0	R3.4.	Develop, maintain, and implement a set of plans for system restoration.	Medium
EOP-001-0	R4.1.	Communications protocols to be used during emergencies.	Medium
EOP-001-0	R4.2.	A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions.	Medium
EOP-001-0	R4.3.	The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.	Medium
EOP-001-0	R4.4.	Staffing levels for the emergency.	Medium

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
EOP-001-0	R7.1.	The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.	Medium
EOP-001-0	R7.2.	The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.	Medium
EOP-001-0	R7.3.	The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)	Medium
EOP-001-0	R7.4.	The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.	Medium
EOP-002-2	R1.	Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate capacity and energy emergencies.	HIGH
EOP-002-2	R2.	Each Balancing Authority shall implement its capacity and energy emergency plan, when required and as appropriate, to reduce risks to the interconnected system.	HIGH
EOP-002-2	R3.	A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.	HIGH
EOP-002-2	R4.	A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load.	HIGH
EOP-002-2	R5.	A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.	HIGH
EOP-002-2	R6.	If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to:	HIGH
EOP-002-2	R6.1.	Loading all available generating capacity.	HIGH

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
EOP-002-2	R6.2.	Deploying all available operating reserve.	HIGH
EOP-002-2	R6.3.	Interrupting interruptible load and exports.	HIGH
EOP-002-2	R6.4.	Requesting emergency assistance from other Balancing Authorities.	HIGH
EOP-002-2	R6.5.	Declaring an Energy Emergency through its Reliability Coordinator; and	HIGH
EOP-002-2	R6.6.	Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.	HIGH
EOP-002-2	R7.	Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall:	HIGH
EOP-002-2	R7.1.	Manually shed firm load without delay to return its ACE to zero; and	HIGH
EOP-002-2	R7.2.	Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0 “Energy Emergency Alert Levels.”	HIGH
EOP-002-2	R8.	A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002-0 “Energy Emergency Alert Levels.” The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.	HIGH
EOP-002-2	R9.	When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources) as permitted in its transmission tariff (See Attachment 1-IRO-006-0 “Transmission Loading Relief Procedure” for explanation of Transmission Service Priorities):	HIGH
EOP-002-2	R9.1.	The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0.	HIGH
EOP-002-2	R9.2.	The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed.	HIGH

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
EOP-002-2	R9.3.	The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.	LOWER
EOP-002-2	R9.4.	The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.	LOWER
EOP-003-1	R1.	After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.	HIGH
EOP-003-1	R2.	Each Transmission Operator and Balancing Authority shall establish plans for automatic load shedding for underfrequency or undervoltage conditions.	HIGH
EOP-003-1	R3.	Each Transmission Operator and Balancing Authority shall coordinate load shedding plans among other interconnected Transmission Operators and Balancing Authorities.	HIGH
EOP-003-1	R4.	A Transmission Operator or Balancing Authority shall consider one or more of these factors in designing an automatic load shedding scheme: frequency, rate of frequency decay, voltage level, rate of voltage decay, or power flow levels.	HIGH
EOP-003-1	R5.	A Transmission Operator or Balancing Authority shall implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.	HIGH
EOP-003-1	R6.	After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.	HIGH
EOP-003-1	R7.	The Transmission Operator and Balancing Authority shall coordinate automatic load shedding throughout their areas with underfrequency isolation of generating units, tripping of shunt capacitors, and other automatic actions that will occur under abnormal frequency, voltage, or power flow conditions.	HIGH
EOP-003-1	R8.	Each Transmission Operator or Balancing Authority shall have plans for operator-controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.	HIGH

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
EOP-004-1	R1.	Each Regional Reliability Organization shall establish and maintain a Regional reporting procedure to facilitate preparation of preliminary and final disturbance reports.	LOWER
EOP-004-1	R2.	A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load-Serving Entity shall promptly analyze Bulk Electric System disturbances on its system or facilities.	MEDIUM
EOP-004-1	R3.	A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load-Serving Entity experiencing a reportable incident shall provide a preliminary written report to its Regional Reliability Organization and NERC.	LOWER
EOP-004-1	R3.1.	The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load-Serving Entity shall submit within 24 hours of the disturbance or unusual occurrence either a copy of the report submitted to DOE, or, if no DOE report is required, a copy of the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report form. Events that are not identified until some time after they occur shall be reported within 24 hours of being recognized.	LOWER
EOP-004-1	R3.2.	Applicable reporting forms are provided in Attachments 022-1 and 022-2.	<blank>
EOP-004-1	R3.3.	Under certain adverse conditions, e.g., severe weather, it may not be possible to assess the damage caused by a disturbance and issue a written Interconnection Reliability Operating Limit and Preliminary Disturbance Report within 24 hours. In such cases, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load-Serving Entity shall promptly notify its Regional Reliability Organization(s) and NERC, and verbally provide as much information as is available at that time. The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load-Serving Entity shall then provide timely, periodic verbal updates until adequate information is available to issue a written Preliminary Disturbance Report.	LOWER
EOP-004-1	R3.4.	If, in the judgment of the Regional Reliability Organization, after consultation with the Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load-Serving Entity in which a disturbance occurred, a final report is required, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load-Serving Entity shall prepare this report within 60 days. As a minimum, the final report shall have a discussion of the events and its cause, the conclusions reached, and recommendations to prevent recurrence of this type of event. The report shall be subject to Regional Reliability Organization approval.	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
EOP-004-1	R4.	When a Bulk Electric System disturbance occurs, the Regional Reliability Organization shall make its representatives on the NERC Operating Committee and Disturbance Analysis Working Group available to the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load-Serving Entity immediately affected by the disturbance for the purpose of providing any needed assistance in the investigation and to assist in the preparation of a final report.	LOWER
EOP-004-1	R5.	The Regional Reliability Organization shall track and review the status of all final report recommendations at least twice each year to ensure they are being acted upon in a timely manner. If any recommendation has not been acted on within two years, or if Regional Reliability Organization tracking and review indicates at any time that any recommendation is not being acted on with sufficient diligence, the Regional Reliability Organization shall notify the NERC Planning Committee and Operating Committee of the status of the recommendation(s) and the steps the Regional Reliability Organization has taken to accelerate implementation.	LOWER
EOP-005-1	R1.	Each Transmission Operator shall have a restoration plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shutdown of its system, including necessary operating instructions and procedures to cover emergency conditions, and the loss of vital telecommunications channels. Each Transmission Operator shall include the applicable elements listed in Attachment 1-EOP-005 in developing a restoration plan.	MEDIUM
EOP-005-1	R2.	Each Transmission Operator shall review and update its restoration plan at least annually and whenever it makes changes in the power system network, and shall correct deficiencies found during the simulated restoration exercises.	MEDIUM
EOP-005-1	R3.	Each Transmission Operator shall develop restoration plans with a priority of restoring the integrity of the Interconnection.	MEDIUM
EOP-005-1	R4.	Each Transmission Operator shall coordinate its restoration plans with the Generator Owners and Balancing Authorities within its area, its Reliability Coordinator, and neighboring Transmission Operators and Balancing Authorities.	MEDIUM
EOP-005-1	R5.	Each Transmission Operator and Balancing Authority shall periodically test its telecommunication facilities needed to implement the restoration plan.	MEDIUM
EOP-005-1	R6.	Each Transmission Operator and Balancing Authority shall train its operating personnel in the implementation of the restoration plan. Such training shall include simulated exercises, if practicable.	HIGH

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
EOP-005-1	R7.	Each Transmission Operator and Balancing Authority shall verify the restoration procedure by actual testing or by simulation.	HIGH
EOP-005-1	R8.	Each Transmission Operator shall verify that the number, size, availability, and location of system blackstart generating units are sufficient to meet Regional Reliability Organization restoration plan requirements for the Transmission Operator's area.	HIGH
EOP-005-1	R9.	The Transmission Operator shall document the Cranking Paths, including initial switching requirements, between each blackstart generating unit and the unit(s) to be started and shall provide this documentation for review by the Regional Reliability Organization upon request. Such documentation may include Cranking Path diagrams.	MEDIUM
EOP-005-1	R10.	The Transmission Operator shall demonstrate, through simulation or testing, that the blackstart generating units in its restoration plan can perform their intended functions as required in the regional restoration plan.	MEDIUM
EOP-005-1	R10.1.	The Transmission Operator shall perform this simulation or testing at least once every five years.	MEDIUM
EOP-005-1	R11.	Following a disturbance in which one or more areas of the Bulk Electric System become isolated or blacked out, the affected Transmission Operators and Balancing Authorities shall begin immediately to return the Bulk Electric System to normal.	HIGH
EOP-005-1	R11.1.	The affected Transmission Operators and Balancing Authorities shall work in conjunction with their Reliability Coordinator(s) to determine the extent and condition of the isolated area(s).	MEDIUM
EOP-005-1	R11.2.	The affected Transmission Operators and Balancing Authorities shall take the necessary actions to restore Bulk Electric System frequency to normal, including adjusting generation, placing additional generators on line, or load shedding.	HIGH
EOP-005-1	R11.3.	The affected Balancing Authorities, working with their Reliability Coordinator(s), shall immediately review the Interchange Schedules between those Balancing Authority Areas or fragments of those Balancing Authority Areas within the separated area and make adjustments as needed to facilitate the restoration. The affected Balancing Authorities shall make all attempts to maintain the adjusted Interchange Schedules, whether generation control is manual or automatic.	HIGH
EOP-005-1	R11.4.	The affected Transmission Operators shall give high priority to restoration of off-site power to nuclear stations.	HIGH

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
EOP-005-1	R11.5.	The affected Transmission Operators may resynchronize the isolated area(s) with the surrounding area(s) when the following conditions are met:	MEDIUM
EOP-005-1	R11.5.1.	Voltage, frequency, and phase angle permit.	HIGH
EOP-005-1	R11.5.2.	The size of the area being reconnected and the capacity of the transmission lines effecting the reconnection and the number of synchronizing points across the system are considered.	HIGH
EOP-005-1	R11.5.3.	Reliability Coordinator(s) and adjacent areas are notified and Reliability Coordinator approval is given.	MEDIUM
EOP-005-1	R11.5.4.	Load is shed in neighboring areas, if required, to permit successful interconnected system restoration.	HIGH
EOP-006-1	R1.	Each Reliability Coordinator shall be aware of the restoration plan of each Transmission Operator in its Reliability Coordinator Area in accordance with NERC and regional requirements.	MEDIUM
EOP-006-1	R2.	The Reliability Coordinator shall monitor restoration progress and coordinate any needed assistance.	HIGH
EOP-006-1	R3.	The Reliability Coordinator shall have a Reliability Coordinator Area restoration plan that provides coordination between individual Transmission Operator restoration plans and that ensures reliability is maintained during system restoration events.	MEDIUM
EOP-006-1	R4.	The Reliability Coordinator shall serve as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators and Transmission Operators or Balancing Authorities not immediately involved in restoration.	MEDIUM
EOP-006-1	R5.	Reliability Coordinators shall approve, communicate, and coordinate the re-synchronizing of major system islands or synchronizing points so as not to cause a Burden on adjacent Transmission Operator, Balancing Authority, or Reliability Coordinator Areas.	HIGH
EOP-006-1	R6.	The Reliability Coordinator shall take actions to restore normal operations once an operating emergency has been mitigated in accordance with its restoration plan.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
EOP-007-0	R1.	Each Regional Reliability Organization shall establish and maintain a system BCP, as part of an overall coordinated Regional SRP. The Regional SRP shall include requirements for verification through analysis how system blackstart generating units shall perform their intended functions and shall be sufficient to meet SRP expectations. The Regional Reliability Organization shall coordinate with and among other Regional Reliability Organizations as appropriate in the development of its BCP. The BCP shall include:	
EOP-007-0	R1.1.	A requirement to have a database that contains all blackstart generators1 designated for use in an SRP within the respective areas. This database shall be updated on an annual basis. The database shall include the name, location, megawatt capacity, type of unit, latest date of test, and starting method.	
EOP-007-0	R1.2.	A requirement to demonstrate that blackstart units perform their intended functions as required in the Regional SRP. This requirement can be met through either simulation or testing. The BCP must consider the availability of designated BCP units and initial transmission switching requirements.	
EOP-007-0	R1.3.	Blackstart unit testing requirements including, but not limited to:	
EOP-007-0	R1.3.1.	Testing frequency (minimum of one third of the units each year).	
EOP-007-0	R1.3.2.	Type of test required, including the requirement to start when isolated from the system.	
EOP-007-0	R1.3.3.	Minimum duration of tests.	
EOP-007-0	R1.4.	A requirement to review and update the Regional BCP at least every five years.	
EOP-007-0	R2.	The Regional Reliability Organization shall provide documentation of its system BCPs to NERC within 30 calendar days of a request.	
EOP-008-0	R1.	Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have a plan to continue reliability operations in the event its control center becomes inoperable. The contingency plan must meet the following requirements:	HIGH
EOP-008-0	R1.1.	The contingency plan shall not rely on data or voice communication from the primary control facility to be viable.	MEDIUM
EOP-008-0	R1.2.	The plan shall include procedures and responsibilities for providing basic tie line control and procedures and for maintaining the status of all inter-area schedules, such that there is an hourly accounting of all schedules.	MEDIUM
EOP-008-0	R1.3.	The contingency plan must address monitoring and control of critical transmission facilities, generation control, voltage control, time and frequency control, control of critical substation devices, and logging of significant power system events. The plan shall list the critical facilities.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
EOP-008-0	R1.4.	The plan shall include procedures and responsibilities for maintaining basic voice communication capabilities with other areas.	HIGH
EOP-008-0	R1.5.	The plan shall include procedures and responsibilities for conducting periodic tests, at least annually, to ensure viability of the plan.	MEDIUM
EOP-008-0	R1.6.	The plan shall include procedures and responsibilities for providing annual training to ensure that operating personnel are able to implement the contingency plans.	MEDIUM
EOP-008-0	R1.7.	The plan shall be reviewed and updated annually.	MEDIUM
EOP-008-0	R1.8.	Interim provisions must be included if it is expected to take more than one hour to implement the contingency plan for loss of primary control facility.	MEDIUM
EOP-009-0	R1.	The Generator Operator of each blackstart generating unit shall test the startup and operation of each system blackstart generating unit identified in the BCP as required in the Regional BCP (Reliability Standard EOP-007-0_R1). Testing records shall include the dates of the tests, the duration of the tests, and an indication of whether the tests met Regional BCP requirements.	MEDIUM
EOP-009-0	R2.	The Generator Owner or Generator Operator shall provide documentation of the test results of the startup and operation of each blackstart generating unit to the Regional Reliability Organizations and upon request to NERC.	LOWER
FAC-001-0	R1.	The Transmission Owner shall document, maintain, and publish facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Reliability Organization, subregional, Power Pool, and individual Transmission Owner planning criteria and facility connection requirements. The Transmission Owner's facility connection requirements shall address connection requirements for:	MEDIUM
FAC-001-0	R1.1.	Generation facilities,	MEDIUM
FAC-001-0	R1.2.	Transmission facilities, and	MEDIUM
FAC-001-0	R1.3.	End-user facilities	MEDIUM
FAC-001-0	R2.	The Transmission Owner's facility connection requirements shall address, but are not limited to, the following items:	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
FAC-001-0	R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:	MEDIUM
FAC-001-0	R2.1.1.	Procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems.	MEDIUM
FAC-001-0	R2.1.2.	Procedures for notification of new or modified facilities to others (those responsible for the reliability of the interconnected transmission systems) as soon as feasible.	MEDIUM
FAC-001-0	R2.1.3.	Voltage level and MW and MVAR capacity or demand at point of connection.	MEDIUM
FAC-001-0	R2.1.4.	Breaker duty and surge protection.	MEDIUM
FAC-001-0	R2.1.5.	System protection and coordination.	MEDIUM
FAC-001-0	R2.1.6.	Metering and telecommunications.	MEDIUM
FAC-001-0	R2.1.7.	Grounding and safety issues.	MEDIUM
FAC-001-0	R2.1.8.	Insulation and insulation coordination.	MEDIUM
FAC-001-0	R2.1.9.	Voltage, Reactive Power, and power factor control.	MEDIUM
FAC-001-0	R2.1.10.	Power quality impacts.	MEDIUM
FAC-001-0	R2.1.11.	Equipment Ratings.	MEDIUM
FAC-001-0	R2.1.12.	Synchronizing of facilities.	MEDIUM
FAC-001-0	R2.1.13.	Maintenance coordination.	MEDIUM
FAC-001-0	R2.1.14.	Operational issues (abnormal frequency and voltages).	MEDIUM
FAC-001-0	R2.1.15.	Inspection requirements for existing or new facilities.	MEDIUM
FAC-001-0	R2.1.16.	Communications and procedures during normal and emergency operating conditions.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
FAC-001-0	R3.	The Transmission Owner shall maintain and update its facility connection requirements as required. The Transmission Owner shall make documentation of these requirements available to the users of the transmission system, the Regional Reliability Organization, and NERC on request (five business days).	MEDIUM
FAC-002-0	R1.	The Generator Owner, Transmission Owner, Distribution Provider, and Load-Serving Entity seeking to integrate generation facilities, transmission facilities, and electricity end-user facilities shall each coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority. The assessment shall include:	MEDIUM
FAC-002-0	R1.1.	Evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems.	MEDIUM
FAC-002-0	R1.2.	Ensurance of compliance with NERC Reliability Standards and applicable Regional, subregional, Power Pool, and individual system planning criteria and facility connection requirements.	MEDIUM
FAC-002-0	R1.3.	Evidence that the parties involved in the assessment have coordinated and cooperated on the assessment of the reliability impacts of new facilities on the interconnected transmission systems. While these studies may be performed independently, the results shall be jointly evaluated and coordinated by the entities involved.	MEDIUM
FAC-002-0	R1.4.	Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance in accordance with Reliability Standard TPL-001-0.	MEDIUM
FAC-002-0	R1.5.	Documentation that the assessment included study assumptions, system performance, alternatives considered, and jointly coordinated recommendations.	MEDIUM
FAC-002-0	R2.	The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each retain its documentation (of its evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems) for three years and shall provide the documentation to the Regional Reliability Organization(s) Regional Reliability Organization(s) and NERC on request (within 30 calendar days).	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
FAC-003-1	R1.	The Transmission owner shall prepare, and keep current, a formal transmission vegetation management (TVM). The TVMP shall include the Transmission Owner's objectives, practices, approved procedures, and work Specifications. 1. ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.	HIGH
FAC-003-1	R1.1.	The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the Transmission Owner's transmission lines.	HIGH
FAC-003-1	R1.2.	The Transmission Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the Transmission Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.	HIGH
FAC-003-1	R1.2.1.	Clearance 1 — The Transmission Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the Transmission Owner plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.	HIGH
FAC-003-1	R1.2.2.	Clearance 2 — The Transmission Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These Transmission Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.	HIGH

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
FAC-003-1	R1.2.2.1.	Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.	HIGH
FAC-003-1	R1.2.2.2.	Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.	HIGH
FAC-003-1	R1.3.	All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner, to perform their duties.	HIGH
FAC-003-1	R1.4.	Each Transmission Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner is restricted from attaining the clearances specified in Requirement 1.2.1.	HIGH
FAC-003-1	R1.5.	Each Transmission Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.	HIGH
FAC-003-1	R2.	The Transmission Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each Transmission Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.	HIGH
FAC-003-1	R3.	The Transmission Owner shall report quarterly to its RRO, or the RRO's designee, sustained transmission line outages determined by the Transmission Owner to have been caused by vegetation.	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
FAC-003-1	R3.1.	Multiple sustained outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of outages within a 24-hour period.	LOWER
FAC-003-1	R3.2.	The Transmission Owner is not required to report to the RRO, or the RRO's designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).	LOWER
FAC-003-1	R3.3.	The outage information provided by the Transmission Owner to the RRO, or the RRO's designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the Transmission Owner.	LOWER
FAC-003-1	R3.4.	An outage shall be categorized as one of the following:	LOWER
FAC-003-1	R3.4.1.	Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;	LOWER
FAC-003-1	R3.4.2.	Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;	LOWER
FAC-003-1	R3.4.3.	Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.	LOWER
FAC-003-1	R4.	The RRO shall report the outage information provided to it by Transmission Owner's, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the RRO as a result of any of the reported outages.	LOWER
FAC-008-1	R1.	The Transmission Owner and Generator Owner shall each document its current methodology used for developing Facility Ratings (Facility Ratings Methodology) of its solely and jointly owned Facilities. The methodology shall include all of the following:	LOWER
FAC-008-1	R1.1.	A statement that a Facility Rating shall equal the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
FAC-008-1	R1.2.	The method by which the Rating (of major BES equipment that comprises a Facility) is determined.	MEDIUM
FAC-008-1	R1.2.1.	The scope of equipment addressed shall include, but not be limited to, generators, transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.	MEDIUM
FAC-008-1	R1.2.2.	The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.	MEDIUM
FAC-008-1	R1.3.	Consideration of the following:	LOWER
FAC-008-1	R1.3.1.	Ratings provided by equipment manufacturers.	MEDIUM
FAC-008-1	R1.3.2.	Design criteria (e.g., including applicable references to industry Rating practices such as manufacturer's warranty, IEEE, ANSI or other standards).	MEDIUM
FAC-008-1	R1.3.3.	Ambient conditions.	MEDIUM
FAC-008-1	R1.3.4.	Operating limitations.	MEDIUM
FAC-008-1	R1.3.5.	Other assumptions.	LOWER
FAC-008-1	R2.	The Transmission Owner and Generator Owner shall each make its Facility Ratings Methodology available for inspection and technical review by those Reliability Coordinators, Transmission Operators, Transmission Planners, and Planning Authorities that have responsibility for the area in which the associated Facilities are located, within 15 business days of receipt of a request.	LOWER
FAC-008-1	R3.	If a Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides written comments on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings Methodology, the Transmission Owner or Generator Owner shall provide a written response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings Methodology and, if no change will be made to that Facility Ratings Methodology, the reason why.	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
FAC-009-1	R1.	The Transmission Owner and Generator Owner shall each establish Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings Methodology.	MEDIUM
FAC-009-1	R2.	The Transmission Owner and Generator Owner shall each provide Facility Ratings for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities to its associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) as scheduled by such requesting entities.	MEDIUM
FAC-010-2.1	R1.	The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:	LOWER
FAC-010-2.1	R1.1.	Be applicable for developing SOLs used in the planning horizon.	LOWER
FAC-010-2.1	R1.2.	State that SOLs shall not exceed associated Facility Ratings.	LOWER
FAC-010-2.1	R1.3.	Include a description of how to identify the subset of SOLs that qualify as IROLs.	LOWER
FAC-010-2.1	R2.	The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:	N/A
FAC-010-2.1	R2.1.	In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.	HIGH
FAC-010-2.1	R2.2.	Following the single Contingencies identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.	HIGH
FAC-010-2.1	R2.2.1.	Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.	MEDIUM
FAC-010-2.1	R2.2.2.	Loss of any generator, line, transformer, or shunt device without a Fault.	MEDIUM
FAC-010-2.1	R2.2.3.	Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	MEDIUM
FAC-010-2.1	R2.3.	Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:	MEDIUM
FAC-010-2.1	R2.3.1.	Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.	MEDIUM
FAC-010-2.1	R2.3.2.	System reconfiguration through manual or automatic control or protection actions.	MEDIUM
FAC-010-2.1	R2.4.	To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
FAC-010-2.1	R2.5.	Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.	MEDIUM
FAC-010-2.1	R2.6.	In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:	MEDIUM
FAC-010-2.1	R2.6.1.	Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.	MEDIUM
FAC-010-2.1	R3.	The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:	LOWER
FAC-010-2.1	R3.1.	Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).	LOWER
FAC-010-2.1	R3.2.	Selection of applicable Contingencies.	LOWER
FAC-010-2.1	R3.3.	Level of detail of system models used to determine SOLs.	LOWER
FAC-010-2.1	R3.4.	Allowed uses of Special Protection Systems or Remedial Action Plans.	MEDIUM
FAC-010-2.1	R3.5.	Anticipated transmission system configuration, generation dispatch and Load level.	LOWER
FAC-010-2.1	R3.6.	Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL Tv.	MEDIUM
FAC-010-2.1	R4.	The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:	LOWER
FAC-010-2.1	R4.1.	Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.	LOWER
FAC-010-2.1	R4.2.	Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.	LOWER
FAC-010-2.1	R4.3.	Each Transmission Planner that works in the Planning Authority's Planning Authority Area.	LOWER
FAC-010-2.1	R5.	If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.	LOWER
FAC-011-2	R1.	The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:	LOWER
FAC-011-2	R1.1.	Be applicable for developing SOLs used in the operations horizon.	LOWER
FAC-011-2	R1.2.	State that SOLs shall not exceed associated Facility Ratings.	LOWER
FAC-011-2	R1.3.	Include a description of how to identify the subset of SOLs that qualify as IROLs.	LOWER
FAC-011-2	R2.	The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:	N/A

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
FAC-011-2	R2.1.	In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.	HIGH
FAC-011-2	R2.2.	Following the single Contingencies identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.	HIGH
FAC-011-2	R2.2.1.	Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.	MEDIUM
FAC-011-2	R2.2.2.	Loss of any generator, line, transformer, or shunt device without a Fault.	MEDIUM
FAC-011-2	R2.2.3.	Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	MEDIUM
FAC-011-2	R2.3.	In determining the system's response to a single Contingency, the following shall be acceptable:	MEDIUM
FAC-011-2	R2.3.1.	Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.	MEDIUM
FAC-011-2	R2.3.2.	Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies	MEDIUM
FAC-011-2	R2.3.3.	System reconfiguration through manual or automatic control or protection actions.	MEDIUM
FAC-011-2	R2.4.	To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.	MEDIUM
FAC-011-2	R3.	The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:	MEDIUM
FAC-011-2	R3.1.	Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)	MEDIUM
FAC-011-2	R3.2.	Selection of applicable Contingencies	MEDIUM
FAC-011-2	R3.3.	A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.	MEDIUM
FAC-011-2	R3.3.1.	This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.	N/A
FAC-011-2	R3.4.	Level of detail of system models used to determine SOLs.	LOWER
FAC-011-2	R3.5.	Allowed uses of Special Protection Systems or Remedial Action Plans.	MEDIUM
FAC-011-2	R3.6.	Anticipated transmission system configuration, generation dispatch and Load level	MEDIUM
FAC-011-2	R3.7.	Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL Tv.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
FAC-011-2	R4.	The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:	LOWER
FAC-011-2	R4.1.	Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.	LOWER
FAC-011-2	R4.2.	Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.	LOWER
FAC-011-2	R4.3.	Each Transmission Operator that operates in the Reliability Coordinator Area.	LOWER
FAC-011-2	R5.	If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.	LOWER
FAC-013-1	R1.	The Reliability Coordinator and Planning Authority shall each establish a set of inter-regional and intra-regional Transfer Capabilities that is consistent with its current Transfer Capability Methodology.	MEDIUM
FAC-013-1	R2.	The Reliability Coordinator and Planning Authority shall each provide its inter-regional and intra-regional Transfer Capabilities to those entities that have a reliability-related need for such Transfer Capabilities and make a written request that includes a schedule for delivery of such Transfer Capabilities as follows:	MEDIUM
FAC-013-1	R2.1.	The Reliability Coordinator shall provide its Transfer Capabilities to its associated Regional Reliability Organization(s), to its adjacent Reliability Coordinators, and to the Transmission Operators, Transmission Service Providers and Planning Authorities that work in its Reliability Coordinator Area.	MEDIUM
FAC-013-1	R2.2.	The Planning Authority shall provide its Transfer Capabilities to its associated Reliability Coordinator(s) and Regional Reliability Organization(s), and to the Transmission Planners and Transmission Service Provider(s) that work in its Planning Authority Area.	MEDIUM
FAC-014-2	R1.	The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.	MEDIUM
FAC-014-2	R2.	The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
FAC-014-2	R3.	The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology.	MEDIUM
FAC-014-2	R4.	The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL Methodology.	MEDIUM
FAC-014-2	R5.	The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows:	HIGH
FAC-014-2	R5.1.	The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:	HIGH
FAC-014-2	R5.1.1.	Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL.	MEDIUM
FAC-014-2	R5.1.2.	The value of the IROL and its associated Tv.	MEDIUM
FAC-014-2	R5.1.3.	The associated Contingency(ies).	MEDIUM
FAC-014-2	R5.1.4.	The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).	MEDIUM
FAC-014-2	R5.2.	The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.	MEDIUM
FAC-014-2	R5.3.	The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area.	MEDIUM
FAC-014-2	R5.4.	The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
FAC-014-2	R6.	The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits.	MEDIUM
FAC-014-2	R6.1.	The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits.	MEDIUM
FAC-014-2	R6.2.	If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.	MEDIUM
INT-001-3	R1.	The Load-Serving, Purchasing-Selling Entity shall ensure that Arranged Interchange is submitted to the Interchange Authority for:	LOWER
INT-001-3	R1.1.	All Dynamic Schedules at the expected average MW profile for each hour.	LOWER
INT-001-3	R2.	The Sink Balancing Authority shall ensure that Arranged Interchange is submitted to the Interchange Authority:	LOWER
INT-001-3	R2.1.	If a Purchasing-Selling Entity is not involved in the Interchange, such as delivery from a jointly owned generator.	LOWER
INT-001-3	R2.2.	For each bilateral Inadvertent Interchange payback.	LOWER
INT-003-2	R1.	Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation.	MEDIUM
INT-003-2	R1.1.	The Sending Balancing Authority and Receiving Balancing Authority shall agree on Interchange as received from the Interchange Authority, including:	LOWER
INT-003-2	R1.1.1.	Interchange Schedule start and end time.	LOWER
INT-003-2	R1.1.2.	Energy profile.	LOWER
INT-003-2	R1.2.	If a high voltage direct current (HVDC) tie is on the Scheduling Path, then the Sending Balancing Authorities and Receiving Balancing Authorities shall coordinate the Interchange Schedule with the Transmission Operator of the HVDC tie.	MEDIUM
INT-004-2	R1.	At such time as the reliability event allows for the reloading of the transaction, the entity that initiated the curtailment shall release the limit on the Interchange Transaction tag to allow reloading the transaction and shall communicate the release of the limit to the Sink Balancing Authority.	LOWER
INT-004-2	R2.	The Purchasing-Selling Entity responsible for tagging a Dynamic Interchange Schedule shall ensure the tag is updated for the next available scheduling hour and future hours when any one of the following occurs:	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
INT-004-2	R2.1.	The average energy profile in an hour is greater than 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than +10%.	LOWER
INT-004-2	R2.2.	The average energy profile in an hour is less than or equal to 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than +25 megawatt-hours.	LOWER
INT-004-2	R2.3.	A Reliability Coordinator or Transmission Operator determines the deviation, regardless of magnitude, to be a reliability concern and notifies the Purchasing-Selling Entity of that determination and the reasons.	LOWER
INT-005-3	R1.	Prior to the expiration of the time period defined in the timing requirements tables in this standard, Column A, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment to all reliability entities involved in the Interchange.	MEDIUM
INT-005-3	R1.1.	When a Balancing Authority or Reliability Coordinator initiates a Curtailment to Confirmed or Implemented Interchange for reliability, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment only to the Source Balancing Authority and the Sink Balancing Authority.	MEDIUM
INT-006-3	R1.	Prior to the expiration of the reliability assessment period defined in the timing requirements tables in this standard, Column B, the Balancing Authority and Transmission Service Provider shall respond to each On-time Request for Interchange (RFI), and to each Emergency RFI and Reliability Adjustment RFI from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange.	LOWER
INT-006-3	R1.1.	Each involved Balancing Authority shall evaluate the Arranged Interchange with respect to:	LOWER
INT-006-3	R1.1.1.	Energy profile (ability to support the magnitude of the Interchange).	LOWER
INT-006-3	R1.1.2.	Ramp (ability of generation maneuverability to accommodate).	LOWER
INT-006-3	R1.1.3.	Scheduling path (proper connectivity of Adjacent Balancing Authorities).	LOWER
INT-006-3	R1.2.	Each involved Transmission Service Provider shall confirm that the transmission service arrangements associated with the Arranged Interchange have adjacent Transmission Service Provider connectivity, are valid and prevailing transmission system limits will not be violated.	LOWER
INT-007-1	R1.	The Interchange Authority shall verify that Arranged Interchange is balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange by verifying the following:	LOWER
INT-007-1	R1.1.	Source Balancing Authority megawatts equal sink Balancing Authority megawatts (adjusted for losses, if appropriate).	LOWER
INT-007-1	R1.2.	All reliability entities involved in the Arranged Interchange are currently in the NERC registry.	LOWER
INT-007-1	R1.3.	The following are defined:	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
INT-007-1	R1.3.1.	Generation source and load sink.	LOWER
INT-007-1	R1.3.2.	Megawatt profile.	LOWER
INT-007-1	R1.3.3.	Ramp start and stop times.	LOWER
INT-007-1	R1.3.4.	Interchange duration.	LOWER
INT-007-1	R1.4.	Each Balancing Authority and Transmission Service Provider that received the Arranged Interchange information from the Interchange Authority for reliability assessment has provided approval.	LOWER
INT-008-3	R1.	Prior to the expiration of the time period defined in the Timing Table, Column C, the Interchange Authority shall distribute to all Balancing Authorities (including Balancing Authorities on both sides of a direct current tie), Transmission Service Providers and Purchasing-Selling Entities involved in the Arranged Interchange whether or not the Arranged Interchange has transitioned to a Confirmed Interchange.	LOWER
INT-008-3	R1.1.	For Confirmed Interchange, the Interchange Authority shall also communicate:	LOWER
INT-008-3	R1.1.1.	Start and stop times, ramps, and megawatt profile to Balancing Authorities.	LOWER
INT-008-3	R1.1.2.	Necessary Interchange information to NERC-identified reliability analysis services.	LOWER
INT-009-1	R1.	The Balancing Authority shall implement Confirmed Interchange as received from the Interchange Authority.	MEDIUM
INT-010-1	R1.	The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement shall ensure that a request for an Arranged Interchange is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no request for Arranged Interchange is required.	LOWER
INT-010-1	R2.	For a modification to an existing Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit the modified Arranged Interchange reflecting that modification within 60 minutes of the initiation of the event.	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
INT-010-1	R3.	For a new Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit an Arranged Interchange reflecting that Interchange schedule within 60 minutes of the initiation of the event.	LOWER
IRO-001-1.1	R1.	Each Regional Reliability Organization, subregion, or interregional coordinating group shall establish one or more Reliability Coordinators to continuously assess transmission reliability and coordinate emergency operations among the operating entities within the region and across the regional boundaries.	HIGH
IRO-001-1.1	R2.	The Reliability Coordinator shall comply with a regional reliability plan approved by the NERC Operating Committee.	HIGH
IRO-001-1.1	R3.	The Reliability Coordinator shall have clear decision-making authority to act and to direct actions to be taken by Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System. These actions shall be taken without delay, but no longer than 30 minutes.	HIGH
IRO-001-1.1	R4.	Reliability Coordinators that delegate tasks to other entities shall have formal operating agreements with each entity to which tasks are delegated. The Reliability Coordinator shall verify that all delegated tasks are understood, communicated, and addressed within its Reliability Coordinator Area. All responsibilities for complying with NERC and regional standards applicable to Reliability Coordinators shall remain with the Reliability Coordinator.	MEDIUM
IRO-001-1.1	R5.	The Reliability Coordinator shall list within its reliability plan all entities to which the Reliability Coordinator has delegated required tasks.	LOWER
IRO-001-1.1	R6.	The Reliability Coordinator shall verify that all delegated tasks are carried out by NERC-certified Reliability Coordinator operating personnel.	MEDIUM
IRO-001-1.1	R7.	The Reliability Coordinator shall have clear, comprehensive coordination agreements with adjacent Reliability Coordinators to ensure that System Operating Limit or Interconnection Reliability Operating Limit violation mitigation requiring actions in adjacent Reliability Coordinator Areas are coordinated.	HIGH

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
IRO-001-1.1	R8.	Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator may implement alternate remedial actions.	HIGH
IRO-001-1.1	R9.	The Reliability Coordinator shall act in the interests of reliability for the overall Reliability Coordinator Area and the Interconnection before the interests of any other entity.	HIGH
IRO-002-1	R1.	Each Reliability Coordinator shall have adequate communications facilities (voice and data links) to appropriate entities within its Reliability Coordinator Area. These communications facilities shall be staffed and available to act in addressing a real-time emergency condition.	HIGH
IRO-002-1	R2.	Each Reliability Coordinator shall determine the data requirements to support its reliability coordination tasks and shall request such data from its Transmission Operators, Balancing Authorities, Transmission Owners, Generation Owners, Generation Operators, and Load-Serving Entities, or adjacent Reliability Coordinators.	MEDIUM
IRO-002-1	R3.	Each Reliability Coordinator – or its Transmission Operators and Balancing Authorities – shall provide, or arrange provisions for, data exchange to other Reliability Coordinators or Transmission Operators and Balancing Authorities via a secure network.	MEDIUM
IRO-002-1	R4.	Each Reliability Coordinator shall have multi-directional communications capabilities with its Transmission Operators and Balancing Authorities, and with neighboring Reliability Coordinators, for both voice and data exchange as required to meet reliability needs of the Interconnection.	HIGH
IRO-002-1	R5.	Each Reliability Coordinator shall have detailed real-time monitoring capability of its Reliability Coordinator Area and sufficient monitoring capability of its surrounding Reliability Coordinator Areas to ensure that potential or actual System Operating Limit or Interconnection Reliability Operating Limit violations are identified. Each Reliability Coordinator shall have monitoring systems that provide information that can be easily understood and interpreted by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure.	HIGH

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
IRO-002-1	R6.	Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be critical to SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area.	HIGH
IRO-002-1	R7.	Each Reliability Coordinator shall have adequate analysis tools such as state estimation, pre- and post-contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays.	HIGH
IRO-002-1	R8.	Each Reliability Coordinator shall continuously monitor its Reliability Coordinator Area. Each Reliability Coordinator shall have provisions for backup facilities that shall be exercised if the main monitoring system is unavailable. Each Reliability Coordinator shall ensure SOL and IROL monitoring and derivations continue if the main monitoring system is unavailable.	HIGH
IRO-002-1	R9.	Each Reliability Coordinator shall control its Reliability Coordinator analysis tools, including approvals for planned maintenance. Each Reliability Coordinator shall have procedures in place to mitigate the effects of analysis tool outages.	MEDIUM
IRO-003-2	R1.	Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.	HIGH
IRO-003-2	R2.	Each Reliability Coordinator shall know the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or IROL violation. Reliability Coordinators shall also know the status of any facilities that may be required to assist area restoration objectives.	HIGH
IRO-004-1	R1.	Each Reliability Coordinator shall conduct next-day reliability analyses for its Reliability Coordinator Area to ensure that the Bulk Electric System can be operated reliably in anticipated normal and Contingency event conditions. The Reliability Coordinator shall conduct Contingency analysis studies to identify potential interface and other SOL and IROL violations, including overloaded transmission lines and transformers, voltage and stability limits, etc.	HIGH

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
IRO-004-1	R2.	Each Reliability Coordinator shall pay particular attention to parallel flows to ensure one Reliability Coordinator Area does not place an unacceptable or undue Burden on an adjacent Reliability Coordinator Area.	HIGH
IRO-004-1	R3.	Each Reliability Coordinator shall, in conjunction with its Transmission Operators and Balancing Authorities, develop action plans that may be required, including reconfiguration of the transmission system, re-dispatching of generation, reduction or curtailment of Interchange Transactions, or reducing load to return transmission loading to within acceptable SOLs or IROLs.	HIGH
IRO-004-1	R4.	Each Transmission Operator, Balancing Authority, Transmission Owner, Generator Owner, Generator Operator, and Load-Serving Entity in the Reliability Coordinator Area shall provide information required for system studies, such as critical facility status, Load, generation, operating reserve projections, and known Interchange Transactions. This information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.	HIGH
IRO-004-1	R5.	Each Reliability Coordinator shall share the results of its system studies, when conditions warrant or upon request, with other Reliability Coordinators and with Transmission Operators, Balancing Authorities, and Transmission Service Providers within its Reliability Coordinator Area. The Reliability Coordinator shall make study results available no later than 1500 Central Standard Time for the Eastern Interconnection and 1500 Pacific Standard Time for the Western Interconnection, unless circumstances warrant otherwise.	HIGH
IRO-004-1	R6.	If the results of these studies indicate potential SOL or IROL violations, the Reliability Coordinator shall direct its Transmission Operators, Balancing Authorities and Transmission Service Providers to take any necessary action the Reliability Coordinator deems appropriate to address the potential SOL or IROL violation.	HIGH
IRO-004-1	R7.	Each Transmission Operator, Balancing Authority, and Transmission Service Provider shall comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events.	HIGH
IRO-005-2	R1.	Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:	HIGH
IRO-005-2	R1.1.	Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading.	HIGH

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
IRO-005-2	R1.2.	Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.	HIGH
IRO-005-2	R1.3.	Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.	HIGH
IRO-005-2	R1.4.	System real and reactive reserves (actual versus required).	HIGH
IRO-005-2	R1.5.	Capacity and energy adequacy conditions.	HIGH
IRO-005-2	R1.6.	Current ACE for all its Balancing Authorities.	HIGH
IRO-005-2	R1.7.	Current local or Transmission Loading Relief procedures in effect.	HIGH
IRO-005-2	R1.8.	Planned generation dispatches.	HIGH
IRO-005-2	R1.9.	Planned transmission or generation outages.	HIGH
IRO-005-2	R1.10.	Contingency events.	HIGH
IRO-005-2	R2.	Each Reliability Coordinator shall be aware of all Interchange Transactions that wheel through, source, or sink in its Reliability Coordinator Area, and make that Interchange Transaction information available to all Reliability Coordinators in the Interconnection.	HIGH
IRO-005-2	R3.	As portions of the transmission system approach or exceed SOLs or IROLs, the Reliability Coordinator shall work with its Transmission Operators and Balancing Authorities to evaluate and assess any additional Interchange Schedules that would violate those limits. If a potential or actual IROL violation cannot be avoided through proactive intervention, the Reliability Coordinator shall initiate control actions or emergency procedures to relieve the violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall ensure all resources, including load shedding, are available to address a potential or actual IROL violation.	HIGH
IRO-005-2	R4.	Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.	HIGH
IRO-005-2	R5.	Each Reliability Coordinator shall identify the cause of any potential or actual SOL or IROL violations. The Reliability Coordinator shall initiate the control action or emergency procedure to relieve the potential or actual IROL violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall be able to utilize all resources, including load shedding, to address an IROL violation.	HIGH
IRO-005-2	R6.	Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.	HIGH

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
IRO-005-2	R7.	The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.	HIGH
IRO-005-2	R8.	Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.	HIGH
IRO-005-2	R9.	The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.	HIGH
IRO-005-2	R10.	As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities.	HIGH
IRO-005-2	R11.	The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.	HIGH
IRO-005-2	R12.	Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.	HIGH
IRO-005-2	R13.	Each Reliability Coordinator shall ensure that all Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities operate to prevent the likelihood that a disturbance, action, or nonaction in its Reliability Coordinator Area will result in a SOL or IROL violation in another area of the Interconnection. In instances where there is a difference in derived limits, the Reliability Coordinator and its Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.	HIGH
IRO-005-2	R14.	Each Reliability Coordinator shall make known to Transmission Service Providers within its Reliability Coordinator Area, SOLs or IROLs within its wide-area view. The Transmission Service Providers shall respect these SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
IRO-005-2	R15.	Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.	HIGH
IRO-005-2	R16.	Each Reliability Coordinator shall confirm reliability assessment results and determine the effects within its own and adjacent Reliability Coordinator Areas. The Reliability Coordinator shall discuss options to mitigate potential or actual SOL or IROL violations and take actions as necessary to always act in the best interests of the Interconnection at all times.	HIGH
IRO-005-2	R17.	When an IROL or SOL is exceeded, the Reliability Coordinator shall evaluate the local and wide-area impacts, both real-time and post-contingency, and determine if the actions being taken are appropriate and sufficient to return the system to within IROL in thirty minutes. If the actions being taken are not appropriate or sufficient, the Reliability Coordinator shall direct the Transmission Operator, Balancing Authority, Generator Operator, or Load-Serving Entity to return the system to within IROL or SOL.	HIGH
IRO-006-4.1	R1.	A Reliability Coordinator experiencing a potential or actual SOL or IROL violation within its Reliability Coordinator Area shall, with its authority and at its discretion, select one or more procedures to provide transmission loading relief. These procedures can be a “local” (regional, interregional, or sub-regional) transmission loading relief procedure or one of the following Interconnection-wide procedures: [Time Horizon: Real-time Operations]	MEDIUM
IRO-006-4.1	R1.1.	The Interconnection-wide Transmission Loading Relief (TLR) procedure for use in the Eastern Interconnection provided in Attachment 1-IRO-006-4. The TLR procedure alone is an inappropriate and ineffective tool to mitigate an IROL violation due to the time required to implement the procedure. Other acceptable and more effective procedures to mitigate actual IROL violations include: reconfiguration, redispatch, or load shedding.	<blank>
IRO-006-4.1	R1.2.	The Interconnection-wide transmission loading relief procedure for use in the Western Interconnection isWECC-IRO-STD-006-0 provided at: ftp://www.nerc.com/pub/sys/all_updl/standards/rrs/IRO-STD-006-0_17Jan07.pdf.	<blank>
IRO-006-4.1	R1.3.	The Interconnection-wide transmission loading relief procedure for use in ERCOT is provided as Section 7 of the ERCOT Protocols, posted at: http://www.ercot.com/mktrules/protocols/current.html	<blank>

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
IRO-006-4.1	R2.	The Reliability Coordinator shall only use local transmission loading relief or congestion management procedures to which the Transmission Operator experiencing the potential or actual SOL or IROL violation is a party. [Time Horizon: Operations Planning]	LOWER
IRO-006-4.1	R3.	Each Reliability Coordinator with a relief obligation from an Interconnection-wide procedure shall follow the curtailments as directed by the Interconnection-wide procedure. A Reliability Coordinator desiring to use a local procedure as a substitute for curtailments as directed by the Interconnection-wide procedure shall obtain prior approval of the local procedure from the ERO. [Time Horizon: Operations Planning]	LOWER
IRO-006-4.1	R4.	When Interconnection-wide procedures are implemented to curtail Interchange Transactions that cross an Interconnection boundary, each Reliability Coordinator shall comply with the provisions of the Interconnection-wide procedure. [Time Horizon: Real-time Operations]	MEDIUM
IRO-006-4.1	R5.	During the implementation of relief procedures, and up to the point that emergency action is necessary, Reliability Coordinators and Balancing Authorities shall comply with applicable Interchange scheduling standards. [Time Horizon: Real-time Operations]	MEDIUM
IRO-STD-006-0	WR1.	Curtailment of Contributing Schedules WECC's Unscheduled Flow Mitigation Plan (Plan), which is on file with FERC and has been accepted by FERC (most recently prior to the date hereof on November 20, 2001 in Docket No. ERO1-3085-000), 1/ specifies that members 2/ shall comply with requests from (Qualified) Transfer Path Operators to take actions that will reduce unscheduled flow on the Qualified Path in accordance with the table entitled "WECC Unscheduled Flow Procedure Summary of Curtailment Actions," which is located in Attachment 1 of the Plan. Plan Section 11: 11.1 When	
IRO-014-1	R1.	The Reliability Coordinator shall have Operating Procedures, Processes, or Plans in place for activities that require notification, exchange of information or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall address Scenarios that affect other Reliability Coordinator Areas as well as those developed in coordination with other Reliability Coordinators.	MEDIUM
IRO-014-1	R1.1.	These Operating Procedures, Processes, or Plans shall collectively address, as a minimum, the following:	LOWER
IRO-014-1	R1.1.1.	Communications and notifications, including the conditions under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and information to be exchanged with other Reliability Coordinators.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
IRO-014-1	R1.1.2.	Energy and capacity shortages.	MEDIUM
IRO-014-1	R1.1.3.	Planned or unplanned outage information.	MEDIUM
IRO-014-1	R1.1.4.	Voltage control, including the coordination of reactive resources for voltage control.	MEDIUM
IRO-014-1	R1.1.5.	Coordination of information exchange to support reliability assessments.	LOWER
IRO-014-1	R1.1.6.	Authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas.	LOWER
IRO-014-1	R2.	Each Reliability Coordinator's Operating Procedure, Process, or Plan that requires one or more other Reliability Coordinators to take action (e.g., make notifications, exchange information, or coordinate actions) shall be:	LOWER
IRO-014-1	R2.1.	Agreed to by all the Reliability Coordinators required to take the indicated action(s).	LOWER
IRO-014-1	R2.2.	Distributed to all Reliability Coordinators that are required to take the indicated action(s).	LOWER
IRO-014-1	R3.	A Reliability Coordinator's Operating Procedures, Processes, or Plans developed to support a Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan shall include:	MEDIUM
IRO-014-1	R3.1.	A reference to the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.	MEDIUM
IRO-014-1	R3.2.	The agreed-upon actions from the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.	LOWER
IRO-014-1	R4.	Each of the Operating Procedures, Processes, and Plans addressed in Reliability Standard IRO-014 Requirement 1 and Requirement 3 shall:	LOWER
IRO-014-1	R4.1.	Include version control number or date	LOWER
IRO-014-1	R4.2.	Include a distribution list.	LOWER
IRO-014-1	R4.3.	Be reviewed, at least once every three years, and updated if needed.	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
IRO-015-1	R1.	The Reliability Coordinator shall follow its Operating Procedures, Processes, or Plans for making notifications and exchanging reliability-related information with other Reliability Coordinators.	MEDIUM
IRO-015-1	R1.1.	The Reliability Coordinator shall make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas.	MEDIUM
IRO-015-1	R2.	The Reliability Coordinator shall participate in agreed upon conference calls and other communication forums with adjacent Reliability Coordinators.	LOWER
IRO-015-1	R2.1.	The frequency of these conference calls shall be agreed upon by all involved Reliability Coordinators and shall be at least weekly.	LOWER
IRO-015-1	R3.	The Reliability Coordinator shall provide reliability-related information as requested by other Reliability Coordinators.	MEDIUM
IRO-016-1	R1.	The Reliability Coordinator that identifies a potential, expected, or actual problem that requires the actions of one or more other Reliability Coordinators shall contact the other Reliability Coordinator(s) to confirm that there is a problem and then discuss options and decide upon a solution to prevent or resolve the identified problem.	MEDIUM
IRO-016-1	R1.1.	If the involved Reliability Coordinators agree on the problem and the actions to take to prevent or mitigate the system condition, each involved Reliability Coordinator shall implement the agreed-upon solution, and notify the involved Reliability Coordinators of the action(s) taken.	MEDIUM
IRO-016-1	R1.2.	If the involved Reliability Coordinators cannot agree on the problem(s) each Reliability Coordinator shall re-evaluate the causes of the disagreement (bad data, status, study results, tools, etc.).	MEDIUM
IRO-016-1	R1.2.1.	If time permits, this re-evaluation shall be done before taking corrective actions.	MEDIUM
IRO-016-1	R1.2.2.	If time does not permit, then each Reliability Coordinator shall operate as though the problem(s) exist(s) until the conflicting system status is resolved.	MEDIUM
IRO-016-1	R1.3.	If the involved Reliability Coordinators cannot agree on the solution, the more conservative solution shall be implemented.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
IRO-016-1	R2.	The Reliability Coordinator shall document (via operator logs or other data sources) its actions taken for either the event or for the disagreement on the problem(s) or for both.	LOWER
MOD-001-1	R1.	Each Transmission Operator shall select one of the methodologies listed below for calculating Available Transfer Capability (ATC) or Available Flowgate Capability (AFC) for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area: [Time Horizon: Operations Planning] ☐ The Area Interchange Methodology, as described in MOD-028 ☐ The Rated System Path Methodology, as described in MOD-029 ☐ The Flowgate Methodology, as described in MOD-030	LOWER
MOD-001-1	R2.	Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s): [Time Horizon: Operations Planning]	LOWER
MOD-001-1	R2.1.	Hourly values for at least the next 48 hours.	
MOD-001-1	R2.2.	Daily values for at least the next 31 calendar days.	
MOD-001-1	R2.3.	Monthly values for at least the next 12 months (months 2-13).	
MOD-001-1	R3.	Each Transmission Service Provider shall prepare and keep current an Available Transfer Capability Implementation Document (ATCID) that includes, at a minimum, the following information: [Time Horizon: Operations Planning]	LOWER
MOD-001-1	R3.1.	Information describing how the selected methodology (or methodologies) has been implemented, in such detail that, given the same information used by the Transmission Service Provider, the results of the ATC or AFC calculations can be validated.	
MOD-001-1	R3.2.	A description of the manner in which the Transmission Service Provider will account for counterflows including:	
MOD-001-1	R3.2.1.	How confirmed Transmission reservations, expected Interchange and internal counterflow are addressed in firm and non-firm ATC or AFC calculations.	
MOD-001-1	R3.2.2.	A rationale for that accounting specified in R3.2.	
MOD-001-1	R3.3.	The identity of the Transmission Operators and Transmission Service Providers from which the Transmission Service Provider receives data for use in calculating ATC or AFC.	
MOD-001-1	R3.4.	The identity of the Transmission Service Providers and Transmission Operators to which it provides data for use in calculating transfer or Flowgate capability.	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
MOD-001-1	R3.5.	A description of the allocation processes listed below that are applicable to the Transmission Service Provider: • Processes used to allocate transfer or Flowgate capability among multiple lines or sub-paths within a larger ATC Path or Flowgate. • Processes used to allocate transfer or Flowgate capabilities among multiple owners or users of an ATC Path or Flowgate. • Processes used to allocate transfer or Flowgate capabilities between Transmission Service Providers to address issues such as forward looking congestion management and seams coordination.	
MOD-001-1	R3.6.	A description of how generation and transmission outages are considered in transfer or Flowgate capability calculations, including:	
MOD-001-1	R3.6.1.	The criteria used to determine when an outage that is in effect part of a day impacts a daily calculation.	
MOD-001-1	R3.6.2.	The criteria used to determine when an outage that is in effect part of a month impacts a monthly calculation.	
MOD-001-1	R3.6.3.	How outages from other Transmission Service Providers that can not be mapped to the Transmission model used to calculate transfer or Flowgate capability are addressed.	
MOD-001-1	R4.	The Transmission Service Provider shall notify the following entities before implementing a new or revised ATCID: [Time Horizon: Operations Planning]	LOWER
MOD-001-1	R4.1.	Each Planning Coordinator associated with the Transmission Service Provider's area.	
MOD-001-1	R4.2.	Each Reliability Coordinator associated with the Transmission Service Provider's area.	
MOD-001-1	R4.3.	Each Transmission Operator associated with the Transmission Service Provider's area.	
MOD-001-1	R4.4.	Each Planning Coordinator adjacent to the Transmission Service Provider's area.	
MOD-001-1	R4.5.	Each Reliability Coordinator adjacent to the Transmission Service Provider's area.	
MOD-001-1	R4.6.	Each Transmission Service Provider whose area is adjacent to the Transmission Service Provider's area.	
MOD-001-1	R5.	The Transmission Service Provider shall make available the current ATCID to all of the entities specified in R4. [Time Horizon: Operations Planning]	LOWER
MOD-001-1	R6.	When calculating Total Transfer Capability (TTC) or Total Flowgate Capability (TFC) the Transmission Operator shall use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that time period. [Time Horizon: Operations Planning]	LOWER
MOD-001-1	R7.	When calculating ATC or AFC the Transmission Service Provider shall use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that time period. [Time Horizon: Operations Planning]	LOWER
MOD-001-1	R8.	Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed: [Time Horizon: Operations Planning]	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
MOD-001-1	R8.1.	Hourly values, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the ATC equation.	
MOD-001-1	R8.2.	Daily values, once per day.	
MOD-001-1	R8.3.	Monthly values, once per week.	
MOD-001-1	R9.	Within thirty calendar days of receiving a request by any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator for data from the list below solely for use in the requestor's ATC or AFC calculations, each Transmission Service Provider receiving said request shall begin to make the requested data available to the requestor, subject to the conditions specified in R9.1 and R9.2: [Time Horizon: Operations Planning] • Expected generation and Transmission outages, additions, and retirements. • Load forecasts. • Unit commitments and order of dispatch, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run, in one of the following formats chosen by the data provider: Dispatch Order Participation Factors Block Dispatch • Aggregated firm capacity set-aside for Network Integration Transmission Service and aggregated non-firm capacity set aside for Network Integration Transmission Service (i.e. Secondary Service). • Firm and non-firm Transmission reservations. • Aggregated capacity set-aside for Grandfathered obligations • Firm roll-over rights. • Any firm and non-firm adjustments applied by the Transmission Service Provider to reflect parallel path impacts. • Power flow models and underlying assumptions. • Contingencies, provided in one or more of the following formats: A list of	LOWER
MOD-001-1	R9.1.	The Transmission Service Provider shall make its own current data available, in the format maintained by the Transmission Service Provider, for up to 13 months into the future (subject to confidentiality and security requirements).	
MOD-001-1	R9.1.1.	If the Transmission Service Provider uses the data requested in its transfer or Flowgate capability calculations, it shall make the data used available	
MOD-001-1	R9.1.2.	If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, but maintains that data, it shall make that data available	
MOD-001-1	R9.1.3.	If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, and does not maintain that data, it shall not be required to make that data available	
MOD-001-1	R9.2.	This data shall be made available by the Transmission Provider on the schedule specified by the requestor (but no more frequently than once per hour, unless mutually agreed to by the requester and the provider).	
MOD-004-1	R1.	The Transmission Service Provider that maintains CBM shall prepare and keep current a "Capacity Benefit Margin Implementation Document" (CBMID) that includes, at a minimum, the following information: [Time Horizon: Operations Planning, Long-term Planning]	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
MOD-004-1	R1.1.	The process through which a Load-Serving Entity within a Balancing Authority Area associated with the Transmission Service Provider, or the Resource Planner associated with that Balancing Authority Area, may ensure that its need for Transmission capacity to be set aside as CBM will be reviewed and accommodated by the Transmission Service Provider to the extent Transmission capacity is available.	
MOD-004-1	R1.2.	The procedure and assumptions for establishing CBM for each Available Transfer Capability (ATC) Path or Flowgate.	
MOD-004-1	R1.3.	The procedure for a Load-Serving Entity or Balancing Authority to use Transmission capacity set aside as CBM, including the manner in which the Transmission Service Provider will manage situations where the requested use of CBM exceeds the amount of CBM available.	
MOD-004-1	R2.	The Transmission Service Provider that maintains CBM shall make available its current CBMID to the Transmission Operators, Transmission Service Providers, Reliability Coordinators, Transmission Planners, Resource Planners, and Planning Coordinators that are within or adjacent to the Transmission Service Provider's area, and to the Load Serving Entities and Balancing Authorities within the Transmission Service Provider's area, and notify those entities of any changes to the CBMID prior to the effective date of the change. [Time Horizon: Operations Planning]	LOWER
MOD-004-1	R3.	Each Load-Serving Entity determining the need for Transmission capacity to be set aside as CBM for imports into a Balancing Authority Area shall determine that need by: [Time Horizon: Operations Planning]	LOWER
MOD-004-1	R3.1.	Using one or more of the following to determine the GCIR: Loss of Load Expectation (LOLE) studies Loss of Load Probability (LOLP) studies Deterministic risk-analysis studies Reserve margin or resource adequacy requirements established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities	
MOD-004-1	R3.2.	Identifying expected import path(s) or source region(s).	
MOD-004-1	R4.	Each Resource Planner determining the need for Transmission capacity to be set aside as CBM for imports into a Balancing Authority Area shall determine that need by: [Time Horizon: Operations Planning]	LOWER
MOD-004-1	R4.1.	Using one or more of the following to determine the GCIR: Loss of Load Expectation (LOLE) studies Loss of Load Probability (LOLP) studies Deterministic risk-analysis studies Reserve margin or resource adequacy requirements established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
MOD-004-1	R4.2.	Identifying expected import path(s) or source region(s).	
MOD-004-1	R5.	At least every 13 months, the Transmission Service Provider that maintains CBM shall establish a CBM value for each ATC Path or Flowgate to be used for ATC or Available Flowgate Capability (AFC) calculations during the 13 full calendar months (months 2-14) following the current month (the month in which the Transmission Service Provider is establishing the CBM values). This value shall: [Time Horizon: Operations Planning]	LOWER
MOD-004-1	R5.1.	Reflect consideration of each of the following if available: Any studies (as described in R3.1) performed by Load-Serving Entities for loads within the Transmission Service Provider's area Any studies (as described in R4.1) performed by Resource Planners for loads within the Transmission Service Provider's area Any reserve margin or resource adequacy requirements for loads within the Transmission Service Provider's area established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities	
MOD-004-1	R5.2.	Be allocated as follows: For ATC Paths, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners For Flowgates, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners and the distribution factors associated with those paths or regions, as determined by the Transmission Service Provider	
MOD-004-1	R6.	At least every 13 months, the Transmission Planner shall establish a CBM value for each ATC Path or Flowgate to be used in planning during each of the full calendar years two through ten following the current year (the year in which the Transmission Planner is establishing the CBM values). This value shall: [Time Horizon: Long-term Planning]	LOWER
MOD-004-1	R6.1.	Reflect consideration of each of the following if available: Any studies (as described in R3.1) performed by Load-Serving Entities for loads within the Transmission Planner's area Any studies (as described in R4.1) performed by Resource Planners for loads within the Transmission Planner's area Any reserve margin or resource adequacy requirements for loads within the Transmission Planner's area established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
MOD-004-1	R6.2.	Be allocated as follows: For ATC Paths, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners For Flowgates, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners and the distribution factors associated with those paths or regions, as determined by the Transmission Planner.	
MOD-004-1	R7.	Less than 31 calendar days after the establishment of CBM, the Transmission Service Provider that maintains CBM shall notify all the Load-Serving Entities and Resource Planners that determined they had a need for CBM on the Transmission Service Provider's system of the amount of CBM set aside. [Time Horizon: Operations Planning]	LOWER
MOD-004-1	R8.	Less than 31 calendar days after the establishment of CBM, the Transmission Planner shall notify all the Load-Serving Entities and Resource Planners that determined they had a need for CBM on the system being planned by the Transmission Planner of the amount of CBM set aside. [Time Horizon: Operations Planning]	LOWER
MOD-004-1	R9.	The Transmission Service Provider that maintains CBM and the Transmission Planner shall each provide (subject to confidentiality and security requirements) copies of the applicable supporting data, including any models, used for determining CBM or allocating CBM over each ATC Path or Flowgate to the following: [Time Horizon: Operations Planning, Long-term Planning]	LOWER
MOD-004-1	R9.1.	Each of its associated Transmission Operators within 30 calendar days of their making a request for the data.	
MOD-004-1	R9.2.	To any Transmission Service Provider, Reliability Coordinator, Transmission Planner, Resource Planner, or Planning Coordinator within 30 calendar days of their making a request for the data.	
MOD-004-1	R10.	The Load-Serving Entity or Balancing Authority shall request to import energy over firm Transfer Capability set aside as CBM only when experiencing a declared NERC Energy Emergency Alert (EEA) 2 or higher. [Time Horizon: Same-day Operations]	LOWER
MOD-004-1	R11.	When reviewing an Arranged Interchange using CBM, all Balancing Authorities and Transmission Service Providers shall waive, within the bounds of reliable operation, any Real-time timing and ramping requirements. [Time Horizon: Same-day Operations]	MEDIUM
MOD-004-1	R12.	The Transmission Service Provider that maintains CBM shall approve, within the bounds of reliable operation, any Arranged Interchange using CBM that is submitted by an "energy deficient entity " under an EEA 2 if: [Time Horizon: Same-day Operations]	MEDIUM
MOD-004-1	R12.1.	The CBM is available	
MOD-004-1	R12.2.	The EEA 2 is declared within the Balancing Authority Area of the "energy deficient entity," and	
MOD-004-1	R12.3.	The Load of the "energy deficient entity" is located within the Transmission Service Provider's area.	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
MOD-006-0.1	R1.	R1. Each Transmission Service Provider shall document its procedure on the use of Capacity Benefit Margin (CBM) (scheduling of energy against a CBM reservation). The procedure shall include the following three components:	LOWER
MOD-006-0.1	R1.1.	Require that CBM be used only after the following steps have been taken (as time permits): all non-firm sales have been terminated, Direct-Control Load Management has been implemented, and customer interruptible demands have been interrupted. CBM may be used to reestablish Operating Reserves.	LOWER
MOD-006-0.1	R1.2.	Require that CBM shall only be used if the Load-Serving Entity calling for its use is experiencing a generation deficiency and its Transmission Service Provider is also experiencing Transmission Constraints relative to imports of energy on its transmission system.	LOWER
MOD-006-0.1	R1.3.	Describe the conditions under which CBM may be available as Non-Firm Transmission Service.	LOWER
MOD-006-0.1	R2.	Each Transmission Service Provider shall make its CBM use procedure available on a web site accessible by the Regional Reliability Organizations, NERC, and transmission users.	LOWER
MOD-007-0	R1.	Each Transmission Service Provider that uses CBM shall report (to the Regional Reliability Organization, NERC and the transmission users) the use of CBM by the Load-Serving Entities' Loads on its system, except for CBM sales as Non-Firm Transmission Service. (This use of CBM shall be consistent with the Transmission Service Provider's procedure for use of CBM.)	LOWER
MOD-007-0	R2.	The Transmission Service Provider shall post the following three items within 15 calendar days after the use of CBM for an Energy Emergency. This posting shall be on a web site accessible by the Regional Reliability Organizations, NERC, and transmission users.	LOWER
MOD-007-0	R2.1.	Circumstances.	LOWER
MOD-007-0	R2.2.	Duration.	LOWER
MOD-007-0	R2.3.	Amount of CBM used.	LOWER
MOD-008-1	R1.	Each Transmission Operator shall prepare and keep current a TRM Implementation Document (TRMID) that includes, as a minimum, the following information: [Time Horizon: Operations Planning]	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
MOD-008-1	R1.1.	Identification of (on each of its respective ATC Paths or Flowgates) each of the following components of uncertainty if used in establishing TRM, and a description of how that component is used to establish a TRM value: - Aggregate Load forecast. - Load distribution uncertainty. - Forecast uncertainty in Transmission system topology (including, but not limited to, forced or unplanned outages and maintenance outages). - Allowances for parallel path (loop flow) impacts. - Allowances for simultaneous path interactions. - Variations in generation dispatch (including, but not limited to, forced or unplanned outages, maintenance outages and location of future generation). - Short-term System Operator response (Operating Reserve actions). - Reserve sharing requirements. - Inertial response and frequency bias.	
MOD-008-1	R1.2.	The description of the method used to allocate TRM across ATC Paths or Flowgates.	
MOD-008-1	R1.3.	The identification of the TRM calculation used for the following time periods:	
MOD-008-1	R1.3.1.	Same day and real-time.	
MOD-008-1	R1.3.2.	Day-ahead and pre-schedule.	
MOD-008-1	R1.3.3.	Beyond day-ahead and pre-schedule, up to thirteen months ahead.	
MOD-008-1	R2.	Each Transmission Operator shall only use the components of uncertainty from R1.1 to establish TRM, and shall not include any of the components of Capacity Benefit Margin (CBM). Transmission capacity set aside for reserve sharing agreements can be included in TRM. [Time Horizon: Operations Planning]	LOWER
MOD-008-1	R3.	Each Transmission Operator shall make available its TRMID, and if requested, underlying documentation (if any) used to determine TRM, in the format used by the Transmission Operator, to any of the following who make a written request no more than 30 calendar days after receiving the request. [Time Horizon: Operations Planning] • Transmission Service Providers • Reliability Coordinators • Planning Coordinators • Transmission Planner • Transmission Operators	LOWER
MOD-008-1	R4.	Each Transmission Operator that maintains TRM shall establish TRM values in accordance with the TRMID at least once every 13 months. [Time Horizon: Operations Planning]	LOWER
MOD-008-1	R5.	The Transmission Operator that maintains TRM shall provide the TRM values to its Transmission Service Provider(s) and Transmission Planner(s) no more than seven calendar days after a TRM value is initially established or subsequently changed. [Time Horizon: Operations Planning]	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
MOD-010-0	R1.	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide appropriate equipment characteristics, system data, and existing and future Interchange Schedules in compliance with its respective Interconnection Regional steady-state modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-011-0_R 1.	MEDIUM
MOD-010-0	R2.	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide this steady-state modeling and simulation data to the Regional Reliability Organizations, NERC, and those entities specified within Reliability Standard MOD-011-0_R 1. If no schedule exists, then these entities shall provide the data on request (30 calendar days).	MEDIUM
MOD-012-0	R1.	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R1) shall provide appropriate equipment characteristics and system data in compliance with the respective Interconnection-wide Regional dynamics system modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-013-0_R1.	MEDIUM
MOD-012-0	R2.	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R4) shall provide dynamics system modeling and simulation data to its Regional Reliability Organization(s), NERC, and those entities specified within the applicable reporting procedures identified in Reliability Standard MOD-013-0_R 1. If no schedule exists, then these entities shall provide data on request (30 calendar days).	MEDIUM
MOD-016-1.1	R1.	The Planning Authority and Regional Reliability Organization shall have documentation identifying the scope and details of the actual and forecast (a) Demand data, (b) Net Energy for Load data, and (c) controllable DSM data to be reported for system modeling and reliability analyses.	LOWER
MOD-016-1.1	R1.1.	The aggregated and dispersed data submittal requirements shall ensure that consistent data is supplied for Reliability Standards TPL-005, TPL-006, MOD-010, MOD-011, MOD-012, MOD-013, MOD-014, MOD-015, MOD-016, MOD-017, MOD-018, MOD-019, MOD-020, and MOD-021. The data submittal requirements shall stipulate that each Load-Serving Entity count its customer Demand once and only once, on an aggregated and dispersed basis, in developing its actual and forecast customer Demand values.	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
MOD-016-1.1	R2.	The Regional Reliability Organization shall distribute its documentation required in Requirement 1 and any changes to that documentation, to all Planning Authorities that work within its Region.	LOWER
MOD-016-1.1	R2.1.	The Regional Reliability Organization shall make this distribution within 30 calendar days of approval.	LOWER
MOD-016-1.1	R3.	The Planning Authority shall distribute its documentation required in R1 for reporting customer data and any changes to that documentation, to its Transmission Planners and Load-Serving Entities that work within its Planning Authority Area.	LOWER
MOD-016-1.1	R3.1.	The Planning Authority shall make this distribution within 30 calendar days of approval.	LOWER
MOD-017-0.1	R1.	The Load-Serving Entity, Planning Authority and Resource Planner shall each provide the following information annually on an aggregated Regional, subregional, Power Pool, individual system, or Load-Serving Entity basis to NERC, the Regional Reliability Organizations, and any other entities specified by the documentation in Standard MOD-016-1_R1.	MEDIUM
MOD-017-0.1	R1.1.	Integrated hourly demands in megawatts (MW) for the prior year.	MEDIUM
MOD-017-0.1	R1.2.	Monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year.	MEDIUM
MOD-017-0.1	R1.3.	Monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years.	MEDIUM
MOD-017-0.1	R1.4.	Annual Peak hour forecast demands (summer and winter) in MW and annual Net Energy for load in GWh for at least five years and up to ten years into the future, as requested.	MEDIUM
MOD-018-0	R1.	The Load-Serving Entity, Planning Authority, Transmission Planner and Resource Planner's report of actual and forecast demand data (reported on either an aggregated or dispersed basis) shall:	MEDIUM
MOD-018-0	R1.1.	Indicate whether the demand data of nonmember entities within an area or Regional Reliability Organization are included, and	MEDIUM
MOD-018-0	R1.2.	Address assumptions, methods, and the manner in which uncertainties are treated in the forecasts of aggregated peak demands and Net Energy for Load.	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
MOD-018-0	R1.3.	Items (MOD-018-0_R 1.1) and (MOD-018-0_R 1.2) shall be addressed as described in the reporting procedures developed for Standard MOD-016-1_R 1.	LOWER
MOD-018-0	R2.	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each report data associated with Reliability Standard MOD-018-0_R1 to NERC, the Regional Reliability Organization, Load-Serving Entity, Planning Authority, and Resource Planner on request (within 30 calendar days).	LOWER
MOD-019-0.1	R1.	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each provide annually its forecasts of interruptible demands and Direct Control Load Management (DCLM) data for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions to NERC, the Regional Reliability Organizations, and other entities (Load-Serving Entities, Planning Authorities, and Resource Planners) as specified by the documentation in Reliability Standard MOD-016-1_R 1.	MEDIUM
MOD-020-0	R1.	The Load-Serving Entity, Transmission Planner, and Resource Planner shall each make known its amount of interruptible demands and Direct Control Load Management (DCLM) to Transmission Operators, Balancing Authorities, and Reliability Coordinators on request within 30 calendar days.	LOWER
MOD-021-0.1	R1.	The Load-Serving Entity, Transmission Planner, and Resource Planner's forecasts shall each clearly document how the Demand and energy effects of DSM programs (such as conservation, time-of-use rates, interruptible Demands, and Direct Control Load Management) are addressed.	LOWER
MOD-021-0.1	R2.	The Load-Serving Entity, Transmission Planner, and Resource Planner shall each include information detailing how Demand-Side Management measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load in the data reporting procedures of Standard MOD-016-0_R 1.	LOWER
MOD-021-0.1	R3.	The Load-Serving Entity, Transmission Planner, and Resource Planner shall each make documentation on the treatment of its DSM programs available to NERC on request (within 30 calendar days).	LOWER
MOD-028-1	R1.	Each Transmission Service Provider shall include in its Available Transfer Capability Implementation Document (ATCID), at a minimum, the following information relative to its methodology for determining Total Transfer Capability (TTC): [Time Horizon: Operations Planning]	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
MOD-028-1	R1.1.	Information describing how the selected methodology has been implemented, in such detail that, given the same information used by the Transmission Operator, the results of the TTC calculations can be validated.	
MOD-028-1	R1.2.	A description of the manner in which the Transmission Operator will account for Interchange Schedules in the calculation of TTC.	
MOD-028-1	R1.3.	Any contractual obligations for allocation of TTC.	
MOD-028-1	R1.4.	A description of the manner in which Contingencies are identified for use in the TTC process.	
MOD-028-1	R1.5.	The following information on how source and sink for transmission service is accounted for in ATC calculations including:	
MOD-028-1	R1.5.1.	Define if the source used for Available Transfer Capability (ATC) calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation	
MOD-028-1	R1.5.2.	Define if the sink used for ATC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation	
MOD-028-1	R1.5.3.	The source/sink or POR/POD identification and mapping to the model.	
MOD-028-1	R1.5.4.	If the Transmission Service Provider's ATC calculation process involves a grouping of generation, the ATCID must identify how these generators participate in the group.	
MOD-028-1	R2.	When calculating TTC for ATC Paths, the Transmission Operator shall use a Transmission model that contains all of the following: [Time Horizon: Operations Planning]	LOWER
MOD-028-1	R2.1.	Modeling data and topology of its Reliability Coordinator's area of responsibility. Equivalent representation of radial lines and facilities 161 kV or below is allowed.	
MOD-028-1	R2.2.	Modeling data and topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination areas.	
MOD-028-1	R2.3.	Facility Ratings specified by the Generator Owners and Transmission Owners.	
MOD-028-1	R3.	When calculating TTCs for ATC Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's area. The Transmission Operator shall also include the following data associated with Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed: [Time Horizon: Operations Planning]	LOWER
MOD-028-1	R3.1.	For on-peak and off-peak intra-day and next-day TTCs, use the following (as well as any other values and additional parameters as specified in the ATCID):	
MOD-028-1	R3.1.1.	Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.	
MOD-028-1	R3.1.2.	Load forecast for the applicable period being calculated.	
MOD-028-1	R3.1.3.	Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.	
MOD-028-1	R3.2.	For days two through 31 TTCs and for months two through 13 TTCs, use the following (as well as any other values and internal parameters as specified in the ATCID):	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
MOD-028-1	R3.2.1.	Expected generation and Transmission outages, additions, and Retirements, included as specified in the ATCID.	
MOD-028-1	R3.2.2.	Daily load forecast for the days two through 31 TTCs being calculated and monthly forecast for months two through 13 months TTCs being calculated.	
MOD-028-1	R3.2.3.	Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.	
MOD-028-1	R4.	When calculating TTCs for ATC Paths, the Transmission Operator shall meet all of the following conditions: [Time Horizon: Operations Planning]	LOWER
MOD-028-1	R4.1.	Use all Contingencies meeting the criteria described in the ATCID.	
MOD-028-1	R4.2.	Respect any contractual allocations of TTC.	
MOD-028-1	R4.3.	Include, for each time period, the Firm Transmission Service expected to be scheduled as specified in the ATCID (filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers) for the Transmission Service Provider, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed modeling the source and sink as follows: - If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source. - If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate representation" in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source. - If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point, an "equivalence," or an "aggregate representation" in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as	
MOD-028-1	R5.	Each Transmission Operator shall establish TTC for each ATC Path as defined below: [Time Horizon: Operations Planning]	LOWER
MOD-028-1	R5.1.	At least once within the seven calendar days prior to the specified period for TTCs used in hourly and daily ATC calculations.	
MOD-028-1	R5.2.	At least once per calendar month for TTCs used in monthly ATC calculations.	
MOD-028-1	R5.3.	Within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a transformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage, provided such outage is expected to last 24 hours or longer.	
MOD-028-1	R6.	Each Transmission Operator shall establish TTC for each ATC Path using the following process: [Time Horizon: Operations Planning]	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
MOD-028-1	R6.1.	Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either: - A System Operating Limit is reached on the Transmission Service Provider's system, or - A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater .	
MOD-028-1	R6.2.	If the limit in step R6.1 can not be reached by adjusting any combination of load or generation, then set the incremental Transfer Capability by the results of the case where the maximum adjustments were applied.	
MOD-028-1	R6.3.	Use (as the TTC) the lesser of: The sum of the incremental Transfer Capability and the impacts of Firm Transmission Services, as specified in the Transmission Service Provider's ATCID, that were included in the study model, or The sum of Facility Ratings of all ties comprising the ATC Path.	
MOD-028-1	R6.4.	For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Service Provider so the TTC does not exceed each Transmission Service Provider's contractual rights.	
MOD-028-1	R7.	The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: [Time Horizon: Operations Planning]	LOWER
MOD-028-1	R7.1.	One calendar day after its determination for TTCs used in hourly and daily ATC calculations.	
MOD-028-1	R7.2.	Seven calendar days after its determination for TTCs used in monthly ATC calculations.	
MOD-028-1	R8.	When calculating Existing Transmission Commitments (ETCs) for firm commitments (ETCF) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: [Time Horizon: Operations Planning] ***See Standard for Formula***	LOWER
MOD-028-1	R9.	When calculating ETC for non-firm commitments (ETCNF) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: [Time Horizon: Operations Planning] ***See Standard for Formula***	LOWER
MOD-028-1	R10.	When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall utilize the following algorithm: [Time Horizon: Operations Planning] ***See Standard for Formula***	LOWER
MOD-028-1	R11.	When calculating non-firm ATC for a ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [Time Horizon: Operations Planning] ***See Standard for Formula***	LOWER
MOD-029-1	R1.	When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements: [Time Horizon: Operations Planning]	LOWER
MOD-029-1	R1.1.	The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
MOD-029-1	R1.1.1.	Includes at least:	
MOD-029-1	R1.1.1.1.	The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.	
MOD-029-1	R1.1.1.2.	All Transmission Operator areas contiguous with its own Transmission Operator area. (Equivalent representation is allowed.)	
MOD-029-1	R1.1.1.3.	Any other Transmission Operator area linked to the Transmission Operator's area by joint operating agreement. (Equivalent representation is allowed.)	
MOD-029-1	R1.1.2.	Models all system Elements as in-service for the assumed initial conditions.	
MOD-029-1	R1.1.3.	Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the studied area.	
MOD-029-1	R1.1.4.	Models phase shifters in non-regulating mode, unless otherwise specified in the Available Transfer Capability Implementation Document (ATCID).	
MOD-029-1	R1.1.5.	Uses Load forecast by Balancing Authority.	
MOD-029-1	R1.1.6.	Uses Transmission Facility additions and retirements.	
MOD-029-1	R1.1.7.	Uses Generation Facility additions and retirements.	
MOD-029-1	R1.1.8.	Uses Special Protection System (SPS) models where currently existing or projected for implementation within the studied time horizon.	
MOD-029-1	R1.1.9.	Models series compensation for each line at the expected operating level unless specified otherwise in the ATCID.	
MOD-029-1	R1.1.10.	Includes any other modeling requirements or criteria specified in the ATCID.	
MOD-029-1	R1.2.	Uses Facility Ratings as provided by the Transmission Owner and Generator Owner	
MOD-029-1	R2.	The Transmission Operator shall use the following process to determine TTC: [Time Horizon: Operations Planning]	LOWER
MOD-029-1	R2.1.	Except where otherwise specified within MOD-029-1, adjust base case generation and Load levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the ATC Path while at the same time satisfying all planning criteria contingencies as follows:	
MOD-029-1	R2.1.1.	When modeling normal conditions, all Transmission Elements will be modeled at or below 100% of their continuous rating.	
MOD-029-1	R2.1.2.	When modeling contingencies the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its Emergency Rating.	
MOD-029-1	R2.1.3.	Uncontrolled separation shall not occur.	
MOD-029-1	R2.2.	Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction. If the TTC in the prevailing flow direction is dependant on a Special Protection System (SPS), set the TTC for the non-prevailing flow direction equal to the greater of the maximum flow that can be simulated in the non-prevailing flow direction or the maximum TTC that can be achieved in the prevailing flow direction without use of a SPS.	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
MOD-029-1	R2.3.	For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R2.1.	
MOD-029-1	R2.4.	For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.	
MOD-029-1	R2.5.	The Transmission Operator shall identify when the TTC for the ATC Path being studied has an adverse impact on the TTC value of any existing path. Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1. The Transmission Operator shall include the resolution of this adverse impact in its study report for the ATC Path.	
MOD-029-1	R2.6.	Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.	
MOD-029-1	R2.7.	For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken to have the path rated using a different method, set the TTC at that previously established amount.	
MOD-029-1	R2.8.	Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.	
MOD-029-1	R3.	Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. [Time Horizon: Operations Planning]	LOWER
MOD-029-1	R4.	Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. [Time Horizon: Operations Planning]	LOWER
MOD-029-1	R5.	When calculating ETC for firm Existing Transmission Commitments (ETCF) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below: [Time Horizon: Operations Planning] ***See Standard for Formula***	LOWER
MOD-029-1	R6.	When calculating ETC for non-firm Existing Transmission Commitments (ETCNF) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm: [Time Horizon: Operations Planning] ***See Standard for Formula***	LOWER
MOD-029-1	R7.	When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [Time Horizon: Operations Planning] ***See Standard for Formula***	LOWER
MOD-029-1	R8.	When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm:[Time Horizon: Operations Planning] ***See Standard for Formula***	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
MOD-030-2	R1.	The Transmission Service Provider shall include in its "Available Transfer Capability Implementation Document" (ATCID): [Time Horizon: Operations Planning]	To Be Determined
MOD-030-2	R1.1.	The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations.	
MOD-030-2	R1.2.	The following information on how source and sink for transmission service is accounted for in AFC calculations including:	
MOD-030-2	R1.2.1.	Define if the source used for AFC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.	
MOD-030-2	R1.2.2.	Define if the sink used for AFC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.	
MOD-030-2	R1.2.3.	The source/sink or POR/POD identification and mapping to the model.	
MOD-030-2	R1.2.4.	If the Transmission Service Provider's AFC calculation process involves a grouping of generators, the ATCID must identify how these generators participate in the group.	
MOD-030-2	R2.	The Transmission Operator shall perform the following: [Time Horizon: Operations Planning]	To Be Determined
MOD-030-2	R2.1.	Include Flowgates used in the AFC process based, at a minimum, on the following criteria:	
MOD-030-2	R2.1.1.	Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator's system up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an OTDF of at least 5% and within the Transmission Operator's system are included as Flowgates.	
MOD-030-2	R2.1.1.1.	Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Special Protection Systems.	
MOD-030-2	R2.1.1.2.	Only the most limiting element in a series configuration needs to be included as a Flowgate.	
MOD-030-2	R2.1.1.3.	If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.	
MOD-030-2	R2.1.2.	Results of a first Contingency transfer analysis from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) of at least 5% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology.	
MOD-030-2	R2.1.2.1.	Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Special Protection Systems.	
MOD-030-2	R2.1.2.2.	Only the most limiting element in a series configuration needs to be included as a Flowgate.	
MOD-030-2	R2.1.2.3.	If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
MOD-030-2	R2.1.3.	Any limiting Element/Contingency combination at least within its Reliability Coordinator's Area that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, unless the limiting Element/Contingency combination is accounted for using another ATC methodology or was created to address temporary operating conditions.	
MOD-030-2	R2.1.4.	Any limiting Element/Contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:	
MOD-030-2	R2.1.4.1.	The coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and - Any generator within the Transmission Service Provider's area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or - A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area adjacent has at least a 5% PTDF or OTDF impact on the Flowgate. - The Transmission Operator may utilize distribution factors less than 5% if desired.	
MOD-030-2	R2.1.4.2.	The limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.	
MOD-030-2	R2.2.	At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgate definitions at least once per calendar year.	
MOD-030-2	R2.3.	At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgates that have been requested as part of R2.1.4 within thirty calendar days from the request.	
MOD-030-2	R2.4.	Establish the TFC of each of the defined Flowgates as equal to: - For thermal limits, the System Operating Limit (SOL) of the Flowgate. - For voltage or stability limits, the flow that will respect the SOL of the Flowgate.	
MOD-030-2	R2.5.	At a minimum, establish the TFC once per calendar year.	
MOD-030-2	R2.5.1.	If notified of a change in the Rating by the Transmission Owner that would affect the TFC of a flowgate used in the AFC process, the TFC should be updated within seven calendar days of the notification.	
MOD-030-2	R2.6.	Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.	
MOD-030-2	R3.	The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [Time Horizon: Operations Planning]	To Be Determined
MOD-030-2	R3.1.	Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the Generator Owners of the Facilities within the model.	
MOD-030-2	R3.2.	Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.	
MOD-030-2	R3.3.	Updated at least once per month for AFC calculations for months two through 13.	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
MOD-030-2	R3.4.	Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and Facilities161kV or below is allowed.	
MOD-030-2	R3.5.	Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.	
MOD-030-2	R4.	When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: [Time Horizon: Operations Planning] - If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source. - If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source. - If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source. - If the source, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source. - If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the sink. - If the sink, as specified in the ATCID, has been identified in the reservation and the point can be	To Be Determined
MOD-030-2	R5.	When calculating AFCs, the Transmission Service Provider shall: [Time Horizon: Operations Planning]	To Be Determined
MOD-030-2	R5.1.	Use the models provided by the Transmission Operator.	
MOD-030-2	R5.2.	Include in the transmission model expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the applicable period of the AFC calculation for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.	
MOD-030-2	R5.3.	For external Flowgates, identified in R2.1.4, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.	
MOD-030-2	R6.	When calculating the impact of ETC for firm commitments (ETCFi) for all time periods for a Flowgate, the Transmission Service Provider shall sum the following: [Time Horizon: Operations Planning]	To Be Determined
MOD-030-2	R6.1.	The impact of firm Network Integration Transmission Service, including the impacts of generation to load, in the model referenced in R5.2 for the Transmission Service Provider's area, based on:	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
MOD-030-2	R6.1.1.	Load forecast for the time period being calculated, including Native Load and Network Service load	
MOD-030-2	R6.1.2.	Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.	
MOD-030-2	R6.2.	The impact of any firm Network Integration Transmission Service, including the impacts of generation to load in the model referenced in R5.2 and has a distribution factor equal to or greater than the percentage used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed based on:	
MOD-030-2	R6.2.1.	Load forecast for the time period being calculated, including Native Load and Network Service load	
MOD-030-2	R6.2.2.	Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.	
MOD-030-2	R6.3.	The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider’s area.	
MOD-030-2	R6.4.	The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts having a distribution factor equal to or greater than the percentage used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.	
MOD-030-2	R6.5.	The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider’s area.	
MOD-030-2	R6.6.	The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.	
MOD-030-2	R6.7.	The impact of other firm services determined by the Transmission Service Provider.	
MOD-030-2	R7.	When calculating the impact of ETC for non-firm commitments (ETCNFi) for all time periods for a Flowgate the Transmission Service Provider shall sum: [Time Horizon: Operations Planning]	To Be Determined
MOD-030-2	R7.1.	The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled for the Transmission Service Provider’s area.	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
MOD-030-2	R7.2.	The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, that have a distribution factor equal to or greater than the percentage used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.	
MOD-030-2	R7.3.	The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.	
MOD-030-2	R7.4.	The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.	
MOD-030-2	R7.5.	The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider's area (i.e., secondary service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.	
MOD-030-2	R7.6.	The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.	
MOD-030-2	R7.7.	The impact of other non-firm services determined by the Transmission Service Provider.	
MOD-030-2	R8.	When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [Time Horizon: Operations Planning] ***See Standard for Formula***	To Be Determined
MOD-030-2	R9.	When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [Time Horizon: Operations Planning] ***See Standard for Formula***	To Be Determined
MOD-030-2	R10.	Each Transmission Service Provider shall recalculate AFC, utilizing the updated models described in R3.2, R3.3, and R5, at a minimum on the following frequency, unless none of the calculated values identified in the AFC equation have changed: [Time Horizon: Operations Planning]	To Be Determined
MOD-030-2	R10.1.	For hourly AFC, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the AFC equation.	
MOD-030-2	R10.2.	For daily AFC, once per day.	
MOD-030-2	R10.3.	For monthly AFC, once per week.	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
MOD-030-2	R11.	When converting Flowgate AFCs to ATCs for ATC Paths, the Transmission Service Provider shall convert those values based on the following algorithm: [Time Horizon: Operations Planning] ***See Standard for Formula***	To Be Determined
NUC-001-2	R1.	The Nuclear Plant Generator Operator shall provide the proposed NPIRs in writing to the applicable Transmission Entities and shall verify receipt	LOWER
NUC-001-2	R2.	The Nuclear Plant Generator Operator and the applicable Transmission Entities shall have in effect one or more Agreements that include mutually agreed to NPIRs and document how the Nuclear Plant Generator Operator and the applicable Transmission Entities shall address and implement these NPIRs.	MEDIUM
NUC-001-2	R3.	Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall incorporate the NPIRs into their planning analyses of the electric system and shall communicate the results of these analyses to the Nuclear Plant Generator Operator.	MEDIUM
NUC-001-2	R4.	Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall:	HIGH
NUC-001-2	R4.1.	Incorporate the NPIRs into their operating analyses of the electric system.	
NUC-001-2	R4.2.	Operate the electric system to meet the NPIRs.	
NUC-001-2	R4.3.	Inform the Nuclear Plant Generator Operator when the ability to assess the operation of the electric system affecting NPIRs is lost.	
NUC-001-2	R5.	The Nuclear Plant Generator Operator shall operate per the Agreements developed in accordance with this standard.	HIGH
NUC-001-2	R6.	Per the Agreements developed in accordance with this standard, the applicable Transmission Entities and the Nuclear Plant Generator Operator shall coordinate outages and maintenance activities which affect the NPIRs.	MEDIUM
NUC-001-2	R7.	Per the Agreements developed in accordance with this standard, the Nuclear Plant Generator Operator shall inform the applicable Transmission Entities of actual or proposed changes to nuclear plant design, configuration, operations, limits, protection systems, or capabilities that may impact the ability of the electric system to meet the NPIRs.	HIGH
NUC-001-2	R8.	Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall inform the Nuclear Plant Generator Operator of actual or proposed changes to electric system design, configuration, operations, limits, protection systems, or capabilities that may impact the ability of the electric system to meet the NPIRs.	HIGH
NUC-001-2	R9.	The Nuclear Plant Generator Operator and the applicable Transmission Entities shall include, as a minimum, the following elements within the agreement(s) identified in R2:	MEDIUM
NUC-001-2	R9.1.	Administrative elements:	
NUC-001-2	R9.1.1.	Definitions of key terms used in the agreement.	
NUC-001-2	R9.1.2.	Names of the responsible entities, organizational relationships, and responsibilities related to the NPIRs.	
NUC-001-2	R9.1.3.	A requirement to review the agreement(s) at least every three years.	
NUC-001-2	R9.1.4.	A dispute resolution mechanism.	
NUC-001-2	R9.2.	Technical requirements and analysis:	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
NUC-001-2	R9.2.1.	Identification of parameters, limits, configurations, and operating scenarios included in the NPIRs and, as applicable, procedures for providing any specific data not provided within the agreement.	
NUC-001-2	R9.2.2.	Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs.	
NUC-001-2	R9.2.3.	Types of planning and operational analyses performed specifically to support the NPIRs, including the frequency of studies and types of Contingencies and scenarios required.	
NUC-001-2	R9.3.	Operations and maintenance coordination:	
NUC-001-2	R9.3.1.	Designation of ownership of electrical facilities at the interface between the electric system and the nuclear plant and responsibilities for operational control coordination and maintenance of these facilities.	
NUC-001-2	R9.3.2.	Identification of any maintenance requirements for equipment not owned or controlled by the Nuclear Plant Generator Operator that are necessary to meet the NPIRs.	
NUC-001-2	R9.3.3.	Coordination of testing, calibration and maintenance of on-site and off-site power supply systems and related components.	
NUC-001-2	R9.3.4.	Provisions to address mitigating actions needed to avoid violating NPIRs and to address periods when responsible Transmission Entity loses the ability to assess the capability of the electric system to meet the NPIRs. These provisions shall include responsibility to notify the Nuclear Plant Generator Operator within a specified time frame.	
NUC-001-2	R9.3.5.	Provision for considering, within the restoration process, the requirements and urgency of a nuclear plant that has lost all off-site and on-site AC power.	
NUC-001-2	R9.3.6.	Coordination of physical and cyber security protection of the Bulk Electric System at the nuclear plant interface to ensure each asset is covered under at least one entity's plan.	
NUC-001-2	R9.3.7.	Coordination of the NPIRs with transmission system Special Protection Systems and underfrequency and undervoltage load shedding programs.	
NUC-001-2	R9.4.	Communications and training:	
NUC-001-2	R9.4.1.	Provisions for communications between the Nuclear Plant Generator Operator and Transmission Entities, including communications protocols, notification time requirements, and definitions of terms.	
NUC-001-2	R9.4.2.	Provisions for coordination during an off-normal or emergency event affecting the NPIRs, including the need to provide timely information explaining the event, an estimate of when the system will be returned to a normal state, and the actual time the system is returned to normal.	
NUC-001-2	R9.4.3.	Provisions for coordinating investigations of causes of unplanned events affecting the NPIRs and developing solutions to minimize future risk of such events.	
NUC-001-2	R9.4.4.	Provisions for supplying information necessary to report to government agencies, as related to NPIRs.	
NUC-001-2	R9.4.5.	Provisions for personnel training, as related to NPIRs.	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
PER-001-0.1	R1.	Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.	HIGH
PER-002-0	R1.	Each Transmission Operator and Balancing Authority shall be staffed with adequately trained operating personnel.	HIGH
PER-002-0	R2.	Each Transmission Operator and Balancing Authority shall have a training program for all operating personnel that are in:	HIGH
PER-002-0	R2.1.	Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System.	HIGH
PER-002-0	R2.2.	Positions directly responsible for complying with NERC standards.	HIGH
PER-002-0	R3.	For personnel identified in Requirement R2, the Transmission Operator and Balancing Authority shall provide a training program meeting the following criteria:	HIGH
PER-002-0	R3.1.	A set of training program objectives must be defined, based on NERC and Regional Reliability Organization standards, entity operating procedures, and applicable regulatory requirements. These objectives shall reference the knowledge and competencies needed to apply those standards, procedures, and requirements to normal, emergency, and restoration conditions for the Transmission Operator and Balancing Authority operating positions.	MEDIUM
PER-002-0	R3.2.	The training program must include a plan for the initial and continuing training of Transmission Operator and Balancing Authority operating personnel. That plan shall address knowledge and competencies required for reliable system operations.	MEDIUM
PER-002-0	R3.3.	The training program must include training time for all Transmission Operator and Balancing Authority operating personnel to ensure their operating proficiency.	LOWER
PER-002-0	R3.4.	Training staff must be identified, and the staff must be competent in both knowledge of system operations and instructional capabilities.	LOWER
PER-002-0	R4.	For personnel identified in Requirement R2, each Transmission Operator and Balancing Authority shall provide its operating personnel at least five days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.	HIGH

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
PER-003-0	R1.	Each Transmission Operator, Balancing Authority, and Reliability Coordinator shall staff all operating positions that meet both of the following criteria with personnel that are NERC-certified for the applicable functions:	HIGH
PER-003-0	R1.1.	Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System.	HIGH
PER-003-0	R1.2.	Positions directly responsible for complying with NERC standards.	HIGH
PER-004-1	R1.	Each Reliability Coordinator shall be staffed with adequately trained and NERC-certified Reliability Coordinator operators, 24 hours per day, seven days per week.	HIGH
PER-004-1	R2.	All Reliability Coordinator operating personnel shall each complete a minimum of five days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.	HIGH
PER-004-1	R3.	Reliability Coordinator operating personnel shall have a comprehensive understanding of the Reliability Coordinator Area and interactions with neighboring Reliability Coordinator Areas.	HIGH
PER-004-1	R4.	Reliability Coordinator operating personnel shall have an extensive understanding of the Balancing Authorities, Transmission Operators, and Generation Operators within the Reliability Coordinator Area, including the operating staff, operating practices and procedures, restoration priorities and objectives, outage plans, equipment capabilities, and operational restrictions.	HIGH
PER-004-1	R5.	Reliability Coordinator operating personnel shall place particular attention on SOLs and IROLs and inter-tie facility limits. The Reliability Coordinator shall ensure protocols are in place to allow Reliability Coordinator operating personnel to have the best available information at all times.	HIGH
PRC-001-1	R1.	Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.	HIGH
PRC-001-1	R2.	Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:	HIGH
PRC-001-1	R2.1.	If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.	HIGH

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
PRC-001-1	R2.2.	If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	HIGH
PRC-001-1	R3.	A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.	<blank>
PRC-001-1	R3.1.	Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.	HIGH
PRC-001-1	R3.2.	Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.	HIGH
PRC-001-1	R4.	Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.	HIGH
PRC-001-1	R5.	A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the protection systems of others:	HIGH
PRC-001-1	R5.1.	Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's protection systems.	HIGH
PRC-001-1	R5.2.	Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' protection systems.	HIGH
PRC-001-1	R6.	Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.	HIGH

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
PRC-STD-001-1	WR1.	Each Transmission Operator or Transmission Owner identified in Section 4.1 must submit documentation that an officer of the organization certifies that: a. All protective relay applications are appropriate for the Bulk Power Transmission Paths ("BPTP") identified in Attachment A – Table 2 of this Standard pursuant to applicable WECC Standards and NERC Standards; b. The BPTP protective relay settings and logic are appropriate pursuant to applicable WECC Standards and NERC Standards; c. Since the last certification or for the last three years all network changes in the path, at the terminals of the path, or in nearby facilities that affect operation of the path have been considered in the protective relay application and settings; d. All relay operations since the last certification or during the last three-year period have been analyzed for correctness and appropriate corrective action taken pursuant to applicable WECC Standards and NERC Standards; e. Up-to-date relay information has been provided to the on-shift operating personnel and the appropriate Reliability Coordinator.	
PRC-STD-003-1	WR1.	Owners of protective relays and Remedial Action Schemes (RAS) applied to path elements of selected WECC major transmission path facilities (listed in Attachment A – Table 2) and RAS (listed in Attachment B – Table 3) must take the following action for each known or probable relay misoperation: a. If functionally equivalent protective relaying or RAS remains in service to ensure bulk transmission system reliability; the relay or RAS that misoperated is to be removed from service for repair or modification within 22 hours of the relay or RAS misoperation. The relay or RAS shall be replaced, repaired, or modified such that the incorrect operation will not be repeated. b. If functionally equivalent protective relaying or RAS does not remain in service that will ensure bulk transmission system reliability, and the relay or RAS that misoperated cannot be repaired and placed back in service within 22 hours, the associated transmission path facility must be removed from service. The remaining path facilities, if any, must be de-rated to a reliable operating level. c. If the relay or RAS misoperates and there is some protection but not entirely functionally equivalent, the relay or RAS must be repaired or removed from service within 22 hours. The associated transmission may remain in service; however, system operation must fully comply with WECC and NERC operating standards. This may require an adjustment of operating levels.	
PRC-004-1	R1.	The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1.	HIGH

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
PRC-004-1	R2.	The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for PRC-003 R1.	HIGH
PRC-004-1	R3.	The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.	LOWER
PRC-005-1	R1.	Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:	HIGH
PRC-005-1	R1.1.	Maintenance and testing intervals and their basis.	HIGH
PRC-005-1	R1.2.	Summary of maintenance and testing procedures.	HIGH
PRC-005-1	R2.	Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:	LOWER
PRC-005-1	R2.1.	Evidence Protection System devices were maintained and tested within the defined intervals.	HIGH
PRC-005-1	R2.2.	Date each Protection System device was last tested/maintained.	HIGH

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
PRC-STD-005-1	WR1.	All bulk power transmission elements (i.e. lines, stations and rights of way) included as part of the transmission facilities (or required to maintain transfer capability) impacting each of the transmission paths listed in Attachment A – WECC Table 2 shall be inspected and maintained in accordance with this criterion, taking into consideration diverse environmental and climatic conditions, terrain, equipment, maintenance philosophies, and design practices. a. General This Transmission Maintenance Standard requires each Responsible Entity identified in Section A.4.1 to develop and implement a Transmission Maintenance and Inspection Plan (TMIP) detailing the Responsible Entity's inspection and maintenance activities applicable to the transmission facilities comprising each of the transmission paths identified in Attachment A – Table 2. b. Standard Requirements (i) TMIP To comply with this Standard, each Responsible Entity identified in Section A4.1 must develop and implement a TMIP. • Because maintenance and inspection practices vary, it is the intent of this Transmission Maintenance Standard to allow flexibility in inspection and maintenance practices while still requiring a description of certain specific inspection and maintenance practices. (a) TMIP Contents The TMIP may be performance-based, time-based, conditional¬based, or a combination of all three as may be appropriate. The TMIP shall: • Identify the facilities for which it is covering by listing the names of each transmission path and the quantities of each equipment component, such as; circuit breaker, relay scheme, transmission line; • Include the scheduled interval (e.g., every two years) for any time-based maintenance activities and a description of conditions that will initiate any condition or performance-based activities; • Describe the maintenance, testing and	
PRC-007-0	R1.	The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall ensure that its UFLS program is consistent with its Regional Reliability Organization's UFLS program requirements.	MEDIUM
PRC-007-0	R2.	The Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide, and annually update, its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a UFLSprogram database.	LOWER
PRC-007-0	R3.	The Transmission Owner and Distribution Provider that owns a UFLS program (as required by its Regional Reliability Organization) shall provide its documentation of that UFLS program to its Regional Reliability Organization on request (30 calendar days).	LOWER
PRC-008-0	R1.	The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall have a UFLS equipment maintenance and testing program in place. This UFLS equipment maintenance and testing program shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
PRC-008-0	R2.	The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall implement its UFLS equipment maintenance and testing program and shall provide UFLS maintenance and testing program results to its Regional Reliability Organization and NERC on request (within 30 calendar days).	MEDIUM
PRC-009-0	R1.	The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall analyze and document its UFLS program performance in accordance with its Regional Reliability Organization's UFLS program. The analysis shall address the performance of UFLS equipment and program effectiveness following system events resulting in system frequency excursions below the initializing set points of the UFLS program. The analysis shall include, but not be limited to:	MEDIUM
PRC-009-0	R1.1.	A description of the event including initiating conditions.	MEDIUM
PRC-009-0	R1.2.	A review of the UFLS set points and tripping times.	MEDIUM
PRC-009-0	R1.3.	A simulation of the event.	MEDIUM
PRC-009-0	R1.4.	A summary of the findings.	MEDIUM
PRC-009-0	R2.	The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide documentation of the analysis of the UFLS program to its Regional Reliability Organization and NERC on request 90 calendar days after the system event.	LOWER
PRC-010-0	R1.	The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall periodically (at least every five years or as required by changes in system conditions) conduct and document an assessment of the effectiveness of the UVLS program. This assessment shall be conducted with the associated Transmission Planner(s) and Planning Authority(ies).	MEDIUM
PRC-010-0	R1.1.	This assessment shall include, but is not limited to:	MEDIUM
PRC-010-0	R1.1.1.	Coordination of the UVLS programs with other protection and control systems in the Region and with other Regional Reliability Organizations, as appropriate.	MEDIUM
PRC-010-0	R1.1.2.	Simulations that demonstrate that the UVLS programs performance is consistent with Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
PRC-010-0	R1.1.3.	A review of the voltage set points and timing.	MEDIUM
PRC-010-0	R2.	The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall provide documentation of its current UVLS program assessment to its Regional Reliability Organization and NERC on request (30 calendar days).	LOWER
PRC-011-0	R1.	The Transmission Owner and Distribution Provider that owns a UVLS system shall have a UVLS equipment maintenance and testing program in place. This program shall include:	MEDIUM
PRC-011-0	R1.1.	The UVLS system identification which shall include but is not limited to:	MEDIUM
PRC-011-0	R1.1.1.	Relays.	MEDIUM
PRC-011-0	R1.1.2.	Instrument transformers.	MEDIUM
PRC-011-0	R1.1.3.	Communications systems, where appropriate.	MEDIUM
PRC-011-0	R1.1.4.	Batteries.	MEDIUM
PRC-011-0	R1.2.	Documentation of maintenance and testing intervals and their basis.	MEDIUM
PRC-011-0	R1.3.	Summary of testing procedure.	MEDIUM
PRC-011-0	R1.4.	Schedule for system testing.	MEDIUM
PRC-011-0	R1.5.	Schedule for system maintenance.	MEDIUM
PRC-011-0	R1.6.	Date last tested/maintained.	MEDIUM
PRC-011-0	R2.	The Transmission Owner and Distribution Provider that owns a UVLS system shall provide documentation of its UVLS equipment maintenance and testing program and the implementation of that UVLS equipment maintenance and testing program to its Regional Reliability Organization and NERC on request (within 30 calendar days).	LOWER
PRC-015-0	R1.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall maintain a list of and provide data for existing and proposed SPSs as specified in Reliability Standard PRC-013-0_R 1.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
PRC-015-0	R2.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-0_R1 prior to being placed in service.	MEDIUM
PRC-015-0	R3.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of SPS data and the results of studies that show compliance of new or functionally modified SPSs with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).	LOWER
PRC-016-0.1	R1.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall analyze its SPS operations and maintain a record of all misoperations in accordance with the Regional SPS review procedure specified in Reliability Standard PRC-012-0_R1.	MEDIUM
PRC-016-0.1	R2.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall take corrective actions to avoid future misoperations.	MEDIUM
PRC-016-0.1	R3.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).	LOWER
PRC-017-0	R1.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have a system maintenance and testing program(s) in place. The program(s) shall include:	HIGH
PRC-017-0	R1.1.	SPS identification shall include but is not limited to:	HIGH
PRC-017-0	R1.1.1.	Relays.	HIGH
PRC-017-0	R1.1.2.	Instrument transformers.	HIGH
PRC-017-0	R1.1.3.	Communications systems, where appropriate.	HIGH
PRC-017-0	R1.1.4.	Batteries.	HIGH
PRC-017-0	R1.2.	Documentation of maintenance and testing intervals and their basis.	HIGH
PRC-017-0	R1.3.	Summary of testing procedure.	HIGH

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
PRC-017-0	R1.4.	Schedule for system testing.	HIGH
PRC-017-0	R1.5.	Schedule for system maintenance.	HIGH
PRC-017-0	R1.6.	Date last tested/maintained.	MEDIUM
PRC-017-0	R2.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).	LOWER
PRC-018-1	R1.	Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard PRC-002 Requirements 1-3) shall have DMEs installed that meet the following requirements:	LOWER
PRC-018-1	R1.1.	Internal Clocks in DME devices shall be synchronized to within 2 milliseconds or less of Universal Coordinated Time scale (UTC)	LOWER
PRC-018-1	R1.2.	Recorded data from each Disturbance shall be retrievable for ten calendar days..	LOWER
PRC-018-1	R2.	The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization's installation requirements (reliability standard PRC-002 Requirements 1 through 3).	LOWER
PRC-018-1	R3.	The Transmission Owner and Generator Owner shall each maintain, and report to its Regional Reliability Organization on request, the following data on the DMEs installed to meet that region's installation requirements (reliability standard PRC-002 Requirements1.1, 2.1 and 3.1):	LOWER
PRC-018-1	R3.1.	Type of DME (sequence of event recorder, fault recorder, or dynamic disturbance recorder).	LOWER
PRC-018-1	R3.2.	Make and model of equipment.	LOWER
PRC-018-1	R3.3.	Installation location.	LOWER
PRC-018-1	R3.4.	Operational status.	LOWER
PRC-018-1	R3.5.	Date last tested.	LOWER
PRC-018-1	R3.6.	Monitored elements, such as transmission circuit, bus section, etc.	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
PRC-018-1	R3.7.	Monitored devices, such as circuit breaker, disconnect status, alarms, etc.	LOWER
PRC-018-1	R3.8.	Monitored electrical quantities, such as voltage, current, etc.	LOWER
PRC-018-1	R4.	The Transmission Owner and Generator Owner shall each provide Disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements (reliability standard PRC-002 Requirement 4).	LOWER
PRC-018-1	R5.	The Transmission Owner and Generator Owner shall each archive all data recorded by DMEs for Regional Reliability Organization-identified events for at least three years.	LOWER
PRC-018-1	R6.	Each Transmission Owner and Generator Owner that is required by its Regional Reliability Organization to have DMEs shall have a maintenance and testing program for those DMEs that includes:	LOWER
PRC-018-1	R6.1.	Maintenance and testing intervals and their basis.	LOWER
PRC-018-1	R6.2.	Summary of maintenance and testing procedures.	LOWER
PRC-021-1	R1.	Each Transmission Owner and Distribution Provider that owns a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall annually update its UVLS data to support the Regional UVLS program database. The following data shall be provided to the Regional Reliability Organization for each installed UVLS system:	LOWER
PRC-021-1	R1.1.	Size and location of customer load, or percent of connected load, to be interrupted.	LOWER
PRC-021-1	R1.2.	Corresponding voltage set points and overall scheme clearing times.	MEDIUM
PRC-021-1	R1.3.	Time delay from initiation to trip signal.	LOWER
PRC-021-1	R1.4.	Breaker operating times.	LOWER
PRC-021-1	R1.5.	Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and Special Protection Systems.	LOWER
PRC-021-1	R2.	Each Transmission Owner and Distribution Provider that owns a UVLS program shall provide its UVLS program data to the Regional Reliability Organization within 30 calendar days of a request.	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
PRC-022-1	R1.	Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall analyze and document all UVLS operations and Misoperations. The analysis shall include:	MEDIUM
PRC-022-1	R1.1.	A description of the event including initiating conditions.	LOWER
PRC-022-1	R1.2.	A review of the UVLS set points and tripping times.	MEDIUM
PRC-022-1	R1.3.	A simulation of the event, if deemed appropriate by the Regional Reliability Organization. For most events, analysis of sequence of events may be sufficient and dynamic simulations may not be needed.	LOWER
PRC-022-1	R1.4.	A summary of the findings.	LOWER
PRC-022-1	R1.5.	For any Misoperation, a Corrective Action Plan to avoid future Misoperations of a similar nature.	MEDIUM
PRC-022-1	R2.	Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall provide documentation of its analysis of UVLS program performance to its Regional Reliability Organization within 90 calendar days of a request.	LOWER
PRC-023-1	R1.	Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (R1.1 through R1.13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees: [Mitigation Time Horizon: Long Term Planning].	HIGH
PRC-023-1	R1.1.	Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).	
PRC-023-1	R1.2.	Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating2 of a circuit (expressed in amperes).	
PRC-023-1	R1.3.	Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sendingend and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:	
PRC-023-1	R1.3.1.	An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.	
PRC-023-1	R1.3.2.	An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
PRC-023-1	R1.4.	Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of: - 115% of the highest emergency rating of the series capacitor. - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with R1.3, using the full line inductive reactance.	
PRC-023-1	R1.5.	Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).	
PRC-023-1	R1.6.	Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability.	
PRC-023-1	R1.7.	Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.	
PRC-023-1	R1.8.	Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.	
PRC-023-1	R1.9.	Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.	
PRC-023-1	R1.10.	Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that they do not operate at or below the greater of: - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment. - 115% of the highest operator established emergency transformer rating.	
PRC-023-1	R1.11.	For transformer overload protection relays that do not comply with R1.10 set the relays according to one of the following: - Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater. The protection must allow this overload for at least 15 minutes to allow for the operator to take controlled action to relieve the overload. - Install supervision for the relays using either a top oil or simulated winding hot spot temperature element. The setting should be no less than 100° C for the top oil or 140° C for the winding hot spot temperature3.	
PRC-023-1	R1.12.	When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:	
PRC-023-1	R1.12.1.	Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.	

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
PRC-023-1	R1.12.2.	Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.	
PRC-023-1	R1.12.3.	Include a relay setting component of 87% of the current calculated in R1.12.2 in the Facility Rating determination for the circuit.	
PRC-023-1	R1.13.	Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.	
PRC-023-1	R2.	The Transmission Owner, Generator Owner, or Distribution Provider that uses a circuit capability with the practical limitations described in R1.6, R1.7, R1.8, R1.9, R1.12, or R1.13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. [Time Horizon: Long Term Planning]	MEDIUM
PRC-023-1	R3.	The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities from 100 kV to 200 kV that must meet Requirement 1 to prevent potential cascade tripping that may occur when protective relay settings limit transmission loadability. [Time Horizon: Long Term Planning]	MEDIUM
PRC-023-1	R3.1.	The Planning Coordinator shall have a process to determine the facilities that are critical to the reliability of the Bulk Electric System.	
PRC-023-1	R3.1.1.	This process shall consider input from adjoining Planning Coordinators and affected Reliability Coordinators.	
PRC-023-1	R3.2.	The Planning Coordinator shall maintain a current list of facilities determined according to the process described in R3.1.	
PRC-023-1	R3.3.	The Planning Coordinator shall provide a list of facilities to its Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within 30 days of the establishment of the initial list and within 30 days of any changes to the list.	
TOP-001-1	R1.	Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.	HIGH
TOP-001-1	R2.	Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.	HIGH

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
TOP-001-1	R3.	Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority, or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.	HIGH
TOP-001-1	R4.	Each Distribution Provider and Load-Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load-Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.	HIGH
TOP-001-1	R5.	Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real-time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.	HIGH
TOP-001-1	R6.	Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.	HIGH
TOP-001-1	R7.	Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless:	HIGH
TOP-001-1	R7.1.	For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.	HIGH
TOP-001-1	R7.2.	For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.	HIGH

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
TOP-001-1	R7.3.	When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.	HIGH
TOP-001-1	R8.	During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.	HIGH
TOP-002-2a	R1.	Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.	MEDIUM
TOP-002-2a	R2.	Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.	MEDIUM
TOP-002-2a	R3.	Each Load-Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.	MEDIUM
TOP-002-2a	R4.	Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.	MEDIUM
TOP-002-2a	R5.	Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
TOP-002-2a	R6.	Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.	MEDIUM
TOP-002-2a	R7.	Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.	MEDIUM
TOP-002-2a	R8.	Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.	MEDIUM
TOP-002-2a	R9.	Each Balancing Authority shall plan to meet Interchange Schedules and Ramps.	LOWER
TOP-002-2a	R10.	Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).	MEDIUM
TOP-002-2a	R11.	The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.	MEDIUM
TOP-002-2a	R12.	The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.	MEDIUM
TOP-002-2a	R13.	At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.	MEDIUM
TOP-002-2a	R14.	Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:	MEDIUM
TOP-002-2a	R14.1.	Changes in real output capabilities.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
TOP-002-2a	R14.2.	Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)	LOWER
TOP-002-2a	R15.	Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).	LOWER
TOP-002-2a	R16.	Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to:	MEDIUM
TOP-002-2a	R16.1.	Changes in transmission facility status.	HIGH
TOP-002-2a	R16.2.	Changes in transmission facility rating.	HIGH
TOP-002-2a	R17.	Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.	HIGH
TOP-002-2a	R18.	Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers, and Load-Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.	MEDIUM
TOP-002-2a	R19.	Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.	MEDIUM
TOP-003-0	R1.	Generator Operators and Transmission Operators shall provide planned outage information.	<blank>
TOP-003-0	R1.1.	Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements.	MEDIUM
TOP-003-0	R1.2.	Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
TOP-003-0	R1.3.	Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.	MEDIUM
TOP-003-0	R2.	Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.	MEDIUM
TOP-003-0	R3.	Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.	MEDIUM
TOP-003-0	R4.	Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.	MEDIUM
TOP-004-2	R1.	Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).	HIGH
TOP-004-2	R2.	Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.	HIGH
TOP-004-2	R3.	Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.	HIGH
TOP-004-2	R4.	If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.	HIGH
TOP-004-2	R5.	Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.	HIGH
TOP-004-2	R6.	Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including:	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
TOP-004-2	R6.1.	Monitoring and controlling voltage levels and real and reactive power flows.	MEDIUM
TOP-004-2	R6.2.	Switching transmission elements.	MEDIUM
TOP-004-2	R6.3.	Planned outages of transmission elements.	MEDIUM
TOP-004-2	R6.4.	Responding to IROL and SOL violations.	MEDIUM
TOP-005-1.1	R1.	Each Transmission Operator and Balancing Authority shall provide its Reliability Coordinator with the operating data that the Reliability Coordinator requires to perform operational reliability assessments and to coordinate reliable operations within the Reliability Coordinator Area.	MEDIUM
TOP-005-1.1	R1.1.	Each Reliability Coordinator shall identify the data requirements from the list in Attachment 1-TOP-005-0 “Electric System Reliability Data” and any additional operating information requirements relating to operation of the bulk power system within the Reliability Coordinator Area.	MEDIUM
TOP-005-1.1	R2.	As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for “Electric System Reliability Data.”	LOWER
TOP-005-1.1	R3.	Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.	MEDIUM
TOP-005-1.1	R4.	Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.	MEDIUM
TOP-006-1	R1.	Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use.	MEDIUM
TOP-006-1	R1.1.	Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
TOP-006-1	R1.2.	Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.	MEDIUM
TOP-006-1	R2.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.	HIGH
TOP-006-1	R3.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel.	MEDIUM
TOP-006-1	R4.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.	MEDIUM
TOP-006-1	R5.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.	MEDIUM
TOP-006-1	R6.	Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.	HIGH
TOP-006-1	R7.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.	HIGH
TOP-007-0	R1.	A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits.	HIGH
TOP-007-0	R2.	Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.	HIGH
TOP-007-0	R3.	A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R 2.	HIGH
TOP-007-0	R4.	The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.	HIGH

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
TOP-STD-007-0	WR1.	Operating Transfer Capability Limit Criteria Actual power flow and net scheduled power flow over an interconnection or transfer path shall be maintained within Operating Transfer Capability Limits ("OTC"). The OTC is the maximum amount of actual power that can be transferred over direct or parallel transmission elements comprising: • An interconnection from one Transmission Operator area to another Transmission Operator area; or • A transfer path within a Transmission Operator area. The net schedule over an interconnection or transfer path within a Transmission Operator area shall not exceed the OTC, regardless of the prevailing actual power flow on the interconnection or transfer path. a. Operating limits. No elements within the interconnection shall be scheduled above continuous operating limits. An element is defined as any generating unit, transmission line, transformer, bus, or piece of electrical equipment involved in the transfer of power within an interconnection. b. Stability. The interconnected power system shall remain stable upon loss of any one single element without system cascading that could result in the successive loss of additional elements. The system voltages shall be within acceptable limits defined in the WECC Reliability Criteria for Transmission System Planning. If a single event could cause loss of multiple elements, these shall be considered in lieu of a single element outage.	
TOP-008-1	R1.	The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.	HIGH
TOP-008-1	R2.	Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.	HIGH
TOP-008-1	R3.	The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.	HIGH
TOP-008-1	R4.	The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
TPL-001-0.1	R1.	The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:	HIGH
TPL-001-0.1	R1.1.	Be made annually.	MEDIUM
TPL-001-0.1	R1.2.	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.	MEDIUM
TPL-001-0.1	R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).	MEDIUM
TPL-001-0.1	R1.3.1.	Cover critical system conditions and study years as deemed appropriate by the entity performing the study.	MEDIUM
TPL-001-0.1	R1.3.2.	Be conducted annually unless changes to system conditions do not warrant such analyses.	MEDIUM
TPL-001-0.1	R1.3.3.	Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.	MEDIUM
TPL-001-0.1	R1.3.4.	Have established normal (pre-contingency) operating procedures in place.	MEDIUM
TPL-001-0.1	R1.3.5.	Have all projected firm transfers modeled.	MEDIUM
TPL-001-0.1	R1.3.6.	Be performed for selected demand levels over the range of forecast system demands.	MEDIUM
TPL-001-0.1	R1.3.7.	Demonstrate that system performance meets Table 1 for Category A (no contingencies).	MEDIUM
TPL-001-0.1	R1.3.8.	Include existing and planned facilities.	MEDIUM
TPL-001-0.1	R1.3.9.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
TPL-001-0.1	R1.4.	Address any planned upgrades needed to meet the performance requirements of Category A.	MEDIUM
TPL-001-0.1	R2.	When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0_R1, the Planning Authority and Transmission Planner shall each:	MEDIUM
TPL-001-0.1	R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.	MEDIUM
TPL-001-0.1	R2.1.1.	Including a schedule for implementation.	MEDIUM
TPL-001-0.1	R2.1.2.	Including a discussion of expected required in-service dates of facilities.	MEDIUM
TPL-001-0.1	R2.1.3.	Consider lead times necessary to implement plans.	MEDIUM
TPL-001-0.1	R2.2.	Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.	LOWER
TPL-001-0.1	R3.	The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.	LOWER
TPL-002-0a	R1.	The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:	HIGH
TPL-002-0a	R1.1.	Be made annually.	MEDIUM
TPL-002-0a	R1.2.	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
TPL-002-0a	R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).	MEDIUM
TPL-002-0a	R1.3.1.	Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.	MEDIUM
TPL-002-0a	R1.3.2.	Cover critical system conditions and study years as deemed appropriate by the responsible entity.	MEDIUM
TPL-002-0a	R1.3.3.	Be conducted annually unless changes to system conditions do not warrant such analyses.	MEDIUM
TPL-002-0a	R1.3.4.	Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.	MEDIUM
TPL-002-0a	R1.3.5.	Have all projected firm transfers modeled.	MEDIUM
TPL-002-0a	R1.3.6.	Be performed and evaluated for selected demand levels over the range of forecast system Demands.	MEDIUM
TPL-002-0a	R1.3.7.	Demonstrate that system performance meets Category B contingencies.	MEDIUM
TPL-002-0a	R1.3.8.	Include existing and planned facilities.	MEDIUM
TPL-002-0a	R1.3.9.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.	MEDIUM
TPL-002-0a	R1.3.10.	Include the effects of existing and planned protection systems, including any backup or redundant systems.	MEDIUM
TPL-002-0a	R1.3.11.	Include the effects of existing and planned control devices.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
TPL-002-0a	R1.3.12.	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.	MEDIUM
TPL-002-0a	R1.4.	Address any planned upgrades needed to meet the performance requirements of Category B of Table I.	MEDIUM
TPL-002-0a	R1.5.	Consider all contingencies applicable to Category B.	MEDIUM
TPL-002-0a	R2.	When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1, the Planning Authority and Transmission Planner shall each:	MEDIUM
TPL-002-0a	R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:	MEDIUM
TPL-002-0a	R2.1.1.	Including a schedule for implementation.	MEDIUM
TPL-002-0a	R2.1.2.	Including a discussion of expected required in-service dates of facilities.	MEDIUM
TPL-002-0a	R2.1.3.	Consider lead times necessary to implement plans.	MEDIUM
TPL-002-0a	R2.2.	Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.	MEDIUM
TPL-002-0a	R3.	The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.	LOWER
TPL-003-0a	R1.	The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:	HIGH

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
TPL-003-0a	R1.1.	Be made annually.	MEDIUM
TPL-003-0a	R1.2.	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.	MEDIUM
TPL-003-0a	R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).	MEDIUM
TPL-003-0a	R1.3.1.	Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.	MEDIUM
TPL-003-0a	R1.3.2.	Cover critical system conditions and study years as deemed appropriate by the responsible entity.	MEDIUM
TPL-003-0a	R1.3.3.	Be conducted annually unless changes to system conditions do not warrant such analyses.	MEDIUM
TPL-003-0a	R1.3.4.	Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.	MEDIUM
TPL-003-0a	R1.3.5.	Have all projected firm transfers modeled.	MEDIUM
TPL-003-0a	R1.3.6.	Be performed and evaluated for selected demand levels over the range of forecast system demands.	MEDIUM
TPL-003-0a	R1.3.7.	Demonstrate that System performance meets Table 1 for Category C contingencies.	MEDIUM
TPL-003-0a	R1.3.8.	Include existing and planned facilities.	MEDIUM
TPL-003-0a	R1.3.9.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.	MEDIUM
TPL-003-0a	R1.3.10.	Include the effects of existing and planned protection systems, including any backup or redundant systems.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
TPL-003-0a	R1.3.11.	Include the effects of existing and planned control devices.	MEDIUM
TPL-003-0a	R1.3.12.	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.	MEDIUM
TPL-003-0a	R1.4.	Address any planned upgrades needed to meet the performance requirements of Category C.	MEDIUM
TPL-003-0a	R1.5.	Consider all contingencies applicable to Category C.	MEDIUM
TPL-003-0a	R2.	When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0_R1, the Planning Authority and Transmission Planner shall each:	MEDIUM
TPL-003-0a	R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:	MEDIUM
TPL-003-0a	R2.1.1.	Including a schedule for implementation.	MEDIUM
TPL-003-0a	R2.1.2.	Including a discussion of expected required in-service dates of facilities.	MEDIUM
TPL-003-0a	R2.1.3.	Consider lead times necessary to implement plans.	MEDIUM
TPL-003-0a	R2.2.	Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.	MEDIUM
TPL-003-0a	R3.	The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.	LOWER
TPL-004-0	R1.	The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:	MEDIUM
TPL-004-0	R1.1.	Be made annually.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
TPL-004-0	R1.2.	Be conducted for near-term (years one through five).	MEDIUM
TPL-004-0	R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).	MEDIUM
TPL-004-0	R1.3.1.	Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.	MEDIUM
TPL-004-0	R1.3.2.	Cover critical system conditions and study years as deemed appropriate by the responsible entity.	MEDIUM
TPL-004-0	R1.3.3.	Be conducted annually unless changes to system conditions do not warrant such analyses.	MEDIUM
TPL-004-0	R1.3.4.	Have all projected firm transfers modeled.	MEDIUM
TPL-004-0	R1.3.5.	Include existing and planned facilities.	MEDIUM
TPL-004-0	R1.3.6.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.	MEDIUM
TPL-004-0	R1.3.7.	Include the effects of existing and planned protection systems, including any backup or redundant systems.	MEDIUM
TPL-004-0	R1.3.8.	Include the effects of existing and planned control devices.	MEDIUM
TPL-004-0	R1.3.9.	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.	MEDIUM
TPL-004-0	R1.4.	Consider all contingencies applicable to Category D.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
TPL-004-0	R2.	The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.	LOWER
VAR-001-1	R1.	Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators.	HIGH
VAR-001-1	R2.	Each Transmission Operator shall acquire sufficient reactive resources within its area to protect the voltage levels under normal and Contingency conditions. This includes the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.	HIGH
VAR-001-1	R3.	The Transmission Operator shall specify criteria that exempts generators from compliance with the requirements defined in Requirement 4, and Requirement 6.1.	LOWER
VAR-001-1	R3.1.	Each Transmission Operator shall maintain a list of generators in its area that are exempt from following a voltage or Reactive Power schedule.	LOWER
VAR-001-1	R3.2.	For each generator that is on this exemption list, the Transmission Operator shall notify the associated Generator Owner.	LOWER
VAR-001-1	R4.	Each Transmission Operator shall specify a voltage or Reactive Power schedule at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (AVR in service and controlling voltage).	MEDIUM
VAR-001-1	R5.	Each Purchasing-Selling Entity shall arrange for (self-provide or purchase) reactive resources to satisfy its reactive requirements identified by its Transmission Service Provider.	HIGH
VAR-001-1	R6.	The Transmission Operator shall know the status of all transmission Reactive Power resources, including the status of voltage regulators and power system stabilizers.	MEDIUM
VAR-001-1	R6.1.	When notified of the loss of an automatic voltage regulator control, the Transmission Operator shall direct the Generator Operator to maintain or change either its voltage schedule or its Reactive Power schedule.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
VAR-001-1	R7.	The Transmission Operator shall be able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow.	HIGH
VAR-001-1	R8.	Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including reactive generation scheduling; transmission line and reactive resource switching; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits.	HIGH
VAR-001-1	R9.	Each Transmission Operator shall maintain reactive resources to support its voltage under first Contingency conditions.	HIGH
VAR-001-1	R9.1.	Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when Contingencies occur.	HIGH
VAR-001-1	R10.	Each Transmission Operator shall correct IROL or SOL violations resulting from reactive resource deficiencies (IROL violations must be corrected within 30 minutes) and complete the required IROL or SOL violation reporting.	HIGH
VAR-001-1	R11.	After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.	LOWER
VAR-001-1	R12.	The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.	HIGH
VAR-002-1.1a	R1.	The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.	MEDIUM
VAR-002-1.1a	R2.	Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings. [1] as directed by the Transmission Operator	MEDIUM
VAR-002-1.1a	R2.1.	When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.	MEDIUM

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
VAR-002-1.1a	R2.2.	When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.	MEDIUM
VAR-002-1.1a	R3.	Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:	MEDIUM
VAR-002-1.1a	R3.1.	A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.	MEDIUM
VAR-002-1.1a	R3.2.	A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.	MEDIUM
VAR-002-1.1a	R4.	The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.	LOWER
VAR-002-1.1a	R4.1.	For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:	LOWER
VAR-002-1.1a	R4.1.1.	Tap settings.	LOWER
VAR-002-1.1a	R4.1.2.	Available fixed tap ranges.	LOWER
VAR-002-1.1a	R4.1.3.	Impedance data.	LOWER
VAR-002-1.1a	R4.1.4.	The +/- voltage range with step-change in % for load-tap changing transformers.	LOWER
VAR-002-1.1a	R5.	After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement.	MEDIUM
VAR-002-1.1a	R5.1.	If the Generator Operator can't comply with the Transmission Operator's specifications, the Generator Operator shall notify the Transmission Operator and shall provide the technical justification.	LOWER

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Standard Number	Requirement Number	Text of Requirement	Violation Risk Factors
VAR-STD-002a-1	WR1.	Automatic voltage control equipment on synchronous generators shall be kept in service at all times, unless one of the exemptions listed in Section C (Measures) applies, with outages coordinated to minimize the number out of service at any one time. All synchronous generators with automatic voltage control equipment shall normally be operated in voltage control mode and set to respond effectively to voltage deviations. (Source: WECC Criterion)	
VAR-STD-002b-1	WR1.	Power System Stabilizers on generators shall be kept in service at all times, unless one of the exemptions listed in Section C (Measures) applies, and shall be properly tuned in accordance with WECC requirements. (Source: WECC Criterion)	

Exhibit G

Matrix of Violation Severity Levels for Approval

Complete Violation Severity Levels Matrix

Encompassing All FERC-Approved Reliability Standards

Complete Violation Severity Level Matrix (BAL) Encompassing All FERC-Approved Reliability Standards

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
BAL-001-0.1a	R1.	Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating Committee. ***See Standard for Formula.***	The Balancing Authority Area's value of CPS1 is less than 100% but greater than or equal to 95%.	The Balancing Authority Area's value of CPS1 is less than 95% but greater than or equal to 90%.	The Balancing Authority Area's value of CPS1 is less than 90% but greater than or equal to 85%.	The Balancing Authority Area's value of CPS1 is less than 85%.
BAL-001-0.1a	R2.	Each Balancing Authority shall operate such that its average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit, referred to as L_{10}. ***See Standard for Formula.***	The Balancing Authority Area's value of CPS2 is less than 90% but greater than or equal to 85%.	The Balancing Authority Area's value of CPS2 is less than 85% but greater than or equal to 80%.	The Balancing Authority Area's value of CPS2 is less than 80% but greater than or equal to 75%.	The Balancing Authority Area's value of CPS2 is less than 75%.
BAL-001-0.1a	R3.	Each Balancing Authority providing Overlap Regulation Service shall evaluate Requirement R1 (i.e., Control Performance Standard 1 or CPS1) and Requirement R2 (i.e., Control Performance Standard 2 or CPS2) using the characteristics of the combined ACE and combined Frequency Bias Settings.	N/A	N/A	N/A	The Balancing Authority providing Overlap Regulation Service failed to use a combined ACE and frequency bias.
BAL-001-0.1a	R4.	Any Balancing Authority receiving Overlap Regulation Service shall not	N/A	N/A	N/A	The Balancing Authority receiving

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		have its control performance evaluated (i.e. from a control performance perspective, the Balancing Authority has shifted all control requirements to the Balancing Authority providing Overlap Regulation Service).				Overlap Regulation Service failed to ensure that control performance was being evaluated in a manner consistent with the calculation methodology as described in BAL-001-01 R3.
BAL-002-0	R1.	Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.	N/A	N/A	N/A	The Balancing Authority does not have access to and/or operate Contingency Reserve to respond to Disturbances.
BAL-002-0	R1.1.	A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such cases, the Reserve Sharing Group shall have the same responsibilities and obligations as each Balancing Authority with respect to monitoring and meeting the requirements of Standard BAL-002.	N/A	N/A	N/A	The Balancing Authority has elected to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group and the Reserve Sharing Group has not provided the same responsibilities and obligations as required of the responsible entity with respect to monitoring and meeting the requirements of Standard BAL-002.
BAL-002-0	R2.	Each Regional Reliability Organization, sub-Regional Reliability	The Regional Reliability	The Regional Reliability	The Regional Reliability	The Regional Reliability

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including:	Organization, sub-Regional Reliability Organization, or Reserve Sharing Group has failed to specify 1 of the following sub-requirements.	Organization, sub-Regional Reliability Organization, or Reserve Sharing Group has failed to specify 2 or 3 of the following sub-requirements.	Organization, sub-Regional Reliability Organization, or Reserve Sharing Group has failed to specify 4 or 5 of the following sub-requirements.	Organization, sub-Regional Reliability Organization, or Reserve Sharing Group has failed to specify all 6 of the following sub-requirements.
BAL-002-0	R2.1.	The minimum reserve requirement for the group.	N/A	N/A	N/A	The Regional Reliability Organization, sub-Regional Reliability Organization, or Reserve Sharing Group has failed to specify the minimum reserve requirement for the group.
BAL-002-0	R2.2.	Its allocation among members.	N/A	N/A	N/A	The Regional Reliability Organization, sub-Regional Reliability Organization, or Reserve Sharing Group has failed to specify the allocation of reserves among members.
BAL-002-0	R2.3.	The permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve.	N/A	N/A	N/A	The Regional Reliability Organization, sub-Regional Reliability Organization, or Reserve Sharing Group has failed to specify the permissible mix of Operating Reserve –

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve.
BAL-002-0	R2.4.	The procedure for applying Contingency Reserve in practice.	N/A	N/A	N/A	The Regional Reliability Organization, sub-Regional Reliability Organization, or Reserve Sharing Group has failed to provide the procedure for applying Contingency Reserve in practice.
BAL-002-0	R2.5.	The limitations, if any, upon the amount of interruptible load that may be included.	N/A	N/A	N/A	The Regional Reliability Organization, sub-Regional Reliability Organization, or Reserve Sharing Group has failed to specify the limitations, if any, upon the amount of interruptible load that may be included.
BAL-002-0	R2.6.	The same portion of resource capacity (e.g., reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by multiple Balancing Authorities.	N/A	N/A	N/A	The Regional Reliability Organization, sub-Regional Reliability Organization, or Reserve Sharing Group has allowed the same portion of resource capacity (e.g., reserves from jointly owned generation) to be

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						counted more than once as Contingency Reserve by multiple Balancing Authorities.
BAL-002-0	R3.	Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS.	The Balancing Authority or Reserve Sharing Group's Average Percent Recovery per the NERC DCS quarterly report was less than 100% but greater than or equal to 95%.	The Balancing Authority or Reserve Sharing Group's Average Percent Recovery per the NERC DCS quarterly report was less than 95% but greater than or equal to 90%.	The Balancing Authority or Reserve Sharing Group's Average Percent Recovery per the NERC DCS quarterly report was less than 90% but greater than or equal to 85%.	The Balancing Authority or Reserve Sharing Group's Average Percent Recovery per the NERC DCS quarterly report was less than 85%.
BAL-002-0	R3.1.	As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency. All Balancing Authorities and Reserve Sharing Groups shall review, no less frequently than annually, their probable contingencies to determine their prospective most severe single contingencies.	The Balancing Authority or Reserve Sharing Group failed to review their probable contingencies to determine their prospective most severe single contingencies annually.	N/A	N/A	The Balancing Authority or Reserve Sharing Group failed to carry at least enough Contingency Reserve to cover the most severe single contingency.
BAL-002-0	R4.	A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:	The Balancing Authority or Reserve Sharing Group met the Disturbance Recovery Criterion within the Disturbance Recovery Period for more than 90% and less than 100% of Reportable Disturbances.	The Balancing Authority or Reserve Sharing Group met the Disturbance Recovery Criterion within the Disturbance Recovery Period for more than 80% and less than or equal to 90% of Reportable Disturbances.	The Balancing Authority or Reserve Sharing Group met the Disturbance Recovery Criterion within the Disturbance Recovery Period for more than 70% and less than or equal to 80% of Reportable Disturbances.	The Balancing Authority or Reserve Sharing Group met the Disturbance Recovery Criterion within the Disturbance Recovery Period for more than 0% and less than or equal to 70% of Reportable Disturbances.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
BAL-002-0	R4.1.	A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.	N/A	N/A	N/A	The Balancing Authority failed to return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero or for negative initial ACE values failed to return ACE to its pre-Disturbance value.
BAL-002-0	R4.2.	The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee.	N/A	N/A	N/A	N/A
BAL-002-0	R5.	Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Balancing Authority.) Compliance may be demonstrated by either of the following two methods:	The Reserve Sharing Group met the DCS requirement for more than 90% and less than 100% of Reportable Disturbances.	The Reserve Sharing Group met the DCS requirements for more than 80% and less than or equal to 90% of Reportable Disturbances.	The Reserve Sharing Group met the DCS requirements for more than 70% and less than or equal to 80% of Reportable Disturbances.	The Reserve Sharing Group met the DCS requirements for more than 0% and less than or equal to 70% of Reportable Disturbances.
BAL-002-0	R5.1.	The Reserve Sharing Group reviews	N/A	N/A	N/A	N/A

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.				
BAL-002-0	R5.2.	The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.	N/A	N/A	N/A	N/A
BAL-002-0	R6.	A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period for its Interconnection.	The Balancing Authority or Reserve Sharing Group restored less than 100% but greater than 90% of its contingency reserves during the Contingency Reserve Restoration Period.	The Balancing Authority or Reserve Sharing Group restored less than or equal to 90% but greater than 80% of its contingency reserves during the Contingency Reserve Restoration Period.	The Balancing Authority or Reserve Sharing Group restored less than or equal to 80% but greater than or equal to 70% of its Contingency Reserve during the Contingency Reserve Restoration Period.	The Balancing Authority or Reserve Sharing Group restored less than 70% of its Contingency Reserves during the Contingency Reserve Restoration Period.
BAL-002-0	R6.1.	The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period.	N/A	N/A	N/A	N/A
BAL-002-0	R6.2.	The default Contingency Reserve Restoration Period is 90 minutes. This period may be adjusted to better suit the reliability targets of the	N/A	N/A	N/A	N/A

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Interconnection based on analysis approved by the NERC Operating Committee.				
BAL-003-0.1b	R1.	Each Balancing Authority shall review its Frequency Bias Settings by January 1 of each year and recalculate its setting to reflect any change in the Frequency Response of the Balancing Authority Area.	N/A	N/A	The Balancing Authority reviewed its Frequency Bias Settings prior January 1, but failed to recalculate its setting to reflect any change in the Frequency Response of the Balancing Authority Area.	The Balancing Authority failed to review its Frequency Bias Settings prior to January 1, and failed to recalculate its setting to reflect any change in the Frequency Response of the Balancing Authority Area.
BAL-003-0.1b	R1.1.	The Balancing Authority may change its Frequency Bias Setting, and the method used to determine the setting, whenever any of the factors used to determine the current bias value change.	N/A	N/A	N/A	The Balancing Authority changed its Frequency Bias Setting by changing the method used to determine the setting, without any of the factors used to determine the current bias value changing.
BAL-003-0.1b	R1.2.	Each Balancing Authority shall report its Frequency Bias Setting, and method for determining that setting, to the NERC Operating Committee.	The Balancing Authority has not reported its method for calculating frequency bias setting.	The Balancing Authority has not reported its frequency bias setting.	The Balancing Authority has not reported its method for calculating frequency bias and has not reported its frequency bias setting.	The Balancing Authority has failed to report as directed by the requirement.
BAL-003-0.1b	R2.	Each Balancing Authority shall establish and maintain a Frequency Bias Setting that is as close as practical to, or greater than, the Balancing Authority's Frequency Response. Frequency Bias may be	N/A	N/A	N/A	The Balancing Authority established and maintained a Frequency Bias Setting that was less than, the Balancing Authority's

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		calculated several ways:				Frequency Response.
BAL-003-0.1b	R2.1.	The Balancing Authority may use a fixed Frequency Bias value which is based on a fixed, straight-line function of Tie Line deviation versus Frequency Deviation. The Balancing Authority shall determine the fixed value by observing and averaging the Frequency Response for several Disturbances during on-peak hours.	N/A	N/A	N/A	The Balancing Authority determination of the fixed Frequency Bias value was not based on observations and averaging the Frequency Response from Disturbances during on-peak hours.
BAL-003-0.1b	R2.2.	The Balancing Authority may use a variable (linear or non-linear) bias value, which is based on a variable function of Tie Line deviation to Frequency Deviation. The Balancing Authority shall determine the variable frequency bias value by analyzing Frequency Response as it varies with factors such as load, generation, governor characteristics, and frequency.	N/A	N/A	N/A	The Balancing Authorities variable frequency bias maintained was not based on analyses of Frequency Response as it varied with factors such as load, generation, governor characteristics, and frequency.
BAL-003-0.1b	R3.	Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection reliability.	N/A	N/A	N/A	The Balancing Authority did not operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, during periods when such operation would not have been adverse to system or Interconnection reliability.
BAL-003-0.1b	R4.	Balancing Authorities that use Dynamic Scheduling or Pseudo-ties for jointly owned units shall reflect	N/A	N/A	N/A	The Balancing Authority that used Dynamic Scheduling

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		their respective share of the unit governor droop response in their respective Frequency Bias Setting.				or Pseudo-ties for jointly owned units did not reflect their respective share of the unit governor droop response in their respective Frequency Bias Setting.
BAL-003-0.1b	R4.1.	Fixed schedules for Jointly Owned Units mandate that Balancing Authority (A) that contains the Jointly Owned Unit must incorporate the respective share of the unit governor droop response for any Balancing Authorities that have fixed schedules (B and C). See the diagram below.	N/A	N/A	N/A	The Balancing Authority (A) that contained the Jointly Owned Unit with fixed schedules did not incorporate the respective share of the unit governor droop response for any Balancing Authorities that have fixed schedules (B and C).
BAL-003-0.1b	R4.2.	The Balancing Authorities that have a fixed schedule (B and C) but do not contain the Jointly Owned Unit shall not include their share of the governor droop response in their Frequency Bias Setting. ***See Standard for Graphic***	N/A	N/A	N/A	The Balancing Authorities that have a fixed schedule (B and C) but do not contain the Jointly Owned Unit, included their share of the governor droop response in their Frequency Bias Setting.
BAL-003-0.1b	R5.	Balancing Authorities that serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of the Balancing Authority's estimated yearly peak demand per 0.1 Hz change.	N/A	N/A	N/A	The Balancing Authority that served native load failed to have a monthly average Frequency Bias Setting that was at least 1% of the entities

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						estimated yearly peak demand per 0.1 Hz change.
BAL-003-0.1b	R5.1.	Balancing Authorities that do not serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of its estimated maximum generation level in the coming year per 0.1 Hz change.	N/A	N/A	N/A	The Balancing Authority that does not serve native load did not have a monthly average Frequency Bias Setting that was at least 1% of its estimated maximum generation level in the coming year per 0.1 Hz change.
BAL-003-0.1b	R6.	A Balancing Authority that is performing Overlap Regulation Service shall increase its Frequency Bias Setting to match the frequency response of the entire area being controlled. A Balancing Authority shall not change its Frequency Bias Setting when performing Supplemental Regulation Service.	N/A	The Balancing Authority that was performing Overlap Regulation Service changed its Frequency Bias Setting while performing Supplemental Regulation Service.	The Balancing Authority that was performing Overlap Regulation Service failed to increase its Frequency Bias Setting to match the frequency response of the entire area being controlled.	N/A
BAL-004-0	R1.	Only a Reliability Coordinator shall be eligible to act as Interconnection Time Monitor. A single Reliability Coordinator in each Interconnection shall be designated by the NERC Operating Committee to serve as Interconnection Time Monitor.	N/A	N/A	N/A	The responsible entity has designated more than one interconnection time monitor for a single interconnection.
BAL-004-0	R2.	The Interconnection Time Monitor shall monitor Time Error and shall initiate or terminate corrective action orders in accordance with the NAESB Time Error Correction Procedure.	N/A	N/A	N/A	The RC serving as the Interconnection Time Monitor failed to initiate or terminate corrective action orders in accordance with the NAESB Time

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						Error Correction Procedure.
BAL-004-0	R3.	Each Balancing Authority, when requested, shall participate in a Time Error Correction by one of the following methods:	The Balancing Authority participated in more than 75% and less than 100% of requested Time Error Corrections for the calendar year.	The Balancing Authority participated in more than 50% and less than or equal to 75% of requested Time Error Corrections for the calendar year.	The Balancing Authority participated in more than 25% and less than or equal to 50% of requested Time Error Corrections for the calendar year.	The Balancing Authority participated in less than or equal to 25% of requested Time Error Corrections for the calendar year.
BAL-004-0	R3.1.	The Balancing Authority shall offset its frequency schedule by 0.02 Hertz, leaving the Frequency Bias Setting normal; or	The Balancing Authority failed to offset its frequency schedule by 0.02 Hertz and leave their Frequency Bias Setting normal for 0 to 25% of the time error corrections for the year.	The Balancing Authority failed to offset its frequency schedule by 0.02 Hertz and leave their Frequency Bias Setting normal for 25 to 50% of the time error corrections for the year.	The Balancing Authority failed to offset its frequency schedule by 0.02 Hertz and leave their Frequency Bias Setting normal for 50 to 75% of the time error corrections for the year.	The Balancing Authority failed to offset its frequency schedule by 0.02 Hertz and leave their Frequency Bias Setting normal for 75% or more of the time error corrections for the year.
BAL-004-0	R.3.2.	The Balancing Authority shall offset its Net Interchange Schedule (MW) by an amount equal to the computed bias contribution during a 0.02 Hertz Frequency Deviation (i.e. 20% of the Frequency Bias Setting).	The Balancing Authority failed to offset its net interchange schedule frequency schedule by 20% of their frequency bias for 0 to 25% of the time error corrections.	The Balancing Authority failed to offset its net interchange schedule frequency schedule by 20% of their frequency bias for 25 to 50% of the time error corrections.	The Balancing Authority failed to offset its net interchange schedule frequency schedule by 20% of their frequency bias for 50 to 75% of the time error corrections.	The Balancing Authority failed to offset its net interchange schedule frequency schedule by 20% of their frequency bias for 75% or more of the time error corrections.
BAL-004-0	R4.	Any Reliability Coordinator in an Interconnection shall have the authority to request the Interconnection Time Monitor to terminate a Time Error Correction in progress, or a scheduled Time Error Correction that has not begun, for	N/A	N/A	N/A	The RC serving as the Interconnection Time Monitor failed to initiate or terminate corrective action orders in accordance with the NAESB Time Error Correction

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		reliability considerations.				Procedure.
BAL-004-0	R4.1.	Balancing Authorities that have reliability concerns with the execution of a Time Error Correction shall notify their Reliability Coordinator and request the termination of a Time Error Correction in progress.	N/A	N/A	N/A	The Balancing Authority with reliability concerns failed to notify the Reliability Coordinator and request the termination of a Time Error Correction in progress.
BAL-005-0.1b	R1.	All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.	N/A	N/A	N/A	N/A
BAL-005-0.1b	R1.1.	Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.	N/A	N/A	N/A	The Generator Operator with generation facilities operating in an Interconnection failed to ensure that those generation facilities were included within metered boundaries of a Balancing Authority Area.
BAL-005-0.1b	R1.2.	Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.	N/A	N/A	N/A	The Transmission Operator with transmission facilities operating in an Interconnection failed to ensure that those transmission facilities were included within metered boundaries of a Balancing Authority

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						Area.
BAL-005-0.1b	R1.3.	Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a Balancing Authority Area.	N/A	N/A	N/A	The Load-Serving Entity with load operating in an Interconnection failed to ensure that those loads were included within metered boundaries of a Balancing Authority Area.
BAL-005-0.1b	R2.	Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.	N/A	N/A	N/A	The Balancing Authority failed to maintain Regulating Reserve that can be controlled by AGC to meet Control Performance Standard.
BAL-005-0.1b	R3.	A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications and control equipment are employed to prevent such service from becoming a Burden on the Interconnection or other Balancing Authority Areas.	N/A	N/A	N/A	The Balancing Authority providing Regulation Service failed to ensure adequate metering, communications, and control equipment was provided.
BAL-005-0.1b	R4.	A Balancing Authority providing Regulation Service shall notify the Host Balancing Authority for whom it is controlling if it is unable to provide the service, as well as any Intermediate Balancing Authorities.	N/A	N/A	N/A	The Balancing Authority providing Regulation Service failed to notify the Host Balancing Authority for whom it is controlling if it was unable to provide the service, as well as any Intermediate Balancing

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						Authorities.
BAL-005-0.1b	R5.	A Balancing Authority receiving Regulation Service shall ensure that backup plans are in place to provide replacement Regulation Service should the supplying Balancing Authority no longer be able to provide this service.	N/A	N/A	N/A	The Balancing Authority receiving Regulation Service failed to ensure that back-up plans were in place to provide replacement Regulation Service.
BAL-005-0.1b	R6.	The Balancing Authority's AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's ACE. Single Balancing Authorities operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control. If a Balancing Authority is unable to calculate ACE for more than 30 minutes it shall notify its Reliability Coordinator.	The Balancing Authority failed to notify the Reliability Coordinator within 30 minutes of its inability to calculate ACE.	The Balancing Authority failed to calculate ACE as specified in the requirement.	N/A	The Balancing Authority failed to notify the Reliability Coordinator within 30 minutes of its inability to calculate ACE and failed to use the ACE calculation specified in the requirement in its attempt to calculate ACE.
BAL-005-0.1b	R7.	The Balancing Authority shall operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become inoperative, the Balancing Authority shall use manual control to adjust generation to maintain the Net Scheduled Interchange.	N/A	N/A	N/A	The Balancing Authority failed to operate AGC continuously when there were no adverse impacts OR if their AGC was inoperative the Balancing Authority failed to use manual control to adjust generation to maintain the Net Scheduled Interchange.
BAL-005-0.1b	R8.	The Balancing Authority shall ensure that data acquisition for and	N/A	N/A	N/A	The Balancing Authority failed to

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		calculation of ACE occur at least every six seconds.				ensure that data acquisition for and calculation of ACE occurred at least every six seconds.
BAL-005-0.1b	R8.1.	Each Balancing Authority shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide a minimum availability of 99.95%.	N/A	N/A		The Balancing Authority failed to provide redundant and independent frequency metering equipment that automatically activated upon detection of failure, such that the minimum availability was less than 99.95%.
BAL-005-0.1b	R9.	The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.	N/A	N/A	N/A	The Balancing Authority failed to include all Interchanged Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.
BAL-005-0.1b	R9.1.	Balancing Authorities with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection may choose to omit the Interchange Schedule related to the HVDC link from the ACE equation if it is modeled as internal generation or load.	N/A	N/A	N/A	The Balancing Authority with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection chose to omit the Interchange Schedule related to the HVDC link from the

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						ACE equation. but failed to model it as internal generation or load.
BAL-005-0.1b	R10.	The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.	N/A	N/A	N/A	The Balancing Authority failed to include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.
BAL-005-0.1b	R11.	Balancing Authorities shall include the effect of Ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE.	N/A	N/A	N/A	The Balancing Authority failed to include the effect of Ramp rates in the Scheduled Interchange values to calculate ACE.
BAL-005-0.1b	R12.	Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.	N/A	N/A	N/A	The Balancing Authority failed to include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.
BAL-005-0.1b	R12.1.	Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment. Balancing Authorities shall ensure that megawatt-hour data is telemetered or reported at the end of each hour.	N/A	N/A	N/A	The Balancing Authority failed to ensure Tie Line MW metering was telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Balancing Authority failed to ensure that megawatt-hour data is telemetered or reported at the end of each hour.
BAL-005-0.1b	R12.2.	Balancing Authorities shall ensure the power flow and ACE signals that are utilized for calculating Balancing Authority performance or that are transmitted for Regulation Service are not filtered prior to transmission, except for the Anti-aliasing Filters of Tie Lines.	N/A	N/A	N/A	The Balancing Authority failed to ensure the power flow and ACE signals that are utilized for calculating Balancing Authority performance or that are transmitted for Regulation Service were filtered prior to transmission, except for the Anti-aliasing Filters of Tie Lines.
BAL-005-0.1b	R12.3.	Balancing Authorities shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more Balancing Authorities to deliver the output of Jointly Owned Units or to serve remote load.	N/A	N/A	N/A	The Balancing Authority failed to install common metering equipment where Dynamic Schedules or Pseudo-Ties were implemented between two or more Balancing Authorities to deliver the output of Jointly Owned Units or to serve remote load.
BAL-005-0.1b	R13.	Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the accuracy of its control	N/A	N/A	N/A	The Balancing Authority failed to perform hourly error checks using Tie Line megawatt-hour meters

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		equipment. The Balancing Authority shall adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error (IME) term of the ACE equation to compensate for any equipment error until repairs can be made.				with common time synchronization to determine the accuracy of its control equipment OR the Balancing Authority failed to adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error (IME) term of the ACE equation to compensate for any equipment error until repairs can be made.
BAL-005-0.1b	R14.	The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the Balancing Authority shall provide its operating personnel with real-time values for ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.	N/A	N/A	N/A	The Balancing Authority failed to provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance.
BAL-005-0.1b	R15.	The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority's control center and other critical locations to ensure continuous operation of AGC and vital data	N/A	N/A	The Balancing Authority failed to periodically test backup power supplies at the Balancing Authority's control center and other	The Balancing Authority failed to provide adequate and reliable backup power supplies to ensure continuous operation of AGC and vital data

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		recording equipment during loss of the normal power supply.			critical locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.	recording equipment during loss of the normal power supply.
BAL-005-0.1b	R16.	The Balancing Authority shall sample data at least at the same periodicity with which ACE is calculated. The Balancing Authority shall flag missing or bad data for operator display and archival purposes. The Balancing Authority shall collect coincident data to the greatest practical extent, i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time.	The Balancing Authority failed to collect coincident data to the greatest practical extent.	N/A	The Balancing Authority failed to flag missing or bad data for operator display and archival purposes.	The Balancing Authority failed to sample data at least at the same periodicity with which ACE is calculated.
BAL-005-0.1b	R17.	Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below: ***See Standard for Values***	N/A	N/A	N/A	The Balancing Authority failed to at least annually check and calibrate its time error and frequency devices against a common reference.
BAL-006-1.1	R1.	Each Balancing Authority shall calculate and record hourly Inadvertent Interchange.	N/A	N/A	N/A	Each Balancing Authority failed to calculate and record hourly Inadvertent Interchange.
BAL-006-1.1	R2.	Each Balancing Authority shall include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. The Balancing Authority shall take into account interchange	N/A	N/A	The Balancing Authority failed to include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its	The Balancing Authority failed to include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		served by jointly owned generators.			Inadvertent Interchange account. OR Failed to take into account interchange served by jointly owned generators.	Inadvertent Interchange account. AND Failed to take into account interchange served by jointly owned generators.
BAL-006-1.1	R3.	Each Balancing Authority shall ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities.	N/A	N/A	N/A	The Balancing Authority failed to ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities.
BAL-006-1.1	R4.	Adjacent Balancing Authority Areas shall operate to a common Net Interchange Schedule and Actual Net Interchange value and shall record these hourly quantities, with like values but opposite sign. Each Balancing Authority shall compute its Inadvertent Interchange based on the following:	The Balancing Authority failed to record Actual Net Interchange values that are equal but opposite in sign to its Adjacent Balancing Authorities.	The Balancing Authority failed to compute Inadvertent Interchange.	The Balancing Authority failed to operate to a common Net Interchange Schedule that is equal but opposite to its Adjacent Balancing Authorities.	N/A
BAL-006-1.1	R4.1.	Each Balancing Authority, by the end of the next business day, shall agree with its Adjacent Balancing Authorities to:	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly values of Net Interchanged

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						Schedule. AND The hourly integrated megawatt-hour values of Net Actual Interchange.
BAL-006-1.1	R4.1.1.	The hourly values of Net Interchange Schedule.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly values of Net Interchanged Schedule.
BAL-006-1.1	R4.1.2.	The hourly integrated megawatt-hour values of Net Actual Interchange.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly integrated megawatt-hour values of Net Actual Interchange.
BAL-006-1.1	R4.2.	Each Balancing Authority shall use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month.	N/A	N/A	N/A	The Balancing Authority failed to use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month.
BAL-006-1.1	R4.3.	A Balancing Authority shall make	N/A	N/A	N/A	The Balancing

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		after-the-fact corrections to the agreed-to daily and monthly accounting data only as needed to reflect actual operating conditions (e.g. a meter being used for control was sending bad data). Changes or corrections based on non-reliability considerations shall not be reflected in the Balancing Authority's Inadvertent Interchange. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the Adjacent Balancing Authority(ies).				Authority failed to make after-the-fact corrections to the agreed-to daily and monthly accounting data to reflect actual operating conditions or changes or corrections based on non-reliability considerations were reflected in the Balancing Authority's Inadvertent Interchange.
BAL-006-1.1	R5.	Adjacent Balancing Authorities that cannot mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month shall, for the purposes of dispute resolution, submit a report to their respective Regional Reliability Organization Survey Contact. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy.	Adjacent Balancing Authorities that could not mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities, submitted a report to their respective Regional Reliability Organizations Survey Contact describing the nature and the cause of the dispute but failed to provide a process for correcting the discrepancy.	Adjacent Balancing Authorities that could not mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month, failed to submit a report to their respective Regional Reliability Organizations Survey Contact describing the nature and the cause of the dispute as well as a process for correcting the discrepancy.	N/A	N/A

Complete Violation Severity Level Matrix (CIP)
Encompassing All FERC-Approved Reliability Standards

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
CIP-001-1	R1.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall have procedures for the recognition of and for making their operating personnel aware of sabotage events on its facilities and multi site sabotage affecting larger portions of the Interconnection.	N/A	N/A	The responsible entity has procedures for the recognition of sabotage events on its facilities and multi site sabotage affecting larger portions of the Interconnection but does not have a procedure for making their operating personnel aware of said events.	The responsible entity failed to have procedures for the recognition of and for making their operating personnel aware of sabotage events on its facilities and multi site sabotage affecting larger portions of the Interconnection.
CIP-001-1	R2.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall have procedures for the communication of information concerning sabotage events to appropriate parties in the Interconnection.	N/A	N/A	The responsible entity has demonstrated the existence of a procedure to communicate information concerning sabotage events, but not all of the appropriate parties in the interconnection are identified.	The responsible entity failed to have a procedure for communicating information concerning sabotage events.
CIP-001-1	R3.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall provide its operating personnel with sabotage response guidelines, including personnel to contact, for reporting disturbances due to sabotage events.	N/A	The responsible entity has demonstrated the existence of a response guideline for reporting disturbances due to sabotage events, but the guideline did not list all of the appropriate personnel to contact.	The responsible entity has demonstrated the existence of a response guideline for reporting disturbances due to sabotage events, including all of the appropriate personnel to contact, but the guideline was not available to its	The responsible entity failed to have a response guideline for reporting disturbances due to sabotage events.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
					operating personnel.	
CIP-001-1	R4.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall establish communications contacts, as applicable, with local Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP) officials and develop reporting procedures as appropriate to their circumstances.	N/A	N/A	The responsible entity has established communications contacts, as applicable, with local Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP) officials, but has not developed a reporting procedure.	The responsible entity failed to establish communications contacts, as applicable, with local Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP) officials, nor developed a reporting procedure.
CIP-002-1	R1.	Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.	N/A	N/A	N/A	The responsible entity has not documented a risk-based assessment methodology to use to identify its Critical Assets as specified in R1.
CIP-002-1	R1.1	The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.	N/A	The Responsible Entity maintained documentation describing its risk-based assessment methodology which includes evaluation criteria, but does not include procedures. .	The Responsible Entity maintained documentation describing its risk-based assessment methodology that includes procedures but does not include evaluation criteria.	The Responsible Entity did not maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.
CIP-002-1	R1.2	The risk-based assessment shall consider the following assets:	N/A	N/A	N/A	The Responsible Entity did not consider all of the asset types listed in R1.2.1 through R1.2.7 in its risk-based assessment.
CIP-002-1	R1.2.1.	Control centers and backup control centers	N/A	N/A	N/A	N/A

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		performing the functions of the entities listed in the Applicability section of this standard.				
CIP-002-1	R1.2.2.	Transmission substations that support the reliable operation of the Bulk Electric System.	N/A	N/A	N/A	N/A
CIP-002-1	R1.2.3.	Generation resources that support the reliable operation of the Bulk Electric System.	N/A	N/A	N/A	N/A
CIP-002-1	R1.2.4.	Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration.	N/A	N/A	N/A	N/A
CIP-002-1	R1.2.5.	Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.	N/A	N/A	N/A	N/A
CIP-002-1	R1.2.6.	Special Protection Systems that support the reliable operation of the Bulk Electric System.	N/A	N/A	N/A	N/A
CIP-002-1	R1.2.7.	Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.	N/A	N/A	N/A	N/A
CIP-002-1	R2.	Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.	N/A	N/A	The Responsible Entity has developed a list of Critical Assets but the list has not been reviewed and updated annually as required.	The Responsible Entity did not develop a list of its identified Critical Assets even if such list is null.
CIP-002-1	R3.	Critical Cyber Asset Identification — Using the list of Critical Assets developed	N/A	N/A	The Responsible Entity has developed a	The Responsible Entity did not develop

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		pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:			list of associated Critical Cyber Assets essential to the operation of the Critical Asset list as per requirement R2 but the list has not been reviewed and updated annually as required.	a list of associated Critical Cyber Assets essential to the operation of the Critical Asset list as per requirement R2 even if such list is null.
CIP-002-1	R3.1	The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,	N/A	N/A	N/A	A Cyber Asset essential to the operation of the Critical Asset was identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.
CIP-002-1	R3.2.	The Cyber Asset uses a routable protocol within a control center; or,	N/A	N/A	N/A	A Cyber Asset essential to the operation of the Critical Asset was identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.
CIP-002-1	R3.3.	The Cyber Asset is dial-up accessible.	N/A	N/A	N/A	A Cyber Asset

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						essential to the operation of the Critical Asset was identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.
CIP-002-1	R4.	Annual Approval — A senior manager or delegate(s) shall approve annually the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of the senior manager or delegate(s)'s approval of the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)	N/A	N/A	The Responsible Entity does not have a signed and dated record of the senior manager or delegate(s)'s annual approval of the list of Critical Assets. OR The Responsible Entity does not have a signed and dated record of the senior manager or delegate(s)'s annual approval of the list of Critical Cyber Assets (even if such lists are null.)	The Responsible Entity does not have a signed and dated record of the senior manager or delegate(s)'s annual approval of **both** the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)
CIP-003-1	R1.	Cyber Security Policy — The Responsible Entity shall document and implement a cyber security policy that represents management's commitment and ability to secure its Critical Cyber Assets. The Responsible Entity shall, at minimum, ensure the following:	N/A	N/A	The Responsible Entity has documented but not implemented a cyber security policy.	The Responsible Entity has not documented nor implemented a cyber security policy.
CIP-003-1	R1.1.	The cyber security policy addresses the requirements in Standards CIP-002 through	N/A	N/A	N/A	The Responsible Entity's cyber security

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		CIP-009, including provision for emergency situations.				policy does not address all the requirements in Standards CIP-002 through CIP-009, including provision for emergency situations.
CIP-003-1	R1.2.	The cyber security policy is readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets.	N/A	N/A	N/A	The Responsible Entity's cyber security policy is not readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets.
CIP-003-1	R1.3	Annual review and approval of the cyber security policy by the senior manager assigned pursuant to R2.	N/A	N/A	The Responsible Entity's senior manager, assigned pursuant to R2, annually reviewed but did not annually approve its cyber security policy.	The Responsible Entity's senior manager, assigned pursuant to R2, did not annually review **nor** approve its cyber security policy.
CIP-003-1	R2.	Leadership — The Responsible Entity shall assign a senior manager with overall responsibility for leading and managing the entity's implementation of, and adherence to, Standards CIP-002 through CIP-009.	N/A	N/A	N/A	The Responsible Entity has not assigned a senior manager with overall responsibility for leading and managing the entity's implementation of, and adherence to, Standards CIP-002 through CIP-009.
CIP-003-1	R2.1.	The senior manager shall be identified by name, title, business phone, business address, and date of designation.	N/A	The senior manager is identified by name, title, and date of designation but the	The senior manager is identified by business phone and business address but the	The senior manager is not identified by name, title, business phone, business

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				designation is missing business phone or business address	designation is missing one of the following: name, title, or date of designation	address, and date of designation.
CIP-003-1	R2.2.	Changes to the senior manager must be documented within thirty calendar days of the effective date.	Changes to the senior manager were documented in greater than 30 but less than 60 days of the effective date.	Changes to the senior manager were documented in 60 or more but less than 90 days of the effective date.	Changes to the senior manager were documented in 90 or more but less than 120 days of the effective date.	Changes to the senior manager were documented in 120 or more days of the effective date.
CIP-003-1	R2.3.	The senior manager or delegate(s), shall authorize and document any exception from the requirements of the cyber security policy.	N/A	N/A	N/A	The senior manager or delegate(s) did not authorize and document any exception from the requirements of the cyber security policy as required.
CIP-003-1	R3.	Exceptions — Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and authorized by the senior manager or delegate(s).	N/A	N/A	In Instances where the Responsible Entity cannot conform to its cyber security policy (pertaining to CIP 002 through CIP 009), exceptions were documented, **but** were not authorized by the senior manager or delegate(s).	In Instances where the Responsible Entity cannot conform to its cyber security policy (pertaining to CIP 002 through CIP 009), exceptions were not documented, **and** were not authorized by the senior manager or delegate(s).
CIP-003-1	R3.1.	Exceptions to the Responsible Entity's cyber security policy must be documented within thirty days of being approved by the senior manager or delegate(s).	Exceptions to the Responsible Entity's cyber security policy were documented in more than 30 but less than 60 days of being approved by the senior manager or	Exceptions to the Responsible Entity's cyber security policy were documented in 60 or more but less than 90 days of being approved by the senior manager or	Exceptions to the Responsible Entity's cyber security policy were documented in 90 or more but less than 120 days of being approved by the senior manager or	Exceptions to the Responsible Entity's cyber security policy were documented in 120 or more days of being approved by the senior manager or delegate(s).

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			delegate(s).	delegate(s).	delegate(s).	
CIP-003-1	R3.2.	Documented exceptions to the cyber security policy must include an explanation as to why the exception is necessary and any compensating measures, or a statement accepting risk.	N/A	N/A	The Responsible Entity has a documented exception to the cyber security policy (pertaining to CIP 002 through CIP 009) but did not include **either**: 1) an explanation as to why the exception is necessary, or 2) any compensating measures or a statement accepting risk.	The Responsible Entity has a documented exception to the cyber security policy (pertaining to CIP 002 through CIP 009) but did not include **both:** 1) an explanation as to why the exception is necessary, and 2) any compensating measures or a statement accepting risk.
CIP-003-1	R3.3.	Authorized exceptions to the cyber security policy must be reviewed and approved annually by the senior manager or delegate(s) to ensure the exceptions are still required and valid. Such review and approval shall be documented.	N/A	N/A	Exceptions to the cyber security policy (pertaining to CIP 002 through CIP 009) were reviewed but not approved annually by the senior manager or delegate(s) to ensure the exceptions are still required and valid.	Exceptions to the cyber security policy (pertaining to CIP 002 through CIP 009) were not reviewed **nor** approved annually by the senior manager or delegate(s) to ensure the exceptions are still required and valid.
CIP-003-1	R4.	Information Protection — The Responsible Entity shall implement and document a program to identify, classify, and protect information associated with Critical Cyber Assets.	N/A	The Responsible Entity implemented but did not document a program to identify, classify, and protect information associated with Critical Cyber Assets.	The Responsible Entity documented but did not implement a program to identify, classify, and protect information associated with Critical Cyber Assets.	The Responsible Entity did not implement nor document a program to identify, classify, and protect information associated with Critical Cyber Assets.
CIP-003-1	R4.1.	The Critical Cyber Asset information to be	N/A	N/A	The information	The information

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		protected shall include, at a minimum and regardless of media type, operational procedures, lists as required in Standard CIP-002, network topology or similar diagrams, floor plans of computing centers that contain Critical Cyber Assets, equipment layouts of Critical Cyber Assets, disaster recovery plans, incident response plans, and security configuration information.			protection program does not include one of the minimum information types to be protected as detailed in R4.1.	protection program does not include two or more of the minimum information types to be protected as detailed in R4.1.
CIP-003-1	R4.2.	The Responsible Entity shall classify information to be protected under this program based on the sensitivity of the Critical Cyber Asset information.	N/A	N/A	N/A	The Responsible Entity did not classify the information to be protected under this program based on the sensitivity of the Critical Cyber Asset information.
CIP-003-1	R4.3.	The Responsible Entity shall, at least annually, assess adherence to its Critical Cyber Asset information protection program, document the assessment results, and implement an action plan to remediate deficiencies identified during the assessment.	N/A	The Responsible Entity annually assessed adherence to its Critical Cyber Asset information protection program, documented the assessment results, which included deficiencies identified during the assessment but did not implement a remediation plan.	The Responsible Entity annually assessed adherence to its Critical Cyber Asset information protection program, did not document the assessment results, and did not implement a remediation plan.	The Responsible Entity did not annually, assess adherence to its Critical Cyber Asset information protection program, document the assessment results, **nor** implement an action plan to remediate deficiencies identified during the assessment.
CIP-003-1	R5.	Access Control — The Responsible Entity shall document and implement a program for managing access to protected Critical Cyber Asset information.	N/A	The Responsible Entity implemented but did not document a program for managing access to protected Critical Cyber Asset	The Responsible Entity documented but did not implement a program for managing access to protected Critical Cyber Asset	The Responsible Entity did not implement nor document a program for managing access to protected Critical

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				information.	information.	Cyber Asset information.
CIP-003-1	R5.1.	The Responsible Entity shall maintain a list of designated personnel who are responsible for authorizing logical or physical access to protected information.	N/A	N/A	The Responsible Entity maintained a list of designated personnel for authorizing either logical or physical access but not both.	The Responsible Entity did not maintain a list of designated personnel who are responsible for authorizing logical or physical access to protected information.
CIP-003-1	R5.1.1.	Personnel shall be identified by name, title, business phone and the information for which they are responsible for authorizing access.	N/A	N/A	The Responsible Entity did identify the personnel by name, title, business phone but did not identify the information for which they are responsible for authorizing access.	The Responsible Entity did not identify the personnel by name, title, business phone nor the information for which they are responsible for authorizing access.
CIP-003-1	R5.1.2.	The list of personnel responsible for authorizing access to protected information shall be verified at least annually.	N/A	N/A	N/A	The Responsible Entity did not verify at least annually the list of personnel responsible for authorizing access to protected information.
CIP-003-1	R5.2.	The Responsible Entity shall review at least annually the access privileges to protected information to confirm that access privileges are correct and that they correspond with the Responsible Entity's needs and appropriate personnel roles and responsibilities.	N/A	N/A	N/A	The Responsible Entity did not review at least annually the access privileges to protected information to confirm that access privileges are correct and that they correspond with the Responsible Entity's needs and appropriate personnel roles and

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						responsibilities.
CIP-003-1	R5.3.	The Responsible Entity shall assess and document at least annually the processes for controlling access privileges to protected information.	N/A	N/A	N/A	The Responsible Entity did not assess and document at least annually the processes for controlling access privileges to protected information.
CIP-003-1	R6.	Change Control and Configuration Management — The Responsible Entity shall establish and document a process of change control and configuration management for adding, modifying, replacing, or removing Critical Cyber Asset hardware or software, and implement supporting configuration management activities to identify, control and document all entity or vendor related changes to hardware and software components of Critical Cyber Assets pursuant to the change control process.	The Responsible Entity has established but not documented a change control process OR The Responsible Entity has established but not documented a configuration management process.	The Responsible Entity has established but not documented both a change control process and configuration management process.	The Responsible Entity has not established and documented a change control process OR The Responsible Entity has not established and documented a configuration management process.	The Responsible Entity has not established and documented a change control process AND The Responsible Entity has not established and documented a configuration management process.
CIP-004-1	R1.	Awareness — The Responsible Entity shall establish, maintain, and document a security awareness program to ensure personnel having authorized cyber or authorized unescorted physical access receive on-going reinforcement in sound security practices. The program shall include security awareness reinforcement on at least a quarterly basis using mechanisms such as: • Direct communications (e.g., emails, memos, computer based training, etc.); • Indirect communications (e.g., posters, intranet, brochures, etc.); • Management support and reinforcement	The Responsible Entity established and maintained but did not document a security awareness program to ensure personnel having authorized cyber or authorized unescorted physical access receive on-going reinforcement in sound security practices.	The Responsible Entity established and maintained but did not document a security awareness program to ensure personnel having authorized cyber or authorized unescorted physical access receive on-going reinforcement in sound security practices. AND The Responsible Entity did not provide	The Responsible Entity did document but did not establish nor maintain a security awareness program to ensure personnel having authorized cyber or authorized unescorted physical access receive on-going reinforcement in sound security practices.	The Responsible Entity did not establish, maintain, nor document a security awareness program to ensure personnel having authorized cyber or authorized unescorted physical access receive on-going reinforcement in sound security practices.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		(e.g., presentations, meetings, etc.).		security awareness reinforcement on at least a quarterly basis.		
CIP-004-1	R2.	Training — The Responsible Entity shall establish, maintain, and document an annual cyber security training program for personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets, and review the program annually and update as necessary.	The Responsible Entity established and maintained but did not document an annual cyber security training program for personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets.	The Responsible Entity established and maintained but did not document an annual cyber security training program for personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets AND The Responsible Entity did not review the training program on an annual basis.	The Responsible Entity did document but did not establish nor maintain an annual cyber security training program for personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets.	The Responsible Entity did not establish, maintain, nor document an annual cyber security training program for personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets.
CIP-004-1	R2.1.	This program will ensure that all personnel having such access to Critical Cyber Assets, including contractors and service vendors, are trained within ninety calendar days of such authorization.	At least one individual but less than 5% of personnel having access to Critical Cyber Assets, including contractors and service vendors, were not trained within ninety calendar days of such authorization.	At least 5% but less than 10% of all personnel having access to Critical Cyber Assets, including contractors and service vendors, were not trained within ninety calendar days of such authorization.	At least 10% but less than 15% of all personnel having access to Critical Cyber Assets, including contractors and service vendors, were not trained within ninety calendar days of such authorization.	15% or more of all personnel having access to Critical Cyber Assets, including contractors and service vendors, were not trained within ninety calendar days of such authorization.
CIP-004-1	R2.2.	Training shall cover the policies, access controls, and procedures as developed for the Critical Cyber Assets covered by CIP-004, and include, at a minimum, the following required items appropriate to personnel roles and responsibilities:	N/A	The training does not include one of the minimum topics as detailed in R2.2.1, R2.2.2, R2.2.3, R2.2.4.	The training does not include two of the minimum topics as detailed in R2.2.1, R2.2.2, R2.2.3, R2.2.4.	The training does not include three or more of the minimum topics as detailed in R2.2.1, R2.2.2, R2.2.3, R2.2.4.

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CIP-004-1	R2.2.1.	The proper use of Critical Cyber Assets;	N/A	N/A	N/A	N/A
CIP-004-1	R2.2.2.	Physical and electronic access controls to Critical Cyber Assets;	N/A	N/A	N/A	N/A
CIP-004-1	R2.2.3.	The proper handling of Critical Cyber Asset information; and,	N/A	N/A	N/A	N/A
CIP-004-1	R2.2.4.	Action plans and procedures to recover or re-establish Critical Cyber Assets and access thereto following a Cyber Security Incident.	N/A	N/A	N/A	N/A
CIP-004-1	R2.3.	The Responsible Entity shall maintain documentation that training is conducted at least annually, including the date the training was completed and attendance records.	N/A	N/A	The Responsible Entity did maintain documentation that training is conducted at least annually, but did not include either the date the training was completed or attendance records.	The Responsible Entity did not maintain documentation that training is conducted at least annually, including the date the training was completed or attendance records.
CIP-004-1	R3.	Personnel Risk Assessment —The Responsible Entity shall have a documented personnel risk assessment program, in accordance with federal, state, provincial, and local laws, and subject to existing collective bargaining unit agreements, for personnel having authorized cyber or authorized unescorted physical access. A personnel risk assessment shall be conducted pursuant to that program within thirty days of such personnel being granted such access. Such program shall at a minimum include:	N/A	The Responsible Entity has a personnel risk assessment program, in accordance with federal, state, provincial, and local laws, and subject to existing collective bargaining unit agreements, for personnel having authorized cyber or authorized unescorted physical access, but the program is not documented.	The Responsible Entity has a personnel risk assessment program as stated in R3, but conducted the personnel risk assessment pursuant to that program in more than thirty (30) days of such personnel being granted such access.	The Responsible Entity does not have a documented personnel risk assessment program, in accordance with federal, state, provincial, and local laws, and subject to existing collective bargaining unit agreements, for personnel having authorized cyber or authorized unescorted physical access.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Responsible Entity did not conduct the personnel risk assessment pursuant to that program for personnel granted such access.
CIP-004-1	R3.1.	The Responsible Entity shall ensure that each assessment conducted include, at least, identity verification (e.g., Social Security Number verification in the U.S.) and seven year criminal check. The Responsible Entity may conduct more detailed reviews, as permitted by law and subject to existing collective bargaining unit agreements, depending upon the criticality of the position.	N/A	N/A	The Responsible Entity did not ensure that an assessment conducted included an identity verification (e.g., Social Security Number verification in the U.S.) **or** a seven-year criminal check.	The Responsible Entity did not ensure that each assessment conducted include, at least, identity verification (e.g., Social Security Number verification in the U.S.) and seven-year criminal check.
CIP-004-1	R3.2.	The Responsible Entity shall update each personnel risk assessment at least every seven years after the initial personnel risk assessment or for cause.	N/A	The Responsible Entity did not update each personnel risk assessment at least every seven years after the initial personnel risk assessment but did update it for cause when applicable.	The Responsible Entity did not update each personnel risk assessment for cause (when applicable) but did at least updated it every seven years after the initial personnel risk assessment.	The Responsible Entity did not update each personnel risk assessment at least every seven years after the initial personnel risk assessment nor was it updated for cause when applicable.
CIP-004-1	R3.3.	The Responsible Entity shall document the results of personnel risk assessments of its personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets, and that personnel risk assessments of contractor and service vendor personnel with such access are conducted pursuant to Standard CIP-004.	The Responsible Entity did not document the results of personnel risk assessments for at least one individual but less than 5% of all personnel with authorized cyber or	The Responsible Entity did not document the results of personnel risk assessments for 5% or more but less than 10% of all personnel with authorized cyber or authorized	The Responsible Entity did not document the results of personnel risk assessments for 10% or more but less than 15% of all personnel with authorized cyber or authorized	The Responsible Entity did not document the results of personnel risk assessments for 15% or more of all personnel with authorized cyber or authorized unescorted

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			authorized unescorted physical access to Critical Cyber Assets, pursuant to Standard CIP-004.	unescorted physical access to Critical Cyber Assets, pursuant to Standard CIP-004.	unescorted physical access to Critical Cyber Assets, pursuant to Standard CIP-004.	physical access to Critical Cyber Assets, pursuant to Standard CIP-004.
CIP-004-1	R4.	Access — The Responsible Entity shall maintain list(s) of personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including their specific electronic and physical access rights to Critical Cyber Assets.	The Responsible Entity did not maintain complete list(s) of personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including their specific electronic and physical access rights to Critical Cyber Assets, missing at least one individual but less than 5% of the authorized personnel.	The Responsible Entity did not maintain complete list(s) of personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including their specific electronic and physical access rights to Critical Cyber Assets, missing 5% or more but less than 10% of the authorized personnel.	The Responsible Entity did not maintain complete list(s) of personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including their specific electronic and physical access rights to Critical Cyber Assets, missing 10% or more but less than 15%of the authorized personnel.	The Responsible Entity did not maintain complete list(s) of personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including their specific electronic and physical access rights to Critical Cyber Assets, missing 15% or more of the authorized personnel.
CIP-004-1	R4.1.	The Responsible Entity shall review the list(s) of its personnel who have such access to Critical Cyber Assets quarterly, and update the list(s) within seven calendar days of any change of personnel with such access to Critical Cyber Assets, or any change in the access rights of such personnel. The Responsible Entity shall ensure access list(s) for contractors and service vendors are properly maintained.	N/A	The Responsible Entity did not review the list(s) of its personnel who have access to Critical Cyber Assets quarterly.	The Responsible Entity did not update the list(s) within seven calendar days of any change of personnel with such access to Critical Cyber Assets, nor any change in the access rights of such personnel.	The Responsible Entity did not review the list(s) of all personnel who have access to Critical Cyber Assets quarterly, nor update the list(s) within seven calendar days of any change of personnel with such access to Critical Cyber Assets, nor any change in the access rights of such personnel.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
CIP-004-1	R4.2.	The Responsible Entity shall revoke such access to Critical Cyber Assets within 24 hours for personnel terminated for cause and within seven calendar days for personnel who no longer require such access to Critical Cyber Assets.	N/A	The Responsible Entity did not revoke access within seven calendar days for personnel who no longer require such access to Critical Cyber Assets.	The Responsible Entity did not revoke access to Critical Cyber Assets within 24 hours for personnel terminated for cause.	The Responsible Entity did not revoke access to Critical Cyber Assets within 24 hours for personnel terminated for cause nor within seven calendar days for personnel who no longer require such access to Critical Cyber Assets.
CIP-005-1	R1.	Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The Responsible Entity shall identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s).	The Responsible Entity did not document one or more access points to the electronic security perimeter(s).	The Responsible Entity identified but did not document one or more Electronic Security Perimeter(s).	The Responsible Entity did not ensure that one or more of the Critical Cyber Assets resides within an Electronic Security Perimeter. OR The Responsible Entity did not identify nor document one or more Electronic Security Perimeter(s).	The Responsible Entity did not ensure that one or more Critical Cyber Assets resides within an Electronic Security Perimeter, and the Responsible Entity did not identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s) for all Critical Cyber Assets.
CIP-005-1	R1.1.	Access points to the Electronic Security Perimeter(s) shall include any externally connected communication end point (for example, dial-up modems) terminating at any device within the Electronic Security Perimeter(s).	N/A	N/A	N/A	Access points to the Electronic Security Perimeter(s) do not include all externally connected communication end point (for example, dial-up modems) terminating at any device within the Electronic Security

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						Perimeter(s).
CIP-005-1	R1.2.	For a dial-up accessible Critical Cyber Asset that uses a non-routable protocol, the Responsible Entity shall define an Electronic Security Perimeter for that single access point at the dial-up device.	N/A	N/A	N/A	For one or more dial-up accessible Critical Cyber Assets that use a non-routable protocol, the Responsible Entity did not define an Electronic Security Perimeter for that single access point at the dial-up device.
CIP-005-1	R1.3.	Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points of these communication links within the Electronic Security Perimeter(s) shall be considered access points to the Electronic Security Perimeter(s).	N/A	N/A	N/A	At least one end point of a communication link within the Electronic Security Perimeter(s) connecting discrete Electronic Security Perimeters was not considered an access point to the Electronic Security Perimeter.
CIP-005-1	R1.4.	Any non-critical Cyber Asset within a defined Electronic Security Perimeter shall be identified and protected pursuant to the requirements of Standard CIP-005.	N/A	One or more non-critical Cyber Asset within a defined Electronic Security Perimeter is not identified but is protected pursuant to the requirements of Standard CIP-005.	One or more non-critical Cyber Asset within a defined Electronic Security Perimeter is identified but not protected pursuant to the requirements of Standard CIP-005.	One or more non-critical Cyber Asset within a defined Electronic Security Perimeter is not identified and is not protected pursuant to the requirements of Standard CIP-005.
CIP-005-1	R1.5.	Cyber Assets used in the access control and monitoring of the Electronic Security Perimeter(s) shall be afforded the protective measures as a specified in Standard CIP-003, Standard CIP-004 Requirement R3,	A Cyber Asset used in the access control and monitoring of the Electronic Security Perimeter(s) is	A Cyber Asset used in the access control and monitoring of the Electronic Security Perimeter(s) is	A Cyber Asset used in the access control and monitoring of the Electronic Security Perimeter(s) is	A Cyber Asset used in the access control and monitoring of the Electronic Security Perimeter(s) is not

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Standard CIP-005 Requirements R2 and R3, Standard CIP-006 Requirements R2 and R3, Standard CIP-007, Requirements R1 and R3 through R9, Standard CIP-008, and Standard CIP-009.	provided with all but one (1) of the protective measures as specified in Standard CIP-003, Standard CIP-004 Requirement R3, Standard CIP-005 Requirements R2 and R3, Standard CIP-006 Requirements R2 and R3, Standard CIP-007, Requirements R1 and R3 through R9, Standard CIP-008, and Standard CIP-009.	provided with all but two (2) of the protective measures as specified in Standard CIP-003, Standard CIP-004 Requirement R3, Standard CIP-005 Requirements R2 and R3, Standard CIP-006 Requirements R2 and R3, Standard CIP-007, Requirements R1 and R3 through R9, Standard CIP-008, and Standard CIP-009.	provided all but three (3) of the protective measures as specified in Standard CIP-003, Standard CIP-004 Requirement R3, Standard CIP-005 Requirements R2 and R3, Standard CIP-006 Requirements R2 and R3, Standard CIP-007, Requirements R1 and R3 through R9, Standard CIP-008, and Standard CIP-009.	provided four (4) or more of the protective measures as specified in Standard CIP-003, Standard CIP-004 Requirement R3, Standard CIP-005 Requirements R2 and R3, Standard CIP-006 Requirements R2 and R3, Standard CIP-007, Requirements R1 and R3 through R9, Standard CIP-008, and Standard CIP-009.
CIP-005-1	R1.6.	The Responsible Entity shall maintain documentation of Electronic Security Perimeter(s), all interconnected Critical and non-critical Cyber Assets within the Electronic Security Perimeter(s), all electronic access points to the Electronic Security Perimeter(s) and the Cyber Assets deployed for the access control and monitoring of these access points.	N/A	N/A	The Responsible Entity did not maintain documentation of one of the following: Electronic Security Perimeter(s), interconnected Critical and non-critical Cyber Assets within the Electronic Security Perimeter(s), electronic access point to the Electronic Security Perimeter(s) or Cyber Asset deployed for the access control and monitoring of these access points.	The Responsible Entity did not maintain documentation of two or more of the following: Electronic Security Perimeter(s), interconnected Critical and non-critical Cyber Assets within the Electronic Security Perimeter(s), electronic access points to the Electronic Security Perimeter(s) and Cyber Assets deployed for the access control and monitoring of these access points.
CIP-005-1	R2.	Electronic Access Controls — The	N/A	The Responsible	The Responsible	The Responsible

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for control of electronic access at all electronic access points to the Electronic Security Perimeter(s).		Entity implemented but did not document the organizational processes and technical and procedural mechanisms for control of electronic access at all electronic access points to the Electronic Security Perimeter(s).	Entity documented but did not implement the organizational processes and technical and procedural mechanisms for control of electronic access at all electronic access points to the Electronic Security Perimeter(s).	Entity did not implement nor document the organizational processes and technical and procedural mechanisms for control of electronic access at all electronic access points to the Electronic Security Perimeter(s).
CIP-005-1	R2.1.	These processes and mechanisms shall use an access control model that denies access by default, such that explicit access permissions must be specified.	N/A	N/A	N/A	The processes and mechanisms did not use an access control model that denies access by default, such that explicit access permissions must be specified.
CIP-005-1	R2.2.	At all access points to the Electronic Security Perimeter(s), the Responsible Entity shall enable only ports and services required for operations and for monitoring Cyber Assets within the Electronic Security Perimeter, and shall document, individually or by specified grouping, the configuration of those ports and services.	N/A	At one or more access points to the Electronic Security Perimeter(s), the Responsible Entity did not document, individually or by specified grouping, the configuration of those ports and services required for operation and for monitoring Cyber Assets within the Electronic Security Perimeter.	At one or more access points to the Electronic Security Perimeter(s), the Responsible Entity enabled ports and services not required for operations and for monitoring Cyber Assets within the Electronic Security Perimeter but did document, individually or by specified grouping, the configuration of those ports and services.	At one or more access points to the Electronic Security Perimeter(s), the Responsible Entity enabled ports and services not required for operations and for monitoring Cyber Assets within the Electronic Security Perimeter, and did not document, individually or by specified grouping, the configuration of those ports and services.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
CIP-005-1	R2.3.	The Responsible Entity shall maintain a procedure for securing dial-up access to the Electronic Security Perimeter(s).	N/A	N/A	N/A	The Responsible Entity did not maintain a procedure for securing dial-up access to the Electronic Security Perimeter(s) where applicable.
CIP-005-1	R2.4.	Where external interactive access into the Electronic Security Perimeter has been enabled, the Responsible Entity shall implement strong procedural or technical controls at the access points to ensure authenticity of the accessing party, where technically feasible.	N/A	N/A	N/A	Where external interactive access into the Electronic Security Perimeter has been enabled the Responsible Entity did not implement strong procedural or technical controls at the access points to ensure authenticity of the accessing party, where technically feasible.
CIP-005-1	R2.5.	The required documentation shall, at least, identify and describe:	The required documentation for R2 did not include one of the elements described in R2.5.1 through R2.5.4	The required documentation for R2 did not include two of the elements described in R2.5.1 through R2.5.4	The required documentation for R2 did not include three of the elements described in R2.5.1 through R2.5.4	The required documentation for R2 did not include any of the elements described in R2.5.1 through R2.5.4
CIP-005-1	R2.5.1.	The processes for access request and authorization.	N/A	N/A	N/A	N/A
CIP-005-1	R2.5.2.	The authentication methods.	N/A	N/A	N/A	N/A
CIP-005-1	R2.5.3.	The review process for authorization rights, in accordance with Standard CIP-004 Requirement R4.	N/A	N/A	N/A	N/A
CIP-005-1	R2.5.4.	The controls used to secure dial-up accessible connections.	N/A	N/A	N/A	N/A

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
CIP-005-1	R2.6.	Appropriate Use Banner — Where technically feasible, electronic access control devices shall display an appropriate use banner on the user screen upon all interactive access attempts. The Responsible Entity shall maintain a document identifying the content of the banner.	The Responsible Entity did not maintain a document identifying the content of the banner. OR Where technically feasible less than 5% electronic access control devices did not display an appropriate use banner on the user screen upon all interactive access attempts.	Where technically feasible 5% but less than 10% of electronic access control devices did not display an appropriate use banner on the user screen upon all interactive access attempts.	Where technically feasible 10% but less than 15% of electronic access control devices did not display an appropriate use banner on the user screen upon all interactive access attempts.	Where technically feasible, 15% or more electronic access control devices did not display an appropriate use banner on the user screen upon all interactive access attempts.
CIP-005-1	R3.	Monitoring Electronic Access — The Responsible Entity shall implement and document an electronic or manual process(es) for monitoring and logging access at access points to the Electronic Security Perimeter(s) twenty-four hours a day, seven days a week.	The Responsible Entity did not document the electronic or manual processes for monitoring and logging access to access points. OR The Responsible Entity did not implement electronic or manual processes monitoring and logging at less than 5% of the access points.	The Responsible Entity did not implement electronic or manual processes monitoring and logging at 5% or more but less than 10% of the access points.	The Responsible Entity did not implement electronic or manual processes monitoring and logging at 10% or more but less than 15 % of the access points.	The Responsible Entity did not implement electronic or manual processes monitoring and logging at 15% or more of the access points.
CIP-005-1	R3.1.	For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall implement and document monitoring process(es) at each	The Responsible Entity did not document the electronic or manual	Where technically feasible, the Responsible Entity did not implement	Where technically feasible, the Responsible Entity did not implement	Where technically feasible, the Responsible Entity did not implement

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		access point to the dial-up device, where technically feasible.	processes for monitoring access points to dial-up devices. OR Where technically feasible, the Responsible Entity did not implement electronic or manual processes for monitoring at less than 5% of the access points to dial-up devices.	electronic or manual processes for monitoring at 5% or more but less than 10% of the access points to dial-up devices.	electronic or manual processes for monitoring at 10% or more but less than 15% of the access points to dial-up devices.	electronic or manual processes for monitoring at 15% or more of the access points to dial-up devices.
CIP-005-1	R3.2.	Where technically feasible, the security monitoring process(es) shall detect and alert for attempts at or actual unauthorized accesses. These alerts shall provide for appropriate notification to designated response personnel. Where alerting is not technically feasible, the Responsible Entity shall review or otherwise assess access logs for attempts at or actual unauthorized accesses at least every ninety calendar days.	N/A	N/A	Where technically feasible, the Responsible Entity implemented security monitoring process(es) to detect and alert for attempts at or actual unauthorized accesses, however the alerts do not provide for appropriate notification to designated response personnel.	Where technically feasible, the Responsible Entity did not implement security monitoring process(es) to detect and alert for attempts at or actual unauthorized accesses. OR Where alerting is not technically feasible, the Responsible Entity did not review or otherwise assess access logs for attempts at or actual unauthorized accesses at least every ninety calendar days
CIP-005-1	R4.	Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of the electronic	The Responsible Entity did not perform a	The Responsible Entity did not perform a Vulnerability	The Responsible Entity did not perform a Vulnerability	The Responsible Entity did not perform a Vulnerability

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		access points to the Electronic Security Perimeter(s) at least annually. The vulnerability assessment shall include, at a minimum, the following:	Vulnerability Assessment at least annually for less than 5% of access points to the Electronic Security Perimeter(s).	Assessment at least annually for 5% or more but less than 10% of access points to the Electronic Security Perimeter(s).	Assessment at least annually for 10% or more but less than 15% of access points to the Electronic Security Perimeter(s).	Assessment at least annually for 15% or more of access points to the Electronic Security Perimeter(s). OR The vulnerability assessment did not include one (1) or more of the subrequirements R 4.1, R4.2, R4.3, R4.4, R4.5.
CIP-005-1	R4.1.	A document identifying the vulnerability assessment process;	N/A	N/A	N/A	N/A
CIP-005-1	R4.2.	A review to verify that only ports and services required for operations at these access points are enabled;	N/A	N/A	N/A	N/A
CIP-005-1	R4.3.	The discovery of all access points to the Electronic Security Perimeter;	N/A	N/A	N/A	N/A
CIP-005-1	R4.4.	A review of controls for default accounts, passwords, and network management community strings; and,	N/A	N/A	N/A	N/A
CIP-005-1	R4.5.	Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.	N/A	N/A	N/A	N/A
CIP-005-1	R5.	Documentation Review and Maintenance — The Responsible Entity shall review, update, and maintain all documentation to support compliance with the requirements of Standard CIP-005.	The Responsible Entity did not review, update, and maintain at least one but less than or equal to 5% of the documentation to support	The Responsible Entity did not review, update, and maintain greater than 5% but less than or equal to 10% of the documentation to	The Responsible Entity did not review, update, and maintain greater than 10% but less than or equal to 15% of the documentation to	The Responsible Entity did not review, update, and maintain greater than 15% of the documentation to support compliance with the requirements

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			compliance with the requirements of Standard CIP-005.	support compliance with the requirements of Standard CIP-005.	support compliance with the requirements of Standard CIP-005.	of Standard CIP-005.
CIP-005-1	R5.1.	The Responsible Entity shall ensure that all documentation required by Standard CIP-005 reflect current configurations and processes and shall review the documents and procedures referenced in Standard CIP-005 at least annually.	N/A	The Responsible Entity did not provide evidence of an annual review of the documents and procedures referenced in Standard CIP-005.	The Responsible Entity did not document current configurations and processes referenced in Standard CIP-005.	The Responsible Entity did not document current configurations and processes and did not review the documents and procedures referenced in Standard CIP-005 at least annually.
CIP-005-1	R5.2.	The Responsible Entity shall update the documentation to reflect the modification of the network or controls within ninety calendar days of the change.	For less than 5% of the applicable changes, the Responsible Entity did not update the documentation to reflect the modification of the network or controls within ninety calendar days of the change.	For 5% or more but less than 10% of the applicable changes, the Responsible Entity did not update the documentation to reflect the modification of the network or controls within ninety calendar days of the change.	For 10% or more but less than 15% of the applicable changes, the Responsible Entity did not update the documentation to reflect the modification of the network or controls within ninety calendar days of the change.	For 15% or more of the applicable changes, the Responsible Entity did not update the documentation to reflect the modification of the network or controls within ninety calendar days of the change.
CIP-005-1	R5.3.	The Responsible Entity shall retain electronic access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008.	The Responsible Entity retained electronic access logs for 75 or more calendar days, but for less than 90 calendar days.	The Responsible Entity retained electronic access logs for 60 or more calendar days, but for less than 75 calendar days.	The Responsible Entity retained electronic access logs for 45 or more calendar days , but for less than 60 calendar days.	The Responsible Entity retained electronic access logs for less than 45 calendar days.
CIP-006-1	R1.	Physical Security Plan — The Responsible Entity shall create and maintain a physical security plan, approved by a senior manager or delegate(s) that shall address, at a minimum, the following:	N/A	N/A	The Responsible Entity created a physical security plan but did not gain approval by a senior	The Responsible Entity did not create and maintain a physical security plan.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
					manager or delegate(s). OR The Responsible Entity created but did not maintain a physical security plan.	
CIP-006-1	R1.1.	Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.	N/A	Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity has deployed but not documented alternative measures to control physical access to the Critical Cyber Assets.	Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity has not deployed alternative measures to control physical access to the Critical Cyber Assets.	The Responsible Entity's physical security plan does not include processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. OR Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity has not deployed and documented alternative measures to control physical access to the Critical Cyber Assets.
CIP-006-1	R1.2.	Processes to identify all access points through each Physical Security Perimeter and measures to control entry at those access points.	N/A	The Responsible Entity's physical security plan includes measures to control entry at access points but not processes to identify all access	The Responsible Entity's physical security plan includes processes to identify all access points through each Physical Security Perimeter but	The Responsible Entity's physical security plan does not include processes to identify all access points through each Physical Security

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				points through each Physical Security Perimeter.	not measures to control entry at those access points.	Perimeter nor measures to control entry at those access points.
CIP-006-1	R1.3	Processes, tools, and procedures to monitor physical access to the perimeter(s).	N/A	N/A	N/A	The Responsible Entity's physical security plan does not include processes, tools, and procedures to monitor physical access to the perimeter(s).
CIP-006-1	R1.4	Procedures for the appropriate use of physical access controls as described in Requirement R3 including visitor pass management, response to loss, and prohibition of inappropriate use of physical access controls.	N/A	N/A	N/A	The Responsible Entity's physical security plan does not include procedures for the appropriate use of physical access controls as described in Requirement R3.
CIP-006-1	R1.5	Procedures for reviewing access authorization requests and revocation of access authorization, in accordance with CIP-004 Requirement R4.	N/A	N/A	The Responsible Entity's physical security plan does not include either the procedures for reviewing access authorization requests or revocation of access authorization, in accordance with CIP-004 Requirement R4.	The Responsible Entity's physical security plan does not include procedures for reviewing access authorization requests and revocation of access authorization, in accordance with CIP-004 Requirement R4.
CIP-006-1	R1.6	Procedures for escorted access within the physical security perimeter of personnel not authorized for unescorted access.	N/A	N/A	N/A	The Responsible Entity's physical security plan does not include procedures for escorted access within the physical security

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						perimeter.
CIP-006-1	R1.7	Process for updating the physical security plan within ninety calendar days of any physical security system redesign or reconfiguration, including, but not limited to, addition or removal of access points through the physical security perimeter, physical access controls, monitoring controls, or logging controls.	N/A	N/A	The Responsible Entity's physical security plan includes a process for updating the physical security plan within ninety calendar days of any physical security system redesign or reconfiguration **but** the plan was not updated within 90 calendar days of any physical security system redesign or reconfiguration.	The Responsible Entity's physical security plan does not include a process for updating the physical security plan within ninety calendar days of any physical security system redesign or reconfiguration.
CIP-006-1	R1.8	Cyber Assets used in the access control and monitoring of the Physical Security Perimeter(s) shall be afforded the protective measures specified in Standard CIP-003, Standard CIP-004 Requirement R3, Standard CIP-005 Requirements R2 and R3, Standard CIP-006 Requirement R2 and R3, Standard CIP-007, Standard CIP-008 and Standard CIP-009.	A Cyber Asset used in the access control and monitoring of the Physical Security Perimeter(s) is provided all but one (1) of the protective measures as specified in Standard CIP-003, Standard CIP-004 Requirement R3, Standard CIP-005 Requirements R2 and R3, Standard CIP-006 Requirements R2 and R3, Standard CIP-007, Standard CIP-008, and Standard CIP-009.	A Cyber Asset used in the access control and monitoring of the Physical Security Perimeter(s) is provided all but two (2) of the protective measures as specified in Standard CIP-003, Standard CIP-004 Requirement R3, Standard CIP-005 Requirements R2 and R3, Standard CIP-006 Requirements R2 and R3, Standard CIP-007, Standard CIP-008, and Standard CIP-009.	A Cyber Asset used in the access control and monitoring of the Physical Security Perimeter(s) is provided all but three (3) of the protective measures as specified in Standard CIP-003, Standard CIP-004 Requirement R3, Standard CIP-005 Requirements R2 and R3, Standard CIP-006 Requirements R2 and R3, Standard CIP-007, Standard CIP-008, and Standard CIP-009.	A Cyber Asset used in the access control and monitoring of the Physical Security Perimeter(s) is not provided four (4) or more of the protective measures as specified in Standard CIP-003, Standard CIP-004 Requirement R3, Standard CIP-005 Requirements R2 and R3, Standard CIP-006 Requirements R2 and R3, Standard CIP-007, Standard CIP-008, and Standard CIP-009.
CIP-006-1	R1.9	Process for ensuring that the physical	N/A	N/A	N/A	The Responsible

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		security plan is reviewed at least annually.				Entity's physical security plan does not include a process for ensuring that the physical security plan is reviewed at least annually.
CIP-006-1	R2	Physical Access Controls — The Responsible Entity shall document and implement the operational and procedural controls to manage physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. The Responsible Entity shall implement one or more of the following physical access methods:	N/A	The Responsible Entity **has implemented but not documented** the operational and procedural controls to manage physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week using at least one of the access control methods identified in R2.1, R2.2, R2.3, or R2.4.	The Responsible Entity **has documented but not implemented** the operational and procedural controls to manage physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week using at least one of the access control methods identified in R2.1, R2.2, R2.3, or R2.4	The Responsible Entity has not documented nor implemented the operational and procedural controls to manage physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week using at least one of the access control methods identified in R2.1, R2.2, R2.3, or R2.4.
CIP-006-1	R2.1.	Card Key: A means of electronic access where the access rights of the card holder are predefined in a computer database. Access rights may differ from one perimeter to another.	N/A	N/A	N/A	N/A
CIP-006-1	R2.2.	Special Locks: These include, but are not limited to, locks with “restricted key” systems, magnetic locks that can be operated remotely, and “man-trap” systems.	N/A	N/A	N/A	N/A
CIP-006-1	R2.3.	Security Personnel: Personnel responsible for controlling physical access who may reside on-site or at a monitoring station.	N/A	N/A	N/A	N/A

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
CIP-006-1	R2.4.	Other Authentication Devices: Biometric, keypad, token, or other equivalent devices that control physical access to the Critical Cyber Assets.	N/A	N/A	N/A	N/A
CIP-006-1	R3	Monitoring Physical Access — The Responsible Entity shall document and implement the technical and procedural controls for monitoring physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. Unauthorized access attempts shall be reviewed immediately and handled in accordance with the procedures specified in Requirement CIP-008. One or more of the following monitoring methods shall be used:	N/A	The Responsible Entity **has implemented but not documented** the technical and procedural controls for monitoring physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week using at least one of the monitoring methods identified in Requirements R3.1 or R3.2.	The Responsible Entity **has documented but not implemented** the technical and procedural controls for monitoring physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week using at least one of the monitoring methods identified in Requirements R3.1 or R3.2.	The Responsible Entity **has not documented nor implemented** the technical and procedural controls for monitoring physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week using at least one of the monitoring methods identified in Requirements R3.1 or R3.2. OR One or more unauthorized access attempts have not been reviewed immediately and handled in accordance with the procedures specified in CIP-008.
CIP-006-1	R3.1.	Alarm Systems: Systems that alarm to indicate a door, gate or window has been opened without authorization. These alarms must provide for immediate notification to personnel responsible for response.	N/A	N/A	N/A	N/A
CIP-006-1	R3.2.	Human Observation of Access Points: Monitoring of physical access points by	N/A	N/A	N/A	N/A

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		authorized personnel as specified in Requirement R2.3.				
CIP-006-1	R4	Logging Physical Access — Logging shall record sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week. The Responsible Entity shall implement and document the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent:	The Responsible Entity **has implemented but not documented** the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the logging methods identified in Requirements R4.1, R4.2, or R4.3, and has provided logging that records sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week.	The Responsible Entity has implemented the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the logging methods identified in Requirements R4.1, R4.2, or R4.3, **but** has not provided logging that records sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week.	The Responsible Entity **has documented but not implemented** the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the logging methods identified in Requirements R4.1, R4.2, or R4.3.	The Responsible Entity **has not implemented nor documented** the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the logging methods identified in Requirements R4.1, R4.2, or R4.3.
CIP-006-1	R4.1.	Computerized Logging: Electronic logs produced by the Responsible Entity's selected access control and monitoring method.	N/A	N/A	N/A	N/A
CIP-006-1	R4.2.	Video Recording: Electronic capture of video images of sufficient quality to determine identity.	N/A	N/A	N/A	N/A
CIP-006-1	R4.3.	Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel	N/A	N/A	N/A	N/A

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		authorized to control and monitor physical access as specified in Requirement R2.3.				
CIP-006-1	R5	Access Log Retention — The responsible entity shall retain physical access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008.	The Responsible Entity retained physical access logs for 75 or more calendar days, but for less than 90 calendar days.	The Responsible Entity retained physical access logs for 60 or more calendar days, but for less than 75 calendar days.	The Responsible Entity retained physical access logs for 45 or more calendar days , but for less than 60 calendar days.	The Responsible Entity retained physical access logs for less than 45 calendar days.
CIP-006-1	R6	Maintenance and Testing — The Responsible Entity shall implement a maintenance and testing program to ensure that all physical security systems under Requirements R2, R3, and R4 function properly. The program must include, at a minimum, the following:	The Responsible Entity has implemented a maintenance and testing program to ensure that all physical security systems under Requirements R2, R3, and R4 function properly **but** the program does not include one of the requirements R6.1, R6.2, and R6.3.	The Responsible Entity has implemented a maintenance and testing program to ensure that all physical security systems under Requirements R2, R3, and R4 function properly **but** the program does not include two of the requirements R6.1, R6.2, and R6.3.	The Responsible Entity has implemented a maintenance and testing program to ensure that all physical security systems under Requirements R2, R3, and R4 function properly **but** the program does not include any of the requirements R6.1, R6.2, and R6.3.	The Responsible Entity has not implemented a maintenance and testing program to ensure that all physical security systems under Requirements R2, R3, and R4 function properly.
CIP-006-1	R6.1.	Testing and maintenance of all physical security mechanisms on a cycle no longer than three years.	N/A	N/A	N/A	N/A
CIP-006-1	R6.2.	Retention of testing and maintenance records for the cycle determined by the Responsible Entity in Requirement R6.1.	N/A	N/A	N/A	N/A
CIP-006-1	R6.3.	Retention of outage records regarding access controls, logging, and monitoring for a minimum of one calendar year.	N/A	N/A	N/A	N/A
CIP-007-1	R1.	Test Procedures — The Responsible Entity shall ensure that new Cyber Assets and significant changes to existing Cyber	N/A	The Responsible Entity did create, implement and	The Responsible Entity did not create, implement and	The Responsible Entity did not create, implement and

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		Assets within the Electronic Security Perimeter do not adversely affect existing cyber security controls. For purposes of Standard CIP-007, a significant change shall, at a minimum, include implementation of security patches, cumulative service packs, vendor releases, and version upgrades of operating systems, applications, database platforms, or other third-party software or firmware.		maintain the test procedures as required in R1.1, **but did not document** that testing is performed as required in R1.2. OR The Responsible Entity did not document the test results as required in R1.3.	maintain the test procedures as required in R1.1.	maintain the test procedures as required in R1.1, AND The Responsible Entity did not document that testing was performed as required in R1.2 AND The Responsible Entity did not document the test results as required in R1.3.
CIP-007-1	R1.1.	The Responsible Entity shall create, implement, and maintain cyber security test procedures in a manner that minimizes adverse effects on the production system or its operation.	N/A	N/A	N/A	N/A
CIP-007-1	R1.2.	The Responsible Entity shall document that testing is performed in a manner that reflects the production environment.	N/A	N/A	N/A	N/A
CIP-007-1	R1.3.	The Responsible Entity shall document test results.	N/A	N/A	N/A	N/A
CIP-007-1	R2.	Ports and Services — The Responsible Entity shall establish and document a process to ensure that only those ports and services required for normal and emergency operations are enabled.	N/A	The Responsible Entity **established but did not document** a process to ensure that only those ports and services required for normal and emergency operations are enabled.	The Responsible Entity **documented but did not establish** a process to ensure that only those ports and services required for normal and emergency operations are enabled.	The Responsible Entity did not establish nor document a process to ensure that only those ports and services required for normal and emergency operations are enabled.
CIP-007-1	R2.1.	The Responsible Entity shall enable only	The Responsible	The Responsible	The Responsible	The Responsible

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		those ports and services required for normal and emergency operations.	Entity enabled ports and services not required for normal and emergency operations on at least one but less than 5% of the Cyber Assets inside the Electronic Security Perimeter(s).	Entity enabled ports and services not required for normal and emergency operations on 5% or more but less than 10% of the Cyber Assets inside the Electronic Security Perimeter(s).	Entity enabled ports and services not required for normal and emergency operations on 10% or more but less than 15% of the Cyber Assets inside the Electronic Security Perimeter(s).	Entity enabled ports and services not required for normal and emergency operations on 15% or more of the Cyber Assets inside the Electronic Security Perimeter(s).
CIP-007-1	R2.2.	The Responsible Entity shall disable other ports and services, including those used for testing purposes, prior to production use of all Cyber Assets inside the Electronic Security Perimeter(s).	The Responsible Entity did not disable other ports and services, including those used for testing purposes, prior to production use for at least one but less than 5% of the Cyber Assets inside the Electronic Security Perimeter(s).	The Responsible Entity did not disable other ports and services, including those used for testing purposes, prior to production use for 5% or more but less than 10% of the Cyber Assets inside the Electronic Security Perimeter(s).	The Responsible Entity did not disable other ports and services, including those used for testing purposes, prior to production use for 10% or more but less than 15% of the Cyber Assets inside the Electronic Security Perimeter(s).	The Responsible Entity did not disable other ports and services, including those used for testing purposes, prior to production use for 15% or more of the Cyber Assets inside the Electronic Security Perimeter(s).
CIP-007-1	R2.3.	In the case where unused ports and services cannot be disabled due to technical limitations, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure or an acceptance of risk.	N/A	N/A	N/A	For cases where unused ports and services cannot be disabled due to technical limitations, the Responsible Entity did not document compensating measure(s) applied to mitigate risk exposure or state an acceptance of risk.
CIP-007-1	R3.	Security Patch Management — The Responsible Entity, either separately or as a component of the documented	The Responsible Entity established and documented,	The Responsible Entity **established but did not document**,	The Responsible Entity **documented but did not establish**,	The Responsible Entity **did not establish nor**

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		configuration management process specified in CIP-003 Requirement R6, shall establish and document a security patch management program for tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).	either separately or as a component of the documented configuration management process specified in CIP-003 Requirement R6, a security patch management program **but** did not include one or more of the following: tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).	either separately or as a component of the documented configuration management process specified in CIP-003 Requirement R6, a security patch management program for tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).	either separately or as a component of the documented configuration management process specified in CIP-003 Requirement R6, a security patch management program for tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).	**document**, either separately or as a component of the documented configuration management process specified in CIP-003 Requirement R6, a security patch management program for tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).
CIP-007-1	R3.1.	The Responsible Entity shall document the assessment of security patches and security upgrades for applicability within thirty calendar days of availability of the patches or upgrades.	The Responsible Entity documented the assessment of security patches and security upgrades for applicability as required in Requirement R3 in more than 30 but less than 60 calendar days after the availability of the patches and upgrades.	The Responsible Entity documented the assessment of security patches and security upgrades for applicability as required in Requirement R3 in 60 or more but less than 90 calendar days after the availability of the patches and upgrades.	The Responsible Entity documented the assessment of security patches and security upgrades for applicability as required in Requirement R3 in 90 or more but less than 120 calendar days after the availability of the patches and upgrades.	The Responsible Entity documented the assessment of security patches and security upgrades for applicability as required in Requirement R3 in 120 calendar days or more after the availability of the patches and upgrades.
CIP-007-1	R3.2.	The Responsible Entity shall document the implementation of security patches. In any case where the patch is not installed, the Responsible Entity shall document compensating measure(s) applied to	N/A	N/A	N/A	The Responsible Entity did not document the implementation of applicable security

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		mitigate risk exposure or an acceptance of risk.				patches as required in R3. OR Where an applicable patch was not installed, the Responsible Entity did not document the compensating measure(s) applied to mitigate risk exposure or an acceptance of risk.
CIP-007-1	R4.	Malicious Software Prevention — The Responsible Entity shall use anti-virus software and other malicious software (“malware”) prevention tools, where technically feasible, to detect, prevent, deter, and mitigate the introduction, exposure, and propagation of malware on all Cyber Assets within the Electronic Security Perimeter(s).	The Responsible Entity, as technically feasible, did not use anti-virus software and other malicious software (“malware”) prevention tools, nor implemented compensating measures, on at least one but less than 5% of Cyber Assets within the Electronic Security Perimeter(s).	The Responsible Entity, as technically feasible, did not use anti-virus software and other malicious software (“malware”) prevention tools, nor implemented compensating measures, on at least 5% but less than 10% of Cyber Assets within the Electronic Security Perimeter(s).	The Responsible Entity, as technically feasible, did not use anti-virus software and other malicious software (“malware”) prevention tools, nor implemented compensating measures, on at least 10% but less than 15% of Cyber Assets within the Electronic Security Perimeter(s).	The Responsible Entity, as technically feasible, did not use anti-virus software and other malicious software (“malware”) prevention tools, nor implemented compensating measures, on 15% or more Cyber Assets within the Electronic Security Perimeter(s).
CIP-007-1	R4.1.	The Responsible Entity shall document and implement anti-virus and malware prevention tools. In the case where anti-virus software and malware prevention tools are not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure or an acceptance of risk.	N/A	N/A	N/A	The Responsible Entity did not document the implementation of antivirus and malware prevention tools for cyber assets within the electronic security perimeter. OR

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						The Responsible Entity did not document the implementation of compensating measure(s) applied to mitigate risk exposure or an acceptance of risk where antivirus and malware prevention tools are not installed.
CIP-007-1	R4.2.	The Responsible Entity shall document and implement a process for the update of anti-virus and malware prevention "signatures." The process must address testing and installing the signatures.	The Responsible Entity, as technically feasible, documented and implemented a process for the update of anti-virus and malware prevention "signatures.", but the process did not address testing and installation of the signatures.	The Responsible Entity, as technically feasible, **did not document but implemented** a process, including addressing testing and installing the signatures, for the update of anti-virus and malware prevention "signatures."	The Responsible Entity, as technically feasible, **documented but did not implement** a process, including addressing testing and installing the signatures, for the update of anti-virus and malware prevention "signatures."	The Responsible Entity, as technically feasible, **did not document nor implement** a process including addressing testing and installing the signatures for the update of anti-virus and malware prevention "signatures."
CIP-007-1	R5.	Account Management — The Responsible Entity shall establish, implement, and document technical and procedural controls that enforce access authentication of, and accountability for, all user activity, and that minimize the risk of unauthorized system access.	N/A	The Responsible Entity implemented but did not document technical and procedural controls that enforce access authentication of, and accountability for, all user activity.	The Responsible Entity documented but did not implement technical and procedural controls that enforce access authentication of, and accountability for, all user activity.	The Responsible Entity did not document nor implement technical and procedural controls that enforce access authentication of, and accountability for, all user activity.
CIP-007-1	R5.1.	The Responsible Entity shall ensure that individual and shared system accounts and authorized access permissions are	N/A	N/A	N/A	The Responsible Entity did not ensure that individual and

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		consistent with the concept of "need to know" with respect to work functions performed.				shared system accounts and authorized access permissions are consistent with the concept of "need to know" with respect to work functions performed.
CIP-007-1	R5.1.1.	The Responsible Entity shall ensure that user accounts are implemented as approved by designated personnel. Refer to Standard CIP-003 Requirement R5.	At least one user account but less than 1% of user accounts implemented by the Responsible Entity, were not approved by designated personnel.	One (1) % or more of user accounts but less than 3% of user accounts implemented by the Responsible Entity were not approved by designated personnel.	Three (3) % or more of user accounts but less than 5% of user accounts implemented by the Responsible Entity were not approved by designated personnel.	Five (5) % or more of user accounts implemented by the Responsible Entity were not approved by designated personnel.
CIP-007-1	R5.1.2.	The Responsible Entity shall establish methods, processes, and procedures that generate logs of sufficient detail to create historical audit trails of individual user account access activity for a minimum of ninety days.	N/A	The Responsible Entity generated logs with sufficient detail to create historical audit trails of individual user account access activity, **however** the logs do not contain activity for a minimum of 90 days.	The Responsible Entity generated logs with insufficient detail to create historical audit trails of individual user account access activity.	The Responsible Entity did not generate logs of individual user account access activity.
CIP-007-1	R5.1.3.	The Responsible Entity shall review, at least annually, user accounts to verify access privileges are in accordance with Standard CIP-003 Requirement R5 and Standard CIP-004 Requirement R4.	N/A	N/A	N/A	The Responsible Entity did not review, at least annually, user accounts to verify access privileges are in accordance with Standard CIP-003 Requirement R5 and Standard CIP-004

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						Requirement R4.
CIP-007-1	R5.2.	The Responsible Entity shall implement a policy to minimize and manage the scope and acceptable use of administrator, shared, and other generic account privileges including factory default accounts.	N/A	N/A	N/A	The Responsible Entity did not implement a policy to minimize and manage the scope and acceptable use of administrator, shared, and other generic account privileges including factory default accounts.
CIP-007-1	R5.2.1.	The policy shall include the removal, disabling, or renaming of such accounts where possible. For such accounts that must remain enabled, passwords shall be changed prior to putting any system into service.	N/A	N/A	The Responsible Entity's policy did not include the removal, disabling, or renaming of such accounts where possible, **however** for accounts that must remain enabled, passwords were changed prior to putting any system into service.	For accounts that must remain enabled, the Responsible Entity did not change passwords prior to putting any system into service.
CIP-007-1	R5.2.2.	The Responsible Entity shall identify those individuals with access to shared accounts.	N/A	N/A	N/A	The Responsible Entity did not identify all individuals with access to shared accounts.
CIP-007-1	R5.2.3.	Where such accounts must be shared, the Responsible Entity shall have a policy for managing the use of such accounts that limits access to only those with authorization, an audit trail of the account use (automated or manual), and steps for securing the account in the event of personnel changes (for example, change in	N/A	Where such accounts must be shared, the Responsible Entity has a policy for managing the use of such accounts, **but is missing 1** of the following 3 items:	Where such accounts must be shared, the Responsible Entity has a policy for managing the use of such accounts, **but is missing 2** of the following 3 items:	Where such accounts must be shared, the Responsible Entity does not have a policy for managing the use of such accounts that limits access to only those with

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		assignment or termination).		a) limits access to only those with authorization, b) has an audit trail of the account use (automated or manual), c) has specified steps for securing the account in the event of personnel changes (for example, change in assignment or termination).	a) limits access to only those with authorization, b) has an audit trail of the account use (automated or manual), c) has specified steps for securing the account in the event of personnel changes (for example, change in assignment or termination).	authorization, an audit trail of the account use (automated or manual), and steps for securing the account in the event of personnel changes (for example, change in assignment or termination).
CIP-007-1	R5.3.	At a minimum, the Responsible Entity shall require and use passwords, subject to the following, as technically feasible:	The Responsible Entity requires and uses passwords as technically feasible, but only addresses 2 of the requirements in R5.3.1, R5.3.2., R5.3.3.	The Responsible Entity requires and uses passwords as technically feasible but only addresses 1 of the requirements in R5.3.1, R5.3.2., R5.3.3.	The Responsible Entity **requires but does not use passwords** as required in R5.3.1, R5.3.2., R5.3.3 and did not demonstrate why it is not technically feasible.	The Responsible Entity **does not require nor use passwords** as required in R5.3.1, R5.3.2., R5.3.3 and did not demonstrate why it is not technically feasible.
CIP-007-1	R5.3.1.	Each password shall be a minimum of six characters.	N/A	N/A	N/A	N/A
CIP-007-1	R5.3.2.	Each password shall consist of a combination of alpha, numeric, and "special" characters.	N/A	N/A	N/A	N/A
CIP-007-1	R5.3.3.	Each password shall be changed at least annually, or more frequently based on risk.	N/A	N/A	N/A	N/A
CIP-007-1	R6.	Security Status Monitoring — The Responsible Entity shall ensure that all Cyber Assets within the Electronic Security Perimeter, as technically feasible,	The Responsible Entity, as technically feasible, did not implement automated	The Responsible Entity, as technically feasible, did not implement automated	The Responsible Entity did not implement automated tools or organizational	The Responsible Entity did not implement automated tools or organizational

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		implement automated tools or organizational process controls to monitor system events that are related to cyber security.	tools or organizational process controls to monitor system events that are related to cyber security for at least one but less than 5% of Cyber Assets inside the Electronic Security Perimeter(s).	tools or organizational process controls to monitor system events that are related to cyber security for 5% or more but less than 10% of Cyber Assets inside the Electronic Security Perimeter(s).	process controls, as technically feasible, to monitor system events that are related to cyber security for 10% or more but less than 15% of Cyber Assets inside the Electronic Security Perimeter(s).	process controls, as technically feasible, to monitor system events that are related to cyber security for 15% or more of Cyber Assets inside the Electronic Security Perimeter(s).
CIP-007-1	R6.1.	The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for monitoring for security events on all Cyber Assets within the Electronic Security Perimeter.	N/A	The Responsible Entity **implemented but did not document** the organizational processes and technical and procedural mechanisms for monitoring for security events on all Cyber Assets within the Electronic Security Perimeter.	The Responsible Entity **documented but did not implement** the organizational processes and technical and procedural mechanisms for monitoring for security events on all Cyber Assets within the Electronic Security Perimeter.	The Responsible Entity **did not implement nor document** the organizational processes and technical and procedural mechanisms for monitoring for security events on all Cyber Assets within the Electronic Security Perimeter.
CIP-007-1	R6.2.	The security monitoring controls shall issue automated or manual alerts for detected Cyber Security Incidents.	N/A	N/A	N/A	The Responsible entity's security monitoring controls do not issue automated or manual alerts for detected Cyber Security Incidents.
CIP-007-1	R6.3.	The Responsible Entity shall maintain logs of system events related to cyber security, where technically feasible, to support incident response as required in Standard CIP-008.	N/A	N/A	N/A	The Responsible Entity did not maintain logs of system events related to cyber security, where

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						technically feasible, to support incident response as required in Standard CIP-008.
CIP-007-1	R6.4.	The Responsible Entity shall retain all logs specified in Requirement R6 for ninety calendar days.	The Responsible Entity retained the logs specified in Requirement R6, for at least 60 days, but less than 90 days.	The Responsible Entity retained the logs specified in Requirement R6, for at least 30 days, but less than 60 days.	The Responsible Entity retained the logs specified in Requirement R6, for at least one day, but less than 30 days.	The Responsible Entity did not retain any logs specified in Requirement R6.
CIP-007-1	R6.5.	The Responsible Entity shall review logs of system events related to cyber security and maintain records documenting review of logs.	N/A	N/A	N/A	The Responsible Entity did not review logs of system events related to cyber security nor maintain records documenting review of logs.
CIP-007-1	R7.	Disposal or Redeployment — The Responsible Entity shall establish formal methods, processes, and procedures for disposal or redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005.	The Responsible Entity established formal methods, processes, and procedures for disposal and redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005 **but** did not maintain records as specified in R7.3.	The Responsible Entity established formal methods, processes, and procedures for disposal of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005 **but** did not address redeployment as specified in R7.2.	The Responsible Entity established formal methods, processes, and procedures for redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005 **but** did not address disposal as specified in R7.1.	The Responsible Entity did not establish formal methods, processes, and procedures for disposal or redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005.
CIP-007-1	R7.1.	Prior to the disposal of such assets, the Responsible Entity shall destroy or erase the data storage media to prevent unauthorized retrieval of sensitive cyber	N/A	N/A	N/A	N/A

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		security or reliability data.				
CIP-007-1	R7.2.	Prior to redeployment of such assets, the Responsible Entity shall, at a minimum, erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.	N/A	N/A	N/A	N/A
CIP-007-1	R7.3.	The Responsible Entity shall maintain records that such assets were disposed of or redeployed in accordance with documented procedures.	N/A	N/A	N/A	N/A
CIP-007-1	R8	Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of all Cyber Assets within the Electronic Security Perimeter at least annually. The vulnerability assessment shall include, at a minimum, the following:	The Responsible Entity performed at least annually a Vulnerability Assessment that included 95% or more but less than 100% of Cyber Assets within the Electronic Security Perimeter.	The Responsible Entity performed at least annually a Vulnerability Assessment that included 90% or more but less than 95% of Cyber Assets within the Electronic Security Perimeter.	The Responsible Entity performed at least annually a Vulnerability Assessment that included more than 85% but less than 90% of Cyber Assets within the Electronic Security Perimeter.	The Responsible Entity performed at least annually a Vulnerability Assessment for 85% or less of Cyber Assets within the Electronic Security Perimeter. OR The vulnerability assessment did not include one (1) or more of the subrequirements 8.1, 8.2, 8.3, 8.4.
CIP-007-1	R8.1.	A document identifying the vulnerability assessment process;	N/A	N/A	N/A	N/A
CIP-007-1	R8.2.	A review to verify that only ports and services required for operation of the Cyber Assets within the Electronic Security Perimeter are enabled;	N/A	N/A	N/A	N/A
CIP-007-1	R8.3.	A review of controls for default accounts; and,	N/A	N/A	N/A	N/A
CIP-007-1	R8.4.	Documentation of the results of the assessment, the action plan to remediate or	N/A	N/A	N/A	N/A

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		mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.				
CIP-007-1	R9	Documentation Review and Maintenance — The Responsible Entity shall review and update the documentation specified in Standard CIP-007 at least annually. Changes resulting from modifications to the systems or controls shall be documented within ninety calendar days of the change.	N/A	N/A	The Responsible Entity did not review and update the documentation specified in Standard CIP-007 at least annually **or** the Responsible Entity did not document Changes resulting from modifications to the systems or controls within ninety calendar days of the change.	The Responsible Entity did not review and update the documentation specified in Standard CIP-007 at least annually **nor** were Changes resulting from modifications to the systems or controls documented within ninety calendar days of the change.
CIP-008-1	R1.	Cyber Security Incident Response Plan — The Responsible Entity shall develop and maintain a Cyber Security Incident response plan. The Cyber Security Incident Response plan shall address, at a minimum, the following:	N/A	The Responsible Entity has developed but not maintained a Cyber Security Incident response plan.	The Responsible Entity has developed a Cyber Security Incident response plan but the plan does not address one or more of the subrequirements R1.1 through R1.6	The Responsible Entity has not developed a Cyber Security Incident response plan.
CIP-008-1	R1.1.	Procedures to characterize and classify events as reportable Cyber Security Incidents.	N/A	N/A	N/A	N/A
CIP-008-1	R1.2.	Response actions, including roles and responsibilities of incident response teams, incident handling procedures, and communication plans.	N/A	N/A	N/A	N/A
CIP-008-1	R1.3.	Process for reporting Cyber Security Incidents to the Electricity Sector Information Sharing and Analysis Center (ES ISAC). The Responsible Entity must	N/A	N/A	N/A	N/A

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		ensure that all reportable Cyber Security Incidents are reported to the ES ISAC either directly or through an intermediary.				
CIP-008-1	R1.4.	Process for updating the Cyber Security Incident response plan within ninety calendar days of any changes.	N/A	N/A	N/A	N/A
CIP-008-1	R1.5.	Process for ensuring that the Cyber Security Incident response plan is reviewed at least annually.	N/A	N/A	N/A	N/A
CIP-008-1	R1.6.	Process for ensuring the Cyber Security Incident response plan is tested at least annually. A test of the incident response plan can range from a paper drill, to a full operational exercise, to the response to an actual incident.	N/A	N/A	N/A	N/A
CIP-008-1	R2	Cyber Security Incident Documentation — The Responsible Entity shall keep relevant documentation related to Cyber Security Incidents reportable per Requirement R1.1 for three calendar years.	The Responsible Entity has kept relevant documentation related to Cyber Security Incidents reportable per Requirement R1.1 for two but less than three calendar years.	The Responsible Entity has kept relevant documentation related to Cyber Security Incidents reportable per Requirement R1.1 for less than two calendar years.	The Responsible Entity has kept relevant documentation related to Cyber Security Incidents reportable per Requirement R1.1 for less than one calendar year.	The Responsible Entity has not kept relevant documentation related to Cyber Security Incidents reportable per Requirement R1.1.
CIP-009-1	R1	Recovery Plans — The Responsible Entity shall create and annually review recovery plan(s) for Critical Cyber Assets. The recovery plan(s) shall address at a minimum the following:	N/A	The Responsible Entity has not annually reviewed recovery plan(s) for Critical Cyber Assets.	The Responsible Entity has created recovery plan(s) for Critical Cyber Assets but did not address one of the requirements CIP-009-1 R1.1 **or** R1.2.	The Responsible Entity has not created recovery plan(s) for Critical Cyber Assets that address at a minimum both requirements CIP-009-1 R1.1 **and** R1.2.
CIP-009-1	R1.1.	Specify the required actions in response to events or conditions of varying duration and severity that would activate the	N/A	N/A	N/A	N/A

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		recovery plan(s).				
CIP-009-1	R1.2.	Define the roles and responsibilities of responders.	N/A	N/A	N/A	N/A
CIP-009-1	R2	Exercises — The recovery plan(s) shall be exercised at least annually. An exercise of the recovery plan(s) can range from a paper drill, to a full operational exercise, to recovery from an actual incident.	N/A	N/A	N/A	The Responsible Entity's recovery plan(s) have not been exercised at least annually.
CIP-009-1	R3	Change Control — Recovery plan(s) shall be updated to reflect any changes or lessons learned as a result of an exercise or the recovery from an actual incident. Updates shall be communicated to personnel responsible for the activation and implementation of the recovery plan(s) within ninety calendar days of the change.	The Responsible Entity's recovery plan(s) have been updated to reflect any changes or lessons learned as a result of an exercise or the recovery from an actual incident but the updates were communicated to personnel responsible for the activation and implementation of the recovery plan(s) in more than 90 but less than or equal to 120 calendar days of the change.	The Responsible Entity's recovery plan(s) have been updated to reflect any changes or lessons learned as a result of an exercise or the recovery from an actual incident but the updates were communicated to personnel responsible for the activation and implementation of the recovery plan(s) in more than 120 but less than or equal to 150 calendar days of the change.	The Responsible Entity's recovery plan(s) have been updated to reflect any changes or lessons learned as a result of an exercise or the recovery from an actual incident but the updates were communicated to personnel responsible for the activation and implementation of the recovery plan(s) in more than 150 but less than or equal to 180 calendar days of the change.	The Responsible Entity's recovery plan(s) have not been updated to reflect any changes or lessons learned as a result of an exercise or the recovery from an actual incident. OR The Responsible Entity's recovery plan(s) have been updated to reflect any changes or lessons learned as a result of an exercise or the recovery from an actual incident but the updates were communicated to personnel responsible for the activation and implementation of the recovery plan(s) in more than 180 calendar days of the change.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
CIP-009-1	R4	Backup and Restore — The recovery plan(s) shall include processes and procedures for the backup and storage of information required to successfully restore Critical Cyber Assets. For example, backups may include spare electronic components or equipment, written documentation of configuration settings, tape backup, etc.	N/A	N/A	N/A	The Responsible Entity's recovery plan(s) do not include processes and procedures for the backup and storage of information required to successfully restore Critical Cyber Assets.
CIP-009-1	R5	Testing Backup Media — Information essential to recovery that is stored on backup media shall be tested at least annually to ensure that the information is available. Testing can be completed off site.	N/A	N/A	N/A	The Responsible Entity's information essential to recovery that is stored on backup media has not been tested at least annually to ensure that the information is available.

Complete Violation Severity Level Matrix (COM)
Encompassing All FERC-Approved Reliability Standards

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
COM-001-1.1	R1.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide adequate and reliable telecommunications facilities for the exchange of Interconnection and operating information:	The responsible entity's telecommunications is not redundant or diversely routed as applicable by other operating entities for the exchange of interconnection or operating data.	The responsible entity's telecommunications is not redundant or diversely routed as applicable and has failed to establish telecommunications internally for the exchange of interconnection or operating data needed to maintain BES reliability.	The responsible entity's telecommunications is not redundant or diversely routed as applicable and has failed to establish telecommunications internally and with **other** Reliability Coordinators, Transmission Operators, or Balancing Authorities for the exchange of interconnection or operating data needed to maintain BES reliability.	The responsible entity's telecommunications is not redundant or diversely routed as applicable and has failed to establish telecommunications internally and with both **other** and **its** Reliability Coordinators, Transmission Operators, or Balancing Authorities for the exchange of interconnection or operating data needed to maintain BES reliability.
COM-001-1.1	R1.1.	Internally.	N/A	N/A	N/A	The responsible entity has failed to establish telecommunications internally for the exchange of interconnection or operating data needed to maintain BES reliability.
COM-001-1.1	R1.2.	Between the Reliability Coordinator and its Transmission Operators and Balancing Authorities.	N/A	N/A	N/A	The responsible entity has failed to establish telecommunications with its Reliability Coordinator, Transmission Operators, or

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						Balancing Authorities for the exchange of interconnection or operating data needed to maintain BES reliability.
COM-001-1.1	R1.3.	With other Reliability Coordinators, Transmission Operators, and Balancing Authorities as necessary to maintain reliability.	N/A	N/A	NA	The responsible entity has failed to establish telecommunications with other Reliability Coordinators, Transmission Operators, or Balancing Authorities for the exchange of interconnection or operating data needed to maintain BES reliability.
COM-001-1.1	R1.4.	Where applicable, these facilities shall be redundant and diversely routed.	N/A	N/A	N/A	The responsible entity's telecommunications is not redundant or diversely routed where applicable for the exchange of interconnection or operating data.
COM-001-1.1	R2.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall manage, alarm, test and/or actively monitor vital telecommunications facilities. Special attention shall be given to emergency telecommunications facilities and equipment not used for routine communications.	N/A	The responsible entity has failed to manage, alarm, and test or actively monitor its emergency telecommunications facilities.	The responsible entity has failed to manage, alarm, and test or actively monitor its primary telecommunications facilities.	The responsible entity has failed to manage, alarm, and test or actively monitor its primary and emergency telecommunications facilities.
COM-001-	R3.	Each Reliability Coordinator, Transmission	N/A	N/A	The responsible entity	The responsible entity

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
1.1		Operator and Balancing Authority shall provide a means to coordinate telecommunications among their respective areas. This coordination shall include the ability to investigate and recommend solutions to telecommunications problems within the area and with other areas.			failed to assist in the investigation and recommending of solutions to telecommunications problems within the area and with other areas.	failed to provide a means to coordinate telecommunications among their respective areas including assisting in the investigation and recommending of solutions to telecommunications problems within the area and with other areas.
COM-001-1.1	R4.	Unless agreed to otherwise, each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use English as the language for all communications between and among operating personnel responsible for the real-time generation control and operation of the interconnected Bulk Electric System. Transmission Operators and Balancing Authorities may use an alternate language for internal operations.	N/A	N/A	N/A	If using a language other than English, the responsible entity failed to provide documentation of agreement to use a language other than English for all communications between and among operating personnel responsible for the real-time generation control and operation of the interconnected Bulk Electric System.
COM-001-1.1	R5.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have written operating instructions and procedures to enable continued operation of the system during the loss of telecommunications facilities.	N/A	N/A	N/A	The responsible entity did not have written operating instructions and procedures to enable continued operation of the system during the loss of telecommunications facilities.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
COM-001-1.1	R6.	Each NERCNet User Organization shall adhere to the requirements in Attachment 1-COM-001-0, "NERCNet Security Policy."	The NERCNet User Organization failed to adhere to less than 25% of the requirements listed in COM-001-0, Attachment 1, "NERCNet Security Policy".	The NERCNet User Organization failed to adhere to 25% or more but less than 50% of the requirements listed in COM-001-0, Attachment 1, "NERCNet Security Policy".	The NERCNet User Organization failed to adhere to 50% or more but less than 75% of the requirements listed in COM-001-0, Attachment 1, "NERCNet Security Policy".	The NERCNet User Organization failed to adhere to 75% or more of the requirements listed in COM-001-0, Attachment 1, "NERCNet Security Policy".
COM-002-2	R1.	Each Transmission Operator, Balancing Authority, and Generator Operator shall have communications (voice and data links) with appropriate Reliability Coordinators, Balancing Authorities, and Transmission Operators. Such communications shall be staffed and available for addressing a real-time emergency condition.	N/A	The responsible entity did not have data links with appropriate Reliability Coordinators, Balancing Authorities, and Transmission Operators.	The responsible entity did not staff the communications (voice and data links) on a 24 hour basis.	The responsible entity failed to have communications (voice and data links) with appropriate Reliability Coordinators, Balancing Authorities, and Transmission Operators.
COM-002-2	R1.1.	Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator, and all other potentially affected Balancing Authorities and Transmission Operators through predetermined communication paths of any condition that could threaten the reliability of its area or when firm load shedding is anticipated.	N/A	N/A	The responsible entity failed to notify all other potentially affected Balancing Authorities and Transmission Operators through predetermined communication paths of any condition that could threaten the reliability of its area or when firm load shedding is anticipated.	The responsible entity failed to notify its Reliability Coordinator, and all other potentially affected Balancing Authorities and Transmission Operators through predetermined communication paths of any condition that could threaten the reliability of its area or when firm load shedding is anticipated.
COM-002-2	R2.	Each Reliability Coordinator, Transmission	N/A	The responsible entity	The responsible entity	The responsible entity

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Operator, and Balancing Authority shall issue directives in a clear, concise, and definitive manner; shall ensure the recipient of the directive repeats the information back correctly; and shall acknowledge the response as correct or repeat the original statement to resolve any misunderstandings.		provided a clear directive in a clear, concise and definitive manner and required the recipient to repeat the directive, but did not acknowledge the recipient was correct in the repeated directive.	provided a clear directive in a clear, concise and definitive manner, but did not require the recipient to repeat the directive.	failed to provide a clear directive in a clear, concise and difinitive manner when required.

Complete Violation Severity Level Matrix (EOP)
Encompassing All FERC-Approved Reliability Standards

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
EOP-001-0	R1.	Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for less than 25% of the adjacent BAs. Or less than 25% of those agreements do not contain provisions for emergency assistance.	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 25% to 50% of the adjacent BAs. Or 25 to 50% of those agreements do not contain provisions for emergency assistance.	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 50% to 75% of the adjacent BAs. Or 50% to 75% of those agreements do not contain provisions for emergency assistance.	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 75% or more of the adjacent BAs. Or more than 75% of those agreements do not contain provisions for emergency assistance.
EOP-001-0	R2.	The Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes.	The Transmission Operator has demonstrated the existence of the emergency load reduction plan but the plan will take longer than 30 minutes.	N/A	The Transmission Operator fails to include details on how load reduction is to be implemented in sufficient amount and time to mitigate IROL violation.	The Transmission Operator failed to demonstrate the existence of emergency load reduction plans for all identified IROLs.
EOP-001-0	R3.	Each Transmission Operator and Balancing Authority shall:	The Transmission Operator or Balancing Authority failed to comply with one (1) of the sub-components.	The Transmission Operator or Balancing Authority failed to comply with two (2) of the sub-components.	The Transmission Operator or Balancing Authority has failed to comply with three (3) of the sub-components.	The Transmission Operator or Balancing Authority has failed to comply with four (4) of the sub-components.
EOP-001-0	R3.1.	Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.	The Transmission Operator or Balancing Authority's emergency plans to mitigate insufficient generating capacity	The Transmission Operator or Balancing Authority's has demonstrated the existence of	The Transmission Operator or Balancing Authority's emergency plans to mitigate insufficient generating capacity emergency	The Transmission Operator or Balancing Authority has failed to develop emergency mitigation plans for insufficient generating

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			are missing minor details or minor program/procedural elements.	emergency plans to mitigate insufficient generating capacity emergency plans but the plans are not maintained.	plans are not maintained nor implemented.	capacity.
EOP-001-0	R3.2.	Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.	The Transmission Operator or Balancing Authority's plans to mitigate transmission system emergencies are missing minor details or minor program/procedural elements.	The Transmission Operator or Balancing Authority's has demonstrated the existence of transmission system emergency plans but are not maintained.	The Transmission Operator or Balancing Authority's transmission system emergency plans are not maintained nor implemented.	The Transmission Operator or Balancing Authority has failed to develop, maintain, and implement operating emergency mitigation plans for emergencies on the transmission system.
EOP-001-0	R3.3.	Develop, maintain, and implement a set of plans for load shedding.	The Transmission Operator or Balancing Authority's load shedding plans are missing minor details or minor program/procedural elements.	The Transmission Operator or Balancing Authority's has demonstrated the existence of load shedding plans but are not maintained.	The Transmission Operator or Balancing Authority's load shedding plans are partially compliant with the requirement but are not maintained nor implemented.	The Transmission Operator or Balancing Authority has failed to develop, maintain, and implement load shedding plans.
EOP-001-0	R3.4.	Develop, maintain, and implement a set of plans for system restoration.	The Transmission Operator or Balancing Authority's system restoration plans are missing minor details or minor program/procedural elements.	The Transmission Operator or Balancing Authority's system restoration plans are partially compliant with the requirement but are not maintained.	The Transmission Operator or Balancing Authority's restoration plans are not maintained nor implemented.	The Transmission Operator or Balancing Authority has failed to develop, maintain, and implement operating emergency mitigation plans for system restoration.
EOP-001-0	R4.	Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority	The Transmission Operator or Balancing Authority failed to comply with one (1) of the sub-	The Transmission Operator or Balancing Authority failed to comply with two (2) of the	The Transmission Operator or Balancing Authority has failed to comply with three (3) of the sub-components.	The Transmission Operator or Balancing Authority has failed to comply with all four (4) of the sub-

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		emergency plans shall include:	components.	sub-components.		components.
EOP-001-0	R4.1.	Communications protocols to be used during emergencies.	The Transmission Operator or Balancing Authority's communication protocols included in the emergency plan are missing minor program/procedural elements.	N/A	N/A	The Transmission Operator or Balancing Authority has failed to include communication protocols in its emergency plans to mitigate operating emergencies.
EOP-001-0	R4.2.	A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions.	The Transmission Operator or Balancing Authority's list of controlling actions has resulted in meeting the intent of the requirement but is missing minor program/procedural elements.	N/A	The Transmission Operator or Balancing Authority provided a list of controlling actions; however the actions fail to resolve the emergency within NERC-established timelines.	The Transmission Operator or Balancing Authority has failed to provide a list of controlling actions to resolve the emergency.
EOP-001-0	R4.3.	The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.	The Transmission Operator or Balancing Authority has demonstrated coordination with Transmission Operators and Balancing Authorities but is missing minor program/procedural elements.	N/A	N/A	The Transmission Operator or Balancing Authority has failed to demonstrate the tasks to be coordinated with adjacent Transmission Operator and Balancing Authorities as directed by the requirement.
EOP-001-0	R4.4.	Staffing levels for the emergency.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority's emergency plan does not include staffing levels for the

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						emergency
EOP-001-0	R5.	Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001-0 when developing an emergency plan.	The Transmission Operator and Balancing Authority emergency plan has complied with 90% or more of the number of sub-components.	The Transmission Operator and Balancing Authority emergency plan has complied with 70% to 90% of the number of sub-components.	The Transmission Operator and Balancing Authority emergency plan has complied with between 50% to 70% of the number of sub-components.	The Transmission Operator and Balancing Authority emergency plan has complied with 50% or less of the number of sub-components
EOP-001-0	R6.	The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.	The Transmission Operator and Balancing Authority is missing minor program/procedural elements.	The Transmission Operator and Balancing Authority has failed to annually review one of it's emergency plans	The Transmission Operator and Balancing Authority has failed to annually review 2 of its emergency plans or communicate with 1 of its neighboring Balancing Authorities.	The Transmission Operator and Balancing Authority has failed to annually review and/or communicate any emergency plans with its Reliability Coordinator, neighboring Transmission Operators or Balancing Authorities.
EOP-001-0	R7.	The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable:	The Transmission Operator and/or the Balancing Authority failed to comply with one (1) of the sub-components.	The Transmission Operator and/or the Balancing Authority failed to comply with two (2) of the sub-components.	The Transmission Operator and/or the Balancing Authority has failed to comply with three (3) of the sub-components.	The Transmission Operator and/or the Balancing Authority has failed to comply with four (4) or more of the sub-components.
EOP-001-0	R7.1.	The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority has failed to establish and maintain reliable communication between interconnected

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						systems.
EOP-001-0	R7.2.	The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority has failed to arrange new interchange agreements to provide for emergency capacity or energy transfers with required entities when existing agreements could not be used.
EOP-001-0	R7.3.	The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)	N/A	N/A	N/A	The Transmission Operator or Balancing Authority has failed to coordinate transmission and generator maintenance schedules to maximize capacity or conserve fuel in short supply.
EOP-001-0	R7.4.	The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority has failed to arrange for deliveries of electrical energy or fuel from remote systems through normal operating channels.
EOP-002-2.1	R1.	Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate	N/A	N/A	N/A	The Balancing Authority or Reliability Coordinator does not have responsibility and clear decision-

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		capacity and energy emergencies.				making authority to take whatever actions are needed to ensure the reliability of its respective area OR The Balancing Authority or Reliability Coordinator did not exercise its authority to alleviate capacity and energy emergencies.
EOP-002-2.1	R2.	Each Balancing Authority shall implement its capacity and energy emergency plan, when required and as appropriate, to reduce risks to the interconnected system.	N/A	N/A	N/A	The Balancing Authority did not implement its capacity and energy emergency plan, when required and as appropriate, to reduce risks to the interconnected system.
EOP-002-2.1	R3.	A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.	N/A	N/A	The Balancing Authority communicated its current and future system conditions to its Reliability Coordinator but did not communicate to one or more of its neighboring Balancing Authorities.	The Balancing Authority has failed to communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.
EOP-002-2.1	R4.	A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to	N/A	N/A	N/A	The Balancing Authority has failed to perform the necessary actions as required and stated in the requirement.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		reduce firm load.				
EOP-002-2.1	R5.	A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.	N/A	N/A	The Balancing Authority used the assistance provided by the Interconnection's frequency bias for more time than needed to implement corrective actions.	The Balancing Authority used the assistance provided by the Interconnection's frequency bias for more time than needed to implement corrective actions and unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes.
EOP-002-2.1	R6.	If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to:	The Balancing Authority failed to comply with one of the sub-components.	The Balancing Authority failed to comply with 2 of the sub-components.	The Balancing Authority failed to comply with 3 of the sub-components.	The Balancing Authority failed to comply with more than 3 of the sub-components.
EOP-002-2.1	R6.1.	Loading all available generating capacity.	N/A	N/A	N/A	The Balancing Authority did not use all available generating capacity.
EOP-002-2.1	R6.2.	Deploying all available operating reserve	N/A	N/A	N/A	The Balancing Authority did not deploy all of its available operating reserve.
EOP-002-2.1	R6.3.	Interrupting interruptible load and exports.	N/A	N/A	N/A	The Balancing Authority did not interrupt interruptible

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						load and exports.
EOP-002-2.1	R6.4.	Requesting emergency assistance from other Balancing Authorities.	N/A	N/A	N/A	The Balancing Authority did not request emergency assistance from other Balancing Authorities.
EOP-002-2.1	R6.5.	Declaring an Energy Emergency through its Reliability Coordinator; and	N/A	N/A	N/A	The Balancing Authority did not declare an Energy Emergency through its Reliability Coordinator.
EOP-002-2.1	R6.6.	Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.	N/A	N/A	N/A	The Balancing Authority did not implement one or more of the procedures stated in the requirement.
EOP-002-2.1	R7.	Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall:	N/A	N/A	The Balancing Authority has met only one of the two requirements	The Balancing Authority has not met either of the two requirements
EOP-002-2.1	R7.1.	Manually shed firm load without delay to return its ACE to zero; and	N/A	N/A	N/A	The Balancing Authority did not manually shed firm load without delay to return it's ACE to zero.
EOP-002-2.1	R7.2.	Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0 "Energy Emergency Alert Levels."	The Balancing Authority's implementation of an Energy Emergency Alert has missed minor program/procedural	N/A	N/A	The Balancing Authority has failed to meet one or more of the requirements of Attachment 1-EOP-002-0.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			elements in Attachment 1-EOP-002-0.			
EOP-002-2.1	R8.	A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002-0 "Energy Emergency Alert Levels." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.	The Reliability Coordinator's implementation of an Energy Emergency Alert has missed minor program/procedural elements in Attachment 1-EOP-002-0.	N/A	N/A	The Reliability Coordinator has failed to meet one or more of the requirements of Attachment 1-EOP-002-0.
EOP-002-2.1	R9.	When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources) as permitted in its transmission tariff (See Attachment 1-IRO-006-0 "Transmission Loading Relief Procedure" for explanation of Transmission Service Priorities):	The Reliability Coordinator failed to comply with one (1) of the sub-components.	The Reliability Coordinator failed to comply with two (2) of the sub-components.	The Reliability Coordinator has failed to comply with three (3) of the sub-components.	The Reliability Coordinator has failed to comply with all four (4) of the sub-components.
EOP-002-2.1	R9.1.	The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0.	N/A	N/A	N/A	The Load-Serving Entity failed to request its Reliability Coordinator to initiate an Energy Emergency Alert.
EOP-002-2.1	R9.2.	The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed.	N/A	N/A	N/A	The Reliability Coordinator has failed to report to NERC as directed in the requirement.
EOP-002-2.1	R9.3.	The Reliability Coordinator shall use EEA 1	N/A	N/A	N/A	The Reliability

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.				Coordinator failed to use EEA 1 to forecast the change of the priority of transmission service as directed in the requirement.
EOP-002-2.1	R9.4.	The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.	N/A	N/A	N/A	The Reliability Coordinator failed to use EEA 2 to announce the change of the priority of transmission service as directed in the requirement.
EOP-003-1	R1.	After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority has failed shed customer load.
EOP-003-1	R2.	Each Transmission Operator and Balancing Authority shall establish plans for automatic load shedding for underfrequency or undervoltage conditions.	N/A	N/A	N/A	The applicable entity did not establish plans for automatic load-shedding, as directed by the requirement.
EOP-003-1	R3.	Each Transmission Operator and Balancing Authority shall coordinate load shedding plans among other interconnected Transmission Operators and Balancing Authorities.	The applicable entity did not coordinate load shedding plans, as directed by the requirement, affecting 5% or less of its required entities.	The applicable entity did not coordinate load shedding plans, as directed by the requirement, affecting between 5-10% of its required entities.	The applicable entity did not coordinate load shedding plans, as directed by the requirement, affecting 10-15%, inclusive, of its required entities.	The applicable entity did not coordinate load shedding plans, as directed by the requirement, affecting greater than 15% of its required entities.
EOP-003-1	R4.	A Transmission Operator or Balancing Authority shall consider one or more of	N/A	N/A	N/A	The applicable entity did not consider one

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		these factors in designing an automatic load shedding scheme: frequency, rate of frequency decay, voltage level, rate of voltage decay, or power flow levels.				of the five required elements, as directed by the requirement.
EOP-003-1	R5.	A Transmission Operator or Balancing Authority shall implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority has failed to implement load shedding as directed in the requirement.
EOP-003-1	R6.	After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority did not shed load.
EOP-003-1	R7.	The Transmission Operator and Balancing Authority shall coordinate automatic load shedding throughout their areas with underfrequency isolation of generating units, tripping of shunt capacitors, and other automatic actions that will occur under abnormal frequency, voltage, or power flow conditions.	The applicable entity did not coordinate automatic load shedding, as directed by the requirement, affecting 5% or less of its automatic actions.	The applicable entity did not coordinate automatic load shedding, as directed by the requirement, affecting between 5 - 10% of its automatic actions.	The applicable entity did not coordinate automatic load shedding, as directed by the requirement, affecting 10-15%, inclusive, of its automatic actions.	The applicable entity did not coordinate automatic load shedding, as directed by the requirement, affecting greater than 15% of its automatic actions.
EOP-003-1	R8.	Each Transmission Operator or Balancing Authority shall have plans for operator-controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.	N/A	The applicable entity did not have plans for operator controlled manual load shedding, as directed by the requirement.	The applicable entity did not have the capability to implement the load shedding, as directed by the requirement.	The applicable entity did not have plans for operator controlled manual load shedding, as directed by the requirement nor had the capability to implement the load shedding, as directed by the requirement.
EOP-004-1	R1.	Each Regional Reliability Organization	The Regional	The Regional	The Regional	The Regional

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		shall establish and maintain a Regional reporting procedure to facilitate preparation of preliminary and final disturbance reports.	Reliability Organization has demonstrated the existence of a regional reporting procedure, but the procedure is missing minor details or minor program/procedural elements.	Reliability Organization Regional reporting procedure have been is missing one element that would make the procedure meet the requirement.	Reliability Organization Regional has a regional reporting procedure but the procedure is not current.	Reliability Organization does not have a regional reporting procedure.
EOP-004-1	R2.	A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load-Serving Entity shall promptly analyze Bulk Electric System disturbances on its system or facilities.	N/A	The responsible entities has failed to analyze 1% to 25% of its disturbances on the BES or was negligent in the timeliness of analyzing the disturbances 1% to 25% of the time.	The responsible entities has failed to analyze 26% to 50% of its disturbances on the BES or was negligent in the timeliness of analyzing the disturbances 26% to 50% of the time.	The responsible entities has failed to analyze more than 50% of its disturbances on the BES or negligent in the timeliness of analyzing the disturbances more than 50% of the time
EOP-004-1	R3.	A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load-Serving Entity experiencing a reportable incident shall provide a preliminary written report to its Regional Reliability Organization and NERC.	N/A	N/A	N/A	The responsible entities failed to provide a preliminary written report as directed by the requirement.
EOP-004-1	R3.1.	The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load-Serving Entity shall submit within 24 hours of the disturbance or unusual occurrence either a copy of the report submitted to DOE, or, if no DOE report is required, a copy of the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report form. Events that are not identified until some time after they		The responsible entities submitted the report within 25 to 36 hours of the disturbance or discovery of the disturbance.	The responsible entities submitted the report within 36 to 48 hours of the disturbance or discovery of the disturbance.	The responsible entities submitted the report more than 48 hours after the disturbance or discovery of the disturbance.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		occur shall be reported within 24 hours of being recognized.				
EOP-004-1	R3.2.	Applicable reporting forms are provided in Attachments 022-1 and 022-2.	N/A	N/A	N/A	N/A
EOP-004-1	R3.3.	Under certain adverse conditions, e.g., severe weather, it may not be possible to assess the damage caused by a disturbance and issue a written Interconnection Reliability Operating Limit and Preliminary Disturbance Report within 24 hours. In such cases, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load-Serving Entity shall promptly notify its Regional Reliability Organization(s) and NERC, and verbally provide as much information as is available at that time. The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load-Serving Entity shall then provide timely, periodic verbal updates until adequate information is available to issue a written Preliminary Disturbance Report.	The responsible entity provided its Reliability Coordinator and NERC with periodic, verbal updates about a disturbance, but the updates did not include all information that was available at the time.	N/A	N/A	The responsible entity did not provide its Reliability Coordinator and NERC with verbal updates about a disturbance as specified in R3.3.
EOP-004-1	R3.4.	If, in the judgment of the Regional Reliability Organization, after consultation with the Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load-Serving Entity in which a disturbance occurred, a final report is required, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load-Serving Entity shall prepare this report within 60 days. As a minimum, the final report shall have a discussion of the events and its cause, the conclusions reached, and recommendations to prevent	The responsible entities final report is missing minor details or minor program/procedural elements.	The responsible entities final report was 30 days late or was missing one of the elements specified in the requirement.	The responsible entities final report was more than 30 days late or was missing two of the elements specified in the requirement.	The responsible entities final report was not submitted or was missing more than two of the elements specified in the requirement.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		recurrence of this type of event. The report shall be subject to Regional Reliability Organization approval.				
EOP-004-1	R4.	When a Bulk Electric System disturbance occurs, the Regional Reliability Organization shall make its representatives on the NERC Operating Committee and Disturbance Analysis Working Group available to the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load-Serving Entity immediately affected by the disturbance for the purpose of providing any needed assistance in the investigation and to assist in the preparation of a final report.	N/A	N/A	N/A	The RRO did not make its representatives on the NERC Operating Committee and Disturbance Analysis Working Group available for the purpose of providing any needed assistance in the investigation and to assist in the preparation of a final report.
EOP-004-1	R5.	The Regional Reliability Organization shall track and review the status of all final report recommendations at least twice each year to ensure they are being acted upon in a timely manner. If any recommendation has not been acted on within two years, or if Regional Reliability Organization tracking and review indicates at any time that any recommendation is not being acted on with sufficient diligence, the Regional Reliability Organization shall notify the NERC Planning Committee and Operating Committee of the status of the recommendation(s) and the steps the Regional Reliability Organization has taken to accelerate implementation.	The Regional Reliability Organization reviewed all final report recommendations less than twice a year.	The Regional Reliability Organization reviewed 75% or more final report recommendations twice a year.	The Regional Reliability Organization has not reported on any recommendation has not been acted on within two years to the NERC Planning and Operating Committees.	The Regional Reliability Organization has not reviewed the final report recommendations or did not notify the NERC Planning and Operating Committees.
EOP-005-1	R1.	Each Transmission Operator shall have a restoration plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shutdown of its system, including necessary operating	The responsible entity has a restoration plan that includes 75 % or more but less than 100% of the	The responsible entity has a restoration plan that includes 50% to 75% of the	The responsible entity has a restoration plan that includes 25% - 50% of the applicable elements listed in	The responsible entity has a restoration plan that includes less than 25% of the applicable elements listed in

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		instructions and procedures to cover emergency conditions, and the loss of vital telecommunications channels. Each Transmission Operator shall include the applicable elements listed in Attachment 1-EOP-005 in developing a restoration plan.	applicable elements listed in Attachment 1.	applicable elements listed in Attachment 1.	Attachment 1.	Attachment 1 OR the responsible entity has no restoration plan.
EOP-005-1	R2.	Each Transmission Operator shall review and update its restoration plan at least annually and whenever it makes changes in the power system network, and shall correct deficiencies found during the simulated restoration exercises.	The Transmission Operator failed to review or update its restoration plan when it made changes in the power system network.	The Transmission Operator failed to review and update its restoration plan at least annually.	The Transmission Operator failed to review and update its restoration plan at least annually or whenever it made changes in the power system network, and failed to correct deficiencies found during the simulated restoration exercises.	The Transmission Operator failed to review and update its restoration plan at least annually and whenever it made changes in the power system network, and failed to correct deficiencies found during the simulated restoration exercises.
EOP-005-1	R3.	Each Transmission Operator shall develop restoration plans with a priority of restoring the integrity of the Interconnection.	N/A	N/A	N/A	The Transmission Operator's restoration plans failed to make restoration of the integrity of the Interconnection a top priority.
EOP-005-1	R4.	Each Transmission Operator shall coordinate its restoration plans with the Generator Owners and Balancing Authorities within its area, its Reliability Coordinator, and neighboring Transmission Operators and Balancing Authorities.	The Transmission Operator failed to coordinate its restoration plans with one of the entities listed in the requirement.	The Transmission Operator failed to coordinate its restoration plans with two of the entities listed in the requirement.	The Transmission Operator failed to coordinate its restoration plans with three of the entities listed in the requirement.	The Transmission Operator failed to coordinate its restoration plans with four or more of the entities listed in the requirement.
EOP-005-1	R5.	Each Transmission Operator and Balancing Authority shall periodically test its telecommunication facilities needed to implement the restoration plan.	N/A	N/A	N/A	The responsible entity failed to periodically test its telecommunication facilities needed to

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						implement the restoration plan.
EOP-005-1	R6.	Each Transmission Operator and Balancing Authority shall train its operating personnel in the implementation of the restoration plan. Such training shall include simulated exercises, if practicable.	The responsible entity only trained less than 100% but greater than or equal to 67 % of its operating personnel in the implementation of the restoration plan.	The responsible entity only trained less than 67 % but greater than or equal to 33 % of its operating personnel in the implementation of the restoration plan.	The responsible entity only trained less than 33 % of its operating personnel in the implementation of the restoration plan.	The responsible entity did not trained any of its operating personnel in the implementation of the restoration plan.
EOP-005-1	R7.	Each Transmission Operator and Balancing Authority shall verify the restoration procedure by actual testing or by simulation.	The responsible entity verified 76% to 99% of the restoration procedure by actual testing or by simulation.	The responsible entity verified 51% to 75% of the restoration procedure by actual testing or by simulation.	The responsible entity verified 26% to 50% of the restoration procedure by actual testing or by simulation.	The responsible entity verified less than 26% of the restoration procedure by actual testing or by simulation.
EOP-005-1	R8.	Each Transmission Operator shall verify that the number, size, availability, and location of system blackstart generating units are sufficient to meet Regional Reliability Organization restoration plan requirements for the Transmission Operator's area.	N/A	N/A	N/A	The Transmission Operator failed to verify that the number, size, availability, and location of system blackstart generating units are sufficient to meet Regional Reliability Organization restoration plan requirements for the Transmission Operator's area.
EOP-005-1	R9.	The Transmission Operator shall document the Cranking Paths, including initial switching requirements, between each blackstart generating unit and the unit(s) to be started and shall provide this	N/A	N/A	N/A	The Transmission Operator shall document the Cranking Paths, including initial

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		documentation for review by the Regional Reliability Organization upon request. Such documentation may include Cranking Path diagrams.				switching requirements, between each blackstart generating unit and the unit(s) to be started and shall provide this documentation for review by the Regional Reliability Organization upon request.
EOP-005-1	R10.	The Transmission Operator shall demonstrate, through simulation or testing, that the blackstart generating units in its restoration plan can perform their intended functions as required in the regional restoration plan.	The Transmission Operator only demonstrated, through simulation or testing, that between 67 and 99% of the blackstart generating units in its restoration plan can perform their intended functions as required in the regional restoration plan.	The Transmission Operator only demonstrated, through simulation or testing, that between 33 and 66% of the blackstart generating units in its restoration plan can perform their intended functions as required in the regional restoration plan.	The Transmission Operator only demonstrated, through simulation or testing, that less than 33% of the blackstart generating units in its restoration plan can perform their intended functions as required in the regional restoration plan.	The Transmission Operator did not demonstrate, through simulation or testing, that any of the blackstart generating units in its restoration plan can perform their intended functions as required in the regional restoration plan.
EOP-005-1	R10.1.	The Transmission Operator shall perform this simulation or testing at least once every five years.	N/A	N/A	N/A	The Transmission Operator failed to perform the required simulation or testing at least once every five years.
EOP-005-1	R11.	Following a disturbance in which one or more areas of the Bulk Electric System become isolated or blacked out, the affected Transmission Operators and Balancing Authorities shall begin immediately to return the Bulk Electric System to normal.	The responsible entity failed to comply with less than 25% of the number of sub-components.	The responsible entity failed to comply with 25% or more and less than 50% of the number of sub-components.	The responsible entity failed to comply with 50% or more and less than 75% of the number of sub-components.	The responsible entity failed to comply with more than 75% of the number of sub-components.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
EOP-005-1	R11.1.	The affected Transmission Operators and Balancing Authorities shall work in conjunction with their Reliability Coordinator(s) to determine the extent and condition of the isolated area(s).	N/A	N/A	N/A	The responsible entity failed to work in conjunction with their Reliability Coordinator to determine the extent and condition of the isolated area(s)
EOP-005-1	R11.2.	The affected Transmission Operators and Balancing Authorities shall take the necessary actions to restore Bulk Electric System frequency to normal, including adjusting generation, placing additional generators on line, or load shedding.	N/A	N/A	N/A	The affected Transmission Operators and Balancing Authorities failed to take the necessary actions to restore Bulk Electric System frequency to normal.
EOP-005-1	R11.3.	The affected Balancing Authorities, working with their Reliability Coordinator(s), shall immediately review the Interchange Schedules between those Balancing Authority Areas or fragments of those Balancing Authority Areas within the separated area and make adjustments as needed to facilitate the restoration. The affected Balancing Authorities shall make all attempts to maintain the adjusted Interchange Schedules, whether generation control is manual or automatic.	N/A	N/A	The responsible entity failed to make all attempts to maintain adjusted Interchange Schedules as required in R11.3	The responsible entity failed to immediately review the Interchange Schedules between those Balancing Authority Areas or fragments of those Balancing Authority Areas within the separated area and make adjustments to facilitate the restoration as required in R11.3.
EOP-005-1	R11.4.	The affected Transmission Operators shall give high priority to restoration of off-site power to nuclear stations.	N/A	N/A	N/A	The affected Transmission Operators failed to give high priority to restoration of off-site power to nuclear

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						stations.
EOP-005-1	R11.5.	The affected Transmission Operators may resynchronize the isolated area(s) with the surrounding area(s) when the following conditions are met:	The responsible entity failed to include one of the subrequirements.	The responsible entity failed to include two of the subrequirements.	The responsible entity failed to include three of the subrequirements.	The responsible entity failed to include four of the subrequirements.
EOP-005-1	R11.5.1.	Voltage, frequency, and phase angle permit.	N/A	N/A	N/A	The responsible entity failed to meet this requirement before resynchronizing isolated areas.
EOP-005-1	R11.5.2.	The size of the area being reconnected and the capacity of the transmission lines effecting the reconnection and the number of synchronizing points across the system are considered.	N/A	N/A	N/A	The responsible entity failed to meet this requirement before resynchronizing isolated areas.
EOP-005-1	R11.5.3.	Reliability Coordinator(s) and adjacent areas are notified and Reliability Coordinator approval is given.	N/A	N/A	N/A	The responsible entity failed to meet this requirement before resynchronizing isolated areas.
EOP-005-1	R11.5.4.	Load is shed in neighboring areas, if required, to permit successful interconnected system restoration.	N/A	N/A	N/A	The responsible entity failed to meet this requirement before resynchronizing isolated areas.
EOP-006-1	R1.	Each Reliability Coordinator shall be aware of the restoration plan of each Transmission Operator in its Reliability Coordinator Area in accordance with NERC and regional requirements.	The Reliability Coordinator is aware of more than 75% of its Transmission Operators restoration plans.	The Reliability Coordinator is aware of more than 50% but less than 75%of its Transmission Operators restoration plans.	The Reliability Coordinator is aware of more than 25% but less than 50% of its Transmission Operators restoration plans.	The Reliability Coordinator is not aware of any of its Transmission Operators restoration plans.
EOP-006-1	R2.	The Reliability Coordinator shall monitor restoration progress and coordinate any needed assistance.	N/A	N/A	The Reliability Coordinator failed to monitor restoration progress or failed to	The Reliability Coordinator failed to monitor restoration progress and failed to

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
					coordinate assistance.	coordinate assistance.
EOP-006-1	R3.	The Reliability Coordinator shall have a Reliability Coordinator Area restoration plan that provides coordination between individual Transmission Operator restoration plans and that ensures reliability is maintained during system restoration events.	N/A	The Reliability Coordinator's Reliability Coordinator Area restoration plan did not coordinate with one individual Transmission Operator restoration plans.	The Reliability Coordinator's Reliability Coordinator Area restoration plan did not coordinate with more than one individual Transmission Operator restoration plans.	The Reliability Coordinator does not have a Reliability Coordinator Area restoration plan.
EOP-006-1	R4.	The Reliability Coordinator shall serve as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators and Transmission Operators or Balancing Authorities not immediately involved in restoration.	The Reliability Coordinator failed to disseminate information regarding restoration to one neighboring Reliability Coordinator or Transmission Operator or Balancing Authority not immediately involved in restoration.	The Reliability Coordinator failed to disseminate information regarding restoration to two neighboring Reliability Coordinators or Transmission Operators or Balancing Authorities not immediately involved in restoration.	The Reliability Coordinator failed to disseminate information regarding restoration to three neighboring Reliability Coordinators or Transmission Operators or Balancing Authorities not immediately involved in restoration.	The Reliability Coordinator failed to disseminate information regarding restoration to four or more neighboring Reliability Coordinators or Transmission Operators or Balancing Authorities not immediately involved in restoration.
EOP-006-1	R5.	Reliability Coordinators shall approve, communicate, and coordinate the re-synchronizing of major system islands or synchronizing points so as not to cause a Burden on adjacent Transmission Operator, Balancing Authority, or Reliability Coordinator Areas.	N/A	N/A	N/A	The Reliability Coordinators failed to approve, communicate, and coordinate the re-synchronizing of major system islands or synchronizing points and caused a Burden on adjacent Transmission Operator, Balancing

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						Authority, or Reliability Coordinator Areas.
EOP-006-1	R6.	The Reliability Coordinator shall take actions to restore normal operations once an operating emergency has been mitigated in accordance with its restoration plan.	N/A	N/A	N/A	The Reliability Coordinator failed to take actions to restore normal operations once an operating emergency has been mitigated in accordance with its restoration plan.
EOP-008-0	R1.	Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have a plan to continue reliability operations in the event its control center becomes inoperable. The contingency plan must meet the following requirements:	The Reliability Coordinator, Transmission Operator and Balancing Authority failed to comply with one of the sub-requirements.	The Reliability Coordinator, Transmission Operator and Balancing Authority failed to comply with two of the sub-requirements.	The Reliability Coordinator, Transmission Operator and Balancing Authority failed to comply with three or four of the sub-requirements.	The Reliability Coordinator, Transmission Operator and Balancing Authority failed to comply with more than four of the sub-requirements.
EOP-008-0	R1.1.	The contingency plan shall not rely on data or voice communication from the primary control facility to be viable.	The responsible entity's contingency plan relies on data or voice communication from the primary control facility for up to 25% of the functions identified in R1.2 and R1.3.	The responsible entity's contingency plan relies on data or voice communication from the primary control facility for 25% to 50% of the functions identified in R1.2 and R1.3.	The responsible entity's contingency plan relies on data or voice communication from the primary control facility for 50% to 75% of the functions identified in R1.2 and R1.3.	The responsible entity's contingency plan relies on data and voice communication from the primary control facility for more than 75% of the functions identified in R1.2 and R1.3.
EOP-008-0	R1.2.	The plan shall include procedures and responsibilities for providing basic tie line control and procedures and for maintaining the status of all inter-area schedules, such that there is an hourly accounting of all schedules.	N/A	N/A	N/A	The responsible entity's plan failed to include procedures and responsibilities for providing basic tie line control and procedures and for

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						maintaining the status of all inter-area schedules, such that there is an hourly accounting of all schedules.
EOP-008-0	R1.3.	The contingency plan must address monitoring and control of critical transmission facilities, generation control, voltage control, time and frequency control, control of critical substation devices, and logging of significant power system events. The plan shall list the critical facilities.	The responsible entity's contingency plan failed to address one of the elements listed in the requirement.	The responsible entity's contingency plan failed to address two of the elements listed in the requirement.	The responsible entity's contingency plan failed to address three of the elements listed in the requirement.	The responsible entity's contingency plan failed to address four or more of the elements listed in the requirement.
EOP-008-0	R1.4.	The plan shall include procedures and responsibilities for maintaining basic voice communication capabilities with other areas.	N/A	N/A	N/A	The responsible entity's plan failed to include procedures and responsibilities for maintaining basic voice communication capabilities with other areas.
EOP-008-0	R1.5.	The plan shall include procedures and responsibilities for conducting periodic tests, at least annually, to ensure viability of the plan.	N/A	N/A	N/A	The responsible entity's plan failed to include procedures and responsibilities for conducting periodic tests, at least annually, to ensure viability of the plan.
EOP-008-0	R1.6.	The plan shall include procedures and responsibilities for providing annual training to ensure that operating personnel are able to implement the contingency plans.	N/A	N/A	N/A	The responsible entity's plan failed to include procedures and responsibilities for providing annual training to ensure that operating personnel are able to implement

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						the contingency plans.
EOP-008-0	R1.7.	The plan shall be reviewed and updated annually.	The responsible entity's plan was reviewed within 3 months of passing its annual review date.	The responsible entity's plan was reviewed within 6 months of passing its annual review date.	The responsible entity's plan was reviewed within 9 months of passing its annual review date.	The responsible entity's plan was reviewed more than 9 months of passing its annual review date.
EOP-008-0	R1.8.	Interim provisions must be included if it is expected to take more than one hour to implement the contingency plan for loss of primary control facility.	N/A	N/A	N/A	The responsible entity failed to make interim provisions when it is took more than one hour to implement the contingency plan for loss of primary control facility.
EOP-009-0	R1.	The Generator Operator of each blackstart generating unit shall test the startup and operation of each system blackstart generating unit identified in the BCP as required in the Regional BCP (Reliability Standard EOP-007-0_R1). Testing records shall include the dates of the tests, the duration of the tests, and an indication of whether the tests met Regional BCP requirements.	The Generator Operator Blackstart unit testing and recording is missing minor program/procedural elements.	Startup and testing of each Blackstart unit was performed, but the testing records are incomplete. The testing records are missing 25% or less of data requested in the requirement'.	The Generator Operator's failed to test 25% or less of the Blackstart units or testing records are incomplete. The testing records are missing between 25% and 50% of data requested in the requirement.	The Generator Operator failed to test more than 25% of its Blackstart units or does not have Blackstart testing records or is missing more than 50% of the required data.
EOP-009-0	R2.	The Generator Owner or Generator Operator shall provide documentation of the test results of the startup and operation of each blackstart generating unit to the Regional Reliability Organizations and upon request to NERC.	The Generator Operator has provided the Blackstart testing documentation to its Regional Reliability Organization. However the documentation provided had missing minor program/procedural elements or failed to provide the	N/A	N/A	The Generator Operator did not provide the required Blackstart documentation to its Regional Reliability Organization.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			documentation requested to NERC in 30 days.			

Complete Violation Severity Level Matrix (FAC)
Encompassing All FERC-Approved Reliability Standards

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
FAC-001-0	R1.	The Transmission Owner shall document, maintain, and publish facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Reliability Organization, subregional, Power Pool, and individual Transmission Owner planning criteria and facility connection requirements. The Transmission Owner's facility connection requirements shall address connection requirements for:	Not Applicable.	The Transmission Owner's facility connection requirements failed to address connection requirements for one of the subrequirements.	The Transmission Owner's facility connection requirements failed to address connection requirements for two of the subrequirements.	The Transmission Owner's facility connection requirements failed to address connection requirements for three of the subrequirements.
FAC-001-0	R1.1.	Generation facilities,	The Transmission Owner has Generation facility connection requirements, but they have not been updated to include changes that are currently in effect, but have not been in effect for more than one month.	The Transmission Owner has Generation facility connection requirements, but they have not been updated to include changes that were effective more than one month ago, but not more than six months ago.	The Transmission Owner has Generation facility connection requirements, but they have not been updated to include changes that were effective more than six months ago.	The Transmission Owner does not have Generation facility connection requirements.
FAC-001-0	R1.2.	Transmission facilities, and	The Transmission Owner has Transmission facility connection requirements, but they have not been updated to include changes that are currently in effect, but have not been in effect for more than one month.	The Transmission Owner has Transmission facility connection requirements, but they have not been updated to include changes that were effective more than one month ago, but not more than six months ago.	The Transmission Owner has Transmission facility connection requirements, but they have not been updated to include changes that were effective more than six months ago.	The Transmission Owner does not have Transmission facility connection requirements.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
FAC-001-0	R1.3.	End-user facilities	The Transmission Owner has End-user facility connection requirements, but they have not been updated to include changes that are currently in effect, but have not been in effect for more than one month.	The Transmission Owner has End-user facility connection requirements, but they have not been updated to include changes that were effective more than one month ago, but not more than six months ago.	The Transmission Owner has End-user facility connection requirements, but they have not been updated to include changes that were effective more than six months ago.	The Transmission Owner does not have End-user facility connection requirements.
FAC-001-0	R2.	The Transmission Owner's facility connection requirements shall address, but are not limited to, the following items:	The Transmission Owner's facility connection requirements do not address one to four of the sub-components. (R2.1.1 to R2.1.16)	The Transmission Owner's facility connection requirements do not address five to eight of the sub-components. (R2.1.1 to R2.1.16)	The Transmission Owner's facility connection requirements do not address nine to twelve of the sub-components. (R2.1.1 to R2.1.16)	The Transmission Owner's facility connection requirements do not address thirteen or more of the sub-components. (R2.1.1 to R2.1.16)
FAC-001-0	R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:	The Transmission Owner's facility connection requirements do not address one to four of the sub-components. (R2.1.1 to R2.1.16)	The Transmission Owner's facility connection requirements do not address five to eight of the sub-components. (R2.1.1 to R2.1.16)	The Transmission Owner's facility connection requirements do not address nine to twelve of the sub-components. (R2.1.1 to R2.1.16)	The Transmission Owner's facility connection requirements do not address thirteen or more of the sub-components. (R2.1.1 to R2.1.16)
FAC-001-0	R2.1.1.	Procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems failed to include this subrequirement.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
FAC-001-0	R2.1.2.	Procedures for notification of new or modified facilities to others (those responsible for the reliability of the interconnected transmission systems) as soon as feasible.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems failed to include this subrequirement.
FAC-001-0	R2.1.3.	Voltage level and MW and MVAR capacity or demand at point of connection.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems failed to include this subrequirement.
FAC-001-0	R2.1.4.	Breaker duty and surge protection.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems failed to include this subrequirement.
FAC-001-0	R2.1.5.	System protection and coordination.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						transmission systems failed to include this subrequirement.
FAC-001-0	R2.1.6.	Metering and telecommunications.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems failed to include this subrequirement.
FAC-001-0	R2.1.7.	Grounding and safety issues.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems failed to include this subrequirement.
FAC-001-0	R2.1.8.	Insulation and insulation coordination.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems failed to include this subrequirement.
FAC-001-0	R2.1.9.	Voltage, Reactive Power, and power factor control.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						facilities and their impacts on the interconnected transmission systems failed to include this subrequirement.
FAC-001-0	R2.1.10.	Power quality impacts.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems failed to include this subrequirement.
FAC-001-0	R2.1.11.	Equipment Ratings.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems failed to include this subrequirement.
FAC-001-0	R2.1.12.	Synchronizing of facilities.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems failed to include this subrequirement.
FAC-001-0	R2.1.13.	Maintenance coordination.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems failed to include this subrequirement.
FAC-001-0	R2.1.14.	Operational issues (abnormal frequency and voltages).	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems failed to include this subrequirement.
FAC-001-0	R2.1.15.	Inspection requirements for existing or new facilities.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems failed to include this subrequirement.
FAC-001-0	R2.1.16.	Communications and procedures during normal and emergency operating conditions.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						failed to include this subrequirement.
FAC-001-0	R3.	The Transmission Owner shall maintain and update its facility connection requirements as required. The Transmission Owner shall make documentation of these requirements available to the users of the transmission system, the Regional Reliability Organization, and NERC on request (five business days).	The Transmission Owner made the requirements available more than five business days after a request, but not more than ten business days after a request.	The Transmission Owner made the requirements available more than ten business days after a request, but not more than twenty business days after a request.	The Transmission Owner made the requirements available more than twenty business days after a request, but not more than thirty business days after a request.	The Transmission Owner made the requirements available more than thirty business days after a request.
FAC-002-0	R1.	The Generator Owner, Transmission Owner, Distribution Provider, and Load-Serving Entity seeking to integrate generation facilities, transmission facilities, and electricity end-user facilities shall each coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority. The assessment shall include:	The Responsible Entity failed to include in their assessment one of the subrequirements.	The Responsible Entity failed to include in their assessment two of the subrequirements.	The Responsible Entity failed to include in their assessment three of the subrequirements.	The Responsible Entity failed to include in their assessment four or more of the subrequirements.
FAC-002-0	R1.1.	Evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems.	Not Applicable.	Not Applicable.	Not Applicable.	The responsible entity's assessment did not include the evaluation.
FAC-002-0	R1.2.	Ensurance of compliance with NERC Reliability Standards and applicable Regional, subregional, Power Pool, and individual system planning criteria and facility connection requirements.	Not Applicable.	Not Applicable.	Not Applicable.	The responsible entity’s assessment did not include the ensurance of compliance.
FAC-002-0	R1.3.	Evidence that the parties involved in the assessment have coordinated and cooperated on the assessment of the reliability impacts of new facilities on the interconnected transmission systems. While these studies may be performed independently, the results shall be jointly evaluated and coordinated by the entities	Not Applicable.	Not Applicable.	Not Applicable.	The responsible entity’s assessment did not include the evidence of coordination.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		involved.				
FAC-002-0	R1.4.	Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance in accordance with Reliability Standard TPL-001-0.	Not Applicable.	Not Applicable.	Not Applicable.	The responsible entity's assessment did not include the evidence of the studies.
FAC-002-0	R1.5.	Documentation that the assessment included study assumptions, system performance, and alternatives considered, and jointly coordinated recommendations.	Not Applicable.	Not Applicable.	Not Applicable.	The responsible entity's assessment did not include the documentation.
FAC-002-0	R2.	The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each retain its documentation (of its evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems) for three years and shall provide the documentation to the Regional Reliability Organization(s) Regional Reliability Organization(s) and NERC on request (within 30 calendar days).	The responsible entity provided the documentation more than 30 calendar days, but not more than 45 calendar days, after a request.	The responsible entity provided the documentation more than 45 calendar days, but not more than 60 calendar days, after a request.	The responsible entity provided the documentation more than 60 calendar days, but not more than 120 calendar days, after a request.	The responsible entity provided the documentation more than 120 calendar days after a request or was unable to provide the documentation.
FAC-003-1	R1.	The Transmission owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the Transmission Owner's objectives, practices, approved procedures, and work Specifications. 1. ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.	The applicable entity did not include and keep current one of the four required elements of its TVMP, as directed by the requirement.	The applicable entity did not include and keep current two of the four required elements of its TVMP, as directed by the requirement.	The applicable entity did not include and keep current three of the four required elements of its TVMP, as directed by the requirement.	The applicable entity did not include and keep current four of the four required elements of the TVMP, as directed by the requirement.
FAC-003-1	R1.1.	The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be	N/A	N/A	The applicable entity TVMP did not define a schedule, as directed by	The applicable entity TVMP did not define a schedule, as directed

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the Transmission Owner's transmission lines.			the requirement, or the type of ROW vegetation inspections, as directed by the requirement.	by the requirement, nor the type of ROW vegetation inspections, as directed by the requirement.
FAC-003-1	R1.2.	The Transmission Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the Transmission Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission Owner's TVMP does not specify clearances.
FAC-003-1	R1.2.1.	Clearance 1 — The Transmission Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the Transmission Owner plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission Owner's TVMP does not specify Clearance 1 values.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.				
FAC-003-1	R1.2.2.	Clearance 2 — The Transmission Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These Transmission Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission Owner's TVMP does not specify Clearance 2 values.
FAC-003-1	R1.2.2.1.	Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.	Not Applicable.	Not Applicable.	Not Applicable.	Where transmission system transient overvoltage factors are known, clearances were not derived from Table 5, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.
FAC-003-1	R1.2.2.2.	Where transmission system transient	Not Applicable.	Not Applicable.	Not Applicable.	Where transmission

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.				system transient overvoltage factors are known, clearances were not derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.
FAC-003-1	R1.3.	All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner, to perform their duties.	One or more persons directly involved in the design and implementation of the TVMP (but not more than 35% of the all personnel involved), did not hold appropriate qualifications and training to perform their duties.	More than 35% of all personnel directly involved in the design and implementation of the TVMP (but not more than 70% of all personnel involved), did not hold appropriate qualifications and training to perform their duties.	More than 70% of all personnel directly involved in the design and implementation of the TVMP (but not 100% of all personnel involved), did not hold appropriate qualifications and training to perform their duties.	None of the persons directly involved in the design and implementation of the Transmission Owner's TVMP held appropriate qualifications and training to perform their duties.
FAC-003-1	R1.4.	Each Transmission Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner is restricted from attaining the clearances specified in Requirement 1.2.1.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission Owner's TVMP does not include mitigation measures to achieve sufficient clearances where restrictions to the ROW are in effect.
FAC-003-1	R1.5.	Each Transmission Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that	N/A	N/A	N/A	The applicable entity did not establish or did not document a process, as directed by the requirement.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.				
FAC-003-1	R2.	The Transmission Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each Transmission Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.	The Transmission Owner did not meet one of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	The Transmission Owner did not meet two of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	The Transmission Owner did not meet the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	The Transmission Owner does not have an annual plan for vegetation management, or the Transmission Owner has not implemented the annual plan for vegetation management.
FAC-003-1	R3.	The Transmission Owner shall report quarterly to its RRO, or the RRO's designee, sustained transmission line outages determined by the Transmission Owner to have been caused by vegetation.	The Transmission Owner did not submit a quarterly report to its RRO and did not have any outages to report	The Transmission Owner did not report an outage specified as reportable in R3 to its RRO	The Transmission Owner did not report multiple outages specified as reportable in R3 to its RRO	The Transmission Owner did not report one or more outages specified as reportable in R3 to its RRO for two consecutive quarters
FAC-003-1	R3.1.	Multiple sustained outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of outages within a 24-hour	Not applicable.	Not applicable.	Not applicable.	The Transmission Owner failed to report, as a single outage, multiple sustained

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		period.				outages within a 24-hour period on an individual line, if caused by the same vegetation.
FAC-003-1	R3.2.	The Transmission Owner is not required to report to the RRO, or the RRO's designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).	Not applicable.	Not applicable.	Not applicable.	The Transmission Owner made reports for outages not considered reportable based on the categories listed in this requirement.
FAC-003-1	R3.3.	The outage information provided by the Transmission Owner to the RRO, or the RRO's designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the Transmission Owner.	The outage information provided by the Transmission Owner to the RRO, or the RRO's designee, did not include one of the required elements.	The outage information provided by the Transmission Owner to the RRO, or the RRO's designee, did not include two of the required elements.	The outage information provided by the Transmission Owner to the RRO, or the RRO's designee, did not include three of the required elements.	The outage information provided by the Transmission Owner to the RRO, or the RRO's designee, did not include four or more of the required elements.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
FAC-003-1	R3.4.	An outage shall be categorized as one of the following:	Not applicable.	Not applicable.	Not applicable.	The outage was not classified in the correct category.
FAC-003-1	R3.4.1.	Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;	Not applicable.	Not applicable.	Not applicable.	The outage was not classified in the correct category.
FAC-003-1	R3.4.2.	Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;	Not applicable.	Not applicable.	Not applicable.	The outage was not classified in the correct category.
FAC-003-1	R3.4.3.	Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.	Not applicable.	Not applicable.	Not applicable.	The outage was not classified in the correct category.
FAC-003-1	R4.	The RRO shall report the outage information provided to it by Transmission Owner's, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the RRO as a result of any of the reported outages.	Not applicable.	Not applicable.	The RRO did not submit a quarterly report to NERC for a single quarter.	The RRO did not submit a quarterly report to NERC for more than two consecutive quarters.
FAC-008-1	R1.	The Transmission Owner and Generator Owner shall each document its current methodology used for developing Facility Ratings (Facility Ratings Methodology) of its solely and jointly owned Facilities. The methodology shall include all of the following:	Not applicable.	Not applicable.	Not applicable.	The Transmission Owner or Generation Owner does not have a documented Facility Ratings Methodology for use in developing facility ratings.
FAC-008-1	R1.1.	A statement that a Facility Rating shall equal the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.	The Facility Rating methodology respects the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility but there is no statement in the	Not applicable.	Not applicable.	The Transmission Owner or Generator Owner has failed to demonstrate that its Facility Rating Methodology respects the most limiting applicable Equipment Rating of the

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			documentation of the methodology that states this.			individual equipment that comprises that Facility.
FAC-008-1	R1.2.	The method by which the Rating (of major BES equipment that comprises a Facility) is determined.	Not applicable.	Not applicable.	Not applicable.	The Transmission Owner's or Generation Owner's Facility Ratings Methodology does not specify the manner in which a rating is determined.
FAC-008-1	R1.2.1.	The scope of equipment addressed shall include, but not be limited to, generators, transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.	Not applicable.	The Transmission Owner or Generator Owner has demonstrated that it has a Facility Rating Methodology that includes methods of rating BES equipment but the equipment rating methods don't address one of the applicable required devices.	The Transmission Owner or Generator Owner has demonstrated the existence of methods of rating equipment but the equipment rating methods don't address two of the applicable required devices.	The Transmission Owner or Generator Owner has demonstrated the existence of methods of rating equipment but the equipment rating methods don't address more than two of the applicable required devices.
FAC-008-1	R1.2.2.	The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.	Not applicable.	The Transmission Owner or Generator Owner's equipment Ratings methodology does address a methodology for determining emergency ratings but fails to include a methodology for determining normal ratings for its BES	The Transmission Owner or Generator Owner's equipment Ratings methodology fails to include a methodology for determining emergency ratings for of its BES equipment.	The Transmission Owner or Generator Owner's equipment Ratings methodology fails to demonstrate the inclusion of any method for determining normal or emergency ratings for of its BES equipment.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				equipment.		
FAC-008-1	R1.3.	Consideration of the following:	The rating methodology did not consider one of the sub requirements.	The rating methodology did not consider two of the sub requirements.	The rating methodology did not consider three of the sub requirements.	The rating methodology did not consider four or more of the sub requirements.
FAC-008-1	R1.3.1.	Ratings provided by equipment manufacturers.	Not applicable.	Not applicable.	Not applicable.	The Transmission Owner or Generator Owner has failed to demonstrate the existence (in its Facility Rating Methodology) of how it considered ratings provided by equipment manufacturers.
FAC-008-1	R1.3.2.	Design criteria (e.g., including applicable references to industry Rating practices such as manufacturer's warranty, IEEE, ANSI or other standards).	Not applicable.	Not applicable.	Not applicable.	The Transmission Owner or Generator Owner has failed to demonstrate how it considered design criteria in developing its equipment Ratings.
FAC-008-1	R1.3.3.	Ambient conditions.	Not applicable.	Not applicable.	Not applicable.	The Transmission Owner or Generator Owner has failed to demonstrate how it considered ambient conditions in developing its equipment Ratings.
FAC-008-1	R1.3.4.	Operating limitations.	Not applicable.	Not applicable.	Not applicable.	The Transmission Owner or Generator Owner has failed to demonstrate how it

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						considered operating limitations in developing its equipment Ratings.
FAC-008-1	R1.3.5.	Other assumptions.	Not applicable.	Not applicable.	Not applicable.	The Transmission Owner or Generator Owner has failed to demonstrate how it considered other assumptions in developing its equipment Ratings.
FAC-008-1	R2.	The Transmission Owner and Generator Owner shall each make its Facility Ratings Methodology available for inspection and technical review by those Reliability Coordinators, Transmission Operators, Transmission Planners, and Planning Authorities that have responsibility for the area in which the associated Facilities are located, within 15 business days of receipt of a request.	The Transmission Owner or Generator Owner has made its Facility Ratings Methodology available to all required entities but not within 15 business days of a request.	The Transmission Owner or Generator Owner has not made its Facility Ratings Methodology available to one of the required entities, but did make the methodology available to all other required entities.	The Transmission Owner or Generator Owner fails to provide its Facility Ratings Methodology available to two or more of the required entities.	The Transmission Owner or Generator Owner has not made its Facility Rating Methodology available to any of the required entities in accordance with Requirement R2 within 60 business days of receipt of a request.
FAC-008-1	R3.	If a Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides written comments on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings Methodology, the Transmission Owner or Generator Owner shall provide a written response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings Methodology and, if no change will be made to that Facility Ratings Methodology, the reason	The responsible entity provided a response as required but took longer than 45 business days.	The responsible entity provided a response and the response indicated that a change will not be made to the Facility Ratings Methodology but did not indicate why no change will be made.	The responsible entity provided a response but the response did not indicate whether a change will be made to the Facility Ratings Methodology.	The responsible entity did not provide any evidence to demonstrate that it provided a response to a comment on its Facility Ratings Methodology in accordance with Requirement R3 within 90 business days.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		why.				
FAC-009-1	R1.	The Transmission Owner and Generator Owner shall each establish Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings Methodology.	The Transmission Owner or Generator Owner developed Facility Ratings for all its solely owned and jointly owned Facilities, but the ratings weren't consistent with the associated Facility Rating Methodology in one minor area.	The Transmission Owner or Generator Owner developed Facility Ratings for most, but not all of its solely and jointly owned Facilities following the associated Facility Ratings Methodology OR the Transmission Owner or Generator Owner developed Facility Ratings for all its solely and jointly owned Facilities but failed to follow the associated Facility Ratings Methodology in one significant area.	The Transmission Owner or Generator Owner developed Facility Ratings following the associated Facility Ratings Methodology but failed to develop any Facility Ratings for a significant number of its solely and jointly owned Facilities OR the Transmission Owner or Generator Owner has developed Facility Ratings for all its solely owned and jointly owned Facilities, but failed to follow the associated Facility Ratings Methodology in more than one significant area.	The Transmission Owner or Generator Owner has failed to demonstrate that it developed any Facility Ratings using its Facility Rating Methodology
FAC-009-1	R2.	The Transmission Owner and Generator Owner shall each provide Facility Ratings for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities to its associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) as scheduled by such requesting entities.	The Transmission Owner or Generator Owner provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by up to 15 calendar days.	The Transmission Owner or Generator Owner provided its Facility Ratings to all but one of the requesting entities.	The Transmission Owner or Generator Owner provided its Facility Ratings to two of the requesting entities.	The Transmission Owner or Generator Owner has provided its Facility Ratings to none of the requesting entities within 30 calendar days of the associated schedules.
FAC-010-2.1	R1	The Planning Authority shall have a documented SOL Methodology for use in	Not applicable.	The Planning Authority has a	The Planning Authority has a documented SOL	The Planning Authority has a

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		developing SOLs within its Planning Authority Area. This SOL Methodology shall:		documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.2	Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.	documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1. OR The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.
FAC-010-2.1	R1.1.	Be applicable for developing SOLs used in the planning horizon.	Not applicable.	Not applicable.	Not applicable.	Planning Authority SOL methodology is not applicable for developing SOL in the planning horizon.
FAC-010-2.1	R1.2.	State that SOLs shall not exceed associated Facility Ratings.	Not applicable.	Not applicable.	Not applicable.	Planning Authority SOL Methodology did not state that SOLs shall not exceed associated Facility Ratings
FAC-010-2.1	R1.3.	Include a description of how to identify the subset of SOLs that qualify as IROLs.	Not applicable.	Not applicable.	Not applicable.	Planning Authority SOL Methodology did not include a description of how to identify the subset of SOLs that qualify as IROLs.
FAC-010-2.1	R2.	The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following				

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
FAC-010-2.1	R2.1.	In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.	Not applicable.	Not applicable.	Not applicable.	The Planning Authority's methodology does not include a requirement that SOLs provide BES performance consistent with sub-requirement R2.1.
FAC-010-2.1	R2.2.	Following the single Contingencies identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.	Not applicable.	Not applicable.	Not applicable.	The Planning Authority's methodology does not include a requirement that SOLs provide BES performance consistent with sub-requirement R2.2.
FAC-010-2.1	R2.2.1.	Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.	Not applicable.	Not applicable.	Not applicable.	The methodology does not address single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.
FAC-010-2.1	R2.2.2.	Loss of any generator, line, transformer, or shunt device without a Fault.	Not applicable.	Not applicable.	Not applicable.	The methodology does not address the loss of any generator, line, transformer, or shunt device without a Fault.
FAC-010-2.1	R2.2.3.	Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	Not applicable.	Not applicable.	Not applicable.	The methodology does not address single pole block, with Normal

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						Clearing, in a monopolar or bipolar high voltage direct current system.
FAC-010-2.1	R2.3.	Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:	Not applicable.	Not applicable.	Not applicable.	The methodology does not include one or more of the following: 2.3.1. through 2.3.3.
FAC-010-2.1	R2.3.1.	Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.	Not applicable.	Not applicable.	Not applicable.	The SOL Methodology does not provide that starting with all Facilities in service, the system's response to a single Contingency may include planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.
FAC-010-2.1	R2.3.2.	System reconfiguration through manual or automatic control or protection actions.	Not applicable.	Not applicable.	Not applicable.	The SOL Methodology does not provide that starting with all Facilities in service, the system's response to a single Contingency may include System reconfiguration through manual or automatic control or protection actions.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
FAC-010-2.1	R2.4.	To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.	Not applicable.	Not applicable.	Not applicable.	The SOL Methodology does not provide that in order to prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.
FAC-010-2.1	R2.5.	Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.	Not applicable.	Not applicable.	Not applicable.	The SOL methodology does not include a requirement that SOLs provide BES performance consistent with sub-requirement R2.5.
FAC-010-2.1	R2.6.	In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:	Not applicable.	Not applicable.	Not applicable.	Not applicable.
FAC-010-2.1	R2.6.1.	Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.	Not applicable.	Not applicable.	Not applicable.	The SOL Methodology does not provide that in determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						identified in R2.3.1 and R2.3.2, Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers shall be acceptable.
FAC-010-2.1	R3.	The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:	The Planning Authority has a methodology for determining SOLs that includes a description for all but one of the following: R3.1 through R3.6.	The Planning Authority has a methodology for determining SOLs that includes a description for all but two of the following: R3.1 through R3.6.	The Planning Authority has a methodology for determining SOLs that includes a description for all but three of the following: R3.1 through R3.6.	The Planning Authority has a methodology for determining SOLs that is missing a description of four or more of the following: R3.1 through R3.6.
FAC-010-2.1	R3.1.	Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).	Not applicable.	Not applicable.	Not applicable.	The methodology does not include a study model that includes the entire Planning Authority Area, and the critical modeling details of other Planning Authority Areas that would impact the facility or facilities under study.
FAC-010-2.1	R3.2.	Selection of applicable Contingencies.	Not applicable.	Not applicable.	Not applicable.	The methodology does not include the selection of applicable

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						Contingencies.
FAC-010-2.1	R3.3	Level of detail of system models used to determine SOLs.	Not applicable.	Not applicable.	Not applicable.	The methodology does not describe the level of detail of system models used to determine SOLs.
FAC-010-2.1	R3.4.	Allowed uses of Special Protection Systems or Remedial Action Plans.	Not applicable.	Not applicable.	Not applicable.	The methodology does not describe the allowed uses of Special Protection Systems or Remedial Action Plans.
FAC-010-2.1	R3.5.	Anticipated transmission system configuration, generation dispatch and Load level.	Not applicable.	Not applicable.	Not applicable.	The methodology does not include the description of anticipated transmission system configuration, generation dispatch and Load level.
FAC-010-2.1	R3.6.	Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_V.	Not applicable.	Not applicable.	Not applicable.	The methodology does not include a description of the criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_V.
FAC-010-2.1	R4.	The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to	One or both of the following: The Planning	One of the following:	One of the following: The Planning Authority issued its SOL	One of the following: The Planning Authority failed to

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		the effectiveness of the change:	Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology,	issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
					the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. The Planning Authority issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.
FAC-010-2.1	R4.1.	Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.	Not applicable.	Not applicable.	Not applicable.	The Planning Authority did not issue its SOL Methodology and any change to that methodology, prior to the effectiveness of the change, to each adjacent Planning

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.
FAC-010-2.1	R4.2.	Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.	Not applicable.	Not applicable.	Not applicable.	The Planning Authority did not issue its SOL Methodology and any change to that methodology, prior to the effectiveness of the change, to each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.
FAC-010-2.1	R4.3.	Each Transmission Planner that works in the Planning Authority's Planning Authority Area.	Not applicable.	Not applicable.	Not applicable.	The Planning Authority did not issue its SOL Methodology and any change to that methodology, prior to the effectiveness of the change, to each Transmission Planner that works in the Planning Authority's Planning Authority Area prior to the effectiveness of the change.
FAC-010-2.1	R5.	If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that	The Planning Authority received documented technical comments on its SOL	The Planning Authority received documented technical comments	The Planning Authority received documented technical comments on its SOL Methodology	The Planning Authority received documented technical comments on its SOL

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.	Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.	on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.	and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days. OR The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	Methodology and provided a complete response in a time period that was 90 calendar days or longer. OR The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.
FAC-011-2	R1.	The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:	Not applicable.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1. OR The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area.
FAC-011-2	R1.1.	Be applicable for developing SOLs used in the operations horizon.	Not applicable.	Not applicable.	Not applicable.	The Reliability Coordinator's SOL methodology is not applicable for

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						developing SOL in the operations horizon.
FAC-011-2	R1.2.	State that SOLs shall not exceed associated Facility Ratings.	Not applicable.	Not applicable.	Not applicable.	The Reliability Coordinator's SOL Methodology did not state that SOLs shall not exceed associated Facility Ratings
FAC-011-2	R1.3	Include a description of how to identify the subset of SOLs that qualify as IROLs	Not applicable.	Not applicable.	Not applicable.	The Reliability Coordinator's SOL Methodology did not include a description of how to identify the subset of SOLs that qualify as IROLs.
FAC-011-2	R2.	The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:				
FAC-011-2	R2.1.	In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.	Not applicable.	Not applicable.	Not applicable.	The SOL methodology does not include a requirement that SOLs provide BES performance consistent with sub-requirement R2.1.
FAC-011-2	R2.2.	Following the single Contingencies1 identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation	Not applicable.	Not applicable.	Not applicable.	The SOL methodology does not include a requirement that SOLs provide BES performance consistent with sub-requirement R2.2.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		shall not occur.				
FAC-011-2	R2.2.1.	Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device	Not applicable.	Not applicable.	Not applicable.	The methodology does not require that SOLs provide BES performance consistent with: single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.
FAC-011-2	R2.2.2.	Loss of any generator, line, transformer, or shunt device without a Fault.	Not applicable.	Not applicable.	Not applicable.	The methodology does not address the loss of any generator, line, transformer, or shunt device without a Fault.
FAC-011-2	R2.2.3.	Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	Not applicable.	Not applicable.	Not applicable.	The methodology does not address single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.
FAC-011-2	R2.3.	In determining the system's response to a single Contingency, the following shall be acceptable:	Not applicable.	Not applicable.	Not applicable.	The methodology does not include one or more of the following 2.3.1. through 2.3.3.
FAC-011-2	R2.3.1.	Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.	Not applicable.	Not applicable.	Not applicable.	The methodology does not address that, in determining the systems response to a single contingency, Planned or controlled

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area is acceptable.
FAC-011-2	R2.3.2.	Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies	Not applicable.	Not applicable.	Not applicable.	The methodology does not address that, in determining the systems response to a single contingency, Interruption of other network customers is acceptable, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies.
FAC-011-2	R2.3.3.	System reconfiguration through manual or automatic control or protection actions.	Not applicable.	Not applicable.	Not applicable.	The methodology does not address that, in determining the systems response to a single contingency, system reconfiguration through manual or automatic control or protection actions is acceptable.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
FAC-011-2	R2.4.	To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.	Not applicable.	Not applicable.	Not applicable.	The methodology does not provide that to prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.
FAC-011-2	R3.	The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but one of the following: R3.1 through R3.7.	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but two of the following: R3.1 through R3.7.	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but three of the following: R3.1 through R3.7.	The Reliability Coordinator has a methodology for determining SOLs that is missing a description of four or more of the following: R3.1 through R3.7.
FAC-011-2	R3.1.	Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)	Not applicable.	Not applicable.	Not applicable.	The methodology does not include a description of the study model to be used which must include the entire Reliability Coordinator area, and the critical details of other Reliability Coordinator areas that would impact the facility or facilities under study
FAC-011-2	R3.2.	Selection of applicable Contingencies	Not applicable.	Not applicable.	Not applicable.	The methodology does not include the selection of applicable Contingencies.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
FAC-011-2	R3.3.	A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.	Not applicable.	Not applicable.	Not applicable.	The methodology does not include a description of a process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.
FAC-011-2	R3.3.1.	This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies	Not applicable.	Not applicable.	Not applicable.	The methodology for determining SOL's does not address the need to modify the limits described in R3.3, the list of limits, or the list of associated multiple contingencies.
FAC-011-2	R3.4.	Level of detail of system models used to determine SOLs.	Not applicable.	Not applicable.	Not applicable.	Methodology does not describe the level of detail of system models used to determine SOLs.
FAC-011-2	R3.5.	Allowed uses of Special Protection Systems or Remedial Action Plans.	Not applicable.	Not applicable.	Not applicable.	The methodology does not describe the allowed uses of Special Protection Systems or Remedial

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						Action Plans.
FAC-011-2	R3.6.	Not applicable.	Not applicable.	Not applicable.	The methodology does not describe the anticipated transmission system configuration, generation dispatch and Load level.	
FAC-011-2	R3.7.	Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.	Not applicable.	Not applicable.	Not applicable.	The methodology does not describe criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit and criteria for developing any associated IROL T_v.
FAC-011-2	R4	The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:	One or both of the following : The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the two following : The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the	One of the following : The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that	One of the following: The Reliability Coordinator failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	calendar days or more after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change
FAC-011-2	R4.1.	Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.	Not applicable.	Not applicable.	Not applicable.	The Reliability Coordinator did not issue its SOL Methodology or any changes to that methodology to each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.
FAC-011-2	R4.2.	Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.	Not applicable.	Not applicable.	Not applicable.	The Reliability Coordinator did not issue its SOL Methodology or any changes to that methodology to each Planning Authority or Transmission Planner that models any portion of the

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						Reliability Coordinator's Reliability Coordinator Area.
FAC-011-2	R4.3.	Each Transmission Operator that operates in the Reliability Coordinator Area.	Not applicable.	Not applicable.	Not applicable.	The Reliability Coordinator did not issue its SOL Methodology or any changes to that methodology to each Transmission Operator that operates in the Reliability Coordinator Area.
FAC-011-2	R5.	If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
FAC-013-1	R1.	The Reliability Coordinator and Planning Authority shall each establish a set of inter-regional and intra-regional Transfer Capabilities that is consistent with its current Transfer Capability Methodology.	The Reliability Coordinator or Planning Authority has established a set of Transfer Capabilities, but one or more Transfer Capabilities, but not more than 25% of all Transfer Capabilities required to be established, are not consistent with the current Transfer Capability Methodology.	The Reliability Coordinator or Planning Authority has established a set of Transfer Capabilities, but more than 25% of those Transfer Capabilities, but not more than 50% of all Transfer Capabilities required to be established, are not consistent with the current Transfer Capability Methodology.	The Reliability Coordinator or Planning Authority has established a set of Transfer Capabilities, but more than 50% of those Transfer Capabilities, but not more than 75% of all Transfer Capabilities required to be established, are not consistent with the current Transfer Capability Methodology.	The Reliability Coordinator or Planning Authority has established a set of Transfer Capabilities, but more than 75% of those Transfer Capabilities are not consistent with the current Transfer Capability Methodology OR The Reliability Coordinator or Planning Authority has not established a set of Transfer Capabilities.
FAC-013-1	R2.	The Reliability Coordinator and Planning Authority shall each provide its inter-regional and intra-regional Transfer Capabilities to those entities that have a reliability-related need for such Transfer Capabilities and make a written request that includes a schedule for delivery of such Transfer Capabilities as follows:	The Reliability Coordinator or Planning Authority has provided its Transfer Capabilities but missed meeting one schedule by up to 15 calendar days.	The Reliability Coordinator or Planning Authority has provided its Transfer Capabilities but missed meeting two schedules.	The Reliability Coordinator or Planning Authority has provided its Transfer Capabilities but missed meeting more than two schedules.	The Reliability Coordinator or Planning Authority has provided its Transfer Capabilities but missed meeting all schedules within 30 calendar days of the associated schedules.
FAC-013-1	R2.1.	The Reliability Coordinator shall provide its Transfer Capabilities to its associated Regional Reliability Organization(s), to its adjacent Reliability Coordinators, and to the Transmission Operators, Transmission Service Providers and Planning Authorities that work in its Reliability Coordinator Area.	Not applicable.	The Reliability Coordinator provided its Transfer Capabilities to all but one of the required entities.	The Reliability Coordinator failed to provide its Transfer Capabilities to more than one of the required entities.	The Reliability Coordinator provided its Transfer Capabilities to none of the required entities.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
FAC-013-1	R2.2.	The Planning Authority shall provide its Transfer Capabilities to its associated Reliability Coordinator(s) and Regional Reliability Organization(s), and to the Transmission Planners and Transmission Service Provider(s) that work in its Planning Authority Area.	Not applicable.	The Planning Authority provided its Transfer Capabilities to all but one of the required entities.	The Planning Authority failed to provide its Transfer Capabilities to more than one of the required entities.	The Planning Authority provided its Transfer Capabilities to none of the required entities.
FAC-014-2	R1.	The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.	There are SOLs, for the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs, for the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs, for the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs for the Reliability Coordinator Area, but one or more of these the SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)
FAC-014-2	R2.	The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)
FAC-014-2	R3.	The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology	There are SOLs, for the Planning Coordinator Area, but from 1% up to, but less than, 25% of these SOLs are inconsistent with the Planning	There are SOLs, for the Planning Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the	There are Sols for the Planning Coordinator Area, but 10% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's	There are SOLs, for the Planning Coordinator Area, but 75% or more of these SOLs are inconsistent with the Planning Coordinator's SOL

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Coordinator's SOL Methodology. (R3)	Planning Coordinator's SOL Methodology. (R3)	SOL Methodology. (R3)	Methodology. (R3)
FAC-014-2	R4.	The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL Methodology.	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but up to 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	The Transmission Planner has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but one or more of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)
FAC-014-2	R5.	The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows	The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules by less than 15 calendar days. (R5)	One of the following: The responsible entity provided its SOLs to all but one of the requesting entities within the schedules provided. (R5) OR The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 15 or more but less than 30 calendar days. (R5) OR	One of the following: The responsible entity provided its SOLs to all but two of the requesting entities within the schedules provided. (R5) OR The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 30 or more but less than 45 calendar days. (R5) OR The supporting information provided with the IROLs does	One of the following: The responsible entity failed to provide its SOLs to more than two of the requesting entities within 45 calendar days of the associated schedules. (R5) OR The supporting information provided with the IROLs does not address 5.1.1 and 5.1.2.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The supporting information provided with the IROLs does not address 5.1.4	not address 5.1.3	
FAC-014-2	R5.1.	The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information	Not applicable.	Not applicable.	Not applicable.	The Reliability Coordinator did not provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area.
FAC-014-2	R5.1.1.	Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL	Not applicable.	Not applicable.	Not applicable.	For any IROL, the Reliability Coordinator did not provide the Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
FAC-014-2	R5.1.2.	The value of the IROL and its associated Tv.	Not applicable.	Not applicable.	Not applicable.	For any IROL, the Reliability Coordinator did not provide the value of the IROL and its associated Tv.
FAC-014-2	R5.1.3.	The associated Contingency (ies).	Not applicable.	Not applicable.	Not applicable.	For any IROL, the Reliability Coordinator did not provide the associated Contingency(ies).
FAC-014-2	R5.1.4.	The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).	Not applicable.	Not applicable.	Not applicable.	For any IROL, the Reliability Coordinator did not provide the type of limitation represented by the IROL (e.g., voltage collapse, angular stability).
FAC-014-2	R5.2.	The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.	Not applicable.	Not applicable.	Not applicable.	The Transmission Operator did not provide the complete set of SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.
FAC-014-2	R5.3.	The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators	Not applicable.	Not applicable.	Not applicable.	The Planning Authority did not provide its complete set of SOLs (including the subset of SOLs

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		and Reliability Coordinators that work within its Planning Authority Area.				that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area.
FAC-014-2	R5.4.	The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.	Not applicable.	Not applicable.	Not applicable.	The Transmission Planner did not provide its complete set of SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.
FAC-014-2	R6.	The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits.	Not applicable.	Not applicable.	Not applicable.	The Planning Authority did not identify the subset of multiple contingencies which result in stability limits. (R6)

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
FAC-014-2	R6.1.	The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits.	Not applicable.	Not applicable.	Not applicable.	The Planning Authority did not identify the subset of multiple contingencies, from TPL-003 that resulted in stability limits and provide the complete list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits.
FAC-014-2	R6.2.	If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.	Not applicable.	Not applicable.	Not applicable.	The Planning Authority did not notify the Reliability Coordinator that it did not identify any stability-related multiple contingencies,

Complete Violation Severity Level Matrix (INT)
Encompassing All FERC-Approved Reliability Standards

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
INT-001-3	R1.	The Load-Serving, Purchasing-Selling Entity shall ensure that Arranged Interchange is submitted to the Interchange Authority for:	The Load-Serving, Purchasing-Selling Entity experienced one instance of failing to ensure that Arranged Interchange was submitted to the Interchange Authority for: (see below)	The Load-Serving, Purchasing-Selling Entity experienced two instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority for: (see below)	The Load-Serving, Purchasing-Selling Entity experienced three instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority for: (see below)	The Load-Serving, Purchasing-Selling Entity experienced four instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority for: (see below)
INT-001-3	R1.1.	All Dynamic Schedules at the expected average MW profile for each hour.	The Load-Serving, Purchasing-Selling Entity experienced one instance of failing to ensure that Arranged Interchange was submitted to the Interchange Authority for all Dynamic Schedules at the expected average MW profile for each hour.	The Load-Serving, Purchasing-Selling Entity experienced two instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority for all Dynamic Schedules at the expected average MW profile for each hour.	The Load-Serving, Purchasing-Selling Entity experienced three instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority for all Dynamic Schedules at the expected average MW profile for each hour.	The Load-Serving, Purchasing-Selling Entity experienced four instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority for all Dynamic Schedules at the expected average MW profile for each hour.
INT-001-3	R2.	The Sink Balancing Authority shall ensure that Arranged Interchange is submitted to the Interchange Authority:	The Sink Balancing Authority experienced one instance of failing to ensure that Arranged Interchange was submitted to the Interchange Authority (see below)	The Sink Balancing Authority experienced two instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority (see below)	The Sink Balancing Authority experienced three instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority (see below)	The Sink Balancing Authority experienced four instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority (see below)

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
INT-001-3	R2.1.	If a Purchasing-Selling Entity is not involved in the Interchange, such as delivery from a jointly owned generator.	The Sink Balancing Authority experienced one instance of failing to ensure that Arranged Interchange was submitted to the Interchange Authority if a Purchasing-Selling Entity was not involved in the Interchange, such as delivery from a jointly owned generator.	The Sink Balancing Authority experienced two instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority if a Purchasing-Selling Entity was not involved in the Interchange, such as delivery from a jointly owned generator.	The Sink Balancing Authority experienced three instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority if a Purchasing-Selling Entity was not involved in the Interchange, such as delivery from a jointly owned generator.	The Sink Balancing Authority experienced four instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority if a Purchasing-Selling Entity was not involved in the Interchange, such as delivery from a jointly owned generator.
INT-001-3	R2.2.	For each bilateral Inadvertent Interchange payback.	The Sink Balancing Authority experienced one instance of failing to ensure that Arranged Interchange was submitted to the Interchange Authority for each bilateral Inadvertent Interchange payback.	The Sink Balancing Authority experienced two instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority for each bilateral Inadvertent Interchange payback.	The Sink Balancing Authority experienced three instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority for each bilateral Inadvertent Interchange payback.	The Sink Balancing Authority experienced four instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority for each bilateral Inadvertent Interchange payback.
INT-003-2	R1.	Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation.	There shall be a separate Lower VSL, if either of the following conditions exists: One instance of entering a schedule into its ACE equation without confirming the	There shall be a separate Moderate VSL, if either of the following conditions exists: Two instances of entering a schedule into its ACE equation	There shall be a separate High VSL, if either of the following conditions exists: Three instances of entering a schedule into its ACE equation without confirming the schedule	There shall be a separate Severe VSL, if either of the following conditions exists: Four or more instances of entering a schedule into its ACE equation without

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. One instance of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. Two instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	as specified in R1, R1.1, R1.1.1 and R1.1.2. Three instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. Four or more instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2
INT-003-2	R1.1.	The Sending Balancing Authority and Receiving Balancing Authority shall agree on Interchange as received from the Interchange Authority, including:	The Balancing Authority experienced one instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced four instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.
INT-003-2	R1.1.1.	Interchange Schedule start and end time.	The Balancing Authority experienced one instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced four instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.
INT-003-2	R1.1.2.	Energy profile.	The Balancing Authority experienced	The Balancing Authority	The Balancing Authority experienced	The Balancing Authority experienced

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			one instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	experienced two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	four instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.
INT-003-2	R1.2.	If a high voltage direct current (HVDC) tie is on the Scheduling Path, then the Sending Balancing Authorities and Receiving Balancing Authorities shall coordinate the Interchange Schedule with the Transmission Operator of the HVDC tie.	The sending or receiving Balancing Authority experienced one instance of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	The sending or receiving Balancing Authority experienced two instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	The sending or receiving Balancing Authority experienced three instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	The sending or receiving Balancing Authority experienced four instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2
INT-004-2	R1.	At such time as the reliability event allows for the reloading of the transaction, the entity that initiated the curtailment shall release the limit on the Interchange Transaction tag to allow reloading the transaction and shall communicate the release of the limit to the Sink Balancing Authority.	The entity that initiated the curtailment failed to communicate the transaction reload to the Sink Balancing Authority	The entity that initiated the curtailment failed to reload the transaction and failed to communicate to the Sink Balancing Authority	N/A	N/A
INT-004-2	R2.	The Purchasing-Selling Entity responsible for tagging a Dynamic Interchange Schedule shall ensure the tag is updated for the next available scheduling hour and future hours when any one of the following occurs:	The Purchase-Selling entity failed to update the tags when required less than 25% of times it was required, as determined in R2.1, R2.2, or R2.3.	The Purchase-Selling entity failed to update the tags when required 25% or more and less than 50% of the times it was	The Purchase-Selling entity failed to update the tags when required 50% or more but less than75% of the times it was required, as determined in R2.1,	The Purchase-Selling entity failed to update the tags when required 75% or more of the times it was required, as determined in R2.1, R2.2, or R2.3.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				required, as determined in R2.1, R2.2, or R2.3.	R2.2, or R2.3.	
INT-004-2	R2.1.	The average energy profile in an hour is greater than 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than +10%.	The Purchase-Selling entity failed to update the tags when required less than 25% of times it was required.	The Purchase-Selling entity failed to update the tags when required 25% or more and less than 50% of the times it was required.	The Purchase-Selling entity failed to update the tags when required 50% or more but less than75% of the times it was required.	The Purchase-Selling entity failed to update the tags when required 75% or more of the times it was required.
INT-004-2	R2.2.	The average energy profile in an hour is less than or equal to 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than +25 megawatt-hours.	The Purchase-Selling entity failed to update the tags when required less than 25% of times it was required.	The Purchase-Selling entity failed to update the tags when required 25% or more and less than 50% of the times it was required.	The Purchase-Selling entity failed to update the tags when required 50% or more but less than75% of the times it was required.	The Purchase-Selling entity failed to update the tags when required 75% or more of the times it was required.
INT-004-2	R2.3.	A Reliability Coordinator or Transmission Operator determines the deviation, regardless of magnitude, to be a reliability concern and notifies the Purchasing-Selling Entity of that determination and the reasons.	The Purchase-Selling entity failed to update the tags when required less than 25% of times it was required.	The Purchase-Selling entity failed to update the tags when required 25% or more and less than 50% of the times it was required.	The Purchase-Selling entity failed to update the tags when required 50% or more but less than75% of the times it was required.	The Purchase-Selling entity failed to update the tags when required 75% or more of the times it was required.
INT-005-3	R1.	Prior to the expiration of the time period defined in the timing requirements tables in this standard, Column A, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment to all reliability entities involved in the Interchange.	The Interchange Authority experienced one occurrence of not distributing information to all involved reliability entities.	The Interchange Authority experienced two occurrences of not distributing information to all involved reliability entities	The Interchange Authority experienced three occurrences of not distributing information to all involved reliability entities	The Interchange Authority experienced four occurrences of not distributing information to all involved reliability entities
INT-005-3	R1.1.	When a Balancing Authority or Reliability	The Interchange	The Interchange	The Interchange	The Interchange

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Coordinator initiates a Curtailment to Confirmed or Implemented Interchange for reliability, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment only to the Source Balancing Authority and the Sink Balancing Authority.	Authority experienced one occurrence of not distributing information to all involved reliability entities.	Authority experienced two occurrences of not distributing information to all involved reliability entities	Authority experienced three occurrences of not distributing information to all involved reliability entities	Authority experienced four occurrences of not distributing information to all involved reliability entities
INT-006-3	R1.	Prior to the expiration of the reliability assessment period defined in the timing requirements tables in this standard, Column B, the Balancing Authority and Transmission Service Provider shall respond to each On-time Request for Interchange (RFI), and to each Emergency RFI and Reliability Adjustment RFI from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange	The Responsible Entity failed on one occasion to respond to a request from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange.	The Responsible Entity failed on two occasions to respond to a request from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange.	The Responsible Entity failed on three occasions to respond to a request from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange.	The Responsible Entity failed on four occasions to respond to a request from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange.
INT-006-3	R1.1.	Each involved Balancing Authority shall evaluate the Arranged Interchange with respect to:	The Balancing Authority failed to evaluate arranged interchange with respect to one of the requirements in the 3 sub-components.	N/A	The Balancing Authority failed to evaluate arranged interchange with respect to two of the requirements in the 3 sub-components.	The Balancing Authority failed to evaluate arranged interchange with respect to three of the requirements in the 3 sub-components.
INT-006-3	R1.1.1.	Energy profile (ability to support the magnitude of the Interchange).	N/A	N/A	N/A	The Balancing Authority failed to evaluate Energy profile (ability to support the magnitude of the Interchange).
INT-006-3	R1.1.2.	Ramp (ability of generation maneuverability to accommodate).	N/A	N/A	N/A	The Balancing Authority failed to evaluate Ramp (ability of generation maneuverability to accommodate).

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
INT-006-3	R1.1.3.	Scheduling path (proper connectivity of Adjacent Balancing Authorities).	N/A	N/A	N/A	The Balancing Authority failed to evaluate Scheduling path (proper connectivity of Adjacent Balancing Authorities).
INT-006-3	R1.2.	Each involved Transmission Service Provider shall confirm that the transmission service arrangements associated with the Arranged Interchange have adjacent Transmission Service Provider connectivity, are valid and prevailing transmission system limits will not be violated	The Transmission Service Provider experienced one instance of failing to confirm that the transmission service arrangements associated with the Arranged Interchange had adjacent Transmission Service Provider connectivity, were valid and prevailing transmission system limits would not be violated.	The Transmission Service Provider experienced two instances of failing to confirm that the transmission service arrangements associated with the Arranged Interchange had adjacent Transmission Service Provider connectivity, were valid and prevailing transmission system limits would not be violated.	The Transmission Service Provider experienced three instances of failing to confirm that the transmission service arrangements associated with the Arranged Interchange had adjacent Transmission Service Provider connectivity, were valid and prevailing transmission system limits would not be violated.	The Transmission Service Provider experience four instances of failing to confirm that the transmission service arrangements associated with the Arranged Interchange had adjacent Transmission Service Provider connectivity, were valid and prevailing transmission system limits would not be violated.
INT-007-1	R1.	The Interchange Authority shall verify that Arranged Interchange is balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange by verifying the following:	The Interchange Authority failed to verify one time, as indicated in R1.1, R1.2, R1.3, R1.3.1, R1.3.2, R1.3.3, or R1.3.4 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed	The Interchange Authority failed to verify two times, as indicated in R1.1, R1.2, R1.3, R1.3.1, R1.3.2, R1.3.3, or R1.3.4 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to	The Interchange Authority failed to verify three times, as indicated in R1.1, R1.2, R1.3, R1.3.1, R1.3.2, R1.3.3, or R1.3.4 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify four times, as indicated in R1.1, R1.2, R1.3, R1.3.1, R1.3.2, R1.3.3, or R1.3.4 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Interchange.	Confirmed Interchange.		Interchange.
INT-007-1	R1.1.	Source Balancing Authority megawatts equal sink Balancing Authority megawatts (adjusted for losses, if appropriate).	The Interchange Authority failed to verify one time, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify two times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify three times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify four times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.
INT-007-1	R1.2.	All reliability entities involved in the Arranged Interchange are currently in the NERC registry.	The Interchange Authority failed to verify one time, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify two times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify three times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify four times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.
INT-007-1	R1.3.	The following are defined:	The Interchange Authority failed to verify one time, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify two times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed	The Interchange Authority failed to verify three times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify four times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Interchange.		
INT-007-1	R1.3.1.	Generation source and load sink.	The Interchange Authority failed to verify one time, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify two times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify three times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify four times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.
INT-007-1	R1.3.2.	Megawatt profile.	The Interchange Authority failed to verify one time, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify two times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify three times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify four times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.
INT-007-1	R1.3.3.	Ramp start and stop times.	The Interchange Authority failed to verify one time, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify two times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify three times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify four times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
INT-007-1	R1.3.4.	Interchange duration.	The Interchange Authority failed to verify one time, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify two times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify three times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify four times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.
INT-007-1	R1.4.	Each Balancing Authority and Transmission Service Provider that received the Arranged Interchange information from the Interchange Authority for reliability assessment has provided approval.	Each Balancing Authority and Transmission Service Provider that received the Arranged Interchange information from the Interchange Authority for reliability assessment has provided approval, with minor exception and is substantially compliant with the directives of the requirement.	Each Balancing Authority and Transmission Service Provider that received the Arranged Interchange information from the Interchange Authority for reliability assessment has provided approval, with some exception and is mostly compliant with the directives of the requirement.	Each Balancing Authority and Transmission Service Provider that received the Arranged Interchange information from the Interchange Authority for reliability assessment has provided approval but was substantially deficient in meeting the directives of the requirement.	Each Balancing Authority and Transmission Service Provider that received the Arranged Interchange information from the Interchange Authority for reliability assessment did not provided approval and failed to meet the requirement.
INT-008-3	R1.	Prior to the expiration of the time period defined in the Timing Table, Column C, the Interchange Authority shall distribute to all Balancing Authorities (including Balancing Authorities on both sides of a direct current tie), Transmission Service Providers and Purchasing-Selling Entities involved in the Arranged Interchange whether or not the	The Interchange Authority experienced one occurrence of not distributing information to all involved reliability entities as deliniated in R1.1, R1.1.1 or	The Interchange Authority experienced two occurrences of not distributing information to all involved reliability	The Interchange Authority experienced three occurrences of not distributing information to all involved reliability entities.	The Interchange Authority experienced four occurrences of not distributing information to all involved reliability entities or no evidence

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Arranged Interchange has transitioned to a Confirmed Interchange.	R1.1.2.	entities.		provided.
INT-008-3	R1.1.	For Confirmed Interchange, the Interchange Authority shall also communicate:	The Interchange Authority experienced one occurrence of not distributing information to all involved reliability entities as defined in R1.	The Interchange Authority experienced two occurrences of not distributing information to all involved reliability entities as defined in R1.	The Interchange Authority experienced three occurrences of not distributing information to all involved reliability entities as defined in R1.	The Interchange Authority experienced four occurrences of not distributing information to all involved reliability entities as defined in R1 or no evidence provided.
INT-008-3	R1.1.1.	Start and stop times, ramps, and megawatt profile to Balancing Authorities.	The Interchange Authority experienced one occurrence of not distributing information to all involved reliability entities as defined in R1.	The Interchange Authority experienced two occurrences of not distributing information to all involved reliability entities as defined in R1.	The Interchange Authority experienced three occurrences of not distributing information to all involved reliability entities as defined in R1.	The Interchange Authority experienced four occurrences of not distributing information to all involved reliability entities as defined in R1 or no evidence provided.
INT-008-3	R1.1.2.	Necessary Interchange information to NERC-identified reliability analysis services.	The Interchange Authority experienced one occurrence of not distributing information to all involved reliability entities as defined in R1.	The Interchange Authority experienced two occurrences of not distributing information to all involved reliability entities as defined in R1.	The Interchange Authority experienced three occurrences of not distributing information to all involved reliability entities as defined in R1.	The Interchange Authority experienced four occurrences of not distributing information to all involved reliability entities as defined in R1 or no evidence provided.
INT-009-1	R1.	The Balancing Authority shall implement Confirmed Interchange as received from the Interchange Authority.	The Balancing Authority experienced one occurrence of not implementing a Confirmed Interchange as received from the Interchange Authority.	The Balancing Authority experienced two occurrences of not implementing a Confirmed Interchange as received from the	The Balancing Authority experienced three occurrences of not implementing a Confirmed Interchange as received from the Interchange Authority.	The Balancing Authority experienced four occurrences of not implementing a Confirmed Interchange as received from the Interchange Authority.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Interchange Authority.		
INT-010-1	R1.	The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement shall ensure that a request for an Arranged Interchange is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no request for Arranged Interchange is required.	The Balancing Authority that experienced a loss of resource covered by an energy sharing agreement failed one time to submit a request for an Arranged Interchange within the specified time period.	The Balancing Authority that experienced a loss of resource covered by an energy sharing agreement failed two times to submit request for an Arranged Interchange within the specified time period.	The Balancing Authority that experienced a loss of resource covered by an energy sharing agreement failed three times to submit a request for an Arranged Interchange within the specified time period.	The Balancing Authority that experienced a loss of resource covered by an energy sharing agreement failed four or more times to submit a request for an Arranged Interchange within the specified time period.
INT-010-1	R2.	For a modification to an existing Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit the modified Arranged Interchange reflecting that modification within 60 minutes of the initiation of the event.	The Reliability Coordinator failed one time to direct the submittal of a new or modified Arranged Interchange; or the Balancing Authority failed one time to submit the modified schedule as directed.	The Reliability Coordinator failed two times to direct the submittal of a new or modified Arranged Interchange; or the Balancing Authority failed two times to submit the modified schedule as directed.	The Reliability Coordinator failed three times to direct the submittal of a new or modified Arranged Interchange; or the Balancing Authority failed three times to submit the modified schedule as directed.	The Reliability Coordinator failed four times to direct the submittal of a new or modified Arranged Interchange; or the Balancing Authority failed four times to submit the modified schedule as directed.
INT-010-1	R3.	For a new Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit an Arranged Interchange reflecting that Interchange schedule within 60 minutes of the initiation of the event.	The Reliability Coordinator failed one time to direct the submittal of a new or modified Arranged Interchange; or the Balancing Authority failed one time to submit a schedule as directed.	The Reliability Coordinator failed two times to direct the submittal of a new or modified Arranged Interchange ; or the Balancing Authority failed two times to submit a schedule as directed.	The Reliability Coordinator failed three times to direct the submittal of a new or modified Arranged Interchange ; or the Balancing Authority failed three times to submit a schedule as directed.	The Reliability Coordinator failed four times to direct the submittal of a new or modified Arranged Interchange; or the Balancing Authority failed four times or more to submit a schedule as directed.

Complete Violation Severity Level Matrix (IRO)
Encompassing All FERC-Approved Reliability Standards

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
IRO-001-1.1	R1.	Each Regional Reliability Organization, subregion, or interregional coordinating group shall establish one or more Reliability Coordinators to continuously assess transmission reliability and coordinate emergency operations among the operating entities within the region and across the regional boundaries.	The RRO, subregion or interregional coordinating group did not communicate the assignment of the Reliability Coordinators to operating entities clearly.	The RRO, subregion or interregional coordinating group did not clearly identify the coordination of Reliability Coordinator areas within the region.	The RRO, subregion or interregional coordinating group did not coordinate assignment of the Reliability Coordinators across regional boundaries.	The RRO, subregion or interregional coordinating group did not assign any Reliability Coordinators.
IRO-001-1.1	R2.	The Reliability Coordinator shall comply with a regional reliability plan approved by the NERC Operating Committee.	The Reliability Coordinator has failed to follow the administrative portions of its regional reliability plan.	The Reliability Coordinator has failed to follow steps in its regional reliability plan that requires operator interventions or actions.	The Reliability Coordinator does not have a regional reliability plan approved by the NERC OC.	The Reliability Coordinator does not have an unapproved regional reliability plan.
IRO-001-1.1	R3.	The Reliability Coordinator shall have clear decision-making authority to act and to direct actions to be taken by Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System. These actions shall be taken without delay, but no longer than 30 minutes.	N/A	N/A	The Reliability Coordinator cannot demonstrate that it has clear authority to act or direct actions to preserve transmission security and reliability of the Bulk Electric System.	The Reliability Coordinator failed to take or direct to preserve the reliability and security of the Bulk Electric System within 30 minutes of identifying those actions.
IRO-001-1.1	R4.	Reliability Coordinators that delegate tasks to other entities shall have formal operating agreements with each entity to which tasks are delegated. The Reliability Coordinator shall verify that all delegated tasks are understood, communicated, and addressed within its Reliability Coordinator Area. All	1. Less than 25% of the tasks are not documented in the agreement or 2. Less than 25% of the tasks are not performed according	1. More than 25% but 50% or less of the tasks are not documented in the agreement or 2. More than 25% but 50% or less of	1. More than 50% but 75% or less of the tasks are not documented in the agreement or 2. More than 50% but 75% or less of the tasks are not performed	1. There is no formal operating agreement for tasks delegated by the Reliability Coordinator, 2. More than 75% of the tasks are not

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		responsibilities for complying with NERC and regional standards applicable to Reliability Coordinators shall remain with the Reliability Coordinator.	to the agreement.	the tasks are not performed according to the agreement.	according to the agreement.	documented in the agreement or 3. More than 75% of the tasks are not performed according to the agreement.
IRO-001-1.1	R5.	The Reliability Coordinator shall list within its reliability plan all entities to which the Reliability Coordinator has delegated required tasks.	25% or less of the delegate entities are not identified in the reliability plan.	More than 25% but 50% or less of the delegate entities are not identified in the reliability plan.	More than 50% but 75% or less of the delegate entities are not identified in the reliability plan.	1. There is no reliability plan or 2. More than 75% of the delegate entities are not identified in the reliability plan.
IRO-001-1.1	R6.	The Reliability Coordinator shall verify that all delegated tasks are carried out by NERC-certified Reliability Coordinator operating personnel.	N/A	1. The Reliability Coordinator has failed to demonstrate at least one delegated task was performed by NERC certified Reliability Coordinator operating personnel or 2. The Reliability Coordinator did not require the delegate entity to have NERC certified Reliability Coordinator operating personnel.	1. The Reliability Coordinator has failed to demonstrate at least one delegated task was performed by NERC certified Reliability Coordinator operating personnel and did not require the delegate entity to have NERC certified Reliability Coordinator operating personnel or 2. The Reliability Coordinator has failed to demonstrate at least two delegated task were performed by NERC certified Reliability Coordinator operating personnel.	The Reliability Coordinator has failed to demonstrate any delegated tasks were performed by NERC certified Reliability Coordinator operating personnel and did not require the delegate entity to have NERC certified Reliability Coordinator operating personnel.
IRO-001-1.1	R7.	The Reliability Coordinator shall have clear, comprehensive coordination agreements with adjacent Reliability Coordinators to ensure that System Operating Limit or	The Reliability Coordinator has demonstrated the existence of	The Reliability Coordinator has demonstrated the existence of the	The Reliability Coordinator has demonstrated the existence of the	The Reliability Coordinator has failed to demonstrate the existence of any

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Interconnection Reliability Operating Limit violation mitigation requiring actions in adjacent Reliability Coordinator Areas are coordinated.	coordination agreements with adjacent Reliability Coordinators but the agreements are not clear or comprehensive.	coordination agreements with adjacent Reliability Coordinators but the agreements do not coordinate actions required in the adjacent Reliability Coordinator to mitigate SOL or IROL violations in its own Reliability Coordinator area.	coordination agreements with adjacent Reliability Coordinators but the agreements do not coordinate actions required in the adjacent Reliability Coordinator to mitigate SOL and IROL violations in its own Reliability Coordinator area.	coordination agreements with adjacent Reliability Coordinators.
IRO-001-1.1	R8.	Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator may implement alternate remedial actions.	Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities followed the Reliability Coordinators directive with a delay not caused by equipment problems but did notify the Reliability Coordinator of the delay.	Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities followed the Reliability Coordinators directive with a delay not caused by equipment problems and did not notify the Reliability Coordinator of the delay.	Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities followed the majority of the Reliability Coordinators directive and did not notify the Reliability Coordinator that it could not fully follow the directive because it would violate safety, equipment, statutory or regulatory requirements.	Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities did not follow the Reliability Coordinators directive and did not notify the Reliability Coordinator that it could not follow the directive because it would violate safety, equipment, statutory or regulatory requirements.
IRO-001-1.1	R9.	The Reliability Coordinator shall act in the interests of reliability for the overall Reliability Coordinator Area and the Interconnection before the interests of any	N/A	N/A	N/A	The Reliability Coordinator did not act in the interests of reliability for the

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		other entity.				overall Reliability Coordinator Area and the Interconnection before the interests of one or more other entities.
IRO-002-1	R1.	Each Reliability Coordinator shall have adequate communications facilities (voice and data links) to appropriate entities within its Reliability Coordinator Area. These communications facilities shall be staffed and available to act in addressing a real-time emergency condition.	The Reliability Coordinator has demonstrated communication facilities for both voice and data exist to all appropriate entities and that they are staffed and available but they are less than adequate.	The Reliability Coordinator has failed to demonstrate that is has: 1) Voice communication links with one appropriate entity or 2) Data links with one appropriate entity.	The Reliability Coordinator has failed to demonstrate that is has: 1) Voice communication links with two appropriate entities or 2) Data links with two appropriate entities.	The Reliability Coordinator has failed to demonstrate that is has: 1) Voice communication links with more than two appropriate entities or 2) Data links with more than two appropriate entities or 3) Communication facilities are not staffed or 4) Communication facilities are not ready.
IRO-002-1	R2.	Each Reliability Coordinator shall determine the data requirements to support its reliability coordination tasks and shall request such data from its Transmission Operators, Balancing Authorities, Transmission Owners, Generation Owners, Generation Operators, and Load-Serving Entities, or adjacent Reliability Coordinators.	The Reliability Coordinator demonstrated that it 1) determined its data requirements and requested that data from its Transmission Operators, Balancing Authorities, Transmission Owners, Generation Owners, Generation Operators, and Load-Serving Entities or Adjacent Reliability Coordinators with a	The Reliability Coordinator demonstrated that it determined the majority but not all of its data requirements necessary to support its reliability coordination functions and requested that data from its Transmission Operators, Balancing	The Reliability Coordinator demonstrated that it determined 1) some but less than the majority of its data requirements necessary to support its reliability coordination functions and requested that data from its Transmission Operators, Balancing Authorities, Transmission Owners, Generation Owners, Generation Operators,	The Reliability Coordinator failed to demonstrate that it 1) determined its data requirements necessary to support its reliability coordination functions and requested that data from its Transmission Operators, Balancing Authorities, Transmission Owners, Generation Owners, Generation Operators, and Load-Serving

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			material impact on the Bulk Electric System in its Reliability Coordination Area but did not request the data from Transmission Operators, Balancing Authorities, Transmission Owners, Generation Owners, Generation Operators, and Load-Serving Entities or Adjacent Reliability Coordinators with minimal impact on the Bulk Electric System in its Reliability Coordination Area or 2) determined its data requirements necessary to perform its reliability functions with the exceptions of data that may be needed for administrative purposes such as data reporting.	Authorities, Transmission Owners, Generation Owners, Generation Operators, and Load-Serving Entities or Adjacent Reliability Coordinators.	and Load-Serving Entities or Adjacent Reliability Coordinators or 2) all of its data requirements necessary to support its reliability coordination functions but failed to demonstrate that it requested data from two of its Transmission Operators, Balancing Authorities, Transmission Owners, Generation Owners, Generation Operators, and Load-Serving Entities or Adjacent Reliability Coordinators.	Entities or Adjacent Reliability Coordinators or 2) requested the data from three or more of its Transmission Operators, Balancing Authorities, Transmission Owners, Generation Owners, Generation Operators, and Load-Serving Entities or Adjacent Reliability Coordinators.
IRO-002-1	R3.	Each Reliability Coordinator – or its Transmission Operators and Balancing Authorities – shall provide, or arrange provisions for, data exchange to other Reliability Coordinators or Transmission Operators and Balancing Authorities via a secure network.	N/A	The Reliability Coordinator or designated Transmission Operator and Balancing Authority has failed to demonstrate it provided or	The Reliability Coordinator or designated Transmission Operator and Balancing Authority has failed to demonstrate it provided or arranged provision for the exchange of data	The Reliability Coordinator or designated Transmission Operator and Balancing Authority has failed to demonstrate it provided or arranged provision for the

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				arranged provision for the exchange of data with one of the other Reliability Coordinators or Transmission Operators and Balancing Authorities.	with two of the other Reliability Coordinators or Transmission Operators and Balancing Authorities.	exchange of data with three of the other Reliability Coordinators or Transmission Operators and Balancing Authorities.
IRO-002-1	R4.	Each Reliability Coordinator shall have multi-directional communications capabilities with its Transmission Operators and Balancing Authorities, and with neighboring Reliability Coordinators, for both voice and data exchange as required to meet reliability needs of the Interconnection.	N/A	The Reliability Coordinator has failed to demonstrate multi-directional communication capabilities to one of the Transmission Operators and Balancing Authorities in its Reliability Coordinator Area and with neighboring Reliability Coordinators.	The Reliability Coordinator has failed to demonstrate multi-directional communication capabilities to two or more of the Transmission Operators and Balancing Authorities in its Reliability Coordinator Area and with neighboring Reliability Coordinators.	The Reliability Coordinator has failed to demonstrate multi-directional communication capabilities to all of the Transmission Operators and Balancing Authorities in its Reliability Coordinator Area and with all neighboring Reliability Coordinators.
IRO-002-1	R5.	Each Reliability Coordinator shall have detailed real-time monitoring capability of its Reliability Coordinator Area and sufficient monitoring capability of its surrounding Reliability Coordinator Areas to ensure that potential or actual System Operating Limit or Interconnection Reliability Operating Limit violations are identified. Each Reliability Coordinator shall have monitoring systems that provide information that can be easily understood and interpreted by the Reliability Coordinator's operating personnel, giving	The Reliability Coordinator's monitoring systems provide information in a way that is not easily understood and interpreted by the Reliability Coordinator's operating personnel or particular emphasis was not given to alarm	The Reliability Coordinator has failed to demonstrate that is has detailed real-time monitoring capabilities in its Reliability Coordinator Area and sufficient monitoring capabilities of its	The Reliability Coordinator has failed to demonstrate that is has detailed real-time monitoring capabilities in its Reliability Coordinator Area and sufficient monitoring capabilities of its surrounding Reliability Coordinator Areas to ensure that two or more	The Reliability Coordinator has failed to demonstrate that is has detailed real-time monitoring capabilities in its Reliability Coordinator Area and sufficient monitoring capabilities of its surrounding Reliability Coordinator Areas to

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure.	management and awareness systems, automated data transfers and synchronized information systems.	surrounding Reliability Coordinator Areas to ensure that one potential or actual SOL or IROL violation is not identified.	potential and actual SOL and IROL violations are not identified.	ensure that all potential and actual SOL and IROL violations are identified.
IRO-002-1	R6.	Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be critical to SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area.	The Reliability Coordinator failed to monitor: 1) the status, real power flow or reactive power flow of Bulk Electric System elements that could result in one SOL violations or 2) or operating reserves for a small portion of the Reliability Authority Area.	The Reliability Coordinator failed to monitor: 1) the status, real power flow or reactive power flow of Bulk Electric System elements critical to assessing one IROL or to system restoration, 2) the status, real power flow or reactive power flow of Bulk Electric System elements that could result in multiple SOL violations, or 3) operating reserves.	The Reliability Coordinator failed to monitor: 1) the status, real power flow or reactive power flow of Bulk Electric System elements critical to assessing two or more IROLs; or one IROL and to system restoration, 2) the status, real power flow or reactive power flow of Bulk Electric System elements that could result in multiple SOL violations and operating reserves, or 3) the status, real power flow or reactive power flow of Bulk Electric System elements critical to assessing one IROL or system restoration and operating reserves.	The Reliability Coordinator failed to monitor: 1) the status, real power flow or reactive power flow of Bulk Electric System elements critical to assessing all IROLs and to system restoration, or 2) the status, real power flow or reactive power flow of Bulk Electric System elements critical to assessing all SOL violations and operating reserves.
IRO-002-1	R7.	Each Reliability Coordinator shall have adequate analysis tools such as state	The Reliability Coordinator failed to	The Reliability Coordinator failed	The Reliability Coordinator failed to	The Reliability Coordinator failed to

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		estimation, pre- and post-contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays.	demonstrate that it has: 1) analysis tools capable of assessing all pre-contingency flows, 2) analysis tools capable of assessing all post-contingency flows, or 3) all necessary wide-area overview displays exist.	to demonstrate that it has: 1) analysis tools capable of assessing the majority of pre-contingency flows, 2) analysis tools capable of assessing the majority of post-contingency flows, or 3) the majority of necessary wide-area overview displays exist.	demonstrate that it has: 1) analysis tools capable of assessing a minority of pre-contingency flows, 2) analysis tools capable of assessing a minority of post-contingency flows, or 3) a minority of necessary wide-area overview displays exist.	demonstrate that it has: 1) analysis tools capable of assessing any pre-contingency flows, 2) analysis tools capable of assessing any post-contingency flows, or 3) any necessary wide-area overview displays exist.
IRO-002-1	R8.	Each Reliability Coordinator shall continuously monitor its Reliability Coordinator Area. Each Reliability Coordinator shall have provisions for backup facilities that shall be exercised if the main monitoring system is unavailable. Each Reliability Coordinator shall ensure SOL and IROL monitoring and derivations continue if the main monitoring system is unavailable.	The Reliability Coordinator failed to demonstrate that: 1) it or a delegated entity monitored SOLs when the main monitoring system was unavailable or 2) it has provisions to monitor SOLs when the main monitoring system is not available.	The Reliability Coordinator failed to demonstrate that: 1) it or a delegated entity monitored one IROL when the main monitoring system was unavailable or 2) it has provisions to monitor one IROL when the main monitoring system is not available.	The Reliability Coordinator failed to demonstrate that: 1) it or a delegated entity monitored two or more IROLs when the main monitoring system was unavailable, 2) it or a delegated entity monitored SOLs and one IROL when the main monitoring system was unavailable 3) it has provisions to monitor two or more IROLs when the main monitoring system is not available, or 4) it has provisions to monitor SOLs and one IROL when the main monitoring system was unavailable.	The Reliability Coordinator failed to demonstrate that it continuously monitored its Reliability Authority Area.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
IRO-002-1	R9.	Each Reliability Coordinator shall control its Reliability Coordinator analysis tools, including approvals for planned maintenance. Each Reliability Coordinator shall have procedures in place to mitigate the effects of analysis tool outages.	Reliability Coordinator has approval rights for planned maintenance outages of analysis tools but does not have approval rights for work on analysis tools that creates a greater risk of an unplanned outage of the tools.	Reliability Coordinator has approval rights for planned maintenance but does not have plans to mitigate the effects of outages of the analysis tools.	Reliability Coordinator has approval rights for planned maintenance but does not have plans to mitigate the effects of outages of the analysis tools and does not have approval rights for work on analysis tools that creates a greater risk of an unplanned outage of the tools.	Reliability Coordinator approval is not required for planned maintenance.
IRO-003-2	R1.	Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.	N/A	N/A	The Reliability Coordinator failed to monitor **all** Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.	The Reliability Coordinator failed to monitor Bulk Electric System facilities, which may include sub-transmission information, within adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
IRO-003-2	R2.	Each Reliability Coordinator shall know the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or IROL violation. Reliability Coordinators shall also know the status of any facilities that may be required to assist area restoration objectives.	N/A	N/A	The Reliability Coordinator failed to know either the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or IROL violation or the status of any facilities that may be required to assist area restoration objectives.	The Reliability Coordinator failed to know the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or IROL violation and the status of any facilities that may be required to assist area restoration objectives.
IRO-004-1	R1.	Each Reliability Coordinator shall conduct next-day reliability analyses for its Reliability Coordinator Area to ensure that the Bulk Electric System can be operated reliably in anticipated normal and Contingency event conditions. The Reliability Coordinator shall conduct Contingency analysis studies to identify potential interface and other SOL and IROL violations, including overloaded transmission lines and transformers, voltage and stability limits, etc.	The Reliability Coordinator failed to conduct next-day reliability analyses or contingency analysis for its Reliability Coordinator Area for one (1) day during a calendar month.	The Reliability Coordinator failed to conduct next-day reliability analyses or contingency analysis for its Reliability Coordinator Area for two (2) to three (3) days during a calendar month.	The Reliability Coordinator failed to conduct next-day reliability analyses or contingency analysis for its Reliability Coordinator Area for four (4) to five (5) days during a calendar month.	The Reliability Coordinator failed to conduct next-day reliability analyses or contingency analysis for its Reliability Coordinator Area for more than five (5) days during a calendar month.
IRO-004-1	R2.	Each Reliability Coordinator shall pay particular attention to parallel flows to ensure one Reliability Coordinator Area does not place an unacceptable or undue Burden on an adjacent Reliability Coordinator Area.	N/A	N/A	N/A	The Reliability Coordinator failed to monitor parallel flows to ensure one Reliability Coordinator Area does not place an unacceptable or undue Burden on an adjacent Reliability Coordinator Area.
IRO-004-1	R3.	Each Reliability Coordinator shall, in	The Reliability	The Reliability	The Reliability	The Reliability

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		conjunction with its Transmission Operators and Balancing Authorities, develop action plans that may be required, including reconfiguration of the transmission system, re-dispatching of generation, reduction or curtailment of Interchange Transactions, or reducing load to return transmission loading to within acceptable SOLs or IROLs.	Coordinator, in conjunction with its Transmission Operators and Balancing Authorities, failed to develop action plans that may be required, including reconfiguration of the transmission system, re-dispatching of generation, reduction or curtailment of Interchange Transactions, or reducing load to return transmission loading to within acceptable SOLs or IROLs for one (1) day during a calendar month.	Coordinator, in conjunction with its Transmission Operators and Balancing Authorities, failed to develop action plans that may be required, including reconfiguration of the transmission system, re-dispatching of generation, reduction or curtailment of Interchange Transactions, or reducing load to return transmission loading to within acceptable SOLs or IROLs for two (2) to three (3) days during a calendar month.	Coordinator, in conjunction with its Transmission Operators and Balancing Authorities, failed to develop action plans that may be required, including reconfiguration of the transmission system, re-dispatching of generation, reduction or curtailment of Interchange Transactions, or reducing load to return transmission loading to within acceptable SOLs or IROLs for four (4) to five (5) days during a calendar month.	Coordinator, in conjunction with its Transmission Operators and Balancing Authorities, failed to develop action plans that may be required, including reconfiguration of the transmission system, re-dispatching of generation, reduction or curtailment of Interchange Transactions, or reducing load to return transmission loading to within acceptable SOLs or IROLs for more than five (5) days during a calendar month.
IRO-004-1	R4.	Each Transmission Operator, Balancing Authority, Transmission Owner, Generator Owner, Generator Operator, and Load-Serving Entity in the Reliability Coordinator Area shall provide information required for system studies, such as critical facility status, Load, generation, operating reserve projections, and known Interchange Transactions. This information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.	The responsible entity in the Reliability Coordinator Area provided the information required for system studies, such as critical facility status, Load, generation, operating reserve projections, and known Interchange Transactions, but said information was	The responsible entity in the Reliability Coordinator Area provided the information required for system studies, such as critical facility status, Load, generation, operating reserve projections, and known Interchange Transactions, but	The responsible entity in the Reliability Coordinator Area provided the information required for system studies, such as critical facility status, Load, generation, operating reserve projections, and known Interchange Transactions, but said information was provided after the	The responsible entity in the Reliability Coordinator Area provided the information required for system studies, such as critical facility status, Load, generation, operating reserve projections, and known Interchange Transactions, but said information was

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			provided after the required time as stated in IRO-004-1 R4 for one (1) day during a calendar month.	said information was provided after the required time as stated in IRO-004-1 R4 for two (2) to three (3) days during a calendar month.	required time as stated in IRO-004-1 R4 for four (4) to five (5) days during a calendar month.	provided after the required time as stated in IRO-004-1 R4 for more than five (5) days during a calendar month.
IRO-004-1	R5.	Each Reliability Coordinator shall share the results of its system studies, when conditions warrant or upon request, with other Reliability Coordinators and with Transmission Operators, Balancing Authorities, and Transmission Service Providers within its Reliability Coordinator Area. The Reliability Coordinator shall make study results available no later than 1500 Central Standard Time for the Eastern Interconnection and 1500 Pacific Standard Time for the Western Interconnection, unless circumstances warrant otherwise.	The Reliability Coordinator failed to share the results of its system studies, when conditions warranted or was requested, with other Reliability Coordinators and with Transmission Operators, Balancing Authorities, and Transmission Service Providers within its Reliability Coordinator Area for one (1) day during a calendar month.	The Reliability Coordinator failed to share the results of its system studies, when conditions warranted or was requested, with other Reliability Coordinators and with Transmission Operators, Balancing Authorities, and Transmission Service Providers within its Reliability Coordinator Area for two (2) to three (3) days during a calendar month.	The Reliability Coordinator failed to share the results of its system studies, when conditions warranted or was requested, with other Reliability Coordinators and with Transmission Operators, Balancing Authorities, and Transmission Service Providers within its Reliability Coordinator Area for four (4) to five (5) days during a calendar month.	The Reliability Coordinator failed to share the results of its system studies, when conditions warranted or was requested, with other Reliability Coordinators and with Transmission Operators, Balancing Authorities, and Transmission Service Providers within its Reliability Coordinator Area for more than five (5) days during a calendar month.
IRO-004-1	R6.	If the results of these studies indicate potential SOL or IROL violations, the Reliability Coordinator shall direct its Transmission Operators, Balancing Authorities and Transmission Service Providers to take any necessary action the Reliability Coordinator deems appropriate to address the potential SOL or IROL violation.	The Reliability Coordinator failed to direct action to address a potential SOL or IROL violation on one (1) occasion during a calendar month.	The Reliability Coordinator failed to direct action to address a potential SOL or IROL violation on two (2) to three (3) occasions during a calendar month.	The reliability Coordinator failed to direct action to address a potential SOL or IROL violation on four (4) to five (5) occasions during a calendar month.	The Reliability Coordinator failed to direct action to address a potential SOL or IROL violation on more than five (5) occasions during a calendar month.
IRO-004-1	R7.	Each Transmission Operator, Balancing	The responsible entity	The responsible	The responsible entity	The responsible entity

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Authority, and Transmission Service Provider shall comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events.	failed to comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events on one (1) occasion during a calendar month.	entity failed to comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events on two (2) to three (3) occasions during a calendar month.	failed to comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events on four (4) to five (5) occasions during a calendar month.	failed to comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events on more than five (5) occasions during a calendar month.
IRO-005-2	R1.	Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:	The Reliability Coordinator failed to monitor one (1) of the elements listed in IRO-005-2 R1.1 through R1.10.	The Reliability Coordinator failed to monitor two (2) of the elements listed in IRO-005-2 R1.1 through R1.10.	The Reliability Coordinator failed to monitor three (3) of the elements listed in IRO-005-2 R1.1 through R1.10.	The Reliability Coordinator failed to monitor more than three (3) of the elements listed in IRO-005-2 R1.1 through R1.10.
IRO-005-2	R1.1.	Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading.	N/A	N/A	N/A	The Reliability Coordinator failed to monitor the current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading.
IRO-005-2	R1.2.	Current pre-contingency element conditions (voltage, thermal, or stability), including any	N/A	N/A	N/A	The Reliability Coordinator failed to

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.				monitor current pre-contingency element conditions (voltage, thermal, or stability); including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
IRO-005-2	R1.3.	Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.	N/A	N/A	N/A	The Reliability Coordinator failed to monitor current post-contingency element conditions (voltage, thermal, or stability); including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
IRO-005-2	R1.4.	System real and reactive reserves (actual versus required).	N/A	N/A	N/A	The Reliability Coordinator failed to monitor system real and reactive reserves (actual versus required).
IRO-005-2	R1.5.	Capacity and energy adequacy conditions.	N/A	N/A	N/A	The Reliability Coordinator failed to monitor capacity and energy adequacy conditions.
IRO-005-2	R1.6.	Current ACE for all its Balancing Authorities.	N/A	N/A	N/A	The Reliability Coordinator failed to monitor current ACE for all its Balancing

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						Authorities.
IRO-005-2	R1.7.	Current local or Transmission Loading Relief procedures in effect.	N/A	N/A	N/A	The Reliability Coordinator failed to monitor current local or Transmission Loading Relief procedures in effect.
IRO-005-2	R1.8.	Planned generation dispatches.	N/A	N/A	N/A	The Reliability Coordinator failed to monitor planned generation dispatches.
IRO-005-2	R1.9.	Planned transmission or generation outages.	N/A	N/A	N/A	The Reliability Coordinator failed to monitor planned transmission or generation outages.
IRO-005-2	R1.10.	Contingency events.	N/A	N/A	N/A	The Reliability Coordinator failed to monitor contingency events.
IRO-005-2	R2.	Each Reliability Coordinator shall be aware of all Interchange Transactions that wheel through, source, or sink in its Reliability Coordinator Area, and make that Interchange Transaction information available to all Reliability Coordinators in the Interconnection.	N/A	N/A	The Reliability Coordinator was aware of all Interchange Transactions that wheeled through, sourced or sinked in its Reliability Coordinator Area, but failed to make that Interchange Transaction information available to all Reliability Coordinators in the Interconnection.	The Reliability Coordinator failed to be aware of all Interchange Transactions that wheeled through, sourced or sinked in its Reliability Coordinator Area, and failed to make that Interchange Transaction information available to all Reliability Coordinators in the Interconnection.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
IRO-005-2	R3.	As portions of the transmission system approach or exceed SOLs or IROLs, the Reliability Coordinator shall work with its Transmission Operators and Balancing Authorities to evaluate and assess any additional Interchange Schedules that would violate those limits. If a potential or actual IROL violation cannot be avoided through proactive intervention, the Reliability Coordinator shall initiate control actions or emergency procedures to relieve the violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall ensure all resources, including load shedding, are available to address a potential or actual IROL violation.	N/A	The Reliability Coordinator worked with its Transmission Operators and Balancing Authorities, as portions of the transmission system approached or exceeded SOLs or IROLs, to evaluate and assess any additional Interchange Schedules that would violate those limits and initiated control actions or emergency procedures to relieve the violation within 30 minutes, but failed to ensure all resources, including load shedding, were available to address a potential or actual IROL violation.	The Reliability Coordinator worked with its Transmission Operators and Balancing Authorities, as portions of the transmission system approached or exceeded SOLs or IROLs, to evaluate and assess any additional Interchange Schedules that would violate those limits and ensured all resources, including load shedding, were available to address a potential or actual IROL violation, but failed to initiate control actions or emergency procedures to relieve the violation within 30 minutes.	The Reliability Coordinator failed to work with its Transmission Operators and Balancing Authorities, as portions of the transmission system approached or exceeded SOLs or IROLs, to evaluate and assess any additional Interchange Schedules that would violate those limits and failed to initiate control actions or emergency procedures to relieve the violation within 30 minutes.
IRO-005-2	R4.	Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. If necessary, the Reliability Coordinator shall direct the Balancing	N/A	The Reliability Coordinator failed to direct the Balancing Authorities in the Reliability Coordinator Area to arrange for	The Reliability Coordinator failed to issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.	The Reliability Coordinator failed to monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves was provided

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.		assistance from neighboring Balancing Authorities.		and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements.
IRO-005-2	R5.	Each Reliability Coordinator shall identify the cause of any potential or actual SOL or IROL violations. The Reliability Coordinator shall initiate the control action or emergency procedure to relieve the potential or actual IROL violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall be able to utilize all resources, including load shedding, to address an IROL violation.	N/A	N/A	The Reliability Coordinator identified the cause of a potential or actual SOL or IROL violation, but failed to initiate a control action or emergency procedure to relieve the potential or actual IROL violation within 30 minutes.	The Reliability Coordinator failed to identify the cause of a potential or actual SOL or IROL violation and failed to initiate a control action or emergency procedure to relieve the potential or actual IROL violation.
IRO-005-2	R6.	Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.	N/A	N/A	The Reliability Coordinator ensured its Transmission Operators and Balancing Authorities were aware of Geo-Magnetic Disturbance (GMD) forecast information, but failed to assist, when needed, in the development of any required response plans.	The Reliability Coordinator failed to ensure its Transmission Operators and Balancing Authorities were aware of Geo-Magnetic Disturbance (GMD) forecast information.
IRO-005-2	R7.	The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.	N/A	N/A	N/A	The Reliability Coordinator failed to disseminate information within its Reliability Coordinator Area, when required.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
IRO-005-2	R8.	Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.	N/A	N/A	The Reliability Coordinator monitored system frequency and its Balancing Authorities' performance but failed to direct any necessary rebalancing to return to CPS and DCS compliance.	The Reliability Coordinator failed to monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance or the responsible entity failed to utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.
IRO-005-2	R9.	The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real-time and next-day reliability analysis timeframes.	N/A	The Reliability Coordinator coordinated with Transmission Operators, Balancing Authorities, and Generator Operators, as needed, to develop action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations but failed to implement said plans, or the Reliability Coordinator	The Reliability Coordinator failed to coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations, or the Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission	The Reliability Coordinator failed to coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations and the Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				coordinated pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in the real-time reliability analysis timeframe but failed to coordinate pending generation and transmission maintenance outages in the next-day reliability analysis timeframe.	Operators, Balancing Authorities, and Generator Operators as needed in both the real-time and next-day reliability analysis timeframes.	with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real-time and next-day reliability analysis timeframes.
IRO-005-2	R10.	As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities.	N/A	N/A	N/A	The Reliability Coordinator failed to assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities, when necessary.
IRO-005-2	R11.	The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the	N/A	The Reliability Coordinator identified sources of large Area Control Errors that were	The Reliability Coordinator identified sources of large Area Control Errors that were contributing to	The Reliability Coordinator failed to identify sources of large Area Control Errors that were

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.		contributing to Frequency Error, Time Error, or Inadvertent Interchange and discussed corrective actions with the appropriate Balancing Authority but failed to direct the Balancing Authority to comply with CPS and DCS.	Frequency Error, Time Error, or Inadvertent Interchange but failed to discuss corrective actions with the appropriate Balancing Authority.	contributing to Frequency Error, Time Error, or Inadvertent Interchange.
IRO-005-2	R12.	Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.	N/A	N/A	N/A	The Reliability Coordinator failed to be aware of the impact on inter-area flows of an inter-Balancing Authority or inter-Transmission Operator, following the operation of a Special Protection System that is armed (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation), or the Transmission Operator failed to immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						operate as expected.
IRO-005-2	R13.	Each Reliability Coordinator shall ensure that all Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities operate to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordinator Area will result in a SOL or IROL violation in another area of the Interconnection. In instances where there is a difference in derived limits, the Reliability Coordinator and its Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.	N/A	N/A	N/A	The Reliability Coordinator failed to shall ensure that all Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities operated to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordinator Area could result in a SOL or IROL violation in another area of the Interconnection or the responsible entity failed to operate the Bulk Electric System to the most limiting parameter in instances where there was a difference in derived limits..
IRO-005-2	R14.	Each Reliability Coordinator shall make known to Transmission Service Providers within its Reliability Coordinator Area, SOLs or IROLs within its wide-area view. The Transmission Service Providers shall respect these SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer	N/A	N/A	N/A	The Reliability Coordinator failed to make known to Transmission Service Providers within its Reliability Coordinator Area, SOLs or IROLs within

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Calculation processes.				its wide-area view, or the Transmission Service Providers failed to respect these SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.
IRO-005-2	R15.	Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.	N/A	The Reliability Coordinator failed to notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem had been mitigated.	N/A	The Reliability Coordinator who foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area failed to issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area, or the receiving Reliability Coordinator failed to disseminate this information to its impacted Transmission Operators and Balancing Authorities.
IRO-005-2	R16.	Each Reliability Coordinator shall confirm reliability assessment results and determine	N/A	N/A	The Reliability Coordinator confirmed	The Reliability Coordinator failed to

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		the effects within its own and adjacent Reliability Coordinator Areas. The Reliability Coordinator shall discuss options to mitigate potential or actual SOL or IROL violations and take actions as necessary to always act in the best interests of the Interconnection at all times.			the reliability assessment results and determine the effects within its own and adjacent Reliability Coordinator Areas and discussed options to mitigate potential or actual SOL or IROL violations, but failed to take actions as necessary to always act in the best interests of the Interconnection at all times.	confirm reliability assessment results and determine the effects within its own and adjacent Reliability Coordinator Areas, or failed to discuss options to mitigate potential or actual SOL or IROL violations and take actions as necessary to always act in the best interests of the Interconnection at all times.
IRO-005-2	R17.	When an IROL or SOL is exceeded, the Reliability Coordinator shall evaluate the local and wide-area impacts, both real-time and post-contingency, and determine if the actions being taken are appropriate and sufficient to return the system to within IROL in thirty minutes. If the actions being taken are not appropriate or sufficient, the Reliability Coordinator shall direct the Transmission Operator, Balancing Authority, Generator Operator, or Load-Serving Entity to return the system to within IROL or SOL.	N/A	N/A	N/A	The Reliability Coordinator either failed to evaluate the local and wide-area impacts of an IROL or SOL that was exceeded, in either real-time or post-contingency, or the Reliability Coordinator evaluated the local and wide-area impacts of an IROL or SOL that was exceeded, both real-time and post-contingency, and determined that the actions being taken were not appropriate and sufficient to return the system to within IROL in thirty (30)

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						minutes, but failed to direct the Transmission Operator, Balancing Authority, Generator Operator, or Load-Serving Entity to return the system to within IROL or SOL.
IRO-006-4.1	R1.	A Reliability Coordinator experiencing a potential or actual SOL or IROL violation within its Reliability Coordinator Area shall, with its authority and at its discretion, select one or more procedures to provide transmission loading relief. These procedures can be a "local" (regional, interregional, or sub-regional) transmission loading relief procedure or one of the following Interconnection-wide procedures:	For each TLR in the Eastern Interconnection, the Reliability Coordinator violates one (1) requirement of the applicable Interconnection-wide procedure	For each TLR in the Eastern Interconnection, the Reliability Coordinator violated two (2) to three (3) requirements of the applicable Interconnection-wide procedure	For each TLR in the Eastern Interconnection, the applicable Reliability Coordinator violated four (4) to five (5) requirements of the applicable Interconnection-wide procedure	For each TLR in the Eastern Interconnection, the Reliability Coordinator violated six (6) or more of the requirements of the applicable Interconnection-wide procedure.
IRO-006-4.1	R1.1	The Interconnection-wide Transmission Loading Relief (TLR) procedure for use in the Eastern Interconnection provided in Attachment 1-IRO-006-4. The TLR procedure alone is an inappropriate and ineffective tool to mitigate an IROL violation due to the time required to implement the procedure. Other acceptable and more effective procedures to mitigate actual IROL violations include: reconfiguration, redispatch, or load shedding.				While attempting to mitigate an existing IROL violation in the Eastern Interconnection, the Reliability Coordinator applied TLR as the sole remedy for an existing IROL violation.
IRO-006-4.1	R1.2	The Interconnection-wide transmission loading relief procedure for use in the Western Interconnection isWECC-IRO-STD-006-0 provided at: ftp://www.nerc.com/pub/sys/all_updl/standards/rrs/IRO-STD-006-0_17Jan07.pdf.				While attempting to mitigate an existing constraint in the Western Interconnection using the "WSCC Unscheduled Flow

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						Mitigation Plan", the Reliability Coordinator did not follow the procedure correctly.
IRO-006-4.1	R1.3	The Interconnection-wide transmission loading relief procedure for use in ERCOT is provided as Section 7 of the ERCOT Protocols, posted at: http://www.ercot.com/mktrules/protocols/current.html				While attempting to mitigate an existing constraint in ERCOT using Section 7 of the ERCOT Protocols, the Reliability Coordinator did not follow the procedure correctly.
IRO-006-4.1	R2	The Reliability Coordinator shall only use local transmission loading relief or congestion management procedures to which the Transmission Operator experiencing the potential or actual SOL or IROL violation is a party.	N/A	N/A	N/A	A Reliability Coordinator implemented local transmission loading relief or congestion management procedures to relieve congestion but the Transmission Operator experiencing the congestion was not a party to those procedure
IRO-006-4.1	R3	Each Reliability Coordinator with a relief obligation from an Interconnection-wide procedure shall follow the curtailments as directed by the Interconnection-wide procedure. A Reliability Coordinator desiring to use a local procedure as a substitute for curtailments as directed by the Interconnection-wide procedure shall obtain prior approval of the local procedure from the ERO.	N/A	N/A	N/A	A Reliability Coordinator implemented local transmission loading relief or congestion management procedures as a substitute for curtailment as directed by the

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						Interconnection-wide procedure but the local procedure had not received prior approval from the ERO
IRO-006-4.1	R4	When Interconnection-wide procedures are implemented to curtail Interchange Transactions that cross an Interconnection boundary, each Reliability Coordinator shall comply with the provisions of the Interconnection-wide procedure.	When requested to curtail an Interchange Transaction that crosses an Interconnection boundary utilizing an Interconnection-wide procedure, the responding Reliability Coordinator did not comply with the provisions of the Interconnection-wide procedure as requested by the initiating Reliability Coordinator	N/A	N/A	N/A
IRO-006-4.1	R5	During the implementation of relief procedures, and up to the point that emergency action is necessary, Reliability Coordinators and Balancing Authorities shall comply with applicable Interchange scheduling standards.	The Reliability Coordinators or Balancing Authorities did not comply with applicable Interchange scheduling standards during the implementation of the relief procedures, up to the point emergency action is necessary	N/A	N/A	N/A
IRO-014-1	R1.	The Reliability Coordinator shall have Operating Procedures, Processes, or Plans in place for activities that require notification,	N/A	N/A	The Reliability Coordinator has Operating Procedures,	The Reliability Coordinator failed to have Operating

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		exchange of information or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall address Scenarios that affect other Reliability Coordinator Areas as well as those developed in coordination with other Reliability Coordinators.			Processes, or Plans in place for activities that require notification, exchange of information or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability, but failed to address Scenarios that affect other Reliability Coordinator Areas.	Procedures, Processes, or Plans in place for activities that require notification, exchange of information or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability.
IRO-014-1	R1.1.	These Operating Procedures, Processes, or Plans shall collectively address, as a minimum, the following:	The Reliability Coordinator failed to include one of the elements listed in IRO-014-1 R1.1.1 through R1.1.6 in there Operating Procedures, Processes, or Plans.	The Reliability Coordinator failed to include two of the elements listed in IRO-014-1 R1.1.1 through R1.1.6 in there Operating Procedures, Processes, or Plans.	The Reliability Coordinator failed to include more than two of the elements listed in IRO-014-1 R1.1.1 through R1.1.6 in there Operating Procedures, Processes, or Plans.	N/A
IRO-014-1	R1.1.1.	Communications and notifications, including the conditions under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and information to be exchanged with other Reliability Coordinators.	N/A	N/A	N/A	The Reliability Coordinator failed to address communications and notifications, including the conditions under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and information

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						to be exchanged with other Reliability Coordinators in its Operating Procedure, Process or Plan.
IRO-014-1	R1.1.2.	Energy and capacity shortages.	N/A	N/A	N/A	The Reliability Coordinator failed to address energy and capacity shortages in its Operating Procedure, Process or Plan.
IRO-014-1	R1.1.3.	Planned or unplanned outage information.	N/A	N/A	N/A	The Reliability Coordinator failed to address planned or unplanned outage information in its Operating Procedure, Process or Plan.
IRO-014-1	R1.1.4.	Voltage control, including the coordination of reactive resources for voltage control.	N/A	N/A	N/A	The Reliability Coordinator failed to address voltage control, including the coordination of reactive resources for voltage control in its Operating Procedure, Process or Plan.
IRO-014-1	R1.1.5.	Coordination of information exchange to support reliability assessments.	N/A	N/A	N/A	The Reliability Coordinator failed to address the coordination of information exchange to support reliability assessments in its Operating Procedure, Process or Plan.

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IRO-014-1	R1.1.6.	Authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas.	N/A	N/A	N/A	The Reliability Coordinator failed to address authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas in its Operating Procedure, Process or Plan.
IRO-014-1	R2.	Each Reliability Coordinator's Operating Procedure, Process, or Plan that requires one or more other Reliability Coordinators to take action (e.g., make notifications, exchange information, or coordinate actions) shall be:	N/A	N/A	N/A	The Reliability Coordinator's Operating Procedure, Process, or Plan failed to comply with either IRO-014-1 R2.1 or R2.2.
IRO-014-1	R2.1.	Agreed to by all the Reliability Coordinators required to take the indicated action(s).	N/A	N/A	N/A	The Reliability Coordinator's Operating Procedure, Process, or Plan was not agreed to by all the Reliability Coordinators required to take the indicated action(s).
IRO-014-1	R2.2.	Distributed to all Reliability Coordinators that are required to take the indicated action(s).	N/A	N/A	N/A	The Reliability Coordinator's Operating Procedure, Process, or Plan was not distributed to all Reliability Coordinators that are required to take the indicated action(s).

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
IRO-014-1	R3.	A Reliability Coordinator's Operating Procedures, Processes, or Plans developed to support a Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan shall include:	N/A	N/A	N/A	The Reliability Coordinator's Operating Procedure, Process, or Plan failed to comply with either IRO-014-1 R3.1 or R3.2.
IRO-014-1	R3.1.	A reference to the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.	N/A	N/A	N/A	The Reliability Coordinator's Operating Procedure, Process, or Plan failed to reference the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.
IRO-014-1	R3.2.	The agreed-upon actions from the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.	N/A	N/A	N/A	The Reliability Coordinator's Operating Procedure, Process, or Plan failed to include the agreed-upon actions from the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.
IRO-014-1	R4.	Each of the Operating Procedures, Processes, and Plans addressed in Reliability Standard IRO-014 Requirement 1 and Requirement 3 shall:	N/A	N/A	N/A	The Reliability Coordinator developed an Operating Procedure, Process, or Plan in accordance with IRO-014 Requirement 1 and

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						Requirement 3, but failed to comply with one of the elements listed in IRO-014-1 R4.1 through R4.3.
IRO-014-1	R4.1.	Include version control number or date	N/A	N/A	N/A	The Reliability Operator failed to include the version control number or date in its Operating Procedure, Process, or Plan.
IRO-014-1	R4.2.	Include a distribution list.	N/A	N/A	N/A	The Reliability Operator failed to include a distribution list in its Operating Procedure, Process, or Plan.
IRO-014-1	R4.3.	Be reviewed, at least once every three years, and updated if needed.	N/A	N/A	N/A	The Reliability Operator failed to review, at least once every three years, and update if needed, its Operating Procedure, Process, or Plan.
IRO-015-1	R1.	The Reliability Coordinator shall follow its Operating Procedures, Processes, or Plans for making notifications and exchanging reliability-related information with other Reliability Coordinators.	N/A	The Reliability Coordinator failed to follow its Operating Procedures, Processes, or Plans for making notifications and exchanging reliability-related information with other Reliability	N/A	The Reliability Coordinator failed to follow its Operating Procedures, Processes, or Plans for making notifications and exchanging reliability-related information with other Reliability Coordinators and adverse reliability impacts resulted from

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				Coordinators but no adverse reliability impacts resulted from the incident.		the incident.
IRO-015-1	R1.1.	The Reliability Coordinator shall make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas.	N/A	The Reliability Coordinator failed to make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas but no adverse reliability impacts resulted from the incident.	N/A	The Reliability Coordinator failed to make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas and adverse reliability impacts resulted from the incident.
IRO-015-1	R2.	The Reliability Coordinator shall participate in agreed upon conference calls and other communication forums with adjacent Reliability Coordinators.	N/A	N/A	N/A	The Reliability Coordinator failed to participate in agreed upon conference calls and other communication forums with adjacent Reliability Coordinators.
IRO-015-1	R2.1.	The frequency of these conference calls shall be agreed upon by all involved Reliability Coordinators and shall be at least weekly.	N/A	N/A	N/A	The Reliability Operator failed to participate in the assessment of the need and frequency of conference calls with other Reliability Operators.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
IRO-015-1	R3.	The Reliability Coordinator shall provide reliability-related information as requested by other Reliability Coordinators.	N/A	N/A	N/A	The Reliability Coordinator failed to provide reliability-related information as requested by other Reliability Coordinators.
IRO-016-1	R1.	The Reliability Coordinator that identifies a potential, expected, or actual problem that requires the actions of one or more other Reliability Coordinators shall contact the other Reliability Coordinator(s) to confirm that there is a problem and then discuss options and decide upon a solution to prevent or resolve the identified problem.	The Reliability Coordinator that identified a potential, expected, or actual problem that required the actions of one or more other Reliability Coordinators, contacted the other Reliability Coordinator(s) to confirm that there was a problem, discussed options and decided upon a solution to prevent or resolve the identified problem, but failed to have evidence that it coordinated with other Reliability Coordinators.	N/A	N/A	The Reliability Coordinator that identified a potential, expected, or actual problem that required the actions of one or more other Reliability Coordinators failed to contact the other Reliability Coordinator(s) to confirm that there was a problem, discuss options and decide upon a solution to prevent or resolve the identified problem.
IRO-016-1	R1.1.	If the involved Reliability Coordinators agree on the problem and the actions to take to prevent or mitigate the system condition, each involved Reliability Coordinator shall implement the agreed-upon solution, and notify the involved Reliability Coordinators of the action(s) taken.	The responsible entity agreed on the problem and the actions to take to prevent or mitigate the system condition, implemented the agreed-upon solution, but failed to notify the involved Reliability Coordinators of the	N/A	N/A	The responsible entity agreed on the problem and the actions to take to prevent or mitigate the system condition, but failed to implement the agreed-upon solution.

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			action(s) taken.			
IRO-016-1	R1.2.	If the involved Reliability Coordinators cannot agree on the problem(s) each Reliability Coordinator shall re-evaluate the causes of the disagreement (bad data, status, study results, tools, etc.).	N/A	N/A	N/A	The involved Reliability Coordinators could not agree on the problem(s), but a Reliability Coordinator failed to re-evaluate the causes of the disagreement (bad data, status, study results, tools, etc.).
IRO-016-1	R1.2.1.	If time permits, this re-evaluation shall be done before taking corrective actions.	N/A	N/A	N/A	The Reliability Coordinator failed to re-evaluate the problem prior to taking corrective actions, during periods when time was not an issue.
IRO-016-1	R1.2.2.	If time does not permit, then each Reliability Coordinator shall operate as though the problem(s) exist(s) until the conflicting system status is resolved.	N/A	N/A	N/A	The Reliability Coordinator failed to operate as though the problem(s) exist(s) until the conflicting system status was resolved, during periods when time was an issue.
IRO-016-1	R1.3.	If the involved Reliability Coordinators cannot agree on the solution, the more conservative solution shall be implemented.	N/A	N/A	N/A	The Reliability Coordinator implemented a solution other than the most conservative solution, when agreement on the solution could not be

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						reached.
IRO-016-1	R2.	The Reliability Coordinator shall document (via operator logs or other data sources) its actions taken for either the event or for the disagreement on the problem(s) or for both.	N/A	N/A	N/A	The Reliability Coordinator failed to document (via operator logs or other data sources) its actions taken for either the event or for the disagreement on the problem(s) or for both.

Complete Violation Severity Level Matrix (MOD)
Encompassing All FERC-Approved Reliability Standards

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
MOD-006-0.1	R1.	Each Transmission Service Provider shall document its procedure on the use of Capacity Benefit Margin (CBM) (scheduling of energy against a CBM reservation). The procedure shall include the following three components:	The Transmission Service Provider documented its procedure on the use of Capacity Benefit Margin (CBM) but failed to include one (1) of the components as specified in R1.1, R1.2 or R1.3.	The Transmission Service Provider documented its procedure on the use of Capacity Benefit Margin (CBM) but failed to include two (2) of the components as specified in R1.1, R1.2 or R1.3.	The Transmission Service Provider documented its procedure on the use of Capacity Benefit Margin (CBM) but failed to include three (3) of the components as specified in R1.1, R1.2 or R1.3.	The Transmission Service Provider failed to document its procedure on the use of Capacity Benefit Margin (CBM).
MOD-006-0.1	R1.1.	Require that CBM be used only after the following steps have been taken (as time permits): all non-firm sales have been terminated, Direct-Control Load Management has been implemented, and customer interruptible demands have been interrupted. CBM may be used to reestablish Operating Reserves.	N/A	The Transmission Service Provider required that CBM be used only after all non-firm sales have been terminated and Direct-Control Load Management has been implemented but failed to include customer interruptible demands that have been interrupted.	The Transmission Service Provider required that CBM be used only after all non-firm sales have been terminated but failed to include Direct-Control Load Management has been implemented and customer interruptible demands that have been interrupted.	The Transmission Service Provider failed to require that CBM be used only after all non-firm sales have been terminated, Direct-Control Load Management has been implemented and customer interruptible demands that have been interrupted.
MOD-006-0.1	R1.2.	Require that CBM shall only be used if the Load-Serving Entity calling for its use is experiencing a generation deficiency and its Transmission Service Provider is also experiencing Transmission Constraints relative to imports of energy on its transmission system.	N/A	The Transmission Service Provider required that CBM shall only be used if the Load-Serving Entity calling for its use is experiencing a generation deficiency but failed to require that CBM	N/A	The Transmission Service Provider failed to require that CBM shall only be used if the Load-Serving Entity calling for its use is experiencing a generation deficiency and its Transmission Service Provider is

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				shall only be used if its Transmission Service Provider is also experiencing Transmission Constraints relative to imports of energy on its transmission system.		also experiencing Transmission Constraints relative to imports of energy on its transmission system.
MOD-006-0.1	R1.3.	Describe the conditions under which CBM may be available as Non-Firm Transmission Service.	N/A	N/A	N/A	The Transmission Service Provider has failed to describe the conditions under which CBM may be available as Non-Firm Transmission Service.
MOD-006-0.1	R2.	Each Transmission Service Provider shall make its CBM use procedure available on a web site accessible by the Regional Reliability Organizations, NERC, and transmission users.	The Transmission Service Provider has demonstrated the procedure is available on the Web but is deficient with minor details.	N/A	N/A	The Transmission Service Provider has failed to provide the procedure on the Web as directed by the requirement.
MOD-007-0	R1.	Each Transmission Service Provider that uses CBM shall report (to the Regional Reliability Organization, NERC and the transmission users) the use of CBM by the Load-Serving Entities' Loads on its system, except for CBM sales as Non-Firm Transmission Service. (This use of CBM shall be consistent with the Transmission Service Provider's procedure for use of CBM.)	N/A	Each Transmission Service Provider that uses CBM reported (to the Regional Reliability Organization, NERC and the transmission users) the use of CBM by the Load-Serving Entities' Loads on its system but failed to use CBM that is consistent with the	N/A	Each Transmission Service Provider that uses CBM failed to report (to the Regional Reliability Organization, NERC and the transmission users) the use of CBM by the Load-Serving Entities' Loads on its system.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Transmission Service Provider's procedure for use of CBM.		
MOD-007-0	R2.	The Transmission Service Provider shall post the following three items within 15 calendar days after the use of CBM for an Energy Emergency. This posting shall be on a web site accessible by the Regional Reliability Organizations, NERC, and transmission users.	The Transmission Service Provider that uses CBM for an Energy Emergency complied with the posting of the 3 required items but is deficient regarding minor details.	The Transmission Service Provider that uses CBM for an Energy Emergency complied with the posting but is deficient regarding one of the 3 requirements.	The Transmission Service Provider that uses CBM for an Energy Emergency complied with the posting but is deficient regarding two of the 3 requirements.	The Transmission Service Provider that uses CBM for an Energy Emergency did not comply with the posting as required.
MOD-007-0	R2.1.	Circumstances.	The Transmission Service Provider posted the circumstance more than 15 but less than or equal to 20 calendar days after the use of CBM for an Energy Emergency.	The Transmission Service Provider posted the circumstance more than 20 but less than or equal to 25 calendar days after the use of CBM for an Energy Emergency.	The Transmission Service Provider posted the circumstance more than 25 but less than or equal to 30 calendar days after the use of CBM for an Energy Emergency.	The Transmission Service Provider failed to post the circumstance more than 30 calendar days after the use of CBM for an Energy Emergency.
MOD-007-0	R2.2.	Duration.	The Transmission Service Provider posted the duration more than 15 but less than or equal to 20 calendar days after the use of CBM for an Energy Emergency.	The Transmission Service Provider posted the duration more than 20 but less than or equal to 25 calendar days after the use of CBM for an Energy Emergency.	The Transmission Service Provider posted the duration more than 25 but less than or equal to 30 calendar days after the use of CBM for an Energy Emergency.	The Transmission Service Provider failed to post the duration more than 30 calendar days after the use of CBM for an Energy Emergency.
MOD-007-0	R2.3.	Amount of CBM used.	The Transmission Service Provider posted the amount of CBM used more than	The Transmission Service Provider posted the amount of CBM used more	The Transmission Service Provider posted the amount of CBM used more than 25 but	The Transmission Service Provider failed to post the amount of CBM used more than

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			15 but less than or equal to 20 calendar days after the use of CBM for an Energy Emergency.	than 20 but less than or equal to 25 calendar days after the use of CBM for an Energy Emergency.	less than or equal to 30 calendar days after the use of CBM for an Energy Emergency.	30 calendar days after the use of CBM for an Energy Emergency.
MOD-010-0	R1.	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide appropriate equipment characteristics, system data, and existing and future Interchange Schedules in compliance with its respective Interconnection Regional steady-state modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-011-0_R 1.	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide less than or equal to 25% of the appropriate equipment characteristics, system data, and existing and future Interchange Schedules in compliance with its respective Interconnection Regional steady-state modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-011-0_R 1	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide greater than 25% but less than or equal to 50% of the appropriate equipment characteristics, system data, and existing and future Interchange Schedules in compliance with its respective Interconnection Regional steady-state modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-011-0_R1.	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide greater than 50% but less than or equal to 75% of the appropriate equipment characteristics, system data, and existing and future Interchange Schedules in compliance with its respective Interconnection Regional steady-state modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-011-0_R1.	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide greater than 75% of the appropriate equipment characteristics, system data, and existing and future Interchange Schedules in compliance with its respective Interconnection Regional steady-state modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-011-0_R1.
MOD-010-0	R2.	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-011-	The Transmission Owners, Transmission Planners, Generator Owners, and Resource	The Transmission Owners, Transmission Planners, Generator	The Transmission Owners, Transmission Planners, Generator Owners, and Resource	The Transmission Owners, Transmission Planners, Generator Owners, and Resource

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		0_R1) shall provide this steady-state modeling and simulation data to the Regional Reliability Organizations, NERC, and those entities specified within Reliability Standard MOD-011-0_R 1. If no schedule exists, then these entities shall provide the data on request (30 calendar days).	Planners failed to provide less than or equal to 25% of the steady-state modeling and simulation data to the Regional Reliability Organizations, NERC, and those entities specified within Reliability Standard MOD-011-0_R 1. OR If no schedule exists, The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners provided data more than 30 but less than or equal to 35 calendar days following the request.	Owners, and Resource Planners failed to provide greater than 25% but less than or equal to 50% of the steady-state modeling and simulation data to the Regional Reliability Organizations, NERC, and those entities specified within Reliability Standard MOD-011-0_R 1. OR If no schedule exists, The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners provided data more than 35 but less than or equal to 40 calendar days following the request.	Planners failed to provide greater than 50% but less than or equal to 75% of the steady-state modeling and simulation data to the Regional Reliability Organizations, NERC, and those entities specified within Reliability Standard MOD-011-0_R 1. OR If no schedule exists, The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners provided data more than 40 but less than or equal to 45 calendar days following the request.	Planners failed to provide greater than 75% of the steady-state modeling and simulation data to the Regional Reliability Organizations, NERC, and those entities specified within Reliability Standard MOD-011-0_R 1. OR If no schedule exists, The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide data more than 45 calendar days following the request.
MOD-012-0	R1.	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R1) shall provide appropriate equipment characteristics and system data in compliance with the respective Interconnection-wide	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide less than or equal to 25% of the	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide greater than 50% but less than 75%	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide greater than 75% of the appropriate

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Regional dynamics system modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-013-0_R1.	appropriate equipment characteristics and system data in compliance with the respective Interconnection-wide Regional dynamics system modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-013-0_R1	greater than 25% but less than 50% of the appropriate equipment characteristics and system data in compliance with the respective Interconnection-wide Regional dynamics system modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-013-0_R1.	of the appropriate equipment characteristics and system data in compliance with the respective Interconnection-wide Regional dynamics system modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-013-0_R1.	equipment characteristics and system data in compliance with the respective Interconnection-wide Regional dynamics system modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-013-0_R1.
MOD-012-0	R2.	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R4) shall provide dynamics system modeling and simulation data to its Regional Reliability Organization(s), NERC, and those entities specified within the applicable reporting procedures identified in Reliability Standard MOD-013-0_R 1. If no schedule exists, then these entities shall provide data on request (30 calendar days).	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide less than or equal to 25% of the dynamics system modeling and simulation data to its Regional Reliability Organization(s), NERC, and those entities specified within the applicable reporting procedures identified in Reliability Standard MOD-013-0_R 1 OR	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide greater than 25% but less than 50% of the dynamics system modeling and simulation data to its Regional Reliability Organization(s), NERC, and those entities specified within the applicable reporting procedures identified in Reliability Standard	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide greater than 50% but less than 75% of the dynamics system modeling and simulation data to its Regional Reliability Organization(s), NERC, and those entities specified within the applicable reporting procedures identified in Reliability Standard MOD-013-0_R 1. OR If no schedule exists,	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide greater than 75% of the dynamics system modeling and simulation data to its Regional Reliability Organization(s), NERC, and those entities specified within the applicable reporting procedures identified in Reliability Standard MOD-013-0_R 1. OR If no schedule exists,

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			If no schedule exists, The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners provided data more than 30 but less than or equal to 35 calendar days following the request.	MOD-013-0_R 1. OR If no schedule exists, The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners provided data more than 35 but less than or equal to 40 calendar days following the request.	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners provided data more than 40 but less than or equal to 45 calendar days following the request.	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide data more than 45 calendar days following the request.
MOD-016-1.1	R1.	The Planning Authority and Regional Reliability Organization shall have documentation identifying the scope and details of the actual and forecast (a) Demand data, (b) Net Energy for Load data, and (c) controllable DSM data to be reported for system modeling and reliability analyses.	N/A	The Planning Authority and Regional Reliability Organization has documentation identifying the scope and details of the actual and forecast data but failed to have documentation identifying the scope data and details for one (1) of the following actual and forecast data to be reported for system modeling and reliability analyses: (a) Demand data, (b) Net Energy for Load	The Planning Authority and Regional Reliability Organization has documentation identifying the scope and details of the actual and forecast data but failed to have documentation identifying the scope data and details for two (2) of the following actual and forecast data to be reported for system modeling and reliability analyses: (a) Demand data, (b) Net Energy for Load data, or (c) controllable DSM data.	The Planning Authority and Regional Reliability Organization has failed to have documentation identifying the scope and details of the actual and forecast data to be reported for system modeling and reliability analyses.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				data, or (c) controllable DSM data.		
MOD-016-1.1	R1.1.	The aggregated and dispersed data submittal requirements shall ensure that consistent data is supplied for Reliability Standards TPL-005, TPL-006, MOD-010, MOD-011, MOD-012, MOD-013, MOD-014, MOD-015, MOD-016, MOD-017, MOD-018, MOD-019, MOD-020, and MOD-021. The data submittal requirements shall stipulate that each Load-Serving Entity count its customer Demand once and only once, on an aggregated and dispersed basis, in developing its actual and forecast customer Demand values.	The Planning Authority and Regional Reliability Organization failed to ensure that consistent data is supplied for less than or equal to 25% or the Reliability Standards as specified in R1.1	The Planning Authority and Regional Reliability Organization failed to ensure that consistent data is supplied for greater than 25% but less than or equal to 50% of the Reliability Standards as specified in R1.1.	The Planning Authority and Regional Reliability Organization failed to ensure that consistent data is supplied for greater than 50% but less than or equal to 75% of the Reliability Standards as specified in R1.1.	The Planning Authority and Regional Reliability Organization failed to ensure that consistent data is supplied for greater than 75% of the Reliability Standards as specified in R1.1. OR The Planning Authority and Regional Reliability Organization failed to stipulate that each Load-Serving Entity count its customer Demand once and only once, on an aggregated and dispersed basis, in developing its actual and forecast customer Demand values.
MOD-016-1.1	R2.	The Regional Reliability Organization shall distribute its documentation required in Requirement 1 and any changes to that documentation, to all Planning Authorities that work within its Region.	N/A	N/A	The Regional Reliability Organization distributed its documentation as specified in R1 but failed to distribute any changes to that documentation, to all Planning Authorities that work within its	The Regional Reliability Organization failed to distribute its documentation as specified in R1 to all Planning Authorities that work within its Region.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
					Region.	
MOD-016-1.1	R2.1.	The Regional Reliability Organization shall make this distribution within 30 calendar days of approval.	The Regional Reliability Organization distributed the documentation more than 30 but less than or equal to 37 calendar days following approval.	The Regional Reliability Organization made the distribution more than 37 but less than or equal to 51 calendar days following approval.	The Regional Reliability Organization made the distribution more than 51 but less than or equal to 58 calendar days following approval.	The Regional Reliability Organization failed to make the distribution more than 58 calendar days following approval.
MOD-016-1.1	R3.	The Planning Authority shall distribute its documentation required in R1 for reporting customer data and any changes to that documentation, to its Transmission Planners and Load-Serving Entities that work within its Planning Authority Area.	N/A	N/A	The Planning Authority distributed its documentation as specified in R1 for reporting customer data but failed to distribute any changes to that documentation, to its Transmission Planners and Load-Serving Entities that work within its Planning Authority Area.	The Planning Authority failed to distribute its documentation as specified in R1 for reporting customer data to its Transmission Planners and Load-Serving Entities that work within its Planning Authority Area.
MOD-016-1.1	R3.1.	The Planning Authority shall make this distribution within 30 calendar days of approval.	The Planning Authority distributed the documentation more than 30 but less than or equal to 37 calendar days following approval.	The Planning Authority made the distribution more than 37 but less than or equal to 51 calendar days following approval.	The Planning Authority made the distribution more than 51 but less than or equal to 58 calendar days following approval.	The Planning Authority failed to make the distribution more than 58 calendar days following approval
MOD-017-0.1	R1.	The Load-Serving Entity, Planning Authority, and Resource Planner shall each provide the following information annually on an aggregated Regional, subregional, Power Pool, individual system, or Load-Serving Entity basis to NERC, the Regional Reliability Organizations, and any other	The Load-Serving Entity, Planning Authority, and Resource Planner failed to provide one of the elements of information as	The Load-Serving Entity, Planning Authority, and Resource Planner failed to provide two of the elements of information as	The Load-Serving Entity, Planning Authority, and Resource Planner failed to provide three of the elements of information as specified	The Load-Serving Entity, Planning Authority, and Resource Planner failed to provide all of the elements of information as

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		entities specified by the documentation in Standard MOD-016-1_R 1.	specified in R1.1, R1.2, R1.3 or R1.4 on an annual basis.	specified in R1.1, R1.2, R1.3 or R1.4 on an annual basis.	in R1.1, R1.2, R1.3 or R1.4 on an annual basis.	specified in R1.1, R1.2, R1.3 or R1.4 on an annual basis.
MOD-017-0.1	R1.1.	Integrated hourly demands in megawatts (MW) for the prior year.	N/A	N/A	N/A	The Load-Serving Entity, Planning Authority, and Resource Planner failed to provide Integrated hourly demands in megawatts (MW) for the prior year on an annual basis.
MOD-017-0.1	R1.2.	Monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year.	N/A	N/A	N/A	The Load-Serving Entity, Planning Authority, and Resource Planner failed to provide monthly and annual peak hour actual demands in MW Net Energy for Load in gigawatthours (GWh) for the prior year.
MOD-017-0.1	R1.3.	Monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years.	N/A	N/A	N/A	The Load-Serving Entity, Planning Authority, and Resource Planner failed to provide Monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years.
MOD-017-0.1	R1.4.	Annual Peak hour forecast demands (summer and winter) in MW and annual Net Energy for load in GWh for at least five years and up	N/A	N/A	N/A	The Load-Serving Entity, Planning Authority, and

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		to ten years into the future, as requested.				Resource Planner failed to provide Annual Peak hour forecast demands (summer and winter) in MW and annual Net Energy for load in GWh for at least five years and up to ten years into the future, as requested.
MOD-018-0	R1.	The Load-Serving Entity, Planning Authority, Transmission Planner and Resource Planner's report of actual and forecast demand data (reported on either an aggregated or dispersed basis) shall:	N/A	The Load-Serving Entity, Planning Authority, Transmission Planner and Resource Planner failed to report one (1) of the items as specified in R1.1, R1.2, or R1.3.	The Load-Serving Entity, Planning Authority, Transmission Planner and Resource Planner failed to report two (2) of the items as specified in R1.1, R1.2, or R1.3.	The Load-Serving Entity, Planning Authority, Transmission Planner and Resource Planner failed to report all of the items as specified in R1.1, R1.2, and R1.3.
MOD-018-0	R1.1.	Indicate whether the demand data of nonmember entities within an area or Regional Reliability Organization are included, and	N/A	N/A	N/A	The Load-Serving Entity, Planning Authority, Transmission Planner and Resource Planner failed to indicate whether the demand data of nonmember entities within an area or Regional Reliability Organization are included.
MOD-018-0	R1.2.	Address assumptions, methods, and the manner in which uncertainties are treated in the forecasts of aggregated peak demands and Net Energy for Load.	N/A	N/A	N/A	The Load-Serving Entity, Planning Authority, Transmission Planner

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						and Resource Planner failed to address assumptions, methods, and the manner in which uncertainties are treated in the forecasts of aggregated peak demands and Net Energy for Load.
MOD-018-0	R1.3.	Items (MOD-018-0_R 1.1) and (MOD-018-0_R 1.2) shall be addressed as described in the reporting procedures developed for Standard MOD-016-1_R 1.	N/A	N/A	N/A	The Load-Serving Entity, Planning Authority, Transmission Planner and Resource Planner failed to address items (MOD-018-0_R 1.1) and (MOD-018-0_R 1.2) as described in the reporting procedures developed for Standard MOD-016-1_R1.
MOD-018-0	R2.	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each report data associated with Reliability Standard MOD-018-0_R1 to NERC, the Regional Reliability Organization, Load-Serving Entity, Planning Authority, and Resource Planner on request (within 30 calendar days).	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner reported the data associated with Reliability Standard MOD-018-0_R1 to NERC, the Regional Reliability Organization, Load-Serving Entity, Planning Authority, and Resource Planner	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner reported the data associated with Reliability Standard MOD-018-0_R1 to NERC, the Regional Reliability Organization, Load-Serving Entity, Planning Authority,	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner reported the data associated with Reliability Standard MOD-018-0_R1 to NERC, the Regional Reliability Organization, Load-Serving Entity, Planning Authority, and Resource Planner more	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner failed to report the data associated with Reliability Standard MOD-018-0_R1 to NERC, the Regional Reliability Organization, Load-Serving Entity, Planning Authority, and Resource Planner

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			more than 30 but less than or equal to 45 calendar days following the request.	and Resource Planner more than 45 but less than or equal to 60 calendar days following the request.	than 60 but less than or equal to 75 calendar days following the request.	more than 75 calendar days following the request.
MOD-019-0.1	R1.	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each provide annually its forecasts of interruptible demands and Direct Control Load Management (DCLM) data for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions to NERC, the Regional Reliability Organizations, and other entities (Load-Serving Entities, Planning Authorities, and Resource Planners) as specified by the documentation in Reliability Standard MOD-016-0_R 1.	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner failed to provide annually less than or equal to 25% of the interruptible demands and Direct Control Load Management (DCLM) data for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions to NERC, the Regional Reliability Organizations, and other entities (Load-Serving Entities, Planning Authorities, and Resource Planners) as specified by the documentation in Reliability Standard MOD-016-0_R 1.	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner failed to provide annually greater than 25% but less than or equal to 50% of the interruptible demands and Direct Control Load Management (DCLM) data for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions to NERC, the Regional Reliability Organizations, and other entities (Load-Serving Entities, Planning Authorities, and Resource Planners) as specified by the documentation in Reliability Standard	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner failed to provide annually greater than 50% but less than or equal to 75% of the interruptible demands and Direct Control Load Management (DCLM) data for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions to NERC, the Regional Reliability Organizations, and other entities (Load-Serving Entities, Planning Authorities, and Resource Planners) as specified by the documentation in Reliability Standard MOD-016-0_R1.	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner failed to provide annually greater than 75% of the interruptible demands and Direct Control Load Management (DCLM) data for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions to NERC, the Regional Reliability Organizations, and other entities (Load-Serving Entities, Planning Authorities, and Resource Planners) as specified by the documentation in Reliability Standard MOD-016-0_R1.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				MOD-016-0_R1.		
MOD-020-0	R1.	The Load-Serving Entity, Transmission Planner, and Resource Planner shall each make known its amount of interruptible demands and Direct Control Load Management (DCLM) to Transmission Operators, Balancing Authorities, and Reliability Coordinators on request within 30 calendar days.	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner made known its amount of interruptible demands and Direct Control Load Management (DCLM) more than 30 but less than 45 calendar days following the request from Transmission Operators, Balancing Authorities, and Reliability Coordinators.	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner made known its amount of interruptible demands and Direct Control Load Management (DCLM) more than 45 but less than 60 calendar days following the request from Transmission Operators, Balancing Authorities, and Reliability Coordinators.	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner made known its amount of interruptible demands and Direct Control Load Management (DCLM) more than 60 but less than 75 calendar days following the request from Transmission Operators, Balancing Authorities, and Reliability Coordinators.	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner failed to make known its amount of interruptible demands and Direct Control Load Management (DCLM) more than 75 calendar days following the request from Transmission Operators, Balancing Authorities, and Reliability Coordinators.
MOD-021-0.1	R1.	The Load-Serving Entity, Transmission Planner, and Resource Planner's forecasts shall each clearly document how the Demand and energy effects of DSM programs (such as conservation, time-of-use rates, interruptible Demands, and Direct Control Load Management) are addressed.	Load-Serving Entity, Transmission Planner, and Resource Planner's forecasts document how the Demand and energy effects of DSM programs but failed to document how one (1) of the following elements of the Demand and energy effects of DSM programs are	Load-Serving Entity, Transmission Planner, and Resource Planner's forecasts document how the Demand and energy effects of DSM programs but failed to document how two (2) of the following elements of the Demand and energy effects of DSM	Load-Serving Entity, Transmission Planner, and Resource Planner's forecasts document how the Demand and energy effects of DSM programs but failed to document how three (3) of the following elements of the Demand and energy effects of DSM programs are addressed: conservation, time-of-	Load-Serving Entity, Transmission Planner, and Resource Planner's forecasts failed to document how the Demand and energy effects of DSM programs are addressed.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			addressed: conservation, time-of-use rates, interruptible Demands or Direct Control Load Management.	programs are addressed: conservation, time-of-use rates, interruptible Demands or Direct Control Load Management.	use rates, interruptible Demands or Direct Control Load Management.	
MOD-021-0.1	R2.	The Load-Serving Entity, Transmission Planner, and Resource Planner shall each include information detailing how Demand-Side Management measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load in the data reporting procedures of Standard MOD-016-0_R 1.	N/A	N/A	N/A	The Load-Serving Entity, Transmission Planner, and Resource Planner failed to include information detailing how Demand-Side Management measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load in the data reporting procedures of Standard MOD-016-0_R 1.
MOD-021-0.1	R3.	The Load-Serving Entity, Transmission Planner, and Resource Planner shall each make documentation on the treatment of its DSM programs available to NERC on request (within 30 calendar days).	The Load-Serving Entity, Transmission Planner, and Resource Planner provided documentation on the treatment of its DSM programs more than 30 but less than 45 calendar days following the request from NERC.	The Load-Serving Entity, Transmission Planner, and Resource Planner provided documentation on the treatment of its DSM programs more than 45 but less than 60 calendar days following the request from NERC.	The Load-Serving Entity, Transmission Planner, and Resource Planner provided documentation on the treatment of its DSM programs more than 60 but less than 75 calendar days following the request from NERC.	The Load-Serving Entity, Transmission Planner, and Resource Planner failed to provide documentation on the treatment of its DSM programs more than 75 calendar days following the request from NERC.

Complete Violation Severity Level Matrix (NUC)
Encompassing All FERC-Approved Reliability Standards

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
NUC-001-2	R1.	The Nuclear Plant Generator Operator shall provide the proposed NPIRs in writing to the applicable Transmission Entities and shall verify receipt.	The Nuclear Plant Generator Operator did not verify receipt of the proposed NPIR's.	The Nuclear Plant Generator Operator submitted an incomplete proposed NPIR to the applicable transmission entities.	The Nuclear Plant Generator Operator did not provide the proposed NPIR's to some applicable entities.	The Nuclear Plant Generator Operator did not provide the proposed NPIR's to any applicable entities.
NUC-001-2	R2.	The Nuclear Plant Generator Operator and the applicable Transmission Entities shall have in effect one or more Agreements that include mutually agreed to NPIRs and document how the Nuclear Plant Generator Operator and the applicable Transmission Entities shall address and implement these NPIRs.	N/A	N/A	N/A	The Nuclear Plant Generator Operator or the applicable Transmission Entity does not have in effect one or more agreements that include NPIRs and document the implementation of the NPIRs.
NUC-001-2	R3.	Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall incorporate the NPIRs into their planning analyses of the electric system and shall communicate the results of these analyses to the Nuclear Plant Generator Operator.	The applicable Transmission Entity incorporated the NPIRs into its planning analyses and identified no areas of concern but it did not communicate these results to the Nuclear Plant Generator Operator.	The applicable Transmission Entity incorporated the NPIRs into its planning analyses and identified one or more areas of concern but did not communicate these results to the Nuclear Plant Generator Operator.	The applicable Transmission Entity did not incorporate the NPIRs into its planning analyses of the electric system.	N/A
NUC-001-2	R4.	Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall:	The applicable Transmission Entity failed to incorporate one or more	The applicable Transmission Entity failed to incorporate any NPIRs into their	The applicable Transmission Entity failed to operate the system to meet the	N/A

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			applicable NPIRs into their operating analyses.	operating analyses OR did not inform NPG operator when their ability of assess the operation of the electric system affecting the NPIRs was lost.	NPIRs	
NUC-001-2	R4.1	Incorporate the NPIRs into their operating analyses of the electric system.	N/A	N/A	N/A	N/A
NUC-001-2	R4.2	Operate the electric system to meet the NPIRs.	N/A	N/A	N/A	N/A
NUC-001-2	R4.3	Inform the Nuclear Plant Generator Operator when the ability to assess the operation of the electric system affecting NPIRs is lost.	N/A	N/A	N/A	N/A
NUC-001-2	R5.	The Nuclear Plant Generator Operator shall operate per the Agreements developed in accordance with this standard.	The Nuclear Operator failed to operate the plant in accordance with one or more of the administrative or training elements within the agreements.	The Nuclear Operator failed to operate the plant in accordance with one or two of the technical, operations, and maintenance or communication elements within the agreements.	The Nuclear Operator failed to operate the plant in accordance with three or more of the technical, operations, and maintenance or communication elements within the agreements.	N/A
NUC-001-2	R6.	Per the Agreements developed in accordance with this standard, the applicable Transmission Entities and the Nuclear Plant Generator Operator shall coordinate outages and maintenance activities which affect the NPIRs.	The Nuclear Operator or Transmission Entity failed to coordinate outages or maintenance activities in accordance with one or more of the administrative elements within the agreements.	The Nuclear Operator or Transmission Entity failed to provide outage or maintenance schedules to the appropriate parties as described in the agreement or on a time period consistent with the	The Nuclear Operator or Transmission Entity failed to coordinate one or more outages or maintenance activities in accordance the requirements of the agreements.	N/A

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				agreements.		
NUC-001-2	R7.	Per the Agreements developed in accordance with this standard, the Nuclear Plant Generator Operator shall inform the applicable Transmission Entities of actual or proposed changes to nuclear plant design, configuration, operations, limits, protection systems, or capabilities that may impact the ability of the electric system to meet the NPIRs.	The Nuclear Plant Generator Operator did not inform the applicable Transmission Entities of proposed changes to nuclear plant design, configuration, operations, limits, protection systems, or capabilities that may impact the ability of the electric system to meet the NPIRs.	The Nuclear Plant Generator Operator did not inform the applicable Transmission Entities of actual changes to nuclear plant design, configuration, operations, limits, protection systems, or capabilities that may impact the ability of the electric system to meet the NPIRs.	The Nuclear Plant Generator Operator did not inform the applicable Transmission Entities of actual changes to nuclear plant design, configuration, operations, limits, protection systems, or capabilities that directly impact the ability of the electric system to meet the NPIRs.	N/A
NUC-001-2	R8.	Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall inform the Nuclear Plant Generator Operator of actual or proposed changes to electric system design, configuration, operations, limits, protection systems, or capabilities that may impact the ability of the electric system to meet the NPIRs.	The applicable Transmission Entities did not inform the Nuclear Plant Generator Operator of proposed changes to transmission system design, configuration, operations, limits, protection systems, or capabilities that may impact the ability of the electric system to meet the NPIRs.	The applicable Transmission Entities did not inform the Nuclear Plant Generator Operator of actual changes to transmission system design, configuration, operations, limits, protection systems, or capabilities that may impact the ability of the electric system to meet the NPIRs.	The applicable Transmission Entities did not inform the Nuclear Plant Generator Operator of actual changes to transmission system design, configuration, operations, limits, protection systems, or capabilities that directly impacts the ability of the electric system to meet the NPIRs.	N/A
NUC-001-2	R9.	The Nuclear Plant Generator Operator and the applicable Transmission Entities shall include, as a minimum, the following elements within the agreement(s) identified in R2:	The agreement identified in R2. between the Nuclear Plant Generator Operator and the applicable Transmission Entities	The agreement identified in R2. between the Nuclear Plant Generator Operator and the applicable Transmission Entities	The agreement identified in R2. between the Nuclear Plant Generator Operator and the applicable Transmission Entities is missing from six to ten of the	The agreement identified in R2. between the Nuclear Plant Generator Operator and the applicable Transmission Entities

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			is missing one or more sub-components of R9.1.	is missing from one to five of the combined sub-components in R9.2, R9.3 and R9.4.	combined sub-components in R9.2, R9.3 and R9.4.	is missing eleven or more of the combined sub-components in R9.2, R9.3 and R9.4.
NUC-001-2	R9.1	Administrative elements:				
NUC-001-2	R9.1.1	Definitions of key terms used in the agreement.				
NUC-001-2	R9.1.2	Names of the responsible entities, organizational relationships, and responsibilities related to the NPIRs.				
NUC-001-2	R9.1.3	A requirement to review the agreement(s) at least every three years.				
NUC-001-2	R9.1.4	A dispute resolution mechanism.				
NUC-001-2	R9.2	Technical requirements and analysis:				
NUC-001-2	R9.2.1	Identification of parameters, limits, configurations, and operating scenarios included in the NPIRs and, as applicable, procedures for providing any specific data not provided within the agreement.				
NUC-001-2	R9.2.2	Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs.				
NUC-001-2	R9.2.3	Types of planning and operational analyses performed specifically to support the NPIRs, including the frequency of studies and types of Contingencies and scenarios required.				
NUC-001-2	R9.3	Operations and maintenance coordination:				
NUC-001-2	R9.3.1	Designation of ownership of electrical facilities at the interface between the electric system and the nuclear plant and responsibilities for operational control coordination and maintenance of these				

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		facilities.				
NUC-001-2	R9.3.2	Identification of any maintenance requirements for equipment not owned or controlled by the Nuclear Plant Generator Operator that are necessary to meet the NPIRs.				
NUC-001-2	R9.3.3	Coordination of testing, calibration and maintenance of on-site and off-site power supply systems and related components.				
NUC-001-2	R9.3.4	Provisions to address mitigating actions needed to avoid violating NPIRs and to address periods when responsible Transmission Entity loses the ability to assess the capability of the electric system to meet the NPIRs. These provisions shall include responsibility to notify the Nuclear Plant Generator Operator within a specified time frame.				
NUC-001-2	R9.3.5	Provision for considering, within the restoration process, the requirements and urgency of a nuclear plant that has lost all off-site and on-site AC power.				
NUC-001-2	R9.3.6	Coordination of physical and cyber security protection of the Bulk Electric System at the nuclear plant interface to ensure each asset is covered under at least one entity's plan.				
NUC-001-2	R9.3.7	Coordination of the NPIRs with transmission system Special Protection Systems and underfrequency and undervoltage load shedding programs.				
NUC-001-2	R9.4	Communications and training:				
NUC-001-2	R9.4.1	Provisions for communications between the Nuclear Plant Generator Operator and Transmission Entities, including communications protocols, notification time				

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		requirements, and definitions of terms.				
NUC-001-2	R9.4.2	Provisions for coordination during an off-normal or emergency event affecting the NPIRs, including the need to provide timely information explaining the event, an estimate of when the system will be returned to a normal state, and the actual time the system is returned to normal.				
NUC-001-2	R9.4.3	Provisions for coordinating investigations of causes of unplanned events affecting the NPIRs and developing solutions to minimize future risk of such events.				
NUC-001-2	R9.4.4	Provisions for supplying information necessary to report to government agencies, as related to NPIRs.				
NUC-001-2	R9.4.5	Provisions for personnel training, as related to NPIRs.				

Complete Violation Severity Level Matrix (PER)
Encompassing All FERC-Approved Reliability Standards

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
PER-001-0.1	R1.	Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.	N/A	N/A	The Transmission Operator and Balancing Authority has failed to demonstrate the communication to the operating personnel their responsibility OR their authority to implement real-time actions to ensure a stable and reliable operation of the Bulk Electric System.	The Transmission Operator and Balancing Authority has failed to demonstrate the communication to the operating personnel their responsibility AND authority to implement real-time actions to ensure a stable and reliable operation of the Bulk Electric System.
PER-002-0	R1.	Each Transmission Operator and Balancing Authority shall be staffed with adequately trained operating personnel.	The applicable entity did not adequately staff and train operating personnel, affecting 5% or less of its operating personnel.	The applicable entity did not adequately staff and train operating personnel, affecting between 5-10% of its operating personnel.	The applicable entity did not adequately staff and train operating personnel, affecting 10-15%, inclusive, of its operating personnel.	The applicable entity did not adequately staff and train operating personnel, affecting greater than 15% of its operating personnel.
PER-002-0	R2.	Each Transmission Operator and Balancing Authority shall have a training program for all operating personnel that are in:	Each Transmission Operator and Balancing Authority has produced the training program for more than 75% but less than 100% of their real-time operating personnel.	Each Transmission Operator and Balancing Authority has produced the training program for more than 50% but less than or equal to 75% of their real-time operating personnel.	Each Transmission Operator and Balancing Authority has produced the training program for more than 25% but less than or equal to 50% of their real-time operating personnel.	Each Transmission Operator and Balancing Authority has produced the training program for more than or equal to 0% but less than or equal to 25% of their real-time operating personnel.
PER-002-0	R2.1.	Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk	N/A	N/A	N/A	The Transmission Operator and Balancing Authority failed to produce

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Electric System.				training program for their operating personnel.
PER-002-0	R2.2.	Positions directly responsible for complying with NERC standards.	N/A	N/A	N/A	The Transmission Operator and Balancing Authority failed to produce training program for positions directly responsible for complying with NERC Standards.
PER-002-0	R3.	For personnel identified in Requirement R2, the Transmission Operator and Balancing Authority shall provide a training program meeting the following criteria:	The applicable entity did not comply with one of the four required elements.	The applicable entity did not comply with two of the four required elements.	The applicable entity did not comply with three of the four required elements.	The applicable entity did not comply with any of the four required elements.
PER-002-0	R3.1.	A set of training program objectives must be defined, based on NERC and Regional Reliability Organization standards, entity operating procedures, and applicable regulatory requirements. These objectives shall reference the knowledge and competencies needed to apply those standards, procedures, and requirements to normal, emergency, and restoration conditions for the Transmission Operator and Balancing Authority operating positions.	The responsible entity's training program objectives were incomplete (e.g. The responsible entity failed to define training program objectives for less than 25% of the applicable BA and TOP NERC and Regional Reliability Organizations standards, entity operating procedures, and regulatory requirements.)	The responsible entity's training program objectives were incomplete (e.g. The responsible entity failed to define training program objectives for 25% or more but less than 50% of the applicable BA & TOP NERC and Regional Reliability Organizations standards, entity operating procedures, and regulatory requirements.)	The responsible entity's training program objectives were incomplete (e.g. The responsible entity failed to define training program objectives for 50% or more but less than 75% of the applicable BA & TOP NERC and Regional Reliability Organizations standards, entity operating procedures, and regulatory requirements.)	The responsible entity's training program objectives were incomplete (e.g. The responsible entity failed to define training program objectives for 75% or more of the applicable BA & TOP NERC and Regional Reliability Organizations standards, entity operating procedures, and regulatory requirements.)
PER-002-0	R3.2.	The training program must include a plan for the initial and continuing training of Transmission Operator and Balancing	The responsible entity does not have a plan for continuing	The responsible entity does not have a plan for continuing	The responsible entity does not have a plan for continuing training of	The responsible entity does not have a plan for continuing training

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Authority operating personnel. That plan shall address knowledge and competencies required for reliable system operations.	training of operating personnel. OR The responsible entity does not have a plan for initial training of operating personnel. OR The responsible entity's plan does not address the knowledge and competencies required for reliable system operations.	training of operating personnel. OR The responsible entity does not have a plan for initial training of operating personnel. AND The responsible entity's plan does not address the knowledge and competencies required for reliable system operations.	operating personnel. AND The responsible entity does not have a plan for initial training of operating personnel. OR The responsible entity's plan does not address the knowledge and competencies required for reliable system operations.	of operating personnel. AND The responsible entity does not have a plan for initial training of operating personnel. AND The responsible entity's plan does not address the knowledge and competencies required for reliable system operations.
PER-002-0	R3.3.	The training program must include training time for all Transmission Operator and Balancing Authority operating personnel to ensure their operating proficiency.	The responsible entity has produced the training program with more than 75% but less than 100% of operating personnel provided with training time.	The responsible entity has produced the training program with more than 50% but less than or equal to 75% of operating personnel provided with training time.	The responsible entity has produced the training program with more than 25% but less than or equal to 50% of operating personnel provided with training time.	The responsible entity has produced the training program with more than or equal to 0% but less than or equal to 25% of operating personnel provided with training time.
PER-002-0	R3.4.	Training staff must be identified, and the staff must be competent in both knowledge of system operations and instructional capabilities.	N/A	The responsible entity has produced the training program with training staff identified that lacks knowledge of system operations. OR The responsible entity has produced the training program	The responsible entity has produced the training program with training staff identified that lacks knowledge of system operations. AND The responsible entity has produced the training program with training staff identified that lacks	The responsible entity has produced the training program with no training staff identified.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				with training staff identified that lacks instructional capabilities.	instructional capabilities.	
PER-002-0	R4.	For personnel identified in Requirement R2, each Transmission Operator and Balancing Authority shall provide its operating personnel at least five days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.	The applicable entity did not provide five days per year of training and drills, as directed by the requirement, affecting 5% or less of its operating personnel.	The applicable entity did not provide five days per year of training and drills, as directed by the requirement, affecting between 5-10% of its operating personnel.	The applicable entity did not provide five days per year of training and drills, as directed by the requirement, affecting 10-15%, inclusive, of its operating personnel.	The applicable entity did not provide five days per year of training and drills, as directed by the requirement, affecting greater than 15% of its operating personnel.
PER-003-0	R1.	Each Transmission Operator, Balancing Authority, and Reliability Coordinator shall staff all operating positions that meet both of the following criteria with personnel that are NERC-certified for the applicable functions:	The responsible entity failed to staff an operating position with NERC certified personnel for greater than 0 hours and less 12 hours for any operating position for a calendar month.	The responsible entity failed to staff an operating position with NERC certified personnel for greater than 12 hours and less 36 hours for any operating position for a calendar month.	The responsible entity failed to staff an operating position with NERC certified personnel for greater than 36 hours and less 72 hours for any operating position for a calendar month.	The responsible entity failed to staff an operating position with NERC certified personnel for greater than 72 hours for any operating position for a calendar month.
PER-003-0	R1.1.	Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System.	The responsible entity failed to staff an operating position with NERC certified personnel for greater than 0 hours and less 12 hours for any operating position for a calendar month.	The responsible entity failed to staff an operating position with NERC certified personnel for greater than 12 hours and less 36 hours for any operating position for a calendar month.	The responsible entity failed to staff an operating position with NERC certified personnel for greater than 36 hours and less 72 hours for any operating position for a calendar month.	The responsible entity failed to staff an operating position with NERC certified personnel for greater than 72 hours for any operating position for a calendar month.
PER-003-0	R1.2.	Positions directly responsible for complying with NERC standards.	The responsible entity failed to staff an operating position with NERC certified personnel for greater than 0 hours and less	The responsible entity failed to staff an operating position with NERC certified personnel for greater than 12 hours and	The responsible entity failed to staff an operating position with NERC certified personnel for greater than 36 hours and less 72	The responsible entity failed to staff an operating position with NERC certified personnel for greater than 72 hours for any

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			12 hours for any operating position for a calendar month.	less 36 hours for any operating position for a calendar month.	hours for any operating position for a calendar month.	operating position for a calendar month.
PER-004-1	R1.	Each Reliability Coordinator shall be staffed with adequately trained and NERC-certified Reliability Coordinator operators, 24 hours per day, seven days per week.	N/A	N/A	N/A	The responsible entity has failed to be staffed with adequately trained and NERC-certified Reliability Coordinator operators, 24 hours per day, seven days per week.
PER-004-1	R2.	All Reliability Coordinator operating personnel shall each complete a minimum of five days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.	The Reliability Coordinator's operating personnel completed at least 4 (but less than 5) days of emergency training.	The Reliability Coordinator's operating personnel completed at least 3 (but less than 4) days of emergency training.	The Reliability Coordinator's operating personnel completed at least 2 (but less than 3) days of emergency training.	The Reliability Coordinator's operating personnel completed less than 2 days of emergency training.
PER-004-1	R3.	Reliability Coordinator operating personnel shall have a comprehensive understanding of the Reliability Coordinator Area and interactions with neighboring Reliability Coordinator Areas.	Reliability Coordinator personnel have a comprehensive understanding of the interactions with at least 75% and less than 100% of neighboring Reliability Coordinator areas.	Reliability Coordinator personnel have a comprehensive understanding of the interactions with 50% or more and less than 75% of neighboring Reliability Coordinator areas.	Reliability Coordinator personnel have a comprehensive understanding of the interactions with 25% or more and less than 50% of neighboring Reliability Coordinator areas.	Reliability Coordinator personnel have a comprehensive understanding of the interactions less than 25% of neighboring Reliability Coordinator areas.
PER-004-1	R4.	Reliability Coordinator operating personnel shall have an extensive understanding of the Balancing Authorities, Transmission Operators, and Generation Operators within the Reliability Coordinator Area, including the operating staff, operating practices and procedures, restoration priorities and objectives, outage plans, equipment	Reliability Coordinator operating personnel have an extensive understanding of the operations of more than 75% and less than 100% of all	Reliability Coordinator operating personnel have an extensive understanding of the operations of more than 50% and less than 75% of all	Reliability Coordinator operating personnel have an extensive understanding of the operations of more than 25% and less than 50% of all Balancing Authorities,	Reliability Coordinator operating personnel have an extensive understanding of the operations of less than 25% of all Balancing Authorities,

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		capabilities, and operational restrictions.	Balancing Authorities, Transmission Operators and Generator Operators in the Reliability Coordinator Area.	Balancing Authorities, Transmission Operators and Generator Operators in the Reliability Coordinator Area.	Transmission Operators and Generator Operators in the Reliability Coordinator Area.	Transmission Operators and Generator Operators in the Reliability Coordinator Area.
PER-004-1	R5.	Reliability Coordinator operating personnel shall place particular attention on SOLs and IROLs and inter-tie facility limits. The Reliability Coordinator shall ensure protocols are in place to allow Reliability Coordinator operating personnel to have the best available information at all times.	Reliability Coordinator has failed to provide its operating personnel with less than 25% of the SOL and IROL limits and for inter-tie facility limits OR the protocols to ensure best available data at all times is not in place.	Reliability Coordinator has failed to provide its operating personnel with 25% or more and less than 50% of the SOL and IROL limits and for inter-tie facility limits.	Reliability Coordinator has failed to provide its operating personnel with 50% or more and less than 75% of the SOL and IROL limits and for inter-tie facility limits.	Reliability Coordinator has failed to provide its operating personnel with 75% or more of the SOL and IROL limits and for inter-tie facility limits.

Complete Violation Severity Level Matrix (PRC)
Encompassing All FERC-Approved Reliability Standards

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
PRC-001-1	R1.	Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.	N/A	N/A	The responsible entity was familiar with the purpose of protection system schemes applied in its area but failed to be familiar with the limitations of protection system schemes applied in its area.	The responsible entity failed to be familiar with the purpose and limitations of protection system schemes applied in its area.
PRC-001-1	R2.	Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:	N/A	N/A	N/A	The responsible entity failed to notify any reliability entity of relay or equipment failures.
PRC-001-1	R2.1.	If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.	N/A	Notification of relay or equipment failure was not made to the Transmission Operator and Host Balancing Authority, but corrective action was taken.	Notification of relay or equipment failure was made to the Transmission Operator and Host Balancing Authority, but corrective action was not taken.	Notification of relay or equipment failure was not made to the Transmission Operator and Host Balancing Authority, and corrective action was not taken.
PRC-001-1	R2.2.	If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	N/A	Notification of relay or equipment failure was not made to the Reliability Coordinator and affected Transmission Operators and Balancing Authorities, but corrective action was taken.	Notification of relay or equipment failure was made to the Reliability Coordinator and affected Transmission Operators and Balancing Authorities, but corrective action was not taken.	Notification of relay or equipment failure was not made to the Reliability Coordinator and affected Transmission Operators and Balancing Authorities, and corrective action was not taken.
PRC-001-1	R3.	A Generator Operator or Transmission	N/A	N/A	N/A	N/A

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Operator shall coordinate new protective systems and changes as follows.				
PRC-001-1	R3.1.	Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.	The Generator Operator failed to coordinate one new protective system or one protective system change with either its Transmission Operator or its Host Balancing Authority or both.	The Generator Operator failed to coordinate two new protective systems or two protective system changes with either its Transmission Operator or its Host Balancing Authority, or both.	The Generator Operator failed to coordinate three new protective systems or three protective system changes with either its Transmission Operator or its Host Balancing Authority, or both.	The Generator Operator failed to coordinate more than three new protective systems or more than three changes with its Transmission Operator and Host Balancing Authority.
PRC-001-1	R3.2.	Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.	The Transmission Operator failed to coordinate one new protective system or one protective system change with either its Transmission Operator or its Host Balancing Authority or both.	The Transmission Operator failed to coordinate two new protective systems or two protective system changes with either its Transmission Operator or its Host Balancing Authority, or both.	The Transmission Operator failed to coordinate three new protective systems or three protective system changes with either its Transmission Operator or its Host Balancing Authority, or both.	The Transmission Operator failed to coordinate more than three new protective systems or more than three system changes with neighboring Transmission Operators and Balancing Authorities.
PRC-001-1	R4.	Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.	The Transmission Operator failed to coordinate protection systems on major transmission lines and interconnections with one of its neighboring Generator Operators, Transmission Operators, or Balancing Authorities.	The Transmission Operator failed to coordinate protection systems on major transmission lines and interconnections with two of its neighboring Generator Operators, Transmission Operators, or Balancing	The Transmission Operator failed to coordinate protection systems on major transmission lines and interconnections with three of its neighboring Generator Operators, Transmission Operators, or Balancing Authorities.	The Transmission Operator failed to coordinate protection systems on major transmission lines and interconnections with three or more of its neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Authorities.		
PRC-001-1	R5.	A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the protection systems of others:	N/A	N/A	N/A	The responsible entity failed to coordinate changes in generation, transmission, load or operating conditions that could require changes in the protection systems of others:
PRC-001-1	R5.1.	Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's protection systems.	N/A	N/A	N/A	The Generator Operator failed to notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's protection systems.
PRC-001-1	R5.2.	Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' protection systems.	N/A	N/A	N/A	The Transmission Operator failed to notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' protection systems.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
PRC-001-1	R6.	Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.	N/A	N/A	Notification of a change in status of a Special Protection System was not made to the affected Transmission Operators and Balancing Authorities.	The responsible entity failed to monitor the status of each Special Protection System in its area, and did not notify affected Transmission Operators and Balancing Authorities of each change in status.
PRC-004-1	R1.	The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1.	Documentation of Misoperations is complete, but documentation of Corrective Action Plans is incomplete.	Documentation of Misoperations is incomplete, and documentation of Corrective Action Plans is incomplete.	Documentation of Misoperations is incomplete, and there are no associated Corrective Action Plans.	Misoperations have not been analyzed
PRC-004-1	R2.	The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for PRC-003 R1.	Documentation of Misoperations is complete, but documentation of Corrective Action Plans is incomplete.	Documentation of Misoperations is incomplete, and documentation of Corrective Action Plans is incomplete.	Documentation of Misoperations is incomplete, and there are no associated Corrective Action Plans.	Misoperations have not been analyzed
PRC-004-1	R3.	The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures	The responsible entity provided its Regional Reliability Organization with documentation of its Misoperations analyses and its Corrective Action	N/A	The responsible entity provided its Regional Reliability Organization with documentation of its Misoperations analyses but did not provide its Corrective Action Plans.	The responsible entity did not provide its Regional Reliability Organization with documentation of its Misoperations analyses and did not provide its Corrective

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		developed for PRC-003 R1.	Plans, but did not provide these according to the Regional Reliability Organization's procedures.			Action Plans.
PRC-005-1	R1.	Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:	N/A	N/A	The responsible entity that owned a transmission Protection System or Generator Owner that owned a generation Protection System failed to have either a Protection System maintenance program or a Protection System testing program for Protection Systems that affect the reliability of the BES.	The responsible entity that owned a transmission Protection System or Generator Owner that owned a generation Protection System failed to have a Protection System maintenance program and a Protection System testing program for Protection Systems that affect the reliability of the BES.
PRC-005-1	R1.1.	Maintenance and testing intervals and their basis.	Maintenance and testing intervals and their basis was missing for no more than 25% of the applicable devices.	Maintenance and testing intervals and their basis was missing for more than 25% but less than or equal to 50% of the applicable devices.	Maintenance and testing intervals and their basis was missing for more than 50% but less than or equal to 75% of the applicable devices.	Maintenance and testing intervals and their basis was missing for more than 75% but of the applicable devices.
PRC-005-1	R1.2.	Summary of maintenance and testing procedures.	Summary of maintenance and testing procedures was missing for no more than 25% of the applicable devices.	Summary of maintenance and testing procedures was missing for more than 25% but less than or equal to 50% of the	Summary of maintenance and testing procedures was missing for more than 50% but less than or equal to 75% of the applicable devices.	Summary of maintenance and testing procedures was missing for more than 75% but of the applicable devices.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				applicable devices.		
PRC-005-1	R2.	Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:	The responsible entity provided documentation of its Protection System maintenance and testing program for more than 30 but less than or equal to 40 days following a request from its Regional Reliability Organization and/or NERC.	The responsible entity provided documentation of its Protection System maintenance and testing program for more than 40 but less than or equal to 50 days following a request from its Regional Reliability Organization and/or NERC.	The responsible entity provided documentation of its Protection System maintenance and testing program for more than 50 but less than or equal to 60 days following a request from its Regional Reliability Organization and/or NERC.	The responsible entity did not provide documentation of its Protection System maintenance and testing program for more than 60 days following a request from its Regional Reliability Organization and/or NERC.
PRC-005-1	R2.1.	Evidence Protection System devices were maintained and tested within the defined intervals.	Evidence Protection System devices were maintained and tested within the defined intervals was missing for no more than 25% of the applicable devices.	Evidence Protection System devices were maintained and tested within the defined intervals was missing more than 25% but less than or equal to 50% of the applicable devices.	Evidence Protection System devices were maintained and tested within the defined intervals was missing more than 50% but less than or equal to 75% of the applicable devices.	Evidence Protection System devices were maintained and tested within the defined intervals was missing more than 75% of the applicable devices.
PRC-005-1	R2.2.	Date each Protection System device was last tested/maintained.	Date each Protection System device was last tested/maintained was missing no more than 25% of the applicable devices.	Date each Protection System device was last tested/maintained was missing for more than 25% but less than or equal to 50% of the applicable devices.	Date each Protection System device was last tested/maintained was missing for more than 50% but less than or equal to 75% of the applicable devices.	Date each Protection System device was last tested/maintained was missing for more than 75% of the applicable devices.
PRC-007-0	R1.	The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall ensure that its UFLS program is consistent with its Regional Reliability	The evaluation of the entity's UFLS program for consistency with its Regional Reliability	The amount of load shedding is less than 95 percent of the Regional requirement in any	The amount of load shedding is less than 90 percent of the Regional requirement in any of the load steps.	The amount of load shedding is less than 85 percent of the Regional requirement in any of the load

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Organization's UFLS program requirements.	Organization's UFLS program is incomplete or inconsistent in one or more of the Regional Reliability Organization program requirements, but is consistent with the required amount of load shedding.	of the load steps.		steps.
PRC-007-0	R2.	The Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide, and annually update, its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a UFLS program database.	The responsible entity has demonstrated the reporting of information but failed to satisfy one database reporting requirements.	The responsible entity has demonstrated the reporting of information but failed to satisfy two database reporting requirements.	The responsible entity has demonstrated the reporting of information but failed to satisfy at three database reporting requirements.	The responsible entity has demonstrated the reporting of information but failed to satisfy four or more database reporting requirements or has not provided the information.
PRC-007-0	R3.	The Transmission Owner and Distribution Provider that owns a UFLS program (as required by its Regional Reliability Organization) shall provide its documentation of that UFLS program to its Regional Reliability Organization on request (30 calendar days).	The responsible entity has provided the documentation in more than 30 calendar days but less than 40 calendar days.	The responsible entity has provided the documentation in more than 39 calendar days but less than 50 calendar days.	The responsible entity has provided the documentation in more than 49 calendar days but less than 60 calendar days.	The responsible entity has not provided the documentation within 60 calendar days.
PRC-008-0	R1.	The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall have a UFLS equipment maintenance and testing program in place. This UFLS equipment maintenance and testing program shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance.	The UFLS equipment identification, schedule for UFLS equipment testing or the schedule for UFLS equipment testing in the responsible entity's UFLS equipment maintenance and testing program was	The UFLS equipment identification, schedule for UFLS equipment testing or the schedule for UFLS equipment testing in the responsible entity's UFLS equipment maintenance and	The UFLS equipment identification, schedule for UFLS equipment testing or the schedule for UFLS equipment testing in the responsible entity's UFLS equipment maintenance and testing program was missing for more than 50% but less than or equal to 75% of	The UFLS equipment identification, schedule for UFLS equipment testing or the schedule for UFLS equipment testing in the responsible entity's UFLS equipment maintenance and testing program was

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			missing for no more than 25% of the applicable relays.	testing program was missing for more than 25% but less than or equal to 50% of the applicable relays.	the applicable relays.	missing for more than 75% of the applicable relays.
PRC-008-0	R2.	The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall implement its UFLS equipment maintenance and testing program and shall provide UFLS maintenance and testing program results to its Regional Reliability Organization and NERC on request (within 30 calendar days).	The responsible entity provided documentation of its UFLS equipment maintenance and testing program for more than 30 but less than or equal to 40 days following a request from its Regional Reliability Organization and/or NERC.	The responsible entity provided documentation of its UFLS equipment maintenance and testing program for more than 40 but less than or equal to 50 days following a request from its Regional Reliability Organization and/or NERC.	The responsible entity provided documentation of its UFLS equipment maintenance and testing program for more than 50 but less than or equal to 60 days following a request from its Regional Reliability Organization and/or NERC.	The responsible entity did not provide documentation of its UFLS equipment maintenance and testing program for more than 60 days following a request from its Regional Reliability Organization and/or NERC.
PRC-009-0	R1.	The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall analyze and document its UFLS program performance in accordance with its Regional Reliability Organization's UFLS program. The analysis shall address the performance of UFLS equipment and program effectiveness following system events resulting in system frequency excursions below the initializing set points of the UFLS program. The analysis shall include, but not be limited to:	The responsible entity that owns or operates a UFLS program failed to include one of the elements listed in PRC-009-0 R1.1 through R1.4 in the analysis of the performance of UFLS equipment and Program effectiveness, as described in PRC-009-0 R1, following system events resulting in system frequency excursions below the initializing set points of the UFLS	The responsible entity that owns or operates a UFLS program failed to include two of the elements listed in PRC-009-0 R1.1 through R1.4 in the analysis of the performance of UFLS equipment and Program effectiveness, as described in PRC-009-0 R1, following system events resulting in system frequency excursions below the	The responsible entity that owns or operates a UFLS program failed to include three of the elements listed in PRC-009-0 R1.1 through R1.4 in the analysis of the performance of UFLS equipment and Program effectiveness, as described in PRC-009-0 R1, following system events resulting in system frequency excursions below the initializing set points of the UFLS program.	The responsible entity that owns or operates a UFLS program failed to conduct an analysis of the performance of UFLS equipment and Program effectiveness, as described in PRC-009-0 R1, following system events resulting in system frequency excursions below the initializing set points of the UFLS program.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			program.	initializing set points of the UFLS program.		
PRC-009-0	R1.1.	A description of the event including initiating conditions.	N/A	N/A	N/A	The responsible entity failed to include a description of the event, including initiating conditions, that triggered an analysis of the performance of UFLS equipment and Program effectiveness, as described in PRC-009-0 R1, following system events resulting in system frequency excursions below the initializing set points of the UFLS program.
PRC-009-0	R1.2.	A review of the UFLS set points and tripping times.	N/A	N/A	N/A	The responsible entity failed to include a review of the UFLS set points and tripping times in the analysis of the performance of UFLS equipment and Program effectiveness, as described in PRC-009-0 R1, following system events resulting in system frequency excursions below the initializing set points of the UFLS

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						program.
PRC-009-0	R1.3.	A simulation of the event.	N/A	N/A	N/A	The responsible entity failed to conduct a simulation of the event that triggered an analysis of the performance of UFLS equipment and Program effectiveness, as described in PRC-009-0 R1, following system events resulting in system frequency excursions below the initializing set points of the UFLS program.
PRC-009-0	R1.4.	A summary of the findings.	N/A	N/A	N/A	The responsible entity failed to include a summary of the findings in the analysis of the performance of UFLS equipment and Program effectiveness, as described in PRC-009-0 R1, following system events resulting in system frequency excursions below the initializing set points of the UFLS program.
PRC-009-0	R2.	The Transmission Owner, Transmission Operator, Load-Serving Entity, and	The responsible entity has provided the	The responsible entity has provided	The responsible entity has provided the	The responsible entity has provided the

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide documentation of the analysis of the UFLS program to its Regional Reliability Organization and NERC on request 90 calendar days after the system event.	documentation in more than 90 calendar days but less than 105 calendar days.	the documentation in more than 105 calendar days but less than 129 calendar days.	documentation in more than 129 calendar days but less than 145 calendar days.	documentation in 145 calendar days or more.
PRC-010-0	R1.	The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall periodically (at least every five years or as required by changes in system conditions) conduct and document an assessment of the effectiveness of the UVLS program. This assessment shall be conducted with the associated Transmission Planner(s) and Planning Authority(ies).	The responsible entity conducted an assessment of the effectiveness of its UVLS system within 5 years or as required by changes in system conditions but did not include the associated Transmission Planner(s) and Planning Authority(ies).	The responsible entity did not conduct an assessment of the effectiveness of its UVLS system for more than 5 years but did in less than or equal to 7 years.	The responsible entity did not conduct an assessment of the effectiveness of its UVLS system for more than 7 years but did in less than or equal to 10 years.	The responsible entity did not conduct an assessment of the effectiveness of its UVLS system for more than 10 years.
PRC-010-0	R1.1.	This assessment shall include, but is not limited to:	N/A	The assessment of the effectiveness of the responsible entity's UVLS system did not address one of the elements in R1.1.1 through R1.1.3.	The assessment of the effectiveness of the responsible entity's UVLS system did not address two of the elements in R1.1.1 through R1.1.3.	The assessment of the effectiveness of the responsible entity's UVLS system did not address any of the elements in R1.1.1 through R1.1.3.
PRC-010-0	R1.1.1.	Coordination of the UVLS programs with other protection and control systems in the Region and with other Regional Reliability Organizations, as appropriate.	The responsible entity is non-compliant in the coordination of the UVLS programs with no more than 25% of the appropriate protection and control systems in the Region and with other	The responsible entity is non-compliant in the coordination of the UVLS programs with more than 25% but less than or equal to 50% of the appropriate	The responsible entity is non-compliant in the coordination of the UVLS programs with more than 50% but less than or equal to 75% of the appropriate protection and control systems in the Region	The responsible entity is non-compliant in the coordination of the UVLS programs with more than 75% of the appropriate protection and control systems in the Region and with other Regional

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Regional Reliability Organizations.	protection and control systems in the Region and with other Regional Reliability Organizations.	and with other Regional Reliability Organizations.	Reliability Organizations.
PRC-010-0	R1.1.2.	Simulations that demonstrate that the UVLS programs performance is consistent with Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0.	The responsible entity's analysis was non-compliant in that no more than 25% of the simulations needed to demonstrate consistency with Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0 were not performed.	The responsible entity's analysis was non-compliant in that more than 25% but less than or equal to 50% of the simulations needed to demonstrate consistency with Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0 were not performed.	The responsible entity's analysis was non-compliant in that more than 50% but less than or equal to 75% of the simulations needed to demonstrate consistency with Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0 were not performed.	The responsible entity's analysis was non-compliant in that more than 75% of the simulations needed to demonstrate consistency with Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0 were not performed.
PRC-010-0	R1.1.3.	A review of the voltage set points and timing.	The responsible entity's analysis is non-compliant in that a review of no more than 25% of the corresponding voltage set points and timing was not performed.	The responsible entity's analysis is non-compliant in that a review of more than 25% but less than or equal to 50% of the corresponding voltage set points and timing was not performed.	The responsible entity's analysis is non-compliant in that a review of more than 50% but less than 75% of the corresponding voltage set points and timing was not performed.	The responsible entity's analysis is non-compliant in that a review of more than 75% of the corresponding voltage set points and timing was not performed.
PRC-010-0	R2.	The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall provide documentation of its current UVLS program assessment to its Regional Reliability Organization and	The responsible entity provided documentation of its current UVLS program assessment more than 30 but less	The responsible entity provided documentation of its current UVLS program assessment more than 40 but	The responsible entity provided documentation of its current UVLS program assessment more than 50 but less than or equal to 60 days	The responsible entity did not provide documentation of its current UVLS program assessment for more than 60 days

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		NERC on request (30 calendar days).	than or equal to 40 days following a request from its Regional Reliability Organization and/or NERC.	less than or equal to 50 days following a request from its Regional Reliability Organization and/or NERC.	following a request from its Regional Reliability Organization and/or NERC.	following a request from its Regional Reliability Organization and/or NERC.
PRC-011-0	R1.	The Transmission Owner and Distribution Provider that owns a UVLS system shall have a UVLS equipment maintenance and testing program in place. This program shall include:	The responsible entity's UVLS equipment maintenance and testing program did not address one of the elements in R1.1 through R1.6.	The responsible entity's UVLS equipment maintenance and testing program did not address two or three of the elements in R1.1 through R1.6.	The responsible entity's UVLS equipment maintenance and testing program did not address four or five of the elements in R1.1 through R1.6.	The responsible entity's UVLS equipment maintenance and testing program did not address any of the elements in R1.1 through R1.6.
PRC-011-0	R1.1.	The UVLS system identification which shall include but is not limited to:	The responsible entity's UVLS program system identification did not address one of the elements in R1.1.1 through R1.1.4.	The responsible entity's UVLS program system identification did not address two of the elements in R1.1.1 through R1.1.4.	The responsible entity's UVLS program system identification did not address three of the elements in R1.1.1 through R1.1.4.	The responsible entity's UVLS program system identification did not address any of the elements in R1.1.1 through R1.1.4.
PRC-011-0	R1.1.1.	Relays.	The responsible entity's UVLS program system identification was missing no more than 25% of the applicable relays.	The responsible entity's UVLS program system identification was missing more than 25% but less than or equal to 50% of the applicable relays.	The responsible entity's UVLS program system identification was missing more than 50% but less than or equal to 75% of the applicable relays.	The responsible entity's UVLS program system identification was missing more than 75% of the applicable relays.
PRC-011-0	R1.1.2.	Instrument transformers.	The responsible entity's UVLS program system identification was missing no more than 25% of the applicable instrument	The responsible entity's UVLS program system identification was missing more than 25% but less than or equal to 50% of the	The responsible entity's UVLS program system identification was missing more than 50% but less than or equal to 75% of the applicable instrument transformers.	The responsible entity's UVLS program system identification was missing more than 75% of the applicable instrument

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			transformers.	applicable instrument transformers.		transformers.
PRC-011-0	R1.1.3.	Communications systems, where appropriate.	The responsible entity's UVLS program system identification was missing no more than 25% of the appropriate communication systems.	The responsible entity's UVLS program system identification was missing more than 25% but less than or equal to 50% of the appropriate communication systems.	The responsible entity's UVLS program system identification was missing more than 50% but less than or equal to 75% of the appropriate communication systems.	The responsible entity's UVLS program system identification was missing more than 75% of the appropriate communication systems.
PRC-011-0	R1.1.4.	Batteries.	The responsible entity's UVLS program system identification was missing no more than 25% of the applicable batteries.	The responsible entity's UVLS program system identification was missing more than 25% but less than or equal to 50% of the applicable batteries.	The responsible entity's UVLS program system identification was missing more than 50% but less than or equal to 75% of the applicable batteries.	The responsible entity's UVLS program system identification was missing more than 75% of the applicable batteries.
PRC-011-0	R1.2.	Documentation of maintenance and testing intervals and their basis.	The responsible entity's UVLS equipment maintenance and testing program was non-compliant in that documentation of maintenance and testing intervals and their basis was missing for no more than 25% of the UVLS equipment.	The responsible entity's UVLS equipment maintenance and testing program was non-compliant in that documentation of maintenance and testing intervals and their basis was missing for more than 25% but less than or equal to 50% of the UVLS equipment.	The responsible entity's UVLS equipment maintenance and testing program was non-compliant in that documentation of maintenance and testing intervals and their basis was missing for more than 50% but less than or equal to 75% of the UVLS equipment.	The responsible entity's UVLS equipment maintenance and testing program was non-compliant in that documentation of maintenance and testing intervals and their basis was missing for more than 75% of the UVLS equipment.
PRC-011-0	R1.3.	Summary of testing procedure.	The responsible	The responsible	The responsible entity's	The responsible

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			entity's UVLS equipment maintenance and testing program was non-compliant in that a summary of the testing procedure was missing for no more than 25% of the UVLS equipment.	entity's UVLS equipment maintenance and testing program was non-compliant in that a summary of the testing procedure was missing for more than 25% but less than or equal to 50% of the UVLS equipment.	UVLS equipment maintenance and testing program was non-compliant in that a summary of the testing procedure was missing for more than 50% but less than or equal to 75% of the UVLS equipment.	entity's UVLS equipment maintenance and testing program was non-compliant in that a summary of the testing procedure was missing for more than 75% of the UVLS equipment.
PRC-011-0	R1.4.	Schedule for system testing.	The responsible entity's UVLS equipment maintenance and testing program was non-compliant in that a schedule for system testing was missing for no more than 25% of the UVLS equipment.	The responsible entity's UVLS equipment maintenance and testing program was non-compliant in that a schedule for system testing was missing for more than 25% but less than or equal to 50% of the UVLS equipment.	The responsible entity's UVLS equipment maintenance and testing program was non-compliant in that a schedule for system testing was missing for more than 50% but less than or equal to 75% of the UVLS equipment.	The responsible entity's UVLS equipment maintenance and testing program was non-compliant in that a schedule for system testing was missing for more than 75% of the UVLS equipment.
PRC-011-0	R1.5.	Schedule for system maintenance.	The responsible entity's UVLS equipment maintenance and testing program was non-compliant in that a schedule for system maintenance was missing for no more than 25% of the UVLS equipment.	The responsible entity's UVLS equipment maintenance and testing program was non-compliant in that a schedule for system maintenance was missing for more than 25% but less than or equal to 50% of the UVLS equipment.	The responsible entity's UVLS equipment maintenance and testing program was non-compliant in that a schedule for system maintenance was missing for more than 50% but less than or equal to 75% of the UVLS equipment.	The responsible entity's UVLS equipment maintenance and testing program was non-compliant in that a schedule for system maintenance was missing for more than 75% of the UVLS equipment.

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PRC-011-0	R1.6.	Date last tested/maintained.	The responsible entity's UVLS equipment maintenance and testing program was non-compliant in that the date last tested/maintained was missing for no more than 25% of the UVLS equipment.	The responsible entity's UVLS equipment maintenance and testing program was non-compliant in that the date last tested/maintained was missing for more than 25% but less than or equal to 50% of the UVLS equipment.	The responsible entity's UVLS equipment maintenance and testing program was non-compliant in that the date last tested/maintained was missing for more than 50% but less than or equal to 75% of the UVLS equipment.	The responsible entity's UVLS equipment maintenance and testing program was non-compliant in that the date last tested/maintained was missing for more than 75% of the UVLS equipment.
PRC-011-0	R2.	The Transmission Owner and Distribution Provider that owns a UVLS system shall provide documentation of its UVLS equipment maintenance and testing program and the implementation of that UVLS equipment maintenance and testing program to its Regional Reliability Organization and NERC on request (within 30 calendar days).	The responsible entity provided documentation of its UVLS equipment maintenance and testing program more than 30 but less than or equal to 40 days following a request from its Regional Reliability Organization and/or NERC.	The responsible entity provided documentation of its UVLS equipment maintenance and testing program more than 40 but less than or equal to 50 days following a request from its Regional Reliability Organization and/or NERC.	The responsible entity provided documentation of its UVLS equipment maintenance and testing program more than 50 but less than or equal to 60 days following a request from its Regional Reliability Organization and/or NERC.	The responsible entity did not provide documentation of its UVLS equipment maintenance and testing program for more than 60 days following a request from its Regional Reliability Organization and/or NERC.
PRC-015-0	R1.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall maintain a list of and provide data for existing and proposed SPSs as specified in Reliability Standard PRC-013-0_R 1.	N/A	The responsible entity's list of existing or proposed SPSs did not address one of the elements in R1.1 through R1.3 as specified in Reliability Standard PRC-013-0_R1.	The responsible entity's list of existing or proposed SPSs did not address two of the elements in R1.1 through R1.3 as specified in Reliability Standard PRC-013-0_R1.	The responsible entity's list of existing or proposed SPSs did not address any of the elements in R1.1 through R1.3 as specified in Reliability Standard PRC-013-0_R1.
PRC-015-0	R2.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS	The responsible entity was not compliant in	The responsible entity was not	The responsible entity was not compliant in that	The responsible entity was not compliant in

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		shall have evidence it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-0_R1 prior to being placed in service.	that evidence that it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization's procedures did not address one of the elements in R1.1 through R1.9 as specified in Reliability Standard PRC-012-0_R1 prior to being placed in service.	compliant in that evidence that it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization's procedures did not address two to four of the elements in R1.1 through R1.9 as specified in Reliability Standard PRC-012-0_R1 prior to being placed in service.	evidence that it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization's procedures did not address five to seven of the elements in R1.1 through R1.9 as specified in Reliability Standard PRC-012-0_R1 prior to being placed in service.	that evidence that it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization's procedures did not address eight or more of the elements in R1.1 through R1.9 as specified in Reliability Standard PRC-012-0_R1 prior to being placed in service.
PRC-015-0	R3.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of SPS data and the results of studies that show compliance of new or functionally modified SPSs with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).	The responsible entity provided documentation of its SPS data and the results of the studies that show compliance of new or functionally modified SPSs more than 30 but less than or equal to 40 days following a request from its Regional Reliability Organization and/or NERC.	The responsible entity provided documentation of its SPS data and the results of the studies that show compliance of new or functionally modified SPSs more than 40 but less than or equal to 50 days following a request from its Regional Reliability Organization and/or NERC.	The responsible entity provided documentation of its SPS data and the results of the studies that show compliance of new or functionally modified SPSs more than 50 but less than or equal to 60 days following a request from its Regional Reliability Organization and/or NERC.	The responsible entity provided documentation of its SPS data and the results of the studies that show compliance of new or functionally modified SPSs for more than 60 days following a request from its Regional Reliability Organization and/or NERC.
PRC-016-0.1	R1.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall analyze its SPS operations and maintain a record of all misoperations in accordance with the Regional SPS review procedure	The responsible entity was not compliant in that evidence that it analyzed its SPS operations and	The responsible entity was not compliant in that evidence that it analyzed its SPS	The responsible entity was not compliant in that evidence that it analyzed its SPS operations and maintained a record of	The responsible entity was not compliant in that evidence that it analyzed its SPS operations and

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		specified in Reliability Standard PRC-012-0_R 1.	maintained a record of all misoperations in accordance with the Regional SPS review procedure did not address one of the elements in R1.1 through R1.9 as specified in Reliability Standard PRC-012-0_R1.	operations and maintained a record of all misoperations in accordance with the Regional SPS review procedure did not address two to four of the elements in R1.1 through R1.9 as specified in Reliability Standard PRC-012-0_R1.	all misoperations in accordance with the Regional SPS review procedure did not address five to seven of the elements in R1.1 through R1.9 as specified in Reliability Standard PRC-012-0_R1.	maintained a record of all misoperations in accordance with the Regional SPS review procedure did not address eight or more of the elements in R1.1 through R1.9 as specified in Reliability Standard PRC-012-0_R1.
PRC-016-0.1	R2.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall take corrective actions to avoid future misoperations.	The responsible entity did not take corrective actions to avoid future SPS misoperations for no more than 25% of the events.	The responsible entity did not take corrective actions to avoid future SPS misoperations for more than 25% but less than or equal to 50% of the events.	The responsible entity did not take corrective actions to avoid future SPS misoperations for more than 50% but less than or equal to 75% of the events.	The responsible entity did not take corrective actions to avoid future SPS misoperations for more than 75% of the events.
PRC-016-0.1	R3.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).	The responsible entity provided documentation of its SPS misoperation analyses and the corrective action plans more than 90 but less than or equal to 120 days following a request from its Regional Reliability Organization and/or NERC.	The responsible entity provided documentation of its SPS misoperation analyses and the corrective action plans more than 120 but less than or equal to 150 days following a request from its Regional Reliability Organization and/or NERC.	The responsible entity provided documentation of its SPS misoperation analyses and the corrective action plans more than 150 but less than or equal to 180 days following a request from its Regional Reliability Organization and/or NERC.	The responsible entity provided documentation of its SPS misoperation analyses and the corrective action plans more than 180 days following a request from its Regional Reliability Organization and/or NERC.
PRC-017-0	R1.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have a system maintenance and testing	The responsible entity's SPS system maintenance and	The responsible entity's SPS system maintenance and	The responsible entity's SPS system maintenance and testing program did	The responsible entity's SPS system maintenance and

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		program(s) in place. The program(s) shall include:	testing program did not address one of the elements in R1.1 through R1.6.	testing program did not address two or three of the elements in R1.1 through R1.6.	not address four or five of the elements in R1.1 through R1.6.	testing program did not address any of the elements in R1.1 through R1.6.
PRC-017-0	R1.1.	SPS identification shall include but is not limited to:	The responsible entity's SPS program identification did not address one of the elements in R1.1.1 through R1.1.4.	The responsible entity's SPS program identification did not address two of the elements in R1.1.1 through R1.1.4.	The responsible entity's SPS program identification did not address three of the elements in R1.1.1 through R1.1.4.	The responsible entity's SPS program identification did not address any of the elements in R1.1.1 through R1.1.4.
PRC-017-0	R1.1.1.	Relays.	The responsible entity's SPS program identification was missing no more than 25% of the applicable relays.	The responsible entity's SPS program identification was missing more than 25% but less than or equal to 50% of the applicable relays.	The responsible entity's SPS program identification was missing more than 50% but less than or equal to 75% of the applicable relays.	The responsible entity's SPS program identification was missing more than 75% of the applicable relays.
PRC-017-0	R1.1.2.	Instrument transformers.	The responsible entity's SPS program identification was missing no more than 25% of the applicable instrument transformers.	The responsible entity's SPS program identification was missing more than 25% but less than or equal to 50% of the applicable instrument transformers.	The responsible entity's SPS program identification was missing more than 50% but less than or equal to 75% of the applicable instrument transformers.	The responsible entity's SPS program identification was missing more than 75% of the applicable instrument transformers.
PRC-017-0	R1.1.3.	Communications systems, where appropriate.	The responsible entity's SPS program identification was missing no more than 25% of the appropriate communication systems.	The responsible entity's SPS program identification was missing more than 25% but less than or equal to 50% of the appropriate communication systems.	The responsible entity's SPS program identification was missing more than 50% but less than or equal to 75% of the appropriate communication systems.	The responsible entity's SPS program identification was missing more than 75% of the appropriate communication systems.

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PRC-017-0	R1.1.4.	Batteries.	The responsible entity's SPS program identification was missing no more than 25% of the applicable batteries.	The responsible entity's UVLS program system identification was missing more than 25% but less than or equal to 50% of the applicable batteries.	The responsible entity's UVLS program system identification was missing more than 50% but less than or equal to 75% of the applicable batteries.	The responsible entity's UVLS program system identification was missing more than 75% of the applicable batteries.
PRC-017-0	R1.2.	Documentation of maintenance and testing intervals and their basis.	The responsible entity's SPS maintenance and testing program was non-compliant in that documentation of maintenance and testing intervals and their basis was missing for no more than 25% of the SPS equipment.	The responsible entity's SPS maintenance and testing program was non-compliant in that documentation of maintenance and testing intervals and their basis was missing for more than 25% but less than or equal to 50% of the SPS equipment.	The responsible entity's SPS maintenance and testing program was non-compliant in that documentation of maintenance and testing intervals and their basis was missing for more than 50% but less than or equal to 75% of the SPS equipment.	The responsible entity's SPS maintenance and testing program was non-compliant in that documentation of maintenance and testing intervals and their basis was missing for more than 75% of the SPS equipment.
PRC-017-0	R1.3.	Summary of testing procedure.	The responsible entity's SPS maintenance and testing program was non-compliant in that a summary of the testing procedure was missing for no more than 25% of the SPS equipment.	The responsible entity's SPS maintenance and testing program was non-compliant in that a summary of the testing procedure was missing for more than 25% but less than or equal to 50% of the SPS equipment.	The responsible entity's SPS maintenance and testing program was non-compliant in that a summary of the testing procedure was missing for more than 50% but less than or equal to 75% of the SPS equipment.	The responsible entity's SPS maintenance and testing program was non-compliant in that a summary of the testing procedure was missing for more than 75% of the SPS equipment.
PRC-017-0	R1.4.	Schedule for system testing.	The responsible entity's SPS maintenance and	The responsible entity's SPS equipment	The responsible entity's SPS maintenance and testing program was	The responsible entity's SPS maintenance and

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			testing program was non-compliant in that a schedule for system testing was missing for no more than 25% of the SPS equipment.	maintenance and testing program was non-compliant in that a schedule for system testing was missing for more than 25% but less than or equal to 50% of the SPS equipment.	non-compliant in that a schedule for system testing was missing for more than 50% but less than or equal to 75% of the SPS equipment.	testing program was non-compliant in that a schedule for system testing was missing for more than 75% of the SPS equipment.
PRC-017-0	R1.5.	Schedule for system maintenance.	The responsible entity's SPS maintenance and testing program was non-compliant in that a schedule for system maintenance was missing for no more than 25% of the SPS equipment.	The responsible entity's SPS maintenance and testing program was non-compliant in that a schedule for system maintenance was missing for more than 25% but less than or equal to 50% of the SPS equipment.	The responsible entity's SPS maintenance and testing program was non-compliant in that a schedule for system maintenance was missing for more than 50% but less than or equal to 75% of the SPS equipment.	The responsible entity's SPS maintenance and testing program was non-compliant in that a schedule for system maintenance was missing for more than 75% of the SPS equipment.
PRC-017-0	R1.6.	Date last tested/maintained.	The responsible entity's SPS maintenance and testing program was non-compliant in that the date last tested/maintained was missing for no more than 25% of the SPS equipment.	The responsible entity's SPS maintenance and testing program was non-compliant in that the date last tested/maintained was missing for more than 25% but less than or equal to 50% of the SPS equipment.	The responsible entity's SPS maintenance and testing program was non-compliant in that the date last tested/maintained was missing for more than 50% but less than or equal to 75% of the SPS equipment.	The responsible entity's SPS maintenance and testing program was non-compliant in that the date last tested/maintained was missing for more than 75% of the SPS equipment.
PRC-017-0	R2.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the program	The responsible entity provided documentation of its	The responsible entity provided documentation of its	The responsible entity provided documentation of its SPS maintenance	The responsible entity did not provide documentation of its

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).	SPS maintenance and testing program more than 30 but less than or equal to 40 days following a request from its Regional Reliability Organization and/or NERC.	SPS maintenance and testing program more than 40 but less than or equal to 50 days following a request from its Regional Reliability Organization and/or NERC.	and testing program more than 50 but less than or equal to 60 days following a request from its Regional Reliability Organization and/or NERC.	SPS maintenance and testing program for more than 60 days following a request from its Regional Reliability Organization and/or NERC.
PRC-018-1	R1.	Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard PRC-002 Requirements 1-3) shall have DMEs installed that meet the following requirements:	N/A	N/A	The responsible entity is not compliant in that the installation of DMEs does not include one of the elements in R1.1 and R1.2.	The responsible entity is not compliant in that the installation of DMEs does not include any of the elements in R1.1 and R1.2.
PRC-018-1	R1.1.	Internal Clocks in DME devices shall be synchronized to within 2 milliseconds or less of Universal Coordinated Time scale (UTC)	Less than or equal to 25% of DME devices did not comply with R1.1	Less than or equal to 37.5% but greater than 25% of DME devices did not comply with R1.1	Less than or equal to 50% but greater than 37.5% of DME devices did not comply with R1.1	Greater than 50% of DME devices did not did not comply with R1.1
PRC-018-1	R1.2.	Recorded data from each Disturbance shall be retrievable for ten calendar days.	Less than or equal to 12% of installed DME devices did not comply with R1.2	Less than or equal to 18% but greater than 12% of installed DME devices did not comply with R1.2	Less than or equal to 24% but greater than 18% of installed DME devices did not comply with R1.2	Greater than 24% of installed DME devices did not did not comply with R1.2
PRC-018-1	R2.	The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization's installation requirements (reliability standard PRC-002 Requirements 1 through 3).	The responsible entity is non-compliant in that no more than 10% of the DME devices were not installed in accordance with its Regional Reliability Organization's installation requirements as	The responsible entity is non-compliant in that more than 10% but less than or equal to 20% of the DME devices were not installed in accordance with its Regional Reliability	The responsible entity is non-compliant in that more than 20% but less than or equal to 30% of the DME devices were not installed in accordance with its Regional Reliability Organization's installation requirements	The responsible entity is non-compliant in that more than 30% of the DME devices were not installed in accordance with its Regional Reliability Organization's installation requirements as

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			defined in PRC-002 Requirements 1 through 3.	Organization's installation requirements as defined in PRC-002 Requirements 1 through 3.	as defined in PRC-002 Requirements 1 through 3.	defined in PRC-002 Requirements 1 through 3.
PRC-018-1	R3.	The Transmission Owner and Generator Owner shall each maintain, and report to its Regional Reliability Organization on request, the following data on the DMEs installed to meet that region's installation requirements (reliability standard PRC-002 Requirements1.1, 2.1 and 3.1):	The responsible entity was not compliant in that evidence that it maintained data on the DMEs installed to meet that region's installation requirements was missing or not reported for one of the elements in Requirements 3.1 through 3.8.	The responsible entity was not compliant in that evidence that it maintained data on the DMEs installed to meet that region's installation requirements was missing or not reported for two or three of the elements in Requirements 3.1 through 3.8.	The responsible entity was not compliant in that evidence that it maintained data on the DMEs installed to meet that region's installation requirements was missing or not reported for four or five of the elements in Requirements 3.1 through 3.8.	The responsible entity was not compliant in that evidence that it maintained data on the DMEs installed to meet that region's installation requirements was missing or not reported for more than five of the elements in Requirements 3.1 through 3.8.
PRC-018-1	R3.1.	Type of DME (sequence of event recorder, fault recorder, or dynamic disturbance recorder).	Less than or equal to 25% of the required data per R3.1 was not maintained or reported.	Less than or equal to 37.5% but greater than 25% of the required data per R3.1 was not maintained or reported.	Less than or equal to 50% but greater than 37.5% of the required data per R3.1 was not maintained or reported.	Greater than 50% of the required data per R3.1 was not maintained or reported.
PRC-018-1	R3.2.	Make and model of equipment.	Less than or equal to 25% of the required data per R3.2 was not maintained or reported.	Less than or equal to 37.5% but greater than 25% of the required data per R3.2 was not maintained or reported.	Less than or equal to 50% but greater than 37.5% of the required data per R3.2 was not maintained or reported.	Greater than 50% of the required data per R3.2 was not maintained or reported.
PRC-018-1	R3.3.	Installation location.	Less than or equal to 25% of the required data per R3.3 was not	Less than or equal to 37.5% but greater than 25% of the	Less than or equal to 50% but greater than 37.5% of the required	Greater than 50% of the required data per R3.3 was not

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			maintained or reported.	required data per R3.3 was not maintained or reported.	data per R3.3 was not maintained or reported.	maintained or reported.
PRC-018-1	R3.4.	Operational status.	Less than or equal to 25% of the required data per R3.4 was not maintained or reported.	Less than or equal to 37.5% but greater than 25% of the required data per R3.4 was not maintained or reported.	Less than or equal to 50% but greater than 37.5% of the required data per R3.4 was not maintained or reported.	Greater than 50% of the required data per R3.4 was not maintained or reported.
PRC-018-1	R3.5.	Date last tested.	Less than or equal to 25% of the required data per R3.5 was not maintained or reported.	Less than or equal to 37.5% but greater than 25% of the required data per R3.5 was not maintained or reported.	Less than or equal to 50% but greater than 37.5% of the required data per R3.5 was not maintained or reported.	Greater than 50% of the required data per R3.5 was not maintained or reported.
PRC-018-1	R3.6.	Monitored elements, such as transmission circuit, bus section, etc.	Less than or equal to 25% of the required data per R3.6 was not maintained or reported.	Less than or equal to 37.5% but greater than 25% of the required data per R3.6 was not maintained or reported.	Less than or equal to 50% but greater than 37.5% of the required data per R3.6 was not maintained or reported.	Greater than 50% of the required data per R3.6 was not maintained or reported.
PRC-018-1	R3.7.	Monitored devices, such as circuit breaker, disconnect status, alarms, etc.	Less than or equal to 25% of the required data per R3.7 was not maintained or reported.	Less than or equal to 37.5% but greater than 25% of the required data per R3.7 was not maintained or reported.	Less than or equal to 50% but greater than 37.5% of the required data per R3.7 was not maintained or reported.	Greater than 50% of the required data per R3.7 was not maintained or reported.
PRC-018-1	R3.8.	Monitored electrical quantities, such as voltage, current, etc.	Less than or equal to 25% of the required data per R3.8 was not maintained or	Less than or equal to 37.5% but greater than 25% of the required data per	Less than or equal to 50% but greater than 37.5% of the required data per R3.8 was not	Greater than 50% of the required data per R3.8 was not maintained or

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			reported.	R3.8 was not maintained or reported.	maintained or reported.	reported.
PRC-018-1	R4.	The Transmission Owner and Generator Owner shall each provide Disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements (reliability standard PRC-002 Requirement 4).	The responsible entity is not compliant in that it did not provide less than or equal to 10% of the disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements.	The responsible entity is not compliant in that it did not provide less than or equal to 20% but greater than 10% of the disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements.	The responsible entity is not compliant in that it did not provide less than or equal to 30% but greater than 20% of the disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements.	The responsible entity is not compliant in that it did not provide greater than 30% of the disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements.
PRC-018-1	R5.	The Transmission Owner and Generator Owner shall each archive all data recorded by DMEs for Regional Reliability Organization-identified events for at least three years.	The responsible entity is not compliant in that no more than 25% of the data recorded by DMEs for Regional Reliability Organization-identified events was not archived for at least three years.	The responsible entity is not compliant in that more than 25% but less than or equal to 50% of the data recorded by DMEs for Regional Reliability Organization-identified events was not archived for at least three years.	The responsible entity is not compliant in that more than 50% but less than or equal to 75% of the data recorded by DMEs for Regional Reliability Organization-identified events was not archived for at least three years.	The responsible entity is not compliant in that more than 75% of the data recorded by DMEs for Regional Reliability Organization-identified events was not archived for at least three years.
PRC-018-1	R6.	Each Transmission Owner and Generator Owner that is required by its Regional Reliability Organization to have DMEs shall have a maintenance and testing program for those DMEs that includes:	N/A	N/A	The responsible entity is not compliant in that the maintenance and testing program for DMEs does not include one of the elements in R6.1 and 6.2.	The responsible entity is not compliant in that the maintenance and testing program for DMEs does not include any of the elements in R6.1 and 6.2.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
PRC-018-1	R6.1.	Maintenance and testing intervals and their basis.	The responsible entity's DME maintenance and testing program was non-compliant in that documentation of maintenance and testing intervals and their basis was missing for no more than 25% of the DME equipment.	The responsible entity's DME maintenance and testing program was non-compliant in that documentation of maintenance and testing intervals and their basis was missing for more than 25% but less than or equal to 50% of the DME equipment.	The responsible entity's DME maintenance and testing program was non-compliant in that documentation of maintenance and testing intervals and their basis was missing for more than 50% but less than or equal to 75% of the DME equipment.	The responsible entity's DME maintenance and testing program was non-compliant in that documentation of maintenance and testing intervals and their basis was missing for more than 75% of the DME equipment.
PRC-018-1	R6.2.	Summary of maintenance and testing procedures.	The responsible entity's DME maintenance and testing program was non-compliant in that the summary of maintenance and testing procedures documentation was missing for no more than 25% of the DME equipment.	The responsible entity's DME maintenance and testing program was non-compliant in that the summary of maintenance and testing procedures documentation was missing for more than 25% but less than or equal to 50% of the DME equipment.	The responsible entity's DME maintenance and testing program was non-compliant in that the summary of maintenance and testing procedures documentation was missing for more than 50% but less than or equal to 75% of the DME equipment.	The responsible entity's DME maintenance and testing program was non-compliant in that the summary of maintenance and testing procedures documentation was missing for more than 75% of the DME equipment.
PRC-021-1	R1.	Each Transmission Owner and Distribution Provider that owns a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall annually update its UVLS data to support the Regional UVLS program database. The following data shall be provided to the Regional Reliability Organization for each installed UVLS system:	UVLS data was provided but did not address one of the elements in R1.1 through R1.5.	UVLS data was provided but did not address two of the elements in R1.1 through R1.5.	UVLS data was provided but did not address three of the elements in R1.1 through R1.5.	No annual UVLS data was provided OR UVLS data was provided but did not address four or more of the elements in R1.1 through R1.5.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
PRC-021-1	R1.1.	Size and location of customer load, or percent of connected load, to be interrupted.	The responsible entity is non-compliant in the reporting of no more than 25% of the size or location of customer load, or percent of customer load to be interrupted.	The responsible entity is non-compliant in the reporting of more than 25% but less than or equal to 50% of the size or location of customer load, or percent of customer load to be interrupted.	The responsible entity is non-compliant in the reporting of more than 50% but less than or equal to 75% of the size or location of customer load, or percent of customer load to be interrupted.	The responsible entity is non-compliant in the reporting of more than 75% of the size or location of customer load, or percent of customer load to be interrupted.
PRC-021-1	R1.2.	Corresponding voltage set points and overall scheme clearing times.	The responsible entity is non-compliant in the reporting of no more than 25% of the corresponding voltage set points and overall scheme clearing times.	The responsible entity is non-compliant in the reporting of more than 25% but less than or equal to 50% of the corresponding voltage set points and overall scheme clearing times.	The responsible entity is non-compliant in the reporting of more than 50% but less than or equal to 75% of the corresponding voltage set points and overall scheme clearing times.	The responsible entity is non-compliant in the reporting of more than 75% of the corresponding voltage set points and overall scheme clearing times.
PRC-021-1	R1.3.	Time delay from initiation to trip signal.	The responsible entity is non-compliant in the reporting of no more than 25% of the time delay from initiation to trip signal data.	The responsible entity is non-compliant in the reporting of more than 25% but less than or equal to 50% of the time delay from initiation to trip signal data.	The responsible entity is non-compliant in the reporting of more than 50% but less than or equal to 75% of the time delay from initiation to trip signal data.	The responsible entity is non-compliant in the reporting of more than 75% of the time delay from initiation to trip signal data.
PRC-021-1	R1.4.	Breaker operating times.	The responsible entity is non-compliant in the reporting of no more than 25% of the breaker operating times.	The responsible entity is non-compliant in the reporting of more than 25% but less than or equal to 50% of the breaker	The responsible entity is non-compliant in the reporting of more than 50% but less than or equal to 75% of the breaker operating times.	The responsible entity is non-compliant in the reporting of more than 75% of the breaker operating times.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				operating times.		
PRC-021-1	R1.5.	Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and Special Protection Systems.	The responsible entity is non-compliant in the reporting of no more than 25% of any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and Special Protection Systems.	The responsible entity is non-compliant in the reporting of more than 25% but less than or equal to 50% of any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and Special Protection Systems.	The responsible entity is non-compliant in the reporting of more than 50% but less than or equal to 75% of any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and Special Protection Systems.	The responsible entity is non-compliant in the reporting of more than 75% of any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and Special Protection Systems.
PRC-021-1	R2.	Each Transmission Owner and Distribution Provider that owns a UVLS program shall provide its UVLS program data to the Regional Reliability Organization within 30 calendar days of a request.	The responsible entity updated its UVLS data more than 30 but less than or equal to 40 days following a request from its Regional Reliability Organization.	The responsible entity updated its UVLS data more than 40 but less than or equal to 50 days following a request from its Regional Reliability Organization.	The responsible entity updated its UVLS data more than 50 but less than or equal to 60 days following a request from its Regional Reliability Organization.	The responsible entity did not update its UVLS data for more than 60 days following a request from its Regional Reliability Organization.
PRC-022-1	R1.	Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall analyze and document all UVLS operations and Misoperations. The analysis shall include:	The responsible entity failed to analyze and document no more than 25% of all UVLS operations and misoperations.	The responsible entity failed to analyze and document more than 25% but less than or equal to 50% of all UVLS operations and misoperations or the overall analysis program did not	The responsible entity failed to analyze and document more than 50% but less than or equal to 75% of all UVLS operations and misoperations or the overall analysis program did not address two or three of the elements in	The responsible entity failed to analyze and document more than 75% of all UVLS operations and misoperations or the overall analysis program did not address four or more of the elements in

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				address one of the elements in R1.1 through R1.5.	R1.1 through R1.5.	R1.1 through R1.5.
PRC-022-1	R1.1.	A description of the event including initiating conditions.	The responsible entity's analysis is missing a description of the event including initiating conditions for no more than 25% of all UVLS operations and misoperations.	The responsible entity's analysis is missing a description of the event including initiating conditions for more than 25% but less than or equal to 50% of all UVLS operations and misoperations.	The responsible entity's analysis is missing a description of the event including initiating conditions for more than 50% but less than or equal to 75% of all UVLS operations and misoperations.	The responsible entity's analysis is missing a description of the event including initiating conditions for more than 75% of all UVLS operations and misoperations.
PRC-022-1	R1.2.	A review of the UVLS set points and tripping times.	The responsible entity's analysis is missing a review of the UVLS set points and tripping times for no more than 25% of all UVLS operations and misoperations.	The responsible entity's analysis is missing a review of the UVLS set points and tripping times for more than 25% but less than 50% of all UVLS operations and misoperations.	The responsible entity's analysis is missing a review of the UVLS set points and tripping times for more than 50% but less than 75% of all UVLS operations and misoperations.	The responsible entity's analysis is missing a review of the UVLS set points and tripping times for more than 75% of all UVLS operations and misoperations.
PRC-022-1	R1.3.	A simulation of the event, if deemed appropriate by the Regional Reliability Organization. For most events, analysis of sequence of events may be sufficient and dynamic simulations may not be needed.	The responsible entity's analysis is missing a simulation of the event, if deemed appropriate by the Regional Reliability Organization for no more than 25% of all UVLS operations and misoperations.	The responsible entity's analysis is missing a simulation of the event, if deemed appropriate by the Regional Reliability Organization for more than 25% but less than or equal to 50% of all UVLS operations and misoperations.	The responsible entity's analysis is missing a simulation of the event, if deemed appropriate by the Regional Reliability Organization for more than 50% but less than or equal to 75% of all UVLS operations and misoperations.	The responsible entity's analysis is missing a simulation of the event, if deemed appropriate by the Regional Reliability Organization for more than 75% of all UVLS operations and misoperations.
PRC-022-1	R1.4.	A summary of the findings.	The responsible	The responsible	The responsible entity's	The responsible

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			entity's analysis is missing a summary of the findings for no more than 25% of all UVLS operations and misoperations.	entity's analysis is missing a summary of the findings for more than 25% but less than or equal to 50% of all UVLS operations and misoperations.	analysis is missing a summary of the findings for more than 50% but less than or equal to 75% of all UVLS operations and misoperations.	entity's analysis is missing a summary of the findings for more than 75% of all UVLS operations and misoperations.
PRC-022-1	R1.5.	For any Misoperation, a Corrective Action Plan to avoid future Misoperations of a similar nature.	The responsible entity's analysis is missing a Corrective Action Plan to avoid future Misoperations of a similar nature for no more than 25% of all UVLS operations and misoperations.	The responsible entity's analysis is missing a Corrective Action Plan to avoid future Misoperations of a similar nature for more than 25% but less than or equal to 50% of all UVLS operations and misoperations.	The responsible entity's analysis is missing a Corrective Action Plan to avoid future Misoperations of a similar nature for more than 50% but less than or equal to 75% of all UVLS operations and misoperations.	The responsible entity's analysis is missing a Corrective Action Plan to avoid future Misoperations of a similar nature for more than 75% of all UVLS operations and misoperations.
PRC-022-1	R2.	Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall provide documentation of its analysis of UVLS program performance to its Regional Reliability Organization within 90 calendar days of a request.	The responsible entity provided documentation of the analysis of UVLS program performance more than 90 but less than or equal to 120 days following a request from its Regional Reliability Organization.	The responsible entity provided documentation of the analysis of UVLS program performance more than 120 but less than or equal to 150 days following a request from its Regional Reliability Organization.	The responsible entity provided documentation of the analysis of UVLS program performance more than 150 but less than or equal to 180 days following a request from its Regional Reliability Organization.	The responsible entity did not provide documentation of the analysis of UVLS program performance for more than 180 days following a request from its Regional Reliability Organization.
PRC-023-1	R1.	Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (R1.1 through R1.13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system		Evidence that relay settings comply with criteria in R1.1 though 1.13 exists, but evidence is incomplete or		Relay settings do not comply with any of the sub requirements R1.1 through R1.13 OR Evidence does not

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees: [Mitigation Time Horizon: Long Term Planning].		incorrect for one or more of the subrequirements.		exist to support that relay settings comply with one of the criteria in subrequirements R1.1 through R1.13.
PRC-023-1	R2.	The Transmission Owner, Generator Owner, or Distribution Provider that uses a circuit capability with the practical limitations described in R1.6, R1.7, R1.8, R1.9, R1.12, or R1.13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. [Time Horizon: Long Term Planning]	Criteria described in R1.6, R1.7. R1.8. R1.9, R1.12, or R.13 was used but evidence does not exist that agreement was obtained in accordance with R2.			
PRC-023-1	R3.	The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities from 100 kV to 200 kV that must meet Requirement 1 to prevent potential cascade tripping that may occur when protective relay settings limit transmission loadability. [Time Horizon: Long Term Planning]		Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 31 days and 45 days after the list was established or updated.	Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 46 days and 60 days after list was established or updated.	Does not have a process in place to determine facilities that are critical to the reliability of the Bulk Electric System. OR Does not maintain a current list of facilities critical to the reliability of the Bulk Electric System, OR Did not provide the list of facilities critical to the reliability of the Bulk Electric System to the appropriate

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers, or provided the list more than 60 days after the list was established or updated.

Complete Violation Severity Level Matrix (TOP)
Encompassing All FERC-Approved Reliability Standards

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
TOP-001-1	R1.	Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.	N/A	N/A	N/A	The Transmission Operator has no evidence that clear decision-making authority exists to assure reliability in its area or has failed to exercise this authority to alleviate operating emergencies.
TOP-001-1	R2.	Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.	N/A	N/A	N/A	The Transmission Operator failed to have evidence that it took immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.
TOP-001-1	R3.	Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority, or Generator Operator shall immediately inform the	N/A	N/A	N/A	The responsible entity failed to comply with reliability directives issued by the Reliability Coordinator or the Transmission Operator (when applicable), when said directives would not have resulted in actions that would violate safety,

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.				equipment, regulatory or statutory requirements, or under circumstances that said directives would have resulted in actions that would violate safety, equipment, regulatory or statutory requirements the responsible entity failed to inform the Reliability Coordinator or Transmission Operator (when applicable) of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator could implement alternate remedial actions.
TOP-001-1	R4.	Each Distribution Provider and Load-Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load-Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.	N/A	N/A	N/A	The responsible entity failed to comply with all reliability directives issued by the Transmission Operator, including shedding firm load, when said directives would not have resulted in actions that would violate safety, equipment, regulatory or statutory requirements, or under

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						circumstances when said directives would have violated safety, equipment, regulatory or statutory requirements, the responsible entity failed to immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator could implement alternate remedial actions.
TOP-001-1	R5.	Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real-time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.	N/A	N/A	N/A	The Transmission Operator failed to inform its Reliability Coordinator and any other potentially affected Transmission Operators of real-time or anticipated emergency conditions, or failed to take actions to avoid, when possible, or mitigate the emergency.
TOP-001-1	R6.	Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.	N/A	N/A	N/A	The responsible entity failed to render all available emergency assistance to others as requested, after the requesting entity had implemented its comparable

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						emergency procedures, when said assistance would not have resulted in actions that would violate safety, equipment, or regulatory or statutory requirements.
TOP-001-1	R7.	Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless:	N/A	N/A	N/A	The responsible entity removed Bulk Electric System facilities from service under conditions other than those listed in TOP-001-1 R7.1 through R7.3 and removal of said facilities burdened a neighboring system.
TOP-001-1	R7.1.	For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.	N/A	N/A	N/A	The Generator Operator failed to notify and coordinate with the Transmission Operator, or the Transmission Operator failed to notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.
TOP-001-1	R7.2.	For a transmission facility, the Transmission Operator shall notify and coordinate with its	N/A	N/A	N/A	The Transmission Operator failed to

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.				notify and coordinate with its Reliability Coordinator, or failed to notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.
TOP-001-1	R7.3.	When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.	N/A	N/A	N/A	The Generator Operator failed to notify the Transmission Operator, or the Transmission Operator failed to notify its Reliability Coordinator and adjacent Transmission Operators during periods when time did not permit such notifications and coordination, or when immediate action was required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities.
TOP-001-1	R8.	During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request	N/A	N/A	N/A	The responsible entity failed to take immediate actions to restore the Real and Reactive Power Balance during a system emergency, or

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.				the responsible entity failed to request emergency assistance from the Reliability Coordinator during periods when it was unable to restore the Real and Reactive Power Balance, or during periods when corrective actions or emergency assistance was not adequate to mitigate the Real and Reactive Power Balance, the responsible entity failed to implement firm load shedding.
TOP-002-2a	R1.	Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.	N/A	N/A	The responsible entity maintained a set of current plans that were designed to evaluate options and set procedures for reliable operation through a reasonable future time period, but failed utilize all available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.	The responsible entity failed to maintain a set of current plans that were designed to evaluate options and set procedures for reliable operation through a reasonable future time period.
TOP-002-2a	R2.	Each Balancing Authority and Transmission Operator shall ensure its operating personnel	N/A	N/A	N/A	The responsible entity failed to ensure its

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.				operating personnel participated in the system planning and design study processes.
TOP-002-2a	R3.	Each Load-Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.	N/A	The Load-Serving Entity or Generator Operator failed to coordinate (where confidentiality agreements allow) its seasonal operations with its Host Balancing Authority and Transmission Service Provider, or the Balancing Authority or Transmission Service Provider failed to coordinate its seasonal operations with its Transmission Operator.	N/A	The Load-Serving Entity or Generator Operator failed to coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider, or the Balancing Authority or Transmission Service Provider failed to coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.
TOP-002-2a	R4.	Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.	N/A	The responsible entity failed to coordinate (where confidentiality agreements allow) its seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability	N/A	The responsible entity failed to coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Coordinator.		Reliability Coordinator.
TOP-002-2a	R5.	Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.	N/A	N/A	N/A	The responsible entity failed to plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.
TOP-002-2a	R6.	Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.	N/A	N/A	N/A	The responsible entity failed to plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.
TOP-002-2a	R7.	Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.	N/A	N/A	N/A	The Balancing Authority failed to plan to meet capacity and energy reserve requirements, including the deliverability/capabilit y for any single Contingency.
TOP-002-2a	R8.	Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.	N/A	N/A	N/A	The Balancing Authority failed to plan to meet voltage and/or reactive limits,

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						including the deliverability/capability for any single contingency.
TOP-002-2a	R9.	Each Balancing Authority shall plan to meet Interchange Schedules and Ramps.	N/A	N/A	N/A	The Balancing Authority failed to plan to meet Interchange Schedules and Ramps.
TOP-002-2a	R10.	Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).	N/A	N/A	N/A	The responsible entity failed to plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).
TOP-002-2a	R11.	The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.	N/A	N/A	The Transmission Operator performed seasonal, next-day, and current-day Bulk Electric System studies, reflecting current system conditions, to determine SOLs, but failed to make the results of Bulk Electric System studies available to all of the Transmission Operators, Balancing Authorities (subject confidentiality requirements), or to its Reliability Coordinator.	The Transmission Operator failed to perform seasonal, next-day, or current-day Bulk Electric System studies, reflecting current system conditions, to determine SOLs.
TOP-002-2a	R12.	The Transmission Service Provider shall	N/A	N/A	N/A	The Transmission

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.				Service Provider failed to include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.
TOP-002-2a	R13.	At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.	N/A	N/A	N/A	The Generator Operator failed to perform generating real and reactive capability verification that included, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, or failed to provide the results of generating real and reactive verifications Balancing Authority or Transmission Operator operating personnel, when requested.
TOP-002-2a	R14.	Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:	N/A	N/A	N/A	The Generator Operator failed to notify their Balancing Authority and Transmission Operator

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						of changes in capabilities and characteristics.
TOP-002-2a	R14.1.	Changes in real output capabilities.	N/A	N/A	N/A	The Generator Operator failed to notify its Balancing Authority or Transmission Operator of changes in real output capabilities.
TOP-002-2a	R14.2.	Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)				
TOP-002-2a	R15.	Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).	N/A	N/A	N/A	The Generation Operator failed to provide, at the request of the Balancing Authority or Transmission Operator, a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).
TOP-002-2a	R16.	Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to:	N/A	N/A	N/A	The Transmission Operator failed to notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics, within the terms and conditions of standards of conduct and confidentiality

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						agreements.
TOP-002-2a	R16.1.	Changes in transmission facility status.	N/A	N/A	N/A	The Transmission Operator failed to notify their Reliability Coordinator and Balancing Authority of changes in transmission facility status, within the terms and conditions of standards of conduct and confidentiality agreements.
TOP-002-2a	R16.2.	Changes in transmission facility rating.	N/A	N/A	N/A	The Transmission Operator failed to notify their Reliability Coordinator and Balancing Authority of changes in transmission facility rating, within the terms and conditions of standards of conduct and confidentiality agreements.
TOP-002-2a	R17.	Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.	N/A	N/A	N/A	The responsible entity failed to communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.
TOP-002-2a	R18.	Neighboring Balancing Authorities, Transmission Operators, Generator	N/A	N/A	N/A	The responsible entity failed to use uniform

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Operators, Transmission Service Providers, and Load-Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.				line identifiers when referring to transmission facilities of an interconnected network.
TOP-002-2a	R19.	Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.	N/A	N/A	N/A	The responsible entity failed to maintain accurate computer models utilized for analyzing and planning system operations.
TOP-003-0	R1.	Generator Operators and Transmission Operators shall provide planned outage information.				
TOP-003-0	R1.1.	Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements.	N/A	N/A	N/A	The Generator Operator failed to provide outage information, in accordance with its Transmission Operators established outage reporting requirements, to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW).
TOP-003-0	R1.2.	Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any	N/A	N/A	N/A	The Transmission Operator failed to provide outage information, in accordance with its Reliability

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements.				Coordinators established outage reporting requirement, to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation.
TOP-003-0	R1.3.	Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.	N/A	N/A	N/A	The responsible entity failed to provide the information by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.
TOP-003-0	R2.	Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators,	N/A	N/A	N/A	The responsible entity failed to plan or coordinate scheduled outages of system voltage regulating

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.				equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators when required.
TOP-003-0	R3.	Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.	The responsible entity planned and coordinated scheduled outages of telemetering and control equipment and associated communication channels with its Reliability Coordinator, but failed to coordinate with affected neighboring Transmission Operators, Balancing Authorities, and Generator Operators.	N/A	N/A	The responsible entity failed to plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.
TOP-003-0	R4.	Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.	N/A	N/A	N/A	The Reliability Coordinator failed to resolve any scheduling of potential reliability conflicts.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
TOP-004-2	R1.	Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).	N/A	N/A	The Transmission Operator operated within the Interconnection Reliability Operating Limits (IROLs), but failed to operate within the System Operating Limits (SOLs).	The Transmission Operator failed to operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).
TOP-004-2	R2.	Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.	N/A	N/A	N/A	The Transmission Operator failed to operate so that instability, uncontrolled separation, or cascading outages would not occur as a result of the most severe single contingency.
TOP-004-2	R3.	Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.	N/A	N/A	N/A	The Transmission Operator failed to operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.
TOP-004-2	R4.	If a Transmission Operator enters an unknown operating state (i.e., any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to	The Transmission Operator entering an unknown operating state (i.e., any state for which valid operating	The Transmission Operator entering an unknown operating state (i.e., any state for which valid operating	The Transmission Operator entering an unknown operating state (i.e., any state for which valid operating	The Transmission Operator entering an unknown operating state (i.e., any state for which valid operating

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		respect proven reliable power system limits within 30 minutes.	limits have not been determined), failed to restore operations to respect proven reliable power system limits for more than 30 minutes but less than or equal to 35 minutes.	limits have not been determined), failed to restore operations to respect proven reliable power system limits for more than 35 minutes but less than or equal to 40 minutes.	limits have not been determined), failed to restore operations to respect proven reliable power system limits for more than 40 minutes but less than or equal to 45 minutes.	limits have not been determined), failed to restore operations to respect proven reliable power system limits for more than 45 minutes.
TOP-004-2	R5.	Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.	N/A	N/A	N/A	The Transmission Operator does not have evidence that the actions taken to protect its area, resulting in its disconnection from the Interconnection, were necessary to prevent the danger of violating an IROL or SOL.
TOP-004-2	R6.	Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including:	The Transmission Operator developed, maintained, and implemented formal policies and procedures to provide for transmission reliability, addressing the execution and coordination of activities that impact inter- and intra-Regional reliability, including the elements listed in TOP-004-2 R6.1 through R6.4, but failed to include other Transmission Operators in the	The Transmission Operator, individually and jointly with other Transmission Operators, developed, maintained, and implemented formal policies and procedures to provide for transmission reliability, addressing the execution and coordination of activities that impact inter- and intra-Regional reliability, but failed to include one of the elements listed in TOP-004-2	The Transmission Operator, individually and jointly with other Transmission Operators, developed, maintained, and implemented formal policies and procedures to provide for transmission reliability, addressing the execution and coordination of activities that impact inter- and intra-Regional reliability, but failed to include two of the elements listed in TOP-004-2	The Transmission Operator, individually and jointly with other Transmission Operators, developed, maintained, and implemented formal policies and procedures to provide for transmission reliability, addressing the execution and coordination of activities that impact inter- and intra-Regional reliability, but failed to include three or more of the elements listed in

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			development of said policies and procedures.	R6.1 through R6.4.	R6.1 through R6.4.	TOP-004-2 R6.1 through R6.4.
TOP-004-2	R6.1.	Monitoring and controlling voltage levels and real and reactive power flows.	N/A	N/A	N/A	The Transmission Operator failed to include monitoring and controlling voltage levels and real and reactive power flows in the development, maintenance, and implementation of formal policies and procedures to provide for transmission reliability as described in TOP-004-2 R6.
TOP-004-2	R6.2.	Switching transmission elements.	N/A	N/A	N/A	The Transmission Operator failed to include switching transmission elements in the development, maintenance, and implementation of formal policies and procedures to provide for transmission reliability as described in TOP-004-2 R6.
TOP-004-2	R6.3.	Planned outages of transmission elements.	N/A	N/A	N/A	The Transmission Operator failed to include planned outages of transmission elements in the development, maintenance, and

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						implementation of formal policies and procedures to provide for transmission reliability as described in TOP-004-2 R6.
TOP-004-2	R6.4.	Responding to IROL and SOL violations.	N/A	N/A	N/A	The Transmission Operator failed to include responding to IROL and SOL violations in the development, maintenance, and implementation of formal policies and procedures to provide for transmission reliability as described in TOP-004-2 R6.
TOP-005-1.1	R1.	Each Transmission Operator and Balancing Authority shall provide its Reliability Coordinator with the operating data that the Reliability Coordinator requires to perform operational reliability assessments and to coordinate reliable operations within the Reliability Coordinator Area.	The responsible entity failed to provide all of the data requested by its Reliability Coordinator.	N/A	N/A	The responsible entity failed to provide all of the data requested by its Reliability Coordinator.
TOP-005-1.1	R1.1.	Each Reliability Coordinator shall identify the data requirements from the list in Attachment 1-TOP-005-0 "Electric System Reliability Data" and any additional operating information requirements relating to operation of the bulk power system within the Reliability Coordinator Area.	N/A	N/A	N/A	The Reliability Coordinator failed to identify the data necessary to perform operational reliability assessments and to coordinate reliable operations within the Reliability Coordinator Area.
TOP-005-	R2.	As a condition of receiving data from the	N/A	N/A	N/A	The ISN data recipient

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
1.1		Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric System Reliability Data."				failed to sign the NERC Confidentiality Agreement for "Electric System Reliability Data".
TOP-005-1.1	R3.	Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.	The responsible entity failed to provide any of the data requested by other Balancing Authorities or Transmission Operators.	N/A	N/A	The responsible entity failed to provide all of the data requested by its host Balancing Authority or Transmission Operator.
TOP-005-1.1	R4.	Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.	The responsible entity failed to provide any of the data requested by other Balancing Authorities or Transmission Operators.	N/A	N/A	The responsible entity failed to provide all of the data requested by its host Balancing Authority or Transmission Operator.
TOP-006-1	R1.	Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use.	N/A	N/A	N/A	The responsible entity failed to know the status of all generation and transmission resources available for use, even though said information was reported by the Generator Operator,

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						Transmission Operator, or Balancing Authority.
TOP-006-1	R1.1.	Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.	N/A	N/A	N/A	The Generator Operator failed to inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.
TOP-006-1	R1.2.	Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.	N/A	N/A	N/A	The responsible entity failed to inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.
TOP-006-1	R2.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.	N/A	The responsible entity monitors the applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, but is not aware of the status of rotating and static reactive resources.	The responsible entity fails to monitor all of the applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of all rotating and static reactive resources.	The responsible entity fails to monitor any of the applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.
TOP-006-1	R3.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their	The responsible entity failed to provide any of the appropriate technical information	N/A	N/A	The responsible entity failed to provide all of the appropriate technical information

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		operating personnel.	concerning protective relays to their operating personnel.			concerning protective relays to their operating personnel.
TOP-006-1	R4.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.	N/A	N/A	The responsible entity has either weather forecasts or past load patterns, available to predict the system's near-term load pattern, but not both.	The responsible entity failed to have both weather forecasts and past load patterns, available to predict the system's near-term load pattern.
TOP-006-1	R5.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.	N/A	N/A	The responsible entity used monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions, but does not have indication of the need for corrective action.	The responsible entity failed to use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions.
TOP-006-1	R6.	Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.	N/A	N/A	N/A	The responsible entity failed to use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.
TOP-006-1	R7.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.	N/A	N/A	N/A	The responsible entity failed to monitor system frequency.
TOP-007-0	R1.	A Transmission Operator shall inform its Reliability Coordinator when an IROL or	N/A	N/A	The Transmission Operator informed its	The Transmission Operator failed to

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		SOL has been exceeded and the actions being taken to return the system to within limits.			Reliability Coordinator when an IROL or SOL had been exceeded but failed to provide the actions being taken to return the system to within limits.	inform its Reliability Coordinator when an IROL or SOL had been exceeded.
TOP-007-0	R2.	Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.	Following a Contingency or other event that resulted in an IROL violation of a magnitude up to and including 5%, the Transmission Operator failed to return its transmission system to within IROL in less than or equal to 35 minutes.	Following a Contingency or other event that resulted in an IROL violation, the Transmission Operator failed to return its transmission system to within IROL in accordance with the following: (a) an IROL with a magnitude up to and including 5% for a period of time greater than 35 minutes but less than or equal to 45 minutes, or (b) an IROL with a magnitude greater than 5% but less than or equal to 10% for a period of time less than or equal to 40 minutes, or (c) an IROL with a magnitude greater than 10% but less than or equal to 15% for a period of time less than or equal to 35 minutes.	Following a Contingency or other event that resulted in an IROL violation, the Transmission Operator failed to return its transmission system to within IROL in accordance with the following: (a) an IROL with a magnitude up to and including 5% for a period of time greater than 45 minutes, or (b) an IROL with a magnitude greater than 5% but less than or equal to 10% for a period of time greater than 40 minutes, or (c) an IROL with a magnitude greater than 10% but less than or equal to 15% for a period of time greater than 35 minutes but less than or equal to 45 minutes, or (d) an IROL with a magnitude greater than 15% but less than or equal to 20% for a	Following a Contingency or other event that resulted in an IROL violation, the Transmission Operator failed to return its transmission system to within IROL in accordance with the following: (a) an IROL with a magnitude greater than 10% but less than or equal to 15% for a period of time greater than 45 minutes, or (b) an IROL with a magnitude greater than 15% but less than or equal to 20% for a period of time greater than 40 minutes, or (c) an IROL with a magnitude greater than 20% but less than or equal to 25% for a period of time greater than 35 minutes, or (d) an IROL with a magnitude greater than 25% for a period of greater than 30

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
					period of time less than or equal to 40 minutes, or (e) an IROL with a magnitude greater than 20% but less than or equal to 25% for a period of time less than or equal to 35 minutes.	minutes.
TOP-007-0	R3.	A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R 2.	N/A	N/A	N/A	The Transmission Operator failed to take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to return the transmission system to IROL within 30 minutes.
TOP-007-0	R4.	The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.	N/A	N/A	N/A	The Reliability Coordinator failed to evaluate actions taken to address an IROL or SOL violation and, if the actions taken were not appropriate or sufficient, direct actions required to return the system to within limits.
TOP-008-1	R1.	The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.	N/A	N/A	N/A	The Transmission Operator experiencing or contributing to an IROL or SOL violation failed to take immediate steps to relieve the condition,

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						which may have included shedding firm load.
TOP-008-1	R2.	Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.	N/A	The Transmission Operator operated to prevent the likelihood that a disturbance, action, or inaction would result in an IROL or SOL violation in its area or another area of the Interconnection but failed to operate the Bulk Electric System to the most limiting parameter in instances where there was a difference in derived operating limits.	The Transmission Operator operated to prevent the likelihood that a disturbance, action, or inaction would result in an IROL or SOL violation in its area but failed to operate to prevent the likelihood that a disturbance, action, or inaction would result in an IROL or SOL violation in another area of the Interconnection.	The Transmission Operator failed to operate to prevent the likelihood that a disturbance, action, or inaction would result in an IROL or SOL violation in its area or another area of the Interconnection.
TOP-008-1	R3.	The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.	N/A	The Transmission Operator disconnected the affected facility when the overload on a transmission facility or abnormal voltage or reactive condition persisted and equipment was endangered but failed to notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection either prior to switching, if time	N/A	The Transmission Operator failed to disconnect the affected facility when the overload on a transmission facility or abnormal voltage or reactive condition persisted and equipment was endangered.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				permitted, otherwise, immediately thereafter.		
TOP-008-1	R4.	The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.	N/A	N/A	The Transmission Operator had sufficient information and analysis tools to determine the cause(s) of SOL violations and used the results of these analyses to immediately mitigate the SOL violation(s), but failed to conduct these analyses in all operating timeframes.	The Transmission Operator failed to have sufficient information and analysis tools to determine the cause(s) of SOL violations or failed to use the results of analyses to immediately mitigate the SOL violation.

Complete Violation Severity Level Matrix (TPL)
Encompassing All FERC-Approved Reliability Standards

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
TPL-001-0.1	R1.	The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:	The responsible entity is non-compliant with 25% or less of the sub-components.	The responsible entity is non-compliant with more than 25% but less than 50% of the sub-components.	The responsible entity is non-compliant with 50% or more but less than 75% of the sub-components.	The responsible entity is non-compliant with 75% or more of the sub-components.
TPL-001-0.1	R1.1.	Be made annually.	N/A	N/A	N/A	The assessments were not made on an annual basis.
TPL-001-0.1	R1.2.	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.	The responsible entity has failed to demonstrate a valid assessment for the long-term period, but a valid assessment for the near-term period exists.	The responsible entity has failed to demonstrate a valid assessment for the near-term period, but a valid assessment for the long-term period exists.	N/A	The responsible entity has failed to demonstrate a valid assessment for the near-term period AND long-term planning period.
TPL-001-0.1	R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability	The responsible entity is non-compliant with 25% or less of the sub-components.	The responsible entity is non-compliant with more than 25% but less than 50% of the sub-components.	The responsible entity is non-compliant with 50% or more but less than 75% of the sub-components.	The responsible entity is non-compliant with 75% or more of the sub-components.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Organization(s).				
TPL-001-0.1	R1.3.1.	Cover critical system conditions and study years as deemed appropriate by the entity performing the study.	N/A	N/A	N/A	The responsible entity has failed to cover critical system conditions and study years as deemed appropriate.
TPL-001-0.1	R1.3.2.	Be conducted annually unless changes to system conditions do not warrant such analyses.	The responsible entity's most recent long-term studies (and/or system simulation testing) were not performed in the most recent annual period AND significant system changes (actual or proposed) indicate that past studies (and/or system testing) are no longer valid.	The responsible entity's most recent near-term studies (and/or system simulation testing) were not performed in the most recent annual period AND significant system changes (actual or proposed) indicate that past studies (and/or system testing) are no longer valid.	N/A	The responsible entity's most recent near-term studies (and/or system testing) AND most recent long-term studies (and/or system simulation testing) were not performed in the most recent annual period AND significant system changes (actual or proposed) indicate that past studies (and/or system testing) are no longer valid.
TPL-001-0.1	R1.3.3.	Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.	N/A	N/A	N/A	The responsible entity failed to produce evidence of a past or current year long-term study and/or system simulation testing (beyond 5-year planning horizon) when past or current year near-term studies and/or system simulation testing

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						show marginal conditions that may require longer lead-time solutions.
TPL-001-0.1	R1.3.4.	Have established normal (pre-contingency) operating procedures in place.	N/A	N/A	N/A	No precontingency operating procedures are in place for existing facilities.
TPL-001-0.1	R1.3.5.	Have all projected firm transfers modeled.	The system model(s) used for current or past analysis did not properly represent up to (but less than) 25% of the firm transfers to/from the responsible entity's service territory.	The system model(s) used for current or past analysis did not properly represent 25% or more but less than 50% of the firm transfers to/from the responsible entity's service territory.	The system model(s) used for current or past analysis did not properly represent 50% or more but less than 75% of the firm transfers to/from the responsible entity's service territory.	The system model(s) used for current or past analysis did not properly represent 75% or more of the firm transfers to/from the responsible entity's service territory.
TPL-001-0.1	R1.3.6.	Be performed for selected demand levels over the range of forecast system demands.	N/A	N/A	N/A	The responsible entity has failed to produce evidence of a valid current or past study and/or system simulation testing reflecting analysis over a range of forecast system demands.
TPL-001-0.1	R1.3.7.	Demonstrate that system performance meets Table 1 for Category A (no contingencies).	N/A	N/A	N/A	No past or current study results exist showing pre-contingency system analysis.
TPL-001-0.1	R1.3.8.	Include existing and planned facilities.	The responsible entity’s transmission model used for past or current studies and/or	The responsible entity’s transmission model used for past or current studies and/or	N/A	The responsible entity's transmission model used for past or current studies and/or

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			system simulation testing properly reflects existing facilities, but is deficient in reflecting planned facilities.	system simulation testing properly reflects planned facilities, but is deficient in reflecting existing facilities.		system simulation testing is deficient in reflecting existing AND planned facilities.
TPL-001-0.1	R1.3.9.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.	N/A	N/A	N/A	The responsible entity has failed to ensure in a past or current study and/or system simulation testing that sufficient reactive power resources are available to meet required system performance.
TPL-001-0.1	R1.4.	Address any planned upgrades needed to meet the performance requirements of Category A.	N/A	N/A	N/A	The responsible entity has failed to demonstrate that a corrective action plan exists in order to satisfy Category A planning requirements.
TPL-001-0.1	R2.	When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0_R1, the Planning Authority and Transmission Planner shall each:	The responsible entity is non-compliant with 25% or less of the sub-components.	The responsible entity is non-compliant with more than 25% but less than 50% of the sub-components.	The responsible entity is non-compliant with 50% or more but less than 75% of the sub-components.	The responsible entity is non-compliant with 75% or more of the sub-components.
TPL-001-0.1	R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.	N/A	N/A	N/A	The responsible entity has failed to provide documented evidence of corrective action plans in order to satisfy Category A planning requirements.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
TPL-001-0.1	R2.1.1.	Including a schedule for implementation.	N/A	N/A	N/A	A schedule for the responsible entity's corrective action plan does not exist.
TPL-001-0.1	R2.1.2.	Including a discussion of expected required in-service dates of facilities.	N/A	N/A	N/A	Anticipated in-service dates, for the responsible entity's corrective action plan do not exist.
TPL-001-0.1	R2.1.3.	Consider lead times necessary to implement plans.	N/A	N/A	N/A	The responsible entity failed to consider necessary lead times to implement its corrective action plan.
TPL-001-0.1	R2.2.	Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.	N/A	N/A	N/A	The responsible entity has failed to demonstrate the continuing need for previously identified facility additions through subsequent annual assessments.
TPL-001-0.1	R3.	The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.	N/A	The responsible entity documented the results of its reliability assessments and corrective plans but did not annually provided them to its respective NERC Regional Reliability Organization(s) as required by the Regional Reliability Organization	N/A	The responsible entity DID NOT document the results of its annual reliability assessments and corrective plans AND did not annually provided them to its respective NERC Regional Reliability Organization(s) as required by the Regional Reliability Organization

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
TPL-002-0a	R1.	The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:	The responsible entity is non-compliant with 25% or less of the sub-components.	The responsible entity is non-compliant with more than 25% but less than 50% of the sub-components.	The responsible entity is non-compliant with 50% or more but less than 75% of the sub-components.	The responsible entity is non-compliant with 75% or more of the sub-components.
TPL-002-0a	R1.1.	Be made annually.	N/A	N/A	N/A	The assessments were not made on an annual basis.
TPL-002-0a	R1.2.	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.	The responsible entity has failed to demonstrate a valid assessment for the long-term period, but a valid assessment for the near-term period exists.	The responsible entity has failed to demonstrate a valid assessment for the near-term period, but a valid assessment for the long-term period exists.	N/A	The responsible entity has failed to demonstrate a valid assessment for the near-term period AND long-term planning period.
TPL-002-0a	R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).	The responsible entity is non-compliant with 25% or less of the sub-components.	The responsible entity is non-compliant with more than 25% but less than 50% of the sub-components.	The responsible entity is non-compliant with 50% or more but less than 75% of the sub-components.	The responsible entity is non-compliant with 75% or more of the sub-components.
TPL-002-0a	R1.3.1.	Be performed and evaluated only for those Category B contingencies that would	N/A	The responsible entity provided evidence	N/A	The responsible entity did not provided

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.		through current or past studies and/or system simulation testing that selected NERC Category B contingencies were evaluated, however, no rational was provided to indicate why the remaining Category B contingencies for their system were not evaluated.		evidence through current or past studies and/or system simulation testing to indicate that any NERC Category B contingencies were evaluated.
TPL-002-0a	R1.3.2.	Cover critical system conditions and study years as deemed appropriate by the responsible entity.	N/A	N/A	N/A	The responsible entity has failed to cover critical system conditions and study years as deemed appropriate.
TPL-002-0a	R1.3.3.	Be conducted annually unless changes to system conditions do not warrant such analyses.	The responsible entity's most recent long-term studies (and/or system simulation testing) were not performed in the most recent annual period AND significant system changes (actual or proposed) indicate that past studies (and/or system testing) are no longer valid.	The responsible entity's most recent near-term studies (and/or system simulation testing) were not performed in the most recent annual period AND significant system changes (actual or proposed) indicate that past studies (and/or system testing) are no longer valid.	N/A	The responsible entity's most recent near-term studies (and/or system simulation testing) AND most recent long-term studies (and/or system testing) were not performed in the most recent annual period AND significant system changes (actual or proposed) indicate that past studies (and/or system simulation testing) are no longer valid.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
TPL-002-0a	R1.3.4.	Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.	N/A	N/A	N/A	The responsible entity failed to produce evidence of a past or current year long-term study and/or system simulation testing (beyond 5-year planning horizon) when past or current year near-term studies and/or system simulation testing show marginal conditions that may require longer lead-time solutions.
TPL-002-0a	R1.3.5.	Have all projected firm transfers modeled.	The system model(s) used for current or past analysis did not properly represent up to (but less than) 25% of the firm transfers to/from the responsible entity's service territory.	The system model(s) used for current or past analysis did not properly represent 25% or more but less than 50% of the firm transfers to/from the responsible entity's service territory.	The system model(s) used for current or past analysis did not properly represent 50% or more but less than 75% of the firm transfers to/from the responsible entity's service territory.	The system model(s) used for current or past analysis did not properly represent 75% or more of the firm transfers to/from the responsible entity's service territory.
TPL-002-0a	R1.3.6.	Be performed and evaluated for selected demand levels over the range of forecast system Demands.	N/A	N/A	N/A	The responsible entity has failed to produce evidence of a valid current or past study and/or system simulation testing reflecting analysis over a range of forecast system demands.
TPL-002-0a	R1.3.7.	Demonstrate that system performance meets Category B contingencies.	N/A	N/A	N/A	No past or current study results exist

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						showing Category B contingency system analysis.
TPL-002-0a	R1.3.8.	Include existing and planned facilities.	The responsible entity's transmission model used for past or current studies and/or system simulation testing properly reflects existing facilities, but is deficient in reflecting planned facilities.	The responsible entity's transmission model used for past or current studies and/or system simulation testing properly reflects planned facilities, but is deficient in reflecting existing facilities.	N/A	The responsible entity's transmission model used for past or current studies and/or system simulation testing is deficient in reflecting existing AND planned facilities.
TPL-002-0a	R1.3.9.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.	N/A	N/A	N/A	The responsible entity has failed to ensure in a past or current study and/or system simulation testing that sufficient reactive power resources are available to meet required system performance.
TPL-002-0a	R1.3.10.	Include the effects of existing and planned protection systems, including any backup or redundant systems.	N/A	N/A	The responsible entity's transmission model used for past or current studies is deficient with respect to the effects of planned protection systems, including any backup or redundant systems.	The responsible entity's transmission model used for past or current studies is deficient with respect to the effects of existing protection systems, including any backup or redundant systems.
TPL-002-0a	R1.3.11.	Include the effects of existing and planned control devices.	N/A	N/A	The responsible entity's transmission model used for past or current studies is	The responsible entity's transmission model used for past or current studies is

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
					deficient with respect to the effects of planned control devices.	deficient with respect to the effects of existing control devices.
TPL-002-0a	R1.3.12.	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.	N/A	N/A	N/A	The responsible entity's transmission model used for past or current studies is deficient with respect to the inclusion of planned maintenance outages of bulk electric transmission facilities.
TPL-002-0a	R1.4.	Address any planned upgrades needed to meet the performance requirements of Category B of Table I.	N/A	N/A	N/A	The responsible entity has failed to demonstrate that a corrective action plan exists in order to satisfy Category B planning requirements.
TPL-002-0a	R1.5.	Consider all contingencies applicable to Category B.	The responsible entity has considered the NERC Category B contingencies applicable to their system, but was deficient with respect to 25% or less of all applicable contingencies.	The responsible entity has considered the NERC Category B contingencies applicable to their system, but was deficient with respect to more than 25% but less than 50% of all applicable contingencies.	The responsible entity has considered the NERC Category B contingencies applicable to their system, but was deficient with respect to more than 50% but less than 75% of all applicable contingencies.	The responsible entity has considered the NERC Category B contingencies applicable to their system, but was deficient 75% or more of all applicable contingencies.
TPL-002-0a	R2.	When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1, the Planning Authority and	The responsible entity is non-compliant with 25% or less of the sub-components.	The responsible entity is non-compliant with more than 25% but less than 50% of the	The responsible entity is non-compliant with 50% or more but less than 75% of the sub-	The responsible entity is non-compliant with 75% or more of the sub-components.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Transmission Planner shall each:		sub-components.	components.	
TPL-002-0a	R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:	N/A	N/A	N/A	The responsible entity has failed to provide documented evidence of corrective action plans in order to satisfy Category B planning requirements.
TPL-002-0a	R2.1.1.	Including a schedule for implementation.	N/A	N/A	N/A	A schedule for the responsible entity's corrective action plan does not exist.
TPL-002-0a	R2.1.2.	Including a discussion of expected required in-service dates of facilities.	N/A	N/A	N/A	Anticipated in-service dates, for the responsible entity's corrective action plan does not exist. This would reflect effective dates for pre-contingency operating procedures or in-service dates for proposed system changes.
TPL-002-0a	R2.1.3.	Consider lead times necessary to implement plans.	N/A	N/A	N/A	The responsible entity failed to consider necessary lead times to implement its corrective action plan.
TPL-002-0a	R2.2.	Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.	N/A	N/A	N/A	The responsible entity has failed to demonstrate the continuing need for previously identified facility additions

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						through sub-sequent annual assessments.
TPL-002-0a	R3.	The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.	N/A	The responsible entity documented the results of its reliability assessments and corrective plans but did not annually provided them to its respective NERC Regional Reliability Organization(s) as required by the Regional Reliability Organization	N/A	The responsible entity DID NOT document the results of its annual reliability assessments and corrective plans AND did not annually provided them to its respective NERC Regional Reliability Organization(s) as required by the Regional Reliability Organization
TPL-003-0a	R1.	The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:	The responsible entity is non-compliant with 25% or less of the sub-components.	The responsible entity is non-compliant with more than 25% but less than 50% of the sub-components.	The responsible entity is non-compliant with 50% or more but less than 75% of the sub-components.	The responsible entity is non-compliant with 75% or more of the sub-components.
TPL-003-0a	R1.1.	Be made annually.	N/A	N/A	N/A	The assessments were not made on an annual basis.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
TPL-003-0a	R1.2.	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.	The responsible entity has failed to demonstrate a valid assessment for the long-term period, but a valid assessment for the near-term period exists.	The responsible entity has failed to demonstrate a valid assessment for the near-term period, but a valid assessment for the long-term period exists.	N/A	The responsible entity has failed to demonstrate a valid assessment for the near-term period AND long-term planning period.
TPL-003-0a	R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).	The responsible entity is non-compliant with 25% or less of the sub-components.	The responsible entity is non-compliant with more than 25% but less than 50% of the sub-components.	The responsible entity is non-compliant with 50% or more but less than 75% of the sub-components.	The responsible entity is non-compliant with 75% or more of the sub-components.
TPL-003-0a	R1.3.1.	Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.	N/A	The responsible entity provided evidence through current or past studies that selected NERC Category C contingencies were evaluated, however, no rational was provided to indicate why the remaining Category C contingencies for their system were not evaluated.	N/A	The responsible entity did not provided evidence through current or past studies to indicate that any NERC Category C contingencies were evaluated.
TPL-003-0a	R1.3.2.	Cover critical system conditions and study years as deemed appropriate by the responsible entity.	N/A	N/A	N/A	The responsible entity has failed to cover critical system

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						conditions and study years as deemed appropriate.
TPL-003-0a	R1.3.3.	Be conducted annually unless changes to system conditions do not warrant such analyses.	The responsible entity's most recent long-term studies (and/or system simulation testing) were not performed in the most recent annual period AND significant system changes (actual or proposed) indicate that past studies (and/or system testing) are no longer valid.	The responsible entity's most recent near-term studies (and/or system simulation testing) were not performed in the most recent annual period AND significant system changes (actual or proposed) indicate that past studies (and/or system testing) are no longer valid.	N/A	The responsible entity's most recent near-term studies (and/or system simulation testing) AND most recent long-term studies (and/or system testing) were not performed in the most recent annual period AND significant system changes (actual or proposed) indicate that past studies (and/or system simulation testing) are no longer valid.
TPL-003-0a	R1.3.4.	Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.	N/A	N/A	N/A	The responsible entity failed to produce evidence of a past or current year long-term study and/or system simulation testing (beyond 5-year planning horizon) when past or current year near-term studies and/or system testing show marginal conditions that may require longer lead-time solutions.
TPL-003-0a	R1.3.5.	Have all projected firm transfers modeled.	The system model(s)	The system model(s)	The system model(s)	The system model(s)

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			used for current or past analysis did not properly represent up to (but less than) 25% of the firm transfers to/from the responsible entity's service territory.	used for current or past analysis did not properly represent 25% or more but less than 50% of the firm transfers to/from the responsible entity's service territory.	used for current or past analysis did not properly represent 50% or more but less than 75% of the firm transfers to/from the responsible entity's service territory.	used for current or past analysis did not properly represent 75% or more of the firm transfers to/from the responsible entity's service territory.
TPL-003-0a	R1.3.6.	Be performed and evaluated for selected demand levels over the range of forecast system demands.	N/A	N/A	N/A	The responsible entity has failed to produce evidence of a valid current or past study and/or system simulation testing reflecting analysis over a range of forecast system demands.
TPL-003-0a	R1.3.7.	Demonstrate that System performance meets Table 1 for Category C contingencies.	N/A	N/A	N/A	No past or current study results exists showing Category C contingency system analysis.
TPL-003-0a	R1.3.8.	Include existing and planned facilities.	The responsible entity’s transmission model used for past or current studies and/or system simulation testing properly reflects existing facilities, but is deficient in reflecting planned facilities.	The responsible entity’s transmission model used for past or current studies and/or system simulation testing properly reflects planned facilities, but is deficient in reflecting existing facilities.	N/A	The responsible entity's transmission model used for past or current studies and/or system simulation testing is deficient in reflecting existing AND planned facilities.
TPL-003-0a	R1.3.9.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.	N/A	N/A	N/A	The responsible entity has failed to ensure in a past or current study and/or system

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						simulation testing that sufficient reactive power resources are available to meet required system performance.
TPL-003-0a	R1.3.10.	Include the effects of existing and planned protection systems, including any backup or redundant systems.	N/A	N/A	The responsible entity's transmission model used for past or current studies is deficient with respect to the effects of planned protection systems, including any backup or redundant systems.	The responsible entity's transmission model used for past or current studies is deficient with respect to the effects of existing protection systems, including any backup or redundant systems.
TPL-003-0a	R1.3.11.	Include the effects of existing and planned control devices.	N/A	N/A	The responsible entity's transmission model used for past or current studies is deficient with respect to the effects of planned control devices.	The responsible entity's transmission model used for past or current studies is deficient with respect to the effects of existing control devices.
TPL-003-0a	R1.3.12.	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.	N/A	N/A	N/A	The responsible entity's transmission model used for past or current studies is deficient with respect to the inclusion of planned maintenance outages of bulk electric transmission facilities.
TPL-003-0a	R1.4.	Address any planned upgrades needed to meet the performance requirements of Category C.	N/A	N/A	N/A	The responsible entity has failed to demonstrate that a

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						corrective action plan exists in order to satisfy Category C planning requirements.
TPL-003-0a	R1.5.	Consider all contingencies applicable to Category C.	The responsible entity has considered the NERC Category C contingencies applicable to their system, but was deficient with respect to 25% or less of all applicable contingencies.	The responsible entity has considered the NERC Category C contingencies applicable to their system, but was deficient with respect to more than 25% but less than 50% of all applicable contingencies.	The responsible entity has considered the NERC Category C contingencies applicable to their system, but was deficient with respect to more than 50% but less than 75% of all applicable contingencies.	The responsible entity has considered the NERC Category C contingencies applicable to their system, but was deficient 75% or more of all applicable contingencies.
TPL-003-0a	R2.	When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0_R1, the Planning Authority and Transmission Planner shall each:	The responsible entity is non-compliant with 25% or less of the sub-components.	The responsible entity is non-compliant with more than 25% but less than 50% of the sub-components.	The responsible entity is non-compliant with 50% or more but less than 75% of the sub-components.	The responsible entity is non-compliant with 75% or more of the sub-components.
TPL-003-0a	R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:	N/A	N/A	N/A	The responsible entity has failed to provide documented evidence of corrective action plans in order to satisfy Category C planning requirements.
TPL-003-0a	R2.1.1.	Including a schedule for implementation.	N/A	N/A	N/A	A schedule for the responsible entity's corrective action plan does not exist.
TPL-003-0a	R2.1.2.	Including a discussion of expected required in-service dates of facilities.	N/A	N/A	N/A	Anticipated in-service dates, for the responsible entity's

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						corrective action plan does not exist. This would reflect effective dates for pre-contingency operating procedures or in-service dates for proposed system changes.
TPL-003-0a	R2.1.3.	Consider lead times necessary to implement plans.	N/A	N/A	N/A	The responsible entity failed to consider necessary lead times to implement its corrective action plan.
TPL-003-0a	R2.2.	Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.	N/A	N/A	N/A	The responsible entity has failed to demonstrate the continuing need for previously identified facility additions through sub-sequent annual assessments.
TPL-003-0a	R3.	The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.	N/A	The responsible entity documented the results of its reliability assessments and corrective plans but did not annually provided them to its respective NERC Regional Reliability Organization(s) as required by the Regional Reliability Organization	N/A	The responsible entity DID NOT document the results of its annual reliability assessments and corrective plans AND did not annually provided them to its respective NERC Regional Reliability Organization(s) as required by the Regional Reliability Organization
TPL-004-0	R1.	The Planning Authority and Transmission	The responsible entity	The responsible entity	The responsible entity	The responsible entity

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:	is non-compliant with 25% or less of the sub-components.	is non-compliant with more than 25% but less than 50% of the sub-components.	is non-compliant with 50% or more but less than 75% of the sub-components.	is non-compliant with 75% or more of the sub-components.
TPL-004-0	R1.1.	Be made annually.	N/A	N/A	N/A	The assessments were not made on an annual basis.
TPL-004-0	R1.2.	Be conducted for near-term (years one through five).	N/A	N/A	N/A	The responsible entity has failed to demonstrate a valid assessment for the near-term period.
TPL-004-0	R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).	The responsible entity is non-compliant with 25% or less of the sub-components.	The responsible entity is non-compliant with more than 25% but less than 50% of the sub-components.	The responsible entity is non-compliant with 50% or more but less than 75% of the sub-components.	The responsible entity is non-compliant with 75% or more of the sub-components.
TPL-004-0	R1.3.1.	Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.	N/A	The responsible entity provided evidence through current or past studies that selected NERC Category D contingencies were evaluated, however, no rational was provided to indicate why the remaining	N/A	The responsible entity did not provided evidence through current or past studies to indicate that any NERC Category D contingencies were evaluated.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Category D contingencies for their system were not evaluated.		
TPL-004-0	R1.3.2.	Cover critical system conditions and study years as deemed appropriate by the responsible entity.	N/A	N/A	N/A	The responsible entity has failed to cover critical system conditions and study years as deemed appropriate.
TPL-004-0	R1.3.3.	Be conducted annually unless changes to system conditions do not warrant such analyses.	N/A	N/A	N/A	The responsible entity did not perform a near-term Category D study and/or system simulation test in the most recent annual period AND system changes (actual or proposed) indicate that past studies and/or system simulation testing are no longer valid
TPL-004-0	R1.3.4.	Have all projected firm transfers modeled.	The system model(s) used for current or past analysis did not properly represent up to (but less than) 25% of the firm transfers to/from the responsible entity's service territory.	The system model(s) used for current or past analysis did not properly represent 25% or more but less than 50% of the firm transfers to/from the responsible entity's service territory.	The system model(s) used for current or past analysis did not properly represent 50% or more but less than 75% of the firm transfers to/from the responsible entity's service territory.	The system model(s) used for current or past analysis did not properly represent 75% or more of the firm transfers to/from the responsible entity's service territory.
TPL-004-0	R1.3.5.	Include existing and planned facilities.	The responsible entity’s transmission model used for past or current studies and/or system simulation	The responsible entity’s transmission model used for past or current studies and/or system simulation	N/A	The responsible entity's transmission model used for past or current studies and/or system simulation

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			testing properly reflects existing facilities, but is deficient in reflecting planned facilities.	testing properly reflects planned facilities, but is deficient in reflecting existing facilities.		testing is deficient in reflecting existing AND planned facilities.
TPL-004-0	R1.3.6.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.	N/A	N/A	N/A	The responsible entity has failed to ensure in a past or current study and/or system simulation testing that sufficient reactive power resources are available to meet required system performance.
TPL-004-0	R1.3.7.	Include the effects of existing and planned protection systems, including any backup or redundant systems.	N/A	N/A	The responsible entity's transmission model used for past or current studies is deficient with respect to the effects of planned protection systems, including any backup or redundant systems.	The responsible entity's transmission model used for past or current studies is deficient with respect to the effects of existing protection systems, including any backup or redundant systems.
TPL-004-0	R1.3.8.	Include the effects of existing and planned control devices.	N/A	N/A	The responsible entity's transmission model used for past or current studies is deficient with respect to the effects of planned control devices.	The responsible entity's transmission model used for past or current studies is deficient with respect to the effects of existing control devices.
TPL-004-0	R1.3.9.	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for	N/A	N/A	N/A	The responsible entity's transmission model used for past or current studies is

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		which planned (including maintenance) outages are performed.				deficient with respect to the inclusion of planned maintenance outages of bulk electric transmission facilities.
TPL-004-0	R1.4.	Consider all contingencies applicable to Category D.	The responsible entity has considered the NERC Category D contingencies, but was deficient with respect to 25% or less of all applicable contingencies	The responsible entity has considered the NERC Category D contingencies, but was deficient with respect to more than 25% but less than 50% of all applicable contingencies.	The responsible entity has considered the NERC Category D contingencies, but was deficient with respect to more than 50% but less than 75% of all applicable contingencies.	The responsible entity has considered the NERC Category D contingencies, but was deficient 75% or more of all applicable contingencies.
TPL-004-0	R2.	The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.	N/A	The responsible entity documented the results of its reliability assessments but did not annually provided them to its respective NERC Regional Reliability Organization(s) as required by the Regional Reliability Organization	N/A	The responsible entity DID NOT document the results of its annual reliability assessments AND did not annually provided them to its respective NERC Regional Reliability Organization(s) as required by the Regional Reliability Organization

Complete Violation Severity Level Matrix (VAR)
Encompassing All FERC-Approved Reliability Standards

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
VAR-001-1	R1.	Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators.	The applicable entity did not ensure the development and/or maintenance and/or implementation of formal policies and procedures, as directed by the requirement, affecting 5% or less of their individual and neighboring areas voltage levels and Mvar flows.	The applicable entity did not ensure the development and/or maintenance and/or implementation of formal policies and procedures, as directed by the requirement, affecting between 5-10% of their individual and neighboring areas voltage levels and Mvar flows.	The applicable entity did not ensure the development and/or maintenance and/or implementation of formal policies and procedures, as directed by the requirement, affecting 10-15%, inclusive, of their individual and neighboring areas voltage levels and Mvar flows.	The applicable entity did not ensure the development and/or maintenance and/or implementation of formal policies and procedures, as directed by the requirement, affecting greater than 15% of their individual and neighboring areas voltage levels and Mvar flows.
VAR-001-1	R2.	Each Transmission Operator shall acquire sufficient reactive resources within its area to protect the voltage levels under normal and Contingency conditions. This includes the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.	The Transmission Operator acquired 95% but less than 100% of the reactive resources within its area needed to protect the voltage levels under normal and Contingency conditions including the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.	The Transmission Operator acquired 90% but less than 95% of the reactive resources within its area needed to protect the voltage levels under normal and Contingency conditions including the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.	The Transmission Operator acquired 85% but less than 90% of the reactive resources within its area needed to protect the voltage levels under normal and Contingency conditions including the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.	The Transmission Operator acquired less than 85% of the reactive resources within its area needed to protect the voltage levels under normal and Contingency conditions including the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.
VAR-001-1	R3.	The Transmission Operator shall specify criteria that exempts generators from compliance with the requirements defined in Requirement 4, and Requirement 6.1.	N/A	N/A	N/A	The Transmission Operator did not specify criteria that exempts generators from compliance with

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						the requirements defined in Requirement 4, and Requirement 6.1. to all of the parties involved.
VAR-001-1	R3.1.	Each Transmission Operator shall maintain a list of generators in its area that are exempt from following a voltage or Reactive Power schedule.	The Transmission Operator maintain the list of generators in its area that are exempt from following a voltage or Reactive Power schedule but is missing one or more entities. The missing entities shall represent less than 25% of those eligible for the list	The Transmission Operator maintain the list of generators in its area that are exempt from following a voltage or Reactive Power schedule but is missing two or more entities. The missing entities shall represent less than 50% of those eligible for the list	The Transmission Operator maintain the list of generators in its area that are exempt from following a voltage or Reactive Power schedule but is missing three or more entities. The missing entities shall represent less than 75% of those eligible for the list	The Transmission Operator maintain the list of generators in its area that are exempt from following a voltage or Reactive Power schedule but is missing four or more entities. The missing entities shall represent 75% or more of those eligible for the list.
VAR-001-1	R3.2.	For each generator that is on this exemption list, the Transmission Operator shall notify the associated Generator Owner.	The Transmission Operator failed to notify up to 25% of the associated Generator Owner of each generator that are on this exemption list.	The Transmission Operator failed to notify 25% up to 50% of the associated Generator Owners of each generator that are on this exemption list.	The Transmission Operator failed to notify 50% up to 75% of the associated Generator Owner of each generator that are on this exemption list.	The Transmission Operator failed to notify 75% up to 100% of the associated Generator Owner of each generator that are on this exemption list.
VAR-001-1	R4.	Each Transmission Operator shall specify a voltage or Reactive Power schedule at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode	N/A	N/A	The Transmission Operator provide Voltage or Reactive Power schedules were for some but not all generating units as required in R4.	The Transmission Operator provide No evidence that voltage or Reactive Power schedules were provided to Generator Operators as required in R4.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		(AVR in service and controlling voltage).				
VAR-001-1	R5.	Each Purchasing-Selling Entity shall arrange for (self-provide or purchase) reactive resources to satisfy its reactive requirements identified by its Transmission Service Provider.	The applicable entity did not arrange for reactive resources, as directed by the requirement, affecting 5% or less of its reactive requirements.	The applicable entity did not arrange for reactive resources, as directed by the requirement, affecting between 5-10% of its reactive requirements.	The applicable entity did not arrange for reactive resources, as directed by the requirement, affecting 10-15%, inclusive, of its reactive requirements.	The applicable entity did not arrange for reactive resources, as directed by the requirement, affecting greater than 15% of its reactive requirements.
VAR-001-1	R6.	The Transmission Operator shall know the status of all transmission Reactive Power resources, including the status of voltage regulators and power system stabilizers.	The applicable entity did not know the status of all transmission reactive power resources, including the status of voltage regulators and power system stabilizers, as directed by the requirement, affecting 5% or less of the required resources.	The applicable entity did not know the status of all transmission reactive power resources, including the status of voltage regulators and power system stabilizers, as directed by the requirement, affecting between 5-10% of the required resources.	The applicable entity did not know the status of all transmission reactive power resources, including the status of voltage regulators and power system stabilizers, as directed by the requirement, affecting 10-15%, inclusive, of the required resources.	The applicable entity did not know the status of all transmission reactive power resources, including the status of voltage regulators and power system stabilizers, as directed by the requirement, affecting 15% or greater of required resources.
VAR-001-1	R6.1.	When notified of the loss of an automatic voltage regulator control, the Transmission Operator shall direct the Generator Operator to maintain or change either its voltage schedule or its Reactive Power schedule.	N/A	N/A	N/A	The Transmission Operator has not provided evidence to show that directives were issued to the Generator Operator to maintain or change either its voltage schedule or its Reactive Power schedule in accordance with R6.1.
VAR-001-1	R7.	The Transmission Operator shall be able to operate or direct the operation of devices	The applicable entity was not able to operate	The applicable entity was not able to	The applicable entity was not able to operate	The applicable entity was not able to operate

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		necessary to regulate transmission voltage and reactive flow.	or direct the operation of devices necessary to regulate transmission voltage and reactive flow, affecting 5% or less of the required devices.	operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow, affecting between 5-10% of the required devices.	or direct the operation of devices necessary to regulate transmission voltage and reactive flow, affecting 10-15%, inclusive, of the required devices.	or direct the operation of devices necessary to regulate transmission voltage and reactive flow, affecting greater than 15% of the required devices.
VAR-001-1	R8.	Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including reactive generation scheduling; transmission line and reactive resource switching; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits.	The applicable entity did operate or direct the operation of capacitive and inductive reactive resources or load shedding within its area, as directed by the requirement, affecting 5% or less of the required resources.	The applicable entity did operate or direct the operation of capacitive and inductive reactive resources or load shedding within its area, as directed by the requirement, affecting between 5-10% of the required resources.	The applicable entity did operate or direct the operation of capacitive and inductive reactive resources or load shedding within its area, as directed by the requirement, affecting 10-15%, inclusive, of the required resources.	The applicable entity did operate or direct the operation of capacitive and inductive reactive resources or load shedding within its area, as directed by the requirement, affecting greater than 15% of the required resources.
VAR-001-1	R9.	Each Transmission Operator shall maintain reactive resources to support its voltage under first Contingency conditions.	The Transmission Operator maintains 95% or more of the reactive resources needed to support its voltage under first Contingency conditions.	The Transmission Operator maintains 85% or more but less than 95% of the reactive resources needed to support its voltage under first Contingency conditions.	The Transmission Operator maintains 75% or more but less then 85% of the reactive resources needed to support its voltage under first Contingency conditions.	The Transmission Operator maintains less than 75% of the reactive resources needed to support its voltage under first Contingency conditions.
VAR-001-1	R9.1.	Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when Contingencies occur.	The applicable entity did not disperse and/or locate the reactive resources, as directed in the requirement, affecting 5% or less of the resources.	The applicable entity did not disperse and/or locate the reactive resources, as directed in the requirement, affecting between 5-10% of the resources.	The applicable entity did not disperse and/or locate the reactive resources, as directed in the requirement, affecting 10-15%, inclusive, of the resources.	The applicable entity did not disperse and/or locate the reactive resources, as directed in the requirement, affecting greater than 15% of the resources.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
VAR-001-1	R10.	Each Transmission Operator shall correct IROL or SOL violations resulting from reactive resource deficiencies (IROL violations must be corrected within 30 minutes) and complete the required IROL or SOL violation reporting.	The applicable entity did not correct the IROL or SOL violations and/or complete the required IROL or SOL violation reporting, as directed by the requirement, affecting 5% or less of the violations.	The applicable entity did not correct the IROL or SOL violations and/or complete the required IROL or SOL violation reporting, as directed by the requirement, affecting between 5-10% of the violations.	The applicable entity did not correct the IROL or SOL violations and/or complete the required IROL or SOL violation reporting, as directed by the requirement, affecting 10-15%, inclusive, of the violations.	The applicable entity did not correct the IROL or SOL violations and/or complete the required IROL or SOL violation reporting, as directed by the requirement, affecting greater than 15% of the violations.
VAR-001-1	R11.	After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.	The Transmission Operator provided documentation to the Generator Owner specifying required step-up transformer tap changes and a timeframe for making these changes, but failed to provide technical justification for these changes.	The Transmission Operator provided documentation to the Generator Owner specifying required step-up transformer tap changes, but failed to provide a timeframe for making these changes and technical justification for these changes.	The Transmission Operator failed to provide documentation to the Generator Owner specifying required step-up transformer tap changes, a timeframe for making these changes, and technical justification for these changes.	N/A
VAR-001-1	R12.	The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.	N/A	N/A	N/A	The Transmission Operator has failed to direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.
VAR-002-1.1a	R1.	The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in	The Generator Operator failed to notify the Transmission Operator as identified in R1 for	The Generator Operator failed to notify the Transmission	The Generator Operator failed to notify the Transmission Operator	The Generator Operator failed to notify the Transmission Operator

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.	less than 25% of its generators.	Operator as identified in R1 for 25% or more but less tan 50% of its generators.	as identified in R1 for 50% or more but less tan 75% of its generators.	as identified in R1 for 75% or more of its generators.
VAR-002-1.1a	R2.	Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings. [1] as directed by the Transmission Operator	The Generator Operator failed to maintain a voltage or reactive power schedule for less than 25% of its generators.	The Generator Operator failed to maintain a voltage or reactive power schedule for 25% or more but less tan 50% of its generators.	The Generator Operator failed to maintain a voltage or reactive power schedule for 50% or more but less tan 75% of its generators.	The Generator Operator failed to maintain a voltage or reactive power schedule for 75% or more of its generators.
VAR-002-1.1a	R2.1.	When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.	The Generator Operator failed to use an alternate method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule for less than 25% of its generators.	The Generator Operator failed to use an alternate method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule for 25% or more but less tan 50% of its generators.	The Generator Operator failed to use an alternate method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule for 50% or more but less tan 75% of its generators.	The Generator Operator to use an alternate method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule for 75% or more of its generators.
VAR-002-1.1a	R2.2.	When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.	The Generator Operator failed to comply with required voltage modifications or provide an explanation of why the modifications could not be met less the 25% of the time.	The Generator Operator failed to comply with required voltage modifications or provide an explanation of why the modifications could not be met less than 50% of the time but more than or equal to 25% of the time.	The Generator Operator failed to comply with required voltage modifications or provide an explanation of why the modifications could not be met less than 75% of the time but more than or equal to 50% of the time.	The Generator Operator failed to comply with required voltage modifications or provide an explanation of why the modifications could not be met more than 75% of the time.
VAR-002-1.1a	R3.	Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the	The Generator Operator had one incident of failing to notify the	The Generator Operator had more than one but less than	The Generator Operator had more than five but less than	The Generator Operator had ten or more incidents of

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		following:	Transmission Operator as identified in R3.	five incidents of failing to notify the Transmission as identified in R3.1 R3.2.	ten incidents of failing to notify the Transmission Operator as identified in R3.1 R3.2	failing to notify the Transmission Operator as identified in R3.1 R3.2.
VAR-002-1.1a	R3.1.	A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.	N/A	N/A	N/A	The Generator Operator failed to notify the Transmission Operator of a status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.
VAR-002-1.1a	R3.2.	A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.	N/A	N/A	N/A	The Generator Operator failed to notify the Transmission Operator of a status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.
VAR-002-1.1a	R4.	The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.	The Generator Owner had one (1) incident of failing to notify its associated	The Generator Owner had more than one (1) incident but less than five (5) incidents	The Generator Owner had more than five (5) incidents but less than ten (10) incidents of	The Generator Owner had more than ten (10) incidents of failing to notify its associated

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Transmission Operator and Transmission Planner within 30 calendar days of a request for information, as described in R4.1.1 through R4.1.4, regarding generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage.	of failing to notify its associated Transmission Operator and Transmission Planner within 30 calendar days of a request for information, as described in R4.1.1 through R4.1.4, regarding generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage.	failing to notify its associated Transmission Operator and Transmission Planner within 30 calendar days of a request for information, as described in R4.1.1 through R4.1.4, regarding generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage.	Transmission Operator and Transmission Planner within 30 calendar days of a request for information, as described in R4.1.1 through R4.1.4, regarding generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage.
VAR-002-1.1a	R4.1.	For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:	N/A	N/A	N/A	The Generator Owner failed to notify its associated Transmission Operator and Transmission Planner within 30 calendar days of a request for information, as described in R4.1.1 through R4.1.4, regarding generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage.
VAR-002-	R4.1.1.	Tap settings.	N/A	N/A	N/A	The Generator Owner

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
1.1a						failed to notify its associated Transmission Operator and Transmission Planner within 30 calendar days of a request for tap settings on generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage.
VAR-002-1.1a	R4.1.2.	Available fixed tap ranges.	N/A	N/A	N/A	The Generator Owner failed to notify its associated Transmission Operator and Transmission Planner within 30 calendar days of a request for available fixed tap ranges on generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage.
VAR-002-1.1a	R4.1.3.	Impedance data.	N/A	N/A	N/A	The Generator Owner failed to notify its associated Transmission Operator and Transmission Planner within 30 calendar days of a request for impedance

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						data on generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage.
VAR-002-1.1a	R4.1.4.	The +/- voltage range with step-change in % for load-tap changing transformers.	N/A	N/A	N/A	The Generator Owner failed to notify its associated Transmission Operator and Transmission Planner within 30 calendar days of a request for the +/- voltage range with tap change in percent (%) for load-tap changing transformers on generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage.
VAR-002-1.1a	R5.	After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement.	The Generator Owner had one (1) incident of failing to change the step-up transformer tap settings in accordance with the specifications provided by the Transmission Operator when said actions would not have violated safety, an equipment rating, a regulatory	The Generator Owner had more than one (1) incident but less than or equal to five (5) incidents of failing to change the step-up transformer tap settings in accordance with the specifications provided by the Transmission	The Generator Owner had more than five (5) incident but less than or equal to ten (10) incidents of failing to change the step-up transformer tap settings in accordance with the specifications provided by the Transmission Operator when said actions	The Generator Owner had more than ten (10) incidents of failing to change the step-up transformer tap settings in accordance with the specifications provided by the Transmission Operator when said actions would not have violated safety, an

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			requirement, or a statutory requirement.	Operator when said actions would not have violated safety, an equipment rating, a regulatory requirement, or a statutory requirement.	would not have violated safety, an equipment rating, a regulatory requirement, or a statutory requirement.	equipment rating, a regulatory requirement, or a statutory requirement.
VAR-002-1.1a	R5.1.	If the Generator Operator can't comply with the Transmission Operator's specifications, the Generator Operator shall notify the Transmission Operator and shall provide the technical justification.	The Generator Operator had one (1) incident of failing to notify and provide technical justification to the Transmission Operator concerning non-compliance with Transmission Operator's specifications.	The Generator Operator had more than one (1) incident but less than or equal to five (5) incidents of failing to notify and provide technical justification to the Transmission Operator concerning non-compliance with Transmission Operator's specifications.	The Generator Operator had more than five (5) incident but less than or equal to ten (10) incidents of failing to notify and provide technical justification to the Transmission Operator concerning non-compliance with Transmission Operator's specifications.	The Generator Operator had more than ten (10) incidents of failing to notify and provide technical justification to the Transmission Operator concerning non-compliance with Transmission Operator's specifications.

Exhibit H

NERC Approved Reliability Standards Pending At FERC

Date Filed with FERC	NERC Approved Reliability Standards Pending at FERC
April 21, 2010	CIP-005-2a
April 21, 2010	CIP-001-1a
April 20, 2010	CIP-006-2c
December 31, 2009	IRO-008-1 IRO-009-1 IRO-010-1a EOP-001-2 IRO-002-2 IRO-004-2 IRO-005-3 TOP-003-1 TOP-005-2 TOP-006-2
December 31, 2009[1]	EOP-001-1 EOP-005-2 EOP-006-2
December 22, 2009	CIP-006-2a CIP-006-2b
December 2, 2009	MOD-001-1a MOD-029-1a
November 24, 2009	TOP-005-1.1a IRO-005-2a
November 20, 2009	FAC-010-2.1
November 20, 2009	INT-003-3 BAL-006-2
November 17, 2009	TPL-002-0b
November 17, 2009	PRC-005-1a
September 30, 2009[2]	PER-004-2 PER-005-1
March 11, 2009	BAL-004-1
March 5, 2009	VAR-002-1.1b

[1] Upon FERC approval of this December 31, 2009 filing, NERC also requested that EOP-007-0 and EOP-009-0 be retired.

[2] Upon FERC approval of this September 30, 2009 filing, NERC also requested that PER-002-0 be retired.

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

April 21, 2011

VIA ELECTRONIC FILING
Ms. Nancy McNeil
Regulatory Affairs Officer/Clerk
Nova Scotia Utility and Review Board
3rd Floor
1601 Lower Water Street
Halifax, Nova Scotia B3J 3P6

Re: North American Electric Reliability Corporation – Reliability Standards and Northeast Power Coordinating Council, Inc. – Regional Reliability Criteria
NERC-R-10/Matter No. M03324
Final Submission of Northeast Power Coordinating Council, Inc.

Dear Ms. McNeil:

In accordance with the timeline established in connection with the application of the Northeast Power Coordinating Council, Inc. ("NPCC") for approval of the Regional Reliability Criteria in Nova Scotia, NPCC hereby provides its Final Submission. NPCC's application was filed on June 29, 2010 and noticed by the Nova Scotia Utility and Review Board ("NSUARB") on July 26, 2010.

As noted in NPCC's June 29 application, approval of the Regional Reliability Criteria in Nova Scotia would facilitate co-operative efforts in improving the reliability of the bulk power system and enhance the exchange of experience, information and data related to that system. The desire to achieve these benefits is reflected in the December 22, 2006 memorandum of understanding between the NSUARB and the North American Electric Reliability Corporation ("NERC") and the framework for doing so is set forth in the May 11, 2010 memorandum of understanding between NERC, NPCC and Nova Scotia Power Incorporated ("NSPI"). By approving the Regional Reliability Criteria for application in Nova Scotia, the NSUARB is furthering the twin aims of both memoranda.

Moreover, adoption of the Regional Reliability Criteria is recommended by NERC and NSPI, the latter which, in its letter dated December 17, 2010, indicated that such approval would not change its

operating practices as NSPI already adheres to the NPCC Regional Reliability Criteria as a consequence of being a Member of NPCC.

Finally, in addition to supporting the NSUARB's adoption of the NERC Reliability Standards in Nova Scotia, NPCC supports the NERC recommendation that the NSUARB initiate a quarterly review process following the filing of new Reliability Standards and Regional Reliability Criteria.

Respectfully submitted,

Edward A. Schwerdt
President and Chief Executive Officer
Northeast Power Coordinating Council, Inc.

c:	S. Bruce Outhouse, Q.C. Board Counsel	By email
	Nicole Godbout, Regulatory Counsel, NSPI	By email
	Rene Gallant, General Manager, Regulatory Affairs	By email
	Eric Ferguson, Director, Regulatory Affairs	By email
	Sara Tingley, Project Manager, Regulatory Affairs	By email
	NSPI Admin.	By email
	Rebecca J. Michael, Counsel, NERC	By email
	David N. Cook, VP & General Counsel, NERC	By email
	V. Davis Smith, Attorney, NERC	By email
	Margaret Mayora, Compliance Attorney, NPCC	By email
	John H. Reynolds, Quetta Inc.	By email

DECISION

NSUARB-NERC-R-10
2011 NSUARB 113

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF THE PUBLIC UTILITIES ACT

- and -

IN THE MATTER OF AN APPLICATION by **NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION** for approval of its Reliability Standards, and an application by **NORTHEAST POWER COORDINATING COUNCIL, INC.** for approval of its Regional Reliability Criteria

BEFORE: Peter W. Gurnham, Q.C., Chair
Kulvinder S. Dhillon, P.Eng., Member
Murray E. Doehler, CA, P.Eng., Member

PARTICIPANTS:

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
V. Davis Smith, Attorney

NORTHEAST POWER COORDINATING COUNCIL, INC.
Edward A. Schwerdt, President & CEO

NOVA SCOTIA POWER INC.
Nicole Godbout, LL.B.

QUETTA INC.
John Reynolds, P.Eng.

FINAL SUBMISSIONS: April 21, 2011

DECISION DATE: **July 20, 2011**

DECISION: **Decision is summarized in paragraphs 36-39**

I INTRODUCTION

[1] The North American Electric Reliability Corporation ("NERC") is responsible for the development of reliability standards for the electricity grid in North America. The Northeast Power Coordinating Council, Inc. ("NPCC") is the organization that enforces the standards with respect to Nova Scotia Power Inc. ("NSPI"). The intent of the development and enforcement of these standards is to minimize, if not eliminate, the chances of a widespread electrical blackout. Up until this Decision, NSPI was required to comply with the standards, but this was not mandated by the Nova Scotia Utility and Review Board (the "Board").

[2] NPCC applied to the Board for approval of its Regional Reliability Criteria ("Criteria"). The application was dated June 29, 2010.

[3] NERC applied to the Board for approval of its Reliability Standards and associated Glossary of Terms ("Standards") to be applicable to users, owners, and operators of the bulk power system within the Province of Nova Scotia. The application was dated June 30, 2010.

[4] In its application, NERC also requested Board approval of the associated Violation Risk Factors ("VRFs") and the Violation Severity Levels ("VSLs").

[5] The Board issued a Notice of Filings by advertisement in the Chronicle Herald newspaper on August 5, August 14 and August 19, 2010. The Board received only two Notices of Intervention, one from NSPI and the other from Quetta Inc.

[6] In a letter dated September 17, 2010, to NERC, NPCC and NSPI, the Board requested that NSPI propose a timeline for Board approval of the Standards and Criteria. In its letter of October 15, 2010, NSPI submitted the proposed timeline. The

timeline had been agreed to by NERC and NPCC, and the Board accepted the timeline for the proceeding, as follows:

NSPI Recommendation	December 16, 2010
IRs to NSPI, NERC and NPCC	January 20, 2011
Responses to IRs	February 10, 2011
Intervenor Evidence/Comment	March 3, 2011
IRs to Intervenors	March 17, 2011
Responses to IRs	April 7, 2011
Final Submissions by NSPI, NERC, NPCC	April 21, 2011
Reply	May 5, 2011
Anticipated UARB decision	by August 2011

[NSPI Letter to Board, October 15, 2010, p. 2]

[7] Board staff issued Information Requests ("IRs") to NSPI, NERC and NPCC on January 20, 2011. IRs were issued by NSPI to NERC and NPCC on the same date. All IRs were responded to on February 10, 2011.

[8] Final submissions were filed by NSPI, NERC and NPCC on April 21, 2011. No reply submissions were filed.

[9] The Board did not deem it necessary to hold an oral hearing.

II BACKGROUND

[10] The Board exercises general supervision over NSPI pursuant to the *Public Utilities Act*, R.S.N.S. 1989, c. 380, as amended (the "*Act*"). Under the *Act*, NSPI is required to provide reasonably safe and adequate service and facilities.

[11] A Memorandum of Understanding ("MOU") dated December 22, 2006, between the Board and NERC, outlined a process by which the Standards would be made mandatory and enforced.

[12] The MOU further recognizes that once the Board approves a Standard, compliance with the Standard will be mandatory in Nova Scotia.

[13] An MOU dated May 9, 2010, among NSPI, NPCC and NERC, defines the methodology to approve and implement the mandatory Standards and Criteria in Nova Scotia.

[14] The May 9, 2010 MOU states:

> In accordance with NSPI's designation as a Registered Entity, NSPI agrees to comply with NERC Reliability Standards and NPCC Regional Reliability Criteria.
>
> Upon approval by the NSUARB, the NERC Reliability Standards and NPCC Regional Reliability Criteria will become mandatory in Nova Scotia.
>
> [Exhibit N-11, p. 2]

[15] Further, the May 9, 2010 MOU directs NSPI to provide the Board with a recommendation either to approve the Standards and Criteria, or pursue a different course of action.

[16] On December 17, 2010, NSPI filed its recommendations with the Board. In the letter, NSPI stated:

> The approval of the Reliability Standards and Regional Reliability Criteria will not change NSPI's operating practices as NSPI already manages to compliance on all appropriate standards and criteria....
>
> [Exhibit N-13, p. 2

[17] The above statement is supported in the same letter by a discussion of a compliance audit performed by NPCC on NSPI in 2010. Although the final audit report had not yet been published, preliminary findings were that NSPI was compliant with the applicable Standards, with one minor possible violation, which involved revoking access within seven days of one employee, who had passed away during the audit period.

[18] NSPI closed its December 17, 2010 letter with two recommendations:

1. The Board approve the NERC Reliability Standards and the NPCC Regional Reliability Criteria.

2. The Board not approve the VRFs and the VSLs.

[19] Upon reviewing the above noted submissions and documentation, in the Board's view there are four issues which must be decided:

- Approval of the Standards and Criteria
- The procedure by which amendments or additions to the Standards and Criteria will be approved
- Approval of VRFs and VSLs
- Compliance Monitoring and Enforcement

III ANALYSIS AND FINDINGS

1. Standards and Criteria

[20] In response to Board IR-2, NERC provided its report entitled "A Summary of Canadian Provincial Adoption of Reliability Standards Framework". A review of the report indicates widespread acceptance and adoption of the Standards in Canadian jurisdictions.

[21] In response to NSPI IR-1, NPCC stated:

> The provinces of New Brunswick, Ontario, Quebec and Nova Scotia reside within the boundaries of NPCC. To date, NPCC has filed, and Ontario and New Brunswick have adopted, the Regional Reliability Criteria contained in the NPCC Directories. It should be noted, however, that the larger market participants, including Reliability Coordinators and Balancing Authorities, in the remaining provinces within NPCC are NPCC Full Members and, as such, have agreed to abide by the NPCC Bylaws and, through those bylaws, comply with the NPCC Regional Reliability Criteria.
>
> [Exhibit N-18, p. 1]

[22] As noted above, NSPI stated that it already manages its operation to be in compliance with appropriate Standards and Criteria. NPCC's response to Board IR-2

included a copy of the 2010 NSPI compliance audit, which confirms that NSPI is in compliance.

[23] There were no objections to the Board approving the Criteria and Standards.

[24] The Board hereby approves the Criteria and Standards as submitted.

2. Amendments or Additions

[25] Regarding notification and approval of amendments and/or additions to the Standards and Criteria, the May 9, 2010 MOU suggests the following approach:

> The signatories anticipate that there will be ongoing amendments and/or additions made to the NERC Reliability Standards and NPCC Regional Reliability Criteria by NERC and NPCC, respectively. These amendments and/or additions will require approval by the NSUARB before they will become mandatory in Nova Scotia.
>
> The signatories will utilize a regular notification process that identifies to the NSUARB proposed amendments and/or additions to be made by NERC and NPCC to Reliability Standards and Regional Reliability Criteria, respectively.
>
> NERC shall concurrently notify NSPI and the NSUARB of Reliability Standards adopted by NERC. NPCC shall concurrently notify the NSPI and the NSUARB of Regional Reliability Criteria adopted by NPCC.
>
> Periodically, NERC and NPCC shall file all proposed amendments and/or additions to the Reliability Standards adopted by NERC and the Regional Reliability Criteria adopted by NPCC with the NSUARB for approval.
>
> As is contemplated with the initial filing, NSPI will provide the NSUARB with a recommendation with respect to the Reliability Standards and NPCC Regional Reliability Criteria being proposed.
>
> [Exhibit N-11, p. 3]

[26] In summary, it is expected that the Board would follow, essentially, the same process for approval of future amendments and new Standards and Criteria as was used in processing the filings, which are the subject of this Decision. The Board has no objection to proceeding in that manner.

[27] In its December 17, 2010 letter, NSPI also agreed with this approach, with one exception:

> NSPI recommends that the UARB implement this process for approval of future NPCC Reliability Criteria and NERC Reliability Standards, as contemplated by the UARB and NERC in their MOU, with one suggested change. The process contemplated by NERC and the UARB requires NERC to file its proposed Reliability Standard with the UARB upon the NERC registered ballot body and NERC Board of Trustees having approved a reliability standard. In the United States, there is an additional step before a NERC Reliability Standard becomes effective. That is the requirement of FERC approval.
>
> NSPI proposes that the UARB not take any action on approving, or remanding, a reliability standard until such time as it is determined that FERC has approved the standard. The United States Federal Energy Regulatory Commission (FERC) does not have jurisdiction in Nova Scotia and the UARB may determine it appropriate to remand a standard that the FERC has approved or approve a standard that the FERC has remanded. However, if the UARB approves a standard that the FERC has not yet approved, or a standard that the FERC ultimately remands, NSPI will face conflicting compliance requirements by virtue of the different requirements arising from the UARB having approved a standard that is not in place within the FERC's jurisdiction. There could also be a duplication of process whereby it might be necessary to re-consider the Nova Scotia approval after a remand by the FERC.
>
> NSPI notes that while NERC did file the NERC Board of Trustees-approved but FERC approval-pending Standards with the UARB (Exhibit H), it has not sought UARB approval of those Standards as of yet. This approach is consistent with NSPI's recommendation for approval of standards on a go-forward basis.
>
> NSPI suggests that on an application for approval of future standards, the UARB stay any process for approval of such new Reliability Standards until such time as the FERC has approved or remanded such standard in the United States, so that the UARB can be better informed about the effect on NSPI and its customers.
>
> NSPI also suggests that the process for approval of new criteria or standards be an annual process which would avoid the potential for having numerous applications before the UARB in a given year. Reliability Standards or Criteria changes could be accumulated over a year and filed in a single efficient process annually.
>
> [Exhibit N-13, pp. 3-4]

[28] In its response to Board IR-1, NERC recommended a quarterly review process:

> With respect to the process by which the NSUARB evaluates the Reliability Standards, NERC recommends that the NSUARB initiate a quarterly standards review process following the provision of each Reliability Standards filing by NERC. While NERC understands the desire to coordinate the standards review process, an annual review process would prove inadequate as NERC requires a common set of Reliability Standards to enforce promptly. The regular and responsive review of Reliability

> Standards provides for reasonable notice and opportunity for public comment, due process, openness, and balance of interests while preserving reliability and avoiding undue discrimination. Therefore, NERC does not concur with NSPI's recommendation that the process for approval of new criteria or standards occur on an annual basis.
>
> [Exhibit N-15, p. 1]

[29] In its final submission, NSPI agreed that the quarterly review process was appropriate.

[30] The Board, in considering future amendments and new Standards and Criteria, will follow the same process as used for the filings which are the subject of this Decision on a quarterly basis. Such future applications will not be processed by the Board until the Federal Energy Regulatory Commission ("FERC") has approved or remanded the standards in the United States.

3. VRFs and VSLs

[31] In its application, NERC also requested Board approval of the VRFs and VSLs. In its December 17, 2010 letter to the Board, NSPI disagreed that Board approval of VRFs and VSLs was necessary:

> NERC has also requested that the UARB approve Violation Risk Factors (VRFs) and Violations Security Levels (VSLs). It is not clear to NSPI what would be gained from UARB approval of VRFs and VSLs in Nova Scotia. NSPI understands that these documents intend to assess the impact to reliability of violating a specific request, and define the degree to which compliance with a requirement is not achieved, the purpose of which is to assist the UARB in understanding any recommendation which may be made by NERC or NPCC to the UARB during a potential enforcement proceeding in the event of a violation.
>
> NSPI has no objection to NERC filing these types of documents with the UARB, nor to the UARB receiving these documents from NERC. Given that the UARB has the discretion to make its own findings with respect to assessments of impact of a violation or the degree to which compliance is or is not achieved, it does not appear, that a formal UARB approval of VRFs and VSLs is necessary. NSPI recommend that the UARB not approve the VRFs and VSLs.
>
> [Exhibit N-13, p 8]

[32] NERC, in its final submission, argued that:

> ... VRFs and VSLs provide important signals as to the seriousness and severity of the violations of the standards. The determination of violations and any associated sanctions will be made by NSUARB following its appropriate processes.
>
> [NERC Final Submission, p. 2]

[33] Upon reviewing the VRFs and VSLs filed by NERC, the Board recognizes that they provide guidance in the determination of potential consequences arising from non-compliance with the Standards and Criteria. The Board accepts the VRFs and VSLs as guidance in the event the Board is required to review matters of compliance in future; however, the Board agrees with NSPI that formal approval of the VRFs and VSLs is not required at this time.

4. Compliance Monitoring and Enforcement

[34] The May 9, 2010 MOU provides the following:

> NSPI, as a Registered Entity, will be subject to NERC's Compliance Monitoring and Enforcement Program ("CMEP") as implemented by NPCC. NPCC in its determination of a NSPI violation may identify the specific NERC Reliability Standard violated as well as the associated violation risk factor and violation severity level of the non-compliance. As applicable, NPCC will review for acceptability from a reliability perspective any NSPI mitigation plans to bring NSPI into compliance and may propose a non-monetary penalty, to the Nova Scotia Utility and Review Board. NSPI can also make a submission to the Board on the situation.
>
> The parties understand that the Board will receive this information for use in enforcement proceedings, which proceedings will be conducted under the Board's direction and control and the Board will determine whether any violation has occurred and, if so, what remedial measures or non-monetary penalties should be imposed.
>
> [Exhibit N-11, p. 4]

[35] The Board understands that the intent is that the Board be ultimately responsible to ensure that NSPI is in compliance with the Standards and Criteria. However, the parties should understand that the Board's authority does not extend to

the imposition of penalties on NSPI. Should NPCC choose to bring a matter of non-compliance before the Board, the Board will make a determination at that time as to how it would proceed. If the Board decides that a review is warranted, and finds that non-compliance exists, the Board would issue direction to NSPI for its mitigation.

IV SUMMARY OF FINDINGS AND DIRECTIVES

[36] The Criteria filed by the NPCC are approved.

[37] The Standards and associated Glossary of Terms filed by NERC are approved.

[38] The Standards and the Criteria are mandatory and enforceable for users, owners and operators of the bulk power system in Nova Scotia.

[39] The Board accepts the VRFs and VSLs for guidance only in the event the Board is required to review matters of compliance in future.

[40] An Order will issue accordingly.

DATED at Halifax, Nova Scotia, this 20th day of July, 2011.

Peter W. Gurnham

Kulvinder S. Dhillon

Murray E. Doehler

Nova Scotia Utility and Review Board

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July 20, 2011

By email: davis.smith@nerc.net

North American Electric Reliability Corporation
c/o Davis Smith, LL.B.
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By email: eschwerdt@npcc.org

Northeast Power Coordinating Council, Inc.
c/o Edward A. Schwerdt
President and CEO
1040 Avenue of the Americas, 10th Floor
New York, NY 10018

Dear Ms. Smith and Mr. Schwerdt:

North American Electric Reliability Corporation – Reliability Standards; and Northeast Power Coordinating Council, Inc. – Regional Reliability Criteria – NERC-R-10 / Matter No. M03324

Attached are copies of an Order and Decision of the Board dated the 20th day of July, 2011, in the matter of the above-noted applications.

Yours very truly,

Nancy McNeil
Regulatory Affairs Officer/Clerk

c.c.	S. Bruce Outhouse, Q.C., Board Counsel	By email
	Margaret Mayora, NPCC	By email
	Nicole Godbout, Regulatory Counsel, NSPI	By email
	Eric Ferguson, Director, Regulatory Affairs	By email
	John Reynolds, Quetta	By email

May 9, 2010

MEMORANDUM OF UNDERSTANDING

BETWEEN

NOVA SCOTIA POWER INCORPORATED

AND

THE NORTHEAST POWER COORDINATING COUNCIL Inc

AND

THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

This Memorandum of Understanding ("MOU") between Nova Scotia Power Incorporated ("NSPI"), the Northeast Power Coordinating Council Inc. ("NPCC") and the North American Electric Reliability Corporation ("NERC"), supports the December 22, 2006 Memorandum of Understanding between the Nova Scotia Utility and Review Board ("NSUARB," "Board") and NERC. This MOU sets forth mutual understandings of the signatories in relation to the approval and implementation of mandatory NERC Reliability Standards and NPCC Regional Reliability Criteria in Nova Scotia and other related matters.

Nothing in this MOU limits the responsibility or authority of any signatory in carrying out its respective mandate.

1. General Matters

Interpretation

References in this MOU to NERC Reliability Standards include the following:

- reliability standards that are developed and adopted by NERC and approved by industry, as well as amendments to or revisions of NERC reliability standards; and

- regional reliability standards that are developed by NPCC, approved by members and adopted by NERC, as well as amendments to or revisions of such reliability standards.

References in this MOU to NPCC Regional Reliability Criteria include any Reliability Criteria or Reliability Directories that are developed and adopted by NPCC and approved by NPCC Full Members, which Reliability Criteria or Reliability Directories are not subject to review, adoption or approval by NERC, as well as amendments to or revisions of such Reliability Criteria or Reliability Directories.

The Signatories

NSPI is a public utility in Nova Scotia, pursuant to the Nova Scotia *Public Utilities Act*, R.S.N.S. 1989, c. 380, Public Utilities Act. NSPI is a member of the NERC registered ballot body and a Full Member of NPCC.

NERC is a self regulating not for profit corporation responsible for ensuring the reliability of the bulk power system in North America. In the United States, the Federal Energy Regulatory Commission ("FERC") delegates to NERC the authority to create and enforce compliance with reliability standards. On December 22, 2006, NERC signed a Memorandum of Understanding ("December 22, 2006 MOU")

with the NSUARB to agree, among other things, to commence a process for approval and implementation of NERC standards in Nova Scotia. A copy of the December 22, 2006 MOU is attached as Schedule 1.

NPCC is one of eight Regional Entities responsible for promoting and enhancing the reliability and efficient operation of the international, interconnected bulk power system in Northeastern North America. NPCC is delegated authority from NERC in the United States to enforce NERC Reliability Standards. In addition, consistent with the *Amended and Restated By-laws of Northeast Power Coordinating Council, Inc.*, NPCC has authority to enforce NPCC Regional Reliability Criteria. In Canada, NPCC has signed Memoranda of Understanding with applicable Canadian Provincial regulatory and/or governmental authorities to support the approval and application of mandatory Standards and Criteria in Canadian jurisdictions.

2. *Development and Application of NERC Reliability Standards and NPCC Regional Reliability Criteria*

In accordance with NSPI's designation as a Registered Entity, NSPI agrees to comply with NERC Reliability Standards and NPCC Regional Reliability Criteria.

Upon approval by the NSUARB, the NERC Reliability Standards and NPCC Regional Reliability Criteria will become mandatory in Nova Scotia.

NERC will prepare a consolidated filing for NSUARB approval which includes all approved NERC Reliability Standards. Concurrently, NPCC will prepare a consolidated filing for NSUARB approval which includes all NPCC Regional Reliability Criteria.

Responsibilities and Timeline

NERC and NPCC shall endeavour to file the NERC Reliability Standards and NPCC Regional Reliability Criteria, for approval, with the Board by no later than the end of Q2 2010. In this and subsequent filings, NERC and NPCC will advise the Board of the status of the Standards and Criteria at FERC and in other Canadian jurisdictions.

It is anticipated by the signatories that, as a first step, the NSUARB will direct NSPI to review and provide comment on the filings. In response NSPI will provide the Board with a recommendation that the NSUARB:

- Approve the NERC Reliability Standards or NPCC Regional Reliability Criteria as mandatory;
- Request additional information;
- Remand;
- Adopt the NSUARB's own reliability standard on the issue;
- Dismiss as not relevant to Nova Scotia; or
- Other action as NSPI considers appropriate.

As necessary NSPI will consult with NERC and NPCC in the development of its recommendation and will seek to develop consensus with NPCC in the development of its filing to the NSUARB.

NSPI will endeavor to file its recommendation by the end of 2010. NSPI will, in consultation with NERC and NPCC, propose a timeline for the NSUARB approval of the Standards and Criteria.

Stakeholder Participation

The signatories anticipate that the NSUARB will require notification to stakeholders of the NERC application and the NPCC application and will provide opportunity for review and comment on the applications by stakeholders. It is understood that the NSUARB has authority in its discretion to order stakeholder discovery on the applications and an oral hearing if it determines it to be appropriate.

The signatories acknowledge that if the NSUARB directs a formal discovery process and/or oral hearing, they will have responsibilities to respond to Information Requests posed by the NSUARB and/or stakeholders and a responsibility for appropriate representative(s) of their respective organizations to testify as witnesses if the NSUARB determines it appropriate to order an oral hearing. The signatories acknowledge that this process will require their compliance with NSUARB process timelines.

The signatories anticipate generally that their responsibilities to respond to the NSUARB and/or stakeholders would fall into the following general topics and assignments:

NERC – technical appropriateness of NERC Reliability Standards from a reliability standpoint;

NPCC – technical appropriateness of NPCC Regional Reliability Criteria from a reliability standpoint;

NSPI – Nova Scotia context, cost considerations.

Notification and Approval of Amendments and/or Additions to NERC Reliability Standards and NPCC Regional Reliability Criteria

The signatories anticipate that there will be ongoing amendments and/or additions made to the NERC Reliability Standards and NPCC Regional Reliability Criteria by NERC and NPCC, respectively. These amendments and/or additions will require approval by the NSUARB before they will become mandatory in Nova Scotia.

The signatories will utilize a regular notification process that identifies to the NSUARB proposed amendments and/or additions to be made by NERC and NPCC to Reliability Standards and Regional Reliability Criteria, respectively.

NERC shall concurrently notify NSPI and the NSUARB of Reliability Standards adopted by NERC. NPCC shall concurrently notify the NSPI and the NSUARB of Regional Reliability Criteria adopted by NPCC.

Periodically, NERC and NPCC shall file all proposed amendments and/or additions to the Reliability Standards adopted by NERC and the Regional Reliability Criteria adopted by NPCC with the NSUARB for approval.

As is contemplated with the initial filing, NSPI will provide the NSUARB with a recommendation with respect to the Reliability Standards and NPCC Regional Reliability Criteria being proposed.

3. *Compliance Aspects*

Compliance Accountability in Nova Scotia

NSPI, as a Registered Entity, will be subject to NERC's Compliance Monitoring and Enforcement Program ("CMEP") as implemented by NPCC. NPCC in its determination of a NSPI violation may identify the specific NERC Reliability Standard violated as well as the associated violation risk factor and violation severity level of the non-compliance. As applicable, NPCC will review for acceptability from a reliability perspective any NSPI mitigation plans to bring NSPI into compliance and may propose a non-monetary penalty, to the Nova Scotia Utility and Review Board. NSPI can also make a submission to the Board on the situation.

The parties understand that the Board will receive this information for use in enforcement proceedings, which proceedings will be conducted under the Board's direction and control and the Board will determine whether any violation has occurred and, if so, what remedial measures or non-monetary penalties should be imposed.

Investigations

NERC and NPCC, in exercising their respective authority regarding compliance, may investigate alleged violations in Nova Scotia of Reliability Standards or NPCC Regional Reliability Criteria, as appropriate.

In order to promote effective and efficient enforcement of the NERC Reliability Standards and the NPCC Regional Reliability Criteria, NERC and NPCC will collaborate on, and coordinate their investigations while preserving their independent determination of the outcome of an investigation. The cooperation among NERC and NPCC, where applicable, will include the sharing of alleged violations and subsequent investigative information, the confidentiality of which will be protected according to NERC's and NPCC's existing policies and procedures.

Reporting Requirements

NSPI will provide NPCC all information respecting reporting requirements contained in the CMEP for both NERC Reliability Standards and NPCC Regional Reliability Criteria. NSPI will be responsible for providing information to NPCC regarding its Regional Reliability Criteria, including all information respecting routine reporting, investigations, and event based disturbance reporting.

NERC Compliance Audits

NSPI will be subject to compliance audits performed by NPCC related to NERC Reliability Standards and NPCC Regional Reliability Criteria.

NPCC Regional Reliability Criteria Compliance Audit

NSPI will be subject to NPCC Regional Reliability Criteria compliance audits.

4. *Amendment and Termination of this MOU*

This MOU will continue until replaced or amended by the signatories, or terminated on 30 days notice given by any signatory to the others.

5. *Points of Contact*

For all purposes related to this MOU, the points of contact shall be as follows:

For NERC:

David Cook
Vice President & General Counsel
North American Electric Reliability Corporation
116-390 Village Blvd.
Princeton, New Jersey 08540
(609) 4522-8060
david.cook@nerc.net

For NPCC:

Edward A. Schwerdt
President & CEO
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10th Floor
New York, NY 10018
(212) 840-1070
eschwerdt@npcc.org

For NSPI:

Eric Ferguson
Director Regulatory Affairs (Acting)
Nova Scotia Power Incorporated
1894 Barrington St., P.O. Box 910
Halifax, Nova Scotia B3J 2W5
(902) 428-6078
eric.ferguson@nspower.ca

These points of contact may be changed at any time by notification to the other signatories.

7. ***Signatures***

Signed this 11th day of May, 2010:

North American Electric Reliability Corporation Name President & CEO Title	Northeast Power Coordinating Council, Inc. Name President & CEO Title
Nova Scotia Power Incorporated Name Executive Vice-President & Chief Operating Officer Title	

NOVA SCOTIA POWER
An Emera Company

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DEC 17 2010
Nova Scotia
Utility and Review Board

December 17, 2010

Nancy McNeil
Regulatory Affairs Officer/Clerk
Nova Scotia Utility and Review Board
1601 Lower Water Street, 3rd Floor
PO Box 1692, Unit "M"
Halifax, NS B3J 3S3

Re: North American Electric Reliability Corporation – Reliability Standards; and Northeast Power Coordinating Council, Inc. – Regional Reliability Criteria – NERC-R-10/Matter No. M03324

Dear Ms. McNeil:

On June 29, 2010, the Northeast Power Coordinating Council (NPCC) filed its Regional Reliability Criteria for approval by the Nova Scotia Utility Review Board (UARB). Specifically, NPCC requests UARB approval of 14 Reliability Criteria as contained in Exhibits A, B, and C of its application.

On June 30, 2010, the North American Electric Reliability Corporation (NERC) filed its Reliability Standards for approval by the UARB. NERC requested that the UARB approve all FERC approved Reliability Standards, including Reliability Standards that are currently mandatory and enforceable in the United States as well as those Reliability Standards which are approved by FERC but which are not expected to take effect until January, 2011. In addition, NERC requested that the UARB approve associated Violation Risk Factors (VRFs) and Violation Security Levels (VSLs) as set out in Exhibits F and G. VRFs assess the impact to reliability of violating a specific requirement. VSLs define the degree to which compliance with a requirement is not achieved.

On July 21, 2010, NERC made a supplemental filing with the UARB clarifying that it requests UARB approval of Exhibits C, E, F and G of its June 30, 2010 application. NSPI understands that Exhibits A, B, D, and H are provided as supporting information purposes but that NERC is not specifically seeking approval of these documents.

On July 29, 2010, the UARB issued a Notice of Filing and requested that interested parties file a notice of intervention by August 25, 2010. Nova Scotia Power Inc. (NSPI) has filed a Notice of Intervention.

NERC's and NPCC's filings request that the UARB make the Reliability Standards and the Regional Reliability Criteria mandatory and enforceable for users, owners and

operators of the bulk power system in Nova Scotia. NSPI has intervened as a user, and as the operator and owner of Nova Scotia's bulk power system.

At the Board's request, NSPI filed a timeline which was agreed to by NERC and NPCC for this proceeding. The UARB has accepted that timeline. The first deliverable is for NSPI to file its recommendations with respect to NERC's and NPCC's filings. NSPI is pleased to now provide in this correspondence its recommendations.

Background

This matter has arisen as a result of the UARB having signed a Memorandum of Understanding with NERC dated December 22, 2006 wherein the UARB and NERC committed to a process for making NERC Reliability Standards mandatory, and assuring enforcement of those standards. Please refer to Attachment 1 for a copy of the MOU between the UARB and NERC.

NSPI, NERC and NPCC entered into an implementation Memorandum of Understanding effective May 11, 2010. Please refer to Attachment 2 for a copy of the MOU between NSPI, NERC and NPCC.

The approval of the Reliability Standards and Regional Reliability Criteria will not change NSPI's operating practices as NSPI already manages to compliance on all appropriate standards and criteria. NSPI has already been subject to three audits by NPCC of NERC Reliability Standards; one in 2006 (11 standards), one in 2007 (16 standards) and the third which was just completed in 2010, of 127 Reliability Standards.

NSPI's bulk power system consists of the 345 kV transmission system interconnecting Lakeside – Onslow – Hopewell – Woodbine and Memramcook, New Brunswick; the 230 kV transmission system interconnecting Brushy Hill – Onslow – Lingan and Point Aconi; and some selected 138 kV lines that have been identified as part of the bulk power system.

Please see Attachment 3 for a diagram of NSPI's Bulk Power System.

Process for Approval of Standards in the Future

NSPI's comments in this recommendation are specific to the Reliability Criteria and Reliability Standards filed by NPCC and NERC on June 29, 2010 and June 30, 2010. From time to time, amendments or new Reliability Criteria are approved by NPCC and amendments or new Reliability Standards are approved by FERC. The implementation MOU between NSPI, NPCC and NERC recognizes that NPCC and NERC will bring these new Criteria and Standards before the UARB for approval from time to time. The MOU further recognizes that, as with this initial filing, the process for approval will

involve NSPI providing its recommendation with respect to such amendments or new Reliability Criteria or Reliability Standards.

The MOU between NERC and the UARB also recognizes this issue and states:

> Development of Reliability Standards
>
> NERC and the Board acknowledge the importance of the active participation of electricity sector participants from the Province in NERC's standards development process.
>
> NERC commits to notify the Board of the major milestones in the development of each reliability standard.
>
> Once the NERC registered ballot body and NERC board of trustees have approved a reliability standard, NERC will file the proposed reliability standard with the Board, accompanied by a request that the Board adopt the reliability standard. NERC will file its proposed reliability standards contemporaneously in all relevant jurisdictions. NERC will notify the Board of the actions of other jurisdictions regarding the proposed reliability standards. NERC will immediately notify the Board if any jurisdiction remands a proposed reliability standard and will work with stakeholders and all relevant jurisdictions to resolve the issues raised.
>
> Upon receiving a request from NERC to adopt a reliability standard or standards, the Board may, following its own process which may include a public hearing, adopt some or all of the standards. The Board may remand to NERC one or more reliability standards that it does not approve with a request that NERC address the issues of concern to the Board. The parties recognize that the Board may separately adopt such reliability standard or standards as it deems necessary in the public interest.

NSPI recommends that the UARB implement this process for approval of future NPCC Reliability Criteria and NERC Reliability Standards, as contemplated by the UARB and NERC in their MOU, with one suggested change. The process contemplated by NERC and the UARB requires NERC to file its proposed Reliability Standard with the UARB upon the NERC registered ballot body and NERC Board of Trustees having approved a reliability standard. In the United States, there is an additional step before a NERC Reliability Standard becomes effective. That is the requirement of FERC approval.

NSPI proposes that the UARB not take any action on approving, or remanding, a reliability standard until such time as it is determined that FERC has approved the standard. The United States Federal Energy Regulatory Commission (FERC) does not

have jurisdiction in Nova Scotia and the UARB may determine it appropriate to remand a standard that the FERC has approved or approve a standard that the FERC has remanded. However, if the UARB approves a standard that the FERC has not yet approved, or a standard that the FERC ultimately remands, NSPI will face conflicting compliance requirements by virtue of the different requirements arising from the UARB having approved a standard that is not in place within the FERC's jurisdiction. There could also be a duplication of process whereby it might be necessary to re-consider the Nova Scotia approval after a remand by the FERC.

NSPI notes that while NERC did file the NERC Board of Trustees-approved but FERC approval-pending Standards with the UARB (Exhibit H), it has not sought UARB approval of those Standards as of yet. This approach is consistent with NSPI's recommendation for approval of standards on a go-forward basis.

NSPI suggests that on an application for approval of future standards, the UARB stay any process for approval of such new Reliability Standards until such time as the FERC has approved or remanded such standard in the United States, so that the UARB can be better informed about the effect on NSPI and its customers.

NSPI also suggests that the process for approval of new criteria or standards be an annual process which would avoid the potential for having numerous applications before the UARB in a given year. Reliability Standards or Criteria changes could be accumulated over a year and filed in a single efficient process annually.

2010 Audit

NPCC performed a compliance audit on NSPI in two stages in 2010. The first stage was completed from August 9 to the 13, 2010 and was an audit of 43 Reliability Standards and 349 of their requirements/sub-requirements. Based on the information and documentation provided by NSPI, the audit team found NSPI to be compliant with 42 standards and 302 applicable requirements. The audit team determined that 1 standard and 47 various requirements/sub-requirements were not applicable to NSPI. The audit team identified no Possible Violations.

The second stage of the audit was completed October 5 to the 8, 2010 and was an audit of eight Critical Infrastructure Protection (CIP) standards and their 43 requirements/sub-requirements. Based on the information and documentation provided by NSPI, the audit team found NSPI to be compliant with eight CIP standards and their 42 requirements/sub-requirements. A possible violation was identified within CIP-004 R4 due to not revoking the access within the seven day requirement of one employee who had passed away within the audit period.

NPCC has not published the final audit report as of the time of writing.

Regulatory Implications in Nova Scotia

As part of the interconnected North American bulk power system, NSPI is currently required to comply with NERC Reliability Standards and NPCC Reliability Criteria. NSPI has brought forward capital work order applications in the past where compliance with NERC is a justification for the project.

The 2010 ACE Plan included two items that were justified on the basis of NERC or NPCC compliance.

1. CI 38266 - 2010 Protection Upgrades

   In 2008, NPCC approved new criteria (Criteria Document A-10) for determining whether a substation bus is categorized as bulk power. The criterion is used to identify substation busses that, if a fault was not successfully cleared by protection, the situation could result in disturbances outside the local operating area. Stations identified through this criterion are required to have fully redundant protection, control and communication schemes. The 79N- Hopewell substation busses met the criteria for a bulk power element and did not have fully redundant protection, control, and communication schemes in place.

2. CI 38182 - 2010 Backup Control Centre

   NERC requires all Transmission Operators and Balancing Authorities have a back-up control strategy in place by Q1 of 2012.

   NSPI's requirement for a Back-up Control Centre (BCC) originated from a business need to provide constant monitoring of the bulk power system and the emerging NERC standard (EOP-008-1). This standard requires a back-up plan that "includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all reliability standards". NSPI's single point of failure (no redundancy) would have been at the Ragged Lake Control Centre (RAL). All communications and control for the bulk power system is through RAL. An industrial or natural disaster could limit or curtail NSPI in such a way where the only visibility on the grid would be individuals stationed at major sub-stations and plants. In 2010, NSPI had a simple BCC in the Scotia Square basement, dependent on the infrastructure at RAL. The NERC requirements state that "backup capabilities should not depend on the primary control center for any functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality".

With the NERC EOP-008 standard there is a requirement that a back-up plan be in place by Q1 of 2012.

Two items are expected to be brought forward in 2011 which are justified on the basis of NERC or NPCC compliance. In particular:

1. CI 40231 – 2011 Protections Upgrades at Lakeside

   In 2008, NPCC approved new criteria (Criteria Document A-10) for determining whether a substation bus is categorized as bulk power. The criterion is used to identify substation busses that, if a fault was not successfully cleared by protection, the situation could result in disturbances outside the local operating area. Stations identified through this criterion are required to have fully redundant protection, control and communication schemes. The 103H-Lakeside substation bus has met the criteria for a bulk power element and currently does not have fully redundant protection, control, and communication schemes in place.

2. CI 40233 – 2011 Protections Upgrades at Tufts Cove

   In 2008, NPCC approved new criteria (Criteria Document A-10) for determining whether a substation bus is categorized as bulk power. The criteria is used to identify substation busses that, if a fault was not successfully cleared by protection, the situation could result in disturbances outside the local operating area. Stations identified through this criterion are required to have fully redundant protection, control and communication schemes. The A-10 Criteria requires the 91H-Tufts Cove substation bus to be upgraded to satisfy the A-10 Criteria.

Assuming the UARB approves the NERC Reliability Standards and the NPCC Reliability Criteria, NSPI does not expect the process for capital projects justification to proceed differently than it does today. While the UARB may approve the Standards and Criteria as requested by NERC and NPCC as part of this proceeding, such approval would not constitute approval of any capital expenditures on the part of NSPI. Any capital expenditures necessary for compliance with the Standards or Criteria would require NSPI to follow ACE guidelines and process and put forward a capital work order application at the appropriate time, and would be subject to the regulatory rigor of UARB review.

Emerging Issues

There are two issues which are currently under consideration in North America which could have a material effect on reliability regulation in Nova Scotia; 1) the Bulk-Electric System definition and the 2) the ongoing expansion of CIP standards. NSPI's comments on each of these are offered for the UARB's consideration. No action is requested of the UARB at this time.

Bulk Electric System Definition

Within the NPCC, the definition of Bulk Electric System (BES) has been focused on system elements which could potentially affect system reliability in other jurisdictions. For Nova Scotia, this has been generally accepted to be the 345 kV and 230 kV system.

The FERC is proposing to standardize the definition of BES across North America by adoption of a 100 kV "bright-line" standard. As provided in its Final Rule, dated November 18, 2010, FERC advises that NERC should

> maintain a bright-line threshold that includes all facilities operated at or above 100 kV except defined radial facilities, and establish an exemption process and criteria for excluding facilities that are not necessary for operating the interconnected transmission network.

Canadian members of the NPCC, including NSPI, oppose this change on the basis that it could lead to significant cost increases without providing material improvements to system reliability. If the bright-line approach is ultimately adopted by NERC, the Company may need to propose an alternative approach in Nova Scotia.

CIP Standard Expansion

Due in large part to concern with potential criminal attacks on the North American bulk power system, a major focus of reliability standard changes has been a shift towards increasingly stringent CIP Standards. These changes have the potential to increase the cost of service for NSPI.

For instance, CIP-002 defines the methodology for the identification of critical cyber assets to which the requirements of CIP-003 to CIP-009 standards apply. Proposed changes to CIP-002 could bring additional assets into scope for the application of CIP-003 to CIP-009 requirements, potentially driving costs for additional physical security, electronic security, and associated procedures and processes. A more stringent CIP-002 standard could not only identify more critical cyber assets but also more sites with critical cyber assets where cyber security measures would need to be implemented.

NSPI will continue to monitor these developments and where concerns are identified, alternatives to NERC and/or NPCC adopted measures may need to be considered.

Recommendation

NSPI recommends that the UARB approve the NERC Reliability Standards as requested in its application of June 30, 2010 and the NPCC Reliability Criteria as requested in its application of June 29, 2010.

NERC has also requested that the UARB approve Violation Risk Factors (VRFs) and Violations Security Levels (VSLs). It is not clear to NSPI what would be gained from UARB approval of VRFs and VSLs in Nova Scotia. NSPI understands that these documents intend to assess the impact to reliability of violating a specific request, and define the degree to which compliance with a requirement is not achieved, the purpose of which is to assist the UARB in understanding any recommendation which may be made by NERC or NPCC to the UARB during a potential enforcement proceeding in the event of a violation.

NSPI has no objection to NERC filing these types of documents with the UARB, nor to the UARB receiving these documents from NERC. Given that the UARB has the discretion to make its own findings with respect to assessments of impact of a violation or the degree to which compliance is or is not achieved, it does not appear, that a formal UARB approval of VRFs and VSLs is necessary. NSPI recommend that the UARB not approve the VRFs and VSLs.

Yours most respectfully,

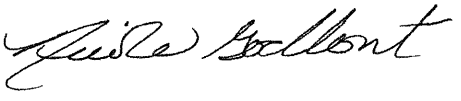

Nicole Godbout
Regulatory Counsel

c: S. Bruce Outhouse, Q.C.
Davis Smith, NERC
Margaret Mayora, NPCC
David Cook, NERC
Registered Intervenors
J. René Gallant
Eric Ferguson
Sara Tingley

COPY

Memorandum of Understanding between Nova Scotia Utility and Review Board and North American Electric Reliability Corporation

General Provisions

This Memorandum of Understanding (MOU) between the Nova Scotia Utility and Review Board (Board) and the North American Electric Reliability Corporation (NERC) reflects the desire for a continuing and cooperative relationship in improving the reliability of the North American bulk power system and in the exchange of experience, information, and data related to that system.

The Board exercises general supervision over all electric utilities operating as public utilities within the Province, pursuant to the Nova Scotia Public Utilities Act. NERC is an organization, sponsored by all sectors of the electric utility industry, whose mission is to ensure that the bulk electric system in North America is reliable, adequate and secure. NERC develops reliability standards, monitors compliance with those standards, and periodically assesses the reliability of the bulk power system in North America. .

Through this MOU, NERC recognizes the Board's regulatory authority over electric utilities operating in Nova Scotia, and the Board recognizes the role that NERC has with respect to the North American bulk power system.

This MOU sets forth the mutual expectations that the Board and NERC have with respect to making reliability standards developed by NERC mandatory within the Province, assuring enforcement of those standards, and providing for payment of a fair allocation of NERC's reasonable costs for carrying out its mission. This MOU is not intended to be an enforceable agreement or contract by or against either party, notwithstanding the occasional use of the term "agree" or the use of mandatory language such as "shall" or "will" in either the MOU or its appendices.

This MOU recognizes that the Board is a statutory body with specific legislative powers and authorities which cannot be delegated, and that those powers and authorities are subject to limitations and constraints, including limitations and constraints that flow from the Board's status as a quasi-judicial tribunal.

Development of an Electric Reliability Organization

The parties understand that NERC has been certified by the U.S. Federal Energy Regulatory Commission as the "electric reliability organization" (ERO) under U.S. legislation. NERC agrees to consult with the Board on a regular basis, including with respect to amendments to its bylaws, so that the organization takes

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appropriate account of Canadian and provincial issues, reflecting the international nature of the North American bulk electric system.

Development of Reliability Standards

NERC and the Board acknowledge the importance of the active participation of electricity sector participants from the Province in NERC's standards development process.

NERC commits to notify the Board of the major milestones in the development of each reliability standard.

Once the NERC registered ballot body and NERC board of trustees have approved a reliability standard, NERC will file the proposed reliability standard with the Board, accompanied by a request that the Board adopt the reliability standard. NERC will file its proposed reliability standards contemporaneously in all relevant jurisdictions. NERC will notify the Board of the actions of other jurisdictions regarding the proposed reliability standards. NERC will immediately notify the Board if any jurisdiction remands a proposed reliability standard and will work with stakeholders and all relevant jurisdictions to resolve the issues raised.

Upon receiving a request from NERC to adopt a reliability standard or standards, the Board may, following its own process which may include a public hearing, adopt some or all of the standards. The Board may remand to NERC one or more reliability standards that it does not approve with a request that NERC address the issues of concern to the Board. The parties recognize that the Board may separately adopt such reliability standard or standards as it deems necessary in the public interest.

Compliance

The parties understand that, once the Board approves a reliability standard, compliance with the reliability standard will be mandatory in Nova Scotia. The Board may enforce approved reliability standards directly. The parties also understand that NERC, working through a designated regional entity, intends to conduct compliance activities with respect to its reliability standards. The Board agrees to receive compliance information and recommendations from NERC or the regional entity for use in enforcement proceedings, which proceedings shall be conducted under the Board's direction and control. NERC or the regional entity may recommend a particular penalty for any violation that NERC or the regional entity reports, but the Board will be responsible for determining whether any violation has occurred and, if so, what remedial measures or penalties should be imposed.

The parties will work together to establish a system for disclosure by NERC of violations and to provide for assessment and reporting by NERC of inter-region

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reliability risks to or from entities outside of Nova Scotia where coordinated action is required to address those risks.

The parties agree that NERC will provide relevant information on issues related to reliability compliance including reports on:

- Compliance audits and spot checks
- Readiness evaluations
- Disturbance reports
- Reliability assessments and benchmarking information
- Reports by regional organizations, where applicable

ERO Funding

NERC and the Board acknowledge that the costs associated with NERC and regional councils are currently included, directly or indirectly, in the rates of entities subject to the Board's jurisdiction. The parties agree on the importance of continuing a stable source of funding for NERC and associated regional entities. Therefore, the present method of funding should continue, with the opportunity for Board review of the costs as part of the rate cases of its jurisdictional entities.

NERC commits to a fair allocation of its reasonable costs to entities within the Province, based generally on relative share of net-energy-for-load. NERC will make an informational filing of its annual budget and funding requirement with the Board, contemporaneously with its filing in other jurisdictions.

Points of Contact

The points of contact shall be for NERC:

David Cook
Vice President & General Counsel
116-390 Village Blvd.
Princeton, New Jersey 08540
(609) 452-8060

and for the Board:

Regulatory Affairs Clerk/Officer
Nova Scotia Utility and Review Board
3rd Floor
1601 Lower Water Street
Halifax, Nova Scotia B3J 3P6
(902) 424-4448

These points of contact can be amended at any time by notification to the other party.

NERC agrees to include the Board contact on its email circulation list.

Amendment and Termination of This Memorandum

This MOU will continue until replaced or amended by the signatories or terminated by either signatory on 30 days notice.

Signatures

Signed this 22 day of Dec, 2006:

North American Electric Reliability Corporation	Nova Scotia Utilities and Review Board
Richard P Sergel	
Name	Name
President & CEO	CHAIR
Title	Title

Received Time Jul. 14. 2008 2:40PM No. 0092

May 9, 2010

MEMORANDUM OF UNDERSTANDING
BETWEEN
NOVA SCOTIA POWER INCORPORATED
AND
THE NORTHEAST POWER COORDINATING COUNCIL Inc
AND
THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

This Memorandum of Understanding ("MOU") between Nova Scotia Power Incorporated ("NSPI"), the Northeast Power Coordinating Council Inc. ("NPCC") and the North American Electric Reliability Corporation ("NERC"), supports the December 22, 2006 Memorandum of Understanding between the Nova Scotia Utility and Review Board ("NSUARB," "Board") and NERC. This MOU sets forth mutual understandings of the signatories in relation to the approval and implementation of mandatory NERC Reliability Standards and NPCC Regional Reliability Criteria in Nova Scotia and other related matters.

Nothing in this MOU limits the responsibility or authority of any signatory in carrying out its respective mandate.

I. General Matters

Interpretation

References in this MOU to NERC Reliability Standards include the following:

- reliability standards that are developed and adopted by NERC and approved by industry, as well as amendments to or revisions of NERC reliability standards; and

- regional reliability standards that are developed by NPCC, approved by members and adopted by NERC, as well as amendments to or revisions of such reliability standards.

References in this MOU to NPCC Regional Reliability Criteria include any Reliability Criteria or Reliability Directories that are developed and adopted by NPCC and approved by NPCC Full Members, which Reliability Criteria or Reliability Directories are not subject to review, adoption or approval by NERC, as well as amendments to or revisions of such Reliability Criteria or Reliability Directories.

The Signatories

NSPI is a public utility in Nova Scotia, pursuant to the Nova Scotia *Public Utilities Act*, R.S.N.S. 1989, c. 380, Public Utilities Act. NSPI is a member of the NERC registered ballot body and a Full Member of NPCC.

NERC is a self regulating not for profit corporation responsible for ensuring the reliability of the bulk power system in North America. In the United States, the Federal Energy Regulatory Commission ("FERC") delegates to NERC the authority to create and enforce compliance with reliability standards. On December 22, 2006, NERC signed a Memorandum of Understanding ("December 22, 2006 MOU")

with the NSUARB to agree, among other things, to commence a process for approval and implementation of NERC standards in Nova Scotia. A copy of the December 22, 2006 MOU is attached as Schedule 1.

NPCC is one of eight Regional Entities responsible for promoting and enhancing the reliability and efficient operation of the international, interconnected bulk power system in Northeastern North America. NPCC is delegated authority from NERC in the United States to enforce NERC Reliability Standards. In addition, consistent with the *Amended and Restated By-laws of Northeast Power Coordinating Council, Inc.*, NPCC has authority to enforce NPCC Regional Reliability Criteria. In Canada, NPCC has signed Memoranda of Understanding with applicable Canadian Provincial regulatory and/or governmental authorities to support the approval and application of mandatory Standards and Criteria in Canadian jurisdictions.

2. *Development and Application of NERC Reliability Standards and NPCC Regional Reliability Criteria*

In accordance with NSPI's designation as a Registered Entity, NSPI agrees to comply with NERC Reliability Standards and NPCC Regional Reliability Criteria.

Upon approval by the NSUARB, the NERC Reliability Standards and NPCC Regional Reliability Criteria will become mandatory in Nova Scotia.

NERC will prepare a consolidated filing for NSUARB approval which includes all approved NERC Reliability Standards. Concurrently, NPCC will prepare a consolidated filing for NSUARB approval which includes all NPCC Regional Reliability Criteria.

Responsibilities and Timeline

NERC and NPCC shall endeavour to file the NERC Reliability Standards and NPCC Regional Reliability Criteria, for approval, with the Board by no later than the end of Q2 2010. In this and subsequent filings, NERC and NPCC will advise the Board of the status of the Standards and Criteria at FERC and in other Canadian jurisdictions.

It is anticipated by the signatories that, as a first step, the NSUARB will direct NSPI to review and provide comment on the filings. In response NSPI will provide the Board with a recommendation that the NSUARB:

- Approve the NERC Reliability Standards or NPCC Regional Reliability Criteria as mandatory;
- Request additional information;
- Remand;
- Adopt the NSUARB's own reliability standard on the issue;
- Dismiss as not relevant to Nova Scotia; or
- Other action as NSPI considers appropriate.

As necessary NSPI will consult with NERC and NPCC in the development of its recommendation and will seek to develop consensus with NPCC in the development of its filing to the NSUARB.

NSPI will endeavor to file its recommendation by the end of 2010. NSPI will, in consultation with NERC and NPCC, propose a timeline for the NSUARB approval of the Standards and Criteria.

Stakeholder Participation

The signatories anticipate that the NSUARB will require notification to stakeholders of the NERC application and the NPCC application and will provide opportunity for review and comment on the applications by stakeholders. It is understood that the NSUARB has authority in its discretion to order stakeholder discovery on the applications and an oral hearing if it determines it to be appropriate.

The signatories acknowledge that if the NSUARB directs a formal discovery process and/or oral hearing, they will have responsibilities to respond to Information Requests posed by the NSUARB and/or stakeholders and a responsibility for appropriate representative(s) of their respective organizations to testify as witnesses if the NSUARB determines it appropriate to order an oral hearing. The signatories acknowledge that this process will require their compliance with NSUARB process timelines.

The signatories anticipate generally that their responsibilities to respond to the NSUARB and/or stakeholders would fall into the following general topics and assignments:

NERC – technical appropriateness of NERC Reliability Standards from a reliability standpoint;

NPCC – technical appropriateness of NPCC Regional Reliability Criteria from a reliability standpoint;

NSPI – Nova Scotia context, cost considerations.

Notification and Approval of Amendments and/or Additions to NERC Reliability Standards and NPCC Regional Reliability Criteria

The signatories anticipate that there will be ongoing amendments and/or additions made to the NERC Reliability Standards and NPCC Regional Reliability Criteria by NERC and NPCC, respectively. These amendments and/or additions will require approval by the NSUARB before they will become mandatory in Nova Scotia.

The signatories will utilize a regular notification process that identifies to the NSUARB proposed amendments and/or additions to be made by NERC and NPCC to Reliability Standards and Regional Reliability Criteria, respectively.

NERC shall concurrently notify NSPI and the NSUARB of Reliability Standards adopted by NERC. NPCC shall concurrently notify the NSPI and the NSUARB of Regional Reliability Criteria adopted by NPCC.

Periodically, NERC and NPCC shall file all proposed amendments and/or additions to the Reliability Standards adopted by NERC and the Regional Reliability Criteria adopted by NPCC with the NSUARB for approval.

As is contemplated with the initial filing, NSPI will provide the NSUARB with a recommendation with respect to the Reliability Standards and NPCC Regional Reliability Criteria being proposed.

May 9, 2010

3. *Compliance Aspects*

Compliance Accountability in Nova Scotia

NSPI, as a Registered Entity, will be subject to NERC's Compliance Monitoring and Enforcement Program ("CMEP") as implemented by NPCC. NPCC in its determination of a NSPI violation may identify the specific NERC Reliability Standard violated as well as the associated violation risk factor and violation severity level of the non-compliance. As applicable, NPCC will review for acceptability from a reliability perspective any NSPI mitigation plans to bring NSPI into compliance and may propose a non-monetary penalty, to the Nova Scotia Utility and Review Board. NSPI can also make a submission to the Board on the situation.

The parties understand that the Board will receive this information for use in enforcement proceedings, which proceedings will be conducted under the Board's direction and control and the Board will determine whether any violation has occurred and, if so, what remedial measures or non-monetary penalties should be imposed.

Investigations

NERC and NPCC, in exercising their respective authority regarding compliance, may investigate alleged violations in Nova Scotia of Reliability Standards or NPCC Regional Reliability Criteria, as appropriate.

In order to promote effective and efficient enforcement of the NERC Reliability Standards and the NPCC Regional Reliability Criteria, NERC and NPCC will collaborate on, and coordinate their investigations while preserving their independent determination of the outcome of an investigation. The cooperation among NERC and NPCC, where applicable, will include the sharing of alleged violations and subsequent investigative information, the confidentiality of which will be protected according to NERC's and NPCC's existing policies and procedures.

Reporting Requirements

NSPI will provide NPCC all information respecting reporting requirements contained in the CMEP for both NERC Reliability Standards and NPCC Regional Reliability Criteria. NSPI will be responsible for providing information to NPCC regarding its Regional Reliability Criteria, including all information respecting routine reporting, investigations, and event based disturbance reporting.

NERC Compliance Audits

NSPI will be subject to compliance audits performed by NPCC related to NERC Reliability Standards and NPCC Regional Reliability Criteria.

NPCC Regional Reliability Criteria Compliance Audit

NSPI will be subject to NPCC Regional Reliability Criteria compliance audits.

May 9, 2010

4. *Amendment and Termination of this MOU*

This MOU will continue until replaced or amended by the signatories, or terminated on 30 days notice given by any signatory to the others.

5. *Points of Contact*

For all purposes related to this MOU, the points of contact shall be as follows:

For NERC:

David Cook
Vice President & General Counsel
North American Electric Reliability Corporation
116-390 Village Blvd.
Princeton, New Jersey 08540
(609) 4522-8060
david.cook@nerc.net

For NPCC:

Edward A. Schwerdt
President & CEO
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10th Floor
New York, NY 10018
(212) 840-1070
eschwerdt@npcc.org

For NSPI:

Eric Ferguson
Director Regulatory Affairs (Acting)
Nova Scotia Power Incorporated
1894 Barrington St., P.O. Box 910
Halifax, Nova Scotia B3J 2W5
(902) 428-6078
eric.ferguson@nspower.ca

These points of contact may be changed at any time by notification to the other signatories.

May 9, 2010

7. ***Signatures***

Signed this 11th day of May, 2010:

North American Electric Reliability Corporation Name President & CEO Title	Northeast Power Coordinating Council, Inc. Name President & CEO Title
Nova Scotia Power Incorporated Name Executive Vice-President & Chief Operating Officer Title	

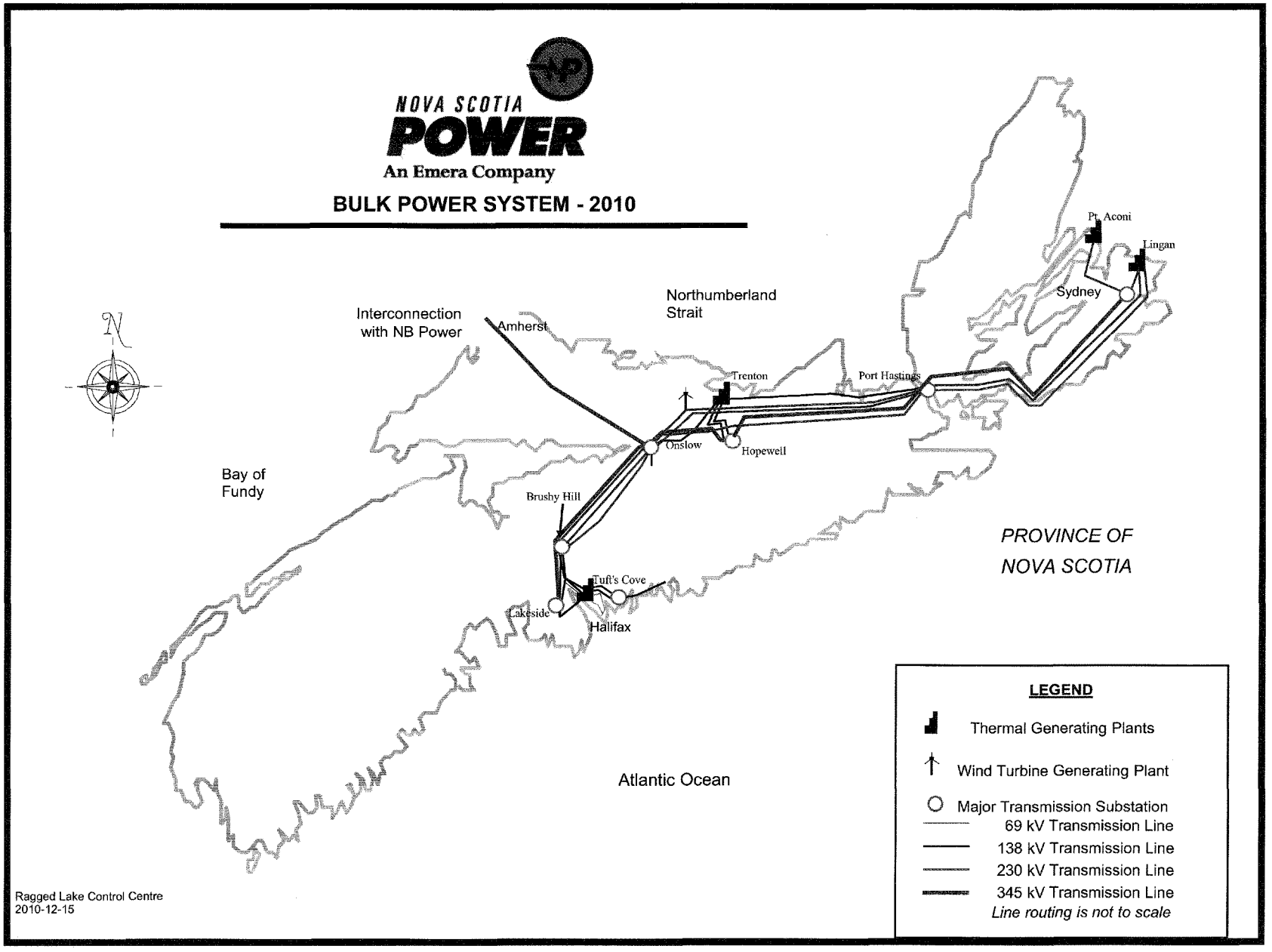
NOVA SCOTIA
POWER
An Emera Company
BULK POWER SYSTEM - 2010
N
Interconnection
with NB Power
Amherst
Northumberland
Strait
Trenton
Port Hastings
Pt. Aconi
Lingan
Sydney
Onslow
Hopewell
Bay of
Fundy
Brushy Hill
Tuft's Cove
Lakeside
Halifax
PROVINCE OF
NOVA SCOTIA
Atlantic Ocean
LEGEND
Thermal Generating Plants
Wind Turbine Generating Plant
Major Transmission Substation
69 kV Transmission Line
138 kV Transmission Line
230 kV Transmission Line
345 kV Transmission Line
Line routing is not to scale
Ragged Lake Control Centre
2010-12-15

NOVA SCOTIA POWER
An Emera Company

October 15, 2010

Nancy McNeil
Regulatory Affairs Officer/Clerk
Nova Scotia Utility and Review Board
1601 Lower Water Street, 3rd Floor
Halifax, NS B3J 3P6

Dear Ms. McNeil:

Re: North American Electric Reliability Corporation – Reliability Standards; and Northeast Power Coordinating Council, Inc. – Regional Reliability Criteria – NERC-R-10/Matter No. M03324

The Utility and Review Board (UARB) has requested that Nova Scotia Power Inc. (NSPI) propose a timeline for the approval of the NERC Reliability Standards and NPCC Regional Reliability Criteria by October 15, 2010.

NSPI is currently undergoing a comprehensive NERC compliance audit, the first stage of which commenced in July, 2010 with the second and final stage expected to be complete later this month. At the time of signing the Memorandum of Understanding, NSPI, NERC and NPCC were cognizant of the fact that the audit would occupy significant NSPI resources and that the same staff resources who are involved in the audit will be involved in the proceeding before the UARB on the issue of the approval of the NERC Standards and NPCC Criteria. The parties agreed that it would therefore be appropriate for NSPI to file its recommendation by the end of Q4, 2010, after the full audit results were known and could be assessed.

Another benefit to waiting for the completion of the audit is that the results of the audit will be of assistance to all parties, including the UARB, in assessing the filings by NERC and NPCC. In particular, NSPI will be able to comment on its standing relative to compliance at the time it makes its recommendation to the Board.

NSPI understands that only one other intervenor, other than itself, has registered with the UARB in this matter. NSPI agrees with the Board's comments in its letter to Ms. Davis Smith of May 28, 2010 that this approval process is likely best served through a 'paper' process as opposed to an oral hearing. NSPI assumes that would involve a timeframe for IRs, Intervenor Evidence, Final Submissions, and Reply.

NSPI suggests that given there are three parties potentially answering IRs, two of which are large out of the jurisdiction organizations and new to UARB process, at least three weeks would be appropriate for answering the IRs. NSPI suggests the following approximate timeline for the Board's consideration:

NSPI Recommendation	December 16, 2010
IRs to NSPI, NERC and NPCC	January 20, 2011
Responses to IRs	February 10, 2011
Intervenor Evidence/Comment	March 3, 2011
IRs to Intervenors	March 17, 2011
Responses to IRs	April 7, 2011
Final Submissions by NSPI, NERC, NPCC	April 21, 2011
Reply	May 5, 2011
Anticipated UARB decision	by August 2011

NSPI has reviewed this proposed timeline with NERC and NPCC and the parties are in agreement.

NSPI would be pleased to discuss further, if the Board wishes.

Yours truly,

Nicole Godbout
Regulatory Counsel

cc: S. Bruce Outhouse, Q.C.
Davis Smith, NERC
Margaret Mayora, NPCC
David Cook, NERC
J. René Gallant
Eric Ferguson
Sara Tingley

July 21, 2010

VIA ELECTRONIC FILING

Ms. Nancy McNeil
Nova Scotia Utility and Review Board
3rd Floor
1601 Lower Water Street
Halifax, Nova Scotia B3J 3P6

Re: Nova Scotia Notice of Filing - Application for Approval of Reliability Standards

Dear Ms. McNeil:

On June 30, 2010, the North American Electric Reliability Corporation ("NERC") submitted its *Application for Approval of Reliability Standards* to the Nova Scotia Utility and Review Board ("NSUARB"). By this writing, NERC clarifies that it submitted the following Exhibits for approval:

> (1) **Exhibits C and E** - the Reliability Standards approved by FERC and the associated NERC Glossary of Terms;[1] (2) **Exhibit F** - the associated Violation Risk Factors; and (3) **Exhibit G** - the associated Violation Severity Levels.

In addition, NERC submitted the following Exhibits for in support of its request:

> (1) **Exhibit A** - a listing of the Reliability Standards approved by FERC that are currently effective; (2) **Exhibit B** - a summary of the current effective Reliability Standards approved by FERC, including each standard's purpose, applicability, ballot body approval percentages, and other pertinent information; (3) **Exhibit D** - the critical infrastructure protection ("CIP") implementation plan for Version 2 of the CIP Reliability Standards; and (4) **Exhibit H** - a list of additional Reliability Standards approved by the NERC Board of Trustees that are pending before FERC.

Accordingly, NERC respectfully requests that the NSUARB accept this supplemental filing and issue an order approving **Exhibits C, E, F, and G**.

[1] The NERC Glossary of Terms includes Regional definitions that do not apply to the Province of Nova Scotia.

Respectfully submitted,

/s/ V. Davis Smith
V. Davis Smith
Attorney for North American Electric Reliability Corporation

cc: Mr. Ken Montgomery, NSUARB
Mr. David Cook, NERC
Ms. Ed Schwerdt, NPCC
Ms. Margaret Mayora, NPCC

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

June 29, 2010

VIA FEDERAL EXPRESS
Ms. Nancy McNeil
Regulatory Affairs Officer/Clerk
Nova Scotia Utility and Review Board
1601 Lower Water Street, 3rd Floor
Halifax, Nova Scotia B3J 3P6

RE: Application For Approval of Regional Reliability Criteria

Dear Ms. McNeil:

Pursuant to the May 11, 2010 Memorandum of Understanding between and among Nova Scotia Power Incorporated, the North American Reliability Corporation and the Northeast Power Coordinating Council, Inc. (NPCC), please find enclosed two (2) copies of NPCC's Application For Approval of Regional Reliability Criteria in Nova Scotia. An additional version will be sent to you electronically.

Yours very truly,

Edward A. Schwerdt
President and Chief Executive Officer

Enclosures

c (w/o enc.) Gerry Cauley, NERC
David Cook, NERC
S. Bruce Outhouse, Q.C., Board Counsel
Nicole Godbout, Regulatory Counsel, NSPI
Eric Ferguson, Director, Regulatory Affairs
Margaret Mayora, NPCC

From: Philip A. Fedora
To: grpStaff
Subject: FW: Occasional News: Blackouts
Date: Monday, September 26, 2011 7:54:56 AM

FYI - Phil

From: PSERCNWS [mailto:PSERCNWS@asu.edu] **On Behalf Of** Dennis Ray
Sent: Sunday, September 25, 2011 9:58 PM
To: PSERCNWS@ASU.EDU
Subject: Occasional News: Blackouts

Blackout News:

- Grid operators didn't share info during blackout. The San Diego Union Tribune. Sep. 23.
- San Diego Blackout Briefing to the California Public Utility Commission (16 MB PPT-starting at slide 37). Sep. 22.
- Desert transformers, Mexican generator dragged SD County into blackout. North County Times. Sep. 20.
- Widespread power blackout hits much of Chile. The Mainichi Daily News. Sep. 26.
- Massive power blackout hits Chile. Toronto Sun. Sep. 25.
- No power reserves during partial blackout. The Korea Times. Sep. 22.
- Korea Blackout: Cause & Aftermath. Korea's Global TV. Sep. 20.
- KEPCO to develop measures to prevent power outage. The Korea Herald. Sep. 23.

PSERC Event Reminder:

PSERC Webinar, September 27, 1-2 PM Central Time: Impact of PHEV's on Design of Distributed Electrically-Islanded Resources (Overview | Webcast)

Dennis Ray, Ph.D.
Deputy Director
Power Systems Engineering Research Center (PSERC)
"Empowering Minds to Engineer the Future Electric Energy System"
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Federal Energy Regulatory Commission

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

September 9, 2011
Contacts: Mary O'Driscoll, FERC (202) 502-8680
Kimberly Mielcarek, NERC (202) 383-2622

NERC, FERC Announce Joint Inquiry into Outage

The Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC) today announced a joint inquiry into the September 8 power outage that left more than 1 million customers in Southern California, parts of Arizona and Northern Baja Mexico without electricity. As of 2:15 a.m. PDT today, all but 200 MW of the initial 4,300 MW lost had been restored.

FERC and NERC will coordinate with the Department of Energy and other federal agencies, the California ISO, the Western Electricity Coordinating Council, California and Arizona state regulators and the companies involved to monitor the situation. The inquiry will focus on causes of the outages.

"NERC and FERC are partnering to conduct a full inquiry into the cause of this event," said Gerry Cauley, president and chief executive officer of NERC. "Partnering brings together the expertise of both organizations, and emphasizes the importance placed on reliability of the bulk power system."

"This inquiry is an effective way for us to protect consumers and ensure the reliability of the bulk power system," FERC Chairman Jon Wellinghoff said.

The initial focus remains on ensuring a timely and safe restoration of power to customers. Updates will continue as more information is confirmed.

FERC is charged with oversight of reliability of the nation's bulk power system. FERC has designated NERC as the organization that develops and enforces mandatory reliability standards.

R-11-37

Slide 1

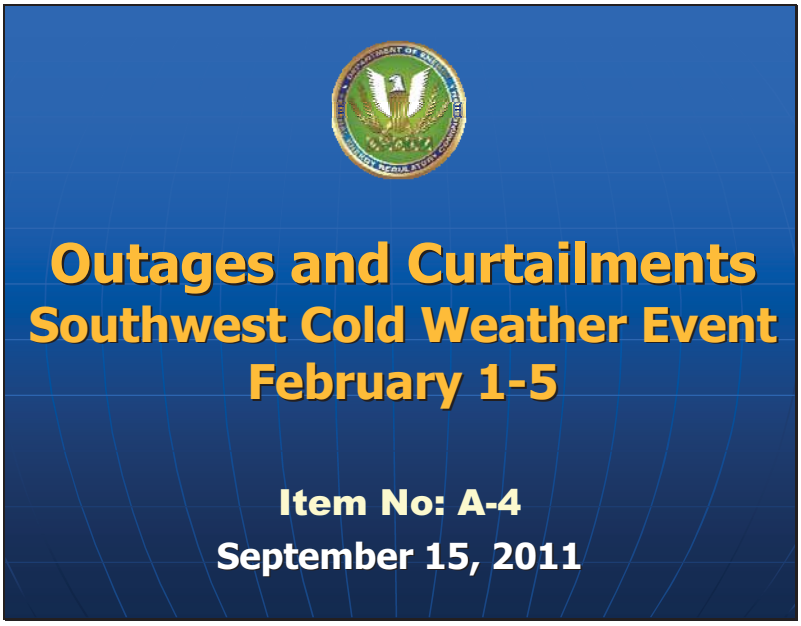

Mr. Chairman, Commissioners, I am pleased to present a summary of the Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011, published on August 16, 2011. I am Loye Hull with the Office of Electric Reliability. With me are Kathryn Kuhlen, James Meade, Heather Polzin and Thomas Pinkston of the Office of Enforcement. This was, however, a true multi-office effort with members of nearly every office on the team, including Office of General Counsel, Office of Energy Projects, Office of Administrative Litigation, Office of Energy Market Regulation, Office of Energy Policy & Innovation, and Office of External Affairs, and I would also like to ask members of those offices, as well as the additional members of OER and OE that participated in the task force to stand and be recognized.

On February 14, 2011, the Commission ordered an Inquiry in Case AD-11-9-000 into the causes of widespread electricity outages and gas curtailments in the Southwest. Approximately 4.4 million electric customers in ERCOT and WECC were affected, while over 50,000 gas customers had their service curtailed in New Mexico, Arizona and Texas. The Commission ordered staff to identify the causes and "appropriate actions for preventing a recurrence." The Commission established a staff task force, and ordered it to report its findings and recommendations "as soon as practicable." Commission Staff and NERC cooperated from the beginning, and in May, the Commission formally announced that FERC and NERC would issue a joint Report. The task force completed the Inquiry and the Commission published the joint report with NERC in six months.

The task force obtained approximately 54 gigabytes of data, issued over 200 data requests, conducted numerous site visits and meetings to gather information from gas and electric entities, conducted numerous outreach meetings with the gas and electric industries, and, in addition to NERC, coordinated with Regional Entities and state legislative and regulatory bodies. We thank NERC for its cooperation and contribution to the work of the task force.

I will be summarizing the task force's findings and recommendations on electricity outages, while Tom Pinkston will be summarizing the gas findings and recommendations.

Slide 2

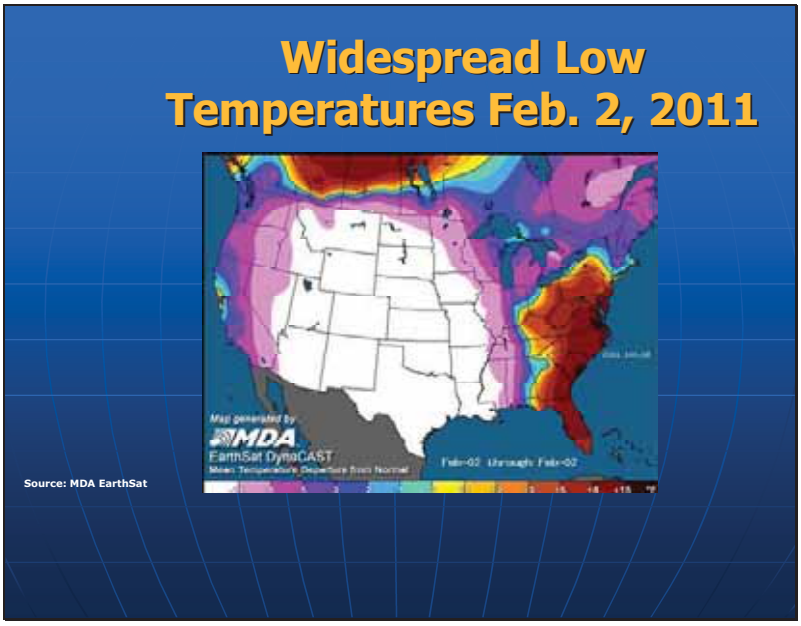

The task force concluded that temperatures considerably lower than normal, representing the longest sustained cold spell in 25 years, along with steady winds, were the primary causes of the widespread electricity outages. The white areas on this graphic show those areas where the mean temperature was **at least** 15 degrees colder than normal on February 2, the day when outages peaked. For example, Albuquerque hit almost 40 degrees below normal. Such cold weather was not unprecedented in the Southwest. ERCOT experienced a very similar event in 1989, when it also shed firm load, but the lessons learned from that event were not used to prevent outages during the 2011 event.

Slide 3

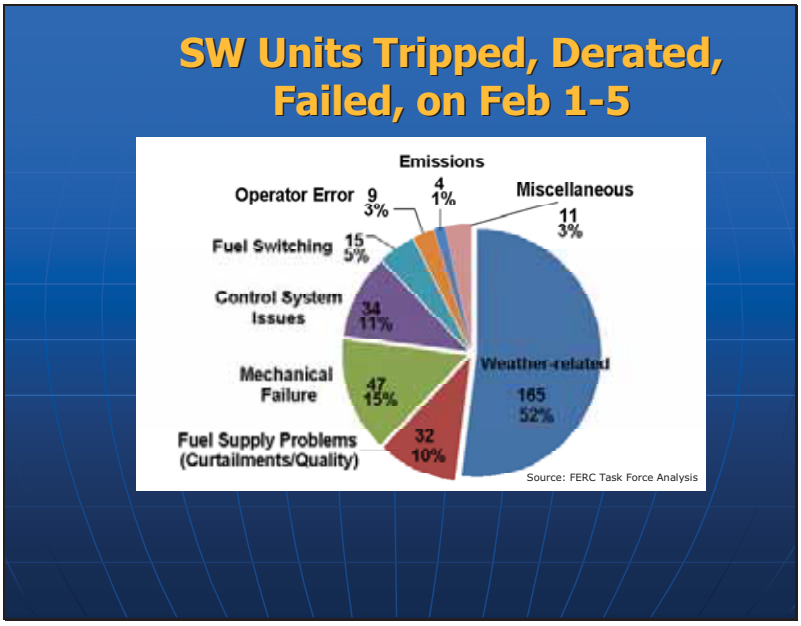

From February 1 to 5, over 250 electric generating units in ERCOT, WECC and SPP experienced outages. By number of units, 52% were directly weather-related, while another 15% were indirectly related to the weather, either due to gas supply problems or attempts to switch from gas to alternate fuels.

Slide 4

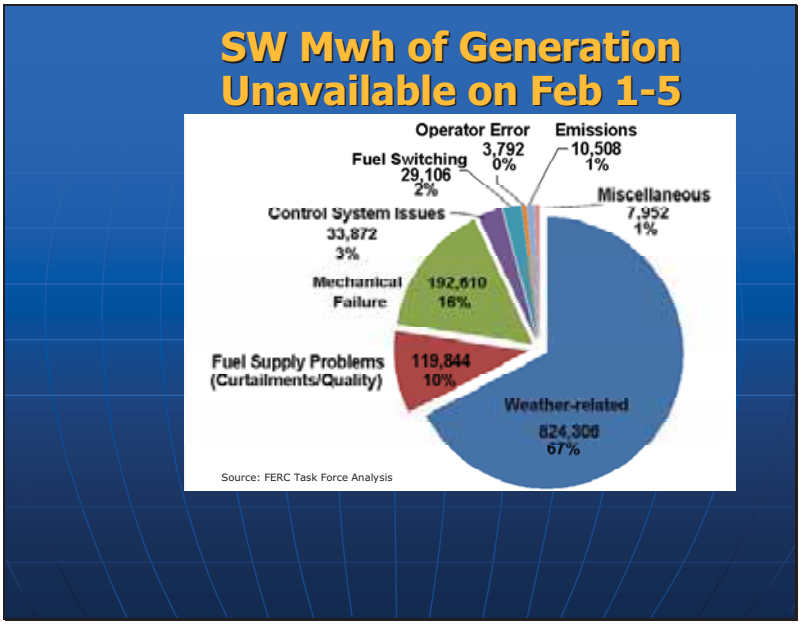

During the same 5 day period, approximately 1.2 million megawatt hours of electric generation was unavailable. On a megawatt hour basis, 67% of the outages were directly weather related, while an additional 12 percent were indirectly related, again due to gas supply problems and fuel switching.

The single largest problem causing electric outages was frozen sensing lines, followed by frozen equipment, water lines and valves. Wind turbines experienced outages due to blade icing and low temperature limits.

These outages could have been minimized if generators had proactively executed critical winterization procedures such as inspecting and maintaining heat tracing and thermal insulation, and installing wind breaks and enclosures to protect equipment and lines vulnerable to freezing. This event emphasized the lack of any Reliability Standard that directly requires generators to develop, maintain and implement plans to winterize their units. NERC has agreed to submit a Standard Authorization Request to begin the process of developing such a standard. Prompt action could allow a Standard to be in place before winter 2012.

The balancing authorities could have been better prepared for this event by, among other things, requiring accurate information about temperature design limits from generators, not allowing planned outages requested when extreme weather is expected, raising reserve levels when extreme weather is expected, and having procedures that would allow them to order some units to warm up (and be compensated) before extreme weather hits.

We found that balancing authorities and reserve sharing groups need to review their distribution of reserves to ensure that they are useable and deliverable during contingencies, taking into account such factors as transmission constraints, other

demands on reserve sharing resources, and the possibility that more than one reserve sharing group member might experience simultaneous emergencies.
To protect the gas supply, we also recommended that transmission operators and distribution providers review where critical gas production and transmission facilities are located on the electrical transmission and distribution systems, and determine whether these facilities can be protected in the event of system stress or load shedding.

We also recommended that balancing authorities improve communications during extreme weather events with transmission owner/operators, distribution providers, and other market participants.

Commission Staff is committed to working with NERC and the Regional Entities to ensure that generators, balancing authorities and other registered entities implement applicable recommendations before extreme weather arrives. The conditions experienced in early February could reoccur in the Southwest or even in the South, with similar results, if generators are not prepared for extreme winter weather.
Tom Pinkston will now discuss the task force's findings and recommendations in the area of natural gas.

Slide 5

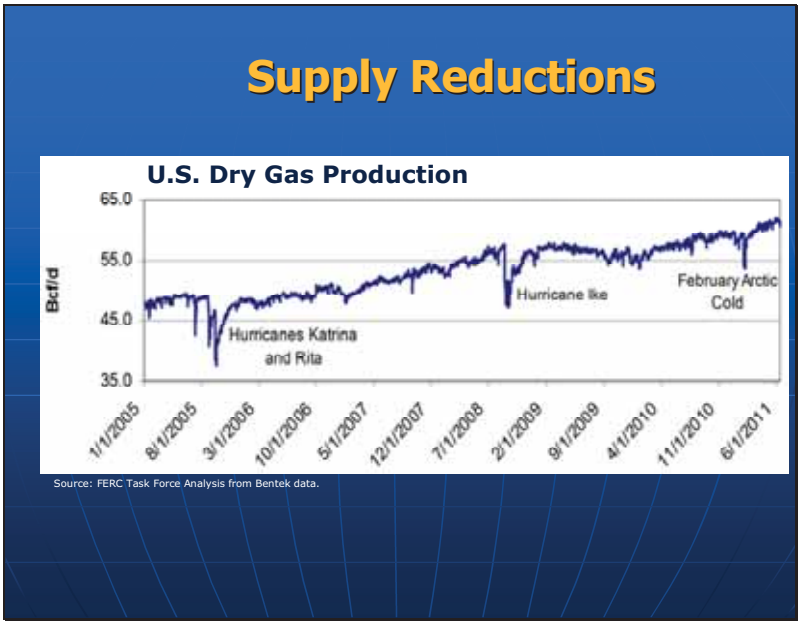

The impact of this cold weather event on natural gas supply to the region was unprecedented. Over 50,000 customers in the Southwest lost gas service – 30,000 in New Mexico, 20,000 in Arizona, and close to 900 in the city of El Paso, Texas. Because it takes much longer to restore gas service than it does electric service, some of these customers were without natural gas for days, or even as long as a week.

The task force's inquiry into the causes of the gas outages began with the local utility companies and the interstate and intrastate pipelines that serve the region, but also extended to gas processing plants and production companies. Although we were unable to contact all of the processors and producers in the area, we reached out to a broad cross section of those sectors, representing approximately 40 percent of the gas production in the area.

The data and information we obtained from the industry confirmed that the primary cause of the gas outages was the extreme, prolonged cold weather, which resulted in widespread freeze-offs at wellheads, gathering systems, and processing plants, reducing the flow of gas in the Texas and New Mexico production basins by approximately 20 percent, a much greater extent than has occurred in the past. The prolonged cold caused production shortfalls in the San Juan and Permian Basins, the main supply areas for the local gas utilities that eventually curtailed service to customers in New Mexico, Arizona, and Texas. Wellhead freeze-offs normally occur several times a winter in the San Juan Basin but are not common in the Permian Basin, which is the supply source that utilities in the Southwest region typically rely upon when cold weather threatens production in the San Juan Basin.

We also learned that in parts of Texas, icy road conditions contributed to the production losses, as crews were unable to access production sites for necessary maintenance, repairs and disposal of produced water.

In addition, the rolling blackouts and other electrical outages in Texas and New Mexico contributed to the cold weather problems faced by gas producers, processors, and storage facilities, which depend on electric pumps and compressors to keep gas flowing. However, the pipeline companies, which tend to use larger, gas-fired compressors and which typically have back up generation and compression, were not significantly affected by electric outages.

As you can see from this chart, the effect on production was comparable to that of a major hurricane. From February 1 to 5, production losses in the Southwest totaled almost 15 billion cubic feet of gas.

The extreme cold weather also created an unprecedented demand for gas, which further strained the ability of the utilities and pipelines to maintain sufficient operating pressure.

Although producers in the New Mexico and Texas production areas routinely implement some winterization measures, those measures were generally inadequate in light of the extreme, prolonged cold weather that occurred.

The pipelines and gas utilities prepared for cold weather by increasing their line pack – the amount of gas stored in their pipeline and distribution systems – to maximum levels. As freeze-offs interrupted gas deliveries while demand was increasing, significantly more gas was taken out of pipeline than was put in causing line pack and pipeline operating pressures to decline drastically.

Slide 6

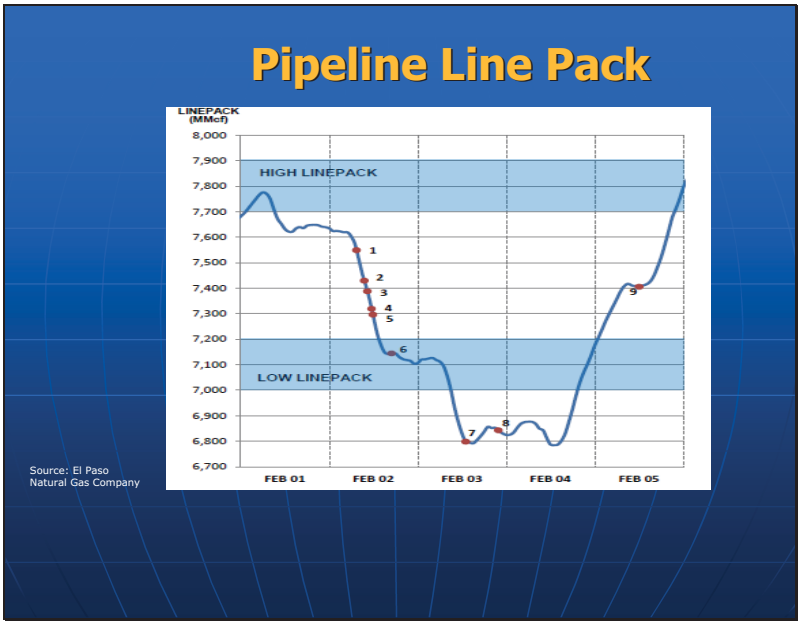

This chart shows the rapid fall of line pack on El Paso Natural Gas, one of the major interstate pipelines that serve New Mexico and Arizona. The numbers refer to key events. For instance No. 1 was a notice of SOC and Nos. 7 and 8 were pressure falling below 600 psi and a low pressure force majeure. In the course of two days, the system pressures declined from a high line pack condition to below the minimum pressures required for normal operation. These low delivery pressures on the El Paso system, resulting from supply failures, were a major factor in the retail outages that occurred in Arizona and southern New Mexico on Feb 3rd.

We also found that some of the local distribution systems were simply unable to deliver the unprecedented volume of gas demanded by residential customers during the cold snap.

However, as a general matter, the pipeline network, both interstate and intrastate, showed good flexibility in adjusting flows to meet demand and compensate for supply shortfalls. We found no evidence that interstate or intrastate pipeline design, system limitations, or equipment failures contributed significantly to the gas outages.

Additional gas storage capacity in Arizona and New Mexico could have prevented many of the outages that occurred by making additional supply available during the periods of peak demand. Additional gas storage capacity in the downstream market areas closer to demand centers might have prevented most of the outages that occurred by making additional supply available in a more timely manner during peak demand periods.

We found that specific measures can and should be taken to improve the reliability of natural gas supply to consumers during extreme cold weather events. Because our recommendations involve sectors of the industry that are not currently subject to the

Commission's jurisdiction, they are directed to state regulators, legislators, and industry participants.

Our recommendations are as follows:

Lawmakers in Texas and New Mexico should work with state regulators and members of the gas industry to determine whether minimum, uniform standards for the winterization of natural gas production and processing facilities could be adopted to improve the reliability of supply during extreme cold weather events.

State utility commissions should work with local gas utilities to determine whether curtailment plans are up to date and can be implemented as efficiently as possible, and whether local distribution systems can be improved to help preserve gas supply when shortages develop.

State regulators, balancing authorities, electricity generators, and local gas and electric utilities should work together to determine whether and under what circumstances residential gas customers should receive priority over electrical generating plants during a gas supply emergency. Gas-fired generators consume large amounts of natural gas, and in some instances, curtailing supply to generators could avoid outages affecting large numbers of residential customers.

While the cold weather that struck the Southwest in early February was unusually severe and long lasting, we believe many of the outages suffered by residents of Texas, New Mexico and Arizona could have been prevented, and it is our hope that state and regional authorities and the energy industry will carefully consider our recommendations and work together to implement them.

This concludes our presentation and we'd be happy to answer any questions.

Slide 7

Outages and Curtailments
Southwest Cold Weather Event
February 1-5

Item No: A-4

September 15, 2011

From: anthony.jablonski@rfirst.org
To: rsg
Subject: RE: Balloting Software
Date: Tuesday, August 02, 2011 9:23:37 AM
Attachments: image001.png

Good Morning Steve,

RFC currently uses an in house application to run our voting and commenting functions which is housed within a MS SharePoint 7 environment. Most of the voting type applications (ballot body registration, ballot pool formation, ballot periods, voting results, etc.) were custom applications developed specifically by our IT staff. With that said, we may be looking to modify this custom code in the future (or possibly move to a new platform) to ease the dependency on IT staff for support (a number of the custom applications are written using a variety of different types of software/code). Thanks and have a great day.

From: Rueckert, Steve [mailto:Steve@wecc.biz]
Sent: Monday, August 01, 2011 6:21 PM
To: rsg
Subject: Balloting Software

RSG members,

WECC's Board of Directors recently approved revisions to the WECC Regional Reliability Standards voting procedure that will bring our voting procedure much closer to the NERC process, and I think more in line with what the majority of the other regions have. I was wondering if you could share with me what software packages you are using for registering voters and tabulating votes.

Thank you,

Steven Rueckert
Director of Standards
Western Electricity Coordinating Council
155 North 400 West
Suite 200
Salt Lake City, Utah 84103-1114
Phone (801) 883-6878
Cell (801) 558-0301
www.wecc.biz

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Y

Y

From: Pat Huntley
To: rsg
Subject: RE: Balloting Software
Date: Tuesday, August 02, 2011 10:33:56 AM
Attachments: image001.png

Steve,

SERC uses some custom software to register ballot pool members and to record their vote along with any accompanying ballot comments. The registered ballot body is setup as a separate committee on our portal. The software is designed leverage our portal logins and committee roles. Tabulation of the ballot results is done outside the portal using a spreadsheet.

We considered other more expensive options, but this currently meets our needs since we have relatively few ballots.

Pat Huntley
Manager, Reliability Standards
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2815 Coliseum Centre Drive, Suite 500
Charlotte, NC 28217
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(704) 281-2342 (Cellular)

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Y

Y

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

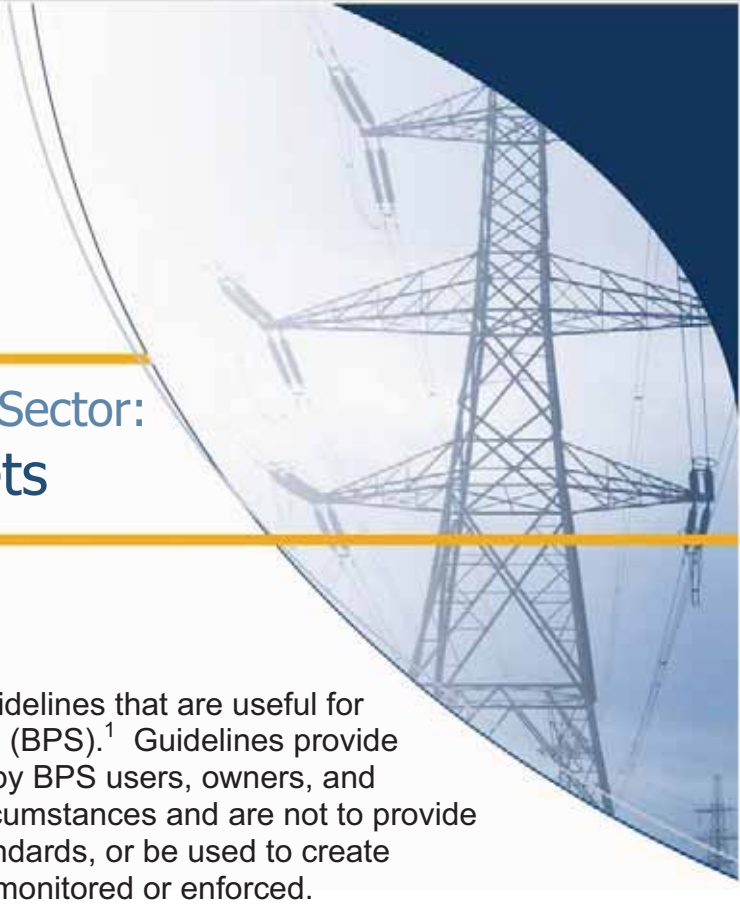

Security Guideline for the Electricity Sector: Identifying Critical Cyber Assets

Preamble:

It is in the public interest for NERC to develop Guidelines that are useful for improving the reliability of the Bulk Power System (BPS).[1] Guidelines provide suggested guidance on a particular topic for use by BPS users, owners, and operators according to each entity's facts and circumstances and are not to provide binding norms, establish mandatory reliability standards, or be used to create parameters by which compliance to standards is monitored or enforced.

This Guideline provides an approach to developing a list of Critical Cyber Assets essential to the reliable operation of Critical Assets. It builds on earlier guidance that provides a methodology to identify Critical Assets essential to the reliability and operability of the BPS.

Purpose:

This Guideline is intended to assist a Responsible Entity in identifying Critical Cyber Assets as described in CIP-002 R3. In this Guideline references to CIP-002 refer to CIP-002-1, CIP-002-2 and CIP-002-3.

Applicability:

NERC Standard CIP-002 R3 requires that Responsible Entities develop a list of Critical Cyber Assets essential to the operation of its Critical Assets, which in turn have been previously identified through a risk-based assessment methodology.

[1] Note: For purposes of this document, the terms "Bulk Power System" and "Bulk Electric System" are considered to be identical.

The term Critical Assets is defined in the *NERC Glossary of Terms Used in Reliability Standards* ("NERC Glossary") as: "Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System." The term Critical Cyber Assets is defined in the NERC Glossary as "Cyber Assets essential to the reliable operation of Critical Assets." This Guideline provides guidance for identifying Critical Cyber Assets by evaluating potential impacts to "reliable operation" of a Critical Asset.

As further specified by the NERC CIP-002 Section 4.2, this Guideline does not directly apply to facilities regulated by the U.S. Nuclear Regulatory Commission (NRC) or the Canadian Nuclear Safety Commission, with one exception described in FERC Order 706-B. In a nuclear facility, non-nuclear-safety-related balance of plant equipment not subject to NRC cyber security regulations is subject to the NERC CIP standards. If a Responsible Entity determines, through application of a risk-based methodology as specified in CIP-002 R1 that it has non-safety Critical Assets not subject to NRC cyber security regulations, then this Guideline is applicable to the determination of the Critical Cyber Assets for the identified Critical Asset.

In addition, this Guideline does not apply to the identification of Cyber Assets that are directly associated with communication networks and data communication links between discrete Electronic Security Perimeters (ESPs). Those assets are exempt from standard CIP-002.

Definitions:

NERC Glossary Terms Used:

Automatic Generation Control
Bulk Electric System
Critical Assets
Cyber Assets
Critical Cyber Assets
Electronic Security Perimeter (ESP)
Facility
Physical Security Perimeter (PSP)
Special Protection System (SPS)
Real-time
Remedial Action Scheme (RAS)
Wide Area

Additional Terms Used in the Document Not Defined as NERC Glossary Terms:

Common Mode Impact – Impact on multiple components, systems, units or facilities with similar, same or related functions due to a single event.

Compromise - The misuse or unauthorized modification of a Cyber Asset or supporting system.

Degradation - Decline in the quality of performance of the Cyber Asset or supporting system.

Loss – Complete unavailability of the Cyber Asset or supporting system.

Control Center – A Control Center is capable of performing one or more of the functions listed below for multiple (i.e., two or more) BPS assets, such as generation plants and transmission substations. Functions that support Real-time operations of a Control Center typically include one or more of the following:

- Supervisory control of BPS assets, including generation plants, transmission facilities, substations, Automatic Generation Control systems, and automatic load-shedding systems
- Acquisition, aggregation, processing, inter-utility exchange, or display of BPS reliability and/or operability data, used for Real-time operations
- BPS and system status monitoring and processing for reliability and asset management purposes (e.g., providing information used by Responsible Entities to make operational decisions regarding reliability and operability of the BPS)
- Alarm monitoring and processing specific to operation and restoration functions
- Coordination of BPS restoration activities

Guideline Details:

Overall Approach

This Guideline is intended to assist Responsible Entities in developing a process for identification of Cyber Assets associated with its Critical Assets and to determine if

these Cyber Assets are Critical Cyber Assets. This approach assumes that the Responsible Entity has already identified its Critical Assets and the essential functions of those Critical Assets as described in the earlier Guideline, "Security Guideline for the Electricity Sector: Identifying Critical Assets". Understanding the functionality that makes a particular BPS asset critical can help in identifying Cyber Assets that are essential to reliable operation of the Critical Asset. Cyber Assets that are connected to support systems (such as environmental, continuous power, or alarm systems) that support the operation of the Critical Cyber Assets could also be addressed. The process described in this Guideline consists of the following five steps:

A. Identify Cyber Assets associated with a Critical Asset
B. Group Cyber Assets
C. Determine Cyber Assets which are essential
D. Identify Cyber Assets with qualifying connectivity
E. Compile the list of Critical Cyber Assets

Section A describes how to identify Cyber Assets associated with a Critical Asset and why a complete list of Cyber Assets is important. Section B describes grouping Cyber Assets by application and how this could assist in the overall determination of criticality. Section C describes how to assess the Cyber Assets and narrow the list based on identifying those Cyber Assets that support one or more essential functions of a Critical Asset. Section D describes the application of qualifying connectivity requirements to further narrow the list. Section E discusses compiling the final list of Critical Cyber Assets.

This approach assumes that a large percentage of the Responsible Entity's Cyber Assets have qualifying connectivity as described in Section D of this document. If this assumption is not true (for example, a Responsible Entity has already determined that only a small percentage of its Cyber Assets meet the CIP-002 R3 characteristics), the steps could be performed in another order for efficiency (e.g., Step D could be exchanged with Step A). The order of the steps is not as important as the comprehensive identification of affected Cyber Assets. The determination process flow described in this Guideline is shown in Figure 1.

Figure 1 Critical Cyber Asset Determination

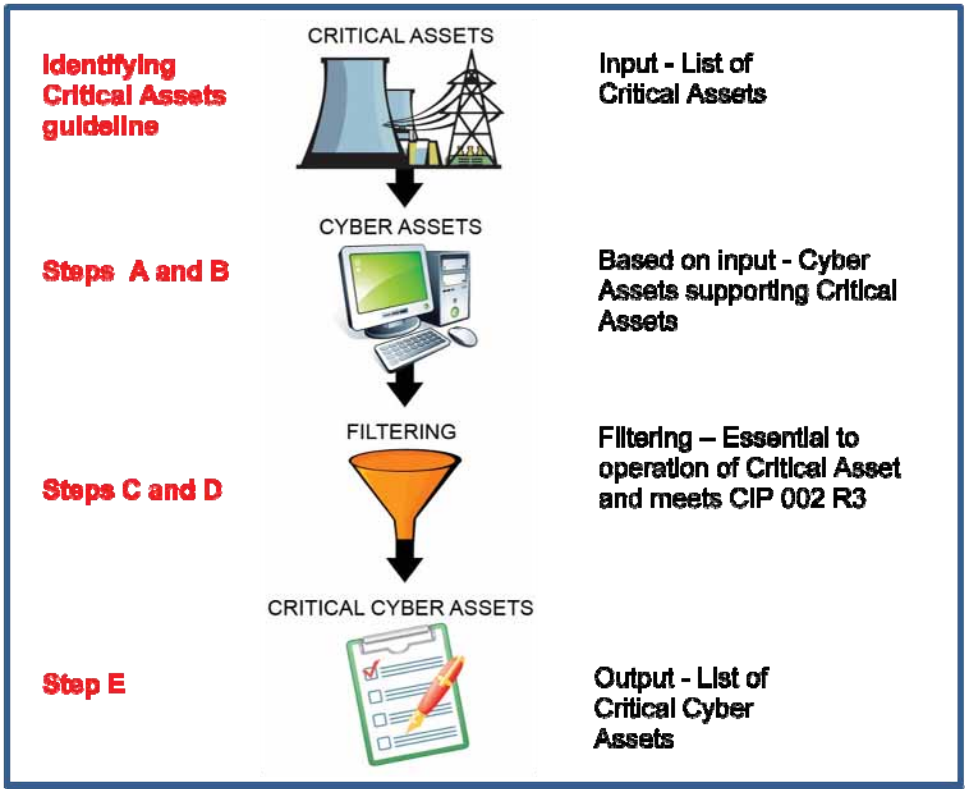

A. Identify Cyber Assets Associated with a Critical Asset

A Responsible Entity should first identify Cyber Assets associated with the operation of each identified Critical Asset. This is not intended to be a complete inventory[2] of all Cyber Assets at the facility, but rather an evaluation and then identification of all Cyber Assets that could impact the reliable operation of a Critical Asset. Responsible Entities may want to perform complete inventories of Cyber Assets if there are questions about the nature of their impact on reliable operation. This will ensure that all appropriate Cyber Assets have been considered in the assessment. Because Cyber Assets are defined to be "[p]rogrammable electronic devices and communication networks including hardware, software, and data.", software, data and cabling are considered to exist within the framework of the Cyber Asset and therefore are not separate Cyber Assets themselves.

[2] Although a comprehensive Cyber Asset inventory would be helpful in supporting CIP-005-1 compliance

Cyber Assets that should be considered include, at a minimum:

- Control systems comprising devices or sets of devices that act to manage, command, or regulate the behavior of processes[3], devices, or other systems
- Data acquisition systems comprising collections of sensors and communication links that act to sample, collect, and provide data regarding the facility's systems to a centralized location for display, archiving, or further processing
- Networking equipment including devices such as routers, hubs, switches, firewalls, and modems
- Hardware platforms running virtual machines or virtual storage

When identifying Cyber Assets, the entity should consider the different roles and functions that Cyber Assets play which could impact the reliable operation of a Critical Asset such as:

- Provides operation information in Real-time
- Controls manual or automated parameters
- Calculates parameters or limits
- Generates or displays prompts or alarms to an operator
- Provides connectivity between Cyber Assets
- Supports continuity of operations of the Critical Assets or local recovery plans

Consideration of Cyber Assets in secondary or supporting systems whose Loss, Degradation, or Compromise impacts both operation of Critical Cyber Asset(s) and their associated Critical Asset(s) is suggested. These secondary or supporting systems may include:

- Cyber Assets deployed in installed standby mode or installed spare Cyber Assets which may be used during recovery and restoration
- Stand alone virus and malware scanners, archival, backup and restore systems, and log monitoring systems (except Cyber Assets used in the access control and/or monitoring of the ESP or Physical Security Perimeter)
- Environmental systems such as heating, ventilation, and air conditioning (HVAC)
- Support systems such as uninterruptable power supplies (UPS) and alarm systems

The basis for this consideration may be supported by engineering walk downs[4] and technical descriptions and drawings including topological diagrams showing the

[3] Processes and systems that contribute to the successful function of the Critical Asset like cooling systems or lube oil systems should not be overlooked.

location and the relationship of Cyber Assets to the Critical Asset and the Cyber Assets' connectivity to other Cyber Assets.

B. Group Cyber Assets

In addition to applying the general guidance provided in Section A, entities may find it helpful in the Critical Cyber Asset identification process to consider grouping Cyber Assets as a way to simplify the process. Cyber Assets might be grouped according to the computer application software they communicate with in support of a function associated with a Critical Asset. Another grouping might be Cyber Assets associated with a specific operational function that supports a Critical Asset.

For example, if Loss, Degradation, or Compromise of a particular computer software application can be shown to fail or degrade reliable operation of a Critical Asset, then it might be assumed that all the Cyber Assets that play a role in the function provided by the computer software application could cause the same failure or Degradation. Once the effect of the Loss, Degradation, or Compromise of a grouping of Cyber Assets is known, then the effect of the Loss, Degradation or Compromise of supporting Cyber Assets can be assumed to be known.

C. Determine Cyber Assets Which are Essential

To determine whether Cyber Assets are essential, their impact on the reliable operation of a Critical Asset should be evaluated. If a Cyber Asset is associated with or is connected to a Critical Asset, but has no impact on the reliable operation of the Critical Asset, then it can be removed from further consideration as a Critical Cyber Asset. Cyber Assets that have any impact require further consideration.

A Cyber Asset could be considered essential to the reliable operation of a Critical Asset, if one or more of the following criteria is met:

1. The Cyber Asset participates in, or is capable of, supervisory or autonomous control that is essential to the reliable operation of a Critical Asset.
2. The Cyber Asset displays, transfers, or contains information relied on to make Real-time operational decisions that are essential to the reliable operation of a Critical Asset.

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[4] An engineering walk down is an inspection where an engineer or team walks through a plant, following pipes, cable trays and other equipment with blueprints to confirm that the existing condition matches what is described in plant documentation.

3. The Cyber Asset fulfils another function essential to the reliable operation of the associated Critical Asset and its Loss, Degradation, or Compromise would affect the reliability or operability of the BPS.

The concepts of Loss, Degradation, and Compromise are used in specific ways in this Guideline. In Criterion #3, the term "Loss" means that the loss of the Cyber Asset would have an immediate adverse impact on the reliable operation of the Critical Asset. The term "Degradation" means that the Cyber Asset is not fully functional and could adversely impact the reliable operation of a Critical Asset. The term "Compromise" means that information or control is modified in a way to produce an undesirable outcome that impacts the reliable operation of the Critical Asset.

The criteria presented, in the form of questions, can be used to determine whether a Cyber Asset is essential to the reliable operation of a Critical Asset. Tables C-1, C-2, C-3 and C-4 illustrate this approach. These example tables present questions to be asked for each of the three criteria. These questions, as presented, are directed at applications or systems, rather than Cyber Assets, based on the assumption that the Cyber Assets are grouped as described in Section B of this Guideline. If an application or system supports reliable operation of a Critical Asset (i.e., if the answer to any of these questions is "Yes") then the Cyber Assets supporting the application or system could be designated as Critical Cyber Assets.

Environmental (e.g., HVAC) or other support systems (e.g., UPS) for Critical Cyber Assets do not always require the same protection as the associated Critical Cyber Asset.[5] However, it is suggested that evaluation of Cyber Assets include consideration of these secondary support systems if their Loss, Degradation, or Compromise can impact both operation of Critical Cyber Assets and their associated Critical Assets(s). For example, Loss or Compromise of HVAC can lead to Loss, Degradation or Compromise of a Critical Cyber Asset which in-turn cause the Critical Asset to unacceptably affect the reliability or operability of the BPS. Similar consideration should be given to voice systems and private branch exchange (PBX) systems, as appropriate, based on the functions they perform. Note that if the support systems are within the same ESP as a Critical Cyber Asset, they must be afforded the same protection given Critical Cyber Assets required in other Cyber Security Standards.

Redundancy is not a factor in the determination of the criticality of any Cyber Asset; instead redundancy used to improve reliability and availability may indicate that each redundant Cyber Asset is critical.[6] Because redundancy may increase the

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[5] Per NERC CIP-002-1 FAQ-12 at: http://www.nerc.com/fileUploads/File/Standards/Revised_CIP-002-1_FAQs_20090217.pdf.
[6] Per NERC CIP-002-1 FAQ-5 at:

opportunities for a successful cyber attack, each Critical Cyber Asset and redundant Critical Cyber Asset should be protected under the Cyber Security Standards as Critical Cyber Assets.

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http://www.nerc.com/fileUploads/File/Standards/Revised_CIP-002-1_FAQs_20090217.pdf.

Table C-1 Example Determination of Cyber Assets Supporting Reliable Operations for Transmission Substations

Critical Asset: Transmission Substation				
Essential functions (EFs) found in Column 2 of Table C-1 of *Security Guideline for the Electrical Sector: identifying Critical Assets*: 1. Essential to BPS restoration. 2. Essential to critical generation for the BPS. 3. Essential for voltage or frequency support or stability of the BPS.				
Applications or systems using cyber elements	*Used in supervisory or autonomous control impacting reliable operation of the Critical Asset?*	*Displays, transfers or contains information relied on to make Real-time decisions impacting reliable operation of the Critical Asset?*	*Loss, Degradation or Compromise impacts the reliable operation of the Critical Asset?*	Efs
Telemetering	No (Does not provide supervisory control.)	Yes (Provides Real-time information to Control Center.)	Yes	1,2,3
Remote Terminal Unit (RTU)	Yes (Provides input, monitoring and control for Control Center Supervisory Control and Data Acquisition (SCADA).)	Yes (Provides Real-time information to Control Center; may provide local alarming, monitoring and short term historical information.)	Yes	1,2,3
Substation automation system (normally comprised of multiple Cyber Assets)	Yes (Provides local SCADA, process control, and RTU function to the Control Center.)	Yes (Provides information to staff that operate or maintain substation equipment.)	Yes	1,2,3

Critical Asset: Transmission Substation				
Essential functions (EFs) found in Column 2 of Table C-1 of *Security Guideline for the Electrical Sector: identifying Critical Assets*: 1. Essential to BPS restoration. 2. Essential to critical generation for the BPS. 3. Essential for voltage or frequency support or stability of the BPS.				
Applications or systems using cyber elements	*Used in supervisory or autonomous control impacting reliable operation of the Critical Asset?*	*Displays, transfers or contains information relied on to make Real-time decisions impacting reliable operation of the Critical Asset?*	*Loss, Degradation or Compromise impacts the reliable operation of the Critical Asset?*	Efs
Protective relaying	Yes (Performs Real-time protection function; may provide monitoring and historical information.)	Yes (Normally provides power system monitoring and historical information locally into substation automation system and Control Center.)	Yes	1,2,3
Special protection systems (SPS/RAS) – the remote end	Yes (SPS master or remote system end providing autonomous control.)	No (Normally provides control and not information used to make Real-time decisions.)	Yes	3
Phasor Measurement Unit (PMU[7])	No (In the future may provide input for control actions at Control Center.)	No (In the future may provide wide area monitoring (WAM) for Control Centers.)	No	1,3

[7] NERC has not yet acknowledged these systems as there are no current implemented applications.

Critical Asset: Transmission Substation				
Essential functions (EFs) found in Column 2 of Table C-1 of *Security Guideline for the Electrical Sector: identifying Critical Assets*: 1. Essential to BPS restoration. 2. Essential to critical generation for the BPS. 3. Essential for voltage or frequency support or stability of the BPS.				
Applications or systems using cyber elements	*Used in supervisory or autonomous control impacting reliable operation of the Critical Asset?*	*Displays, transfers or contains information relied on to make Real-time decisions impacting reliable operation of the Critical Asset?*	*Loss, Degradation or Compromise impacts the reliable operation of the Critical Asset?*	Efs
Historical long-term database supporting offsite storage.	No (Does not affect Real-time operation.)	No (Provided short-term storage is available to support monitoring and logging functions as required by CIP-002 through CIP-009.)	No	None
Fault Recorders	No	No	No (Important but not critical to BPS.)	None
Equipment monitoring	No	No	No (Important but not critical to BPS.)	None
Computer networks that connects control functions between assets within a single ESP	Yes	Yes	Yes (Failures due to Common Mode Impact for an aggregate group of assets large enough to affect BPS.)	1,2,3

Critical Asset: Transmission Substation				
Essential functions (EFs) found in Column 2 of Table C-1 of *Security Guideline for the Electrical Sector: identifying Critical Assets*: 1. Essential to BPS restoration. 2. Essential to critical generation for the BPS. 3. Essential for voltage or frequency support or stability of the BPS.				
Applications or systems using cyber elements	*Used in supervisory or autonomous control impacting reliable operation of the Critical Asset?*	*Displays, transfers or contains information relied on to make Real-time decisions impacting reliable operation of the Critical Asset?*	*Loss, Degradation or Compromise impacts the reliable operation of the Critical Asset?*	Efs
Revenue Meter	No	No	No	None
Station computer	Yes (Runs an algorithm related to autonomous control.)	Yes	Yes	1,2,3
Station computer HMI	Yes	Yes	Yes	1,2,3

Table C-2 Example Determination of Cyber Assets Supporting Essential Functions for a Generation Resource

Critical Asset: Hydro Generator				
Essential functions(Efs) found in Column 2 of Table C-2 of the *Security Guideline for the Electrical Sector: Identifying Critical Assets:* 1. Essential generation for the BPS. 2. Essential to mitigate known BPS constraint(s), including voltage or frequency support or stability. 3. Essential to BPS Restoration.				
Applications or systems using cyber assets	*Used in supervisory or autonomous control impacting reliable operation of the Critical Asset?*	*Displays, transfers or contains information relied on to make Real-time decisions impacting reliable operation of the Critical Asset?*	*Loss, Degradation or Compromise impacts the reliable operation of the Critical Asset?*	Efs
Main turbine speed computer control	Yes (Controls key parameters.)	Yes (Display key control parameters.)	Yes (Loss or manipulation of control parameters could impact reliable operations immediately or over time.)	1,2,3
Seal water flow computer control to Main turbine	Yes (Controls key parameters.)	No (Does not display, inform, prompt or store key control parameter information.)	Yes (Loss or manipulation of seal water flow could impact reliable operations immediately or over time.)	1,2,3
Engineering workstation access to main turbine set-points.	No (Cannot affect supervisory control.)	No (Is not the primary display of information used in Real-time decision-making.)	Yes (Key set-points that are altered could produce out-of-limit conditions that could impact reliable operations immediately or over time.)	1,2,3

Critical Asset: Hydro Generator				
Essential functions(Efs) found in Column 2 of Table C-2 of the *Security Guideline for the Electrical Sector: Identifying Critical Assets:* 1. Essential generation for the BPS. 2. Essential to mitigate known BPS constraint(s), including voltage or frequency support or stability. 3. Essential to BPS Restoration.				
Applications or systems using cyber assets	*Used in supervisory or autonomous control impacting reliable operation of the Critical Asset?*	*Displays, transfers or contains information relied on to make Real-time decisions impacting reliable operation of the Critical Asset?*	*Loss, Degradation or Compromise impacts the reliable operation of the Critical Asset?*	Efs
Turbine trending analysis database	No (Not used in control.)	No (Not used in Real-time decision.)	No	1,2,3
Electrical generator efficiency calculator	No (Does not calculate or control parameters that can affect the essential function.)	No (Does not calculate display, inform, prompt, or store information related to essential functions control parameters.)	No	None
Computer networks that connects control functions between assets within a single ESP	Yes	Yes (Failures due to Common Mode Impact for an aggregate group of assets large enough to affect BPS.)	Yes	1,2,3
Revenue Meter	No	No	No	None

Critical Asset: Coal-Fired Generating Plant				
Essential functions (Efs) found in Column 2 of Table C-2 of *Security Guideline for the Electricity Sector: Identifying Critical Cyber Assets:* 1. Essential to generation for the BPS. 2. Essential to mitigate known BPS constraint(s), including voltage or frequency support or stability. 3. Essential to BPS Restoration.				
Applications or systems using cyber elements	*Used in supervisory or autonomous control impacting reliable operation of the Critical Asset?*	*Displays transfers or contains information relied on to make Real-time decisions impacting reliable operation of the Critical Asset?*	*Loss, Degradation or Compromise impacts the reliable operation of the Critical Asset?*	Efs
Integrated Plant Control System (integrated turbine, steam generator, water treatment controls)	Yes (Controls key parameters.)	Yes (Display key control parameters.)	Yes (Displays and controls that support an essential function.)	1,2
Continuous Emissions Monitoring System (CEMS)	No (Not used in supervisory or autonomous control impacting the essential functions.)	No (Does not display, inform, prompt or store key control parameter information.)	No (No other essential functions supported.)	None
Turbine control system	Yes (Sets set-points for key control parameters)	Yes (Displays key control parameters)	Yes (controls essential function)	1,2
Main feed water control system	Yes (Controls key parameters.)	No (Does not display key control parameters.)	Yes (Controls support an essential function.)	1,2

Critical Asset: Coal-Fired Generating Plant				
Essential functions (Efs) found in Column 2 of Table C-2 of *Security Guideline for the Electricity Sector: Identifying Critical Cyber Assets:* 1. Essential to generation for the BPS. 2. Essential to mitigate known BPS constraint(s), including voltage or frequency support or stability. 3. Essential to BPS Restoration.				
Applications or systems using cyber elements	*Used in supervisory or autonomous control impacting reliable operation of the Critical Asset?*	*Displays transfers or contains information relied on to make Real-time decisions impacting reliable operation of the Critical Asset?*	*Loss, Degradation or Compromise impacts the reliable operation of the Critical Asset?*	Efs
Computer networks that connect control functions between assets within a single ESP	Yes (Failures due to Common Mode Impact for an aggregate group of assets large enough to affect BPS.)	Yes	Yes (Manipulation of aggregate control function could impact reliable operations.)	1,2,3
Revenue Meter	No	No	No	None

Table C-3 Example Determination of Cyber Assets Supporting Essential Functions for a Control Center

Critical Asset: Control Center				
Essential functions (Efs) found in Column 2 of Table C-3 of *Security Guideline for the Electricity Sector: Identifying Critical Assets:* 1. Essential by virtue of their functions supporting reliability or operability of the BPS. 2. Essential for providing information used by a Responsible Entity to make Real-time operational decisions regarding the reliability and operability of the BPS. 3. Essential for Real-time inter-utility data exchange critical to reliable BPS operation. 4. Essential for control or data acquisition for a BPS asset determined to be a Critical Asset. 5. Essential for Control Center functionality for a set of BPS assets determined to collectively impact reliability and operability of the BPS.				
Applications or systems using cyber elements	*Used in supervisory or autonomous control impacting reliable operation of the Critical Asset?*	*Displays transfers or contains information relied on to make Real-time decisions impacting reliable operation of the Critical Asset?*	*Loss, Degradation or Compromise impacts the reliable operation of the Critical Asset?*	Efs
SCADA Supervisory Control	Yes	Yes (Information required to perform a control function.)	Yes (Direct control of a Critical Asset *or* a set of assets determined collectively to be critical to reliability and operability of the BPS.)	4,5
SCADA Alarms	No	Yes (Real-time alarm data used to make operational decisions.)	Yes (Loss of alarms or spurious alarms could lead to operational decisions that impact reliable operation.)	1,2,3, 4,5

Critical Asset: Control Center				
Essential functions (Efs) found in Column 2 of Table C-3 of *Security Guideline for the Electricity Sector: Identifying Critical Assets:* 1. Essential by virtue of their functions supporting reliability or operability of the BPS. 2. Essential for providing information used by a Responsible Entity to make Real-time operational decisions regarding the reliability and operability of the BPS. 3. Essential for Real-time inter-utility data exchange critical to reliable BPS operation. 4. Essential for control or data acquisition for a BPS asset determined to be a Critical Asset. 5. Essential for Control Center functionality for a set of BPS assets determined to collectively impact reliability and operability of the BPS.				
Applications or systems using cyber elements	*Used in supervisory or autonomous control impacting reliable operation of the Critical Asset?*	*Displays transfers or contains information relied on to make Real-time decisions impacting reliable operation of the Critical Asset?*	*Loss, Degradation or Compromise impacts the reliable operation of the Critical Asset?*	Efs
SCADA/Inter-Control Center Communications Protocol (ICCP) Applications	Yes (In some instances.)	Yes (ICCP functions handle exchange and processing of data used to make operational decisions, may be used for remote control.)	Yes (Loss or manipulation of data could lead to operational decisions that impact reliable operation).	1,2,3, 4,5
State Estimation	No	Yes (Provides information to Control Center operators used to make operational decisions.)	Yes (Loss or manipulation of information could lead to operational decisions that impact reliable operation.)	1,2
Voltage Stability Analysis	No	Yes (Provides information to Control Center operators used to make operational decisions.)	Yes (Loss or manipulation of analysis could lead to operational decisions that impact reliable operation.)	1,2

Critical Asset: Control Center				
Essential functions (Efs) found in Column 2 of Table C-3 of *Security Guideline for the Electricity Sector: Identifying Critical Assets:* 1. Essential by virtue of their functions supporting reliability or operability of the BPS. 2. Essential for providing information used by a Responsible Entity to make Real-time operational decisions regarding the reliability and operability of the BPS. 3. Essential for Real-time inter-utility data exchange critical to reliable BPS operation. 4. Essential for control or data acquisition for a BPS asset determined to be a Critical Asset. 5. Essential for Control Center functionality for a set of BPS assets determined to collectively impact reliability and operability of the BPS.				
Applications or systems using cyber elements	*Used in supervisory or autonomous control impacting reliable operation of the Critical Asset?*	*Displays transfers or contains information relied on to make Real-time decisions impacting reliable operation of the Critical Asset?*	*Loss, Degradation or Compromise impacts the reliable operation of the Critical Asset?*	Efs
Computer networks that connect control functions between assets within a single ESP	Yes (Failures due to Common Mode Impact for an aggregate group of assets large enough to affect BPS.)	Yes	Yes (Manipulation of aggregate control function could impact reliable operations.)	1,2,3, 4,5

Table C-4 Example Determination of Cyber Assets Supporting Essential Functions for a Special System

Critical Asset: Special System				
Essential functions (Efs) found in Column 2 of Table C-4 of *Security Guideline for the Electrical Sector: Identifying Critical Assets:* 1. Essential Remedial Action Scheme/Special Protection System that supports the reliability or operability of the BPS 2. System critical to automatic load shedding supporting the reliability or operability of the BPS. 3. Demand-Side Management or Direct Control Load Management that supports the reliability or operability of the BPS. 4. Essential by virtue of their functions to the BPS.				
Applications or systems using cyber elements	*Used in supervisory or autonomous control impacting reliable operation of the Critical Asset?*	*Displays, transfers or contains information relied on to make Real-time decisions impacting reliable operation of the Critical Asset?*	*Loss, Degradation or Compromise impacts the reliable operation of the Critical Asset?*	Efs
Special protection systems (SPS/RAS)	Yes (SPS master or remote system end providing autonomous control.)	No (Normally provides control and not information used to make Real-time decisions.)	Yes	1,2,3
Protection System	Yes (Reference to systems indentified in PRC standards Operates as protective controls.)	No (Depends if autonomous action also provides information.)	Yes	1
Under frequency load shedding (UFLS) (Includes aggregation and/or centralized control or common component)	Yes	No (Depends if autonomous action also provides information.)	Yes	2

Critical Asset: Special System				
Essential functions (Efs) found in Column 2 of Table C-4 of *Security Guideline for the Electrical Sector: Identifying Critical Assets:* 1. Essential Remedial Action Scheme/Special Protection System that supports the reliability or operability of the BPS 2. System critical to automatic load shedding supporting the reliability or operability of the BPS. 3. Demand-Side Management or Direct Control Load Management that supports the reliability or operability of the BPS. 4. Essential by virtue of their functions to the BPS.				
Applications or systems using cyber elements	*Used in supervisory or autonomous control impacting reliable operation of the Critical Asset?*	*Displays, transfers or contains information relied on to make Real-time decisions impacting reliable operation of the Critical Asset?*	*Loss, Degradation or Compromise impacts the reliable operation of the Critical Asset?*	Efs
UVLS Includes aggregation and/or centralized control or common component)	Yes	No (Depends if autonomous action also provides information.)	Yes	2
Demand Side Management (DSM)/Direct Control Load Management (DCLM) (Includes aggregation and/or centralized control or common component)	Yes	No (Depends if autonomous action also provides information.)	Yes	3
DSM (Does not Include centralized control or common component)	No	Yes (Information provided to influence individual customers.)	Yes (Manipulation of an aggregate group of assets large enough to affect BPS.)	3
Dynamic feeder rating system (Includes aggregation and/or centralized control or common component)	Yes	Yes (Normally provides continuous information.)	Yes (Depends on implementation or contingency occurring.)	4

Critical Asset: Special System				
Essential functions (Efs) found in Column 2 of Table C-4 of *Security Guideline for the Electrical Sector: Identifying Critical Assets:* 1. Essential Remedial Action Scheme/Special Protection System that supports the reliability or operability of the BPS 2. System critical to automatic load shedding supporting the reliability or operability of the BPS. 3. Demand-Side Management or Direct Control Load Management that supports the reliability or operability of the BPS. 4. Essential by virtue of their functions to the BPS.				
Applications or systems using cyber elements	*Used in supervisory or autonomous control impacting reliable operation of the Critical Asset?*	*Displays, transfers or contains information relied on to make Real-time decisions impacting reliable operation of the Critical Asset?*	*Loss, Degradation or Compromise impacts the reliable operation of the Critical Asset?*	Efs
Computer networks that connect control functions between assets within a single ESP	Yes (Failures due to Common Mode Impact for an aggregate group of assets large enough to affect BPS.)	Yes	Yes (Manipulation of aggregate control function could impact reliable operations.)	1,2,3 ,4

D. Identify Cyber Assets with Qualifying Connectivity

Standard CIP-002 R3 further qualifies Critical Cyber Assets as those assets that meet any of the following qualifying connectivity requirements:

> "**R3.1.** The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,
> **R3.2.** The Cyber Asset uses a routable protocol within a Control Center; or,
> **R3.3.** The Cyber Asset is dial-up accessible."

Determining whether or not a Cyber Asset meets either the third qualifying requirement (dial-up-accessible) will generally be a simple, one-step exercise. However, determining whether or not a Cyber Asset uses a routable protocol to communicate outside an ESP or within a Control Center will generally require multiple steps, including defining a "preliminary" ESP.

Preliminary ESP

One possible approach to defining a preliminary ESP is to examine network drawings and network address plan information for the site in question (e.g., plant, substation, or Control Center). If the Cyber Assets being evaluated are connected to a network with an IP address that is unique to that site, then there should generally be at least one router or similar Layer 3 networking[8] device linking that network to other local or wide-area networks. That router can then be considered as being the access point of a preliminary ESP.

Once a preliminary ESP has been defined, determining whether the qualifying requirement of CIP-002 Requirement R3.1 applies is a matter of asking whether or not a Cyber Asset: a) uses either serial or routable protocols within the preliminary ESP, and b) communicates outside the preliminary ESP via a routable protocol. Likewise, once a preliminary ESP has been defined for a Control Center, evaluating a given Cyber Asset's connectivity against CIP-002 Requirement R3.2 can be done by determining whether or not it communicates using a routable protocol.

After determination of the preliminary ESP, non-critical Cyber Assets that are within the ESP could be examined to determine if they could be moved outside of the ESP without impacting the functionality of the Critical Cyber Assets. Any non-critical Cyber Assets remaining within the ESP must be identified as per CIP-

[8] Per the Open System Interconnection reference model Layer 3 and the NERC Frequently Asked Questions No. 6 for Standard CIP-002-1.

005. Non-critical Cyber Assets virtualized on the same hardware platform as a Critical Cyber Asset should also be identified.

The Open System Interconnection Reference Model

The Open System Interconnection (OSI) Reference Model describes a communications architecture comprising seven “layers” arranged in a stack. Each layer provides services to the layer above it and requests services from the layer below.

Information from a given layer is treated as data by the layer below it, which will generally add its own header information before forwarding it “down” the protocol stack to the next lower layer during transmission. Similarly, a layer will remove header information during receipt before sending data “up” the protocol stack to the next higher layer.

Communicating devices such as computers, typically referred to as nodes in this context, generally implement communications software corresponding to each of the layers. In any communication between two nodes, each node’s individual layers are considered to be communicating with the corresponding layers in the other node (e.g., Layer 7 on the first node talks to Layer 7 on the second node, while simultaneously Layer 4 on the first node talks to Layer 4 on the second node).

This guideline is concerned with the bottom 3 layers of the model, namely:

- Layer 1, the physical layer
- Layer 2, the data link layer, and,
- Layer 3, the network layer.

Layer 1 consists of basic communications functions, generally implemented in hardware. It describes the electrical (e.g., voltage), optical (e.g., frequency), or radio (e.g., wave shape) characteristics of the data transmission at its most fundamental level. Examples of Layer 1 technologies include RS-232, T1, DSL, 802.11 (PHY), and Ethernet (the Ethernet specification defines both Layer 1 and Layer 2).

Layer 2 consists of the hardware and software necessary to transmit and receive data transmitted on a single Layer 1 network. Any Layer 1 communications media that allows more than one node (e.g., Ethernet) uses an addressing scheme at Layer 2 to ensure that data is received by the correct node. Examples of Layer 2 protocols include ARP, SLIP, PPP, Frame Relay, and Ethernet (the Ethernet specification defines both Layer 1 and Layer 2).

Layer 3 provides for communication between different Layer 1 or Layer 2 networks even if the Layer 1 or Layer 2 implementation is different on the two nodes. Examples of Layer 3 protocols include IP, and IPX.

Routable vs. Non-Routable Protocols

Routable protocols use addresses and require those addresses to have at least two parts: A "network" address and a "device" address. Routable protocols allow devices to communicate between two different networks by forwarding packets between the two networks. Non-routable protocols only use a "device" address, and do not allow messages to be sent from one network to another, thus allowing communications to take place only on a single network.

Routing takes place at Layer 3 (also called the routing layer), thus using a routing protocol, such as IP, to route data from one local area network to another.

In general, if the communications uses "IP" ("Internet protocol") or IPX/SPX ("Internetwork Packet Exchange/Sequenced Packet Exchange"), it is considered routable; if the communications does not use IP or IPX/SPX, it is not routable. (Note that other routable protocols such as OSI exist, but are not widely used in North America.) Thus, "DNP over IP" is routable, while "DNP" over a serial connection is not routable.

Also, Layer 3 protocols such as IP are often encapsulated in Layer 2 protocols such as Frame Relay, ATM ("Asynchronous Transfer Mode"), and MPLS ("Multiprotocol Label Switching") for delivery of packets to distant networks. When such mechanisms are employed, the IP routable protocol is still in use.

Legacy protocols and Supervisory Control and Data Acquisition (SCADA) communications existed before the OSI Reference Model existed, and therefore don't fit into the model. These protocols combine the necessary characteristics of multiple layers of the model into their data streams, and do not allow for the interchangeability of different layer-specific implementations. They do, however, need to provide Layer 2 functionality, by embedding "device" addresses as part of the data. This is not a communication problem in these instances, because all the communication happens between the central site where the SCADA system resides, and the remote site where the Remote Terminal Unit (RTU) resides. A SCADA central system would communicate with an RTU by specifying the "line" and addressing a command to the "device". The "line" designation was only used at the SCADA system to ensure communication via the correct physical communications circuit; the line designation never appeared in the communication. Based on communication loading (i.e., the amount of data needed from a given RTU), and telephone line physical connections, multiple devices could reside on a given communications line (e.g., one "large" RTU, or

three to five “small” RTUs), each with a “device” address unique to that line. Individual devices did not communicate with each other on the same communications line, much less between communications lines.

With the advent of large wide-area networks and the requirement for communications between “devices” located on multiple local area networks, routing was introduced to allow “devices” on one local area network to communicate to “devices” on another local area network. This required that the local area network component of the address be communicated along with the “device” component of the address. Since both the local area network address and “device” address are included in the transmitted data, devices called “routers” are used to determine how to get packets from the source local area network to the destination local area network address. Once on the destination local area network, the “device” component of the address is used to ensure the data is sent to the correct end “device”.

Examples of routable protocols used in the power industry include:

- DNP/IP
- ICCP (IEC 60870-6/TASE.2)/IP
- IEC 60870-5-104/IP
- IEC 61850/IP
- MODBUS/TCP
- Telegyr 8979/ UDP

Examples of non-routable protocols used in the power industry include:[9]

- CONITEL
- CDC Type 1 and Type 2
- DNP (serial)
- GETAC
- Harris 9000
- IEC 60870-5-101
- MODBUS / MODBUS RTU (serial)
- TRW 2000
- SCI RDACS

Examples of Layer 1 and Layer 2 communication protocols used in power industry which could support either non-routable or routable protocols, or could use an out-of-band but routable protocol for network management include:

- ANSI T1.40x (T-1, E-1, T-3, etc.)
- x DSL
- SONET

[9] There are over 100 legacy non-routable protocols.

- ATM
- Frame Relay
- WDM / DWDM

Any Cyber Asset that uses a routable protocol to connect to a device outside the ESP or within a Control Center should be considered to have qualifying connectivity. An essential Cyber Asset using a non-routable protocol (e.g., serially-connected) within a preliminary ESP would still be considered to have qualifying connectivity if it communicates outside the preliminary ESP via another device using a routable protocol. A Cyber Asset which can communicate via dial-up (routable or non-routable) would be considered to have qualifying connectivity.

Serial Cyber Assets that are Accessible via Routable Protocol

Requirement 3.1 requires that the Cyber Asset "use a routable protocol to communicate outside the Electronic Security Perimeter" to be considered as having qualifying connectivity. The requirement does not state that the Cyber Asset itself must be directly connected by a routable protocol. Thus, serially-connected Cyber Assets can meet the qualifying connectivity criterion in Requirement 3.1, if a routable connection is used to communicate outside the preliminary ESP.

Essential serially-connected Cyber Assets that meet the qualifying connectivity criterion described above must be located within an ESP.
Nonessential serially-connected Cyber Assets that meet the qualifying connectivity criterion described above are not required to be located within an ESP.

Essential or nonessential serially-connected Cyber Assets that do not communicate with systems outside the preliminary ESP using a routable protocol are not required to be located within an ESP.
Essential serially-connected Cyber Assets, such as RTUs, which communicate outside the preliminary ESP using a routable protocol, for example to an Energy Management System (EMS), meet the qualifying connectivity requirement of R3.1, regardless of whether they communicate using a data concentrator or through a local control system.

Serially-connected Cyber Assets, such as a temperature or pressure sensor or a feed-water pump control (i.e., sensors and actuators) at a generating plant may be connected to a plant control system, which, in turn communicates outside the preliminary ESP, for example to an EMS. The temperature or pressure data is not transmitted to the EMS; only information resulting from processing that primary data is transmitted to the EMS. Similarly, the EMS does not directly

control the feed-water pump; it is controlled by the plant control system, perhaps as a result of receiving a command from the EMS. Because none of these example Cyber Assets send data to or receive control inputs from the EMS directly, they do not use a routable protocol to communicate to the EMS.

Serial Cyber Assets that are Accessible via Dial-up

Requirement 3.3 addresses to Cyber Assets that are “dial-up accessible”, not those directly connected to a modem. Many Cyber Assets are accessible via a dial-up connection through the use of modem-sharing switches and other modem-sharing technologies, such as remote access gateways or data concentrators, that allow a single telephone line or dial-up connection to access multiple Cyber Assets simultaneously. Because these Cyber Assets are “accessible” from a dial-up connection, they meet the qualifying connectivity requirement of R3.3.

As with the serially-connected Cyber Assets described previously, essential dial-up-accessible Cyber Assets that meet the qualifying connectivity criterion described above must be located within an ESP.

As provided in the response to Question 7 in the CIP-002 FAQs, dial-up-accessible access refers to any temporary (non-permanent), interruptible, or not continuously-connected communication access to a Cyber Asset from any remote site. Access to a Cyber Asset via a permanent communication connection from a specific computer over a dedicated communication circuit would not be considered dial-up-accessible-access.

Process Diagrams

Figure 2, below, illustrates a process to determine whether Cyber Assets determined to be essential to the operation of a particular Critical Asset (or set of Critical Assets) meet any of the qualifying characteristics of CIP-002 R3.

Figure 3 illustrates how that process might be modified in cases where a Responsible Entity elects to identify Cyber Assets with qualifying connectivity as the first step in its overall process of identifying Critical Cyber Assets.

Figure 2. Evaluating CIP-002 R3 Qualifying Communication Characteristics

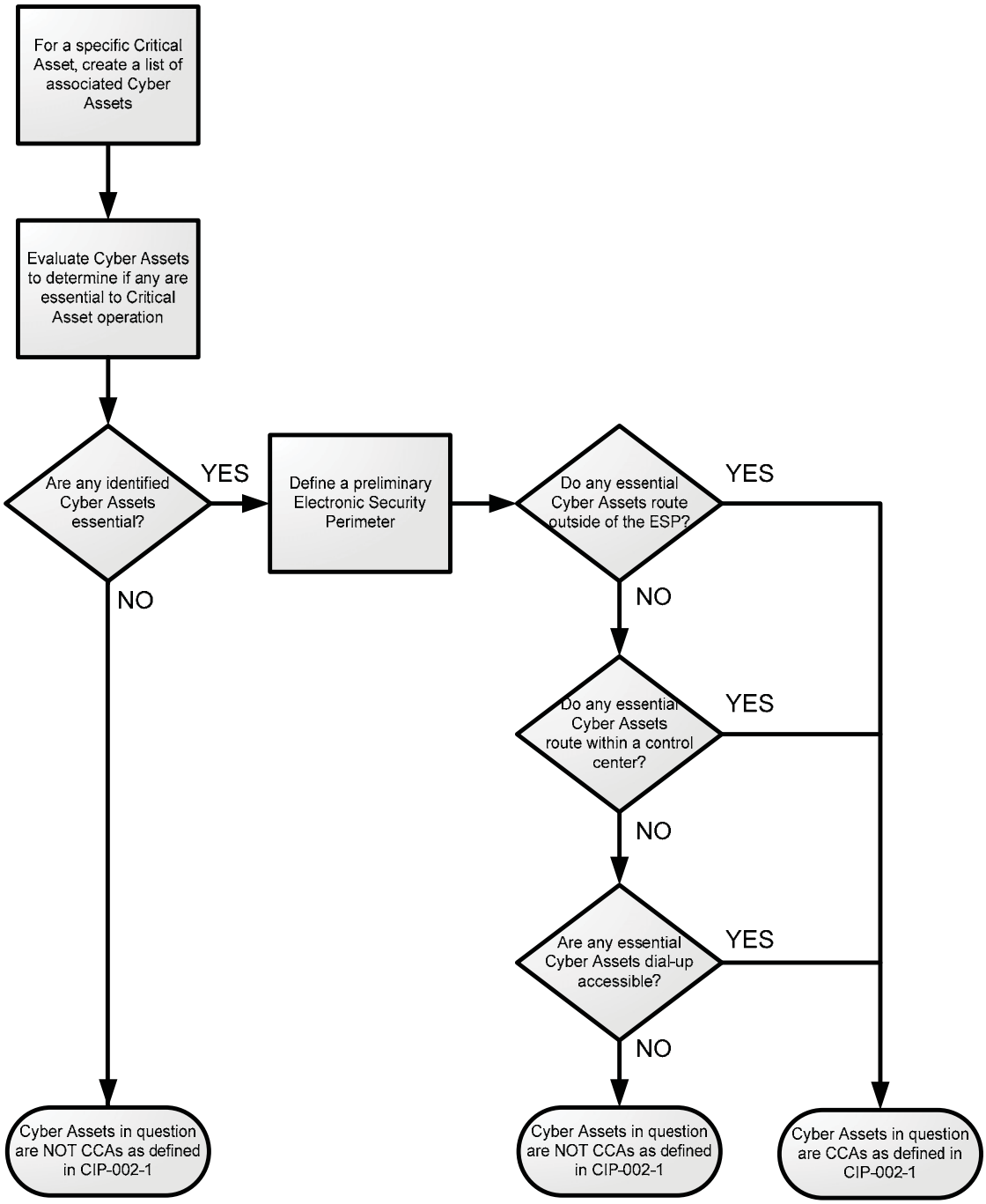

Figure 3. Evaluating CIP-002 R3 Qualifying Communication Characteristics as the First Step in Overall CCA Identification Process

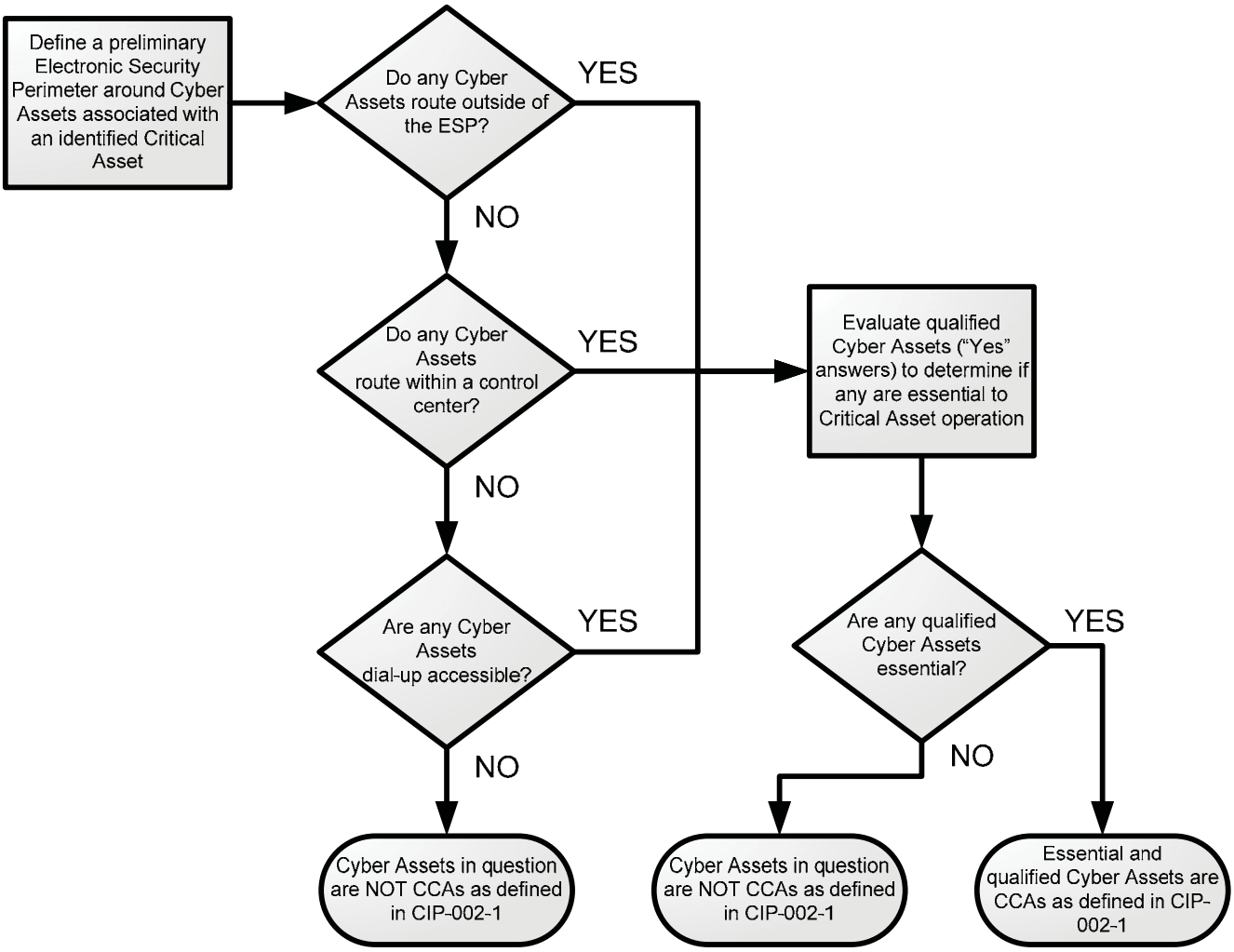

Example Configurations

Attachment 1 provides example configurations of essential-to-Critical-Asset and not-essential-to-Critical-Asset Cyber Assets that communicate using routable and non-routable protocols, as well as via dial-up access. These configurations are considered to represent different possible arrangements of dial-up and ESP access points, ESP boundaries and position within or outside a Control Center. For each example configuration, Critical Cyber Asset designations are suggested for those essential Cyber Assets that are considered to meet one of the qualifying characteristics defined in CIP-002 R3.1, R3.2 or R3.3. These drawings are high-level and many variations of configurations are not shown.

E. Compile the List of Critical Cyber Assets

After narrowing down the complete list of Cyber Assets to only those that are both essential to the reliable operation of a Critical Asset and that meet the qualifying connectivity criteria, a final list of Critical Cyber Assets can be compiled and documented. An example format for a list of Critical Cyber Assets and supporting information in that determination is shown in Attachment 2.

Related Documents and Links:

NIST Special Publication 800-30, *Risk Management Guide for Information Technology Systems,* computer Security Division, Information Technology Laboratory, National Institute of Standards and Technology, Gaithersburg, MD, July 2002.
http://csrc.nist.gov/publications/nistpubs/800-30/sp800-30.pdf

NERC CIP Guideline, *Control System – Business network Electronic Connectivity*, Critical Infrastructure Protection Committee, North American Electric Reliability Corporation, May 2005.
http://www.esisac.com/publicdocs/Guides/SecGuide_ElectronicSec_BOTapprvd3may05.pdf

NERC Glossary of Terms Used in Reliability Standards, April 2009.
www.nerc.com/files/Glossary_2009April20.pdf

NERC Security Guideline for the Electrical Sector: *Identifying Critical Assets*. Sept 2009.
http://www.nerc.com/docs/cip/sgwg/Critical_Asset_ID_Final_Clean.pdf

Attachment 1
Interpretation of Qualification per CIP-002 R3 Qualifying Connectivity Requirements for Example Configurations

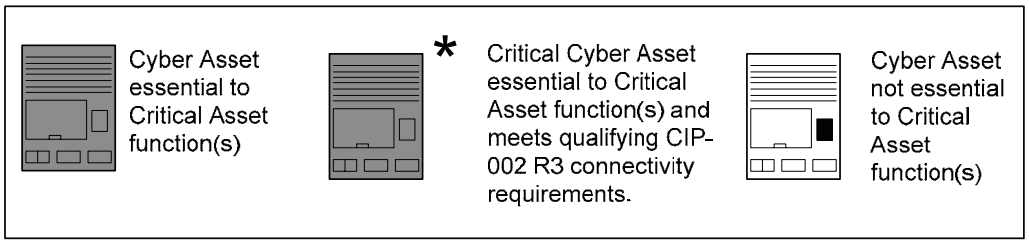

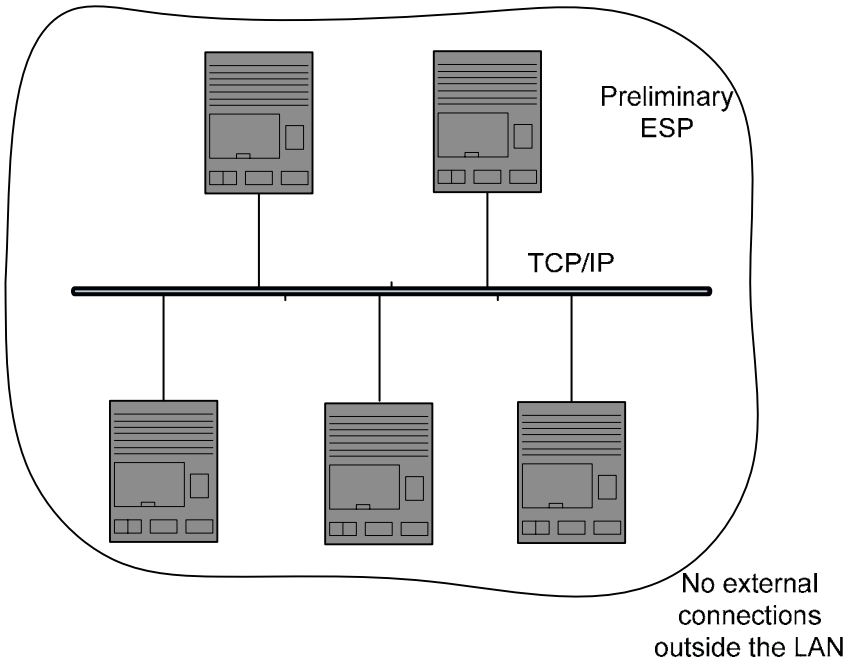

Drawing 1

Essential Cyber Assets on an autonomous LAN outside of a Control Center communicate with each other using a routable protocol. There are no external connections to this network. Therefore, these essential Cyber Assets are not Critical Cyber Assets.

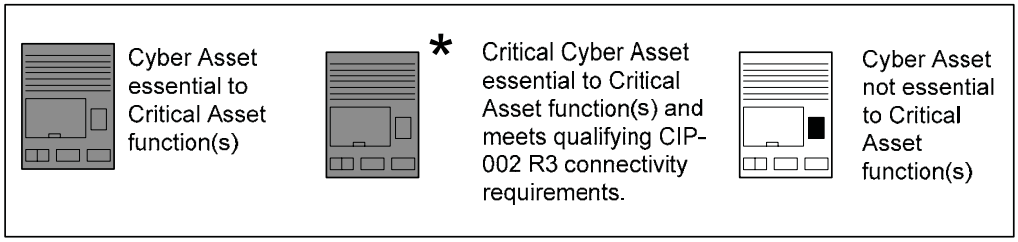

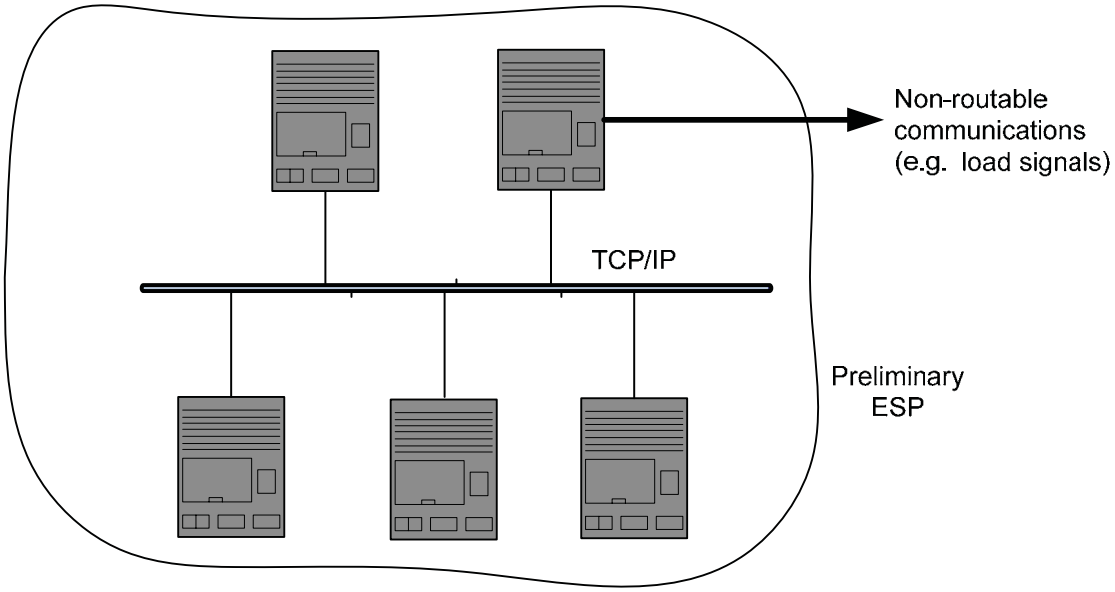

Drawing 2

Essential Cyber Assets on an autonomous LAN outside of a Control Center communicate with each other using a routable protocol. One essential Cyber Asset communicates with systems outside the preliminary ESP using a non-routable protocol on a permanent connection. This is the only connection outside the preliminary ESP. Since this does not meet the criteria of CIP-002 R3.1 or R3.3, the Cyber Assets shown are not Critical Cyber Assets.

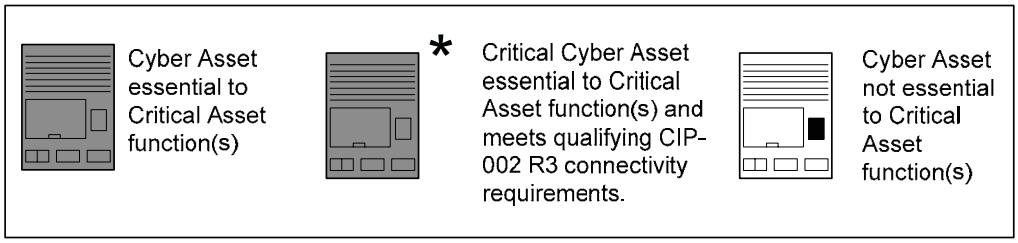

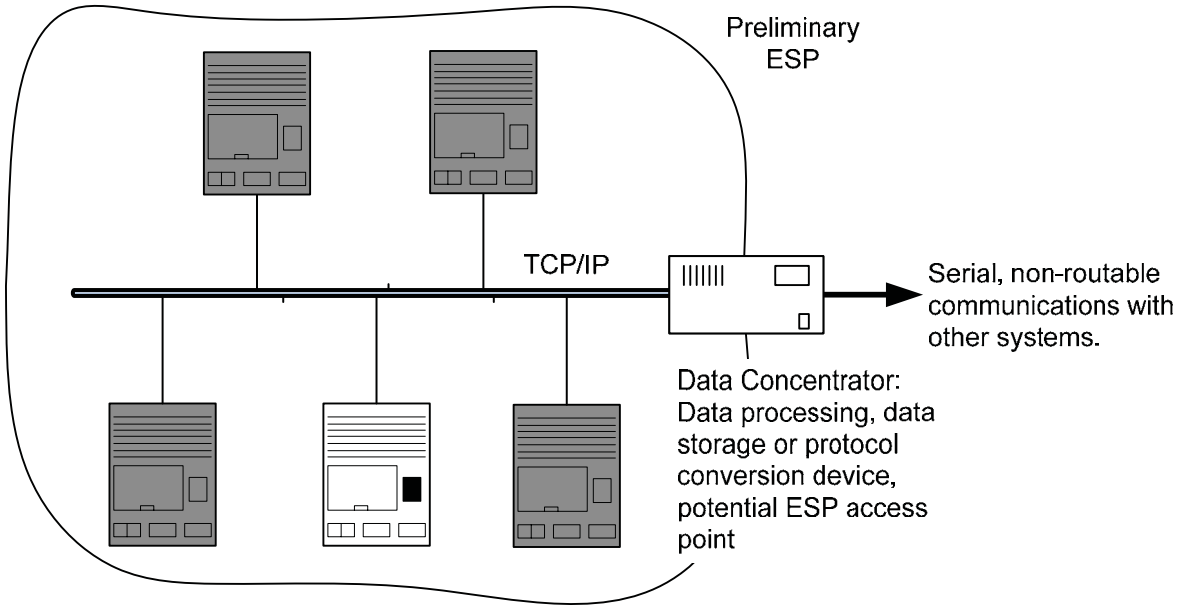

Drawing 3

Essential and nonessential Cyber Assets on a LAN outside of a Control Center communicate with each other using a routable protocol. They also communicate with remote systems via a data concentrator that performs protocol conversion for communication outside the preliminary ESP using a serial non-routable connection. The essential Cyber Assets shown do not use a routable protocol to communicate with systems outside of the preliminary ESP and do not meet the criterion of CIP-002 R3.1; therefore they are not Critical Cyber Assets. Because there are no Critical Cyber Assets, no ESP or is needed and the data concentrator does not need to be designated as an ESP access point.

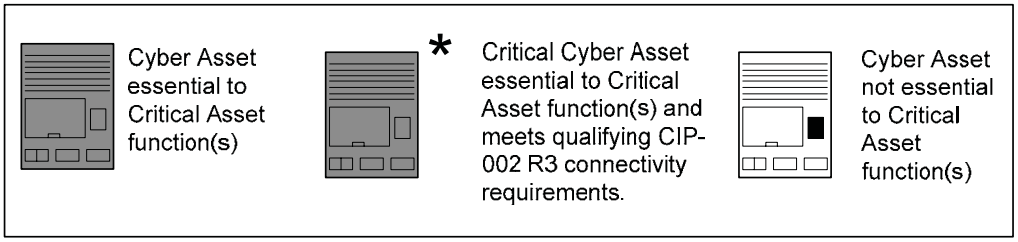

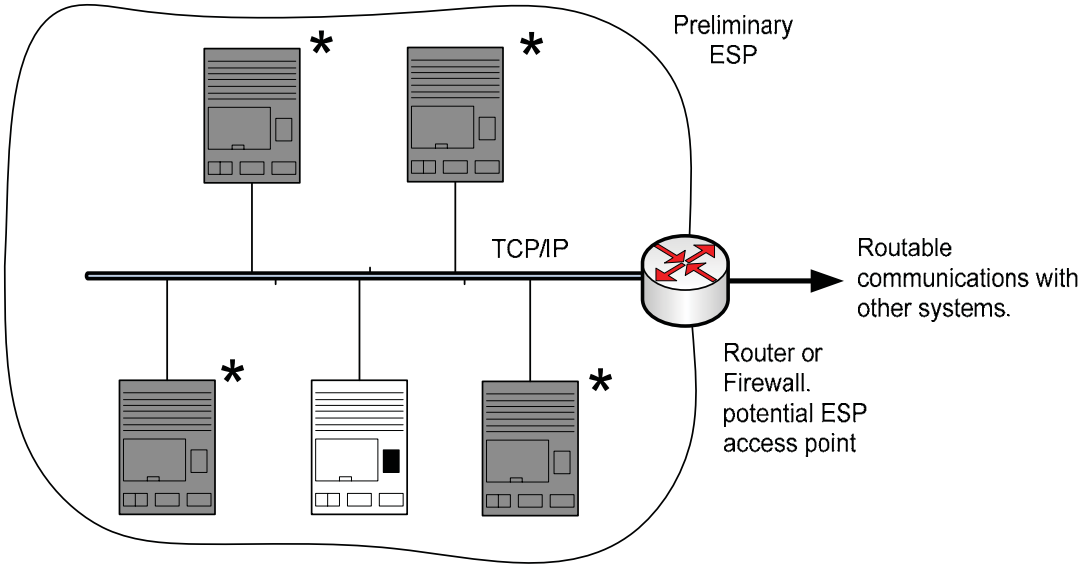

Drawing 4

Essential and nonessential Cyber Assets on a LAN outside of a Control Center communicate with each other and with outside systems on a WAN or other LAN using a routable protocol. Essential Cyber Assets are Critical Cyber Assets per CIP-002 R3.1 based on preliminary ESP design. The fact that all the Cyber Assets could communicate with systems outside the ESP using a routable protocol qualifies the essential Cyber Assets as Critical Cyber Assets.

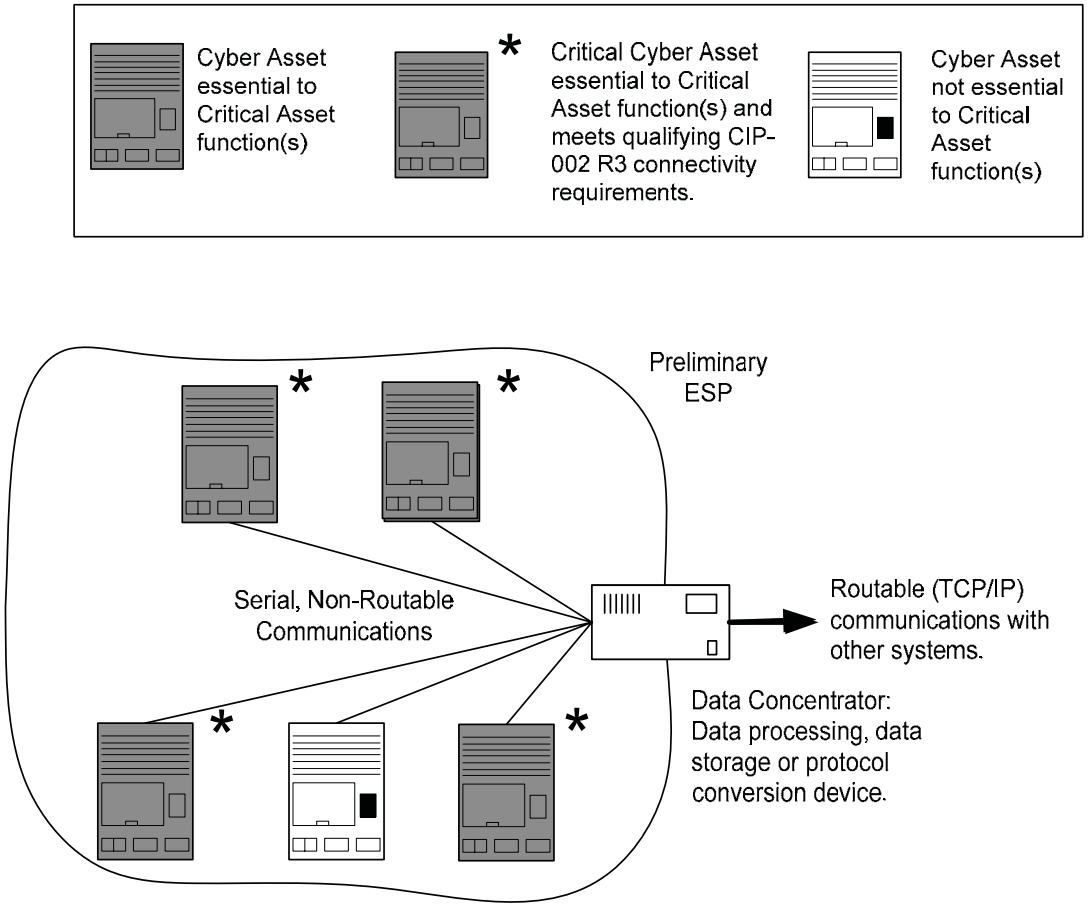

Drawing 5

Essential and nonessential Cyber Assets outside of a Control Center communicate to remote systems (e.g., SCADA) via a data concentrator that performs protocol conversion for communication outside the preliminary ESP using a routable protocol. The essential Cyber Assets shown are Critical Cyber Assets per CIP-002 R3.1, because they use a routable protocol to communicate with systems outside the preliminary ESP. Access to these essential Cyber Assets from outside the ESP using a routable protocol dictates the need for cyber security protection as prescribed by the CIP Standards. The nonessential Cyber Asset shown in the drawing is not a Critical Cyber Asset, so when the actual ESP is established this Cyber Asset is not required to be inside the ESP.

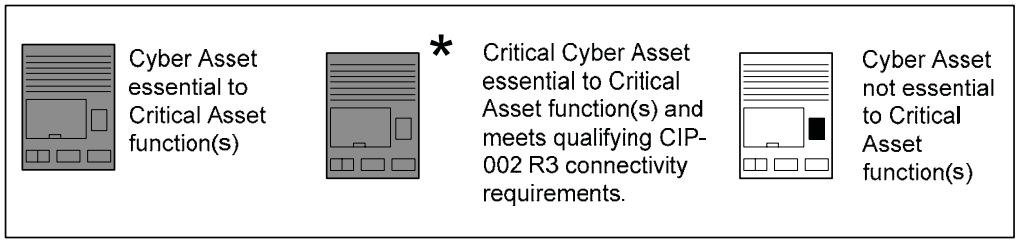

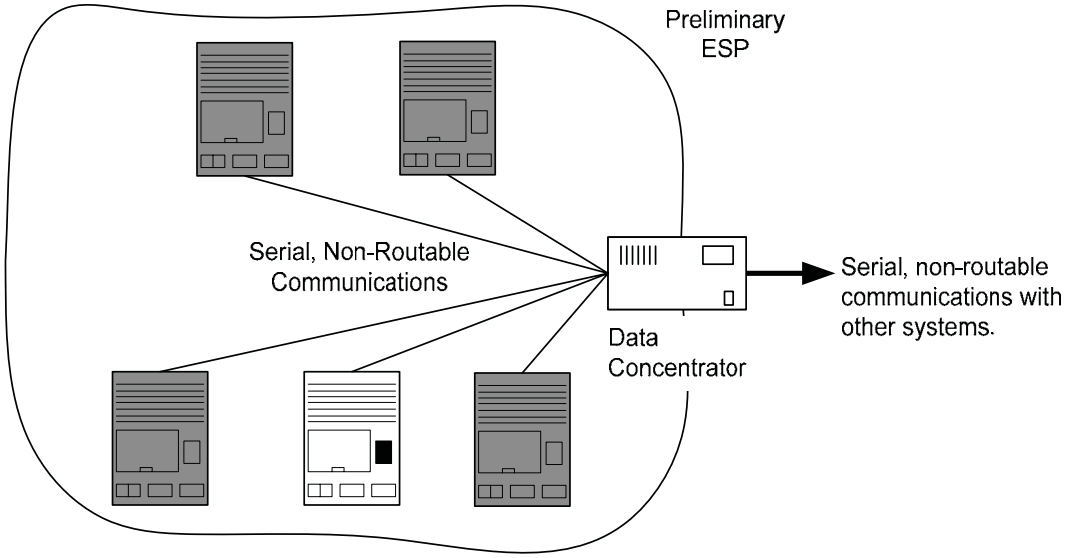

Drawing 6

Essential and nonessential Cyber Assets outside of a Control Center communicate to remote systems (e.g., SCADA) via a data concentrator that communicates with systems outside preliminary ESP using a non-routable protocol. The essential Cyber Assets shown do not use a routable protocol inside or outside of the preliminary ESP, do not meet the criterion of CIP-002 R3.1, and therefore, are not Critical Cyber Assets. Because there are no Critical Cyber Assets, no ESP is needed.

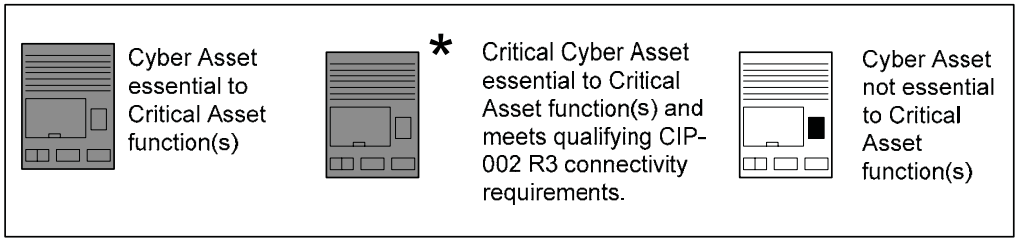

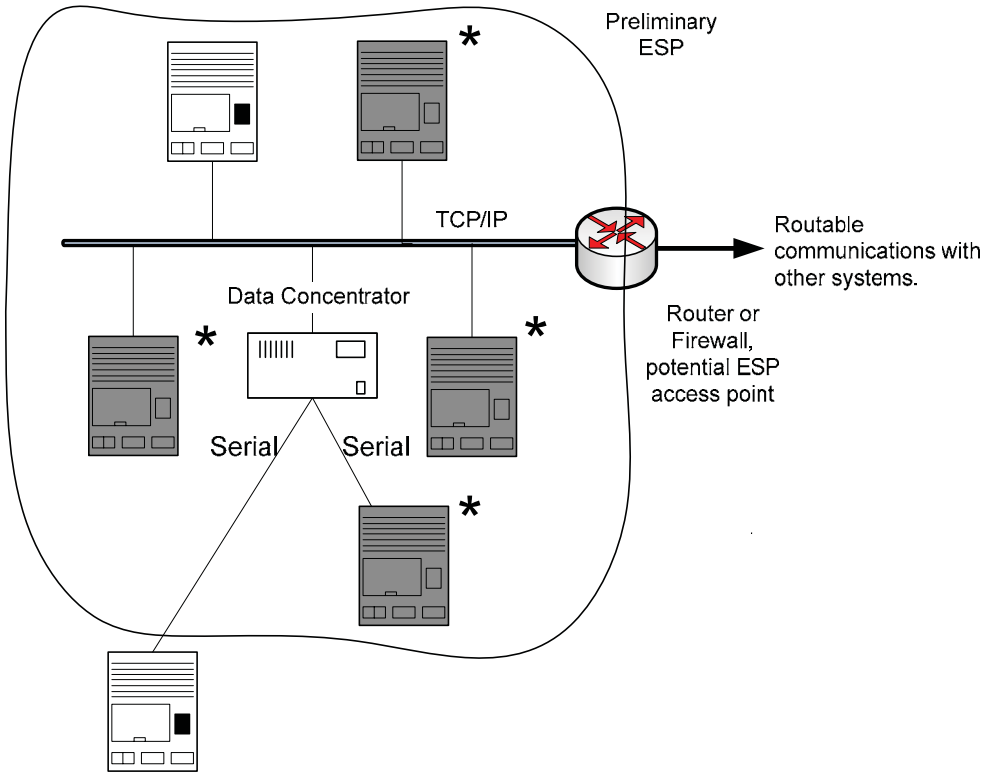

Drawing 7

Essential and nonessential Cyber Assets on a LAN outside of a control center communicate with each other using a routable protocol. The essential Cyber Assets which have TCP/IP connectivity also communicate with systems outside the ESP using a routable protocol which qualifies them as Critical Cyber Assets. This includes the serially-connected essential Cyber Asset that is connected to the TCP/IP LAN via a data concentrator and connected inside the ESP to TCP/IP via a serial connection but communicates with systems outside the ESP using a routable protocol. The nonessential serially-connected Cyber Asset shown in the drawing is not a Critical Cyber Asset, so when the actual ESP is established this Cyber Asset is not required to be inside the ESP.

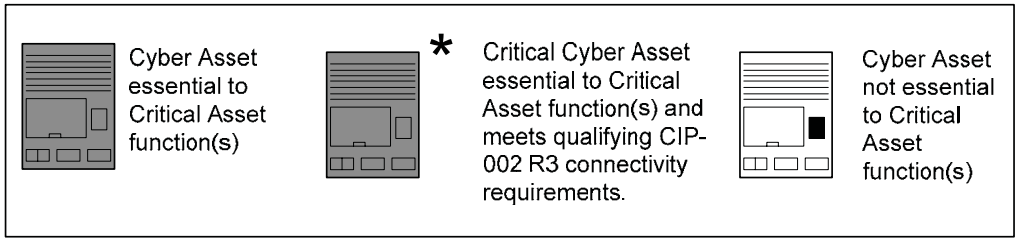

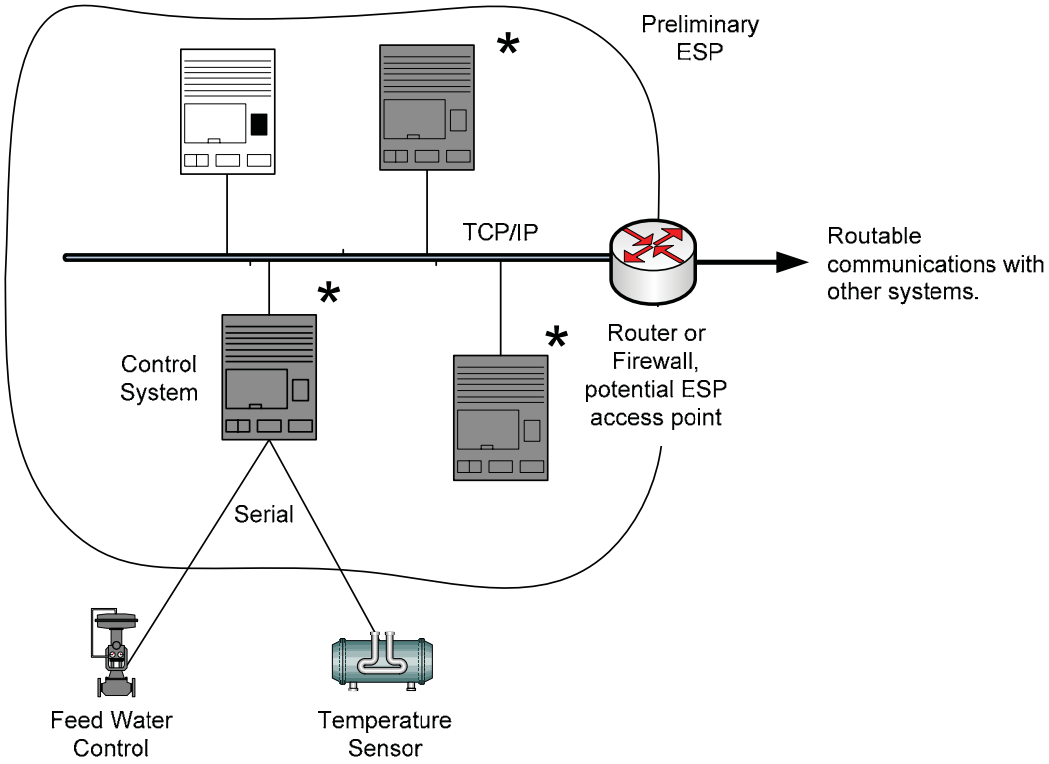

Drawing 8

Essential and nonessential Cyber Assets on a LAN outside of a control center communicate with each other using a routable protocol. The essential Cyber Assets with TCP/IP connectivity communicate with systems outside the ESP using a routable protocol which qualifies them as Critical Cyber Assets. The two serially-connected Cyber Assets controlling feed water flow and monitoring temperature are not Critical Cyber Assets, even if they are essential, provided that they do not pass data directly to or receive commands directly from systems outside the ESP (i.e., the local control system that they are connected to communicates only processed data to systems outside the ESP.)

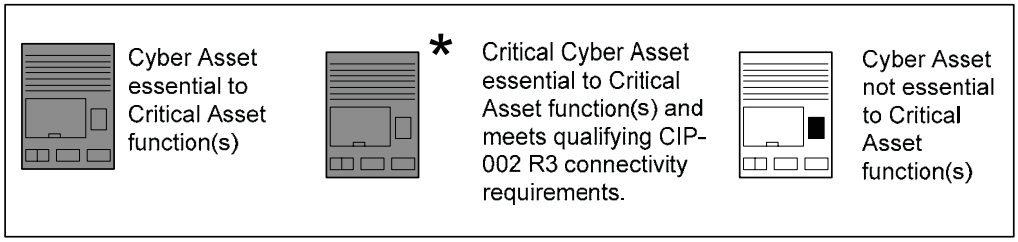

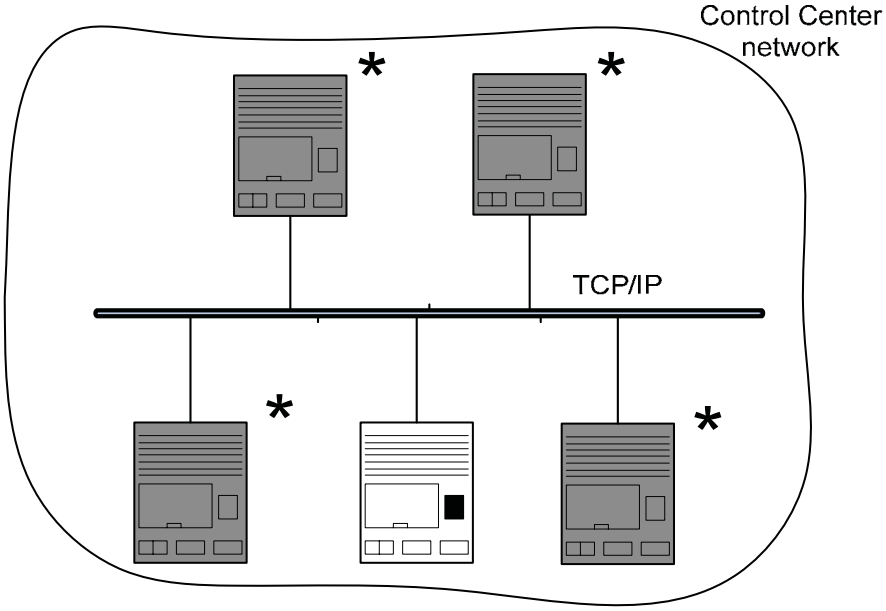

Drawing 9

Essential and nonessential Cyber Assets on a LAN within a Control Center communicate with each other using a routable protocol. Essential Cyber Assets that use a routable protocol within a Control Center are Critical Cyber Assets per CIP-002-1 R3.2. Communication outside the Control Center is not a consideration for Critical Cyber Asset identification at the Control Center.

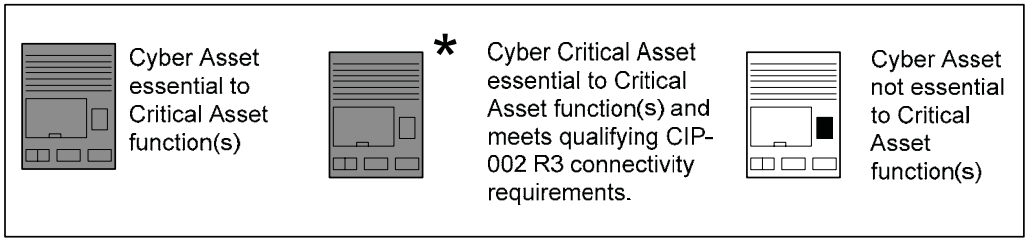

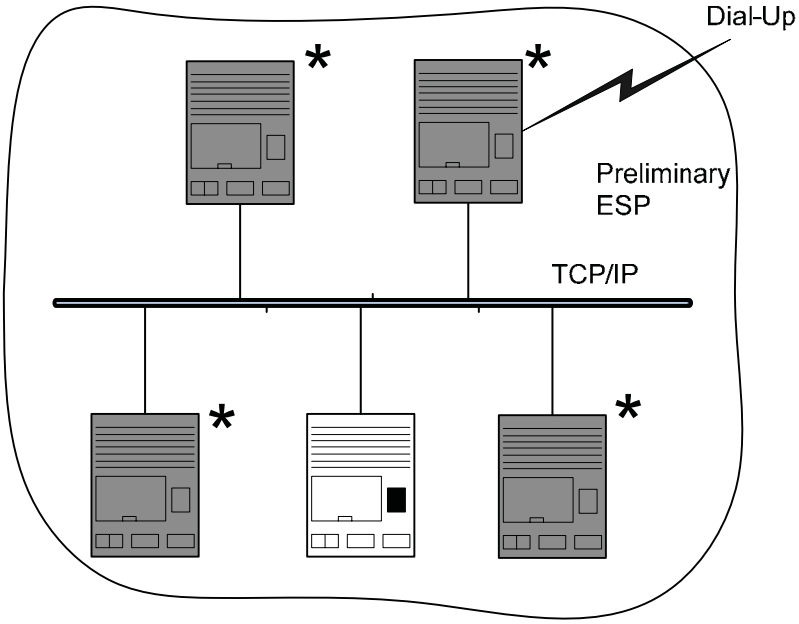

Drawing 10

Essential and nonessential Cyber Assets on an autonomous LAN outside of a Control Center communicate with each other using a routable protocol. One essential Cyber Asset is dial-up-accessible and is therefore a Critical Cyber Asset per CIP-002 R3.3. It might be possible to gain access to this dial-up system and then to other Cyber Assets on the LAN, therefore all essential Cyber Assets shown should be identified as Critical Cyber Assets. If dial-up access is removed, none of these Cyber Assets meet the CIP-002 R3 connectivity criteria, and therefore, would not be Critical Cyber Assets.

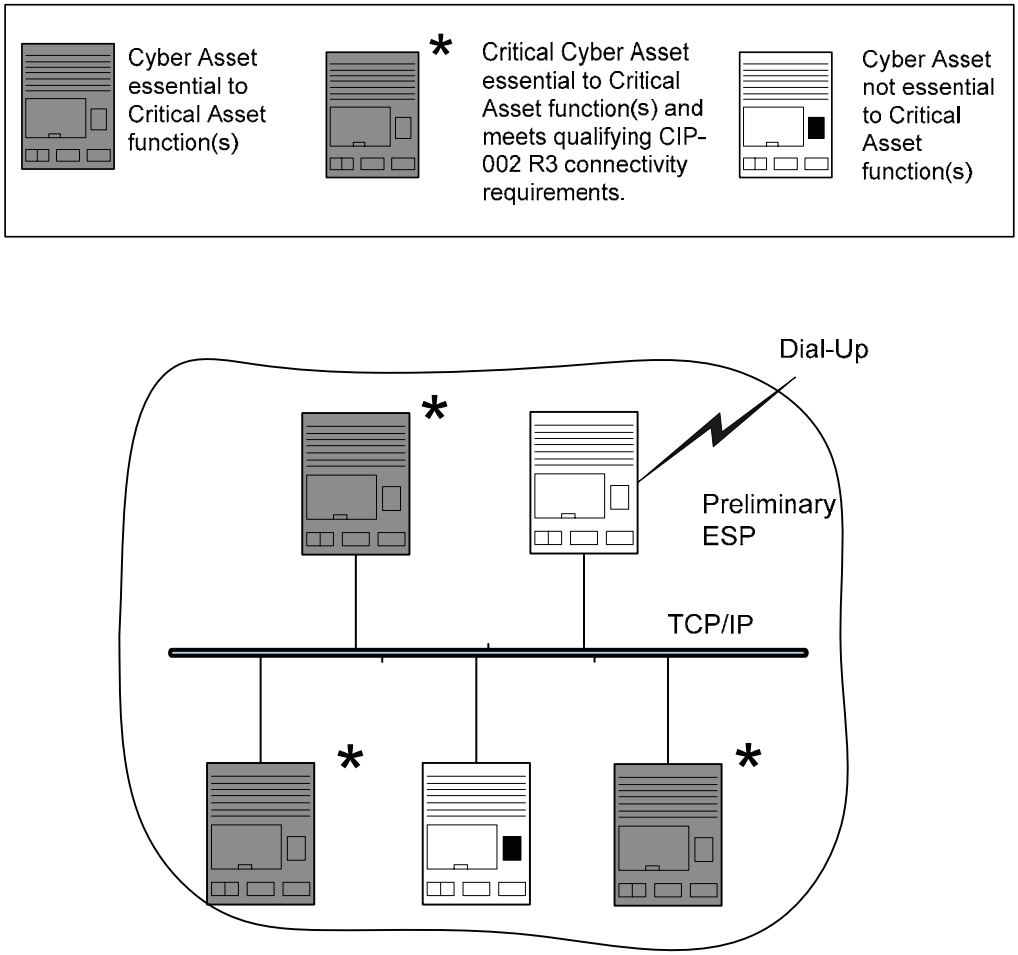

Drawing 11

Essential and nonessential Cyber Assets on an autonomous LAN outside of a Control Center communicate with each other using a routable protocol. One nonessential Cyber Asset is dial-up-accessible. It might be possible to gain access to this dial-up system and then to other Cyber Assets on the LAN, therefore all essential Cyber Assets shown should be identified as Critical Cyber Assets. If dial-up access is removed, none of these Cyber Assets meet the CIP-002 R3 connectivity criteria, and therefore, would not be Critical Cyber Assets

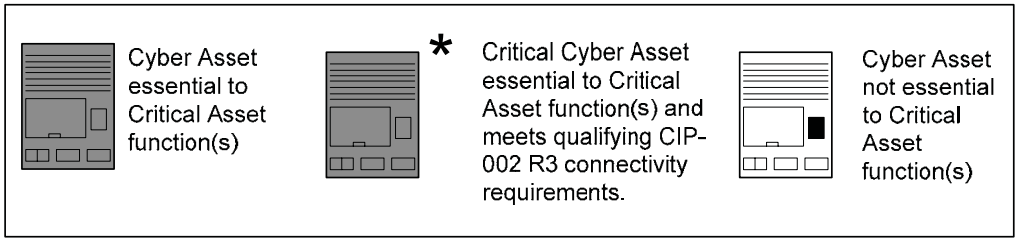

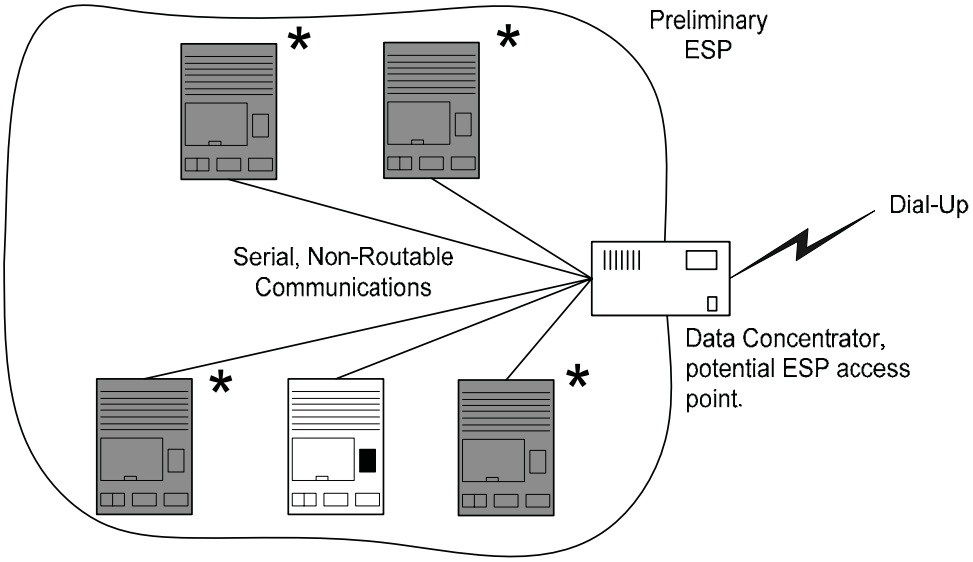

Drawing 12

Essential and nonessential Cyber Assets outside of a Control Center communicate with systems (e.g., SCADA) via a data concentrator that performs protocol conversion for communication with systems outside the preliminary ESP using a dial-up connection. The essential Cyber Assets shown do not use a routable protocol that communicates outside the ESP; however, they are connected via dial-up, therefore they meet the criterion of CIP-002 R3.3, and must be considered Critical Cyber Assets.

Attachment 2
Example Cyber Inventory List

Cyber Asset	Network Address	Application or Function	Associated Critical Asset	Used in supervisory or autonomous control impacting reliable operation of the Critical Asset?	Displays, transfers, or contains information relied on to make Real-time decisions impacting reliable operation of the Critical Asset?	Loss, Degradation or Compromise impacts the reliable operation of the Critical Asset?	Communicate with systems outside the ESP using a routable protocol?	Routable Protocol within a Control Center?	Dial-up Accessible?	Critical Cyber Asset?
(Entity-specific identifier)	192.168.5.8	SCADA Supervisory Control – Primary Server	Primary Control Center	Yes	Yes	Yes	No	Yes	No	YES
(Entity-specific identifier)	192.168.5.9	SCADA Supervisory Control – Backup Server	Primary Control Center	Yes	Yes	Yes	No	Yes	No	YES
(Entity-specific identifier)	192.168.5.10	State Estimator – App Server	Primary Control Center	No	Yes	Yes	No	Yes	No	YES
(Entity-specific identifier)	192.168.5.11	State Estimator – DB Server	Primary Control Center	No	No	Yes	No	Yes	No	YES
(Entity-specific identifier)	192.168.5.25	Print Server	Primary Control Center	No	No	No	No	Yes	No	NO

Revision History:

Date	Version Number	Reason/Comments
9/18/08	0.0	Initial version in NERC template
10/03/08	0.1	Results of October 3rd 2008 RAWG teleconference.
10/23/08	0.2	Results of October 23 rd 2008 RAWG teleconference.
10/30/08	0.3	Results of October 30th 2008 RAWG teleconference.
03/09/09	0.4	Results of March 9th 2009 RAWG teleconference.
04/03/09	0.5	Results of April 3rd 2009 RAWG teleconference.
04/17/09	0.6	Results of April 17th 2009 RAWG teleconference.
04/24/09	0.7	Results of April 24th 2009 RAWG teleconference.
05/08/09	0.8	Results of May 8th 2009 RAWG teleconference.
05/15/09	0.9	Results of May 15th 2009 RAWG teleconference.
05/22/09	0.901	Results of May 22nd 2009 RAWG teleconference.
06/05/09	0.902	Results of June 5th 2009 RAWG teleconference.
10/13/09	0.903	Results of October 13th 2009 RAWG online meeting.
10/19/09	0.904	Results of October 19th 2009 RAWG online meeting.
10/27/09	0.905	Results of October 27th 2009 RAWG online meeting.
11/03/09	0.906	Results of November 3rd 2009 RAWG online meeting.
11/10/09	0.907	Results of November 10th 2009 RAWG online meeting.
11/16/09	0.908	Results of November 16th 2009 RAWG online meeting.
11/23/09	0.909	Results of November 23rd 2009 RAWG online meeting.

11/24/09	0.910	Results of November 24th 2009 RAWG online meeting.
11/30/09	0.911	Results of November 30th 2009 RAWG online meeting.
1/18/10	0.912	Prepare for round of comments from industry
03/04/10	0.913	Results of March 4th 2010 RAWG online meeting.
03/15/10	0.914	Results of March 15th 2010 RAWG online meeting.
03/23/10	0.915	Results of March 23rd 2010 RAWG online meeting.
03/31/10	0.916	Results of March 31st 2010 RAWG online meeting.
04/07/10	0.917	Results of April 07st 2010 RAWG online meeting.
04/20/10	0.918	Results of April 20th 2010 RAWG online meeting.
04/27/10	0.919	Results of April 27th 2010 RAWG online meeting.
04/29/10	0.920	Results of April 29th 2010 RAWG online meeting.
05/06/10	0.921	Results of May 6th 2010 RAWG online meeting.
05/14/10	0.922	Results of edits made by email the week of May 10th.
5/21/10	0.923	Last edit during approval
6/17/10	1.0	Final Document – Approved by CIPC

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Agenda
Project 2008-06 Cyber Security Order 706 - Industry Webinar

August 24, 2011 | 11:00 a.m. - 12:30 p.m. ET
Meeting Location: Industry Webinar
Dial-in: 1.800.698.9012 | Access Code: 8816510 | Broadcast Audio: 234090

11:00 – 11:05 a.m.	Welcome and Opening Remarks
11:05 – 11:15 a.m.	Cyber Security Order 706 Drafting Team Schedule Update
11:15 – 11:55 a.m.	CIP-002 to CIP-011 Version 5 Revisions
11:55 a.m. – 12:00 p.m.	Implementation Plan
12:00 – 12:30 p.m.	Questions and Answers
12:30 p.m.	Adjourn

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FAC Recommendation Update

September 22, 2011 Webinar

Roman Carter, Manager – NERC Situation Awareness

RELIABILITY | ACCOUNTABILITY

FAC Recommendation Update

Webinar Agenda:

- Brief Background
- July 15th Report Results
- Overview of "Enhanced" Reporting Spreadsheet
- Q & A

FAC Recommendation Update

Background:

- A vegetation contact by a Transmission Owner identified actual **field conditions that varied significantly from design assumptions** – to the point where some facility ratings were considered inaccurate or in question.
- Follow-up resulted in the conclusion that this **situation was not restricted to one entity or region**.
- As a result, NERC issued an Alert (Recommendation) to proactively identify other such conditions and **promote corrective actions**.

FAC Recommendation Update

FAC Recommendation information provided:

- Oct 7, 2010 - Original Alert issued
- Oct 28th / Nov 29th 2010 – Informational webinars
- Nov 30, 2010 - Revised Alert / Cauley Letter
- Jan 14, 2011 - Q&A document issued
- Apr 26, 2011 – Assessment Plan Criteria issued
- May 12, 2011 – Webinar: Discussed Assessment Plan Review Criteria and reporting by Owners
- June 16, 2011 – Published Webinar Q&A Answers
- July 15, 2011 – First “high” priority assessment due date

FAC Recommendation Update

- On **July 15, 2011**, NERC received the first of two "high priority" assessment responses from NERC Facility Owners indicating there were approximately **278 owner assessments** performed.
- Results of the "high" priority assessments by the Facility Owners showed **over 200 discrepancies**. Of the discrepancies reported, approximately **68% had been mitigated** as of July 15th.
- The following slides provide an overview of the information received from the July 15, 2011 responses.

FAC Recommendation Update

Discrepancy Category Breakdown

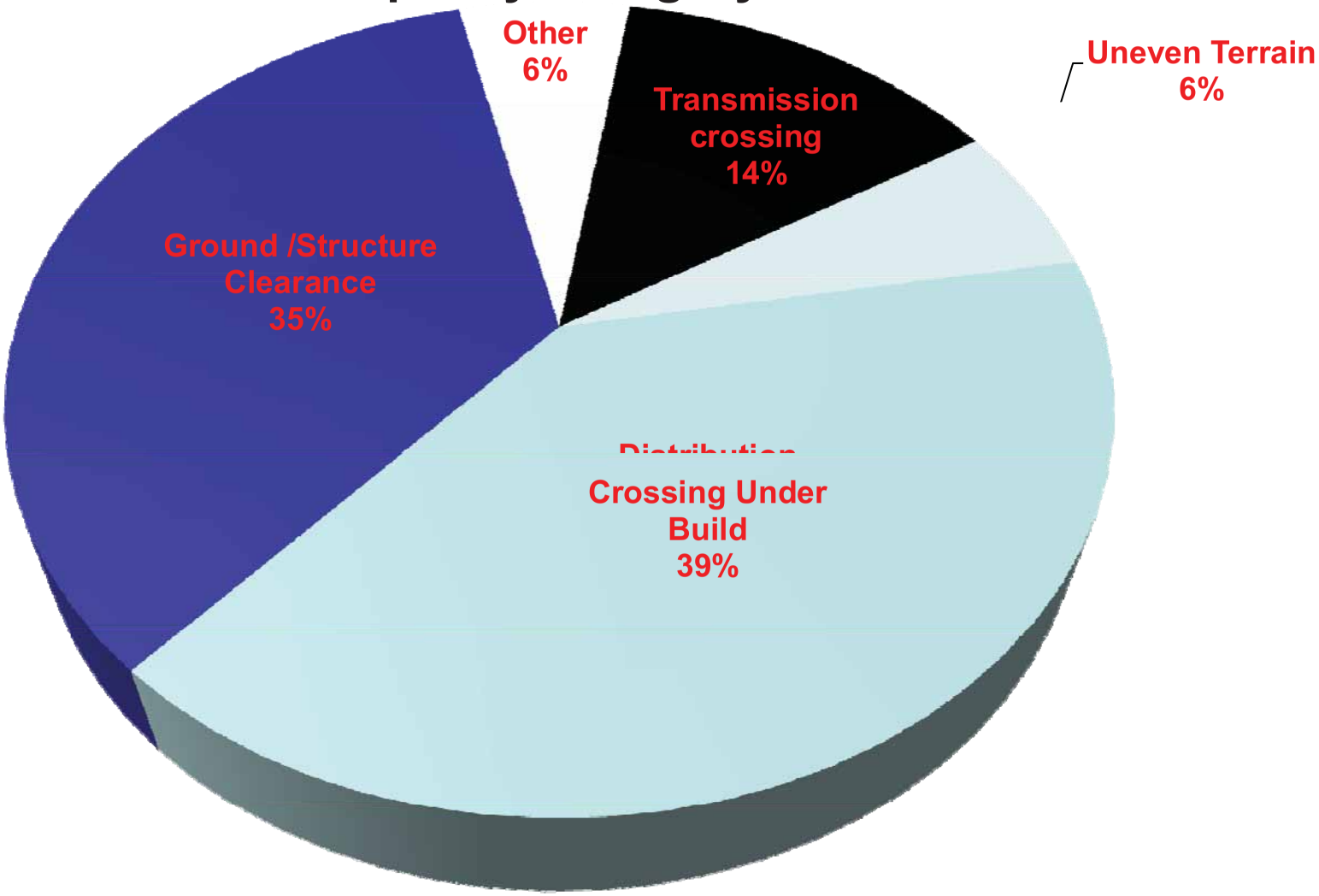

FAC Recommendation Update

Top 7 Inspection Method for Assessments

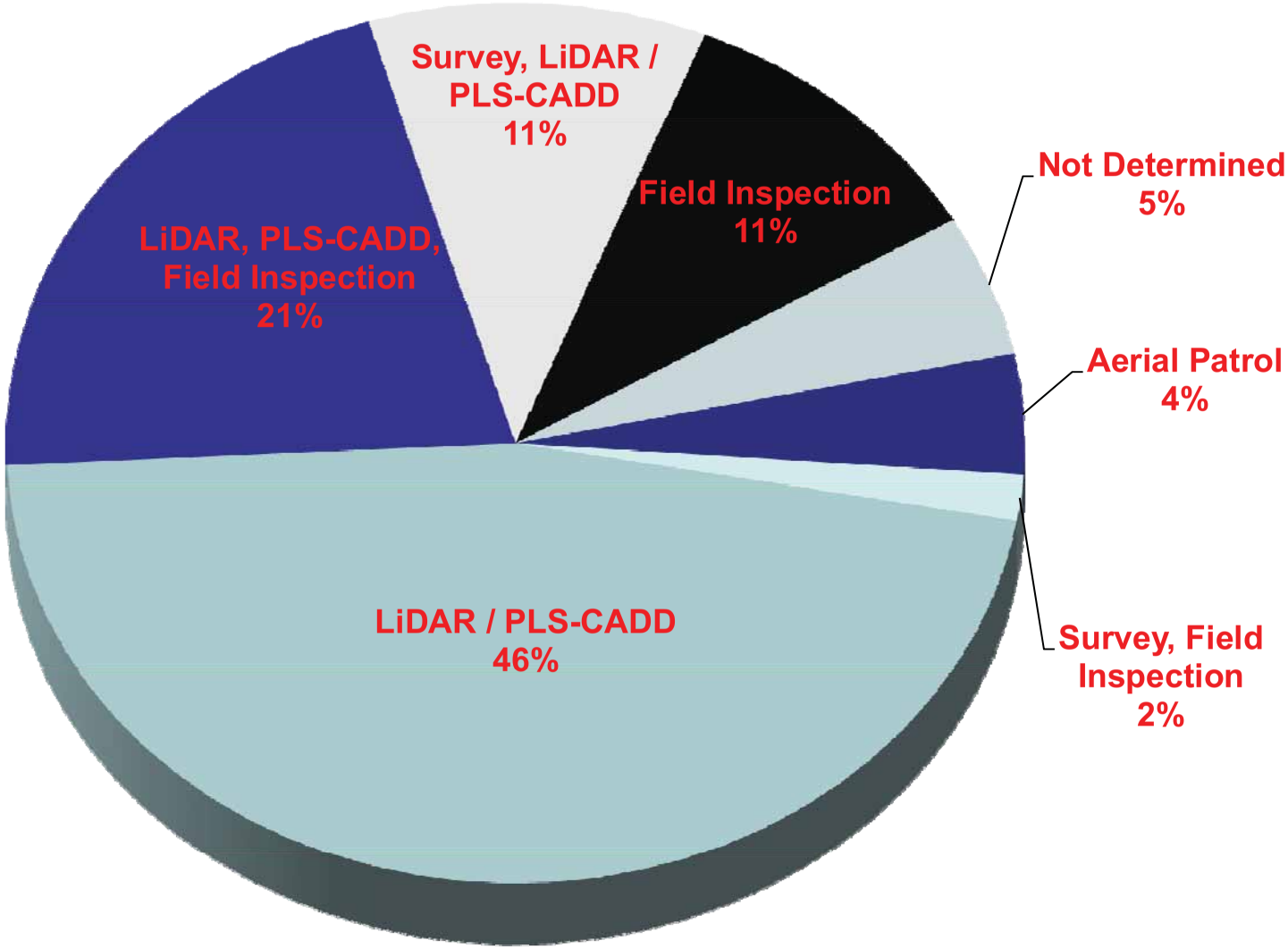

FAC Recommendation Update

Top 5 Remediation Categories

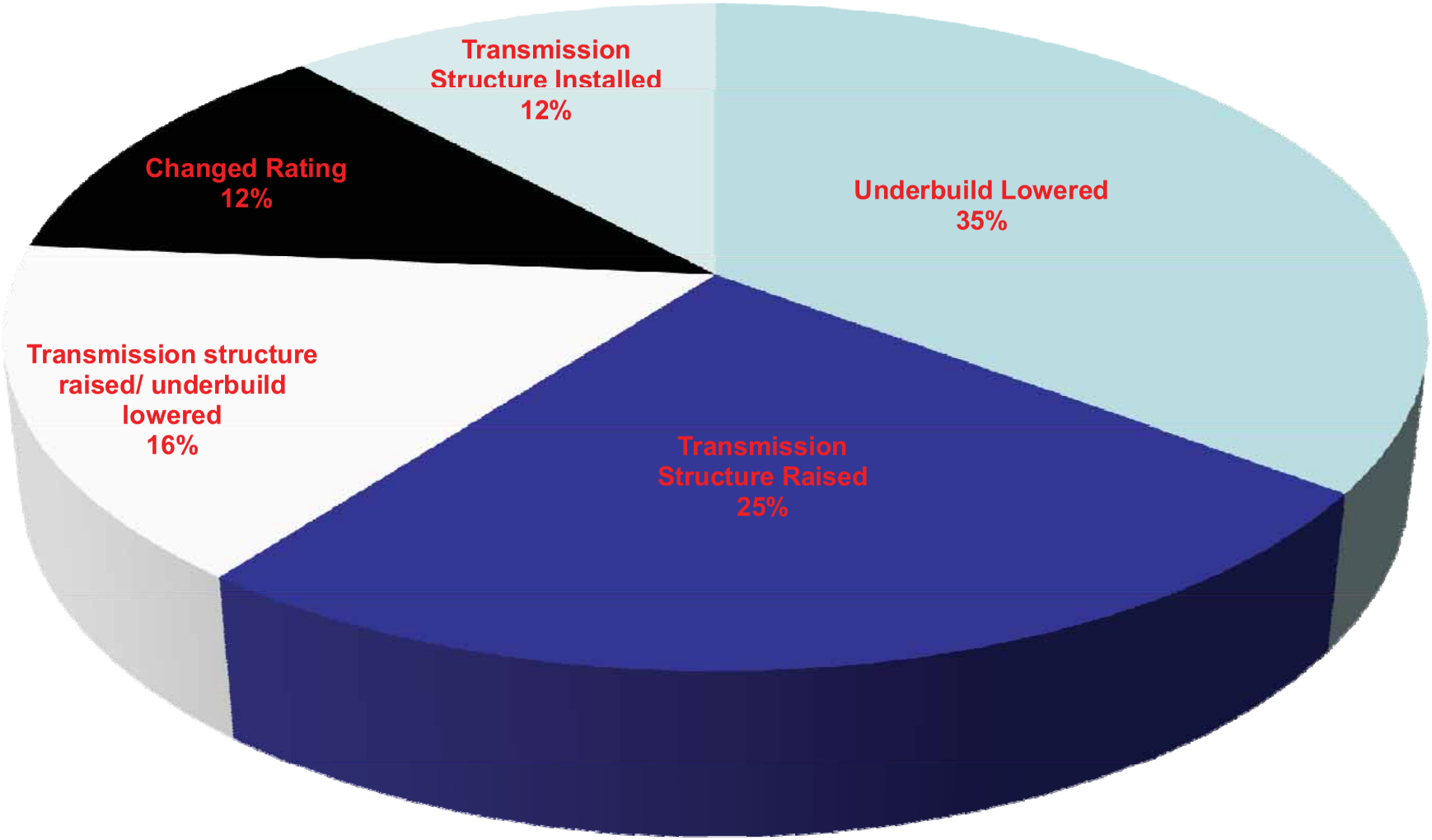

FAC Recommendation Update

Issues with some July 15th Responses:

1. Information placed in wrong column
2. Multiple answers given for single circuit
3. Inappropriate responses for given question.
4. Requested information left blank.
5. Did not accept Medium or Low assessments.
6. User changed format of Spreadsheet

FAC Recommendation Update

Enhancements Made to Report Spreadsheet:

1. Added *Entity Info* Tab accepting "Medium" and "Low" priority response information
2. Added drop down boxes for user to select options for: *Inspection Type*, *Rated KV*, *Discrepancy Category*, *Remediation Category*,etc.
3. Summary Tab to request "totals" information
4. Added Data Dictionary to help explain the information being requested.
5. "Hover Over" text provided for each cell.

FAC Recommendation Update

Schedule for the Remaining Assessments:

- The second "high" priority assessment response is due to the Regions on January 15th, 2012.
- The two "medium" priority assessments are due to the Regions on July 15, 2012 and January 15th, 2013.
- The "low" priority assessments are due to the Regions July 15, 2013 and January 15, 2014

FAC Recommendation Update

Questions

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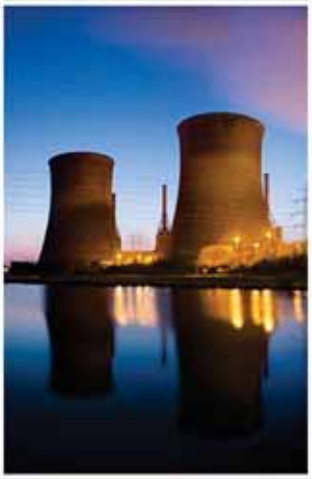

Media Release

NERC Announces New Enforcement Initiative

August 4, 2011

WASHINGTON, DC – The North American Electric Reliability Corporation announced a new initiative for processing violations of Reliability Standards at its quarterly board meeting in Vancouver. The initiative complements other efforts already underway at NERC.

After five years as the electric reliability organization, NERC recognizes that treating all compliance violations with equal weight is not the best way to ensure the reliability of the grid. The new enforcement process is designed to refocus efforts on reliability excellence, eliminate undue regulatory burdens, streamline paperwork requirements, increase caseload processing, and encourage continued timely and thorough self-reporting and mitigation.

"Process should evolve as experience evolves," said Gerry Cauley, president and chief executive officer at NERC. "This new enforcement process allows us to do our job as the ERO more efficiently and effectively. A mature ERO must use the tools available to focus on issues that pose the greatest risk to reliability."

The new process differentiates issues of noncompliance based on the level of potential risk to the reliability of the bulk power system. All instances of noncompliance will continue to be identified and mitigated. Issues that pose a more serious risk to the reliability of the bulk power system will be filed at the Federal Energy Regulatory Commission on a monthly basis in a further streamlined spreadsheet Notice of Penalty format. Matters that pose a low risk to reliability will be processed on a "find, fix, track and report" spreadsheet that will be submitted on a monthly basis to FERC.

"The 'find, fix, track and report' process recognizes the experience of the Regional Entities and NERC in assessing violations and builds on the success of

CONTACT:
Kimberly Mielcarek
202-383-2622

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Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Abbreviated Notices of Penalty and the Administrative Citation Notice of Penalty Process," said Rebecca Michael, associate general counsel and acting director of enforcement at NERC. The new process changes the manner in which potential non-compliance issues are handled, not the fact that they occur. In all cases, Regional Entities will track and report all issues of concern identified. All instances must be mitigated – regardless of the risk level.

The new enforcement process, which will begin with an initial filing at FERC in September, will improve reliability and risk management by improving the way NERC identifies and processes compliance issues. NERC remains committed to ensuring reliability by maintaining accountability for all stakeholders in the compliance enforcement process.

###

The North American Electric Reliability Corporation's mission is to ensure the reliability of the North American bulk power system. NERC is the electric reliability organization (ERO) certified by the Federal Energy Regulatory Commission to establish and enforce reliability standards for the bulk-power system. NERC has equivalent relationships with provincial and federal authorities in Canada. NERC develops and enforces reliability standards; assesses adequacy annually via a 10-year forecast, and summer and winter forecasts; monitors the bulk power system; and educates, trains and certifies industry personnel. Learn more at www.nerc.com

From: Elizabeth Heenan
To: Elizabeth Heenan
Subject: NERC ANNOUNCEMENT - NERC Announces New Enforcement Initiative
Date: Thursday, August 04, 2011 5:24:04 PM

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Announcement

NERC Announces New Enforcement Initiative

Click here for the full announcement

WASHINGTON, DC – The North American Electric Reliability Corporation announced a new initiative for processing violations of Reliability Standards at its quarterly board meeting in Vancouver. The initiative complements other efforts already underway at NERC.

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For more information or assistance, please contact Kimberly Mielcarek at (202) 383-2622.

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NERC Compliance Webinar

Compliance Application Notice (CAN) Process Update

September 2, 2011

RELIABILITY | ACCOUNTABILITY

Administrative

- NERC Anti-Trust Guidelines
- Notice of Open Meeting
- Introduction of NERC Staff
- Submit questions through Ready Talk

Agenda

- Overview of Changes to CAN Process
  - NERC BOTCC Meeting in Vancouver on August 4, 2011
- Review of Revised CAN Process Document
- Review of Recently Retired CANs
- Brief Overview of Rewritten CANs
- Question and Answer Session
- Closing Remarks

Purpose

- Provide an update on changes to the CAN Process
  - Focus on Compliance Enforcement Authorities (CEA)
- Provide status for previously posted CANs

Background

- Compliance Application Notices (CANs) provide instruction for Compliance Enforcement Authority (CEA) staff on how to assess compliance with NERC reliability standards.
- CANs fulfill NERC's obligations under FERC Order No. 693 to provide compliance instruction to ERO auditors on a going forward basis.

Background

- Compliance Application Notices (CANs) have been a major topic of discussion in the industry.
- The Chairman of the NERC Board requested policy input from the NERC Member Representatives Committee (MRC).
- CANs were discussed at the August MRC meeting, with the NERC Board in attendance.
- At the NERC Board meeting the next day, guidance was provided.

NERC Board Guidance

- Review and revise the CAN Process Document
  - CAN Purpose:
    - To *establish consistency* in the application of compliance criteria across all CEAs; and
    - To *provide transparency* to industry on how a CEA will apply compliance with a NERC Reliability Standard.

NERC Board Guidance

- CAN Scope:
  - A CAN provides instructions to CEAs regarding the boundaries within which to assess compliance with standards and requirements.
  - A CAN cannot expand a standard.
  - A CAN cannot add new requirements to a standard.
  - NERC is responsible for issues that impact the reliability of the BPS.

NERC Board Guidance

Contesting a CAN:

A registered entity or its representatives may (in order of hierarchy):

- Submit technical evidence to have a CAN changed or removed;
- Propose a change to the standard through a request for a formal interpretation or a Standard Authorization Request (SAR); or
- Request a higher-level review of the CAN:
  - First level of review by NERC's Chief Executive Officer;
  - Second level of review by NERC Board of Trustees Compliance Committee (BOTCC).

In accordance with the NERC Rules of Procedure, a registered entity may contest a violation that was assessed due to the application of a CAN.

Initial Industry Feedback

- CAN Process was posted on the NERC web site on August 15, 2011
- Comments are due on September 6, 2011
- Initial feedback includes requests for:
  - More detail on the CAN development process, to include vetting
  - Posting all industry comments with the analysis for transparency
  - Detail on feedback mechanism to Standards for issues not dealt with in the CAN
  - Specification regarding the higher level review process, format and timelines
  - Detail regarding the higher level review options

Retired CANs

CANs Retired on August 31, 2011:

- CAN-0001 INT-004-2 R1: Correction to VRF Matrix
- CAN-0002 TOP-003-0 R1.3: Correction to VRF Matrix and 2010 Actively Monitored List (AML)
- CAN-0003 IRO-006-4.1 R2: Correction to 2010 AML
- CAN-0004 IRO-004-1 R3: Correction to VRF Matrix and 2010 AML

Reposted for Comment

Comments due September 6, 2011

Submit comments to **cancomments@nerc.net**

- Revised CAN Process
- CAN-0016 CIP-001 R1: Sabotage Reporting Procedure

Changes to CAN-0016

- Target audience is now Compliance Enforcement Authorities
  - "CEAs are instructed to verify…"
- Updated issue statements
- Revised Compliance Application section
- Revised language in the Effective Period for CAN section
- Evidence of Compliance is now directed at the CEA, not the registered entity

Excerpts from CAN-0016

Compliance Application Section:

- ***"The emphasis of the standard is for the registered entity's personnel to be able to recognize sabotage event(s) that may impact the reliability of the Bulk Power System (BPS) and make operating personnel aware of recognized sabotage event(s).***
- *A CEA is to verify that the entity's procedure provides sufficient detail as to how it determines whether 1) events are sabotage-related and 2) the event has the potential to impact the reliability of the BPS.*
  - *Examples may include but are not limited to: events or activities that may threaten the reliability of the BPS, create a threat to the reliability of the BPS or impede the utilities ability to reliably operate the BPS.*
- *When assessing compliance, CEAs are not to consider a registered entity's determinations regarding whether events were sabotage-related or whether the events were reported. A CEA is to verify whether the registered entity made the determination and reporting decision according to the entity's sabotage reporting procedure."*

Excerpts from CAN-0016

Effective Period of CAN Section:

- *"CEAs are instructed to assess compliance by the registered entity's current sabotage reporting procedure and the facts and circumstances surrounding that procedure. 'Current' means the sabotage reporting procedure in effect at the time of the audit.*
- *For example:*
  - *If, following the posting of this CAN, a registered entity's sabotage reporting procedure contains the elements specified by the standard and outlined in this CAN, CEAs are to evaluate the entity's current sabotage reporting procedure. The CEA is not to look further back in time to determine non-compliance or a Possible Violation because prior versions of the entity's sabotage reporting procedure did not include each of the elements identified in this CAN, or specifically excluded certain facilities that, if subjected to a sabotage event, could impact the BPS.*
  - *The CEA is to identify non-compliance and a Possible Violation if a registered entity:*
    - *did not respond to compliance guidance and therefore its current sabotage reporting procedure specifically excludes facilities that, if subjected to a sabotage event, could impact the BPS; or*
    - *responded to this compliance guidance only in preparation for an upcoming audit."*

Excerpts from CAN-0016

Evidence of Compliance Section:

- *"A CEA is to assess the following to obtain reasonable assurance of the entity's compliance:*
  - *evidence of the entity's sabotage reporting procedure, including how it will identify sabotage events that impact the reliability of the BPS, and*
  - *evidence that the entity is following its procedure, including a list of events that were analyzed."*

  …
- *"For any enforcement action in process and for audits that have been initiated, a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether this CAN should be applied.*
  - *'Initiated' means that a registered entity has received notification of the upcoming audit."*

CANs Reposted for Comment

Comments Due September 21, 2011

- CAN-0005 CIP-002 R3: Critical Cyber Asset Designation for System Operator Laptops
- CAN-0006 EOP-005: Verification of Restoration
- CAN-0007 CIP-004 R4: Revocation of Access to CCAs
- CAN-0008 PRC-005 R2: Pre-June 18, 2007 Evidence
- CAN-0018 FAC-008: Terminal Equipment

Future CANs for Comment

CANs to be Posted for Comment in the Near Future

- CAN-0009 FAC-008 and FAC-009: Facility Ratings and Design Specifications
- CAN-0010 Multiple Standards: Definition of "Annual"
- CAN-0011 PRC-005-1 R2: New Equipment
- CAN-0012 CIP-002 through CIP-009: Completion of Periodic Activity by Effective Date
- CAN-0013 PRC-023 R1 and R2: Switch on to Fault Schemes
- CAN-0015 Multiple Standards: NERC Software Tools
- CAN-0022 VAR-002 R1: Generator Operation in Manual Mode
- CAN-0026 TOP-006 R3: Protection Relays
- CAN-0028 TOP-006 R1.2: Reporting

CAN Process Questions

- Please submit questions through Ready Talk

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Submit CAN comments to: cancomments@nerc.net

Link to CAN web site: http://www.nerc.com/page.php?cid=3|22|354

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Registration & Certification Update

Processes, Procedures and Responsibilities

September 9, 2011

RELIABILITY | ACCOUNTABILITY

Topics

- Purpose and Background
- Organization Certification
  - New Entity
  - Provisional Certification
  - Change/Expanding Footprint
- Registration Options
  - Individual Registration
  - Joint Registration Organization (JRO)
  - Coordinated Functional Registration (CFR)
  - Concurrent
- Completing a Master Matrix (List)

Purpose and Background

- Purpose: To provide an update on Registration and Certification processes, procedures, and responsibilities
  - RoP Section 500 and Appendices 5A & 5B
- Background: Industry Feedback requesting
  - Additional guidance regarding certification processes for Balancing Authorities (BA), Reliability Coordinators (RC) & Transmission Operators (TOP)
  - Additional guidance regarding registration options (JRO/CFR/Individual/Concurrent Registrations)
    - Recent changes to the NERC Rules of Procedure Section 500 and Appendices 5A & 5B address these issues

Certification – New Entity

- Scope is for BA, RC, or TOP
- New entity must certify before going operational per RoP 500 and Appendix 5A
  - Entity must submit application to the Region(s)
  - No compliance issues because the entity is not operating
  - Process takes 1- 9 months to complete
  - Entity must go operational within 1 year after being certified

Provisional Certification

- The Organization Registration & Certification Subcommittee (ORCS) established a process
  - Already operating RC, BA, or TOP;
  - Has completed a compliance audit in the applicable function(s); and
  - Has completed a readiness assessment in the applicable function(s)
    - Readiness assessments are no longer being performed by the ERO
- If the entity has not completed both the above, a certification review will be completed by the Regional Entity with NERC

Certification- Change/Expansion

- Entity is already certified as an RC, BA, or TOP
- Per RoP Appendix 5A, items to consider when this entity may need to certify:
  - Changes to an entity's footprint or operational challenges (i.e., TLRs) due to the changes
  - Organizational restructuring that could impact the BPS reliability
  - Relocation of the control center(s)
  - Changes to entity ownership requiring major operating procedure changes

Certification- Change/Expansion

- Items to consider (continued)
  - Significant changes to JRO/CFR assignments or agreements
    - Such as addition of a member to a CFR
  - Complete replacement of a SCADA/EMS
- The decision to certify this entity is a collaborative decision between NERC and the Regional Entity
  - It could be an aggregate of the above
  - **Focus will be on the changes**

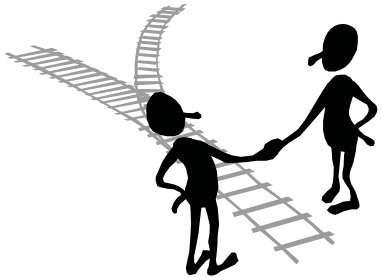

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Registration Options

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Individual Registration

- "Organizations will be responsible to register and to comply with approved reliability standards to the extent that they are owners, operators, and users of the bulk power system(…)"
- That entity must fully comply with the applicable NERC Reliability Standards
  - Delegated Reliability Tasks
  - NERC Bulletin 2010-004 provides guidance… "Guidance for Entities that Delegate Reliability Tasks to a Third Party Entity"

Guidance Recommendations

- Ensure that non-registered entities performing reliability tasks on its behalf comply with the applicable NERC Reliability Standard requirements;
- Ensure that non-registered entities provide evidence of such compliance; and
- Registered entity must ensure that NERC and the Regional Entity are aware of 3rd party performing reliability tasks in its behalf
  - Compliance Responsibilities cannot be delegated

Joint Registration Organization

- Identified in RoP 507
  - Entity may register for itself and one or more of its members for one or more functions
  - Takes full compliance responsibility for itself and it's member(s)
  - Application made to the Regional Entity(s)
  - The JRO must have an agreement with its member(s)
  - JROs posted on NERC Web (Formerly Type I JRO)
  - The JRO is responsible for all CMEP activities
- Typically a Coop, G&T, or JAA

Coordinated Functional Registration

- Identified in RoP 508
  - Entity may register with one or more entities for a single function
  - Allocating or assigning compliance responsibility amongst entities
  - Application made to the applicable Regional Entity(s)
  - Application must identify the CFRs Point of Contact (POC)
  - Agreement clearly articulating compliance responsibilities (typically an attached list)
  - List (matrix) must be kept up to date by a single POC

Coordinated Functional Registration

- Identified in RoP 508 (continued)
  - CFRs posted on NERC Web (Formerly Type II JRO)
  - CFR does not change compliance responsibilities for other function(s) for which each entity in the CFR may be registered
  - Region is to ensure no unnecessary duplication or areas lacking in the CFR
    - Work closely with the Regional registration manager

Coordinated Functional Registration

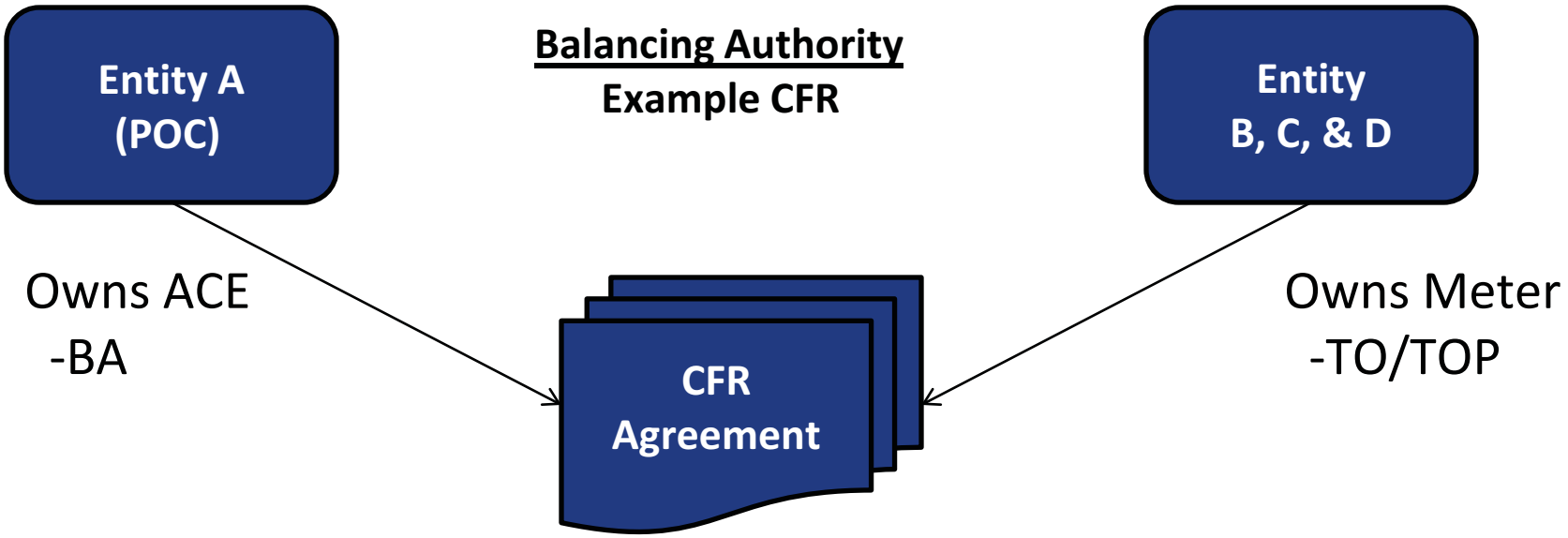

Coordinated Functional Registration

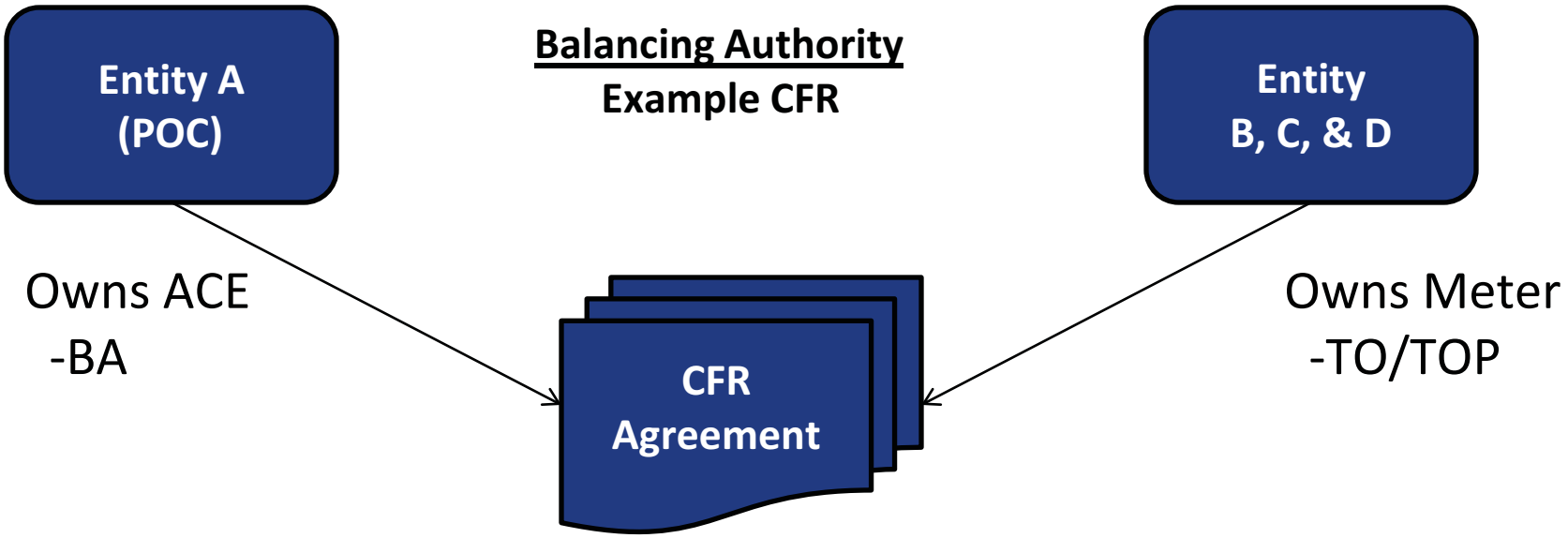

Entity A is the BA for Entity B, C, & D

- BAL-001-0 R1 Entity A Only (Area Control Error-ACE)

Coordinated Functional Registration

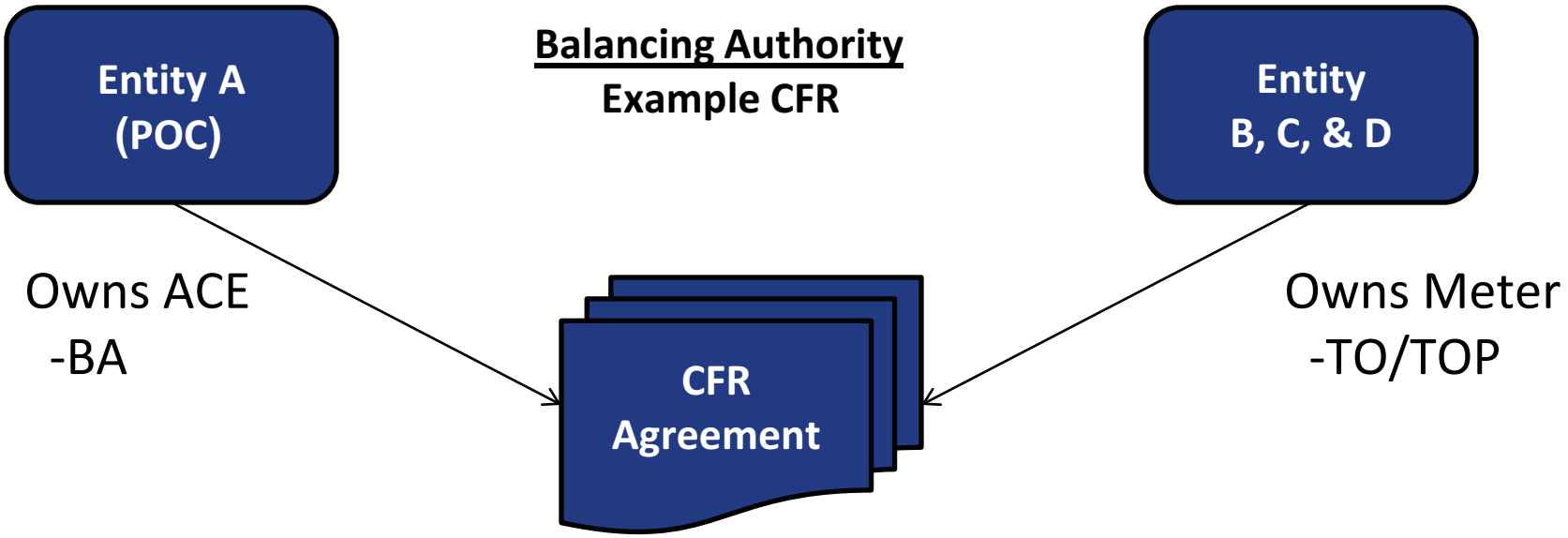

Entity A is the BA for Entity B, C, & D

- BAL-001-0 R1 — Entity A Only (Area Control Error-ACE)
- BAL-005-0.1b R13 — Split (Entity A owns ACE & Members own Meters)

Coordinated Functional Registration

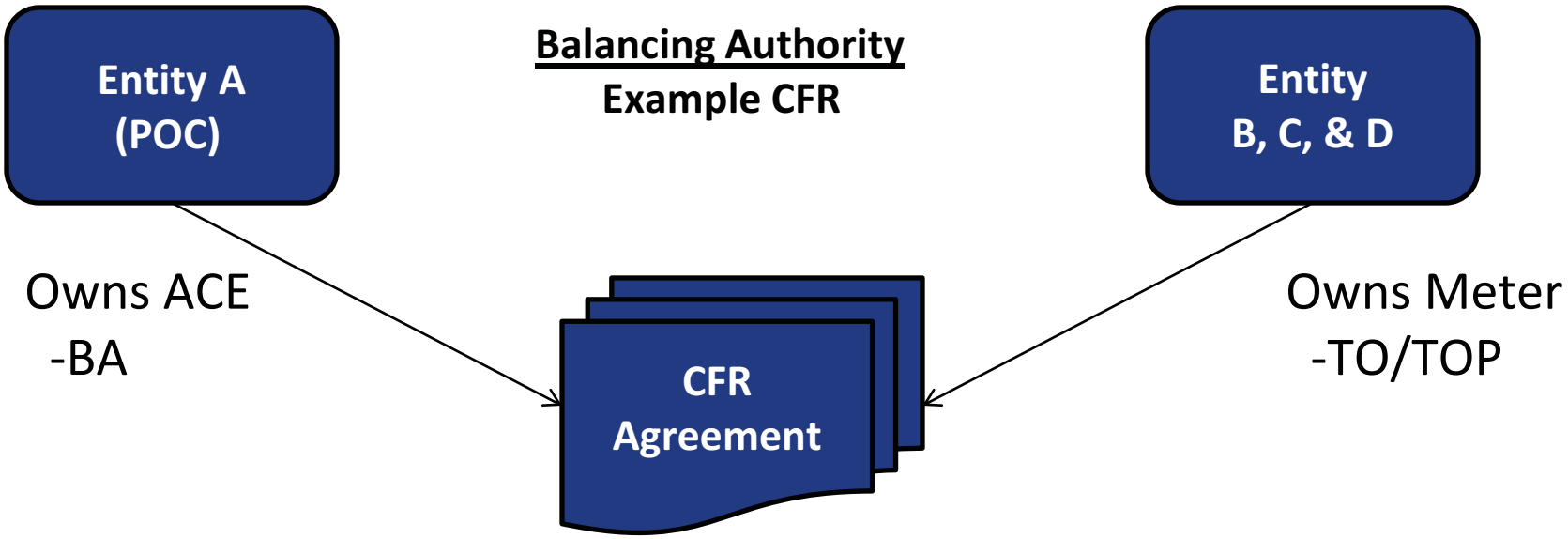

Entity A is the BA for Entity B, C, & D

- BAL-001-0 R1 — Entity A Only (Area Control Error-ACE)
- BAL-005-0.1b R13 — Split (Entity A owns ACE & Members own Meters)
- After CFR is approved by the region and posted on the NERC Compliance Registry, all will be registered as a BA under the CFR

Concurrent Registration

- Multiple entities concurrently register for compliance with a single BES component (i.e., generator) or common control area
  - Should have agreements in place
    - There may be legacy agreements involved
  - Registered entities should provide a list to the Regional Entity that clearly articulates which requirements are divided amongst all those that are concurrently registered
    - Each registered entity should be able to point to sections of their agreement(s) that support their position(s)
      - Manage compliance risk/exposure

Compliance Registry Criteria

- Provides the criteria for registration of a user, owner, or operator of the bulk power system
- That entity may appeal its registration per the NERC Rules of Procedure Section 500 and Appendices 5A & 5B
  - Work closely with the Regional registration manager if you think you should be deregistered

References

- FERC Order #672, #693, and #706
  - http://www.nerc.com/files/final_rule_reliability_Order_672.pdf
  - http://www.nerc.com/files/order_693.pdf
  - http://www.nerc.com/files/FERC_Order_706.pdf
- NERC Bulletin #2010-004
  - http://www.nerc.com/files/2010-004%20v1%200.pdf
- Statement of Compliance Registry Criteria
  - http://www.nerc.com/files/Statement_Compliance_Registry_Criteria-V5-0.pdf

References

- NERC Rules of Procedure
  - Section 500 “Organization Registration and Certification”
  - Appendix 5A “Organization Registration and Certification Manual”
  - Appendix 5B “Statement of Compliance Registry Criteria”

http://www.nerc.com/page.php?cid=1|8|169

Conclusions

- There are various options regarding registration
  - Single registration
  - JRO – RoP 507
  - CFR – RoP 508
  - Concurrent registration
- Fully understand your compliance risks and accountability for each!
  - NERC Guidance under Bulletin 2010-004
    - Guidance for written contracts per section 2
  - Work with the Regional Entity registration contact

Contacts

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- Ryan Stewart
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- Regional Entity Websites
  - http://www.nerc.com/page.php?cid=3|23

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Compliance: *Regional Programs*

Compliance enforcement activities are carried out on behalf of NERC by the eight regional entities based on the NERC Compliance Monitoring and Enforcement Program and their respective delegation agreements. NERC oversees these programs to ensure consistency and fairness.

Click on any link below to visit a NERC region's compliance program Web site:

- Florida Reliability Coordinating Council - FRCC
- Midwest Reliability Organization - MRO
- Northeast Power Coordinating Council - NPCC
- ReliabilityFirst Corporation - RFC
- SERC Reliability Corporation - SERC
- Southwest Power Pool Regional Entity - SPP RE
- Texas Reliability Entity - TRE
- Western Electricity Coordinating Council - WECC

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Completing a Master Matrix

Ryan Stewart

Engineer of Organization Registration, Certification, and Compliance Monitoring

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Disclaimer

- The guidance and examples in this document are provided for informational purposes only, and are being used in this presentation to provide examples of items that could be included in an entity's compliance program. An entity's adherence to the examples contained within this presentation does not constitute compliance with the NERC Compliance Monitoring and Enforcement Program ("CMEP") requirements or any other NERC rules, and NERC reserves the right to request additional information and/or to require actions not discussed in this presentation. All entities must independently evaluate for accuracy their own "list" to determine what should be included in their program.
- This material is the property of the North American Electric Reliability Corporation ("NERC") and may not be copyrighted, duplicated, or reproduced in whole or in part without prior written permission from NERC.

Master Matrix Uses

- For a CFR, spreadsheet denoting responsibilities
- Can be used during certifications
- May also be used for concurrent registrations
- We will use the example presented earlier for a BA CFR

Master Matrix *What is it?*

- An excel spreadsheet taken from the NERC Web site
- Shows which standards and requirements are applicable to each function
- Found here on left site as "VRF Matrix": http://www.nerc.com/page.php?cid=2|20
- Suggested tool for many uses
- **Can be used for registration and certification activities**

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VRF Matrix on Web Site

http://www.nerc.com/page.php?cid=2|20

File Edit View Favorites Tools Help Convert Select

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Reliability Standards

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About Standards

Reliability Standards
- -Functional Model
- -Glossary of Terms
- -Mandatory Effective Dates
- -Inactive Standards
- -VRF Matrix
- -VSL Matrix

Standards Under Development

Balloting

Regional Reliability Standards

Home Page

Resource Documents

Standards: *Reliability Standards*

This page provides a copy of the latest version of the standard approved by the NERC Board of Trustees and any prior versions that were BOT approved and are still in effect in at least one regulatory jurisdiction. Note that not all the standards on this page have been approved by governmental authorities as enforceable standards. The Mandatory Effective Dates Web pages identify, by regulatory jurisdiction, the status of the standards and the applicable dates. Prior versions of standards may be found on the Inactive Standards Web page.

All standards on this page have been adopted by the NERC Board of Trustees. The date field indicates the date on which the NERC Board of Trustees adopted the standard.

All comments should be forwarded to sarcomm@nerc.net. Questions? E-mail Herb Schrayshuen or call **609-452-8060**.

Complete Set of Reliability Standards ▾ VIEW

Resource and Demand Balancing (BAL) ▾ VIEW

Communications (COM) ▾ VIEW

Master Matrix

- Download and save the VRF Matrix-Reopen
- Under the FERC Approved Standards tab in the spreadsheet , filter for the appropriate function (For Example, RC, BA, or TOP)
  - To do this, select the first row, and then press the filter feature
- Copy the “Standard Number” – “Requirement Number” – and “Violation Risk Factor” for the function selected

Master Matrix

- Create a new column
  - Titled: “Entity Response” or “How Requirement Met”
  - The response shows how the registered entity(ies) meets each requirement
- The file can be easily updated to denote changes to a CFR, conduct a certification, etc.

How to Use for a CFR

- Columns in a spreadsheet displays
  - Standard
  - Requirement
  - How a registered entity complies through processes, procedures, or tools
  - Responsibilities
- Either a single, shared, or split responsibility
- An example in Excel

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Blank Master Matrix

BA Master Matrix						
Standard	Req	Process, Procedure, Tools for How Registered Entity Meets Requirement	Text of Requirement	Entity A	Other	Responsibility

Master Matrix

BA Master Matrix						
Standard	Req	Process, Procedure, Tools for How Registered Entity Meets Requirement	Text of Requirement	Entity A	Other	Responsibility
BAL-001-0	R1.	Entity A is solely responsible for this requirement. Entity A calculates ACE for the CFR footprint.	Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B times the corresponding clock-minute averages of the Interconnection's Frequery Error is less than a specific limit.	X		Single

Master Matrix

BA Master Matrix

Standard	Req	Process, Procedure, Tools for How Registered Entity Meets Requirement	Text of Requirement	Entity A	Other	Responsibility
BAL-001-0	R1.	Entity A is solely responsible for this requirement. Entity A calculates ACE for the CFR footprint.	Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B times the corresponding clock-minute averages of the Interconnection's Frequery Error is less than a specific limit.	X		Single
BAL-005-0.1b	R13.	Entity A calculates ACE. For the interchange meter error (IME) term of the ACE, Entity A uses an aggregate of the other entities IME for the tielines external to Entity A's BA Area. Entities B, C, D shall provide to Entity A an interchange meter error value for its external tie lines. Entity A sums the interchange meter error values from the other entities to obtain the aggregate interchange meter error term for Entity A's BA ACE. Entities B, C, D shall perform hourly error checks using Tie Line megawatthour meters with common time synchronization to determine the accuracy of its control equipment. Entities B, C, D shall also take corrective action to adjust any components that are in error.	Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the accuracy of its control equipment. The Balancing Authority shall adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error term of the ACE equation to compensate for any equipment error until repairs can be made.	X	X	Split

Master Matrix

BA Master Matrix

Standard	Req	Process, Procedure, Tools for How Registered Entity Meets Requirement	Text of Requirement	Entity A	Other	Responsibility
BAL-001-0	R1.	Entity A is solely responsible for this requirement. Entity A calculates ACE for the CFR footprint.	Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B times the corresponding clock-minute averages of the Interconnection's Frequery Error is less than a specific limit.	X		Single
BAL-005-0.1b	R13.	Entity A calculates ACE. For the interchange meter error (IME) term of the ACE, Entity A uses an aggregate of the other entities IME for the tielines external to Entity A's BA Area. Entities B, C, D shall provide to Entity A an interchange meter error value for its external tie lines. Entity A sums the interchange meter error values from the other entities to obtain the aggregate interchange meter error term for Entity A's BA ACE. Entities B, C, D shall perform hourly error checks using Tie Line megawatthour meters with common time synchronization to determine the accuracy of its control equipment. Entities B, C, D shall also take corrective action to adjust any components that are in error.	Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the accuracy of its control equipment. The Balancing Authority shall adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error term of the ACE equation to compensate for any equipment error until repairs can be made.	X	X	Split
CIP-001-1	R1.	Entities, A, B, C, D each have their own processes and procedures for making their operating personnel aware of sabotage events. As an example, Entity A's procedure is called XYZ_Sabotage_Reporting.v1.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the recognition of and for making their operating personnel aware of sabotage events on its facilities and multi-site sabotage affecting larger portions of the interconnection.	X	X	Shared

Master Matrix Notes

- Work closely with your Regional Entity contact
- Regional Entities may use other methods for outlining responsibility of a JRO/CFR
- Master matrix is a suggestion
- Very easy to update when changes in membership or requirements occur

Questions?

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Webinar

Project 2007-17 Protection System Maintenance and Testing

September 15, 2011

RELIABILITY | ACCOUNTABILITY

Project Overview

- Combines four existing approved standards into one standard
  - PRC-005-1 – Transmission and Generation Protection System Maintenance and Testing
  - PRC-008-0 – Underfrequency Load Shedding (UFLS) Equipment Maintenance Program
  - PRC-011-0 – Undervoltage Load Shedding System (UVLS) Maintenance and Testing
  - PRC-017-0 – Special Protection System (SPS) Maintenance and Testing

Project Overview

- Establishes **maximum** maintenance intervals and **minimum** maintenance activities for all components
  - Establishes opportunity to use condition monitoring to minimize hands-on maintenance
  - Establishes opportunity to use performance history to establish alternative maximum maintenance intervals

Driving Factors

- FERC Order 693 (2007)
  - Directed changes to all four legacy standards
- Compliance Violation History for PRC-005-1
  - Single most-violated standard since 2007 – mostly with $ penalties
    - R1 – failure to address all five component types within Protection System
    - R1 – failure to have basis (or acceptable basis) for intervals and activities
    - R1 – failure to have summary of maintenance and testing procedures
    - R2 – failure to fully implement program according to established intervals (missed activities)

Driving Factors

- NERC System Protection Control Task Force/System Protection Control Subcommittee work
  - Assessment of legacy standards (2007)
  - "Protection System Maintenance – A Technical Reference" (2007)
- Industry Uncertainty
  - As evidenced by several Interpretation Requests
  - Also, "What generation Protection Systems are included?"

Project History

- Fall 2007 – Standard Authorization Request (SAR) Approved
- September 8, 2009 – Draft 1 Formal Comment Posting
- July 17, 2010 – Draft 2 Formal Comment Posting and Concurrent Initial Ballot – 23% Approval (Failed)
- December 20, 2010 – Draft 3 Formal Comment Posting and Concurrent Successive Ballot – 45% Approval (Failed)

Project History

- May 13, 2011 – Draft 4 Formal Comment Posting and Concurrent Successive Ballot – 67% Approval (Approved)
- June 30, 2011 – Draft 5 Recirculation Ballot – 64.76% Approval (Failed)
  - Several common issues in negative comments
  - Have made several minor changes to address areas of concern

Project History

- Standards Committee (SC) has directed
  - Post SAR for a 45-day informal comment period
  - Post standard for a 45-day formal comment period
  - Form new ballot body
  - Conduct an initial ballot in last 10 days of formal comment period
  - Post invitations for additional Standard Drafting Team (SDT) members

Major Areas of Concern on Draft 5

- Concerns about “3 Calendar Month Intervals”
- Concerns about impact on Distribution Owners with distributed UFLS/UVLS/SPS
- Concerns about alignment with Board of Trustees (BOT)-Approved 2009-17 Interpretation – Definition of “transmission Protection System” regarding the use of the term in PRC-004-1 and PRC-005-1

"3 Calendar Month Intervals"

- This interval applied to two activities related to unmonitored components:
  - Verify station dc supply voltage , and inspect electrolyte level and presence of any unintentional grounds
  - Verify that the communications system is functional
- The intent of the SDT was to accomplish this on a quarterly/three month interval
  - Based on prevailing industry practice

"3 Calendar Month Intervals"

- Industry feedback:
  - Due to the no grace period stipulation, such a requirement would drive most owners to schedule this activity every two months in order to ensure a three month maximum interval
  - Performing inspections at this frequency would result in six inspections each year instead of the four that were intended
- The maximum interval was changed to four calendar months
  - Accomplished the original intent of the SDT and is supported by the industry

Impact on Distribution Owners with UFLS/UVLS/SPS

- A **DISTRIBUTED** UFLS or UVLS scheme contains individual relays which make independent load shed decisions based on applied settings and localized voltage and/or current inputs. A distributed scheme may involve an enable/disable contact in the scheme and still be considered a distributed scheme.[1]

  Distributed UFLS and UVLS systems, which use local sensing on the distribution system and trip co-located non-BES interrupting devices, are addressed in **TABLE 3** with reduced maintenance activities.[2]
- A **NON-DISTRIBUTED** UFLS or UVLS scheme involves a system where there is some type of centralized measurement and load shed decision being made. A non-distributed UFLS/UVLS scheme is considered similar to an SPS scheme and falls under **TABLE 1** for maintenance activities and intervals.[1]

1. Text from Page 33 of the PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ, Dated July 29, 2011.
2. Text from Page 26 of the PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ, Dated July 29, 2011.

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Impact on Distribution Owners with Distributed UFLS/UVLS[3]

- **RELAYS** have the **SAME** maintenance activities and intervals as Table 1-1.
- **VOLTAGE AND CURRENT SENSING DEVICES** have the **SAME** maintenance activity and interval as Table 1-2.
- **DC SYSTEMS** need **ONLY** have their **VOLTAGE READ** at the relay every **12 YEARS.**
- **CONTROL CIRCUITS** have the following maintenance activities every **12 YEARS**:
  - Verify the trip path between the relay and lock-out and/or auxiliary tripping device(s).
  - Verify operation of any lock-out and/or auxiliary tripping device(s) used in the trip circuit.
  - No verification of trip path required between the lock-out and/or auxiliary tripping device(s) and the non-Bulk Electric System (BES) interrupting device.
  - No verification of trip path required between the relay and trip coil of the non-BES interrupting device for circuits that have no lock-out and/or auxiliary tripping device(s).
  - No verification of trip coil required.
- **NO MAINTENANCE ACTIVITY** is required for **ASSOCIATED COMMUNICATION SYSTEMS**.

3. Text from Page 86 of the PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ, Dated July 29, 2011.

Impact on Distribution Owners with Distributed UFLS/UVLS[3]

- **NON-BES INTERRUPTING DEVICES** that participate in a distributed UFLS or UVLS scheme are **EXCLUDED FROM THE TRIPPING REQUIREMENT, AND PART OF THE CONTROL CIRCUIT TEST REQUIREMENT**; however the part of the trip path control circuitry between the load shed relay and lock-out or auxiliary tripping relay must be tested at least once every 12 years.
- In the case where there is **NO LOCK-OUT OR AUXILIARY TRIPPING RELAY** used in a distributed UFLS or UVLS scheme which is not part of the BES, there is **NO CONTROL CIRCUIT TEST REQUIREMENT**.
- There are many circuit interrupting devices in the distribution system that will be operating for any given under-frequency event that requires tripping for that event. A failure in the tripping-action of a single distributed system circuit breaker (or non-BES equipment interruption device) will be far less significant than, for example, any single BES Protection System failure such as a failure of a bus differential lock-out relay. While many failures of these distributed system circuit breakers (or non-BES equipment interruption device) could add up to be significant, it is also believed that many circuit breakers operate often for fault clearing duty and are consequently operated at least as frequently as any requirements that appear in this standard.

3. Text from Page 86 of the PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ, Dated July 29, 2011.

Alignment with BOT-Approved 2009-17 Interpretation

- *Today's* PRC-004-1 & -005-1 cite "*transmission Protection System*"
- NERC Glossary defines "Protection System" but not "transmission"
- Interpretation 2009-17 says:
  - *"A Protection System for a radially-connected transformer energized from the BES would be considered a transmission Protection System … only if the protection trips an interrupting device that interrupts current supplied directly from the BES and the transformer is a BES element."*
- An *interpretation* cannot expand the apparent meaning of PRC-005-1 – it had to accommodate existing regional interpretations.

Alignment with BOT-Approved 2009-17 Interpretation

- PRC-005-2 *Applicability* Section 4.2.1 says *"Protection Systems that are installed for the purpose of detecting faults on BES Elements (lines, buses, transformers, etc.)"* – terms are fully defined.
- In developing PRC-005-2, the SDT's goal is to ensure the applicability, requirements, and measures achieve the purpose of the standard and do not introduce interpretation(s), or the need for interpretation(s) into the standard. The SDT believes the stated Applicability supports the purpose and does not utilize or depend upon an interpretation or definition of the term "transmission Protection System".

Future Actions and Schedule

- SC directed
  - Post SAR for a 45-day informal comment period
  - Post standard for a 45-day formal comment period
  - Form new ballot body
  - Conduct an initial ballot in last 10 days of formal comment period
  - Post invitations for additional SDT members

Future Actions and Schedule

- SAR and standard recently posted per SC directives
- Future schedule dependent on ballot results and comment volume
  - SDT meeting scheduled for November, 2011

Standard Drafting Team Information

- 16 industry members
  - Diverse in region, transmission/generation/distribution, company size and structure
  - All with many years of experience in establishing, managing, and/or implementing Protection System maintenance programs
- Approximately 8-10 very active observers
  - Approximately 25 other observers have attended at least one SDT meeting

Standard Drafting Team Information

- Currently seeking additional members – particularly from small entities
- Encourage interested Subject Matter Experts to become involved as observers – either within meetings or via “plus” list
  - Contact NERC Project Coordinator to be added to “plus” list

Resource Links

- Project website
  - http://www.nerc.com/filez/standards/Protection_System_Maintenance_Project_2007-17.html
- Charles Rogers, Chair
  - cwrogers@cmsenergy.com
- Al McMeekin – NERC Project Coordinator
  - al.mcmeekin@nerc.net

Questions?

- Please submit your questions via the chat window on ReadyTalk.
- The presenters will respond to as many questions as possible during remainder of the scheduled Webinar.
- Unanswered questions will be addressed and posted on NERC website.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC News

August 2011

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Headlines

FERC and NERC Release Task Force Report on Southwest Outages

The Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC) released a staff report making recommendations to help prevent a recurrence of rolling blackouts and natural gas curtailments experienced by customers in the Southwest during extreme cold weather the first week of February 2011.

Concluding a six-month inquiry, the task force found a majority of the electric outages and gas shortages were due to weather-related causes. Although generators and gas producers reported having winterization procedures and practices in place, responses were generally reactive in their approach to winterization and preparedness.

"The task force has identified several proactive steps that can be taken by state regulators, electric generators and natural gas suppliers in the Southwest to improve the reliability of energy supply for customers during extreme cold weather," FERC Chairman Jon Wellinghoff said. "We urge them to carefully consider those recommendations and to work together to implement them before another cold weather event hits the region."

"This joint report demonstrates the high priority both NERC and FERC place on reliability," said Gerry Cauley, president and chief executive officer at NERC. "By combining technical resources and partnering, this report provides a comprehensive analysis and identifies a strong set of recommendations for the industry to use to better prepare in the future."

Despite the importance of winterizing plants, the task force found that no state, regional or NERC standards required generators to do so. The report - *Outages and Curtailments During the Southwest Cold Weather Event on February 1-5, 2011* - recommends that states in the Southwest examine whether to require winterization plans, and NERC plans to work with industry to develop changes to NERC Reliability Standards to properly address winterization needs.

The task force attributed most of the natural gas shortages and outages to prolonged freezing weather that resulted in dramatically reduced supply and unprecedented high demand. Interstate and intrastate pipelines showed flexibility in meeting demand and compensating for supply shortfalls, it said, but additional storage capacity in Arizona and New Mexico might have prevented many of the outages. Most electric outages were caused by weather-related mechanical problems such as frozen sensing lines, equipment, water lines and valves.

In other recommendations, the report said:

- Generation owners and operators should ensure adequate construction, maintenance and inspection of freeze protection elements such as insulation, heat tracing and wind breaks.
- Reliability coordinators and balancing authorities should require generators to provide accurate data about the temperature limits of units so they know whether they can rely on those units during extreme weather.
- Balancing authorities should review the distribution of reserves to ensure that they are useable and deliverable during contingencies.
- State lawmakers and regulators in Texas and New Mexico, working with industry, should determine if weather-related production shortages can be mitigated through the adoption of minimum winterization standards for natural gas production and processing facilities.

NERC Board Focuses on Improving Efforts; Approves Four Standards

The North American Electric Reliability Corporation (NERC) had its quarterly Board of Trustees meeting on August 4 in Vancouver. Gerry Cauley, president and chief executive officer of NERC, welcomed NERC

Board of Trustees; Federal Energy Regulatory Commission staff; and industry stakeholders.

Entering its fifth year as the electric reliability organization, NERC continues to strive for excellence by evolving and adapting to better meet the mission of ensuring the reliability of the bulk power system.

"A mature organization is constantly using the experience it gains to develop better procedures and make course corrections as needed," Cauley said. "We have strong standards and processes in place, and we will use our gained knowledge to make them even stronger."

To continue toward reliability excellence, NERC committed to reviewing its Compliance Application Notice program. NERC staff will review and revise existing CANs to ensure they provide clear, concise guidance for auditors to use consistently across the Regions. A process guide document also is being developed to provide more transparency to the effort. The board will review the CAN process again in November.

Also discussed was progress on the bulk electric system definition. The board directed the Standards Committee and the standard drafting team to consider feedback received during meeting while drafting the BES standard, and to submit a draft of the proposed standard and technical justification to the board by September 9. NERC introduced a new compliance enforcement initiative that differentiates issues of noncompliance based on the level of potential risk to the reliability of the bulk power system. The new enforcement initiative is designed to refocus efforts on reliability excellence, eliminate undue regulatory burdens, streamline paperwork requirements, increase caseload processing, and encourage continued timely and thorough self-reporting and mitigation.

The board approved four standards - *Project 2006-02 Assess Transmission Future Needs and Develop Transmission Plans* (TPL-001-2) and *Project 2006-06 Reliability Coordination* (IRO-002-3, IRO-005-4 and IRO-014-2); as well as the Planning Committee's strategic plan and revised charter, which better aligns activities with NERC's enterprise strategic plan.

Also approved were the *Generating Availability Data System: Mandatory Reporting of Conventional Generation Performance Data* report; the Regional Delegation Agreement metrics and the *2011 Risk Assessment of Reliability Performance* report.

The next board meeting is November 3 in Atlanta.

Compliance

NERC Announces New Compliance Enforcement Initiative

The North American Electric Reliability Corporation (NERC) announced a new initiative for processing violations of Reliability Standards during its quarterly board meeting in Vancouver. The initiative complements other efforts already underway at NERC.

After five years as the electric reliability organization, NERC recognizes that treating all compliance violations with equal weight is not the best way to ensure the reliability of the grid. The new enforcement process is designed to refocus efforts on reliability excellence, eliminate undue regulatory burdens, streamline paperwork requirements, increase caseload processing, and encourage continued timely and thorough self-reporting and mitigation.

"Process should evolve as experience evolves," said Gerry Cauley, president and chief executive officer at NERC. "This new enforcement process allows us to do our job as the ERO more efficiently and effectively. A mature ERO must use the tools available to focus on issues that pose the greatest risk to reliability."

The new process differentiates issues of noncompliance based on the level of potential risk to the reliability of the bulk power system. All instances of noncompliance will continue to be identified and mitigated. Issues that pose a more serious risk to the

reliability of the bulk power system will be filed at the Federal Energy Regulatory Commission on a monthly basis in a further streamlined spreadsheet Notice of Penalty format. Matters that pose a low risk to reliability will be processed on a "find, fix, track and report" spreadsheet that will be submitted to FERC.

"The 'find, fix, track and report' process recognizes the experience of the Regional Entities and NERC in assessing violations and builds on the success of Abbreviated Notices of Penalty and the Administrative Citation Notice of Penalty Process," said Rebecca Michael, associate general counsel and acting director of enforcement at NERC. The new process changes the manner in which potential non-compliance issues are handled, not the fact that they occur. In all cases, Regional Entities will track and report all issues of concern identified. All instances must be mitigated – regardless of the risk level.

The new enforcement process, which will begin with an initial filing with FERC in September, will improve reliability and risk management by improving the way NERC identifies and processes compliance issues. NERC remains committed to ensuring reliability by maintaining accountability for all stakeholders in the compliance enforcement process.

Update on Compliance Application Notice Progress

The process of rewriting CANs to reflect the direction garnered from the August Board of Trustees and Members Representative Committee meetings has begun. All previously posted CANs are being revised and posted for another industry comment period.

In the new approach, CANs will be written as guidance to Compliance Enforcement Authority auditors, rather than as instructional documents for industry. The rewritten CANs also will provide more direction under the "effective date" section and may potentially modify compliance assessment instructions.

NERC requests that industry submit comments that should be included that fulfill the requirements of the standard. The CAN may be expanded to include the new method. CANs will be able to define if there is one way or a range of ways for a CEA to assess compliance.

The CAN process and CAN-0016, the first CAN to be rewritten, were posted on August 15 and comments are due on September 6. Comments for CANs 0005, 0006, 0007, 0008 and 0018, which were posted on August 31 are due September 21. NERC plans to post another set of revised CANs in the coming weeks. During this process, the current version of final CANs, as well as the new draft versions, will be posted online. Please continue to send comments for these CANs to cancomments@nerc.net and include the CAN number in the email subject line.

Upcoming Compliance Workshops and Webinars

- Click here for slides from the July 15 Compliance Application Notice webinar.
- **October 26–28** - NERC Standards and Compliance Workshop in Atlanta. (See Standards section below for more information).
- **December 6** - Compliance Workshop in Atlanta. Agenda topics include an About NERC session; JRO/CFR Concurrent Registration; CANs Update; Critical Infrastructure Protection Auditing Issues; Entities' panel discussion on successful audits; Enforcement Direction; and the 2012 Compliance Monitoring and Enforcement Program Implementation Plan. An announcement will be sent out with a registration link in mid-September.

Send any suggestions for future webinars and workshops to cancomments@nerc.net.

Critical Infrastructure

Make Plans: NERC GridSecCon 2011

NERC is hosting the 2011 Grid Security Conference (GridSecCon) on October 18-20 at the JW Marriott in

New Orleans. GridSecCon will bring together both physical and cybersecurity thought leaders to discuss current security issues facing the bulk power system. To view the agenda and to register, click here or contact Brian Harrell (brian.harrell@nerc.net).

Standards

Modifications to Mandatory Effective Dates Webpage for Reliability Standards

NERC is pleased to announce several modifications to the Mandatory Effective Dates webpage for U.S. Reliability Standards. These improvements were made in response to input from stakeholders and to improve NERC's service.

In the upper left hand corner of the new webpage, select from a drop-down box on of the following reports:

- Mandatory Standards Subject to Enforcement.
- Standards Subject to Future Enforcement.
- Standards Pending Regulatory Approval.
- Inactive Standards.

For the Mandatory Standards Subject to Enforcement and Standards Subject to Future Enforcement reports, all dates, except the enforcement date, have been removed. The enforcement date now links to the order in which FERC approved the standard. For standards that have different enforcement dates and inactive dates for their requirements, the date in the enforcement date column is the earliest enforcement date of all the requirements. A detail column includes a link to those standards, which lists the requirement and sub-requirement numbers of the standard, each requirement and sub-requirement's enforcement date, and each requirement and sub-requirement's inactive date.

For the Standards Pending Regulatory Approval report, the date columns have been modified to include the NERC Board of Trustees approval date and FERC filing date (if applicable). For standards with a FERC filing date, the date links to the filing submitted by NERC to FERC requesting FERC's approval of the standard.

The Inactive Standards report includes the initial enforcement date (if applicable) and the inactive date. A standard becomes inactive at midnight on the day immediately prior to the effective date of the superseding standard.

In the future, NERC plans to address the status of Canadian standards and effective dates for reliability standards in each Canadian province. Contact Kristin Iwanechko with questions or feedback regarding the new format.

Regional Standards Update

This year has been an active one for regional standards. To date, NERC has filed one regional standard, PRC-002-NPCC-01, and one regional variance for Texas Regional Entity, CIP-001-2a, with FERC. Two additional regional standards have been approved by their respective Boards of Directors and will be submitted to the NERC Board of Trustees for adoption at its next meeting in November. In addition, seven quality reviews have been performed on regional standards under development, and three regional standards have been posted for comment on NERC's website.

Also, NERC has updated its Regional Standards Under Development web page to improve how information is provided. The website includes links to all regional standards under development, and lists by month meetings that are relevant to regional standards.

To view, click on the month of interest and known meetings in each region. Information is updated monthly. NERC is working hard to ensure that the web page is a useful resource for stakeholders, and feedback is always welcome.

Finally, the Northeast Power Coordinating Council (NPCC) is soliciting comments on its Cost Effectiveness Analysis Procedure, with comments due by September 19. More information is available on NPCC's website.

Update: 2012-2014 Reliability Standards Development Plan

Last month, NERC's Standards Committee (SC) began prioritizing projects to identify how best to allocate its resources over the next three years. Standards Committee members reviewed the proposed set of projects and assigned scores in the areas of reliability benefit, time sensitivity, and practicality benefit. These scores will be consolidated and analyzed to develop an initial prioritization, which NERC staff will in turn use to develop a first draft of the Reliability Standards Development Plan (the Plan).

This month, NERC will post the initial results of the Standards Committee's prioritization efforts for industry comment. NERC will post the first draft of the Plan for comment as well.

Prior to the posting period, NERC will have a webinar to answer any questions about the prioritization process and the development of the Plan. Andy Rodriquez, director of Standards Development, will provide a presentation and discuss the process being used this year. In addition to answering questions received live via the ReadyTalk chat feature, participants may also submit questions in advance to Andy Rodriquez. The webinar is scheduled for 1:30-2:30 p.m. (ET) September 9, and interested stakeholders can register online.

During the posting period, the industry is encouraged to review both the prioritization and the draft Plan and to provide input. If you have suggestions regarding alternate prioritizations, please provide your reasoning for the Standards Committee to consider.

Following the posting period, NERC staff will consolidate the comments received and provide them to the members of the Standards Committee for their consideration. In October, the Standards Committee will review responses received and make adjustments to the Plan as necessary. The Standards Committee is targeting the approval of a final version of the Plan for its October 12-13 meeting. Following approval, the Standards Committee will submit the plan to NERC's Board of Trustees.

NERC Standards and Compliance Workshop Registration Open

NERC will host its second Standards and Compliance Workshop of 2011 on October 26-28 at the JW Marriott Buckhead in Atlanta.

The workshop will focus on the interrelationship between standards and compliance and will include a NERC Standards 101 presentation along with the following sessions: feedback loops among the standards and compliance departments; standards activities and plans for the future; the Bulk Electric System definition project; critical infrastructure protection issues; and CANs, interpretations, and other standards improvement processes.

All interested stakeholders should register to attend in-person (a $250 registration fee) or via webinar (a $100 registration fee). The two-hour NERC Standards 101 presentation – ideal for stakeholders new to NERC's standards process or anyone looking for a refresher – requires no additional fee, but a separate registration is required. All fees are payable by Visa, MasterCard or check, and cancellations will be accepted up to one week prior to the workshop. All registration refunds will be charged $50.

More details about the workshop are available on NERC's website, and NERC will circulate a draft agenda to the industry soon. For more information on the workshop, please contact Mallory Huggins. For registration assistance, please contact Eleanor Crouch.

Standard Drafting Team Vacancies

Any industry stakeholder meeting the indicated qualifications for one of the following three vacant appointments may submit a self-nomination form to sarcomm@nerc.com. More instructions can be found on the Drafting Team Vacancies page on NERC's website.

Project 2007-06 System Protection Coordination
Seeking an individual from a Canadian entity with experience in coordination of protection systems (new installations and revisions).

Project 2007-12 Frequency Response
Seeking an individual representing Transmission Dependent Utilities with experience in analyzing or modeling frequency response.

Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities
Seeking an individual from a Canadian entity with operations experience in the SCADA/EMS area. Also seeking an individual from the Western Interconnection with operations experience with SCADA/EMS and, preferably, familiarity with the use of nomograms.

In addition to these vacancies, the **Project 2007-17 Protection System Maintenance and Testing** drafting team is seeking individuals with experience in developing, managing, or supporting a maintenance program or testing a program for one or more of the following: generator protection systems, transmission protection systems, under-frequency load shedding equipment, under-voltage load shedding equipment, and/or special protection systems. The specific focus of this solicitation is to add members representing smaller entities. If you are interested in serving on this drafting team, please complete this project-specific nomination form by September 23, 2011. Further details are included on the Project 2007-17 project page.

Please contact Andy Rodriquez with questions regarding the vacancies.

Training and Certification

NERC System Operator Certification Exam

NERC is publishing the updated operator certification exams in the first quarter of 2012 - projected for mid-February.

An extensive job analysis survey of certified operators across the industry provided the basis for the new exam revision process. The job analysis survey resulted in a new exam content outline for each of the four exams. The exam content outline is the framework used to associate tasks to exam questions. NERC contracts with psychometric consultants who assist a working group of certified system operators in the development and maintenance of each exam. The exam working group consists of subject matter experts coming from all regions of North America. The resulting exams are technically valid and without regional variations in operating philosophies.

The System Operator Certification Program website includes the 2012 exam study guide and the exam content outlines for each of the four exams: Reliability Operator; Balancing, Interchange and Transmission Operator; Transmission Operator; and Balancing Operator.

The exams are based on the NERC Reliability Standards, effective October 1. A document including the applicable standards will be posted to the System Operator Certification Site in September.

For more information, contact Nancy DeLeon, NERC's manager of Personnel Certification.

Filings

NERC Filings to FERC

(click on the link for full filing)

August 11, 2011
Motion to Further Defer Action on Time Error Correction Reliability Standard
NERC submits a Motion to Further Defer Action on the Time Error Correction Reliability Standard. *Docket No. RM09-13-000*

August 24, 2011
Request of NERC for Acceptance of 2012 Business Plan and Budget and the 2012 Business Plans and Budget of Regional Entities and for Approval of Proposed Assessments to Fund Budgets
NERC files a Request for Acceptance of 2012 Business Plan and Budget and the 2012 Business Plans and Budget of Regional

Entities and for Approval of Proposed Assessments to Fund Budgets. *Docket No. RR11-__-000*

NERC Filings in Canada

(click here for full filings by Province)

Notice of Filing of the NERC 2012 Business Plan and Budget and the 2012 BPB of the Relevant Regional Entity and of Proposed Assessments to Fund Budgets

Careers at NERC

Assistant to the President
Location: Atlanta
Details

Senior Compliance Enforcement Engineering Analyst
Location: Washington, DC
Details

Data Management System Specialist
Location: Washington, DC
Details

Director of Compliance Enforcement
Location: Washington, DC
Details

Compliance Enforcement Regulatory Assistant
Location: Washington, DC
Details

Manager of Compliance Analysis, Reporting and Tracking
Location: Washington, DC
Details

Compliance Auditor
Location: Atlanta
Details

Critical Infrastructure Protection Cybersecurity Standards Specialist
Location: Washington, DC
Details

Event Investigator
Location: Atlanta
Details

IT Specialist – Client-side Support Level II
Location: Atlanta
Details

Technical Writer – Independent Contractor
Location: Atlanta
Details

Business Analyst
Location: Atlanta
Details

Manager of Power System Analysis
Location: Atlanta
Details

Reliability Standards Adviser
Location: Atlanta
Details

Standards Specialist
Location: Atlanta
Details

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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FERC and NERC Release Task Force Report on Southwest Outages

DOE Releases Draft of Cybersecurity Risk Management Process Guideline for Comment

DOE Releases New Roadmap to Guide Public-Private Cybersecurity Initiatives

Chief Reliability Officer Resigns to Become President/CEO of Transmission Forum

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RSAW Update Completed

Critical Infrastructure

Reminder: Register Now for GridSecCon 2011

Reliability Assessment and Performance Analysis

NERC Releases Analysis on Frequency Response During February Extreme Weather

NERC Releases Report Assessing Risk to Reliability Performance of Bulk Power System

Standards

Progress Report on Critical Infrastructure Protection Standards

Keep up with Standards Projects Via Listservs

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NERC Seeks Talented Professionals

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NERC, FERC Announce Joint Inquiry into September Outage

The Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC) announced a joint inquiry into the September 8 power outage that left more than 2 million customers in Southern California, parts of Arizona and Northern Baja Mexico without electricity. As of 2:15 a.m. PDT today, all but 200 MW of the initial 4,300 MW lost had been restored.

FERC and NERC will coordinate with the Department of Energy and other federal agencies, the California ISO, the Western Electricity Coordinating Council, California and Arizona state regulators and the companies involved to monitor the situation. The inquiry will focus on causes of the outages.

"NERC and FERC are partnering to conduct a full inquiry into the cause of this event," said Gerry Cauley, president and chief executive officer of NERC. "Partnering brings together the expertise of both organizations, and emphasizes the importance placed on reliability of the bulk power system."

"This inquiry is an effective way for us to protect consumers and ensure the reliability of the bulk power system," FERC Chairman Jon Wellinghoff said.

The initial focus remains on ensuring a timely and safe restoration of power to customers. Updates will continue as more information is confirmed.

FERC is charged with oversight of reliability of the nation's bulk power system. FERC has designated NERC as the organization that develops and enforces mandatory reliability standards.

FERC and NERC Release Task Force Report on Southwest Outages

The Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC) released a staff report making recommendations to help prevent a recurrence of rolling blackouts and natural gas curtailments experienced by customers in the Southwest during extreme cold weather the first week of February 2011.

Concluding a six-month inquiry, the task force found a majority of the electric outages and gas shortages were due to weather-related causes. Although generators and gas producers reported having winterization procedures and practices in place, responses were generally reactive in their approach to winterization and preparedness.

"The task force has identified several proactive steps that can be taken by state regulators, electric generators and natural gas suppliers in the Southwest to improve the reliability of energy supply for customers during extreme cold weather," FERC Chairman Jon Wellinghoff said. "We urge them to carefully consider those recommendations and to work together to implement them before another cold weather event hits the region."

"This joint report demonstrates the high priority both NERC and FERC place on reliability," said Gerry Cauley, president and chief executive officer at NERC. "By combining technical resources and partnering, this report provides a comprehensive analysis and identifies a strong set of recommendations for the industry to use to better prepare in the future."

Despite the importance of winterizing plants, the task force found that no state, regional or NERC standards required generators to do so. The report recommends that states in the Southwest examine whether to require winterization plans, and NERC plans to work with industry to develop changes to NERC Reliability Standards to properly address winterization needs.

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Most electric outages were caused by weather-related mechanical problems such as frozen sensing lines, equipment, water lines and valves.

In other recommendations, the report said:

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- Reliability coordinators and balancing authorities should require generators to provide accurate data about the temperature limits of units so they know whether they can rely on those units during extreme weather.
- Balancing authorities should review the distribution of reserves to ensure that they are useable and deliverable during contingencies.
- State lawmakers and regulators in Texas and New Mexico, working with industry, should determine if weather-related production shortages can be mitigated through the adoption of minimum winterization standards for natural gas production and processing facilities.

DOE Releases Draft of Cybersecurity Risk Management Process Guideline for Comment

The Department of Energy, in collaboration with the National Institute of Standards and Technology and the North American Electric Reliability Corporation, released a draft of the Electricity Sector Cybersecurity Risk Management Process (RMP) Guideline for public comment. The RMP Guideline was drafted by a joint public-private sector team that also included representatives from the Federal Energy Regulatory Commission, the Department of Homeland Security, and utilities. The initiative to develop the RMP Guideline is led by the Department's Office of Electricity Delivery and Energy Reliability.

The RMP Guideline is designed to help utilities better understand their cybersecurity risks, assess severity, and allocate resources more efficiently to manage those risks. Available online for public comment until October 28, the RMP Guideline offers a flexible approach to managing cybersecurity risks across all levels of the organization. Feedback provided by industry, vendors, and other electricity sector stakeholders will be used to further refine and improve the RMP Guideline prior to final publication.

"Addressing cyber security is critical to enhancing the security and reliability of the nation's electric grid," said Patricia Hoffman, Assistant Secretary for the Office of Electricity Delivery and Energy Reliability. "The Department of Energy has been working closely with the Department of Homeland Security, other government agencies, and industry for years to reduce the risk of energy disruptions due to cyber attack. The RMP Guideline will provide utilities with consistent, adaptable solutions that help them manage their cybersecurity risks more effectively."

Over the past few decades, the Electricity Sector has increasingly relied on digital technology to reduce costs, increase efficiency, and maintain reliability during the generation, transmission, and distribution of electric power. Managing cybersecurity risk is critical to the success of organizations in achieving their strategic goals and objectives, including reliability, resiliency, security, and safety.

DOE Releases New Roadmap to Guide Public-Private Cybersecurity Initiatives

As part of the Obama Administration's goals to enhance the security and reliability of the nation's energy infrastructure, the Department of Energy released the 2011 *Roadmap to Achieve Energy Delivery Systems Cybersecurity*. Developed as an update to the 2006 *Roadmap to Secure Control Systems in the Energy Sector*, today's report outlines a strategic framework over the next decade among industry, vendors, academia and government stakeholders to design, install, operate and maintain a resilient energy delivery system capable of surviving a cyber incident while sustaining critical functions.

"Increased insight from private-public collaborations will allow us to better protect the nation's energy

delivery systems that keep our lights on and the power flowing," said U.S Energy Secretary Steven Chu. "The 2011 Roadmap takes the necessary steps to strengthen the security and reliability of our country's electric grid, in a climate of increasingly sophisticated cyber incidents."

Based on ideas and input from the energy sector, the 2011 *Roadmap* signifies a continued effort by public and private stakeholders to identify steps to build, deploy, and improve the cyber resilience of the nation's computer-based systems that manage operational processes in the electric, oil, and natural gas industries. The 2011 *Roadmap* also supports the Administration's goal of building a 21st Century clean energy economy supported by a secure, reliable, electricity system delivering power to American homes and businesses.

"This update marks a continued effort by public and private energy sector stakeholders to reduce cyber vulnerabilities that could disrupt the nation's ability to deliver power and energy," said White House Cybersecurity Coordinator Howard A. Schmidt. "It extends the commitment of industry and government to work in partnership to develop, deploy, and maintain resilient energy delivery systems that sustain the essential energy services our national security, safety, and economy depend upon."

"The Roadmap, in addition to the North American Electric Reliability Corporation's (NERC's) current efforts, proactively addresses evolving cybersecurity threats and vulnerabilities that threaten electricity reliability," said Gerry Cauley, president and chief executive officer at NERC and chairman of the Electricity Sub-sector Coordinating Council. "This public-private partnership brings together the expertise from government and industry to ensure the security and reliability of the bulk power system."

Developed by the Energy Sector Control Systems Working Group, a partnership of energy infrastructure cybersecurity leaders from government and industry, the 2011 *Roadmap to Achieve Energy Delivery Systems Cybersecurity* outlines five strategies that must be pursued to achieve the report's agenda. The five strategies include:

- **Build a Culture of Security.** When integrated with reliability practices, a culture of security ensures sound risk management practices are periodically reviewed and challenged to confirm that established security controls remain in place and changes in the energy delivery system or emerging threats do not diminish their effectiveness.
- **Assess and Monitor Risk.** Assessing and monitoring risk gives companies a thorough understanding of their current security posture, enabling them to continually assess evolving cyber threats and vulnerabilities, their risks, and responses to those risks.
- **Develop and Implement New Protective Measures to Reduce Risk**. In this strategy, new protective measures are developed and implemented to reduce system risks to an acceptable level as security risks—including vulnerabilities and emerging threats—are identified or anticipated. These security solutions are built into next-generation energy delivery systems, and appropriate solutions are devised for legacy systems.
- **Manage Incidents**. When proactive and protective measures fail to prevent a cyber incident, detection, remediation, recovery, and restoration activities minimize the impact of an incident on an energy delivery system. Post-incident analysis and forensics enable energy sector stakeholders to learn from the incident.
- **Sustain Security Improvements**. Sustaining aggressive and proactive energy delivery systems security improvements over the long term requires a strong and enduring commitment of resources, clear incentives, and close collaboration among stakeholders. Energy sector collaboration provides the resources and incentives required for facilitating and increasing sector resilience.

Chief Reliability Officer Resigns to Become President/CEO of Transmission Forum

The North American Electric Reliability Corporation announced that Thomas J. Galloway, senior vice president and chief reliability officer at NERC, has accepted the position of president and chief executive officer at the North American Transmission Forum, effective October 16.

"Tom has been an outstanding leader at NERC, and will no doubt continue his commitment to reliability excellence in his new role," said Gerry Cauley, president and chief executive officer at NERC. "NERC and the Forum share the goal of improving reliability and accountability within the electric industry, and Tom's appointment ensures a strong and beneficial relationship between the two organizations."

Galloway joined NERC in July 2010 with responsibility for NERC's Operations and Engineering, Standards, and Compliance Operations functions, where he helped promote the Electric Reliability Organization's risk-based model of reliability. Galloway worked on numerous reliability initiatives, including the facility ratings effort and the joint FERC/NERC effort on the southwest cold outage report.

Prior to joining NERC, Galloway served as the interim president and CEO for SERC Reliability Corporation in Charlotte, N.C., stepping in after Cauley was named president and CEO of NERC in 2010. He also served as an evaluation team manager, assistance team leader, and senior representative at the Institute of Nuclear Power Operations.

"I'm extremely excited to take on this important leadership opportunity," Galloway said. "The North American Transmission Forum and NERC have complementary roles toward the common objective of reliability."

Compliance

Update on Compliance Analysis Reports

NERC posts Compliance Analysis Reports on its website to provide guidance and information to the industry. To date, NERC has posted eight CARs that focus on the most frequently violated NERC Reliability Standards. In October, NERC will post the first these CARs concerning NERC and Regional Entities' Organization Registration Program and Organization Certification Program, as well as NERC Reliability Standard TOP-002 in the new NERC template. NERC and the Regional Entities are currently producing a CAR on CIP-005.

Certifications

It is expected that the number of certifications, approximately ten per year, will remain relatively stable considering the anticipated number of future agreements and market changes. To reduce the burden on entities for certifications, NERC and the Regional Entities are working to provide opportunities to lessen the need for on-site visits for those entities that have previously gone through the certification process. An on-site visit for a change in operational footprint for an entity that has previously gone through the certification process will not be necessary in most cases.

Certifications: 2007-2011					
Lead	#	Function	Lead	#	Function
NERC	5	BA	RFC	1	BA
NERC	3	RC	RFC	1	BA/TOP
TRE	13	TOP	SERC	5	BA
WECC	3	BA	SERC	1	TOP
WECC	3	TOP			

GO.TO Directive

With assistance from the Regions, NERC is in the process of issuing a directive that provides interim guidance to address the reliability gap that exists with GO/GOPs that own/operate transmission facilities (meeting the NERC Statement of Compliance Registry Criteria), but are not registered as TO/TOPs. The directive will ensure consistency across the Regions for GO/GOPs that meet the Compliance Registry Criteria to be registered as TO/TOPs. There will be an appropriate Industry Comment period, followed by a review of the comments with the Regions, and it is

NERC's intent to publish a final directive by the end of year.

ERO Auditor Workshop

NERC offered its bi-annual ERO Auditor Workshop at its Atlanta offices on September 20-22. More than 70 participants from seven Regions attended in the multi-discipline presentations covering both 693 and CIP issues. FERC, NERC and Regional Entity representatives presented helpful guidance in what participants can do to improve the reliability of the bulk power system in their day-to-day activities. Topics included the 2012 Actively Monitored List and Implementation Plan, Audit Processes, Audit Documentation, the Compliance Enforcement Initiative, as well as 693 and CIP breakout sessions. Slides from the presentations can be found on the NERC website.

NERC has already made arrangements for its upcoming ERO Auditor Workshops in February 2012 and September 2012.

RSAWs Update Completed

The work to develop or revise the Reliability Standard Audit Worksheets (RSAWs) required for the 2012 Compliance Monitoring and Enforcement Program (CMEP) Implementation Plan and Actively Monitored List (AML) has been completed, and is in final review. Once approved, the RSAWs will be posted on the NERC website – anticipated the first week of October.

The 2012 CMEP Implementation Plan and AML required the update to the RSAWs. Several current RSAWs were revised for Reliability Standards included in the 2012 AML; possible revisions could include updated regulatory language, questionnaires and minor formatting changes, as well as other minor revisions.

NERC provides notification to the industry whenever there is a major posting of RSAWs, but does not provide this same notification when individual RSAWs are updated and posted; it is recommended that all Regional Entities and Registered Entities regularly check the NERC website to ensure use of the most updated version of the RSAWs. Questions or feedback on the RSAWs can be directed to Craig Struck.

Critical Infrastructure

Reminder: Register Now for GridSecCon 2011

As a reminder, NERC is hosting the 2011 Grid Security Conference (GridSecCon) on October 18-20 at the JW Marriott in New Orleans. GridSecCon 2011 will bring together both physical and cybersecurity thought leaders to discuss current security issues facing the bulk power system. To view the agenda and to register, click here or contact Brian Harrell.

Reliability Assessment and Performance Analysis

NERC Releases Report Assessing Risk to Reliability Performance of Bulk Power System

The North American Electric Reliability Corporation (NERC) released a report that marks a new approach to assessing the reliability performance of the North American bulk power system.

This foundational report - *2011 Risk Assessment of Reliability Performance* - integrates NERC's multiple analysis efforts, combining characteristics of risk to reliability and their trends, to provide feedback and meaningful trend information to industry stakeholders and policymakers on reliability performance.

"Through analysis of reliability performance and trends, we can develop better risk control measures and better inform reliability management business decisions," said Gerry Cauley, president and chief executive officer at NERC. "This is the intelligent feedback on grid reliability performance we have been seeking to ensure that NERC and the industry are focused on the most important risks to reliability."

This report, which measures key aspects of reliability from 2008 to 2010, lays the groundwork for an annual report beginning in 2012 that communicates the effectiveness of bulk power system reliability programs. Future reports will build on these initial metrics, such as Interconnection Frequency Response,

System Voltage Performance and Transmission Constraint Mitigation, which will enable industry to measure meaningful trends and take action to support improved reliability.

"The performance measures are designed to ultimately identify common areas of risk clusters that have the greatest potential impact to affect bulk power system reliability," said Mark Lauby, vice president and director of Reliability Assessments and Performance Analysis. "Industry can then prioritize their actions toward those areas that can have the most significant improvement."

Click here to visit NERC's Reliability Indicators page.

NERC Releases Analysis on Frequency Response During February Extreme Weather

The North American Electric Reliability Corporation released an event analysis that analyzes how the bulk power system performed during the February 1-5, 2011, extreme weather conditions in the southwestern region of United States.

This report – *Analysis of Power System Impacts and Frequency Response Performance: February 1-5, 2011 Texas and Southwestern U.S. Cold Snap* - summarizes the analysis completed by NERC to assess bulk power system impacts in the El Paso, New Mexico and Arizona areas, and the frequency response performance with the affected interconnections – Eastern, Western and Texas. This analysis is a companion to the joint inquiry report by NERC and FERC, released in August, which addresses the Texas and southwestern United States extreme weather event and identified opportunities for improvement.

Standards

Progress Report on Critical Infrastructure Protection Standards

Over the past several months, there has been much activity with regard to NERC's Critical Infrastructure Protection (CIP) cyber security standards.

First, the Standards Committee created a standing CIP interpretation drafting team (CIP IDT) of 18 members. The CIP body of standards has had more requests for interpretation than any other area, and a standing team provides flexibility to draw upon a pool of candidates to more quickly address particular projects.

The first priority for the CIP IDT is to complete work on the three interpretations that are in various stages of development. A project team recently began work on revising the interpretation and responding to comments for Project 2008-10 (the interpretation of CIP-006-1 for Progress Energy), and the details of that project's development are available on the interpretation's project page. The team has finished initial work on the project, and the revised interpretation has just been through NERC's quality review. Upon the team's consideration of the quality review, it will be posted for successive ballot in the coming weeks.

Next, the Cyber Security Order 706 (Project 2008-06) standard drafting team recently submitted Version 5 of the CIP cybersecurity standards to NERC for quality review and subsequent posting for comment and ballot. Since filing Version 4, which transitions from a risk-based identification approach to bright line criteria for identifying Critical Cyber Assets, the team has continued to address the remaining directives contained in FERC's Order 706 in its development of Version 5. This set of CIP standards will also address any industry issues identified after three years' experience in implementing Versions 1 through 3 of the CIP cybersecurity standards.

The drafting team just concluded its 38th meeting at Southern California Edison's Advanced Technologies Laboratory in Westminster, Calif. In between the monthly meetings, the team has also conducted almost daily teleconferences to finalize the Version 5 drafts for posting.

To support the quality review of the Version 5 CIP cybersecurity standards, NERC is hosting two consolidated quality review sessions at NERC's

headquarters in Atlanta. More than 50 volunteers have signed up to help in the effort, which includes 10 separate standards and accompanying documentation. Following a plenary session to provide contextual and background information on the body of standards, the quality reviewers will review each standard and provide individualized and comprehensive feedback for the team's consideration before posting.

Following NERC's quality review, the drafting team plans to post the Version 5 CIP cyber security standards for comment and concurrent ballot on November 3.

CIP drafting team in Westminster, Calif.

Keep up with Standards Projects Via Listservs

NERC is always working on a number of standards projects. Industry can stay updated by visiting the Standards Under Development page, and by monitoring the Standards Progress Report linked at the top of that page. Users can also stay informed by subscribing to NERC listservs. NERC maintains a general Standards listserv, as well as a public list for each standard project (informally know as the "plus list" because it is made up of the drafting team *plus* interested observers). Subscribers will receive all meeting and conference call agendas and minutes, along with other relevant information. Many drafting teams use their plus lists for all email communication, so it's a great source of information. Before signing up, take into consideration the volume of email. If interested in monitoring all standards projects, the general standards listserv is the best list to receive.

To sign up for general standards lists or specific plus lists, please email Mallory Huggins. Make sure to note whether you would like to subscribe to all general standards lists, a project plus list (please include the name of the project), or both.

NERC also maintains two types of listservs for individuals eligible to ballot standards. First, NERC maintains a listserv of all members of the Registered Ballot Body. Each time someone joins the Registered Ballot Body, they are automatically added to this listserv, which is used to announce the formation of new ballot pools and for other announcements that are specifically relevant to balloting. Additionally, whenever a ballot pool is joined, the subscriber automatically is added to that ballot pool's listserv. During the pre-ballot window (but not during balloting), members of each ballot pool may communicate with one another by using their ballot pool listserv. The email addresses for each ballot pool listserv are provided when NERC staff sends an announcement inviting stakeholders to join that pool.

NERC is always working to improve its standards communication efforts. NERC is updating the Standards website so that it is more useful, as a well-organized and comprehensive resource for news about standards projects. For feedback about NERC communication efforts, contact Mallory Huggins, the NERC coordinator for the Standards Committee Communications and Planning Subcommittee. For specific feedback on standards web pages, contact Kristin Iwanechko, manager of standards information.

Update: 2012-2014 Reliability Standards Development Plan

In September, NERC posted the draft 2012-2014 Reliability Standards Development Plan (the Plan) for industry comment. The plan was posted September 12-26 and NERC received 15 sets of comments, including comments from approximately 63 different people from approximately 38 companies representing all 10 of the industry segments. In

general, comments were supportive of the Plan and the process used to develop it. Some comments, however, suggested changes to the prioritization and to the work plan. NERC staff is evaluating these comments to determine options for modifying the Plan, if deemed necessary.

Next, NERC staff will present the options for modification to the Standards Committee for evaluation at its October 12-13 meeting in Atlanta. The Standards Committee will be asked to take action approving either the posted version or a modified version of the Plan. Following Standards Committee approval, NERC staff will submit the Plan to NERC's Board of Trustees for consideration at its November meeting.

Reminder: Register Now for NERC Standards and Compliance Workshop

NERC is hosting its second Standards and Compliance Workshop of the year October 26-28, 2011 at the JW Marriott Buckhead in Atlanta.

The workshop will focus on the interrelationship between standards and compliance and will include a NERC Standards 101 presentation along with sessions on feedback loops among the standards and compliance departments; standards activities and plans for the future; the Bulk Electric System definition project; critical infrastructure protection issues; CANs, interpretations, and other standards improvement processes; and more.

All interested stakeholders can still register to attend in-person (a $250 registration fee) or via webinar (a $100 registration fee). The two-hour NERC Standards 101 presentation – ideal for stakeholders new to NERC's standards process or anyone looking for a refresher – requires no additional fee, but a separate registration is required. All fees are payable by Visa, MasterCard or check, and cancellations will be accepted up to one week prior to the workshop. All registration refunds will be charged $50.

Further details about the workshop are available on NERC's website, and a draft agenda will be circulated to the industry within the week.

For more information on the workshop, please contact Mallory Huggins. For registration assistance, please contact Eleanor Crouch.

Standard Drafting Team Vacancies

Any industry stakeholder meeting the indicated qualifications for one of the following three vacant appointments may submit a self-nomination form to sarcomm@nerc.com. Further instructions can be found on the Drafting Team Vacancies page on NERC's website.

Project 2007-06 System Protection Coordination

Seeking an individual from a Canadian entity with experience in coordination of protection systems (new installations and revisions).

Project 2007-12 Frequency Response

Seeking an individual representing Transmission Dependent Utilities with experience in analyzing or modeling frequency response.

Project 2010-07 Generator Requirements at the Transmission Interface

Seeking an individual, preferably from a Regional Entity, with a compliance role or background. Candidate should have experience working with generation, transmission, or both. The candidate should also be familiar with the history of the GOTO Ad Hoc Group, recent registration activity, and the work of the Project 2010-07 SDT.

In addition to these vacancies, the **Project 2007-17 Protection System Maintenance and Testing** drafting team is seeking individuals with experience in developing, managing, or supporting a maintenance program or testing a program for one or more of the following: generator protection systems, transmission protection systems, under-frequency load shedding equipment, under-voltage load shedding equipment, and/or special protection systems.

The specific focus of this solicitation is to add members representing smaller entities. If you are interested in serving on this drafting team, please complete this project-specific nomination form by

September 23, 2011. Further details are included on the Project 2007-17 project page.

Please contact Andy Rodriquez with questions regarding the vacancies.

Training and Certification

Exam Working Group Seeks New Member

The System Operator Certification Program is holding open nominations to fill one opening on the Exam Working Group. The term of service will be from the date of appointment until January 31, 2013. Nominations will be accepted until **October 30.**

A brief description of responsibilities include attendance and participation in Item Writing Workshops, Exam Development meetings, and Job Analysis Advisory Group. For more information click on EWG Nomination Letter, EWG Scope Document, Nomination Form

System Operator Database Updates

The System Operator Certification and Continuing Education Database rolled out system updates on September 28. The updates affect providers and system operators and a summary can be found in the "What's New" section of the System Operator Certification site.

Filings

NERC Filings to FERC

(click on the item link for full filing)

September 9, 2011

Petition for Approval of Interpretations to Requirements of Reliability Standards EOP-001-0 and EOP-001-2 -- Emergency Operations Planning

NERC files a petition for approval of an interpretation to Requirement R1 of EOP-001-0 — Emergency Operations Planning (EOP-001-0), and an interpretation to Requirement R3.2 of EOP-001-0 — Emergency Operations Planning (EOP-001-0). *Docket No. RM11-__-000*

September 9, 2011

Joint Motion for Extension of Time

NERC and WECC submit a joint motion for extension of time from September 14, 2011 to November 14, 2011 to allow NERC to submit a compliance filing in response to the Commission's June 16, 2011 Order regarding the registration of Cedar Creek Wind Energy, LLC and Milford Wind Corridor Phase I, LLC. The Commission directed NERC to submit a compliance filing identifying the Reliability Standards and Requirements that will be applicable to Cedar Creek and Milford. *Docket Nos. RC11-1-000 and RC11-2-000*

September 19, 2011

Additional Comments in Support of NP11-238

NERC submits additional comments in support of the Notice of Penalty filed on July 28, 2011 regarding a Notice of Penalty for Southwestern Power Administration. *Docket No. NP11-238-000*

NERC Filings in Canada, click here

(click on the link above for full filing)

September 2, 2011

1st Quarterly Application for Approval of Reliability Standards (Nova Scotia)

NERC submits to the Nova Scotia Utility and Review Board a quarterly application for approval of NERC Reliability Standards and an updated NERC Glossary of Terms approved by FERC since NERC's June 30, 2010 Application for Approval of Reliability Standards.

September 26, 2011

Notice of Filing of Compliance Monitoring and Enforcement Agreement Between NPCC and WECC and related Amendments to Delegation Agreements

NERC submits a notice of filing of (1) an Agreement Between Northeast Power Coordinating Council [NPCC] and Western Electricity Coordinating Council [WECC] Concerning Compliance Monitoring and Enforcement of WECC Registered Functions, (2) to the extent necessary, an Agreement between NERC and WECC concerning termination of their existing Agreement Concerning Compliance Monitoring and Enforcement of WECC Registered Functions, and (3) related amendments to the Delegation Agreements between NERC and NPCC and NERC and WECC.

Notice of Filing of NERC's Report of Comparisons of Budgeted to Actual Costs for 2010 for NERC and Relevant Regional Entities

NERC submits a notice of filing a true-up Report of Comparisons of Budgeted to Actual Costs for 2010 for NERC and the Regional Entities.

Notice of Filing of Interpretations to Requirements of Reliability Standards EOP-001-0 and EOP-001-2 -- Emergency Operations Planning

NERC submits a notice of filing of an interpretation to Requirement R1 of EOP-001-0 — Emergency Operations Planning

(EOP-001-0), and an interpretation to Requirement R3.2 of EOP-001-0 — Emergency Operations Planning (EOP-001-0).

Notice of Filing of Amendments to NPCC Delegation Agreement, Bylaws and Regional Standards Development Procedure
NERC submits a notice of filing of proposed amendments to NERC's Delegation Agreement with the Northeast Power Coordinating Council, Inc. (NPCC) and approval of amendments to NPCC's Bylaws and Regional Reliability Standards Development Procedure (included in Exhibits B and C to the Delegation Agreement) as "Regional Entity Rules."

Careers at NERC

Associate General Counsel and Director of Compliance Enforcement
Location: Washington, DC
Details

Compliance Enforcement Analyst
Location: Washington, DC
Details

Manager of Notice of Penalty Development
Location: Washington, DC
Details

Senior Compliance Enforcement Engineering Analyst
Location: Washington, DC
Details

Data Management System Specialist
Location: Washington, DC
Details

Compliance Enforcement Regulatory Assistant
Location: Washington, DC
Details

Manager of Compliance Analysis, Reporting, and Tracking
Location: Washington, DC
Details

Compliance Auditor
Location: Atlanta
Details

Critical Infrastructure Protection Cybersecurity Standards Specialist
Location: Atlanta
Details

Event Investigator
Location: Atlanta
Details

Attorney
Location: Washington, DC
Details

Technical Writer - Independent Contractor Position
Location: Atlanta
Details

Business Analyst
Location: Atlanta
Details

Manager of Power System Analysis
Location: Atlanta
Details

Reliability Standards Analyst
Location: Atlanta
Details

Reliability Standards Adviser
Location: Atlanta
Details

Standards Specialist
Location: Atlanta
Details

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Lesson Learned

Backup Control Center Operation and Training

Primary Interest Groups
Reliability Coordinator
Balancing Authority
Transmission Owners
Transmission Operators

Problem Statement
Evacuation of an entity's Primary Control Center (PCC) was required due to a fire on the second floor of the Operations Building. System Operators promptly evacuated the PCC and activated the Backup Control Center (BCC). Incorrect contact information in the contingency plans and the inability of support tools to connect to the corporate network impeded a timely and efficient transfer of operations.

Details
The PCC, which is the center for transmission operations, is located at the lower level (basement) of the building. Smoke from the fire began to enter surrounding office areas, as well as the PCC space, forcing System Operators to evacuate. All control room personnel relocated to the BCC and re-established command and control of the Transmission and Distribution (T&D) System.

The Transmission Operator had detailed contingency plans and procedures in place for continued reliable operations of the T&D System in the event the PCC became inoperable. These plans were implemented.

Some of the issues operators encountered when they implemented the contingency plans and procedures are as follows:

- Personnel and contact phone numbers listed in the contingency plan were incorrect and outdated.
- Operators could not log into or connect one of the personal computers (PCs) to the corporate network because the computer had not accessed the corporate computer network in a while. The time between the last logon onto the corporate network for the PC and this evacuation logon exceeded company mandated time limits.

- The cable television utilized by the operators for weather and news broadcasts did not work. The cable company recently mandated that a cable box be used for the installation.

Corrective Action

The entity immediately added personnel on the site who provided current contact lists. The evacuation contingency plan was updated with this information. Later, a schedule was developed for more frequent reviews of these lists.

Additional personnel also resolved the computer logon issue. The operator training schedule was changed to allow more opportunities for operating personnel to practice activating the backup control center and checking the tools. This schedule ensured that the PCs' login credentials were active and current.

A cable box from the cable company was obtained that allowed operators to view weather and news broadcasts.

Lesson Learned

Entities should have processes in place to insure their contingency plans are up-to-date; that all tools that support operation functions can be accessed and work correctly; and that any tools that are dependent on outside service that the entity cannot provide, such as cable television, are up-to-date and working correctly.

Simulation exercises should be used not only for training but also to judge the ability of the entity to be able to evacuate the PCC and establish BCC operation quickly, without additional help required by other personnel. To completely test an entity's contingency plan, simulation scenarios should exercise all functions required for operation at the BCC. One of the goals of these simulations should be for the entity to have contingency plans and tools that ensure operators encounter no issues in establishing operation quickly at the BCC.

BCC operation scenarios should often include the actual evacuation of a group of operators from the PCC and the establishment of operations being run from the BCC just as would incur if an evacuation were needed. The scenario should include operation from the BCC for a period of time to really judge the effectiveness of the tools and plans.

Operators can play a significant role in testing an entity's evacuation and contingency plans as well as the needed operator tools. All operators should have the opportunity to participate in scenarios that include PCC evacuation and operation at the BCC. Operation from the BCC provides a double benefit in that the tools are tested and operators are afforded training. Providing this training to all operators allows more opportunities to test the plans and the tools.

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Source of Lesson Learned: Northeast Power Coordinating Council

This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing reliability standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

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Lesson Learned

Special Protection Systems Maintenance Precautions

Primary Interest Groups
Balancing Authority
Generator Owners
Generator Operators
Transmission Operators
Transmission Owners

Problem Statement
During the planned maintenance of a special protection system (SPS), blocking switches, used to isolate one relay output from causing an action on another, were operated out of sequence, causing an undesired operation of the SPS that tripped units at a generating station.

Details
The SPS in this instance is designed to remove a situation where the generator may go unstable upon the loss of a specific transmission line. The field report from the maintenance work indicated that the order of operation of the blocking switches caused the SPS scheme to incorrectly believe this transmission line was open at the substation terminal. By operating the blocking switch for the transmission line prior to the switch that disarmed the SPS, the SPS operated during maintenance testing. An unconventional/non–standard blocking switch sequence that existed at this substation was not noted in the design and field drawings.

Corrective Actions
For the short term, written instructions were placed on the protection panels indicating that the blocking switches should be opened in such a manner that the protection outputs are isolated prior to the logic inputs. This was achieved by mounting a red tag with the appropriate instructions affixed to the panels above the DC blocking switches.

As a result of this event, a review of all the bulk power protection schemes within the affected Transmission Operator's system was conducted to identify any similar designs with a plan to fix any problems.

Lesson Learned

- Protection drawings should be reviewed prior to removing protection devices from service at all locations and assumptions should not be made that all sequences are standard.

- All status inputs to the protection scheme should be separated from the protection outputs through the addition of test plugs and switches with an input blocking switch.
- Transmission Engineering and Relay Engineering should review the design and ensure that the exposure to this type of sequencing scheme does not exist during the design and commissioning phases. If any are identified, the necessary changes to mitigate such situations should be made.

For more information please contact:

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Source of Lesson Learned: Northeast Power Coordinating Council

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Lesson Learned

Protection Relaying – Out of date prints

Primary Interest Groups
Generator Owners
Generator Operators
Transmission Owners
Transmission Operators

Problem Statement
Following a Main Bus outage, it was discovered that human error was responsible for an improperly wired relay which caused a false Breaker Failure relay action and the forced outage of 2 generators and firm load.

Details
The problem occurred while personnel were working on a Unit Control Modernization project at a generating plant. The effort involved the rewiring and upgrading of relaying and controls on generators. An incorrect wiring of relaying set up the false Breaker Failure condition which removed all components of a main bus including the outage of Units 4 and 5 and firm load. The prints that were being used were outdated and included actual cabling which should have been removed and excluded in the re-wiring process. Maintenance personnel following the incorrect prints connected the new replacement relay to the wrong cable.

Corrective Actions
Following restoration of the Main Bus, 69-kV Bus, 69-kV Load, and Units 4 and 5, action was taken to review and modify the construction drawings to include the as-built print changes needed to complete the work. The remaining work was completed without incident.

Lesson Learned
This outage could have been avoided if accurate prints had been provided to the installation team. Procedures should be implemented which assure that proper print reviews are conducted prior to issuing the drawings.

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Source of Lesson Learned: Western Electricity Coordinating Council

This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing reliability standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

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Lesson Learned

Transmission Relaying – Coupling Capacitor Voltage Transformer Failure Indications for Operations

Primary Interest Groups
Transmission Operators
Transmission Owners

Problem Statement
The failure of a single phase coupling capacitor voltage transformer (CCVT) caused remote relay operation to outage five transmission lines and the substation where the CCVT failed. Operations was not aware that there were indications to them that the CCVT was about to fail and may have been able to take steps to stop the resulting outages.

Details
Coupling Capacitor Voltage Transformers (CCVTs) are commonly used devices to supply AC potential to protective relays, particularly transmission line relays. The failure of one or more CCVTs will affect the functioning of all Protection Systems connected to it. In some cases, the CCVT potential output was found to deviate well before its ultimate failure. Although digital relays provide options through application logic on how to operate when there is a loss of potential; the various configurations/options of this relay logic result in different consequences that need to be considered.

One single phase CCVT on a line terminal failed catastrophically causing a phase to ground fault. Approximately one hour before the CCVT failed, high and low voltage alarms had been received by system operators, including a loss of AC potential alarm from both the primary and backup relays for the line. This symptom of an impending CCVT failure has been observed in multiple events over the years and often is the result of failures of internal series capacitor units within the CCVT that are used to divide the primary phase voltage to a lower usable voltage level. As these internal capacitor units fail and short out, they force the remaining capacitor units in the string to be subjected to a higher distributed voltage. The primary and backup relays for the line were supplied from separate secondary windings from this line CCVT. By the entity's design, the Loss of Potential (LOP) logic in both the primary and backup relays for the line was programmed to provide an alarm and to block operation of all distance and directional overcurrent elements. The purpose of this blocking was to prevent false operation during an LOP condition. As the condition of the CCVT deteriorated, the primary and backup relays declared an LOP condition as it was designed. Since the relays on the terminal at the substation were effectively blocked from operating per the programmed logic, when the phase to ground fault occurred, it had to be

cleared by the operation of remote backup relay elements. These remote relay operations resulted in outages to five transmission lines and the substation where the CCVT failed.

Corrective Actions

The entity replaced the failed CCVT and continues to evaluate approaches to LOP logic settings and alarming. The entity has discussed with other utilities their LOP practices and continues to participate in industry meetings and forums to help establish best practices. Improvements in the training of operators to recognize the possible CCVT failure indications were implemented.

Lesson Learned

Unusual voltage changes at a location and LOP alarms may be an early indication of an impending CCVT failure and warrants immediate investigation by transmission operators. Operators should also be cognizant of the implications that an LOP condition has on the performance of protective relays. Training should be provided to operators on the implications of a LOP condition, early indication of a CCVT failure and corrective action.

The referenced IEEE report provides a good summary of LOP considerations including consequences and probabilities, reliability, descriptions of typical schemes and issues with operational configurations.

Reference: IEEE Power Engineering Society, Power System Relaying Committee, Line Protection Subcommittee Working Group D-7, "Loss of ac Voltage Considerations for Line Protection," 2005.

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Source of Lesson Learned: ReliabilityFirst Corporation

This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing reliability standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

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Lesson Learned

Transmission Relaying – Removing Unused Components

Primary Interest Groups
Transmission Owners
Generation Owners
Distribution Providers

Problem Statement
Auxiliary potential transformers (PTs) from a previous relay scheme were left in service after the relay equipment was replaced. The unused equipment contributed to the false tripping of another line during a normal relay operation to clear a fault on another line.

Details
A high impedance phase to ground fault occurred on line "A." The fault was cleared with high speed relaying. During the fault, terminal "1" of line "B" upstream from the faulted line tripped. Analysis indicated that the Primary relay at terminal "1" properly sent the permissive overreaching transfer trip (POTT) signal. However, the Primary relay at terminal "2" at the opposite end of line "B" did not properly sense the fault in the reverse direction, so it echoed the POTT signal back to terminal "1." Upon receiving the signal, terminal "1" of line "B" tripped.

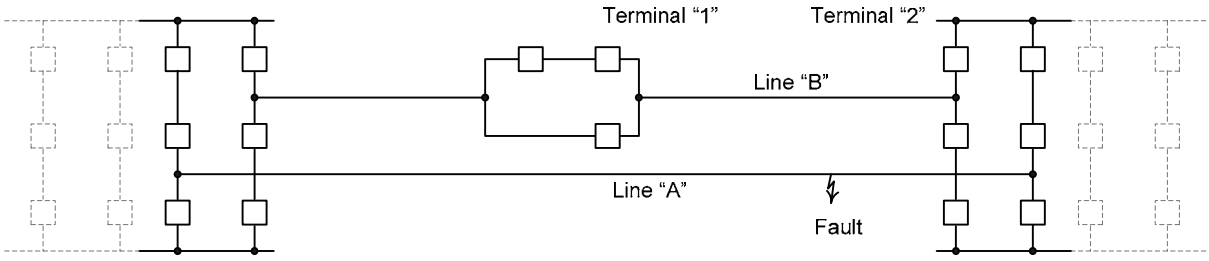

Inspection found a blown potential fuse (on the same phase as the fault) feeding the line "B" Primary relay at terminal "2." The blown fuse should have been sensed as a loss of potential condition and caused a station alarm but this did not occur. Further analysis determined that a backfeed condition was occurring on the relay potential, keeping the relay potential at normal voltage even when the fuse was removed. The source of the backfeed was from an unneeded set of "wye - broken delta" auxiliary potential transformers (PT). The broken delta PTs had been used to supply an overvoltage relay used to detect a loss of potential condition. This relay was no longer required because the loss of potential logic was accomplished in the digital relay. When the digital relays were put in service, the overvoltage relay was removed. However, the auxiliary PTs were not

removed and the broken delta side of the auxiliary PTs was incorrectly shorted. The shorted broken delta winding was the source of the undesired backfeed. This backfeed combined with the blown PT secondary phase fuse, caused the "B" line Primary relay at terminal "2" to sense the fault improperly. Refer to the figures below showing the auxiliary PTs.

Corrective Actions

The auxiliary PTs were removed from the circuit. The entity then performed random spot checks to ascertain that this design problem was an isolated incident. They later reviewed their AC schematics for all recently replaced line relaying to ensure this problem did not exist anywhere else on the system.

Lesson Learned

Leaving energized unneeded components in a protection scheme, such as auxiliary PTs in this example, can adversely affect the functioning of Protection Systems. When replacing relays, care should be taken to remove unneeded circuitry and components. These unneeded components can influence whether relaying will operate properly.

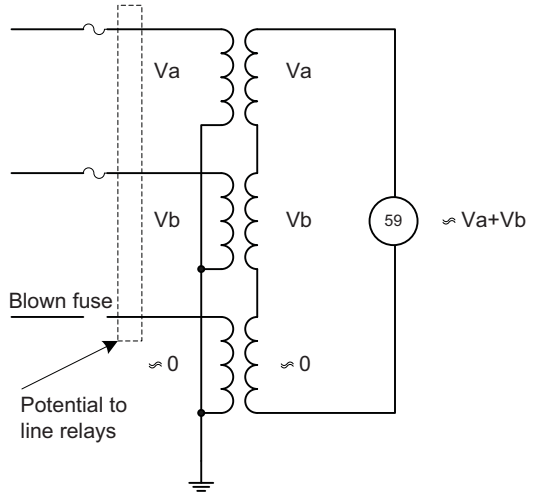

Original circuit – when a fuse blows, the overvoltage relay would see a voltage across it and alarm

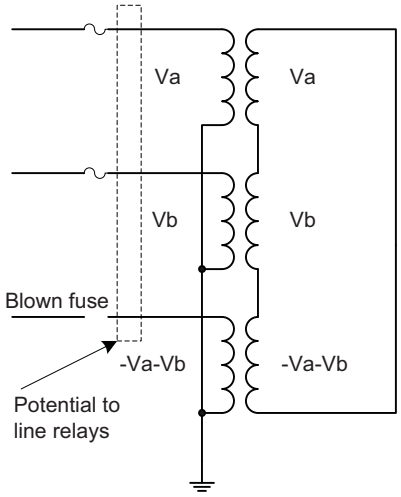

Potential circuit with aux. PTs shorted – when a fuse blows, voltage backfeeds to the line relays

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Source of Lesson Learned: ReliabilityFirst Corporation

This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing reliability standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

Lesson Learned

Plant Instrument and Sensing Equipment Freezing Due to Heat Trace and Insulation Failures

Primary Interest Groups
Generator Owners
Generator Operators

Problem Statement
During an extreme winter weather event, a Combined Cycle Gas Turbine (CCGT) plant (5 units available/1200 Mw) had units which failed to start or tripped numerous times due to frozen instrument transmitters and instrument sensing lines within the plant. The subsequent loss of generation and reliable operation contributed to the balancing authority and reliability coordinator having to shed load.

Details
The CCGT plant was designed to operate at a minimum ambient operating temperature of four degrees (F). Before the event, due to the weather forecasts, the plant officials held meetings to discuss the impending cold weather and additional personnel were called in to assist with any impending issues as they arose. The plant personnel verified all *heat trace equipment was functioning and ensured all insulation was in place. The area experienced extreme cold weather with temperatures in the single digits and wind chill factors below zero. This combination of frigid temperatures and continuously blowing wind removed heat from critical instrumentation and instrument sensing lines. Insufficient insulation and failed heat trace were major factors in the freezing of critical sensing and transmitting equipment. The equipment freezing caused numerous automatic and operator initiated shutdowns of Combustion Turbines (CTs) and Gas Turbines (GTs) as well as preventing numerous units from starting. The following is a partial list of the frozen equipment which froze and the resulting effect.

- Low pressure drum level transmitter sensing lines froze, which led to a failed start.
- GT combustor pressure transmitter sensing lines froze, which led to a failed start.
- GT economizer inlet valve and associated piping froze, which led to a failed start. This start was attempted after the unit tripped due to high cooling air temperatures as the flow of cooling water was restricted by frozen components.
- High pressure (HP) Steam Attemperator Flow Transmitter sensing line froze, which led to equipment protective events when the attemperator was driven to 100% open and flooded the condensate drain system.
- HP feed water pump Net Positive Suction Head (NPSH) sensing line froze, which caused a trip of the HP feed water pump.

- Condensate tank levels and drain pot levels froze as a result of the heat trace processor for the condensate system malfunctioning. The heat trace processor was providing control of the amount of heat which was being applied through the heat trace and the processor failure resulted in various heat trace components functioning improperly. A unit tripped as a result.
- GT combustor pressure transmitters sensing lines froze, which led to automatic protective actions tripping a unit.
- Pressure line to the GT auxiliary enclosure fire protection system froze and ruptured, causing the fire protection system to activate.
- Water from the fire protection system, which had been incorrectly activated, entered the valve positioner causing the Sequential EnViromental (SEV) fuel gas control valve to register an incorrect valve position, which resulted in a unit trip.

The plant personnel performed short term actions to repair the problems, including placing tarps, space heaters, and additional insulation in locations to protect instrumentation and equipment as required. Additionally, extra staff was brought in to help, resulting in four units being brought back online later during the same day after the morning peak and one unit back online the next day

Corrective Actions

The Generator Owner/Operator performed a review of the components that experienced problems during the winter event. Identification of the failure mode was performed and it included the following categories – insulation, heat trace, heaters, heated box enclosures, etc. A corrective action plan was implemented to mitigate these problems for future cold weather events.

Lessons Learned

- Appropriate considerations should be given to the potential effects of wind in removing heat from equipment.
- The cooling water system, if possible, should be bypassed during severe cold weather events to mitigate freezing.
- It is necessary to purge transmitter sensing lines inside of the GT enclosure prior to winter weather events to make sure there is no condensation build up which could freeze.
- Before winter season, identify unit-specific critical freeze protection areas and the corresponding work needed to decrease the likelihood of long duration freeze impacts.
- Plants should have in place emergency operation plans which adequately address procedures to operate the units in freezing weather conditions with the potential loss of critical instrumentation.

Heat Trace Equipment

- Perform a complete evaluation of all heat trace lines, heat trace power supplies including all breakers and fuses and associated control systems to ensure they maintain their accuracy. This inspection should include checking for loose connections, broken wires, corrosion, and other damage to the integrity of electrical insulation which could lead to the heat trace malfunctioning.
- Where feasible, install additional heat trace circuitry metering to provide more efficient verification and monitoring of circuit integrity. Frequent monitoring of heat trace circuit integrity and protective equipment temperatures are keys to early identification of potential freezing issues during severe cold weather conditions. This active monitoring of heat trace temperatures also prevents "boiling out" of sensors and pipes, e.g. critical fluid filled sensor lines.
- Heat tracing that is modified, such as adding parallel circuits to provide additional coverage, can present problems. Testing has found that although the circuits passed continuity tests, one or more legs of the parallel circuitry (which is often covered with insulation) may fail. The partial failure can result in sub-optimal protection.
- The effect of wind should always be considered in applying heat trace and in the application of insulation.
- The amperage and voltage for heat trace circuits should be calculated. The circuits should be tested to determine whether the circuits are still producing the design output. Repairs should be made to the circuits as needed.
- The useful life of the heat trace equipment, in accordance with the manufacturer's recommendations, should be used in the routine preventative maintenance and replacement plan or schedule.

Insulation

- Before winter begins, all accessible thermal insulation should be inspected to ensure it has not reached the end of its useful life and verified that there are no cuts, tears, or holes .After maintenance on equipment, all insulation designed or intended for the equipment should be evaluated to insure it meets ithe original specifications and was correctly re-installed.
- Valves and valve connections should be insulated to the same temperature specifications as the piping connected to the valves.

* Heat trace or electric trace heating, also known as heat tape or surface heating, is a system used to maintain or raise the temperature of pipes and vessels. Trace heating takes the form of an electrical heating element placed in physical contact along the length of a pipe. The pipe must then be covered with thermal insulation to prevent heat losses from the pipe. Heat generated by the element then maintains the temperature of the pipe. Heat trace may be used to protect pipes from freezing, or to maintain process temperatures for piping that must transport substances that solidify at low ambient temperatures. Electric trace heating cables are an alternative to steam trace heating where steam is not available or unwanted.

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Source of Lesson Learned: Texas Reliability Entity

This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing reliability standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Lesson Learned
Plant Fuel Switching and Cold Weather

Primary Interest Groups
Reliability Coordinator
Balancing Authority
Plant Owners
Plant Operators

Problem Statement
During a cold weather event, both equipment freezing and infrequent use of alternative fuels caused a plant's generation to become unreliable, contributing to the balancing authority (BA) and reliability coordinator (RC) having to shed load.

Details
A two unit 900 Mw natural gas powered plant developed significant fuel switching issues and unit reliability problems during a severe winter weather event. The plant experienced temperatures low as 18 degrees (F), wind chill as low as 1 degree (F). For three days, the daytime temperatures stayed below freezing. During the winter weather event, the plant's gas supply was interrupted. Operation on fuel oil was infrequent, thus fuel oil burning equipment remained dormant much of the time. As a result, equipment required for burning fuel oil had high failure rates, in part due to sub-freezing temperatures, but also due to infrequent use. The plant experienced:

- Instrumentation sensor lines freezing
- Condensation freezing in the air inlet needle valve for a Gas Turbine (GT)
- Unit output reduced due to gas transmission curtailments
- Failed oil cooler fan due to freezing issues
- Unit tripping multiple times when attempting to fire on fuel oil due to equipment malfunctioning and operator error

Corrective Actions
The plant's generator owner (GO)/generator operator (GOP) reviewed the fuel oil capabilities required at the plant. A team re-evaluated what upgrades, maintenance, modifications, testing and training were needed to meet required fuel oil burning capabilities and are in the process of implementing the changes.

Lessons Learned
GOs and GOPs should review their winter maintenance plans and ensure critical sensing and operating equipment are protected and can operate at the plant's designed minimum operating ambient temperature for all fuels the plant is capable of burning.

GO/GOPs should consider the following if they have dual fuel operation capability:

- Reliable unit fuel oil operation requires dormant equipment to be tested and maintained. Entities should evaluate their testing programs to insure all systems can operate reliably at all times and provide training to appropriate personnel on the maintaining and operation of the equipment.
- A review and update of procedures should be performed periodically for unit fuel oil operation and maintenance based upon expected operation capabilities to ensure reliable operation.
- Training plans should consider incorporation of processes to institutionalize the knowledge of procedures for fuel switching and operation for the non primary fuel mode of operation.
- Alternate fuel supplies should be tested for contamination or degradation

BAs and RCs should consider the following if they have plants which have duel fuel capability:

- Verification of the output of each fuel capability provides more accurate unit commitment planning.
- Verification might include the following:
  - Document time to switch
  - Document unit capacity and maximum runtimes while on alternate fuel

For more information please contact:

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Source of Lesson Learned: SERC Reliability Corporation

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From: Sandy Shiflett
To: Sandy Shiflett
Subject: NERC ANNOUNCEMENT: Lessons Learned
Date: Wednesday, August 10, 2011 4:41:20 PM

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Announcement:
Lessons Learned
August 10, 2011

Five new lessons learned have been posted on the NERC website under the "Events Analysis – Lessons Learned" tab:

The new lessons address the following topics:

- Backup Control Center Operation and Training
- Special Protection Systems Maintenance Precautions
- Protection Relaying – Out of date prints
- Transmission Relaying – Voltage Transformer Failure
- Transmission Relaying – Removing Unused Components

I welcome any feedback you have on the information contained within these lessons.

Sincerely,

Earl Shockley
Director of Event Analysis and Investigations

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From:	Philip A. Fedora
To:	rcc
Cc:	jtfc; Philip Raymond; John Moura; cp8; aadamson@nycap.rr.com; "Curt.Dahl@us.ngrid.com"; Ford@pjm.com; Glenn Haringa; John G. Mosier Jr.
Subject:	FW: FERC and NERC Release Task Force Report on Southwest Outages
Date:	Tuesday, August 16, 2011 3:40:30 PM

FYI

Don – please distribute to the NYSRC-EC

John Moura – please distribute to the NERC RAS

Thanks,

Phil

From: Susan Morris [mailto:Susan.Morris@ferc.gov]
Sent: Tuesday, August 16, 2011 3:25 PM
To: dbessdt_plus
Subject: FERC and NERC Release Task Force Report on Southwest Outages

http://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf

News Release: August 16, 2011
FERC Docket No.: AD11-9-000

FERC and NERC Release Task Force Report on Southwest Outages

The Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC) today released a staff report making recommendations to help prevent a recurrence of rolling blackouts and natural gas curtailments experienced by customers in the Southwest during extreme cold weather the first week of February 2011.

Concluding a six-month inquiry, the task force found a majority of the electric outages and gas shortages were due to weather-related causes. Although generators and gas producers reported having winterization procedures and practices in place, responses were generally reactive in their approach to winterization and preparedness.

"The task force has identified several proactive steps that can be taken by state regulators, electric generators and natural gas suppliers in the Southwest to improve the reliability of energy supply for customers during extreme cold weather," FERC Chairman Jon Wellinghoff said. "We urge them to carefully consider those recommendations and to work together to implement them before another cold weather event hits the region."

"This joint report demonstrates the high priority both NERC and FERC place on reliability," said Gerry Cauley, president and chief executive officer at NERC. "By combining technical resources and partnering, this report provides a comprehensive analysis and identifies a strong set of recommendations for the industry to use to better prepare in the future."

Despite the importance of winterizing plants, the task force found that no state, regional or NERC standards required generators to do so. The report recommends that states in the Southwest examine whether to require winterization plans, and NERC plans to work with industry to develop changes to NERC Reliability Standards to properly address winterization needs.

The task force attributed most of the natural gas shortages and outages to prolonged freezing

weather that resulted in dramatically reduced supply and unprecedented high demand. Interstate and intrastate pipelines showed flexibility in meeting demand and compensating for supply shortfalls, it said, but additional storage capacity in Arizona and New Mexico might have prevented many of the outages. Most electric outages were caused by weather-related mechanical problems such as frozen sensing lines, equipment, water lines and valves.

In other recommendations, the report said:

Generation owners and operators should ensure adequate construction, maintenance and inspection of freeze protection elements such as insulation, heat tracing and wind breaks.
Reliability coordinators and balancing authorities should require generators to provide accurate data about the temperature limits of units so they know whether they can rely on those units during extreme weather.
Balancing authorities should review the distribution of reserves to ensure that they are useable and deliverable during contingencies.
State lawmakers and regulators in Texas and New Mexico, working with industry, should determine if weather-related production shortages can be mitigated through the adoption of minimum winterization standards for natural gas production and processing facilities.

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Y

Federal Energy Regulatory Commission

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

August 16, 2011
Contacts: Mary O'Driscoll, FERC (202) 502-8680
Kimberly Mielcarek, NERC (202) 383-2622
Docket No.: AD11-9-000

FERC and NERC Release Task Force Report on Southwest Outages

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From: bounce-29770-47983@spplist.spp.org on behalf of Melissa Rinehart
To: SPP Compliance Contacts
Subject: NERC Standards Under Development 08-17-11
Date: Wednesday, August 17, 2011 9:17:32 AM

SPP Southwest Power Pool

COMPLIANCE UPDATE

A publication of SPP's RTO Compliance Department

IN THIS EDITION

Below is the current NERC Standards Under Development summary, which the SPP RTO Compliance Department updates and sends out weekly. As an industry stakeholder, your role in commenting is very important and we hope that you will take advantage of this opportunity to make your voices heard. Whether your company decides to submit separate comments, or helps to shape the separate comments that SPP may submit, this is one of the few chances that you will have to let NERC hear your concerns about the proposed standard(s) prior to a standard becoming effective and enforceable.

A WebEx/Conference Call has been scheduled for Thursday morning, August 18, 2011 at 9:00 AM CDT for the SPP Reliability Standards group to review and compile comments on the following:

MVTF Draft Procedures for Validation of Powerflow and Dynamics Cases- As directed by NERC's Planning Committee, the NERC Model Validation Task Force (MVTF) has posted the "Procedures for Validation of Powerflow and Dynamics Cases" for comment. Documents associated with this can be found here. This document has been posted for an industry review and comment period through August 26, 2011.

Please be prepared to discuss this document on August 18th. If you would like to attend this WebEx/Conference Call please register online using the SPP Calendar. Upon registration, you will be sent the WebEx/Conference call information. Please call April Brooks at 501.688.1641 if you have any questions.

Posted for Comment
(Closes at 8pm EST)

Project 2007-17 Protection System Maintenance and Testing

Comment period: August 15, 2011 – September 28, 2011
Join ballot pool: August 15, 2011 – September 14, 2011
Join non-binding poll: August 15, 2011 – September 14, 2011
Ballot period: September 19, 2011 – September 28, 2011

Applicable Entities: TO, GO, DP that owns a transmission Protection System

Status: After PRC-005-2 failed to reach ballot pool approval in the recirculation ballot that ended 6/30/11, the drafting team revised the standard, and updated the Supplemental Reference and FAQ. The Standards Committee authorized re-initiating the project with a posting of the SAR and revised standard for a 45-day comment period, with an initial ballot of the standard conducted during the last 10 days of the comment period. The drafting team will conduct a webinar during the time the standard is posted to explain the changes that were made and answer questions.

Purpose/Industry Need:

The purpose of standard PRC-005 should remain "To ensure all transmission and generation Protection Systems

affecting the reliability of the Bulk Electric System (BES) are maintained and tested."
In Order 693, the Federal Energy Regulatory Commission directed that changes be made to these standards. These standards should be consolidated into a single standard to reduce the costs of compliance and a number of technical short comings in these standards should be corrected to provide reliable performance when responding to abnormal system conditions.

Recently Finalized Compliance Application Notices

For a complete listing of Compliance Application Notices, please visit the NERC website.

CAN-0028 TOP-006 R1.2 Reporting Responsibilities
Primary Interest Groups: NERC, RE, TOP, BA, GOP, RC
Issue: What are resource reporting responsibilities for the Balancing Authorities (BA) and Transmission Operators (TOP) under TOP-006?

Recently Posted NERC Lessons Learned

Backup Control Center Operation and Training
Primary Interest Groups: RC, BA, TO, TOP

Special Protection Systems Maintenance Precautions
Primary Interest Groups: BA, GO, GOP, TO, TOP

Protection Relaying - Out of date prints
Primary Interest Groups: GO, GOP, TO, TOP

Transmission Relaying - Coupling Capacitor Voltage Transformer Failure Indications for Operations
Primary Interest Groups: TO, TOP

Transmission Relaying - Removing Unused Components
Primary Interest Groups: DP, GO, TO

Market Rules

Chapter 5
Power System Reliability

Power to Ontario.
On Demand.

Issue Date: July 8, 2011

Library Record No.	MDP_RUL_0002_05
Document Name	Market Rules for the Ontario Electricity Market
Issue	Issue 21.0
Reason for Issue	Effective date for MR-00379
Effective Date	July 8, 2011

Document Change History

Issue/Draft	Reason for Issue	Date
Issue 1.0	Baseline 8.0	September 25, 2002
Issue 2.0	Baseline 8.1	December 5, 2002
Issue 3.0	Baseline 9.0	March 5, 2003
Issue 4.0	Baseline 9.1	June 4, 2003
Issue 5.0	Baseline 10.0	September 10, 2003
Issue 6.0	Baseline 10.1	December 10, 2003
Issue 7.0	Baseline 11.1	June 2, 2004
Issue 8.0	Baseline 13.0	March 9, 2005
Issue 9.0	Baseline 14.1	December 7, 2005
Issue 10.0	Baseline 15.0	March 8, 2006
Issue 11.0	Baseline 16.0	September 13, 2006
Issue 12.0	Baseline 16.1	December 6, 2006
Issue 13.0	Baseline 17.0	March 7, 2007
Issue 14.0	Baseline 18.0	September 12, 2007
Issue 15.0	Baseline 18.1	December 12, 2007
Issue 16.0	Baseline 19.0	March 5, 2008
Issue 17.0	Baseline 20.0	September 10, 2008
Issue 18.0	Baseline 22.0	September 9, 2009
Issue 19.0	Effective date for MR-00366	May 8, 2010
Issue 20.0	Baseline 23.1	June 2, 2010
Issue 21.0	Effective date for MR-00379	July 8, 2011

Related Documents

Library Record No.	Document Title	Version
MDP_RUL_0002	Market Rules for the Ontario Electricity Market	43.0

Document Control

Authorities

Prepared by
Market Evolution

Reviewed by
Technical Panel
Legal Affairs
IESO Change Management

Approved by
IESO Board

Distribution List

Name	**Organization**

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1. Purposes, Interpretation and General Principles

1.1 Purposes of Chapter 5 and Interpretation

1.1.1 Pursuant to section 5 of the Electricity Act, 1998, one of the objects of the *IESO* is to maintain the *reliability* of the *IESO-controlled grid*. This Chapter of the *market rules* sets forth:

1.1.1.1 rules governing maintenance of the *reliability* of the *IESO-controlled grid*;

1.1.1.2 conditions under which the *IESO* shall have authority to intervene in the *IESO-administered markets* and issue directions to *market participants* so as to maintain the *reliability* of the *IESO-controlled grid* and of electricity service;

1.1.1.3 procedures to be used by the *IESO*, including the issuance of directions, in the event of an *emergency,* an *emergency operating state* or a *high-risk operating state;*

1.1.1.4 minimum requirements for communication and information exchange between the *IESO* and *market participants* relating to the *reliability* of the *IESO-controlled grid*; and

1.1.1.5 the *IESO's* reporting requirements associated with its responsibilities for maintaining the *reliability* of the *IESO-controlled grid*.

1.1.2 For the purposes of this Chapter, "maintaining" *reliability* shall include re-establishing or restoring *reliability* and "maintain" and "maintenance" shall be interpreted accordingly.

1.1.3 In the event of a contradiction or inconsistency between the provisions of this Chapter 5 and any other provision of the *market rules*, the provisions of this Chapter 5 shall govern. In performing any act, power, or duty under the *market rules*, the *IESO* shall have due regard to and, when necessary to ensure the *reliability* of the *IESO-controlled grid*, give precedence to the provisions of this Chapter 5.

1.2 General Principles

1.2.1 To the fullest extent possible consistent with maintaining the *reliability* of the *IESO-controlled grid*, the *IESO* shall apply the *market rules* relating to *reliability* so as to minimize the *IESO's* intervention into the operation of the *IESO-administered markets*. However, the maintenance of a *reliable IESO-controlled grid* shall be considered of paramount importance under these *market rules*, and the *IESO* shall have authority to intervene in the *IESO-administered markets* to the extent necessary to maintain the *reliability* of the *IESO-controlled grid.*

1.2.2 In all cases, except as otherwise noted in this Chapter, where the *IESO* takes action under this Chapter, it shall attempt to coordinate its actions with affected *market participants* unless, in the *IESO's* opinion, conditions dictate the need for immediate action.

1.2.3 Nothing in this Chapter is intended to prevent *market participants* from acting to protect their assets from physical damage or to protect the safety of their employees, the public or the environment, provided that any such actions that may affect the *reliability* of the *IESO-controlled grid* are coordinated with the *IESO* to the fullest extent practicable and are, in any event, reported or notified to the *IESO* where required by these *market rules* to be so reported or notified.

1.2.4 Section 7.5 of Chapter 1 does not apply to this Chapter and any action or event that is required to occur on or by a stipulated time or day under this Chapter, or under a direction, instruction or order of the *IESO* issued pursuant to this Chapter, shall occur on or by that time, whether or not a business hour, or on or by that day, whether or not a *business day*, unless otherwise specified in this Chapter.

1.2.5 Unless a direction, instruction or order of the *IESO* provides otherwise, wherever this Chapter specifies that an action is to be taken "promptly" or "immediately", such action shall be taken as soon as possible after receiving the direction, instruction or order from the *IESO* or after becoming aware that an action is to be taken or is required not to be taken but in all events within five minutes, subject only to delay necessitated by concerns for the safety of equipment, employees, the public or the environment.

1.2.6 Subject to section 1.2.7, *reliability standards* established by a *standards authority* that have not otherwise been stayed or revoked and referred back to the *standards authority* for further consideration by the *Ontario Energy Board* shall be declared in force in Ontario:

1.2.6.1 when the *reliability standards* are declared in force in the United States or, for *NPCC* reliability criteria, when declared in force by *NPCC*; and

1.2.6.2 after the expiry of the period for initiating a review before the *Ontario Energy Board* and the conclusion of any such review;

and shall cease to be in force in Ontario when they cease to be in force in the United States. For certainty, the operation of any *reliability standard* that had been in force in Ontario but had not been declared in force in the United States when this rule amendment went into effect shall be stayed until such *reliability standard* has been declared in force in the United States.

1.2.7 Notwithstanding section 1.2.6, where a *reliability standard* approved by *NERC* failed to achieve approval by the *NERC* registered ballot body as specified in *NERC*'s Rules of Procedure, the *reliability standard* will not be in force in Ontario unless and until the *IESO* determines, in consultation with affected *market participants*, that all or part of the *reliability standard* is in force in Ontario. The *IESO* shall *publish* notice of its determination and where applicable, such *reliability standard* will come into effect in accordance with section 1.2.6.

2. IESO-Controlled Grid and Operating States

2.1 Scope of IESO-Controlled Grid

2.1.1 The specific *facilities* included within the *IESO-controlled grid* shall be identified in the *operating agreements* between the *IESO* and each *transmitter* that are entered into in accordance with the Electricity Act, 1998. To the extent the *IESO* concludes, on its own initiative or further to a request made by a *market participant*, that, in order to meet its obligations to *reliably* operate the *IESO-controlled grid* or administer the *IESO-administered markets*, additional *transmission systems* or distribution *facilities* should be included within the *IESO-controlled grid*, the *IESO* shall negotiate to amend the applicable *operating agreement* to include such *transmission systems or facilities* or to conclude an *operating agreement* with the *transmitter* or owner of such *facilities* with whom no *operating agreement* has yet been concluded, as the case may be.

2.1.2 Subject to the licence of the *IESO* or of the applicable transmitter or distributor, if the *IESO* and a *transmitter* or *distributor* are unable to reach agreement on the inclusion of *facilities* within the *IESO-controlled grid*, the matter shall be resolved using the dispute resolution procedures in the applicable *operating agreement* or, in the absence of same, the procedures set forth in Section 2 of Chapter 3.

2.2 Normal Operating State

2.2.1 The *IESO-controlled grid* shall be considered as being in a *normal operating state* when:

2.2.1.1 the voltage magnitudes at all energized busbars at any switchyard or substation of the *IESO-controlled grid* are within the ratings set by relevant *transmitters*;

2.2.1.2 the current flows on all transmission *facilities* of the *IESO-controlled grid* are within the equipment ratings established by the relevant *transmitters*;

2.2.1.3 all other electric plant forming part of, or having or likely to have a material impact on the operation of, the *IESO-controlled grid* is being operated within the equipment ratings defined by the relevant *transmitters*, *generators* and *distributors*;

2.2.1.4 all *interconnected systems* having or likely to have a material impact on the operation of the *IESO-controlled grid* are being operated within the equipment ratings that are jointly established between the *IESO* and the relevant *transmitters*;

2.2.1.5 the configuration of the *IESO-controlled grid* is such that the severity of any potential fault is within the capability of circuit breakers to disconnect the faulted circuit or equipment; and

2.2.1.6 conditions on the *IESO-controlled grid* are secure in accordance with the requirements set forth in Section 5.

2.3 Emergency Operating State

2.3.1 The *IESO-controlled grid* shall be considered as being in an *emergency operating state* when observance of *security limits* under a *normal operating state* will either:

2.3.1.1 require curtailment of *non-dispatchable load*; or

2.3.1.2 restrict transactions on interconnected systems during an emergency on the IESO-controlled grid or on a neighbouring electricity system.

2.3.2 The *IESO* shall not take any action or refrain from taking any action that will, in the *IESO*'s opinion, be reasonably likely to lead to an *emergency operating state*.

2.3.3 The *IESO* shall promptly inform *market participants* when an *emergency operating state* is anticipated or has been declared, and when it ceases to exist or to be anticipated. During an *emergency operating state*, the *IESO* shall have the authority to modify *security limits* as necessary to manage conditions on the *IESO-controlled grid*, and to take such other action or refrain from taking such other action consistent with *good utility practice* as may be required to restore the *IESO-controlled grid* to a *normal operating state* and with as little disruption to electric service or adverse impact on the operation of the *IESO-administered markets* as is reasonably practicable in the circumstances.

2.3.3A Without limiting the generality of section 2.3.3 and notwithstanding any other provision of the *market rules*, the *IESO* may, when the *IESO-controlled grid* is in an *emergency operating state*, acquire *emergency energy* in accordance with all applicable *reliability standards* and any applicable *interconnection agreement* in order to maintain the *reliability* of the *IESO-controlled grid.* The *IESO* shall not exercise this power where *market participants* have *offered* to provide sufficient quantities of *energy*, eligible for *dispatch* or scheduling, to enable the *IESO* to maintain the *reliability* of the *IESO-controlled grid*. The costs associated with the acquisition of such *emergency energy* paid by the *IESO* pursuant to the applicable *interconnection agreement* shall be recovered in accordance with section 4.8 of Chapter 9.

2.3.4 Further provisions relating to system and market operations during *emergency* conditions are set forth in Chapter 7.

2.4 High-Risk Operating State

2.4.1 The *IESO-controlled grid* shall be considered to be in a *high-risk operating state* when the observance of *security limits* under a *normal operating state* will expose the *integrated power system* to a significantly higher than normal probability of one or more *contingency events* and associated consequences, or of a condition that may lead to, but is not yet, an *emergency*. The conditions under which the *IESO-controlled grid* may be considered as entering into or exiting a *high-risk operating state* shall be defined in the *IESO*'s operating procedures, it being understood that, without limiting the generality of the foregoing, a *high-risk*

operating state is normally associated with adverse weather conditions (such as lightening or freezing rain), extreme weather conditions (such as tornadoes or hurricanes) or equipment-related problems (such as the operation of equipment known to be unreliable or defective).

2.4.2 The *IESO* shall not take any action or refrain from taking any action that will, in the opinion of the *IESO*, be reasonably likely to lead to a *high-risk operating state*.

2.4.3 The *IESO* shall promptly inform *market participants* when a *high-risk operating state* is anticipated or has been declared, and when it ceases to exist or to be anticipated. During a *high-risk operating state*, the *IESO* shall have the authority to modify *security limits* as necessary to manage conditions on the *IESO-controlled grid*, and to take such other action or refrain from taking such other action consistent with *good utility practice* as may be required and with as little disruption to electric service or adverse impact on the operation of the *IESO-administered markets* as is reasonably practicable in the circumstances.

3. Obligations and Responsibilities

3.1 Objectives

3.1.1 This section 3 sets forth the responsibilities, obligations and authorities of the *IESO* and each *market participant* in order to maintain the *reliability* of the *IESO-controlled grid.*

3.2 Obligations of the IESO

3.2.1 The *IESO* shall direct the operations of the *IESO-controlled grid* pursuant to the provisions of all applicable *operating agreements* and shall maintain the *reliability* of the *IESO-controlled grid*. The *IESO's* responsibilities in this regard shall include, but are not limited to, the monitoring of, and the issuing of orders, directions or instructions to *dispatch generation, dispatchable loads*, distribution *facilities* and transmission *facilities* on the *IESO-controlled grid.*

3.2.2 The *IESO* shall carry out its obligations in accordance with all applicable *reliability standards.*

3.2.3 In order to meet its obligations under this Chapter and under other provisions of the *market rules*, the *IESO* shall maintain written operating procedures and instructions and shall make same available for inspection at all times by *market participants*. The Board of Directors of the *IESO* may *amend* the *market rules* to include any such operating procedures and instructions within the *market rules*.

3.2.4 The *IESO* shall *publish* on a calendar month time-frame, six months from the end of each subject month, the monthly average *maximum continuous rating* of each generating station based on information provided to it by *market participants*. The *maximum continuous ratings* for generating stations with ratings less than 20 MVA can be aggregated by area.

Identification of Reliability Standards

3.2.5 The *IESO* shall, in consultation with each *market participant*, advise the *market participant* of the *reliability standards'* obligations or requirements that the *IESO* determines apply to that *market participant* as of the date of the assessment. The *IESO* may revise its determination under this section at any time on notice to the *market participant*.

3.2.6 When a *reliability standard* is amended or a new *reliability standard* comes into effect, the *IESO* shall, in consultation with each *market participant,* advise the *market participant* of the new or amended *reliability standards'* obligations or requirements that the *IESO* determines apply to that *market participant* as of the date of the assessment. The *IESO* may revise its determination under this section at any time on notice to the *market participant*.

3.2.7 A *market participant* may request the *IESO* review a determination under section 3.2.5 or 3.2.6 with respect to that *market participant*. The *IESO* shall, following consideration of any representations made by the *market participant,* determine whether the *reliability standards'* obligations or requirements apply to that *market participant*.

3.2A Technical Feasibility Exceptions

3.2A.1 The *IESO* may:

3.2A.1.1 reject or accept a *TFE application* in whole or in part;

3.2A.1.2 approve a *TFE application*, in whole or in part, subject to and including any terms and conditions the *IESO* determines appropriate or disapprove a *TFE application*, in whole or in part;

3.2A.1.3 upon the request of a *market participant* amend or transfer a *TFE*, in whole or in part, subject to and including any terms and conditions the *IESO* determines appropriate; or

3.2A.1.4 terminate or amend an approved *TFE*, in whole or in part, subject to any terms and conditions the *IESO* determines appropriate.

3.2A.2 A *TFE applicant* may, in accordance with the applicable *market manual*, request the *IESO* approve, amend, transfer, or terminate one or more *TFEs* by filing with the *IESO* a *TFE application* for each required *TFE*, and shall, in accordance with the applicable *market manual* submit to the *IESO* an initial deposit. A *TFE applicant* may withdraw a *TFE application* at any time.

3.2A.3 Upon request by the *IESO*, a *TFE applicant* shall provide to the *IESO*:

3.2A.3.1 a substantive review deposit amount;

3.2A.3.2 any supporting documentation; and

3.2A.3.3 an executed agreement pursuant to which the *TFE applicant* agrees to pay to the *IESO* an amount equal to all of the reasonable costs incurred by the *IESO* in assessing the *TFE application.*

3.2A.4 The *IESO* shall assess a *TFE application* in accordance with Ontario-adapted *NERC* procedures for processing *TFE applications* as set out in the applicable *market manual*.

3.2A.5 Where applicable, for each *TFE application,* the *IESO* shall establish a cost threshold or subsequent cost thresholds which it considers to be reasonable and which will form part of the executed agreement set out in section 3.2A.3.3 and will monitor expenditures against the assessment costs of a *TFE application* and where that threshold is reached:

3.2A.5.1 the *IESO* shall advise the *TFE applicant* of the work and costs incurred to date;

3.2A.5.2 the *IESO* shall provide an estimate to the *TFE applicant* of the further work and costs necessary to complete the assessment of the *TFE application*; and

3.2A.5.3 the *TFE applicant* may choose to continue with the assessment of the *TFE application* or discontinue the assessment of the *TFE application*. In the event that the *TFE applicant* chooses to discontinue the assessment by withdrawing the *TFE application*, the *IESO* shall issue

an *invoice* to the *TFE applicant* for the reasonable costs incurred by the *IESO* to that point.

3.2A.6 The *IESO* may utilize an independent third party to review a *TFE application* submitted by a *TFE applicant*.

3.2A.7 The *IESO* may consult with *NERC* or *NPCC* in its assessment of a *TFE application*.

3.2A.8 A failure by a *market participant* or the *IESO* to meet any of the terms and conditions of an approved *TFE* shall be a breach of the *market rules* and the *IESO* may terminate the approved *TFE* and require the *TFE applicant* to become compliant with the applicable *NERC reliability standard*.

3.2A.9 Subject to section 3.2A.4, all *TFE*s which remain in effect are subject to periodic review, in accordance with the applicable *market manual*, to verify continuing justification for the *TFE*.

3.2A.10 The *IESO* shall submit an *invoice* to a *TFE applicant* upon completion of the processing of that applicant's *TFE application* in an amount equal to all of the *IESO's* costs and expenses relating to the processing of the *TFE applicant's TFE application* less the amount of any deposit paid pursuant to section 3.2A.3.1.

3.2A.11 A *TFE applicant* shall, within thirty days of the date of an *invoice* referred to in section 3.2A.5.3 or 3.2A.10, pay to the *IESO* the amount owing.

3.3 Reliability-Related Information

3.3.1 Within 90 days after the date of coming into force of this Chapter, the *IESO* shall *publish* a list of the categories of *reliability*-related information that it shall make available to *market participants*, the time periods within which such information will be provided, and the manner in which such information will be provided. Such information shall include, but not be limited to, information designed to:

3.3.1.1 enable *market participants* to initiate procedures to manage the potential risk of any action taken by the *IESO* to maintain the *reliability* of the *IESO-controlled grid*;

3.3.1.2 assist *market participants* in meeting their obligations under this Chapter; and

3.3.1.3 notify *market participants* of any operating changes or decisions that may have an impact on their operations, *facilities* or equipment.

3.3.2 Within 90 days after the date of coming into force of this Chapter, the *IESO* shall publish a catalogue of the *reliability*-related information that the *IESO* shall require be provided to it by *market participants*, including the information referred to in section 14.1.3, the time periods within which such information will be provided and the manner in which such information will be provided. At the same time, the *IESO* shall *publish* initial monitoring indices that the *IESO* shall use in evaluating the information so provided.

3.3.3 *Market participants* shall provide the *IESO* with the information referred to in section 3.3.2 within the time and in the manner required.

3.3.4 Subject to the confidentiality provisions of Chapters 3 and 4, the *IESO* shall, if requested to do so by a *market participant*, provide to that *market participant* *reliability*-related information not contained in the list referred to in section 3.3.1, provided that the *IESO* shall be under no obligation to provide any information that, in the *IESO's* opinion, would provide the requesting *market participant* with an undue advantage in the *IESO-administered markets*. In order to prevent any such undue advantage, the *IESO* may provide *market participants* with notice of the request prior to providing such information and may make the information requested by a *market participant* simultaneously available to all *market participants*.

3.4 Obligations of Transmitters

3.4.1 Each *transmitter* shall operate and maintain its transmission *facilities* and equipment in a manner that is consistent with the *reliable* operation of the *IESO-controlled grid* and shall assist the *IESO* in the discharge of its responsibilities relating to *reliability*. Such obligation shall include, but not be limited to, the following:

3.4.1.1 ensuring that systems and procedures for load-shedding in *emergencies* are provided for as specified in section 10;

3.4.1.2 ensuring there are controls, monitoring and secure communication systems to facilitate a manually initiated, rotational load-shedding and restoration process in order to assist the *IESO* in the management of a prolonged, major shortage of electrical supply or an extreme disruption to or *emergency* on the *IESO-controlled grid*;

3.4.1.3 providing the *IESO* with functional descriptions, equipment ratings, and operating restrictions for its equipment;

3.4.1.4 promptly informing the *IESO* of any change or anticipated change in the capability of its transmission *facilities* or the status of its equipment or *facilities* forming part of the *IESO-controlled grid*, and of any other change or anticipated change in its transmission *facilities* that could have a material effect on the *reliability* of the *IESO-controlled grid* or the operation of the *IESO-administered markets;* and

3.4.1.5 promptly complying with the *IESO's* directions, including directions to *disconnect facilities* or equipment from the *IESO-controlled grid* or its *transmission system* for *reliability* purposes, unless the *transmitter* reasonably believes that following the *IESO's* direction poses a real and substantial risk of damage to its equipment, to the safety of its employees or the public, or of undue injury to the environment. In all cases where the *transmitter* does not intend to follow the *IESO's* directions for any such reasons, it shall promptly notify the *IESO* of this fact and shall nonetheless comply with the *IESO's* directions to the fullest extent possible without causing the harms described above.

3.4.2 Each *transmitter* shall carry out its obligations under this Chapter in accordance with all applicable *reliability standards,* subject to the information reporting requirements specified in section 14.1.2.

3.5 Obligations of Wholesale Customers

3.5.1 Each *connected wholesale customer* shall operate and maintain its *facilities* and equipment in a manner that is consistent with the *reliable* operation of the *IESO-controlled grid* and shall assist the *IESO* in the discharge of its responsibilities relating to *reliability*. Such obligation shall include, but not be limited to, the following:

3.5.1.1 ensuring there are controls, monitoring, and secure communication systems to facilitate a manually initiated, rotational load-shedding and restoration process in order to assist the *IESO* in the management of a prolonged, major shortage of electrical supply or an extreme disruption to or *emergency* on the *IESO-controlled grid*;

3.5.1.2 promptly informing the *IESO* of any change or anticipated change in the status of any *facility* or equipment that it operates and that is under the *dispatch* control of the *IESO* as described in these *market rules* or of any other change or anticipated change in its *facilities* or equipment

that could have a material effect on the *IESO-controlled grid* or the operation of the *IESO-administered markets;*

3.5.1.3 promptly complying with the *IESO's* directions, including directions to disconnect equipment from the *IESO-controlled grid* for *reliability* purposes, unless the *connected wholesale customer* reasonably believes that following the *IESO's* direction poses a real and substantial risk of damage to its *equipment*, to the safety of its employee or the public, or of undue injury to the environment. In all cases where the *connected wholesale customer* does not intend to follow the *IESO's* directions for any such reasons, it shall promptly notify the *IESO* of this fact and shall nonetheless comply with the *IESO's* directions to the fullest extent possible without causing the harms described above; and

3.5.1.4 [Intentionally left blank]

3.5.1.5 providing, no later than 14:00 EST on the last *trading day* of every second *trading week*, or more frequently if requested by the *IESO*, the following information:

a. the timing and duration of any *planned outage*, closure, test or other similar operational event scheduled to commence or occur in the immediately succeeding four *trading weeks*, or during such longer period as may be requested by the *IESO*, in respect of any *facility* that it operates, where such *planned outage*, closure, test or other similar operational event is expected to result in a change in *demand* of 20 MW or more; relative to the average weekday demand of that *facility*; and

b. the timing and duration of any *planned outage*, closure, test or other similar operational event scheduled to commence or occur in the immediately succeeding four *trading weeks*, or during such longer period as may be requested by the *IESO*, in respect of any *facility* that it operates and that has been specifically designated by the *IESO* for this purpose.

3.5.2 Each *wholesale consumer* that is an *embedded market participant* and that operates a *registered facility* that is not directly *connected* to the *IESO-controlled grid* shall provide, no later than 14:00 EST on the last *trading day* of every second *trading week*, or more frequently if requested by the *IESO*, the following information:

3.5.2.1 the timing and duration of any *planned outage*, closure, test or other similar operational event scheduled to commence or occur in the

immediately succeeding four *trading weeks*, or during such longer period as may be requested by the *IESO*, in respect of any such *registered facility*, where such *planned outage*, closure, test or other similar operational event is expected to result in a change in *demand* of 20 MW or more relative to the average weekday demand of that *registered facility*; and

3.5.2.2 the timing and duration of any *planned outage*, closure, test or other similar operational event scheduled to commence or occur in the immediately succeeding four *trading weeks*, or during such longer period as may be requested by the *IESO*, in respect of such *registered facility* that has been specifically designated by the *IESO* for this purpose.

3.5.3 Each *wholesale customer* shall carry out its obligations under this Chapter in accordance with all applicable *reliability standards,* subject to the information reporting requirements specified in section 14.1.2.

3.6 Obligations of Generators (Embedded and Non-embedded)

3.6.1 Each *generator* that participates in the *IESO-administered markets* or that causes or permits electricity to be conveyed into, through or out of the *IESO-controlled grid* shall operate and maintain its *generation facilities* and equipment in a manner that is consistent with the *reliable* operation of the *IESO-controlled grid* and shall assist the *IESO* in the discharge of its responsibilities related to *reliability*. Such obligation shall include, but not be limited to, the following:

3.6.1.1 ensuring there are controls, monitoring and secure communication systems to facilitate a manually initiated restoration process in order to assist the *IESO* in the management of a prolonged, major shortage of electrical supply or an extreme disruption to or *emergency* on the *IESO-controlled grid*;

3.6.1.2 providing the *IESO* with functional descriptions, equipment ratings, and operating restrictions for its equipment, as required by the *IESO* to *reliably* operate the *IESO-controlled grid*;

3.6.1.3 promptly informing the *IESO* of any change or anticipated change in the status of any *generation facility* or related equipment that it operates and that is under the *dispatch* control of the *IESO* as described in these *market rules* or of any other change or anticipated

change in its *generation facilities* or equipment that could have a material effect on the *IESO-controlled grid* or the operation of the *IESO-administered markets.* Such change shall include, but not be limited to, any change in status that could affect the maximum output of a *generation unit*, the minimum load of a *generation unit*, the ability of a *generation unit* to operate with *automatic voltage regulation*, or the availability of a *generation unit* to provide *ancillary services* (unless no application has been made to provide *ancillary services* to the *IESO-administered markets* in respect of a given *generation unit);*

3.6.1.4 promptly informing the *IESO* if any of the *generation facilities* that it operates are unable for any reason to operate in accordance with the schedules determined pursuant to Chapter 7;

3.6.1.5 providing the *IESO* with current information showing the maximum unit capabilities of each of its *generation units* to facilitate *dispatch* in an *emergency operating state*. Such maximum unit capabilities shall consist of the maximum physical-rating of the *generation unit* and shall not be limited to the unit capabilities contained in the *offers* submitted for such *generation unit* pursuant to Chapter 7;

3.6.1.6 promptly complying with the *IESO's* directions, including directions to disconnect equipment from the *IESO-controlled grid* for *reliability* purposes, unless the *generator* reasonably believes that following the *IESO's* direction poses a real and substantial risk of damage to its equipment, to the safety of its employee or the public, or of undue injury to the environment. In all cases where the *generator* does not intend to follow the *IESO's* directions for any such reasons, it shall promptly notify the *IESO* of this fact and shall nonetheless comply with the *IESO's* directions to the fullest extent possible without causing the harms described above; and

3.6.1.7 [Intentionally left blank]

3.6.2 Each *generator* shall carry out its obligations under this Chapter in accordance with all applicable *reliability standards,* subject to the information reporting requirements specified in section 14.1.2.

3.7 Obligations of Distributors

3.7.1 Each *distributor* shall operate and maintain its distribution *facilities* and equipment in a manner that is consistent with the *reliable* operation of the *IESO-controlled grid* and shall assist the *IESO* in the discharge of its responsibilities

relating to *reliability*. Such obligation shall include, but not be limited to, the following:

3.7.1.1 ensuring that systems and procedures for load-shedding in *emergencies* are provided for as specified in section 10;

3.7.1.2 promptly informing the *IESO* of any change or anticipated change in the capability of its equipment or distribution *facilities* connected to the *IESO-controlled grid* that could have a material effect on the *reliable* operation of the *IESO-controlled grid* or the operation of the *IESO-administered markets*;

3.7.1.3 promptly informing the *IESO* of any event or circumstance in its service territory that could have a material effect on the *reliability* of the *IESO-controlled grid;*

3.7.1.4 providing the *IESO* with functional descriptions, equipment ratings, and operating restrictions for equipment and distribution *facilities* that are included within the *IESO-controlled grid*;

3.7.1.5 promptly complying with the *IESO's* directions, including directions to *disconnect facilities* or equipment from the *IESO-controlled grid* or its *distribution system* for *reliability* purposes, unless the *distributor* reasonably believes that following the *IESO's* direction poses a real and substantial risk of damage to its equipment, to the safety of its employee or the public, or of undue injury to the environment. In all cases where the *distributor* does not intend to follow the *IESO's* directions for any such reasons, it shall promptly notify the *IESO* of this fact and shall nonetheless comply with the *IESO's* directions to the fullest extent possible without causing the harms described above;

3.7.1.6 providing, no later than 14:00 EST on the last *trading day* of every second *trading week*, or more frequently if requested by the *IESO*, the following information:

a. the timing and duration of any *planned outage*, closure, test or other event scheduled to commence or occur in the immediately succeeding four *trading weeks*, or during such longer period as may be requested by the *IESO*, in respect of any *facility* which is not a *registered facility* that draws electrical *energy* from or injects electrical *energy* into its *distribution system*, where such *planned outage*, closure, test or other event is expected to result in a change in *demand* or supply by that *facility* of 20 MW or more relative to the average weekday demand or supply of that *facility*; and

b. the timing and duration of any *planned outage*, closure, test or other event scheduled to commence or occur in the immediately succeeding four *trading weeks*, or during such longer period as may be requested by the *IESO*, in respect of any *facility* which is not a *registered facility* that draws electrical *energy* from or injects electrical *energy* into its *distribution system* and that has been specifically designated by the *IESO* for this purpose, where such *planned outage*, closure, test or other event is expected to result in a change in *demand* or supply by such *facility* relative to the average weekday *demand* or supply of that *facility*; and

3.7.1.7 [Intentionally left blank]

3.7.2 Each *distributor* shall carry out its obligations under this Chapter in accordance with all applicable *reliability standards,* subject to the information reporting requirements specified in section 14.1.2.

4. System Reliability

4.1 Objectives

4.1.1 The objective of this section 4 is to set forth the requirements to ensure the availability of sufficient *generation capacity* and *ancillary services* to the *IESO-administered markets.*

4.2 Standards for Ancillary Services

4.2.1 The *IESO* shall operate the *IESO-administered markets* and contract for *ancillary services*, including by means or within the scope of an *operating agreement* or another agreement of similar nature, to ensure that sufficient *ancillary services* are available to ensure the *reliability* of the *IESO-controlled grid*. *Ancillary services* shall be procured by the *IESO* in accordance with this Chapter and Chapter 7.

4.2.2 The requirements for *ancillary services* shall be determined based on all applicable *reliability standards* and actual and expected conditions on the *IESO-controlled grid.* Requirements for *ancillary services* may be adjusted from time to time by the *IESO* to take into account, among other things, variations in *integrated power system* conditions, real-time *dispatch* constraints, *contingency*

events, the prevailing level of system risks or vulnerability, and the results of assessments of the voltage and dynamic stability of the *integrated power system*.

4.2.3 The *IESO* shall, in accordance with the procedures set forth in section 4 of Chapter 3, periodically review the operation of the *IESO-administered markets* for *ancillary services* to determine whether any revision to the requirements and standards for *ancillary services* is required for *reliability* purposes. As a minimum, the *IESO* shall conduct such reviews to accommodate revisions to applicable criteria established by relevant *standards authorities*.

4.3 Generic Performance Requirements for Ancillary Services

4.3.1 *Ancillary services* may be provided to the *IESO* only by *registered facilities* as required by Chapter 7. *Ancillary services* may be offered to the *IESO* in its daily and hourly *physical markets* or provided to the *IESO* under *contracted ancillary service* contracts through the *IESO's ancillary services procurement markets* or by means or within the scope of *operating agreements* or another agreement of a similar nature. Prior to entering into a contract with any *ancillary service provider*, the *IESO* shall determine whether the *facilities* and procedures of such *ancillary service provider* meet the requirements for registration as a *registered facility* in respect of the *ancillary service(s)* to be provided and are otherwise in compliance with the technical requirements of this Chapter. The *IESO* shall not contract for *ancillary services* with an *ancillary services provider* whose *facilities* are not in compliance with such requirements.

4.3.2 In order to make the determination referred to in section 4.3.1, the *IESO* may require each *ancillary service provider* to demonstrate through physical tests or other appropriate means specified by the *IESO* that the *registered facilities* or equipment that will be used to provide the *ancillary service* meet the performance standards for each *ancillary service* set forth in Appendix 5.1 or in the applicable *market manual*.

4.3.3 [Intentionally left blank – section deleted]

4.3.4 [Intentionally left blank – section deleted]

4.4 Regulation

4.4.1 The *IESO* shall maintain sufficient *regulation* to allow the *IESO* to meet all applicable *reliability standards*.

4.4.2 The *IESO* shall determine the quantity of *regulation* capacity needed for each hour of the following day. As a minimum, the requirement shall be +/- 100 MW, with a ramp rate of 50 MW/min.

4.4.3 If the *IESO* is unable to comply with applicable *reliability standards*, it shall take corrective action to achieve compliance with applicable *reliability standards* within three months.

4.4.4 *Area control error (ACE)* shall be calculated by the *IESO* in accordance with section 4.4.5 and all applicable *reliability standards*. Control signals shall be sent from the *IESO* to *registered facilities* providing *regulation*, as required by the *IESO*.

4.4.5 The calculation of *ACE* shall occur at least every four seconds.

4.4A Assistance to Other Control Areas

4.4A.1 Notwithstanding any other provision of the *market rules*, when a *transmission system* in another *control area* is in a state identical or comparable to an *emergency operating state*, the *IESO* may, in accordance with all applicable *reliability standards* and any applicable *interconnection agreement*, provide *emergency energy* to the *control area* within which such other *transmission system* is located in order to maintain the *reliability* of such *transmission system.* The *IESO* shall only provide *emergency energy* to another *control area* in circumstances where *energy* could not be obtained by that *control area* using the *offer* and *bid* processes described in Chapter 7. The compensation associated with the provision of such *emergency energy* that is received by the *IESO* pursuant to the applicable *interconnection agreement* shall be distributed in accordance with section 4.8 of Chapter 9.

4.5 Operating Reserve

4.5.1 *Operating reserve* is capacity that, for any given operating interval or *dispatch interval*, is in excess to that required to meet anticipated requirements for *energy* for that operating interval or dispatch interval, and is available to the *integrated power system* for *dispatch* by the *IESO* within a specified time period, such as 10 minutes or 30 minutes. *Operating reserves* may be provided by *generation facilities, dispatchable loads* and *boundary entities* to the extent that each meets the applicable requirements to be a *registered facility* in respect of each category of *operating reserves*. Neighbouring *control areas* may also provide *operating*

reserve through shared activation of *operating reserve* and regional reserve sharing programs. *Operating reserve* is required to:

4.5.1.1 cover or offset unanticipated increases in load during a *dispatch day* or *dispatch hour*;

4.5.1.2 replace or offset capacity lost due to the *forced outage* of generation or transmission equipment; or

4.5.1.3 cover uncertainty associated with the performance of *generation facilities* or *dispatchable loads* in responding to the *IESO's dispatch instructions*.

4.5.2 The *IESO* shall maintain sufficient *operating reserve* to meet all applicable *reliability standards.*

4.5.3 The *IESO* shall maintain, as a minimum, total *operating reserve* that is the sum of the *ten-minute operating reserve* requirement and the *thirty-minute operating reserve* requirement.

4.5.4 Part of the requirement for *ten-minute operating reserve* shall be synchronised with the *IESO-controlled grid* consistent with section 4.5.9.

4.5.5 The *IESO* shall ensure that *operating reserve* is distributed throughout the *IESO-controlled grid* such that sufficient *operating reserve* can be activated and delivered to any location on the *integrated power system*.

Shared Activation of Reserve

4.5.6 The *IESO* may share with nearby systems in *NPCC* and *PJM* the activation of its *ten-minute operating reserve* to respond to *contingency events* in accordance with agreements between the *IESO* and such systems. Similarly, such systems may activate their *operating reserve* when requested to meet *contingency events* in the *IESO control area* in accordance with agreements between the *IESO* and such systems. Such shared activation of *operating reserve* is solely for the purpose of maintaining the *reliability* of *interconnection systems* and shall not alter the *operating reserve* requirements of the *IESO*.

Control Action Operating Reserve

4.5.6A The *IESO* may include voltage reductions, and reductions in the *thirty-minute operating reserve* requirements within allowable *reliability standards* as standing *offers* in the *operating reserve markets* subject to the following conditions:

4.5.6A.1 the *IESO* shall introduce such standing *offers* in increasing quantities;

4.5.6A.2 the quantities referred to in section 4.5.6A.1 and the prices therefore shall be determined by the *IESO Board* and such quantities and prices shall be *published* by the *IESO*;

4.5.6A.3 the *IESO Board* may specify the circumstances under which any one or more of the quantities may either be withdrawn or not introduced and the manner in which any such withdrawal will be effected and the *publishing* thereof;

4.5.6A.4 the *IESO* shall *publish* the times and quantities of the voltage reductions and reduction in *thirty-minute operating reserve* when these sources of *operating reserve* have been scheduled to provide *operating reserve;* and

4.5.6A.5 the prices and quantities of the standing *offers* set by the *IESO Board* in accordance with section 4.5.6A.2 shall be monitored by the *IESO* to assess their impacts and that any changes to the prices and quantities would be recommended to the *IESO Board* as necessary.

Regional Reserve Sharing

4.5.6B The *IESO* may participate in regional reserve sharing programs with neighbouring *control areas*. Subject to availability and deliverability of the associated energy, the *IESO* may count towards its *ten-minute operating reserve* requirement a contribution of up to 100 MW from neighbouring *control areas* in accordance with applicable regional reserve sharing programs and applicable *reliability standards.* The *IESO* shall activate *energy* from regional reserve sharing programs in accordance with applicable *reliability standards*.

Ten-Minute Operating Reserve

4.5.7 *Ten-minute operating reserve* is capacity that is available to the *integrated power system* in excess of anticipated requirements for *energy* and that can be made available and used within ten minutes. It includes resources that are either synchronised or non-synchronised with the *IESO-controlled grid*.

4.5.8 The *IESO* shall maintain sufficient *ten-minute operating reserve* to meet the requirements of all applicable *reliability standards.* This shall be at least equal to the largest first contingency loss sustainable on the *IESO-controlled grid.*

4.5.9 *Ten-minute operating reserve* shall be synchronised with the *IESO-controlled grid* to the extent required by all applicable *reliability standards*.

4.5.10 If, for any reason, there is a deficiency of *ten-minute operating reserve*, the *IESO* shall replace such *reserve* in accordance with the applicable *reliability standards* referenced in the *market manuals*.

4.5.11 The *IESO* shall, in accordance with Chapter 7, *publish* daily its estimates of the quantity of *ten-minute operating reserve* that is required for each hour of the following day.

4.5.12 A *registered facility* that is a *boundary entity* that is used as *ten-minute operating reserve* shall be treated as *operating reserve* that is non-synchronised with the *IESO-controlled grid*.

4.5.13 The reduction in load that can be effected by curtailing pumping hydroelectric *generation facilities* is eligible to be treated as *operating reserve* that is synchronised with the *IESO-controlled grid*.

4.5.13A [Intentionally left blank – section deleted]

4.5.14 [Intentionally left blank]

4.5.15 [Intentionally left blank]

4.5.16 [Intentionally left blank]

4.5.17 [Intentionally left blank]

Thirty-Minute Operating Reserve

4.5.18 *Thirty-minute operating reserve* is capacity in excess of anticipated requirements for *energy* that can be made available and used within thirty-minutes and that is not included as *ten-minute operating reserve*.

4.5.19 Subject to section 4.5.20, the requirement for *thirty-minute operating reserve* shall be one-half of the largest *second contingency loss* sustainable on the *IESO-controlled grid*. However, when a *generation unit* is commissioning and is one of the two largest *contingency events*, the requirement for *thirty-minute operating reserve* shall equal the *second contingency loss*.

4.5.20 If such a commissioning *generation unit* is not one of the two largest *contingency events*, the requirement for *thirty-minute operating reserve* shall be the larger of one-half of the *second contingency loss* or the output of the commissioning *generation unit*.

4.5.21 The requirement for *thirty-minute operating reserve* shall be maintained in accordance with the applicable *reliability standards* referenced in *the market manuals*.

4.6 Reactive Support and Voltage Control

4.6.1 *Reactive support service and voltage control service* is the control and maintenance of prescribed voltages on the *IESO-controlled grid*. The devices that supply reactive power to the *integrated power system* include but are not limited to, capacitors, static VAR compensators, reactors, synchronous *generation facilities*, and synchronous condensers.

4.6.1A The *IESO* shall direct the operation of the *IESO-controlled grid* to meet all applicable *reliability standards* with respect to the *dispatch* of reactive power resources.

4.6.2 The *IESO* shall ensure that sufficient resources are available throughout the *IESO-controlled grid* to meet all applicable *reliability standards* for *reactive support service and voltage control service*. Voltage levels shall be maintained within acceptable levels within the *IESO-controlled grid*. As part of its assessment of system *adequacy* under the *market rules*, the *IESO* shall on a continual basis assess whether sufficient reactive resources are available to the *IESO*.

4.6.3 The *IESO* shall direct providers of *reactive support service and voltage control service* to take any actions necessary to maintain stable voltage levels in accordance with *reliability standards* and to prevent the collapse of voltages on the *IESO-controlled grid*.

4.6.4 [Intentionally left blank]

4.6.5 [Intentionally left blank]

4.6.6 [Intentionally left blank]

4.6.7 [Intentionally left blank]

4.6.8 [Intentionally left blank]

4.6.9 The *IESO* shall obtain reactive power resources to maintain *reactive support service* and *voltage control service* in accordance with all applicable *reliability standards*. *Reactive support service* and *voltage control service* shall be made available by *market participants* from, but not limited to, the following:

4.6.9.1 reactive resources produced from within the standard power factor range of a *generation facility* as described in Chapter 4, which shall be *dispatchable* by the *IESO*;

4.6.9.2 equipment owned by *market participants* (capacitors, SVCs, synchronous condensers and reactors) that is made available to the *IESO* pursuant to the *market rules* and any *operating agreement* between the *IESO* and a *market participant*; and

4.6.9.3 reactive resources produced outside the standard power factor range of a *generation facility* as required in Chapter 4 of the *market rules* (synchronous condensers or hydroelectric units in condense mode) as acquired by the *IESO* through *contracted ancillary services* contracts.

4.7 Black Start Service

4.7.1 [Intentionally left blank]

4.7.2 The *IESO* shall determine the required amounts and locations of *black start capability* across the *IESO-controlled grid*, as required to satisfy the requirements of the *Ontario power system restoration plan* and all applicable *reliability standards.* The *IESO* shall notify *market participants* of these requirements before entering into agreements for the provision of *certified black start facilities*.

4.7.3 *Ancillary service providers* providing *certified black start facilities* must also be *restoration participants*.

4.8 Reliability Must-Run Resources

4.8.1 The *IESO* may need to call on specific *registered facilities*, excluding *non-dispatchable load facilities*, to maintain the *reliability* of the *IESO-controlled grid* whenever sufficient resources for the provision of *physical services*, other than *contracted ancillary services*, are not otherwise offered in the *IESO-administered markets*. Such applicable *registered facilities* are referred to as *reliability must-run resources* and shall be procured either through *reliability must-run contracts* in accordance with this section 4.8 and sections 9.6 and 9.7 of Chapter 7 or by means of the process for directing the submission of *dispatch data* referred to in sections 3.3.10 to 3.3.17 of Chapter 7.

4.8.2 The *IESO* shall identify all *reliability must-run resources* in respect of which it wishes to conclude *reliability must-run contracts* and may enter into *reliability must-run contracts* with the *registered market participant* or prospective

registered market participant for such *reliability must-run resources*. Where the *IESO* identifies such a *reliability must-run resource*, the *registered market participant* or prospective *registered market participant* for such *reliability must-run resource* shall, subject to section 9.6.4 of chapter 7, contract with the *IESO* to supply *physical services,* other than *contracted ancillary services,* to the *IESO-controlled grid* for *reliability* purposes in accordance with sections 9.6 and 9.7 of Chapter 7. Each such *reliability must-run contract* shall provide the *IESO* with the ability to call on the *reliability must-run resources* covered by the *reliability must-run contract* in accordance with section 9 of Chapter 7 and shall comply with Chapter 7.

4.8.3 [Intentionally left blank]

4.8.4 The provisions of this section 4.8 and of any *reliability must-run contracts* shall be consistent with the provisions of the *license* of the *IESO* that incorporate the terms of any directive issued by the *Minister* to the *Ontario Energy Board* pursuant to subsection 28(1) of the *Ontario Energy Board Act, 1998* or that incorporate terms imposed by the *Ontario Energy Board* in furtherance of the exercise of its powers under subsection 70(5) of the *Ontario Energy Board Act, 1998*. In the event of any inconsistency between such terms and the provisions of this section 4.8 or of any *reliability must-run contracts*, such terms shall govern.

4.8A [Intentionally left blank – section deleted]

4.8A.1 [Intentionally left blank – section deleted]

4.8A.2 [Intentionally left blank – section deleted]

4.9 Auditing and Testing of Ancillary Services

4.9.1 The *IESO* shall test *facilities* that will or do provide *ancillary services* to the *IESO-controlled grid.* The *IESO* shall use such tests to determine whether to register each *facility* as a *registered facility* for the provision of *ancillary services* and to ensure that each applicable *registered facility* continues to meet the requirements for registration to provide the relevant *ancillary services.*

4.9.1.1 [Intentionally left blank]

4.9.1.2 [Intentionally left blank]

4.9.2 Tests of the *facilities* or *registered facilities* of *ancillary service providers* or of prospective *ancillary service providers* referred to in section 4.9.1 shall include,

but not be limited to, testing in the manner set forth in this section 4.9.2, to determine whether the *ancillary service provider* can supply the *ancillary services* which it wishes to supply or has contracted or been registered to supply:

4.9.2.1 the *IESO* may test the synchronised *ten-minute operating reserve* capability of a *generation facility* by issuing unannounced *dispatch instructions* requiring the *generation facility* to ramp up to its ten-minute capability;

4.9.2.2 the *IESO* may test the non-synchronised *ten-minute operating reserve* capability of a *generation facility* or *dispatchable load* by issuing unannounced *dispatch instructions* requiring the *generation facility* or *dispatchable load* to come on line and ramp up or to reduce *demand*, in either case to its ten-minute capability;

4.9.2.3 the IESO may test the thirty-minute operating reserve capability of a generation facility or dispatchable load by issuing unannounced dispatch instructions requiring the generation facility or dispatchable load to come on line and ramp up or to reduce demand, in either case to its thirty-minute capability;

4.9.2.4 a *certified black start facility* must perform tests on auxiliary and control equipment and alternate sources of power in accordance with and using the testing criteria and testing frequency requirements specified in the *Ontario power system restoration plan*;

4.9.2.4A a *certified black start facility* must pass the tests required for *certified black start facilities* in accordance with and using the testing criteria specified in the *Ontario power system restoration plan*;

4.9.2.4B the *IESO* may direct line energization tests of a *certified black start facility* to determine whether the *certified black start facility* can energize a transmission path specified by the *IESO*;

4.9.2.5 the *IESO* may test the *reactive support and voltage control* that has been contracted from a *registered facility* that is a *generation facility* by issuing unannounced *dispatch instructions* requiring the *generation facility* to provide such support within its contracted capability; and

4.9.2.6 the *IESO* shall at least annually test a *registered facility* providing *regulation* for compliance with the performance standards referred to in sections 1.1.3 and 1.1.4 of Appendix 5.1 in accordance with the testing procedures specified in the applicable *contracted ancillary services* contract.

4.9.3 The costs incurred by the *IESO* in conducting and evaluating any tests pursuant to section 4.9.1 or 4.9.2 shall be recovered by the *IESO* as part of the costs to the *IESO* of contracting for the applicable *ancillary service* in accordance with section 4.2 of Chapter 9.

4.9.4 Any costs incurred by the *ancillary service provider* in conducting any tests pursuant to section 4.9.1 or 4.9.2 shall be borne by the *ancillary service provider*.

4.10 Consequences of Failure to Pass a Test

4.10.1 If an *ancillary service provider's registered facility* fails a test performed pursuant to section 4.9.1 or 4.9.2 in respect of an *ancillary service*, the *IESO* shall not schedule such *ancillary services* from such *registered facility* until the *ancillary service provider* demonstrates that it can provide the relevant *ancillary service*.

4.10.2 Without prejudice to the application of section 4.10.1, an *ancillary service provider* whose *registered facility* fails a test performed pursuant to section 4.9.1 or 4.9.2:

4.10.2.1 in the case of an *ancillary service provider* providing a *certified black start facility* or *regulation* under a *contracted ancillary service* contract:

a. where there is sufficient information available to determine the date as of which the applicable *contracted ancillary service* was not provided, the *IESO* may require the *ancillary service provider* to refund the compensation it has received for such *contracted ancillary service* from such date to the date of the failed test; or

b. in all other cases, the *ancillary service provider* shall provide such refund of compensation, if any, as may be specified in its *contracted ancillary service* contract;

4.10.2.2 in the case of an *ancillary service provider* providing a *certified black start facility* or *regulation* under a *contracted ancillary service* contract, shall be subject to such penalties and sanctions as may be specified in its *contracted ancillary service* contract; and

4.10.2.3 in the case of any other *ancillary service provider*, shall be subject to financial penalties in accordance with section 6.6 of Chapter 3 and to such other sanctions as may be provided for in these *market rules*.

4.11 Emergency Conditions

4.11.1 Notwithstanding any other provision of the *market rules*, when the *IESO-controlled grid* is in an *emergency operating state*, the *IESO* may acquire *ancillary services* from any *market participant*, whether or not such *market participant* satisfies all of the standards and registration requirements applicable in respect of such *ancillary services*.

5. System Security

5.1 Objectives and General Obligations

5.1.1 The objective of this section is to detail the procedures necessary to enable the *IESO* to ensure the *security* of the *IESO-controlled grid* in accordance with all applicable *reliability standards.*

5.1.2 In order to maintain the *security* of the *IESO-controlled grid*, the *IESO* shall:

5.1.2.1 monitor the real-time operating status of the *IESO-controlled grid*;

5.1.2.2 establish and *publish security limits* for all *facilities* that are part of the *IESO-controlled grid*;

5.1.2.3 establish and *publish* criteria and margins to be used in the development of *security limits* and a process for reviewing and revising such criteria and margins;

5.1.2.4 establish available *transmission transfer capabilities* in accordance with all applicable *reliability standards* and manage the use of transmission in accordance with such *transmission transfer capabilities* and the *market rules*;

5.1.2.5 direct the operation of *facilities* that are part of the *IESO-controlled grid* within the appropriate *security limits* and in accordance with the applicable *operating agreements*;

5.1.2.6 direct any *market participant* to take or to refrain from taking any action necessary to maintain the *IESO-controlled grid* in a *normal operating state*;

5.1.2.7 act as the *control area operator* and as *security coordinator* for the province of Ontario and interact with other *control area operators*, *security coordinators* and *interconnected transmitters* as required to establish *security limits* and rules for interconnected operations including, but not limited to, entering into *interconnection agreements* with adjacent *control area operators*, *security coordinators* and *interconnected transmitters* that provide for interconnected operations, other than with respect to the physical *facility* and equipment requirements for *interconnections* which shall be the responsibility of *transmitters*. In the event of flows or exchanges of *physical services* across the *interconnections* or *interties* which are not directly attributable to the transactions of *market participants*, the *IESO* may provide for such exchanges through the sale or purchase of these *physical services* in the *IESO-administered markets*;

5.1.2.8 represent Ontario in the context of the work of *standards authorities* with respect to the *reliable* operation of the *IESO-controlled grid* and the *interconnected systems*, and the operation of the *IESO-administered markets*, other than with respect to the physical facility and equipment requirements for *reliability* of the *IESO-controlled grid* which shall be the responsibility of the relevant *transmitters*, *distributors* and *generators* as applicable;

5.1.2.9 investigate major operational incidents on the *IESO-controlled grid* and initiate plans to manage abnormal situations or significant deficiencies which, in the *IESO's* opinion, threaten the *reliability* of the *IESO-controlled grid*;

5.1.2.10 issue directions to market participants in order to manage high-risk operating states and emergency operating states; and

5.1.2.11 assess the future *reliability* of the *IESO-controlled grid.*

5.2 Security Limits

5.2.1 The *IESO* shall establish and *publish security limits* to prevent, contain and alleviate the effects of *contingency events*. Such *security limits* shall be as described in section 5.2.4 and shall be observed by the *IESO* in the minute-to-minute operation of the *IESO-controlled grid.*

5.2.2 The *IESO* shall calculate and *publish transmission transfer capabilities*.

5.2.3 *Market participants* shall immediately respond to directions from the *IESO* to alter their operations to stay within the *security limits* and *transmission transfer capabilities* established by the *IESO*.

5.2.4 Two types of *security limits* shall be established by the *IESO*:

5.2.4.1 *security limits* based on the dynamic response of the *IESO-controlled grid*, including transient stability limits, voltage stability limits, dynamic stability limits, and voltage decline limits; and

5.2.4.2 *security limits* based on the ratings of equipment, including the thermal ratings of lines and transmission equipment (e.g. the design characteristic of lines and equipment and weather conditions) and the short circuit capability of equipment.

5.2.5 Each *market participant* shall:

- establish thermal ratings for the equipment that it owns and that is part of the *IESO-controlled grid*, and
- provide such ratings (including continuous and limited time ratings) to the *IESO* in a form suitable for *IESO* monitoring

The *IESO* shall not deliberately operate or plan to operate equipment comprising the *IESO-controlled grid* in excess of the thermal rating for such equipment as communicated to the *IESO* by the relevant *market participants*.

5.2.6 The *IESO* shall respect all pre-and post-contingency *security* criteria that are used to establish *security limits*.

5.3 The Use of Tie-Lines and Associated Facilities

5.3.1 The *IESO-controlled grid* is interconnected with utilities in Canada and the United States via *tielines* such that *interconnected systems* can be used to help maintain the *security* of the *IESO-controlled grid.*

5.3.2 With respect to the use of *tielines*:

5.3.2.1 the *IESO* shall endeavour to conduct studies on a coordinated basis with adjacent *control areas* so that normal and emergency transfer limits on all *tielines* are established or reaffirmed at least annually;

5.3.2.2 the *IESO* shall endeavour to cooperate with other *control area operators* to determine and reaffirm total *transmission transfer capability* with other *control areas* at least annually;

5.3.2.3 the *IESO* shall operate the *IESO-controlled grid* so that there is no net transfer of reactive power, provided that reactive power may be exchanged or transferred from one system to another under contractual agreement with adjacent *control areas;*

5.3.2.4 the maximum net scheduled interchange across *tielines* shall not exceed the lower of the continuous rating of the *tielines* or the incremental transfer capability of the first *contingency event*;

5.3.2.5 for *interconnected systems* that are entirely controlled by phase-shifters, such as Manitoba and Minnesota, the *IESO* shall maintain MW flows at the scheduled transfer level;

5.3.2.6 unless there is prior agreement to that effect between *control areas*, the *IESO* shall not move phase shifters or make changes to fixed-tap positions; and

5.3.2.7 the *IESO* shall abide by all applicable *reliability standards* with respect to the management of *tielines*.

5.3.3 Each *market participant* shall comply with all relevant *reliability standards* relating to the *reliability* of *interconnections* and:

5.3.3.1 each *registered market participant* submitting an *energy offer* or an *energy bid* in respect of a *boundary entity* shall comply with the scheduling and notification procedures for the source or sink *control area*, as applicable, and any intervening *control areas* and with all other applicable procedural and information requirements established by relevant *standards authorities* and other relevant entities for registering transactions and/or arranging transmission access;

5.3.3.2 each *registered market participant* submitting an offer to provide *operating reserve* in respect of a *boundary entity* shall comply with all applicable procedural and information requirements established by relevant *standards authorities* and other relevant entities for registering transactions and/or arranging transmission access; and

5.3.3.3 the notification of the activation of the *energy* associated with an *operating reserve offer* and the scheduling coordination shall be the responsibility of the *IESO*.

5.3.4 Where:

5.3.4.1 the quantity of a *physical service* delivered to or withdrawn from the *IESO-controlled grid* by a *registered market participant* is reduced relative to that *registered market participant's* most recent valid *bid* or *offer*; and

5.3.4.2 such reduction is initiated pursuant to *reliability standards* by an entity, other than the *IESO*, having authority under such *reliability standards*;

the *registered market participant* shall not be entitled to compensation for any financial loss suffered as a result of such action.

Where such reduction was initiated by the *IESO*, the *registered market participant* shall be entitled to compensation, which shall be calculated and paid in accordance with section 3.5 of Chapter 9.

5.4 Reliability Policy for Area Supply

5.4.1 In coordination with *transmitters*, the *IESO* may develop and apply specific *security* criteria in areas of the *IESO-controlled grid* where the consequences of *contingency events* are localized and do not have a significant adverse impact on the *reliability* of the *IESO-controlled grid* ("*local areas*").

5.4.2 The following criteria shall be used to assess the *security* of a *local area*, as determined at the delivery point demarcating the boundary between the *local area* and the remainder of the *IESO-controlled grid*, on the one hand, and individual and collective *connection points* of the *IESO-controlled grid*, on the other:

5.4.2.1 the extent to which severe *contingency events* are experienced; and

5.4.2.2 the *reliability* of transmission *facilities* which directly affect the exchange of electricity to the *local area*.

5.4.3 The *IESO* shall coordinate with *transmitters* to review the performance at *connection points* at least once annually in order that they can jointly assess the *reliability* of *local areas*.

5.5 Interconnection Assistance

5.5.1 The *IESO* shall use and support *interconnected systems* in accordance with agreements between the *IESO* and other *security coordinators, control area operators* or *interconnected transmitters* and to the extent necessary to maintain the *security* of the *IESO-controlled grid*.

5.5.1A Information provided to the *IESO* under an *interconnection agreement* by a *security coordinator, control area operator* or *interconnected transmitter* and identified by the person providing the information as confidential shall be *confidential information* and shall not be disclosed or made available without the prior written consent of the particular *security coordinator, control area operator* or *interconnected transmitter*.

5.5.2 In requesting assistance from *market participants* and from other *security coordinators*, the *IESO* shall take effective action in the *IESO control area* prior to, or concurrently with, similar action being taken by the *interconnected system* providing assistance.

5.5.3 All agreements entered into by the *IESO* and other *security coordinators* relating to *security* shall meet all applicable *reliability standards*.

5.6 Inadvertent Interchange

5.6.1 Inadvertent interchange is the difference between the scheduled interchange on a single *interconnection*, or the sum of scheduled interchanges with several *interconnected systems*, on the one hand, and the actual metered flow on the *interconnection* point(s), on the other.

5.6.2 Inadvertent interchange shall be addressed in any agreement relating to *security* between the *IESO* and other *security coordinators*. The means used to mitigate inadvertent interchange shall respect all applicable *reliability standards.*

5.7 The Management of Violations to Security Limits

5.7.1 When there is a violation of a *security limit* on the *IESO-controlled grid* while in a *normal operating state*, the sequence of control actions taken by the *IESO* shall be defined in its operating procedures and instructions.

5.7.2 The operating procedures and instructions of the *IESO* shall allow the use of market mechanisms to the maximum extent possible for purposes of responding to violations of *security limits*.

5.7.3 Where market mechanisms fail or are not sufficient to maintain the *security* of the *IESO-controlled grid*, the *IESO* may direct *market participants* to take actions to either prevent the loss of *non-dispatchable load* or to prepare for *contingency events*.

5.8 Operation Under an Emergency Operating State

5.8.1 Once an *emergency operating state* has been declared by the *IESO*, the *IESO* may take such action as it determines appropriate including, but not limited to:

5.8.1.1 [Intentionally left blank]

5.8.1.2 [Intentionally left blank]

5.8.1.3 [Intentionally left blank]

5.8.1.4 coordinating with other *security coordinators*; acquiring *emergency energy* in accordance with section 2.3.3A;

5.8.1.5 issuing directions to *market participants* to reduce *demand* through voltage reductions and interruptions in accordance with section 10.3 and through the Emergency Load Reduction Program in accordance with section 15.3 of Chapter 7; and

5.8.1.6 operate to those *security limits* appropriate for an *emergency operating state* to allow for increased power transfers.

5.9 Operation Under a High-Risk Operating State

5.9.1 Once a *high-risk operating state* has been declared by the *IESO*, the *IESO* may take such action as it determines appropriate including, but not limited to:

5.9.1.1 [Intentionally left blank]

5.9.1.2 [Intentionally left blank]

5.9.1.3 [Intentionally left blank]

5.9.1.4 operating to *security limits* appropriate for a *high-risk operating state*;

5.9.1.5 coordinating with neighbouring *security coordinators*;

5.9.1.6 issuing directions to *market participants* to reduce *demand* through voltage reductions or interruptions in accordance with section 10.3 and through the Emergency Load Reduction Program in accordance with section 15.3 of Chapter 7; and

5.9.1.7 temporarily and selectively increase the level of *security* on the *IESO-controlled grid*.

5.10 Restoration of System Security Following a Contingency Event

5.10.1 *Market participants* shall be prepared for, shall be able to manage and shall take such actions as may be necessary to restore *security* of the *IESO-controlled grid* following a *contingency event,* as directed by the *IESO*.

5.10.2 The *IESO* shall establish:

5.10.2.1 procedures that identify the steps necessary to restore the operation of the *IESO-controlled grid* to an *emergency operating state* respecting corresponding *security limits*, within 30 minutes or, where a *high risk operating state* existed on some part of the *IESO-controlled grid* prior to the *contingency event*, within 15 minutes;

5.10.2.2 procedures to attempt to restore supply first to individual loads identified by *market participants* as critical in nature, once the minimum acceptable level of *security* on the *IESO-controlled grid* has been restored; and

5.10.2.3 in consultation with relevant *market participants*, procedures to restore the operation of the *IESO-controlled grid* and of *facilities connected* to a *transmission system* that forms part of the *IESO-controlled grid* following automatic *outages*.

6. Outage Coordination

6.1 Introduction

6.1.1 The objectives of this section 6 are to enable the *IESO* to review and assess the impact of *outage* schedules on the fulfillment by the *IESO* of its *reliability-related*

responsibilities under the Electricity Act, 1998, its *license*, and the *market rules*, to require *market participants* to obtain the approval of the *IESO* in respect of *planned outage* schedules and to permit the *IESO* to reject, revoke *advance approval* of and recall *outages* that may have an impact on the *reliability* of the *IESO-controlled grid* or a material impact on the operation of the *IESO-administered markets*.

6.1.2 The *IESO* shall maintain a database of all submissions to the *outage* planning and scheduling process.

6.1.3 The *IESO* shall develop, and include in the applicable *market manual*, a full list of the equipment and *facilities* the *outage* of which must be reported to and scheduled with the *IESO* in accordance with this section 6. The *IESO* shall use as the basis for including *facilities* and equipment on this list that any change or anticipated change to the *facilities* or equipment could have a material effect on the value of an operating *security limit*, the *reliable* operation of *IESO-controlled grid* or operation of the *IESO-administered markets*, including, but not be limited to, the following:

6.1.3.1 *facilities* forming part of the *IESO-controlled grid*;

6.1.3.2 *generation facilities* and auxiliary equipment connected to the *IESO-controlled grid* or in respect of which a *generator* is participating in the *real-time markets*;

6.1.3.3 protection systems; and

6.1.3.4 communication equipment, including related hardware and software systems.

6.1.4 [Intentionally left blank]

6.1.5 Nothing in this section 6 shall relieve a *market participant* from its responsibility for and arising from the performance of all work relating to any *outage* or test, whether in respect of energized or de-energized *facilities* or equipment, including, but not limited to, its responsibility in respect of worker safety.

6.1.6 No *market participant* shall remove equipment or *facilities* from service except in accordance with this section 6 unless such removal from service is necessary to prevent damage to the *market participant's* equipment or *facilities* or to protect the safety of employees, the public or the environment. If any equipment or *facilities* are removed from service for these reasons, the *market participant* shall promptly notify the *IESO*.

6.1.7 The *IESO* shall coordinate *outages* with *market participants* except that, with respect to *outages* to any portion of the *transmission system* during a *normal operating state*, the applicable *transmitter* shall, pursuant to the Transmission System Code, coordinate the *outage* with affected *market participants* directly connected to that portion of the *transmission system* unless the *IESO* determines it necessary to coordinate such activities in order to maintain *reliability*.

6.2 Outage Planning

6.2.1 Each *market participant* shall inform the *IESO* of its long-term plans for *outages* in accordance with the provisions of this section 6.2.

6.2.2 Each *market participant* shall establish its *outage* planning process in such manner as will enable it to comply with its reporting and scheduling obligations under this section 6. Without limiting the generality of the foregoing, *market participants* shall be required to plan *outages* at least 33 calendar days in advance of the anticipated date of the *planned outage* and may be required by the *IESO* to plan *outages* further in advance than 33 calendar days as the *IESO* may determine appropriate.

6.2.2A *Market participants* applying to register their *facilities* as *transitional scheduling generators* shall provide, as part of the information required by section 2.2 of Chapter 7, a schedule of up to two *planned outages* per calendar year per *facility* that are demonstrably related to:

a) contractual obligations owed to *OEFC* or a third party in respect of a *transitional scheduling generator*, or

b) significant resource mobilization issues pursuant to such contractual obligations.

Requests for 14-Day Advance Approval – Generation Facility Outages

6.2.2B A *market participant* may request *14-day advance approval* for one *planned outage* for a *generation facility* per calendar year. If the *IESO* either:

- does not grant 14-day advance approval for the planned outage; or
- does grant 14-day advance approval but subsequently revokes the 14-day advance approval or recalls the planned outage;

the *market participant* may make a second request for *14-day advance approval* for that *planned outage* for that *generation facility* in the same calendar year. If the *IESO* then either:

- does not grant 14-day advance approval for the planned outage; or
- does grant 14-day advance approval but subsequently revokes the 14-day advance approval or recalls the planned outage;

the *market participant* may make a third request for *14-day advance approval* for that *planned outage* for that *generation facility* in the same calendar year.

6.2.2C A *market participant* may request *14-day advance approval* for two *planned outages* per calendar year for *generation units* within a single *generation facility* or for separate *generation facilities* with co-dependent electricity production provided that:

- the *market participant* can satisfy the *IESO* that the two *planned outages* are co-dependent; and
- the *market participant* identifies the total capacity impact for the *generation facility* or *generation facilities* in question for each *planned outage*.

If the *IESO* either:

- does not grant *14-day advance approval* for a co-dependent *planned outage*; or
- does grant *14-day advance approval* but subsequently revokes the *14-day advance approval* or recalls a co-dependent *planned outage*;

the *market participant* may make a second request for *14-day advance approval* for that co-dependent *planned outage* in the same calendar year. If the *IESO* then either:

- does not grant *14-day advance approval* for the co-dependent *planned outage*; or
- does grant *14-day advance approval* but subsequently revokes the *14-day advance approval* or recalls the co-dependent *planned outage*;

the *market participant* may make a third request for *14-day advance approval* for that co-dependent *planned outage* for that *generation facility* in the same calendar year.

6.2.2D A *market participant* may request *14-day advance approval* of *planned outages* for a *generation facility* more often than permitted under sections 6.2.2B and 6.2.2C. The *market participant* must satisfy the *IESO* as to why the *planned outages* should be considered for *14-day advance approval*.

Requests for 14-Day Advance Approval – Transmission, Distribution and Load Equipment Outages

6.2.2E A *market participant* may request *14-day advance approval* for up to two *planned outages* per calendar month for:

- equipment associated with a *load facility*;
- transmission equipment; or
- distribution equipment.

6.2.2F A *market participant* may request *14-day advance approval* for *planned outages* for transmission equipment, distribution equipment or equipment associated with a *load facility* more often than permitted under sections 6.2.2E. The *market participant* must satisfy the *IESO* as to why the *planned outage* should be considered for *14-day advance approval*.

IESO Obligation to Consider Planned Outages for 14-Day Advance Approval

6.2.2G The *IESO* shall consider all *planned outages* submitted under sections 6.2.2B, 6.2.2C, and 6.2.2E for *14-day advance approval*.

6.2.2H The *IESO* may consider *planned outages* submitted under sections 6.2.2D and 6.2.2F for *14-day advance approval*.

IESO Obligation to Include Planned Outages in Weekly Assessments

6.2.3 The *IESO* shall include in the weekly assessments referred to in section 7.3.1.3 all *outages* planned or scheduled by *market participants* to occur in the immediately following 33 calendar days as reported or scheduled by *market participants* and shall include in the quarterly assessments referred to in section 7.3.1.2 all *outages* planned or scheduled to occur in the immediately following 18 months as reported or scheduled by *market participants*.

Transmitter and Generator Obligation to Provide Planned Outage Information for 18-Month Assessments

6.2.4 To support the 18-month assessments referred to in section 7.3.1.2, and subject to section 6.2.5, for those *facilities* and equipment on the list developed in accordance with section 6.1.3, *transmitters* and *generators* shall, as frequently as may be necessary to maintain the accuracy of the information provided, report to the *IESO* the *outage* plans for transmission *facilities* forming part of the *IESO-controlled grid* and for *generation facilities*, respectively, as follows:

6.2.4.1 for *outages* starting 3 months or more in the future, those with a scheduled duration of 5 days or more; and

6.2.4.2 for *outages* starting less than 3 months in the future, those with a scheduled duration of 4 hours or more.

Exclusions of Outages for Generation Facilities

6.2.5 Notwithstanding any other provision of section 6, *outages* to the following *generation facilities* do not need to be reported to support the 18-month assessments referred to in section 7.3.1.2:

6.2.5.1 in the case of all *generators, generation facilities* having a *capacity* of less than 20 MW; or

6.2.5.2 in the case of a *generator* whose total available capacity inside the *IESO control area* exceeds 4000 MW, *generation facilities* that represent less than 0.5 percent of the total *capacity* of such *generator,* unless the *generation facilities* have been identified by the *IESO* as affecting the *reliability* of the *IESO-controlled grid.* The *IESO* shall notify the relevant *generators* of any *generation facilities* so identified.

6.3 Outage Scheduling with the IESO

Planned Outages

6.3.1 Subject to section 6.1.3, each *market participant* shall, no later than 33 calendar days prior to a *planned outage*, submit its current schedule of all *planned outages*, regardless of duration, to the *IESO*.

6.3.2 A *planned outage* submitted by a *market participant* pursuant to section 6.3.1 shall represent the intent of the *market participant* to take the relevant equipment out of service at the scheduled time and to return the relevant equipment to service at the scheduled time.

6.3.3 The *IESO* shall reflect all *planned outages* submitted by *market participants* pursuant to section 6.3.1 in the weekly and monthly assessments referred to in section 6.2.3.

Forced Outages

6.3.4 Each *market participant* shall to the maximum extent possible notify the *IESO* in advance of a *forced outage* and provide a brief description of the nature and causes of the *forced outage.* When such advance notice cannot be given, the *market participant* shall promptly notify the *IESO* of the occurrence of a *forced outage* and provide a brief description of the nature and causes of the *forced outage*.

6.3.5 Whenever, in the opinion of the *IESO*, a *forced outage* has had a significant impact on the *reliability* of the *IESO-controlled grid*, or gives rise to potential *reliability* concerns, the *IESO* may require the *market participant* experiencing the *forced outage* to provide a detailed description of the nature and causes of the *forced outage* to the *IESO*. Such description of the *forced outage* shall be provided as soon as practicable and in any event within 48 hours, or within such longer period of time as may be agreed to by the *IESO* in any given case, following the start of the *forced outage.* The *IESO* may also require the *market participant* experiencing the *forced outage* to provide a detailed description of the steps that the *market participant* intends to take to prevent any recurrence of the circumstances that led to the *forced outage*. Such description shall also be provided as soon as practical and in any event within 48 hours, or within such longer period of time as may be agreed to by the *IESO*, following the start of the *forced outage*.

Replacement Energy to Support Planned Outages

6.3.6 A *generator* may, no later than the time specified in section 6.4.1, in requesting a *planned outage* in accordance with section 6.3.1, notify the *IESO* that the *generator* shall arrange replacement *energy offers* in the form of an import to support the *outage* request. A *generator* may, when requesting an extension to an *outage* under section 6.4.7 or rescheduling an *outage* under section 6.4.10, notify the *IESO* that the *generator* shall arrange replacement *energy offers* in the form of an import to support the *outage* extension or re-scheduling request. For certainty, this section shall not under any circumstances impose any explicit or implicit obligation on either a *generator* to so notify the *IESO*, or if so notified, the *IESO* to approve or accept any such arrangement. Upon notice to the *IESO*, a *generator* may withdraw the arrangement for replacement *energy offers* at any time up to final approval of the *outage* or up to the final approval of the extension to or rescheduling of the *outage.*

6.3.7 The *generator* shall provide the following information to the *IESO* when in accordance with section 6.3.6 it either submits a *planned outage* request or requests the extension to or rescheduling of an *outage*:

6.3.7.1 Subject to the approval of the *IESO*, the *intertie* zone or zones through which the replacement *energy* is intended to be scheduled; and,

6.3.7.2 The *registered market participant* associated with a *registered facility* that is a *boundary entity* that shall submit the *offers* and, pursuant to section 7.5.8A of Chapter 7, schedule the replacement *energy* if *dispatched* by the *IESO.*

6.3.8 The *IESO* may limit the number and aggregate size of *outages* supported by replacement *energy* and, where the number and aggregate size of *outages* is limited the *IESO* shall determine the precedence of the *outages*, in accordance with sections 6.4.13 through 6.4.18.

6.3.9 The *IESO* may specify and inform the *generator* of the minimum amount of replacement *energy* in megawatts and the duration of *offers* necessary to support the *planned outage* request or the request for the extension to or rescheduling of the *outage*.

6.3.10 If the *registered market participant* associated with a *registered facility* that is a *boundary entity* referred to in section 6.3.7.2 fails to submit *offers* for the replacement *energy,* that have been arranged by the *generator*, the *generator* shall be subject to the financial penalties calculated in accordance with the provisions of section 6.6.8 of Chapter 3.

6.4 Confirmation of Outage Schedules and IESO Approval of Outage Schedules

6.4.1 In order to obtain *IESO* approval of a *planned outage*, a *market participant* shall confirm a *planned outage* with the *IESO* under the timelines specified in section 6.4.1A. At the time of the confirmation, the *market participant* shall:

6.4.1.1 provide information about the recall of the *planned outage*, including the time required to return the *facilities* or equipment to service and other applicable conditions of recall;

6.4.1.2 if a *generator*, *distributor* or *wholesale consumer*, provide the costs or expenses associated with the cancellation or deferral of the *planned outage* and the estimated costs or expenses associated with the recall of the *planned outage*; and

6.4.1.3 confirm, if applicable, the request for *14-day advance approval* for the *planned outage*.

6.4.1A If requesting a *14-day advance approval* of a *planned outage*, the *market participant* shall confirm the *planned outage* with the *IESO* no earlier than 33 calendar days and no later than 10:00 EST on the 21st calendar day prior to the start date of the *planned outage*.

If requesting a *two-day advance approval* of a *planned outage*, the *market participant* shall confirm the *planned outage* with the *IESO* no earlier than 33 calendar days and no later than 10:00 EST on the third *business day* prior to the start date of a *planned outage*.

6.4.2 Where the scheduling of *planned outages* submitted by different *market participants* conflicts such that the *planned outages* cannot both or all be approved by the *IESO*, the *IESO* shall inform the affected *market participants* and request that they resolve the conflict. Should the conflict remain unresolved, the *IESO* shall determine which of the *planned outages* can be approved on the basis of the precedence accorded to each *planned outage* pursuant to sections 6.4.13 to 6.4.18.

6.4.3 No *planned outage* shall occur or be permitted by a *market participant* to occur unless:

6.4.3.1 the *planned outage* has been confirmed with the *IESO* in accordance with section 6.4.1;

6.4.3.2 the *planned outage* has been approved by the *IESO* in accordance with this section 6.4;

6.4.3.3 immediately prior to the scheduled commencement of the *planned outage* or at a pre-arranged time specified by the *IESO* when providing the *advance approval* referred to in section 6.4.4.5, the *market participant* has requested from the *IESO* and has received the *IESO*'s final approval to the *planned outage*; and

6.4.3.4 the removal from service of the relevant equipment or *facilities* is undertaken under the direction of the *IESO* where the *IESO* has made the determination referred to in section 6.4.4.6.

6.4.4 The *IESO* shall:

6.4.4.1 provide *advance approval* for a *planned outage* confirmed to it pursuant to section 6.4.1 and shall provide its final approval to the

planned outage pursuant to section 6.4.3.3 unless it determines, based primarily on the weekly assessment referred to in section 7.3.1.3 with emphasis on the first two weeks and on the daily assessments referred to in section 7.3.1.4, that the *planned outage,* including but not limited to a *planned outage* identified by an *embedded generator,* will or is reasonably likely to have an adverse impact on the *reliable* operation of the *IESO-controlled grid;*

6.4.4.2 following receipt of confirmation pursuant to section 6.4.1, assess each confirmed *planned outage*;

6.4.4.3 following receipt of an *outage* submission pursuant to section 6.2.1 or 6.3.1, or of confirmation pursuant to section 6.4.1, advise the relevant *market participant* of the existence of any conflict with a *planned outage* planned by another *market participant*;

6.4.4.4 if the *market participant* confirmed the *planned outage* with the *IESO* under section 6.4.1, advise the relevant *market participant* of the expected outcome of the approval process;

6.4.4.4A if the *market participant* confirmed its *planned outage* and request for *14-day advance approval* under section 6.4.1A, advise the *market participant* whether or not *14-day advance approval* of the *planned outage* has been granted no later than 14:00 EST on the last *business day* that is at least 14 calendar days before the schedule start date of the *planned outage*. Where the *IESO* does not grant *14-day advance approval*, the *IESO* shall consider the *planned outage* for *two-day advance approval*;

6.4.4.5 if applicable advise the *market participant* of the *two-day advance approval* or rejection of the *planned outage* no earlier than 10:00 EST on the third *business day* prior to the date of the *planned outage* and no later than 14:00 EST on the second *business day* prior to the day on which the *planned outage* is scheduled to commence; and

6.4.4.6 when providing the final approval referred to in section 6.4.4.1, advise the *market participant* if the confirmed *planned outage* is to be undertaken under the direction of the *IESO* where the *IESO* has made a determination that this is necessary to maintain the *reliability* of the *IESO-controlled grid.* If it is known in advance, the *IESO* will advise the *market participant* of this requirement when providing the *advance approval* referred to in sections 6.4.4.4A or 6.4.4.5 or as soon as possible thereafter.

6.4.5 Where the *IESO* does not provide *advance approval* of a *planned outage* or does not give its final approval to a *planned outage* pursuant to section 6.4.4, the *IESO* shall work with the relevant *market participant* to re-schedule the *planned outage* to a date and time at which the *planned outage* will not or is not reasonably likely to have an adverse impact on the *reliable* operation of the *IESO-controlled grid.* In re-scheduling the *planned outage*, the *IESO* shall where reasonably practicable take into account the date and time preferences of the *market participant.*

Request on Short Notice

6.4.6 If for any reason a *market participant* is unable to confirm a *planned outage* in accordance with section 6.4.1, the *market participant* may make a request to the *IESO* for approval of a *planned outage* after 10:00 EST on the third *business day* prior to the date proposed by the *market participant* for the *planned outage*. The *IESO* will process these short notice *outage* requests based on time stamp priority and on a best effort basis following the completion of its *reliability* assessments.

Extensions

6.4.7 Each *market participant* shall notify the *IESO* if a *planned outage* which has been approved by the *IESO* will have a duration which exceeds the duration originally approved by the *IESO*, which notice shall include a request that the *IESO* approve the extension. Such notice shall be provided to the *IESO* as soon as possible and will be treated as a new *outage* request.

6.4.8 If the *IESO* determines that an extension to the duration of a *planned outage* will or is reasonably likely to adversely affect the *reliability* of the *IESO-controlled grid* or will or is reasonably likely to require the re-scheduling of a *planned outage* confirmed to the *IESO* pursuant to section 6.4.1 or the revoking of *advance approval*, deferral or recall of a *planned outage* approved pursuant to section 6.4.4, the *IESO* shall reject such extension and the *market participant* shall use its reasonable best efforts to ensure that the duration of the *planned outage* does not exceed the duration originally approved by the *IESO* or such longer period as the *IESO* may advise in rejecting the extension requested.

Revoke Advance Approvals

6.4.9 The *IESO* may, where necessary to maintain the *reliability* of the *IESO-controlled grid*, revoke an *advance approval* of a *planned outage*. Without limiting the generality of the foregoing, the *IESO* may revoke an *advance approval* if:

6.4.9.1 the *IESO* determines that either an *emergency operating state* or a *high-risk operating state* is occurring or is reasonably likely to occur at the time at which the *planned outage* would otherwise take place; or

6.4.9.2 necessary to avoid recalling a *planned outage* pursuant to section 6.4.11.

A *planned outage* that receives *advance approval* under section 6.4.4 but does not receive final approval pursuant to section 6.4.3.3 shall be considered to have had its *advance approval* revoked.

6.4.10 Where the *IESO* revokes *advance approval* of a *planned outage* pursuant to section 6.4.9, the *market participant* may elect either to defer or to cancel the *outage*. When the *market participant* elects to defer the *outage*, the *IESO* shall work with the relevant *market participant* to re-schedule the *planned outage* to a date and time at which the *planned outage* will not or is not reasonably likely to have an adverse impact on the reliable operation of the *IESO-controlled grid*. In re-scheduling the *planned outage*, the *IESO* shall where reasonably practicable take into account the date and time preferences of the *market participant*. A *planned outage* that is re-scheduled under this section is not considered a short-notice *planned outage* for the purposes of compensation under section 6.7.

Recalls

6.4.11 The *IESO* may, where necessary to maintain the *reliability* of the *IESO-controlled grid*, recall a *planned outage* that has already commenced, having due regard to the time needed to return the *facilities* or equipment to service as identified by the relevant *market participant* pursuant to section 6.4.1.1 and shall so advise the relevant *market participant*. Such *market participant* shall arrange for the accelerated return to service of the *facilities* or equipment in accordance with the schedule identified by the *market participant* pursuant to section 6.4.1.1. The *IESO* shall not recall a *planned outage* unless further control action is required and it has revoked *advance approval* or rejected requests for approval of all other *planned outages* the revocation or rejection of which could eliminate the need to recall the *planned outage* that has already commenced.

Embedded Generators

6.4.12 Each *distributor* shall, in reporting to the *IESO* pursuant to sections 6.2 and 6.3, identify to the *IESO* any *outages* that potentially constrain an *embedded generator* that is connected to its *distribution system.*

Determining Precedence of Outages

6.4.13 The *IESO* shall time stamp each *outage* submission received by the *IESO*. Where the *IESO* is required or permitted by this section 6 to approve, reject, revoke *advance approval* of or recall one or more *planned outages*, such *planned outages* shall:

6.4.13.1 be given advance or final approval in order of precedence determined on the basis of sections 6.4.14 to 6.4.18; and

6.4.13.2 be rejected, be re-scheduled, have *advance approval* revoked or be recalled in reverse order of precedence determined on the basis of sections 6.4.14 to 6.4.18.

6.4.13A Subject to section 6.2.2A and notwithstanding section 6.4.13, where the *IESO* is required or permitted by this section 6 to approve, reject, revoke *advance approval* of or recall one or more *planned outages* referred to in section 6.2.2A that were submitted at least 30 days prior to the *market commencement date*, such *planned outages* shall:

- be the first to be given advance or final approval; and
- be the last to be rejected, revoked or recalled.

6.4.14 Where a *market participant* confirms a *planned outage* referred to in a previous *outage* submission prior to the applicable confirmation deadline referred to in section 6.4.1A without changing the commencement, duration or nature of the *planned outage* as described in that previous *outage* submission, the time stamp associated with such previous *outage* submission shall be used by the *IESO* in determining the precedence to be given to the *planned outage*. Where a *market participant* confirms a *planned outage* referred to in a previous *outage* submission subsequent to the applicable confirmation deadline referred to in section 6.4.1A without changing the commencement, duration or nature of the *planned outage* as described in that previous *outage* submission, the time stamp associated with the time of receipt by the *IESO* of such confirmation shall be the time stamp used by the *IESO* in determining the precedence to be given to the *planned outage*.

6.4.15 Where a *market participant* gives notice of a change in the commencement, duration or nature of a *planned outage* relative to the most recent *outage* submission, the *IESO* shall stamp such notice with the time at which it was received by the *IESO*, which time shall be used by the *IESO* in determining the precedence to be given to the *planned outage*. Where such notice reflects only a shortening in the duration of a *planned outage* relative to the most recent *outage* submission for that *planned outage*, the time stamp associated with such previous *outage* submission shall be retained in determining the precedence to be given to the *planned outage*.

6.4.15A Where notice is given in respect of a *transitional scheduling generator* of a change in the commencement, duration or nature of a *planned outage* relative to an outage submission referred to in section 6.2.2A no later than 10:00 EST on the third *business day* prior to the date of the *planned outage*, the *IESO* shall use the

time stamp associated with such previous *outage* submission in determining the precedence to be given to the *planned outage*.

6.4.16 Where:

6.4.16.1 the *IESO* revokes *advance approval* of a *planned outage* prior to the commencement thereof;

6.4.16.2 the *market participant* subsequently re-confirms the *planned outage* with the *IESO*; and

6.4.16.3 the *IESO* approves the re-confirmation,

the time stamp of the approved *planned outage* prior to the revocation of *advance approval* shall be deemed to be the time stamp of the re-confirmed *planned outage* for purpose of determining the precedence to be given to the *planned outage*.

6.4.17 Where:

6.4.17.1 a *planned outage* is, within 7 days of the date on which it was scheduled to commence, required by the *IESO* pursuant to this section 6 to be re-scheduled;

6.4.17.2 the *IESO* did not identify, through one or more of its reliability forecasts, a concern relating to reliability of the *IESO-controlled grid* in respect of the time scheduled for the *planned outage*; and

6.4.17.3 the *planned outage* is re-scheduled to a date that is within 9 days of the originally scheduled commencement date,

the time stamp of the *planned outage* prior to the re-scheduling will be deemed to be the time stamp of the re-scheduled *planned outage* for purposes of determining the precedence to be given to the *planned outage*.

6.4.18 Where the *IESO* has rejected a *planned outage* pursuant to section 6.4.5, the time of receipt of confirmation of the *planned outage* pursuant to section 6.4.1 shall be retained until such time as the confirmed commencement date of the *planned outage* has passed so as to facilitate the possible consent to the occurrence of the *planned outage* on the confirmed commencement date, in the event that the *reliability* concerns that prompted the rejection cease to preclude the occurrence of the *planned outage*.

6.4A Return of Equipment or Facilities to Service

6.4A.1 No *market participant* shall return to service any equipment or *facilities* that are undergoing a *planned outage* unless:

6.4A.1.1 immediately prior to its return to service, the *market participant* has requested and has received the *IESO's* approval to return the equipment or *facilities* to service; and

6.4A.1.2 the return to service of the relevant equipment or *facilities* is undertaken under the direction of the *IESO* where the *IESO* has made the determination referred to in section 6.4A.2.3.

6.4A.2 The *IESO* shall:

6.4A.2.1 approve the return to service of equipment or *facilities* that are undergoing a *planned outage* unless it determines that such return to service will or is reasonably likely to have an adverse impact on the *reliability* of the *IESO-controlled grid*;

6.4A.2.2 promptly notify the *market participant* if a determination is made that a return to service of equipment or *facilities* will or is reasonably likely to have an adverse impact on the *reliability* of the *IESO-controlled grid*; and

6.4A.2.3 when providing the approval referred to in section 6.4A.2.1, advise the *market participant* if the return to service of equipment or *facilities* is to be undertaken under the direction of the *IESO* where the *IESO* has made a determination that this is necessary to maintain the *reliability* of the *IESO-controlled grid*.

6.4A.3 Where the *IESO* does not approve the return to service of equipment or *facilities* pursuant to section 6.4A.2.1, the *IESO* shall, subject to final confirmation by the *IESO* pursuant to 6.4A.1, advise the *market participant* when the equipment or *facilities* may be returned to service.

6.4B Notification of Commencement and Completion of Planned Outages

6.4B.1 Each *market participant* shall notify the *IESO*:

6.4B.1.1 of the commencement of a *planned outage* at the time the relevant equipment or *facilities* are removed from service; and

6.4B.1.2 of the completion of a *planned outage* at the time the relevant equipment or *facilities* are fully returned to service.

6.5 Information

6.5.1 Each *transmitter* and each *generator* shall provide to the *IESO* such *outage* information as may be requested by the *IESO* to enable the *IESO* to review and schedule *outages*.

6.5.2 Subject to the confidentiality provisions of Chapter 3, the *IESO* shall *publish* the *planned outage* information provided to it pursuant to section 6.5.1.

6.5.3 Notwithstanding any other provision of these *market rules*, *planned outage* information that is provided to the *IESO* by *market participants* pursuant to this Chapter may be exchanged between the *IESO* and other *security coordinators, control area operators*, and *interconnected transmitters* who are signatories to the *NERC confidentiality agreement* or who are otherwise legally bound to withhold the information from any person competing with the *market participant* that provided the information.

6.5.4 The *IESO* shall *publish* on a calendar month time-frame, six months from the end of each subject month, the monthly *capability factor* and the monthly *planned capability factor* of each generating station based on information provided to it by *market participants*. *Capability factors* for generating stations with ratings less than 20 MVA can be aggregated by area.

6.5.5 The *IESO* shall *publish generator outage* information aggregated by fuel type based on information provided to it by *market participants*.

6.6 Tests

6.6.1 A *market participant* who wishes to engage in a test that could affect the *reliability* of the *IESO-controlled grid* or the operation of the *IESO-administered markets* shall provide the information referred to in section 6.6.2 to the *IESO*.

6.6.2 As a minimum, the information referred to in section 6.2.1 shall identify:

6.6.2.1 the equipment involved;

6.6.2.2 the relevant details of contracts or agreements as they relate to the test activities;

6.6.2.3 preferred and alternative dates and times for the conduct of the test activities;

6.6.2.4 unusual system configurations or setup;

6.6.2.5 the expected impact of the test activities on power flows, voltage and frequency, and of any other dynamic that could interfere with the *reliability* of the *IESO-controlled grid*;

6.6.2.6 details of special readings or observations, as available; and

6.6.2.7 the names of and methods of communication with personnel who will be involved in the test activities and who may be contacted with respect thereto.

6.6.3 Tests covered by the requirements of this section 6.6 shall include, but are not limited to:

6.6.3.1 the deliberate application of short circuits;

6.6.3.2 stability tests of *generation facilities* and transmission *facilities*;

6.6.3.3 planned actions which could cause abnormal voltage, frequency or overload; and

6.6.3.4 planned abnormal station or system configurations with inherent risk.

6.6.4 The *IESO* shall permit a test referred to in this section 6.6 to be performed if the *IESO* determines that the performance of the test will not have an adverse effect on the *reliability* of the *IESO-controlled grid* or on the operation of the *IESO-administered markets.*

6.6.5 In permitting a test to be performed, the *IESO* shall endeavour to permit the test to be performed at the time and on the date preferred as identified by the *market participant* pursuant to section 6.6.2.3.

6.6.6 This section 6.6 also applies to tests conducted pursuant to section 5 of Chapter 4.

6.6.7 During performance testing, a *market participant* shall keep the *IESO* informed of the expected operating capability of the *market participant's generation facility* using the outage management process as specified in the applicable *market manual*.

6.7 Compensation

Revoke Advance Approvals or Recalls

6.7.1 *Transmitters* whose *outages* are rejected or have *advance approvals* revoked or have *outages* recalled by the *IESO* shall not be entitled to compensation for any costs, losses or damage associated with such rejection, revocation or recall.

6.7.2 *Generators*, *distributors* or *wholesale consumers* whose *outages* have *advance approval* revoked or have outages recalled by the *IESO* shall, subject to the exceptions defined in sections 6.7.3 and 6.7.3A, be entitled to compensation for out-of-pocket expenses associated with such revocation or recall only if:

6.7.2.1 the *outage* was originally approved by the *IESO* pursuant to 6.4.4;

6.7.2.2 the *outage* was recalled or had *advance approval* revoked by reason of a material error in the *IESO's* demand forecast, a failure of *generation facilities* within the *IESO control area,* a failure of *facilities* forming part of the *IESO-controlled grid* or a failure of *interconnection facilities*;

6.7.2.3 the out-of-pocket expenses were identified to the *IESO* in accordance with section 6.4.1.2; and

6.7.2.4 the out-of-pocket expenses exceed $1000.00.

6.7.3 No *generator*, *distributor* or *wholesale consumer* shall be entitled to compensation under section 6.7.2 in respect of an *outage* that was approved by the *IESO* on short notice under section 6.4.6.

6.7.3A A *market participant* shall not be entitled to compensation under section 6.7.2 with respect to a *planned outage* of its *generation facility* that received a *14-day advance approval* and that *advance approval* was subsequently revoked by the *IESO* if:

6.7.3A.1 the IESO revoked the 14-day advance approval as a result of a forced outage of another generation facility with the same registered market participant as the generation facility that was the subject of the planned outage and the forced outage occurred before 14:00 E.S.T. on the second business day prior to the scheduled start of the planned outage; or

6.7.3A.2 the *14-day advance approval* was revoked as a result of a delayed return to service from a *planned outage* or *forced outage* of another *generation facility* with the same *registered market participant* as the *generation facility* that was the subject of the *planned outage*.

6.7.4 The out-of-pocket expenses claimed by *generators*, *distributors* or *wholesale consumers* pursuant to section 6.7.2 shall be subject to verification and audit by the *IESO* and shall, where paid, be recovered by the *IESO* in accordance with section 4.8 of Chapter 9.

6.7.5 A *generator*, *distributor* or *wholesale consumer* shall not be entitled to compensation for any costs, expenses, losses or damage associated with an *outage* which has been rejected by the *IESO* provided that, in exceptional circumstances and where a *generator*, *distributor* or *wholesale consumer* has suffered substantial financial harm as a direct result of such rejection, the *generator*, *distributor* or *wholesale consumer* may request that an *arbitrator* be appointed pursuant to section 2 of Chapter 3 to determine whether and the amount of any compensation which the *generator*, *distributor* or *wholesale consumer* shall be entitled to recover as a result of the rejection of the *outage* by the *IESO.* In the case of *generators*, no such compensation shall be recoverable under this section 6.7.5 unless the *generator* demonstrates that the amount claimed cannot be recovered through market prices.

6.7.6 Where a *generator*, *distributor* or *wholesale consumer planned outage* has been deferred as a result of the *IESO* either revoking *advance approval* of or recalling the *planned outage*, the compensation entitlement for each such deferral occurrence shall not exceed the compensation entitlement that would apply for cancellation as provided in section 6.4.1.2.

6.7.7 Each act of revocation or recall by the *IESO* shall be treated separately for compensation purposes.

7. Forecasts and Assessments

7.1 Forecasts Prepared by the IESO

7.1.1 The *IESO* shall produce and *publish* the following ongoing *demand* forecasts for Ontario or parts thereof:

7.1.1.1 [Intentionally left blank – section deleted]

7.1.1.2 on a daily basis, a forecast of *demand* for each of the 14 days following the current day, by hour;

7.1.1.3 on a weekly basis, a forecast of *demand* for the next 28 days, by day and by hour; and

7.1.1.4 on a quarterly basis, a forecast of *demand* for the next 18 months, by week.

7.1.1.5 [Intentionally left blank – section deleted]

7.1.2 The forecasts referred to in section 7.1.1 shall be prepared by the *IESO* in such form as may be specified in the applicable *market manual,* shall be used in conducting the assessments referred to in section 7.3, and shall, in the case of the forecast referred to in section 7.1.1.4, be included in the reports referred to in section 7.3.1.2.

7.1.3 The *IESO* shall *publish* the method to be used to perform the forecasts described in section 7.1.1.

7.1.4 [Intentionally left blank – section deleted]

7.1.5 Each *distributor, connected wholesale customer* and other load-serving entity shall, for the purpose of enabling the *IESO* to produce the forecasts referred to in section 7.1.1, provide to the *IESO* the load forecasts described in the applicable *market manual* in such form, at such time and having such resolution as may be specified in such *market manual.*

7.2 Basis for IESO Forecasts

7.2.1 The *IESO* shall develop forecasts of peak *demand* and *energy demand*, by area, that are based on, but potentially differ from, the forecasts provided to it by *distributors*, other load-serving entities and *connected wholesale customers* pursuant to section 7.1.5, and which account for the *demands* of loads not required to make forecasts. These forecasts shall be developed on an area basis, as required to meet the purposes of these forecasts.

7.3 Advance Assessments of System Reliability

7.3.1 The *IESO* shall prepare for the purposes referred to in section 7.4 and based on the information received pursuant to section 7.5.1 and such other information as the *IESO* considers appropriate, and *publish,* the following reports of its findings in relation to such *reliability* assessments:

7.3.1.1 [Intentionally left blank – section deleted]

7.3.1.2 on a quarterly basis and no later than 5 *business days* prior to the end of each calendar quarter, an assessment covering an eighteen-month period commencing with the following calendar month;

7.3.1.3 on a weekly basis and within two *business days* of the date of receipt from *market participants* of the weekly information specified in the *market manual* referred to in section 7.5.1, an assessment covering the third and fourth week of a four-week period commencing with the following day;

7.3.1.4 on a daily basis and not later than 17:00 EST on each day, an assessment covering a fourteen-day period commencing on the following day; and

7.3.1.5 as required, an assessment of the *reliability* of the *IESO-controlled grid*.

7.3.2 Any information derived from the s*ecurity* and *adequacy* assessment process shall be used to provide a basis for informing *market participants* about expected conditions on the *IESO-controlled grid* and in the *IESO-administered markets*. It is expected that the information will trigger appropriate responses under other market processes, such as *outage* coordination, transmission investment planning, and the activation of the *capacity reserve market*.

7.3A Liability

7.3A.1 Notwithstanding section 13.1.2 of Chapter 1, no *market participant* shall be entitled to compensation from the *IESO* for any costs, loss or damage sustained by the *market participant* as a result of any difference between:

7.3A.1.1 *demand* as forecasted pursuant to section 7.1.1 and actual *demand*;

7.3A.1.2 conditions on the *IESO-controlled grid* as forecasted in the assessments referred to in section 7.3.1 and actual conditions on the *IESO-controlled grid*; or

7.3A.1.3 information contained in succeeding forecasts *published* pursuant to section 7.1.1 or reports *published* pursuant to section 7.3.1 that cover in whole or in part the same time frame.

7.3B Succession of Forecasts and Reports

7.3B.1 Each forecast *published* pursuant to section 7.1.1 or report *published* pursuant to section 7.3.1 shall, to the extent that it covers in whole or in part the same time frame as that covered in a previous *published* forecast or report, supercede such previous *published* forecast or report.

7.4 Purpose of Assessments

7.4.1 [Intentionally left blank – section deleted]

7.4.1.1 [Intentionally left blank – section deleted]

7.4.1.2 [Intentionally left blank – section deleted]

7.4.1.3 [Intentionally left blank – section deleted]

7.4.1.4 [Intentionally left blank – section deleted]

7.4.2 The *IESO* shall conduct the quarterly assessments referred to in section 7.3.1.2 to:

7.4.2.1 provide forecasts, by month, of expected *demand*, *generation capacity* and transmission capacity, *energy* capability of *generation facilities*, and the possibility of any *security*-related events on the *IESO-controlled grid* that could require contingency planning by *market participants* or by the *IESO*;

7.4.2.2 allow the *IESO* to identify exigencies potentially impacting on the coordination of *outages* that could give rise to shortfalls in *generation capacity* and thus provide information by which *market participants* could act to reschedule *outage* plans to avoid such projected shortfalls; and

7.4.2.3 allow the *IESO* to meet its obligations to relevant *standards authorities* so as to enable the latter organizations to assess the expected *reliability* of the regional power systems to match generation and *demand*.

7.4.3 The *IESO* shall conduct the weekly assessments referred to in section 7.3.1.3 to:

7.4.3.1 provide forecasts, by day, of expected daily *demand*, *generation capacity* and transmission capacity, *energy* capability of *generation facilities*, exports and imports of *energy*, and the availability of transmission that may affect the *security* of the *IESO-controlled grid* or affect operational decisions to be taken by the *IESO* that must be made more than a day in advance;

7.4.3.2 allow the *IESO* to identify exigencies potentially impacting on the coordination of *outages* that may give rise to shortfalls in *generation capacity* and thereby assist *market participants* in finalizing *outage* plans and submitting *outage* schedules to the *IESO*; and

7.4.3.3 allow the *IESO* to meet its obligations to relevant *standards authorities* so as to enable the latter organizations to assess the expected *reliability* of regional power systems to match generation and *demand*, particularly in peak seasons and peak periods.

7.4.4 The *IESO* shall conduct the daily assessments referred to in section 7.3.1.4 to:

7.4.4.1 provide forecasts, by day, of expected hourly *demand*, *generation capacity* and transmission capacity, *energy* capability of *generation facilities*, exports and imports of *energy*, and the availability of transmission that may affect the *security* of the *IESO-controlled grid* or affect operational decisions to be taken by the *IESO* that must be made more than a day in advance; and

7.4.4.2 allow the *IESO* to meet its obligations to relevant *standards authorities* so as to enable the latter organizations to assess the expected *reliability* of regional power systems to match generation and *demand*, on a daily and hourly basis, particularly in peak seasons and in peak hours.

7.4.5 The *IESO* shall conduct the assessments referred to in section 7.3.1.5 to:

7.4.5.1 meet its obligations to maintain the *reliability* of the *IESO-controlled grid*;

7.4.5.2 meet the requirements of *standards authorities*; and

7.4.5.3 assist the *OEB* and the *OPA* in meeting their respective objectives.

7.5 Information Requirements

7.5.1 Each *market participant* shall, for the purpose of enabling the *IESO* to perform the *reliability* assessments referred to in section 7.3.1, provide to the *IESO* the information described in the applicable *market manual* in such form, at such time and having such resolution as may be specified in such *market manual*.

7.6 The Reporting of Reliability Assessments

7.6.1 The reports referred to in section 7.3.1 shall be prepared by the *IESO* in such form and shall contain such information as may be specified in the applicable *market manual*.

7.6.2 [Intentionally left blank – section deleted]

7.7 Updated and Related Reports

7.7.1 [Intentionally left blank – section deleted]

7.7.2 [Intentionally left blank – section deleted]

7.7.3 [Intentionally left blank – section deleted]

7.7.4 [Intentionally left blank – section deleted]

Interim Updates

7.7.5 The *IESO* may *publish* additional updated versions of any of the assessment reports referred to in section 7.3.1 in the event of changes that, in the *IESO*'s opinion, are significant and should be communicated to *market participants*.

Related Reports

7.7.6 From the material and assessments in the assessment reports referred to in section 7.3.1, the *IESO* may produce additional related reports as required by relevant *standards authorities*, the *IESO Board*, the *OEB*, the *OPA*, and the Government of Ontario.

7.8 [Intentionally left blank – section deleted]

7.8.1 [Intentionally left blank – section deleted]

7.8.2 [Intentionally left blank – section deleted]

7.9 Provision of Information to Transmitters

7.9.1 [Intentionally left blank – section deleted]

7.9.2 Notwithstanding any other provision of these *market rules*, the *IESO* may, if necessary to enable *transmitters* to prepare plans for the expansion or modification of the *IESO-controlled grid*, provide to relevant *transmitters* information provided by *market participants* pursuant to this Chapter regarding their forecasts and plans. Any such information which is *confidential information* shall be provided to *transmitters* on a confidential basis and the receiving *transmitter* shall use all reasonable endeavours to protect such *confidential information* and shall use such *confidential information* solely for the purpose of preparing plans for the expansion or modification of the *IESO-controlled grid*.

7.9.3 Where the *IESO* intends to disclose to a *transmitter confidential information* pertaining to a *market participant* pursuant to section 7.9.2, the *IESO* shall provide the *market participant* with advance notice of such intention and shall provide the *market participant* with a reasonable opportunity to make representation as to why the *confidential information* should not be disclosed.

7.10 IESO Actions

Actions Within Next Twelve Months

7.10.1 If the *IESO* identifies an adverse condition on the *IESO-controlled grid* that requires action to be initiated within the next twelve months in order to maintain the *reliability* of the *IESO-controlled grid*, the *IESO* may:

- conduct and *publish* a *reliability* assessment in accordance with section 7.3.1.5; and
- take any additional steps necessary to ensure that the *reliability* of the *IESO-controlled grid is* maintained.

7.10.2 If the *IESO* does not believe that *market participants* have or will voluntarily put forward reasonable commitments for technically feasible options to alleviate the

condition identified in section 7.10.1, the *IESO* may direct the *transmitter(s)* in the relevant location(s) to prepare a detailed proposal for the enhancement of the *IESO-controlled grid*. The *transmitter(s)* shall submit the proposal to the *OEB*, the *OPA*, and other governmental agencies having authority to approve the proposal, in the form of an application for approval of the enhancement. The *IESO* shall notify the *OEB* and the *OPA* of its identification of the adverse condition.

Actions Beyond the Next Twelve Months

7.10.3 If the *IESO* identifies an adverse condition on the *IESO-controlled grid* that does not require action to be initiated within the next twelve months, the *IESO*:

- shall notify the *OEB* and the *OPA* of its determination; and
- may provide support to the *OPA* in the *OPA's* assessment of the options that may be available for *market participants* or others to remove or alleviate the condition.

Actions Independent of IESO Recommendations

7.10.4 Nothing in this section 7.10 is intended to limit the ability of any *market participant* to file for approval a proposal to invest in *facilities* on the *integrated power system* that are not the subject of specific recommendations made by the *IESO*. A *market participant* interested in sponsoring a new or modified *connection* to the *IESO-controlled grid* may submit a *request for connection assessment* in accordance with section 6.1.6 of Chapter 4.

8. Special Protection Systems (SPS)

8.1 Objectives

8.1.1 *Special protection systems* ("*SPS*") have been installed in a number of locations on the *IESO-controlled grid* which automatically initiate one or more of the following control actions:

8.1.1.1 load rejection;

8.1.1.2 generation rejection;

8.1.1.3 generation runback;

8.1.1.4 shunt capacitor switching;

8.1.1.5 shunt reactor switching; and

8.1.1.6 cross-tripping.

8.1.2 The *IESO* shall direct the arming of *SPSs* installed on the *IESO-controlled grid* as necessary to:

8.1.2.1 increase the capability of power transfers on the *IESO-controlled grid;* or

8.1.2.2 provide additional *security* beyond that required to manage *contingency events* in a *normal operating state*.

8.1.3 New *SPSs* shall be installed and utilized on the basis of agreements between and/or among the parties involved.

8.2 Responsibilities of the IESO

8.2.1 The *IESO* shall classify all *SPSs* and obtain approval for their use in accordance with all applicable *reliability standards.*

8.2.2 The *IESO* shall determine the need for utilizing an *SPS* for *security* reasons.

8.2.2A The *IESO* shall direct the arming of all *SPSs* installed on the *IESO-controlled grid* in accordance with applicable *reliability standards* and applicable agreements including those negotiated under section 8.4.3.

8.2.3 The *IESO* shall direct the arming of an *SPS* to mitigate the adverse effects of specific extreme *contingency events* and to mitigate congestion provided that there are no overriding concerns related to the *security* of the *IESO-controlled grid*.

8.2.4 The *IESO* shall establish and *publish* criteria for arming and activation of *SPSs* in sufficient detail and precision to allow a *market participant* whose *facility* forms part of an *SPS* to understand the conditions under which that *SPS* would be armed and activated. Prior to establishing changes to such criteria, the *IESO* shall consult with, and, where practicable, gain the agreement of, the *market participant* whose *facility* is part of the *SPS* to the intended changes. In the event that agreement cannot be reached, the *IESO* may change the criteria for the *SPS* if necessary to maintain *reliable* operation of the *IESO-controlled grid.*

8.2.5 The *IESO* shall from time to time review or cause to be reviewed the performance of *SPSs*.

8.2.6 In the event that a *market participant* applies to the *IESO* for compensation under section 8.4.1, the *IESO* shall, upon verification that the amount being claimed is correct, pay such compensation by crediting the *market participant's preliminary settlement statement* for the last day of the month in which the application for compensation was received.

8.3 Responsibilities of SPS Equipment Owners

8.3.1 Owners of *SPS* equipment shall:

8.3.1.1 maintain *SPS* equipment in accordance with all applicable *reliability standards*;

8.3.1.2 test and report operating statistics associated with an *SPS* to the *IESO* on an annual basis;

8.3.1.3 report the performance of an *SPS* when requested to do so by the *IESO*;

8.3.1.4 evaluate and notify the *IESO* of any request from affected *market participants* for permanent exemptions from *connection* to the *SPS*; and

8.3.1.5 provide written notice to the *IESO* of any proposal to install a new, or modify an existing, *SPS*, which notice shall be provided with sufficient lead time and in sufficient detail for the *IESO* to review and seek, if necessary, approval from the relevant *standards authorities* for such new or modified *SPS*; and

8.3.1.6 specify to the *IESO* and *market participants* whose *facilities* form part of an *SPS* the means used to arm the *SPS*.

8.4 Responsibilities of Market Participants Whose Facilities Form Part of an SPS

8.4.1 A *market participant* with a *dispatchable generation facility* that is not a *quick start facility* and that is part of an *SPS* may, in the time and manner specified in the applicable *market manual*, apply to the *IESO* for compensation, if that *facility* is tripped offline as a result of the activation of the *SPS*. The amount of

compensation that may be claimed shall be determined in accordance with the applicable *market manual* and shall be the equivalent of up to the first two hours of constrained off congestion management *settlement* credit payments that would otherwise be calculated if the *facility* had been constrained down to zero and its circuit breaker had remained closed.

8.4.2 Section 8.4.1 shall apply only as long as section 3.5 of Chapter 9 is in effect.

8.4.3 *Market participants* whose *facilities* form part of an existing *SPS* or may form part of a new SPS may request notification and/or status annunciation of *SPS* arming, disarming and activation and may enter into agreements with the *SPS* equipment owner/operator and the *IESO* to determine the appropriate status annunciation and notification. The *market participant*, *SPS* equipment owner/operator and the *IESO* shall use the following criteria in determining and implementing the appropriate status annunciation and/or notification:

8.4.3.1 licensing/legal requirements of the *market participant* related to the operation of its *facility* that is part of the *SPS*;

8.4.3.2 practicality of status annunciation and/or notification;

8.4.3.3 cost-effectiveness of status annunciation and/or notification;

8.4.3.4 the status annunciation and/or notification does not adversely impact the intended use of the *SPS*; and

8.4.3.5 comparison to the notification and annunciation of *SPS* arming and activation provided to other *market participants* whose *facilities* form part of an *SPS*.

In the event that they cannot agree on the status annunciation and notification requirements and implementation, the *SPS* owner/operator, the *IESO* and the *market participant* shall use the dispute resolution provisions in section 2 of Chapter 3 to resolve the issue.

8.4.4 *Market participants* whose *facilities* form part of an *SPS* shall notify the *IESO* in accordance with the applicable *market manual* or applicable agreements including those negotiated under section 8.4.3 if the *facility* is unavailable for *SPS* arming.

8.4.5 If an *SPS* has been armed and the *market participant* whose *facility* forms part of the *SPS* reasonably believes that a subsequent activation of that *SPS* would endanger the safety of any person, damage equipment or violate any *applicable law*, the *market participant* whose *facility* is part of that *SPS* may take action in accordance with applicable agreements including those negotiated under

section 8.4.3 or may request that the *IESO* disarm the *SPS*. Upon such a request, the *IESO* shall, as soon as the *IESO* can take action to maintain reliable operation of the *IESO-controlled grid*, disarm the *SPS*.

9. Voltage Control

9.1 General

9.1.1 No *market participant* shall make changes in equipment status or operations that could materially adversely affect the voltage profile of the *IESO-controlled grid* without the prior approval of the *IESO*. To this end, each *market participant* shall notify the *IESO* of the *market participant's* intention to make any such change. The *IESO* shall approve such change unless it determines that the change is reasonably likely to adversely affect the *reliability* and voltage profile of the *IESO-controlled grid.*

9.2 Under Load Tap Changers

9.2.1 The *IESO* shall direct the operation of under loads tap changers installed on auto-transformers on the *IESO-controlled grid* to control the voltage profile of the *IESO-controlled grid* while ensuring that acceptable voltages at the *connections* to *IESO-controlled grid* are maintained. No *market participant* shall make any changes to such taps without the prior approval of the *IESO*. The *IESO* shall approve such changes unless it determines that such changes could affect the *IESO's* ability to control voltage on the *IESO-controlled grid*, that procedures for such changes cannot be adopted or both.

9.2A Under Load Tap Changers – Connection Transformers

9.2A.1 The *IESO* shall not direct the operation of under load tap changers on *connections* to the *IESO-controlled grid* unless, in the *IESO's* opinion, the operation of such equipment otherwise will or is likely to affect the *reliability* of the *IESO-controlled grid.*

9.3 Off Load Tap Changers

9.3.1 No *market participant* shall make any changes to off load taps of transformers on the *IESO-controlled grid* without the prior approval of the *IESO*. The *IESO* shall approve such change unless it determines that the change is reasonably likely to adversely affect the *reliability* and voltage profile of the *IESO-controlled grid.*

10. Demand Control

10.1 Introduction

10.1.1 This section 10 applies in situations on the *integrated power system* where there is insufficient capacity available to satisfy expected *demand*, where operating problems (such as frequency, voltage levels or thermal over-loads) exist which affect the ability to serve load, or where there is a breakdown on any part of the *IESO-controlled grid*. This section 10 identifies actions that the *IESO* may take or direct *market participants* to take to assist in achieving reductions in *demand* to either avoid or alleviate such situations.

10.1.2 Pursuant to Chapter 7, the *IESO* shall continuously inform *market participants* of conditions on the *IESO-controlled grid* that may require the *IESO* to initiate reductions in *demand* by *non-dispatchable loads*.

10.2 Demand Control Initiated by a Market Participant

10.2.1 *Market participants* shall notify the *IESO* of any action initiated by them to control *demand* in accordance with this section 10.2.

10.2.2 Each *market participant* that can intentionally and directly cut *dispatchable load* shall provide the following information to the *IESO*:

10.2.2.1 the proposed date, time, and duration of the cuts by *connection point* on the *IESO-controlled grid*, by hour;

10.2.2.2 the proposed MW reduction of *demand* by *connection point* on the *IESO-controlled grid*, by hour; and

10.2.2.3 the details of the actual decrease in *dispatchable load* that was achieved.

10.2.3 Each *transmitter* and *distributor* that intends to initiate a voltage reduction shall:

10.2.3.1 by 10:00 EST each day, notify the *IESO* of all such planned voltage reductions and consequent reduction in load for the following day;

10.2.3.2 immediately notify the *IESO* of a voltage reduction that is planned after 10:00 EST for the following day;

10.2.3.3 the proposed date, time, and duration of the voltage reduction by connection point on the *IESO-controlled grid*, by hour;

10.2.3.4 the proposed MW reduction by *connection point* on the *IESO-controlled grid*, by hour; and

10.2.3.5 details of the actual voltage reduction achieved, in MWs.

10.2.4 Each *distributor* or *transmitter* that intends to initiate a disconnection in load (including, but not limited to, interruptible loads and demand management activities) shall:

10.2.4.1 by 10:00 EST each day, notify the *IESO* of all such planned disconnections in load and consequent reduction in loads for the following day;

10.2.4.2 immediately notify the *IESO* of a disconnection in load that is planned after 10:00 EST for the following day;

10.2.4.3 the proposed date, time, and duration of the disconnection in load by *connection point* on the *IESO-controlled grid*, by hour;

10.2.4.4 the proposed reduction, in MWs, of loads by *connection point* on the *IESO-controlled grid*, by hour; and

10.2.4.5 details of the actual reduction in loads achieved, in MWs.

10.2.5 Each *distributor* and *transmitter* that has operational control over load shall:

10.2.5.1 make arrangements that enable it to *disconnect* load immediately under an *emergency operating state* declared by the *IESO*;

10.2.5.2 make arrangements that enable it to apply *disconnections* to load to individual or specific groups of *connection points* on the *IESO-controlled grid* as determined in a coordinated fashion by the *IESO* and *market participants*;

10.2.5.3 provide the *IESO* in writing, by week 24 in each calendar year, its total forecasted peak *demand* for the immediately following twelve-month period, by *connection point* on the *IESO-controlled grid*; and

10.2.5.4 provide the *IESO* in writing, by week 24 in each calendar year, the total forecasted peak *demand* for the immediately following twelve-month period that can be *disconnected* within the following time scales: immediately, 15 minutes, 1 hour and more than 1 hour. This information shall be provided by *connection point* on the *IESO-controlled grid.*

10.2.6 No *distributor* or *transmitter* that has *disconnected* load pursuant to section 10.2.4 shall reconnect the load until directions have been received from the *IESO* permitting it to do so. Such *distributor* or *transmitter* shall commence restoration of load immediately following receipt of such directions.

10.3 Demand Control Initiated by the IESO in an Emergency Operating State

10.3.1 When an *emergency operating state* has been declared by the *IESO*, the actions available to the *IESO* to safeguard the *security* of the *IESO-controlled grid* may include issuing directions to *market participants* to reduce *demand* for electricity.

10.3.2 Whenever possible, the *IESO* shall issue a warning by 16:00 EST on the previous day when requesting a reduction of *demand* through voltage reductions or interruptions.

10.3.3 Each *market participant* that receives a direction from the *IESO* to reduce *demand* shall achieve the reduction in *demand* within 5 minutes of receipt of the direction and shall notify the *IESO* that it has done so.

10.3.4 Each *market participant* may interchange customers to whom the *demand* reduction has been applied provided the necessary *demand* reduction required by the *IESO* is achieved by the interchange.

10.3.5 No *market participant* that has reduced *demand* pursuant to this section 10.3 shall restore *demand* until directions have been received from the *IESO* permitting it to do so. Such *market participant* shall commence restoration of *demand* immediately following receipt of such directions.

10.3.6 The *IESO* shall maintain, *publish* and revise as required, following appropriate consultations with *market participants*, the *Electricity Emergency Priorities - Policy* regarding exclusions to load management activities that are undertaken for the purpose of controlling *demand*.

10.3.7 The *IESO* shall release to all *market participants* an estimate of aggregate load *curtailed* as soon as practicable following the return to a *normal operating state*.

10.4 Under-Frequency Load Shedding

10.4.1 Automatic under-frequency load shedding shall be accomplished to maintain the frequency of the *IESO-controlled grid* and to restore the *IESO-controlled grid* to normal frequency following frequency deviations outside of the range established by the *IESO*.

10.4.2 Each *transmitter* shall, where possible and upon receipt of an under-frequency alarm or an indication of declining frequency and voltage, identify to the *IESO* frequency values for stations under its control.

10.4.3 Each *transmitter* shall undertake the following actions immediately and independently as pre-authorized by the *IESO* pursuant to the Operating Agreement between the *transmitter* and the *IESO*:

10.4.3.1 when frequency is between 58.5 and 59.0 Hz, take immediate independent action to shed 25% of controlled load. The block of load to be shed shall not include load connected to under-frequency load-shedding relays; or

10.4.3.2 when frequency is below 58.5 Hz, take immediate independent action to shed affected load until the frequency is restored to 59.0 Hz or, in the case of known island situations, to 60 Hz.

10.4.4 Each affected *transmitter* shall notify the *IESO* of the approximate amounts and locations of loads that were shed and of conditions on the *IESO-controlled grid*.

10.4.5 Once loads have been shed to maintain the frequency of the *IESO-controlled grid*, the *IESO* shall immediately report conditions on the *IESO-controlled grid* to affected *transmitters*.

10.4.6 Each *distributor* and *connected wholesale customer*, in conjunction with the relevant t*ransmitter*, shall make arrangements to enable the disconnection of automatic under-frequency *demand* of at least 30% of its total peak customer *demand*.

10.4.7 The *demand* of each *distributor* and *connected wholesale customer* that is subject to automatic under-frequency load shedding pursuant to section 10.4.6 shall be split into discrete MW blocks. The number, location, size and associated low frequency settings of these blocks shall be as specified by the *IESO*. Such specifications shall be established by the *IESO*, following consultations with the relevant *market participants*, by week 24 in each calendar year to cover the immediately following twelve-month period.

10.4.8 No *market participant* shall restore load that has been shed pursuant to this section 10.4 until directions have been received from the *IESO* permitting it to do so. Such *market participant* shall commence the restoration of load immediately following receipt of such direction.

10.4.9 Each *distributor* and *connected wholesale customer* shall provide the *IESO* with an estimate of the *demand* reduction that has occurred as a result of *disconnecting* under-frequency *demand*.

10.4.10 The amount of load rejected by automatic under-frequency load shedding shall conform to the minimum requirements set forth in all applicable *reliability standards*.

10.4.11 The *IESO* shall, maintain, *publish* and revise as required, following appropriate consultations with *market participants*, the *Electricity Emergency Priorities - Policy* regarding exclusions to load management activities that are undertaken for the purpose of shedding load during under-frequency conditions.

10.5 Generator Obligations During Abnormal Frequency

10.5.1 Abnormal frequency excursions on the *IESO-controlled grid* may require immediate actions by *generators* to restore the frequency to an acceptable level.

10.5.2 A g*enerator* that observes a frequency excursion greater than 60.2 Hz or less than 59.8 Hz shall immediately report this condition to the *IESO* and shall carry out frequency restoration actions as directed by the *IESO*.

10.5.3 No *generator* shall be precluded by the restoration actions referred to in section 10.5.2 from taking action for the purpose of protecting the safety of its equipment, its employees, the public or the environment. Any such directives shall be immediately reported to the *IESO*.

11. Emergency Preparedness and System Restoration

11.1 Objective

11.1.1 The objective of this section 11 is to establish the means by which the *IESO* and *market participants* will fulfil their respective *emergency* preparedness and system restoration obligations, including regular and real-time testing; the preparation by the *IESO* of the *Ontario electricity emergency plan* and the *Ontario power system restoration plan*; the preparation by *market participants* of *emergency preparedness plans* that support and are coordinated with the *Ontario electricity emergency plan*; and the preparation of *restoration participant attachments* that support and are coordinated with the *Ontario power system restoration plan*. This objective will be met through co-operation and in consultation with all relevant *market participants.*

11.2 Emergency Preparedness Plans and Ontario Electricity Emergency Plan

11.2.1 The *IESO* shall develop and maintain, in consultation with all relevant *market participants*, the *Ontario electricity emergency plan* describing the responsibilities of, and coordinating the actions of, *market participants* and the *IESO* for the purpose of alleviating the effects of an *emergency* on the *electricity system,* having regard to the mitigation of the impact of an *emergency* on public health and safety as identified in each *market participant's emergency preparedness plan.*

11.2.2 The *IESO* shall file with the *Minister* the *Ontario electricity emergency plan* and such other emergency plans as the *Minister* may require pursuant to subsection 39(1) of the *Electricity Act, 1998*.

11.2.3 In order to assist the *IESO* in fulfilling its responsibilities under section 39 of the *Electricity Act, 1998*, each *market participant* shall prepare and submit to the *IESO* an *emergency preparedness plan* and such other *emergency* preparedness-related information as the *IESO* considers necessary. Each *market participant* shall ensure that its *emergency preparedness plan* complies with section 11.2.4 and is submitted to the *IESO* not later than the *market commencement date*, or at such later times as the *IESO* shall specify.

11.2.4 Each *market participant* shall ensure that its *emergency preparedness plan*:

11.2.4.1 describes such planning, testing, information, communication and other elements designated by the *IESO*;

11.2.4.2 complies with such *emergency* planning criteria as may be designated by the *IESO*;

11.2.4.3 complies with all relevant *reliability standards*;

11.2.4.4 is consistent with the *emergency* planning and preparedness procedures established by relevant government authorities;

11.2.4.5 indicates the manner in which the impact of an *emergency* on public health and safety will be mitigated;

11.2.4.6 indicates the manner in which the *market participant* will minimize the cutting and expedite the restoration of critical loads and priority loads during short and prolonged *emergencies*; and

11.2.4.7 is submitted with a statement certified by an officer or equivalent of the *market participant* stating that the *emergency preparedness plan* is a true and complete copy as at the date of the certification.

11.2.5 The *IESO* shall assist *market participants* in the development of *emergency preparedness plans* for the purpose of ultimately establishing *emergency preparedness plans* that support and are coordinated with the *Ontario electricity emergency plan*.

11.2.6 [Intentionally left blank]

11.3 Ontario Power System Restoration Plan and Restoration Participant Attachments

11.3.1 The *IESO* shall develop and maintain, in consultation will all relevant *market participants*, the *Ontario power system restoration plan* for restoring the *security* of the *IESO-controlled grid* following a major *contingency event* or *emergency* as required by all applicable *reliability standards* and considered prudent by the *IESO* for Ontario.

11.3.2 The *Ontario power system restoration plan* shall cover each of the planning, testing, information, load reduction, load restoration, communication and other

elements described in section 10 and section 11 and such other elements as the *IESO* deems necessary to implement effective system restoration.

11.3.3 The *Ontario power system restoration plan* shall include, but not be limited to:

11.3.3.1 plans for managing major disturbances on the *IESO-controlled grid* that blackout all or a portion of the *IESO-controlled grid*;

11.3.3.2 plans for the testing and verification of *emergency* preparedness facilities and procedures; and

11.3.3.3 descriptions of the roles of the IESO and various restoration participants in the Ontario power system restoration plan.

11.3.4 The *IESO* shall file with the *Minister* the *Ontario power system restoration plan* and such other restoration documentation as the *Minister* may require under subsection 39(1) of the *Electricity Act, 1998*.

11.3.5 Each *restoration participant* shall prepare and submit to the *IESO* a *restoration participant attachment* to the *Ontario power system restoration plan* and such other system restoration-related information as the *IESO* considers necessary. Each *restoration participant* shall ensure that its *restoration participant attachment* complies with section 11.3.6 and is submitted to the *IESO* not later than the *market commencement date*, or at such later times as the *IESO* shall specify.

11.3.6 Each *restoration participant* shall ensure that its *restoration participant attachment*:

11.3.6.1 includes the elements described in section 11.3.7;

11.3.6.2 complies with such restoration planning criteria as may be designated by the *IESO*; and

11.3.6.3 complies with all relevant *reliability standards,* subject to the information reporting requirements specified in section 14.1.2.

11.3.7 Each *restoration participant* shall ensure that its *restoration participant attachment* includes:

11.3.7.1 a statement describing that the *restoration participant*: (i) has an operator training program in place, (ii) uses trained operating personnel, and (iii) maintains operator training records;

11.3.7.2 documentation detailing organizational responsibility for co-ordinating with the *IESO* the development of and participation in system restoration drills. Such development and participation shall be conducted by the *restoration participant* at its own expense;

11.3.7.3 a statement describing the program in place to test the *restoration participant's* equipment as may be designated in the *Ontario power system restoration plan*. Such testing shall be conducted by the *restoration participant* at its own expense;

11.3.7.4 a statement of policy and supporting documentation demonstrating how the *restoration participant* will minimize the cutting and expedite the restoration of critical loads and priority loads under system restoration conditions;

11.3.7.5 any other documentation that the *IESO* deems necessary to support or facilitate the successful implementation of the *Ontario power system restoration plan*; and

11.3.7.6 a statement certified by an officer or equivalent of the *market participant* stating that the *restoration participant attachment* is a true and complete copy as at the date of the certification.

11.3.8 [Intentionally left blank]

11.3.9 The *IESO* shall assist *restoration participants* in the development of *restoration participant attachments* that support and are coordinated with the *Ontario power system restoration plan* for the purpose of ultimately establishing one integrated restoration plan for Ontario.

11.3.10 Each *restoration participant* shall ensure that the guidelines and procedures applicable to it and set forth in the *Ontario power system restoration plan* are carried out by trained operating staff with sufficient authority to take any action that may be necessary to ensure that all relevant equipment is operated in a timely, stable and reliable manner.

11.3.11 The *IESO* shall direct *market participants* in restoring the *IESO-controlled grid* following major disturbances. Each such *market participant* shall be responsible for carrying out these *IESO* directions, in accordance with the provisions of the *Ontario power system restoration plan.*

11.4 Review and Audit

11.4.1 The *IESO* shall review each *emergency preparedness plan* and each *restoration participant attachment* submitted to it and shall prepare and provide to the relevant *market participant* or *restoration participant* a record of review indicating the changes, if any, required to be made and the date by which the revised *emergency preparedness plan* or *restoration participant attachment* must be submitted with the *IESO*.

11.4.2 Each *market participant* shall make such changes to its *emergency preparedness plan* or *restoration participant attachment* as may be required by the record of review and shall submit to the *IESO* a revised *emergency preparedness plan* or *restoration participant attachment* within the time specified in the record of review or within such other period as may be agreed with the *IESO*.

11.4.3 Each *market participant* shall review its *emergency preparedness plan* and *restoration participant attachment* at least annually, or as required, and shall, following such review, submit to the *IESO*:

11.4.3.1 a statement certified by an officer or equivalent of the *market participant* confirming that the review has not required any change to be made to its *emergency preparedness plan* or its *restoration participant attachment*; or

11.4.3.2 a revised version of its *emergency preparedness plan* or *restoration participant attachment*, amended as may be required by the results of the review, together with a statement certified by an officer or equivalent of the *market participant* identifying such amendments, as the case may be. Each *market participant* shall ensure that any revised *emergency preparedness plan* or *restoration participant attachment* prepared and submitted pursuant to this section 11.4.3 complies with section 11.2.4 or 11.3.6, respectively.

11.4.4 When directed by the *IESO*, the *market participant* shall have an independent audit of its *emergency preparedness plan* and/or *restoration participant attachment* conducted. The independent audit may be conducted by, without limitation, the *market participant's* internal auditors or before a peer review team having diverse membership or industry *emergency preparedness* expertise. The cost of conducting such an audit shall be borne by the *market participant*. Each *market participant* shall, following such audit, submit to the *IESO* a copy of the audit report, together with:

11.4.4.1 a statement certified by an officer or equivalent of the *market participant* confirming that the audit has not required any change to be made to its *emergency preparedness plan* or its *restoration participant attachment*; or

11.4.4.2 a revised version of its *emergency preparedness plan* or *restoration participant attachment*, amended as may be required by the results of the audit, together with a statement certified by an officer or equivalent of the *market participant* identifying such amendments, as the case may be. Each *market participant* shall ensure that any revised *emergency preparedness plan* or *restoration plan market participant attachment* prepared and submitted pursuant to this section 11.4.4 complies with section 11.2.4 or 11.3.6, respectively.

11.4.5 [Intentionally left blank – section deleted]

11.4.6 The *IESO* shall review its *emergency preparedness plan,* the *Ontario electricity emergency plan* and the *Ontario power system restoration plan* at least annually, or as required. When directed by the *Minister*, the *IESO* shall have an independent audit conducted of these plans. The independent audit may be conducted by, without limitation, the *IESO's* internal auditors or before a peer review team having diverse membership or industry *emergency preparedness* expertise. The cost of such an audit shall be borne by the *IESO*.

11.4.7 [Intentionally left blank – section deleted]

11.5 [Intentionally left blank]

11.6 Emergency Facilities

11.6.1 The *IESO* may evacuate its principal control centre in the event that a circumstance arises that poses a hazard to *IESO* personnel. During and following such evacuation, operation of the *IESO-controlled grid* shall be effected in accordance with this section 11.6.

11.6.2 The *IESO-administered markets* shall continue to operate during an evacuation of the *IESO*'s principal control centre unless conditions exist that would warrant a suspension of market operations as described in Chapter 7.

11.6.3 During the interval between the evacuation of the *IESO' s* principal control centre and the establishment of a backup control centre:

11.6.3.1 the *IESO* shall designate an interim emergency system coordinator to act in its stead, as required; and

11.6.3.2 all *generators* and *transmitters* shall manage their *facilities* and support the emergency system coordinator in the operation of the *IESO-controlled grid.*

11.6.4 The *IESO* shall test the backup control centre and associated procedures and facilities on a regular basis, and each *market participant* connected to the *IESO-controlled grid* shall, at its own expense and as directed by the *IESO*, support and actively participate in evacuation tests and simulations.

11.7 Testing

11.7.1 Each *market participant* shall ensure that the capability and reliability of its personnel, procedures, and equipment are maintained to the extent necessary to fulfill its obligations under its *emergency preparedness plan* and its *restoration participant attachment*.

11.7.2 The *IESO* shall develop, schedule, implement and conduct such tests as are provided for in the *Ontario electricity emergency plan* and the *Ontario power system restoration plan.*

11.7.3 [Intentionally left blank]

11.7.4 Each *market participant* shall support and actively participate, at its own expense and as directed by the *IESO*, in the implementation and testing of its *emergency preparedness plan*, its *restoration participant attachment*, the *Ontario electricity emergency plan,* the *Ontario power system restoration plan* and voice communications facilities.

11.7.5 The *IESO* shall schedule the tests referred to in section 11.7.4 at an appropriate time of the year and time of day, in consideration of the needs of *market participants* and of the desire to minimize their costs relating to such tests. To the extent practicable, such tests of the *restoration participant attachment* shall be scheduled in a manner consistent with the *outage* coordination process described in section 6.

11.8 Enforcement

11.8.1 Failure by a *market participant* to take any action required to be taken in, or to act in a manner consistent with, its *emergency preparedness plan*, its *restoration*

participant attachment or its accountabilities within the *Ontario power system restoration plan* shall be deemed to constitute a breach of the *market rules.*

12. Communications

12.1 Communication Methods

12.1.1 Communication between the *IESO* and:

12.1.1.1 market participants;

12.1.1.2 *embedded generators* required by Appendix 2.2 of Chapter 2 to provide or install and maintain voice communication facilities, facilities relating to monitoring and control or both; and

12.1.1.3 *embedded load consumers* required by Appendix 2.2 of Chapter 2 to provide or install and maintain voice communication facilities, facilities relating to monitoring and control or both,

shall take place through a combination of methods as identified in Appendix 2.2 of Chapter 2 and as directed by the *IESO* pursuant to section 12.2.3.2.

12.1.2 For the purposes of section 12.1.1, the *IESO* shall provide and maintain, at its cost, a dedicated, real-time communication network from the *IESO's* facilities to the communication terminal point between such network and:

12.1.2.1 the monitoring and control devices; and

12.1.2.2 where applicable, the *dispatch workstation*

of the persons referred to in sections 12.1.1.1 to 12.1.1.3 to enable communication between the *IESO* and such persons.

12.1.3 The *IESO* shall provide real-time communication network channels to the persons referred to in sections 12.1.1.1 to 12.1.1.3 as follows:

12.1.3.1 one communication channel and, where available and justified for *reliable* operation of the *IESO-controlled grid* and efficient operation of the *IESO-administered markets*, a redundant physically diverse communication channel, for:

a. each *facility* to which the high performance information monitoring standard applies in accordance with Appendices 4.19 to 4.23 of Chapter 4, and

b. each *facility* that is providing monitoring information for two or more *facilities*;

12.1.3.2 one communication channel for each *facility* to which the medium performance information monitoring standard applies in accordance with Appendices 4.19 to 4.23 of Chapter 4.

12.1.3.3 [Intentionally left blank]

12.1.3.4 [Intentionally left blank]

12.1.3.5 [Intentionally left blank]

12.1.4 The *IESO* may, in respect of a given *facility*, provide additional real-time network communication channels in addition to those referred to in section 12.1.3 where the *IESO* considers, based on the size and location of the *facility*, and, where applicable, the number of *facilities* monitored at a single *facility*, that such additional channels are desirable for purposes of maintaining the *reliability* of the *IESO-controlled grid*.

12.1.5 Where a market participant wishes to submit dispatch data, physical bilateral contract data, EFM bids or EFM offers in the day-ahead energy forward market or TR bids or TR offers in the TR market using private network dedicated communication links, all costs associated with such use, including but not limited to the cost of the provision and maintenance of the required communication channel, shall be borne by the market participant.

12.1.6 Where problems exist which require methods of communication other than those referred to in section 12.1.1, such alternative communication capabilities as shall be selected by the *IESO*, including facsimile capability, shall be used.

12.2 Voice Communication

12.2.1 [Intentionally left blank]

12.2.2 [Intentionally left blank]

12.2.3 Each market participant, embedded generator and embedded load consumer shall provide and maintain:

12.2.3.1 the applicable voice communication facilities required by Appendix 2.2 of Chapter 2 and that meet the requirements of that Appendix; and

12.2.3.2 such additional or other voice communication facilities as the *IESO* may direct in respect of *facilities* that the *IESO* considers to be significant for purposes of maintaining the *reliability* of the *IESO-controlled grid*.

12.2.4 Each person referred to in section 12.2.3 shall ensure that the overall mean time between failures of the voice communication facilities referred to in section 12.2.3 is no less than five years.

12.2.5 Each person referred to in section 12.2.3 shall respond to an outage of or defect in the voice communication facilities referred to in section 12.2.3:

12.2.5.1 immediately, in the case of an outage of or defect in a *high priority path facility*; and

a. [Intentionally left blank]

b. [Intentionally left blank]

c. [Intentionally left blank]

d. [Intentionally left blank]

e. [Intentionally left blank]

f. [Intentionally left blank]

g. [Intentionally left blank]

12.2.5.2 no later than the next day following the day on which the outage or defect is discovered, in the case of an outage of or defect in a *normal priority path facility*.

a. [Intentionally left blank]

b. [Intentionally left blank]

c. [Intentionally left blank]

d. [Intentionally left blank]

e. [Intentionally left blank]

f. [Intentionally left blank]

12.2.6 Each person referred to in section 12.2.3 shall ensure that the voice communication facilities referred to in section 12.2.3 are restored to a fully operational state following an *outage* of or defect in such facilities as follows:

12.2.6.1 in the case of the *high priority path facilities* referred to in section 12.2.5.1, within 24 hours of the time at which the *outage* or defect is discovered;

12.2.6.2 in the case of the *normal priority path facilities* referred to in section 12.2.5.2, within 48 hours of the time at which the *outage* or defect is discovered; and

12.2.6.3 in all other cases, within 14 days of the time at which the *outage* or defect is discovered.

12.2.7 The *IESO* may direct a person referred to in section 12.2.3 to respond and restore a voice communication facility to a fully operational state following an *outage* of or defect in such facility within such longer or shorter time periods than those referred to in sections 12.2.5 and 12.2.6 based on the immediate or short-term impact of the unavailability of the voice communication facility on the *reliable* operation of the *IESO-controlled grid*.

12.2.8 Each person referred to in section 12.2.3 shall notify the *IESO* of any *planned outage* of the voice communication facilities referred to in section 12.2.3 no less than four days prior to the *planned outage*.

12.2.9 The *IESO* shall:

12.2.9.1 maintain, at each of its principal control center and back-up control center, *high priority path facilities* and *normal priority path facilities* that meet the requirements of sections 1.1.7 and 1.1.8 of Appendix 2.2 of Chapter 2, respectively, for the purpose of voice communication with the persons referred to in section 12.2.3 and with neighbouring *security coordinators*; and

12.2.9.2 ensure that its voice communication facilities include facilities that permit telephone conference calls between six parties.

12.2.10 The *IESO* shall develop, in consultation with all relevant *market participants*, test plans and procedures for voice communication during an *emergency* on or a major disturbance of the *IESO-controlled grid*.

12.2.11 Each person referred to in section 12.2.3 shall, at its own expense, not less than annually or more frequently as may be directed by the *IESO*, monitor and test its

voice communication facilities and shall, at its own expense and as directed by the *IESO*, support and actively participate in the testing of voice communication facilities.

12.2.12 Where problems exist which require methods of communication other than those referred to in section 12.2.3, such alternative communication capabilities as shall be selected by the *IESO*, including facsimile capability, shall be used.

12.3 Electronic Data

12.3.1 *Energy* management system (EMS) information shall be exchanged between the communication system of the *IESO* and the communication system of each *market participant* in order to support real-time functions such as:

12.3.1.1 the monitoring of the *IESO-controlled grid*;

12.3.1.2 the control and analysis of *generation facilities*;

12.3.1.3 an analysis of the *security* of the *IESO-controlled grid*;

12.3.1.4 the scheduling of *generation facilities*;

12.3.1.5 the monitoring of compliance with *dispatch instructions*; and

12.3.1.6 [Intentionally left blank]

12.3.1.7 reports.

12.3.2 The *IESO* and *market participants* shall exchange EMS information between their respective communication systems via dedicated data circuits.

12.3.3 For the exchange of schedules referred to in Chapter and of *outage* and planning data between *market participants* and the *IESO*, a computer path distinct from the EMS path shall be used. Communications shall occur over separate data links using a different protocol than that used for EMS information. Real-time *dispatch instructions* for *generation facilities,* transmission *facilities* and load shall be communicated electronically through the EMS path and shall be integrated with the EMS messaging system for logging purposes.

12.4 Voice Links and Other Communications

12.4.1 The *IESO* shall develop and notify all *market participants* of standard operating terms, abbreviations and definitions that shall be approved for use in communications between the *IESO* and *market participants*. Such approved, standard operating terms, abbreviations and definitions shall wherever possible be used by the *IESO* and *market participants* in their communications with one another.

12.4.2 All communications between a *market participant* and the *IESO* with respect to the *reliability* of the *IESO-controlled grid* shall be recorded and the records shall be retained by the *IESO* for 7 years.

12.4.3 The *IESO* shall maintain a log of activities related to the *reliable* operation of the *IESO-controlled grid.*

13. Prior Arrangements

13.1 Market Participant Review of Arrangements

13.1.1 Each *market participant* shall review any contractual or other arrangements relating to the *reliability* of the *IESO-controlled grid* which it may have with other *market participants* or with *interconnected systems* on the date of coming into force of this Chapter for the purpose of determining whether such arrangements are consistent with the requirements of, or the obligations imposed on the *market participant* by, this Chapter. Where such contractual or other arrangement is consistent with the requirements and obligations imposed on the *market participant* by this Chapter, no further action with respect to such contract or arrangement is required.

13.1.2 Where a *market participant* determines that a contractual or other arrangement referred to in section 13.1.1 is inconsistent with the requirements of, or the obligations imposed on the *market participant* by, this Chapter, the *market participant* shall:

13.1.2.1 negotiate an amendment to the contract or a modification to the arrangement which removes the inconsistency; or

13.1.2.2 report the inconsistency to the *technical panel*, which shall make a determination as to whether the inconsistency will or is reasonably

likely to have an adverse effect on the *reliability* of the *IESO-controlled grid*.

13.1.3 Where the *technical panel* determines under section 13.1.2 or 13.1.4 that the inconsistency will or is reasonably likely to have an adverse effect on the *reliability* of the *IESO-controlled grid*, the *IESO* shall take appropriate actions to mitigate the effect of the inconsistency until the inconsistency is removed.

13.1.4 Where the *IESO* becomes aware that a contractual or other arrangement referred to in section 13.1.1 is inconsistent with the requirements of, or the obligations imposed on a *market participant* by, this Chapter, it may report the inconsistency to the *technical panel* notwithstanding that the inconsistency may not have been reported by the *market participant* and the *technical panel* shall make the determination referred to in section 13.1.2.2 in respect of that inconsistency.

14. Information and Reporting Requirements

14.1.1 The *reliable* operation of the *IESO-controlled grid* requires the rapid and continuous flow of accurate information among the *IESO*, *market participants* and *interconnected systems*, with due regard for maintaining the confidentiality of information where appropriate. To that end, the *IESO* shall establish and periodically up-date and inform all *market participants* with respect to the specific information it requires from *market participants* for *reliability* purposes.

14.1.2 Each *market participant* shall provide the information referred to in section 14.1.1 to the *IESO* in the manner and within the time prescribed by the *IESO*. By submitting such information to the *IESO,* a *market participant* is considered to have fulfilled any requirement under a *reliability standard* to report such information to one or more *standards authorities*. The *IESO* shall provide such information to other *standards authorities,* as required.

14.1.3 The *IESO* shall establish a catalogue of reporting requirements listing the *reliability*-related information to be exchanged between the *IESO* and *market participants.* Such reporting requirements shall include, but not be limited to, the following:

14.1.3.1 each *market participant* shall report to the *IESO* the planned implementation of a change to a setting on a fixed-tap transformer. This information shall be reported to the *IESO* in writing one week

prior to the date scheduled for implementation of such change, provided that where such change is effected on an unplanned, emergency basis, the information shall be reported to the *IESO* within one *business day* of implementation of the change;

14.1.3.2 each *market participant* shall report to the *IESO* any change in equipment and *facilities* to that which has been provided pursuant to Chapter 4;

14.1.3.3 each *market participant* shall report to the *IESO* a list of all of its equipment for which periodic maintenance has been performed on *special protection systems* in the previous 12 months, as required by relevant *standards authorities*. This information shall be reported no later than the first day of December in each year;

14.1.3.4 each *market participant* shall provide to the *IESO* a report describing any modification proposed to be made to protection on a primary relay. The report shall be delivered to the *IESO* within one week of the date on which the *IESO* approves such modification pursuant to section 6 of Chapter 4, or, where the modification is effected on an unplanned, emergency basis, within one week of the date of modification;

14.1.3.5 each *market participant* shall annually provide to the *IESO* a written summary of actions taken to control *demand* in the previous 12 months;

14.1.3.6 each *market participant* shall annually provide to the *IESO* a written summary of automatic under-frequency load shedding activities taken in the previous 12 months; and

14.1.3.7 each *market participant* shall annually provide to the *IESO* a report of *reliability*-related performance measures for transmission *facilities* and *connections* to the *IESO-controlled grid* in accordance with all applicable *reliability standards*.

14.1.4 Each *market participant* shall provide to the *IESO* such data as may be required by the *IESO* to enable it to satisfy a request by a *standards authority.*

14.1.5 The *IESO* shall file such reports including, but not limited to, disturbance reports, and participate in such discussions as may be required by relevant *standards authorities*. Each *market participant* shall provide to the *IESO* such information and reports as may be required by the *IESO* to facilitate preparation by the *IESO* of such disturbance reports.

From: david.kiguel@HydroOne.com
To: Lee R. Pedowicz
Subject: RE: Standard"s Effective Dates
Date: Wednesday, August 17, 2011 11:00:37 AM

Good morning Lee,

The market rule amendment became effective on July 8, 2011. It is in Chapter 5 of the market rules to be found in:

http://www.ieso.ca/imoweb/pubs/marketRules/mr_chapter5.pdf

For your convenience I reproduce the sections 1.2.6 and 1.2.7 here:

1.2.6 Subject to section 1.2.7, *reliability standards* established by a *standards authority* that have not otherwise been stayed or revoked and referred back to the *standards authority* for further consideration by the *Ontario Energy Board* shall be declared in force in Ontario:

1.2.6.1 when the *reliability standards* are declared in force in the United States or, for *NPCC* reliability criteria, when declared in force by *NPCC*; and

1.2.6.2 after the expiry of the period for initiating a review before the *Ontario Energy Board* and the conclusion of any such review;

and shall cease to be in force in Ontario when they cease to be in force in the United States. For certainty, the operation of any *reliability standard* that had been in force in Ontario but had not been declared in force in the United States when this rule amendment went into effect shall be stayed until such *reliability standard* has been declared in force in the United States.

1.2.7 Notwithstanding section 1.2.6, where a *reliability standard* approved by *NERC* failed to achieve approval by the *NERC* registered ballot body as specified in *NERC*'s Rules of Procedure, the *reliability standard* will not be in force in Ontario unless and until the *IESO* determines, in consultation with affected *market participants*, that all or part of the *reliability standard* is in force in Ontario. The *IESO* shall *publish* notice of its determination and where applicable, such *reliability standard* will come into effect in accordance with section 1.2.6.

The effective date change applies not only moving forward but also to those standards that have not become effective in the US yet, in which case Ontario is reverting back to the previous version (e.g. EOP-001).
Regards,
David

From: Lee R. Pedowicz [mailto:lpedowicz@npcc.org]
Sent: Wednesday, August 17, 2011 10:20 AM
To: KIGUEL David
Subject: Standard's Effective Dates

Good morning, David.

Hope all is well. I was asked this morning if the mandatory and effective dates in Ontario were the same as here in the United States, the date of FERC approval. At the May RSC Meeting you reported that Ontario would be following those dates. Has anything been written to confirm that? Where would I find it?

Thanks.

Best regards,

Lee

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From:	Howard Gugel
To:	rsg
Subject:	NERC - RSG - August 15 call follow-up
Date:	Wednesday, August 17, 2011 8:49:14 AM
Attachments:	Project Prioritization - 2011.pptx
Importance:	High

Attached is the 2011 NERC Standards Project Prioritization. We are in the process of developing the 2012 list. Please examine and let me know of any projects not in the top twelve that should given a higher priority based on your region's needs or RSG needs to replace fill-in-the-blank standards. I need your response by August 19, if possible. Thanks.

Howard Gugel
Manager of Regional Standards
NERC
(609) 651-2269
howard.gugel@nerc.net

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Y

Standards Committee Proposal

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- High Priority Projects
  - Continue on 12 projects identified as highest priority
  - Continue work on projects scheduled for completion in 1st quarter (even if not in top 12)
  - Respond to new regulatory and policy priorities as they emerge
- Remaining Ongoing Projects
  - Continue efforts to develop technical justifications where needed
  - Communicate with team leaders: Informal work may continue without Standards Staff support; otherwise, develop and document logical stopping points and begin placing project on hold
- Remaining "New" Projects (where stds. drafting has not begun)
  - No start until higher priority projects are completed
  - Technical Committees will be encouraged to work on refining the technical foundations for the projects

Project Prioritization – High Priority Projects

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Top Twelve Projects 2011

1. 2008-06 Cyber Security Order 706
2. 2007-17 Protection System Maintenance and Testing
3. 2007-06 System Protection Coordination
4. 2010-07 Generator Requirements at the Transmission Interface
5. 2007-12 Frequency Response
6. 2007-02 Operation Personnel Communications Protocols

Project Prioritization Results – High Priority Projects

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Top Twelve Projects 2011

7. 2006-02 Assess Transmission Future Needs
8. 2010-17 Definition of Bulk Electric System
9. 2007-03 Real Time Operations
10. 2007-09 Generator Verification
11. 2009-01 Disturbance and Sabotage Reporting
12. 2010-05 Protection Systems

Project Prioritization Results – Remaining Ongoing Projects

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Informal Development Work: continue development of technical justification/outreach w/o Standards Staff support; develop and document logical stopping point; begin placing projects on hold

13. 2006-06 Reliability Coordination (continuing)
14. 2010-14 Balancing Authority Reliability Controls (informal)
15. 2007-07 Vegetation Management (continuing)
16. 2007-11 Disturbance Monitoring Equipment (informal)
17. 2008-01 Voltage and Reactive Planning and Control (informal)
18. 2010-13 Relay Loadability (informal)
19. 2009-02 Real-time Reliability Monitoring and Analysis Capabilities (informal)
20. 2009-03 Emergency Operations (informal)
21. 2008-12 Coordinate Interchange (informal)

Project Prioritization Results – Remaining "New" Projects

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No start until higher priority projects are completed; Standing Committees encouraged to refine project's technical foundation

22. 2010-01 Support Personnel Training
23. 2009-04 Phasor Measurement Units
24. 2008-02 Under-voltage Load Shedding
25. 2009-07 Reliability of Protection Systems
26. 2010-08 Functional Model Glossary Revisions
27. 2010-04 Demand Data
28. 2010-03 Modeling Data
29. 2009-05 Resource Adequacy Assessments
30. 2012-02 Physical Protection
31. 2010-02 Connecting New Facilities to the Grid
32. 2012-01 Equipment Monitoring and Diagnostic Devices

From: Guy V. Zito
To: rsg
Subject: RE: NERC - RSG - August 15 call follow-up
Date: Wednesday, August 17, 2011 9:54:38 AM

Howard et al,

I am sorry I was not able to make the RSG call. I am currently on vacation and reviewing issues as the opportunity arises. I support the list as presented. Furthermore, in the past some members of the RSG have expressed concern with promoting the "fill in the blank" standards and although these are cited in the Order 693 and need to be brought to resolution, I do not believe these standards should necessarily be top priorities. The ERO needs to concentrate on standards that ensure reliablity, maintain security and address cyber related concerns along. In addition we need to effectively address the needs and perceptions of regulatory authorities and the industry with the prioritization. The current list of standards, in my view, accomplishes this.

Thanks,

Guy V. Zito
Assistant Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10 th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

_____
From: Howard Gugel [Howard.Gugel@nerc.net]
Sent: Wednesday, August 17, 2011 8:45 AM
To: rsg
Subject: NERC - RSG - August 15 call follow-up

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Howard Gugel
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You are curr

From: david.kiguel@HydroOne.com
To: Lee R. Pedowicz
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Regards,
David

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Sent: Wednesday, August 17, 2011 10:20 AM
To: KIGUEL David
Subject: Standard's Effective Dates

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Thanks.

Best regards,

Lee

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From: Lee R. Pedowicz
To: rscmembers; donald.e.nelson@state.ma.us; michael.jones@us.ngrid.com; rjfalsetti@cogeco.ca
Subject: FW: NERC Announcement: ERO Best Practices
Date: Thursday, August 18, 2011 11:22:56 AM

For information.

From: Sandy Shiflett [mailto:sandy.shiflett@nerc.net]
Sent: Thursday, August 18, 2011 10:46 AM
To: Sandy Shiflett
Subject: NERC Announcement: ERO Best Practices

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Announcement:
ERO Best Practices
August 18, 2011

NERC is pleased to announce the development of ERO Best Practices publications. ERO Best Practices are publications that highlight selected registered entity practices that are recognized by NERC as unique and add significant reliability benefit. ERO Best Practices allow other entities to leverage that information to the benefit of Bulk Power System (BPS) reliability.

One new best practice has been posted on the NERC website under the "Event Analysis – Best Practices" tab.

The new best practice addresses the following topic:

- Event Analysis – Extent of Condition Evaluations

I welcome any feedback you have on the information contained within this practice.

Sincerely,

Earl Shockley
Director of Event Analysis and Investigations

These documents are designed to convey best practices learned from NERC's various event analysis activities. They are not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any of the existing reliability standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this best practice is not a substitute for compliance with requirements in NERC's Reliability Standards.

You are currently subscribed to nerc-info as: lpedowicz@npcc.org
To unsubscribe send a blank email to leave-1267945-325654.1ca6f85fb1574a8515cc07df72d3bfe0@listserv.nerc.com

From: Eleanor Crouch
To: canonly
Subject: NERC: Announcement – Modifications to Mandatory Effective Dates Web page for U.S. Reliability Standards
Date: Thursday, August 25, 2011 3:27:51 PM

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Announcement:

Modifications to Mandatory Effective Dates Web page for US Reliability Standards

NERC is pleased to announce several modifications to the Mandatory Effective Dates webpage for U.S. Reliability Standards located at http://www.nerc.net/standardsreports/standardssummary.aspx. In the upper left hand corner of the new webpage, there is a drop down box from which the following reports can be selected:

- Mandatory Standards Subject to Enforcement
- Standards Subject to Future Enforcement
- Standards Pending Regulatory Approval
- Inactive Standards

For the Mandatory Standards Subject to Enforcement and Standards Subject to Future Enforcement reports, all dates except the enforcement date have been removed. The enforcement date now links to the Order in which FERC approved the standard. For those standards that have different enforcement dates and inactive dates for its requirements, the date in the Enforcement date column is the earliest enforcement date of all the requirements. There is a Detail column that will include a link to a pop-up for those standards. This pop-up will list the requirement and sub-requirement numbers of the standard, each requirement and sub-requirement's enforcement date, and each requirement and sub-requirement's inactive date.

For the Standards Pending Regulatory Approval report, the date columns have been modified to include the NERC Board of Trustees Approval Date and FERC Filing Date (if applicable). If there is a FERC Filing Date, that date will include a link to the filing submitted by NERC to FERC requesting FERC's approval of the standard.

The Inactive Standards report includes the Initial Enforcement Date (if applicable) and the Inactive Date. A standard becomes inactive at midnight on the day immediately prior to the effective date of the superseding standard.

NERC has made these improvements in response to input from stakeholders and in order to improve our service to you.

In the future NERC plans to address the status of Canadian standards and effective dates for Reliability Standards in each Canadian province.

If you have any questions regarding the new format, please contact Kristin Iwanechko at Kristin.Iwanechko@nerc.net.

Eleanor Crouch
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Introduction

1. **Title:** Automatic Underfrequency Load Shedding Requirements

2. **Number:** PRC-006-SERC–01

3. **Purpose:** To establish consistent and coordinated requirements for the design, implementation, and analysis of automatic underfrequency load shedding (UFLS) programs among all SERC applicable entities.

4. **Applicability:**
   4.1 Planning Coordinators
   4.2 UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:
   4.2.1 Transmission Owners
   4.2.2 Distribution Providers
   4.3 Generator Owners

5. **Background**
   The SERC UFLS Standard: PRC-006-SERC-1 ("SERC UFLS Standard") was developed to provide regional UFLS requirements to entities in SERC. UFLS requirements have been in place at a continent-wide level and within SERC for many years prior to implementation of federally mandated reliability compliance standards in 2007.

   When reliability standards were implemented in 2007, the Federal Energy Regulatory Commission ("FERC"), which is the government body with regulatory responsibility for electric reliability, issued FERC Order 693, recognizing 83 NERC Reliability Standards as enforceable by FERC and applicable to users, owners, and operators of the bulk power system (BPS). FERC did not approve the NERC UFLS standard, PRC-006-0 in Order 693. FERC's reason for not approving PRC-006-0 was that it recognized PRC-006-0 as a "fill-in the blank standard," and regional procedures associated with the standard were not submitted along with the standard. FERC's ruling in Order 693 required Regional Entities to provide the regional requirements necessary for completing the UFLS standard.

   In 2008, SERC commenced work on PRC-006-SERC-01. NERC also began work on revising PRC-006-0 at a continent-wide level. The SERC standard has been developed to be consistent with the NERC UFLS standard.

   PRC-006-1 clearly defines the roles and responsibilities of parties to whom the standard applies. The standard identifies the Planning Coordinator ("PC") as the entity responsible for developing UFLS schemes within their PC area. The regional standard adds specificity not contained in the NERC standard for development and implementation of a UFLS scheme in the SERC Region that effectively mitigates the consequences of an underfrequency event.

Requirements and Measures

R1. Each Planning Coordinator shall include its SERC subregion as an identified island in the criteria (required by the NERC PRC standard on UFLS) for selecting portions of the BPS that may form islands. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- A Planning Coordinator may adjust island boundaries to differ from subregional boundaries where necessary for the sole purpose of producing a contiguous subregional island more suitable for simulation.

M1. Each Planning Coordinator shall have evidence such as a methodology, procedure, report, or other documentation indicating that its criteria included selection of its SERC subregion(s) as an island per Requirement R1.

Studying the Region as an island is required by the NERC standard. Most regions have only one or a few different UFLS schemes. Where there is more than one scheme, studying this island demonstrates that the schemes are coordinated and performing adequately. Because there are so many different UFLS schemes in SERC (18 different schemes were represented in the 2007 SERC UFLS study), the SDT believes that applying the schemes to each subregion as an island is a necessary additional test of the coordination of the various UFLS schemes. Without this additional test, a poorly performing scheme may be masked by the large number of good performing schemes in the Region. A subregion island study, which would have a smaller number of schemes, would be more likely to uncover the poorly performing scheme and therefore get it fixed. This approach will result in a much better overall performance of the UFLS programs in SERC. The SDT recognized that there may be simulation problems due to opening the ties to utilities outside the subregion. Therefore, the subregion island boundaries are allowed to be adjusted to produce an island more suitable for simulation.
(Note: The SERC Subregions are identified in paragraph 4.2 of the SERC Reliability Corporation Bylaws: "The Region is currently geographically divided into five subregions that are identified as Southeastern, Central, VACAR, Delta, and Gateway.")

R2. Each Planning Coordinator shall select or develop an automatic UFLS scheme (percent of load to be shed, frequency set points, and time delays) for implementation by UFLS entities within its area that meets the following minimum requirements: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Have the capability of shedding at least 30 percent of the Peak Demand (MW) served from the Planning Coordinator's transmission system.

2.2. Shed load with a minimum of three frequency set points.

2.3. The highest frequency set point for relays used to arrest frequency decline shall be no lower than 59.3 Hz and not higher than 59.5 Hz.

- This does not apply to UFLS relays with time delay of one second or longer and a higher frequency setpoint applied to prevent the frequency from stalling at less than 60 Hz when recovering from an underfrequency event.

2.4. The lowest frequency set point shall be no lower than 58.4 Hz.

2.5. The difference between frequency set points shall be at least 0.2 Hz but no greater than 0.5 Hz.

2.6. Time delay (from frequency reaching the set point to the trip signal) shall be at least six cycles.

M2. Each Planning Coordinator shall have evidence such as reports or other documentation that the UFLS scheme for its area meets the design requirements specified in Requirement R2.

These requirements for the UFLS schemes in SERC have been in place for many years (except 2.6). The SDT believes that these requirements are still needed to ensure consistency for the various schemes which are used in SERC. Part 2.6 is designed to prevent spurious operations due to transient frequency swings.

R3. Each Planning Coordinator, when performing design assessments specified in the NERC PRC standard on UFLS, shall conduct simulations of its UFLS scheme for an imbalance between load and generation of 13%, 22%, and 25% for all identified island(s) where such imbalance equals [(load minus actual generation output) / load]. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M3. Each Planning Coordinator shall have evidence such as reports or other documentation that it performed the simulations of its UFLS scheme as required in Requirement R3.

R4 of the NERC standard PRC-006-1 requires the PC to conduct assessments of UFLS schemes through dynamic simulations to verify that they meet performance requirements for generation/load imbalances of up to 25%. This requirement defines specific imbalances that are to be studied within SERC. The 13% and 22% levels were determined from simulations of the worst case frequency overshoot for the UFLS schemes in SERC.

R4. Each UFLS entity that has a total load of 100 MW or greater in a Planning Coordinator area in the SERC Region shall implement the UFLS scheme developed by their Planning Coordinator. UFLS entities may implement the UFLS scheme developed by the Planning Coordinator by coordinating with other UFLS entities. The UFLS scheme shall meet the following requirements on May 1 of each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. The percent of load shedding to be implemented shall be based on the actual or estimated distribution substation or feeder demand (including losses) of the UFLS entities at the time coincident with the previous year actual Peak Demand.

4. 2. The amount of load in each load shedding step shall be within -1.0 and +3.0 of the percentage specified by the Planning Coordinator (for example, if the specified percentage step load shed is 12%, the allowable range is 11 to 15%).

4. 3. The amount of total UFLS load of all steps combined shall be within -1.0 and +5.0 of the percentage specified by the Planning Coordinator for the total UFLS load in the UFLS scheme.

M4. Each UFLS entity that has a total load of 100 MW or greater in a Planning Coordinator area in the SERC Region shall have evidence such as reports or other documentation demonstrating that its implementation of the UFLS scheme on May 1 of each calendar year meets the requirements of Requirement R4 (including all the data elements in Parts 4.1, 4.2, and 4.3) unless scheme changes per Requirement R6 are in process.

The SDT believes it is necessary to put a requirement on how well the UFLS scheme is implemented. This requirement specifies how close the actual load shedding amounts must be to the percentage of load called for in the scheme. A 4 percentage point range is allowed for each individual step, but the allowed range for all steps combined is 6 percentage points.

R5. Each UFLS entity that has a total load less than 100 MW in a Planning Coordinator area in the SERC Region shall implement the UFLS scheme developed by their Planning Coordinator, but shall not be required to have more than one UFLS step. UFLS entities may implement the UFLS scheme developed by the Planning Coordinator by coordinating with other UFLS entities . The UFLS scheme shall meet the following requirements on May 1 of each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

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5.1. The percent of load shedding to be implemented shall be based on the actual or estimated distribution substation or feeder demand (including losses) of the UFLS entities at the time coincident with the previous year actual Peak Demand.

5.2. The amount of total UFLS load shall be within ± 5.0 of the percentage specified by the Planning Coordinator for the total UFLS load in the UFLS scheme.

M5. Each UFLS entity that has a total load less than 100 MW in a Planning Coordinator area in the SERC Region shall have evidence such as reports or other documentation demonstrating that its implementation of the UFLS scheme on May 1 of each calendar year meets the requirements of Requirement R5 (including all the data elements in Parts 5.1and 5.2) unless scheme changes per Requirement R6 are in process.

The SDT believes it is necessary to put a requirement on how well the UFLS scheme is implemented. This requirement specifies how close the actual load shedding amounts must be to the percentage of load called for in the scheme. The SDT recognizes that UFLS entities with a load of less than 100 MW may have difficulty in implementing more than one UFLS step and in meeting a tight tolerance. The basis of the 100 MW comes from typical feeder load dropped by UFLS relays, and the use of a 100 MW threshold in other regional UFLS standards.

R6. Each UFLS entity shall implement changes to the UFLS scheme which involve frequency settings, relay time delays, or changes to the percentage of load in the scheme within 18 months of notification by the Planning Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M6. Each UFLS entity shall have evidence such as reports or other documentation demonstrating that it has made the appropriate scheme changes within 18 months per Requirement R6. Such evidence is only required if the Planning Coordinator makes changes to the UFLS scheme as specified in Requirement R6.

The SDT believes it is necessary to put a requirement on how quickly changes to the scheme should be made. This requirement specifies that changes must be made within 18 months of notification by the PC. The 18 month interval was chosen to give a reasonable amount of time for making changes in the field. All of the SERC region has existing UFLS schemes which, based on periodic simulations, have provided reliable protection for years. Events which result in islanding and an activation of the UFLS schemes are extremely rare. Therefore, the SDT does not believe that changes to an existing UFLS scheme will be needed in less than 18 months. However, if a PC desires that changes to the UFLS scheme be made faster than that, then the PC may request the implementation to be done sooner than 18 months. The UFLS entity may oblige but will not be required to do so.

R7. Each Planning Coordinator shall provide the following information to SERC according to the schedule specified by SERC. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1. Underfrequency trip set points (Hz)

7.2. Total clearing time associated with each set point (sec). This includes the time from when frequency reaches the set point and ends when the breaker opens.

7.3. Amount of previous year actual or estimated load associated with each set point, both in percent and in MW. The percentage and the Load demand (MW) shall be based on the time coincident with the previous year actual Peak Demand.

M7. Each Planning Coordinator shall have evidence such as reports or other documentation that data specified in Requirement R7 was provided to SERC in accordance with the schedule.

The NERC standard requires that a UFLS database be maintained by the Planning Coordinator. This requirement specifies what data must be reported to SERC. A SERC UFLS database is needed to facilitate data sharing across the SERC Region, with other regions, and with NERC.

R8. Each Generator Owner shall provide the following information within 30 days of a request by SERC to facilitate post-event analysis of frequency disturbances. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1. Generator protection automatic underfrequency and overfrequency trip set points (Hz).

8.2. Total clearing time associated with each set point (sec). This is defined as the time that begins when frequency reaches the set point and ends when the breaker opens. If inverse time underfrequency relays are used, provide the total clearing time at 59.0, 58.5, 58.0, and 57.0 Hz.

8.3. Maximum generator net MW that could be tripped automatically due to an underfrequency or overfrequency condition.

M8. Each Generator Owner shall have evidence such as reports or other documentation that data specified in Requirement R8 was provided to SERC as requested.

The SDT believes that generator over and under frequency tripping data is needed to supplement the UFLS data provided by the Planning Coordinator for post-event analysis of frequency disturbances. This requirement states what data must be reported to SERC by the Generator Owners.

Since the inverse time curve cannot easily be placed into the SERC database, four clearing times based on data from the curve are requested. These clearing times are intended to cover a range of frequencies needed for event replication as well as provide information about generators that trip at a higher frequency than is allowed by the NERC standard.

Compliance

Compliance enforcement authority

SERC Reliability Corporation

Compliance monitoring and assessment process

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

Evidence retention

Each Planning Coordinator, UFLS Entity and Generator Owner shall keep data or evidence to show compliance as identified below unless directed by SERC to retain specific evidence for a longer period of time as part of an investigation.

Each Planning Coordinator, UFLS Entity and Generator Owner shall retain the current evidence of each Requirement and Measure as well as any evidence necessary to show compliance since the last compliance audit.

If a Planning Coordinator, UFLS Entity or Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the retention period specified above, whichever is longer.

The compliance enforcement authority shall keep the last audit records and all requested and submitted subsequent audit records.

Time Horizons, Violation Risk Factors, and Violation Severity Levels

Table 1						
R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Long-term Planning	Medium	N/A	N/A	N/A	The Planning Coordinator did not have evidence that its criteria included selection of its SERC subregion(s) as an island, with or without adjusted boundaries.
R2	Long-term Planning	Medium	The Planning Coordinator's scheme did not meet one of the UFLS system design requirements identified in 2.2 through 2.6	The Planning Coordinator's scheme did not meet two of the UFLS system design requirements identified in 2.2 through 2.6.	The Planning Coordinator's scheme did not meet three of the UFLS system design requirements identified in 2.2 through 2.6.	The Planning Coordinator's scheme did not meet 2.1 **OR** Four or more of the UFLS system design requirements identified in 2.2 through 2.6.
R3	Long-term Planning	High	N/A	The Planning Coordinator failed to conduct one of the required simulations of its UFLS scheme.	N/A	The Planning Coordinator failed to conduct two of the required simulations of its UFLS scheme.
R4	Operations Planning	Medium	The UFLS entity's implemented UFLS scheme had one load shedding step outside the range specified in 4. 2.	The UFLS entity's implemented UFLS scheme had two load shedding steps outside the range specified in 4. 2.	The UFLS entity's implemented UFLS scheme had three or more load shedding steps outside the range specified in 4.2.	The UFLS entity's implemented UFLS scheme had three or more load shedding steps outside the range specified in 4.2.

Table 1						
R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
					OR The UFLS entity's implemented UFLS scheme had a total load outside the range specified in 4.3.	**AND** The UFLS entity's implemented UFLS scheme had a total load outside the range specified in 4.3.
R5	Operations Planning	Medium	N/A	N/A	N/A	The UFLS entity's implemented UFLS scheme had a total load outside the range specified in 5.2.
R6	Long-term Planning	Medium	The UFLS entity implemented required scheme changes but made them 1 to 30 days after the scheduled date.	The UFLS entity implemented required scheme changes but made them 31 to 40 days after the scheduled date.	The UFLS entity implemented required scheme changes but made them 41 to 50 days after the scheduled date.	The UFLS entity implemented required scheme changes but made them more than 50 days after the scheduled date OR The UFLS entity failed to implement the required scheme changes.
R7	Long-term Planning	Lower	The Planning Coordinator provided the data required in R7 to SERC 1 to 10 days after the scheduled submittal date.	The Planning Coordinator provided the data required in R7 to SERC 11 to 20 days after the scheduled submittal date.	The Planning Coordinator provided the data required in R7 to SERC 21 to 30 days after the scheduled submittal date.	The Planning Coordinator provided the data required in R7 to SERC more than 30 days after the scheduled submittal date.

Table 1						
R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
				OR The Planning Coordinator did not provide to SERC one piece of information listed in R7.	**OR** The Planning Coordinator did not provide to SERC two pieces of information listed in R7.	**OR** The Planning Coordinator did not provide to SERC any of the information listed in R7.
R8	Long-term Planning	Lower	The Generator Owner provided the data required in R8 to SERC 1 to 10 days after the requested submittal date.	The Generator Owner provided the data required in R8 to SERC 11 to 20 days after the requested submittal date. **OR** The Generator Owner did not provide to SERC one piece of information listed in R8.	The Generator Owner provided the data required in R8 to SERC 21 to 30 days after the requested submittal date. **OR** The Generator Owner did not provide to SERC two pieces of information listed in R8.	The Generator Owner provided the data required in R8 to SERC more than 30 days after the requested submittal date. **OR** The Generator Owner did not provide to SERC any of the information listed in R8.

Administrative Procedure

Regional Variances

None

Interpretations

None

Guideline and Technical Basis

1. **Existing UFLS schemes**
   Each Planning Coordinator should consider the existing UFLS programs which are in place and should consider input from the UFLS entities in developing the UFLS scheme.

2. **Basis for SERC standard requirements**
   SERC Standard PRC-006-SERC-01 is not a stand-alone standard, but was written to be followed in conjunction with NERC Standard PRC-006-1. The primary focus of SERC Standard PRC-006-SERC-01 was to provide region-specific requirements for the implementation of the higher tier NERC standard requirements with the goals of a) adding clarity and b) providing for consistency and a coordinated UFLS scheme for the SERC region as a whole. Generally speaking, requirements already in the NERC standard were not repeated in the SERC standard. Therefore, both the NERC and SERC standards must be followed to ensure full compliance.

3. **Basis for applying a percentage load shedding value to Forecast Load versus Actual Load**
   The Planning Coordinator will develop a UFLS scheme to meet the performance requirements of NERC Standard PRC-006-1 Requirement R3 and SERC Standard PRC-006-SERC-01 Requirement R2. This development will result in certain percentages of load for each UFLS entity in the Planning Coordinator's area for which automatic under frequency load shedding must be implemented. The Planning Coordinator develops these percentages based on forecast peak load demand. However, the UFLS entity implements these percentages based on the previous year's actual peak demand. Applying the same percentage to these different base values was intentional to ensure that both the Planning Coordinator and UFLS entities had a clear, measurable value to use in performing their respective roles in meeting the standard. Planning Coordinators typically use forecast demands in their work. Whereas the previous year's actual (or estimated) demand is typically more available to UFLS entities. Additionally, the use of percentages based on these different base values tends to minimize the error due to the time lag between design and actual field implementation. Since a percentage is provided by the Planning Coordinator to the UFLS entities, any differences between the design values (i.e., forecast load) and the implemented values (i.e., previous year's actual) would naturally tend to match up reasonably well. For example, if the total planning area load in MW for which UFLS was installed during the time of implementation was slightly higher or lower than the MW value used in the design by the Planning Coordinator, multiplying by the specified percentage would result in an implemented load shedding scheme that also had a reasonably similar higher or lower MW value.

4. Basis for May 1 and 18 month time frames

Each UFLS entity must annually review that the amount of UFLS load shedding implemented is within a certain tolerance as specified by SERC Standard PRC-006-SERC-01 Requirement R4 or Requirement R5 by May 1 of the current year. May 1 was chosen to allow sufficient time after the previous year's peak occurred to make adjustments in the field to the implementation if necessary to meet the tolerances specified in Requirement R4 or Requirement R5. Therefore, the May 1 date applies only to implementation of the existing percentages of load shedding specified by the Planning Coordinator. On the other hand, the 18-month time frame specified in PRC-006-SERC-01 Requirement R6 is intended to allow sufficient budgeting, procurement, and installation time for additional equipment, or for significant setting changes to existing equipment necessary to meet a revised load shedding scheme design that has been specified by the Planning Coordinator. During this 18-month transition period, the May 1 measurement of R4 or Requirement R5 would not apply.

5. Basis for smaller entity threshold of 100 MW

Most distribution substations have transformers rated in the range of 10 to 40 MVA. Usually most transformers would serve 1 to 4 feeders and each feeder will normally carry between 8 and 10 MVA. In general, assuming that each feeder would carry 10 MW, an entity with a load slightly greater than 100 MW would have at least 10 feeders available. For a program with three 10 % steps, only 3 feeders would be required to have under frequency load shed capabilities. The 100 MW threshold seems to provide adequate flexibility for implementing load shedding in three steps for entities slightly greater than 100 MW.

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Subject:	SERC UFLS Standard Posted for Review by SERC Board of Directors
Date:	Thursday, September 01, 2011 1:47:41 PM

To SERC Board of Directors:

The proposed SERC Underfrequency Load Shedding (UFLS) regional standard (PRC-006-SERC-01) has been posted for a 15-day review period, as specified in Step 11 of the SERC Regional Reliability Standard Development Procedure (see below link). Approval of the standard is on the agenda for the SERC Board Executive Committee meeting on September 19, 2011.

UFLS Standard PRC-006-SERC-01

Background:
The standard received ballot pool approval on June 6, 2011. It has since been submitted for a NERC Quality Review and for a 45-day NERC comment posting on process issues, as required by the NERC procedure to approve a regional standard. The SERC UFLS Standard Drafting Team developed responses to both the Quality Review recommendations and the comments received at their meeting on August 25-26, 2011. The SERC Standards Committee approved those responses on August 31, 2011.

In addition to the standard, also posted are the SAR, Implementation Plan, Technical Rationale, VRF and VSL Justification, Comments and Responses, and other documents associated with development record and the draft request to NERC for approval of a regional standard (see below link).

UFLS Standard PRC-006-SERC-01: Associated Documents

This notice is being provided for you information.

Cc: SERC CIPC Representatives and Alternates
SERC EC Representatives and Alternates
SERC OC Representatives and Alternates
SERC Registered Ballot Body
SERC Registered Entity Contacts
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From:	Pat Huntley
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Subject:	Pre-Ballot Review and Ballot Pool Enrollment Period for Draft Revision of SERC Standard Procedure: September 1-16, 2011
Date:	Thursday, September 01, 2011 2:38:02 PM

To: SERC CIPC Representatives and Alternates
SERC EC Representatives and Alternates
SERC OC Representatives and Alternates
SERC Registered Entity Contacts
SERC Registered Ballot Body

Draft 3 of the proposed Revision-2 of the SERC Regional Standard Development Procedure of the has been posted for a 15-day pre-ballot review period (see below link). The procedure is Exhibit C to the Regional Entity Delegation Agreement between NERC and SERC.

http://www.serc1.org/Documents/SERC%20Standards%20Committee/SERC%20Draft%20Standards%20Posted%20for%20Pre-ballot%20Review/SERC%20Regional%20Stds%20Develoment%20Procedure_Rev%202_Draft-3/SERC%20DA%20Exhibit%20C%20-%20Reg%20Stds%20Dev%20Procedure_Draft-3%20Rev%202%20(08-31-11)%20Clean.pdf

The drafting team has agreed that the draft revision of the procedure is ready to be submitted to the SERC Registered Ballot Body for approval. The review period is September 1-16, 2011. Voting will begin shortly after the pre-ballot review closes. A separate notice with details on the ballot procedure will be issued to the Ballot Pool.

The Drafting Team has updated the draft procedure in response to comments received on Draft 2. Included in the posting are Clean and Redline (back to Draft 2) versions of the procedure and the Consideration of Comments on Draft 2. Information on previous comments postings and supporting documents are also posted on the website (see below link).

Revision 2 of SERC Regional Standards Development Procedure Table

The window for members of the SERC Registered Ballot Body (RBB) to join the ballot pool to be eligible to vote on the proposed Revision-2 of the SERC Regional Standard Development Procedure is open through the pre-ballot review period of September 1-16, 2011 (see below link to join the ballot pool).

Rev 2 of SERC Standards Procedure Ballot Pool Enrollment

Cc: SERC Standards Committee
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20110908-3000 FERC PDF (Unofficial) 09/08/2011

FEDERAL ENERGY REGULATORY COMMISSION NEWS

September 6, 2011

News Media Contact:
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FERC Announces 2012 Commission Open Meeting Schedule

Federal Energy Regulatory Commission Chairman Jon Wellinghoff has announced the schedule for the Commission's open meetings for calendar year 2012. Meetings will be on the third Thursday of every month. FERC does not meet in August.

The open meeting dates for calendar year 2012 are as follows:

January 19
February 16
March 15
April 19
May 17
June 21
July 19
September 20
October 18
November 15
December 20

The meetings, at FERC's headquarters at 888 First Street, N.E., in Washington, D.C., are open to the public consistent with the Government in the Sunshine Act.

R-11-36

(30)

20110908-3000 FERC PDF (Unofficial) 09/08/2011

Document Content(s)

2012 Commission meeting dates.DOC.....1-1

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

PRC-005-1 Key Reliability Standard Spot-Check

September 14, 2011

RELIABILITY | ACCOUNTABILITY

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Executive Summary

The Key Reliability Standards Spot Check (KRSSC) Program is designed to improve consistency of compliance auditing implementation by capturing a snapshot of the procedures and processes being used by the eight Regional Entities to audit registered entities for compliance to those Reliability Standards that, if violated, have the highest potential for having a major impact on the Bulk Power System (BPS). Emphasis is placed on selecting Reliability Standards that, in addition to having a high impact on the BPS, could have a direct and immediate impact on real-time operations and which have been effective for an audit cycle, in order to fairly evaluate this consistency of regional auditing practices. The Reliability Standard selected was PRC-005-1 "Transmission and Generation Protection System Maintenance and Testing."[1] PRC-005 -1 is applicable to a Transmission Owner (TO), Generator Owner (GO) and a Distribution Provider (DP).

The KRSSC Program examined a recent compliance audit of PRC-005-1 performed by each Regional Entity. The objective is to select compliance audits within a six month time period; however, for this review, one of the compliance audits selected fell outside the six month review criteria. This was due to the Regional Entity's compliance audit scheduling for the applicable functions required by PRC-005-1.

Since the program involved a review of a single audit by each Regional Entity, the results of the program are not appropriate for use to arrive at conclusions regarding regional auditing practices. However, this snapshot of audits of PRC-005-1 does provide insight into the issues facing compliance auditors in auditing PRC-005-1 and points out the variation in processes and procedures being used by the Regional Entities that may require additional guidance to improve performance and consistency.

The KRSSC Program objectives are to:

- Identify issues regional audit teams experience when evaluating compliance with the selected Reliability Standard.
- Identify areas in Regional Entity audit evaluations in which additional guidance may be needed to improve evaluation processes or to promote consistency in evaluations.

The review of the Regional Entities' audits and the follow-up teleconferences with the Regional Entities' compliance personnel revealed several areas where consistency of compliance auditing across all Regional Entities need to be addressed.

[1] http://www.nerc.com/files/PRC-005-1.pdf

The areas identified in which variation in auditing processes and procedures exists are as follows:

- Requiring evidence of testing prior to 6/18/2007 to confirm testing is being performed within currently stated intervals.
- Appropriately sizing sample sets to include all device types as described in the current FERC-approved Interpretation of Protection System Reliability Standard.[2]
- Requiring evidence of continuous monitoring of protection system elements.
- Accepting computerized files of test dates as evidence of testing.
- Verifying historical experience as basis for testing and maintenance intervals.
- Verifying basis for grace periods that are allowed beyond the defined testing and maintenance intervals.

These areas are discussed in detail in the KRSSC Program Results section below.

KRSSC Program Process

The KRSSC Program involves a review of the auditing processes and procedures for a single selected Reliability Standard in a recent audit performed by each of the Regional Entities. The Reliability Standard selected is one that has been identified as having a potentially high impact on the BPS.

Scope

This was the initial application of the KRSSC concept, and PRC-005-1 was selected as the Reliability Standard for review.

The audits selected covered a time span from October 2009 through May 2010. In seven of the selected compliance audits, the registered entities were registered for applicable functions of PRC-005-1 (TO, GO and DP). The eighth registered entity was registered for the TO and DP functions applicable to PRC-005-1 and was not registered as a GO.

Methodology

The KRSSC Program process for this review of the auditing of PRC-005-1 was as follows:

1. Select an audit recently performed by each Regional Entity that involved auditing the selected Reliability Standard. The compliance audits chosen for review was selected by NERC staff based upon the functions being audited that were applicable to PRC-005-1 and the audit having been recently completed.

[2] http://www.ferc.gov/whats-new/comm-meet/2010/121610/E-10.pdf

2. For each selected audit, the final audit report, completed Reliability Standard Audit Worksheets (RSAWs), and the Regional Entity's audit evidence files for the selected audit were requested from each Regional Entity to be transmitted to a secure NERC file storage. NERC staff performed a preliminary review of the evidence received from each Regional Entity and provided follow-up requests if data appeared to be incomplete.
3. Two NERC auditors worked as a team to access the use of tools, processes and procedures and indentify any issues of consistency across the Regional Entity's footprint.
4. A teleconference was held with each of the Regional Entities' compliance personnel to discuss any remaining questions regarding the compliance audit and allow each Regional Entity to provide additional input concerning issues related to consistency in auditing the selected Reliability Standard.
5. A report was developed to address areas needing improvement and to enhance consistency across all Regions. A summary report was provided that addressed issues related to consistency across all Regions.
6. Guidance will be developed, as needed, to enhance consistency across all Regions.

The NERC audit team's review of the Regional Entity audit did not include the following items:

- Exposure to the pre-audit review or discussions among the audit team members.
- Exposure to the on-site interviews and question and answers conducted by the audit team while on-site.
- Exposure to the discussions of the audit team during deliberations concerning audit evidence and interviews.
- Exposure to the audit team's post-audit drafting and comment periods of the final audit report.
- Review of the Exit Presentation made the audit team.

KRSSC Program Results

The intent of the initial pilot was to determine the level of consistency and identify issues faced by regional audit teams that may require additional guidance in the auditing of PRC-005-1. It was not the intent of the program to identify the minimum auditing approach acceptable for determining compliance or to determine the best practices for determining compliance with PRC-005-1.

The areas identified by NERC's audit team that need additional attention are discussed below.

1. **Requiring Evidence of Testing Prior to 6/18/2007 to Confirm Testing is Being Performed Within Stated Intervals:**

   The majority of the Regional Entities require registered entities to provide their last two test dates in order to verify that testing is being accomplished within intervals specified by the registered entity, regardless of whether or not one of the test dates occurred prior to 6/18/2007, the mandatory implementation date for PRC-005. Most of the Regional Entities also require evidence of testing when test dates prior to 6/18/2007 are required to be provided. Some of the Regions only require a test date to be provided as long as the stated testing interval seems "reasonable." The determination of what is a "reasonable" interval is typically based on the Regional Entity's experience in auditing PRC-005-1 or a NERC document, such as the draft of PRC-005-2.

   The NERC Compliance Application Notice (CAN-008-PRC-005-1) addresses is on point and states that Regional Entities may require evidence of testing prior to 6/18/07 in order to confirm that testing is being performed within stated intervals.3 CAN-008 will improve the consistency of auditing the maintenance and testing intervals across all Regions.

2. **Selecting or Expanding Sample Sets to Include All Device Types:**

   All of the Regions are using the Draft Sampling Methodology Guidelines and Criteria, which is currently undergoing field tests. However, the methodology has been used inconsistently; mainly due to unfamiliarity with the actual processes outlined in the document. The majority of the Regions follow the Primary/Dependent population criteria approach described for auditing PRC-005 in Appendix B of the Sampling Methodology Guidelines and Criteria, as well as the RAT-STATS statistical software or a haphazard selection process to select samples. This approach is designed to ensure an appropriate sample of each type of protection system element is in use (i.e. relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry). The core of the sample methodology is the RAT-STATS statistical audit tool used by the audit departments of numerous government agencies. This tool has been independently validated by statisticians. Upon final revision and approval, the Sample Methodology Guidelines and Criteria will be posted publicly.

   The majority of the Regions also supplement sampling by pulling additional samples to ensure all transmission voltage levels, looking at system areas where there are event-driven concerns, and looking also at both generation and transmission substations. Some Regions use a sampling methodology that draws a sample directly from the population of protection system elements identified for the system being audited.

[3] http://www.nerc.com/page.php?cid=3|22|354

This approach may result in a sample set that does not include all protection system elements (*i.e*., batteries, current transformers, potential transformer, direct current control circuits, *etc*.).

Revising the "Draft Sampling Methodology Guidelines and Criteria" document to require each type of protection system element to be included in the sample population (*i.e*., relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry) will achieve consistency across all Regional Entities in the selection of sample test items. The Compliance Monitoring Program Working Group (CMPWG) representatives unanimously agreed to include all protection system elements in their sample population, January 25, 2011. Compliance Managers from each of the Regional Entities comprise this working group

3. **Requiring Evidence of Continuous Monitoring of Protection System Elements:**

All the Regional Entities recognize continuous monitoring as a substitute for a stated maintenance and testing intervals and a basis for elements of protection systems if it is stated in the registered entity's program. When continuous monitoring is claimed as a reason for not identifying testing intervals, all Regional Entities verify that the Energy Management System, has a screen with which to display the status of the monitored device and a failure alarm. A few of the Regions verify with system operators that they have the capability to monitor the element (including a display and an alarm), and verify that the EMS monitoring and alarm system is also monitored for failure.

The NERC audit team recommends that all Regional Entities require evidence of alarming and continuous monitoring by an operator that can initiate corrective actions.

The draft of PRC-005-2, if adopted and approved by applicable governmental authorities as currently written, addresses elements of protection systems being continuously monitored and generally requires that the monitoring devices also be monitored. It further requires alarms to be automatically reported to a location where corrective action can be taken. PRC-005-2 will resolve inconsistency in application, however since it will take some time to reach the final regulatory approval stage, the NERC audit team recommends an interim solution a CAN be developed which will provide additional guidance to the Regional Entities and registered entities to address the evidence required to demonstrate compliance and enhance consistency across the Regions.

4. **Accepting Computerized Summary Files of Test Dates as Evidence of Testing:**

As the registered entities develop methods of tracking and storing the information required to demonstrate compliance, computerized files are becoming more prevalent as evidence submitted for audits. For PRC-005, computerized summary logs of test dates are a common item submitted. The files are useful to quickly review large quantities of data and as a starting point for selecting a sample of system protection elements for the audit.

The majority of the Regional Entities are using the computerized files in this manner, and after the audit sample is selected, the test dates in the computerized summary files are all verified against actual field test records. A few Regional Entities verify a small set of the audit sample against actual test records to determine whether to accept the computerized summary data set as evidence of compliance. In some cases, the computerized files of test dates are accepted as evidence without verification against field records. In this case, the entities' procedures must be understood and if the entities' process and systems have become "paperless," *i.e*. technicians enter data via electronic devices at the site of work; auditors must take this into account.

The NERC audit team recommends that all Regional Entities require actual test records as evidence of performance, and not just computerized summary printouts with device names and test dates. The NERC audit team recommends that the treatment of computerized files be addressed in the training program for compliance auditors as a part of the quality of evidence training.

5. <u>Verifying Historical Experience as Basis for Testing and Maintenance Intervals:</u>

When historical experience is claimed as a basis for testing and maintenance intervals by a registered entity, some Regions require evidence of the historical experience to verify the statement of the basis for the intervals. Some Regions accept the basis statement without verification as long as the intervals are considered "reasonable" as discussed in Program result 1 above.

The NERC audit team recommends that all Regional Entities require proof of analysis of these types of basis statements. As discussed in #3 above, approval of PRC-005-2 should eliminate the basis for intervals as an area of concern and enhance consistency in the determinations of whether intervals specified by the registered entities are proper.

In order to provide the appropriate guidance to the Regional Entities and registered entities in the interim, the NERC audit team recommends that a CAN be developed to address the evidence required to demonstrate compliance when historical experience, or a similar approach, is stated as the basis for maintenance and testing intervals. This item will also be addressed at ERO Compliance Auditor Workshops.

6. <u>Verifying Basis for Intervals Detailed within the Registered Entities' Defined Testing and Maintenance Plans:</u>

Many entities have developed testing and maintenance plans with some flexibility for interval. Some Regions accept the flexibility without a review of the basis statements, as long as the defined intervals plus the grace period are considered "reasonable." Some Regions require that the basis for any flexibility be separately stated and evidence provided for the basis, or the flexibility has to be included in the basis presented for the maintenance and testing intervals.

The NERC audit team recommends that all Regional Entities require evidence to justify any flexibility that extends beyond the justified intervals. Again, PRC-005-2 as currently written will eliminate the basis for flexibility as an area of concern and enhance consistency in determining whether intervals specified by the registered entities are proper. The NERC audit team recommends that a CAN be developed to address flexibility in testing and maintenance intervals must be specified in the registered entity's program, and therefore must have a basis which shall be verified by the audit team.

7. Miscellaneous Items to Facilitate Auditing, Enhance Consistency, and Improve Audit Records:

(a) Test records, whether performed by registered entity personnel or contractors are not uniform and are often difficult to interpret. Since this item was discovered, NERC revised the PRC-005-1 QRSAW[4] to include a notation requesting that each registered entity provide a sample annotated test record for each type of test record provided, with an explanation of what the test indicated and a definition of each relevant heading. This revision will aide in the registered entities' understanding of what is required for the Regional Entities' audit teams to perform a thorough and efficient evaluation of the records.

(b) All Regions state that they are retaining test records for the sample(s) audited; however, the specific elements sampled are not being identified by all Regions, and the associated test records may not be retained in the Regions' files in a manner that allows the audit to be quickly reviewed. The NERC audit team recommends that the Regions review their procedures for maintaining records of audits and consider changes that need to be made to facilitate reviews.

(c) Verifying whether DC control circuitry and/or associated communications are being tested as a part of functional testing of relays continues to be an area that requires the audit teams to routinely request the registered entities to provide additional information (*i.e.*, detailed relay diagrams, functional test procedures, *etc.*). The NERC audit team recommends this be added as a topic for discussion in auditor training and regional compliance meetings to clearly describe the type of information required to demonstrate compliance.

(d) PRC-005-1 R1.2 requires a "Summary of maintenance and testing procedures," which is generally understood to be a short, concise statement covering the important aspects of the maintenance and testing procedures, such as the system protection elements tested, elements continuously monitored, functional test performed, testing intervals and basis. In some cases, it appears the registered entities and the audit teams are searching for anything that could be called a summary, including detailed test procedures for different types of system protection elements. The NERC audit team recommends this be added as a topic for discussion at regional compliance meetings to clarify what evidence needs to be provided.

[4] http://www.nerc.com/page.php?cid=3|22

Conclusion

The outcome of the KRSSC program of PRC-005-1 identified six main areas of inconsistencies in the compliance audit application across the eight Regional Entities. The current draft of PRC-005-2, still under development will address the majority of the inconsistency issues. In the meantime, NERC will develop appropriate communications in the form of a CAN, bulletin or a revised QRSAW, as applicable, to address these differences. This will provide the proper guidance to the Regional Entities and the registered entities and provide transparency in compliance monitoring.
In addition to providing the results of the KRSSC program individually to each Regional Entity, NERC provided the Regional Entity compliance auditors the results of the KRSSC program of PRC-005-1 at the ERO workshop held February 24, 2011 and reinforced NERC's expectation in auditing practices going forward.

The results of the pilot evaluation of PRC-005-1 provide clear indicators of the value added by performance of the KRSSC Program. The KRSSC Program is a valuable tool in assessing and identifying consistency issues in the application of key Reliability Standards across the eight Regional Entities. Determination of where inconsistencies exist, allows NERC to provide the proper guidance to the Regional Entities and registered entities to improve the compliance monitoring process. This also allows NERC to further its goal of being a learning organization and maintaining transparency in the compliance monitoring process.

From: Stacia-Ann Chambers
To: Stacia-Ann Chambers
Subject: NERC: Key Reliability Standard Spot Check (KRSSC) Program Report Announcement
Date: Thursday, September 15, 2011 2:23:08 PM

Announcement

The Key Reliability Standard Spot Check (KRSSC) Program

September 15, 2011

Click Here for: KRSSC Report

(KRSSC) Program Report – The Key Reliability Standard Spot Check (KRSSC) Program Report is posted on the NERC website. The KRSSC program is designed to improve consistency of Regional Entities' compliance auditing implementation and practices. NERC Compliance Operation, Audit Assurance and Oversight selected Reliability Standard PRC-005-1 for its pilot program. The results of the pilot program are contained within the report.

For more information or assistance, please contact Jacki Power (via email).

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From: Guy V. Zito
To: rsc
Subject: Draft RSC 2012-2013 Workplan
Date: Friday, September 16, 2011 9:45:08 AM
Attachments: RSC_2012_13_Work_Plan--Redline_to_BOD_Approved_2-8-11_GVZ_9_16_11.docx

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RSC Members and All,

I received and incorporated the comments received on the subject attached document. Please review. I will be seeking your approval at the next RSC meeting for presentation to the NPCC BOD. Also, we have a revised RSC Scope that I would like considered for RSC approval at our October meeting.

Lee,

Please redistribute the latest redline scope document and ensure both appear on the agenda.

Thanks,

Guy V. Zito
Assistant Vice President-Standards
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The following Regional Standards Committee (RSC) activities planned for 2012~~1~~ -2013~~2~~ will be consistent with the NPCC 201~~1~~2 and 2013~~2~~ Business Plans and Budgets, ~~and~~ Organizational Goals, and also will continue to be supportive to the Results Based Standards ~~initiative put forward to the NERC BOT in response to concerns expressed in the NERC Performance Evaluation~~currently underway. Also, the plan will be responsive to the new NERC Reliability Standards Development Process, containing expedited schedules with rapid and successive revision and ballot provisions.

Core Reliability Standards Functions

- Review, ~~and~~ promote, and support the Results Based Standards initiative and ~~"proof of concept"~~continuation of standards developmental work going on within NERC.
- Promulgate the Results Based Standards initiative throughout the Northeast.
- ~~Develop~~ Finalize, refine and implement Cost~~/Benefit~~ Effective Analysis Procedure~~ess~~ and apply to NPCC regional standards development. Promote NERC consideration and adoption of NPCC Cost~~/Benefit~~ Effective Analysis Procedure~~ss~~.
- Develop and/or utilize NERC tools to incorporate the "Results Based" types of requirements into the NPCC Regional Standards under development.
- Review and participate in the Regional Standards development process, and develop NPCC Regional Reliability Standards on a schedule as directed by NERC and the reliability related needs of the Region.
- Coordinate NPCC Regional Standards development with the development of standards appearing in the NERC reliability standards development~~work~~ plan.
- Coordinate the NPCC participation in the review and the revision of the CIP standards per Order 706.
- Coordinate and support NERC's CEO top reliability related issues and priorities
- Coordinate the NPCC participation in the review and the revision of NERC Standards per Order 693 addressing Directives from the Commission and any Provincial Regulatory directives.
- Review and revise the Regional Reliability Standards Development Procedure for filing with the ~~revised Regional Delegation Agreement~~FERC, ~~if~~as may be necessary to promote consistency and support the ERO One Enterprise model, as necessary.
- Manage the Regional Reliability Standards development processes.
- Manage the development and revision of the Regional Reliability Directories
- Continue to ~~A~~assist the NPCC Compliance Committee by developing Phase 2 of the Directory Project involving revision of criteria language into requirements that are measureable and conducive to compliance assessments.
- Coordinate and provide input to the development and prioritization of ERO reliability standards within NERC reliability standards work plan.
- Conduct thorough reviews of all NERC standards being developed or revised and coordinate comments for Northeastern North America utilizing the NPCC Triage Process as necessary to ensure timely reviews.
- Ensure the NERC standards have measurable "Results Based" ~~draft~~ requirements.

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- Develop and submit Standard Authorization Requests for revisions when necessary to improve and address reliability related issues for approved or draft standards.~~after document review.~~
- Develop ballot recommendations or "issues statements" for all NERC standards under development.
- Review and develop ballot recommendations for all NERC Formal Interpretations to standards.
- Review posted Compliance Application Notices "CANs" and coordinate NPCC Member comments and submissions.
- Participate in NERC and NPCC Quality Reviews of standards on a schedule as determined by NERC, NPCC and government regulatory authorities.
- ~~Conduct training and p~~Provide guidance for NPCC regional standard drafting teams in critical areas of Results Based Standards, Violation Severity Level, and Violation Risk Factor development as well as in ensuring quality.
- Review of North American Energy Standards Board (NAESB) postings and activities for potential conflicts with reliability related issues and objectives.
- Review FERC Orders and Provincial rulings pertaining to standards and standards development activities to ensure directives are addressed.
- Participate in the regional standards development activities and processes in other regions within the Eastern Interconnection.
- Participate in the proceedings of various NERC groups to contribute to the continual improvement to NERC standards and processes. These groups include but are not limited to:
  - NERC Standards Committee
  - NERC Standards Committee Process Subcommittee
  - NERC Standards Committee Communications Subcommittee
  - NERC Functional Model Working Group
  - NERC Regional Standards Group
  - NERC SAR and Standards Drafting Teams

NERC ERO Reliability Standards Activities

Comment [gvz1]: This section is not finalized yet at the ERO. Once final, the results will be added in here.

The following Standards are scheduled for revision and or development in the "NERC Reliability Standards Development Plan : 2012~~1~~ – 2014~~3~~", and include the following Standards Projects. Note that some standards appear in more than one project due to potential retirement issues and potential division of requirements of that standard into multiple other standards and projects.

Standards Scheduled for 2012~~1~~-2014~~-~~3 include a total of 36 Projects of Continent-wide Standards with 17 as High Priority Projects Under Development:

- **Project 2006-02 Assess Transmission and Future Needs**
- **Project 2006-06 Reliability Coordination**
- **Project 2007-01 Underfrequency Load Shedding**

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- **Project 2007-02 Operating Personnel Communications Protocols**
- **Project 2007-03 Real-time Transmission Operations**
- **Project 2007-07 Vegetation Management**
- **Project 2007-09 Generator Verification**
- **Project 2007-12 Frequency Response**
- **Project 2007-17 Protection System Maintenance and Testing**
- **Project 2008-01 Voltage and Reactive Planning and Control**
- **Project 2008-06 Cyber Security — Order 706**
- **Project 2009-01 Disturbance and Sabotage Reporting**
- **Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities**
- **Project 2009-03 Emergency Operations**
- **Project 2010-10 FAC Order 729**
- **Project 2010-11 TPL Table 1 Order**
- **Project 2010-13 Relay Loadability Order**

Additional Priority Projects (near completion):

- **Project 2006-08 Transmission Loading Relief**
- **Project 2007-04 Certifying System Operators**

Additional Projects to be Initiated in Order of Priority:

- **Project 2010-05 Protection Systems**
- **Project 2010-07 Transmission Requirements at the Generator Interface**
- **Project 2007-11 Disturbance Monitoring**
- **Project 2007-06 System Protection Coordination**
- **Project 2010-14 Balancing Authority Reliability-based Control**
- **Project 2008-02 Undervoltage Load Shedding**
- **Project 2010-03 Modeling Data**
- **Project 2010-04 Demand Data**
- **Project 2010-02 Connecting New Facilities to the Grid**
- **Project 2008-12 Coordinate Interchange Standards**
- **Project 2010-08 Functional Model Glossary Revisions**
- **Project 2009-04 Phasor Measurements**
- **Project 2009-07 Reliability of Protection Systems**
- **Project 2010-01 Support Personnel Training**
- **Project 2012-02 Physical Protection**
- **Project 2009-05 Resource Adequacy Assessments**
- **Project 2012-01 Equipment Monitoring and Diagnostic Devices**

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NERC will also continue to coordinate standards development activities with the business practices developed by the North American Energy Standards Board (NAESB).

NPCC Regional Standard and Directory Activities and Requirements

- Develop the following regional standards and requirements utilizing the NPCC Regional Reliability Standards Development Procedure if necessary and directed by the ERO or as needed in response to the revision of the ERO standard(s);
  - Special Protection Systems standard
  - Regional Reserve Sharing standard

- NPCC ~~R~~regional Underfrequency Load Shedding Standard, complete development and once approved, compile historical documentation and submit to NERC BOT for approval
- Develop ~~submittal~~ any required responses to regulatory inquiry for NPCC Regional Disturbance Monitoring Standard and provide to FERC and the applicable Provincial regulatory authorities for their information or approvals, as may be required, i.e. data requests, filings to address directives etc.
- Develop the necessary regional standard filings with the FERC and applicable Provincial regulatory authorities for the NPCC Underfrequency Load Shedding Standard
- Address any outstanding issues with the regulatory authorities in the US and all applicable Provincial authorities for regional standards or NPCC Directories
- Draft Regional Standards Authorization Requests, RSARs
- Produce initial drafts of regional standards for Drafting Teams to start with
- Develop proposed standards utilizing regional technical committees as assigned by the NPCC RCC.
- Work with the NPCC CC to develop the necessary compliance elements of the standards, i.e. Violation Severity Levels
- Coordinate Directory criteria requirements with Regional Standards requirements to ensure no inconsistencies exist and identify potential areas for improvement
- Develop filing for the Directories for New York State Public Service Commission to fulfill obligations for the "Carveout" outlined in Order 672 of mandatory adherence to more stringent regional criteria for NY State
- Develop filings of Directories as required with the Provincial regulators per the various Memorandums of Understanding

RSC Ongoing Activities

- Implement technical aspects related to the implementation of the Energy Policy Act of 2005, focusing on Standards/Criteria Development, and related FERC and ERO requirements.
- Implement the NPCC CEAP and apply initially to the developing regional standards and investigate application to the draft ERO continent wide standards.

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- Review the Standards Authorization Requests, Standards, and Interpretations ~~-~~and provide comments as well as participate in the NERC process.
- Implement the NPCC Triage Process and ~~E~~ensure that the appropriate NPCC Task Forces review NERC issuances, and provide input to support a consensus opinion.
- Solicit technically qualified candidates from Northeastern North America to participate on each of the NERC drafting teams and additional members to the regional drafting teams and ensure sufficient regional representation exists on the drafting teams.
- Review ~~and develop comments on~~ FERC rulings and communicate the rulings to the NPCC members and coordinate issues for the Members.
- Participate in ballots for ERO standards and provide recommendations to the NPCC Members of the NERC Registered Ballot Body.
- Review and develop comments on FERC Notice of Proposed Rulemaking (NOPR) for any and all standards related issues as appropriate.
- Use the NPCC Triage Process to ~~E~~evaluate proposed standards utilizing regional technical committees, task forces and working groups.
- Educate and notify stakeholders and regulators about issues related to standards development.
- Provide a forum for NPCC review of proposed and posted documents from the NERC Critical Infrastructure Protection Committee (CIPC) and NPCC Task Force on Infrastructure Security and Technology (TFIST).
- Achieve NPCC reliability goals and objectives by initiating and efficiently completing standards development activities.
- Leverage internet and web based tool functionality to ensure interregional consistency, uniformity, and quality of regional reliability standards.
- Establish long-term strategy for standards improvement and initiate implementation.
- Ensure the topics addressed by the reliability standards parallel changing industry needs.
- Business Practices Interface
    - Coordinate the review of standards with NPCC members of the North American Energy Standards Board, details above.
    - Identify potential market issues for Regional Standards through NPCC Reliability Coordinating Committee (RCC) reviews.
- Process Improvement
    - Identify efficiencies for a coordinated NERC standards development process and NPCC Regional Standards Development Procedure and recommend revisions as applicable.
    - Participate in the revision and redrafting of the NERC rules and procedures related to standards development such as, but not limited to:
        - The NERC Functional Model Working Group
        - The NERC Regional Standards Group
        - The NERC Standards Committee
        - The NERC Standards Committee Process Subcommittee
    - Establish goals/targets for NERC and NPCC standards procedure improvement.
- Streamline and improve the regional standards process and continue to enhance program tools.
- Communications

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- Automate notifications process to assure awareness of dates and proceedings of all standard development activities.
- Strengthen the relationship with the industry's technical committees to ensure adequate input to standards development.
- Sponsor NPCC Workshops and participate in NERC/ERO workshops to promote awareness and educate the industry of standards related activities.
- Promote the reliability objectives of the NERC standards as appropriate to the NPCC members of the NERC Registered Ballot Body.
- Educate and inform industry stakeholders through web based tools such as "Webinars" and participation in NERC Reliability Standards Workshops, as necessary.
- Update and inform governmental regulators and/or authorities on the standards development work plan and processes through individual project discussions and annual meetings/conferences.
- Develop standards program communications that support NERC's overall communications platform.
- Develop and maintain NPCC Reliability Directories that will enable users, owners and operators of the international bulk power system in the Region the ability to apply reliability requirements in NERC and NPCC as well as the more stringent NPCC regionally-specific criteria.
- Identify future regional standard opportunities by developing a set of Regional Reliability Directories incorporating the ERO Reliability Standards, Regional Standards and regionally-specific more stringent Criteria.
- Accomplish all directives of ERO and governmental and/or regulatory authorities with regard to regional standards development and procedures.
- Adhere to and surpass the ERO work plan milestones, when practical, as they pertain to targets for the regional standards.

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The following Regional Standards Committee (RSC) activities planned for 2012~~1~~ -2013~~2~~ will be consistent with the NPCC 201~~1~~2 and 2013~~2~~ Business Plans and Budgets~~, and~~ Organizational Goals, and also will continue to be supportive ~~to~~ of the Results Based Standards efforts ~~initiative put forward to the NERC BOT in response to concerns expressed in the NERC Performance Evaluation~~currently underway. Also, the plan will be responsive to the new NERC Reliability Standards Development Process, containing expedited schedules with rapid and successive revision and ballot provisions.

Core Reliability Standards Functions

- Review~~, and~~ promote, and support the Results Based Standards initiative and ~~"proof of concept"~~continuation of standards developmental work going on within NERC.
- Promulgate the Results Based Standards initiative throughout the Northeast.
- ~~Develop~~ Refine, ~~F~~Finalize, ~~refine~~ and implement Cost~~/Benefit~~ Effective Analysis Procedure~~ess~~ and apply to NPCC regional standards development. Promote NERC consideration and adoption of NPCC Cost~~/Benefit~~ Effective Analysis Procedure~~ss~~.
- Develop and/or utilize NERC tools to incorporate the "Results Based" types of requirements into the NPCC Regional Standards under development.
- Review and participate in the Regional Standards development process, and develop NPCC Regional Reliability Standards on a schedule as directed by NERC and the reliability related needs of the Region.
- Coordinate NPCC Regional Standards development with the development of standards appearing in the NERC reliability standards development~~work~~ plan.
- Coordinate the NPCC participation in the review and the revision of the CIP standards per Order 706.
- Coordinate and support NERC's CEO top reliability related issues and priorities
- Coordinate the NPCC participation in the review and the revision of NERC Standards per Order 693 addressing Directives from the Commission and any Provincial Regulatory directives.
- Review and revise the Regional Reliability Standards Development Procedure for filing with the ~~revised Regional Delegation Agreement~~FERC, ~~if~~as may be necessary to promote consistency and support the ERO One Enterprise model~~, as necessary~~.
- Manage the Regional Reliability Standards development processes.
- Manage the development and revision of the Regional Reliability Directories
- Continue to ~~A~~assist the NPCC Compliance Committee by developing Phase 2 of the Directory Project involving revision of criteria language into requirements that are measureable and conducive to compliance assessments.
- Coordinate and provide input to the development and prioritization of ERO reliability standards within NERC reliability standards work plan.
- Conduct thorough reviews of all NERC standards being developed or revised and coordinate comments for Northeastern North America utilizing the NPCC Triage Process as necessary to ensure timely reviews.
- Ensure the NERC standards have measurable "Results Based" ~~draft~~ requirements.

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- Develop and submit Standard Authorization Requests for revisions when necessary to improve and address reliability related issues for approved or draft standards.~~after document review.~~
- Develop comments and ballot recommendations or "issues statements" for all NERC standards under development.
- Review and develop ballot recommendations for all NERC Formal Interpretations to standards.
- Review posted Compliance Application Notices "CANs" and coordinate NPCC Member comments and submissions.
- Participate in NERC and NPCC Quality Reviews of standards on a schedule as determined by NERC, NPCC and government regulatory authorities.
- ~~Conduct training and p~~Provide guidance for NPCC regional standard drafting teams in critical areas of Results Based Standards, Violation Severity Level, and Violation Risk Factor development as well as in ensuring quality.
- Review and monitor the NERC definition of Bulk Electric System with respect to existing standards and the impact on the northeast with assistance from the NPCC Task Forces to determine if any Regional Differences need to be initiated or revisions to Regional Standards.
- Review of North American Energy Standards Board (NAESB) postings and activities for potential conflicts with reliability related issues and objectives.
- Review FERC Orders and Provincial rulings pertaining to standards and standards development activities to ensure directives are addressed.
- Participate in the regional standards development activities and processes in other regions within the Eastern Interconnection.
- Participate in the proceedings of various NERC groups to contribute to the continual improvement to NERC standards and processes. These groups include but are not limited to:
  - NERC Standards Committee
  - NERC Standards Committee Process Subcommittee
  - NERC Standards Committee Communications Subcommittee
  - NERC Functional Model Working Group
  - NERC Regional Standards Group
  - NERC SAR and Standards Drafting Teams

NERC ERO Reliability Standards Activities

Comment [gvz1]: This section is not finalized yet at the ERO. Once final, the results will be added in here.

The following Standards are scheduled for revision and or development in the latest draft of the "NERC Reliability Standards Development Plan : 2012~~1~~ – 2014~~3~~", and include the following Standards Projects. NERC has recently undertaken a prioritization of the projects into three classes; Reliablity, Time Sensitivity, and Practicality and the below list is subject to change. Also ~~N~~ note that some standards appear in more than one project due to potential retirement issues and potential division of requirements of that standard into multiple other standards and projects.

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Standards Scheduled for 2012~~1~~-2014~~-~~3 development activity include a total of 36 Projects of Continent-wide Standards ~~with 17 as High Priority Projects Under~~ Development:

- **2006-06 Reliability Coordination. This project ranked #13 in Reliability Priority.**
- **2007-02 Operating Personnel Communication Protocols. This project ranked #5 in Reliability Priority.**
- **2007-03 Real-time Transmission Operations. This project ranked #4 in Practicality Priority.**
- **2007-06 Protection System Coordination. This project ranked #4 in Reliability Priority.**
- **2007-07 Vegetation Management.**
- **2007-09 Generator Verification.**
- **2007-12 Frequency Response. This project ranked #10 in Reliability Priority, and was tied for #2 in Time Sensitivity Priority.**
- **2007-17 Protection System Maintenance and Testing. This project ranked #3 in Reliability Priority.**
- **2008-06 Cyber Security - Order 706. This project ranked #1 in Reliability Priority.**
- **2009-01 Disturbance and Sabotage Reporting. This project ranked #7 in Reliability Priority.**
- **2010-05.1 Phase 1 of Protection Systems: Misoperations. This project ranked #8 in Reliability Priority.**
- **2010-07 Generator Requirements at the Transmission Interface. This project ranked #13 in Practicality Priority, and was tied for #2 in Time Sensitivity Priority.**
- **2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves. This project ranked #1 in Time Sensitivity Priority, and #2 in Practicality Priority.**
- **2010-17 Definition of Bulk Electric System. This project ranked #10 in Reliability Priority, and was tied for #2 in Time Sensitivity Priority.**
- **2008-02 Undervoltage Load Shedding. This project ranked #14 in Reliability Priority, and will be started upon the completion of 2006-06 Reliability Coordination.**

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- 2009-02 Real-time Monitoring and Analysis Capabilities. This project ranked #1 in Practicality Priority, and will be started started upon the completion of 2007-03 Real-time Transmission Operations.
- 2009-03 Emergency Operations. This project ranked #3 in Practicality Priority, and will be started upon the completion of 2008-06 Cyber Security – Order 706.
- 2010-01 Support Personnel Training. This project ranked #15 in Reliability Priority, and will be started upon the completion of 2009-01 Disturbance and Sabotage Reporting.
- 2010-05.2 Phase 2 of Protection Systems: SPS and RAS. This project ranked #11 in Reliability Priority, and will be started upon the completion of the first phase of the project, 2010-05.1 Phase 1 of Protection Systems: Misoperations.
- 2010-13.2 Phase 2 of Relay Loadability: Generation. This project has been identified as having a higher priority, as it has a FERC deadline. While this was accounted for in the Prioritization, the SC agreed that this should take precedence over the 5-year review projects considered in the Prioritization. This project will be started upon the completion of 2007-12 Frequency Response.
- 2012-04 Protection System Commissioning Testing. This project ranked #9 in Reliability Priority, and will be started upon the completion of 2007-17 Protection System Maintenance and Testing
- 2007-11 Disturbance Monitoring. This project will start upon completion of 2010-17 Definition of Bulk Electric System.
- 2008-01 Voltage and Reactive Panning and Control. This project ranked #6 in practicality, and will start upon completion of 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves
- 2008-12 Coordinate Interchange Standards. This project will start upon completion of 2010-07 Generator Requirements at the Transmission Interface.
- 2009-07 Reliability of Protection Systems. This project ranked #2 in Reliability Priority, and will start upon completion of 2007-06 Protection System Coordination.
- 2010-14.2 Project 2010-14.2 Phase 2 of Balancing Authority Reliability-based Control: Time Error, AGC, and Inadvertent. This project will start upon completion of 2009-02 Real-time Monitoring and Analysis Capabilities.
- 2012-01 Equipment Monitoring and Diagnostic Devices. This project will start upon completion of 2007-02 Operating Personnel Communication Protocols.
- 2012-06 Generator Capabilities, This project ranked #6 in Reliability Priority,

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and will start upon completion of both 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves and 2007-09 Generator Verification.

- 2009-04 Phasor Measurements. This project will start upon completion of 2009-03 Emergency Operations.
- 2009-05 Resource Adequacy Assessments. This project will start upon completion of 2012-04 Protection System Commissioning Testing.
- 2010-03 Modeling Data. This project will start upon completion of 2008-01 Voltage and Reactive Panning and Control.
- 2010-04 Demand Data. This project will start upon completion of 2010-05.2 Phase 2 of Protection Systems: SPS and RAS.
- 2010-08 Functional Glossary Model Revisions. This project will start upon completion of 2010-01 Support Personnel Training.
- 2010-13.3 Phase 3 of Relay Loadability: Stable Power Swings. This project will start upon completion of the second phase of this project, 2010-13.2 Phase 2 of Relay Loadability: Generation.
- 2010-16 Definition of System Operator. This project will start upon completion of 2012-04 Protection System Commissioning Testing.
- 2012-05 ATC Revisions - Order 729. This project will start upon completion of 2008-12 Coordinate Interchange Standards.

In addition there another 12 projects in the latest draft of the NERC Reliablity Standards Development Plan scheduled to start beyond 2013, some of which have not been prioritized and may affect the list above. The total number of standards projects currently listed in NERC's is 48.

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- ~~Project 2006-02 Assess Transmission and Future Needs~~
- ~~Project 2006-06 Reliability Coordination~~
- ~~Project 2007-01 Underfrequency Load Shedding~~
- ~~Project 2007-02 Operating Personnel Communications Protocols~~
- ~~Project 2007-03 Real-time Transmission Operations~~
- ~~Project 2007-07 Vegetation Management~~
- ~~Project 2007-09 Generator Verification~~
- ~~Project 2007-12 Frequency Response~~
- ~~Project 2007-17 Protection System Maintenance and Testing~~
- ~~Project 2008-01 Voltage and Reactive Planning and Control~~
- ~~Project 2008-06 Cyber Security — Order 706~~

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- ~~Project 2009-01 Disturbance and Sabotage Reporting~~
- ~~Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities~~
- ~~Project 2009-03 Emergency Operations~~
- ~~Project 2010-10 FAC Order 729~~
- ~~Project 2010-11 TPL Table 1 Order~~
- ~~Project 2010-13 Relay Loadability Order~~

Additional Priority Projects (near completion):

- **Project 2006-08 Transmission Loading Relief**
- **Project 2007-04 Certifying System Operators**
- **Project 2010-17 Definition of Bulk Electric System and conforming changes to NERC Rules of Procedure**
- **PRC-002-NPCC ~~[currently before FERC, but what if it comes back with FERC directive for changes?]~~NPCC UFLS Regional Standard**

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~~**Additional Projects to be Initiated in Order of Priority:**~~

- ~~Project 2010-05 Protection Systems~~
- ~~Project 2010-07 Transmission Requirements at the Generator Interface~~
- ~~Project 2007-11 Disturbance Monitoring~~
- ~~Project 2007-06 System Protection Coordination~~
- ~~Project 2010-14 Balancing Authority Reliability-based Control~~
- ~~Project 2008-02 Undervoltage Load Shedding~~
- ~~Project 2010-03 Modeling Data~~
- ~~Project 2010-04 Demand Data~~
- ~~Project 2010-02 Connecting New Facilities to the Grid~~
- ~~Project 2008-12 Coordinate Interchange Standards~~
- ~~Project 2010-08 Functional Model Glossary Revisions~~
- ~~Project 2009-04 Phasor Measurements~~
- ~~Project 2009-07 Reliability of Protection Systems~~
- ~~Project 2010-01 Support Personnel Training~~
- ~~Project 2012-02 Physical Protection~~
- ~~Project 2009-05 Resource Adequacy Assessments~~
- ~~Project 2012-01 Equipment Monitoring and Diagnostic Devices~~

NERC will also continue to coordinate standards development activities with the business practices developed by the North American Energy Standards Board (NAESB).

NPCC Regional Standard and Directory Activities and Requirements

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- Develop the following regional standards and requirements utilizing the NPCC Regional Reliability Standards Development Procedure if necessary and directed by the ERO or as needed in response to the revision of the ERO standard(s);
    - Special Protection Systems standard
    - Regional Reserve Sharing standard

- NPCC ~~R~~regional Underfrequency Load Shedding Standard, complete development and once approved, compile historical documentation and submit to NERC BOT for approval
- Develop ~~submittal~~ any required responses to regulatory inquiry for NPCC Regional Disturbance Monitoring Standard and provide to FERC and the applicable Provincial regulatory authorities for their information or approvals, as may be required, i.e. data requests, filings to address directives etc.
- Develop the necessary regional standard filings with the FERC and applicable Provincial regulatory authorities for the NPCC Underfrequency Load Shedding Standard
- Address any outstanding issues with the regulatory authorities in the US and all applicable Provincial authorities for regional standards or NPCC Directories
- Draft Regional Standards Authorization Requests, RSARs
- Produce initial drafts of regional standards for Drafting Teams to start with
- Develop proposed standards utilizing regional technical committees as assigned by the NPCC RCC.
- Work with the NPCC CC to develop the necessary compliance elements of the standards, i.e. Violation Severity Levels
- Coordinate Directory criteria requirements with Regional Standards requirements to ensure no inconsistencies exist and identify potential areas for improvement
- Develop filing for the Directories for New York State Public Service Commission to fulfill obligations for the "Carve-out" outlined in Order 672 of mandatory adherence to more stringent regional criteria for NY State
- Develop filings of Directories as required with the Provincial regulators per the various Memorandums of Understanding

RSC Ongoing Activities

- Implement technical aspects related to the implementation of the Energy Policy Act of 2005, focusing on Standards/Criteria Development, and related FERC and ERO requirements.
- Implement the NPCC CEAP and apply initially to the developing regional standards and investigate application to the draft ERO continent wide standards.
- Review the Standards Authorization Requests, Standards, and Interpretations and provide comments as well as participate in the NERC process.
- Implement the NPCC Triage Process and ~~E~~ensure that the appropriate NPCC Task Forces review NERC issuances, and provide input to support a consensus opinion.
- Solicit technically qualified candidates from Northeastern North America to participate on each of the NERC drafting teams and additional members to the regional drafting teams and ensure sufficient

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regional representation exists on the drafting teams.

- Review ~~and develop comments on~~ FERC rulings and communicate the rulings to the NPCC members and coordinate issues for the Members.
- Participate in ballots for ERO standards and provide recommended comments and ballot positions~~ations~~ to the NPCC Members of the NERC Registered Ballot Body.
- Review and develop comments on FERC Notice of Proposed Rulemaking (NOPR) for any and all ~~standards~~ standards-related issues as appropriate.
- Use the NPCC Triage Process to ~~E~~evaluate proposed standards utilizing regional technical committees, task forces and working groups.
- Educate and notify stakeholders and regulators about issues related to standards development.
- Provide a forum for NPCC review of proposed and posted documents from the NERC Critical Infrastructure Protection Committee (CIPC) and NPCC Task Force on Infrastructure Security and Technology (TFIST).
- Achieve NPCC reliability goals and objectives by initiating and efficiently completing standards development activities.
- Leverage internet and web based tool functionality to ensure interregional consistency, uniformity, and quality of regional reliability standards.
- Establish long-term strategy for standards improvement and initiate implementation.
- Ensure the topics addressed by the reliability standards parallel changing industry needs.
- Business Practices Interface
    - Coordinate the review of standards with NPCC members of the North American Energy Standards Board, details above.
    - Identify potential market issues for Regional Standards through NPCC Reliability Coordinating Committee (RCC) reviews.
- Process Improvement
    - Identify efficiencies for a coordinated NERC standards development process and NPCC Regional Standards Development Procedure and recommend revisions as applicable.
    - Participate in the revision and redrafting of the NERC rules and procedures related to standards development such as, but not limited to:
        - The NERC Functional Model Working Group
        - The NERC Regional Standards Group
        - The NERC Standards Committee
        - The NERC Standards Committee Process Subcommittee
    - Establish goals/targets for NERC and NPCC standards procedure improvement.
- Streamline and improve the regional standards process and continue to enhance program tools.

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- Communications
    - Automate notifications process to assure awareness of dates and proceedings of all standard development activities.
    - Strengthen the relationship with the industry's technical committees to ensure adequate input to standards development.
    - Sponsor NPCC Workshops and participate in NERC/ERO workshops to promote awareness

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and educate the industry of standards–related activities.

- Promote the reliability objectives of the NERC standards as appropriate to the NPCC members of the NERC Registered Ballot Body.
- Educate and inform industry stakeholders through web based tools such as "Webinars" and participation in NERC Reliability Standards Workshops, as necessary.
- Update and inform governmental regulators and/or authorities on the standards development work plan and processes through individual project discussions and annual meetings/conferences.
- Develop standards program communications that support NERC's overall communications platform.
- Develop and maintain NPCC Reliability Directories that will enable users, owners and operators of the international bulk power system in the Region the ability to apply reliability requirements in NERC and NPCC as well as the more stringent NPCC regionally-specific criteria.
- Identify future regional standard opportunities by developing a set of Regional Reliability Directories incorporating the ERO Reliability Standards, Regional Standards and regionally-specific more stringent Criteria.
- Accomplish all directives of ERO and governmental and/or regulatory authorities with regard to regional standards development and procedures.
- Adhere to and surpass the ERO work plan milestones, when practical, as they pertain to targets for the regional standards.

From: Brian Hogue
To: grpStaff
Subject: CIPC notes
Date: Saturday, September 17, 2011 4:40:47 PM

Agenda in light blue. Notes in black. Interesting notes in red. Ask if you have questions.

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Critical Infrastructure Protection Committee

September 14, 2011 | 1:00 – 5:00 p.m. (CDT)
September 15, 2011 | 8:00 a.m. – Noon (CDT)
Sheraton St. Louis City Center Hotel & Suites
400 South 14th Street
St. Louis, MO 63103

Administrative
- a. Welcome and Introductions — Chair Barry Lawson
- b. Arrangements — Secretary Scott Mix
- c. Parliamentary Procedures — Scott Mix
- d. Announcement of Alternates and Quorum — Scott Mix
- e. NERC Antitrust Compliance Guidelines and Public Announcement — Scott Mix

Consent Agenda
1. Minutes*
- APPROVE minutes of June 8, 2011

Regular Agenda
2. CIPC Chair Report — Barry Lawson
   - High level review of agenda
   - DC legislative update
     - Trade Associations working closely
     - At today's hearing, all FERC Commissioners said that cyber security is the #1 issue
     - a. Board of Trustees highlights
       - August 4
         - Refreshing Guidelines
         - CATF progressing on schedule but a heavy lift
     - b. Executive Committee activities
       - July 26 conference call
         - Jeff Mitchell (PC Chair) brought up the idea of 3 annual meetings instead of 4
         - Also discussed lengthening CIPC meetings
         - December 2011 CIPC includes a cleared briefing
     - c. Standing Committee Coordinating Group activities
3. Elections of CIPC Chair and Vice Chairs* — Robert McClanahan
   - a. Review of CIPC officer election process
     - Region – expertise – US/Canada
     - 6 nominations
     - Terms start January 1, 2012
     - Slate of Executive Committee will be presented at December 2011 CIPC

b. Presentation of candidates
Chuck Abell, Ameren as chair
Cyber – IOU – SERC
Jim Brenton as vice-chair
Cyber – ERCOT –
Nathan Mitchell as vice-chair
c. VOTE and election
Chuck Abell unanimously elected
Jim and Nathan unanimously elected

4. NERC/ES-ISAC Updates — Mark Weatherford and NERC Staff
a. NERC/CSO update (Mark Weatherford)
Bob Canada now works for NERC CIP
formerly Southern physical security and CIPC vice-chair
will report to Brian Harrell
Sufficiency Reviews going well
Even though Ralph Anderson out on medical
Cyber Risk Preparedness Assessment
2012 Critical Infrastructure Department Strategic Plan
What does ES cyber security look like in 5 or 10 years
More interaction with industry CSO's
Enterprise cyber security training
Partnership for Critical Infrastructure Security (PCIS)
Mark is vice-chair
Cross Sector Supply Chain Risk Management WG
Communications & Outreach WG
Infrastructure Protection Threat Information Sharing WG
Presidential Policy Directive 8 WG
Homeland Security Directive 7 WG
Potential CIPC Projects
Support ECSS WG – Roadmap to Achieve Energy Delivery System Cybersecurity
ESCC endorsed in February 2011
ES Personnel Security Clearances
DHS more cooperative
Jim Caverly – not all companies need clearance, some might need 10
Security Metrics
Proposes a new CIPC WG
b. Electricity Sub-Sector Coordinating Council and PCIS update
c. ISAC update (Tim Roxey)
New ES-ISAC web site
Sit between ICS-CERT, US-CERT and
federal government (CIA, FBI, etc) as conduit to/from industry
participating in daily interISAC briefings
October – November is the next Aurora reporting time frame
Socializing public-private partnership
d. Alerts update (Tim Roxey)
August 24 - Remote Access Guidance
Real teeth will be in Version 5 Standards
August 2 – Programmable Logic Controller Protocol Weakness
August 2 – Telephony Enabled Weakness
Pending – ES Targeted Attacks Observed
Will include instructions on getting additional instructions from

ICS-CERT

IBM researcher working on ICCP vulnerabilities whitepaper

Due October

International standard driven by vendors

Will be driven into one of the previously mentioned public-private partnerships

Multi-year upgrade

Probably one or more future Alerts

e. Cyber Security Standards update (Scott Mix)

Version 4 on tomorrow's FERC agenda

i. CSO706 – "Version 5"

Will be balloted separately

Private discussion yielded that NERC will continue balloting until the package passes so that the package is forwarded to FERC

Nearly complete with technical development

Final technical issues meeting on September 20

Quality Review in October

Post for 45 day comment and concurrent ballot

November 3 – December 19

Webinars during posting but prior to ballot

Expect successive/recirculation in first half of 2012

File with regulators in 3Q2012

New/Modified Terms (some may not make final version)

CIP Exceptional Circumstances

Cyber Assets

BES Cyber Assets

BES Cyber System

Control Center

...

CIP002 – CIP011

010 – Configuration Management and Vulnerability Assessment

011 – Information Protection

CIP-002

Built on CIP-002-4 bright lines

Version 4 Control Centers – high

Other Version 4 CA – medium

Version 4 non-critical CC – medium

Transmission looking at capacity instead of # of lines at voltage level

Catch-all category – low

Non-jurisdictional are off the table (distribution, marketing, business, etc)

New format

Following results-based Standards format

Requirements and Measurements side-by-side

Rationale – still a work-in-progress

Still determining final format – posted may be different than filed

Applicability

Consistent terminology

Examples

Connectivity
No longer a blanket exception
Listed in applicability section
Routable protocol applies in high volume, real-time comm Req
Low impact
"programmatic" controls – have a program
Intent not to list every low impact BES Cyber System
MRO asked if the auditors will audit to the new Standards
Mark offered to work/train the auditors towards this objective
TFEs
Attempted to minimize
But cannot eliminate
Implementation Plan
Multi-phased
Still under discussion

ii. Interpretation Team
Steve Noess (NERC) is the NERC facilitator
Also facilitates the Version 5 SDT
Working on
CIP-006-1 (Progress Energy) wiring
CIP-004-1 (WECC) authorized access
CIP-002-1 (Duke Energy) essential
Others in pipeline

f. GridSecCon (Brian Harrell)
October 19-20 in New Orleans
Speakers include White House, DHS and ? (in the room)
Topics include
Stuxnet
...
ES-ISAC
Access control
October 18 is two concurrent workshops – INL (which is full) and SANS (costs)
Need more attendees

g. GridEx (Brian Harrell)
November 16-17
Desktop exercise
What – geographically distributed event
Who – NERC, Entities, Regions and select government agencies
...
Objectives
Timeline
Started in April
Core development team created the scenario
Same contractor as Cyber Storm (Booz, Allen & Hamiltion)
Resources
26 organizations supplying at one full time expert
Observers – some Entities are resource constrained, but want to observe
Still accepting for participants and observers

h. Sufficiency reviews (Brian Harrell)
    - Not an audit or part of compliance
    - Learning/training event
    - Timeline off because Ralph Anderson (NERC) is sick
    - Designed to increase BPS security and reliability
    - Voluntary
    - Accepting volunteers for 2012

5. FBI Briefing (Jeff Morgan)
    - US ES faces high cyber exploitation threat, low cyber attack threat
    - ES is BES and distribution
    - FBI's highest priority is cyber crime
    - Cyber exploitation – not destructive
    - Cyber attack – destructive
    - Cyber threat groups
        - Foreign states
        - Terrorist
        - Criminal
        - Hacker
        - Hacktivist
        - Insider
    - Considerations
        - Social engineering
        - Publicly available information
        - System design
        - HR Policies
        - Network security requires dedicated auditing resources
        - Identify networks impacted
        - Maintain institutional knowledgebase for contingency operations
        - Circumstances impact intent
        - If it ain;t broke, fix it anyway
6. DOE/NIST/NERC Risk Management Framework — Brian Harrell and Matt Light (DOE) and Summer Esquerre (NextEra)
    - Voluntary guideline
    - Shows Congress that cyber security is important
    - Need industry feedback
    - Dave Norton (FERC) concerned that ICS is always mentioned with IT
        - so people will conclude that ICS is an IT issue
7. Coordinated Action Plan Task Force Reports — Stuart Brindley
    - Overview
    - Reviewed history
    - Timeline goes beyond 2012 for some groups
        - Geomagnetic Disturbance
            - Full technical vetting regarding transformer impact assessment
            - Continued government funding of observational satellites
        - Cyber Attack
        - Severe Impact Resilience
        - Spare Equipment DB
            - Voluntary versus mandatory
        - Other Initiatives

a. CATF — Mark Engels
    - 70+ members/observers
    - Working on the assigned scenario which is one of four
        - Across multiple Regions

Transmission & distribution
Affects communications
Reviewed history
Send report to CIPC for 45 day review
Outline
Executive Overview
Potential adversaries
Details are classified but this report is not
Analysis
Attack Trees
Detection Capabilities
Defensive Capabilities
Responses to Attacks
Recommendations
References and Appendices

8. CIPC Working Group / Task Force Updates — Barry Lawson
   a. CSSWG — Mark Engels
      Cyber Attack TF taken precedence
      Would like to finish the Patch Management Guideline because it has changes
   b. Substations Guideline Task Force — John Breckenridge
      Combined 2007 PS guideline and 2004 PS – Substation Guideline
      Removed redundancies
      where possible changed “substation” to “site/asset”
      created 4 general areas of focus
      created specific section for each area
      removed “security/asset matrix”
      struggling with “critical”
      high level documents with links
   c. Protecting Sensitive Information Guideline Task Force — Nathan Mitchell (APPA)
      In 30 day CIPC comment period – starting next Monday
      Outline
      Definition of sensitive information
      Identifying sensitive information
      Classification
      Labeling
      Security
      How to respond to requests
      Responding to inadvertent or unauthorized
      Disclosures
      …
      Timetable
      October/November – update based on comments
      December CIPC – submit for 45 day comment period
      May request electronic approval
      No NPCC Members
   d. Business Continuity Guideline Task Force* — Darren Myers
      History
      Combined Business Continuity Guideline and Business
      Operations Continuity Guideline
      Recommendation to use voluntary Private Sector Preparedness
      Accreditation

and Certification Program (PS-Prep)
Comments
7 comments
Why is NPCC not listed?
Common theme – concerned that it could become a Standard
DT rejected because supposed to use Standards Development process
Motion to approve
Stuart Brindley and chair spoke in favor this approach

i. APPROVE Guideline*

Unanimously approved

e. Updates to Physical and Electronic Response Guidelines based on DHS NTAS updates

Barry Lawson
Were set up to match the DHS color coding system – which no longer exists
EC will determine what to do with these two Guidelines

f. Spare Equipment Database Task Force* — Mark Lauby

Belongs to OC
Already approved by OC and PC
Voluntary
strict confidentiality
Dave Batz - EEI appreciates the opportunity to work with NERC
Not a replacement for existing agreements
Not a shopping list to run a system under spared
Not a mandatory mechanism when things go bad
EEI supports this initiative
Does not share information with EEI's Step Program
Michael Mertz (MRO) – Canadians enthusiastic on this initiative
Mark Lauby
after endorsement will be sent to ESCC and BOD for approval
implementation starts 1Q2012

i. APPROVE Report – unanimously approved

9. DSR Standards Drafting Team (Project 2009-01) Update — Scott Mix

With Bob Canada's retirement, vice-chair Brian Evans-Mongeon is chair
Meeting at FERC to address FERC's concern
Coordination with CIP-008
Retiring CIP-008-(4) R1.3
CIP-008 defines what to report
EOP-004-2 defines how to report
Meetings with DOE regarding OE-417 reporting
Quality Review complete
Waiting on EAWG October posting
Drafting RoP changes

10. Adequate Level of Reliability Task Force (ALRTF) Report – Kent Kujala (RFC?)

History
June 30 kick off conference call
July 27-28 first meeting (Atlanta)
Discussed boundaries of BES reliability
August 23-24 (Denver)
Further developed reliability objectives and associated attributes
Tentative agreement on reliability objectives
CIPC specific discussion

Tentative directions discussed not yet concluded

Future

October 4-5 (Chicago)

Starting drafting definitions and supporting technical documents

Develop reliability principles and metrics

One more in 2011

2 more in 1Q2012

Schedule

Present initial finding at December meetings

Present final report at March 2012 meetings

Present final report to BOT in May 2012

11. Washington, DC Legislative Activities Update — Dave Batz, EEI

Slide on Digistar

COMMENT – why?

Questions security of internet and cloud computing

Looking like multi-sector

DHS – critical designation

Risk assessment framework

coordination with existing regulating bodies (TBD)

publication of high level summary …

continued negotiations between Senate committees

Administration and Senate leadership prefer multi-sector approach

Rule 14 from Senate Majority Leader

Bipartisan issue

Timing

Focus on Debt – Money – Spending

House floated a TF on Cyber Security chaired by Mac Thornberry (R – Tx)

Incentives for Critical Infrastructure information sharing

Updating cyber crime laws

Public-private partnership

Senator Schumer – utilities need FBI to run background checks thanks to a DHS report

Irresponsible speculation

no bill in 2011

we are 14 days away – after a big cyber event

12. Round-table Discussion*

a. Changing OC/PC/CIPC meetings from 4 to 3 times per year and from 1 day to 1.5 or 2 days

Rob (MRO) supports because of the two travel days for each meeting

Kent Kujala (RFC?) sees more work so three meeting means longer meetings

David Godfrey (APPA) supports 3 meetings

Jim Brenton (ERCOT) supports 4 meeting because of more work coming and cleared briefings

Rob McClanahan (SPP?) conflicting comments - does not want external people to perceive less commitment, someone else can determine how long meetings should, supports more training opportunities like yesterday's Improvised Explosive Devices

Barry Lawson (NRECA and chair) how should he take the silence?

Larry Bugh (RFC) coming work like CIPv5 is a lot more, supports 4 meetings and stay aligned with other Standing Commitees, supports 1.5 day meetings

David Grubbs (TRE?) agrees with Rob and Larry, supports longer

meetings
Rick Lilligren (MRO?) thinks we schedule more effectively with training and joint sessions in mind
Darren Myers (FRCC?) how do we plan to address physical in addition to all of the cyber discussions?
Mark Weatherford (NERC CSO) need to provide value, interested in more training, is flexible can go either way
John Breckenridge () sometimes the 1 PM starts allows morning travel
Dave Norton (FERC) personal comment – you can probably convince FERC of anything. Just don't use cost as the reason. David Godfrey (APPA) responds that cost is a factor for the rate payers.

13. CIPC Strategic Plan Discussion* — Barry Lawson
14. Blast Protection for Power Transformers Project – Braden Lusk (University of Kentucky)
    Expert in Blast Protection
    Objective – focuses on improving critical infrastructure reliability
    Three solutions
    This project focuses on protection
    Looked at 4 substations – two in Kentucky and two large sites
    Type I and II charges considered
    Delivery – pedestrian or vehicle
    Testing
        weakest link theory
        UK lab
        Videos
    Ballistic Protection
        Protection schemes
        Users can choose their protection level
    More testing before results
    Needs help communicating results to industry

Agency Reports

15. Department of Homeland Security
    Annual clearance refresh
16. Department of Energy
    a. National Electric Sector Cybersecurity Organization (NESCO)—(requested) Stacy Bresler
        Since October 1, out in the field finding ES cyber security concerns
        Looking for common themes like ICS
        DOE calls NESCO a matchmaker
        Want to do work that Asset Owners want
            Facilitated a TFE WG to reduce burden and focus on security
            Open Source that can benefit the industry – looking into 10 cases
17. Public Safety Canada/Royal Canadian Mounted Police
18. Federal Energy Regulatory Commission

Closing

19. Follow-up Items and Future Actions — Barry Lawson
20. 2011/12 Future Meetings — Scott Mix
        December 14–15, 2011, Atlanta, GA
        March 7-8, 2012**, Phoenix, AZ (not confimed)

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-brian

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

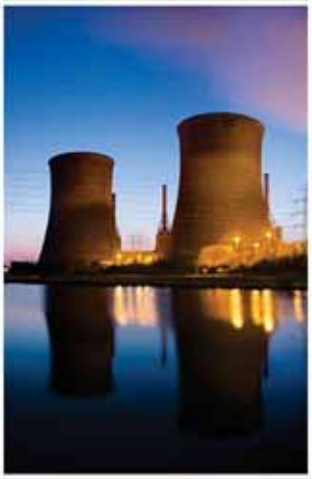

Announcement

NERC Releases Report Assessing Risk to Reliability Performance of Bulk Power System

September 20, 2011

ATLANTA – The North American Electric Reliability Corporation (NERC) released a report that marks a new approach to assessing the reliability performance of the North American bulk power system.

This foundational report - *2011 Risk Assessment of Reliability Performance* - integrates NERC's multiple analysis efforts, combining characteristics of risk to reliability and their trends, to provide feedback and meaningful trend information to industry stakeholders and policymakers on reliability performance.

"Through analysis of reliability performance and trends, we can develop better risk control measures and better inform reliability management business decisions," said Gerry Cauley, president and chief executive officer at NERC. "This is the intelligent feedback on grid reliability performance we have been seeking to ensure that NERC and the industry are focused on the most important risks to reliability."

This report, which measures key aspects of reliability from 2008 to 2010, lays the groundwork for an annual report beginning in 2012 that communicates the effectiveness of bulk power system reliability programs. Future reports will build on these initial metrics, such as Interconnection Frequency Response, System Voltage Performance and Transmission Constraint Mitigation, which will enable industry to measure meaningful trends and take action to support improved reliability.

"The performance measures are designed to ultimately identify common areas of risk clusters that have the greatest potential impact to affect bulk power system reliability," said Mark Lauby, vice president and director of Reliability

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Assessments and Performance Analysis. "Industry can then prioritize their actions toward those areas that can have the most significant improvement."

Click here to download the *2011 Risk Assessment of Reliability Performance* report. Click here to visit NERC's Reliability Indicators page.

###

The North American Electric Reliability Corporation's mission is to ensure the reliability of the North American bulk power system. NERC is the electric reliability organization (ERO) certified by the Federal Energy Regulatory Commission to establish and enforce reliability standards for the bulk-power system. NERC has equivalent relationships with provincial and federal authorities in Canada. NERC develops and enforces reliability standards; assesses adequacy annually via a 10-year forecast, and summer and winter forecasts; monitors the bulk power system; and educates, trains and certifies industry personnel. Learn more at www.nerc.com

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2011 Risk Assessment of Reliability Performance

to ensure the reliability of the bulk power system

July 2011

3353 Peachtree Rd. NE
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Atlanta, GA 30326
404.446.2560 | www.nerc.com

NERC's Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority established to evaluate reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; assesses adequacy annually via a ten-year forecast and winter and summer forecasts; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is the electric reliability organization for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[1]

NERC assesses and reports on the reliability and adequacy of the North American bulk power system, which is divided into eight Regional areas, as shown on the map and table below. The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the U.S., Canada, and a portion of Baja California Norte, México.

Note: The highlighted area between SPP RE and SERC denotes overlapping Regional area boundaries. For example, some load serving entities participate in one Region and their associated transmission owner/operators in another.

NERC Regional Entities

FRCC Florida Reliability Coordinating Council	**SERC** SERC Reliability Corporation
MRO Midwest Reliability Organization	**SPP RE** Southwest Power Pool Regional Entity
NPCC Northeast Power Coordinating Council	**TRE** Texas Reliability Entity
RFC Reliability*First* Corporation	**WECC** Western Electricity Coordinating Council

[1] As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has recently adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards-setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory. Nova Scotia and British Columbia also have frameworks in place for reliability standards to become mandatory and enforceable. NERC is working with the other governmental authorities in Canada to achieve equivalent recognition.

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Executive Summary

2011 Transition Report

The *2011 Risk Assessment of Reliability Performance* is a foundational report, with the goal to provide a view of risks to reliability based on historic performance. The objective is to integrate many ongoing efforts underway providing technical analysis and feedback on risk attributes and reliability trends to stakeholders, regulators, policymakers and industry. The joint report development was led by NERC staff in collaboration with several groups independently analyzing specific aspects of bulk power system reliability, including the Reliability Metrics Working Group (RMWG), Transmission Availability Data System Working Group (TADSWG), Generating Availability Data System Task Force (GADSTF), and Event Analysis Working Group (EAWG).

Figure ES1: State of Reliability

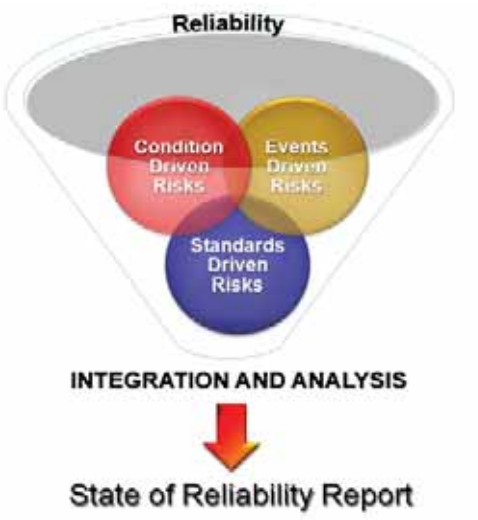

Since its inaugural report,[2] the RMWG has advanced the development and understanding of risk attributes impacting reliability performance and the corresponding metrics that provide insight to the performance of the bulk power system. As this work proceeds, industry continues to investigate those risk attribute areas which enhance the understanding and insights that can be drawn for system reliability (Figure ES1). Other committees, working groups, and task forces, in addition to NERC staff, are undertaking additional reliability analysis of the system. These efforts have resulted in an evolving body of work.

The *2011 Risk Assessment of Reliability Performance* begins a transition from a 2009 metric performance assessment to a more complete risk impact evaluation of reliability. This transition is expected to crystallize as more data becomes available and understanding of the data and trends matures. The annual *Risk Assessment of Reliability Performance* report will provide a technically sound platform to ultimately communicate the effectiveness of ERO (Electric Reliability Organization) reliability programs, set the foundation of a learning and accountable ERO, and present an overall view of risk impacts affecting reliability performance.

By addressing the key, measurable components of bulk power system reliability, the *Risk Assessment of Reliability Performance* report will provide insights, guidance, and direction to those areas in which reliability goals can be more effectively and sustainably achieved. Also, the report will serve as a foundation to streamline and align the data and information reporting arising from multiple technical

[2] http://www.nerc.com/docs/pc/rmwg/RMWG_Metric_Report-09-08-09.pdf

groups, thereby providing efficient data and information transparency. The key findings and recommendations are envisioned as input to NERC's Reliability Standards and project prioritization, compliance process improvement, event analysis, reliability assessment, and critical infrastructure protection.

The ultimate goal of the State of Reliability report is twofold. First, the report will illuminate the historical, overall bulk power system reliability picture. By using robust data, the reliability of the system can be explained and documented. Currently, there are no measures, datasets, or reports that explicitly and completely state the historical performance of the system.

Second, the report will help identify risk clusters, prioritize, and create actionable results for reliability improvement. Once a risk universe has been found, it can be parsed into component clusters.[3] These significant risk clusters can be selected as priority projects to develop coordinated and multifunctional solutions to relevant problems. The State of Reliability report will provide an industry reference for historical bulk power system reliability, analytical insights with a view to action, and will enable the discovery and prioritization of specific, actionable risk control steps.

Key Findings and Recommendations

Reliability Metrics Performance

The Operating and Planning Committees approved eighteen metrics that address the characteristics of an adequate level of reliability (ALR), the following seven metrics are improving based on metric trends, indicating the bulk power system is performing better during the time frame analyzed:

- ALR1-3: Planning Reserve Margin
- ALR1-4: BPS Transmission Related Events Resulting in Loss of Load
- ALR2-5: Disturbance Control Events Greater than Most Severe Single Contingency
- ALR6-2: Energy Emergency Alert 3 (EEA3)
- ALR6-3: Energy Emergency Alert 2 (EEA2)
- ALR6-11: Automatic Transmission Outages Initiated by Failed Protection System Equipment
- ALR6-13: Automatic Transmission Outages Initiated by Failed AC Substation Equipment

The remaining metrics do not have sufficient data to derive useful conclusions, or currently lack data. With a more thorough data matrix for these metrics, more conclusions about reliability will be ascertained. All metrics will be evaluated on a regular basis to determine each metric's contribution to quantitative reliability measurement.

[3] Malcolm K. Sparrow, *The Regulatory Craft*, The Brookings Institution, 2000.

Transmission Availability Performance

On a NERC-wide average basis, the automatic transmission outage rate has improved from 2008 to 2010. Considering both automatic and non-automatic outages, 2010 records indicate transmission element availability percentage exceeds 95%.

Unexpectedly, almost one-third of all sustained, automatic outages are dependent or common mode events. Though a number of protection systems are intended to trip three or more circuits, many events go beyond their design basis. In addition, a number of multiple outage events were initiated by protection system misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry. More focus into this problem would improve the design basis assumed for reliable operation of the system. A joint team should be formed to analyze these outages.

Generating Availability Performance

On the average, units appear to require maintenance with increasing regularity to meet unit availability goals. In the last three years, the Equivalent Forced Outage Rate – Demand (EFORd) increased, indicating a higher risk that a unit may not be available to meet generating requirements due to forced outages or de-ratings. From 2009 to 2010, the average maintenance hours increased by 24 hours per unit. The three leading root causes for multiple unit forced trips are transmission outages, lack of fuel, and weather. Detailed analysis is needed to identify the root causes of increasing forced outage rate.

Disturbance Events

One of most important bulk power system performance measures is the number of significant disturbance events and their impact on system reliability. The trends have been captured in the severity risk curve analysis featured in the reliability metrics assessment.

Since the event analysis field test commenced in October 2010, a total of 42 events within five categories were reported through the end of 2010. Equipment failure is the number one cause identified from the event analyses completed from 2010. This suggests more data and analysis into equipment failure may prove fruitful. However, with such a small dataset, no conclusions can be drawn.

Report Organization

Following the introductory chapter, the second chapter details results for 2010 RMWG approved performance metrics and lays out methods for integrating the variety of risks into an integrated risk index. This chapter also addresses concepts for measuring bulk power system events. The third chapter outlines transmission system performance results that the TADSWG have endorsed using the three-year history of TADS data. Reviewed by the GADSTF, the fourth chapter provides an overview of generating availability trends for 72 percent of generators in North America. The fifth chapter provides a brief summary of reported disturbances based on event categories described in the EAWG's enhanced event analysis field test process document.

Introduction

Metric Report Evolution

The NERC Reliability Metrics Working Group (RMWG) work has progressed since its formation and following the release of the initial reliability metric whitepaper in December 2007[4]. Since that time, a metric development process has been built with the use of SMART[5] ratings (Specific, Measurable, Attainable, Relevant and Tangible) featured in the 2009 report,[6] expanding the approved metrics to eighteen, and identifying the need for additional data by issuing a data request for ALR3-5: Interconnection Reliability Operating Limit/System Operating Limit (IROL/SOL) Exceedances.

The first annual report published in June 2010 provided an analysis of seven. In August 2010, the RMWG released its *Integrated Bulk Power System Risk Assessment Concepts* paper[7] introducing new concepts, such as the "universe of risk" of the bulk power system. In the concepts paper, a method to assess "event-driven" risks was introduced and the Severity Risk Index (SRI) was established to quantify the impact of various events of the bulk power system. The concepts paper was subsequently endorsed by NERC's Operating (OC) and Planning Committees (PC).

Figure 1: State of Reliability Concepts

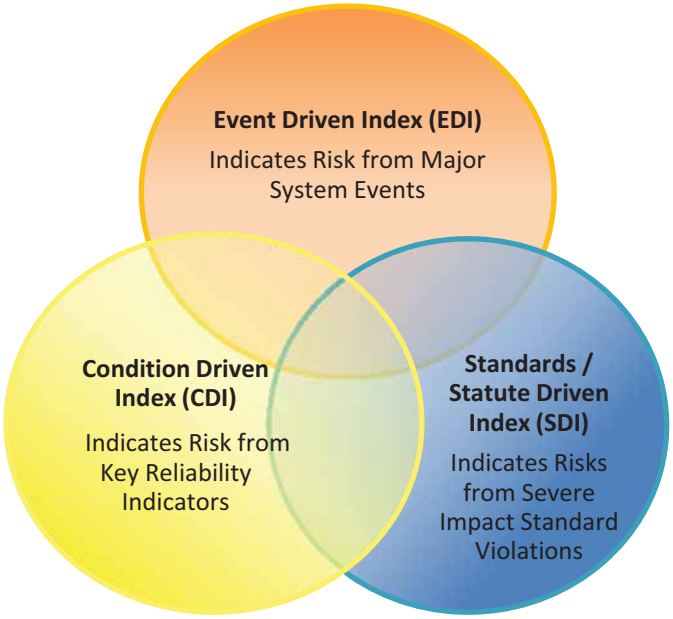

Subsequently, a conceptual model was developed to be used to provide an integrated reliability assessment of bulk power system performance. This year's report builds on previous work towards establishing a single Integrated Reliability Index (IRI) comprised of three components: event driven index (EDI), condition driven index (CDI), and standards/statute driven index (SDI) as shown in Figure 1.

These individual components will be used to develop a reliability index to assess the current state of reliability. This is an ambitious undertaking, and it will continue to evolve as an understanding of what factors contribute to, or indicate the level of, reliability develops. In the coming years, analysis of the SRI will expand to an integrated reliability index (IRI) with deeper analysis of the approved reliability

[4] The initial reliability metrics whitepaper is located at http://www.nerc.com/docs/pc/rmwg/Reliability_Metrics_white_paper.pdf.

[5] SMART rating definitions are located at: http://www.nerc.com/docs/pc/rmwg/SMART_%20RATING_8.26.pdf.

[6] 2009 Bulk Power System Reliability Performance Metric Recommendations can be found at http://www.nerc.com/docs/pc/rmwg/RMWG_Metric_Report-09-08-09.pdf.

[7] http://www.nerc.com/docs/pc/rmwg/Integrated_Bulk_Power_System_Risk_Assessment_Concepts_Final.pdf

metrics, and establish the cornerstones for developing an IRI. Chapter two of this report elaborates on recommendations for next steps to better refine and weigh the components of the IRI, as well as its use to establish a "State of Reliability" for the bulk power system in North America.

For this work to be effective and useful to stakeholders, it must use existing data sources, align with other industry analyses, and integrate with other initiatives as shown in Figure 2. NERC's data resources are introduced in this report: Transmission Availability Data System (TADS), Generating Availability Data System (GADS), Event Analysis database, and, in the future, Demand Response Availability Data System (DADS).[8]

An open development process is used, incorporating continuous improvement through leveraging industry expertise and technical judgment. As new data becomes available, more concrete conclusions from the reliability metrics will be drawn and recommendations for reliability standards and compliance process improvement will be developed.

Figure 2: Data Source Integration and Analysis

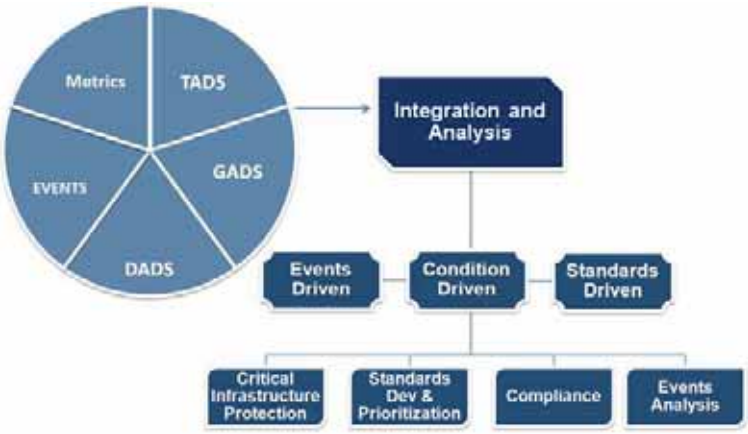

This evolution will take time, and the first assessment of ongoing reliability using the three components of an integrated reliability assessment is expected in the 2012 Annual Report. The goal is not only to measure performance, but to highlight areas for improvement as well as reinforcing and measuring industry success. As this view of reliability is developed, the quarterly performance metrics will be updated as illustrated in Figure 3 on a Reliability Indicators dashboard at NERC's website.[9] Industry will be kept informed of the evolution through yearly webinars, providing quarterly data updates, and publishing its annual report.

Roadmap for the Future

As shown in Figure 4, the 2011 Reliability Performance Analysis report begins a transition from a metric performance assessment to a "S*tate of Reliability*" report by collaborating with other groups to form a unified approach to historical reliability performance analysis. This process will require engagement with a number of NERC industry subject matter experts to develop a broad picture of the bulk power system's historic reliability.

[8] DADS will begin mandatory data collection from April 2011 through October 2011, with data due on December 15, 2011.

[9] Reliability Indicators' dashboard is available at: http://www.nerc.com/page.php?cid=4|331.

Figure 3: NERC Reliability Indicators Dashboard

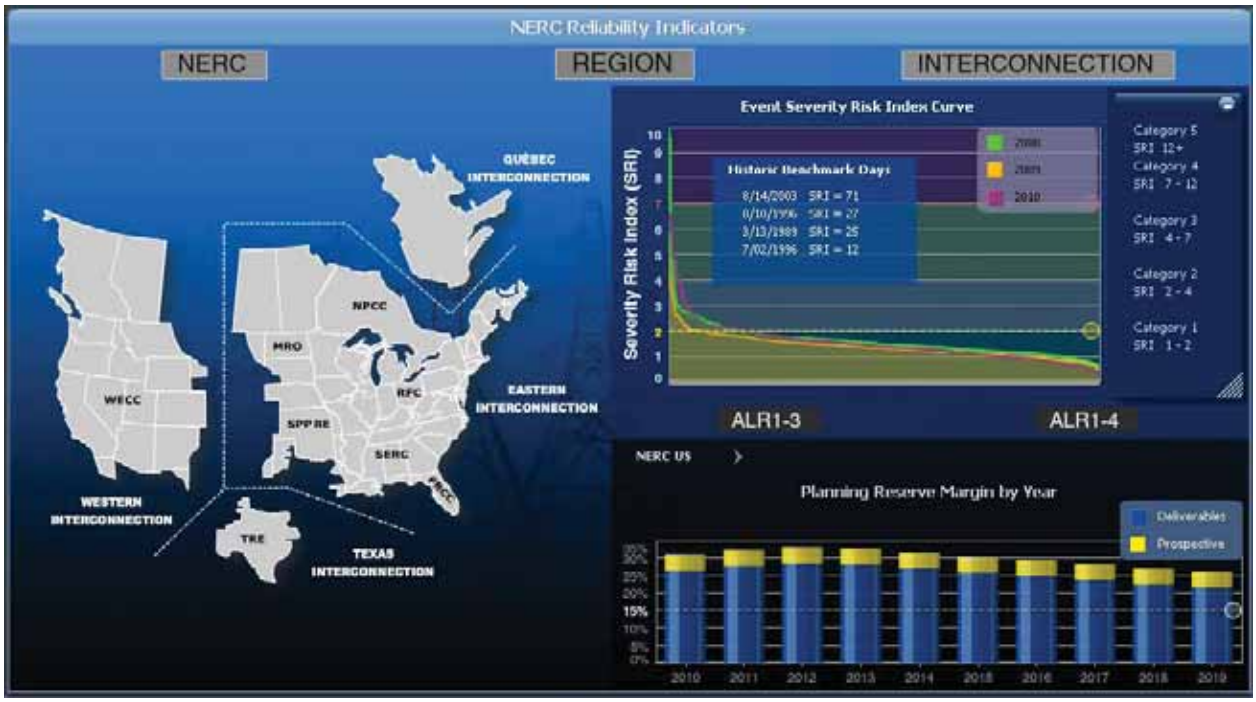

Alignment to other industry reports is also important. Analysis from the frequency response completed by the Resources Subcommittee (RS), physical and cyber security assessment provided by the Critical Infrastructure Protection Committee (CIPC), the wide area reliability coordination conducted by the Reliability Coordinator Working Group (RCWG) , the spare equipment availability system enhanced by the Spare Equipment Database Task Force (SEDTF), the post seasonal assessment developed by the Reliability Assessment Subcommittee (RAS), and demand response deployment summarized by the Demand Response Data Task Force (DRDTF), will provide a significant foundation from which this report draws. Collaboration derived from these stakeholder groups further refines the metrics; and use of additional datasets will broaden the industry's tool-chest for improving reliability of the bulk power system.

The annual *State of Reliability* report will be aimed to communicate the effectiveness of NERC, by presenting an integrated view of reliability performance. A platform will be created for sound technical analysis and a way to provide feedback on reliability trends to stakeholders, regulators, policymakers, and industry. The key findings and recommendations will ultimately be used as input to standards changes and project prioritization, reliability assessment, compliance process improvement, event analysis, and critical infrastructure protection areas.

Figure 4: Overview of the Transition to the 2012 State of Reliability Report

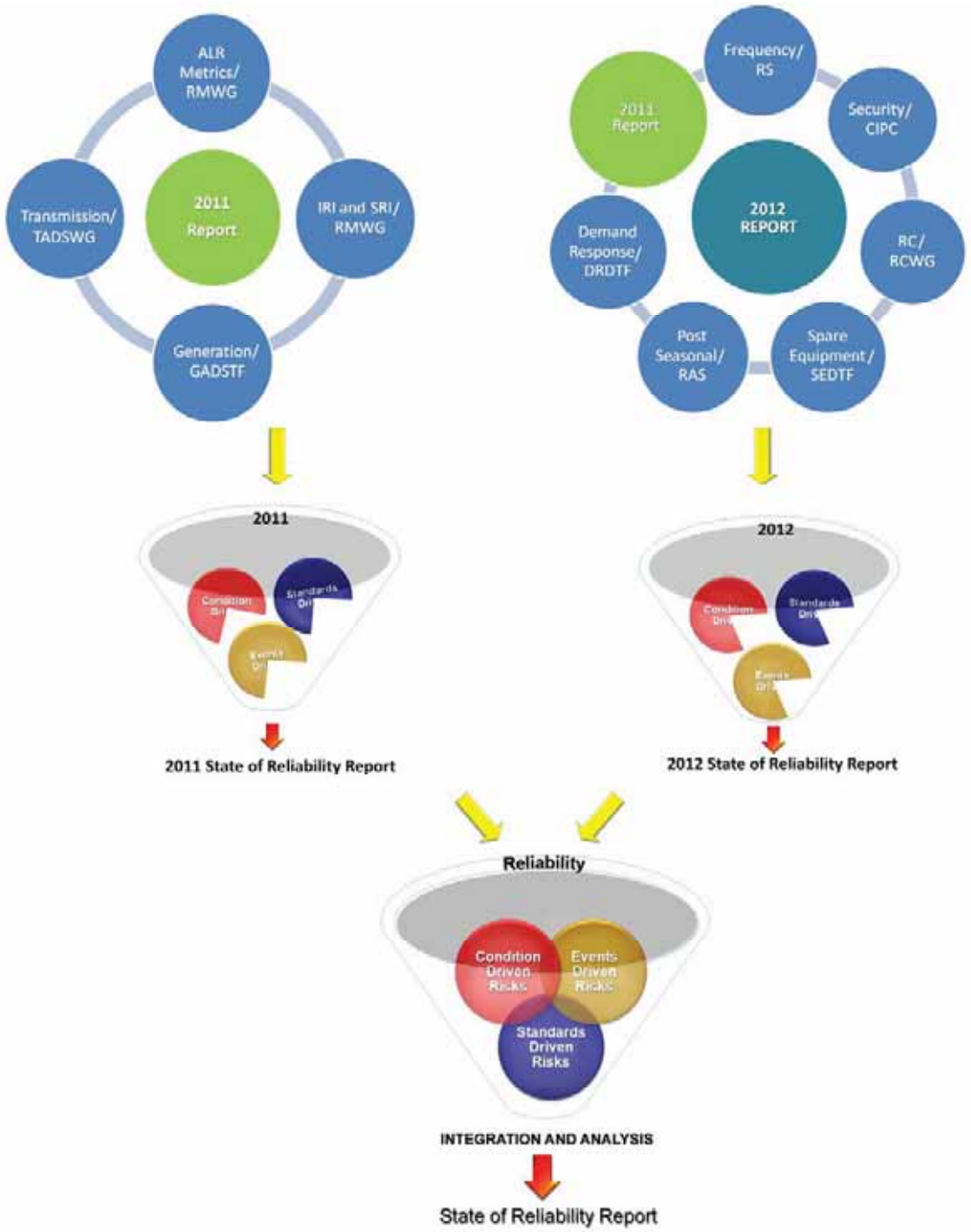

Reliability Metrics Performance

Introduction

Building upon last year's metric review, the results of eighteen performance metrics continue to be assessed. Due to data availability, each of the performance metrics does not address the same time periods (some metrics have just been established, while others have data over many years).This will be an important improvement in the future. At this time, the number of metrics is expected to remain constant; however, other metrics may supplant existing metrics which may have more merit. In spite of the potentially changing mix of approved metrics, historical and current assessments will still be possible.

These metrics exist within an overall reliability framework, and, in total, the performance metrics being considered address the fundamental characteristics of an adequate level of reliability (ALR).[10] Each of the elements being measured by the metrics should be considered in aggregate when making an assessment of the reliability of the bulk power system, with no single metric indicating exceptional or poor performance of the power system.

Importantly, due to regional differences (size of the region, operating practices, etc.), comparing the performance of one Region to another would be erroneous and inappropriate. Furthermore, depending on the region being evaluated, one metric may be more relevant to a specific region's performance than others, and assessment may not be strictly mathematical, rather more subjective. Finally, choosing one region's best metric performance to define targets for other regions is also inappropriate.

Another key principle is to retain anonymity of any individual reporting organization. Thus, granularity will be attempted to the point that such action might compromise anonymity of any given reporting entity. Certain reporting entities may appear inconsistent, but they have been preserved to maintain maximum granularity while balancing individual organization anonymity.

Although assessments have been made in a number of the performance categories, others do not have sufficient data to derive conclusions from the metric results. Continued assessment of these metrics should continue until sufficient data is available. Each of the eighteen performance metrics are presented, in summary, with their trend ratings in Table 1. The table provides a summary view of the metrics with an assessment of the current metric trends.

[10] http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf.

Table 1: Metric Trend Ratings		
ALR	**Improvements**	**Trend Rating**
1-3	Planning Reserve Margin	☆
1-4	BPS Transmission Related Events Resulting in Loss of Load	☆
2-5	Disturbance Control Events Greater than Most Severe Single Contingency	☆
6-2	Energy Emergency Alert 3 (EEA3)	☆
6-3	Energy Emergency Alert 2 (EEA2)	☆
6-11	Automatic AC Transmission Outages Initiated by Failed Protection System Equipment	☆
6-13	Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment	☆
	Inconclusive	
2-3	Activation of Under Frequency Load Shedding	⊗
2-4	Average Percent Non-Recovery Disturbance Control Standard Events	⊗
4-1	Automatic Transmission Outages Caused by Failed Protection System Equipment	⊗
6-12	Automatic AC Transmission Outages Initiated by Human Error	⊗
6-14	Automatic AC Transmission Outages Initiated by Failed AC Circuit Equipment	⊗
	New Data	
3-5	Interconnected Reliability Operating Limit/ System Operating Limit (IROL/SOL) Exceedance	◆
6-1	Transmission Constraint Mitigation	◆
6-15	Element Availability Percentage (APC)	◆
6-16	Transmission System Unavailability	◆
	No Data	
1-5	System Voltage Performance	⊘
1-12	Interconnection Frequency Response	⊘

Trend Rating Symbols	
Significant Improvement	☆☆
Slight Improvement	☆
Inconclusive	⊗
Slight Deterioration	⚠
Significant Deterioration	⚠⚠
New Data	◆
No Data	⊘

2010 Performance Metrics Results and Trends

ALR1-3 Planning Reserve Margin

Background

The Planning Reserve Margin[11] is a measure of the relationship between the amount of resource capacity forecast and the expected demand in the planning horizon.[12] Coupled with probabilistic analysis, calculated Planning Reserve Margins is an industry standard used by system planners for decades as an indication of system resource adequacy.

Planning Reserve Margin is the difference between forecast capacity and projected peak demand (50/50 forecast[13]), normalized by projected peak demand and shown as a percentage. Based on experience, for portions of the bulk power system that are not energy-constrained, Planning Reserve Margin indicates the amount of capacity available to maintain reliable operation, while meeting unforeseen increases in demand (e.g., extreme weather) and unexpected unavailability of existing capacity (e.g., long-term generation outages). Further, from a planning perspective, Planning Reserve Margin trends identify whether capacity additions are projected to keep pace with demand growth.

Assessment

Planning Reserve Margins, considering anticipated capacity resources and adjusted potential capacity resources,[14] decrease in the latter years of the 10-year forecasts in each of the four interconnections for both the 2009[15] and 2010 resource projections. Typically, the early years provide more certainty since new generation is either in-service or under construction with firm commitments. In the later years, there is less certainty about the resources that will be needed to meet peak demand. Declining Planning Reserve Margins are inherent in a conventional forecast (assuming load growth) and do not necessarily indicate a trend of a degrading resource adequacy. Rather, they are an indication of the potential need for additional resources. In addition, key observations can be made about the Planning Reserve Margin forecast, such as short-term assessment comparison to target margins, rate of margin change through the assessment period, identification of margins that are approaching or below a target requirement, and comparisons from year-to-year forecasts.

While resource planners are able to forecast the need for resources, the type of resource that will actually be built or acquired to fill the need is less certain. For example, in the northeast U.S. markets, with a three to five year forward capacity market, firm commitments are not made in the long-term. However, resource planners do recognize the need for resources in their long-term planning and

[11] Detailed calculations of Planning Reserve Margin are available at: http://www.nerc.com/page.php?cid=4|331|333.

[12] The Planning Reserve Margin indicated here is not the same as an operating reserve margin that system operators use for near-term operations decisions.

[13] These demand forecasts are based on "50/50" or median weather (a 50 percent chance of the weather being warmer and a 50 percent chance of the weather being cooler).

[14] See Terms Used in this Report of the *2010 Long-Term Reliability Assessment*, http://www.nerc.com/files/2010_LTRA_v2-.pdf.

[15] 2009 Long-Term Reliability Assessment, http://www.nerc.com/files/2009_LTRA.pdf.

account for these resources through generator queues. These queues are then adjusted to reflect an adjusted forecast of resources—pro-rated by approximately 20 percent, depending on the assessment area.

When comparing the assessment of planning reserve margins between 2009 and 2010, the interconnection Planning Reserve Margins are slightly higher, on an annual basis, in the 2010 forecast compared to those of 2009, as shown in Figure 5.

Figure 5: Planning Reserve Margin by Interconnection and Year

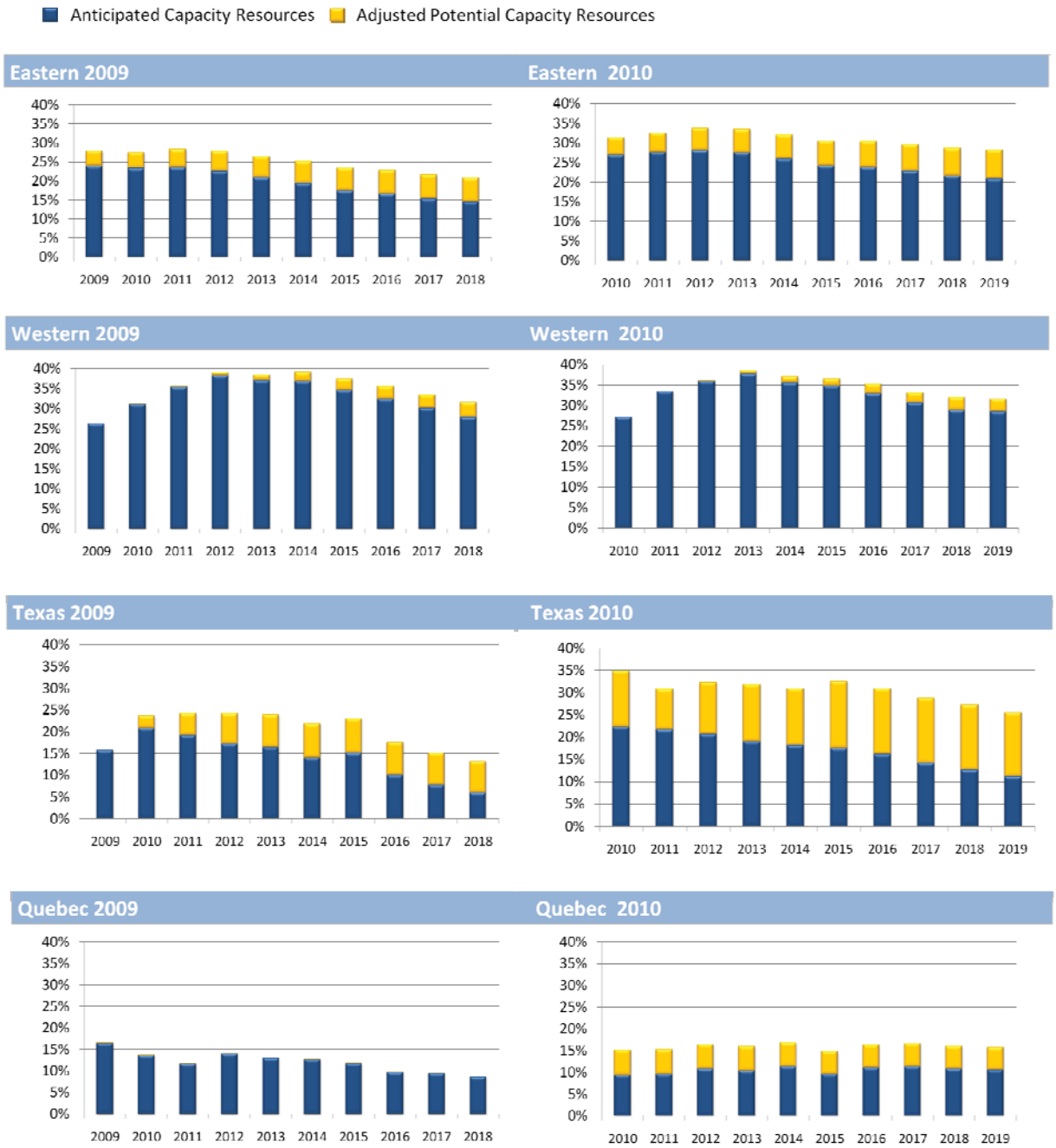

This conclusion results from slightly higher capacity forecasts and slightly lower demand forecasts. Importantly, the pace of any economic recovery will affect future comparisons.[16] This metric can be used by NERC to assess the individual interconnections in the ten-year long-term reliability assessments. If a noticeable change occurs, further investigation is necessary to determine the causes and likely effects on reliability, and the potential need for additional resources.

Special Considerations

The Planning Reserve Margin is a capacity-based metric. Therefore, it does not provide an accurate assessment of performance in energy-limited systems (e.g., hydro capacity with limited water resources or systems with significant variable generation penetration). In addition, the Planning Reserve Margin does not provide a measure of potential transmission constraints internal to their respective assessment areas. Planning Reserve Margin data, shown in Figure 6, is used for NERC's seasonal and long-term reliability assessments as the primary metric to determine the resource adequacy of assessment areas.

The North American bulk power system is divided into four distinct interconnections. These interconnections are loosely connected with limited ability to share capacity or energy across the interconnection. To reflect this limitation, the Planning Reserve Margins are calculated in this report based on interconnection values rather than by national boundaries, as is the practice of the Reliability Assessment Subcommittee (RAS).

ALR1-4 BPS Transmission Related Events Resulting in Loss of Load

Background

This metric measures bulk power system transmission-related events resulting in the loss of load, excluding weather-related outages. Planners and operators can use this metric to validate their design and operating criteria by identifying the number of instances when loss of load occurs.

For the purposes of this metric, an "event" is an unplanned transmission disturbance that produces an abnormal system condition due to equipment failures or system operational actions, and results in the loss of firm system demand for more than 15 minutes. The reporting criteria for such events are outlined below:[17]

[16] *Potential Reliability Impacts of Swift Demand Growth after a Long-Term Recession,* http://www.nerc.com/files/NERC_Swift_Scenario_Aug_2010.pdf

[17] Details of event definitions are available at: http://www.nerc.com/files/EOP-004-1.pdf.

- Entities with a previous year recorded peak demand of more than 3,000 MW are required to report all such losses of firm demand totaling more than 300 MW.
- All other entities are required to report all such losses of firm demands totaling more than 200 MW or 50 percent of the total customers being supplied immediately prior to the incident, whichever is less.
- Firm load shedding of 100 MW or more used to maintain the continuity of the bulk power system reliability.

Assessment

Figure 6 illustrates that the number of bulk power system transmission-related events resulting in loss of firm load from 2002 to 2009 is relatively constant and suggests an average of between 7 - 10 events per year is experienced. The magnitude of load loss, shown in Table 2, associated with these events appears to reflect a downward trend since 2007. Further analysis and continued assessment of the trends over time is recommended.

Figure 6: Bulk Power System Transmission Related Events Resulting in Loss of Load (2002-2009)

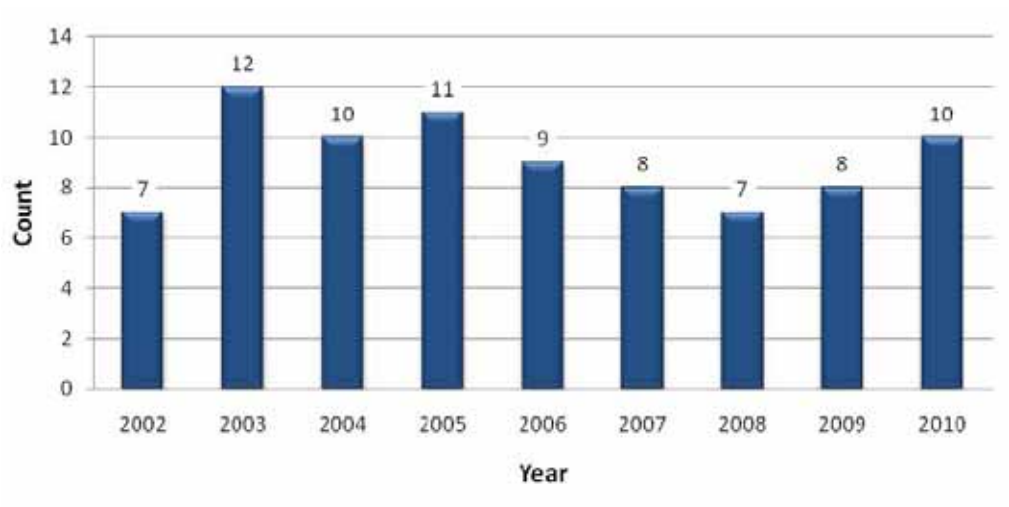

Table 2: Bulk Power System Transmission Related Events Resulting in Loss of Load (2002-2009)	
Year	**Load Loss (MW)**
2002	3,762
2003	65,263
2004	2,578
2005	6,720
2006	4,871
2007	11,282
2008	5,200
2009	2,965
2010	4,256

Special Considerations

The collected data does not indicate whether load loss, during an event, occurred as designed or not as designed. Further investigation into the usefulness of separating load loss as designed and unexpected load loss should be conducted.

ALR1-12 Interconnection Frequency Response

Background

This metric is used to track and monitor Interconnection Frequency Response. Frequency Response is a measure of an Interconnection's ability to stabilize frequency immediately following the sudden loss of generation or load. It is a critical component to the reliable operation of the bulk power system, particularly during disturbances and restoration. The metric measures the average frequency response for all events where frequency drops more than 35 mHz within a year.

Assessment

During the study period, there was no formal, established data collection process for ALR1-12. Therefore, no assessment was possible. Full use of data being gathered from the frequency response project should be used to derive this metric.

ALR2-3 Activation of Under Frequency Load Shedding

Background

The purpose of Under Frequency Load Shedding (UFLS) is to balance generation and load in an island following an extreme event. The UFLS activation metric measures the number of times it is activated and the total MW of load interrupted in each Regional Entity and NERC-wide.

Assessment

Figure 7 and Table 3 illustrate a history of UFLS events from 2006 through 2010. Notably, single events had a load shedding range from 15 MW to 2,273 MW. The activation of UFLS is the last automated reliability measure associated with a decline in frequency in order to rebalance the system. Further assessment of the MW loss for these activations is recommended.

Because of the large range of load lost in UFLS events, the need to establish a UFLS total load loss threshold is under evaluation. The significance of a UFLS activation compared to the total load loss of the activation will be assessed over time.

Figure 7: ALR2-3 Count of Activations by Year and Regional Entity (2006-2010)

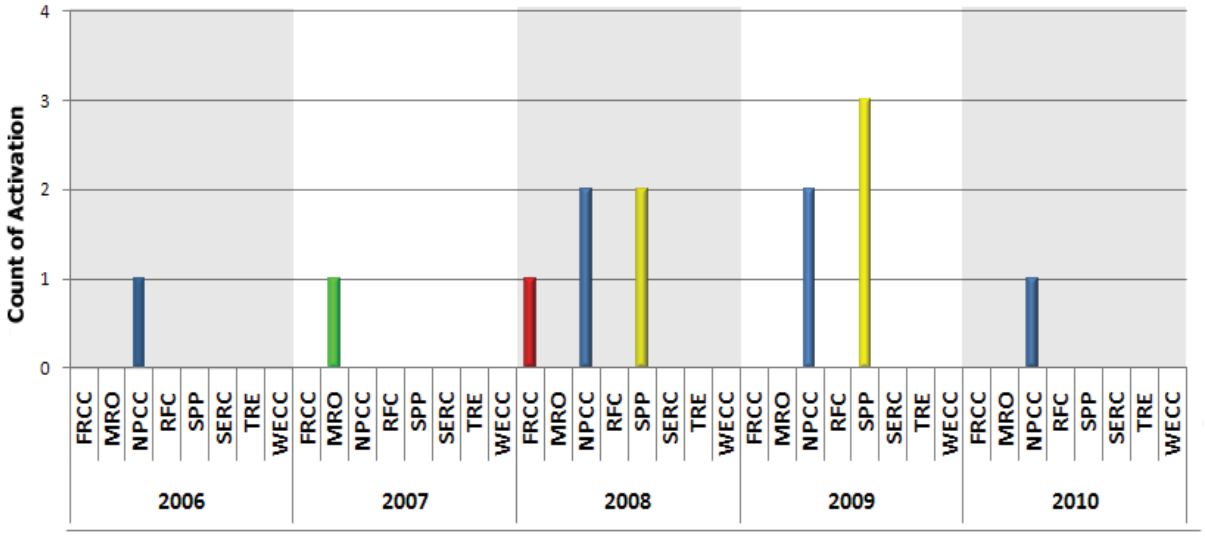

Table 3: ALR2-3 Under Frequency Load Shedding					
	MW Loss				
	2006	2007	2008	2009	2010
FRCC	-	-	2,273	-	-
MRO	-	486	-	-	-
NPCC	94	-	63	20	25
RFC	-	-	-	-	-
SPP	-	-	672	15	-
SERC	-	-	-	-	-
TRE	-	-	-	-	-
WECC	-	-	-	-	-

Special Considerations

The use of a single metric cannot capture all of the relevant information associated with UFLS events as the events relate to each respective UFLS plan. Namely, use of UFLS as designed is a successful measure of system performance. The ability to measure the reliability of the bulk power system is directly associated with how it performs compared to what is planned.

ALR2-4 Average Percent Non-Recovery Disturbance Control Standards (DCS)

Background

This metric measures the Balancing Authority's (BA) or Reserve Sharing Group's (RSG) ability to balance resources and demand with the timely deployment of contingency reserve, thereby returning the interconnection frequency to within defined limits following a Reportable Disturbance.[18] The relative percentage provides an indication of performance measured at a BA or RSG.

Assessment

Figure 8 illustrates the average percent non-recovery of DCS events from 2006 to 2010. The graph provides a high-level indication of the performance of each Regional Entity. However, a single event may not reflect all the reliability issues within a given RE. In order to understand the reliability aspects, it may be necessary to request individual Regional Entities to further investigate and provide a more comprehensive reliability report. Further investigation may indicate that sufficient contingency reserve were available, but, through their implementation process, failed to meet DCS recovery.

Continued trend assessment is recommended. Where trends indicated potential issues, the Regional Entity will be requested to investigate and report their findings.

Figure 8: Average Percent Non-Recovery of DCS Events (2006-2010)

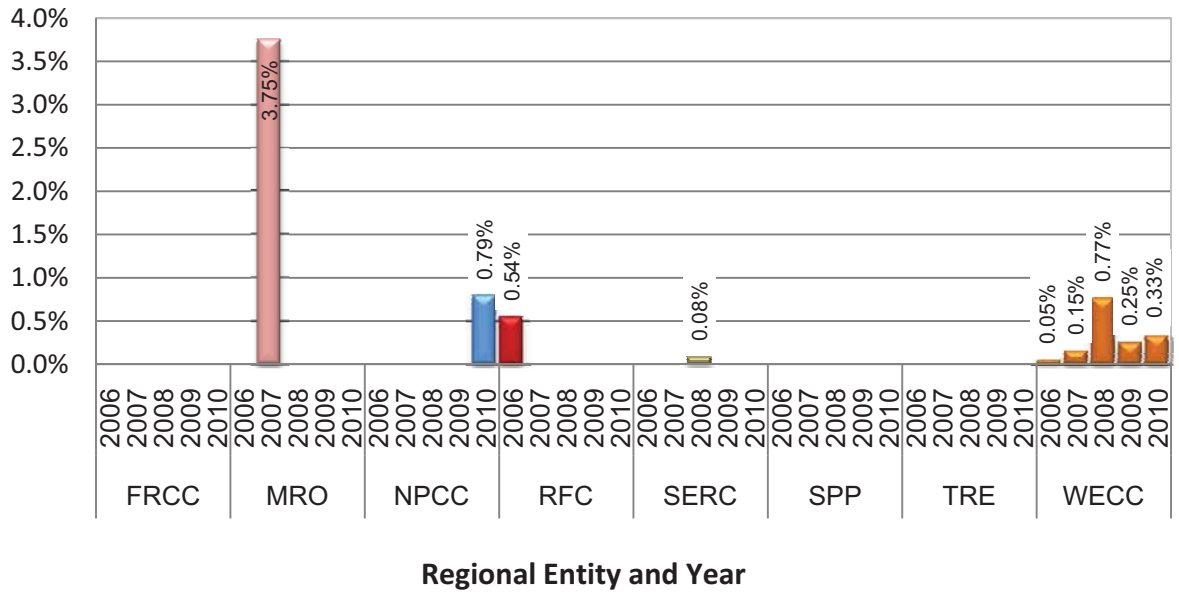

[18] Details of the Disturbance Control Performance Standard and Reportable Disturbance definitions are available at: http://www.nerc.com/files/BAL-002-0.pdf.

Special Considerations

This metric aggregates the number of events based on reporting from individual Balancing Authorities or Reserve Sharing Groups. It does not capture the severity of the DCS events. Most Regional Entities use 80 percent of the Most Severe Single Contingency to establish the minimum threshold for reportable disturbance, while others use 35 percent.[19]

ALR2-5 Disturbance Control Events Greater Than Most Severe Single Contingency

Background

This metric represents the number of disturbance events that exceed the Most Severe Single Contingency (MSSC), and is specific to each BA. Each Regional Entity reports disturbances greater than the MSSC on behalf of the BA or Reserve Sharing Group (RSG). The result validates current contingency reserve requirements. The MSSC is determined based on the specific configuration of each BA or RSG and can vary in significance and impact on the BPS.

Assessment

Figure 9 represents the number of DCS events within each RE that are greater than the MSSC from 2006 to 2010. This metric and resulting trend can provide insight regarding the risk of events greater than the MSSC and the potential for loss of load.

In 2010, SERC had 16 BAL-002 reporting entities; eight Balancing Areas elected to maintain Contingency Reserve levels independent of any reserve sharing group. These 16 entities experienced 79 reportable DCS events—21 of which were categorized as greater than their most severe single contingency. Every DCS event categorized as greater than the most severe single contingency occurred within a Balancing Area maintaining independent Contingency Reserve levels. Significantly, all 79 Regional Entities reported compliance with the Disturbance Recovery Criterion, including for those Disturbances that were considered greater than their most severe single contingency. This supports a conclusion that regardless of the size of the BA or participation in a Reserve Sharing Group, SERC's BAL-002 reporting entities have demonstrated the ability in 2010 to use Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following Reportable Disturbances.

If the SERC Balancing Areas without large generating units and who do not participate in a Reserve Sharing Group change the determination of their most severe single contingencies to effect an increase in the DCS reporting threshold (and concurrently the threshold for determining those disturbances which are greater than the most severe single contingency), there will be a reduction in both the gross count of DCS events in SERC and in the subset considered under ALR2-5. Masking the discrete events which cause Balancing Area to respond may not reduce "risk" to the system. However, it is desirable to maintain a reporting threshold which encourages the Balancing Authority to respond to any unexplained

[19] http://www.wecc.biz/Standards/Development/Lists/Request%20Form/DispForm.aspx?ID=69&Source=/Standards/Development/Pages/WECCStandardsArchive.aspx.

change in automatic control error (ACE) in a manner which supports Interconnection frequency based on demonstrated performance. SERC plans to continue to monitor DCS performance and will continue to evaluate contingency reserve requirements but does not consider 2010 ALR2-5 performance to be an adverse trend in "extreme or unusual" contingencies, but rather within the normal range of expected occurrences.

Figure 9: Disturbance Control Events Greater Than Most Severe Single Contingency (2006-2010)

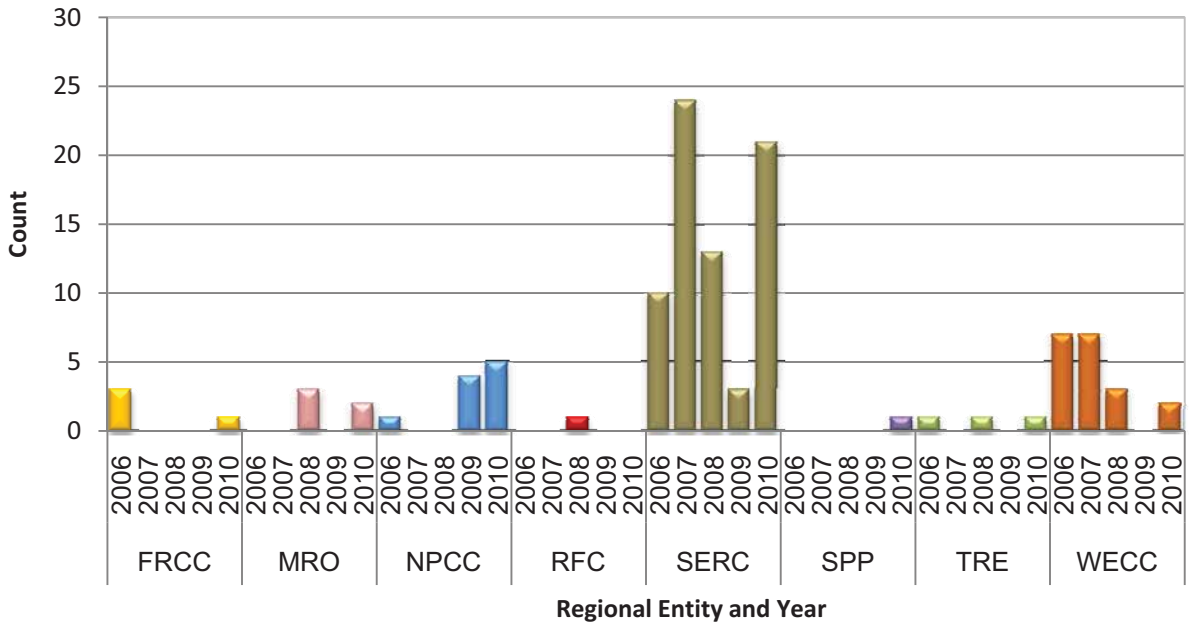

Special Considerations

The metric reports the number of DCS events greater than MSSC without regards to the size of a BA or RSG, and without respect to the number of reporting entities within a Regional Entity. Because of the potential for differences in the magnitude of MSSC and the resultant frequency of events, trending should be within each Regional Entity to provide any potential reliability indicators. Each Regional Entity should investigate the cause and relative effect on reliability of the events within their footprints. Small BA or RSG may have a relatively small value of MSSC. As such, a high number of DCS greater than MCCS may not indicate a reliability problem for the reporting RE but may indicate an issue for the respective BA or RSG. In addition, events greater than MSSC may not cause a reliability issue for some BA, RSG or RE if they have more stringent standards which require contingency reserves greater than MSSC.

ALR 1-5 System Voltage Performance

Background

The purpose of this metric is to measure the transmission system voltage performance (either absolute or per unit of a nominal value) over time. This should provide an indication of the reactive capability available to the transmission system. The metric is intended to record the amount of time that system voltage is outside a predetermined band around nominal.

Special Considerations

With a pilot program specified in early 2011, NERC's Operating and Planning Committees approved a voluntary data request letter for respective Transmission Owners (TOs) to submit relevant data on key buses. The number of buses, the monitored voltage levels, and the acceptable voltage ranges may vary by reporting entities. Based upon the usefulness of the data collected in the pilot program, additional data needs will be reviewed in the future.

ALR3-5 Interconnection Reliability Operating Limit/ System Operating Limit (IROL/SOL) Exceedances

Background

This metric measures the number of times that a defined Interconnection Reliability Operating Limit (IROL) or System Operating Limit (SOL) was exceeded and the duration of these events. Exceeding IROL/SOLs could lead to outages if prompt operator control actions are not taken in a timely manner to return the system to within normal operating limits. Also, exceeding the limits may not directly lead to an outage, but it puts the system at risk if an outage were to occur during the time the system is outside it limit.

This metric was approved by NERC's Operating and Planning Committees in June 2010 and a data request was subsequently issued in August 2010 to collect the data for this metric. Based on the results of the pilot conducted in the third and fourth quarter of 2010, there is merit in continuing measurement of this metric. The reporting of IROL/SOL exceedances became mandatory in 2011, and data collected in Table 4 for 2010 has been provided voluntarily.

Table 4: ALR3-5 IROL/SOL Exceedances

	3Q2010	4Q2010	1Q2011
Number of Reporting RCs	9	10	15
≤ 10 minutes	123	226	124
10 minutes < Duration ≤ 20 minutes	10	36	12
20 minutes < Duration ≤ 30 minutes	3	7	3
> 30 minutes	0	1	0

ALR4-1 Automatic Transmission Outages Caused by Protection System Misoperations

Background

Originally titled *Correct Protection System Operations*, this metric has undergone a number of changes since its initial development. To ensure that it best portrays how misoperations affect transmission outages, it was necessary to establish a common understanding of misoperations and the data needed to support the metric. NERC's ERO-Reliability Assessment and Performance Analysis (ERO-RAPA) group evaluated several options of transitioning from existing procedures for the collection of misoperations data to a consistent approach which was introduced at the beginning of 2011. With the NERC System Protection and Control Subcommittee's (SPCS) technical guidance, NERC and the Regional Entities have agreed upon a set of specifications for misoperations reporting including format, categories, event type codes, and reporting period to have a final consistent reporting template.[20] Only automatic transmission outages 200 kV and above, including AC circuits and transformers, will be used in the calculation of this metric.

Special Considerations

Data collection will begin in the third quarter of 2011 for the second quarter of misoperation events. As revised, this metric cannot be calculated for this report at the current time. The revised title and metric form can be viewed at the NERC website.[21]

ALR6-11 – ALR6-14

ALR6-11	**Automatic AC Transmission Outages Initiated by Failed Protection System Equipment**
ALR6-12	**Automatic AC Transmission Outages Initiated by Human Error**
ALR6-13	**Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment**
ALR6-14	**Automatic AC Circuit Outages Initiated by Failed AC Circuit Equipment**

Background

These metrics evolved from the original ALR4-1 metric for correct protection system operations and now illustrate a normalized count (on a per circuit basis) of AC transmission element outages (i.e., TADS momentary and sustained automatic outages)[22] that were initiated by: Failed Protection System

[20] The current Protection System Misoperation template is available at: http://www.nerc.com/filez/rmwg.html.
[21] The current metric ALR4-1 form is available at: http://www.nerc.com/docs/pc/rmwg/ALR_4-1Percent.pdf.
[22] Definitions for TADS outages are located on page 4 of http://www.nerc.com/docs/pc/tadswg/Appendix%207%2020101202a%20clean.pdf.

Equipment, (ALR6-11); Human Error (ALR6-12); Failed AC Substation Equipment (ALR6-13); and Failed AC Circuit Equipment (ALR6-14). These metrics are all related to the non-weather related initiating cause codes for automatic outages of AC circuits and transformers operated 200 kV and above.

Assessment

Figure 10 through Figure 13 show the normalized automatic outages per circuit and automatic outages per transformer for facilities operated at 200 kV and above. As shown in all eight of the charts, there are some regional trends in the three years of outage data. However, some Regional Entity's values have increased from one year to the next, stayed the same, or decreased with no discernable regional trends. For example, ALR6-11 computes the automatic AC Circuit automatic outages initiated by failed protection system equipment.

There are some trends to the ALR6-11 to ALR6-14 data, but many Regional Entities do not have enough data for a valid trend analysis to be performed. NERC's outage rate seems to be improving every year. On a regional basis, metric ALR6-11, along with ALR6-12 through ALR6-14 may not be statistically significant, and will require confidence intervals[23] are calculated. ALR metric outage frequency rates and regional equipment inventories that are smaller than others are likely to require more than 36 months of outage data. Some numerically larger frequency rates and areas with larger equipment inventories (such as NERC) may not require more than 36 months of data to obtain a reasonably narrow confidence interval.

While more data is still needed on a regional basis to determine if each Regional Entity's bulk power system is becoming more reliable year-to-year; there are areas of potential improvement which include power system condition, protection performance, and human factors. The industry can benefit from detailed analysis of these outage causes by identifying lessons learned and rolling average trends of NERC-wide performance. With a confidence interval of relatively narrow bandwidth, changes in statistical data can be determined to be primarily due to random sampling error or if they are significantly different due to performance.

[23] The detailed Confidence Interval computation is available at: http://www.nerc.com/docs/pc/tadstf/TADS_Nov_2_2007APPENDIX_C_Confidence_Interval.pdf.

ALR 6-11 – Automatic Outages Initiated by Failed Protection System Equipment

Automatic outages with an initiating cause code of failed protection system equipment are in Figure 10.

Figure 10: ALR6-11 by Regional Entity (Includes NERC-Wide)

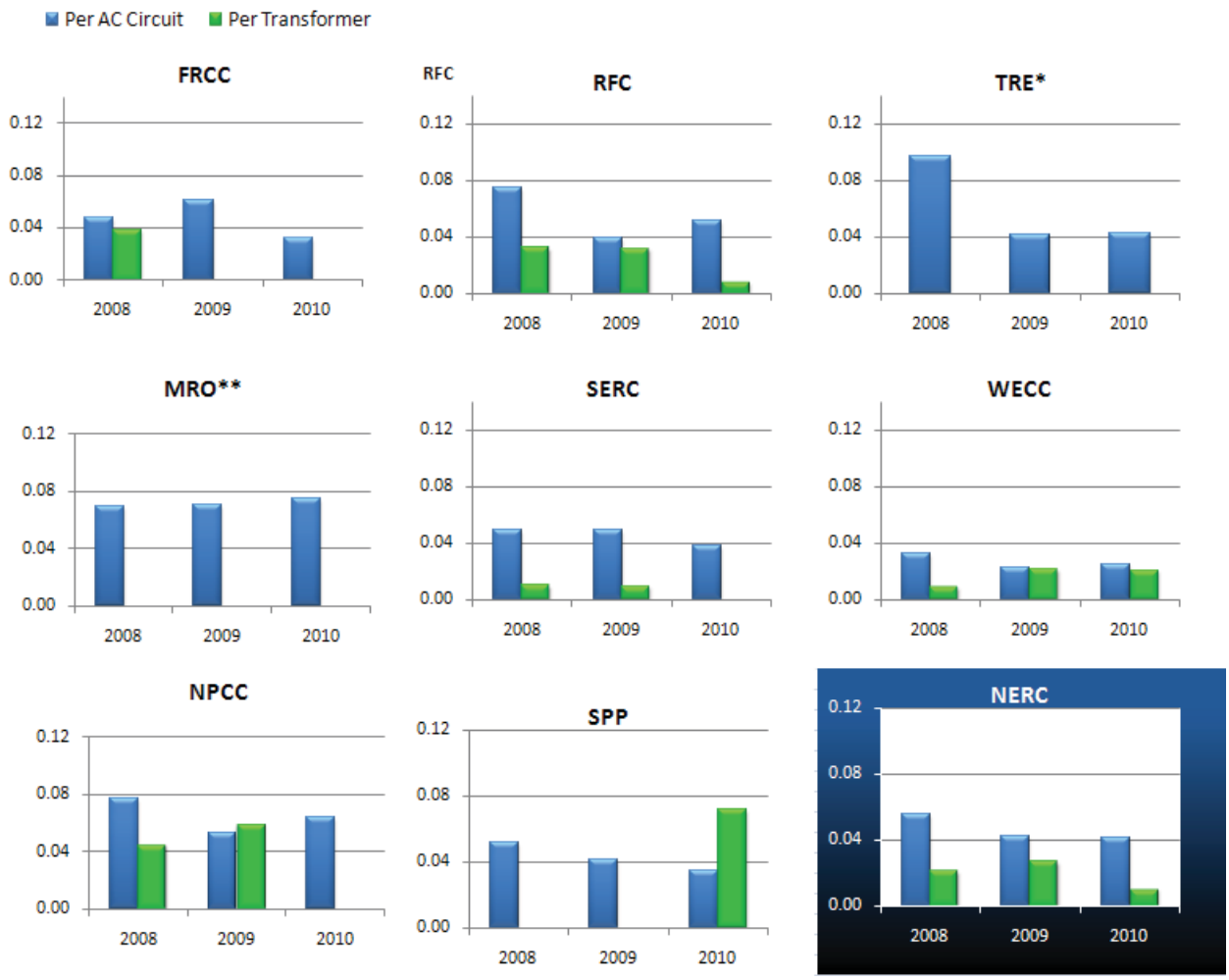

**Note: TRE has no transformers with low-side voltages at 200 kV and above.*

***Note: MRO has no transformer outage occurrences.*

This code covers automatic outages initiated by the failure of protection system equipment. This includes any relay and/or control misoperations, except those that are caused by incorrect relay or control settings that do not coordinate with other protective devices.

ALR6-12 – Automatic Outages Initiated by Human Error

Figure 11 shows the automatic outages with an initiating cause code of human error. This code covers automatic outages initiated by any incorrect action traceable to employees and/or contractors for companies operating, maintaining, and/or providing assistance to the Transmission Owner.

Figure 11: ALR6-12 by Regional Entity (Includes NERC-Wide)

**Note: TRE has no transformers with low-side voltages at 200 kV and above.*

***Note: SPP has no transformer outage occurrences.*

Also, any human failure or interpretation of standard industry practices and guidelines that initiate an automatic outage will be reported in this category.

ALR6-13 – Automatic Outages Initiated by Failed AC Substation Equipment

Figure 12 shows the automatic outages with an initiating cause code of failed AC substation equipment. This code covers automatic outages initiated by the failure of AC Substation; i.e., equipment "inside the substation fence" including transformers and circuit breakers but excluding protection system equipment.[24]

Figure 12: ALR6-13 by Regional Entity (Includes NERC-Wide)

**Note: TRE has no transformers with low-side voltages at 200 kV and above.*

[24]TADS Initiating Cause Code definitions are located at: http://www.nerc.com/docs/pc/tadswg/TADS_Definitions_Appendix_7_092909.pdf.

ALR6-14 Automatic AC Transmission Outages Initiated by Failed AC Circuit Equipment

Figure 13 shows the automatic outages with an initiating cause code of failed AC circuit equipment. These automatic outages are initiated by the failure of AC Circuit equipment, i.e., overhead or underground equipment "outside the substation fence." [25]

Figure 13: ALR6-14 by Regional Entity (Includes NERC-Wide)

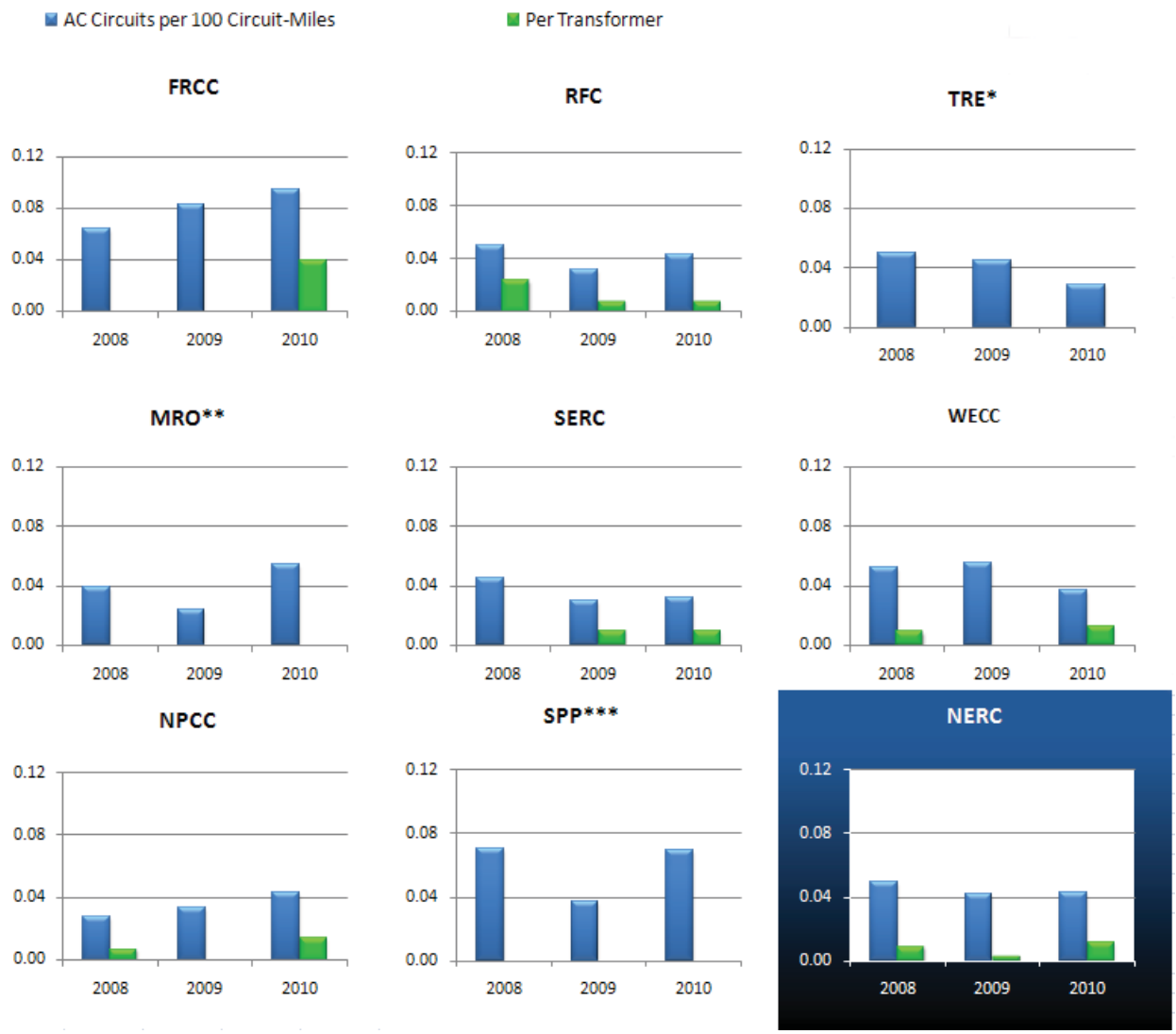

**Note: TRE has no transformers with low-side voltages at 200 kV and above.*

***Note: MRO and SPP have no transformer outage occurrences.*

[25] TADS Initiating Cause Code definitions are located at: http://www.nerc.com/docs/pc/tadswg/TADS_Definitions_Appendix_7_092909.pdf.

ALR6-15 Element Availability Percentage (APC)

Background

This metric uses data and calculations directly from the NERC TADS effort and provides the overall percent of time the aggregate of transmission facilities are available and in service. This is an aggregate value using sustained outages (automatic and non-automatic) for both lines and transformers operated at 200 kV and above for each Regional Entity, Interconnection, and for NERC.

Assessment

Figure 14 shows the aggregate element availability percentage (APC) for AC circuits and transformer facilities operated at 200 kV and above. The values are all over 90 percent. Continued metric assessment is required for at least a few more years in order to determine the value of this metric.

Figure 14: ALR6-15 Element Availability Percentages (2010)

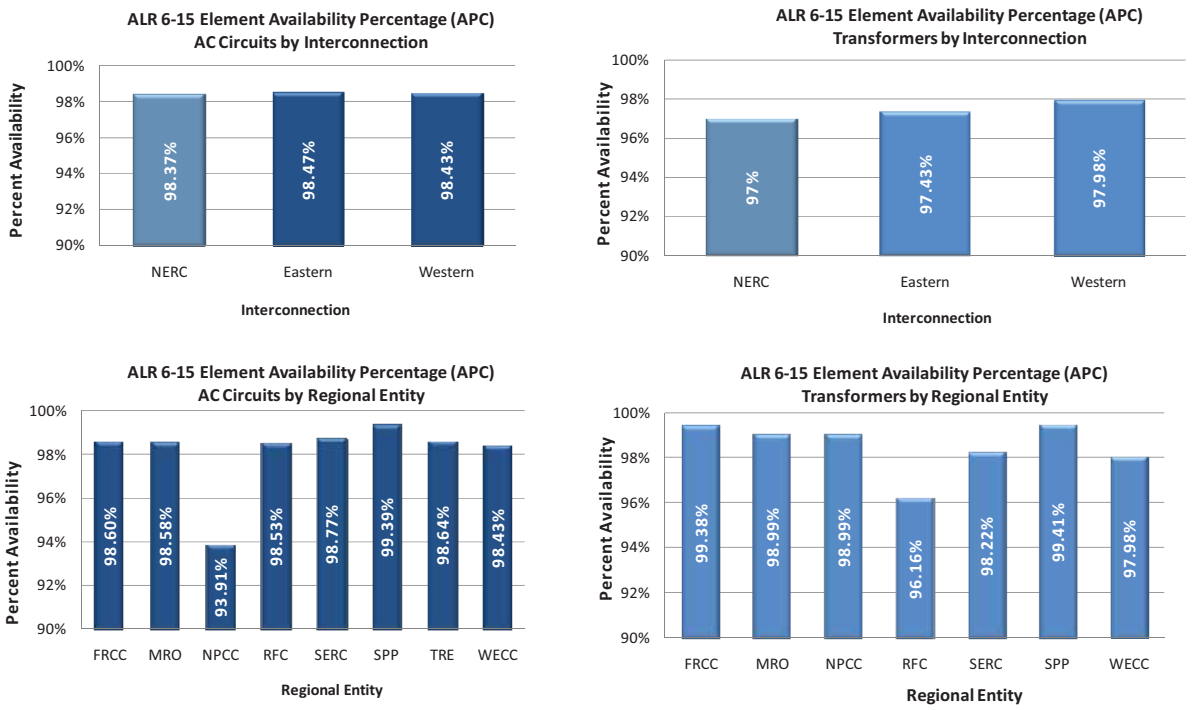

Notably, the Eastern Interconnection does not include Québec or ERCOT. ERCOT does not have transformers with low-side voltages at 200 kV and above.

Special Consideration

The non-automatic outage data needed to calculate this metric was first collected for the calendar year 2010 as part of the TADS process.

ALR6-16 Transmission System Unavailability

Background

This metric uses data and calculations directly from the NERC TADS effort and shows the overall percent of time that AC circuit and transformer TADS elements are unavailable due to sustained automatic and non-automatic outages. This is an aggregate value using sustained outages for both AC circuits and transformers operated at 200 kV and above for each Regional Entity and consolidated values for NERC.

Assessment

Figure 15 and Figure 16 illustrate the 2010 aggregate unavailability percentage for AC circuits and transformer facilities operated at 200 kV and above. The values for AC circuits are all under 3 percent, which represents excellent system availability.

Continued metric assessment is recommended in order to determine the value of this metric.

Special Consideration

The non-automatic outage data needed to calculate this metric was first collected for the calendar year 2010 as part of the TADS process.

Figure 15: ALR6-16 Transmission System Unavailability (2010)

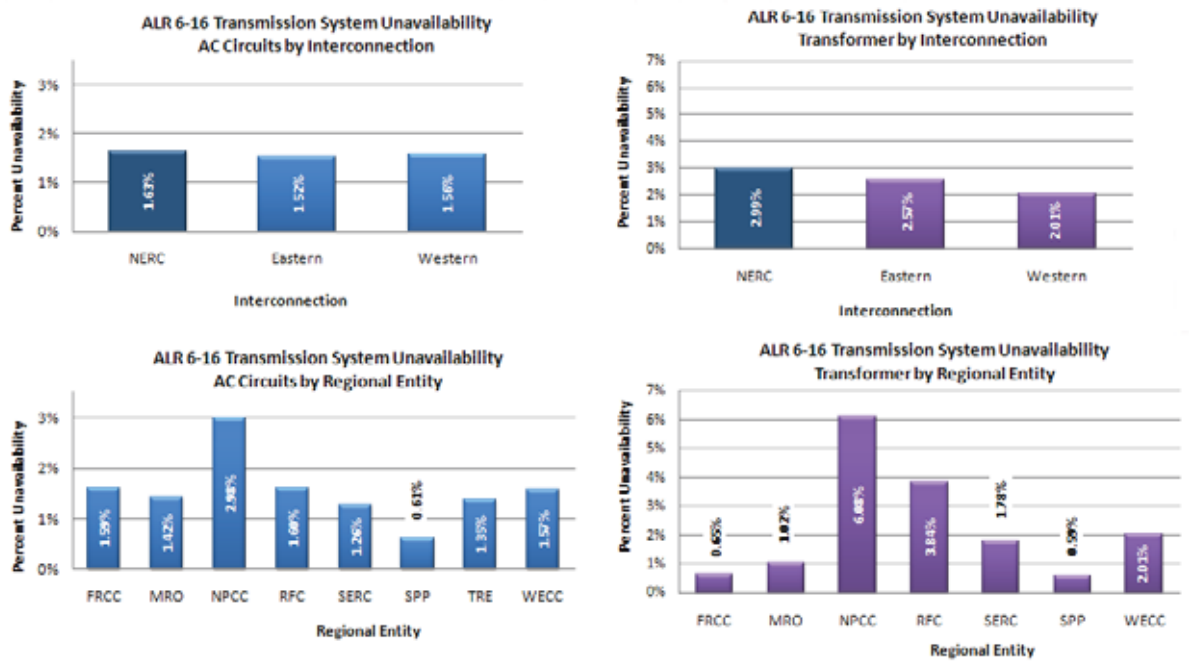

Figure 16: ALR6-16 Transmission System Unavailability by Outage Type (2010)

Notably, the Eastern Interconnection does not include Québec or ERCOT. Also, ERCOT does not have any transformers with low-side voltages at 200 kV and above.

ALR6-2 Energy Emergency Alert 3 (EEA3)

Background

This metric identifies the number of times Energy Emergency Alerts Level 3 (EEA3) is issued. EEA3 events are firm-load interruptions due to capacity and energy deficiency and is currently reported, collected and maintained in NERC's Reliability Coordinator Information System (RCIS), defined in the NERC Standard EOP-002.[26] The number of EEA3s per year provides a relative indication of performance measured at a Balancing Authority or Interconnection level. As historical data is gathered, trends provide an indication of either decreasing or increasing use of EEA3s, signaling adequacy of the electric supply system. This metric can also be considered in the context of Planning Reserve Margin. Significant increases or decreases in EEA3 events with relatively constant ALR1-3 Planning Reserve Margins could indicate changes in the adequacy of the bulk power system requiring review of resources.

[26] The latest version of EOP-002 is available at: http://www.nerc.com/page.php?cid=2|20.

Assessment

Figure 17 shows the number of EEA3 events from 2006 to 2010 at a Regional Entity level. An interactive presentation is available at the Reliability Indicator's page.[27] The number of EEA3s declared in 2010 was significantly reduced. The reason the EEA volume decreased from 2009 to 2010 in SPP was because the SPP ICT RC[28] coordinated an operating agreement between the five operating companies in the Acadiana Load Pocket (ALP). The operating agreement included a cost sharing re-dispatch that alleviated the need of a Transmission Loading Relief (TLR-5) declaration[29]. During 2009, there was no operating agreement; therefore, an entity had to provide Network and Native Load (NNL) relief when a TLR-5 was called by the ICT RC. When the TLR-5 was the primary tool to control the post contingent loading in the ALP, some of the BAs would have their firm transmission curtailed to the point where they could no longer serve their load; therefore, the EEA 3 was needed to communicate a capacity/reserve deficiency.

Figure 17: ALR6-2 Energy Emergency Alert 3 (EEA3) Counts by Regional Entity (2006-2010)

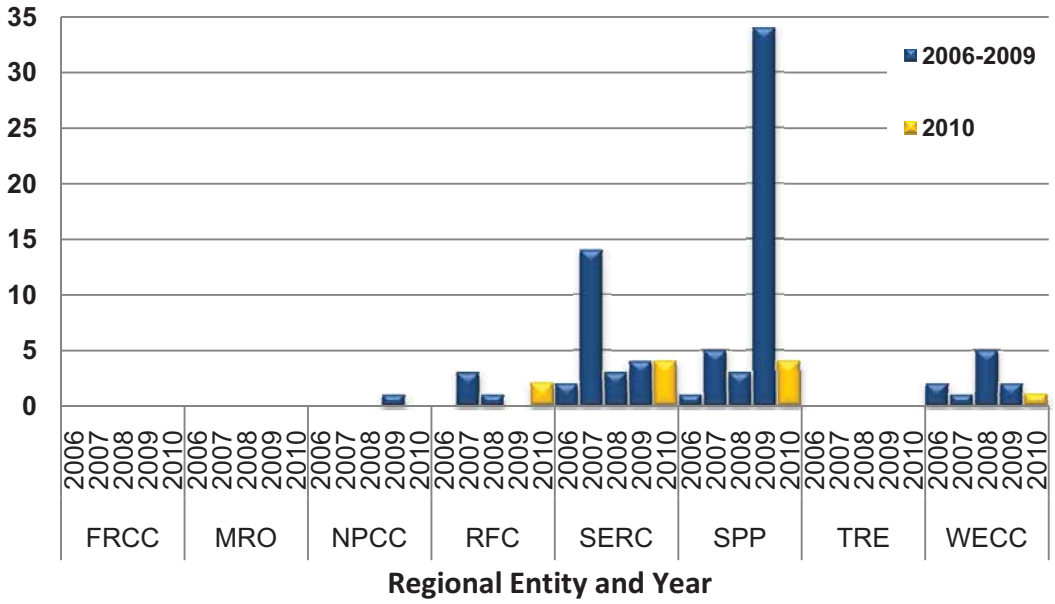

Cleco Power, Entergy and Lafayette Utilities System (LUS) are currently constructing an estimated $200 million transmission infrastructure improvement project to mitigate transmission constraints into ALP. Construction of the project is scheduled to be complete in 2012. Completion of the project should help alleviate some of the transmission congestion in this area. EEAs filed by the SPP Regional Entity continue to decline.

[27] The EEA3 interactive presentation is available on the NERC website at: http://www.nerc.com/page.php?cid=4|331|335.

[28] Southwest Power Pool (SPP) Independent Coordinator of Transmission (ICT) Reliability Coordinator (RC)

[29] More information on Transmission Load Relief is contained in the IRO-006 standard which is located at: http://www.nerc.com/files/IRO-006-4.pdf. In particular, TLR-5 definitions are referenced on page 16 and 17.

SPP RTO continues to coordinate operating plans with the operating entities in this area. Mitigation plans and local operating guides in place are expected to provide sufficient flexibility should issues arise. NERC will continue to monitor this area for Reliability Impacts and coordinate any actions with the SPP Reliability Coordinator and SPP Regional Entity.

Special Considerations

The need to include the magnitude and duration of the EEA3 declarations in this metric is under evaluation.

ALR 6-3 Energy Emergency Alert 2 (EEA2)

Background

The Energy Emergency Alert 2 (EEA2) metric measures the number of events that BAs declare for deficient capacity and energy during peak load periods. The number of EEA2 events, and any trends in their reporting, indicates how robust the system is in supplying aggregate load requirements. The EEA2 declarations may also serve as a leading indicator of energy and capacity shortfall in the adequacy of the electric supply system. EEA2 declarations provide a sense of the frequency of precursor events to more severe EEA3 declarations. This metric measures the number of events that Balancing Authorities declare for deficient capacity and energy during peak load periods. At this time, however, this data reflects inclusion of Demand Side Resources that would not be indicative of inadequacy of the electric supply system.

Demand response is a legitimate resource to be called upon by balancing authorities and does not indicate a reliability concern. The historical record may include demand response activations and non-firm load interruptions, per applicable contracts, within the EEA alerts.[30] EEA2 events called solely for activation of demand response or interruption of non-firm load per applicable contracts should be excluded from this metric.

This metric can also be considered in the context of the Planning Reserve Margin. Significant increases or decreases in EEA2 events with relatively constant Planning Reserve Margins could indicate volatility in the actual loads compared to forecasted levels or changes in the adequacy of the bulk power system required to meet load demands. As more data is gathered, there might be an indication of either decreasing or increasing adequacy in the electric supply system's Planning Reserve Margins.

Assessment

Figure 18 shows the number of EEA2 events by Regional Entity from 2006 to 2010 from the EEA2 interactive reports available online.[31] The general trend continues to show improved performance which may have been influenced by the overall reduction in demand throughout NERC caused by the economic downturn.

[30] The EEA2 is defined at http://www.nerc.com/files/EOP-002-2.pdf.

[31] EEA2 interactive version located at: http://www.nerc.com/page.php?cid=4|331|341.

There two issues that should be assessed further for the EEA2 metric. To begin, specific performance for any one region should be investigated for issues or events that may affect the results. Secondly, determining whether performance reported includes those events resulting from the economic operation of DSM and non-firm load interruption should also be investigated.

Figure 18: ALR6-3 Energy Emergency Alert 2 (EEA2)

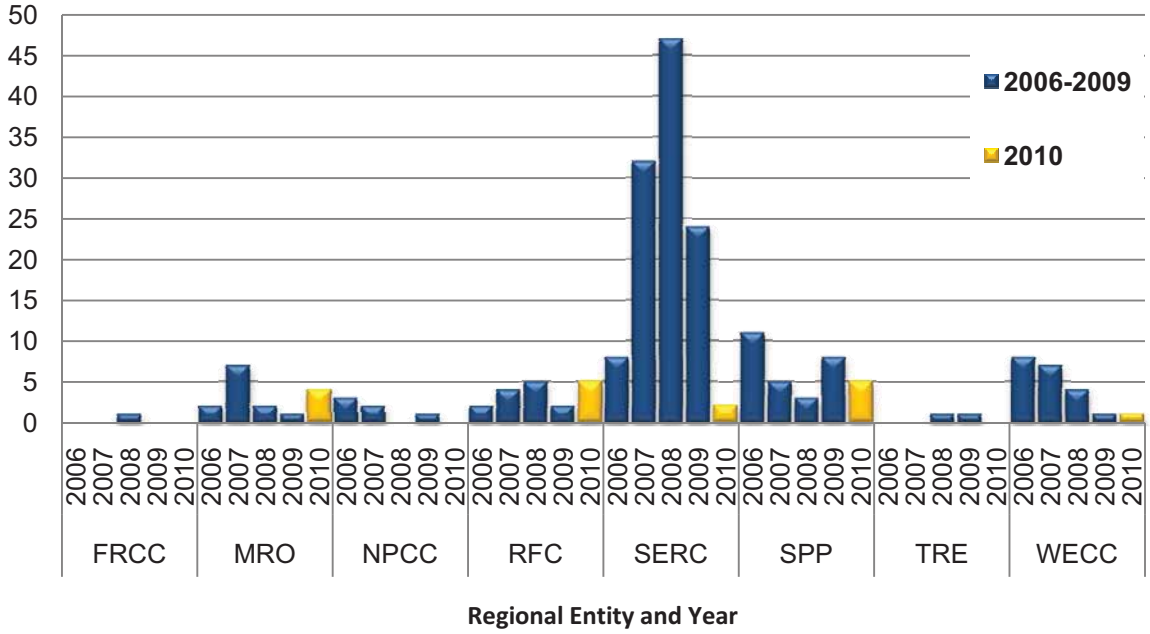

Special Considerations

The intent of this metric is to measure only EEAs that are called for reliability reasons and not for economic factors, such as demand side management (DSM) and non-firm load interruption. The historical data for this metric may include events that were called for economic factors. However, recent data should only include EEAs called for reliability reasons.

ALR 6-1 Transmission Constraint Mitigation

Background

The intent of this metric is to identify trends in the number of mitigation measures (Special Protection Schemes (SPS), Remedial Action Schemes (RAS), and Operating Procedures) required to meet Transmission Planning (TPL)[32] reliability requirements. By their nature, SPS do not indicate an inherent weakness in the bulk power system; they are an indication of methods that are taken to operate the system through the range of conditions it must perform.

[32] In particular, the standard is TPL-005-0 and is located at http://www.nerc.com/files/TPL-005-0.pdf.

Assessment

A pilot with four Regional Entities was completed and, based on the results, the pilot data collection was expanded to all regions. The initial results of the data collection are shown in Figure 19 and Table 5. Per Regional Entity, there are a relatively constant number of regional mitigation measure plans over the data collection time period.

Figure 19: ALR6-1 Transmission Constraint Mitigation by SPS/RAS (2009-2014)

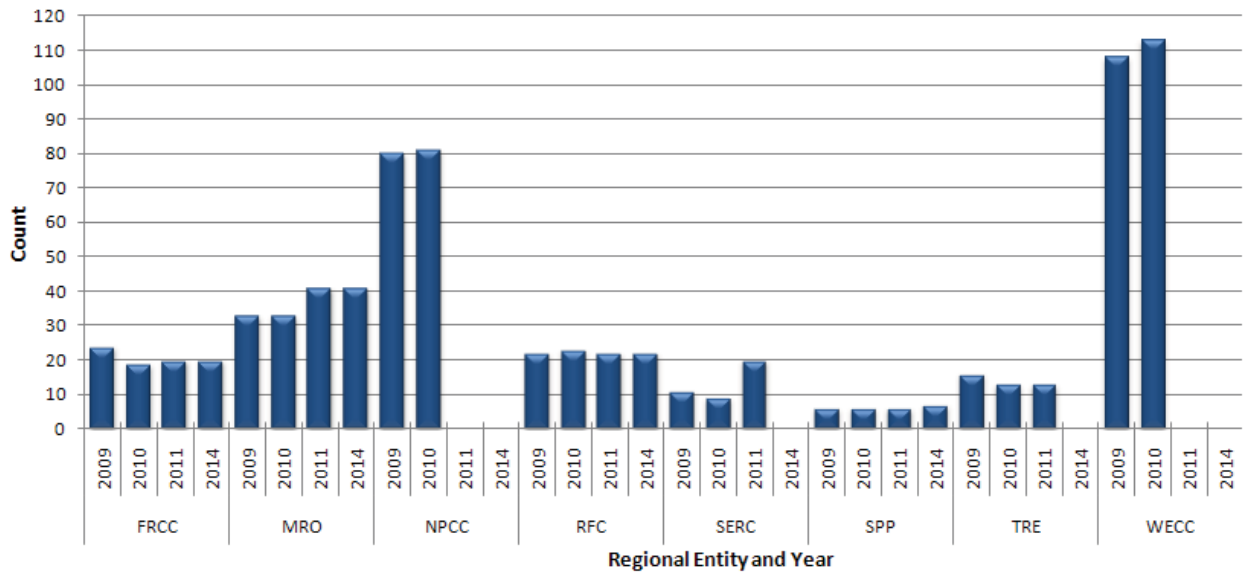

Table 5: ALR6-1 Transmission Constraint Mitigation by Operating Procedure/Guides (2009-2014)				
	2009	2010	2011	2014
FRCC	-	107	75	66
MRO	79	79	81	81
NPCC	-	-	-	-
RFC	2	1	3	4
SPP	39	40	40	40
SERC	6	7	15	-
TRE	29	25	25	-
WECC	110	111	-	-

**"-" data is not available.*

Special Considerations

This metric is only intended to evaluate the trend use of these plans, and whether the metric indicates robustness of the transmission system is increasing, remaining static, or decreasing. A certain number of SPS mitigation plans may be necessary to support reliable operation of the system. An increase of SPS may indicate additional, required transmission capacity is required. Correspondingly, a reduction in

the number of SPS may be an indicator of increased generation or transmission facilities being place in-service, which may imply greater robustness of the bulk power system. However, changes in the quantity of mitigation plans may indicate a year-on-year difference in the system being evaluated.

In general, mitigation plans are a viable and valuable tool for effective operation of the bulk power system. In power system planning, reliability, operability, capacity and cost-efficiency are simultaneously considered through a variety of system scenarios. Mitigation measures are a method for optimizing a power system across these scenarios.

Integrated Bulk Power System Risk Assessment

Introduction

In developing eighteen metrics to measure acceptable levels of reliability, any such measurement of reliability must include consideration of the risks present within the bulk power system to appropriately prioritize and manage these system risks. This approach not only can be used to measure risk reduction over time. Also, a uniform event analysis process can be applied to identify significant events for further detailed review.

The Operating Committee (OC) and Planning Committee (PC) endorsed the concepts and framework[33] of the risk-based approach in their September 2010 joint meeting, and further supported the event severity risk index (SRI) calculation[34] in March 2011.

Recommendations

- NERC should embrace the use of risk assessment to identify trends and lessons learned to improve bulk power system reliability.
- The SRI should be integrated into the event analysis process and root cause analysis.
- As trend evaluations increase the knowledge of risks to the bulk power system, data required to support additional assessment should be gathered.

Event Severity Risk Index (SRI)

Risk assessment is an essential tool for achieving the alignment between organizations, people and technology. This will assist in quantifying inherent risks, identifying where potential high risks exist, and evaluating where the most significant risk reduction can be achieved. NERC, the Regional Entities, and registered entities can use this tool to focus on the areas of highest reliability risk to provide a sound basis for development of results-based standards and compliance programs. Risk assessment also serves to engage all stakeholders in a dialogue about specific risk factors and a strategic plan for risk reduction and early detection.

[33] http://www.nerc.com/docs/pc/rmwg/Integrated_Bulk_Power_System_Risk_Assessment_Concepts_Final.pdf
[34] http://www.nerc.com/docs/pc/rmwg/SRI_Equation_Refinement_May6_2011.pdf

The SRI is a daily, blended metric where transmission loss, generation loss, and load loss events are aggregated into a single value that represents risk to the system. Each element (transmission, generation, and load loss) is weighted by the inventory for that element to rate significant events appropriately. On a yearly basis, these daily performance measurements are sorted in descending order to evaluate the year-on-year performance of the system.

To pilot the concepts, SRI values were derived for historically memorable days. Once these calculations were complete, they were reviewed and evaluated by various stakeholders for reasonableness. Based upon feedback, modifications to the calculation were made and assessed against the historic days. This iterative process locked down the details for the calculation of SRI with a range of zero (normal operation) to 1,000 (a theoretical condition in which every transmission line, all generation units and all load lost across the system in a single day).

Figure 20 captures the daily severity risk index value from 2008 to 2010 including the historic significant events used to pilot the calculation. Since there is significant disparity between normal days and events in terms of SRI values, the curve is depicted using a logarithmic scale. Each year's data is sorted in descending order. At the left-side of the curve, the days that the system is severely stressed are plotted. The central, more linear portion of the curve identifies the routine daily performance. Finally, the far, right side of the curve shows the values plotted for days when the system is operating normally.

Based on the SRI, 2009 and 2010 had fewer extreme days than 2008. Routine daily performance remains consistent across all three years. Figure 20 captures the days for each year benchmarked with historically significant events.

In Figure 20, the NERC event categories and SRI ratings are directly related. As the SRI increases, the category, or severity, of the event increases. Historical events are shown to give a perspective of how a well-known event would register on the SRI scale.

The event analysis process[35] benefits from the SRI as it enables a numerical comparison of events. By using this measure, an event can be prioritized by its severity. In a severe event, this is unnecessary. For most events, however, this prioritization can be a challenge. By using the SRI, the event analysis process can see which events to learn from and reduce, which events to avoid, and when resilience needs to be increased under high impact, low frequency events.

[35] http://www.nerc.com/page.php?cid=5|365

Figure 20: NERC Annual Daily Severity Risk Index (SRI) Sorted Descending with Historic Benchmark Days

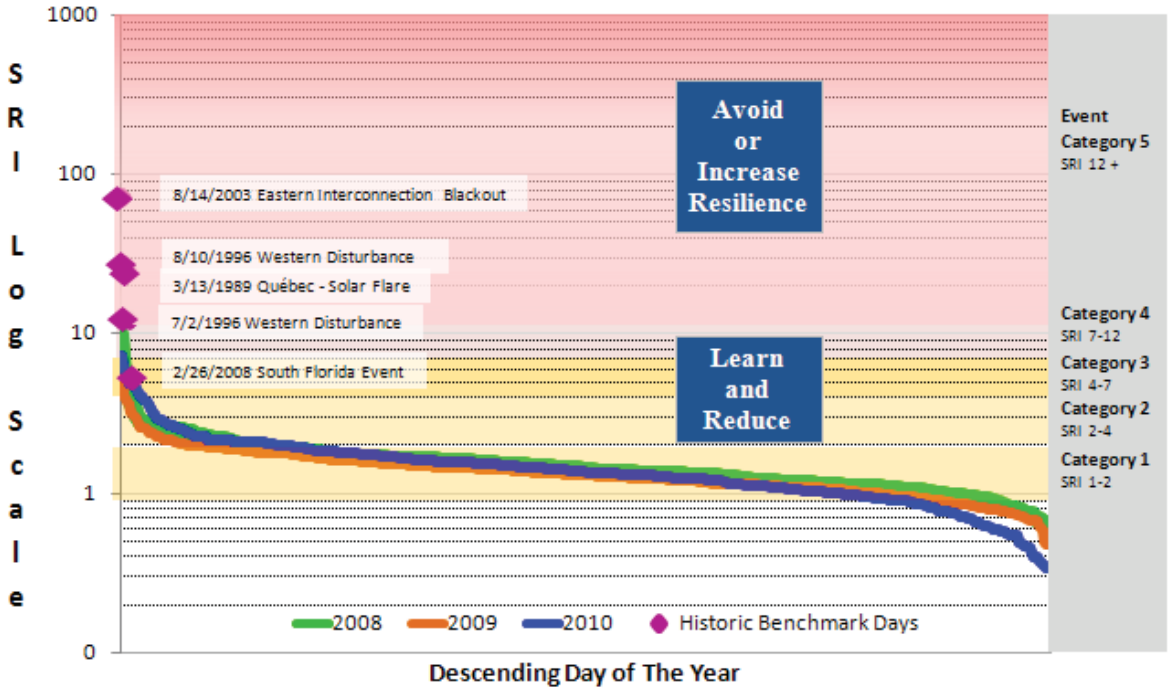

Other factors that impact severity of a particular event to be considered in the future include whether equipment operated as designed and resulted in loss of load from a reliability perspective (intentional and controlled load-shedding). Also, mechanisms for enabling ongoing refinement to include the historic and simulated events for future severity risk calculations are being explored.

While the SRI curves have become useful in characterizing the performance of the bulk power system, there are enhancements which would provide further benefit to the industry. Namely, the curve could provide greater value in assessing the performance of the system if the viewer were able to distinguish which days were fundamentally driven by causes outside the control of the industry, namely weather, and the extent to which the day's score was the result of the system operating as designed. This could result in particular data points being shown as a range of performance, with the "as experienced" performance could be compared against a calculated "as designed" performance.

Reliability Metrics Conclusions and Recommendations

Among the eighteen metrics that address the characteristics of an adequate level of reliability (ALR), trends indicate the system is performing better in the following seven areas:

- ALR1-3 Planning Reserve Margin
- ALR1-4 BPS Transmission Related Events Resulting in Loss of Load
- ALR2-5 Disturbance Control Events Greater than Most Severe Single Contingency
- ALR6-2 Energy Emergency Alert 3 (EEA3)
- ALR6-3 Energy Emergency Alert 2 (EEA2)
- ALR6-11 Automatic Transmission Outages Initiated by Failed Protection System Equipment
- ALR6-13 Automatic Transmission Outages Initiated by Failed AC Substation Equipment

Many of the remaining metrics do not have sufficient data to derive useful conclusions. With a more thorough data matrix, more conclusions about reliability could be drawn. All metrics will be assessed on a regular basis to determine their contribution to quantitative reliability measurement. In addition to further collection, an investigation into the data collection processes for some metrics will also be investigated. In particular, a study should be conducted to determine the usefulness of a 100 MW load loss threshold for ALR2-3.

For the IRI, more investigation is needed to determine the overlap of the components (CDI, EDI, and SDI). At this time, components of the IRI should be solidified before the IRI will be useful. In particular, the CDI should be more thoroughly understood as an index by collecting more data over time.

Future Advancements: Integrated Reliability Index

As the next step to the severity risk index, an integrated reliability index (IRI) is under development to provide a more complete bulk power system reliability picture. Currently, the concept of the IRI is in a whitepaper status.[36] Upon completion, the IRI should peer beyond the severity risk index's narrow, event based scope and illuminate a broader, quantitative picture of total bulk power system reliability.

The IRI is composed of three component indices that attempt to capture different families of risk to the bulk power system. These are the Event Driven Index (EDI), Standards/Statute Driven Index (SDI), and Condition Driven Index (CDI) as shown in Figure 21.

The ultimate goal of the IRI is to provide the industry meaningful trends of the bulk power system's performance and guidance on how the industry can improve reliability and support risk-informed decision making. The development of these composite indices aims to inform, increase transparency, and quantify the effectiveness of risk reduction or mitigation actions. Also, these metrics will facilitate unitary assessment of risks which impacted reliability of the bulk power system.

[36] http://www.nerc.com/docs/pc/rmwg/Integrated_Reliability_Index_WhitePaper_DRAFT.pdf

Figure 21: Risk Model for Bulk Power System

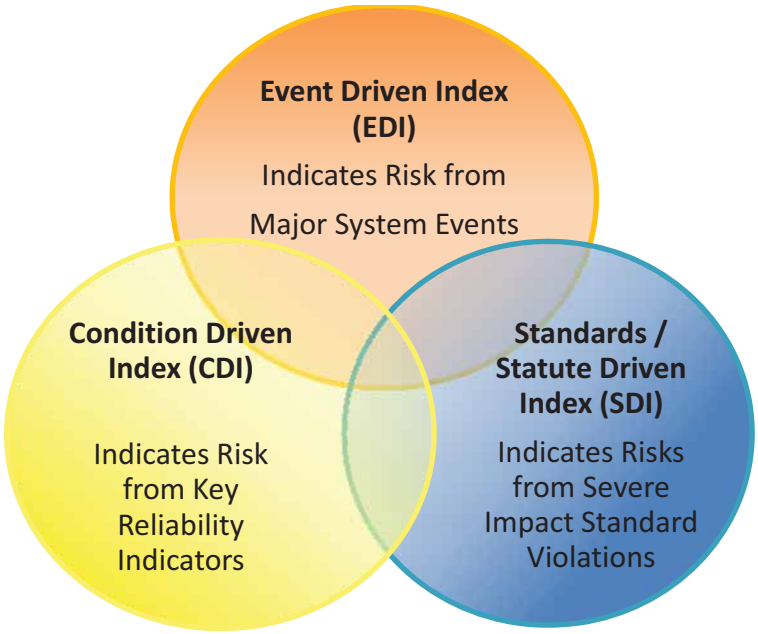

The integrated model of event-driven, condition-driven, and standards/statute-driven risk information can be constructed to illustrate all possible logical relations between the three risk sets. Due to the nature of the system, there is some overlap among the components. This overlap and its implications to blended metric calculations will be explored in the future.

The Three Components of the IRI

The three components of the IRI work together as shown in Figure 22 to comprise a full picture of the state of reliability.

Figure 22: An overview of the components that comprise the Integrated Reliability Index (IRI)

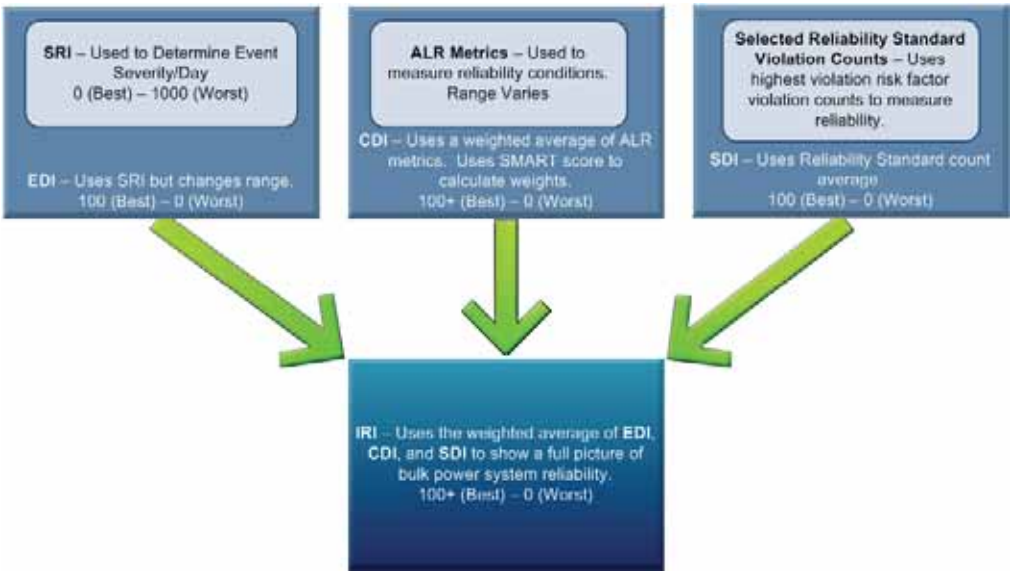

Event-Driven Index (EDI)

The Event-Driven Index provides a basis for the prioritization of events, based on bulk power system integrity, equipment performance, and engineering judgment. This indicator can serve as a high value risk assessment tool to investigate disturbance history and measure the severity of events. Currently, the EDI is a derivative of SRI results for a specific time period, but it transforms that performance into a form of an availability index. However, the specific formula for the EDI is under development.

Condition-Driven Indicators (CDI)

The Condition-Driven Indicators focus on a set of measurable system conditions (performance measures) to assess bulk power system reliability. The CDI will use metrics that directly tie to acceptable level of reliability (ALR) characteristics. These metrics will overlap all components of reliability and provide the majority of the IRI component data.

However, there is not yet a comprehensive set of metrics for each of the characteristics of reliability, nor is there sufficient history to know what the benchmark for any of these values should be. In the interim, this composite metric should be lessened in importance, but continue to be explored to achieve its long-term value to the industry.

Standards/Statute-Driven Indicators (SDI)

The Standards/Statute-Driven Indicator measures the success of compliance, based upon the subset of high-value standards, and is divided by the number of participants who could have received the violation within the time period considered. Also, based on these factors, known unmitigated violations of elevated risk factor requirements are weighted higher than lower risk factors. The index decreases if the compliance improvement is achieved over the trending period.

IRI Index Calculation

At this time, three individual components should be strengthened separately and should be blended into a single metric. The final integration should only occur after each component index bears sufficient relevance to actual reliability. To perform integration of the component indices, each component would be weighted and a combining formula would be used to calculate IRI.

The conceptual model for developing a single IRI would inherently include future modification. This modification would be necessary after gaining experience with the new metric and consideration of the industry's feedback. The IRI is intended to be a composite metric which integrates several forms of individual risks to the bulk power system. Since the three components range across many stakeholder organizations, any integrating formula is only a starting point for continued study and evaluation.

IRI Recommendations

For the IRI, more investigation should be performed to determine the best way to integrate EDI, CDI, and SDI into an Integrated Reliability Index (IRI) that quantitatively represents the reliability of the bulk power system. To this end, study into determining the amount of overlap between the components is

necessary. Also, the CDI component of the IRI needs to be solidified. More accurate metric data is needed to paint a fuller picture of system conditions. Many of the metrics used to calculate the CDI are new, or have limited supporting data. Compared to the SDI, which measures well-known violation counts, and the EDI, which uses the well-defined SRI, the CDI lacks the depth of rigor and should be improved with further investigation.

Transmission Equipment Performance

Introduction

The Transmission Availability Data System (TADS) was launched with the establishment of a TADS task force by the NERC Planning Committee in October 2006[37]. On October 27, 2007, the NERC Board of Trustees approved the collection of automatic transmission outage data beginning in calendar year 2008 (Phase I). Subsequently, on October 29, 2008, the NERC Board of Trustees approved the collection of non-automatic outage data beginning in calendar year 2010 (Phase II).

This chapter focuses on automatic outage trends from calendar year 2008 to 2010. Since only one year of non-automatic outages has been collected, insufficient information is available for use in this report.

When calculating bulk power system performance, care must be exercised when interpreting results. Misinterpretation can lead to erroneous conclusions regarding system performance. A mathematical confidence interval technique was applied to determine the relevance of trending for transmission metrics.[38] On a regional basis, there was not enough data to perform statistically relevant trending. On a NERC-wide basis, however, there is enough information to accurately determine whether the yearly outage variation compared to the average is due to random statistical variation, or the particular year in question is significantly different in performance.

Performance Trends

Transmission performance information has been provided by Transmission Owners (TOs) within NERC through the NERC TADS process. The data presented reflects momentary and sustained AC automatic outages of transmission elements that operate at voltages greater than or equal to 200 kV with the criteria specified in the TADS process. The following elements listed below are included:

- AC Circuits ≥ 200 kV (Overhead and Underground Circuits). Radial circuits are included;
- DC Circuits with ≥ +/-200 kV DC voltage;
- Transformers with ≥ 200 kV low-side voltage; and
- AC/DC Back-to-Back (BTB) Converters with ≥ 200 kV AC voltage, on both sides.

[37] For additional details on TADS, the Data Reporting Instruction Manual is located at: http://www.nerc.com/docs/pc/tadswg/Data%20Reporting%20Instr%20Manual%2020101202a%20clean.pdf.

[38] The detailed Confidence Interval computation is available at: http://www.nerc.com/docs/pc/tadstf/TADS_Nov_2_2007APPENDIX_C_Confidence_Interval.pdf.

AC Element Outage Summary and Leading Causes

Table 6 shows the 2008, 2009, and 2010 NERC total AC transmission element inventory and a summary of the associated outages. The number of circuits increased from year-to-year due to new construction or reconstruction to higher voltages. For every outage experienced on the transmission system, cause codes are recorded according to the TADS process.[39] Causes of both momentary and sustained outages have been indicated. These causes are analyzed to identify trends, similarities, and to provide insight into what could be done to prevent future occurrences.

Figure 23 and Figure 24 describe the top ten initiating cause codes for sustained and momentary automatic outages from 2008 to 2010. Based on the two figures, the relationship between the total number of outages and total outage hours are provided. Failed AC Substation Equipment and Failed AC Circuit Equipment are the top two causes of sustained outage hours with 65 percent of the total outage hours. The two largest causes of momentary outage hours within NERC are "Lightning" and "Weather, excluding Lightning".

Importantly, Human Error, Failed Protection System Equipment, and Failed AC Circuit Equipment initiating cause codes have very similar totals numbers of outages and should all be considered significant focus points in reducing the number of sustained automatic outages for all elements.

[39]Please refer to section F in http://www.nerc.com/docs/pc/tadswg/Appendix%207%2020101202a%20clean.pdf for TADS automatic outage codes.

Table 6: NERC - All AC Elements Sustained and Momentary Outage Performance Summary*

2008 Number of Outages						
AC Voltage Class	No of Circuits	Circuit Miles	Sustained	Momentary	Total Outages	Total Outage Hours
200-299kV	4,369	102,131	1,560	1,062	2,622	56,595
300-399kV	1,585	53,631	793	753	1,546	14,681
400-599kV	586	31,495	389	196	585	11,766
600-799kV	110	9,451	43	40	83	369
All Voltages	6,650	196,708	2,785	2,051	4,836	83,626
2009 Number of Outages						
AC Voltage Class	No of Circuits	Circuit Miles	Sustained	Momentary	Total Outages	Total Outage Hours
200-299kV	4,468	102,935	1,387	898	2,285	28,828
300-399kV	1,619	56,447	641	610	1,251	24,714
400-599kV	592	32,045	265	166	431	9,110
600-799kV	110	9,451	53	38	91	442
All Voltages	6,789	200,879	2,346	1,712	4,038	63,094
2010 Number of Outages						
AC Voltage Class	No of Circuits	Circuit Miles	Sustained	Momentary	Total Outages	Total Outage Hours
200-299kV	4,567	104,722	1,506	918	2,424	54,941
300-399kV	1,676	62,415	721	601	1,322	16,043
400-599kV	605	31,590	292	174	466	10,442
600-799kV	111	9,477	63	50	113	2,303
All Voltages	6,957	208,204	2,582	1,743	4,325	83,729

**Note: The NERC table does not show redacted outages, DC Circuit outages, Transformer outages, or AC/DC converter outages.*

Figure 23: NERC - Top Ten Momentary Automatic Outage Hours by Cause Code

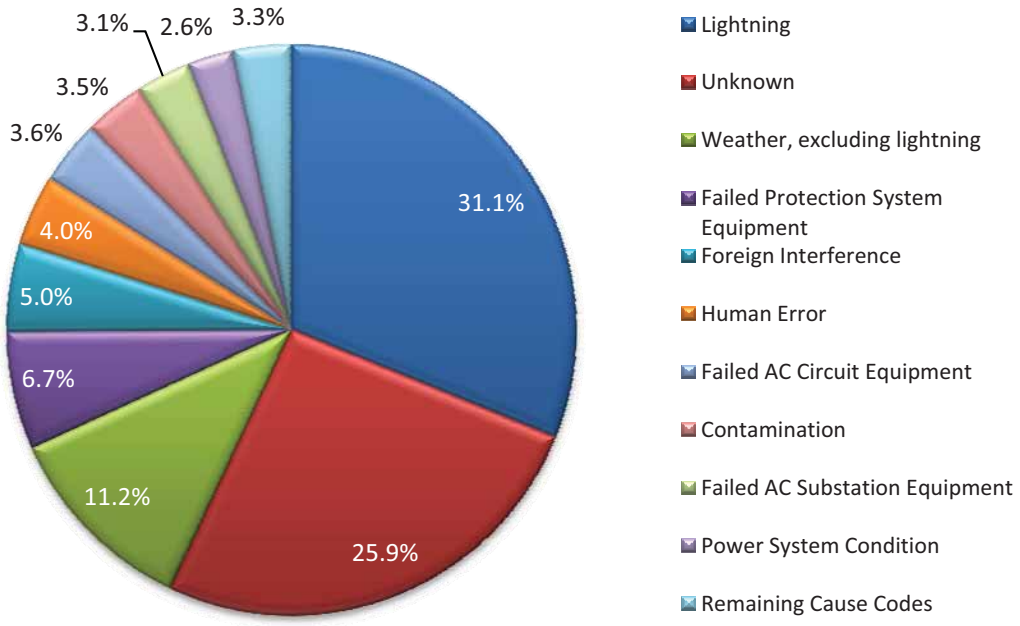

Figure 24: NERC - Top Ten Sustained Automatic Outage Hours by Cause Code

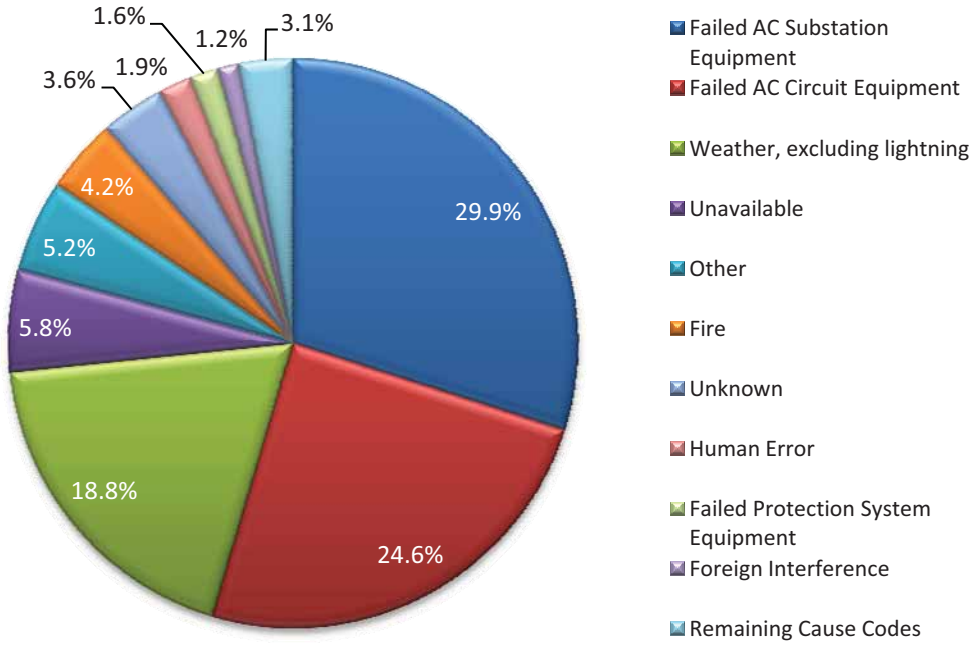

Transmission Monthly Outages

Figure 25 displays the total number of automatic outages on a monthly basis. The three months with the highest total of automatic outages were June, July, and August. From a seasonal perspective, winter, November 1 to the end of February, had a monthly, 3-year average of 271 outages. Summer, June 1 through September 30, had a monthly, 3-year average of 453 outages. Summer included the months of April-October

Figure 25: Number of Automatic Outages by Month for AC Circuits (2008-2010)*

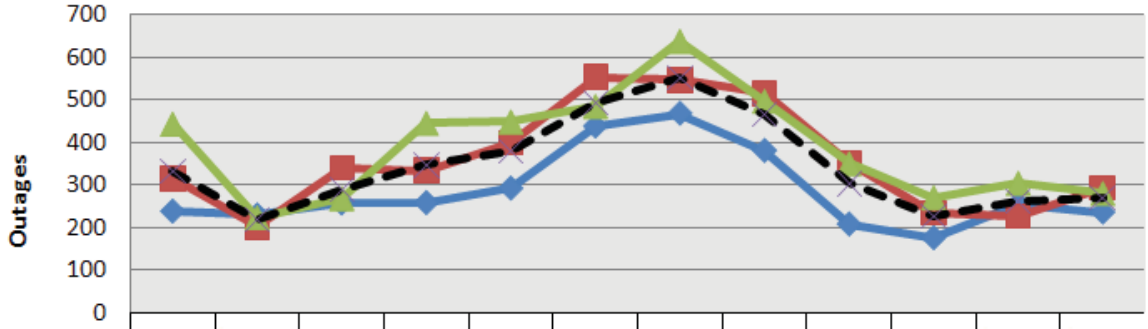

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2008	238	229	257	258	292	437	467	380	208	176	255	236
2009	315	201	339	334	398	553	546	515	351	235	226	294
2010	444	224	269	446	449	486	639	498	351	271	305	281
3 Year AVG	332	218	288	346	380	492	551	464	303	227	262	270

**This figure does not show redacted outages, DC Circuit outages, Transformer outages, or AC/DC Converter outages.*

Outage Initiation Location

For every outage experienced on the transmission system, the outage initiation code is identified and recorded. The outage initiation code can be measured to identify trends and similarities and provide insight into areas for improvement.

The "Outage Initiation Code" describes where an automatic outage was initiated on the power system. The five codes are as follows:

- Element-Initiated
- Other Element-Initiated
- AC Substation-Initiated
- AC/DC Terminal-Initiated (for DC circuits)
- Other Facility Initiated: any facility not included in any other outage initiation code

Notably, the protection system is not part of an "AC Substation" or an "AC/DC Terminal". If a protection system misoperates and initiates an outage, it will be classified as "Other-Facility Initiated". Figure 26 and

Figure 27 show the initiating location of sustained and momentary automatic outages from 2008 to 2010. With both momentary and sustained automatic outages taken into account; the outage was initiated on the TADS element –AC circuit or transformer– more than 60 percent of the time, as shown in Figure 26 and Figure 27.

Figure 26: Sustained Automatic Outage Initiation Code

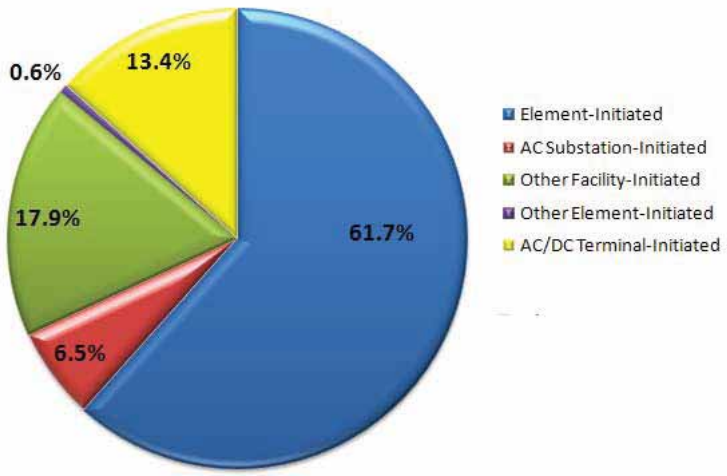

Figure 27: Momentary Automatic Outage Initiation Code

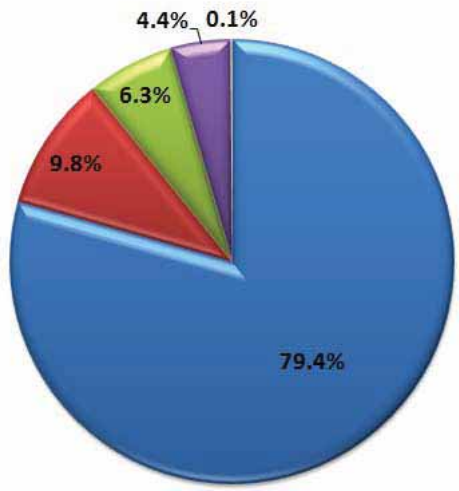

Transmission Outage Events

Figure 28 illustrates the relationship between the numbers of automatic outages per TADS event. All three years, 2008, 2009, and 2010, follow a similar trend. The largest number of automatic outages per event is fourteen in 2010, thirteen in 2009, and eight in 2008. There are around 70 to 100 events that contain between fourteen and three automatic outages (see below). There are around 330 to 400 events that contain two or more automatic outages. Each of the other events contains only one automatic outage. In the figure, the total number of events in 2008 to 2010 ranged from 3,920 to 4,569 events per year. In 2010, over 90 percent of TADS events contained at least one automatic outage.

Figure 28: Event Histogram (2008-2010)

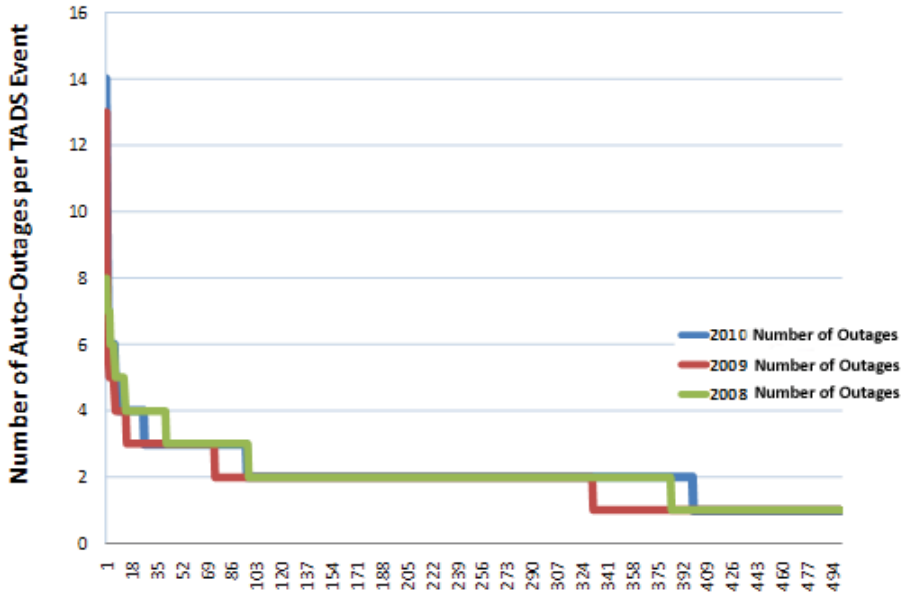

Top 500 out of 12,612 events from 2008-2010:
- 4,569 events in 2008
- 3,920 events in 2009
- 4,123 events in 2010

Transmission Outage Modes

Figure 29 and Figure 30 show the percentage of outage modes. The "outage mode code" relates one automatic outage to other automatic outages. A definition of each outage mode code is provided in Table 7.

Table 7: Outage Mode Codes

Outage Mode Code	Automatic Outage Description
Single Mode	A single element outage which occurs independently of another automatic outage
Dependent Mode Initiating	A single element outage that initiates at least one subsequent element automatic outage
Dependent Mode	An automatic outage of an element which occurred as a result of an initiating outage, whether the initiating outage was an element outage or a non-element outage
Common Mode	One of at least two automatic outages with the same initiating cause code where the outages are not consequences of each other and occur nearly simultaneously
Common Mode Initiating	A common mode outage that initiates one or more subsequent automatic outages

Over 70% of sustained and momentary automatic outages are single mode. This reinforces the long held belief that the majority of all sustained and momentary automatic outages are single mode. However, a significant percent of automatic outages, 29.6% sustained and 22.6% momentary, are in the dependent or

common mode family. Based on the design criteria of withstanding single mode outages, the discovery of significant non-single mode outages might be a reliability risk.

An investigation into the root causes of dependent and common mode events which include three or more automatic outages, identified in the 2008 to 2010 data, is a high priority. Some protection systems are designed to trip three or more circuits, but some events go beyond what is designed. In addition, protection system misoperations are associated with a number of multiple outage events.

Figure 29: Sustained Automatic Outage Mode Code (2008-2010)

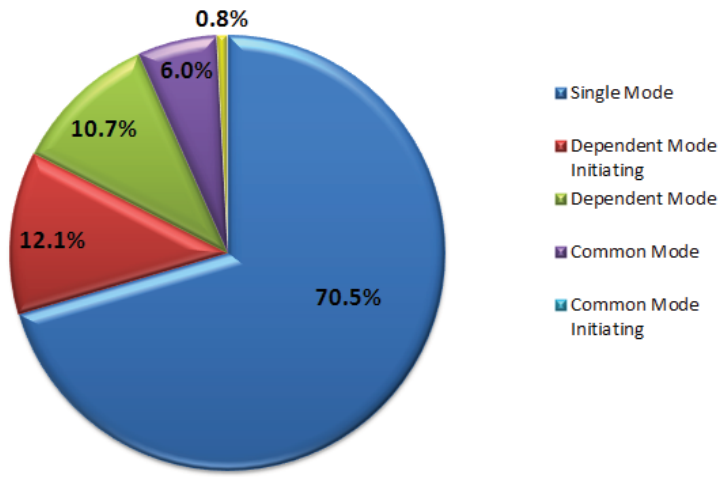

Figure 30: Momentary Automatic Outage Mode Code (2008 -2010)

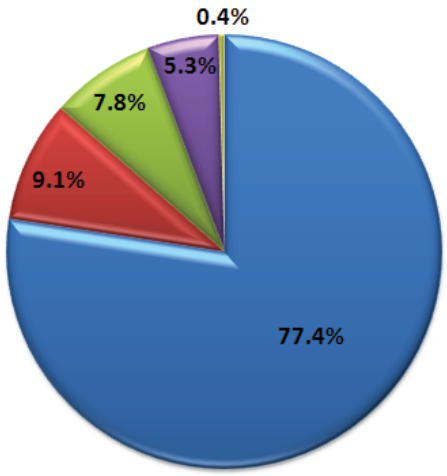

Conclusions

On a NERC-wide average basis, the automatic transmission outage rates are improving from 2008 to 2010. For 2010, the data indicates that the transmission element availability percentage exceeded 95%.

There are two potential improvements to reliability based on the data. Firstly, the cause codes of Human Error, Failed Protection System Equipment, and Failed AC Circuit should be a focal point to reduce the number of sustained automatic outages for all elements. Secondly, a deeper investigation into the root causes of dependent and common mode events which include three or more automatic outages is a high priority. Therefore, a joint team should be formed to analyze dependent and common mode events. These events, which go beyond design criteria, represent a tangible threat to reliability. More analysis would improve the design basis assumed for reliable operation of the system.

Generation Equipment Performance

Introduction

The development of the Generating Availability Data System (GADS) began in 1982. This data system collects, records, and retrieves voluntarily provided operating information. By pooling individual unit information, generating unit availability performance is calculated. Also, the information supports equipment reliability, availability analyses and risk-informed decision-making to relevant parties. Finally, reports and information resulting from the data collected through GADS are now used for benchmarking and analyzing electric power plants.

Currently, the data collected through GADS contains 72 percent of North American generating units with generating capacity of 20 MW or higher.[40] However, many newer combined-cycle plants are not reporting information, and a full view of each unit type is not presented. Rather, a sample of all the units in North America that fit a given, more general category is provided[41] for the 2008 to 2010 assessment period.

Generation Key Performance Indicators

Three key performance indicators[42] used to measure the availability of generating units are Equivalent Availability Factor (EAF), Net Capacity Factor (NCF), and Equivalent Forced Outage Rate – Demand (EFORd). In Table 8, the North American fleet average EAF, NCF, and EFORd compared to unit age for all generating units with a capacity of 20 MW and higher is provided for the years 2008-2010. For this period, the same group of units was used, so a true measure of comparable trending could be completed. During the last three years, the EAF has declined, NCF dropped in 2008 and has partly recovered in 2010, and EFORd has increased. Overall, the fleet of units reported to GADS is aging overall. On a three-year average, fossil units are around 12 years older than the rest of the fleet.

During this three-year period, the average FOH was 287 hours, average MOH (including extensions to MO) was 171 hours, and the average POH (with extensions of PO) was 470 hours as shown in Figure 31.

Table 8: General Availability Review of GADS Fleet Units by Year*

	2008	2009	2010	Average
Equivalent Availability Factor (EAF)	87.52	87.53	86.38	87.15
Net Capacity Factor (NCF)	50.49	46.87	48.30	48.55
Equivalent Forced Outage Rate - Demand (EFORd)	5.66	5.57	6.24	5.82
Number of Units ≥20 MW	3,991	3,991	3,991	3,991
Average Age of the Fleet in Years (all unit types)	31.1	31.9	33.0	32.0
Average Age of the Fleet in Years (fossil units only)	42.2	43.2	44.3	43.2

**Includes only GADS reporting units with greater than 20MW generation capability*

[41] GADS contains 1,500+ units under 20 MW that are not included in this report.

[42] http://www.nerc.com/page.php?cid=4|43

Figure 31: Average Outage Hours for Units > 20 MW

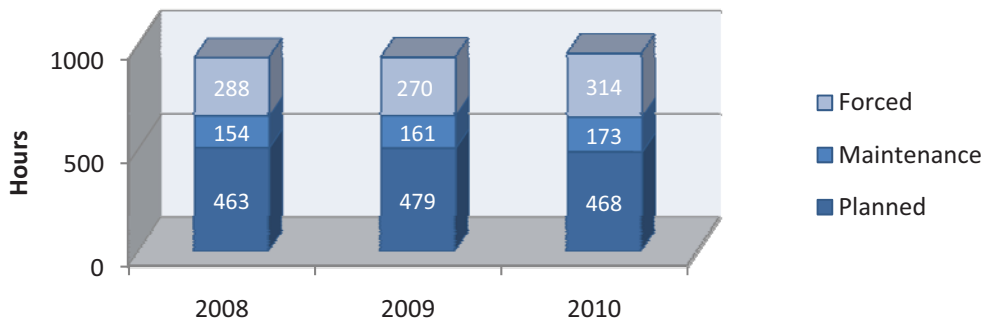

Forced outage hours jumped from 266 to 310 hours per unit between 2009 and 2010. At the same time, maintenance events also increased by 24 hours per unit. Planned outage events experienced a slight increase. More planned outage time is needed to repair the generating fleet. Whether age is the cause of the increased need for planned outage time remains unknown, and further investigation into the cause for longer planned outage time is warranted, if the trend continues.

Multiple Unit Forced Outages and Causes

Multiple unit forced outages constitute a reliability risk, and the trend of multiple unit outages is tracked. Table 9 provides the annual multiple-unit forced outage trips resulting from the same cause for each of the assessment years, 2008 to 2010. The "single unit" trips are large units with a Net Dependable Capacity of 750 MW or more. The trip of "two units" or more is any combination of unit capacity with the total amount of lost capacity more than 750 MW.

Table 9 also presents more information on a particular pattern of outages. During 2008-2010, there were a large number of double-unit outages resulting from the same event. Investigations show that some of these trips were at a single plant, caused by common control and instrumentation for the units. The incidents occurred several times for several months and are a common mode issue internal to the plant.

Table 9: Number of Multiple Unit Forced Outages and Frequency/Year*

	2008			2009			2010		
Type of Unit Trip	**# of Trips**	**Avg Outage Hr/ Trip**	**Avg Outage Hr/ Unit**	**# of Trips**	**Avg Outage Hr/ Trip**	**Avg Outage Hr/ Unit**	**# of Trips**	**Avg Outage Hr/Trip**	**Avg Outage Hr/ Unit**
Single	591	58	58	284	64	64	339	66	66
Two	281	43	22	508	96	48	206	41	20
Three	74	48	16	223	146	48	47	109	36
Four	12	77	19	111	112	28	40	121	30
Five	11	1,303	260	60	443	88	19	199	10
> Five	20	166	16	93	206	50	37	246	6

**Loss of ≥ 750 MW per Trip*

In 2008, the high five-unit average outage hours/trip is attributed to damage and cleanup from Hurricane Ike hitting the Gulf Coast. The highest total number of multiple unit trips occurred in 2009; however, the data collection for 2010 is incomplete. The majority of 2009 multiple unit trips have three main causes, transmission, lack of fuel, and storms. A summary of the three categories for single and multiple unit outages are reflected in .

Table 10: Top Three Causes of Multiple Unit Forced Outages (2009)*

Cause	Number of Events	Average MW Size of Unit
Transmission	1,583	16
Lack of Fuel (Coal Mines, Gas Lines, etc.) Not in Operator Control[43]	812	448
Storms, Lightning, and Other Acts of Nature	591	112

**Includes all unit capacities*

In 2009, many of the storm-based, transmission outages were caused by the same reasons because the storms may have caused transmission interference. However, the plants reported the problems inconsistently with either the transmission interference or storms cause code. Therefore, they are depicted as two different causes of forced outage. Transmission caused outages were much higher than the number two and three causes. Thirty-five percent came from one utility with a large number of hydroelectric units. The company related the trips to various problems including weather (lightning, storms), wildlife, "line bumps", and problems on the receiving end of the transmission line. Nine hundred and eighty-five transmission trips (62 percent) were from hydroelectric units.[44]

In 2009, only ten transmission trips resulted in a loss of 750 MW or more per trip. Twenty two generating plants were affected by the ten trips. Causes for the trips include feeder line trips (1 trip), breakers in the switchyard (8 trips), personnel errors (2 trips), and unknown (10 trips.)

The "Lack of Fuel" outages are of interest as these events occur when a unit is available to operate, but there is an interruption in fuel to operate the unit. These events do not include interruptions of fuel due to contracts. The "Lack of Fuel" cause code only takes into account units that are expecting fuel that do not receive it when requested. Table 11 presents the distribution of "Lack of Fuel" events by NERC Regional Entity.

[43] One company contributed to the majority of oil-fired lack of fuel events. The units need gas to start when running on oil. Upon shutdown, the units must switch to gas to clean themselves. Due to a gas restriction, the units cannot start, and the units go on a forced outage. Until the restriction is lifted, the two units will continue to be on a forced outage cycle.

[44] The average size of the hydroelectric units were small – 3.35 MW.

Table 11: Forced Outages Due to Lack of Fuel by Regional Entity	
Regional Entity	**Number of Lack of Fuel Problems Reported**
FRCC	0
MRO	3
NPCC	24
RFC	88
SERC	17
SPP	3
TRE	7
WECC	29

Event records also provide descriptions of why the unit was without fuel with the majority of descriptions being:

- Temperatures affecting gas supply valves
- Unexpected maintenance of gas pipe-lines
- Compressor problems/maintenance

Table 12 provides the top causes of forced outage for several major generating unit types.

Table 12: Causes of Forced Outage for Different Unit Types (2008-2010)

Rank	Description	Occurrence per Unit-year	MWH per Unit-year	Average Hours To Repair	Average Hours Between Failures	Unit-years
Fossil - all MW sizes; all fuels						
1	Waterwall (furnace wall)	0.64	14,735	59.5	13,484	3,984
2	Second Superheater Leaks	0.20	5,660	63.2	44,446	3,984
3	First Reheater Leaks	0.17	5,221	65.1	49,112	3,984
Combined-Cycle Blocks						
1	HP Turbine Buckets Or Blades	0.02	4,663	1,830	1,839,600	466
2	Turbine Control Valves	0.04	2,777	100	216,424	466
3	Gas Turbine Compressor - High Pressure Shaft	0.01	2,266	663	613,200	466
Nuclear Units - all reactor types						
1	LP Turbine Buckets or Blades	0.01	26,415	8,760	153,042	288
2	Containment Structure	0.01	9,233	1,226	200,132	288
3	Main Transformer	0.07	7,881	101	108,495	288
Simple-Cycle Gas Turbine Jet Engines						
1	Main Transformer	0.03	1,611	1,016	138,023	4,181
2	Other Gas Turbine Controls And Instrument Problems	0.12	428	70	64,137	4,181
3	Other Gas Turbine Problems	0.09	400	119	81,961	4,181

2008-2010 Review of Summer and Winter Availability

To address seasonality of unit availability from 2008 to 2010, unit information for the months of June to September (summer) and December through February (winter) were pooled to calculate forced outage events.[45] Figure 32 shows the average Equivalent Availability Factor (EAF) is three percentage points higher, and the average Equivalent Forced Outage Rate - Demand (EFORd) is slightly under one-half of a percentage point lower in the summer period than in the winter period. The units were more reliable with less forced events during high-demand times during the summer season than the winter season. On average, units have a higher Net Capacity Factor (NCF) of 4.5 percentage points in the summer season.

During the spring season (March-May), 77 percent of the units took a planned outage (PO) for an average 231 hours, 9.6 days. In fall (October-November), only 42 percent of the units experienced a PO, and the average duration was a shorter 134 hours, 5.6 days. Some units took both spring and fall planned outages, although this is rare. Based on this assessment, generating units are prepared for the summer peak demand. The resulting availability indicates that spring and fall maintenance was, on average, successful. This is measured by an increased EAF and a lowered EFORd.

Figure 32: Summer-Winter Average EAF, NCF, and EFORd (2008-2010)

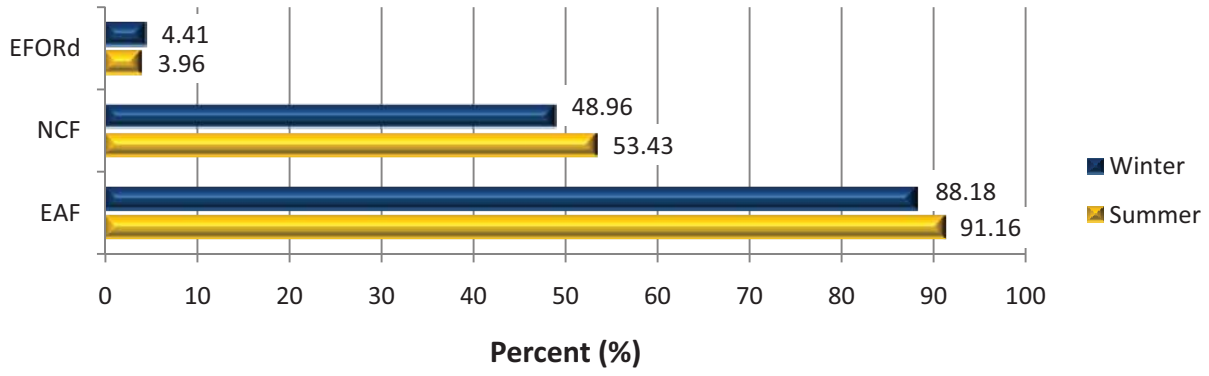

Conclusions

During 2008-2010, the average Equivalent Availability Factor (EAF), which measures the overall availability of generating units, decreased. At the same time, the average Net Capacity Factor (NCF), an indicator of energy production, decreased in 2009 and rebounded in 2010. The average number of forced outages in 2010 is greater than in 2008, while at the same time, the average planned outage times have slightly increased. As a result, the Equivalent Forced Outage Rate – Demand (EFORd) also increased illustrating that more units have experienced forced events during peak-demand times in 2010, than in the previous two years. Potentially, with shorter planned outage periods in 2010, there may be less time to repair equipment

[45] A study of peak periods was conducted by the NERC Generating Availability Trend Evaluation (GATE) Working Group several years ago, see http://www.nerc.com/files/Seasonal-Performance-Trends.pdf

and prevent forced unit outages. Detailed analysis to delve into the root causes of increasing forced outage rate should be performed.

In the last three years, there has been an increase in Equivalent Forced Outage Rate – Demand (EFORd). This indicator measures the rate of forced outage events on generating units during periods of load demand. Forced outage hours jumped from 266 to 310 hours per unit between 2009 and 2010. At the same time, maintenance events also increased by 24 hours per unit. Planned outage events increased slightly over the three-year period. The resulting conclusions from this trend are:

- More or longer planned outage time is needed to repair the generating fleet. Whether age is the cause of the increased need for planned outage time remains unknown, and further investigation into the cause for longer planned outage time is warranted, if the trend continues.
- From 2008 to 2010, there were a large number of double-unit outages resulting from the same event. Investigations show that some of these trips were at a single plant, and the trips were caused by common control and instrumentation for the units.

In addition, there are many multiple unit forced outages due to lack of fuel. The majority of multiple unit trips have three main causes: transmission, lack of fuel, and storms. With special interest in the forced outages due to "Lack of Fuel," additional analysis revealed that 77 percent of the units experiencing unexpected fuel stoppage are oil-fired fossil units while gas-fired units experienced 15 percent of the unexpected fuel stoppages.

Finally, based on the information assessed, generating units continue to be more reliable during the peak summer periods.

Disturbance Event Trends

Introduction

The purpose of this section is to report event analysis trends from the beginning of the event analysis field test[46], October 25, 2011, to the end of 2010. One of the companion goals of the event analysis program is the identification of trends in events and their associated causes. These causes could include human error, equipment failure, protection system misoperation, or a multitude of other causes. The information provided in the event analysis database (EADB) and various event analysis reports have been used to track and identify trends in bulk power system events, in conjunction with other databases (TADS, GADS, metric and benchmarking database.)

The Event Analysis Working Group (EAWG) continuously gathers event data and works towards an integrated approach to analyzing data, assessing trends and communicating the results to the industry.

Performance Trends

The event category is classified[47] as shown in Figure 33. Figure 34 depicts disturbance trends in Category 1 to 5 system events from the beginning of event analysis field test to the end of 2010.[48] From the figure, November and December had substantially events than October. This is due to the field trial starting on October 25, 2010.

Figure 33: BPS Event Category

Category 1: An event resulting in one or more of the following:

a. Unintended loss of three or more BPS elements caused by common mode failure.
b. Intended and controlled system separation by the proper operation of a Special Protection System Scheme (SPS) / Remedial Action Scheme (RAS) in Alberta from the Western Interconnection, New Brunswick or Florida from the Eastern Interconnection.
c. Failure or misoperation of an SPS/RAS.
d. System-wide voltage reduction of 3% or more.
e. Unintended BPS system separation resulting in an island of 100 MW to 999 MW.
f. Unplanned evacuation from a control center facility with BPS SCADA functionality for 30 minutes or more.

Category 2: An event resulting in one or more of the following:

a. Complete loss of all BPS control center voice communication system(s) for 30 minutes or more.
b. Complete loss of SCADA, control or monitoring functionality for 30 minutes or more.
c. Voltage excursions equal to or greater than 10% lasting more than five minutes.
d. Loss of off-site power (LOOP) to a nuclear generating station.
e. Unintended system separation resulting in an island of 1,000 MW to 4,999 MW.
f. Unintended loss of 300MW or more of firm load for more than 15 minutes.
g. Violation of an Interconnection Reliability Operating Limit (IROL) for more than 30 minutes.

Category 3: An event resulting in one or more of the following:

a. The loss of load or generation of 2,000 MW or more in the Eastern Interconnection or
b. Western Interconnection, or 1,000 MW or more in the ERCOT or Québec Interconnections.
c. Unintended system separation resulting in an island of 5,000 MW to 10,000 MW.
d. Unintended system separation resulting in an island of Florida from the Eastern Interconnection.

Category 4: An event resulting in one or more of the following:

a. The loss of load or generation from 5,001 MW to 9,999 MW.
b. Unintended system separation resulting in an island of more than 10,000 MW (with the exception of Florida as described in Category 3c).

Category 5: An event resulting in one or more of the following:

a. The loss of load of 10,000 MW or more.
b. The loss of generation of 10,000 MW or more.

[46] http://www.nerc.com/docs/eawg/Galloway-Industry-EA-Field-Test-102210.pdf

[47] http://www.nerc.com/files/2011-05-02%20Event_Analysis_Process_Phase%202%20Field%20Test%20Draft%20-%20Final%20-%20For%20posting.pdf

[48] Documents for the EA Field Test are located at: http://www.nerc.com/page.php?cid=5|365.

Figure 34: Event Category by Month (October 25, 2010 – December 31, 2010)

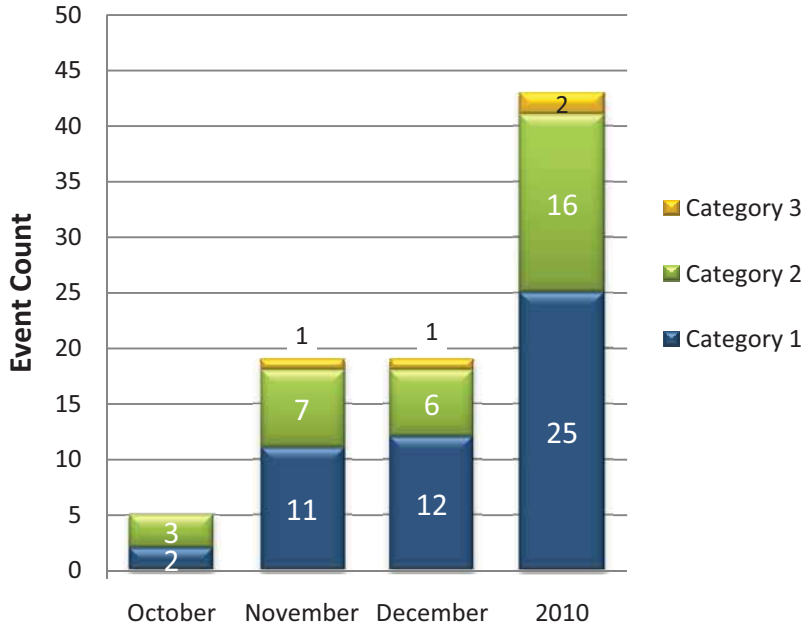

In addition to the category of the events, an event's status plays a critical role in data accuracy. By examining Figure 35, over 80% of the events reported in 2010 have been closed, meaning the category, root cause, and other important information have been sufficiently finalized in order for analysis to be accurate for each event. At this time, there is not enough data to draw any long-term conclusions about event analysis performance.

Figure 35: Event Count by Status

(October 25, 2010 – December 31, 2010)

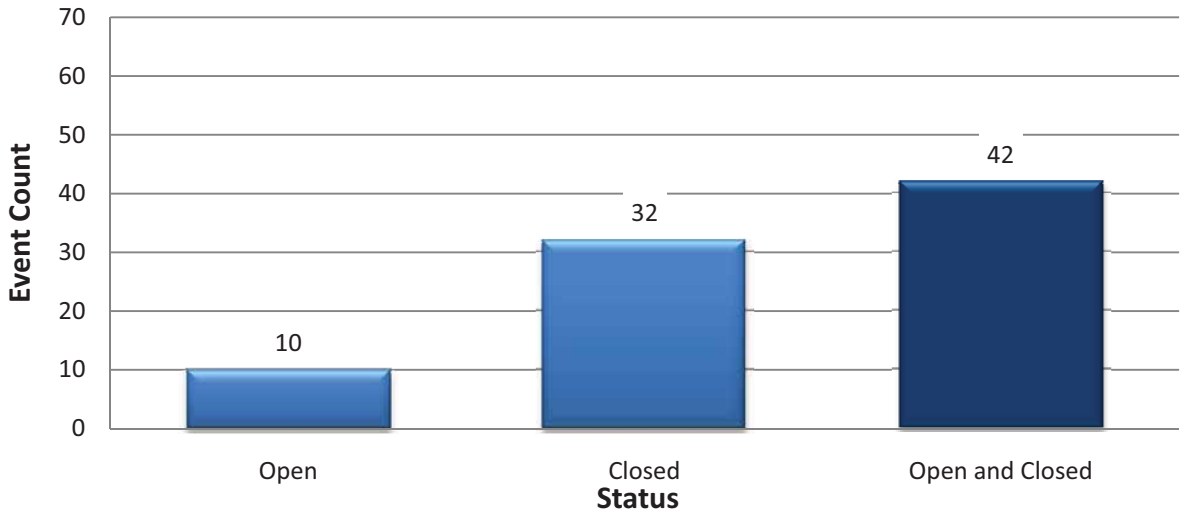

Figure 36 shows the top 3 event causes: equipment failure and protection system misoperation. Because of how new and limited the data is, however, there may not be statistical significance for this result. Further

trending of cause codes for closed events and the development of a richer dataset is needed to assess trends between event cause codes and event counts.

Figure 36: Top 3 Event Counts by Cause Code for all 2010 Closed

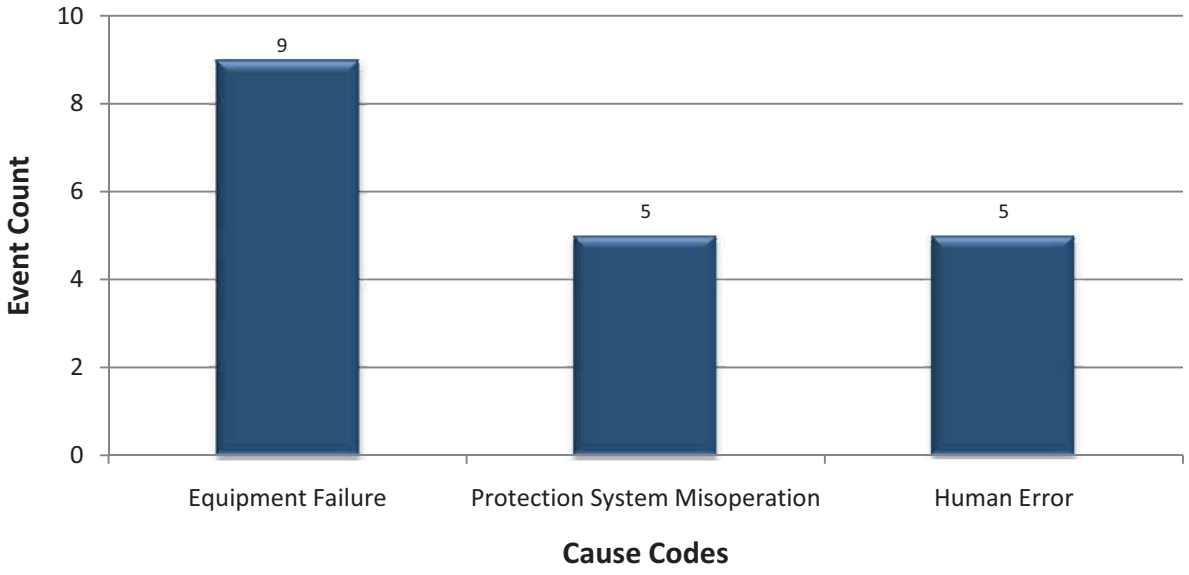

Conclusions

Due to the relatively new process for events analysis and categorization, more time is required before conclusive recommendations may be obtained. Further analysis and data will provide valuable statistics in the future.

Abbreviations Used in This Report

Acronym	Definition
ALP	Acadiana Load Pocket
ALR	Adequate Level of Reliability
ARR	Automatic Reliability Report
BA	Balancing Authority
BPS	Bulk Power System
CDI	Condition Driven Index
CEII	Critical Energy Infrastructure Information
CIPC	Critical Infrastructure Protection Committee
CLECO	Cleco Power LLC
DADS	Future Demand Availability Data System
DCS	Disturbance Control Standard
DOE	Department Of Energy
DSM	Demand Side Management
EA	Event Analysis
EAF	Equivalent Availability Factor
ECAR	East Central Area Reliability
EDI	Event Drive Index
EEA	Energy Emergency Alert
EFORd	Equivalent Forced Outage Rate, Demand
EMS	Energy Management System
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
ESAI	Energy Security Analysis, Inc.
FERC	Federal Energy Regulatory Commission
FOH	Forced Outage Hours
FRCC	Florida Reliability Coordinating Council
GADS	Generation Availability Data System
GOP	Generation Operator
IEEE	Institute of Electrical and Electronics Engineers
IESO	Independent Electricity System Operator
IROL	Interconnection Reliability Operating Limit

Acronym	Definition
IRI	Integrated Reliability Index
LOLE	Loss of Load Expectation
LUS	Lafayette Utilities System
MAIN	Mid-America Interconnected Network, Inc
MAPP	Mid-continent Area Power Pool
MOH	Maintenance Outage Hours
MRO	Midwest Reliability Organization
MSSC	Most Severe Single Contingency
NCF	Net Capacity Factor
NEAT	NERC Event Analysis Tool
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OC	Operating Committee
OL	Operating Limit
OP	Operating Procedures
ORS	Operating Reliability Subcommittee
PC	Planning Committee
PO	Planned Outage
POH	Planned Outage Hours
RAPA	Reliability Assessment Performance Analysis
RAS	Remedial Action Schemes
RC	Reliability Coordinator
RCIS	Reliability Coordination Information System
RCWG	Reliability Coordinator Working Group
RE	Regional Entity
RFC	Reliability First Corporation
RMWG	Reliability Metrics Working Group
RSG	Reserve Sharing Group
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SDI	Standard/statute Driven Index
SERC	SERC Reliability Corporation

Acronym	Definition
SRI	Severity Risk Index
SMART	Specific, Measurable, Attainable, Relevant and Tangible
SOL	System Operating Limit
SPS	Special Protection Schemes
SPCS	System Protection and Control Subcommittee
SPP	Southwest Power Pool
SRI	System Risk Index
TADS	Transmission Availability Data System
TADSWG	Transmission Availability Data System Working Group
TO	Transmission Owner
TOP	Transmission Operator
WECC	Western Electricity Coordinating Council

Contributions

Acknowledgements

NERC would like to express its appreciation to the many people who provided review and commentary during the development of this report. Special gratitude goes to the staff at the US Department of Energy (DOE) who shared their knowledge and offered improvement ideas. In particular, Stan Kaplan, Orhan Yildiz, and Cha-Chi Fan offered invaluable technical insights of the statistical analysis.

NERC Industry Groups

Table 13 lists the NERC industry group contributors.

Table 13: NERC Industry Group Contributions[49]

NERC Group	Relationship	Contribution
Reliability Metrics Working Group (RMWG)	Reports to the OC/PC	• Lead Development of Report • Provide Reliability Metrics Data • Responsible for Reliability Metrics Performance Chapter
Transmission Availability Working Group (TADSWG)	Reports to the PC	• Provide Transmission Availability Data • Responsible for Transmission Equipment Performance Chapter • Content Review
Generation Availability Data System Task Force (GADSTF)	Reports to the PC	• Provide Generation Availability Data • Responsible for Generation Equipment Performance Chapter • Content Review
Event Analysis Working Group (EAWG)	Reports to the OC/PC	• Provide Events Data • Responsible for Disturbance Events Trends Chapter • Content Review

[49] Rosters for RMWG, TADSWG, GADSTF, and EAWG are available at http://www.nerc.com/files/roster.pdf.

Regional Entity Staff

Table 15 provides a list of the Regional Entity staff who provided the data and content review.

Table 14: Contributing Regional Entity Staff

Name	Regional Entity
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John Seidel	MRO
Phil Fedora	NPCC
Jeffery Mitchell	RFC
Carter Edge	SERC
Alan Wahlstrom	SPP
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NERC Staff

Table 15 provides a list of the NERC staff who contributed to this report.

Table 15: Contributing NERC Staff

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to ensure
the reliability of the
bulk power system

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Electric Reliability Organization Event Analysis Process

Field Test Draft
October 25, 2010

to ensure the reliability of the bulk power system

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Section 1 — Goals of the Event Analysis Program

Promoting Reliability

The principal goal of the Electric Reliability Organization (ERO) is to promote the reliability of the bulk power systems in North America. This goal is directly supported by evaluating bulk power system events, undertaking appropriate levels of analysis to determine the causes of the events, promptly implementing corrective actions, and providing recommendations and lessons learned to the industry. Event analysis also provides valuable feedback to the reliability standards development process, compliance enforcement, training and education, and reliability trend analysis efforts, all of which support continued reliability improvement.

Developing a Culture of Reliability Excellence

The event analysis program strives to motivate the entire industry to develop a culture of reliability excellence that promotes and rewards aggressive self-critical review and analysis of operations, planning, and critical infrastructure protection processes. This self-critical focus must be ongoing and recognize that registered entities are linked together by their individual and collective performance. This focus drives to understand the underlying cause of events, to the decision-making involved in event analysis, how to respond to the event, the sharing of lessons learned from events, the timely mitigation of event causes, and the avoidance of similar or repeated events by registered entities across North America.

Collaboration

Successful event analysis relies on a collaborative approach through which registered entities, Regional Entities (RE), and NERC work together to achieve a common goal. The process requires clarity, certainty, and consistent adherence to reliability principles by bulk power system owners, operators, and users that perform a wide array of reliability functions

Being a Learning Organization

As a learning organization, event analysis serves an integral function of providing insight and guidance by identifying and disseminating valuable information to owners, operators, and users of the bulk power system that enable improved, enhanced, and more reliable operation. As such, event analysis is one of the pillars of a strong ERO.

Section 2 — Philosophy and Key Ingredients of the ERO Event Analysis Program

The ERO enterprise-wide event analysis program is based on the recognition that bulk power system events that occur, or have the potential to occur, have varying levels of significance. The manner in which registered entities, REs, and NERC evaluate and process these events is intended to reflect the significance of the event and/or specific system conditions germane to the reliability of the bulk power system and the circumstances involved.
The key ingredients of an effective event analysis program are to:

- identify what transpired – sequence of events;
- understand the causes of events;
- identify and ensure timely implementation of corrective actions;
- develop and disseminate recommendations and valuable lessons learned to the industry to enhance operational performance and avoid repeat events;
- develop the capability for integrating risk analysis into the event analysis process; and
- feed forward key results to facilitate enhancements in and support of the various NERC programs and initiatives (e.g., performance metrics, standards, compliance monitoring and enforcement, training and education, etc.)

The underlying characteristics that make for a comprehensive and successful event analysis program are:

- greater emphasis on a bottom-up approach in which registered entities serve in the primary role, taking first steps in analysis, development of lessons learned, self-identification of recommendations, and self-mitigation of reliability issues;
- appropriate RE and NERC review and oversight of registered entity event analysis results;
- emphasis directed toward proactive improvement of bulk power system reliability;
- clarity and certainty about what system events are relevant to analyze and to what level;
- clarity and certainty about event analysis roles, responsibilities, and expectations for respective entities, including target timeframes for completing certain actions;
- events affecting reliability or potential vulnerabilities to the reliability of the bulk power system are prioritized for analysis — concise reviews for minor events, more detailed analyses for more significant events;
- providing registered entities incentives, encouragement, and recognition for cooperation, openness, and thoroughness in conducting rigorous self-analysis of events, prompt mitigation of identified causes, and support for developing industry lessons learned;
- timely development and dissemination of valuable lessons learned to the industry, resulting in real reliability improvement;
- proper confidentiality of data and information is maintained at all times by all parties; and
- tracking and timely reporting of event and event analysis trends.

Section 3 — Purpose of the Event Analysis Process Document

Events that impact the bulk power system[1] are everyday occurrences. The purpose of this document is to provide a clear and concise framework for the identification, reporting, and analysis of events so their causes can be identified and corrected so important recommendations and lessons learned can be shared with the industry.

This document is not a cookbook and cannot prescribe an exact procedure that is best for all possible events. It does, however, describe a defined, repeatable process for identifying bulk power system events that warrant prompt reporting and the level of analysis required. It also establishes clear roles, responsibilities, and expectations for registered entities, REs, and NERC regarding the analysis of events.

The document also aims to promote consistency, comparability, flexibility, and timeliness in the event analysis process. The process detailed within provides the registered entities guidance in determining which events need to be reported and why (standards requirement, lessons learned, trending, initiatives, etc.), as well as guidance as to the level of detail expected in event analysis and Event Analysis Reports. The appendices and references contain valuable tools and templates to help the involved entities categorize, analyze, and report on events. References to various cause analysis techniques are included.

Among the topics addressed in the document are:

- timely submission of information and reports;
- use of standard cause analysis methodologies[2];
- development of findings;
- identification of corrective actions; and
- development and sharing of recommendations and lessons learned.

[1] The term "bulk-power system" means facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. [As defined in Section 215 of the Federal Power Act.]

[2] Refer to "Cause Analysis Methods for NERC, Regional Entities and Registered Entities" [link to be provided] for methods and tools that may be used for this purpose. Generally, use of detailed root cause analysis methods would be reserved for actual or potential higher impact events.

Section 4 — ERO Event Analysis Process

Event Reporting

Registered entities are required to report the occurrence of defined bulk power system disturbances and unusual occurrences to the applicable RE and NERC in accordance with various NERC and Regional reliability standards and other requirements, including but not limited to: EOP-002, EOP-004, TOP-007, CIP-001, and CIP-008. Each of these standards specifies timeframes within which initial and final Event Reports are required. The expectations for reporting additional information on such events as described below, do not relieve the registered entity from the reporting requirements under the above standards.

Information on certain system events or system reliability vulnerabilities learned from reported system events will also be communicated via Electricity Sector – Information Sharing and Analysis Center (ES-ISAC) messages, Department of Homeland Security Industrial Control Systems – Cyber Emergency Response Team (DHS ICS-CERT) Portal messages, Geomagnetic Disturbance (GMD) Alerts, etc. If the information provided through any of these sources is insufficient to understand the nature and extent of the event or potential vulnerability, the RE or NERC may request additional details from the involved registered entities.

Registered entities, REs and NERC need to become aware quickly of events and disturbances that take place throughout the bulk power system. This set of 'initial impression' kinds of information and insight needs to be produced and delivered quickly and made available to personnel with planning and operations responsibilities across the system. This initial information sets forth a workable structure for very short-term analyses and reports, which can be followed by more intensive studies. First and foremost however, a quick situation report and 'rough' study should be developed and shared within a few days.

In all cases, the registered entity should be expected to provide at least a preliminary event report within five (5) business days (many are required within 24 hours) of the event. Depending on the category of the event, a more extensive event analysis report may need to be completed within 10 business days. If this is not possible due to the scale of the event, instead of a completed event analysis report at that time, a comprehensive description of what is known, a scope of work and proposed schedule for the analysis to be conducted should be provided, along with an associated schedule for periodic progress reports thereafter, to keep the RE and NERC appropriately informed.

In reporting on events, registered entities are requested to use the event report template provided in **Appendix A** as a guideline for reporting the event to its applicable RE and NERC. In some cases, a supplemental report may be needed as additional information is learned about an event or questions are raised by the RE or NERC. In those cases, the registered entity should so indicate this in any subsequent event report.

Registered entities are encouraged to include along with the written description of the event a simple one-line diagram or other representation of the facility(s) involved in the event, if applicable and helpful in understanding what happened in the event. Such diagrams may be marked CEII if necessary, and will be treated accordingly. Special provisions will be made to

submit such CEII-marked documents to secure, password protected webfolders using an encrypted transmission mechanism.

NERC is cognizant of the burden imposed on system operators for reporting on events at a time when they are engaged in system restoration and implementing their own mitigation measures as a result of an event. To this end, registered entities need to provide the necessary support personnel to assist system operators in completing the necessary event reports in a timely manner.

Where the RE or NERC already receives information regarding events, for example through NERC TADS reporting or reporting of relay misoperations as per RE procedures, this information will be used to the extent it is available on a sufficiently timely basis.

Lessons Learned from Off-Nominal Events

In normal operations, events may occur on the transmission system that do not meet the reporting thresholds of the defined event categories but that may, nevertheless, yield lessons of value to the industry. These lessons can include the adoption of unique operating procedures, the identification of generic equipment problems, or the need for enhanced personnel training. In such cases, an event analysis report would not necessarily be required, but the event analysis program encourages registered entities to share with their RE any potential lessons learned that could be useful to others in the industry and work with the RE and NERC to develop them for dissemination. The examples following would be indicative of such incidents.

- An extreme event that occurs during a period of low load, thus not interrupting customer demand and not otherwise reportable. However, the event resulted in lessons to be learned and/or interesting operational observations.
- The planning of a facility may require a review of the realities of its day-to-day usage. (For example, a planned cable installation was designed explicitly following the manufacturer's recommended rating. These specifications assumed typical cooling cycles; however, in practice the cable was operated close to its maximum limit most of the time. When this was recognized by the transmission owner, the ratings were adjusted accordingly.)
- Full or partial loss of EMS or SCADA functionality. (In most cases, such a loss will not result in a reportable event affecting the bulk power system, but analysis of the causes of such a loss could be helpful in correcting conditions on the registered entity's EMS or SCADA system and possibly lead to the identification of useful lessons learned for the industry.)

In some cases the RE, after discussions with the registered entity, may mutually agree that an event analysis report would be useful in learning more about the event and establish a plan and timeframe for its development. In such cases, the registered entity should also consider initiating its own compliance analysis activity.

Categorizing Events

The registered entity is expected to categorize events according to the event categories and levels of analysis defined in **Appendix B**. The event categories are intended to allow the registered entity to quickly and unambiguously identify the event thresholds and the levels of analysis expected. **Table 1** below provides the target timeframes for completion of event reports, draft lessons learned, and event analysis reports.

Table 1 — Target Timeframes for Completion of Event Reports, Draft Lessons Learned, and Event Analysis Reports[3]

Event Category	Event Report	Draft Lessons Learned	Event Analysis Report	Close Event Analysis
1	Within 5 business days	Within 15 business days	10 business days (if required)	30 business days following receipt of Event Analysis Report
2	Within 5 business days	Within 15 business days	15 business days	30 business days following receipt of Event Analysis Report
3	Within 5 business days	Within 20 business days	20 business days	30 business days following receipt of Event Analysis Report
4	Within 5 business days	Within 60 business days	Upon Completion	60 business days following receipt of Event Analysis Report
5	Within 5 business days	Within 60 business days	Upon Completion	60 business days following receipt of Event Analysis Report

The categories listed in Appendix B do not cover all possible events related to CIP, EMS loss of functionality, or loss of BPS "visibility" that could occur. To the extent that such events occur, their analysis will be discussed with the affected registered entity, involved RE, and NERC.

Registered entities are best positioned to perform initial analyses, especially for those smaller and more geographically confined events, or events that involve a single piece of equipment. Ownership of the analyses becomes more complicated for events that involve a broader geographic area, involve multiple companies, or include a complex set of facts and circumstances.

Registered entities that reside in two RE footprints should report events to both REs. Following the initial event report, the two REs will determine which one will have the lead for the remaining steps of the event analysis process. When multiple registered entities are involved in or affected by an event, all should report in accordance with the requirements of applicable NERC and Regional Reliability Standards. After reviewing all event reports, the RE will determine which entity(s) will be responsible for conducting and reporting on event analysis results.

[3] All timeframes are subject to extension to accommodate special circumstances with agreement of the applicable RE.

The registered entity will is expected to identify prospective lessons learned from events and assist the RE and NERC in developing them for dissemination to the industry. For small events where there are lessons to be learned, these may be very evident and be easily identified. However, for larger more complex events (e.g., Category 4 or 5) allowing 15 – 20 or even 60 days for draft lessons learned may be optimistic without the knowledge of a complete event analysis report. In these cases, the registered entity would be expected to identify the prospective areas in which lessons learned may be forthcoming but not necessarily the lessons themselves until completion of the event analysis report.

Category 1 Events

There will not normally be a need for an event analysis report for most Category 1 events, unless requested by the applicable RE. If the RE makes a request of the registered entity, it will specify the extent of the analysis expected and the target timeframe for its completion. If an event analysis report is called for, it would normally be due in 10 business days.

In addition, the registered entity will provide to the applicable RE a draft of any suggested lessons learned associated with the event that may be applicable to the industry as well as recommendations that apply only to the affected registered entity, within 15 business days of the occurrence of the event.

Category 2 and 3 Events

Registered entities are expected to self-initiate analyses of events that fall under Categories 2 or 3. The information to be included in the entity's event analysis report will generally include:

- a detailed sequence of events;
- a description of how the power system actually responded during the event versus how it was designed to respond, (i.e., noting any response that was not anticipated or per design);
- the identification of any system protection misoperations/relay operation different from its designed response;
- an analysis of the cause(s) of the event making appropriate use of established cause analysis methods;
- any recommendations for corrective actions to be taken by the involved registered entity; and
- any possible recommendations or lessons learned for sharing with the industry.

The registered entity should first develop and submit to its applicable RE, within five (5) business days of the occurrence of the event, an event analysis plan. If the registered entity does not submit an analysis plan within this target timeframe, and absent an explicit extension by the RE, the RE will formally request the registered entity to prepare an event analysis report, with a specified level of detail and target timeframe commensurate with the nature and scope of the event. Requests to registered entities by the RE to prepare an event analysis report may include instructions to retain data and information pertaining to the event for possible use in any subsequent RE or NERC analysis. Copies of these requests will be made available to NERC.

It is recognized that there may be considerable differences in the levels of analysis required for events that fall into Category 2 versus those that fall into Category 3, as well as differences within each of these categories. The registered entity's analysis plan should reflect these differences and the planned level of analysis commensurate with the nature and scope of the

particular event. Upon review of the plan, the RE may make suggestions to the registered entity for an expansion or contraction of that plan.

The registered entity will proceed to carry out its analysis plan unless the RE disagrees with or has suggestions for changes to the plan. The registered entity will provide its event analysis report to the applicable RE within the target timeframe unless otherwise agreed to by the RE. The registered entity will also be expected to respond to follow-up questions from the RE and NERC within a timeframe agreed to by the RE.

The registered entity will maintain close communication with the RE during the development of its event analysis report and the RE will follow the registered entity's progress.

Upon receipt of the completed event analysis report, the RE will review the report for thoroughness and completeness of analysis. If additional information is required, the RE will make that request, again with a specified deadline, and inform NERC. If the RE is satisfied with the event analysis report, and NERC has no further questions, the RE may close the analysis.

In addition to the Event Analysis Report, the registered entity will provide to the applicable RE a draft of any suggested lessons learned associated with the event within 15 business days of the occurrence of the event for Category 2 events and within 20 business days for Category 3 events.

Category 4 and 5 Events

The first step following occurrence of a Category 4 or 5 event is a conference call involving the affected registered entities, RE(s) involved, and NERC to discuss the event and how the event analysis should proceed. In most cases, the analysis of Category 4 and 5 events will be conducted by an event analysis team led by the applicable RE or NERC. The decision on the composition of the event analysis team, the team lead, the information needed from affected registered entities, and the required scope of the analysis will be discussed and agreed to by the affected registered entities, RE(s) involved, and NERC staff. An Event Evaluation Checklist (**Appendix C**) is provided to assist in making this determination. The RE and NERC will collaborate on the request for information from the affected registered entities.

For multi-entity events within a Region, the RE will generally coordinate or facilitate the event analysis, with participation by NERC. The RE will close the analysis with the agreement of NERC.

For multi-Regional or other large scale events within a Region, either the RE or NERC will generally coordinate or facilitate the event analysis, with participation by all the affected REs and registered entities. NERC will close the analysis with the agreement of the RE(s).

In the case of events that draw a high level of attention by government agencies or the media, NERC and RE staff, along with the affected registered entities, will discuss and agree on how the event analysis should proceed, even as the final event report is being prepared. Registered entities, the RE(s), and NERC will collaborate on the development of any findings, recommendations, corrective actions, and lessons learned associated with Category 4 and 5 events.

As specified in the ERO Rules of Procedure, Section 807.e, the NERC president will determine whether any event warrants analysis at the NERC level. REs may also request NERC to elevate any analysis to the NERC level. Regardless of whether an RE or NERC is leading the analysis

team, registered entities would be expected to actively participate in the analysis of the event and in the preparation of their respective portions of the final Event Analysis Report.

The target timeframe for completion of event analysis reports for Category 4 and 5 events will vary with the nature and extent of the event. Normally, draft lessons learned would be expected to be developed within 60 days of the occurrence of the event.

Event Report — prepared by impacted registered entities, sent to NERC and the affected RE. (Event report is a generic term; the actual notification that an event has occurred may come from a variety of sources such as, but not limited to, EOP-004, OE-417, and/or ES-ISAC report.

Draft Lessons Learned — prepared by impacted registered entities in cooperation with RE or NERC Event Analysis team; finalized and issued by NERC. Prepared in parallel with event analysis report. See **Appendix D** for Lessons Learned template.

Event Analysis Report — A report detailing what happened and why, prepared by either the impacted entity or the impacted entity in coordination with the event analysis team as defined in the EA process. Target timeframe for completion is time following event report. For event analyses that require more than two weeks to complete (e.g. Category 4 and 5 events), progress reports will be made bi-weekly to the RE and NERC and interim reports issued every six months.

Final event analysis reports should match corrective actions to each contributing or "root" cause and also document what went well during or after an event in addition to what did not. This is a key part of a continuous learning and improvement program.

Appendix E provides a summary of roles, responsibilities, and expectations for event reporting and analysis, and **Appendix F** provides a registered entity process checklist.

The design and content of event analysis reports must be such that insights that should be shared with planning and operations personnel are not held hostage to the needs of compliance enforcement or withheld because of issues of confidentiality or CEII-protected information. Since the ultimate goal for NERC is bulk power system reliability, event analysis reports should be configured so as to provide information valuable to others in the industry on a timely basis.

Section 5 — Event Analysis Interface with Compliance

Registered entities deserve and should expect to be recognized and given credit for cooperation, openness, and thoroughness in conducting rigorous self-analysis of events, prompt mitigation of identified causes, support for developing industry lessons learned, performing a detailed compliance self assessment, and self-reporting possible standards violations. Entities should participate fully in the identification of lessons learned from the events they experience, and help in the dissemination and explanation of those lessons as a way of assisting other entities avoid similar issues. If the registered entity makes a good faith effort to self-identify and self-report possible violations stemming from their event analysis, but later analysis by the RE or NERC reveals other possible violations, the registered entity will still be given credit for its cooperation.

Registered entities will be encouraged to consider establishing a liaison between their own internal event analysis and compliance functions internal to the registered entity during their event analysis process. This will facilitate the development of a registered entity compliance analysis report and assist in the self-reporting of possible violations through the established Compliance Monitoring and Enforcement Program processes as soon as practical. REs will also be encouraged to establish an appropriate liaison between their event analysis and compliance functions to facilitate sharing of event analysis results so as to minimize or avoid duplication of data and information requests and analyses. The nature and extent of these liaison arrangements will be up to the involved registered entities and REs.

Registered entities are expected to perform a thorough compliance analysis and develop a compliance analysis report for events in which there could be a gap between actual system or human performance and the requirements of NERC or regional standards. Such compliance analysis reports should include:

- a listing of all NERC or Regional Reliability Standards potentially implicated by the event;
- a written disposition and supported conclusion by the registered entity whether a possible violation of any of those reliability standards occurred; and
- a self-reporting through existing Compliance Monitoring and Enforcement Program procedures of possible violations associated with events.

Entities are encouraged to use a systematic approach to the evaluation of issues for the purpose of identifying possible violations and developing supporting conclusions regarding whether a reliability standard may have been violated or appear to be violated as a result of the event. A suggested Compliance Analysis Template is included in **Appendix G** for this purpose.

If the registered entity is fully cooperative in their self-analysis, identification and timely implementation of corrective actions, development of lessons learned, and self-reporting of possible violations, they will be afforded credit during any possible enforcement phase of the Compliance Monitoring and Enforcement Program.

Section 6 — Confidentiality Considerations

Certain data and information gathered during the course of an event analysis may need to be labeled CONFIDENTIAL and protected from disclosure beyond the event analysis team if the registered entity providing the data and information, or the RE or NERC receiving the information, believe it to be Critical Energy Infrastructure Information (CEII) or commercially sensitive information. See Section 1500 of the NERC Rules of Procedure for further details on the definition and protection of "Confidential Information."

Portions of draft and final Event Analysis Reports may also be subject to confidentiality restrictions as warranted. However, every effort should be made to make as much of these reports available to the industry in order to promote dissemination of lessons learned from events.

The rights and responsibilities of all entities participating in an event analysis or receiving a draft or final event analysis report, will be specified in signed confidentiality agreements, where necessary, and in the foreword of draft and final reports.

Special procedures may need to be implemented in the case of CIP issues related to an event.

Data and information provided to the RE and/or NERC for analysis of a cross-border event will be maintained separately for U.S. and Canadian entities and only shared with governmental authorities for the jurisdiction within which the entities operate, consistent with applicable MOUs or other agreements.

Section 7 — Event Analysis Trends

One of the by-products of the event analysis program is the identification of trends in the number, magnitude and frequency of events, and their associated causes, such as human error, relay coordination, relay misoperations, etc. The information provided in event reports and event analysis reports, in conjunction with other databases (TADS, GADS, Metric and Benchmarking Database, etc.), will be used to track and identify trends in bulk power system events.

Section 8 — Appendixes and Other Suggested References

Appendix A — Event Report Template
Appendix B — Event Categories and Levels of Analysis [August 20, 2010 DRAFT]
Appendix C — Event Analysis Scope Template
Appendix D — Lessons Learned Template
Appendix E — Summary of Roles, Responsibilities, and Expectations for Event Reporting and Analysis
Appendix F — Registered Entity Process Checklist
Appendix G — Compliance Analysis Template

Other References
NERC Blackout and Disturbance Analysis Objectives, Analysis Approach, Schedule, and Status – Attachment D from Appendix 8 of NERC Rules of Procedure

Appendix A — Event Report Template

1.	Entity filing the report:		
2.	Date and Start Time of disturbance. Date: (mm/dd/yy) Time/Zone:		
3.	Name of contact person: Email address: Telephone Number:		
4.	Did the event originate in your system?	Yes☐ No☐	
5.	Under which NERC function are you reporting?	RC ☐ BA ☐ TO/TOP☐ LSE ☐ GO/GOP ☐ Other ☐ [explain]	
6.	Brief Description of Event: (More detail should be provided in the Sequence of Events section below.)		
7.	Generation tripped off-line. MW Total List units tripped		
8.	Frequency. Just prior to disturbance (Hz): Immediately after disturbance (Hz max): Immediately after disturbance (Hz min):		
9.	List transmission facilities (lines, transformers, buses, etc.) tripped and locked-out. (Specify voltage level of each facility listed and extent of equipment damage, if any).		
10.		FIRM	INTERRUPTIBLE
	Demand tripped (MW):		
	Number of affected customers:		
	Demand lost (MW-Minutes):		
11.	Restoration Time.	INITIAL[4]	FINAL
	Transmission:		
	Generation:		
	Demand:		

[4] INITIAL refers to the time when restoration begins.

12.	Sequence of Events:
13.	Identify root and contributing causes of the event to the extent known:
14.	Identify any protection system misoperations to the extent known:
15.	Additional Information that helps to further explain the event; e.g., a simple one-line diagram or other representation of the substation(s) involved in the event, if applicable.[5] **At the end of x hours determine what is the next step**
16.	Identify the significance and duration of any monitoring and control events, such as loss of bulk power system visibility, loss of data links etc.

[5] Special provisions will be made for the transmittal of confidential or CEII-protected information to the RE and/or NERC.

Appendix B — Event Categories and Levels of Analysis

The purpose of this document is to identify events that may require further analysis. Each event is categorized to help the Regional Entities (REs) and registered entity(s) impacted determine the appropriate level of analysis or review.

Event Analysis Levels
Impacted registered entity(ies), the associated RE and when appropriate, NERC, will collaboratively determine the appropriate level of any event analysis that should be conducted. The following provides a summary of the various reports that are expected per the EAWG process:

- **Event Report** — prepared by impacted entities, sent to NERC and the affected RE. The event report is a generic term and the actual notification may come from a variety of sources such as, but not limited to EOP-004, OE-417, and/or ES-ISAC report.
- **Event Analysis Report** — A report detailing what happened and why. Prepared by either the impacted entity or the impacted entity in coordination with the event analysis team as defined in the EA process.

The following will be used to determine the level of analysis to be conducted:

- **Category 1** — event report. (Normally there is no follow-up anticipated for category 1 reports unless requested by the RE).
- **Category 2 and 3** — An event report and an event analysis report prepared by the registered entity and follow-up as directed by the RE.
- **Category 4 and 5** — An event report and an event analysis report developed by an event analysis team led by the RE or NERC.

Operating Reliability Event Categories
Operating reliability events are those events that are deemed to have significantly impacted the reliable operation of interconnected system. These events are divided into five (5) categories that account for their different system impact and help determine the level of analysis that is warranted[6]. The lists below are intended to provide examples as to the types of events that fall into each category. For events not covered below, the impacted entity, in conjunction with the RE, will determine the categorization.

Category 1: An event resulting in one or more of the following:

a. The loss of a bulk power transmission component(s) in response to a single-phase line-to-ground fault with delayed clearing[7] (stuck breaker or protection system failure). (Refer to Table I. Transmission System Standards — Normal and Emergency Conditions of the TPL standards categories C6 through C9).
b. Loss of three or more bulk power system (BPS) elements (i.e. generators, transmission lines, and buses).

[6] The highest category that characterizes an event shall be used.

[7] Delayed clearing of a fault is due to failure of a circuit breaker or of any protection system component such as a relay or current transformer, and not because of an intentional design delay.

c. Frequency below the Low Frequency Trigger Limit (FTL) or above the High FTL for more than 15 minutes.[8]
.
d. Intended and controlled system separation by the proper operation of a Special Protection System Scheme (SPS) / Remedial Action Scheme (RAS) in Alberta from the Western Interconnection, New Brunswick or Florida from the Eastern Interconnection.
e. Failure, degradation or misoperation of SPS/RAS.
f. Unintended loss of an entire dc converter station
g. System wide voltage reduction of 3 percent or more
i. Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the BPS
j. Fuel supply emergencies that could impact BPS adequacy or reliability
k. Unintended system separation resulting in an island of up to 1,000 MW.

Category 2: An event resulting in one or more of the following:

a. Loss of all BPS control center voice or data functionality for 30 minutes or more.
b. Unplanned evacuation from BPS control center facility
c. Voltage excursions equal to or greater than ±10 percent lasting more than five (5) minutes
d. The loss of an entire generation station of five (5) or more generators (aggregate generation of 500 MW or higher).
e. Loss of off-site power (LOOP) to a nuclear generating station.
f. Load shedding resulting in a loss of load of 100 MW or greater as a result of:
    1. Manual load shedding;
    2. Underfrequency load shedding; or
    3. Undervoltage load shedding.
g. Unintended system separation resulting in an island of 1,001 MW to 4,999 MW.
h. Equipment failures or SPS/RAS actions which result in the loss of firm system demands for more than 15 minutes, as described below:
    1. Entities with a previous year recorded peak demand of more than 3,000 MW are required to report all such losses of firm demands totaling more than 300 MW.
    2. All other entities are required to report all such losses of firm demands totaling more than 200 MW or 50 percent of the total customers being supplied immediately prior to the incident, whichever is less.
i. An Interconnection Reliability Operating Limit (IROL) violation as defined in reliability standard TOP-007.

Category 3: An event resulting in one or more of the following:

a. The loss of load or generation (excluding SPS/RAS, UFLS, or UVLS actuation) of 2,000 MW or more in the Eastern Interconnection or Western Interconnection, or 1,000 MW or more in the ERCOT or Québec Interconnections.
b. Unintended system separation resulting in an island of 5,000 MW to 10,000 MW.

[8] In case of an FTL exceedence, the reporting of the event occurs automatically through the NERC ACE and Frequency Monitoring System. Analysis of these events will normally be conducted by the NERC Operating Committee's Resources Subcommittee.

c. Unintended system separation resulting in an island of Alberta from the Western Interconnection, New Brunswick, or Florida from the Eastern Interconnection.

Category 4: An event resulting in one or more of the following:

a. The loss of load or generation from 5,001 MW to 9,999 MW (excluding SPS/RAS as noted in Category 2, UFLS, or UVLS actuation).
b. Unintended system separation resulting in an island of more than 10,000 MW (with the exception of Alberta, New Brunswick, and Florida as described in category 3C above).

Category 5: An event resulting in one or more of the following:

a. The loss of load of 10,000 MW or more.
b. The loss of generation of 10, 000 MW or more.

Appendix C — Event Evaluation Checklist

Contributing Factor	Explanation of Contributing Factor	Contributing Factor in Causing The Event, Increasing Its Severity, Or Hindering Restoration? (Yes or No)	Explanation
1. Power System Facilities	The existence of sufficient physical facilities to provide a reliable bulk power system.		
2. Relaying Systems	Detection of bulk power supply parameters that are outside normal operating limits and activation of protective devices to prevent or limit damage to the system. (UFLS/UVLS)		
3. System Monitoring, Operating Control, And Communication Facilities	Ability of dispatch and control facilities to monitor and control operation of the bulk power supply system. Adequacy of communication facilities to provide information within and between entities.		
4. Operating Personnel Performance	Ability of system personnel to react properly to unanticipated circumstances which require prompt decisive action.		
5. Operational Planning	Study of near-term operating conditions. Application of results to system operation.		
6. System Reserve and Generation Response	Ability of generation or load reduction equipment to maintain or restore system frequency and tie-line flows to acceptable levels following a system disturbance.		
7. Preventive	A program of routine		

Maintenance	inspections and tests to detect and correct potential equipment failures.		
8. Load Relief	The intentional disconnection of customer load in a planned and systematic manner or restoration of the balance between available power supply and demand.		
9. Restoration	Orderly and effective procedures to quickly re-establish customer service and restore the bulk power supply system to a reliable condition.		
10. Special Protection Systems (or Remedial Action Schemes)	An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability.		
11. System Planning	Comprehensive planning work using appropriate planning criteria to provide a reliable bulk power supply system.		
12. Reliability Coordinator action	Directives, actions, or procedures of the Reliability Coordinator(s).		
13. Cyber security	Ability of personnel to react properly to unanticipated circumstances that requires prompt decisive action.		
14. Other	Any other factor not listed above which was significant in causing the disturbance, making the disturbance more severe or adversely affecting restoration.		

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Lesson Learned — DRAFT

TITLE

Primary Interest Groups
Transmission Operators
Transmission Owners

Problem Statement
Details
Corrective Actions
Lesson Learned

For more information please contact:

Earl Shockley
Director of Event Analysis and Investigation
earl.shockley@nerc.net
609-651-5995

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Manager of Educational Product Delivery
karen.spolar@nerc.net
609-524-7022

This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing reliability standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

Appendix E — Summary of Roles, Responsibilities, and Expectations for Event Reporting and Analysis

Category 1 Events			
Entity	**Event Report**	**Event Analysis Report (EAR)**	**Lessons Learned**
Registered Entity	Initial event report to RE and NERC in accordance with requirements specified in applicable NERC standards. Content of report consistent with Event Report Template included in Appendix A. Final event report in 5 business days or less.	If requested by RE, initiate and complete event analysis report within 10 business days of final event report, or by a time agreed to by the RE and Entity.	Draft of suggested lessons learned to RE within 15 business days of event occurrence. If EAR is requested, draft of possible lessons learned within 10 business days; completion of draft lessons learned provided along with completion of EAR.
Regional Entity (RE)	Request additional event information from registered entity as needed.	Request event analysis report, if necessary, by specified deadline. If requested, review event analysis report for sufficiency and request additional analysis or information as deemed necessary. Specify deadline. Notify registered entity that event analysis is closed unless NERC has additional questions.	Review draft lessons learned from registered entity. Request additional information as deemed necessary. Work with registered entity and NERC to prepare final lessons learned for review by EAWG.
NERC	Coordinate with RE to determine whether additional event report information from registered entity should be provided.	Review final version of event analysis report, as necessary, and provide comments to RE. Raise additional questions before RE closes event analysis if not satisfied with final event analysis report.	Work with registered entity and RE to prepare final lessons learned for review by EAWG. Disseminate final lessons learned to industry.

Appendix E — Summary of Roles, Responsibilities, and Expectations for Event Reporting and Analysis

Category 2 and 3 Events			
Entity	**Event Report**	**Event Analysis Report (EAR)**	**Lessons Learned**
Registered Entity	Initial event report to RE and NERC in accordance with requirements specified in applicable NERC standards. Content of report consistent with Event Report Template included in Appendix A. Final event report 5 business days or less.	Event analysis plan to RE within 5 business days of occurrence of event. Event analysis report to RE within 15 business days for Category 2 event or 20 business days for Category 3 event following submittal of event analysis plan to RE, unless RE raises questions or agrees to alternative timeframe.	Draft of suggested lessons learned to RE coincident with agreed upon completion of EAR. (Typically within 15 business days of event occurrence for Category 2 event and within 20 business days for Category 3 event.)
Regional Entity (RE)	Request additional event information from registered entity as determined by RE or in collaboration with NERC.	Request event analysis report if not initiated by registered entity. Specify deadline. Follow progress of event analysis and report preparation with Entity. Review event analysis report for sufficiency and request additional analysis or information as deemed necessary. Specify deadline and inform NERC. Notify registered entity that event analysis is closed unless NERC has additional questions.	Review draft lessons learned from registered entity. Request additional information as deemed necessary. Work with registered entity and NERC to prepare final lesson learned for review by EAWG.
NERC	Where warranted, coordinate with RE to determine whether additional event report information from registered entity should be provided.	Review final version of event analysis report, as necessary, and provide comments to RE. Raise additional questions before RE closes event analysis if not satisfied with final event analysis report.	Work with registered entity and RE to prepare final lessons learned for review by EAWG. Disseminate final lesson learned to industry.

Appendix E — Summary of Roles, Responsibilities, and Expectations for Event Reporting and Analysis

Category 4 and 5 Events			
Entity	**Event Report**	**Event Analysis Report (EAR)**	**Lessons Learned**
Registered Entity	Initial event report to RE and NERC in accordance with requirements specified in applicable NERC standards. Content of report consistent with Event Report Template included in Appendix A. Final event report in 5 business days or less.	Suggestions for event analysis plan to RE within 5 business days of final event report. Participate in event analysis as directed by RE and NERC.	Draft of suggested lessons learned to RE within 60 business days of event.
Regional Entity (RE)	Request additional event information from registered entity as determined by RE or requested by NERC.	Conference call of affected registered entities, REs involved, and NERC within 5 business days of occurrence of event to discuss approach for conduct of event analysis and agreement on composition and lead for event analysis team. Collaborate with NERC on request for information from affected registered entities. Lead event analysis for multi-entity events within RE. (Category 4) Participate in multi-regional event analysis led by NERC. (Category 5) Follow progress of event analysis and report preparation. Notify registered entity that event analysis is closed with	Review draft lessons learned from registered entity. Request additional information as deemed necessary. Work with registered entity and NERC to prepare final lessons learned for review by EAWG.

		agreement of NERC for Category 4 events.	
Category 4 and 5 Events			
NERC	Request RE to provide additional event report information from registered entity, as needed.	Conference call of affected registered entities, REs involved, and NERC within 5 business days of occurrence of event to discuss approach for conduct of event analysis and agreement on composition and lead for event analysis team. Collaborate with RE(s) involved on request for information from affected registered entities. Participate in multi-entity events within RE, led by RE. (Category 4) Lead multi-regional event analyses when determined by NERC president. (Category 4 or 5) Notify registered entity that event analysis is closed for Category 5 events, with agreement of involved REs.	Work with registered entities and RE(s) to prepare final lessons learned for review by EAWG. Disseminate final lessons learned to industry.

Appendix F — Registered Entity Process Checklist

1. Event Occurs
2. Determine Category AND analysis/reporting requirements
3. IF Category 1 THEN:
    a. **Event Report**: Report in accordance with NERC or Regional Reliability Standards requirements or as otherwise requested by Regional Entity. Final Event Report in 5 business days or less.
    b. **Event Analysis Report**: Initiate and complete report within 10 business days of final Event Report, or by time agreed to with Regional Entity.
    c. **Lessons Learned**: Draft of suggested lessons learned to Regional Entity within 15 business days of event occurrence if no Event Analysis Report required; within 10 business days of final Event Analysis Report, if required.
    d. **Compliance Review**: Initiate concurrently with Event Analysis Report; complete within 30 days of final Event Analysis Report.
    e. **Corrective Action Plan**: File plan with Regional Entity within 5 business days of final Event Analysis Report.
4. IF Category 2 THEN:
    a. **Event Report**: Report in accordance with NERC or Regional Reliability Standards requirements or as otherwise requested by Regional Entity. Final Event Report in 5 business days or less.
    b. **Event Analysis Plan**: Submit to Regional Entity within 5 business days of occurrence of event.
    c. **Event Analysis Report**: Initiate and submit report to Regional Entity within 15 business days of submittal of event analysis plan (or by time agreed to with Regional Entity).
    d. **Lessons Learned**: Draft of suggested lessons learned to Regional Entity coincident with agreed upon completion of Event Analysis Report. (Typically within 15 business days of event occurrence.)
    e. **Compliance Review**: Initiate concurrently with Event Analysis Report; complete within 30 days of final Event Analysis Report.
    f. **Corrective Action Plan**: File plan with Regional Entity within 5 business days of final Event Analysis Report.
5. IF Category 3 THEN:
    a. **Event Report**: Report in accordance with NERC or Regional Reliability Standards requirements or as otherwise requested by Regional Entity. Final Event Report in 5 business days or less.
    b. **Event Analysis Plan**: Submit to Regional Entity within 5 business days of occurrence of event.
    c. **Event Analysis Report**: Initiate and submit report to Regional Entity within 20 business days of submittal of event analysis plan (or by time agreed to with Regional Entity).
    d. **Lessons Learned**: Draft of suggested lessons learned to Regional Entity coincident with agreed upon completion of Event Analysis Report. (Typically within 20 business days of event occurrence.)
    e. **Compliance Review**: Initiate concurrently with Event Analysis Report; complete within 30 days of final Event Analysis Report.
    f. **Corrective Action Plan**: File plan with Regional Entity within 5 business days of final Event Analysis Report.

6. IF Category 4 THEN:
    a. **Event Report**: Report in accordance with NERC or Regional Reliability Standards requirements or as otherwise requested by Regional Entity. Final Event Report in 5 business days or less.
    b. **Event Analysis Plan**: Submit suggestions for event analysis plan to Regional Entity within 5 business days of occurrence of event.
    c. **Event Analysis Report**: Participate in event analysis and development of event analysis report as directed by Regional Entity and NERC.
    d. **Lessons Learned**: Draft of suggested lessons learned to Regional Entity within 60 business days of event occurrence.
    e. **Compliance Review**: Initiate concurrently with Event Analysis Report; complete within 30 days of final Event Analysis Report.
    f. **Corrective Action Plan**: File plan with Regional Entity within 5 business days of final Event Analysis Report.
7. IF Category 5 THEN:
    a. **Event Report**: Report in accordance with NERC or Regional Reliability Standards requirements or as otherwise requested by Regional Entity. Final Event Report in 5 business days or less.
    b. **Event Analysis Plan**: Submit suggestions for event analysis plan to Regional Entity within 5 business days of occurrence of event.
    c. **Event Analysis Report**: Participate in event analysis and development of event analysis report as directed by Regional Entity and NERC.
    d. **Lessons Learned**: Draft of suggested lessons learned to Regional Entity within 60 business days of event occurrence.
    e. **Compliance Review**: Initiate concurrently with Event Analysis Report; complete within 30 days of final Event Analysis Report.
    f. **Corrective Action Plan**: File plan with Regional Entity within 5 business days of final Event Analysis Report.

Appendix G — Compliance Assessment Template

The registered entity's compliance function is expected to perform an initial compliance assessment, concurrent with the registered entity's event analysis process.

A systematic, methodical compliance assessment process might include the following steps:

1. Refer to the causes and contributing factors of the event as determined by the registered entity's event analysis process.
2. Identify any applicable Reliability Standards requirements that may have been implicated by the causes and contributing factors of the event.
3. Develop conclusions after reviewing the facts and circumstances of the event that are relevant to step 2 above as they apply to the applicable Reliability Standards requirements.
4. On request by the RE, or on its own motion, the registered entity's compliance function will provide a copy of their compliance assessment report to the Regional Entity Compliance Group. Such report should reference the separate event analysis report provided to the RE.
5. Self-report any findings of non-compliance to the Regional Entity per the CMEP procedures.

Sample Template for Compliance Assessment Summary

Event causes or contributing factors	Applicable NERC Reliability Standards	Details of Compliance Assessment Effort	Findings
Cause	AAA-000-0 Requirement 1	Identify the process used to assess compliance with this requirement. Identify any evidence that demonstrates compliance. Identify any evidence that suggests non-compliance?	Findings of possible violations should be identified. If there are no findings of non compliance, that should be noted.
	AAA-000-0 Requirement 2		
Contributing factor	BBB-000-0 Requirement 1		

Meeting Dates for Approval
2012 Board of Directors
Northeast Power Coordinating Council, Inc. (NPCC)

Tuesday, January 31, 2012 – NPCC Board Strategy Session & Dinner

Wednesday, February 1, 2012 – NPCC Offices - 8 a.m. start

Tuesday, March 13, 2012 – BES Special Teleconference

Tuesday, May 1, 2012 – Teleconference

Tuesday, June 26, 2012 – NPCC Offices

Tuesday, August 7, 2012 – Teleconference

Tuesday, September 18, 2012 – NPCC Offices

Tuesday, October 30, 2012 – Teleconference

Wednesday, November 28, 2012 – Montreal, Quebec (Breakfast Meeting)

From: Guy V. Zito
To: Lee R. Pedowicz
Subject: FW: RCC Meeting and BOD Schedule for 2012?
Date: Wednesday, October 05, 2011 8:58:35 PM

Lee,

Meeting Materials Package for RSC...

Guy V. Zito
Assistant Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10 th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

From: Maritza Feliciano
Sent: Tuesday, October 04, 2011 10:27 AM
To: Jennifer Budd Mattiello
Cc: Guy V. Zito
Subject: RE: RCC Meeting and BOD Schedule for 2012?

RCC Meetings (subject to change)

March 1, 2012
June 6, 2012
Sept. 6, 2012
Nov. 27, 2012

From: Jennifer Budd Mattiello
Sent: Tuesday, October 04, 2011 10:23 AM
To: Guy V. Zito; Maritza Feliciano
Subject: RE: RCC Meeting and BOD Schedule for 2012?

BOD meetings thus far are – they could although I doubt it – change something at the meeting on 10/16 Guy

Jenn

From: Guy V. Zito
Sent: Tuesday, October 04, 2011 10:18 AM
To: Maritza Feliciano
Cc: Jennifer Budd Mattiello
Subject: RCC Meeting and BOD Schedule for 2012?

Is there a schedule with all the dates yet ?

I would like to schedule my 2012 RSC meetings at the October 2011 meeting.

Thanks,

Guy V. Zito
Assistant Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10 th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC News

September 2011

Headlines

NERC, FERC Announce Joint Inquiry into September Outage

FERC and NERC Release Task Force Report on Southwest Outages

DOE Releases Draft of Cybersecurity Risk Management Process Guideline for Comment

DOE Releases New Roadmap to Guide Public-Private Cybersecurity Initiatives

Chief Reliability Officer Resigns to Become President/CEO of Transmission Forum

Compliance

Update on Compliance Analysis Reports

RSAW Update Completed

Critical Infrastructure

Reminder: Register Now for GridSecCon 2011

Reliability Assessment and Performance Analysis

NERC Releases Analysis on Frequency Response During February Extreme Weather

NERC Releases Report Assessing Risk to Reliability Performance of Bulk Power System

Standards

Progress Report on Critical Infrastructure Protection Standards

Keep up with Standards Projects Via Listservs

Update: 2012-2014 Reliability Standards Development Plan

Reminder: Register Now for NERC Standards and Compliance Workshop

Standard Drafting Team Vacancies

Training and Certification

Exam Working Group Seeks New Member

System Operator Database Updates

NERC Filings

Documents filed with FERC and/or Canada during the month

Careers

NERC Seeks Talented Professionals

Headlines

NERC, FERC Announce Joint Inquiry into September Outage

The Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC) announced a joint inquiry into the September 8 power outage that left more than 2 million customers in Southern California, parts of Arizona and Northern Baja Mexico without electricity. As of 2:15 a.m. PDT today, all but 200 MW of the initial 4,300 MW lost had been restored.

FERC and NERC will coordinate with the Department of Energy and other federal agencies, the California ISO, the Western Electricity Coordinating Council, California and Arizona state regulators and the companies involved to monitor the situation. The inquiry will focus on causes of the outages.

"NERC and FERC are partnering to conduct a full inquiry into the cause of this event," said Gerry Cauley, president and chief executive officer of NERC. "Partnering brings together the expertise of both organizations, and emphasizes the importance placed on reliability of the bulk power system."

"This inquiry is an effective way for us to protect consumers and ensure the reliability of the bulk power system," FERC Chairman Jon Wellinghoff said.

The initial focus remains on ensuring a timely and safe restoration of power to customers. Updates will continue as more information is confirmed.

FERC is charged with oversight of reliability of the nation's bulk power system. FERC has designated NERC as the organization that develops and enforces mandatory reliability standards.

FERC and NERC Release Task Force Report on Southwest Outages

The Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC) released a staff report making recommendations to help prevent a recurrence of rolling blackouts and natural gas curtailments experienced by customers in the Southwest during extreme cold weather the first week of February 2011.

Concluding a six-month inquiry, the task force found a majority of the electric outages and gas shortages were due to weather-related causes. Although generators and gas producers reported having winterization procedures and practices in place, responses were generally reactive in their approach to winterization and preparedness.

"The task force has identified several proactive steps that can be taken by state regulators, electric generators and natural gas suppliers in the Southwest to improve the reliability of energy supply for customers during extreme cold weather," FERC Chairman Jon Wellinghoff said. "We urge them to carefully consider those recommendations and to work together to implement them before another cold weather event hits the region."

"This joint report demonstrates the high priority both NERC and FERC place on reliability," said Gerry Cauley, president and chief executive officer at NERC. "By combining technical resources and partnering, this report provides a comprehensive analysis and identifies a strong set of recommendations for the industry to use to better prepare in the future."

Despite the importance of winterizing plants, the task force found that no state, regional or NERC standards required generators to do so. The report recommends that states in the Southwest examine whether to require winterization plans, and NERC plans to work with industry to develop changes to NERC Reliability Standards to properly address winterization needs.

The task force attributed most of the natural gas shortages and outages to prolonged freezing weather that resulted in dramatically reduced supply and unprecedented high demand. Interstate and intrastate pipelines showed flexibility in meeting demand and compensating for supply shortfalls, it said, but additional storage capacity in Arizona and New Mexico might have prevented many of the outages.

Most electric outages were caused by weather-related mechanical problems such as frozen sensing lines, equipment, water lines and valves.

In other recommendations, the report said:

- Generation owners and operators should ensure adequate construction, maintenance and inspection of freeze protection elements such as insulation, heat tracing and wind breaks.
- Reliability coordinators and balancing authorities should require generators to provide accurate data about the temperature limits of units so they know whether they can rely on those units during extreme weather.
- Balancing authorities should review the distribution of reserves to ensure that they are useable and deliverable during contingencies.
- State lawmakers and regulators in Texas and New Mexico, working with industry, should determine if weather-related production shortages can be mitigated through the adoption of minimum winterization standards for natural gas production and processing facilities.

DOE Releases Draft of Cybersecurity Risk Management Process Guideline for Comment

The Department of Energy, in collaboration with the National Institute of Standards and Technology and the North American Electric Reliability Corporation, released a draft of the Electricity Sector Cybersecurity Risk Management Process (RMP) Guideline for public comment. The RMP Guideline was drafted by a joint public-private sector team that also included representatives from the Federal Energy Regulatory Commission, the Department of Homeland Security, and utilities. The initiative to develop the RMP Guideline is led by the Department's Office of Electricity Delivery and Energy Reliability.

The RMP Guideline is designed to help utilities better understand their cybersecurity risks, assess severity, and allocate resources more efficiently to manage those risks. Available online for public comment until October 28, the RMP Guideline offers a flexible approach to managing cybersecurity risks across all levels of the organization. Feedback provided by industry, vendors, and other electricity sector stakeholders will be used to further refine and improve the RMP Guideline prior to final publication.

"Addressing cyber security is critical to enhancing the security and reliability of the nation's electric grid," said Patricia Hoffman, Assistant Secretary for the Office of Electricity Delivery and Energy Reliability. "The Department of Energy has been working closely with the Department of Homeland Security, other government agencies, and industry for years to reduce the risk of energy disruptions due to cyber attack. The RMP Guideline will provide utilities with consistent, adaptable solutions that help them manage their cybersecurity risks more effectively."

Over the past few decades, the Electricity Sector has increasingly relied on digital technology to reduce costs, increase efficiency, and maintain reliability during the generation, transmission, and distribution of electric power. Managing cybersecurity risk is critical to the success of organizations in achieving their strategic goals and objectives, including reliability, resiliency, security, and safety.

DOE Releases New Roadmap to Guide Public-Private Cybersecurity Initiatives

As part of the Obama Administration's goals to enhance the security and reliability of the nation's energy infrastructure, the Department of Energy released the 2011 *Roadmap to Achieve Energy Delivery Systems Cybersecurity*. Developed as an update to the 2006 *Roadmap to Secure Control Systems in the Energy Sector*, today's report outlines a strategic framework over the next decade among industry, vendors, academia and government stakeholders to design, install, operate and maintain a resilient energy delivery system capable of surviving a cyber incident while sustaining critical functions.

"Increased insight from private-public collaborations will allow us to better protect the nation's energy

delivery systems that keep our lights on and the power flowing," said U.S Energy Secretary Steven Chu. "The 2011 Roadmap takes the necessary steps to strengthen the security and reliability of our country's electric grid, in a climate of increasingly sophisticated cyber incidents."

Based on ideas and input from the energy sector, the 2011 *Roadmap* signifies a continued effort by public and private stakeholders to identify steps to build, deploy, and improve the cyber resilience of the nation's computer-based systems that manage operational processes in the electric, oil, and natural gas industries. The 2011 *Roadmap* also supports the Administration's goal of building a 21st Century clean energy economy supported by a secure, reliable, electricity system delivering power to American homes and businesses.

"This update marks a continued effort by public and private energy sector stakeholders to reduce cyber vulnerabilities that could disrupt the nation's ability to deliver power and energy," said White House Cybersecurity Coordinator Howard A. Schmidt. "It extends the commitment of industry and government to work in partnership to develop, deploy, and maintain resilient energy delivery systems that sustain the essential energy services our national security, safety, and economy depend upon."

"The Roadmap, in addition to the North American Electric Reliability Corporation's (NERC's) current efforts, proactively addresses evolving cybersecurity threats and vulnerabilities that threaten electricity reliability," said Gerry Cauley, president and chief executive officer at NERC and chairman of the Electricity Sub-sector Coordinating Council. "This public-private partnership brings together the expertise from government and industry to ensure the security and reliability of the bulk power system."

Developed by the Energy Sector Control Systems Working Group, a partnership of energy infrastructure cybersecurity leaders from government and industry, the 2011 *Roadmap to Achieve Energy Delivery Systems Cybersecurity* outlines five strategies that must be pursued to achieve the report's agenda. The five strategies include:

- **Build a Culture of Security.** When integrated with reliability practices, a culture of security ensures sound risk management practices are periodically reviewed and challenged to confirm that established security controls remain in place and changes in the energy delivery system or emerging threats do not diminish their effectiveness.
- **Assess and Monitor Risk.** Assessing and monitoring risk gives companies a thorough understanding of their current security posture, enabling them to continually assess evolving cyber threats and vulnerabilities, their risks, and responses to those risks.
- **Develop and Implement New Protective Measures to Reduce Risk**. In this strategy, new protective measures are developed and implemented to reduce system risks to an acceptable level as security risks—including vulnerabilities and emerging threats—are identified or anticipated. These security solutions are built into next-generation energy delivery systems, and appropriate solutions are devised for legacy systems.
- **Manage Incidents**. When proactive and protective measures fail to prevent a cyber incident, detection, remediation, recovery, and restoration activities minimize the impact of an incident on an energy delivery system. Post-incident analysis and forensics enable energy sector stakeholders to learn from the incident.
- **Sustain Security Improvements**. Sustaining aggressive and proactive energy delivery systems security improvements over the long term requires a strong and enduring commitment of resources, clear incentives, and close collaboration among stakeholders. Energy sector collaboration provides the resources and incentives required for facilitating and increasing sector resilience.

Chief Reliability Officer Resigns to Become President/CEO of Transmission Forum

The North American Electric Reliability Corporation announced that Thomas J. Galloway, senior vice president and chief reliability officer at NERC, has accepted the position of president and chief executive officer at the North American Transmission Forum, effective October 16.

"Tom has been an outstanding leader at NERC, and will no doubt continue his commitment to reliability excellence in his new role," said Gerry Cauley, president and chief executive officer at NERC. "NERC and the Forum share the goal of improving reliability and accountability within the electric industry, and Tom's appointment ensures a strong and beneficial relationship between the two organizations."

Galloway joined NERC in July 2010 with responsibility for NERC's Operations and Engineering, Standards, and Compliance Operations functions, where he helped promote the Electric Reliability Organization's risk-based model of reliability. Galloway worked on numerous reliability initiatives, including the facility ratings effort and the joint FERC/NERC effort on the southwest cold outage report.

Prior to joining NERC, Galloway served as the interim president and CEO for SERC Reliability Corporation in Charlotte, N.C., stepping in after Cauley was named president and CEO of NERC in 2010. He also served as an evaluation team manager, assistance team leader, and senior representative at the Institute of Nuclear Power Operations.

"I'm extremely excited to take on this important leadership opportunity," Galloway said. "The North American Transmission Forum and NERC have complementary roles toward the common objective of reliability."

Compliance

Update on Compliance Analysis Reports

NERC posts Compliance Analysis Reports on its website to provide guidance and information to the industry. To date, NERC has posted eight CARs that focus on the most frequently violated NERC Reliability Standards. In October, NERC will post the first these CARs concerning NERC and Regional Entities' Organization Registration Program and Organization Certification Program, as well as NERC Reliability Standard TOP-002 in the new NERC template. NERC and the Regional Entities are currently producing a CAR on CIP-005.

Certifications

It is expected that the number of certifications, approximately ten per year, will remain relatively stable considering the anticipated number of future agreements and market changes. To reduce the burden on entities for certifications, NERC and the Regional Entities are working to provide opportunities to lessen the need for on-site visits for those entities that have previously gone through the certification process. An on-site visit for a change in operational footprint for an entity that has previously gone through the certification process will not be necessary in most cases.

Certifications: 2007-2011					
Lead	#	Function	Lead	#	Function
NERC	5	BA	RFC	1	BA
NERC	3	RC	RFC	1	BA/TOP
TRE	13	TOP	SERC	5	BA
WECC	3	BA	SERC	1	TOP
WECC	3	TOP			

GO.TO Directive

With assistance from the Regions, NERC is in the process of issuing a directive that provides interim guidance to address the reliability gap that exists with GO/GOPs that own/operate transmission facilities (meeting the NERC Statement of Compliance Registry Criteria), but are not registered as TO/TOPs. The directive will ensure consistency across the Regions for GO/GOPs that meet the Compliance Registry Criteria to be registered as TO/TOPs. There will be an appropriate Industry Comment period, followed by a review of the comments with the Regions, and it is

NERC's intent to publish a final directive by the end of year.

ERO Auditor Workshop

NERC offered its bi-annual ERO Auditor Workshop at its Atlanta offices on September 20-22. More than 70 participants from seven Regions attended in the multi-discipline presentations covering both 693 and CIP issues. FERC, NERC and Regional Entity representatives presented helpful guidance in what participants can do to improve the reliability of the bulk power system in their day-to-day activities. Topics included the 2012 Actively Monitored List and Implementation Plan, Audit Processes, Audit Documentation, the Compliance Enforcement Initiative, as well as 693 and CIP breakout sessions. Slides from the presentations can be found on the NERC website.

NERC has already made arrangements for its upcoming ERO Auditor Workshops in February 2012 and September 2012.

RSAWs Update Completed

The work to develop or revise the Reliability Standard Audit Worksheets (RSAWs) required for the 2012 Compliance Monitoring and Enforcement Program (CMEP) Implementation Plan and Actively Monitored List (AML) has been completed, and is in final review. Once approved, the RSAWs will be posted on the NERC website – anticipated the first week of October.

The 2012 CMEP Implementation Plan and AML required the update to the RSAWs. Several current RSAWs were revised for Reliability Standards included in the 2012 AML; possible revisions could include updated regulatory language, questionnaires and minor formatting changes, as well as other minor revisions.

NERC provides notification to the industry whenever there is a major posting of RSAWs, but does not provide this same notification when individual RSAWs are updated and posted; it is recommended that all Regional Entities and Registered Entities regularly check the NERC website to ensure use of the most updated version of the RSAWs. Questions or feedback on the RSAWs can be directed to Craig Struck.

Critical Infrastructure

Reminder: Register Now for GridSecCon 2011

As a reminder, NERC is hosting the 2011 Grid Security Conference (GridSecCon) on October 18-20 at the JW Marriott in New Orleans. GridSecCon 2011 will bring together both physical and cybersecurity thought leaders to discuss current security issues facing the bulk power system. To view the agenda and to register, click here or contact Brian Harrell.

Reliability Assessment and Performance Analysis

NERC Releases Report Assessing Risk to Reliability Performance of Bulk Power System

The North American Electric Reliability Corporation (NERC) released a report that marks a new approach to assessing the reliability performance of the North American bulk power system.

This foundational report - *2011 Risk Assessment of Reliability Performance* - integrates NERC's multiple analysis efforts, combining characteristics of risk to reliability and their trends, to provide feedback and meaningful trend information to industry stakeholders and policymakers on reliability performance.

"Through analysis of reliability performance and trends, we can develop better risk control measures and better inform reliability management business decisions," said Gerry Cauley, president and chief executive officer at NERC. "This is the intelligent feedback on grid reliability performance we have been seeking to ensure that NERC and the industry are focused on the most important risks to reliability."

This report, which measures key aspects of reliability from 2008 to 2010, lays the groundwork for an annual report beginning in 2012 that communicates the effectiveness of bulk power system reliability programs. Future reports will build on these initial metrics, such as Interconnection Frequency Response,

System Voltage Performance and Transmission Constraint Mitigation, which will enable industry to measure meaningful trends and take action to support improved reliability.

"The performance measures are designed to ultimately identify common areas of risk clusters that have the greatest potential impact to affect bulk power system reliability," said Mark Lauby, vice president and director of Reliability Assessments and Performance Analysis. "Industry can then prioritize their actions toward those areas that can have the most significant improvement."

Click here to visit NERC's Reliability Indicators page.

NERC Releases Analysis on Frequency Response During February Extreme Weather

The North American Electric Reliability Corporation released an event analysis that analyzes how the bulk power system performed during the February 1-5, 2011, extreme weather conditions in the southwestern region of United States.

This report – *Analysis of Power System Impacts and Frequency Response Performance: February 1-5, 2011 Texas and Southwestern U.S. Cold Snap* - summarizes the analysis completed by NERC to assess bulk power system impacts in the El Paso, New Mexico and Arizona areas, and the frequency response performance with the affected interconnections – Eastern, Western and Texas. This analysis is a companion to the joint inquiry report by NERC and FERC, released in August, which addresses the Texas and southwestern United States extreme weather event and identified opportunities for improvement.

Standards

Progress Report on Critical Infrastructure Protection Standards

Over the past several months, there has been much activity with regard to NERC's Critical Infrastructure Protection (CIP) cyber security standards.

First, the Standards Committee created a standing CIP interpretation drafting team (CIP IDT) of 18 members. The CIP body of standards has had more requests for interpretation than any other area, and a standing team provides flexibility to draw upon a pool of candidates to more quickly address particular projects.

The first priority for the CIP IDT is to complete work on the three interpretations that are in various stages of development. A project team recently began work on revising the interpretation and responding to comments for Project 2008-10 (the interpretation of CIP-006-1 for Progress Energy), and the details of that project's development are available on the interpretation's project page. The team has finished initial work on the project, and the revised interpretation has just been through NERC's quality review. Upon the team's consideration of the quality review, it will be posted for successive ballot in the coming weeks.

Next, the Cyber Security Order 706 (Project 2008-06) standard drafting team recently submitted Version 5 of the CIP cybersecurity standards to NERC for quality review and subsequent posting for comment and ballot. Since filing Version 4, which transitions from a risk-based identification approach to bright line criteria for identifying Critical Cyber Assets, the team has continued to address the remaining directives contained in FERC's Order 706 in its development of Version 5. This set of CIP standards will also address any industry issues identified after three years' experience in implementing Versions 1 through 3 of the CIP cybersecurity standards.

The drafting team just concluded its 38th meeting at Southern California Edison's Advanced Technologies Laboratory in Westminster, Calif. In between the monthly meetings, the team has also conducted almost daily teleconferences to finalize the Version 5 drafts for posting.

To support the quality review of the Version 5 CIP cybersecurity standards, NERC is hosting two consolidated quality review sessions at NERC's

headquarters in Atlanta. More than 50 volunteers have signed up to help in the effort, which includes 10 separate standards and accompanying documentation. Following a plenary session to provide contextual and background information on the body of standards, the quality reviewers will review each standard and provide individualized and comprehensive feedback for the team's consideration before posting.

Following NERC's quality review, the drafting team plans to post the Version 5 CIP cyber security standards for comment and concurrent ballot on November 3.

CIP drafting team in Westminster, Calif.

Keep up with Standards Projects Via Listservs

NERC is always working on a number of standards projects. Industry can stay updated by visiting the Standards Under Development page, and by monitoring the Standards Progress Report linked at the top of that page. Users can also stay informed by subscribing to NERC listservs. NERC maintains a general Standards listserv, as well as a public list for each standard project (informally know as the "plus list" because it is made up of the drafting team *plus* interested observers). Subscribers will receive all meeting and conference call agendas and minutes, along with other relevant information. Many drafting teams use their plus lists for all email communication, so it's a great source of information. Before signing up, take into consideration the volume of email. If interested in monitoring all standards projects, the general standards listserv is the best list to receive.

To sign up for general standards lists or specific plus lists, please email Mallory Huggins. Make sure to note whether you would like to subscribe to all general standards lists, a project plus list (please include the name of the project), or both.

NERC also maintains two types of listservs for individuals eligible to ballot standards. First, NERC maintains a listserv of all members of the Registered Ballot Body. Each time someone joins the Registered Ballot Body, they are automatically added to this listserv, which is used to announce the formation of new ballot pools and for other announcements that are specifically relevant to balloting. Additionally, whenever a ballot pool is joined, the subscriber automatically is added to that ballot pool's listserv. During the pre-ballot window (but not during balloting), members of each ballot pool may communicate with one another by using their ballot pool listserv. The email addresses for each ballot pool listserv are provided when NERC staff sends an announcement inviting stakeholders to join that pool.

NERC is always working to improve its standards communication efforts. NERC is updating the Standards website so that it is more useful, as a well-organized and comprehensive resource for news about standards projects. For feedback about NERC communication efforts, contact Mallory Huggins, the NERC coordinator for the Standards Committee Communications and Planning Subcommittee. For specific feedback on standards web pages, contact Kristin Iwanechko, manager of standards information.

Update: 2012-2014 Reliability Standards Development Plan

In September, NERC posted the draft 2012-2014 Reliability Standards Development Plan (the Plan) for industry comment. The plan was posted September 12-26 and NERC received 15 sets of comments, including comments from approximately 63 different people from approximately 38 companies representing all 10 of the industry segments. In

general, comments were supportive of the Plan and the process used to develop it. Some comments, however, suggested changes to the prioritization and to the work plan. NERC staff is evaluating these comments to determine options for modifying the Plan, if deemed necessary.

Next, NERC staff will present the options for modification to the Standards Committee for evaluation at its October 12-13 meeting in Atlanta. The Standards Committee will be asked to take action approving either the posted version or a modified version of the Plan. Following Standards Committee approval, NERC staff will submit the Plan to NERC's Board of Trustees for consideration at its November meeting.

Reminder: Register Now for NERC Standards and Compliance Workshop

NERC is hosting its second Standards and Compliance Workshop of the year October 26-28, 2011 at the JW Marriott Buckhead in Atlanta.

The workshop will focus on the interrelationship between standards and compliance and will include a NERC Standards 101 presentation along with sessions on feedback loops among the standards and compliance departments; standards activities and plans for the future; the Bulk Electric System definition project; critical infrastructure protection issues; CANs, interpretations, and other standards improvement processes; and more.

All interested stakeholders can still register to attend in-person (a $250 registration fee) or via webinar (a $100 registration fee). The two-hour NERC Standards 101 presentation – ideal for stakeholders new to NERC's standards process or anyone looking for a refresher – requires no additional fee, but a separate registration is required. All fees are payable by Visa, MasterCard or check, and cancellations will be accepted up to one week prior to the workshop. All registration refunds will be charged $50.

Further details about the workshop are available on NERC's website, and a draft agenda will be circulated to the industry within the week.

For more information on the workshop, please contact Mallory Huggins. For registration assistance, please contact Eleanor Crouch.

Standard Drafting Team Vacancies

Any industry stakeholder meeting the indicated qualifications for one of the following three vacant appointments may submit a self-nomination form to sarcomm@nerc.com. Further instructions can be found on the Drafting Team Vacancies page on NERC's website.

Project 2007-06 System Protection Coordination

Seeking an individual from a Canadian entity with experience in coordination of protection systems (new installations and revisions).

Project 2007-12 Frequency Response

Seeking an individual representing Transmission Dependent Utilities with experience in analyzing or modeling frequency response.

Project 2010-07 Generator Requirements at the Transmission Interface

Seeking an individual, preferably from a Regional Entity, with a compliance role or background. Candidate should have experience working with generation, transmission, or both. The candidate should also be familiar with the history of the GOTO Ad Hoc Group, recent registration activity, and the work of the Project 2010-07 SDT.

In addition to these vacancies, the **Project 2007-17 Protection System Maintenance and Testing** drafting team is seeking individuals with experience in developing, managing, or supporting a maintenance program or testing a program for one or more of the following: generator protection systems, transmission protection systems, under-frequency load shedding equipment, under-voltage load shedding equipment, and/or special protection systems.

The specific focus of this solicitation is to add members representing smaller entities. If you are interested in serving on this drafting team, please complete this project-specific nomination form by

September 23, 2011. Further details are included on the Project 2007-17 project page.

Please contact Andy Rodriquez with questions regarding the vacancies.

Training and Certification

Exam Working Group Seeks New Member

The System Operator Certification Program is holding open nominations to fill one opening on the Exam Working Group. The term of service will be from the date of appointment until January 31, 2013. Nominations will be accepted until **October 30.**

A brief description of responsibilities include attendance and participation in Item Writing Workshops, Exam Development meetings, and Job Analysis Advisory Group. For more information click on EWG Nomination Letter, EWG Scope Document, Nomination Form

System Operator Database Updates

The System Operator Certification and Continuing Education Database rolled out system updates on September 28. The updates affect providers and system operators and a summary can be found in the "What's New" section of the System Operator Certification site.

Filings

NERC Filings to FERC

(click on the item link for full filing)

September 9, 2011

Petition for Approval of Interpretations to Requirements of Reliability Standards EOP-001-0 and EOP-001-2 -- Emergency Operations Planning

NERC files a petition for approval of an interpretation to Requirement R1 of EOP-001-0 — Emergency Operations Planning (EOP-001-0), and an interpretation to Requirement R3.2 of EOP-001-0 — Emergency Operations Planning (EOP-001-0). *Docket No. RM11-__-000*

September 9, 2011

Joint Motion for Extension of Time

NERC and WECC submit a joint motion for extension of time from September 14, 2011 to November 14, 2011 to allow NERC to submit a compliance filing in response to the Commission's June 16, 2011 Order regarding the registration of Cedar Creek Wind Energy, LLC and Milford Wind Corridor Phase I, LLC. The Commission directed NERC to submit a compliance filing identifying the Reliability Standards and Requirements that will be applicable to Cedar Creek and Milford. *Docket Nos. RC11-1-000 and RC11-2-000*

September 19, 2011

Additional Comments in Support of NP11-238

NERC submits additional comments in support of the Notice of Penalty filed on July 28, 2011 regarding a Notice of Penalty for Southwestern Power Administration. *Docket No. NP11-238-000*

NERC Filings in Canada, click here

(click on the link above for full filing)

September 2, 2011

1st Quarterly Application for Approval of Reliability Standards (Nova Scotia)

NERC submits to the Nova Scotia Utility and Review Board a quarterly application for approval of NERC Reliability Standards and an updated NERC Glossary of Terms approved by FERC since NERC's June 30, 2010 Application for Approval of Reliability Standards.

September 26, 2011

Notice of Filing of Compliance Monitoring and Enforcement Agreement Between NPCC and WECC and related Amendments to Delegation Agreements

NERC submits a notice of filing of (1) an Agreement Between Northeast Power Coordinating Council [NPCC] and Western Electricity Coordinating Council [WECC] Concerning Compliance Monitoring and Enforcement of WECC Registered Functions, (2) to the extent necessary, an Agreement between NERC and WECC concerning termination of their existing Agreement Concerning Compliance Monitoring and Enforcement of WECC Registered Functions, and (3) related amendments to the Delegation Agreements between NERC and NPCC and NERC and WECC.

Notice of Filing of NERC's Report of Comparisons of Budgeted to Actual Costs for 2010 for NERC and Relevant Regional Entities

NERC submits a notice of filing a true-up Report of Comparisons of Budgeted to Actual Costs for 2010 for NERC and the Regional Entities.

Notice of Filing of Interpretations to Requirements of Reliability Standards EOP-001-0 and EOP-001-2 -- Emergency Operations Planning

NERC submits a notice of filing of an interpretation to Requirement R1 of EOP-001-0 — Emergency Operations Planning

(EOP-001-0), and an interpretation to Requirement R3.2 of EOP-001-0 — Emergency Operations Planning (EOP-001-0).

Notice of Filing of Amendments to NPCC Delegation Agreement, Bylaws and Regional Standards Development Procedure
NERC submits a notice of filing of proposed amendments to NERC's Delegation Agreement with the Northeast Power Coordinating Council, Inc. (NPCC) and approval of amendments to NPCC's Bylaws and Regional Reliability Standards Development Procedure (included in Exhibits B and C to the Delegation Agreement) as "Regional Entity Rules."

Careers at NERC

Associate General Counsel and Director of Compliance Enforcement
Location: Washington, DC
Details

Compliance Enforcement Analyst
Location: Washington, DC
Details

Manager of Notice of Penalty Development
Location: Washington, DC
Details

Senior Compliance Enforcement Engineering Analyst
Location: Washington, DC
Details

Data Management System Specialist
Location: Washington, DC
Details

Compliance Enforcement Regulatory Assistant
Location: Washington, DC
Details

Manager of Compliance Analysis, Reporting, and Tracking
Location: Washington, DC
Details

Compliance Auditor
Location: Atlanta
Details

Critical Infrastructure Protection Cybersecurity Standards Specialist
Location: Atlanta
Details

Event Investigator
Location: Atlanta
Details

Attorney
Location: Washington, DC
Details

Technical Writer - Independent Contractor Position
Location: Atlanta
Details

Business Analyst
Location: Atlanta
Details

Manager of Power System Analysis
Location: Atlanta
Details

Reliability Standards Analyst
Location: Atlanta
Details

Reliability Standards Adviser
Location: Atlanta
Details

Standards Specialist
Location: Atlanta
Details

From: bounce-30527-47983@spplist.spp.org on behalf of Melissa Rinehart
To: SPP Compliance Contacts
Subject: NERC Standards Under Development
Date: Wednesday, October 19, 2011 10:18:58 AM

SPP Southwest Power Pool

COMPLIANCE UPDATE

A publication of SPP's RTO Compliance Department

IN THIS EDITION

Below is the current NERC Standards Under Development summary, which the SPP RTO Compliance Department updates and sends out weekly. As an industry stakeholder, your role in commenting is very important and we hope that you will take advantage of this opportunity to make your voices heard. Whether your company decides to submit separate comments, or helps to shape the separate comments that SPP may submit, this is one of the few chances that you will have to let NERC hear your concerns about the proposed standard(s) prior to a standard becoming effective and enforceable.

Announcements

Industry Webinar: Establishing an Electronic Security Perimeter Where None Previously Existed
November 18, 2011 | 10:00 a.m. – 11:00 p.m. CT
Teleconference: 800-379-4140 | **Access Code:** 4003018 | **Broadcast Code:** 444030

Topic: This webinar will present an overview of a process that can be used to establish an Electronic Security Perimeter (ESP) where one does not currently exist. It will discuss how to determine where the ESP should be established, along with how to determine what traffic rule sets are needed for the ESP to operate properly.

Information on determining where the ESP should be established is taken from the CIPC-approved *Security Guideline for the Electricity Sector: Identifying Critical Cyber Assets* which can be found **HERE**.

Posted for Comment

** (note that ballot pools close at 7:00 Central Time *in the morning*, while comment periods and ballots close at 7:00 Central Time *in the evening*)

Project 2010-17 Rules of Procedure Development Team: BES Definition Exception Process
Comment form: September 13, 2011 – October 27, 2011

Applicable entities: ALL

Status: NERC is requesting public comments through October 27, 2011 on the second draft of a new procedure for facility-by-facility determinations of inclusions or exclusions to the Bulk Electric System resolved through exceptions to the definition of Bulk Electric System. This exception process is proposed to be included in the NERC Rules of Procedure as Appendix 5C.

Interpretation 2011-INT-01 Revision of MOD-028-1 for FP&L
Join ballot pool: October 4, 2011 – November 2, 2011
Initial ballot: November 7, 2011 – November 16, 2011
Comment form: October 4, 2011 – November 16, 2011

Applicable entities: TO, TSP

Background: In May 2011, FPL requested an interpretation of MOD-028-1, Requirement R3.1. The request asks for clarification of the timing and frequency of TTC calculations needed for ATC calculations. At its July 2011 meeting the Standards Committee approved addressing FPL's request for interpretation through a rapid revision to the MOD-028-1 standard.

Project 2009-22 Interpretation of COM-002-2 R2 for the IRC

Join ballot pool: October 4, 2011 – November 3, 2011
Initial ballot: November 8, 2011 – November 17, 2011
Comment form: October 4, 2011 – November 17, 2011

Applicable entities: BA, RC, GOP, TOP

Status: A revised draft interpretation is posted for a 45-day formal comment period from October 4 through November 17, 2011. An initial ballot of the interpretation will be conducted from November 8 through November 17, 2011.

Background: On October 1, 2009, clarification was requested by ISO-RTO Council on Requirement R2, specifically on whether "directives" are limited to actual and anticipated emergency operating conditions, or whether routine operating instructions are also considered "directives."

The effort was delayed following discussion with the requester based on the anticipation that more clarity regarding the term, "directives" would be identified through standard development work in Project 2007-02. When it became clear that the work in Project 2007-02 would require considerable industry debate, a drafting team was formed and prepared a draft interpretation, which was posted for a 30-day formal comment period that ended December 18, 2010. Reprioritization of the total standards workload in accordance with guidance from the NERC Board of Trustees issued November 2009 and a delay as the Standards Committee developed more formal processes for addressing interpretations resulted in a delay in further processing; the Standards Committee directed that work resume on the Interpretation in April 2011.

Project 2010-07 Generator Requirements at the Transmission Interface

Join ballot pool October 5, 2011 – November 4, 2011
Initial ballot: November 9, 2011 – November 18, 2011
Comment form October 5, 2011 – November 18, 2011

Applicable entities: TO, RRO, GO, DP

Status: The SDT has reviewed comments received during a 30-day formal comment period that took place earlier this year, from June 17-July 17, 2011, and thanks all those who provided feedback during that comment period.

With the exception of the errata change to PRC-004-2.1, which is being posted for the first time, this is the second formal comment period and first ballot period for the standards included in Project 2010-07. Revised drafts of FAC-001-1 and two versions of FAC-003 – FAC-003-3 and FAC-003-X – along with minor modifications to PRC-004-2.1, have been posted for a formal comment period and initial ballot that will end on Friday, Nov. 18, 2011.
Purpose/Industry Need: The proposed changes to the requirements and the addition of new requirements will add significant clarity to Generator Owners and Generator Operators regarding their reliability standard obligations at the interface with the interconnected grid.

Project 2008-10 Interpretation of CIP-006-1 R1.1 for Progress Energy

Join ballot pool October 12, 2011 – November 10, 2011
Successive ballot: November 11, 2011 – November 21, 2011
Comment form October 12, 2011 – November 21, 2011

Applicable entities: RC, BA, IA, TSP, TO TOP, GO, GOP, LSE, RE, NERC

Background: Progress Energy asked if Electronic Security Perimeter wiring external to a Physical Security

Perimeter must be protected within a six-wall boundary.

Compliance Application Notices

For a complete listing of Compliance Application Notices, please visit the NERC website. The CAN Comment Form can be found in the "Compliance Application Notices Processes and Tools" tab, listed as CAN Process Appendix 3 – CAN Comment Form.

Industry Comments are due on October 31, 2011 for the following CANs:

CAN-0010 Definition of "Annual" and Implementation of Annual Requirements

Applicable entities: ALL

NERC received a request for clarification of the definition of the term "annual" and guidance regarding the implementation of annual requirements.

CAN-0011 PRC-005-1 R2 New Equipment

Applicable entities: NERC, RE, TO, GO, DP

Registered entities have requested that NERC provide clarification on whether the NERC Reliability Standard PRC-005 requires evidence of the pre-operational testing[1] of a registered entity's protective system equipment.

CAN-0012 Completion of Periodic Activity by Effective Date

Applicable entities: NERC, Regional Entities, Registered Entities

NERC received a request for clarification on whether a registered entity must provide evidence that it completed a periodic action or event required by a NERC Reliability Standard (Standard) prior to the registered entity's effective date for the Standard.

CAN-0013 PRC-023-1 R1 and R2: Switch-On-To-Fault Schemes
Applicable entities: NERC, Regional Entities, TO, GO, DP, PC

NERC received a request to clarify the effective date for switch-on-to-fault schemes included on 1) transmission lines operated at 200 kV and above, and 2) transformers with low voltage terminals connected at 200 kV and above under PRC-023-1 Requirement (R) 1 and R2.

CAN-0015 Unavailability of NERC Software Tools

Applicable entities: NERC, Regional Entities, Registered Entities
NERC received a request to clarify a registered entity's performance obligation when a NERC Software Tool is unavailable.

CAN-0022 VAR-001-1.1b R1 and R3 Generator Operation in Manual Mode

Applicable entities: NERC, Regional Entities, GOP, GO

NERC received requests for clarification regarding whether a generator may be operated in manual mode during start-up.

CAN-0024 CIP-002 - CIP-009 R3 Routable Protocols and Data Diode Devices

Applicable entities: NERC, Regional Entities, CEA, RC, TO, TOP, BA, GO, BOP, LSE, IA, TSP
For the purpose of aiding a CEA, this CAN provides instruction for assessing whether the communication characteristics of data diode devices can be used to exclude non-critical Cyber Assets from consideration as

Critical Cyber Assets (CCA) when a routable protocol is implemented.

CAN-0026 TOP-006 R3 Protection Relays

Applicable entities: NERC, Regional Entities, TOP, BA, RC

NERC received a request for clarification of whether a RC, TOP and BA, under TOP-006 Requirement (R) 3, needs to provide appropriate technical information to its operating staff for all protective relays in its area whether or not it has the responsibility or ownership of the protective relays.

CAN-0028 TOP-006 R1.2 Reporting Responsibilities

Applicable entities: NERC, Regional Entities, TOP, BA, GOP, RC

NERC received a request for clarification of whether a BA is responsible for reporting generation or transmission resources available for use to RCs and other affected BAs and TOPs under TOP-006 Requirement (R) 1.2.

NERC also received a request for clarification of whether a TOP is responsible for reporting transmission or generation resources available for use to RCs and other affected BAs and TOPs under TOP-006 R1.2.

Dismissal Analysis

An analysis of the dismissal reasons for certain self reported violations was conducted and is shown here. Providing information to the registered entities on common reasons for dismissals may reduce self reporting of actions that do not constitute violations. NERC and the regions produced this list of self reported dismissals to provide the industry with a better understanding of common reasons for dismissals.

NERC Lessons Learned

Transmission Line Splice Failure
Primary Interest Groups: RC, TOP, TO, BA

Generating Unit Temperature Design Parameters and Extreme Winter Conditions
Primary Interest Groups: GO, GOP, BA, RC

Adequate Maintenance and Inspection of Generator Freeze Protection
Primary Interest Groups: GO, GOP

From: bounce-30456-47983@spplist.spp.org on behalf of Melissa Rinehart
To: SPP Compliance Contacts
Subject: NERC Standards Under Development
Date: Wednesday, October 12, 2011 9:24:41 AM

SPP Southwest Power Pool

COMPLIANCE UPDATE

A publication of SPP's RTO Compliance Department

IN THIS EDITION

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Posted for Comment

** (note that ballot pools close at 8:00 *in the morning*, while comment periods and ballots close at 8:00 *in the evening*)

Project 2007-07 Transmission Vegetation Management
Recirculation ballot: October 4, 2011 – October 13, 2011

Applicable entities: TO, RRO

Status: A successive ballot closed in February 2011 and achieved a quorum of 79.28% and an approval of 79.34%. The drafting team has been working to address a set of questions posed by Standards Committee chairman Allen Mosher aimed at documenting the technical justification for the proposed requirements and verifying that the team has addressed the associated directives from Order 693. A recirculation ballot will be conducted through October 13, 2011.

Project 2011-INT-01 Interpretation of MOD-028-1 for FP&L
Join ballot pool: October 4, 2011 – November 2, 2011

Initial ballot: November 7, 2011 – November 16, 2011
Comment form: October 4, 2011 – November 16, 2011

Applicable entities: TO, TSP

Background: In May 2011, FPL requested an interpretation of MOD-028-1, Requirement R3.1. The request asks for clarification of the timing and frequency of TTC calculations needed for ATC calculations. At its July 2011 meeting the Standards Committee approved addressing FPL's request for interpretation through a rapid revision to the MOD-028-1 standard.

Project 2009-22 Interpretation of COM-002-2 — Communications and Coordination R2 for the ISO/RTO Council

Join ballot pool: October 4, 2011 – November 3, 2011
Initial ballot: November 8, 2011 – November 17, 2011
Comment form: October 4, 2011 – November 17, 2011

Applicable entities: BA, RC, GOP, TOP

Status: A revised draft interpretation is posted for a 45-day formal comment period from October 4 through November 17, 2011. An initial ballot of the interpretation will be conducted from November 8 through November 17, 2011.

Background: On October 1, 2009, clarification was requested by ISO-RTO Council on Requirement R2, specifically on whether "directives" are limited to actual and anticipated emergency operating conditions, or whether routine operating instructions are also considered "directives."

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Comment form October 5, 2011 – November 18, 2011

Status: The SDT has reviewed comments received during a 30-day formal comment period that took place earlier this year, from June 17-July 17, 2011, and thanks all those who provided feedback during that comment period.

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Transmission Line Splice Failure
Primary Interest Groups: RC, TOP, TO, BA

Generating Unit Temperature Design Parameters and Extreme Winter Conditions
Primary Interest Groups: GO, GOP, BA, RC

Adequate Maintenance and Inspection of Generator Freeze Protection
Primary Interest Groups: GO, GOP

Compliance Application Notices

For a complete listing of Compliance Application Notices, please visit the NERC website.

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

October 5, 2011

Members, Reliability Coordinating Committee
and
Members, Task Force on Coordination of Operation
Members, Task Force on Coordination of Planning
Members, Task Force on Infrastructure Security and Technology
Members, Task Force on System Protection
Members, Task Force on System Studies

Re: Minutes of the June 1, 2011 Reliability Coordinating Committee meeting

Sir / Madam:

Attached find the minutes of the June 1, 2011 meeting of the NPCC Reliability Coordinating Committee, as approved at the September 8, 2011 meeting.

Sincerely,

Phil Fedora

Philip A. Fedora
Assistant Vice President-
Reliability Services

cc: NPCC Staff

NORTHEAST POWER COORDINATING COUNCIL
Reliability Coordinating Committee Minutes
June 1, 2011

Mr. Gates called the meeting of the Reliability Coordinating Committee (RCC), held at Consolidated Edison, New York, New York, on June 1, 2011 to order at 10:00 am.

Attendance

Officers of the Reliability Coordinating Committee

Donald L. Gates, Chair	ISO-New England
Alden Briggs, Co-Vice Chair	New Brunswick System Operator
Michael Schiavone, Co-Vice Chair	National Grid USA

Sector 1 - Transmission Owners

Central Hudson Gas & Electric Corp.	Thomas Duffy
Central Maine Power Company	Brian Conroy
Consolidated Edison Company of New York, Inc.	Michael Forte
Hydro One Networks Inc.	Paul Tremblay
Hydro-Québec TransÉnergie	Jean-Marie Gagnon
Long Island Power Authority	(proxy to Curt Dahl)
National Grid USA	Michael Schiavone
New Brunswick Power Transmission Corporation	(proxy to Alden Briggs)
New York Power Authority	Michael Parisi – Alternate (via phone)
New York State Electric & Gas Corp.	Raymond Kinney (via phone)
Northeast Utilities	Brad Bentley
Nova Scotia Power Incorporated	Paul Casey
Rochester Gas & Electric Corporation	John Allen (via phone)
United Illuminating Company	Robert Pellegrini
Vermont Transco	(proxy to Kim Moulton - via phone)

Sector 2 – Reliability Coordinators

Hydro-Québec TransÉnergie	(proxy to Jean-Marie Gagnon)
Independent Electricity System Operator	(proxy to Barbara Constantinescu)
ISO-New England, Inc.	Donald L. Gates
New Brunswick System Operator	Alden Briggs
New York Independent System Operator	Henry Chao

Sector 3 – Transmission Dependent Utilities, Distribution Companies and Load Serving Entities

Hydro-Québec Distribution	(via written proxy)
Long Island Power Authority	Curt Dahl

New York Power Authority	(proxy to Michael Parisi – via phone)
Northeast Utilities	(proxy to Brad Bentley)

Sector 4 Generation Owners

Dominion Energy Marketing, Inc.	(via written proxy)
Dynegy, Inc.	Jim Watson (via phone)
Entergy Nuclear Northeast	(proxy to Tom Czerniewski)
Long Island Power Authority	(proxy to Curt Dahl)
NextEra Energy Resources	(proxy to Matt Pawloski)
New York Power Authority	(proxy to Mike Parisi – via phone)
Northeast Utilities	(proxy to Brad Bentley)
Ontario Power Generation, Inc.	Brian Gooder

Sector 5 – Marketers, Brokers, and Aggregators

Constellation Energy Commodities Group, Inc.	(via written proxy)
Hydro Québec Energy Services (US) Inc.	(via written proxy)
Long Island Power Authority	(proxy to Curt Dahl)
New York Power Authority	(proxy to Mike Parisi – via phone)
PPL EnergyPlus LLC	Bradley Weghorst (via phone)
Utility Services, LLC	Brian Evans-Mongeon

Sector 6 – Customers

None Designated

Sector 7 – State and provincial Regulatory and/or Governmental Authorities

New York Power Authority	(proxy to Mike Parisi – via phone)
New York State Department of Public Service	(via written proxy)

Sector 8 – Sub-Regional Reliability Councils, other Regional Entities and Interested Entities

New York State Reliability Council, LLC	Roger Clayton

NPCC Staff

Jack Alvarez	Senior Engineer
Gerry Dunbar	Senior Criteria Specialist
Donal Kidney	Manager, System Studies
Stanley Kopman	Assistant Vice President of Compliance Registration & Enforcement
Quoc Le	Manager, System Planning & Protection

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL
Reliability Coordinating Committee Minutes
June 1, 2011

Jennifer Mattiello (part-time)	Vice President and Chief Operating Officer
John Mosier, Jr.	Assistant Vice President of System Operations
Frantz Roc	Manager, Information Technologies
Paul Roman	Manager, Operations Planning
Edward A. Schwerdt	President & Chief Executive Officer
Guy Zito	Assistant Vice President, Standards

Guests

Jonathan Applebaum	The United Illuminating Company
David A. Daley (via phone)	Chair, Task Force on Coordination of Operation
David M. Conroy	Chair, Task Force on System Studies
Gregory Goodrich	Chair, Task Force on Infrastructure Security & Technology
Zach Smith	New York ISO
Nickesha Carrol	Consolidated Edison
Peter Yost	Consolidated Edison
Daren Verner (via phone)	Chair, Task Force on System Protection
Isen Widjaja (via phone)	Chair, SS-38 Working Group
Chris Orzel	NextEra Energy Resources
Christian Deguire	Hydro-Québec TransEnergie

Quorum Statement

Mr. Fedora indicated that a quorum had been achieved, by member attendance, proxy or alternate designation. He also noted receiving written proxies from Messrs. Dufresne (Hydro-Québec Distribution - Sector No. 3), Garton (Dominion Resources Inc. - Sector No. 4), Leuthauser, McCartney and Vennes (Hydro-Québec Energy Service (US) Inc., Constellation Energy Commodities Group, Inc., and HQ Energy Marketing, Inc. respectively - Sector No. 5), and Schrom (New York State Department of Public Service - Sector No. 7).

Antitrust Guidelines for NPCC Meetings

Mr. Fedora reviewed the NPCC Antitrust Guidelines in the Agenda package, and suggested contacting NPCC Inc.'s Assistant Secretary, Andrianne S. Payson, at (212) 424-8218 for further information.

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL
Reliability Coordinating Committee Minutes
June 1, 2011

President & CEO Report

Mr. Schwerdt reported that following the unanimous approval of its Board of Trustees, NERC, on May 25th filed two petitions with the U.S. Federal Energy Regulatory Commission on behalf of NPCC. The first filing was a request to revise the NPCC-NERC Regional Delegation Agreement to incorporate the revised *Amended and Restated Bylaws of NPCC,* which provide for the creation of a hybrid Board effective January 1, 2012 with independent Directors. The revised RDA also includes conforming changes to the Regional Standards Development Process and the construct of the NPCC Hearing Body.

The second petition filed with FERC requested that NPCC be established as the Compliance Enforcement Authority (CEA) effective January 1, 2012 for certain registered entity functions performed directly by the Western Electricity Coordinating Council (WECC). The filing identifies that NPCC, at no cost to its membership, would replace NERC as the CEA for the WECC registered functions of Reliability Coordinator and Interchange Authority. FERC had previously ruled that since WECC directly performs these functions, it cannot be the CEA for itself. FERC's notice of acceptance of these filings sets June 15th as the cutoff date for any comments.

He stated that the above actions were also reported on in this week's issue of Platts Electric Utility Week (EUW). In the EUW article, the changes to the NPCC Board structure are characterized as "evolutionary", and intended to add efficiency, effectiveness and enhancements to NPCC's operations, and to remove any suggestion of a stakeholder bias within decision making.

Ms. Mattiello then presented an overview of the initial draft of NERC's 2012 Business Plan and Budget. She reported that the Draft #2 NERC Business Plan and Budget will be made available following tomorrow morning's NERC Finance and Audit Committee meeting. All of the Regional Entities will participate at this meeting and present summaries of their respective Draft #2 plans that have incorporated stakeholder input to the extent possible.

NERC's first draft identified that:

- ✓ for the Standards Program Area**,** a key resource driver will be increased throughput of standards and reduced backlog;
- ✓ Compliance operations will be driven by risk-based Regional Entity audits and audit practices and improved registration processes;
- ✓ Compliance enforcement will be driven by efficiency and productivity measures with regard to violations processing including the administrative citation process and other streamlining measures including options to increase discretion;

- ✓ with regard to Reliability Assessment and Performance Analysis there will be significant effort to evaluate the reliability effects of electromagnetic pulses and geomagnetic disturbances as well as data management work in the areas of the spare equipment database, a centralized assessments database, modeling improvement initiatives, and metrics enhancement;
- ✓ Situation Awareness will continue advancement of the North American Synchro Phasor Initiative and SAFNR;
- ✓ the Events Analysis program will be driven by the goal to expand and disseminate lessons learned within the industry;
- ✓ Critical Infrastructure Protection is planned to include implementation of a secure portal for communications with industry and governmental authorities. Internet monitoring and analytical tools will be deployed to identify cyber attack trends affecting the electric sector among other efforts;
- ✓ with the expansion of reliability training and education delivery from NERC, an e-library of reliability resources will be initiated;
- ✓ NERC plans to design and deploy information technology infrastructure to implement business process improvements; and,
- ✓ in the legal and regulatory area NERC's resource requirements will support standards and compliance program areas initiatives.

Based on identified priorities and program area drivers as summarized in May, NERC has projected a $7.9 million dollar or 16.1% increase in operating costs and capital expenditures as compared with 2011. This compares with a $10.3 million dollar or 26.7% increase in 2011 as compared to 2010.

NERC's Draft #1 projects total expenses of nearly $55.85 million dollars with a total funding requirement of $56.6 million dollars and a Full Time Equivalent count of 178 people.

NPCC has submitted comments regarding the NERC 2012 Business Plan and Budget with an expectation that staffing expansion will be explained and that trimming of the overall budget in Draft #2 would be appropriate.

Ms. Mattiello then presented the Draft #2 of the NPCC 2012 Business Plan and Budget, as provided in the Agenda package.

Mr. Schwerdt provided a brief summary of the May NERC Member Representatives Committee and NERC Board of Trustees meetings. At these meetings, Mr. Cauley, NERC's President and CEO, focused on the dual themes of reliability and accountability for NERC and the industry. He identified the new standards prioritization process and

the need for the ERO to increase its productivity in developing and implementing meaningful standards as critical. NPCC's pilot of a Cost-Effectiveness Analysis Procedure was reported on, and well received. Mr. Cauley also noted the challenge that a backlog of between 32 to 35 months for enforcement of standards violations poses to getting compliance lessons out to the industry. NPCC is averaging approximately 21 months from violation discovery to regional close-out and will be undertaking steps to improve on that metric.

Reports on the Bulk Electric System definition drafting and the associated Rules of Procedure changes were well received, and Mr. Fedora will expand on the status of the BES efforts later in today's agenda. Additionally, Mr. Schwerdt mentioned that NPCC was recognized for its leadership role in the Events Analysis process and for producing the first three lessons learned from Events Analysis posted on the NERC website.

Chair Report

Meeting Agenda

Mr. Gates referred to an addition to the Consent Agenda regarding approval of a revision to the NPCC Special Protection System (SPS) definition. The intent of this revision is to remove the reference to NPCC Document No. A-3 (which is no longer applicable) and to make the definition consistent with the NERC definition. RCC action would be to recommend NPCC Membership vote on the revision. The RCC agreed leaving this item on the Consent Agenda.

The RCC approved the Agenda as provided in the Agenda Package.

Procedure for RCC Membership Changes

Mr. Fedora explained that proposed changes to RCC Membership would be first reviewed at RCC meetings, prior to recommendation for NPCC Board approval.

NPCC Website

Mr. Zito informed the RCC of the NPCC website redesign project underway, and described the reasons and need for the redesign. He anticipated completion of the project by this summer.

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL
Reliability Coordinating Committee Minutes
June 1, 2011

Consent Agenda

The Reliability Coordinating Committee approved the following Consent Agenda items (one opposed – Mr. Garton, Dominion Resources, Inc. – Sector 5)):

March 3, 2011 Meeting Minutes

The Draft-For-Approval Minutes of the March 3, 2011 Reliability Coordinating Committee, as included in the Agenda package, were approved, with minor changes noted.

Committee Changes

The following RCC Membership changes to be submitted to the NPCC Board for approval:

Sector 1 - Transmission Owners

- ✓ Mr. Jonathan Appelbaum as The United Illuminating Company alternate.
- ✓ Mr. Peter Yost as Consolidated Edison Company of New York, Inc. alternate, replacing John McAvoy.

Sector 2 - Reliability Coordinators

- ✓ Ms. Barbara Constantinescu as the Independent Electricity System Operator member, replacing Mr. Kim Warren.

Sector 4 - Generator Owners

- ✓ Mr. Thomas Czerniewski as Entergy Nuclear Northeast, Inc. member, replacing Mr. Robert Giguere.

Task Force Roster Changes

The following changes to Task Force memberships:

Task Force on System Studies

- ✓ Mr. Alan McBride of ISO New England, Inc. as a member.
- ✓ Mr. Brent Oberlin of ISO New England, Inc. as an alternate.

Task Force on System Protection

- ✓ Mr. Daren Verner of New Brunswick Transmission as Chairman, replacing Mr. Bryan Gwyn.
- ✓ Mr. Paul DiFilippo of Hydro One as Vice Chairman, replacing Mr. Daren Verner.

Task Force on Infrastructure Security and Technology

- ✓ Mr. David Gordon of Massachusetts Municipal Wholesale Electric Company as a member.
- ✓ Ms. Tammie Jones of The United Illuminating Company as a member.

- ✓ Mr. Mario Lajoie Hydro-Québec TransEnergie as a member, replacing Mr. Martin Ferland.

Working Group on Telecommunications (IST-2)

- ✓ Mr. Ray Kappes of New York Independent System Operator as Chair, replacing Tim Montgomery.
- ✓ Mr. Peter Woo of Independent Electricity System Operator as a member.

SS-37 Working Group on Base Case Development

- ✓ Ms. Joy Brake of Nova Scotia Power Inc. as a member.
- ✓ Mr. Stephen D. Boutilier of Nova Scotia Power Inc. as an alternate.

SP-7 Working Group on Protection System Misoperation Review

- ✓ Ms. Nicole Schwimmer of The United Illuminating Company as a member.

Revised TFSP Scope

Approved as provided in the Agenda package.

NPCC Tie Benefits Analysis

Approved as provided in the Agenda package.

Revised Document A-07 SPS Definition

Recommended for approval by the NPCC Membership, as included in the Agenda package.

Reliability Coordinating Committee Actions

2010 New York Comprehensive Area Transmission Review

Mr. Conroy introduced Mr. Smith, Manager, Transmission Studies, New York Independent System Operator who then reviewed the subject report for the RCC. The major findings were highlighted, provided in a presentation included in the Agenda package.

Both the Task Force on System Studies and the Task Force on Coordination of Planning concurred with the report's conclusion that the bulk power system planned for New York, as planned for the period through 2015 is in conformance with the NPCC Regional Reliability Reference Directory No. 1, "Design and Operation of the Bulk Power System" and recommend RCC approval.

The NPCC Reliability Coordinating Committee approved the 2010 New York Comprehensive Area Transmission Review, as provided in the Agenda package.

Alternative Underfrequency Loadshedding (UFLS) Implementation Plan for Ontario

Ms. Constantinescu, Director, Planning & Assessments for the Independent Electricity System Operator (IESO) reviewed the request for an extension of the UFLS Implementation Plan developed by Hydro One Networks from June 24, 2015 to March 31, 2007, provided in the Agenda package. She observed that Directory No. 12 does not include requirements for automatic switching of capacitor banks or any other elements if needed to control over-voltages resulting from underfrequency load shedding. As such, the original Directory No. 12 implementation plan did not allow time for providing this capability. However, the recently approved NERC PRC-006-1 Standard does include provisions for such switching should the Planning Coordinator identify such a need. She indicated that the IESO considers Hydro One's proposed extension achieving full compliance with regional UFLS requirements to be reasonable and justified.

Messrs. Daley and Conroy reported that the NPCC Task Force on Coordination of Operation and the NPCC Task Force on System Studies respectively reviewed and accepted the extension requested by the IESO and recommends approval of the plan by the RCC.

The RCC approved the Alternate UFLS Extension Plan for Ontario, as provided in the Agenda package (two abstentions – Mr. Evans-Mongeon, Utility Services – Sector 5, and Mr. Leuthauser, Hydro-Québec Energy Services (US) Inc. – Sector 5).

In response to a question by Mr. Schwerdt, Mr. Dunbar verified that the current development of the NPCC Regional Standard on UFLS has addressed the issues raised by the IESO. The draft implementation plan for the NPCC Regional UFLS Standard has been modified accordingly and the recommendation comports with the requirements of the NERC PRC-006-1 Standard.

NPCC 2011-2012 Winter Probabilistic Multi-Area Reliability Assessment

Mr. Fedora reviewed the subject report for the RCC, highlighting the major findings in a presentation included in the Agenda package.

Mr. Briggs said that the Task Force on Coordination of Planning had reviewed the report, agreed with its conclusions and recommended the RCC approval.

The RCC approved the NPCC 2011-2012 Winter Probabilistic Multi-Area Reliability Assessment, as provided in the Agenda package (one abstention – Mr. Dahl, Long Island Power Authority - Sector 3).

Status Reports

Mr. Gates referred the RCC to the materials provided in the Agenda package; the RCC discussed the following Agenda items:

NPCC Regional Standards Committee (RSC) Report

Mr. Zito reviewed NPCC Cost Effeteness Analysis Procedure provided in the Agenda package. He explained that the RSC is developing a first draft of this procedure to evaluate and determine if a standard is cost effective in achieving a reliability objective.

He reported that the RSC is also developing a first draft of a "Triage" procedure to evaluate Standards and standards related issues in an expedited manner. The Procedure is envisioned to identify potential adverse impacts and rapidly determine if a draft Standard accomplishes its reliability objective(s) and produce information the RSC will utilize in the development of comments and ballot recommendations for NERC Standards.
With respect to the NPCC Directory development, Mr. Zito said that Phase 2 of the Directory Project has commenced and will result in a reformatting of the Directories in order to provide specific measurable Criteria requirements. This reformatting effort will be coordinated with the respective Task Force review of each Directory and will clearly delineate the NPCC regional criteria that are more specific and more stringent within each document.

He added that NPCC expects to establish a new *NPCC Glossary* and a *Directory Development Process Manual* by the end of 2011. The new glossary will contain all of the NPCC specific definitions that currently reside in the Directories into a new glossary and any inconsistencies between NERC terms and NPCC terms will be addressed; the Directory manual will provide guidance to the Task Forces regarding document development, management and coordination.

NPCC Compliance Committee Report

Mr. Kopman highlighted four items provided in the Compliance Report provided in the Agenda package:

- ✓ registered entity culture of compliance survey – the goal is to have this project completed by the end of the year;
- ✓ NERC the Régie de l'énergie agreed on final versions of the QCMEP, QROP and a second implementation agreement between NERC, NPCC and the Régie de l'énergie. These documents are now being prepared for submittal to the Quebec ministry for their review and approval;
- ✓ Meeting with the New York ISO and New York Transmission Owners regarding registration issues related to a new definition for the Bulk Electric System; and,
- ✓ Increased efficiencies in violation processing.

Blackout Study Recommendations

Mr. Kidney reviewed the materials included in the Agenda package regarding the need for improved load response models in dynamic voltage and frequency simulations. The goal is to produce a white paper summarizing the issues by November 2012.

Coordination of NPCC Reliability Practices

The Task Force Chairs from the Task Force on System Protection, Task Force on Coordination of Operation, Task Force on Coordination of Planning, and the Task Force on System Studies discussed the assignment and provided an overview of their respective Task Force activities, as provided in the Agenda package.

Mr. Gates said that recognizing that today is the due date for responses, and that not all responses expected have been received, he suggested a follow-up Joint Task Force Chairs teleconference, scheduled in the coming weeks before the Task Forces next meet, in order to consider the responses received and agree on any follow-up approaches.

In response to a question by Mr. Gagnon, Mr. Schwerdt stated that this project was a proactive strategy to coordinate what is already done for 100 kV and above facilities for all of NPCC, and, as such, he would encourage and value Canadian participation.

Task 5 of the NPCC August 14, 2003 Northeast Blackout Study

Mr. Widjaja reviewed the status report and schedule provided in the Agenda package; he reported that in the coming months, the SS-38 Working Group will perform analysis of step 5 of Task 5 to simulate controlled island formation and assess performance. The SS-38 Working Group will also continue to review the simulations and document the results completed in steps 2, 3, and 4 of Task 5.

Procedure for Analysis and Reporting of Protection System Misoperations

Mr. Verner reported that the Task Force on System Protection (TFSP) has successfully completed the open process review and conversion of Document B-21, NPCC *Guide for Analysis and Reporting of Protection System Misoperations* to NPCC Document C-45.

He said that comments received in the NPCC Open Process were addressed and NPCC Document C-45 was modified accordingly and has been approved by TFSP for use by NPCC. NPCC Document C-45 (included in the Agenda package) can now be used to support on-going efforts at NERC and NPCC through the Compliance Committee to implement consistent format and specifications for Registered Entities to report protection system misoperations for the NERC Standards PRC-003, PRC-004, PRC-016 and PRC-022. Through the effort of the NPCC SP-7 Working Group, data from

misoperation reports will also be used to support the development of the new NERC reliability metric ALR4-1 for protection misoperations.

Review of Proposed UF trip settings for Nuclear units with Motor-Generator sets
Mr. Conroy reported that based on the responses to the Task Force on System Studies request sent out in late 2009; proposed Fitzpatrick and Vermont Yankee unit setting changes would provide adequate coordination. Revised effective frequency thresholds and tolerances for the Pilgrim unit are necessary to confirm that the changes provide adequate coordination. Threshold change to Nine Mile Point unit No. 2 is still required to provide adequate coordination.

Based on TFSS review of the proposed changes, owners of the Pilgrim unit and Nine Mile Point unit No. 2 will be contacted for additional information and threshold change, respectively.

2011-2012 Work Plan Progress
Mr. Gates referred the RCC to the Task Force Work Plan progress reports included in the Agenda package.

Additionally, Mr. Mosier reported on the status of NPCC Directory No. 5; Mr. Goodrich reported on the NERC Alert on AUROA, and the Idaho National Labs assessment of the ICCP protocol vulnerabilities.

NPCC Reliability Assessment Program Highlights
Mr. Fedora referred the RCC to the highlights report posted on the NPCC website.

NERC Highlights and Agenda Items

Operating Committee (OC)
Mr. Mosier reviewed the following topics on the June 2011 OC Agenda:

- ✓ Agenda Item 5.c – Approve Situation Awareness for FERC, NERC, and the Regional Entities (SAFNR), version 2;
- ✓ Agenda Item 5.d – Approve Adequate Level of Reliability Scope of Technical Committee Work; and,
- ✓ Agenda item 6.a – Approve Revised Operating Reliability Subcommittee (ORS) Scope (merges the Reliability Coordinator Working Group into the ORS.

Planning Committee (PC)
Mr. Fedora highlighted the following topics on the June 2011 NERC PC Agenda:

- ✓ Agenda Item 5.a - Revised draft of PC Strategic Plan, proposed Charter changes, and revised PC Work Plan;

- ✓ PC Agenda Item 6.e.2 – Generating Availability Data System Task Force – endorse report for NERC BOT approval;
- ✓ Agenda Item 6.f.1 & 6.f.2 – Approve Transmission Issues Subcommittee (TIS) Frequency Response Assignment Scope of Work and approve TIS Recommendation of the Frequency Response Criteria;
- ✓ Agenda Item 6.f.3 – Approve – TIS Collaboration with the System Protection and Control Subcommittee on their review of NERC Standards related to Special Protection Systems and Remedial Actions Schemes;
- ✓ Agenda Item 6.g.2 – Approve the System Protection and Control Subcommittee Coordination with TIS to address failure of Special Protection Systems; and,
- ✓ Agenda Item 6.h.1.2 – Approve Transmission Availability Data Systems (TADS) Task Force Scope of additional analysis of data by the TADS Working Group.

Critical Infrastructure Protection Committee (CIPC)

Mr. Hogue provided an overview of the following items on the June 2011 CIPC Agenda:

- ✓ Version 5 CIP Standards;
- ✓ Agenda Item 3.g – GridEX; the exercise is scheduled for November 16 and 17, 2011;
- ✓ Agenda Item 3.i – Adequate Level of Reliability Task Force approval;
- ✓ Agenda Item 8.d.1 – Approve CIPC Guideline for Business Continuity; and,
- ✓ Agenda Item 12 – Update on Washington DC Legislative Activities.

Informational Items

Mr. Gates referred the RCC to the materials included in the Agenda package. The following Informational Items were discussed at the meeting:

NERC 2011 Summer Reliability Assessment

Mr. Fedora indicated that the Press announcement for the NERC 2011 Summer Reliability Assessment was recently released and was included in the Agenda package.

Definition of Bulk Electric System (BES) Standards Drafting Team (Project 2010-17)

Mr. Fedora referred to the presentation from the recent NERC Webinar regarding the status of the BES Drafting Team's efforts to revise BES the definition. The BES Drafting Team will be meeting in the following weeks to review the comments received on the posting of the initial BES Definition and Exception Criteria. Each comment received will be considered and a response supplied in the second posting of the BES Definition. He thanked NPCC Members for taking the time to provide comments for this project.

Eastern Interconnection Planning Collaborative (EIPC)

Mr. Gates referred to the presentation included in the RCC Agenda package, and indicated additional information could be found on the EIPC website (http://www.eipconline.com/).

Other Matters

Mr. Gates noted that Mr. Gagnon has announced his retirement effective June 30, 2011, and recognized his contributions to NPCC and NERC; the RCC wished him well in his retirement and future activities.

Having no other items to consider, the RCC meeting was then adjourned.

Next RCC Meeting Date	Location
September 8, 2011	Offices of the Consolidated Edison Company of New York, Inc.-New York, New York

Distribution of Approved Minutes

NPCC Full & General Member Representatives and Alternates
Members, NPCC Board of Directors
Members, NPCC Reliability Coordinating Committee
Members, NPCC Public Information Committee
Members, NPCC Compliance Committee
Members, NPCC Regional Standards Committee
Members, NPCC Task Force on Coordination of Operation
Members, NPCC Task Force on Coordination of Planning
Members, NPCC Task Force on Infrastructure Security and Technology
Members, NPCC Task Force on System Protection
Members, NPCC Task Force on System Studies
NPCC Officers
NPCC Staff
Andrew J. Fawbush, Esq.
Catherine P. McCarthy, Esq.
Andrianne S. Payson, Esq.
and
Federal Energy Regulatory Commission – Joseph McClelland
La Régie de L'Énergie – Caroline Dupuis
Ontario Energy Board – Peter Fraser
United States Department of Energy – David Meyer
New Brunswick Department of Energy – Stephen Waycott
Nova Scotia Utility & Review Board – S. Bruce Outhouse, Q.C.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Electric Reliability Organization Compliance Analysis Report

Reliability Standard TOP-002
Normal Operations Planning

October 2011

RELIABILITY | ACCOUNTABILITY

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
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ERO Compliance Analysis Report

NERC and the Regional Entities have completed eight Compliance Analysis Reports to date. Their focus has been on those Reliability Standards most violated and having the highest actual or potential impact on reliability. NERC welcomes feedback on which Reliability Standards should be analyzed for Compliance Analysis Reports as well as important issues once a report has been announced and posted. NERC recently published a VAR-002 Compliance Analysis Report addendum that addressed a specific issue with the VAR-002 report.

The purpose of this TOP-002 Compliance Analysis Report is to provide information to the industry on common violation descriptions and provide feedback on how entities can be compliant with the Requirements of this standard.

There are three main reasons TOP-002 was chosen for a Compliance Analysis Report:

1. TOP-002 is the 4th most violated non-CIP standard, all-time;
2. TOP-002 is the 5th most violated non-CIP standard in the last 12 months; and
3. TOP-002 is applicable to over 63% of Registered Entities.

Summary of Practical Information and Suggestions

This summary is intended to capture the analysis detailed below by providing some essential elements of the Requirements, and by offering some suggestions for industry consideration. It is not a complete list of all possible elements or actions. Evaluating or undertaking such actions or suggestions does not guarantee compliance and does not replace the NERC Reliability Standards language.

TOP-002 Overview (Common violation descriptions are provided later in this report)

- Of the five Requirements with double digit violations:
  - Requirement R1 had five of 11 violations self-identified where a lack of documentation for proving compliance was the main finding.
  - Requirement R3 had 16 of 18 violations self-identified where a lack of documentation for proving compliance was the main finding.
  - Requirement R11 had eight of 15 violations self-identified. Most of the seven violations not self-identified had a potential moderate to severe impact on reliability. Entities should maintain documentation that it is performing seasonal, next-day and current day studies.
  - Requirement R14 had nine of 11 violations self-identified. Of the two not self-identified, one had a potential severe impact to reliability as the entity did not notify their BA and TOP of changes in real and reactive output capabilities. The generating unit could not come on line at the request of the Independent System Operator (ISO) due to ongoing maintenance work.
  - Requirement R18 had 20 of 22 violations self-identified. Requirement R18 will be deleted and incorporated into COM-003-1 when it becomes effective.[1] The current draft of COM-003-1 Requirement R7, developed in response to Recommendation 26 of *Final Report on the August 14, 2003 Blackout*,[2] states: "Each Reliability Coordinator, Balancing Authority, Transmission Owner, Transmission Operator, Generator Operator, Transmission Service Provider, Load Serving Entity and Distribution Provider shall use pre-determined identifiers for interface Elements/Facilities during verbal and written Operating Communications." Recommendation 26 reads, "Tighten communications protocols, especially for communications during alerts and emergencies. Upgrade communication system hardware where appropriate."

[1] From the Project 2007-02 Standard Authorization Request (SAR): Operating Personnel Communications Protocols.

[2] *Final Report on the August 14, 2003 Blackout in the United Stated and Canada: Causes and Recommendations,"* U.S.-Canada Power System Outage Task Force, April 5, 2004.

Overview of the TOP-002 Standard

Background

Titled *Normal Operations Planning*, the purpose of the TOP-002 Reliability Standard is to ensure that current operations plans and procedures essential for reliable operations are in place, including planned response to unplanned events. TOP-002-2a is the current version of the TOP-002 standard in effect. The NERC Board of Trustees adopted the standard on February 10, 2009, and the effective date was immediately after FERC approval on December 2, 2009. There are 19 high level Requirements, with three sublevel Requirements. The five registered functions that TOP-002 applies to are: Balancing Authority (BA), Transmission Operator (TOP), Generator Operator (GOP), Load Serving Entity (LSE) and Transmission Service Provider (TSP).

As of May 10, 2011, the regional breakdown of the five applicable functions is:

NERC Compliance Registry Matrix

Statistical Data

Registration Status as of 5/10/2011

Region	# of Registered Entities	BA	GOP	LSE	TOP	TSP	Total # of Functions
ERCOT	138	1	86	58	15	1	161
FRCC	43	10	31	19	16	8	84
MRO	82	20	45	57	20	13	155
NCEA	1	1	0	0	1	1	3
NPCC	198	6	133	62	14	14	229
RFC	191	13	145	54	16	3	231
SERC	161	32	90	78	27	16	243
SPP	83	17	50	51	18	5	141
WECC	319	33	203	147	51	34	468
TOTALS:	**1216**	**133**	**783**	**526**	**178**	**95**	**1715**

TOP-002 is applicable to 1,216 of the 1,920 Registered Entities, or approximately 63% of all Registered Entities.

For the 2012 Actively Monitored List (AML), TOP-002 R17 and R18 are both Tier 1 Requirements and must be audited while all other Requirements for this standard are Tier 2. Tier 1 Requirements are the most critical to the purpose of the Reliability Standard and address the ERO high risk priorities. Tier 1 requirements represent the minimum audit scope. Tier 2 Requirements are critical to the purpose of the Reliability Standard, but less so than Tier 1. Tier 2 Requirements support the ERO high risk priorities but to a lower degree than Tier 1 Requirements.

Metrics of TOP-002 Violations

TOP-002 Violations by Requirement		
Requirement	**Violations**	**Percentage**
R1 – BA and TOP maintaining of current plans to evaluate options and set procedures for reliable operation	11	7.9%
R2 – BA and TOP ensuring its operating personnel participate in system planning and design study processes	6	4.3%
R3 – LSE and GO coordinating its current-day, next-day, and seasonal operations with its BA and TSP; BA and TSP coordinating same operations with its TOP	18	12.9%
R4 – BA and TOP coordinating its current-day, next-day, and seasonal operations with neighboring BAs, TOPs and with its RC	8	5.8%
R5 – BA and TOP planning to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns	6	4.3%
R6 – BA and TOP planning to meet unscheduled changes in system configuration and generation dispatch	6	4.3%
R7 – BA planning to meet capacity and energy reserve requirements	2	1.4%
R8 – BA planning to meet voltage and/or reactive limits	0	0.0%
R9 – BA planning to meet Interchange Schedules and ramps	1	0.7%
R10 – BA and TOP planning to meet all System Operation Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs)	2	1.4%
R11 – TOP performing current-day, next-day, and seasonal studies to determine SOLs; TOP update and make available	15	10.8%
R12 – TSP including known SOLs and IROLs within its area and neighboring areas	0	0.0%
R13 – At request of BA or TOP, GOP shall perform generating real and reactive capability verifications and provide the results to the BA or TOP as requested	4	3.0%
R14 – GOP notifying their BA and TOP of changes in capabilities and characteristics in changes in real output capabilities	11	7.9%
R15 – GOP providing a forecast of expected real power output	3	2.2%
R16 – TOP notifying their BA and RC of changes in capabilities and characteristics in transmission facility status or rating	7	5.0%
R17 – BA and TOP communicating information in R1 through R16 to RC	9	6.5%
R18 – BAs, TOPs, GOPs, TSPs, and LSEs using uniform line identifiers referring to transmission facilities on an interconnected network	22	15.8%
R19 – BA and TOP maintaining accurate computer models for planning system operations	8	5.8%
Totals	139	100%

As indicated in the table on the previous page, there are a total of 139 violations of TOP-002. All of the violations discussed in this report were submitted to NERC by the Regional Entities prior to July 1, 2011 and relate to both TOP-002-2 and TOP-002-2a.

The average number of violations per Requirement is 7.3, with R18 having 22 violations (most) with R8 and R12 having zero violations (least). A graphical representation of the TOP-002 violations by Requirement is shown below.

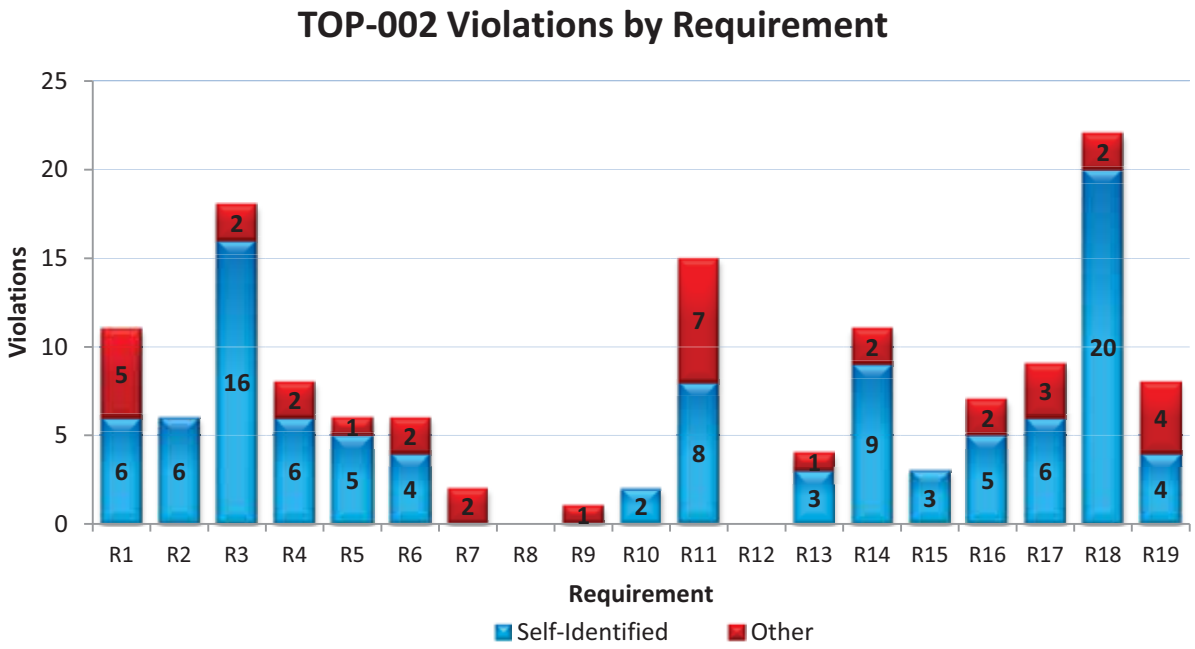

Violations by Method of Discovery

An important metric is the number of violations by method of discovery.

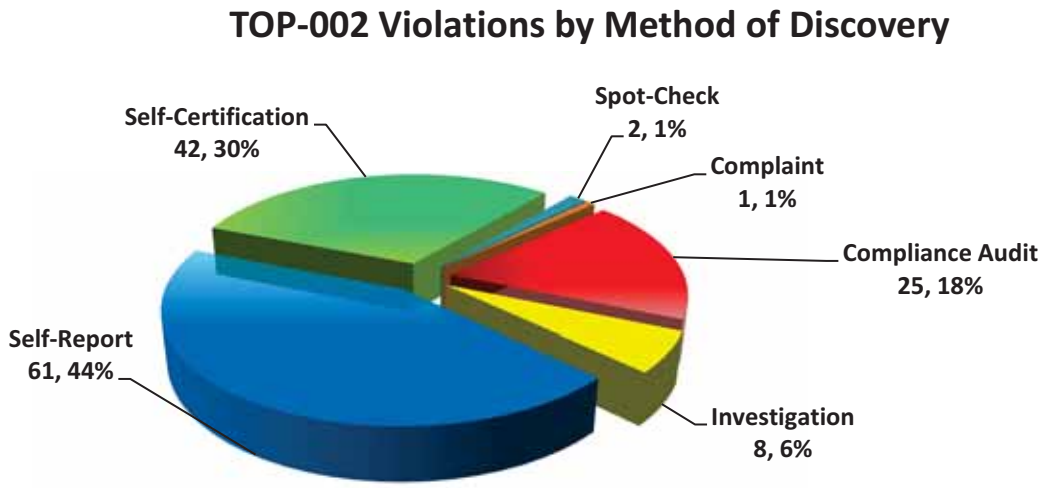

Self-reports and self-certifications account for 74% of the violations. Registered Entities are encouraged to self-identify possible violations. This metric shows an active and aggressive compliance monitoring program and a good internal compliance program (ICP). Next, there were eight violations discovered through investigations. Of the 78 violations in WECC, 29 (or 37% in WECC) resulted from forced and abrupt registration changes. These 29 violations also represent over 20% of the total 139 violations.

Violations by Region

This section of the TOP-002 Compliance Analysis Report covers the violations by Region.

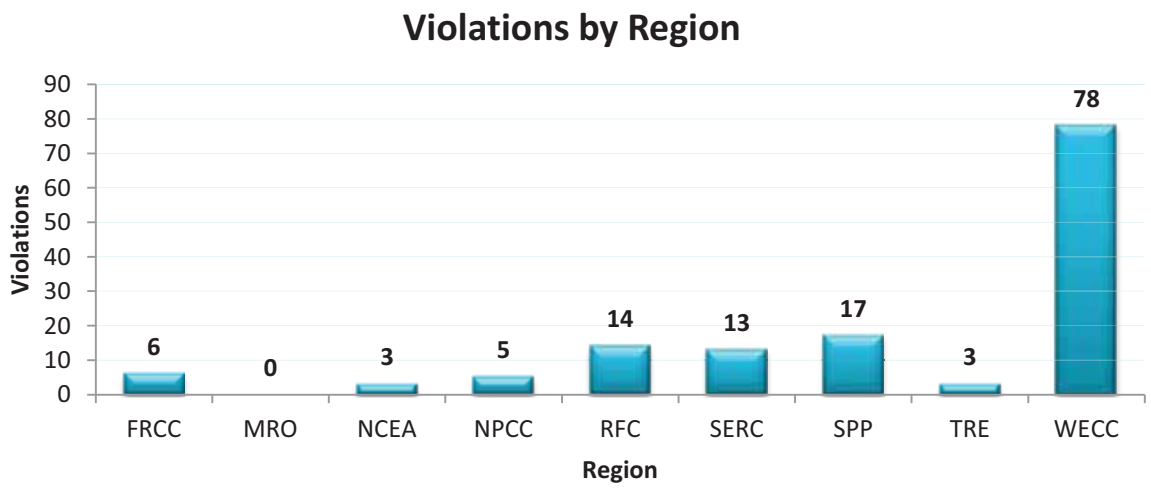

Violations by Date

Trending by violation date shows how the industry is complying with the standard as a whole. With 15 violations in the first half of 2011, TOP-002 remains a frequently violated standard.

Analysis of TOP-002 Violation Descriptions

This section of the TOP-002 Compliance Analysis Report covers common violation descriptions and recommendations by Requirement.

Requirement 1

R1. *Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.*

Violation Descriptions

- Entity states that this Requirement is the responsibility of another entity but has no documentation to support that another entity has accepted delegation of this responsibility.
- Entity does not have written current day plans for maintaining system reliability, complete with assessment of current conditions and options for contingencies.
- Entity failed to maintain a set of current plans designed to evaluate options and set procedures for reliable operation through a reasonable future time period.

Suggested Enhancements with R1

- If the set of current plans designed to evaluate options and set procedures for reliable operations are the responsibility of another entity, the Registered Entity needs to have an agreement in place showing the other entity has accepted delegations of this responsibility.

Requirement 3

R3. *Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.*

With 18 violations in five different Regions, there is a need for guidance to the industry on compliance information with this Requirement. Eight of the violations were from entities registered as GOPs, nine from entities registered as LSEs, one from an entity registered as both a GOP and LSE, and one from entity registered as a BA. It is important to note that all violations were self-identified.

Violation Descriptions

- With the exception of one of its facilities, the entity did not provide evidence that current-day, next-day and seasonal operations had been coordinated with its host Balancing Authority and Transmission Service Provider.

- The system operator was not required to significantly alter their dispatch operating plan due to the unavailability of the Generator and has not otherwise made any findings of adverse impacts to the Bulk Electric System due to the outage approval failure.
- The entity did not provide the host BA the generation resources availability for one day.
- The entity did not provide the host BA the load forecast for one day.

An entity had been providing a 14-day forecast of planned power exports. The export forecast was emailed as updates that occurred, typically 2-3 times per week and not on weekends. Upon discovering this information was not being sent daily, the entity self- reported a possible violation and began emailing the two-week export forecast daily, including weekends.

Suggested Enhancements with R3

- Processes and records of actions should be kept to verify the appropriate coordination is completed.

Requirement 4

R4. *Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.*

There has been only one violation of Requirement R4 from the beginning of 2010.

Violation Descriptions

- Interview confirmed the entity does not provide this information with its neighboring BA, TOP, and RC.

Suggested Enhancements with R4

- Procedure should be in place that identifies entities with which coordination should occur.
- Records of coordination should be maintained.

Requirement 11

R11. *The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.*

Roughly half of the violations of this Requirement were discovered through a compliance audit. It is important to note that failing to perform current day and next day operational studies does not prepare the TOP for what to expect for the next day of operations.

Identifying critical issues that could cause a cascading failure is critical to understanding how the system should be operated. Failing to understand this costs lots of time in an emergency. Failure to perform assessment of current and next day studies when system conditions are in a normal state could lead to a lack of situational awareness by Transmission Operators. Furthermore, the operating personnel need to provide input on observed problems not predicted by studies.

Violation Descriptions

- Entity did not perform seasonal, next-day, and current-day BES studies to determine SOLs. Therefore, the entity could not utilize identical SOLs for common facilities among its neighboring TOPs and the entity could not update these BES studies as necessary to reflect current system conditions and make the results of BES studies available to the TOPs, BAs (subject to confidentiality requirements), and RC.
- Entity did not produce any evidence that it independently performs these studies and did not produce evidence that there is an agreement with the RC to produce studies compliant with this requirement.
- Entity failed to perform seasonal, next-day, and current-day BES studies to determine SOLs.
- Through the Registered Entities' notification at the spring 2010 Compliance Workshop, the registered entity has stated that the RTO current and next-day studies are not sufficient for a TOP to use to meet the requirements in TOP-002-2a R11. The Registered Entity does not perform current and next-day studies and has relied on the RTO reporting in the past.

Suggested Enhancements with R11

- Entities must provide evidence that valid studies for current and next-day are available.

<u>Requirement 14</u>

R14. *Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to: Changes in real output capabilities.*

Violation Descriptions

- Entity did not make timely notification of change in real-time output of units due to reduction of the unit capability due to loss of fuel.
- Changes in capabilities and characteristics are not being reported to the TOP.
- Interview confirmed that the entity does not currently provide generator capability updates to its BA.
- Entity did not update RC on change in the capability of its generation resources on 11/29/07.

Suggested Enhancements with R14

- Develop a process or procedure to inform both the BA and TOP of changes in real output capabilities.
- Develop a process to document such notifications.

Requirement 16

R16. *Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to: Changes in transmission facility status or rating.*

Violation Descriptions

- Entity self-reported they did not notify their RC of a change in the facility rating of a transformer.

Suggested Enhancements with R16

- Implementation of a process or procedure to notify both the BA and the RC of such changes.
- Document, through e-mails, log entries or other such records, such notification.

Requirement 17

R17. *Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in requirements R1 to R16 above to their Reliability Coordinator.*

Violation Descriptions

- Study results not communicated to the RC.

Suggested Enhancements with R17

- Document, through e-mails, log entries or other such records, such notification.

Requirement 18

R18. *Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.*

Requirement R18 is an important Requirement and may not be as well understood to the industry as it could be. Using the same uniform line identifiers for substations and transmission lines is critical to real-time communications and operations. In one Region, the general practice adopted is to identify substation to substation for developing uniform line identifiers. It is supported by one of the RC's outage scheduling tools, and thus is used by all of the appropriate entities.

Exchanging naming conventions is the first step toward developing uniform line identifiers. This may be an area where the industry lacks understanding as there may be a lack of explicit coordination between the RCs, BAs, TOPs, GOPs, TSPs, and LSEs to use the same naming conventions for substations and transmission lines. For example, there has been a concern

from the industry on why GOPs should have naming conventions for transmission lines when they do not own them. As such, GOPs are not required to have naming conventions, but are required to use uniform line identifiers when communicating with other entities, such as their interconnecting TOP. Furthermore, as a good practice example, two TOPs discussing an outage use the uniform line identifiers that relate to their RC's outage scheduler.

As stated in the summary section earlier in this report, this Requirement will no longer be in effect when COM-003-1 is effective.

Violation Descriptions

- Entity was unable to demonstrate that transmission line and equipment identifiers used were uniform with the identifiers used by the interconnected transmission operator.
- Designators used on 115 kV devices not consistent with TOP/TSP designations.

Suggested Enhancements with R18

- Identify all interconnection entities and exchange with them your naming conventions for all affected transmission facilities.
- Document a process that verifies with the appropriate interconnected entities that they are using uniform line identifiers.

Conclusion

TOP-002 is a NERC Reliability Standard that is critical to the reliability of the Bulk Power System. As the violations continue to steadily accumulate, the ERO needs to provide feedback that will aid the Registered Entities with compliance. Already in 2011 there have been 22 violations of TOP-002, so this report was written to curtail that number for 2011 and inform the industry of important compliance information with this standard.

Registered Entities should go through this report and read common violation descriptions, and make sure they provide and maintain evidence that covers all facets of the Requirements. It is also advised that the Registered Entities have an active and aggressive compliance monitoring program, a strong internal compliance program, and a solid culture of compliance within their organizations.

If you have any questions, please see below for contact information.

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From: Stacia-Ann Chambers
To: canonly
Subject: NERC: ERO Compliance Analysis Report
Date: Wednesday, October 05, 2011 8:17:05 PM

Announcement

Compliance Analysis Report Posting

October 5, 2011

Click here for: NERC Organization Certifications Report
Click here for: NERC Compliance Registry and Registration Appeals Report
Click here for: TOP-002 Report

Ladies and Gentlemen:

The Electric Reliability Organization (ERO) Compliance Analysis Report: NERC Organization Certifications, NERC Compliance Registry and Registration Appeals and TOP-002 have been posted.

The ERO is welcoming comments to the report from the industry. If you would like to provide comments, please contact Ryan Stewart.

For more information or assistance, please contact **Ryan Stewart** (via email).

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Suite 600, North Tower
Atlanta, GA 30326
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From:	Howard Gugel
To:	rsg
Subject:	NERC - RSG - Whitepaper on regional standards and variances
Date:	Friday, October 14, 2011 8:51:17 AM
Attachments:	Whitepaper on Regional Standards and Variances.doc

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As promised, attached is a Word version of the whitepaper discussed at the October RSG meeting in Atlanta. Please review and provide comments by October 28. Thanks.

If you have problems viewing the flowchart at the end, it is a Visio object.

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Where to Put Requirements that Apply on Less Than a Continent-wide Basis

Regional Standards and Variances – *What was Approved in the ERO Certification Order and Rules of Procedure*

FERC has indicated it will consider approving regional differences (variances) and Regional Standards that meet the following criteria:

Item 34: ¶ 274 of the ERO Certification Order:

> "The Commission has stated that we will accept the following two types of regional differences, provided they are otherwise just, reasonable, not unduly discriminatory or preferential and in the public interest, as required under the statute:
>
> (1) a regional difference that is more stringent than the continent-wide Reliability Standard, including a regional difference that addresses matters that the continent-wide Reliability Standard does not; and
>
> (2) a regional Reliability Standard that is necessitated by a physical difference in the Bulk-Power System.

The FERC-approved definitions of Regional Standard and Variance (from the Rules of Procedure) are:

> **"Regional reliability standard"** means a type of reliability standards that is applicable only within a particular regional entity or group of regional entities. A regional reliability standard may augment, add detail to, or implement another reliability standard or cover matters not addressed by other reliability standards. Regional reliability standards, upon adoption by NERC and approval by the applicable ERO governmental authority(ies), shall be reliability standards and shall be enforced within the applicable regional entity or regional entities pursuant to delegated authorities.
>
> **"Variance"** means an aspect or element of a reliability standard that applies only within a particular regional entity or group of regional entities, or to a particular entity or class of entities. A variance allows an alternative approach to meeting the same reliability objective as the reliability standard, and is typically necessitated by a physical difference. A variance is embodied within a reliability standard and as such, if adopted by NERC and approved by the ERO governmental authority, shall be enforced within the applicable regional entity or regional entities pursuant to delegated authority.

Regional Standards and Variances – *What was Approved in the Standard Processes Manual*

The latest approved version of the Standard Processes Manual includes the following language:

> NERC's drafting teams shall aim to develop standards with requirements that apply on a continent-wide basis, minimizing the need for variances while still achieving the standard's reliability objectives. If one or more requirements cannot be met or complied with as written because of a physical difference in the bulk power system or because of an operational difference (such as a conflict with a Federally or Provincially approved tariff), but the requirement's reliability objective can be achieved in a different fashion, an entity or a group of entities may pursue a variance from

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one or more requirements in a continent-wide standard. It is the responsibility of the entity that needs a variance to identify that need and initiate the processing of that variance through the submittal of a SAR that includes a clear definition of the basis for the variance.

There are two types of variances – those that apply on an interconnection-wide basis, and those that apply to one or more entities on less than an interconnection-wide basis.

Interconnection-wide Variances

Any variance from a NERC reliability standard requirement that is proposed to apply to responsible entities within a regional entity organized on an interconnection-wide basis shall be considered an Interconnection-wide Variance and shall be developed through that regional entity's NERC-approved regional reliability standards development procedure.

While an interconnection-wide variance may be developed through the associated Regional Entity standards development process, regional entities are encouraged to work collaboratively with existing continent-wide drafting team to reduce potential conflicts between the two efforts.

An Interconnection-wide Variance from a NERC reliability standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with other applicable standards of governmental authorities shall be made part of the associated NERC reliability standard. NERC shall rebuttably presume that an Interconnection-wide Variance from a NERC reliability standard that is developed, in accordance with a standards development procedure approved by NERC, by a regional entity organized on an interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest.

Variances that Apply on Less than an Interconnection-wide Basis

Any variance from a NERC reliability standard requirement that is proposed to apply to one or more entities but less than an entire Interconnection (e.g., a variance that would apply to a regional transmission organization or particular market or to a subset of bulk power system owners, operators, or users), shall be considered a Variance. A Variance may be requested while a standard is under development or a Variance may be requested at any time after a standard is approved. Each request for a Variance shall be initiated through a SAR, and processed and approved in the same manner as a continent-wide standard, using the standards development process defined in this manual.

Regional Standards and Variances - *Requirements that Apply on Less than a Continent-wide Basis*

NERC's goal is to have a set of reliability requirements that provides an 'adequate level of reliability.' In some instances, a continent-wide standard cannot be written so that the desired level of reliability is attained with requirements that apply to all entities – in some instances an alternative requirement that mandates performance not addressed in the continent-wide requirements is needed to attain the desired level of reliability – and in some instances requirements with more stringent performance are needed to maintain an adequate level of reliability. Regional standards and variances give NERC the tools it needs to develop and maintain a core set of standards that apply throughout the continent – augmented by a small set of supplementary requirements that address unique situations where a continent-wide requirement is not necessary.

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FERC, in its Orders, has indicated that it will apply a single set of criteria for approving both Regional Standards and Regional Differences.

Since all standards approved by NERC and applicable regulatory authorities are subject to the same level of enforceability – the location of a requirement (in a regional standard or a continent-wide standard) does not have any impact on either reliability or enforceability.

There are three ways of developing a requirement that identifies performance necessary for reliability that applies on less than a continent-wide basis:

- Within a continent-wide standard, a requirement can include alternative performance based on different facility characteristics, different regions, or different interconnections. (See INT-006-3 for an example.)
- A continent-wide standard can include a variance that specifies one or more alternative requirements that apply to a functional entity meeting certain characteristics, one or more Regions, or an Interconnection. (See FAC-011-2 for an example.)
- A regional standard can include mandatory performance that is needed for reliability only in that region. (See VAR-STD-002b-1 for an example.)

Each of these methods achieves the same goal – that of developing a requirement that specifies mandatory performance needed for reliability.

The process of developing and approving standards that apply on a Regional or Interconnection-wide basis differs from the process used to develop a continent-wide standard. Typically, standards developed on a continent-wide basis are subject to more scrutiny because there is a broader population reviewing and providing comments on a continent-wide standard.

With limited resources to allocate to standard development, developing regional standards and continent-wide standards requiring very similar performance is not desired. When a continent-wide standard is developed and there is a need to support the continent-wide standard with region-specific requirements, the region-specific requirements may be developed either as regional standards or the regional performance can be embedded within the continent-wide standard's requirements. In some cases, regional requirements that identify 'how' to implement a continent-wide standard may be developed as regional procedures rather than Regional Standards.

Some Regions have technical committees that study reliability issues and identify areas where new or different reliability requirements may be needed. Before embarking on an effort to develop a set of requirements for a new regional standard, it would be beneficial to determine if the new/revised requirement should apply on a broader basis – to other regions, to an entire Interconnection, or to the entire continent.

The Regional Standards Group (RSG) could support posting proposals for new/revised requirements that may apply on less than a continent-wide basis and solicit continent-wide stakeholder feedback on the scope of the reliability-related need for the new/revised requirements.

As envisioned, a proposal for new/revised requirements would be posted for an informal 30-day comment period with a webinar conducted during that comment period. The posting would consist of a 'Technical Concepts' paper that includes a description of the proposed new/revised requirements and a summary of the technical work done accompanied by a comment form. The comment form would, as a minimum, identify whether stakeholders agree that there is a need for a new/revised requirements; whether the requirements should apply on a regional, interconnection, or continent-wide basis; and whether stakeholders agree that the technical work done is sufficient, or believe additional work is

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needed before developing the requirements. NERC staff would assemble the comments and share them with both the RSG and the Standards Committee.

If stakeholders determine that the proposed requirements should apply on a continent-wide basis and the technical justification already developed by the Region is applicable on a continent-wide basis, then the Region should work with the Standards Committee to identify a priority for developing the standard before starting development of the Regional Standard.

- If the new standard is closing an identified gap in reliability, then it should receive a high priority and development should start within a timeframe acceptable to the sponsoring Region.
- If the Standards Committee cannot commit to starting the project in a time frame acceptable to the sponsoring Region (either because the priority is not high enough or because there are already too many projects under active development) then the sponsoring Region should proceed with developing the standard as a Regional Standard.
- The Standards Committee should make a commitment to use the work done in developing the Regional Standard as a starting point for developing the continent-wide standard.

If the technical justification developed by the Region is applicable to a subset of the continent, and additional time is needed to determine if the requirements should apply on a continent-wide basis, the RSG should coordinate its actions with the Standards Committee before starting development of the Regional Standard.

- The Standards Committee should work with NERC's technical committees to develop the technical justification for the continent-wide requirements and report to the RSG on the proposed timeline for development of any necessary technical justification.
- If the sponsoring Region needs enforceable requirements before a determination is made on whether the proposed requirements should apply on a continent-wide basis, then the Region should proceed with developing the standard as a Regional Standard.
- If a determination is made that the requirements should apply on a continent-wide basis, the Standards Committee should make a commitment to use the work done in developing the Regional Standard as a starting point for developing the continent-wide standard.

If stakeholders determine that the proposed new/revised requirements are needed for reliability and should apply on less than a continent-wide basis and less than an Interconnection-wide basis, then the RSG should work with the sponsoring Region to consider the best method of approaching development of that standard – as a variance to a continent-wide standard or as a regional standard. In making this determination, the RSG should consider FERC's differentiation between variances and regional standards.

- If new requirements address a topic not covered in a continent-wide standard, then the new requirements should be developed as a "Regional Standard" following the Regional Standards Development Process.
- If new requirements are more stringent or cover an aspect of a topic already addressed in a continent-wide standard, then the new requirements should be proposed as a Variance to the continent-wide standard. To initiate development of a Variance, the Region or entity wanting the Variance must submit the Variance, the technical justification for the Variance, and a SAR to the NERC Standard Process Manager. The RSG should work with the Standards Committee to identify a priority for developing the Variance.

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If stakeholders determine that the proposed new/revised requirements are needed for reliability and should apply on an Interconnection-wide basis, and the Interconnection does not have a NERC approved single Regional Standards Development Process that is applicable to the entire Interconnection, then that Interconnection should develop the Interconnection-wide Variance using the continent-wide standard development process. (Submit the Variance, the technical justification for the Variance, and a SAR to the NERC Standard Processes Manager and then work with the Standards Committee to establish a priority for the project.)

If stakeholders determine that the proposed new/revised requirements are needed for reliability and should apply on an Interconnection-wide basis, and the Interconnection has a NERC approved Regional Standards Development Process, then that Interconnection should develop the Interconnection-wide Variance using its Standard Development Process.

If "new" requirements address an activity that is:	And the standard is:	And the standard applies to:	Then the standard belongs in:	With the standard developed following:
Addressed in continent-wide standard	More stringent than continent-wide requirement	An entire Interconnection	Interconnection-wide variance to continent-wide standard	SAR submitted through continent-wide process
	Different method of achieving same reliability goal; difference necessary for physical difference or other reason	A Region, set of Regions, or a specific set of functional entities	Less than interconnection-wide variance to continent-wide standard	
Not addressed in continent-wide standard	Not needed for reliability on a continent-wide basis	An entire Interconnection	Interconnection-wide standard	Interconnection-wide regional standard process
		A single Region	Regional Standard	Regional standard process
	Needed for reliability on a continent-wide basis	Entire continent	Continent-wide standard	Continent-wide standard process

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Requesting a Variance to a Continent-wide Standard

The Standard Processes Manual clarifies that there are two types of variances – those that apply to an entire interconnection and those that apply to entities on a less than interconnection-wide basis.

When any request for a Variance to a continent-wide standard is submitted with a SAR, the request should include the following:

- A technical justification for the variance suitable for posting so that all stakeholders understand the need for the variance
- A statement indicating whether the proposed requirement is "in addition to" or "an alternative to" one or more specific requirements in the continent-wide standard
- For each requirement proposed, the associated Violation Risk Factor, Time Horizon, Measure, Evidence Retention, and set of Violation Severity Levels

Retiring or Revising Regional Standards to Avoid Duplication or Conflict with Continent-wide Standards:

When a continent-wide standard is developed and addresses the same topic as addressed in a Regional standard, a joint implementation plan is needed to ensure stakeholders are not accountable for performance with two different requirements addressing the same performance at the same time.

- If the performance in the Regional Standard is more stringent than the performance in the continent-wide standard, then the Regional Standard should be absorbed into the continent-wide standard with the more stringent requirements addressed either in a table (similar to the tables in INT-006-3) or as a variance to the continent-wide standard.
- If the continent-wide standard addresses some but not all of the performance in the Regional Standard, then on a case-by-case basis, the Region, working with the continent-wide drafting team, should determine what to do with the requirements that identify performance not included in the continent-wide standard. Acceptable choices include:
    - Revising the Regional Standard to remove only the requirements duplicated in the continent-wide standard;
    - Moving requirements that explain 'how' into a regional procedure, or
    - Adding requirements from the Regional Standard into the continent-wide standard in the form of a Regional Variance.
- If the performance in the Regional Standard is less stringent than the performance in the continent-wide standard, then the Regional Standard must be retired at the time that the continent-wide standard goes into effect.

Proposals:

1. The language in the Standard Processes Manual allows a broader range of variances than identified in the Rules of Procedure. The language in the Rules of Procedure should be modified to align more closely with the language in the SPM.

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2. The Standards Committee should add criteria to its prioritization tool to encourage the development of variances as opposed to regional standards and should give priority to these proposals to minimize the Regions' needs to develop Regional standards that will later be displaced by continent-wide standards addressing the same topic.
3. The Regional Standards Group should seek stakeholder feedback on a continent-wide basis for all proposed regional standards at the project proposal stage.

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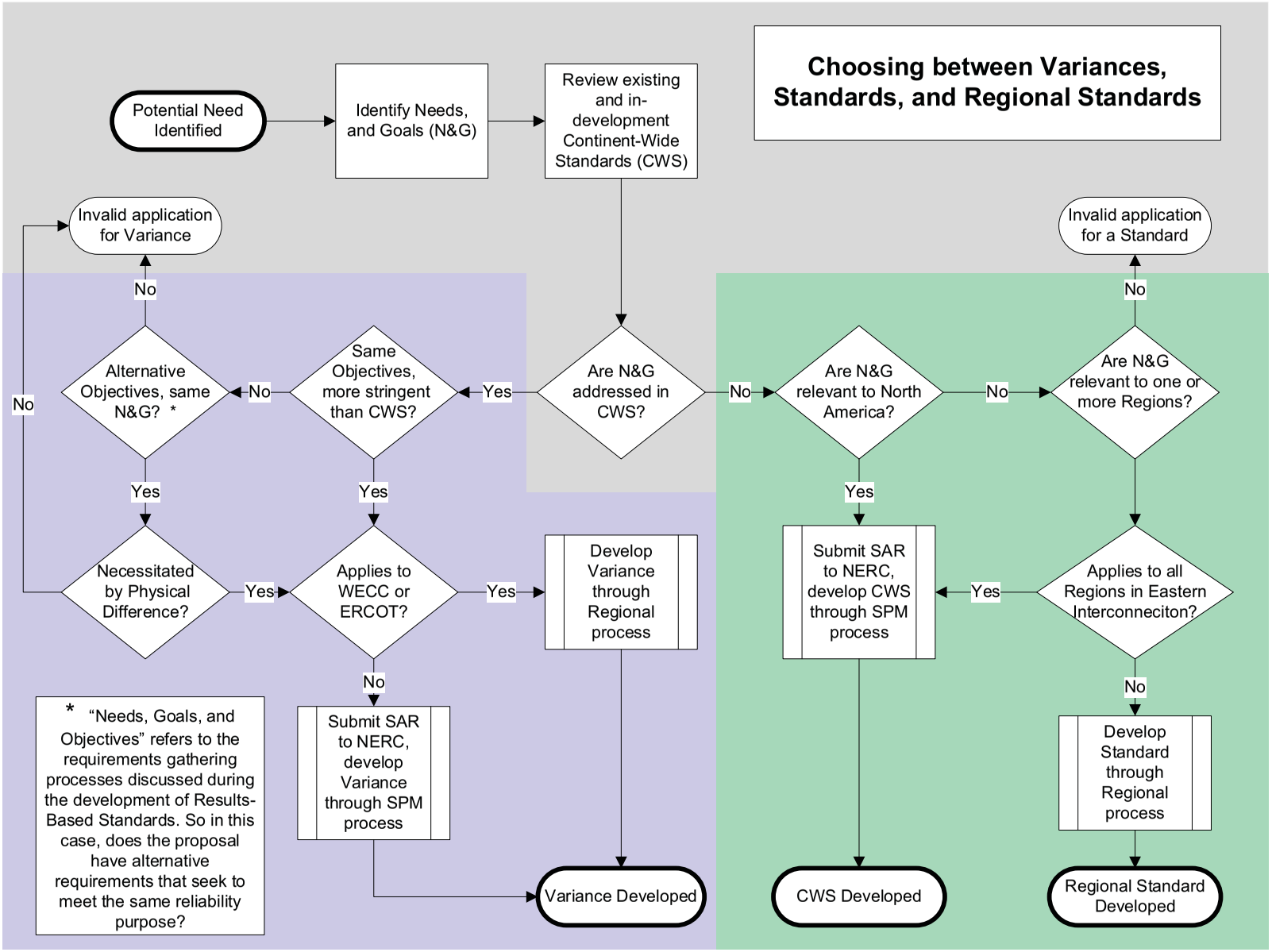
Choosing between Variances, Standards, and Regional Standards
Potential Need Identified
Identify Needs, and Goals (N&G)
Review existing and in-development Continent-Wide Standards (CWS)
Are N&G addressed in CWS?
Yes
Same Objectives, more stringent than CWS?
No
Alternative Objectives, same N&G? *
No
Invalid application for Variance
Yes
Necessitated by Physical Difference?
No
Yes
Applies to WECC or ERCOT?
Yes
Develop Variance through Regional process
No
Submit SAR to NERC, develop Variance through SPM process
Variance Developed
* "Needs, Goals, and Objectives" refers to the requirements gathering processes discussed during the development of Results-Based Standards. So in this case, does the proposal have alternative requirements that seek to meet the same reliability purpose?
No
Are N&G relevant to North America?
No
Are N&G relevant to one or more Regions?
No
Invalid application for a Standard
Yes
Submit SAR to NERC, develop CWS through SPM process
CWS Developed
Yes
Applies to all Regions in Eastern Interconneciton?
No
Develop Standard through Regional process
Regional Standard Developed

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

NERC Compliance Process Directive #2011-CAG-001

Directive Regarding Generator Transmission Leads

Version 1.0

DRAFT

DATE, 2011 | Public Process Announcement

Introduction and Purpose

This directive provides interim guidance to address the following reliability gap, which was identified early in the mandatory compliance and enforcement period: a Generator Owner (GO) and/or Generator Operator (GOP) owned and/or operated transmission facilities that were not registered for the NERC Reliability Standards that cover Transmission Owners (TO) and/or Transmission Operators (TOP). As a result of this reliability gap, NERC and the Regional Entities (RE) began registering GO/GOPs that owned and/or operated transmission facilities as TO/TOPs, in addition to their registration as GO/GOP. The ERO has been evaluating whether a subset of the TO/TOP standards and requirements rather than the full suite of TO/TOP standards should be developed to apply to certain of these entities.

In accordance with section 8c of the Regional Delegation Agreements (RDA),[1] this *Directive Regarding Generation Connection Leads* (Directive) is provided to the Regional Entities (RE) to ensure consistency in the application of NERC Reliability Standards and Requirements for a GO and/or GOP that is registered or should be registered as a TO and/or TOP in accordance with the NERC Statement of Compliance Registry Criteria.[2] This directive is an interim solution because it supports the longer term efforts of reliability standard drafting teams charged with revising NERC Reliability Standards specifically associated with generator transmission leads, such as the *Generator Requirements at the Transmission Interface (GO/TO)* Standards Drafting Team.[3] Additionally, Project 2010-07 Generator Requirements at the Transmission Interface Background Resource Document and this directive are preceded by and built upon the work reflected in the *Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface* completed November 16, 2009.[4]

Attachment 1 of this Directive provides examples of typical generator transmission leads. Based upon the RE's risk assessment of the registered entity, as noted above, the RE can determine that standards and requirements may need to be added to or excluded from the list of Reliability Standards set forth in Appendix 1 to the Memorandum of Understanding (MOU) with respect to a particular registered entity. This Directive specifically recognizes the need for flexibility between the Regional Entity and the

[1] The current RDAs are located on NERC's website: http://www.nerc.com/page.php?cid=1%7C9%7C119%7C181.
[2] http://www.nerc.com/files/Appendix_5B-StatementOfComplianceRegistryCriteria.pdf
[3] Project 2010-07 "Generator Requirements at the Transmission Interface," available at: http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html.
[4] "Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface,"available at: http://www.nerc.com/files/GO-TO_Final_Report_Complete_2009Nov16.pdf.

registered entity to reach agreement on the final list of applicable Reliability Standards which will be attached to the executed MOU. The list may be increased if the Regional Entity determines, based on the entity's specific facts and circumstances, merit it, or decreased if the entity provides to the Regional Entity technical or physical justification why the standard/requirement should not apply. If agreement cannot be reached, the entity will be registered in accordance with the criteria specified in the ROP Appendix 5B '*Statement of Compliance Registry Criteria*.'. The Regional Entity also has flexibility to prioritize the order in registering specific GO/GOPs as TO/TOPs.

This interim measure is not intended to prejudge, and should not be read as prejudging, the outcome of the Standard Development Process Projects. In identifying the minimum applicable NERC Reliability Standards listed in Appendix 1 to the MOU, NERC is taking into account physical and technical limitations, as well as reliability considerations, that support applicability of a subset of reliability standards to registered entities with generator transmission leads.

Background

The ERO recognized a gap in reliability as it relates to particular types of transmission facilities that connect generators directly to the bulk power system (BPS) in the event such entities are not registered as TOs/TOPs. This gap is realized in the following standards:

- (EOP) System Restoration
- (FAC) Connerction Requirements
- (FAC) Vegetation Management
- (PER) Specific training
- (PRC) System Protection Coordination
- (TOP) System Relay Protection

For transmission facilities identified above, Project 2010-07 states that "such Facilities are only to be included in the reliability standards requirements applicable to the Generator Owner or Generator Operator. To ensure that responsibility for the generator interconnection Facilities is included in all necessary standards, however, a select number of standards need to have Generator Owners added to their applicability."[5]

Since a GO/GOP does not operate a generator transmission lead similarly to the manner in which a traditional utility operates other transmission facilities, an interim solution is to apply a more limited subset of TO/TOP reliability standards to GOs/GOPs until the efforts of the longer term reliability standard drafting teams are completed.

Since June 2007 (date of mandatory and enforceable NERC Standards under FERC Order 693)[6], three registration appeals have been decided in which FERC upheld the registrations of GOs/GOPs as TOs/TOPs and recognized the ability to consider a modified set of applicable NERC Reliability

[5] http://www.nerc.com/docs/standards/sar/2010-07_Project_2010-07_Background_Resource_Document_061711.pdf
[6] Docket No. RM06-16-000; Order No. 693 Issued March 16, 2007 "Mandatory Reliability Standards for the Bulk-Power System"

Standards. These registration appeals involved New Harquahala Generating Company, LLC, (New Harquahala)[7], Cedar Creek Wind Energy, LLC (Cedar Creek)[8] and Milford Wind Corridor Phase I, LLC (Milford).[9] NERC's request for clarification or rehearing on the FERC Cedar Creek and Milford order concerning applicability of standards outside the standards development process is currently pending.[10]

Applicability

GOs/GOPs that have the following characteristics based on the factual circumstances will have the opportunity to work with their RE and enter into an MOU that identifies the list of applicable standards as a TO/TOP:

1. has blackstart capability, or
2. a facility that is/has some portion operated at 100 kV or higher and has interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities, or
3. meets the criteria for registration as a TO/TOP as set forth in the NERC Statement of Registry Criteria, or
4. a facility that has some portion operated at 100 kV or higher and has a generator transmission line leading to the inter-connection that has a visual impediment to the inter-connection or has at least three tower structures that include the one connecting span at each end tower.

Process

As discussed above, a GO/GOP that owns or operates a transmission facility that connects the generator to the BPS must comply with a limited set of NERC Reliability Standards and Requirements applicable to TOs and TOPs under the conditions listed below and more fully detailed in the MOU and its Appendix 1, List of Applicable Standards.

Entities that execute an MOU will have six months from the date that the MOU is executed to come into compliance with the applicable standards identified in the executed MOU. During the six-month period, entities are encouraged to identify and mitigate any risks to the BPS. After the six-month implementation period, entities will be registered as a TO and/or TOP and and required to comply with and be subject to Uniform Compliance Monitoring and Enforcement Program[11] (CMEP) provisions for compliance with respect to the reliability standards and associated requirements identified in the MOU. A pro forma MOU is included as Attachment 2, with its Appendix 1.

---

[7] 123 FERC ¶ 61,173(May 16, 2008).
[8] 135 FERC ¶ 61,241 (June 16, 2011).
[9] 135 FERC ¶ 61,241 (June 16, 2011).
[10] 135 FERC ¶ 61,241 at p. 7 ("In short, the Commission should clarify that the minimum lists of Reliability Standards included in the June 16 Order are not intended to prejudge either the outcome of the Reliability Standards development process for Project 2010-07, or the Reliability Standards that should apply to Cedar Creek and Milford in advance of the Commission-ordered negotiations.").
[11] http://www.nerc.com/files/Appendix4C_Uniform_CMEP_20110101.pdf

Scheduling of audits for GO/GOPs also registered as a TO/TOPs[12] will be scheduled at the discretion of the RE.[13]

For those GO/GOP entities that have already been registered as TO/TOPs, those entities may request that the list of standards and requirements applied to their TO/TOP obligations be reevaluated by the RE. For those entities with agreed applicability lists that FERC has approved, FERC approval of a change in the list of applicable standards will be required before any changes are implemented.

Concurrent with the end of the six-month implementation period, certification[14] of the entity as a TOP may be accomplished via a desktop process such as webinar and telephone conference presentations.

An alternative into which the GO/GOP may enter is the Coordinated Functional Registration or other duly executed legal agreement for the TO/TOP function. NERC has provided guidance to facilitate a better understanding of the compliance responsibility, registration, and accountability for entities that delegate the performance of reliability related tasks to a third party, specifically NERC Compliance Public Bulletin #2010-004.[15]

Attachments

Attachment 1: Typical Generation Transmission Tie Lines Diagrams

Attachment 2: Pro Forma MOU

Appendix 1: List of Applicable Standards Including Technical Rationale

Contact Information

If you have any questions please contact:

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[12] CMEP 3.1.4.1 Reliability Standards A Compliance Audit shall include those Reliability Standards applicable to the Registered Entity that are identified in the NERC Implementation Plan for the current year.

[13] CMEP 3.1.3 Frequency of Compliance Audits ……an unscheduled Compliance Audit of any Registered Entity (i) may be initiated at any time by the Compliance Enforcement Authority if reasonably determined to be necessary to ensure the Registered Entity's compliance with Reliability Standards.

[14] The TOP function is a 'certifiable' function in accordance with the NERC Rules of Procedure (RoP) Section 500 and Appendix 5A *Organization Registration and Certification Manual*.

[15] NERC Compliance Public Bulletin #2010-004 "Guidance for Entities that Delegate Reliability Tasks to a Third Party Entity" available at http://www.nerc.com/files/2010-004%20v1%200.pdf.

From: Stacia-Ann Chambers
To: Stacia-Ann Chambers
Subject: NERC: The Reliability Standard Audit Worksheet (RSAW)
Date: Tuesday, October 18, 2011 10:15:55 PM

Announcement

The Reliability Standard Audit Worksheets (RSAW)

October 18, 2011

Click here for: RSAW

Ladies and Gentlemen:

The Reliability Standard Audit Worksheet (RSAW) posted on the NERC website have been updated. The website now includes the individual RSAWs, as well as a compressed ZIP file, of all RSAWs which are required for the 2012 Actively Monitored List.

It is recommended that all Regional Entities and Registered Entities check the NERC website regularly to ensure the latest versions of the RSAWs are being used as they are updated on an as needed basis and notifications are only sent for major postings

NERC would like to thank the Regional Entities for their continued support in the development and revision of the RSAWs.

For more information or assistance, please contact Craig Struck (via email).

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From: Philip A. Fedora
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Subject: NB Energy Sector plan unveiled
Date: Wednesday, October 19, 2011 1:33:14 PM

News Release

Energy

New plan for energy sector unveiled

19 October 2011

Media Contact(s)

Brent Staeben, communications, Department of Energy, 506-444-2207.

FREDERICTON (CNB) – The provincial government today released its new energy blueprint, which outlines a 10-year vision and a three-year action plan for the energy sector.

Energy Minister Craig Leonard unveiled the *New Brunswick Energy Blueprint*, which serves as the provincial government's response to the final report of the New Brunswick Energy Commission, released May 24.

"The blueprint is about lowering costs, creating efficiencies and making the right choices now to protect New Brunswickers today and for the next decade," said Leonard. "These action items will help keep rates for all energy sources competitive and stable while meeting our responsibilities to the environment in a balanced and incremental manner."

The blueprint outlines five key objectives that summarized the views of those who participated in the commission's public engagement process:

- low and stable energy prices;
- energy security;
- reliability of the electrical system;
- environmental responsibility; and
- effective regulation.

These objectives are intended to serve as the foundation of a new vision for the provincial energy sector.

The commission's 67 recommendations are integrated into a list of 20 action items that the provincial government intends to pursue during the next three years.

Significant items included in the action plan include:

- the amalgamation of the NB Power group of companies into a single, vertically integrated Crown utility;
- a review of the natural gas distribution model to achieve lower rates;
- subjecting all NB Power operations and rate changes to a strengthened and more transparent regulatory oversight system;
- the establishment of an office of the public energy advocate;
- an increased commitment to renewable energy sources; and
- a new focus on energy efficiency and better managing energy demand.

"NB Power is an extremely valuable asset and will remain a Crown corporation owned by the provincial government," said Leonard. "We are directing the utility to pursue an aggressive agenda that will see NB Power as a lower cost, more efficient organization that is paying down debt and building equity but, most importantly, protecting New Brunswick families and businesses by keeping rates competitive and stable for the next decade."

New Brunswickers have the lowest electricity rates in Atlantic Canada, and all customers are benefiting from a three-year rate freeze. Still, the action plan recognizes the need for competitive electricity costs for large industrial users, so the provincial government will introduce the new Large Industrial Renewable Energy Purchase Program. This will effectively match Canadian average electricity costs for qualifying large industrial customers and provide incentives for New Brunswick companies to build their own renewable generation.

NB Power is also being mandated to pursue a significant increase in renewable generation. While New Brunswick obtains 28 per cent of its in-province electricity demand from wind, biomass, hydro and other renewable sources, the provincial government will increase its commitment to renewable energy by ensuring that this amount is increased to a minimum of 40 per cent by 2020.

The result will be that, by 2020, New Brunswick will procure at least 75 per cent of its electricity from more stable-priced, clean, renewable or emission-free sources, including nuclear energy from the refurbished Point Lepreau generating station.

The action plan also dictates that New Brunswick pursue more efficient uses of energy.

"More efficient use of energy is generally less expensive than building or buying new supply to meet future energy demands," said Leonard. "Our success in reducing demand from existing sources will reduce future expenditures on new generation and help to ensure the affordability of energy for families and the competitiveness of our industry, while protecting the environment."

The *New Brunswick Energy Blueprint* is on the Department of Energy website.

LINK:

- *New Brunswick Energy Blueprint*: www.gnb.ca/energy

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

ERO Compliance Monitoring and Enforcement Program

2012 Implementation Plan

Version 1.0

NOTE:
CMEP Implementation Plan and the 2012 Actively Monitored Reliability Standards List are posted at:
http://www.nerc.com/commondocs.php?cd=3

October 14, 2011

to ensure the reliability of the bulk power system

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ERO Compliance Monitoring and Enforcement Program

Reliability and accountability are basic tenets of the Compliance Monitoring and Enforcement Program (CMEP). The objective of the North American Electric Reliability Corporation (NERC) and the Regional Entities is to achieve the highest possible level of reliability for the Bulk Power System (BPS). NERC, as the FERC-certified Electric Reliability Organization (ERO), together with the Regional Entities, is accountable to government regulators and industry stakeholders. The CMEP is critically important in supporting reliability and accountability, since effective compliance is a necessary, yet insufficient, activity for assuring the highest levels of reliability. The CMEP covers not only monitoring and enforcement activities, but also education, training and informational activities designed to assist the industry in achieving and sustaining effective compliance and enhanced reliability. The CMEP also complements other critical ERO activities aimed at improving reliability such as: facilitating the industry in the development and improvement of Reliability Standards, providing reliability assessments, and identifying lessons learned from events analysis that can assist the industry in enhancing reliability. There is clear ERO and industry accountability for the development of Reliability Standards in accordance with the 2005 Federal Power Act[1] and FERC Order No. 672[2], which duly recognize the collective expertise, experience and judgment needed to develop and improve Reliability Standards. NERC continues to refine and improve the annual CMEP and Actively Monitored List (AML) by focusing its efforts and resources on those areas that pose the greatest risk to reliability of the BPS.

As a reminder to all Registered Entities, NERC Rules of Procedure (RoP)[3] state that all Bulk Power System users, owners, and operators are required to comply with all applicable ERO governmental authority-approved Reliability Standards at all times. Regional Reliability Standards and regional variances approved by NERC and the applicable ERO governmental authority are enforceable and apply to all Registered Entities responsible for meeting those Reliability Standards within the Regional Entity boundaries, whether or not the BPS user, owner, or operator is a member of the Regional Entity.

The CMEP is developed under Section 215(c) of the Federal Power Act[4] to establish and enforce Reliability Standards for the BPS, subject to review by FERC and in general accordance with the "Principles for an Electric Reliability Organization that can Function

[1] Section 215(d)(2) of the Federal Power Act located at http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=109_cong_bills&docid=f:h6enr.txt.pdf

[2] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*,114 FERC ¶ 61, 104 (2006) at P 324 located at http://www.nerc.com/files/final_rule_reliability_Order_672.pdf.

[3] *See* Rules of Procedure, Section 401.2 at http://www.nerc.com/page.php?cid=1|8|169.

[4] *Federal Power Act*, *16 U.S.C. 824o. a.3 (2005).* Located at http://www.nerc.com/fileUploads/File/AboutNERC/HR6_Electricity_Title.pdf

on an International Basis."[5] The CMEP is designed to improve reliability through the effective and efficient enforcement of Reliability Standards.

FERC Order No. 672 provides the framework for the ERO and its corresponding certification process. On July 20, 2006, FERC certified NERC as the ERO[6]. FERC regulations provide that an ERO must submit an assessment of its performance three years from the date of certification by the Commission, and every five years thereafter. On September 16, 2010 FERC recertified NERC as the ERO[7] following the three-year assessment.

To help fulfill its responsibilities under its rules filed with regulatory authorities, NERC, as the international ERO, has delegated authority to qualified Regional Entities to monitor and enforce compliance with Reliability Standards by users, owners, and operators of the BPS. This delegation is governed by Regional Delegation Agreements (RDA) that have been approved by the appropriate regulatory authorities. NERC and these Regional Entities are responsible for carrying out the CMEP. Each Regional Entity submits its regional CMEP Implementation Plan to NERC for approval based on the requirements of this document.

NERC and the Regional Entities recognize that there are important reliability matters that require prompt communication to industry. NERC has used the Alerts/Advisory[8] process to rapidly inform the industry of such matters. The Implementation Plan strongly encourages the applicable Registered Entities to proactively address such communications as a way of demonstrating good utility practice and a strong culture of compliance and reliability excellence.

[5] Bilateral Electric Reliability Oversight Group, August 3, 2005 (the "Bilateral Principles").
[6] ERO Certification Order at P 3.
[7] *North American Electric Reliability Corporation, Reliability Standards Development and NERC and Regional Entity Enforcement*, "Order on the Electric Reliability Organization's Three-Year Performance Assessment," 132 FERC ¶ 61,217 (2010 at P 1.
[8] *See* Events Analysis: Alerts at http://www.nerc.com/page.php?cid=5|63.

Introduction

The ERO CMEP Implementation Plan is the annual operating plan for compliance monitoring and enforcement activities to ensure that NERC, as the international ERO, and the Regional Entities fulfill their responsibilities under legislation in the United States and other applicable obligations in jurisdictions in Canada and Mexico[9]. Currently, Reliability Standards are mandatory and enforceable in the U.S. and the Canadian provinces of British Columbia[10], Ontario[11], New Brunswick[12], and Saskatchewan[13]. The Canadian province of Alberta[14] has adopted some of the Reliability Standards and is in the process of reviewing others. The legislative framework to make Reliability Standards mandatory and enforceable exists in Manitoba[15], Nova Scotia[16], and Quebec[17]. In Nova Scotia, the Reliability Standards are pending the approval of the Nova Scotia Utility and Review Board. The National Energy Board of Canada[18] is in the process of making Reliability Standards mandatory and enforceable for international power lines.

The compliance monitoring and enforcement activities are carried out by NERC and the eight Regional Entities based on the regulatory authority-approved uniform CMEP[19], the NERC RoP[20], the respective RDA[21] with the eight Regional Entities, and other agreements including Memoranda of Understanding with the Canadian provinces. This plan outlines the implementation requirements to be followed by NERC and the eight Regional Entities. Each Regional Entity submits its 2012 Implementation Plan by November 1, 2011 to NERC. NERC is responsible for approving the Regional Entity Implementation Plans.[22]

The 2012 Implementation Plan includes a set of Reliability Standards that were selected based upon ERO-identified high-risk priorities and a three-tiered approach to compliance auditing. The implementation plan also requires Regional Entities to consider a registered entity's compliance history when determining the scope of compliance monitoring activities. The objectives of the Implementation Plan are to:

- Promote the reliability of the BPS through rigorous compliance monitoring and enforcement activities.

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[9] http://www.cre.gob.mx/pagina_a.aspx?id=23
[10] http://www.nerc.com/files/British-Columbia112706.pdf
[11] http://www.nerc.com/files/MOU_between_IESO_NERC_NPCC_02052010.pdf
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[21] http://www.nerc.com/page.php?cid=1%7C9%7C119%7C181
[22] *See* Appendix 4C of the NERC RoP at Section 4.2: http://www.nerc.com/page.php?cid=1|8|169

- Facilitate improved consistency of compliance activities throughout North America.
- Monitor all regulatory authority approved Reliability Standards by using the eight CMEP compliance monitoring methods.
- Use risk-based and performance-based criteria for determining the scope for compliance audits.
- Allow flexibility for the ERO and Regional Entities to investigate trends that may pose a near term risk to reliability either across the North American BPS, across an Interconnection or within a Regional Entity boundary.
- Improve the compliance program by analyzing the compliance monitoring experience across North America and implementing necessary improvements.

Risk-Based Compliance Monitoring Approach

The premise of risk-based compliance monitoring is that the amount of scrutiny a registered entity receives in terms of compliance monitoring will be directly commensurate with the risk it poses to the reliability of the BPS. Compliance monitoring encompasses a range of activities, including spot checks, self certifications, audits, and personal correspondence to an entity from the ERO. For entities that do not pose a significant reliability risk, the activities specifically prescribed in this Implementation Plan may suffice. For entities that do pose a significant risk to reliability, it will be necessary for those entities to undergo additional compliance monitoring such as additional focused spot checks, a greater number of self certifications, or broader and deeper audits of greater frequency, etc.

Registered Entities are responsible for compliance with all regulatory approved Reliability Standards and Requirements in effect per their registered function at all times, regardless of what is specified in the AML.

One of the key components to an effective risk-based audit approach is the incorporation of performance-based auditing. Performance audits, according to the United States Government Accountability Office[23], are defined as engagements that provide assurance or conclusions based on an evaluation of sufficient, appropriate evidence against stated criteria, such as specific requirements, measures, or defined business practices. The second component includes a more detailed review and testing of the registered entity's programs and procedures to assure actual performance of the stated programs are being implemented, rather than relying solely on documentation.

To assist the Regional Entities in determining how much risk an entity poses to reliability, a number of aspects have been identified that point to activities, behaviors, and qualities that warrant additional concern prompting an enhanced application of compliance monitoring. Specifically, these aspects include the Technical and Risk Profile of an entity, Reliability Performance Metrics, an entity's Internal Compliance Program, Compliance and Enforcement Metrics and Status, and Regional Entity Qualitative Assessment, which are concepts described in generally accepted government auditing standards (GAGAS)[24]. These five aspects are described below:

- **Technical and Risk Profile:** This profile details the technical components of the Registered Entity. It highlights various aspects of the company's structure and identifies key information that is relative to its risk. Such components include

[23] *See* United States Government Accountability Office – Government Auditing Standards (GAGAS) at Chapter 1: Use and Application of GAGAS at Section 1.25 http://www.gao.gov/new.items/d07731g.pdf.
[24] *See* GAGAS at Chapter 7: Field Work Standards for Performance Audits http://www.gao.gov/new.items/d07731g.pdf

MW capacities, registration information, points of interconnection, and affiliated companies.

- **Reliability Performance Metrics (Trends):** Metrics provide a quantitative approach for measuring a registered entity's performance. Consistent metrics yield a baseline to measure performance as well as compare performance to previous years.
- **Internal Compliance Program:** The strength of a registered entity's internal compliance program evidences its activities to self-monitor reliability and compliance through internal controls, corrective action programs and a culture of compliance. An assessment of a registered entity's internal compliance program includes an evaluation of how the entity addresses the standard FERC 13 questions and the additional FERC 1b compliance criteria, and outlines areas for improvement in the internal compliance program.
- **Compliance and Enforcement Metrics and Status:** These metrics detail the violation history and any open enforcement actions of the registered entity, including consideration of the facts and circumstances surrounding the violations. The evaluation includes consideration of the methods of discovery, with specific focus on repeat violations, the status of any open mitigation plans, and compliance improvements over time.
- **Regional Entity Qualitative Assessment:** This area provides an opportunity for the Regional Entities to include qualitative assessment and regional expertise for what the entity is doing well and areas for improvement.

NERC and the Regional Entities will work together to develop an Entity Risk Profile Assessment template for use across the entire ERO before the end of 2011. When complete, this template will be publically posted on NERC's website for the benefit of both the Regional Entities and registered entities. For registered entities, the template may prove valuable for conducting critical self-assessments in preparation of compliance monitoring actions and other times. Also, the template will be invaluable for the Regions in order to scope audits appropriately.

It must be emphasized that registered entities are responsible for compliance with all regulatory approved Reliability Standards and Requirements in effect per their registered function at all times, regardless of what a registered entity's risk profile may indicate. Regional Entities have the authority and responsibility to expand the scope of an audit, spot check, or any other compliance monitoring process if they consider it necessary when evaluating the compliance of a registered entity.

2012 Implementation Plan Development Methodology

As part of an overall compliance plan, NERC developed the AML of Reliability Standards for 2012 based on the methodology outlined in this section. This framework is a continuation of the initial development process for the 2011 Implementation Plan.

The 2012 Implementation Plan is designed to realize risk-based approaches for ERO programs, priorities and initiatives that meet reliability goals and improve efficiencies. Achieving these goals will be accomplished through the development, maintenance, and implementation of a list of the highest priority Reliability Standards. The Reliability Standards and associated Requirements populating this list will be determined through an annual review of the following:

- ERO High-Risk Priorities
- FERC Orders and Guidance
- Compliance History and Culture
- Input from NERC Staff including Compliance Operations, Critical Infrastructure Protection, Enforcement, Events Analysis and Investigations, Legal, Reliability Assessments and Performance Analysis, and Standards
- Future Considerations

ERO High-Risk Priorities

The purpose of identifying and using a set of priorities is to move away from focusing on processes for "administrative and documentation-related violations that have no effect on bulk power system reliability," as the Edison Electric Institute (EEI) has stated[25]. Instead, the focus is on those Reliability Standards, and more specifically those Requirements within the Reliability Standards, that are most critical to the reliability of the BPS as determined by a set of risk-based criteria. The priorities and correlated Reliability Standards are explained in further detail in *Appendix 1 - 2012 ERO High-Risk Priorities with High Value Associated Reliability Standards*. NERC and the Regional Entities considered these priorities and identified a number of Reliability Standards that apply to each criteria. Many of these Reliability Standards apply to multiple priorities, bolstering their importance and reason for inclusion into the AML.

FERC Order and Guidance

FERC Order No. 729 states that "the Commission hereby adopts the NOPR proposal to direct the ERO to conduct an audit of the various implementation documents developed by transmission service providers to confirm that the complete available transfer capability methodologies reflected therein are sufficiently transparent to allow the Commission and others to replicate and verify those calculations. The Commission clarifies that these audits are not intended to address the competitive effects of these MOD Reliability Standards. Instead, the audit should review each component of

[25] http://www.nerc.com/docs/bot/finance/2010BPB_EEI_Draft2comments.pdf

available transfer or flowgate capability, including the transmission service provider's calculation of capacity benefit margin and transmission reliability margin, for transparency and verifiability to ensure compliance with the MOD Reliability Standards."[26]

The Reliability Standards associated with this order that will be integrated into the 2012 Implementation Plan are MOD-001, MOD-004, and MOD-008.

Violation Trend History

An analysis of the compliance history of Reliability Standards is only one aspect for determining the risk-based compliance approach, and provides insight into which Reliability Standards have proven most challenging for registered entities. Reliability Standards that are understood by registered entities appear to result in more possible violations through the self-report monitoring method. Reliability Standards that are not understood by registered entities, or are complicated, appear to result in more possible violations through the audit and spot check monitoring methods. Through the identification and inclusion of these Reliability Standards in the annual compliance plan, registered entities will have the ability to learn through personal experience, regional workshops, and other outreach programs and resources on how best to improve their compliance programs. Improved compliance programs will result not only in enhanced compliance for these Reliability Standards in particular, but also for all remaining Reliability Standards, through the growth of compliance processes and systems.

A collection of violation statistics results for all Reliability Standards, displayed for all regions as referenced by the ERO and according to each Interconnection, can be seen according to the near term and since June 18, 2007 in Tables 1 and 2 respectively.

Table 1: Top 10 Violation Statistics for the near term in all Regions and by Interconnection for all Reliability Standards.

	Rolling 12 Month (3.28.2010 to 3.28.2011)							
	NERC		Eastern Interconnection		Western Interconnection		ERCOT Interconnection	
	Standard	Violations	Standard	Violations	Standard	Violations	Standard	Violations
1	CIP-007	297	CIP-007	187	CIP-007	84	PRC-005	29
2	PRC-005	199	CIP-004	128	CIP-004	55	CIP-007	26
3	CIP-004	192	PRC-005	121	CIP-006	53	CIP-001	19
4	CIP-006	133	CIP-005	83	PRC-005	49	CIP-004	9
5	CIP-005	131	CIP-006	72	CIP-003	43	CIP-006	8
6	CIP-003	107	CIP-001	62	CIP-005	40	CIP-005	8
7	CIP-002	90	CIP-003	61	CIP-002	36	IRO-001	8
8	CIP-001	89	VAR-002	54	CIP-009	25	VAR-002	7
9	VAR-002	77	CIP-002	52	VAR-002	16	PRC-001	6
10	CIP-009	59	FAC-008	36	CIP-008	9	TPL-002	6

[26] *See Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the Bulk-Power System*, 129 FERC ¶ 61,155 (2009) at P 106.

Table 2: Top 10 Violation Statistics for all time in all Regions and by Interconnection for all Reliability Standards.

	All Time							
	NERC		Eastern Interconnection		Western Interconnection		ERCOT Interconnection	
	Standard	Violations	Standard	Violations	Standard	Violations	Standard	Violations
1	PRC-005	678	PRC-005	425	PRC-005	214	PRC-005	39
2	CIP-001	442	CIP-004	260	CIP-001	184	CIP-001	30
3	CIP-004	390	CIP-007	232	CIP-004	119	CIP-007	26
4	CIP-007	372	CIP-001	228	CIP-007	114	FAC-008	19
5	CIP-006	178	FAC-008	123	TOP-002	80	IRO-001	12
6	FAC-008	171	CIP-006	109	EOP-005	72	CIP-004	11
7	VAR-002	158	CIP-005	103	CIP-003	64	PRC-008	10
8	CIP-005	156	VAR-002	95	CIP-006	61	VAR-002	10
9	CIP-003	152	FAC-009	94	PER-002	55	FAC-009	9
10	CIP-002	135	CIP-002	86	VAR-002	53	CIP-006	8

With the significant presence of FERC Order No. 706[27] (CIP) Reliability Standards among violations, especially in the near term, it becomes difficult to gauge how the FERC Order No. 693[28] Reliability Standards rank in terms of violations. Removing the CIP Reliability Standards from this analysis, the violation statistics for 693 Reliability Standards in the near term and for all time can be seen in Tables 3 and 4 respectively.

Table 3: Top 10 Violation Statistics for the near term in all Regions and by Interconnection for FERC Order No. 693 Reliability Standards.

	Rolling 12 Month (3.28.2010 to 3.28.2011) w/o CIP							
	NERC		Eastern Interconnection		Western Interconnection		ERCOT Interconnection	
	Standard	Violations	Standard	Violations	Standard	Violations	Standard	Violations
1	PRC-005	199	PRC-005	121	PRC-005	49	PRC-005	29
2	VAR-002	77	VAR-002	54	VAR-002	16	IRO-001	8
3	FAC-008	42	FAC-008	36	PRC-008	9	VAR-002	7
4	PRC-008	36	TOP-002	30	BAL-004	5	PRC-001	6
5	FAC-009	32	FAC-009	25	EOP-005	5	TPL-002	6
6	TOP-002	32	PRC-008	23	IRO-STD	4	FAC-009	5
7	COM-002	24	COM-002	20	PER-002	4	TOP-001	5
8	PER-002	21	FAC-001	17	PRC-023	4	PRC-008	4
9	PRC-001	21	PER-002	17	COM-002	3	PRC-004	4
10	FAC-001	20	FAC-003	16	FAC-001	3	FAC-008	4

[27] *Mandatory Reliability Standards for Critical Infrastructure Protection*, 122 FERC ¶ 61,040 (2008) (Order No. 706).

[28] *Mandatory Reliability Standards for the Bulk-Power System,* 72 FR 16,416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242 (2007) (Order No. 693). NERC realizes each Canadian province has separate Memoranda of Understanding and the use of 693 and 706 in this document for referencing CIP and non-CIP standards.

Table 4: Top 10 Violation Statistics for all time in all Regions and by Interconnection for FERC Order No. 693 Reliability Standards.

	All Time w/o CIP							
	NERC		Eastern Interconnection		Western Interconnection		ERCOT Interconnection	
	Standard	Violations	Standard	Violations	Standard	Violations	Standard	Violations
1	PRC-005	678	PRC-005	425	PRC-005	214	PRC-005	39
2	FAC-008	171	FAC-008	123	TOP-002	80	FAC-008	19
3	VAR-002	158	VAR-002	95	EOP-005	72	IRO-001	12
4	TOP-002	133	FAC-009	94	VAR-002	53	PRC-008	10
5	EOP-005	129	EOP-005	57	EOP-001	50	VAR-002	10
6	FAC-009	127	FAC-003	56	FAC-001	47	FAC-009	9
7	PRC-008	104	FAC-001	53	PRC-008	46	PRC-001	6
8	FAC-001	100	TOP-002	52	VAR-001	44	TOP-001	6
9	PER-002	98	PRC-008	48	TPL-002	35	TPL-002	6
10	EOP-001	84	PER-002	43	COM-001	31	IRO-004	4

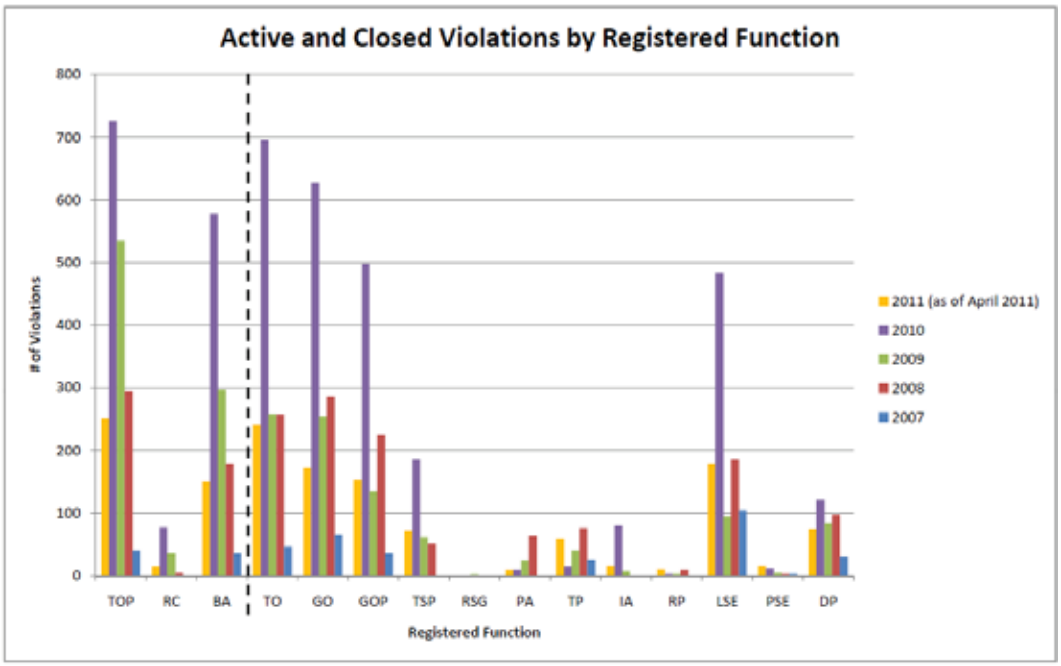

Figure 1: Active and Closed violation summary history per function since 2007.

As a final perspective on violations for recent years, Figure 1 displays the number of active and closed violations attributed to the various registered functions since June 18, 2007. The violations for each function are not necessarily specific or unique violations to each function alone in all cases. Rather, in many cases, a single violation will be applicable to more than one function, resulting in each of the applicable functions reflecting this one violation.

Risk-based compliance includes high-impact violations as well as low-impact violations that are widespread enough to, as an aggregate, represent a high impact to reliability. Thus, violation history is an important tool for assessing which Reliability Standards and, in turn, which functions have proven to be most difficult for compliance and require more attention during audits.

AML and Implementation Plan Input

All eight Regional Entities provided valuable input into the development of the 2012 AML and Implementation Plan. Input was received from members of the ERO Compliance and Enforcement Management Group (ECEMG), the Compliance Monitoring Processes Working Group (CMPWG), and various Regional Entity compliance and enforcement staff.

In addition to the input provided by the Regional Entities, several NERC departments provided insight in terms of the relationship of Reliability Standards to ERO High-Risk Priorities, supplementary information from these groups has been provided in order to help further refine the list of High-Risk Priority Standards. Specifically, the departments that contributed to the 2012 Implementation Plan include Compliance Operations, Critical Infrastructure Protection, Enforcement, Events Analysis and Investigations, Legal, Resource Assessments and Performance Analysis, and Standards.

The Reliability Assessment and Performance Analysis department has completed an analysis in which a subset of Requirements with the highest impact to reliability has been identified according to a Standards/Statute Driven Index (SDI), which measures improvement in compliance with Reliability Standards, as part of a Reliability Metrics and Integrated Risk Assessment study[29]. This subset consists of 26 Requirements and is found in Table 5. These Requirements have high Violation Risk Factors (VRFs) and the violations of these Requirements had severe Reliability Impact Statements (RIS), as determined by the Regional Entity.

Table 5: 26 Requirements considered by the Standards/Statute Index as part of Reliability Metrics and Integrated Risk Assessment

Standard	Req.	Standard	Req.	Standard	Req.	Standard	Req.	Standard	Req.
EOP-001-0	R1.	FAC-009-1	R1.	PER-002-0	R3.	PRC-005-1	R2.	TOP-004-2	R1.
EOP-003-1	R7.	IRO-005-2	R17.	PER-002-0	R4.	TOP-001-1	R3.	TOP-004-2	R2.
EOP-005-1	R6.	PER-001-0	R1.	PRC-004-1	R1.	TOP-001-1	R6.	TOP-006-1	R6.
EOP-008-0	R1.	PER-002-0	R1.	PRC-004-1	R2.	TOP-001-1	R7.	TOP-008-1	R2.
FAC-003-1	R1.	PER-002-0	R2.	PRC-005-1	R1.	TOP-002-2	R17.	VAR-001-1	R1.
FAC-003-1	R2.								

The Reliability Assessment and Performance Analysis group has also completed an analysis of the BPS transmission system through the Transmission Availability Data System (TADS). As shown in Figure 2, this analysis points to several causes for sustained outages experienced by North America's transmission system. Keeping these outage causes in mind can be helpful in determining the priority of individual Requirements within already designated, high-risk priority Reliability Standards.

[29] http://www.nerc.com/docs/pc/rmwg/Integrated_Reliability_Index_WhitePaper_DRAFT.pdf

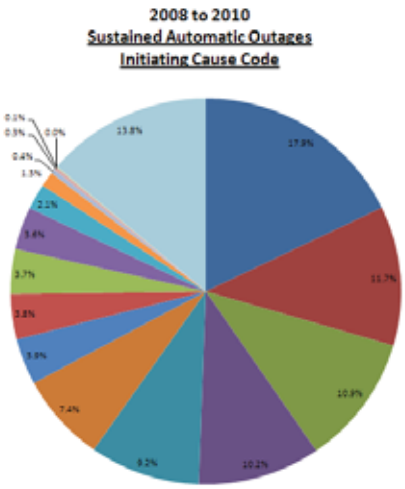

Initiating Cause	Sustained	Percent
Weather, excluding lightning	1379	17.9%
Lightning	902	11.7%
Human Error	842	10.9%
Failed AC Substation Equipment	784	10.2%
Failed AC Circuit Equipment	707	9.2%
Failed Protection System Equipment	572	7.4%
Foreign Interference	299	3.9%
Fire	292	3.8%
Power System Condition	289	3.7%
Other	276	3.6%
Contamination	165	2.1%
Vegetation	97	1.3%
Environmental	28	0.4%
Vandalism, Terrorism, or Malicious Acts	20	0.3%
Unavailable	7	0.1%
Failed AC/DC Terminal Equipment	1	0.0%
Unknown	1064	13.8%
TOTAL	7724	100.0%

Figure 2: Initiating causes of sustained outages for the BPS from 2008 to 2010.

Future Considerations

Future considerations refer to those Reliability Standards that are not yet enforceable, but are implicated by the 2012 ERO high-risk priorities as referenced in Appendix 1. Thus, these suggested Reliability Standards provide guidance on what should immediately be considered for incorporation into the AML following FERC approval and given the current priorities. As indicated by the NERC standards group, the applicable Reliability Standards subject to future enforcement include EOP-005-2, PER-005-1, and PRC-004-2.

Three-Tiered Compliance Approach

Following the compilation of the complete list of highest priority Reliability Standards, the AML, being the minimum scope of compliance audits, will include a subset[30] of Requirements per the FERC-approved RoP. The Requirements identified for the 2012 AML by using a three-tiered approach are described below.

Three-Tiered Approach to Requirements Specification

After selecting a set of Reliability Standards based upon the priorities and criteria identified above, it is necessary to identify the specific Requirements within each of the Reliability Standards that most directly relate to the purpose of the standard itself in terms of its relationship to the identified ERO high-risk priorities and, ultimately, its support for the reliability of the BPS.

In accordance with the FERC-approved Rules of Procedure, the ERO has selected a subset of the Reliability Standards and Requirements to be actively monitored and audited in the ERO annual compliance program for 2012. The three-tiered approach for identifying the Requirements of the Actively Monitored List is described below. For

[30] *See* NERC RoP, Section 401.6.

further information regarding the Implementation Plan methodology, refer to *Appendix 1 – 2012 ERO High-Risk Priorities with High Value Associated Reliability Standards.*

Tier 1 Requirements are those that are the most critical to the purpose and intent of the standard of which they are a part. Additionally, the ability of a registered entity to demonstrate compliance with Tier 1 Requirements will provide guidance to audit teams on the necessity to investigate further and broaden an audit's scope in additional Requirements and/or Reliability Standards.

Tier 2 Requirements are also critical to the purpose of a standard, but less so than Tier 1 in that Tier 2 does not address the ERO high-risk priorities as does Tier 1. Tier 2 also does not pose as severe a risk as Tier 1. This is not to say that compliance with Tier 2 Requirements is not mandatory. Instead, Tier 2 Requirements represent an additional level of inquiry that must be undertaken when a registered entity does not display clear compliance with those most critical Requirements of Tier 1. In the process of this added level of investigation, it may become necessary to branch off into other Reliability Standards that were not identified as relating directly to an ERO priority.

Tier 3 Requirements are those that, while still being significant to BPS reliability, do not represent the purpose of a Reliability Standard directly or are not representative of ERO priorities. The exploration of an audit team into the compliance of a registered entity with Tier 3 Requirements will be initiated through links between identified deficiencies in Tier 1 and 2 Requirements and those of Tier 3.

Regional Entity audit teams are authorized and obligated to expand the scope of a compliance audit to include Tier 2 and Tier 3 Requirements and any other requirements they may deem necessary based on the results of the Registered Entity Profile Assessment or the audit team's collective professional judgment. Audit scope expansion can occur at any point during the process: from the initial review of the Registered Entity Profile Assessment through the close of the audit.

The implementation plan for 2012 will use Tier 1 Requirements as the AML of Reliability Standards. The basis for the requirements of the high-risk priority Reliability Standards in the Tier 1 classification is covered in the following section.

Three-Tiered Approach to Audit Scope Determination

The three-tiered approach is new for 2012. Tier 1 Requirements are identified in the 2012 AML and represent the minimum scope of compliance audits. The potential expansion of an audit into Tier 2 and Tier 3 Requirements will be determined by the Regional Entity based on the results of a risk-based compliance monitoring and entity profile assessment or as determined during the audit process. When a Regional Entity determines that an increased audit scope is necessary based on a risk-based compliance monitoring approach, then the Regional Entity shall notify the registered entity of the increased audit scope. This notification shall include the Reliability Standards and

Requirements that are included in the increased scope, as well as the justification for the increased scope. This notification shall be part of the audit notification package when increased scope is determined early enough in the process. When a Regional Entity determines that an increased audit scope is necessary after the notification package is sent, or while the audit team is on-site, then the Regional Entity shall notify the registered entity of the increased audit scope as soon as possible.

The audit scope for registered entities that are registered to perform identical "functions" will not always be identical across or within the Regional Entities. Registered entities will be advised of the audit scope when they receive the formal audit notice. Compliance information and data archived by the Regional Entity from the implementation of previous monitoring methods will be used in the development of a registered entity's audit scope, including but not limited to previous audits, self certifications, events, and previous or current enforcement actions. Regional Entities will determine the registered entity's specific audit scope based upon the NERC Actively Monitored Reliability Standards List.

Regional Entities are authorized and obligated to implement the annual NERC Implementation Plan. Regional Entity staff may increase the scope of compliance activities related to the NERC program, as described above, but cannot reduce the scope of compliance activities without NERC consent. Where Regional Entities determine that a reduced scope is appropriate, the Regional Entity will submit the *Regional Entity Request to Defer or Reduce the Scope of a Compliance Audit*, which is located in Appendix 3 to the NERC Compliance Operations department at least 90 days prior to the audit for approval.

For Reliability Standards that are incorporated into a compliance audit as the result of a scope expansion, the registered entity that is subject to review of these additional Reliability Standards will not be expected to provide evidence outside of the audit period under review. Registered entities will not be expected to provide evidence outside of the current audit period for the purposes of demonstrating compliance with Reliability Standards unless that evidence is required in accordance with the processes and procedures of the registered entity. For example, a registered entity is expected to provide evidence outside of the current audit period for substantiating long range plans that are longer than an audit period, such as Protection System maintenance and testing intervals. For those Reliability Standards that do not involve long-range plans, an audit team will not be able to request information that is outside of the bounds of the current audit—either three or six years—nor can it identify possible non-compliance outside of this audit period. In other words, the completion of an audit closes one audit period and initiates another, excluding future audit teams from reviewing a registered entity's compliance during past audit periods. This exclusion does not apply to ERO enforcement actions or investigations. Generally speaking, spot checks, data submittals, and self-certifications will not require evidence that precedes the current audit period. This exclusion does not apply to ERO enforcement, investigations, or events analysis. Generally speaking, spot checks, data submittals and self-certifications will not require evidence that precedes the current audit period.

The overall monitoring scope of the 2012 Implementation Plan and AML is based on Reliability Standards that are anticipated to be in effect on January 1 2012. To the extent new or revised Reliability Standards are adopted, approved by the regulatory authority or in effect during the course of 2012, NERC will work with the Regional Entities to determine whether the 2012 program needs to be amended.

All NERC Reliability Standards identified in the 2012 Implementation Plan are listed in the 2012 CMEP Actively Monitored Reliability Standard list posted on the NERC website at the following link: http://www.nerc.com/commondocs.php?cd=3

The 2012 Actively Monitored Reliability Standards list includes several worksheets. A description of each is listed below:

- **Summary Tabs:** Quick reference listings of the Reliability Standards and Requirements identified for compliance audits, self-certifications and spot checks required by NERC in 2012, and mandatory effective dates for Reliability Standards. These tabs are designed to give the user a quick reference of the Implementation Plan lists. There are also comparisons of the number of Reliability Standards and Requirements monitored in the 2007, 2008, 2009, 2010, and 2011 programs.
- **Requirements Detail Tab:** A detailed list of the Requirements included in the 2012 Implementation Plan.
- **Revision History:** The revision history that will allow users, owners and operators of the BPS to see all of the changes to the 2012 Actively Monitored Reliability Standards spreadsheets.

An analysis of the applicability of Tier 1to the various registered functions is located in Appendix 2. Table 6 highlights some of this analysis and compares the 2012 AML to previous years.

Table 6: Requirements Analysis for the 2012 AML and those going back to 2007

	Requirements Analysis								
Function	Total Applicable Reqs as of 1/1/2012	2012 AML (All Reqs)	2012 AML (CIP only)	2012 AML (693 only)	2011	2010	2009	2008	2007
TOP	499	170	109	61	246	321	134	142	115
RC	397	136	109	27	203	299	97	131	76
BA	408	155	109	46	206	305	107	175	95
TO	369	134	107	27	222	271	70	86	86
GO	302	119	107	12	198	242	34	47	40
GOP	254	121	109	12	168	242	27	38	13
TSP	318	166	107	59	202	206	5	7	2
RSG	20	2	0	2	0	6	6	20	20
PA/PC	178	6	0	6	42	88	56	89	86
TP	143	13	0	13	49	83	51	86	86
IA	184	107	107	0	145	168	0	0	0
RP	22	3	0	3	3	0	0	0	0
LSE	267	123	109	14	157	214	12	26	13
PSE	11	1	0	1	1	3	3	4	3
DP	129	9	0	9	51	54	21	51	51
Avg Reqs	233	84	65	19	126	167	42	60	46

Reliability Standards Subject to 2012 CMEP Implementation

The regulatory authority-approved Reliability Standards and Requirements are monitored through at least one of the CMEP compliance monitoring methods. For the "audit" monitoring method, NERC and the Regional Entities have developed and implemented risk-based and performance-based criteria for determining the scope of the Reliability Standards to be reviewed during the conduct of the audit; risk-based and performance-based audits are discussed in *Chapter 3 - 2012 Implementation Plan Development Methodology*. In addition to these established priorities, other elements considered include FERC Orders and Guidance, compliance history, NERC departmental input, and future considerations utilizing a three-tiered approach. Audit scope is determined by factors that are associated with BPS issues across North America, across the respective Interconnection, and within a Regional Entity boundary, as well as specifics associated with a registered entity.

High-Risk Priority Standards List

Given the considerations of the ERO-identified high-risk priorities, as discussed in Appendix 1, which includes compliance history and violation trend analysis, the number of high priority Reliability Standards is 50, as shown in Table 7. From this group of Reliability Standards, it has been the primary task of Compliance Operations working with input from other groups within NERC to determine and rank the specific Requirements of each standard that best represent the core purpose of that standard to ensure the reliability of the BPS. With the further refined list of Requirements, a subset has been taken as the 2012 AML and will be monitored by the Regions during the year in accordance with the CMEP.

Table 7: High-Risk Priority Reliability Standards

BAL-002	CIP-009	FAC-001	MOD-004	PRC-011
BAL-003	COM-001	FAC-002	MOD-008	PRC-023
CIP-001	COM-002	FAC-003	NUC-001	TOP-001
CIP-002	EOP-001	FAC-008	PER-001	TOP-002
CIP-003	EOP-002	FAC-009	PER-002	TOP-003
CIP-004	EOP-003	IRO-002	PRC-001	TOP-004
CIP-005	EOP-004	IRO-004	PRC-004	TOP-006
CIP-006	EOP-005	IRO-005	PRC-005	TOP-008
CIP-007	EOP-006	IRO-006	PRC-007	TPL-003
CIP-008	EOP-008	MOD-001	PRC-008	TPL-004

High-Risk Priority Standards and Tier 1 Requirements

For each high priority standard identified in Table 7 above, only those Requirements that are recognized as Tier 1 Requirements will become part of the AML of Reliability Standards that must be examined during compliance audits. This section presents a synopsis of the details considered within each group of Reliability Standards to determine the Requirements that meet Tier 1 criteria. Refer to the 2012 AML to view the specific Requirements selected for each of the high-risk priority Reliability Standards.

BAL – Resource and Demand Balancing

BAL-002-0 and BAL-003-0.1b have been identified as high priority Reliability Standards. The performance aspect of BAL-002 is reviewed quarterly through periodic data submittals, but recent winter weather events have shown that contingency reserve is a critical issue, such that special attention should be given here. BAL-003-0.1b has been subject to spot checks in the past, but technical issues discovered through its enforcement have yet to be addressed. Until additional guidance is provided through interpretations, revisions, or otherwise, the Requirements of BAL-003 will be treated as Tier 2 Requirements.

CIP – Critical Infrastructure Protection

CIP-001-2a, CIP-002-3, CIP-003-3, CIP-004-3, CIP-005-3a, CIP-006-3, CIP-007-3, CIP-008-3, and CIP-009-3 have been identified as high priority standards. CIP-001 has an important role as BPS personnel become aware of and properly report sabotage events. Preparedness for reporting, as well as procedures to determine to whom reports should be issued, are critical in mitigating the occurrence of any such event. CIP-002 through CIP-009, or 706 Reliability Standards, are fundamental to the reliability of the BPS in terms of cyber security. Additionally, the CIP Reliability Standards represent eight of the Top 10 Reliability Standards violated over the past year and seven of the Top 10 for all time, indicating that registered entities are having difficulty with compliance issues. Several groups, including NERC, FERC, and the Regional Entities, have provided insight into the various Requirements in greatest support of the purpose of these Reliability Standards.

COM – Communications

COM-001-1.1 and COM-002-2 have been identified as high priority Reliability Standards. COM-001 details and mandates the adequacy of telecommunication facilities, thus supporting nearly every function, and is critical to normal and emergency operations. COM-002 has some similar coverage as COM-001, but goes above and beyond with three-part communication and a methodology for formulating directives. Also, COM-002 is the seventh-most-violated 693 standard for the past year as noted above in Table 3.

EOP – Emergency Preparedness and Operations

EOP-001-0, EOP-002-2.1, EOP-003-1, EOP-004-1, EOP-005-1, EOP-006-1, and EOP-008-0 have been identified as high priority Reliability Standards. EOP-001 is critical in

terms of Energy Emergency Alerts (EEAs), which were important for mitigating impacts from winter weather events taking place during early 2011. EOP-002 complements EOP-001 by assuring the performance of mitigating actions for the both the RC and the BA. EOP-003 designates load-shedding as a suitable action for maintaining the reliability of the BPS, but its action is implied in EOP-001, and therefore the Requirements of EOP-003 are not considered Tier 1 Requirements. EOP-004 is critical in terms of events analysis and helping with the process of mitigating future events, and it is vital that the disturbance reports do not stay within a region, but are shared with NERC for dissemination across North America. EOP-005 sets the foundation for system restoration if actions identified in other EOP Reliability Standards fail and the testing and confirmation of a blackstart capability process is engaged. EOP-006 ensures that the Reliability Coordinator takes the lead role in system restoration initiated through EOP-005, such that coordination in these efforts is not an oversight. EOP-008 accounts for loss of a primary control center and many Requirements not accounted for in any other standard, so this is vital to include.

FAC – Facilities Design, Connections, and Maintenance

FAC-001-0, FAC-002-0, FAC-003-1, FAC-008-1, and FAC-009-1 have been identified as high priority Reliability Standards. FAC-001 designates connections requirements for facilities, which is especially critical in terms of protection and construction of new facilities. With these facilities properly coordinated and accounted for, existing system performance will improve. FAC-002 expands on FAC-001 by requiring that assessments for facilities be undertaken and results coordinated. FAC-003 concerns vegetation management, which is a primary initiator of many events and points to the necessity of an effective vegetation management program. FAC-008 is a documentation-based standard for Facility Ratings Methodology whose execution is accounted for in FAC-009. While both are heavily violated Reliability Standards historically, a review of FAC-009 can lead to the determination of compliance with FAC-008. Additionally, FAC-009 requires coordination of facility ratings, which opens those ratings to peer review as a further check. In that case the Requirements of FAC-008 are not considered Tier 1 Requirements.

IRO – Interconnection Reliability Operations and Coordination

IRO-002-2, IRO-004-2, IRO-005-3a, and IRO-006-5 have been identified as high priority Reliability Standards. IRO-002 determines the sufficiency of tools needed for the RC to perform its role in maintaining the reliability of the BPS, which becomes increasingly imperative when emergency situations arise and Balancing Authorities and Transmission Operators require oversight. IRO-004 covers the planning the Reliability Coordinators must perform and ensures preparations are properly made for seen and unseen emergency events in the operation horizon. IRO-005 gives authority to the Reliability Coordinators to initiate all required control actions in order to mitigate system violations in terms of operating conditions. IRO-006 discusses the process of transmission load relief (TLR), and while this is an important topic, performance is covered in IRO-005, and therefore the Requirements of IRO-006 are not considered Tier 1 Requirements.

MOD – Modeling, Data, and Analysis

MOD-001-1a, MOD-004-1, and MOD-008-1 have been identified as high priority Reliability Standards. These three Reliability Standards determine the procedure by which Available Transmission Capability (ATC) is to be calculated by Transmission Service Providers. The proper setting of ATC is vital so facilities are not overloaded, which could lead to possible system emergencies. FERC has mandated that this standard be audited following regulatory approval of the Reliability Standard.

NUC – Nuclear

NUC-001-2 has been identified as a high priority Reliability Standard. The Nuclear Plant Interface Requirements (NIPRs) in NPIR agreements are essential components of NUC-001-2. NERC strongly recommends that generation and transmission entities carefully review their respective obligations under these agreements, including coordinated communication to ensure that parties share a clear and precise understanding of their obligations under these agreements.

PER – Personnel Performance, Training, and Qualifications

PER-001-0.1 and PER-002-0 have been identified as high priority Reliability Standards. PER-001 grants operating personnel the authority to operate the system reliably, but this standard is addressed in many other Reliability Standards with more specific language based upon the function considered, and therefore the Requirements of PER-001 are not considered Tier 1 Requirements. PER-002 encompasses the development of training as well as the training itself of all operating personnel responsible for ensuring reliability of the BPS. Training, especially in preparedness for dealing with or the prevention of emergency events is essential.

PRC – Protection and Control

PRC-001-1, PRC-004-1, PRC-005-1, PRC-007-0, PRC-008-0, PRC-011-0, and PRC-023-1 have been identified as high priority Reliability Standards. PRC-001 promotes understanding of the limitations and performance of protection systems, which is especially important from an operational standpoint such that protection systems are not overloaded and the system cannot be controlled. PRC-004 is a particularly important standard as it applies to misoperations analysis and reporting. As significant protection system misoperations are considered disturbance events, those misoperations for which BPS reliability is affected that are always addressed in PRC-004 are captured by EOP-004 R3 as well, and therefore the Requirements of PRC-004 are not considered Tier 1 Requirements. . Significant misoperations are those that result in such actions as modifications to operating procedures or equipment and identification of lessons learned as identified by Attachment 1 to EOP-004.

PRC-005 is the most violated standard of all time, and its mission to organize and implement protection system maintenance is especially critical for ensuring system reliability. PRC-007 and PRC-008 deal with underfrequency load-shedding (UFLS) while PRC-011-0 involves undervoltage load-shedding (UVLS). Both UFLS and UVLS

protection systems are important, but the level of compliance of a Registered Entity with PRC-005 will be most telling for compliance with these Reliability Standards. As a result, the Requirements of PRC-007, PRC-008, and PRC-011 are not considered Tier 1 Requirements. PRC-023, as with all Reliability Standards, has the chief purpose of promoting reliability in the BPS, and in this case it relates to transmission relay protection settings. The concerns surrounding these settings are that they are proper for detecting and protecting against fault conditions. As with UFLS and UVLS maintenance programs, the compliance performance of a registered entity with PRC-005 is a good guide as to how well protection systems at that entity are maintained and tested, which is applicable to PRC-023 as an indicator of the due diligence of an entity in properly setting relays and reviewing transmission system protection schemes. Also, significant misoperations resulting from improper relay settings are addressed through EOP-004, which would allow for a complete review of Requirements in PRC-023 in response to any such event. For those reasons listed, the Requirements of PRC-023 are not considered Tier 1 Requirements.

TOP – Transmission Operations

TOP-001-1, TOP-002-2a, TOP-003-0, TOP-004-2, TOP-006-1, and TOP-008-1 have been identified as high priority Reliability Standards. TOP-001 sets down operation authority for the TOP function, and in so doing, re-iterates language from the EOPs and IROs addressing this same issue. In an event where it can be demonstrated that an operator was not aware of his authority to act, this standard will be important for an entity to be audited on. However, as the authority of system operators is generally well understood, and therefore the Requirements of TOP-001 are not considered Tier 1 Requirements.. TOP-002 deals with normal operations planning, and one of the key concepts to this standard is communications. The outage coordination that is discussed in TOP-003 is implied by TOP-002 in normal operations planning, and therefore the Requirements of TOP-003 are not considered Tier 1 Requirements. . TOP-004 addresses operating in an unknown state and points to insufficient or faulty equipment, processes, planning, etc. and should be considered a high priority issue especially in terms of preparedness for emergencies. TOP-006, the monitoring of reliability parameters, can be gauged from compliance with TOP-008, which complements IRO-005 but this time for the TOP function. The Requirements of TOP-006 will not be considered Tier 1 Requirements while TOP-008 will be.

TPL – Transmission Planning

TPL-003-0a and TPL-004-0 have been identified as high priority Reliability Standards. TPL -003 accounts for the loss of two or more BPS elements, and TPL-004 addresses extreme events, both of which go hand-in-hand with minimizing the impact of emergency events affecting the system. By accounting for N-2 system losses in TPL-003 and losses of several elements in TPL-004, even if projects are not constructed to mitigate all issues that are identified, acknowledgement of and familiarity with potential events will allow for expedited recovery, should one actually occur.

CMEP Discovery Methods

Compliance Audits

The Reliability Standards selected for compliance audit are determined based on the 2012 Implementation Plan Methodology. The Regional Entities will provide to the registered entity the scope of the compliance audit with the audit notification letter. The scope document will contain the Regional Entities' analysis of their risk and performance-based approach, which determines the audit scope for the registered entity being audited. The intervals for compliance audits is three years for entities registered as a Reliability Coordinator, Balancing Authority, or Transmission Operator, and is six years for entities registered for all other functions[31]. Registered Entities may be audited more frequently as needed based upon the results of risk and performance based assessments performed by the Regional Entities as well as the facts and circumstances surrounding.

Regional Entities have the authority to expand an audit to include other Reliability Standards and Requirements, but cannot reduce the scope without NERC's consent. Regional Entities shall consider past performance, including historical violation trends across the Region and those specific to the registered entity, and changes to compliance responsibility resulting from mergers, acquisitions, corporate re-organizations, open investigations and other factors that in the judgment of the Regional Entity audit staff should be considered as part of the normal planning required for a compliance audit and consistent with generally accepted audit practices.

Regional Entity audit teams are authorized and obligated to expand the scope of a compliance audit to include Tier 2 and Tier 3 Requirements and any other requirements they may deem necessary based on the results of the Registered Entity Profile Assessment or the audit team's collective professional judgment. Audit scope expansion can occur at any point during the process, from the initial review of the Registered Entity Profile Assessment through the close of the audit.

The scope of the registered entities' compliance audits will include a review of all mitigation plans[32] that are open during the on-site audit, as discussed in the CMEP. Regional Entities must provide the compliance audit team with the status, documentation and evidence for all mitigation plans that are to be reviewed.

Should an expanded scope be required based upon significant issues discovered during the on-site portion of the audit process, the audit team will have the discretion to schedule

[31] *See* Rules of Procedure, Section 403.11.1 at http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20110412.pdf

[32] *See* Appendix 4C of the NERC RoP at Sections 3.1.4.3 and 6.6: http://www.nerc.com/files/Appendix4C_Uniform_CMEP_20110101.pdf

a follow-up spot check for reviewing the registered entity's compliance with the Reliability Standards and Requirements forming the expanded scope. The audit team will issue a new 30-day notification letter for a spot check in order to allow the registered entity proper time to prepare evidence necessary for the expanded audit scope. The additional compliance monitoring performed by the audit team as a result of the expanded audit scope should not exceed the current audit period.

For compliance audits, NERC provides additional guidance:

Audit Focus or Scope

To increase the efficiency of compliance audits in 2012 the Regional Entity audit teams will have the option of limiting the review of processes and procedures to the Registered Entity's current, in-force documentation, and to the implementation of the Registered Entity's internal compliance program. The audit teams will have the flexibility to review historical information on an as needed basis; this approach allows the audit team to focus on the current reliability risk and determining compliance. In accordance with NERC's RoP[33], documentation submitted to audit teams must be signed, either directly or electronically, by an authorized representative of the registered, regardless of whether or not the document is current or historical. In the event a finding of a possible violation is determined based upon the current, in-force documents, the audit team will review previous versions of the process and procedure documentation to determine the full extent of the possible violation.

In 2012, the audit period, being the range of time for which a registered entity is audited, will be individual to each entity based upon several factors. Depending upon a registered entity's particular situation, the start date for the audit period may be one of several possibilities:

1. the day after the prior audit, or
2. when other monitoring activity by the Compliance Enforcement Authority ended, or
3. the later of June 18, 2007 or the Registered Entity's date of registration if the Registered Entity has not previously been subject to a Compliance Audit.

The end date for the period of time to be covered during compliance audits in 2012 will be the end date for the compliance audits as outlined in the current CMEP, Section 3.1.4.2[34].

It should be noted that, except for those entities that have been recently registered, all Balancing Authorities (BAs), Transmission Operators (TOPs), and Reliability Coordinators (RCs) have experienced at least one compliance audit prior to the end of

[33] *See* Section 3.0 of Appendix 4C of the NERC RoP at: http://www.nerc.com/files/Appendix4C_Uniform_CMEP_20110101.pdf
[34] *See* Appendix 4C of the NERC RoP at http://www.nerc.com/files/Appendix4C_Uniform_CMEP_20110101.pdf

2010. For these Registered Entities that have undergone compliance audits already, all available versions of supporting documentation were reviewed for the entire audit periods, which began on June 18, 2007 and ended at their respective audit completion dates.

CIP Reliability Standards Compliance Audits

Registered entities are subject to audits for compliance with all Requirements of CIP-002-3 through CIP-009-3, which took effect October 1, 2010. If there are indications of possible non-compliance, auditors are authorized and obligated to review an entity's compliance throughout the entire audit period, which includes previous versions of CIP Reliability Standards, in order to determine the extent of possible violations.

If a responsible entity has active Technical Feasibility Exceptions (TFEs), Section 8 of NERC RoP - Appendix 4D[35], Procedure for Requesting and Receiving TFEs to NERC CIP Standards requires that subsequent Compliance Audits of the Responsible Entity conducted prior to the Expiration Date shall include audit of implementation and maintenance of the compensating measures and/or mitigating measures and implementation of steps and conduct of research and analyses towards achieving Strict Compliance with the Applicable Requirement. These topics are to be included in Compliance Audits regardless of whether the audit was otherwise scheduled to include the CIP Standard that includes the Applicable Requirement. Audit Team Leads of CIP audits will have requisite experience, training, and/or credentials in cyber security and/or IT auditing due to the need for subject matter expertise and the complexity of these Reliability Standards.

2012 Compliance Audit Schedule

The 2012 ERO compliance audit schedule, which is a compilation of all regional schedules, will be posted on the Compliance Resource page on the NERC website.[36] This posted schedule is updated at least quarterly, allowing the Registered Entities to have access to the schedule for the upcoming year as soon as possible.

The compliance audits listed on the schedule are labeled as on-site audits or off-site audits. This distinction is only relevant to the location of the audit activities, not the rigor of the audits. Both on-site and off-site audits are compliance audits and are performed using the same Reliability Standards Audit Worksheets (RSAW) and other audit tools and processes. The major difference is that on-site audits would entail physical access to the audited entity's premises. In fact, a large portion of the pre-audit work associated with an on-site audit may actually occur off-site.

Nevertheless, certain types of audits must contain an on-site component because of the nature or functions of the Registered Entity. For example, Reliability Coordinator, Balancing Authority and Transmission Operator functions must be audited on-site. For other BPS users, owners, and operators on the NERC Compliance Registry, the Regions and NERC can use discretion on the location and the conduct of the audit. In either case, the Regional Entity should plan the audit to assure proper scope and rigor.

[35] http://www.nerc.com/files/Appendix4D_TFE_Procedures_20110412.pdf
[36] http://www.nerc.com/commondocs.php?cd=3

Compliance Audit Reports

Regional Entities are obligated to provide written audit reports for all compliance audits and spot checks in accordance with *NERC Compliance Process Directive #2010-CAG-001 - Regional Entity Compliance Audit Report Processing*[37]. NERC posts all public versions of the Regional Entities' compliance audit reports of registered entities on the NERC website to satisfy requirements of the CMEP. Regional Entities submit two audit reports for each compliance audit of a Registered Entity: a public report and a non-public report. The public report does not contain critical energy infrastructure information or any other information deemed confidential. The public report does not include a description of how the audit team determined its findings; rather, it includes a listing of the findings. The names of the Regional Entity personnel and registered entity personnel participating in the audit are excluded from the public report, and all participants are identified by title. In accordance with FERC expectations[38], the non-public report shall document all areas of concern related to situations that do not appear to involve a current or ongoing violation of a Reliability Standard requirement, but instead represent an area of concern that could become a violation. The non-public report contains confidential information and detailed evidence that supports the audit findings. The names and titles of all Regional Entity personnel and all registered entity personnel participating in the audit are included in the non-public report.

Public and non-public compliance audit reports that do not contain possible violations are completed by the Regional Entities and are submitted to NERC at the same time. Upon receipt of the reports NERC posts the public reports on its website and submits the non-public audit reports to the applicable regulatory authority.

Public and non-public audit reports that contain possible violations are submitted to NERC at different times. The non-public compliance audit reports are completed by the Regional Entities as soon as practical after the last day of the audit and are then submitted to NERC. Upon receipt of the non-public reports, NERC submits them to the Applicable Governmental Authority. The public reports that contain possible violations are completed by redacting all confidential information in the non-public reports. The Regional Entities retain the public version of compliance audit reports that contains possible violations until all violations are processed through the NERC CMEP. Due process is considered complete when all possible violations are dismissed or when a violation is confirmed or a settlement is reached and a decision has been rendered, if applicable, by the regulatory authority (e.g. Notice of Penalty (NOP) has been issued in the United States). Upon completion of due process, the Regional Entities submit the public version of the compliance audit reports to the registered entities for review and comment prior to submitting them to NERC. Upon receipt of the public reports NERC posts them on the NERC website[39].

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[37] http://www.nerc.com/page.php?cid=3|22

[38] *Compliance with Mandatory Reliability Standards,* "Guidance Order on Compliance Audits Conducted by the Electric Reliability Organization and Regional Entities," 126 FERC ¶ 61,038 (2009) at P13, http://www.nerc.com/files/GuidanceOrderOnComplianceAudits-01152009.pdf

[39] Public audit reports can be found at: http://www.nerc.com/page.php?cid=3|26|246

In order to promote transparency and to provide the industry with guidance for improving compliance, NERC will be publishing a document containing the areas of concern, lessons learned, recommendations, and suggestions developed by ERO audit teams as part of the compliance monitoring process for 2011. This document will be similar to the Case Notes[40] that NERC currently provides in regard to the lessons learned as a result of registered entities completing their mitigation plans. The document will not mention or make reference to any registered entities specifically, but will instead focus on those various aspects for supporting and helping to enhance compliance programs.

Compliance Tools

The RSAWs are designed to add clarity and consistency to the assessment of compliance with Reliability Standards. The RSAWs are used for multiple compliance monitoring methods. Comments on these and any of the ERO's auditor resources are welcome and can be directed to the Regional Entity Compliance Managers[41].

The RSAWs are posted on the NERC public website[42] and provide information to the industry about expectations of the ERO compliance auditors when evaluating compliance with a Reliability Standard. NERC works in close coordination with the Regional Entities to ensure the information in existing RSAWs is updated with the latest regulatory authority language and guidance, and new RSAWs are developed as Reliability Standards are approved. It is recommended that Regional Entities and registered entities check the NERC website regularly to ensure the latest available versions of RSAWs are being used.

NERC works with Regional Entities to review these RSAWs on a continual basis for improvement. NERC plans to migrate RSAWs to a database format in the future to support timely updates as Reliability Standards are approved, modified, or retired.

Mitigation Plans

Registered Entities must be in compliance with all Reliability Standards at all times. NERC and the Regional Entities encourage aggressive self-assessments and analysis and self reporting of noncompliance by registered entities. Registered entities are further encouraged to draft mitigation plans upon identification and self reporting of possible violations, prior to the required submission timeline per the CMEP. Mitigation plans are not an admission of a violation and are treated as voluntary corrective action. However, mitigation plans duly prepared and promptly submitted to the Regional Entity will be used to demonstrate a positive, proactive culture of compliance in any potential enforcement action.

[40] http://www.nerc.com/page.php?cid=3|22|371
[41] Information concerning Regional Entity programs is available at: http://www.nerc.com/page.php?cid=3|23
[42] http://www.nerc.com/page.php?cid=3|22

Self-Certification

All registered entities are required to participate in the annual self-certification each year per the NERC Actively Monitored Reliability Standard list. Regional Entities, at their discretion, may include additional Reliability Standards to include in the Regional 2012 Implementation Plan. Registered entities will receive guidance and instruction from their respective Regional Entity concerning self-certification submittals. Self-certification is an important component of the ERO Compliance Monitoring and Enforcement Program. It is one of the discovery methods that monitor a Registered Entity's compliance with Reliability Standards, especially those that have not been included in audit scopes in recent years. Self-certification waivers are not available as all applicable Reliability Standards must be self-certified.

CIP-002-3 through CIP-009-3 Reliability Standards

Registered entities are required to self-certify once per year, as scheduled by the Regional Entity and according to the Regional Entity's 2012 Implementation Plan. However, self-certification may expand to include CIP supplemental questionnaires as directed by NERC or an Applicable Governmental Authority. For further information, refer to Implementation Plan for Newly Identified Critical Cyber Assets and Newly Registered Entities[43].

A unique characteristic of the CIP Standards pertains to self-certification: CIP-002-3 R4 requires all entities to annually approve their risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets, even if such lists are null. Thus, entities will need to submit self-certification for CIP-002-3 even if they conclude they have no Critical Assets.

The requirements for Self-Certification differ from the reporting requirements for approved TFEs. TFE reporting requirements for Responsible Entities are described in Section 6 of NERC RoP - Appendix 4D, Procedure for Requesting and Receiving TFEs to NERC CIP Standards.

Spot Checks

Spot checks are compliance audits with a much narrower focus, but are performed with the same rigor as a compliance audit. NERC and the Regional Entities have the authority to conduct spot checks of any regulatory approved Reliability Standards. Regional Entities may expand the list of Reliability Standards and Requirements they have scheduled for spot checks in their Regional Implementation Plan. Regional Entities shall ensure, however, that they satisfy all spot check requirements in the NERC Reliability Standards, RoP, and CMEP. Regional Entities are obligated to provide written audit reports for all compliance audits and spot checks in accordance with *NERC Compliance Process Directive #2010-CAG-001 - Regional Entity Compliance Audit Report*

[43] http://www.nerc.com/docs/standards/sar/Imp-Plan_Newly_Identified_CCA_RE_clean_last_approval_2009Nov19.pdf.

Processing[44]. The standard audit report template and procedure provided in NERC Compliance Process Directive #2010-CAG-001 will be used for all spot check reports.

CIP Reliability Standards

Selected Reliability Standards Requirements of CIP-002-3 through CIP-009-3 will be audited and additional spot checks may be performed at the Regional Entity's discretion. CIP audits, including CIP spot checks, will require the appropriate reports per the RoP, CMEP, and *NERC Compliance Process Directive #2010-CAG-001 - Regional Entity Compliance Audit Report Processing*[45].

Periodic Data Submittals

Specific Reliability Standards and Requirements have been identified for periodic data submittals. The periodic data submittals for 2012 are as shown on the Requirements Tab of the 2012 Actively Monitored Reliability Standards list. Specific information regarding periodic data submittals is defined in the Regional Entity Implementation Plans.

Self-Reporting

Registered Entities are encouraged to self-report compliance violations with any regulatory authority-approved Reliability Standard. In most cases, self-reports of compliance violations are provided to the appropriate Regional Entity.[46] The ERO strongly encourages Registered Entities to report violations of Reliability Standards as soon as possible to ensure that the entity receives any potential cooperation credits[47] for self-reporting[48] and minimizing any ongoing risk to the BPS.

Exception-Reporting

Specific Reliability Standards and Requirements in the 2012 Actively Monitored Reliability Standards list have been identified for exception reporting. The Registered Entities are expected to report to the Regional Entities for all events or conditions occurring that are exceptions to the associated Reliability Standard Requirement.

Reporting Credit

Currently, self-reporting credits will not be given to those registered entities for filing reports they are required to make[49]. Additionally, there are no reporting credits available during the enforcement process for mandatory reporting of self-certifications and self-reports during or after an audit. Cooperation credits may be available to a registered

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[44] http://www.nerc.com/page.php?cid=3|22

[45] http://www.nerc.com/page.php?cid=3|22

[46] The exception would be where the self-reporting entity is itself a Regional Entity, in which case the self-report should go directly to NERC in accordance with the Regional Entity's delegation agreement and other agreements with NERC.

[47] *North American Electric Reliability Corporation*, "Order on Review of Notice of Penalty," 134 FERC ¶ 61,209 (2011) at P 13, http://www.ferc.gov/whats-new/comm-meet/2011/031711/E-3.pdf

[48] *Guidance o Filing Reliability Notices of Penalty, North American Electric Reliability Corporation*, "Order on Review of Notice of Penalty," 124 FERC ¶ 61,015 (2008) at P 32, http://www.ferc.gov/EventCalendar/Files/20080703131349-AD08-10-000.pdf

[49] *North American Electric Reliability Corporation*, "Order on Review of Notice of Penalty," 134 FERC ¶ 61,209 (2011) at P 47, http://www.ferc.gov/whats-new/comm-meet/2011/031711/E-3.pdf

entity during the enforcement process based on facts and circumstances.

NERC has requested a rehearing on the issue of self-reporting credits from FERC[50]. NERC recognizes that self-reporting credit is a critical component to entity compliance and BPS reliability and encourages registered entities to continue to self-report all possible violations as soon as possible.

Complaint

All regulatory authority-approved Reliability Standards or Requirements can be the subject of a complaint regarding a compliance violation by a Registered Entity. Complaints, if validated, can initiate one of the other compliance monitoring methods in order to determine the full extent of potential non-compliance.

NERC maintains a Compliance Hotline that is administered by the Event Analysis & Investigation (EA&I) group. Any person may submit a complaint to report a possible violation of a Reliability Standard by calling 404-446-2575, sending an e-mail directly to hotline@nerc.net or completing the form on https://www.nerc.net/hotline/. Unless specifically authorized by the complainant, NERC and Regional Entity staff will withhold the name of the complainant in any communications with the violating entity. All information provided will be held as confidential in accordance with the NERC Rules of Procedure. EA&I will informally seek additional information regarding the potential violation of Reliability Standards from the submitter and others, as appropriate. EA&I may refer the matter for further investigation by NERC or the appropriate Regional Entity.

Note: The NERC Compliance Hotline is for reporting complaints or possible compliance violations of Reliability Standards by an entity. For other questions regarding the NERC CMEP or Reliability Standards, please send an email to compliancefeedback@nerc.net.

Compliance Investigations

A Compliance Investigation may be initiated at any time by the NERC or the Regions in response to a system disturbance, Complaint, or the possible violation of a Reliability Standard identified by any other means. Compliance Investigations are confidential, unless FERC directs otherwise and are generally led by the Regional Entity's staff. NERC reserves the right to assume the leadership of a Compliance Investigation.

The Compliance Enforcement Authority reviews information to determine compliance with the Reliability Standards. The Compliance Enforcement Authority may request additional data and/or information as necessary through formal Requests for Information, site visits, sworn statements, etc. to perform its assessment.

[50] http://www.nerc.com/files/FinalFiled_Req_For_Clarification_Turlock_Order_20100418.pdf

ERO Compliance Monitoring and Enforcement Program Organization

The focus of the ERO Enterprise's compliance program is to improve the reliability of the BPS in North America by fairly and consistently enforcing compliance with regulatory approved Reliability Standards. Specifically, the program is designed to ensure that the right practices are in place so that the likelihood and severity of future system disturbances are substantially reduced, while recognizing that no Reliability Standards or enforcement process can fully prevent all such disturbances from occurring. In order to fulfill these responsibilities the NERC compliance organization is comprised of four primary groups: Compliance Operations, Compliance Enforcement, Event Analysis and Investigation, and Regional Entities.

- The overriding goal of the Compliance Operations Department is ensuring success of the Regional Entities and registered entities with respect to reliability compliance.

- The Compliance Enforcement Department is tasked with ensuring strong, consistent, and expeditious enforcement of Reliability Standard violations.

- The Event Analysis and Investigation Department combines the technical expertise of NERC's situation awareness staff, events analysis staff and its event investigators to facilitate efficient processing of these complementary activities to provide lessons learned, which will promote increased reliability of the BPS.

- The Regional Entities execute the CMEP on behalf of the ERO according to their respective Regional Delegation Agreements.

In addition to the ERO's responsibilities, the CMEP (RoP Appendix 4C) states that all entities that are registered in the NERC Compliance Registry have the obligation to comply with all enforceable Reliability Standards for the functions for which the entity is registered. All registered entities are subject to the compliance monitoring methods included in the CMEP, and should be aware of their obligations. Every registered entity should have an aggressive internal compliance program for identifying and performing its CMEP responsibilities. Also, the registered entities are encouraged to participate in the Reliability Standards development process, recognizing that the Reliability Standards serve as the basis for compliance.

Compliance Enforcement

Program Scope and Functional Description

NERC's Compliance Enforcement department conducts all of NERC's enforcement activities, including:

- Docketing of all possible violations coming into the NERC enforcement program,
- Prosecution of compliance violation matters arising out of NERC-led investigations and audits,
- Review of all mitigation plans and dismissals approved by Regional Entities,
- Processing of all compliance violations prosecuted by Regional Entities, and
- Analysis of compliance statistics.

2012 Goals and Deliverables

A priority for this department is to achieve greater efficiencies in enforcement processing by focusing both NERC and Regional Entity compliance enforcement resources on the cases that have the most significant impact on the reliability of the BPS. This should reduce the overall ERO compliance caseload by ensuring that the number of cases processed through the filing of a notice of penalty exceeds the number of cases coming into the ERO docket and should thus allow NERC to close out cases expeditiously to provide timely lessons learned to the industry. NERC's Compliance Enforcement staff has realized significant efficiencies and expects to gain efficiencies through better utilization of existing resources in the future.[51]

Despite efforts to attain greater efficiencies, a significant gap is anticipated in the number of cases coming into the enforcement process and the number of cases the enforcement team can close out on a monthly basis. In the past year, as reflected in Figure 3, the ERO's caseload of active violations expanded from 2006 in January 2010 to 3193 in

[51] There is substantial evidence of this increased efficiency. In 2010, Compliance Enforcement rolled out new risk-based processes in early 2010. These processes, including the introduction of the Disposition Document, Abbreviated Notice of Penalties, and other process improvements, have helped streamline compliance enforcement. Over the course of the year, Compliance Enforcement has also increased collaboration with Regional Entities and increased the number and expertise of Enforcement Staff. As a consequence, Compliance Enforcement has increased by 3.5 times the number of violations processed each month in 2010 compared to the number of violations processed each month in 2009 (70/month vs. 20/month).

An administrative citation process was initiated in January 2011 that will enable NERC and the Regional Entities to address new violations by submitting a single streamlined NOP covering numerous lower risk violations. See North American Electric Reliability Corporation, 134 "Notice of No Further Review of Initial Administrative Citation Notice of Penalty," 134 FERC ¶ 61,157 (2011) ("March 3, 2011 Order").

As of September 30, 2011, the compliance enforcement initiative will introduce a new enforcement process that will retire the administrative citation process. This is described in further detail below, in the 'Key CMEP Activities and Initiatives' section of the implementation plan.

January 2011. The rate of new violations coming into the case load has increased dramatically from an average of 140 violations per month in early 2010 to an average of 203 violations per month at the start of 2011. The increase in caseload is primarily attributable to the large number of violations of CIP Standards that have been and will be entering the system. As reflected in Figure 4, the number of incoming violations each month from non-CIP Reliability Standards has been relatively stable since June 2008, but with the staged implementation of the CIP Reliability Standards, the number of incoming violations each month from CIP Reliability Standards continues to rise.

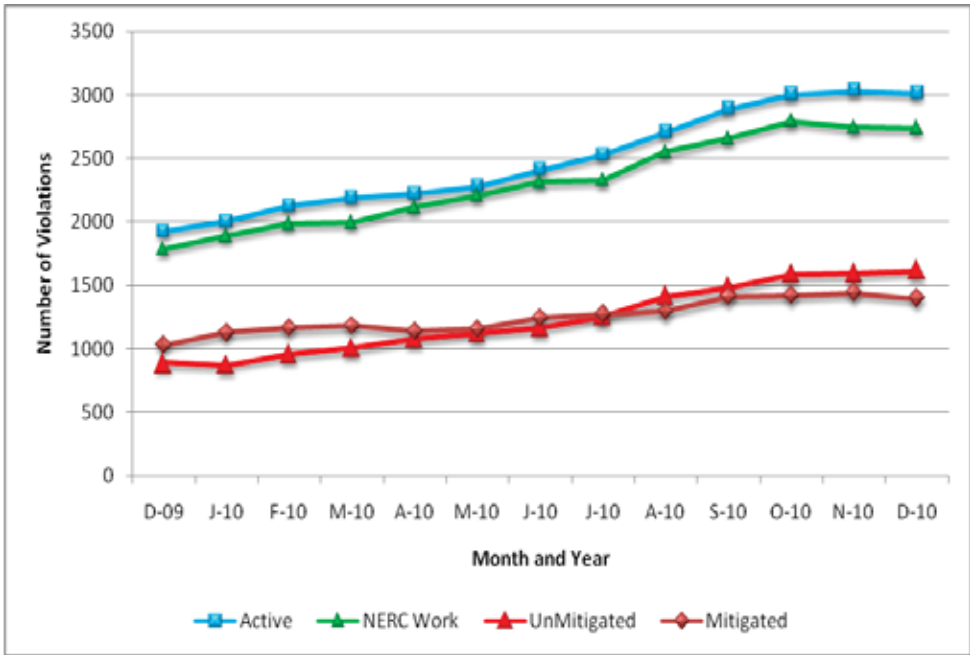

Figure 3: Compliance Processing Statistics for Calendar Year 2010.

The influx of new violations is expected to outstrip the number of violations NERC can process each month. Compliance Enforcement processed to BOTCC approval an average of 70 violations per month in 2010. With the implementation of streamlined procedures and the advent of the administrative citation process, the team has processed an average of 130 violations per month for the first three months of 2011. Still, further streamlining is required to reduce the overall caseload. NERC staff is actively working with Regional Entities and registered entities to develop further ways in which to streamline the enforcement process and ensure that enforcement resources are efficiently deployed to address the most significant risks to bulk power system reliability.

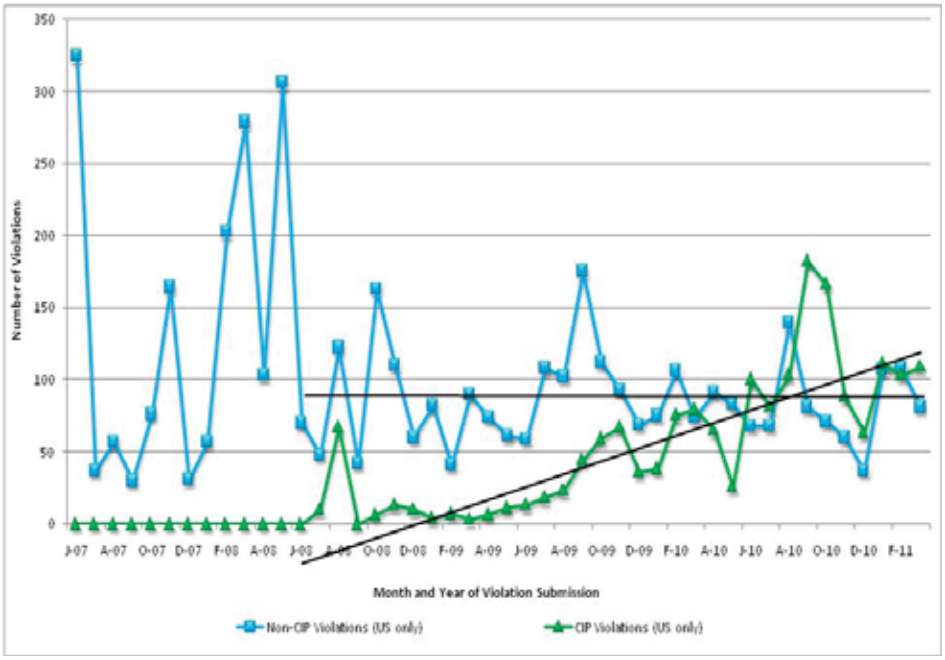

Figure 4: Violations Submitted per Month (CIP vs. Non-CIP).

Beyond management of the caseload, another significant area of focus for the next year will be to improve the submittal and completion of mitigation plans. As reflected in Figure 1 above, the increase in active violations in 2010 brought with it an increase in the number of unmitigated violations and a decline in the overall percentage of active violations subject to a mitigation plan. Currently, less than half of the active violations in the caseload have been mitigated, and a number of violations dating back to 2007 are not yet covered by mitigation plans. To help manage risk to the BPS, Compliance Enforcement will focus on understanding and improving upon the mitigation process.

Key CMEP Activities and Initiatives

NERC and the Regional Entities receive CMEP implementation feedback from the Members Representative Committee (MRC), Compliance and Certification Committee (CCC) and other stakeholders through the use of audited entity feedback forms. All feedback and input from these groups, among others, are reviewed on a continual basis for opportunities for improvement. NERC and the Regional Entities are committed to continuous improvement of the CMEP implementation.

CMEP Transparency Elements

NERC and the Regional Entities continuously balance the request from the industry to improve transparency with the confidential nature of the CMEP processes. Figure 5 is a pictorial view of the compliance process, and it shows how most of the processes in the CMEP fall under a window of confidentiality. NERC and the Regional Entities are continuously identifying and implementing innovative ways to share CMEP process information while honoring confidentiality. Additional initiatives are underway to increase transparency of CMEP elements in 2011. They are discussed later in this Chapter.

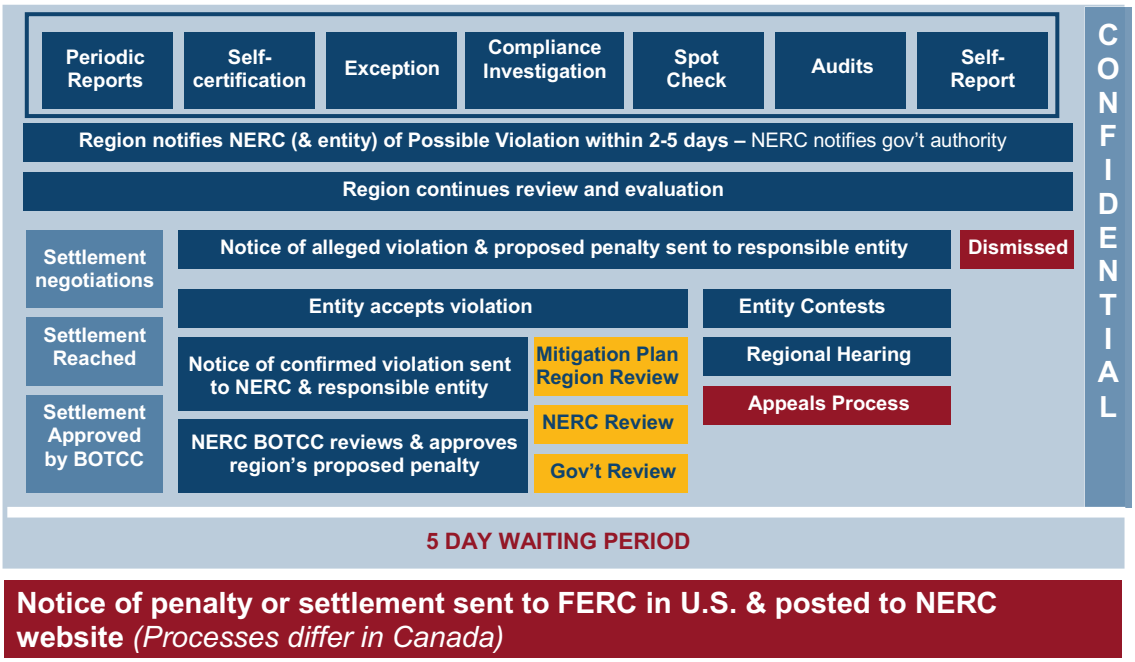

Figure 5: Compliance Process

In 2010, NERC began publicly posting CMEP implementation and process information. NERC Compliance Operations will continue to review and publicly post CMEP implementation and process information in the form of public notices[52] in order to increase transparency of the CMEP application to registered entities.

[52] Public notices are available at: http://www.nerc.com/page.php?cid=3|22

Compliance Operations and REs Communications

Seminars and Workshops

Seminars and workshops for compliance activities are conducted at both the Regional Entity and NERC levels. Each Regional Entity provides Compliance Workshops at least once a year. NERC offers four workshops per year for registered entities. Two of these workshops focus on "Standards and Compliance," and two of these workshops focus on assisting registered entities in improving their compliance programs. The seminars and workshops are important learning exercises for those subject to Reliability Standards. NERC and the Regional Entities will continue compliance seminars, workshops and panel discussions to educate registered entities and to increase transparency of CMEP processes that are important to reliability.

Transparency Communications

The NERC Compliance Operations Program and the Regional Entities are working toward common goals related to improving consistency, increasing transparency, and creating more efficiency in compliance processes. Past field experience gained by Regional Entities and NERC is an important part of meeting the goal to provide clarity on particular items and state the proper expectations. NERC provides transparency information in various formats, depending on the scope of the matter and relevance to the particular functions within the BPS. These include the following, as well as other means as NERC deems necessary:

CANs – Compliance Application Notices[53]

CANs focus on current and future auditable compliance applications. CANs provide continued compliance and enforcement guidance as a means to facilitate information to industry while Reliability Standards are revised and improved as discussed in FERC Order No. 693.

CARs – Compliance Analysis Reports[54]

CARS are a historical look at compliance trends for individual Reliability Standards and will include addendums when the information is updated.

Case Notes[55]

Case Notes provide examples of mitigation plans for recent possible violations that have not completed processing through an enforcement action. Case notes do not identify the Registered Entity.

Bulletins[56]

Bulletins provide general information or clarification on current and future issues.

[53] http://www.nerc.com/page.php?cid=3|22|354
[54] http://www.nerc.com/page.php?cid=3|329
[55] http://www.nerc.com/page.php?cid=3|22|371
[56] http://www.nerc.com/page.php?cid=3|22

Directives[57]

Directives provide notice of a mandatory action and guidance for Regional Entities.

Lessons Learned[58]

Lessons Learned result from an event analysis. They provide examples of how a problem occurred and was identified, and the corrective action taken.

Annual CMEP Reports[59]

Annual CMEP Reports are assessment of the previous year's CMEP and are used in the planning and development of future years' annual CMEP Implementation Plans.

Compliance Application Notices

CANs provide necessary compliance guidance and fulfill NERC's obligations under FERC Order No. 693 to provide compliance guidance going forward.

In FERC Order No. 693[60] several commenter's argued there were gaps and ambiguities in the standards and requested relief from monetary penalties and even compliance with the Reliability Standards. According to paragraph 274 FERC opined, "As discussed in our standard-by-standard review, each Reliability Standard that we approve contains Requirements that are sufficiently clear as to be enforceable and do not create due process concerns."

Further, in Order No. 693 paragraph 277, the Commission agreed with NERC that, even if some clarification of a particular Reliability Standard would be desirable at the outset, making it mandatory allows the ERO and the Regional Entities to provide that clarification on a going-forward basis while still requiring compliance with Reliability Standards.[61]

Thus, the Compliance Application Notice (CAN) serves two purposes:

1. To provide *transparency to industry* on how an ERO compliance enforcement authority will apply compliance criteria to determine possible non-compliance with a NERC Reliability Standard; and
2. To *establish consistency in the application of compliance criteria* across all compliance enforcement authorities.

In practice, auditors must make in-the-field determinations of what constitutes possible non-compliance of a Reliability Standard. In essence, the auditor, without guidance,

[57] http://www.nerc.com/page.php?cid=3|22
[58] http://www.nerc.com/page.php?cid=5|385
[59] http://www.nerc.com/page.php?cid=3|26
[60] FERC Order No. 693, Docket No. RM06-16-000 (March 16, 2007).
[61] "NERC can maximize consistency and appropriateness of treatment in compliance matters most efficiently if it has the ability to advise or provide direction…at an early stage…," FERC Order on NERC Three Year Assessment, Docket Nos. RR09-7-000 and AD10-14-000, §216.

must make an interpretation of the standard. A CAN attempts to gather the practices that occur in the field, and, if the practices are consistent, provide transparency of the compliance application to industry. In the event that auditor practices vary, the posted CAN establishes a consistent compliance application that all auditors will adopt going forward. The implementation of this type of compliance application may create some change as it drives consistency across the ERO.

A CAN provides significant advantages to industry. Registered Entities will have visibility into how compliance will be applied and will be able to depend upon the compliance application being consistent across auditors and regions. In the event that an inconsistency occurs, a registered entity will be able to point to the CAN as the auditable compliance application. Additionally, CANs can be generated in a relatively short period – approximately three months – compared to the codified Standards Development Process,[62] which may take longer than a year.

CANs are posted for a three-week industry comment period. All comments that are received for each CAN are carefully reviewed and considered. Industry comments are especially important when the compliance application varies across auditors or regions, as the CAN will establish a consistent application.

NERC's belief is that transparent, open communication is beneficial, and transparency of compliance applications provides an opportunity to formally address areas of concern. When industry disagrees with the compliance application identified in a CAN, there are existing processes that continue to be available for formal resolution. A registered entity may:

1. request a formal interpretation;[63] or
2. submit a Standard Authorization Request (SAR) to modify the standard; or
3. if a registered entity is found to have a non-compliance based on the compliance application identified in a CAN, to contest the violation; or
4. submit a technical rationale why the compliance application is incorrect or should be modified.

The compliance application identified in a CAN will be retired when a future standard or interpretation that addresses the issue – either by supporting the CAN or changing it – has been approved by FERC and is enforceable. Further, a CAN may be revoked or revised if additional information is brought forward to demonstrate that the CAN is incorrect.

As of June 29, 2011, there are 16 CANs posted as final on the NERC website and 26 additional CANs in various stages of the development process, plus over 20 CAN requests pending development.

[62] See the NERC Rules of Procedure, Appendix 3A, Standards Process Manual, Effective September 3, 2010.

[63] An interpretation is conducted through the Standards Development Process. As such, it is formally filed with FERC and will result in an order issued by FERC Commissioners.

Compliance Analysis Reports

Registered entities can use Compliance Analysis Reports (CAR) and any corresponding addendums to view historical information on highly violated Reliability Standards and those most critical to reliability. For those Requirements in each standard that have similar violation descriptions for multiple registered entities, NERC and the Regional Entities provide suggestions for registered entities to improve their programs to comply with the Requirements. The registered entities can also see the discovery method of each of the violations. If the registered entities have a high percentage of violations discovered through self-reports or self-certifications, it shows an aggressive ICP. If the standard has a high percentage of violations discovered through compliance audits, there should be some concern that the registered entities are uncertain how to comply. The report serves as a mechanism to deliver some clarity and information to improve compliance.

Regional Entities can use the reports to point out any regional issues that may have resulted from the violations that could involve compliance, registration, or enforcement issues. They can also use the violation descriptions to improve consistency on auditing to the standard.

Training

Compliance Auditors

The NERC compliance auditor training is based in part on generally accepted auditing practices found in documents such as the Government Accounting Office (GAO) Generally Accepted Government Auditing Standards, and is revised from time to time. Continuing education will provide training on specific auditing issues to promote consistency and increased reliability.

In 2012, NERC Compliance Operations will design and develop a tiered system of qualifications for compliance staff with requisite testing and/or credentials. Training is an important part of delivering consistency across NERC and the Regions.

In addition, NERC sponsors seminars on specific matters as a way to provide continuous education to ERO staff. Two such seminars were performed in 2011, and two are scheduled for 2012.

Specialized training for CIP auditors was performed in 2011 and will continue in 2012. It is intended not only to address technical issues unique to the CIP Standards environment, but also to increase the skills of CIP auditor staff. Two sessions of CIP Standards Training (CIP Basics for Auditors) are scheduled for 2012. NERC encourages the CIP audit staff to have requisite experience, training and credentials in cyber security and IT auditing.

Compliance Investigative (CI) Staff

A “Fundamentals of CI” course/seminar has been conducted for NERC and Regional Entity staff by NERC over the last two years. The training is scheduled to be conducted twice annually and is revised from time to time.

Mitigation Plans

Non-Confirmed Violations Without Submitted Mitigation Plans

In 2010, Compliance Enforcement staff began analyzing various violation processing trends for the Board of Trustees Compliance Committee and for stakeholders. A trend has been identified in an increasing number of active violations in NERC's violation processing database for which the registered entities have not yet submitted mitigation plans. While there are a number of different reasons for the increase, NERC would like to remind registered entities of the importance of timely mitigation plans and that the submission of a mitigation plan is not an admission of a confirmed violation. Voluntary correction of possible violations in a timely manner may also reduce the potential of a penalty consistent with section 4.3.3 of NERC's Sanctions Guidelines[64].

Compliance Enforcement staff will continue to clarify that the submission of a mitigation plan is not an admission of confirmed violation. Prior to, and if, enforcement confirms a possible violation to an alleged violation, the mitigation plan is treated as a voluntary corrective action. The evidence collected by ERO enforcement will determine whether a violation exists.

Registration and Certification

The purpose of the Organization Registration Program is to clearly identify those entities that are responsible for compliance with the regulatory approved Reliability Standards and is described in the NERC Rules of Procedure Appendix 5A Organization Registration and Certification Manual. As described in the NERC Statement of Compliance Registry Criteria, NERC will include in its compliance registry each entity that the ERO concludes can materially impact the reliability of the BPS. NERC is obligated to identify all organizations to be listed in the NERC compliance registry. Identifying these organizations is necessary and prudent for the purpose of determining resource needs both at the NERC and Regional Entity level, and to begin the process of communication with these entities regarding their potential responsibilities and obligations.

Multi-Regional Registered Entities (MRRE)

There are several activities related to registration, compliance monitoring and enforcement involving registered entities that are registered and operate and/or conduct business in multiple regions. NERC and the Regional Entities have worked together to develop a process for MRREs that will delineate the CMEP implementation for these types of registrations. The purpose of the Multi-Regional Registered Entity (MRRE) process is to describe the coordinated CMEP processes that will be used by NERC and the Regional Entities for a subset of registered entities that are registered in multiple regions on a voluntary basis. The MRRE process allows these entities the ability to request to be accountable to one Compliance Enforcement Authority (CEA). This

[64] See Appendix 4B *Sanction Guidelines of the North American Electric Reliability Corporation* from NERC's Rules of Procedure at:
http://www.nerc.com/files/Appendix4B_Sanction_Guidelines_20110101.pdf

coordinated process provides for increased efficiencies in compliance resource allocation for NERC, the Regional Entities, and the registered entities while maintaining the reliability of the BPS. Due to potential Regional Entity jurisdictional issues, the MRRE process is on hold as of May 2011 pending NERC legal's review and determination of these issues.

Joint Registration Organization and Coordinated Functional Registration

Joint Registration Organization (JRO)[65]: In addition to registering as the entity responsible for all functions that it performs itself, an entity may register as a JRO on behalf of one or more of its members or related entities for one or more functions for which such members or related entities would otherwise be required to register, and, thereby, accept on behalf of such members or related entities all compliance responsibility for that function or those functions, including all reporting requirements.

Coordinated Functional Registration (CFR)[66]: In addition to registering as an entity responsible for all functions that it performs itself, multiple entities may each register using a CFR for one or more reliability standard and/or for one or more requirements/sub-requirements within particular reliability standards applicable to a specific function. The CFR submission must include a written agreement that governs itself and clearly specifies the entities' respective compliance responsibilities. The registration of the CFR is the complete registration for each entity. Additionally, each entity shall take full compliance responsibility for those Reliability Standards and/or requirements/sub-requirements it has registered for in the CFR. Due to abrupt or forced registration changes, as described below, this form of registration may become more common in 2012.

Results of Abrupt or Forced Registration Changes

The conclusions drawn from a of the EOP-005 System restoration and Blackstart Compliance Analysis Report completed by NERC indicate that an increasing number of self-reported Possible Violations (PVs) are being issued due to abrupt or forced registrations.

As such, these types of PVs involve a heavier case load for Registered Entities, as some of the violations require lengthy mitigation plans. Furthermore, for issues that involve certifiable functions, a NERC certification must be completed per the Rules of Procedure.

NERC and the Regional Entities will continue to work together in the development of appropriate actions to efficiently manage the compliance issues resulting from abrupt and forced registration changes.

[65] Section 507 of the NERC RoP, http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20110412.pdf
[66] Section 508 of the NERC RoP, http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20110412.pdf

The Compliance Enforcement Initiative

After five years as the ERO, NERC continues to seek ways to improve and adapt its processes and Reliability Standards. NERC, FERC and the industry have discussed significant ways to retool efficiency efforts through multiple technical conferences. A key outcome was the recognition that compliance matters should be treated differently based on the level of risk posed to the reliability of the BPS.

NERC's new Compliance Enforcement Initiative (CEI) is designed to handle issues more efficiently, focus on issues posing a higher risk to reliability, streamline administrative paperwork, and continue to encourage self-reporting and mitigation.

NERC is not looking to reduce the number of compliance items identified with this new initiative, but is rather looking to treat matters differently based upon the risk associated with them. By identifying, mitigating and resolving issues that do not pose a serious risk to the reliability of the BPS, more resources can be focused on violations that do pose a risk to reliability.

The CEI is being launched in accordance with NERC's existing rules and procedures. The new initiative is not about whether issues will be addressed. Rather, it is about how they are addressed.

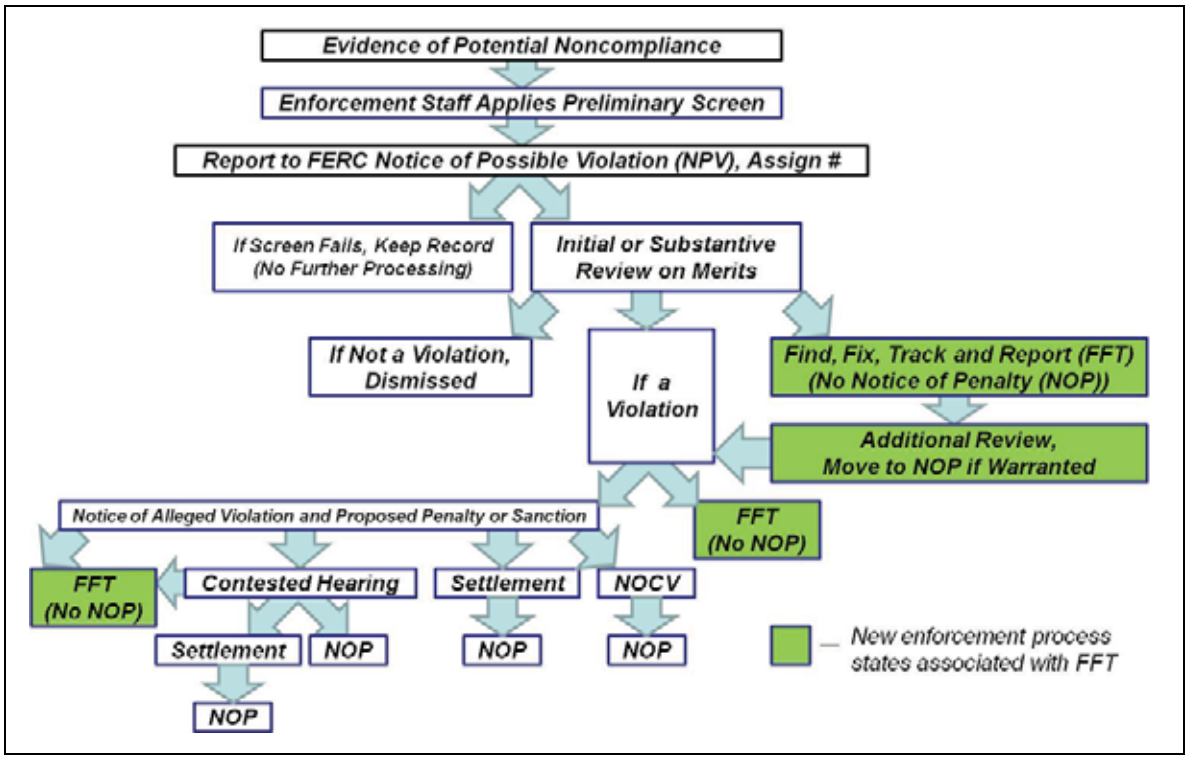

Figure 6: New Enforcement Process incorporating the Find, Fix, Track, and Report (FFT) Approach.

Following NERC's filing[67] of the CEI on September 30, 2011, there will be three possible tracks, see Figure 6, for dealing with compliance matters: Dismissal; Find, Fix, Track and Report (FFT); and Notice of Penalty (NOP). Dismissals occur where there are no violations, when the entity is not registered for and/or subject to a particular requirement, or where there are duplicate entries of issues. No changes are being made with respect to dismissals.

The FFT is the new portion of the compliance initiative. This process will apply when a Possible Violation poses a lesser (minimal to moderate) risk to bulk power system reliability. All matters identified via FFT or NOP must be fixed; the registered entity must provide a statement of completion and completion of mitigation activities is subject to verification by the Regional Entity as part of an audit, spot check or random sampling. The issue must be fixed prior to inclusion in a report to FERC. A Possible Violation processed through the FFT track becomes a remediated issue once included in an FFT informational filing and such filing concludes processing of that matter by Regional Entities and NERC. No penalties or sanctions will be applied to FFT issues. These remediated issues will be included as part of a registered entity's compliance history and will be taken into account in future actions as appropriate. Mitigation activities must be described in the FFT spreadsheet; however, a formal mitigation plan will not be required.

For those matters that pose a more serious risk to reliability of the bulk power system, NOPs will be filed. They may be filed either in a spreadsheet format or a full NOP format.

Regions will review current cases and determine which disposition approach will be used based on the issue. Training of compliance and enforcement staff will take place as part of Phase I, which is targeted to occur over a 12-18 month period after the initial kickoff of the CEI at the end of September 2011. During Phase I, compliance staff may make recommendations to enforcement staff for ultimate disposition of an issue as part of an FFT or NOP. In Phase II, both compliance and enforcement staff may determine the ultimate disposition of an issue.

Almost 70 percent of violations are a result of four compliance monitoring methods (self-report, self-certification, data-submittal and exception-reporting) that provide self-identified possible violation reporting by a registered entity. NERC encourages registered entities to include a full factual description of the issue, detailed information regarding mitigation activities, identification of the potential and actual risk posed as well as mitigating factors in effect while a Possible Violation is awaiting a determination of which processing track it will be treated with. This will help illustrate that the registered entity understands the full scope of the violation and has taken actions to correct it and prevent recurrence.

[67] *See* North American Electric Reliability Corporation, "Petition Requesting Approval of New Enforcement Mechanisms and Submittal of Initial Informational Filing Regarding NERC's Efforts to Refocus Implementation of its Compliance Monitoring and Enforcement Program": http://www.nerc.com/files/FinalFiled_CEI_Document_20110930.pdf

NERC will continue to compile trend data and keep historical records on registered entities, which will allow NERC to target areas for increased education as needed. Registered entities are expected to provide information that is sufficient, complete and validated to support the issues identified for FFT or NOP treatment.

The CEI, featuring the FFT approach to lesser risk remediated issues, is a paradigm shift in how issues are processed, not whether they are addressed. In all cases, they must be found, fixed and tracked. The CEI reflects a risk-based approach that acknowledges all Possible Violations are not equal and should not be treated as such. By focusing resources on violations that have a serious risk to the reliability of the bulk power system, NERC is able to better fulfill its mission as the ERO.

Events Analysis Interface with Compliance

Beginning in May, 2011, NERC has initiated a second phase of the Events Analysis field test, which is described in the *Electric Reliability Organization Event Analysis Process*.[68] As explained in this process, registered entities are expected to perform a thorough compliance analysis and to develop a compliance self-assessment report proportional to the severity of the event/risk to the BPS for categorized events in which there could be a gap between actual system or human performance and the requirements of NERC or regional reliability standards. Compliance self-assessment reports are encouraged for all events in Category 1 and above and are requested to be submitted to the Regional Entity compliance liaison for Category 2 and above. Compliance self-assessments should include:

- A list of all applicable NERC or Regional Reliability Standards and/or specific requirements potentially implicated by the event
- A written narrative/conclusion by the registered entity that compliance to the implicated reliability standards occurred
- A self-report of any possible violations through the existing Compliance Monitoring and Enforcement Program procedures associated with said event(s), with notification that they were discovered as a result of participating in the ERO event analysis program and completing the compliance self-assessment

To facilitate the development of a rigorous self-assessment, NERC Events Analysis has developed the Compliance Analysis Template, which is found in Appendix G of its process.[69] Additionally, this Compliance Analysis Template is attached below as Appendix 5.

[68] *See* http://www.nerc.com/page.php?cid=5|365
[69] *See* page 35, Appendix G, "Electric Reliability Organization Event Analysis Process": http://www.nerc.com/files/2011-05-02%20Event_Analysis_Process_Phase%202%20Field%20Test%20Draft%20-%20Final%20-%20For%20posting.pdf

Regional Entities CMEP Implementation Plans

The Regional Entities Implementation Plan is an annual plan, submitted to NERC no later than October 1 of each year for approval that, in accordance with NERC RoP Section 401.6 and the NERC CMEP Implementation Plan, identifies:

1. All Reliability Standards identified by NERC in the 2012 CMEP Actively Monitored Reliability Standards list.
2. Other Reliability Standards proposed for monitoring by the Regional Entity; these will include any regional Reliability Standards and additional NERC Reliability Standards.
3. The methods to be used by the Regional Entity for reporting, monitoring, evaluation, and assessment of performance criteria with each Reliability Standard. NERC expects at a minimum for the Regional Entities to perform the compliance monitoring methods identified in the NERC 2012 Actively Monitored Reliability Standards list. When a Regional Entity determines that an increased audit scope is necessary, then the Regional Entity shall notify the registered entity of the increased audit scope. This notification shall be part of the audit notification package and shall include the Reliability Standards and Requirements that are included in the increased scope, as well as the justification for the increased scope. When a Regional Entity determines that an increased audit scope is necessary after the notification package is sent, or while the audit team is on-site, then the Regional Entity shall notify the registered entity of the increased audit scope as soon as possible. For references to NERC guidance or Implementation Plans such as the CIP Guidance, a link should be included in the Regional Entity Implementation Plan instead of listing the entire document.
4. The Regional Entity's Annual Implementation Plan should include a list of registered entity names that are on the 2012 schedule, NERC Compliance Registration ID, and the year they will be audited. The Regional Entity can provide its audit plan for multiple years in the future.
5. The Regional Entity's Annual Plan should address Key CMEP Activities and Initiatives.

Conclusion

The ERO CMEP Implementation Plan, which is developed according to Section 215(c) of the Federal Power Act, is the operating plan for annual compliance monitoring and enforcement activities. NERC, as the international ERO, and the Regional Entities through their delegation agreements with NERC, monitor and enforce compliance of registered entities with all regulatory approved Reliability Standards. Registered entities include all BPS owners, operators and users.

While the actions of the ERO in accordance with the CMEP are critical to the reliability of the BPS, it is only one part of an overall plan to ensure system reliability. The other part consists of the actions of the registered entities and the electric power industry at large, and these are equally as critical to system reliability. The registered entities must participate in the educational, informational and developmental efforts that are being undertaken not only to maintain reliability, but to enhance it as well. The sharing of the industry's technical expertise, experience, and judgment as well as its participation in the ERO's processes will help to further identify and remove reliability gaps and shortcomings. The ERO continuously seeks to improve the execution of its role in ensuring system reliability, as is the case with the advancements of the annual CMEP Implementation Plan undertaken for 2012, but the industry must continue to participate for the overall reliability plan to be successful.

REVISION NUMBER	DATE	NATURE OF CHANGE	REVIEWER	APPROVAL
0	5/5/2011	Original Development	Jacki Power Craig Struck Kyle Howells Jodi Ernst	Michael Moon
0.1	6/3/11	Incorporated appropriate comments from NERC staff.	Jacki Power Craig Struck Kyle Howells	Michael Moon
0.2	6/25/11	Incorporated appropriate comments from FERC, Compliance and Certification Committee, and Regional Entities.	Jacki Power Craig Struck Kyle Howells	Michael Moon
0.3	6/30/11	Final review for content and formatting. Changed from Draft document to working document.	Jacki Power Craig Struck Kyle Howells Caroline Clouse	Michael Moon
0.4	7/5/11	Added references to Regional Entity input into AML and Implementation Plan on pages 6, 11, 12, and 16.	Craig Struck	Michael Moon
0.5	7/12/11	Incorporated appropriate comments from the NERC Board of Trustees Compliance Committee.	Craig Struck Kyle Howells Jodi Ernst	Michael Moon
0.6	8/1/11	Original posting. Editorial corrections made to Figure 5, Compliance Processes, on page 36.	Craig Struck	Michael Moon
0.7	8/25/11	Revised posting. Updates to Table 6 and Appendix 2 to reflect minor revisions to the 2012 AML as well as minor editorial corrections to the Implementation Plan	Kyle Howells	Michael Moon
1.0	10/19/11	Revised posting. Incorporated a description of the Compliance Enforcement Initiative as well as the Events Analysis Interface with Compliance. Updated the basis for NUC-001 inclusion into the 2012 AML.	Kyle Howells	Michael Moon

Appendix 1 – 2012 ERO High-Risk Priorities with High Value Associated Reliability Standards

The ERO high-risk priorities are those current issues challenging the BPS. These issues have been identified through the analysis of significant events on the BPS, such as the August 2003 blackout, and the execution of compliance actions in addition to input provided by numerous groups, including the Regional Entities, NERC's CEO, and many other industry stakeholders. Additionally, recent events within North America have highlighted several areas of importance within the BPS, and the lessons learned and circumstances surrounding these events have been taken into account as well. Therefore, the high-risk priorities are as follows:

1. **Misoperations of relay protection and control systems** – Nearly all major system failures, excluding perhaps those caused by severe weather, have misoperations of relays or automatic controls as a factor contributing to the propagation of the failure. Protection systems are designed to operate reliably when needed under the presence of a fault on the system, to quickly isolate a piece of equipment or a 'zone' of the BPS, without allowing the fault to transfer into adjoining facilities. The greater the number of facilities involved in an event, the more severe the impact to the rest of the BPS, with cascading failure such as the "Zone 3 Relay" issue in the August 2003 blackout being the extreme. Relays can misoperate, either operate when not needed or fail to operate when needed, for a number of reasons. First, the device could experience an internal failure – but this is rare. Most commonly, relays fail to operate correctly due to incorrect settings, improper coordination (of timing and set points) with other devices, ineffective maintenance and testing, or failure of communications channels or power supplies. Preventable errors can be introduced by field personnel and their supervisors or more programmatically by the organization. Adding to the risk is that system protection is an extremely complex engineering field – there are many practitioners but few masters.

2. **Human errors by field personnel** – Field personnel play an important role in the maintenance and operation of the BPS. They often switch equipment in and out of service and align alternative configurations. Risks can be introduced when field personnel operate equipment in a manner that reduces the redundancy of the BPS, sometimes even creating single points of failure that would not exist normally. Taking outages of equipment to conduct maintenance is a routine and necessary part of reliable BPS operation. However, any alterations to the configuration of the network must be carefully planned in advance to minimize loss of redundancy and avoid unintended single points of failure. It is also important that such changes and risks be communicated to system operators and reliability coordinators in advance, so that they can make adjustments in their operating plans and reliability assessments.

3. **Ambiguous or incomplete voice communications** – Out of longstanding tradition, system operators and reliability coordinators are comfortable with informal communications with field and power plant personnel and neighboring systems. Experience from analyzing various events indicates there is often a sense of awkwardness when personnel transition from conversational discussion to issuing reliability instructions. It is also human nature to be uncomfortable in applying formal communication procedures after personnel have developed informal styles over many years. Confusion in making the transition from normal conversation to formal communications can introduce misunderstandings and possibly even incorrect actions or assumptions. Further, once the need to transition to more formal structure is recognized, the transition is often not complete or effective. Results can include unclear instructions, confusion as to whether an instruction is a suggestion or a directive, whether specific action is required or a set of alternative actions are permissible, and confusion over what elements of the system are being addressed.

4. **Right-of-way maintenance** – The August 14, 2003 blackout highlighted effective vegetation management programs as a key recommendation for avoiding future cascading failures. More broadly, any encroachments in the right-of-way that reduce clearances to the point of lowering facility ratings or reducing the randomness of possible contacts can be a risk to reliability. Although these impacts may not always be readily apparent, under extreme wind and temperature conditions they may become more of a risk to BPS reliability. There are many challenges to effective right-of-way maintenance, especially maintaining proper clearances, including interventions by private landowners, local municipalities, and federal and state landowners.

5. **Changing resource mix** – Energy and environmental policies along with energy markets are driving proposals toward unprecedented changes in the resource mix of the BPS. Examples include integration of significant amounts of renewable energy (variable such as wind and solar), natural gas, storage and demand resources to provide energy and capacity. Industry's knowledge of the characteristics of the BPS comes from nearly a century of operational experience with the existing resource mix. However, integration of these new resources results in operating characteristics significantly different from conventional steam production facilities. An array of reliability services must be provided over a range of time horizons from seconds to minutes to hours and days, and annually such as load following, contingency reserves, frequency response, reactive supply, capacity and voltage control, and power system stability. Continued reliable operation of the BPS will require an industry dialog with policymakers and regulators. Understanding the impacts on reliability will depend on accurate modeling of new resources, and development of new methods and tools for the provision of essential reliability services.

6. **Integration of new technologies** – While the electric utility industry was once thought to be slow in adopting new technologies, smart grid initiatives across the country have proven this not be the case as of late. To continue this proactive trend of incorporating new technologies as well as to ensure proper coordination, a number of Reliability Standards should be considered in order to make this priority possible. Introduction of electric vehicles, demand-side management, variable generation, distributed resources and smart grid technologies presents tremendous opportunities but also introduces changes to the operating characteristics of the BPS. Integration of these new technologies requires changes in the way the BPS is planned and operated to maintain reliability. Further, additional tools/models are required to support their integration to meet policy and strategic goals. Without these changes, it will be challenging to maintain reliability with large-scale deployments. For example, some smart grid devices/systems increase exposure to cyber threats, while variable generation requires additional ancillary services. Integration of these new technologies must be achieved in a manner that does not undermine existing levels of stability, resilience and security of the BPS.

7. **Preparedness for -impact, low-frequency events** – Although there is a wide range of threats labeled "high-impact, low-frequency," the greatest concern is being prepared for possible events that could debilitate the BPS for extended periods, such as widespread, coordinated physical/cyber attacks or geomagnetic storms. The industry must consider improving the design of the BPS to address these potential risks, prepare coordinated North American response plans for use during catastrophic events, and be ready to deploy those plans to restore essential services in a timely manner.

8. **Non-traditional threats via cyber-security vulnerabilities –** Establishment of enterprise risk-based programs, policies and processes to prepare for, react to, and recover from cyber-security vulnerabilities is a high priority for the industry. The BPS has not yet experienced wide-spread cyber-attacks, and a contributing factor has been the traditional physical separation between the industrial control system/SCADA environment and the business and administrative networks. This situation, however, is rapidly changing, predominantly due to the efficiencies that can be achieved by leveraging shared networks and resources, so now even physically separated environments are susceptible. For example, the BPS could be as vulnerable to digital threats as IT systems, but with far more critical implications, as the recent Stuxnet virus has shown. Disabling or turning systems off in a binary fashion is concerning enough, but as illustrated by Stuxnet, industrial control system software can be changed and data can be stolen without intrusions even being detected. These injection vectors serve as a blueprint for future attackers who wish to access controllers, safety systems, and protection devices to insert malicious code-targeting changes to set points and switches as well as alteration or suppression of measurements.

9. **Other**
   Certain considerations that have potentially high impacts to reliability do not fit cleanly into other categories. Such considerations include the Frequency Response Initiative and Winter Weather Events from the Southwest and Texas in February of 2011. The Reliability Standards relating to these considerations, especially those corresponding to emergency procedures, are important in terms of enacting lessons learned and preventing detrimental conditions in the future.

NERC has identified a number of Reliability Standards associated with each of the ERO high-risk priorities. These associated Reliability Standards have a high value in that they most directly address the concerns raised by the high-risk priorities. The relationships of these high-value Reliability Standards to the high-risk priorities are laid out in the list below.

1. Ambiguous, Incomplete Voice Communications
    - COM-002
    - EOP-002
    - EOP-005
    - EOP-006
    - EOP-008
    - IRO-002
    - IRO-006
    - TOP-002

2. Mis-Operations of Relay and Controls Systems
    - EOP-005
    - EOP-008
    - FAC-001
    - PRC-001
    - PRC-004
    - PRC-005
    - PRC-023
    - TPL-003
    - TPL-004

3. Human Errors by Field Personnel
    - COM-002
    - EOP-005
    - EOP-008
    - FAC-003
    - PER-002

4. High-Priority CIP and Supporting Standards
    - CIP-001
    - CIP-002
    - CIP-005
    - CIP-006
    - CIP-007
    - COM-001
    - COM-002
    - EOP-005
    - EOP-008

5. Right-of-Way Maintenance and Clearances
    - FAC-003
    - FAC-008
    - FAC-009
    - TOP-002
    - TPL-003
    - TPL-004

6. Changing Resource Mix
    - EOP-001
    - EOP-005
    - EOP-002
    - IRO-002
    - TOP-002

7. High-Impact, Low-Frequency Events
    - EOP-003
    - EOP-005
    - EOP-008
    - IRO-004
    - IRO-005
    - NUC-001
    - TOP-004
    - TOP-007

8. Other
    - Frequency response initiative
        - BAL-003
    - Winter Weather Events (Texas, February 2011)
        - BAL-002
        - EOP-001
        - EOP-002
        - EOP-004
        - EOP-005

9. Integration of New Technologies
    - COM-001
    - FAC-001
    - FAC-002
    - FAC-009
    - IRO-002
    - PRC-001

Appendix 2 – 2012 Actively Monitored List (AML) Analysis

As with the Reliability Standards selected for audit in 2012, the Reliability Standards selected for annual self-certification in 2012 represent the results of a risk-based approach. Due to the breadth of the AML, it can be helpful to perform targeted analysis in order to corroborate that the ERO priorities are being properly addressed. As a synopsis of the AML, Table 8 shows a breakdown of the applicable requirements within the AML for 2012 and in years past. The average number of Requirements per function for 2012 has been reduced substantially from previous years. In fact, since the CIPs have been incorporated into the AML in 2010, the average number of Requirements by function has been reduced to half of its maximum; there were an average of 167 Requirements to be audited per function in 2010 while there are 84 in 2012.

Table 8: Requirements Analysis for the 2012 AML and those going back to 2007

	Requirements Analysis								
Function	Total Applicable Reqs as of 1/1/2012	2012 AML (All Reqs)	2012 AML (CIP only)	2012 AML (693 only)	2011	2010	2009	2008	2007
TOP	499	170	109	61	246	321	134	142	115
RC	397	136	109	27	203	299	97	131	76
BA	408	155	109	46	206	305	107	175	95
TO	369	134	107	27	222	271	70	86	86
GO	302	119	107	12	198	242	34	47	40
GOP	254	121	109	12	168	242	27	38	13
TSP	318	166	107	59	202	206	5	7	2
RSG	20	2	0	2	0	6	6	20	20
PA/PC	178	6	0	6	42	88	56	89	86
TP	143	13	0	13	49	83	51	86	86
IA	184	107	107	0	145	168	0	0	0
RP	22	3	0	3	3	0	0	0	0
LSE	267	123	109	14	157	214	12	26	13
PSE	11	1	0	1	1	3	3	4	3
DP	129	9	0	9	51	54	21	51	51
Avg Reqs	233	84	65	19	126	167	42	60	46

When looking at the total number of in-effect Requirements as of January 1, 2012 within the 2012 AML as applicable by function, there is a strong correlation between the potential reliability impact of a function and the proportion of its applicable Requirements that are represented on the 2012 AML. For instance, the Reliability Coordinator, Balancing Authority, and Transmission Operator certified functions, all have over 30% of their applicable Requirements on the AML. For other functions, such as the Purchasing-Selling Entity (PSE) or Distribution Provider (DP), a much smaller proportion of their Reliability Standards is incorporated. These results are shown in Table 9.

In some cases, such as the TSP, Generator Operator (GOP), Interchange Authority (IA), and Load-Serving Entity (LSE), there is perhaps an unexpectedly high percentage of applicable Reliability Standards within the 2012 AML. The TSP has a large number due to the inclusion by FERC Order 729 of MOD-001, MOD-004, and MOD-008, which alone count for 76 Requirements. The GOP, IA, and LSE functions have a large proportion of Requirements due to

CIP. Looking at Table 10, which is similar to Table 9 but accounts only for 693 Reliability Standards, the GOP, IA, and LSE functions are shown to have 15%, 0%, and 15% of applicable 693 Requirements within the 2012 AML respectively, which are much more reasonable numbers.

Table 9: Percent of total in effect Requirements as of 1/1/2012 represented in the 2012 AML

	Requirements Analysis		
Function	Total Applicable Reqs as of 1/1/2012	2012 (All Reqs)	% of Total
TOP	499	170	34%
RC	397	136	34%
BA	408	155	38%
TO	369	134	36%
GO	302	119	39%
GOP	254	121	48%
TSP	318	166	52%
RSG	20	2	10%
PA/PC	178	6	3%
TP	143	13	9%
IA	184	107	58%
RP	22	3	14%
LSE	267	123	46%
PSE	11	1	9%
DP	129	9	7%

Table 10: Percent of total in effect 693 Requirements as of 1/1/2012 represented in the 2012 AML

	Requirements Analysis		
Function	Total Applicable 693 Reqs as of 1/1/2012	2012 (693 Reqs)	% of Total
TOP	327	61	19%
RC	225	27	12%
BA	236	46	19%
TO	201	27	13%
GO	134	12	9%
GOP	82	12	15%
TSP	150	59	39%
RSG	20	2	10%
PA/PC	178	6	3%
TP	143	13	9%
IA	16	0	0%
RP	22	3	14%
LSE	95	14	15%
PSE	11	1	9%
DP	129	9	7%

Table 11 shows that only 29.72% of all Requirements within the three tier structure are included in the 2012 AML, which is represented by Tier 1 Requirements.

Table 11: Requirement counts by Tier

2012 AML - Tier 1	Tier 2	Tier 3
274	397	251

The following figures, Figure 6 and 7, display the information discussed already, but provides it in a different format for ease of comparison. Figure 6 displays the number of AML Requirements by registered function across all years of mandatory compliance in addition to the total number of applicable Requirements as of January 1, 2012. Figure 7 shows the same information, but only for the 2012 AML and the total number of applicable Requirements as of January 1, 2012.

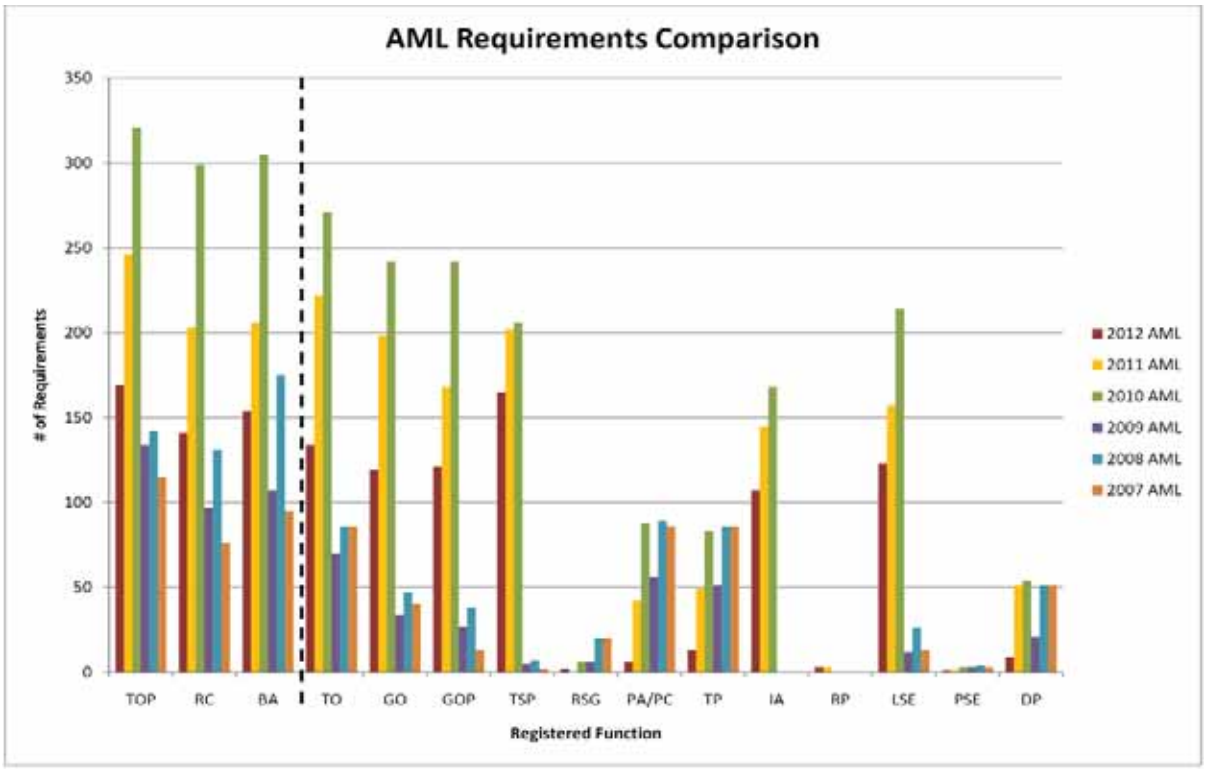

Figure 6: Number of applicable Requirements to each function within a given year's AML and for all Requirements currently in effect.

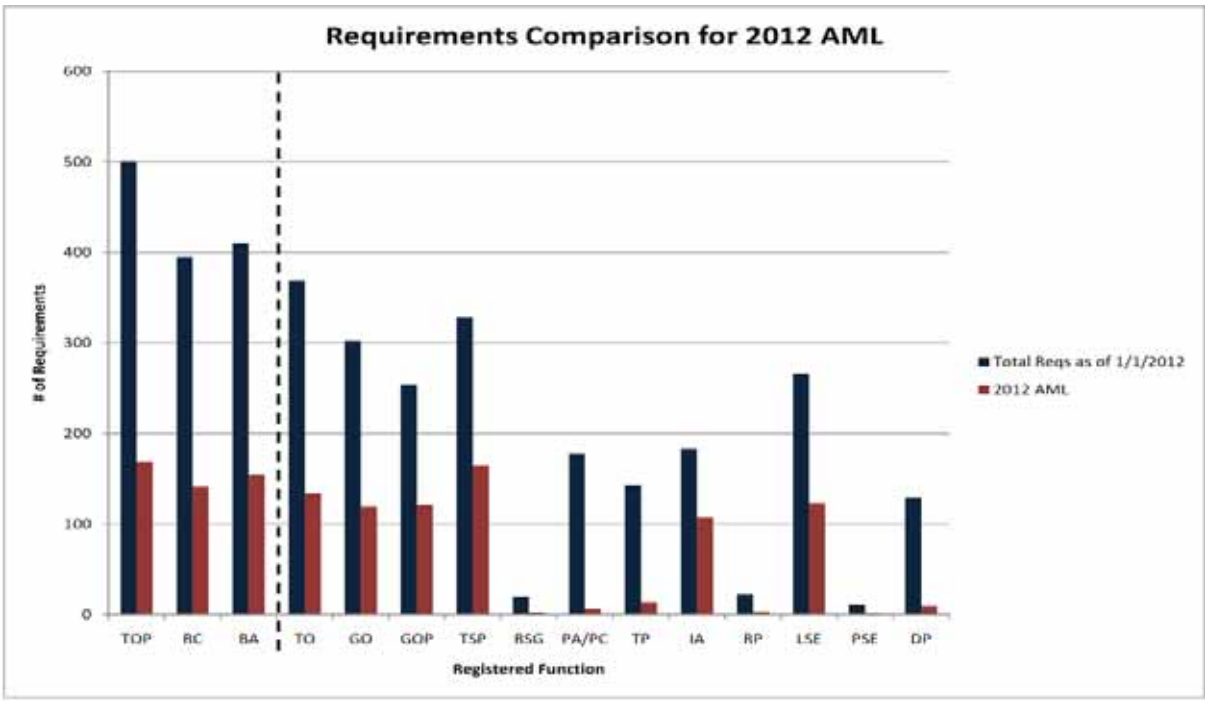

Figure 7: Direct comparison of Requirements in the 2012 AML as compared to all in effect Requirements as of 1/1/2012.

Appendix 3 – 2012 Regional Entity Request to Defer or Reduce the Scope of a Compliance Audit

Request to Reduce Scope or Deferment of a Compliance Audit
This form should be submitted as both a Word and PDF file to NERC Compliance Operations at least 90 days prior to the audit for approval. Email forms to Jacki.Power@nerc.net and Stacia-Ann.Chambers@nerc.net

Requesting Regional Entity Information

Date:	
Name:	
Title:	
Region:	
State the basis for Reduced Audit Scope or Deferment of Compliance Audit:	
State other methods used for compliance monitoring during period of reduced scope or deferment?	
State requested duration of deferment, if applicable.	
State whether this is a MRRE audit?	
Applicable Region(s):	FRCC ☐ MRO ☐ NPCC ☐ RFC ☐ SERC ☐ SPP ☐ TRE ☐ WECC ☐

Registered Entity Information

Registered Entity's Legal Name:	
NCR ID Number:	
Date of Last Compliance Audit:	
Date of Next Compliance Audit:	

Regional Entity's Additional Information

Comments:	

Regional Entity Authorized Signature

ERO Analysis Results

State information reviewed and basis for determination	

ERO Final Determination

Approved: ☐ Declined: ☐

ERO, Director of Compliance Operations

Appendix 4 – 2012 CMEP Implementation Plan Survey

Questions to the Regional Entities concerning the 2012 CMEP Implementation Plan

Instructions: Each Regional Entity shall complete the 2012 CMEP Implementation Plan Survey and provide it to NERC no later than January 31, 2013. This feedback is needed as soon as possible, as it will be used as input into the 2014 CMEP Implementation Plan and 2014 budget development.

I. Compliance Monitoring

1. Please provide statistics on the number and types of compliance audits conducted (Please separate CIP from Order 693 audits)
    a. Were all planned audits completed?
        i. If not, please indicate the reasons.
    b. How many compliance audit reports were completed in 2012?
        i. For the 693 compliance audit reports, did you complete them within the CMEP suggested timeframe of 60 days?
        ii. If not, what challenges did you face for completing compliance audit reports?
2. Please provide statistics on the other methods used by the Regional Entity for reporting, monitoring, evaluation, and assessment of performance criteria with each Reliability Standard as indicated by your annual Implementation Plan (Please separate CIP from Order 693).
    a. Were all mandatory Spot Checks completed?
3. Please provide a status of your three-year and six- year Compliance Audit program plan. Is your Regional Entity compliance audit program on schedule?
4. What actions did you take to address the Outstanding Issues list that NERC issues each month?
5. Do you have processes in place to monitor the progress of settlement negotiations to make sure they are progressing well?

II. Compliance Outreach

6. Please provide statistics on your Regional Compliance Workshop.
    a. How many workshops?
    b. Number of participants?
    c. What feedback was received from the workshops?
    d. What should be added to the workshops?
7. Describe any other communication mediums used to promote the consistency and transparency of the NERC Compliance Program for 2012?
    a. How successful were your consistency and transparency efforts?

b. What improvements are planned for 2013?

III. Compliance Enforcement

8. Please describe any efforts you have undertaken to improve the efficiency of your compliance enforcement process.
    a. Utilization of NERC's streamlined enforcement templates (disposition documents, settlement templates)
    b. Participation in the administrative citation program
    c. Staffing and other initiatives to improve efficiency
10. Please describe any efforts you have undertaken to improve mitigation of Reliability Standards violations.
    a. Encouragement of prompt submission of mitigation plans
    b. Monitoring of mitigation plan completion and encouragement of early mitigation plan completion
11. What has been your experience with the effectiveness of penalty and sanctions levied to incite compliance and eliminate repeat offenders?
12. What has been your experience in moving violations back into the Notice of Confirmed Violation and Proposed Penalty or Sanction (NOCV) process by ceasing negotiations and issuing a Notice of Alleged Violation and Proposed Penalty or Sanction (NAVAPS)?

IV. Program Effectiveness

13. Describe any general observations, best practices, lessons learned, and trends for the Regional Entities as well as registered entities.
14. Describe any significant changes (e.g. process, communication changes) from the 2011 program that were implemented in your 2012 Regional Compliance Program.
    a. What were the positive and/or negative experiences associated with these changes, if any?
15. Discuss any significant challenges encountered in 2012, describe the action taken, or suggest potential remedial actions.

V. Events Analysis and Compliance Reviews

16. How many events analyses were conducted in 2012 within your region?

VI. Projection for the Future

17. What changes would you propose to reduce the 2013 Actively Monitored List? How would you revise the risk-based criteria?
18. Do you have any specific recommendations for the NERC Compliance Monitoring and Enforcement Program that you would like to include in the NERC annual report this year?
19. How do you plan to address the "risk-based" approach in your auditing program?
20. What type of budget issues did you face in implementation of the 2012 CMEP? Are there any budgetary issues that need to be addressed for 2013

Appendix 5 – Events Analysis Process Appendix G - Compliance Assessment Template

Events Analysis Process Appendix G - Compliance Assessment Template

The registered entity's compliance function is expected to perform an initial compliance assessment, concurrent with the registered entity's event analysis process.

A systematic, methodical compliance assessment process might include the following steps:

1. Refer to the causes and contributing factors of the event as determined by the registered entity's event analysis process.
2. Identify any applicable Reliability Standards requirement that may have been implicated by the causes and contributing factors of the event.
3. Develop conclusions after reviewing the facts and circumstances of the event that are relevant to step 2 above as they apply to the applicable Reliability Standards requirements.
4. Self-report any findings of non-compliance to the Regional Entity per the CMEP procedures.

Sample Template for Compliance Assessment Summary

Event causes or contributing factors	**Applicable NERC Reliability Standards**	**Details of Compliance Assessment Effort**	**Findings**
Cause	AAA-000-0 Requirement 1	Identify the process used to assess compliance with this requirement. Identify any evidence that demonstrates compliance. Identify any evidence that suggests non-compliance.	Findings of possible violations should be identified. If there are no findings of non-compliance, that should be noted.
	AAA-000-0 Requirement 2		
Contributing factor	BBB-000-0 Requirement 1		

Category 1a Example

Event causes or contributing factors	Applicable NERC Reliability Standards	Details of Compliance Assessment Effort	Findings*
Equipment failure of a high side transformer– cleared along with two transmission lines.	**TOP-002-2a** **R6.** Each BA and TOP shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, sub-regional and local reliability requirements.	Established transfer limits were followed such that the event did not result in instability. The limit for operating across this internal interface is established in the RC. "XYZ Interface All Lines In Stability Guide" (document provided)	No findings of non-compliance.*
Equipment failure of a high side transformer– cleared along with two transmission lines.	**TOP-002-2a** **R10.** Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).	No SOLs were violated. There are no IROLs associated with the loss of equipment in this event. See the specific guide referenced in the response to **TOP-002-2a R6**.	No findings of non-compliance.*
Equipment failure of a high side transformer– cleared along with two transmission lines.	**TOP-004-2** **R1.** Each TOP shall operate within the IROLs and SOLs. **R2.** Each TOP shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.	The system was operated to remain within transfer limits across the "XYZ" internal interface established as a result of stability studies as delineated in the Transmission Operating Guide developed by RC. See the specific guide referenced in the response to **TOP-002-2a R6**.	No findings of non-compliance*
Equipment failure of a high side transformer– cleared along with two transmission lines.	**PRC-001** **R1.** Each TOP, BA and GOP shall be familiar with the purpose and limitations of protection system schemes applied in its area.	Both the RC and the TOPs are trained on the Transmission Operating Guides as well as relaying and SPSs on the BPS. Protection operated correctly and as planned.	No findings of non-compliance*
Equipment failure of a high side transformer– cleared along with two transmission lines.	**PRC-004** **R1.** The TOP and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.	System Protection engineers evaluated the relay operations and determined that all relaying operated correctly and as planned.	No findings of non-compliance*
Equipment failure of a high side transformer– cleared	**TOP-008** **R1.** The TOP experiencing or contributing to an IROL or SOL	R1 Operators used their EMS-based tools to ensure that there were no	No findings of non-compliance*

along with two transmission lines.	violation shall take immediate steps to relieve the condition, which may include shedding firm load. **R2.** Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the TOP shall always operate the BPS to the most limiting parameter. **R3.** The TOP shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the TOP shall notify its RC and all neighboring TOPs impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter. **R4.** The TOP shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The TOP shall use the results of these analyses to immediately mitigate the SOL violation.	SOL/IROL violations. R2 by following the TOP Guides developed by RC, violations do not occur. R3 no conditions occurred that required disconnection. R4 Operators used their EMS-based tools to ensure that there were no SOL/IROL violations.	
Equipment failure of a high side transformer– cleared along with two transmission lines.	**TOP-006** **R2.** Each RC, TOP and BA shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources. **R5** Each RC, TOP and BA shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.	The EMSs at both the RC and the TOP provide operators with the information needed to evaluate system conditions and notify operators when conditions are off normal. EMS system visibility and communications were not lost during this event.	No findings of non-compliance*

			*Findings as the outcome of a compliance self-assessment will result in either a statement of "No Findings" or that of "Possible Violation (PV)." Should the latter be the result, the entity will be given the opportunity to self-report the PV to the Regional Compliance Enforcement department, in accordance with the existing procedures set forth in the CMEP. In doing so, the entity self-reporting should inform the Regional Compliance Enforcement department that this has been done consistent with the event analysis process and the completion of a compliance self-assessment (**Appendix G**) to obtain the credit prescribed.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Number of Reliability Standards						
Year	2007	2008	2009	2010	2011	2012
Compliance Audit	39	60	49	56	39	36
Self-Certification	39	60	52	60	53	36
Periodic Data Submittals	--	--	12	13	14	14
Exception Reporting	--	--	14	19	13	13
Spot Check	0	0	13	19	1	0
Subject to Compliance Violation Investigation	--	--	94	95	102	107
Subject to Self-Reporting	--	--	94	95	102	107
Subject to Complaint	--	--	94	95	102	107

2012 CMEP Reliability Standards Summary			
Reliability Standards (FERC Approved)	Self-Certification Annual (A)	Annual Program Audit - Tier 1 (X)	Spot Check (SC)
BAL-001-0.1a			
BAL-002-0 (BAL-002-1 Effective 04/01/2012)		X	
BAL-003-0.1b			
BAL-004-0			
BAL-005-0.1b			
BAL-006-2			
CIP-001-2a	A	X	
CIP-002-3	A	X	
CIP-003-3	A	X	
CIP-004-3	A		
CIP-005-3a	A	X	
CIP-006-3c	A	X	
CIP-007-3	A	X	
CIP-008-3	A	X	
CIP-009-3	A	X	
COM-001-1.1	A	X	
COM-002-2	A	X	

EOP-001-0	A	X	
EOP-002-3	A	X	
EOP-003-1			
EOP-004-1		X	
EOP-005-1	A	X	
EOP-006-1		X	
EOP-008-0	A	X	
EOP-009-0			
FAC-001-0		X	
FAC-002-1		X	
FAC-003-1	A	X	
FAC-008-1	A		
FAC-009-1	A	X	
FAC-010-2.1			
FAC-011-2			
FAC-013-1			
FAC-014-2	A		
INT-001-3			
INT-003-3			
INT-004-2			
INT-005-3			
INT-006-3			
INT-007-1			
INT-008-3			
INT-009-1			
INT-010-1			
IRO-001-1.1			
IRO-002-2		X	
IRO-003-2			
IRO-004-2	A	X	
IRO-005-3a	A	X	
IRO-006-5			
IRO-006-EAST-1			
IRO-006-WECC-1			
IRO-008-1			
IRO-009-1			
IRO-010-1			
IRO-014-1			
IRO-015-1			
IRO-016-1			
MOD-001-1a	A	X	
MOD-004-1	A	X	

MOD-008-1	A	X	
MOD-010-0			
MOD-012-0			
MOD-016-1.1			
MOD-017-0.1			
MOD-018-0			
MOD-019-0.1			
MOD-020-0			
MOD-021-1			
MOD-028-1			
MOD-029-1a			
MOD-030-2			
NUC-001-2		X	
PER-001-0.1			
PER-002-0	A	X	
PER-003-0			
PER-004-1			
PER-004-2			
PER-005-1			
PRC-001-1	A	X	
PRC-004-1 (PRC-004-2 Effective 4/1/2012)	A		
PRC-005-1	A	X	
PRC-007-0			
PRC-008-0	A		
PRC-009-0			
PRC-010-0			
PRC-011-0	A		
PRC-015-0			
PRC-016-0.1			
PRC-017-0	A		
PRC-018-1			
PRC-021-1			
PRC-022-1			
PRC-023-1	A		
TOP-001-1			
TOP-002-2a	A	X	
TOP-003-1			
TOP-004-2	A	X	
TOP-005-2a			
TOP-006-2			
TOP-007-0		X	
TOP-008-1			

TPL-001-0.1			
TPL-002-0a			
TPL-003-0a		X	
TPL-004-0		X	
VAR-001-2	A		
VAR-002-1.1b	A		

Note: The Reliability Standards listed for the above monitoring methods does not necessarily imply all requirements are included in the 2011 Reliability Standard Actively Monitored list. Refer to the "Requirements Detail Tab" for specifics concerning each Reliability Standard monitoring details.

Compliance is required with all regulatory authority approved Reliability Standards whether or not included in the subset of reliability standards and requirements designated to be audited in the NERC implementation plan. All requirements are subject to a possible CVI, Self-Report, or Complaint.

Reliability Standard (FERC Approved)	Requirement Number	Supporting Requirement Number	Text of Requirement	Violation Risk Factor	Functions Monitored	2012 Annual Program Audit - 1st Tier	2012 Annual Program Audit - 2nd Tier	2012 Annual Program Audit - 3rd Tier		Self-Cert. Annual (A)	Periodic Data Submittals: Monthly (M), Quarterly (Q), Annual (A)	Exception Reporting (ER)	Spot Check (SC)		2011 Annual Program Audit (X)
			RESOURCE AND DEMAND BALANCING												
BAL-001-0.1a	R1.		Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control	MEDIUM	BA						M				
BAL-001-0.1a	R2.		Each Balancing Authority shall operate such that its average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a	MEDIUM	BA						M				
BAL-001-0.1a	R3.		Each Balancing Authority providing Overlap Regulation Service shall evaluate Requirement R1 (i.e., Control Performance Standard 1 or CPS1) and Requirement R2	LOWER	BA										
BAL-001-0.1a	R4.		Any Balancing Authority receiving Overlap Regulation Service shall not have its control performance evaluated (i.e. from a control performance perspective,	LOWER	BA										
BAL-002-0	R1.		Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied	HIGH	BA, RSG			x			Q				
BAL-002-0		R1.1.	A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such cases, the	HIGH	BA, RSG			x			Q				
BAL-002-0	R2.		Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including:	MEDIUM	RRO, RSG			x			Q				
BAL-002-0		R2.1.	The minimum reserve requirement for the group.	HIGH	RRO, RSG			x			Q				
BAL-002-0		R2.2.	Its allocation among members.	LOWER	RRO, RSG			x			Q				
BAL-002-0		R2.3.	The permissible mix of Operating Reserve - Spinning and Operating Reserve - Supplemental that may be included in Contingency Reserve.	LOWER	RRO, RSG			x			Q				
BAL-002-0		R2.4.	The procedure for applying Contingency Reserve in practice.	LOWER	RRO, RSG			x			Q				
BAL-002-0		R2.5.	The limitations, if any, upon the amount of interruptible load that may be included.	LOWER	RRO, RSG			x			Q				
BAL-002-0		R2.6.	The same portion of resource capacity (e.g., reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by	MEDIUM	RRO, RSG			x			Q				
BAL-002-0	R3.		Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS.	HIGH	BA, RSG	x					Q				
BAL-002-0		R3.1.	As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency. All	HIGH	BA, RSG	x					Q				
BAL-002-0	R4.		A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable	MEDIUM	BA, RSG			x			Q				
BAL-002-0		R4.1.	A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE	MEDIUM	BA, RSG			x			Q				
BAL-002-0		R4.2.	The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an	No VRF Assigned	BA, RSG			x			Q				
BAL-002-0	R5.		Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group	LOWER	RSG			x			Q				
BAL-002-0		R5.1.	The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its	No VRF Assigned	RSG			x			Q				
BAL-002-0		R5.2.	The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its	No VRF Assigned	RSG			x			Q				

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BAL-002-0	R6.		A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period for its Interconnection.	MEDIUM	BA, RSG			x			Q				
BAL-002-0		R6.1.	The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period.	No VRF Assigned	BA, RSG			x			Q				
BAL-002-0		R6.2.	The default Contingency Reserve Restoration Period is 90 minutes. This period may be adjusted to better suit the reliability targets of the Interconnection	No VRF Assigned	BA, RSG			x			Q				
BAL-002-1 (effective 4/1/2012)	R1.		Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied	HIGH	BA, RSG										
BAL-002-1 (effective 4/1/2012)		R1.1.	A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such cases, the	HIGH	BA, RSG										
BAL-002-1 (effective 4/1/2012)	R2.		Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including:	MEDIUM	RRO, RSG										
BAL-002-1 (effective 4/1/2012)		R2.1.	The minimum reserve requirement for the group.	HIGH	RRO, RSG										
BAL-002-1 (effective 4/1/2012)		R2.2.	Its allocation among members.	LOWER	RRO, RSG										
BAL-002-1 (effective 4/1/2012)		R2.3.	The permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve.	LOWER	RRO, RSG										
BAL-002-1 (effective 4/1/2012)		R2.4.	The procedure for applying Contingency Reserve in practice.	LOWER	RRO, RSG										
BAL-002-1 (effective 4/1/2012)		R2.5.	The limitations, if any, upon the amount of interruptible load that may be included.	LOWER	RRO, RSG										
BAL-002-1 (effective 4/1/2012)		R2.6.	The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by	MEDIUM	RRO, RSG										
BAL-002-1 (effective 4/1/2012)	R3.		Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS.	HIGH	BA, RSG										
BAL-002-1 (effective 4/1/2012)		R3.1.	As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency. All	HIGH	BA, RSG										
BAL-002-1 (effective 4/1/2012)	R4.		A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable	MEDIUM	BA, RSG										
BAL-002-1 (effective 4/1/2012)		R4.1.	A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE	MEDIUM	BA, RSG										
BAL-002-1 (effective 4/1/2012)		R4.2.	The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance.	No VRF Assigned	BA, RSG										
BAL-002-1 (effective 4/1/2012)	R5.		Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group	LOWER	RSG										
BAL-002-1 (effective 4/1/2012)		R5.1.	The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its	No VRF Assigned	RSG										
BAL-002-1 (effective 4/1/2012)		R5.2.	The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its	No VRF Assigned	RSG										
BAL-002-1 (effective 4/1/2012)	R6.		A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period for its Interconnection.	MEDIUM	BA, RSG										
BAL-002-1 (effective 4/1/2012)		R6.1.	The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period.	No VRF Assigned	BA, RSG										
BAL-002-1 (effective 4/1/2012)		R6.2.	The default Contingency Reserve Restoration Period is 90 minutes.	No VRF Assigned	BA, RSG										
BAL-003-0.1b	R1.		Each Balancing Authority shall review its Frequency Bias Settings by January 1 of each year and recalculate its setting to reflect any change in the Frequency	LOWER	BA			x							
BAL-003-0.1b		R1.1.	The Balancing Authority may change its Frequency Bias Setting, and the method used to determine the setting, whenever any of the factors used to determine the	LOWER	BA			x							

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BAL-003-0.1b		R1.2.	Each Balancing Authority shall report its Frequency Bias Setting, and method for determining that setting, to the NERC Operating Committee.	LOWER	BA			x			A	ER			
BAL-003-0.1b	R2.		Each Balancing Authority shall establish and maintain a Frequency Bias Setting that is as close as practical to, or greater than, the Balancing Authority's Frequency	MEDIUM	BA		x								
BAL-003-0.1b		R2.1.	The Balancing Authority may use a fixed Frequency Bias value which is based on a fixed, straight-line function of Tie Line deviation versus Frequency Deviation.	LOWER	BA		x								
BAL-003-0.1b		R2.2.	The Balancing Authority may use a variable (linear or non-linear) bias value, which is based on a variable function of Tie Line deviation to Frequency Deviation.	LOWER	BA		x								
BAL-003-0.1b	R3.		Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection reliability. *See Standard for Approved Interpretation of R3 for WECC WATEC Procedure*	MEDIUM	BA			x							
BAL-003-0.1b	R4.		Balancing Authorities that use Dynamic Scheduling or Pseudo-ties for jointly owned units shall reflect their respective share of the unit governor droop	LOWER	BA			x							
BAL-003-0.1b		R4.1.	Fixed schedules for Jointly Owned Units mandate that Balancing Authority (A) that contains the Jointly Owned Unit must incorporate the respective share of the	LOWER	BA			x							
BAL-003-0.1b		R4.2.	The Balancing Authorities that have a fixed schedule (B and C) but do not contain the Jointly Owned Unit shall not include their share of the governor droop	LOWER	BA			x							
BAL-003-0.1b	R5.		Balancing Authorities that serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of the Balancing Authority's estimated	MEDIUM	BA			x							
BAL-003-0.1b		R5.1.	Balancing Authorities that do not serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of its estimated maximum generation level	MEDIUM	BA			x							
BAL-003-0.1b	R6.		A Balancing Authority that is performing Overlap Regulation Service shall increase its Frequency Bias Setting to match the frequency response of the entire area	MEDIUM	BA			x							
BAL-004-0	R1.		Only a Reliability Coordinator shall be eligible to act as Interconnection Time Monitor. A single Reliability Coordinator in each Interconnection shall be	LOWER	RC										
BAL-004-0	R2.		The Interconnection Time Monitor shall monitor Time Error and shall initiate or terminate corrective action orders in accordance with the NAESB Time Error	LOWER	RC										
BAL-004-0	R3.		Each Balancing Authority, when requested, shall participate in a Time Error Correction by one of the following methods:	MEDIUM	BA										
BAL-004-0		R3.1.	The Balancing Authority shall offset its frequency schedule by 0.02 Hertz, leaving the Frequency Bias Setting normal; or	LOWER	BA										
BAL-004-0		R3.2.	The Balancing Authority shall offset its Net Interchange Schedule (MW) by an amount equal to the computed bias contribution during a 0.02 Hertz	LOWER	BA										
BAL-004-0	R4.		Any Reliability Coordinator in an Interconnection shall have the authority to request the Interconnection Time Monitor to terminate a Time Error Correction in	LOWER	RC										
BAL-004-0		R4.1.	Balancing Authorities that have reliability concerns with the execution of a Time Error Correction shall notify their Reliability Coordinator and request the	LOWER	BA							ER			
BAL-005-0.1b	R1.		All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.	No VRF Assigned	GOP, LSE, TOP										
BAL-005-0.1b		R1.1.	Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered	MEDIUM	GOP										
BAL-005-0.1b		R1.2.	Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within	MEDIUM	TOP										
BAL-005-0.1b		R1.3.	Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a	MEDIUM	LSE										
BAL-005-0.1b	R2.		Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.	HIGH	BA										
BAL-005-0.1b	R3.		A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications, and control equipment are employed to	MEDIUM	BA										

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BAL-005-0.1b	R4.		A Balancing Authority providing Regulation Service shall notify the Host Balancing Authority for whom it is controlling if it is unable to provide the	MEDIUM	BA										
BAL-005-0.1b	R5.		A Balancing Authority receiving Regulation Service shall ensure that backup plans are in place to provide replacement Regulation Service should	MEDIUM	BA										
BAL-005-0.1b	R6.		The Balancing Authority's AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine	MEDIUM	BA										
BAL-005-0.1b	R7.		The Balancing Authority shall operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become	MEDIUM	BA										
BAL-005-0.1b	R8.		The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every six seconds.	MEDIUM	BA										
BAL-005-0.1b		R8.1.	Each Balancing Authority shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of	MEDIUM	BA										
BAL-005-0.1b	R9.		The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE	LOWER	BA										
BAL-005-0.1b		R9.1.	Balancing Authorities with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection	LOWER	BA										
BAL-005-0.1b	R10.		The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.	HIGH	BA										
BAL-005-0.1b	R11.		Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled	MEDIUM	BA										
BAL-005-0.1b	R12.		Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.	MEDIUM	BA										
BAL-005-0.1b		R12.1.	Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon	LOWER	BA										
BAL-005-0.1b		R12.2.	Balancing Authorities shall ensure the power flow and ACE signals that are utilized for calculating Balancing Authority performance or that are	MEDIUM	BA										
BAL-005-0.1b		R12.3.	Balancing Authorities shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more	MEDIUM	BA										
BAL-005-0.1b	R13.		Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the	LOWER	BA										
BAL-005-0.1b	R14.		The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of	LOWER	BA										
BAL-005-0.1b	R15.		The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority's	LOWER	BA										
BAL-005-0.1b	R16.		The Balancing Authority shall sample data at least at the same periodicity with which ACE is calculated. The Balancing Authority shall flag missing or bad data	MEDIUM	BA										
BAL-005-0.1b	R17.		Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall	MEDIUM	BA										
BAL-006-2	R1.		Each Balancing Authority shall calculate and record hourly Inadvertent Interchange.	LOWER	BA										
BAL-006-2	R2.		Each Balancing Authority shall include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. The	LOWER	BA										
BAL-006-2	R3.		Each Balancing Authority shall ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with	LOWER	BA										
BAL-006-2	R4.		Adjacent Balancing Authority Areas shall operate to a common Net Interchange Schedule and Actual Net Interchange value and shall record these hourly	LOWER	BA						M				
BAL-006-2		R4.1.	Each Balancing Authority, by the end of the next business day, shall agree with its Adjacent Balancing Authorities to:	LOWER	BA						M				
BAL-006-2		R4.1.1.	The hourly values of Net Interchange Schedule.	LOWER	BA						M				

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BAL-006-2		R4.1.2.	The hourly integrated megawatt-hour values of Net Actual Interchange.	LOWER	BA					M			
BAL-006-2		R4.2.	Each Balancing Authority shall use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak	LOWER	BA					M			
BAL-006-2		R4.3.	A Balancing Authority shall make after-the-fact corrections to the agreed-to daily and monthly accounting data only as needed to reflect actual operating conditions (e.g.	LOWER	BA								
BAL-006-2	R5.		Adjacent Balancing Authorities that cannot mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the	LOWER	BA						ER		
			CRITICAL INFRASTRUCTURE PROTECTION										
CIP-001-2a	R1.		Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall have procedures for the	MEDIUM	BA, GOP, LSE, RC, TOP		x		A				X
CIP-001-2a	R2.		Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall have procedures for the communication of information concerning sabotage events to appropriate parties in the Interconnection.	MEDIUM	BA, GOP, LSE, RC, TOP	x			A				X
CIP-001-2a	R3.		Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall provide its operating	MEDIUM	BA, GOP, LSE, RC, TOP	x			A				X
CIP-001-2a	R4.		Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall establish communications	MEDIUM	BA, GOP, LSE, RC, TOP		x		A				X
CIP-002-3	R1.		Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x			A				X
CIP-002-3		R1.1.	The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x			A				X
CIP-002-3		R1.2.	The risk-based assessment shall consider the following assets:	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x			A				X
CIP-002-3		R1.2.1.	Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x			A				X
CIP-002-3		R1.2.2.	Transmission substations that support the reliable operation of the Bulk Electric System.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x			A				X
CIP-002-3		R1.2.3.	Generation resources that support the reliable operation of the Bulk Electric System.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x			A				X
CIP-002-3		R1.2.4.	Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x			A				X
CIP-002-3		R1.2.5.	Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x			A				X
CIP-002-3		R1.2.6.	Special Protection Systems that support the reliable operation of the Bulk Electric System.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x			A				X
CIP-002-3		R1.2.7.	Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x			A				X
CIP-002-3	R2.		Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x			A				X
CIP-002-3	R3.		Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x			A				X
CIP-002-3		R3.1.	The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x			A				X
CIP-002-3		R3.2.	The Cyber Asset uses a routable protocol within a control center; or,	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x			A				X
CIP-002-3		R3.3.	The Cyber Asset is dial-up accessible	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x			A				X

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CIP-002-3	R4.		Annual Approval — The senior manager or delegate(s) shall approve annually the risk-based assessment methodology, the list of Critical Assets and the list of	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-003-3	R1.		Cyber Security Policy — The Responsible Entity shall document and implement a cyber security policy that represents management's commitment and ability to	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					
CIP-003-3		R1.1.	The cyber security policy addresses the requirements in Standards CIP-002-3 through CIP-009-3, including provision for emergency situations.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					
CIP-003-3		R1.2.	The cyber security policy is readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					
CIP-003-3		R1.3.	Annual review and approval of the cyber security policy by the senior manager assigned pursuant to R2.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					
CIP-003-3	R2.		Leadership — The Responsible Entity shall assign a single senior manager with overall responsibility and authority for leading and managing the entity's	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-003-3		R2.1.	The senior manager shall be identified by name, title, and date of designation.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-003-3		R2.2.	Changes to the senior manager must be documented within thirty calendar days of the effective date.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-003-3		R2.3.	Where allowed by Standards CIP-002-3 through CIP-009-3, the senior manager may delegate authority for specific actions to a named delegate or delegates.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-003-3		R2.4.	The senior manager or delegate(s), shall authorize and document any exception from the requirements of the cyber security policy.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-003-3	R3.		Exceptions — Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and authorized	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC			x		A					
CIP-003-3		R3.1.	Exceptions to the Responsible Entity's cyber security policy must be documented within thirty days of being approved by the senior manager or	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC			x		A					
CIP-003-3		R3.2.	Documented exceptions to the cyber security policy must include an explanation as to why the exception is necessary and any compensating	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC			x		A					
CIP-003-3		R3.3.	Authorized exceptions to the cyber security policy must be reviewed and approved annually by the senior manager or delegate(s) to ensure the exceptions	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC			x		A					
CIP-003-3	R4.		Information Protection — The Responsible Entity shall implement and document a program to identify, classify, and protect information associated with	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC			x		A					
CIP-003-3		R4.1.	The Critical Cyber Asset information to be protected shall include, at a minimum and regardless of media type, operational procedures, lists as required in Standard	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC			x		A					
CIP-003-3		R4.2.	The Responsible Entity shall classify information to be protected under this program based on the sensitivity of the Critical Cyber Asset information.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC			x		A					
CIP-003-3		R4.3.	The Responsible Entity shall, at least annually, assess adherence to its Critical Cyber Asset information protection program, document the assessment	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC			x		A					
CIP-003-3	R5.		Access Control — The Responsible Entity shall document and implement a program for managing access to protected Critical Cyber Asset information.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-003-3		R5.1.	The Responsible Entity shall maintain a list of designated personnel who are responsible for authorizing logical or physical access to protected information.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-003-3		R5.1.1.	Personnel shall be identified by name, title, and the information for which they are responsible for authorizing access.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-003-3		R5.1.2.	The list of personnel responsible for authorizing access to protected information shall be verified at least annually.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-003-3		R5.2.	The Responsible Entity shall review at least annually the access privileges to protected information to confirm that access privileges are correct and that they	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-003-3		R5.3.	The Responsible Entity shall assess and document at least annually the processes for controlling access privileges to protected information.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-003-3	R6.		Change Control and Configuration Management — The Responsible Entity shall establish and document a process of change control and configuration	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X

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CIP-004-3	R1.		Awareness — The Responsible Entity shall establish, document, implement, and maintain a security awareness program to ensure personnel having authorized cyber	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					
CIP-004-3	R2.		Training — The Responsible Entity shall establish, document, implement, and maintain an annual cyber security training program for personnel having authorized	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					
CIP-004-3		R2.1.	This program will ensure that all personnel having such access to Critical Cyber Assets, including contractors and service vendors, are trained prior to their	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					
CIP-004-3		R2.2.	Training shall cover the policies, access controls, and procedures as developed for the Critical Cyber Assets covered by CIP-004-3, and include, at a minimum, the	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					
CIP-004-3		R2.2.1.	The proper use of Critical Cyber Assets;	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					
CIP-004-3		R2.2.2.	Physical and electronic access controls to Critical Cyber Assets;	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					
CIP-004-3		R2.2.3.	The proper handling of Critical Cyber Asset information; and,	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					
CIP-004-3		R2.2.4.	Action plans and procedures to recover or re-establish Critical Cyber Assets and access thereto following a Cyber Security Incident.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					
CIP-004-3		R2.3.	The Responsible Entity shall maintain documentation that training is conducted at least annually, including the date the training was completed and attendance	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					
CIP-004-3	R3.		Personnel Risk Assessment —The Responsible Entity shall have a documented personnel risk assessment program, in accordance with federal,	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-004-3		R3.1.	The Responsible Entity shall ensure that each assessment conducted include, at least, identity verification (e.g., Social Security Number verification in the U.S.)	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-004-3		R3.2.	The Responsible Entity shall update each personnel risk assessment at least every seven years after the initial personnel risk assessment or for cause.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-004-3		R3.3.	The Responsible Entity shall document the results of personnel risk assessments of its personnel having authorized cyber or authorized unescorted physical access	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-004-3	R4.		Access — The Responsible Entity shall maintain list(s) of personnel with authorized cyber or authorized unescorted physical access to Critical	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-004-3		R4.1.	The Responsible Entity shall review the list(s) of its personnel who have such access to Critical Cyber Assets quarterly, and update the list(s) within seven	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-004-3		R4.2.	The Responsible Entity shall revoke such access to Critical Cyber Assets within 24 hours for personnel terminated for cause and within seven calendar days for	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-005-3a	R1.		Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R1.1.	Access points to the Electronic Security Perimeter(s) shall include any externally connected communication end point (for example, dial-up modems) terminating at	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R1.2.	For a dial-up accessible Critical Cyber Asset that uses a non-routable protocol, the Responsible Entity shall define an Electronic Security Perimeter for that	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R1.3.	Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R1.4.	Any non-critical Cyber Asset within a defined Electronic Security Perimeter shall be identified and protected pursuant to the requirements of Standard CIP-005-	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R1.5.	Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall be afforded the protective measures as a specified in	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R1.6.	The Responsible Entity shall maintain documentation of Electronic Security Perimeter(s), all interconnected Critical and non-critical Cyber Assets within the	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a	R2.		Electronic Access Controls — The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R2.1.	These processes and mechanisms shall use an access control model that denies access by default, such that explicit access permissions must be specified.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X

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CIP-005-3a		R2.2.	At all access points to the Electronic Security Perimeter(s), the Responsible Entity shall enable only ports and services required for operations and for	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R2.3.	The Responsible Entity shall implement and maintain a procedure for securing dial-up access to the Electronic Security Perimeter(s).	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R2.4.	Where external interactive access into the Electronic Security Perimeter has been enabled, the Responsible Entity shall implement strong procedural or technical	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R2.5.	The required documentation shall, at least, identify and describe:	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-005-3a		R2.5.1.	The processes for access request and authorization.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-005-3a		R2.5.2.	The authentication methods.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-005-3a		R2.5.3.	The review process for authorization rights, in accordance with Standard CIP-004-3 Requirement R4.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-005-3a		R2.5.4.	The controls used to secure dial-up accessible connections.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-005-3a		R2.6.	Appropriate Use Banner — Where technically feasible, electronic access control devices shall display an appropriate use banner on the user	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a	R3.		Monitoring Electronic Access — The Responsible Entity shall implement and document an electronic or manual process(es) for monitoring and logging	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R3.1.	For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall implement and document monitoring process(es) at	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R3.2.	Where technically feasible, the security monitoring process(es) shall detect and alert for attempts at or actual unauthorized accesses. These alerts shall	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a	R4.		Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of the electronic access points to the Electronic Security	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R4.1.	A document identifying the vulnerability assessment process;	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-005-3a		R4.2.	A review to verify that only ports and services required for operations at these access points are enabled;	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R4.3.	The discovery of all access points to the Electronic Security Perimeter;	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R4.4.	A review of controls for default accounts, passwords, and network management community strings;	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R4.5.	Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a	R5.		Documentation Review and Maintenance — The Responsible Entity shall review, update, and maintain all documentation to support compliance with the requirements	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R5.1.	The Responsible Entity shall ensure that all documentation required by Standard CIP-005-3 reflect current configurations and processes and shall review the	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R5.2.	The Responsible Entity shall update the documentation to reflect the modification of the network or controls within ninety calendar days of the change.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R5.3.	The Responsible Entity shall retain electronic access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-006-3c	R1.		Physical Security Plan — The Responsible Entity shall document, implement, and maintain a physical security plan, approved by the senior manager or	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-006-3c		R1.1.	All Cyber Assets within an Electronic Security Perimeter shall reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall")	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-006-3c		R1.2.	Identification of all physical access points through each Physical Security Perimeter and measures to control entry at those access points.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X

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CIP-006-3c		R1.3.	Processes, tools, and procedures to monitor physical access to the perimeter(s).	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-006-3c		R1.4.	Appropriate use of physical access controls as described in Requirement R4 including visitor pass management, response to loss, and prohibition of	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-006-3c		R1.5.	Review of access authorization requests and revocation of access authorization, in accordance with CIP-004-3 Requirement R4.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-006-3c		R1.6.	A visitor control program for visitors (personnel without authorized unescorted access to a Physical Security Perimeter), containing at a minimum the following:	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-006-3c		R1.6.1.	Logs (manual or automated) to document the entry and exit of visitors, including the date and time, to and from Physical Security Perimeters.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-006-3c		R1.6.2.	Continuous escorted access of visitors within the Physical Security Perimeter.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-006-3c		R1.7.	Update of the physical security plan within thirty calendar days of the completion of any physical security system redesign or reconfiguration,	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-006-3c		R1.8.	Annual review of the physical security plan.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-006-3c	R2.		Protection of Physical Access Control Systems — Cyber Assets that authorize and/or log access to the Physical Security Perimeter(s), exclusive of hardware at the	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-006-3c		R2.1.	Be protected from unauthorized physical access.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-006-3c		R2.2.	Be afforded the protective measures specified in Standard CIP-003-3; Standard CIP-004-3 Requirement R3; Standard CIP-005-3 Requirements R2 and R3; Standard	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-006-3c	R3.		Protection of Electronic Access Control Systems — Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-006-3c	R4.		Physical Access Controls — The Responsible Entity shall document and implement the operational and procedural controls to manage physical access at all	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-006-3c	R5.		Monitoring Physical Access — The Responsible Entity shall document and implement the technical and procedural controls for monitoring physical access at	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-006-3c	R6.		Logging Physical Access — Logging shall record sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-006-3c	R7.		Access Log Retention — The Responsible Entity shall retain physical access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-006-3c	R8.		Maintenance and Testing — The Responsible Entity shall implement a maintenance and testing program to ensure that all physical security systems	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-006-3c		R8.1.	Testing and maintenance of all physical security mechanisms on a cycle no longer than three years.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-006-3c		R8.2.	Retention of testing and maintenance records for the cycle determined by the Responsible Entity in Requirement R8.1.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-006-3c		R8.3.	Retention of outage records regarding access controls, logging, and monitoring for a minimum of one calendar year.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3	R1.		Test Procedures — The Responsible Entity shall ensure that new Cyber Assets and significant changes to existing Cyber Assets within the Electronic Security	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R1.1.	The Responsible Entity shall create, implement, and maintain cyber security test procedures in a manner that minimizes adverse effects on the	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R1.2.	The Responsible Entity shall document that testing is performed in a manner that reflects the production environment.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R1.3.	The Responsible Entity shall document test results.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3	R2.		Ports and Services — The Responsible Entity shall establish, document and implement a process to ensure that only those ports and services required for	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X

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CIP-007-3		R2.1.	The Responsible Entity shall enable only those ports and services required for normal and emergency operations.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R2.2.	The Responsible Entity shall disable other ports and services, including those used for testing purposes, prior to production use of all Cyber Assets inside the	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R2.3.	In the case where unused ports and services cannot be disabled due to technical limitations, the Responsible Entity shall document compensating	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3	R3.		Security Patch Management — The Responsible Entity, either separately or as a component of the documented configuration management process	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R3.1.	The Responsible Entity shall document the assessment of security patches and security upgrades for applicability within thirty calendar days of availability of the	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R3.2.	The Responsible Entity shall document the implementation of security patches. In any case where the patch is not installed, the Responsible Entity shall document	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3	R4.		Malicious Software Prevention — The Responsible Entity shall use anti-virus software and other malicious software ("malware") prevention tools, where	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R4.1.	The Responsible Entity shall document and implement anti-virus and malware prevention tools. In the case where anti-virus software and malware prevention	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R4.2.	The Responsible Entity shall document and implement a process for the update of anti-virus and malware prevention "signatures." The process must address	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3	R5.		Account Management — The Responsible Entity shall establish, implement, and document technical and procedural controls that enforce access	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R5.1.	The Responsible Entity shall ensure that individual and shared system accounts and authorized access permissions are consistent with the concept of "need to	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R5.1.1.	The Responsible Entity shall ensure that user accounts are implemented as approved by designated personnel. Refer to Standard CIP-003-3 Requirement R5.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R5.1.2.	The Responsible Entity shall establish methods, processes, and procedures that generate logs of sufficient detail to create historical audit trails of individual user	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R5.1.3.	The Responsible Entity shall review, at least annually, user accounts to verify access privileges are in accordance with Standard CIP-003-3 Requirement R5 and	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R5.2.	The Responsible Entity shall implement a policy to minimize and manage the scope and acceptable use of administrator, shared, and other generic account	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R5.2.1.	The policy shall include the removal, disabling, or renaming of such accounts where possible. For such accounts that must remain enabled, passwords shall be	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R5.2.2.	The Responsible Entity shall identify those individuals with access to shared accounts.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R5.2.3.	Where such accounts must be shared, the Responsible Entity shall have a policy for managing the use of such accounts that limits access to only those with	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R5.3.	At a minimum, the Responsible Entity shall require and use passwords, subject to the following, as technically feasible:	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R5.3.1.	Each password shall be a minimum of six characters.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R5.3.2.	Each password shall consist of a combination of alpha, numeric, and "special" characters.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R5.3.3.	Each password shall be changed at least annually, or more frequently based on risk.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3	R6.		Security Status Monitoring — The Responsible Entity shall ensure that all Cyber Assets within the Electronic Security Perimeter, as technically feasible,	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R6.1.	The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for monitoring for security	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R6.2.	The security monitoring controls shall issue automated or manual alerts for detected Cyber Security Incidents.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X

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CIP-007-3		R6.3.	The Responsible Entity shall maintain logs of system events related to cyber security, where technically feasible, to support incident response as required in	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R6.4.	The Responsible Entity shall retain all logs specified in Requirement R6 for ninety calendar days.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R6.5.	The Responsible Entity shall review logs of system events related to cyber security and maintain records documenting review of logs.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3	R7.		Disposal or Redeployment — The Responsible Entity shall establish and implement formal methods, processes, and procedures for disposal or	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R7.1.	Prior to the disposal of such assets, the Responsible Entity shall destroy or erase the data storage media to prevent unauthorized retrieval of sensitive cyber	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R7.2.	Prior to redeployment of such assets, the Responsible Entity shall, at a minimum, erase the data storage media to prevent unauthorized retrieval of sensitive cyber	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R7.3.	The Responsible Entity shall maintain records that such assets were disposed of or redeployed in accordance with documented procedures.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3	R8.		Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of all Cyber Assets within the Electronic Security	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R8.1.	A document identifying the vulnerability assessment process;	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-007-3		R8.2.	A review to verify that only ports and services required for operation of the Cyber Assets within the Electronic Security Perimeter are enabled;	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R8.3.	A review of controls for default accounts; and,	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R8.4.	Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3	R9.		Documentation Review and Maintenance — The Responsible Entity shall review and update the documentation specified in Standard CIP-007-3 at least annually.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-008-3	R1.		Cyber Security Incident Response Plan — The Responsible Entity shall develop and maintain a Cyber Security Incident response plan and implement the plan in	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-008-3		R1.1.	Procedures to characterize and classify events as reportable Cyber Security Incidents.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-008-3		R1.2.	Response actions, including roles and responsibilities of Cyber Security Incident response teams, Cyber Security Incident handling procedures, and communication	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-008-3		R1.3.	Process for reporting Cyber Security Incidents to the Electricity Sector Information Sharing and Analysis Center (ES-ISAC). The Responsible Entity must	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-008-3		R1.4.	Process for updating the Cyber Security Incident response plan within thirty calendar days of any changes.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-008-3		R1.5.	Process for ensuring that the Cyber Security Incident response plan is reviewed at least annually.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-008-3		R1.6.	Process for ensuring the Cyber Security Incident response plan is tested at least annually. A test of the Cyber Security Incident response plan can range from a	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-008-3	R2.		Cyber Security Incident Documentation — The Responsible Entity shall keep relevant documentation related to Cyber Security Incidents reportable per	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-009-3	R1.		Recovery Plans — The Responsible Entity shall create and annually review recovery plan(s) for Critical Cyber Assets. The recovery plan(s) shall address at a	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-009-3		R1.1.	Specify the required actions in response to events or conditions of varying duration and severity that would activate the recovery plan(s).	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-009-3		R1.2.	Define the roles and responsibilities of responders.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-009-3	R2.		Exercises — The recovery plan(s) shall be exercised at least annually. An exercise of the recovery plan(s) can range from a paper drill, to a full operational exercise,	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X

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CIP-009-3	R3.		Change Control — Recovery plan(s) shall be updated to reflect any changes or lessons learned as a result of an exercise or the recovery from an actual incident.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC			x		A					
CIP-009-3	R4.		Backup and Restore — The recovery plan(s) shall include processes and procedures for the backup and storage of information required to successfully	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-009-3	R5.		Testing Backup Media — Information essential to recovery that is stored on backup media shall be tested at least annually to ensure that the information is	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					
			COMMUNICATIONS												
COM-001-1.1	R1.		Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide adequate and reliable telecommunications facilities for the exchange of Interconnection and operating information:	HIGH	BA, RC, TOP	x				A					X
COM-001-1.1		R1.1.	Internally.	HIGH	BA, RC, TOP	x				A					X
COM-001-1.1		R1.2.	Between the Reliability Coordinator and its Transmission Operators and Balancing Authorities.	HIGH	BA, RC, TOP	x				A					X
COM-001-1.1		R1.3.	With other Reliability Coordinators, Transmission Operators, and Balancing Authorities as necessary to maintain reliability.	HIGH	BA, RC, TOP	x				A					X
COM-001-1.1		R1.4.	Where applicable, these facilities shall be redundant and diversely routed.	HIGH	BA, RC, TOP	x				A					X
COM-001-1.1	R2.		Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall manage, alarm, test and/or actively monitor vital telecommunications facilities. Special attention shall be given to emergency telecommunications facilities and equipment not used for routine communications.	MEDIUM	BA, RC, TOP	x				A					X
COM-001-1.1	R3.		Each Reliability Coordinator, Transmission Operator and Balancing Authority shall provide a means to coordinate telecommunications among their respective areas. This coordination shall include the ability to investigate and recommend solutions to telecommunications problems within the area and with other areas.	LOWER	BA, RC, TOP		x			A					X
COM-001-1.1	R4.		Unless agreed to otherwise, each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use English as the language for all communications between and among operating personnel responsible for the real-time generation control and operation of the interconnected Bulk Electric System. Transmission Operators and Balancing Authorities may use an alternate language for internal operations.	MEDIUM	BA, RC, TOP			x		A					X
COM-001-1.1	R5.		Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have written operating instructions and procedures to enable continued operation of the system during the loss of telecommunications facilities.	LOWER	BA, RC, TOP		x			A					X
COM-001-1.1	R6.		Each NERCNet User Organization shall adhere to the requirements in Attachment 1-COM-001-0, "NERCNet Security Policy."	LOWER	NERC_Net Users			x		A					X
COM-002-2	R1.		Each Transmission Operator, Balancing Authority, and Generator Operator shall have communications (voice and data links) with appropriate Reliability Coordinators, Balancing Authorities, and Transmission Operators. Such communications shall be staffed and available for addressing a real-time emergency condition.	HIGH	BA, GOP, TOP			x		A					X

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COM-002-2		R1.1.	Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator, and all other potentially affected Balancing Authorities and Transmission Operators through predetermined communication paths of any condition that could threaten the reliability of its area or when firm load shedding is anticipated.	HIGH	BA, TOP			x	A				X
COM-002-2	R2.		Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall issue directives in a clear, concise, and definitive manner; shall	MEDIUM	BA, RC, TOP	x			A				X
			EMERGENCY PREPAREDNESS AND OPERATIONS										
EOP-001-0	R1.		Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency	HIGH	BA			x					
EOP-001-0	R2.		The Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes.	MEDIUM	TOP		x						X
EOP-001-0	R3.		Each Transmission Operator and Balancing Authority shall:	MEDIUM	BA, TOP	x			A				X
EOP-001-0		R3.1.	Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.	MEDIUM	BA, TOP	x			A				X
EOP-001-0		R3.2.	Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.	MEDIUM	BA, TOP	x			A				X
EOP-001-0		R3.3.	Develop, maintain, and implement a set of plans for load shedding.	MEDIUM	BA, TOP	x			A				X
EOP-001-0		R3.4.	Develop, maintain, and implement a set of plans for system restoration.	MEDIUM	BA, TOP	x			A				
EOP-001-0	R4.		Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum,	MEDIUM	BA, TOP		x						
EOP-001-0		R4.1.	Communications protocols to be used during emergencies.	MEDIUM	BA, TOP		x						
EOP-001-0		R4.2.	A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one	MEDIUM	BA, TOP		x						
EOP-001-0		R4.3.	The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.	MEDIUM	BA, TOP		x						
EOP-001-0		R4.4.	Staffing levels for the emergency.	MEDIUM	BA, TOP		x						
EOP-001-0	R5.		Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001-0 when developing an emergency	MEDIUM	BA, TOP			x	A				X
EOP-001-0	R6.		The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing	MEDIUM	BA, TOP			x					
EOP-001-0	R7.		The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate.	MEDIUM	BA, TOP		x						
EOP-001-0		R7.1.	The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.	MEDIUM	BA, TOP		x						
EOP-001-0		R7.2.	The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing	MEDIUM	BA, TOP		x						
EOP-001-0		R7.3.	The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in	MEDIUM	BA, TOP	x							
EOP-001-0		R7.4.	The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating	MEDIUM	BA, TOP	x							

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EOP-002-3	R1.		Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to	HIGH	BA, RC			x							
EOP-002-3	R2.		Each Balancing Authority shall, when required and as appropriate, take one or more actions as described in its capacity and energy emergency plan, , to reduce	HIGH	BA			x							
EOP-002-3	R3.		A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its	HIGH	BA			x							
EOP-002-3	R4.		A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available	HIGH	BA			x							
EOP-002-3	R5.		A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective	HIGH	BA			x							
EOP-002-3	R6.		If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to	HIGH	BA			x							
EOP-002-3		R6.1.	Loading all available generating capacity.	HIGH	BA			x							
EOP-002-3		R6.2.	Deploying all available operating reserve.	HIGH	BA			x							
EOP-002-3		R6.3.	Interrupting interruptible load and exports.	HIGH	BA			x							
EOP-002-3		R6.4.	Requesting emergency assistance from other Balancing Authorities.	HIGH	BA			x							
EOP-002-3		R6.5.	Declaring an Energy Emergency through its Reliability Coordinator; and	HIGH	BA			x							
EOP-002-3		R6.6.	Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.	HIGH	BA			x							
EOP-002-3	R7.		Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency	HIGH	BA	x				A					X
EOP-002-3		R7.1.	Manually shed firm load without delay to return its ACE to zero; and	HIGH	BA	x				A					X
EOP-002-3		R7.2.	Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0 "Energy Emergency Alert Levels."	HIGH	BA	x				A					X
EOP-002-3	R8.		A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate	HIGH	RC	x				A					X
EOP-002-3	R9.		When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network	HIGH	LSE, RC			x							
EOP-002-3		R9.1.	The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0.	HIGH	LSE			x							
EOP-002-3		R9.2.	The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission	HIGH	RC			x				ER			
EOP-002-3		R9.3.	The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6	LOWER	RC			x				ER			
EOP-002-3		R9.4.	The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6	LOWER	RC			x				ER			
EOP-003-1	R1.		After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.	HIGH	BA, TOP		x								
EOP-003-1	R2.		Each Transmission Operator and Balancing Authority shall establish plans for automatic load shedding for underfrequency or undervoltage conditions.	HIGH	BA, TOP			x							X

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EOP-003-1	R3.		Each Transmission Operator and Balancing Authority shall coordinate load shedding plans among other interconnected Transmission Operators and Balancing Authorities.	HIGH	BA, TOP			x					X
EOP-003-1	R4.		A Transmission Operator or Balancing Authority shall consider one or more of these factors in designing an automatic load shedding scheme: frequency, rate of frequency decay, voltage level, rate of voltage decay, or power flow levels.	HIGH	BA, TOP			x					X
EOP-003-1	R5.		A Transmission Operator or Balancing Authority shall implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of	HIGH	BA, TOP			x					
EOP-003-1	R6.		After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system	HIGH	BA, TOP			x					
EOP-003-1	R7.		The Transmission Operator and Balancing Authority shall coordinate automatic load shedding throughout their areas with underfrequency isolation of generating units, tripping of shunt capacitors, and	HIGH	BA, TOP			x					
EOP-003-1	R8.		Each Transmission Operator or Balancing Authority shall have plans for operator-controlled manual load shedding to respond to real-time emergencies. The	HIGH	BA, TOP		x						X
EOP-004-1	R1.		Each Regional Reliability Organization shall establish and maintain a Regional reporting procedure to facilitate preparation of preliminary and final	LOWER	RRO			x					
EOP-004-1	R2.		A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load-Serving Entity shall promptly analyze Bulk Electric	MEDIUM	BA, GOP, LSE, RC, TOP			x					
EOP-004-1	R3.		A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load-Serving Entity experiencing a reportable incident	LOWER	BA, GOP, LSE, RC, TOP	x					ER		
EOP-004-1		R3.1.	The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load-Serving Entity shall submit within 24	LOWER	BA, GOP, LSE, RC, TOP			x			ER		
EOP-004-1		R3.2.	Applicable reporting forms are provided in Attachments 022-1 and 022-2.	No VRF Assigned	BA, GOP, LSE, RC, TOP			x					
EOP-004-1		R3.3.	Under certain adverse conditions, e.g., severe weather, it may not be possible to assess the damage caused by a disturbance and issue a written	LOWER	BA, GOP, LSE, RC, TOP			x			ER		
EOP-004-1		R3.4.	If, in the judgment of the Regional Reliability Organization, after consultation with the Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load-Serving Entity in which a disturbance occurred, a final report is required, the affected Reliability Coordinator, Balancing	LOWER	BA, GOP, LSE, RC, TOP	x							
EOP-004-1	R4.		When a Bulk Electric System disturbance occurs, the Regional Reliability Organization shall make its representatives on the NERC Operating	LOWER	RRO			x			ER		
EOP-004-1	R5.		The Regional Reliability Organization shall track and review the status of all final report recommendations at least twice each year to ensure they are being	LOWER	RRO			x			ER		
EOP-005-1	R1.		Each Transmission Operator shall have a restoration plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shutdown of its system, including necessary operating instructions and procedures to cover emergency conditions, and the loss of vital telecommunications channels. Each Transmission Operator shall include the applicable elements listed in Attachment 1-EOP-005 in developing a restoration plan.	MEDIUM	TOP		x		A				X
EOP-005-1	R2.		Each Transmission Operator shall review and update its restoration plan at least annually and whenever it makes changes in the power system network, and shall	MEDIUM	TOP	x			A				X
EOP-005-1	R3.		Each Transmission Operator shall develop restoration plans with a priority of restoring the integrity of the Interconnection.	MEDIUM	TOP		x		A				X
EOP-005-1	R4.		Each Transmission Operator shall coordinate its restoration plans with the Generator Owners and Balancing Authorities within its area, its Reliability	MEDIUM	TOP	x			A				X
EOP-005-1	R5.		Each Transmission Operator and Balancing Authority shall periodically test its telecommunication facilities needed to implement the restoration plan.	MEDIUM	BA, TOP		x		A				X

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EOP-005-1	R6.		Each Transmission Operator and Balancing Authority shall train its operating personnel in the implementation of the restoration plan. Such training	HIGH	BA, TOP	x			A				X
EOP-005-1	R7.		Each Transmission Operator and Balancing Authority shall verify the restoration procedure by actual testing or by simulation.	HIGH	BA, TOP		x		A				X
EOP-005-1	R8.		Each Transmission Operator shall verify that the number, size, availability, and location of system blackstart generating units are sufficient to meet Regional	HIGH	TOP		x		A				
EOP-005-1	R9.		The Transmission Operator shall document the Cranking Paths, including initial switching requirements, between each blackstart generating unit and the	MEDIUM	TOP		x		A				X
EOP-005-1	R10.		The Transmission Operator shall demonstrate, through simulation or testing, that the blackstart generating units in its restoration plan can perform	MEDIUM	TOP		x		A				X
EOP-005-1		R10.1.	The Transmission Operator shall perform this simulation or testing at least once every five years.	MEDIUM	TOP	x			A				X
EOP-005-1	R11.		Following a disturbance in which one or more areas of the Bulk Electric System become isolated or blacked out, the affected Transmission Operators and	HIGH	BA, TOP			x					
EOP-005-1		R11.1.	The affected Transmission Operators and Balancing Authorities shall work in conjunction with their Reliability Coordinator(s) to determine the extent	MEDIUM	BA, TOP			x					
EOP-005-1		R11.2.	The affected Transmission Operators and Balancing Authorities shall take the necessary actions to restore Bulk Electric System frequency to normal, including	HIGH	BA, TOP			x					
EOP-005-1		R11.3.	The affected Balancing Authorities, working with their Reliability Coordinator(s), shall immediately review the Interchange Schedules between those	HIGH	BA			x					
EOP-005-1		R11.4.	The affected Transmission Operators shall give high priority to restoration of off-site power to nuclear stations.	HIGH	TOP	x							
EOP-005-1		R11.5.	The affected Transmission Operators may resynchronize the isolated area(s) with the surrounding area(s) when the following conditions are met:	MEDIUM	TOP			x					
EOP-005-1		R11.5.1.	Voltage, frequency, and phase angle permit.	HIGH	TOP			x					
EOP-005-1		R11.5.2.	The size of the area being reconnected and the capacity of the transmission lines effecting the reconnection and the number of synchronizing points across	HIGH	TOP			x					
EOP-005-1		R11.5.3.	Reliability Coordinator(s) and adjacent areas are notified and Reliability Coordinator approval is given.	MEDIUM	TOP			x					
EOP-005-1		R11.5.4.	Load is shed in neighboring areas, if required, to permit successful interconnected system restoration.	HIGH	TOP			x					
EOP-006-1	R1.		Each Reliability Coordinator shall be aware of the restoration plan of each Transmission Operator in its Reliability Coordinator Area in accordance with	MEDIUM	RC			x					
EOP-006-1	R2.		The Reliability Coordinator shall monitor restoration progress and coordinate any needed assistance.	HIGH	RC	x							
EOP-006-1	R3.		The Reliability Coordinator shall have a Reliability Coordinator Area restoration plan that provides coordination between individual Transmission Operator	MEDIUM	RC		x						
EOP-006-1	R4.		The Reliability Coordinator shall serve as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators and	MEDIUM	RC			x					
EOP-006-1	R5.		Reliability Coordinators shall approve, communicate, and coordinate the re-synchronizing of major system islands or synchronizing points so as not to cause a	HIGH	RC	x							
EOP-006-1	R6.		The Reliability Coordinator shall take actions to restore normal operations once an operating emergency has been mitigated in accordance with its	MEDIUM	RC			x					
EOP-008-0	R1.		Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have a plan to continue reliability operations in the event its	HIGH	BA, RC, TOP	x			A				X
EOP-008-0		R1.1.	The contingency plan shall not rely on data or voice communication from the primary control facility to be viable.	MEDIUM	BA, RC, TOP	x							X
EOP-008-0		R1.2.	The plan shall include procedures and responsibilities for providing basic tie line control and procedures and for maintaining the status of all inter-area schedules, such that there is an hourly accounting of all schedules.	MEDIUM	BA, RC, TOP			x					X

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EOP-008-0		R1.3.	The contingency plan must address monitoring and control of critical transmission facilities, generation control, voltage control, time and frequency	MEDIUM	BA, RC, TOP	x				A					X
EOP-008-0		R1.4.	The plan shall include procedures and responsibilities for maintaining basic voice communication capabilities with other areas.	HIGH	BA, RC, TOP		x								X
EOP-008-0		R1.5.	The plan shall include procedures and responsibilities for conducting periodic tests, at least annually, to ensure viability of the plan.	MEDIUM	BA, RC, TOP	x				A					X
EOP-008-0		R1.6.	The plan shall include procedures and responsibilities for providing annual training to ensure that operating personnel are able to implement the	MEDIUM	BA, RC, TOP	x				A					X
EOP-008-0		R1.7.	The plan shall be reviewed and updated annually.	MEDIUM	BA, RC, TOP			x							X
EOP-008-0		R1.8.	Interim provisions must be included if it is expected to take more than one hour to implement the contingency plan for loss of primary control facility.	MEDIUM	BA, RC, TOP			x							X
EOP-009-0	R1.		The Generator Operator of each blackstart generating unit shall test the startup and operation of each system blackstart generating unit identified in the BCP as	MEDIUM	GOP										
EOP-009-0	R2.		The Generator Owner or Generator Operator shall provide documentation of the test results of the startup and operation of each blackstart generating	LOWER	GO, GOP						A				
			FACILITIES DESIGN, CONNECTIONS AND MAINTENANCE												
FAC-001-0	R1.		The Transmission Owner shall document, maintain, and publish facility connection requirements to ensure compliance with NERC Reliability Standards and applicable	MEDIUM	TO			x							
FAC-001-0		R1.1.	Generation facilities,	MEDIUM	TO			x							
FAC-001-0		R1.2.	Transmission facilities, and	MEDIUM	TO			x							
FAC-001-0		R1.3.	End-user facilities	MEDIUM	TO			x							
FAC-001-0	R2.		The Transmission Owner's facility connection requirements shall address, but are not limited to, the following items:	MEDIUM	TO	x									
FAC-001-0		R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:	MEDIUM	TO	x									
FAC-001-0		R2.1.1.	Procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems.	MEDIUM	TO			x							
FAC-001-0		R2.1.2.	Procedures for notification of new or modified facilities to others (those responsible for the reliability of the interconnected transmission systems) as	MEDIUM	TO	x									
FAC-001-0		R2.1.3.	Voltage level and MW and MVAR capacity or demand at point of connection.	MEDIUM	TO			x							
FAC-001-0		R2.1.4.	Breaker duty and surge protection.	MEDIUM	TO		x								
FAC-001-0		R2.1.5.	System protection and coordination.	MEDIUM	TO	x									
FAC-001-0		R2.1.6.	Metering and telecommunications.	MEDIUM	TO			x							
FAC-001-0		R2.1.7.	Grounding and safety issues.	MEDIUM	TO			x							
FAC-001-0		R2.1.8.	Insulation and insulation coordination.	MEDIUM	TO			x							
FAC-001-0		R2.1.9.	Voltage, Reactive Power, and power factor control.	MEDIUM	TO			x							
FAC-001-0		R2.1.10.	Power quality impacts.	MEDIUM	TO			x							

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FAC-001-0		R2.1.11.	Equipment Ratings.	MEDIUM	TO			x					
FAC-001-0		R2.1.12.	Synchronizing of facilities.	MEDIUM	TO			x					
FAC-001-0		R2.1.13.	Maintenance coordination.	MEDIUM	TO			x					
FAC-001-0		R2.1.14.	Operational issues (abnormal frequency and voltages).	MEDIUM	TO	x							
FAC-001-0		R2.1.15.	Inspection requirements for existing or new facilities.	MEDIUM	TO			x					
FAC-001-0		R2.1.16.	Communications and procedures during normal and emergency operating conditions.	MEDIUM	TO		x						
FAC-001-0	R3.		The Transmission Owner shall maintain and update its facility connection requirements as required. The Transmission Owner shall make	MEDIUM	TO			x					
FAC-002-1	R1.		The Generator Owner, Transmission Owner, Distribution Provider, and Load-Serving Entity seeking to integrate generation facilities, transmission	MEDIUM	DP, GO, LSE, TO	x							
FAC-002-1		R1.1.	Evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems.	MEDIUM	DP, GO, LSE, TO		x						
FAC-002-1		R1.2.	Ensurance of compliance with NERC Reliability Standards and applicable Regional, subregional, Power Pool, and individual system planning criteria and	MEDIUM	DP, GO, LSE, TO		x						
FAC-002-1		R1.3.	Evidence that the parties involved in the assessment have coordinated and cooperated on the assessment of the reliability impacts of new facilities on the	MEDIUM	DP, GO, LSE, TO	x							
FAC-002-1		R1.4.	Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance under both normal and	MEDIUM	DP, GO, LSE, TO		x						
FAC-002-1		R1.5.	Documentation that the assessment included study assumptions, system performance, alternatives considered, and jointly coordinated recommendations.	MEDIUM	DP, GO, LSE, TO		x						
FAC-002-1	R2.		The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each retain its	LOWER	DP, GO, LSE, PA, PC, TO, TP			x					
FAC-003-1	R1.		The Transmission owner shall prepare, and keep current, a formal transmission vegetation management (TVM). The TVMP shall include the Transmission Owner's	HIGH	TO	x			A				X
FAC-003-1		R1.1.	The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for	HIGH	TO	x			A				X
FAC-003-1		R1.2.	The Transmission Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking	HIGH	TO	x			A				X
FAC-003-1		R1.2.1.	Clearance 1 — The Transmission Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation	HIGH	TO	x			A				X
FAC-003-1		R1.2.2.	Clearance 2 — The Transmission Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under	HIGH	TO	x			A				X
FAC-003-1		R1.2.2.1.	Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground	HIGH	TO	x			A				X
FAC-003-1		R1.2.2.2.	Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with	HIGH	TO	x			A				X
FAC-003-1		R1.3.	All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission	HIGH	TO	x			A				X
FAC-003-1		R1.4.	Each Transmission Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies	HIGH	TO	x			A				X
FAC-003-1		R1.5.	Each Transmission Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent	HIGH	TO	x			A				X
FAC-003-1	R2.		The Transmission Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the	HIGH	TO	x			A				X

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FAC-003-1	R3.		The Transmission Owner shall report quarterly to its RRO, or the RRO's designee, sustained transmission line outages determined by the Transmission	LOWER	TO			x			Q				
FAC-003-1		R3.1.	Multiple sustained outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of	LOWER	TO			x			Q				
FAC-003-1		R3.2.	The Transmission Owner is not required to report to the RRO, or the RRO's designee, certain sustained transmission line outages caused by vegetation: (1)	LOWER	TO			x			Q				
FAC-003-1		R3.3.	The outage information provided by the Transmission Owner to the RRO, or the RRO's designee, shall include at a minimum: the name of the circuit(s)	LOWER	TO			x			Q				
FAC-003-1		R3.4.	An outage shall be categorized as one of the following:	LOWER	TO			x			Q				
FAC-003-1		R3.4.1.	Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW.	LOWER	TO			x			Q				
FAC-003-1		R3.4.2.	Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW.	LOWER	TO			x			Q				
FAC-003-1		R3.4.3.	Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.	LOWER	TO			x			Q				
FAC-003-1	R4.		The RRO shall report the outage information provided to it by Transmission Owner's, as required by Requirement 3, quarterly to NERC, as well	LOWER	RRO			x			Q				
FAC-008-1	R1.		The Transmission Owner and Generator Owner shall each document its current methodology used for developing Facility Ratings (Facility Ratings Methodology) of	LOWER	GO, TO		x			A					X
FAC-008-1		R1.1.	A statement that a Facility Rating shall equal the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.	MEDIUM	GO, TO		x			A					X
FAC-008-1		R1.2.	The method by which the Rating (of major BES equipment that comprises a Facility) is determined.	MEDIUM	GO, TO		x			A					X
FAC-008-1		R1.2.1.	The scope of equipment addressed shall include, but not be limited to, generators, transmission conductors, transformers, relay protective devices, terminal	MEDIUM	GO, TO		x			A					X
FAC-008-1		R1.2.2.	The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.	MEDIUM	GO, TO		x			A					X
FAC-008-1		R1.3.	Consideration of the following:	LOWER	GO, TO		x			A					X
FAC-008-1		R1.3.1.	Ratings provided by equipment manufacturers.	MEDIUM	GO, TO		x			A					X
FAC-008-1		R1.3.2.	Design criteria (e.g., including applicable references to industry Rating practices such as manufacturer's warranty, IEEE, ANSI or other standards).	MEDIUM	GO, TO		x			A					X
FAC-008-1		R1.3.3.	Ambient conditions.	MEDIUM	GO, TO		x			A					X
FAC-008-1		R1.3.4.	Operating limitations.	MEDIUM	GO, TO		x			A					X
FAC-008-1		R1.3.5.	Other assumptions.	LOWER	GO, TO		x			A					X
FAC-008-1	R2.		The Transmission Owner and Generator Owner shall each make its Facility Ratings Methodology available for inspection and technical review by those Reliability Coordinators, Transmission Operators, Transmission Planners, and Planning Authorities that have responsibility for the area in which the associated Facilities are located, within 15 business days of receipt of a request.	LOWER	GO, TO			x							X
FAC-008-1	R3.		If a Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides written comments on its technical review of a	LOWER	GO, TO			x							
FAC-009-1	R1.		The Transmission Owner and Generator Owner shall each establish Facility Ratings for its solely and jointly owned Facilities that are consistent with the	MEDIUM	GO, TO	x				A					X

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FAC-009-1	R2.		The Transmission Owner and Generator Owner shall each provide Facility Ratings for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities to its associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) as scheduled by such requesting entities.	MEDIUM	GO, TO	x									X
FAC-010-2.1	R1.		The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology	LOWER	PA, PC										
FAC-010-2.1		R1.1.	Be applicable for developing SOLs used in the planning horizon.	LOWER	PA, PC										
FAC-010-2.1		R1.2.	State that SOLs shall not exceed associated Facility Ratings.	LOWER	PA, PC										
FAC-010-2.1		R1.3.	Include a description of how to identify the subset of SOLs that qualify as IROLs.	LOWER	PA, PC										
FAC-010-2.1	R2.		The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:	No VRF Assigned	PA, PC										
FAC-010-2.1		R2.1.	In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within	HIGH	PA, PC										
FAC-010-2.1		R2.2.	Following the single Contingencies1 identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and	HIGH	PA, PC										
FAC-010-2.1		R2.2.1.	Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.	MEDIUM	PA, PC										
FAC-010-2.1		R2.2.2.	Loss of any generator, line, transformer, or shunt device without a Fault.	MEDIUM	PA, PC										
FAC-010-2.1		R2.2.3.	Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	MEDIUM	PA, PC										
FAC-010-2.1		R2.3.	Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:	MEDIUM	PA, PC										
FAC-010-2.1		R2.3.1.	Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by	MEDIUM	PA, PC										
FAC-010-2.1		R2.3.2.	System reconfiguration through manual or automatic control or protection actions.	MEDIUM	PA, PC										
FAC-010-2.1		R2.4.	To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the	MEDIUM	PA, PC										
FAC-010-2.1		R2.5.	Starting with all facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall	MEDIUM	PA, PC										
FAC-010-2.1		R2.6.	In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in	MEDIUM	PA, PC										
FAC-010-2.1		R2.6.1.	Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the	MEDIUM	PA, PC										
FAC-010-2.1	R3.		The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied	LOWER	PA, PC										
FAC-010-2.1		R3.1.	Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would	LOWER	PA, PC										
FAC-010-2.1		R3.2.	Selection of applicable Contingencies.	LOWER	PA, PC										
FAC-010-2.1		R3.3.	Level of detail of system models used to determine SOLs.	LOWER	PA, PC										
FAC-010-2.1		R3.4.	Allowed uses of Special Protection Systems or Remedial Action Plans.	MEDIUM	PA, PC										

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FAC-010-2.1		R3.5.	Anticipated transmission system configuration, generation dispatch and Load level.	LOWER	PA, PC										
FAC-010-2.1		R3.6.	Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated	MEDIUM	PA, PC										
FAC-010-2.1	R4.		The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:	LOWER	PA, PC										
FAC-010-2.1		R4.1.	Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.	LOWER	PA, PC										
FAC-010-2.1		R4.2.	Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.	LOWER	PA, PC										
FAC-010-2.1		R4.3.	Each Transmission Planner that works in the Planning Authority's Planning Authority Area.	LOWER	PA, PC										
FAC-010-2.1	R5.		If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a	LOWER	PA, PC										
FAC-011-2	R1.		The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.	LOWER	RC										
FAC-011-2		R1.1.	Be applicable for developing SOLs used in the operations horizon.	LOWER	RC										
FAC-011-2		R1.2.	State that SOLs shall not exceed associated Facility Ratings.	LOWER	RC										
FAC-011-2		R1.3.	Include a description of how to identify the subset of SOLs that qualify as IROLs.	LOWER	RC										
FAC-011-2	R2.		The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:	No VRF Assigned	RC										
FAC-011-2		R2.1.	In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within	HIGH	RC										
FAC-011-2		R2.2.	Following the single Contingencies identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and	HIGH	RC										
FAC-011-2		R2.2.1.	Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.	MEDIUM	RC										
FAC-011-2		R2.2.2.	Loss of any generator, line, transformer, or shunt device without a Fault.	MEDIUM	RC										
FAC-011-2		R2.2.3.	Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	MEDIUM	RC										
FAC-011-2		R2.3.	In determining the system's response to a single Contingency, the following shall be acceptable:	MEDIUM	RC										
FAC-011-2		R2.3.1.	Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by	MEDIUM	RC										
FAC-011-2		R2.3.2.	Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-	MEDIUM	RC										
FAC-011-2		R2.3.3.	System reconfiguration through manual or automatic control or protection actions.	MEDIUM	RC										
FAC-011-2		R2.4.	To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the	MEDIUM	RC										
FAC-011-2	R3.		The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability	MEDIUM	RC										
FAC-011-2		R3.1.	Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would	MEDIUM	RC										
FAC-011-2		R3.2.	Selection of applicable Contingencies	MEDIUM	RC										

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FAC-011-2		R3.3.	A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with	MEDIUM	RC										
FAC-011-2		R3.3.1.	This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies	No VRF Assigned	RC										
FAC-011-2		R3.4.	Level of detail of system models used to determine SOLs.	LOWER	RC										
FAC-011-2		R3.5.	Allowed uses of Special Protection Systems or Remedial Action Plans.	MEDIUM	RC										
FAC-011-2		R3.6.	Anticipated transmission system configuration, generation dispatch and Load level	MEDIUM	RC										
FAC-011-2		R3.7.	Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated	MEDIUM	RC										
FAC-011-2	R4.		The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a	LOWER	RC										
FAC-011-2		R4.1.	Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.	LOWER	RC										
FAC-011-2		R4.2.	Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.	LOWER	RC										
FAC-011-2		R4.3.	Each Transmission Operator that operates in the Reliability Coordinator Area.	LOWER	RC										
FAC-011-2	R5.		If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a	LOWER	RC										
FAC-013-1	R1.		The Reliability Coordinator and Planning Authority shall each establish a set of inter-regional and intra-regional Transfer Capabilities that is consistent with its	MEDIUM	PA, PC, RC										
FAC-013-1	R2.		The Reliability Coordinator and Planning Authority shall each provide its inter-regional and intra-regional Transfer Capabilities to those entities that have a	MEDIUM	PA, PC, RC										
FAC-013-1		R2.1.	The Reliability Coordinator shall provide its Transfer Capabilities to its associated Regional Reliability Organization(s), to its adjacent Reliability Coordinators, and to	MEDIUM	RC										
FAC-013-1		R2.2.	The Planning Authority shall provide its Transfer Capabilities to its associated Reliability Coordinator(s) and Regional Reliability Organization(s), and to the	MEDIUM	PA, PC										
FAC-014-2	R1.		The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are	MEDIUM	RC										
FAC-014-2	R2.		The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are	MEDIUM	RC, TOP										
FAC-014-2	R3.		The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology.	MEDIUM	PA, PC										
FAC-014-2	R4.		The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's	MEDIUM	PA, PC, TP										
FAC-014-2	R5.		The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need	HIGH	PA, PC, RC, TP										
FAC-014-2		R5.1.	The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators	HIGH	RC										
FAC-014-2		R5.1.1.	Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL.	MEDIUM	RC										
FAC-014-2		R5.1.2.	The value of the IROL and its associated Tv.	MEDIUM	RC										
FAC-014-2		R5.1.3.	The associated Contingency(ies).	MEDIUM	RC										
FAC-014-2		R5.1.4.	The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).	MEDIUM	RC										

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FAC-014-2		R5.2.	The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of	MEDIUM	TOP										
FAC-014-2		R5.3.	The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission	MEDIUM	PA, PC										
FAC-014-2		R5.4.	The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission	MEDIUM	TP										
FAC-014-2	R6.		The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits.	MEDIUM	PA, PC										
FAC-014-2		R6.1.	The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities	MEDIUM	PA, PC										
FAC-014-2		R6.2.	If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.	MEDIUM	PA, PC										
			INTERCHANGE SCHEDULING AND COORDINATION												
INT-001-3	R1.		The Load-Serving, Purchasing-Selling Entity shall ensure that Arranged Interchange is submitted to the Interchange Authority for:	LOWER	PSE							ER			
INT-001-3		R1.1.	All Dynamic Schedules at the expected average MW profile for each hour.	LOWER	PSE							ER			
INT-001-3	R2.		The Sink Balancing Authority shall ensure that Arranged Interchange is submitted to the Interchange Authority:	LOWER	BA							ER			
INT-001-3		R2.1.	If a Purchasing-Selling Entity is not involved in the Interchange, such as delivery from a jointly owned generator.	LOWER	BA							ER			
INT-001-3		R2.2.	For each bilateral Inadvertent Interchange payback.	LOWER	BA							ER			
INT-003-3	R1.		Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing	MEDIUM	BA							ER			
INT-003-3		R1.1.	The Sending Balancing Authority and Receiving Balancing Authority shall agree on Interchange as received from the Interchange Authority, including:	LOWER	BA							ER			
INT-003-3		R1.1.1.	Interchange Schedule start and end time.	LOWER	BA							ER			
INT-003-3		R1.1.2.	Energy profile.	LOWER	BA							ER			
INT-003-3		R1.2.	If a high voltage direct current (HVDC) tie is on the Scheduling Path, then the Sending Balancing Authorities and Receiving Balancing Authorities shall	MEDIUM	BA							ER			
INT-004-2	R1.		At such time as the reliability event allows for the reloading of the transaction, the entity that initiated the curtailment shall release the limit on the Interchange	LOWER	BA, PSE, RC, TOP										
INT-004-2	R2.		The Purchasing-Selling Entity responsible for tagging a Dynamic Interchange Schedule shall ensure the tag is updated for the next available scheduling hour and	LOWER	PSE										
INT-004-2		R2.1.	The average energy profile in an hour is greater than 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile	LOWER	PSE										
INT-004-2		R2.2.	The average energy profile in an hour is less than or equal to 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy	LOWER	PSE										
INT-004-2		R2.3.	A Reliability Coordinator or Transmission Operator determines the deviation, regardless of magnitude, to be a reliability concern and notifies the Purchasing-	LOWER	PSE										
INT-005-3	R1.		Prior to the expiration of the time period defined in the Timing Table, Column A, the Interchange Authority shall distribute the Arranged Interchange information for	MEDIUM	IA										
INT-005-3		R1.1.	When a Balancing Authority or Reliability Coordinator initiates a Curtailment to Confirmed or Implemented Interchange for reliability, the Interchange Authority	MEDIUM	IA										
INT-006-3	R1.		Prior to the expiration of the reliability assessment period defined in the Timing Table, Column B, the Balancing Authority and Transmission Service Provider shall	LOWER	BA, TSP										

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INT-006-3		R1.1.	Each involved Balancing Authority shall evaluate the Arranged Interchange with respect to:	LOWER	BA										
INT-006-3		R1.1.1.	Energy profile (ability to support the magnitude of the Interchange).	LOWER	BA										
INT-006-3		R1.1.2.	Ramp (ability of generation maneuverability to accommodate).	LOWER	BA										
INT-006-3		R1.1.3.	Scheduling path (proper connectivity of Adjacent Balancing Authorities).	LOWER	BA										
INT-006-3		R1.2.	Each involved Transmission Service Provider shall confirm that the transmission service arrangements associated with the Arranged Interchange	LOWER	TSP										
INT-007-1	R1.		The Interchange Authority shall verify that Arranged Interchange is balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange by	LOWER	IA										
INT-007-1		R1.1.	Source Balancing Authority megawatts equal sink Balancing Authority megawatts (adjusted for losses, if appropriate).	LOWER	IA										
INT-007-1		R1.2.	All reliability entities involved in the Arranged Interchange are currently in the NERC registry.	LOWER	IA										
INT-007-1		R1.3.	The following are defined:	LOWER	IA										
INT-007-1		R1.3.1.	Generation source and load sink.	LOWER	IA										
INT-007-1		R1.3.2.	Megawatt profile.	LOWER	IA										
INT-007-1		R1.3.3.	Ramp start and stop times.	LOWER	IA										
INT-007-1		R1.3.4.	Interchange duration.	LOWER	IA										
INT-007-1		R1.4.	Each Balancing Authority and Transmission Service Provider that received the Arranged Interchange information from the Interchange	LOWER	IA										
INT-008-3	R1.		Prior to the expiration of the time period defined in the Timing Table, Column C, the Interchange Authority shall distribute to all Balancing Authorities (including	LOWER	IA										
INT-008-3		R1.1.	For Confirmed Interchange, the Interchange Authority shall also communicate:	LOWER	IA										
INT-008-3		R1.1.1.	Start and stop times, ramps, and megawatt profile to Balancing Authorities.	LOWER	IA										
INT-008-3		R1.1.2.	Necessary Interchange information to NERC-identified reliability analysis services.	LOWER	IA										
INT-009-1	R1.		The Balancing Authority shall implement Confirmed Interchange as received from the Interchange Authority.	MEDIUM	BA										
INT-010-1	R1.		The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement shall ensure that a request for an Arranged Interchange is	LOWER	BA										
INT-010-1	R2.		For a modification to an existing Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the	LOWER	RC										
INT-010-1	R3.		For a new Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall	LOWER	RC										
			INTERCONNECTION RELIABILITY OPERATIONS AND COORDINATION												
IRO-001-1.1	R1.		Each Regional Reliability Organization, subregion, or interregional coordinating group shall establish one or more Reliability Coordinators to continuously	HIGH	RRO										
IRO-001-1.1	R2.		The Reliability Coordinator shall comply with a regional reliability plan approved by the NERC Operating Committee.	HIGH	RC										

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IRO-001-1.1	R3.		The Reliability Coordinator shall have clear decision-making authority to act and to direct actions to be taken by Transmission Operators, Balancing	HIGH	RC								
IRO-001-1.1	R4.		Reliability Coordinators that delegate tasks to other entities shall have formal operating agreements with each entity to which tasks are delegated. The Reliability	MEDIUM	RC								
IRO-001-1.1	R5.		The Reliability Coordinator shall list within its reliability plan all entities to which the Reliability Coordinator has delegated required tasks.	LOWER	RC								
IRO-001-1.1	R6.		The Reliability Coordinator shall verify that all delegated tasks are carried out by NERC-certified Reliability Coordinator operating personnel.	MEDIUM	RC								
IRO-001-1.1	R7.		The Reliability Coordinator shall have clear, comprehensive coordination agreements with adjacent Reliability Coordinators to ensure that System	HIGH	RC								
IRO-001-1.1	R8.		Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling	HIGH	BA, GOP, LSE, PSE, TOP, TSP								
IRO-001-1.1	R9.		The Reliability Coordinator shall act in the interests of reliability for the overall Reliability Coordinator Area and the Interconnection before the interests of	HIGH	RC								
IRO-002-2	R1.		Each Reliability Coordinator shall have adequate communications facilities (voice and data links) to appropriate entities within its Reliability Coordinator Area.	HIGH	RC		x						
IRO-002-2	R2.		Each Reliability Coordinator — or its Transmission Operators and Balancing Authorities — shall provide, or arrange provisions for, data exchange to other	MEDIUM	RC			x					
IRO-002-2	R3.		Each Reliability Coordinator shall have multi-directional communications capabilities with its Transmission Operators and Balancing Authorities, and	MEDIUM	RC			x					
IRO-002-2	R4.		Each Reliability Coordinator shall have detailed real-time monitoring capability of its Reliability Coordinator Area and sufficient monitoring capability of its	HIGH	RC			x					
IRO-002-2	R5.		Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could	HIGH	RC		x						
IRO-002-2	R6.		Each Reliability Coordinator shall have adequate analysis tools such as state estimation, pre- and post-contingency analysis capabilities (thermal, stability,	HIGH	RC	x							
IRO-002-2	R7.		Each Reliability Coordinator shall continuously monitor its Reliability Coordinator Area. Each Reliability Coordinator shall have provisions for	HIGH	RC			x					
IRO-002-2	R8.		Each Reliability Coordinator shall control its Reliability Coordinator analysis tools, including approvals for planned maintenance. Each Reliability Coordinator	HIGH	RC	x							
IRO-003-2	R1.		Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability	HIGH	RC								
IRO-003-2	R2.		Each Reliability Coordinator shall know the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or	HIGH	RC								
IRO-004-2	R1.		Each Transmission Operator, Balancing Authority, and Transmission Service Provider shall comply with the directives of its Reliability Coordinator based on the	HIGH	BA, TOP, TSP	x			A		ER		X
IRO-005-3a	R1.		Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:	Pending	RC		x		A				X
IRO-005-3a		R1.1.	Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special	Pending	RC		x		A				X
IRO-005-3a		R1.2.	Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations,	Pending	RC		x		A				X
IRO-005-3a		R1.3.	Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations,	Pending	RC		x		A				X
IRO-005-3a		R1.4.	System real and reactive reserves (actual versus required).	Pending	RC		x		A				X
IRO-005-3a		R1.5.	Capacity and energy adequacy conditions.	Pending	RC		x		A				X
IRO-005-3a		R1.6.	Current ACE for all its Balancing Authorities.	Pending	RC		x		A				X

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IRO-005-3a		R1.7.	Current local or Transmission Loading Relief procedures in effect.	Pending	RC		x			A					X
IRO-005-3a		R1.8.	Planned generation dispatches.	Pending	RC		x			A					X
IRO-005-3a		R1.9.	Planned transmission or generation outages.	Pending	RC		x			A					X
IRO-005-3a		R1.10.	Contingency events.	Pending	RC		x			A					X
IRO-005-3a	R2.		Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and	Pending	RC		x			A					X
IRO-005-3a	R3.		Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information	Pending	RC	x				A					X
IRO-005-3a	R4.		The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.	Pending	RC		x			A					X
IRO-005-3a	R5.		Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS	Pending	BA, RC, TOP		x			A					X
IRO-005-3a	R6.		The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and	Pending	RC	x				A					X
IRO-005-3a	R7.		As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring	Pending	RC		x			A					X
IRO-005-3a	R8.		The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange	Pending	RC		x			A					X
IRO-005-3a	R9.		Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect	Pending	RC, TOP	x				A					X
IRO-005-3a	R10.		In instances where there is a difference in derived limits, the Transmission Operators, Balancing Authorities, Generator Operators, Transmission	Pending	BA, GOP, LSE, PSE, TOP, TSP	x				A					X
IRO-005-3a	R11.		The Transmission Service Provider shall respect SOLs and IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available	Pending	TSP			x		A					X
IRO-005-3a	R12.		Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability	Pending	RC	x				A					X
IRO-006-5	R1.		A Reliability Coordinator experiencing a potential or actual SOL or IROL violation within its Reliability Coordinator Area shall, with its authority and at its	HIGH	RC		x								
IRO-006-EAST-1	R1.		When acting or instructing others to act to mitigate the magnitude and duration of the instance of exceeding an IROL within that IROL's TV, each Reliability	HIGH	RC		x								
IRO-006-EAST-1	R2.		To ensure operating entities are provided with information needed to maintain an awareness of changes to the Transmission System, when initiating the	MEDIUM	RC		x								
IRO-006-EAST-1		R2.1.	A list of congestion management actions to be implemented, and	MEDIUM	RC		x								
IRO-006-EAST-1		R2.2.	One of the following TLR levels: TLR-1, TLR-2, TLR-3A, TLR-3B, TLR-4, TLR-5A, TLR-5B, TLR-6, TLR-0	MEDIUM	RC		x								
IRO-006-EAST-1	R3.		Upon the identification of the TLR level and a list of congestion management actions to be implemented, the Reliability Coordinator initiating this TLR procedure	MEDIUM	RC		x								
IRO-006-EAST-1		R3.1.	Notify all Reliability Coordinators in the Eastern Interconnection of the identified TLR level	MEDIUM	RC		x								
IRO-006-EAST-1		R3.2.	Communicate the list of congestion management actions to be implemented to 1.) all Reliability Coordinators in the Eastern Interconnection, and 2.) those	MEDIUM	RC		x								
IRO-006-EAST-1		R3.3.	Request that the congestion management actions identified in Requirement R2, Part 2.1 be implemented by: 1.) Each Reliability Coordinator	MEDIUM	RC		x								
IRO-006-EAST-1	R4.		Each Reliability Coordinator that receives a request as described in Requirement R3, Part 3.3. shall, within 15 minutes of receiving the request, implement the	HIGH	RC		x								

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IRO-006-WECC-1	R1.		Upon receiving a request of Step 4 or greater (see Attachment 1-IRO-006-WECC-1) from the Transmission Operator of a Qualified Transfer Path, the Reliability	MEDIUM	RC		x								
IRO-006-WECC-1	R2.		The Balancing Authorities shall approve curtailment requests to the schedules as submitted, implement alternative actions, or a combination there of that collectively	MEDIUM	BA		x								
IRO-008-1	R1.		Each Reliability Coordinator shall perform an Operational Planning Analysis to assess whether the planned operations for the next day within its Wide Area, will	MEDIUM	RC										
IRO-008-1	R2.		Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is	HIGH	RC										
IRO-008-1	R3.		When a Reliability Coordinator determines that the results of an Operational Planning Analysis or Real-Time Assessment indicates the need for specific operational	MEDIUM	RC										
IRO-009-1	R1.		For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability	MEDIUM	RC										
IRO-009-1	R2.		For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability	MEDIUM	RC										
IRO-009-1	R3.		When an assessment of actual or expected system conditions predicts that an IROL in its Reliability Coordinator Area will be exceeded, the Reliability	HIGH	RC										
IRO-009-1	R4.		When actual system conditions show that there is an instance of exceeding an IROL in its Reliability Coordinator Area, the Reliability Coordinator shall, without	HIGH	RC										
IRO-009-1	R5.		If unanimity cannot be reached on the value for an IROL or its Tv, each Reliability Coordinator that monitors that Facility (or group of Facilities) shall,	HIGH	RC										
IRO-010-1a	R1.		The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring,	LOWER	RC										
IRO-010-1a		R1.1.	List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-	LOWER	RC										
IRO-010-1a		R1.2.	Mutually agreeable format.	LOWER	RC										
IRO-010-1a		R1.3.	Timeframe and periodicity for providing data and information (based on its hardware and software requirements, and the time needed to do its Operational	LOWER	RC										
IRO-010-1a		R1.4.	Process for data provision when automated Real-Time system operating data is unavailable.	LOWER	RC										
IRO-010-1a	R2.		The Reliability Coordinator shall distribute its data specification to entities that have Facilities monitored by the Reliability Coordinator and to entities that provide	LOWER	RC										
IRO-010-1a	R3.		Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and	MEDIUM	BA, GO, GOP, IA, LSE, RC, TO, TOP										
IRO-014-1	R1.		The Reliability Coordinator shall have Operating Procedures, Processes, or Plans in place for activities that require notification, exchange of information or	MEDIUM	RC		x								
IRO-014-1		R1.1.	These Operating Procedures, Processes, or Plans shall collectively address, as a minimum, the following:	LOWER	RC		x								
IRO-014-1		R1.1.1.	Communications and notifications, including the conditions under which one Reliability Coordinator notifies other Reliability Coordinators; the process to	MEDIUM	RC		x								
IRO-014-1		R1.1.2.	Energy and capacity shortages.	MEDIUM	RC		x								
IRO-014-1		R1.1.3.	Planned or unplanned outage information.	MEDIUM	RC		x								
IRO-014-1		R1.1.4.	Voltage control, including the coordination of reactive resources for voltage control.	MEDIUM	RC		x								
IRO-014-1		R1.1.5.	Coordination of information exchange to support reliability assessments.	LOWER	RC		x								
IRO-014-1		R1.1.6.	Authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas.	LOWER	RC		x								

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IRO-014-1	R2.		Each Reliability Coordinator's Operating Procedure, Process, or Plan that requires one or more other Reliability Coordinators to take action (e.g., make notifications,	LOWER	RC			x							
IRO-014-1		R2.1.	Agreed to by all the Reliability Coordinators required to take the indicated action(s).	LOWER	RC			x							
IRO-014-1		R2.2.	Distributed to all Reliability Coordinators that are required to take the indicated action(s).	LOWER	RC			x							
IRO-014-1	R3.		A Reliability Coordinator's Operating Procedures, Processes, or Plans developed to support a Reliability Coordinator-to-Reliability Coordinator	MEDIUM	RC			x							
IRO-014-1		R3.1.	A reference to the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.	MEDIUM	RC			x							
IRO-014-1		R3.2.	The agreed-upon actions from the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.	LOWER	RC			x							
IRO-014-1	R4.		Each of the Operating Procedures, Processes, and Plans addressed in Reliability Standard IRO-014 Requirement 1 and Requirement 3 shall:	LOWER	RC			x							
IRO-014-1		R4.1.	Include version control number or date	LOWER	RC			x							
IRO-014-1		R4.2.	Include a distribution list.	LOWER	RC			x							
IRO-014-1		R4.3.	Be reviewed, at least once every three years, and updated if needed.	LOWER	RC			x							
IRO-015-1	R1.		The Reliability Coordinator shall follow its Operating Procedures, Processes, or Plans for making notifications and exchanging reliability-related information	MEDIUM	RC										
IRO-015-1		R1.1.	The Reliability Coordinator shall make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may	MEDIUM	RC										
IRO-015-1	R2.		The Reliability Coordinator shall participate in agreed upon conference calls and other communication forums with adjacent Reliability Coordinators.	LOWER	RC										
IRO-015-1		R2.1.	The frequency of these conference calls shall be agreed upon by all involved Reliability Coordinators and shall be at least weekly.	LOWER	RC										
IRO-015-1	R3.		The Reliability Coordinator shall provide reliability-related information as requested by other Reliability Coordinators.	MEDIUM	RC										
IRO-016-1	R1.		The Reliability Coordinator that identifies a potential, expected, or actual problem that requires the actions of one or more other Reliability Coordinators shall	MEDIUM	RC										
IRO-016-1		R1.1.	If the involved Reliability Coordinators agree on the problem and the actions to take to prevent or mitigate the system condition, each involved Reliability	MEDIUM	RC										
IRO-016-1		R1.2.	If the involved Reliability Coordinators cannot agree on the problem(s) each Reliability Coordinator shall re-evaluate the causes of the disagreement (bad data,	MEDIUM	RC										
IRO-016-1		R1.2.1.	If time permits, this re-evaluation shall be done before taking corrective actions.	MEDIUM	RC										
IRO-016-1		R1.2.2.	If time does not permit, then each Reliability Coordinator shall operate as though the problem(s) exist(s) until the conflicting system status is resolved.	MEDIUM	RC										
IRO-016-1		R1.3.	If the involved Reliability Coordinators cannot agree on the solution, the more conservative solution shall be implemented.	MEDIUM	RC										
IRO-016-1	R2.		The Reliability Coordinator shall document (via operator logs or other data sources) its actions taken for either the event or for the disagreement on the	LOWER	RC										
			MODELING, DATA AND ANALYSIS												
MOD-001-1a	R1.		Each Transmission Operator shall select one of the methodologies1 listed below for calculating Available Transfer Capability	Pending	TOP	x				A					X
MOD-001-1a	R2.		Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its	Pending	TSP	x				A					X

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MOD-001-1a		R2.1.	Hourly values for at least the next 48 hours.	Pending	TSP	x				A					X
MOD-001-1a		R2.2.	Daily values for at least the next 31 calendar days.	Pending	TSP	x				A					X
MOD-001-1a		R2.3.	Monthly values for at least the next 12 months (months 2-13).	Pending	TSP	x				A					X
MOD-001-1a	R3.		Each Transmission Service Provider shall prepare and keep current an Available Transfer Capability Implementation Document (ATCID) that includes, at a	Pending	TSP	x				A					X
MOD-001-1a		R3.1.	Information describing how the selected methodology (or methodologies) has been implemented, in such detail that, given the same information used by the	Pending	TSP	x				A					X
MOD-001-1a		R3.2.	A description of the manner in which the Transmission Service Provider will account for counterflows including:	Pending	TSP	x				A					X
MOD-001-1a		R3.2.1.	How confirmed Transmission reservations, expected Interchange and internal counterflow are addressed in firm and non-firm ATC or	Pending	TSP	x				A					X
MOD-001-1a		R3.2.2.	A rationale for that accounting specified in R3.2.	Pending	TSP	x				A					X
MOD-001-1a		R3.3.	The identity of the Transmission Operators and Transmission Service Providers from which the Transmission Service Provider receives data for use in	Pending	TSP	x				A					X
MOD-001-1a		R3.4.	The identity of the Transmission Service Providers and Transmission Operators to which it provides data for use in calculating transfer or Flowgate	Pending	TSP	x				A					X
MOD-001-1a		R3.5.	A description of the allocation processes listed below that are applicable to the Transmission Service Provider: a) Processes used to allocate transfer or	Pending	TSP	x				A					X
MOD-001-1a		R3.6.	A description of how generation and transmission outages are considered in transfer or Flowgate capability calculations, including:	Pending	TSP	x				A					X
MOD-001-1a		R3.6.1.	The criteria used to determine when an outage that is in effect part of a day impacts a daily calculation.	Pending	TSP	x				A					X
MOD-001-1a		R3.6.2.	The criteria used to determine when an outage that is in effect part of a month impacts a monthly calculation.	Pending	TSP	x				A					X
MOD-001-1a		R3.6.3.	How outages from other Transmission Service Providers that can not be mapped to the Transmission model used to calculate transfer	Pending	TSP	x				A					X
MOD-001-1a	R4.		The Transmission Service Provider shall notify the following entities before implementing a new or revised ATCID:	Pending	TSP	x				A					X
MOD-001-1a		R4.1.	Each Planning Coordinator associated with the Transmission Service Provider's area.	Pending	TSP	x				A					X
MOD-001-1a		R4.2.	Each Reliability Coordinator associated with the Transmission Service Provider's area.	Pending	TSP	x				A					X
MOD-001-1a		R4.3.	Each Transmission Operator associated with the Transmission Service Provider's area.	Pending	TSP	x				A					X
MOD-001-1a		R4.4.	Each Planning Coordinator adjacent to the Transmission Service Provider's area.	Pending	TSP	x				A					X
MOD-001-1a		R4.5.	Each Reliability Coordinator adjacent to the Transmission Service Provider's area	Pending	TSP	x				A					X
MOD-001-1a		R4.6.	Each Transmission Service Provider whose area is adjacent to the Transmission Service Provider's area.	Pending	TSP	x				A					X
MOD-001-1a	R5.		The Transmission Service Provider shall make available the current ATCID to all of the entities specified in R4.	Pending	TSP	x				A					X
MOD-001-1a	R6.		When calculating Total Transfer Capability (TTC) or Total Flowgate Capability (TFC) the Transmission Operator shall use assumptions no more	Pending	TOP	x				A					X
MOD-001-1a	R7.		When calculating ATC or AFC the Transmission Service Provider shall use assumptions no more limiting than those used in the planning of operations for the	Pending	TSP	x				A					X

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MOD-001-1a	R8.		Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values	Pending	TSP	x			A				X
MOD-001-1a		R8.1.	Hourly values, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required	Pending	TSP	x			A				X
MOD-001-1a		R8.2.	Daily values, once per day	Pending	TSP	x			A				X
MOD-001-1a		R8.3.	Monthly values, once per week.	Pending	TSP	x			A				X
MOD-001-1a	R9.		Within thirty calendar days of receiving a request by any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator for	Pending	TSP	x			A				X
MOD-001-1a		R9.1.	Transmission Service.	Pending	TSP	x			A				X
MOD-001-1a		R9.1.1.	If the Transmission Service Provider uses the data requested in its transfer or Flowgate capability calculations, it shall make the data	Pending	TSP	x			A				X
MOD-001-1a		R9.1.2.	If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, but maintains that	Pending	TSP	x			A				X
MOD-001-1a		R9.1.3.	If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, and does not maintain that	Pending	TSP	x			A				X
MOD-001-1a		R9.2.	This data shall be made available by the Transmission Provider on the schedule specified by the requestor (but no more frequently than once per hour, unless	Pending	TSP	x			A				X
MOD-004-1	R1.		The Transmission Service Provider that maintains CBM shall prepare and keep current a "Capacity Benefit Margin Implementation Document" (CBMID) that	Pending	TSP	x			A				X
MOD-004-1		R1.1.	The process through which a Load-Serving Entity within a Balancing Authority Area associated with the Transmission Service Provider, or the	Pending	TSP	x			A				X
MOD-004-1		R1.2.	The procedure and assumptions for establishing CBM for each Available Transfer Capability (ATC) Path or Flowgate.	Pending	TSP	x			A				X
MOD-004-1		R1.3.	The procedure for a Load-Serving Entity or Balancing Authority to use Transmission capacity set aside as CBM, including the manner in which the	Pending	TSP	x			A				X
MOD-004-1	R2.		The Transmission Service Provider that maintains CBM shall make available its current CBMID to the Transmission Operators, Transmission Service	Pending	TSP	x			A				X
MOD-004-1	R3.		Each Load-Serving Entity determining the need for Transmission capacity to be set aside as CBM for imports into a Balancing Authority Area shall determine that need	Pending	LSE	x			A				X
MOD-004-1		R3.1.	Using one or more of the following to determine the GCIR: a) Loss of Load Expectation (LOLE) studies	Pending	LSE	x			A				X
MOD-004-1		R3.2.	Identifying expected import path(s) or source region(s).	Pending	LSE	x			A				X
MOD-004-1	R4.		Each Resource Planner determining the need for Transmission capacity to be set aside as CBM for imports into a Balancing Authority Area shall determine that need	Pending	RP	x			A				X
MOD-004-1		R4.1.	Using one or more of the following to determine the GCIR: a) Loss of Load Expectation (LOLE) studies	Pending	RP	x			A				X
MOD-004-1		R4.2.	Identifying expected import path(s) or source region(s).	Pending	RP	x			A				X
MOD-004-1	R5.		At least every 13 months, the Transmission Service Provider that maintains CBM shall establish a CBM value for each ATC Path or Flowgate to be	Pending	TSP	x			A				X
MOD-004-1		R5.1.	Reflect consideration of each of the following if available: a) Any studies (as described in R3.1) performed by Load-Serving Entities for	Pending	TSP	x			A				X
MOD-004-1		R5.2.	Be allocated as follows: a) For ATC Paths, based on the expected import paths or source regions provided by Load-Serving Entities or Resource	Pending	TSP	x			A				X
MOD-004-1	R6.		At least every 13 months, the Transmission Planner shall establish a CBM value for each ATC Path or Flowgate to be used in planning during each of the	Pending	TP	x			A				X

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MOD-004-1		R6.1.	Reflect consideration of each of the following if available: a) Any studies (as described in R3.1) performed by Load-Serving Entities for	Pending	TP	x			A				X
MOD-004-1		R6.2.	Be allocated as follows: a) For ATC Paths, based on the expected import paths or source regions provided by Load-Serving Entities or Resource	Pending	TP	x			A				X
MOD-004-1	R7.		Less than 31 calendar days after the establishment of CBM, the Transmission Service Provider that maintains CBM shall notify all the Load-Serving Entities and	Pending	TSP	x			A				X
MOD-004-1	R8.		Less than 31 calendar days after the establishment of CBM, the Transmission Planner shall notify all the Load-Serving Entities and Resource Planners that	Pending	TP	x			A				X
MOD-004-1	R9.		The Transmission Service Provider that maintains CBM and the Transmission Planner shall each provide (subject to confidentiality and security requirements)	Pending	TSP, TP	x			A				X
MOD-004-1		R9.1.	Each of its associated Transmission Operators within 30 calendar days of their making a request for the data.	Pending	TSP, TP	x			A				X
MOD-004-1		R9.2.	To any Transmission Service Provider, Reliability Coordinator, Transmission Planner, Resource Planner, or Planning Coordinator within 30 calendar days of	Pending	TSP, TP	x			A				X
MOD-004-1	R10.		The Load-Serving Entity or Balancing Authority shall request to import energy over firm Transfer Capability set aside as CBM only when experiencing a declared	Pending	BA, LSE	x			A				X
MOD-004-1	R11.		When reviewing an Arranged Interchange using CBM, all Balancing Authorities and Transmission Service Providers shall waive, within the bounds of reliable	Pending	BA, TSP	x			A				X
MOD-004-1	R12.		The Transmission Service Provider that maintains CBM shall approve, within the bounds of reliable operation, any Arranged Interchange using CBM that is	Pending	TSP	x			A				X
MOD-004-1		R12.1.	The CBM is available	Pending	TSP	x			A				X
MOD-004-1		R12.2.	The EEA 2 is declared within the Balancing Authority Area of the "energy deficient entity," and	Pending	TSP	x			A				X
MOD-004-1		R12.3.	The Load of the "energy deficient entity" is located within the Transmission Service Provider's area.	Pending	TSP	x			A				X
MOD-008-1	R1.		Each Transmission Operator shall prepare and keep current a TRM Implementation Document (TRMID) that includes, as a minimum, the following information:	*Pending*	TOP	x			A				X
MOD-008-1		R1.1.	Identification of (on each of its respective ATC Paths or Flowgates) each of the following components of uncertainty if used in establishing TRM, and a	*Pending*	TOP	x			A				X
MOD-008-1		R1.2.	The description of the method used to allocate TRM across ATC Paths or Flowgates.	*Pending*	TOP	x			A				X
MOD-008-1		R1.3.	The identification of the TRM calculation used for the following time periods:	*Pending*	TOP	x			A				X
MOD-008-1		R1.3.1.	Same day and real-time.	*Pending*	TOP	x			A				X
MOD-008-1		R1.3.2.	Day-ahead and pre-schedule.	*Pending*	TOP	x			A				X
MOD-008-1		R1.3.3.	Beyond day-ahead and pre-schedule, up to thirteen months ahead.	*Pending*	TOP	x			A				X
MOD-008-1	R2.		Each Transmission Operator shall only use the components of uncertainty from R1.1 to establish TRM, and shall not include any of the components of	*Pending*	TOP	x			A				X
MOD-008-1	R3.		Each Transmission Operator shall make available its TRMID, and if requested, underlying documentation (if any) used to determine TRM, in the format used by the	*Pending*	TOP	x			A				X
MOD-008-1	R4.		Each Transmission Operator that maintains TRM shall establish TRM values in accordance with the TRMID at least once every 13 months.	*Pending*	TOP	x			A				X
MOD-008-1	R5.		The Transmission Operator that maintains TRM shall provide the TRM values to its Transmission Service Provider(s) and Transmission Planner(s) no more than	*Pending*	TOP	x			A				X
MOD-010-0	R1.		The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of	MEDIUM	GO, RP, TO, TP								

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MOD-010-0	R2.		The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of	MEDIUM	GO, RP, TO, TP						A				
MOD-012-0	R1.		The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of	MEDIUM	GO, RP, TO, TP										
MOD-012-0	R2.		The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of	MEDIUM	GO, RP, TO, TP						A				
MOD-016-1.1	R1.		The Planning Authority and Regional Reliability Organization shall have documentation identifying the scope and details of the actual and forecast (a)	LOWER	PA, PC, RRO										
MOD-016-1.1		R1.1.	The aggregated and dispersed data submittal requirements shall ensure that consistent data is supplied for Reliability Standards TPL-005, TPL-006, MOD-010,	LOWER	PA, PC, RRO										
MOD-016-1.1	R2.		The Regional Reliability Organization shall distribute its documentation required in Requirement 1 and any changes to that documentation, to all	LOWER	RRO										
MOD-016-1.1		R2.1.	The Regional Reliability Organization shall make this distribution within 30 calendar days of approval.	LOWER	RRO										
MOD-016-1.1	R3.		The Planning Authority shall distribute its documentation required in R1 for reporting customer data and any changes to that documentation, to its Transmission	LOWER	PA, PC										
MOD-016-1.1		R3.1.	The Planning Authority shall make this distribution within 30 calendar days of approval.	LOWER	PA, PC										
MOD-017-0.1	R1.		The Load-Serving Entity, Planning Authority and Resource Planner shall each provide the following information annually on an aggregated Regional,	MEDIUM	LSE, PA, PC, RP										
MOD-017-0.1		R1.1.	Integrated hourly demands in megawatts (MW) for the prior year.	MEDIUM	LSE, PA, PC, RP										
MOD-017-0.1		R1.2.	Monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year.	MEDIUM	LSE, PA, PC, RP										
MOD-017-0.1		R1.3.	Monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years.	MEDIUM	LSE, PA, PC, RP										
MOD-017-0.1		R1.4.	Annual Peak hour forecast demands (summer and winter) in MW and annual Net Energy for load in GWh for at least five years and up to ten years into the	MEDIUM	LSE, PA, PC, RP										
MOD-018-0	R1.		The Load-Serving Entity, Planning Authority, Transmission Planner and Resource Planner's report of actual and forecast demand data (reported on either	MEDIUM	LSE, PA, PC, RP, TP										
MOD-018-0		R1.1.	Indicate whether the demand data of nonmember entities within an area or Regional Reliability Organization are included, and	MEDIUM	LSE, PA, PC, RP, TP										
MOD-018-0		R1.2.	Address assumptions, methods, and the manner in which uncertainties are treated in the forecasts of aggregated peak demands and Net Energy for Load.	LOWER	LSE, PA, PC, RP, TP										
MOD-018-0		R1.3.	Items (MOD-018-0_R 1.1) and (MOD-018-0_R 1.2) shall be addressed as described in the reporting procedures developed for Standard MOD-016-1_R 1.	LOWER	LSE, PA, PC, RP, TP										
MOD-018-0	R2.		The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each report data associated with Reliability Standard MOD-	LOWER	LSE, PA, PC, RP, TP										
MOD-019-0.1	R1.		The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each provide annually its forecasts of interruptible	MEDIUM	LSE, PA, PC, RP, TP										
MOD-020-0	R1.		The Load-Serving Entity, Transmission Planner, and Resource Planner shall each make known its amount of interruptible demands and Direct Control Load	LOWER	LSE, RP, TP										
MOD-021-1	R1.		The Load-Serving Entity, Transmission Planner and Resource Planner's forecasts shall each clearly document how the Demand and energy effects of DSM	LOWER	LSE, RP, TP										
MOD-021-1	R2.		The Load-Serving Entity, Transmission Planner and Resource Planner shall each include information detailing how Demand-Side Management measures are	LOWER	LSE, RP, TP										
MOD-021-1	R3.		The Load-Serving Entity, Transmission Planner and Resource Planner shall each make documentation on the treatment of its DSM programs available to NERC on	LOWER	LSE, RP, TP										
MOD-028-1	R1.		Each Transmission Service Provider shall include in its Available Transfer Capability Implementation Document (ATCID), at a minimum, the following information	Pending	TSP		x								

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MOD-028-1		R1.1.	Information describing how the selected methodology has been implemented, in such detail that, given the same information used by the Transmission	Pending	TSP		x								
MOD-028-1		R1.2.	A description of the manner in which the Transmission Operator will account for Interchange Schedules in the calculation of TTC.	Pending	TSP		x								
MOD-028-1		R1.3.	Any contractual obligations for allocation of TTC.	Pending	TSP		x								
MOD-028-1		R1.4.	A description of the manner in which Contingencies are identified for use in the TTC process.	Pending	TSP		x								
MOD-028-1		R1.5.	The following information on how source and sink for transmission service is accounted for in ATC calculations including:	Pending	TSP		x								
MOD-028-1		R1.5.1.	Define if the source used for Available Transfer Capability (ATC) calculations is obtained from the source field or the Point of Receipt	Pending	TSP		x								
MOD-028-1		R1.5.2.	Define if the sink used for ATC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission	Pending	TSP		x								
MOD-028-1		R1.5.3.	The source/sink or POR/POD identification and mapping to the model	Pending	TSP		x								
MOD-028-1		R1.5.4.	If the Transmission Service Provider's ATC calculation process involves a grouping of generation, the ATCID must identify how	Pending	TSP		x								
MOD-028-1	R2.		When calculating TTC for ATC Paths, the Transmission Operator shall use a Transmission model that contains all of the following:	Pending	TOP		x								
MOD-028-1		R2.1.	Modeling data and topology of its Reliability Coordinator's area of responsibility. Equivalent representation of radial lines and facilities 161 kV or	Pending	TOP		x								
MOD-028-1		R2.2.	Modeling data and topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination areas.	Pending	TOP		x								
MOD-028-1		R2.3.	Facility Ratings specified by the Generator Owners and Transmission Owners.	Pending	TOP		x								
MOD-028-1	R3.		When calculating TTCs for ATC Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's area. The Transmission	Pending	TOP		x								
MOD-028-1		R3.1.	For on-peak and off-peak intra-day and next-day TTCs, use the following (as well as any other values and additional parameters as specified in the ATCID):	Pending	TOP		x								
MOD-028-1		R3.1.1.	Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.	Pending	TOP		x								
MOD-028-1		R3.1.2.	Load forecast for the applicable period being calculated.	Pending	TOP		x								
MOD-028-1		R3.1.3.	Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the	Pending	TOP		x								
MOD-028-1		R3.2.	For days two through 31 TTCs and for months two through 13 TTCs, use the following (as well as any other values and internal parameters as specified in the	Pending	TOP		x								
MOD-028-1		R3.2.1.	Expected generation and Transmission outages, additions, and Retirements, included as specified in the ATCID.	Pending	TOP		x								
MOD-028-1		R3.2.2.	Daily load forecast for the days two through 31 TTCs being calculated and monthly forecast for months two through 13 months	Pending	TOP		x								
MOD-028-1		R3.2.3.	Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the	Pending	TOP		x								
MOD-028-1	R4.		When calculating TTCs for ATC Paths, the Transmission Operator shall meet all of the following conditions:	Pending	TOP		x								
MOD-028-1		R4.1.	Use all Contingencies meeting the criteria described in the ATCID.	Pending	TOP		x								
MOD-028-1		R4.2.	Respect any contractual allocations of TTC.	Pending	TOP		x								

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MOD-028-1		R4.3.	Include, for each time period, the Firm Transmission Service expected to be scheduled as specified in the ATCID (filtered to reduce or eliminate duplicate	Pending	TOP		x								
MOD-028-1	R5.		Each Transmission Operator shall establish TTC for each ATC Path as defined below:	Pending	TOP		x								
MOD-028-1		R5.1.	At least once within the seven calendar days prior to the specified period for TTCs used in hourly and daily ATC calculations.	Pending	TOP		x								
MOD-028-1		R5.2.	At least once per calendar month for TTCs used in monthly ATC calculations.	Pending	TOP		x								
MOD-028-1		R5.3.	Within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a transformer with a low-side voltage of 200 kV or higher for TTCs in effect during	Pending	TOP		x								
MOD-028-1	R6.		Each Transmission Operator shall establish TTC for each ATC Path using the following process:	Pending	TOP		x								
MOD-028-1		R6.1.	Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing	Pending	TOP		x								
MOD-028-1		R6.2.	If the limit in step R6.1 can not be reached by adjusting any combination of load or generation, then set the incremental Transfer Capability by the results of the	Pending	TOP		x								
MOD-028-1		R6.3.	Use (as the TTC) the lesser of: - The sum of the incremental Transfer Capability and the impacts of Firm Transmission Services, as specified in the	Pending	TOP		x								
MOD-028-1		R6.4.	For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Service Provider so the TTC does not exceed each	Pending	TOP		x								
MOD-028-1	R7.		The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than:	Pending	TOP		x								
MOD-028-1		R7.1.	One calendar day after its determination for TTCs used in hourly and daily ATC calculations.	Pending	TOP		x								
MOD-028-1		R7.2.	Seven calendar days after its determination for TTCs used in monthly ATC calculations.	Pending	TOP		x								
MOD-028-1	R8.		When calculating Existing Transmission Commitments (ETCs) for firm commitments (ETCF) for all time periods for an ATC Path the Transmission Service	Pending	TSP		x								
MOD-028-1	R9.		When calculating ETC for non-firm commitments (ETCNF) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm:	Pending	TSP		x								
MOD-028-1	R10.		When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall utilize the following algorithm:	Pending	TSP		x								
MOD-028-1	R11.		When calculating non-firm ATC for a ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm:	Pending	TSP		x								
MOD-029-1a	R1.		When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements:	Pending	TOP		x								
MOD-029-1a		R1.1.	The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:	Pending	TOP		x								
MOD-029-1a		R1.1.1.	Includes at least:	Pending	TOP		x								
MOD-029-1a		R1.1.1.1.	The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.	Pending	TOP		x								
MOD-029-1a		R1.1.1.2.	All Transmission Operator areas contiguous with its own Transmission Operator area. (Equivalent representation is allowed.)	Pending	TOP		x								
MOD-029-1a		R1.1.1.3.	Any other Transmission Operator area linked to the Transmission Operator's area by joint operating agreement. (Equivalent representation is allowed.	Pending	TOP		x								
MOD-029-1a		R1.1.2.	Models all system Elements as in-service for the assumed initial conditions.	Pending	TOP		x								
MOD-029-1a		R1.1.3.	Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the studied	Pending	TOP		x								

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MOD-029-1a		R1.1.4.	Models phase shifters in non-regulating mode, unless otherwise specified in the Available Transfer Capability Implementation	Pending	TOP		x								
MOD-029-1a		R1.1.5.	Uses Load forecast by Balancing Authority.	Pending	TOP		x								
MOD-029-1a		R1.1.6.	Uses Transmission Facility additions and retirements.	Pending	TOP		x								
MOD-029-1a		R1.1.7.	Uses Generation Facility additions and retirements.	Pending	TOP		x								
MOD-029-1a		R1.1.8.	Uses Special Protection System (SPS) models where currently existing or projected for implementation within the studied time	Pending	TOP		x								
MOD-029-1a		R1.1.9.	Models series compensation for each line at the expected operating level unless specified otherwise in the ATCID.	Pending	TOP		x								
MOD-029-1a		R1.1.10.	Includes any other modeling requirements or criteria specified in the ATCID.	Pending	TOP		x								
MOD-029-1a		R1.2.	Uses Facility Ratings as provided by the Transmission Owner and Generator Owner	Pending	TOP		x								
MOD-029-1a	R2.		The Transmission Operator shall use the following process to determine TTC:	Pending	TOP		x								
MOD-029-1a		R2.1.	Except where otherwise specified within MOD-029-1, adjust base case generation and Load levels within the updated power flow model to determine	Pending	TOP		x								
MOD-029-1a		R2.1.1.	When modeling normal conditions, all Transmission Elements will be modeled at or below 100% of their continuous rating.	Pending	TOP		x								
MOD-029-1a		R2.1.2.	When modeling contingencies the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its Emergency	Pending	TOP		x								
MOD-029-1a		R2.1.3.	Uncontrolled separation shall not occur.	Pending	TOP		x								
MOD-029-1a		R2.2.	Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line),	Pending	TOP		x								
MOD-029-1a		R2.3.	For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the reliability limit as	Pending	TOP		x								
MOD-029-1a		R2.4.	For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and	Pending	TOP		x								
MOD-029-1a		R2.5.	The Transmission Operator shall identify when the TTC for the ATC Path being studied has an adverse impact on the TTC value of any existing path. Do this	Pending	TOP		x								
MOD-029-1a		R2.6.	Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in	Pending	TOP		x								
MOD-029-1a		R2.7.	For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has	Pending	TOP		x								
MOD-029-1a		R2.8.	Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the	Pending	TOP		x								
MOD-029-1a	R3.		Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path.	Pending	TOP		x								
MOD-029-1a	R4.		Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service	Pending	TOP		x								
MOD-029-1a	R5.		When calculating ETC for firm Existing Transmission Commitments (ETCF) for a specified period for an ATC Path, the Transmission Service Provider shall use	Pending	TSP		x								
MOD-029-1a	R6.		When calculating ETC for non-firm Existing Transmission Commitments (ETCNF) for all time horizons for an ATC Path the Transmission Service Provider	Pending	TSP		x								
MOD-029-1a	R7.		When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm:	Pending	TSP		x								

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MOD-029-1a	R8.		When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm:	Pending	TSP		x								
MOD-030-2	R1.		The Transmission Service Provider shall include in its "Available Transfer Capability Implementation Document" (ATCID):	Pending	TSP		x								
MOD-030-2		R1.1.	The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate	Pending	TSP		x								
MOD-030-2		R1.2.	The following information on how source and sink for transmission service is accounted for in AFC calculations including:	Pending	TSP		x								
MOD-030-2		R1.2.1.	Define if the source used for AFC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.	Pending	TSP		x								
MOD-030-2		R1.2.2.	Define if the sink used for AFC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.	Pending	TSP		x								
MOD-030-2		R1.2.3.	The source/sink or POR/POD identification and mapping to the model.	Pending	TSP		x								
MOD-030-2		R1.2.4.	If the Transmission Service Provider's AFC calculation process involves a grouping of generators, the ATCID must identify how these generators	Pending	TSP		x								
MOD-030-2	R2.		The Transmission Operator shall perform the following: [Violation Risk Factor:	Pending	TOP		x								
MOD-030-2		R2.1.	Include Flowgates used in the AFC process based, at a minimum, on the following criteria:	Pending	TOP		x								
MOD-030-2		R2.1.1.	Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator's system up to the path capability such that at a minimum the	Pending	TOP		x								
MOD-030-2		R2.1.1.1.	Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of	Pending	TOP		x								
MOD-030-2		R2.1.1.2.	Only the most limiting element in a series configuration needs to be included as a Flowgate.	Pending	TOP		x								
MOD-030-2		R2.1.1.3.	If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to	Pending	TOP		x								
MOD-030-2		R2.1.2.	Results of a first Contingency transfer analysis from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path	Pending	TOP		x								
MOD-030-2		R2.1.2.1.	Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of	Pending	TOP		x								
MOD-030-2		R2.1.2.2.	Only the most limiting element in a series configuration needs to be included as a Flowgate.	Pending	TOP		x								
MOD-030-2		R2.1.2.3.	If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to	Pending	TOP		x								
MOD-030-2		R2.1.3.	Any limiting Element/Contingency combination at least within its Reliability Coordinator's Area that has been subjected to an	Pending	TOP		x								
MOD-030-2		R2.1.4.	Any limiting Element/Contingency combination within the Transmission model that has been requested to be included by any other Transmission	Pending	TOP		x								
MOD-030-2		R2.1.4.1.	The coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and - Any	Pending	TOP		x								
MOD-030-2		R2.1.4.2.	The limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.	Pending	TOP		x								
MOD-030-2		R2.2.	At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgate definitions at least once per calendar year.	Pending	TOP		x								
MOD-030-2		R2.3.	At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgates that have been requested as part of R2.1.4 within thirty	Pending	TOP		x								
MOD-030-2		R2.4.	Establish the TFC of each of the defined Flowgates as equal to: - For thermal limits, the System Operating Limit (SOL) of the Flowgate.	Pending	TOP		x								

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MOD-030-2		R2.5.	At a minimum, establish the TFC once per calendar year.	Pending	TOP		x								
MOD-030-2		R2.5.1.	If notified of a change in the Rating by the Transmission Owner that would affect the TFC of a flowgate used in the AFC process, the TFC should be updated	Pending	TOP		x								
MOD-030-2		R2.6.	Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.	Pending	TOP		x								
MOD-030-2	R3.		The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability	Pending	TOP		x								
MOD-030-2		R3.1.	Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the Generator Owners of the Facilities within the model.	Pending	TOP		x								
MOD-030-2		R3.2.	Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.	Pending	TOP		x								
MOD-030-2		R3.3.	Updated at least once per month for AFC calculations for months two through 13.	Pending	TOP		x								
MOD-030-2		R3.4.	Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and	Pending	TOP		x								
MOD-030-2		R3.5.	Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.	Pending	TOP		x								
MOD-030-2	R4.		When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: - If the	Pending	TSP		x								
MOD-030-2	R5.		When calculating AFCs, the Transmission Service Provider shall:	Pending	TSP		x								
MOD-030-2		R5.1.	Use the models provided by the Transmission Operator.	Pending	TSP		x								
MOD-030-2		R5.2.	Include in the transmission model expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the	Pending	TSP		x								
MOD-030-2		R5.3.	For external Flowgates, identified in R2.1.4, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.	Pending	TSP		x								
MOD-030-2	R6.		When calculating the impact of ETC for firm commitments (ETCFi) for all time periods for a Flowgate, the Transmission Service Provider shall sum the following:	Pending	TSP		x								
MOD-030-2		R6.1.	The impact of firm Network Integration Transmission Service, including the impacts of generation to load, in the model referenced in R5.2 for the	Pending	TSP		x								
MOD-030-2		R6.1.1.	Load forecast for the time period being calculated, including Native Load and Network Service load	Pending	TSP		x								
MOD-030-2		R6.1.2.	Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as	Pending	TSP		x								
MOD-030-2		R6.2.	The impact of any firm Network Integration Transmission Service, including the impacts of generation to load in the model referenced in R5.2 and	Pending	TSP		x								
MOD-030-2		R6.2.1.	Load forecast for the time period being calculated, including Native Load and Network Service load	Pending	TSP		x								
MOD-030-2		R6.2.2.	Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as	Pending	TSP		x								
MOD-030-2		R6.3.	The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts,	Pending	TSP		x								
MOD-030-2		R6.4.	The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from	Pending	TSP		x								
MOD-030-2		R6.5.	The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.	Pending	TSP		x								
MOD-030-2		R6.6.	The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the	Pending	TSP		x								

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MOD-030-2		R6.7.	The impact of other firm services determined by the Transmission Service Provider.	Pending	TSP		x								
MOD-030-2	R7.		When calculating the impact of ETC for non-firm commitments (ETCNFi) for all time periods for a Flowgate the Transmission Service Provider shall sum:	Pending	TSP		x								
MOD-030-2		R7.1.	The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled for the Transmission Service Provider's area.	Pending	TSP		x								
MOD-030-2		R7.2.	The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts	Pending	TSP		x								
MOD-030-2		R7.3.	The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.	Pending	TSP		x								
MOD-030-2		R7.4.	The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the	Pending	TSP		x								
MOD-030-2		R7.5.	The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service	Pending	TSP		x								
MOD-030-2		R7.6.	The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to	Pending	TSP		x								
MOD-030-2		R7.7.	The impact of other non-firm services determined by the Transmission Service Provider.	Pending	TSP		x								
MOD-030-2	R8.		When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes	Pending	TSP		x								
MOD-030-2	R9.		When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to	Pending	TSP		x								
MOD-030-2	R10.		Each Transmission Service Provider shall recalculate AFC, utilizing the updated models described in R3.2, R3.3, and R5, at a minimum on the following frequency,	Pending	TSP		x								
MOD-030-2		R10.1.	For hourly AFC, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which	Pending	TSP		x								
MOD-030-2		R10.2.	For daily AFC, once per day.	Pending	TSP		x								
MOD-030-2		R10.3.	For monthly AFC, once per week	Pending	TSP		x								
MOD-030-2	R11.		When converting Flowgate AFCs to ATCs for ATC Paths, the Transmission Service Provider shall convert those values based on the following algorithm:	Pending	TSP		x								
			NUCLEAR												
NUC-001-2	R1.		The Nuclear Plant Generator Operator shall provide the proposed NPIRs in writing to the applicable Transmission Entities and shall verify receipt	LOWER	Nuclear GO and Nuclear GOP			x							
NUC-001-2	R2.		The Nuclear Plant Generator Operator and the applicable Transmission Entities shall have in effect one or more Agreements[FN1] that include mutually	MEDIUM	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2	R3.		Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall incorporate the NPIRs into their planning	MEDIUM	Transmission Entities that can include: BA, DP, GO, GOP, LSE, PA,			x							
NUC-001-2	R4.		Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall:	HIGH	Transmission Entities that can include: BA, DP, GO, GOP, LSE, PA,	x									
NUC-001-2		R4.1.	Incorporate the NPIRs into their operating analyses of the electric system.	Part of Main Requirement	Transmission Entities that can include: BA, DP, GO, GOP, LSE, PA,	x									
NUC-001-2		R4.2.	Operate the electric system to meet the NPIRs.	Part of Main Requirement	Transmission Entities that can include: BA, DP, GO, GOP, LSE, PA,	x									
NUC-001-2		R4.3.	Inform the Nuclear Plant Generator Operator when the ability to assess the operation of the electric system affecting NPIRs is lost.	Part of Main Requirement	Transmission Entities that can include: BA, DP, GO, GOP, LSE, PA,	x									
NUC-001-2	R5.		The Nuclear Plant Generator Operator shall operate per the Agreements developed in accordance with this standard.	HIGH	Nuclear GO and Nuclear GOP	x									

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NUC-001-2	R6.		Per the Agreements developed in accordance with this standard, the applicable Transmission Entities and the Nuclear Plant Generator Operator shall	MEDIUM	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2	R7.		Per the Agreements developed in accordance with this standard, the Nuclear Plant Generator Operator shall inform the applicable Transmission	HIGH	Nuclear GO and Nuclear GOP			x							
NUC-001-2	R8.		Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall inform the Nuclear Plant Generator	HIGH	Transmission Entities that can include: BA, DP, GO, GOP, LSE, PA,			x							
NUC-001-2	R9.		The Nuclear Plant Generator Operator and the applicable Transmission Entities shall include, as a minimum, the following elements within the agreement(s)	MEDIUM	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.1.	Administrative elements:	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.1.1.	Definitions of key terms used in the agreement.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.1.2.	Names of the responsible entities, organizational relationships, and responsibilities related to the NPIRs.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.1.3.	A requirement to review the agreement(s) at least every three years.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.1.4.	A dispute resolution mechanism.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.2.	Technical requirements and analysis:	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.2.1.	Identification of parameters, limits, configurations, and operating scenarios included in the NPIRs and, as applicable, procedures for providing any specific	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.2.2.	Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.2.3.	Types of planning and operational analyses performed specifically to support the NPIRs, including the frequency of studies and types of	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.3.	Operations and maintenance coordination:	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.3.1.	Designation of ownership of electrical facilities at the interface between the electric system and the nuclear plant and responsibilities for operational control	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.3.2.	Identification of any maintenance requirements for equipment not owned or controlled by the Nuclear Plant Generator Operator that are necessary to meet the	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.3.3.	Coordination of testing, calibration and maintenance of on-site and off-site power supply systems and related components.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.3.4.	Provisions to address mitigating actions needed to avoid violating NPIRs and to address periods when responsible Transmission Entity loses the ability to	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.3.5.	Provision for considering, within the restoration process, the requirements and urgency of a nuclear plant that has lost all off-site and on-site AC power.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,		x								
NUC-001-2		R9.3.6.	Coordination of physical and cyber security protection of the Bulk Electric System at the nuclear plant interface to ensure each asset is covered under at	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.3.7.	Coordination of the NPIRs with transmission system Special Protection Systems and underfrequency and undervoltage load shedding programs.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.4.	Communications and training:	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,		x								
NUC-001-2		R9.4.1.	Provisions for communications between the Nuclear Plant Generator Operator and Transmission Entities, including communications protocols, notification	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,		x								
NUC-001-2		R9.4.2.	Provisions for coordination during an off-normal or emergency event affecting the NPIRs, including the need to provide timely information explaining the event,	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.4.3.	Provisions for coordinating investigations of causes of unplanned events affecting the NPIRs and developing solutions to minimize future risk of such events.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,		x								

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NUC-001-2		R9.4.4.	Provisions for supplying information necessary to report to government agencies, as related to NPIRs.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,		x						
NUC-001-2		R9.4.5.	Provisions for personnel training, as related to NPIRs.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,		x						
			PERSONNEL PERFORMANCE, TRAINING AND QUALIFICATIONS										
PER-001-0.1	R1.		Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement	HIGH	BA, TOP		x						
PER-002-0	R1.		Each Transmission Operator and Balancing Authority shall be staffed with adequately trained operating personnel.	HIGH	BA, TOP		x		A				X
PER-002-0	R2.		Each Transmission Operator and Balancing Authority shall have a training program for all operating personnel that are in:	HIGH	BA, TOP	x			A				X
PER-002-0		R2.1.	Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk	HIGH	BA, TOP	x			A				X
PER-002-0		R2.2.	Positions directly responsible for complying with NERC standards.	HIGH	BA, TOP	x			A				X
PER-002-0	R3.		For personnel identified in Requirement R2, the Transmission Operator and Balancing Authority shall provide a training program meeting the following	HIGH	BA, TOP	x			A				X
PER-002-0		R3.1.	A set of training program objectives must be defined, based on NERC and Regional Reliability Organization standards, entity operating procedures, and applicable	MEDIUM	BA, TOP	x			A				X
PER-002-0		R3.2.	The training program must include a plan for the initial and continuing training of Transmission Operator and Balancing Authority operating personnel. That plan	MEDIUM	BA, TOP	x			A				X
PER-002-0		R3.3.	The training program must include training time for all Transmission Operator and Balancing Authority operating personnel to ensure their	LOWER	BA, TOP	x			A				X
PER-002-0		R3.4.	Training staff must be identified, and the staff must be competent in both knowledge of system operations and instructional capabilities.	LOWER	BA, TOP	x			A				X
PER-002-0 (retired 4/1/2011)	R4.		For personnel identified in Requirement R2, each Transmission Operator and Balancing Authority shall provide its operating personnel at least five days per	HIGH	BA, TOP				A				X
PER-003-0	R1.		Each Transmission Operator, Balancing Authority, and Reliability Coordinator shall staff all operating positions that meet both of the following criteria with	HIGH	BA, RC, TOP						ER		
PER-003-0		R1.1.	Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk	HIGH	BA, RC, TOP						ER		
PER-003-0		R1.2.	Positions directly responsible for complying with NERC standards.	HIGH	BA, RC, TOP						ER		
PER-004-1 (retired 4/1/2011)	R1.		Each Reliability Coordinator shall be staffed with adequately trained and NERC-certified Reliability Coordinator operators, 24 hours per day, seven days per week.	HIGH	RC								X
PER-004-1 (retired 4/1/2011)	R2.		All Reliability Coordinator operating personnel shall each complete a minimum of five days per year of training and drills using realistic simulations of system	HIGH	RC								
PER-004-1	R3.		Reliability Coordinator operating personnel shall have a comprehensive understanding of the Reliability Coordinator Area and interactions with	HIGH	RC								
PER-004-1	R4.		Reliability Coordinator operating personnel shall have an extensive understanding of the Balancing Authorities, Transmission Operators, and	HIGH	RC								
PER-004-1 (retired 4/1/2011)	R5.		Reliability Coordinator operating personnel shall place particular attention on SOLs and IROLs and inter-tie facility limits. The Reliability Coordinator shall	HIGH	RC								
PER-004-2	R1.		Each Reliability Coordinator shall be staffed with adequately trained and NERC-certified Reliability Coordinator operators, 24 hours per day, seven days per week.	Pending	RC								
PER-004-2	R2.		Reliability Coordinator operating personnel shall place particular attention on SOLs and IROLs and inter-tie facility limits. The Reliability Coordinator shall	Pending	RC								
PER-005-1 (effective 4/1/2013)	R1.		Each Reliability Coordinator, Balancing Authority and Transmission Operator shall use a systematic approach to training to establish a training program for	MEDIUM	BA, RC, TOP								

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PER-005-1 (effective 4/1/2013)		R1.1.	Each Reliability Coordinator, Balancing Authority and Transmission Operator shall create a list of BES company-specific reliability-related tasks performed	MEDIUM	BA, RC, TOP								
PER-005-1 (effective 4/1/2013)		R1.1.1.	Each Reliability Coordinator, Balancing Authority and Transmission Operator shall update its list of BES company-specific reliability-related tasks performed	MEDIUM	BA, RC, TOP								
PER-005-1 (effective 4/1/2013)		R1.2.	Each Reliability Coordinator, Balancing Authority and Transmission Operator shall design and develop learning objectives and training materials based on	MEDIUM	BA, RC, TOP								
PER-005-1 (effective 4/1/2013)		R1.3.	Each Reliability Coordinator, Balancing Authority and Transmission Operator shall deliver the training established in R1.2.	MEDIUM	BA, RC, TOP								
PER-005-1 (effective 4/1/2013)		R1.4.	Each Reliability Coordinator, Balancing Authority and Transmission Operator shall conduct an annual evaluation of the training program established in R1, to	MEDIUM	BA, RC, TOP								
PER-005-1 (effective 4/1/2013)	R2.		Each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify each of its System Operator's capabilities to perform each assigned task	HIGH	BA, RC, TOP								
PER-005-1 (effective 4/1/2013)		R2.1.	Within six months of a modification of the BES company-specific reliability-related tasks, each Reliability Coordinator, Balancing Authority and Transmission	HIGH	BA, RC, TOP								
PER-005-1 (effective 4/1/2011)	R3.		At least every 12 months each Reliability Coordinator, Balancing Authority and Transmission Operator shall provide each of its System Operators with at least 32	MEDIUM	BA, RC, TOP			x					
PER-005-1 (effective 4/1/2014)		R3.1	Each Reliability Coordinator, Balancing Authority and Transmission Operator that has operational authority or control over Facilities with established IROLs or has	MEDIUM	BA, RC, TOP								
			PROTECTION AND CONTROL										
PRC-001-1	R1.		Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.	HIGH	BA, GOP, TOP	x			A				X
PRC-001-1	R2.		Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:	HIGH	GOP, TOP		x		A				X
PRC-001-1		R2.1.	If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority.	HIGH	GOP	x			A				X
PRC-001-1		R2.2.	If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected	HIGH	TOP	x			A				X
PRC-001-1	R3.		A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.	No VRF Assigned	GOP, TOP		x		A				X
PRC-001-1		R3.1.	Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host	HIGH	GOP	x			A				X
PRC-001-1		R3.2.	Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and	HIGH	TOP	x			A				X
PRC-001-1	R4.		Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators,	HIGH	TOP		x		A				X
PRC-001-1	R5.		A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require	HIGH	GOP, TOP		x		A				X
PRC-001-1		R5.1.	Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in	HIGH	GOP		x		A				X
PRC-001-1		R5.2.	Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating	HIGH	TOP		x		A				X
PRC-001-1	R6.		Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected	HIGH	BA, TOP		x		A				X
PRC-004-1 (PRC-004-2 R1 Eff. 4/1/12)	R1.		The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1.	HIGH	DP, TO		x		A				X

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PRC-004-1	R2.		The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for PRC-003 R1.	HIGH	GO		x						X
PRC-004-1	R3.		The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective	LOWER	DP, GO, TO		x						
PRC-004-2 effective 4/1/2012	R1.		The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to	HIGH	DP, TO								
PRC-004-2 effective 4/1/2012	R2.		The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's	HIGH	GO								
PRC-004-2 effective 4/1/2012	R3.		The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective	LOWER	DP, GO, TO								
PRC-005-1	R1.		Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation	HIGH	DP, GO, TO		x		A				X
PRC-005-1		R1.1.	Maintenance and testing intervals and their basis.	HIGH	DP, GO, TO		x		A				X
PRC-005-1		R1.2.	Summary of maintenance and testing procedures.	HIGH	DP, GO, TO		x		A				X
PRC-005-1	R2.		Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation	LOWER	DP, GO, TO	x			A				X
PRC-005-1		R2.1.	Evidence Protection System devices were maintained and tested within the defined intervals.	HIGH	DP, GO, TO	x			A				X
PRC-005-1		R2.2.	Date each Protection System device was last tested/maintained.	HIGH	DP, GO, TO	x			A				X
PRC-007-0	R1.		The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall ensure that its UFLS	MEDIUM	DP, TO								
PRC-007-0	R2.		The Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide, and annually update, its underfrequency data as necessary for its Regional Reliability Organization to	LOWER	DP, LSE, TO, TOP					A			
PRC-007-0	R3.		The Transmission Owner and Distribution Provider that owns a UFLS program (as required by its Regional Reliability Organization) shall provide its	LOWER	DP, TO								
PRC-008-0	R1.		The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall have a UFLS equipment maintenance and testing program in place. This UFLS equipment maintenance and testing program shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance.	MEDIUM	DP, TO			x	A				X
PRC-008-0	R2.		The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall implement its UFLS	MEDIUM	DP, TO			x	A				X
PRC-009-0	R1.		The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by	MEDIUM	DP, LSE, TO, TOP								
PRC-009-0		R1.1.	A description of the event including initiating conditions.	MEDIUM	DP, LSE, TO, TOP								
PRC-009-0		R1.2.	A review of the UFLS set points and tripping times.	MEDIUM	DP, LSE, TO, TOP								

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PRC-009-0		R1.3.	A simulation of the event.	MEDIUM	DP, LSE, TO, TOP										
PRC-009-0		R1.4.	A summary of the findings.	MEDIUM	DP, LSE, TO, TOP										
PRC-009-0	R2.		The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by	LOWER	DP, LSE, TO, TOP										
PRC-010-0	R1.		The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall	MEDIUM	DP, LSE, TO, TOP										
PRC-010-0		R1.1.	This assessment shall include, but is not limited to:	MEDIUM	DP, LSE, TO, TOP										
PRC-010-0		R1.1.1.	Coordination of the UVLS programs with other protection and control systems in the Region and with other Regional Reliability Organizations, as appropriate.	MEDIUM	DP, LSE, TO, TOP										
PRC-010-0		R1.1.2.	Simulations that demonstrate that the UVLS programs performance is consistent with Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-	MEDIUM	DP, LSE, TO, TOP										
PRC-010-0		R1.1.3.	A review of the voltage set points and timing.	MEDIUM	DP, LSE, TO, TOP										
PRC-010-0	R2.		The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall provide	LOWER	DP, LSE, TO, TOP										
PRC-011-0	R1.		The Transmission Owner and Distribution Provider that owns a UVLS system shall have a UVLS equipment maintenance and testing program in place. This program	MEDIUM	DP, TO			x							X
PRC-011-0		R1.1.	The UVLS system identification which shall include but is not limited to:	MEDIUM	DP, TO			x							X
PRC-011-0		R1.1.1.	Relays.	MEDIUM	DP, TO			x							X
PRC-011-0		R1.1.2.	Instrument transformers.	MEDIUM	DP, TO			x							X
PRC-011-0		R1.1.3.	Communications systems, where appropriate.	MEDIUM	DP, TO			x							X
PRC-011-0		R1.1.4.	Batteries.	MEDIUM	DP, TO			x							X
PRC-011-0		R1.2.	Documentation of maintenance and testing intervals and their basis.	MEDIUM	DP, TO			x							X
PRC-011-0		R1.3.	Summary of testing procedure.	MEDIUM	DP, TO			x							X
PRC-011-0		R1.4.	Schedule for system testing.	MEDIUM	DP, TO			x							X
PRC-011-0		R1.5.	Schedule for system maintenance.	MEDIUM	DP, TO			x							X
PRC-011-0		R1.6.	Date last tested/maintained.	MEDIUM	DP, TO			x							X
PRC-011-0	R2.		The Transmission Owner and Distribution Provider that owns a UVLS system shall provide documentation of its UVLS equipment maintenance and testing program and the implementation of that UVLS equipment maintenance and testing program to its Regional Reliability Organization and NERC on request (within 30 calendar days).	LOWER	DP, TO			x		A					
PRC-015-0	R1.		The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall maintain a list of and provide data for existing and proposed	MEDIUM	DP, GO, TO										
PRC-015-0	R2.		The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it reviewed new or functionally modified	MEDIUM	DP, GO, TO										
PRC-015-0	R3.		The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of SPS data and the results of studies that	LOWER	DP, GO, TO										

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PRC-016-0.1	R1.		The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall analyze its SPS operations and maintain a record of all	MEDIUM	DP, GO, TO										
PRC-016-0.1	R2.		The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall take corrective actions to avoid future misoperations.	MEDIUM	DP, GO, TO										
PRC-016-0.1	R3.		The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the misoperation analyses and the	LOWER	DP, GO, TO							ER			
PRC-017-0	R1.		The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have a system maintenance and testing program(s) in place. The program(s) shall include:	HIGH	DP, GO, TO			x							X
PRC-017-0		R1.1.	SPS identification shall include but is not limited to:	HIGH	DP, GO, TO			x							X
PRC-017-0		R1.1.1.	Relays.	HIGH	DP, GO, TO			x							X
PRC-017-0		R1.1.2.	Instrument transformers.	HIGH	DP, GO, TO			x							X
PRC-017-0		R1.1.3.	Communications systems, where appropriate.	HIGH	DP, GO, TO			x							X
PRC-017-0		R1.1.4.	Batteries.	HIGH	DP, GO, TO			x							X
PRC-017-0		R1.2.	Documentation of maintenance and testing intervals and their basis.	HIGH	DP, GO, TO			x							X
PRC-017-0		R1.3.	Summary of testing procedure.	HIGH	DP, GO, TO			x							X
PRC-017-0		R1.4.	Schedule for system testing.	HIGH	DP, GO, TO			x							X
PRC-017-0		R1.5.	Schedule for system maintenance.	HIGH	DP, GO, TO			x							X
PRC-017-0		R1.6.	Date last tested/maintained.	MEDIUM	DP, GO, TO			x							X
PRC-017-0	R2.		The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the program and its implementation to	LOWER	DP, GO, TO			x		A					X
PRC-018-1	R1.		Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard PRC-002	LOWER	GO, TO										
PRC-018-1		R1.1.	Internal Clocks in DME devices shall be synchronized to within 2 milliseconds or less of Universal Coordinated Time scale (UTC)	LOWER	GO, TO										
PRC-018-1		R1.2.	Recorded data from each Disturbance shall be retrievable for ten calendar days..	LOWER	GO, TO										
PRC-018-1	R2.		The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization's installation requirements	LOWER	GO, TO										
PRC-018-1	R3.		The Transmission Owner and Generator Owner shall each maintain, and report to its Regional Reliability Organization on request, the following data on the DMEs	LOWER	GO, TO										
PRC-018-1		R3.1.	Type of DME (sequence of event recorder, fault recorder, or dynamic disturbance recorder).	LOWER	GO, TO										
PRC-018-1		R3.2.	Make and model of equipment.	LOWER	GO, TO										
PRC-018-1		R3.3.	Installation location.	LOWER	GO, TO										
PRC-018-1		R3.4.	Operational status.	LOWER	GO, TO										
PRC-018-1		R3.5.	Date last tested.	LOWER	GO, TO										

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PRC-018-1		R3.6.	Monitored elements, such as transmission circuit, bus section, etc.	LOWER	GO, TO										
PRC-018-1		R3.7.	Monitored devices, such as circuit breaker, disconnect status, alarms, etc.	LOWER	GO, TO										
PRC-018-1		R3.8.	Monitored electrical quantities, such as voltage, current, etc.	LOWER	GO, TO										
PRC-018-1	R4.		The Transmission Owner and Generator Owner shall each provide Disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's	LOWER	GO, TO										
PRC-018-1	R5.		The Transmission Owner and Generator Owner shall each archive all data recorded by DMEs for Regional Reliability Organization-identified events for at least	LOWER	GO, TO										
PRC-018-1	R6.		Each Transmission Owner and Generator Owner that is required by its Regional Reliability Organization to have DMEs shall have a maintenance and testing	LOWER	GO, TO										
PRC-018-1		R6.1.	Maintenance and testing intervals and their basis.	LOWER	GO, TO										
PRC-018-1		R6.2.	Summary of maintenance and testing procedures.	LOWER	GO, TO										
PRC-021-1	R1.		Each Transmission Owner and Distribution Provider that owns a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES	LOWER	DP, TO						A				
PRC-021-1		R1.1.	Size and location of customer load, or percent of connected load, to be interrupted.	LOWER	DP, TO						A				
PRC-021-1		R1.2.	Corresponding voltage set points and overall scheme clearing times.	MEDIUM	DP, TO						A				
PRC-021-1		R1.3.	Time delay from initiation to trip signal.	LOWER	DP, TO						A				
PRC-021-1		R1.4.	Breaker operating times.	LOWER	DP, TO						A				
PRC-021-1		R1.5.	Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration	LOWER	DP, TO						A				
PRC-021-1	R2.		Each Transmission Owner and Distribution Provider that owns a UVLS program shall provide its UVLS program data to the Regional Reliability	LOWER	DP, TO										
PRC-022-1	R1.		Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program to mitigate the risk of voltage collapse or voltage	MEDIUM	DP, LSE, TOP										
PRC-022-1		R1.1.	A description of the event including initiating conditions.	LOWER	DP, LSE, TOP										
PRC-022-1		R1.2.	A review of the UVLS set points and tripping times.	MEDIUM	DP, LSE, TOP										
PRC-022-1		R1.3.	A simulation of the event, if deemed appropriate by the Regional Reliability Organization. For most events, analysis of sequence of events may be sufficient	LOWER	DP, LSE, TOP										
PRC-022-1		R1.4.	A summary of the findings.	LOWER	DP, LSE, TOP										
PRC-022-1		R1.5.	For any Misoperation, a Corrective Action Plan to avoid future Misoperations of a similar nature.	MEDIUM	DP, LSE, TOP										
PRC-022-1	R2.		Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall provide documentation of its analysis of	LOWER	DP, LSE, TOP										

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PRC-023-1	R1.		Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (R1.1 through R1.13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees:	HIGH	TO, GO, DP		x		A				X
PRC-023-1		R1.1.	Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading	Part of Main Requirement	TO, GO, DP		x		A				X
PRC-023-1		R1.2.	Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating of a circuit (expressed in amperes).	Part of Main Requirement	TO, GO, DP		x		A				X
PRC-023-1		R1.3.	Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle	Part of Main Requirement	TO, GO, DP		x		A				X
PRC-023-1		R1.3.1.	An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.	Part of Main Requirement	TO, GO, DP		x		A				X
PRC-023-1		R1.3.2.	An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.	Part of Main Requirement	TO, GO, DP		x		A				X
PRC-023-1		R1.4.	Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line,	Part of Main Requirement	TO, GO, DP		x		A				X
PRC-023-1		R1.5.	Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in	Part of Main Requirement	TO, GO, DP		x		A				X
PRC-023-1		R1.6.	Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the	Part of Main Requirement	TO, GO, DP		x		A				X
PRC-023-1		R1.7.	Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum	Part of Main Requirement	TO, GO, DP		x		A				X
PRC-023-1		R1.8.	Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of	Part of Main Requirement	TO, GO, DP		x		A				X
PRC-023-1		R1.9.	Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of	Part of Main Requirement	TO, GO, DP		x		A				X
PRC-023-1		R1.10.	Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that they do not operate at	Part of Main Requirement	TO, GO, DP		x		A				X
PRC-023-1		R1.11.	For transformer overload protection relays that do not comply with R1.10 set the relays according to one of the following:	Part of Main Requirement	TO, GO, DP		x		A				X
PRC-023-1		R1.12.	When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays	Part of Main Requirement	TO, GO, DP		x		A				X
PRC-023-1		R1.12.1.	Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.	Part of Main Requirement	TO, GO, DP		x		A				X
PRC-023-1		R1.12.2.	Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.	Part of Main Requirement	TO, GO, DP		x		A				X
PRC-023-1		R1.12.3.	Include a relay setting component of 87% of the current calculated in R1.12.2 in the Facility Rating determination for the circuit.	Part of Main Requirement	TO, GO, DP		x		A				X
PRC-023-1		R1.13.	Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such	Part of Main Requirement	TO, GO, DP		x		A				X
PRC-023-1	R2.		The Transmission Owner, Generator Owner, or Distribution Provider that uses a circuit capability with the practical limitations described in R1.6, R1.7, R1.8,	MEDIUM	TO, GO, DP			x					
PRC-023-1	R3.		The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals	MEDIUM	PA, PC		x		A				
PRC-023-1		R3.1.	The Planning Coordinator shall have a process to determine the facilities that are critical to the reliability of the Bulk Electric System.	Part of Main Requirement	PA, PC		x		A				

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PRC-023-1		R3.1.1.	This process shall consider input from adjoining Planning Coordinators and affected Reliability Coordinators.	Part of Main Requirement	PA, PC		x			A					
PRC-023-1		R3.2.	The Planning Coordinator shall maintain a current list of facilities determined according to the process described in R3.1.	Part of Main Requirement	PA, PC		x			A					
PRC-023-1		R3.3.	The Planning Coordinator shall provide a list of facilities to its Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution	Part of Main Requirement	PA, PC		x			A					
			TRANSMISSION OPERATIONS												
TOP-001-1	R1.		Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.	HIGH	TOP		x								
TOP-001-1	R2.		Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules,	HIGH	TOP		x								
TOP-001-1	R3.		Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission	HIGH	BA, GOP, TOP		x								
TOP-001-1	R4.		Each Distribution Provider and Load-Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including	HIGH	DP, LSE		x								
TOP-001-1	R5.		Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real-time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.	HIGH	TOP		x								
TOP-001-1	R6.		Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the	HIGH	BA, GOP, TOP		x								
TOP-001-1	R7.		Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden	HIGH	GOP, TOP		x								
TOP-001-1		R7.1.	For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the	HIGH	GOP, TOP		x								
TOP-001-1		R7.2.	For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify	HIGH	TOP		x								
TOP-001-1		R7.3.	When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer	HIGH	GOP, TOP		x								
TOP-001-1	R8.		During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to	HIGH	BA, RC, TOP		x								
TOP-002-2a	R1.		Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.	MEDIUM	BA, TOP		x								
TOP-002-2a	R2.		Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study	MEDIUM	BA, TOP		x								

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TOP-002-2a	R3.		Each Load-Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.	MEDIUM	BA, GOP, LSE, TSP		x			A					X
TOP-002-2a	R4.		Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal	MEDIUM	BA, TOP		x								
TOP-002-2a	R5.		Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange	MEDIUM	BA, TOP		x								
TOP-002-2a	R6.		Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.	MEDIUM	BA, TOP		x								X
TOP-002-2a	R7.		Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single	MEDIUM	BA		x								
TOP-002-2a	R8.		Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.	MEDIUM	BA		x								
TOP-002-2a	R9.		Each Balancing Authority shall plan to meet Interchange Schedules and Ramps.	LOWER	BA		x								
TOP-002-2a	R10.		Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating	MEDIUM	BA, TOP		x								
TOP-002-2a	R11.		The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission	MEDIUM	TOP		x			A					X
TOP-002-2a	R12.		The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in	MEDIUM	TSP		x								
TOP-002-2a	R13.		At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that	MEDIUM	GOP		x								
TOP-002-2a	R14.		Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and	MEDIUM	GOP		x								
TOP-002-2a		R14.1.	Changes in real output capabilities. (Effective August 1, 2007)	MEDIUM	GOP		x								
TOP-002-2a		R14.2.	Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)	LOWER	GOP		x								
TOP-002-2a	R15.		Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in	LOWER	GOP		x								
TOP-002-2a	R16.		Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability	MEDIUM	TOP		x								
TOP-002-2a		R16.1.	Changes in transmission facility status.	HIGH	TOP		x								
TOP-002-2a		R16.2.	Changes in transmission facility rating.	HIGH	TOP		x								
TOP-002-2a	R17.		Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16	HIGH	BA, TOP	x									
TOP-002-2a	R18.		Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers, and Load-Serving Entities shall	MEDIUM	BA, GOP, LSE, TOP, TSP	x				A					X
TOP-002-2a	R19.		Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system	MEDIUM	BA, TOP		x								
TOP-003-1	R1.		Generator Operators and Transmission Operators shall provide planned outage information.	No VRF Assigned	GOP, TOP										

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TOP-003-1		R1.1.	Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next	MEDIUM	GOP, TOP										
TOP-003-1		R1.2.	Each Transmission Operator shall provide outage information daily to affected Balancing Authorities and Transmission Operators for scheduled generator and	MEDIUM	RC, TOP										
TOP-003-1		R1.3.	Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western	MEDIUM	GOP, TOP										
TOP-003-1	R2.		Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment,	MEDIUM	BA, GOP, TOP										
TOP-003-1	R3.		Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and	MEDIUM	BA, GOP, TOP										
TOP-003-1	R4.		Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.	MEDIUM	RC										
TOP-004-2	R1.		Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).	HIGH	TOP		x								
TOP-004-2	R2.		Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single	HIGH	TOP		x								
TOP-004-2	R3.		Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as	HIGH	TOP		x								
TOP-004-2	R4.		If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in	HIGH	TOP	x									
TOP-004-2	R5.		Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining	HIGH	TOP		x								
TOP-004-2	R6.		Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including:	MEDIUM	TOP			x		A					X
TOP-004-2		R6.1.	Monitoring and controlling voltage levels and real and reactive power flows.	MEDIUM	TOP			x		A					X
TOP-004-2		R6.2.	Switching transmission elements.	MEDIUM	TOP			x		A					X
TOP-004-2		R6.3.	Planned outages of transmission elements.	MEDIUM	TOP			x		A					X
TOP-004-2		R6.4.	Responding to IROL and SOL violations.	MEDIUM	TOP			x		A					X
TOP-005-2a	R1.		As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric	Pending	NERC_Net Users							ER			
TOP-005-2a	R2.		Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate	Pending	BA, TOP							ER			
TOP-005-2a	R3.		Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to	Pending	PSE							ER			
TOP-006-2	R1.		Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use.	MEDIUM	BA, TOP										
TOP-006-2		R1.1.	Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.	MEDIUM	GOP										
TOP-006-2		R1.2.	Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission	MEDIUM	BA, TOP										
TOP-006-2	R2.		Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive	HIGH	BA, RC, TOP										

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TOP-006-2	R3.		Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning	MEDIUM	BA, RC, TOP										
TOP-006-2	R4.		Each Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to	MEDIUM	BA, TOP										
TOP-006-2	R5.		Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating	MEDIUM	BA, RC, TOP										
TOP-006-2	R6.		Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable)	HIGH	BA, TOP										
TOP-006-2	R7.		Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.	HIGH	BA, RC, TOP										
TOP-007-0	R1.		A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within	HIGH	TOP		x					ER			
TOP-007-0	R2.		Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as	HIGH	TOP		x					ER			
TOP-007-0	R3.		A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply	HIGH	TOP	x									
TOP-007-0	R4.		The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions	HIGH	RC		x					ER			
TOP-008-1	R1.		The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include	HIGH	TOP		x								
TOP-008-1	R2.		Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or	HIGH	TOP		x								
TOP-008-1	R3.		The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition	HIGH	TOP		x								
TOP-008-1	R4.		The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be	MEDIUM	TOP		x								
			TRANSMISSION PLANNING												
TPL-001-0.1	R1.		The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-	HIGH	PA, PC, TP										
TPL-001-0.1		R1.1.	Be made annually.	MEDIUM	PA, PC, TP										
TPL-001-0.1		R1.2.	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.	MEDIUM	PA, PC, TP										
TPL-001-0.1		R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance	MEDIUM	PA, PC, TP										
TPL-001-0.1		R1.3.1.	Cover critical system conditions and study years as deemed appropriate by the entity performing the study.	MEDIUM	PA, PC, TP										
TPL-001-0.1		R1.3.2.	Be conducted annually unless changes to system conditions do not warrant such analyses.	MEDIUM	PA, PC, TP										
TPL-001-0.1		R1.3.3.	Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.	MEDIUM	PA, PC, TP										
TPL-001-0.1		R1.3.4.	Have established normal (pre-contingency) operating procedures in place.	MEDIUM	PA, PC, TP										
TPL-001-0.1		R1.3.5.	Have all projected firm transfers modeled.	MEDIUM	PA, PC, TP										
TPL-001-0.1		R1.3.6.	Be performed for selected demand levels over the range of forecast system demands.	MEDIUM	PA, PC, TP										

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TPL-001-0.1		R1.3.7.	Demonstrate that system performance meets Table 1 for Category A (no contingencies).	MEDIUM	PA, PC, TP										
TPL-001-0.1		R1.3.8.	Include existing and planned facilities.	MEDIUM	PA, PC, TP										
TPL-001-0.1		R1.3.9.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.	MEDIUM	PA, PC, TP										
TPL-001-0.1		R1.4.	Address any planned upgrades needed to meet the performance requirements of Category A.	MEDIUM	PA, PC, TP										
TPL-001-0.1	R2.		When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0_R1, the Planning Authority and	MEDIUM	PA, PC, TP										
TPL-001-0.1		R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.	MEDIUM	PA, PC, TP										
TPL-001-0.1		R2.1.1.	Including a schedule for implementation.	MEDIUM	PA, PC, TP										
TPL-001-0.1		R2.1.2.	Including a discussion of expected required in-service dates of facilities.	MEDIUM	PA, PC, TP										
TPL-001-0.1		R2.1.3.	Consider lead times necessary to implement plans.	MEDIUM	PA, PC, TP										
TPL-001-0.1		R2.2.	Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation	LOWER	PA, PC, TP										
TPL-001-0.1	R3.		The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually	LOWER	PA, PC, TP						A				
TPL-002-0a	R1.		The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is	HIGH	PA, PC, TP			x							X
TPL-002-0a		R1.1.	Be made annually.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.2.	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.3.1.	Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.3.10.	Include the effects of existing and planned protection systems, including any backup or redundant systems.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.3.11.	Include the effects of existing and planned control devices.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.3.12.	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.3.2.	Cover critical system conditions and study years as deemed appropriate by the responsible entity.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.3.3.	Be conducted annually unless changes to system conditions do not warrant such analyses.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.3.4.	Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.3.5.	Have all projected firm transfers modeled.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.3.6.	Be performed and evaluated for selected demand levels over the range of forecast system Demands.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.3.7.	Demonstrate that system performance meets Category B contingencies.	MEDIUM	PA, PC, TP			x							X

Reliability Standard (FERC Approved)	Requirement Number	Supporting Requirement Number	Text of Requirement	Violation Risk Factor	Functions Monitored	2012 Annual Program Audit - 1st Tier	2012 Annual Program Audit - 2nd Tier	2012 Annual Program Audit - 3rd Tier		Self-Cert. Annual (A)	Periodic Data Submittals: Monthly (M), Quarterly (Q), Annual (A)	Exception Reporting (ER)	Spot Check (SC)		2011 Annual Program Audit (X)
TPL-002-0a		R1.3.8.	Include existing and planned facilities.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.3.9.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.4.	Address any planned upgrades needed to meet the performance requirements of Category B of Table I.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.5.	Consider all contingencies applicable to Category B.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a	R2.		When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1, the Planning Authority and	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R2.1.1.	Including a schedule for implementation.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R2.1.2.	Including a discussion of expected required in-service dates of facilities.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R2.1.3.	Consider lead times necessary to implement plans.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R2.2.	Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation	MEDIUM	PA, PC, TP			x							X
TPL-002-0a	R3.		The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually	LOWER	PA, PC, TP		x				A				
TPL-003-0a	R1.		The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is	HIGH	PA, PC, TP			x							X
TPL-003-0a		R1.1.	Be made annually.	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.2.	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.3.1.	Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.3.10.	Include the effects of existing and planned protection systems, including any backup or redundant systems.	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.3.11.	Include the effects of existing and planned control devices.	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.3.12.	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.3.2.	Cover critical system conditions and study years as deemed appropriate by the responsible entity.	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.3.3.	Be conducted annually unless changes to system conditions do not warrant such analyses.	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.3.4.	Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.3.5.	Have all projected firm transfers modeled.	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.3.6.	Be performed and evaluated for selected demand levels over the range of forecast system demands.	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.3.7.	Demonstrate that System performance meets Table 1 for Category C contingencies.	MEDIUM	PA, PC, TP			x							X

Reliability Standard (FERC Approved)	Requirement Number	Supporting Requirement Number	Text of Requirement	Violation Risk Factor	Functions Monitored	2012 Annual Program Audit - 1st Tier	2012 Annual Program Audit - 2nd Tier	2012 Annual Program Audit - 3rd Tier		Self-Cert. Annual (A)	Periodic Data Submittals: Monthly (M), Quarterly (Q), Annual (A)	Exception Reporting (ER)	Spot Check (SC)		2011 Annual Program Audit (X)
TPL-003-0a		R1.3.8.	Include existing and planned facilities.	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.3.9.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.4.	Address any planned upgrades needed to meet the performance requirements of Category C.	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.5.	Consider all contingencies applicable to Category C.	MEDIUM	PA, PC, TP			x							X
TPL-003-0a	R2.		When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0_R1, the Planning Authority and	MEDIUM	PA, PC, TP		x								
TPL-003-0a		R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:	MEDIUM	PA, PC, TP		x								
TPL-003-0a		R2.1.1.	Including a schedule for implementation.	MEDIUM	PA, PC, TP		x								
TPL-003-0a		R2.1.2.	Including a discussion of expected required in-service dates of facilities.	MEDIUM	PA, PC, TP		x								
TPL-003-0a		R2.1.3.	Consider lead times necessary to implement plans.	MEDIUM	PA, PC, TP		x								
TPL-003-0a		R2.2.	Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation	MEDIUM	PA, PC, TP		x								
TPL-003-0a	R3.		The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually	LOWER	PA, PC, TP	x					A				
TPL-004-0	R1.		The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is	MEDIUM	PA, PC, TP		x								
TPL-004-0		R1.1.	Be made annually.	MEDIUM	PA, PC, TP		x								
TPL-004-0		R1.2.	Be conducted for near-term (years one through five).	MEDIUM	PA, PC, TP		x								
TPL-004-0		R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance	MEDIUM	PA, PC, TP		x								
TPL-004-0		R1.3.1.	Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the	MEDIUM	PA, PC, TP		x								
TPL-004-0		R1.3.2.	Cover critical system conditions and study years as deemed appropriate by the responsible entity.	MEDIUM	PA, PC, TP		x								
TPL-004-0		R1.3.3.	Be conducted annually unless changes to system conditions do not warrant such analyses.	MEDIUM	PA, PC, TP		x								
TPL-004-0		R1.3.4.	Have all projected firm transfers modeled.	MEDIUM	PA, PC, TP		x								
TPL-004-0		R1.3.5.	Include existing and planned facilities.	MEDIUM	PA, PC, TP		x								
TPL-004-0		R1.3.6.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.	MEDIUM	PA, PC, TP		x								
TPL-004-0		R1.3.7.	Include the effects of existing and planned protection systems, including any backup or redundant systems.	MEDIUM	PA, PC, TP		x								
TPL-004-0		R1.3.8.	Include the effects of existing and planned control devices.	MEDIUM	PA, PC, TP		x								
TPL-004-0		R1.3.9.	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand	MEDIUM	PA, PC, TP		x								
TPL-004-0		R1.4.	Consider all contingencies applicable to Category D.	MEDIUM	PA, PC, TP		x								

Reliability Standard (FERC Approved)	Requirement Number	Supporting Requirement Number	Text of Requirement	Violation Risk Factor	Functions Monitored	2012 Annual Program Audit - 1st Tier	2012 Annual Program Audit - 2nd Tier	2012 Annual Program Audit - 3rd Tier	Self-Cert. Annual (A)	Periodic Data Submittals: Monthly (M), Quarterly (Q), Annual (A)	Exception Reporting (ER)	Spot Check (SC)	2011 Annual Program Audit (X)
TPL-004-0	R2.		The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities'	LOWER	PA, PC, TP	x				A			
			VOLTAGE AND REACTIVE										
VAR-001-2	R1.		Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed,	HIGH	TOP		x		A				X
VAR-001-2	R2.		Each Transmission Operator shall acquire sufficient reactive resources – which may include, but is not limited to, reactive generation scheduling; transmission line	HIGH	TOP		x		A				X
VAR-001-2	R3.		The Transmission Operator shall specify criteria that exempts generators from compliance with the requirements defined in Requirement 4, and Requirement 6.1.	LOWER	TOP			x	A				X
VAR-001-2		R3.1.	Each Transmission Operator shall maintain a list of generators in its area that are exempt from following a voltage or Reactive Power schedule.	LOWER	TOP			x	A				X
VAR-001-2		R3.2.	For each generator that is on this exemption list, the Transmission Operator shall notify the associated Generator Owner.	LOWER	TOP			x	A				X
VAR-001-2	R4.		Each Transmission Operator shall specify a voltage or Reactive Power schedule at the interconnection between the generator facility and the Transmission Owner's	MEDIUM	TOP		x		A				X
VAR-001-2	R5.		Each Purchasing-Selling Entity and Load Serving Entity shall arrange for (self-provide or purchase) reactive resources – which may include, but is not limited to,	HIGH	LSE, PSE			x					
VAR-001-2	R6.		The Transmission Operator shall know the status of all transmission Reactive Power resources, including the status of voltage regulators and power system stabilizers.	MEDIUM	TOP			x	A				X
VAR-001-2		R6.1.	When notified of the loss of an automatic voltage regulator control, the Transmission Operator shall direct the Generator Operator to maintain or change	MEDIUM	TOP			x	A				X
VAR-001-2	R7.		The Transmission Operator shall be able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow.	HIGH	TOP			x					
VAR-001-2	R8.		Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – which may include, but is not	HIGH	TOP			x					
VAR-001-2	R9.		Each Transmission Operator shall maintain reactive resources – which may include, but is not limited to, reactive generation scheduling; transmission line	HIGH	TOP		x		A				X
VAR-001-2		R9.1.	Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when	HIGH	TOP		x		A				X
VAR-001-2	R10.		Each Transmission Operator shall correct IROL or SOL violations resulting from reactive resource deficiencies (IROL violations must be corrected within 30	HIGH	TOP			x					
VAR-001-2	R11.		After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide	LOWER	TOP			x					
VAR-001-2	R12.		The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are	HIGH	TOP			x					
VAR-002-1.1b	R1.		The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode	MEDIUM	GOP		x		A				X
VAR-002-1.1b	R2.		Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable	MEDIUM	GOP		x		A				X
VAR-002-1.1b		R2.1.	When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and	MEDIUM	GOP		x		A				X
VAR-002-1.1b		R2.2.	When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.	MEDIUM	GOP		x		A				X
VAR-002-1.1b	R3.		Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:	MEDIUM	GOP		x		A				X
VAR-002-1.1b		R3.1.	A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system	MEDIUM	GOP		x		A				X
VAR-002-1.1b		R3.2.	A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status	MEDIUM	GOP		x		A				X

Reliability Standard (FERC Approved)	Requirement Number	Supporting Requirement Number	Text of Requirement	Violation Risk Factor	Functions Monitored	2012 Annual Program Audit - 1st Tier	2012 Annual Program Audit - 2nd Tier	2012 Annual Program Audit - 3rd Tier		Self-Cert. Annual (A)	Periodic Data Submittals: Monthly (M), Quarterly (Q), Annual (A)	Exception Reporting (ER)	Spot Check (SC)		2011 Annual Program Audit (X)
VAR-002-1.1b	R4.		The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.	LOWER	GO			x							
VAR-002-1.1b		R4.1.	For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:	LOWER	GO			x							
VAR-002-1.1b		R4.1.1.	Tap settings.	LOWER	GO			x							
VAR-002-1.1b		R4.1.2.	Available fixed tap ranges.	LOWER	GO			x							
VAR-002-1.1b		R4.1.3.	Impedance data.	LOWER	GO			x							
VAR-002-1.1b		R4.1.4.	The +/- voltage range with step-change in % for load-tap changing transformers.	LOWER	GO			x							
VAR-002-1.1b	R5.		After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap	MEDIUM	GO			x							
VAR-002-1.1b		R5.1.	If the Generator Operator can't comply with the Transmission Operator's specifications, the Generator Operator shall notify the Transmission Operator	LOWER	GOP			x							
															2011 Total
				2012	Totals	274	397	250		414	51	32	0		462

REGISTERED FUNCTION ABBREVIATIONS

BA - Balancing Authority

DP - Distribution Provider

GO - Generation Owner

GOP - Generation Operator

IA - Interchange Authority

LSE - Load-Serving Entity

PA/PC - Planning Authority, Planning Coordinator

PSE - Purchasing-Selling Entities

RC - Reliability Coordinator

RE - Regional Entity

RP - Resource Planner

RSG - Reserve Sharing Group

TO - Transmission Owner

TOP - Transmission Operator

TP - Transmission Planner

TSP - Transmission Service Provider

Reliability Standard (FERC Approved)	Requirement Number	Supporting Requirement Number	Text of Requirement	Violation Risk Factor	Functions Monitored	2012 Annual Program Audit - 1st Tier	2012 Annual Program Audit - 2nd Tier	2012 Annual Program Audit - 3rd Tier		Self-Cert. Annual (A)	Periodic Data Submittals: Monthly (M), Quarterly (Q), Annual (A)	Exception Reporting (ER)	Spot Check (SC)		2011 Annual Program Audit (X)

Revision Number	Date	Standard/Process
0	3/18/11	Development
1	5/12/11	Development
1.1	6/30/11	Production
2	7/12/11	Revision
2.1	8/11/11	Revision
2.2	8/19/11	Revision
3	10/19/11	Revision

Revision History

Description
Initial Draft
Incorporated feedback for CIPs and 693 Standards
Final review and approval.
Updated list of Reliability Standards subject to spot check
Updated in-effect version for 2012: CIP-005-3a, IRO-004-2, IRO-005-2a, IRO-006-5, IRO-006-EAST-1, and IRO-006-WECC-1. Removed Reliability Standards: MOD-006-0.1 and MOD-007-0.
Updated in-effect version for 2012: BAL-006-2, CIP-001-2a, INT-003-3, IRO-005-3a, PER-004-1, PER-004-2, and
Updated Summary tab, corrected PRC-004-2 implementation dates, corrected IRO-002-2 R3 applicability, and

From: Stacia-Ann Chambers
To: Stacia-Ann Chambers
Subject: NERC: 2012 Actively Monitored List of Reliability Standards and 2012 ERO CMEP Implementation Plan
Date: Wednesday, October 19, 2011 1:58:38 PM

Announcement

2012 Actively Monitored List of Reliability Standards and 2012 ERO CMEP Implementation Plan

Minor Revision and Additions

October 19, 2011

Click here for: 2012 Implementation Plan

Click here for: 2012 Actively Monitored List

Ladies and Gentlemen:

NERC Compliance Operations has made a few minor revisions to the 2012 Actively Monitored List (AML). The implementation date for PRC-004-2 was corrected to reflect its April 1, 2012 in-effect date. PER-005-1 R3, which is properly identified as Tier 3 in the 'Requirement Detail' tab of the AML, was improperly designated as Tier 1 on the 'Summary Tab' of the AML, but this error has been corrected.

Also, the applicability of IRO-002-2 R2 has been amended to reflect its applicability to the RC function only. Lastly, INT-006-3 had been mislabeled as INT-005-3 and now this along with the hyperlink have been corrected.

Additionally, Compliance Operations has made additions to the 2012 ERO CMEP Implementation Plan. The additions include a section describing the Compliance Enforcement Initiative, a section providing an overview of Events Analysis Interface with Compliance, and a new appendix containing the Events Analysis Process Appendix G – Compliance Assessment Template.

For more information or assistance, please contact Kyle Howells or Jacki Power (via email).

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WECC

Newsletter
September/October 2011

Project update:

WISP Implementation Remains On Track

The Western Interconnection Synchrophasor Program (WISP) is installing more than 300 new or upgraded Phasor Measurement Units (PMU). Together, these synchrophasors can help operators and Reliability Coordinators (RC) identify and analyze system vulnerabilities in real time, as well as detect evolving disturbances on the Bulk Electric System in the Western Interconnection.

Scheduled for completion in March 2013, this "early warning" mechanism will enable WECC and WISP's Participant Entities to better understand the state of the power system, and take timely actions that will help avoid widespread system disturbances.

WECC is meeting the project's key milestones:

- The data center expansion and initial test infrastructure installation is complete in Vancouver.
- Construction is under way for the data center expansion in Loveland with expected completion in October.
- ALSTOM Grid Inc. was awarded the contract for Applications, the Phasor Data Concentrators (PDC), and Historical Archives in late August.
- Harris Corporation was awarded the Wide-Area Network (WAN) contract in June and is working with WECC and the participants for end-to-end WAN testing and implementation scheduling. *(Continued on page 3)*

WECC Releases 1st Transmission Plan

On Sept. 22, 2011, WECC's Board of Directors approved the release of the WECC 10-Year Regional Transmission Plan (Plan). This is WECC's first transmission plan for the Western Interconnection.

Looking ahead to 2020, the Plan focuses on how to meet the Western Interconnection's transmission requirements — including transmission expansion; new generation development; and adapting to local, state/provincial, and federal policy changes, and their associated financial and environmental costs.

The objective of the Plan is to provide detailed information for decision-making processes regarding where and when to build new transmission, and to help assure that the Western Interconnection is reliable, low-cost, efficient, and environmentally sound. The Plan provides policy- and decision-makers with observations and recommendations about the current state and future needs of the transmission system in the Western Interconnection.

The Plan is a product of WECC's Regional Transmission Expansion Planning (RTEP) project that was funded by a $14.5 million U.S. Department of Energy (DOE) grant provided through the American Recovery and Reinvestment Act. This funding allowed WECC to significantly expand its existing regional transmission planning activities and broaden stakeholder involvement in planning processes.

An Executive Summary of the Plan is available on WECC's home page under "announcements." A more detailed summary of the Plan, as well as the complete Plan with all supporting documents, is also available on WECC's website.

Energy Imbalance Market Activities Reviewed by Board

WECC staff provided a straw functional specification, a WECC-specific Cost Analysis, a Risk Assessment, and a Governance and Structure Analysis for an Energy Imbalance Market to the Board of Directors at their September Board meeting.

The staff also presented a series of possible decisions to be addressed if the design process continues to move forward, and the Board discussed next steps.

As a result, the Board of Directors directed WECC staff — prior to the December 2011 Board Meeting — to:

1. Investigate potential funding sources to develop an RFP-quality market design specification;
2. Hold meetings with FERC staff concerning funding and organizational options;
3. Issue an RFI to determine interest, cost, and schedule for a third-party facilitator; and
4. Evaluate the feasibility of, and develop a plan for, sharing operational data with a third-party market operator.

For questions on the completed analyses or next steps, contact mmizumori@wecc.biz.

WECC Assumes Management of WREGIS

Immediately following expiration of the California Energy Commission (CEC) contract on March 30, 2012, WECC will assume management of Western Renewable Energy Generation Information System (WREGIS) operations. WREGIS will become an operating division of WECC and the WREGIS Committee's role will change.

WREGIS is a renewable energy tracking system for the region covered by WECC. It tracks renewable energy generation from units that register in the system, using verifiable data and creates renewable energy certificates (RECs) for this generation. WREGIS Certificates can be used to verify compliance with state and provincial regulatory requirements (e.g., Renewable Portfolio Standards) and in voluntary market programs.

Under the CEC contract and the charter WECC's Board approved, the WREGIS Committee was a semi-autonomous governing body assisted by WECC staff.

"We will develop a charter for the new WREGIS committee, and subsequent to the regular process for approval here, will bring it to WECC's Board at its December meeting," said Andrea Coon, WREGIS Director for WECC. "We will have all of our documents in place before the WREGIS Committee reforms in March."

The committee will provide input important to the success of the program by providing advice, guidance, and feedback to WECC management and by sharing decision-making responsibility for proposed changes in fee schedules, the terms of use, and the operating rules.

Reliability Standards Update

At its March 2011 meeting, WECC's Board of Directors approved a document entitled *Reliability Standards Development Procedures*, which is a revision of the previous *Process for Developing and Approving WECC Standards*.

This newest document calls for the creation of a WECC Standards Committee and requires changes to the WECC Bylaws. It also includes a revision to the current voting procedures for WECC Regional Reliability Standards and Regional Criteria, incorporating voting by industry segment.

Before the new procedures can be implemented, and before the revised WECC Bylaws can become effective, they must be approved by NERC and FERC. The revised documents have been provided to NERC for consideration at its November 3, 2011, Board of Trustees meeting.

To avoid a delay in implementing the new procedures (after approval by FERC) WECC is identifying all eligible voting entities and the segments in which they will be eligible to vote.

In other news, the Project WECC-0083, BAL-002-WECC-1 Contingency Reserves Drafting Team has posted a revised version of BAL-002-WECC-1 for industry review and comment. The drafting team believes that these revisions address all issues identified in the FERC remand order, as well as respond to any negative comments received during the unsuccessful May 2011 Operating Committee vote.

The revised BAL-002-WECC-1 Contingency Reserves Regional Reliability Standard and a Guidance Document was posted on the WECC Standards website for a 30-day comment period.

The Drafting Team will review stakeholder comments and reply to each comment it received.

SMUD's Jim Shetler Joins WECC Board

James R. Shetler, assistant general manager of Energy Supply for the Sacramento Municipal Utility District (SMUD), was elected as a Class 2 Director on WECC's Board of Directors.

Shetler is responsible for overseeing the purchase and sale of SMUD's gas and electric commodities, the reliability of SMUD's transmission system and electric generating facilities, and its research and development efforts; including renewable portfolio standards.

SMUD serves 592,000 customers and a total population of about 1.4 million, making it the sixth-largest public utility in the country.

Prior to this appointment, Shetler served as assistant general manager of Customer Services and was responsible for overseeing energy delivery and customer services as SMUD prepared to enter the new, competitive electricity market. Shetler holds a Bachelor of Science degree in chemical engineering from Clarkson University.

Shetler serves on various boards and commissions, including United Way California Capital Region, Transmission Agency of Northern California (TANC), Balancing Authority of Northern California (BANC), Central Valley Project (CVP) Corp., and Western Energy Institute (WEI). He is also SMUD's executive representative the California Transmission Planning Group (CTPG).

WECC Board Meeting

The WECC Board of Directors will meet November 30 through December 2 in Salt Lake City.

Make Plans to Attend These Upcoming Meetings

The following meetings will be held in October 2011. Complete details for these meetings are posted on WECC's calendar.

Oct. 24-28: Schedulers; Salt Lake City.

Oct. 25-26: Overview of System Operations Workshop; Salt Lake City.

Oct. 25: DWG Conference Call; Webinar.

Oct. 25-26: WECC-0083, BAL-003-WECC1; Salt Lake City.

Oct. 26: WECC-0076 INT Rewrite Project; Webinar.

Oct. 26: LTPT Interface Task Force; Webinar.

Oct. 31-Nov. 2: RASRS Meeting; Salt Lake City.

Oct. 31-Nov. 2: TAS Meeting; San Diego.

Oct. 31-Nov. 4: Switching; Salt Lake City.

Nov. 1: DWG Conference Call; Webinar.

Nov. 1-2: SPSG; San Diego.

Nov.1: Project WECC-0068 Drafting Team; Phoenix.

Nov. 2-3: PWG Meeting Nov. 2011; Phoenix.

Nov. 2: WECC-0076 INT Rewrite Project; Webinar.

Nov. 2-3: TEPPC Meeting; San Diego.

Nov. 2: LTPT Interface Task Force Meeting; Webinar.

Nov. 3-4: RWG Meeting; Salt Lake City.

Nov. 3-4: TELWG Meeting; Salt Lake City.

Nov. 7-11: M&VWG Meeting; Phoenix.

Nov. 7-11: Generation Balance; Salt Lake City.

Nov. 8: TEPPC Coordination Call; Webinar.

Nov. 8: DWG Conference Call; Webinar.

Nov. 9: LTPT Interface Task Force; Webinar.

Nov. 10: WECC-0083 BAL-002-WECC-1; Webinar.

Nov. 14-18: Emergency Operations; Salt Lake City.

Nov. 14-15: Joint DEWG & EMSWG; Salt Lake City.

Nov. 15: DWG Conference Call; Webinar.

Nov. 16-18: SRWG Meeting; Salt Lake City.

Nov. 16: LTPT Interface Task Force; Webinar.

Nov. 17: Compliance Open Webinar.

Nov.22: DWG Conference Call; Webinar.

Nov. 23: LTPT Interface Task Force; Webinar.

Nov. 29: DWG Conference Call; Webinar.

Nov. 30-Dec. 2: Board Meeting; Salt Lake City.

Nov. 30: RPIC Meeting; Salt Lake City.

Nov. 30: FAC Meeting; Salt Lake City.

Nov. 30: WCC Meeting; Salt Lake City.

Nov. 30: HRCC Meeting; Salt Lake City.

Nov. 30: GNC Meeting; Salt Lake City.

Nov. 30: LTPT Interface Task Force Meeting; Webinar.

WISP On Track

(Continued from page 1)

Testing of oscillation modal analysis functionality (a key situational awareness application) is currently underway.

- The prototype environment is receiving PMU data from the Salt River Project, Tennessee Valley Authority, and Bonneville Power Administration.
- Development of a PMU registry, Wide-Area View, and historical-archival system access is underway and progressing well.
- Participants have begun completing PMU and PDC installations.

Seven of the eight original Cost Share Partners have signed their Letters of Agreement with the one remaining in final stages of legal review and approval. Ten additional participants have their project planning underway.

Introducing WECC New Hires

Loveland:

Matt Fietek, Reliability Coordinator.

Salt Lake City:

Ruben H. Arredondo, Sr. Legal Counsel;
David Price, Enterprise Architect;
Darren Nielsen, Compliance Auditor;
Jennifer Salisbury, Program Coordinator;
Merrill Brimhall, Staff Engineer – Standards.
Parker Wicks, Program Analyst – WREGIS.

Vancouver:

Ryan Clemente, Intern - EMS;
Patrick Moast, Compliance Auditor, Monitoring.

Visit WECC employment opportunities.

Implementation Plan

VAR-001-2 WECC Variance

The Project WECC-0046 Regional Variance Drafting Team proposes that the WECC Variance become effective on the first day of the first calendar quarter six months after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months after NERC Board of Trustees' approval. Six months will provide Transmission Operators sufficient time to review scheduling practices; to revise existing procedures and other documents that contain scheduling practices; and to distribute any required revisions to those documents in order to be in compliance with the WECC Variance. Six months will also allow time for Generator Operators to develop voltage schedule conversion methodologies from the reference point to the AVR set point as required in the WECC Regional Variance to VAR-001-2 Requirement E.A.16.

Unofficial Comment Form for Regional Reliability Standard VAR-001-2 – WECC Variance

Please **DO NOT** use this form. Please use the electronic form located at the link below to submit comments on the Regional Reliability Standard VAR-001-2 – WECC Variance comments must be submitted by **December 5, 2011.** If you have questions please contact Howard Gugel at howard.gugel@nerc.net or Barb Nutter at barbara.nutter@nerc.net

http://www.nerc.com/filez/regional_standards/regional_reliability_standards_under_development.html

Background Information

Any variance from a NERC reliability standard requirement that is proposed to apply to responsible entities within a regional entity organized on an interconnection-wide basis shall be considered an Interconnection-wide Variance and shall be developed through that regional entity's NERC-approved regional reliability standards development procedure.

While an interconnection-wide variance may be developed through the associated Regional Entity standards development process, regional entities are encouraged to work collaboratively with existing continent-wide drafting team to reduce potential conflicts between the two efforts.

An Interconnection-wide Variance from a NERC reliability standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with other applicable standards of governmental authorities shall be made part of the associated NERC reliability standard. NERC shall rebuttably presume that an Interconnection-wide Variance from a NERC reliability standard that is developed, in accordance with a standards development procedure approved by NERC, by a regional entity organized on an interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest.

VAR-001-2 – Western Electricity Coordinating Council Variance

The **Western Electricity Coordinating Council** Variance shall enable or support one or more of the NERC reliability principles, thereby ensuring that each standard serves a purpose in support of the reliability of the regional bulk electric system. Each of those standards shall also be consistent with all of the NERC reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence. The NERC reliability principles supported by this variance are the following:

- Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform under normal and abnormal conditions as defined in the NERC Standards.
- The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
- Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

The proposed **WECC** variance is not inconsistent with, or less stringent than established NERC Reliability Standards. Once approved by the appropriate authorities, the **WECC** variance obligates **WECC** to monitor and enforce compliance, apply sanctions, if any, consistent with the NERC rules.

VAR-001-2

Requirements

E.A.13. Each Transmission Operator shall issue any one of the following types of voltage schedules to the Generator Operators for each of their generation resources that are on-line and part of the Bulk Electric System within the Transmission Operator Area:

E.A.14. Each Transmission Operator shall provide one of the following voltage schedule reference points for each generation resource in its Area to the Generator Operator.

E.A.15. Each Generator Operator shall convert each voltage schedule specified in Requirement E.A.13 into the voltage set point for the generator excitation system.

E.A.16. Each Generator Operator shall provide its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals within 30 calendar days of request by its Transmission Operator.

E.A.17. Each Transmission Operator shall provide to the Generator Operator, within 30 calendar days of a request for data by the Generator Operator, its transmission equipment data and operating data that supports development of the voltage set point conversion methodology.

E.A.18. Each Generator Operator shall meet the following control loop specifications if the Generator Operator uses control loops external to the Automatic Voltage Regulators (AVR) to manage MVar loading:

The approval process for a Interconnection-wide Variance requires NERC to publicly notice and request comment on the proposed variance. Comments shall be permitted only on the following criteria (technical aspects of the standard are vetted through the regional standards development process):

Unfair or Closed Process — The Interconnection-wide variance was not developed in a fair and open process that provided an opportunity for all interested parties to participate. Although a NERC-approved regional reliability standards development procedure shall be presumed to be fair and open, objections could be raised regarding the implementation of the procedure.

Adverse Reliability or Commercial Impact on Other Interconnections — The Interconnection-wide variance would have a significant adverse impact on reliability or commerce in other interconnections.

Deficient Standard — The Interconnection-wide variance fails to provide a level of reliability of the bulk power system such that the regional reliability standard would be likely to cause a serious and substantial threat to public health, safety, welfare, or national security.

Adverse Impact on Competitive Markets within the Interconnection — The Interconnection-wide variance would create a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability.

1. **Do you agree the proposed variance is being developed using the associated Regional Reliability Standards Development Procedure?**

   ☐ Yes

   ☐ No

   Comments:

2. **Does the proposed variance pose an adverse impact to reliability or commerce in a neighboring region or interconnection?**

   ☐ Yes

   ☐ No

   Comments:

3. **Does the proposed variance pose a serious and substantial threat to public health, safety, welfare, or national security?**

   ☐ Yes
   ☐ No

   Comments:

4. **Does the proposed variance pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?**

   ☐ Yes

   ☐ No

   Comments:

5. **Does the proposed variance meet at least one of the following criteria?**

   - **The proposed variance has more specific criteria for the same requirements covered in a continent-wide standard**
   - **The proposed variance has requirements that are not included in the corresponding continent-wide reliability standard**

- **The proposed regional difference is necessitated by a physical difference in the bulk power system.**

☐ Yes

☐ No

Comments:

6. **If you have any other comments that you have not already provided in the response to the prior questions, please provide them here**.

From: Eleanor Crouch
To: Eleanor Crouch
Subject: Updated Regional Reliability Standards Announcement - VAR-001-2 WECC Variance | 45-Day Comment Period October 20-December 5, 2011
Date: Friday, October 21, 2011 10:42:06 AM

Regional Reliability Standards Announcement

Comment Period Open for VAR-001-2 WECC Variance
October 20 – December 5, 2011

Now Available -**Updated**

Proposed Interconnection-wide Variance for the Western Electricity Coordinating Council

WECC has requested NERC to post the Interconnection-wide Variance VAR-001-2 — Voltage and Reactive Control for a 45-day industry review as permitted by the NERC Rules of Procedure.

Instructions:
Please use this electronic form (updated) to submit comments. If you experience any difficulties in using
the electronic form, please contact Eleanor Crouch at eleanor.crouch@nerc.net. An off-line, unofficial copy of the comment form is posted on the regional standards development page.

Background:
The purpose of this regional variance to a NERC Reliability Standard is to ensure that voltage levels are within limits in real time to protect equipment and the reliable operation of the Western Interconnection.

The WECC Variance to VAR-001-2 is an alternative approach to meeting the same reliability objective as the NERC VAR-001-2 Reliability Standard. The proposed regional variance in Section E contains requirements that are more stringent than the continent-wide Requirements R3 and R4 of VAR-001-2 or provides a specific alternative approach to meeting the same reliability objective.

Regional Reliability Standards Development Process:
Section 300 of the *Rules of Procedure for the Electric Reliability Organization* governs the regional reliability standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Eleanor Crouch at eleanor.crouch@nerc.net.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

You are currently subscribed to nerc-info as: lpedowicz@npcc.org
To unsubscribe send a blank email to leave-1274197-325654.1ca6f85fb1574a8515cc07df72d3bfe0@listserv.nerc.com

Regional Variance Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

Completed Actions	Completion Date
1. Post draft standard for initial industry comments	December 14, 2009
2. Receive Initial industry comments from First Posting	January 29, 2010
3. Drafting Team to review and respond to initial industry comments	March 4, 2010
4. Post second draft standard for industry comments	May 6, 2010
5. Second draft comment period ended	July 12, 2010
6. Drafting Team to review and respond to industry comments	August 11, 2010
7. Post third draft standard for industry comments	September 24, 2010
8. Industry comments for third draft standard are due	October 25, 2010
9. Drafting Team to review and respond to industry comments	November 24, 2010
10. Post fourth draft as a regional variance to NERC VAR-001-2 Requirements R3 and R4	December 7, 2010
11. Comments from fourth posting are due	January 7, 2011
12. Post draft standard for Operating Committee approval	January 26, 2011
13. Operating Committee approved proposed standard	March 2-4, 2011
14. Posted draft standard for WECC Board approval	May 2011
15. WECC Board approved proposed standard	June 22, 2011

Description of Current Draft:

The current draft has been converted from a regional reliability standard into a regional variance to the NERC VAR-001-2 Standard. The format incorporates the WECC Regional Variance into the NERC Standard with minor additions to address the scope of the variance. The regional variance specifics are included as Section E and in this case are intended to replace NERC VAR-001-2 Requirements R3 and R4 as noted at the beginning of Section E. The redline version of Section E identifies what was changed from the last posting.

The purpose of this regional variance to a NERC Reliability Standard is to ensure that voltage levels are within limits in real time to protect equipment and the reliable operation of the Western Interconnection. The “Rules of Procedure of the North American Electric Reliability Corporation” (Appendix 3A, page 32) permit the development of a regional variance to a NERC Reliability Standard on an Interconnection-wide basis when the Regional Reliability Organization has valid justification, and when the variance is not inconsistent with or less

stringent than the NERC Reliability Standard. The variance is an alternative method for obtaining the same reliability objective as the continent-wide standard and is typically necessitated by a physical difference. A variance is embodied within a reliability standard and as such, if adopted by NERC and approved by the electric reliability organization governmental authority, shall be enforced within the applicable regional entity or regional entities pursuant to delegated authority.

Analysis of disturbances in the Western Interconnection have demonstrated that during and immediately following a disturbance, the generator's Automatic Voltage Regulator (AVR) — operating in automatic voltage control mode — is needed to stabilize the Bulk Electric System's voltage. Transmission Operators are responsible for determining the voltage levels required to maintain reliable operation of the Interconnection and convey the required voltage level information to Generator Operators.

The NERC VAR-001-2 Requirement R3 allows Transmission Operators the option of specifying criteria that exempt generators from compliance with the requirements defined in NERC Standard VAR-001-2 Requirement 4 and Requirement 6.1. The drafting team and WECC stakeholders believe that permitting such exemptions reduces the proper voltage support when generation and transmission outages occur, adversely impacting the reliability of the Western Interconnection.

The NERC VAR-001-2 Requirement R4 allows Transmission Operators the option of providing reactive power schedules rather than voltage schedules; however, operating against a reactive power schedule will not enhance reliability in the Western Interconnection by ensuring that generators provide the proper voltage support when generation and transmission outages occur. This conclusion is based on the interpretation that generator operators given reactive schedules under NERC VAR-001-2 are required to maintain the reactive output defined in the schedule at all times. This will require generator operators to modify the AVR set point as system conditions change to maintain the specified reactive output of the schedule.

This variance to a NERC Standard restricts the Transmission Operator to providing only a voltage schedule, but allows the schedule to be conveyed through a reactive power level, provided that the reactive power level is converted to a voltage level for the AVR's automatic voltage control mode setting. Once a reactive power level is converted to a voltage level, that voltage level defines the schedule until a new voltage schedule — which may be in reactive power terms — is provided by the Transmission Operator.

In the Western Interconnection, System Operating Limits for transmission paths in the Bulk Electric System assume that the AVRs are in service to control voltage to support the transfer capabilities. As noted below the previous approvals and rulings regarding VAR-002-WECC-1 have directed Generator Operators to operate AVRs in voltage control mode controlling voltage to support transfer capabilities in the Western Interconnection.

- April 16, 2008: the WECC Board of Directors approved VAR-002-WECC-1 to ensure that the AVRs are in service and controlling voltage so that generators provide the proper voltage support when generation and transmission outages occur.
- October 29, 2008: the NERC Board of Trustees approved VAR-002-WECC-1.
- April 21, 2011: FERC issued an Order approving VAR-002-WECC-1.

The NERC Rules of Procedure allow that WECC regional reliability standard requirements may be more, but not less, stringent than NERC requirements. NERC VAR-002-1.1b requires Generator

Operators to maintain the voltage or Reactive Power output as directed by the Transmission Operators. VAR-002-WECC-1 requires that Generators Operators maintain the AVRs in service operating in automatic voltage control mode with some defined exceptions. This proposed variance to VAR-001-2 does not allow AVR operation to be defined by a reactive power schedule.

If the Transmission Operator provides a schedule of voltages to the Generator Operator, the Generator Operator can more easily maintain compliance with the requirement. If the Transmission Operator provides voltage schedule information in another format, such as in reactive power terms, compliance with the proposed requirements require conversion of the operating instruction to a voltage value by the Generator Operator. The Generator Operator uses the converted value to set the automatic voltage control. The resulting voltage needs to be monitored by the Transmission Operator to ensure the desired outcome is achieved or the Transmission Operator needs to issue additional schedules.

During the VAR-002-WECC-1 standard development process, the industry comments noted that not all WECC Transmission Operators provide voltage schedules to their Generator Operators. Providing reactive power schedules (instead of specific voltage levels) forces Generator Operators to manually adjust their AVR voltage setting to a setting that will provide the exact amount of reactive power in the schedule.

It is recognized that during the course of a day, system dynamics may result in changes in reactive output such that the generator will no longer produce the amount of reactive power specified by the Transmission Operator's reactive power schedule. If the Generator Operator alters the amount of reactive power provided by the generator to return it to the schedule, there is higher risk that such action will result in the generator doing the exact opposite of what is needed to maintain system reliability: ensuring that generators provide the proper voltage support when generation and transmission outages occur.

The drafting team surveyed Transmission Operators and Generator Operators to identify scheduling practices that are causing confusion. The survey results identified a rationale that will accommodate the continued practice of providing direction in reactive power terms rather than requiring all Transmission Operators to define the stable system voltage with the exclusive use of a voltage schedule.

WECC is requesting NERC Board of Trustee approval of the draft regional variance to the NERC VAR-001-2 Standard. The WECC Regional Variance requires Transmission Operators to issue schedules but identifies the methodologies to be used by Generator Owners for implementing the schedules so as to maintain compliance without burdensome manual intervention by operating personnel.

The WECC Variance to VAR-001-2 is an alternative approach to meeting the same reliability objective as the NERC VAR-001-2 Reliability Standard. The proposed regional variance in Section E contains requirements that are more stringent than the continent-wide Requirements R3 and R4 of VAR-001-2 or provides a specific alternative approach to meeting the same reliability objective.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Request NERC 45-day Posting	~~September~~October 2011
2. Post draft standard for 45-day NERC comment period	~~October 2011~~To be determined
3. NERC comment period ends	To be determined
4. Drafting Team completes review and consideration of industry comments to NERC posting	To be determined
5. Submit NERC Board approval request	To be determined
6. Receive NERC Board approval	To be determined
7. Request FERC approval	To be determined

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these definitions will be removed from the standard and added to the Glossary.

None

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Standard VAR-001-2 — Voltage and Reactive Control

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A. Introduction

1. **Title:** **Voltage and Reactive Control**
2. **Number:** VAR-001-2
3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in real time to protect equipment and the reliable operation of the Interconnection.
4. **Applicability:**
   - **4.1.** Transmission Operators.
   - **4.2.** Purchasing-Selling Entities.
   - **4.3.** Load Serving Entities.
   - **4.4.** Generator Operators within the Western Interconnection.
5. **(Proposed) Effective Date:** The first day of the first calendar quarter six months after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months after Board of Trustees' adoption.

B. Requirements

R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators.

R2. Each Transmission Operator shall acquire sufficient reactive resources – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching;, and controllable load – within its area to protect the voltage levels under normal and Contingency conditions. This includes the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.

R3. The Transmission Operator shall specify criteria that exempts generators from compliance with the requirements defined in Requirement 4, and Requirement 6.1.

- **R3.1.** Each Transmission Operator shall maintain a list of generators in its area that are exempt from following a voltage or Reactive Power schedule.
- **R3.2.** For each generator that is on this exemption list, the Transmission Operator shall notify the associated Generator Owner.

R4. Each Transmission Operator shall specify a voltage or Reactive Power schedule [1] at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (AVR in service and controlling voltage).

R5. Each Purchasing-Selling Entity and Load Serving Entity shall arrange for (self-provide or purchase) reactive resources – which may include, but is not limited to, reactive generation

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[1] The voltage schedule is a target voltage to be maintained within a tolerance band during a specified period.

scheduling; transmission line and reactive resource switching;, and controllable load– to satisfy its reactive requirements identified by its Transmission Service Provider.

R6. The Transmission Operator shall know the status of all transmission Reactive Power resources, including the status of voltage regulators and power system stabilizers.

R6.1. When notified of the loss of an automatic voltage regulator control, the Transmission Operator shall direct the Generator Operator to maintain or change either its voltage schedule or its Reactive Power schedule.

R7. The Transmission Operator shall be able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow.

R8. Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching; controllable load; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits.

R9. Each Transmission Operator shall maintain reactive resources – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching;, and controllable load– to support its voltage under first Contingency conditions.

R9.1. Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when Contingencies occur.

R10. Each Transmission Operator shall correct IROL or SOL violations resulting from reactive resource deficiencies (IROL violations must be corrected within 30 minutes) and complete the required IROL or SOL violation reporting.

R11. After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.

R12. The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.

C. Measures

M1. The Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule as specified in Requirement 4 to each Generator Operator it requires to follow such a schedule.

M2. The Transmission Operator shall have evidence to show that, for each generating unit in its area that is exempt from following a voltage or Reactive Power schedule, the associated Generator Owner was notified of this exemption in accordance with Requirement 3.2.

M3. The Transmission Operator shall have evidence to show that it issued directives as specified in Requirement 6.1 when notified by a Generator Operator of the loss of an automatic voltage regulator control.

M4. The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with Requirement 11.

D. Compliance

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1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority

   Regional Entity.

   1.2. Compliance Monitoring Period and Reset Time Frame

   One calendar year.

   1.3. Compliance Monitoring and Enforcement Processes:

   Compliance Audits

   Self-Certifications

   Spot Checking

   Compliance Violation Investigations

   Self-Reporting

   Complaints

   1.4. Data Retention

   The Transmission Operator shall retain evidence for Measures 1 through 4 for 12 months.

   The Compliance Monitor shall retain any audit data for three years.

   1.5. Additional Compliance Information

   The Transmission Operator shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. **Violation Severity Levels (no changes)**

E. Regional ~~Differences~~Variances

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~~None identified.~~

E.A. Regional Variance for the Western Electricity Coordinating Council

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R3 and R4. Please note that Requirement R3 is deleted and R4 is replaced with the following requirements.

Requirements

E.A.13. Each Transmission Operator shall issue any one of the following types of voltage schedules to the Generator Operators for each of their generation resources that are on-line and part of the Bulk Electric System within the Transmission Operator Area: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- A voltage set point with a voltage tolerance band and a specified period.
- An initial volt-ampere reactive output or initial power factor output with a

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voltage tolerance band for a specified period that the Generator Operator uses to establish a generator bus voltage set point.

- A voltage band for a specified period.

E.A.14. Each Transmission Operator shall provide one of the following voltage schedule reference points for each generation resource in its Area to the Generator Operator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*:

- The generator terminals.
- The high side of the generator step-up transformer.
- The point of interconnection.
- A location designated by mutual agreement between the Transmission Operator and Generator Operator.

E.A.15. Each Generator Operator shall convert each voltage schedule specified in Requirement E.A.13 into the voltage set point for the generator excitation system. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

E.A.16. Each Generator Operator shall provide its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals within 30 calendar days of request by its Transmission Operator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

E.A.17. Each Transmission Operator shall provide to the Generator Operator, within 30 calendar days of a request for data by the Generator Operator, its transmission equipment data and operating data that supports development of the voltage set point conversion methodology. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

E.A.18. Each Generator Operator shall meet the following control loop specifications if the Generator Operator uses control loops external to the Automatic Voltage Regulators (AVR) to manage MVar loading: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

E.A.18.1. Each control loop's design incorporates the AVR's automatic voltage controlled response to voltage deviations during System Disturbances.

E.A.18.2. Each control loop is only used by mutual agreement between the Generator Operator and the Transmission Operator affected by the control loop.

Measures[2]

[2] The number for each measure corresponds with the number for each requirement, i.e. M.E.A.13 means the measure for Requirement E.A.13.

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M.E.A.13. Each Transmission Operator shall have and provide upon request, evidence that it provided the voltage schedules to the Generator Operator. Dated spreadsheets, reports, voice recordings, or other documentation containing the voltage schedule including set points, tolerance bands, and specified periods as required in Requirement E.A.13 are acceptable as evidence.

M.E.A.14. The Transmission Operator shall have and provide upon request, evidence that it provided one of the voltage schedule reference points in Requirement E.A.14 for each generation resource in its Area to the Generator Operator. Dated letters, e-mail, or other documentation that contains notification to the Generator Operator of the voltage schedule reference point for each generation resource are acceptable as evidence.

M.E.A.15. Each Generator Operator shall have and provide upon request, evidence that it converted a voltage schedule as described in Requirement E.A.13 into a voltage set point for the AVR. Dated spreadsheets, logs, reports, or other documentation are acceptable as evidence.

M.E.A.16. The Generator Operator shall have and provide upon request, evidence that within 30 calendar days of request by its Transmission Operator it provided its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals. Dated reports, spreadsheets, or other documentation are acceptable as evidence.

M.E.A.17. The Transmission Operator shall have and provide upon request, evidence that within 30 calendar days of request by its Generator Operator it provided data to support development of the voltage set point conversion methodology. Dated reports, spreadsheets, or other documentation are acceptable as evidence.

M.E.A.18. If the Generator Operator uses outside control loops to manage MVar loading, the Generator Operator shall have and provide upon request, evidence that it met the control loop specifications in sub-parts E.A.18.1 through E.A.18.2. Design specifications with identified agreed-upon control loops, system reports, or other dated documentation are acceptable as evidence.

Violation Severity Levels

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.13	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to at least one generation resource but less than or equal to 5% of the generation	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 5% but less than or equal to 10% of the generation	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 10% but less than or equal to 15% of the generation	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 15% of the generation resources that are on-line and part of

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E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	resources that are on-line and part of the BES in the Transmission Operator Area.	resources that are on-line and part of the BES in the Transmission Operator Area.	resources that are on-line and part of the BES in the Transmission Operator Area.	the BES in the Transmission Operator Area.
E.A.14	The Transmission Operator did not provide a voltage schedule reference point for at least one but less than or equal to 5% of the generation resources in the Transmission Operator area.	The Transmission Operator did not provide a voltage schedule reference point for more than 5% but less than or equal to 10% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not a voltage schedule reference point for more than 10% but less than or equal to 15% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not provide a voltage schedule reference point for more than 15% of the generation resources in the Transmission Operator Area.
E.A.15	The Generator Operator failed to convert at least one voltage schedule in Requirement E.A.13 into the voltage set point for the AVR for less than 25% of the voltage schedules.	The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 25% or more but less than 50% of the voltage schedules.	The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 50% or more but less than 75% of the voltage schedules.	The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 75% or more of the voltage schedules.
E.A.16	The Generator Operator provided its voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Transmission Operator.	The Generator Operator did not provide its voltage set point conversion methodology within 120 days of a request by the Transmission Operator.
E.A.17	The Transmission Operator provided its data to support development of the voltage set point conversion methodology than 30 days but less than or equal to 60 days of a request by the	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request	The Transmission Operator did not provide its data to support development of the voltage set point conversion methodology within 120 days of a request by the Generator

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E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Generator Operator.	by the Generator. Operator.	by the Generator. Operator.	Operator.
E.A.18	N/A	The Generator Operator did not meet the control loop specifications in EA18.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in EA18.1 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in EA18.1 through EA18.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	July 3, 2007	Added "Generator Owners" and "Generator Operators" to Applicability section.	Errata
1	August 23, 2007	Removed "Generator Owners" and "Generator Operators" to Applicability section.	Errata
2	TBD	Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.	Revised.
2		Modified to add a WECC region variance	

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda
Standards Oversight and Technology Committee

November 2, 2011 | 9:00-10:30 a.m. Eastern
Westin Buckhead Atlanta
3391 Peachtree Road, NE
Atlanta, GA 30326
404-365-0065

Introductions and Chair's Remarks

NERC Antitrust Compliance Guidelines and Public Announcement

Agenda

1. **Minutes* — Approve**
   a. August 3, 2011 meeting
2. **Standards Presentation and Policy Issues for Discussion and Guidance***
   a. Update on proposals to revise Violation Risk Factor (VRF)/Violation Severity Level (VSL) criteria
   b. Balanced assessment of NERC Reliability Standards
   c. ANSI – Forward looking obligations
   d. Five-Year Assessment and Rule of Procedure 317 [note correction]
   e. Industry request to change our position on CIP v4 - Discussion
   f. Policy Discussion on Reliability Standards Development Plan (RSDP) long-term adjustments
3. **Standards Written Report***
   a. Status report looking ahead (interpretations and standards)
   b. Regional report and work plan
   c. Update on identifying a list of all outstanding directives
4. **Standards Committee Report***
5. **NASPI Update and Presentations* – Mark Lauby, Russell Robertson, Alison Silverstein**
6. **ERO Enterprise Solutions Roadmap***
7. **IT 90-Day Plan and Roadmap Update***

*Background materials included.

Antitrust Compliance Guidelines

I. General

It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition.

It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

II. Prohibited Activities

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

- Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

III. Activities That Are Permitted

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation, Bylaws, and Rules of Procedure are followed in conducting NERC business.

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of the mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.
- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.
- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.

Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Draft Minutes
Standards Oversight and Technology Committee

August 3, 2011 | 9:15-10:15 a.m. PT
Vancouver Marriott Pinnacle
1128 West Hastings Street
Vancouver, BC VE 4R5 Canada

Chair Ken Peterson convened a duly noticed open meeting of the Standards Oversight and Technology Committee of the North American Electric Reliability Corporation on August 3, 2011 at 9:15 a.m. local time, and a quorum was declared present. The agenda is attached as **Exhibit A**.

NERC Antitrust Compliance Guidelines
Chair Peterson directed the participants' attention to the NERC Antitrust Compliance Guidelines.

Minutes
The committee approved the May 10, 2011 meeting minutes (**Exhibit B**).

Standards Status Report
Herb Schrayshuen, vice president and director of standards, provided a presentation (**Exhibit C**) where he reviewed the status of high priority deliverables, rapid development project and ANSI accreditation, as well as Project 2007-17 Protection System Maintenance and Testing. Further, Mr. Schrayshuen reviewed the Regional Standards priorities which led to an extensive discussion with industry stakeholders. The conclusion of the discussion relative to the integration of the regional standards development programs into the overall standards development process was that NERC management would work with Regional Executives to resolve any conflicting priorities.

Standards Committee Report
Herb Schrayshuen and Allen Mosher, Standards Committee Chair, provided an in-depth report of Standards Committee activities (**Exhibit D**).

ERO IT Strategy Development
Lynn Costantini, vice president and chief information officer, reported on the status of the ERO IT strategy development and business automation initiative. The project, which launched earlier this year, will result in new tools and technologies to meet evolving business requirements across the ERO enterprise (**Exhibit E**).

NERC Tools Update
Lynn Costantini, vice president and chief information officer, provided a status update three main topics the reliability tools transition; SAFNR, and NASPI. Her presentation is attached as **Exhibit F**.

Future Meetings
Chair Peterson reviewed future meetings of the committee.

There being no further business, Chair Peterson adjourned the meeting at 10:20 a.m.

Submitted by,

Herb Schrayshuen

Agenda Item 2
SOTC Meeting
November 2, 2011

Standards Presentation and Policy Issues for Discussion and Guidance

a. Update on proposals to revise Violation Risk Factor (VRF)/Violation Severity Level (VSL) criteria
b. Balanced assessment of NERC Reliability Standards
c. ANSI – Forward looking obligations
d. Five-Year Assessment and Rule of Procedure 317 [note correction]
e. Industry request to change our position on CIP v4 - Discussion
f. Policy Discussion on Reliability Standards Development Plan (RSDP) long-term adjustments

a. Update on Proposals to Revise Violation Risk Factor (VRF)/Violation Severity Level (VSL) Criteria

VRFs

The goal of this effort is to standardize a method to determine VRF assignments for individual requirements. As a part of this effort, the team is proposing to create definitions for five VRFs, rather than the current three VRFs.

Definitions and a tool to help assist in determining the VRF were presented to stakeholders for comment in mid-2010. Comments were favorable.

An updated set of definitions, as well as an updated tool for use in analyzing VRFs, is being prepared for a second round of industry comment.

Next steps are to vet the proposal through NERC staff and Regional Entities, and to update the Standards Committee (SC) and Compliance and Certification Committee (CCC) at the December 2011 meeting on staff's position and regional input.

VSLs

The goal of this effort is to develop a generalized approach for creating VSLs to be used in lieu of the current approach of performing an exhaustive analysis of possible violations for inclusion in the VSLs. The team is updating the proposal for informal review and feedback prior to posting for industry comment.

Next steps are to vet the proposal through NERC staff and Regional Entities and to update the SC and CCC at the December SC meeting regarding staff's position and regional input.

b. Balanced Assessment of NERC Reliability Standards

Background

The NERC Reliability Standards are a portfolio of performance, risk, and competency-based mandatory requirements that collectively provide a defense-in-depth structure for reliably planning, operating, and protecting the North American bulk power system. NERC's standards hold all users, owners, and operators of the bulk power system accountable for meeting specific reliability-related performance.

NERC staff works with the SC, electric power industry experts, and applicable regulatory and governmental authorities in the United States and Canada in identifying, prioritizing, and implementing the standards development projects identified in the *Reliability Standards Development Plan,* following the processes outlined in the *Standard Processes Manual.*

Process

In compliance with the *Standard Processes Manual,* the SC makes key decisions regarding the reliability standards development process for North American standards with the process and administrative input of NERC staff.

Once a proposed Reliability Standard is developed following the *Standard Processes Manual,* which is part of the NERC Rules of Procedure, and is presented to the NERC Board of Trustees (Board) for adoption prior to being filed with applicable regulatory authorities for approval.

Board Adoption

NERC Standards staff is responsible for preparing the package of material presented to the Board when a Reliability Standard is presented to the Board for adoption. When organizing and preparing the material for Board action, the drafting team responsible for the proposed standard submits an extensive set of documentation related to the standard's development. Included in the documentation is evidence of consensus, the reliability-related benefits of the proposal, and a listing of significant unresolved minority issues.

From the material provided by the standard drafting team, NERC staff prepares a summary document for Board action. The Board also has access to the public project page. The goal is to provide the Board with sufficient information to make an informed decision as to whether to either adopt the standard, direct the SC to make additional modifications to the standard, or provide the SC other direction with respect to the proposed standard.

It is the responsibility of the Board to adopt Reliability Standards that ensure the reliability of the North American bulk power system taking into consideration the reliability benefit of the standard.[1] In the course of development of a Reliability Standard, much debate occurs

[1] NERC Bylaws, Article IX, Section 1

relative to the reliability benefit of the standard. Rarely is 100 percent consensus achieved, and at the conclusion of the standards development process, there usually exists some level of disagreement amongst the parties involved in the standard's development. The drafting team responsible for the proposed standard is required to make its best effort at addressing all issues brought to its attention.

The Board is informed of the significant unresolved minority issues remaining at the conclusion of the standards development process.

From time to time there are significantly divergent views on issues involving a standard, definition, or interpretation. When the standard is taken to ballot it is likely to achieve sufficient affirmative votes to gain approval, but may not result in an obvious improvement to reliability or leave open the question of whether the reliability objective has been met.

When considering adoption of a Reliability Standard, the Board must consider not only the reliability impact of the standard (i.e., is the current level of reliability at least maintained, if not improved, by adopting the standard), but the Board must also consider the minority opinions highlighted in the material provided to the Board in the summary package.[2] If the Board is not satisfied with the drafting team's resolution of a minority opinion, the Board has the option to direct the SC to revise the standard or take some other action relative to the standard before the standard is resubmitted to the Board for adoption at a future date. The engagement that the Board can provide the SC is not limited and needs to take into consideration the specific known issues at the time the standard is presented to the Board for action.

Issue

The following is a list of considerations for process change going forward.

- An early alert to the Board or Standards Oversight and Technology Committee (SOTC) that a given standard may require more detailed attention prior to voting.
- A process for engaging, perhaps a subset of the Board or SOTC when this occurs.
- Does the Board want NERC staff to adhere to its prior recommendation of engaging directly in the process as any other commenter, or to have an additional role in preparing the answers to any questions the Board may have about the reliability benefit of a given industry proposal?
- How will the Board or SOTC weigh various factors?
- How can the new standard maintain or improve reliability?
- How does learning since the previous standard adoption support a modified standard?

[2] Standards Process page 20

- How can assessment tasks and performance measures engage the industry in thinking and working beyond the minimum level of performance?
- What assessment strategies are best suited to advancing Reliability Standards content and skills?

Recommendation

That the Standards Oversight and Technology Committee direct NERC staff to develop a specific plan of action based on the discussion at this meeting to identify the process steps necessary to address the case where a proposed standard requires more investigation than normal to ascertain the net benefit to reliability.

c. ANSI – Forward Looking Obligations

NERC received notice that effective September 9, 2011, NERC's standard development process has been re-approved as an ANSI-accredited standard development process. The following statement was included in the approval letter:

"NERC is expected to continue to make progress towards its stated goal of submitting documents to ANSI for consideration as proposed American National Standards (ANS)."

Options

- Reaccredit every five years as we have been
- Move to a continual accreditation process by submitting standards to ANSI for approval.

Proposal

In order to investigate the feasibility of the second option, NERC will initiate a dialogue with Canadian stakeholders to identify obstacles associated with submitting NERC standards to ANSI for approval. In the past the Canadian stakeholders have objected to a review by a United States accrediting organization. The benefits of seeking separate Canadian approval of NERC's standard development process must be weighed against the associated costs.

- Submitting standards to the Standards Council of Canada would require, among other things, that NERC first have its standards development process accredited by the Standards Council of Canada.
- Standards approved by the Standards Council of Canada must be published in both English and French, and would increase NERC's costs associated with developing standards.

If a determination is made that it is not necessary to obtain parallel approval of NERC's standard development process from the Standards Council of Canada, amend Rule of Procedure (ROP) 316 accordingly.

Currently ROP 316 states:

> 316. Accreditation
> NERC shall seek continuing accreditation of the NERC reliability standards development process by the American National Standards Institute and the Standards Council of Canada.

d. Five-Year Assessment and Rule of Procedure 317

The purpose of this agenda item is to engage in a discussion of the high level options below so that more direction on development of a plan (i.e., which option is preferred) can be provided.

Under Rule of Procedure 317, NERC is required to review each standard within five years of its effective date.

> 317. Five-Year Review of Standards
> NERC shall complete a review of each NERC reliability standard at least once every five years from the effective date of the standard or the latest revision to the standard, whichever is later. The review process shall be conducted in accordance with the NERC Standard Processes Manual. The standards process manager shall be responsible for administration of the five-year review of reliability standards. As a result of this review, the NERC reliability standard shall be reaffirmed, revised, or withdrawn. If the review indicates a need to revise or withdraw the standard, a request for revision or withdrawal shall be prepared, submitted and addressed in accordance with the NERC Standard Processes Manual.

The five-year review obligation is incorporated in the prioritization process; however, because of projects with higher reliability impact outweighing those with less, NERC will not achieve this goal based on current assumptions.

Status

NERC has 23 Reliability Standards that are expected to miss their five-year obligation by more than six months. Of those, 13 are forecast to miss by two years or more. Of those, six are forecast to miss by four years or more. The five-year review was included in the Rules of Procedure to comply with an ANSI accreditation requirement. The ANSI accreditation requirement is associated with ANSI-approved standards, and at this point, NERC does not have any ANSI-approved standards. NERC's regional standards are not developed in accordance with an ANSI accredited standard development process.

With over 100 enforceable standards, compliance with the five-year review requires review and revision of at least 20 standards each year, a number that would overwhelm the industry's resources at this time. All of the standards that are coming up for their five-year review are "Version 0" standards and are likely to require significant industry debate to make necessary improvements.

At a future time, when all of the "Version 0" standards have undergone a major revision such that the need for additional significant revisions is minimized, the five-year review of then stable standards should be achievable.

Solutions (high level)

1. Seek board approval of an extension to the due date and provide timely notice to FERC and other governmental authorities;
2. Reassign resources to focus on five-year review; and
3. With the next revision to the Standard Processes Manual, separate the maintenance requirements for standards that are and are not approved as ANSI process standards; and add the option of maintaining some approved standards under ANSI's more flexible "continuous maintenance" and "stabilized maintenance" methods.

e. Industry Request to Change Our Position on CIP v4

Certain stakeholder groups are advocating that NERC consider withdrawing CIP-002 v4 and that the industry await the development and delivery of CIP v5.

Background

Version 4 of the CIP standards was limited in scope and meant to be an interim step for addressing more immediate concerns raised in FERC Order No. 706, paragraph 236. The key changes to Version 4 from Version 3 include replacing the "risk-based" assessment methodology with "bright line" criteria, and an attempt to move toward more uniform application by eliminating subjectivity regarding what is "critical."

The Industry approved Version 4 on December 30, 2010. NERC submitted a petition for approval of CIP Version 4 to FERC on February 10, 2011, requesting approval of the standards. FERC issued a NOPR proposing to approve CIP Version 4 on September 15, 2011.

Version 5 addresses the remaining FERC Order No. 706 directives. NERC anticipates moving the proposed standards to initial ballot in December 2011. The Version 5 standards accomplish several key goals:

- The proposed standards will address the remaining FERC directives, approved interpretations, and existing Compliance Application Notices (CANs);
- They transition the concepts of "Critical Asset" and "Critical Cyber Asset" to a high, medium, and low impact classification system for requirement applicability;
- They provide guidance and context for each requirement, and leverage current stakeholder investment used for complying with existing standards; and
- They develop requirements that foster a "culture of security" to improve reliability.

The policy question for consideration is what the process should be when approved actions have been over taken by other events.

f. Policy Discussion on Reliability Standards Development Plan (RSDP) Long-term Adjustments

This year, the process for developing the RSDP considered areas not explicitly accounted for in the past. The SC considered the NERC President's Top Priority Issues for Bulk Power System Reliability and used them to help prioritize work, which the SC used to allocate resources to work on projects related to reliability, time-sensitivity, and practicality. However, the plan does not sufficiently consider the most current changes to the long-term strategic direction of the ERO. For example, although there are efforts underway to examine specific topics related to High-Impact/Low Frequency events, the plan does not include any significant note of this effort. Similarly, the plan does not include a project to address the cold weather issues related to the Texas event, although analysis of that need is ongoing.

Accordingly, there is likely to be a need to make adjustments in the 2012-2014 RSDP to address these shortcomings. The SC may need to defer some of the projects slated for initiation in 2012 to address these strategic priority areas.

Regarding longer-term solutions to this disconnect between planning efforts and being able to react to changing needs, there will need to be some more specific actions taken, such as:

- More coordination will be needed during the development of the RSDP with the strategic leadership of the Board and the ERO;
- Beginning the planning process earlier, to ensure all aspects are considered in the planning cycle;
- Building the plan to recognize the dynamic nature of our priorities and ensuring the plan can easily accommodate change, and that the plan treats such change as an expectation, rather than an exception; and
- Integrate the emerging issues process from the Reliability Assessment and Performance Analysis activities under the Planning Committee with the Standards development process.

If Trustees have questions or need additional information, they may contact Herb Schrayshuen at herb.schrayshuen@nerc.net.

Agenda Item 3
SOTC Meeting
November 3, 2011

Standards Written Report

a. Status report looking ahead (interpretations and standards)
b. Regional report and work plan
c. Update on identifying a list of all outstanding directives

a. Status Report Looking Ahead (Interpretations and Standards)

i. Standards

Project forecast to require special Board of Trustees meeting for action in January 2012

- 2010-17 Definition of BES (partial; remainder Q2 2013)

Project forecast for action at the February 2012 Board of Trustees meeting

- 2007-03 Real-time Operations

Projects forecast for action at the May 2012 Board of Trustees meeting

- 2009-01 Disturbance and Sabotage Reporting
- 2006-06 Reliability Coordination (remainder)
- 2007-12 Frequency Response

Projects forecast for action at the August 2012 Board of Trustees meeting

- 2007-09 Generator Verification (partial; remainder February 2013)
- 2007-17 Protection System Maintenance and Testing
- 2008-06 Cyber Security Order 706

Projects forecast for action at the November 2012 Board of Trustees meeting

- 2010-14.1 Phase 1 of Balancing Authority Reliability-Based Controls: Reserves
- 2010-07 Generator Requirements at the Transmission Interface (possibly partial)
- 2010-05.1 Phase 1 of Protection Systems: Misoperations

ii. Interpretations

Two interpretations are expected to require action at the February 2012 Board of Trustees meeting, including one CIP interpretation. In addition, a pilot effort to address a request for interpretation through a rapid revision of the standard may be ready for Board action in February.

b. Regional Report and Work Plan

Please see the attachment.

c. Update on Identifying a List of All Outstanding Directives

The Standards staff continues to coordinate with FERC staff on identification of FERC regulatory directives focused on standards development. On July 26, 2011 NERC submitted a report to FERC summarizing the progress made, and plans for addressing the standards-related directives received from applicable ERO governmental authorities.

The following charts summarize the progress on standards-related directives since the last report to the Standards Oversight and Technology Committee.

Previous 693 Directives Analysis
(as of July 7, 2011)

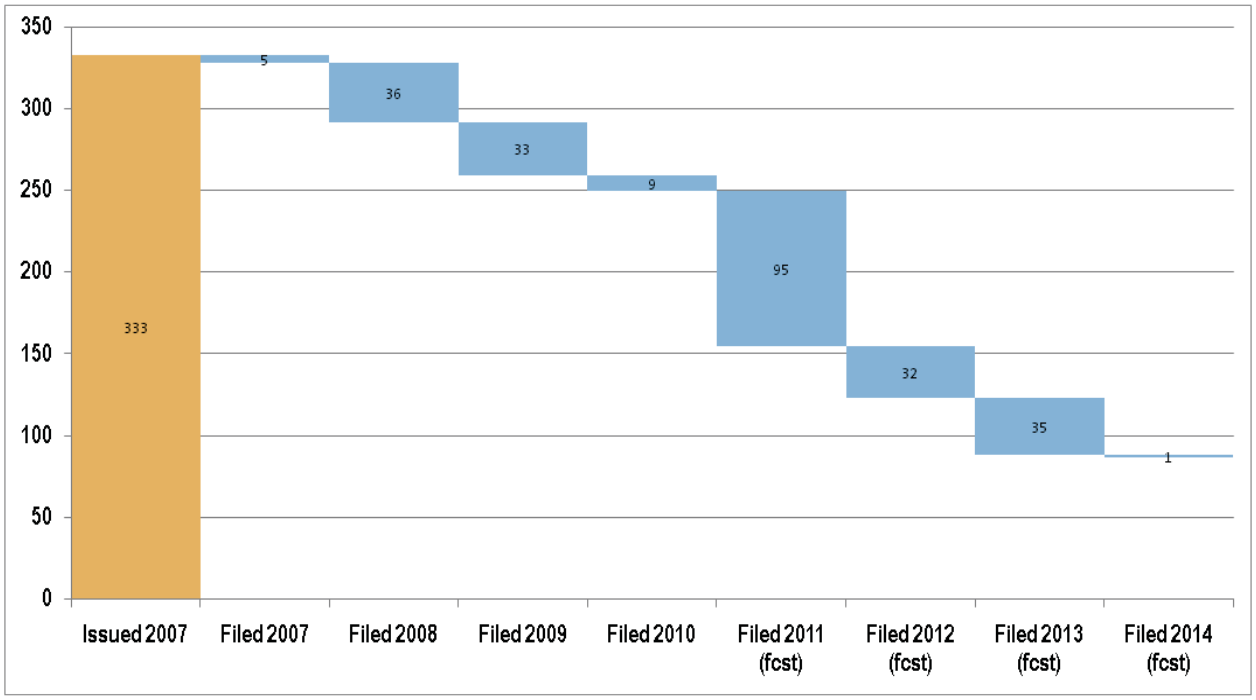

Current 693 Directives Analysis
(as of October 3, 2011)

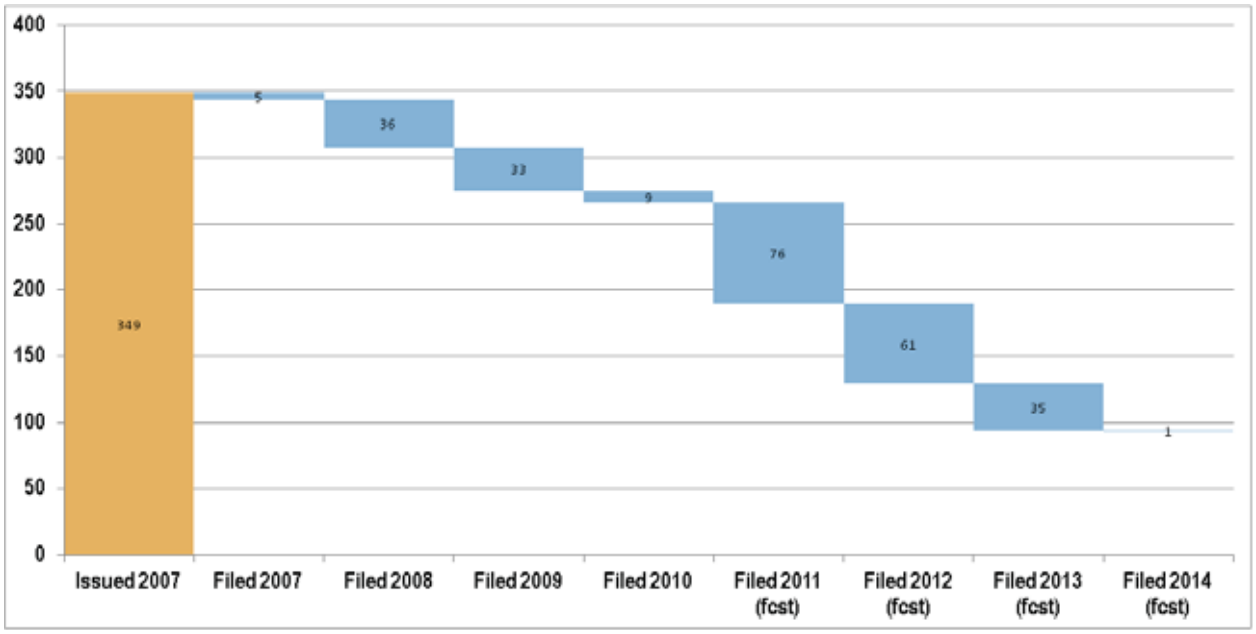

Previous "All Directives" Analysis
(as of July 7, 2011)

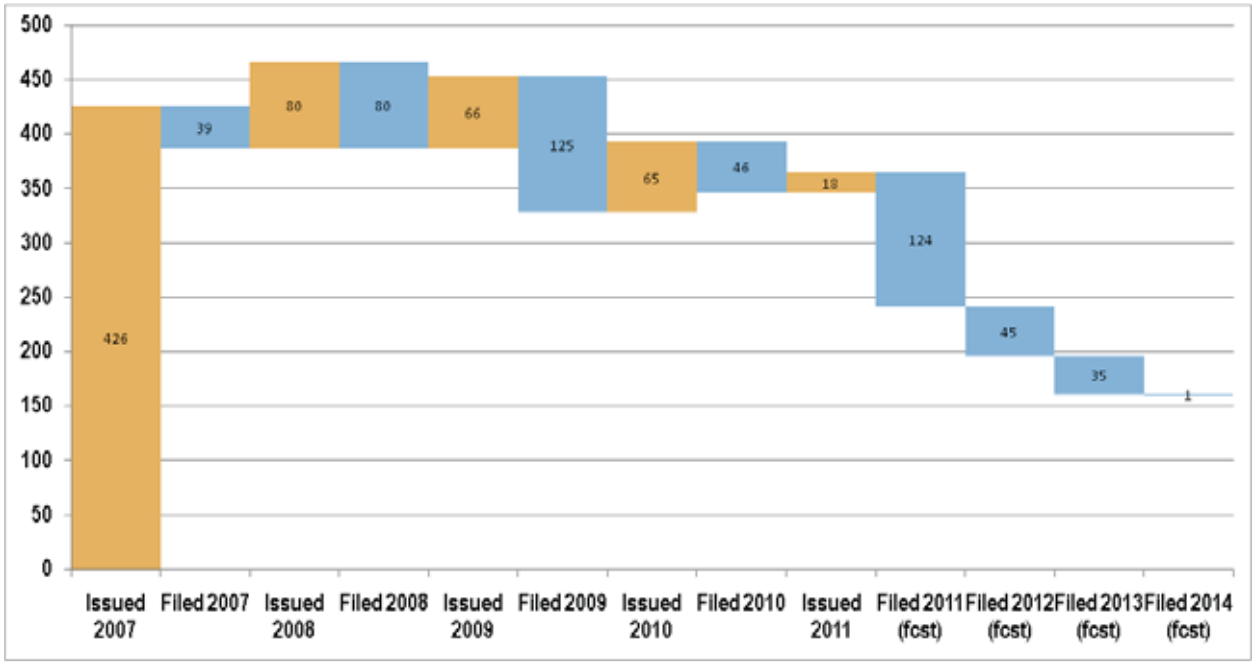

Current "All Directives" Analysis
(as of October 3, 2011)

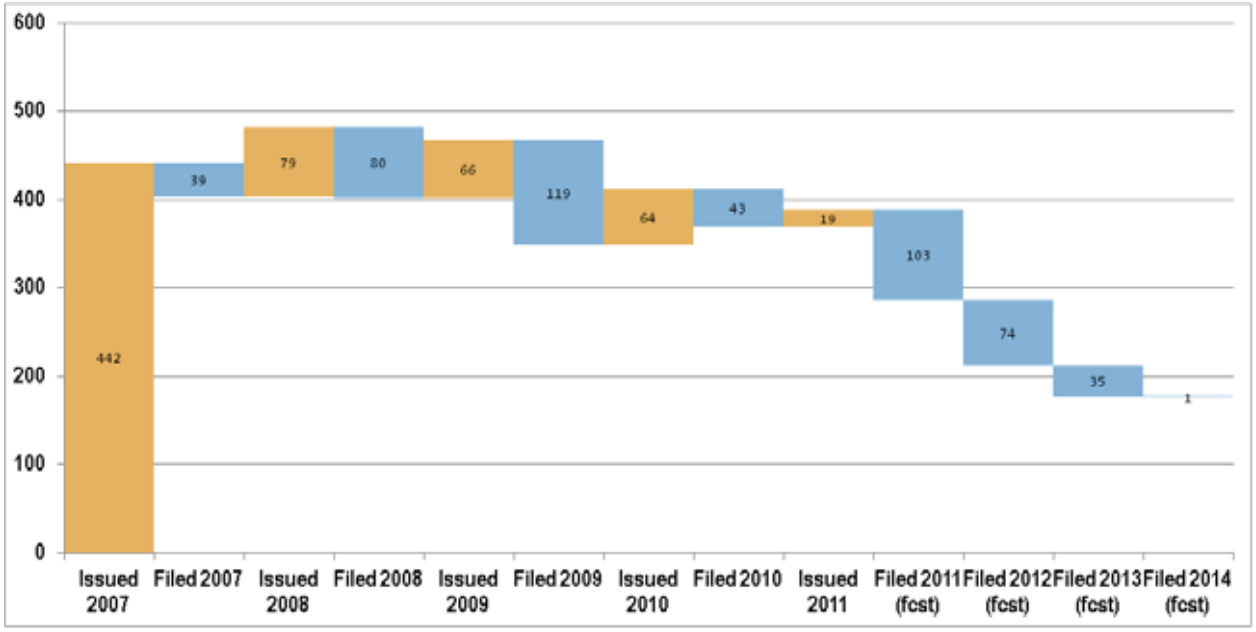

Comparison of Directives Analysis

693 Directives	Iss. '07	Filed '07	Filed '08	Filed '09	Filed'10	Filed '11 (fcst)	Filed '12 (fcst)	Filed '13 (fcst)	Total Remain
Previous Estimate	333	5	36	33	9	95	32	35	**88**
Current Estimate	349	5	36	33	9	76	61	35	**94**
Difference	**16**	**0**	**0**	**0**	**0**	**-19**	**29**	**0**	**6**

All Directives	Iss. '07	Filed '07	Iss. '08	Filed '08	Iss. '09	Filed '09	Iss '10	Filed'10	Iss '11	Filed '11 (fcst)	Filed '12 (fcst)	Filed '13 (fcst)	Total Remain
Previous Estimate	426	39	80	80	66	125	65	46	18	124	45	35	**249**
Current Estimate	442	39	79	80	66	119	64	43	19	103	74	35	**242**
Difference	**16**	**0**	**-1**	**0**	**0**	**-6**	**-1**	**-3**	**1**	**-21**	**29**	**0**	**-7**

The changes between the two time periods are due primarily to the coordination effort between NERC and FERC staffs focusing on the accuracy of the data and the change in the delivery date for Project 2007-03 Real-time Transmission Operations from 2011 to 2012.

Additional changes to the “directive counts” are expected to continue based on the coordination effort between FERC and NERC staffs until the directives report is prepared the in the first quarter of 2012.

November 2011
Regional Standards Group Report to the SOTC

This report highlights the key activities of NERC and the Regions in support of the RSG charter obligations in the period since January 1, 2011.

The Regional Standards Group (RSG) meets on a monthly basis and has held 10 meetings this year in-person or by phone.

The regions have worked to perform quality reviews, post regional standards to the NERC website, and file regional standards and variances with FERC. As a result of these efforts we report the following:

Regional Standards YTD:

- Regional Standards and Variances filed by NERC with FERC:
  - PRC-002-NPCC-01
  - CIP-001-2a (TRE regional variance to CIP-001 – Sabotage Reporting)
- Regional Standards and Variances approved by Regional Entity Board (not included above) – YTD:
  - MOD-25-RFC-01
  - IRO-006-TRE-01
  - PRC-006-SERC-01

Regional Standards Development Activities and Accomplishments – YTD:

- Seven of the eight regional standards development projects provided milestones for coordination of processing purposes to NERC.
- NERC Regional Standards staff has:
  - prepared a unified schedule for all regional projects in development
  - processed 5 regional postings for comment on behalf of the regions
  - performed 10 Quality Reviews on Regional Standards and Variances
  - attended 12 regional Standards Development team meetings (in-person or by phone) for coordination purposes
  - attended 4 Regional Standard Committee meetings on-site for coordination purposes

- updated the NERC Regional Reliability Standards Under Development webpage
- prepared a white paper on a comparison of regional standards, regional variances, and regional procedures

Other Activities

- NPCC solicited comments on their Cost Effectiveness Analysis Procedure (CEAP)
- SERC has a proposed update of the SERC Regional Standards Development Procedure – to be presented at the February 2012 Board of Trustees meeting
- RFC proposed revised standard development procedures which were approved for filing with FERC by the BOT. Subsequent to BOT approval, RFC requested the filing with FERC be held pending additional changes requested by RFC stakeholders.

Agenda Item 4
SOTC Meeting
November 2, 2011

Standards Committee Report

Since the last Board of Trustees meeting, the Standards Committee (SC) has met by conference call on August 11 and September 8 and met in person on October 12-13, 2011. SC meeting agendas and minutes are posted at: http://www.nerc.com/filez/scmin.html

This report outlines major ongoing activities and policy issues under consideration by the SC and its subcommittees that may be of interest to the Standards Oversight and Technology Committee.

Reliability Standards Development Plan 2012-2014
The SC worked with NERC staff to develop and solicit industry support for the Reliability Standards Development Plan 2012-14 (RSDP) that is scheduled for Board of Trustees approval at the November 2011 Board of Trustees meeting. The following are several elements of the RSDP that are worthy of note:

- The SC used a new standards prioritization tool that provides for scoring of projects based on reliability benefits (*e.g.*, the project addresses NERC strategic priorities, fills a reliability gap or improves upon existing standards), cost considerations, time sensitivity (regulatory deadlines or ANSI review) and practical considerations (addresses compliance issues or stakeholder concerns).
- The SC has for the first time introduced consideration of the cost of implementation and administration into the prioritization process. These metrics may require significant future work to ensure that the metrics give costs appropriate consideration. Projects have been grouped into three development branches, based on reliability benefits, time sensitivity, and practicality, to ensure a balanced NERC standards development program.
- A number of projects targeted for development beginning in late 2012 and throughout 2013 will require research and industry outreach to ensure that the technical foundation for standard development has been completed before active standard development is initiated. The SC will work closely with the NERC Operating and Planning Committees on this issue.
- Regulatory orders, such as the orders issued and rulemakings initiated at the September 15 FERC Open Meeting, may have a significant impact on the priority and sequencing of projects within the RSDP. Similarly, new technical reports and insights may lead to mid-course corrections. However, the SC does not expect to put ongoing projects on hold in 2012.

Interpretations and Compliance Application Notices
The SC has expressed concerns about conflicting outcomes and duplication of effort between the formal standard interpretations developed under the *NERC Standard Processes Manual* and Section 300 of the NERC Rules of Procedure, compared to the Compliance Application Notice (CAN) process administered by the NERC Compliance Operations department. The NERC SC Chair has requested and the Standards Committee has agreed to await NERC staff consideration of stakeholder comments on the revised CAN process document as well as a number of CANs that have been posted for industry comment before raising these concerns again. Nonetheless, a number of SC members have significant concerns that may not be alleviated by revisions to the CAN process and the issuance of revised CANs. The SC Chair continues to believe a single NERC portal for industry requests for formal interpretations, informal interpretations and a range of compliance and enforcement guidance is needed.

Rapid Revision of Standards in Lieu of Interpretations
The SC is field-testing a process whereby a simple request for an interpretation could be addressed through a permanent revision to the standard. As envisioned, the process is consistent with the approved *NERC Standard Processes Manual*. If an interpretation drafting team identifies simple, straightforward modifications to a standard that can more effectively address an interpretation request than an interpretation, the drafting team may elect to develop the proposed changes to the standard and submit them with an associated SAR. Following SC review, the changes may move directly to comment and ballot. If minor changes are needed, the drafting team will make those changes and attempt to move the change through the standards process. However, if major changes are needed to reach consensus, the SC may decide to move the project out of Rapid Revision into the normal standard development process. A field test using a request for an interpretation of MOD-028-1 – Area Interchange Methodology is underway. The results of this field test will be used to analyze the use of the Rapid Revision process as an alternative to some requests for interpretation.

Process and Quality Innovations: Learning from Experience
The SC held an informal SDT Leadership Workshop prior to the SC's October 2011 meeting in Atlanta, to provide drafting team leaders with an opportunity to meet with members of the SC and have a candid exchange of thoughts and ideas about how to improve upon the NERC standards program, now and in the future. The following is a list of some the issues discussed:

- Clarification on the drafting team's obligations to address comments submitted by NERC staff, the Board of Trustees, or the Member Representatives Committee either during formal comment periods or informally.
- Experience with Rapid Development "field test."
- Opportunities to use technical writers and attorneys earlier in the standard development process than during formal quality reviews.
- Opportunities to review and improve the quality review process.
- Need for administrative support for inactive (future) projects, e.g., setting up meetings, helping with informal postings, etc.

- Dealing with stakeholder concerns about how a standard will affect compliance rather than focusing on the reliability implications.
- Need for periodic updates/communication to drafting teams to provide status so teams are aware of when their projects will move forward in the standard development process.
- Maintenance of drafting team membership through the life cycle of a project.
- Need for improved processes for collecting and assembling comments submitted on proposed standards.

Modification to the Standards Process to Allow Waiver of Process Steps for Good Cause Shown

From time to time, the SC faces an issue unanticipated in the processes established in the Standard Processes Manual. For example, such a dilemma occurred when the drafting team that developed PRC-005 – Protection System Maintenance asked the SC to allow the team to repeat the recirculation ballot. The Standard Processes Manual does not address this situation, and SC members felt obligated to uphold the processes as outlined in the manual, which require that when a ballot of a standard fails, if the drafting team wants to continue with the project, it must return to the initial stage of the standards process. The SC may explore options to modify the standard process to provide more flexibility so that the SC has authority to approve a wider range of variations to the process, provided the variations approved still support ANSI principles that the standards process is open, transparent, builds consensus, provides for a fair balance of interests, ensures due process, and is timely.

Agenda Item 5
SOTC Meeting
November 2, 2011

North American SynchroPhasor Initiative and Technology Development

Action
None

Background
In 2008, NERC's Board of Trustees approved a $6.5M, five-year project to support the North American SynchronPhasor Initiative (NASPI) and technology development through the Grid Protection Alliance (GPA). The NERC NASPI project was created, in part, for NERC to take on funding of TVA's funding of the Eastern Interconnection (EI) phasor data hub. Both activities represent a collaborative effort between the U.S. Department of Energy, NERC, and North American electric utilities, vendors, consultants, federal and private researchers and academics. The project, as initially envisioned, would expedite the development and deployment of synchrophasor technology to enhance grid security and reliability. The original project objectives were to:

- Develop advanced applications for phasor data;
- Support the TVA SuperPDC and the use of phasor data for wide-area situational awareness across the Eastern Interconnection; and
- Identify, document, and share information on the business case value of synchrophasor systems for reliability coordinators, balancing authorities, and transmission operators.

NERC has provided direction and funding by support to two specific ongoing efforts:

- NERC's project management and meeting funding supports three meetings per year of industry experts to share and advance the deployment of synchrophasor technology and expedite phasor data applications to maintain bulk electric system reliability. The mission of the North American SynchroPhasor Initiative is to improve power system reliability and visibility through wide area measurement and control, which NASPI achieves through issue identification, information sharing, and coordination of expert resources and efforts.
- Given federal Smart Grid Investment Grants (SGIG) funding for phasor measurement units (PMU) and communications system deployment and phasor data applications development, NERC's funding with GPA, leveraged with the U.S. Department of Energy, has been focused on building software tools to facilitate data exchange between PMUs and phasor data concentrators (PDCs) with enhanced security and performance. GPA's mission is to improve the reliability and resiliency of the electric grid.

NERC's 2011 budget allocated $1M for GPA activities and $150k for NASPI project management, with additional costs for meetings. GPA leverages NERC's funds with DOE investments, while NASPI offsets all of its meeting costs for 2011 with over $100,000 in attendee meeting registration fees and over $30,000 in vendor sponsorships for NASPI meetings.

The goal of the discussions at the Standards Oversight and Technology Committee meeting will be to provide a status report of both NASPI and GPA activities and preview upcoming deliverables in 2012:

- Alison Silverstein, NASPI project manager, will review NASPI's recent accomplishments, outline plans for 2012, and outline the NERC-DOE plan to mainstream NASPI community activities over the next three years.
- Russell Robertson, GPA director, will review GPA's recent deliverables and accomplishments and outline GPA's plans and major work products for the coming year.

Synchrophasor Project Update

Grid Protection Alliance

November 2, 2011

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Synchrophasor Epochs

- Academic leadership
- Small group of innovators (BPA, TVA)

- Slow phasor measurement unit (PMU) growth
- R&D driven innovation
- North American Synchro Phasor Initiative (NASPI) seeks consensus solutions
- NASPInet is the hot topic

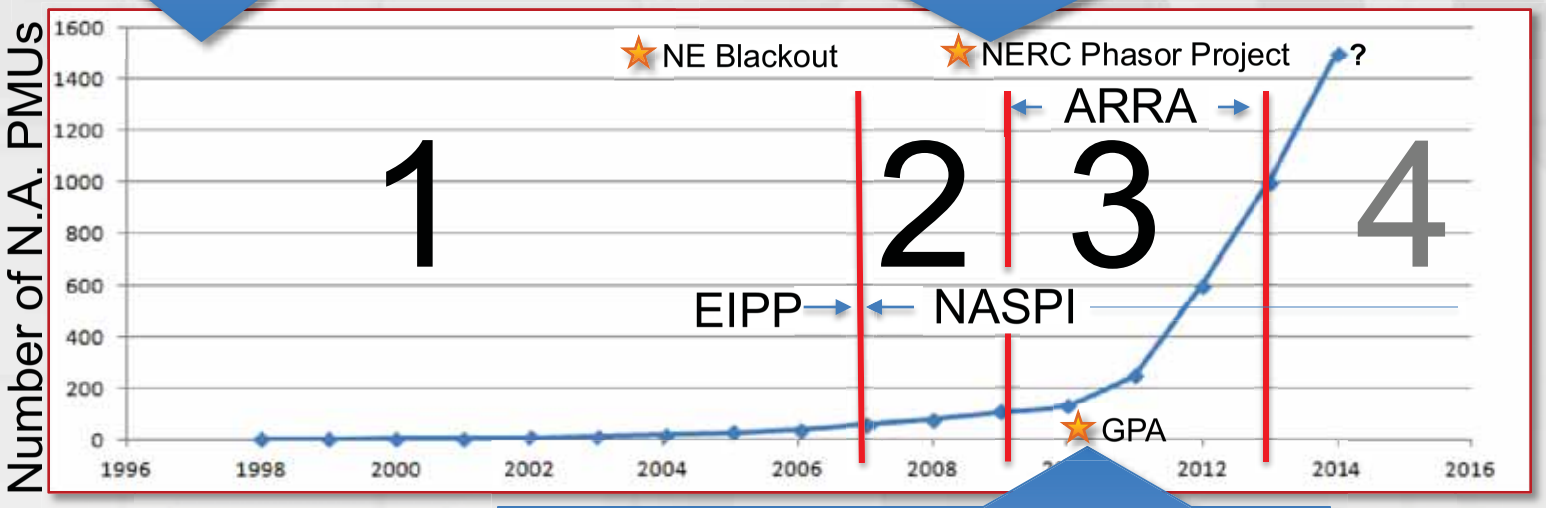

PMU Numbers Representative

- Smart Grid Investment Grant (SGIG) -- $300M phasor investment
- Individual project driven solutions
- More capable vendor support

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Grid Protection Alliance

GPA is a not-for-profit company that builds collaborative efforts among government, regulators, vendors, grid owners and grid operators.

- **Mission** – to improve the reliability and resiliency of the electric grid

- **Purpose** – to advance the technology of the electric grid by providing services and systems that create lasting value for electric energy producers, transmission & distribution companies, and consumers.

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Why open source …

- Best way to accelerate innovation in phasor measurement systems
- Increases quality and puts “many eyes” to work to improve security
- Provides assurance that client investments are not encumbered with “vendor lock in”
- Provides a direct path to commercialization

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Open Source Software (OSS) Development Model

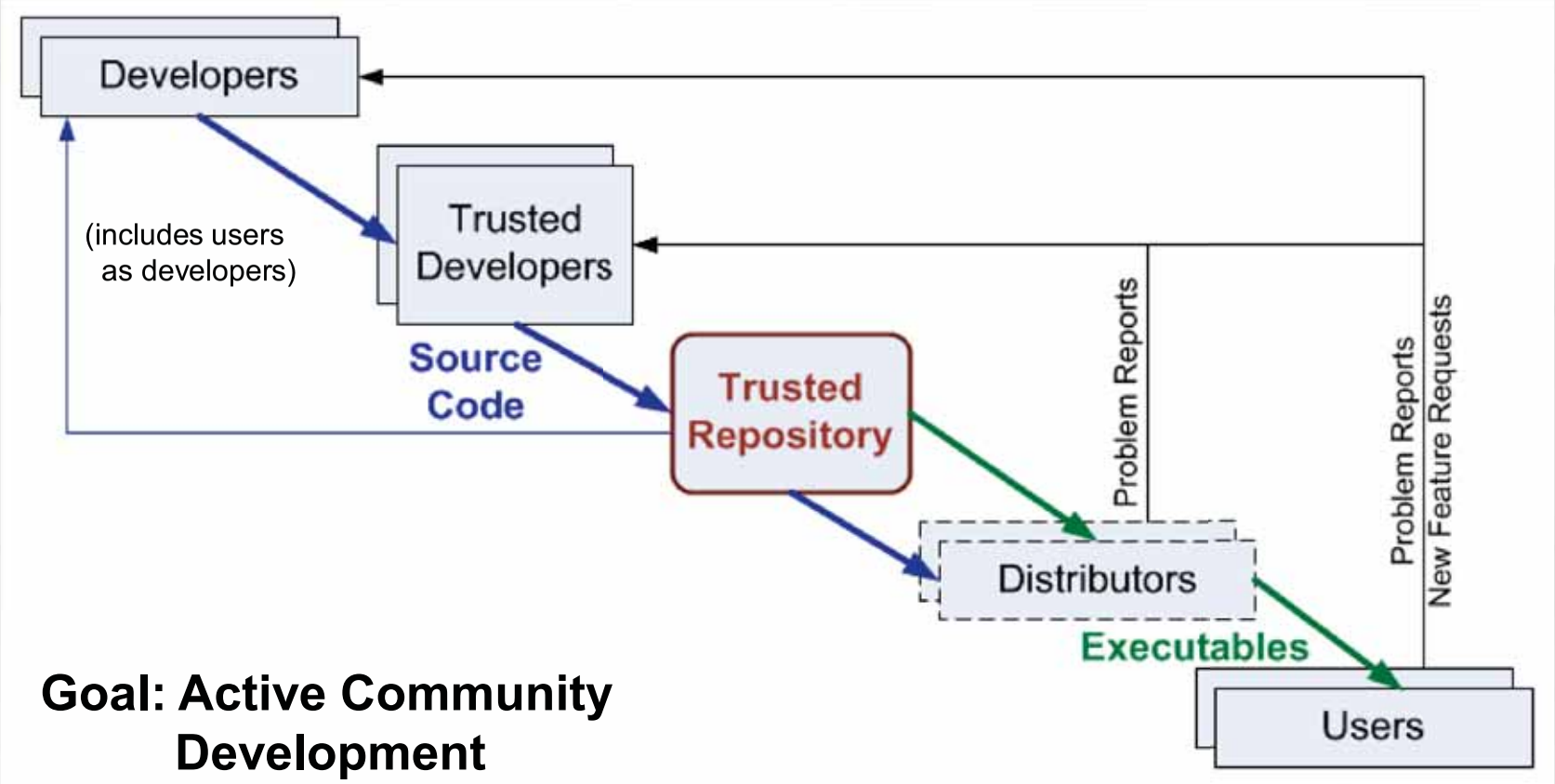

Goal: Active Community Development

From David A. Wheeler Presentation, 11/4/2009

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openPDC

Open Source Phasor Data Concentrator

Google

openPDC

openpdc
openpdc **download**
openpdc **hadoop**
openpdc **codeplex**

Advanced search

Search

Everything
Images
Maps
Videos
News
Shopping
More

Chattanooga, TN
Change location

Show search tools

OpenPDC - CodePlex
openpdc.codeplex.com/
Oct 7, 2009 – The **openPDC** is a complete Phasor Data Concentrator designed to process streaming time-series data in real-time. Measured data gathered ...

openPDC Getting Started
openpdc.codeplex.com/wikipage?...
The **openPDC** installer will ...

How to Use the ...
openpdc.codeplex.com/wikipage?...
The **openPDC** Manager is a ...

openPDC v1.0 Release
openpdc.codeplex.com/releases/.../3...
This is the current ...

Does the ...
openpdc.codeplex.com/wikipage?...
Answer: There are two primary ...

Download
openpdc.codeplex.com/.../52461
Enabling the optional ...

openPDC DM-Tools ...
https://openpdc.svn.codeplex.com/...
Example guide on how to use ...

More results from codeplex.com »

OpenPDC - Wikipedia, the free encyclopedia
en.wikipedia.org/wiki/OpenPDC
From Wikipedia, the free encyclopedia. Jump to: navigation, search. The **openPDC** is a complete set of applications for processing streaming time-series data in ...

The Android of the Smart Grid: **openPDC** — Cleantech News and ...
gigaom.com/cleantech/the-google-android-of-the-smart-grid-openpdc/
Nov 10, 2009 – Can an open source data management system do for the smart grid what Google's open mobile operating system Android is doing for cell ...

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openPDC

Open Source Phasor Data Concentrator

openPDC
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CodePlex
Open Source Community

Search all CodePlex projects | Search

Home | Downloads | Documentation | Discussions | Issue Tracker | Source Code | People | License | RSS

View All Comments | Print View | Page Info | Change History (all pages)

Search Wiki & Documentation

Home

Quick Links

News -- About the openPDC -- Commercial Extensions -- Community Involvement -- Code Blog -- Nightly Builds -- Attributions

The openPDC is a complete Phasor Data Concentrator software system designed to process streaming time-series data in real-time. Measured data gathered with GPS-time from many hundreds of input sources is time-sorted and provided to user defined actions as well as to custom outputs for archival.

News

July 18, 2011 Please join us for the Inaugural Grid Protection Alliance User's Forum for the Time Series Framework and openPDC to be held in the Georgia Power Building in Atlanta, GA on September 7, 2011. If you can come out a day early, on September 6

40 people are following this project (follow)

Download

CURRENT	openPDC v1.4 SP1 Release
DATE	Mon May 2 2011 at 7:00 AM
STATUS	Stable
RATING	No Ratings
	1116 downloads
MORE	View all downloads

Join Us

Project is open to developers looking to contribute n-unit tests, bug fixes, power system calculators and new adapters for systems integration.

Sign in to join this project.

Activity 7 30 All days

Page Views	1646

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openPDC

Open Source Phasor Data Concentrator

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Among the openPDC users are …

- MISO
- Entergy
- Southern Company
- TVA
- OG&E
- Duke Energy
- FP&L
- BPA

- WECC
- PG&E
- ISO-NE
  - Central Maine Power
  - Bangor Hydro
  - Northeast Utilities
  - NSTAR
  - VELCO
  - United Illuminating

- <u>Under Consideration</u>
  - Dominion
  - PacifiCorp
  - Idaho Power
  - BC Hydro
  - Manitoba Hydro

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openPG

Open Source Phasor Gateway

Business Case for the Open Phasor Gateway

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The openPG provides required security isolation as it reduces operational costs

Application Profile
The openPG is a back office system that is used to securely send and receive high sample rate synchrophasor data with owners of other openPGs.

Hardware
The openPG executes on standard server hardware. As a massively threaded application, it effectively utilizes all CPU resources presented to it. A production openPG is not intended for implementation in a virtualized environment.

Required OS and Services
The openPG is a Microsoft .net application and is intended for deployment using Windows Server 2005 or 2008. However, the openPG will run under other Windows operating systems.

Business Needs
Recent growth in the amount of phasor information and the need to share it among grid operators is a call for an appliance that:

- Creates a hardened security buffer between critical internal and external systems.
- Provides high-quality encryption to protect the confidentiality of reliability and market sensitive BES data.
- Facilitates and reduces the cost of phasor data exchange.

This need was anticipated by DOE in 2008 as they funded the development of the NASPInet technical specification. This specification called for an appliance named the phasor data gateway. The openPG is an implementation of this gateway for real-time phasor data exchange.

openPG Overview
The Phasor Gateway provides an easy-to-configure interface to other phasor information systems. Development of the openPG has been funded by NERC.

The openPG:

- Only exchanges data with other openPGs where a trusted union has been established.
- Automatically discovers the phasor measurements that have been made available by other openPGs and allows the selective subscription to these measurement points.
- Provides tools for administrators to limit the phasor data that is available for subscription by a specific openPG.
- Supports strong encryption of the data exchanged between gateways.

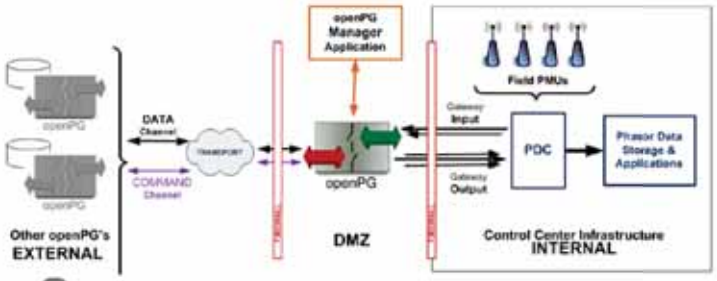

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Business Case for the openPG

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Benefits

Using the openPG rather than standard protocols, such as IEEE C37.118, has the advantage of:

- Improving security and reducing bandwidth by only exchanging the measurement points that are needed.
- Simplified configuration management through automated metadata exchange and ability to easily rename imported data points.
- Reduced latency for most phasor data since the concentration step of a PDC is not required.
- Scalability and extensibility.

Compliance Assurance. As a security device, the openPG is intended to be installed at the edge of a security perimeter, and its functionality is purposely limited to secure communication with other openPGs. The openPG provides:

- NERC Data Sharing — The openPG promotes BES reliability improvement by providing an easy and secure way to exchange phasor data with others — as an ICCP node does today. Phasor data exchange can only occur between pairs of gateways that have established trusted unions.
- Change Testing — The openPG improves change resiliency and provides the tools for operation staff to quickly validate phasor information system changes.
- Change Logging — To meet CIP requirements all configuration changes to the openPG are logged.
- Operations Logging — The openPG includes an operational log historian that records a collection of key gateway operating statistics every 10 seconds.
- Access Control — Administrator access credentials can be maintained in external systems, such as MS Active Directory, or can be stored locally in encrypted configuration files.
- System Currency — The openPG is easy to test, update and patch as new versions are released.

Data Confidentiality. The openPG utilizes best practice encryption with frequent key change to provide the highest levels of data confidentiality.

Configuration Flexibility and Efficiency. The openPG reduces costs by making phasor data exchange easy to manage.

- Exchange of Gateway Meta Data — The openPG sends its configuration information to other trusted openPG's on request. Measurements are assigned a Globally Unique Identifier (GUID) so that the common name to reference the point can be changed as needed by each gateway user. This feature allows the gateway to assign or update names to points sent or received without impacting gateway operator or downstream applications.
- Quick Additions of New Points — Each sending gateway provides a list of available points to other openPGs. Selecting a new point for subscription just requires a few mouse clicks.
- Configuration Alignment — The ability to dynamically update configuration information results in faster, lower cost openPG operation. As an openPG owner makes changes to measurement metadata, these changes are made known to all other connected gateways.
- Data Transfer Efficiency — Data is transferred among gateways on a point-by-point basis with each point transferred requiring only 9 bytes through use of GPA's Gateway Exchange Protocol.
- Open Source Reduces Total Cost — Redistribution and modifications of the openPG are allowed without royalties or licensing costs. Thorough community review lowers risk and improves quality. The openPG is released under the Eclipse Public License.

Low Latency. The openPG can receive multiple input data streams and forward this phasor data to the specified gateways without the need for data concentration delays.

High Availability. The openPG is designed to be deployed as a service within a clustered server environment.

High Quality Solution. The openPG is an object oriented system that is open source with many eyes on code quality.

System Integration. The openPG is designed to leverage the full suite of input and output adapters developed for the openPDC. As support for new protocols are developed for the openPDC, these improvements will dynamically be available to the openPG as well.

Future Proofing. As an open source product, there is no vendor lock-in with the openPG. Any open source community improvements to GPA's time series library are seamlessly incorporated into new openPG releases.

The openPG is available for download at: http://openPG.codeplex.com

- **An edge device for the security perimeter**
- **Lowers the cost of configuration management**

DOE Project -- SIEGate

Secure Information Exchange for Grid Operations

A generalized, security hardened appliance for the exchange of real-time grid operating information.

- Open source
- Productized by Alstom
- Security tested by PNNL
- Demonstrated by PJM
- NERC provides cost share via NASPI project

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Current State of BES Data Exchange is Complex

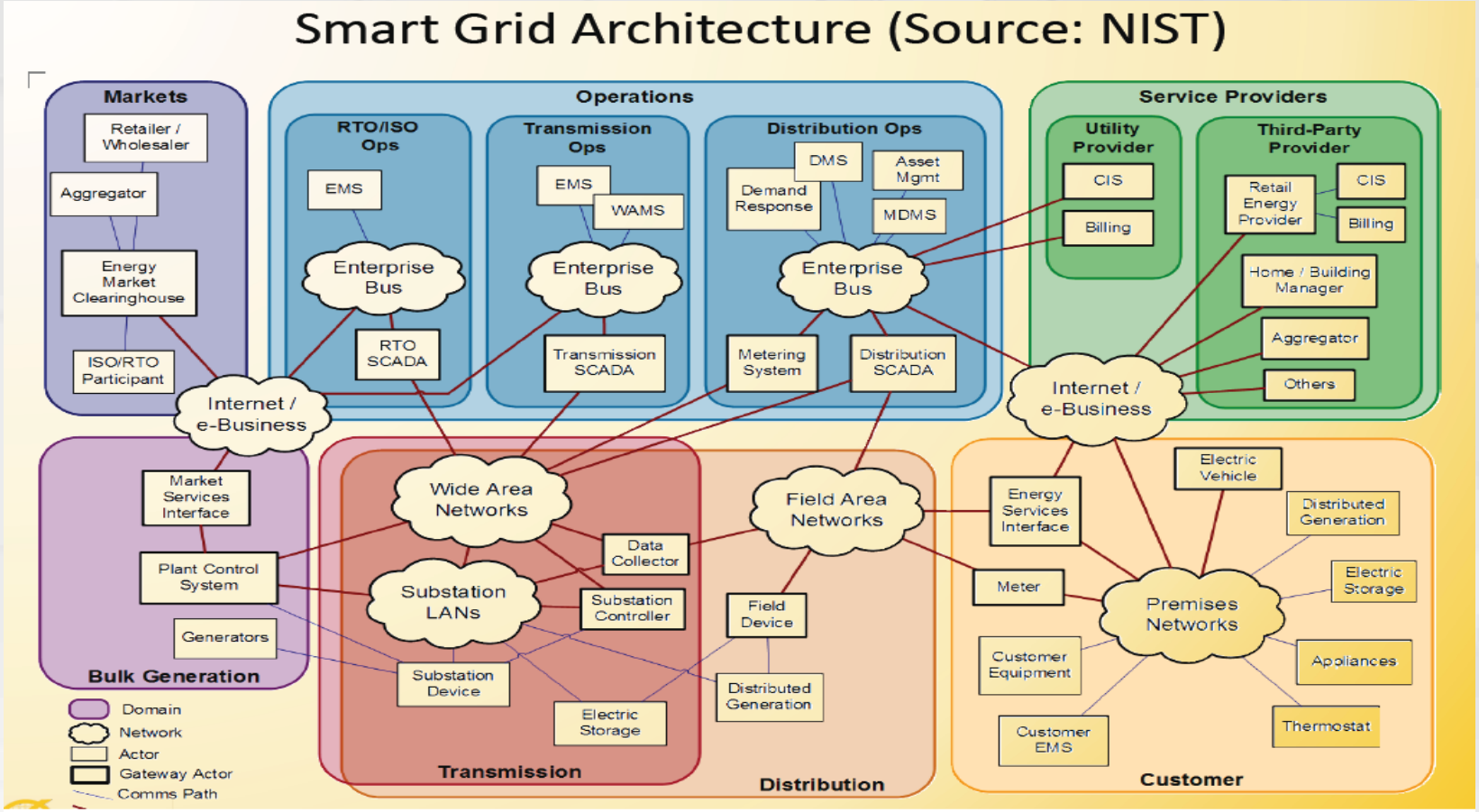

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SIEGate Secures and Simplifies

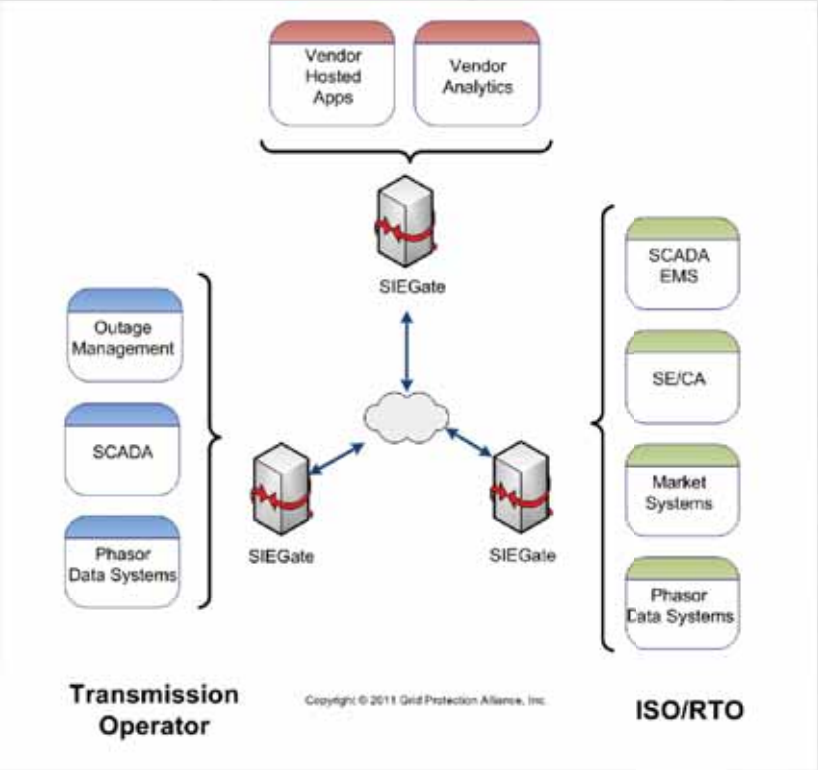

- Support for Multiple Data Types
  - Periodic Real-Time (e.g., SCADA & Phasor)
  - Alarms
  - Files (e.g., SDX & Disturbance Data)
- Focus on ease of configuration and use
- Full software stack security

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TVA Support

- TVA providing EI-wide phasor data storage until other phasor data hubs are operational
- 120 PMUs connected but data availability is volatile.
  - From day-to-day the number of PMUs transferring data to the concentrator can range from 30% to 70%
- Over 30 TB of saved phasor data
- Real-time data exported to Entergy, MISO and WECC (for testing)

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GPA 2012 Work Plan

- Security test and improve the openPG
- openPG demonstration:
  - Data Exchange Working Group (DEWG)
  - SGIG winners
- Develop SIEGate
- Support NASPI and NERC
- Support TVA Phasor Data Concentrator

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GPA Product Timeline

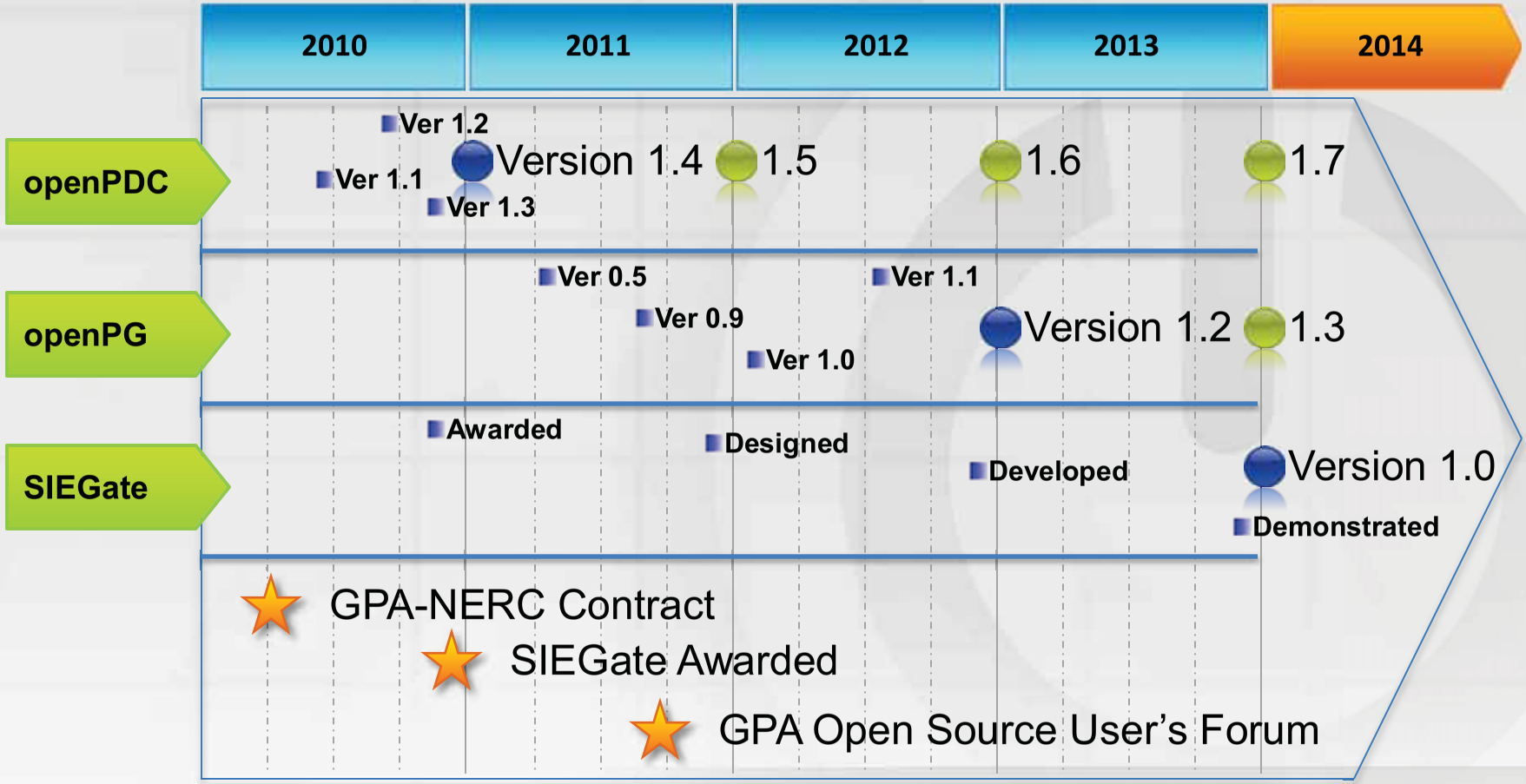

= NERC Supported

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NASPI Project Budget and Costs

- Approved in July 2008 as a 5-Year ~$6.5M Project, about $4M for TVA, and later GPA

	NERC Budget Year					
Approved Budget	2009	2010	2011	2012	2013	Total
	$ 698,000	$ 1,075,000	$ 996,000	$ 863,000	$ 476,000	$ 4,108,000

	Actual	*Acutal*	*Planned*	*Budgeted*	*Estimated*	
Costs	2009	2010	2011	2012	2013	Total
GPA		$ 808,405	$ 780,000	$ 660,000	$ 400,000	$ 3,212,821
TVA	$ 368,282	$ 83,486	$ 72,648	$ 40,000	$ -	$ 564,416
Total	**$ 368,282**	**$ 891,891**	**$ 852,648**	**$ 700,000**	**$ 400,000**	**$ 3,777,237**

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NASPI Status Report
Accomplishments and Plans

Alison Silverstein, Project Manager
North American SynchroPhasor Initiative

NERC Board of Trustees
Standards Oversight & Technology Committee

November 2, 2011

NASPI background

- Voluntary collaboration between NERC, electric industry and DOE to advance adoption and use of phasor technology for grid reliability and economics
- Collaborative community -- members include utility and RTO/ISO staff, vendors, consultants, national lab staff, academics, students
- Three Work Group meetings a year cover broad themes and updates (SGIG project updates, vendor offerings, international, research)
  - Recent meeting attendance ranges from 170 to 270 people
  - NERC charges registration fees of $200/person ($75/student)
  - Industry sponsorships are bringing in $10k to $25k/meeting
- Five Task Teams (Data & Network Management, Operations, Performance Standards, Planning Initiatives, Research) do most of the real work
- Project manager coordinates meetings, issue identification, articulates strategy, handles outreach to industry and media
- www.naspi.org

PMUs now and later

Early 2011

-- about 250 PMUs

End of 2013

-- over 1,000 high-grade PMUs thanks to 10 industry SGIG projects

2015

-- maybe 1,300, then growing again

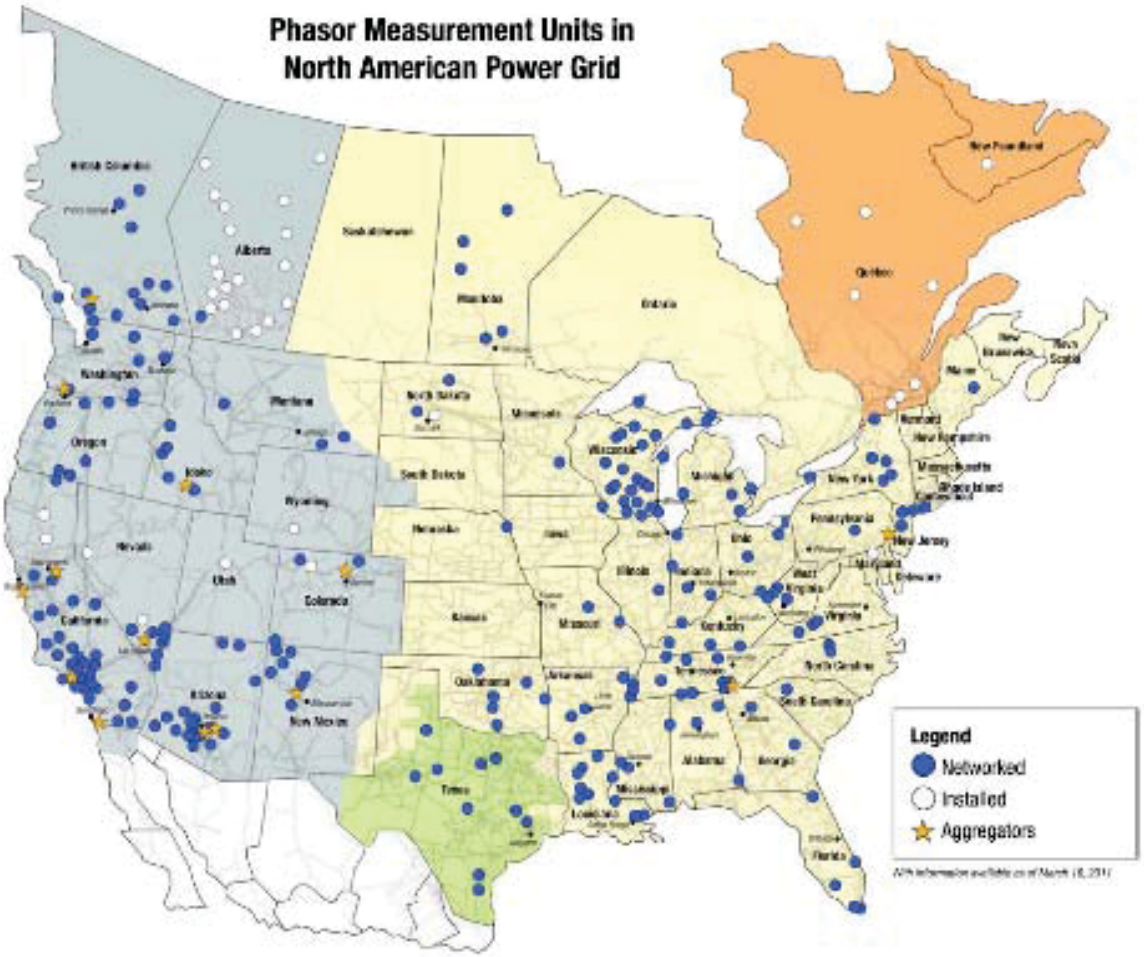

NASPI

Major NASPI accomplishments

- Prepared NASPInet communications architecture framework for phasor data networks
- Existence of NASPI convinced DOE to dedicate SGIG funds for phasor technology, and NASPI work helped frame project priorities and research tasks
- Helping SGIG award recipients identify project solutions
- Helping vendors identify awardees' needs and drive PMU and PDC product maturity
- Prepared vision and reference documents
  - phasor technology roadmap and strategic plan
  - applications review
  - NASPInet
  - fact sheets
  - RAPIR report
  - presentations for outreach and boilerplate
- Articulating R&D needs (esp baselining and pattern recognition)
- Developed WECC data-sharing agreement

NASPI Accomplishments (2)

- Major role in identifying needs and accelerating development of phasor technology interoperability standards, now working through IEEE and IEC adoption process (see next page)
  - Phasor measurement
  - PMU capabilities and communications, calibration and testing
  - Timing standards
  - PDC guidelines
  - Phasor data storage needs
- Early identification of issues and solution needs
  - Data-sharing for operations and research
  - PMU functionality for SGIG purchase specs
  - PDC performance and data archiving
  - PMU placement guidelines
  - End-to-end interoperability for data and devices
  - Cyber-security for synchrophasor systems
  - PMU or synchrophasor Registry and nomenclature standardization
  - Real-time data quality and availability (problems and causes)
  - GPS availability and trustworthiness
  - Operator training

Phasor Measurement System & Standards

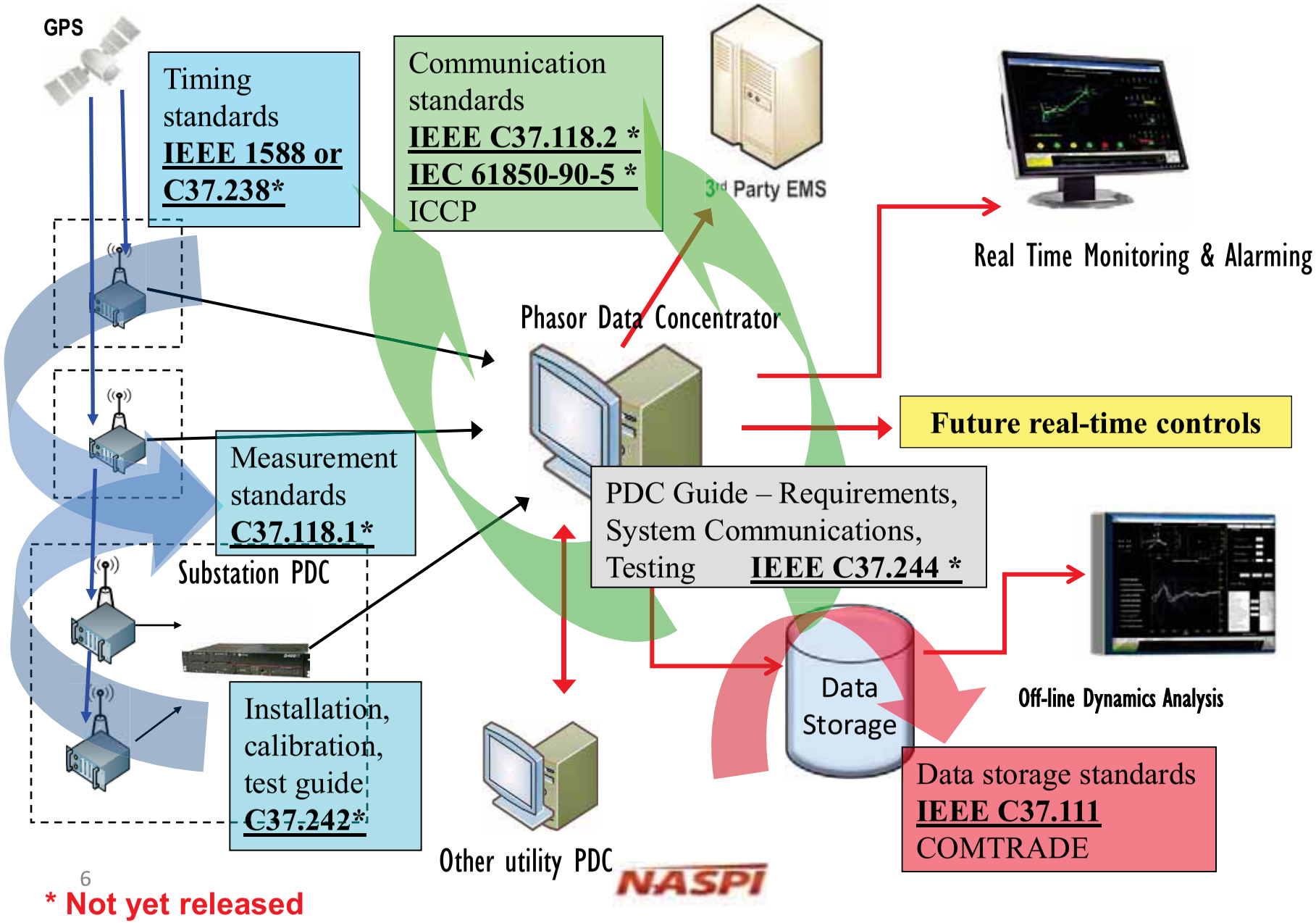

* Not yet released

Current NASPI activities and priorities

- Three meetings each year (10/12-13/11 on SGIG projects; 2/29-3/1/12 on research and training; 6/13-14/12 vendor show and success stories; 10/17-18/12 on SGIG projects) with 170 to 270 attendees per meeting
- Develop new technology roadmap to update RAPIR report (see https://www.naspi.org/site/StaticPDF/resource/rapir_final_20101017.pdf), with summary SGIG project info in NASPI Annual Report to support DOE
- With PMU and PDC functionality settling out, looking at how to ensure high-quality, production-grade performance of the entire synchrophasor system, with high-quality data worth feeding into applications
- Recognize and document applications that offer highest value to industry (requires continued baselining research and data-sharing)
- Identify effective operator and user training methods
- Continue outreach and education on phasor technology to support mainstreaming strategy

Likely synchrophasor applications maturity and adoption sequence

- Forensic uses ready and accepted now
- Planning uses ready next
  - Model validation uses routine today within WECC
  - Planning and other uses require several more years of data collection, baselining analysis, research and tool development
- Real-time operator uses will take longer
  - Wide-area visualization tools are commercially available today but require some time to gain operator familiarity
  - Need better communications systems for fast, high-quality data delivery
  - Need more time for data collection and analysis to inform operator support tools
  - Automated equipment action will come last (e.g., RAS schemes)

What's the future path?

Several questions about institutionalization:

1. how does synchrophasor technology get mainstreamed?
2. how does synchrophasor community get mainstreamed -- what happens to NASPI task teams and functions?
3. in the meantime, what happens to several existing projects?

We have an initial plan for all this so integration is smooth and successful. But the plan will require more industry leadership and evolving NERC support, and the transition cannot be expected to move much faster than the technology's value to the industry.

NASPI Transition Plan -- summary

- Migrate work of Planning and Operations Task Teams into NERC PC and OC
- Migrate work of Data & Network Management Task Team back into industry and to NERC DEWG and CIPC
- Migrate work of Performance Standards Task Team to IEEE, IEC, and PSRC.
- Dial back NERC funding of GPA for infrastructure after 2013 with pick-up by industry and vendors
- Keep NASPI conference and project management function going through 2013 and evaluate continuing need then; maybe migrate role to NATF or ISO-RTO Council?
- Migrate NERC and DOE funding of TVA SuperPDC operation to Eastern Interconnection RCs
- DOE to continue funding some phasor technology R&D; applications development and technology improvements move to industry lead (SGIG awardees and vendors)
- Details in background slides….

NASPI Transition Plan Background

Evolution of NASPI as an organization

- NERC is funding NASPI meetings and project manager now, and expects to do so through at least 2013.
  - NASPI charges attendee registration fees and takes vendor sponsorships for some meeting meals, so meeting costs are break-even
- DOE funds synchrophasor research projects, interoperability standards development, and National Lab staff technical and admin support for NASPI task teams, leadership, and website.
- NASPI is mostly a voluntary community with no formal governance or authority, so members are frustrated when their proposals don't get adopted or enforced.
- All NASPI functions (see later pages) are useful now, but not all need to be continued.
- Industry members would like to see NASPI continue in its current role beyond 2013.

Task Team transition

1. **Planning Implementation Task Team**
   - Coordinating work on modeling, baselining, oscillatory patterns, integrating phasor data into system planning, PMU placement
   - Baselining research supported by DOE through PNNL and EPG
   - Proposed transition path – increase NERC PC focus on synchrophasors, transition PITT functions into appropriate subcommittees of the PC (incl. Stds) with selected research funding from DOE
2. **Operations Implementation Task Team**
   - Working on how to use phasor data in operations (RTDMS and other visualization tools, state estimation, renewables integration, operator training)
   - SuperPDC/RTDMS provision for Eastern Intercon supported by NERC and DOE funds
   - Proposed transition path – increase NERC OC focus on synchrophasors, transition OITT functions into appropriate subcommittees of the OC (incl. Stds), but esp. RCWG, with selected research funding from DOE. However, end NERC and DOE funding for TVA SuperPDC/RTDMS provision (see below)

Task Team transition

3. **Performance Standards Task Team**
   - Developing technical interoperability standards and protocols
   - DOE funding for technical support by EPG and PNNL staff
   - Proposed transition path – DOE funding ends when current IEEE 37.118 and IEC 61850 are adopted. When current wave of standards development is ended, PSTT role moves over to IEC and PSRC.
4. **Data & Network Management Task Team**
   - Working on issues like network architecture, data classes, naming conventions, Registry
   - Limited DOE funding since NASPInet study includes Phasor Gateway testing; NERC funds GPA work on phasor system infrastructure tools (Open PDC, Phasor Gateway)
   - Proposed transition path – some issues move to NERC DEWG, others move to individual industry decisions
5. **Research Initiatives Task Team**
   - Focus is on sharing findings, not research formulation or management
   - Limited DOE funding for meeting support and website
   - Proposed transition path – none needed. DOE will independently continue to fund specific research projects.

NERC- and DOE-funded projects

1. TVA-hosted SuperPDC and RTDMS, supported by GPA (NERC-funded) and EPG (DOE-funded) is the largest budget item.
   - Eastern entities won't need this as the SGIG projects go into operation. TVA-hosted SuperPDC/RTDMS will mostly fill data gaps, but soon it will no longer be needed.
   - Proposed transition milestone – execution of data-sharing agreements among MISO, PJM, NYISO and ISO-NE; maybe also Southern and Entergy. NERC and DOE should support TVA installation no longer than one year past this date, or no later than 2015.
2. Other projects discussed above
3. NASPI Leadership and technical support
   - As NASPI Task Teams evolve (as discussed above), formal support for NASPI (as an organization) by DOE and NERC will wind down -- likely, no later than 2015, when the DOE SGIG project work is completed and results shared with industry.

NASPI functions

FUNCTION	POTENTIAL DESTINATIONS
Convening and conferences • Work Group and Task Team meetings • Networking • Cross-pollination of ideas • Facilitate cooperation (e.g., vendor show, multi-vendor data network demo, SGIG awardee info sharing)	• Absorb TTs into NERC and IEEE ctts (PITT into PC, OITT into OC, DNMTT into DEWG, PSTT into PSRC) • Create another NERC ctt focusing on phasor technology? • Vendor community user groups • Professional society conferences • Private subscription-model trade assn?
Information sharing • Research results • How-to guidance	• PSRC and/or university • Regional planning or operating authorities
Technology advancement • Technical standards and protocol development • Product and concept development (e.g, NASPInet, Registry) • Expedite revelation of buyer needs and vendor capabilities to speed product maturity	• Industry technical groups and standards bodies • Vendors, vendor user groups, consultants
Strategy development • Technology roadmap • Policy issues and positions (data-sharing, cyber-security)	• DOE, CERTS • NERC committees • FERC and state regulators

NASPI functions (2)

FUNCTIONS	POTENTIAL DESTINATIONS
Analysis • Identify timely issues and focus attention on their resolution (e.g., NASPInet, Registry, PMU placement, phasor data quality, PMU capabilities) • Perform research and analysis (e.g., phasor-based reliability tools, GPS vulnerability) • Help DOE identify and document impacts of SGIGs	• DOE and industry members and consultants?
Outreach and communications to key publics • Single point of contact for phasor interests (media inquiries, industry briefings, NARUC) • Prepare resource materials (RAPIR report, fact sheets, powerpoints, upcoming technology roadmap and status report)	• Industry, NERC, DOE
Coordinate activities, policy, effort • Research needs • Consensus view on key ideas and work products • Support DOE and NERC ctts with reports, contacts • Provide leads, contacts, suggestions	• DOE, CERTS • NATF, NERC ctts, ISO-RTO Council

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ERO Enterprise Solutions Roadmap

Catherine Sills
Manager of ERO Enterprise Projects

November 2, 2011

RELIABILITY | ACCOUNTABILITY

ERO Enterprise Solutions Roadmap

- Regional Entities and NERC agree to adopt the ERO IT Strategy.
- Adoption will drive consistency, efficiency, and performance measurement that should result in higher productivity.
- Considers the areas of governance, process, technology and resources, and comprises approximately 30 guiding principles and recommendations for implementation.

ERO Enterprise Solutions Roadmap

- Governance
  - Collaborative model
  - NERC and Regional EMG – decision authority
  - Establish ERO Project Management Office (PMO) – process, methodology, structure
  - ITSG – advisory role
- Process
  - Define set of common processes
  - Redesign for consistency and standardization
  - Data definition

ERO Enterprise Solutions Roadmap

- Technology
  - Standard security policy
  - Standard data management policy
  - Standard technology footprint
- Resources
  - Develop funding and resource model
  - Dedicated NERC resources

ERO Enterprise Solutions Roadmap

- Next Steps
  - Launch dedicated staff
  - Implement collaborative model
  - Develop 2012/2013 resource and project plan
  - Business process mapping
  - Develop policies

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IT 90-Day Plan and Roadmap Update

Marvin Santerfeit
Director of Information Technology and Services

November 2, 2011

RELIABILITY | ACCOUNTABILITY

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Executive Summary

Landscape
Multiple Applications
Inconsistent Process & Controls
Inexperienced technology staff
Enterprise responsibility w/o Enterprise authority
Unknown or undocumented business process
Limited Analytics or Decision Analysis tools
Conflicting Responsibilities (Internal / ERO)

IT Strategy
Inventory / Process / Workflow Mapping
Stabilization (Network)
ITIL / ISO Framework
Organizational Resource Alignment
Plan, Design, Implement, Operate (PDIO)
Transparency / Metrics
Technology Alignment (SharePoint / Data Warehouse)

Result
Documented Processes
Stable, Redundant, Secure Network
Consistent, Repeatable, Documented Processes
Roles & Responsibilities Match Skills
Standardized and Accepted Business Practice
Solid Foundation for Decision Making Process
Consistent View, Analytics, Data Availability

90-Day Plan

- 90-Day Plan
  - Stabilize Network Infrastructure
    - Complete Princeton Data Center to Atlanta Data Center move by end of year
    - Complete Washington DC (new office) build-out and move in by Dec. 16
    - Review 2012 resource requirements and organizational alignment
    - Implement technology reporting and metrics
    - Complete application review and establish ownership
    - Improve customer satisfaction (response/follow-up/documentation)
    - Launch re-designed (SharePoint) NERC Intranet site
    - Review/update policies and procedures
    - Build methodology and resource model for ERO Project Management Office (PMO)
    - Refine NERC support methodology – single point of ownership

Next Steps

- IT Roadmap
  - Realign IT Organization – Support, Infrastructure, Development, PMO, Security
  - Application discovery and functional analysis
  - Implement methodology – plan, design, implement, operational
  - SharePoint 2010 Design and Implementation Model
  - IT Service Desk implementation (ITIL Framework) – best practice model
  - Draft IT Disaster Recovery/Business Continuity plan
  - Vendor assessment and consolidation
  - Identify and leverage outsource opportunities ex., firewall management
  - Create and implement virtualization strategy
  - Create Information Security Management System (plan, do, check, act)
  - Create Development Model (development, QA, Pre-Pro, production)
  - Assess “cloud” computing opportunities
  - ERO application re-design or enhancement priorities
  - Hardware, software, network and database design

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Agenda
Board of Trustees Compliance Committee – OPEN Session

November 2, 2011 | 10:45 a.m.-Noon Eastern
Westin Buckhead Atlanta
3391 Peachtree Road, NE
Atlanta, GA 30326
404-365-0065

Introductions and Chair's Remarks

NERC Antitrust Compliance Guidelines and Public Announcement

Agenda

1. **Minutes* — Approve**
   a. August 3, 2011 meeting
2. **Compliance Enforcement Initiatives***

   Purpose: Update to BOTCC and industry on implementation of the initiative to date.
3. **Risk-Based Reliability Compliance and Entity Assessment***

   Purpose: Provide industry information and the initial template for the entity assessment to be used to inform compliance monitoring activities per the 2012 CMEP Implementation plan.
4. **Compliance Operations Update***

   Purpose: Provide information on latest Compliance Analysis reports and GO/TO Directive.
5. **Quarterly Statistics***

   Purpose: Update to BOTCC and industry on quarterly statistics to fulfill the Committee's mandate obligations.
6. **MRO/NPCC Item***

*Background materials included.

Antitrust Compliance Guidelines

I. General

It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition.

It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

II. Prohibited Activities

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

- Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

III. Activities That Are Permitted

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation, Bylaws, and Rules of Procedure are followed in conducting NERC business.

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of the mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.
- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.
- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.

Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

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Item 1.a

Draft Meeting Minutes
Board of Trustees Compliance Committee

August 3, 2011 | 10:30 a.m.–Noon PT
Vancouver Marriott Pinnacle

Chair Bruce Scherr called to order a duly noticed open meeting of the Board of Trustees Compliance Committee of the North American Electric Reliability Corporation on August 3, 2011, at approximately 10:35 a.m., Pacific Time, and a quorum was declared present. The agenda and list of attendees are attached as **Exhibits A** and **B,** respectively.

NERC Antitrust Compliance Guidelines
Chair Scherr acknowledged NERC's Antitrust Compliance Guidelines.

Overview of Meeting Objectives and Process
Chair Scherr reviewed the meeting's objectives.

Consent Agenda
On motion of Paul Barber, the committee approved the meeting minutes of May 10, 2011.

NERC Staff Update

Compliance Enforcement
Rebecca Michael, associate general counsel corporate and regulatory matters and acting director of compliance enforcement, presented an update to the BOTCC and the industry on plans to enhance the compliance and enforcement program process. The new process differentiates matters based upon the level of risk to the reliability of the bulk power system (BPS). All issues will continue to be identified and corrected. Issues that pose a more serious risk to the reliability of the BPS will be filed at the Federal Energy Regulatory Commission ("FERC") on a monthly basis in a further streamlined spreadsheet Notice of Penalty format. Matters that pose a lesser risk to reliability will be processed on a "find, fix, track and report" (FFT) spreadsheet that will be submitted on a monthly basis to FERC. NERC will submit a filing to FERC on September 30, 2011 that will set forth the initiative in detail and will include the two new spreadsheet formats.

Ms. Michael also provided to the committee the quarterly trending statistics.

Compliance Operations
Michael Moon, director of compliance operations, presented an update on the 2012 Implementation Plan and Actively Monitored List and the Risk-Based Compliance Monitoring approach. Mr. Moon noted that NERC and Regional Entities are continuing work to develop an Entity Risk Profile Assessment template for use across the entire ERO before the end of 2011.

Adjournment
There being no further business, Chair Scherr adjourned the meeting at 12:05 p.m. PT.

Submitted by,

Rebecca J. Michael

Rebecca J. Michael
Committee Secretary

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Exhibit A

Agenda — Open Session
Compliance Committee

August 3, 2011 | 10:30 a.m.–Noon PT
Vancouver Marriott Pinnacle
1128 West Hastings Street
Vancouver, BC VE 4R5 Canada
604-684-1128

Introductions and Chair's Remarks

NERC Antitrust Compliance Guidelines

Agenda

1. **Overview of Meeting Objectives and Process**
2. **Consent Agenda* — Approve**
   a. May 10, 2011 Meeting Minutes
   b. Future Meetings
3. **NERC Staff Update***
   a. Compliance Enforcement Improvement Initiatives

      Objective: Update to BOTCC and Industry on plans to enhance the enforcement process. Included among these plans are:

      - A focus group session on July 14 with a representative group of registered entities to understand their experiences in the compliance enforcement process.
      - A filing with the U.S. Federal Energy Regulatory Commission planned for late-Summer or early-Fall to set forth the basis and outline the procedures by which the ERO will exercise enforcement discretion over certain violations that come into the caseload.
      - A proposal to be included in the above referenced filing to restructure NERC's notices of penalty in a streamlined spreadsheet format for all violations that proceed to a notice of penalty other than those violations reflecting a serious or substantial risk to bulk power system reliability.
      - A program to review and digest dismissals to distill information helpful to registered entities in determining whether to self-report.

b. Compliance Operations

i. 2012 Implementation Plan and AML (update, use of top reliability risk priorities and posting)

Objective: Present to industry with BOTCC Support – goal is to have the 2012 plan to BOTCC for approval in July – post Aug 1 and then present major parts to industry at the BOTCC Open

ii. Risk Based Reliability Compliance

Objective: Continue to update the BOTCC and Industry on the evolution of NERC Compliance Monitoring and Enforcement Entity Assessment

c. Quarterly Statistics

Objective: Update to BOTCC and Industry on quarterly statistics to fulfill the Committee's mandate obligations.

4. **Other Matters**

*Background material included.

Exhibit B

List of Attendees
Open Board of Trustees Compliance Committee Meeting
Vancouver, BC
August 3, 2011

Board of Trustees Compliance Committee	
Chairman of Board of Trustees	John Q. Anderson
Chairman of Board of Trustee Compliance Committee	Bruce Scherr
Member	Vicky Bailey
Member	Paul Barber
Member	Fred Gorbet
Member	Ken Peterson
Member	Jan Shori

Regional Executives	
MRO	Dan Skaar
NPCC	Edward A. Schwerdt
Texas Reliability Entity	Larry Grimm
FRCC	Sarah Rogers
SERC	~~Scott Henry~~
Reliability*First*	Tim Gallagher

Guest	
Chairman	Bill Gallagher
Vice Chairman	Scott Helyer
Investor-Owned Utility	Carol Chinn
Investor-Owned Utility	Thomas Burgess
State/Municipal Utility	Timothy Arlt
State/Municipal Utility	~~John DiStasio~~ **(Proxy: Alan Mosher)**
Cooperative Utility	~~Michael Smith~~ **(Proxy: Barry Lawson)**
Cooperative Utility	~~Eric Baker~~ **(Proxy: Barry Lawson)**
Federal/Provincial Utility	Julius Pataky
Federal/Provincial Utility	Anthony Montoya
Federal/Provincial Utility	Lorne Midford
Federal/Provincial Utility	~~Carmine Marcello~~ **(Proxy: Ajay Garg)**
Transmission Dependent Utility	John Twitty

Transmission Dependent Utility	Terry Huval **(Proxy: John Twitty)**
Merchant Electricity Generator	Kathryn Mirr
Merchant Electricity Generator	William Taylor III
Electricity Marketer	~~Roy True~~ **(Proxy: Jason Marshall)**
Electricity Marketer	Jack Cashin
Large End-Use Electricity Customer	Michelle D'Antuono
Large End-Use Electricity Customer	John Anderson
Small End-Use Electricity Customer	Lawrence Nordell
Small End-Use Electricity Customer	~~Charles Acquard~~ **(Proxy: Larry Nordell)**
ISO/RTO	Paul Murphy
ISO/RTO	Terry Boston
Regional Entity (Voting)	Stacy Dochoda (SPP)
Regional Entity (Voting)	Craven Crowell (TRE)
State Government	~~Thomas Dvorsky~~
State Government	~~Robin Lunt~~ **(Proxy: Steve Johnson)**
Canadian Provincial	~~Jean-Paul Théorêt~~ **(Proxy: Gilbert Neveu)**
Canadian Federal	Amitabha Gangopadhyay
U.S. – Federal	Pat Hoffman
U.S. – Federal	Joseph McClelland
Regional Entity	~~Gorden Gillette (FRCC)~~ **(Proxy: Sarah Rogers)**
Regional Entity	Ed Tymofichuk (MRO)
Regional Entity	Harvey Reed (NPCC)
Regional Entity	Susan Ivey (RFC)
Regional Entity	Maureen Borkowski (SERC)
Regional Entity	David Areghini (WECC)
Secretary	Dave Nevius

FERC	Aileen Roder
APPA	Alan Mosher
Ben Li Associates	Ben Li
Progress Energy	Ben Crisp
CPPC	Bill Gaines
MISO	Bill Phillips
BC Utilities Commission	Brian Williston
Georgia Systems Operations Corporation	Clay Smith
WECC	Constance White
FERC	Christy Walsh

Exelon	Dave Belanger
Northeast Utility	Dave Boguslawski
SPP	Dave Christiano
NERC	David Cook
EEI	David Dworzak
WECC	David Godfrey
Dominion	David Roop
Deloitte & Touche LLP	Dmitriy Bonvih
BC Utilities Commission	Don Flintoff
PSE&G	Don Holdsworth
NERC	Ed Kichline
Quanta Technologies	Farnoosh Rahmatran
Lafayette Utilities System	Gini Ingram
BPA	Hardev Juj
NERC	Herb Schrayshuen
DP&L	Hertzel Shamash
NERC	Holly Hawkins
Natural Resources Canada	Ivan Harvie
NERC	Janet Sena
MidAmerican Energy Holdings	Jay Carrier
ReliabilityFirst	Jeff Mitchell
PSE&G	Jeff Mueller
NPCC	Jennifer Budd Matiello
NEB	Jim Davidson
EEI	Jim Fama
Wisconsin Electric	Jim Keller
PSEG	John Seelke
SERC	John Twitchall
FERC	Joshua Konecni
SERC	Ken Keels
Detroit Edison	Kent Kujala
SERC	Kevin Berent
NERC	Kimberly Mielcarek
FERC	Larry Gasteiger
FRCC	Linda Campbell
NERC	Liz Merlucci

Dominion	Lou Oberski
Constellation Energy	Maggy Powell
NERC	Mark Lauby
NERC	Mark Weatherford
ERCOT	Matt Morais
SPP	Michael Desselle
Dominion	Michael Gildea
Sacramento Municipal Utility District	Michael Gianunzio
MRO	Miggie Crambilt
FERC	Mike Bardee
NERC	Mike Moon
NERC	Mike Walker
Sacramento Municipal Utility District	Michael Gianunzio
CEA	Patrick Brown
NERC	Pete Knoetgen
FRCC	Peter Heidrich
Canadian Electricity Association	Pierre Guimond
RFC	Ray Palmieri
NERC	Rebecca Michael
Quanta Technology	Reza Nasri
NERC	Ric Cameron
FERC	Roger Morie
Deloitte & Touche LLP	Samuel Icasiano
MRO	Sara Patrick
Dominion	Scot Hathaway
AEP	Scott Moore
WECC	Steve Goodwill
Exelon	Steve Naumann
NARUC	Steve Johnson
NERC-consultant	Stuart Brindley
TRE	Susan Vincent
Hydro Quebec TransEnergie	Sylvain Clermont
WECC	Taud Olsen
The Energy Grouop	Ted Risner
Midwest ISO	Terry Bilke
SC Public Service	Terry Blackwell

NERC	Tina McClellan
PJM	Tom Bowe
NERC	Tom Galloway
NERC	Gerry Cauley
NERC	Val Agnew

Agenda Item 2
Compliance Committee Meeting
November 2, 2011

Compliance Enforcement Initiative

Action
None

Background
September 30, 2011, NERC filed with the Federal Energy Regulatory Commission (FERC) a *Petition Requesting Approval of New Enforcement Mechanisms and Submittal of Initial Informational Filing.* The petition included: (i) a description of NERC's new compliance enforcement initiative (CEI), by which the ERO will exercise its inherent enforcement discretion to process Possible Violations pursuant to different tracks, according to risk; and (ii) for FERC's information, the first group of 117 Remediated Issues that were processed under a new enforcement track referred to as Find, Fix, Track and Report (FFT). On the same day, in separate proceedings, NERC also submitted 75 violations in a new Spreadsheet Notice of Penalty (NOP) format, as well as 27 violations in three Full NOPs.

FERC issued a notice for comment on NERC's petition, with filings due by third parties October 21, 2011. There is no set timeline for FERC action on the petition. FERC is expected to act within 30 days on the violations filed in the new Spreadsheet NOP and the three Full NOPs.

The CEI represents a more comprehensive and integrated compliance and enforcement strategy that differentiates and addresses compliance issues according to their significance to the reliability of the bulk power system (BPS). The goal of the CEI is to: (i) refocus industry efforts on achieving reliability excellence through attention to matters that pose risks to the reliability of the bulk power system; (ii) reduce undue regulatory burdens on users, owners and operators; and (iii) improve caseload processing. The CEI is designed to enhance reliability, maintain accountability and ensure reliability.

Under the CEI, possible violations are still expected to be found, fixed, and reported to Regional Entities, NERC, and the FERC. Lesser risk issues that have been corrected will be reported to FERC as Remediated Issues in a FFT spreadsheet submitted for informational purposes only. Violations that posed a more serious risk will continue to be processed through to a NOP, either as a Spreadsheet NOP or a Full NOP, depending on the case. The Spreadsheet NOP is an evolution of the Administrative Citation Process spreadsheet, using the spreadsheet reporting format for a larger group of violations.

The CEI represents a change in the way the ERO monitors compliance with and enforces reliability standards and is not limited to the September 30, 2011 filing. Going forward, the Regional Entities will continue to designate, and NERC will continue to file, Remediated Issues with FERC each month in an FFT informational filing. In the initial phase of CEI, auditors and other compliance staff will be able to recommend FFT treatment of certain findings, but the ultimate disposition will be determined by Regional Entity enforcement staff. In a second phase of CEI, which will be implemented at least 12 to 18 months after the September 30, 2011 filing and after significant training of compliance staff, compliance staff will be able to designate certain findings for FFT treatment without enforcement staff oversight. NERC will hold a series of webinars and workshops to guide compliance and enforcement staff at all levels on successful use of FFT.

Since the Committee's open meeting in Vancouver in August, NERC staff and Regional Entity staffs have worked collaboratively to shape the elements of the CEI. NERC staff continued its outreach to industry trade associations, legal advisory committee, and individual stakeholders. Trade associations and industry stakeholders also were provided an opportunity to provide written comments to NERC for consideration in finalization of the CEI. NERC and Regional Entities also met with FERC staff in advance of the filing. This inclusive process helped to shape the CEI and will continue to inform implementation of the program.

Going forward, monthly calls and meetings with Regional Entities, Compliance and Certification Committee representatives and trade associations will be held to gain feedback on the program. Ongoing ERO review of the CEI will occur over the next six to twelve months to determine further areas of improvement or efficiency gains and to track success of the program. Another focus group meeting may be held to assess progress of the initiative. Finally, NERC anticipates further discussions with FERC staff about program implementation. NERC has committed to file reports at six months and one year on the implementation of the initiative.

In addition to the public outreach described above, NERC has posted on its website information and forms regarding the CEI. These forms include guidance to Registered Entities on self-reporting in order to assist Regional Entities in the understanding of the potential noncompliance, assessment of the risk, and ultimate disposition of the issue. NERC will also hold webinars and workshops with industry to enhance understanding of FFT and the ERO's enforcement efforts.

Risk-Based Reliability Compliance and Entity Assessment

Action
None

Background
NERC staff will provide industry an update on the development of the template for the entity assessment to be used to inform compliance monitoring activities per the 2012 Compliance Monitoring and Enforcement Program (CMEP) Implementation plan.

Five major components will make up the entity assessment:

1. Technical and Risk Profile; size, functions
2. Reliability Metrics
   - Generating Availability Data System (GADS) data
   - Transmission Availability Data System (TADS) data
   - Relay Misoperations Data
   - Integrated Reliability Index (IRI)

   http://www.nerc.com/docs/pc/rmwg/Integrated_Reliability_Index_WhitePaper_DRAFT.pdf
3. Internal Compliance Program
   - Internal controls
   - Self-identification of compliance issues and possible violations
   - Corrective Action Program
4. Historical CMEP Information and Status of Current Actions
   - Method of discovery
   - Timeliness of mitigation
   - Trends
5. Regional Assessment

Work continues in the development of the template. Two significant efforts include careful selection of measures and metrics and establishing processes and procedures for the entity assessment template and its use.

The reliability metrics development must deliberately consider the various metrics and measures available and determine the most appropriate. Further, metrics and measures must be considered not as point in time statistics but in terms of trends over time to better gauge performance and determine increasing or decreasing performance relative to benchmarks by interconnection, region and/or function.

The entity assessment template will also be accompanied by a process that details how the assessment will be developed and used by the region and the industry.

Compliance Operations Update

Action
None

Background
NERC staff will provide information on latest Compliance Analysis Reports and the draft Directive on Registration of Generator Owner/Operators to cover applicable Transmission Owner/Operator Functions.

Compliance Analysis Reports
On October 5, 2011 NERC posted the following Compliance analysis reports to the NERC website:

Reliability Standard TOP-002 – Normal Operations Planning TOP-002 Report
NERC Organization Certifications Report
NERC Compliance Registry and Registration Appeals Report

The ERO welcomes comments to these reports from the industry and suggestions for future reports. If you would like to provide comments or suggestions, please contact Ryan Stewart.

Draft Directive on GO/TO Registration
NERC developed a draft "Compliance Process Directive #2011-CAG-001 *Directive Regarding Generator Transmission Leads*" and:

- Coordinated with the regions in the directive development
- Overview discussed at the NERC Quarterly Update to the Trade Associations and Forums on October 4, 2011
- Distributed to select industry representatives in October for review and comment (comments requested by October 28, 2011)
- After consideration of industry comment and approval by NERC executive management the final directive will be posted to the NERC website by the end of the year.

Quarterly Statistics

Action
None

Background
NERC staff will present its regular quarterly report to the Committee and stakeholders on compliance statistics to fulfill the Committee's mandate obligations.

Risk-Based Reliability Compliance and Entity Assessment

Action Required
None

Background
Senior Staff from MRO and NPCC will provide regional entity perspective on risk based reliability compliance and entity assessment.

Each region is conducting entity assessments in some manner and the review of the entities culture of compliance is a key part of this assessment.

Individual assessment of entities requires judgment and must include an understanding of the entity, including its system and business practices.

Both MRO and NPCC have further reached out to industry for input and perspective. Appropriately assessing entities must be thoughtful, deliberate and will evolve over the next couple of years but in the long run will be the basis of a better compliance monitoring program.

NPCC has conducted extensive information gathering in its region on Internal Compliance Programs and Culture of Compliance. MRO has been working with stakeholders on guidelines and assurance controls.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda
Member Representatives Committee

November 2, 2011| 1:00 p.m. – 5 p.m. Eastern

Westin Buckhead Atlanta
3391 Peachtree Road NE
Atlanta, GA 30326
404-365-0065

Introductions and Chair's Remarks

NERC Antitrust Compliance Guidelines and Public Announcement

Consent Agenda — Approve

1. **Minutes***
   a. October 5, 2011 Conference Call
   b. August 3, 2011 Meeting

2. **Future Meetings***

Regular Agenda[1]

3. **Welcome to Atlanta**

4. **Remarks By Gerry Cauley, NERC President and CEO**

5. **September 8, 2011 Southwestern Outage***

6. **February 2011 Cold Snap Report and Recommendations***

7. **Election of Committee Officers for 2012***

[1] Board Chairman John Q. Anderson has invited input from the committee sector representatives on specific agenda items (see attached).

8. **Status of MRC Sector Nominations***

9. **NERC Compliance Enforcement Initiative* – Status**[2]

10. **Compliance Application Notices – Status***

11. **Status of CIP Standards Version 4 and 5 and Implementation Plans***

12. **BES Definition and Rules of Procedure – Status***

13. **ALR Task Force Status Report***

14. **Culture of Reliability Excellence – LG&E/KU***

15. **Rules of Procedure Changes**

16. **Looking Ahead to February 8, 2012 Meeting – Key Agenda Items**

17. **Comments by Outgoing Chairman**

18. **Comments by Chairman Elect**

Information Only – No Discussion

19. **Update on Regulatory Matters***

*Background materials included.

[2] This item will be presented initially in the Board Compliance Committee meeting, which precedes the MRC meeting on November 2. MRC members will engage in further discussion of the Compliance Enforcement Initiative during the MRC meeting.

Antitrust Compliance Guidelines

I. General

It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition.

It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

II. Prohibited Activities

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

- Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

III. Activities That Are Permitted

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation, Bylaws, and Rules of Procedure are followed in conducting NERC business.

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of the mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.
- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.
- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.

Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

Future Meetings

Action
None

Background
The below are the future meetings as approved by the board on May 11, 2011.

2012 Dates

February 8-9	Phoenix, AZ
May 8-9	Baltimore/Washington, DC area
August 15-16	Quebec City, Canada
November 6-7	New Orleans, LA

2013 Dates

February 6-7	San Diego, CA
May 8-9	Philadelphia, PA
August 14-15	Montreal, Canada
November 6-7	Atlanta, GA

2014 Dates

February 5-6	Phoenix, AZ

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RELIABILITY CORPORATION

October 6, 2011

Mr. William Gallagher, Chairman
NERC Member Representatives Committee
104 Hampton Meadows
Hampton, New Hampshire 03842

Re: Policy Input to NERC Board of Trustees

Dear Bill:

The agenda for the November 2, 2011 Member Representatives Committee (MRC) meeting is chock full of substantive items, several of which will warrant high interest by members of the Board of Trustees (board). The board always is interested in policy input from the committee members on any issue, but would especially like to hear members' views on the following:

Compliance Enforcement Initiative (BOTCC-2 and MRC-9) — NERC filed late last week with FERC its decision to shift how it deals with Possible Violations that pose lesser risks to the bulk power system (BPS). As the filing explains, NERC and the Regional Entities are employing a more comprehensive and integrated risk control strategy that differentiates and addresses compliance issues according to their significance to the reliability of the BPS. In addition, NERC and the Regional Entities are increasing the utilization of their inherent enforcement discretion in the implementation of compliance and enforcement activities. The board will be very interested in the reaction of committee members to this filing and NERC's continuing efforts to improve the efficiency and effectiveness of its compliance enforcement process.

Compliance Application Notices – Status (MRC 10) — NERC continues to work to improve both the process and content of Compliance Application Notices. The board welcomes comments on whether the changes to date are addressing effectively the issues raised at the August meeting.

Status of CIP Standards Version 4 and 5 Implementation Plans (MRC-11) — I understand that a number of concerns have been voiced by the industry regarding the draft implementation plans for Versions 4 and 5 of the CIP Standards regarding duplication of effort and backwards looking compliance requirements. While we do not have formal input from stakeholders until the posting of draft proposals, the board would still like to hear discussion by the MRC on the concerns they have with the staging of these proposed implementation plans. I understand that this discussion will begin in the Standards Oversight and Technology meeting and continue during the MRC meeting.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Bulk Electric System (BES) Definition and Rules of Procedure – Status (MRC-12) — The board is very interested in how the BES Definition project is progressing since the August meeting. I understand that the drafting team took very seriously the board's views and is proposing to address the FERC directive in one phase and the remaining industry issues in a subsequent phase. The board wants to stay actively involved as this effort progresses, and to that end asks the MRC to continue its review and discussion at the November meeting.

Rules of Procedure Changes (MRC-15) — At the August MRC meeting some issues were raised regarding some of the Rules of Procedure changes that were being proposed, namely the provision to impose penalties in the event registered entities failed to respond to NERC data requests. While the proposed changes are still being discussed by NERC and the Regional Entities, and will not be posted for industry comment until after the November meetings, the board would like to hear of any concerns the committee has with the general direction of the proposed changes.

Thank you in advance for providing written comments to Dave Nevius, MRC secretary (dave.nevius@nerc.net) **by October 24, 2011** so they can be packaged and sent to the board members in advance of the meeting.

Thank you,

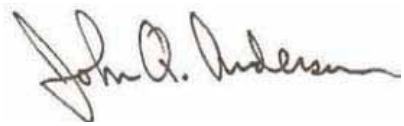

John Q. Anderson
NERC Board of Trustees Chair

cc: NERC Board of Trustees
Member Representatives Committee

September 8, 2011 Southwestern Outage

Action
Discuss

Background
The electric power system outage that occurred in the Southwest on September 8, 2011, left over two million customers in Southern California, parts of Arizona, and Northern Baja California Mexico without electricity. The blackout resulted in the loss of approximately 7,800 MW of customer load and 5,000 MW of generation.

The Federal Energy Regulatory Commission (FERC) and NERC announced on September 9 that they were conducting a joint inquiry of the outage. To date, FERC and NERC have conducted interviews with Arizona Public Service and the California ISO, and are arranging interviews with Imperial Irrigation District and the Western Electricity Coordinating Council (WECC) Reliability Coordinator.

Teams have been formed comprising members of FERC and NERC technical staff to gather and catalog detailed technical data and information, develop a detailed sequence of events, establish and validate system models to simulate each step of the event, review performance of system equipment, including protection and control systems, evaluate system operator visibility before and during the event, conduct detailed root cause analysis, evaluate the restoration process, and finally to develop lessons learned and other recommendations to prevent a recurrence. Several industry subject matter experts will serve as technical consultants to NERC and assist several of the teams that are part of this joint inquiry.

The data captured by phasor measurement units (PMUs) and digital frequency recorders (DFRs), including system voltages, frequency, real and reactive power flows, power angles, and other details of system behavior at various points in the system, are invaluable in determining an accurate sequence of events and thorough understanding of how and why the event occurred. Until this accurate fact base is established, any conjecture on the root causes of the blackout is premature and counterproductive.

Dave Nevius, NERC Senior Vice President, who is representing NERC on the FERC/NERC joint inquiry, will describe the status of the inquiry and plans for producing a report on the event.

February 2011 Cold Snap Report and Recommendations

Action
None

Background
In early February 2011, a major cold wave swept across the Southwest United States with extreme low temperatures, wind, ice, and snow. Faced with a possible all-time high winter peak electrical demand and cold-weather-related issues with generators and fuel supplies, an electrical generation capacity shortfall occurred as generators tripped off-line and reserves dwindled.

There were a total of 26 electric recommendations issued.

- Planning and reserves (5)
- Coordination with generator owners/operators (5)
- Winterization (10)
  - Plant design
  - Maintenance/inspections
  - Specific freeze protection maintenance items
  - Thermal insulation
  - Use of windbreaks/enclosures
  - Training
  - Other generator operator actions
  - Transmission facilities
- Communications (4)
- Load Shedding (2)
- There were 6 recommendations on the natural gas side of the inquiry.

Earl Shockley, Director of Events Analysis and Investigations, NERC, will discuss the recommendations from the final joint FERC/NERC report "Outages and Curtailments during the Southwest Cold Weather Event."

Election of Committee Officers for 2012

Action
Elect Officers for 2012

Background
Article VIII, Section 5 of the NERC Bylaws addresses election of the chairman and vice chairman of the Member Representatives Committee. It states:

> **Section 5 — Officers of the Member Representatives Committee** — At the initial meeting of the Member Representatives Committee, and annually thereafter prior to the annual election of representatives to the Member Representatives Committee, the Member Representatives Committee shall select a chairman and vice chairman from among its voting members by majority vote of the members of the Member Representatives Committee to serve as chairman and vice chairman of the Member Representatives Committee during the upcoming year; provided, that the incumbent chairman and vice chairman shall not vote or otherwise participate in the selection of the incoming chairman and vice-chairman. The newly selected chairman and vice chairman shall not have been representatives of the same sector. Selection of the chairman and vice chairman shall not be subject to approval of the board. The chairman and vice chairman, upon assuming such positions, shall cease to act as representatives of the sectors that elected them as representatives to the Member Representatives Committee and shall thereafter be responsible for acting in the best interests of the members as a whole.

The nominating period for the two officer positions of the Member Representatives Committee for 2012 opened on August 31, 2011 for a 30-day nominating period that closed September 30, 2011. The election of officers at this meeting and the currently open nominating period for sector members for 2012–2013 provides for filling sector vacancies resulting from a member being elected to an officer position. The nominating period for sector members continues through November 11, 2011.

The nominees for MRC chairman and vice chairman for 2012 are:
Chairman – Scott M. Helyer
Vice Chairman – Carol Chinn

Status of MRC Sector Nominations

Action
None

Background
The nomination period for sector representatives to the MRC to fill terms that will expire February 2012 is September 12, 2011 to November 11, 2011, with elections scheduled to occur between December 12 and 22, 2011.

As of October 5, 2011, all sectors have nominated representatives to serve two-year terms expiring February 2013 except:

- Sector 10 – Independent System Operator/Regional Transmission Organization

Also, to comply with Article VIII, Section 4 of the NERC Bylaws — "Adequate Representation of Canadian Interests on the Member Representatives Committee," there may be a need for one or more additional Canadian representatives beyond the one current nominee from Canada.

Compliance Application Notices — Status

Action
Discuss

Background
The CAN Process was recently revised based on the NERC Board of Trustees' (BOT) guidance and requests from industry. NERC staff posted a redlined version on the NERC web site that incorporated the guidance provided by the BOT on August 15, 2011. The external document accepted those changes and provides a redline of additional changes that NERC incorporated, most of which were at the request of industry (**Attachment 1**).

The changes that were incorporated following guidance received from the BOT at the August meeting in Vancouver include:

1. Transpose the purpose statement so that the primary purpose is to create consistency across Compliance Enforcement Authorities (CEAs) and the secondary purpose is to provide transparency to the industry.
2. Add language in the scope section to clarify CANs are not to expand the standard or add requirements.
3. Avoid words such as "must."
4. Provide a higher level review process.

Subsequent to receiving industry comments, additional modifications were incorporated. These changes include:

1. Tracking and providing CAN requestor segment/source
2. Providing a systematic method for prioritizing CANs
3. Stating that NERC will solicit prioritization input from the Standards Committee and the Compliance and Certification Committee
4. Providing increased detail on the CAN development process, include vetting
5. Clarifying the Regional Entity comment period
6. Stating that all industry comments will be posted for transparency
7. Providing more detail in NERC's responses to groups of comments
8. Detailing the higher level review process, format and timelines
9. Detailing the higher level reviewer(s) options
10. Providing appendix templates for industry use (attached in two separate documents)

CAN-0016 Final Draft

During the Member Representative Committee (MRC) meeting on August 3, 2011, there was a discussion on CAN-0016 that covers NERC Reliability Standard CIP-001 Requirement R1, Sabotage Reporting. Pursuant to the direction of the NERC Board of Trustees on August 4, 2011, all CANs that had been posted as final were to be rewritten to incorporate the guidance and to re-evaluate the compliance instruction. CAN-0016 was the first to be redrafted. Attached are two drafts – (**Attachment 2**), a redline version and (**Attachment 3**), a clean version.

When commenting on the original CAN, industry expressed concerns over whether NERC expanded the standard with regard to non-BES facilities. The original CAN stated that a registered entity's sabotage reporting procedure could not specifically exclude non-BES facilities. This was re-examined and modified in the revised CAN to state that "a CEA is not to consider whether a registered entity listed any of its facilities in its sabotage reporting procedure when assessing compliance." However, the CAN further states, "a CEA is to assess a possible non-compliance when a registered entity's sabotage reporting procedure specifically excludes facilities that have the potential to impact the reliability of the BPS."

The language in the revised CAN created a new concern from industry. The concern was over whether a CEA is to verify a registered entity's evidence of implementing its sabotage reporting procedure.

This CAN was approved by the NERC CAN Executive Approval Team and is to be provided to FERC staff for comment.

As noted in Chairman Anderson's policy input request letter, the board welcomes comment on whether the changes to date are addressing effectively the issues raised at the August meeting.

NERC
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RELIABILITY CORPORATION

Compliance Application Notice (CAN) Process

October 2011

DRAFT

RELIABILITY | ACCOUNTABILITY

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Introduction

Compliance Applications Notices (CANs) were created by NERC to fulfill ERO obligations under FERC Order 693[1] to provide compliance guidance to Compliance Enforcement Authority (CEA)[2] staff and to provide transparency to industry in regard to compliance monitoring[3] with NERC Reliability Standards. CANs encourage accountability for both CEAs and registered entities~~,~~ and were issued in response to requests for compliance guidance from industry stakeholders.

ERO Basis and Authority

NERC is the FERC-certified ERO and is accountable to the Commission and the industry for providing compliance guidance with regard to NERC Reliability Standards. The ERO's implementation of a thorough compliance program and appropriate enforcement actions, and providing continuing education and information campaigns to assist the industry sustain compliance, will enhance reliability of the Bulk Power System (BPS).

In FERC Order No. 693,[4] several commenters argued that the standards were not comprehensive in nature and requested relief from monetary penalties and compliance with the NERC Reliability Standards. FERC responded, "As discussed in our standard-by-standard review, each ~~Reliability~~ reliability ~~Standard~~ standard that we approve contains requirements that are sufficiently clear as to be enforceable and do not create due process concerns."[5]

Further, the Commission agreed with NERC that, even if some clarification of a particular NERC Reliability Standard would be desirable at the outset, making it mandatory allows the ERO and the Regional Entities to provide that clarification on a going-forward basis while still requiring compliance with NERC Reliability Standards.[6]

In addition, NERC and industry are accountable for the development of NERC Reliability Standards, as articulated in the 2005 Federal Power Act[7] and FERC Order No. 672,[8] which duly recognize~~s~~ the

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[1] FERC Order 693, Docket No. RM06-16-000.

[2] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard requirements.

[3] The Three-Year ERO Performance Assessment stated that NERC should "evaluate and implement ways to make registered entities more aware of means currently available to them to obtain guidance on how to comply with reliability standards and how to demonstrate compliance." Appendix A – Progress in Implementing Specific NERC Actions from the Three-Year ERO Performance Assessment – March 16, 2011, p. 19.

[4] FERC Order No. 693, Docket No. RM06-16-000.

[5] *Id.* at Paragraph 274.

[6] "NERC can maximize consistency and appropriateness of treatment in compliance matters most efficiently if it has the ability to advise or provide direction…at an early stage…" FERC Order on NERC Three-Year Assessment, Docket Nos. RR09-7-000 and AD10-14-000, §216.

[7] Section 215.d.2 located at http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=109_cong_bills&docid=f:h6enr.txt.pdf.

[8] See P. 324 located at http://www.nerc.com/files/final_rule_reliability_Order_672.pdf

requisite collective expertise, experience and judgment of all parties involved to develop and improve standards.

Purpose

There are two significant and mutually reinforcing purposes of a CAN:

1. To *establish consistency* in the application of compliance criteria across all CEAs; and
2. To *provide transparency* to industry on how a CEA will apply compliance with a NERC Reliability Standard.

NERC received numerous industry comments requesting detailed compliance clarification of the NERC Reliability Standards. Below is a sampling of comments[9] that NERC received during the comment periods of the NERC Three-Year Assessment[10] and the NOPR of FERC Order No. 693. This feedback from industry factored significantly in the decision for NERC to implement CANs.

- NERC "need[s] to provide more information and guidance to registered entities concerning the compliance and enforcement process. This includes providing guidance on what it takes to comply with and demonstrate compliance with Reliability Standards, eliminating the backlog of audit reports and enforcement violations so that more precedents are available to industry, and providing more uniformity and consistency in audits between Regional Entities and different audit teams."[11]

- "A clear communication channel is fundamental to the success of the ERO. Connecting the feedback from different program areas, such as compliance monitoring and enforcement, reliability assessments and event analysis, will prove valuable."[12]

- "Without a designated communication process, the most efficient and effective compliance process is not in place between compliance staff and registered entities. Currently, each company and Regional Entity struggles with this problem on an inefficient, case-by-case basis. Hence, the [CAN] process NERC is recommending will increase efficiency and use less resources."[13]

- "Some commenters argue that certain Reliability Standards require additional specificity or else users, owners and operators will not understand the consequences of a violation."[14]

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[9] Commenters included industry trade associations that represent over 70 percent of utility customers in North America.
[10] NERC Three-Year Assessment, Docket No. RR09-7-000, July 20, 2009.
[11] *Id.*
[12] *Id.*
[13] *Id.*
[14] FERC Order No. 693, Docket No. RM06-16-000.

NERC appreciates interaction from Industry during comment periods, and channels of communication remain open at all times if questions or concerns regarding a particular CAN arise.

Scope

A CAN is not a formal interpretation ~~or~~ of a NERC Reliability Standard. Further, a CAN cannot modify or change an interpretation or NERC Reliability Standard. CANs instruct CEAs to assess compliance by using either a specific method, or, if there are multiple ways for a registered entity to meet the requirements of a standard, a range of acceptable compliance actions.

Concisely stated, a CAN is based on the following four principles:

a. A CAN provides instructions to CEAs regarding the boundaries within which to assess compliance with effective standards and requirements

   ~~i. A registered entity may demonstrate that it has an equally efficient and effective alternative to maintain compliance from a reliability objective~~

b. A CAN cannot expand a standard

c. A CAN cannot add new requirements

d. A CAN applies to any facilities that affect the reliability of the BPS

The CAN process includes several crosschecks with other NERC programs and departments, including a review by NERC legal staff and the NERC Executive Approval Team.[15] CANs provide timely compliance instruction to CEAs to ensure consistent application of the standards. In the event that CEA practices vary, the posted CAN establishes a benchmark that all CEAs must adopt. By making instructions to CEAs transparent to industry, CANs also include the benefit of informing registered entities what to expect during an audit.

CAN Process

The CAN process is designed to give CEAs instruction ~~of~~ on specific compliance applications in an expeditious manner. NERC follows several steps when developing CANs, including identifying issues that need clarification, prioritizing the issues, researching and developing CANs, providing the Regional

[15] Chief Executive Officer, Senior Vice President and General Counsel, Senior Vice President and Chief Reliability Officer, Vice President and Director of Standards, Vice President and Director of Reliability Assessments, Vice President and Chief Security Officer, Associate General Counsel (693), Assistant General Counsel (CIP), Director of Compliance Operations, Director of Events Analysis and Investigations, Director of Training, Director of Situation Awareness and Director of Compliance Enforcement.

Entities and industry time to comment, and submitting CANs to the Commission for review before posting them on the NERC Web site as final.

A. Issue Identification

NERC receives CAN topics through a variety of avenues, such as:

1. Industry comments received from individual registered entities, trade associations, and large corporations that have entities in multiple Regional Entities;
2. Regional Entities and issues they observe;
3. NERC in various oversight activities in CMEP and standards development; and
4. Other regulatory bodies at the National or Provincial level.

NERC tracks the category source[16] of the CAN request and will include it on the CAN Status spreadsheet posted on the NERC Compliance Application Notices web page.

CAN issues may relate to specific standards and requirements, crosscutting issues that cover various standards and requirements, or compliance monitoring processes and procedures.

NERC encourages any interested party to submit an issue by sending a completed ~~an email~~Appendix 1 – CAN Template to cancomments@nerc.net~~. NERC does not require any format to submit a CAN request, and each issue will be reviewed~~ .

~~B. by NERC staff.~~

~~C.~~B. ~~Review~~ Determination of whether a CAN is the Appropriate Vehicle

Once an issue is received by NERC, the issue is reviewed ~~for relevance as to~~to determine whether a CAN ~~will be drafted.~~is the appropriate vehicle to resolve the issue. In this relevance determination, several factors are analyzed, including the number of entities that may be affected, the impact to reliability of the BPS, whether there are questions regarding compliance monitoring, if there are perceived inconsistencies in audit practices among Regional Entities, and if there is a need for clarity among industry stakeholders. NERC considers all requests for clarification, but in order for a CAN to be drafted, the issue must apply to multiple entities, multiple issues, or broad issues that apply to many industry members.

If it is determined that a CAN is not the appropriate vehicle to resolve the issue, NERC will determine if there is another vehicle. For example, if the issue is a question regarding the mandatory and effective date of a revision to a standard, a bulletin/public notice may be a better vehicle.

~~D.~~C. ~~and Prioritiz~~Prioritiz~~ing~~ation of CANs

[16] A category ~~would~~would not identify the name of source and would be a broad designation such as ~~a r~~Registered ~~e~~Entity type, Regional Entity, Trade Association, etc. ~~but would not identify the name of source~~.

After the CAN issues are reviewed and it has been determined that a CAN ~~should be drafted~~is the appropriate vehicle to address the issue, ~~it~~ the CAN is listed on the CAN ~~potential issues~~Status spreadsheet, posted on the NERC Web site[17] and ~~is~~ assigned a priority level.

There are several components that determine the priority of a CAN:

- Factors surrounding the issue
- Input from the Standards Committee (SC) and the Certification and Compliance Committee (CCC)
- Input from Industry

NERC ~~uses a prioritization tool to~~will determine the ~~There are several CANs being drafted concurrently, and the determination of~~ priority of the CAN~~is~~ based on ~~several~~ factors~~-~~ surrounding the issue, which may include~~ing~~ the significance of the issue,[18] its impact to reliability of the BPS, its urgency, ~~and,~~ the number of violations that have occurred due to the issue, the standard and requirement, and the number of registered entities that are affected~~, or the level of confusion on the issue~~.

NERC will solicit input from the Standards Committee and the Certification and Compliance Committees regarding prioritization and any initial input on the issue.

Industry may also provide input as to the prioritization of a CAN and any initial comments on the issue by submitting a completed Appendix 2 – Industry Prioritization Recommendation Form to ~~the~~ NERC's cancomments@nerc.net.~~-~~ The posting on the CAN Status spreadsheet will strive to provide sufficient information for interested parties to be able to submit a prioritization request or initial comments on the issue. ~~A priority level of a CAN may be changed based upon need. CANs are developed in the order that will help the most registered entities at the moment.~~

~~When an CAN is prioritized, there are three buckets groups in which the issue can be placed. They areingroups.~~The priority level of a CAN may change based upon 1) a change to the factors surrounding the issue, 2) the identification of a higher priority CAN to be developed, or 3) input from either the SC, CCC, or industry. ~~Issues that impact the BPS are the highest of priority levels, and there are moderate issues and lower-level administrative issues. CANs with the highest priority will be drafted first, followed by moderate issues, then lower-level administrative issues. Interested parties may submit requests to change the assigned priorities of specific CANs in the queue.~~

~~E.~~D. Development Process

[17] The complete list of CAN issues and prioritization can be found on the NERC web site: http://www.nerc.com/files/CANs%20Status.pdf.

[18] One determination of significance of the issue is whether the issue is related to one of the NERC identified ~~H~~high risk factors for the reliability of the BPS: (1) Misoperations of relay protection and control systems; (2) Human errors by field personnel; (3) Ambiguous or incomplete voice communications; (4) Right-of-way maintenance; (5) Changing resource mix; (6) Integration of new technologies; (7) Preparedness for high-impact, low frequency events; and (8) Non-traditional threats via cyber-security vulnerabilities.

After an issue is identified and a priority is assigned, NERC staff begins the CAN development process. Before any drafting is done, the CAN team ~~conducts investigation~~reviews ~~of~~ the issue. The first step is a review of the NERC Reliability Standard in its entirety, including applicable FERC orders, approved standards interpretations, the standards drafting team's intent, ~~investigating~~ investigation of how CEAs are currently applying compliance, and any other existing communications and guidance. The CAN team also reviews the input~~s~~ that ~~were~~was received during the prioritization process.

Then, research ~~process also~~is conducted, which includes~~es~~ obtaining~~receiving~~ technical information from subject matter specialists, standards drafting teams, CEAs and Regional Entities. The input from subject matter specialists may include soliciting input from ~~industry~~stakeholder committees or ~~individuals~~their subcommittes, as appropriate. This research is conducted to determine the level of consistency that exists in regards to the issue.

When the research is concluded and a draft is complete, the CAN is presented to the NERC Executive Approval Team~~, who discusses the issues, checks for accuracy,~~ ~~and approves the draft to move to the Regional Entities comment period, then the industry comment period~~for the first level of approval.

~~F.~~E. Regional Entity Comment Period

Following NERC approval, the CAN is sent to the Regional Entities for verification of the compliance application. The Regional Entities, as a part of the ERO, ~~have been~~are involved throughout the development process. At this point, ~~T~~the Regional Entities are provided a~~n~~ ~~initial review~~ period ~~time of three to~~of five days to conduct a review of the drafted document prior to posting. This provides the Regional Entities an opportunity to identify any issues or concerns that occurred in the editing of the draft that would prevent the CAN from moving forward in the process. In the event that a Regional Entity discovers content in the CAN that is technically incorrect or any other issue that should prevent the CAN from moving forward, the Regional Entity will notify NERC.

In the event that the Regional Entities support progression of the CAN, it will be posted on the NERC Web site for industry comment. The Regional Entities~~'~~ may provide additional comments ~~period will continue~~ throughout the industry comment period. ~~In addition to the Regional Entities' initial review prior to posting the CAN, the Regional Entity has had opportunity to comment throughout the entire CAN development process.~~

~~G.~~F. Industry Comment Period

The industry period lasts 21 days~~,~~ and extensions of time may be granted upon request. Registered entities or their representatives may submit their comments via Appendix 3 - the CAN Comment Form.[19] In order to keep the CAN process transparent, NERC ~~will~~ ~~will~~ posts all industry comments on the NERC Web site ~~as they are received~~.

After the comment period, NERC staff analyzes all comments received and reviews the CAN for potential changes based on the comments. ~~In order to keep the CAN process transparent, NERC will~~

[19] See Appendix 3 for the CAN Comment Form.

~~post all industry comments on the NERC Web site as they are received. Registered entities or their representatives may submit their comments via the CAN Comment Form.~~[20] ~~NERC staff will review each comment and make changes to the CAN as appropriate.~~ NERC ~~will~~ provides rationale for any changes made or not made to the CAN and ~~will~~ posts the rationale on the NERC Web site.

Industry comments are especially important when the compliance application varies, as the CAN will establish a consistent application. Industry, in this context, includes registered entities, their trade associations or forums, and NERC stakeholder committees, as appropriate.

~~H.~~G. Final Review and Posting

The final draft of the CAN is presented to the CAN Executive Approval Team for a second review of the CAN, including any modifications that were made, or were not made, after industry comments. Upon approval by the CAN Executive Approval Team, ~~T~~the CAN is sent to FERC staff and Canadian Regulators[21] for review, after which it is posted as final on the NERC web site.

Once the CAN is posted, an email announcement is sent to all registered entities and CEAs.

~~I.~~H. Webinars and Training

NERC conducts webinars after CANs are posted as final on the NERC Web site to provide opportunities for questions from industry and CEAs. The webinar slides ~~and the Q&A from the webinars~~ are posted on the NERC Web site.

NERC also provides training for CEAs and industry to develop awareness of the CANs and consistency in the use of the compliance application. Recent CANs and the CAN process are presented at trade forums, compliance workshops and committee meetings.

~~J.~~I. Expiration or Removal of CANs

CANs are retired when a revised standard or interpretation that addresses the compliance application issue in the CAN is approved by FERC and ~~is~~ becomes enforceable. Further, a CAN may be revoked or revised if a higher level of review directs the CAN to be withdrawn or modified, or additional information is brought forward to demonstrate that the CAN is incorrect.

~~20 See Appendix 3 for the CAN Comment Form.~~

21 As requested by each Province.

Benefits of CANs

The advantages of issuing a CAN are significant. CEAs receive instruction so compliance monitoring of the NERC Reliability Standards is conducted consistently. The result of the transparent process provides registered entities with visibility into how compliance will be applied. Additionally, CANs are generated in a relatively short time period compared to a much lengthier formal process.

A. Provide Formal Feedback to Standards

For each CAN that is drafted, NERC staff submits the issues raised during the CAN development process to ~~the~~ applicable Standards Development Teams and the standards issue database, to be considered in ongoing or future standards projects, revisions to existing standards, or the initiation of new standards. All of the decisions concerning standards development rest with the stakeholders through the actions of the Standards Committee.

B. Time to Develop

The timeline for CAN development from issue identification to final posting ~~takes approximately three~~is measured in terms of months~~; –typically 3 – 6~~three to six months. This process is designed to be much more responsive than either the formal Standards Interpretation Process or the Standards Development Process,[22] which may take 18 - 36 months, plus FERC approval time.

CAN Issues and Concerns

During the development of the CAN process, NERC received issues and concerns from industry stakeholders. This section will highlight some concerns and provide answers to the questions received.

- *NERC received comments that CANs are overreaching the standards*. CANs give the necessary instruction to CEAs in order to monitor compliance to the standards in a consistent manner. CANs are temporary in nature and will be retired when a standard or interpretation that addresses the issues therein becomes effective.

- *NERC received comments that the CAN process is circumventing the standards process*. The CAN process and the standards process serve different purposes. The Standards Development Process, codified by ~~is a codified~~the Federal Power Act of 2005, Section 215, [23] ~~process that~~ creates mandatory and enforceable ~~laws~~regulation. The CAN process provides instruction on how CEAs are to assess compliance with ~~those laws~~that regulation. Therefore, NERC must balance the long-term standards development process with the day-to-day compliance monitoring and enforcement responsibilities as the FERC-certified ERO.

[22] See the NERC Rules of Procedure, Appendix 3A, Standards Process Manual, Effective September 3, 2010.

~~[23] Define codified~~

Contesting a CAN

NERC's belief is that transparent, open communication of compliance applications provides an opportunity to formally address areas of concern. When industry takes issue with an application identified in a CAN, there are several existing processes available for formal resolution. In accordance with the NERC Rules of Procedure, a registered entity may contest a violation that was assessed due to the application of a CAN.

A registered entity or its representatives (requestor) may (in order of hierarchy):

1. Submit technical evidence in support of a request to NERC to have a CAN changed or removed.
    a. ~~If~~ NERC will acknowledge receipt of the issue ~~within two business days~~ and will keep the requestor informed of progress. Folowing NERC's determination, ~~does not respond to the request within a reasonable time as determined by the requestor, or i~~~~I~~if the ~~registered entity~~requestor is not satisfied with the change to the CAN ~~based on NERC's review of the technical evidence provided~~, then the~~a~~ ~~registered entity~~requestor may:
2. Propose a change to the standard through a request for a formal interpretation[24] or a Standard Authorization Request (SAR); or
3. Request a higher-level review of the CAN[25]
    a. The first level of review -would be conducted by NERC's Chief Executive Officer~~. —~~.
        ~~i.~~
    b. If a registered entity is not satisfied with the results of the first level of review, the registered entity may request a second level of review by the NERC Board of Trustees Compliance Committee (BOTCC).

The higher-level review of the CAN may result in three options for disposition: (1) affirm the CAN as written, (2) make recommended changes to CAN or (3) withdraw the CAN. If ~~a~~the CAN is modified or withdrawn, there will be an announcement to industry and to ERO Compliance Enforcement Authorities to ~~clarify~~announce the change.

The higher-level review will begin when the registered entity or its representative submits the CAN Higher-L~~l~~evel Review Form (Appendix 5) to NERC. ~~NERC will have 21 days to respond to the registered entity or its representative as to whether the request will be heard. The next step will be a review by~~

[24] A formal interpretation is conducted through the Standards Development Process. As such, it is formally filed with FERC and will result in an order issued by FERC Commissioners.

[25] See Appendix 5 for the CAN Higher-level Review Form.

NERC's Chief Executive Officer or his designee~~, who~~ will have 14~~28~~ days to review the CAN and determine~~decide~~ whether the CAN will be affirmed, ~~changed~~modified or withdrawn.

If a registered entity or its representative decides to ~~continue~~pursue the higher level of review to the Board of Trustees Compliance Committee (BOTCC), they must submit a second request for ~~H~~higher-level ~~R~~review by completing additional information and ~~re-~~submitting a revised Appendix 5. The BOTCC will review the comments and the applicable CAN at the next available time during its monthly ~~closed-closed~~ BOTCC ~~and~~meeting and make a de~~cision~~termination whether to ~~either~~ uphold the CAN ~~NERC Chief Executive Officer's decision, or to overturn the decision.~~ . ~~If t~~The BOTCC ~~decides to~~will review the ~~decision~~complete record~~, it will do so on a de novo basis,~~ and determine whether ~~its decision will be~~ to either uphold the CAN, direct the CAN to be ~~changed~~modified~~,~~ or to withdraw the CAN.

~~At any time through the higher-level review process an entity or its representative may withdraw its request for review.~~

Summary

Compliance Application Notices fulfill NERC's obligation as the ERO to provide a consistent compliance monitoring program under FERC Order No. 693. CANs carry out the requests of industry for clarification and provide timely compliance guidance in a transparent manner. CANs not only assist CEAs in monitoring compliance, but the industry benefits from understanding what the issues are and how to prepare for an upcoming audit. The CAN process is evolving, and changes have been made to the program based on feedback from industry stakeholders, Regional Entities, and the NERC Board of Trustees.

Version History

Version	Date	Action
0	May 2010	Initial Draft
1	December 10, 2010	Updated CAN Process
2	April 14, 2011	Updated CAN Process with detailed steps
3	July 8, 2011	Updated CAN Process to include specific industry requests
4	August 15, 2011	Updated Purpose Section, Contesting a CAN Section, based on Board of Trustee recommendations.
5	October 2011	Updated CAN Prioritization Process, Regional Entity comment section, industry comment section, CAN higher-level review section, and added Appendices 1-5.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Draft ~~DRAFT~~ Compliance Application Notice — 0016

~~Compliance Application: CIP-001[1] R1~~CIP-001 R1 – Sabotage Reporting Procedure ~~Applicability to Non-BES Facilities~~

Posted: **June 17, 2011**

Re-~~Posted~~vised: ~~[DATE]~~Month XX, 2011

Primary Interest Groups
Compliance Enforcement Authorit~~ies~~y (CEA)[2]
NERC
Regional ~~Entities~~Entity
Registered ~~Entities~~ Entity

Issue: What ~~The inclusion of~~ facilities should be included in a registered entity's sabotage reporting procedure?
For the purpose of aiding a CEA, this CAN provides instruction for assessing whether registered entities have developed sabotage reporting procedures that fulfill the requirements of CIP-001.

~~NERC received a request to clarify whether registered entities were required to include either BES or non-BES facilities in their Sabotage Reporting Procedures in order to be compliant with the NERC Reliability Standard CIP-001 Requirement (R) 1.~~

~~Reliability Objective~~
~~The reliability objective is to foster compliance with the NERC Reliability Standards through clear communication of performance obligations.~~

~~Background~~

[1] ~~This CAN is in effect for CIP-001 Versions 0, 1 and 1a, and will remain in effect until the issue is addressed by a future version of the standard. In Canada, this CAN is in effect for applicable versions of CIP-001 pursuant to each Canadian Province's corresponding Memorandum of Understanding (MOU), which may be accessed on the NERC Web site.~~
[2] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard requirements.

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~~Registered entities have requested clarification as to whether the Sabotage Reporting Procedures required by CIP-001-1 R1 must include a list of registered entity's facilities and whether excluding any of its facilities, specifically non-BES facilities, constitutes noncompliance with the requirement.~~

~~CEA~~ Compliance Application

~~The~~ CIP-001~~-1 R1~~[3] ~~reads~~provides, in pertinent part:

> ***R1.*** *Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the recognition of and for making their operating personnel aware of sabotage events on its facilities*[4] *and multi-site sabotage affecting larger portions of the Interconnection.*

Therefore, ~~to be compliant with~~CEAs are instructed to verify: ~~CIP-001-1 R1:~~[5]

1. a registered entity ~~is required to have~~ has procedures for the recognition of sabotage events;[6]~~;~~
2. a registered entity has procedures for personnel recognizing a sabotage event to make the entity's operating personnel aware of the sabotage event(s);
3. pursuant to its procedures, a registered entity's ~~employees~~ personnel ~~should be~~are able to recognize sabotage events that happen on the registered entity's facilities; and
4. pursuant to its procedures, a registered entity's ~~employees~~ personnel ~~should~~ are able to recognize sabotage events that happen across multiple sites that would affect larger portions ~~or~~ of the ~~interconnection~~Interconnection.

The emphasis of the standard is for the registered entity's ~~employees~~ personnel to be able to recognize a sabotage event(s) that may impact[7] the reliability of the ~~b~~Bulk ~~p~~Power ~~s~~System (BPS) and to make operating personnel aware of a recognized sabotage event(s). A CEA is to verify that the entity's procedure provides sufficient detail as to how it ~~will~~ determines whether 1) events are sabotage--related and 2) the event has the potential to impact the reliability of the BPS.

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[3] Pursuant to section 215 of the Federal Power Act (FPA), the Commission approved CIP-001-1 in FERC Order No. 693. *Mandatory Reliability Standards for the Bulk Power System*, FERC Stats. & Regs. ¶ 31,242 (2007) (Order No. 693), *rehearing denied*, 120 FERC ¶ 61,053 (2007) (Order No. 693-A).

[4] The standard includes the word "facilities,"~~;~~ which is not capitalized and therefore does not denote an identified term. *The NERC Glossary of Terms Used in Reliability Standards* defines "Facility" as "A set of electrical equipment that operates as a single Bulk Electric System Element (*e.g.*, a line, a generator, a shunt compensator, transformer, *etc.*)."

[5] ~~In Order No. 672, the Commission concluded that it is appropriate for each user, owner and operator of the Bulk Power System to be required to abide by any such Commission-approved Rules and added a subsection (b) to 18 C.F.R. section 39.2, stating: (b) All entities subject to the Commission's reliability jurisdiction under section 39.2(a) shall comply with applicable Reliability Standards, the Commission's regulations, and applicable Electric Reliability Organization Rules and Regional Entity Rules made effective under this part. *See* FERC 18 C.F.R. Part 39; *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards* (Order No. 672), III FERC Stats. & Regs. ¶ 31,204 (2006).~~

[6] ~~CEAs' verification of a registered entity's sabotage reporting procedure is to include flexibility for a registered entity to have established procedures that appropriately address the expertise of employees across the company. However, CEAs are to verify that registered entities must have a procedure where, at a minimum, employees that are not aware of how to recognize potential experts sabotage events are trained aware ofto spot unusual events that could potentially be sabotage related and obtain the opinion of expert trained employeespersonnel.~~

[7] Examples may include but are not limited to: events or activities that may threaten the reliability of the BPS, create a threat to the reliability of the BPS or impede the utilities ability to reliably operate the BPS.

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When assessing compliance, CEAs are not to consider a registered entity's determinations regarding whether events were sabotage-related or whether the events were reported. A CEA is to verify whether the registered entity made the determination and reporting decision according to the entity's sabotage reporting procedure.

While a registered entity's sabotage reporting procedure may ~~include~~ require personnel to be aware ~~awareness~~ of specific items for a particular facility, a CEA is not to consider whether a registered entity ~~is not required to~~ listed any ~~all~~ of its facilities in its sabotage reporting procedure when assessing compliance. If an employee is ~~properly trained~~aware of how to recognize a sabotage event, the employee ~~should willis to~~will be able to ~~be able~~ recognize a sabotage event regardless of where on, or in, the registered entity's facilities it occurred. However, a CEA is to assess a possible non-compliance when a registered entity's sabotage reporting procedure specifically excludes facilities that have the potential to impact the reliability of the BPS.

~~The registered entity would be considered non-compliant with the standard if its Sabotage Reporting Procedure **excludes** any of its facilities from its procedure, including but not limited to non-BES facilities.~~

Effective Period for CAN

This revised CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance from June 17, 2011, regardless of the start date of the violation. It will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

~~This CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance is effective for CIP-001 upon posting the posting of this CAN on the NERC Web site. It supersedes all prior communications and It will remain in effect until a future CAN supersedes it or until such time that a future version of a standard or interpretation addresses this specific issue and is enforceable.~~.

It is anticipated that EOP-004-2, in Standards Development Project 2009-1 Disturbance and Sabotage Reporting, will ultimately define sabotage reporting obligations in CIP-001-1a after industry approval, BOT approval and FERC approval.

CEAs are instructed to assess compliance by the registered entity's current[8] sabotage reporting procedure and the facts and circumstances surrounding that procedure. For example:

1. If, following the posting of this CAN, a registered entity's sabotage reporting procedure contains the elements specified by the standard and outlined in this CAN, CEAs ~~will~~are to evaluate ~~look at~~ the entity's current sabotage reporting procedure. The CEA is not to look further back in time to determine non-compliance or a Possible Violation because prior versions of the entity's sabotage reporting procedure did not include each of the elements identified in this CAN, or specifically excluded certain facilities that, if subjected to a sabotage event, could impact the BPS.
2. ~~However t~~The CEA is to identify non-compliance and a Possible Violation~~,~~ if a registered entity:

[8] "Current" means the ~~S~~sabotage ~~R~~reporting ~~P~~procedure in effect at the time of the audit.

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a. did not respond to ~~this~~ compliance guidance and therefore its current sabotage reporting procedure specifically excludes facilities that, if subjected to a sabotage event, could impact the BPS~~,~~; or

b. responded to this compliance guidance only in preparation for an upcoming audit. In this situation a CEA is to look at the entity's previous versions of its sabotage reporting procedure and make an assessment of the registered entity's actions based on the content in its revised sabotage reporting procedure as well as the facts and circumstances surrounding the revision.

For any enforcement action in process and for audits that have been initiated,[9]~~,~~ a ~~Regional Entity will~~CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether this CAN should be applied.

~~Providing~~ Evidence of Compliance

A CEA is to assess the following to obtain reasonable assurance of the entity's compliance:~~An Auditor is to request:~~

1. evidence of the entity's sabotage reporting procedure, including how it will identify sabotage events that impact the reliability of the BPS, and
2. evidence that the entity is following its procedure, including a list of events that were analyzed. For example:
   - If a registered entity had a sabotage event or activity, the entity could demonstrate how it followed its procedure to:
     1. recognize a sabotage event that may have an impact on the BPS, and
     2. make its operating personnel aware of the event.
   - If a registered entity had a suspect event or activity that the entity determined was not due to sabotage or would not have an impact on the BPS, it could demonstrate how it followed its sabotage procedure to make that determination.
   - If a registered entity did not have a sabotage event or activity, the entity could demonstrate that its employees ~~were~~are ~~trained~~aware ~~on~~ of its procedure and would be able to implement the procedure if such an event or activity occurred. An entity may also provide an attestation that no suspect events or activities had occurred.

~~are impact the reliability of the BPS and~~

~~evidence that the entity is following its procedure.~~

~~Therefore, if a registered entity includes language in its Sabotage Reporting Procedure that non-BES, or any other, facilities are **excluded** from its procedure the registered entity would be non-compliant with CIP-001-1 R1.~~

For more information please contact:

[9] "Initiated" means that a registered entity has received notification of the upcoming audit.

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This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

~~*This document is designed to convey compliance monitoring instruction. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards.*~~

~~*This document is designed to convey compliance guidance from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time.*~~

Revision History

Posted Date	Action	Revision
June 17, 2011	Posted Final CAN	
~~[DATE]~~Month XX, 2011	Posted Revised CAN	Revised ~~for~~ target audience to CEA

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DRAFT Compliance Application Notice – 0016

CIP-001 R1 Sabotage Reporting Procedure
Posted: June 17, 2011
Revised: Month day, 2011

Primary Interest Groups
Compliance Enforcement Authority (CEA)[1]
NERC
Regional Entity
Registered Entity

Issue: What facilities should be included in a registered entity's sabotage reporting procedure?
For the purpose of aiding a CEA, this CAN provides instruction for assessing whether registered entities have developed sabotage reporting procedures that fulfill the requirements of CIP-001.

Compliance Application
CIP-001[2] provides, in pertinent part:

> ***R1****. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the recognition of and for making their operating personnel aware of sabotage events on its facilities[3] and multi-site sabotage affecting larger portions of the Interconnection.*

Therefore, CEAs are instructed to verify:

1. a registered entity has procedures for the recognition of sabotage events;
2. a registered entity has procedures for personnel recognizing a sabotage event to make the entity's operating personnel aware of the sabotage event(s);
3. pursuant to its procedures, a registered entity's personnel are able to recognize sabotage events that happen on the registered entity's facilities; and
4. pursuant to its procedures, a registered entity's personnel are able to recognize sabotage events that happen across multiple sites that would affect larger portions of the Interconnection.

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard requirements.
[2] Pursuant to section 215 of the Federal Power Act (FPA), the Commission approved CIP-001-1 in FERC Order No. 693. *Mandatory Reliability Standards for the Bulk Power System*, FERC Stats. & Regs. ¶ 31,242 (2007) (Order No. 693), *rehearing denied*, 120 FERC ¶ 61,053 (2007) (Order No. 693-A).
[3] The standard includes the word "facilities," which is not capitalized and therefore does not denote an identified term. *The NERC Glossary of Terms Used in Reliability Standards* defines "Facility" as "A set of electrical equipment that operates as a single Bulk Electric System Element (*e.g.*, a line, a generator, a shunt compensator, transformer, *etc.*)."

The emphasis of the standard is for the registered entity's personnel to be able to recognize a sabotage event(s) that may impact[4] the reliability of the Bulk Power System (BPS) and to make operating personnel aware of a recognized sabotage event(s). A CEA is to verify that the entity's procedure provides sufficient detail as to how it determines whether 1) events are sabotage-related and 2) the event has the potential to impact the reliability of the BPS.

When assessing compliance, CEAs are not to consider a registered entity's determinations regarding whether events were sabotage-related or whether the events were reported. A CEA is to verify whether the registered entity made the determination and reporting decision according to the entity's sabotage reporting procedure.

While a registered entity's sabotage reporting procedure may require personnel to be aware of specific items for a particular facility, a CEA is not to consider whether a registered entity listed any of its facilities in its sabotage reporting procedure when assessing compliance. If an employee is aware of how to recognize a sabotage event, the employee will be able to recognize a sabotage event regardless of where on, or in, the registered entity's facilities it occurred. However, a CEA is to assess a possible non-compliance when a registered entity's sabotage reporting procedure specifically excludes facilities that have the potential to impact the reliability of the BPS.

Effective Period for CAN

This revised CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance from June 17, 2011, regardless of the start date of the violation. It will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

It is anticipated that EOP-004-2, in Standards Development Project 2009-1 Disturbance and Sabotage Reporting, will ultimately define sabotage reporting obligations in CIP-001-1a after industry approval, BOT approval and FERC approval.

CEAs are instructed to assess compliance by the registered entity's current[5] sabotage reporting procedure and the facts and circumstances surrounding that procedure. For example:

1. If, following the posting of this CAN, a registered entity's sabotage reporting procedure contains the elements specified by the standard and outlined in this CAN, CEAs are to evaluate the entity's current sabotage reporting procedure. The CEA is not to look further back in time to determine non-compliance or a Possible Violation because prior versions of the entity's sabotage reporting procedure did not include each of the elements identified in this CAN, or specifically excluded certain facilities that, if subjected to a sabotage event, could impact the BPS.

[4] Examples may include but are not limited to: events or activities that may threaten the reliability of the BPS, create a threat to the reliability of the BPS or impede the utilities ability to reliably operate the BPS.
[5] "Current" means the sabotage reporting procedure in effect at the time of the audit.

2. The CEA is to identify non-compliance and find a Possible Violation if a registered entity:
   a. did not respond to compliance guidance and therefore its current sabotage reporting procedure specifically excludes facilities that, if subjected to a sabotage event, could impact the BPS; or
   b. responded to this compliance guidance only in preparation for an upcoming audit. In this situation a CEA is to look at the entity's previous versions of its sabotage reporting procedure and make an assessment of the registered entity's actions based on the content in its revised sabotage reporting procedure as well as the facts and circumstances surrounding the revision.

For any enforcement action in process and for audits that have been initiated,[6] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether this CAN should be applied.

Evidence of Compliance

A CEA is to assess the following to obtain reasonable assurance of the entity's compliance:

1. evidence of the entity's sabotage reporting procedure, including how it will identify sabotage events that impact the reliability of the BPS, and
2. evidence that the entity is following its procedure, including a list of events that were analyzed. For example:
   - If a registered entity had a sabotage event or activity, the entity could demonstrate how it followed its procedure to:
     1. recognize a sabotage event that may have an impact on the BPS, and
     2. make its operating personnel aware of the event.
   - If a registered entity had a suspect event or activity that the entity determined was not due to sabotage or would not have an impact on the BPS, it could demonstrate how it followed its sabotage procedure to make that determination.
   - If a registered entity did not have a sabotage event or activity, the entity could demonstrate that its employees are aware of its procedure and would be able to implement the procedure if such an event or activity occurred. An entity may also provide an attestation that no suspect events or activities had occurred.

[6] "Initiated" means that a registered entity has received notification of the upcoming audit.

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This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

Revision History

Posted Date	Action	Revision
June 17, 2011	**Posted Final CAN**	
Month XX, 20XX	**Posted Revised CAN**	**Revised target audience to CEAs**

Status of CIP Standards Version 4 and 5 and Implementation Plans

Action
None

Background
Version 4 of the CIP Standards was limited in scope and meant to be an interim step for addressing more immediate concerns raised in FERC Order No. 706, paragraph 236. The key changes to Version 4 from Version 3 include replacing the "risk-based" assessment methodology with "bright line" criteria, and an attempt to move toward more uniform application by eliminating subjectivity regarding what is "critical."

The Industry approved Version 4 on December 30, 2010. NERC submitted a petition for approval of CIP Version 4 to FERC on February 10, 2011, requesting approval of the standards. FERC issued a NOPR proposing to approve CIP Version 4 on September 15, 2011.

Version 5 addresses the remaining FERC Order No. 706 directives. The Version 5 standards are expected to accomplish several key goals:

- Address the remaining FERC directives, approved interpretations, and existing CANs;
- Transition the concepts of "Critical Asset" and "Critical Cyber Asset" to a High, Medium, and Low impact classification system for requirement applicability;
- Provide guidance and context for each requirement, and leverage current stakeholder investment used for complying with existing standards; and
- Develop requirements that foster a "culture of security" to improve reliability.

Herb Schrayshuen, vice president of standards and training, NERC, will review the status of CIP Standards Version 4 and 5 and Implementation Plans.

This item will be presented initially in the Board Standards Oversight Technology Committee meeting, which precedes the MRC meeting on November 2. MRC members will engage in further discussion of the CIP Standards issue during the MRC meeting.

BES Definition and Rules of Procedure – Status

Action
None

Background
As indicated in John Q. Anderson's policy input request letter, the board is very interested in how the Bulk Electric System (BES) Definition project is progressing since the August 2011 MRC and board meetings. Chairman Anderson indicated the board wants to stay actively involved as this effort progresses and asked the MRC to continue its review and discussion at this November meeting.

Current Status
The proposed definition of BES and its implementation plan were posted for a 45-day concurrent posting (formal comment period and initial ballot) until October 10, 2011, as was the draft application form (*Detailed Information to Support an Exception Request*. The definition includes a default threshold of 100 kV augmented by a list of five categories of facilities that are included in the BES and a list of four categories of facilities that are excluded from the BES. In addition, the drafting team has clarified what is meant by 'radial' and drafted a specific exclusion for local networks serving a distribution function. The bright-line definition has established criteria for the determination of BES Elements, which can be applied consistently across North America.

The draft Rules of Procedure Exception Process was posted for comment through October 27, 2011. This is being processed following the NERC procedure for making a change to the Rules of Procedure (described in Section 1400 of the NERC Rules of Procedure). Once a facility is determined to be included or excluded by application of the bright-line definition, the exceptions process may be used to adjust this determination based on whether an element is necessary for the Reliable Operation of the interconnected bulk power transmission system as evidenced by Required Information provided.

The BES Definition Standard Drafting Team (SDT) adopted the recommendations of the Member Representatives Committee and the NERC Board of Trustees and subdivided Project 2010-17 Definition of BES into multiple phases. In the opinion of the Standards Committee, SDT, and NERC staff, this establishes the best way to meet the FERC filing deadline of January 25, 2012 while also giving serious consideration to issues raised by stakeholders. The first phase of this project, which is currently in development, will address the directives established by FERC in Order Nos. 743 and 743-A. The second phase of this project will address concerns raised by SDT members and concerns received from stakeholders through the standard development process. Commenters have been informed that the issues identified above will be fully addressed in the next phase of Project 2010-17 Definition of BES.

Ballot Results for BES Definition and Technical Exception Request
The ballot windows for (1) the BES Definition and associated implementation plan, and (2) the draft application form titled *Detailed Information to Support an Exception Request* referenced in the Rules of Procedure Exception Process, closed at 8 p.m. Eastern on Monday, October 10, 2011. The results were:

BES Definition
Quorum: 92.97%
Approval: 71.68%

Detailed Information to Support an Exception Request
Quorum: 89.53%
Approval: 64.03%

Next Steps

The SDT will consider all comments received, and decide whether to make additional revisions to the BES Definition, the associated implementation plan, and the application form titled *Detailed Information to Support an Exception Request* referenced in the Rules of Procedure Exception Process. The Rules of Procedure team will consider all comments received and decide whether to make additional changes to the Exception Process. Bothteams are working to meet the regulatory deadline established in FERC Orders 743 and 743A (filing by January 25, 2012).

Pete Heidrich, chair of the BES Definition SDT, and Carter Edge, chair of the Rules of Procedure team, will discuss the current status of their teams' efforts and next steps.

ALR Task Force Status Report

Action
None

Background
At its meeting in February 2011, the Member Representatives Committee (MRC) was asked to advise the Board on any policy issues related to the definitions of Bulk Electric System (BES) and Adequate Level of Reliability (ALR). A subgroup of the MRC, including leadership of NERC's Standing Committees, select experts, and NERC staff, was formed to address these specific policy issues — MRC BES/ALR Policy Issues Task Force.

Reliability priorities cannot be addressed without a common understanding of the meaning and scope of reliability, as well as what criteria will be used to determine ALR.[1] Therefore, the MRC task force assigned the following questions regarding the ALR definition to an *ad hoc* team, which prepared the enclosed draft white paper outlining its views on three interrelated questions, and made the following recommendations:

The task team reviewed each of the three issues developed a recommendation for each to guide the standing committees' Adequate Level of Reliability Task Force (ALRTF):

1. How should cost/benefit be factored into ALR? How and by whom should those decisions be made? [Jurisdictional issues]*:*

   Recommendation: *Assess the reliability objectives of ALR criteria and provide an explicit recognition of high-level macro cost-effectiveness of requirements within a reliability standard to meet the reliability objectives.*

2. Is the impact of all load loss equal? For example, is the impact of "X" MWs of load loss in a major metropolitan area the same as "X" MWs in a rural area?

   Recommendation: *Revise ALR defining criteria to differentiate among the different characteristics of loss of supply, transmission and load loss as a function of planning design, operator preparations and ability to control outcomes from events; and refine the incorporation of resilience and recovery in the ALR elements.*

3. How should "cascading" be defined?

   Recommendation: *No change to the definition of Cascading.*

The whitepaper followed a pre-specified "*Issue Summary Format*" suggested by the Task Force that includes the Issue Statement, Recommendations, Background, and Options and Analysis, including advantages and disadvantages of each option. This whitepaper is offered to guide the policy-level discussion by the MRC.

[1] http://www.nerc.com/files/Adequate_Level_of_Reliability_Defintion_05052008.pdf

White Paper: *September 2011*

Cost/Benefit, Load Loss, Cascading Task Team

Introduction

At its meeting in February 2011, the Member Representatives Committee (MRC) was asked to advise the Board on any policy issues related to the definitions of Bulk Electric System (BES) and Adequate Level of Reliability (ALR). A subgroup of the MRC, leadership of NERC's Standing Committees, select experts, and NERC staff, was formed to address these specific policy issues — MRC BES/ALR Policy Issues Task Force.

Reliability priorities cannot be addressed without a common understanding of the meaning and scope of reliability, as well as what criteria will be used to determine ALR.[1] Therefore, the MRC task force assigned the following questions regarding the ALR definition to an ad hoc team, which prepared this draft white paper outlining its views on three interrelated questions on the definition of ALR:

1. How should cost/benefit be factored into ALR? How and by whom should those decisions be made? [Jurisdictional issues] ***Cost/Benefit***
2. Is the impact of all load loss equal? For example, is the impact of *"X"* MWs of load loss in a major metropolitan area the same as *"X"* MWs in a rural area? ***Load Loss***
3. How should "cascading" be defined? ***Cascading Defined***

Issue 1: Cost/Benefit

Issue:

How should cost/benefit be factored into ALR? How and by whom should those decisions be made? [Jurisdictional issues]

Recommendation: [Option 2]

Assess the reliability objectives of ALR criteria and provide an explicit recognition of high-level macro cost-effectiveness of requirements within a reliability standard to meet the reliability objectives.

Background:

The objective of the Task Team is to advise on the policy ramifications of whether the explicit incorporation of cost/benefit analysis is warranted within the ALR measurable criteria.

[1] http://www.nerc.com/files/Adequate_Level_of_Reliability_Defintion_05052008.pdf

In the past, an essential element in the way NERC's current Reliability Standards were developed included processes to secure input from all stakeholders as well as balloting for approval of reliability standards. These aspects of NERC's stakeholder process inherently attempt to balance cost/benefit of a reliability objective with cost-effective requirements within a standard. An important consideration of reliability is cost balanced with the associated reliability benefits. Reliability investments, captured in NERC's Reliability Standards, compliance program, alerts, and other initiatives, are driven by overall objectives of balance among reliability and cost effectiveness to customers and ratepayers. It is important to achieve reliability risk mitigation in a manner that balances affordability of electricity in a global, competitive market, with the need to ensure the reliable performance and security of the North American electricity infrastructure. Priorities must be driven by a clear understanding of risks and consequences, along with the costs and benefits associated with addressing them.

As a first step, ALR criteria provide suitable and measureable reliability benefits, along with an assessment of unacceptable consequences. Risk information provides useful input to determine reliability benefits, though reliability objectives can, at times, include "defense-in-depth," considerations, where the resulting impacts on reliability (consequences) are deemed not acceptable, even though the risks may be low.

Once the reliability objectives have been refined to provide the desired reliability benefits, measureable cost-effective approaches or alternatives should be investigated. The reasonable balancing point between reliability benefits and cost-effective approaches is difficult to articulate in the abstract. For example, certain ALR criteria may provide a good measure of reliability benefits, but may not reach the balance point between cost and reliability. At first, it may be impossible to provide an acceptable balance, until the ALR is measured against specific case studies, which can be indicative of reasonableness. At the same time, the current recognized level of reliability in the North American grid can be considered to generally reflect an implicit recognition of the inherent economic/cost effective balance. Such balance points provide a long-term calibration of the validity of the current set of ALR factors, which should shift only gradually over time as the implications are potentially significant capital investments are needed to alter the balance. Yet, as additional information is obtained over time, adjustments or refinements can be made to ensure clarity in the balance of reliability objectives and cost-effective actions.

While a complete and detailed cost-effective assessment would theoretically include not only system-specific technical solutions, but represent jurisdictional considerations, and local impacts, the policy consequences of making such explicit calculations are manifestly difficult, widely susceptible to varying assumptions, inputs, and resulting conclusions. These economic effective aspects of reliability concerns are best represented by Federal jurisdictions for interstate and international responsibilities, and State/Provincial/Local regulators and end-user stakeholder groups for local considerations to ensure reliability objectives are met in a jurisdictionally cost-effective appropriate fashion.

However, on a macro level, NERC can work with its stakeholders to provide North American-wide greater transparency of the cost effectiveness of potential reliability initiatives with high-level estimates that can then be balanced against reliability objectives. In this way, making some explicit recognition of the cost effectiveness balanced against the reliability benefit objectives, can lead to adjustments to ensure that reliability objectives and cost-effective approaches remain balanced.

Options and Analysis:
PROS and CONS for each option that state the arguments for and against that option.

Option#	Option	Advantages	Disadvantages
1	Do not explicitly calculate or measure cost/benefit for Reliability Standards or ALR Criteria. Measurable criteria for ALR, once vetted by industry, would consider cost/benefit. Current approach for Standard generation and RoP 1600 for Data or Information, considers cost/benefit as part of industry review and comments. Also, existing Reliability Standards such as TPL (N-1), etc. are part of industry's ability to account for jurisdictional cost/benefits.	Each jurisdiction assesses Reliability Standards and RoP based on cost/benefit specifics based on their own situation. Measurable ALR criteria, including data requirements, would be vetted by industry and jurisdictional costs/benefits would be included in this assessment.	No rigorous calculations completed. Regional/ subregional, individual assessment comparisons not possible. Industry-wide costs not accounted for, relative to potential benefits. A consistent method across all jurisdictions may be difficult to achieve.
2 (Selected)	Assess the reliability objectives of ALR criteria and provide an explicit recognition of high-level macro cost-effectiveness of requirements within a reliability standard to meet the reliability objectives.	Ensures that reliability objectives are balanced against more explicit recognition of cost-effective aspects.	High level analysis will not necessarily consistently predict localized cost/benefits. Specific cost-effective solutions will vary depending on system specifics and jurisdictional considerations.
3	Measure cost/benefit for ALR Criteria.	Rigorous comparison available. Regional/ subregional, individual assessment comparisons possible. Industry-wide costs not accounted for, relative to potential benefits.	No consistent way to comparatively complete this analysis.

Issue 2: Load Loss

Issue:

Is the impact of all load loss equal? For example, is the impact of *"X"* MWs of load loss in a major metropolitan area the same as *"X"* MWs in a rural area?

Alternative statement of question: *To what extent is load loss, and its root causes, considered evidence of an inadequate level of reliability?*

Recommendation: [Option 1]

Revise ALR defining criteria to differentiate among the different characteristics of loss of supply, transmission and load loss as a function of planning design, operator preparations and ability to control outcomes from events; and refine the incorporation of resilience and recovery in the ALR elements.

Background:

The focus is directing efforts on determining to what extent load loss classifications should be made and how should they be incorporated into the definition of ALR. The goal is to determine what circumstances that load loss represents actions in support of ALR (i.e., Energy Emergency Alert – EEA3) and those instances in which it doesn't. As a result, only a portion of incidents occurring on the bulk system that include load loss, reflect an inadequate level of reliability, while the balance reflect controlled system actions as designed and operated.

To provide a basis for this aspect of the definition of ALR, there must be a differentiation between uncontrolled load loss caused by unexpected failures, and intentional, controlled load loss either by design or manually initiated, perhaps as part of Emergency Operating Procedures or planning design criteria, executed to maintain bulk power system reliability. Load reduction is a vital component in design and an essential operational tool for preserving the overall stability and integrity of the grid, avoiding more widespread and severe consequences, such as cascading of the bulk electric system. FERC has in several instances raised the notion of continuity of service to customers as a factor that should be considered. However, the load loss attributes are diverse, in part dependent on the nature and design of the interconnection and, for purposes of defining load loss as an attribute of an adequate level of reliability, requires greater discrimination. Those aspects that industry depends upon to preserve the integrity of the bulk electric system is separate conceptually from end-use customer service goals – recognizing that from an end-use customer perspective, an outage is directly consequential on them.

Load loss or reduction needed to preserve reliability is part of the design basis or operational procedures to ensure the bulk power system remains stable, that all power flows and voltages remain within applicable ratings, and the system is able to withstand a critical contingency, without resulting in bulk power system instability, uncontrolled separation or uncontrolled cascading; e.g., under-frequency/undervoltage load shedding, manual load shedding, etc., depending on jurisdictional requirements and operating conditions.

In normal situations, if a bulk electric system element is lost, based on design, no load is lost. In other instances, 'consequential' load loss is directly designed/anticipated through the bulk system protection

and network topology that, for example, interrupts a transmission circuit due a lightning strike or equipment failure with tapped transformers with attached load supply thereby localizing and controlling the extent of the disruption. Load reduction that is part of the design basis and operating procedures. Correct protection scheme operation provides the control needed to maintain reliability, and thus load loss by itself does not reflect an inadequate level of reliability.

The goal is to ensure that there is no uncontrolled load loss resulting from credible contingencies and events, as defined in NERC's Reliability Standards. However, uncontrolled load loss can result from extreme events (severe weather, earthquakes, etc.). That said, due to the resiliency of the bulk power system, industry addresses these extreme events with an orderly restoration and recovery of the bulk electric system to service, along with system reconstruction as needed. In addition, for high-impact, low frequency event risks, NERC's Severe Impact Resiliency Task Force will provide guidance and options to enhance the resilience of the bulk power system to withstand and recover from three severe-impact events (Coordinated physical and cyber attacks or geomagnetic disturbances) as described in the Coordinated Action Plan.[2]

Therefore, the amount and duration of load loss is not, by itself, an appropriate interpretation of event severity or an indicator of an inadequate level of reliability – rather those types of load losses resulting from uncontrolled or cascading actions on the bulk system or resulting from mis-operations would be indicative of an inadequate level of reliability. Even in severe weather/storm conditions where the loss of load is an anticipated consequence, the most relevant aspect for ALR purposes is the resilience/recovery aspect, rather than the direct measure of load lost. To this extent, some additional reflection of the resilience and recovery aspects should be incorporated in the ALR elements. NERC has recognized the need to measure relative severity and risk to reliability, through the development of its Risk/Severity metrics, where weightings of various events include the amount of lost generation, transmission, and if it occurs, both controlled and uncontrolled load loss.

Options and Analysis:

Option #	Option	Advantages	Disadvantages
1 (Selected)	Revise ALR defining criteria to differentiate among the different characteristics of loss of supply, transmission and load loss as a function of planning design, operator preparations and ability to control outcomes from events; and refine the incorporation of resilience and recovery in the ALR elements.	Develop categories of supply, transmission and controlled/ uncontrolled load loss based on a set of agreed upon causes. Also gather the effect of load loss, including duration and customer type (residential, commercial and industrial).	Must be clear and concise definitions and categorization. Otherwise, inaccurate interpretations could result.

[2] http://www.nerc.com/docs/ciscap/Critical_Infrastructure_Strategic_Initiatives_Coordinated_Action_Plan_BOT_Apprd_11-2010.pdf

Option #	Option	Advantages	Disadvantages
2	Do not include load loss in the ALR criteria.	Easy to implement. Load loss is only an indication of the relative severity, but sever events can occur without load loss.	Identification of causes and impacts could be lost.

Issue 3: Definition of Cascading

Issue:

How should "cascading" be defined?

Recommendation: [Option 1]

No change to Cascading definition.

Background:

The Task Team's goal is to define cascading, in light of the cost/benefit and load loss recommendations, and to make this a measurable part of ALR criteria.

The current definition in NERC's Glossary[3] for Cascading is:

> *The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.*

"Cascading" is included in the statutory language of FPA Section 215 (a)(4) in the definition of "reliable operation:"

> FPA Sec 215 (a)(4): *"The term 'reliable operation' means operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such a system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements"*

Assessment of Cascading is a system planning and operational planning activity; operators can intervene with the processes already developed, once it begins. Planners test the bulk power system for B, C and D category events as defined in the TPL[4] Reliability Standards. If the bulk power system cannot survive these tests, Cascading is assumed to result. In NERC's TPL Reliability Standards, a number of extreme contingencies resulting in the unplanned loss of two or more (multiple) elements are studied (Category D events) to test the system's robustness and evaluate the reliability risks and consequences of such extreme contingencies. These extreme contingencies may result in substantial loss of load and/or generation in a widespread area or areas. Portions or all of the interconnected systems may or may not achieve a new, stable operating point. The extreme event evaluation may

[3] http://www.nerc.com/files/Glossary_of_Terms_2011Mar15.pdf
[4] http://www.nerc.com/files/Reliability_Standards_Complete_Set.pdf

require joint studies with neighboring systems. Planning Coordinators and Transmission Planners study these extreme events annually.

As described above, Cascading is far more than results from a single relay misoperation. For several decades, reliability has meant preventing Cascading, preserving the integrity of the grid, and providing an adequate bulk power supply. This could mean local load shedding to ensure that the effects from system failures are localized and managed so as to not spread.

The Federal Energy Regulatory Commission (FERC) has, in several instances, raised the notion of continuity of service to customers as an additional factor for consideration. However, there must be a differentiation between intentional load shedding used as an essential operational tool, and load loss caused by transitioning into abnormal operating states. Jurisdictional issues are also an important consideration, as increased costs may result from adding facilities which are focused on load loss reduction brought on by system failures.

If normally expected preparations by planners, operational planners and operators are undertaken, and events unfold as expected, then the event should not be classified as a cascade. However, if the bulk power system transitions in an unplanned, unexpected manner into an abnormal operating state, which results in uncontrolled system element and/or load loss, then the event should be classified as cascading.

Options and Analysis:

Option #	Option	Advantages	Disadvantages
1 (Selected)	No change to the definition of Cascading.	Easy to implement and measurable. The following information can be probed to measure cascading events: 1. Transmission Availability Data 2. Generator Availability Data 3. Events Analysis database and OE-417 As suggested in the "Load Loss" response, further data collection on the controlled/ uncontrolled load loss can add measurability	None

Conclusions and Actions

The task team reviewed each of the three issues, and, for each, developed a recommendation for each to guide the standing committee's Adequate Level of Reliability Task Force (ALRTF):

1. How should cost/benefit be factored into ALR? How and by whom should those decisions be made? [Jurisdictional issues]*:*

Recommendation: *Assess the reliability objectives of ALR criteria and provide an explicit recognition of high-level macro cost-effectiveness of requirements within a reliability standard to meet the reliability objectives.*

2. Is the impact of all load loss equal? For example, is the impact of *"X"* MWs of load loss in a major metropolitan area the same as "*X*" MWs in a rural area?

   Recommendation: *Revise ALR defining criteria to differentiate among the different characteristics of loss of supply, transmission and load loss as a function of planning design, operator preparations and ability to control outcomes from events; and refine the incorporation of resilience and recovery in the ALR elements.*

3. How should "cascading" be defined?

   Recommendation: *No change to the definition of Cascading.*

Culture of Reliability Excellence – LG&E and KU Energy

Action
None

Background
The MRC is continuing with its series of presentations on the "Culture of Reliability Excellence." At this meeting, Ed Staton, Director Transmission, LG&E and KU Energy, will discuss what his organization is doing to incorporate a culture of reliability excellence and compliance into its strategic agenda.

Attachment 1 – Ed Staton biography

Ed Staton
Director, Transmission
LG&E and KU Energy

Ed Staton is Director, Transmission, within the Energy Services organization of LG&E and KU Energy LLC. The company provides natural gas, electricity and related services to 1.2 million customers in Kentucky and Virginia. LG&E and KU Energy is owned by PPL Corporation, based in Allentown, Pennsylvania, which delivers electricity and natural gas to about 5.2 million customers in the United States and United Kingdom.

In his role, Ed leads the people, strategic planning and performance of activities necessary to support LG&E and KU's electric transmission systems. Ed directs all aspects of the transmission organization, including line and substation engineering and construction, system planning and operations, policy and tariff administration, and reliability compliance. He is responsible for establishing and implementing strategic objectives and long- and short-range investment planning for the electric transmission business. Ed currently serves on the SERC board of directors and is a member of both the Board Executive and the Human Resource Compensation Committees.

Ed has over 28 years experience in the electric and gas utility industry. He began his career with Kentucky Utilities Company as a student laborer in the Substation Construction Department. He subsequently held positions in the Transmission Engineering, Line Construction, and Service departments. In 1992, Ed was promoted to Service Manager in KU's Eddyville office in western Kentucky. In 1998, after the successful merger of LG&E Energy and KU Energy, Ed was named District Manager of the Heritage District (Elizabethtown) in central Kentucky. Upon completion of the "One Utility" initiative merging operations between LG&E and KU, Ed was named Manager, Operations, for LG&E's Auburndale Operations Center. In 2003, he assumed the role of Director, Distribution Operations, for KU. He was named to his current position in August 2007.

Ed holds a bachelor's degree in business administration from the University of Southern Indiana and a master's degree in business administration from the Gordon Ford School of Business, Western Kentucky University. He has also completed the Executive Management Program in Innovation and Corporate Strategy at the Sloan School of Management at MIT.

Ed has been very involved during his career in civic organizations and professional development. He has been a board member of the Larue County Industrial Foundation and a member of the Kentucky Industrial Development Council. He also has served as Vice Chairman of the Eddyville Industrial Foundation, President of the Lyon County Chamber of Commerce, a board member of the Elizabethtown Chamber of Commerce, a Louisville Junior Achievement classroom instructor, and participated in the Elizabethtown Leadership Program. Ed is currently a board member of Junior Achievement of the Bluegrass in Lexington, Ky. Ed is married and has two sons.

Rules of Procedure Changes

Action
Discussion

Background
Non-substantive revisions
On November 3, 2011, NERC will request that the Board of Trustees approve proposed revisions to the NERC Rules of Procedure and all existing Appendices to the Rules of Procedure (3A, 3B, 3C, 4A, 4B, 4C, 4D, 4E, 5A, 5B, 6 and 8), as well as proposed new Appendix 2, Definitions of Terms Used in the Rules of Procedure. The objectives of the proposed revisions are: (1) to place all definitions of defined terms used anywhere in the Rules of Procedure in a single, readily-accessible location (proposed Appendix 2); (2) to capitalize defined terms throughout the Rules of Procedure where they are intended to be used in their defined meanings; and (3) to lower-case other terms that are currently capitalized in the Rules of Procedure but are not defined terms.

These revisions are being proposed in response to Paragraph 93 of the Order of the Federal Energy Regulatory Commission (FERC or Commission) issued October 21, 2010,[1] in which the Commission invited NERC to submit a filing making consistent use of defined terms throughout the Rules of Procedure and Appendices. The October 21, 2010 Order invited NERC to make such a filing by January 1, 2011. NERC was unable to develop, post for comment, obtain Board of Trustees approval, and file the proposed revisions for this purpose by January 1, 2011; however, NERC recognizes that there is a need for greater consistency in definitions and the use of capitalization in the Rules of Procedure and Appendices, and therefore is proceeding with this initiative at this time. If these revisions are approved by the Board, NERC will file the proposed revisions with Applicable Governmental Authorities promptly thereafter.

Substantive revisions
Provided for discussion purposes in Attachment 1 is a summary of proposed Rules of Procedure revisions, many of which are being made for simplification of the documents, more consistent use of defined terms, moving provisions to different sections where they more logically belong and/or consolidation of material from multiple sections to one place, greater consistency among different documents that address the same topic, conforming cross references, and similar reasons.

An initial set of proposed revisions to Sections 100-1600 and Appendices 4B and 4C was posted for public comment on June 30, 2011. Comments were submitted on August 15, 2011. Based on the comments received, some additional changes have been made. Other revisions also

[1] *North American Electric Reliability Corporation*, 133 FERC ¶ 61,061 (2010).

have been developed in addition to the first posted set. Following the Board meeting in November, 2011, a consolidated and further revised set of changes to the NERC Rules of Procedure and applicable Appendices will be posted for public comment. The revisions will be submitted for Board approval at the February, 2012 meeting. If these revisions are approved by the Board, NERC will file the proposed revisions with Applicable Governmental Authorities promptly thereafter.

Summary of Proposed Rules of Procedure Revisions

I. Rules of Procedure Sections 100-1600[1]

A. Section 200 – Definitions of Terms

Confirmed Violation – revised definition to be consistent with revised definition in Appendix 4C, Compliance Monitoring and Enforcement Program.

Compliance enforcement authority – added definition (same definition as in Appendix 4C, CMEP).

Entity variance – deleted definition – this term is not used.

Remedial action directive – added definition here (same definition as in Appendix 4C, CMEP).

Variance – revised definition to be consistent with definition in Appendix 3A, Standard Processes Manual.

B. Section 300 – Reliability Standards Development

Section 304.1 – Added "and entities" for clarity and completeness.

Section 304.4 – Revised for consistency with Appendix 3A, Standard Processes Manual.

Section 305.5 – Corrected Appendix reference from Appendix 3A to Appendix 3D.

Section 306.1 – Added text to reflect that the Standards Committee will include "two officers elected to represent the interests of the industry as a whole."

Section 306.2 – Corrected reference from Appendix 2 to Appendix 3B.

Section 306.3 – Deleted specific provisions on Canadian representation and replaced them with: "The Standards Committee will include Canadian representation as provided in **Appendix 3B**, *Procedure for the Election of Members of the NERC Standards Committee*." This topic is covered substantively in Appendix 3B.

Section 307 – Changed title to "Standards Process Management"; revised text to describe functions of the NERC regional standards manager as well as the NERC standards process manager.

Sections 308.1 – Revised text to refer to expedited processes for developing reliability standards, including developing reliability standards to address national security situations that involve

[1] Sections that do not have proposed revisions are not listed in this Summary.

confidential issues (replacing reference to "urgent action" reliability standards). "Urgent action" is no longer used in Appendix 3A.

Section 308.2 & 308.3 – Revised text to reflect that reliability standards are "adopted," not "approved," by the NERC Board of Trustees (in accordance with ANSI requirements).

Section 309.1 -- Revised text to reflect that reliability standards are "adopted," not "approved," by the NERC Board of Trustees (in accordance with ANSI requirements).

Section 309.2 – Changed reference from "expedited action procedure" to "expedited standards development process".

Section 309.3 – Deleted provision that where an ERO governmental authority directs development of a standard by a deadline, NERC staff must, after preparing a SAR, attempt to find a stakeholder sponsor for the SAR. Also changed reference from "expedited action procedures" to "expedited action process" for consistency with Appendix 3A.

Section 309.3.1 – Deleted this section as no longer necessary based on the current version of Appendix 3A.

Section 311.3.1.3 – Changed text from "control the vote on a matter" to "dominate a matter" to be consistent with terminology in §304.4 and in Appendix 3A.

Section 311.3.1.6 – Deleted reference to accreditation of a Regional Standards Development Procedure by the Standards Council of Canada as sufficient to establish compliance with the evaluation criteria in §311.3.1. The Standards Council of Canada has advised NERC that accreditation by that body is not available to entities based in the U.S.

Section 312.1 – Revised text to make clear that Regional Reliability Standards must be submitted to NERC for adoption, and, if adopted, become part of the NERC reliability standards.

Section 313.1 – Added "NERC" before "reliability standards" for clarity.

Section 315 – Changed title of section to refer to the NERC Standard Processes Manual, which is the current title of Appendix 3A.

Section 316 – Deleted reference to seeking "continuing" accreditation since ANSI does not grant "continuing" accreditation, and replaced it with a statement that NERC will "seek and maintain" accreditation. Also, deleted reference to seeking accreditation from the Standards Council of Canada; the Standards Council of Canada has advised that accreditation is not available to NERC since it is not based in Canada.

Section 317 – Revised text as follows: "NERC shall complete a review of each NERC reliability standard at least once every five years<u>, or such longer period as is permitted by the American National Standards Institute,</u> from the effective date of the standard or the latest revision to the

standard, whichever is later." It may be possible to obtain relief from ANSI from the requirement that each standard be reviewed at least every five years.

Section 318 – Deleted reference to ISO/RTO Council. Although NERC strives to maintain close working relationships with the ISO/RTO Council and with industry associations and other, similar organizations, based on experience NERC has not found it necessary to work specifically with the ISO/RTO Council to coordinate wholesale electric business standards and market protocols with NERC reliability standards.

Section 319 – Changed reference to "standards that expired or were replaced" to "standards that have been retired," which is consistent with the terminology NERC uses elsewhere to describe standards no longer in effect. Also, changed reference to "NERC standards manager" to "NERC standards information manager" – the position of standards information process manager will be responsible for receiving and responding to requests for archived standards information.

Section 320 – The section has been revised to describe generally the process for developing and approving VRFs and VSLs, rather than just the alternate method for adopting VRFs. New §320.1 states that NERC will follow the process for developing VRFs and VSLs set forth in the Standard Processes Manual. New §320.2 states that if an ERO governmental authority remands or directs a revision to a Board-approved VRF or VSL, the NERC director of standards (based on consultation with the standard drafting team), the Standards Committee, and the NERC director of compliance options, will recommend one of three actions to the Board: (1) file a request for clarification, (2) file a request for rehearing, or (3) approve the directed revision. Section 320.3, which now contains the "alternative procedure," has been amended to apply to VSLs and well as to VRFs. Section 320.3 (which includes content being moved from ROP §1403, as it is more appropriately located in §300), has also been amended to specify that there will be notice and opportunity for comment before the Board approves a VRF or VSL, and that the Board will consider the inputs of the MRC and affected stakeholders.

C. Section 400 – Compliance Enforcement

Section 401.6 – For clarity of this point, the second sentence is amended as follows: "Compliance is required, and NERC and the regional entities have authority to monitor compliance, with all NERC reliability standards whether or not they are included in the subset of reliability standards and requirements designated to be actively monitored and audited in the NERC annual compliance program." Registered entities are subject to monitoring for compliance with all standards applicable to their registered functions, not just the standards on the actively monitored list.

Section 401.7 – Changed reference to "remedial actions" to "remedial action directives," which is a defined term. (This change has been made in a number of places throughout the ROP.)

Section 401.8 – Amended section to specify that a registered entity shall not be subject to an enforcement action by more than one Regional Entity for the same violation.

Section 401.9 – Changed reference to "remedial actions" to "remedial action directives."

Section 401.11 – Added reference to "or other mitigating activities" after "mitigation plan." This revision, which is made in a number of places throughout the ROP, reflects the fact that actions taken by a registered entity to correct and prevent recurrence of a non-compliance, while they are accepted by the CEA, are not always memorialized in a formal mitigation plan.

Section 402.5 – The revisions are intended to make the text more consistent with the definition of remedial action directive.

Section 402.6 – Changed reference to "remedial actions" to "remedial action directives."

Section 403.4 – Changed reference to "Hearing Process" to "Hearing Procedures" (Attachment 2 to Appendix 4C).

Section 403.6 – Added reference to "mitigating activities" and changed reference to "remedial actions" to "remedial action directives."

Section 403.7.3 – Changed reference to "remedial actions" to "remedial action directives."

Section 403.14 – In the title of this section, changed reference to "remedial actions" to "remedial action directives." Also, this section is amended to make clear that confirmed violations, penalties and sanctions specified in a Regional Entity hearing body final decision (as well as confirmed violations, penalties and sanctions developed by the Regional Entity through the enforcement process without a hearing) will be provided to NERC for review and filing with the applicable ERO governmental authorities as a notice of penalty.

Section 403.15 – The last paragraph of this section is amended to provide that a regional entity (as well as a bulk power system owner, operator or user) may appeal a Regional Entity hearing body decision to NERC in accordance with §409.

Section 403.16 – Amended to advance the date by which annual Regional Entity compliance enforcement program implementation plans are to be submitted to NERC, from November 1 to October 1 of the preceding year.

Section 407.1 – Changed references to "remedial actions" to "remedial action directives" to reflect the context. In addition, the section is amended to provide that NERC will review penalties, sanctions and remedial action directives specified by a Regional Entity hearing body final decision, to determine if the determination is supported by a sufficient record, consistent with the *Sanction Guidelines* and other directives, guidance and directions issued by NERC pursuant to the delegation agreement, and consistent with penalties, sanctions and remedial action directives imposed by the Regional Entity and by other Regional Entities for violations involving the same or similar facts and circumstances. In order to perform its function of ensuring consistency in penalty determinations for similar violations and among Regional Entities, it is necessary for NERC to review penalties determined by Regional Entity hearing bodies just as it determines penalties determined by Regional Entity compliance enforcement staff.

Section 408 – Several references to the NERC director of compliance are changed to the NERC director of enforcement. Additionally, §408.1 is revised to add reference to Regional Entities appealing decisions of Regional Entity hearing bodies pursuant to ROP §409.

Section 409.1 – The section is amended to reflect that a Regional Entity acting as the compliance enforcement authority, as well as a bulk power system owner, operator or user, may appeal a final decision of a Regional Entity hearing body. Additional amendments are made to use defined terms. Another amendment specifies that the entity appealing must submit its notice of appeal to the NERC director of enforcement (formerly director of compliance) and provide copies to the Regional Entity and any other participants in the Regional Entity hearing body proceeding. The last sentence of the section is deleted as unnecessary.

Section 409.2 – Changed "compliance hearing" to "proceeding."

Section 409.3 & 409.4 – Changed to reflect that the Regional Entity may file an appeal of a Regional Entity hearing body decision, to specify that the Regional Entity shall file the entire record of the Regional Entity hearing body with the NERC director of enforcement, to specify that participants in the hearing body proceeding other than the appellant shall file their responses to the issues raised in the notice of appeal 35 days after the date of appeal (which will allow for at least a 14-day period after the record of the hearing body proceedings is filed with the NERC director of enforcement), and to provide that the appellant may file a reply to the responses within 7 days.

Section 409.5 – Changed to specify that in considering an appeal from a Regional Entity hearing body decision, the BOTCC may allow other participants to the Regional Entity (in addition to the party appealing), to appear before the BOTCC.

Section 409.8 – New section is added to specify that Section 409 is not applicable to an appeal taken from a decision of the Regional Entity hearing body granting or denying a motion to intervene in the Regional Entity hearing, and that such appeals shall be conducted in accordance with ROP §414.

Section 412 – This new section sets forth the procedures by which the NERC BOTCC will accept or reject a question certified to the BOTCC by a Regional Entity hearing body (pursuant to §1.5.12 of the Hearing Procedures in Appendix 4C), and if the BOTCC decides to accept the certified question, the procedure for receiving argument from the participants on, and deciding, the question. Section 412.2 specifies that written decisions of the BOTCC on certified questions will be posted on the NERC web site, with redaction of the names of the participants and of any other information that is necessary to maintain the non-public nature of the Regional Entity hearing body proceeding.

Section 413 – This new section specifies that NERC shall review and process final decisions of Regional Entity hearing bodies concerning alleged violations, proposed penalties or sanctions, or proposed mitigation plans, that are not appealed to the BOTCC, as though the determination was made by the Regional Entity compliance program, and may require that the decision be modified by the Regional Entity, in accordance with sections 5.8, 5.9 and 6.5 of Appendix 4C. In order to

perform its function of ensuring consistency in violation, penalty and mitigation plan determinations for similar facts and circumstances and among Regional Entities, it is necessary for NERC to review penalties determined by Regional Entity hearing bodies just as it reviews violations, penalties and mitigation plans determined or approved by Regional Entity compliance enforcement staffs.

Section 414 – This new section establishes procedures for review and decision by the NERC BOTCC of appeals of decisions of a Regional Entity hearing body to grant or deny a request for intervention in the Regional Entity hearing body proceeding. Addition of these procedures is needed due to the proposed amendment to §1.4.4 of the Hearing Procedures to allow the Regional Entity hearing body to grant requests to intervene in limited circumstances. New §414.5 recognizes that the BOTCC's decision on the appeal may thereafter be appealed to FERC or to another ERO governmental authority having jurisdiction over the matter, in accordance with the authorities, rules and procedures of the ERO governmental authority.

D. Section 500 – Organization Registration and Certification

Section 501 – The first paragraph is revised for clarification to refer to certification of entities performing certain functions, rather than entities applying to a RC, BA or TOP.

Section 501.1.3.1 – This section is revised to provide greater specificity with respect to the effective date of an entity's registration, particularly in the case of registrations resulting from sales or transfers of BPS assets or from corporate reorganizations that result in a new legal entity owning BPS assets formerly owned by another registered entity. The effective date will be stated in NERC's notification of registration. Where the organization is being registered for the first time and its BPS facilities were not previously owned by another registered entity, the effective date of the registration will be the date agreed to by the entity to be registered and the applicable Regional Entity. Where the organization is being registered because it has acquired BPS facilities from a registered entity, or based on an internal restructuring or name change where the organization has been registered under a different entity name, the effective date of the registration will be the effective date of the transaction that results in the organization performing the reliability functions that require it to be registered.

Section 501.2 – This section is amended to refer to the need for certification of RCs, TOPs and BAs and entities that perform some or all of the reliability functions of RCs, TOPs and BAs. Additionally, reference to the NERC Provisional Certification Process is deleted, as that process is no longer needed and is being eliminated.

Section 501.2.1 – Amended to refer to entities intending to perform (as well as entities performing) the functions of RC, TOPs and BAs, since the certification process applies to entities seeking to perform these functions as well as entities already performing the functions.

E. Section 600 – Personnel Certification

Section 600 has been substantially revised and expanded. Appendix 6, System Operator Certification Program Manual, is being deleted in its entity and its substantive provisions are

being moved into Section 600.

Section 601 – Scope of Personnel Certification – This section is amended to state (1) that the Personnel Certification Program awards system operator certification credentials to individuals who demonstrate that they have attained essential knowledge relating to NERC reliability standards as well as principles of BPS operations, and (2) that except as necessary to obtain approval of the ROP, the NERC Personnel Certification Governance Committee (PCGC) is the governing body that establishes the polices, sets fees, and monitors the performance of the Personnel Certification Program for system operators.

Section 602 – Structure of ERO Personnel Certification Program – This section contains existing provisions describing the structure of the Personnel Certification Program.

Section 603 – Examination and Maintenance of NERC System Operator Certification Credentials – Section 603 is a new section encompassing material being moved from Appendix 6. It describes the basic requirements for obtaining a system operator certification (*i.e.*, passing an examination) and maintaining the certification (*i.e.*, earning the necessary number of Continuing Education (CE) hours during the ensuing three-year period). It also states what occurs should the certified operator fail to obtain the necessary amount of CE hours during the three-year period, including the procedure for requested a hardship clause exception.

Section 604 – Dispute Resolution Process – Section 604 is a new section encompassing material being moved from Appendix 6. It describes the NERC System Operator Certification Dispute Resolution Process for resolving disputes that arise under the System Operator Certification Program concerning any aspect of the certification process. The Dispute Resolution Process is for the use of persons who hold an operator certification or persons wishing to be certified to dispute the validity of the examination, the content of the test, the content outlines, or the registration process.

Section 605 – Disciplinary Action – Section 605 is a new section encompassing material being moved from Appendix 6. It describes the grounds and procedures for disciplinary action against a system operator, including the hearing process and the possible decisions that may be rendered against the system operator. It also describes the Credential Review Task Force, which will make factual determinations and ultimate determinations as to disciplinary action.

Section 606 – Candidate Testing Mechanisms – This section is currently Section 603 of the ROP. The text has not been revised.

Section 607 – Public Information About the Personnel Certification Program – This section is currently Section 604 of the ROP. It has been revised to state that the Personnel Certification Program shall maintain and publish publicly a System Operator Certification Program Manual, covering listed topics; and shall maintain and publish publicly a comprehensive summary or outline of the of the information, knowledge, or functions covered by each system operator certification examination and a summary of certification activities for the program.

Section 608 – Responsibilities to Applicants for Certification or Recertification – This section is currently Section 605 of the ROP. Items 8 and 9 in the list of duties and responsibilities of the Personnel Certification Program (implement and publish policies and procedures providing due process for applicants questioning eligibility determination, examination results and certification status, and develop and maintain a program manual containing the processes and procedures for applicants for certification and recertification) have been deleted since these topics are covered in Sections 604 and 607.

Section 609 – Responsibilities to the Public and to Employers of Certified Practitioners – This section is currently Section 606 of the ROP. It has been revised (1) to delete the provision that the Personnel Certification Program shall periodically publish a current list of those persons who are certified, and (2) to delete a reference to the disciplinary action program being contained in Appendix 6, as it will be included in Section 605.

F. Section 800 – Reliability Assessment and Performance Analysis

Sections 807 and 808 have been revised to provide for a more consistent use of terms in these sections including "major event" and "occurrences." Similar revisions have been made in Appendix 8.

Section 807a is revised to state that in responding to a major event, NERC will work with registered entities as well as with Regional Entities and RCs.

Sections 807c and 808.3 are amended to refer to NERC Reliability Standard EOP-004 which sets forth specific criteria and procedures for reporting BPS disturbances and events described in that standard, with which registered entities subject to EOP-004 must comply. These sections further states that BPS users, owners and operators shall also provide NERC and Regional Entities with such additional information they request as is necessary to enable them to carry out their responsibilities under these sections.

Section 807e is amended to provide that NERC will establish, maintain, and revise from time to time based on experience a manual setting forth procedures and protocols for communications and sharing and exchange of information between and among NERC, Regional Entities, governmental authorities, industry organizations, and BPS users, owners and operators, concerning the investigation and analysis of major events.

Section 807f is amended to reflect the revised title of Appendix 8.

Section 807g is amended to state that NERC will disseminate to the industry findings and recommendations of general applicability from event analyses, "through various means appropriate to the circumstances," including in accordance with ROP §810. This revision will give NERC greater flexibility in determining and using the most effective means to disseminate information gained from event analyses to the industry.

Section 808.2 has a similar amendment to §807g as described immediately above.

Section 810.4 has been amended to provide that failure to submit, in a timely manner or in the form requested, reports requested by NERC in a Level 2 (Recommendations) or Level 3 (Essential Actions) notifications may result in imposition of a fine, or other action, to the BPS user, operator or owner in accordance with ROP §1800.

G. Section 1000 – Situation Awareness and Infrastructure Security

Section 1002 has been amended to state NERC's new policy regarding maintenance and financial support of existing and potential new reliability tools and support services. NERC will work with industry to identify new tools, collaboratively develop requirements, support development, provide an incubation period, and at the end of that period transition the tool or service to another group or owner for long term operation of the tool or provision of the service. NERC may also develop reliability tools on its own, but will consult with industry concerning the need for the tool prior to development. Tools and services being maintained by NERC as of January 1, 2012 will be reviewed and, as warranted, transitioned to an appropriate industry group or organization.

H. Section 1200 – Regional Delegation Agreements

Section 1208 – The title is revised to delete the word "Audits," thereby correcting a previous scrivener's error.

I. Section 1400 – Amendments to the NERC Rules of Procedure

Section 1401 is revised to provide that requests to amend or repeal the ROP may be submitted by (among other sources) (i) fifty (rather than ten) members of NERC, which must include members from at least three membership sectors (rather than "segments"), (ii) a committee (rather than "standing committee") of NERC, or (iii) an officer of NERC (rather than of "the ERO"). These revisions are necessary to correct inconsistencies with Article XI, section 2 of the NERC Bylaws.

Section 1403 is deleted and its subject matter, which is more appropriately placed in ROP §300, is moved to §320.3.

J. Section 1500 – Confidential Information

Section 1502.1 is revised to correct an existing typographical error.

K. Section 1700 – Placeholder

Section 1700 is noted as a placeholder. Other new provisions for the ROP that will be placed in Section 1700 are under development in a separate process. These new provisions are not part of this package.

L. Section 1800 (New) – Non-Submittal of Requested Information by Registered Entities

New Section 1800 provides procedures to be used by NERC in the event that a registered entity fails to provide request information in response to a NERC Level 2 (Recommendations) or Level 3 (Essential Actions) notification. The procedures include the potential imposition of a fine, not to exceed $5,000, on the registered entity for failure to provide requested information. As originally proposed, these procedures would also have applied to failure to provide information requested of a registered entity in connection with a compliance monitoring and enforcement process or an event analysis. However, as now proposed, the provisions will apply only to failure to provide requested information in response to NERC Level 2 or Level 3 notifications. The procedures detailed in Section 1800 will be employed by NERC and not by Regional Entities.

Section 1802 details the steps that NERC will take where a registered entity has not provided data, information or reports requested or required pursuant to Section 810 of the ROP. The procedures require two follow-up notifications to the registered entity (in addition to the original request or requirement), before NERC may consider imposition of a fine.

Section 1803 sets forth the procedures for imposition of a fine for failure to provide data, information or reports. The procedures include issuing a notice of the proposed fine to the registered entity, stating the circumstances that have resulted in the proposed fine, and opportunity for the registered entity to submit a response (14 days allowed). Further, imposition of the fine (which may be in a different amount than initially proposed) must be approved by resolution of the NERC Board or a Board-level committee. The specific amount of the fine shall be set based on consideration of all the facts and circumstances, including the number of follow-up notifications that are sent to the registered entity and the volume, detail and complexity of the data, information or report requested or required.

Section 1803.8 is a statement of intent that the provisions of §1803 are intended to be applied where a registered entity does not respond by the required due date to an initial request for information and does not respond to one or more subsequent request(s) by the stated deadline(s), and is not intended to apply where the registered entity seasonably responds to the initial request or requirement with requests for clarification, definition or scope, or similar questions concerning the request, or seasonably requests additional time to respond based on the scope or difficulty of the request or requirement or the amount or form of the information requested or required, and works with NERC in good faith to respond to the request or requirement.

II. Appendix 3C – Procedure for Coordinating Reliability Standards Approvals, Remands, and Directives

Appendix 3C is revised to eliminate the list of specific names and contact information for persons at the various U.S. and Canadian regulatory authorities. As amended, Appendix 3C states that NERC will maintain a current list of government contacts at Applicable Governmental Authorities and other relevant government entities, and lists the Applicable Governmental Authorities and other relevant government entities for which contact information will be maintained. With this amendment, it will not be necessary to revise Appendix 3C when the

name of or contact information for the specific contact person at an Applicable Governmental Authority or other relevant government entity changes.

III. Appendix 4B – Sanction Guidelines

A principal objective of the proposed amendments to Appendix 4B is to eliminate text that does not relate to the purpose of the Sanction Guidelines, namely, how penalties and sanctions for violations of reliability standards are determined, and to eliminate internally duplicative or repetitive text. The following portions of Appendix 4B are being completely or substantially deleted consistent with this objective: (1) current section 2, Document Scope and Exclusions; (2) current §3.1, Necessary Elements of NERC Compliance Program; (3) current §3.2, Settlement of Compliance Violations, as well as the current sections captioned "Settlement Request" and "Settlement Effect on Continuation of Determination of Penalties, Sanctions, or Remedial Actions;" (4) current §3.7, "No Influence of Penalty, Sanction or Remedial Action Upon Violation Confirmation Process;" and (5) current §6, "Remedial Action" (remedial action directives are covered in §7.0 of Appendix 4C); as well as portions of the texts of other sections.

Text paraphrasing or referring to various statutory provisions and Commission regulations and orders has also been deleted, as these authorities speak for themselves; however, a statement has been added in §1 that "NERC and the regional entities will apply the provisions of this document in accordance with applicable statutory provisions and with the regulations, orders, and statements of policy of FERC and other ERO governmental authorities that are applicable to the determination and imposition of penalties and sanctions for violations of reliability standards in the respective jurisdictions."

Revisions have been made throughout Appendix 4B for more consistent use of terms within the document and as used elsewhere in the ROP, such as remedial action directive, possible violation, alleged violation, and registered entity.

In current §3.2/renumbered §2.1, text is retained specifying that provisions in a settlement agreement regarding penalties or sanctions can supersede any corresponding penalties or sanctions that would otherwise be determined pursuant to the Sanction Guidelines.

In renumbered §2.5, "Multiple Violations," text has been added to state that where penalties or sanctions for several unrelated violations by an entity are being determined at the same time, NERC or the regional entity may determine and issue a single aggregate penalty or sanction bearing a reasonable relationship to the aggregate of the violations. This is consistent with long-standing practice.

In renumbered §3.2.2, which discusses how the fact that a violation is a registered entity's first violation will be considered in determining (reducing or excusing) the Base Penalty Amount, text has been added to provide that this relief generally will not be afforded if NERC or the regional entity determines the violator has a poor internal compliance program or culture of compliance (as well as a poor compliance record, as stated in the existing text). This is consistent with longstanding practice, and also consistent with the increased emphasis NERC is placing in

compliance monitoring and enforcement activities on the registered entity's internal compliance program and culture of compliance.

In renumbered §3.3, which lists adjustment factors that will be considered in determining the penalty after the Base Penalty Amount is established, subpart c lists as an adjustment factor disclosure of the violation by the violator through self-reporting, or as the result of a compliance self-analysis following a bulk power system event, and voluntary mitigating activities (which is a broader term than the current "corrective action") by the violator. Subpart d, which refers to the degree and quality of cooperation by the violator in the investigation, has been amended to include reference to the violator's cooperation in an event analysis concerning, and the performance of a compliance self-analysis by the violator following, a BPS event in which the violation occurred or to which it related. The references to cooperation in the analysis of, and performance of a compliance self-analysis following, a system event, is consistent with proposed amendments to Appendix 8 to reflect expectations that registered entities will conduct self-analyses of system events in which they are involved. In subpart f, "settlement" has been added as an explicit adjustment factor.

In renumbered §3.3.1, which discusses repetitive violations and the violator's compliance history as an adjustment factor, text has been added to state that in evaluating the violator's compliance history, NERC or the regional entity will take into account previous violations by affiliates of the violator, particularly violations of the same or similar reliability standard requirements, and will evaluate whether any such prior violations reflect recurring conduct by affiliates that are operated by the same corporate entity or whose compliance activities are conducted by the same corporate entity. This addition is consistent with a 2010 guidance order from FERC, and should also promote the sharing of compliance information and lessons learned between registered entities that are corporate affiliates.

Also, in renumbered §3.3.1, the term "violation reset time period" has been changed to "reset period or reset time frame," as these are the terms used in several reliability standards.

Renumbered §3.3.3, retitled "Disclosure of the Violation Through Self-reporting and Voluntary Mitigating Activities by the Violator," has been revised consistent with subpart c of §3.3.3 as described above. In addition, the following text has been added: "If a self-report or self-certification by the violator accurately identifies a violation of a Reliability Standard, an identification of the same violation in a subsequent compliance audit or spot check will not subject the violator to an escalated penalty as a result of the compliance audit process unless the severity of the violation is found to be greater than reported by the violator in the self-report or self-certification." A similar statement is currently contained in §3.0 of Appendix 4C, but it is being moved to Appendix 4B as it more appropriately relates to penalty determinations than to compliance monitoring processes.

Renumbered §3.3.4, retitled "Degree and Quality of Cooperation," has been revised consistent with subpart d of §3.3 as described above.

Renumbered §3.3.5, retitled "Presence and Quality of the Violator's Internal Compliance Program," has been revised to add reference to "other indicators of the violator's culture of compliance" as an adjustment factor.

Section 3.3.6, "Settlement," has been added consistent with the addition of subpart f in §3.3 as described above.

Renumbered §3.3.7, retitled "Violation Concealment and Responsiveness," has been revised to state that NERC or the regional entity shall consider an increase to the penalty if NERC or the regional entity determines, based on its review of the facts, that the violator resisted or impeded the discovery and review of a violation.

In numerous other areas of Appendix 4B, revisions have been made for the purpose of simplifying the text. The text of current Appendix 4B is extremely elaborate and the simplification of the text will make the document easier to use for all participants. As part of this effort, in numerous places text has been revised to state that "NERC and the regional entity will do X," rather than the current text structure of "X will occur" or "X will be taken into account."

IV. Appendix 4C – Compliance Monitoring and Enforcement Program

Throughout Appendix 4C, "Regional Entity" has been revised to "Compliance Enforcement Authority" (CEA in this summary) in numerous places. In addition, since sections have been added and deleted and, as a result, other sections have been renumbered in this Appendix, there are revisions throughout the Appendix to change cross-references.

A. Section 1.0 -- Introduction

Section 1.1 – Definitions – A cross-reference has been added to incorporate definitions in Section 1500 of the ROP.

Section 1.1.2 – Annual Audit Plan – reference to including "Compliance Audit Participant Requirements" in the Annual Audit Plan has been deleted.

Section 1.1.9 – Confirmed Violation – the definition has been expanded to more comprehensively capture the circumstances that constitute a "Confirmed Violation," based on experience, and will include entry into a settlement agreement.

Section 1.1.12 – Mitigation Plan – Text not necessary to define the term is being deleted.

Section 1.1.15 – The defined term "Notice of Alleged Violation" is changed to "Notice of Alleged Violation and Proposed Penalty or Sanction," which is the term more commonly used; Notices of Alleged Violation typically include a proposed penalty or sanction.

Section 1.1.17 – Notice of Confirmed Violation – text is deleted that is not necessary to define "Notice of Confirmed Violation." The subject matter of the deleted text is covered (more appropriately) in the definition of "Confirmed Violation."

Section 1.1.21 – Possible Violation – text is deleted that is not necessary to define the term, and potentially inaccurate (a Possible Violation could be identified by a means other than one of the compliance monitoring and enforcement processes enumerated in Section 3.0).

Section 1.1.22 – Preliminary Screen – an additional component is added to the determinations to be made in the Preliminary Screen: "if known, the potential noncompliance is not a duplicate of a Possible Violation or Alleged Violation which is currently being processed."

Section 1.23 – Public Notification List – This new definition pertains to new §5.11 (described below).

Section 1.1.24 (renumbered) – Regional Implementation Plan – revised to reflect that the Regional plans are now to be submitted to NERC by October 1 (rather than November 1) of the preceding year.

Section 1.1.26 (renumbered) – Remedial Action Directive – revised to state that a Remedial Action Directive is immediately necessary to protect the reliability of the Bulk Power System from an imminent <u>or actual</u> threat.

Section 1.1.28 (renumbered) – Self-Certification – Definition is expanded to reflect that additional possible responses to a self-certification request will be allowed, *i.e.*, that the Registered Entity does not own facilities that are subject to the Reliability Standard requirement, or that the Reliability Standard requirement is not applicable to the Registered Entity.

Section 1.1.29 (renumbered) – Self-Report – (1) The defined term is changed from Self-Reporting to Self-Report (this revision is made throughout the document). (2) Definition is revised to provide that the Self-Report may state that the Registered Entity believes it has, <u>or may have</u>, violated a Reliability Standard. (3) The provision that the Self-Report should state the actions that have been taken or will be taken to resolve the violation is deleted; this requirement could delay submission of a Self-Report while the Registered Entity determines what actions are to be taken.

Section 1.1.30 (renumbered) – Spot Check – (1) The defined term is changed from Spot Checking to Spot Check (this revision is made throughout the document). (2) In the third basis stated in the definition on which a Spot Check may be initiated, reference to "events, as described in the Reliability Standard" is deleted and "risk-based assessments" is added. The addition is consistent with NERC's developing risk-based assessment approach to determining the frequency with which to conduct compliance monitoring activities.

B. Section 2.0 – Identification of Organizations Responsible for Complying with Reliability Standards

Section 2.0 is revised to specify that a Registered Entity must inform NERC or the applicable Regional Entity promptly of changes to the Registered Entity's compliance information "including planned or completed changes in ownership of Bulk Power System facilities, registration status, address or other contact information, and name of designated compliance

contact." Experience has indicated that NERC and the Regional Entities are not receiving timely notification of such information, which may affect registration status, identification of the correct/current Registered Entity, or the ability to contact the Registered Entity.

Detailed text concerning disclosure of confidential compliance information to FERC and other Applicable Governmental Authorities has been deleted here (and in other sections where it was repeated), and replaced with: "Any such provision of information to FERC or to another Applicable Governmental Authority shall be in accordance with Section 8,0, Reporting and Disclosure." The complete text of this provision will now appear in one section (Section 8.0).

C. Section 3.0 – Compliance Monitoring Processes

In the title of Section 3.0, reference to "Enforcement" is deleted; and in the first sentence of the section, "assess and enforce" is deleted. Section 3.0 encompasses only compliance monitoring processes, while Section 5.0 encompasses enforcement.

Throughout Section 3.0, footnotes stating that a particular compliance process normally completes within a specified time period have been deleted; the time required to complete individual compliance processes has varied widely based on particular facts and circumstances.

Text has been added in the first paragraph of the section stating that scheduled compliance monitoring processes will be conducted in accordance with NERC and Regional Annual Implementation Plans and individual entity audit plans; and that compliance monitoring processes can also be initiated on an unscheduled basis as needed, based on factors such as those enumerated in the text, such as the compliance history of the Registered Entity and the quality of its internal reliability compliance program. This text is consistent with NERC's developing risk-based assessment approach to compliance monitoring.

Text has been added to state that if a potential noncompliance is identified through one of the compliance monitoring processes described in Section 3.0 or through another means, the Compliance Enforcement Authority (CEA) will conduct a Preliminary Screen of the information in accordance with Section 3.8; if the Preliminary Screen results in an affirmative determination with respect to the Preliminary Screen criteria, a Possible Violation exists and the CEA will proceed in accordance with Section 5.0, Enforcement Actions.

Text describing the enforcement actions that may be taken by the CEA is deleted, as this topic is covered in Section 5.0, not in this section.

Text is added to state that the CEA has authority to collect documents, data and information in the manner it deems most appropriate, including removing copies of documents, data and information from the Registered Entity's location in accordance with appropriate security procedures conforming to ROP Section 1500 and other safeguards as appropriate in the circumstances to maintain the confidential or other protected status of the documents, data and information, such as information held by a governmental entity that is subject to an exemption from disclosure under the United States Freedom of Information Act, or a comparable state or provincial law, that would be lost if the information were placed into the public domain.

This section is revised to state that a Registered Entity that believes a request for documents, data or information is unreasonable may request a determination from the NERC General Counsel (changed from the NERC "compliance program officer").

Section 3.1 – Compliance Audits – Revised to state that Generally Accepted Auditing Standards, Generally Accepted Government Auditing Standards, and standards sanctioned by the Institute of Internal Auditors, are examples of professional auditing standards on which Compliance Audit processes for Compliance Audits in the U.S. should be based.

Section 3.1.1 – Compliance Audit Process Steps – (1) The first step is revised to state that the Annual Audit Plan will be posted, rather than distributed to all Compliance Audit Participants. (2) The second step is revised to provide that the CEA will notify the Registered Entity of the Compliance Audit and the Reliability Standards to be evaluated, 90 days (rather then 2 months) prior to commencement of a regularly scheduled Compliance Audit. (3) The fourth step is revised to delete the statement that the audit team will review the Registered Entity's submitted information "prior to performing the Compliance Audit" – the submitted information may be reviewed before or during the on-site audit activities. Text stating that the audit team "follows NERC audit guidance in the implementation of the Compliance Audit" is also deleted here, as this statement is applicable to all the process steps. (4) The fifth step is revised to state that the audit reported will be completed in accordance with Section 3.1.6, which addresses the form and contents of the audit report. (5) A step has been added that if the audit team identifies evidence of a potential noncompliance, the CEA will conduct a Preliminary Screen in accordance with Section 3.0. Other process steps describing enforcement actions are deleted here, since enforcement processes are covered in Section 5.0.

Section 3.1.2 – Compliance Enforcement Authority Annual Audit Plan and Schedule – (1) Revised to state that Registered Entities scheduled for Compliance Audits in a year will be notified by October 1 of the preceding year (rather than by January 1 of the year in which the audit is to be conducted). (2) Text is changed to state that the CEA will give due consideration to schedule changes requested by a Registered Entity "for reasonable cause" (rather than "to avoid unnecessary burden") which will allow a broader basis for justification of schedule change requests.

Section 3.1.3 – Frequency of Compliance Audits – The last sentence is deleted because the subject of objections to the composition of the audit team is covered in Section 3.1.5.4.

Section 3.1.4.1 – Reliability Standards – Revised to clarify that a Compliance Audit may include other standards applicable to the Registered Entity, that are not identified in the NERC Implementation Plan, whether or not the other standards are identified in the Regional Entity's Implementation Plan.

Section 3.1.4.2 – Reliability Standards – (1) Revised to emphasize that the Registered Entity's data and information must show compliance with the standards being audited for the entire period covered by the Compliance Audit. (2) Text is added to state that the CEA will indicate the beginning and End Date of the audit period in its notice of the Compliance Audit. (3) Revised to state that the start of the audit period will be the End Date of the previous Compliance Audit

(which may be a different date than the last day of the previous Compliance Audit). (4) The existing second sentence of this section, concerning modification of the audit period, is deleted and replaced with a more straightforward sentence ("The Compliance Enforcement Authority may modify the beginning date of the audit period for any given Reliability Standard requirement based on an intervening compliance monitoring process."). (5) Text is revised to state that the End Date may be a predetermined specific date or may be stated generally as the last day of the Compliance Audit.

Section 3.1.4.3 – Review of Mitigating Activities – The term "Mitigation Plan" is replaced with "mitigating activities." "Mitigating activities" is a broader term, reflecting that actions taken by a registered entity to correct and prevent recurrence of a noncompliance, while they are accepted by the CEA, are not always memorialized in a formal Mitigation Plan.

Section 3.1.5.1 – Composition of Compliance Audit Teams – (1) Revised to state that the audit team will be comprised of members who the CEA has determined to have the requisite knowledge, training, and skills to conduct the Compliance Audit. (2) Revised to clarify who may be included on Compliance Audit teams, in addition to staff of the Regional Entity: (i) contractors and industry subject matter experts, (ii) NERC staff members (which may include contractors to NERC), (iii) compliance staff members of other Regional Entities, and (iv) representatives of FERC and of other Applicable Governmental Entities that have reliability jurisdiction with respect to the Registered Entity.

Section 3.1.5.2 – Requirements for Compliance Audit Team Members – (1) First bullet is revised to state that audit team members must be free of conflicts of interest "in accordance with Compliance Enforcement Authority policies." (2) Fourth bullet is revised to eliminate the requirement that the CEA provide to the Registered Entity copies of the confidentiality agreements or acknowledgements executed by the audit team members; instead, the CEA will provide confirmation to the Registered Entity that all audit team members have executed confidentiality agreements or acknowledgements.

Section 3.1.5.3 – Compliance Audit Observers and Other Attendees – Revised to clarify the distinctions between audit team members (§3.1.5.1), observes, and attendees. The first paragraph is amended to specify that the following may participate as observers: NERC staff, other members of the Regional Entity's compliance staff, with the Regional Entity's permission, compliance staff members of other Regional Entities, and representatives of FERC and of other Applicable Governmental Entities that have reliability jurisdiction with respect to the Registered Entity. The second paragraph, which is not being revised (and was approved by the Commission in its October 7, 2011 Order) states who may be attendees at the audit. A new third paragraph has been added to state that "Compliance Audit observers and attendees are not audit team members and do not participate in conducting the Compliance Audit or in making audit findings and determinations."

Section 3.1.5.4 – Registered Entity Objections to Compliance Audit Team – (1) Revised to delete "other than a member of NERC or FERC staff" in the sentence "A Registered Entity subject to a Compliance Audit may object to any member of the audit team [deletion] on grounds of a conflict of interest or the existence of other circumstances that could interfere with the team

member's impartial performance of his or her duties." NERC (and numerous stakeholders who commented on this provision) believe that while a Registered Entity should not be able to object to participation by NERC staff or FERC staff on a Compliance Audit team (as FERC has indicated in prior orders), a Registered Entity should be allowed to object to the inclusion of a particular individual NERC staff or FERC staff member on the audit team based on conflict of interest, bias or similar specific grounds (*e.g.*, the NERC staff member of FERC staff member is a former employee of the Registered Entity).

Section 3.1.6 – Compliance Audit Reports – (1) In the second line, "evidence of possible noncompliance" is changed to "evidence of potential noncompliance" to avoid confusion with the defined term "Possible Violation." (2) In the first paragraph, the phrase "other mitigating activities" is added to "Mitigation Plan," as not all actions taken by Registered Entities to correct a noncompliance and prevent recurrence are memorialized in formal Mitigation Plans. (3) The first paragraph is also revised to state that the audit report may also state areas of concern and recommendations identified by the audit team (rather than specifying that any recommendations of the audit team be provided in a separate document). (4) In the second paragraph, the first sentence is revised to specify that CEA will provide the final audit report to the Registered Entity on or before the date the report is provided to NERC. (5) Text concerning the provision of non-public compliance information to FERC or to another Applicable Governmental Entity is deleted and replaced with a reference to §8.0, where the full text on this topic is provided.

Section 3.2 – Self-Certification – The second paragraph of this section is deleted because its substance has been moved to Appendix 4B, *Sanction Guidelines*, where it is more appropriately placed.

Section 3.2.1 – Self-Certification Process Steps – (1) The first step is revised to specify that the posted reporting schedule should include the applicable reporting periods. (2) The first step is also revised to specify that NERC, along with the CEA, will be responsible to ensure that the appropriate standards, compliance procedures and submittal forms are maintained and available (which may be through a means other than electronic). (3) Consistent with the revised definition of Self-Certification (§1.1.27), the third step is revised to list the four possible responses in a Self-Certification. (4) The fourth step is revised to state that, at a minimum, the CEA will review Self-Certifications of non-compliance and Self-Certifications stating that the Registered Entity does not own facilities that are subject to the Reliability Standard requirement or that the requirement is not applicable to the Registered Entity. (5) The fifth step is revised to state that if the CEA identifies a potential noncompliance, the CEA conducts a Preliminary Screen. (6) A paragraph is added stating that receipt of a Self-Certification by the CEA shall not be construed as a finding by the CEA that the Registered Entity is compliant with, not compliant with, or not subject to, the Reliability Standard requirement. This additional text is intended to negate the assumption that if a CEA makes no further response to a Registered Entity concerning a Self-Certification, the CEA has determined that the Registered Entity is compliant with the Reliability Standard requirement.

Section 3.3 – Spot Check – (1) Revised to state that a Spot Check may be initiated at the discretion of the CEA or as directed by NERC, including on a random schedule. The list of potential reasons is revised to include risk-based assessments based on the Registered Entity's

BPS facilities and operations and their significance to the reliability of the BPS and the Registered Entity's compliance history and internal compliance program or other indicators of its culture of compliance. This addition is consistent with NERC's developing program of using risk-based assessments to determine when and which compliance monitoring processes should be initiated with respect to a Registered Entity.

Section 3.3.1 – Spot Check Process Steps – (1) The first step is revised to state that a "notification letter" will be issued by the CEA to the Registered Entity, which will include the scope of the Spot Check including the Reliability Standard requirements that will be covered. (2) The second step is revised to state that the notification package will include the names and employment histories of the persons who will perform the Spot Check. It is also revised to state that the CEA shall provide confirmation to the Registered Entity that the Spot Check team members have executed confidentiality agreements or acknowledgements. (3) The third step is revised to specify that the Registered Entity must provide the required information to the CEA by the date specified in the request. (4) The fifth step is revised to state that if the Spot Check team's review of the information submitted indicates a potential noncompliance, the CEA will conduct a Preliminary Screen. (5) The sixth step is revised to state that the Spot Check team will prepare a draft Spot Check report and the Registered Entity will be given ten business days to comment on it. (6) The sixth step is revised to provide that the Spot Check team will consider any corrections based on the Registered Entity's comments, finalize the Spot Check report and provide it to the Registered Entity and to NERC. (7) The step stating that the CEA will send the Registered Entity a Notice of Possible Violation is deleted, as that step will now be covered in Section 5.0, Enforcement Actions.

Section 3.4 – Compliance Investigations – In two places, "possible violation" is replaced with "potential noncompliance" to avoid confusion with the defined term "Possible Violation."

Section 3.4.1 – Compliance Investigation Process Steps – (1) The first step is revised to provide that the CEA will take certain actions within three (rather than within two) business days of the decision to initiate a Compliance Investigation. (2) The second step is revised to provide that within three (rather than two) business days after receiving notice of the decision to initiate a Compliance Investigation, NERC will notify FERC and other Applicable Governmental Authorities. In addition, text concerning the provision of non-public compliance information to FERC or to another Applicable Governmental Entity is deleted and replaced with a reference to Section 8.0, where the full text is provided. (4) The fourth step is revised to provide that the Registered Entity must provide any required information to the CEA by the Required Date as specified in the request. (5) The eighth step is revised to provide that the CEA may review any mitigating activities (in addition to Mitigation Plans), since not all actions taken by a Registered Entity to correct a noncompliance and prevent recurrence are memorialized in a formal Mitigation Plan. (6) The ninth step is revised to provide that if the CEA identifies a potential noncompliance, it will conduct a Preliminary Screen. (7) In the tenth step, text concerning the provision of non-public compliance information to FERC or to another Applicable Governmental Entity is deleted and replaced with a reference to Section 8.0, where the full text is provided.

Section 3.5 – Self-Reports – A sentence is added stating that if possible, and without delaying the Self-Report, a Self-Report may include the actions that have been taken or will be taken to resolve the violation. This addition is consistent with the change to the definition of Self Report (§1.1.28).

Section 3.5.1 – Self-Report Process Steps – (1) The first step is revised to delete reference to the CEA's Web site; the CEA may make the Self-Report submittal forms available through other means. (2) The fourth step is revised to provide that the CEA will conduct a Preliminary Screen of the Self-Report information.

Section 3.6.1 – Periodic Data Submittals Process Steps – (1) The first step is revised to delete reference to the CEA's Web site; the CEA may make the submittal forms available through other means. (2) The third step is revised to provide that the Registered Entity must provide any required information to the CEA by the Required Date as specified in the request. (3) The fifth step is revised to provide that if the CEA's review of the data submittal indicates a potential noncompliance, the CEA will perform a Preliminary Screen. (4) A paragraph is added at the end of this section stating that receipt of a Periodic Data Submittal by the CEA shall not be construed as a finding by the CEA that the Registered Entity is compliant with, not compliant with, or not subject to, the Reliability Standard requirement. This additional text is intended to negate the assumption that if a CEA makes no further response to a Registered Entity concerning a Periodic Data Submittal, the CEA has determined that the Registered Entity is compliant with the Reliability Standard requirement.

Section 3.7 – Exception Reporting – This section is deleted and Exception Reporting will no longer be considered one of the compliance monitoring processes, as exception reports are triggered by requirements of particular Reliability Standard, and not on the initiative of the CEA. However, an exception report containing evidence of a potential noncompliance may still result in performance of a Preliminary Screen and initiation of an enforcement action (see revised Section 2.0).

Section 3.7 (as renumbered) – Complaints – In the first paragraph, text stating that NERC will review any Complaint "that is related to a Regional Entity or its affiliates, divisions, committees or subordinate structures." Regional Entities as such are not subject to Reliability Standards; and for those Regional Entities that perform registered functions (FRCC, SPP and WECC), there are in place (or pending before the Commission for approval) agreements by which other Regional Entities, not NERC, perform the CEA responsibilities with respect to the registered functions.

Section 3.8 – Preliminary Screen – (1) The provisions relating to performance of Preliminary Screen are relocated to Section 3.8 from Section 5.1, as the Preliminary Screen is considered a step in the compliance monitoring process (Section 3.0), rather than in the compliance enforcement process (Section 5.0). (2) Section 3.8 states that the Preliminary Screen will be conducted within five business days after the CEA identifies the potential noncompliance, except that (i) if the CEA identifies the potential noncompliance during a Compliance Audit, the Preliminary Screen will be conducted immediately following the exit briefing of the Registered Entity, and (ii) if the CEA identifies the potential noncompliance during a Compliance Investigation, the Preliminary Screen shall be conducted immediately after the Registered Entity

is first notified of the potential noncompliance identified by the Compliance Investigation. The two exceptions are necessary so that the Registered Entity does not receive a Notice of Possible Violation before being notified that the Compliance Audit or Compliance Investigation has found a potential noncompliance. (3) Consistent with the change in definition (§1.1.22), the Preliminary Screen will now include a determination of whether, if known, the potential noncompliance is not a duplication of a Possible Violation or Alleged Violation that is currently being processed. (4) The revised section provides that if the Preliminary Screen results in an affirmative determination with respect to the three criteria, a Possible Violation exists and the CEA shall proceed in accordance with Section 5.0.

D. Section 4.0 – Annual Implementation Plans

Section 4.1 – NERC Compliance Monitoring and Enforcement Program Implementation Plans – (1) Revised to provide that the NERC Implementation Plan will be provided to the Regions by on or about September 1 (rather than October 1) of the prior year. (2) Revised to state that NERC may update and revise its Implementation Plan during the course of the year. (3) Revised to state that Regional Entities have discretion to make modifications to the NERC Implementation Plan with respect to individual Registered Entities, based on a determination concerning the Registered Entity's past and current compliance performance.

Section 4.2 – Regional Entity Implementation Plan – (1) Consistent with the revised schedule in §4.1, revised to provide that the Regional Implementation Plans will be submitted on or about October 1 (rather than November 1) of the previous year. (2) Revised to state that a Regional Entity may update and revise its Implementation Plan during the year as necessary, with NERC approval or as directed by NERC. (3) Revised to state that Regional Entities have discretion to make modifications to their Implementation Plans with respect to individual Registered Entities, based on a determination concerning the Registered Entity's past and current compliance performance.

E. Section 5.0 – Enforcement Actions

In the first paragraph of §5.0, "remedial actions" is replaced with "mitigating activities," to avoid possible confusion with the defined term Remedial Action Directive.

A statement is added that imposition and acceptance of penalties and sanctions shall not be considered an acceptable alternative to a Registered Entity's continuing obligations to comply with Reliability Standards.

Text is added to state that the CEA has authority to collect documents, data and information in the manner it deems most appropriate, including removing copies of documents, data and information from the Registered Entity's location in accordance with appropriate security procedures conforming to ROP Section 1500 and other safeguards as appropriate in the circumstances to maintain the confidential or other protected status of the documents, data and information, such as information held by a governmental entity that is subject to an exemption from disclosure under the United States Freedom of Information Act, or a comparable state or provincial law, that would be lost if the information were placed into the public domain.

This section is revised to state that a Registered Entity that believes a request for documents, data or information is unreasonable may request a determination from the NERC General Counsel (changed from the NERC "compliance program officer").

A statement is added that under the circumstances presented by some Possible Violations, Alleged Violations or Confirmed Violations, absolute adherence to the enforcement process in §5.0, to the exclusion of other approaches, may not be the most appropriate, efficient or desirable means by which to achieve the overall objectives of the Compliance Program for NERC, the CEA and the Registered Entity; in such circumstances, other approaches may be considered and employed. A similar statement is found in current Appendix 4B, but is being deleted there, as it is more appropriately placed in Appendix 4C.

Section 5.1 – Preliminary Screen – This section is deleted and the topic is now covered in Section 3.8 (as discussed above).

Section 5.1 – Notice of Possible Violation – (1) Revised to state that the Notice of Possible Violation will state the dates involved in the Possible Violation "if known." (2) Revised to state that the CEA will report the Possible Violation to NERC (rather than entering it into the compliance reporting and tracking system). (3) Revised to state that NERC will report the Possible Violation to other Applicable Governmental Authorities, as applicable (in addition to FERC), in accordance with §8.0, Reporting and Disclosure.

Section 5.3 – Notification to Registered Entity of Alleged Violation – (1) Revised to provide that the CEA will notify the Registered Entity of the determination of an Alleged Violation, even if the CEA and the Registered Entity have entered into settlement negotiations. (2) Revised to state that the CEA will issue a Notice of Alleged Violation and Proposed Penalty or Sanction "or similar notification," to recognize that some Registered Entities' processes may involve providing notification through a different means than a Notice of Alleged Violation and Proposed Penalty or Sanction. Similar revisions are made in other sections. (3) Revised to state that the notification of Alleged Violation will be issued by e-mail and will be effective as of the date of the electronic mail message; this will promote consistency in the methods of delivering notification. Also, the requirements that the notification be signed by an officer or designee of the CEA, and be sent to the CEO of the Registered Entity, are deleted; the notification will be sent to the Registered Entity's compliance contact. (4) Revised to state that the CEA will report the Alleged Violation to NERC (rather than entering it into the compliance reporting and tracking system). (5) In item (v) of the list of contents of a notification of Alleged Violation, "or other mitigating activities" is added after "implement a Mitigation Plan," to reflect that some actions taken by Registered Entities to correct and prevent recurrence of a noncompliance, although they are approved by the CEA, are not memorialized in a formal Mitigation Plan. (6) In item (vii) of the list of contents of a notification of alleged violation, "full hearing procedure" is changed to "general hearing procedure" consistent with a revision in the Hearing Procedures. (7) Text concerning the provision of non-public compliance information to FERC or another Applicable Governmental Entity is deleted and replaced with a reference to §8.0, where the full text is provided. (8) The last paragraph of this section is deleted, as completion of the enforcement action and issuance of a Notice of Confirmed Violation is covered in later sections.

Section 5.4 – Registered Entity Response -- (1) Revised to add agreement by the Registered Entity with the notification of Alleged Violation as establishing acceptance of the CEA's determination of violation and penalty or sanction. (2) Revised to provide that the 30 day period runs from the date of notification of Alleged Violation by electronic mail (consistent with a revision to §5.3, above). (3) Revised to state that the CEA will issue a Notice of Confirmed Violation "or similar notification," to recognize that some Registered Entities' processes may involve providing notification through a different means than a Notice of Confirmed Violation. Similar revisions are made in other sections. (4) Revised to state that the CEA will report the Confirmed Violation to NERC (rather than entering it into the compliance reporting and tracking system). (5) Revised to state that the Registered Entity will be allowed to provide a written explanatory statement to accompany the filing with FERC and public posting of the Confirmed Violation. (6) Revised to state that if the Registered Entity contests the Alleged Violation or proposed penalty or sanction, it must submit a response within 30 days following the date of notification of the Alleged Violation. (7) Reference to issuing a Notice of Confirmed Violation by the CEA is deleted, as this topic is covered in a subsequent section.

Section 5.6 – Settlement Process -- (1) Revised to provide that the Registered Entity or the CEA may terminate settlement negotiations at any time. Either party should have discretion to terminate settlement negotiations if they are not progressing in a productive manner. (2) Revised to provide that the time for the Registered Entity to respond to the notification of Alleged Violation pursuant to §5.4 is suspended during settlement negotiations. (3) Revised to state that the CEA and the Registered Entity will execute a settlement agreement (rather than that the CEA will issue a letter) setting forth the final settlement terms. (4) Revised to state that within five business days after NERC advises the CEA of NERC's approval, rejection or proposed revisions to a settlement agreement, the CEA will notify the Registered Entity. Notification to the Registered Entity should come from the CEA, not from NERC which has not been in negotiation or other contact with the Registered Entity. (5) Text concerning the provision of non-public compliance information to FERC or another Applicable Governmental Entity is deleted and replaced with a reference to §8.0, where the full text is provided. (6) Text is added to clarify that in the public posting of the settlement agreement or of the terms of the settlement, any Critical Energy Infrastructure Information or Confidential Information will be redacted.

Section 5.7 – NERC Appeal Process – Revised to provide that the CEA, as well as the Regional Entity, may appeal the decision of the Regional Entity hearing body, in accordance with amended Section 409 of the ROP.

Section 5.9 – Notice of Penalty – (1) Revised to provide that the Registered Entity shall be informed that the Notice of Penalty is pending public filing at least five business days prior to the public filing and posting. (2) Text concerning the provision of non-public compliance information to FERC or another Applicable Governmental Entity is deleted and replaced with a reference to §8.0, where the full text is provided.

Section 5.10 – Completion of Enforcement Action – The title of this section is revised from "Closure of Enforcement Action."

Section 5.11 -- Special Procedures for an Enforcement Action Against an ISO/RTO Where the Monetary Penalty May be Allocated by the ISO/RTO to Other Entities – This is a new section to establish procedures pursuant to which (1) an ISO/RTO can request the CEA to make a determination, during the enforcement process for a Notice of Possible Violation issued to the ISO/RTO, that one or more specified other entities were responsible, in whole or on part, for actions or omissions that caused or contributed to the violation (if approved), and (2) the specified other entity(ies) can request and be allowed to participate in the enforcement process.

Section 5.11.1 specifies that NERC will maintain on its website, based on information to be provided by the ISO/RTO, a Public Notification List of Entities that an ISO/RTO contends it has authority to allocate to, pursuant to a proceeding under §205 of the Federal Power Act, some or all of a monetary penalty imposed on the ISO/RTO for a violation or a Reliability Standard. Pursuant to §5.11.3, the ISO/RTO will not be allowed to invoke the procedures of §5.11, and the CEA will not make the requested determination, with respect to another Entity that was not listed on the Public Notification List as of the date of issuance of the Notice of Possible Violation to the ISO/RTO, unless the ISO/RTO demonstrates and the CEA concludes that there are extraordinary circumstances that warrant the CEA making the requested determination with respect to the specified other Entity(ies).

Section 5.11.2 specifies that in order to request the CEA to make a determination in an enforcement action that a specified other entity(ies) was responsible, in whole or in part, for actions or omissions that caused or contributed to a violation (if confirmed) of a Reliability Standard for which the ISO/RTO has received a Notice of Possible Violation, the ISO/RTO shall, no later than five business days after receiving the Notice of Possible Violation (i) submit a written request to the CEA and (ii) issue a notice to the specified other Regional Entity(ies). Section 5.11.2 contains the content and delivery requirements for the ISO/RTO's request and notice. Pursuant to §5.11.3, upon verifying that the specified other entity(ies) were on the Public Notification List as of the date of issuance of the Notice of Possible Violation, that the ISO/RTO has authority to allocate all or a portion of any monetary penalty to the other entity(ies), and that the other entity(ies) received a timely notice from the ISO/RTO in accordance with §5.11.2, the CEA will contact the other entity(ies) to provide further information concerning their right to participate in the enforcement process for the Notice of Possible Violation. In order to participate in the enforcement process, the other entity(ies) will be required to submit a written request to participate and to execute a nondisclosure agreement. The specified other entity(ies) must request to participate in the enforcement process prior to, as applicable (i) the date of execution of a settlement agreement between the CEA and the ISO/RTO, and (ii) the date that the CEA issues a Notice of Confirmed Violation to the ISO/RTO. Pursuant to §5.11.5, upon receiving notice from the CEA that it is allowed to participate in the enforcement action, the specified other entity may participate in the same manner as the ISO/RTO and shall be subject to all applicable requirements and deadlines specified in the Compliance Program.

Section 5.11.6 provides that, assuming all the precedent conditions described above have been met, and if the enforcement action is not resolved by a settlement agreement stating whether or not the specified other entity(ies) was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation identified in the Notice of Possible Violation, the CEA shall make, and include in its proposed Notice of Penalty, its determination of whether or not the

specified other entity(ies) were responsible, in whole or in part, for actions or omissions that caused or contributed to the violation.

Section 5.11.7 provides that if an ISO/RTO's tariffs, agreement or other relevant governance documents establish procedures, that have been approved by FERC, that allow members of the ISO/RTO to directly assign to the ISO/RTO monetary penalties imposed on the ISO/RTO member(s) for violations of Reliability Standards, then the ISO/RTO members may follow the same requirements of §5.11.2, 511.3 and 511.5 as are applicable to an ISO/RTO under those sections, and the ISO/RTO shall be afforded the same rights to participate in the enforcement action as a specified other entity under §5.11.2, 5.11.3, 5.11.5 and 5.11.6, subject to the same requirements and conditions specified in those sections.

Section 5.11.8 specifies that the ISO/RTO shall be obligated and responsible to pay any monetary penalty imposed by the CEA on the ISO/RTO for violation of a Reliability Standard, in accordance with §5.10 of Appendix 4C, (i) regardless of whether the CEA has made a determination that a specified other entity was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation, (ii) without regard to the timing of any separate proceeding(s) in which the ISO/RTO seeks to allocate some or all of the monetary penalty to a specified other entity(ies), and (iii) without regard to whether or when the ISO/RTO receives payment from the specified other entity(ies).

F. Section 6.0 – Mitigation of Violations of Reliability Standards

Text is added to state that the CEA has authority to collect documents, data and information in the manner it deems most appropriate, including removing copies of documents, data and information from the Registered Entity's location in accordance with appropriate security procedures conforming to ROP Section 1500 and other safeguards as appropriate in the circumstances to maintain the confidential or other protected status of the documents, data and information, such as information held by a governmental entity that is subject to an exemption from disclosure under the United States Freedom of Information Act, or a comparable state or provincial law, that would be lost if the information were placed into the public domain.

This section is revised to state that a Registered Entity that believes a request for documents, data or information is unreasonable may request a determination from the NERC General Counsel (changed from the NERC "compliance program officer").

Section 6.2 – Contents of Mitigation Plans – Revised to eliminate the requirement that the representative of the Registered Entity who signs the Mitigation Plan shall be (if applicable) the person that signed the Self-Certification or Self-Report submittal.

Section 6.3 – Timetable for Completion of Mitigation Plans – (1) Detailed text concerning the timing by which a Mitigation Plan should be completed is deleted and replaced with "shall be completed <u>in accordance with its terms</u>." (2) Examples of grounds on which the completion deadline may be extended are revised to include operational issues such as the ability to schedule an outage to complete mitigating activities and construction requirements that require longer to complete than originally anticipated.

Section 6.4 – Submission of Mitigation Plans – Revised to provide that a Mitigation Plan may be reflected in a settlement agreement or Notice of Penalty (in addition to the option of being submitted as a separate document. This is consistent with longstanding practice, *e.g.*, that the terms of the Mitigation Plan are often included in the settlement agreement rather than in a separate "Mitigation Plan" document.

Section 6.6 – Completion/Confirmation of Implementation of Mitigation Plans – (1) Revised to delete reference to the CEA verifying that the Registered Entity is in compliance with the requirements of the Reliability Standard a noncompliance with which led to the Mitigation Plan. The CEA will only be required to verify that all required actions in the Mitigation Plan have been completed. (2) Revised to state that the Regional Entity will provide to NERC the quarterly status reports from Registered Entities on progress in completing Mitigation Plans, "upon request by NERC" (rather than as a matter of course).

G. Section 7.0 – Remedial Action Directives

Consistent with the revision to the definition of Remedial Action Directive (§1.1.25), this section is revised to state that a Remedial Action Directive is issued when the action is immediately necessary to protect the reliability of the BPS from an imminent or actual threat.

The third paragraph is revised to remove the text that the CEA shall consult the Reliability Coordinator for the Registered Entity "to ensure that the Remedial Action Directive is not in conflict with directives issued by the Reliability Coordinator," *i.e.*, the consultation will not be limited to this topic.

The fourth paragraph is revised to expand the information to be included in a notice of Remedial Action Directive, including the requirement the CEA is imposing to remove the threat to reliability of the BPS; a schedule for specific periodic updates to the CEA on progress to achieving compliance; and a statement that the Registered Entity is in a state of noncompliance with the Reliability Standard until the requirements of the Remedial Action Directive are completed and certified complete by an officer of the Registered Entity.

The fifth paragraph is revised to provide that the notice of the Remedial Action Directive that is delivered by electronic mail shall be sent to both the Registered Entity's CEO and its designated contact person for reliability matters; and that the notice will be deemed received on the earlier of the actual date of receipt of the electronic submission or receipt of the express courier delivery of the notice as specified by the courier service's verification of delivery.

The sixth paragraph is revised to specify that the CEA will copy NERC on all correspondence sent to the Registered Entity.

H. Section 8.0 – Reporting and Disclosure

This section is revised to contain two subsections, as described below.

Section 8.1 – Information to be Reported -- This section lists the information to be provided by Regional Entities to NERC via electronic reports. A sentence is added that NERC will work with Regional Entities to specify form, content, timing and method of submitting reports and notices. The revised list of information to be reported includes the status of the review and assessment of all Possible Violations, Alleged Violations and Confirmed Violation; the potential impact of any Alleged Violation of Confirmed Violation on the reliability of the BPS; and the name of a Regional Entity staff person knowledgeable about the information to serve as a point of contact, as well as other information specific in current §8.0.

Section 8.2 – Reporting to Applicable Governmental Authorities and Public Disclosure -- Text concerning procedures for the disclosure of non-public U.S. compliance information to Applicable Governmental Authorities other than FERC, and disclosure of non-public non-U.S. compliance information to FERC, which is currently found in several sections of Appendix 4C, has been placed into §8.2 and deleted from all other sections. As described above with respect to the revisions to other sections in which this text is being deleted, it is replaced with a reference to §8.0. This section is also revised to state that NERC will publicly post on its web site each Notice of Penalty, with any Critical Energy Infrastructure Information or Confidential Information redacted, when NERC files the Notice of Penalty with FERC pursuant to §5.9.

I. Section 9.0 – Data Retention and Confidentiality

There are no changes to Section 9.0 other than changes in capitalization of terms and changes in certain terms to be consistent with the changes to those terms elsewhere in Appendix 4C.

V. Attachment 1 to Appendix 4C – Process for Non-Submittal of Requested Data

Attachment 1 to Appendix 4C has been revised to match the process steps that the CEA will follow for non-submittal of requested or required data in proposed new ROP §1800 (described earlier in this summary), but without the authority provided in §1800 for the CEA to impose fines for the failure to provide requested or required data. However, as in the current Attachment 1, the Registered Entity's failure to provide the requested data or information after follow-up notifications may result in a Reliability Standard violation at the severe Violation Severity Level.

VI. Attachment 2 to Appendix 4C – Hearing Procedures

Throughout Appendix 2, (1) references to "[HEARING BODY]" (which were originally intended to allow each Regional Entity to insert the name of its Hearing Body) have been replaced with "Hearing Body;" and (2) references to provisions within Attachment 2 have been changed from "Paragraph" to "Section." Additionally, in numerous sections, the text has been divided into lettered subsections ((a), (b), (c), etc.).

A. Section 1.1 -- Applicability, Definitions and Interpretation

Section 1.1.1 – Procedure Governed – (1) Subsection (b) is revised to provide that where the Hearing Body is comprised, in whole or in part, of industry stakeholders, the composition of the hearing body shall be such that no two industry segments may control, and no single industry

segment may veto, any decision by the Hearing Body; and where the Hearing Body is comprised solely of independent members and an independent Hearing Officer, the Hearing Body, decisions shall require a majority vote. This revision is intended to accommodate NPCC's new Hearing Body composition which is presently pending before the Commission for approval. (2) A new subsection (d) has been added providing that if a final order has been entered by the Hearing Body, or the Hearing Body has issued a ruling determining that there are no issues to be decided regarding the Alleged Violation, proposed Penalty amount, proposed Mitigation Plan or proposed Remedial Action Directive, or the Registered Entity and the CEA have entered into a settlement agreement resolving the matters that are the subject of the hearing, the hearing shall be terminated by the Hearing Body and no further proceedings shall be conducted.

Section 1.1.2 – Deviation -- A reference to the Hearing Officer "as defined in Paragraph [now Section] 1.1.5 has been deleted as unnecessary.

Section 1.1.4 – Interpretation – A new subsection (b) is added to provide that "Any ruling, order or decision of the Hearing Officer referenced in these Hearing Procedures shall be made by the Hearing Body where the composition of the Hearing Body consists of independent members and an independent Hearing Officer." This additional text is intended to accommodate NPCC's new Hearing Body composition which is presently pending before the Commission for approval; it avoids a situation in which the Hearing Officer, as a member of the Hearing Body, would be required to review his or her own decisions.

Section 1.1.5 – Definitions – (1) The definition of "Clerk" is expanded to identify his/her duties ("perform administrative tasks relating to the conduct of hearings as described in these Hearing Procedures"). (2) The definition of "Director of Compliance" is expanded to include an individual designated by the CEA (regardless of title) who is responsible for management and direction of the Compliance Staff. (3) Two new definitions are added, "Evidentiary Hearing" and "Testimonial Hearing." An Evidentiary Hearing is a hearing at which one or more Participants submit evidence for the record, while a Testimonial Hearing is an Evidentiary Hearing at which one or more witnesses appear in person to present testimony and be subject to cross-examination. (Corresponding revisions are made throughout the Hearing Procedures as necessary to identify references to hearings as "Evidentiary" or "Testimonial".) (4) A definition of "Hearing Body" is added, consistent with the revision of this term from "[HEARING BODY]" as described above. (5) The definition of "Participant" is revised consistent with the revisions to Section 1.2.12 (described below) that provide for the Hearing Body to be able to grant intervention into the hearing in specific, limited circumstances.

B. Section 1.2 – General Provisions including Filing, Service, Transcription and Participation

Section 1.2.1 – Contents of Filing – In subsection (d) a reference to "documents" is changed to the broader term "evidence."

Section 1.2.3 – Submission of Documents – (1) In subsection (a), the placeholder for insertion of the CEA's regular business hour is deleted and replaced with "during the Compliance Enforcement Authority's regular business hours." (2) In subsection (b), the placeholder for

insertion of the CEA's time of close of business is deleted and replaced with "5:00 P.M." (3) In subsection (e), the statement "The signature on a filing constitutes a certificate that the signer has read the filing and knows its contents, and that the contents are true to the best of the signer's knowledge and belief" is deleted, since this topic is now covered in new §1.2.15.

Section 1.2.4 – Service – (1) In subsection (a), the statement that the Registered Entity's "designated agent for service" shall automatically be included on the service list is changed to "compliance contact." (2) In subsection (b), a proviso "subject to the provisions of Section 1.5.10" is added. Section 1.5.10 is the section of the Hearing Procedures on Protective Orders. (3) Subsection (c) is revised to state that the Clerk shall transmit a copy of the record to the ERO at the time the CEA transmits (rather than "serves") to the ERO a Notice of Penalty or a Hearing Body final order than includes a Notice of Penalty.

Section 1.2.8 – Transcripts – (1) The text in subsection (a) is amended to provide that the court reporter shall file a copy of each transcript with the Clerk, and that upon receipt of a transcript from the court reporter, the Clerk shall send notice to the Participants stating that a transcript has been filed by the court reporter, the date or dates of the hearing that the transcript records, and the date the transcript was filed with the Clerk. This filing and notice initiate the time period within which the Participants may file transcript corrections. (2) In subsection (b), the time within which a Participant may file suggested transcript corrections is changed to within 14 days from the date of the Clerk's notice that the transcript has been filed with the Clerk. In addition, this subsection is revised to provide that the Hearing Officer shall only allow changes that conform the transcript to "the statements being transcribed" (rather than suggesting that the testimony given could be revisited).

Section 1.2.11 – Participant Participation – the statement that witnesses shall personally appear at the evidentiary hearing if required by Paragraph 1.6.6 is deleted and replaced with "except as required by Section 1.6.6" (§1.6.6 addresses the requirements for witness attendance at Testimonial Hearings).

Section 1.2.12 – Interventions – (1) The title of this section is changed from "Interventions Are Not Permitted," as the revised section will authorize the Hearing Body to allow intervention under limited, specific circumstances. (2) The section is revised as necessary throughout to reflect that the Hearing Body (as well as FERC) will be allowed to permit interventions. (3) New subsection (b) provides that the Hearing Body may allow a Person to intervene only if the Hearing Body determines that the Person seeking intervention has a direct and substantial interest in the outcome of the Alleged Violation, proposed penalty or sanction, Mitigation Plan, or Remedial Action Directive that is the subject of the proceeding. Two examples of a "direct and substantial interest in the outcome" are provided in the text. Two examples of situations that will not constitute "a direct and substantial interest in the outcome" and will not be grounds on which intervention may be allowed, are also provided in the text (including "seek[ing] to intervene to advocate an interpretation of the Reliability Standard requirement(s) or provision(s) of the *Sanction Guidelines* that are at issue"). (3) Subsections (c), (d) and (e) set forth the procedures and timing requirements for submission of a motion to intervene (including the required contents), responses by other Participants, issuance of a recommendation by the Hearing Officer, and the Hearing Body's decision on the motion to intervene. (4) Subsection (f)

authorizes the Hearing Officer or the Hearing Body to stay or suspend the proceedings while a request to intervene filed with the Hearing Body or with FERC, or any appeal of the ruling on the request to intervene, is being resolved. (5) Subsection (g) provides that a Person allowed to intervene shall be deemed to be aligned with the Respondent(s), unless the Hearing Body specifies that the Person intervening shall be aligned with another Participant. (6) Subsection (h) provides that a Person allowed to intervene must take the record and procedural status of the proceeding as it stands on the date the motion to intervene is granted by the Hearing Body. (7) Subsection (i) provides that appeals of decisions of the Hearing Body granting or denying requests to intervene may be appealed to NERC in accordance with ROP §414, and that the notice of appeal must be filed with the NERC director of enforcement no later than seven days following the date of the decision of the Hearing Body granting or denying the intervention.

Section 1.2.14 – Docketing System – Revised to state that a docketed proceeding shall be created upon the filing of a request for hearing (rather than upon issuance of a Notice of Alleged Violation). Docketed hearing proceedings need to be created by the Regional Entity Hearing Body only when a request for a hearing on a matter is filed.

Section 1.2.15 – Representation Deemed to be Made in All Pleadings – This is a new section. It provides that a Participant presenting any pleading to the Hearing Officer or Hearing Body shall be deemed to certify to the best of the Participant's knowledge, information and belief, formed after and based on an inquiry that is reasonable under the circumstances, certain specified matters as to the factual allegations in the pleading, the denials in the pleading of factual allegations made by another Participant, the claims, defenses and other contentions set forth in the pleading, and that the pleading is not being presented for any improper purpose such as to harass, cause unnecessary delay, or needlessly increase the cost incurred by any Participant.

C. Initiation of the Hearing Process

Section 1.3.1 – Registered Entity's Option to Request a Hearing – (1) This section has been divided into subsections. (2) In subsection (d), concerning notification in a Notice of Alleged Violation of hearing options, a reference to Section 5.3 of the Compliance Monitoring and Enforcement Program is added. (3) Subsection (e) sets forth the required contents of a Registered Entity's request for hearing, and provides that the Registered Entity may state two or more alternative grounds for its position. (4) Subsection (f) contains the provisions for determining if the general hearing procedure (referred to in the current Hearing Procedures as the "full" hearing procedures) or the shortened hearing procedure will be used, based on the Registered Entity's request and the response by the Compliance Staff and any other Participants (there are no substantive changes to this provision).

Section 1.3.2 – Compliance Staff's Response to Request for Hearing – This section specifies that the Compliance Staff must file a response to the request for hearing (i) if the request for hearing requests use of the shortened hearing procedure or (ii) the request for hearing requests that the Registered Entity's proposed revised Mitigation Plan be approved. In all other situations, the Compliance Staff may, but is not required to, file a response to the request for hearing. Any response by the Compliance Staff must be filed within 15 days after the date the request for hearing was filed, unless the Hearing Officer or Hearing Body allows a longer time.

Section 1.3.3 – Notice of Hearing – This new section provides that the Clerk shall issue a notice of hearing not less than 16 days nor more than 21 days after the request for hearing is filed, stating whether the shortened hearing procedure or the general hearing procedure will be used; and identifying the Hearing Officer and the date, time and place for the initial prehearing conference (which shall be set for seven days following the date of the notice if the shortened hearing procedure is to be used, and 14 days following the date of the notice if the general hearing procedure is to be used).

Section 1.3.4 – Shortened Hearing Procedure – There are a number of revisions to this section to conform to terminology changes elsewhere in the revised Hearing Procedures; however, the following two revisions are substantive: (1) Compliance Staff is to make Documents available to the Registered Entity for inspection and copying pursuant to §1.5.7 within ten days (rather than five days) after the issuance of the notice of hearing; and (2) it shall be the objective of the Hearing Body to issue its final order within 120 days (rather than 90 days) after the notice of hearing.

D. General Hearing Procedure

Section 1.4.1 – [Currently] Notice of Hearing – The text of this section, which in the current Hearing Procedures covers issuance of the initial notice of hearing, is deleted (this topic will be covered in new §1.3.3), and the section is intentionally left blank to avoid the need to renumber all the following subsections in §1.4.

Section 1.4.2 – Hearing Officer – (1) In subsection (a), text is revised to provide that the CEA shall (rather than may) utilize a Hearing Officer to preside over the hearing. (2) Correspondingly, subsection (b) is revised to provide that the Hearing Officer is responsible (rather than may be delegated authority) for the conduct of the hearing. (3) In subsection (b), the list of the Hearing Officer's responsibilities is modified to include to "hear argument on all objections, motions and other requests."

Section 1.4.3 – Hearing Body – (1) New subsection (a) provides that the composition of the Hearing Body, after any recusals or disqualifications, shall be such that no two industry segments may control, and no single industry segment may veto, any decision of the Hearing Body. (2) The text in subsection (b) is revised to specify that upon receiving a filing by a Participant, the Clerk shall promptly send a notice to the members of the Hearing Body identifying the date of the filing and the Participant making the filing and briefly describing the nature of the filing, and that any member of the Hearing Body may request from the Clerk a copy of any filing made by a Participant. (3) Subsection (b) is also revised to specify that the Clerk shall send all issuances of the Hearing Officer to the Hearing Body members. (4) Text is added to subsection (b) to specify that at any prehearing conference or hearing attended by a member of the Hearing Body, the Hearing Body member may ask questions directly of any Participant or witness.

Section 1.4.4 – Interlocutory Review – Revised to provide that a petition for interlocutory review shall be supported by either references to the record or by affidavit if based on facts that do not appear in the record.

Section 1.4.5 – Disqualification – Revised to provide that where a replacement Hearing Officer is appointed after the hearing has commenced, the replacement Hearing Officer may recall any witness or may take other steps necessary to ensure familiarity with the record.

Section 1.4.7 – No Ex Parte Communications – (1) Text is added to specify that the proscription against ex parte communications does not prohibit (i) communications between the Hearing Officer or members of the Hearing Body to the Clerk for the purpose of transmitting documents, giving instructions to the Clerk, or discussing scheduling or other procedural matters, or (ii) communications between or among the Clerk, the Hearing Body and representatives of the CEA for purposes of establishing the hearing forum. (2) In subsection (c), text is revised to require that a report of a prohibited communication be made by any member of the Hearing Body, the Hearing Officer or a Technical Advisor who receives or makes or knowingly allows (currently "knowingly causes to be made") a prohibited communication.

Section 1.4.8 – Appearances – Text is added to specify that all representatives appearing before the Hearing Body or Hearing Officer shall conform to the standards of ethical conduct required of practitioners before the courts of the United States.

Section 1.4.10 – Consolidation of Proceedings – (1) Revised to provide that consolidation may be considered on motion of a Participant (in addition to by the Hearing Body on its own motion). (2) References to "transaction" are changed to "occurrence," as more descriptive of the types of events that might result in an Alleged Violation, proposed penalty or proposed Mitigation Plan and ultimately result in a hearing before a Regional Entity Hearing Body.

E. Section 1.5 – Prehearing Procedure

Section 1.5.2 – Prehearing Conferences – (1) Revised to require the Hearing Officer to hold at least one prehearing conference. (2) Topics are added to the topics to be discussed at the initial prehearing conference. (3) Text is added to specify that the scheduled date for the Evidentiary Hearing shall be within 90 days of the initial prehearing conference, unless a different date is specified by the Hearing Officer or the Hearing Body with the consent of all Participants or for good cause shown. (4) Text is added to require the Hearing Officer to hold a final prehearing conference prior to the Evidentiary Hearing, to discuss specified topics and other topics suggested by the Participants.

Section 1.5.3 – Summary Disposition – (1) The basis for granting summary disposition is revised to state that there are no issues of material fact and a Participant is entitled to issuance of a final order in its favor. (2) More detailed requirements are added for the contents of a motion requesting summary disposition and the responses in opposition.

Section 1.5.4 – Status Hearing – (1) Text is added to expand the reasons for a status hearing to include "other matters relevant to the conduct of the hearing." (2) Text is added to require that a Participant requesting a status hearing to resolve a dispute shall include in its request a certification that it has made a good faith effort to resolve the dispute with the other Participant(s) before requesting the status hearing.

Section 1.5.7 – Inspection and Copying of Documents in Possession of Staff – (1) Revised to specify that Staff is to make Documents available for inspection and copying by other Participants (rather than by just the Respondent) within 25 days after the request for hearing is filed (rather than within 5 days after the notice of hearing is issued). Corresponding revisions of "Respondent" to "Participants" are made throughout this section. (2) The requirements for production of later-received Documents are tied to the scheduled date of the Evidentiary Hearing (rather than "the hearing"). (3) The provision concerning privileged and work product Documents that may be withheld by Compliance Staff is revised to Documents that are privileged to, or work product of counsel to, the CEA (rather than the Compliance Staff). (4) Text is revised to provide that inspection reports, internal memoranda or other notes or writings prepared by Compliance Staff may be withheld if they will not be offered in evidence "or otherwise relied on by Staff in the hearing." (5) The provision concerning Documents that may be withheld by Compliance Staff because they would disclose an examination, investigatory or enforcement technique or guideline is revised to specify that the protected information must not otherwise be made public. (6) Subsection (c) is revised to require that the Compliance Staff's withheld Documents list must include a statement of the grounds that support withholding the Documents. (7) Subsection (c) is also revised to specify that the Hearing Officer, for good cause shown, may order Compliance Staff to make available any withheld Document other than a Document that is subject to attorney-client privilege. (8) Subsection (e) is revised to make it clear that a Participant may remove from the CEA's offices copies of the Documents made available by the CEA.

Section 1.5.8 – Other Discovery Procedures – (1) Text is revised to provide that the Hearing Officer, for good cause shown, may order a Participant to make a withheld Document available to other Participants, for inspection or copying. (2) The time period during which discovery should be completed is revised to 6 months following the date the request for hearing was filed (changed from 6 months from the date of the initial prehearing conference).

Section 1.5.9 – Pre-Evidentiary Hearing Submission of Testimony and Evidence – Revised to clarify that all Participant witness direct testimony to be submitted in an Evidentiary Hearing must be prepared in written form.

Section 1.5.11 – Pre-Evidentiary Hearing Memorandum – (1) Revised to eliminate the need for the Hearing Officer or Hearing Body to have grounds for requesting submission of pre-Evidentiary Hearing memoranda. (2) Revised to provide that the topics directed to be included in the pre-Evidentiary Hearing Memoranda may include "such other matters as may be directed by the Hearing Officer or the Hearing Body."

Section 1.5.12 – Certification of Questions to the NERC Board of Trustees – This new section provides for certification by the Hearing Body to the NERC Board of Trustees, for decision, a significant question of law, policy or procedure the resolution of which may be determinative of the issues in the proceeding in whole or in part, or as to which there are other extraordinary circumstances that make prompt consideration of the question by the Board of Trustees appropriate, pursuant to ROP §412. The section specifies that questions of fact presented by the particular matter in dispute in a hearing shall not be the subject of a certification. The section provides the procedures for requesting certification of a question or considering whether a

question should be certified. The Hearing Body shall determine whether any proposed question shall be certified to the NERC Board for decision. The Hearing Body shall also determine whether or not the hearing should be stayed or suspended while a certified question is pending before the NERC Board.

F. Section 1.6 – Procedure at Evidentiary Hearing

Section 1.6.1 – Purpose of Evidentiary Hearing – Revised to delete the provision that the evidentiary hearing also may be used to address any other issue pending between the Participants.

Section 1.6.6 – Witness Attendance at Testimonial Hearing – A provision is added to specify that a person compelled to appear, voluntarily testifying, or making a statement may be accompanied, represented and advised by an attorney.

Section 1.6.14 – Cross-Examination – (1) Revised to provide that leading questions are permitted on cross-examination. (2) Text is added to state that the credibility of a witness may be attacked by any Participant, including the Participant calling the witness. (3) Revised to delete the requirement that if a member of the Hearing Body seeks to ask a witness questions, the Hearing Body member shall do so by submitting the questions in writing to the Hearing Officer to ask the witness.

Section 1.6.15 – Redirect Examination – Revised to delete the requirement that if a member of the Hearing Body seeks to ask a witness questions, the Hearing Body member shall do so by submitting the questions in writing to the Hearing Officer to ask the witness.

Section 1.6.17 – Close of the Evidentiary Record – (1) Revised to state that the Hearing Officer may reopen the evidentiary record for good cause shown prior to issuance of the Hearing Body's final order. (2) A statement is added that for purposes of reopening the evidentiary record, newly discovered evidence that is material to the issues in dispute and could not, by due diligence, have been discovered prior to or during the Evidentiary Hearing, shall constitute good cause.

G. Section 1.7 – Post-Evidentiary Hearing Procedure

Section 1.7.1 – Briefs – (1) Revised to allow the Hearing Officer to allow oral closing statements in addition to (not just in lieu of) briefs, and to delete the requirement that there must be agreement of the Participants in order for the Hearing Officer allow oral closing statements in addition to or in lieu of briefs. (2) Revised to allow the Hearing Officer to impose reasonable word limits (rather than page limits) on briefs.

Section 1.7.4 – Hearing Officer's Initial Opinion – Revised to eliminate the provision that if the initial opinion proposes a Penalty, the initial opinion shall include a proposed Notice of Penalty. Notices of Penalty are prepared by NERC. Corresponding revisions are made in other sections of the Hearing Procedures to delete references to Notices of Penalty prepared by the Hearing Officer or the Hearing Body.

Section 1.7.5 – Exceptions – Revised to allow the Hearing Officer to impose reasonable word limits (rather than page limits) on briefs.

Section 1.7.7 – Additional Hearings – Revised to state that the Hearing Officer may reopen the record and hold additional hearings before issuance of the Hearing Body's final order (rather than before issuance of the Hearing Officer's initial decision).

Section 1.7.10 – Appeal – (1) Revised to state that a Participant or a Regional Entity acting as the CEA may appeal a final order of the Hearing Body to NERC in accordance with NERC ROP §409. (2) The statement that the Clerk shall transmit the record to NERC for any proceeding that appealed is deleted, as the procedures governing appeals are set forth in ROP §409.

H. Section 1.8 -- Settlement

Consistent with revisions in Section 5.6 of the Compliance Monitoring and Enforcement Program, this section is revised to provide that the CEA may terminate settlement negotiations at any time.

I. Section 1.9 – Remedial Action Directives

Section 1.9.1 – Initiation of Remedial Action Directive Hearing – Revised to specify that the CEA will notify NERC within two business days after issuance of a Remedial Action Directive.

Section 1.9.2 – Remedial Action Directive Hearing Procedure – (1) Revised to state that the hearing shall (rather than may) be presided over by a Hearing Officer. (2) Revised to state that the Hearing Body shall issue its summary written decision within 10 days following submission of the last brief (rather than within 10 days following the hearing). (3) Text is added to clarify that "upon issuance of the summary written decision, the Registered Entity is required to comply with the Remedial Action Directive as specified in the summary written decision;" that is, the obligation to comply is not postponed until the Hearing Body issues its full written decision.

VII. Appendix 5A – Organization Registration and Certification Manual

A. Section I – Executive Summary

A number of revisions have been made throughout Appendix 4A for more consistent use of terms and acronyms, such as "BPS," "RC," "TOP" and BA," and "user, owner or operator" (of the BPS).

The section captioned "Where to Access and Submit Form(s)?" is revised to specify that completed registration and certification forms should be sent to the website location and/or individual(s) responsible for registration and/or certification at the Regional Entity.

In the section captioned "Roles and Responsibilities," the descriptions of the roles and responsibilities of NERC and the Regional Entities in the registration and certification processes have been revised in accordance with current practice.

B. Section II – Introduction to Organization Registration and Organization Certification Processes

In the section captioned "Organization Certification," text has been revised to specify that all entities registered in the NERC Compliance Registry for the RC, TOP and BA functions, and entities that perform some or all of the reliability functions for or with the RC, TOP or BA, shall be certified.

C. Section III – Organization Registration Process

The section captioned "Organization Registration Process," including Figure 1, Organization Registration Process Overview, has been revised consistent with current practice as to the respective responsibilities of NERC and the Regional Entities in the organization registration process.

D. Organization Certification Process

In the section captioned "Purpose and Scope," the reference to certification of a new entity that will become NERC certified and registered as a BA, TOP or RC has been expanded to include those entities that perform some or all of the reliability functions of an RC, BA or TOP.

In the section captioned "Organization Certification Process," the text describing the Provisional Certification Process has been deleted, since the Provisional Certification Process is no longer needed. In subsection 8c of that section, the reference to the Regional Entity as the entity to which an entity undergoing certification may express its objections to a member of the Certification Team (CT), has been changed to the Certification Team Lead. A new subsection 8e has been added to describe the composition of the CT where an existing certified entity is seeking to expand its footprint. In subsection 13, an exception has been added to the requirement that the CT shall conduct at least one on-site visit to the entity's facilities, specifically, where only a minor change in the existing footprint of an existing certified entity is under review, in which case the CT may determine that an on-site visit is not necessary. In Section 21, the provision that NERC shall update the Compliance Registry (for a new certification) "prior to the entity going operational" is changed to "in accordance with the registration rules."

F. Section V – NERC Organization Registration Appeals Process

The title and address of the NERC employee with whom registration appeals must be filed is revised. Registration appeals should now be submitted to the NERC Director of Compliance Operations.

G. Section VI – NERC Organization Certification Appeals Process

In the section captioned "Organization Certification Appeals Procedure," the title of the NERC employee with whom registration appeals must be filed is revised. Registration appeals should now be submitted to the NERC Director of Compliance Operations. Subsection 5d has been

revised to more clearly describe the actions to be taken by NERC based on the Board of Trustees Compliance Committee's decision on the registration dispute.

VIII. Appendix 6 – System Operator Program Certification Manual

Appendix 6 is being deleted from the ROP, and, as described above in the summary of the revisions to ROP Section 600, the substantive provisions of Appendix 6 are being moved into Section 600. It was determined that Appendix 6 contained a significant amount of administrative detail about the System Operator Certification Program that does not need to be in the ROP.

IX. Appendix 8 – NERC Event Response Procedures

Appendix 8 is being comprehensively revised. The title of this Appendix is changed to "NERC Event Responses Procedures." Consistent with the proposed revisions to ROP Sections 807 and 808 (described above), Appendix 8 has been revised to provide for a more consistent use of terms including "major event" and "occurrences."

Some material has been deleted from Appendix 8 because it will be covered in NERC's Event Analysis Process Manual, or is otherwise administrative detail concerning event analysis that does not need to be included in the ROP. For example, current Attachments A (Typical Team Assignments for Analysis of Blackouts or Disturbances), B (Guidelines for Analysis Team Scopes), C (NERC Confidentiality Agreement for Analysis of Blackouts and Disturbances), and E (Guidelines for NERC Reports on Blackouts and Disturbances) are deleted. Current Attachment D (retitled "NERC Major Event Analysis Objectives, Analysis Approach, Schedule, and Status") is retained, but with sections added for Personnel, Procedures and Communications; System Restoration; System Planning and Design; and Conclusions and Recommendations.

The "Introduction" section of revised Appendix 8 provides an overview of the event response and analysis procedures, including the critical components of an effective event analysis effort.

The section "Categorization of Events" provides a description of the categorization of events, both as Category 1 (least significant) to Category 5 (most significant) events, and by level of significance: "Significant," "Conditionally Significant," "Consequential and Noteworthy," "Non-Consequential but Noteworthy," and "Not Consequential." Descriptions of the levels of significance are provided. As used in revised Appendix 8, the term "major event" is generally intended to refer to a Category 4 or 5, or a Significant or Conditionally Significant, event; and the term "other event" is generally intended to refer to a Category 1, 2 or 3, or a Consequential and Noteworthy, Non-Consequential but Noteworthy, or Not Consequential, event.

The section "Responsibility for Event Analysis Based on Category or Significance of Event" describes NERC's role in event analysis in the case of a major event and in the case of another event.

The section "Response to and Analysis of Major Events" describes the activities that will occur or be performed by the involved participants in the case of a major event. This section describes the four phases of responding to a major event: (1) Situation Assessment and Communications,

(2) Situation Tracking and Communications, (3) Data Collection, Investigation, Analysis, and Reporting (which is the event analysis phase), and (4) Publishing of Recommendations (lessons learned, best practices, and alerts, if applicable). In the Data Collection, Investigation, Analysis, and Reporting phase (*i.e.*, event analysis), based on the scope, magnitude and impact of a major event, NERC may (1) perform an overview analysis of BPS and generator response, (2) rely on a Regional Entity to conduct the analysis and monitor the analysis results, (3) work with a Regional Entity in its analysis, or (4) conduct a NERC-level analysis. Appendix 8 describes the following steps for the Data Collection, Investigation, Analysis, and Reporting phase: (a) collecting pertinent data on the major event, (b) detailed sequence of occurrences leading to and triggering the major event, (c) detailed BPS analysis, (d) cause analysis, and (e) findings, conclusions and recommendations.

The section "Event Analysis of Other Events" describes the process steps for an event analysis of another event (*i.e.*, a non-major event).

A table is included in the revised Appendix listing, by Category of event, the reports that Registered Entities involved in the event are expected to prepare and submit and the timing requirements for each report.

The section "Development of Lessons Learned from Events" describes the process for developing lessons learned from an event, to be disseminated to the industry.

The section "Reporting and Analysis Requirements for Registered Entities in Connection with Events" specifies that Registered Entities are required to report the occurrence of defined BPS disturbances and unusual occurrences to the applicable Regional Entity and to NERC in accordance with NERC and Regional Reliability Standards and other requirements.

The section "Event Analysis Interface with Compliance" states that to support a strong culture of compliance, Registered Entities are expected to conduct a rigorous self-analysis of events to determine if there have been Possible Violation(s) of a NERC Reliability Standard(s). Registered Entities are also strongly encouraged to submit a compliance self-assessment report to the applicable Regional Entity compliance liaison. This section states that, as provided in Appendix 4B, *Sanction Guidelines*, if the Registered Entity is fully cooperative in the event analysis process, conducts a self-analysis of the event and submits a timely compliance self-assessment report, and submits Self-Reports of any Possible Violations of Reliability Standards and implements corrective and mitigating actions, then in any subsequent enforcement actions, the Registered Entities' actions will be considered as mitigating factors in the determination of any penalties or sanctions for violations of Reliability Standards in connection with the event.

Comments Received on "Definitions and Capitalization" Posting

The posting and stakeholder comment period was recently completed on NERC's proposed revisions to the Rules of Procedure to make definitions consistent throughout the ROP and to capitalize defined terms throughout the ROP. A number of stakeholder comments were received on that posting that should be considered as a basis for revisions to the ROP, but for which the revisions would be more substantive, or otherwise outside the limited intended scope, of the "definitions and capitalization" initiative. However, these comments should be considered in connection with the set of substantive ROP revisions that will be posted for a stakeholder comments period following the November Board meeting. Following is a list (not necessarily exhaustive) of those comments. Some of the items listed below reflect aggregation of comments from several stakeholders on the same point.

1. The Standards Process Manager position should be identified and his/her duties described in Appendix 3A.

2. A broader definition of "Critical Infrastructure Protection Standards" should be developed, for example including CIP-001 and Regional CIP Standards

3. ROP §305.4 needs to be corrected to reflect that the Registered Ballot Body Segments are not defined in Appendix 3A (or, alternatively, the Segments should be defined in Appendix 3A).

4. A defined term should be developed for the date that a new or revised Reliability Standard becomes mandatory and enforceable. (The term "Effective Date" is used in Appendix 4D as the date on which the rejection, disapproval or termination of a TFE Request becomes effective).

5. ROP §1400 should not be revised to require 50 NERC Members to propose an amendment to the ROP (thereby becoming consistent with the provision in the NERC Bylaws); rather, the Bylaws should be amended to lower to number of Members required from 50. [This comment has also been received in connection with an earlier posting of the proposed substantive revisions.]

6. Inclusion of a definition of "Adequate Level of Reliability" based on current work in progress of a task force. [A definition was included in the posted version of Appendix 2, but has been deleted.]

7. Delete the term "market operator" from the list of Functional Entities in the ROP (*e.g.*, §302), as it currently is not a type of Registered Entity; or, alternatively, create or adopt a definition for "market operator."

8. In Appendix 5B, make the list of function types consistent with the NERC *Reliability Functional Model Version 5*.

9. There is an apparent error in §1.3 of Appendix 4D, specifically, the reference to "CIP-006-3c, including the Interpretation in Appendix 3," should refer to "Appendix 2."

10. The defined term "Protected FOIA Information" and its applicability should be revised/expanded. [Currently only used in Appendix 4D.]

11. The defined term "Protected FOIA Information" should be added to the definition of "Confidential Information."

12. The provision(s) describing the development of the annual Reliability Standards Development Plan should include reference to the stakeholder review aspect of the development of the plan.

Update on Regulatory Matters
(As of October 5, 2011)

Action
None

Regulatory Matters in Canada

1. Negotiation of the second agreement among NERC, the Régie and NPCC regarding implementation of mandatory standards in Québec has been tentatively concluded and the agreement is under consideration by the provincial government. The Régie has issued a preliminary decision regarding adoption of mandatory standards for Québec.
2. NERC Reliability Standards adopted as mandatory July 2011 in Nova Scotia.
3. Adoption of NERC Reliability Standards ongoing in Alberta.
4. Implementing regulations being developed in Manitoba.
5. Implementing regulations being developed in British Columbia.

FERC Orders Issued Since the Last Update

1. July 13, 2011 – Order Nos. 748-A and 749-A – Order on Clarification in which the Commission granted NERC's request for clarification of certain aspects of Order No. 748 including: (1) the proper effective date language for Reliability Standard IRO-004-2; (2) the correct version identification for the approval of EOP-001 intended by the Commission; and (3) the proper effective date for Reliability Standard EOP-001-2. The Commission also granted NERC's request for clarification of Order No. 749 with respect to the version EOP-001 the Commission intended to approve and its effective date. *Docket Nos. RM10-15-001 and RM10-16-001*
2. July 20, 2011 – Commission found there is insufficient consensus for the five families of smart grid interoperability standards under consideration and declined to institute a rulemaking proceeding with respect to these standards and terminated this docket. Docket No. RM11-2-000
3. July 21, 2011 – Commission denied Nebraska Public Power District's and Southwest Power Pool Regional Entity's requests to permit transfer of the Nebraska Entities' compliance registrations from Midwest Reliability Organization to Southwest Power Pool Regional Entity. Docket Nos. RR11-1-000, RR11-1-001
4. July 29, 2011 – Order on Notices of Penalty – June 29, 2011 Notices of Penalty –The Commission issued an Order stating that it would not further review, on its own motion, the following Notices of Penalty in Docket Nos. NP11-201-000 Lane Electric Cooperative Inc.; NP11-202-000 High Desert Power Project, LLC; NP11-203-000 City of Loveland, Colorado;

NP11-204-000 Unidentified Registered Entity; NP11-205-000 Unidentified Registered Entity; NP11-206-000 Unidentified Registered Entity; NP11-207-000 Troy Energy, LLC; NP11-208-000 Black Hills/Colorado Electric Utility Co.; NP11-209-000 Blachly-Lane Electric Cooperative; NP11-210-000 Indianapolis Power & Light Co.; NP11-211-000 Unidentified Registered Entity; NP11-212-000 Unidentified Registered Entity; NP11-213-000 Unidentified Registered Entity; NP11-214-000 T.E.S. Filer City Station, LP; NP11-215-000 Boise-Kuna Irrigation District; NP11-216-000 Merced Irrigation District; NP11-217-000 High Trail Wind Farm, LLC; NP11-218-000 Unidentified Registered Entity; NP11-219-000 City of Batavia Municipal Electric ; NP11-220-000 Elwood Energy, LLC; NP11-221-000 Columbia Rural Electric Assoc.; NP11-222-000 Luminant Energy Co.; NP11-223-000 Unidentified Registered Entity; NP11-224-000 Alcoa Power Generating Inc.; NP11-225-000 Unidentified Registered Entity; NP11-226-000 Unidentified Registered Entity; NP11-227-000 Springfield Utility Board and NP11-228-000 Administrative Citation NOP.

5. August 2, 2011 – Order Approving Reliability Standard CIP-001-2a Sabotage Reporting with a Regional Variance for Texas Reliability Entity, Inc. Docket No. RD11-6-000

6. August 22, 2011 – Notice of FERC Audit of NERC – The Division of Audits in the Office of Enforcement of FERC commenced an audit of NERC. Docket No. FA11-21-000

7. August 25, 2011 – Letter Order Approving NERC's December 1, 2010 Standards Process Manual Filing in compliance with FERC's September 2010 Order. Docket No RR10-12-001

8. August 29, 2011 – Order on Notices of Penalty – July 28 and July 29, 2011 Notices of Penalty – The Commission issued an Order stating that it would not further review, on its own motion, the following Notices of Penalty in Docket Nos. NP11-229-000 Unidentified Registered Entity; NP11-230-000 Unidentified Registered Entity; NP11-231-000 Ripon Cogeneration LLC; NP11-232-000 The Detroit Edison Company; NP11-233-000 Unidentified Registered Entity; NP11-234-000 Unidentified Registered Entity; NP11-235-000 New Covert Generating Company, LLC; NP11-236-000 Scurry County Wind LP; NP11-237-000 Unidentified Registered Entity; NP11-239-000 Public Utility District No. 1 of Snohomish County; NP11-240-000 Public Service Company of New Mexico; NP11-241-000 Dynegy Inc.; NP11-242-000 Panoche Energy Center LLC; NP11-243-000 Unidentified Registered Entity; NP11-244-000 NextEra Energy Resources, LLC; NP11-245-000 Exelon Generation Co., LLC; NP11-246-000 Scrubgrass Generating Company, LP; NP11-247-000 Unidentified Registered Entity; NP11-248-000 Unidentified Registered Entity; NP11-249-000 Unidentified Registered Entity; NP11-250-000 Unidentified Registered Entity; NP11-251-000 Unidentified Registered Entity; NP11-252-000 Arizona Electric Power Cooperative, Inc.; NP11-253-000 Administrative Citation Notice of Penalty.

9. August 29, 2011 – The Commission issued an order initiating a review of the July 28, 2011 Notice of Penalty for Southwestern Power Administration and established a filing deadline for any answers, interventions or comments. Docket No. NP11-238-000

10. August 29, 2011 – The Commission approves the Stipulation and Consent Agreement between the Office of Enforcement, NERC, and Grand River Dam Authority. Docket No. IN11-7-000

11. September 9, 2011 – The Commission issued an Order stating that it would not further review, on its own motion, the following Notice of Penalty regarding an Unidentified Registered Entity. Docket No. NP11-184-000
12. September 9, 2011 – The Commission issued an Order stating that it would not further review, on its own motion, the following Notices of Penalty in Docket Nos. NP11-254-000 Rochester Public Utilities; NP11-255-000 AES Deepwater, Inc.; NP11-256-000 Progress Energy Florida; NP11-257-000 Optim Energy Marketing, LLC; NP11-258-000 Iberdrola Renewables and NP11-259-000 Western Electricity Coordinating Council.
13. September 15, 2011 – Notice of Proposed Rulemaking proposing to approve the Transmission Relay Loadability Standard PRC-023-2 and accompanying NERC Rules of Procedure modifications. Docket No. RM11-16-000
14. September 15, 2011 – Order No. 754 – Order Approving Interpretation of TPL-002-0 Requirement R1.3.10. Docket No. RM10-6-000; Order No. 754
15. September 15, 2011 – Notice of Proposed Rulemaking on Version 4 CIP Reliability Standards proposed to approve eight modified Critical Infrastructure Protection (CIP) Reliability Standards, CIP-002-4 through CIP-009-4. Docket RM11-11-000
16. September 15, 2011 – Order No. 733-B – Order Denying Reconsideration and Granting Clarification in Part and Denying Clarification in Part regarding the requests for clarification or reconsideration of Order No. 733-A, which addressed requests for rehearing and clarification of FERC's Final Rule on NERC Reliability Standard PRC-023-1 regarding "Relay Loadability." Docket No. RM08-13-004
17. September 15, 2011 – Order Approving Personnel Performance, Training, and Qualification Reliability Standard PER-003-1. Docket No. RD11-7-000
18. September 15, 2011 – Order No. 753 – Order Approving ERO Interpretation of Transmission Operations Reliability Standard TOP-001-1 Requirement R8. Docket No. RM10-29-000; Order No. 753
19. September 21, 2011 – A Technical Conference on Penalty Guidelines to discuss the impact of the guidelines on compliance and enforcement matters will be held on November 17, 2011. Docket No. PL10-4-000
20. September 26, 2011 – Order Approving Interpretations to PRC-004-1 and PRC-005-1. Docket No. RD11-5-000
21. September 26, 2011 – A Technical Conference on CIP-006-2 to explore the risks of leaving dial-up intelligent electronic devices that are part of the Bulk-Power System and that use non-routable protocols physically unprotected will be held on October 25, 2011. Docket No. RD10-8-000
22. September 30, 2011 – Order on Notices of Penalty – August 31, 2011 Notices of Penalty – The Commission issued an Order stating that it would not further review, on its own motion, the following Notices of Penalty in Docket Nos. NP11-260-000 Louisiana Energy and Power Authority; NP11-261-000 Unidentified Registered Entity; NP11-262-000 Unidentified Registered Entity; NP11-263-000 Unidentified Registered Entity; NP11-264-000 Unidentified

Registered Entity; NP11-265-000 Cleco Corporation; and NP11-266-000 Administrative Citation Notice of Penalty.

NERC Filings Since the Last Update

1. July 13, 2011 - Comments in Support of the Supplemental Comments in the July 13, 2011 filing of the Trade Associations (Edison Electric Institute, the American Public Power Association, the National Rural Electric Cooperative Association, the Electric Power Supply Association, the Transmission Access Policy Study Group, and the Canadian Electricity Association) regarding the proposed interpretation of Reliability Standard TPL-002, Requirement R1.3.10. Docket No. RM10-6-000
2. July 15, 2011 - Supplemental Informational Filing regarding the June 29, 2011 Notice of Penalty for an Unidentified Registered Entity. Docket No. NP11-213-000
3. July 18, 2011 - Request for Clarification or, in the Alternative, Rehearing of the Order Denying Appeals of Compliance Registry Determinations of Milford Wind Corridor Phase I, LLC, and Cedar Creek Wind Energy. Docket Nos. RC11-1-001 and RC11-2-001
4. July 20, 2011 - Supplemental Filing for a Notice of Penalty regarding an Unidentified Registered Entity. Docket No. NP11-206-000
5. July 21, 2011 - Filing in Support of the June 20, 2011 compliance filing of the Western Electricity Coordinating Council in Response to Order Numbers 751 and 752 on Version One Regional Reliability Standards. Docket No. RM11-11-000
6. July 21, 2011 - Informational Filing in Response to Order 733-A on Rehearing, Clarification, and Request for an Extension of Time addressing certain aspects of the August 14, 2003 blackout investigation relative to operation of protective relays in response to stable power swings. Docket No. RM08-13-000
7. July 26, 2011 - Informational Report on NERC Standards Status and Timetable for Addressing Regulatory Directives received from applicable ERO governmental authorities. Docket No. RR09-6-003
8. July 28, 2011 – Notices of Penalty regarding the following entities in Docket Nos. NP11-229-000 Unidentified Registered Entity; NP11-230-000 Unidentified Registered Entity; NP11-231-000 Ripon Cogeneration LLC; NP11-232-000 The Detroit Edison Company; NP11-233-000 Unidentified Registered Entity; NP11-234-000 Unidentified Registered Entity; NP11-235-000 New Covert Generating Company, LLC; NP11-236-000 Scurry County Wind LP; NP11-237-000 Unidentified Registered Entity; NP11-239-000 Public Utility District No. 1 of Snohomish County; NP11-240-000 Public Service Company of New Mexico; NP11-241-000 Dynegy Inc.; NP11-242-000 Panoche Energy Center LLC; NP11-243-000 Unidentified Registered Entity; NP11-244-000 NextEra Energy Resources, LLC; NP11-245-000 Exelon Generation Co., LLC; NP11-246-000 Scrubgrass Generating Company, LP; NP11-247-000 Unidentified Registered Entity; NP11-248-000 Unidentified Registered Entity; NP11-249-000 Unidentified Registered Entity; NP11-250-000 Unidentified Registered Entity; NP11-251-000 Unidentified Registered Entity; and NP11-252-000 Arizona Electric Power Cooperative, Inc.

9. July 29, 2011 - Informational Report on Analysis of Standard Process Results for the Second Quarter 2011. Docket Nos. RR06-1-000, RR09-7-000
10. July 29, 2011 – Administrative Citation Notice of Penalty in NP11-253-000.
11. August 11, 2011 - Motion to Further Defer Action on Time Error Correction Reliability Standard. Docket No. RM09-13-000
12. August 11, 2011 – Notices of Penalty regarding the following entities in Docket Nos. NP11-254-000 Rochester Public Utilities; NP11-255-000 AES Deepwater, Inc.; NP11-256-000 Progress Energy Florida; NP11-257-000 Optim Energy Marketing, LLC; NP11-258-000 Iberdrola Renewables and NP11-259-000 Western Electricity Coordinating Council.
13. August 24, 2011 - Request of NERC for Acceptance of 2012 Business Plan and Budget and the 2012 Business Plans and Budget of Regional Entities and for Approval of Proposed Assessments to Fund Budgets. Docket No. RR11-7-000
14. August 31, 2011 - Second Quarter 2011 Compliance Filing in Response to Paragraph 629 of Order No. 693. Docket No. RM06-16-000
15. August 31, 2011 – Notices of Penalty regarding the following entities in Docket Nos. NP11-260-000 Louisiana Energy and Power Authority; NP11-261-000 Unidentified Registered Entity; NP11-262-000 Unidentified Registered Entity; NP11-263-000 Unidentified Registered Entity; NP11-264-000 Unidentified Registered Entity; NP11-265-000 Cleco Corporation; and NP11-266-000 Administrative Citation Notice of Penalty.
16. September 6, 2011 – Supplemental Informational Filing regarding the August 31, 2011 Administrative Citation Notice of Penalty. Docket No. NP11-266-000
17. September 9, 2011 - Petition for Approval of Interpretations to Requirements to Requirements R1 and R3.2 of EOP-001-0 — Emergency Operations Planning (EOP-001-0). Docket No. RM11- 32-000
18. September 13, 2011 - NERC and WECC submit a joint motion for extension of time from September 14, 2011 to November 14, 2011 to allow NERC to submit a compliance filing in response to the Commission's June 16, 2011 Order regarding the registration of Cedar Creek Wind Energy, LLC and Milford Wind Corridor Phase I, LLC. The Commission directed NERC to submit a compliance filing identifying the Reliability Standards and Requirements that will be applicable to Cedar Creek and Milford. Docket Nos. RC11-1-000 and RC11-2-000
19. September 19, 2011Additional Comments in Support of the Notice of Penalty filed on July 28, 2011 regarding Southwestern Power Administration. Docket No. NP11-238-000
20. September 28, 2011 - First Annual Report on Wide-Area Analysis of Technical Feasibility Exceptions. Docket No. RR10-1-000
21. September 30, 2011 - Petition Requesting Approval of New Enforcement Mechanisms and Submittal of Initial Find Fix and Track (FFT) Informational Filing. Docket No. RC11-6-000
22. September 30, 2011 - Notices of Penalty regarding the following entities in Docket Nos. NP11-267-000 Metropolitan Edison Company; NP11-268-000 Electric Reliability Council of

Texas, Inc.; NP11-269-000 Unidentified Registered Entity; and NP11-270 Spreadsheet Notice of Penalty.

23. October 3, 2011 - Motion to Intervene and Comments regarding the appeal of the City of Holland, Michigan Board of Public Works. Docket No. RC11-5-000

Anticipated NERC Filings

1. October 14, 2011 – NERC will file a Petition for Approval of Revised Transmission Planning System Performance Requirements Reliability Standard and Seven Glossary Terms and for Retirement of Six Existing Reliability Standards for the TPL-001-2 standard.
2. November/December 2011 – NERC will submit proposed changes to the NERC Rules of Procedure.
3. November 21, 2011 – NERC must submit comments in response to the September 15, 2011 Transmission Relay Loadability Notice of Proposed Rulemaking. Docket No. RM11-16-000
4. November 21, 2011 – NERC must submit comments in response to the September 15, 2011 Version 4 Critical Infrastructure Protection Reliability Standards Notice of Proposed Rulemaking. Docket No. RM11-11-000
5. December 2011 – Reliability Standards Development Plan: 2012-2014. NERC is required, pursuant to Rule 310 of the NERC Rules of Procedure, to file an updated annual work plan for the development of Reliability Standards. Docket Nos. RM05-25-000, RM05-17-000, RM06-16-000.
6. December 31, 2011 – NERC must submit an informational filing regarding the restructured audit program of the Regional Entities. (see December 23, 2010) Docket Nos. RR09-7-000 and RR10-11-000
7. January 25, 2012 – NERC must submit a filing within one year of the January 25, 2011 effective date of the November 18, 2010 Order regarding the Revision to ERO Definition of the Bulk Electric System. NERC's filing will include a proposed change to the definition of "Bulk Electric System" and corresponding changes to the NERC Rules of Procedure. NERC, Order No. 743, Docket No. RM09-18-000
8. March 15, 2012 – NERC must submit an informational filing, six months from the issuance of the Order No. 754 which approved the interpretation of Requirement R1.3.10 of TPL-002-0, to explain whether there is a further system protection issue that needs to be addressed and if so, what forum and process should be used to address that issue and what priority it should be accorded relative to the other reliability initiatives planned by NERC. Docket No. RM10-6-000
9. April to June 2012 (Second Quarter 2012) – NERC's timeline to address all outstanding issues from Order No. 706 directives, anticipated that NERC will submit next version of CIP Standards to the NERC Board of Trustees. See NERC's May 27, 2011 Response to Data Requests, Response 1 and the 2011-2013 Informational Filing on the Standards Development Plan. Docket Nos. RM05-17-000, RM05-25-000, RM06-16-000 and RM11-11-000

10. May 2012 – NERC must submit a revised BAL-003 Standard (See October 25, 2010 NERC Filing). Docket No. RM06-16-011
11. May 22, 2012 –NERC and WECC will submit a revised Standard that includes the Violation Severity Levels associated with each requirement of the revised BAL-004-WECC-1 Standard (See May 21, 2009 Order) (See November 22, 2010 NERC submittal). Docket No. RM08-12-000
12. May 31, 2012 – NERC's true-up filing for the 2010 business plans and budgets.
13. July to September 2012 (Third Quarter 2012) – NERC's timeline to address all outstanding issues from Order No. 706 directives, anticipated that NERC will file next version of CIP Standards at FERC. See NERC's May 27, 2011 Response to Data Requests, Response 1 and the 2011-2013 Informational Filing on the Standards Development Plan. Docket Nos. RM05-17-000, RM05-25-000, RM06-16-000 and RM11-11-000
14. August 23, 2012 – NERC must address Order No. 693 Directives to consider if EMS application support personnel should be included in training Reliability Standard. Docket No. RM09-25-000
15. February 17, 2013 – NERC must comply with directives in Order No. 733 for filing the test and the results from a representative sample of utilities in each of the three Interconnections (see February 17, 2011 Order No. 733-A). Docket No. RM08-13-001

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda
Board of Trustees

November 3, 2011 | 8:00 a.m.-Noon Eastern
Westin Buckhead Atlanta
3391 Peachtree Road, NE
Atlanta, GA 30326
404-365-0065

Introductions and Chair's Remarks

NERC Antitrust Compliance Guidelines and Public Announcement

Consent Agenda* — Approve

1. **Minutes**
   a. August 4, 2011 meeting
2. **Committee Membership Appointments and Changes**
   a. Critical Infrastructure Protection Committee
   b. Compliance and Certification Committee

Regular Agenda

3. **Comments by Commissioner John Norris**
4. **Comments by Commissioner Cheryl LaFleur**
5. **President's Report**
6. **Reliability Standards*— Approve**
   a. Project 2007-07 – Vegetation Management – FAC-003-2
   b. Reliability Standards Development Plan 2012-2014
   c. MOD-025-RFC-1: Reactive Power Capability
   d. IRO-006-TRE-1: IROL and SOL Mitigation in the ERCOT Interconnection
   a. PRC-006-SERC-1: Automatic Underfrequency Load Shedding (UFLS) Requirements
7. **NERC Rules of Procedure Nonsubstantive Capitalization and Definition Changes — Approve**
8. **Reinstatement of NERC Rules of Procedure Section 402.1.3.2 — Approve**
9. **Amendments to WECC Bylaws, and Reliability Standards Development Procedures — Approve**
10. **Spare Equipment Database — Accept**

11. **Bulk Electric System Definition Project — Review**
12. **Status of Action Items from NERC Three-Year ERO Performance Assessment — Review**
13. **Presentation by Tom Bowe, PJM Interconnection**
14. **Regulatory Update — Information**

Standing Committee Reports (Agenda Item 15)*

a. Compliance and Certification Committee
b. Critical Infrastructure Protection Committee
c. Member Representatives Committee
d. Operating Committee
e. Personnel Certification Governance Committee
f. Planning Committee
g. Standards Committee
h. Electricity Sub-Sector Coordinating Council

Forum and Group Reports (Agenda Item 16)*

a. North American Energy Standards Board
b. Regional Entity Management Group
c. North American Transmission Forum
d. North American Generator Forum

Board Committee Reports

17. **Corporate Governance and Human Resources**
    a. Establishment of 457(b) Plan **— Approve**
18. **Compliance**
19. **Nominating**
20. **Finance and Audit**
    a. Review and Accept Statement of Activities; Year End Projection **— Accept**
    b. Risk Management Framework **— Approve**
21. **Standards Oversight and Technology**

*Background materials included.

Antitrust Compliance Guidelines

I. General

It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition.

It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

II. Prohibited Activities

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

- Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

III. Activities That Are Permitted

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation, Bylaws, and Rules of Procedure are followed in conducting NERC business.

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of the mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.
- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.
- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.

Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

Draft Minutes
Board of Trustees

August 4, 2011 | 8:00 a.m.-Noon PT
Vancouver Marriott Pinnacle
1128 West Hastings Street
Vancouver, BC VE 4R5 Canada

Chair John Q. Anderson called to order a duly noticed meeting of the North American Electric Reliability Corporation Board of Trustees on August 4, 2011 at 8 a.m., local time, and a quorum was declared present. The Agenda and list of attendees are attached as **Exhibits A** and **B**, respectively.

NERC Antitrust Compliance Guidelines
David Cook, senior vice president and general counsel, directed participants' attention to the NERC Antitrust Compliance Guidelines included in the agenda.

Executive Session
Chairman Anderson reported that, as is its custom, the board met in executive session before the open meeting, without the chief executive officer present, to review management activities.

Consent Agenda
On motion of President and CEO Gerry Cauley, the board approved the consent agenda, as follows:

Minutes
The board approved the following draft minutes (**Exhibit C**):

- May 24, 2011 Conference Call
- May 11, 2011 Meeting

Committee Membership Appointments and Charter Changes
The board approved the proposed nominations to the membership of the Compliance and Certification, Operating, and Planning Committees (**Exhibit D**).

Future Meetings
The slate of approved meetings dates is attached as **Exhibit E.**

President's Report

In lieu of his standard President's Report, Mr. Cauley stated that he would be focusing on four main topics derived from the constructive conversations held at the Member Representatives Committee meeting held the prior day. The first item Mr. Cauley addressed was the Compliance Application Notices (CANs) Program. NERC staff will review and revise existing CANs to ensure they provide clear, concise guidance for auditors to use consistently across the Regions. Mr. Cauley stated a process guide document also is being developed to provide more transparency to the effort. The board will review the CAN process again in November.

Next, Mr. Cauley addressed the NERC Rules of Procedure changes that have been planned but were not effectively communicated to the industry. Mr. Cauley recommends reviewing the changes and separating them as non-substantive and substantive changes and adjusting deadlines accordingly providing then necessary avenues for posting and effective communication.

The third topic of discussion was the compliance enforcement initiative. Mr. Cauley observed that the initiative differentiates issues of noncompliance based on the level of potential risk to the reliability of the bulk power system. This new initiative is designed to refocus efforts on reliability excellence, eliminate undue regulatory burdens, streamline paperwork requirements, increase caseload processing, and encourage continued timely and thorough self-reporting and mitigation. Mr. Cauley stated that NERC was still on target for the late September filing, but acknowledges the communication around the initiative was deficient and he requests and welcomes input from the trades, commission, and industry stakeholders.

Finally, Mr. Cauley spoke to the Bulk Electric System Definition project. Mr. Cauley stated he has concerns based on the conversation during the Member Representatives Committee meeting. Mr. Cauley offered a motion to the board to direct the Standards Committee and the standard drafting team to consider feedback received during the meeting while drafting the Bulk Electric System standard, and to submit a draft of the proposed standard and technical justification to the board by September 9. Following discussion, the board approved the following resolution:

> In furtherance of the Board's oversight of the standards development process and in anticipation of the Board's ultimate responsibility to determine whether the revised definition of "Bulk Electric System" that emerges from the standards development process should be approved and filed with the Federal Energy Regulatory Commission no later than January 25, 2012, as NERC's response to the directives in Order No. 743, the Board:
>
> (1) directs the Standards Committee and the Standard Drafting Team to consider the feedback heard at the August 4, 2011 board meeting regarding the development of the Bulk Electric System definition; and
> (2) further directs that the Standards Committee submit to the Board by September 9, 2011:
>
> (a) the draft of the proposed Bulk Electric System definition as it exists on that date;

(b) the best justification that the Standard Drafting Team has prepared to support the change in generator threshold from 20 MVA to 75 MVA; and

(c) an options paper that addresses possible options for moving forward with the development of the proposed definition and responding to the Commission by the January 25, 2012 deadline; and

(3) expects the Standards Drafting Team to continue its work on the Bulk Electric System definition.

Reliability Standards

Herb Schrayshuen, vice president and director of standards, gave a presentation on the Reliability Standards Program (**Exhibit F**) and presented the following items for board action.

Project 2006-02 – Assess Transmission Future Needs and Develop Transmission Plans

On motion of Fred Gorbet, the board approved the following resolutions:

RESOLVED, that the board approves the TPL-001-2 – Transmission System Planning Performance Requirements Reliability Standard (**Exhibit G**);

FURTHER RESOLVED, that the board approves the associated implementation plan, which provides the following (**Exhibit H**):

(a) An effective date for the requirements associated with establishing responsibility for conducting the assessments and maintaining the models (Requirements R1 and R7) effective the first day of the first calendar quarter 12 months after regulatory approval (or the first day of the first calendar quarter 12 months after board approval where regulatory approval is not required);

(b) An effective date for the requirements associated with developing, performing, and or validating new and/or modified studies, methodologies, assessments, and procedures necessary to implement and meet the TPL-001-2 requirements and allow sufficient time to create a viable Corrective Action Plan (Requirements R2, R3, R4, R5, R6, and R8) effective 24 months after regulatory or board approval.

(c) Retirement of the following standards at midnight of the day immediately prior to the effective date of TPL-001-2:

- TPL-001-1
- TPL-002-1b
- TPL-003-1a
- TPL-004-1

- TPL-005-0
- TPL-006-0.1

FURTHER RESOLVED, that the board approves the following new definitions included in the TPL-001-2 Reliability Standard, to become effective the first day of the first calendar quarter 12 months after applicable regulatory approval; where regulatory approval is not required, all five definitions to become effective 12 months after board adoption:

- Bus-tie Breaker
- Consequential Load Loss
- Long-Term Transmission Planning Horizon
- Non-Consequential Load Loss
- Planning Assessment

FURTHER RESOLVED, that the board approves the Violation Risk Factors and Violation Severity Levels for the proposed TPL-001-2 Reliability Standard (**Exhibit I**);

FURTHER RESOLVED, that NERC Staff shall make the appropriate filings with ERO governmental authorities.

Project 2006-06 – Reliability Coordination
On motion of Paul Barber, the board approved the following resolutions:

RESOLVED, that the board approves the IRO-002-3 – Reliability Coordination – Analysis Tools; the IRO-005-4 – Reliability Coordination – Current Day Operations; and the IRO-014-2 – Coordination Among Reliability Coordinators Reliability Standards (**Exhibit J**);

FURTHER RESOLVED, that the board approves the associated implementation plans, which provide the following (**Exhibit K**):

(1) An effective date for IRO-002-3, IRO-005-4, and IRO-014-2 effective the first day of the first calendar quarter 12 months after applicable regulatory approval or where no regulatory approval is applicable, the first day of the first calendar quarter 12 months after Board of Trustees approval;
(2) The retirement of IRO-002-2 at midnight of the day immediately prior to the effective date of IRO-002-3;

(3) The retirement of IRO-005-3a at midnight the day immediately prior to the effective date of IRO-005-4;

(4) The retirement of IRO-014-1, IRO-015-1, and IRO-016-1 at midnight the day immediately prior to the Effective Date of IRO-014-2.

FURTHER RESOLVED, that the board approves the revised definition of "Adverse Reliability Impact" included in the IRO-014-2 Reliability Standard;

FURTHER RESOLVED, that the board approves the Violation Risk Factors and Violation Severity Levels for the IRO-002-3, IRO-005-4, and IRO-014-2 Reliability Standards (**Exhibit L**);

FURTHER RESOLVED, that NERC Staff shall make the appropriate filings with ERO governmental authorities.

Planning Committee Strategic Plan and Charter

Mark Lauby, vice president and director of reliability assessment and performance analysis reviewed the Planning Committee Strategic Plan and Charter (**Exhibit M**).

On motion of Ken Peterson, the board approved the following resolution:

WHEREAS, in December 2010, the Planning Committee appointed an *ad hoc* team to review the Planning Committee's Strategic Plan and recommend changes needed to align activities with the NERC ERO enterprise's strategic plan and top priority issues; and

WHEREAS, the Planning Committee approved the 2011-2016 Strategic Plan and resulting charter changes at its June 7-8, 2011 meeting;

RESOLVED, that the board approves the Planning Committee 2011-2016 Strategic Plan and the revised Planning Committee Charter, to replace the charter approved by the Board of Trustees on February 16, 2010.

Generating Availability Data System: Section 1600 Data Request

Mr. Ben Crisp, gave a presentation on the Generating Availability Data System: Section 1600 Data Request (**Exhibit N**). Mr. Crisp reviewed the impacts to the grid, the performance analysis, and recommended the approval of the Section 1600 data request. On motion of Tom Berry, the board approved the following resolution:

WHEREAS, in June 2010, the Planning Committee created the Generating Availability Data System Task Force ("GADSTF") to review and recommend the reporting by Generator Owners on NERC's Compliance Registry of GADS data on a mandatory basis; and

WHEREAS, on March 21, 2011, NERC posted the proposal for mandatory reporting by Generator Owners for a 45-day public comment period as required by Section 1600 of NERC's Rules of Procedure; and

WHEREAS, the GADSTF evaluated the 39 sets of comments received and made appropriate revisions to the proposal in light of the comments received and submitted its final recommendations and report to the Planning Committee; and

WHEREAS, on June 8, 2011, the Planning Committee endorsed the final recommendations and report by the GADSTF for consideration and approval by NERC's Board of Trustees;

RESOLVED, that the board approves the report *Generator Availability Data System: Mandatory Reporting of Conventional Generation Performance Data* **(Exhibit D)**, to be issued as a mandatory data and information request to Generator Owners on NERC's Compliance Registry under Section 1600 of the NERC Rules of Procedure.

2011 Risk Assessment of Reliability Performance

Mr. Lauby provided the 2011 Risk Assessment of Reliability Performance (**Exhibit O**) and recommended board approval. On motion of Tom Berry, the board approved the following resolution:

WHEREAS, NERC, in collaboration with the Reliability Metrics Working Group, the Transmission Availability Data System Working Group, the Generating Availability Data System Task Force, and the Event Analysis Working Group, jointly developed the *2011 Risk Assessment of Reliability Performance* report; and

WHEREAS, the Planning and Operating Committees endorsed the report on July 11, 2011 and July 19, 2011, respectively;

RESOLVED, that the board approves the 2011 *Risk Assessment of Reliability Performance* report for use, among other things, as input to NERC's Reliability Standards and project prioritization, compliance process improvement, event analysis, reliability assessment, and critical infrastructure protection areas.

Regional Delegation Agreement Metrics

Dave Nevius, senior vice president, delivered a presentation on the Regional Delegation Agreement Metrics (**Exhibit P**) and recommended board approval. On motion of Paul Barber, the board approved the following resolution:

WHEREAS, NERC and the Regional Entities developed Regional Delegation Agreement Metrics as a first step in measuring how NERC and the Regional Entities carry out their respective roles under the Regional Delegation Agreements, Rules of Procedure, and applicable regulations,

RESOLVED, that the board approves the Regional Delegation Agreements Metrics for initial use by NERC and the Regional Entities.

Standing Committee Reports

Compliance and Certification Committee

Mr. Terry Bilke provided the Compliance and Certification Committee (CCC) report on behalf of Chair Clay Smith. Mr. Bilke referred to the written report (**Exhibit Q**) included in the Board's agenda package. Further, Mr. Bilke presented the Criteria for Annual Regional Entity Program Evaluation (**Exhibit R**) for board action.

On motion of Ken Peterson, the board approved the following resolutions:

> RESOLVED, that the board approves the Criteria for Annual Regional Entity Program Evaluation CCCPP-010-1 for consideration in developing NERC's annual Regional Entity program evaluation.(Exhibit G-1);
>
> FURTHER RESOLVED, that the board accepts the 2011 Summary Report of NERC Program Monitoring – Self Certifications (Exhibit G-2).

Critical Infrastructure Protection Committee

Barry Lawson, chair, highlighted items from the committee's written report to the board (**Exhibit S**).

Critical Infrastructure Strategic Initiative – Coordinated Action Plan Activities. The CIPC, Operating Committee (OC) and Planning Committee (PC) officers and NERC staff continue to direct and manage the coordinated action plan activities as they relate to the recently created task forces. The committee leadership accomplishes this work via conference calls and in-person meetings as needed.
Classified Briefing for CIPC and Other Industry Participants. The CIPC and NERC staff continue to work with DHS and DOE staff to plan for a Secret level classified briefing for CIPC members and other industry participants in conjunction with the December 2011 CIPC meeting planned for Atlanta. We will work with our government partners to encourage the provision of quality take-away information that can be shared with industry outside of a classified environment. The efforts by DHS and DOE in this area are very much appreciated and further the goal of increasing the value of the public-private partnership.

CIPC Executive Committee Review of Draft NERC Alerts. The CIPC Executive Committee has reviewed and provided feedback to NERC staff on CIP-related draft Alerts. This industry stakeholder review provides NERC with beneficial and quick feedback on draft Alerts before they are finalized and issued to industry. We remain ready to provide requested feedback to NERC staff as needed on future draft Alerts.

CIPC Continues to Provide a Venue for All Electricity Sector Entities to Discuss CIP Matters. The CIPC meetings provide opportunity for significant and needed discussion on various critical infrastructure protection matters, including those related to the CIP standards,

copper theft, recent NERC Alerts, communications with government partners, and other physical, operational and cyber security areas of concern.

CIPC Long-Term Strategic Plan. The CIPC will begin work on developing a long-term strategic plan that will use similar plans from other standing committees as a guide/model. The goal is to have such a plan before the CIPC for approval in the first quarter of 2012.

Member Representatives Committee
Bill Gallagher, chair reported to the board a summary of the matters presented during the Member Representatives Committee.

Operating Committee
Tom Bowe, chair, opened his remarks extending his sincerest thanks to Mr. Sam Holeman for his outstanding leadership of the Operating Committee. Mr. Bowe referenced the lessons learned presented by Mr. Tom Galloway stating that the committee is very proud of the progress and work completed. Mr. Bowe ended his presentation stating further details on the actions of the committee can be found in their written report to the board (**Exhibit T**).

Personnel Certification Governance Committee
Jake Burger, chair, presented the report for the Personnel Certification Governance Committee stating that as of June 30, 2011 there were 6,000 certified associates, that the pass rate on the exams is at 69.8 percent, and there were 282 new credentials issued. The Exam Working Group is developing the next version of exams and are targeting a release during the first quarter 2012. Additional activities can be found in their written report (**Exhibit U**).

Planning Committee
Jeff Mitchell, chair, open his remarks extending his appreciation to Tom Burgess for his exemplary work with the Planning Committee. Mr. Mitchell stated the Gas Electric Interdependency Report would be reviewed at the Planning Committee meeting in September and that the committee was also working on the Post Winter Assessment Report.
Standards Committee
Allen Mosher, chair, stated he had no further items to review and had provided his comments during the Member Representatives Committee and Board f Trustees meetings on respective items.

Electricity Sub-Sector Coordinating Council
Gerry Cauley, chair, referred to the written report to the board (**Exhibit V**) and stated he had no further comments.

Board Committee Reports

Corporate Governance and Human Resources

Chair Janice Case provided a summary report of the Corporate Governance and Human Resources Committee (CGHRC) closed and open meetings held on August 3. Chair Case reviewed the proposed Workers, Retiree and Employee Recovery Act of 2008 Amendment requesting board approval and on motion of Roy Thilly the board approved the following resolution:

> RESOLVED, that the board approves the proposed Workers, Retiree and Employee Recovery Act of 2008 Amendment to NERC's prototype 401(k) plan, as recommended by Vanguard (**Exhibit W**).

Chair Case also reviewed changes to Finance and Audit Committee mandate requesting board approval. On motion by Vicky Bailey the board approved the following resolution:

> RESOLVED, that the board approves the proposed amendments to the mandate of the Finance and Audit Committee (**Exhibit X**).

Nominating Committee

Chair David Goulding reported that the Nominating Committee will be producing a summary report and will bring to the Member Representatives Committee in December.

Finance and Audit Committee

Chair Fred Gorbet stated he had two items for consideration (**Exhibits Y and Z**). Following discussion of the 2012 business plan and budget, on motion of Fred Gorbet, the board approved the following resolutions:

> RESOLVED, that the Board of Trustees approves the following, substantially in the form presented:
>
> (1) the proposed NERC 2012 business plan and budget (Exhibit I-1);
>
> (2) the proposed 2012 business plans and budgets of the eight regional entities and the Western Interconnection Regional Advisory Board (Exhibit I-2); and
>
> (3) the proposed 2012 assessments to recover the costs of the approved 2012 budgets, subject to adjustments to reflect final NEL numbers (Exhibit I-3).
>
> FURTHER RESOLVED, that management is directed to file the 2012 business plans, budgets and assessments with ERO governmental authorities, together with such additional explanatory material as is appropriate.

Chair Gorbet also reviewed the current status of the Risk Management Framework noting that a new committee will not be formed but that a subcommittee of the Finance and Audit Committee would be formed comprising Finance and Audit Committee members along with non-trustee members. The

framework will be put out for comment and reviewed during the Finance and Audit Committee conference call on October 27, 2011.

Standards Oversight and Technology Committee
Chair Peterson provided a brief review of the actions of the committee the day prior.

Closing
Chair Anderson thanked the industry for their attendance and their continued support. He reconfirmed that the policy input is beneficial to the board and requests that the industry members continue to submit their comments.

Adjournment
There being no further business, Chair Anderson terminated the meeting at 11:15 a.m.

Submitted by,

David N. Cook
Corporate Secretary

Agenda Item 2a
Board of Trustees Meeting
November 3, 2011

Critical Infrastructure Protection Committee
Membership Appointments and Changes

Action

Approve the following committee membership appointments and changes.

Officers

- Chair Elect: Chuck Abell
- Vice Chair Elect: Jim Brenton, Nathan Mitchell

(Chair and Vice Chair positions effective January 1, 2012)

CIPC Roster

Representing	Name	Affiliation	Discipline
TRE	Jim Brenton	ERCOT	Cyber
TRE	David Grubbs	City of Garland	Operations
TRE	Scott Rosenberger	Luminent	Physical
FRCC	Paul McClay	TECO	Cyber
FRCC	Rich Powell	JEA	Physical
FRCC	Darren Myers	Progress	Operations
MRO	Marc Child	Great River	Cyber
MRO	Paul Crist	LES	Physical
MRO	Rick Liljegren	MN Power	Operations
NPCC	Mike Puscas	NU	Operations
NPCC	John Lim	ConEd	Cyber
NPCC	Benoit Tardif	HQ	Physical
RFC	Larry Bugh	RFC	Cyber
RFC	Kent Kujala	Detroit	Operations
RFC	Jeff Fuller	DPL	Physical
SERC	Chuck Abell	Ameren	Operations
SERC	Cark Eng	Dominion	Cyber
SERC	Mark Engels	Dominion	Physical
SPP	John Breckenridge	KCPL	Physical
SPP	Allen Klassen	Westar	Operations
SPP	Robert McClanahan	AECC	Cyber
WECC	Scott Bordenkircher	APS	Physical
WECC	Robert Matthews	PGE	Cyber
WECC	Jamie Sample	PGE	Operations
APPA	David Godfrey	TMPA	
APPA	Nathan Mitchell	APPA	
CEA	Chris McColm	Manitoba	
CEA	Ross Johnson	Capital Power	
NRECA	Robert Richhart	Hooser	
NRECA	Barry Lawson	NRECA	

Agenda Item 2b
Board of Trustees Meeting
November 3, 2011

Compliance and Certification Committee Membership Appointment and Change

Action

Approve the nomination to the Compliance and Certification Committee (CCC) of **Ms. Jana Van Ness** of Arizona Public Service to represent the Investor-Owned Utility sector for a three-year term beginning December 31, 2011.

Summary and Background

The CCC, a stakeholder Committee of NERC comprising 26 members representing various industry sectors, serves and reports directly to the NERC Board of Trustees. The CCC is responsible for engaging with, supporting, and advising the NERC Board and NERC Compliance staff regarding all facets of the NERC Compliance Monitoring and Enforcement Program, the NERC Organization Registration Program, and the NERC Organization Certification Program.

Agenda Item 6
Board of Trustees Meeting
November 3, 2011

Reliability Standards

Action
Approve or discuss reliability standards and plans as follows:

a. Project 2007-07 – Vegetation Management – FAC-003-2 — **Approve**
b. Reliability Standards Development Plan 2012-2014 — **Approve**
c. MOD-025-RFC-1: Reactive Power Capability — **Approve**
d. IRO-006-TRE-1: IROL and SOL Mitigation in the ERCOT Interconnection — **Approve**
e. PRC-006 –SERC-1 - Automatic Underfrequency Load Shedding (UFLS) Requirements — **Approve**

6a. Project 2007-07 Vegetation Management – FAC-003-2

Action

Approve the following standards documents and direct staff to file with applicable regulatory authorities:

- **Reliability Standard FAC-003-2 - Transmission Vegetation Management** (FAC-003-2) effective consistent with the Implementation Plan for FAC-003-2

  [FAC-003-2-clean] [Redline not available due to extent of changes.]
  [Clean version of previously approved standard FAC-003]

- **Industry Proposed Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for FAC-003-2:**

  [Included in the Standard above] [Staff VSL proposal redlined against Industry Proposal-Sent as separate attachment]

  ***The Standards Staff has proposed alternative VSLs–discussion below**

  Implementation Plan for FAC-003-2: [Implementation Plan]

  FAC-003-2 is proposed to be effective on the first day of the first calendar quarter one year after the date of regulatory approval in order to provide entities time to make revisions to their existing transmission vegetation management programs to comply with the new requirements.

- **Definitions:** [Definitions – Clean and Redline]
  - Right-of-Way
  - Vegetation Inspection
  - Minimum Vegetation Clearance Distance (MCVD)

  All three definitions become effective on the first day of the first calendar quarter one year after the date of regulatory approval.

- **Retirements:**
  Retire the following at midnight of the day immediately prior to the effective date of FAC-003-2:
  - FAC-003-1 Transmission Vegetation Management Program (FAC-003-1)
  - Definition of Right-of-Way
  - Definition of Vegetation Inspection

Background

The currently approved vegetation management standard (FAC-003-1) was approved by the Commission in Order No. 693 on March 16, 2007. Project 2007-07 Vegetation Management was initiated on June 27, 2007 to review and modify FAC-003-1.

The proposed FAC-003-2 standard embodies a defense-in-depth approach to improve the reliability of the electric Transmission System by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance;
- Requiring documentation of the maintenance strategies, procedures, processes, and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods, and the inspection frequency;
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment;
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constraints such as legal injunctions;
- Requiring annual inspections of vegetation conditions; and
- Requiring completion of the annual work needed to prevent flash-over.

The standard drafting team summarized the improvements to the standard from the previous version as follows:

- It removes the "fill-in-the-blank" ambiguity previously contained in FAC-003-1.
- It separates performance requirements (R1, R2, R4, R5, R6, and part of R7) from documentation requirements (R3 and the remainder of R7), and minimizes the burden of those documentation requirements.
- It has explicit and therefore clearer expectations to manage vegetation to: 1) prevent observable vegetation encroachments inside the Minimum Vegetation Clearance Distance (MVCD) and 2) prevent a confirmed Fault even in the absence of a Sustained Outage (R1, R2).
- It places more emphasis on those lines that pose the greatest risk to the reliability of the interconnected transmission system. This is accomplished by converting the previous FAC-003-1 R1 into the new R1 and R2 and assigning the high VRF to the more important lines in R1.
- It requires the management of vegetation to prevent encroachments by specific types, which are indicative of the quality of that management. Those quality-related encroachment types also allow more specificity for determining the severity level of a violation.
- It establishes a clear, industry proven method for calculating flash-over distance (clearance) that is not subject to external standards established for other purposes (through use of the Gallet Equations to establish the MVCD).
- It has an unambiguous expectation for Vegetation Inspection intervals.
- It separates inspections and communications of imminent threats into individual and clearer requirements that can be appropriately weighted by VRFs and VSLs (both of these items were previously addressed in sub-requirements of FAC-003-1 R1).

- It correctly moves reporting obligations from the requirements section (FAC-003-1 R3) to the Additional Compliance Information Section.
- It has additional supporting text in the Background, Rationale, and Guidelines and Technical Basis sections to aid the industry in using the standard and understanding conductor dynamics and the interrelationship of vegetation growth, inspection frequencies, and vegetation control methods.
- It requires vegetation be managed with equal rigor over all lands regardless of the ownership of those lands.

Directives

The drafting team for Project 2007-07 Vegetation Management addressed eight directives from FERC Order No. 693. For a summary of the directives and the drafting team's responses, please see Consideration of Issues and Directives document.

Standard Development Process

FAC-003-2 was processed through the normal standards development process, which included six postings for stakeholder comment over a three-year period, an initial ballot, a successive ballot, and a recirculation ballot. The changes made between comment periods improved the clarity of the requirements and modified other requirements. A comparison of the currently-approved version of the standard against the latest posted draft of the proposed standard results in some requirements that are more stringent, and others that are less stringent.

The drafting team prepared several documents to explain its rationale and justification for the approaches it took; however, there were several unresolved minority issues:

- The "Purpose" section of proposed FAC-003-2 focuses on managing vegetation on rights-of-way that could lead to cascading outages. Some commenters indicated the purpose in the already approved version of the standard is more appropriate as it includes preventing a wider range of vegetation related outages, and includes vegetation from outside rights-of-way that could impact transmission lines.
    - The team indicated that the ERO's responsibility is to develop standards that prevent cascading, uncontrolled separation, and instability.
- The proposed FAC-003-2 uses Gallet equations to define the Minimum Vegetation Clearance Distance (MVCD) referenced in Requirements R1, R2, R3, R5 and R7. While the Gallet equations identify a minimum flash-over clearance, some commenters expressed concern that defining the MVCD to be equal to the flash-over distance as determined by the Gallet equations does not provide any built in safety factor.
    - The team indicated that, while there is no explicit "margin" established in Requirement R3, the standard requires the entity to establish procedures it uses to prevent encroachments for all Ratings and Rated Operating Conditions, and that those procedures account for conductor movement and vegetation growth. This effectively replaces "Clearance 1" from the existing standard. Combined with R1 and R2, this obliges entities to maintain vegetation appropriately without using a one-size-fits-all approach.

- Some commenters felt the proposed Requirement R7 in FAC-003-2 is not enforceable as written. Requirement R7 sets the requirement for each Transmission Owner to complete 100 percent of its annual vegetation work plan; however, there is no requirement in FAC-003-2 for an entity to develop or have a documented annual plan for vegetation management. In addition, Requirement R7 provides a list of examples for modification to the "annual plan" providing entities with a number of reasons, such as contractor unavailability and changes in land ownership, for not completing 100 percent of the plan.
    - The team included the list of exemptions to ensure that Transmission Owners are not penalized for a failure to complete the work in their annual plan as long as the changes to the plan did not lead to any vegetation-related encroachments into the MVCD.
- Proposed Requirement R3 lacks specificity and requires entities to have "maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable transmission lines" but does not require an entity to have a formal documented work plan for vegetation management.
    - The team interpreted Requirement R3 as a "results-based" requirement that specified "what" without specifying the details of "how". As a results-based standard, this requirement focuses on what is needed without requiring an explicit format.
- The proposed FAC-003-2 excludes vegetation fall-ins and blow-ins from outside the right-of-way on the basis that they are not preventable, an assertion that some stated is incorrect as it does not account for situations where a Transmission Owner has the legal right to manage vegetation outside the defined right-of-way. Most (81 percent) of the vegetation-related sustained outages reported by Transmission Owners since 2008 have involved vegetation falling into transmission lines from outside the right-of-way.
    - The team did not include fall-ins from outside the right-of-way because not all Transmission Owners have legal access to manage vegetation outside the right-of-way. While it would be desirable to deal with all possible transgressions from outside the right-of-way, the uncertainty in forecasting when an apparently sound tree off the right-of-way may fall and the contentious nature of dealing with these trees makes a requirement to handle all of them impractical.
- The separation of IROL (any voltage level) and non-IROL (200 kV and above) Transmission Lines into separate requirements with different VRFs, which some stated to be inappropriate, and limiting of the NERC Compliance Monitoring and Enforcement Program (CMEP) by creating two separate requirements with similar purposes but covering different categories of equipment.
    - The team divided the requirements and the types of vegetation-related outages to bring the anticipated penalties in line with the reliability-related risk of different types of vegetation-related encroachments. This is consistent with FERC VRF Guideline 5.

- Some commenters stated the force majeure provisions are unnecessary and call into question whether NERC and the regions have enforcement discretion to take such things into account as part of the CMEP.
    - The team included the force majeure provisions to prevent Transmission Owners from having to develop burdensome self-reports of violations for conditions that were outside their control. Explicitly noting these concerns should not have any impact on enforcement discretion related to this or any other standard.

Proposed VRFs and VSLs

The non-binding poll of the drafting team's proposed VRFs and VSLs achieved a quorum with 77 percent of those who registered to participate in providing an opinion and 79 percent of those who provided an opinion indicated support for the VRFs and VSLs that were proposed by the drafting team.

NERC's standards staff recommends approval of all the VRFs and all of the VSLs for Requirements R3 through R7 that were developed by the drafting team, but recommends approval of alternative VSLs developed by the standards staff for R1 and R2. Requirements R1 and R2 require management of vegetation to prevent encroachment into the MVCD and sustained outages from vegetation-related fall-ins, contacts from vegetation and lines blowing together, and contacts from vegetation growth. The drafting team proposed graduated VSLs for both Requirements R1 and R2 as follows:

- Lower VSL for encroachment into the MVCD without a sustained outage
- Medium VSL for a fall-in from within the right-of-way that leads to a sustained outage
- High VSL for a contact caused by vegetation and lines blowing together that leads to a sustained outage
- Severe VSL for a vegetation contact that leads to a sustained outage

The drafting team proposed that its VSLs indicate how poorly a vegetation management program met its goal of preventing encroachment into the MVCD, assuming that the vegetation management program includes different tasks, with different knowledge and skill requirements, and a failure to meet performance associated with more complex tasks would be a more severe indication of a program failure and should be assigned a higher VSL. The method of assigning VSLs proposed by the drafting team does not meet NERC's VSL guidelines. NERC's guidelines assign VSLs based on how well the performance measured meets the reliability-related intent of the associated requirement. In this case, the reliability intent of both R1 and R2 is to prevent encroachment into the MVCD.

The standards staff proposes a High VSL for failure to prevent encroachment into the MVCD that doesn't lead to a sustained outage and a Severe VSL for failure to manage vegetation that leads to any of the identified vegetation-related sustained outages.

- A High VSL represents noncompliant performance that misses a significant part of the reliability intent of the requirement. Each Transmission Owner establishes the MVCD and has an obligation under R1 and R2 to prevent vegetation from entering into this flashover distance. If vegetation does enter this MVCD, this indicates that the program wasn't managed to the point where it met its objective. While partial credit should be provided for preventing actual contact between vegetation and lines, the reliability

objective of preventing encroachment into the MVCD was missed by a significant margin.

- A Severe VSL represents noncompliant performance that totally or mostly misses the reliability intent of the requirement. In any situation where vegetation under the control of the transmission owner was not managed to the point where there was contact that led to a sustained outage, the reliability intent of the requirement was totally missed.

The staff proposed alternative VSLs were posted for stakeholder comment with the VSLs proposed by the drafting team from June 17-July 17, 2010. Forty-five sets of comments were submitted, representing views of more than 100 different people from over 50 companies, representing seven of the 10 industry segments. While some stakeholders did not indicate a preference for one set of VSLs over another, stakeholders overwhelmingly (by more than a two to one margin) indicated a preference for the VSLs proposed by the drafting team.

A link to the project history and files is included here for reference:
http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

If trustees have questions or need additional information, they may contact Herb Schrayshuen at herb.schrayshuen@nerc.net.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SC approved SAR for initial posting (January 11, 2007).
2. SAR posted for comment (January 15–February 14, 2007).
3. SAR posted for comment (April 10–May 9, 2007).
4. SC authorized moving the SAR forward to standard development (June 27, 2007).
5. First draft of proposed standard posted (October 27, 2008-November 25, 2008)).
6. Second draft of revised standard posted (September 10, 20-October 24, 2009).
7. Third draft of revised standard posted (March 1, 2010-March 31, 2010).
8. Fourth draft of revised standard posted (June 17, 2010-July 17, 2010).
9. Fifth draft of revised standard posted (February 18, 2011-February 28, 2011)
10. Sixth draft of revised standard posted (September xx - 2011)

Proposed Action Plan and Description of Current Draft

This is the fourth posting of the proposed revisions to the standard in accordance with Results-Based Criteria and the sixth draft overall.

Future Development Plan

Anticipated Actions	Anticipated Date
Recirculation ballot of standards.	September 2011
Receive BOT approval	November 2011

Effective Dates

This standard becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval is required. Where no regulatory approval is required, the standard becomes effective on the first calendar day of the first calendar quarter one year after Board of Trustees adoption.

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.

2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.

3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.

4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.

5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

Version History

Version	Date	Action	Change Tracking
1	TBA	1. Added "Standard Development Roadmap." 2. Changed "60" to "Sixty" in section A, 5.2. 3. Added "Proposed Effective Date: April 7, 2006" to footer. 4. Added "Draft 3: November 17, 2005" to footer.	01/20/06
1	April 4, 2007	Regulatory Approval — Effective Date	New
2			

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Right-of-Way (ROW)
The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria.

The current glossary definition of this NERC term is modified to address the issues set forth in Paragraph 734 of FERC Order 693.

Vegetation Inspection
The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.

Current definition of Vegetation Inspection: The systematic examination of a transmission corridor to document vegetation conditions.

Minimum Vegetation Clearance Distance (MVCD)
The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.

A. Introduction

1. **Title:** Transmission Vegetation Management

2. **Number:** FAC-003-2

3. **Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

4. **Applicability**

   4.1. Functional Entities:

   4.1.1 Transmission Owners

   4.2. Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities:

   4.2.1. Each overhead transmission line operated at 200kV or higher.

   4.2.2. Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.

   4.2.3. Each overhead transmission line operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

   4.2.4. Each overhead transmission line identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

Rationale: The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) NERC has a project in place to address at a later date the applicability of this standard to Generation Owners. 4) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies."*

Enforcement:
The Requirements within a Reliability Standard govern and will be enforced. The Requirements within a Reliability Standard define what an entity must do to be compliant and binds an entity to certain obligations of performance under Section 215 of the Federal Power Act. Compliance will in all cases be measured by determining whether a party met or failed to meet the Reliability Standard Requirement given the specific facts and circumstances of its use, ownership or operation of the bulk power system.

Measures provide guidance on assessing non-compliance with the Requirements. Measures are the evidence that could be presented to demonstrate compliance with a Reliability Standard Requirement and are not intended to contain the quantitative metrics for determining satisfactory performance nor to limit how an entity may demonstrate compliance if valid alternatives to demonstrating compliance are available in a specific case. A Reliability Standard may be enforced in the absence of specified Measures.

Entities must comply with the "Compliance" section in its entirety, including the Administrative Procedure that sets forth, among other things, reporting requirements.

The "Guideline and Technical Basis" section, the Background section and text boxes with "Examples" and "Rationale" are provided for informational purposes. They are designed to convey guidance from NERC's various activities. The "Guideline and Technical Basis" section and text boxes with "Examples" and "Rationale" are not intended to establish new Requirements under NERC's Reliability Standards or to modify the Requirements in any existing NERC Reliability Standard. Implementation of the "Guideline and Technical Basis" section, the Background section and text boxes with "Examples" and "Rationale" is not a substitute for compliance with Requirements in NERC's Reliability Standards."

5. Background:

This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

a) Performance-based — defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome*?

b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system*?

c) Competency-based — defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what*

conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term "public lands" includes municipal lands, village lands, city lands, and a host of other governmental entities.

This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

B. Requirements and Measures

R1. Each Transmission Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[2] [*Violation Risk Factor: High*] [*Time Horizon: Real-time*]:

1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage[3],
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage[4],
3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[4],
4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage[4].

Rationale for R1 and R2:
Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a Transmission Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.

2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.

3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.

4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

[2] This requirement does not apply to circumstances that are beyond the control of a Transmission Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.

[3] If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

[4] Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

M1. Each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

R2. Each Transmission Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[2] [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time*]:

1. An encroachment into the MVCD, observed in Real-time as shown in FAC-003-Table 2, absent a Sustained Outage[3],
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage[4],
3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[4],
4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage[4]

M2. Each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)

R3. Each Transmission Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following:

3.1 Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;

3.2 Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

[*Violation Risk Factor: Lower*] [*Time Horizon: Long Term Planning*]:

Rationale

The documentation provides a basis for evaluating the competency of the Transmission Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the Transmission Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions. See Figure 1 for an illustration of possible conductor locations.

M3. The maintenance strategies or procedures or processes or specifications provided demonstrate that the Transmission Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

R4. Each Transmission Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the Transmission Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time*].

Rationale

This is to ensure expeditious communication between the Transmission Owner and the control center when a critical situation is confirmed.

M4. Each Transmission Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

R5. When a Transmission Owner is constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the Transmission Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

Rationale

Legal actions and other events may occur which result in constraints that prevent the Transmission Owner from performing planned vegetation maintenance work.
In cases where the transmission line is put at potential risk due to constraints, the intent is for the Transmission Owner to put interim measures in place, rather than do nothing. The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

M5. Each Transmission Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

R6. Each Transmission Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW[5] [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

Rationale

Inspections are used by Transmission Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

[5] When the Transmission Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO is granted a time extension that is equivalent to the duration of the time the TO was prevented from performing the Vegetation Inspection.

M6. Each Transmission Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

R7. Each Transmission Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

Rationale

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

- Change in expected growth rate/ environmental factors
- Circumstances that are beyond the control of a Transmission Owner[6]
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Emerging technologies

M7. Each Transmission Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

[6] Circumstances that are beyond the control of a Transmission Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or an applicable regulatory body.

C. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

1.2 Regional Entity Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, Measures M1, M2, M3, M5, M6 and M7 for three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaint

Periodic Data Submittal

1.4 Additional Compliance Information

Periodic Data Submittal: The Transmission Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the Transmission Owner to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the Transmission Owner.

A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

The Regional Entity will report the outage information provided by Transmission Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Real-time	High	The Transmission Owner failed to manage vegetation in a manner such that the Transmission Owner had an encroachment into the MVCD observed in Real-time, absent a Sustained Outage.	The Transmission Owner failed to manage vegetation in a manner such that the Transmission Owner had an encroachment into the MVCD due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage.	The Transmission Owner failed to manage vegetation in a manner such that the Transmission Owner had an encroachment into the MVCD due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage.	The Transmission Owner failed to manage vegetation in a manner such that the Transmission Owner had an encroachment into the MVCD due to a grow-in that caused a vegetation-related Sustained Outage.
R2	Real-time	Medium	The Transmission Owner failed to manage vegetation in a manner such that the Transmission Owner had an encroachment into the MVCD observed in Real-time, absent a Sustained Outage.	The Transmission Owner failed to manage vegetation in a manner such that the Transmission Owner had an encroachment into the MVCD due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage.	The Transmission Owner failed to manage vegetation in a manner such that the Transmission Owner had an encroachment into the MVCD due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage.	The Transmission Owner failed to manage vegetation in a manner such that the Transmission Owner had an encroachment into the MVCD due to a grow-in that caused a vegetation-related Sustained Outage.
R3	Long-Term Planning	Lower		The Transmission Owner has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the Transmission Owner's	The Transmission Owner has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the Transmission Owner's	The Transmission Owner does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the Transmission Owner's applicable lines.

				applicable lines. (Requirement R3, Part 3.2)	applicable lines. Requirement R3, Part 3.1)	
R4	Real-time	Medium			The Transmission Owner experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The Transmission Owner experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5	Operations Planning	Medium				The Transmission Owner did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6	Operations Planning	Medium	The Transmission Owner failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The Transmission Owner failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The Transmission Owner failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The Transmission Owner failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7	Operations Planning	Medium	The Transmission Owner failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The Transmission Owner failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The Transmission Owner failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The Transmission Owner failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Differences

None.

E. Interpretations

None.

F. Associated Documents

Guideline and Technical Basis (attached).

Guideline and Technical Basis

Effective dates:
The first two sentences of the Effective Dates section is standard language used in most NERC standards to cover the general effective date and is sufficient to cover the vast majority of situations. Five special cases are needed to cover effective dates for individual lines which undergo transitions after the general effective date. These special cases cover the effective dates for those lines which are initially becoming subject to the standard, those lines which are changing their applicability within the standard, and those lines which are changing in a manner that removes their applicability to the standard.

Case 1 is needed because the Planning Coordinators may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2011 may identify a line to have that designation beginning in PY 2021, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the Transmission Owner to make the necessary preparations to achieve compliance on that line. The table below has some explanatory examples of the application.

Date that Planning Study is completed	PY the line will become an IROL element	Date 1	Date 2	Effective Date The latter of Date 1 or Date 2
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Case 2 is needed because a line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Case 3 is needed because a line operating at 200 kV or above that once was designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network. Such changes result in the need to apply R1 to that line until that date is reached and then to apply R2 to that line thereafter.

Case 4 is needed because an existing line that is to be operated at 200 kV or above can be acquired by a Transmission Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the Transmission Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network which will thereafter make the line subject to the standard.

Case 5 is needed because an existing line that is operated below 200 kV can be acquired by a Transmission Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the Transmission owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network. In this special case the line upon acquisition was designated as an element of an Interconnection Reliability Operating Limit (IROL) or an element of a Major WECC Transfer Path.

Defined Terms:

Explanation for revising the definition of ROW:
The current NERC glossary definition of Right of Way has been modified to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This modified definition represents a slight but significant departure from the strict legal definition of "right of way" in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the revised definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

Explanation for revising the definition of Vegetation Inspections:
The current glossary definition of this NERC term is being modified to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

Explanation of the definition of the MVCD:
The MVCD is a calculated minimum distance that is derived from the Gallet Equations. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 below provides MVCD values for various voltages and altitudes. Details of the equations and an example calculation are provided in Appendix 1 of the Technical Reference Document.

Requirements R1 and R2:
R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each Transmission Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element of an IROL or Major WECC Transfer Path. R2 is applicable to all other lines that are not elements of IROLs, and not elements of Major WECC Transfer Paths.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations as described more fully in the Technical Reference document.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by a Transmission Operator or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage.

Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of a Transmission Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with a Transmission Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will prevent transmission outages.

If the Transmission Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the TO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

Requirement R3: R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, a Transmission Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the Transmission Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the Transmission Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the Transmission Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach a Transmission Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the Transmission Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below. In the Technical Reference document more figures and explanations of conductor dynamics are provided.

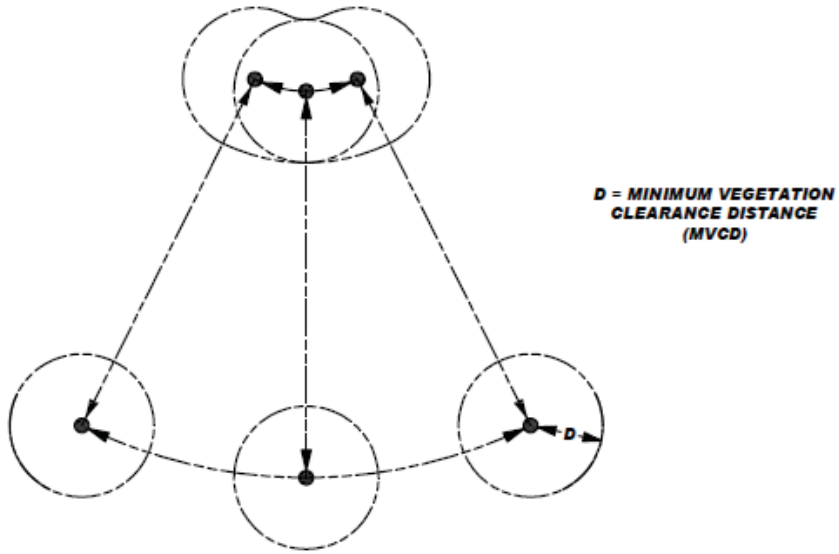

Figure 1

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

Requirement R4:
R4 is a risk-based requirement. It focuses on preventative actions to be taken by the Transmission Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of a Transmission Owner's employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The Transmission Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some Transmission Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5:
R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the Transmission Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the Transmission Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the Transmission Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the Transmission Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the Transmission Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the Transmission Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.

- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the Transmission Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The Transmission Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6:
R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner's ability to meet this requirement. However, the Transmission Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the Transmission Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when a Transmission Owner operates 2,000 miles of applicable transmission lines this Transmission Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The "Low VSL" for R6 would apply in this example.

Requirement R7:
R7 is a risk-based requirement. The Transmission Owner is required to complete its an annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a "span-by-span", or even a "line-by-line" detailed description of all work to be performed. It is only intended to require that the Transmission Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

For example, when a Transmission Owner identifies 1,000 miles of applicable transmission lines to be completed in the Transmission Owner's annual plan, the Transmission Owner will be responsible completing those identified miles. If a Transmission Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be: 1000 – 100 (deferred miles) = 900 modified annual plan, or 900 / 900 = 100% completed annual miles. If a Transmission Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be: 1000 – 875 = 125 miles failed to complete then, 125 miles (not completed) / 1000 total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the Transmission Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the Transmission Owner's system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.

In general, the vegetation management maintenance approach should use the full extent of the Transmission Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the Transmission Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Transmission Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the Transmission Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[7]
For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)	(AC) Maximum System Voltage (kV)[8]	MVCD (feet) Over sea level up to 500 ft	MVCD (feet) Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft
765	800	8.2ft	8.33ft	8.61ft	8.89ft	9.17ft	9.45ft	9.73ft	10.01ft	10.29ft	10.57ft	10.85ft	11.13ft
500	550	5.15ft	5.25ft	5.45ft	5.66ft	5.86ft	6.07ft	6.28ft	6.49ft	6.7ft	6.92ft	7.13ft	7.35ft
345	362	3.19ft	3.26ft	3.39ft	3.53ft	3.67ft	3.82ft	3.97ft	4.12ft	4.27ft	4.43ft	4.58ft	4.74ft
287	302	3.88ft	3.96ft	4.12ft	4.29ft	4.45ft	4.62ft	4.79ft	4.97ft	5.14ft	5.32ft	5.50ft	5.68ft
230	242	3.03ft	3.09ft	3.22ft	3.36ft	3.49ft	3.63ft	3.78ft	3.92ft	4.07ft	4.22ft	4.37ft	4.53ft
161*	169	2.05ft	2.09ft	2.19ft	2.28ft	2.38ft	2.48ft	2.58ft	2.69ft	2.8ft	2.91ft	3.03ft	3.14ft
138*	145	1.74ft	1.78ft	1.86ft	1.94ft	2.03ft	2.12ft	2.21ft	2.3ft	2.4ft	2.49ft	2.59ft	2.7ft
115*	121	1.44ft	1.47ft	1.54ft	1.61ft	1.68ft	1.75ft	1.83ft	1.91ft	1.99ft	2.07ft	2.16ft	2.25ft
88*	100	1.18ft	1.21ft	1.26ft	1.32ft	1.38ft	1.44ft	1.5ft	1.57ft	1.64ft	1.71ft	1.78ft	1.86ft
69*	72	0.84ft	0.86ft	0.90ft	0.94ft	0.99ft	1.03ft	1.08ft	1.13ft	1.18ft	1.23ft	1.28ft	1.34ft

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

[7] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[8] Where applicable lines are operated at nominal voltages other than those listed, The Transmission Owner should use the maximum system voltage to determine the appropriate clearance for that line.

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[7]

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)	(AC) Maximum System Voltage (kV)[8]	MVCD meters Over sea level up to 152.4 m	MVCD meters Over 152.4 m up to 304.8 m	MVCD meters Over 304.8 m up to 609.6m	MVCD meters Over 609.6m up to 914.4m	MVCD meters Over 914.4m up to 1219.2m	MVCD meters Over 1219.2m up to 1524m	MVCD meters Over 1524 m up to 1828.8 m	MVCD meters Over 1828.8m up to 2133.6m	MVCD meters Over 2133.6m up to 2438.4m	MVCD meters Over 2438.4m up to 2743.2m	MVCD meters Over 2743.2m up to 3048m	MVCD meters Over 3048m up to 3352.8m
765	800	2.49m	2.54m	2.62m	2.71m	2.80m	2.88m	2.97m	3.05m	3.14m	3.22m	3.31m	3.39m
500	550	1.57m	1.6m	1.66m	1.73m	1.79m	1.85m	1.91m	1.98m	2.04m	2.11m	2.17m	2.24m
345	362	0.97m	0.99m	1.03m	1.08m	1.12m	1.16m	1.21m	1.26m	1.30m	1.35m	1.40m	1.44m
287	302	1.18m	0.88m	1.26m	1.31m	1.36m	1.41m	1.46m	1.51m	1.57m	1.62m	1.68m	1.73m
230	242	0.92m	0.94m	0.98m	1.02m	1.06m	1.11m	1.15m	1.19m	1.24m	1.29m	1.33m	1.38m
161*	169	0.62m	0.64m	0.67m	0.69m	0.73m	0.76m	0.79m	0.82m	0.85m	0.89m	0.92m	0.96m
138*	145	0.53m	0.54m	0.57m	0.59m	0.62m	0.65m	0.67m	0.70m	0.73m	0.76m	0.79m	0.82m
115*	121	0.44m	0.45m	0.47m	0.49m	0.51m	0.53m	0.56m	0.58m	0.61m	0.63m	0.66m	0.69m
88*	100	0.36m	0.37m	0.38m	0.40m	0.42m	0.44m	0.46m	0.48m	0.50m	0.52m	0.54m	0.57m
69*	72	0.26m	0.26m	0.27m	0.29m	0.30m	0.31m	0.33m	0.34m	0.36m	0.37m	0.39m	0.41m

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[7]
For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)
	Over sea level up to 500 ft	Over 500 ft up to 1000 ft	Over 1000 ft up to 2000 ft	Over 2000 ft up to 3000 ft	Over 3000 ft up to 4000 ft	Over 4000 ft up to 5000 ft	Over 5000 ft up to 6000 ft	Over 6000 ft up to 7000 ft	Over 7000 ft up to 8000 ft	Over 8000 ft up to 9000 ft	Over 9000 ft up to 10000 ft	Over 10000 ft up to 11000 ft
	(Over sea level up to 152.4 m)	(Over 152.4 m up to 304.8 m	(Over 304.8 m up to 609.6m)	(Over 609.6m up to 914.4m	(Over 914.4m up to 1219.2m	(Over 1219.2m up to 1524m	(Over 1524 m up to 1828.8 m)	(Over 1828.8m up to 2133.6m)	(Over 2133.6m up to 2438.4m)	(Over 2438.4m up to 2743.2m)	(Over 2743.2m up to 3048m)	(Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

Notes:

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet Equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 uses the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-01 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 per unit. This value is a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet Equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet "wet" formulas are not vastly different when the same transient overvoltage factors are used; the "wet" equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

While EPRI is currently trying to establish empirical data for spark-over distances to live vegetation, there are no spark-over formulas currently derived expressly for vegetation to conductor minimum distances. Therefore the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.
The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

Comparison of spark-over distances computed using Gallet wet equations vs. IEEE 516-2003 MAID distances

(AC) Nom System Voltage (kV)	(AC) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	Table 7 (Table D.5 for feet) IEEE 516-2003 MAID (ft) @ Alt. 3000 feet
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

Project 2007-07 Vegetation Management

Alternative VSLs

NERC Staff proposes the following alternative VSLs.

Clean

R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Real-time	High	NA	NA	The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and operating within its Rating and all Rated Electrical Operating Conditions, such that an encroachment into the MVCD as shown in FAC-003-Table 2 was observed in Real-time, absent a Sustained Outage.	The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and operating within its Rating and all Rated Electrical Operating Conditions, and a vegetation-realted sustsained outage was caused by one of the following: • An encroachment due to a fall-in from inside the ROW • An encroachment due to the blowing together of applicable lines and vegetation located

						inside the ROW • An encroachment due to vegetation growth into the MVCD
R2	Real-time	Medium	NA	NA	The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and operating within its Rating and all Rated Electrical Operating Conditions, such that an encroachment into the MVCD as shown in FAC-003-Table 2 was observed in Real-time, absent a Sustained Outage.	The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and operating within its Rating and all Rated Electrical Operating Conditions, and a vegetation-related sustained outage was caused by one of the following: • An encroachment due to a fall-in from inside the ROW • An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW • An encroachment due to vegetation growth into the MVCD
R3	Long-Term Planning	Lower		The Transmission Owner has maintenance strategies or documented procedures or processes or specifications but	The Transmission Owner has maintenance strategies or documented procedures or processes or specifications but	The Transmission Owner does not have any maintenance strategies or documented procedures or processes or

				has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the Transmission Owner's applicable lines. (Requirement R3, Part 3.2)	has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the Transmission Owner's applicable lines. Requirement R3, Part 3.1)	specifications used to prevent the encroachment of vegetation into the MVCD, for the Transmission Owner's applicable lines.
R4	Real-time	Medium			The Transmission Owner experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The Transmission Owner experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5	Operations Planning	Medium				The Transmission Owner did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6	Operations Planning	Medium	The Transmission Owner failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The Transmission Owner failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The Transmission Owner failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The Transmission Owner failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7	Operations	Medium	The Transmission Owner	The Transmission Owner	The Transmission Owner failed	The Transmission Owner failed

	Planning		failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

Redline

R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Real-time	High	NA	NA	The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and operating within its Rating and all Rated Electrical Operating Conditions, such that an encroachment into the MVCD as shown in FAC-003-Table 2 was observed in Real-time, absent a Sustained Outage.	The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and operating within its Rating and all Rated Electrical Operating Conditions, and a vegetation-realted sustsained outage was caused by one of the following: • An encroachment due to a fall-in from inside the ROW • An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW

Deleted: The Transmission Owner failed to manage vegetation in a manner such that the Transmission Owner had an encroachment into the MVCD observed in Real-time, absent a Sustained Outage.

Deleted: The Transmission Owner failed to manage vegetation in a manner such that the Transmission Owner had an encroachment into the MVCD due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage.

Deleted: in a manner such that the Transmission Owner had an encroachment into the MVCD due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage.

						• An encroachment due to vegetation growth into the MVCD
R2	Real-time	Medium	NA	NA	The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and operating within its Rating and all Rated Electrical Operating Conditions, such that an encroachment into the MVCD as shown in FAC-003-Table 2 was observed in Real-time, absent a Sustained Outage.	The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and operating within its Rating and all Rated Electrical Operating Conditions, and a vegetation-related sustained outage was caused by one of the following: • An encroachment due to a fall-in from inside the ROW • An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW • An encroachment due to vegetation growth into the MVCD
R3	Long-Term Planning	Lower		The Transmission Owner has maintenance strategies or documented procedures or processes or specifications but has not accounted for the	The Transmission Owner has maintenance strategies or documented procedures or processes or specifications but has not accounted for the	The Transmission Owner does not have any maintenance strategies or documented procedures or processes or specifications used to prevent

Deleted: in a manner such that the Transmission Owner had an encroachment into the MVCD due to a grow-in that caused a vegetation-related Sustained Outage.

Deleted: The Transmission Owner failed to manage vegetation in a manner such that the Transmission Owner had an encroachment into the MVCD observed in Real-time, absent a Sustained Outage.

Deleted: The Transmission Owner failed to manage vegetation in a manner such that the Transmission Owner had an encroachment into the MVCD due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage.

Deleted: in a manner such that the Transmission Owner had an encroachment into the MVCD due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage.

Deleted: in a manner such that the Transmission Owner had an encroachment into the MVCD due to a grow-in that caused a vegetation-related Sustained Outage.

				inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the Transmission Owner's applicable lines. (Requirement R3, Part 3.2)	movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the Transmission Owner's applicable lines. Requirement R3, Part 3.1)	the encroachment of vegetation into the MVCD, for the Transmission Owner's applicable lines.
R4	Real-time	Medium			The Transmission Owner experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The Transmission Owner experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5	Operations Planning	Medium				The Transmission Owner did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6	Operations Planning	Medium	The Transmission Owner failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The Transmission Owner failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The Transmission Owner failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The Transmission Owner failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7	Operations Planning	Medium	The Transmission Owner failed to complete 5% or	The Transmission Owner failed to complete more than	The Transmission Owner failed to complete more than 10% and	The Transmission Owner failed to complete more than 15% of

			less of its annual vegetation work plan for its applicable lines (as finally modified).	5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	its annual vegetation work plan for its applicable lines (as finally modified).

6b. Reliability Standards Development Plan 2012-2014

Action

Approve the Reliability Standards Development Plan 2012-2014 (RSDP) and direct staff to file with applicable regulatory authorities.

[2012-2014 Reliability Standards Development Plan Final Draft – for BOT Consideration]

Executive Summary

The 2012-2014 RSDP has been drafted and approved by the Standards Committee (SC). It represents the completion of a multi-month undertaking to review previous work and plan for new work. NERC completed seven standards development projects in 2011 and expects to complete an additional seven in 2012. Upon completion of these projects, additional projects will be initiated. NERC forecasts new projects will commence next year addressing protection systems, training, emergency operations, and real-time tools.

NERC is asking for the Board's approval of the plan for submission to the appropriate regulatory authorities pursuant to Section 310 of the Rules of Procedure.

Background

Developed over the past several months, the RSDP provides a status of work undertaken in 2011, as well as a forecast of work for the next three years.

During the month of July 2011, NERC solicited the industry at-large for additional projects to be considered for inclusion in the 2012-2014 plan. In August, the SC began reviewing all of the known projects and potential projects, assigning them various scores based on input from constituents within their respective segments. Similar to last year, the SC utilized a simple scoring mechanism to identify key considerations for use in determining standards project priorities. The SC also began trial testing a new metric that accounts for "cost considerations," and using a more sophisticated analysis of each of the key drivers in project prioritization. This allowed the SC to consider each of those factors separately, as well as in aggregate, to determine how best to allocate resources.

NERC staff assembled the results in September, and an initial Prioritization and Work Plan was approved for posting at the September meeting of the SC. This Work Plan assumed an overall throughput capability of 13 projects in development concurrently, which is an increase above the 2011 target of 12. This is due to staffing increases in the NERC Standards department, which have allowed for some additional work to be considered. The SC allocated that throughput capability to three areas.

A link to the RSDP, history, and files is included here for reference:
http://www.nerc.com/page.php?cid=2|247|290

If trustees have questions or need additional information, they may contact Herb Schrayshuen at herb.schrayshuen@nerc.net.

6c. MOD-025-RFC-1: Reactive Power Capability

Action

Approve the following standards documents and direct staff to file with applicable regulatory authorities:

- **Reliability Standard MOD-025-RFC-01 – Verification and Data Reporting of Generator Gross and Net Reactive Power Capability** effective consistent with the Implementation Plan for MOD-025-RFC-01
  [MOD-025-RFC-01 – Clean] [No redline available]
- **Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for MOD-025-RFC-01:**
  [Included in the Standard above]
- **Implementation Plan for MOD-025-RFC-01:**
  Upon regulatory approval, the standard will be mandatory and enforceable (with monetary penalties for non-compliance) to all applicable NERC registered entities within the Reliability*First* footprint.

Retirement

- None

Background

The MOD-025-RFC-01 standard was developed to provide planning entities with accurate generator gross and net Reactive Power capability modeling data to use in system planning studies. This standard was also developed to meet the "fill in the blank" requirements assigned to the Regional Reliability Organizations as set forth in the NERC approved MOD-025-1 standard.

The Reliability*First* MOD-025-RFC-01 standard contains two main requirements for applicable entities within the Reliability*First* geographic area. The standard includes the following:

- Requirement R1, which requires the Generator Owner to verify the operating range of Reactive Power capability for each of its applicable units every five years in accordance with MOD-025-RFC-01 Attachment 1; and
- Requirement R2, which requires the Generator Owner to provide specific data from the most recent Reactive Power capability verification within 30 calendar days of a written request from its Transmission Planner, Transmission Operator, Reliability Coordinator or Planning Coordinator.

When Project 2007-09 Generator Verification develops modifications to the continent-wide standard MOD-025-1, this regional standard will be reviewed by Reliability*First* to ensure that any duplicative requirements or any requirements that are less restrictive or do not add additional detail will be considered for retirement. The steps outlined in the Reliability*First* Reliability Standards Development Procedure will be followed for any such revisions or retirements.

Directives

None

Standard Development Process

The standard was processed through the approved Reliability*First* Reliability Standards Development Procedure, which included five postings for stakeholder comment over a three-year period, a ballot, and approval by the Reliability*First* Board of Directors.

There were two minority issues raised during the ballot as identified below:

- Issue: There is no need for this regional standard since continent-wide MOD-025-1 has not been approved by FERC. NERC assigned the Generator Verification Standard Drafting Team the responsibility of drafting a new MOD-025 standard that will not be a "fill-in the blank" standard.

  Response: Reliability*First* is fulfilling its obligation under the current NERC approved MOD-025-1. When the new NERC MOD-025 standard is approved, the Reliability*First* standard will be reviewed for duplicative requirements. Additionally, replacement of the legacy documents is required in Reliability*First*'s Bylaws and addresses ambiguities, inconsistencies, and deficiencies in those documents.

- Issue: Attachment 1 Section 2.1 is too rigid; it will hinder the ability to obtain reactive power test results when plant conditions do not allow the real power to be at the level reported in MOD-024-RFC-01, perhaps due to water temperatures, coal conditions, or ambient temperatures. The requirement should be revised to allow the verification to begin at or above 95 percent of the reported real power capability.

  Response: The reported capability under MOD-024-RFC-01 is a capability that is equal to the unit's continuous and sustainable output that can be produced seven days a week, 24 hours a day without encountering any equipment limits (this may not be the maximum capacity of the unit). This capability is a normalized value that takes into account differences in the ambient conditions during the verification and 15 -year weather averages (*See*, R4 of MOD-024-RFC-01). The normalization can also be used to adjust the actual achievable real power output during the reactive verification to the normalized real power capability determined during the MOD-024-RFC-01 verification. If a unit cannot reach its MOD-024-RFC-01 reported capability (at any time during the five year verification period), the unit's Real Power capability may need to be re-examined to make sure the reported capability is actually the correct value.

Proposed VRFs and VSLs

The VRFs and VSLs were included with the standard when balloted. NERC standards staff is not recommending any modifications to the VRFs and VSLs that were balloted.

A link to the project history and files is included here for reference:
https://rsvp.rfirst.org/MOD025RFC01/default.aspx

6d. IRO-006-TRE-1: IROL and SOL Mitigation in the ERCOT Interconnection

Action

Approve the following standards documents and direct staff to file with applicable regulatory authorities:

- **Reliability Standard IRO-006-TRE-1 — IROL and SOL Mitigation in the ERCOT Interconnection**
  [IRO-006-TRE-1 - Clean] [New Standard - No redline available]
- **Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for IRO-006-TRE-1**
  [VRFs and VSLs embedded in the Standard above]
- **Implementation Plan for IRO-006-TRE-1**
  The effective date for IRO-006-TRE-1 is the first day of the first calendar quarter after applicable regulatory approval.

Retirement

- None

Background

IRO-006-TRE-1 provides enforceable requirements associated with the existing Electric Reliability Council of Texas (ERCOT) congestion management procedures. This Regional Standard addresses the FERC directive in Paragraph 964 of Order No. 693, in which FERC determined that the ERCOT transmission loading relief procedures were superior to the national standard, and directed the ERO to provide Reliability Standards including requirements, measures and levels of non-compliance corresponding to the ERCOT protocols for application in the ERCOT Region.

The TRE IRO-006-TRE-1 standard requires:

- Requirement 1

  The RC (ERCOT) to have procedures to identify and mitigate exceedances of identified Interconnection Reliability Operating Limits ("IROLs") and System Operating Limits ("SOLs") that will not be resolved by the automatic actions of the ERCOT Nodal market operations system.

- Requirement 2

  The RC to act according to its procedures to identify and mitigate exceedances of identified Interconnection Reliability Operating Limits and System Operating Limits that will not be resolved by the automatic actions of the ERCOT Nodal market operations system.

Directives

This Regional Standard addresses the FERC directives in Paragraph 964 of Order No. 693 by:

- Modifying the ERCOT protocols to ensure consistency with the standard form of the Reliability Standards including Requirements, Measures and Levels of Non-Compliance.

  [link to Order No. 693]

Standard Development Process

The standard was developed and approved in accordance with Texas RE's FERC-approved Regional Standards Development Process (included as Appendix to Exhibit C to the Delegation Agreement between NERC and Texas RE). The process included formation of an expert standard drafting team to develop the standard, a posting for stakeholder comment, a stakeholder ballot, and approval by Texas RE's Reliability Standards Committee and Board of Directors.

There were no minority issues raised during the comment period that were not resolved.

The standard was approved by an ERCOT Regional stakeholder ballot with 12 votes in favor of the proposed standard, zero votes against, and one abstention. All industry segments participated in the ballot. The proposed VRFs and VSLs were approved in a non-binding poll with seven votes in favor and zero votes against.[1] ERCOT, which is the only entity that has compliance responsibilities under this standard, actively participated on the standard drafting team and voted in favor of the standard and the VRFs and VSLs.

NERC Standards Staff's View of VRFs and VSLs

The VRFs and VSLs were included with the standard when balloted. NERC standards staff is not recommending any modifications be made to the VRFs and VSLs that were balloted.

A link to the project history and files is included here for reference:
http://www.texasre.webvote.oati.net/texasre_webvote/action/PubMainAction?type=Detail&id=26

[1] Several ballot pool members did not vote in the VRF/VSL poll.

6e. PRC-006-SERC-1: Automatic Underfrequency Load Shedding (UFLS) Requirements

Action

Approve the following standards documents and direct staff to file with applicable regulatory authorities:

- **Reliability Standard PRC-006-SERC-01 – Automatic Underfrequency Load Shedding Requirements**

  [PRC-006-SERC-01- Clean] [New Standard – No redline available]
- **Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for PRC-006-SERC-01**

  [VRFs and VSLs are available in the Standard above]
- **Implementation Plan for PRC-006-SERC-01**

  The Implementation Plan is staged over a 30-month window to allow entities to respond to any changes in UFLS settings due to this standard. In addition, the implementation date of Requirement R1 is dependent on FERC adoption of the continent-wide standard PRC-006-1.

Retirement

- None

Background

The SERC UFLS Standard: PRC-006-SERC-01 ("SERC UFLS Standard") provides regional UFLS requirements for registered entities in the SERC Region. UFLS requirements have been in place at a continent-wide level and within SERC for many years prior to implementation of FERC-approved Reliability Standards in 2007.

In 2008, SERC commenced work on PRC-006-SERC-01. NERC also began work on revising PRC-006-0 at a continent-wide level. The SERC standard is consistent with and complementary to the continent-wide UFLS standard.

PRC-006-1 identifies the Planning Coordinator (PC) as the entity responsible for developing UFLS schemes within its PC area. This regional standard adds specificity not contained in the NERC standard for development and implementation of a UFLS scheme in the SERC Region that effectively mitigates the consequences of an underfrequency event.

Directives

None

Standard Development Process

The standard was processed through SERC's approved standards development process, which included five postings for stakeholder comment over a three-year period, three ballots, and approval by SERC's Board Executive Committee.

There were two minority issues raised that were not resolved as identified below:

- Issue: Question the correlation between the NERC and SERC standards and how the two standards work together.

  Response: The SERC standard provides regional detail on specificity for some of the NERC requirements. It should also be noted that the SERC standard is not a stand-alone standard but needs to be applied in conjunction with the NERC UFLS standard.

- Issue: There is no need for this regional standard. PRC-006-1 is sufficient.

  Response: Not only do the requirements of the SERC standard provide regional consistency and coordination, they also are more stringent than the national standard. For example, Requirement 2 sets specific boundaries on UFLS schemes that are not requirements in the national standard.

Standards Staff's View of VRFs and VSLs

The non-binding poll of VRFs and VSLs was conducted during the final ballot of the associated standard. NERC standards staff is not recommending modifications be made to the VRFs and VSLs that were posted for the nonbinding poll.

A link to the project history and files is included here for reference:
http://serc.centraldesktop.com/standardhomepage/doc/10467819/w-RegionalUflsStandard

Agenda Item 7
Board of Trustees Meeting
November 3, 2011

NERC Rules of Procedure Non-substantive Capitalization and Definition Changes

Action

Approve

Background

NERC requests that the Board of Trustees (Board) approve proposed revisions to the NERC Rules of Procedure and all existing Appendices to the Rules of Procedure (3A, 3B, 3C, 4A, 4B, 4C, 4D, 4E, 5A, 5B, 6, and 8), as well as proposed new Appendix 2, Definitions of Terms Used in the Rules of Procedure.

The objectives of the proposed revisions are: (1) to place all definitions of defined terms used anywhere in the Rules of Procedure in a single, readily-accessible location (proposed Appendix 2); (2) to capitalize defined terms throughout the Rules of Procedure where they are intended to be used in their defined meanings; and (3) to lower-case other terms that are currently capitalized in the Rules of Procedure but are not defined terms.

These revisions are being proposed in response to Paragraph 93 of the Order of the Federal Energy Regulatory Commission (FERC or Commission) issued October 21, 2010,[1] in which the Commission invited NERC to submit a filing making consistent use of defined terms throughout the Rules of Procedure and Appendices. The October 21, 2010 Order invited NERC to make such a filing by January 1, 2011. NERC was unable to develop, post for comment, obtain Board approval, and file the proposed revisions for this purpose by January 1, 2011; however, NERC recognizes that there is a need for greater consistency in definitions and the use of capitalization in the Rules of Procedure and Appendices, and therefore is proceeding with this initiative at this time. If these revisions are approved by the Board, NERC will file the proposed revisions with the Commission for approval promptly thereafter.

The sources of the defined terms listed in proposed Appendix 2 are: (1) definitions currently found throughout the existing Rules of Procedure, including, among other places, in Section 200, Section 1500, and Appendices 4C, 4D, 5B and 6, (2) the NERC Glossary of Terms Used in Reliability Standards, (3) definitions in the NERC Bylaws, (4) definitions in Section 215 of the Federal Power Act, and (5) definitions in FERC regulations at 18 C.F.R. Parts 39 and 388. Efforts have been made to reconcile non-identical definitions currently used in different parts of the Rules of Procedure; however, for certain terms, the definitions used in different parts of the Rules of Procedure were sufficiently different that it was not possible to develop a single definition without changing the meaning of the term as used in one of the parts of the Rules. In those cases, the definition in Appendix 2 incorporates both meanings, with the applicable meaning to be used being dependent on the context (or, in some cases, to be used only in a specifically-identified provision or Appendix of the Rules). For the purposes of this initiative,

[1] *North American Electric Reliability Corporation*, 133 FERC ¶ 61,061 (2010).

which was not intended to result in substantive changes to the Rules of Procedure, this approach was considered preferable to changing an established term or its definition to achieve consistency.

A small number of new definitions (*i.e.*, explicit definitions not presently found in any of the above referenced sources) for frequently-used terms in the Rules of Procedure have been created and appear in proposed Appendix 2. These new definitions are denoted by "[Note: new definition]."

There are a number of defined terms that appear only within Appendix 2 and do not appear elsewhere in the Rules of Procedure. These defined terms are internal to the definitions of other defined terms. For the most part, these "internal" definitions are found within definitions of other terms that are taken from the NERC Glossary of Terms Used in Reliability Standards, and they are themselves taken from the NERC Glossary. Thus, the "internal" definitions are necessary for a complete understanding of the defined terms that are used elsewhere in the Rules of Procedure. The objective of this approach is to establish Appendix 2 as a complete source of all definitions used in the Rules of Procedure, without the need to refer to other sources outside the Rules of Procedure.

In the Rules of Procedure and Appendices, terms listed in Appendix 2, if not currently capitalized where used in the Rules of Procedure, have been revised to be capitalized where they are intended to be used with their defined meanings. Where a term defined in Appendix 2 appears in the Rules of Procedure but is not capitalized, the term is there being used in its ordinary and commonly understood meaning and not as defined in Appendix 2 (if different). Other terms that are not defined terms, such as the names of entities, organizations, committees, or programs; position titles; titles of documents or forms; section headings or captions; geographic locations; and other terms commonly presented as proper nouns, are also capitalized in the Rules of Procedure without being defined in this Appendix.

Although all definitions used in the Rules of Procedure and Appendices have been collected in proposed Appendix 2, "Definitions" sections in current Appendices have not been deleted in the proposed revisions, but rather have been retained for convenience of reference to the user. However, definitions in these "Definitions" sections have been revised where necessary to conform to the definition presented in Appendix 2.

The Rules of Procedure and Appendices marked with the proposed revisions are the currently-effective Rules of Procedure and Appendices as approved by the Commission, and do not reflect any additional proposed revisions currently pending before the Commission for approval. However, it is intended that the same approach to presentation of definitions and capitalization of defined terms used in the proposed revised Rules of Procedure will be applied prospectively to all future substantive revisions.

Agenda Item 8
Board of Trustees Meeting
November 3, 2011

Reinstatement of NERC Rules of Procedure Section 402.1.3.2

Action

Approve the reinstatement of Section 402.1.3.2 to the NERC Rules of Procedure.

Background

This revision to the NERC Rules of Procedure (ROP) is required by a FERC order issued on October 7, 2011.[1] FERC's October 7 order has directed NERC to make a compliance filing to reinstate this Section to the ROP by November 7, 2011.

On June 9, 2010, and as supplemented on June 17, 2010, NERC submitted a filing to FERC requesting approval of revisions to the Regional Delegation Agreements (RDAs) and to certain ROP provisions. FERC conditionally accepted the June 9, 2010 filing on October 21, 2010[2] and directed NERC to submit a compliance filing, which NERC submitted on February 18, 2011. The October 7 order conditionally accepted the February 18, 2011 compliance filing and the additional RDA and ROP revisions submitted with the compliance filing, with one exception. Specifically, FERC rejected NERC's proposed deletion of Section 402.1.3.2 from the ROP, and FERC directed NERC to file a compliance filing by November 7, 2011 restoring Section 402.1.3.2 to the ROP. FERC stated that NERC had not provided sufficient justification for deleting that provision.

Section 402.1.3.2 pertains to the "audit verification" program whereby NERC verifies the results of compliance audits conducted by Regional Entities. The language of the Section reads as follows:

> 1.3.2 NERC shall establish a program to audit bulk power system owners, operators, and users operating within a regional entity to verify the findings of previous compliance audits conducted by the regional entity to evaluate how well the regional entity compliance enforcement program is meeting its delegated authority and responsibilities.

NERC requests approval to reinsert this provision in the ROP in order to comply with the FERC order. The audit validation will be integrated into the restructured Regional Entity Audit Program as a distinct module. NERC staff is developing the informational filing and program document for the restructured RE Audit Program, which will be presented to the Board of Trustees Compliance Committee at its December 2011 meeting.

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[1] *North American Electric Reliability Corporation*, 137 FERC ¶ 61,028 (2011).
[2] *North American Electric Reliability Corporation*, 133 FERC ¶ 61,061 (2010).

Agenda Item 9
Board of Trustees Meeting
November 3, 2011

Amendments to WECC Bylaws and Reliability Standards Development Procedures

Action

Approve requested amendments to WECC documents.

Summary

WECC has requested that the Board approve, and direct NERC staff to file with FERC for approval, amendments to the Amended and Restated Delegation Agreement between NERC and WECC, consisting of amendments to Exhibit B – the WECC Bylaws, and to Exhibit C – the WECC Reliability Standards Development Procedures ("RSDP;" formerly titled the "Process for Developing and Approving WECC Standards").

> **Attachment 1** is a letter from WECC requesting Board approval of the amendments to the WECC Bylaws and WECC RSDP. Specifically, the Board is requested to approve the proposed amendments in substantially the form shown on:
>
> **Attachment 2** – Redlined version of Exhibit B to the NERC-WECC Delegation Agreement (WECC Bylaws), marked to show the proposed amendments.
>
> **Attachment 3** – Redlined version of Exhibit C to the NERC-WECC Delegation Agreement (WECC RSDP), marked to show the proposed amendment to the WECC RSDP and corresponding revisions to the "common attributes" for a regional reliability standards development procedure.

There are no proposed revisions to any other portions of the NERC-WECC Delegation Agreement, and therefore only the redlined versions of Exhibit B and Exhibit C are being provided with this agenda item.

Board approval of the amendments to Exhibits B and C of the NERC-WECC Delegation Agreement will also constitute approval of the amendments to the WECC Bylaws and RSDP as "regional entity rules." The proposed amendments to Exhibits B and C have received the necessary approvals from the WECC Board of Directors and Membership.

The remainder of this memorandum describes the proposed amendments and their basis and purpose.

Amendments to Exhibit B (WECC Bylaws)

1. The WECC Bylaws require the WECC Board to conduct a review of WECC's effectiveness every five years. The Board has delegated this function to the WECC Governance and Nominating Committee ("GNC"). The GNC's most recent review, initiated in 2010 and completed in 2011, noted, among other things, (i) that the WECC RSDP currently limits the WECC Board to either accepting a standard proposed by a standing committee or

returning it to the committee; and (ii) that WECC has no "backstop" process to develop or modify a Regional Reliability Standard in response to a regulatory directive or when the WECC Board believes one is needed to protect regional reliability, in cases where the WECC standing committees are unable to develop or approve the needed Regional Standard within a reasonable amount of time, or when the Board believes a Regional Standard recommended by the committee should be modified. Accordingly, a number of amendments to the WECC Bylaws, and substantial revisions to the WECC RSDP, are proposed to address these findings. Specifically, Amendments are proposed to revise or add the following sections of the WECC Bylaws: 3.6 (new section), 3.7 (new section), 3.35 (new section), 3.39, 3.41 (renumbered from 3.40), 4.5.5 (new section), 5.1, 8.3.2 (new section), 8.5.4, 8.5.5.2 (new section), 8.5.5.3 (renumbered from 8.5.5.2), 8.5.5.4 (new section), 8.5.6, 8.6.1 (including new subsection 8.6.1.3), and 8.6.2. The purpose of these amendments (along with amendments to the WECC RSDP, discussed below), is (i) to more closely align WECC's procedure to the procedure used by NERC for balloting continent-wide standards, and (ii) to provide the WECC Board with "backstop" authority concerning issuance of Regional Reliability Standards comparable to the authority of the NERC Board under Section 321 of the NERC Rules of Procedure. The new procedure includes the formation of a WECC Standards Committee and a WECC Ballot Body, which will allow meaningful participation in the Regional Reliability Standards development process by all persons who represent WECC Members in any forum, not just those persons who represent their Member entity in a particular WECC standing committee.

- New Section 3.6 adds a new defined term "Ballot Body." The Ballot Body consists of WECC members and non-members that have been determined to be eligible for the voting sectors in Section 8.5.5.2 and may, therefore, vote on Regional Criteria and Regional Reliability Standards.
- New Section 3.7 adds a new defined term "Ballot Pool." The Ballot Pool will consist of a self-selected set of members of the Ballot Body who join the Ballot Pool for a given Regional Criterion or Regional Reliability Standard during a designated time window prior to balloting or to the close of balloting.
- New Section 3.35 adds a new defined term "Regional Criteria." Regional Criteria are documents developed through the WECC RSDP and approved by the WECC Board to establish consistency among WECC member entities with respect to their business practices, or their technical, documentation or administrative procedures.
- Section 3.41 (renumbered from 3.40) is amended to reflect the revised title of the WECC RSDP.
- New Section 4.5.5 pertains to processing applications from non-WECC members to join the Ballot Body. In their applications, non-WECC members will be required to identify their affiliation(s) with other Ballot Body members, and WECC staff will limit voting of affiliated non-WECC members in the same manner as voting by WECC members would be limited.

- Section 5.1, Quorum, is amended to state that the provisions of that section do not apply to voting on Regional Reliability Standards and Regional Criteria under the oversight of the WECC Standards Committee.
- New Section 8.3.2 assigns responsibility to the WECC Standards Committee to oversee the process for responding to requests for Regional Reliability Standards and Regional Criteria, including (i) for determining if a request is within the scope of WECC's activities, and (ii) for overseeing the drafting, comment and voting process for the Regional Reliability Standard or Regional Criteria. The Standards Committee will also oversee the process for responding to requests for interpretations of Regional Reliability Standards and Regional Criteria. The Standards Committee will consist of one member from each of the WECC Standards Voting Sectors (Section 8.5.5.2) and a member of the WECC Board who shall act as committee chair. Finally, Section 8.3.2 requires the WECC Board to approve a Standards Committee Charter that describes the membership selection process for the committee.
- Section 8.5.4 is amended to provide that the right of any WECC Member to designate a voting member of any standing committee or other committee does not apply to the Standards Committee established under Section 8.3.2.
- Section 8.5.5.1 is amended to provide that the three classes of membership for WECC committees do not apply to the Standards Committee.
- New Section 8.5.5.2 establishes the WECC Standards Voting Sectors for the Ballot Body, comprised of five registered sector (*i.e.*, Entities registered in the NERC Compliance Registry and Canadian and Mexican Entities performing functions that, if performed in the U.S, would result in registration) and three non-registered sectors: (i) Transmission, (ii) Generation, (iii) Marketers and Brokers, (iv) Distribution, (v) System Coordination, (vi) End Use Representative (non-registered member of WECC Member Class Four), (vii) State and Provincial Representatives (non-registered members of WECC Member Class Five), and (viii) Other non-registered WECC Members and Participating Stakeholders. An Entity can be in more than one registered Sector but in only one non-registered Sector. WECC staff shall confirm the eligibility of Participating Stakeholders for Sectors, with decisions of WECC Staff on Sector eligibility appealable to the WECC GNC and decisions of the GNC appealable to the WECC Board.
- Section 8.5.5.3 (renumbered from 8.5.5.2) is amended to specify that the provision allowing each committee member to have one vote does not apply to the voting for proposed Regional Reliability Standards and Regional Criteria, under the voting procedures established in Section 8.5.5.4.
- New Section 8.5.5.4 establishes voting procedures for proposed Regional Reliability Standards and Regional Criteria. When the Standards Committee determines that a draft Regional Reliability Standard or Regional Criteria is ready for consideration by the Ballot Body, it will be presented for a vote. Ballot Body members will be provided the opportunity to opt in to the Ballot Pool for the vote. A two-thirds

quorum of the Ballot Pool is required for a valid vote. Members of the Ballot Pool who are eligible to vote in more than one of the Sectors may cast one vote in each Sector for which they are eligible. Calculation of the vote will be pursuant to a weighted sector voting formula as described in the WECC RSDP. If the Ballot Pool approves a proposed Regional Reliability Standard or Regional Criteria, it will be recommended to the WECC Board.

- Section 8.5.6 is amended so as to make the provisions of that section and of Section 8.6 not applicable to committee recommendations and decisions related to development and approval of reliability standards. This section previously governed posting and notice requirements for proposed reliability standards prior to action by the WECC Standing Committee; however, since under the new procedures, proposed standards will not go through the Standing Committees for approval, there is no need for this section to specify such posting and notice requirements.
- Sections 8.6.1 and 8.6.1.1 are amended to add references to Regional Criteria as well as to Reliability Standards. In addition, section 8.6.1.1 is amended so as to provide that WECC Members and Participating Stakeholders have the right to participate in all discussions, voting and appeals pertaining to a proposed new or revised Reliability Standard or Regional Criteria, not just to committee or subcommittee discussions, votes or appeals in such matters.
- Section 8.6.1.2 is amended to specify that a Participating Stakeholder (*i.e.*, a non-WECC Member) is only entitled to vote on Regional Criteria if the proposed Regional Criteria could result in sanctions to an entity that is not a WECC Member.
- New Section 8.6.1.3 provides authority for the WECC Board to use the special procedures to address regulatory directives (the "backstop" authority) in the event the procedures for drafting and voting on Reliability Standards do not produce a responsive product. The special procedures are set forth in the WECC RSDP. To exercise this authority, the WECC Board must find that the proposed Reliability Standard or revision is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is helpful to reliability, practical, technically sound, technically feasible, and cost justified. If the Board is unable to make this finding, then it may direct that the proposed Reliability Standard be filed with the Applicable Regulatory Authority as a compliance filing in response to the regulatory directive, along with a recommendation that the standard not be made effective and an explanation of the basis for the recommendation.

2. Section 1, Mission, has been amended, for simplification, to delete the list of states and provinces that are fully or partially within the Western Interconnection. As amended, the first paragraph of Section 1 states: "The Western Interconnection is the geographic area containing the synchronously operated electric grid in the western part of North America." The definition of "Western Interconnection" (Section 3.43; renumbered from 3.42) is being amended as follows: "The geographic area containing the synchronously

operated electric transmission grid in the western part of North America, which includes ~~parts of Montana, Nebraska, New Mexico, South Dakota, Texas, Wyoming, and Mexico and all of~~ in the United States Arizona, California, ~~Colorado,~~ Idaho, Nevada, Oregon, Utah, and Washington, as well as parts of Montana, Nebraska, New Mexico, South Dakota, Texas, Wyoming, and Colorado; part of ~~and~~ the Canadian Provinces of British Columbia and Alberta; and Baja California Norte, Mexico.

3. In Section 3.5, a new defined term, "Balancing Authority," has been added, defined as follows: "The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time." (This is the same definition of this term as in the NERC *Glossary of Terms Used in Reliability Standards*.) Correspondingly, the defined term "Control Area" (presently Section 3.11) is being deleted. In the definitions of "Grid Operating Entity" (Section 3.22, renumbered from 3.20) and "Local Regional Entity" (Section 3.24, renumbered from 3.23), the terms "control area operator" and "Control Area" are being deleted and replaced with the term "Balancing Authority."

4. Present Section 3.21, which is the definition of "Participating Stakeholder," is not placed in alphabetical order in the Definitions section of the WECC Bylaws. The text of this section has been moved to be Section 3.33, where it is placed in alphabetical order among the defined terms.

5. The defined term "Reliability Practices," presently Section 3.38, is being deleted as no longer needed.

6. The definition of "Reliability Standard" (Section 3.40, renumbered from 3.39) is being amended to state that a Reliability Standard for the Western Interconnection shall only apply to entities outside the U.S. portion of the Western Interconnection upon approval by the appropriate Canadian or Mexican authority. This definition is also being amended to state that (i) "Reliability Standards include Regional Reliability Standards and Continent-wide standards;" and (ii) Reliability Standards are adopted by NERC; Regional Reliability Standards are specific to the Western Interconnection and shall be established using the WECC RSDP.

7. Section 5.9, "Minimum Participation Requirements," is being amended to eliminate the provision specifying that at least two weeks prior to the WECC Annual Meeting, WECC will send a notice to any Member that has not, within the previous year, satisfied the minimum participation requirement to be counted for quorum purposes at a meeting of the membership as a whole or a Class meeting. This section is also being amended to provide that a Member who has met the minimum participation requirement, and therefore has become an "inactive" Member, can restore its active status by participating in at least one WECC meeting (including meetings of the WECC Board, committees and subcommittees) by attending in person, sending an alternate, or voting an absentee, rather than solely by participating in a WECC Annual Meeting (as provided

in the current section). Finally, this section is being amended to delete the provision that "an inactive Member will not be entitled to vote at WECC meetings until the Member is reinstated to 'active' status;" as amended, the section states that an inactive Member will not be counted toward establishing a quorum of the membership as a whole or of a Class; and specifies the means by which an "inactive" Member" may return to active status.

8. Section 6.2 is being amended to permit the WECC Board to add the WECC CEO to the Board. This amendment results from recent work of a CEO Search Subcommittee of the WECC Human Resources and Compensation Committee, which recommended that WECC have the ability to offer candidates for the CEO position a voting seat on the WECC Board in order to enhance the attractiveness of the CEO position. Additionally, the amendment limits the role of the CEO on the Board by prohibiting the CEO (i) from being a member of a Board Committee and (ii) from casting a tie-creating or tie-breaking vote on any matter.

9. Section 6.5.2.1 is being amended to require a threshold for member nomination of non-affiliated directors for the WECC Board of no fewer than ten members, at least three of whom must be from two different Member Classes, rather than the current threshold of the greater of three members of any Class or ten percent of the members of the Class. Under the WECC Bylaws, the GNC is responsible for nominating a slate of non-affiliated director candidates. It is important for members to have the ability to add candidates to the GNC nomination slate where there is significant member dissatisfaction with the GNC nominations. However, the ability of members to easily nominate candidates, and thereby create an adversarial election, can create difficulties for WECC in attracting quality Board candidates (who may not want to deal with the uncertainty of a contested election) and obtaining the fully independent judgment of sitting non-affiliated directors. The current member nomination threshold was adopted when WECC had less than half the membership it has today. In practice, if a Member Class is small, the current threshold can require a competitive election if fewer than one percent of the members ask for it. WECC advises that every member who provided comments on this proposed amendment expressed agreement that the threshold should be increased.

10. Section 6.12, "Delegation of Board Authority," is being amended to remove limitations on the ability of the WECC Board to delegate contracting authority to the CEO (currently, the Bylaws prohibit the WECC Board from delegating authority to the CEO to enter into contracts for amounts exceeding $50,000). This amendment leaves limitations on the CEO's contracting authority to Board resolutions, which can be modified from time to time as appropriate.

11. Section 7.2 is being amended to clarify that for most decisions of the WECC Board, when a Board member abstains, that vote is not counted as a negative vote; and that only "ayes" and "nays" are counted to determine the result.

12. Current Section 8.4, "Committee Assessment and Streamlining," is being repealed as no longer necessary. This section requires the WECC Board to perform a thorough review of standing committee activities no later than three years after the organizing meeting of WECC to assess whether there are any aspects of the standing committees' functions or procedures that impede development of WECC standards, obligations, processes, and decisions that are timely, fair, effective, and reasonable in view of the commercial, legal, regulatory, and economic needs and objectives of the affected members. This review occurred as required in 2004. Section 8.4 also requires, no later than three years after the organizing meeting of WECC, the automatic dissolution of all member groups other than the standing committees. In connection with the repeal of Section 8.4, the defined term "Organizing Meeting" in current Section 3.32 is being deleted.

13. Section 8.5.5.3 (renumbered from 8.5.5.2) is being amended to give the WECC Board more control over voting and record-keeping procedures of Board Committees. The GNC recommended that the Board be given sole authority to adopt voting procedures that could be amended as necessary to refine the process, without having to further amend the Bylaws. In response, the word "Committees" in this section is being replaced with "The Board;" therefore, the section will read, in pertinent part: "The Board will adopt voting and record-keeping procedures to ensure that committee voting is conducted consistent with these Bylaws."

14. Section 9.6.2 is being amended to replace the term "Interested Stakeholders" with the term "Participating Stakeholders." This amendment should have been implemented in connection with earlier amendments in which "Interested Stakeholders" was changed to the defined term "Participating Stakeholders" throughout the WECC Bylaws; however, this amendment to Section 9.6.2 was missed at that time.

15. Numerous sections of the WECC Bylaws have been amended to change references to "the WECC" to "WECC" (*i.e.*, to delete the word "the"). The sections amended in this manner are 2 (caption), 2.1.1, 2.1.2, 2.1.3, 2.1.4, 2.1.5, 2.1.6, 2.1.7, 2.1.8, 2.1.9, 2.1.10, 2.1.11, 2.2.1, 2.2.2, 2.3, 3.4, 3.15 (renumbered from 3.13), 3.23 (renumbered from 3.22), 3.27 (renumbered from 3.26), 4.1, 4.2, 4.2.7, 4.3, 4.6, 4.6.3, 4.6.9, 4.8, 4.9, 5.3, 6.1, 6.4.2, 6.4.4, 6.5.1.1, 6.5.2.2, 6.10.1, 6.11, 6.12, 7.3, 7.4.1, 8.1, 8.2.1, 8.2.2, 8.8, 9.1, 9.3, 9.6.2, 10.4, 11, 12.1.1, 12.1.2, 12.3, 14, 16, and 17, and various places in Appendix A and Appendix B to the Bylaws. (Some of these sections also have other amendments that are discussed elsewhere in this memorandum.)

16. Several sections of the WECC Bylaws have been amended to change references to "Web site" to "website." The sections amended in this manner are 5.6.3, 6.12.1, 7.4.1, 7.5.2, 7.5.3, 8.7.1 and 9.6.3.

17. In addition to the above amendments, WECC seeks approval for an amendment to Section 3.24 (renumbered from 3.23), the defined term "Local Regional Entity" that was approved by the WECC Board in April 2006 and implemented in the Bylaws document,

but was never explicitly presented to the NERC Board (or to the Commission) for approval. The amendment is the deletion of a sentence from the definition of "Local Regional Entity" as shown below:

A regional transmission organization or some other formally or informally constituted regional organization or group within the Western Interconnection, including but not limited to a Control Area, a group of Control Areas acting in concert, or a group of Entities that own or operate Transmission Facilities acting in concert. ~~At the time of the formation of the WECC, regions will define their boundaries and establish formal or informal coordination as necessary. These~~ Local Regional Entity boundaries can be reevaluated or modified over time.

As described in item 3 above, this section is also being amended to replace "Control Area" and "Control Areas" with "Balancing Authority" and "Balancing Authorities."

Amendment to Exhibit C (WECC RSDP)

1. In Exhibit C, the text for the following "Common Attributes" of an acceptable regional reliability standard development procedure is being revised to be consistent with the proposed amended WECC RSDP: nos. 5, 6, and 9 through 20.

2. In general, the amendments to the NERC RSDP (name of the document changed from "Process for Developing and Approving WECC Standards" to "Reliability Standards Development Procedures") remove responsibility for development of WECC Regional Reliability Standards and Regional Criteria from the WECC standing committees and place responsibility with the WECC Standards Committee (WSC) and Drafting Teams. The amendments also add a procedure for proposing, developing and adopting interpretations of Regional Reliability Standards and Regional Criteria, and special procedures for addressing regulatory directives with respect to a proposed Regional Reliability Standard.

   - The "Terms" section of the WECC RSDP adds defined terms used in the revised process, such as Ballot Body, Ballot Pool, Draft Standard, Standard Authorization Request (SAR), WECC Standards Committee (WSC), and WECC Standards Voting Sectors; and deletes defined terms that are no longer needed. The defined term WECC Standards Voting Sectors lists the eight sectors (five registered sectors and three non-registered sectors) for purposes of voting on Standards, consistent with new Section 8.5.5.2 of the WECC Bylaws.

   - The "Normal Process for Standards" section sets forth the eleven steps in the process for development and adoption of WECC Standards:

     Step 1 – Request to Revise or Develop a Standard (*i.e.*, submission of a SAR)

Step 2 – Standard Authorization Request Validation and Submission to the WSC. In this step, the WSC determines if the SAR is within the scope of WECC's authority and is appropriate; if so, the WSC selects and oversees a Drafting Team formed to draft a Draft Standard.

Step 3 – Drafting Team Begins Drafting Phase and Submits Draft Standard to WSC. Upon reaching a determination, by majority vote, on the language for a Draft Standard, the Drafting Team submits the Draft Standard to the WSC, along with an impact assessment report, any additional technical studies performed, and any other materials that significantly contributed to the Drafting Team's evaluation and drafting of the Draft Standard.

Step 4 – Draft Standard Posted for Comment. The WSC determines whether to (i) post the Draft Standard for a 45-day comment period, (ii) further modify the Draft Standard, (iii) return the Draft Standard to the Drafting Team for further work, as directed, or (iv) terminate the Standard development activity. A majority vote of the authorized membership of the WSC is required to terminate a Draft Standard at this stage.

Step 5 – WSC Deliberates on Comments received during the comment period.

Step 6 – WSC Submits Draft Standard for Ballot Body Vote and Ballot Pools Are Established. The WSC will post the final Draft Standard at least 30 days before the voting window. After the Draft Standard is posted, the WECC Standing Committees shall participate in at least one Joint Session addressing the Draft Standard; and individual Standing Committees may conduct additional discussions or webinars.

Step 7 – Ballot Pool Vote on Recommendation to Board. The voting window will be 15 days, but may be extended by the WSC until a quorum is achieved. Each WECC member or Participating Stakeholder may cast one vote in each eligible voting sector. Voters rejecting the Draft Standard will be required to provide an explanation of their vote. A two-thirds quorum of the Ballot Pool based on the total number of Ballot Pool members (counting abstentions and incomplete responses) is required. A weighted majority vote of the Ballot Pool is required for a Draft Standard to be approved. Step 7 sets forth the procedure for calculating the weighted Sector vote. If the Ballot Pool approves the Draft Standard, the WSC shall submit it to the WECC Board. If the Ballot Pool rejects the Draft Standard, the WSC may, by majority vote of its membership, decide to amend or modify the Draft Standard or to remand it to the Drafting Team to amend or modify it, followed thereafter by a reballot; or, the WSC may allow the Draft Standard to terminate.

Step 8 – Appeals Process. The WSC may be asked to reconsider its decisions. The rejection of a request for reconsideration by the WSC may be appealed to the WECC Board. A Draft Standard recommended by the WSC may be appealed on either technical or due process grounds.

Step 9 – Board Approval. A majority vote of the WECC Board, in accordance with Sections 7.2 and 7.4.1 of the WECC Bylaws, is required to approve a recommended Standard. If the Draft Standard is not approved, the WECC Board may return it to the WSC for further work, or may terminate the Standard development activity.

Step 10 – ERO Review, FERC [or applicable Canadian or Mexican authority] Approval and Implementation of Reliability Standards.

Step 11 – Implementation of Standards Not Subject to ERO/FERC/Other Approval. All new and modified WECC Standards not subject to ERO review and FERC, Canadian or Mexican approval (Step 10) shall become effective as ordered by the WECC Board.

- The Interpretation of Regional Standards and Regional Criteria section is a new section that establishes procedures for requesting, developing (through an Interpretation Drafting Team), balloting, adopting (by the WECC Board), and submitting to NERC and to FERC (and/or applicable Canadian or Mexican authorities) for approval, an interpretation of a Regional Reliability Standard or Regional Criteria.
- The Special Procedures for Addressing Regulatory Directives section is a new section that establishes procedures for further actions if the WECC Board determines that the WECC Standards Process did not result in a proposed Draft Standard that addresses a directive issued by FERC or by an applicable Canadian or Mexican regulatory authority. The actions available to the WECC Board include remanding to the WSC a Standard that the Ballot Pool has approved; and remanding to the WSC a Standard that the Ballot Pool failed to approve, for additional consideration and reballoting. If the Draft Standard is not approved through a reballot, the WECC Board has the authority to (i) submit the Draft Standard to the regulatory authority with a request that it be made effective or a recommendation that it not be made effective; or (ii) direct the WSC to prepare a Draft Standard that addresses the regulatory directive, which the WECC Board may then submit to the regulatory authority with a request that it be made effective or a recommendation that it not be made effective.

ATTACHMENT 1

LETTER FROM WECC

Steven F. Goodwill
Vice President and General Counsel

801-883-6857
sgoodwill@wecc.biz

VIA EMAIL

October 3, 2011

Mr. David N. Cook
Senior Vice President and General Counsel
North American Electric Reliability Corporation
1120 G Street, N.W.
Suite 990
Washington, D.C. 20005

Dear Mr. Cook:

The attached amendments to the WECC Bylaws and standards development procedures were approved by the WECC Board of Directors and Membership in accordance with the Bylaws at meetings of the Board and Membership in August 2008 and March and June 2011. WECC requests the amended Bylaws and revised standards development procedures be presented for NERC Board of Trustees (BOT) approval at its scheduled meeting on November 3, 2011 and subsequent filing for Federal Energy Regulatory Commission (FERC) approval.

Approval by FERC will necessitate revision of Exhibits B and C of the NERC-WECC delegation agreement. Consequently, WECC will be prepared to execute the revised delegation agreement following receipt of Commission approval of the Bylaws amendments and revised standards development procedures.

If you need anything further regarding this matter, please don't hesitate to contact me at sgoodwill@wecc.biz or 801-883-6857.

Sincerely,

Steven F. Goodwill
Vice President and General Counsel

Attachments:
1. Amended WECC Bylaws – redline version
2. Revised Standards Development Procedures – redline version

ATTACHMENT 2

EXHIBIT B TO WECC DELEGATION AGREEMENT –

WECC BYLAWS

REDLINED TO SHOW PROPOSED AMENDMENTS

Exhibit B – Governance

Exhibit B shall set forth the Regional Entity's bylaws, which NERC agrees demonstrate that the Regional Entity meets the following criteria:

CRITERION 1: The Regional Entity shall be governed by an independent board, a balanced stakeholder board, or a combination independent and balanced stakeholder board. (Federal Power Act § 215(e)(4)(A), 18 C.F.R. § 39.8(c)(1), Order No. 672 at ¶ 727.)

CRITERION 2: The Regional Entity has established rules that assure its independence of the users and owners and operators of the bulk power system, while assuring fair stakeholder representation in the selection of its directors. Federal Power Act § 215(c)(2)(A) and (e)(4), 18 C.F.R. § 39.8(c)(2), Order No. 672 at ¶¶ 699, 700.)

CRITERION 3: If the Regional Entity has members, the Regional Entity has established rules that assure that its membership is open, that it charges no more than a nominal membership fee and agrees to waive the fee for good cause shown, and that membership is not a condition for participating in the development of or voting on proposed Regional Reliability Standards. (Federal Power Act § 215(c)(2)(A) and (e)(4), 18 C.F.R. § 39.8(c)(2), Order No. 672 at ¶¶ 170-173.)

CRITERION 4: The Regional Entity has established rules that assure balance in its decision-making committees and subordinate organizational structures and assure no two industry sectors can control any action and no one industry sector can veto any action. (Federal Power Act § 215(c)(2)(A) and (e)(4), 18 C.F.R. § 39.8(c)(2), Order No. 672 at ¶ 728.)

CRITERION 5: The Regional Entity has established rules that provide reasonable notice and opportunity for public comment, due process, openness, and balance of interests in exercising its duties. (Federal Power Act § 215(c)(2)(D) and (e)(4), 18 C.F.R. § 39.8(c)(2).)

BYLAWS

OF

THE

WESTERN ELECTRICITY COORDINATING COUNCIL

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BYLAWS

Of

The

WESTERN ELECTRICITY COORDINATING COUNCIL

1. Mission.

The Western Interconnection is the geographic area containing the synchronously operated electric grid in the western part of North America~~, which includes parts of Montana, Nebraska, New Mexico, South Dakota, Texas, Wyoming, and Mexico and all of Arizona, California, Colorado, Idaho, Nevada, Oregon, Utah, Washington and the Canadian provinces of British Columbia and Alberta~~.

The Western Electricity Coordinating Council ("WECC") is a Utah nonprofit corporation with the mission to do the following consistent with these Bylaws: 1) maintain a reliable electric power system in the Western Interconnection that supports efficient competitive power markets ("Reliability Mission"); and 2) assure open and non-discriminatory transmission access among Members and provide a forum for resolving transmission access disputes between Members consistent with FERC policies where alternative forums are unavailable or where the Members agree to resolve a dispute using the mechanism provided in Section 11 ("Transmission Access Mission").

2. Furtherance of ~~the~~ WECC's Mission

2.1 Activities to Carry Out WECC's Reliability Mission.

2.1.1 Compliance with the Federal Power Act. ~~The~~ WECC will carry out responsibilities and exercise rights of a Regional Entity organized on an interconnection-wide basis pursuant to Section 215 of the Federal Power Act, including any responsibilities and rights delegated to it by the ERO pursuant to a Delegation Agreement.

2.1.2 Agreements with Canada and Mexico. ~~The~~ WECC will carry out responsibilities and exercise rights pursuant to International Reliability Agreements with Canadian or Mexican authorities.

2.1.3 Regional Coordination. ~~The~~ WECC will act as a coordinating entity for the entire Western Interconnection for activities of regional organizations with responsibilities for reliability and market functions.

2.1.4 Standard Setting. ~~The~~ WECC will develop and adopt reliability, operating, and planning standards, criteria and guidelines necessary to maintain the reliable operation of the Western Interconnection's interconnected bulk power system, including seeking, as appropriate, variances from standards of the ERO (or any

successor organization which may be created by legislation or otherwise), as well as providing a process for regional variances.

2.1.5 Certification of Grid Operating Entities. ~~The~~ WECC will certify Grid Operating Entities in the Western Interconnection.

2.1.6 Reliability Assessment. ~~The~~ WECC will ensure that interconnected bulk electric system reliability assessments are conducted as needed. ~~The~~ WECC will do this work in conjunction with the Regional Entities to the greatest extent possible. ~~The~~ WECC will also facilitate coordinated reliability assessments among Regional Entities.

2.1.7 Compliance Activities. With respect to enforcement of reliability standards, ~~the~~ WECC will:

2.1.7.1 implement the Reliability Management System in effect as of ~~the~~ WECC's formation and as the Reliability Management System may be subsequently modified in accordance with its terms;

2.1.7.2 implement any enforcement mechanisms delegated to it pursuant to Section 215 of the Federal Power Act and any Delegation Agreement with the ERO, or required by any International Reliability Agreement with a Canadian or Mexican authority; and

2.1.7.3 administer any other enforcement mechanisms developed through voluntary processes after ~~the~~ WECC's formation, where ~~the~~ WECC is designated to perform administration.

2.1.8 Coordinated Regional Planning. With respect to the coordination of regional planning activities, ~~the~~ WECC:

2.1.8.1 will develop coordinated planning policies and procedures for the Western Interconnection, including facilitation of market-based solutions, consistent with WECC/ERO standards and FERC policy.

2.1.8.2 will review and assess Local Regional Entity planning processes to determine whether WECC planning procedures have been satisfied;

2.1.8.3 will refer planning matters back to the originating Local Regional Entity for revision or other corrective actions when the WECC Board determines that WECC planning procedures have not been satisfied; and

2.1.8.4 may perform other interconnection-wide studies as needed.

2.1.9 Coordinated Operations. With respect to coordinating reliable operating activities within the Western Interconnection, ~~the~~ WECC will develop, coordinate and promote

consistent interregional operating policies and procedures for the Western Interconnection, consistent with WECC/ERO standards and FERC policy.

2.1.10 Market Interface Issues. With respect to Market Interface issues ~~the~~ WECC will:

2.1.10.1 facilitate development of compatible and efficient practices across the Western Interconnection; and

2.1.10.2 exercise Backstop Authority where an unresolved Market Interface issue will cause Material External Impacts by taking some or all of the following actions: 1) providing a forum for and coordinating voluntary solutions among Members; 2) recommending specific solutions for voluntary adoption by Members; and 3) if necessary, proposing solutions to an Applicable Regulatory Authority.

2.1.11 Dispute Resolution. ~~The~~ WECC will provide a process for the timely resolution of disputes between WECC Members as set forth in Section 11.

2.2 Activities to Carry Out WECC's Non-Discriminatory Access Mission.

2.2.1 In accordance with Section 10 of these Bylaws, ~~the~~ WECC will ensure the provision of non-discriminatory transmission access between Members.

2.2.2 In accordance with Section 10 of these Bylaws, ~~the~~ WECC will provide for the submission of Open Access Transmission Tariffs (or petitions for exemption) by all Members that own or operate Transmission Facilities.

2.3 Organizational Characteristics.

As ~~the~~ WECC carries out activities to fulfill its mission, it will seek to develop and maintain the following characteristics:

2.3.1 dedication to serving the individuals, businesses, and other organizations that generate, transmit, distribute, market, and use electrical energy in the Western Interconnection;

2.3.2 efficiency in its administration, decision-making, policy and standards development, and dispute resolution processes;

2.3.3 the ability to maintain status as an Interconnection-wide regional reliability entity and be afforded deference and delegation by ERO (or successor organization); and

2.3.4 fair and open processes through which practices, policies, and standards are developed and implemented based on sound technical and policy analysis.

2.3.5 Promote an efficient western electric market by reducing or eliminating conflict, duplication and overlap among electric organizations in the Western Interconnection.

3. Definitions.

3.1 Affiliate.

An Entity that directly or indirectly through one (1) or more intermediaries, controls, or is controlled by, or is under common control with, another Entity. An Entity "controls" any Entity in which it has the power to vote, directly or indirectly, 5% or more of the voting interests in such entity or, in the case of a partnership, if it is a general partner. Notwithstanding the foregoing definition, for purposes of these Bylaws: 1) electric distribution cooperatives that are member-owners of a generation and transmission cooperative are not Affiliates of the generation and transmission cooperative or of each other; 2) an entity controlled by or operating as a unit, agency, or subdivision of a local, state, provincial, or U.S. federal or Canadian or Mexican national government will not be considered an Affiliate of any other entity controlled by or operating as a unit, agency, or subdivision of a local, state, provincial, or federal government; 3) separate agencies of a single state or province, or of the U.S. federal or Canadian or Mexican national government will not be considered Affiliates of each other, regardless of any commonality of political control; 4) members of any joint powers authority, and such joint powers authority, will not be considered Affiliates of each other; and 5) members of an RTO will not be considered Affiliates of such RTO or of each other solely as a result of such membership.

3.2 Annual Meeting.

The annual membership meeting of WECC, as described in Section 5.3.

3.3 Applicable Regulatory Authority.

The FERC or any state or provincial government agency with jurisdiction to regulate or directly affect the transmission of electricity within the Western Interconnection.

3.4 Backstop Authority.

The ability, obligation, or responsibility of ~~the~~ WECC to address an issue when the WECC Board determines that a Local Regional Entity(ies) holding Primary Authority has not resolved an issue, has created incompatible resolutions or has not acted. In each case where these Bylaws authorize ~~the~~ WECC to exercise Backstop Authority, the provisions that authorize Backstop Authority will also specify the conditions necessary to trigger Backstop Authority and the actions that fall within ~~the~~ WECC's exercise of Backstop Authority.

3.5 Balancing Authority.

The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

3.6 Ballot Body.

The Ballot Body consists of WECC members and non-members that have been determined eligible for the voting sectors described in 8.5.5.2 and may, therefore, vote on Regional Criteria and Regional Reliability Standards.

3.7 Ballot Pool.

A Ballot Pool consists of a self-selected set of members of the Ballot Body who join the Ballot Pool for a given Regional Criterion or Regional Reliability Standard during a designated window of opportunity provided by WECC either prior to balloting or prior to the close of balloting.

~~3.5~~3.8 Board of Directors (Board).

WECC Board of Directors, collectively, as described in Section 6.

~~3.6~~3.9 Canadian Delegation.

Canadian WECC Members.

~~3.7~~3.10 Canadian Director.

A member of the WECC Board of Directors that is either a representative from a Canadian Member of WECC or an individual currently residing in Canada and qualified to provide expertise on Canadian interests on the WECC Board of Directors.

~~3.8~~3.11 Class.

A grouping of Members described in Sections 4.2.1 through 4.2.7 and 4.3.

~~3.9~~3.12 Commercial Practices.

The products and practices involved in trading electricity. The term "Commercial Practices" only refers to an interaction among market entities that does not affect or require assistance from Grid Operating Entities that have grid reliability responsibilities.

~~3.10~~3.13 Compliance Hearing Body.

The hearing body formed in accordance with procedures established in the WECC Delegation Agreement with the ERO for the purpose of providing a balanced compliance panel to conduct hearings for the resolution of disputes concerning compliance with or enforcement of Reliability Standards that may arise between WECC (acting as Compliance Enforcement Authority for the Western Interconnection) and a Registered Entity.

~~**3.11 Control Area.**~~

~~An electric power system (or combination of electric power systems) to which a common automatic generation control scheme is applied in order to: 1) match, at all times, the power output of the generating units within the electric power system(s), plus the energy purchased from entities outside the electric system(s), minus energy sold to entities outside the electric system(s), with the demand within the electric power system(s); 2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice; 3) maintain the frequency of the electric power system(s)~~

~~within reasonable limits in accordance with Good Utility Practice; and 4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.~~

~~3.12~~3.14 Cross-Border Regional Entity.
A Regional Entity that encompasses a part of the United States and a part of Canada or Mexico, and may therefore be delegated authority to propose and enforce Reliability Standards in Canada or Mexico by virtue of applicable contractual or regulatory mechanisms.

~~3.13~~3.15 Delegation Agreement.
An agreement between the ERO and ~~the~~ WECC pursuant to Section 215 of the Federal Power Act by which the ERO delegates to ~~the~~ WECC designated powers, rights and responsibilities regarding the administration within the Western Interconnection of electric Reliability Standards adopted or approved by the ERO and the FERC.

~~3.14~~3.16 Director.
An individual member of the WECC's Board of Directors.

~~3.15~~3.17 Electric Line of Business.
The generation, transmission, distribution, or trading of electricity or the provision of related energy services in the Western Interconnection.

~~3.16~~3.18 Electric Reliability Organization (ERO).
The organization certified by FERC under 18 C.F.R. §39.3, the purpose of which is to establish and enforce Reliability Standards for the bulk-power system in the United States, subject to FERC review.

~~3.17~~3.19 Entity.
Any individual, person, corporation, partnership, association, governmental body or organization of any kind.

~~3.18~~3.20 FERC.
The Federal Energy Regulatory Commission or any successor.

~~3.19~~3.21 Good Utility Practice.
Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

~~3.20~~3.22 **Grid Operating Entity.**

Any operating entity, such as a ~~control area operator~~ Balancing Authority, that is certified pursuant to Section 2.1.5 of these Bylaws to be responsible for reliable operation of a portion of the Western Interconnection.

~~**3.21 Participating Stakeholder.**~~

~~Any person or entity that is not a WECC Member, but is an interested stakeholder and has applied and been granted, pursuant to Section 8.6.2, the participation and voting rights set forth in Section 8.6.1.~~

~~3.22~~3.23 **International Reliability Agreement**.

An agreement between ~~the~~ WECC and any appropriate Canadian or Mexican authority related to WECC's powers, rights and responsibilities regarding the administration within the Western Interconnection of electric Reliability Standards.

~~3.23~~3.24 **Local Regional Entity.**

A regional transmission organization or some other formally or informally constituted regional organization or group within the Western Interconnection, including but not limited to a ~~Control Area~~ Balancing Authority, a group of ~~Control Areas~~Balancing Authorities acting in concert, or a group of Entities that own or operate Transmission Facilities acting in concert. These Local Regional Entity boundaries can be reevaluated or modified over time.

~~3.24~~3.25 **Market Interface.**

Market Interface involves all interactions among market entities and Grid Operating Entities related to transmission service and physical delivery.

~~3.25~~3.26 **Material External Impacts (MEI).**

Significant effects on another Local Regional Entity or market within the Western Interconnection but outside of the Local Regional Entity or market adopting a policy, standard, practice or procedure, or implementing an action.

~~3.26~~3.27 **Member.**

Any entity that has applied and been accepted for membership in ~~the~~ WECC and is current in the payment of dues.

~~3.27~~3.28 **Member Class Director.**

A Director elected by a Class in accordance with Section 6.4 of these Bylaws.

~~3.28~~3.29 **Mexican Delegation.**

Mexican WECC Members.

~~3.29~~3.30 **Mexican Director.**

A member of the WECC Board of Directors that is either a representative from a Mexican Member of WECC or an individual currently residing in Mexico and qualified to represent Mexican interests on the WECC Board of Directors.

~~3.30~~3.31 **Non-Affiliated Director.**
A Director elected by the Members who satisfies the requirements of Section 6.5.1 of these Bylaws.

~~3.31~~3.32 **Open Access Tariff.**
A tariff offering transmission service which meets the requirements applicable to FERC orders regarding open access.

3.33 Participating Stakeholder.
Any person or entity that is not a WECC Member, but is an interested stakeholder and has applied and been granted, pursuant to Section 8.6.2, the participation and voting rights set forth in Section 8.6.1.

~~**3.32 Organizing Meeting.**~~
~~The first formal membership meeting of the WECC.~~

~~3.33~~3.34 **Primary Authority.**
The ability, obligation, or responsibility of an entity to address an issue in the first instance.

3.35 Regional Criteria
A WECC Board Approved document whose purpose is to establish consistency among WECC member entities with respect to business practices, technical procedures, documentation procedures or administrative procedures. Regional Criteria include specific procedures or requirements and must be approved by the Board. New and revised Regional Criteria shall be established using the WECC Standards Development Procedures.

~~3.34~~3.36 **Regional Entity (RE).**
An entity having enforcement authority pursuant to 18 C.F.R. §39.8.

~~3.35~~3.37 **Regional Transmission Organization (RTO).**
An entity approved by the Federal Energy Regulatory Commission as meeting the requirements and performing the functions of a regional transmission organization pursuant to FERC Order 2000 and subsequent related orders.

~~3.36~~3.38 **Registered Entity.**
An owner, operator, or user of the bulk-power system or the entities registered as their delegates for the purpose of compliance in the North American Electric Reliability Corporation Regional Compliance Registry.

~~3.37~~3.39 **Reliability Management System**
The contracts, separate from these Bylaws, by which Members and other parties agree to certain procedures and sanctions intended to enforce specified Reliability Practices to maintain reliable electric service throughout the Western Interconnection.

~~3.38 Reliability Practices.~~
~~Policies, practices and standards designed to ensure the adequacy and security of the Western Interconnection in accordance with applicable reliability criteria (e.g. ERO, WECC, Local Regional Entity criteria).~~

~~3.39~~3.40 Reliability Standard.
A requirement approved by FERC under section 215 of the Federal Power Act, to provide for reliable operation of the bulk-power system in the United States. The term includes requirements for the operation of existing bulk-power system facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity. A Reliability Standard for the Western Interconnection shall only apply to entities outside of the U.S. portion of the Western Interconnection upon approval by the appropriate Canadian or Mexican regulatory authority. Reliability Standards include Regional Reliability Standards and Continent- wide standards. Reliability Standards are adopted by the North American Electric Reliability Corporation ("NERC"). Regional Reliability Standards are specific to the Western Interconnection and shall be established using the WECC Standards Development Procedures~~may also be approved by Canadian and Mexican regulatory authorities~~.

~~3.40~~3.41 Reliability Standards Development Procedures.
The ~~P~~process for ~~D~~developing and ~~A~~approving WECC Regional Reliability Standards (or its successor) attached as Exhibit C to the Delegation Agreement between WECC and North American Electric Reliability Corporation.

~~3.41~~3.42 Transmission Facilities.
Those facilities that are defined as "transmission facilities" by FERC for purposes of the open access requirements of Section 210 and 211 of the Federal Power Act or any facilities which would be so defined if the Member were subject to FERC jurisdiction.

~~3.42~~3.43 Western Interconnection.
The geographic area containing the synchronously operated electric transmission grid in the western part of North America, which includes ~~parts of Montana, Nebraska, New Mexico, South Dakota, Texas, Wyoming, and Mexico and all of~~in the United States Arizona, California, ~~Colorado,~~ Idaho, Nevada, Oregon, Utah, and Washington, as well as parts of Montana, Nebraska, New Mexico, South Dakota, Texas, Wyoming, and Colorado; parts of ~~and~~ the Canadian Provinces of British Columbia and Alberta; and Baja California Norte, Mexico.

4. Members and Membership.

4.1 Voluntary Membership.
Except as otherwise may be required by applicable authority, membership in ~~the~~ WECC is voluntary. A Member may withdraw upon giving the Secretary thirty (30) days' advance

written notice. Notwithstanding such notice of withdrawal, all contracts (including any Reliability Management System Agreement), FERC orders, unpaid Member costs, decisions of arbitration and requests for transmission service made to the withdrawing Member in effect or pending as of the date of the written notice of withdrawal will be followed through to completion, pursuant to these Bylaws, by the withdrawing Member; however, pending requests for transmission service to be provided to such withdrawing Member will be void for the purposes of these Bylaws. Nothing herein will relieve any Member withdrawing from ~~the~~ WECC from any obligation it may have under applicable law including, but not limited to, Section 215 of the Federal Power Act. A Member that withdraws is obligated to pay any unpaid dues owed through the remainder of the fiscal year in which its resignation becomes effective. Any Director employed by a withdrawing Member will be deemed to have resigned pursuant to Section 6.8.

4.2 Eligibility for Membership.

Subject to Section 4.5, any Entity that is an interested stakeholder or that meets the criteria for membership in the membership classes described in Sections 4.2.1 through 4.2.7 may be a Member of ~~the~~ WECC:

4.2.1 Class 1. Electric Line of Business Entities owning, controlling or operating more than 1000 circuit miles of transmission lines of 115 kV and higher voltages within the Western Interconnection.

4.2.2 Class 2. Electric Line of Business Entities owning, controlling or operating transmission or distribution lines, but not more than 1,000 circuit miles of transmission lines of 115 kV or greater, within the Western Interconnection.

4.2.3 Class 3. Electric Line of Business Entities doing business in the Western Interconnection that do not own, control or operate transmission or distribution lines in the Western Interconnection, including power marketers, independent power producers, load serving entities and any other Entity whose primary business is the provision of energy services.

4.2.4 Class 4. End users of significant amounts of electricity in the Western Interconnection, including industrial, agricultural, commercial and retail entities as well as organizations in the Western Interconnection that represent the interests of a substantial number of end users or a substantial number of persons interested in the impacts of electric systems on the public or the environment.

4.2.5 Class 5. Representatives of states and provinces in the Western Interconnection, provided that such representatives will have policy or regulatory roles and do not represent state or provincial agencies and departments whose function involves significant direct participation in the market as end users or in Electric Line of Business activities.

4.2.6 Class 6. Canadian members of other classes pursuant to Section 4.3.

4.2.7 Class 7. Members at large, that is, entities that are not eligible for membership in the other Member Classes and who have a substantial interest in the purposes of ~~the~~ WECC.

4.3 Designation of Membership Class.

A Member of WECC may not belong to more than one Class except that for purposes of electing Canadian Directors and for populating the Governance and Nominating Committee, there shall be a Class 6 composed of all Canadian Members from any of the Member Classes defined in Section 4.2 except Class 7. An applicant for membership will designate the Class for which it qualifies based upon the criteria for membership set forth in Section 4.2 and these additional requirements: 1) all Members that are Electric Line of Business Entities must belong to Classes 1, 2 or 3; and 2) any Member owning, controlling or operating Transmission Facilities or distribution facilities must belong to Class 1 or 2 unless the Board grants the Member's petition for a change in Member Class pursuant to the provisions of Section 4.4 of these Bylaws. Applications for membership will be submitted to ~~the~~ WECC. WECC staff will review the application to verify eligibility for membership and Member Class designation. An applicant whose application has been rejected or any Member who disputes the WECC staff's determination regarding the appropriate Member Class designation may request review by the Governance and Nominating Committee. If the applicant or any Member disagrees with the Governance and Nominating Committee's decision, the applicant or such Member may appeal this decision to the Board.

4.4 Changes in Membership Class.

Notwithstanding any other provision of these Bylaws, upon a petition from a Member, the WECC staff (subject to review by the Governance and Nominating Committee and appeal to the Board) may allow the Member to change Member Class if the interest of the Member is more closely aligned with the proposed Class than the Member's current Class.

4.5 Affiliates and Distinct Business Entities.

An Affiliate of a Member that satisfies the membership qualifications may also become a Member provided:

4.5.1 The Affiliate applying for membership and the Member disclose to the Chief Executive Officer all Affiliates that are WECC Members and the Classes to which the Affiliates belong. Every Member will promptly notify the Chief Executive Officer whenever it becomes, or ceases to be, an Affiliate of any other Member.

4.5.2 Affiliates may be members of the same Class; provided, however, a group of Affiliates within a single Class may only have one vote in any WECC forum. A group of Affiliates within a single Class may, by providing written notice to the Chief Executive Officer, split their single vote pro rata or designate a single Affiliate as the group's voting Member.

4.5.3 For good cause shown and with the express approval of the Board, a company or organization containing functionally distinct entities within it may obtain separate

memberships for such entities; provided that such entities will be considered Affiliates.

4.5.4 The Board may adopt a policy regarding whether Members may share the benefits of membership (including the right to receive information that is only available to Members) with a non-member Affiliate.

4.5.5 Upon receiving applications from non-WECC members to join the Ballot Body, WECC staff shall require such non-WECC members to identify their affiliations with other Ballot Body members in their applications to join the Ballot Body. WECC staff shall limit voting of affiliated non-WECC members in the same manner that would be used to limit voting by WECC member organizations.

4.6 Rights and Obligations of Membership.
Except as otherwise provided in these Bylaws or other applicable authority, Members of ~~the~~ WECC have the following general rights and obligations:

4.6.1 The right to elect and remove Directors as described in Sections 6.4, 6.5 and 6.7;

4.6.2 The right to amend these Bylaws, and to review and rescind any Board amendment of these Bylaws, in accordance with Section 13;

4.6.3 The right to receive appropriate meeting notices, as well as reports and information produced by ~~the~~ WECC;

4.6.4 The right to attend, participate and vote in all WECC Member meetings and the right to attend Board meetings (other than closed sessions of Board meetings) and to comment upon all matters considered in such meetings;

4.6.5 The right to be a member of, attend meetings of, and to introduce motions, debate and to vote in the deliberations of WECC committees, subject to the limitations of these Bylaws and such other reasonable limitations as the Board may adopt from time to time;

4.6.6 The right to obtain non-discriminatory transmission access from other Members in accordance with applicable law and Section 10 of these Bylaws;

4.6.7 The right to invoke the dispute resolution provisions of these Bylaws;

4.6.8 The right to petition the Board to take any action consistent with applicable law (including Section 215 of the Federal Power Act and implementing orders and regulations), these Bylaws and the articles of incorporation and to have such petition voted upon in a reasonable and timely manner;

4.6.9 The obligation to abide by these Bylaws, decisions resulting from the dispute resolution process, and all standards or decisions of ~~the~~ WECC, subject to the exceptions set forth in Section 4.7 and the enforcement provisions of Section 4.8.

4.6.10 For Members owning or operating Transmission Facilities, or possessing transmission capacity rights by contract, the obligation to provide non-discriminatory transmission access to other Members through a regional transmission organization, the submittal of an Open Access Tariff with the FERC or in accordance with Section 10 of these Bylaws;

4.6.11 The obligation to notify the Chief Executive Officer promptly of changes with respect to Affiliates as provided in Section 4.5.1 of these Bylaws; and

4.6.12 The obligation to pay in a timely manner the membership dues pursuant to Section 12.

4.6.13 The obligation to provide system data that the Board has determined is necessary for WECC functions and does not impose an undue burden on the Members; provided, however, that the Board shall adopt appropriate limitations on this obligation or procedures that protect, and avoid the unnecessary collection of, confidential, privileged, trade secret, cybersecurity or critical energy infrastructure information or other information that the Board determines merits such protection consistent with applicable law.

4.7 Limitations on Member Obligations.

The obligation of Members pursuant to Section 4.6.9 will not require any Member to take any action which the Member in good faith determines: 1) would exceed the physical capabilities of the Member's electric system (or any part of another's electric system that the Member has the legal right to cause to comply with a WECC action governed by Section 4.6.9); 2) would create serious and immediate risks to public health or safety (provided, however, that the shedding of load shall not in and of itself be deemed a serious and immediate risk to public health and safety for the purpose of this section); 3) would create an immediate risk of serious damage to facilities or equipment within its electric system or cause it to operate any of its electric facilities or equipment in an unsafe manner; 4) would cause the Member to violate or improperly implement an applicable law, regulation, rule, order, FERC license provision or other legal obligation; or 5) would conflict with any non-power requirement applicable to the Member (including without limitation any obligation under environmental laws, regulations, court and administrative decisions or biological opinions).

Each Member shall retain sole control of its facilities and the use thereof, and a Member shall not be required to construct or dedicate facilities for the benefit of any other Member, or be required to take action, or refrain from action, as may be deemed necessary to maintain reliable service to its own customers and/or to fulfill its obligations to third parties; provided, that a Member shall comply with duly-adopted reliability standards applicable to its system and shall comply with any directives under existing security coordination agreements.

Nothing in these Bylaws is intended to preclude application of Section 210 or 211 of the Federal Power Act and Section 10 of these Bylaws. The above limitations shall not be construed as altering a Member's obligation to comply with applicable Reliability Standards or enforcement orders, or any other obligation arising under 18 C.F.R. Part 39.

4.8 Compliance and Enforcement.

The power of ~~the~~ WECC to enforce Member obligations other than compliance with Reliability Standards and other obligations arising under 18 C.F.R. Part 39 and applicable Canadian and Mexican regulatory requirements is limited to suspension or termination of membership as set forth in this Section; provided, however, that: 1) nothing in this Section will limit the power of Members to agree to additional enforcement provisions in separate contracts (such as contracts pursuant to the Reliability Management System); 2) nothing in this Section will limit the power of ~~the~~ WECC to propose solutions regarding Market Interface issues to any Applicable Regulatory Authority as described in Section 2.1.10; and 3) nothing in this Section will limit WECC's delegated authority under Section 215 of the Federal Power Act and 18 C.F.R. Part 39 and applicable Canadian and Mexican regulatory requirements to enforce Reliability Standards and perform other delegated functions within the Western Interconnection. The Board may suspend or, to the extent consistent with applicable law, terminate the membership of any Member for a material failure to meet any obligation of membership set forth in these Bylaws, including, but not limited to: 1) non-payment of dues sixty (60) days after the dues become delinquent; 2) intentionally or repeatedly violating any WECC Bylaw; 3) materially breaching or intentionally violating any FERC order or arbitration decision issued pursuant to these Bylaws; or 4) willfully obstructing any lawful purpose or activity of ~~the~~ WECC. The Board will give the affected Member not less than twenty-one (21) days prior written notice of any proposed suspension or termination, which will include the specific basis for the proposed action and, if applicable, instructions on curing the problem.

4.8.1 Suspension. The suspension of a Member will not affect the Member's rights and obligations other than that the Member, and any Director employed by or affiliated with the Member, will not be entitled to vote at any meeting of the Members, Classes, Directors, or any committee until the suspension is removed except that a suspended Member may vote in WECC committee and subcommittee meetings on proposed Reliability Standards or revisions to Reliability Standards.

4.8.2 Termination. The termination of membership will have the same effect, and be subject to the same continuing obligations, as such Member's withdrawal pursuant to Section 4.1 (including the provision therein regarding resignation of any Director employed by such Member), except that it will be effective immediately upon the noticed date pursuant to Section 4.8.

4.9 WECC Structure and Governance Review Related to Regional Transmission Organizations.

At least each five years, the Board of Directors will conduct a thorough assessment of whether ~~the~~ WECC is fulfilling its purposes in a manner that is consistent with: 1) the provisions of Section 2.3 of these Bylaws; and 2) the then-current state and the expected

future evolution of the electric power industry within the Western Interconnection. In particular, the Board will focus on whether the standards, obligations, processes, and decisions ~~the~~ WECC imposes on its Members are timely, fair, effective, and reasonable in view of the commercial, legal, regulatory, and economic needs and objectives of the affected Members. The Board will evaluate ~~the~~ WECC's Board composition, Member Class structure, committee structure and activities, and staff responsibilities as they relate to the foregoing considerations. The assessment required by this Section 4.9 will be accompanied by Board recommendations for any changes the Board determines are warranted by the assessment. The assessment and recommendations prepared by the Board in accordance with this Section 4.9 will be submitted in writing to the Members at the first annual Member meeting held after they are completed.

5. Procedures for Member Decisions.

5.1 Quorum.

With the exception of voting on Regional Reliability Standards and Regional Criteria under the oversight of the WECC Standards Committee, m~~M~~embers may conduct business and take votes only at duly noticed Member meetings. Members may not conduct any business of the membership as a whole at any meeting unless a quorum is first established. A majority of all Members, including a majority in at least three (3) Classes, will constitute a quorum for all meetings of the membership as a whole. A majority of the members of a Class will constitute a quorum for all Member Class meetings. Inactive Members, as defined in Section 5.9 of these Bylaws, will not be counted in determining a quorum at membership or Member Class meetings. A quorum, once established, will be deemed to continue for the balance of any Member or Member Class meeting, except that no election of Directors may occur without a quorum being present. Members may designate an alternate representative or submit an absentee ballot in a form consistent with Section 6.6 for any Member or Member Class meeting. No Class may elect Member Class Directors without a majority of the members of the class being present either in person, or by designation of an alternate representative, or by the submission of an absentee vote. At a duly noticed meeting of the membership as a whole where a quorum of the membership has not been established, or at any duly noticed meeting of a Class meeting on its own, a Class may elect Member Class Directors notwithstanding the lack of quorum for action by the membership as a whole, provided a majority of the Members of a Class are present in person, or by designation of an alternate representative, or have submitted an absentee vote.

5.2 General Membership Meetings.

All business of the Members acting as a whole will be conducted at meetings called by advance notice to all WECC Members provided in accordance with Section 5.5. Unless stated otherwise in these Bylaws, decisions at all meetings of the Members or of Member Classes will be by simple majority vote of the Members present or otherwise represented in accordance with these Bylaws, with each Member having one vote. The Chair of the Board will preside over all Member meetings.

5.3 Annual Member Meetings.

~~The~~ WECC will hold an Annual Meeting of all Members at a time and place determined by the Board. At the Annual Meeting, in addition to such other actions the Members may take,

all Member Classes together will elect Non-Affiliated Directors and each Class eligible to do so will elect Member Class Directors.

5.4 Special Member Meetings.
Members may hold special meetings whenever called by the Board. The Board will call special Member meetings whenever a majority of the Members of any Class request a special meeting or at such other times as it deems appropriate. The Chair of the Board will preside over all special Member meetings.

5.5 Member Class Meetings
An individual WECC Member Class, including Class 6 consisting of the Canadian Delegation, may hold a meeting for any purpose relevant to the interests of Class Members, including the election of Member Class Directors by Classes eligible to do so. Such meeting will be initiated by request by one or more Class Member(s), and agreement by at least fifty percent (50%) of Class Members.

5.6 Notice of Member Meetings.

5.6.1 Annual Meeting. The Chief Executive Officer will provide at least thirty (30) days' advance notice to all Members and the Board of the date, place and time of the Annual Meeting of the Members and an agenda of the business to be conducted at such meeting.

5.6.2 Other Member Meetings. The Chief Executive Officer will provide notice of regularly scheduled and special meetings of the Members to the Members not less than fifteen (15) days before the meeting if delivered by first-class mail, or not less than ten (10) days before the meeting if the notice is delivered personally, by telephone, by facsimile, electronic mail or express mail. Notice of meetings may not be sent solely by electronic mail. If mailed, such notice will be deemed given when deposited in the United States mail, with first-class postage thereon prepaid, addressed to a Member. Such notice will state the date, time and place of the meeting and the meeting agenda.

5.6.3 Public and ~~Web S~~Website Notice. Public notice of each meeting of the Members will be placed on WECC's ~~Web~~ website at least ten (10) days before such meeting. In addition, the Chief Executive Officer will provide notice in the same manner and time as set forth in Section 5.6.2 of each meeting to each member of the public who so requests and who has provided appropriate information regarding delivery of notice.

5.7 Open Meetings.
All Membership meetings are open to observation by the public.

5.8 Policymaking Authority.
The Board of Directors may adopt policies for the interpretation and implementation of the meeting and voting procedures established in this Section 5.

5.9 Minimum Participation Requirement.

In order to be counted for quorum purposes at a meeting of the membership as a whole or Class meeting, a WECC Member must actively participate (by attending in person, sending an alternate, or voting absentee) in at least one WECC meeting (including meetings of the Board, committees and subcommittees) each year. ~~At least two weeks prior to the WECC Annual Meeting, WECC staff will send a notice to any Member that has, according to organizational records, not satisfied this minimum participation requirement within the previous year. The notice will inform the Member that in order to be counted as an active Member of WECC for voting and quorum purposes, the Member must at a minimum either register for an attend the Annual Meeting and associated Class meetings or participate in the Annual Meeting and associated Class meetings by casting an absentee ballot.~~ If the Member does not meet this minimum participat~~e~~ion requirement, the Member will be considered an "inactive" Member until its active status is restored by participation in ~~a WECC Annual Meeting~~at least one WECC meeting (including meetings of the Board, committees and subcommittees) by attending in person, sending an alternate, or voting absentee. An inactive Member will not be counted toward establishing a quorum of the membership as a whole or of a Class~~, and an inactive Member will not be entitled to vote at WECC meetings until the Member is reinstated to "active" status by attending in person, sending an alternate or voting absentee at an Annual Meeting and associated Class meetings~~. An applicant for WECC membership or a WECC Member may at any time self-designate itself an inactive Member. Such designation will be effective until the Member is reinstated to "active" status.

6. Governance.

6.1 Board of Directors.

Subject to those matters expressly requiring approval of the Membership, a Board of Directors elected by the Members will govern ~~the~~ WECC.

6.2 Composition of the Board.

Except as provided in Sections 6.2.1 and 6.2.2, the Board consists of thirty-two Directors as follows: 1) twenty-four (24) Member Class Directors elected by the Member Classes eligible to do so, including Class 6 as defined in Section 6.2.1, (four from Classes 1 through 6); 2) seven (7) Non-Affiliated Directors elected by the WECC Members as a whole (which may include the Chief Executive Officer), and 3) one Mexican Director elected according to Section 6.2.2. As indicated in Section 6.2.1, if there is no Non-affiliated Director whose background and experience would provide the Board expertise on Canadian interests, then the Board size would be increased by one more Director elected by Class 6. In addition, the Board may provide for the CEO of WECC to be a voting member of the Board through the inclusion of such a provision in the resolution the Board adopts appointing WECC's CEO. Such provision shall not permit the CEO to be a member of a Board committee or to cast either a tie-breaking vote or a vote that creates a tie.

6.2.1 Canadian Interests. For purposes of providing fair and adequate representation of Canadian Interests in numbers that are approximately proportionate to the contribution of net energy for load in that portion of the Western Interconnection located in Canada, the Canadian Delegation shall constitute Class 6 and shall elect

four (4) Canadian Directors, provided that at least one of these Canadian Directors must be affiliated with each of Member Classes 1, 3, and 5. Members of the Canadian Delegation shall vote for Directors in this Class 6 and shall not vote in other Member Class elections. In the initial election of these four Class 6 Directors, one shall have a term of four years, one shall have a term of three years, one shall have a term of two years, and one shall have a term of one year. Thereafter all Canadian Directors will serve a term of three years. Class 6 will also elect a fifth Canadian Director if, following the election of Non-Affiliated Directors at the Annual Meeting, there is no Non-Affiliated Director qualified by virtue of background and experience in Canadian industry or government to provide Board expertise on Canadian interests. This fifth Canadian Director shall serve until the earlier of: 1) the end of a three-year term (provided that this provision will remain in effect and may continue to cause the election of an additional Director); or 2) the election by the Members of a Non-Affiliated Director with the background and experience described in this Section.

6.2.2 Mexican Interests. Whenever there are at least two (2) Members whose head offices and principal place of business are in Mexico or there is one such Member that operates a portion of the Western Interconnection and has signed the Reliability Management System agreement or has agreed to abide by any successor standards compliance system and no person has been elected to the Board by the Classes or Members whose experience or affiliation reflects Mexican interests, the number of Class Member Directors will be expanded by one (1) and the additional Member Class Director will be elected by the Mexican Delegation. This Mexican Director will serve until the earlier of: 1) the end of a three-year term (provided that this provision will remain in effect and may continue to cause the election of an additional Director); or 2) the election by the Members or a Member Class of a person with the experience or affiliation described in this Section.

6.3 Term of Office.

Each Director will hold office for three (3) years. For Directors elected at the Annual Membership Meeting, each three (3) year term shall commence upon the adjournment of the portion of the Annual Member Meeting provided for in Section 5.3, in which all Members are counted for purposes of determining a quorum. Similarly, the three year terms of outgoing Directors shall end upon the adjournment of that portion of the Annual Member Meeting in which all Members are counted for purposes of determining a quorum, whether that results in a longer or shorter term than exactly three years.

6.4 Selection and Compensation of Member Class Directors.

6.4.1 Selection of Member Class Directors. With the exception of Class 7, each Member Class shall be eligible to elect Member Class Directors. Member Class Directors will be elected by Members of their respective Classes of Membership. Each Member Class eligible to elect Member Class Directors may develop its own list of Director candidates or it may ask the Governance and Nominating Committee to develop a list of candidates. If the Governance Nominating Committee is used, it will select at

least two (2) candidates for each vacancy for Member Class Director. In addition, in identifying candidates for Member Class Director positions, the Governance and Nominating Committee will seek to produce a slate of candidates who, together with the Directors from all Member Classes standing for election and continuing in office, will reflect the diversity of regional interests and characteristics within the Western Interconnection. The proposed slate of candidates will be mailed to the Members of the Class at least sixty (60) days before each Member Class Meeting at which the elections are to be held. Additional candidates may be added to the slate upon the submittal of a nomination to the Chief Executive Officer signed by three (3) Members of the Class, or ten percent (10%) of the total number of Members of the Class, whichever is greater. The Chief Executive Officer must receive such nominations at least thirty (30) days before the Member Class Meeting. All candidates identified by the Class (as provided above) or by the Governance and Nominating Committee will be submitted to the Class for election at the Member Class Meeting. Candidates will provide reasonable background information regarding their qualifications and a disclosure statement regarding any affiliations with Electric Line of Business Entities in the Western Interconnection to the Members before each election. The Director candidate(s) receiving the highest number of votes cast by Members of the Class will be elected to the position of Director.

6.4.2 Member Class Director Qualifications. Member Classes eligible to elect Member Class Directors may elect any person as a Member Class Director, provided that no Member or group of Affiliated Members may have more than one Director associated with them. Nothing in this Section regarding the election of Directors by Classes of Members is intended to limit, qualify or alter in any manner the fiduciary obligation of Directors to ~~the~~ WECC set forth in Section 6.10.1. A Member Class Director shall notify all Members of the Class from which the Director was elected of any significant change in employment or other significant change in circumstances relevant to the Director's qualifications. Such notice shall be provided in writing as soon as possible and not later than sixty (60) days following the change.

6.4.3 Minimum Number of Class Members. Each Class eligible to elect Member Class Directors must have at least four (4) Members to be qualified to nominate and elect representatives to the Board of Directors. If a Class eligible to elect Member Class Directors contains less than four (4) members, then the Director positions for that Class will remain vacant until the first Annual Meeting at which the Class has the minimum number of members, at which time two of the vacant positions will be filled by election to three year terms and two by election to two year terms. If a Class eligible to elect Member Class Directors falls below the minimum number of members after having elected Directors, such Directors will continue to serve out their terms. However, upon expiration of their terms, the Director positions will remain vacant until such time as the Class contains sufficient members.

6.4.4 Member Class Director Compensation. Member Class Directors will not be compensated for their service by ~~the~~ WECC. ~~The~~ WECC will reimburse Member

Class Directors for reasonable and actual out-of-pocket expenses (such as travel and lodging) that are not subject to reimbursement from any Member or other source.

6.5 Selection and Compensation of Non-Affiliated Directors.

6.5.1 Non-Affiliated Director Qualifications.

6.5.1.1 Non-Affiliation. The Non-Affiliated Directors of the Board may not be affiliated with any Entity that is a Member of ~~the~~ WECC or is eligible for membership in Classes 1 through 3 of ~~the~~ WECC, provided that status as a residential electricity customer will not disqualify a person from sitting as a Director. A candidate will not be qualified to serve as a Director if the candidate, or the spouse or a minor child of the candidate, derives any of his or her annual income from a Member of WECC, an Entity that is eligible for membership in Classes 1 through 3, or a bulk power user in the Western Interconnection. ~~The~~ WECC shall maintain a list of such Members and Entities which shall be updated periodically. Non-Affiliated Directors, candidates and others shall be entitled to rely upon the list to determine compliance with these requirements.

6.5.1.1.1 Notwithstanding the provisions of Section 6.5.1.1, a candidate for Non-Affiliated Director will not be disqualified for owning shares in a mutual fund that owns an interest in a Member or an Affiliate of a Member as long as the mutual fund does not specialize exclusively or predominantly in the energy sector. The disqualification standards described in Section 6.5.1.1 will not disqualify a candidate who is receiving payments from a pension plan of a Member or an Affiliate of a Member in a form other than securities of such Member or Affiliate and the pension plan payments bear no relationship to the economic performance of the Member or Affiliate.

6.5.1.1.2 The disqualification standards described in Section 6.5.1.1 will not apply to disqualify a candidate solely by virtue of an employment or contractual relationship with a state that has one or more agencies that are eligible to be Members of Class 5 of WECC, provided that:

1. In the case of a candidate's employment relationship, the employer is not a member of WECC;

2. In the case of a candidate's contractual relationship with a state agency, no member or employee of the state agency is a member of the WECC Board;

3. In the case of a candidate's employment relationship with a contractor to a state agency, no member or employee of the state agency is a member of the WECC Board; and
4. In the case of a candidate's employment or contractual relationship with a state agency which is a WECC Member or employs a WECC Board member, if the Governance and Nominating Committee determines that the candidate's employment duties do not include significant work for or representation of that state agency.

6.5.1.1.3 Notwithstanding the provisions of this Section 6.5.1.1, a candidate for Non-Affiliated Director will not be disqualified for being affiliated with an organization that represents a substantial number of end users or a substantial number of persons interested in the impacts of electric systems on the public interest or the environment.

6.5.1.2 Expertise. The Governance and Nominating Committee will nominate Non-Affiliated Director candidates with the objective of having at least one Non-Affiliated Director with expertise in electric transmission operations and planning. The Governance and Nominating Committee will also have the objective of nominating persons with: 1) experience in corporate leadership at the senior management or board of directors level; 2) leadership experience in law, finance, economics, accounting, engineering, regulation, natural resources or commercial commodity markets and associated risk management; 3) experience representing a substantial number of end users or a substantial number of persons interested in the impacts of electric systems on the public or the environment; 4) a well-developed understanding of the distinct operational, resource, political, and interest-based characteristics of various regions within the Western Interconnection; and 5) a well-developed understanding of Canadian power systems or Canadian regulatory issues.

6.5.2 Selection of Non-Affiliated Directors.

6.5.2.1 Selection of Non-Affiliated Directors. After the initial election of Non-Affiliated Directors, the Governance and Nominating Committee will make nominations. Before the end of each Non-Affiliated Director's term, the Governance and Nominating Committee may select an independent search firm to provide the Governance and Nominating Committee with a list of qualified candidates for each vacant position. Incumbent Directors, if qualified and willing to serve, may be considered for nomination by the Governance and Nominating Committee. The Governance and Nominating Committee will consider each candidate for Non-Affiliated Director to determine whether that candidate is qualified to stand for election to the

Board. From the list of candidates accepted by the Governance and Nominating Committee to stand for election, the Governance and Nominating Committee will select a slate of candidates for the vacant Non-Affiliated Director positions. The Governance and Nominating Committee's slate of candidates will be e-mailed to the Members no later than sixty (60) days prior to the Annual Meeting. Additional candidates may be added to the slate upon the submittal of a nomination to the Chief Executive Officer signed by no fewer than 10 Members, including at least 3 from each of two different Member Classes~~three (3) Members of any Class, or ten percent (10%) of the total number of Members of any Class, whichever is greater~~. The Chief Executive Officer must receive such nomination at least thirty (30) days before the Annual Meeting. The Chief Executive Officer will place such nominations before the Members for possible election unless he or she determines in writing that a proposed nominee does not meet the criteria for eligibility to be a Non-Affiliated Director in these Bylaws.

6.5.2.2 Disclosure Statement. Candidates for Non-Affiliated Director will provide to the Governance and Nominating Committee and, if nominated, to the Members, a statement describing their expertise and disclosing any present or past affiliations, relationships or associations relevant to their qualification to serve as a Non-Affiliated Director. A candidate for Non-Affiliated Director will be required to disclose any economic interest in any Member of ~~the~~ WECC or any Entity eligible for membership in Classes 1 through 3 of ~~the~~ WECC held by themselves, their spouse or their children as well as any such interest known to the candidate held by the candidate's parents, siblings, aunts, uncles, or first cousins.

6.5.2.3 Election. The number of Non-Affiliated Director candidate(s) corresponding to the number of vacant positions receiving the highest number of votes cast at the Annual Meetings of the Members will be elected to the position of Non-Affiliated Director.

6.5.3 Non-Affiliated Director Compensation. The Non-Affiliated Directors will receive a level of compensation as determined from time to time by the Member Class Directors.

6.6 Tie Vote.

In the event of an inability to select Directors due to a tie vote, a second vote will be taken to determine the placement of the tied candidates. The second vote will be limited to the tied candidates, with the candidate(s) receiving the highest number of votes being selected. If another tie vote results, additional votes will be taken (after the elimination of any candidate receiving fewer votes than the tied candidates) until a candidate can be selected. If a tie cannot be resolved pursuant to the foregoing procedures, it will be resolved by lot. For the purpose of such second (and subsequent) votes, absentee ballots shall allow voters to list all candidates in order of preference such that absentee ballots may be counted by striking those candidates not participating in the run-off. Absentee ballots that express an order of

preference for fewer than all candidates will be counted if the ballot demonstrates clear preference among the runoff candidates.

6.7 Removal of Directors.

The Members or the Board may remove a Director before completion of the Director's term of office pursuant to the following provisions.

6.7.1 Removal by the Members. Member Class Directors may be removed at will by a vote of at least sixty percent (60%) of the Members of the Class that elected that Director. Non-Affiliated Directors may be removed only for gross negligence, violation of local, state, provincial, or federal laws, gross misconduct, or failure to meet the fiduciary obligations of Directors. Removal of a Non-Affiliated Director will be by a vote of at least fifty percent (50%) of the entire WECC membership, including a vote of at least fifty percent (50%) of each Class.

6.7.2 Removal by the Board. The Board may remove any Director for gross negligence, violation of local, state, provincial, or federal laws, gross misconduct, or failure to meet the fiduciary obligations of Directors. Such removal will only occur upon the affirmative vote of not less than twenty-one (21) Directors.

6.8 Resignation.

Any Director may resign from his or her office or position at any time by written notice to the Board by delivery to the Chair. Pursuant to Sections 4.1 and 4.8.2, a Director employed by a withdrawing or expelled Member will be deemed to have resigned. The acceptance of a resignation will not be required to make it effective.

6.9 Procedures for Filling Vacant Director Positions.

6.9.1 Member Class Director Vacancies. If the position of any Director elected by a Member Class becomes vacant, the remaining Directors elected by the same Class will promptly choose a successor to that position who will serve until the next Annual Meeting.

6.9.2 Non-Affiliated Director Vacancies. If the position of any Non-Affiliated Director becomes vacant, the remaining Directors may charge the Governance and Nominating Committee with selecting a successor immediately. The Governance and Nominating Committee will follow the requirements set out in Section 6.5.2.1 in its selection of any successor Non-Affiliated Director. Alternatively, if less than one (1) year remains in the term of that Director, the remaining Directors may choose to leave the position vacant for the remainder of the term.

6.9.3 Holdover to Cure Procedural Vacancies. Whenever a vacancy in any Member Class or Non-Affiliated Director position would be created due to expiration of a Director's term combined with a lack of a quorum or other procedural inability to elect a new Director, the expired Director's term shall be extended until such time as a proper election of a new Director can be conducted.

6.10 Duties of Directors.

The Directors will have the following duties:

6.10.1 Fiduciary Obligation to ~~the~~ WECC: All Directors, including Member Class Directors, will have a fiduciary obligation to ~~the~~ WECC consistent with the requirements for Directors of Utah non-profit corporations. Notwithstanding any affiliation with individual Members or Class of membership, Members of the Board will at all times act in conformance with such requirements, these Bylaws and the Standards of Conduct set forth in Appendix A.

6.10.2 Preserve Non-Affiliated Status: Throughout their terms, Non-Affiliated Directors will have a duty to avoid any affiliation that is inconsistent with the standards for Non-Affiliated Directors in Section 6.5.1.1 of these Bylaws. If a Non-Affiliated Director becomes aware of any such affiliation, he/she must either resign or eliminate the affiliation (e.g., dispose of securities) within six (6) months.

6.11 Powers of Directors.

The management of all the property and affairs of ~~the~~ WECC will be vested in the Board of Directors. The Board will hold annual elections to select a Board Chair and to fill any other Board officer positions that may be created by the Board or required by applicable law. The Board may exercise all the powers of ~~the~~ WECC and do all lawful acts and things (including the adoption of such rules and regulations for the conduct of its meetings, the exercise of its powers and the management of ~~the~~ WECC) as are consistent with these Bylaws and the Articles of Incorporation.

6.12 Delegation of Board Authority.

The Board may delegate to the Chief Executive Officer or to any Board Committee formed pursuant to Section 7.7 any or all of its powers and authority except: 1) any power which it may not delegate pursuant to applicable Utah law; 2) the power to adopt any reliability standard; 3) the power to determine when to exercise the Backstop Authority of ~~the~~ WECC; 4) the power to approve budgets; 5) the power to form committees; 6) the power to amend the Bylaws; 7) the power to elect the Chair and other officers of the Board; ~~8) the power to enter into contracts obligating the WECC to pay an amount exceeding $50,000;~~ and ~~9~~8) the power to hire, fire or set the terms of employment of the Chief Executive Officer. The Board may also delegate to any Member committee the power to make specific decisions, subject to the right of any Member to appeal any of such decisions to the Board within 30 days of the committee vote on the decision by writing a letter to the Chief Executive Officer that describes in reasonable detail the grounds for appeal, and requests that the appeal be considered by the Board at its next regularly scheduled meeting, subject to applicable notice requirements. Delegation will be by express decision and will require the affirmative vote of not less than twenty (20) Directors. Any Director may call for a vote to rescind such delegation at any time and such delegation will be rescinded if eight (8) or more Directors vote to do so.

6.12.1 Notice to Members. Within seven (7) days of any decision delegated pursuant to Section 6.12, except for routine decisions of the Chief Executive Officer, Members will be notified of the decision by electronic mail, posting on the WECC ~~Web~~

website and any other means determined appropriate by the Board. Routine decisions of the Chief Executive Officer will be noticed in periodic reports to the Board and Members as determined by the Board, which will be sent to Members by electronic mail and posted on the WECC ~~Web~~ website.

6.12.2 Board Review of Delegated Decisions. Decisions delegated pursuant to Section 6.12 will be reviewed by the Board at the request of any Director, provided such request is lodged with the Secretary within thirty (30) days of the notice. Whenever it determines that a matter requires an urgent decision, the Board may shorten the deadline for requests for review, provided that: 1) the notice and opportunity for review will be reasonable under the circumstances; and 2) notices to Members will always contain clear notification of the procedures and deadlines for Board review. A request for review of a decision will stay the effect of the decision pending review unless the Board in making the delegation expressly determines otherwise.

7. Procedures for Board Decisions.

7.1 Quorum.

No business will be conducted by the Board unless at least seventeen (17) Directors are present, including at least three (3) Non-Affiliated Directors and at least one Director elected by each of not less than four (4) of the Member Classes; provided, that if all Member Class Director positions for a Class are vacant, or if a Class is not entitled to elect Member Class Directors, then no Director elected by such Class will be required to be present for the Board to conduct business.

7.2 Majority Vote.

A decision of the Board will require an affirmative vote of a majority of Directors present and not abstaining. Directors may not vote by proxy or by absentee ballot, but Directors may participate in Board meetings by telephone as provided in Section 7.3 of these Bylaws.

7.3 Attendance at Board Meetings by Teleconference.

Any or all of ~~the~~ WECC's Directors may participate in any meeting of the Board by telephone conference or any other means of communication that enable all Directors participating in the meeting to simultaneously hear one another. Every Director participating in a meeting in the manner described in the preceding sentence will be deemed to be present in person at that meeting.

7.4 Board Action by Unanimous Consent.

7.4.1 Action Without a Meeting. Unless ~~the~~ WECC's Articles of Incorporation or applicable law provides otherwise, action required or permitted to be taken at a meeting of the Board may be taken without a meeting through one or more written consents describing the action taken. Any Board action taken by written consent must be signed by all Directors in office at the time the action is taken. Such actions must be noticed to Members in accordance with Section 7.5 and Members must be given an opportunity to comment prior to the Board taking such actions through electronic mail, comments on the ~~Web~~ website or other appropriate means. The

required notice of such meeting may generally describe the arrangements (rather than the place) for the holding of the meeting. All other provisions herein contained or referred to will apply to such meeting as though it were physically held at a single place. All Board actions by written consent must be filed with ~~the~~ WECC's Board meeting minutes. Action taken under this Section is effective when the last Director signs the consent, unless the consent specifies an earlier or later effective date. Any action by written consent has the same effect as a meeting vote and may be described as such in any document.

7.4.2 Waiver of Procedures. For any specific action at any noticed meeting of the Board, and under exigent or unusual circumstances, the Board by unanimous vote of those present may waive any procedural requirement applicable to Board decision-making, including any requirement for notice of a specific potential action, except for the following: 1) the requirement for notice of the time and place of the meeting pursuant to Section 7.5; 2) the quorum and voting requirements of Sections 7.1 and 7.2; and 3) any non-procedural limitation on the power of the Board to make a decision, including, but not limited to, those restrictions in Sections 6.12 (limiting the power to delegate) and 13.1 (limiting the power to amend the Bylaws). Whenever such action is taken, a statement describing the action, the exigent or unusual circumstances, the specific procedure waived, the basis for the waiver and the votes of all Directors present shall be posted on the web~~-~~site and communicated in writing or by e-mail to all Members within five (5) days.

7.5 Notice of Board Meetings.

7.5.1 Regular Meetings. Except as set forth in Section 7.5.2 regarding urgent business, all regular business of the Board will occur at the Board meetings, at least twenty-one (21) days' advance notice of which has been provided by the Chief Executive Officer to all Directors and all Members. Notice will include an agenda that will identify those matters on which a vote will be taken at the meeting. The foregoing requirement shall not preclude the Board from taking an action that is different from the specific proposed action identified in the agenda, as long as the relevant subject matter has been reasonably identified in the agenda. The Directors will establish a regular meeting schedule that will be made available to the Members. The schedule will include not less than two meetings of the Board annually.

7.5.2 Special Meetings. Whenever the Chair of the Board or any three (3) Directors find that there is urgent business requiring Board action before the next regular Board meeting, a special meeting of the Board may be called. Such special meetings will be held upon as much written notice to each Board Member and all Members as is possible under the circumstances, which will not be less than three (3) days. However, this notice of special meetings may be waived if: 1) the waiver is by a writing signed by a quorum of Board members; and 2) as much notice of the meeting as practicable has been given to WECC Members via e-mail and posting on the WECC ~~Web~~ website.

7.5.3 Public and Webs~~ S~~ite Notice. Public notice of each meeting of the Board will be placed on WECC's ~~Web~~ website at least ten (10) days before such meeting (or such lesser time as provided pursuant to Section 7.5.2). In addition, the Chief Executive Officer will provide notice of each meeting by first-class mail, facsimile or electronic mail to each member of the public who so requests and who has provided appropriate information regarding delivery of notice.

7.6 Open Meetings.

Except as provided in Section 7.6.1, all regular and special meetings of the Board will be open to observation by any Member and any member of the public.

7.6.1 Closed Session. Notwithstanding the provisions of Section 7.6, upon an affirmative vote of two-thirds (2/3) of the Directors present, the Board may meet in closed session: 1) to consider the employment, evaluation of performance, or dismissal of an employee of WECC and to deliberate regarding decisions the Board may be called upon to make regarding the nomination, qualification, appointment, or removal of a member of the Board of Directors; 2) to discuss pending or proposed litigation and to receive confidential attorney-client communications from legal counsel; and 3) to receive and discuss any information that is privileged, trade secret, cybersecurity, critical energy infrastructure information (as defined by the FERC), protected from public disclosure by law or that the Board determines should be confidential in order to protect a legitimate public interest.

7.6.1.1 Attendance by an Affected Director. Closed sessions of the Board may not be attended by a Director under the following circumstances: 1) where the qualifications or performance of the Director or the Director's spouse or children are being discussed; 2) where the Director is employed by an entity that is or is likely to become a party to the litigation being discussed; and 3) where the Director or the Board determines that the Director would have a serious and substantial conflict of interest by becoming privy to confidential attorney-client or trade secret information that is to be presented to the Board in closed session.

7.6.1.2 Announcement of Closed Session. Before adjourning into closed session, the Chair of the Board will announce the purpose of the closed session in a manner that provides the public an understanding of the general subject matter to be discussed but which does not reveal sensitive or personal information. The Board will not discuss additional items outside the scope of this description.

7.6.1.3 Confidentiality of Closed Session. All Directors and others present will maintain the confidentiality of discussions and decisions made in closed session. The Board will appoint a secretary for closed session to keep a minute book for the purpose of recording the subject matter discussed in closed session and any actions taken in closed session.

7.7 Board Committees.

7.7.1 Governance and Nominating Committee. The Chair will appoint a Governance and Nominating Committee that shall: 1) return slates of candidates as required by these Bylaws; 2) oversee implementation and amendment of these Bylaws; and 3) address such other issues pertinent to Governance as the Board may choose to delegate to it. The Governance and Nominating Committee will consist of one Director from each of the six Member Classes eligible to elect such Directors and one Non-Affiliated Director. The Chair will designate one of the appointed Directors to be the Chair of the Governance and Nominating Committee.

7.7.2 Other Board Committees. The Board may appoint such Board committees as it deems necessary from time to time to carry out its business affairs. In appointing such committees, the Board will specify their purpose, membership, voting, notice and meeting procedures and such other direction as the Board may deem appropriate. The Board may appoint one or more Members or other persons to participate in Board committees as full voting members or as non-voting advisory members.

7.7.3 Standards of Conduct for Board Committee Members. Members of Board committees shall comply with the Board Member Standards of Conduct set forth in Appendix A.

8. Member Committees.

8.1 Purpose.
~~The~~ WECC will have committees composed of its Members to advise and make recommendations to the Board. Such committees will include both standing committees required by these Bylaws and such other committees as the Board may choose to create.

8.2 Standing Committees.
WECC will have the following standing committees:

8.2.1 Planning Coordination Committee. This committee will advise and make recommendations to the Board on all matters within the jurisdiction of ~~the~~ WECC pertaining to maintaining reliability through evaluating generation and load balance and the adequacy of the physical infrastructure of interconnected bulk electric systems within the Western Interconnection.

8.2.2 Operating Committee. This committee will advise and make recommendations to the Board on all matters within the jurisdiction of ~~the~~ WECC pertaining to maintaining reliability through the operation and security of the interconnected bulk western electric systems in the Western Interconnection.

8.2.3 Market Interface Committee. This committee will advise and make recommendations to the Board on the development of consistent Market Interface practices and compatible commercial practices within the Western Interconnection. It will consider

matters pertaining to the impact of WECC's reliability standards, practices, and procedures on the commercial electricity market in the Western Interconnection, and facilitate analysis of the impact of electricity market practices on electric system reliability.

8.3 Other Committees.

8.3.1 The Board may create such other committees as it may desire from time to time. The Board will specify the functions, duties and responsibilities of any such committee at the time of its creation. The Board will also specify the membership rules, quorum requirements, voting levels and meeting and notice requirements at the time of creation. Any changes in the membership rules, quorum requirements, or voting levels of a committee, once established by the Board, will require a seventy-five percent (75%) vote of the Board to alter. The specific function or sunset date for a committee will be designated by the Board at the time of the committee's creation. The committee will terminate its activities upon the completion of its function or the expiration of the date set by the Board.

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8.3.2 The WECC Standards Committee is the committee that will oversee the process for responding to requests for Regional Reliability Standards and Regional Criteria in accordance with the Reliability Standards Development Procedures. . The WECC Standards Committee is responsible for determining if a request for a Regional Reliability Standard or a Regional Criteria is within the scope of WECC's activities, and for overseeing the drafting, comment and voting process for a Regional Reliability Standard or Regional Criteria. The WECC Standards Committee shall also oversee the process for responding to requests for interpretations of Regional Reliability Standards and Regional Criteria. The WECC Standards Committee shall consist of one member from each of the WECC Standards Voting Sectors set forth in Section 8.5.5.2, and a member of the WECC Board who shall act as chair of this committee. The WECC Board shall approve a Charter for the WECC Standards Committee that describes the WECC Standards Committee membership selection process.

8.4 ~~Committee Assessment and Streamlining.~~[Repealed]

~~8.4.1 Assessment of Standing Committee Activities. No later than three (3) years following the Organizing Meeting of the WECC, the Board of Directors will conduct a thorough review of the activities of each of the WECC's standing committees (as defined in Section 8.2 of these Bylaws) to assess whether they are effectively furthering the WECC's purposes in a manner that is consistent with: 1) the provisions of Section 2.3 of these Bylaws; and 2) the then-current state and the expected future evolution of the electric power industry within the Western Interconnection. The Board's review will assess whether there are any aspects of the standing committees' functions or procedures that impede development of WECC standards, obligations, processes, and decisions that are timely, fair, effective, and reasonable in view of the commercial, legal, regulatory, and economic needs and~~

~~objectives of the affected Members. The Board will propose to the membership, at the first annual Member meeting held after completion of the review required by this Section 8.4.1, any changes to standing committee structures, functions, or procedures that the Board determines are warranted by its review.~~

~~8.4.2 Dissolution of Additional Member Groups.~~

~~8.4.2.1 Except as otherwise provided in Section 8.4.2.2 below, no later than three (3) years following the Organizing Meeting of the WECC, all WECC Member groups other than the WECC's standing committees (as defined in Section 8.2 of these Bylaws) will dissolve automatically. The Member groups to automatically dissolve under this Section 8.4.2.1 will include, without limitation, all WECC Member subcommittees, work groups, and task forces. There will thereafter be no committees, subcommittees, or other groups of WECC Members other than: 1) the WECC's standing committees (as defined in Section 8.2 of these Bylaws); and 2) any established by the Board after it determines that the committee, subcommittee, or other group, when established, will satisfy the terms of assessment for standing committees set forth in Section 8.4.1 above.~~

~~8.4.2.2 If, at the time specified for dissolution of Member groups that are not standing committees in accordance with Section 8.4.2.1 above, FERC-approved Regional Transmission organizations carrying on commercial operations within the Western Interconnection do not cover at least one-half the load in the Western Interconnection, the Board may delay the implementation of the actions specified in Section 8.4.2.1 until no later than six (6) months after FERC-approved regional transmission organizations covering at least one-half the load within the Western Interconnection are in place and carrying on commercial operations.~~

8.5 Procedures for Committee Decision-Making.

8.5.1 Reports to Board of Directors. Action by a committee will be in the form of a recommendation for Board action except in those instances in which the Board has, by resolution, specifically delegated to a committee the power to take action subject to an appeal to the Board by any Member. The recommendation of a committee must be forwarded to the Board for its action along with any minority or dissenting reports filed with the committee Chair or Vice-Chair.

8.5.2 Subcommittees, Task Forces and Ad Hoc Groups. Any Board or member committee may create such subcommittees, task forces or other ad hoc groups ("subcommittee") as it deems appropriate to carry out the committee's responsibilities consistent with these Bylaws and the direction of the Board. The composition, responsibilities and procedures of such groups shall be specified by the committee as appropriate; provided, however that: 1) the committee may only delegate to such subcommittee responsibilities that are within the scope of the

committee's responsibilities pursuant to these Bylaws and direction of the Board; and 2) the subcommittee may only make recommendations to the committee. A committee may create a subcommittee without prior approval of the Board; provided, however, that the committee shall promptly inform the Board in writing and at the next Board meeting regarding the creation of the subcommittee. The notification to the Board shall include a charter for the subcommittee that describes how members of the subcommittee will be selected, the duties of the subcommittee, and whether the committee has established a sunset date for review of (1) the need for the subcommittee and (2) the charter of the subcommittee.

8.5.3 Committee Officers. The Board will appoint the Chair and Vice-Chair of each committee. The Committee Chair or Vice-Chair will preside over all meetings of the committee and will report recommendations of the committee to the Board of Directors. The Chair and Vice-Chair will be responsible for informing the Board regarding minority opinions and other information required by the Board along with overall committee recommendations. Whenever the committee elects to form a subcommittee to represent regions or address specific tasks, the Chair (or in the absence of the Chair, the Vice-Chair) will have the power to appoint the members of such subcommittee from both members of the committees and non-members. Upon resignation of the Committee Chair, the Vice Chair shall serve as Chair until the Board appoints a replacement. Upon resignation of the Vice Chair, the Chair may appoint a temporary Vice Chair to serve until the Board appoints a replacement. Upon resignation of both the Chair and Vice Chair, the Chair of the Board may appoint one or more temporary replacements to serve until the Board appoints permanent replacements.

8.5.4 Committee Membership. Except as provided in Sections 8.3.2 and 8.5.4.1, any Member of WECC may designate one representative as its committee member to any standing committee or other committee. The WECC Member will have one vote at any committee meeting through that committee member. Any number of other persons may attend a committee meeting, but such persons will have no right to vote without a prior designation of representation by a WECC Member, except that interested stakeholders may, under Section 8.6, vote on proposed Reliability Standards or revisions to Reliability Standards.

8.5.4.1 Dual Representation for Functionally-Separated Members. A Member which has distinct and functionally-separated interests as both a transmission provider and a transmission customer may designate two representatives as committee members to any standing committee, one to represent each functionally separate interest. Each such committee member will have one vote. The privilege granted by this Section is subject to revocation by the Board on a case-by-case basis or generally whenever the Board finds, upon petition from any Member or its own motion, that such dual representation creates unfairness or imbalance within a committee.

8.5.5 Committee Voting and Classes.

8.5.5.1 Classes. For purposes of voting, committees, excluding the WECC Standards Committee, will have three classes of membership:

8.5.5.1.1 Transmission Provider Members ~~or Participating Stakeholders~~;

8.5.5.1.2 Transmission Customer Members ~~or Participating Stakeholders~~; and

8.5.5.1.3 States and Provincial Members (Member Class 5).

8.5.5.2 WECC Standards Voting Sectors. For purposes of voting on Regional Reliability Standards and Regional Criteria, a Ballot Body consisting of five registered sectors (8.5.5.2.1 through 8.5.5.2.5) and three non-registered sectors (8.5.5.2.6 through 8.5.5.2.8) shall be established. If an Entity is eligible for a registered sector, then that Entity may be eligible for more than one registered sector. An Entity can only be in one non-registered sector. An Entity cannot be in both a registered and a non-registered sector. The first five sectors (8.5.5.2.1 through 8.5.5.2.5) shall be limited to Entities which are listed in the North American Electric Reliability Corporation ("NERC") compliance registry and to those Canadian and Mexican Entities that perform functions that, if performed in the United States, would allow these Entities to be registered for compliance in the NERC compliance registry. A WECC member or Participating Stakeholder who wishes to participate in voting on Reliability Standards and Regional Criteria shall apply for membership in the Ballot Body in any or all of the registered WECC Standards Voting Sector(s) for which it believes it is eligible, or one of the three non-registered sectors. WECC staff shall confirm Participating Stakeholder's eligibility for such Sector(s). Decisions of the staff to approve, deny, or restrict the admission of an entity to a voting sector may be appealed to the Governance and Nominating Committee. Decisions of the Governance and Nominating Committee to affirm or reverse such decisions of staff may be appealed to the Board. The following sectors are established:

8.5.5.2.1 Transmission Sector. This sector consists of Western Interconnection Entities registered in the NERC compliance registry as transmission owners, transmission operators, transmission service providers, or transmission planners;[1]

8.5.5.2.2 Generation Sector. This sector consists of Western Interconnection Entities registered in the NERC compliance registry as generation owners or generation operators;

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1 For the five registered sectors, Canadian and Mexican Entities that would be eligible for the indicated NERC compliance registry category, if they performed these functions in the United States, shall be eligible for these sectors.

8.5.5.2.3 Marketers and Brokers Sector. This sector consists of Western Interconnection Entities registered in the NERC compliance registry as purchasing-selling Entities;

8.5.5.2.4 Distribution Sector. This sector consists of Western Interconnection Entities registered in the NERC compliance registry as distribution providers or load-serving Entities;

8.5.5.2.5 System Coordination Sector. This sector consists of Western Interconnection Entities registered in the NERC compliance registry as balancing authorities, reserve sharing groups, planning authorities, resource planners, interchange authorities, or reliability coordinators. WECC may cast a vote in this sector;

8.5.5.2.6 End Use Representative Sector. This sector consists of non-registered members of WECC Member Class Four;

8.5.5.2.7 State and Provincial Representatives Sector. This sector consists of non-registered WECC members of WECC Member Class Five;

8.5.5.2.8 Other non-registered WECC Members and Participating Stakeholders Sector. This sector consists of consultants and other members of WECC Member Class Seven, or interested stakeholders who qualify for Participating Stakeholder status but are not registered in the NERC compliance registry.

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~~8.5.5.2~~8.5.5.3 Voting. Except as provided in Section 4.5.2 and 8.5.5.4, each committee member ~~and Participating Stakeholder (if any)~~ will have one vote. In order for a recommendation to be made to the Board, such recommendation must receive a simple majority vote of both: 1) committee members ~~and Participating Stakeholders (if any)~~ present and voting from the Transmission Provider Class; and 2) committee members ~~and Participating Stakeholders (if any)~~ present and voting from Transmission Customer Class. ~~Committees~~ The Board will adopt voting and record-keeping procedures to ensure that committee voting is conducted consistent with these Bylaws. This requirement will also apply where decision making power has been delegated to a committee pursuant to Section 6.12.

8.5.5.3.1 State and Provincial Votes. The position of the state and provincial Class committee members must be recorded, but the failure of a proposed recommendation or decision to obtain a simple majority vote of the state and provincial committee members will not prevent the recommendation or decision from being posted for due process comment or sent to the Board of Directors.

8.5.5.4 Voting on Regional Reliability Standards and Regional Criteria. Whenever the WECC Standards Committee determines that a draft Regional Reliability Standard or Regional Criteria is ready for consideration by the Ballot Body, it shall be presented for a vote. Members of the Ballot Body shall be provided an opportunity to opt into a Ballot Pool formed for purposes of voting on each of the proposed Regional Reliability Standards or Regional Criteria as described in the Reliability Standards Development Procedures. A two-thirds quorum of the specially formed Ballot Pool is required for a valid vote. Members of the Ballot Pool shall cast their vote in the WECC Standard Voting Sectors listed in 8.5.5.2. When members of the Ballot Body who are eligible to vote in more than one of the sectors defined in 8.5.5.2 join the Ballot Pool, they may cast one vote in each voting sector in which they are eligible. Calculation of the vote by the WECC Standard Voting Sectors will be pursuant to a weighted sector voting formula as described in the Reliability Standards Development Procedures. If the Ballot Pool approves a proposed Regional Reliability Standard or Regional Criteria, then that proposed Regional Reliability Standard or Regional Criteria will be recommended to the WECC Board. The process of approving proposed Regional Reliability Standards and Regional Criteria is further guided by the Reliability Standards Development Procedures.

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8.5.6 Notice and Review of Committee Recommendations and Decisions (Due Process). Committee recommendations or decisions delegated to a committee pursuant to Section 6.12 will be subject to the due process provisions of this Section. ~~Committee recommendations or decisions related to the development or approval of Reliability Standards will be subject to the provisions of this Section 8.5.6 and Section 8.6.~~ Following a committee's development of a proposed recommendation or decision, the committee will post the proposed recommendation or decision on the WECC ~~Web~~ website for review and comment by other WECC Members, ~~interested stakeholders (if the recommendation or decision concerns a Reliability Standard or revision),~~ and other interested parties. The committee will provide all Members ~~and Participating Stakeholders (if the recommendation or decision concerns a Reliability Standard or revision)~~ e-mail notification of the posting and will allow at least thirty (30) days for comment on the proposal. The committee will consider all such additional input before reaching its final recommendation or decision. If the committee's recommendation or decision changes significantly as a result of comment received, the committee will post the revised recommendation or decision on the ~~Web~~ website, provide e-mail notification to Members ~~and Participating Stakeholders (if the recommendation or decision concerns a Reliability Standard or revision),~~ and provide no less than ten (10) days for additional comment before reaching its final recommendation or decision. Upon reaching its final recommendation or decision, the committee will forward it to the Board. Whenever it determines that a matter requires an urgent decision, the Board may shorten any time period set forth in this Section, provided that: 1) notice and opportunity for

comment on recommendations or decisions will be reasonable under the circumstances; and 2) notices to Members will always contain clear notification of the procedures and deadlines for comment.

8.6 Procedures for Developing and Voting on Reliability Standards.

8.6.1 Rights and Obligations of WECC Members and Participating Stakeholders. All WECC Members and ~~interested~~ Participating stakeholders are entitled to participate in the development of and to vote on Reliability Standards, Regional Criteria or revisions ~~to Reliability Standards~~, subject to any applicable obligations, limitations and conditions set forth in these Bylaws, and in accordance with the WECC Reliability Standards Development Procedures.

8.6.1.1 Participation. The right to participate in Reliability Standards and Regional Criteria development and voting includes the right to request the development or revision of a Reliability Standard, the right to receive notice of, attend and participate in related WECC ~~committee and subcommittee~~ discussions, the right to review information relevant to a Reliability Standard or revision, the right to provide written comments on a proposed Reliability Standard, Regional Criteria, or revision, the right to participate in ~~committee or subcommittee~~ voting on a Reliability Standard, Regional Criteria, or revision and the right to file an appeal requesting review of any ~~committee or subcommittee~~ decision on a Reliability Standard, Regional Criteria, or revision.

8.6.1.2 Voting. The procedures and conditions for voting by WECC Members and Participating Stakeholders are set forth in the Reliability Standards Development Procedures and in Sections ~~8.5.5 and~~ 8.5.5.2 and 8.5.5.4 of these Bylaws. A Participating Stakeholder may only vote on a proposed Reliability Standard or revision if they have applied for and been granted Participating Stakeholder status in accordance with Section 8.6.2 below. A Participating Stakeholder is only entitled to vote on Reliability Standards and revisions, and may only vote on Regional Criteria if the proposed Regional Criteria could result in sanctions to a non-WECC member. A Participating Stakeholder is not entitled to vote in any other WECC committee balloting process or in elections for WECC Directors.

~~8.6.1.2~~

8.6.1.3 Special Procedures to Address Regulatory Directives. If the Board determines that the procedures for drafting and voting on Reliability Standards did not result in a proposed Reliability Standard that addresses a directive issued by an Applicable Regulatory Authority, the Board shall have authority to take certain actions as described in the Reliability Standards Development Procedures to ensure that a Reliability Standard responsive to an Applicable Regulatory Authority's directive is drafted, approved and/or submitted to the Applicable Regulatory Authority. In the event that a Reliability Standard or revision that is proposed in response to an Applicable

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Regulatory Authority's directive fails to achieve a majority vote of the Ballot Pool, or if a quorum of the Ballot Pool was not established upon re-ballot of a proposed Reliability Standard, then the Board has the authority to take appropriate actions, as described in the Reliability Standards Development Procedures, to ensure that a Reliability Standard responsive to a regulatory directive can be submitted to NERC and FERC with a request that it be made effective. To exercise such authority, the Board must find that the proposed Reliability Standard or revision is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is helpful to reliability, practical, technically sound, technically feasible, and cost-justified. If the Board is unable to make this finding, then the Board may direct that the proposed Reliability Standard be filed with the Applicable Regulatory Authority as a compliance filing in response to the regulatory directive, along with a recommendation that the standard not be made effective and an explanation of the basis for the recommendation.

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8.6.2 Participating Stakeholder Application Process. Any person or entity that is an interested stakeholder may apply to WECC for Participating Stakeholder status and, upon WECC's acceptance of such application, acquire the participation and voting rights set forth above in Section 8.6.1. WECC staff, under the direction of the CEO, will process applications and make the initial determination of eligibility for Participating Stakeholder status. Denial of Participating Stakeholder status may be appealed to the WECC Governance and Nominating Committee and, if denied by the Governance and Nominating Committee, to the WECC Board. A person or entity's Participating Stakeholder status will be maintained so long as the Participating Stakeholder continues to meet the requirements set forth in Section 3.33~~21~~ and participates in at least one WECC meeting per year at which a Reliability Standard or revision is discussed ~~and/or voted on~~. In the event a person or entity's Participating Stakeholder status lapses due to failure to meet the above minimum participation requirement, the person or entity may restore Participating Stakeholder status by re-applying for Participating Stakeholder status and attending a WECC meeting at which a Reliability Standard is discussed ~~and/or voted on~~.

8.7 Notice of Committee Meetings.

8.7.1 Standing Committees. The committee Chair, with the assistance of the Chief Executive Officer, will ensure that not less than ten (10) days' notice of all standing committee meetings is posted on the WECC ~~Web~~ website and is also provided to: 1) members of the committee; 2) Participating Stakeholders (if the meeting concerns development or approval of a Reliability Standard or revision); and 3) any WECC Member or member of the public requesting notice. A committee may take up any matter at a duly noticed meeting including matters not expressly identified in the notice; provided, however, that a final recommendation to the Board must be made in accordance with Section 8.5.6.

8.7.2 Other Committees. Notice of other committee meetings will be provided in the manner adopted for such notice by the affected Members and in accordance with the requirements of Section 8.6.1.

8.8 Open Meetings.

All committee meetings of ~~the~~ WECC (including Board committees) will be open to any WECC Member and for observation by any member of the public, except as set forth in policies on closed sessions that the Board may adopt for the purpose of preventing public disclosure of information that the Board might consider in closed session pursuant to Section 7.6.1.

9. The Chief Executive Officer, Officers, and Employees.

9.1 Designation of Officers and Terms of Office.

~~The~~ WECC will have a Chief Executive Officer, a Secretary, and any other officers specified by the Board from time to time. The Chief Executive Officer will also hold the title of President of ~~the~~ WECC if applicable law requires ~~the~~ WECC to have a President. Each officer will be appointed by the Board and will serve for the term of office specified in the Board action appointing the officer and until his or her successor is appointed. Any two or more offices may be held by the same person except the offices of Chief Executive Officer and Secretary.

9.2 Chief Executive Officer Qualifications.

The Chief Executive Officer will be a person with senior management level experience and knowledge of bulk power electric transmission systems reliability, planning and operations.

9.3 Standards Applicable to All Employees.

A person may not be an officer or employee of WECC if: 1) the person is also the employee of or has a contractual relationship with any Entity, or any Affiliate of any Entity, that is eligible for membership in ~~the~~ WECC; or 2) the person has a financial interest that, in the judgment of the Board or the Chief Executive Officer, creates the fact or appearance of bias, undue influence or lack of objectivity regarding any action or decision of ~~the~~ WECC. The Board will adopt Standards of Conduct for officers and employees setting forth their duty of care, duty of loyalty, duty to avoid conflicts of interest and related matters intended to promote their neutrality, objectivity and professionalism. Upon adoption, such standards shall be attached hereto as Appendix B.

9.3.1 Exemptions from the disqualification criteria found in Section 9.3 are as follows:

9.3.1.1 Status as a residential electricity customer will not disqualify a person from employment with WECC.

9.3.1.2 A candidate for Chief Executive Officer or employee of WECC will not be disqualified for owning shares in a mutual fund because the mutual fund owns an interest in a Member or an Affiliate of a Member.

9.3.1.3 The disqualification standards described in Section 9.3 will not apply to disqualify a candidate who is receiving payments from a pension plan of a Member or an Affiliate of a Member in a form other than securities of such Member or Affiliate if the pension plan payments bear no relationship to the economic performance of the Member or Affiliate.

9.3.2 If an officer or employee receives a gift or inheritance of securities in any Member or Affiliate, he/she must resign or dispose of such securities within six (6) months of the date of receipt. Within six (6) months of the time a new Member is added in which an officer or employee owns securities, the officer or employee will resign or dispose of those securities.

9.4 Employment.

The Chief Executive Officer will be employed by the Board of Directors and will serve at the Board's pleasure. Any contract of employment with a Chief Executive Officer will permit the Board to dismiss the officer with or without cause.

9.5 Chief Executive Officer's Duties.

Subject to the Board's direction, the Chief Executive Officer or his/her designees will have the following duties, among others:

9.5.1 Execute policies at the direction of the Board and be responsible to the Board for the performance of the WECC functions described in Section 2;

9.5.2 Hire and fire staff within the constraints of the annual budget;

9.5.3 Perform administrative duties, such as preparing annual budgets for the approval of the Board, making employment decisions and ensuring conformance with regulatory requirements;

9.5.4 Develop and implement employment policies and standards of conduct; and

9.5.5 Accept or reject membership applications in accordance with the criteria of these Bylaws.

9.6 Secretary's Duties.

9.6.1 Maintain Member and Affiliates Lists. The Secretary will maintain continuously updated lists of all Members and Affiliates.

9.6.2 Maintain Official Records. The Secretary will keep minutes of all WECC Board and Member meetings and will receive and maintain minutes of committee meetings and all other official records of ~~the~~ WECC. Within five (5) business days after any vote taken by Members, the Board, a Class or any committee, the Secretary will provide notice to all Members and ~~Interested~~ Participating Stakeholders (if applicable) of the

results of such a vote through postings on the website, email and/or other means of communication.

9.6.3 Maintain Webs~~ S~~ite. The Secretary will oversee the creation, maintenance, and updating of the WECC's ~~Web~~ website and the information published through it.

10. Transmission Service Obligations.

10.1 Non-Discriminatory Transmission Access.

All Members owning, controlling or operating Transmission Facilities, or possessing rights to transmission capacity through contract, will provide interconnection and access to available transmission capacity to all other Members in a non-discriminatory manner through one of the following mechanisms: 1) a Regional Transmission Organization approved by the FERC in accordance with FERC Order 2000 and any successor order(s); 2) submission of an Open Access Tariff to the FERC; or 3) provision of non-discriminatory service in accordance with this Section 10.

10.1.1 Regional Transmission Organizations. A Member that is a Regional Transmission Organization approved by the FERC in accordance with FERC Order 2000 and any successor order(s), or a Member whose transmission capacity is controlled or operated by such a Regional Transmission Organization, will be deemed to be in compliance with Section 10 by virtue of its compliance with FERC Order 2000 and any successor order(s) and is exempt from Sections 10.2 through 10.4. Such a member will use the dispute resolution process specified in the bylaws, contracts, or tariffs of the applicable Regional Transmission Organization or other Local Regional Entity, provided that nothing in these Bylaws will prevent such a Member from using the dispute resolution process set forth in Section 11 where authorized or required by the bylaws, contracts, or tariffs of the applicable Regional Transmission Organization.

10.1.2 Members with Open Access Tariffs Filed with FERC. A Member which is not exempt pursuant to Section 10.1.1, but which has an Open Access Tariff which has been accepted for filing by the FERC, will be deemed to be in compliance with this Section 10 by virtue of its compliance with applicable FERC requirements governing its Open Access Tariff. Such Member is exempt from Sections 10.2 and 10.3; provided, however, that such Member must resolve transmission access disputes with other Member(s) in accordance with Sections 10.4, 10.5.2 and 11 of these Bylaws.

10.1.3 Other Members. Any Member subject to Section 10.1, but not eligible for exemption pursuant to Sections 10.1.1 or 10.1.2, will provide non-discriminatory interconnection and transmission access to other Members in accordance with Sections 10.2 through 10.5 of these Bylaws.

10.1.4 Canadian and Mexican Members. At the request of any Canadian or Mexican Member, the Board may adopt alternative provisions to this Section 10 applicable to the requesting Member provided that: 1) the alternative provisions differ from this

Section 10 to the minimum extent necessary to respect the laws and regulatory authorities governing the requesting Member; and 2) the alternative provisions require the requesting Member to provide interconnection and transmission service to other Members that is substantively equivalent to that required by this Section 10.

10.2 Service to be Provided.

Members described in Section 10.1.3 will provide non-discriminatory interconnection and transmission service to other Members comparable to that which would be required of an entity subject to Sections 210 through 213 of the Federal Power Act. The provision of service may be pursuant to an agreement negotiated between such Members, or, if applicable, pursuant to a service agreement under a tariff filed in accordance with Section 10.3. In no event will these Bylaws require a Member to provide transmission service that FERC is precluded from ordering under Sections 212(g) and 212(h) of the Federal Power Act. However, nothing in these Bylaws will be construed as prohibiting any Member from providing retail wheeling voluntarily or pursuant to a state statute or a lawful decision of a regulatory agency or court of law. Nothing in this section is intended to imply that any non-jurisdictional entity Member is subject to FERC jurisdiction.

10.3 Open Access Tariffs.

Except as provided in Section 10.3.1, Members described in Section 10.1.3 will file an Open Access Tariff or Tariffs consistent with Section 10.2 with the Secretary within sixty (60) days of becoming a Member. Upon the request of any Member, a Member subject to this Section 10.3 will provide a copy of its Open Access Tariff or Tariffs. Additionally, any change in any Open Access Tariff or Tariffs previously filed with the Secretary will be promptly filed with the Secretary after its adoption.

10.3.1 Petition for Exemption. Any Member described in Section 10.1.3 may petition the Board for an exemption from Section 10.3. The Board may grant such petition only if it finds that such Member is unlikely to receive a transmission service request. The granting of such a petition will not relieve the Member from the requirement to provide non-discriminatory access pursuant to Section 10.2 if the Member receives a transmission service request. If a Member has been granted an exemption from the filing of an Open Access Tariff by a Local Regional Entity based on criteria equivalent to this Section, such Member will be exempt from Section 10.3 of these Bylaws without the filing of a petition unless the Board determines otherwise.

10.4 Requests Involving Members of Regional Entities.

If a request for transmission service involves only Members who are also members of the same Local Regional Entity and the tariffs or governing documents of such Local Regional Entity provide for a process for requesting interconnection or transmission service, the process of the Local Regional Entity, as opposed to that set forth in this Section 10, will be followed. To the extent the governing documents of the Local Regional Entity establish different principles regarding the provision of interconnection or transmission service than those of ~~the~~ WECC, the principles of the Local Regional Entity will govern as among members of the Local Regional Entity; provided, however, that Members who are members of Regional Entities who receive requests for interconnection or transmission service from

Members who are not members of the same Local Regional Entity will not be precluded from substantively responding to such requests in a manner consistent with the tariffs or governing documents of such Local Regional Entity, provided that such responses will be subject to the dispute resolution provisions of Section 11.

10.5 Request Process and Dispute Resolution.

Members requesting interconnection or transmission service from Members described in Section 10.1.1 or 10.1.2 will do so in accordance with the applicable tariffs of the Member receiving the request. Members requesting such service from Members described in Section 10.1.3 will do so in accordance with this Section 10.5 in lieu of filing for such service pursuant to Sections 210 through 213 of the Federal Power Act.

10.5.1 Request Process and Interpretation of FERC Policy. Members described in Section 10.1.3 receiving requests from another Member for interconnection or transmission service pursuant to these Bylaws will respond to such requests in an expeditious and good faith manner. The Board may adopt procedural requirements regarding the processing of such requests to the extent it deems necessary and appropriate; provided, however, that the Board may not impose substantive obligations for the provision of interconnection or transmission service that are different from the substantive policies of the FERC applicable to such Members pursuant to Section 10.2. For the general guidance of arbitrators and Members and as it deems necessary, the Board may either request statements of policy from the FERC or adopt its own interpretations of FERC policy which will be subject to appeal to the FERC.

10.5.2 Dispute Resolution. Except as otherwise provided in Section 10.4, Members described in Sections 10.1.2 and 10.1.3, and any Member requesting interconnection or transmission service from such a Member, will resolve disputes regarding such requests in accordance with Section 11.

11. Dispute Resolution.

Except as may be otherwise provided herein, and subject to the conditions set forth in Appendix C, Section A.1, disputes between Members and/or ~~the~~ WECC will be resolved pursuant to the WECC Dispute Resolution Procedures set forth in Appendix C. Matters subject to the jurisdiction of the WECC Compliance Hearing Body are not subject to the procedures in Appendix C.

12. Costs and Finances.

12.1 Funding of Reliability Activities.

12.1.1 U.S. Statutory Funding. ~~The~~ WECC shall fund all activities undertaken pursuant to Section 215 of the Federal Power Act in accordance with the funding provisions and procedures of that law and related FERC regulations and orders. The Board shall approve a budget for such activities in time for submission to the ERO and to the FERC for approval of such funding in accordance with applicable requirements.

12.1.2 International Funding. ~~The~~ WECC shall fund reliability activities undertaken pursuant to any agreements with appropriate Canadian or Mexican authorities in accordance with the provisions of those agreements.

12.1.3 Equitable Allocation of Funding. In adopting budgets for the costs of reliability activities, the Board shall endeavor to achieve an equitable allocation as between funding through Sections 12.1.1 and 12.1.2 based upon the net energy to load and other relevant factors consistent with applicable law, the Delegation Agreement and any International Reliability Agreements.

12.2 Dues.

The Board may require Members and Participating Stakeholders to pay nominal annual dues consistent with applicable FERC requirements (or those of International Reliability Agreements as applicable) to cover reasonable costs of membership and/or participation in standards development that are not funded through Sections 12.1.1 or 12.1.2. Initial dues of a Member or Participating Stakeholder will be submitted with a completed application for membership or Participating Stakeholder status and will be for the prorated share of the full annual amount based on the Member's or Participating Stakeholder's actual months of membership or participation in the calendar year. In determining nominal dues, the Board may consider all relevant factors including, but not limited to, the ability of different classes of membership or Participating Stakeholders to pay such dues. The Board may also reduce, defer or eliminate the dues obligation of an individual Member or Participating Stakeholder for good cause shown.

12.3 Funding of Non-Statutory Activities.

To the extent that ~~the~~ WECC elects to fund any activities not eligible for funding pursuant to Sections 12.1.1 and 12.1.2, it shall do so through the use of service fees, charges or dues applicable to the persons or entities that voluntarily participate in such activities. Participation in or funding of such activities shall not be a condition of membership in ~~the~~ WECC.

13. Amendments to these Bylaws.

These Bylaws may be amended by either the Board or by the Members in accordance with the following procedures.

13.1 Amendment by the Board.

Except for those provisions described below, the Board may approve an amendment of the Bylaws after providing not less than thirty (30) days' notice of the proposed amendment to all Members. Approval of such an amendment requires the affirmative votes of not less than two-thirds (2/3) of the Directors in office. Such amendment will become effective sixty (60) days after its approval by the Board unless the vote is appealed to the Members prior to that time. Such an appeal will occur whenever a majority of any Class files a petition with the Secretary seeking such amendment. A vote on the appeal will occur at the next Annual Meeting unless the Board calls a special meeting of the Members beforehand. Upon appeal, the amendment will be deemed approved unless a majority of all Members vote to rescind the amendment. Notwithstanding the foregoing, the Board may not amend Sections 6.2 through

6.10 of the Bylaws, Section 8.4, Appendix C or this Section 13.1 without submitting such amendment to the Members for their prior approval.

13.2 Amendment by the Members.

Upon petition filed with the Secretary by any Member or Director, at any Annual Meeting the Members may amend any provision of these Bylaws; provided: 1) the proposed amendment has first been presented to the Board and not adopted (this provision will not apply to amendments which the Board is prohibited from adopting); 2) Members have received not less than sixty (60) days' notice of the proposed amendment, the reasons there for and a statement of the Board's position regarding it; and 3) the amendment receives the affirmative votes of not less than two-thirds (2/3) of all Members.

13.3 Amendments in Response to Mandatory Membership.

If at any time, pursuant to legislation or otherwise, membership becomes mandatory for some or all Members, upon the request of the affected Member(s) the Board will consider amendments to these Bylaws appropriate to such mandatory membership.

13.4 Amendments proposed by FERC.

FERC, upon its own motion or upon complaint, may propose an amendment to these Bylaws pursuant to 18 C.F.R. § 39.10(b).

14. Termination of Organization.

~~The~~ WECC may be terminated upon a vote of a majority of the Members in accordance with the provisions of Utah law, the Federal Power Act and the requirements of the Delegation Agreement and applicable International Reliability Agreements. Immediately upon such a vote, the Board will, after paying all debts of ~~the~~ WECC, distribute any remaining assets in accordance with the requirements of Utah law, the Internal Revenue Code and these Bylaws.

15. Miscellaneous Provisions.

15.1 Limitation on Liability.

It is the express intent, understanding and agreement of the Members that the remedies for nonperformance expressly included in Section 4.8 hereof shall be the sole and exclusive remedies available hereunder for any nonperformance of obligations under these Bylaws. Subject to any applicable state or federal law which may specifically limit a Member's ability to limit its liability, no Member, its directors, members of its governing bodies, officers or employees shall be liable to any other Member or Members or to third parties for any loss or damage to property, loss of earnings or revenues, personal injury, or any other direct, indirect, or consequential damages or injury which may occur or result from the performance or nonperformance of these Bylaws, including any negligence, gross negligence, or willful misconduct arising hereunder. This Section 15.1 of these Bylaws applies to such liability as might arise between Members under these Bylaws. This Section 15.1 does not apply to parties to the Agreement Limiting Liability Among Western Interconnected Systems ("WIS Agreement") with respect to matters covered by the WIS Agreement and does not apply to any liability provision in any other agreement.

15.2 Indemnification.

WECC shall indemnify and hold harmless its Directors, officers, employees, agents and advisors against any and all damages, losses, fines, costs and expenses (including attorneys' fees and disbursements), resulting from or relating to, in any way, any claim, action, proceeding or investigation, instituted or threatened, arising out of or in any way relating to any action taken or omitted to have been taken (or alleged to have been taken or omitted to have been taken) by such person in connection with actions on behalf of WECC, and against any and all damages, losses, fines, costs and expenses (including attorneys' fees and disbursements) incurred in connection with any settlement of any such claim, action, proceeding or investigation unless such action of such person is determined to constitute fraud, gross negligence, bad faith or willful misconduct with respect to the matter or matters as to which indemnity is sought.

15.3 No Third Party Beneficiaries.

Nothing in these Bylaws shall be construed to create any duty to, any standard of care with reference to or any liability to any third party.

15.4 Informal Inquiries for Information.

Nothing in these Bylaws shall preclude: 1) a Member from making an informal inquiry for information outside of the procedures outlined in Section 4.6.13 hereof to another Member and 2) that other Member from responding voluntarily to that informal inquiry, provided, however, that any such response to an informal inquiry for information shall not be binding upon that other Member and shall be used by the Member making the informal inquiry for informational purposes only.

16. Incorporation.

WECC shall organize itself as a non-profit corporation pursuant to the laws of the state of Utah regarding non-profit corporations under the name "Western Electricity Coordinating Council." All Members agree to take no actions that would contravene the ability of ~~the~~ WECC to maintain its status as a non-profit corporation existing pursuant to the Utah Act. The Board shall adopt these Bylaws as the Bylaws of ~~the~~ WECC as a non-profit corporation.

WECC is intended to qualify as an organization described in Section 501(c)(6) of the Internal Revenue Code. No part of any net earnings of ~~the~~ WECC shall inure to the benefit of any Member or individual. Upon liquidation, to the extent consistent with the Internal Revenue Code and Utah law, any monies remaining from assessments paid by Members for the costs of ~~the~~ WECC shall be rebated to Members in proportion to their payments. Any remaining assets of ~~the~~ WECC shall be transferred to another organization exempt from tax under Section 501(a) of the Internal Revenue Code, or government agency, promoting the same purposes as ~~the~~ WECC, as designated by the Board.

17. Governing Law.

Unless otherwise agreed, if any conflict of law arises under these Bylaws among the Members, the laws of the United States of America shall govern, as applicable. The venue for any legal action initiated under these Bylaws which concerns a specific request for transmission service shall be the city and state (or province) in which the headquarters of the Member providing the service is located.

The venue for any other legal action initiated under these Bylaws shall be the city and state (or province) in which the headquarters of ~~the~~ WECC is located.

APPENDICES

A. Board Member Standards of Conduct

B. Officers and Employees Standards of Conduct

C. WECC Dispute Resolution Procedures

Appendix A
Standards of Conduct for
Members of the WECC Board of Directors

By accepting appointment to the Board of Directors (the "Board") of the Western Electricity Coordinating Council (~~the~~ "WECC"), a Director agrees to abide by the duties required of corporate directors and trustees. Utah law (and similar law in other states) imposes quasi-fiduciary duties of care and loyalty on all corporate directors or trustees, including directors and trustees of nonprofit corporations. For as long as he or she remains a member of the Board of Directors of ~~the~~ WECC, a Director will abide by the following standards of conduct.

I. Duty of care. The Directors of a corporation are bound to use due care and to be diligent in respect to the management and administration of the affairs of the corporation. This duty of care is generally thought to have two components: the time and attention devoted to corporate affairs and the skill and judgment reflected in business decisions.

A. Each Director will regularly attend Board of Directors meetings, digest the materials sent to him or her, participate in Board discussions and make independent inquiries as needed.

B. In voting on any matter before the Board or otherwise acting in his or her capacity as a Director, each Director will:

1. make reasonable inquiry to inform himself or herself of the nature and consequences of the matter or action at issue;

2. exercise, at a minimum, the degree of care, skill, and diligence that an ordinarily prudent business person would exercise under similar circumstances; and

3. act in a manner the Director, in the exercise of his or her independent judgment, believes to be in the best interests of ~~the~~ WECC and the membership of ~~the~~ WECC, taken as a whole.

C. In exercising the duty of care described in paragraphs IA and B above, a Director has the right to rely on statements by the persons immediately in charge of business areas of ~~the~~ WECC, to rely on professionals and experts (such as engineers, accountants and lawyers) and to rely on committees of ~~the~~ WECC, unless facts or circumstances appear which would prompt further concerns of the ordinarily prudent person.

II. Duty of loyalty. The duty of loyalty imposes on a Director the obligation to remain loyal to ~~the~~ WECC, acting at all times in the best interests of WECC and its Members as a whole and unhampered by any personal pecuniary gain. This duty does not preclude a Director from being employed in a competing or related business so long as the Director acts in good faith and does not interfere with the business of ~~the~~ WECC.

A. Each Director will carry out his or her duties as a Director in good faith.

B. Each Director will refrain from using any influence, access, or information gained through his or her service as a Director to confer any improper personal benefit (financial or otherwise) upon himself or herself, any family member, or any person living in the Director's household.

C. Each Director will refrain from using any influence, access, or information gained through his or her service as a Director to confer an improper benefit (financial or otherwise) on any organization:

1. for which the Director serves as an officer, director, employee, consultant, or in any other compensated or management position; or

2. in which the Director or any family member or person living in the Director's household has a material financial interest (whether as a shareholder, partner, or otherwise).

D. To the extent permitted by law, each Director will maintain the confidentiality of:

1. any confidential or proprietary information of ~~the~~ WECC disclosed or available to the Director;

2. any confidential or proprietary information of WECC Member(s) to which the Director has access by virtue of his or her status as Director; and

3. any confidential or proprietary information of third parties that has been provided to ~~the~~ WECC or the Board on condition of confidentiality.

E. Conflicts of Interest. Because conflicts of interest may arise from time to time, specific guidelines are provided. In general, conflicts of interest involving a Director are not inherently illegal nor are they to be regarded as a reflection on the integrity of the Board or of the Director. It is the manner in which the Director and the Board deal with a disclosed conflict that determines the propriety of the transaction.

Directors of nonprofit corporations may have interests in conflict with those of the corporation. The duty of loyalty requires that a Director be conscious of the potential for such conflicts and act with candor and care in dealing with these situations.

The following are guidelines for Directors with actual or potential conflicts of interest:

1. Each Director has a responsibility to recognize potential conflicts of interest and to be guided when acting as a Director by his or her independent judgment of what is in the best interests of ~~the~~ WECC and the membership of ~~the~~ WECC, taken as a whole. If any Director has questions about whether a conflict of interest exists, he or she may make inquiry to the Chief Executive Officer of ~~the~~ WECC for advice.

2. Potential conflicts of interest may arise because of a Director's private, individual interests (personal conflicts of interest) or because of relationships the Director may have with other organizations or interest groups (organizational conflicts of interest). Current or past employment or other compensation-based relationships with one or more WECC Members are examples of potential organizational conflicts of interest. Whether a potential conflict of interest is personal or organizational, in all cases involving WECC affairs a Director's conflicting interests are subordinate to those of ~~the~~ WECC and the membership of ~~the~~ WECC, taken as a whole.

3. Personal conflicts of interest.

   a. Personal conflicts of interest exist if a Director, a member of the Director's family, or a person sharing the Director's household: 1) has a material financial interest in a matter or transaction that comes before the Board for action; or 2) stands to receive a benefit (in money, property, or services) from a transaction involving ~~the~~ WECC to which the person is not legally entitled.

   b. In cases of personal conflicts of interest, the affected Director's obligations are to:

      (1) disclose to the Board, before the Board acts with respect to that matter, the material facts concerning the Director's personal conflict of interest; and

      (2) refrain from voting, and from attempting to influence the vote of any other Director(s), in those matters in which the Director has a personal conflict of interest.

4. Organizational conflicts of interest.

   a. An organization has a "direct" conflict of interest if a decision by the Board would confer material benefits on that organization that other WECC Members would not share, or impose material detriments or costs on that organization that other WECC Members would not share. The fact that many if not all Members are affected to some extent by Board decisions on core issues such as standards, new transmission lines and their ratings, does not create or constitute a "direct" conflict of interest.

   b. It is not a "direct" conflict of interest for a Director to be associated with an organization or an interest group that may stand to benefit from decisions made or actions taken by the Board, so long as the Director does not attempt to use his or her position as a Director to confer special benefits on associated organizations or interest groups when other WECC Members would not share in those benefits.

c. In cases of potential "direct" organizational conflicts of interest, the affected Director's obligations are to:

(1) disclose to the Board, before the Board acts with respect to the matter, the material facts concerning the organizational conflict of interest; and

(2) refrain from voting and from attempting to influence the vote of any other Director(s) with respect to the proposed action or decision.

Appendix B
Officers and Employee
Standards of Conduct

By accepting employment with the Western Electricity Coordinating Council (~~the~~ "WECC"), an Employee agrees to abide by these Standards of Conduct. For the purpose of these Standards, an Employee includes each and all officers, employees and substantially full-time consultants and contractors of ~~the~~ WECC.

I. Duty of care. The Employees of ~~the~~ WECC are bound to use due care and to be diligent in respect to the management and administration of the affairs of the corporation. This duty of care is generally thought to have two components: the time and attention devoted to corporate affairs and the skill and judgment reflected in business decisions.

Employees shall not have any outside employment that limits in any way their ability to fulfill their employment responsibilities to WECC. If an Employee has any question about whether outside employment is consistent with this standard, they should consult with their supervisor.

II. Duty of loyalty. The duty of loyalty imposes on an Employee the obligation to remain loyal to the WECC, acting at all times in the best interests of WECC and its Members as a whole and unhampered by any personal pecuniary gain. ~~The~~ WECC expects all Employees to avoid adversely affecting the public's confidence in the integrity and reputation of ~~the~~ WECC. Any conduct or activities of any Employee should be capable of being justified and withstanding public scrutiny.

A. Each Employee will carry out his or her duties as an Employee in good faith, with integrity and in a manner consistent with these Standards and all applicable laws governing ~~the~~ WECC.

B. Each Employee will refrain from using, or creating the appearance of using, any influence, access, or information gained through his or her service as an Employee to confer any improper personal benefit (financial or otherwise) upon himself or herself, or Family Member.[2] Employees shall not accept gifts or entertainment that would tend to affect, or give the appearance of affecting, the performance of their duties; provided, however, that Employees may accept de minimus food or entertainment or non-cash gifts received as part of a social or special occasion in amounts not to exceed $1000 per source per year.

C. Each Employee will refrain from using, or creating the appearance of using, any influence, access, funds or information gained through his or her service as an Employee to confer an improper benefit (financial or otherwise) on any organization. The

2 For purposes of these Standards, a Family Member includes a spouse, domestic partner, child of the Employee, or a relative living in the same home as the Employee.

obligation to avoid the appearance of impropriety shall apply in particular to any organization:

1. for which the Employee is serving or has in the past served as an officer, director, employee, consultant, or in any other compensated or management position; or

2. in which the Employee, or Family Member has a material financial interest known to the Employee (whether as a shareholder, partner, or otherwise).

D. Employees shall not use their WECC position, WECC funds or WECC resources to support any political party, candidate or proposition except as expressly authorized by the Board.

E. To the extent permitted by law, each Employee shall maintain the confidentiality of:

1. any confidential or proprietary information of ~~the~~ WECC disclosed or available to the Employee;

2. any confidential or proprietary information of WECC Member(s) to which the Employee has access by virtue of his or her status as Employee; and

3. any confidential or proprietary information of third parties that has been provided to ~~the~~ WECC or the Board on condition of confidentiality.

F. Conflicts of Interest. The following conflicts of interest policy shall apply to all WECC Employees. Conflicts of interest may arise from time to time. In general, conflicts of interest involving an Employee are not inherently illegal, nor are they to be regarded as a reflection on the integrity of ~~the~~ WECC or of the Employee. It is the manner in which the Employee and ~~the~~ WECC deal with a disclosed conflict that determines the propriety of the transaction. The following are guidelines for Employees with actual or potential conflicts of interest:

1. In general, personal conflicts of interest exist if an Employee, or a Family Member, has a material financial interest in a matter or transaction that comes before WECC for action, or stands to receive a benefit (in money, property, or services) from a transaction involving WECC to which the person is not legally entitled. For purposes of determining whether stock constitutes a material financial interest, see Paragraph F(6) below.

2. Organizational conflicts of interest exist if an Employee, or a Family Member, has a relationship with an organization or interest group that would cause a reasonable person to believe such Employee's judgment, loyalty, or objectivity might be influenced in a way that is adverse to the interests of WECC.

3. Where there is any question about potential conflicts of interest, the Employee shall disclose to the Chief Executive Officer as soon as possible and prior to when

WECC takes action with respect to that matter, the material facts concerning the Employee's personal conflict of interest, and refrain from participating in, or from attempting to influence the action of any Directors or Employee(s) of WECC regarding those matters in which the Employee has a conflict of interest.

4. No Employee may be an employee, director of, or consultant to or provide services to or be associated in any way with any WECC Member without full disclosure to, and written consent of, the Chief Executive Officer. To the extent that an Employee becomes aware that a Family Member is or will in the future be engaged in activity described in this Paragraph F(4), the Employee shall promptly notify the Chief Executive Officer, who shall review all the material facts and determine whether they constitute a conflict of interest pursuant to Paragraphs F(1) and F(2), above.

5. No Employee shall participate in any electric energy transaction other than for ordinary personal use except to the extent necessary to, and consistent with, the functions of WECC. Participation in an energy transaction includes, but is not limited to, purchasing, selling, marketing, or brokering of electricity, ancillary services, electricity transmission or electricity distribution. To the extent that an Employee becomes aware that a Family Member is or will in the future be engaged in activity described in this Paragraph F(5), the Employee shall promptly notify the Chief Executive Officer who shall review all the material facts and determine whether they constitute a conflict of interest pursuant to Paragraphs F(1) and F(2), above.

6. All Employees shall promptly disclose to the CEO and the Chair of the Board any direct or indirect financial interest in excess of $5,000 (including the direct or indirect ownership of securities) held by the Employee or a Family Member living with the Employee[3] in any Electric Line of Business entity as defined in Section 3.15 of the Bylaws doing business in the Western Interconnection. Upon such disclosure, the CEO and the Chair of the Board shall determine whether such financial interest constitutes a conflict of interest, or the appearance thereof, in light of the duties of the Employee, the ability to divest such financial interest without undue hardship and the totality of the circumstances. In response to such disclosure, the CEO and the Chair may impose such remedies as are reasonable under the circumstances and consistent with section 9.3 of the Bylaws. Such remedies may include, but are not limited to, restrictions on the Employee's duties or involvement in certain matters, transfer of the Employee to another position, broader disclosure of the financial interest, voluntary or mandatory divestiture of the interest (in whole or in part) or other remedies. Pursuant to section 9.3.2 of the

3 Nothing in this section shall require an Employee to investigate the financial interests of Family Members not living with the Employee. However, to the extent known to the Employee, the financial interests of a Family Member not living with the Employee may create a potential conflict of interest (or appearance thereof) subject to Sections II(B) and/or II(F)(1) of these standards, in which case disclosure pursuant to Section II(F)(3) is appropriate.

Bylaws, if an Employee (not a Family Member) receives a gift or inheritance of securities of a Member of ~~the~~ WECC, or if a new Member joins ~~the~~ WECC in which the Employee (not a Family Member) holds securities, the Employee must resign or divest such securities within six months thereafter. For the purposes of this section, none of the following shall constitute a direct or indirect financial interest:

a. An interest that exists through diversified mutual funds;

b. An interest that exists for six months following receipt of a gift or inheritance of securities of a Market Participant or acceptance of employment with ~~the~~ WECC, whichever is later (provided that employees of the WSCC shall have two years from ~~the~~ WECC organizational meeting to divest securities in their possession as of that date);

c. An interest that exists through a pre-existing participation in a qualified defined benefits pension plan or health benefits plan of a Market Participant so long as the benefits under such plan do not vary with the economic performance or value of the securities of such Market Participant.

Appendix C

WECC Dispute Resolution Procedures

C. DISPUTE RESOLUTION.

C.1 Obligation To Comply with Dispute Resolution Procedures. If any dispute concerning one or more issues identified in Section C.2 below arises between a Member and one or more other Members, or between one or more Members and WECC, all of the parties to the dispute shall, to the extent permitted by law, be obligated to comply with the dispute resolution procedures specified in these Bylaws (except to the extent all of the parties to the dispute may agree otherwise as provided in Section C.4 below). Only Members and WECC have the right to invoke the provisions of this Appendix C and, except where all affected parties have separately agreed otherwise with respect to a particular dispute, only Members and WECC are obligated to carry out the dispute resolution procedures set forth herein. Any dispute subject to the provisions of this Appendix C to which WECC is made a party shall be subject to the additional requirements specified in Section C.3 below if the dispute is initiated by a party other than WECC. To the extent permitted by law (and except as otherwise permitted by the provisions of Section C.6.3), no party to a dispute subject to the provisions of this Appendix C may pursue any other available remedy with respect to the dispute until all of the parties to the dispute have fully complied with the dispute resolution procedures specified herein, *provided, however,* that if any party to a dispute subject to the provisions of this Appendix C refuses to comply with the dispute resolution procedures specified herein, all other parties to the dispute shall subsequently be relieved of any further obligation to comply with these dispute resolution procedures before pursuing other remedies in connection with that dispute.

C.2 Issues Subject to Dispute Resolution Procedures. Any dispute between or among the parties identified in Section C.1 above (that the parties to the dispute do not resolve through negotiations between or among themselves) shall be subject to the dispute resolution procedures set forth in this Appendix C if the dispute concerns: (i) the application, implementation, interpretation, or fulfillment of any guidelines, criteria, policies, procedures, or Bylaws of WECC or the North American Electric Reliability Council (or any successor organization); or (ii) any matter specified in Section C.6.2 below; except that any matter that is subject to the jurisdiction of the WECC Compliance Hearing Body is not subject to the requirements of this Appendix C. Notwithstanding the foregoing provisions of this Section C.2, however, neither WECC nor any Member shall be obligated to comply with the dispute resolution procedures of these Bylaws if: (a) the matter in dispute falls within the scope of the dispute resolution procedures set forth in the governing agreements of the Western Regional Transmission Association, the Southwest Regional Transmission Association, or the Northwest Regional Transmission Association to the extent that such organizations continue to exist; (b) the dispute is between two or more Members (or WECC), all of which, at the time of the dispute, are parties to the WECC Reliability Management System Agreement and the matter is within the scope of the dispute resolution procedures set forth in that agreement; or (c) the dispute is between two or more Members, all of which, at the time of the dispute, are parties to a separate agreement or treaty or where an applicable tariff, rate schedule, or other legal obligation of one of the parties provides for the parties to resolve the dispute in a manner other than in accordance with the provisions of this Appendix C of the Bylaws. With regard to a transmission access matter pursuant to Sections 10.1.2, 10.1.3, 10.5 and C.6.2.3, however, members agree that their rights and obligations pursuant to

Sections 210 and 211 of the FPA shall not by themselves supersede or relieve them of their obligation, if any, to participate in the procedures set forth in this Appendix C.

C.3 Limitations on Members' Rights To Make WECC a Party to a Dispute. In addition to the other provisions of this Appendix C of the Bylaws, any dispute (other than a dispute initiated by WECC) to which WECC is made a party shall be subject to the limitations set forth in Sections C.3.1 and C.3.2 below.

C.3.1 Bases for Using Dispute Resolution Procedures To Challenge WECC Action. Subject to any limitation set forth in these Bylaws or in applicable statute, regulation or FERC order, one or more Members may use the dispute resolution procedures specified in this Appendix C to challenge any final action of WECC only on one or more of the following bases: (i) the action is contrary to applicable law or regulation; (ii) the action is contrary to WECC's Articles of Incorporation or these Bylaws (including WECC's purposes as set forth in those documents); (iii) the action was taken in violation of applicable procedures of WECC governing that action; or (iv) the action encompasses a decision in which there was plain error material to the decision. For purposes of this Appendix C, action taken by WECC shall be deemed final if: (a) the action has been taken or adopted or approved or accepted by WECC's Board of Directors (other than by a motion specifically providing that the action is conditional or will have temporary application not to exceed six months); (b) all conditions specified to make any conditional action of WECC's Board of Directors effective have been fulfilled; or (c) the action has been taken or adopted or approved or accepted by a committee, subcommittee, task force, or other group or person acting under authority of WECC without any provision making the action

subject to further approval or adoption or acceptance by the Board of Directors. Nothing contained in this Appendix C shall limit any rights any Member (or any other party) may have under applicable law or regulation to initiate or participate in an administrative or legal action to which WECC is made a party in accordance with applicable provisions of law or regulation.

C.3.2 Obligation to Bear WECC's Share of Facilitator Costs. If one or more Members initiate a dispute under this Appendix C to challenge an action of WECC, the Member(s) initiating the challenge shall be obligated to bear all of the costs of facilitators' services incurred to comply with the requirement of Section C.5 below, except to the extent WECC agrees to pay a share of the costs of facilitators' services.

C.4 Ability to Modify Dispute Resolution Procedures by Agreement. Any provision of the dispute resolution procedures set forth in this Appendix C may be modified, waived, or omitted by agreement of all of the parties to the dispute. Parties to a dispute subject to these provisions are obligated to comply with its procedures unless all of the parties to the dispute agree to do otherwise. The manner in which the dispute resolution procedures set forth in this Appendix C may be varied include (by way of example and not as limitation): the manner of selecting a facilitator or arbitrator; the procedures or time lines to be followed during mediation or arbitration; the grounds or forum or right to appeal an arbitrator's decision; the manner of allocating fees and costs associated with the dispute; whether the parties are obligated to proceed to arbitration if the dispute is not resolved through mediation; and whether a decision rendered through arbitration is binding on the parties. In addition, any dispute that does not fall within the scope specified in Section C.2 above may

be resolved according to the procedures set forth in Appendix C of these Bylaws if all of the parties to the dispute agree to do so.

C.5 Mediation.

C.5.1 Notice to Other Parties and WECC's Chief Executive Officer. To initiate the dispute resolution process with respect to a dispute governed by the provisions of this Appendix C, the Member or WECC that has elected to initiate the dispute shall deliver to all other parties to the dispute and to WECC's Chief Executive Officer (whether or not WECC is a party to the dispute) written notice invoking the dispute resolution procedures set forth in this Appendix C (a "Dispute Notice").

C.5.1.1 The Dispute Notice shall: (i) include a brief, general description of the matter(s) in dispute; (ii) include a complete list of all other Members the party submitting the Dispute Notice intends to make a party to the dispute; and (iii) state whether or not WECC is to be made a party to the dispute.

C.5.1.2 Within five business days of receiving a Dispute Notice, any party to the dispute may elect to deliver a brief supplemental description of the dispute to WECC's Chief Executive Officer.

C.5.1.3 Within 10 business days of receiving an initial Dispute Notice, WECC's Chief Executive Officer shall: (a) publish (or cause to be published) in WECC's newsletter or on its electronic bulletin board a notice containing a list of the parties to the dispute and a summary of the descriptions of the matter(s) in dispute provided by the parties to the dispute; and (b) deliver to each party to the dispute a copy of WECC's then-current standing list of

qualified facilitators, knowledgeable in the matters addressed by WECC (as approved by the Board of Directors).

C.5.1.4 No person may be listed on WECC's standing list of qualified facilitators unless the person has agreed to: (i) disclose, at any time the person is selected to serve as a facilitator under this Appendix C, any personal or financial interest the facilitator may have with respect to the matter(s) in dispute (including any indirect personal or financial interest that could arise because of interests or relationships affecting any of the facilitator's immediate family members); (ii) disclose any relationship the facilitator may have with any party to the dispute that is not permitted under Section C.5.2 below; and (iii) abide by all applicable provisions of these Bylaws, including restrictions on disclosure of matters discussed and information exchanged during mediation as provided in Section C.5.3 below.

C.5.2 Selection of a Facilitator. Within 10 calendar days after the delivery of a Dispute Notice, the parties to the dispute shall select a neutral facilitator by mutual agreement. If the parties to the dispute cannot agree on a facilitator within 10 calendar days after delivery of a Dispute Notice, the facilitator shall be selected from WECC's standing list of qualified facilitators as follows: The parties to the dispute shall take turns striking names from WECC's standing list of qualified facilitators until there is only one name remaining. (The parties to the dispute shall draw lots to determine the order in which they take turns striking names.) The last person whose name remains on the list shall serve as the facilitator. No facilitator other than a facilitator chosen by agreement of all the parties to the dispute may (i) have a

personal or financial interest in the matter(s) in dispute (including any indirect personal or financial interest that could arise because of interests or relationships affecting any of the facilitator's immediate family members); or (ii) be (or have an immediate family member who is) a past or present director, commissioner, officer, employee, consultant, agent, or other representative of any of the parties to the dispute. If the facilitator selected through the process of striking names specified above is disqualified under the preceding sentence, the facilitator whose name was stricken last shall serve in his or her place. In addition, if WECC is a party to a dispute initiated by one or more Members, turns striking names from the standing list of qualified facilitators shall alternate between WECC on the one hand and all other parties to the dispute on the other.

C.5.3 Mediation Process. The facilitator and representatives of all of the parties to the dispute shall meet within 14 calendar days after the facilitator has been selected and attempt in good faith to negotiate a resolution to the dispute. Each party's representative designated to participate in the mediation process must have the authority to settle the dispute (or, at a minimum, be authorized to negotiate on behalf of the party and make recommendations with respect to settlement of the dispute if final authority to approve a settlement is reserved to a party's board, executive committee, commission, or other governing body). At the parties' initial meeting with the facilitator, the facilitator shall, after soliciting input from the parties to the dispute, set the schedule for further meetings among the parties to the dispute (subject to the 60-day maximum mediation period specified in Section C.5.6 below). The parties to the dispute shall comply with the schedule set by the facilitator and attempt in good faith at every meeting to negotiate a resolution to the dispute. To the

extent permitted by law, neither the facilitator nor any party to the dispute may publicly disclose, rely on, or introduce as evidence in any subsequent arbitration, FERC proceeding, Canadian Regulatory Authority proceeding, proceeding before a Mexican Regulatory Authority, appeal, or litigation concerning the same or any related dispute: (i) any views expressed or suggestions made by another party to the dispute with respect to a possible settlement of the dispute; (ii) admissions made by another party to the dispute in the course of the mediation proceedings; (iii) proposals made or views expressed by the facilitator; or (iv) the fact that another party to the dispute has or has not indicated willingness to accept a proposal for settlement made by the facilitator. In those cases in which a party to a dispute subject to the provisions of this Appendix C of the Bylaws is a membership organization (including WECC, if applicable), nothing in the preceding sentence shall prohibit that organization from reasonably communicating with its members and governing body to share general information about the dispute, such as the parties, status, disputed issues, and positions of each of the parties with respect to the disputed issues.

C.5.4 Referral for Resolution. With the consent of all parties to the dispute, a resolution may include referring the matter to a technical body (such as a technical advisory panel of WECC) for resolution or an advisory opinion, to arbitration, directly to FERC or, in a dispute involving a Canadian Member, directly to the appropriate Canadian Regulatory Authority, or, in a dispute involving a Mexican Member, directly to the appropriate Mexican Regulatory Authority.

C.5.5 Mediation Participation by WECC Staff When WECC Not a Party. If, during the course of mediation to which WECC is not a party, the facilitator or any party to the dispute wishes to solicit the views of WECC concerning the application,

implementation, interpretation, or fulfillment of any guidelines, criteria, standards, policies, or procedures of WECC, the facilitator may request or permit the submission of WECC staff views only if: (i) any participation by WECC staff takes place exclusively in the presence of all parties to the dispute; (ii) participating WECC staff members agree to be equally available upon request to all parties to the dispute; and (iii) participating WECC staff members agree to comply with the restrictions on disclosure contained in Section C.5.3.

C.5.6 Mediation Deemed at Impasse After 60 Days. If the parties to the dispute have met and negotiated in good faith in accordance with the schedule set by the facilitator but have not succeeded in negotiating a resolution of the dispute within 60 calendar days after the first meeting with the facilitator pursuant to Section C.5.3 above, the parties to the dispute shall be deemed to be at impasse and, except as otherwise provided in Section C.5.6.2 below, shall also be deemed to have fulfilled their obligations under Section C.1 of these Bylaws to fully comply with the dispute resolution provisions before pursuing any other available remedy. If any party participating in the mediation process is subject to a contractual or statutory limitations period with respect to the matter in dispute, and the limitations period will expire before the 60-day period for mediation under this Section C.5.6 is completed, then the parties shall be deemed at impasse on the seventh calendar day preceding the expiration of the shortest applicable limitations period.

C.5.6.1 Disputes Not Subject to Provisions of Section C.6.2. Unless the matter in dispute is subject to the provisions of Section C.6.2 below, at any time after the parties to the dispute are deemed at impasse, the dispute may be submitted to binding arbitration in accordance with the procedures set forth in Section C.7 of these Bylaws (but only by agreement of all of the parties to the dispute). If the matter in dispute is subject to the provisions of

Section C.6.2 below, the parties' obligations with respect to submitting the matter to binding arbitration under Sections C.6 and C.7 of these Bylaws shall be as specified in Section C.5.6.2 below. In all other cases, if the parties to the dispute do not agree to submit the dispute to binding arbitration in accordance with the procedures set forth in Section C.7 of these Bylaws, any party to the dispute may at any time thereafter pursue any other remedy available under regulation, law, or equity (subject to the restrictions on disclosure set forth in Section C.5.3 above).

C.5.6.2 Disputes Covered by Section C.6.2. If the parties to a dispute concerning a matter subject to the provisions of Section C.6.2 either: (i) are deemed at impasse after attempting to resolve the matter through mediation as provided in Sections C.5.1 through C.5.6 above; or (ii) have agreed to submit the matter directly to binding arbitration without attempting to resolve the matter through mediation as provided in Sections C.5.1 through C.5.6 above, the parties to the dispute shall submit the matter to binding arbitration in accordance with the procedures set forth in Sections C.6 and C.7 of these Bylaws.

C.5.7 Costs of Facilitator's Services. Except as otherwise provided under Section C.3.2, the costs of the facilitator's services shall be born equally by all parties to the dispute unless the parties to the dispute agree otherwise, but the parties also intend that the costs of mediation should be taken into account in any resolution proposed through the mediation process.

C.5.8 Notice to WECC of Completion of Mediation. Within 10 calendar days after either: (i) reaching a negotiated resolution through the mediation process set forth in Section C.5; or (ii) reaching deemed impasse in accordance with Section C.5.6 above, the parties to the dispute shall jointly deliver to WECC's Chief Executive Officer a written notice briefly describing the outcome of the mediation process. Promptly

after receiving written notice describing the outcome of a mediation conducted in accordance with Section C.5, WECC's Chief Executive Officer shall publish (or cause to be published) in WECC's newsletter or on its electronic bulletin board a brief description of the outcome of the mediation, together with a list of all of the parties to the dispute.

C.6 General Provisions Relating to Binding Arbitration.

C.6.1 Matters for Which Binding Arbitration is Elective. Except with respect to any dispute that concerns one or more matters specified in Section C.6.2 below, the binding arbitration procedures set forth in Section C.7 may be invoked only by agreement of all of the parties to the dispute to be arbitrated and are solely for the convenience of WECC and its Members. If a dispute governed by this Appendix C does not concern a matter specified in Section C.6.2 below, a party to the dispute shall be deemed to have fulfilled its obligations to comply with Appendix C of these Bylaws (irrespective of whether the parties to the dispute agree to proceed with binding arbitration) to the extent that either: (i) that party has fully performed the obligations set forth in Sections C.1 through C.5.8; or (ii) all of the parties to the dispute have agreed to a different process for resolving the dispute and the agreed-upon process has been fully carried out.

C.6.2 Matters for Which Binding Arbitration Is Obligatory. If a dispute is governed by Appendix C of these Bylaws and is not resolved through the process of mediation in accordance with Sections C.5.1 through C.5.6 above, the parties shall be obligated to submit the matter to binding arbitration in accordance with the procedures set forth in Section C.7 (subject to the limitations on the arbitrator's authority set forth in Section C.6.3 below) if the dispute concerns one or more of the following matters:

C.6.2.1 a decision of WECC's Board of Directors or a Committee of the Board acting on the recommendation of, or on a matter within the jurisdiction of, the Operating Transfer Capability Policy Group ("OTCPG") or successor;

C.6.2.2 a transmission path rating, or a modification to a transmission path rating, assigned to one or more transmission paths operated by a Member (or jointly operated by more than one Member);

C.6.2.3 transmission access, pursuant to Sections 10.1.2, 10.1.3, and 10.5; or

C.6.2.4 any matter that, by vote of both WECC's Board of Directors and WECC's Membership, is designated as a matter to be subject to the provisions of Section C.6.2 of these Bylaws, provided that any matter submitted to WECC's Membership pursuant to this provision must be approved by at least the number of votes required to amend these Bylaws under Section 13.2.

C.6.3 Limitations on Arbitrator's Authority with Respect to Matters Specified in Section C.6.2. Unless all of the parties to a dispute agree otherwise, an arbitrator rendering a decision with respect to any matter specified in Section C.6.2 above shall have no authority to consider or award remedies for past economic harm or damages of any kind, including without limitation actual or direct damages; indirect, consequential, or incidental damages; or exemplary or punitive damages. Nothing in this Section C.6.3 shall: (i) limit any rights that a party to a dispute concerning a matter specified in Section C.6.2 above may have to pursue legal claims for damages or other economic remedies after the arbitrator has rendered his or her decision on that matter (within the scope of his or her authority under this Section C.6.3); or (ii) limit an

arbitrator's authority under Section C.8 below to shift costs or impose monetary sanctions for "good cause" (as that term is defined in Section C.8).

C.6.4 Arbitration Decisions Not To Modify Underlying Rights and Obligations. Unless all of the parties to a dispute agree otherwise, the resolution through binding arbitration of any dispute governed by this Appendix C shall not have the effect of increasing, decreasing, or otherwise modifying WECC's or any Member's obligation to abide by, or ability to enforce or impose penalties or sanctions with respect to, any guidelines, criteria, standards, policies, procedures, decisions, or Bylaws of WECC or any limitation on the foregoing, whether established by law; regulation; judicial, executive, or administrative order, decree, or decision; tariff; contract; course of performance; treaty; or otherwise.

C.6.5 Laws Relating to Binding Arbitration. WECC and its Members recognize that some Members may be subject to laws (including without limitation United States federal or state laws, Canadian or provincial laws, or Mexican laws) that limit or define those Members' ability to agree in advance to be subject to binding arbitration. If a Member has the right or obligation under applicable law to refuse to submit to binding arbitration in connection with any dispute that would otherwise be subject to binding arbitration under Section C.6.2 of these Bylaws, that Member shall not be obligated to comply with the binding arbitration procedures set forth in Sections C.6 and C.7. Any Member subject to any law or other legally binding authority that may limit (or permit the Member to limit) its obligation to comply with the provisions requiring binding arbitration under Sections C.6 and C.7 or to fully comply with a valid arbitrator's decision rendered in accordance with this Appendix C shall provide

notice to this effect to all other disputing parties and WECC's Chief Executive Officer upon initiation of any dispute involving that Member if the dispute is subject to Section C.6.2. Upon receiving a notice under Section C.6.5, any other party to the dispute shall thereafter be relieved of any obligation to comply with the provisions Sections C.6 and C.7 in connection with that dispute, except to the extent that the Member giving notice agrees to be fully bound by procedures governing and results of any arbitration proceeding. If there are more than two parties to a dispute covered by the preceding sentence, however, then all parties to the dispute other than the party giving notice under Section C.6.5 shall make good faith efforts to establish a mutually acceptable approach for resolving among themselves whatever aspects of the dispute can reasonably be resolved through the procedures set forth in this Appendix C without the participation of the party giving notice under Section C.6.5. If any Member fails to submit to binding arbitration, or fails to abide by a valid arbitrator's decision rendered in accordance with this Appendix C, that Member shall thereafter have no right to enforce any of the provisions of Section C.6.2 (concerning obligations to submit specified disputes to binding arbitration) against any other Member or WECC until such time as the WECC Board of Directors, or a delegate designated by the Board, determines that it is appropriate to restore the Member's ability to enforce the provisions of Section C.6.2.

C.6.6 Consistency with Laws, Regulatory Jurisdiction and Orders, Etc. Nothing contained in this Appendix C and no arbitrator's decision rendered in accordance with Section C.7 shall be construed to require or shall otherwise operate to cause any Member or WECC to incur any obligation or take any action that is contrary to: (i) any

applicable law or regulation; (ii) any applicable authority, order, decree, rule, or decision of a regulatory, judicial, administrative, executive, or other governmental body having jurisdiction over one or more of the matters or parties subject to this Appendix C or covered by an arbitrator's decision; or (iii) any applicable rate schedule, tariff, treaty, or valid, pre-existing contractual obligation with which any party subject to this Appendix C or covered by an arbitrator's decision is legally obligated to comply.

C.7 Arbitration Procedures.

C.7.1 Notice to WECC of Initiation of Binding Arbitration. Within 10 calendar days after all of the parties to a dispute have agreed (or become obligated under Section C.6.2 above) to submit the dispute to binding arbitration under Sections C.6 and C.7, the parties to the dispute shall deliver written notice to WECC's Chief Executive Officer (an "Arbitration Notice").

C.7.1.1 The Arbitration Notice shall: (i) include a brief, general description of the issues to be arbitrated; and (ii) identify all parties who have agreed (or become obligated) to submit the dispute to binding arbitration under Sections C.6 and C.7.

C.7.1.2 Within five business days of receiving an Arbitration Notice, WECC's Chief Executive Officer shall: (a) publish (or cause to be published) in WECC's newsletter or on its electronic bulletin board a notice containing a list of the parties to the arbitration and the parties' brief, general description of the issues to be arbitrated; and (b) deliver to each party to the dispute a copy of

WECC's then-current standing list of qualified arbitrators, knowledgeable in matters addressed by WECC (as approved by the Board of Directors).

C.7.1.3 No person may be listed on WECC's standing list of qualified arbitrators unless the person has agreed to: (a) disclose, at any time the person is selected to serve as a arbitrator under this Appendix C, any personal or financial interest the arbitrator may have with respect to the matter(s) in dispute (including any indirect personal or financial interest that could arise because of interests or relationships affecting any of the arbitrator's immediate family members); (b) disclose any relationship the arbitrator may have with any party to the dispute that is not permitted under Section C.7.2 below; (c) assemble a complete record of the arbitration process and the materials received as evidence by the arbitrator if any of the parties to the dispute elect to appeal or contest the arbitrator's decision; and (d) abide by all applicable provisions of and procedures specified by Sections C.6 and C.7.

C.7.2 Selection of an Arbitrator. Within 10 calendar days after all of the parties to a dispute have agreed (or become obligated) to submit the dispute to binding arbitration under Sections C.6 and C.7, the parties to the dispute shall select an arbitrator by mutual agreement. If the parties cannot agree on an arbitrator within 10 calendar days after agreeing to arbitrate their dispute, the arbitrator shall be selected from WECC's standing list of qualified arbitrators as follows: The parties to the dispute shall take turns striking names from WECC's standing list of qualified arbitrators until there is only one name remaining. (The parties to the dispute shall draw lots to determine the order in which they take turns striking names.) The last

person whose name remains on the list shall serve as the arbitrator. No arbitrator other than an arbitrator chosen by agreement of all the parties to the dispute may (i) have a personal or financial interest in the matter(s) in dispute (including any indirect personal or financial interest that could arise because of interests or relationships affecting any of the arbitrator's immediate family members); or (ii) be (or have an immediate family member who is) a past or present director, commissioner, officer, employee, consultant, agent, or other representative of any of the parties to the dispute. If the arbitrator selected through the process of striking names specified above is disqualified under the preceding sentence, the arbitrator whose name was stricken last shall serve in his or her place.

C.7.3 Initial Statements and Proposed Arbitration Decisions. Within 10 calendar days after the selection of an arbitrator under Section C.7.2 above, each party to the dispute shall submit a statement in writing to all other parties to the dispute and to the arbitrator. Each disputing party's statement shall set forth in reasonable detail the nature of the dispute, the issues to be arbitrated, and the party's reasonable, good faith proposal for resolving the dispute. As provided in Section C.5.3 above, to the extent permitted by law, no party to an arbitration conducted under Sections C.6 and C.7 shall publicly disclose, rely on, or introduce as evidence in any arbitration, FERC proceeding, Canadian Regulatory Authority proceeding, proceeding before a Mexican Regulatory Authority, appeal, or litigation concerning the same or any related dispute any information required to be kept confidential by the terms of Section C.5.3.

C.7.4 Procedural Matters. The arbitrator shall determine discovery procedures, how evidence shall be taken, what written submittals may be made, and other such procedural matters, taking into account the complexity of the issues involved, the extent to which factual matters are disputed and the extent to which the credibility of witnesses is relevant to a resolution. Each party to the dispute shall produce all evidence determined by the arbitrator to be relevant and material to the issues presented. If such evidence involves proprietary or confidential information, the party submitting the evidence shall petition the arbitrator for a protective order, and to the extent the arbitrator determines there is good cause the arbitrator shall issue an appropriate protective order and all parties to the dispute shall comply with the protective order. The arbitrator may elect to resolve the arbitration matter solely on the basis of written evidence and arguments.

C.7.5 Out-of-Court Sworn Testimony. At the request of any disputing party, the arbitrator shall have the discretion to allow that party to examine witnesses through sworn out-of-court testimony (referred to in the United States as "deposition" and in Canada as "discovery") to the extent the arbitrator deems the evidence sought to be relevant and appropriate. In general, out-of-court witness examinations shall be limited to a maximum of three per party and shall be held within 30 calendar days after the making of a request. Each witness examination shall be limited to a maximum of three hours' duration. The arbitrator shall have the discretion to permit the number and duration of examination sessions allowed under this Section C.7.5 to be increased, and to extend the 30-day time limit, upon request for good cause shown.

All objections are reserved for the arbitration hearing except for objections based on privilege and proprietary or confidential information.

C.7.6 Intervention by Other Parties. Unless all of the parties to the dispute agree otherwise, no one (whether a Member, WECC, or any other entity or person) that is not a party to a dispute at the initiation of arbitration under Sections C.6 and C.7 shall have the right to intervene in the arbitration. Any party wishing to intervene in an arbitration under Sections C.6 and C.7 may petition the arbitrator for permission to intervene, provided that the petition is submitted to the arbitrator not more than 30 calendar days after notice of the arbitration is posted by WECC's Chief Executive Officer in accordance with Section C.7.1. The arbitrator shall have the discretion to permit a party to intervene if the arbitrator determines that the party petitioning to intervene has a direct and substantial interest in the outcome of the arbitration. In exercising his or her discretion concerning a requested intervention, the arbitrator shall also consider any additional complexity or delay that may be caused by allowing the intervention and also any other remedies available to the party requesting intervention. Any party that is granted the privilege of intervening in an arbitration under Sections C.6 and C.7 shall be permitted to intervene subject to the same terms, conditions, limitations, rights, and obligations of all other parties to the dispute, including without limitation the binding effect of arbitrator's decision, limitations on rights of appeal, the obligation to share equally in the costs of the arbitrator, and the obligation to be subject to the provisions of Section C.8.

C.7.7 Consideration of WECC Criteria, Etc. The Arbitrator shall give due consideration to the reliability criteria, standards, guidelines, policies, and procedures of WECC and

the North American Electric Reliability Council (or any successor organization) to the extent they are relevant to resolution of the matter(s) in dispute. If the arbitrator's decision will include interpretation of any of WECC's reliability criteria, standards, guidelines, policies, and procedures, (and WECC is not a party to the arbitration), the arbitrator shall, before rendering his or her decision, consult with WECC (subject to the provisions of Section C.7.10 below) concerning the interpretation of WECC's applicable reliability criteria, standards, guidelines, policies, and procedures.

C.7.8 Evidence and Rebuttal. The arbitrator shall consider all issues material to the matter(s) in dispute. The arbitrator shall take evidence submitted by the parties to the dispute in accordance with procedures established by the arbitrator and may request additional information the arbitrator deems material to the resolution of the dispute. With the consent of all parties to the dispute, the arbitrator's request for additional information may include the opinion of any individual or organization with recognized expertise in the matter(s) in dispute, subject to the following conditions: (i) any verbal communication with an expert consulted by the arbitrator must take place exclusively in the presence of all parties to the dispute and copies of any written communications must be provided to all parties to the dispute; (ii) any expert consulted by the arbitrator must agree to be equally available upon request to all of the parties to the dispute; (iii) any expert consulted by the arbitrator must agree to comply with the restrictions on disclosure contained in Section C.5.3; and (iv) all parties to the dispute shall be afforded a reasonable opportunity to question the expert and to rebut any additional information submitted by the expert at the request of the arbitrator.

C.7.9 Arbitrator's Decision. The arbitrator shall make all reasonable efforts to complete hearings (if applicable) and submissions of written evidence not more than 90 calendar days after receiving initial statements submitted under Section C.7.3 above. As soon as practicable, but in no event more than 30 calendar days after the completion of hearings and evidence submittals, the arbitrator shall render his or her final decision for resolving the dispute. By agreement of all of the parties to the dispute or at the discretion of the arbitrator for good cause, the foregoing deadline for delivery of the arbitrator's decision may be extended. The arbitrator's decision shall be based on the arbitrator's good faith determination of a resolution that will: (i) be consistent with any laws, rules, and regulations applicable to the matter(s) in dispute; (ii) be consistent with any valid pre-existing agreements among the parties to the dispute that bear on the matter(s) in dispute; (iii) not require any party to the dispute to take action that is not in compliance with any of WECC's reliability criteria, standards, guidelines, policies, and procedures; and (iv) best serve to promote or maintain reliable operation of the interconnected bulk power systems of the Western Interconnection, without imposing inequitable burdens or benefits on any of the parties to the dispute or others that may be affected by implementation of the arbitrator's decision. The arbitrator shall deliver to each of the parties to the dispute, along with his or her decision, a written statement including specific findings of fact, conclusions of law (if applicable), and an explanation of the arbitrator's basis for rendering his or her decision. Subject to any protective order that may have been issued under Section C.7.4 above, WECC's Chief Executive Officer shall publish (or cause to be published) in WECC's newsletter or electronic bulletin board a brief

summary of the arbitrator's decision. An arbitrator's decision that is not appealed shall not be deemed to be precedential in any other arbitration related to a different dispute.

C.7.10 WECC Staff Participation in Arbitration When WECC Not a Party. If, during the course of binding arbitration conducted under Sections C.6 and C.7 (in which WECC is not a party) the arbitrator or any party to the dispute wishes to solicit the views of WECC staff concerning the application, implementation, interpretation, or fulfillment of any guidelines, criteria, standards, policies, or procedures of WECC, the arbitrator may request or permit the submission of WECC staff views only with the consent of all of the parties to the dispute and only if: (i) any participation by WECC staff takes place exclusively in the presence of all parties to the dispute; (ii) participating WECC staff members agree to be equally available upon request to all parties to the dispute; and (iii) participating WECC staff members agree to comply with the restrictions on disclosure contained in Section C.5.3.

C.7.11 Compliance and Costs. Unless one or more of the parties to the dispute initiates and notifies all other parties to the dispute that it has initiated a process to contest or appeal the arbitrator's decision under Sections C.9 through C.13, upon the decision by the arbitrator, the parties to the dispute shall, within the time frame specified by the arbitrator, and, subject to Section C.6.6 above, take whatever action is required to comply with the arbitrator's decision to the extent the arbitrator's decision does not require regulatory action. To the extent the arbitrator's decision affects jurisdictional rates, terms and conditions of service, or facilities or otherwise requires local, state, federal, or provincial approval or regulatory action, or a FERC filing or a Canadian

Regulatory Authority filing by a Canadian Member or a Mexican Regulatory Authority filing by a Mexican Member, the affected Member (or WECC, if WECC is the party with the obligation to seek regulatory action) shall, within the time frame specified by the arbitrator, submit the arbitrator's decision or an appropriate filing to implement the arbitrator's decision and support the appropriate authority's acceptance or approval of the arbitrator's decision or implementation filing, except in cases where any party to the dispute has given notice of its intent to contest or appeal the arbitrator's decision. All costs associated with the arbitration (not including costs associated with attorney and expert witness fees incurred by the parties to the dispute) shall be divided equally among the parties to the dispute unless: (i) all of the parties to the dispute agree to an alternate method of allocating costs; or (ii) in rendering his or her decision, the arbitrator exercises his or her discretion under Section C.8 below to assess fees, costs, or other monetary sanctions against one or more of the parties to the dispute for good cause.

C.7.12 Entry of Judgment. At any time after an arbitrator has rendered his or her decision in an arbitration conducted under Sections C.6 and C.7 (provided that the time provided for initiating an appeal under Sections C.11.1 and C.12 below has expired and no appeal or other means of contesting the arbitrator's decision has been initiated), judgment on the decision rendered by the arbitrator may be entered by any court of competent jurisdiction (subject to the provisions of Sections C.6.3, C.6.4, and C.6.6 above). If the award is against the United States, a party to the arbitration may apply to the United States District Court for the district in which the principal office of the

applicable United States department or agency is located for an order confirming the award pursuant to 5 U.S.C. § 580.

C.8 Arbitrator's Discretion to Shift Costs or Impose Sanctions for Cause. Each party to any dispute submitted to arbitration under Sections C.6 and C.7 shall bear its own costs and fees associated with representation and participation in the arbitration process, and shall share equally in the arbitrator's fees except that the arbitrator shall have the discretion, to the extent permitted by law, to require one or more of the parties to the dispute to pay part or all of the costs and fees (including without limitation attorneys' and arbitrator's fees) of one or more other parties to the dispute, or to impose monetary sanctions on some other basis that is reasonable under the circumstances, for good cause. As used in this Section C.8, "good cause" means conduct involving serious abuse of or failure to comply with the dispute resolution process set forth in this Appendix C, willfully undertaken to harass or delay other parties to the dispute or to substantially impede the arbitrator's ability to render a decision consistent with the provisions set forth in Section C.7.9.

C.9 Rights to Appeal Arbitration Decisions. Except to the extent otherwise provided by applicable United States state or federal law, applicable Canadian or provincial law, or applicable Mexican law, a party to a dispute resolved by arbitration under Sections C.6 and C.7 may appeal or contest the arbitrator's decision only on one or more of the bases specified in Section C.9.1 below and only in accordance with the procedures set forth in Sections C.9.2 through C.13.

C.9.1 Grounds for Appealing Arbitration Decisions. A party to a dispute resolved by arbitration under Sections C.6 and C.7 may contest or appeal the arbitrator's decision only on the basis that: (i) the arbitrator's decision is contrary to applicable law or

regulation (including without limitation the FPA or FERC's then-applicable standards or policies, or comparable types of provisions that may apply under applicable Canadian, provincial, Mexican, or other laws and regulations); (ii) the arbitrator's decision is demonstrably arbitrary and capricious and without support in the record assembled during the arbitration; (iii) the arbitrator failed to afford one or more parties to the dispute an opportunity for a fair and meaningful hearing; (iv) the arbitrator engaged in serious misconduct in connection with the arbitration; (v) the arbitrator exceeded the authority conferred upon him or her under this Appendix C or as otherwise established by agreement of all the parties to the dispute; or (vi) the arbitrator's decision is contrary to the provisions of Section C.6.6.

C.9.2 Matter and One or More Parties to Dispute Subject to FERC Jurisdiction. If (i) the subject matter of a dispute arbitrated under Sections C.6 and C.7 is within the jurisdiction of FERC, and (ii) the conditions specified in Section C.12.1 or C.12.2 are satisfied, the rights of the parties to contest or appeal the arbitrator's decision shall be as set forth in Sections C.10 and C.12 below (subject also to the provisions of Section C.9.1 above). Notwithstanding the foregoing, nothing herein shall be construed or operate to require any Canadian or Mexican party or any other party that is not a "public utility" within the meaning of the FPA to make any filing with FERC under Sections 205 or 206 of the FPA.

C.9.3 All Parties and Matters in Dispute Subject to Jurisdiction of a Canadian Regulatory Authority. If all of the parties to an arbitrated dispute are subject to the jurisdiction of a particular Canadian Regulatory Authority, and if all matters in dispute are also subject to the jurisdiction of the same Canadian Regulatory Authority, any disputing

party may appeal an arbitrator's decision to that Canadian Regulatory Authority, where such Canadian Regulatory Authority has jurisdiction to hear the appeal, or to the appropriate Canadian court. Any appeal to a Canadian Regulatory Authority or Canadian court shall be subject to the provisions set forth in Sections C.10 and C.11 below.

C.9.4 All Parties and the Matter in Dispute Subject to Jurisdiction of a Mexican Regulatory Authority. If all of the parties to an arbitrated dispute are subject to the jurisdiction of a particular Mexican Regulatory Authority, and if all matters in dispute are also subject to the jurisdiction of the same Mexican Regulatory Authority, any disputing party may appeal an arbitrator's decision to the appropriate Mexican Regulatory Authority, subject to the provisions set forth in Sections C.10 and C.11 below.

C.9.5 Appeal to Court. If none of the preceding provisions concerning appealing or contesting an arbitrator's decision before FERC, a Canadian Regulatory Authority, or a Mexican Regulatory Authority apply to an arbitrated dispute, any party to an arbitrator's decision rendered in accordance with the provisions of Sections C.6 and C.7 may appeal the arbitrator's decision to a court of competent jurisdiction as provided under Section C.13 below.

C.10 Appealing or Contesting Arbitrator's Decision to FERC or a Presiding Authority. Subject to the conditions specified in Sections C.9.1 through C.9.5 above, any disputing party may appeal or contest an arbitrator's decision to FERC or an appropriate Presiding Authority as follows:

C.10.1 Record on Appeal. Except as otherwise provided in Section C.10.3 below, any appeal or action to contest an arbitrator's decision to FERC or a Presiding Authority

shall be based solely upon the record assembled by the arbitrator. All parties to arbitrations conducted under Sections C.6 and C.7 intend that: (i) the FERC or other Presiding Authority should afford substantial deference to the factual findings of the arbitrator; (ii) the portion, if any, of the arbitrator's decision relating to issues not of first impression (i.e., matters previously decided by the FERC or other Presiding Authority or a court of competent jurisdiction in cases involving comparable facts and circumstances) should be afforded appropriate deference by the FERC or other Presiding Authority; and (iii) the portion, if any, of the arbitrator's decision relating to issues of first impression should be afforded no deference by the FERC or other Presiding Authority.

C.10.2 No Expansion of Record on Appeal. Except as otherwise provided in Section C.10.3 below, no Member, non-Member, or WECC that has been a party to an arbitration under Sections C.6 and C.7 shall seek to expand the factual record before FERC or a Presiding Authority beyond that assembled by the arbitrator.

C.10.3 Exceptions to Limitations on Record on Appeal. If the arbitrator fails to assemble a complete record of the evidence submitted with respect to an arbitrated decision that is appealed pursuant to Sections C.9 through C.13, the parties to the appeal shall, notwithstanding the provisions of Sections C.10.1 and C.10.2 above, have the right to supplement the arbitrator's record before FERC or the Presiding Authority with any materials received into evidence by the arbitrator but omitted from the record assembled by the arbitrator. If an arbitrator's decision is appealed under Section C.9.1(iii) or (iv) above on the grounds that the arbitrator improperly excluded evidence so as to materially prejudice the outcome of the arbitration with respect to

one or more of the parties to the dispute, any party to the appeal may submit the evidence asserted to be improperly excluded, but only as a basis to request that FERC or the Presiding Authority vacate the arbitrator's decision and remand the matter to the arbitrator (or, if FERC or the Presiding Authority determines that the arbitrator engaged in serious misconduct, to a newly selected arbitrator) for reconsideration of the matter with inclusion of the improperly excluded evidence. If an arbitrator's decision is appealed under Section C.9.1(iv) above on the grounds of serious misconduct by the arbitrator, any party to the appeal may offer new evidence relating to the arbitrator's alleged misconduct.

C.11 Procedures for Appeals to Presiding Authority. If any party to an arbitration under Sections C.6 and C.7 desires to appeal an arbitrator's decision to an appropriate Presiding Authority, it shall provide written notice to that effect to all other parties to the arbitration, the arbitrator, and WECC's Chief Executive Officer within 14 calendar days following the date of the arbitrator's decision. If notice of appeal is timely provided:

C.11.1 Within 30 calendar days after the date of the appealing party's first notice of appeal, the party providing notice of appeal shall file its statement of position regarding the appeal with the Presiding Authority, together with the complete evidentiary record of the arbitration and a copy of the arbitrator's decision. The statement of position shall state that the appeal requested has been the subject of an arbitration pursuant to this Agreement.

C.11.2 Within 30 calendar days after the date of the appealing party's first notice of appeal, any other party that was a party to the arbitration may file its statement of position regarding the appeal with the Presiding Authority.

C.11.3 Copies of all materials filed with the Presiding Authority by any party during the course of an appeal shall be delivered to all other parties to the arbitration and to WECC's Chief Executive Officer.

C.11.4 Implementation of the arbitrator's decision shall be deemed stayed pending an appeal unless and until, at the request of a disputing party, the Presiding Authority issues an order shortening or extending the stay of implementation.

C.11.5 WECC's Chief Executive Officer shall publish (or cause to be published) a summary of each appeal in WECC's newsletter or electronic bulletin board.

C.11.6 The Members and WECC intend that any Presiding Authority's order resulting from an appeal under Sections C.9 and C.11 shall be subject to judicial review pursuant to laws governing the Presiding Authority and the matter in dispute that provide for judicial review of Presiding Authority action.

C.12 Procedures for Contesting or Appealing Arbitrator's Decision Before FERC. If any party to a dispute arbitrated under Sections C.6 and C.7 elects, subject to the limitations set forth in Sections C.9.1 through C.9.5 above, to contest or appeal an arbitrator's decision before FERC, the party so electing shall provide written notice to that effect to all other parties to the arbitration, the arbitrator, and WECC's Chief Executive Officer within 14 calendar days following the date of the arbitrator's decision. The provisions contained in Sections C.10.1, C.10.2, and C.10.3 above shall apply with respect to the record of the arbitration submitted to FERC. In addition, the following provisions shall apply:

C.12.1 FERC Filing by Prevailing Party. If the arbitrator's decision requires the prevailing party to take action that must have FERC approval or involves the provision of FERC-jurisdictional service by the prevailing party, the prevailing party shall file the

arbitrator's decision or make an appropriate filing with FERC to implement the arbitrator's decision. Provided that it has given notice as required under Section C.12 above, any non-prevailing party may contest the prevailing party's filing in accordance's with FERC's applicable rules and regulations.

C.12.2 Complaint to FERC by Prevailing Party. If the arbitrator's decision requires a non-prevailing party to take action that must have FERC approval or involves the provision of FERC-jurisdictional service by any non-prevailing party, then, if the non-prevailing party has given notice as required under Section C.12 above, the prevailing party may submit the arbitrator's decision to FERC in the form of a complaint.

C.13 Appeal to Court. If none of the provisions that govern appealing or contesting an arbitrator's decision before FERC, a Canadian Regulatory Authority, or a Mexican Regulatory Authority as set forth in Sections C.9.2, C.9.3, or C.9.4 above apply, any disputing party may appeal an arbitrator's decision to any court of competent jurisdiction, subject to the conditions specified in Section C.9.1 above. Except as otherwise provided in Section C.10.3 above (substituting the words "court of competent jurisdiction" for "FERC or the Presiding Authority"), any appeal to a court shall be based solely upon the record assembled by the arbitrator, and no Member, non-Member, or WECC who is a party to an arbitration under Sections C.6 and C.7 shall seek to expand the factual record before the court beyond that assembled by the arbitrator.

Appendix of Additional Definitions Relating to Alternative Dispute Resolution Provisions

Arbitration Notice has the meaning specified in Section C.7.1 of these Bylaws.

Canadian Regulatory Authority. The agency or agencies established under the laws of Canada or the applicable Provinces of Canada and having jurisdiction over facilities, interconnections, transmission rates, charges, terms, and conditions of service of a Canadian Member.

Dispute Notice has the meaning specified in Section C.5.1 of these Bylaws.

FERC. The Federal Energy Regulatory Commission or a successor agency.

FPA. The Federal Power Act (16 U.S.C. §§ 824 *et. seq.*), as it may be amended from time to time.

Mexican Regulatory Authority. The agency or agencies established under the laws of Mexico or the applicable states of Mexico and having jurisdiction over facilities, interconnections, transmission rates, charges, terms, and conditions of service of a Mexican Member.

Presiding Authority. As used in Sections C.10 and C.11, the term "Presiding Authority" has the following meanings: with respect to an appeal to an appropriate Canadian Regulatory Authority, "Presiding Authority" means the presiding Canadian Regulatory Authority or Canadian court with jurisdiction to hear the appeal; and with respect to an appeal to an appropriate Mexican Regulatory Authority, "Presiding Authority" means the presiding Mexican Regulatory Authority or Mexican court with jurisdiction to hear the appeal.

ATTACHMENT 3

EXHIBIT C TO WECC DELEGATION AGREEMENT –

WECC RELIABILITY STANDARDS DEVELOPMENT PROCEDURE

REDLINED TO SHOW PROPOSED AMENDMENTS

Exhibit C – Regional Standard Development Procedure

Exhibit C shall set forth WECC's standards development procedure, which NERC agrees meets the following common attributes:

COMMON ATTRIBUTE 1

Proposed regional reliability standards shall be subject to approval by NERC, as the electric reliability organization, and by FERC before becoming mandatory and enforceable under Section 215 of the FPA in the United States. In Canada and Mexico, regional standards must be approved by applicable governmental authorities before becoming mandatory in those respective jurisdictions. No regional reliability standard shall be effective within the WECC area unless filed by NERC with FERC, and any applicable authorities in Canada and Mexico, and approved by FERC and any applicable authorities in Canada and Mexico.

COMMON ATTRIBUTE 2

WECC regional reliability standards shall provide for as much uniformity as possible with reliability standards across the interconnected bulk power system of the North American continent. A WECC reliability standard shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. A regional reliability standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable.

COMMON ATTRIBUTE 3

WECC regional reliability standards, when approved by FERC and applicable authorities in Canada and Mexico, shall be made part of the body of NERC reliability standards and shall be enforced upon all applicable bulk power system owners, operators, and users within the WECC area, regardless of membership in the region.

COMMON ATTRIBUTE 4

Requester — The requester is the sponsor of the regional reliability standard request and may assist in the development of the standard. Any member of WECC, or group within WECC, shall be allowed to request that a regional reliability standard be developed, modified, or withdrawn. Additionally, any entity (person, organization, company, government agency, individual, etc.) that is directly and materially affected by the reliability of the bulk power

system in the WECC area shall be allowed to request a regional reliability standard be developed, modified, or withdrawn.

COMMON ATTRIBUTE 5

Standards ~~Request Routing~~ Committee and ~~Lead~~ Standing Committees — The WECC Standards ~~Request Routing~~ Committee (WS~~RR~~C) manages the standards development process. The WS~~RR~~C will consider which requests for new or revised standards shall be assigned for development (or existing standards considered for deletion). The WSC, with assistance from the ~~lead~~ standing committees, will advise the WECC board on standards presented for adoption.

COMMON ATTRIBUTE 6

~~Registered b~~Ballot body — The ~~registered~~ ballot body consists of WECC members and non-members that have been determined eligible for the WECC Standard Voting Sectors~~comprises all entities or individuals that qualify for one of the stakeholder segments; are registered with WECC as potential ballot participants in the voting on standards; and are current with any designated fees~~. Each member of the ~~registered~~ ballot body is eligible to vote on Regional Reliability S~~s~~tandards and Regional Criteria. The WSC is responsible for voting on ~~E~~each standard ~~action is balloted by the lead standing committee and any registered Participating Stakeholders~~. ~~The representation model of the registered ballot body is provided in Appendix A.~~

COMMON ATTRIBUTE 7

WECC will coordinate with NERC such that the acknowledgement of receipt of a standard request identified in step 2, notice of comment posting period identified in step 4, and notice for vote identified in step 6 below are concurrently posted on both the WECC and NERC websites.

COMMON ATTRIBUTE 8

An acceptable standard request shall contain a description of the proposed regional reliability standard subject matter containing sufficiently descriptive detail to clearly define the purpose, scope, impacted parties, and other relevant information of the proposed standard.

COMMON ATTRIBUTE 9

Within 14 days of receipt of a completed standard request, the WSC~~SRRC~~ shall determine the disposition of the standard request.

COMMON ATTRIBUTE 10

The ~~SRRC~~ WSC may take one of the following actions:

- Accept the standard request as a candidate for development of a new standard, revision of an existing standard, or deletion of an existing standard. The ~~SRRC~~ WSC may, at its discretion, expand or narrow the scope of the standard request under consideration. ~~The lead standing committee shall prioritize the development of standard in relation to other proposed standards, as may be required based on the volume of requests and resources.~~
- Reject the standard request. If the ~~SRRC~~ WSC rejects a standard request, a written explanation for rejection will be delivered to the requester within 14 days of the decision.
- Remand the standard request back to the requester for additional work. The standards process manager will make reasonable efforts to assist the requester in addressing the deficiencies identified by the ~~SRRC~~WSC. The requester may then resubmit the modified standard request using the process above. The requester may choose to withdraw the standard request from further consideration prior to acceptance by the ~~SRRC~~WSC.

COMMON ATTRIBUTE 11

Any standard request that is accepted by the ~~SRRC~~ WSC for development of a standard (or modification or deletion of an existing standard) shall be posted for public viewing on the WECC website within 30 days of acceptance by the committee.

COMMON ATTRIBUTE 12

The WSC~~standards process manager shall submit the proposed~~ will select members of the drafting team ~~to the lead standing committee and the SRRC~~. ~~The lead standing committee and the SRRC shall approve the drafting team membership within 60 days of accepting a standard request for development, modifying the recommendations of the standards process manager as the committee deems appropriate, and assign development of the proposed standard to the drafting team.~~

COMMON ATTRIBUTE 13

At the direction ~~from~~ of the WSC~~lead standing committee~~, the standards process manager shall facilitate the posting of the draft standard on the WECC website, along with a draft implementation plan and supporting documents, for a no less than a 45~~30~~-day comment period. The standards process manager shall provide notice to WECC stakeholders and other potentially interested entities, both within and outside of the WECC area, of the posting using communication procedures then currently in effect or by other means as deemed appropriate.

COMMON ATTRIBUTE 14

The WSC, with assistance from the drafting team as it requests, shall prepare a summary of the comments received and the changes made to the proposed standard as a result of these comments. The WSC~~drafting team~~ shall summarize comments that were rejected by the ~~drafting team~~WSC and the reason(s) that these comments were rejected, in part or whole. The summary, along with a response to each comment received will be posted on the WECC website within 30 days of the close of the comment period~~no later than the next posting of the proposed standard~~.

COMMON ATTRIBUTE 15

Upon recommendation of the ~~drafting team, and if the lead standing committee concurs that all of the requirements for development of the standard have been met~~WSC, the standards process manager shall post the proposed standard and implementation plan for ballot and shall announce the vote to approve the standard, including when the vote will be conducted and the method for voting. Once the notice for a vote has been issued, no substantive modifications may be made to the proposed standard unless the revisions are posted and a new notice of the vote is issued.

COMMON ATTRIBUTE 16

The standards process manager shall schedule a vote by the WECC lead standing committee]. The vote shall commence no sooner than [30~~15~~] days ~~and no later than [30] days~~ following the issuance of the notice for the vote. Voting shall begin no sooner than [7] calendar days following the Joint Session of the Standing Committees at which the draft standard was considered.

COMMON ATTRIBUTE 17

The WECC ~~registered~~ ballot pool shall consist of Ballot Body entities that have opted to vote on a specific standard. The ballot pool~~body~~ shall be able to vote on the proposed standard during a period of not less than 15~~0~~ business days.

COMMON ATTRIBUTE 18

All ~~lead standing committee members of WECC and Participating Stakeholders~~Ballot Body members are eligible to participate in voting on proposed new standards, standard revisions or standard deletions.

COMMON ATTRIBUTE 19

A weighted majority vote of the Ballot Pool is required for a draft standard to be approved by the WECC membership and Participating Stakeholders.~~Approval of the proposed regional reliability standard shall require a majority in the affirmative (affirmative votes divided by the sum of affirmative and negative votes) by both voting classes of the lead standing committee.~~ Abstentions and non-responses shall not count toward the results but will be counted in determining whether a quorum of the Ballot Pool is achieved.

COMMON ATTRIBUTE 20

~~Under no circumstances may t~~The WECC B~~b~~oard may only substantively modify the proposed regional reliability standard in accordance with its backstop authority as authorized by the WECC Bylaws.

COMMON ATTRIBUTE 21

Once a regional reliability standard is approved by the board, the standard will be submitted to NERC for approval and filing with FERC and applicable authorities in Canada and Mexico.

COMMON ATTRIBUTE 22

- **Open** - Participation in the development of a regional reliability standard shall be open to all organizations that are directly and materially affected by the WECC bulk power system reliability. There shall be no undue financial barriers to participation. Participation shall not be conditioned upon membership in WECC, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements. Meetings of drafting teams shall be open to the WECC members and others.

COMMON ATTRIBUTE 23

- **Balanced** - The WECC standards development process strives to have an appropriate balance of interests and shall not be dominated by any two interest categories and no single interest category shall be able to defeat a matter.

COMMON ATTRIBUTE 24

- **Inclusive** — Any entity (person, organization, company, government agency, individual, etc.) with a direct and material interest in the bulk power system in the WECC area shall have a right to participate by: a) expressing a position and its basis, b) having that position considered, and c) having the right to appeal.

COMMON ATTRIBUTE 25

- **Fair due process** — The regional reliability standards development procedure shall provide for reasonable notice and opportunity for public comment. At a minimum, the procedure shall include public notice of the intent to develop a standard, a public comment period on the proposed standard, due consideration of those public comments, and a ballot of Participating Stakeholders.

COMMON ATTRIBUTE 26

- **Transparent** — All actions material to the development of regional reliability standards shall be transparent. All standards development meetings shall be open and publicly noticed on the regional entity's Web site.

COMMON ATTRIBUTE 27

- Does not unnecessarily delay development of the proposed reliability standard.

COMMON ATTRIBUTE 28

Each standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of the reliability of the regional bulk power system. Each standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

COMMON ATTRIBUTE 29

While reliability standards are intended to promote reliability, they must at the same time accommodate competitive electricity markets. Reliability is a necessity for electricity markets, and robust electricity markets can support reliability. Recognizing that bulk power system reliability and electricity markets are inseparable and mutually interdependent, all regional reliability standards shall be consistent with NERC's market interface principles. Consideration of the market interface principles is intended to ensure that standards are written such that they achieve their reliability objective without causing undue restrictions or adverse impacts on competitive electricity markets.

COMMON ATTRIBUTE 30

To ensure uniformity of regional reliability standards, a regional reliability standard shall consist of the elements identified in this section of the procedure. These elements are intended to apply a systematic discipline in the development and revision of standards. This discipline is necessary to achieving standards that are measurable, enforceable, and consistent.

COMMON ATTRIBUTE 31

All mandatory requirements of a regional reliability standard shall be within the standard. Supporting documents to aid in the implementation of a standard may be referenced by the standard but are not part of the standard itself.

COMMON ATTRIBUTE 32

Applicability	Clear identification of the functional classes of entities responsible for complying with the standard, noting any specific additions or exceptions. If not applicable to the entire WECC area, then a clear identification of the portion of the bulk power system to which the standard applies. Any limitation on the applicability of the standard based on electric facility requirements should be described.

COMMON ATTRIBUTE 33

Measure(s)	Each requirement shall be addressed by one or more measures. Measures are used to assess performance and outcomes for the purpose of determining compliance with the requirements stated above. Each measure will identify to whom the measure applies and the expected level of performance or outcomes

	required demonstrating compliance. Each measure shall be tangible, practical, and as objective as is practical. It is important to realize that measures are proxies to assess required performance or outcomes. Achieving the measure should be a necessary and sufficient indicator that the requirement was met. Each measure shall clearly refer to the requirement(s) to which it applies.

COMMON ATTRIBUTE 34

Compliance Monitoring Process	Defines for each measure: • The specific data or information that is required to measure performance or outcomes. • The entity that is responsible for providing the data or information for measuring performance or outcomes. • The process that will be used to evaluate data or information for the purpose of assessing performance or outcomes. • The entity that is responsible for evaluating data or information to assess performance or outcomes. • The time period in which performance or outcomes is measured, evaluated, and then reset. • Measurement data retention requirements and assignment of responsibility for data archiving.

RELIABILITY ~~PROCESS FOR DEVELOPING AND APPROVING WECC~~ STANDARDS DEVELOPMENT PROCEDURES

Introduction

This document explains the WECC process for requesting, announcing, developing, revising, withdrawing and approving WECC Standards as defined below ("WECC Standards Process"). The process involves several steps:

- A request to develop a new Standard or revise an existing Standard
- Decision to proceed with development or revision of a Standard and assignment to a ~~Standing Committee and Subgroup~~ Drafting Team
- Public (including members) notification of intent to develop or revise a Standard
- Drafting stage
- Posting of draft for public comment
- Review of all comments and public posting of decisions reached on each comment
- ~~WECC Standing Committee/Participating Stakeholder~~Ballot Body balloting of the proposed Standard
- Consideration of any appeals
- WECC Board of Directors (Board) decision regarding approval, disapproval or remand of proposed Standard
- Forwarding proposed WECC Reliability Standards to the ERO

The process for developing and approving WECC Standards includes:

1. Notification of pending Standard change before a wide audience of all "interested and affected parties"
2. Posting Standard change drafts for all parties to review
3. Provision for gathering and posting comments from all parties
4. Provision for an appeals process – both "due process" and "technical" appeals

The WECC ~~Standing Committees have~~Standards Committee (WSC) has the responsibility for developing and balloting WECC Standards. ~~Standing Committee chairs are~~The WSC Chair is responsible for ensuring administration of the process and completion of all ~~Standing Committee~~WSC responsibilities. ~~Standing Committees are assisted by a Standards Request Routing Committee and~~ The WSC is supported by ~~Subgroups~~the Standing Committees as well as Drafting Teams that draft the Standards~~, ensure the draft~~. The WSC, with the support of a Drafting Team and Standing Committees, ensures the Draft Standard is properly reviewed consistent with WECC due process requirements, ~~respond~~responses have been provided to comments on the ~~draft~~Draft Standard, ~~and revise~~or the ~~draft~~Draft Standard is revised in response to ~~these~~the comments. Board approval signifies that WECC has adopted the Standard. WECC staff has the role of tracking the Standard as it moves through the process and facilitating resolution of issues. In accordance with Section 8.6 of the WECC Bylaws, ~~interested stakeholders~~Participating Stakeholders may participate in Reliability Standard development ~~and~~by joining the Ballot Body and may vote ~~at the Standing~~

~~Committee level~~electronically on ~~Reliability Standards or revisions to Reliability Standards~~a Draft Standard.

WECC Bylaws Controlling

It is the intention of the drafters of the WECC Standards Process that the procedures described herein be interpreted and applied in a manner that is consistent with the WECC Bylaws. Should any conflict between this WECC Standards Process and the WECC Bylaws arise, the WECC Bylaws will control.

Terms

Ballot Body. The Ballot Body consists of WECC members and non-members that have been determined eligible for the WECC Standard Voting Sectors described in this Reliability Standards Development Process and in section 8.5.5.2 of the WECC Bylaws. The Ballot Body consists of the entities that may vote on Regional Criteria and Regional Reliability Standards, except as otherwise limited by these procedures.

Ballot Pool. The Ballot Pool consists of Ballot Body entities that have opted to vote on a specific Standard. Quorum for voting on a Standard is based on the Ballot Pool.

Days. All references to days in this document refer to calendar days, except as otherwise noted in these procedures.

~~**Due Process Appeals Committee.** The committee that receives all appeals alleging that WECC's due process procedure was not properly followed during the development or revision of a Standard. The Due Process Appeals Committee consists of three Directors appointed by the Board Chair. The WECC Chief Executive Officer or his/her designee will be the staff coordinator for the Due Process Appeals Committee~~

Draft Standard. A Draft Standard includes any proposed new Standards, revisions to existing Standards, or termination of existing Standards. Draft Standards are introduced by use of Standard Authorization Requests or the Special Procedures for Addressing Regulatory Directives, as described in these procedures.

Joint Session. The Joint Session is any collective meeting of the Standing Committees. Such meetings are generally held in conjunction with the regular meetings of the individual Standing Committees.

Participating Stakeholder. A Participating Stakeholder as defined in Section 3.~~21~~33 of the WECC Bylaws.

Standard. In the context of this document, the term Standard refers to a Regional Reliability Standard or a ~~commercial Business Practice.~~ Regional Criterion.

Standard Authorization Request ~~Form.~~(or "SAR"). The form titled WECC Standards/~~Business Practice~~ Regional Criteria Request Form approved by WECC for the purpose of requesting a new Standard ~~or~~, a revision to an existing Standard~~.~~

~~**Standards Request Routing Committee.** This committee consists of the chairs of the three Standing Committees~~, or ~~their designees. This Committee is responsible for determining if a Standard Request is within the scope of WECC's activities, and assigning the request to the appropriate Standing Committee(s).~~termination of an existing Standard.

Standing Committee. The Market Interface Committee (MIC), Operating Committee (OC) or Planning Coordination Committee (PCC).[1] ~~MIC, OC, and PCC will coordinate their responsibilities for those Standards that have a combination of market, operating, and planning implications.~~

~~**Subgroup.** A subcommittee, work group, or task force of the MIC, OC, PCC, or a combination of representatives from these committees that is responsible for developing a draft WECC Standard, posting it for review, and addressing public comments on the draft.[2] Voting members of a Subgroup are the individuals appointed to the group. In addition, one representative of the entity requesting a Standard has the option of joining the Subgroup as a voting member.~~

~~**Technical Appeals Committee.** The committee that receives appeals alleging that a party's technical comments were not properly addressed during the development of a Standard. The Technical Appeals Committee consists of the Vice Chairs of the Market Interface Committee, Operating Committee, Planning Coordination Committee, and a Director appointed by the Board Chair. The WECC Chief Executive Officer or his/her designee will be the staff coordinator for the Technical Appeals Committee. The Director appointed to the committee will act as chair. Replacement of a Technical Appeals Committee member in the event of a conflict of interest will be at the discretion of the Technical Appeals Committee Chair. If the chair has a conflict of interest, the WECC Board Chair will appoint another Director to serve as chair for the duration of the appeal in question.~~

WECC Standards Committee. This committee consists of one representative from each of the eight Voting Sectors described in Section 8.5.5.2 of the Bylaws and a ninth member who shall be a member of the WECC Board of Directors. The members of the WSC shall be appointed by, and serve at the pleasure of, the Board, in accordance with a charter of the WSC approved by the Board. The chair of the Board shall designate a member of the Board of Directors to serve as the chair of the WSC. The WSC is responsible for determining if a Standard Authorization Request is within the scope of WECC's activities, and overseeing the drafting, comment and voting process for a Standard. The WSC is responsible for taking actions described in the Special Procedures for Addressing Regulatory Directives to ensure compliance with directives issued by the Federal Energy Regulatory Commission (FERC) or Mexican or Canadian regulatory authorities. The WSC shall also oversee the process for responding to requests for interpretations of Standards.

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[1] In accordance with WECC Bylaws Section 8.5.4, Membership in WECC's Standing Committees is open to all WECC members.

~~[2] Formation of Subgroups is in accordance with the Market Interface Committee's, Planning Coordination Committee's, and Operating Committee's Organizational Guidelines.~~

WECC Standards Voting Sectors. For purposes of voting on Standards, WECC members and Participating Stakeholders shall vote in the following eight sectors.

1) Transmission Sector. This sector consists of Western Interconnection entities registered in the NERC compliance registry as transmission owners, transmission operators, transmission service providers, or transmission planners;

2) Generation Sector. This sector consists of Western Interconnection entities registered in the NERC compliance registry as generation owners or generation operators;

3) Marketers and Brokers Sector. This sector consists of Western Interconnection entities registered in the NERC compliance registry as purchasing-selling entities.

4) Distribution Sector. This sector consists of Western Interconnection entities registered in the NERC compliance registry as distribution providers or load-serving entities;

5) System Coordination Sector. This sector consists of Western Interconnection entities registered in the NERC compliance registry as balancing authorities, reserve sharing groups, planning authorities, resource planners, interchange authorities, and reliability coordinators. WECC may cast a vote in this sector;

6) End Use Representative Sector. This sector consists of non-registered members of WECC Member Class Four;

7) State and Provincial Representatives Sector. This sector consists of non-registered WECC members of WECC Member Class Five;

8) Other Non-Registered WECC Members and Participating Stakeholders Sector. This sector consists of consultants or other members of WECC Member Class Seven, or interested stakeholders who qualify for Participating Stakeholder status but are not registered in the NERC compliance registry.

For sectors one through five, Western Interconnection entities that perform functions outside the United States, that if conducted in the United States would qualify them for the NERC compliance registries included in these sectors, shall be eligible to vote in the appropriate sector(s), as may be determined by WECC staff.

Each WECC member or Participating Stakeholder shall have a vote that may be cast in each sector for which the member or stakeholder is eligible as described in Section 8.5.5.4 of the Bylaws.

Sectors one through five are the registered sectors, and the three non-registered sectors are sectors six through eight. If an entity is eligible for a registered sector, then that entity may be eligible for more than one registered sector. An entity can only be in one non-registered sector. An entity cannot be in both a registered and a non-registered sector. The first five sectors (1 through 5) shall be in the North American Electric Reliability Corporation ("NERC") compliance registry, with the exception for entities that perform functions outside the United States that are determined eligible for these voting sectors by WECC Staff.

Participating Stakeholders may not vote on Regional Criteria unless the proposed Regional Criteria could result in sanctions to a non-WECC member.

Normal Process for Standards

Step 1 – Request To Revise or Develop a Standard

Requests to develop, terminate, or revise a Standard will be submitted to the WECC staff through the use of the WECC Standard Authorization Request ~~Form.~~("SAR"). Requesters may be any individual or organization. WECC membership is not a requirement as long as the requester has an interest in electric system reliability or commercial business practices in the Western Interconnection.

Step 2 – Standard Authorization Request Validation and ~~Routing~~ Submission to the WSC

The ~~Standard Request Form~~SAR will be reviewed for completeness and assigned a tracking number by the WECC staff. Staff may assist with completing the request, or report to the ~~Standards Request Routing Committee~~WSC that the ~~request~~SAR is incomplete and request guidance. When complete, the WECC staff will forward the ~~request~~SAR to the ~~Standards Request Routing Committee. This committee~~WSC. WECC staff will maintain a web-based form that tracks all SARs through the Standard development process, as well as a Standards development tracking log that is posted on the WECC website.

The WSC will confer either in person or via conference call within two weeks of receipt of a completed request to determine whether the request is within WECC's scope.

~~The WECC staff will maintain a web-based form that tracks all requests through the standard development process, as well as a standards development tracking log that is posted on the WECC website.~~

~~Upon ascertaining that a request is within the scope of WECC's activities, the Standards Request Routing Committee will assign the request to the chair of the~~

~~appropriate Standing Committee(s), who will in turn assign it to a Subgroup. One Standing Committee will be designated as the lead Standing Committee. If the request has implications for any combination of planning, operations, or market issues, the chair of the lead Standing Committee, in consultation with the Standards Request Routing Committee, will evaluate the technical expertise of the Subgroup and may augment membership in the Subgroup for the purpose of drafting the proposed Standard or revision(s) to ensure that the Subgroup includes~~If the WSC determines, by majority vote, that a SAR is outside the WECC's authority or inappropriate, it will prepare an explanation and post it on the WECC website. The party that submitted the SAR, parties subscribing to the WECC standards email list, the Standing Committees, and Board will all be notified of the posting and its location on the WECC website. If the WSC decides to reject a SAR at this stage, such decision may be appealed to the Board in accordance with Step 8.

Upon ascertaining that a SAR is within the scope of WECC's authority and appropriate, the WSC will select and oversee a Drafting Team formed for the purpose of drafting a Draft Standard. The WSC shall ensure that the Drafting Team includes a composite of individuals having the appropriate planning, operations, and market expertise. Notification of such assignments will be posted on the WECC website and sent to all parties that subscribe to the WECC standards ~~e-mail~~email list. In addition, such assignments will be simultaneously noticed to NERC. The ~~Subgroup will act in accordance with duly approved Subgroup guidelines. Any other interested parties may participate in~~WSC shall ensure that the ~~deliberations~~SAR provides the Drafting Team and WECC a description of the ~~Subgroup.~~Draft Standard it expects the Drafting Team to draft, and an explanation as to why the Draft Standard is needed.

Step 3 – ~~Subgroup~~Drafting Team Begins Drafting Phase and ~~Announces on WECC Web Site~~Submits Draft Standard to WSC

The ~~Subgroup~~Drafting Team will begin working on the ~~request at the Subgroup's next scheduled meeting, or no later than a designated number of days~~Draft Standard following assignment ~~from~~by the ~~Routing Committee~~WSC, as directed by the ~~lead Standing Committee~~WSC chair. The WSC shall provide a time period for which the Drafting Team should complete the Draft Standard. The WSC chair shall designate a Drafting Team leader who shall be responsible for coordinating the Drafting Team's efforts. Notification of ~~Subgroup~~Drafting Team meetings will be posted on the WECC website and sent to all parties that subscribe to the WECC standards ~~e-mail~~email list at least ~~30~~15 calendar days prior to the meeting. In addition, notification of all ~~Subgroup~~Drafting Team meetings will be simultaneously noticed to NERC. These meetings will be open to interested stakeholders. The ~~Subgroup chair~~Drafting Team will facilitate interested stakeholder participation in the discussion in order to encourage ~~Subgroup~~ understanding of the issues and consensus among the meeting participants. The ~~Subgroup~~Drafting Team will work to achieve a consensus recommendation. A consensus recommendation is one that strives to eliminate all well-reasoned objections, but if the Drafting Team determines that it is not possible to accommodate

all such points of view, it may proceed to provide a recommendation that is supported by a majority of the Drafting Team members.

Standard requesters have the right, and are encouraged to participate in the ~~Subgroup~~ drafting process. Requesters may be called on to provide additional information, supporting studies, and other information to support the requirements of the ~~proposed~~Draft Standard~~ or revision(s).~~.

All WECC Standards will follow a standard format that refers to the "Responsible Entities" included in the NERC Functional Model and includes compliance measures according to the WECC standard template. The ~~drafting group~~Drafting Team will include definitions for any terms included in the Draft Standard~~ or revision(s)~~ that need to be added to the WECC glossary.

In the course of its review, the ~~Subgroup~~Drafting Team:

- will review the preliminary technical assessment provided by the requester~~.~~
- ~~will compare with existing standards to determine whether a the request is better served by drafting a new standard or modifying an existing standard.~~;
- may perform or request additional technical studies, if necessary~~.~~;
- will complete an impact assessment report as part of its evaluation to assess the potential effects of the request~~.~~;
- may prepare additional supporting documents to support the Draft Standard; and
- may request from the ~~Board or Standing Committee~~WSC additional time to ~~study~~develop the ~~proposed request~~Draft Standard if the ~~Subgroup~~Drafting Team believes it is necessary~~ to fully assess the proposed change~~.

~~Upon reaching a determination, by majority vote, that the requested Standard or revision to an existing Standard is needed, the Subgroup will announce the proposed Standard or proposed revision(s) in an existing Standard by posting on the WECC website a summary of the Standard or revision(s) it expects to draft, and an explanation as to why the new Standard or revision(s) in an existing Standard is needed. Notice of this posting, and its location on the WECC website, will be sent to all parties that subscribe to the WECC standards e-mail list. In addition these notifications will be simultaneously noticed to NERC.~~

~~If the Subgroup determines, by majority vote, that a new or revised Standard is not needed, it will prepare an explanation in consultation with the Standards Request Routing Committee and post it on the WECC website for a specified comment period. The party that submitted the request, parties subscribing to the WECC standards email list, the Standing Committees, and Board will all be notified of the posting and its location on the WECC website.~~

The Drafting Team, upon reaching a determination, by majority vote, on the language for a Draft Standard, shall submit the Draft Standard to the WSC. The Drafting Team shall also supply the WSC with the impact assessment report, any additional technical studies performed, and any other materials that significantly contributed to the Drafting Team's evaluation and drafting of the Draft Standard.

Step 4 – Draft Standard Posted for Comment

~~The Subgroup will post the first draft~~ Upon receiving the Draft Standard from the Drafting Team, the WSC shall decide whether to: (i) post the Draft Standard provided by the Drafting Team for comment; (ii) further revise or modify the Draft Standard provided by the Drafting Team, then post the WSC's revision for comment; (iii) return the Draft Standard to the Drafting Team for further work, as directed; or (iv) terminate the Standard development activity in accordance with the procedures for rejecting a SAR in Step 2. A majority (greater than 50 percent) vote of the ~~new or revised~~authorized membership of the WSC is required to terminate a Draft Standard at this stage. If the WSC chooses to remand the draft back to the Drafting Team, the WSC chair shall provide the Drafting Team with the committee's reason for the remand and provide further guidance, as necessary.

If the WSC chooses to present the Draft Standard for comment, the WSC shall post the initial Draft Standard on the WECC website and provide 45 days for comments. Along with the draft, the ~~Subgroup~~WSC will ~~prepare and~~ post ~~an~~the impact assessment report~~. Alternatively, the Subgroup may request input from affected parties regarding their estimated cost to implement the draft Standard~~ and ~~will use that data to prepare an impact assessment report, which will be posted for comment when it becomes available. The draft~~other supporting materials. The Draft Standard will include all mandatory requirements. In addition, ~~it~~the Draft Standard will include measurements, Violation Risk Factors~~,~~ (VRFs), and Violation Severity Levels~~.~~ (VSLs).[3] Notice of this posting and a solicitation for comments on the draft will be sent to all WECC members and all individuals who subscribe to the WECC standards e-mail list. In addition the notification of posting and solicitation for comments will be simultaneously noticed to NERC. The WSC may request input from affected parties regarding their estimated cost to implement the Draft Standard and may use that data to amend an impact assessment report, which will be posted for comment when it becomes available.

Members of electric industry organizations may respond through their organizations, or directly, or both. All comments will be supplied electronically and will be posted on the WECC website.

Step 5 – ~~Subgroup~~WSC Deliberates on Comments

~~Subgroup chairs are~~The WSC chair is responsible for ensuring that comments are addressed in a timely manner. The ~~Subgroup~~WSC may further employ and oversee the Drafting Team for purposes of analyzing and responding to comments. The WSC will post its response to comments on the WECC website within 30 days of the close of the comment period. All parties that submit comments are strongly encouraged to participate in ~~Subgroup~~WSC deliberations.

[3] Regional Criteria, which are also to be developed under this Procedure, will not contain VRFs of VSLs which are only necessary for Standards that will be enforceable and for which violations may result in penalties.

If the ~~Subgroup~~WSC determines, by majority vote, any technical comments including those on the draft or the impact assessment report are significant, it will repeat Steps 3 and 4 as many times as considered necessary ~~by the Subgroup~~ to ensure adequate opportunity for interested stakeholder input. All interested stakeholders are strongly encouraged to submit their comments as early in the process as possible. The number of days for comment on each subsequent revision to the ~~draft of the proposed Standard or revision(s) will be 30 days. Parties whose comments have been rejected by a Subgroup may request review of such comments by the Standing Committee and Participating Stakeholders when the proposed Standard or revision(s) is brought before the Standing Committee for a vote (in Step 7).~~ Draft Standard will be 30 days.

~~The Subgroup will attempt to achieve a consensus recommendation on a final draft.~~ A majority vote of the ~~Subgroup~~WSC is required to approve submitting the recommended Draft Standard ~~or revision(s)~~ to the ~~Standing Committee and Participating Stakeholders. Voting will be conducted in accordance with this WECC Standards Process, the WECC Bylaws, and any other applicable regulatory requirements~~Ballot Body for a vote. Balloting results will be documented. All WSC member dissenting voters, as well as others participating in the ~~Subgroup~~WSC deliberations, will be encouraged to provide dissenting comments and, if possible, specific language that a party believes would make the Draft Standard acceptable. If the ~~Subgroup~~WSC vote fails to capture a simple majority to approve ~~the~~ submittal to the ~~Standing Committee and Participating Stakeholders~~Ballot Body for a vote, and there is no apparent way to reach a majority agreement, the ~~Subgroup~~WSC will report to and seek guidance from the ~~Standing Committee Chair~~ WECC Board

Step 6 – ~~Subgroup~~WSC Submits Draft Standard for ~~Standing Committee/Participating Stakeholder~~Ballot Body Vote and Ballot Pools Are Established

The ~~Subgroup's~~WSC's final ~~draft~~Draft Standard ~~or revision(s)~~ will be posted on the WECC website ~~and~~at least 30 days prior to the commencement of the voting window and WECC members and Participating Stakeholders who have joined the ~~appropriate Standing Committees and Participating Stakeholders~~Ballot Body[4] will be notified of the ~~Subgroup's~~WSC's recommendation. The posting will include the final ~~Subgroup vote, all~~WSC member vote, any dissenting WSC member comments, a summary addressing comments that were not incorporated into the ~~draft~~Draft Standard, the impact assessment report and the ~~date on~~ period of time during which the ~~Standing Committee and Participating Stakeholders are~~ Ballot Body is scheduled to vote on the ~~Subgroup's~~WSC's recommendation.[5] Notice of the posting also will be sent to the Standing Committees, all Participating Stakeholders, and the standards ~~e-mail~~email

[4] Each WECC Member and Participating Stakeholder shall be permitted to designate a person who is authorized to join Ballot Pools for Standards and to either cast a vote within those Ballot Pools or designate a proxy to cast the vote of the WECC Member or Participating Stakeholder. Each such designated person shall be provided a user name and password for use in electronically identifying that entity's authorization to act within the Ballot Body. The Ballot Body will be renewed every five years as part of WECC's section 4.9 review.

[5] The period of time the vote is scheduled shall take into account the next scheduled Joint Session of the Standing Committees.

list. In addition, the notification of the posting for ballot will be simultaneously noticed to NERC.

After posting of the Draft Standard, the Standing Committees shall participate in at least one Joint Session addressing the Draft Standard. In addition to the Joint Session, individual Standing Committees may undertake additional discussions or webinars.

The notice shall solicit participants for the Ballot Pool for the final Draft Standard scheduled for a vote. Members of the Ballot Body choosing to vote on the Draft Standard shall respond to the WSC's solicitation for Ballot Pools within a period designated by WECC Staff. Responses from Ballot Body members shall indicate within which WECC Standards Voting Sector(s) the party chooses to vote. Where a WECC member or Participating Stakeholder is eligible for multiple WECC Standards Voting Sectors, it may vote in any or all of its eligible sectors as allowed pursuant to the Bylaws (section 8.5.5.2) and this Reliability Standards Development Process. Based on responses to the Ballot Pool solicitation, WECC staff shall form the Ballot Pool for a particular Draft Standard.

Step 7 – ~~Standing Committee/Participating Stakeholders~~Ballot Pool Vote on Recommendation to Board

In accordance with Sections 8.5 and 8.6 of the WECC Bylaws, the ~~Standing Committee and Participating Stakeholders will vote on the draft Standard, revision(s) or withdrawal no later than at the next Standing Committee meeting, subject to applicable notice requirements. A minimum of 30 days notice will be provided prior to all Standing Committee meetings at which new or revised Standards will be considered for approval.[3]Notification of such meetings will be posted on the WECC website and sent to all parties that subscribe to the WECC standards e-mail list. Whenever it determines that a matter requires an urgent decision, the Board may shorten the time period set forth in this section in accordance with the requirements in the WECC Bylaws~~Ballot Pool will vote on the Draft Standard. Voting shall begin at least seven (7) calendar days following the Joint Session of the Standing Committees at which the Draft Standard was considered. Voting on Draft Standards shall be via electronic voting administered by the WECC website, and shall take place over a fifteen (15) business day voting window. Each WECC member or Participating Stakeholder may cast one vote in each eligible voting sector. Voters rejecting the Draft Standard will be required to provide an explanation of their vote. Explanations will be added to the record in order to assist the WSC's and/or the Board's subsequent consideration of the Draft Standard.[4]

~~The Standing Committee~~A weighted majority vote of the Ballot Pool is required for a Draft Standard to be approved by the WECC membership and Participating Stakeholders. Voting among the WECC Standards Voting Sectors will be weighted as follows:

- For each Sector with ten or more voters, the number of affirmative votes cast shall be divided by the sum of the affirmative and negative votes cast to determine the fractional affirmative vote for that Sector. Abstentions, incomplete votes, and non-responses shall not be counted for the purposes of determining the number of voters

in the Sector.

- For each Sector with less than ten voters, the fractional affirmative vote of that Sector shall be multiplied by ten percent (10%) times the number of voters. E.g., for a Sector with nine voters, the fractional affirmative vote will be multiplied by ninety percent (90%). Abstentions, incomplete votes, and non-responses shall not be counted for the purposes of determining the number of voters in the Sector.
- The sum of the fractional affirmative votes from all Sectors divided by the weighted number of Sectors voting shall be used to determine if a majority has been achieved. A Sector shall be considered as voting if any member of the Sector in the Ballot Pool casts either an affirmative or a negative vote. If there are more than ten voters in the Sector, the weighting used for the calculation of "weighted sectors voting" shall be one hundred percent (100%). For Sectors with less than ten voters, the weighting used for the calculation of the "weighted sectors voting" shall be ten percent (10%) per voter. Abstentions, incomplete votes, and non-responses shall not be counted for the purposes of determining the number of voters per Sector.
- A Standard shall be approved by the Ballot Pool if the sum of fractional affirmative votes from all Sectors divided by the weighted number of voting Sectors is a majority (i.e. greater than fifty percent (50%)).

A two-thirds (2/3) quorum of the Ballot Pool is required for each vote. Abstentions and incomplete responses will be counted in determining whether a quorum of the Ballot Pool is achieved. Quorum shall be based on total number of Ballot Pool members, and shall not be based on total number of votes cast. If necessary, the voting window may ~~vote~~ be extended by the WSC until a quorum is achieved.

After a vote by the Ballot Pool, the WSC will take one of the following actions:

(1) If the Ballot Pool approves a Draft Standard, the WSC shall submit the recommended Draft Standard to the WECC Board. The WSC shall provide the Draft Standard, any comments on which the WSC members did not agree, minority opinions of WSC members, explanations supporting votes in opposition to the Draft Standard, and the impact assessment for the Draft Standard to the Board for final approval. To be considered by the Board, any "no" votes by a WSC member on a Draft Standard shall be accompanied by a text explaining the "no" vote and, if possible, should provide specific language that would make the Draft Standard acceptable. Relevant voting information from the Ballot Pool shall be submitted to the Board for its consideration in determining whether or not to approve the Draft Standard. Final Draft Standards and all materials provided to the Board will be posted no less than 30 days prior to the Board vote.[6] The date of the expected Board vote will also be posted.

(2) If the Ballot Pool rejects a Draft Standard, the WSC may, by a majority vote (greater than 50 percent of the WSC membership), decide to amend or modify ~~a proposed~~the initial Draft Standard or ~~revision(s) or~~ remand it back to the ~~Subgroup to propose~~

[6] WECC Bylaws, Section 7.5.1 – "Except as set forth in Section 7.5.2 regarding urgent business, all regular business of the Board will occur at the Board meetings, at least twenty-one (21) days' advance notice of which has been provided…"

~~needed~~ Drafting Team to amend or modify it. Any amended or modified Draft Standard must be resubmitted to the Ballot Pool for a vote before the WSC submits the subsequent Draft Standard to the WECC Board. If the WSC determines by majority vote (greater than 50% of the WSC members) that the modifications~~.~~ to the Draft Standard could be unanticipated by the Ballot Pool or may be controversial, the amended or modified Draft Standard shall be subjected to an additional Joint Session discussion prior to voting. The reasons for the modification(s) will be documented, posted, and provided to the Board. If any changes are made at the ~~Standing Committee~~WSC meeting, the roll call of votes for and against the ~~proposal~~subsequent Draft Standard and abstentions will be recorded at the meeting, and the ~~revised proposal~~subsequent Draft Standard will be posted for 10 days for comments.~~[7]~~ The comments will be posted and distributed to the ~~Standing Committee and Participating Stakeholders. All Standing Committee members and Participating Stakeholders, including those who did not vote at the meeting, will be allowed 10 days from the time comments are posted to submit or change their votes, and the Standing Committee/Participating Stakeholder votes will be recounted based on these new and revised votes to determine whether a majority has voted for the proposal. Any parties that object to the modifications may appeal to the appropriate appeals committee as provided in Step 8~~Ballot Pool and will be made available prior to any subsequent rounds of voting. Unless otherwise directed by the WSC, the Ballot Pool for subsequent votes on a Draft Standard shall consist of the same parties.

~~A majority vote of the Standing Committee and Participating Stakeholders, as specified in Section 8.5.5.2 of the WECC Bylaws, is required to approve submitting the recommended Standard or revision(s) to the Board for a vote. In accordance with Section 8.5.5.2 only Standing Committee members and Participating Stakeholders who are present at a meeting of the Standing Committee may vote on a Standard.~~

~~Although any of the three Standing Committees (together with Participating Stakeholders) may vote on submitting the recommended Standard or revision(s) to the Board, only the vote of the lead Standing Committee and Participating Stakeholders will determine the course of action. If the Standing Committees do not agree, the lead Standing Committee and Participating Stakeholders will decide whether to return the draft to the Subgroup for further work, to submit the recommended Standard or revision(s) to the Board, or terminate the Standard development activity with the posting of an appropriate notice to the Standards requester, the Subgroup, and the Board (if appropriate). The Standing Committee chairs will coordinate input from their respective Committees and Participating Stakeholders to the lead Standing Committee so that the lead Standing Committee and Participating Stakeholders will have all relevant information when voting. Relevant voting information from all Standing Committees will be submitted to the Board for its consideration in determining whether or not to approve the Standard.~~

~~[3] WECC Bylaws, Section 8.5.6 – "If the committee's recommendation or decision changes significantly as a result of comment received, the committee will post the revised recommendation or decision on the Web site, provide e-mail notification to Members and Participating Stakeholders (if the recommendation or decision concerns a Reliability Standard or revision), and provide no less than ten (10) days for additional comment before reaching its final recommendation or decision."~~

~~If the Standing Committee and Participating Stakeholders approve the Standard or revision(s), the Standing Committee sends its recommendation, together with the proposed Standard or revision(s), and any comments on which the Standing Committee and Participating Stakeholders did not agree, plus minority opinions, to the Board for final approval. To be considered by the Board, any "no" votes on a proposed Standard or revision(s) should be accompanied by a text explaining the "no" vote and if possible specific language that would make the Standard or revision(s) acceptable. Proposed Standards or revision(s) will be posted no less than 30 days prior to the Board vote.~~[8]
~~The date of the expected Board vote will also be posted.~~
(3) If the Ballot Pool rejects a Draft Standard, the WSC may allow the Draft Standard to terminate.

Step 8 – Appeals Process

~~Appeals are available at various levels~~Requests for reconsideration of ~~the Standards Development Process as follows:~~

~~Rejection of a Standards Request by the Standards Request Routing Committee may be appealed to a Standing Committee and Participating Stakeholders, and if necessary, to either a Due Process or Technical Appeal Committee, as appropriate.~~

~~Appeals of Subgroup~~WSC decisions~~, including Routing Committee decisions,~~ may be made to ~~a Standing Committee and Participating Stakeholders~~the WSC. The ~~Standing Committee~~WSC will post its findings. The subsequent rejection of such ~~an appeal by a Standing Committee and Participating Stakeholders may be further appealed to an appeals committee. The appeals committee will post and submit its findings and recommendations to the Standing Committee chair who will determine the appropriate course of action. Any submittal to~~ a request by the WSC may be appealed to the Board ~~of Directors for approval will include any findings and recommendations of the appeals committee.~~ .

~~A new Standard or revision(s) to an existing Standard recommended by a Standing Committee and Participating Stakeholders~~A Draft Standard recommended by the WSC may be appealed on either technical or due process grounds. Any due process or technical appeals must be submitted, in writing, to the WECC staff within 15 days of the date the ~~Standing Committee~~WSC posts a recommendation.

~~The WECC staff will conduct an investigation and issue a written report of its findings and recommendations to the appealing party and Standing Committee. If the appealing party does not agree with the staff report, it can request that the appeal be referred to the Technical or Due Process Appeals Committee, which will conduct an investigation and issue a report including findings and recommendations. The Technical Appeals Committee will make assignments as necessary to existing WECC technical work groups and task forces, form new technical groups if necessary, and use other technical resources as required to address technical appeals. The appealing party has the burden~~

[4] ~~WECC Bylaws, Section 7.5.1 – "Except as set forth in Section 7.5.2 regarding urgent business, all regular business of the Board will occur at the Board meetings, at least twenty-one (21) days' advance notice of which has been provided…"~~

~~of proof and must demonstrate that the decision will adversely impact it. The Technical or Due Process Appeals Committee will issue a majority decision.~~

~~Each level of appeal will be completed within 30 days. The Board of Directors, at its discretion, may implement the Standard or revision(s) on an interim or emergency basis during the appeals process using the Urgent Action interim Standard Process set forth below.~~

An appeal to the Board shall be posted on the WECC website and shall be heard at the Board's next regularly scheduled meeting occurring at least 21 days after the appeal is filed.

Step 9 – Board Approval

The WECC Board of Directors will consider the proposed Draft Standard ~~or revision(s)~~ no later than at its next meeting occurring at least 30 days after the ~~lead Standing Committee~~Ballot Pool vote. The Board will consider the ~~Standing Committee's~~WSC's recommendations and minority opinions, all comments that were not incorporated into the draft Standard or revision(s), and the impact assessment report~~, and inputs from the Due Process and Technical Appeals Committees.~~. The Board will not amend or modify a ~~proposed~~Draft Standard, except to make nonmaterial changes to the language of a Standard or revision thereto. If approved, the Standard will be posted on the WECC website and all parties notified.

If the ~~new or modified~~Draft Standard is not approved, the Board may return the Draft Standard to the ~~Standing Committee and Participating Stakeholders~~WSC for further work, or the Board may terminate the Standard activity with an appropriate notice and explanation to the ~~Standard~~SAR requester, ~~Standing Committee~~WSC, and ~~Participating Stakeholders~~participants in the Ballot Pool. These Board actions will also be posted.

A majority vote of the Directors present at a Board meeting, as specified in ~~Section~~Sections 7.2 and 7.~~2~~4.1 of the WECC Bylaws, is required to approve the recommended Standard ~~or revision(s).~~.

Step 10 – ERO Review, FERC Approval and Implementation of Reliability Standards

To the extent required under Section 215 of the Federal Power Act, 18 C.F.R. Part 39, and according to procedures established in the delegation agreement between WECC and the Electric Reliability Organization ("ERO"), the Board shall submit new Reliability Standards ~~and~~, revisions to existing Reliability Standards, and terminations of existing Reliability Standards for review by the ERO and approval by FERC. Upon approval by FERC, the Reliability Standards will be made part of the body of NERC reliability standards and enforced upon all applicable bulk power system owners, operators, and users within the WECC region. Parties' right to participate in the ERO and FERC review processes shall be as established in the applicable regulations and the ERO/WECC delegation agreement. Reliability Standards subject to ERO review shall become

effective as approved by FERC or, for entities outside of the U.S. portion of the Western Interconnection, upon approval by the applicable Canadian or Mexican authorities.

Step 11 – Implementation of Standards Not Subject to ERO/FERC/Other Approval

All new and modified Standards not subject to ERO review and FERC, Canadian or Mexican approval as provided in Step 10 shall become effective as ordered by the WECC Board. As of the effective date of such new or modified Standard, all industry participants in the Western Interconnection that such Standard is applicable to are expected to implement and abide by the Standard. Any and all parties to this Process retain the right of appeal to other authorities as the law allows.

Expedited Process for Urgent Action Interim Standards

In cases requiring urgent action, such as in the development of emergency operating procedures, ~~the~~any Standing Committees ~~and~~or Participating Stakeholders may propose a new or modified interim Standard for approval by the WECC Board through a process that eliminates any or all of the steps outlined above, but only to the extent necessary, and only in a manner that is consistent with the WECC Bylaws. Such interim Standard shall be replaced by a Board-approved permanent Standard, developed using all the steps identified in this document within one year (or such additional time as may reasonably be required to complete all steps) from the date on which the WECC Board approved the interim standard. An interim Standard may be converted to a successor permanent Standard as long as any procedural steps bypassed in developing the interim Standard are completed with respect to the permanent Standard. If necessary, the Board may renew an interim Standard to allow additional time for the development of a successor permanent Standard. Renewal may occur more than once, but a good faith effort must be made to develop a successor permanent Standard.

Interpretation of Regional Standards and Regional Criteria

Any entity may request an interpretation of a Standard by sending a request through the WECC web portal identifying the Standard and requirement or requirements for which additional clarity is sought. The request shall indicate the material impact to the requesting entity or others caused by the actual or potential lack of clarity. An interpretation is limited to clarifying existing requirements in approved Standards. Interpretations may not be developed that expand upon a requirement or that provide guidance on how to apply a requirement.

The WECC Staff shall review the request for clarity and completeness and shall work with the requestor to clarify the request or complete any missing elements of the request if needed. The WECC Staff shall forward the request to the WSC. If the WSC believes that the request is intended to change a requirement or is seeking feedback on how to apply a requirement, rather than interpret the requirement, the request shall be denied and returned to the requestor with an explanation. If denied, the requestor shall be advised of the appeals process.

Within 21 days of receiving the request, the WSC Chair shall assemble an Interpretation Drafting Team (IDT) with the relevant expertise to address the clarification. The IDT should include members from the original Standard Drafting Team to the extent possible, and may be supplemented as deemed appropriate by the WSC Chair, but shall not contain any members representing the entity that submitted the request.

As soon as practicable, but not more than 45 calendar days after the WSC assembles the IDT, the IDT shall draft a written interpretation to the Standard providing the requested clarity. The interpretation shall be posted for a 30-day formal comment period. The IDT shall then have 15 days to respond to the comments and to make any changes to the interpretation. The IDT shall reach a determination on the language for

an interpretation by majority vote of the IDT. The IDT shall then return the interpretation to the WSC which shall then post the interpretation for another 30 days to give entities time to review the interpretation prior to a Ballot Pool vote. Notice of this posting will be sent to the Ballot Body, and the notice shall solicit participants for the Ballot Pool for voting on the interpretation. After posting of the interpretation, the Standing Committees shall participate in at least one Joint Session addressing the interpretation. Voting on the interpretation shall be consistent with the quorum and weighted voting procedures explained in Step 7 of these Reliability Standards Development Procedures. Use of a conference call or web meeting and electronic or email balloting is encouraged to shorten the interpretation process. If the interpretation is approved by a weighted majority of the Ballot Pool, the WSC shall forward the interpretation to the WECC Board of Directors for approval. If the Ballot Pool rejects the interpretation, the WSC shall notify the requestor. The WSC shall also ask the IDT to provide a revised interpretation.

Interpretations of Regional Standards shall be submitted to NERC for processing with a request that the interpretation be adopted by the NERC Board of Trustees and then filed for approval with FERC and applicable Governmental Authorities in British Columbia, Alberta and Mexico.

For entities operating in the United States, once the interpretation of a Regional Standard is approved by FERC, the interpretation shall become effective and shall be appended to the Standard. For entities outside of the U.S. portion of the Western Interconnection, interpretations shall become effective for these entities only upon approval by the appropriate Canadian or Mexican regulatory authority. The interpretation will remain appended to the Standard until such time as the Standard is revised through the normal process incorporating the clarifications provided by the interpretation.

Special Procedures for Addressing Regulatory Directives

If the Board determines that the WECC Standards Process did not result in a proposed Draft Standard that addresses a directive issued by the FERC or by a Mexican or Canadian regulatory authority (Applicable Regulatory Authority), hereinafter, "regulatory directive," then the Board shall have authority to take certain actions to ensure that a Draft Standard responsive to the regulatory directive is drafted, approved and/or submitted to the Applicable Regulatory Authority.[9] The Board shall have the authority to choose which one or more of the actions set out below are appropriate to the circumstances and need not take these actions in sequential steps.

1. Board Remand to the WSC after an Affirmative Vote of the Ballot Pool. If the Board is presented with a Draft Standard that fails to address a regulatory directive, the Board may remand to the WSC the proposed Draft Standard with instructions (including establishing a timetable for action).

[9] The procedures in this section, "Special Procedures for Addressing Regulatory Directives," only apply to draft Regional Reliability Standards.

2. Board Remand to WSC for Additional Public Consideration and Re-ballot. Upon a written finding by the Board that a Ballot Pool has failed to approve a Draft Standard that contains a provision to address a specific matter identified in a regulatory directive, the Board has the authority to remand the Draft Standard to the WSC with instruction to (i) convene a public technical conference to discuss the issues surrounding the regulatory directive, including whether or not the Draft Standard is just, reasonable, not unduly discriminatory or preferential, in the public interest, helpful to reliability, practical, technically sound, technically feasible, and cost-justified; (ii) working with WECC staff, prepare a memorandum discussing the issues, an analysis of the alternatives considered and other appropriate matters; and (iii) re-ballot the Draft Standard one additional time, with such adjustments in the schedule as are necessary to complete a re-ballot of the Draft Standard within forty-five (45) days of the remand. The WSC memorandum shall be made available to the Ballot Pool in connection with the re-ballot. In any re-ballot, negative votes without comment shall be counted for purposes of establishing a quorum, but only affirmative votes and negative votes with comments related to the Draft Standard shall be counted for purposes of determining the number of votes cast and whether the Draft Standard has been approved by the Ballot Pool.

3. Affirmative Vote upon Re-ballot of Draft Standard. If the re-balloted Draft Standard achieves an affirmative majority vote of the Ballot Pool, with a quorum established, then the Draft Standard shall move to the Board for approval.

4. Negative Vote upon Re-ballot of Draft Standard. If the re-balloted proposed Draft Standard fails to achieve an affirmative majority vote of the Ballot Pool, or if a quorum is not established, then the Board has the authority to consider the Draft Standard for approval pursuant to the following:

(i) The Board shall issue notice of its intent to consider the Draft Standard and shall solicit written public comment particularly focused on the technical aspects of the provisions of the Draft Standard that address the specific matter identified in the regulatory directive, including whether or not the Draft Standard is just, reasonable, not unduly discriminatory or preferential, in the public interest, helpful to reliability, practical, technically sound, technically feasible, and cost-justified.

(ii) The Board may convene a public technical conference to receive additional input on the matter.

(iii) After considering the developmental record, the comments received during balloting and the additional input received under (i) and (ii), the Board has authority to act on the Draft Standard. If the Board finds that the Draft Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is helpful to reliability, practical, technically sound, technically feasible, and cost-justified, then the Board has authority to approve the Draft Standard and direct that it be filed with the Applicable Regulatory Authority with a request that it be made effective. If

the Board is unable to find that the proposed Draft Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is helpful to reliability, practical, technically sound, technically feasible, and cost-justified, then it has authority to direct that the Draft Standard and complete developmental record, including the additional input received under (i) and (ii), be submitted to the Applicable Regulatory Authority, as a compliance filing in response to the order giving rise to the regulatory directive, along with a recommendation that the Draft Standard not be made effective and an explanation of the basis for the recommendation.

5. Board Approval or Rejection of a Draft Standard Prepared by the WSC or WECC Staff and Not Balloted. Upon a written finding by the Board that the WSC has failed to develop, or a Ballot Pool has failed to approve, a Draft Standard that contains a provision to address a specific matter identified in a regulatory directive, the Board has the authority to direct the WSC (with the assistance of stakeholders and WECC staff) to prepare a Draft Standard that addresses the regulatory directive, taking account of the entire developmental record pertaining to the matter. If the WSC fails to prepare such Draft Standard, the Board may direct WECC management to prepare such Draft Standard. As part of this process, the Board may convene a public technical conference to receive input on the matter. The Draft Standard shall be posted for a forty-five (45) day public comment period. After considering the entire developmental record, including any comments received during the public comment period, the Board may do one of the following:

(i) The Board may find that the Draft Standard, with such modifications as the Board determines are appropriate in light of the comments received, is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is practical, technically sound, technically feasible, cost-justified and serves the best interests of reliability of the bulk power system. In this case, the Board has the authority to approve the Draft Standard and direct that the proposed Standard be submitted to the Applicable Regulatory Authority with a request that the Draft Standard be made effective.

(ii) The Board may be unable to find that the Draft Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is practical, technically sound, technically feasible, cost-justified and serves the best interests of reliability of the bulk power system. In this case, the Board has the authority to direct that the Draft Standard and the complete developmental record be filed as a compliance filing in response to the regulatory directive with the Applicable Regulatory Authority, with a recommendation that the Draft Standard not be made effective.

WECC shall on or before January 31st of each year file a report with the FERC on the status and timetable for addressing each outstanding directive to address a specific matter received from FERC.

Approved by the WECC Board ~~[Month, Day] 2008~~

June 22, 2011.

Process for Developing and Approving WECC Standards

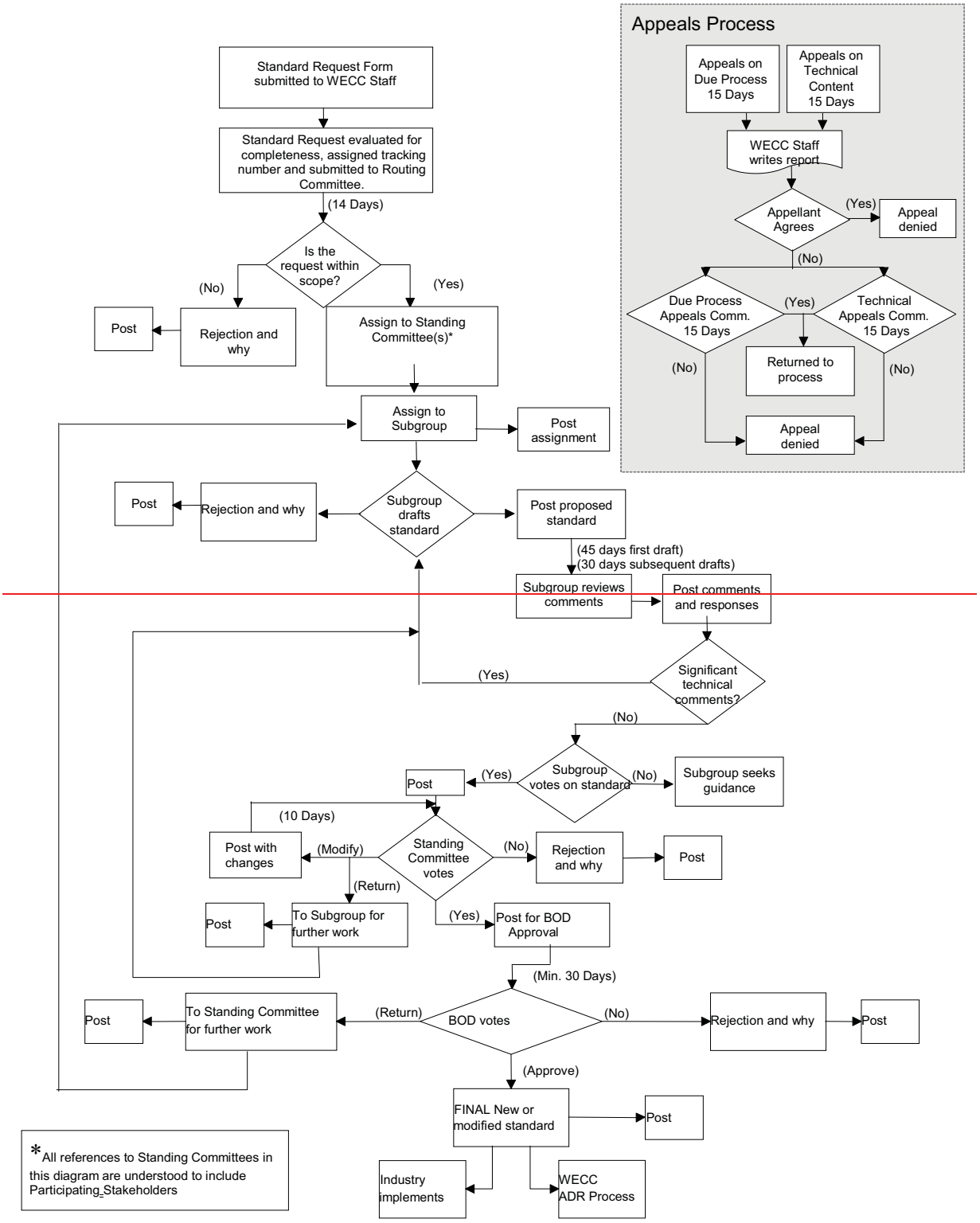

STANDARDS DRAFTING PROCEDURES FLOWCHART

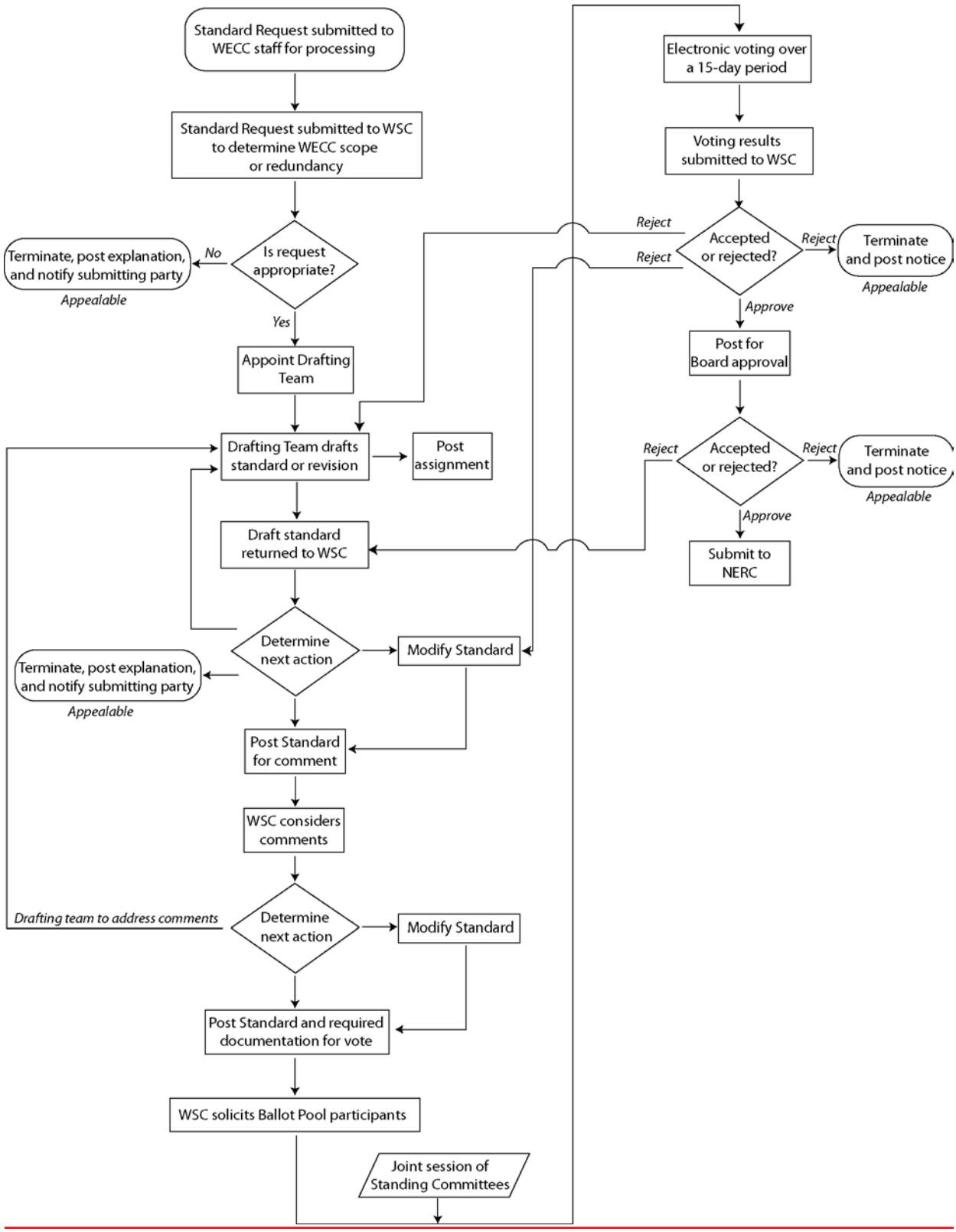

Agenda Item 10
Board of Trustees Meeting
November 3, 2011

Spare Equipment Database

Action

Endorse the Special Report: Spare Equipment Database System and the implementation of the Spare Equipment Database (SED) program in the first quarter of 2012.

Summary and Background

The Special Report: *Spare Equipment Database System* provides a platform for the re-development of a voluntary industry-wide SED, initially focused on providing an inventory of critical transmission and generator step-up (GSU) transformer spares managed by North American bulk electric system Transmission and Generation Owners. The SED was initiated as part of the ESCC's Critical Infrastructure Protection Roadmap[1] and is a function of NERC's Technical Committee's Critical Infrastructure Strategic Initiatives Coordinated Action Plan.[2] The report was developed through an industry-wide group, the SED Task Force reporting to the Planning Committee. The report was endorsed by the NERC Planning, Operating and Critical Infrastructure Protection Committees in September 2011.

As described in the Report, SED will be based on five principles:

- SED participation will be voluntary for all NERC registered Transmission Owners (TOs) and Generator Owners (GOs), whether or not they have available spare equipment.
- SED's content will be long-lead time transformer spares for transmission and GSU transformers. Collected data for each spare will be limited to essential equipment characteristics and contact information.
- SED's timeline has been accelerated with a start date in the first quarter of 2012.
- SED will be operated as a confidential and secure database. All SED participants will be required to sign a confidentiality agreement that outlines their responsibilities.
- SED use and release will be automated and monitored to facilitate timely communications between those who need long-lead time equipment damaged by High Impact, Low Frequency (HILF) events and those equipment owners who may be able to share existing spare equipment.

This database is not meant to replace or supersede any existing transformer sharing agreements, or other neighboring, or regional utility arrangements. The SED is primarily a tool that will be populated and managed by NERC and participating organizations to facilitate timely communications. Further, the SED will aid the assessment of HILF scenarios. Participating organizations will follow defined guidelines, outlined in a signed confidentiality agreement, to identify the spare equipment included in the database.

[1] http://www.nerc.com/docs/escc/ESCC_Critical_Infrastructure_Strategic_Roadmap.pdf
[2] http://www.nerc.com/docs/ciscap/Critical_Infrastructure_Strategic_Initiatives_Coordinated_Action_Plan_BOT_Apprd_11-2010.pdf

Agenda Item 11
Board of Trustees Meeting
November 3, 2011

Bulk Electric System (BES) Definition Project

Action
Review

Project Scope
The Commission has established a filing deadline of January 25, 2012 for all portions of the project which include the definition of BES so that it encompasses all elements and facilities necessary for the reliable operation and planning of the interconnected bulk power system and additional directives including the retention of the radial exclusion, the elimination of regional discretion which exists in the current definition and the development of a process for identifying any elements or facilities that should be excluded from the BES.

This project includes several work products which have been developed in parallel to meet the January 25 deadline:

- A revised *Bulk Electric System definition* developed by the Project 2010-17 Definition of Bulk Electric System standards drafting team (SDT) (Project 2010-17 SDT).
- A BES definition *Implementation Plan* also developed by the Project 2010-17 SDT.
- A new *Appendix 5C* to NERC's Rules of Procedure that addresses the *process for requesting BES exceptions*, drafted by NERC staff and an industry stakeholder team drawn from BES Standards Drafting Team nominees.
- An application form titled *Detailed Information to Support an Exception Request* which identifies potential forms of evidence that can be utilized to support the exception request. This form is referenced in the Rules of Procedure Exception Process and was developed by the Project 2010-17 Standard Drafting Team (SDT).

Current Status
The proposed definition of BES and its implementation plan were posted for a 45-day concurrent posting (formal comment period and initial ballot) until October 10, 2011, as was the draft application form *Detailed Information to Support an Exception Request*.

The initial ballot of the BES definition achieved a quorum of 92.97 percent and weighted ballot pool approval of 71.68 percent. The initial ballot of technical principles required to support a request for a BES exception achieved a quorum of 89.53 percent and a weighted ballot pool approval of 64.03 percent.

The definition includes a default threshold of 100 kV augmented by a list of five categories of facilities that are included in the BES and a list of four categories of facilities that are excluded from the BES. In addition, the drafting team has clarified what is meant by 'radial' and drafted a specific exclusion for local networks serving a distribution function. The definition was designed

to create a "bright line" definition of facilities to be included as part of the BES that can be consistently applied across North America.

The draft Rules of Procedure Exception Process is posted for comment through October 27, 2011. This is being processed following the NERC procedure for making a change to the Rules of Procedure (described in Section 1400 of the NERC Rules of Procedure).

Standard Development Project Subdivided Into Two Phases

During the initial posting of the draft BES definition for industry comment, the Project 2010-17 SDT received many suggestions that fall outside the narrow scope of the regulatory directives in FERC Order No. 743 (as clarified in Order No. 743-A). The following is a list of the areas of concern already identified by the SDT members and stakeholders through the standard development process:

- 100 kV bright-line voltage threshold
- Thresholds for generation resources
- Reliability benefit of a contiguous BES
- Points of demarcation between transmission, generation, and distribution
- Scope of equipment supporting reliable operation of the BES
- Relationship between BES definition and ERO Statement of Compliance Registry Criteria

The Project 2010-17 SDT and NERC staff believe these suggestions deserve serious consideration and fall within the scope of the current project. The SDT initially thought it could address a number of the above suggestions within a project schedule that would meet the Order No. 743 filing deadline of January 25, 2012. However, upon consideration of policy input and direction received from the Member Representatives Committee and the NERC Board of Trustees, the Project 2010-17 SDT quickly determined that developing an adequate technical justification for these additional revisions to the BES definition was highly unlikely in the time frame established by Order No. 743.

The SDT recognizes its obligation to fully respond to both FERC regulatory directives, address all stakeholder concerns, and produce a fully-supported technical justification for the proposed definition, while meeting regulatory expectations for a timely filing. After consideration of policy direction from the Member Representatives Committee and the NERC Board of Trustees and consultation with NERC staff, the SDT concluded that seeking a time extension at this time is not a viable alternative for three reasons:

- NERC has to demonstrate that it can work effectively, using its standard development process, to address tough reliability issues in a timely manner. A request for an extension may be perceived as a failure of NERC to work with stakeholders to solve complex reliability issues in a timely manner.

- If a request for an extension were requested, FERC is not under any obligation to respond within any specific timeframe, and may not respond before the documents must be submitted; the drafting team has to proceed without delay to meet the January 25, 2012 filing deadline.
- There is not sufficient technical information immediately available to support resolution of the issues raised by stakeholders and identified above. Developing that information will take time. To build a defensible case for adoption for some of the proposals, a significant effort is needed to collect information from stakeholders and then analyze that information and develop specific proposals. A firm technical foundation is essential to the success of any proposal that would change current practice. Before submitting a proposal to approve a new threshold for generator resources, for example, NERC must produce strong evidence that changing the threshold will not adversely impact reliability.

A link to the Reliability Standards Plan and history and files is included here for reference:

Definition BES:
http://www.nerc.com/filez/standards/Project2010-17_BES.html

Definition BES Rules of Procedure:
http://www.nerc.com/filez/standards/Rules_of_Procedure-BES.html

If trustees have questions or need additional information, they may contact Herb Schrayshuen at herb.schrayshuen@nerc.net.

Status of Action Items from NERC Three-Year ERO Performance Assessment

Action

None.

Summary

Below are summaries of some of the more significant developments in each NERC program area since the March 16, 2011 report to the board, "Progress in Implementing Specific NERC Actions from the Three-Year ERO Performance Assessment." NERC plans to produce a final, year-end report for presentation to the board at its February 2012 meeting.

Reliability Standards

Prioritizing Standards — NERC is continuing to use the prioritization process for the 2012-2014 Reliability Standards Development Plan (RSDP). In 2011, the standards program revised its prioritization tool to allow for more discrete consideration of various criteria during the project prioritization effort. Projects in the 2012-2014 RSDP have been evaluated in terms of Reliability, Time Sensitivity, and Practicality. An initial review of cost considerations in relative terms has been examined as well, based on the subjective opinions of the members of the Standards Committee. Additionally, the projects have been included in a risk-based work plan, which takes into account industry resource availability (by limiting the number of projects active in any one subject matter area at the same time) and other logistical considerations. The proposed schedule of start dates for projects in 2012 through 2014 takes into account all of the foregoing considerations, and it is included in the RSDP being presented at the November 2011 meeting of the Board of Trustees.

Engagement with Federal Energy Regulatory Commission (FERC or Commission) staff on U.S. filings — In addition to meeting with staff of FERC's Office of Electric Reliability for pre-filing meetings, NERC representatives are also meeting with the staffs of various Commissioners regarding high profile filings.

FERC Directives — NERC processes directives pursuant to its Rules of Procedure. Specifically, when a regulatory order or rule is issued, that order or rule is reviewed and any directives therein related to standards development are added to the NERC Standards Issues Database. NERC then seeks to associate each directive with a specific standard. Standards and their associated regulatory directives are then prioritized for revision using the RSDP, as described above. Since NERC was certified as the Electric Reliability Organization (ERO), FERC has issued 44 orders containing approximately 655 directives related to NERC reliability standards. In 2011, NERC developed the "NERC Standards Report, Status and Timetable for Addressing Regulatory Directives," which will be filed annually with the Commission on or before March 31 of each year in accordance with Section 321.6 of the NERC Rules of Procedure (Rule 321) that was approved by FERC on March 17, 2011.

Rapid Development Process — The standards project on protection system misoperations used a "rapid development" process to initiate the project. This involved a small team tasked with developing the starting point for a full standard and associated Standard Authorization Request (SAR) in order to present the standards development process with a 90 percent completed solution as a starting point. In the case of the misoperations project, a small team of professionals was formed and provided detailed training and coaching on results-based standards and how the team fit within the process. The team was asked to develop the SAR and the first draft of the standard. This small team included a NERC attorney and a contract technical writer who helped draft requirements and language based on team discussions. All meetings of this team were held in NERC's Atlanta office. The team developed the SAR and standard and submitted them concurrently, after which a larger team was created to continue their work. That team was also given training and coaching on results-based standards and how the team fit within the process. At the time of writing, this project is still underway but somewhat behind schedule.

Rapid Revision Process — The Interpretation of MOD-028 R3.1 is in the process of using a "rapid revision" process to address a narrowly focused reliability standard deficiency. In this case, a stakeholder identified a case where a requirement seemed to indicate an obligation unintended by the drafting team. A small team made up of members of the original standard drafting team was assembled, and the team proposed modification to R3 to address the concern. The team submitted a SAR concurrent with the changes to the standard, and it is expected that the process will result in a revised standard that was modified using the normal standards development process, eliminating the need to follow-up with additional standard activity. At the time of writing, this project is still underway.

Organization Registration and Certification

Registration and Certification Training — NERC has conducted a number of training webinars and workshops on the registration and certification process for Regional Entities and the industry, which were open to applicable governmental authorities. These training webinars are posted on the NERC website. A separate presentation that was focused solely on registration options, including Joint Registration Organization (JRO), Coordinated Functional Registration (CFR), and use of other duly executed legal agreements, was developed and presented to the industry via a webinar on September 9, 2011 and will be used in future compliance workshops at both the NERC and Regional Entity levels. NERC has also provided guidance to the industry and the Regional Entities regarding various registration options as it relates to delegation of reliability tasks in NERC Compliance Public Bulletin #2010-004 *Guidance for Entities that Delegate Reliability Tasks to a Third Party Entity*. NERC has also provided a webinar to the Regional Entities and the industry regarding how to complete a sample matrix of functional tasks and responsibilities related to a given registration.

Threshold Criteria for Registration — The processes and procedures for the Multi-Regional Registered Entity (MRRE) pilot program have been completed and the pilot program implemented. While processing selected entities through the pilot program, some

jurisdictional and enforcement issues were identified. NERC is continuing to work on the MRRE with the applicable Regional Entities.

Compliance Monitoring and Enforcement

Compliance Guidance — NERC has been: 1) posting Compliance Application Notices (including draft documents), Compliance Analysis Reports and Case Notes on the NERC website, 2) providing email notifications for activity on the website for these communication vehicles, 3) conducting webinars and workshops for industry, and 4) discussing the use of these communication vehicles at quarterly meetings with industry trade organizations. In addition, in September 2011, NERC began posting public information on dismissals.

NERC posted a revised compliance audit report procedure and report templates to address several areas for improvement, including the requirement to list the specific evidence the audit team used in determining compliance. The audit report template is scheduled for another review during the fourth quarter of 2011. The Compliance Monitoring Process Working Group (CMPWG) plans to review and provide suggested improvements to the audit report template for the purpose of providing more useful examples and guidance to the registered entities.

Compliance Enforcement Initiative — NERC and the Regional Entities are employing a more comprehensive and integrated risk control strategy that differentiates and addresses compliance issues according to their significance to the reliability of the bulk power system (BPS). In addition, NERC and the Regional Entities are increasing the utilization of their inherent enforcement discretion in the implementation of compliance and enforcement activities.

This new initiative is not about whether Possible Violations should or will be addressed. In all cases and regardless of the filing format, such matters are expected to be found, fixed, tracked and reported to the Regional Entities, NERC and the Commission. Lesser risk issues that have been corrected will be presented as Remediated Issues in a Find, Fix, Track and Report (FFT) spreadsheet format that will be submitted to FERC in an informational filing on a monthly basis. More serious risk violations will be submitted in a new Spreadsheet Notice of Penalty (NOP) or Full NOP, as warranted. On September 30, 2011, NERC submitted a filing setting forth its compliance enforcement initiative and new reporting mechanisms and also submitted the first FFT informational filing and the first Spreadsheet NOP.

Auditor Training — NERC conducted two ERO auditor workshops, one in February 2011, with 88 percent of the Regional Entity auditors in attendance, and a second on September 20. Regional Entity audit staffs responsible for auditing compliance with both Order No. 693 standards and CIP standards attended the February 2011 workshop. NERC plans to continue this program going forward and has scheduled two more ERO auditor workshops for 2012. In 2011, NERC started developing an ERO Auditor Certification Program that will include elements for initial auditor training, continuous auditor training, and focused auditor training. Additionally, training is conducted twice a year for investigative personnel in the Regions. Additional information and compliance guidance is available to ERO personnel on the NERC website,

including Reliability Standard Audit Worksheets (RSAWs), Compliance Application Notices, Compliance Analysis Reports and Case Notes.

NERC began development in 2011 on two significant compliance personnel training initiatives: Auditor Training and Auditor Reference Guide for Compliance Application. Auditor Training is planned to include various media including classroom education, on-line materials and web-based training, and will create a hierarchy of auditor expertise levels, allowing auditors of the highest expertise to exercise enforcement discretion. The Auditor Reference Guide for Compliance Application is planned to provide both an on-line reference guide for how auditors are to assess compliance for each family of reliability standards, and a web-based training module for each family of reliability standards. These tools will provide one location for compliance application information and be updated as needed to include answers to current compliance application questions. As such, these will ultimately replace the RSAWs and the Compliance Application Notices.

Improving RSAWs — RSAWs are continuously prioritized and reviewed for updates and improvements as appropriate. Further refinements and the addition of more information in the RSAWs to facilitate compliance are planned in 2011 and 2012. Future enhancements include converting the RSAWs from MS Word documents into a database and then linking them to the reliability standards database. RSAWs are developed based on changes to the Actively Monitored Reliability Standards list (AML). The developments and revisions are performed as an ERO effort that includes input from the eight Regional Entities via the Compliance Monitoring Process Working Group (CMPWG).

Audit Process Improvements — Revisions to the post-audit questionnaires are on the agenda for the CMPWG the fourth quarter of 2011. Compliance Operations, specifically the Audit Assurance and Oversight (AAO) department, reviews its processes for enhancement including the addition of references to the U.S. Government Accountability Office (GAO) Standards. AAO has enhanced its audit observation process and is developing new processes for tracking Regional Entity implementation of the CMEP and Regional Delegation Agreements (RDAs). AAO developed a Risk-Based Compliance Monitoring approach for 2011 and has made substantial changes to address risk-based compliance monitoring in 2012.

In addition, the 2012 CMEP Implementation Plan includes a set of reliability standards that were selected based on the initiative to develop a risk-based approach for compliance monitoring. A substantial change to the 2011 risk-based compliance monitoring is the introduction of a three-tiered approach to compliance auditing. The implementation plan also requires Regional Entities to conduct a registered entity assessment, including an analysis of a registered entity's compliance history and internal compliance program, when determining the scope of compliance monitoring activities.

Compliance Data Retention — The Compliance Process Bulletin #2011-001 "*Data Retention Requirements"* posted on May 20, 2011 superseded the 2009-005: "*Current In-Force Document Data Retention requirements for Registered Entities*."

Event Analysis and Information Exchange
Event Analysis Process Document — The latest version of the process document is planned for review and endorsement by the NERC Operating and Planning Committees and approval by the NERC board in February 2012. The document includes specific analysis threshold criteria. Revisions to the Rules of Procedure with respect to Event Analysis also are planned for board approval in February 2012.

Staffing — The two open positions in Event Analysis and Investigations have been filled with one person having cause analysis expertise and the other with human performance expertise.

Cause Analysis Training — The newly developed cause analysis training program was delivered once in September and second class is scheduled to be delivered in the fourth quarter of 2011.

Reliability Assessment
Improve Granularity; Support Assumptions and Conclusions — NERC has increased granularity on data and information collected towards operating areas, rather than Regional Entities. This has increased the visibility of resource assessments for operating areas, such as Independent System Operators/Regional Transmission Organizations that cross multiple regional entity boundaries. Also, developed more consistency throughout assessment reports whereby conclusions are supported by operating regional assessments

Avoidance of Policy Positions — NERC evaluates the impacts of policy, such as environmental regulations, but does not take policy positions on those policies.

Scenario Assessments — NERC will review in 2011 a high demand case, and use the NERC projects as a reference case for two 2010 Special Reliability Scenario Assessments: Resource Adequacy Assessment of Potential U.S. Environmental Regulations, and Potential Reliability Impacts of Swift Demand Growth after a Long-Term Recession.

Performance Analysis and Metrics
Risk Performance Analysis — The Reliability Metrics Working Group (RMWG) will be submitting its first foundational report, titled "Risk to Reliability Performance" that will provide a consolidated view of risk measurements to NERC's b in 2011.

Integrated Reliability Metrics — Reliability metrics webinars and meetings are ongoing in 2011 and endorsement by the Planning and Operating Committees will be requested in the first quarter of 2012.

Critical Infrastructure Protection
Critical Cyber Asset Identification — NERC developed and delivered one industry webinar on September 1, 2011, presenting the Critical Cyber Asset Identification Guideline. An additional

webinar is scheduled for November 18, 2011, on "Implementing an Electronic Security Perimeter Where None Has Existed Before."

CIP Auditor Workshops — NERC conducted four auditor workshops in 2011 that had CIP-specific components. The ERO Auditor workshops in February and September attracted a majority of CIP auditors, and included information pertinent to all ERO auditors, as well as breakout sessions with special emphasis on CIP compliance issues. In addition to the ERO Auditor workshops, the Critical Infrastructure Division (CID) also sponsored two workshops geared specifically for CIP auditors. The first CID-sponsored workshop was held on June 28 and the second CID-sponsored workshop was held on September 22-23. The CIP issues addressed during the workshops arose from recommendations from NERC staff as well as suggestions from Regional auditors, and included topics such as case studies, audit consistency, interviewing skills, writing data requests, and audit report writing skills.

FERC Order No. 706 Directives — The Drafting Team has completed its work to address all remaining identified directives in FERC Order No. 706 and the order accepting the "ports and services" interpretation to CIP-006. The standards are undergoing NERC Quality Review (QR) during October 2011. Drafting Team responses to the NERC QR comments should be completed by the end of October, and followed by posting in early November. The current schedule anticipates: industry ballot approval by June 2012; NERC board approval in August 2012; and filing with FERC and other applicable governmental authorities in September 2012.

TFE Procedure and Reporting — NERC finalized the TFE procedure, which the NERC board and FERC approved as Appendix 4D to the NERC Rules of Procedure. The current version of Appendix 4D took effect on April 12, 2011, and has guided the day-to-day administration of the ERO's TFE program, as well as tracking and reporting of TFE data. The first TFE report to FERC covered the period from January 1, 2010, to June 30, 2011, and was filed with FERC on September 28, 2011. The TFE Managers, which include representatives from all eight Regions and the NERC TFE Program Manager, will convene a "TFE Summit" with FERC representatives by December 2011 to discuss the annual report and to propose revisions to the TFE program to ease the burden on Responsible Entities and the Regions.

CIP Standards Interpretations — As requested by the Standards Committee, a standing CIP Interpretation Drafting Team (IDT) has been established to address all CIP-related interpretation requests.

CIP Alerts and Information Sharing — In Q1 2011, NERC reviewed the ES-ISAC and identified key areas for improvement. As a result of the review, NERC has implemented several changes to the ES-ISAC, including: hiring personnel to staff the ES-ISAC; deploying an upgraded ES-ISAC website, which contains announcements on threats and vulnerabilities; a calendar to display upcoming meetings and events; links to external security sites; an updated library with reports and public Alert information; and streamlining the NERC Alert process development to shorten the time needed to publish alerts and to ensure key stakeholders—such as Hydra, industry trade organizations, and technical committees—are included in the development process. In

addition, the ES-ISAC issued seven alerts in 2011 and worked with registered entities to track progress in mitigating the Aurora vulnerability.

Contributing to the Alert process, the Hydra group continues to evolve and grow. Hydra was integrated into the NERC Alert development process and has successfully provided critical and timely feedback to NERC. Hydra's involvement was highlighted during the development of several recent NERC Alerts including the "Telephony-enabled Weakness" alert. Hydra will have a collaboration tool in the newly-designed ES-ISAC portal and will continue to evolve and be augmented by specific external subject matter experts as necessary.

Situation Awareness

SAFNR Version 2 —NERC expects to have live streaming of information from four to six Reliability Coordinators by the end of October 2011.

Training, Education, and Personnel Certification

Advanced System Operator Credential — The NERC Personnel Certification Governance Committee (PCGC) issued a white paper for industry comment on this concept, which included additional testing requirements, simulation testing, and specific number of years experience to qualify for the advanced credential. Industry comments indicated no benefit to creating an advanced credential that would be offered on a voluntary basis. As a result, the PCGC halted the project. This was reported to the NERC board and no further work on this concept is expected at this time.

Broaden Operator Certification Program – The PCGC had been working on broadening the renewal process so that certified system operators will be required to take a certain number of task (job)-related courses as part of their renewal requirements. The PCGC has tabled this topic to allow the industry to implement the new PER-005 requirements. This concept may be readdressed in the future.

Improve the System for Tracking Continuing Education Hours – NERC continues to identify improvements to the database. The latest round of changes to improve functionality were tested and implemented in September 2011.

Offer More Targeted and Timely Education Programs – Training resources were added to the training group to provide training expertise to support improved educational programs. NERC hired a new Training Director and a Training Manager in June, and a technical training specialist in August 2011. With the additional training leadership, the ERO Training and Education Group will gain new momentum in identifying educational topics that most benefit the industry. In addition, NERC is working with the Operating Committee's Personnel Subcommittee to develop guidance on the elements of strong training programs.

"Open Source" System for Providing Information — NERC researched the use and benefits of using "open source" collaborative systems for providing information to the industry. The use of tools such as blogs and wiki's has merit, but also drawbacks, such as inappropriate use of

implied guidance from NERC. Because of the resources and attention needed to adequately monitor and control such platforms, no additional action is planned.

Requirements for Training Programs and Providers – NERC is working with the personnel subcommittee to develop guidance on the elements of strong training programs.

Finance and Controls

Multi-year Business Plans and Budgets — As part of the 2012 Business Plans and Budgets, NERC and the Regional Entities included information with respect to 2012-2014 projected resource requirements to meet the Strategic Goals and associated objectives.

Long-Term Strategic Goals — NERC has been working and will continue to work with the Regional Entities to develop long-term strategic goals, objectives, assumptions and financial forecasts and utilize and include this information in the annual business planning and budgeting process and documentation. This effort will be undertaken each year as part of the business planning and budgeting process.

Uniform Budgeting Tool — Common templates have been developed and are used by NERC and the Regional Entities for budget preparation and presentation. Beyond the development and use of common templates, NERC and the Regional Entities have been developing 3-year forecasts for use in each annual business planning and budgeting cycle. This information was included in NERC and the Regional Entities' proposed 2012 Business Plans and Budgets and will continue to be refined and utilized in connection with the preparation of each annual business plan and budget.

Agenda Item 14
Board of Trustees Meeting
November 3, 2011

Update on Regulatory Matters
(As of October 5, 2011)

Action
None

Regulatory Matters in Canada

1. Negotiation of the second agreement among NERC, the Régie and NPCC regarding implementation of mandatory standards in Québec has been tentatively concluded and the agreement is under consideration by the provincial government. The Régie has issued a preliminary decision regarding adoption of mandatory standards for Québec.
2. NERC Reliability Standards adopted as mandatory July 2011 in Nova Scotia.
3. Adoption of NERC Reliability Standards ongoing in Alberta.
4. Implementing regulations being developed in Manitoba.
5. Implementing regulations being developed in British Columbia.

FERC Orders Issued Since the Last Update

1. July 13, 2011 – Order Nos. 748-A and 749-A – Order on Clarification in which the Commission granted NERC's request for clarification of certain aspects of Order No. 748 including: (1) the proper effective date language for Reliability Standard IRO-004-2; (2) the correct version identification for the approval of EOP-001 intended by the Commission; and (3) the proper effective date for Reliability Standard EOP-001-2. The Commission also granted NERC's request for clarification of Order No. 749 with respect to the version EOP-001 the Commission intended to approve and its effective date. *Docket Nos. RM10-15-001 and RM10-16-001*
2. July 20, 2011 – Commission found there is insufficient consensus for the five families of smart grid interoperability standards under consideration and declined to institute a rulemaking proceeding with respect to these standards and terminated this docket. *Docket No. RM11-2-000*
3. July 21, 2011 – Commission denied Nebraska Public Power District's and Southwest Power Pool Regional Entity's requests to permit transfer of the Nebraska Entities' compliance registrations from Midwest Reliability Organization to Southwest Power Pool Regional Entity. *Docket Nos. RR11-1-000, RR11-1-001*
4. July 29, 2011 – Order on Notices of Penalty – June 29, 2011 Notices of Penalty –The Commission issued an Order stating that it would not further review, on its own motion, the following Notices of Penalty in *Docket Nos. NP11-201-000* Lane Electric Cooperative Inc.; *NP11-202-000* High Desert Power Project, LLC; *NP11-203-000* City of Loveland, Colorado; *NP11-204-000* Unidentified Registered Entity; *NP11-205-000* Unidentified

Registered Entity; *NP11-206-000* Unidentified Registered Entity; *NP11-207-000* Troy Energy, LLC; NP11-208-000 Black Hills/Colorado Electric Utility Co.; *NP11-209-000* Blachly-Lane Electric Cooperative; *NP11-210-000* Indianapolis Power & Light Co.; *NP11-211-000* Unidentified Registered Entity; *NP11-212-000* Unidentified Registered Entity; *NP11-213-000* Unidentified Registered Entity; *NP11-214-000* T.E.S. Filer City Station, LP; *NP11-215-000* Boise-Kuna Irrigation District; *NP11-216-000* Merced Irrigation District; *NP11-217-000* High Trail Wind Farm, LLC; *NP11-218-000* Unidentified Registered Entity; *NP11-219-000* City of Batavia Municipal Electric ; *NP11-220-000* Elwood Energy, LLC; *NP11-221-000* Columbia Rural Electric Assoc.; *NP11-222-000* Luminant Energy Co.; *NP11-223-000* Unidentified Registered Entity; *NP11-224-000* Alcoa Power Generating Inc.; *NP11-225-000* Unidentified Registered Entity; *NP11-226-000* Unidentified Registered Entity; *NP11-227-000* Springfield Utility Board and *NP11-228-000* Administrative Citation NOP.

5. August 2, 2011 – Order Approving Reliability Standard CIP-001-2a Sabotage Reporting with a Regional Variance for Texas Reliability Entity, Inc. *Docket No. RD11-6-000*

6. August 22, 2011 – Notice of FERC Audit of NERC – The Division of Audits in the Office of Enforcement of FERC commenced an audit of NERC. *Docket No. FA11-21-000*

7. August 25, 2011 – Letter Order Approving NERC's December 1, 2010 Standards Process Manual Filing in compliance with FERC's September 2010 Order. *Docket No RR10-12-001*

8. August 29, 2011 – Order on Notices of Penalty – July 28 and July 29, 2011 Notices of Penalty – The Commission issued an Order stating that it would not further review, on its own motion, the following Notices of Penalty in *Docket Nos. NP11-229-000* Unidentified Registered Entity; *NP11-230-000* Unidentified Registered Entity; *NP11-231-000* Ripon Cogeneration LLC; *NP11-232-000* The Detroit Edison Company; *NP11-233-000* Unidentified Registered Entity; *NP11-234-000* Unidentified Registered Entity; *NP11-235-000* New Covert Generating Company, LLC; *NP11-236-000* Scurry County Wind LP; *NP11-237-000* Unidentified Registered Entity; *NP11-239-000* Public Utility District No. 1 of Snohomish County; *NP11-240-000* Public Service Company of New Mexico; *NP11-241-000* Dynegy Inc.; *NP11-242-000* Panoche Energy Center LLC; *NP11-243-000* Unidentified Registered Entity; *NP11-244-000* NextEra Energy Resources, LLC; *NP11-245-000* Exelon Generation Co., LLC; *NP11-246-000* Scrubgrass Generating Company, LP; *NP11-247-000* Unidentified Registered Entity; *NP11-248-000* Unidentified Registered Entity; *NP11-249-000* Unidentified Registered Entity; *NP11-250-000* Unidentified Registered Entity; *NP11-251-000* Unidentified Registered Entity; *NP11-252-000* Arizona Electric Power Cooperative, Inc.; *NP11-253-000* Administrative Citation Notice of Penalty.

9. August 29, 2011 – The Commission issued an order initiating a review of the July 28, 2011 Notice of Penalty for Southwestern Power Administration and established a filing deadline for any answers, interventions or comments. *Docket No. NP11-238-000*

10. August 29, 2011 – The Commission approves the Stipulation and Consent Agreement between the Office of Enforcement, NERC, and Grand River Dam Authority. *Docket No. IN11-7-000*
11. September 9, 2011 – The Commission issued an Order stating that it would not further review, on its own motion, the following Notice of Penalty regarding an Unidentified Registered Entity. *Docket No. NP11-184-000*
12. September 9, 2011 – The Commission issued an Order stating that it would not further review, on its own motion, the following Notices of Penalty in *Docket Nos. NP11-254-000* Rochester Public Utilities; *NP11-255-000* AES Deepwater, Inc.; *NP11-256-000* Progress Energy Florida; *NP11-257-000* Optim Energy Marketing, LLC; *NP11-258-000* Iberdrola Renewables and *NP11-259-000* Western Electricity Coordinating Council.
13. September 15, 2011 – Notice of Proposed Rulemaking proposing to approve the Transmission Relay Loadability Standard PRC-023-2 and accompanying NERC Rules of Procedure modifications. *Docket No. RM11-16-000*
14. September 15, 2011 – Order No. 754 – Order Approving Interpretation of TPL-002-0 Requirement R1.3.10. *Docket No. RM10-6-000; Order No. 754*
15. September 15, 2011 – Notice of Proposed Rulemaking on Version 4 CIP Reliability Standards proposed to approve eight modified Critical Infrastructure Protection (CIP) Reliability Standards, CIP-002-4 through CIP-009-4. *Docket RM11-11-000*
16. September 15, 2011 – Order No. 733-B – Order Denying Reconsideration and Granting Clarification in Part and Denying Clarification in Part regarding the requests for clarification or reconsideration of Order No. 733-A, which addressed requests for rehearing and clarification of FERC's Final Rule on NERC Reliability Standard PRC-023-1 regarding "Relay Loadability." *Docket No. RM08-13-004*
17. September 15, 2011 – Order Approving Personnel Performance, Training, and Qualification Reliability Standard PER-003-1. *Docket No. RD11-7-000*
18. September 15, 2011 – Order No. 753 – Order Approving ERO Interpretation of Transmission Operations Reliability Standard TOP-001-1 Requirement R8. *Docket No. RM10-29-000; Order No. 753*
19. September 21, 2011 – A Technical Conference on Penalty Guidelines to discuss the impact of the guidelines on compliance and enforcement matters will be held on November 17, 2011. *Docket No. PL10-4-000*
20. September 26, 2011 – Order Approving Interpretations to PRC-004-1 and PRC-005-1. *Docket No. RD11-5-000*
21. September 26, 2011 – A Technical Conference on CIP-006-2 to explore the risks of leaving dial-up intelligent electronic devices that are part of the Bulk-Power System and that use non-routable protocols physically unprotected will be held on October 25, 2011. *Docket No. RD10-8-000*

22. September 30, 2011 – Order on Notices of Penalty – August 31, 2011 Notices of Penalty – The Commission issued an Order stating that it would not further review, on its own motion, the following Notices of Penalty in *Docket Nos. NP11-260-000* Louisiana Energy and Power Authority; *NP11-261-000* Unidentified Registered Entity; *NP11-262-000* Unidentified Registered Entity; *NP11-263-000* Unidentified Registered Entity; *NP11-264-000* Unidentified Registered Entity; *NP11-265-000* Cleco Corporation; and *NP11-266-000* Administrative Citation Notice of Penalty.

NERC Filings Since the Last Update

1. July 13, 2011 - Comments in Support of the Supplemental Comments in the July 13, 2011 filing of the Trade Associations (Edison Electric Institute, the American Public Power Association, the National Rural Electric Cooperative Association, the Electric Power Supply Association, the Transmission Access Policy Study Group, and the Canadian Electricity Association) regarding the proposed interpretation of Reliability Standard TPL-002, Requirement R1.3.10. *Docket No. RM10-6-000*
2. July 15, 2011 - Supplemental Informational Filing regarding the June 29, 2011 Notice of Penalty for an Unidentified Registered Entity. *Docket No. NP11-213-000*
3. July 18, 2011 - Request for Clarification or, in the Alternative, Rehearing of the Order Denying Appeals of Compliance Registry Determinations of Milford Wind Corridor Phase I, LLC, and Cedar Creek Wind Energy. *Docket Nos. RC11-1-001 and RC11-2-001*
4. July 20, 2011 - Supplemental Filing for a Notice of Penalty regarding an Unidentified Registered Entity. *Docket No. NP11-206-000*
5. July 21, 2011 - Filing in Support of the June 20, 2011 compliance filing of the Western Electricity Coordinating Council in Response to Order Numbers 751 and 752 on Version One Regional Reliability Standards. *Docket No. RM11-11-000*
6. July 21, 2011 - Informational Filing in Response to Order 733-A on Rehearing, Clarification, and Request for an Extension of Time addressing certain aspects of the August 14, 2003 blackout investigation relative to operation of protective relays in response to stable power swings. *Docket No. RM08-13-000*
7. July 26, 2011 - Informational Report on NERC Standards Status and Timetable for Addressing Regulatory Directives received from applicable ERO governmental authorities. *Docket No. RR09-6-003*
8. July 28, 2011 – Notices of Penalty regarding the following entities in *Docket Nos. NP11-229-000* Unidentified Registered Entity; *NP11-230-000* Unidentified Registered Entity; *NP11-231-000* Ripon Cogeneration LLC; *NP11-232-000* The Detroit Edison Company; *NP11-233-000* Unidentified Registered Entity; *NP11-234-000* Unidentified Registered Entity; *NP11-235-000* New Covert Generating Company, LLC; *NP11-236-000* Scurry County Wind LP; *NP11-237-000* Unidentified Registered Entity; *NP11-239-000* Public Utility District No. 1 of Snohomish County; *NP11-240-000* Public Service Company of New Mexico; *NP11-241-000* Dynegy Inc.; *NP11-242-000* Panoche Energy Center LLC; *NP11-243-000* Unidentified Registered Entity; *NP11-244-000* NextEra Energy Resources, LLC;

NP11-245-000 Exelon Generation Co., LLC; *NP11-246-000* Scrubgrass Generating Company, LP; *NP11-247-000* Unidentified Registered Entity; *NP11-248-000* Unidentified Registered Entity; *NP11-249-000* Unidentified Registered Entity; *NP11-250-000* Unidentified Registered Entity; *NP11-251-000* Unidentified Registered Entity; and *NP11-252-000* Arizona Electric Power Cooperative, Inc.

9. July 29, 2011 - Informational Report on Analysis of Standard Process Results for the Second Quarter 2011. *Docket Nos. RR06-1-000, RR09-7-000*

10. July 29, 2011 – Administrative Citation Notice of Penalty in *NP11-253-000*.

11. August 11, 2011 - Motion to Further Defer Action on Time Error Correction Reliability Standard. *Docket No. RM09-13-000*

12. August 11, 2011 – Notices of Penalty regarding the following entities in *Docket Nos. NP11-254-000* Rochester Public Utilities; *NP11-255-000* AES Deepwater, Inc.; *NP11-256-000* Progress Energy Florida; *NP11-257-000* Optim Energy Marketing, LLC; *NP11-258-000* Iberdrola Renewables and *NP11-259-000* Western Electricity Coordinating Council.

13. August 24, 2011 - Request of NERC for Acceptance of 2012 Business Plan and Budget and the 2012 Business Plans and Budget of Regional Entities and for Approval of Proposed Assessments to Fund Budgets. *Docket No. RR11-7-000*

14. August 31, 2011 - Second Quarter 2011 Compliance Filing in Response to Paragraph 629 of Order No. 693. *Docket No. RM06-16-000*

15. August 31, 2011 – Notices of Penalty regarding the following entities in *Docket Nos. NP11-260-000* Louisiana Energy and Power Authority; *NP11-261-000* Unidentified Registered Entity; *NP11-262-000* Unidentified Registered Entity; *NP11-263-000* Unidentified Registered Entity; *NP11-264-000* Unidentified Registered Entity; *NP11-265-000* Cleco Corporation; and *NP11-266-000* Administrative Citation Notice of Penalty.

16. September 6, 2011 – Supplemental Informational Filing regarding the August 31, 2011 Administrative Citation Notice of Penalty. *Docket No. NP11-266-000*

17. September 9, 2011 - Petition for Approval of Interpretations to Requirements to Requirements R1 and R3.2 of EOP-001-0 — Emergency Operations Planning (EOP-001-0). *Docket No. RM11- 32-000*

18. September 13, 2011 - NERC and WECC submit a joint motion for extension of time from September 14, 2011 to November 14, 2011 to allow NERC to submit a compliance filing in response to the Commission's June 16, 2011 Order regarding the registration of Cedar Creek Wind Energy, LLC and Milford Wind Corridor Phase I, LLC. The Commission directed NERC to submit a compliance filing identifying the Reliability Standards and Requirements that will be applicable to Cedar Creek and Milford. *Docket Nos. RC11-1-000 and RC11-2-000*

19. September 19, 2011Additional Comments in Support of the Notice of Penalty filed on July 28, 2011 regarding Southwestern Power Administration. *Docket No. NP11-238-000*

20. September 28, 2011 - First Annual Report on Wide-Area Analysis of Technical Feasibility Exceptions. *Docket No. RR10-1-000*
21. September 30, 2011 - Petition Requesting Approval of New Enforcement Mechanisms and Submittal of Initial Find Fix and Track (FFT) Informational Filing. *Docket No. RC11-6-000*
22. September 30, 2011 - Notices of Penalty regarding the following entities in *Docket Nos. NP11-267-000* Metropolitan Edison Company; *NP11-268-000* Electric Reliability Council of Texas, Inc.; *NP11-269-000* Unidentified Registered Entity; and *NP11-270* Spreadsheet Notice of Penalty.
23. October 3, 2011 - Motion to Intervene and Comments regarding the appeal of the City of Holland, Michigan Board of Public Works. *Docket No. RC11-5-000*

Anticipated NERC Filings

1. October 14, 2011 – NERC will file a Petition for Approval of Revised Transmission Planning System Performance Requirements Reliability Standard and Seven Glossary Terms and for Retirement of Six Existing Reliability Standards for the TPL-001-2 standard.
2. November/December 2011 – NERC will submit proposed changes to the NERC Rules of Procedure.
3. November 21, 2011 – NERC must submit comments in response to the September 15, 2011 Transmission Relay Loadability Notice of Proposed Rulemaking. *Docket No. RM11-16-000*
4. November 21, 2011 – NERC must submit comments in response to the September 15, 2011 Version 4 Critical Infrastructure Protection Reliability Standards Notice of Proposed Rulemaking. *Docket No. RM11-11-000*
5. December 2011 – *Reliability Standards Development Plan: 2012-2014.* NERC is required, pursuant to Rule 310 of the NERC Rules of Procedure, to file an updated annual work plan for the development of Reliability Standards. *Docket Nos. RM05-25-000, RM05-17-000, RM06-16-000.*
6. December 31, 2011 – NERC must submit an informational filing regarding the restructured audit program of the Regional Entities. (*see* December 23, 2010) *Docket Nos. RR09-7-000* and *RR10-11-000*
7. January 25, 2012 – NERC must submit a filing within one year of the January 25, 2011 effective date of the November 18, 2010 Order regarding the Revision to ERO Definition of the Bulk Electric System. NERC's filing will include a proposed change to the definition of "Bulk Electric System" and corresponding changes to the NERC Rules of Procedure. NERC, Order No. 743, *Docket No. RM09-18-000*
8. March 15, 2012 – NERC must submit an informational filing, six months from the issuance of the Order No. 754 which approved the interpretation of Requirement

R1.3.10 of TPL-002-0, to explain whether there is a further system protection issue that needs to be addressed and if so, what forum and process should be used to address that issue and what priority it should be accorded relative to the other reliability initiatives planned by NERC. *Docket No. RM10-6-000*

9. April to June 2012 (Second Quarter 2012) – NERC's timeline to address all outstanding issues from Order No. 706 directives, anticipated that NERC will submit next version of CIP Standards to the NERC Board of Trustees. *See* NERC's May 27, 2011 Response to Data Requests, Response 1 and the 2011-2013 Informational Filing on the Standards Development Plan. *Docket Nos. RM05-17-000, RM05-25-000, RM06-16-000 and RM11-11-000*

10. May 2012 – NERC must submit a revised BAL-003 Standard (*See* October 25, 2010 NERC Filing). *Docket No. RM06-16-011*

11. May 22, 2012 –NERC and WECC will submit a revised Standard that includes the Violation Severity Levels associated with each requirement of the revised BAL-004-WECC-1 Standard (*See* May 21, 2009 Order) (*See* November 22, 2010 NERC submittal). *Docket No. RM08-12-000*

12. May 31, 2012 – NERC's true-up filing for the 2010 business plans and budgets.

13. July to September 2012 (Third Quarter 2012) – NERC's timeline to address all outstanding issues from Order No. 706 directives, anticipated that NERC will file next version of CIP Standards at FERC. *See* NERC's May 27, 2011 Response to Data Requests, Response 1 and the 2011-2013 Informational Filing on the Standards Development Plan. *Docket Nos. RM05-17-000, RM05-25-000, RM06-16-000 and RM11-11-000*

14. August 23, 2012 – NERC must address Order No. 693 Directives to consider if EMS application support personnel should be included in training Reliability Standard. *Docket No. RM09-25-000*

15. February 17, 2013 – NERC must comply with directives in Order No. 733 for filing the test and the results from a representative sample of utilities in each of the three Interconnections (*see* February 17, 2011 Order No. 733-A). *Docket No. RM08-13-001*

Agenda Item 15a
Board of Trustees Meeting
November 3, 2011

NERC Compliance and Certification Committee
Report to the NERC Board of Directors

Action
None

Background
This report provides a summary of the key activities of the Compliance and Certification Committee (CCC) and its associated subgroups in support of the NERC mission and goals and the CCC charter. These activities were performed after the last NERC Board of Trustees meeting in Vancouver, Canada.

CCC Meetings
The CCC held its quarterly meeting on September 21-22, 2011 in Denver, Colorado. The previous CCC meeting minutes of the June meeting in Chicago are posted at **http://www.nerc.com/filez/cccmin.html**.

NERC Stakeholder Effectiveness and Perception Survey Report
The CCC conducted a recent NERC Stakeholder Effectiveness and Perception Survey. The survey gathered comments with respect to stakeholders' perceptions of NERC's policies, practices and effectiveness of the Compliance program, Registration program, and Certification program. The survey results are being evaluated by the CCC, and a report will be provided to the Board of Trustees for its February 2012 meeting.

Spot Check by CCC of NERC's Compliance Monitoring and Enforcement Program and Reliability Standards Applicable to NERC
To fulfill its obligations to monitor NERC's compliance with the Rules of Procedure regarding the Compliance Monitoring and Enforcement Program and Reliability Standards applicable to NERC, the CCC will conduct spot checks of these two areas in 2011.

The spot check of the Reliability Standards applicable to NERC was conducted October 12-13 in Atlanta; the spot check of the Compliance Monitoring and Enforcement Program is scheduled for November 15-18 in Washington, D.C.

The CCC also participated in the NERC Audit Team training conducted in Atlanta by NERC staff.

NERC Standards Quality Reviews
The CCC and its representatives continue to participate on a regular basis in quality reviews as set forth in the *Standard Processes Manual*.

NERC Risk Management and Internal Controls (RMIC) Initiative

The CCC has been working with the Board of Trustees Finance and Audit Committee to structure an enterprise risk management and internal controls program. The CCC has reviewed the Board of Trustees proposal and given comments on how it believes the program will be most effective with respect to the RMIC committee and CCC interfaces.

CCC 2012 Work Plan

The CCC is preparing its 2012 Work Plan. The plan will be developed in accordance with the activities that the CCC and the RMIC coordinate. The work plan will be submitted to the Board of Trustees for approval in February 2012.

NERC Compliance and Enforcement Initiative

The CCC Chair provided comments to NERC with respect to its filing for the new Find, Fix and Track (FFT) compliance and enforcement filing.

Risk-Based Reliability Compliance Working Group (RBRCWG)

The CCC provided NERC a deliverable with regard to structuring a risk-based compliance program.

Risk-Based Reliability Compliance (RBRC) is an approach to reliability compliance where the monitoring and enforcement efforts are proportional to the actual or potential risk or harm[1] to the reliability of the Bulk Electric System (BES). For compliance monitoring this means targeted audits focused on requirements that address significant actual or potential risk to the reliability of the BES. For enforcement this means a more efficient process that focuses necessary resources on violations[2] that result in actual or potential harm to the reliability of the BES and conversely focuses minimal resources on violations that result in minimal or no harm to the reliability of the BES.

Inconsistencies in Standards Task Force

The CCC is working with NERC staff to resolve differences between the CAN and Standard Interpretation Processes.

NERC Trades Meeting

The CCC Chair participated in the NERC Trade Association Update meeting in Washington, D.C. on October 4.

W. Clay Smith
NERC CCC Chair

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[1] The Violation Risk Factors categorize the associated risk of non-compliance for specific reliability standard requirements. However, the actual or potential risk or harm to the reliability of the BES is a function of the specific facts and circumstances related to a specific violation.

[2] Includes violations discovered via any method, e.g., audits, self-reports, self-certifications, etc.

Agenda Item 15b
Board of Trustees Meeting
November 3, 2011

Critical Infrastructure Protection Committee Report

Action
None

Background
This report provides a summary of the key activities of the Critical Infrastructure Protection Committee (CIPC) and its associated subgroups in support of the NERC mission and goals and the CIPC charter. The CIPC meeting minutes for the September 14-15, 2011 meeting are on the NERC website at http://www.nerc.com/filez/cipmin.html.

CIPC Leadership Elections for 2012-2013. At its September meeting the CIPC elected a new Chair and two Vice Chairs for the 2012-2013 term. The new Chair will be Charles Abell of Ameren Corporation, and the Vice Chairs will be Jim Brenton of ERCOT and Nathan Mitchell of the American Public Power Association (APPA). The CIPC Executive Committee will be elected at the December 2011 CIPC meeting.

Critical Infrastructure Strategic Initiative – Coordinated Action Plan Activities. The CIPC, Operating Committee (OC) and Planning Committee (PC) officers and NERC staff continue to direct and manage the coordinated action plan activities as they relate to the recently created task forces. The committee leadership accomplishes this work via conference calls and in-person meetings as needed.

Classified Briefing for CIPC and Other Industry Participants. The CIPC and NERC staff have confirmed a classified secret-level briefing for CIPC members and other industry participants scheduled for 9 a.m. in Atlanta on December 14, 2011. The location in Atlanta has not yet been confirmed. We will work with our government partners to encourage the provision of quality take-away information that can be shared with industry outside of a classified environment. The efforts by DHS and DOE in this area are very much appreciated and further the goal of increasing the value of the public-private partnership.

CIPC Executive Committee Review of Draft NERC Alerts. The CIPC Executive Committee has reviewed and provided feedback to NERC staff on CIP-related draft alerts. This industry stakeholder review provides NERC with beneficial and quick feedback on draft alerts before they are finalized and issued to industry. We remain ready to provide requested feedback to NERC staff as needed on future draft alerts.

CIPC Continues to Provide a Venue for All Electricity Sub-Sector Entities to Discuss CIP Matters. The CIPC meetings provide opportunity for significant and needed discussion on various critical infrastructure protection matters, including those related to the CIP standards, copper theft, recent NERC alerts, communications with government partners, and other physical, operational and cyber security areas of concern.

CIPC Long-Term Strategic Plan. The CIPC will begin work on developing a long-term strategic plan that will use similar plans from other standing committees as a guide/model. The CIPC Executive Committee will be meeting in Atlanta on November 9-10, 2011, to begin the development of the plan. The goal is to have such a plan before the CIPC for approval at its meeting scheduled for March 2012.

CIPC Subgroup Highlights

The CIPC has five subgroups and highlights of their work assignments are shown below.

1. *Business Continuity Guideline Task Force (BCGTF).* The updated Business Continuity Guideline was approved by the CIPC at its meeting on September 14-15, 2011. The BCGTF will be assigned new work or will be retired at the December 2011 CIPC meeting.
2. *Control Systems Security Working Group (CSSWG).* The CSSWG is currently assigned the task of updating and combining nine CIPC control system-related guidelines into one or two electricity sub-sector-specific guidelines for industry use. Work on these guidelines has been delayed due to the CSSWG's need to focus on the Cyber Attack Task Force work that is also assigned.
3. *Cyber Attack Task Force (CATF).* The CSSWG has also been assigned the work of the CATF under the Coordinated Action Plan mentioned above. Work on the CATF assignment is the top priority of the CSSWG and work is proceeding on schedule with delivery to the ESCC expected to be the first or second quarter of 2012. The CATF draft report is currently out for comment to the members of the PC, OC and CIPC.
4. *Protecting Sensitive Information Guideline Task Force (PSIGTF).* The PSIGTF is currently assigned the task of updating the CIPC Protecting Sensitive Information Guideline to take into consideration recent developments and to make it more electricity sub-sector-specific. The PSIGTF is currently evaluating comments received from CIPC. After this is completed, the guideline will be posted for broad industry comment. After broad industry comments have been considered, a final version of the guideline will be submitted to CIPC for final approval by the end of 2011 or in early 2012.
5. *Substation Guideline Task Force (SGTF).* The SGTF is currently assigned the task of updating the CIPC Physical Security Substation Guideline to take into consideration recent developments and to make it more electricity sub-sector-specific. Work is underway on this task force after a leadership change with a final revised guideline expected for CIPC approval by March 2012.
6. *Future working groups or task forces* will be created as needed to address other guidelines that need to be updated, to complete work related to the Coordinated Action Plan Report, and to provide support to new or ongoing standard development work as requested by the NERC Standards Committee. Working groups and task forces will be retired when their work assignments are completed.

Operating Committee Report

Action
None

Background
This report provides a summary of the key activities of the Operating Committee (OC) and its associated subcommittees in support of the NERC or OC mission and corporate goals. All these activities support the NERC or OC mission and NERC corporate goals. The September 2011 OC meeting minutes are posted at OC Meeting Minutes September 13-14, 2011.

Critical Infrastructure Strategic Initiatives: Coordinated Action Plan
The OC was provided status reports from the Spare Equipment Database and the Geomagnetic Disturbance task forces. The committee endorsed the Spare Equipment Database report dated August 2011.

Event Analysis and Investigation Process
The OC received two presentations of lessons learned; one from Dominion Virginia Power regarding tornado damage to the Surry Nuclear Power Station and the other from Associated Electric Cooperative, Inc. regarding a generator motoring event. A WECC representative also provided a brief summary of the Arizona/Southern California/Mexico load loss event. The effort to have such event-based presentations to share timely lessons learned at each OC meeting is a priority for the committee.

Transition of the Interchange Distribution Calculator (IDC)
Frank Koza, PJM's reliability coordinator, presented an overview of the discussions taking place by the Eastern Interconnection reliability coordinators to transition the IDC, and perhaps related reliability applications, to the user community. Mr. Koza noted that the team is focusing on two business models (formation of an LLC and independent service agreements with the IDC vendor). NERC and the vendor are participating as needed to ensure a transparent and seamless transition of this important reliability tool.

North American SynchroPhasor Initiative
Austin White, Oklahoma Gas and Electric (OGE), provided an in-depth review of its use of synchrophasor data. OGE uses phasor measurement data for situation awareness, disturbance/misoperation analysis, state estimator enhancement, system stability assessment, voltage recovery assessment, and wind farm integration/monitoring, and to proactively identify electric grid equipment problems.

OC Strategic Plan
The OC spent several hours brainstorming and discussing its future strategic plan and the process for its development. The OC's intent is to have a draft of the strategic plan ready for committee approval at its December 2011 meeting, with BOT approval in first quarter 2012.

OC Subgroup Highlights

The OC now has 13 subgroups, five of which jointly report to the Planning Committee (PC) and the OC.

Joint OC/PC Subgroups Highlights

1. **Event Analysis Working Group (EAWG)** – The EAWG provided the OC a status report and expectations related to Phase Two of the Event Analysis Process Field Trial. Reporting entities submitted 107 lessons learned during the field trial and 17 of those lessons learned have been posted to the NERC website.
2. **Reliability Metrics Working Group (RMWG)** – The RMWG requested input from the OC regarding the RMWG's responses to the comments received from the posting of the Integrated Reliability Index Concepts white paper.

Other Subgroup Highlights

1. **Resources Subcommittee (RS) –** The RS and NERC staff continue to address issues related to implementation of the manual time error correction elimination field trial. NERC is meeting with the National Institute of Standards and Technology (Division of Time Control) to consider other facets related to the field trial.

   In addition, the RS developed a list of frequency events that occurred in each Interconnection for use by the RMWG in its effort to develop a frequency response metric and for use by the Frequency Response standard drafting team.

Agenda Item 15e
Board of Trustees Meeting
November 3, 2011

Personnel Certification Governance Committee Report

Action
None

New Concepts Being Considered
The Personnel Certification Governance Committee (PCGC) has updated Section 600 of the Rules of Procedure. A separate program manual and user's guide provides detailed instructions for requesting and maintaining certification, along with other program administrative information.

Future Projects
The committee does not expect to propose changes to the certification program that would require posting for comments.

The PCGC continues work on documentation of the credential establishment process and credential benchmarking. The PCGC continues to work on documenting the certification program budget process to assist in developing the PCGC budget.

NERC Certification Examination Passing Rate
Through September 30, 2011, a total of 603 exams were taken with a passing rate of 68.8 percent.

Year	# of Exams Taken	Number of Exams Passed	PASS Percent
2009	1008	652	64.7 %
2010	914	638	69.8 %
2011*	603	415	68.8 %

* Through September 30, 2011

Credential Maintenance
The certification program began allowing operators to use Continuing Education Hours to maintain their credentials on October 1, 2006. The table below shows the number of new certificates issued annually declining and credentials maintained using Continuing Education Hours increasing.

Year	Credentials Renewed	New Certificates
2006	0	943
2007	109	729
2008	833	634
2009	1,200	621
2010	1,597	638
2011*	1,384	415
Totals	**5,123**	**3,980**

* Through September 30, 2011

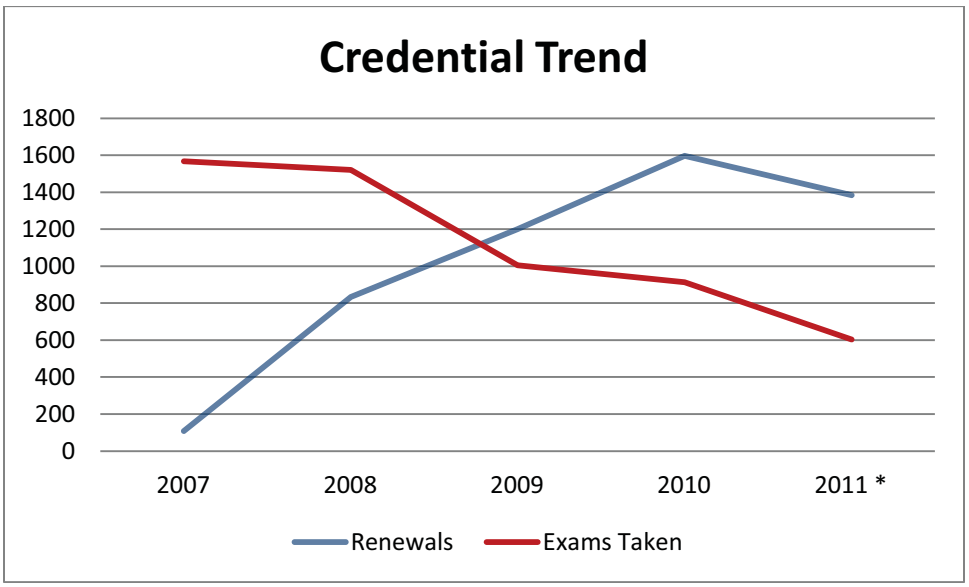

* Through September 30, 2011

Certified Operator Population
The total number of certified system operators with active credentials is 6,088. The population has continued to increase slightly since 2009.

Development of New Certification Exams
The Examination Working Group (EWG) has prepared new certification exams for each of the four credentials. New exam release is scheduled for the First quarter of 2012.

An announcement was in the NERC newsletter and exam resources are posted on the System Operator Certification site.

System Operator Demographics
Approximately 5,589 system operators have provided demographic information since data collection began in early 2009. This information combines system operators taking their initial exams with those who renewed their credentials through continuing education. Three full years are needed to survey the entire system operator population.

The following charts show current trends that are obtained from the demographics collected. Examples are included in Charts 1, 2, and 3, which provide preliminary metrics for average age of system operators, experience in system operations, and years in current position.

Chart 1 – Operator Population Age

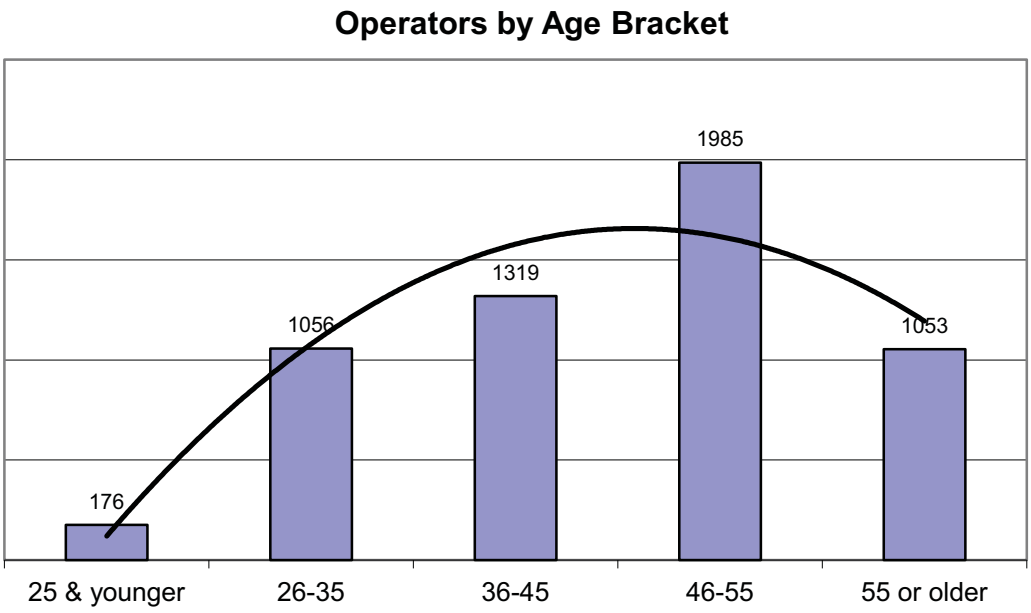

The largest age bracket for system operators is the 46-55 age bracket.
Note: 54 percent of system operators are over 45 years old.

Chart 2 – Experience in System Operations

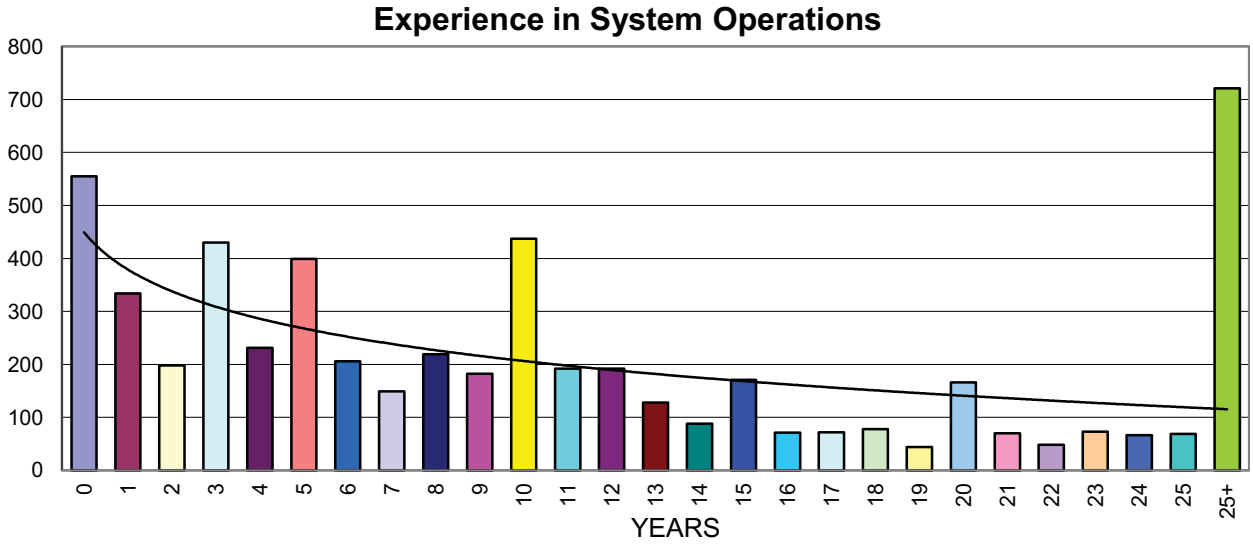

Approximately 60 percent of the certified system operators have 10 years or less experience in system operations. The average experience is nine years with seven years being the median.

Chart 3 - Experience in Position

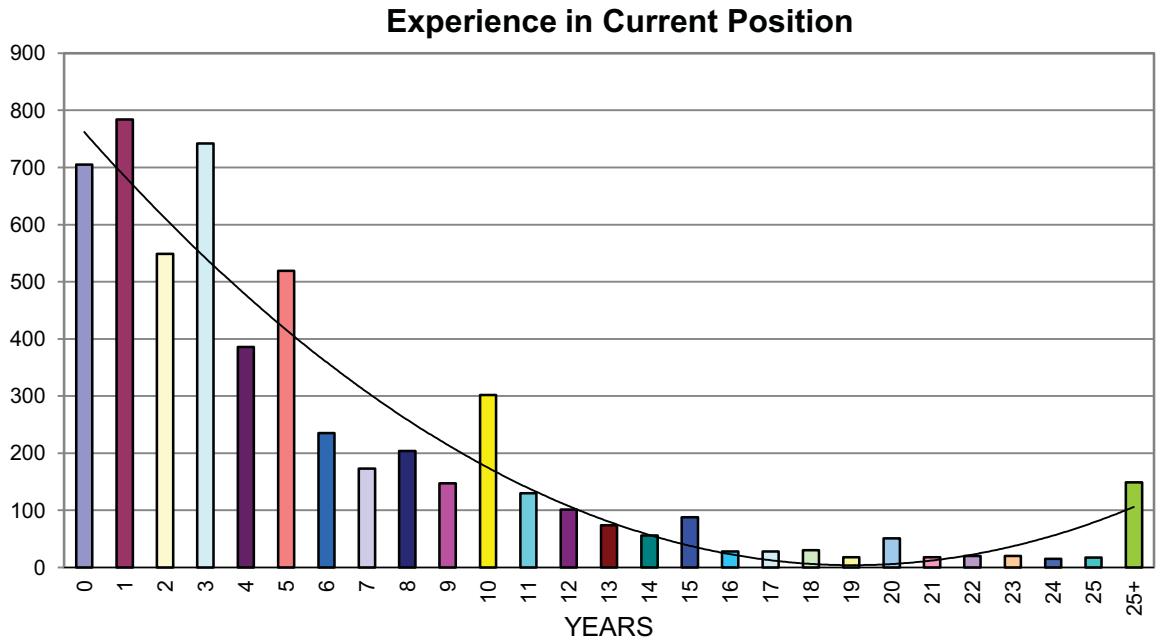

This chart indicates that 66 percent of system operators have five years or less experience in their current position with 50 percent of the population having three years or less experience performing their current position.

Agenda Item 15f
Board of Trustees Meeting
November 3, 2011

Planning Committee Status Report

Action
None

Background
The Planning Committee's (PC) September 2011 meeting was held in St. Louis, MO. The draft minutes are posted at PC DRAFT Meeting Minutes Sept 2011. The following is a summary of the key activities from the meetings and an update on PC activities.

PC Activities

1. **PC Strategic Plan:** The PC reviewed the actions called for in the approved Planning Committee Strategic Plan: Next Steps and Future Work Plan.[1] The plan disbands the following groups with the PC thanks and appreciation:

   - Resource Issues Subcommittee
   - Data Coordination Working Group
   - Load Forecasting Working Group
   - Loss-of-Load Expectation Working Group
   - Reliability Fundamentals Working Group

   The following subcommittees have a revised name, scope, and work plan:

   - Transmission Issues Subcommittee is named the System Analysis and Modeling Subcommittee (SAMS)
   - The Data Coordination Subcommittee and the Reliability Metrics Working Group were merged and named the Performance Analysis Subcommittee (PAS)

   The following Task Forces are converted to Working Groups:

   - Model Validation Task Force (Reporting to SAMS)
   - Demand Response Data Task Force (Reporting to PAS)
   - Generating Availability Data System Task Force (Reporting to PAS)

   The following working groups now report to the PAS

   - Transmission Availability Data System Working Group
   - Events Analysis Working Group

   Each of these subgroups will update their current scopes for consideration at the December 2011 meeting.

[1] http://www.nerc.com/docs/pc/PC_Strategic_Plan_Next%20Steps%20and%20Future%20Work%20Plan%207-27-2011.pdf

2. **Meeting Consolidation and Format:** Chair Mitchell reviewed the proposal of starting in 2012, PC to hold 3 meetings each year for 2 days (with ½ day for Joint Sessions) compared to 4 meetings for 1 day (with ½ day for Joint Session one time per year). Merging of the Technical Committees (OC and PC) was also discussed. PC members noted that there are benefits when common issues exist. Another suggestion is to hold the Joint meeting in the middle of the CIPC and OC/PC meetings. No decision was made on these alternatives

3. **NERC Alert Process:** The PC approved an Alert process, which calls for more coordination between Alert development and provision of expertise by the PC.

4. **Interconnection Modeling:** The PC discussed the different study requirements needed to develop a plan to improve models based on priority lists. Based on information received from the Model Validation Task Force (MVTF), recommendations can be then shared with the different interconnection-wide modeling groups (i.e., WECC, ERAG). While no definitive timelines have been set by the group, information from the MVTF is expected to be shared with the interconnection-wide modeling groups once Regional Executives have the opportunity to approve those recommendations.

5. **Consolidating Reports:** The PC decided to consolidate the analysis from ALR Metrics, IRI/SRI Metrics, TADS, GADS, DADS, Spare Equipment, Operations (Frequency), Security (CIP), and post-seasonal reliability assessments into the annual Performance Analysis Subcommittee (PAS) report on the risk to the bulk electric system reliability (See 2011 report). [2]

Joint OC/PC Subgroups Highlights

1. **Reliability Metrics Working Group (RMWG)**: The RMWG provided a draft 2011 Reliability Performance Report to the OC and PC for review in early June. Comments were requested by June 30. An integrated reliability index (IRI) to support risk informed decision making, support determining achievement of reliability goals, and assist in defining an adequate level of reliability is under development. PC feedback on the whitepaper and approval to post the whitepaper for comment was requested by September 30.

2. **Integration of Variable Generation Task Force (IVGTF):** The report, *Potential Bulk System Reliability Impacts from Distributed Resources*[3] was approved by the PC. Additional reports, per the work plan outlined in the Board Approved final report titled *Accommodating High Levels of Variable Generation*,[4] will be brought to the PC in 2012.

3. **Geomagnetic Disturbance Task Force (GMDTF):** The GMD TF is focusing on the primary concerns related to transformer vulnerability, and the appropriate wave front for characterizing a 100 year storm. Additional discussions on vetting the technical results and managing the policy input from some of the observers will require insights from the Standing Committees.

4. **Spare Equipment Database Task Force (SEDTF):** The final report, titled *Special Report: Spare Equipment Database System* was approved by the PC. This report was driven by

[2] http://www.nerc.com/files/2011RMWG_Annual_Report.pdf
[3] http://www.nerc.com/files/IVGTF_TF-1-8_Reliability-Impact-Distributed-Resources_Final-Draft_2011%20(2).pdf
[4] http://www.nerc.com/files/Special%20Report%20-%20Accommodating%20High%20Levels%20of%20Variable%20Generation.pdf

the Electricity Subsector Coordinating Council's roadmap,[5] and the Joint Steering Group Action Plan.[6]

5. **Event Analysis Working Group (EAWG**): The EAWG has published 17 lessons learned, with additional lessons learned to be released before the end of the year. The target completion date of the EA Process Document is October 1, 2011. Changes in the EA Process Document are expected to result in changes to the NERC Rules of Procedure, which the NERC Board of Trustees is expected to consider for approval in February 2012.

Other Subgroup Highlights

1. **Reliability Assessment Subcommittee (RAS):** The RAS is developing their final results for the *2011 Long-Term Reliability Assessment*. The PC was requested to approve the *2010/2011 Post-Winter Reliability Assessment.*[7] A motion to approve the report was made by Ron Mazur and unanimously approved. The PC is requested to review and provide comment on:
   - *DRAFT Special Reliability Assessment: Gas / Electric Interdependencies – PHASE I*
   - *DRAFT Special Reliability Assessment: Gas / Electric Interdependencies – PHASE II - Work Plan*
   - *DRAFT 2012 Special Reliability Assessment: Reliability Impacts of U.S. Environmental Regulations Scope*
2. **Transmission Issues Subcommittee:** The report, titled *Interconnection Criteria for Frequency Response Requirements – Determination of Interconnection Frequency Response Obligations (IFRO)*[8] was approved by the PC. The criteria are expected to provide input into the BAL-003 Standards Drafting Team, although the drafting team has already selected different criteria.
3. **System Protection and Control Subcommittee (SPCS):** Comments on the report, titled *Technical Reference Document, Use of Circuit Breaker Position Indication in Breaker Failure Protection*,[9] was requested, and the final report will be brought to the PC in December.

[5] http://www.nerc.com/docs/escc/ESCC_Critical_Infrastructure_Strategic_Roadmap.pdf
[6] http://www.nerc.com/docs/ciscap/Critical_Infrastructure_Strategic_Initiatives_Coordinated_Action_Plan_BOT_Apprd_11-2010.pdf
[7] http://www.nerc.com/files/2010-2011_PWRA.pdf
[8] http://www.nerc.com/docs/pc/tis/Agenda_Item_5.d_Draft_TIS_IFRO_Criteria%20Rev_Final.pdf
[9] http://www.nerc.com/docs/pc/spctf/SPCS_Breaker%20Failure%20Design_Draft%20for%20PC%20Approval_20110819.pdf

Agenda Item 15g
Board of Trustees Meeting
November 3, 2011

Standards Committee Report

Action
None

Background
This report highlights some of the key activities of the Standards Committee (SC) and its associated subcommittees in support of ERO Enterprise goals. The SC meets monthly and its meetings minutes are posted at http://www.nerc.com/filez/scmin.html.

Process Efficiencies
The SC is closely monitoring two separate activities aimed at improving efficiency – one aims at improving efficiency of developing a new standard (Rapid Development)and one aims at improving efficiency of processing a focused revision to a standard as an alternative to developing an interpretation (Rapid Revision).

Under the Rapid Development process, a small group of content experts, armed with all the technical documentation needed to support development of a new or significantly revised standard, works with support of compliance personnel and either a lawyer or a technical writer to develop the initial draft of the proposed standard. The small team will work in a focused manner to develop the entire standard over a single multi-day period. In parallel, the SC will form a separate drafting team with more diverse industry representation. The SC will post the initial draft standard for stakeholder comment and assign the new drafting team to take over the refinement of the standard through successive postings and comment periods. As envisioned, a standard developed under the Rapid Development process could be completed (from the initial posting through the final recirculation ballot) in 12 months. The Rapid Development process is being tested with Project 2010-05.1 — Protection Systems: Phase 1 (Misoperations).

Under the Rapid Revision process, a small group of content experts, armed with a request for an interpretation, works to revise only the portion of the standard that needs clarification. The revised standard is then submitted to the SC for posting to collect stakeholder comments in parallel with an initial ballot. As envisioned, a minor revision to a standard that provides clarity sought through an interpretation could be completed (from the initial posting through the final recirculation ballot) in less than six months. The Rapid Revision process is being tested with Project 2011-INT-01 MOD-028-2 — Area Interchange Methodology.

Roles and Responsibilities Document Updated
The Roles and Responsibilities document was originally issued by the SC to all drafting teams in 2009 to provide clarity on the roles of the SC, drafting teams, NERC staff, and FERC staff. While the SC made several edits to this document to bring the language into conformance with changes to the standards process that have been implemented since the document was

originally issued, the most significant revision was to add clarity to the role of NERC staff in submitting technical comments on proposed standards and interpretations.

During its November 2009 meeting the board directed the SC to ensure that the comments of NERC staff and other stakeholders are considered and reported to the board. While this direction was developed in response to differences of opinions offered on an interpretation following the balloting of that interpretation, the same approach is applicable to proposed standards. The intent was to ensure that the views of all interested parties were properly considered prior to completing the interpretation or standard. The SC revised the Roles and Responsibilities document to clarify that NERC staff may submit technical comments on proposed standards, and have those comments addressed by the drafting team, in the same manner as comments submitted by any other stakeholder. If the drafting team disagrees with those comments, the disagreement will be reported to the board as an unresolved minority issue in the same manner as other stakeholders' unresolved issues are reported to the board when a standard or interpretation is presented for board action.

Increased Stakeholder Outreach

In support of the findings in the Three-year ERO Performance Assessment, the SC continues to seek opportunities to increase communications with stakeholders, particularly with smaller stakeholders who may not have the resources necessary to dedicate personnel to joining drafting teams or tracking standards development efforts.

- The SC held a "State of Standards" webinar in July that included over 700 participants.
- The SC is providing support to the second Standards and Compliance workshop this year. (October 26-28, 2011)
- The SC is working closely with the standards staff in developing a series of brief one or two page documents that provide quick facts on issues such as Rapid Development, the Bulk Electric System (BES) Definition, and the Reliability Standard Development Plan.
- The SC is also working with the standards staff to identify possible improvements to the standards website, with a goal of making information easier to find.
- The SC continued a program started in 2010 of meeting face-to-face with drafting team leadership to discuss issues and ideas with a goal of improving the standards development process. (October 11, 2011)

If members of the Board of Trustees have questions or need additional information, they may contact Herb Schrayshuen at herb.schrayshuen@nerc.net or Allen Mosher at amosher@publicpower.org.

Agenda Item 15h
Board of Trustees Meeting
November 3, 2011

Electricity Sub-Sector Coordinating Council (ESCC) Report

Action
None

Background
This report summarizes key activities of the ESCC in support of the NERC mission and corporate goals related to critical infrastructure. The ESCC consists of a member from the NERC Board of Trustees, NERC's CEO, five CEO-level executives appointed by the Member Representatives Committee broadly representative of NERC member organizations, the chair of the NERC Critical Infrastructure Protection Committee (CIPC), and NERC's Chief Security Officer. The ESCC fosters and facilitates the development of policy-related initiatives to improve the reliability and resilience of the electricity sub-sector, including physical and cyber security. ESCC open meeting minutes are posted at: http://www.nerc.com/filez/escc.html.

Summary of August 16, 2011 ESCC Closed Meeting

Monitoring Progress to Implement the Critical Infrastructure Strategic Roadmap
Progress regarding the work of the Task Forces established to implement the *Coordinated Action Plan* is a standing ESCC agenda item through 2011. The ESCC continues to provide guidance and support to the Joint Steering Group[1] (JSG) and task forces assigned under the NERC technical committees to implement these initiatives.

- Geomagnetic Disturbance Task Force
- Cyber Attack Task Force
- Spare Equipment Database Task Force
- Severe Impact Resilience Task Force

Task Force Chairs attended this in-person meeting to discuss in detail the status of their work and expected outcomes. The Chair of the Severe Impact Resilience Task Force was unable to attend and will provide an update at a future ESCC meeting. ESCC members expressed satisfaction with the extent of task force efforts to-date, and anticipate discussing how best to communicate the results of these efforts broadly across the industry as the task forces complete their work. Notably, the Spare Equipment Database Task Force has received approval of their final report by the NERC technical committees at their September meetings and will be seeking endorsement by the Board of Trustees at its November 3, 2011 meeting.

[1] The Joint Steering Group (JSG) consists of senior NERC staff and the leadership of the Planning, Operating and Critical Infrastructure Protection technical committees.

The ESCC discussed the critical infrastructure initiatives underway by NERC and the electricity industry with senior officials from the U.S. Department of Energy (DOE) and Department of Homeland Security (DHS). Topics included:

- The ESCC's endorsement of the new *Roadmap to Achieve Energy Delivery Systems Cybersecurity*
- ESCC comments on DHS' draft National Risk Profile
- DHS reports: "Insider Threat to Utilities" and "Anonymous and Associated Hacker Groups"
- DHS' PS-PREP Framework Guide
- The need for a process to allocate security clearances across the industry

Summary of August 16, 2011 ESCC Open Meeting

During the open portion of the meeting, Chair Gerry Cauley provided a brief summary of items discussed during the closed portion of the meeting. In addition, the ESCC was briefed on a number of other security-related matters:

- Recent NERC Industry Advisories
  - Telephony-Enabled Weakness
  - PLC Protocol Weakness
- NERC's Draft Crisis Plan
- NERC Grid Cyber Exercise, November 16-17, 2011
- NERC Security Summit, October 17-20, 2011
- DOE/NIST/NERC Risk Management Framework

Future ESCC conference calls and meetings are scheduled as follows:

- October 18, 2011 2:00-3:00 pm OPEN conference call
- November 15, 201 1 2:00-4:00 pm CLOSED conference call
- Meetings have been scheduled through 2012

REMG

REGIONAL ENTITY MANAGEMENT GROUP

SARAH ROGERS – FRCC | ED SCHWERDT – NPCC | SCOTT HENRY – SERC | NE LANFORD
DAN SKAAR – MRO | TIM GALLAGHER – RFC | STACY DOCHODA – SPP RE | MARK MAHER – WECC

Date: October 14, 2011

Memo to: NERC Board of Trustees

From: Tim Gallagher, REMG Chair

Subject: Regional Entity Report for the November Board Meeting

The Regional Entities appreciate this opportunity to provide input to the NERC Board of Trustees. All of the Regional Entities take seriously our need to be as consistent as possible in discharging our delegated responsibilities. A key activity toward meeting this objective is our constant collaboration and interaction with each other and NERC. Below are summaries of recent activities of some of the key multi-Regional groups. We also have provided a statement from the Regional Entities regarding the Compliance Enforcement Initiative.

Subgroup: **ERO-Compliance and Enforcement Management Group (ECEMG)**
The ECEMG's purpose is to provide operational and day-to-day policy guidance in the execution of the Regional Entity delegation agreements and the NERC Rules of Procedure, specifically as it pertains to executing the Compliance Monitoring and Enforcement Program (CMEP). The primary initiative of ECEMG is to obtain consistency and uniformity where appropriate, across the ERO enterprise (NERC and the Regional Entities), while ensuring efficient and effective use of resources in executing the statutory responsibilities of the ERO.

Status of current high priority work items:

1. Compliance Enforcement Authority (CEA) Staff Training: Consistent, standardized, effective training for compliance staff continues to be a topic and area of discussion.

2. GO/GOP Registration Directive: A draft Directive has been prepared refining registration requirements for GO/GOP with TO/TOP facilities and functions. This directive is an interim document to provide some clarity and guidance while appropriate standards are revised. Solicit industry for review and comment, finalize, provide to the regions, and post on the NERC website.

   We will continue to work with the NERC Standards Department and Standards Drafting Team as the project to revise the standards continues. The ultimate goal is that once all appropriate standards are revised this directive will be rescinded.

3. Risk Based Reliability Compliance Monitoring: The ECEMG has spent considerable time discussing and scoping the various aspects of this initiative. Several regions are already conducting entity risk assessments and working with entities as part of pilot programs.

Other Assignments from ERO EMG

4. Multi-Region Registered Entity (MRRE) Program: This program will remain an informal process for now. Will encourage large entities to work with their Regional Entities to determine a lead for CMEP activities.

Future Work

5. Customized Self-Certification Forms: This suggestion came from the ERO Enforcement focus group as part of the Compliance Enforcement Initiative. The use of ICP and internal controls to reduce requirements for Self-Cert will also be considered.

Subgroup: **ERO-Reliability Assessments and Performance Analysis Group (ERO-RAPA)**
The ERO RAPA coordinates reliability assessment work across the Regional Entities. Current activities underway include tracking and trending of protective relay mis-operations, improved Interconnection modeling, training for TADS, GADS, and DADs, and feedback on the 'Cold-Snap' report.

Subgroup: **CIP Compliance Working Group (CCWG)**
The CCWG coordinates Regional Entity efforts regarding the monitoring of NERC's CIP Standards. The group meets monthly via phone and quarterly via face-face meetings.

Latest Top Priorities include the following and were approved by the ECEMG on 10/6/11:

1. Develop a CCWG MOSS Site – SharePoint Collaboration Site
2. Develop a CIP Auditor Handbook consisting of Regional CIP Auditor Workbook and Regional CIP Knowledge Sharing topics
3. TFE Process development – Led by NERC and managed by regional TFE Administrators (CCWGT – subgroup of CCWG)
4. Regional Evidence & Data Handling Process Development – Ongoing
5. Support ERO Auditor and CIP Auditor workshops, as required

Subgroup: **Enforcement Sanction Mitigation Working Group (ESMWG) –**
The ESMWG provides a forum for coordination of enforcement matters across the Regional Entities.

In 2011, the ESMWG focused on implementing solutions to streamline violation processing. In addition, the ESMWG focused on improving the CMEP. It provided recommendations to the ECEMG on all sections pertaining to Enforcement and Mitigation as well as the NERC Penalty Sanction Guidelines. Currently, the ESMWG is focusing on reliability risk assessments, FFT processing, dismissals, and CIP NOP processing. The ESMWG, as always, continues to focus on inter-regional collaboration pertaining to Enforcement and Mitigation topics.

Subgroup: **Compliance Monitoring Process Working Group (CMPWG)**
The Compliance Monitoring Process Working (CMPWG) reports to the ECEMG and has the mission of developing and maintaining processes and procedures to provide consistency among the regions in performance of their delegated task of monitoring the registered entities. This group has oversight for the eight monitoring processes utilized by the regions.

Currently, the CMPWG has the following top projects assigned by the ECEMG:

- Update Compliance Auditor Manual
- Update Audit and Spot Check Report Templates

- Develop Audit Approaches for Operations & Planning Standards to be part of Auditor Manual

Some on-going priorities are:

- Explore avenues to share best practices among the regions and entities
- Identify areas where the conduct of an audit can be improved
- Work with other working groups on the development of projects

Some projects completed in 2011:

- Reviewed and Updated QRSAWs for 2012
- Supported ERO Workshops
- Finalized Sampling Methodology and Criteria
- Created audit approaches for high profile standards
- Presented PRC-023 and MOD Audit Approach seminars

Subgroup: **Compliance Information Management Group (CIMG)**
The CIMG is working to revise the current Self-Report and Self-Certification reporting forms to incorporate the new Find, Fix, Track and Report (FFT) process. The CIMG has identified discrepancies in the Regional Self-Certification process (e.g. versions of standards required, schedules, notifications to the Registered Entities, Self-Certification reviews, and processing possible violations) and is working to align across all Regions. Formal recommendations will be submitted to the ECEMG.

The next focus for the CIMG is to document the process for synching data from Regional systems to NERC's Compliance Reporting, Analysis and Tracking System (CRATS). The goal is to document a consistent approach for submitting data from the Regions to NERC and a consistent approach to data sharing from NERC to the Regions. This will include the transmittal of documents from the Regions to NERC via a web service. Other tools and systems the Regions are utilizing to manage their data will be demonstrated and discussed among the Regions during future meetings.

The CIMG is looking to work in conjunction with the Certification and Registration Working Group (CRWG), Compliance Monitoring Processes Working Group (CMPWG), CIP Compliance Working Group (CCWG), and Enforcement, Sanctions, and Mitigation Working Group (ESMWG), to develop tools to manage data from processes identified from these working groups.

NERC Compliance Enforcement Initiative
All the Regional Entities are supportive of NERC's Compliance Enforcement Initiative and are committed to contributing to its success. We will continue to work with Registered Entities to focus resources on where they can have the greatest impact towards addressing risk and improving reliability. We stress, though, that while the first phase of the CEI is an excellent first step toward a more risk-based approach to our work, this is not the end of the journey. We look forward to the implementation of phases II and III of the CEI and to working with NERC staff and the industry on further advances toward our common goal in the future.

North American Transmission FORUM

Report to the NERC Board of Trustees

November 3, 2011

New Desktop Metrics App for Forum Members

Forum members can now create their own custom benchmarking reports from the data they submit to NERC TADS. After downloading the latest set of webTracker data (our version of **NERC's webTADS**) into Microsoft Access, a Forum member can then chose which other Forum members it wants to compare itself with, select the metrics, decide among various built-in report algorithms, and create Excel graphs within a matter of minutes.

The Access database was developed by the Forum members themselves, and adding new reports and statistical analyses is very simple.

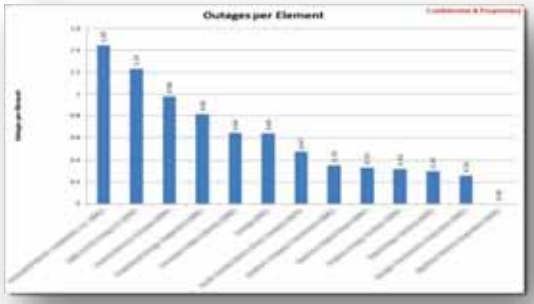

Example of a bar graph produced by Outage Metrics Database showing outages per transmission element for several Forum members. Other reports are available.

Working with the NERC Staff

To keep the Forum's webTracker metrics database in synch with NERC TADS requires a close working relationship between our respective staffs (in this case, Chris Johnson of the Forum staff and **Jim Robinson** of NERC). And this is true with the other Forum programs as well. Our director of security, Karl Perman and **Mark Weatherford** have set up regular phone calls, and Don LeKang and **Mike Moon** and **Valerie Agnew** talk every couple of weeks.

Roman Carter sends the Forum staff draft alerts to review, and we provide a quick turnaround from our various practice groups. The most recent draft advisory on relay maintenance will also provide us with ideas for new Forum practices. We hope NERC will continue to ask the Forum for this kind of assistance. Not only does it provide NERC with a wide perspective and diversity of opinions, the Forum will also ensure the alert, once it's released, will receive wide distribution directly to the subject matter experts.

Tom Galloway, the Forum's new CEO, will help ensure our relationship with NERC remains effective.

Forum Practice Groups

1. Compliance
2. Human Performance
3. Maintenance
4. Modeling
5. Operator Tools
6. Operator Training
7. Security
8. System Protection
9. Vegetation

NERC Standards

All of our practice groups (see list at right) follow the progress of NERC's standards under development, as well as changes to NERC rules and definitions, such as the current efforts to define "bulk electric system." Forum members who serve on NERC standard drafting teams report at our groups' monthly Web meetings and annual workshops on the latest drafts and balloting schedules. This keeps our members apprised of the latest changes and provides the drafting team members with an opportunity to discuss the details of the standards with their colleagues every month.

We've been following FAC -003-2 very closely, and expect that it will have been approved in its recirculation ballot. Even though the new version will not be in place for several months, our Vegetation Management Practices Group will begin revising our practices early next year to align with the changes in the standard and help the Forum members implement the provisions of this new version.

Glossary of Terms Used in NERC Reliability Standards
Updated August 4, 2011

Introduction:
This Glossary lists each term that was defined for use in one or more of NERC's continent-wide or Regional Reliability Standards and adopted by the NERC Board of Trustees from February 8, 2005 through August 4, 2011.

This reference is divided into two sections, and each section is organized in alphabetical order. The first section identifies all terms that have been adopted by the NERC Board of Trustees for use in continent-wide standards; the second section identifies all terms that have been adopted by the NERC Board of Trustees for use in regional standards. (WECC, NPCC and ReliabilityFirst are the only Regions that have definitions approved by the NERC Board of Trustees. If other Regions develop definitions for approved Regional Standards using a NERC-approved standards development process, those definitions will be added to the Regional Definitions section of this glossary.)

Most of the terms identified in this glossary were adopted as part of the development of NERC's initial set of reliability standards, called the "Version 0" standards. Subsequent to the development of Version 0 standards, new definitions have been developed and approved following NERC's Reliability Standards Development Process, and added to this glossary following board adoption, with the "FERC approved" date added following a final Order approving the definition.

Immediately under each term is a link to the archive for the development of that term.

Definitions that have been adopted by the NERC Board of Trustees but have not been approved by FERC, or FERC has not approved but has directed be modified, are shaded in blue. Definitions that have been remanded or retired are shaded in orange.

Any comments regarding this glossary should be reported to the following: sarcomm@nerc.com with "Glossary Comment" in the subject line.

Continent-wide Definitions:

A....4
B....8
C....10
D....14
E....17
F....19
G....22
H....22
I....23
J....25
L....26
M....26
N....27
O....30
P....33
R....35
S....40
T....43
V....46
W....46

Regional Definitions

ReliabilityFirst Regional Definitions 48

NPCC Regional Definitions 49

WECC Regional Definitions 50

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Adequacy [Archive]		2/8/2005	3/16/2007	The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
Adjacent Balancing Authority [Archive]		2/8/2005	3/16/2007	A Balancing Authority Area that is interconnected another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
Adverse Reliability Impact [Archive]		2/7/2006	3/16/2007	The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection.
Adverse Reliability Impact [Archive]		8/4/2011		The impact of an event that results in Bulk Electric System instability or Cascading.
After the Fact [Archive]	ATF	10/29/2008	12/17/2009	A time classification assigned to an RFI when the submittal time is greater than one hour after the start time of the RFI.
Agreement [Archive]		2/8/2005	3/16/2007	A contract or arrangement, either written or verbal and sometimes enforceable by law.
Altitude Correction Factor [Archive]		2/7/2006	3/16/2007	A multiplier applied to specify distances, which adjusts the distances to account for the change in relative air density (RAD) due to altitude from the RAD used to determine the specified distance. Altitude correction factors apply to both minimum worker approach distances and to minimum vegetation clearance distances.

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Ancillary Service [Archive]		2/8/2005	3/16/2007	Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider's transmission system in accordance with good utility practice. (*From FERC order 888-A.*)
Anti-Aliasing Filter [Archive]		2/8/2005	3/16/2007	An analog filter installed at a metering point to remove the high frequency components of the signal over the AGC sample period.
Area Control Error [Archive]	ACE	2/8/2005	3/16/2007	The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error.
Area Interchange Methodology [Archive]		08/22/2008	11/24/2009	The Area Interchange methodology is characterized by determination of incremental transfer capability via simulation, from which Total Transfer Capability (TTC) can be mathematically derived. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC, and Postbacks and counterflows are added, to derive Available Transfer Capability. Under the Area Interchange Methodology, TTC results are generally reported on an area to area basis.
Arranged Interchange [Archive]		5/2/2006	3/16/2007	The state where the Interchange Authority has received the Interchange information (initial or revised).
Automatic Generation Control [Archive]	AGC	2/8/2005	3/16/2007	Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction.

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Available Flowgate Capability [Archive]	AFC	08/22/2008	11/24/2009	A measure of the flow capability remaining on a Flowgate for further commercial activity over and above already committed uses. It is defined as TFC less Existing Transmission Commitments (ETC), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, and plus counterflows.
Available Transfer Capability [Archive]	ATC	2/8/2005	3/16/2007	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin.
Available Transfer Capability [Archive]	ATC	08/22/2008	11/24/2009	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less Existing Transmission Commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, plus counterflows.

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Available Transfer Capability Implementation Document [Archive]	ATCID	08/22/2008	11/24/2009	A document that describes the implementation of a methodology for calculating ATC or AFC, and provides information related to a Transmission Service Provider's calculation of ATC or AFC.
ATC Path [Archive]		08/22/2008	Not approved; Modification directed 11/24/09	Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path[1].

[1] See 18 CFR 37.6(b)(1)

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Balancing Authority [Archive]	BA	2/8/2005	3/16/2007	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
Balancing Authority Area [Archive]		2/8/2005	3/16/2007	The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.
Base Load [Archive]		2/8/2005	3/16/2007	The minimum amount of electric power delivered or required over a given period at a constant rate.
Blackstart Capability Plan [Archive]		2/8/2005 Approved Retirement when EOP-005-2 becomes effective 8/5/2009	3/16/2007	A documented procedure for a generating unit or station to go from a shutdown condition to an operating condition delivering electric power without assistance from the electric system. This procedure is only a portion of an overall system restoration plan.
Blackstart Resource [Archive]		8/5/2009		A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Block Dispatch [Archive]		08/22/2008	11/24/2009	A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, the capacity of a given generator is segmented into loadable "blocks," each of which is grouped and ordered relative to other blocks (based on characteristics including, but not limited to, efficiency, run of river or fuel supply considerations, and/or "must-run" status).
Bulk Electric System [Archive]		2/8/2005	3/16/2007	As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.
Burden [Archive]		2/8/2005	3/16/2007	Operation of the Bulk Electric System that violates or is expected to violate a System Operating Limit or Interconnection Reliability Operating Limit in the Interconnection, or that violates any other NERC, Regional Reliability Organization, or local operating reliability standards or criteria.
Business Practices [Archive]		8/22/2008	Not approved; Modification directed 11/24/09	Those business rules contained in the Transmission Service Provider's applicable tariff, rules, or procedures; associated Regional Reliability Organization or regional entity business practices; or NAESB Business Practices.
Bus-tie Breaker [Archive]		8/4/2011		A circuit breaker that is positioned to connect two individual substation bus configurations.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Capacity Benefit Margin [Archive]	CBM	2/8/2005	3/16/2007	The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Service Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.
Capacity Benefit Margin Implementation Document [Archive]	CBMID	11/13/2008	11/24/2009	A document that describes the implementation of a Capacity Benefit Margin methodology.
Capacity Emergency [Archive]		2/8/2005	3/16/2007	A capacity emergency exists when a Balancing Authority Area's operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements.
Cascading [Archive]		2/8/2005	3/16/2007	The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Cascading Outages [Archive]		11/1/2006 Withdrawn 2/12/2008	FERC Remanded 12/27/2007	~~The uncontrolled successive loss of Bulk Electric System Facilities triggered by an incident (or condition) at any location resulting in the interruption of electric service that cannot be restrained from spreading beyond a pre-determined area.~~
Clock Hour [Archive]		2/8/2005	3/16/2007	The 60-minute period ending at :00. All surveys, measurements, and reports are based on Clock Hour periods unless specifically noted.
Cogeneration [Archive]		2/8/2005	3/16/2007	Production of electricity from steam, heat, or other forms of energy produced as a by-product of another process.
Compliance Monitor [Archive]		2/8/2005	3/16/2007	The entity that monitors, reviews, and ensures compliance of responsible entities with reliability standards.
Confirmed Interchange [Archive]		5/2/2006	3/16/2007	The state where the Interchange Authority has verified the Arranged Interchange.
Congestion Management Report [Archive]		2/8/2005	3/16/2007	A report that the Interchange Distribution Calculator issues when a Reliability Coordinator initiates the Transmission Loading Relief procedure. This report identifies the transactions and native and network load curtailments that must be initiated to achieve the loading relief requested by the initiating Reliability Coordinator.
Consequential Load Loss [Archive]		8/4/2011		All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.
Constrained Facility [Archive]		2/8/2005	3/16/2007	A transmission facility (line, transformer, breaker, etc.) that is approaching, is at, or is beyond its System Operating Limit or Interconnection Reliability Operating Limit.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Contingency [Archive]		2/8/2005	3/16/2007	The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.
Contingency Reserve [Archive]		2/8/2005	3/16/2007	The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.
Contract Path [Archive]		2/8/2005	3/16/2007	An agreed upon electrical path for the continuous flow of electrical power between the parties of an Interchange Transaction.
Control Performance Standard [Archive]	CPS	2/8/2005	3/16/2007	The reliability standard that sets the limits of a Balancing Authority's Area Control Error over a specified time period.
Corrective Action Plan [Archive]		2/7/2006	3/16/2007	A list of actions and an associated timetable for implementation to remedy a specific problem.
Cranking Path [Archive]		5/2/2006	3/16/2007	A portion of the electric system that can be isolated and then energized to deliver electric power from a generation source to enable the startup of one or more other generating units.
Critical Assets [Archive]		5/2/2006	1/18/2008	Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.
Critical Cyber Assets [Archive]		5/2/2006	1/18/2008	Cyber Assets essential to the reliable operation of Critical Assets.
Curtailment [Archive]		2/8/2005	3/16/2007	A reduction in the scheduled capacity or energy delivery of an Interchange Transaction.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Curtailment Threshold [Archive]		2/8/2005	3/16/2007	The minimum Transfer Distribution Factor which, if exceeded, will subject an Interchange Transaction to curtailment to relieve a transmission facility constraint.
Cyber Assets [Archive]		5/2/2006	1/18/2008	Programmable electronic devices and communication networks including hardware, software, and data.
Cyber Security Incident [Archive]		5/2/2006	1/18/2008	Any malicious act or suspicious event that: • Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or, • Disrupts, or was an attempt to disrupt, the operation of a Critical Cyber Asset.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Delayed Fault Clearing [Archive]		11/1/2006	12/27/2007	Fault clearing consistent with correct operation of a breaker failure protection system and its associated breakers, or of a backup protection system with an intentional time delay.
Demand [Archive]		2/8/2005	3/16/2007	1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.
Demand-Side Management [Archive]	DSM	2/8/2005	3/16/2007	The term for all activities or programs undertaken by Load-Serving Entity or its customers to influence the amount or timing of electricity they use.
Direct Control Load Management [Archive]	DCLM	2/8/2005	3/16/2007	Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.
Dispatch Order [Archive]		08/22/2008	11/24/2009	A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, each generator is ranked by priority.
Dispersed Load by Substations [Archive]		2/8/2005	3/16/2007	Substation load information configured to represent a system for power flow or system dynamics modeling purposes, or both.
Distribution Factor [Archive]	DF	2/8/2005	3/16/2007	The portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Distribution Provider [Archive]		2/8/2005	3/16/2007	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.
Disturbance [Archive]		2/8/2005	3/16/2007	1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.
Disturbance Control Standard [Archive]	DCS	2/8/2005	3/16/2007	The reliability standard that sets the time limit following a Disturbance within which a Balancing Authority must return its Area Control Error to within a specified range.
Disturbance Monitoring Equipment [Archive]	DME	8/2/2006	3/16/2007	Devices capable of monitoring and recording system data pertaining to a Disturbance. Such devices include the following categories of recorders[2]: • Sequence of event recorders which record equipment response to the event • Fault recorders, which record actual waveform data replicating the system primary voltages and currents. This may include protective relays. • Dynamic Disturbance Recorders (DDRs), which record incidents that portray power system behavior during dynamic events such as low-frequency (0.1 Hz – 3 Hz) oscillations and abnormal frequency or voltage excursions

[2] Phasor Measurement Units and any other equipment that meets the functional requirements of DMEs may qualify as DMEs.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Dynamic Interchange Schedule or Dynamic Schedule [Archive]		2/8/2005	3/16/2007	A telemetered reading or value that is updated in real time and used as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.
Dynamic Transfer [Archive]		2/8/2005	3/16/2007	The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one Balancing Authority Area into another.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Economic Dispatch [Archive]		2/8/2005	3/16/2007	The allocation of demand to individual generating units on line to effect the most economical production of electricity.
Electrical Energy [Archive]		2/8/2005	3/16/2007	The generation or use of electric power by a device over a period of time, expressed in kilowatthours (kWh), megawatthours (MWh), or gigawatthours (GWh).
Electronic Security Perimeter [Archive]		5/2/2006	1/18/2008	The logical border surrounding a network to which Critical Cyber Assets are connected and for which access is controlled.
Element [Archive]		2/8/2005	3/16/2007	Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.
Emergency or BES Emergency [Archive]		2/8/2005	3/16/2007	Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System.
Emergency Rating [Archive]		2/8/2005	3/16/2007	The rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar or other appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.
Emergency Request for Interchange (Emergency RFI) [Archive]		10/29/2008	12/17/2009	Request for Interchange to be initiated for Emergency or Energy Emergency conditions.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Energy Emergency [Archive]		2/8/2005	3/16/2007	A condition when a Load-Serving Entity has exhausted all other options and can no longer provide its customers' expected energy requirements.
Equipment Rating [Archive]		2/7/2006	3/16/2007	The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady state, short-circuit and transient conditions, as permitted or assigned by the equipment owner.
Existing Transmission Commitments [Archive]	ETC	08/22/2008	11/24/2009	Committed uses of a Transmission Service Provider's Transmission system considered when determining ATC or AFC.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Facility [Archive]		2/7/2006	3/16/2007	A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)
Facility Rating [Archive]		2/8/2005	3/16/2007	The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.
Fault [Archive]		2/8/2005	3/16/2007	An event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection.
Fire Risk [Archive]		2/7/2006	3/16/2007	The likelihood that a fire will ignite or spread in a particular geographic area.
Firm Demand [Archive]		2/8/2005	3/16/2007	That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.
Firm Transmission Service [Archive]		2/8/2005	3/16/2007	The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.
Flashover [Archive]		2/7/2006	3/16/2007	An electrical discharge through air around or over the surface of insulation, between objects of different potential, caused by placing a voltage across the air space that results in the ionization of the air space.
Flowgate [Archive]		2/8/2005	3/16/2007	A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Flowgate [Archive]		08/22/2008	11/24/2009	1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.
Flowgate Methodology [Archive]		08/22/2008	11/24/2009	The Flowgate methodology is characterized by identification of key Facilities as Flowgates. Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the Total Flowgate Capability, and Postbacks and counterflows are added, to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs can be used to determine Available Transfer Capability (ATC).
Forced Outage [Archive]		2/8/2005	3/16/2007	1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. 2. The condition in which the equipment is unavailable due to unanticipated failure.
Frequency Bias [Archive]		2/8/2005	3/16/2007	A value, usually expressed in megawatts per 0.1 Hertz (MW/0.1 Hz), associated with a Balancing Authority Area that approximates the Balancing Authority Area's response to Interconnection frequency error.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Frequency Bias Setting [Archive]		2/8/2005	3/16/2007	A value, usually expressed in MW/0.1 Hz, set into a Balancing Authority ACE algorithm that allows the Balancing Authority to contribute its frequency response to the Interconnection.
Frequency Deviation [Archive]		2/8/2005	3/16/2007	A change in Interconnection frequency.
Frequency Error [Archive]		2/8/2005	3/16/2007	The difference between the actual and scheduled frequency. ($F_A - F_S$)
Frequency Regulation [Archive]		2/8/2005	3/16/2007	The ability of a Balancing Authority to help the Interconnection maintain Scheduled Frequency. This assistance can include both turbine governor response and Automatic Generation Control.
Frequency Response [Archive]		2/8/2005	3/16/2007	(Equipment) The ability of a system or elements of the system to react or respond to a change in system frequency. (System) The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Generator Operator [Archive]		2/8/2005	3/16/2007	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
Generator Owner [Archive]		2/8/2005	3/16/2007	Entity that owns and maintains generating units.
Generator Shift Factor [Archive]	GSF	2/8/2005	3/16/2007	A factor to be applied to a generator's expected change in output to determine the amount of flow contribution that change in output will impose on an identified transmission facility or Flowgate.
Generator-to-Load Distribution Factor [Archive]	GLDF	2/8/2005	3/16/2007	The algebraic sum of a Generator Shift Factor and a Load Shift Factor to determine the total impact of an Interchange Transaction on an identified transmission facility or Flowgate.
Generation Capability Import Requirement [Archive]	GCIR	11/13/2008	11/24/2009	The amount of generation capability from external sources identified by a Load-Serving Entity (LSE) or Resource Planner (RP) to meet its generation reliability or resource adequacy requirements as an alternative to internal resources.
Host Balancing Authority [Archive]		2/8/2005	3/16/2007	1. A Balancing Authority that confirms and implements Interchange Transactions for a Purchasing Selling Entity that operates generation or serves customers directly within the Balancing Authority's metered boundaries. 2. The Balancing Authority within whose metered boundaries a jointly owned unit is physically located.
Hourly Value [Archive]		2/8/2005	3/16/2007	Data measured on a Clock Hour basis.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Implemented Interchange [Archive]		5/2/2006	3/16/2007	The state where the Balancing Authority enters the Confirmed Interchange into its Area Control Error equation.
Inadvertent Interchange [Archive]		2/8/2005	3/16/2007	The difference between the Balancing Authority's Net Actual Interchange and Net Scheduled Interchange. ($I_A - I_S$)
Independent Power Producer [Archive]	IPP	2/8/2005	3/16/2007	Any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, cogenerators and small power producers and all other nonutility electricity producers, such as exempt wholesale generators, who sell electricity.
Institute of Electrical and Electronics Engineers, Inc. [Archive]	IEEE	2/7/2006	3/16/2007	
Interchange [Archive]		5/2/2006	3/16/2007	Energy transfers that cross Balancing Authority boundaries.
Interchange Authority [Archive]		5/2/2006	3/16/2007	The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.
Interchange Distribution Calculator [Archive]	IDC	2/8/2005	3/16/2007	The mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Interchange Schedule [Archive]		2/8/2005	3/16/2007	An agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction.
Interchange Transaction [Archive]		2/8/2005	3/16/2007	An agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries.
Interchange Transaction Tag or Tag [Archive]		2/8/2005	3/16/2007	The details of an Interchange Transaction required for its physical implementation.
Interconnected Operations Service [Archive]		2/8/2005	3/16/2007	A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected Bulk Electric Systems.
Interconnection [Archive]		2/8/2005	3/16/2007	When capitalized, any one of the three major electric system networks in North America: Eastern, Western, and ERCOT.
Interconnection Reliability Operating Limit [Archive]	IROL	2/8/2005	3/16/2007 Retired 12/27/2007	The value (such as MW, MVar, Amperes, Frequency or Volts) derived from, or a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages.
Interconnection Reliability Operating Limit [Archive]	IROL	11/1/2006	12/27/2007	A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading Outages that adversely impact the reliability of the Bulk Electric System.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Interconnection Reliability Operating Limit T_v [Archive]	IROL T_v	11/1/2006	12/27/2007	The maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit's T_v shall be less than or equal to 30 minutes.
Intermediate Balancing Authority [Archive]		2/8/2005	3/16/2007	A Balancing Authority Area that has connecting facilities in the Scheduling Path between the Sending Balancing Authority Area and Receiving Balancing Authority Area and operating agreements that establish the conditions for the use of such facilities
Interruptible Load or Interruptible Demand [Archive]		11/1/2006	3/16/2007	Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.
Joint Control [Archive]		2/8/2005	3/16/2007	Automatic Generation Control of jointly owned units by two or more Balancing Authorities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Limiting Element [Archive]		2/8/2005	3/16/2007	The element that is 1.)Either operating at its appropriate rating, or 2,) Would be following the limiting contingency. Thus, the Limiting Element establishes a system limit.
Load [Archive]		2/8/2005	3/16/2007	An end-use device or customer that receives power from the electric system.
Load Shift Factor [Archive]	LSF	2/8/2005	3/16/2007	A factor to be applied to a load's expected change in demand to determine the amount of flow contribution that change in demand will impose on an identified transmission facility or monitored Flowgate.
Load-Serving Entity [Archive]		2/8/2005	3/16/2007	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.
Long-Term Transmission Planning Horizon [Archive]		8/4/2011		Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.
Market Flow [Archive]		11/4/2010	4/21/2011	The total amount of power flowing across a specified Facility or set of Facilities due to a market dispatch of generation internal to the market to serve load internal to the market.
Misoperation [Archive]		2/7/2006	3/16/2007	▪ Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection. ▪ Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone). ▪ Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Native Load [Archive]		2/8/2005	3/16/2007	The end-use customers that the Load-Serving Entity is obligated to serve.
Near-Term Transmission Planning Horizon [Archive]		1/24/2011		The transmission planning period that covers Year One through five.
Net Actual Interchange [Archive]		2/8/2005	3/16/2007	The algebraic sum of all metered interchange over all interconnections between two physically Adjacent Balancing Authority Areas.
Net Energy for Load [Archive]		2/8/2005	3/16/2007	Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to Balancing Authority Areas through interchange. It includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities.
Net Interchange Schedule [Archive]		2/8/2005	3/16/2007	The algebraic sum of all Interchange Schedules with each Adjacent Balancing Authority.
Net Scheduled Interchange [Archive]		2/8/2005	3/16/2007	The algebraic sum of all Interchange Schedules across a given path or between Balancing Authorities for a given period or instant in time.
Network Integration Transmission Service [Archive]		2/8/2005	3/16/2007	Service that allows an electric transmission customer to integrate, plan, economically dispatch and regulate its network reserves in a manner comparable to that in which the Transmission Owner serves Native Load customers.
Non-Consequential Load Loss [Archive]		8/4/2011		Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Non-Firm Transmission Service [Archive]		2/8/2005	3/16/2007	Transmission service that is reserved on an as-available basis and is subject to curtailment or interruption.
Non-Spinning Reserve [Archive]		2/8/2005	3/16/2007	1. That generating reserve not connected to the system but capable of serving demand within a specified time. 2. Interruptible load that can be removed from the system in a specified time.
Normal Clearing [Archive]		11/1/2006	12/27/2007	A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.
Normal Rating [Archive]		2/8/2005	3/16/2007	The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.
Nuclear Plant Generator Operator [Archive]		5/2/2007	10/16/2008	Any Generator Operator or Generator Owner that is a Nuclear Plant Licensee responsible for operation of a nuclear facility licensed to produce commercial power.
Nuclear Plant Off-site Power Supply (Off-site Power) [Archive]		5/2/2007	10/16/2008	The electric power supply provided from the electric system to the nuclear power plant distribution system as required per the nuclear power plant license.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Nuclear Plant Licensing Requirements (NPLRs) [Archive]		5/2/2007	10/16/2008	Requirements included in the design basis of the nuclear plant and statutorily mandated for the operation of the plant, including nuclear power plant licensing requirements for: 1) Off-site power supply to enable safe shutdown of the plant during an electric system or plant event; and 2) Avoiding preventable challenges to nuclear safety as a result of an electric system disturbance, transient, or condition.
Nuclear Plant Interface Requirements (NPIRs) [Archive]		5/2/2007	10/16/2008	The requirements based on NPLRs and Bulk Electric System requirements that have been mutually agreed to by the Nuclear Plant Generator Operator and the applicable Transmission Entities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Off-Peak [Archive]		2/8/2005	3/16/2007	Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand.
On-Peak [Archive]		2/8/2005	3/16/2007	Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of higher electrical demand.
Open Access Same Time Information Service [Archive]	OASIS	2/8/2005	3/16/2007	An electronic posting system that the Transmission Service Provider maintains for transmission access data and that allows all transmission customers to view the data simultaneously.
Open Access Transmission Tariff [Archive]	OATT	2/8/2005	3/16/2007	Electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission requiring the Transmission Service Provider to furnish to all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves.
Operating Plan [Archive]		2/7/2006	3/16/2007	A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Operating Procedure [Archive]		2/7/2006	3/16/2007	A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a system operator to take in removing a specific transmission line from service is an example of an Operating Procedure.
Operating Process [Archive]		2/7/2006	3/16/2007	A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process.
Operating Reserve [Archive]		2/8/2005	3/16/2007	That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.
Operating Reserve – Spinning [Archive]		2/8/2005	3/16/2007	The portion of Operating Reserve consisting of: • Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Operating Reserve – Supplemental [Archive]		2/8/2005	3/16/2007	The portion of Operating Reserve consisting of: • Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.
Operating Voltage [Archive]		2/7/2006	3/16/2007	The voltage level by which an electrical system is designated and to which certain operating characteristics of the system are related; also, the effective (root-mean-square) potential difference between any two conductors or between a conductor and the ground. The actual voltage of the circuit may vary somewhat above or below this value.
Operational Planning Analysis [Archive]		10/17/2008		An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).
Outage Transfer Distribution Factor [Archive]	OTDF	8/22/2008	11/24/2009	In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more system Facilities removed from service (outaged).
Overlap Regulation Service [Archive]		2/8/2005	3/16/2007	A method of providing regulation service in which the Balancing Authority providing the regulation service incorporates another Balancing Authority's actual interchange, frequency response, and schedules into providing Balancing Authority's AGC/ACE equation.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Participation Factors [Archive]		8/22/2008	11/24/2009	A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, generators are assigned a percentage that they will contribute to serve load.
Peak Demand [Archive]		2/8/2005	3/16/2007	1. The highest hourly integrated Net Energy For Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year). 2. The highest instantaneous demand within the Balancing Authority Area.
Performance-Reset Period [Archive]		2/7/2006	3/16/2007	The time period that the entity being assessed must operate without any violations to reset the level of non compliance to zero.
Physical Security Perimeter [Archive]		5/2/2006	1/18/2008	The physical, completely enclosed ("six-wall") border surrounding computer rooms, telecommunications rooms, operations centers, and other locations in which Critical Cyber Assets are housed and for which access is controlled.
Planning Assessment [Archive]		8/4/2011		Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies.
Planning Authority [Archive]		2/8/2005	3/16/2007	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
Planning Coordinator [Archive]		8/22/2008	11/24/2009	See Planning Authority.
Point of Delivery [Archive]	POD	2/8/2005	3/16/2007	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction leaves or a Load-Serving Entity receives its energy.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Point of Receipt [Archive]	POR	2/8/2005	3/16/2007	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a Generator delivers its output.
Point to Point Transmission Service [Archive]	PTP	2/8/2005	3/16/2007	The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery.
Postback [Archive]		08/22/2008	Not approved; Modification directed 11/24/09	Positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.
Power Transfer Distribution Factor [Archive]	PTDF	08/22/2008	11/24/2009	In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system Facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer
Pro Forma Tariff [Archive]		2/8/2005	3/16/2007	Usually refers to the standard OATT and/or associated transmission rights mandated by the U.S. Federal Energy Regulatory Commission Order No. 888.
Protection System [Archive]		2/7/2006	3/17/07	Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Protection System [Archive]		11/19/2010		Protection System – • Protective relays which respond to electrical quantities, • Communications systems necessary for correct operation of protective functions • Voltage and current sensing devices providing inputs to protective relays, • Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and • Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.
Pseudo-Tie [Archive]		2/8/2005	3/16/2007	A telemetered reading or value that is updated in real time and used as a "virtual" tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.
Purchasing-Selling Entity [Archive]		2/8/2005	3/16/2007	The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.
Ramp Rate or Ramp [Archive]		2/8/2005	3/16/2007	(Schedule) The rate, expressed in megawatts per minute, at which the interchange schedule is attained during the ramp period. (Generator) The rate, expressed in megawatts per minute, that a generator changes its output.
Rated Electrical Operating Conditions [Archive]		2/7/2006	3/16/2007	The specified or reasonably anticipated conditions under which the electrical system or an individual electrical circuit is intend/designed to operate

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Rating [Archive]		2/8/2005	3/16/2007	The operational limits of a transmission system element under a set of specified conditions.
Rated System Path Methodology [Archive]		08/22/2008	11/24/2009	The Rated System Path Methodology is characterized by an initial Total Transfer Capability (TTC), determined via simulation. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from TTC, and Postbacks and counterflows are added as applicable, to derive Available Transfer Capability. Under the Rated System Path Methodology, TTC results are generally reported as specific transmission path capabilities.
Reactive Power [Archive]		2/8/2005	3/16/2007	The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).
Real Power [Archive]		2/8/2005	3/16/2007	The portion of electricity that supplies energy to the load.
Reallocation [Archive]		2/8/2005	3/16/2007	The total or partial curtailment of Transactions during TLR Level 3a or 5a to allow Transactions using higher priority to be implemented.
Real-time [Archive]		2/7/2006	3/16/2007	Present time as opposed to future time. (From Interconnection Reliability Operating Limits standard.)
Real-time Assessment [Archive]		10/17/2008		An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Receiving Balancing Authority [Archive]		2/8/2005	3/16/2007	The Balancing Authority importing the Interchange.
Regional Reliability Organization [Archive]		2/8/2005	3/16/2007	1. An entity that ensures that a defined area of the Bulk Electric System is reliable, adequate and secure. 2. A member of the North American Electric Reliability Council. The Regional Reliability Organization can serve as the Compliance Monitor.
Regional Reliability Plan [Archive]		2/8/2005	3/16/2007	The plan that specifies the Reliability Coordinators and Balancing Authorities within the Regional Reliability Organization, and explains how reliability coordination will be accomplished.
Regulating Reserve [Archive]		2/8/2005	3/16/2007	An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.
Regulation Service [Archive]		2/8/2005	3/16/2007	The process whereby one Balancing Authority contracts to provide corrective response to all or a portion of the ACE of another Balancing Authority. The Balancing Authority providing the response assumes the obligation of meeting all applicable control criteria as specified by NERC for itself and the Balancing Authority for which it is providing the Regulation Service.
Reliability Adjustment RFI [Archive]		10/29/2008	12/17/2009	Request to modify an Implemented Interchange Schedule for reliability purposes.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reliability Coordinator [Archive]		2/8/2005	3/16/2007	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
Reliability Coordinator Area [Archive]		2/8/2005	3/16/2007	The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.
Reliability Coordinator Information System [Archive]	RCIS	2/8/2005	3/16/2007	The system that Reliability Coordinators use to post messages and share operating information in real time.
Remedial Action Scheme [Archive]	RAS	2/8/2005	3/16/2007	See "Special Protection System"
Reportable Disturbance [Archive]		2/8/2005	3/16/2007	Any event that causes an ACE change greater than or equal to 80% of a Balancing Authority's or reserve sharing group's most severe contingency. The definition of a reportable disturbance is specified by each Regional Reliability Organization. This definition may not be retroactively adjusted in response to observed performance.
Request for Interchange [Archive]	RFI	5/2/2006	3/16/2007	A collection of data as defined in the NAESB RFI Datasheet, to be submitted to the Interchange Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reserve Sharing Group [Archive]		2/8/2005	3/16/2007	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.
Resource Planner [Archive]		2/8/2005	3/16/2007	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.
Response Rate [Archive]		2/8/2005	3/16/2007	The Ramp Rate that a generating unit can achieve under normal operating conditions expressed in megawatts per minute (MW/Min).
Right-of-Way (ROW) [Archive]		2/7/2006	3/16/2007	A corridor of land on which electric lines may be located. The Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Scenario [Archive]		2/7/2006	3/16/2007	Possible event.
Schedule [Archive]		2/8/2005	3/16/2007	(Verb) To set up a plan or arrangement for an Interchange Transaction. (Noun) An Interchange Schedule.
Scheduled Frequency [Archive]		2/8/2005	3/16/2007	60.0 Hertz, except during a time correction.
Scheduling Entity [Archive]		2/8/2005	3/16/2007	An entity responsible for approving and implementing Interchange Schedules.
Scheduling Path [Archive]		2/8/2005	3/16/2007	The Transmission Service arrangements reserved by the Purchasing-Selling Entity for a Transaction.
Sending Balancing Authority [Archive]		2/8/2005	3/16/2007	The Balancing Authority exporting the Interchange.
Sink Balancing Authority [Archive]		2/8/2005	3/16/2007	The Balancing Authority in which the load (sink) is located for an Interchange Transaction. (This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)
Source Balancing Authority [Archive]		2/8/2005	3/16/2007	The Balancing Authority in which the generation (source) is located for an Interchange Transaction. (This will also be a Sending Balancing Authority for the resulting Interchange Schedule.)

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Special Protection System (Remedial Action Scheme) [Archive]		2/8/2005	3/16/2007	An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.
Spinning Reserve [Archive]		2/8/2005	3/16/2007	Unloaded generation that is synchronized and ready to serve additional demand.
Stability [Archive]		2/8/2005	3/16/2007	The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances.
Stability Limit [Archive]		2/8/2005	3/16/2007	The maximum power flow possible through some particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers.
Supervisory Control and Data Acquisition [Archive]	SCADA	2/8/2005	3/16/2007	A system of remote control and telemetry used to monitor and control the transmission system.
Supplemental Regulation Service [Archive]		2/8/2005	3/16/2007	A method of providing regulation service in which the Balancing Authority providing the regulation service receives a signal representing all or a portion of the other Balancing Authority's ACE.
Surge [Archive]		2/8/2005	3/16/2007	A transient variation of current, voltage, or power flow in an electric circuit or across an electric system.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Sustained Outage [Archive]		2/7/2006	3/16/2007	The deenergized condition of a transmission line resulting from a fault or disturbance following an unsuccessful automatic reclosing sequence and/or unsuccessful manual reclosing procedure.
System [Archive]		2/8/2005	3/16/2007	A combination of generation, transmission, and distribution components.
System Operating Limit [Archive]		2/8/2005	3/16/2007	The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings) • Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits) • Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability) • System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)
System Operator [Archive]		2/8/2005	3/16/2007	An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Telemetering [Archive]		2/8/2005	3/16/2007	The process by which measurable electrical quantities from substations and generating stations are instantaneously transmitted to the control center, and by which operating commands from the control center are transmitted to the substations and generating stations.
Thermal Rating [Archive]		2/8/2005	3/16/2007	The maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it sags to the point that it violates public safety requirements.
Tie Line [Archive]		2/8/2005	3/16/2007	A circuit connecting two Balancing Authority Areas.
Tie Line Bias [Archive]		2/8/2005	3/16/2007	A mode of Automatic Generation Control that allows the Balancing Authority to 1.) maintain its Interchange Schedule and 2.) respond to Interconnection frequency error.
Time Error [Archive]		2/8/2005	3/16/2007	The difference between the Interconnection time measured at the Balancing Authority(ies) and the time specified by the National Institute of Standards and Technology. Time error is caused by the accumulation of Frequency Error over a given period.
Time Error Correction [Archive]		2/8/2005	3/16/2007	An offset to the Interconnection's scheduled frequency to return the Interconnection's Time Error to a predetermined value.
TLR Log [Archive]		2/8/2005	3/16/2007	Report required to be filed after every TLR Level 2 or higher in a specified format. The NERC IDC prepares the report for review by the issuing Reliability Coordinator. After approval by the issuing Reliability Coordinator, the report is electronically filed in a public area of the NERC Web site.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Total Flowgate Capability [Archive]	TFC	08/22/2008	11/24/2009	The maximum flow capability on a Flowgate, is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated System Operating Limit.
Total Transfer Capability [Archive]	TTC	2/8/2005	3/16/2007	The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.
Transaction [Archive]		2/8/2005	3/16/2007	See Interchange Transaction.
Transfer Capability [Archive]		2/8/2005	3/16/2007	The measure of the ability of interconnected electric systems to move or transfer power *in a reliable manner* from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from "Area A" to "Area B" is *not g*enerally equal to the transfer capability from "Area B" to "Area A."
Transfer Distribution Factor [Archive]		2/8/2005	3/16/2007	See Distribution Factor.
Transmission [Archive]		2/8/2005	3/16/2007	An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Transmission Constraint [Archive]		2/8/2005	3/16/2007	A limitation on one or more transmission elements that may be reached during normal or contingency system operations.
Transmission Customer [Archive]		2/8/2005	3/16/2007	1. Any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service. 2. Any of the following responsible entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.
Transmission Line [Archive]		2/7/2006	3/16/2007	A system of structures, wires, insulators and associated hardware that carry electric energy from one point to another in an electric power system. Lines are operated at relatively high voltages varying from 69 kV up to 765 kV, and are capable of transmitting large quantities of electricity over long distances.
Transmission Operator [Archive]		2/8/2005	3/16/2007	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.
Transmission Operator Area [Archive]		08/22/2008	11/24/2009	The collection of Transmission assets over which the Transmission Operator is responsible for operating.
Transmission Owner [Archive]		2/8/2005	3/16/2007	The entity that owns and maintains transmission facilities.
Transmission Planner [Archive]		2/8/2005	3/16/2007	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Transmission Reliability Margin [Archive]	TRM	2/8/2005	3/16/2007	The amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.
Transmission Reliability Margin Implementation Document [Archive]	TRMID	08/22/2008	11/24/2009	A document that describes the implementation of a Transmission Reliability Margin methodology, and provides information related to a Transmission Operator's calculation of TRM.
Transmission Service [Archive]		2/8/2005	3/16/2007	Services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.
Transmission Service Provider [Archive]		2/8/2005	3/16/2007	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.
Vegetation [Archive]		2/7/2006	3/16/2007	All plant material, growing or not, living or dead.
Vegetation Inspection [Archive]		2/7/2006	3/16/2007	The systematic examination of a transmission corridor to document vegetation conditions.
Wide Area [Archive]		2/8/2005	3/16/2007	The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Year One [Archive]		1/24/2011		The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For an assessment started in a given calendar year, Year One includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One includes the forecasted peak Load period for either 2012 or 2013.

ReliabilityFirst Regional Definitions

The following definitions were developed for use in ReliabilityFirst Regional Standards.

RFC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Resource Adequacy [Archive]		08/05/2009	03/17/2011	The ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses)
Net Internal Demand [Archive]		08/05/2009	03/17/2011	Total of all end-use customer demand and electric system losses within specified metered boundaries, less Direct Control Management and Interruptible Demand
Peak Period [Archive]		08/05/2009	03/17/2011	A period consisting of two (2) or more calendar months but less than seven (7) calendar months, which includes the period during which the responsible entity's annual peak demand is expected to occur
Year One [Archive]		08/05/2009	03/17/2011	The planning year that begins with the upcoming annual Peak Period

NPCC Regional Definitions

The following definitions were developed for use in NPCC Regional Standards.

NPCC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Current Zero Time [Archive]		11/04/2010		The time of the final current zero on the last phase to interrupt.
Generating Plant [Archive]		11/04/2010		One or more generators at a single physical location whereby any single contingency can affect all the generators at that location.

WECC Regional Definitions

The following definitions were developed for use in WECC Regional Standards.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Area Control Error† [Archive]	ACE	3/12/2007	6/8/2007	Means the instantaneous difference between net actual and scheduled interchange, taking into account the effects of Frequency Bias including correction for meter error.
Automatic Generation Control† [Archive]	AGC	3/12/2007	6/8/2007	Means equipment that automatically adjusts a Control Area's generation from a central location to maintain its interchange schedule plus Frequency Bias.
Automatic Time Error Correction [Archive]		3/26/2008	5/21/2009	A frequency control automatic action that a Balancing Authority uses to offset its frequency contribution to support the Interconnection's scheduled frequency.
Average Generation† [Archive]		3/12/2007	6/8/2007	Means the total MWh generated within the Balancing Authority Operator's Balancing Authority Area during the prior year divided by 8760 hours (8784 hours if the prior year had 366 days).
Business Day† [Archive]		3/12/2007	6/8/2007	Means any day other than Saturday, Sunday, or a legal public holiday as designated in section 6103 of title 5, U.S. Code.
Disturbance† [Archive]		3/12/2007	6/8/2007	Means (i) any perturbation to the electric system, or (ii) the unexpected change in ACE that is caused by the sudden loss of generation or interruption of load.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Extraordinary Contingency† [Archive]		3/12/2007	6/8/2007	Shall have the meaning set out in Excuse of Performance, section B.4.c. language in section B.4.c: *means any act of God, actions by a non-affiliated third party, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, earthquake, explosion, accident to or breakage, failure or malfunction of machinery or equipment, or any other cause beyond the Reliability Entity's reasonable control; provided that prudent industry standards (e.g. maintenance, design, operation) have been employed; and provided further that no act or cause shall be considered an Extraordinary Contingency if such act or cause results in any contingency contemplated in any WECC Reliability Standard (e.g., the "Most Severe Single Contingency" as defined in the WECC Reliability Criteria or any lesser contingency).*
Frequency Bias† [Archive]		3/12/2007	6/8/2007	Means a value, usually given in megawatts per 0.1 Hertz, associated with a Control Area that relates the difference between scheduled and actual frequency to the amount of generation required to correct the difference.
Generating Unit Capability† [Archive]		3/12/2007	6/8/2007	Means the MVA nameplate rating of a generator.
Non-spinning Reserve† [Archive]		3/12/2007	6/8/2007	Means that Operating Reserve not connected to the system but capable of serving demand within a specified time, or interruptible load that can be removed from the system in a specified time.
Normal Path Rating† [Archive]		3/12/2007	6/8/2007	Is the maximum path rating in MW that has been demonstrated to WECC through study results or actual operation, whichever is greater. For a path with transfer capability limits that vary seasonally, it is the maximum of all the seasonal values.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Operating Reserve† [Archive]		3/12/2007	6/8/2007	Means that capability above firm system demand required to provide for regulation, load-forecasting error, equipment forced and scheduled outages and local area protection. Operating Reserve consists of Spinning Reserve and Nonspinning Reserve.
Operating Transfer Capability Limit† [Archive]	OTC	3/12/2007	6/8/2007	Means the maximum value of the most critical system operating parameter(s) which meets: (a) precontingency criteria as determined by equipment loading capability and acceptable voltage conditions, (b) transient criteria as determined by equipment loading capability and acceptable voltage conditions, (c) transient performance criteria, and (d) post-contingency loading and voltage criteria.
Primary Inadvertent Interchange [Archive]		3/26/2008	5/21/2009	The component of area (n) inadvertent interchange caused by the regulating deficiencies of the area (n).
Secondary Inadvertent Interchange [Archive]		3/26/2008	5/21/2009	The component of area (n) inadvertent interchange caused by the regulating deficiencies of area (i).
Spinning Reserve† [Archive]		3/12/2007	6/8/2007	Means unloaded generation which is synchronized and ready to serve additional demand. It consists of Regulating reserve and Contingency reserve (as each are described in Sections B.a.i and ii).
WECC Table 2† [Archive]		3/12/2007	6/8/2007	Means the table maintained by the WECC identifying those transfer paths monitored by the WECC regional Reliability coordinators. As of the date set out therein, the transmission paths identified in Table 2 are as listed in Attachment A to this Standard.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Functionally Equivalent Protection System [Archive]	FEPS	10/29/2008	4/21/2011	A Protection System that provides performance as follows: • Each Protection System can detect the same faults within the zone of protection and provide the clearing times and coordination needed to comply with all Reliability Standards. • Each Protection System may have different components and operating characteristics.
Functionally Equivalent RAS [Archive]	FERAS	10/29/2008	4/21/2011	A Remedial Action Scheme ("RAS") that provides the same performance as follows: • Each RAS can detect the same conditions and provide mitigation to comply with all Reliability Standards. • Each RAS may have different components and operating characteristics.
Security-Based Misoperation [Archive]		10/29/2008	4/21/2011	A Misoperation caused by the incorrect operation of a Protection System or RAS. Security is a component of reliability and is the measure of a device's certainty not to operate falsely.
Dependability-Based Misoperation [Archive]		10/29/2008	4/21/2011	Is the absence of a Protection System or RAS operation when intended. Dependability is a component of reliability and is the measure of a device's certainty to operate when required.
Commercial Operation [Archive]		10/29/2008	4/21/2011	Achievement of this designation indicates that the Generator Operator or Transmission Operator of the synchronous generator or synchronous condenser has received all approvals necessary for operation after completion of initial start-up testing.
Qualified Transfer Path Curtailment Event [Archive]		2/10/2009	3/17/2011	Each hour that a Transmission Operator calls for Step 4 or higher for one or more consecutive hours (See Attachment 1 IRO-006-WECC-1) during which the curtailment tool is functional.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Relief Requirement [Archive]		2/10/2009	3/17/2011	The expected amount of the unscheduled flow reduction on the Qualified Transfer Path that would result by curtailing each Sink Balancing Authority's Contributing Schedules by the percentages listed in the columns of WECC Unscheduled Flow Mitigation Summary of Actions Table in Attachment 1 WECC IRO-006-WECC-1.
Transfer Distribution Factor [Archive]	TDF	2/10/2009	3/17/2011	The percentage of USF that flows across a Qualified Transfer Path when an Interchange Transaction (Contributing Schedule) is implemented. [See the WECC Unscheduled Flow Mitigation Summary of Actions Table (Attachment 1 WECC IRO-006-WECC-1).]
Contributing Schedule [Archive]		2/10/2009	3/17/2011	A Schedule not on the Qualified Transfer Path between a Source Balancing Authority and a Sink Balancing Authority that contributes unscheduled flow across the Qualified Transfer Path.
Qualified Transfer Path [Archive]		2/10/2009	3/17/2011	A transfer path designated by the WECC Operating Committee as being qualified for WECC unscheduled flow mitigation.
Qualified Controllable Device [Archive]		2/10/2009	3/17/2011	A controllable device installed in the Interconnection for controlling energy flow and the WECC Operating Committee has approved using the device for controlling the USF on the Qualified Transfer Paths.

Endnotes

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† FERC approved the WECC Tier One Reliability Standards in the Order Approving Regional Reliability Standards for the Western Interconnection and Directing Modifications, 119 FERC ¶ 61,260 (June 8, 2007). In that Order, FERC directed WECC to address the inconsistencies between the regional definitions and the NERC Glossary in developing permanent replacement standards. The replacement standards designed to address the shortcomings were filed with FERC in 2009.